Laboratory Study on 210°C High Temperature and Salt Resistant Drilling Fluid

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Abstract

Combined with the current research status in this area at home and abroad, with the improvement of salt and high temperature resistance as the research goal, the laboratory research of salt and high temperature resistant drilling fluid system has been carried out, and lubricants, inhibitors and stabilizers have been optimized. The final drilling fluid formula is: water + 3% sepiolite + 0.3% Na_2CO_3 + 3% RH-225 + 3% KCOOH + 3% G-SPH + 3% CQA-10 + 1.5% ZX-1 + Xinjiang barite, density 2.2 g/cm^3, using hot-rolling furnace, environmental scanning electron microscope, high temperature and high pressure plugging instrument and Zeiss microscopes and other instruments use core immersion experiments, permeability recovery value experiments, and static stratification index methods to perform temperature resistance, reservoir protection, plugging performance, and static settlement stability performance of the configured drilling fluid., Inhibition performance, biological toxicity, salt resistance, anti-pollution performance have been tested, and it is concluded that the temperature resistance is good under the condition of 210°C, and the salt resistance can meet the requirements of 20% NaCl + 0.5% $CaCl_2$ concentration. It has a good reservoir protection effect, the permeability recovery value can reach more than 90%, the performance of restraining water dispersion and cuttings expansion is good, the heat roll recovery rate can reach more than 85%, and the SSSI value shows that its settlement stability performance is good; Its plugging performance is good under high temperature and high pressure. It laid the foundation for the next step to promote the field application of the drilling fluid system.

Keywords

Salt Resistance, High Temperature Resistance, Drilling Fluid,
Performance Evaluation

1. Introduction

In the drilling of high-temperature deep wells, the difficulty of drilling increases linearly with the increase of well depth, especially in the drilling of ultra-deep wells, when the drilling encounters salt layers or salt-gypsum mixed layers, whether the drilling fluid can maintain good rheology and stable filtration Loss is very important, and good and stable drilling fluid performance is often the primary key factor that directly affects the success or failure of drilling [1] [2] [3].

In order to solve the problem of salt resistance and high temperature resistance of filtrate reducer, Guo Xuelei developed a kind of emulsion polymer filtrate reducer. A polymer fluid loss reducer has been developed by Tian Maoming, which is temperature resistant up to 200˚C salt resistant (in NaCl form) up to 20% and calcium resistant (in $CACL_2$ form) up to 2%. Guo Wenyu and his colleagues developed a composite starch filtrate reducer with good salt and temperature resistance. The FLAPI of 150˚C aged salt water and saturated salt water based pulp aged for 16 hours can be reduced from 132 ml and 160 ml to less than 7 ml with only 1% low addition, the product has been successfully used in deep well drilling of gaomiao-3 [4] [5] [6].

In order to solve the problem of salt resistance and high temperature resistance of plugging agent, Moline et Al developed a profile control plugging agent, which has a temperature resistance of 160˚C and salt resistance of 20%. A cross-linked polymer plugging agent was developed by Li Zhizhen and others. The plugging rate can reach about 98%. The copolymer plugging agent has good water absorption, good strength and elasticity after water absorption. Liu Yang developed a selective plugging agent with good temperature resistance, salt resistance, shear resistance, and good oil water selectivity [7] [8] [9].

This indoor study is based on actual needs to optimize the treatment agent to form a salt-resistant and high-temperature drilling fluid system with a temperature resistance of 210˚C and a density of 2.2 g/cm^3. The performance of the drilling fluid is tested and evaluated indoors. The purpose of field application.

2. Treatment Agent Preferred

2.1. Optimal Lubricant

The thermal stability of RH-5, RH-225, LI-101 and other lubricants was evaluated by laboratory tests. During the experiment, the drilling fluid-based mud (500ml tap water + 0.3% Na2CO3 + 3% bentonite) was selected, because the mud was invaded by many kinds of useless solid, the evaluation of the lubricant was more convincing and scientific. The experimental method is as follows: adding a certain proportion of lubricant to the base slurry, the performance of the base slurry is measured before and after 16 hours of hot rolling in a hot rolling furnace at 210 ℃, determination of the lubricity of base paste before and after high temperature using friction coefficient analyzer. The experimental results are shown in Table 1.

