Hindawi
Geofluids
Volume 2019, Article ID 1201958, 21 pages
https://doi.org/10.1155/2019/1201958

Research Article

Modelling of Time-Dependent Wellbore Collapse in Hard Brittle Shale Formation under Underbalanced Drilling Condition

Shanpo Jia,[1,2] **Zhiqiang Xiao**,[3] **Bisheng Wu**,[4] **Caoxuan Wen**,[3] **and Lufeng Jia**[3]

[1]*Institute of Unconventional Oil & Gas, Northeast Petroleum University, Daqing 163318, China*
[2]*State Key Laboratory of Oil & Gas Reservoir Geology and Exploitation, Southwest Petroleum University, Chengdu 610500, China*
[3]*Research Center of Geomechanics and Geotechnical Engineering, Yangtze University, Jingzhou 434023, China*
[4]*Department of Hydraulic Engineering, Tsinghua University, Beijing 100084, China*

Correspondence should be addressed to Shanpo Jia; jiashanporsm@163.com and Zhiqiang Xiao; xiaozhiqiangxl@163.com

Received 7 December 2018; Revised 14 March 2019; Accepted 19 March 2019; Published 16 April 2019

Academic Editor: Pietro Teatini

In recent years, the lithologic traps in a mid-depth formation are the focus of oil or gas exploration and development for eastern oilfields in China. The Shahejie Formation develops thick hard brittle shale, and the wellbore instability problem is prominent due to obvious hydration effect for long immersion time during drilling. Through the analysis of laboratory tests and field test results of physical and chemical properties and microstructure and mechanical properties of hard brittle shale, the instability mechanism is discussed for the wellbore in the shale formation. To simulate the whole process of progressive collapse of a wellbore in a hard brittle shale formation, a coupled hydraulic-mechanical-chemical (HMC) model is developed and this model is compiled with ABAQUS software as the solver. Then the coupled HMC model is applied to simulate the progressive evolution process of wellbore collapse in a hard brittle shale formation, and the influence of different parameters on the progressive failure of the wellbore is analysed. The results show that the wellbore enlargement rate increases with the drilling fluid immersion time and the influence of different parameters on the wellbore enlargement rate is different. The water absorption diffusion coefficient and the activity of the drilling fluid have the most obvious influence on the expansion of the wellbore, and the sensitivity is strong. The permeability of shale has little effect on the wellbore enlargement rate. The calculated progressive failure process of the wellbore is basically consistent with that of the actual drilling.

1. Introduction

The oil or gas exploration and development of a mid-depth formation have become the focus for eastern oilfields in China. Hard brittle shale in a mid-depth formation, which is affected by the existence of cracks and hydration effects, often causes wellbore instability problem for long immersion time. The wellbore instability in hard brittle shale has become the main bottleneck restricting the drilling speed. From the point of view of reducing drilling costs and accelerating exploration and development for oil or gas, it is of great significance to study the wellbore stability of hard brittle shale in a mid-depth formation.

The Nanpu sag is a continental lacustrine sedimentary basin, which forms a high-quality source of rocks such as semideep lake and deep lake phase shale and oil shale. The main source rock is the lithologic trap of the Shahejie Formation with the depth of more than 4000 m. Several hundred meters of hard brittle shale is developed in the Shahejie Formation, which has high clay mineral content and microcrack development. During the actual drilling process, the hydration effect of hard brittle shale causes the wellbore instability by differential pressure penetration, crack self-water absorption, and long immersion time. Many complicated situations, such as drilling tool resistance and well logging retaining, often occur due to the wellbore collapse and diameter enlargement in a hard brittle shale formation, which seriously affects the drilling efficiency. The original mechanical balance and chemical balance of the formation are broken after the wellbore is drilled. Due to the coupling action of

hydraulic gradient and chemical gradient, the disturbed zone of the wellbore is developed and it becomes a changed heterogeneous area with time by the seepage diffusion and the hydration effect of the drilling fluid. This series of effects has led to a very complex process for the wellbore in hard brittle shale. Aiming at the wellbore stability problem of shale, many scholars have carried out a lot of research work and obtained many meaningful research results. In general, they mainly focus on the following aspects: firstly, from the point of view of physical and chemical characteristic analyses of shale, the collapse mechanism of the shale wellbore is studied and discussed [1, 2]; secondly, from the perspective of coupling experiment of the shale wellbore, different experimental schemes are designed to study the collapse mechanism of the shale wellbore [3–6]; thirdly, the collapse mechanism of the shale wellbore is analysed by numerical simulation method and reasonable suggestions are given [7, 8].

Generally speaking, the development of the coupling model for shale wellbore stability can be divided into four stages. The first stage is the application of the thermoelastic analogy method [9, 10], which compares the hydration expansion stress of shale to the thermal expansion stress and the movement of water into shale to the thermal diffusion. The quantitative model established by this method can consider the effect of water content changes on the shale wellbore stability but ignores the nature of the chemical interaction between the shale and the drilling fluid. The second stage is the method of free energy thermodynamics of water molecules [2, 11]. The theory holds that the difference in activity (chemical potential) between drilling fluid and shale drives free water into and out of the shale, changing the pore pressure of the wellbore to affect the effective stress near the wellbore. By appropriate strength criteria of shale, the optimum mud concentration and optimum mud density for maintaining wellbore stability can be determined. The free energy thermodynamics model of water molecules negates the effect of differential pressure on water movement in shale and also negates the effects of ion diffusion and ion exchange on shale hydration and does not consider time effects. The third stage is the nonequilibrium thermodynamic method [12–16]. Nonequilibrium thermodynamic method is a comprehensive method to study the chemomechanical coupling of wellbore stability of shale. However, it is difficult to determine the model parameters, which can only be applied to ideal solution with low mass concentration. The combined effect of fluid pore pressure and rock deformation is not taken into account, and it is conservative to adopt linear elasticity for shale in the coupled model. The fourth stage is the application of total water potential [17–19]. The method holds that the difference in total water potential (the sum of pore pressure and chemical potential) is the root cause of water flow. The total water potential method can consider the comprehensive effect of pore pressure and chemical potential, but many parameters are difficult to determine, and no solution is given.

According to the previous studies, the wellbore instability mechanism is discussed by analysing the physical and chemical properties and microstructure and mechanical properties of hard brittle shale. To depict the evolution law of wellbore failure, a coupling constitutive model was developed considering the actual unloading process, strength weakening, and plastic deformation of shale during drilling. The influence of different parameters on the progressive failure of the wellbore is analysed, and the understanding of wellbore collapse is improved, which can provide a reference for the optimization of drilling fluid to prevent or slow down the wellbore instability for a hard brittle shale formation.

2. Mechanism of Wellbore Collapse in a Hard Brittle Shale Formation

During drilling, the diameter of shale in the Shahejie Formation varies greatly and the problem of wellbore instability is prominent. The lithology, mineral composition, microstructure, and hydration effect of shale need to be tested and studied.

2.1. Formation Mineral Composition. The whole rock minerals and clay minerals of the hard brittle shale are tested by X-ray diffraction method. The composition of the whole rock and the content of clay minerals are shown in Tables 1 and 2.

Clay and quartz are the main minerals in shale of the Shahejie Formation. Feldspar and calcite are also developed in different degrees. Brittle minerals (quartz, feldspar, and calcite) are relatively developed, with quartz content ranging from 6.71% to 39.94%. The clay content is relatively high, ranging from 19.09% to 43.06%. Illite and illite/montmorillonite are the main clay minerals. The relative content of illite is 34.47~56.64%, and the content of illite/montmorillonite is 6.72~39.74%. No montmorillonite is found in the Shahejie Formation.

2.2. Microstructure Structure of Shale. Microstructure analysis of shale can reveal orientation arrangement, cementation structure of clay minerals, and microcrack distribution. The development degree and size of microcracks are important factors for drilling fluid performance optimization. Scanning electron microscope (SEM) is one of the most effective means to observe microstructures in shale. The microstructure of shale and occurrence of clay minerals in the Shahejie Formation are analysed by SEM, which are shown in Figure 1.

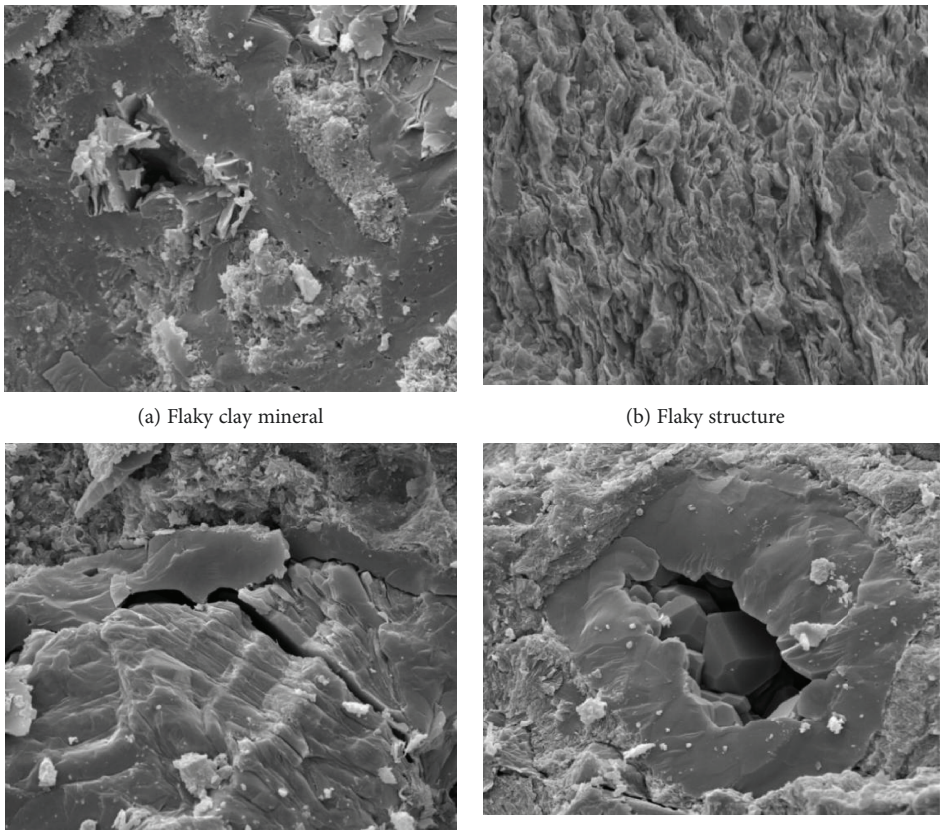
From Figure 1, the shale of the Shahejie Formation is highly compacted and well cemented but the microcracks, microholes, and bedding are well developed. From the viewpoint of rock mechanics, the development of microcracks and microholes can destroy the integrity of shale, weaken the mechanical properties, and provide a channel for drilling fluid to enter the formation during drilling. Under the action of pressure difference and capillary force, the drilling fluid invaded the formation along microcracks or microholes. On the one hand, it may induce hydraulic fracturing and aggravate wellbore failure; on the other hand, it also increases the probability and degree of interaction between drilling fluid and clay minerals in a formation, which leads to the decrease of formation rock mechanical strength and the increase of wellbore instability.

Table 1: Mineral composition of shale.

Well	Depth (m)	Percentage of minerals (%)					
		Clay minerals	Quartz	Calcite	Plagioclase	Orthoclase	Dolomite
W-81	4900.01	43.06	39.94	1.71	12.21	0.00	3.08
W-82	4149.86	25.33	6.71	38.98	0.00	12.73	16.25
W-96	3901.10	19.09	36.45	9.07	27.54	6.42	1.44

Table 2: Relative content of clay minerals.

