Study on high-temperature resistance, salt/calcium resistance of environment-friendly colloidal gas aphron drilling fluid

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Abstract: The Colloidal Gas Aphron (CGA) drilling fluid successfully solved the problems of lost circulation and reservoir damage that are faced by drilling in depleted oil/gas reservoirs and low-pressure areas. However, the lack of high-temperature resistance, salt/calcium resistance are the key problems that restrict its application in complex formations. This study provides an environmentally friendly and non-toxic CGA formula based on self-developed reagents. Microscopic tests showed that stable aphrons were successfully generated in 36%NaCl-CGA or 7.5%$CaCl_2$-CGA aged at 150℃, with stabilization of ＞2 hours. The Herschel-Bulkely model accurately describes the rheological behavior of CGA fluids containing NaCl/$CaCl_2$. The addition of NaCl increases CGA fluid viscosity, while $CaCl_2$ is the opposite. However, CGA fluid maintains appropriate rheological parameters and shear thinning behavior, which means good cutting carrying capacity. With the addition of NaCl/$CaCl_2$, CGA has low filtration volumes, which meets API requirements. NaCl/$CaCl_2$ reduces the lubrication coefficient and increases the adhesion of the mud cake. Moreover, the anti-cuttings pollution ability of 150℃ aged CGA can reach 10%. CGA, 36%NaCl-CGA, and 7.5%$CaCl_2$-CGA all have low linear expansion rates (<28%) and high rolling recovery rates (>84%). Therefore, the CGA system has good inhibitory performance and is compatible with easily hydrated formations.

Key words: CGA drilling fluid; environmentally friendly; underbalanced drilling; high-temperature resistance; Ca^{2+}/Na^{+} contamination tolerance.

1. Introduction

Recently, a near-balanced drilling technology, the colloidal gas aphron (CGA) drilling fluid has been successfully applied in drilling depleted oil/gas reservoirs and other under-pressure areas[1]. It is a near/under-balanced technology which is composed of independent ridgid micro-foams with bubble size ~100μm, and has the following significant advantages: a) As shown in Figure 1, the aphrons are composed of one core and three films. The unique structure makes it have high stability and strong pressure-bearing capacity, which is nearly 10 times that of ordinary foam[2]. Through cyclic pressure/relief experiments and pressure sealing experiments, Xie et al. confirmed that under a pressure of 20MPa, CGA has compressibility and recovery properties, and can effectively seal sandstone formations of 40-60 mesh[3]. Pasdar et al. monitored the behavior of CGA under high pressure using a high-pressure microscope and studied the single bubble behavior and bubble size distribution of CGA. Observations indicate that CGA survived at pressures as high as 13.8MPa may support the idea for field applications of CGA as drilling fluids[4]. Zheng et al. combined microscopy and HTHP filtration experiments to further demonstrate the sealing performance of CGA fluids under conditions of 120-200℃ and 3.5MPa[5]; b) Aphrons can be used as elastic plugging materials to alleviate or avoid lost circulation. Also, aphrons have little affinity with each other or the formation rock surface, and can be easily removed by formation fluid backflow during the production stage[6,7]; c) The construction process is simple and don't need the air compressor. Aphrons are generated by mechanical agitation of surfactants and biopolymers at a speed of higher than 5000rpm or shearing of pipelines[8].

In theoretical research, scholars mainly focus on the aphrons stability and bubble size distribution, the rheology and plugging properties in porous media, and have obtained the following conclusive results:

a) In terms of the optimization of foaming agents and foam stabilizers, scholars have successively evaluated a variety of foam stabilizers (XG, starch, CMC, etc.) and multiple types of foaming agents (SDS, CTAB, X-100, CAPB[9], plant root extraction, etc.). It is proposed that the CGA system prepared by 0.3~0.8% xanthan gum (XG) and ~0.5% sodium dodecyl sulfate (SDS) is the preferred system, with high stability and good rheology[10-15]. The polymer concentration greatly influenced the stability and bubble size of CGA fluids. The most stable CGAs were formed at higher concentrations of polymer[16].

b) The average size of the aphron is affected by many factors such as the type and concentration of surfactant/polymer, temperature, pressure, agitation rate, and more. As the concentration of the foaming agent increases, the aphrons size increases; with the increase of the foam stabilizer, the size of the aphrons decreases, and the stability is significantly enhanced[17]. Alizadeh et al. established the mathematical relationship between the bubble size and temperature-pressure, and pointed out that temperature is the main factor affecting the size of aphrons[18].

c) In 2005, Popov and Growcock took the lead in proving that aphrons would form a plugging zone at the front of the fluid through radial flow experiments[19]; In 2012, Nareh et al. pointed out that more attention should be paid to the size distribution of aphrons rather than its average size under porous media[20]; In 2019, the flow and plugging properties of CGA fluid in heterogeneous porous media were visually observed by Mohsen et al. by using the etched glass plate model and microscope[21]. By analyzing the injection pressure and backflow permeability data, it was confirmed that CGA fluid can significantly control the flow of fluid to fractures.

d) In terms of rheology, Arabloo et al. used eight kinds of rheological models to describe the rheological behavior of a typical CGA drilling fluid m prepared by XG and SDS at 25-45°C, and selected the Herschel-Bulkley, Mizhari-Berk, Sisko, Power-Law and the Robertso-Stiff model[17]. Ehsan et al. further proved that the Herschel-Bulkley model has high applicability to the CGA system, the goodness of fit is higher than 0.999[13]. In the latest research, nanocomposite CGA fluids have attracted much attention. Herschel-Bulkley, Mizhari-Berk, Power Law, and Robertson-Stiff models' predictions have strong consistency with the experimental data of nano-enhanced colloidal gas aphron (NCGA)-based fluids[22]. The CGA fluids have also been used as adsorbents that are easily removed from contaminated wastewater[23,24].

Table 1 lists the field application research progress of CGA drilling fluid in recent years. The CGA drilling fluid has successfully solved the problems of serious lost circulation, reservoir damage, and difficult drilling that often occurred in drilling depleted oil/gas reservoirs and low-pressure areas. The early development of the CGA drilling fluid was mainly to optimize and compound commercial foaming agents and stabilizers to meet the needs of the site. In the past five years, the research direction has gradually changed to the independent synthesis of new treatment agents. The stability, high-temperature resistance, and anti-pollution ability of the system are improved. However, at present, the temperature resistance of CGA drilling fluid is still within 150℃, the salt resistance is ≤20% and the calcium resistance is generally less than 1%. Further breakthroughs must be made in the aspects of high-temperature salt and calcium resistance and its environmental properties[25,26].

In this paper, a novel CGA drilling fluid system was constructed by the self-developed environment-friendly foam stabilizer EST, foaming agent AGS-8, and lubricant ChCl-PEG. A comprehensive evaluation of the stability, rheology, lubricity, filtration, anti-cuttings pollution, inhibition, environmental protection was carried out in high temperature high salt (150℃, ≤36%NaCl) or high temperature high calcium (150℃, ≤7.5%$CaCl_2$) conditions.

2. Technical requirements for CGA drilling fluids

Combined with literature research, this study puts forward the technical requirements for CGA drilling fluid.

(1) Stability: After high-temperature aging, the CGA drilling fluid needs to maintain good stability, which is the premise for safe drilling. In the laboratory test, the change of aphrons morphology can be observed by microscope and combined with the change of drilling fluid density, the drainage, coalescence, and defoaming of aphrons in the drilling fluid, the stability can be analyzed. Generally, one cycle of drilling fluid is usually no more than 2h.

(2) Good rheology: After high-temperature aging, the drilling fluid needs to maintain good rheology to solve the problems of suspension and carrying cuttings in the drilling process, as well as keep the wellbore clean, and ensure downhole safety. Generally, it is suitable to keep the value of flow behavior index (n) at 0.4~0.7 and the value of YP/PV higher than 0.36. In addition, the LSRV is a concerned rheological parameter index in CGA drilling fluids. The LSRV value of the CGA drilling fluid system after high-temperature aging should be higher than 10000mPa·s[10,27].

(3) Low fluid loss: Studies have shown that near/underbalanced drilling still has the possibility of filtration[28]. Therefore, the high-temperature filtration property of the CGA drilling fluid cannot be ignored, and the fluid loss volume (FL_{API}) should be controlled within 15mL.

(4) The pull-up and rotation resistance of the drill string increases greatly with the increase of the well depth, and the drilling tools wear seriously during the drilling process. Drilling fluids and mud cakes need to maintain high lubricity (extreme pressure lubrication coefficient ≤ 0.20) to ensure low friction and torque, reduce sticking, and protect drilling tools[29,30].