Table 1. Lubricant test results.

Numbering	Formula	Experimental conditions	FL$_{HTHP}$ (ml)	AV (mPa·s)	PV (mPa·s)	K$_f$
1	Base slurry	Before aging	31.5	23.0	17.5	0.1558
		After aging	42.8	31.5	22.0	0.2122
2	Base slurry + 1% RH-5	Before aging	12.7	23.5	16.5	0.1329
		After aging	14.2	33.5	24.5	0.2185
3	Base slurry + 3% RH-5	Before aging	13.2	24.5	19.0	0.1053
		After aging	15.4	35.5	28.0	0.2230
4	Base slurry + 5% RH-5	Before aging	12.7	28.5	20.5	0.0945
		After aging	16.2	38.0	21.5	0.2265
5	Base slurry + 1% RH-225	Before aging	12.1	24.5	17.0	0.1033
		After aging	15.5	32.5	21.0	0.0956
6	Base slurry + 3% RH-225	Before aging	11.7	25.0	19.5	0.0793
		After aging	13.5	33.5	22.5	0.0899
7	Base slurry + 5% RH-225	Before aging	10.8	27.0	19.5	0.0659
		After aging	12.8	35.5	24.0	0.0789
8	Base slurry + 1% LU-101	Before aging	13.8	32.0	19.5	0.1032
		After aging	17.4	36.5	22.5	0.1328
9	Base slurry + 3% LU-101	Before aging	12.7	36.5	23.5	0.0921
		After aging	16.3	39.5	28.5	0.1128
10	Base slurry + 5% LU-101	Before aging	11.2	41.0	28.5	0.0798
		After aging	15.8	45.5	31.5	0.1050

From the experimental results in Table 1, it can be seen that among the three selected lubricants, RH-225 has the best temperature resistance effect, a very significant viscosity-reducing effect, and the smallest impact on high temperature and high pressure fluid loss, and the concentration is The effect is relatively good at 3%, so 3% rh-225 was selected as lubricant for drilling fluid system.

2.2. Inhibitor Preference

The role of the inhibitor is to make the drilling fluid have the effect of inhibiting hydration, swelling and dispersion of the clay in the shale formation. The purpose of use is mainly to control the formation of slurry to keep the solid content and rheological properties in a stable state. The second is the role of stabilizing the borehole wall, reducing the difficulty of drilling regular boreholes, and reducing the probability of occurrence of complicated downhole conditions, which is conducive to the conduct of geological logging, electrical logging and cementing operations [10].

The linear swelling test (at 20℃ and normal pressure) was carried out with 2% KCL, KCOOH, NaCOOH, K2SiO3, Na2SiO3 and organic silicon in field cut-

tings to evaluate the inhibition ability of different inhibitors. The results are shown in Table 2.

It can be seen from Table 2 that the expansion rate of laboratory cuttings in KCOOH is the smallest, indicating that its inhibitory effect is the best among them. Therefore, KCOOH is selected as the inhibitor of the configured drilling fluid system. Using cuttings in different concentrations of KCOOH solution, the best dosage of the inhibitor was investigated. The experimental results are shown in Table 3.

When KCOOH reaches 3%, the expansion rate of cuttings does not change much, so KCOOH with concentration of 3% is used as the inhibitor.

2.3. The Optimization of High Temperature Fluid Loss Reducer

A kind of G-SPH as a fluid loss control agent was developed indoors, and it was heated for 16 hours at 210°C for comparison and analysis with similar treatment agents. Base slurry formula: 500 ml tap water + 0.3% Na_2CO_3 + 3% bentonite. The results are shown in Table 4.

The experimental results show that when G-SPH is added to the base slurry, the water loss can be significantly reduced, and the viscosity reduction effect is also very superior. Under the same dosage, G-SPH's fluid loss reduction performance or its viscosity reduction performance far surpasses other similar treatment agents. And when G-SPH is used in drilling fluids at low concentrations, its effectiveness can reach the level of similar treatment agents. The G-SPH

Table 2. Inhibitor linear expansion.

