Optimization of Hydrate Inhibition Performance for Deep Water Shallow Drilling Fluid

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Abstract. Natural gas hydrate (NGH) is one of the great risk for deepwater drilling. The deep water and shallow geological conditions are complex, the soil is loose, the operating pressure window is narrow, the submarine mud line temperature is low, and hydrates are easy to form in the well bore. The drilling fluid is faced with problems such as well bore stability, difficulty in regulating low-temperature rheology, environmental pollution and so on. Therefore, taking the shallow drilling of a deep water well in the South China Sea as the research object, the application status of deep-water shallow drilling fluid is summarized and analyzed, the ECD calculation model and well bore temperature field calculation model is established, and the well bore temperature field distribution and hydrate formation risk during deep-water shallow drilling is analyzed. The hydrate inhibition performance of shallow drilling fluid system is optimized in combination with numerical simulation and indoor experiments. The following research results are obtained. First, compared with the measured data, the average error of ECD calculation model and well bore temperature field calculation model for deep-water shallow drilling is less than 8%; Second, it is calculated that the range of hydrate formation area in the well bore gradually decreases with the increase of drilling depth, but there is still a risk of hydrate formation in the well bore during drilling preparation and early drilling; Third, the conventional semi preventive drilling fluid system is optimized as HEM + 14%NaCl + 6%KCl, which can meet the operation requirements during normal drilling. It is concluded that through the optimization of deep water shallow drilling fluid system, the addition of hydrate inhibitor can be reduced, the drilling fluid formula can be simplified, the drilling cost can be reduced, and the operation efficiency can be improved, which can provide guidance for the drilling fluid design of deep water oil and gas drilling.

Keywords: Deep water and shallow layer · Drilling fluid · Hydrate inhibitor · Generation area · Optimization

1 Introduction

The successful development of the "Deep Sea No. 1" gas field give impetus to the deep water oil and gas resources in the South China Sea to move towards ultra deep water and deep water high-temperature and high-pressure fields. With the continuous

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increase of water depth, deep water drilling operations are facing severe challenges. Deep water drilling, well control, and onshore and shallow water have significant differences, mainly reflected in: (1) narrow density safety windows caused by small fracture pressure gradients; (2) high-pressure and low-temperature environment at the mud line and the complex temperature environment inside the well bore are prone to the formation of natural gas hydrates; (3) the wellhead is installed on the seabed and the high back pressure at the wellhead and significant pressure loss in the choke pipeline result in a different calculation method for the temperature and pressure field of deep water well bore compared to land [1].

Especially when encountering gas bearing formations during deep water drilling, if natural gas enters the drilling fluid in the well bore or annulus, the gas can easily form hydrates in the drilling pipelines, valves and BOPs, blocking the well bore, annulus or BOP which affecting drilling operations. At present, adding hydrate inhibitors to deep water drilling fluid to enhance its hydrate inhibition is a commonly used method both domestically and internationally. During shallow water drilling a semi protective drilling fluid system is used during drilling and a fully protective drilling fluid system is used during stationary periods to ensure job safety. However, the shallow drilling operation process generally takes a short time, and frequent conversion of drilling fluid systems not only affects operation efficiency, but also leads to complex drilling fluid systems and increased costs [2, 3].

Thermodynamic hydrate inhibitors are generally added to the drilling fluid during drilling in shallow layers of the ocean and hydrate reservoirs to shift the phase equilibrium curve of the hydrate towards low temperatures, thereby inhibiting the formation of hydrates. Commonly used drilling fluid systems include high salt drilling fluid systems, high salt/polyol/PHPA drilling fluid systems and oil-based drilling fluid systems [4–6]. This article takes the shallow drilling operation conditions of a deep water gas well in the South China Sea as the research object. Based on the current application status of deep water surface drilling fluid, a drilling model is constructed, and the risk of hydrate generation during shallow drilling is analyzed by combining the hydrate phase curve. The hydrate inhibition performance of the drilling fluid under different working conditions is calculated, and indoor experiments and evaluations of hydrate inhibitors are conducted to verify the accuracy of numerical analysis, thus optimizing the formulation of shallow drilling fluid system, providing technical guidance for practical operations, and ensuring the safety and efficiency of deep water shallow drilling operations.

