Study on Rock Mechanics and Wellbore Stability of Igneous Formation in the Shunbei Area

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ABSTRACT: While drilling into the igneous rock formations of the Shunbei area, problems such as loss of well circulation and borehole collapse occur frequently, seriously hindering the efficient development of oil and gas resources. Aiming to solve this problem, the physicochemical and mechanical properties of igneous rocks are studied through a series of laboratory tests to determine the main factors influencing formation collapse and instability. In addition to the laboratory results, the weak plane effect of fracture mechanics, the seepage effect of drilling fluid, and the hydration effect of the drilling fluid on the borehole wall stability of igneous rock formations are evaluated and analyzed by establishing a mathematical model. The results show that the microfractures in the igneous rock are relatively developed and can be divided into unfilled fractures and calcite-filled fractures. The mechanical strength of the matrix igneous rock is higher than that of the rock samples with microfractures. The compressive strength of calcite-filled and unfilled fracture samples is 1/3 − 1/4 that of matrix igneous rocks, and immersion in the drilling fluid has little influence on the mechanical strength of igneous rocks. The fracture weak plane effect has the greatest influence on wellbore stability. With the increase of the number of fractures at different angles, the collapse pressure equivalent density of the formation subject to the mechanical weak plane effect increases by 21% compared with that of the homogeneous formation without fractures. The seepage effect of the drilling fluid on borehole stability is secondary, and the equivalent density of the formation collapse pressure increases by 11%. Because of the low content of clay minerals, the hydration effect of the drilling fluid on borehole stability was minimal and the equivalent density of collapse pressure increased by only 2%. During the drilling process, considering the weak plane effect of the microfractures and the seepage effect of the drilling fluid, the drilling fluid density should be controlled at about 1.82 g/cm³. The effective plugging ability and rheological properties of the drilling fluid should be improved for the formation with microfractures. The research results can provide a theoretical basis for the safe and efficient development of igneous reservoirs.

1. INTRODUCTION

It is estimated that only about 1% of the world’s total oil and gas resources are in igneous rock reservoirs.¹ However, with the continuous advancement of oil and gas exploration and development techniques, there is increasing potential for the exploration and development of igneous reservoirs.² Igneous rock formations are very prone to borehole instability and collapse, and this greatly increases the cost and difficulty in drilling. Therefore, it is important to study borehole stability during the process of drilling into igneous rock formations.

Scholars at home and abroad have carried out a series of studies on wellbore stability in igneous rock formations with relatively developed fractures. Liu et al. conducted a series of experiments on igneous rock samples from collapsed strata in the Turpan-Hami area, and the results showed that clay minerals are widely distributed in igneous microcracks. The drilling fluid filtrate invades the rock along the microcracks, which leads to the hydration expansion of clay minerals and a change in the igneous rock microstructure. Primary and secondary microcracks can expand and merge into single cracks, which will reduce the cohesion of the rock along the bedding plane and ultimately lead to borehole wall instability.³ Based on the consideration of the igneous rock structure, Liu et al. constructed the multidiscontinuity strength criterion and established the collapse pressure prediction method of igneous rock formation by using the criterion, so as to analyze the borehole wall stability of igneous rock formation. The results show that hydration and weak plane effect are the main factors causing the instability of the borehole wall in igneous strata, and considering their coupling effect is the key to establish the borehole wall stability technology.⁴ Wang et al. used logging technology and field production data to study the development

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types and control factors of igneous fractures and the influence of fractures on high-quality reservoir development and high-yield oil and gas production. The research showed that the rock structure and supergene processes play a particularly important role in determining the development of fractures in igneous rocks, and these fractures have a substantial influence on wellbore stability. Han et al. proposed a safe operation window of drilling fluid density (SOWDFD) in deep igneous rock formations based on the leakage statistics of adjacent wells. The law of leaky formation was revealed through a statistical analysis of the drilling fluid density of the leaky formation group in an adjacent igneous well, and finally, an improved SOWDFD for deep igneous formations was established. Chen et al. used a coupled numerical analysis method to study the impact of rock mass fractures in isotropic and anisotropic stress states on wellbore stability. The study found that both the existence of natural fractures caused by mud infiltration and the reduction of fracture friction angle have a significant impact on wellbore stability. Considering the influence of pore pressure propagation, in situ stress, and wellbore pressure, Ma et al. proposed an analytical method for predicting wellbore stability in fractured formations by using the Hoek–Brown criterion. The results showed that the critical mud weight calculated by the H–B criterion is higher than that calculated by the Mohr–Coulomb criterion, which improved the prediction ability of wellbore stability of fractured reservoirs.