Name Expansion rate (%) Time (h)	8	16	24	48	96
Whater	33.4	41.2	43.5	44.7	45.2
Na_2SiO	26.8	31.5	33.7	34.2	34.9
$KCl + Na_2SiO_3$	18.1	20.1	20.3	20.5	20.8
NaCOOH	13.5	14.6	15.1	16.4	17.2
Silicone	11.5	13.6	13.7	14.2	14.5
K_2SiO_3	9.3	10.2	10.4	11.1	11.5
KCl	8.3	8.7	8.9	9.2	9.5
KCOOH	7.2	7.7	8.0	8.3	8.5

Table 3. Potassium formate expansion rate experiment.

Concentration Expansion rate (%) Time (h)	16	24	48	96
1%	14.2	14.4	14.5	15.1
3%	7.3	7.5	7.9	8.2
5%	6.9	7.2	7.4	7.8
7%	6.6	6.9	7.1	7.4

Table 4. Performance comparison of high temperature fluid loss additives.

System	FL_{HTHP} (ml)	K (mm)	AV (mPa·s)	PV (mPa·s)	YP (Pa)	Gel (Pa)	pH
Base slurry	31.5	1.5	23.0	17.5	5.5	1.0/1.0	9.0
Base slurry + 2%PAC-I	22.3	1.0	25.5	19.0	6.5	1.5/1.5	9.0
Base slurry + 3%PAC-I	19.5	1.0	28.5	21.0	7.5	1.5/1.5	9.0
Base slurry + 4%PAC-I	17.8	1.0	32.0	22.5	9.5	1.5/1.5	9.5
Base slurry + 2%SK-II	15.7	2.0	32.5	21.0	11.5	1.5/1.5	9.5
Base slurry + 3%SK-II	13.5	1.5	35.5	25.0	9.5	1.5/1.5	9.0
Base slurry + 4%SK-II	12.2	1.0	39.5	29.5	10.0	1.5/1.5	9.0
Base slurry + 2% SPNH	16.0	1.5	35.5	22.5	13.0	1.5/1.5	9.0
Base slurry + 3% SPNH	13.2	1.0	38.5	29.0	9.5	1.5/1.5	9.0
Base slurry + 4% SPNH	10.2	1.0	43.5	32.5	11.0	2.0/2.5	9.0
Base slurry + 2% G-SPH	12.9	1.0	26.5	19.5	7.0	1.5/1.5	9.5
Base slurry + 3% G-SPH	8.6	0.5	28.5	21.0	7.5	1.5/2.0	9.0
Base slurry + 4% G-SPH	5.7	0.5	32.5	24.5	8.0	2.0/2.0	9.0

concentration reached 3% to meet the drilling fluid performance requirements, so it was finally decided to choose 3% G-SPH as the high temperature fluid loss reducer of the drilling fluid system.

2.4. The Preferred Weighting Agent

The commonly used weighting agent is barite. We selected barite produced in three places (Sichuan, Xinjiang, Hubei) for comparative experiments, and selected the best performance as the weighting agent of this drilling fluid formulation [11]. The use of these three barites can ensure that the drilling fluid has good rheology and wall-building properties. The maximum density that they can increase is 2.4 g/cm³. When this limit is exceeded, the drilling fluid's Rheology and fluid loss will be difficult to control. The performance comparison results are shown in Figure 1, Figure 2 and Table 5.

According to Figure 1, Figure 2 and Table 5, the result shows that Xinjiang Barite is the best weighting agent for drilling fluid system, it can meet the density requirement of drilling fluid of 2.2 g/cm³, and has good rheology and wall-forming property.

