Integrated Approach for the Wellbore Instability Analysis of a High-pressure, High-temperature Field in the South China Sea

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Abstract: Wellbore instability and lost circulation were frequently encountered while drilling the first batch of exploration wells in a low-permeability, high-pressure, high-temperature (HPHT) gas field in the South China Sea. These problems are attributed to very narrow drilling mud weight windows resulting from the HPHT reservoir conditions. This study focuses on combining and leveraging geophysical data, rock mechanics testing data, and well logging data to predict wellbore instability and lost circulation under HPHT conditions. Full-scale core samples were acquired from HPHT reservoirs of the field, and uniaxial and triaxial rock mechanics tests were performed to determine the mechanical properties of the rock. The influence of heat transfer between the wellbore and the formation, temperature field, mechanical properties, in situ stresses, collapse pressure, and fracture pressure were investigated. According to the results, changes in wellbore temperature generate thermal stress, which may aggravate wellbore instability. The wellbore temperature decreased by 50–60°C during the mud circulation process. Furthermore, the safe mud weight window, which was originally narrow because of the HPHT conditions, became narrower under the influence of temperature change. The use of multi-source data and the integrated model will significantly improve the accuracy of wellbore instability and lost circulation prediction in HPHT fields.

Keyword: wellbore stability, HPHT filed, temperature filed, in situ stress, safe mud weight window

1 Introduction

Wellbore stability studies have played a significant role in the oil and gas industry. In high-pressure, high-temperature (HPHT) wells with a narrow safe mud weight window and a high-pressure gradient, drilling complications such as stuck pipe and lost circulation occur frequently. Therefore, analyzing and maintaining the stability of HPHT boreholes during well planning and drilling is crucial. Traditional wellbore stability studies focus on the calculation of the rock mechanical properties, in situ stress, pore pressure, and safe mud weight window. However, in HPHT wells, in addition to these calculations, the effect of temperature change must be considered as it is nonnegligible. The instability of the wellbore surrounding rock caused by temperature effect has been proved in many engineering studies [1-3]. The effect of temperature change on wellbore stability has been studied for long by many experts [4-8].
Conventional calculation methods of collapse pressure and fracture pressure is not sufficient for HPHT wells, and new models considering the effect of temperature change have been established [9-12]. The aim of this study was to develop an integrated approach to analyze the wellbore instability of an HPHT field in the South China Sea. This approach can help provide a better understanding of the mechanisms of the drilling complexities in HPHT fields, and it will greatly reduce non-productive time and drilling costs for extensive development of the field in the future.

2 Geological setting

The studied field is located in the South China Sea, and several exploration wells were drilled there. The drilling statistics of these wells show that for most of these wells, the depth exceeds 4000 m; the pore pressure coefficient exceeds 2.0 g/cm³; and the bottomhole temperature is higher than 180 °C, sometimes even reaching 200 °C. This information is sufficient to indicate that the studied area is an HPHT field.

The drilled formations can be divided into two parts according to the lithology and drilling complications. The upper formation is composed of mudstone with thin layers of silty mudstone and argillaceous siltstone. Stuck pipe was encountered at times in this formation because of its low compaction degree. The target formation comprised gray mudstone and silty mudstone with gray siltstone and argillaceous siltstone, and a thick layer of light gray fine sandstone in the bottom. Frequent gas cut and lost circulation were encountered, and since these problems were hard to control, some wells were plugged, and abandoned while drilling to the bottom.

In summary, wellbore instability complications occurred frequently in the studied area during drilling, and it was difficult to control these complications without determining the cause and position of the loss accurately. Furthermore, the difficulty of predicting the pressure in the HPHT mudstone formation may lead to severe borehole collapse and stuck pipe problems, especially during the drilling of development wells with large inclination angles.