While drilling into the igneous rock formations of the Shunbei area, problems such as lost circulation of the well and borehole collapse occur frequently, which seriously hinders the efficient development of field oil and gas resources. To solve this problem, the physicochemical and mechanical properties of igneous rocks are tested in this study through laboratory experiments, and the main factors affecting wellbore stability are determined. A theoretical model for evaluating the borehole stability in an igneous rock formation is established based on laboratory experimental results, providing a theoretical basis for the optimization of drilling engineering parameters for igneous rock formations.

2. MATERIALS

2.1. Mineral Composition. The well block of Shunbei is located on the northern edge of the Shuntuogole low uplift and the southern part of the Shaya uplift. The tectonic position and reservoir-forming conditions are superior, the structure is gentle, and the stratum undulation is small. Under regional compression, pressure-torsion, and tensional stresses, the faults have obvious directivity in plane and are mainly characterized as high-angle strike-slip faults. Taking the downhole igneous rock of the Ordovician system in the Shunbei well area as the research object, the mineral composition was tested using the X-ray diffraction instrument first, and the results are shown in Table 1.

The igneous rock is mainly composed of feldspar, containing a small amount of quartz and calcite, and the clay mineral content is very low.

2.2. Microstructural Characteristics of Samples. To better understand the rock properties of igneous formation in the Shunbei region, we performed scanning electron microscopy (SEM) and super-high magnification lens zoom 3D microscope experimental analysis of igneous formation rocks in the Shunbei region. It was found that the igneous rock microfractures are relatively developed and not uniform in direction and that open fractures and closed calcite-filled fractures coexist by salvaging the underground cores, as shown in Figure 1.

![Figure 1](https://example.com/figure1.png)

Figure 1. Downhole core photos of igneous rocks. (a) Rock samples without filling fractures. (b) High-contrast image of (a). (c) Rock samples with calcite filling fractures.

The mesostructure of the igneous rock was imaged using a stereo microscope, as shown in Figure 2.

The microfractures in the igneous rocks are relatively developed, and most of them are open cracks without fillers, with a general width of 0.1–1 mm. The microstructure of the core was analyzed by SEM, as shown in Figure 3.

The igneous rock bedrock is relatively dense, but unfilled fractures or calcite-filled fractures are more developed. Honeycomb or point clay minerals are seen between some cracks, and the crack width is 1–3 μm. The mechanical strength between the fracture plane mainly depends on the filling materials between the fractures. The mechanical strength of unfilled or semifilled fractures is small, and the weak plane effect of fractures reduces the overall mechanical strength of igneous rocks, which means that the rock in the borehole wall is susceptible to collapse along the fracture plane. Therefore, the existence of fractures greatly reduces the strength of igneous rocks (Liu et al.).

### Table 1. Composition of Collected Samples

| Samples no | Component content (wt%) |
|------------|-------------------------|
|            | quartz  | feldspar | calcite | pyroxene | siderite | dolomite | clay |
| 1          | 3.0     | 70.7     | 7.2     | 13.0     | 0.0      | 0.0      | 6.1  |
| 2          | 1.8     | 80.1     | 3.5     | 7.6      | 2.2      | 1.80     | 3.0  |
| 3          | 16.3    | 49.1     | 21.8    | 4.0      | 3.0      | 3.0      | 2.8  |
| 4          | 15.1    | 56.3     | 12.8    | 5.6      | 1.8      | 3.2      | 5.2  |
| 5          | 9.3     | 61.2     | 8.5     | 9.1      | 0.8      | 2.8      | 8.3  |

3. EXPERIMENTAL SECTION

3.1. Experimental Methods. To determine the main factors affecting the wellbore stability of igneous rock formation in the Shunbei area, the physicochemical and mechanical properties of igneous rocks were tested through laboratory experiments, and a theoretical model for the wellbore stability evaluation of igneous rock was established according to the results of laboratory experiments.
First, the porosity and permeability parameters of downhole igneous rocks (developed with different fracture occurrence) are tested. The testing of rock porosity and permeability parameters can be used to evaluate the seepage capacity of borehole wall rocks and provide basic parameters for the dynamic change law of seepage field and stress field between wellbore and formation in the later period. The equipment used is a tight core gas permeability and porosity meter. Nitrogen is used as the test medium to simulate formation pressure conditions, and the porosity and permeability of tight cores are measured based on Boyle’s law and Darcy’s theorem, respectively.

