High Temperature Sealing Performance of Novel Biodegradable Colloidal Gas Aphron (CGA) Drilling Fluid System

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Aphrons are ideal sealing materials and colloidal gas aphron (CGA) drilling fluids have been successfully applied in solving huge leakage problems. As the increase of well temperature, filtration and sealing characteristics of CGA drilling fluids at high-temperature are more concerned, yet less investigated. This study revealed an easily biodegradable CGA drilling fluid system generated by modified starch polymer EST and glycine surfactants AGS-12. Its high-temperature high-pressure (HTHP) filtration performance was evaluated through API filtration test, HTHP filtration test (150-200 °C, 3.5 MPa), and the HTHP sand disc experiment (150 °C, 3.5 MPa). Results indicated that the EST-CGA is a strong sealing ability drilling fluid system with temperature resistance of 200 °C and pressure resistance of 3.5 MPa. It can effectively seal the reservoirs with pore-throat diameters twice the microbubbles average diameter. The optimal sealing effect can be obtained when the ratio of the centralized tendency of the microbubbles and the average pore-throat diameter was close to 1 : 1. The great improvement in HTHP filtration performance of EST-CGA was attributed to the introduction of rigid temperature-resistant groups and hydration groups in the EST-CGA system, as well as the formation of hydrogen bonds between N-H/O-H and COO-

Keywords
Colloidal gas aphron, Drilling fluid, High temperature, Filtration, Sealing, Particle size distribution

1. Introduction

Drilling in depleted oil and gas reservoirs, highly developed pores/fractures and other low-pressure areas is often accompanied by serious drilling fluid invasion. Huge fluid invasion not only causes borehole instability, but also creates severe formation damage and reduces well productivity. Therefore, reducing fluid intrusion is crucial in these reservoirs.

Granular, fibrous, and lamellar solid materials are commonly added in water-based drilling fluids as plugging agents. By designing solid particles size compatible with the pore throat, bridging occurs in the reservoir near the borehole wall to achieve filtration control. As the long-time circulation in the high temperature and high-pressure wellbore, the solid phase material tends to take place complicated problems such as coalescence, settlement, acid dissolution, gelatination, viscoelastic damage, etc.

Therefore, maintaining the size distribution to ensure good sealing against specific rocks is difficult. Moreover, the solid particles remaining in the reservoir have a negative impact on production.

Recently, a colloidal gas aphron (CGA) drilling fluid technology has been successfully applied internationally to solve the huge leakage problems, as listed in Table 1. The fluid system has been proved to have the advantages of reducing fluid invasion and reservoir damage significantly, no need for additional pressurization equipment, high cutting carrying efficiency, shortening drilling cycle and reducing drilling cost. A large number of aphrons generated by surfactants and polymers exist in the CGA fluid. Aphrons are microbubbles composed of a gas core and a thick multi-layered aqueous surfactant shell. These robust and elastic microbubbles are ideal bridging materials with a wide size distribution and can be deformed to adapt to various pores and fractures. Pasdar et al. observed the changes in the particle size of the aphrons under a microscope with sudden or stepwise pressure, and found that the aphrons can survive under 2000 psig and ambient temperature. Growcock et al. further proposed that aphrons can survive at 4000 psig and ambient temperature. More importantly, aphrons show little affinity for each other and for mineral surfaces. Consequently, aphrons can be cleaned up to the ground.
immediately at the start of production stage, which can reduce cost associated with stimulation processes\(^9,10\).

