

Original Paper

Enhancing the performance of high-temperature, high-salinity, high-density water-based drilling fluid using a rheological modifier with low viscosity and high yield point characteristic



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ABSTRACT

Deep oil and gas development is critical for ensuring stable fossil energy supply and facilitating a smooth energy transition. However, under extreme high-temperature, high-salinity, and high-density conditions, the weak network framework of water-based drilling fluids often causes uncontrolled rheology, fluid loss, and poor sedimentation stability. Conventional rheological modifiers strengthen the structure but induce excessive viscosity, creating trade-offs among key performance properties. In this study, a novel zwitterionic polymer modifier (LRM) with an aggregated cluster structure was synthesized, featuring low viscosity and high yield point behavior. LRM significantly improves yield point, reduces sedimentation, and enhances mud cake compactness at 200 °C, 30% NaCl, and 2.4 g/cm³ density, without notably increasing viscosity. Its aggregated clusters act as anchoring points, reinforcing the framework. In high-salinity environments, the anti-polyelectrolyte effect extends LRM chains, promoting multipoint adsorption and bridging with clay particles, while curled chains maintain low viscosity. The unique spatial structure buffers stress and forms recoverable micro-clusters with strong viscoelasticity, giving the fluid high initial resistance to flow and a low-viscosity, high-yield point profile. Furthermore, LRM also shows excellent compatibility with sulfonated, polymer-based, and clay-free systems, enhancing performance under harsh conditions. These results demonstrate LRM's potential for designing high-performance drilling fluids with controllable rheology, low fluid loss, and improved stability.

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1. Introduction

As an indispensable component of oil and gas drilling operations, drilling fluid—often referred to as the “blood” of drilling—performs a wide range of critical functions within the wellbore, including cuttings transportation, bit lubrication, formation pressure balancing, drill string cooling, and mud cake formation to minimize fluid loss (Sun et al., 2024; Wang et al., 2021). The performance of drilling fluids directly affects wellbore cleaning efficiency, borehole wall stability, drilling cycle time, and

overall operational cost (Al-Shafi et al., 2023). As oil and gas exploration and production extend into deeper and more complex formations, drilling fluids must confront increasingly harsh downhole environments, where high temperature, high salinity, and high density pose concurrent challenges to system stability (Xie et al., 2019). Owing to its favorable environmental profile, relatively low cost, and broad adjustability, water-based drilling fluid remains the predominant choice worldwide. Typically, water-based drilling fluids are composed of clay, polymers, salts, and various functional additives (Liu J.P. et al., 2022). Their overall

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performance relies on a stable spatial network structure formed by colloidal particles and polymer chains in the fluid. Under high-temperature conditions, clay deactivation occurs, hydrogen bonding is weakened, and polymer chains degrade and desorb from the surface, causing the hydration shell to collapse (Cheraghian et al., 2018; Esfahanizadeh et al., 2022). The resulting destruction of the original framework leads to severe and often irreversible deterioration of fluid properties (Ma et al., 2024). In high-salinity environments, the influx of cations compresses the diffuse double layer around clay particles, reduces electrostatic repulsion, and promotes particle aggregation and sedimentation (Huang et al., 2021). This, combined with changes in polymer conformation, further destabilizes the structure. Under high-density conditions, the large solid content and strong settling tendency of weighting materials place even greater demands on rheological behavior, suspension capacity, and fluid loss control. These coupled effects frequently render the network structure of the drilling fluid insufficiently robust to meet operational demands (Zhao et al., 2019). Consequently, key performance parameters—such as viscosity, yield point, thixotropy, mud cake integrity, and sedimentation stability—often deteriorate under downhole conditions, posing a serious challenge to safe and efficient drilling in deep and ultra-deep formations (Li et al., 2021). Therefore, maintaining the integrity of the fluid's network structure under high-temperature, high-salinity, and high-density conditions and achieving effective control over rheology, fluid loss, and sedimentation remain critical and unresolved issues in both academic and field applications of water-based drilling fluids.

To address these challenges, extensive research has focused on the development of high-molecular-weight additives, particularly rheological modifiers, that can reinforce the fluid's network structure (He D. et al., 2023; Liu et al., 2023). Conventional viscosity-enhancing and yield point-promoting polymer-based rheological modifiers typically rely on linear or branched macromolecules that entangle, hydrogen bond, and electrostatically adsorb to form three-dimensional frameworks in the fluid (Xie et al., 2019). However, these systems are often plagued by excessive thickening (Ahmad et al., 2018), which significantly reduces flowability—especially in high-density conditions—leading to elevated pump pressures, reduced cuttings transport efficiency, and increased risk of wellbore instability, lost circulation, and stuck pipe incidents. Additionally, some modifiers degrade under high-temperature and high-salinity conditions or experience conformational collapse, severely diminishing their functional effectiveness (Ghaderi et al., 2019). In practice, the performance regulation of drilling fluids often falls into a negative feedback cycle: Enhancing the yield point leads to excessive viscosity, which prompts the use of dilution strategies, ultimately worsening filtration and sedimentation behavior (Gudarzifar et al., 2020; Guo et al., 2023). As a result, trade-offs between performance indicators become inevitable, making it difficult to simultaneously optimize multiple parameters. While newer classes of rheological modifiers—such as nanoparticles (Wang et al., 2018), cross-linked polymers (Luo et al., 2018), and organic-inorganic hybrids (Yang et al., 2022)—have shown promise in laboratory evaluations, their practical applicability is often limited by poor compatibility, low structural stability, or high cost in real-world systems characterized by high-density and multiphase complexity. Therefore, the development of an efficient rheological modifier that can simultaneously enhance the network structure and yield point of drilling fluids without significantly increasing system viscosity, while maintaining stability under high-temperature and high-salinity conditions, has become a critical breakthrough for overcoming the aforementioned challenges.

To overcome these limitations, this study targets the core performance bottlenecks of high-temperature, high-salinity, high-density water-based drilling fluids by designing and synthesizing a novel zwitterionic polymer rheological modifier, LRM, using inverse emulsion polymerization. LRM features a moderate molecular weight and a unique aggregation cluster structure that serves as anchoring points within the fluid framework, enhancing overall structural integrity. In high-salinity environments, the anti-polyelectrolyte effect induces molecular chain extension, facilitating multipoint adsorption, bridging, and network formation with clay particles. This significantly improves the fluid's viscoelasticity, resistance to initial flow, and structural recovery. Experimental results demonstrate that LRM can markedly enhance yield point and mud cake compactness, reduce the sedimentation factor, and improve suspension stability under extreme conditions of 200 °C, 30% NaCl, and a density of 2.4 g/cm³—all without significantly increasing viscosity. Moreover, LRM exhibits excellent compatibility and synergistic effects in various water-based drilling fluid systems, including sulfonated drilling fluids, polymer-based fluids, and clay-free formulations. These findings substantially expand the application potential of LRM and provide a practical strategy for constructing high-performance drilling fluids with controllable rheology, low fluid loss, and enhanced structural stability. This work not only breaks through the long-standing trade-off between thickening and yield-enhancing effects in conventional rheological modifiers but also offers valuable technical support for safe and efficient drilling in deep and ultra-deep well applications.

2. Materials and experiments

2.1. Materials

2-Acrylamido-2-methylpropanesulfonic acid (AMPS, AR), diallyl dimethyl ammonium chloride (DMAAC, AR), *N,N*-dimethylacrylamide (DMAA, AR), lauryl methacrylate (LMA, AR), liquid paraffin (LP, AR), Span-80 (AR), Tween-80 (AR), nano-silica (SiO₂, 200 nm, AR), ultrafine calcium carbonate (CaCO₃, 1 μm, AR), sodium chloride (NaCl, AR), sodium hydroxide (NaOH, AR), sodium carbonate (Na₂CO₃, AR), potassium persulfate (K₂S₂O₈, AR), magnesium lithium silicate (LT), and potassium formate (HCOOK, AR) were purchased from Shanghai Aladdin Biochemical Technology Co., Ltd. Sulfonated phenolic resin (SMP-II), sulfomethyl lignite (SMC), lignite resin (SPNH), and sulfonate copolymer filtrate reducer (DSP-1) were purchased from Shandong Deshun Yuan Petroleum Technology Co., Ltd. Ultra-high temperature filtration agent (Driscal D), polymer for ultra-high temperature drilling fluid (Dristemp), and rheology modifier polymer (HE-300) were purchased from Chevron Phillips Chemical Co., Ltd. The bentonite used to prepare drilling fluid was purchased from Huaian County Tengfei Bentonite Company. Premium barite ($\rho = 4.3 \text{ g/cm}^3$) was purchased from Chongqing Xinyu Fusheng Mining Co., Ltd. Betaine structural (monomer A), high temperature viscosity enhancer (TRM) (Zhang et al., 2026), zwitterionic polymer filtrate reducer (PDA) (Zhang et al., 2025), and polymer nanosphere plugging agent (NF-1) (Huang et al., 2022) were self-made in the laboratory.

2.2. Preparation of LRM

LRM was synthesized via inverse emulsion polymerization as follows:

- (1) Preparation of aqueous and oil phases: 50 parts by weight of deionized water were measured, into which 25 parts of 2-

acrylamido-2-methylpropanesulfonic acid (AMPS) were added. The pH was adjusted to 7–8 using sodium hydroxide (NaOH). Subsequently, 18 parts of *N,N*-dimethylacrylamide (DMAA), 12 parts of dimethyldiallylammonium chloride (DMDAAC), and 5 parts of a betaine-structured monomer A were weighed using an electronic balance and added to the aqueous phase. The mixture was stirred until fully dissolved to obtain the aqueous phase. Separately, 100 parts of liquid paraffin (LP) were weighed and mixed with 5 parts of lauryl methacrylate (LMA), 10 parts of Span-80 (SP-80), and 1 part of OP-10. The mixture was stirred thoroughly using a magnetic stirrer to form the oil phase.