Second, the test of hydration expansion performance of the underground igneous rock core is carried out. Both the hydration expansion performance and the rolling recovery rate can be used to evaluate and analyze the hydration expansion capacity and borehole wall instability mechanism of borehole wall rocks under downhole pressure. The drilling fluid used to soak the core in the experiment is a water-based drilling fluid used in the field. The specific formula of the drilling fluid is as follows: 4% Bentonite + 1% LV-CMC + 1% NH4HPAN + 0.2% Coated with flocculant + 0.5% COP-HFL/LFL + 0.3% NaOH. The underground rock core was immersed in the hydration expansion tester with the drilling fluid for 24 h, and then the hydration expansion performance of underground igneous rocks was evaluated and analyzed under the on-site drilling fluid immersion environment.

Finally, the mechanical properties of underground igneous rocks were tested. Through systematic triaxial mechanical testing, the mechanical parameters of rocks can be accurately obtained within a downhole pressure environment. These parameters can be used to evaluate the influence of different drilling fluid systems, fracture development degree, and fracture strike on the rock mechanical properties of borehole, so as to improve the prediction accuracy of borehole stability. The experimental equipment of this triaxial rock mechanics test is RTR—1000 static (dynamic) triaxial rock mechanics servo test system. The whole set of equipment consists of four parts: a high-temperature and high-pressure triaxial chamber, a confining pressure pressurization system, an axial pressurization system, and an automatic data acquisition and control system. The experimental equipment is mainly used to test the mechanical properties of standard rock samples: compressive strength, Young’s modulus, Poisson’s ratio, friction angle, cohesion, and other parameters. Three types of core columns (without cracks, with calcite-filled cracks, and with unfilled cracks) were selected for this test. The diameter of the core columns was 25 mm, and their length was 50 mm. The rock samples were divided into two groups, one of which was kept dry, while the other group was immersed in the drilling fluid for 48 h. The confining pressure of the triaxial mechanical loading experiment was 20 MPa.

| no | length/cm | diameter/cm | porosity | permeability/mD | sample description |
|----|-----------|-------------|----------|----------------|--------------------|
| 1  | 4.74      | 2.5         | 0.10%    | $1.1 \times 10^{-4}$ | homogeneous without cracks |
| 2  | 4.85      | 2.5         | 0.80%    | $3.08 \times 10^{-3}$ | one fracture was developed, and the calcite was completely filled between the fractures |
| 3  | 4.87      | 2.5         | 1.20%    | $4.72 \times 10^{-3}$ | multiple fractures are developed, which are completely filled with calcite |
| 4  | 4.92      | 2.5         | 1.50%    | $1.52 \times 10^{-2}$ | multiple fractures are developed, which are half-filled with calcite |
| 5  | 4.93      | 2.5         | 1.90%    | $8.14 \times 10^{-2}$ | multiple fractures are developed, which are no filling |
closed calcite-permeability of the rock mass. The permeability of the rock with fractures and pores substantially increase the porosity and permeability of rock masses with half-calcite-permeability parameters also increase. The porosity and permeability of the Ordovician igneous rock mass were characterized using a rock pore-permeability tester; the test results are shown in Table 2.

As the number of fractures increases, the porosity and permeability of the rock increase. Performance Parameters. The hydration expansion performance and rolling recovery rate of igneous rocks soaked in the drilling fluid are shown in Figure 4.

Table 3. Experimental Results of Triaxial Mechanics of Igneous Rocks

| experiment condition | no. | confining pressure/(MPa) | compressive strength/(MPa) | elasticity modulus/(MPa) | Poisson ratio | core description |
|----------------------|-----|--------------------------|---------------------------|--------------------------|--------------|------------------|
| dry sample           | 1   | 20                       | 189.7                     | 17,094.4                 | 0.16         | homogeneous sample |
|                      | 2   |                          | 60.05                     | 7481.6                   | 0.15         | filling fracture development |
|                      | 3   |                          | 48.68                     | 4936.1                   | 0.14         | no filling fracture development |
| drilling fluid       | 4   | 20                       | 178.6                     | 16,321.5                 | 0.16         | homogeneous sample |
| immersion            | 5   |                          | 51.3                      | 7060.1                   | 0.15         | filling fracture development |
|                      | 6   |                          | 40.4                      | 4521.3                   | 0.14         | no filling fracture development |

3.2. Experimental Results and Discussion. 3.2.1. Experimental Test of Rock Porosity and Permeability Parameters. The porosity and permeability of the Ordovician igneous rock mass were characterized using a rock pore-permeability tester; the test results are shown in Table 2.