2.5. Optimal Blocking Agent

A plugging agent CQA-10, which is resistant to salt and high temperature, has been developed. Its mechanism of action is: under the influence of the temperature of the formation, the plugging agent is adsorbed on the well wall after dehydration and coalescence deformation, and then forms a layer of film, and It has a certain strength and can prevent the free water in the drilling fluid from penetrating into the formation; under the effect of poor wellbore formation, the
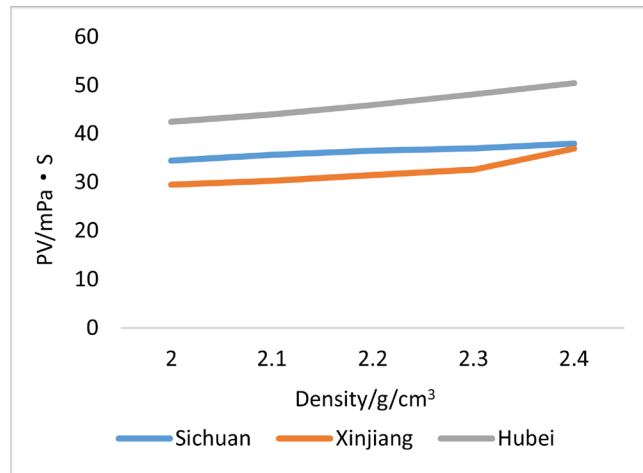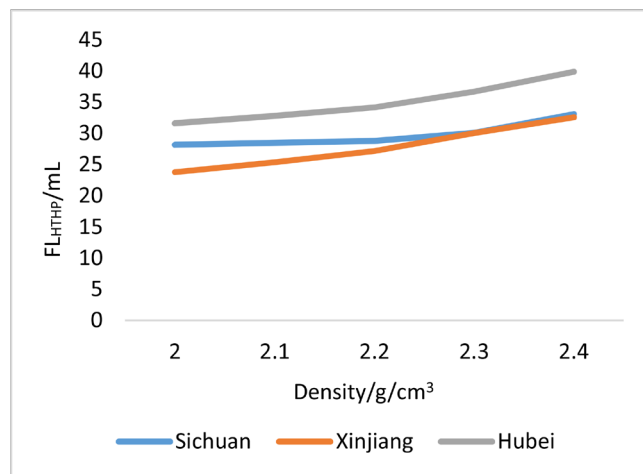
Figure 1. Plastic viscosity curve.

Figure 2. High temperature and high pressure water loss curve.

Table 5. Comparative test of barite properties.

Types of barite	Density (g/cm³)	AV (mPa·s)	PV (mPa·s)	FL$_{HTHP}$ (ml)	K$_f$
Sichuan	2.0	55.5	34.5	28.2	0.0956
	2.2	58.0	36.5	28.8	0.1232
	2.4	60.5	38.0	33.1	0.1584
Xinjiang	2.0	50.0	29.5	23.8	0.0901
	2.2	52.5	31.5	27.2	0.0922
	2.4	54.5	37.0	32.6	0.1032
Hubei	2.0	62.0	42.5	31.6	0.0966
	2.2	66.5	46.0	34.2	0.1328
	2.4	68.0	50.5	39.9	0.1441

high-temperature blocking agent particles will enter the micropores and cracks of the formation, forming a thin film on the surface, and It is insoluble in water and can achieve the effect of preventing water infiltration, so as to reduce the

water loss of HTHP and play the role of anti-collapse [12].

According to the requirements of the experiment, TYDF-121, Koh-5, SOTEX-20, FLT-15A and DYF-20 were selected and compared with CQA-10. The above plugging agents were added into the base slurry (500 ml tap water + 0.3% Na_2CO_3 + 1% bentonite), after 16 hours of hot rolling at 210°C, its properties were tested. The results are shown in Table 6.

The experimental results in Table 6 show that KOH-5 and the developed anti-high temperature plugging agent CQA-10 not only have a smaller water loss at high temperature and high pressure, but also have a smaller viscosity and cut. Therefore, a plugging agent can be selected from the two, considering Considering the factors such as economic cost and effect, the CQA-10 developed in-house was selected as the anti-high temperature plugging agent.

2.6. Optimal Flow Pattern Regulator

Rheology is one of the important parameters of the drilling fluid system. To improve the suspension of the drilling fluid and the ability to carry drill cuttings, it is necessary to add a flow pattern regulator to the drilling fluid [13] [14]. The flow modifier of the salt-resistant and high-temperature drilling fluid system is preferably used in ZX-1 and HV-8. The flow modifier is added to the base slurry (500 ml tap water + 0.3% Na_2CO_3 + 3% bentonite), and the temperature is 210°C Under the experimental conditions, it was heated for 16 hours, and the experimental results are shown in Table 7.

It can be seen from Table 7 that the addition of ZX-1 flow modifier has a better effect on reducing apparent viscosity, plastic viscosity and dynamic shear

Table 6. Contrast test of plugging agent performance.