- (2) Preparation of the inverse emulsion: The oil phase was placed under high-speed shear at 5000 rpm using a homogenizing emulsifier. The aqueous phase was slowly added dropwise under continuous shearing. After complete addition, the mixture was sheared at 5000 rpm for an additional 5 min to form a stable inverse emulsion.
- (3) Polymerization and purification: The water-in-oil emulsion was transferred to a three-necked flask and placed in a thermostatic water bath at 25 °C under a nitrogen atmosphere. Over 30 min, 5 parts of a 2% aqueous potassium persulfate ($K_2S_2O_8$) solution were gradually added as the initiator. The temperature was then increased to 60 °C, and the polymerization reaction proceeded for 5 h. Afterward, the resulting milky-white emulsion was transferred into a dialysis bag and dialyzed against deionized water for 48 h to remove unreacted species, yielding the final LRM product. LRM is added to the drilling fluid in the form of an emulsion, and in subsequent evaluations, LRM is directly weighed based on the mass of the emulsion.

The synthesis procedure and the theoretical molecular structure of LRM are illustrated in Fig. 1.

2.3. Characterization of LRM

To verify the molecular structure of LRM and confirm the success of the synthesis, a series of characterization techniques were employed. Fourier-transform infrared spectroscopy (FTIR) was conducted using the KBr pellet method over a scanning range of 400–4000 cm^{-1} . X-ray photoelectron spectroscopy (XPS) was performed to analyze elemental composition, focusing on the C 1s and O 1s spectra. Proton nuclear magnetic resonance spectroscopy (1H NMR) was conducted with the polymer dissolved in deuterium oxide (D_2O) to further identify the chemical structure. The molecular weight of the polymer was determined using gel permeation chromatography (GPC) in an aqueous phase. Thermal stability was evaluated via thermogravimetric analysis (TGA) in the temperature range of 30–800 °C. In addition, the microstructure of LRM was observed using field-emission transmission electron microscopy (TEM), where samples were dispersed in deionized water and deposited onto copper grids coated with a carbon film.

2.4. LRM performance test

To prepare the basic fluid, 4% bentonite and 0.3% sodium carbonate (Na_2CO_3) were added to fresh water and stirred for 24 h to allow full hydration. Unless otherwise specified, all percentages mentioned in this section and subsequent experiments refer to weight percent. The basic fluid was then blended with varying amounts of LRM, sodium chloride (NaCl), and barite, followed by high-shear mixing at 11,000 rpm for 20 min. The resulting slurries were aged at different temperatures to obtain the test fluids. And

comparative test slurries were prepared using the commonly used inorganic rheology modifier magnesium lithium silicate (LT) and the polymeric rheology modifier (HE-300) for performance comparison.

The fundamental rheological parameters of the drilling fluids were determined based on readings from a six-speed rotational viscometer. A Haake rheometer was employed to measure the apparent viscosity and shear stress of the test fluids across a range of shear rates, as well as the complex modulus under varying shear stresses. Filtration loss (API filtration loss) was measured according to API standards, and the microstructure of the filter cakes was observed via scanning electron microscopy (SEM).

To evaluate sedimentation stability, test fluids of different densities were placed in graduated colorimetric tubes, sealed, and left undisturbed for visual observation. The densities of the upper and lower layers in a cylindrical closed container were measured after settling, and the sedimentation factor (*SF*) was calculated using Eq. (1). Additionally, zeta potential and particle size distribution of clay in various test fluids were determined using a zeta potential analyzer and a laser particle size analyzer, respectively.

$$SF = \frac{\rho_b}{\rho_t + \rho_b} \quad (1)$$

where *SF* is the static sedimentation factor, dimensionless; ρ_t is the upper density of the drilling fluid, g/cm^3 ; ρ_b is the lower density of the drilling fluid, g/cm^3 .

To investigate the effect of LRM on the performance of different types of water-based drilling fluids, sulfonated drilling fluid system, polymer drilling fluid system, and clay-free drilling fluid system were prepared according to the formulations listed in Table 1. The rheological properties, filtration loss, and sedimentation factor of the drilling fluids before and after adding LRM were tested following the aforementioned methods. The initial gel strength and final gel strength (Gel_{10s} and Gel_{10min}) and the high-temperature high-pressure filtration loss (HTHP filtration loss) of the drilling fluid systems were measured in accordance with the methods specified in the Chinese National Standard GB/T 16783.1 (Sun et al., 2023).

3. Results and discussion

3.1. Characterization of LRM

3.1.1. Chemical structure

Fig. 2(a) shows the FTIR spectrum of LRM. The absorption band around 3200–3300 cm^{-1} corresponds to the N–H stretching vibration of amide groups (Lin L. et al., 2024). The peak at 2920 cm^{-1} is attributed to the C–H stretching vibration from the long alkyl chain of lauryl methacrylate (Wang Q.Y. et al., 2024). The peak at 1720 cm^{-1} corresponds to the C=O stretching vibration provided by monomer A with a betaine structure. The peak at 1550 cm^{-1} is due to the C–N stretching vibration of the amide group (Lin Z.W. et al., 2024). The peak at 1040 cm^{-1} corresponds to the symmetric S=O stretching vibration of sulfonic acid groups, while the peak at 950 cm^{-1} is assigned to the bending vibration of the C–N⁺ bond in quaternary ammonium salts (Li D.Q. et al., 2023). The peak at 630 cm^{-1} corresponds to the C–S stretching vibration of sulfonic acid groups (Wang H. et al., 2023). These characteristic peaks align well with the functional groups present in the synthetic monomers.

Fig. 2(b) presents the C 1s and O 1s spectra of LRM from XPS. Using the C–C peak at 284.8 eV as the reference (Lu et al., 2024), the C 1s spectrum is deconvoluted into five peaks. The peak at 284.8 eV corresponds to C–C bonds in the backbone and long

Table 1
Drilling fluid system formulations.

Fluid type	Formulation
Sulfonated drilling fluid system (Huang et al., 2020)	Fresh water + 2% bentonite + 0.5% Na ₂ CO ₃ + 4% SMP-II + 3% SMC + 4% SPNH + 1% DSP-1 + 30% NaCl + barite (until the fluid density is 2.0 g/cm ³)
Polymer drilling fluid system (Wang R. et al., 2024)	Fresh water + 2% bentonite + 0.5% Na ₂ CO ₃ + 3% PDA + 2% Driscall D + 0.5% Dristemp + 3% NF-1 + 30% NaCl + barite (until the fluid density is 2.0 g/cm ³)
Clay-free drilling fluid system (Wang G. et al., 2023)	Fresh water + 2% TRM + 2% PDA + 3% SiO ₂ (200 nm) + 3% CaCO ₃ (1 μm) + 1% HCOOK + 30% NaCl + barite (until the fluid density is 2.0 g/cm ³)

ester groups and the peak at 532.9 eV represents O=C=O in sulfonic acid groups (Khashay et al., 2025). These characteristic peaks reflect the structure of the main chain and side groups of the LRM molecule.

Fig. 2(c) displays the ¹H NMR spectrum of LRM. Peak a ($\delta = 2.95$ ppm) corresponds to the $-\text{CH}_3$ group attached to N in DMAA (Bai et al., 2017). Peak b ($\delta = 1.42$ ppm) is assigned to the two equivalent $-\text{CH}_3$ groups in the $-\text{C}(\text{CH}_3)_2-$ group of AMPS (Chu and Lin, 2019). Peak c ($\delta = 3.08$ ppm) corresponds to the methylene ($-\text{CH}_2-\text{SO}_3\text{H}$) group in AMPS. Peak d ($\delta = 3.79$ ppm) is attributed to the $-\text{CH}_2-\text{N}^+$ group in DMDAAC, and peak e ($\delta = 3.79$ ppm) corresponds to the $-\text{N}^+-\text{CH}_3$ group in DMDAAC (Liu L.M. et al., 2022). Peak f ($\delta = 1.26$ ppm) arises from the methylene groups in the long alkyl chain of LMA, while peak g ($\delta = 0.84$ ppm) corresponds to the terminal methyl group of the LMA alkyl chain (Balaga et al., 2023). Peak h ($\delta = 3.67$ ppm) is attributed to the $-\text{CH}_3$ groups on $-\text{N}^+(\text{CH}_3)_2$ in monomer A with a betaine structure (Chang et al., 2019), and peak i ($\delta = 2.91$ ppm) corresponds to the R₂ group in monomer A. These characteristic peaks confirm that the molecular structure of LRM incorporates features of all the synthetic monomers. Moreover, the absence of signals in the $\delta = 5.0$ – 6.5 ppm region (typically associated with $=\text{CH}_2$ and $=\text{CH}-$ structures) indicates that no residual unreacted monomers remain in the product (Mao et al., 2021).

Comprehensive FTIR analysis, XPS analysis, and ¹H NMR analysis revealed the characteristics of each monomer and the main chain structure, and there were no unreacted monomer residues. The LRM conformed to the expected chemical structure design, and the synthesis was successful.

3.1.2. Thermal stability

Fig. 2(d) presents the thermogravimetric analysis (TGA) curve of LRM. The weight loss process can be roughly divided into three stages. In the first stage, from 30 to 292.5 °C, the sample's mass gradually decreases to 83.6% of its original weight. This slow loss is primarily attributed to the evaporation of bound water associated with highly hydrophilic groups such as amide and sulfonic acid groups, along with the thermal decomposition of a small fraction of thermally less stable moieties (Xie et al., 2023). In the second stage, between 292.5 and 535.3 °C, the weight loss accelerates significantly, indicating that the functional groups on the molecular chain begin to break under thermal stress. Both the main chain and side chains undergo cleavage, and partial degradation of the polymer backbone begins. During this phase, the sample mass decreases to 32.9% of the original weight, and LRM progressively loses its structural integrity (Edalatfar et al., 2021). Above 535.3 °C, the degradation enters the main chain decomposition and carbonization stage. A sharp mass loss is observed, and by approximately 600 °C, the polymer is almost entirely converted into carbonaceous residue. Overall, the molecular backbone of LRM remains largely intact below 292.5 °C, suggesting that the material possesses good intrinsic thermal resistance, and structural stability at elevated temperatures. The material itself possesses good temperature resistance potential.