Well	Relative content (%)					Interlayer ratio (%)
	Illite (I)	Montmorillonite (S)	Illite/montmorillonite (I/S)	Kaolinite (K)	Chlorite (C)	
W-81	49.78	0.00	12.63	6.27	31.33	15.00
W-82	56.54	0.00	6.72	0.00	36.74	10.00
W-96	34.47	0.00	39.74	10.62	15.17	25.00



(a) Flaky clay mineral (b) Flaky structure

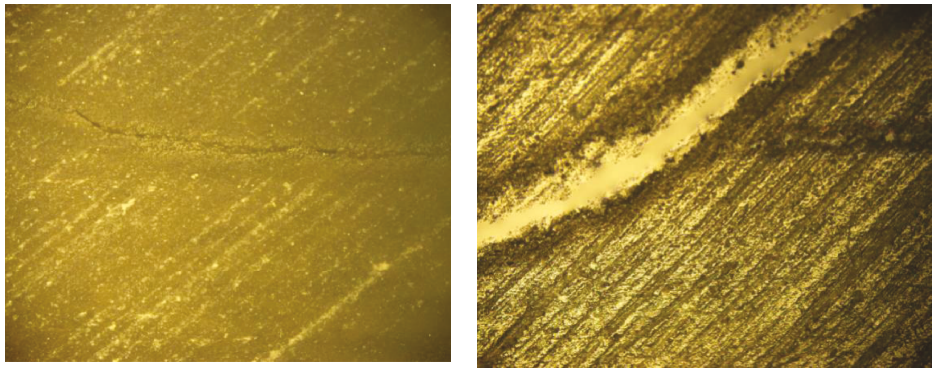
(c) Microcrack (d) Microhole

Figure 1: SEM images of the shale core in well W-82.

2.3. Influence of Drilling Fluid Action on the Shale Structure. After hydration, clay minerals in shale can expand and produce expansion stress. Microcracks in shale can produce stress concentration at the crack tip by the influence of water or drilling mud.

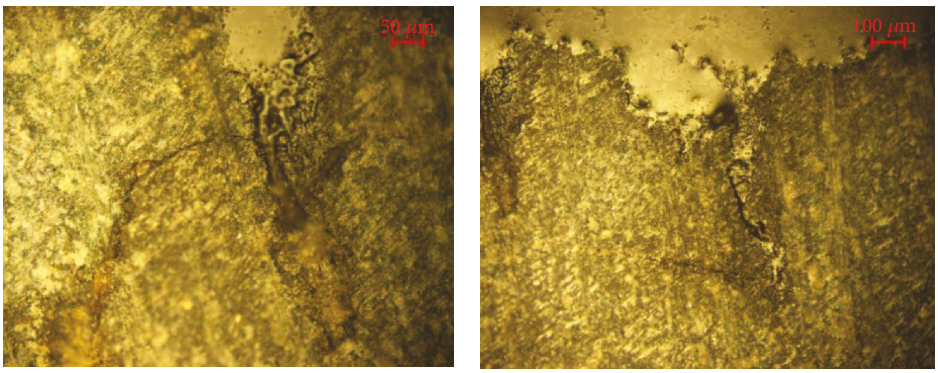
The drilling mud used in the field is water-based KCl filming drilling fluid. The microstructure changes of shale after fluid action were observed by high-power polarizing microscope, which are shown in Figures 2 and 3. Under the action of clear water and drilling mud, microcracks in shale will initiate, expand, or bifurcate and clear water and drilling mud will invade the interior of shale along microcracks, further aggravating the failure of shale.

2.4. Cation Exchange Capacity. Cation exchange, i.e., cation exchange adsorption, is one of the important characteristics of shale and can be used to predict the potential water sensitivity of a formation. When the clay is dispersed in water, the



(a) Before invasion (b) 48 h after invasion

Figure 2: Clear water intrusion along microcracks in shale.



(a) Before invasion (b) 96 h after invasion

Figure 3: Morphological changes of microcracks under the intrusion of drilling fluid.

adsorbed cations will diffuse from the surface of the clay. By measuring the cation exchange capacity (CEC value) of the shale, the hydration, expansion, and dispersion of the shale can be reflected.

The cation exchange capacity of shale samples was measured, and the results show that the range of CEC of the Shahejie Formation was 90~235 mmol/kg with an average of 146.25 mmol/kg. The shale of the Shahejie Formation has a certain hydration ability and is prone to wellbore instability under the action of water-based drilling fluid.

3. Effect of Drilling Fluid on Mechanical Properties of Shale

The mechanical properties of shale are important factors to represent the failure characteristics of the wellbore under external disturbance and drilling fluid, which are directly related to the density of available safe drilling fluid, the performance of drilling fluid, and the manifestations of wellbore accidents.

3.1. Mechanical Properties of Original Shale. To minimize the disturbance of the drilling coring, the rock cores are quickly vacuum sealed and stored in a room with a given temperature and humidity. Considering the water sensitivity of shale, the water drilling method cannot be used for rock sample processing in the laboratory. After the drilling cores are frozen for more than 2 hours, the rock samples can be drilled down by using liquid nitrogen to cool the drill bit. During the rock sample processing, the room is set with a certain humidity and the processing time is also shortened as much as possible for reducing the water evaporation of rock samples. The processing time is controlled within half an hour. The initial water saturation has a significant impact on the shale hydration effect, and the humidity control of the rock sample is set with reference to the initial water content. The initial water saturation is determined according to the following steps: (1) measuring the length and diameter of the rock sample, (2) placing the sample in an oven at 105°C for 48 hours, (3) obtaining the water-containing volume according to the mass difference of the rock sample before and after drying, and (4) calculating the water saturation by dividing the water-containing volume to the pore volume of the rock sample.

The triaxial compression mechanical properties of the original rock were tested from the Shahejie Formation of W-82 well, and the stress-strain curves are shown in Figure 4. The elastic modulus of shale is 18.27~23.59 GPa, the Poisson's ratio is 0.12~0.23, the cohesive force is 24.14 MPa, and the internal friction angle is 21.7°. In addition, the Brazilian splitting experiments were carried out on five samples and the tensile strength of shale is 1.13~6.09 MPa with the average value of 4.41 MPa.

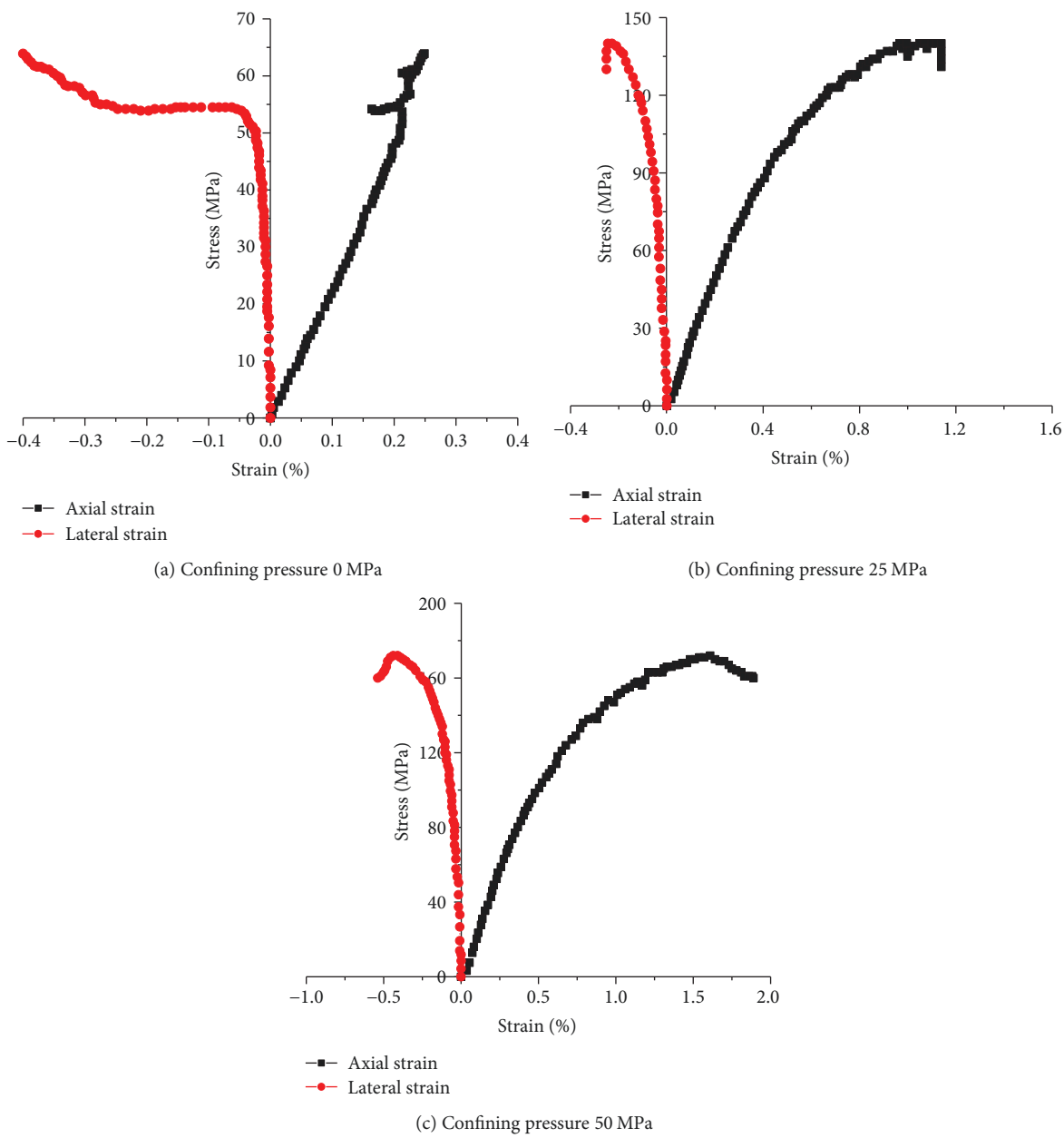


Figure 4: Triaxial test results of original rock in the W-82 well (depth 4150 m).

Brittleness is an inherent mechanical property of rock, which is controlled by rock composition, structure, confining pressure, temperature, and other factors. At present, rock mineral composition and elastic parameters are two widely used evaluation indexes for rock brittleness in the petroleum engineering field. Based on the brittleness evaluation of rock mineral components, the brittleness evaluation results of shale of brittle minerals are as follows: the brittleness index of shale in well W-82 is 0.664, that of shale in well W-96 is 0.809, and that of shale in well W-81 is 0.569.

Rickman et al. [20] thought that the larger the Young's modulus and the smaller the Poisson's ratio, the greater the brittleness of shale. The two parameters can be used to characterize the brittleness of shale. According to the results of triaxial compression tests, the brittleness index of core #1 (confining pressure 0 MPa) is 0.424, that of core #2 (confining pressure 25 MPa) is 0.367, and that of core 3# (confining pressure 50 MPa) is 0.326.

Through the analysis of rock mechanical properties, the shale failure mode is mainly brittle under the condition of triaxial compression. The brittle mineral content is higher, the elastic modulus is relatively higher, and Poisson's ratio is relatively low, indicating that the shale in this formation exhibits high brittleness.

3.2. Effect of Drilling Fluid Action on Mechanical Properties of Shale. To evaluate the change of mechanical properties of shale under the action of drilling fluid and provide a basis for the evaluation of drilling fluid to maintain rock strength performance, the mechanical properties of shale have been

tested under the action of drilling fluid. The fluid for the immersion tests is water-based KCl filming drilling mud.

Hardness is a parameter reflecting the ability of rock to resist tool invasion and failure. The shape requirement of the rock sample for the indentation hardness test is lower than that of the triaxial compression test and direct shear test, which is convenient for a large number of tests. Due to the difficulty to obtain the drilling cores of shale and the limited samples used for triaxial tests, the influence of drilling fluid on the mechanical properties of shale was tested by the hardness testing method.

The change characteristics of the strength of shale can be described by testing the hardness of shale immersed in drilling fluid at different immersion time. Three groups of shale hardness tests were carried out at the same location under original condition, immersed drilling fluid for 6 hours and 12 hours. The test results are shown in Figure 5. It can be seen that the shale hardness decreases gradually with the increase of immersion time. The reduction of shale hardness under drilling fluid immersion indicates that the influence of drilling fluid on shale strength cannot be neglected.

Due to the shortage of drilling cores, the shale samples of the same layer in the adjacent area were tested. The results show that the integrity of shale samples is destroyed during the immersion process and macrocracks are found. Some samples are broken into fragments, and the degree of hydration is serious. Uniaxial and triaxial compression tests of shale samples immersed in drilling fluid for 0 hour (original rock), 6 hours, and 12 hours were carried out. The test results are shown in Table 3. It can be seen that the mechanical strength of hard brittle shale decreases gradually with immersion time in drilling fluid under the same confining pressure. After 6 hours of drilling fluid immersion, the strength of shale decreased by 16.32% on average and the strength decreased by 23.10% on average after immersion for 12 hours.

