# Water-Based Drilling Fluid Containing Bentonite/Poly(Sodium 4-Styrenesulfonate) Composite for Ultrahigh-Temperature Ultradeep Drilling and Its Field Performance

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#### Summary

The rapidly increasing global oil/gas demand and gradual depletion of shallow reservoirs require the development of deep oil/gas reservoirs and geothermal reservoirs. However, deep drilling suffers from drilling-fluid failures under ultrahigh temperature, which cause serious accidents such as wellbore collapse, stuck pipe, and even blowouts. In this study, we revealed the role of polymeric additives in improving the ultrahigh-temperature tolerance of bentonite-based drilling fluids, aiming to provide practical and efficient solutions to the failure of drilling fluids in severe conditions. By adding poly(sodium 4-styrenesulfonate) (PSS) to the original drilling fluid containing bentonite, significant fluid loss—as a consequence of bentonite-particle flocculation causing drilling-fluid shear-stress reduction and high-permeability mud—is successfully suppressed even at temperature as high as 200°C. This drilling fluid containing PSS was applied in the drilling of high-temperature deep wells in Xinjiang province, China, and exhibited high effectiveness in controlling accidents including overflow and leakage.

#### Introduction

With the rapid growth in global oil/gas demand and the depletion of shallow oil/gas resources, alternatives to replace shallow oil/gas are urgently required (De Silva et al. 2016; Becattini et al. 2017). Oil and gas in deep reservoirs could be recovered to fulfill the global energy demand. However, deep reservoirs are generally deeper than 5 km, and currently the deepest reservoir detected is nearly 9 km with a bottomhole temperature of 180–260°C (Aftab et al. 2017).

With the increasing number of deep wells and ultradeep wells, higher requirements for tolerance of drilling fluids to ultrahigh temperatures are put forward. Drilling fluid, commonly regarded as the "blood" of drilling, is a colloid-suspension complex generally formed by clay particles and various chemical agents in aqueous phase (Sehly et al. 2015). During the drilling process, it carries drill cuttings, balances formation pressure, cools and lubricates drilling tools, and transmits hydrai; oc power (Baltoiu et al. 2006). The performance of drilling fluid directly affects drilling safety and efficiency.

The tolerance of drilling fluid to ultrahigh temperatures has been a major challenge in drilling in deep wells (Salami and Plank 2013). However, most of the current drilling-fluid products have critical tolerance temperatures lower than 180°C, which involves considerable risk when being applied in harsh high-temperature conditions. Failure of the drilling fluid at high temperature during drilling would lead to collapses, hard drilling and blowouts, reduced ability to carry rock and weighting materials, which might cause severe accidents such as well collapse, stuck drillpipe, and blowouts, and could even lead to holes being scrapped (Yan et al. 2013). It might further affect the cementing process and long-term zonal isolation by contaminating the cement slurry (Wu et al. 2017). While most of the existing drilling fluids and treatment agents barely meet the requirements of high-temperature tolerance (Clements et al. 1985), it is urgent to develop drilling fluids with acceptable ultrahigh-temperature performance that can be resistant up to 200°C.

Inhibitive drilling fluids have been an important research topic for many years. The common drilling fluids include some kinds of inhibitive systems, such as nanoparticle/bentonite drilling fluids (Sensoy et al. 2009), silicate drilling fluids (Tomislav et al. 2004), potassium chloride (KCl)/hexamethylenediamine drilling fluids (Ike et al. 2011), and novel polyamine drilling fluids (Huadi et al. 2010), and others. Nanoparticle/bentonite drilling fluids were found to decrease the permeability of the Atoka Shale and the Gulf of Mexico Shale dramatically by plugging shale pore throats (Sensoy et al. 2009). The silicate drilling fluids were used to effectively solve problems of high water sensitivity of the shale- and illite-formation drilling, and to successfully drill six wells in the Hayane Block area by forming a blockage or membrane that reduced the permeability of the shale (Tomislav et al. 2004). KCl/hexamethylenediamine drilling fluids showed excellent performance of hydration inhibition, and can effectively inhibit the expansion of Marcellus Shale of West Virginia (Ike et al. 2011). Novel polyamine drilling fluids have been used as an alternative to KCl/polymer drilling fluids by significantly improving the clay/shale inhibition, with a noticeable improvement in cuttings integrity, and were used to drill 12 wells successfully in Offshore East Kalimantan (Huadi et al. 2010). Potassium formate (HCOOK)/amine drilling fluids effectively inhibit the hydration of US shale, and 20% sodium chloride (NaCl) drilling fluids could effectively inhibit the hydration of Middle East shale (Sandra and He 2012). By adding film-forming agents to the waterbased drilling fluid from filtrating into the formation, thereby protecting the reservoir and stabilizing the wellbore (Tan et al. 2002a, 2002b).