Some previous literature has reported the filtration control and sealing performance of CGA fluids\(^{11-14}\). In the core displacement experiment, a higher pressure drop was observed in the CGA fluid through porous media compared with drilling fluids prepared by pure polymer or pure surfactant, confirming that CGA drilling fluid has better sealing ability than water/foam based drilling fluids\(^{15}\). Mohsen et al. built a micro model of a 2D etched glass plate to simulate sandstone reservoirs (fractures and non-fracture). Through the coloring of the matrix, it was observed that the aphprons moved faster than the base fluid and formed a bubble blocking zone in the front of the fluid. Microscopic observation of fluid flow during oil recovery shows that during production, a large portion of aphprons was surrounded by the oil phase (due to their high affinity for oil) and were easily removed in both fracture and non-fracture models by oil production under the differential pressure. The return permeability of CGA fluid in porous media through a visual microscopic model, and proposed a new insight into the “aphron splitting mechanism.” Research found that the microbubbles with larger particle size will split into small bubbles when migrating in porous media\(^{16}\). Xie et al. studied the pressure sealing ability of the XG based CGA drilling fluid at 80 °C by using sand-beds. Results showed that XG based CGA drilling fluid can seal 10-20 mesh and 20-60 mesh sand beds at 3 MPa and 20 MPa, respectively\(^{17}\). Zhu et al., improved the high temperature resistance of XG based CGA drilling fluids by adding attapulgite, and the API filtration after 120 °C aged was controlled within 10 mL\(^{18}\).

The above studies have confirmed the strong sealing performance of aphprons in CGA fluids, and put forward speculations on the sealing mechanism. However, the temperature of these studies has not reached high-temperature drilling (\(>150 \text{ °C}\)). On the other hand, the discussion on the compatibility of pore throat and microbubble particle size distribution is still lacking. The CGA drilling fluid prepared by xanthan gum (XG) as the foam stabilizer and sodium dodecyl sulfate (SDS) as the foaming agent was the preferred system with better foam stability, and has been widely used in drilling sites\(^{19,20}\). However, when the temperature exceeds the conformational transition temperature (usually within 100 °C) of XG, the XG molecules in the solution change from a double helix structure to a disordered coiled structure, accompanied by significant viscosity reduction\(^{21}\). As reported, the initial thermal decomposition of SDS occurs at 127 °C, and the weight loss is 30-40 % at 177 °C\(^{22}\). As a result, the drainage and collapse of aphprons is accelerated and the application of CGA drilling fluids at high temperatures is limited. With the increase of reservoir temperature, the high-temperature resistance of CGA drilling fluids is required.

In this paper, a novel and easily biodegradable EST-CGA drilling fluid system was proposed by using a new type of self-synthesized modified starch EST as foam

### Table 1 Field Application of CGA Drilling Fluids

| Year and ref. | Formula | Performance evaluation | Field application |
|--------------|---------|------------------------|-------------------|
| 2010\(^{13}\) | clay + KPA + ammonium salt + YTF-1 + FA367 + foaming agent DF-1 | The fluid density was 0.87 g/cm\(^3\). The \(FL_{API}\) was in 4.1 mL. The funnel viscosity was 180 s. | CGA drilling fluid was applied to Hai-39 well (1430-2240 m) in Jilin oilfield, China. The leakage volume was 42 m\(^3\). Compared with the polymer drilling fluid, the leakage reduced by 94.6 % and the ROP increased by 61.4 %. |
| 2016\(^{32}\) | water + Na\(_2\)CO\(_3\) + foaming agent LF-2 + foam stabilizer HMC-1/HT-NC + fluid loss agent KH-931/SMP-II | The fluid density was between 0.85-0.95 g/cm\(^3\). After aged at 150 °C for 16 h, the \(FL_{API}\) was in the range of 5.8-7.4 mL. Cuttings recovery and permeability recovery were 88.7 % and 88.87 %, respectively. This system can effectively seal the sand layer of 40-120 mesh. | The solid-free CGA drilling fluid was applied in the C-120 well (2785-4005 m) in Bohai Bay Basin, China. The maximum temperature of the well bottom reached 141.5 °C. Compared with adjacent wells using water-based drilling fluids, the ROP increased by more than 70 %. |
| 2017\(^{33}\) | bentonite + Na\(_2\)CO\(_3\) + XC + PAC-LV + foaming agent | After aged at 80-130 °C, the \(FL_{API}\) was within 5.6 mL. The pressure resistance was above 21 MPa. | CGA drilling fluid was applied to C1-13 well (1220-1510 m) in Baobab Basin, Chad. The density is between 0.7-0.9 g/cm\(^3\). It solved the problem of safe production and geological data admission caused by the vicious leakage in the buried hill section. |
| 2018\(^{34}\) | bentonite + Na\(_2\)CO\(_3\) + NaOH + fluid loss agent + foam stabilizer + foaming agent VES-1 | The density is between 0.94-0.98 g/cm\(^3\). The \(FL_{API}\) was in the range of 4.6-5.2 mL. | CGA drilling fluid was applied to Chu 7-5 well (2835-3105 m) in Block Wen 23, Zhongyuan oilfield, China. During the drilling process, the borehole is stable and there is no leakage. |
stabilizer and a glycine surfactant AGS-12 as foaming agent. The filtration control and sealing ability of EST-CGA under high temperature (150-220 °C) and high pressure (0.69/3.5/7 MPa) was evaluated by API filtration test, high-temperature high-pressure (HTHP) filtration test, and HTHP sand disc test. The impact of the particle size distribution of microbubbles and clay in the CGA system on sealing was discussed. Furthermore, the HTHP sealing mechanism of the EST-CGA was explained by Fourier transform infrared spectroscopy (FT-IR) analysis, microscopic observation of aphrons, and laser particle size analysis.

