Predicting the critical drawdown pressure of sanding onset for perforated wells in ultra-deep reservoirs with high temperature and high pressure

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Abstract
Perforated wells in ultra-deep sandstone reservoirs are characterized by high reservoir temperature, high formation pressure, and high production, and sand production will cause severe safety hazards to these wells. Based on Drucker-Prager (DP) rock failure criterion, a practical analytical model for predicting critical drawdown pressure (CDP) of sanding onset for perforated wells is established by comprehensively considering the influence of drag stress, formation water production, reservoir pressure depletion, temperature difference in the perforated wellbore. The proposed model is verified by field sanding onset monitoring data. The calculation results show that CDP changes with well inclination, and it decreases with the increase in wellbore temperature difference, reservoir pressure depletion, and water saturation. However, the CDP increases with the number of perforations and the ratio of diameter to length. The optimization of perforation parameters has an important influence on sand control. This study can effectively guide the prediction of CDP and provides basis for efficient and safe development of similar ultra-deep and high yield sandstone reservoirs.

KEYWORDS
critical drawdown pressure, perforated wells, sanding onset, ultra-deep reservoirs

1 | INTRODUCTION

The ultra-deep reservoir is characterized by huge reserves and high productivity with high temperature and pressure, which has broad exploration and development prospects. In recent years, sand production often occurs in this kind of reservoirs such as Nanyuan oilfield, Dina gas reservoir, and Tarim Basin in China (Figure 1). Sanding onset has caused serious safety
hazards, including sand accumulation, string damage, ground equipment damage, also high costs and huge economic losses for sand control. In order to ensure the long-term safe production of deep wells, it is necessary to accurately predict the critical drawdown pressure (CDP) of sanding onset.

There are many kinds of sanding onset prediction methods, including field prediction method, empirical formula, neural network method, laboratory method, and theoretical analysis model. The empirical sand production prediction method is based on the production data and initial reservoir dynamics, such as modular method and Schlumberger method. These methods are easy to be used in the field, but the accuracy is not high. In the case of sufficient field data, artificial intelligence-based neural network method is gradually used for sand production prediction, but a large number of field basic data and test data are needed to achieve good prediction effect. In addition, in the experimental study of sand production prediction, the thick wall tube test is the most widely used method to evaluate the initial sand production of sandstone and the stability of open-hole wellbore, which cannot be applied to evaluate the stability of perforating tunnel. The traditional theoretical model is combined with failure criterion to predict sand production, and the failure mechanism of rock structure is mainly divided into tensile failure and shear failure. Another commonly used theoretical model for sand production prediction is the dynamic fluid–solid coupling model, which can determine the CDP and critical production of formation. The numerical simulation method can be used to simulate the rock failure under different perforation parameters, but it is not convenient for the simulation of large-scale formation, full wellbore size, and borehole inclination in the simulation process. Moreover, the process of simulation modeling is quite complex, which also takes a long time and has high computational expense.

Compared with numerical method, analytical model has the advantages of fast and simple calculation. Morita et al found that under the action of in-situ stress and additional stress field caused by seepage, the perforated rock has entered into plastic state. The formation rock will be subjected to shear failure and sand production when the strain of perforated surrounding rock exceeds a certain threshold value. However, this model is more suitable for the analysis of sand production in perforated wells in loose sandstone reservoir. In addition, a large number of scholars have established a single-hole model and given the analytical solution of perforated well. Most of them have studied the stability of perforation channel and the CDP of sanding onset by considering the effects of well trajectory, perforation direction, and formation pressure. Rahman (2010) established a sand production prediction model considering the influence of original in-situ stress, rock strength, borehole trajectory, perforation orientation, and reservoir pressure depletion, which has a guiding position in optimizing perforation direction and designing new well trajectory. Comparing with the CDP prediction model based on Mohr-Coulomb criterion and Drucker-Prager criterion, Oluyemi et al proposed a real-time sand production prediction analysis model based on Hoek-Brown criterion and analyzed the stability of perforating channel by numerical simulation model. It is found that Drucker-Prager can analyze the influence of axial stress, intermediate principal stress, and heterogeneity on sand production after rock failure. Al-Shaaibi et al combined with Mogi-Coulomb failure criterion, a three-dimensional linear pore elastic constitutive model for open-hole wells at the initial stage of sand production is proposed for offshore unconsolidated sandstone reservoir. Hayavi and Abdideh deduced the elastic-plastic stress solution of perforated hole and proposed a sand production prediction model based on tensile failure. Reisabadi et al proposed a new prediction method, which can calculate the stress distribution around the coalbed methane well and predict the occurrence of wellbore rock failure by coupling the effects of formation pressure depletion, rock shrinkage, and wellbore azimuth change. But, such models cannot be used to simulate sand production in high temperature and high-pressure formations.