It can be seen from Table 2 that the igneous bedrock is dense and uniform, and the porosity and permeability of the no-cracked rock mass are extremely low, generally $10^{-4}$ mD. Fractures and pores substantially increase the porosity and permeability of the rock mass. The permeability of the rock with closed calcite-filled fractures is second only to that of bedrock. As the number of fractures increases, the porosity and permeability parameters also increase. The porosity and permeability of rock masses with half-calcite-filled or unfilled fractures are up to 10 times higher than that of bedrock and fully calcite-filled rock masses. Under the action of the positive pressure difference at the bottom of the well, fractures induce the drilling fluid to preferentially migrate along the fractures to the rock of the borehole wall. The pore pressure near the borehole wall increases, weakening the supporting effect of the drilling fluid on the borehole rock. Seepage of the drilling fluid also leads to a splitting effect on the rock cracks in the borehole wall, causing the fractures to expand and crack, which further lubricates the crack surfaces and weakens the mechanical strength between the cracks (Song and Zhang). 3.2.2. Experimental Test of Rock Hydration Expansion Performance Parameters. The hydration expansion performance and rolling recovery rate of igneous rocks soaked in the field drilling fluid for 24 h were tested, and the test results are shown in Figure 4.

The experimental results show that the Ordovician igneous rock is relatively dense and hard, with a low clay mineral content and weak hydration expansion and dispersion performance.

3.2.3. Experimental Testing of Mechanical Properties. The mechanical performance parameters of the rock samples were tested, and the experimental results are shown in Table 3, and the influence of cracks and the effects of immersion in the drilling fluid on the mechanical properties of igneous rocks were analyzed.

As can be seen in Table 3, the compressive strength and elastic modulus of homogeneous unfractured igneous rocks are high, while those of both filled and unfilled fractured rocks are low ($1/3$–$1/4$ of the strength of homogeneous unfractured igneous rocks). The existence of cracks greatly affects the mechanical strength of igneous rocks. The strength of the rock mass with calcite-filled closed fractures is slightly higher than that of the rock mass with unfilled fractures. Because the clay mineral content in igneous rocks is very low, immersion in the drilling fluid has little effect on the mechanical parameters, and the mechanical strength of the rocks is only slightly reduced after immersion. By observing the rock sample after the triaxial mechanical test, it can be seen that igneous rocks containing unfilled or calcite-filled cracks are damaged by external force, and the rock samples are preferably damaged along the direction of the crack, and the failure surfaces almost coincide with the fracture planes. This indicates that the rock mechanical strength of both open and filled fractures is low, and failure along the fracture is preferred under the action of a high external-stress environment. Based on the experimental results, hydration has little effect on the mechanical properties of igneous rock and the stability of the borehole wall. The fractures in igneous rocks are relatively developed, and the mechanical weak plane effect of the fractures is the main factor affecting borehole wall collapse. The fracture conductivity of igneous rocks is strong, and the pressure...
penetration of the drilling fluid along the fracture further affects wellbore stability.18,19

4. CALCULATIONS

Laboratory tests have shown that the Ordovician igneous bedrock in the Shunbei well area is very dense, with high rock mechanical strength and wellbore stability. However, the microfractures of the igneous rock are very well developed, and the rock mechanical strength is obviously subject to the weak plane effect of fracture mechanics. The mechanical strength of rock samples with microfractures is lower than that of bedrock. Microfractures also provide channels for the drilling fluid to filter into the formation, which is the main cause of downhole leakage. To determine the main controlling factors of borehole collapse instability in the Ordovician igneous formation, the effect of the in situ stress field, the weak plane effect of rock microfractures, and the effect of the seepage of drilling fluid on the borehole wall collapse pressure were evaluated and analyzed.

4.1. Influence of Wellbore-Formation Seepage on Formation Effective Stress. 4.1.1. Establishment of a Gas—Liquid Two-Phase Seepage Equation. At present, most igneous reservoirs are gas reservoirs. Therefore, the establishment of a gas—liquid two-phase seepage model during the drilling process is considered to evaluate the influence on wellbore stability. During the drilling process, the sum of the water-phase saturation and the gas-phase saturation in the region of borehole formation should be 1:

\[ S_w + S_g = 1 \]  

(1)

where \( S_w \) is the water-phase saturation and \( S_g \) is the gas-phase saturation.

The capillary force on the water-air two-phase interface is calculated as follows:

\[ P_c = P_w - P_g \]  

(2)

where \( P_c \) is the capillary force, \( P_w \) is the water-phase pressure, and \( P_g \) is the gas-phase pressure (all in MPa).

