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Research Article

Research on Property of Multicomponent Thickening Water Fracturing Fluid and Application in Low Permeability Oil Reservoirs

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The clean fracturing fluid, thickening water, is a new technology product, which promotes the advantages of clean fracturing fluid to the greatest extent and makes up for the deficiency of clean fracturing fluid. And it is a supplement to the low permeability reservoir in fracturing research. In this paper, the study on property evaluation for the new multicomponent and recoverable thickening fracturing fluid system (2.2% octadecyl methyl dihydroxyethyl ammonium bromide (OHDAB) +1.4% dodecyl sulfonate sodium +1.8% potassium chloride and 1.6% organic acids) and guar gum fracturing fluid system (hydroxypropyl guar gum (HGG)) was done in these experiments. The proppant concentration (sand/liquid ratio) at static suspended sand is up to 30% when the apparent viscosity of thickening water is 60 mPa·s, which is equivalent to the sand-carrying capacity of guar gum at 120 mPa·s. When the dynamic sand ratio is 40%, the fracturing fluid is not layered, and the gel breaking property is excellent. Continuous shear at room temperature for 60 min showed almost no change in viscosity. The thickening fracturing fluid system has good temperature resistance performance in medium and low temperature formations. The fracture conductivity of thickening water is between 50.6 μm^2·cm and 150.4 μm^2·cm, and the fracture conductivity damage rate of thickening water is between 8.9% and 17.9%. The fracture conductivity conservation rate of thickening water is more than 80% closing up of fractures, which are superior to the guar gum fracturing fluid system. The new wells have been fractured by thickening water in A block of YC low permeability oil field. It shows that the new type thickening water fracturing system is suitable for A block and can be used in actual production. The actual production of A block shows that the damage of thickening fracturing fluid is low, and the long retention in reservoir will not cause great damage to reservoir.

1. Introduction

Fracturing is one of the main measures for low-permeability reservoir reconstruction. The performance of fracturing fluid is an important factor affecting the increasing production of oil field after construction [1, 2]. The conventional fracturing fluid has the disadvantages of residues, low flow-back rate, and unrecoverable and causes great harm to reservoir [3].

No damage or negative fracturing fluid represents the direction of fluid development in the fracturing industry. At present, clean fracturing fluid is a representative system of low-damage fracturing fluid [4]. Schlumberger's engineers with fluid experts with Eni-Agip have launched a clean fracturing fluid or surfactant fracturing fluid. Since the product has been put into the market, it has been popularized rapidly. The three largest countries and regions at present are Canada, the Gulf of Mexico, and the east of the United States. So far, the fracturing fluid system has been constructed for about 6000 wells and has achieved good economic benefits. According to the data [5], the first surface-active agent used by Schlumberger company is a cationic compound containing long-chain alkyl, and the combined salt is an organic sodium salt and an inorganic potassium salt. After that, Schlumberger has strengthened the further research and development of the

clean fracturing fluid, and has produced a more mature series of the surfactant fracturing fluid. The surface active agent not only has a small molecular weight, but also has a large molecular weight [6, 7]. It is not only cationic, but also other types, and the salt also involves a variety of organic and inorganic salts. BJ Services also developed a clean fracturing fluid system for AquaClear and ElastraFrac. The ElastraFrac gel is a heterogeneous aggregate (three-dimensional network structure) composed of environmentally friendly anionic surfactants and various salts, with a good temperature resistance and up to 120°C.

In 2009, Xinquan et al. published a report on the clean fracturing fluid of viscoelastic surfactant, and pointed out that the viscoelastic surface active agent formed a colloidal vermicular structure in the presence of brine, thus changing the viscoelasticity of the solution [8, 9]. In 2012, Bo et al. reported the performance of the temperature resistant and clean fracturing fluid, and proposed that this fracturing fluid is a kind of viscoelastic surfactant fracturing fluid with good temperature resistance, which can resist 150°C for a short time [10]. In 2013, Xiaojuan et al. reported the performance and application of the FRC-1 clean fracturing fluid system, and reported the clean water base fracturing fluid containing viscoelastic surfactant 2.5%, special stabilizer 0.1%, and chloride salt water 4%. According to its field application in Changqing oil field, it is proposed that the overall performance of FRC-1 clean fracturing fluid can meet the needs of fracturing construction below 60°C [11]. The field is easy to operate, has little damage to the reservoir, easy to return and to break, and does not leave residue. The average daily production increment is 1.34 times. In 2015, Manxue and Yifei reported on the development and application of low injury and clean fracturing fluid VES-1, the thickening agent of the fracturing fluid could be dispersed evenly in 1-2 minutes, and it could form a gel with a temperature resistance of 80°C [12]. After shearing for 60 min at 80°C, the viscosity of the fracturing fluid is still greater than that of 90 mPa·s. In 2017, Yongjun et al. reported the technical performance of leVES-70 clean fracturing fluid. The main agent of VES-70 fracturing fluid was C16 or C18 alkyl three methyl quaternary ammonium salt, which was mixed with organic acids, isopropanol, and other auxiliaries. Its composition is simple, so it is easy to mix. It has excellent viscoelasticity and temperature resistance, shear resistance, gel breaking, and reflow performance [13].