3 Theory and methods

3.1 Determination of the temperature field around the wellbore

Dusseault and Maury (1993) reported on the influence of temperature change on wellbore stability [13]: they showed that for medium-hard to hard rocks, thermal stresses of 0.4–1.0 MPa can be generated for every 1 °C change in rock temperature. However, a variation of 25–50 °C in wellbore temperature in HTHP wells is very common under real drilling conditions, and this may indicate the generation of a corresponding 25–50 MPa thermal stress on the wellbore. Therefore, borehole fracture and collapse may occur because the combination of the thermal stress and original field stress exceeds the strength of the wellbore rock. Therefore, the influence of wellbore temperature change must be considered in the wellbore stability analysis of the studied area.

A method of calculating borehole and formation temperature field in the mud circulation process for vertical wells was developed based on the model proposed by Raymond (1969). The temperature field in drill string can be predicted as follows:
The temperature field in annulus can be predicted as follows:

\[ A_D \rho V_D C_p \frac{\partial T_p(z,t)}{\partial z} + 2\pi r_D U [T_D(z,t) - T_A(z,t)] = -\rho A_D C_p \frac{\partial T_p(z,t)}{\partial t} \]  

(1)

The formation temperature field can be predicted as follows:

\[ A_A \rho V_A C_p \frac{\partial T_f(z,t)}{\partial z} + 2\pi r_D U [T_D(z,t) - T_A(z,t)] + 2\pi r_B h_f [T_f(r_B z,t) - T_A(z,t)] = \rho A_A C_p \frac{\partial T_f(z,t)}{\partial t} \]  

(2)

The formation temperature field can be predicted as follows:

\[ \frac{\partial T_f(r,z,t)}{\partial t} = \frac{K_f}{\rho_f C_p f} \frac{1}{r} \frac{\partial}{\partial r} \left[ r \frac{\partial T_f(r,z,t)}{\partial r} \right] \]  

(3)

Further, the wellbore temperature field can be predicted using the following equation:

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

(4)

where \( T_A, T_D \), and \( T_f \) are the temperature in the annulus, drill pipe, and formation, respectively; \( A_A \) and \( A_D \) are the cross-sectional areas of the annulus and drill pipe, respectively; \( V_A \) and \( V_D \) are the fluid velocities in the annulus and drill pipe, respectively; \( \rho \) and \( \rho_f \) are the densities of the fluid and formation, respectively; \( C_p \) and \( C_p f \) are the heat capacities of the fluid and formation, respectively; \( r_B \) and \( r_D \) are the radii of the borehole and the drill pipe, respectively; \( U \) is the over-all heat transfer coefficient between the drill pipe and annulus; \( h_f \) is borehole wall heat transfer coefficient; \( K_f \) is formation thermal conductivity; \( r \) is the radial space variable; and \( t \) is the time variable.

3.2 Determination of thermal expansion coefficient of the wellbore rock

The thermal expansion coefficient is given directly in the literature on the influence of temperature change on wellbore stability. However, using the coefficient of one kind of rock for the entire well depth may cause considerable error, because the properties of different formations vary greatly. Therefore, in this study, we adopt a combined model (Equation 5) by using log data to predict the thermal expansion coefficient. We also measured the thermal expansion coefficient in the lab using real core simples, and the measured data were used to calibrate the prediction results.

\[ \alpha_t = \alpha_l \alpha_l + \alpha_m \alpha_m + \alpha_s \alpha_s \]  

(5)

where \( \alpha_t \) is the average thermal expansion coefficient; \( \alpha_l, \alpha_m, \) and \( \alpha_s \) are the thermal expansion coefficient of limestone, mudstone, and sandstone, respectively (i.e., the three major components of sedimentary rocks). \( \alpha_l, \alpha_m, \) and \( \alpha_s \) are the mineral composition of limestone, mudstone, and sandstone, respectively, which are determined from well logging data.