The rock skeleton and the water near the borehole wall are considered incompressible, while the gas is compressible in the evaluation of the water-gas two-phase seepage. The flow of water and gas satisfies Darcy’s law and the formation pores near the borehole wall are entirely filled with water and gas. The equations used to describe the movement of the water and air are as follows:

\[ q_w = -\frac{K_0 K_{rw}(S_w)}{\mu_w} \nabla P_w \]  

(3)

\[ q_g = -\frac{K_0 K_{rg}(S_g)}{\mu_g} \nabla P_g \]  

(4)

where \( K_0 \) is the absolute permeability, \( K_{rw}(S_w) \) is the water-phase relative permeability, \( K_{rg}(S_g) \) is the gas-phase relative permeability, \( \mu_w \) is the water-phase viscosity, and \( \mu_g \) is the gas-phase viscosity.

The continuity equations are as follows:

\[ \rho \frac{\partial S_w}{\partial t} + \nabla (\rho_w q_w) = 0 \]  

(5)

\[ \rho \frac{\partial S_g}{\partial t} + \nabla (\rho_g q_g) = 0 \]  

(6)

where \( \rho_w \) is the water density and \( \rho_g \) is the gas density, both in kg/m³.

Because the water is incompressible, \( \rho_w \) is a constant, while for the compressible gas, \( \rho_g \) is related to the gas pressure by a constant ratio at a given temperature. Therefore, the gas pressure can be used to eliminate the gas density value, resulting in the formula:

\[ \rho \frac{\partial (P_S)}{\partial t} + \nabla (P_s g) = 0 \]  

(7)

Substituting eq 4 into eq 6 and eq 5 into eq 7 yields:
\( \frac{\partial S_w}{\partial t} = \nabla \left[ \frac{K_w K_{rw}(S_w)}{\mu_w} \right] \nabla P_w + \frac{K_w K_{rw}(S_w)}{\mu_w} \nabla^2 P_w \) \tag{8} \\
\( \frac{\partial (P_g S_g)}{\partial t} = \nabla \left[ \frac{P_g K_{rg}(S_g)}{\mu_g} \right] \nabla P_g + \frac{P_g K_{rg}(S_g)}{\mu_g} \nabla^2 P_g \) \tag{9}

The initial conditions are:

- \( S_w|_{t=0} = S_{w_0} \)
- \( S_g|_{t=0} = 1 - S_{w_0} \)
- \( P_w|_{t=0} = P_{w_0} \)
- \( P_g|_{t=0} = P_{g_0} \)

where

\[ P_{g_0} - P_{w_0} = P_c(S_{w_0}) \]

and the boundary conditions are:

- \( S_w|_{r=r_w} = S_{\text{max}} \)
- \( S_g|_{r=r_w} = 1 - S_{\text{max}} \)
- \( P_w|_{r=r_w} = P_{\text{mud}} + P_c(S_{\text{max}}) \)

where \( t \) is the water-phase intrusion time (s), \( S_{w_0} \) is the initial water-phase saturation, \( P_{g_0} \) is the initial water-phase pressure (MPa), \( P_{w_0} \) is the initial gas-phase pressure (MPa), \( P_c(S_{w_0}) \) is the capillary force at initial water saturation (MPa), \( S_{\text{max}} \) is the maximum water saturation, \( P_{\text{mud}} \) is the annulus pressure (MPa), and \( P_c(S_{\text{max}}) \) is the capillary force at maximum water saturation (MPa).

Based on the formula established above, the relationship between the pressure and radial distance of the water and gas phases at different times was plotted (Figure 5).

As time increases, the water and gas two-phase pressures increase near the borehole. As the radial distance increases, the pressures decrease. Beyond a certain radial distance, the pressures tend to be constant. Thus, the relationship diagram of the water-phase invasion distance with immersion time was plotted (Figure 6).

As time passes, the distance of the water-phase intrusion into the formation increases, and the intrusion speed gradually decreases, eventually reaching a certain depth of invasion where the water no longer advances.

4.1.2. Influence of Seepage on the Effective Stress of the Borehole Wall. Because of the development of microfractures in the Ordovician igneous rocks, the influence of fluid migration along the microfractures on the effective stress should be considered in the evaluation and analysis of wellbore stability.