Although a lot of work has been done for the analysis of sanding onset for the general loose sand reservoir by predecessors, these methods focus on common reservoir or unconsolidated sandstone reservoir and less methods focus on ultra-deep reservoirs with high temperature and high pressure. The influencing factors of sand production are not fully considered (a) static mechanical failure process, previous studies are less considered the effect of high yield under the condition of drag stress. The perforation channel is extremely narrow, and the drag effect is
more evident, and the rock is more easily to separate from the matrix to form sand.\(^{21}\) (b) The effect of temperature change on the stability of perforation channel and sand production pressure difference is rarely considered. (c) Less attention is paid to the effect of in-situ stress change on sand production pressure difference caused by formation pressure reduction. With the decrease in formation pressure, the maximum and minimum horizontal principal stresses change. The decrease in formation pressure leads to the increase in effective stress, which results in the shear failure and sanding onset. (d) The changing of rock strength influenced by the producing water is seldom considered. The invasion of water will lead to clay expansion and dispersion and greatly reduce the strength of reservoir rock, and sand production is more likely to occur in experimental analysis.\(^{6,28}\) (e) There are few researches on perforation sand control, and the effect of perforation parameters on sand production pressure difference is not clear. In the existing analytical models, the effect of perforation parameters on CDP of sanding onset is not fully considered. The optimization of perforation parameters to prevent sand production and to ensure the stability of perforation channel needs to be further studied. Thus, it is urgent to establish an improved CDP prediction model for ultra-deep perforated wells.

In this paper, considering the characteristics of high temperature, high pressure, and high production wells and various influencing factors, a CDP prediction model for ultra-deep perforated well is established (Section 2). Then, the proposed CDP prediction model is verified by field data and compared with the finite element software simulation results (Section 3). Finally, the sensitivity analysis of the influencing factors on CDP in the whole life cycle of the well is carried out (Section 4). This research can greatly reduce the wellbore safety problems, effectively ensure the high and stable production ultra-deep wells and have guiding significance for the development of similar reservoirs.

2  |  SAND PRODUCTION PREDICTION MODEL

2.1  |  Stress distribution on perforated wellbore

2.1.1  |  Stress induced by in-situ stress and fluid flow pressure

The stress distribution around the perforation wall is approximated as a cylinder, and the axis of the cylinder coincides with the axis of the perforation hole. Assuming good communication between wellbore formation and perforation hole, the perforated hole can be regarded as two orthogonal cylindrical holes of different diameters. The perforation wellbore geometric model and stress redistribution model are shown in Figure 2.

The stress distribution field of perforating hole wall under the combined multiple stresses can be expressed by \(^{17,29}\):

\[
\sigma_{pr} = P_w \left(1 - \frac{r^2}{R^2}\right) + \frac{\sigma_{xx} + \sigma_{yy}}{2} \left(1 - \frac{r^2}{R^2}\right) \left(1 - \frac{2r^2}{R^2} + \frac{3r^4}{R^4}\right) \cos 2\theta + \sigma_{zz} \left(1 - \frac{4r^2}{R^2} + \frac{3r^4}{R^4}\right) \sin^2 \theta
\]

\[
\sigma_{po} = -2P_w (1 + \cos \theta) \left(1 - \frac{r^2}{R^2}\right) + \frac{\sigma_{xx} + \sigma_{yy} + \sigma_{zz}}{2} \left(1 + \frac{r^2}{R^2}\right) \left(1 + \frac{3r^4}{R^4}\right) \cos 2\theta' + \sigma_{zz} \left(1 + \frac{3r^4}{R^4}\right) \cos 2\theta (1 + 2\cos 2\theta')
\]