3.1.3. Molecular weight

In general, the higher the molecular weight of a polymer-based rheological modifier used in drilling fluids, the stronger the intermolecular entanglement and hydration effects in solution, resulting in a more pronounced enhancement of viscosity and yield point. Common thickening and yield-enhancing agents used in drilling fluids often have molecular weights on the order of 10⁷ or even higher. However, this high-viscosity effect also significantly increases the complexity of regulating the rheological behavior of the drilling fluid system. Fig. 2(e) shows the molecular weight distribution curve and cumulative distribution curve of LRM obtained by gel permeation chromatography (GPC). It can be observed that the weight-average molecular weight of LRM is primarily distributed in the range of 10⁵ to 10⁶. The peak molecular weight (M_p) is 1,037,201, and the average weight-average molecular weight (M_w) is 1,704,268. Over 85% of the molecules have molecular weights below the 10⁷ level, classifying LRM as a medium molecular weight polymer in the context of drilling fluid rheological modifiers. This indicates that, in terms of intrinsic material properties, LRM exhibits a relatively weak thickening effect on drilling fluids. Meanwhile, it can be observed that the molecular weight distribution range of LRM is relatively wide, which may be attributed to the special structure of LRM. This point will be further elaborated in subsequent discussions.

3.1.4. Microstructure

Fig. 2(f) shows the TEM image of LRM. It can be observed that LRM is well dispersed in water, exhibiting a network-like morphology characterized by aggregation clusters. Upon further magnification, these aggregation clusters are found to be formed by the agglomeration of LRM molecular chains, which may result from intramolecular electrostatic attraction between the positively and negatively charged groups on the zwitterionic chains. This intrachain attraction likely induces a coiled conformation of the polymer. Such a bulky, sterically hindered structure may contribute to enhancing the three-dimensional network-forming capability of the drilling fluid while exhibiting a lower thickening effect compared to conventional linear polymers. This structural feature and its role in drilling fluid performance will be further discussed in the subsequent section on the mechanism of LRM action.

3.2. Impact on drilling fluid

3.2.1. Effect of LRM dosage on the basic fluid

Different amounts of LRM (0.5%, 1.0%, 1.5%, 2.0%, and 2.5%) were added to the previously described 4% bentonite basic fluid, and the baseline rheological properties and API filtration loss of each test fluid were evaluated before and after hot rolling at 200 °C for 16 h. Fig. 3 shows the apparent viscosity, plastic viscosity, yield point, and API filtration loss of the test fluids with varying LRM concentrations, both before and after aging.

It can be seen that before aging, increasing LRM concentration has only a slight effect on the viscosity of the test fluids. At 2.5%

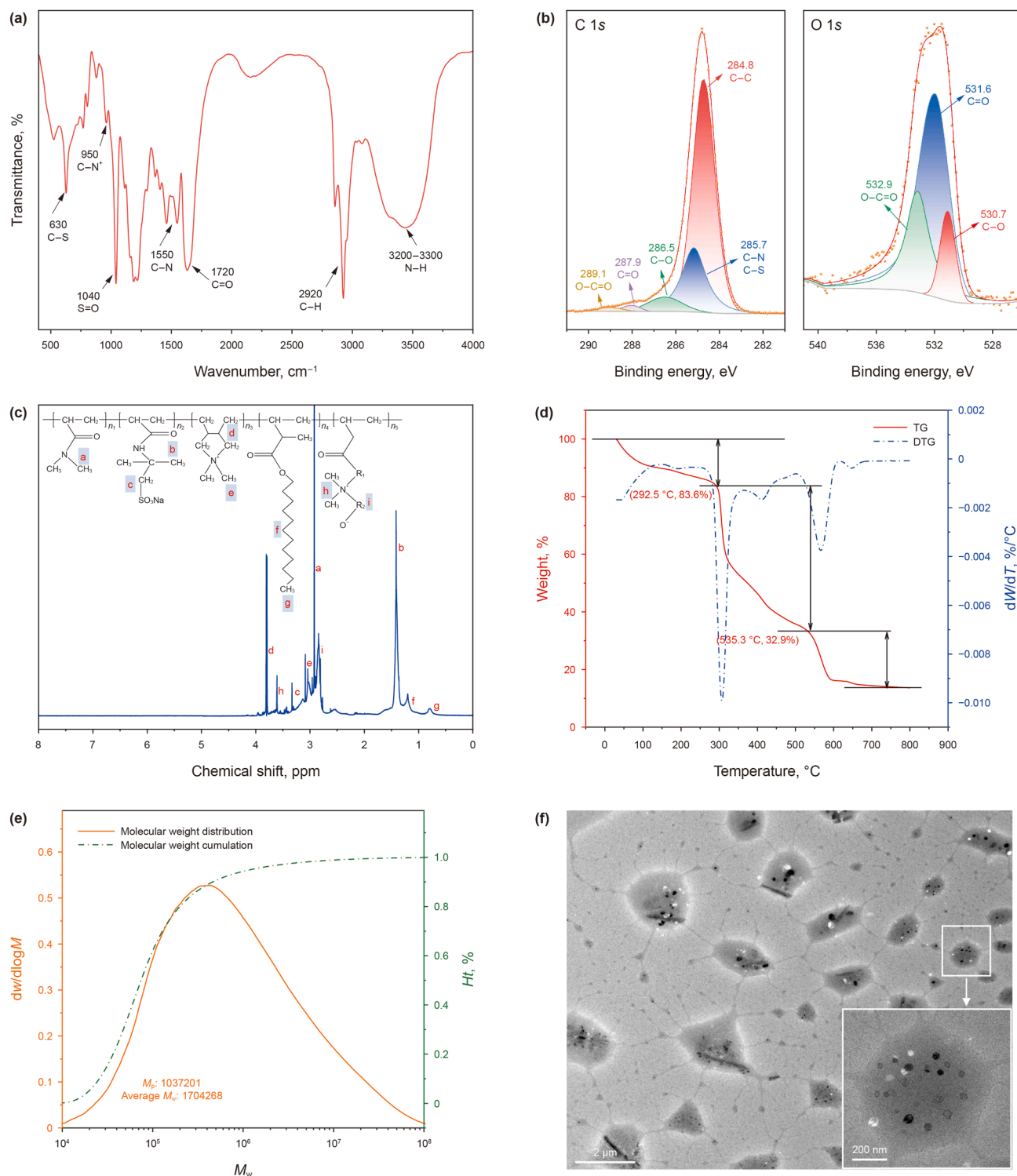


Fig. 2. Characterization of LRM: (a) FTIR spectrum, (b) XPS spectra, (c) ^1H NMR spectrum, (d) TG curve, (e) GPC profile, (f) TEM image.

LRM concentration, the apparent viscosity increases by only 6.5 mPa·s compared to the basic fluid, and the plastic viscosity shows no significant increase. However, the yield point increases by 3.5 times from 2 Pa (basic fluid) to 7 Pa. In addition, a moderate reduction in API filtration loss is also observed. After aging, the viscosity of the test fluids increases with higher LRM concentration. This is mainly attributed to the adsorption of LRM onto clay

surfaces, which protects the clay structure from destruction at elevated temperatures (Liu J. et al., 2022). The greater the LRM dosage, the smaller the difference in viscosity before and after aging. Simultaneously, the API filtration loss decreases significantly. This protective effect on clay also helps maintain the integrity of the three-dimensional network structure of the drilling fluid. The yield point of the aged basic fluid drops to 0.5 Pa,

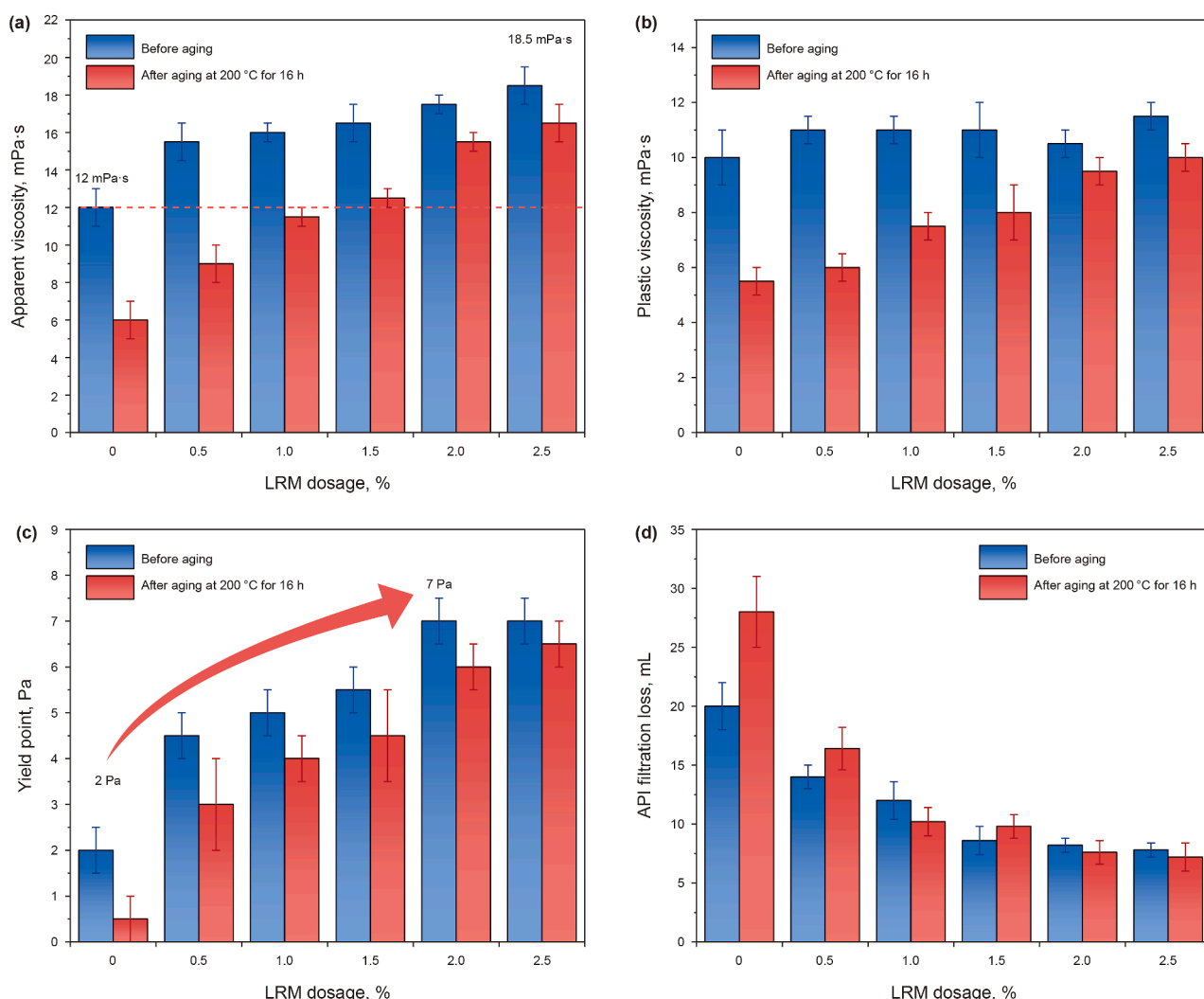


Fig. 3. Effect of LRM dosage on the basic fluid: (a) apparent viscosity, (b) plastic viscosity, (c) yield point, (d) API filtration loss.

while that of the test fluid with 2.5% LRM remains as high as 6 Pa, indicating that LRM effectively stabilizes the structural network of the drilling fluid.