Numbering	Formula	Experimental conditions	FL_{HTHP} (ml)	FL_{API} (ml)
1	Base slurry	Before aging	31.5	15.5
		After aging	42.8	22.6
2	Base slurry + 3% TYDF-121	Before aging	16.5	12.5
		After aging	27.5	14.3
3	Base slurry + 3% KOH-5	Before aging	15.4	13.4
		After aging	24.8	18.5
4	Base slurry + 3% SOTEX-20	Before aging	18.0	11.9
		After aging	31.0	18.6
5	Base slurry + 3% CQA-10	Before aging	14.9	10.5
		After aging	21.5	15.4
6	Base slurry + 3% FLT-15A	Before aging	19.0	15.2
		After aging	31.0	24.2
7	Base slurry + 3% DYF-20	Before aging	21.0	14.9
		After aging	42.5	25.8

force than HV-8 flow modifier. Therefore, ZX-1 was selected as salt and high temperature resistant drilling Flow modifier for liquid system.

3. Performance Evaluation

3.1. Formula

Through the above indoor research, the type and dosage of the treatment agent of the salt-resistant and high-temperature drilling fluid are optimized, and the final formula of the salt-resistant and high-temperature drilling fluid system is determined as follows:

Water + 3% sepiolite + 0.3% Na_2CO_3 + 3% RH-225 + 3% KCOOH + 3% G-SPH + 3% CQA-10 + 1.5% ZX-1 + Xinjiang barite.

3.2. Evaluation of Temperature Resistance

Whether the effect of temperature is reversible is the main content of investigating the temperature resistance of drilling fluid [15]. The performance before and after hot rolling of the developed drilling fluid formula is evaluated, see Table 8. The salt- and high-temperature drilling fluid was heated at different temperatures for 16 hours using a hot-rolling furnace, and then the changes in its structure and morphology were observed through environmental scanning electron microscopy. The result is shown in Figure 3.

According to Figure 3 of the microscopic morphology, it can be found that under different temperature aging, especially after the temperature is lower than 210˚C, the network space structure of the drilling fluid is basically maintained

Table 7. Performance comparison experiment of flow pattern regulator.

Drug	Condition	AV (mPa·s)	PV (mPa·s)	YP (Pa)	FL$_{API}$ (ml)
Base slurry + 1.5% ZX-1	Before aging	20.5	18.0	2.5	4.8
	After aging	23.5	16.0	7.5	3.7
Base slurry + 1.5% HV-8	Before aging	24.5	18.5	6.0	5.2
	After aging	28.0	19.5	9.5	4.0

Table 8. Performance before and after hot rolling

Experimental conditions	AV (mPa·s)	PV (mPa·s)	YP (Pa)	Gel (Pa/Pa)	FL$_{API}$ (ml)	FL$_{HTHP}$ (ml)
Room temperature	46.5	32.0	14.5	1.0/2.0	3.4	6.0
170˚C, 16 h	48.0	33.5	14.5	1.5/2.0	3.6	8.5
180˚C, 16 h	49.5	33.0	16.5	1.5/2.0	3.9	9.0
190˚C, 16 h	51.0	35.5	15.5	1.5/2.0	4.2	9.2
200˚C, 16 h	52.0	38.0	14.0	1.5/2.0	4.5	9.5
210˚C, 16 h	53.5	40.5	13.0	1.5/2.0	5.1	9.6
220˚C, 16 h	68.5	55.0	13.5	2.0/3.5	8.8	15.8

well, and the rheological properties of the configured salt and high temperature resistant drilling fluid are excellent. It has been proved microscopically. From Table 8, Figure 3, it can be seen that the drilling fluid has stable performance at high temperature, not only has good rheological property, but also has the advantage of low filtration, which meets the original purpose of the study.

3.3. Evaluation of Reservoir Protection Effect

According to SY5336-88 "Recommended Methods for Conventional Core Analysis" and SY/T5358-94 "Recommended Experimental Methods for Sandstone Reservoir Sensitivity Evaluation Experiments", it can be seen that the salt-resistant and high-temperature drilling fluid is used to evaluate the permeability recovery value of the drilling fluid. Procedure and method [16] [17] [18], this method is used to carry out the artificial core permeability recovery test. The core results of the experiment are shown in Table 9.