2. Materials and Methods

2.1. Materials and Preparation of CGA Drilling Fluids

A modified starch copolymer EST synthesized by inverse emulsion polymerization was used as viscosifier as well as foam stabilizer in this study. It has been proved that EST is a high-performance drilling fluid additive with temperature resistance of at least 200 °C, cation pollution resistance of 36 wt% NaCl or 20 wt% CaCl2 in our previous research. A dodecyl glycine surfactant AGS-12 synthesized by one-step method was used to generate aphrons. Figure 1 shows the molecular structure of EST and AGS-12. Moreover, the biodegradability results in Table 2 indicate that EST and AGS-12 are environmental-friendly additives and can be easily degraded.

First, the base mud was prepared by mixing 5 L water, 3 % bentonite and 0.2 % Na2CO3 for 1 h and standing for 16 h. Bentonite and Na2CO3 are commercial agents purchased from Weifang Boda Bentonite Co., Ltd. and Beijing Chemical Industry Group Co., Ltd., respectively. Then, by using a high-speed mixer (Model WT-2000C, China), CGA drilling fluids were prepared by mixing all the raw materials, i.e., 200 mL base mud, 2 % EST, 3 % AGS-12 together using a digital mixer at 8000-12000 rpm based on the procedure described in previous literature. As a control group, conventional XG-based CGA drilling fluid was also prepared with 3 % base mud, 0.5 % XG and 0.286 % SDS.

2.2. Evaluation of Sealing Performance

Three kinds of specified equipment were used to evaluate the HTHP sealing capacity of CGA drilling fluids. First, based on the American Petroleum Institute (API) standards, the API filtration volume ($FL_{30min}$) of prepared fluids after aging at 150/180/200/220 °C for 16 h in an aging furnace (Model XGRL-4, China) was recorded by a medium-pressure filtration apparatus (Model SD-6, China). The test was carried out at room temperature and $\Delta P = 0.69$ MPa, also denoted as LTLP. Then, the HTHP filtration apparatus (Model HTD GS500, China) was used to record the fluid loss of CGA drilling fluids at 150/180/200 °C and $\Delta P = 3.5$ MPa within 30 min. The fluid loss measured by the above two kinds of equipment is that of drilling fluid passing through the filter paper under certain conditions. In order to simulate the reservoir pores more accurately, a HTHP sealing apparatus used a customized sand disc to replace the filter paper. Five kinds of sand disc with different permeability (400 mD, 2 D, 5 D, 20 D, 100 D) and average pores throat (10, 20, 40, 55, 120 μm) were used in this study, as shown in Figure 2. The mud placed into a stainless-steel container with an opening at the bottom was exposed to 150 °C and 3.5 MPa pressure, and the filtration volume within 30 min was recorded.