Moreover, the yield point and API filtration loss of the test fluids containing 2% and 2.5% LRM are nearly identical before and after aging, suggesting that LRM exhibits effective performance at a dosage of 2%. Therefore, to better investigate the performance limits of LRM, subsequent experiments are conducted using a fixed LRM concentration of 2%.

3.2.2. LRM temperature resistance capability

Under high-temperature conditions, the hydrogen bonding between polymeric rheological modifiers and water molecules is weakened, leading to a decline in swelling and solubility (Bardhan et al., 2024). Functional groups may become deactivated or even undergo hydrolytic cleavage of the molecular chains, thereby impairing the ability of polymer to form a spatial network structure. As a result, the rheological modification effect is significantly reduced or completely lost (Li et al., 2024). To investigate the upper temperature limit of LRM's effectiveness, a 2% LRM test fluid was subjected to thermal aging at various temperatures, and the

rheological and filtration properties of the aged fluids were evaluated.

Fig. 4 displays the apparent viscosity, plastic viscosity, yield point, and API filtration loss of the test fluids after aging at different temperatures. Below 180 °C, the fluid properties remain largely unchanged with increasing temperature. The apparent viscosity stabilizes around 18 mPa·s, plastic viscosity around 11 mPa·s, and yield point around 7 Pa. These results indicate that the structure and performance of LRM are essentially unaffected within this temperature range. When the aging temperature increases to 200 °C, slight reductions in viscosity and yield point are observed, both within 10%, suggesting that the network structure formed by LRM in the drilling fluid is partially compromised but remains generally stable. The API filtration loss does not show a significant difference compared to lower temperatures. As the temperature further increases to 220 °C, the test fluid exhibits a marked decline in viscosity and yield point, accompanied by a significant increase in API filtration loss. This reflects both a weakening of LRM's functional performance and a loss of its ability to effectively protect clay particles in the drilling fluid, leading to clay degradation at elevated temperatures. In summary, LRM exhibits excellent low-viscosity and high-yield-point performance at

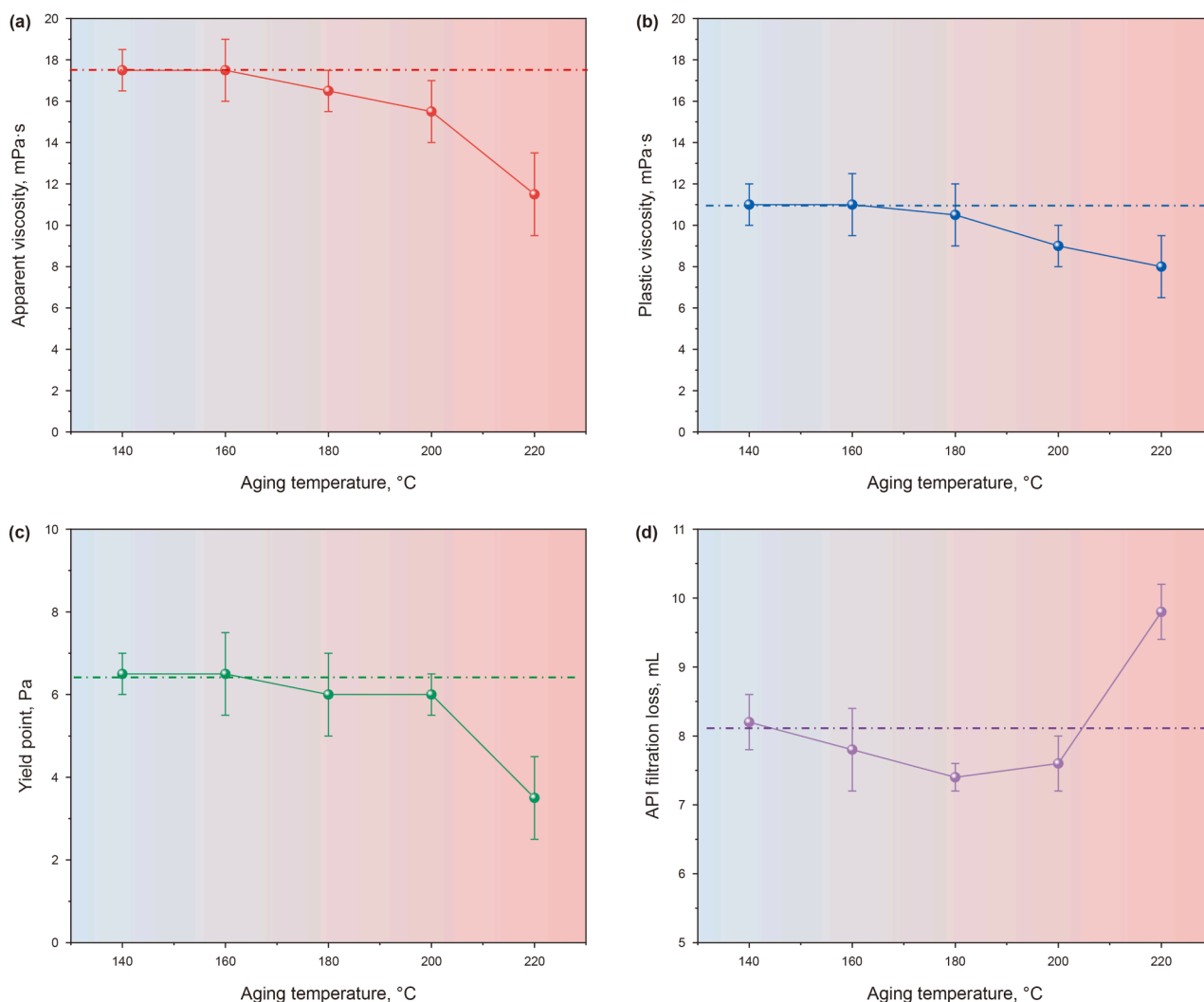


Fig. 4. LRM temperature resistance capability: (a) apparent viscosity, (b) plastic viscosity, (c) yield point, (d) API filtration loss.

200 °C and below, effectively regulating the rheological and filtration properties of drilling fluids. When the temperature reaches 220 °C, the effectiveness of LRM is significantly reduced due to factors such as drilling fluid clay failure and disruption of colloidal stability. This indicates that 220 °C is the recommended maximum operating temperature for LRM without additional adjustments to the drilling fluid formulation.

3.2.3. LRM salt resistance capability

Salt ions compress the hydration layer surrounding polymer chains, altering their conformation and thus affecting the degree of swelling and hydrodynamic volume (Gao et al., 2025). In high-salinity environments, elevated ionic strength also changes the electrostatic interactions both among polymer chains and between polymers and clay particles, which in turn influences the performance of polymer-based rheological modifiers (Li J. et al., 2023). To evaluate the salt resistance of LRM, different concentrations of NaCl were added to the 2% LRM test fluid. The rheological and filtration properties before and after aging were tested and compared with those of the basic fluid.

Fig. 5 shows the apparent viscosity, plastic viscosity, yield point, and API filtration loss of the 2% LRM test fluid with various NaCl concentrations before and after hot rolling at 200 °C for 16 h.

For the basic fluid, high-temperature and high-salinity conditions cause significant damage to the clay's layered structure. Cations neutralize the negative surface charges on the clay, weakening electrostatic repulsion, promoting particle aggregation and sedimentation. As the salt concentration increases, both viscosity and yield point decrease substantially, and filtration loss increases. In contrast, the test fluid containing LRM exhibits slight increases in viscosity and yield point with increasing salt concentration. Moreover, the changes in rheological properties before and after aging are relatively small, and the API filtration loss remains significantly lower than that of the basic fluid. These results indicate that the drilling fluid retains good performance even under high-salinity conditions.

This behavior is likely due to the anti-polyelectrolyte effect of the zwitterionic polymer chains in LRM. In low- or no-salt environments, intramolecular electrostatic attraction between the positively and negatively charged groups on the polymer chain induces a coiled conformation, resulting in reduced viscosity. As the salt concentration increases, the external salt ions shield the intrachain electrostatic attraction, disrupting the coiled conformation and promoting chain extension. The stretched polymer chains are more capable of multipoint adsorption and bridging with clay particles, leading to the formation of a more robust

