A prediction model for borehole instability of ultra-deep fractured reservoir based on fracture and temperature effect

Junhai Chen¹², Jie Ren³⁴, Yunhu Lu³⁴, Mian Chen³⁴, Yingtong Ju³⁴ and Shengchao Huang⁵

¹ State Key Laboratory of Shale Oil and Gas Enrichment Mechanism and Effective Development, Beijing, China
² Sinopec Research Institute of Petroleum Engineering, Beijing, China
³ State Key Laboratory of Petroleum Resources and Prospecting, Beijing, China
⁴ College of Petroleum Engineering, China University of Petroleum, Beijing, China
⁵ Chuanqing Drilling Engineering Co., Ltd. Chuanxi drilling company, Chengdu, China

Abstract. The traditional prediction method of wellbore instability in fractured formation cannot effectively solve the problem of surrounding rock collapse in ultra-deep fractured reservoir. This paper focuses on the coupling effect of complex geological conditions such as high stress, high temperature, fractured formation and drilling fluid. It establishes the induced stress field expression based on the heat exchange effect between drilling fluid and wellbore surrounding rock, and synthesizes the superposition effect of temperature and fracture. The strength failure criterion of wellbore surrounding rock in fractured formation is optimized, and the mechanical model of wellbore instability in fractured reservoir is established based on mechanical-thermal-chemical coupling model. The results show that as drilling fluid density increases, the stability of wellbore surrounding rock in ultra-deep fractured reservoir initially increases and then decreases. In other words, excessive drilling fluid density will aggravate wellbore collapse. In addition, the decrease in the temperature of the surrounding rock of the wellbore caused by the circulation of drilling fluid also leads to the increment in the degree of wellbore collapse. Based on these findings, reasonable drilling fluid density and properties can be optimized, and the instability problem of an ultra-deep fractured reservoir in Northwest China can be alleviated.

1. Introduction
The buried depth of reservoir in Northwest China generally exceeds 6,000 m. The surrounding rock of the wellbore collapses frequently during drilling affected by strong tectonic stress, reservoir cracks, and high formation temperature. Traditional method of improving the drilling fluid density cannot effectively solve this problem. For example, the drilling fluid density in 7,000-7,100 m section of well SN-X in Tarim Basin gradually increased from 1.89g/cm³ to 1.95g/cm³, the solution failed to alleviate the phenomenon of block loss, even caused more serious wellbore collapse. It severely restricts the exploration and development of ultra-deep oil and gas resources in Northwest China. Scholars all over the world have carried out a lot of research on wellbore instability mechanism in fractured reservoir. They believed that the drilling fluid and its filter fluid along the cracks or bedding seepage would change the peripheral stress distribution characteristics of the well and reduce the strength of rock around the wellbore. This leads to the failure of the surrounding rock, which is the main reason of wellbore collapse[1]. The theoretical model and numerical method are used to estimate the formation density.
collapse stress. The theoretical model considers the fluid fixation coupling effect flowing along the crack or bedding surface, and analyzes the influence of ground stress, rock strength and crack on the formation collapse stress[2]. The numerical simulation mainly uses finite element and discrete element method to build a mechanical model with consideration of crack and bedding characteristics. The model simulates the influence of different liquid column pressure, ground stress, rock strength and fracture shape on the degree of wellbore collapse and obtains the bottom liquid column pressure with the minimum risk of wellbore collapse[3]. The above research provides important theoretical support for the optimization of drilling fluid density in fractured formations shallower than 6,000 meters, and has obtained good field application results. For ultra-deep formations, the decrease in the surrounding rock of the borehole wall caused by the heat exchange between the drilling fluid and the formation may be as high as 50-80°C [4]. The influence of thermal stress caused by temperature changes on wellbore stability cannot be ignored. The impact will be more serious as the drilling depth becomes deeper. It is believed that temperature will affect the stability of the wellbore surrounding rock. The decrease in the temperature of wellbore surrounding rock caused by the drilling fluid will reduce the stress distribution around the borehole, resulting in a decrease in the collapse stress of wellbore surrounding rock. [5] It is worth noting that the above understanding is based on the homogeneous integrity formation wellbore stability model, which may be different for high temperature ultra-deep fracture formation due to the reduction of temperature will greatly increase the intensity of wellbore collapse[6].