3.3 Determination of mechanical properties of the wellbore rock

Uniaxial and triaxial compressive tests were conducted to determine the compressive strength, static Young's modulus (\( E_s \)), and Poisson's ratio(\( \mu \)) of the wellbore rock using real core
samples. The tensile strength was determined from uniaxial tensile tests. Fig. 1 shows a group of core samples used for the uniaxial and triaxial tests and one sample after the triaxial compressive test.

The profiles of the dynamic Young's modulus \(E_d\) and Poisson's ratio \(\mu_d\) along the wellbore can be determined using the density and sonic logging data by using the following equations (Asef and Najibi, 2013):

\[
E_d = \rho v_p^2 \left(3v_p^2 - 4v_s^2\right) / \left(v_p^2 - 2v_s^2\right) \\
\mu_d = \frac{v_p^2 - 2v_s^2}{2 \left(v_p^2 - 2v_s^2\right)}
\]

where \(\rho\) is the density, and \(v_p\) and \(v_s\) are the compressional and shear wave velocities, respectively. For wellbore stability analysis, the static Young's modulus and Poisson's ratio should be used. The following empirical equations were used to covert the dynamic parameters calculated from logging data into static ones. The measured results were used to calibrate the calculation results.

\[
E_s = A_1 + K_1 E_d \\
\mu_s = A_2 + K_2 \mu_d
\]

where \(A_1, A_2, K_1,\) and \(K_2\) are empirical coefficients.

The uniaxial compressive strength (UCS), cohesion (C), and internal friction angle (\(\phi\)) are the other important mechanical properties that should be evaluated. These properties were calculated using the following empirical relations:

\[
UCS = 0.77v_p^{2.93} \\
C = -0.417 + 0.289(UCS) - 0.000519(UCS)^2 \\
\phi = 11v_p - 10.2
\]

The constants in these equations were determined by fitting the test data.

### 3.4 Determination of in situ stresses

Generally, three in situ stresses should be determined for wellbore stability analysis — the
vertical stress \( (\sigma_v) \), the minimum horizontal stress \( (\sigma_h) \), and the maximum horizontal stress \( (\sigma_H) \). The vertical stress can usually be obtained by integrating rock densities from the surface to the target depth using density logging data. In this study, the total well depth was separated into water depth and rock depth, considering the difference in their densities. The vertical stress was calculated using the following equation:

\[
\sigma_v = \int_{H_1}^{H_2} \rho_w g dh + \int_{H_2}^{H_3} \rho_r g dh
\]  

(13)

where \( H_1 \), \( H_2 \), and \( H_3 \) are the depths of the sea level, sea bed, and formation, respectively, from the platform. Further, \( \rho_w \) and \( \rho_r \) is the density of water and rock, respectively.

The two horizontal stresses can be estimated using equations (14) and (15) (Deng et al., 1988):

\[
\sigma_H = \left( \frac{\mu_s}{1-\mu_s} + \omega_1 \right) \left( \sigma_v - \alpha P_p \right) + a P_p
\]  

(14)

\[
\alpha_h = \left( \frac{\mu_s}{1-\mu_s} + \omega_2 \right) \left( \sigma_v - \alpha P_p \right) + a P_p
\]  

(15)

where \( \alpha \) is the effective stress coefficient; \( \sigma_H \) and \( \sigma_h \) are the maximum and minimum horizontal stress, respectively; \( \sigma_v \) is the vertical stress; \( \mu \) is Poisson's ratio; \( \omega_1 \) and \( \omega_2 \) are the structural stress coefficients determined as 0.625 and 0.305, respectively, for the study area using leak-off test data. \( P_p \) is the pore pressure that can be calculated based on the sonic logging data using the equation (16) proposed by Eaton (1972):

\[
P_p = OBG - (OBG - P_{pm}) \left( \frac{NCT}{DT} \right)^n
\]  

(16)

where OBG is denoted as the overburden gradient determined using the density log; \( P_{pm} \), the hydrostatic pressure gradient; NTC, the compacted trend line; DT, the P-wave transient time; and \( n \), an empirical parameter.