(5) Inhibitory: For areas with high mudstone content, prone to collapse and clay hydration

problems, the drilling fluid needs to have low fluid loss and strong inhibition to ensure wellbore stability[31].

(6) Cuttings resistance: Solid powder with large specific surface areas, such as cuttings, bad soil, sand, etc., will be produced during drilling. Some Solid dust will defoam or inhibit foaming. Therefore, CGA drilling fluid is also required to have a certain ability to resist cuttings pollution during on-site construction[32,33].

(7) Environmentally friendly: the CGA drilling fluid should not only achieve the due auxiliary drilling effect but also consider environmental protection issues, including non-toxic and easy degradation of raw material, and meeting the discharge standard and easy degradation after waste. Hence, the biodegradability and toxicity of the CGA drilling fluid system were evaluated[34].

3. Materials and Method

3.1 Materials

In this paper, foam stabilizer (EST) is a graft-modified starch prepared by inverse emulsion polymerization. The synthesis method and high-temperature foam stabilization properties of EST have been reported in the previous literature[35]. EST plays the role of stabilizing foam and reducing filtration loss at a dosage of ≥1%. With the increase of EST concentration, the application effect will be enhanced. However, the dosage of EST should be controlled within 5% to avoid the adverse effect of high-concentration EST on slurry preparation.

The foaming agent is an alkyl glycine-type zwitterionic surfactant (AGS-8), which is prepared with sodium chloroacetate and n-octylamine. The surface activity, of AGS-8 can be referred in Table 2 and the published article for details[36]. Research has proved that AGS-8 has a good synergistic stabilization effect with EST, the high-temperature resistance is ≥180℃, and the salt resistance reaches saturation (36%NaCl).

A deep eutectic solvent (DES) ChCl-PEG synthesized by choline chloride and polyethylene glycol was added to the system as a lubricant. DES is a new environmentally friendly, non-toxic and biodegradable solvent discovered, which usually consists of two or three kinds of hydrogen bond donors (HBD) and hydrogen bond acceptors (HBA) [37,38]. The HBA of ChCl-PEG is choline chloride (ChCl) for it contains a lot of positive charges, which is expected to form a physical adsorption film on the surface of the friction pair through electrostatic action. The HBD ChCl-PEG is polyethylene glycol (PEG). PEG can effectively reduce the wear scar and roughness between friction pairs and is a good water-based lubricant.

As Table 3 shows, the biodegradability indexes (Y) of EST, AGS-8, and ChCl-PEG are all greater than 25, and the materials are all easily biodegradable.

3.2 Methods

3.2.1 Preparation and observation of CGA drilling fluid

CGA drilling fluid was prepared with 3%bentonite base mud, EST, AGS-8, and ChCl-PEG. First, the base mud was prepared by mixing freshwater, 0.25%Na_2CO_3, and 3% bentonite. After stirring for 1h, the mud was stood for 16h. Second, add EST and ChCl-PEG to the base slurry (300 mL) in turn, mix and stir at 8000 rpm for 20 min by using a high-speed mixer (Model WT-2000C, China). The polymer is fully dispersed in the base slurry. Add AGS-8 continuously and stir at 10000rpm for 3min to obtain the CGA drilling fluid at normal temperature. Then, CGA drilling fluid was put into a roller furnace (Model XGRL, China) and aged at 150℃ for 16h. After that, high-temperature CGA drilling fluid was obtained by stirring at 10000rpm for 3min again.

The salt-resistance and calcium-resistance of CGA drilling fluid were evaluated by adding a certain concentration of NaCl or $CaCl_2$.

3.2.2 Evaluation of drilling fluid properties

Microscopic observation of aphrons: The CGA drilling fluid sample was placed on the glass slide, and the microbubbles in the system were visually observed by a polarizing microscope with CCD high-speed camera (Model Olympus BX51, Japan). The microbubbles size in the images was measured by Nano-measurer software, and then statistically analyzed in the Origin software[39].

Rheology: The rheological properties of CGA drilling fluids were studied using two viscometers. A Brookfield viscometer (Model Brookfield DV-Ⅱ) was used to test the LSRV of CGA drilling fluids at 0.3 rpm. The six-speed rotational viscometer is used to test the shear stress data at different shear rates of the CGA system. Four commonly used rheological models are used to describe the rheological behavior of CGA fluid under high-temperature, high-salt, or high-calcium, and the optimal model with highest accuracy is selected[40].

$$\text{Binham Model: } \tau=\tau_0+\mu_P\gamma \tag{1}$$

$$\text{Power-law Model: } \tau=K\gamma^n \tag{2}$$

$$\text{Casson Model: } \tau^{1/2}=\tau_c^{1/2}+\eta_\infty^{1/2}\gamma^{1/2} \tag{3}$$

$$\text{Herschel-Bulkely Model: } \tau=\tau_y+K\gamma^n \tag{4}$$

Where, τ is the shear stress, θ is the reading of six-speed viscometer, γ is the shear rate, τ_0 is the yield point, μ_P is the plastic viscosity, K is the consistency index, n is the flow behavior index, τ_c is the yield point of the Casson model, η_∞ is the ultimate high shear viscosity, τ_y is the yield point of the H-B model.

The rheological parameters were calculated according to formulas (5~7). Stir the drilling fluid at 600rpm for 10s, and after standing for 10min, multiply the maximum reading of the dial at 3rpm by 0.511, which is the gel strength (GS_{10}min). The ratio of YP and PV is defined as the YP/PV.

$$\text{Apparent viscosity (AV)}=\theta_{600}*0.5 \tag{5}$$

$$\text{Plastic viscosity (PV)}=\theta_{600}-\theta_{300} \tag{6}$$

$$\text{Yield point (YP)}=0.511*(\theta_{300}-PV) \tag{7}$$

Filtration: According to the American Petroleum Institute (API) standard, the API filtration volume of CGA drilling fluid is tested in the atmosphere of 0.69mpa N_2 by using a medium pressure fluid loss instrument (Model SD -6, China), and the filtration volume (FL_{API}) of the sample within 30min is recorded[41].

Lubricity: The lubrication performance of drilling fluid includes the lubricity of mud cake and the lubricity of fluid. The mud cake adhesion coefficient (f) and extreme pressure lubrication coefficient (K) are the two main technical indexes to evaluate the lubricity of drilling fluid. They are evaluated by mud cake adhesion coefficient instrument (Model EP, China) and extreme pressure lubrication instrument (Model NF-2, China) respectively. The indexes are calculated according to Formula 8-11[42].

$$\text{Adhesion coefficient (f)=Maximum torque value (N)}\times 0.845/100 \tag{8}$$

$$\text{Correction factor (F)=34/Friction coefficient with water as calibration} \tag{9}$$

$$\text{Friction coefficient (M)= The reading of friction coefficient/100} \tag{10}$$

$$\text{Lubrication coefficient (K)= } F\times M \tag{11}$$

Inhibitory: A linear dilatometer and rolling recovery experiment were used to analyze the inhibition of drilling fluid. Immerse the sample into the standard bentonite block that is pressed by the hydraulic instrument, connect the linear dilatometer and computer software, and test the expansion amount and expansion rate of the bentonite block within 16h. Rolling recovery experiments were carried out by using a roller furnace (Model XGRL, China). Take about 20g of sandstone rock samples (6~10 mesh) and 350mL of drilling fluid sample into an aging jar, heat it at 150℃ for 16h. After taking out, rinse and dry, the sample was sieved with a 40-mesh sieve. Collect and weigh the cuttings that do not pass through the 40-mesh sieve, and the ratio of mass to the initial rock sample mass is the rolling recovery rate[43].

3.2.3 Environmental testing

BOD_5/COD method is an important evaluation method for the discharge and treatment of industrial wastewater containing organic matter. Dissolve the sample in deionized water, and test the five-day biochemical oxygen demand (BOD_5) and chemical oxygen demand (COD) of the sample to evaluate the biodegradability of the material. The biodegradability evaluation index (Y) was defined as the percentage rate of BOD_5 and COD.

According to the Standard “SY/T 6788-2010”, the biotoxicity test of the CGA system is carried out by the luminescent bacillus method[44]. When the luminescent ability of luminescent bacteria decreases by half, the concentration of oilfield chemicals is recorded as EC_{50}, which is used to characterize the acute toxicity level of water. The greater the EC_{50} value, the lower the biological toxicity. The corresponding relationship between EC_{50} and the toxicity of drilling fluid is listed in Table 4.