However, there are few studies about the effect of high temperature on wellbore stability in ultra-deep fractured formation. In order to solve the problem of wellbore instability in high temperature and ultra-deep fractured formation, this paper first determines the temperature distribution characteristics of surrounding rock by numerical method, and then coupling the transient boundary conditions of wellbore temperature into the temperature stress field model based on Duhamel's principle to obtain the induced stress caused by temperature change. Then this paper applied the coordinate transformation method and build a three-dimensional weak surface model with consideration of fracture seepage. The additional stress generated by the temperature field is superimposed to obtain the stress distribution characteristics on the fracture surface. Finally, by introducing the stress on the fracture surface into the rock strength failure criterion, the collapse degree and collapse stress of the surrounding rock can be analyzed. The prediction model of wellbore instability in ultra-deep fractured reservoir established in this paper has been applied in a Northwest China. It effectively alleviated the wellbore instability problem in fractured reservoirs deeper than 7,000 meters.

2. Temperature field and thermal stress of the wellbore surrounding rock
The drilling fluid is pumped into the wellbore through the wellhead and flowing up through the annulus to the wellhead (Figure1). During drilling circulation, the drilling fluid not only conducts heat exchange through fluid heat convection, but also conducts heat exchange through heat conduction, such as the heat conduction between the annulus and the fluid in the drill string, and the annulus drilling fluid conducts heat conduction with the formation. (Figure2). In order to study the thermal stress caused by temperature changes, this paper divides drilling fluid circulation in the wellbore into three stages, analyzes the temperature distribution of wellbore surrounding rock of at different times and establishes the expression for the distribution of stress around the wellbore caused by thermal effects[7].

2.1. Wellbore temperature field equation
The drilling fluid circulation in the wellbore is divided into three stages.

Stage 1. The drilling fluid flows into the drill pipe at constant temperature $T_{DP}$ from the inlet of drill pipe. The temperature in the drill pipe is determined by the heat convection rate of the drilling fluid in the drill pipe and the heat transfer rate with the annulus drilling fluid.
Stage 2. The initial temperature of drilling fluid flowing from the drill pipe to the wellbore annulus is $T_0(L,t)$. If the energy consumption of drilling fluid passing through the bit nozzles is ignored, the drilling fluid temperature in the bottom of drill pipe and in the annulus is equal, which is $T_D(L,t)=T_A(L,t)$

![Diagram of drilling fluid circulation in the wellbore](image)

**Figure 1. Schematic diagram of drilling fluid circulation in the wellbore**

Stage 3. In the process of drilling fluid circulation through the annulus up to the wellhead, the temperature in the annulus is related to the thermal convection rate of drilling fluid in the annulus and the heat transfer rate between the formation and drill pipe.

In addition, the following assumptions are made for the circulation process of drilling fluid: 1. the flow pattern of drilling fluid in drill pipe and annulus is turbulent; 2. The axial heat transfer during drilling fluid flow is ignored, and it is assumed that the thermodynamic parameters of drilling fluid do not change with temperature; 3. The viscous dissipation of drilling fluid flow is ignored\(^5\).