For drilling fluids with a temperature tolerance of  $200^{\circ}$ C, the performance of inhibition, rheology, and fluid loss is critical. Inhibitors, such as KCl and NaCl, are less affected by temperature. But the fluid-loss additive and the rheology additive often fail because they cannot withstand a high temperature of  $200^{\circ}$ C (Chu et al. 2013; Salami and Plank 2013; Tiemeyer and Plank 2013).

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The fluid loss additive is a treatment agent in drilling fluid which helps to maintain good filtration properties under various conditions, including high temperature (Chu et al. 2013; Salami and Plank 2013; Tiemeyer and Plank 2013). Modified natural materials are frequently applied as fluid-loss additives, including carboxymethyl cellulose (CMC), hydroxyethyl cellulose (HEC), polyanionic cellulose, and starch, which undergo degradation at high temperatures and become unsuitable for use in deep reservoirs (Anderson and Barker 1974; Warren et al. 2003; Menezes et al. 2010; Dias et al. 2015; Li et al. 2015). Also, pistachio-shell powder was applied in one of the Iranian oil fields at 104.4°C and 3.45 MPa. Nano-sized tapioca starch has been introduced as a natural water-soluble polymer for filtration control in water-based drilling muds, with a temperature tolerance of 93.3°C (Zoveidavianpoor and Samsuri 2016). Nanosepiolite was used to prevent filtration loss of water-based drilling fluids at 185°C and 17.3 MPa (Abdo et al. 2016). Egyptian bentonite, yielding drilling fluid with better rheological and filtrate properties, was discovered for drilling in medium-depth wells (Temraz and Hassanien 2016). Date-seed powder, as the fluid-loss additive, can be equally applicable for freshwater and saltwater-based drilling muds (Amanullah et al. 2016). In addition to modified natural materials, synthetic polymers such as acrylamide-based polymers are alternative fluid-loss additives (Cao et al. 2017; Ahmad et al. 2018). These polymers exhibited good high-temperature tolerance; for instance, acrylamide/acrylic acid showed a temperature tolerance of 90°C (Ahmad et al. 2018), and acrylamide/4-vinylpyridine/ 2-acrylamide-2-methylpropanesulfonic acid could stand a temperature as high as 150°C (Wu et al. 2001; Li et al. 2012; Tiemeyer and Plank 2012; Bai et al. 2015). Because of an antipolyelectrolyte effect (Georgiev et al. 2006; Andreeva et al. 2010; Pourjavadi et al. 2010; Wang et al. 2010, 2015), amphoteric polymers with negative and positive groups (Williams et al. 1984; Tartakovsky et al. 2003; Zou et al. 2013; Liu et al. 2014) can maintain higher viscosity than anionic polymers in saline solution, and have a strong binding interaction on the negatively charged bentonite layers, showing a good performance in controlling fluid loss in water-based drilling fluids.

In this work, we developed, characterized, and performed in-field testing fo a novel water-based drilling fluid with high temperature tolerance; this fluid contained PSS as an ideal fluid-loss additive. Although PSS has a high half maximal effective concentration of more than 30,000 ppm, it is an environmentally friendly polymer. In systematic rheology and filtration characterizations, PSS showed better potential than other candidates (CMC and HEC) in controlling filtration loss during 200°C hot rolling. A distinctive mechanism of PSS tolerance to an ultrahigh temperature of 200°C was then proposed through investigation of the microscopic and macroscopic structure of filter cakes and drilling fluid. Finally, a successful field test of this new drilling fluid in Xinjiang province of China was reported, confirming its excellent performance in enhancing wellbore stability and reducing drilling accidents during high-temperature deep drilling.