The seepage migration of drilling fluid along microfractures will affect the pore pressure near the borehole wall, which will inevitably change the effective stress distribution in the borehole wall zone.21,22 The following formula can be used to evaluate and analyze the effective stress distribution near the borehole wall zone:

\[
\sigma'_{ij} = \frac{\sigma_H + \sigma_i}{2} \left( 1 - \frac{r_w^2}{r^2} \right) + \frac{\sigma_H - \sigma_i}{2} \left( 1 - 4 \frac{r_w^2}{r^2} + 3 \frac{r_w^4}{r^4} \right) \cos 2\theta + \frac{r_w^2}{r^2} p_w - a_p(r,t) \tag{10}
\]
\[
\sigma_0' = \sigma_H + \frac{r_w^2}{r^2} p_w - a_p(r,t) \tag{11}
\]
\[
\sigma_z' = \sigma_i - \frac{r_w^2}{r^2} p_w + 2(\sigma_H - \sigma_i) \frac{r_w^2}{r^2} \cos 2\theta - a_p(r,t) \tag{12}
\]
\[
\tau_{0z} = \sigma_H - \frac{r_w^2}{r^2} p_w \left( 1 - 3 \frac{r_w^4}{r^4} + 2 \frac{r_w^2}{r^2} \right) \sin 2\theta \tag{13}
\]
\[
\tau_{zz} = \tau_{0z} = 0 \tag{14}
\]

where \( \sigma', \sigma_0', \sigma_i' \) and \( \tau' \) are the effective radial stress, circumferential stress, and axial stress, respectively (MPa); \( \sigma_H, \sigma_i, \) and \( \sigma_0 \) are the overburden pressure, maximum horizontal principal stress, and minimum horizontal principal stress, respectively (MPa); \( r_w \) and \( r \) are the borehole radius (m) and the radius between any position point around the well and the borehole axis (m); \( \theta \) is the well circumference angle (degrees); \( a \) is the effective stress coefficient (dimensionless); and \( p(r,t) \) is the formation pore pressure at time \( t \) when the distance from the borehole wall is \( r \).

Based on the mathematical formula established above, the effective stress distribution near the borehole wall zone was evaluated and analyzed (Figure 7).

As the seepage of the drilling fluid migrates to the formation, the effective circumferential and radial stresses acting on the rock of the borehole wall change significantly. The seepage migration of drilling fluid causes the formation pore pressure to increase. With more time, the effective circumferential and radial stresses gradually decrease, and the scope of influence gradually expands. As the radial distance of fluid intrusion into the
formation increases, the effective stress will eventually be equal to the original formation pressure.

4.2. Wellbore Stability Evaluation of Igneous Rock Formation. 4.2.1. Influence of the Weak Plane Effect of Fractures on Wellbore Stability. Fracture development greatly reduces the mechanical strength of igneous rocks. Therefore, the weak plane effect of fractures has a substantial influence on the borehole stability of an igneous formation.

The Jaeger criterion for weak surfaces is often used to characterize the effect of fractures on the mechanical properties of rock masses. The strength criterion of weak rock failure is: \[ \sigma = \sigma_1 + \frac{2(C_w + \sigma_3 \tan \varphi_w)}{(1 - \tan \varphi_w \cot \delta) \sin 2\delta} \delta_1 \leq \delta \leq \delta_2 \] (15)

with:
\[ \delta_1 = \frac{\varphi_w}{2} + \frac{1}{2} \arcsin \left[ \frac{(\sigma_1 + \sigma_3 + 2C_w \cot \varphi_w) \sin \varphi_w}{\sigma_1 - \sigma_3} \right] \]
\[ \delta_2 = \frac{\pi}{2} + \frac{\varphi_w}{2} - \frac{1}{2} \arcsin \left[ \frac{(\sigma_1 + \sigma_3 + 2C_w \cot \varphi_w) \sin \varphi_w}{\sigma_1 - \sigma_3} \right] \] (16)

where \( \sigma_1 \) is the maximum horizontal principal stress (MPa), \( \sigma_3 \) is the minimum horizontal principal stress (MPa), \( C_w \) is the cohesion of the weak plane (MPa), \( \varphi_w \) is the internal friction angle of the weak plane (degrees), and \( \delta \) is the angle between the weak plane normal and the maximum principal stress (degrees).

If the above conditions are not met, rock failure follows the Mohr–Coulomb criterion:
\[ \sigma = \sigma_1 \cot^2 \left( \frac{\pi}{2} - \frac{\varphi_0}{2} \right) + 2C_0 \cot \left( \frac{\pi}{2} - \frac{\varphi_0}{2} \right) \]

\( \delta_2 \leq \delta \leq \delta_1 \) (17)

where \( C_0 \) represents the rock cohesion (MPa) and \( \varphi_0 \) represents the internal friction angle of the rock (degrees).