(1) Temperature field inside the drill pipe:

$$A_D B_D C_L \frac{\partial T_D(z,t)}{\partial z} + 2 \pi r_D U [T_D(z,t) - T_A(z,t)] = - \rho A_D C_L \frac{\partial T_D(z,t)}{\partial z}$$ \hspace{1cm} (1)

(2) Temperature field in the annulus:

$$A_D B_D C_L \frac{\partial T_A(z,t)}{\partial z} + 2 \pi r_A U [T_D(z,t) - T_A(z,t)] + 2 \pi r_T h_f [T_f(r_T,z,t) - T_A(z,t)] = \rho A_D C_L \frac{\partial T_A(z,t)}{\partial z}$$ \hspace{1cm} (2)

(3) Temperature field in the formation:

$$\frac{\partial T_f(r,z,t)}{\partial z} = c_p V^2 T_f(r,z,t)$$ \hspace{1cm} (3)

(4) The following equation is the heat exchange between annulus and formation:

$$2 \pi r_B h_f [T_f(z,t) - T_A(z,t)] = 2 \pi r_B K_f \left[ \frac{\partial T_f(z,t)}{\partial r} \right]_{r=r_B}$$ \hspace{1cm} (4)

Boundary conditions:

The initial and boundary conditions during the drilling circulation are:

$$T_D(z,0) = T_A(z,0) = T_f(z,0) = T_0(z)$$ \hspace{1cm} (5)

Temperature of the drilling fluid at the wellhead:

$$T_D(z = 0,t) = T_0$$ \hspace{1cm} (6)

Temperature at the bottom hole:

$$T_D(z = L,t) = T_A(z = L,t)$$ \hspace{1cm} (7)

The temperature of wellbore surrounding rock is equal to initial formation temperature:
\[ T_f(r, z, t) = T_\infty(z) \]  

(8)

\( A_D \) is the inner circle area of drill pipe; \( A_d \) is the annulus area; \( V_f \) is the flow rate of drilling fluid in the drill pipe; \( V_d \) is the annulus drilling fluid flow rate; \( C_p \) is the specific heat capacity of drilling fluid; \( c_h \) is the thermal diffusion coefficient; \( T_D \) is the internal temperature of drill pipe; \( T_d \) is the annulus temperature; \( T_f \) is the formation temperature; \( z \) is the variable of vertical well depth; \( L \) is the depth of vertical well; \( t \) is the injection time of drilling fluid at wellhead; \( r \) is the radius of a place in the stratum; \( r_d \) is the inner radius of drill pipe; \( r_w \) is the wellbore radius; \( U \) is the overall convective heat transfer coefficient; \( h_f \) is the coefficient of convection heat exchange in the wellbore; \( K_f \) is the thermal conductivity coefficient of the formation; \( \rho \) is the density of drilling fluid.

2.2. Thermal stress of wellbore

Temperature change caused by drilling fluid circulation leads to contraction or expansion of rock skeleton. The weekly thermal stress generated by temperature is:

\[ s\sigma_{rr} = \beta^s(1 - M_{12}/M_{11})[(T_w - T_0)\Psi(\xi_2)] \]  

(9)

\[ s\sigma_{\theta \theta} = -\beta^s(1 - M_{12}/M_{11})[(T_w - T_0)\Omega(\xi_2)] \]  

(10)

\[ s\sigma_{zz} = (\beta^s - 2\nu'\beta^s)T_0 - (\beta^s - 2\nu'\beta^s)sT \]  

(11)

In above equations, it is necessary to determine the temperature distribution characteristics of surrounding rock around the wellbore during the drilling fluid circulation. For the temperature distribution features on the wellbore, fully implicit differential numerical methods are used for discrete simulation.

However, the distribution of formation temperature field in the depth of a well in formula (3) is calculated and analyzed according to the conditions of fixed temperature boundary on the wellbore, and the Duhamel's principle is introduced to simplify the problems of boundary conditions and non-homogeneous terms varying with time. Equation 12 gives the analytical solution in Laplace domain of the temperature distribution equation of surrounding rock on the wellbore at transient temperature boundary conditions:

\[ s \cdot \mathbf{T} = T_0 + s \cdot \int_{0}^{\infty} e^{-st}(f(t) - T_0)dt \cdot \frac{K_0(qh \cdot r)}{K_0(qh \cdot R)} \]  

(12)