2 Current Status of Deep Water Shallow Drilling Fluids

The geological conditions in deep water areas are complex, and the shallow layers in deep water have characteristics such as loose soil, narrow operating pressure window, and low temperature of the seabed mud line, which bring many difficulties to drilling construction. The application of drilling fluid faces problems such as well bore stability, difficulty in regulating low-temperature rheological properties, and environmental pollution. At present, deep water surface drilling operations in the South China Sea generally adopt the technology of ejection method for catheter placement and secondary drilling to achieve simultaneous drilling of two boreholes in one trip, which effectively reducing operation time and well bore settling time, avoiding complex situations such as well bore collapse caused by long-term exposure of shallow boreholes, ensuring the safety of surface drilling operations and improving the efficiency of deep water wells [7–9]. The drilling of the first and second spuds in the deep water surface adopts open-circuit drilling, which does not lower into the riser and BOPs, but uses seawater for drilling without establishing a normal drilling fluid pump in and out circulation process. Due to the low density of seawater, it is not possible to effectively balance the pore and collapse pressure inside the well bore, so the depth of the second spud hole and casing is generally not too deep. Currently, based on the geological characteristics of deep water areas and the optimization of drilling operations, the drilling depth of the second spud hole can reach about 1000 m below the mud line.

At present, the third spud drilling operation in deep water wells generally involves drilling 444.5 mm holes above the target layer, while the fourth or fifth spud drilling is for the target layer. Therefore, this article mainly focuses on optimizing the drilling fluid system during the third spud drilling operation in deep water wells. The well section of the deep water third spud operation is usually longer than 1000 m, and during the operation process, it is necessary to focus on risks such as well bore cleaning, well bore stability, well leakage prevention, and hydrate prevention. At present, the commonly used drilling fluid system for the third spud section is the HEM system, which consists of drilling water + (1%–2%) PF-FLO + (0.3%–0.8%) PF-PAC + (3%–5%) PF-EZCARB + (0.1%–0.3%) PF-XC + (2%–3%) PF-UHIB + (1%–2%) PF-HLUB as the basic formula. It is mainly composed of strong inhibitor polyamine PF-UHIB, anti mud pack lubricant PF-HLUB, filter loss agent PF-FLO, and flow pattern regulator XC. To suppress the formation of hydrates, NaCl or ethylene glycol is usually added to the drilling fluid to construct a semi or fully resistant drilling fluid. During normal drilling, a semi resistant drilling fluid system is selected, and during electrical testing, equipment repair, platform avoidance, and other operations that require waiting for more than 24 h, a fully resistant hydrate drilling fluid system is selected [10–12]. Figure 1 shows the effect of different concentrations of salt inhibitors on the inhibition ability of natural gas hydrates. It can be seen from Fig. 1 that different concentrations of NaCl and KCl have strong inhibition ability on natural gas hydrates. When the two are combined, the inhibition performance is enhanced. For example, when 14% NaCl + 6% KCl is added to the drilling fluid system, the critical temperature for hydrate formation in the drilling fluid is 10.68 °C at a water depth of 1500 m. At this point, when the minimum circulating temperature in the well bore is higher than this temperature, no hydrate is generated.

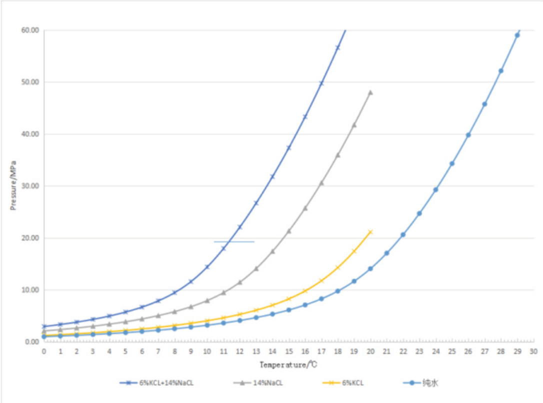


Fig. 1. Effect of different concentrations of salt inhibitors on the phase state curve of NGH