According to the stress field established above and considering the seepage field, the equation for the collapse pressure of the borehole is shown below:
\[ P_{bh} = \frac{\sigma + \sigma_0 - 2(\sigma_{11} - \sigma_{00}) \cos 2\theta + \alpha P(K^2 - 1) - 2CK}{K^2 + 1} \]
\[ + \frac{\sigma - \sigma_0 K^2}{K^2 + 1} \] (18)

among them, \( K = \cot \left( \frac{\pi}{4} - \frac{\varphi_0}{2} \right) \).

Based on the in situ stress and rock mechanical parameters obtained from the experimental tests, the collapse pressure equivalent density of igneous formation was evaluated and analyzed, as shown in Figure 8.

When the in situ stress and bedrock mechanical parameters are considered, without accounting for factors such as the crack weak plane effect and the seepage effect, the maximum equivalent density of the collapse pressure is about 1.42 g/cm³ in the 90° and 270° directions, namely, the direction of...
minimum horizontal principal stress. In the direction of maximum horizontal principal stress, the equivalent density of collapse pressure is the lowest, with a value of about 0.58 g/cm³.

As can be seen from the salvaged cores, the Ordovician igneous microfractures are relatively well developed in the Shunbei well area, and the directions and angles of microfracture development (the angle between the normal direction of the microfracture plane and the direction of the maximum horizontal principal stress) are not uniform. A schematic diagram of igneous strata with relatively developed microfractures was drawn (Figure 9).

In combination with eq. 15–18, the influence of multiple fractures with different angles between the normal direction of the microfracture plane and the direction of the maximum horizontal principal stress on wellbore stability in igneous formations is evaluated and analyzed, and the results are shown in Figure 10.

The equivalent density of the collapse pressure is about 1.4 g/cm³ without considering drilling fluid seepage and the weak plane effect. As the number of fractures increases, the weak plane effect of the microfractures more strongly influences the equivalent density of the collapse pressure around the igneous formation. When the angle between the normal direction of a fracture and the maximum horizontal principal stress is 30°, the equivalent density of the collapse pressure is relatively low.

When the angle between the normal direction of a fracture and the maximum horizontal principal stress is 90°, the equivalent density of the formation collapse pressure is as large as 1.72 g/cm³, and the borehole wall is most likely to collapse. The effects on wellbore stability from the development of single fractures around the borehole depend strongly on the development angle of the fracture. As the number of fractures at different angles increases, the maximum values of the collapse pressure equivalent density curves generated by the various angles merge to form the top curve. The trend of the curve is similar to that of the collapse pressure equivalent density distribution curve of homogeneous formation calculated with the Mohr–Coulomb criterion. It can therefore be inferred that, when there are sufficient disordered fractures around the borehole and the formation is very fragmented, and the rock mechanics parameters of the fractured formation can be obtained through experimental testing; the corresponding equivalent density of the formation collapse pressure can be calculated according to the Mohr–Coulomb criterion.

An evaluation and analysis of the increase in the equivalent density of the formation collapse pressure due to the weak plane effect caused by multiple fractures with different development angles around the borehole were performed (Figure 11).

The weak plane effect of the fractures has a substantial impact on the equivalent density of the collapse pressure of igneous strata around the well. The effect is dependent on the angle between the normal direction of the microfracture plane and the direction of the maximum horizontal principal stress. At 65° and 245°, the maximum value of the collapse pressure equivalent density of the igneous formation is 1.72 g/cm³. Accounting for the weak plane effect of the fractures causes an increase of 21% in the calculated collapse pressure equivalent density of igneous strata, demonstrating the obvious impact of the presence of fractures.

4.2.2. Effect of Drilling Fluid Hydration on Wellbore Stability. Laboratory tests show that igneous bedrock contains a small amount (2∼8%) of clay. The influence of the hydration effect on the collapse pressure equivalent density of igneous strata was comparatively analyzed (Figure 12).

The equivalent density of the collapse pressure of igneous strata increases slightly when the hydration effect is considered. The equivalent density of the formation collapse pressure

![Figure 9. Schematic diagram of igneous formation with microfracture development.](image)

![Figure 10. Collapse pressure equivalent density distribution of igneous strata with different fracture occurrence.](image)
increased to 1.45 g/cm³, an increase of 2% compared with the equivalent density of formation collapse pressure considering only the ground stress and the bedrock mechanical strength.

4.2.3. Influence of the Seepage Effect of the Drilling Fluid on Wellbore Stability. The weak plane effect of relatively developed microfractures in igneous rock formations reduces wellbore stability. Simultaneously, when the igneous rock formation is drilled out, the drilling fluid migrates along the microfractures under the action of the positive bottomhole differential pressure, which leads to an increase in pore pressure near the borehole wall and weakening the effective support of the drilling fluid on the borehole wall, and further reducing wellbore stability in the igneous rock formation (Cui et al.)