4. Results and Discussion

4.1 Orthogonal experiment: determining the optimal concentration of the treatment agents

A three-factor four-level orthogonal experiment was designed to determine the optimal concentration of each reagent in the formula of CGA. The high-temperature stability parameters of the system were used as the evaluation index, recording the time (T_0) when CGA begins to discharge liquid after aging at 150℃ for 16h. The results are shown in Table 5.

Based on the results of 16 sets of experiments, the average values P_1, P_2, P_3, P_4 for each factor and level were calculated, as well as the difference between the maximum average and the minimum average (range R). Results indicate that $R_A>R_B>R_C$, that is, the effects of the three reagents on the stability of the CGA system are EST, AGS-8, and ChCl-PEG in descending order. For factor A (EST dosage), $P_3>P_4>P_2>P_1$, that is, when the dosage of EST is 3%, the system stability is optimal; For factor B (AGS-8 dosage), $P_1>P_4>P_3>P_2$, that is, when the dosage of AGS-8 is 3%, the system stability is optimal; For factor C (ChCl PEG dosage), $P_2>P_4>P_3>P_1$, that is, when the dosage of ChCl-PEG is 3%, the system stability is optimal.

Therefore, based on the high-temperature stability of the CGA drilling fluid system as the evaluation standard, the optimal formula for the CGA system was determined through orthogonal experiments as follows:

3% Bentonite mud+3% EST+3% AGS-8+3% ChCl PEG

4.2 Bubble size distribution and stability of aphrons

The system of CGA, CGA with 36%NaCl, and CGA with 7.5%$CaCl_2$ are taken out after 150℃ aged. After stirring at 10000rpm for 3min, the densities of the drilling fluid decreased from 1.03 g/cm^3 to 0.78, 0.75, and 0.66 g/cm^3, respectively. Figure 2(a) and Figure 3(a) show aphrons and the bubble size distribution in the 150℃ aged CGA system. Through the statistical analysis, it is found that the bubble size of aphrons in the figure is between 27.08~265.45μm, about 87% of the aphrons have a bubble size of 10~150μm, and the average bubble size is 99.15μm.

Figure 2(b) and (c) show that in the CGA system containing 36%NaCl or 7.5%$CaCl_2$, the aphrons always maintain a stable spherical shape with a thick liquid film, and keep independent of each other, which is highly consistent with the description of aphron structure by Sebba et al[45]. In other words, aphrons with stable structures have been proved to be generated at high-temperature high salt, and high-temperature high calcium.

Figure 3(b) shows that the bubble size of the aphron s in the CGA system with 36%NaCl ranges from 33.86 to 266.52μm, the proportion of aphron s in the range of 10~150μm exceeds 93%, and the average diameter is 97.35μm. Figure 3(c) shows that the bubble size of aphrons in CGA with 7.5%$CaCl_2$ ranges from 21.81 to 285.39μm, the proportion in the range of 10~150μm exceeds 96%, and the average diameter is 74.65μm. Under the same conditions, NaCl had little effect on the density and aphron size of the CGA system. The addition of $CaCl_2$ increased the proportion of small-diameter microbubbles in the CGA system and decreased the average diameter.

In general, the bubble size distribution of aphrons in this study is highly consistent with the that of the previous reference, which intuitively proves that CGA drilling fluid is successfully generated under the conditions of high temperature, high salt, or high calcium by using EST, AGS-8, and CHCl-PEG[8].

Figures 4 (a), (b), and (c) show the time-dependent image of aphrons in the CGA system, CGA containing 36%NaCl, and CGA containing 7.5%$CaCl_2$, respectively. The distribution of aphrons is shown in Figure 5. There was no coalescence between foams, and no Plateau boundary in the whole observation period, which indicates that the pressure difference drainage and coalescence combination do not occur violently. As time goes by, gas diffusion takes place between aphrons of different diameters. The small diameter bubble becomes smaller and smaller until it disappears, and the large diameter bubble increases. According to Table 6, the average diameters of CGA and CGA systems containing 7.5% $CaCl_2$ after standing for 2 hours increase by 20.85 and 18.85μm, respectively. The proportion of aphrons with a diameter <100μm decreased by 11.27% and 10.97%, respectively, which is within an acceptable range. The average diameter and bubble size distribution of CGA systems containing 36% NaCl did not show significant changes. In short, the CGA system and CGA containing NaCl or $CaCl_2$ have high stability during an observation period of at least 2 hours.

4.3 Rheology

The rheological properties of the CGA system and the CGA system containing NaCl/$CaCl_2$ before and after aging at 150°C were tested. The fitting results of the four rheological models were analyzed.

The goodness of fit value (R^2) and root mean square error (RMSE) are parameters used to evaluate fitting accuracy. The closer the R^2 value is to 1, the smaller the RMSE value, and the better the fitting of the model. As shown in Table 7, the Bingham model has the lowest fitting accuracy. For the CGA system under different test conditions, the value of R^2 is between 0.909 and 0.973, and the value of RMSE is high, which is between 3.07 and 7.93. The Power-law model and the Carson model have better fitting accuracy. The R^2 value of the Power-law model (0.991-1.000) is closer to 1 than that of the Carson model (0.970-0.997). But the RMSE value of the Power-law model (0.29~1.83) is higher than the Carson model.

Among the four models, the R^2 value of the Herschel-Bulkely model is greater than 0.998 and has a lower RMSE value (0.14~1.04). Therefore, the Herschel-Bulkely model is the optimal model to describe the rheological behavior of the CGA system.

Table 8 lists the rheological parameters of the CGA system. The results show that the apparent viscosity (AV) and plastic viscosity (PV) of the CGA system increase with the increase of NaCl before and after aging at 150°C. The YP/PV of the CGA system with different concentrations of NaCl fluctuated between 0.456 and 0.772, and was always higher than 0.36. The flow behavior index (n) was between 0.451 and 0.691. At this time, the drilling fluid has a high cuttings-carrying capacity and strong shear-thinning properties.

The addition of $CaCl_2$ reduced the viscosity of the system to a certain extent after high-temperature aging. The values of AV and PV of the CGA system containing $CaCl_2$ before and after aging at 150°C remained above 47.5mPa·s and 30mPa·s, respectively. The value of YP/PV (0.444~0.699) and n (0.500~0.689) both fluctuated within appropriate ranges.

In addition, the CGA system always has higher gel strength (GS_{10min}>5.11 Pa) and low shear viscosity (LSRV>29393mPa·s) under different conditions. To sum up, the CGA system has appropriate rheological parameters and high LSRV values under high temperature, high salt and high calcium environment, which shows high cuttings-carrying ability and strong shear-thinning behavior.

4.4 Filtration and lubricity

Table 9 lists the filtration and lubricity parameters of CGA and CGA systems containing different concentrations of NaCl and $CaCl_2$ before and after aging at 150°C. The CGA system maintains a stable low filtration volume under the condition of a high concentration of NaCl/$CaCl_2$. With the increase of NaCl/$CaCl_2$, the FL_{API} of CGA at room temperature fluctuates in the range of 4.8~6.5mL. After 150℃ aging, the filtration property of the CGA system is slightly improved, and the FL_{API} fluctuates within 2.5~4.5mL, which always meets the API requirements[46]. In addition, a low value of fluid loss minimizes hydration expansion and maintains formation stability when drilling into mudstone formations.

With the increase of NaCl/$CaCl_2$, the lubrication coefficient of the CGA system decreased, and the adhesion coefficient of the mud cake increased slightly. In general, with different concentrations of ion contamination, the CGA system maintained a low adhesion coefficient (0.057~0.123) and lubrication coefficient (0.098~0.132) before and after high-temperature aging. In summary, CGA has good filtration properties and lubricity under conditions of high temperature, high salt, and high calcium.

4.5 Cuttings resistance

Add 5%, 10%, and 15% cuttings to the CGA system in turn, and the property changes after aging at 150°C for 16h are shown in Table 10. After adding 5% or 10% cuttings, the viscosity and GS10min changed within an acceptable range, the fluid loss increased slightly, and the lubricity decreased. In general, all parameters met the design requirements. The 15%cuttings significantly reduced the performance of the drilling fluid. The dispersion of rock powder led to a significant increase in the apparent viscosity (AV) and plastic viscosity (PV). The AV and PV values of the CGA system reached 112.5 and 75 mPa·s, respectively, which may lead to difficulty in pump starting and solid-phase removing. In addition, the lubrication coefficient of the CGA system is also far beyond the design requirements. In conclusion, the anti-cuttings pollution ability of CGA after aging at 150℃ is not less than 10%.