### **Materials and Experimental Methods**

**Preparation of Drilling Fluids.** PSS (98%) was obtained from Macklin Biochemical Corporation (Shanghai, China). CMC (60%) and HEC (99%) were obtained from Baoding Huarui Corporation (Hebei, China). Bentonite was supplied by Xiazijie Bentonite Corporation (Xinjiang, China).

A 4% bentonite drilling fluid was prepared by adding 4% (w/v) bentonite in deionized water and then stirred at 2,000 rev/min for 24 hours by a GJSS-B12K high-speed mixer (Qingdao Tongchun Petroleum Instrument Co. Ltd.). This step was basically the same as in the field. Polymer materials were dissolved in the 4% bentonite drilling fluid with 2,000-rev/min stirring for 20 minutes, followed by stirring at 8,000 rev/min for 20 minutes and aging for 24 hours to let the materials interact thoroughly with bentonite particles and ensure the repeatability of the experiment. It is not necessary to maintain 24 hours during the oilfield drilling process. To study the high-temperature performance of the drilling fluid, an aging test was carried out in a GH-3 roller oven (Qingdao Tongchun Petroleum Instrument Co. Ltd.) by rolling at 200°C for 16 hours. For most experiments and characterizations, normally, 300 cm<sup>3</sup> of drilling fluid was used.

**Characterization Methods.** Systematic experiments were conducted to characterize the properties of bentonite-based drilling fluids with or without PSS. Those characterizations include: thermogravimetric analysis (TGA), American Petroleum Institute (API) filtration test, rheology test, zeta-potential measurements, particle-size-distribution tests, scanning-electron microscope (SEM) imaging, and transmission electron microscopy (TEM) imaging. Details of those instruments, methods, and the TGA results, can be found in the Supporting Information.

#### **Lab Experimental Results and Discussion**

American Petroleum Institute (API) Filtration Test. CMC and HEC show good performances in controlling filtration volume ( $FL_{API}$ ) before hot rolling as presented in Fig. 1. When the amount of CMC and HEC ranged from 0.1 to 1%, the  $FL_{API}$  with CMC and HEC decreased from 26.4 and 28.4 to 6.2 and 7.8 cm<sup>3</sup>, respectively. After 200°C hot rolling, the  $FL_{API}$  of 4% bentonite mud with 1% CMC and 1% HEC were 62.4 and 60.2 cm<sup>3</sup>, revealing that CMC and HEC possessed weak high-temperature tolerance.  $FL_{API}$  of the drilling fluid with 1% PSS was slightly increased and only changed from 18.4 to 20.0 cm<sup>3</sup>, indicating that the PSS drilling fluid might have a good performance in controlling filtration at high temperature. When the concentrations of polymers were higher than 0.5%,  $FL_{API}$  demonstrated less dependency on concentration, with a relatively steady tendency. Therefore, an optimized concentration of 1% for each polymer was used for the following characterizations by taking economic cost into consideration.

**Rheological Properties.** The viscosity of the drilling fluid is a key feature that affects the stability of the internal structure of drilling fluids (Ramos-Tejada et al. 2006; Sayindla et al. 2017; Saasen and Ytrehus 2018). A series of rheology tests for drilling fluids containing 4% bentonite with CMC, HEC, and PSS additives were conducted under different temperatures. Detailed methods are shown in Supplementary Information.

The shear rate experienced in a well is mainly in a range of 0-200 1/seconds (Saasen and Ytrehus 2018). At the shear rates lower than 200 1/seconds, the rheology profiles were obtained to reflect the characteristics. The shear stress of bentonite-based drilling fluid containing 1% (w/v) CMC and 1% (w/v) HEC was greatly reduced after aging at 200°C, as shown in **Figs. 2a and 2b.** With the addition of 1% (w/v) PSS in 4% bentonite-based drilling fluid, the shear stress did not change significantly after aging at 200°C and the shear stress was greater than that for drilling fluids with the addition of 1% (w/v) CMC or 1% (w/v) HEC. It shows that PSS can effectively maintain the rheological properties of drilling fluid and carrys cuttings favourably.