Similarly, the stress distribution around the wellbore when the wellbore temperature and drilling fluid pressure change with time, that is, we can convert \( T_w \) and \( T_w - T_0 \) into the following form:

\[ T_w - T_0 \rightarrow s \int_{0}^{\infty} e^{-st}(T(t) - T_0)dt \]

\[ T_w \rightarrow s \int_{0}^{\infty} e^{-st}(T(t) - T_0)dt + T_0 \]  

(13)

For the wellbore, \( \Psi(\xi_2) = 0 \), \( \Omega(\xi_2) = 1 \), after substituting these two conditions into the above equations, the variation of wellbore rock temperature with time in any well depth can be obtained by using the above method. For the volume expansion coefficient of rock and water in equations (9), (10) and (11), we set the thermal expansion coefficient of fluid and the thermal expansion coefficient of rock skeleton as constants, the thermal expansion coefficient of fluid is 0.001 and the thermal expansion coefficient of rock skeleton is 0.000027. Assuming the value does not change with temperature at a certain depth of the formation, the thermal stress generated by temperature can be calculated.

Drilling fluid circulation has different influence on the temperature of wellbore surrounding rock at different well depths. Figure 2 shows the change law of the wellbore temperature field under different well depths and drilling fluid circulation time. It can be seen from Figure 2, at a well depth of 0-2,000 m, as the drilling fluid circulation time increases, wellbore surrounding rock temperature increases; at
a depth of 2,000-4,500 m, with the drilling fluid cycle time increases, the temperature of the wellbore surrounding rock is generally unchanged; at a well depth exceeding 4,500 m, the temperature of the wellbore surrounding rock decreases with the drilling fluid circulation time. For ultra-deep formation, the formation temperature decreased by 50°C after 16 hours of drilling fluid circulation at 6,000 m depth. The effect of thermal stress generated by temperature reduction on wellbore stability cannot be ignored, elaborated in the literature, Ultra-deep drilling fluid circulation produces a large temperature drop on the wellbore. According to the analysis results of Figure 2, the cooling effect of drilling fluid circulation is more important in the ultra-depth because of the greater cooling range.

![Figure 2](image)

**Figure 2.** Temperature distribution on the borehole wall under different time conditions.

3. **Stability mechanical model of surrounding rock on wellbore of ultra-deep fracture reservoir**

For crack strata, there is often a group of dominant crack surfaces controlling the strength of the rock. Cutting failure of the rock body inside the surrounding rock of the wellbore and shear damage along the crack surface. For ultra-deep formation, the rock matrix has great strength, and the main reason for wellbore instability is the existence of natural fractures. Due to the low matrix permeability, we assume that the fracture is the only channel for drilling fluid to enter the surrounding rock of the wellbore, and the drilling fluid flows into the fracture faster, and the pressure in the fracture in the rock stress concentration area around the well is equal to the pressure of liquid column in the well. Meanwhile, the Mohr criterion is used to describe the strength of the rock. Since the poor adhesion and the cohesion force is zero, the strength parameters are reflected by the internal friction angle. We establish the stress distribution formula around the wellbore with consideration of temperature. The stress distribution characteristics on the fracture surface can be obtained by coordinate transformation. Then, the stress on the fracture surface can be substituted into the Mohr-Coulomb criterion to obtain the wellbore stability analysis model.

3.1. **Stress distribution of the crack surface**

When the hole is opened, the wellbore surrounding effect due to ununiform stress and temperature coupling, we establish a well stress distribution model considering pore elasticity and temperature effect, the well stress formula is as follows:

\[
s\sigma_{rr} = -P_0 + S_0 \cos 2(\theta - \theta_r) + (P_0 - P_w)\left(\frac{R^2}{R^2 - R^2_m}\right) + \beta^m(1 - \frac{m_1^2}{m_{13}})[(T_w - T_0)\Psi(\xi)]
\]

\[
s\sigma_{\theta\theta} = -P_0 - S_0 \cos 2(\theta - \theta_r) - (P_0 - P_w)\left(\frac{R^2}{R^2 - R^2_m}\right) - \beta^m(1 - \frac{m_1^2}{m_{13}})[(T_w - T_0)\Omega(\xi)]
\]