From the above analysis of experimental results, the main factors that lead to wellbore instability during the drilling process in hard brittle shale can be summarized as follows:

(1) Shale has high clay mineral content, and the content of illite/montmorillonite mixed layer is well developed. As a mineral between expansive clay and non-expansive clay, the illite/montmorillonite mixed layer is easy to absorb water and cause nonuniform hydration expansion. The cation exchange tests also prove that the shale is prone to hydration reaction and its structural strength is weakened by the external fluid

(2) Microcracks and microholes in shale of the Shahejie Formation are well developed, which provide a flow channel and hydration space for external fluid, resulting in a decrease of shale strength and an increase for the wellbore failure risk

(3) The brittleness of the Shahejie Formation is relatively strong. Stress release or unloading, wellbore pressure fluctuation, low drilling rate, and long immersion time during the drilling process are more likely to lead to wellbore cracks that provide a channel for drilling fluid and aggravate wellbore instability

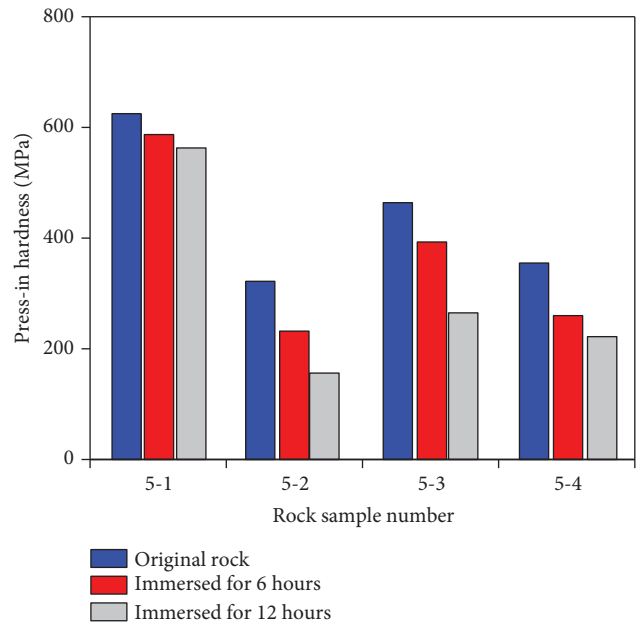


Figure 5: Hardness change with drilling fluid immersion.

For modelling of the time-dependent wellbore failure process in a shale formation, the diffusion and seepage of drilling fluid in the shale formation and its strength weakening behavior should be taken into account [21].

4. Coupled Hydraulic-Mechanical-Chemical (HMC) Model of Shale

According to the governing equation of chemical-pore-elastic mechanics and elastic-plastic constitutive relation, a coupled HMC model describing time-dependent wellbore failure of shale is established. It is assumed that plastic deformation mainly affects the mechanical balance of rock.

4.1. Navier Equation for Displacement. According to Biot's theory, the porous media is assumed to consist of an elastic porous solid matrix, in which pore space is saturated by fluids containing many chemicals. Assuming that the chemical potential expansion coefficients of diluent and solute in solution are the same as those of ω_0, the Navier-type equation for displacement is derived by using momentum balance equation:

$$\left(K+\frac{G}{3}\right)\nabla(\nabla\mathbf{u})+G\nabla^2\mathbf{u}-\alpha\nabla p-\omega_0\left(1-\frac{\rho_s}{\rho_D}\right)\nabla C=0, \quad (1)$$

where K and G are bulk modulus and shear moduli, respectively, $\mathbf{u}$ is rock displacement, α is Biot's coefficient, p is pore pressure, C is the solute mass fraction, and ρ_s and ρ_D are the densities of solute and diluent, respectively.

4.2. Pressure Diffusion and Solute Transport in Shale. When drilling fluid enters the shale formation, the chemical potential difference and hydraulic pressure difference between

Table 3: Strength changes of shale under drilling fluid immersion.

Sample	Immersion time (h)	Confining pressure (MPa)	Compressive strength (MPa)	Cohesion (MPa)	Internal friction angle (°)
1	0	0	30.80	9.83	24.89
2		50	153.46		
3	6	0	23.79	7.86	23.09
4		50	138.30		
5	12	0	21.48	7.32	21.42
6		50	129.00		

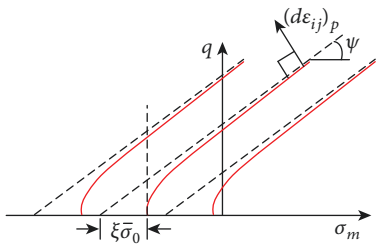


Figure 6: A family of flow potentials in the meridional stress plane.

formation fluid and drilling fluid lead to the redistribution of formation pore pressure. Considering that shale has the semi-membraneous properties in drilling fluid and ignoring the effect of solid deformation on fluid flow, the coupled fluid diffusion equation is given [22, 23]:

$$\frac{k}{\eta C' n}\nabla^2 p + I_m \frac{RT}{V} \ln \frac{1}{C_{\text{shale}}} \frac{\partial C}{\partial t} = \frac{\partial p}{\partial t}, \tag{2}$$

where k is permeability, η is the fluid viscosity, C' is the fluid compressibility, n is the porosity, I_m is membrane efficiency, R is the universal gas constant, T is temperature, V is molar volume, and C_{shale} is the initial mass fraction in shale formation.

The conservation of solutes in rocks produces the following equation for solute transfer:

$$n\dot{C} - D\nabla^2 C = 0, \tag{3}$$

where D is the solute diffusion coefficient.

4.3. Elastoplastic Constitutive Relation. It is assumed that the saturated porous medium exhibits a partial elastic and partially plastic manner after undergoing initial yielding. Therefore, the strain change caused by the stress increment can be divided into elastic and plastic components:

$$d\varepsilon_{ij} = \left(d\varepsilon_{ij}\right)_e + \left(d\varepsilon_{ij}\right)_p. \tag{4}$$

Assuming that the plastic strain increment is proportional to the stress gradient, it can be defined by plastic potential G:

$$\left(d\varepsilon_{ij}\right)_p = d\lambda \frac{\partial G}{\partial \sigma_{ij}}, \tag{5}$$

where $d\lambda$ is proportionality constant and called the plastic multiplier.

To ensure that the plastic flow direction is defined uniquely, the flow potential is chosen as a continuous and smooth function, which is a von Mises circle in the deviatoric stress plane. The potential function asymptotically approaches the linear Drucker-Prager flow potential at high confining pressure stress and intersects the hydrostatic pressure axis at 90°. A family of flow potentials in the meridional stress plane is shown in Figure 6. The plastic potential G is defined as follows:

$$G = \sqrt{(\xi\bar{\sigma}_0 \tan\psi)^2 + q^2} - \sigma_m \tan\psi, \tag{6}$$

where ξ is the model parameter $\xi = 0.1$, $\bar{\sigma}_0$ is initial yield stress, σ_m is the confining pressure, q is Mises stress, and ψ is the dilation angle of the rock.

The general form of the plastic yield function can be given by

$$F\left(\sigma_{ij}, \kappa'\right) = 0, \tag{7}$$

where κ' is the hardening parameter, which is influenced by the hydration effect.

The Drucker-Pracker yield criterion has been widely used in the problem of wellbore stability in shale formations to describe the elastoplastic behavior of shale [24–28]. In this study, the elastoplastic calculation is performed using the Drucker-Prager criterion. A modified Drucker-Prager yield criterion can be expressed as follows [29]:

$$F = \sqrt{{l_0}^2 + q^2} - \sigma_m \tan\varphi - c, \tag{8}$$

where c is cohesion, φ is the friction angle of the rock, $l_0 = c_0 - \sigma_t$, c_0 is initial cohesion, and σ_t is tensile strength.

4.4. Strength Weakening Model of Shale. Rock strength varies with the water content of shale formation. According to the above test results, the strength can be assumed to be approximately linear attenuation with the water content. The strength weakening model of shale can be defined as [22]

$$\begin{cases} c = c_0 - K_s(w - w_0), \\ \varphi = \varphi_0 - L_s(w - w_0), \end{cases} \tag{9}$$

where c_0 and φ_0 are the cohesion and friction angle, respectively, at the initial water content w_0, K_s is cohesion coefficient, and L_s is friction angle coefficient.

According to mass conservation equation, the diffusion equation of water can be defined as [30]

$$C_f\left(\frac{\partial^2 w}{\partial x^2}+\frac{\partial^2 w}{\partial y^2}\right)=\frac{\partial w}{\partial t}, \tag{10}$$

where C_f is water absorption diffusion coefficient of shale.

4.5. Permeability Evolution of Shale. Assuming that elastic deformation of shale cannot causes damage, plastic deformation and damage occur simultaneously. After yielding failure of shale, the internal pore and fracture in rock gradually germinate and penetrate each other and the permeability of shale increases obviously. In the study of wellbore stability, permeability is often considered as constant in most previous studies. However, in fact, permeability around the wellbore varies during drilling excavation.

According the equation of Kozeny-Carman, the permeability and porosity evolution of shale can be defined as

$$\begin{cases} k=k_0\left[\left(\frac{1}{n_0}\right)(1+\varepsilon_v)^{2/3}-\left(\frac{1-n_0}{n_0}\right)(1+\varepsilon_v)^{-1/3}\right]^3, \\ n=1-\frac{1-n_0}{\varepsilon_v+1}, \end{cases} \tag{11}$$

where k_0 is the initial permeability of shale, n_0 is the initial porosity, and ε_v is the volumetric strain.

4.6. Solution Strategy. Based on the above analysis, the decoupled numerical method is adopted to solve the coupled HMC model of shale. Due to the relative independence of solute transport equation and mass conservation equation, they can be solved first. Then the pressure transfer model and the solid deformation can be solved synergistically. The HMC model of shale involves two calculation modules embedded in ABAQUS software, namely, the rock consolidation module and the mass diffusion module.

Although the HM coupling field and mass diffusion field of rock are different, they essentially contain two basic contents: linearization and time step discretization (or load increment). The calculation of the HM field and diffusion field can be designed separately by two independent systems. By means of data communication, the coupling of parameters at each time step can be realized and the related coefficients can be continuously revised at each time step and the mutual correction is carried out at a series of time steps. Based on the previous research on the THM coupling method [31], using MATLAB as the platform and ABAQUS as the solver, the analysis software for modelling time-dependent wellbore collapse in shale formation is developed. The data storage and communication between different calculation modules are realized by ABQMAIN subroutine, and strength weakening and permeability evolution are realized by USDFLD subroutine.

In multifield coupled analysis, the models for mass diffusion analysis and HM analysis require the same meshes, analysis steps, initial time increment, and time period for data communication. The ABAQUS has the interpolation capability to obtain the nodal quantities at a given time. This coupled problem is solved through a "staggered solution technique" as shown in Figure 7 and as follows:

(1) First, a water content analysis is performed using the mass diffusion module in ABAQUS, where water absorption diffusion coefficient of shale is assumed to be constant. Water content histories are written onto an external file used in step 3

(2) The solute mass fraction analysis is performed through the second mass diffusion module in ABAQUS where the solute diffusion coefficient is assumed to be constant and the porosity is changed with time. In the first cycling analysis, the porosity is assumed to be constant, and in the subsequent analysis, it is read from an external file. Solute mass fraction histories are written onto an external file used in step 3

(3) The water content and solute mass fraction histories are used by the rock consolidation module in ABAQUS, in which the rock strength is performed as a function of water content and permeability evolution is the function of volumetric strain by USDFLD subroutine. The HM model calculates stresses, pore pressure, porosity, etc. as function of time. The porosity histories are written onto an external file used in step 2

(4) The ABQMAIN subroutine reads the files with solute mass fraction, water content, and porosity data and creates new files containing histories of solute mass fraction, water content, and porosity. The porosity histories are used by the solute mass fraction model in subsequent analysis

Steps 2-4 are repeated if the material parameter values are found to be different compared to those of the previous solution.