But, application of many fields proves that all the current clean fracturing fluids have residues without exception. These residues are bound to cause serious clogging of the strata and filling layers to greatly reduce the permeability, and the cumulative damage can reach more than 90%, which greatly reduces the effect of fracturing and cannot achieve continuous mixing. This situation is especially prominent for low pressure and low permeability reservoirs, which often leads to fracturing failure.

In order to solve the above problems, a new type of multicomponent thickening water clean fracturing fluid system has been studied. The main component of the thickening fracturing fluid system (2.2% octadecyl methyl dihydroxyethyl ammonium bromide (OHDAB) +1.4% dodecyl sulfonate sodium +1.8% potassium chloride and 1.6% organic acids) can be quickly cross-linked to carry sand, when it encounters crude oil and formation water, it can break gel without adding a gel breaker. After breaking glue, no residue is found, and the viscosity of gel breaker is <5 mPa·s. In addition, the system can be continuously mixed to shorten the fracturing cycle and can carry acid (HCL and HF) of concentration 1%–9% and organic acid 1%–3%, to achieve combination of acidizing and sand fracturing. The flow-back liquid can be recovered directly, and the same thickener can be recycled and reused. It saves water consumption and is suitable for horizontal wells to improve efficiency, to meet the needs of saving energy and environmental protection and large-scale factory operation.

2. Gelling and Gel Breaking Mechanism

The clean fracturing fluid, new multicomponent and recoverable thickening water, is mainly composed of a variety of special surfactants. The application of the composite liquid mutually contains molecular force between material and attachment, and the complex becomes transparent liquid substances, namely thickener. When the thickener is exposed to aqueous solution, the surfactant molecules are released and diffused rapidly under the influence of polar substances and aggregated to form wormlike micelles. The equilibrium system and micelle charge of the special organic ions make the micelles grow. A salt of the variable length wormlike micelles entangled, thus forming a uniform mesh space-like floc-like in the system, so as to form a gel [14–16].

In the gel system, there are mainly physical interactions between the surfactant and the salt, which are different from guar gum in the polymer fracturing system connected with each other in chemistry. Therefore, when the surfactant fracturing fluid meets the appropriate amount of formation water and oil gas, the intermolecular interaction distance between the surfactant and salt will increase. Furthermore, the entanglement state of wormlike micelles is destroyed, even the wormlike micelles disintegrated into simple micelles, and these can make the gel system automatically break [17–22]. The mechanism of gelling and breaking of thickening water is shown in Figure 1.

3. Performance Evaluation of the New Type Thickening Fracturing Fluid

3.1. Experimental Equipment and Reagents. HAD-CQ2A double deflector long-term conductivity tester (Beijing Heng Aude instrument limited company), SNB-2 digital viscometer (Shanghai Jingke day U.S. Trade Co. Ltd.), mixer, 250 mm cylinder, and electric thermostatic water bath (DGSY Beijing) were used.

The new type thickening water fracturing fluid is mainly composed of viscoelastic surfactant solution. The main agent of this experiment is the ionic surfactant with concentration of 2.2% octadecyl methyl dihydroxyethyl ammonium bromide (OHDAB). The role of the additives in thickening water fracturing fluid mainly depends on the cationic group adsorbed on the surfactant, which reduces the repulsive force between

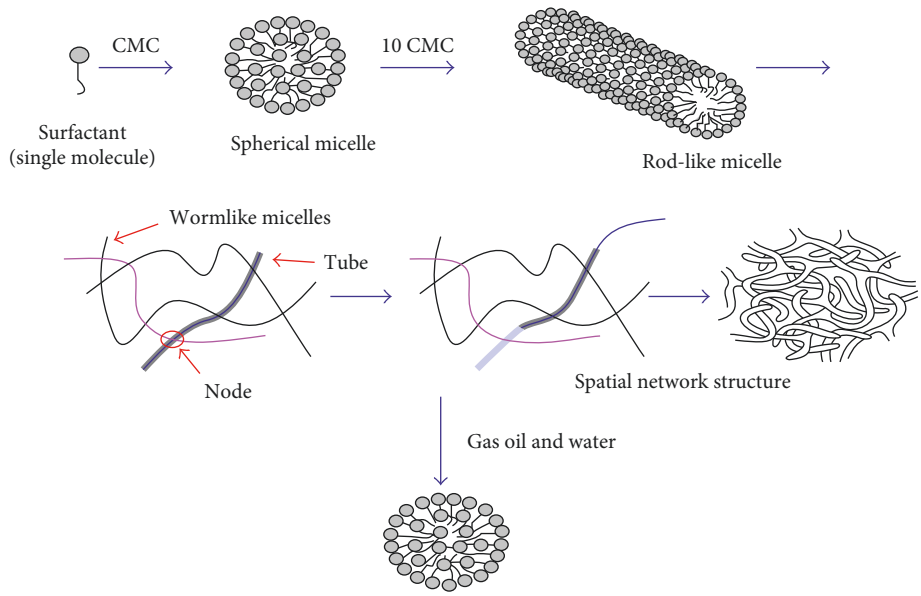

Figure 1: Schematic diagram of the mechanism of thickening water.

Table 1: Comparison of static sand-carrying capacity of two kinds of fracturing fluids.