4.6 Inhibitory

As shown in Figure 6 (a), CGA drilling fluid always maintains a low linear expansion rate (4.29~6.24%) at high-temperature or high-concentration ion pollution, which is equivalent to a variety of strongly inhibitory water-based drilling fluid systems (Table 11). The filtration fluid of the CGA system is also obtained with the medium-pressure filtration instrument. The linear expansion rates of freshwater and filtration fluid are tested and compared, which is more in line with the actual drilling conditions. As shown in Figure 6 (b), the bentonite block has a significant hydration expansion in the freshwater, with an expansion rate of 51.8%. While the expansion rate of the filtration fluid of CGA, CGA+36%NaCl, and CGA+7.5%$CaCl_2$ system, which is between 20.11~27.05%. Therefore, the CGA system has good inhibition properties and compatibility with easily hydrated formation.

According to the rolling recovery experiment (Figure 7), the sandstone particles in freshwater are broken and become fine after hot rolling at 150℃ for 16h. Most of the particles with a particle size of more than 40 mesh are screened out, and the rolling recovery rate is only 43.41%. In the CGA system, the cuttings recovered after aging still maintain a good coarse particle shape and have a high recovery rate (87.98%). The rolling recovery rate of the CGA system with 36%NaCl or 7.5%$CaCl_2$ decreases slightly but remains at a high value (84.94% and 84.26%).

Combined with Table 11 and the test results, it can be found that the inhibition of the CGA system is equivalent to a variety of strongly inhibitory water-based drilling fluids. The CGA system has excellent inhibition at high temperature, high salt, and high calcium conditions, and is suitable for collapse-prone formations like shale or loose sandstone.

4.7 Environmental testing

The biodegradability of the CGA system was tested by the BOD_5/COD method. Results show that the BOD_5 and COD value of CGA drilling fluid is 66.3mg/L and 209mg/L, respectively. The biodegradability evaluation index (Y) was 31.72. Therefore, the CGA system is biodegradable.

Figure 8 shows the “Concentration-Relative luminous intensity” curve of the filtration fluid of the CGA system. The EC_{50} value is 72116mg/L. Based on Table 3, it can be determined that the CGA system is an environmental-friendly and non-toxic drilling fluid system.

5. Conclusion

This study constructs a CGA drilling fluid system with high-temperature resistance (150℃), salt-resistance, and calcium-resistance (36% NaCl or 7.5% $CaCl_2$). The stability, rheology, filtration, lubricity, anti-cuttings pollution ability, inhibition, and biological toxicity of the CGA system were evaluated. The following conclusions can be drawn:

1) Using the high-temperature stability of the CGA system as an indicator, the formula of the CGA system was optimized through three-factors four-levels orthogonal experiments, which is: 3% Bentonite mud+3% EST+3% AGS-8+3% ChCl PEG.

2) Microscopic tests showed that stable aphrons were successfully generated in 36%NaCl-CGA or 7.5%$CaCl_2$-CGA system aged at 150℃. Aphrons maintain a stable morphology throughout a 2-hour observation period without significant coalescence.

3) The Herschel-Bulkely model accurately describes the rheological behavior of CGA fluids containing NaCl/$CaCl_2$. The addition of NaCl increases the viscosity of the CGA fluid, while $CaCl_2$ is the opposite. The CGA fluid maintains appropriate rheological parameters (fluidity index, gel strength, and yield point) and shear thinning behavior, which means good cuttings carrying capacity.

4) With the addition of NaCl/$CaCl_2$, the CGA has a low filtration volume (<7mL) and low value of lubrication coefficient (0.107~0.132), which meets API requirements of filtration and lubricity properties.

5) The anti-cuttings pollution ability of 150℃ aged CGA can reach 10%. CGA, 36%NaCl-CGA, and 7.5%$CaCl_2$-CGA all have low linear expansion rates (<28%) and high rolling recovery rates (>84%). The CGA system has good inhibitory performance and is compatible with sandstone, shale and other easily collapsed formations.

6) The CGA system has been proven to be a biodegradable and non-toxic drilling fluid system.

In summary, this study breaks through the limitations of high temperature, high salinity, and high calcium conditions on the CGA properties, providing possibilities for the application of CGA drilling fluids in complex formations.

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Table 1. Application status of CGA drilling fluid in the field.

Year	Main components	Drilling fluid properties	Field application
2005[47]	Foaming agent HYF and foam stabilizer CMC	ρ: 0.75~0.96 g/cm^3; FL<10mL; YP/PV: 0.62~0.95.	It effectively solves the problems of serious lost circulation in northeastern Sichuan. Compared with similar wells in adjacent areas, the drilling speed is increased by 3~7 times, the drilling time is shortened by 29.5 days, and the direct economic benefit is more than 1 million ¥.
2016[48]	Foaming agent LF-2 and foam stabilizer HMC-1, viscosity increasing agent HT-XC, fluid loss agent	ρ: 0.85~0.95 g/cm^3; FL<7.4 mL; Strong inhibitory and blocking ability; Temperature resistance: 150℃.	The system is used in 21 wells in the oilfields of Cicai, Shencai, and Shenleng, with a maximum well depth of 4005m and a maximum temperature of 141.5℃. Compared with adjacent wells, the ROP in the same layer is increased by 70% after the use of microbubble drilling fluid.

	KH-931 and SMP-Ⅱ		
2018[49]	Foaming agent TSB and foam stabilizer HV-PAC	ρ: 1.08 g/cm^3; FL<5mL; Strong suspension carrying ability and inhibition; Salt resistance: 15%.	It is applied to the well section (2542-2837m) of the Kizivolda gas field in Kazakhstan. The system has a low density and stable wellbore, and there is no scratching or obstruction when drilling large sections of mudstone, gypsum, and gypsum mudstone.
2021[50]	Foaming agent LHPF-1 and BS-12, foam stabilizer XG	ρ: 0.93~0.95 g/cm^3; The plugging rate and penetration recovery rate >90%; Cuttings resistance: 7%.	It is applied to coal-measure strata, without any complicated downhole accidents. It has a high gas coincidence rate, wellbore stability, good inhibition performance, and uniform cuttings returned.

Table 2. Fundamental surfactant parameters of AGS-8.

Sample	CMC (mmol/L)	γ_{CMC} (mN/m)	Γ_{max} (nmol/cm^2)	A_{min} (nm^2)
AGS-8	9.69	38.1	0.15	1.10

Table 3. Biodegradability of materials

Sample	BOD_5 (mg/L)	COD (mg/L)	Y=（BOD_5/COD）*100
EST	55.8	168	33.21
AGS-8	70.7	224	31.56
ChCl-PEG	99.2	285	34.81

If Y＜5.0, the material is difficult to degrade; If 5.0≤Y＜25.0, the material is degradable; If Y≥25.0, the material is easily degradable[51].

Table 4. Biological toxicity classification of drilling fluid

Toxicity classification	Extremely high toxic	High toxic	Moderate toxic	Micro toxic	Non-toxic	Emission standard
EC_{50}	<1	1~100	100~1000	1000~10000	>10000	>30000

Table 5. Orthogonal experimental optimization results of CGA system

	A: dosage of EST	B: dosage of AGS-8	C: dosage of ChCl-PEG	T_0(min)

1	1%	3%	2%	75
2		4%	3%	68
3		5%	4%	60
4		6%	5%	54
5	2%	3%	2%	98
6		4%	3%	75
7		5%	4%	88
8		6%	5%	95
9	3%	3%	2%	120
10		4%	3%	95
11		5%	4%	108
12		6%	5%	135
13	4%	3%	2%	150
14		4%	3%	90
15		5%	4%	110
16		6%	5%	92
P_1	64.25	110.75	87.5	
P_2	89	82	102.75	
P_3	114.5	91.5	91.25	$R_A>R_B>R_C$
P_4	110.5	94	96.75	
R	50.25	28.75	15.25	

Table 6. Data statistics of the bubble size distribution.

Formula and Conditions	Average diameter (μm)	Percentage of bubble size in the range of <100μm (%)	Percentage of bubble size in the range of >100μm (%)
150°C aged CGA	99.15	59.16	40.84
150°C aged CGA--2hours	120.00	47.89	52.11
150°C aged CGA+36%NaCl	97.35	59.65	40.35
150°C aged CGA+36%NaCl--2hours	96.32	56.16	43.84
150°C aged CGA+7.5%$CaCl_2$	74.65	78.18	21.82
150°C aged	93.50	67.21	32.79

CGA+7.5%$CaCl_2$--2hours

Table 7. Fitting results of CGA system to four rheological models.