2.3. Analysis on Sealing Mechanism of High Temperature and High Pressure

2.3.1. Infrared Spectrum Analysis (FT-IR)

FT-IR spectral analysis (400-4000 cm⁻¹) of samples was carried out using a spectrometer (Model Magna-IR 560). After 150/180/200 °C aging and API filtration test, the slurry was dried at 60 °C and crushed into pow-

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**Table 2** Biodegradability of EST and AGS-12

| Sample | Chemical oxygen demand (COD) | Biochemical oxygen demand within 5 days (BOD₅) | 100 × BOD₅/COD [Y] |
|--------|-----------------------------|-----------------------------------------------|--------------------|
| EST    | 168                         | 55.8                                          | 33.2               |
| AGS-12 | 146                         | 50.2                                          | 34.4               |

According to the Standard “GB 8978-1996 Integrated wastewater discharge standard,” if $Y \geq 25.0$, the emissions are easily degradable; if $25 > Y \geq 5$, the emissions are degradable; if $Y < 5$, the emissions are difficult to degrade.

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**Fig. 1** Molecular Structure of Polymer and Surfactant: (a) EST; (b) AGS-12
2.3.2. Particle Size Distribution

The particle size distribution of microbubbles and bentonite particles were tested using a polarizing microscope (Model OLYMPUS BX51) with a CCD camera and laser diffraction particle size analyzer (Model Bettersize 2000), respectively. CGA drilling fluid after the HTHP sealing test was dropped on the glass slide, and the aphrons at five different positions of the glass slide were observed. Then the particle size of aphrons in the pictures was counted with Nano measurer software. To eliminate the impact of aphrons on the particle size test of clay, the CGA drilling fluid was ultrasonically dispersed and defoamed before the test. Sample was dropped into the cylinder of laser particle size analyzer and made the shading degree higher than 12%. The test was performed 5 times to obtain the average value.

3. Results and Discussion

3.1. API Filtration Property

The API filtration experiment records the cumulative filtration volume of CGA drilling fluids after aging at appointed temperatures (150/180/200/220 °C) for 16 h under LTLP conditions within 30 min. API fluid loss is one of the most important indicators for the evaluation of high-temperature resistance of drilling fluids in the oil and gas drilling field. Generally, the total fluid loss within 20 mL is reasonable.

The permeation process of the filtrate fluid through the mud cake and the filter paper conforms to Darcy’s law, which describes the filtration volume $dV$ as a function of time $dt$, permeability $K$, filtration area $A$, pressure differential $ΔP$, filtration fluid viscosity $μ$ and thickness of mud cake $h_c$, which is expressed as Eq. (1).

$$dV = K A ΔP dt$$

The permeability of mud cake can be obtained based on Darcy’s law and the following assumptions: 1) The value of $A$ is 45.8 cm$^2$; 2) The value $ΔP$ is 0.69 MPa; 3) The viscosity of water at 25 °C, i.e. 0.8937 mPa s, is taken as the value of $μ$; 4) Ignoring the change in thickness and compressibility of the mud cake during accumulation, the $h_c$ value is fixed as the final thickness of the mud cake. The static filtration equation of Eq. (2) can be obtained by integral transformation of Eq. (1), where $f_{sc}$ is the solids content in mud cake and $f_{sm}$ is the solids content in drilling fluid.

$$f_{sc} = 1 - f_{sm}$$

As shown in Fig. 3, linear fitting was performed on the data of filtrate volume and the square root of time. The goodness of fit ($R^2$) is between 0.996 and 0.999, indicating that there is a strong linear relationship between them, which is consistent with the static filtration equation. The slope of linear fitting can be used to characterize the speed of drainage.

Filtration parameters of EST-CGA and control group are listed in Table 4. Results show that the filtration volume ($FL_{API}$) and filtration speed of EST-CGA gradually increased with the rising of aging temperature, and maintain a low fluid loss (< 20 mL) within 200 °C. The $FL_{API}$ obviously increased to 33.5 mL at 220 °C, hence the temperature resistance of the EST-CGA drilling fluid was initially determined to be within 200 °C. In contrast, the $FL_{API}$ of the control group after aging at 150 °C was as high as 66 mL, which was far beyond the reasonable range. The $FL_{API}$ and filtration speed of control was 9.2 times and 8.2 times higher than that of EST-CGA aged at 150 °C. The great improvement of high-temperature filtration performance of EST-CGA drilling fluid is attributed to the formation of compacted low-permeability mud cakes during the filtration process. Compared with the control, the thickness of EST-CGA mud cake at 150, 180, 200 and 220 °C reduced by 96.3, 93.8, 93.8 and 91.9 %, respectively, and the permeability decreased by 99.6, 98.7, 98.2, 95.9 %.
Besides, the control group failed to generate aphrons after 180 °C aged for 16 h.