3 Risk Analysis of Hydrate Formation in Deep Water Shallow Drilling

3.1 Basic Overview of the Well

Taking LX-1, a deep water well in the South China Sea, as an example, it is a vertical well with a water depth of 1570 m and a design depth of 4470 m. The pressure coefficient of the well is about 1.00–1.07. The 444.5 mm borehole was drilled from 2560 m to 3670 m in the third spud of the well. The drilling fluid system for this well section adopts HEM system with a density of 1.24 g/cm^3. During the drilling period, 14%NaCl + 6%KCl + 8% ethylene glycol is added to construct a semi anti drilling fluid system. During the stationary period, 25% NaCl + 6%KCl + 20% ethylene glycol is added to construct a fully anti drilling fluid system.

3.2 Establishment and Calibration of Drilling Models

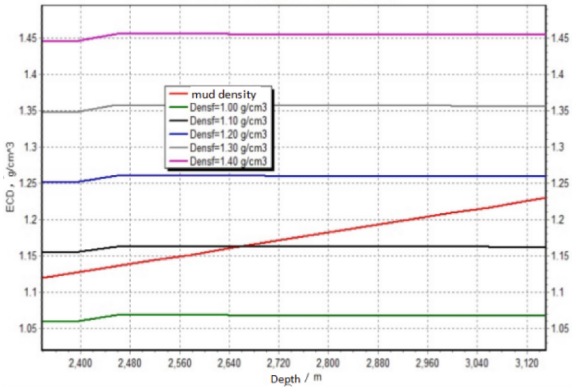
Firstly, establish a drilling model based on the design overview of the well, and simulate and calculate the drilling conditions during the actual drilling period by combining the drill string combination and drilling parameters. Then, predict the temperature field of the well bore at different drilling depths, providing a calculation basis for the risk of hydrate generation.

(1) ECD simulation calculation and calibration

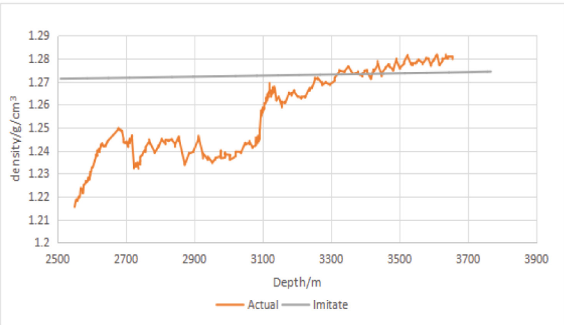
ECD is composed of mud static pressure, mud flow friction, and additional pressure drop of rock cuttings. The main influencing factors include mud displacement, rock cuttings concentration, mud density, mud viscosity, mechanical drilling speed, drill pipe speed, and drill pipe eccentricity and rotation. Based on this, the calculation formula for ECD during normal drilling is established as follows:

$$\rho_{ECD} = \rho_{ESD}(1 - C_a) + \rho_s C_a + \frac{\Delta P_a}{gh} \tag{1}$$

Among them, ρ_{ECD} is equivalent mud circulating density, g/cm^3; ρ_{ESD} is equivalent static density of mud, g/cm^3; ρ_s is rock debris density, g/cm^3; C_a is annular debris concentration, %; Δp_a is annular pressure loss, MPa;h is vertical depth, m.



(a) ECD versus cuttings concentration curve



(b) Comparison of ECD measurement and simulation

Fig. 2. ECD Simulation Calculation and Correction of LX-1 Well

According to the calculation results in Fig. 2 (a), it can be seen that as the concentration of rock debris increases, the ECD increases. For the 444.5 mm well section, due to the low concentration of rock cuttings, the impact of mud displacement gradually weakens. The size and shape of rock cuttings, as well as the mechanical drilling speed, have a greater impact on the concentration of rock cuttings, followed by mud density and effective viscosity, and the impact of drill pipe speed is the smallest. Figure 2 (b) shows the comparison between ECD data and simulated calculation data during the actual drilling period of LX-1. It can be seen from the figure that the measured and calculated ECD values are basically consistent, with an average error of 7.8%.