The USDFLD subroutine is used to redefine the field variable at the material integration point and also to obtain information at the material integration point. Under the conditions of hydration, the mechanical parameters of the rock are affected by the water content and change with the water content. Similarly, the permeability and porosity are influenced by the change of volumetric strain. Here, the water content and volumetric strain can be defined as the field variables, so that the mutual calling between the subroutines and the related module are realized.

5. Application

5.1. Project Overview. The W lithologic trap of Nanpu sag is an important exploration area in the Jidong oilfield in China,

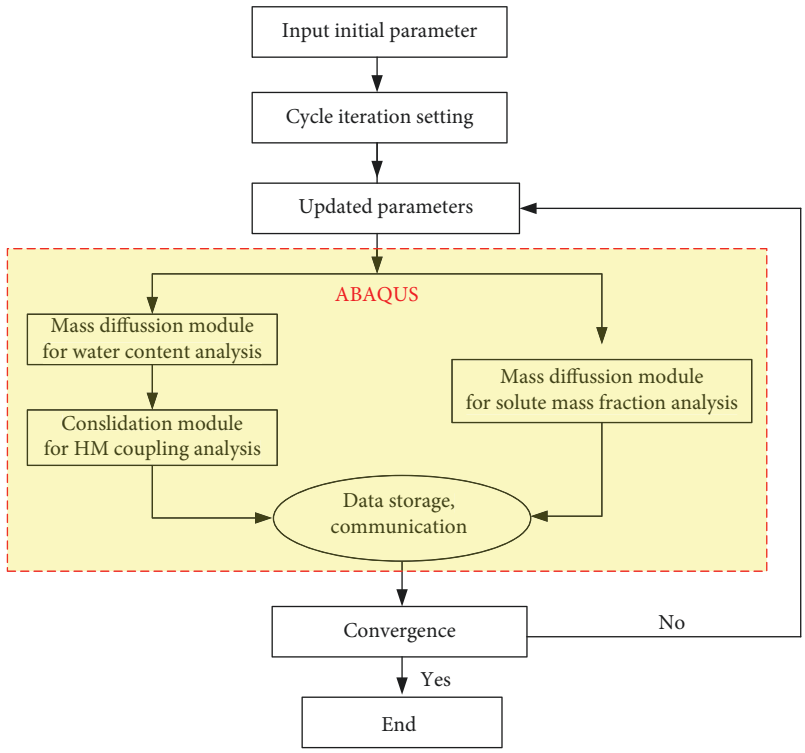


Figure 7: Flowchart of the multifield coupling implementation.

Table 4: Pressure tests of the Shahejie Formation.

Layer	Formation pressure coefficient	Collapse pressure coefficient	Fracture pressure coefficient
Es1	1.31	1.32	1.8
Es2, Es3	1.30	1.33	1.93

which is located in the west of Huanghua Depression in the Bohai Bay Basin. The drilled formations are the Paleogene Shahejie Formation, Dongying Formation, Neogene Guantao Formation, Minghuazhen Formation, and Quaternary Plain Formation from bottom to top. The area, thickness, and closure range of the W trap are 356km^2, 840 m and 1000 m, respectively. The first number of the Shahejie Formation develops a large set of shale as caprock for lithologic reservoirs.

According to the drilling well history, drilling fluid, and well completion data, statistical analysis on drilling complex accidents was done on 20 drilled wells in the W trap. The result shows that the most prominent accident is leakage, followed by borehole wall caving and collapse, and the leakage accident occurs about four times more than the latter. The fracture pressure coefficient in shale target formation is more than 1.8 (Table 4). The maximum equivalent density of drilling fluid used in complex formation is 1.6. Combined with drilling core observation and imaging logs, the fractures are relatively well developed around the wellbore for leakage accidents. Increasing the density of drilling fluid is not ideal for inhibiting wellbore collapse and diameter enlargement. For some wells, the wellbore diameter increases instead when the drilling fluid density increases from 1.23 to 1.39.

The hard brittle shale of the Shahejie Formation has microcracks and some microholes, which provide a channel for drilling fluid to invade. The presence of developed cracks and hydration effect make the leakage problem using the conventional drilling method more serious. Therefore, the implementation of an underbalanced drilling method is an effective way to improve the reservoir protection and prevent drilling fluid leakage. The formation pressure coefficient of the Shahejie Formation is higher than 1.3 (Table 4), and then the liquid-based drilling fluid system is selected for the underbalanced circulation medium. Taking W-82 well as the research object, the dynamic damage law of wellbore under the condition of underbalanced drilling is studied. The total depth of W-82 is 4745 m, and the underbalanced drilling footage is 598.07 m from 4146.93 m to 4745 m in the Shahejie Formation.

5.2. Computational Condition. According to the symmetry of the wellbore, one-quarter of the wellbore is used for modeling analysis, which is shown in Figure 8. To simulate the drilling unloading, the element removing technique is used to deal with the excavated part of the wellbore. The radius of the wellbore is 0.108 m, and the length and width of the calculation model are set as 15 m to reduce the pore pressure influence of the wellbore on the outside of the model. The plane strain quadrilateral element is used to discretize the model, the total number of grids is 1993, and the total number of nodes is 2087. The divided grid is shown in Figure 9.

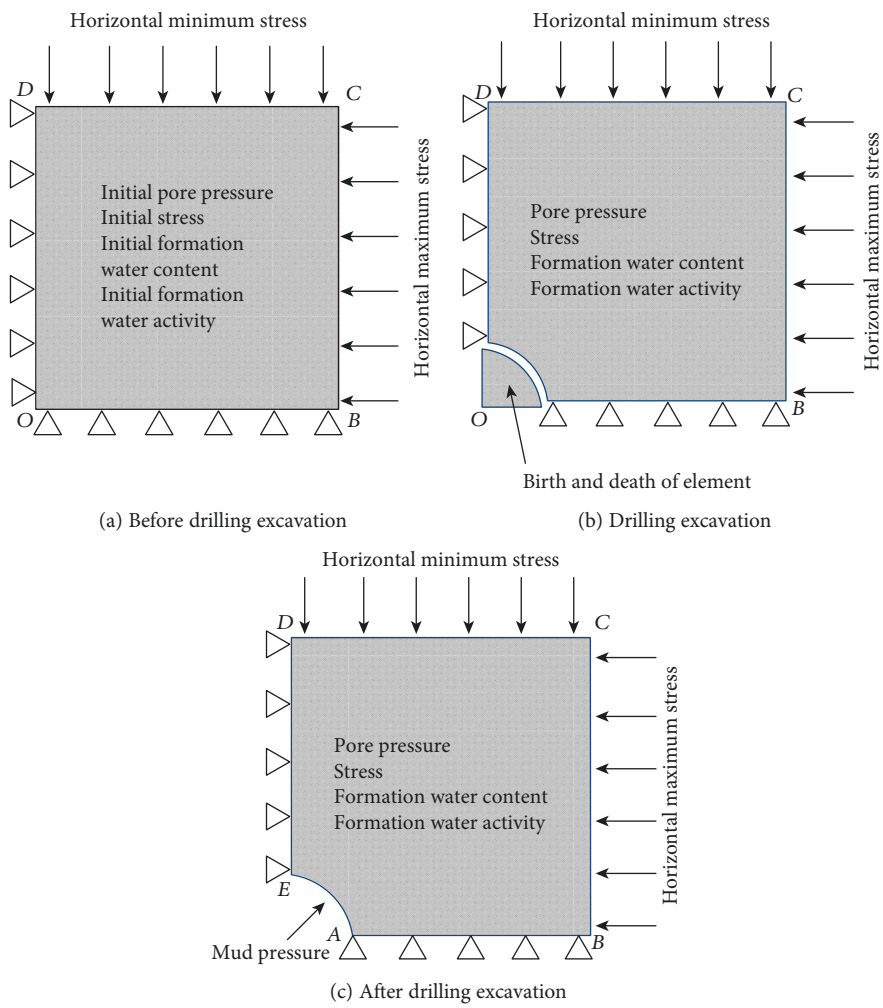


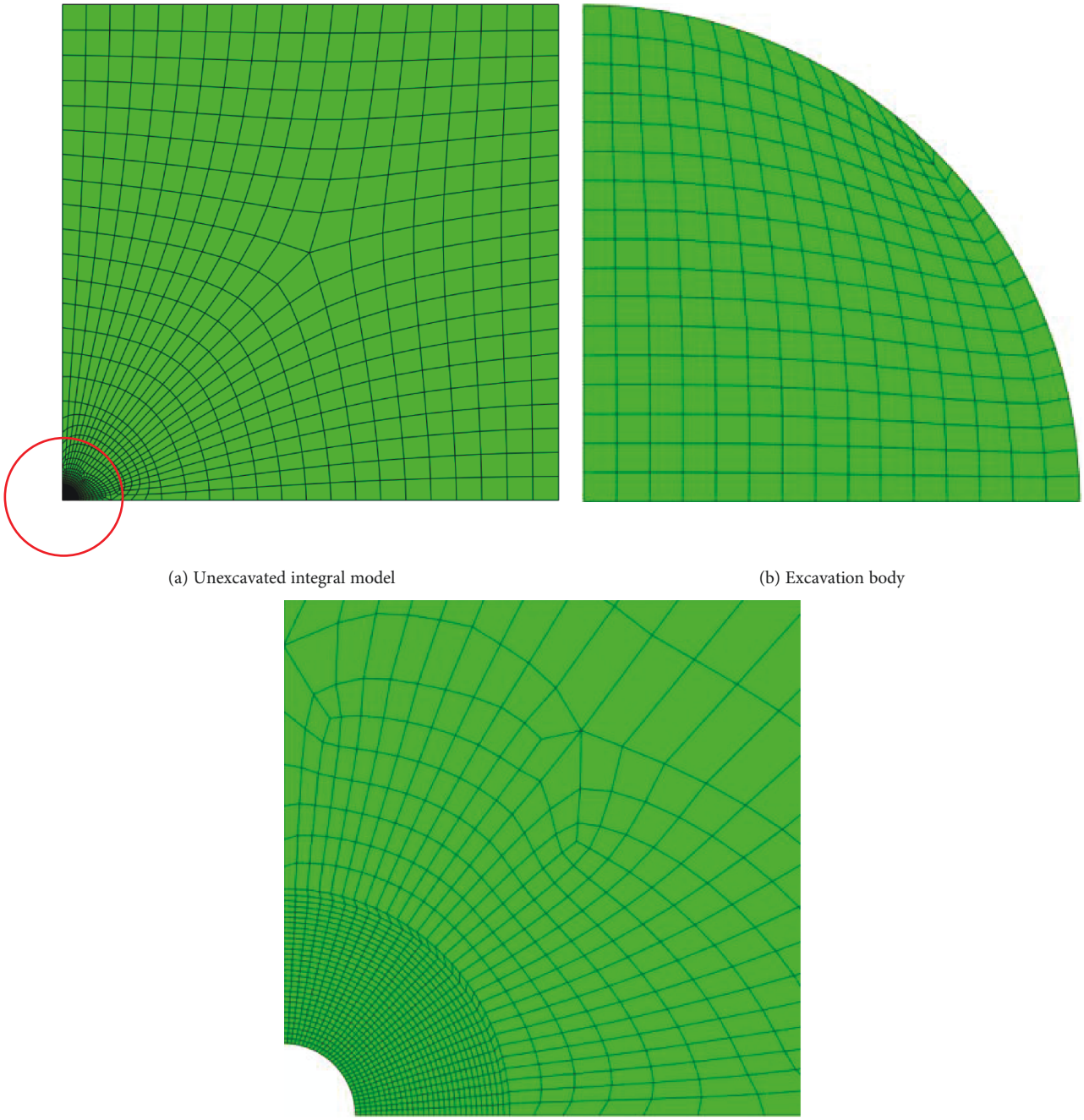
Figure 8: Schematic diagram of the calculation model.

Initial pore pressure, initial stress, initial water content, and initial water activity are defined inside the shale formation. For the mechanical boundary conditions, OB and OD are set as normal constraint conditions, the maximum horizontal earth stress is applied on the BC side, and the minimum horizontal earth stress is applied on the CD side. After drilling excavation, the AE side is applied as mud pressure, water content condition, drilling fluid activity condition, and seepage condition.