The initial gel strength and final gel strength of CMC and HEC drilling fluids were also reduced sharply after hot rolling (Figs. 2c and 2d). The initial gel strengths of 4% bentonite drilling fluids with 1% CMC and 1% HEC decreased from 7 and 6 Pa to 0.5 and 0.5 Pa, respectively. The final gel strengths of 4% bentonite drilling fluids with 1% CMC and 1% HEC decreased from 9 and 8 Pa to 0.5 and 1 Pa, respectively. In contrast, the initial gel strength and final gel strength of the drilling fluid with 1% PSS only changed from 3 and 4 to 2.5 and 3 Pa, respectively, because of its good thermostability.



Fig. 1—API filtration test ( $FL_{API}$ ) of drilling fluids as a function of additive concentrations before and after hot rolling at 200°C. PSS, CMC, and HEC stand for the  $FL_{API}$  of 4% bentonite drilling fluids with different concentrations of PSS, CMC, and HEC, respectively. PSS (HR), CMC (HR), and HEC (HR) stand for the  $FL_{API}$  of 4% bentonite drilling fluids with different concentrations of PSS, CMC, and HEC after hot rolling (HR) at 200°C, respectively.



Fig. 2—(a and b) Evolution of shear stress of drilling fluid with shear rate before and after hot rolling at 200°C. (1 wt% additives are added in 4 wt% bentonite drilling fluids, respectively). (c) Initial gel strength (G') of drilling fluids with the presence of different additive concentrations before and after hot rolling at 200°C. (d) Final gel strength (G'') of drilling fluids with the presence of different additive concentrations before and after hot rolling (HR) at 200°C, respectively.

As mentioned above, the shear stress and gel strength of the drilling fluid with 1% PSS were better than those with 1% CMC or 1% HEC, indicating that the PSS drilling fluid has better high-temperature tolerance comparing to traditional drilling fluids with CMC and HEC.

Characterizations of Bentonite Precipitate and Mudcakes After 200°C Hot Rolling Test. After hot rolling at 200°C, a large amount of bentonite particles in 4% bentonite mud was adsorbed on the wall of the aging tank (Figs. 3a through 3d), and serious

high-temperature aggregation of bentonite occurred. A small amount of bentonite particles in a sample of 1% CMC + 4% bentonite mud was adsorbed on the wall of the aging tank, and the high-temperature aggregation of bentonite disappeared to a large extent. In 1% HEC + 4% bentonite mud, a small amount of bentonite was adsorbed on the wall of the aging tank, indicating that there was still high-temperature aggregation of bentonite. After adding PSS, the wall of the aging tank was clean and tidy, with no obvious bentonite agglomerate particles observed, indicating that PSS is conducive to maintaining the bentonite's high-temperature particle dispersion and effectively avoiding high-temperature coalescence of bentonite. Fig. 3e shows that after high-temperature hot rolling, the filter cake formed by 4% bentonite mud was very thick (approximately 3.64 mm and 2.88 g), which is related to large bentonite particles formed by high-temperature aggregation. The filter cakes formed by bentonite mud after adding 1% CMC and 1% HEC were slightly thinner, with the thickness of 2.14 and 1.98 mm and the weight of 1.72 and 1.43 g, respectively. This is in good agreement with the large FL<sub>API</sub> values of 62.4 and 60.2 cm<sup>3</sup> in Fig. 1, illustrating that the bentonite particles in the drilling fluids were large in size. The mudcake formed by the large bentonite particles might have big pores and high permeability, resulting in significant fluid loss. The filter cake formed in 4% bentonite drilling fluid + 1% PSS was very thin (1.22 mm and 0.92 g), illustrating that the bentonite particles in this drilling fluid are very small in size. The PSS maintains the high-temperature fine particle dispersion of bentonite and effectively prevents it from agglomerating at high temperature. The mudcake formed from bentonite particles was thin and dense, with low permeability, which explains why the API loss of 4% bentonite mud + 1% PSS was small, as shown in Fig. 2.



Fig. 3—Digital images of the tank of drilling fluids after 200°C hot rolling for 16 hours; (a) 4% bentonite drilling fluid; (b) 4% bentonite drilling fluid + 1% CMC; (c) 4% bentonite drilling fluid + 1% HEC; (d) 4% bentonite drilling fluid + 1% PSS; (total volume of drilling fluids was 300 cm<sup>3</sup>). (e) Thickness and weight of drilling-fluid cake after 200°C hot rolling for 16 hours (blank, 4% bentonite drilling fluid; CMC, 4% bentonite drilling fluid + 1% CMC; HEC, 4% bentonite drilling fluid + 1% HEC; PSS, 4% bentonite drilling fluid + 1% PSS; total volume of drilling fluids was 300 cm<sup>3</sup>).