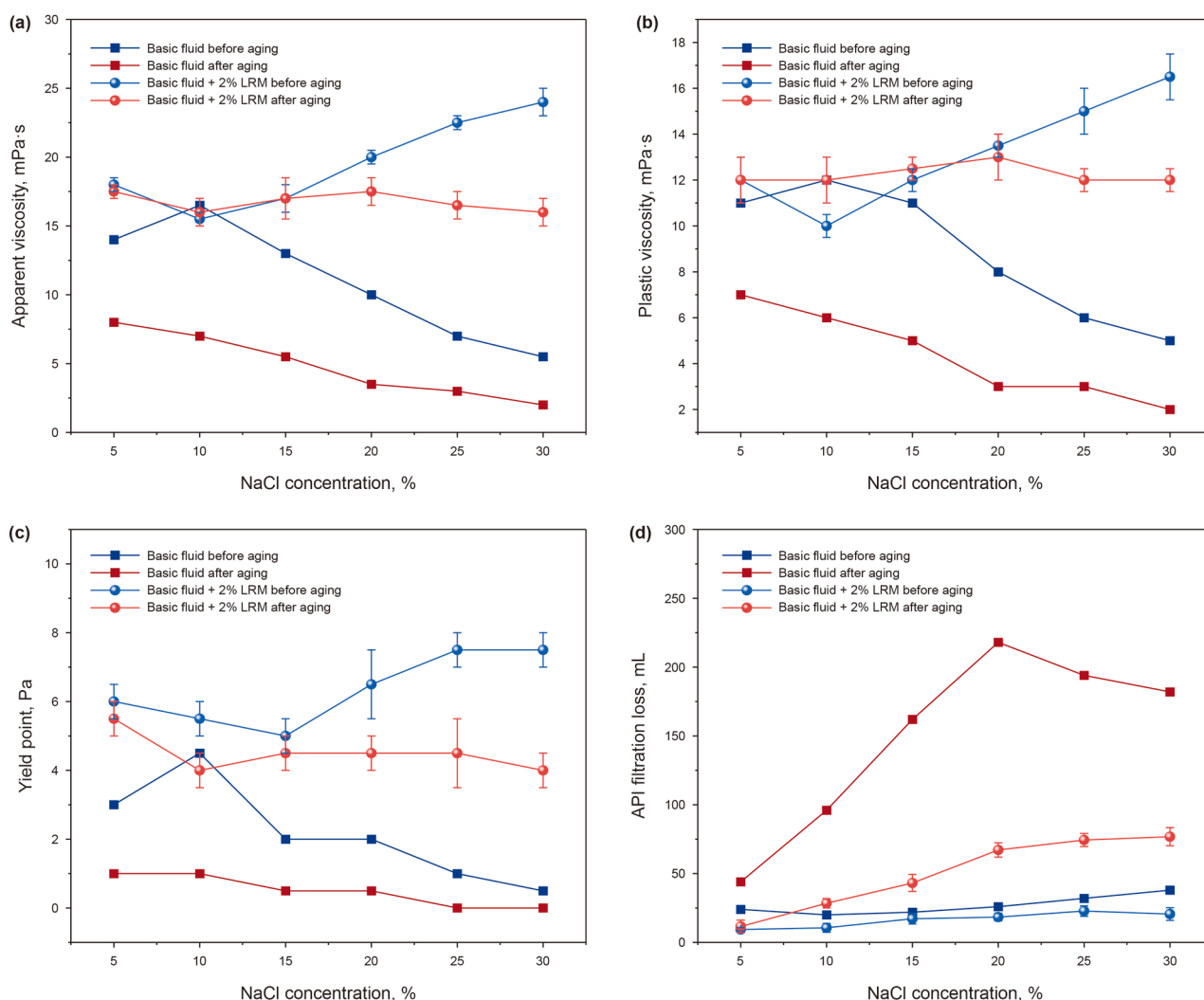


Fig. 5. LRM salt resistance capability: (a) apparent viscosity, (b) plastic viscosity, (c) yield point, (d) API filtration loss.

three-dimensional network structure. This helps maintain good particle dispersion and enhances the internal friction within the network structure, which manifests macroscopically as increased viscosity and yield point and reduced macroscopic loss. Furthermore, the extended conformation of the polymer chains is more resistant to thermal collapse or structural degradation during aging. This explains why the performance of the LRM-based test fluid shows significantly less variation before and after aging compared to the basic fluid.

3.2.4. Effect of LRM under high-density condition

One of the primary objectives of enhancing the yield point of drilling fluids is to improve their suspension capacity for solid phases such as weighting agents and cuttings. However, high-density drilling fluids inherently possess a certain level of viscosity (Leiva et al., 2024). Excessive viscosity increase caused by rheological modifiers may lead to elevated flow resistance, reduced fluidity under high shear rates, and increased risks of stuck pipe incidents. During drilling, this can result in increased pump pressure, formation fracture, and lost circulation, as well as deteriorated particle dispersion, unstable flow regimes, and elevated fluid loss. To evaluate the performance of LRM under

high-density conditions, the 2% LRM slurry was weighted to densities of 1.8, 2.0, 2.2, and 2.4 g/cm³, and its rheological and filtration properties before and after hot rolling at 200 °C for 16 h were investigated.

Fig. 6 shows the apparent viscosity, plastic viscosity, yield point, and API fluid loss of the 2% LRM slurries at different densities before and after aging. Compared with the unweighted fluid, a slight increase in thickening effect was observed, which can be attributed to the increase in total solid content; however, this increase remains within an acceptable range. At a density of 2.4 g/cm³, the apparent viscosity increased from 68.5 to 78 mPa·s, while the yield point increased from 21.5 to 26.0 Pa. More notably, the fluid loss was significantly reduced from 19.2 to 10.2 mL, indicating that the network structure of the drilling fluid was markedly enhanced, resulting in better suspension of solid particles and a denser mud cake formed under differential pressure. The effect became more pronounced after aging. The viscosity and yield point of the basic fluid decreased significantly after hot rolling, with the yield point dropping by more than 50%, suggesting severe degradation of the internal structure. In contrast, the aged 2% LRM slurry exhibited much smaller reductions in viscosity and yield point, with the decreasing by only about 15%, indicating that the

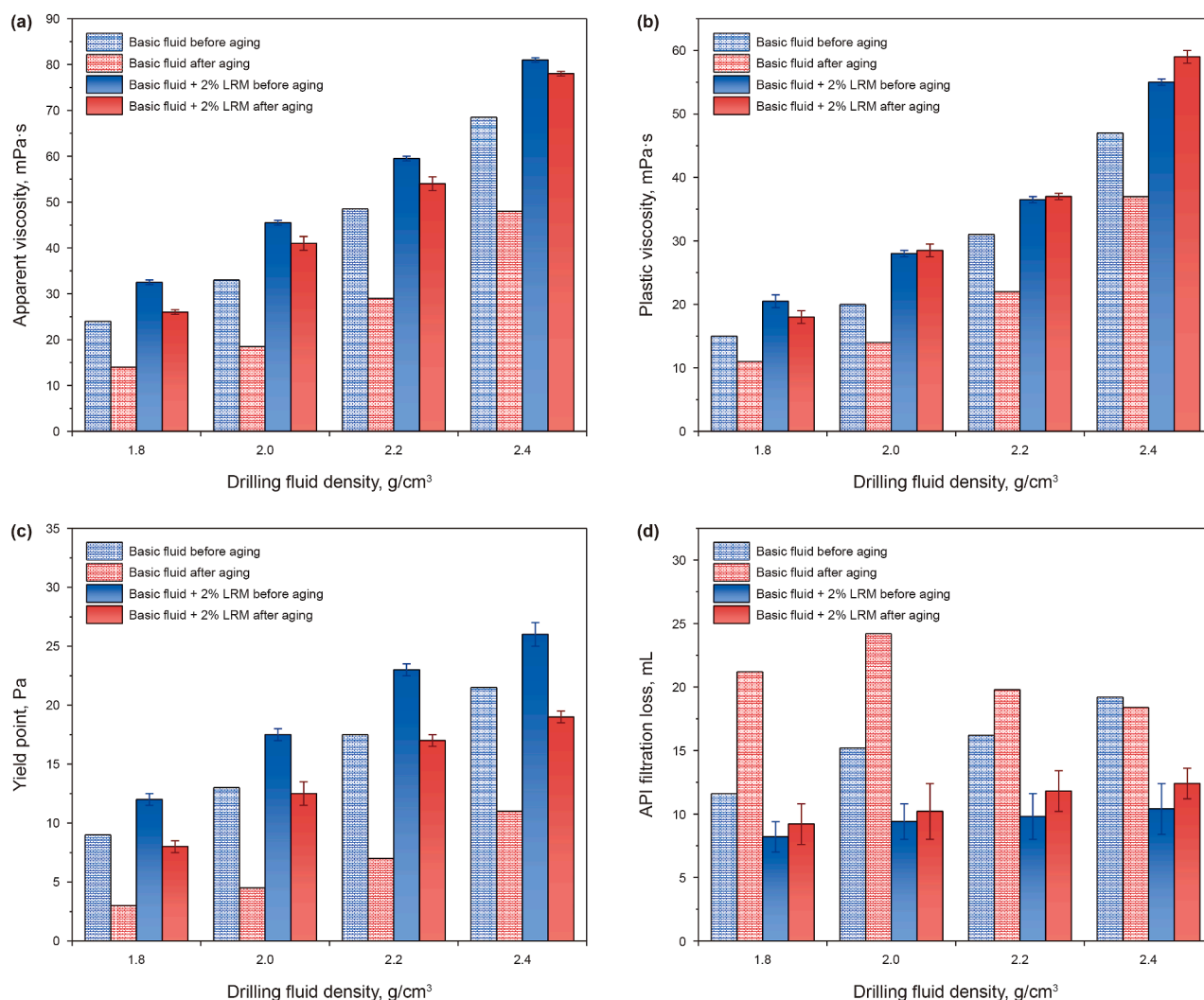


Fig. 6. Effect of LRM under high-density condition: (a) apparent viscosity, (b) plastic viscosity, (c) yield point, (d) API filtration loss.

network structure formed by LRM was sufficiently robust to effectively suspend solid phases and enhance the overall performance of high-density drilling fluids.

3.2.5. Effect of LRM on the settling stability of drilling fluid

The sedimentation stability of drilling fluids is one of the key indicators for evaluating their performance and operational safety. When the sedimentation stability is poor and solid phases cannot remain effectively suspended, the upper liquid phase becomes diluted due to solid depletion, resulting in weak filter cake formation on the borehole wall. Meanwhile, the lower portion thickens due to solid accumulation, leading to aggregation and flocculation. These issues can cause drilling fluid properties to become uncontrollable and significantly increase the risk of drilling accidents (Zhang et al., 2021; Zhang et al., 2024). To simulate harsh conditions of high temperature, high salinity, and high density, 30% NaCl was added to both the basic fluid and the 2% LRM-containing test fluid. The slurries were then weighted to densities of 1.8, 2.0, 2.2, and 2.4 g/cm³ using barite and aged at 200 °C for 16 h. After aging, samples were transferred into capped colorimetric tubes (filled to the highest scale line) and cylindrical sealed containers (completely filled), and then allowed to stand

vertically under static conditions for various time periods to observe sedimentation behavior. The cylindrical container was divided at the midpoint, with the densities of the upper and lower layers measured separately to calculate the sedimentation factor of the drilling fluid.