The analysis steps that simulate the progressive failure process of the wellbore are defined as follows: the first step is in situ stress balance, which is to restore the initial stress field, i.e., the stress state before drilling excavation. By defining the inside stress field and outside boundaries of the model, the initial in situ stress field can meet the requirements of calculation. The second step is the drilling excavation by the technique of element removing. In this step, the shale formation is excavated firstly, and then the wall of the wellbore is applied mud pressure. Due to relatively short drilling excavation, the wall of the wellbore is considered as impermeable. The third step is the seepage and diffusion stage to simulate the seepage and diffusion effect inside and outside the wellbore. In this step, the wall of the wellbore is considered as permeable for a longer period. The strength of the surrounding rock of the wellbore is weakened by hydration effect, and the wellbore failure process is simulated in 53 days.

According to laboratory tests, field data, logs, and related geological data of adjacent areas, the calculation parameters at the depth of 4250 m in the Shahejie Formation are defined as follows: overburden pressure at 91.63 MPa, maximum horizontal principal stress at 81.22 MPa, minimum horizontal principal stress at 68.72 MPa, and formation pressure coefficient at 1.3; elastic modulus of shale at 20.2 GPa, Poisson's ratio at 0.16, cohesion at 24.1 MPa, internal friction angle at 21.7°, equivalent permeability at 1.01 mD, and the porosity at 9%; initial formation water content at 2% and saturated water content at 10%; K_s at 2.71 MPa and L_s at 2.50°; and activity diffusion coefficient at 5×10^{-9} m^2/s and formation water absorption diffusion coefficient at 9.5×10^{-9} m^2/s.

5.3. Progressive Failure Process of the Wellbore. Taking the drilling fluid equivalent density 1.1 as an example, the



(a) Unexcavated integral model

(b) Excavation body

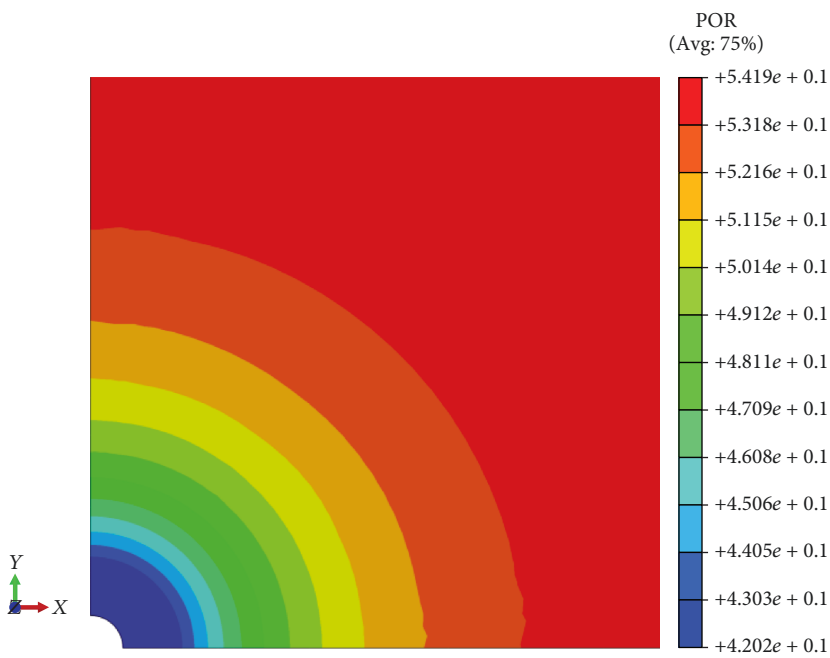
(c) Wellbore local model after excavation

Figure 9: Meshes of the analysis model.

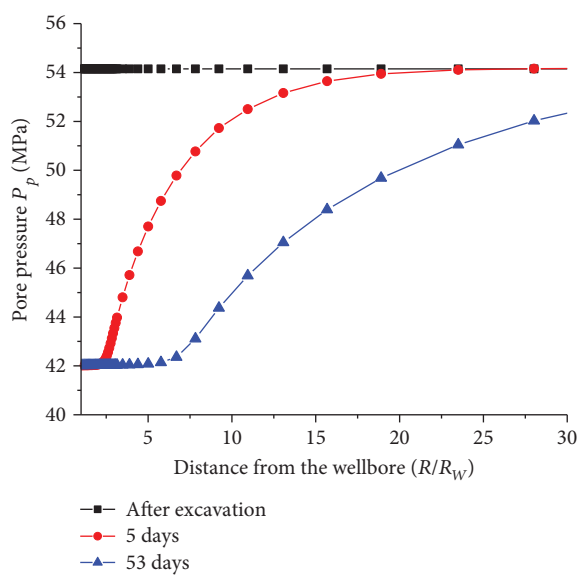
underbalanced drilling method is used to open the shale formation. The above calculation model is simulated to investigate the progressive collapse and failure process of the wellbore considering the influence of the seepage and hydration diffusion in shale by drilling fluid.

Figure 10 shows the pore pressure distribution after drilling excavation. It can be found that the pore pressure gradually increases with the distance from the wellbore wall and tends to the initial pore pressure value. The change rate of pore pressure decreases gradually with drilling time increasing. The disturbed zone of the seepage field is about 20 times of the wellbore radius after 5 days and 55 times after 53 days of drilling excavation.

Figure 11 presents the distribution of water content after the formation was drilled. The water content gradually decreases with the increase of the distance from the wellbore wall and tends to the minimum value of 2%. In the early stage after the formation was drilled, the water content changes sharply and fluctuates to a certain extent. After that, the change rate of the water content



(a) 5 d



(b) Change along the radial direction

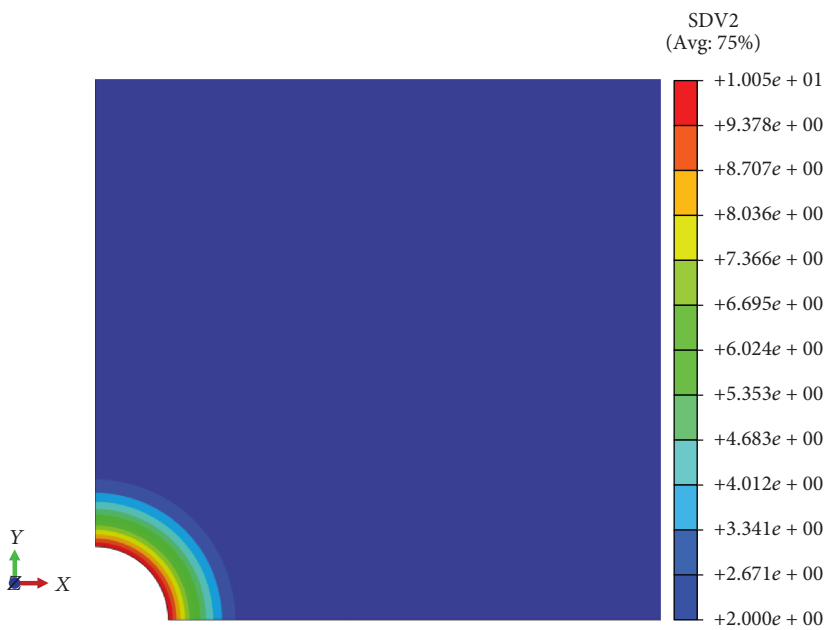
Figure 10: Pore pressure distribution of the wellbore after drilling.

decreased with the increase of the immersion time by drilling fluid.

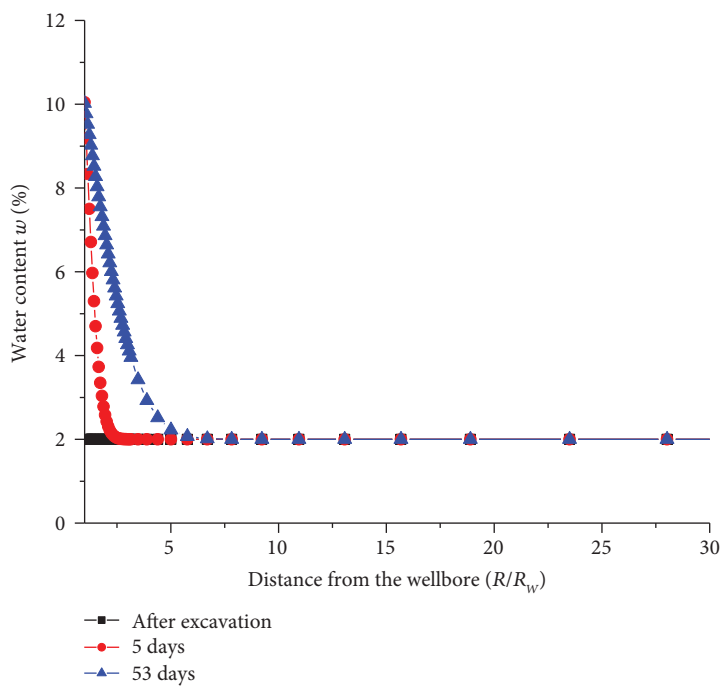
The cohesion and internal friction angle of shale are changed by water content evolution. The distribution and variation laws of cohesion and internal friction angle are similar to that of the water content, which are shown in Figures 12 and 13.

The progressive failure process of the wellbore is shown in Figures 14 and 15. It can be found that the extent and scope of wellbore collapse in the y direction (ED line, shown in Figure 8(c)) are obviously larger than those in the x direction (AB line) and the damaged zone is basically elliptical, which is consistent with the field imaging logs. The collapse scope increases with immersion time. The maximum plastic strain is 0.52% after drilling excavation, while the maximum plastic strain is 0.81% after 5 days of drilling excavation.

For the depth of wellbore collapse (as shown in Figure 16), the damaged zone increased rapidly and then tends to be stable and increases linearly by the influence of hydration effect. Therefore, the hydration effect of shale in the Shahejie Formation is very obvious and the wellbore collapse is a time-dependent progressive failure process.



(a) 5 d



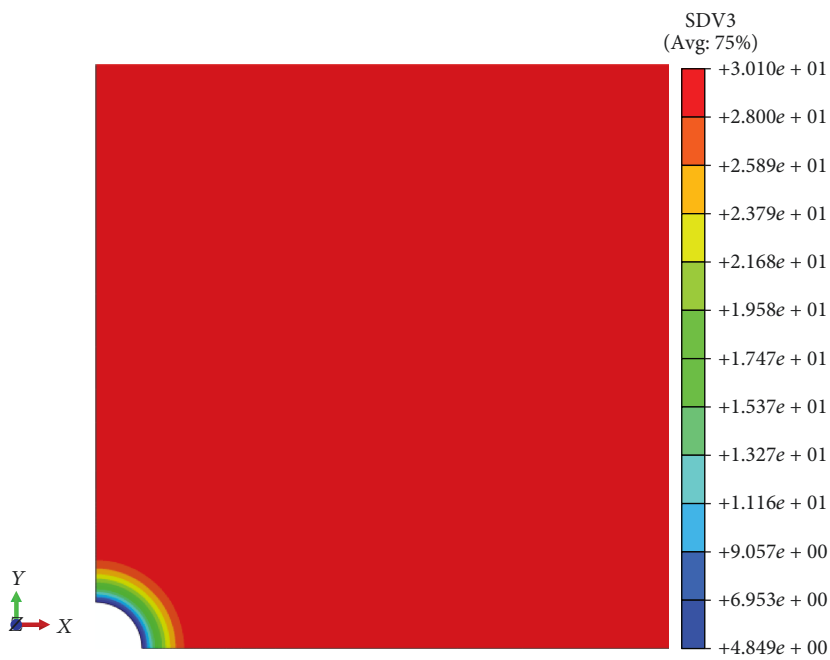
(b) Change along the radial direction

Figure 11: Water content distribution of wellbore after drilling.