Formula	Condition	Bingham Model		Power-law Model		Casson Model		Herschel-Bulkely Model	
		Fitting parameter	R^2 /RMSE	Fitting parameter	R^2 /RMSE	Fitting parameter	R^2 /RMSE	Fitting parameter	R^2 /RMSE
CGA	Before aging	τ_0=8.752 μ_P=0.053	0.973/ 3.13	K=1.123 n=0.571	0.991/1.83	τ_c= 4.193 η_∞=0.033	0.997/0.10	τ_y=4.270 K=0.464 n=0.691	0.999/0.68
	150℃	τ_0=13.788 μ_P=0.071	0.941/ 6.29	K=2.448 n=0.503	0.999/0.91	τ_c=5.973 η_∞=0.047	0.984/0.29	τ_y=2.809 K=1.723 n=0.550	1.000/0.14
+10%NaCl	Before aging	τ_0=8.523 μ_P=0.063	0.972/ 3.74	K=0.983 n=0.612	0.996/1.39	τ_c=3.441 η_∞=0.043	0.996/0.14	τ_y=3.079 K=0.572 n=0.685	0.999/0.58
	150℃	τ_0=13.193 μ_P=0.074	0.938/ 6.74	K=2.252 n=0.519	1.000/0.44	τ_c=5.118 η_∞=0.052	0.981/0.33	τ_y=1.277 K=1.933 n=0.539	1.000/0.17
+20%NaCl	Before aging	τ_0=9.070 μ_P=0.068	0.966/ 4.50	K=1.122 n=0.604	0.998/1.00	τ_c=3.233 η_∞=0.049	0.991/0.23	τ_y=2.163 K=0.799 n=0.649	1.000/0.52
	150℃	τ_0=16.752 μ_P=0.077	0.942/ 6.68	K=3.251 n=0.475	0.996/1.68	τ_c=8.118 η_∞=0.047	0.986/0.27	τ_y=5.118 K=1.807 n=0.553	1.000/0.58
+30%NaCl	Before aging	τ_0=14.021 μ_P=0.060	0.911/ 6.59	K=3.109 n=0.446	0.999/0.66	τ_c=6.330 η_∞=0.038	0.970/0.36	τ_y=0.670 K=2.865 n=0.457	0.999/0.64
	150℃	τ_0=13.888 μ_P=0.084	0.952/ 6.66	K=2.116 n=0.546	0.998/1.30	τ_c=5.497 η_∞=0.059	0.986/0.30	τ_y=2.908 K=1.513 n=0.591	0.999/0.80
+36%NaCl	Before aging	τ_0=17.117 μ_P=0.067	0.909/ 7.48	K=4.047 n=0.427	0.999/0.80	τ_c=8.251 η_∞=0.041	0.970/0.37	τ_y=1.715 K=3.381 n=0.451	0.999/0.69
	150℃	τ_0=16.827 μ_P=0.085	0.934/ 7.93	K=3.112 n=0.494	0.999/0.81	τ_c=7.174 η_∞=0.056	0.981/0.35	τ_y=2.538 K=2.409 n=0.528	1.000/0.22
+5% $CaCl_2$	Before aging	τ_0=13.100 μ_P=0.055	0.927/ 5.41	K=2.871 n=0.445	0.997/1.00	τ_c=6.381 η_∞=0.033	0.977/0.30	τ_y=2.882 K=1.892 n=0.500	0.999/0.64
	150℃	τ_0=7.258 μ_P=0.062	0.963/ 4.26	K=0.885 n=0.622	1.000/0.29	τ_c=2.102 η_∞=0.048	0.989/0.25	τ_y=0.620 K=0.796 n=0.636	1.000/0.15
+7.5%$CaCl_2$	Before aging	τ_0=7.464 μ_P=0.042	0.959/ 3.07	K=1.097 n=0.543	0.993/1.26	τ_c=3.448 η_∞=0.027	0.993/0.14	τ_y=2.844 K=0.557	0.998/0.69

	150℃	τ_0=5.281 μ_P=0.059	0.971/ 3.63	K=0.549 n=0.684	0.998/1.04	τ_c=1.213 η_∞=0.049	0.991/0.22	n=0.634 τ_y=0.203 K=0.528 n=0.689	0.998/1.04

Table 8. Rheological parameters of CGA system with different concentrations of NaCl/$CaCl_2$ before and after aging at 150℃

Formula	Condition	LSRV (mPa·s)	GS_{10min} (Pa)	n	AV (mPa·s)	PV (mPa·s)	YP (Pa)	YP/PV
CGA-2	Before aging	84583	7.154	0.691	59.5	39	20.951	0.537
	150℃/16h	51189	7.665	0.550	80.5	49	32.193	0.657
CGA-2+10%NaCl	Before aging	63394	6.132	0.685	68.5	47	21.973	0.468
	150℃/16h	38995	5.621	0.539	82.5	51	32.193	0.631
CGA-2+20%NaCl	Before aging	63995	5.621	0.649	74	51	23.506	0.461
	150℃/16h	39995	8.176	0.553	89	56	33.726	0.602
CGA-2+30%NaCl	Before aging	71790	7.665	0.457	69	40	29.638	0.741
	150℃/16h	42796	6.132	0.591	94	65	29.638	0.456
CGA-2+36%NaCl	Before aging	75392	9.198	0.451	79	45	34.748	0.772
	150℃/16h	46595	6.132	0.528	96	57	39.858	0.699
CGA-2+5%$CaCl_2$	Before aging	47991	7..665	0.500	64	38	26.572	0.699
	150℃/16h	36195	5.11	0.636	66	46	20.440	0.444
CGA-2+7.5%$CaCl_2$	Before aging	38500	6.132	0.634	47.5	30	17.885	0.596
	150℃/16h	29393	5.11	0.689	62	42	20.440	0.487

Table 9. Filtration and lubricity of CGA system with different concentrations of NaCl/$CaCl_2$

before and after aging at 150℃

Formula	Condition	FL_{API} (mL)	Adhesion coefficient	Lubrication coefficient
CGA	Before aging	6.2	0.057	0.116
	150℃/16h	4.2	0.063	0.122
CGA+10%NaCl	Before aging	6	0.059	0.120
	150℃/16h	4.5	0.078	0.132
CGA+20%NaCl	Before aging	6	0.068	0.117
	150℃/16h	3.5	0.073	0.122
CGA+30%NaCl	Before aging	5.5	0.072	0.108

	150℃/16h	3	0.076	0.114
CGA+36%NaCl	Before aging	4.8	0.073	0.104
	150℃/16h	2.5	0.086	0.107
CGA+5%$CaCl_2$	Before aging	6.5	0.097	0.098
	150℃/16h	4	0.097	0.113
CGA+7.5%$CaCl_2$	Before aging	5.4	0.100	0.102
	150℃/16h	3.5	0.123	0.116

Table 10. Cuttings resistance of CGA.

Formula	LSRV (mPa·s)	GS_{10min} (Pa)	AV (mPa·s)	PV (mPa·s)	YP (Pa)	YP/PV	FL_{API} (mL)	f	K
CGA	51189	7.665	80.5	49	32.19	0.657	4.2	0.063	0.122
CGA+5%Cuttings	56796	6.132	71	42	29.64	0.706	5.2	0.106	0.155
CGA+10% Cuttings	61394	7.154	89	49	40.88	0.834	6.2	0.112	0.191
CGA+15% Cuttings	61993	12.264	112.5	75	38.33	0.511	4.6	0.152	0.246

Table 11. Inhibition performance of various drilling fluid systems.