\[
\frac{dV_t}{dt} = KA\Delta P \mu h_c
\]

(1)

\[
V_t = A \left( \frac{2K\Delta P}{f_{sm}}\left( f_{sc} - 1 \right) \right)^{1/2} \frac{\sqrt{t}}{\mu}
\]

(2)

3.2. HTHP Filtration Property

The HTHP filtration behavior of EST-CGA at 150/180/200 °C and ΔP = 3.5 MPa is depicted in Table 5. EST-CGA maintains a low value of HTHP filtration volume (FLHTHP) within 200 °C. As the temperature increased from 150 to 180 °C and 200 °C, the FLHTHP of EST-CGA gradually increased from 13 to 16.5 mL and 24.5 mL. However, XG-based CGA drilling fluid showed extremely poor HTHP filtration properties. The FLHTHP at 150 °C was 68 mL, which was 423 % higher than EST-CGA. At 180 °C, the fluid was almost all lost and the FLHTHP was as high as 198 mL. Moreover, the polymer water-based drilling fluid reported by AN et al., EST-CGA also showed 35.4 % and 92.7 % FLHTHP increment at 150 °C and 180 °C compared to EST-CGA20).

3.3. HTHP Sand Disc Sealing Experiment

The HTHP sealing experiment was carried out at 150 °C and differential pressure of 3.5 MPa by using sand discs with different permeability instead of filter paper, as shown in Fig. 4. The fluid loss (FL) of control group XG-CGA was also tested by using a 20 D-55 μm sand disc.

Figure 4 shows that the FL accumulated slowly over time. Within 0-30 min (ΔP = 3.5 MPa), the FL of EST-CGA through sand discs with different permeability kept in a reasonable range, which was between 13.5-25 mL. While the fluid loss of the control group that passed through the 55 μm sand disc was as high as 79 mL, which was almost 6 times that of EST-CGA system. The filtration rate fluctuated between 0.262-0.367 mL/min. For the sand disc with the same permeability, the filtration rate of EST-CGA system was 72.3 % lower than that of the control group. Compared to the control group, the great improvement in the HTHP sealing performance of the EST-CGA system was self-evident. On the whole, as the permeability of the sand disc increased from 400 mD to 100 D, and the pore throat diameter increased from 10 to 120 μm, the FL of EST-CGA gradually increased. However, results also show that the sealing materials in EST-CGA had the best compatibility with the sand disc with an average pore throat diameter of 55 μm, which will be discussed in detail in 3.4.

3.4. HTHP Sealing Mechanism Analysis

Good foam stability, clay dispersion, and reasonable particle size gradation are necessary for effective sealing. In this chapter, through FT-IR analysis, microscopic observation of aphrons, and particle size statistics, the reasons for the improvement of the HTHP sealing performance of EST-CGA system and the size compatibility of pore throat and the sealing materials were discussed.
3.4.1. FT-IR Analysis

Figure 5(a) shows the FT-IR spectrum of the CGA drilling fluid system after 150/180/200 °C aged and API fluid filtration test. The peak at ~1585 cm⁻¹ is ascribed to the anti-symmetric stretching vibration of –COO⁻ in AGS-12. The peak at 2850 cm⁻¹ and 2919 cm⁻¹ was the anti-symmetric absorption peak of methylene (–CH₂) and the stretching vibration of methyl (–CH₃), which corresponds to the backbone of AGS-12. The peaks appear at 626, 1012, and 1187 cm⁻¹ correspond to C=S, S=O and S=O of the sulfonic acid group in the graft monomer AMPS, respectively. The peak appeared at 1455 cm⁻¹ is the stretching vibration absorption peak of C=N in the primary amide (CONH₂) of AM. The broad and strong peak band between 3000 cm⁻¹ and 3500 cm⁻¹ is attributed to the N-H of amine groups (–NH₂) in AM and the stretching vibration of O-H in the starch backbone. FT-IR proved that using modified starch EST as a thickener successfully introduced functional groups into the CGA drilling fluid system. The sulfonic acid groups and rigid ring is helpful to improve the temperature resistance of poly-