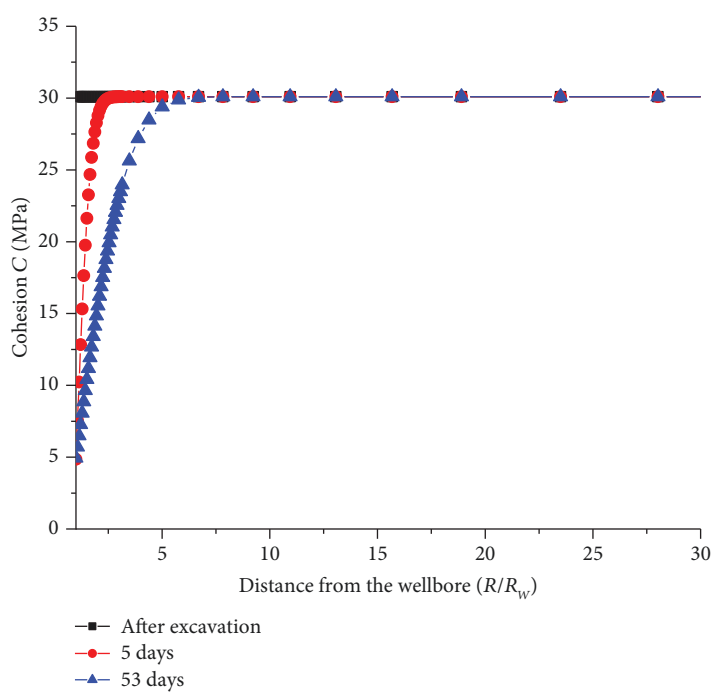
5.4. Parametric Study. By obtaining the plastic zone range corresponding to AB and ED at different time, and taking its average value as the borehole enlargement value, the ratio of the borehole enlargement value to the outer diameter of the drilling bit is defined as the wellbore enlargement rate. Through numerical analysis, the collapse period chart under different influence parameters can be established for shale formation.

Figure 17 shows the wellbore enlargement rate varying with time under different drilling fluid densities. The wellbore enlargement rate increases with the drilling fluid immersion time and the wellbore enlargement rate decrease with the increase of the drilling fluid density. Taking the drilling fluid density of 1.2 as an example, the wellbore enlargement rate is 18.07% after drilling excavation and 58.22% after 7 days of immersion with an increase of 40%. It can be seen that hydration effect by drilling fluid has a great influence on the progressive collapse of wellbore in shale formation.

Figure 18 presents the variation of the wellbore enlargement rate with time under the influence of water absorption diffusion



(a) 5 d

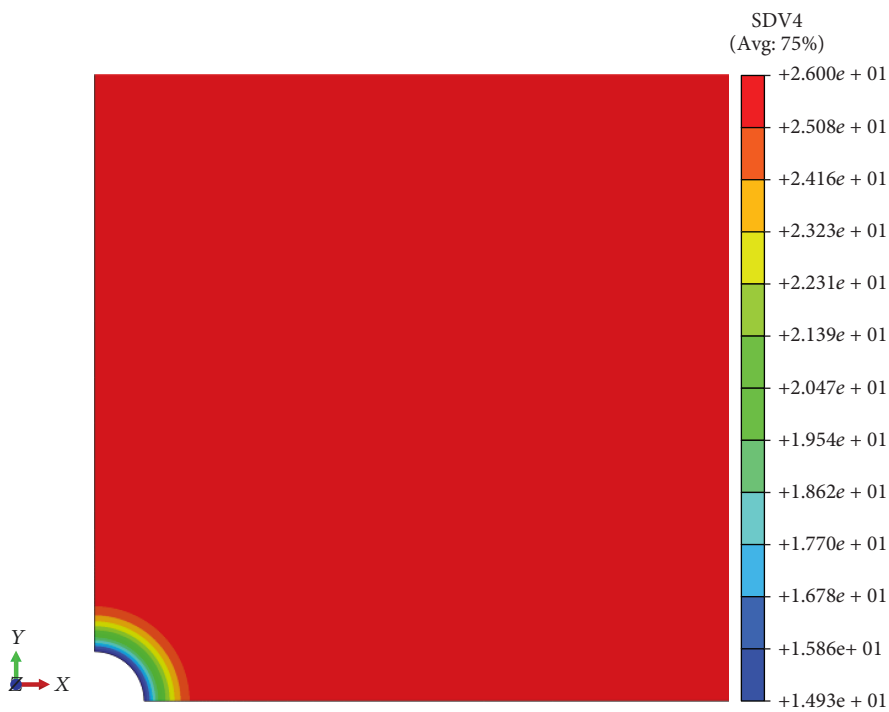


(b) Change along the radial direction

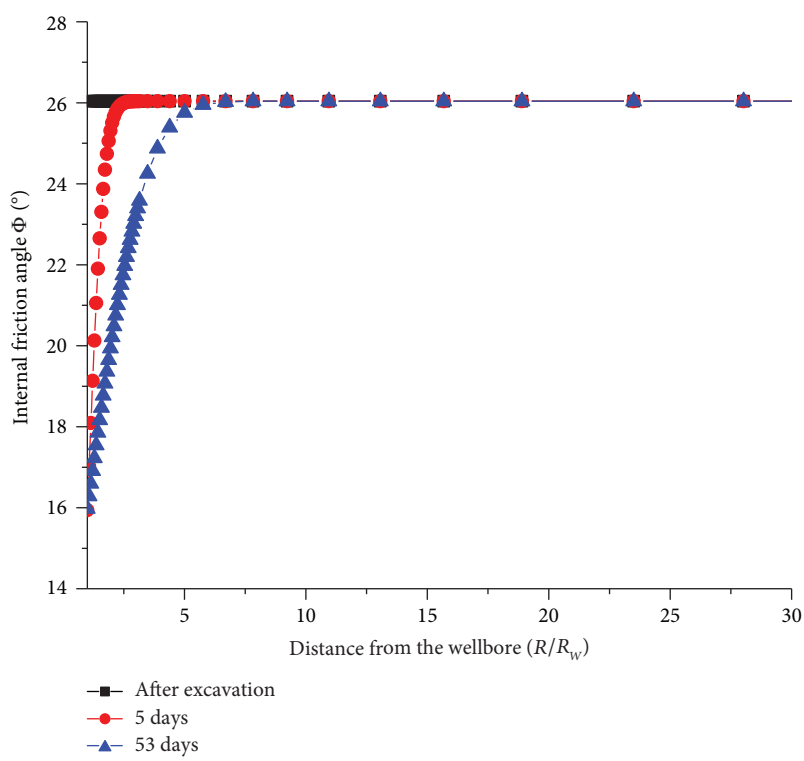
Figure 12: Variation of formation cohesion after drilling.

coefficient. When the water absorption diffusion coefficient is 5.0×10^{-10} m^2/s, the wellbore enlargement rate increases from 18.07% to 47.18% in 53 days. The wellbore enlargement rate is 117.16% after 53 days of drilling fluid immersion for the water absorption diffusion coefficient of 1.4×10^{-8} m^2/s. The water absorption diffusion coefficient has a very large influence on the wellbore collapse, and the larger the water absorption diffusion coefficient, the more obvious the collapse. The water absorption diffusion coefficient is a parameter that characterizes the transfer velocity of water in shale formation, which determines the ability of shale to absorb water and affects the hydration effect.

The inflow and outflow of formation water are affected by the drilling fluid activity. The drilling fluid activity affects the activity of formation water, thus affecting the hydration effect of shale. Figure 19 shows the wellbore enlargement rate with time under different drilling fluid activities. The original activity of formation water is 0.7, while the wellbore collapse does not



(a) 5 d

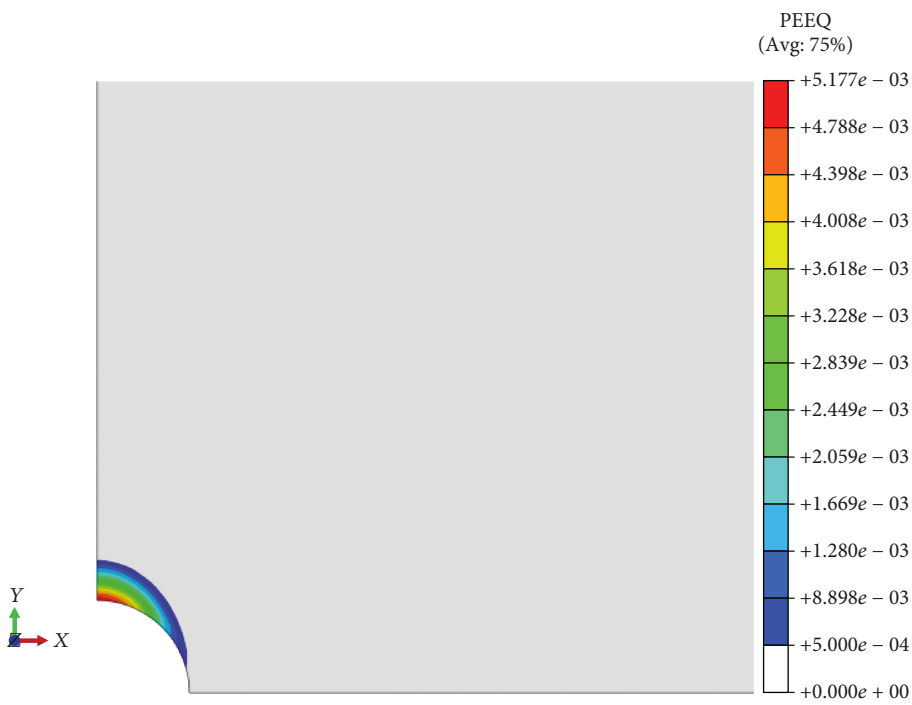


(b) Change along the radial direction

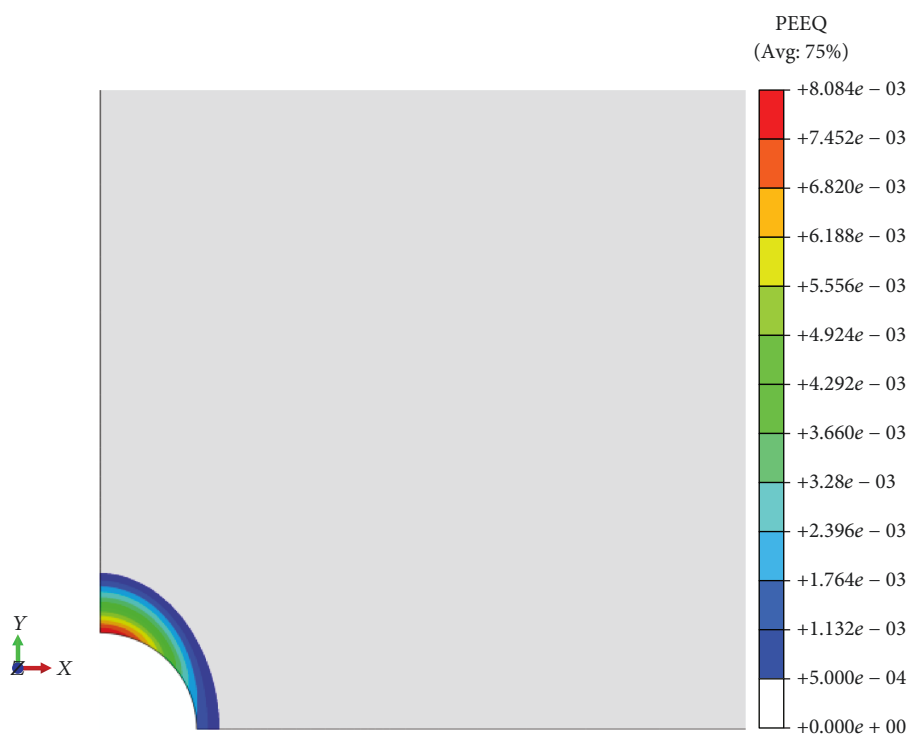
Figure 13: Variation of the friction angle of the formation after drilling.

change with time for the drilling fluid activity less than 0.7. When the drilling fluid activity is greater than the original activity of formation water, the drilling fluid erodes into the formation, causing the hydration effect obviously. With the increase of immersion time, the wellbore enlargement rate increases. When the drilling fluid activity is 0.95, the wellbore enlargement rate increases from 18.07% after excavation to 210.96% after 53 days.