Fig. 7(a1, a2) displays the layering behavior of the basic fluid and the LRM test fluid before and after aging over different sedimentation durations. The basic fluid showed initial signs of stratification after just 1 h of static settling before aging, with clear liquid appearing at the top. By 3 h, noticeable solid–liquid separation was observed, and after 6 h, the upper quarter was entirely clear water. As settling progressed, the clear liquid volume increased, and after 48 h, nearly the entire upper half consisted of clear water. After aging, the basic fluid sedimented even faster, with barite almost completely settling into the lower half after 12 h, indicating that the network framework of the drilling fluid could no longer support effective solid suspension. In contrast, the LRM test fluid exhibited significantly improved sedimentation stability. Before aging, only a small amount of liquid separated at the top even after 48 h. After aging, the sedimentation rate slightly increased, but a distinct clear water layer did not appear until 12 h, and even after 48 h, the clear layer accounted for less than one-

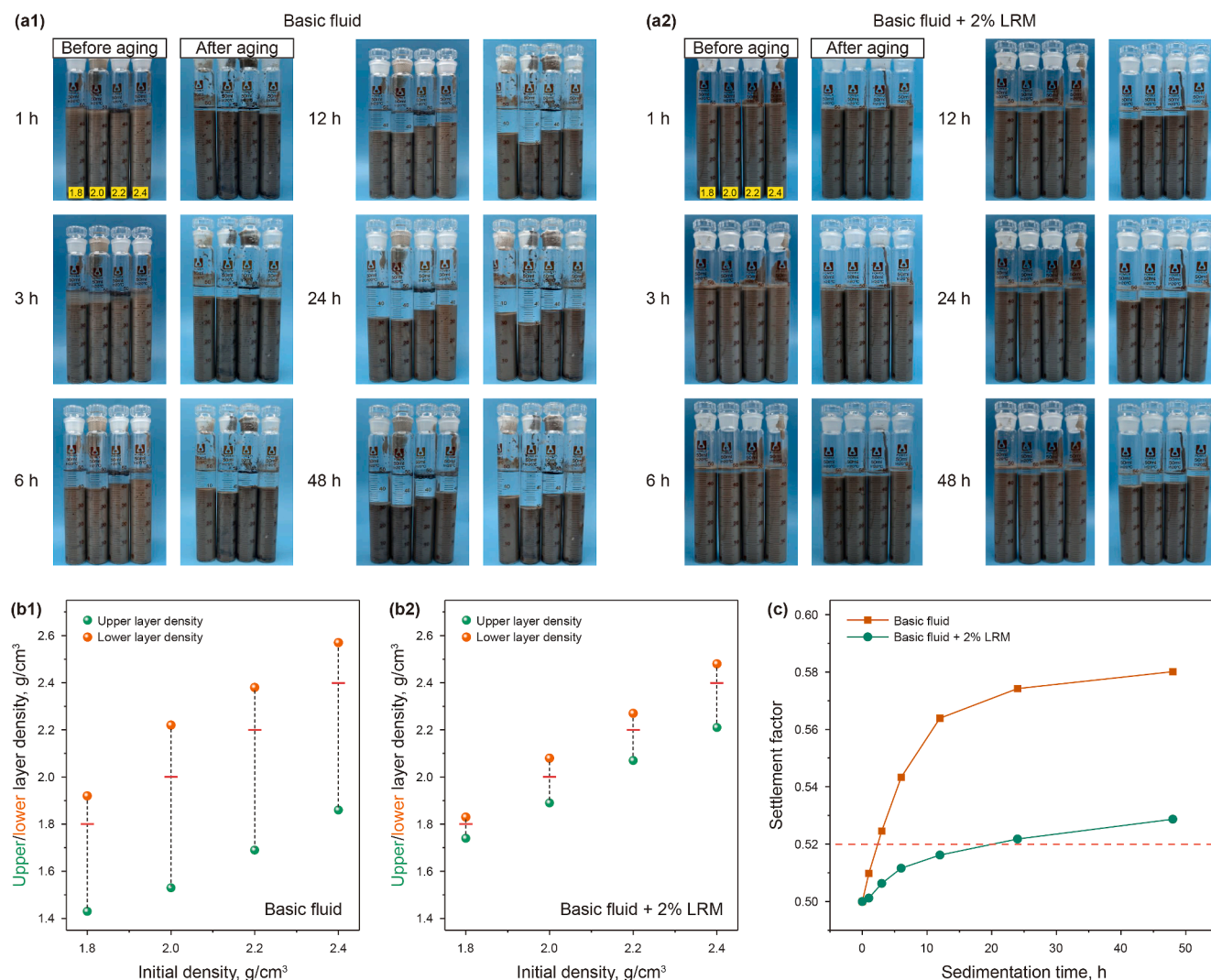


Fig. 7. Effect of LRM on the settling stability of drilling fluid: (a) settling conditions of basic fluid and basic fluid + 2% LRM, (b) densities of the upper and lower layers of basic fluid and basic fluid + 2% LRM after 48 h of sedimentation, (c) comparison of sedimentation factors after prolonged static settling.

fifth of the total volume. These results demonstrate the significant enhancement in sedimentation stability provided by LRM under high-temperature and high-salinity conditions.

Fig. 7(b1, b2) presents the densities of the upper and lower layers of basic fluid and LRM test fluid at different densities after 48 h of sedimentation in sealed containers, quantitatively reflecting the sedimentation behavior of the drilling fluids. After 48 h of settling, the basic fluid exhibits a pronounced density difference between the upper and lower layers, with the upper layer density being nearly 0.8 g/cm³ lower than that of the lower layer. This indicates severe stratification, resulting in non-uniform drilling fluid properties that are difficult to control. In contrast, the density difference between the upper and lower layers of the LRM test fluid is less than one-third of that observed in the basic fluid. Specifically, for the 2.4 g/cm³ test fluid, the density difference between the layers after 48 h of settling is only 0.27 g/cm³, demonstrating excellent sedimentation stability.

Furthermore, the sedimentation factors of the basic fluid and LRM test fluid at a density of 2.4 g/cm³ were calculated. It is generally accepted that a sedimentation factor below 0.52 indicates good sedimentation stability (Pang et al., 2022). As shown in Fig. 7(c), the sedimentation factor of the basic fluid rapidly

increases with sedimentation time, stabilizing at approximately 0.58 after 24 h due to nearly complete settling of barite, which far exceeds the safety threshold of 0.52. In contrast, the sedimentation factor of the LRM test fluid is significantly lower and increases more slowly, remaining below 0.52 for most of the 24-h period and only slightly exceeding 0.52 after 48 h, reflecting its superior sedimentation stability.

3.2.6. Comparison between LRM and conventional rheological modifiers

To objectively evaluate the effectiveness of LRM, a comparison was made with the commonly used inorganic rheology modifier magnesium lithium silicate (LT) and the polymeric rheology modifier (HE-300). The comparison was conducted under conditions of high temperature, high salinity, and high density (200 °C, 30% NaCl, density 2.4 g/cm³). Fig. 8(a) presents the apparent viscosity of the drilling fluids containing different rheology modifiers before aging. It can be observed that the viscosity-increasing effect of LRM is lower than that of the two conventional rheology modifiers. The latter, at higher concentrations, even exceeded the maximum measurement range of the rotational viscometer, indicating an excessively strong viscosity-enhancing effect. Fig. 8(b)

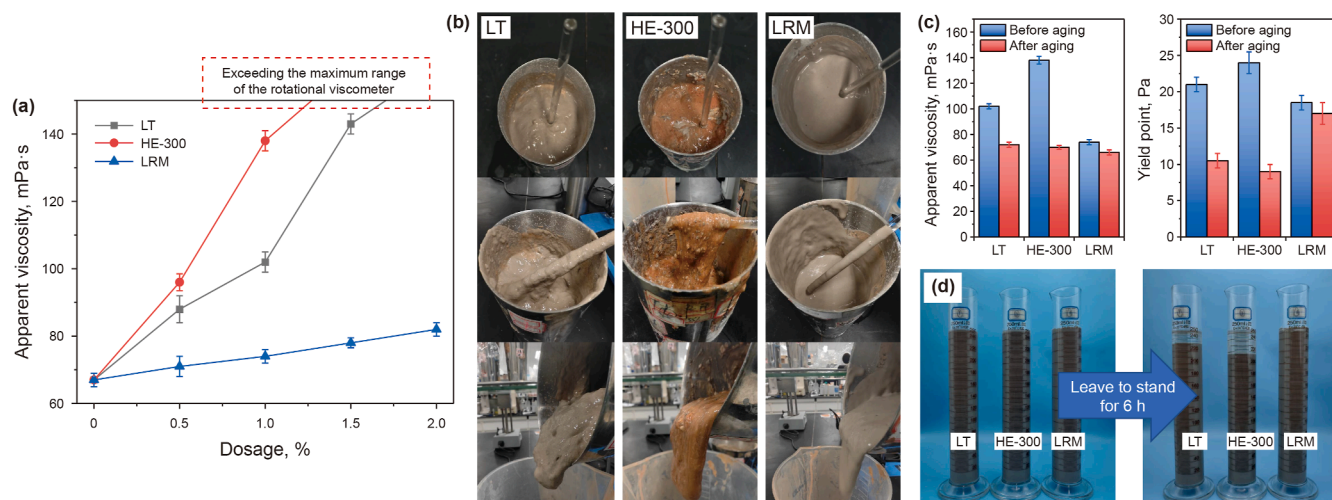


Fig. 8. Comparison between LRM and conventional rheological modifiers: (a) apparent viscosity before aging, (b) flow state of drilling fluids with 2% rheology modifier, (c) apparent viscosity and yield point before and after aging with 1% rheology modifier, (d) static sedimentation condition of drilling fluids after aging with 1% rheology modifier.

visually demonstrates the flow states of the different drilling fluids with a 2% concentration of rheology modifier. The fluids containing LT and HE-300 have essentially lost their fluidity, allowing a glass rod to stand upright in them. The fluid containing HE-300 even exhibited a gelatinous state, preventing proper dispersion of barite. In contrast, the drilling fluid with 2% LRM maintained good fluidity, ensuring the normal preparation of the drilling fluid in practical applications.