(2) Simulation calculation and correction of well bore temperature field

The temperature and pressure field of deep water drilling is mainly the study of heat transfer calculation models for deep water drilling well bore. In the existing thermodynamic model of deep-water gas well development well bore, the whole well bore generally adopts the heat transfer mode of the formation well section, without special consideration of the particularity of the fluid inside and outside the riser in the deep-water seawater well section, ignoring the existence of forced heat convection, natural convection, heat conduction and other heat transfer modes between the riser in the seawater well section and seawater, annulus fluid [13]. Based on the principles of mass and energy conservation and heat transfer, this article establishes the well bore temperature field equation on the basis of previous research as follows:

Temperature field equation inside the drill strings:

$$\frac{\partial(\rho c T_p)}{\partial t} + \frac{\partial(\rho c v_p T_p)}{\partial z} = q_{ap} + q_p \tag{2}$$

Annular temperature field equation:

$$\frac{\partial(\rho c T_a)}{\partial t} - \frac{\partial(\rho c v_a T_a)}{\partial z} = q_{ea} - q_{ap} + q_a \tag{3}$$

Among them, ρ is mud density, g/cm^3; c is specific heat of mud at constant pressure; t is time, s, z is axial coordinates; T_p and T_a is the temperature inside the drill string and in the annulus respectively, °C; A_p and A_a is drill string and annular flow channel area respectively, m^2; v_p and v_a is mud flow rate in the drill string and annulus respectively, m/s; q_{ap} is heat exchange between mud inside the drill string and the annulus, J; q_{ea} is heat exchange between annular mud and seawater or formation, J; $q_p = A_p v_p p_{fp}$ and $q_a = A_a v_a p_{fa}$ is Friction heat generation between drill string and annulus respectively, J; p_{fp} and p_{fa} is axial flow friction gradient of mud in the drill string and annulus, which is related to mud speed, density, rheological property, flow pattern, etc., and varies with temperature and pressure.

Figure 3 shows the simulated calculation of the temperature field of the drill string and annulus when LX-1 well is drilled to different depths. The measured temperature field in the figure is the actual temperature at the drill bit when the third spud section of LX-1 well is drilled to different depths. From the graph, it can be seen that the initial temperature field before drilling gradually decreases with the increase of water depth, and then gradually increases with the increase of well depth, with the lowest temperature at the mud line; When the third spud section was drilled to 3670 m, the well bore temperature field remained around 25 °C in the seawater section, significantly decreased at the mud line, and remained around 35–37 °C in the formation section. It is basically consistent with the measured temperature field when the well was drilled to 3670 m, with an average error of 4.6%.

(3) Prediction of well bore temperature field at different drilling depths

Based on the above drilling model and drilling parameters of LX-1 well, the temperature field curves at different depths were simulated and compared with the measured temperature field, as shown in Fig. 3. From Fig. 3, it can be seen that when drilling from 2560 m, the well bore temperature field gradually decreases with the increase of water depth, and the temperature at the mud line is the lowest. At this point, the initial drilling temperature is the lowest at 3 °C, and then gradually increases to the formation temperature as the well depth increases; As the drilling depth increases and the drilling fluid circulates, the temperature field in the seawater section of the well bore gradually increases at different depths, while the temperature field in the formation section gradually decreases. Moreover, the temperature field in the well bore changes significantly during drilling at the first 100 m of the third spud section, and the temperature field in the subsequent sections remains relatively stable, consistent with the trend of temperature changes measured during actual drilling. However, due to the special nature of the deep water well section, the well bore temperature field will always decrease at the mud line.

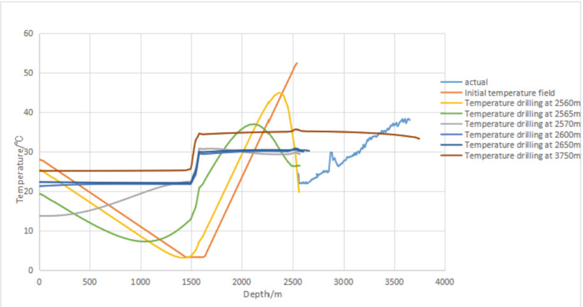


Fig. 3. Simulation calculation and correction of temperature field at different drilling depths in LX-1 well

3.3 Risk Analysis of NGH Formation

The water depth of LX-1 well is 1570 m, belonging to the ultra deep water well. In the ultra deep shallow low-temperature gas well, the well bore temperature field shows a different trend from the typical deep water gas well bore temperature field. The target reservoir of this well belongs to the low-temperature reservoir. Due to the low temperature of the formation fluid itself, after rapid cooling in the lower seawater section, the well bore temperature drops to close to the seawater temperature. After entering the upper seawater section, the seawater temperature begins to rise, The well bore temperature field stopped decreasing and gradually showed a reverse upward trend [14, 15].