Figure 20 shows the wellbore enlargement rate varying with time under different permeabilities of shale. It



(a) Equivalent plastic strain distribution after excavation

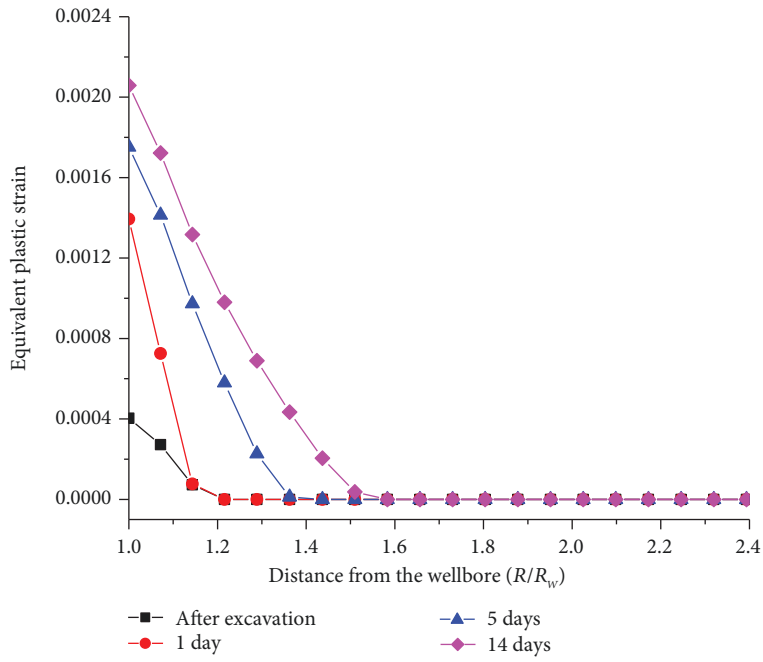


(b) Equivalent plastic strain distribution after 5 days

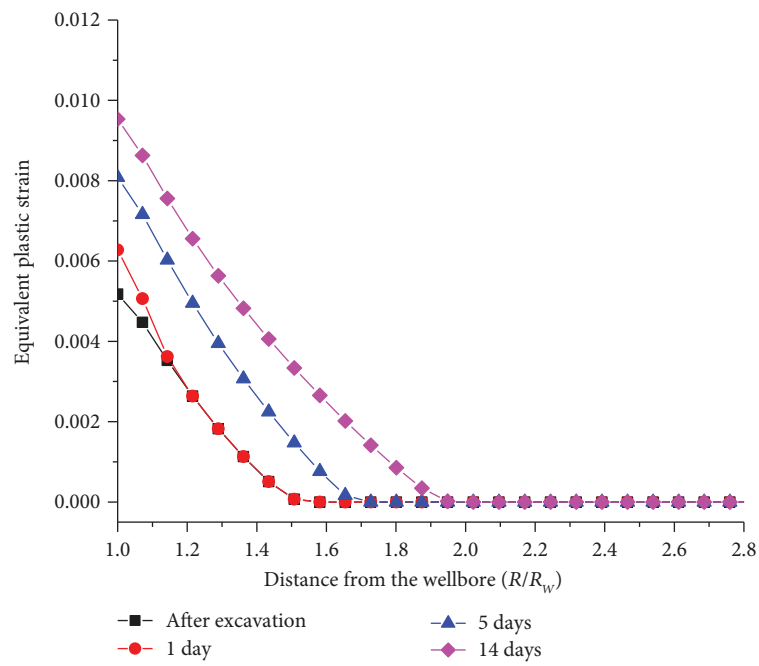
Figure 14: Progressive failure process of the wellbore with a drilling fluid density of 1.1.

can be seen that the influence of permeability on the wellbore enlargement rate is not obvious. However, the overall trend is that the wellbore enlargement rate at a small permeability is slightly smaller than the wellbore enlargement rate at a large permeability. The permeability of shale affects the ability of water to penetrate, but the effect on the wellbore enlargement rate is relatively weak.

According to the above analysis, the effects of different parameters on the wellbore collapse are different. Under underbalanced drilling conditions, drilling excavation disturbances cause the original crack extension and new



(a) AB line



(b) ED line

Figure 15: Equivalent plastic strain along selected lines with a drilling fluid density of 1.1.

microcracks, which causes the shale hydration to expand by the self-water absorption effect of the microcracks. Due to hydration effect, the strength of shale gradually decreases, which is the intrinsic factor that leads to the progressive collapse of the wellbore. For using underbalanced drilling condition in a hard brittle shale formation, the drilling speed should be fast, the strong inhibition of drilling fluid to shale should be strictly controlled, and the circulation time should be minimized.

5.5. Comparison with Field Results. To verify the reliability and accuracy of the coupling model of the wellbore, the numerical results were compared with the field measured data.

In the actual drilling process, the wellbore is allowed to have a certain collapse. There is no drilling accident as long as there is no accumulated rock debris. Generally, the qualified wellbore conditions during drilling are as follows: the average wellbore enlargement rate is not more than 15%, or the maximum wellbore enlargement rate of the oil/gas

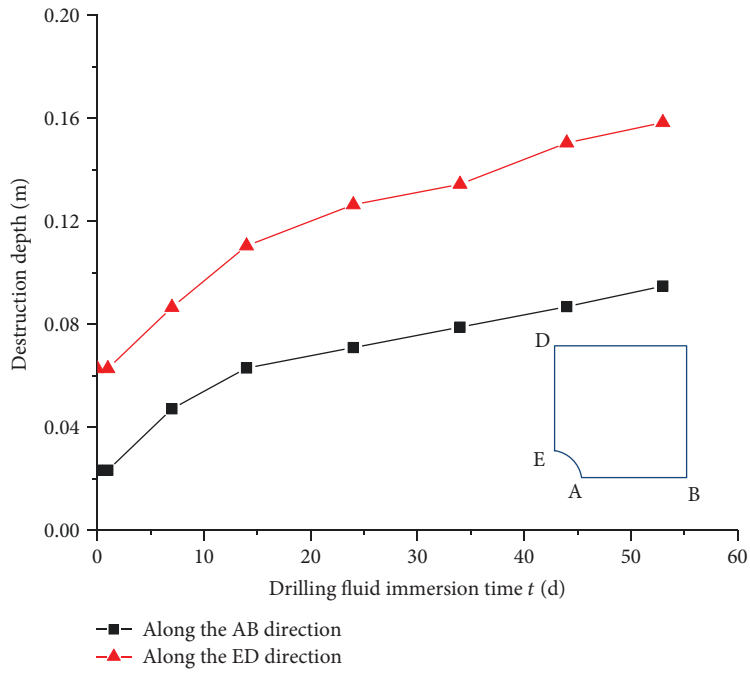


Figure 16: Failure depth change of the wellbore when the drilling fluid density is 1.1.

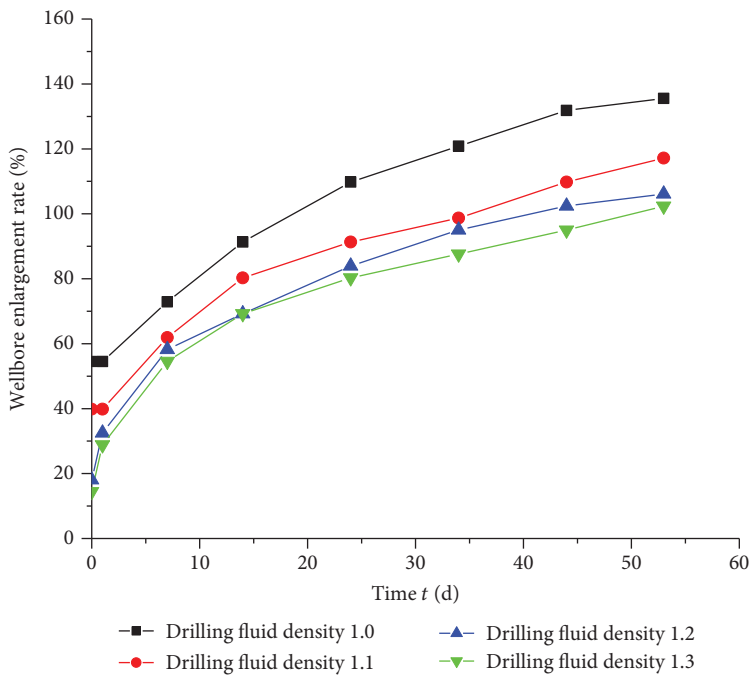


Figure 17: Curves of the wellbore enlargement rate with time under different drilling fluid densities.

reservoir is not more than 30% and the maximum wellbore section accounts for less than 30% of the whole reservoir. For the Shahejie Formation, the density of drilling mud is 1.2 g/cm^3 used for underbalanced drilling condition. During the drilling process, the wellbore is basically stable, only a few slight wellbore collapses occur, and there are no drilling accidents. The wellbore stability condition satisfies the requirements of underbalanced drilling with an average drilling rate of 1.78 m/h. According to the calculation results shown in Figures 18–20, the calculation value of the wellbore enlargement rate is 18% after drilling excavation, which is consistent with the field results.

During the process of water-based underbalanced drilling, the risk of leakage and reservoir damage by drilling fluid is reduced due to the drilling fluid pressure being lower than the formation pressure. However, the existence of capillary force makes the shale absorb water in a countercurrent mode, especially in the microcracks. As a result, the water absorption

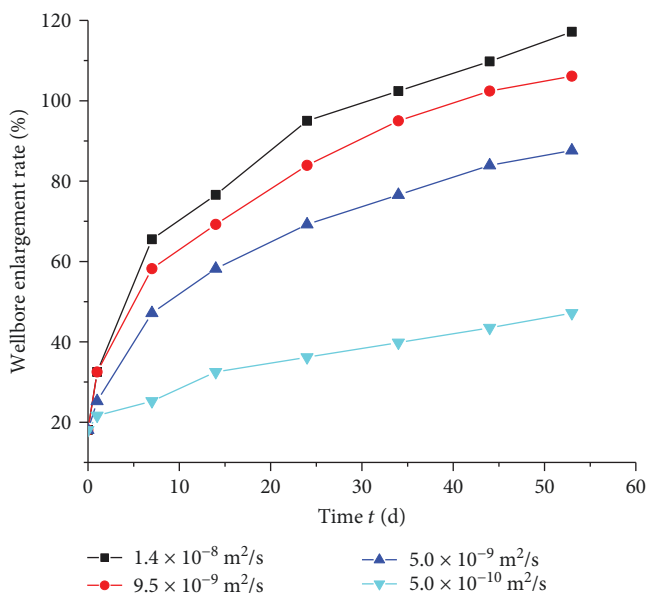


Figure 18: Curve of the wellbore enlargement rate with time under different water absorption and diffusion coefficients.