Fig. 4  Filtration Properties of EST-CGA under Different Sand Discs and Pressures: (a) filtration volume vs. time; (b) filtration rate and filtration volume

Fig. 5  FT-IR Spectrum: (a) CGA drilling fluid system at different temperatures; (b) comparison of the characteristic peak of –COO⁻ in CGA system and pure surfactant AGS-12; (c) comparison of the characteristic peak of N-H/O-H in CGA system and pure polymer EST
The amide group together with a large number of hydroxyl groups in starch can promote the hydration and dispersion of bentonite.

Figures 5(b) and 5(c) are the enlarged images of the characteristic peaks at $\tilde{b}_{1585}$ cm$^{-1}$ and $\tilde{b}_{3300}$ cm$^{-1}$. Compared with the FT-IR image of the surfactant AGS-12, the peak of COO$^-$ in the CGA drilling fluid system exhibited a significant red shift, and the wave number of characteristic peaks reduced from 1591 to 1585 cm$^{-1}$ (150 °C), 1587 cm$^{-1}$ (180 °C) and 1587 cm$^{-1}$ (200 °C). Similarly, compared to polymer EST (3300 cm$^{-1}$), the wave number of N_H and O_H in the CGA system also significantly shifted to low wave numbers (3209-3236 cm$^{-1}$). This indicates that a hydrogen bond was formed between the proton donor (N_H/O_H) and the proton acceptor (C\'O) in the CGA system within 200 °C.

The formation of hydrogen bonds was conducive to the increasing of fluid viscosity. As Table 6 shows, the apparent viscosity (AV) of EST-CGA increased by 145 % and 52.5 % at 150 °C and 180 °C, compared with the control group. The low shear rate viscosity (LSRV) of EST-CGA at 150 °C and 180 °C was 8.3 times and 14.3 times higher than that of the control group. Increasing of AV was helpful to enhance the viscoelasticity of the film, slow down the foam drainage, and prolonged the life of microbubbles. The extremely high value of LSRV would reduce the fluidity of aphrons in porous media, accelerate the accumulation and blocking aphrons.

3.4.2. Microscopic Observation and Particle Size Distribution of Aphrons

After the HTHP sealing test, microscopic observation of aphrons in EST-CGA and XG-CGA was carried out. As Figs. 6(1-5) shows, aphrons generated by EST and AGS-12 can maintain independent spherical structures without the appearance of polygonal boundaries after HTHP tests. They are composed of a gas core and a thick multi-layered aqueous surfactant “shell,” which is highly consistent with the structure of aphrons proposed by Sebba in 1987. This unique structure makes the aphron survive severe conditions for a significant period of time$^{27,28}$. The formation of hydrogen bonds in the EST-CGA system will further increase the strength of the “shell” and prolong the life of aphrons. While in Fig. 6 (6), after the HTHP sealing experiment, the aphrons in XG-CGA became dry foams, and a polygonal Plateau boundary appeared between the bubbles, which means the instability of aphrons.