By combining the hydrate phase state curve of the well with the well bore temperature field at different drilling depths, the temperature pressure point during hydrate phase equilibrium is converted to the temperature depth point under well bore conditions. By comparing the temperature well depth curve and hydrate phase state curve inside the well bore, the hydrate generation area inside the well bore can be obtained to determine the risk of hydrate generation. When the hydrate phase curve intersects on the right side of the well bore temperature curve, the area surrounded by the two curves is the hydrate generation area. The longer the length of this area in the longitudinal direction, the larger the hydrate generation area. If the width is larger horizontally, the super cooling of hydrate formation is greater, and hydrate formation is easier and faster.

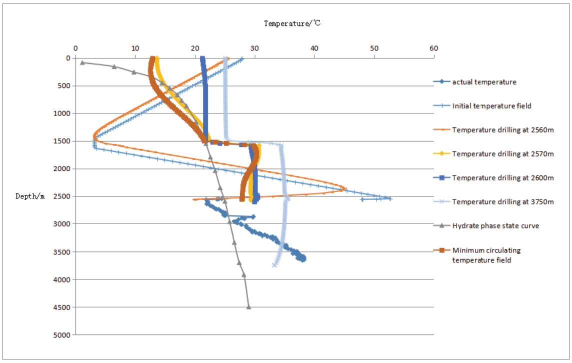


Fig. 4. Risk map of hydrate formation at different drilling depths in LX-1 well

From Fig. 4 it can be seen that the well bore temperature field during the initial drilling period intersects with the hydrate phase curve, posing a risk of hydrate formation. As the drilling depth increases, the well bore temperature field increases, and the risk area of hydrate generation gradually decreases. When drilling to 2600 m, the well bore temperature field curve no longer intersects with the hydrate phase curve, which means there is no longer a risk of hydrate generation. And from the measured temperature field during drilling, it can be seen that the underground temperature during the initial stage of drilling also intersects with the hydrate phase curve, which is consistent with the simulated calculation trend. After calculation, the hydrate generation areas at different drilling depths of the well are shown in Table 1.

Table 1. Prediction of hydrate generation areas during the third spud drilling of LX-1 well

Drilling depth (m)	0 (Drilling preparation)	2560	2575	2600
Hydrate generation area (m)	540–1795	454–1495	549–1098	0

4 Optimization of Hydrate Inhibition in Deep Water Shallow Drilling Fluids

4.1 Research on Numerical Simulation Optimization

According to the calculation results in Sect. 2, it can be seen that the minimum circulating temperature during the drilling operation of the third spud section of LX-1 well is 13.72 °C, and the minimum temperature during the standing period is 3 °C (mud line temperature). Combined with the hydrate phase curve simulation, the hydrate inhibition properties of the semi and fully protected drilling fluids are shown in Fig. 5. From Fig. 5 it can be seen that under the same operating conditions, the critical generation temperature of hydrates formed by the semi protective drilling fluid system is 8.05 °C, which can meet the minimum circulating temperature requirements of the third spud drilling. The critical generation temperature of hydrates formed by the fully protective drilling fluid system is 2.1 °C, which can meet the temperature requirements during the static period, indicating that the two systems can meet the corresponding operating requirements under their respective operating conditions.