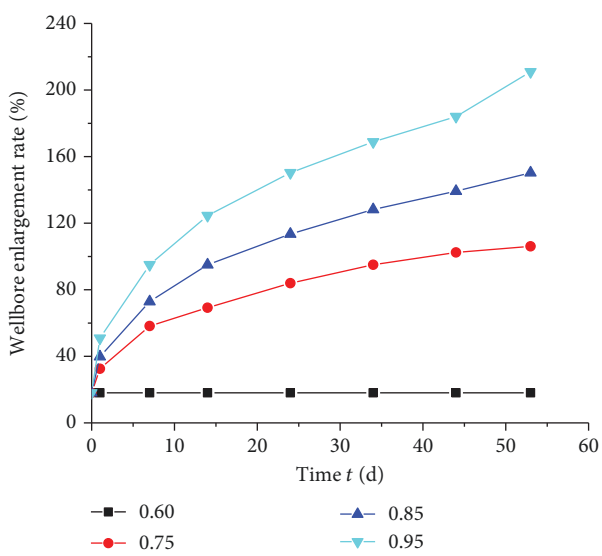


Figure 19: Curve of the wellbore enlargement rate with time under different drilling fluid activities.

causes the shale to be hydrated remarkably. In addition, the wellbore lacks the pressure balance by drilling fluid, which aggravates the wellbore collapse. A large number of falling rock blocks have been returned when pulling the drill string from the hole and starting logging work, and it is difficult to connect the column of the drilling string. Figure 21 shows the well diameter curve of the shale formation in W-82. The wellbore enlargement rate is between 55% and 85% in the depth of 4265 m to 4275 m, and the numerical value of the wellbore enlargement rate is about 84%. Then drill stem testing was carried out, and the wellbore has been immersed by drilling fluid for 53 days from drilling excavation to drilling down through the hole, which causes more rock blocks to be

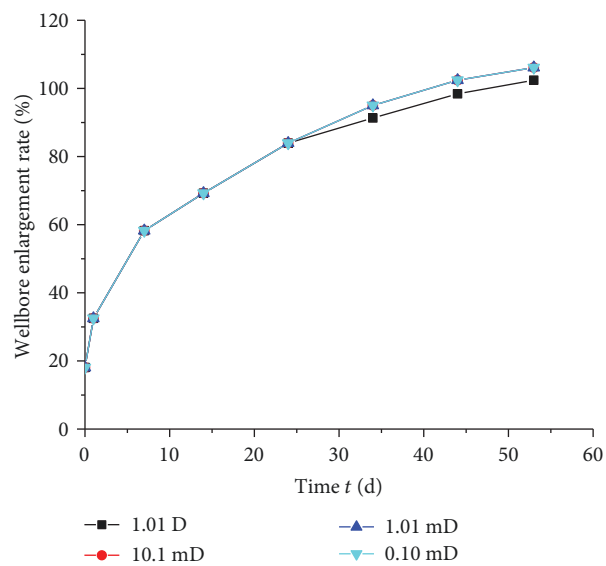


Figure 20: Curve of the wellbore enlargement rate with time under different shale permeabilities.

falling (Figure 22), formation instability, and wellbore collapse. The predicted wellbore enlargement rate in this paper has exceeded 100%, and the wellbore collapse is serious, which basically coincides with the actual drilling. The proposed model in this study can effectively reflect the progressive failure process of the wellbore in shale formation.

6. Conclusions

The microcracks of hard brittle shale in the mid-depth formation are well developed, the content of illite/montmorillonite mineral and illite in the formation is higher, and the shale is easy to be self-water hydration expanded, which is the root cause for wellbore instability during drilling. To simulate the whole process of progressive failure of hard brittle shale, a HMC model is developed, which is compiled with ABAQUS software as the solver.

In the initial stage of underbalanced drilling, there is no instability problem in the wellbore. As the immersion time increases, the wellbore gradually becomes unstable. Due to the influence of hydration, the wellbore enlargement rate increases with the increase of drilling fluid immersion time and different parameters have different effects on the wellbore enlargement rate. Water absorption diffusion coefficient and drilling fluid activity have a great influence on wellbore enlargement, while the permeability of shale on the wellbore enlargement rate is weak. The calculated results are basically consistent with the actual drilling, and the validity of the proposed model is verified.

Whether the drilling fluid can maintain the rock strength of the hard brittle shale well or not largely determines whether the drilling fluid can maintain the wellbore stability of the hard brittle shale formation. As for strong hydration characteristics and developed microcracks of hard brittle shale, the effective solution for the wellbore stabilization technology is to strengthen sealing and improve inhibition

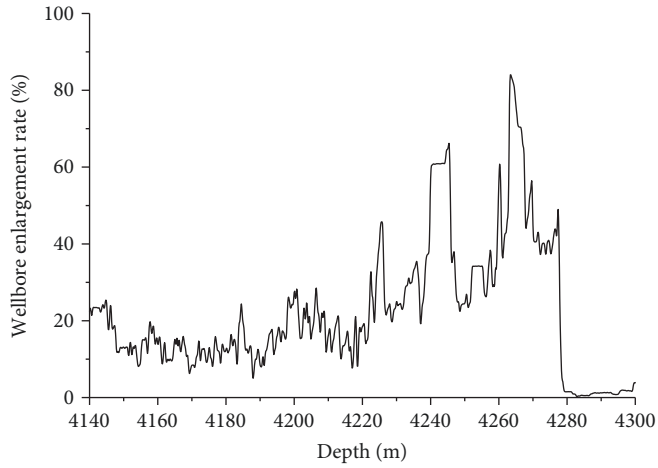


Figure 21: Field results of the enlargement rate of the W-82 well.

Figure 22: Returned rock block in the shale formation of the W-82 well.

ability of drilling fluid, instead of relying on increasing drilling fluid density.

Data Availability

The data used to support the findings of this study are included within the article.

Conflicts of Interest

The authors declare that there are no conflicts of interest regarding the publication of this paper.

Acknowledgments

The authors gratefully acknowledge the support of the Open Research Fund of the State Key Laboratory of the Oil and Gas Reservoir Geology and Exploitation (Grant no. PLN1507).

References

[1] J. Wang, S. Q. Lu, K. L. Zhu et al., "Maintaining wellbore stability in deep shale drilling in Nanpu oilfield," *Offshore Oil*, vol. 32, no. 1, pp. 92–96, 2012.

[2] A. H. Hale, F. K. Mody, and D. P. Salisbury, "Experimental investigation of the influence of chemical potential on wellbore stability," pp. 377–389, 1992.

[3] M. E. Chenevert, "Shale alteration by water adsorption," *Journal of Petroleum Technology*, vol. 22, no. 9, pp. 1141–1148, 1970.

[4] J. P. Simpson and H. L. Dearing, "Downhole simulation cell shows unexpected effects of shale hydration on borehole wall (includes associated papers 19519 and 19885)," *SPE Drilling Engineering*, vol. 4, no. 1, pp. 24–30, 1989.

[5] F. K. Mody and A. T. Uday, "Development of novel membrane efficient water-based drilling fluids through fundamental understanding of osmotic membrane generation in shales," in *SPE Annual Technical Conference and Exhibition*, San Antonio, TX, USA, September 2002.

[6] E. V. Oort, "Manipulation of coupled osmotic flows for stabilization of shales exposed to water-based drilling fluids," in *SPE Annual Technical Conference and Exhibition*, Dallas, TX, USA, October 1995.

[7] T. Huang, X. L. Pu, X. Luo, H. Yu, and S. J. Xu, "Stability analysis of shale wellbore based on fluid-solid coupling theory," *Journal of Oil and Gas Technology*, vol. 36, no. 10, pp. 117–121, 2014.

[8] H. Wen, M. Chen, Y. Jin et al., "Study on stability chemo-mechanical coupling of wellbore in inclined section of hard brittle shale," *Petroleum Exploration and Development*, vol. 41, no. 6, pp. 748–754, 2014.

[9] C. H. Yew and M. E. Chenevert, "Wellbore stress distribution produced by moisture adsorption," *SPE Drilling Engineering*, vol. 5, no. 04, pp. 311–316, 1990.

[10] R. Z. Huang, M. Chen, J. G. Deng, K. P. Wang, and Z. X. Chen, "Study on the coupling of mechanics and chemistry of shale wellbore stability," *Drilling Fluids and Completion Fluids*, vol. 12, no. 3, pp. 15–21, 1995.

[11] F. K. Mody and A. H. Hale, "Borehole-stability model to couple the mechanics and chemistry of drilling-fluid/shale interactions," *Journal of Petroleum Technology*, vol. 45, no. 11, pp. 1093–1101, 1993.

[12] E. V. Oort, A. H. Hale, and F. K. Mody, "Critical parameters in modelling the chemical aspects of wellbore stability in shales and in designing improved water based shale drilling fluids," pp. 171–186, 1996.

[13] F. T. Lomba, M. E. Chenevert, and M. M. Sharma, "The ion-selective membrane behavior of native shales," *Journal of Petroleum Science and Engineering*, vol. 25, no. 1-2, pp. 9–23, 2000.

[14] F. T. Lomba, M. E. Chenevert, and M. M. Sharma, "The role of osmotic effects in fluid flow through shale," *Journal of Petroleum Science and Engineering*, vol. 25, no. 1-2, pp. 25–35, 2000.

[15] M. Yu, G. Chen, and M. E. Chenevert, "Chemical and thermal effects on wellbore stability of shale formations," in *SPE Annual Technical Conference and Exhibition*, New Orleans, LA, USA, September 2001.

[16] J. G. Zhang and M. E. Chenevert, "Maintaining the stability of deviated and horizontal wells: effects of mechanical, chemical and thermal phenomena on well designs," in *International Oil & Gas Conference and Exhibition in China*, Beijing, China, December 2006.

[17] P. T. Chee, G. R. Brian, S. S. Rahman, and R. Andika, "Effects of swelling and hydration stress in shale on wellbore stability," in *SPE Asia Pacific Oil and Gas Conference and Exhibition*, Kuala Lumpur, Malaysia, April 1997.

[18] C. P. Tan, S. S. Rahman, B. G. Richards, and F. K. Mody, "Integrated rock mechanics and drilling fluid design approach to manage shale instability," in *SPE/ISRM Rock Mechanics in Petroleum Engineering*, Trondheim, Norway, July 1998.

[19] C. Tan, B. Richards, and S. S. Rahman, "Managing physicochemical wellbore instability in shales with the chemical potential mechanism," in *SPE Asia Pacific Oil and Gas Conference*, October 1996.

[20] R. Rickman, M. Mullen, E. Petre, B. Grieser, and D. Kundert, "A practical use of shale petrophysics for stimulation design optimization: all shale plays are not clones of the Barnett shale," in *SPE Annual Technical Conference and Exhibition*, Denver, CO, USA, September 2008.

[21] Y. H. Lu, M. Chen, Y. Jin, X. Q. Teng, W. Wu, and X. Q. Liu, "Experimental study of strength properties of deep shale under drilling fluid immersion," *Chinese Journal of Rock Mechanics and Engineering*, vol. 31, no. 7, pp. 1399–1405, 2012.

[22] H. Y. Huang, *Numerical Simulation of Time Dependent Wellbore Instability in Shale Formation and Application*, China University of Petroleum, Qingdao, 2016.

[23] S. Yin, B. F. Towler, M. B. Dusseault, and L. Rothenburg, "Fully coupled THMC modeling of wellbore stability with thermal and solute convection considered," *Transport in Porous Media*, vol. 84, no. 3, pp. 773–798, 2010.

[24] F. Meng, G. F. Fuh, and J. A. Spencer, "Managing geomechanics principles for proper handling of wellbore-stability problems in shale and depletion effects on formations while drilling," in *SPE Annual Technical Conference and Exhibition*, Florence, Italy, September 2010.

[25] C. Y. Zhou and F. X. Zhu, "An elasto-plastic damage constitutive model with double yield surfaces for saturated soft rock," *International Journal of Rock Mechanics and Mining Sciences*, vol. 47, no. 3, pp. 385–395, 2010.

[26] Q. Tao and A. Ghassemi, "Poro-thermoelastic borehole stress analysis for determination of the in situ stress and rock strength," *Geothermics*, vol. 39, no. 3, pp. 250–259, 2010.

[27] T. Hemphill, V. X. Nguyen, Y. Abousleiman, and M. H. Tran, "Changing the safe drilling window with invert emulsion drilling fluids: advanced wellbore stability modeling using experimental results," in *International Oil and Gas Conference and Exhibition in China*, Beijing, China, June 2010.

[28] A. Zervos, P. Papanastasiou, and J. Cook, "Elastoplastic finite element analysis of inclined wellbores," in *SPE/ISRM Rock Mechanics in Petroleum Engineering*, Trondheim, Norway, July 1998.

[29] S. P. Jia, W. Z. Chen, J. P. Yang, and P. S. Chen, "An elastoplastic constitutive model based on modified Mohr-Coulomb criterion and its numerical implementation," *Rock and Soil Mechanics*, vol. 31, no. 7, pp. 2051–2058, 2010.

[30] H. C. Shen and X. Q. Hu, "Research on in-situ stress and wellbore stability of overthrust structural belt and its application," *Xinjiang Petroleum Geology*, vol. 32, no. 2, pp. 193–196, 2011.

[31] S. P. Jia, C. S. Zou, Y. Z. Wang, X. J. Tan, and X. X. Gan, "Numerical analysis of oil drilling construction process based on thermal-flow-solid coupling model," *Rock and Soil Mechanics*, vol. 33, no. s2, pp. 321–328, 2012.