As shown in **Figs. 4a and 4b**, the mudcake of 4% bentonite drilling fluid has a loose structure with large amount of micropores and large particle size caused by severe high-temperature aggregation of bentonite particles. The mudcakes produced by 4% bentonite drilling fluid with 1% CMC and with 1% HEC exhibit similar morphology with loosely packed structure with micropores (Figs. 4c through 4f), preventing CMC and HEC from maintaining the dispersion of the bentonite particles, which is in accordance with the large FL<sub>API</sub> values of the drilling fluid. In contrast, as shown in Figs. 4g and 4h, the mudcake produced by 4% bentonite drilling fluid before and after the hot rolling (18.4 and 20.0 cm<sup>3</sup>) (Fig. 1). It further confirms that PSS could maintain drilling-fluid tolerance to a temperature as high as 200°C.

**Drilling-Fluid Thermostability Characterization.** TEM was further used to verify our assumption. As shown in **Figs. 5a through 5c**, after hot rolling at 200°C, in samples of 4% bentonite drilling fluid, 4% bentonite drilling fluid + 1% CMC, and 4% bentonite drilling fluid + 1% HEC, bentonite particles exhibited coalescence, aggregating to give larger particle size. In a sample containing 1% PSS, bentonite particles maintain a well-defined colloidal dispersion with the minimal width of 12 or 13 nm (Fig. 5d), which is conducive to the formation of dense mudcake and is in good agreement with SEM images. It will prevent the drilling fluid from filtrating into the wellbore and destroying the stability of the wellbore. As shown in Figs. 5e and 5f, before aging, the D<sub>50</sub> particle sizes of 4% bentonite mud, 1% CMC + 4% bentonite mud, 1% HEC + 4% bentonite mud, and 1% PSS + 4% bentonite mud were 18.3, 0.432, 0.575, and 0.689 µm, respectively; after aging, they changed to 82.4, 26.8, 20.5, and 1.39 µm, respectively. D<sub>10</sub> and D<sub>90</sub> also showed the same tendency, demonstrating that the high temperature drives bentonite particles to aggregate into large moieties. CMC and HEC showed only limited capability toward the control over coalescence of bentonite particles. PSS is able to effectively maintain the particle dispersion and colloidal stability of bentonite particles, avoiding the agglomeration of the bentonite particles under high temperature, which is in consistent with morphological studies.

The zeta-potential variation of drilling fluid with different CMC, HEC, and PSS concentrations was investigated. CMC and HEC showed good performance in increasing zeta potential before hot rolling, as displayed in **Fig. 6a**. When the concentrations of CMC and HEC increased from 0.25 to 1%, the zeta potential of drilling fluids would be elevated. However, the zeta potentials of CMC and HEC drilling fluids were greatly reduced after hot rolling at 200°C for 16 hours, from -53.2 and -54.1 to -27.5 and -28.9 mV, respectively. The zeta potential of the drilling fluid with 1% PSS was slightly reduced from -31.7 to -31.2 mV, indicating that the PSS drilling fluid has better high-temperature tolerance compared with CMC and HEC. It suggests that the addition of PSS brings more negative charge to the surface of bentonite particles after wrapping and encapsulation. At a high temperature of 200°C, the clay particles in the drilling fluids are seriously agglomerated because of high-temperature dehydration, losing the space grid structure formed by the edge