Sand/liquid ratio (%)	Settling velocity (mm·s^{-1})					
	60 (mPa·s)		90 (mPa·s)		120 (mPa·s)	
	Thickening water	Guar gum	Thickening water	Guar gum	Thickening water	Guar gum
5	0.02973	0.04136	0.02461	0.03162	0.02016	0.02914
10	0.07823	0.09161	0.07012	0.08136	0.06812	0.07216
20	0.11986	0.14161	0.11014	0.13264	0.10011	0.12234
30	0.14832	0.17214	0.14036	0.16213	0.13613	0.15614
40	0.19613	0.21463	0.18214	0.20436	0.17614	0.19632

the cationic groups and increases the micelle growth. In this experiment, 1.4% dodecyl sulfonate sodium, 1.8% potassium chloride, and 1.6% organic acids are selected as the auxiliaries. The guar gum system used in this experiment is the most commonly used hydroxypropyl guar gum (HGG) in China.

3.2. The Sand-Carrying Capacity

3.2.1. Determination of Static Sand-Carrying Capacity. The new type thickening water gel and guar gum fracturing fluid gel are packed in No. 1 and No. 2 cylinder, and then the proppant with different sand ratio (volume ratio) is added. The static sand-carrying capacity is measured by observing the proppant in two cylinders at the time of settlement, and the results are shown in Table 1 and Figure 2.

It can be seen from Table 1 and Figure 2 that with the increase of sand ratio, the settling velocity of sand in thickening water and guar gum increases. And with the increase of viscosity of fracturing fluid, the sand falling velocity decreases gradually. Compared with thickening water and guar gum under the same viscosity, the sand dropping rate shows that the sand-carrying capacity of condensed water is better than that of guar gum. The sand-carrying capacity of guar gum at 120 mPa·s is equivalent to the carrying capacity of 60 mPa·s of thickened water.

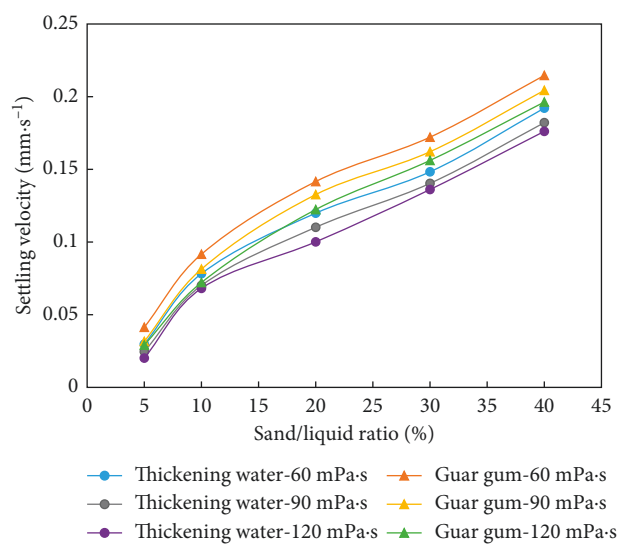

Figure 2: Comparison of static sand-carrying capacity of two kinds of fracturing fluids.

3.2.2. Determination of Dynamic Sand-Carrying Capacity. The dynamic sand-carrying capacity of thickening water (120 mPa·s) and guar gum (120 mPa·s) at different sand

Table 2: Comparison of dynamic sand-carrying capacity of two kinds of fracturing fluids.

Sand/liquid ratio (%)	Thickening water	Guar gum	Clean water
5	No layered	No layered	Layered
10	No layered	No layered	Layered
20	No layered	No layered	Layered
30	No layered	A little precipitation	Layered
40	No layered	Layered	Layered

Table 3: Comparison of gel breaking property of two kinds of fracturing fluids.

Time (min)	Apparent viscosity (mPa·s)					
	50 (°C)		60 (°C)		70 (°C)	
	Thickening water	Guar gum	Thickening water	Guar gum	Thickening water	Guar gum
10	100.3	115.6	80.3	98.2	50.2	70.2
30	80.6	96.5	60.1	75.2	26.2	50.6
60	40.2	62.4	30.6	45.8	12.3	30.7
120	10.2	20.1	10.1	19.6	2.6	16.8
240	4.3	10.6	1.9	8.7	1.3	5.6

ratios was determined at the stirring rate of 100 r/min and 70°C of temperature. The results are shown in Table 2.

It can be seen from Table 2 that the thickening water fracturing fluid can effectively carry sand at the sand ratio of 40% at 70°C, which indicates that the dynamic fracturing performance of the clean fracturing fluid is good. The guar gum precipitates at a sand ratio of 30%, and stratification occurs when the sand ratio is 40%, indicating that the effective sand-carrying ratio must be controlled below 40%. Therefore, when the temperature is 70°C, the dynamic sand-carrying capacity of the thickening water is better than guar gum, and the maximum sand ratio can reach 40%.

After thickening fracturing fluid is subjected to shear action, the network structure formed between micelles is destroyed, resulting in reduced number of micelles. And, the shear does not destroy the structure of the small molecule, but only reduces the degree of polymerization of the micelles; when the shear action stops, the micelles in the solution are rewound through the association to restore the reticular structure, and the viscosity is also restored. However, under the external shear effect, the network structure of gum fracturing fluid is destroyed, and the polymer molecular chain also shortens and degrades, and the viscosity of the system decreases. When the shear effect disappears, the molecule cannot recover the original viscosity through cross-linking. Therefore, compared with the polymer system, the carrying capacity of the thickened water fracturing fluid system is better.