Formula	Linear expansion rate (%)	Rolling recovery rate (%)
CGA	5.63	87.98%
CGA+36%NaCl	6.24	84.94%
CGA+7.5%$CaCl_2$	4.29	84.26%
Water-based drilling fluids based on KCl, polymers, amine-based polyalcohols and nano-wetting modifiers[52]	6.6~7.2	80.8~85.5
Solid-free low damage and strong inhibition water-based drilling fluid system[53]	~5	85.33

Appendix

AGS-8	An Amino Acid Foaming Agent
API	American Petroleum Institute
AV	Apparent Viscosity
BOD_5	the Five-day Biochemical Oxygen Demand
$CaCl_2$	Calcium Chloride
CGA	Colloidal Gas Aphron
ChCl-PEG	Lubricant
CAPB	Coconut Oil Amide Propyl Betaine
CMC	Carboxymethyl Cellulose
COD	Chemical Oxygen Demand
CTAB	Cetyltrimethylammonium Bromide
EC_{50}	the Concentration of Oilfield Chemicals in the Biological Toxicity Test
EST	A Modified Starch Foam Stabilizer
f	the Mud Cake Adhesion Coefficient

FL_{API}	Filtration Volume
GS_{10min}	10 minutes Gel Strength
HTHP	High Temperature High Pressure
k	the Extreme Pressure Lubrication Coefficient
LSRV	Low Shear Rate Viscosity
n	the Flow Behavior Index
R^2	the Goodness of Fit Value
ROP	the Borehole Footage Per Unit Time
RMSE	the Root Mean Square Error
SDS	Sodium Dodecyl Sulfate
XG	Xanthan Gum
X-100	Triton X-100
YP	Yield Point
τ	the Shear Stress
θ	the Reading of Six-speed Viscometer
γ	the Shear Rate
τ_0	the Yield Point of Bingham Model
μ_P	The Plastic Viscosity
τ_c	the Yield Point of the Casson Model
η_∞	the Ultimate High Shear Viscosity
τ_y	the Yield Point of the H-B Model
γ_{CMC}	Surface Tension Corresponding to the Critical Micelle Concentration
Γ_{max}	the Saturated Adsorption Capacity
A_{min}	the Minimum Surface Area

Figure 1. Schematic diagram of the structure of the aphron.

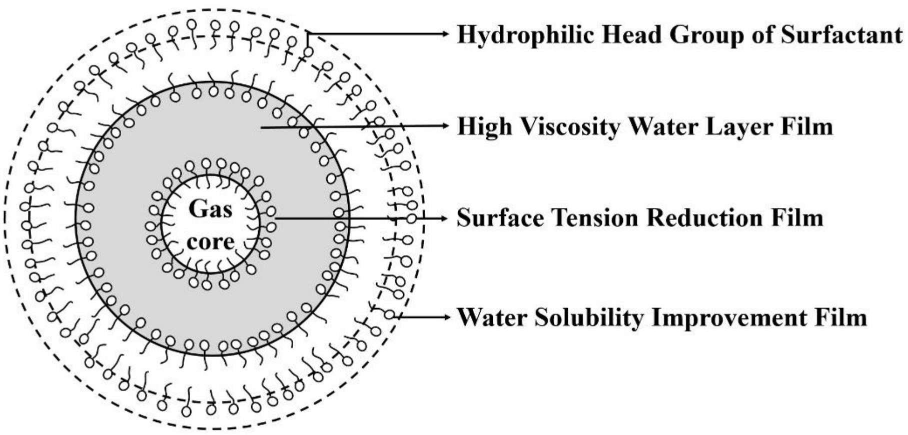
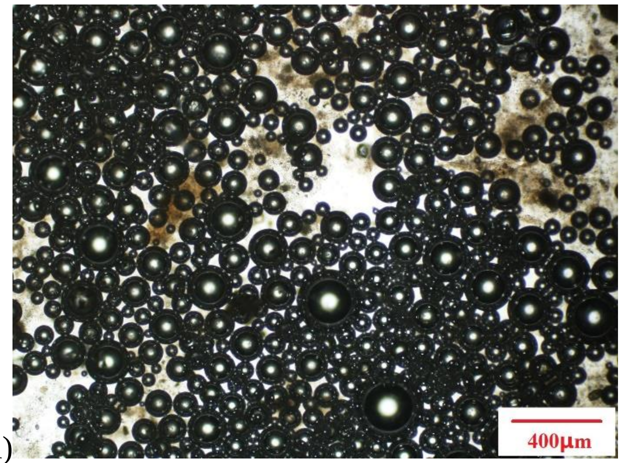
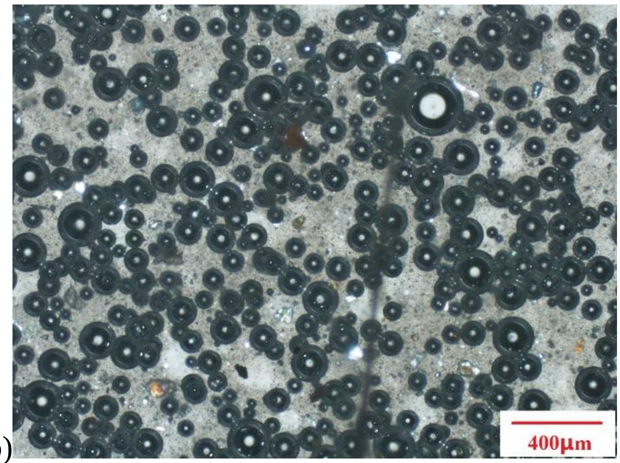


Figure 2. The figures of aphrons in the CGA system aged at 150℃: (a) CGA; (b) CGA+36%NaCl; (c) CGA+7.5%$CaCl_2$

(a)



(b)



(c)

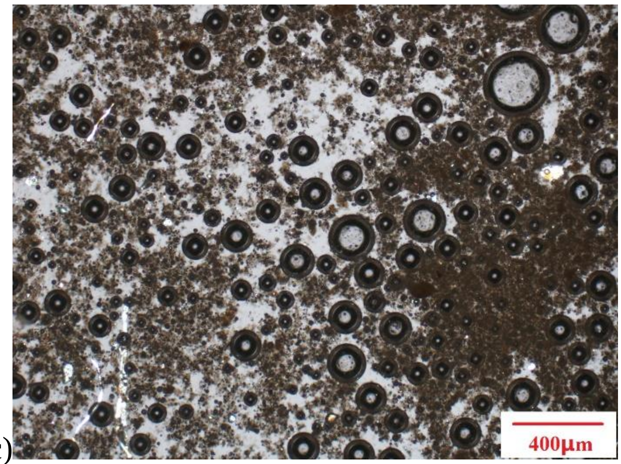
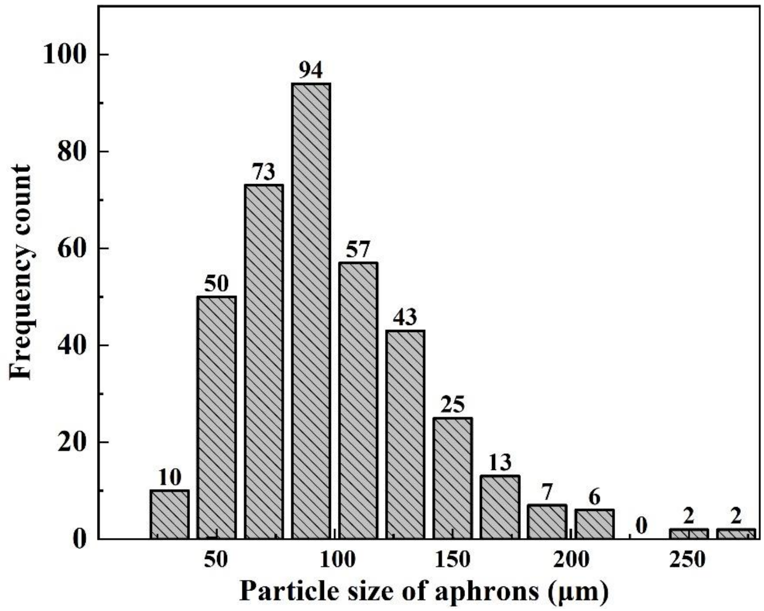
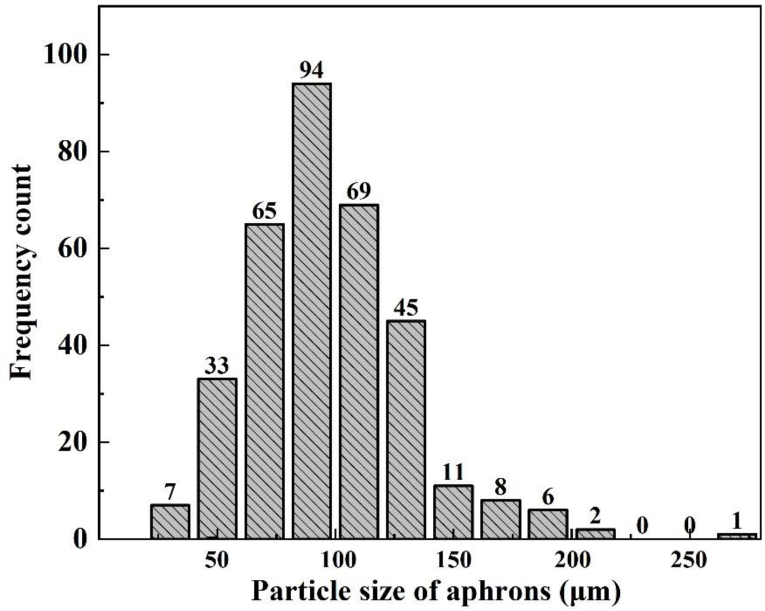