\[
s\sigma_{zz} = \left[ -S_v + v'(S_h + S_M) + (\beta^z - 2v'\beta^s)T_0 \right] + v'(s\sigma_{rr} + s\sigma_{\theta\theta}) - (\beta^z - 2v'\beta^s)T
\]

\[
\overline{\sigma}_{\theta} = -S_0 \sin 2(\theta)
\]

\[
\sigma_{rz} = \sigma_{\theta z} = 0
\]
Pressure boundary conditions are:

$$s\mathbf{P} = p_0(\text{Stroma})s\mathbf{P} = p_w(\text{In fracture}) \quad (19)$$

To judge whether the wellbore surrounding rock has shear failure along the fracture surface, it is necessary to convert the rock stress distribution around the well to the fracture surface coordinate system by coordinate conversion. The specific steps are as follows:

**Figure 3.** Schematic diagram of global, in-situ stress, formation occurrence, inclined wellbore and cylindrical coordinate system.[10]

Step 1: The stress distribution of the surrounding rock around the wellbore under the polar system is converted into Cartesian coordinate system (Figure 3), then the rock stress distribution matrix around the lower polar system is:

$$\sigma_{\text{polar}} = \begin{bmatrix} \sigma_{rr} & \tau_{r\theta} & 0 \\ \tau_{r\theta} & \sigma_{\theta\theta} & 0 \\ 0 & 0 & \sigma_{zz} \end{bmatrix} \quad (20)$$

Conversion Matrix:

$$C = \begin{bmatrix} \cos \theta & \sin \theta & 0 \\ \sin \theta & \cos \theta & 0 \\ 0 & 0 & 1 \end{bmatrix} \quad (21)$$

Stress distribution matrix of surrounding rock in Cartesian coordinate system:

$$\sigma_{\text{cartes}} = C^T \begin{bmatrix} \sigma_{rr} & \tau_{r\theta} & 0 \\ \tau_{r\theta} & \sigma_{\theta\theta} & 0 \\ 0 & 0 & \sigma_{zz} \end{bmatrix} \quad (22)$$

Step 2: The stress distribution around the well is transformed into the effective stress distribution around the well. When the wellbore is perpendicular to the transversely isotropic formation, the effective stress produced by pore pressure is anisotropic:

$$\sigma_{\text{eff}} = \begin{bmatrix} \sigma_x & \tau_{xy} & \tau_{xz} \\ \tau_{xy} & \sigma_y & \tau_{yz} \\ \tau_{xz} & \tau_{yz} & \sigma_z \end{bmatrix} = \begin{bmatrix} -\alpha P_w & 0 & 0 \\ 0 & \alpha P_w & 0 \\ 0 & 0 & -\alpha P_w \end{bmatrix} \quad (23)$$

Step 3: Convert the effective stress distribution around the well to the geodetic system:

Conversion Matrix:
11th Conference of Asian Rock Mechanics Society
IOP Conf. Series: Earth and Environmental Science 861 (2021) 062074
doi:10.1088/1755-1315/861/6/062074

\[ E = \begin{pmatrix} \cos \alpha_s \cos \beta_s & \sin \alpha_s \cos \beta_s & \sin \beta_s \\ -\sin \beta_s & 0 & \cos \alpha_s \\ -\cos \alpha_s \cos \beta_s & -\sin \alpha_s \cos \beta_s & \cos \beta_s \end{pmatrix} \]  (24)

\[ \sigma_e = E^T \times \sigma_{eff} \times E \]  (25)

Step 4: Convert effective stress distribution under geodetic system to weak surface coordinate system:

Conversion Matrix:

\[ W = \begin{pmatrix} -\cos \alpha_w \cos \beta_w & -\sin \alpha_w \cos \beta_w & \sin \beta_w \\ \sin \beta_w & 0 & \cos \alpha_w \\ \cos \alpha_w \cos \beta_w & \sin \alpha_w \cos \beta_w & \cos \beta_w \end{pmatrix} \]  (26)