\[
\sigma_{ps} = -2\sigma_{xx} \left(1 + \frac{3r^4}{R^4}\right) \sin 2\theta (1 + 2\cos 2\theta)
\]

\[
\sigma_{pe} = \sigma_r - \nu \left(2\sigma_{xx} - \sigma_{yy}\right) \left(\frac{R}{r}\right)^2 \cos 2\theta - 4\sigma_{ss} \left(\frac{R}{r}\right)^2 \sin 2\theta
\]
\[
\tau_{pr\theta} = \frac{\sigma_{xx} - \sigma_{yy}}{2} \left( 1 - \frac{3r^4_w}{R^2} + \frac{2r^2_w}{R^2} \right) \sin 2\theta + \sigma_{xy} \left( 1 - \frac{3r^4_w}{R^2} + \frac{2r^2_w}{R^2} \right) \cos 2\theta
\]

(4)

\[
\tau_{prz} = (-\sigma_{xy}\sin \theta + \sigma_{xz}\cos \theta) \left( 1 - \frac{r^2_w}{R^2} \right)
\]

(5)

\[
\tau_{p\theta z} = (\sigma_{xz}\sin \theta - \sigma_{xy}\cos \theta) \left( 1 + \frac{r^2_w}{R^2} \right)
\]

(6)

Where, \( P_w \) is the bottom hole pressure, MPa; \( R \) is the radius distance from a certain point in the surrounding wellbore formation rock to the wellbore axis, m; \( r_w \) is the radius of wellbore, m; \( \theta' \) is the circumferential angle of the perforation tunnel, \( \circ \). \( \sigma_{pr}, \sigma_{p\theta}, \text{and} \sigma_{pz} \) are the radial stress, the circumferential stress, and the axial stress around the perforation, MPa, respectively; \( \tau_{pr}, \tau_{r\theta} \), and \( \tau_{pz} \) are shear stresses on the perforation, respectively, MPa.

The six stress components in the converted coordinate system can be expressed as follows 17:

\[
\sigma_{xx} = (\sigma_H \cos^2 \beta + \sigma_s \sin^2 \beta) \cos^2 \alpha + \sigma_s \sin^2 \alpha
\]

(7)

\[
\sigma_{xy} = \sigma_H \cos^2 \beta + \sigma_s \cos^2 \beta
\]

(8)

\[
\sigma_{zz} = (\sigma_H \cos^2 \beta + \sigma_s \sin^2 \beta) \sin^2 \alpha + \sigma_s \cos^2 \alpha
\]

(9)

\[
\tau_{xy} = (\sigma_h - \sigma_H) \cos \alpha \sin \beta \cos \beta
\]

(10)

\[
\tau_{yz} = (\sigma_h - \sigma_H) \sin \alpha \sin \beta \cos \beta
\]

(11)

\[
\tau_{xz} = (\sigma_H \cos^2 \beta + \sigma_s \sin^2 \beta - \sigma_s) \sin \alpha \cos \alpha
\]

(12)

Where, \( \alpha \) is the well inclination, \( \circ \); \( \beta \) is the well azimuth, \( \circ \).

2.1.2 | In-situ stress change caused by formation pressure reduction

With the production of oil wells, the formation pore pressure gradually decreases, and the counteracting effect of pore pressure on overburden pressure gradually weakens. The maximum and minimum horizontal principal stresses also change, which can be expressed as follows 5:

\[
\sigma_H' = \sigma_H + \alpha \frac{1 - 2\nu}{1 - \nu} (P_c - P_p)
\]

(13)

\[
\sigma_s' = \sigma_s + \alpha \frac{1 - 2\nu}{1 - \nu} (P_c - P_p)
\]

(14)

Where: \( P_i \) is the original pressure, MPa; \( P_p \) is the current formation pressure, MPa.