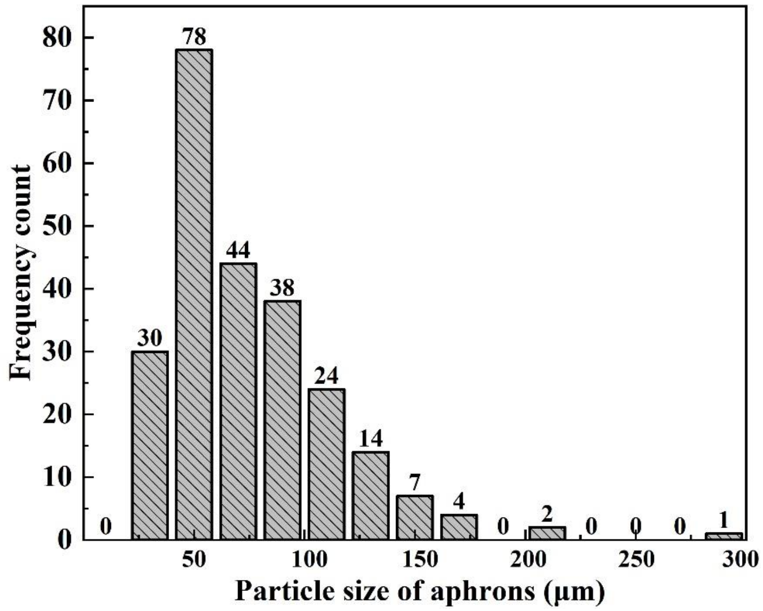
Figure 3. The bubble size distribution of aphrons in the CGA system aged at 150℃: (a) CGA; (b) CGA+36%NaCl; (c) CGA+7.5%$CaCl_2$


Frequency count
0
20
40
60
80
100
10
50
73
94
57
43
25
13
7
6
0
2
2
50
100
150
200
250
Particle size of aphrons (μm)

(a)

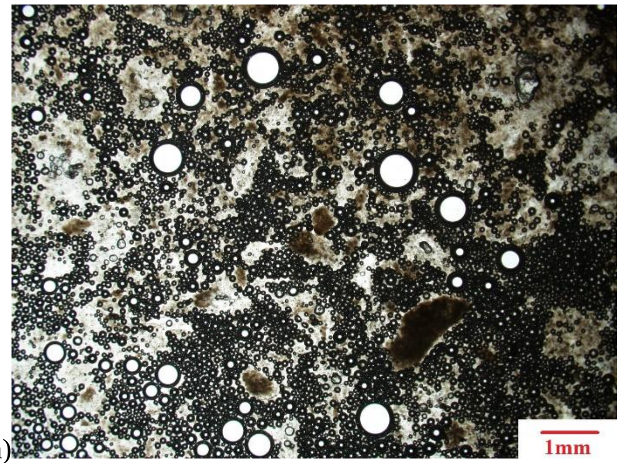

Frequency count
0
20
40
60
80
100
7
33
65
94
69
45
11
8
6
2
0
0
1
50
100
150
200
250
Particle size of aphrons (μm)

(b)

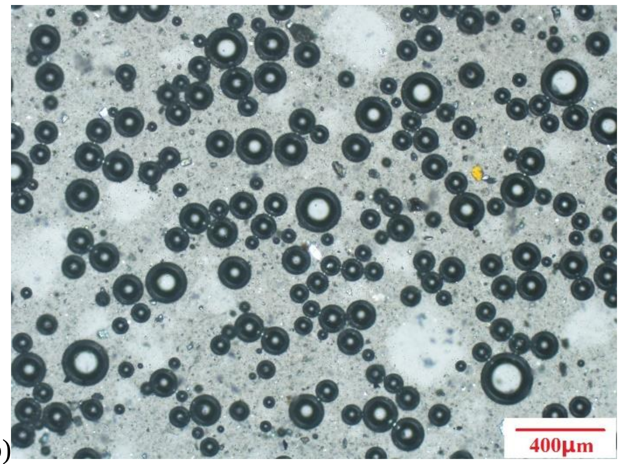


(c)

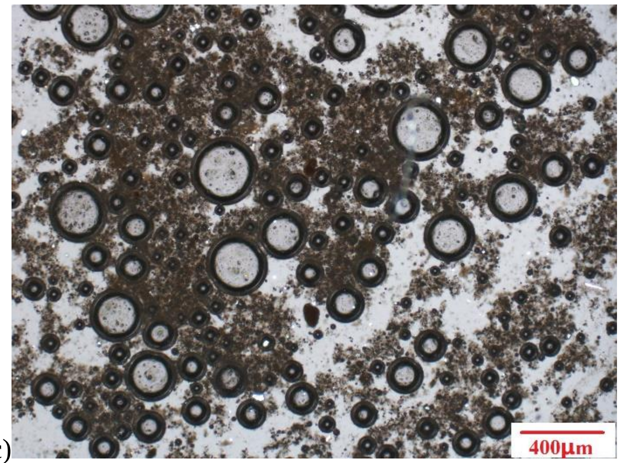
Figure 4. Observation image of Aphrons in CGA aged at 150℃ after standing for 2 hours (one cycle of drilling fluid): (a)CGA system; (b) CGA+36%NaCl; (c) CGA+7.5%$CaCl_2$.



(a)

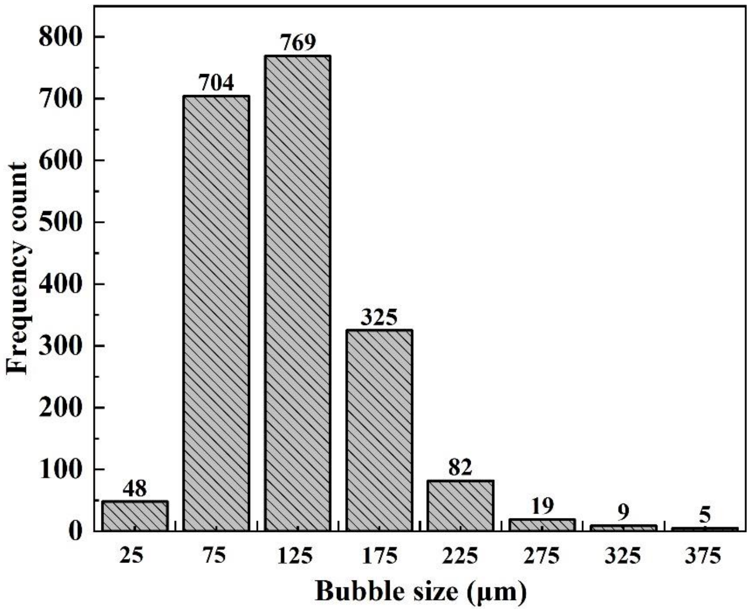


(b)

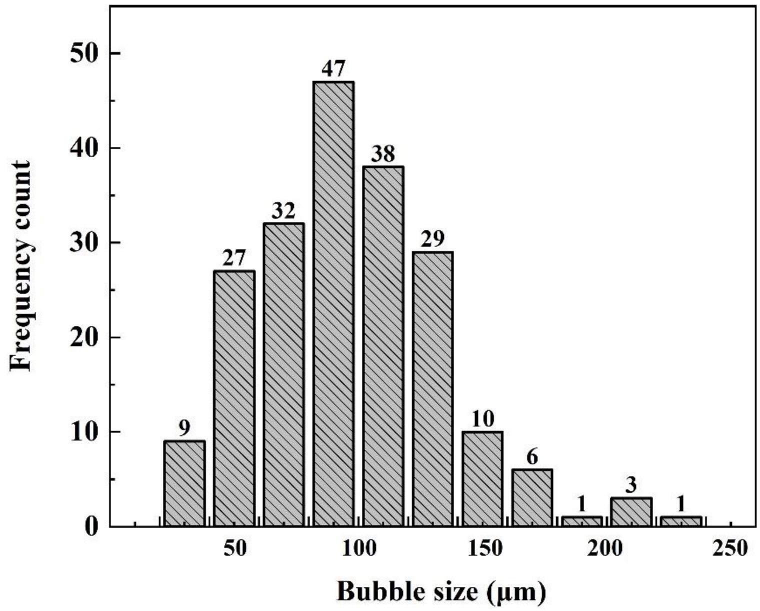


(c)