3.3. The Gel Breaking Property. The experiment is divided into two groups. The volume ratio of simulated oil to thickening water (120 mPa·s) and guar gum fracturing fluid (120 mPa·s) is 1 to 20. The viscosity in different temperature and shear time was measured by the rotating viscometer at the speed of 7.5 r/min, and the results are shown in Table 3 and Figure 3.

The viscosity of water at normal temperature is 1.3 mPa·s. It can be seen from Table 3 and Figure 3 that the

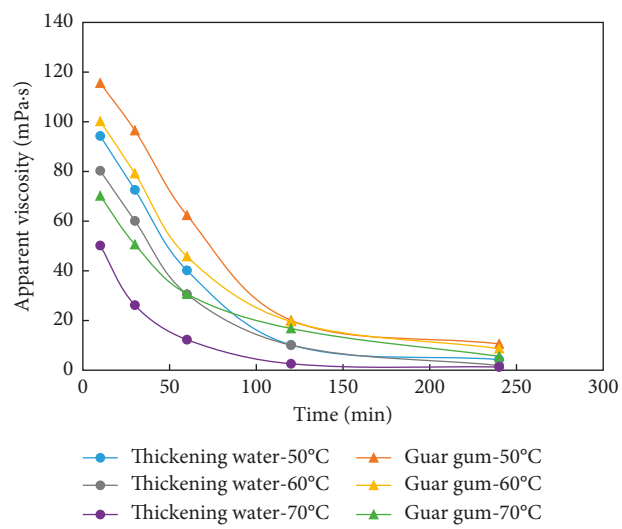

Figure 3: Comparison of gel breaking property of two kinds of fracturing fluids.

viscosity of guar gum fracturing fluid under the three temperature conditions is higher than thickening water fracturing fluid, indicating that thickening water is easier to return than guar gum after fracturing. At 70°C, the viscosity of the thickening water fracturing fluid is very close to the viscosity of the water after breaking the gel. In the experiment, it was found that after the system was broken, the insoluble matter could not be observed, while the guar gum system appeared with different degree of insoluble matter. All the above experimental phenomena show that clean fracturing fluid has excellent gel breaking performance and completely flow-back after gel breaking, which has little damage to formation.

The gel breaking property of fracturing fluid directly affects the damage degree to formation. Gum fracturing fluid needs to add a certain amount of the gel breaker, so that fracturing fluid can break glue and it is difficult to control the

Table 4: Comparison of three properties of two kinds of fracturing fluids.

Closing pressure (MPa)	Thickening water fracturing fluid system			Guar gum fracturing fluid system		
	Fracture conductivity (μm^2·cm)	Diversion retention rate (%)	Diversion damage rate (%)	Fracture conductivity (μm^2·cm)	Diversion retention rate (%)	Diversion damage rate (%)
5	150.4	82.3	17.6	120.1	61.2	40.2
10	130.6	83.1	15.3	100.6	52.3	30.7
20	100.3	84.5	12.1	80.6	63.2	27.6
30	80.1	84.7	10.1	50.1	64.7	16.1
40	50.6	86.2	8.9	26.3	65.1	10.8

Note. Fracture conductivity: after the fracture is closed, the proppant filling zone can pass through the reservoir fluid. Diversion retention rate: determination of the ratio between the conductivity of fractured support and the diversion capacity of formation water measured by hydraulic fracturing after fracturing. Diversion damage rate: the decrease of the diversion capacity of the support fracture induced by the fracturing fluid relative to the formation water.

degree of gel breaking. Unlike the gum fracturing fluid, it is not necessary to add the gel breaking agent in the thickened water clean fracturing fluid, but after the hydrocarbon compounds are encountered, the compound can be transformed into a spherical micelle by solubilizing to the micelles formed by the surfactant, and the mesh structure disintegrates to make it lose the viscoelasticity. Or, under the action of dilution of formation water, the content of surfactant is lower than the critical micelle concentration CMC, which makes the solution lose viscoelasticity and automatically breaks glue.

3.4. The Fracture Conductivity, Diversion Damage Rate, and Diversion Retention Rate. The main experimental instrument is the conductivity tester. The pressure difference and flow rate at each end of each fluid are measured quantitatively when the fracture is supported by simulation. And, when the liquid viscosity and fracture model size are replaced by Darcy's formula, the flow conductivity tester can automatically calculate the diversion capacity value under different closed pressure conditions [23, 24]. The viscosity of the two fracturing fluids is 120 mPa·s, and the fracture body model is selected as a multistage fracture system. The statistical results are shown in Table 4 and Figures 4 and 5.

It can be seen from Table 4 and Figures 4 and 5 that with the increase of the closing pressure, the flow conductivity increases gradually, the diversion retention rate increases gradually, and the diversion damage rate decreases gradually. The flow conductivity of the thickening fracturing fluid system is between 50.6 and 150.4 μm^2·cm, which is obviously higher than that of the guanidine gum fracturing fluid system. The diversion damage rate of the thickening water fracturing fluid system is between 8.9% and 17.6%, which is obviously lower than that of the guanidine gum fracturing fluid system. It is also known that the conductivity retention rate of the thickening hydraulic fracturing fluid system is above 80% after fracture closure, and the retention rate is high.