2.1.3 | High yield fluid drag force

During the production process, the fluid flow velocity in the perforating tunnel is relatively high, which produces a large drag force on the rock particles. The reservoir with high pressure aggravates this effect and makes the force on perforation wall increase, which can be expressed as follows 21:

\[
F = \frac{Q \mu \phi}{2 \pi n_p h_p k_{dp} L_{pl} \ln \frac{1}{2n_p r_p}}
\]

(15)

The oil production can be expressed as follows 20:

\[
Q = \frac{2 \pi k_f h (p_f - P_w)}{\mu_L \left( \ln \frac{L_c}{a} + S_d \right)}
\]

(16)

The drag force exerted on the radial direction at the hole is expressed as follows:

\[
\sigma_{rw} = \eta (p_f - P_w)
\]

(17)

\[
\eta = \frac{k_f h \phi}{n_p h_p k_{dp} L_{pl} \left( \ln \frac{L_c}{a} + S_d \right) \ln \frac{1}{2n_p r_p}}
\]

(18)

Where, \( n_p \) is the perforation density, hole/m; \( h_p \) is the perforated thickness of oil layer, m; \( k_{dp} \) is the permeability of the reservoir around the perforation; \( h \) is reservoir thickness, m; \( L_{pl} \) is the perforation length, m; \( r_p \) is the perforation radius, m; \( k_f \) is the original formation permeability; \( S_d \) is skin coefficient.

2.1.4 | Influence of stress caused by temperature change

A calculation model for predicting the temperature change in perforated wall from the temperature test points of field is proposed. The fluid flow into the wellbore and the heat conduction within the formation and the hole walls after perforating the formation. The rock deformation with the temperature change and certain stress is produced near the borehole wall. The formation rock has the tendency of extrusion deformation in the direction of borehole, which is more likely to lead compressive shear failure. In this case, the energy generated...
by the external force acting on the fluid can be expressed as follows \(^{30,31}\):

\[
\Delta E_g = -\frac{\pi D^2}{4}\Delta y\rho v\sin\theta \quad (19)
\]

The heat conduction rate from the wellbore to the reservoir in the cementing section can be expressed as follows:

\[
\Delta E_{\text{out}} = A|_{r_{\text{rw}}} U_{T_i}|_{r_{\text{rw}}} (T_{\text{wb}} - T_{\text{res}}|_{r_{\text{rw}}}) \quad (20)
\]

Where, \(\Delta E_{\text{out}}\) is the rate of cementing heat transfer, J/s; \(U_{T_i}\) is the combined heat transfer coefficient, W/(m\(^2\)°C); \(A\) is the surface area of micro-element in wellbore, m\(^2\).

The relationship between heat loss and temperature change can be expressed as follows:

\[
\Delta E = Q_o C_{\text{po}} \rho_0 \Delta T \quad (21)
\]

Where, \(\Delta E\) is the energy change, J/s; \(Q_o\) is the oil production, m\(^3\)/s; \(C_{\text{po}}\) is the oil heat capacity, J/(kg·°C).

The temperature difference between measuring point and perforating section can be expressed as follows:

\[
\Delta T' = K_{JT} \Delta p - (\Delta E_g + \Delta E_{\text{out}})/(Q_o C_{\text{po}} \rho_0) \quad (22)
\]

\[
K_{JT} = \frac{\beta T - 1}{C_{\text{po}} \rho_0} \quad (23)
\]

Where, \(K_{JT}\) is the Joule Thompson coefficient, °C/MPa; \(\Delta p\) is the pressure difference between measuring point and perforating section; \(\beta\) is the coefficient of thermal expansion, MPa\(^{-1}\).

The temperature of perforated section (casing) can be expressed as follows:

\[
T_{\text{perf}} = T_{\text{test}} + \Delta T' \quad (24)
\]

The sand surface temperature outside the casing in the perforated production section can be expressed as follows:

\[
T_{\text{sand}} = T_i - K_{JT}(P_p - P_{\text{sand}}) \quad (25)
\]

Where, \(T_{\text{sand}}\) is the sand surface temperature, °C; \(T_i\) is the original formation temperature, °C; \(P_{\text{sand}}\) is the sand surface pressure, MPa.