Reasonable particle size distribution is the key to successful sealing. He Jingang pointed out that when the average diameter of foam is larger than the pore throat diameter, the foam entering the formation with corresponding permeability can play an important role in sealing effectively$^{29}$. Alizadeh et al. built a mathematical model describing the transport of microbubbles in porous media based on filtration theory, and it was found that increasing the ratio of microbubble size to porous media would reduce the length of the invasion zone$^{30}$. However, Amir et al. confirmed that the small
bubbles have greater flow resistance and lower fluidity, and the sealing effect is better through experiments 16). In this study, some more accurate conclusions were found. Figure 7 shows particle size distribution of the observed 1348 aphrons. Most of the aphrons lie in the range of 25-125 μm. The minimum diameter of aphrons is 16.93 μm, the maximum diameter is 182.55 μm, and the average diameter is 61.65 μm. 51.1% of the aphrons were in the range of 45-65 μm, and 74.8% of the aphrons were in the range of 35-75 μm. The diameter of aphrons in EST-CGA was normal distribution. The expected value of the Gaussian fitting curve is 58.07 μm, which means the centralized trend position of the data. Except for the sand discs with lower permeability (400 mD-20 D) and pore-throat diameter (10-55 μm), the sand disc with the pore-throat diameter (120 μm) much higher than the average diameter (61.65 μm) of microbubbles can also be sealed by EST-CGA. In other words, the EST-CGA system can effectively seal the reservoirs with pore-throat diameters twice the aphron average diameter. It was found that when the average particle size of aphrons is 1.12 times of the pore throat, and when the ratio of centralized tendency of the aphrons and the average pore-throat diameter is close to 1 : 1, EST-CGA showed the best sealing effect with the lowest filtration loss and the filtration speed.

3.4.3. Particle Size Distribution of Bentonite

After ultrasonic dispersion and defoaming treatment, the particle size distribution of Bentonite in EST-CGA after HTHP sealing test was tested, as shown in Fig. 8. It can be seen that the particle size of bentonite was widely distributed in the range of 0.3-100 μm, with good dispersibility, no coalescence and sedimentation. The median particle size was 16.82 μm, and the average diameter was 23.04 μm. Peaks appeared at ~0.65, ~6.26 and ~17.52 μm. For 400 mD and 2 D sand discs, the average diameter bentonite is higher than the pore throat, bentonite together with aphrons play a sealing role synergistically. For 5, 20, and 100 D sand discs, the particle size of bentonite is smaller than the pore throat diameter and the size of aphrons. Therefore, bentonite can not be used as a single sealing material, it can only be used as filling particles to supplement the void space between aphrons, as shown in Fig. 9.

4. Conclusion

In this study, EST-based CGA drilling fluids generated by the easily degradable materials EST and the amino acid surfactant AGS-12 was proved to be a drilling fluid system with excellent HTHP sealing performance. The API filtration test preliminary determined that the high-temperature resistance of EST-CGA was within 200 °C. EST-CGA can reduce the filtration rate and control the filtration volume within 20 mL at 200 °C by forming mud cakes with lower permeability. The FL_{HTHP} of EST-CGA at 3.5 MPa was less than 25 mL within 200 °C, while that of the XG-CGA was as high as 198 mL at 180 °C.

Sand disc sealing experiments were carried out by using sand discs to replace the filter paper. Results show that the EST-CGA system can effectively seal the reservoirs with pore-throat diameters twice the aphron average diameter at 150 °C and 3.5 MPa. EST-CGA has the best sealing effect for the 20 D-55 μm sand disc, which was related to the size distribution of sealing materials. The optimal sealing effect can be obtained when the ratio of centralized tendency of the aphrons and the average pore-throat diameter was close to 1 : 1. And the clay with lower particle size was used as a filling material to make up the gaps between the micro-bubbles.

Compared with the traditional CGA drilling fluid system, the improvement of filtration performance of EST-CGA at HTHP conditions is self-evident. According to the FT-IR analysis, on the one hand, the modified starch polymer as a foam stabilizer introduced temperature-resistant groups into the system, such as the amide groups, sulfonic acid groups, and the rigid cyclic structures. On the other hand, the hydration

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Fig. 7 Size Distribution of Aphrons

Fig. 8 Particle Size Distribution of Bentonite
group combines with the carboxylate in AGS-12 to form a hydrogen bond, which significantly improves the fluid viscosity and foam stability in the HTHP environment. High-quality microbubbles and well-dispersed bentonite particles together form a blocking barrier, thereby optimizing the HTHP sealing performance of the CGA system.

There are still some problems to be solved in the field application of EST-CGA drilling fluid, including the optimization of high-temperature rheological properties and the adjustment of the aphron size distribution by the dosage of additives. The next step is in progress.

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