It can be seen from Table 9 that the drilling fluid has a good reservoir protection effect, and the permeability recovery value can reach 91.89%, which meets the requirements of gas reservoir protection.

3.4. Plugging Performance Evaluation

This time, the plugging effect of the salt-resistant and high-temperature resistant drilling fluid is evaluated through the simulated fracture metal fracture plate of the high temperature and high pressure plugging instrument. The equipment is composed of a pressure control system, a simulated crack device and a kettle body device. The test was performed under the experimental conditions of
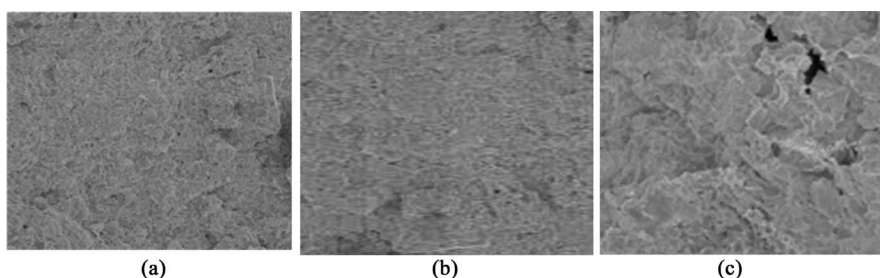

| (a) | (b) | (c) |

Figure 3. Micro-topography after hot rolling. (a) 50 μm 100˚C After aging; (b) 50 μm 210˚C After aging; (c) 50 μm 220˚C After aging.

Table 9. Experimental results of permeability recovery value.

Core	K_o (10^{-3} μm²)	K_d (10^{-3} μm²)	K_d/K_o (%)
150#	4.72	4.31	91.31
72#	9.95	9.02	90.65
98#	10.12	9.30	91.89
305#	11.53	10.48	90.85
17#	12.11	11.02	91.02
215#	12.86	11.73	91.23

210˚C and 3.5 MPa. Then use FL_{API} and FL_{HTHP} filter loss tester to measure the change of filter loss with time in the room. Figure 4 shows the influence of the sealing layer formed during the experiment under the Zeiss stereo microscope. Table 10 Test results.
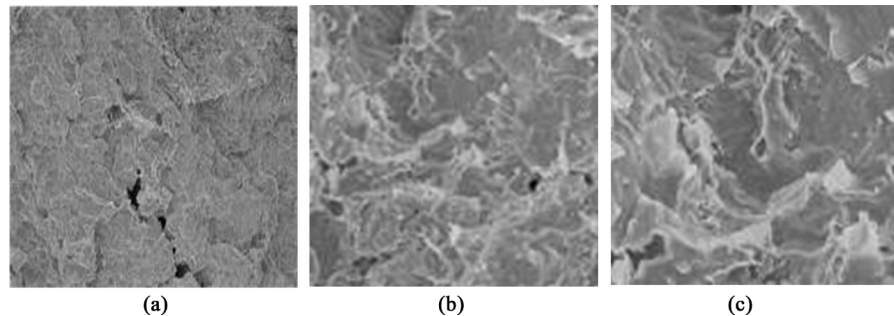
Note: (a), (b), and (c) are salt and high temperature resistant drilling fluid systems(×1000, ×5000, ×10,000 times).

Figure 4. Blocking effect diagram of drilling fluid. (a) 50 μm; (b) 10 μm; (c) 5 μm.

Table 10. Plugging performance test.

t/h	FL_{API} (ml)	FL_{HTHP} (ml)
0.5	3.4	6.1
1.0	3.4	6.2
2.0	3.4	6.4
3.0	3.5	6.6
4.0	3.5	6.8
5.0	3.6	7.0
6.0	3.6	7.2

According to the results of Figure 4, it can be seen that the plugging particles of the salt-resistant and high-temperature resistant drilling fluid become soft and deformed under the combined action of the required high temperature and pressure, and form physical plugging layers in voids, cracks, etc., to stabilize the borehole wall. According to Table 10, FL_{API} (ml) and FL_{HTHP} (ml) are 3.6 ml and 7.2 ml respectively at 6 h. According to the results of two experiments, its plugging performance is good.