According to the basic equations of thermoelastic mechanics and heat conduction theory, the thermal stress generated by temperature change in the plane axisymmetric coordinate system can be expressed as follows:

\[
\sigma_{\theta T} = \frac{a_r E \Delta T}{3(1-v)} \frac{1}{r^2} \int_{rw} T(r)rdr, \quad (27)
\]

\[
\sigma_{z T} = \frac{a_r E \Delta T}{3(1-v)} \quad (28)
\]

Where, \(\sigma_{\theta T}, \sigma_{\theta T}\), and \(\sigma_{z T}\) are the thermal stress in the radial direction, circumferential direction, and vertical direction, respectively, MPa; \(a_r\) is the thermal expansion coefficient of rock, °C; \(E\) is Young’s Elastic modulus of the rock, MPa; \(v\) is Poisson’s ratio of rock; \(T(r)\) is the temperature distribution in the stratum around the borehole wall, °C; \(\Delta T\) is the variation of formation temperature on wellbore wall, °C; \(r\) is the radius from the borehole axis, m.

\[
\sigma'_{pr} = \sigma_{pr} - \sigma_{rw} + \sigma_{\theta T} \quad (29)
\]

\[
\sigma'_{p0} = \sigma_{p0} + \sigma_{\theta T} \quad (30)
\]

\[
\sigma'_{pz} = \sigma_{pz} + \sigma_{z T} \quad (31)
\]

\[
\tau'_{p\theta z} = \tau_{p\theta z} \quad (32)
\]

\[
\tau'_{\theta 0} = 0, \tau'_{\theta z} = 0 \quad (33)
\]

According to the stress value of the hole wall, the stress of the hole wall is reordered, \(\sigma_1, \sigma_2,\) and \(\sigma_3\) can be expressed as follows:

\[
\sigma_1 = \sigma'_{pr} \quad (34)
\]

\[
\sigma_2 = \frac{1}{2} \left[ (\sigma'_{p0} + \sigma'_{pz}) + \sqrt{(\sigma'_{p0} - \sigma'_{pz})^2 + 4 \tau_{p\theta z}^2} \right] \quad (35)
\]

\[
\sigma_3 = \frac{1}{2} \left[ (\sigma'_{p0} + \sigma'_{pz}) - \sqrt{(\sigma'_{p0} - \sigma'_{pz})^2 + 4 \tau_{p\theta z}^2} \right] \quad (36)
\]

2.2 | Prediction model of critical sand-producing pressure difference

2.2.1 | Variation of rock strength caused by water invasion

Water invasion reduces the degree of rock cementation and structural failure, resulting in a decrease in rock strength, especially in the formation with argillaceous cementation or high content of argillaceous shale. Through the core triaxial test, the relationship between cohesion and internal friction angle at different water saturation is determined, which can be expressed as follows \(^5\):
Where: $c_w$ is the cohesion force after water invasion, MPa; $\varphi_w$ is the internal friction angle after water invasion, $^\circ$; $w$ is the water saturation of the rock after water invasion, $\%$; $w_0$ is the original water saturation, $\%$.

### 2.2.2 | Failure criterion of rock strength

Compared with Mohr-Coulomb criterion, Drucker-Prager criterion takes into account the intermediate principal stress, which can be expressed as follows:

\[ c_w = c - 8.7(w - w_0) \]  
\[ \varphi_w = \varphi - 187.5(w - w_0) \]  
\[ \sqrt{J_2} = C_0 + C_1 J_1 \]  
\[ J_1 = \frac{1}{3}(\sigma_1 + \sigma_2 + \sigma_3) \]  
\[ C_0 = \frac{6\tau_0 \cdot \cos\varphi}{\sqrt{3(3 - \sin\varphi)}} \]  
\[ C_1 = \frac{3\sin\varphi}{\sqrt{3(3 - \sin\varphi)}} \]  
\[ \tau_0 = \frac{1}{2} \sigma_c \left( \sqrt{\tau \varphi^2 + 1} - \tau \varphi \right) \]
Where, $J_1$ and $J_2$ are the first invariant component of stress and the second invariant component of stress, respectively; $C_0$ and $C_1$ are material parameters related to cohesion and internal friction; $\sigma_1, \sigma_2,$ and $\sigma_3$ are the three main stresses, respectively, MPa; $\sigma_c$ is the tensile strength, MPa.