Firstly, when the two fracturing fluids are used as prefluid, respectively, the viscosity loss of the thickening water is less than the gum fracturing fluid because of the shear recovery of the thickening water, which is more likely to achieve the fracturing effect. Secondly, when the two fracturing fluids are used as sand-carrying fluid, respectively, the carrying capacity of the thickening fracturing fluid is better than gum fracturing fluid. When the viscosity of the thickening water fracturing fluid is restored through the wellhead hole, it is beneficial to the transportation of the proppant, and the proppant can enter the depth of the crack.

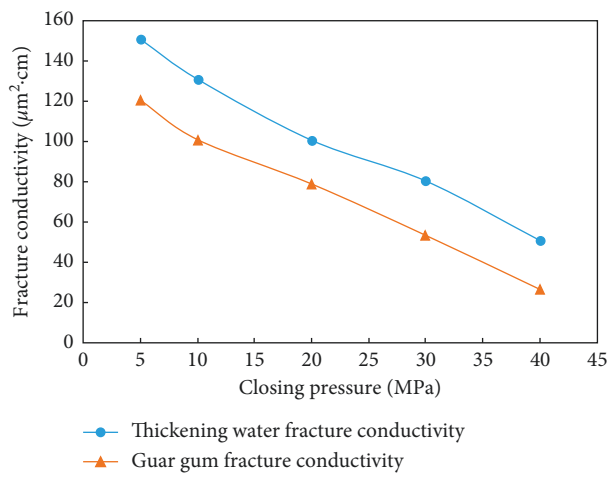

Figure 4: Comparison of fracture conductivity of two kinds of fracturing fluids.

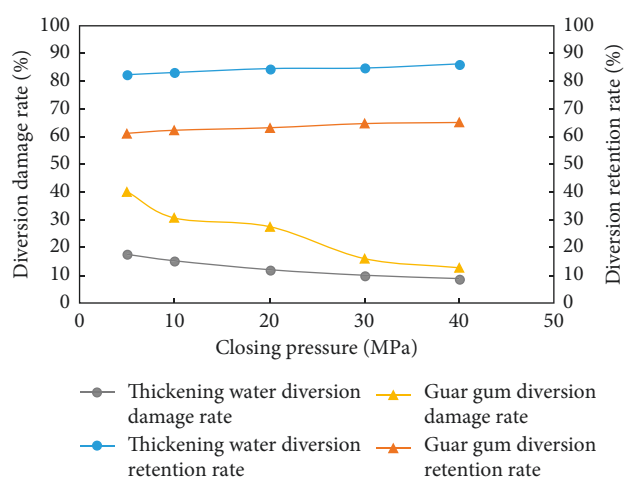

Figure 5: Comparison of diversion retention rate and diversion damage rate of two kinds of fracturing fluids.

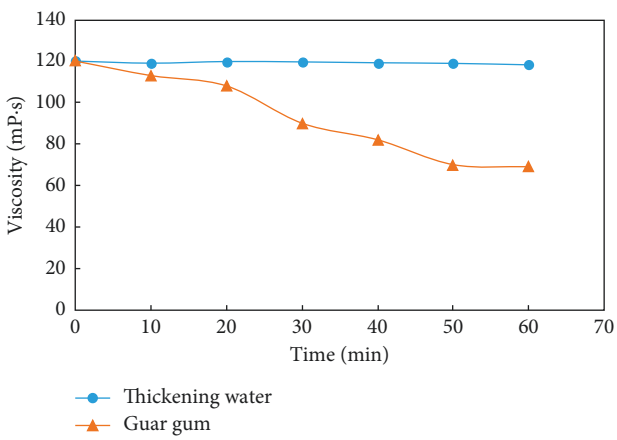

Figure 6: Comparison of viscosity changes with time: two kinds of fracturing fluids.

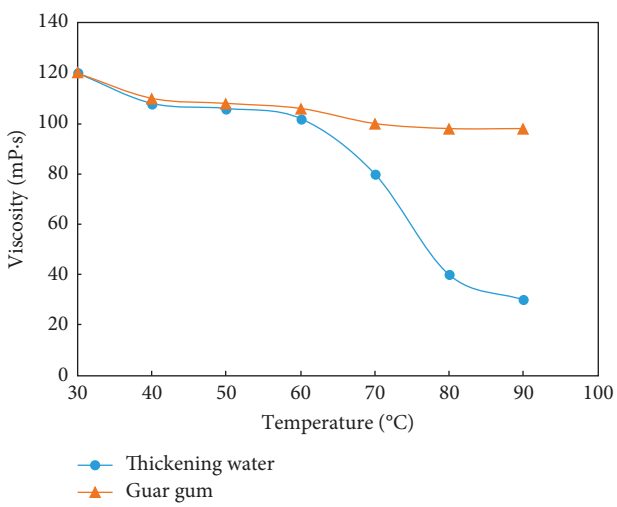

Figure 7: Comparison of viscosity changes with temperature: two kinds of fracturing fluids.

After the fracture is closed, the capacity of the support filling belt to the reservoir fluid is higher than the gum fracturing fluid. Finally, the thickening water fracturing fluid has good gel breaking performance in the formation, and the formation damage rate after controlled pressure reentry is small.