Effective stress distribution matrix of the rock around the wellbore under the weak surface coordinate system:

\[ \sigma_w = W \times \sigma_e \times W^T = \begin{pmatrix} \sigma_{xx}^w & \tau_{xy}^w & \tau_{xz}^w \\ \tau_{yx}^w & \sigma_{yy}^w & \tau_{yz}^w \\ \tau_{zx}^w & \tau_{zy}^w & \sigma_{zz}^w \end{pmatrix} \]  (27)

3.2. Wellbore collapse analysis model

Generally, Mohr-Coulomb criterion is recognized as the most suitable criterion for yield and failure analysis in rock mechanism \(^{[11]}\). The effective stress distribution of the crack surface obtained before is brought into the Mohr-Coulomb failure criterion. By comparing the shear stress parallel to the weak surface and the friction force on the weak surface, we can identify whether the weak surface would slide. The area where relative sliding occurs is the shear failure area:

\[ \sqrt{\left(\tau_{xx}^w\right)^2 + \left(\tau_{xy}^w\right)^2} = S_w + \mu_w \sigma_{zz}^w \]  (28)

Where \( \sigma_{polar} \) is the stress distribution matrix in polar coordinate system; \( \sigma_{decartes} \) is the stress distribution matrix in Cartesian coordinate system; \( \sigma_{eff} \) is the effective stress distribution matrix in Cartesian coordinate system; \( \sigma_e \) is the effective stress distribution in geodetic coordinate system; \( \sigma_w \) is the effective stress distribution matrix in the weak plane coordinate system; \( \sqrt{\left(\tau_{xx}^w\right)^2 + \left(\tau_{xy}^w\right)^2} \) is the weak plane shear stress; \( \sigma_{zz}^w \) is the normal stress of weak plane; \( S_w \) is the weak plane cohesion; \( \mu_w \) is the angle of weak in-plane friction; \( \alpha_w \) and \( \beta_w \) are fracture tendency and dip angle.

4. Calculation results and analysis

4.1. Influence of ground stress

The following groups of figures describe the influence of ground stress on wellbore stability. The horizontal maximum main stress, horizontal minimum main stress and upper covered rock layer pressure are independent variables.
2.167MPa/100m  2.467MPa/100m  2.767MPa/100m

**Figure 4.** Relationship between horizontal maximum main stress and wellbore stability.

As can be seen from Figure 4, when other conditions are fixed, the greater the maximum horizontal main stress, the better the wellbore stability around the well eye, and the stability of the wellbore far from the well eye is increasing and then reduced.

1.615MPa/100m  1.915MPa/100m  2.215MPa/100m

**Figure 5.** Relationship between horizontal minimum principal stress and wellbore stability.

As can be seen from Figure 5, when other conditions are fixed, the greater the horizontal minimum main stress, the better the stability around the wellbore, and the stability of the wellbore far from the well eye changes a little.

2.085MPa/100m  2.385MPa/100m  2.685MPa/100m

**Figure 6.** Relationship between overburden pressure and wellbore stability.

As can be seen from Figure 6, when other conditions are fixed, the stability of the wellbore does not change significantly as the pressure of the overburden layer increases.

4.2. **Influence of the rock strength**

The cohesive force and internal friction angle of the rock are commonly used parameters to describe the rock strength. The greater the cohesion force and internal friction angle, the higher the strength of the rock. The following figures show the relationship between rock cohesion and wellbore stability at different internal friction angles.

1.5MPa  8.6MPa  16.36MPa
**Figure 7.** Relationship between rock cohesion and wellbore stability when the internal friction angle is equal to $14^\circ$

![Figure 7](image1)

1.5MPa  
8.6MPa  
16.36MPa

**Figure 8.** Relationship between rock cohesion and wellbore stability when the internal friction angle is equal to $16^\circ$

![Figure 8](image2)

1.5MPa  
8.6MPa  
16.36MPa

**Figure 9.** Relationship between rock cohesion and wellbore stability when the internal friction angle is equal to $20^\circ$

As can be seen from the figure above, when the other conditions remain fixed, the stability of the wellbore increased significantly with the increasing of the rock adhesion and the internal friction angle.