The critical drawdown pressure of sanding onset in the production process can be expressed as follows:

$$CDP = P_p - P_{cw}$$  \hspace{1cm} (44)

Where, $P_{cw}$ is the critical bottom hole flow pressure.

In the process of sand production pressure difference calculation, sonic logging data and GR logging data are needed to calculate the profiles of rock mechanics parameters and in-situ stress parameter based on these data, so as to obtain the sand production pressure difference profile of the entire well. The profile prediction model can be expressed as follows:

$$CDP(i) = f(\sigma_H, \sigma_h, \alpha, v, E, P_p, \theta, I, L_c, P_f, l_p, d_p, n)$$  \hspace{1cm} (45)

The calculation steps of critical production pressure difference are shown in Figure 3. When determining the CDP and other parameters of a certain depth, the stress around the wellbore is calculated, and the rock failure criterion is introduced to judge the rock failure, and the critical bottom hole flow pressure and production pressure difference are obtained when the failure occurs. By repeating the above steps, the critical sand production pressure profile of the whole well can be calculated by using the above method.

### 3 | MODEL VALIDATION

Taking the exploration well of Cretaceous Qingshuihe formation in the Nanyuan of Xinjiang Oilfield as an example, the accuracy of the model is verified. There is a serious problem of sand production in the process of well testing. When 21mm nozzle is used, the sand production signal is obvious when the production pressure difference is 60 MPa, and the granular sand and nozzle are eroded. The basic parameters of the target well are shown in Table 1.

At the same time, the sand production pressure difference in the well is simulated by using finite element software. The basic composition of the model is shown in the Figure 4. The hexahedral structure is used to divide the well and to refine the formation grid around the well. As shown in Figure 5, the interface between cement sheath and formation is the most dangerous area for borehole instability. The average uniaxial compressive strength of the three layers in target well is 56.02MPa, and the corresponding average critical sand onset pressure difference is 79 MPa. There is a certain difference between the field monitoring sand production pressure difference.

As shown in Figure 6 and Table 2, the minimum values of critical sand production pressure difference corresponding to three layers are 61.9, 67.8, and 62.7 MPa, respectively. The sand production of the well always occurs in the most easily sand production layer. Therefore, the calculated critical sand production pressure difference in the well is 61.9 MPa, and the relative error with field monitoring data is 3.2%.

### 4 | RESULTS AND DISCUSSION

#### 4.1 Influence of well deviation azimuth

As shown in the Figures 7 and 8, when the azimuth is less than 30 degrees, the CDP of perforated well gradually decreases with the increase in the borehole inclination angle under the same perforation direction. The CDP increases gradually with the increase in the borehole inclination angle when the azimuth is greater than 30 degrees, which indicates that the wellbore trajectory could be optimized for sand control.

#### 4.2 Influence of perforation direction

As shown in Figure 9, it can be seen that different perforating directions have an obvious influence on the critical pressure

| Parameter               | Value | Unit | Parameter               | Value | Unit |
|-------------------------|-------|------|-------------------------|-------|------|
| Overburden stress       | 143.2 | MPa  | Porosity                | 0.07  | —    |
| Maximum in-situ horizontal stress | 145.3 | MPa  | Pore pressure           | 135.52| MPa  |
| Minimum in-situ horizontal stress | 138.2 | MPa  | Perforation density     | 16    | Hole/m |
| Young’s modulus         | 24.91 | GPa  | Perforation radius      | 0.006 | m    |
| Formation Poisson’s ratio | 0.17 | —    | Perforation depth       | 0.6   | m    |
| Internal friction angle | 48.22 | °     | Skin factor             | 10    | —    |
| Deviation angle         | 0     | °    | Azimuth angle           | 0     | °    |

**TABLE 1** Basic parameters of target well
difference in sand production. Under different well inclination angles, with the decrease in perforation azimuth, the sand production CDP gradually decreases. With the increase in azimuth angle, its influence on the CDP of sand production in different perforating directions decreases gradually. The CDP of sand production is the largest at 0 degree perforation.
direction, which is most conducive to the stability of perforation when using directional perforating along the maximum principal stress.