Therefore, the seepage migration of the drilling fluid along microfractures is also a key factor affecting borehole stability in igneous formations. Based on the laboratory test results, the influence of drilling fluid seepage migration along microfractures on borehole wall stability was evaluated and analyzed (Figure 13).

It can be seen from Figure 13 that drilling fluid seepage along microfractures increases the collapse pressure of igneous formations and decreases the stability of the borehole wall. The maximum collapse pressure equivalent density of the igneous formation is 1.58 g/cm³ in the 90° and 270° directions when considering only the drilling fluid seepage effect, an increase of 11% compared with the collapse pressure equivalent density of the bedrock. When both the weak plane effect of the fractures and the seepage effect of drilling fluids are considered, the collapse pressure equivalent density of igneous rock formations is further increased. In the directions of 65° and 245°, the collapse pressure equivalent density of igneous rock formations has a maximum value of 1.811 g/cm³, a relative increase of 27.5%. The existence of fractures and the seepage of the drilling fluid along microfractures substantially increase the collapse pressure equivalent density.

The theoretical calculation and analysis have shown that wellbore stability in the Ordovician igneous formation in the Shunbei well area is the result of the combined influence of multiple factors with different ranges of influence. The order of the influence range of these factors is the weak plane effect of microfractures + the seepage effect of drilling fluid (27.5%) > the fracture weak plane effect (21%) > the drilling fluid seepage effect (11%) > the clay hydration effect (2%). Therefore, the main controlling factors affecting the Ordovician igneous rock
formation in the Shunbei well area are the weak plane effect of the fractures and the seepage effect of the drilling fluid. 

The physical, chemical, and mechanical performance parameters of the Ordovician downhole igneous rock in the Shunbei well area were tested experimentally, and a theoretical model was established to evaluate the stability of the igneous rock formation. The weak plane effect of the fractures in the igneous rock and the effect of drilling fluid seepage increase the equivalent density of the borehole wall collapse pressure up to about 1.811 g/cm³, making it necessary to optimize the drilling fluid density to meet the stability requirements for the borehole wall. Wellbore stability is better when drilling along the direction of the maximum horizontal principal stress. Downhole imaging logging is recommended to determine the width and density of microfractures in the downhole pressure environment and the particle size and gradation of the plugging material to select the appropriate drilling fluid. The optimized design of drilling fluid rheology and the improvement of rock carrying capacity can prevent rocks from falling off the borehole wall and accumulating at the bottom of the well, which can prevent downhole resistance.

5. CONCLUSIONS

Through experimental tests and theoretical analysis, the microscopic fabric, the physical and chemical properties, and the rock mechanical parameters of the Ordovician underground igneous rocks in the Shunbei well area were studied. The mechanisms of collapse and instability of the igneous rock formation and the main control factors for the instability were determined. An evaluation model for wellbore stability in igneous rock formations was established, and the following conclusions and understandings were obtained:

1. The Ordovician igneous rocks in the Shunbei well area are mainly feldspar, with a small amount of quartz and calcite and a low clay mineral content. The Ordovician igneous rocks in the Shunbei well area are relatively well developed with open fractures and calcite half-filled and fully filled fractures.

2. The Ordovician igneous rocks in the Shunbei well area demonstrate weak hydration and expansion ability and high rolling recovery. The igneous rock bedrock has high rock mechanical strength, while the rock samples with developed microcracks have low mechanical strength. Immersion in the drilling fluid has little effect on the mechanical strength of igneous rock, and the effects of hydration have little influence on wellbore stability in igneous rock formations.

3. The Ordovician igneous rock formation in the Shunbei well area has relatively developed microfractures, with the weak plane effect of the fractures increasing the formation collapse pressure equivalent density to 1.72 g/cm³, which seriously affects the stability of the borehole wall. The seepage migration of fluid between microfractures weakens the effective support of the drilling fluid for the borehole wall, leading to an increase of stratum collapse pressure and the deterioration of the borehole wall stability.

4. Considering the weak plane effect of the igneous microfractures and the seepage effect of the drilling fluid, the well trajectory should be optimized and the drilling fluid density should be controlled at about 1.82 g/cm³ during the actual drilling process. At the same time, the effective plugging ability of the drilling fluid should be improved and the rheological property of the drilling fluid should be optimized so as to improve the rock-carrying ability of the drilling fluid in the drilling process of microfracture formation.

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Notes
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