3.5. The Antishearing and Heat Resistance. The viscosity changes of two kinds of fracturing fluids under continuous shear for 60 min at room temperature (25 r/min) were measured by a rotating viscometer at 750 rpm. The viscosity of two kinds of fracturing fluids at 30~90°C under rotational speed 75 r/min with a rotational viscometer is shown in Figures 6 and 7.

From Figure 6, we can know that the thickening water fracturing fluid viscosity does not change with the shear time and that viscoelastic clean fracturing fluid keeps the shear stable; this characteristic is decided by the thickening mechanism of it.

The viscoelastic micelle system in the condensed water fracturing fluid has a strong self-healing property, and at the same shear rate, the system reaches a dynamic equilibrium of micelle destruction and repair. Therefore, the system can maintain the degree that will not be significantly decreased in long time under shear. In the guar gum fracturing fluid system, the polymer chains are sheared and the viscosity of the polymer decreases with the decrease of molecular weight.

From Figure 7, it can be seen that the viscosity drop of the thickened hydraulic fracturing fluid system increases more than 70 degrees, which indicates that the fracturing fluid system has good temperature resistance performance in medium and low temperature formations.

When the temperature rises, the solubility of the surfactant molecules in the water increases, thus, increasing the aggregation number of the micelles of the surfactant and speeding up the irregular movement of the micelles. This movement of micelles helps the intertwining between the rod-like micelles, and this movement maintains the viscosity of the gelatin. As the temperature continues to rise and when the temperature exceeds the critical micelle temperature, the micelle molecules dissociate and destroy the structure of some small micellar molecules. The viscosity of the thickened water system is not in a dynamic equilibrium state, so the viscosity of the gel decreases.

4. Field Application

4.1. Block Overview. The area of A block in YC low permeability oil field is 2.03 km^2, and the underground pore volume is $196.3 \times 104\ m^3$. The geological reserve of the target layer is 132.1×10^4 t, the average single well shooting sandstone thickness is 14.32 m, the effective thickness is 10.23 m, and the average effective permeability is $12.3 \times 10^{-3}\ \mu m^2$; A block adopts diamond inverted nine-point well pattern, and there are 83 wells, including 21 injection wells and 62 production wells, and the distance between the injection well and the production well is 300 meters. A block is a typical low porosity and low permeability block, but it has potential for development. In 2016, the new multicomponent thickening water fracturing fluid was used in 3 horizontal wells in A block, and the fracturing effect was improved obviously compared with the previous fracturing production and guar gum system.

4.2. Technical Index of Field Application. The new multicomponent thickened water clean fracturing fluid is a viscoelastic surfactant-based fracturing fluid system. The main component, liquid thickener, can be quickly cross-linked and carries sand when mixed with water. Without adding new equipment, continuous mixing operation can be realized, and the glue can be broken when oil and formation water are encountered. The fracturing fluid can carry different types and concentrations of acid solution. It has the technical features of no residue and low damage, and can be put into operation without swabbing and draining.

(1) The new type thickening water can carry acid (HCL and HF) concentration of 1%–9% and organic acid

Table 5: Comparison of construction process.

Process	Thickening water	Guar gum	Remark
Before fracturing construction	Preparation and thickener	Preparing and cleaning tank, fracturing fluid material to field distribution	Guar gum fracturing fluid is easy to deteriorate by long time of placement
Fracturing construction	Continuous mixing, how much design is required, and how much it can be matched	Construction according to the design requirements	The amount of thickening water can be determined according to the actual amount of field construction, and there is no problem of liquid waste
After fracturing construction	Sand washing, well washing, production	Injection, sand washing, well washing, swabbing, and production	
Overall evaluation	Thickening water clean fracturing fluid system is more practical than guar gum fracturing fluid system		

Table 6: Comparison of operation cycle.

Time	Guar gum	Thickening water	Remarks
Preparation tank Tank cleaning	1-2 days 3-4 h	1-2 days 0 h	Truckage
Liquid distribution	10 h	0 h	There is no need for advance solution for thickening water
Fracture	1–1.5 h	1–1.5 h	The continuous mixing of the thickened water mixture is used in the field, and the amount can be determined according to the actual construction amount of the site
Liquid discharge	2–5 days	1 day	The thickening water can not be discharged and put into production directly
Total	4.5–8 days	1.5–3.5 days	Save 3-4 days

1%–3% to achieve acidification combined with sand fracturing.

(2) The temperature resistance and shear resistance: temperature of new type thickening water is not higher than 75°C and 40°C fracturing fluid continuous shear viscosity of >100 mPa·s, no change of viscosity.

(3) The new type of gel breaking thickening water without adding breaking agent, gel breaking in crude oil and formation water, no residue after gel breaking, and gel breaking liquid viscosity of <5 mPa·s.

(4) The sand-carrying capacity: 40 centigrade and 35% sand ratio, the static state can be suspended more than 60 min.

(5) The core damage rate: the total is less than 20%.

(6) The antiswelling rate of clay is >89%.