### 4.3 Influence of temperature change

As shown in Figure 10, with the increase in crude oil production during production, the temperature near the wellbore increases gradually and the temperature difference increases. This is mainly due to the large pressure difference and high production in the production process, and the instantaneous enthalpy effect is transferred from the formation to the wellbore in the process of wellbore heat transfer into the formation. The results show that the bottom hole flow temperature is higher than the formation temperature. Meanwhile, the influence of wellbore temperature changes directly affects the wellbore stress, the vicinity of the wellbore and the formation tend to squeeze and deform in the direction of borehole, and the CDP of sand production decreases with the increase in temperature. When the oil production increased to 13,500 m³, the temperature difference increased by about 21.5°C. With the increase in crude oil production, the critical sand-producing pressure difference decreases gradually. The greater the temperature difference, the smaller the critical sand pressure difference. For every 10°C increase in the temperature difference, the CDP decreases by about 4.7 MPa.

As shown in Figure 11, with the increase in elastic modulus, the CDP of sand production gradually decreases. At
the same temperature, the effect of temperature change on
sand production pressure difference is more obvious in high
elastic modulus reservoir. With the increase in Poisson's
ratio, the CDP of sand production decreases gradually,
and the CDP of sand production at high Poisson's ratio is
smaller than that of low temperature reservoir. With the
increase in thermal elastic coefficient, the CDP of sand
production decreases gradually. The reservoir with large
thermal elastic coefficient has smaller critical sanding
onset pressure difference.

4.4 | Influence of formation pressure reduction

As shown in Figure 12, assuming that the overburden stress
remains unchanged, the maximum and minimum horizontal
principal stresses are found to gradually decrease with the
decreases of formation pressure. The formation pressure
decreased from 135 to 75 MPa, and the CDP decreased from
70.1 to 0.7 MPa. The results show that the maximum and
minimum principal stresses decrease with the decrease in
formation pressure. The increase in effective stress of rock

FIGURE 11  Variations of elastic
modulus, Poisson's ratio, thermoelastic
coefficient and sand-producing pressure
difference in the case of temperature
variation

FIGURE 12  Variation diagram of in-situ stress and sand-
producing pressure difference ratio under the condition of formation
pressure exhaustion

FIGURE 13  Relationship between the
angle of internal friction and the pressure
difference in sand production under the
condition of formation outflow
skeleton results in the increase in circumferential stress and the decrease in critical sanding onset pressure difference.

4.5 | Influence of formation water production

During water cut stage, the formation rock will expand with the water and hydrolyze, resulting in the destruction of the structure, and the strength of the rock will decrease, especially in the formation with argillaceous cementation. Therefore, when the reservoir is produced at a very high yield, water intrusion is likely to cause formation sand production. As shown in Figure 13, the higher the water saturation of reservoir rock, the lower the CDP. The increase in formation water yield leads to the increase in rock water saturation and the decrease in critical production pressure. Under the condition of high water cut, the CDP of sand production decreases with the increase in cohesion, which is more than that under the condition of low water cut. The smaller the angle of internal friction, the smaller the pressure difference. In the case of high water cut, the CDP decreases more with the increase in internal friction angle than in that of low water cut.

4.6 | Influence of perforation parameters

As shown in Figure 14, with the increase in perforating azimuth angle, the CDP decreases obviously under the condition of high hole density. With the increase in the number of perforating holes, the critical pressure difference in sand production increases gradually, and then decreases when it reaches a certain degree. Optimization of sand control perforating parameters: the ultra-high perforation density sand control perforating can greatly increase the seepage area under the high hole density compared with the conventional perforation. Under the same production capacity, it can reduce the liquid velocity, reduce the pressure difference between the formation and the bottom hole, reduce the drag force of the fluid, and reduce the sand production risk. When the perforation density is low, the CDP decreases with the increase in production, and the influence of CDP on production decreases when the daily oil production is more than 11,900 m³/d. The main reason is that the higher the production rate, the greater the temperature difference and drag force, resulting in the decrease in CDP. When the perforation density reaches more than 50 holes/m, the CDP of sand production basically remains unchanged with the increase in oil production, indicating that the influence of drag force is no longer obvious.