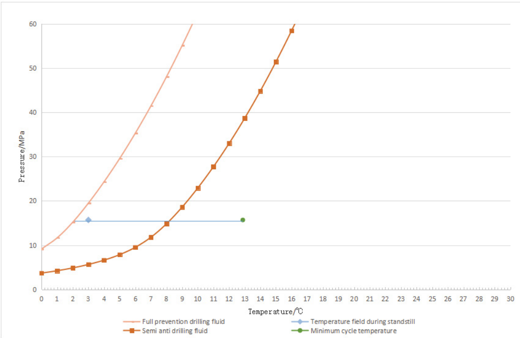


Fig. 5. Inhibition ability of drilling fluid system on natural gas hydrates

Further combine the hydrate phase curves formed by adding different inhibitors and drilling fluid systems with the well bore temperature field at different drilling depths, as shown in Fig. 6. From Fig. 6 it can be seen that when salts or ethylene glycol are added, the phase state curve of the hydrate shifts to the left. When 6% KCl is added, the phase state curve of the hydrate still intersects with the temperature field during drilling, while when 14% NaCl + 6% KCl is added, the phase state curve of the hydrate only intersects with the lowest circulating temperature field during drilling preparation, and does not intersect with the temperature field curve of any drilling depth, Although the 14% NaCl + 6% KCl inhibitor system is not as effective as the semi anti drilling fluid system, it can already meet the needs of normal drilling operations. The ethylene glycol in the original semi anti drilling fluid system (14%NaCl + 6%KCl + 8% ethylene glycol) can be optimized and deleted, but it cannot meet the operational requirements during the static period. From Fig. 6 it can also be seen that only the fully resistant drilling fluid system can meet the hydrate suppression requirements during static and drilling periods. However, salt as a hydrate inhibitor can bring a series of corrosion problems. In addition, when used in drilling fluids, compatibility with other drilling fluid components should be considered. As the salt concentration increases, maintenance and regulation of drilling fluid performance become increasingly difficult. Alcohol has the advantages of low freezing point, strong water solubility, low cost, and good inhibition effect on hydrates.

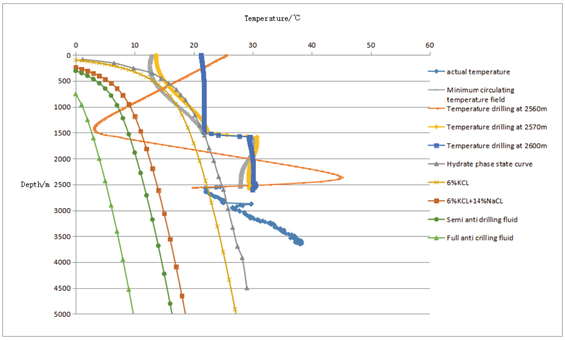


Fig. 6. Optimization of Hydrate Inhibition Performance of Drilling Fluid System

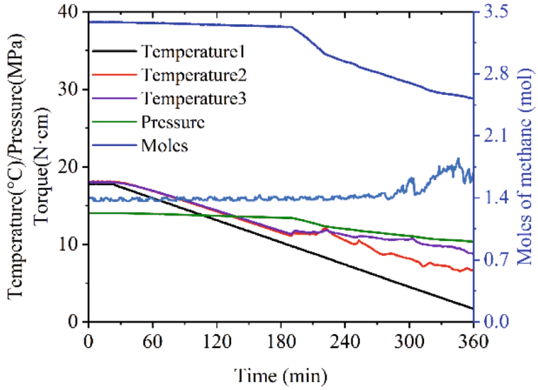
4.2 Research on Experimental Optimization