connection or the side contact of bentonite particles. Thus, the viscosity of the drilling fluid is greatly reduced. Meanwhile, because of the presence of relatively large clay aggregates, the resulting mudcake is thick with high permeability and large micropores, leading to an accelerated fluid loss of the drilling fluid. Encapsulation of PSS polymer chains on the bentonite particles enables the adsorption of water molecules to form a hydration layer (Fig. 6b). It helps to maintain the fine dispersion and colloidal stability of bentonite particles under high-temperature conditions and to form a dense mudcake, reducing drilling fluid loss. PSS preserves its hydration state under high temperature conditions (200°C) by adsorbing onto the surface of the clay particles, maintaining the space grid structure of clay particles, and effectively maintaining the viscosity of the drilling fluid at high temperature. The excellent high-temperature resistance of PSS has an intimate relation with its thermostability. According to the TGA curve (Fig. S-1), compared with PSS, CMC and HEC showed weak thermal stability with larger amount of weight loss at 243 and 262.3°C, respectively. At this temperature range, PSS did not experience significant weight loss, indicating that PSS was not thermally degraded. Major weight loss of PSS started at approximately 426.7°C. The final residual masses of CMC, HEC, and PSS were 48.2, 43.6, and 70.2%, respectively, indicating that PSS possesses excellent thermostability.



(g)

(h)

Fig. 4—SEM images of the drilling fluid cakes after hot rolling for 16 hours at 200°C; (a) and (b) 4% bentonite drilling fluid; (c) and (d) 4% bentonite drilling fluid + 1% CMC; (e) and (f) 4% bentonite drilling fluid + 1% HEC; (g) and (h) 4% bentonite drilling fluid + 1% PSS).



Fig. 5—TEM images of drilling fluid after 200°C hot rolling for 16 hours; (a) 4% bentonite; (b) 4% bentonite + 1% CMC; (c) 4% bentonite + 1% HEC; (d) 4% bentonite + 1% PSS). (e) Size distribution of drilling fluids (bentonite, 4% bentonite; Sample 1, 4% bentonite + 1% PSS; Sample 2, 4% bentonite + 1% CMC; Sample 3, 4% bentonite + 1% HEC). (f) Size distribution of drilling fluids after 200°C hot rolling for 16 hours. Noted that Dx(n) represents the diameter at which n% of the sample's mass consists of particles with a diameter less than this value.

A series of FL<sub>API</sub> tests for CMC, HEC, and PSS were conducted in 4% bentonite mud after hot rolling under different temperatures. As shown in Fig. 7a, with the temperature increasing from 100 to 200°C, FL<sub>API</sub> of 4% bentonite mud, 1% CMC + 4% bentonite mud, and 1% HEC+4% bentonite mud increases from 59.8, 4.2, and 4 to 89.2, 62.4, and 60.2 cm<sup>3</sup>, respectively. The increase of FL<sub>API</sub> of 4% bentonite mud is mainly a result of the aggregation of bentonite particles at high temperature to form larger micropores in filter cake. The FL<sub>API</sub> increase of the samples of 1% CMC + 4% bentonite mud and 1% HEC + 4% bentonite mud is accounted for by the decomposition of CMC and HEC molecular chains at high temperature, which fails to maintain the dispersion of fine bentonite particles under high temperature. Especially after the temperature reached 120°C, the fluid loss of these drilling fluids was accelerated significantly, indicating that the molecular chains of CMC and HEC underwent decomposition. In contrast, FL<sub>API</sub> of 1% PSS + 4% bentonite mud was almost independent from temperature variation, with the  $FL_{API}$  increased slightly from 18.6 to 20.0 cm<sup>3</sup>. This is because PSS could effectively maintain the fine dispersion of bentonite particles under different temperatures and the mudcakes formed were dense in structure. Before hot rolling, as Fig. 7b shows, CMC, HEC, and PSS exhibited good filtration properties. With the time increased from 2.5 to 30 minutes, the FL<sub>API</sub> of 4% bentonite mud increased by 41.8 cm<sup>3</sup>, and the FL<sub>API</sub> of 1% CMC + 4% bentonite mud, 1% HEC + 4% bentonite mud, and 1% PSS + 4% bentonite mud increased by 4.8, 6.0, and 13.8 cm<sup>3</sup>, respectively. The fluid-loss volume demonstrates linear correlation to temperature after 5 minutes, and the filtration rate was calculated by the slope between 5 and 30 minutes. CMC, HEC, and PSS could decrease the filtration rate from 1.21 (blank group) to 0.15, 0.20, and 0.42 cm<sup>3</sup>/min, respectively. After the 200°C hot rolling for 16 hours as shown in Figs. 7c and 7a strong contrast appeared among 4% bentonite mud with CMC, HEC, and PSS. Mud of 4% bentonite with PSS maintained the filtration rate of 0.46 cm<sup>3</sup>/min compared to 1.96 cm<sup>3</sup>/min of the blank group, 1.36 cm<sup>3</sup>/min of CMC, and 1.45 cm<sup>3</sup>/min of HEC. These results clearly demonstrate that the PSS exhibits good properties of maintaining high-temperature tolerance of the drilling fluid.