4.3. Comparison of the Effect of Guar Gum Fracturing Fluid. Guar gum fracturing fluid ensures the success of high-temperature deep fracturing. However, when guar gum fracturing fluid enters the pipeline at high speed and enters the pipeline at high speed during construction, it will cause severe shearing degradation and produce permanent viscosity loss. Moreover, the compound chain of guar gum fracturing fluid is connected with the cross-linked chain between the chains, resulting in the body shape. The result is that the gel breaking is incomplete, so that the residue left behind after breaking the gel will remain in the crack, which will seriously reduce the permeability of proppant filling layer and damage the production layer, resulting in poor fracturing effect. In addition, the cross-linking fracturing fluid is not completely broken, causing sand fracturing well to scour, prolonging operation time, and increasing operating cost. At present, the guar gum fracturing fluid system has high content of water insoluble substance (the national standard requires less than 12% of water insoluble substance) and repeating damage to the formation. The construction process and operation cycle of the two kinds of fracturing fluid are shown in Tables 5 and 6.

4.4. Analysis of Fracturing Effect. The development effect of the new multicomponent thickened water fracturing hydraulic fracturing 3 wells in A area is shown in Table 7, as shown in Figures 8–10.

4.5. Comparison with Conventional Fracturing Effect. At present, the average daily production of 3 wells is 10.3 m^3, with an average daily oil production of 9.27 t. And, 3 horizontal wells were selected as contrast wells in the same block, and the average daily production of 3 wells was 8.2 m^3, with an average daily oil production of 7.28 t. By comparison, the daily production of the test wells increased by 2.1 m^3 compared to the selected wells in the block, and the daily production increased by 1.89 t. It indicates that the

Table 7: The effect of 3 wells fractured by thickening water.

Block	Well	Physical parameters				Oil test		Put into operation		
		Shale content (%)	Porosity (%)	Permeability (md)	Oil saturation (%)	Daily oil (t)	Daily water (t)	Daily liquid (m^3)	Daily oil (t)	Water cut (%)
A	A1	10.3	11.5	9.2	62.2	55.3	1.2	11.9	10.8	9.2
	A2	10.4	10.0	8.7	63.8	42.6	1.0	8.6	7.8	9.4
	A3	15.1	9.3	6.9	65.0	52.1	0.8	9.5	8.6	9.3

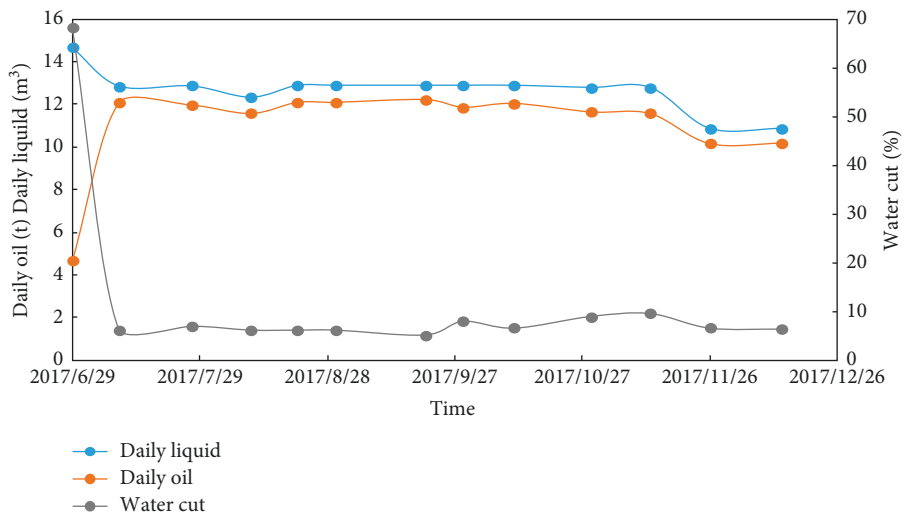

Figure 8: Production curve of A1 well.

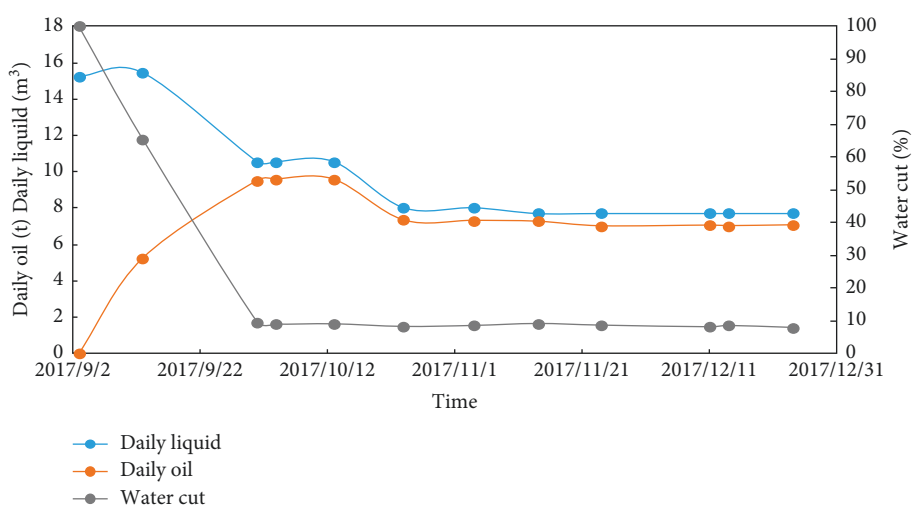

Figure 9: Production curve of A2 well.

acidic clean fracturing fluid of thickening water has a good adaptability to A block, which will pave the way for further promotion Table 8.