4.3. **Influence of the temperature**

![Figure 10](image3)

1h  
4h  
16h

**Figure 10.** Wellbore collapse without considering temperature effect

![Figure 11](image4)

1h  
4h  
16h

**Figure 11.** Wellbore collapse considering temperature effect
Figure 10 shows the collapse of the wellbore without considering the effect of temperature. It can be seen from the figure that the wellbore is broken in a ring shape. As the formation drilling time increases, the wellbore collapse area in the direction of the maximum principal stress and the direction of the minimum principal stress has an increasing trend. After the formation is drilled for 16 hours, except for the direction of the minimum principal stress, the wellbore collapsed in the other directions are all very seriously.

Figure 11 shows the collapse of the wellbore when temperature is considered. It can be seen from the figure that the wellbore is seriously damaged in the direction of the minimum and maximum principal stress, while the wall in the other directions is relatively intact. When the drilling fluid is circulated for 16 hours, the collapse area of the wellbore further increased. The collapse of the wellbore at the direction of the maximum principal stress became more serious and the borehole expansion rate was reduced compared with the case where the temperature effect was not considered.

4.4. Influence of crack
The inclination and tendency of fractures will affect the scope and extent of wellbore collapse. Figure 12 shows the influence of the angle between the fracture tendency and the maximum horizontal principal stress on the instability of the wellbore at a certain wellbore fluid column pressure equivalent drilling fluid density.

![Figure 12. Relationship between fracture tendency and maximum horizontal main stress angle and wellbore stability](image)

As shown in the figures, When the angle between the fracture tendency and the maximum horizontal in-situ stress is $0^\circ/180^\circ$, the wellbore collapses in a small range at $20^\circ$–$40^\circ$, $120^\circ$–$160^\circ$, $190^\circ$–$210^\circ$, $300^\circ$–$340^\circ$, and the wellbore is relatively stable; when the angle between the fracture tendency and the maximum horizontal ground stress is $60^\circ$, large-scale collapse occurs at all angles and the stability of the well wall is very poor; when the angle between the crack tendency and the maximum horizontal ground stress is $90^\circ$, small-scale collapse occurred at all angles and it was slightly more serious at $160^\circ$–$180^\circ$ and $320^\circ$–$360^\circ$, and the wellbore has good stability.

5. Field application
Take a well in Northwest China as an example, it was drilled to 7,300m into a Yijianfang formation, and the lithology is light yellow gray sandy debris micritic limestone, sandy debris micritic limestone, brown gray asphaltene sandy debris micritic limestone with black asphalt, and formation fracture development. The rock Poisson's ratio is 0.229, the Young's modulus is 51.286GPa, the overburden pressure is 177.617MPa, the maximum horizontal principal stress is 162.558MPa, the minimum horizontal principal stress is 134.011MPa, and the internal friction angle is 53.834°, Well deviation 43.5°, Azimuth 244.4°.

The equivalent density of wellbore collapse pressure obtained by traditional calculation method is 1.20g/cm³, the equivalent density of fracture pressure is 2.262g/cm³, and the density of drilling fluid used at first is 1.30g/cm³. When drilling to 7,340.3m, the wellbore collapses.
The above data are substituted by the wellbore stability prediction method in this paper:

![Figures showing wellbore stability at different fluid densities](image)

**Figure 13.** Simulation of wellbore stability at different drilling fluid densities.

As shown in the figure, when the density increases from 1.20g/cm³ to 1.25g/cm³, the wellbore stability improves. However, as the drilling fluid density continues to increase to 1.30g/cm³, the stability decreases significantly, which is similar to the analysis in this paper.