Fig. 6—(a) Zeta potential of drilling fluids at different additive concentrations before and after hot rolling (HR) at 200°C and (b) temperature tolerance mechanism of drilling fluid with or without PSS additive.



Fig. 7—(a) Temperature-dependent  $FL_{API}$  of drilling fluids (4% bentonite; Sample 1, 4% bentonite + 1% PSS; Sample 2, 4% bentonite + 1% CMC; Sample 3, 4% bentonite + 1% HEC). (b) and (c)  $FL_{API}$  of drilling fluids with increasing time before and after hot rolling (4% bentonite; Sample 1, 4% bentonite + 1% PSS; Sample 2, 4% bentonite + 1% CMC; Sample 3, 4% bentonite + 1% HEC).

# **Oilfield Tests**

This new drilling fluid was successfully applied in oil fields. Two high-temperature deep wells [Well (A) and Well (B)] drilled next to each other in Xinjiang province, China, were chosen for the test. Well (A) is 7580 m deep, and the bottom temperature is  $175^{\circ}$ C; Well (B) is 6792 m deep, and the bottom temperature is  $164.5^{\circ}$ C. To match with the casing diameter (139.70 mm), the selected drill-bit diameter in the interval from 6742 to 6790 m of Well (A) and that from 6735 to 6792 m of Well (B) are identical at 168.28 mm. Well (A) was for control test without PSS, and Well (B) was drilled with drilling fluid + PSS.

By comparing the drilling-fluid formulation and formation lithology of the interval from 6742 to 6790 m in Well (A) and those from 6735 to 6792 m in Well (B), it was found that Well (B) contained gypsum salt rock and thick white salt rock, which was more likely to cause downhole accidents, and the lithology was more complicated. The formulation of drilling fluid used in Well (B) contained 1% PSS, and the composition was simpler than that for Well (A). The densities and inhibitor (5% KCl) of the drilling fluids used in the two intervals were the same (**Table 1**).

Well	Depth (m)	Drilling-Fluid Formula	Stratigraphic Lithology
(A)	6742–6790	4% Bentonite + 0.1% NaOH + 0.1% Na <sub>2</sub> CO <sub>3</sub> +5% KCl + 3% high-temperature protection agent + 4% sulfonated phenolic resin + 4% sulfonated brown coal resin + 3% plugging agent 1 + 2% plugging agent 2 + barite (weighting agent)	Sandstone with muddy siltstone and mudstone, fine sandstone, siltstone, thin mudstone
(B)	6735–6792	4% Bentonite + 0.1% NaOH + 0.1% Na <sub>2</sub> CO <sub>3</sub> + 4% KCl+1% PSS + 4% sulfonated phenolic resin + 3% sulfonated brown coal resin + 3% plugging agent 1 + barite (weighting agent)	Gypsum salt rock, thick white salt rock, salty mudstone, creamy mudstone

Table 1—Drilling-fluid formula and stratigraphic lithology.

The gel strength,  $FL_{API}$ , and high-temperature/high-pressure fluid loss ( $FL_{HTHP}$ ) performance of the drilling fluid used in Well B were better than Well A, indicating that the PSS drilling fluid possessed a better high-temperature tolerance compared to drilling fluid used in Well A (Table 2).

The expansion rate of wellbore diameter, denoted as K, is an important parameter for indicating drilling-fluid performance in the field. Here K is defined as  $K = (D_r - D_b)/D_b \times 100\%$ , where  $D_r$  and  $D_b$  are the diameters of the well and of the drill, respectively.  $D_r$  was measured by the HH-2530 imaging-logging ground system (Beijing Huan Ding Company). Excessive expansion rate of the wellbore diameter reduces the upward return velocity of the drilling fluid during drilling, resulting in difficulties for cuttings to return, thus negatively affecting the cementing quality. Therefore, the wellbore diameter should be controlled as much as possible during drilling, and lower expansion rate indicates better drilling-fluid performance. As shown in **Fig. 8a**, before the well depth reached 3000 m, the expansion rates of diameter for both wells were very small (less than 5%). At this depth, the bottomhole temperature was approximately 100°C, and the drilling-fluid loss was low.