As a new type of fracturing fluid, clean fracturing fluid have the characteristics of cleaning, low damage, thoroughly gel breaking, little residues, and high flow-back rate. So, it will have good application prospect in low permeability reservoirs. In particular, the reprocessing liquid can be directly recovered, and the same thickener can be added to recycle, which reduces the reservoir damage and saves the water consumption. It is very suitable for improving the efficiency and saving energy for the horizontal well, as well as protecting environment and meeting the demand of large-scale factory operation.

5. Conclusions

(1) When the shear action stops in new type thickening water, the micelles in the solution are rewound through the association to restore the reticular

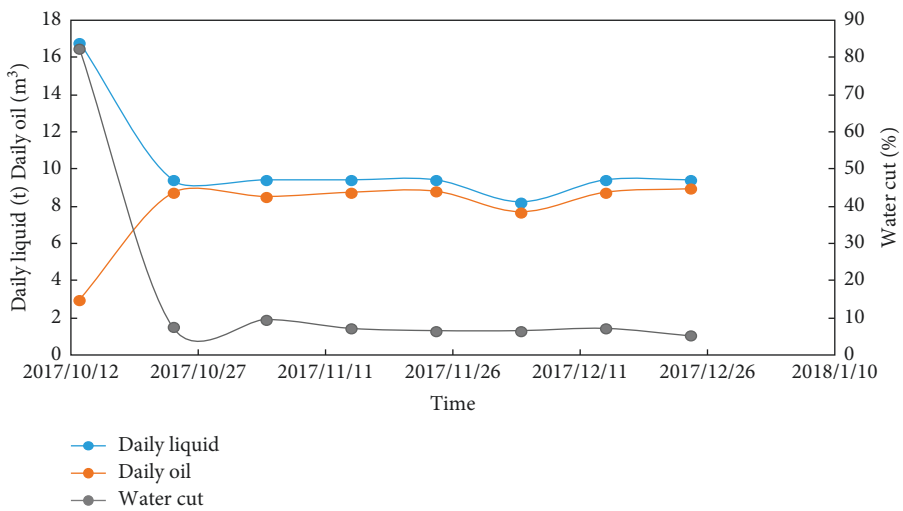

Figure 10: Production curve of A3 well.

Table 8: Comparison of effect between thickening water fracturing wells and conventional fracturing wells.

Well types	Well	Physical parameters				Oil test		Put into operation		
		Shale content (%)	Porosity (%)	Permeability (md)	Oil saturation (%)	Daily oil (t)	Daily water (t)	Daily liquid (m^3)	Daily oil (t)	Water cut (%)
Thickening water fracturing well	3	13.2	8.3	10.3	68.3	50.2	1.0	10.3	9.27	10.0
Guar gum fracturing well	3	14.2	9.4	11.5	60.1	45.2	1.2	8.2	7.38	10.0

structure, and the viscosity is also restored. The sand/liquid ratio at static suspended sand is up to 30% when the apparent viscosity of the new system is 60 mPa·s, which is equivalent to the sand-carrying capacity of guar gum at 120 mPa·s.

(2) When the viscosity of the thickening water is restored through the wellhead hole, it is beneficial to the transportation of the proppant, and the fracture conductivity is between 50.6 μm^2·cm and 150.4 μm^2·cm, and the fracture conductivity damage rate is between 8.9% and 17.9%. The fracture conductivity conservation rate is more than 80% closing up of fractures, which are superior to guar gum.

(3) The new system does not need to be added to the adhesive; after the hydrocarbon compounds are encountered, the compound can be transformed into a spherical micelle by solubilizing to the micelles formed by the surfactant and the reticular structure disintegrates to make it lose the viscoelasticity. Under the action of dilution of formation water, the content of surfactant is lower than the critical micelle concentration CMC, which makes the solution lose viscoelasticity and automatically break the gel.

(4) The viscoelastic micelle system in the multicomponent thickening water has a strong self repair. Under the same shear rate, the system achieves a dynamic balance of the micellar damage and repair. At room temperature, the shear rate is 60 min, and the viscosity is almost unchanged. As the temperature continues to rise and when it exceeds the critical micelle temperature, the micelle molecules dissociate and destroy the structure of some small micellar molecules. The viscosity system is not in a dynamic equilibrium state, so the viscosity of the gel decreases. It shows that the new system has good temperature resistance in middle and low temperature formation.

(5) The actual production of A block shows that the damage of thickening fracturing fluid is low, and the long retention in reservoir will not cause great damage to the reservoir. Therefore, it cannot be pumped directly into production and continuous mixing, shortening the overall testing oil cycle. The flow-back liquid can be recovered directly, and the same thickener can be recycled and reused.

Data Availability

The data used to support the findings of this study are available in the supplementary materials, or from the corresponding author upon request.

Conflicts of Interest

The authors declare that they have no conflicts of interest.

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Supplementary Materials

The supplementary material includes the data of experiments and field application mentioned in the article, and the tables (from Tables 1–8) and figures (from Figures 1–10) are drawn from these data. (*Supplementary Materials*)

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