The Bowers pore pressure model was used for predicting the pore pressure in the reservoir and its adjacent layers. Depending on the formation mechanism of pore pressure, the Bowers model can be expressed as follows:

Formation not unloaded:

\[
P_p = OBG - \frac{\left( \frac{\partial T}{\partial T} \right)^{1/6 \cdot \frac{1}{6}}}{\text{depth}} \]

(17)

Formation unloaded:

\[
P_p = OBG - \frac{(\sigma_{max})^{1-U}}{\text{depth}} \left( \frac{\partial T}{\partial T} \right)^{1/6 \cdot \frac{1}{6}}
\]  

(18)

where \( A \) and \( B \) are virgin curve parameters; \( U \) is the unloading curve parameter; \( \sigma_{max} \) is the effective vertical stress at the onset of unloading; and \( DT_{ml} \) is the theoretical P-wave
transient time.

3.5 Determination of collapse pressure and fracture pressure of the wellbore

The key point to manage wellbore stability is to determine a reasonable drilling fluid density window. The conventional method to determine formation collapse pressure and fracture pressure does not consider the influence of dynamic wellbore and formation temperature changes. This conventional method is not sufficient for HPHT wells. Yu et al. (2005) proposed a calculation model to determine the collapse and fracture pressure under HPHT formation conditions, expressed as shown in equations (19) and (20), respectively. The model takes into account the impact of temperature variation between the wellbore and the formation.

\[
P_b = \frac{3\sigma_h - \sigma_h - 2\xi K + [\delta\xi + \delta\phi K^2 + \alpha(1 + K^2)(1 - \delta)]P_p + E\beta_m(T_w - T_0)/[3(1 - \nu)]}{1 - \delta\xi + \alpha\delta + K^2(1 - \delta\phi - \alpha\delta)}
\]

\[
P_f = \frac{3\sigma_h - \sigma_h + s_t - (\delta\xi + \alpha - \alpha\delta)P_p + E\beta_m(T_w - T_0)/[3(1 - \nu)]}{1 + \alpha\delta - \delta\xi}
\]

where \( P_b \) and \( P_f \) are the collapse pressure and fracture pressure, respectively; \( E \) is Young's modulus; \( \nu \) is Poisson's ratio; \( T_0 \) is the original formation temperature; \( T_w \) is the wellbore temperature; \( \phi \) is the porosity; \( \delta \) is the wellbore seepage coefficient; \( S_t \) is the formation tensile strength; \( \delta = 1 \) when the wellbore is strongly permeable, and \( \delta = 0 \) when the wellbore is impermeable; \( \xi \) is a tectonic stress coefficient expressed as shown in equation (21); and \( K \) can be expressed as shown in equation (22).

\[
\xi = \frac{\alpha(1-2\nu)}{1-\nu} - \phi
\]

\[
K = \cot \left( 45^\circ - \frac{\phi}{2} \right)
\]

4 Results and discussions

4.1 Temperature profile and thermal expansion coefficient

The temperature distribution along the wellbore during drilling is schematically shown in Fig. 2. It shows that the upper wellbore section is heated while the lower section is cooled by the drilling fluid. Fig. 3 shows the temperature field in the surrounding rock from the numerical simulation performed by the method described in Section 3.1. The bottom hole temperature decreases during drilling fluid circulation, and it approaches a constant value after certain time; thereafter, it is no longer affected by drilling fluid circulation. There was a 50–60 °C decrease in the wellbore temperature in the studied wells.
The measurement results of thermal expansion coefficient obtained using field core samples are listed in Table 1. The prediction results obtained using equation (5) for three different wells are shown in Fig. 4. The thermal expansion coefficient was approximately $12.5 \times 10^{-6}$, and it varied little with depth according to the calculation results.