Well	Well Depth (m)	Density (g/cm <sup>3</sup> )	Gel ( <i>G'/G</i> ″) (Pa)	FL <sub>API</sub> (cm <sup>3</sup> )	FL <sub>нтнР</sub> (cm³)
(A)	6742–6790	1.9	3/12	2.6	9.8
(B)	6735–6792	1.9	3/15	1.8	6.2

Table 2—Performance of drilling fluids used in field.



Fig. 8—(a) Casing curve of Well (A) drilling in Xinjiang, (b) casing curve of Well (B) drilling in Xinjiang ( $\mu$  is average-value and  $\sigma$  is standard deviation). The lithology and pressure system (collapse pressure, formation pressure, and fracture pressure) of the two wells were similar (casing curve is that curve of the wellbore diameter).

The performance of Well (A) gradually became worse as the drilling went deeper. At 3000–5000 m, the expansion rate of the diameter of Well (A) gradually increased to less than 15%, although this was still acceptable in drilling. After the well depth exceeded 5000 m, the expansion rate of the diameter of Well (A) turned to be 30%, indicating that the  $FL_{API}$  of drilling fluid increased greatly under high temperature at the bottom of the hole. As the temperature in the bottom of the hole rose, the fluid loss of the drilling fluid, as well as the amount of filtrate entering the formation, increased, and this caused frequent instability of the borehole wall. At this time, a large amount of filtrate entered into the well wall, causing a large number of wellbore-instability accidents. As recorded in **Table 3**, Well (A) encountered one instance of a casing accident, one instance of stuck pipe, three leakage events, and one instance of an overflow accident during the drilling process.

However, for Well (B), the expansion rate of the diameter kept being limited to 15%, which was 50% lower than for Well (A), and the expansion-rate variation was much narrower than for Well (A), as shown in Fig. 8. The  $\mu_2$  and  $\sigma_2$  values of the expansion rate of the diameter of Well (B) were 2.42 and 3.78%, respectively, which were much lower than 5.72 and 6.95% for Well (A), reduced by 57.7 and 45.6%, respectively. In addition, the accident report (Table 3) shows that Well (B) encountered one instance of leakage, which was significantly better than the drilling performance of Well (A).

Well No.	Drilling Time (days)	Depth (m)	Temp. (°C)	Accidents During Drilling
		7580	175	<ol> <li>Casing accident (1 time): casing slip buckle at 263 m depth; loss 6.63 days<sup>a</sup>.</li> </ol>
(A)	385			<ol><li>Hard drill (1 time): sticking occurred at 6093.1 m because of the collapse of the block; loss 7.68 days.</li></ol>
				<ol> <li>Well leakage (2 times): 1 loss at 6388.1 m, loss 2.79 days; loss at 6432.45 m because of crack development.</li> </ol>
				4. Overflow (1 time): overflow occurred at 6274.7 m, loss 10.81 days.
(B)	314	6792	164.5	1 time well leakage:1 loss at 6790.2 m.
<sup>a</sup> Suspende	d number of days caused by a	ccidents.		

Table 3—Accidents during drilling in field.

The comparison between the above two field tests clearly shows that the addition of PSS improves the temperature tolerance of the drilling fluid, reducing the filtrate volume of the drilling fluid under high-temperature conditions, which effectively stabilizes the wellbore.

#### Conclusions

In conclusion, it is demonstrated that the high-temperature performance of bentonite-based drilling fluid is effectively improved by polymeric additive PSS. With an addition of 1% PSS, the drilling fluid remains stable even under a temperature as high as 200°C. By significantly reducing the aggregation of bentonite particles in drilling fluids, the drilling-fluid viscosity reduction resulting from to particle coarsening is successfully limited. Furthermore, the as-formed mudcake thickness and permeability become much lower than those of drilling fluids without PSS. All those above effects reduce drilling-fluid loss considerably at high temperature, and ultrahigh temperature failure becomes less likely. Finally, a drilling fluid with PSS was successfully applied to drilling in a high-temperature deep well in Xinjiang province, China, and showed its great potential in improving wellbore stability and reducing drilling accidents.

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