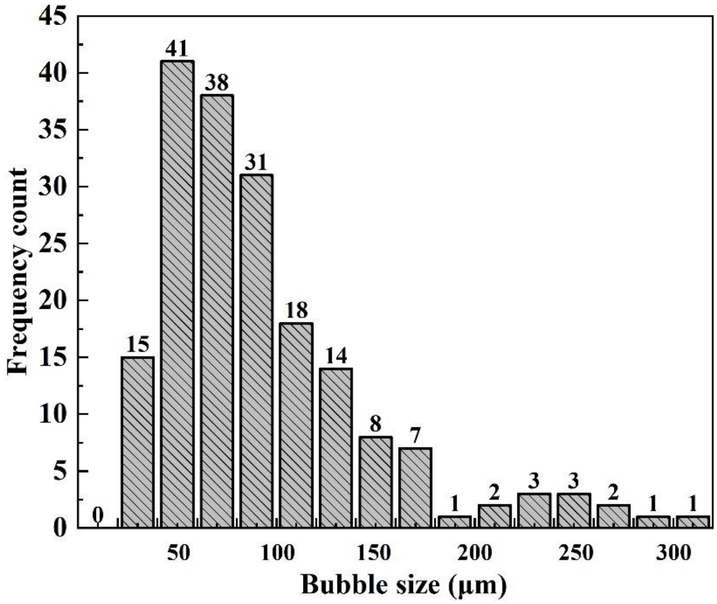
Figure 5. The bubble size distribution of aphrons in the CGA system aged at 150℃ and standing for 2 hours: (a) CGA; (b) CGA+36%NaCl; (c) CGA+7.5%$CaCl_2$



(a)

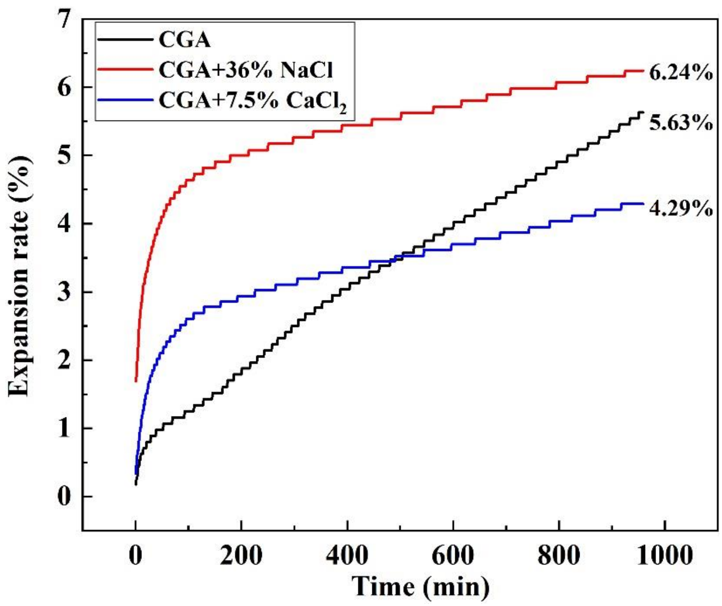


(b)

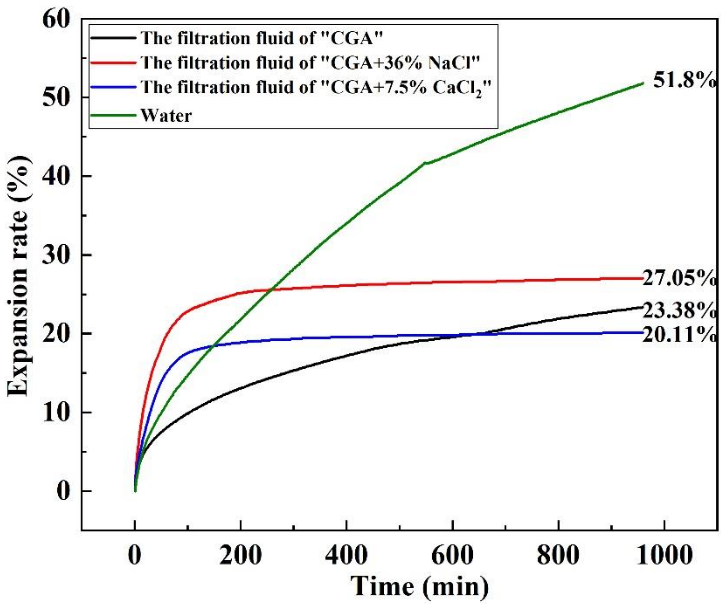


(c)

Figure 6. Curves of "expansion rate-time" of CGA system aged at 150℃: (a) CGA drilling fluid; (b) the filtration fluid of CGA drilling fluid.

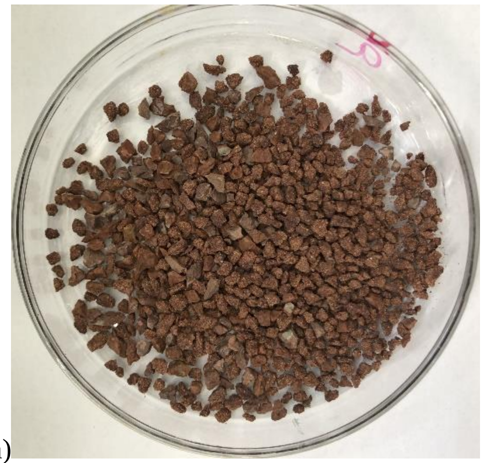


(a)



(b)

Figure 7. Sandstone samples from rolling recovery experiments: (a) initial samples; (b) After boiling in water; (c) After hot rolling in the CGA system; (d) After hot rolling in CGA+36% NaCl; (e) After hot rolling in CGA+7.5% $CaCl_2$.

(a)  (b) 

(c)  (d) 

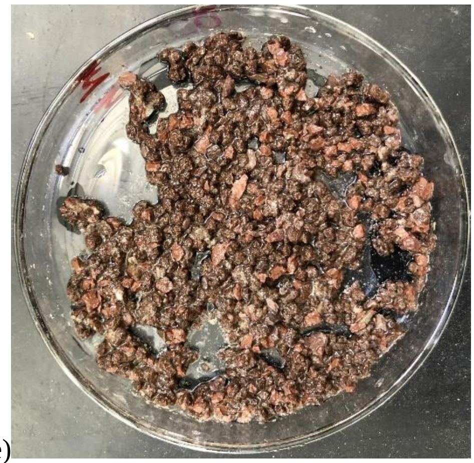
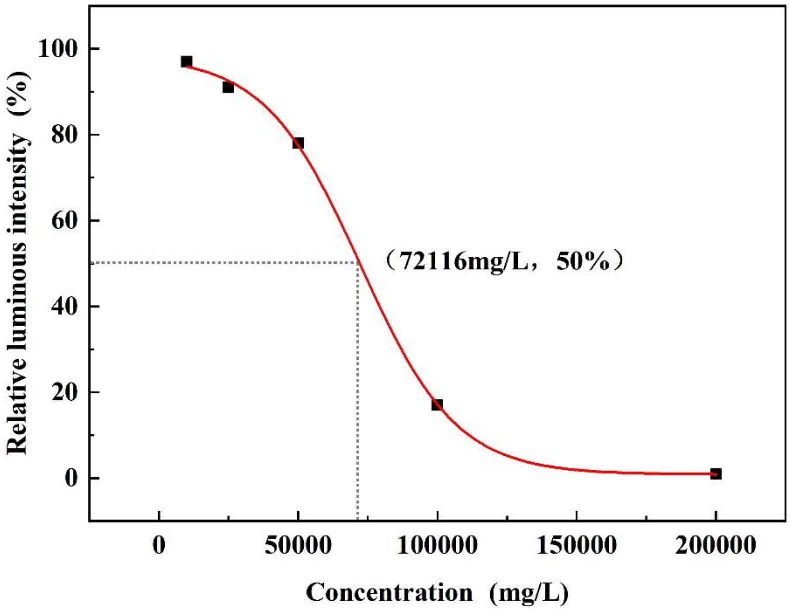
(e) 

Figure 8. The biological toxicity test of CGA system.


Relative luminous intensity（%）
100
80
60
40
20
0
（72116mg/L，50%）
0
50000
100000
150000
200000
Concentration（mg/L)