3.5. Static Settlement Stability Evaluation

The static stratification index method calculates the Static Stable Stratification Index (SSSI). The larger the value, the more serious the sedimentation of the drilling fluid, and vice versa, the more stable it is. Specific test steps: first put the drilling fluid in the aging tank, keep it static at 210˚C for a period of time, and then layer the drilling fluid in the aging tank into four layers: free fluid layer, upper, middle and lower layer., And then observe, record and calculate the volume and density of each layer separately, and calculate the value of the stratifi-

cation index SSSI by formula (1). The larger the value, the more serious the drilling fluid sedimentation, and vice versa, the better the sedimentation stability [19] [20] [21], the results are shown in Table 11.

$$SSSI = \sum_{n=1}^{\infty} \left(ABS\left[V\%_i \times \Delta MW_i \right] \right) \tag{1}$$

where

$SSSI$ is a static stratification index;

ABS is digital absolute value;

$V\%_i$ is the volume fraction of each layer in the aging tank, %;

ΔMW_i is the density difference between the drilling and completion fluid and the initial drilling and completion fluid for each layer, g/cm^3.

From the results in Table 11, referring to the relevant manuals [19] [20] [21], the settling stability of the salt-resistant and high-temperature drilling fluid system is good, and its SSSI value increases with the increase in standing time, and its stability is 7 It is relatively stable during the day.

3.6. Inhibitory Evaluation

Experimental method: The formation cuttings were made into 6 - 10 Mesh particles, 50 g (10% weight-volume ratio) were added to 500 mL experimental liquid, then packed into a high temperature aging tank, and heated for 16 hours at 210°C simulated well temperature, the hot rolled experimental liquid is then passed through a 40 mesh sieve, and the undispersed cuttings are retained on the sieve. After drying, they are re-weighed (expressed as w) and compared with the hot rolled experimental liquid. The experimental results are shown in Table 12.

$$\text{Heat roll recovery rate} = (W/50) \times 100\% \tag{2}$$

Table 11. SSSI evaluation results of drilling fluid at 210°C

t 时间/d	Dispensing rate%	ρ/(g·cm^{-3})			SSSI
		Upper layer	Middle level	Lower level	
0	0	2.20	2.20	2.20	0
1	0.02	2.19	2.21	2.20	0.0004
3	0.05	2.19	2.22	2.21	0.0020
7	0.09	2.18	2.22	2.22	0.0054
15	0.98	2.15	2.25	2.25	0.1470

Table 12. Hot rolling recovery rate results.

System	Initial weight	Remaining weight	Recovery rate
Distilled water	50 g	8.55 g	17.1%
Trisulfon Drilling Fluid: Base slurry + 3% SMC + 3% SMP + 3% SMK	50 g	31.60 g	63.2%
Positive electric glue drilling fluid :Base slurry + 2% CYZ + 2% SPC + 2% SPNH	50 g	40.30 g	80.6%
Formula: Water + 3% sepiolite + 0.3% Na$_2$CO$_3$ + 3% RH-225 + 3% KCOOH + 3% G-SPH + 3% CQA-10 + 1.5% ZX-1 + Xinjiang barite	50 g	43.95 g	87.9%

Experiments show that the developed salt and high temperature resistant drilling fluid system has good inhibitory properties, and the heat roll recovery rate can reach over 87.9%.

3.7. Biological Toxicity Evaluation

Acute Biological Toxicity According to GB/T15441-1995 "Water Quality Determination of Acute Toxicity: Luminescent Bacteria Law" as the standard, the acute biological toxicity EC_{50} of each treatment agent and formulation is determined. When the value is greater than 30,000 mg/L, the tested sample is non-toxic. The drilling fluid treatment agent and formula are respectively formulated into aqueous solutions according to the concentration used, and then the luminosity of the luminescent bacteria of the sample to be tested is measured respectively, until the concentration of the sample to be tested when the luminescent ability of the luminescent bacteria is reduced by half is determined, and this concentration is EC_{50} value. The experimental results are shown in Table 13.

With reference to the relevant classification standards [22] [23], it can be found from Table 13 that the drilling fluid treatment agent we selected and the salt-resistant drilling fluid system formulated there from are non-biologically toxic and meet the environmental protection requirements of drilling fluids.