| Type of rock | Thermal expansion coefficient ($10^{-6}$) |
|--------------|------------------------------------------|
| Diabase      | 12.21                                    |
| Dolomite     | 12.25                                    |
| Limestone    | 12.64                                    |
| Salt rock    | 12.95                                    |
| Tuff         | 12.11                                    |
| Mudstone     | 12.87                                    |
| Sandstone    | 12.10                                    |
4.2 Mechanical properties

The uniaxial and triaxial test results are listed in Table 2 and Table 3. It can be concluded that the Young’s modulus of mudstone is lower than that of sandstone, whereas the Poisson’s ratio of the former is higher. Sandstone has higher compressive strength and is more brittle.

Table 2 Uniaxial tensile test results

| Number | Lithology      | Density (g/cm³) | Load (N) | Tensile strength (MPa) |
|--------|----------------|-----------------|----------|------------------------|
| 1      | Mudstone       | 2.67            | 1155     | 5.42                   |
| 2      | Mudstone       | 2.688           | 1082     | 2.345                  |
| 3      | Sandstone      | 2.26            | 712      | 3.83                   |
| 4      | Sandstone      | 2.26            | 1330     | 5.51                   |
| 5      | Sandstone      | 2.427           | 1855     | 3.906                  |
| 6      | Sandstone      | 2.604           | 2432     | 4.844                  |
| 7      | Sandstone      | 2.549           | 2473     | 4.857                  |
| 8      | Sandstone      | 2.359           | 2762     | 5.979                  |
| 9      | Silty mudstone | 2.542           | 1154     | 2.383                  |
| 10     | Silty mudstone | 2.494           | 1052     | 2.181                  |
| 11     | Silty mudstone | 2.482           | 464      | 0.958                  |
Table 3 Triaxial compressive test results

| Number | Lithology | Confining pressure (MPa) | Density (g/cm³) | E (GPa) | μ | Compressive strength (MPa) | φ (°) | C (MPa) |
|--------|-----------|--------------------------|-----------------|---------|---|---------------------------|------|---------|
| 1      | Mudstone  | 5                        | 2.670           | 17.902  | 0.296 | 60.543                    | -    | -       |
| 2      | Mudstone  | 10                       | 2.499           | 15.0515 | 0.175 | 87.482                    | 47.59| 4.08    |
| 3      | Mudstone  | 10                       | 2.524           | 18.5669 | 0.123 | 97.732                    | 48.92| 4.97    |
| 4      | Mudstone  | 0                        | 2.494           | 1.1110  | 0.023 | 20.094                    |      |         |
| 5      | Mudstone  | 0                        | 2.498           | 4.0491  | 0.125 | 17.161                    | 45.79| 5.92    |
| 6      | Mudstone  | 10                       | 2.556           | 24.3944 | 0.229 | 113.631                   |      |         |
| 7      | Mudstone  | 5                        | 2.515           | 21.765  | 0.275 | 58.636                    |      |         |
| 8      | Mudstone  | 10                       | 2.519           | 14.630  | 0.282 | 77.684                    | 44.3 | 5.9     |
| 9      | Sandstone | 5                        | 2.557           | 20.067  | 0.170 | 134.63                    | -    | -       |
| 10     | Sandstone | 5                        | 2.605           | 17.468  | 0.183 | 107.12                    |      | -       |
| 11     | Sandstone | 5                        | 2.551           | 25.597  | 0.155 | 164.98                    |      |         |
| 12     | Sandstone | 15                       | 2.416           | 29.258  | 0.211 | 213.45                    | -    | -       |
| 13     | Sandstone | 20                       | 2.420           | 23.910  | 0.174 | 224.11                    |      |         |

Fig. 5 and Fig. 6 show the mechanical properties calculated using equations (6)–(10) based on well logging data, and the empirical coefficients determined from the test results. The calculated values are consistent with the test results.