As shown in Figure 15A, the CDP gradually decreases with the increase in the diameter length ratio of the perforating charge from 0° to 90° perforation direction, which indicates that the hole is the most stable when perforating along the direction of the maximum horizontal principal stress at the 0° direction. As shown in Figure 15B, with the increase in diameter length ratio, the increase in CDP increases with the decrease in production. Under the condition of high production, the flow resistance of large hole is smaller, which is
more conducive to the stability of perforating hole. The total perforation area and seepage area per meter are larger in large aperture sand control perforation. The integration of perforation and sand control can be realized by small length diameter ratio and large diameter perforating charge and limiting production pressure difference. Therefore, the long-term stability of perforation tunnel in the production process can be ensured by optimizing perforation parameters.

5 | CONCLUSION

In this paper, the modified CDP prediction model for ultra-deep well is established, and its accuracy is verified by field data. The key results can be concluded as follows:

1. High yield results in large temperature difference between formation and wellbore. At the same temperature, with the increase in thermal elastic coefficient, the CDP of sand production decreases gradually. Moreover, the sand production pressure difference is small under high thermal elastic coefficient. The thermal expansion effect of rock has a certain shear and compression effect on the formation rock in the wellbore direction.

2. With the decrease in formation pressure, the sand production pressure difference decreases gradually. In the reservoir with high water saturation, the smaller the rock cohesion and internal friction angle, the lower the critical production sand pressure difference.

3. With the increase in the number of perforations, the sand production pressure difference increases gradually and then decreases after reaching a certain extent. Large diameter length ratio perforation is beneficial to sand control and long-term stability of perforating hole.

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List of symbols

- $A$: Surface area of micro-element in wellbore
- $C_{po}$: Oil heat capacity
- $C_0 (C_1)$: Material parameters related to cohesion and internal friction
- $c_w$: Cohesion force after water invasion
- $E$: Young's Elastic modulus of the rock
- $h$: Reservoir thickness
- $h_p$: Perforated thickness of oil layer
- $J_1(J_2)$: First invariant component of stress or the second invariant component of stress
- $k_f$: Original formation permeability
- $k_{dp}$: Permeability of the reservoir around the perforation
- $K_{JT}$: Joule Thompson coefficient
- $L_{pl}$: Perforation length
- $n_p$: Perforation density
- $P_i$: Original pressure
- $P_c$: Current formation pressure
- $P_w$: Bottom hole flow pressure
- $P_{sand}$: Sand surface pressure
- $P_{cw}$: Critical bottom hole flow pressure
- $Q_o$: Oil production rate
- $R$: Radius distance from a certain point in the surrounding wellbore formation rock to the wellbore axis
- $r_w$: Radius of wellbore
- $r_p$: Perforation radius
- $S_d$: Skin coefficient
- $T_i$: Original formation temperature
- $T(r)$: Temperature distribution in the stratum around the borehole wall
- $T_{sand}$: Sand surface temperature
- $U_{IT}$: Combined heat transfer coefficient
- $V$: Poisson's ratio of rock
- $w$: Water saturation of the rock after water invasion
- $w_0$: Original water saturation
- $\alpha_s$: Thermal expansion coefficient of rock
- $\beta$: Coefficient of thermal expansion
- $\theta'$: Circumferential angle of the perforation tunnel
- $\sigma_{rT}$: Radial direction
- $\sigma_{\theta T}$: Thermal stress in the circumferential direction
- $\sigma_{zT}$: Vertical direction
- $\sigma_{rr}$: Radial stress
- $\sigma_{\theta \theta}$: Circumferential stress
- $\sigma_{pc}$: Axial stress circumferential stress
- $\sigma_1 (\sigma_2, \sigma_3)$: Main stresses on the perforation
- $\sigma_c$: Tensile strength
- $\phi_w$: Internal friction angle after water invasion
- $\Delta E$: Energy change
- $\Delta E_{out}$: Rate of cementing heat transfer
- $\Delta P$: Pressure difference between measuring point and perforating section
- $\Delta T$: Variation of formation temperature on wellbore wall

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