Since the viscosity of drilling fluids containing magnesium lithium silicate and HE-300 exceeded the maximum measurement range of the six-speed rotational viscometer at concentrations greater than 1%, drilling fluids with 1% rheology modifier were selected. These fluids were aged at 200 °C for 16 h, after which their rheological properties were tested. As shown in Fig. 8(c), the apparent viscosity and yield point of drilling fluids treated with the conventional modifiers decreased significantly after aging. In contrast, the drilling fluid treated with LRM demonstrated better stability, with only minor changes in rheological parameters before and after aging. Fig. 8(d) illustrates the sedimentation condition of the aforementioned drilling fluids after 6 h of static standing post-aging. Drilling fluids treated with conventional modifiers exhibited substantial sedimentation, while no significant sedimentation was observed in the LRM-containing fluid. This indicates that LRM can effectively maintain the working performance of drilling fluids under high-temperature, high-salinity, and high-density conditions. Its performance is superior to that of conventional viscosifying/gel-strengthening rheology modifiers, effectively resolving the inherent conflict where traditional rheology modifiers struggle to balance performance enhancement with viscosity increase.

3.2.7. Effect of LRM on particle size and dispersion of clay

High temperature weakens the hydration layer and electrostatic repulsion on the surfaces of clay particles in drilling fluids, leading to flocculation and aggregation between particles, which destabilizes the fluid structure. If a polymeric rheological modifier exhibits good thermal stability and strong clay adsorption capacity, it can remain stably adsorbed on the clay surface at elevated temperatures, maintaining the drilling fluid's network framework and preserving good clay dispersion, thereby enhancing the overall performance of the drilling fluid. Different dosages of LRM were added to both freshwater-based basic fluid and 30% NaCl brine-

based basic fluid, and particle size distribution and zeta potential analyses were performed on the drilling fluids before and after hot rolling at 200 °C for 16 h to investigate changes in clay particle behavior and the network framework.

Fig. 9(a1) shows the particle size distribution curves of the freshwater-based basic fluid with varying LRM concentrations. Before aging, as the LRM dosage increases, the particle size distribution gradually broadens. This is attributed to the adsorption of LRM onto clay particles, forming a network framework. On one hand, it promotes clay dispersion, increasing the number of particles smaller than 5 μm ; on the other hand, the laser particle size analyzer identifies some aggregated clusters within the network framework as single particles, resulting in the appearance of particles around 100 μm (Wu et al., 2024). After aging, significant clay aggregation occurs in the ordinary basic fluid, with particle sizes mostly exceeding 10 μm . In contrast, the addition of LRM enables clay particles to remain well dispersed under high-temperature conditions, with particle size distribution patterns similar to those before aging, mainly ranging from 1 to 10 μm . The presence of particles around 100 μm further confirms that aggregated clusters within the network framework are well preserved.

Fig. 9(a2) presents the changes in zeta potential of the drilling fluids with varying LRM concentrations before and after aging. Zeta potential represents the electrical potential difference between the adsorbed layer and the diffusion layer surrounding clay particles; the greater the absolute value, the stronger the electrostatic repulsion between particles, and the more stable the dispersion. It is observed that the addition of LRM significantly increases the absolute value of the zeta potential, indicating effective adsorption of LRM onto clay surfaces and enhanced electrostatic repulsion between particles. Moreover, as the LRM dosage increases, the variation in zeta potential values before and after aging decreases, indicating a more stable network framework in the drilling fluid and better maintenance of clay dispersion at high temperature. This stability is beneficial for preserving rheological properties and forming a dense mud cake.

Under high-salinity conditions, the electrical double layer surrounding clay particles in drilling fluids is compressed, weakening the electrostatic repulsion. This alters the connectivity state of clay particles in high-temperature saline basic fluids, causing some particles to flocculate and settle, while others become over-

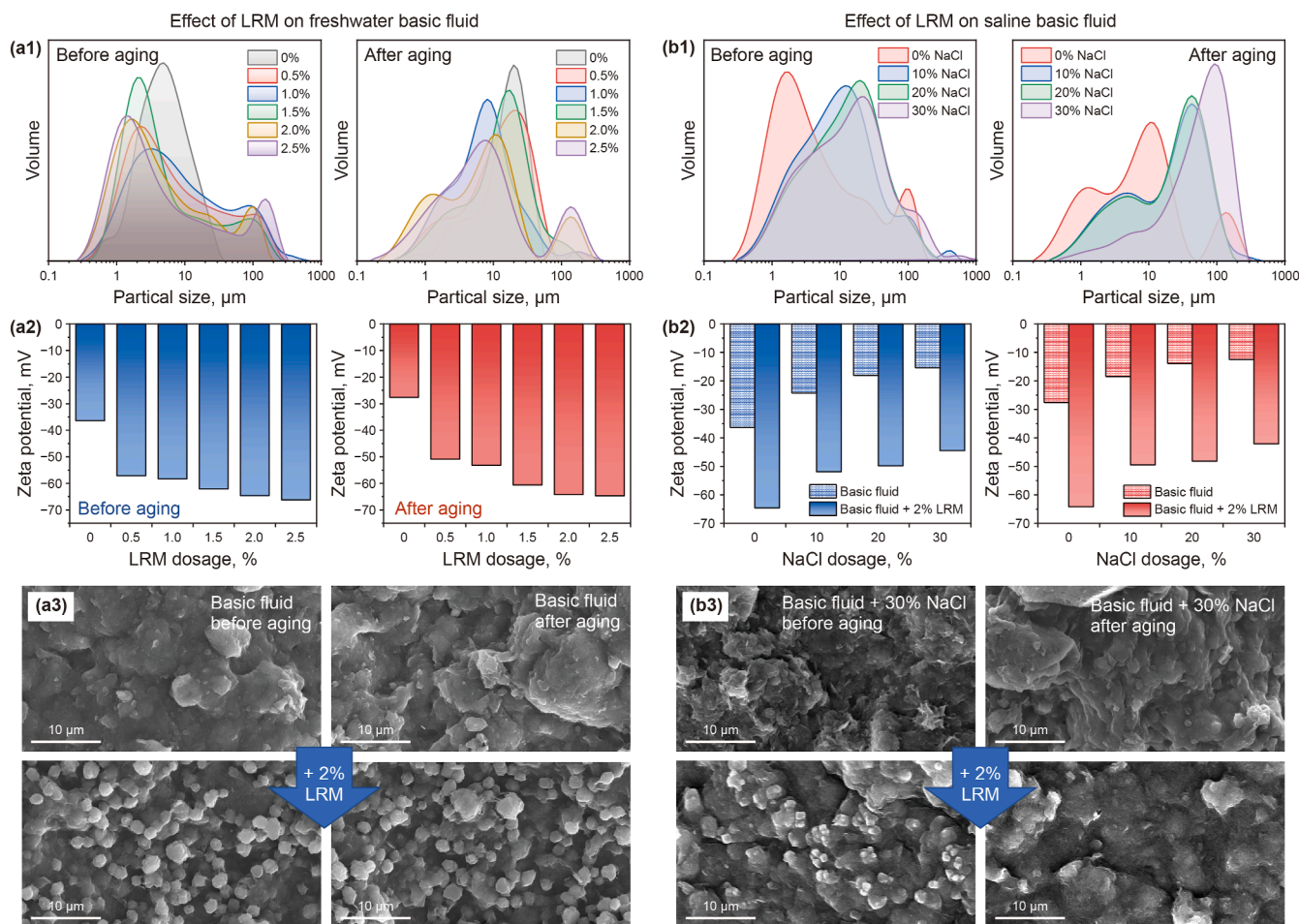


Fig. 9. Effects of LRM on drilling fluid clay and mud cake in freshwater basic fluid (a) and saline basic fluid (b): (a1, b1) particle size, (a2, b2) zeta potential, (a3, b3) filter cake morphology.

dispersed and detach from aggregates and the drilling fluid's network framework. Theoretically, the zwitterionic molecular chains of LRM extend under high-salinity conditions, exposing functional groups that form increased hydrogen bonding and hydration layers with surrounding water molecules. This facilitates stronger adsorption and bridging interactions with more clay particles, resulting in a more robust spatial network structure within the drilling fluid. To further investigate the effect of LRM on clay particles and the network framework under high-salinity conditions, particle size distribution and zeta potential of 2% LRM test fluids with varying NaCl concentrations were measured before and after hot rolling at 200 °C.

As shown in Fig. 9(b1), the particle size distribution shifts toward larger sizes after the addition of NaCl, which reflects the extension of LRM molecular chains and enhanced hydration, leading to tighter adsorption of polymer layers onto clay particles and a more resilient network framework. This trend becomes more pronounced after aging. The particle size increases with the NaCl concentration, indicating that the extended LRM chains effectively adsorb onto and protect the clay. This helps maintain the network framework under high-temperature and high-salinity conditions. To further validate the proposed anti-polyelectrolyte effect of LRM on particle dispersion and network structure, zeta potential of ordinary basic fluids with varying salt concentrations was measured before and after aging at 200 °C for comparison. As shown in Fig. 9(b2), NaCl significantly compresses

the electrical double layer around clay particles, sharply decreasing the absolute value of the zeta potential. This compression is more pronounced under the combined effects of high temperature and high salinity. In contrast, the anti-polyelectrolyte effect of LRM effectively counteracts this compression, maintaining good particle dispersion within the drilling fluid. Under 30% NaCl conditions, 2% LRM increases the absolute zeta potential value by more than twofold, confirming the mechanism proposed earlier for the observed increases in viscosity and yield point of LRM test fluids with increasing salt content. This also indicates that an appropriate salt addition can enhance the performance of LRM in drilling fluids.

3.2.8. Effect of LRM on mud cake of drilling fluid

To visually investigate the clay particles, network framework, and mud cake morphology in different test fluids, freshwater basic fluid, 30% saline basic fluid, 2% LRM freshwater test fluid, and 2% LRM 30% saline test fluid were subjected to hot rolling at 200 °C for 16 h. The resulting API mud cakes, both before and after aging, were dried and observed by scanning electron microscopy (SEM) to analyze their microstructure.

Fig. 9(a3) presents the morphology of mud cakes from freshwater drilling fluids. After adding 2% LRM, semi-transparent aggregated clusters appear on the mud cake surface, with sizes comparable to the aggregated clusters observed in the transmission electron microscopy image of LRM in Fig. 2(f). This

indicates that in freshwater drilling fluid, a portion of the LRM molecular chains participate in the network framework formation as aggregated clusters. Compared to clay particles, these clusters possess superior viscoelastic properties and occupy larger spatial volumes, acting as anchoring points that enhance the overall strength of the network framework and improve the dispersion stability of particles in the drilling fluid. The mud cake morphology correspondingly shows greater compactness. In contrast, the aged basic fluid exhibits partial clay aggregation, resulting in a looser mud cake. Large clay particles and voids between particles are visible in the SEM images, which directly contribute to increased fluid loss. The morphology of the mud cake of the freshwater LRM test fluid after aging remains similar to that before aging, demonstrating that the network framework composed of LRM molecular chains, aggregated clusters, and clay maintains good thermal resistance, thereby preserving drilling fluid performance and forming a dense mud cake.