(a) UCS (b) C (c) φ

Fig. 5 Strength parameter profiles
4.3 In situ stresses and safe mud weight window

The distributions of three principal in situ stresses along well depth as calculated by equations (11)–(13) are shown in Fig. 7. From the calculation results, we can conclude that the in situ stress in the study area is controlled by normal faults, i.e., $\sigma_v > \sigma_{h} > \sigma_h$. Under the influence of high formation pressure, with increase in depth, the contribution of pore pressure to horizontal in situ stresses increases gradually, whereas the contribution of effective decreases.
Collapse and fracture pressure can be calculated using equations (15) and (20), and the result is shown in Fig. 8. The safe mud weight window (i.e., the margin between collapse and fracture pressure) becomes as narrow as 0.4 g/cm³ in the high-pressure formation, leading to frequent wellbore instability and lost circulation problems there.

![Fig. 8 Collapse and fracture pressure](image)

Numerical simulations and experiments were performed to analyze the influence of temperature change on collapse pressure and fracture pressure. The results are provided in Fig. 9 and Table 4. Change in temperature has a great influence on the fracture pressure of vertical wells, but a smaller influence on the collapse pressure. Further, the safe mud weight window becomes narrower as the temperature decreases.

![Fig. 9 Collapse and fracture pressure varies with change in temperature](image)
Table 4 Experimental results of fracture pressure change with decrease in temperature

| Number | Lithology | Density (g/cm³) | E (GPa) | μ | α (10⁻¹²) | ΔT (°C) | ΔPf (g/cm³) |
|--------|-----------|----------------|---------|---|------------|---------|-------------|
| 1      | Mudstone  | 2.67           | 17.902  | 0.296 |           | 12      | 60          | 0.14        |
| 2      | Sandstone | 2.55           | 25.6    | 0.155 |           | 12      | 60          | 0.21        |

where α is the thermal expansion coefficient; ΔT, the decrease in temperature; and ΔPf, fracture pressure reduction.

The fracture pressure reduction of mudstone was about 0.14 g/cm³ and that of sandstone was about 0.21 g/cm³ for a decrease of about 60 °C in temperature. The influence of change in temperature on the fracture pressure of the sandstone is greater than that in the case of mudstone.

Fig. 10 shows the influence of drilling fluid circulation on the safe mud weight window. The fracture pressure decreases with drilling fluid circulation because of the decrease in formation, and it reaches a stable value after the formation temperature is balanced. Therefore, the safe mud weight window becomes narrower during drilling fluid circulation.
5 Conclusions

An integrated approach that combines geophysical data, rock mechanics testing data, and well logging data was developed to predict wellbore instability under HPHT conditions. Geological properties such as \( V_p \), \( V_s \), and density were extracted from log data. Uniaxial and triaxial rock mechanics tests were conducted to determine rock strength. Then, pore pressure was predicted by using Eaton’s equation. The other mechanical properties such as Young’s modulus, Poisson’s ratio, UCS, cohesion, and internal friction angle were calculated using empirical equations based on the log data and test results. The vertical in situ stress was obtained from the integral of rock densities, whereas the horizontal in situ stresses were determined by using a conventional model. The results showed that \( \sigma_v > \sigma_H > \sigma_h \). Thus, it can be inferred that the in situ stress in the study area is controlled by normal faults. Collapse pressure and fracture pressure were calculated using a model which considered the effect of change in temperature in the HPHT formation; the collapse pressure increases as the fracture pressure decreases, resulting in a narrow safe mud weight window in the HPHT formation. The temperature field and its influence on wellbore stability were studied. The temperature distribution in wellbore and formation were predicted by Raymond’s method. The prediction results showed that the upper part of the wellbore is heated by the drilling fluid, while the lower part is cooled. The bottom hole temperature decreased during drilling fluid circulation, and it finally decreased by 50–60 °C. Furthermore, the change in temperature led to decrease in collapse pressure and fracture pressure, which may contribute to well instability.

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