3.8. Salt Resistance Evaluation

Add different concentrations of NaCl and $CaCl_2$ to the formulation system to test its rheological properties and fluid loss reduction performance at high temperatures (210°C).

It can be seen from Table 14 that after adding salt to the modified formula

Table 13. Comparison of biological toxicity

Name	Use concentration (%)	EC_{50}/mg·L^{-1}	Toxicity classification
RH-225	5.0	>30,000	Non-toxic
KCOOH	5.0	>100,000	Non-toxic
G-SPH	4.0	>30,000	Non-toxic
CQA-10	3.0	>100,000	Non-toxic
ZX-1	1.5	>100,000	Non-toxic
Formula	Drilling fluid system	>30,000	Non-toxic

Table 14. Salt resistance test results.

Increase/%	AV (mPa·s)	PV (mPa·s)	YP (Pa)	FL$_{HTHP}$ (ml)
0	53.5	40.5	13.0	9.6
5% NaCl	55.5	43.5	12.0	11.2
5% NaCl + 0.5% CaCl$_2$	58.5	46.5	12.0	12.0
10% NaCl + 0.5% CaCl$_2$	61.5	50.0	11.5	13.1
15% NaCl + 0.5% CaCl$_2$	63.0	54.0	9.0	13.9
20% NaCl + 0.5% CaCl$_2$	66.5	57.5	9.0	14.8

system, AV, PV and YP all maintain a relatively high and reasonable value, and the FL_{HTHP} water loss does not exceed 15 mL, indicating that the formula system can resist at least 20% NaCl + 0.5% $CaCl_2$ The salt shows that the system has strong anti-salt and anti-pollution ability.

3.9. Evaluation of Resistance to Contamination by Drill Cuttings

KCL drilling fluid with a density of 2.2 g/cm³ was prepared by adding different amounts of artificial rock cuttings and artificial rock cuttings powder (less than 10 Mesh).

Table 15. Anti-pollution test results.

System	AV (mPa·s)	PV (mPa·s)	YP (Pa)	Gel (Pa/Pa)	FL_{API} (ml)	FL_{HTHP} (ml)
Formula	53.5	40.5	13.0	1.5/2.0	5.1	9.6
Formula + 1% cuttings and cuttings powder	54.0	40.5	13.5	1.5/2.0	5.3	13.4
Formula + 2% cuttings and cuttings powder	55.5	41.5	14.0	1.5/2.0	5.6	13.5
Formula + 3% cuttings and cuttings powder	56.5	44.5	12.0	1.5/2.0	6.1	13.7
Formula + 4% cuttings and cuttings powder	59.0	47.5	11.5	1.5/2.0	6.6	13.8
Formula + 5% cuttings and cuttings powder	61.5	49.0	12.5	1.5/2.5	7.2	14.0
Formula + 6% cuttings and cuttings powder	70.5	53.5	17.0	1.5/3.5	11.4	20.1

It can be seen from Table 15 that the salt-resistant and high-temperature drilling fluid still maintains a relatively stable rheology and fluid loss under the pollution of 5% of cuttings and cuttings powder. Therefore, this formula meets the performance requirements.

4. Conclusions

1) In this laboratory study of salt and high temperature resistant drilling fluids, through optimization of lubricants, inhibitors and other treatment agents, it is determined that RH-225 lubricant, KCOOH as inhibitor, G-SPH as high temperature fluid loss reducer, Xinjiang Barite is a weighting agent, CQA-10 is a plugging agent, and ZX-1 flow pattern regulator.

2) The formula is determined: water + 3% sepiolite + 0.3% Na_2CO_3 + 3% RH-225 + 3% KCOOH + 3% G-SPH + 3% CQA-10 + 1.5% ZX-1 + Xinjiang barite, with a density of 2.2 g/cm³.

3) Through experiments, a series of performance evaluations of the drilling fluid system has been carried out. It has good lubricity, plugging properties, settlement stability, environmental protection, salt resistance and anti-pollution properties. The temperature resistance reaches 210°C, and it has good storage. Layer protection effect, the permeability recovery value can reach more than 90%, with good inhibition, and the heat roll recovery rate can reach more than 85%.

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Conflicts of Interest

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

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