4.2.1 Experimental Evaluation of HEM Drilling Fluid System for Inhibiting Hydrate Formation

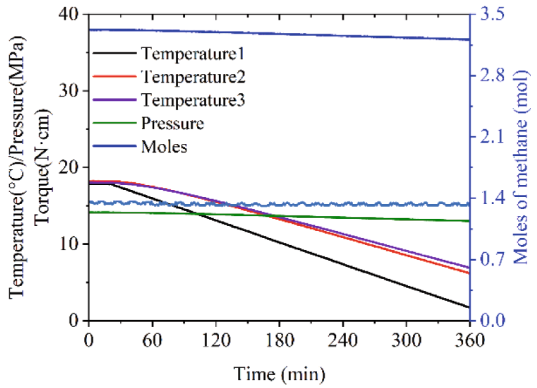
On the basis of numerical simulation research, experimental evaluations were conducted indoors on the hydrate inhibition of the HEM drilling fluid system. The basic formula of the drilling fluid system is described in Sect. 1. The experiment used the constant rotation rate and temperature drop method to evaluate the formation process of hydrates, and the initial gas and liquid phase pressures in the experimental kettle were 14MPa. From the experimental results in Fig. 7 it can be seen that in the experimental kettle without the addition of inhibitors, the decreasing trend of liquid and gas phase temperatures inside the kettle slows down, the pressure inside the kettle gradually decreases, and the torque of the rotor gradually increases under fluctuating conditions. This indicates that the gas and liquid phases inside the kettle decrease, and hydrates gradually form; In the experimental kettle with the addition of 5%KCl, as the experimental time prolonged, the gas and liquid phase temperatures gradually decreased with the decrease of jacket temperature. However, the pressure inside the kettle did not change, and the torque of the rotor remained constant, indicating that there was no hydrate formation. The experimental data is shown in Table 2, which verifies the correctness of the numerical simulation in Sect. 3.1. The 14% NaCl + 6% KCl inhibitor system can meet the hydrate suppression needs during normal drilling, The ethylene glycol optimization in the original semi anti drilling fluid system (14% NaCl + 6% KCl + 8% ethylene glycol) can be deleted.

4.2.2 Experimental Evaluation on the Inhibition of Hydrate Formation by Various Components of HEM Drilling Fluid System

In order to further clarify the mechanism of inhibiting hydrate formation in the HEM drilling fluid system, the hydrate formation inhibition performance of each component in the system was evaluated using the constant rate cooling method [16]. The experimental results are shown in Fig. 8. Based on the evaluation criteria of nucleation temperature, it can be seen that the strength of the hydrate formation inhibition performance of each single agent is: PF-FLO < PF-PAC < PF-XC < PF-UHIB < PF-HLUB. It should be



(a)Inhibition of hydrate formation in a system without added inhibitors



(b) 14% NaCl+6% KCl inhibitor system

Fig. 7. Experimental results of hydrate formation inhibition in HEM drilling fluid system

noted that in the HEM system, only the anti sludge lubricant PF-HLUB has good hydrate formation inhibition ability, but this hydrate inhibition ability only exists under single agent action conditions. Due to the interference of other treatment agents in the system, the HEM system did not show good hydrate formation inhibition ability.

4.3 Mechanism of Inhibition of Hydrate Formation by HEM Drilling Fluid System

The HEM drilling fluid system contains salts such as NaCl and KCl, as well as kinetic inhibitors such as polymers. Based on the results in Figs. 7 and 8, it can be seen that the HEM drilling fluid system with added inhibitors mainly suppresses hydrate formation by adding inhibitor components, and the inhibitory ability is significantly enhanced.

Table 2. Experimental results of hydrate formation inhibition in HEM drilling fluid system

Time, min	Jacket temperature, °C	Liquids temperature, °C	Gas phase temperature, °C	Pressure inside the kettle, MPa	Feedback torque, N·m	Gas Moles, mol
30	17.42	17.97	17.92	14.03	16	3.38087
60	15.99	16.92	16.92	13.94	15.9	3.37459
90	14.57	15.63	15.68	13.82	15.7	3.36439
120	13.14	14.25	14.4	13.69	15.9	3.352
180	10.28	11.51	11.75	13.45	15.8	3.33389
360	1.75	6.57	8.74	10.35	19.3	2.52295
720	16.01	14.85	16.17	11.92	0	2.84277
1020	15.98	15.81	16.47	13.31	0	3.21141
1200	15.98	15.91	16.54	13.64	0	3.29977
1350	15.93	15.9	16.86	13.8	0	3.33758
1500	15.96	15.99	16.91	13.87	0	3.35572