In the process of field application, the drilling fluid density was adjusted from 1.30g/cm³ to 1.25g/cm³. After that, the collapse was reduced and the drilling was carried out smoothly.

6. **conclusions and recommendations**

- During drilling, drilling fluid circulation can significantly reduce the temperature of ultra deep formation, so the resulting thermal stress of wellbore surrounding rock can not be ignored. The research shows that this will greatly increase the degree of wellbore collapse in fractured formation, which is consistent with the actual situation of drilling engineering. This paper explains the shortcomings of the traditional analysis method which does not consider the effect of fractures and considers that reducing the temperature of wellbore surrounding rock is beneficial to wellbore stability.

- Based on the fracture and temperature effect, the prediction model of borehole wall rock instability in ultra deep fractured reservoir shows that with the increase of drilling fluid density, the stability of borehole wall rock in ultra deep fractured reservoir first increases and then decreases, which explains the strange phenomenon that the increase of drilling fluid density leads to the increase of borehole wall collapse.

- The density and performance design of drilling fluid in ultra deep fractured reservoir need to consider the influence of fracture and temperature effect. The prediction method of wellbore stability established in this paper can solve the problem of wellbore instability in a western area of 7,000 meters deep reservoir.

**Acknowledgments**

This research is supported by the national joint fund project "basic theory and method of high temperature and high pressure oil and gas safe and efficient drilling and completion engineering" (U19B6003-05), and Sinopec basic prospective project " Study on wellbore failure mechanism of ultra deep hard brittle dolomite formation in Sichuan Basin " (P21074-1). Thanks for the help of the project team.

**References**

[1] Y. H. Lu, M. Chen, et al. 2013. Influence of porous flow on wellbore stability for an inclined well with weak plane formation[J]. Petroleum Science and Technology, 31 (6): 616-624.

[2] Y. H. Lu, M. Chen, et al.2012. A mechanical model of borehole stability for weak plane formation under porous flow[J]. Petroleum Science and Technology, 30 (15): 1629-1638.

[3] P. J. McLellan.1996. Assessing the risk of wellbore instability in horizontal and inclined wells[J]. Journal of Canadian Petroleum Technology, 35 (05):113-115.
[4] Deng Jingen, Wang Jinfeng, et al. 2002. Calculation model of wellbore collapse pressure and fracture pressure in permeable formation [J]. *Journal of rock mechanics and engineering*, 21(S): 2069-2072. (in Chinese)

[5] Ma Tianshou, Chen Ping. 2015. Mechanical model of hole stability of thermoeleastic well in shale formation [J]. *Journal of rock mechanics and engineering*, 34(S2): 3613-3623. (in Chinese)

[6] Chen Xin, Yang Qiang, et al. 2005. Shaft stability analysis considering anisotropic strength of deep rock mass [J]. *Journal of rock mechanics and engineering*, 24(16):2882-2888. (in Chinese)

[7] Liu Ming, et al. 2015. Oil-based critical mud weight window analyses in HTHP fractured tight formation[J]. *Journal of Petroleum Science and Engineering*, 135: 750-764.

[8] Li Sigui, Li Zhiming. 2002. Discrete element analysis of borehole stability in jointed and fractured strata [J]. *Journal of rock mechanics and engineering*, 21(S): 2139-2143. (in Chinese)

[9] K. Yamamoto, Y. Shioya, et al. 2002. Discrete element approach for the wellbore instability of laminated and fissured rocks[C]. *SPE/ISRM Rock Mechanics Conference*, SPE-78181-MS.

[10] Haifeng Zhao, Mian Chen, et al. 2012. Discrete element model for coal wellbore stability [J]. *International Journal of Rock Mechanics and Mining Sciences*, 54:43-46.

[11] Wenda Li, Mian Chen, et al. 2018. Effect of local thermal non-equilibrium on thermoporoelastic response of a borehole in dual-porosity media[J]. *Applied Thermal Engineering*, 142: 166-183.