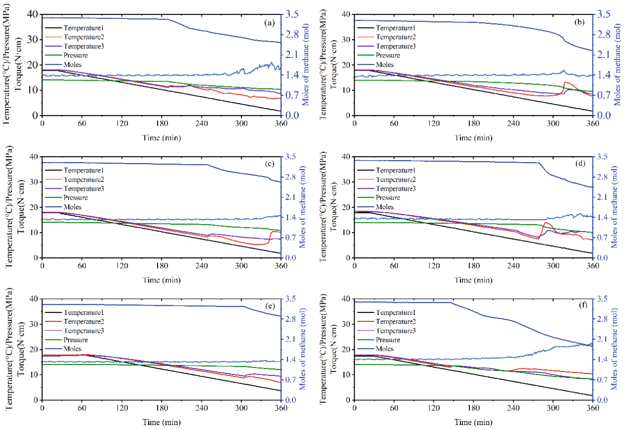


Fig. 8. Experimental results of the inhibitory effect of each component of HEM drilling fluid system on hydrate formation(a) Pure water, (b) PF-FLO, (c) PF-PAC, (d) PF-XC, (e) PF-UHIB, (f) PF-HLUB

Thermodynamic inhibitor mainly changes its Thermodynamic equilibrium conditions by interfering with the hydrogen bond binding between water molecules, which causes the Vapor–liquid equilibrium curve of hydrate to move towards lower temperature and higher pressure, reducing the driving force of hydrate nucleation, thus reducing the formation of gas hydrate. Kinetic inhibitors do not affect the Thermodynamic equilibrium conditions during hydrate formation, but delay it to a certain extent, mainly by destroying the ordered structure of host and guest molecules in the system to interfere with the nucleation rate of hydrate and inhibit the further growth of hydrate crystals. Therefore, by combining thermodynamic and kinetic inhibitors and acting separately from physical and chemical perspectives, a synergistic effect is achieved, becoming a more economical, environmentally friendly and efficient inhibition system. Figure 9 shows the mechanism of a typical complex system inhibiting hydrate formation. Adding NaCl, KCl, etc. to the HEM drilling fluid system, due to the hydrophilicity of Na + and K + ions, can interfere with the formation of stable cage structures of water molecules. After adding dynamic inhibitors such as polymers to the system, polymer molecules will adsorb on its surface, preventing further contact between water molecules and grains, making it impossible for hydrate molecules to continue growing, thus achieving better inhibitory effects.

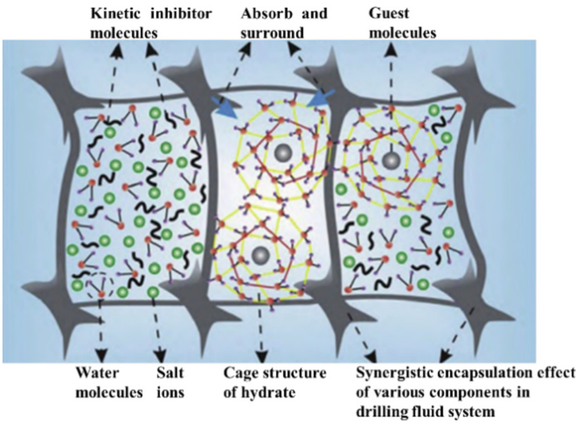


Fig. 9. Mechanism of hydrate inhibition in HEM drilling fluid system

5 Conclusion

(1) On the basis of analyzing the current application status of deep water shallow drilling fluid, a calculation model for ECD and wellbore temperature field in deep water shallow drilling was established. Combined with the actual drilling string combination and drilling parameters during the drilling period, simulation and verification of shallow drilling conditions were carried out. The average error calculated by the model was less than 8% compared to the measured data.

(2) Predictions were made on the temperature field of wellbore at different depths of deep and shallow drilling, and the range of hydrate generation area during drilling was calculated based on the hydrate phase curve. The conclusion was that as the drilling depth increased, the wellbore temperature field increased, and the risk area of hydrate generation gradually decreased. However, during the preparation and early stages of drilling, there was still a risk of hydrate generation in the wellbore.

(3) Numerical simulation research shows that adding 14% NaCl + 6% KCl inhibitor to the HEM system can meet the requirements of normal drilling operations, but it cannot meet the requirements of static operation; The indoor experimental study found that there was no hydrate formation in the reaction kettle with the addition of 14% NaCl + 6% KCl inhibitor. Therefore, the conventional semi anti drilling fluid system can be optimized to HEM + 14% NaCl + 6% KCl without the addition of ethylene glycol, which can meet the operational requirements during normal drilling.

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