Fig. 9(b3) shows the mud cake morphology of 30% saline drilling fluids. As previously analyzed, NaCl compresses the electrical double layer, reducing the electrostatic repulsion between clay particles. Prior to aging, the basic fluid displays aggregated large clay particles with increased interparticle pore sizes. After aging, clay aggregation worsens, and some small clay fragments detach from the overall network framework, resulting in poor mud cake compactness and a sharp increase in fluid loss (Wang et al., 2025). The addition of LRM significantly improves mud cake density. In the saline environment, LRM clusters extend due to the anti-polyelectrolyte effect, and the clusters on the mud cake surface of the saline LRM test fluid are notably smaller. More extended portions of LRM molecular chains adsorb onto the clay surface, providing protective effects and forming a strong, resilient network framework. The mud cake of the aged saline LRM test fluid remains dense, with clay surfaces clearly coated by a polymer layer and particles tightly packed together. Few visible pores are observed, indicating that under high-temperature, high-salinity conditions, the network framework formed by extended LRM molecules and drilling fluid particles possesses good strength. This visually elucidates the mechanism by which LRM enhances saline drilling fluids.

3.2.9. Effect of LRM on the shear properties and grid structure of drilling fluid

Fig. 10(a) presents the shear viscosity versus shear rate curves of test fluids with varying LRM concentrations before and after aging at 200 °C for 16 h, illustrating their shear-thinning behavior. As LRM dosage increases, distinct changes in the curves are observed. Overall viscosity curves shift upward and the slope of the viscosity decline becomes more gradual, indicating enhanced shear resistance of the drilling fluids. Notably, at low shear rates, the rate of viscosity reduction significantly decreases. When the LRM concentration exceeds 1.5%, the viscosity at low shear rates shows minimal decline, suggesting an altered shear-induced disruption process of the drilling fluid's network framework. As discussed previously, LRM aggregated clusters form recoverable microstructures through multipoint adsorption and aggregation, exhibiting strong viscoelasticity. When the external shear stress increases, these aggregates partially disassociate but do not fully break, maintaining structural viscosity. Unlike linear single-chain polymers that concentrate stress locally, the "spherical" or "blocky" conformation of the curled clusters buffers local stress, providing stronger initial resistance to flow (Pang et al., 2023). As the shear rate further increases, the overall network framework in the drilling fluid begins to move, producing an approximately linear decrease in viscosity. This behavior underlies LRM's low-viscosity, high-yield-point performance. From the post-aging

curves, it appears that the quantity of LRM clusters positively correlates with the retention of the low-viscosity, high-yield-point effect. Test fluids with higher LRM content better maintain their shear properties after aging. At 1.5% LRM, the shear behavior begins to approach that of the basic fluid, while fluids with higher LRM concentrations retain curves similar to that before aging, reflecting that the fully formed LRM molecular and drilling fluid particle network framework exhibits strong thermal stability.

Fig. 10(b) shows the shear stress versus shear rate curves of test fluids with different LRM concentrations before and after aging at 200 °C for 16 h. To initiate flow, a certain shear stress must be applied to disrupt the continuous network structure formed by bentonite particle flocculation. At equal shear rates, higher shear stress indicates a stronger network framework (Yang et al., 2023). As the LRM concentration increases, the curves shift upward, and when the slope of the curve begins to slow down, the corresponding shear velocity is higher, indicating that greater shear rates are required to significantly disrupt the network structure, reflecting enhanced shear resistance.

To further study the effect of LRM on the network framework, the complex modulus $|G^*|$ of the test fluids under varying shear stresses before and after aging was measured. The complex modulus $|G^*|$ is defined as the vector sum of the storage modulus G' (elastic response) and the loss modulus G'' (viscous response). For drilling fluids, $|G^*|$ comprehensively represents the total resistance to deformation under dynamic shear, with larger values indicating stronger viscoelastic behavior. Prior to reaching a critical stress, $|G^*|$ remains nearly constant; at the critical stress, $|G^*|$ drops sharply, indicating structural changes in the network framework (Zhang et al., 2020). Fig. 10(c) shows that the LRM addition significantly increases $|G^*|$ compared to the basic fluid, demonstrating a stronger viscoelastic network. Moreover, the critical stress is substantially higher, indicating enhanced network strength. This effect is more pronounced after aging: with 2% LRM, the initial $|G^*|$ value increases nearly fivefold and the critical stress increases by over 40 times. This confirms that LRM effectively reinforces the network framework of the drilling fluid.

3.2.10. Mechanism analysis summary

Based on the above experimental results and analyses, the mechanism by which LRM enhances drilling fluid performance is illustrated in Fig. 11. LRM itself is an amphoteric polymer with moderate molecular weight and anti polyelectrolyte effect. Its enhancement mechanism in drilling fluids can be summarized as follows:

- (1) Under salt-free or low-salinity conditions, electrostatic attractions exist between the positive and negative charges within the amphoteric polymer chain, causing the polymer to adopt a curled conformation. A portion of LRM molecular chains participate in forming the network framework of the drilling fluid as aggregated clusters. Compared to clay particles, these clusters exhibit superior viscoelastic properties and occupy larger spatial volumes, acting as anchoring points that strengthen the overall network framework and enhance the dispersion stability of particles in the drilling fluid.
- (2) As salt concentration increases, external salt ions shield the electrostatic attractions between positive and negative charges, disrupting the original intrachain curling. Some LRM molecular chains extend, facilitating multipoint adsorption, protection, and bridging with clay particles, thereby forming a stronger three-dimensional network structure. This maintains good dispersion of particles in the drilling fluid and increases the internal friction within the

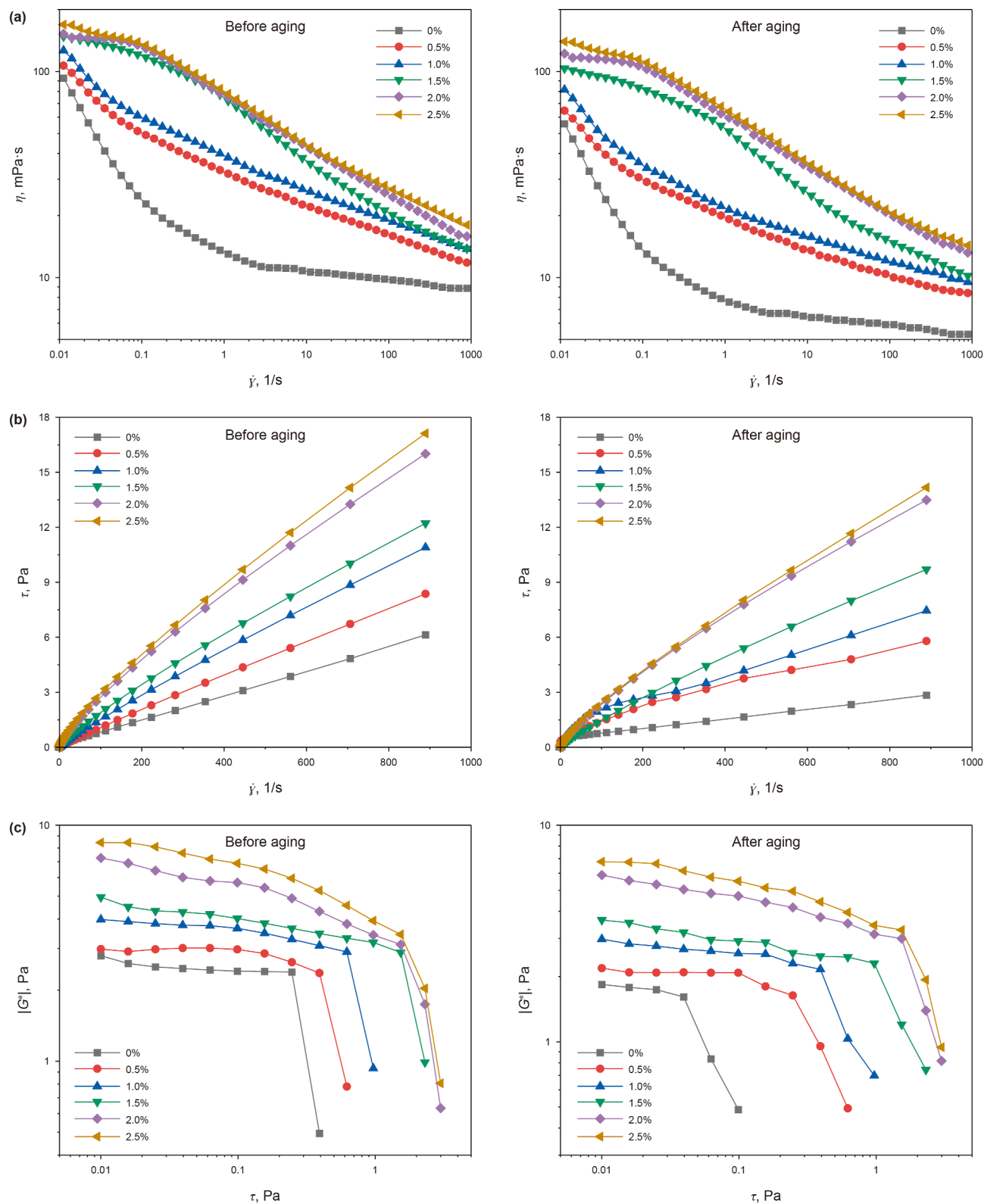


Fig. 10. Effect of LRM on the shear properties and grid structure of drilling fluid before and after aging: (a) viscosity, (b) shear stress, (c) complex modulus.

network framework. Moreover, the polymer chains remain in an extended state, resisting thermal aging-induced chain collapse or structural degradation, which allows the network framework to effectively suspend solid particles.

(3) The curled LRM clusters result in relatively low viscosity effects and differ from linear single-chain polymers that exhibit localized stress concentration. Due to their “spherical” or “blocky” configurations, the curled clusters can

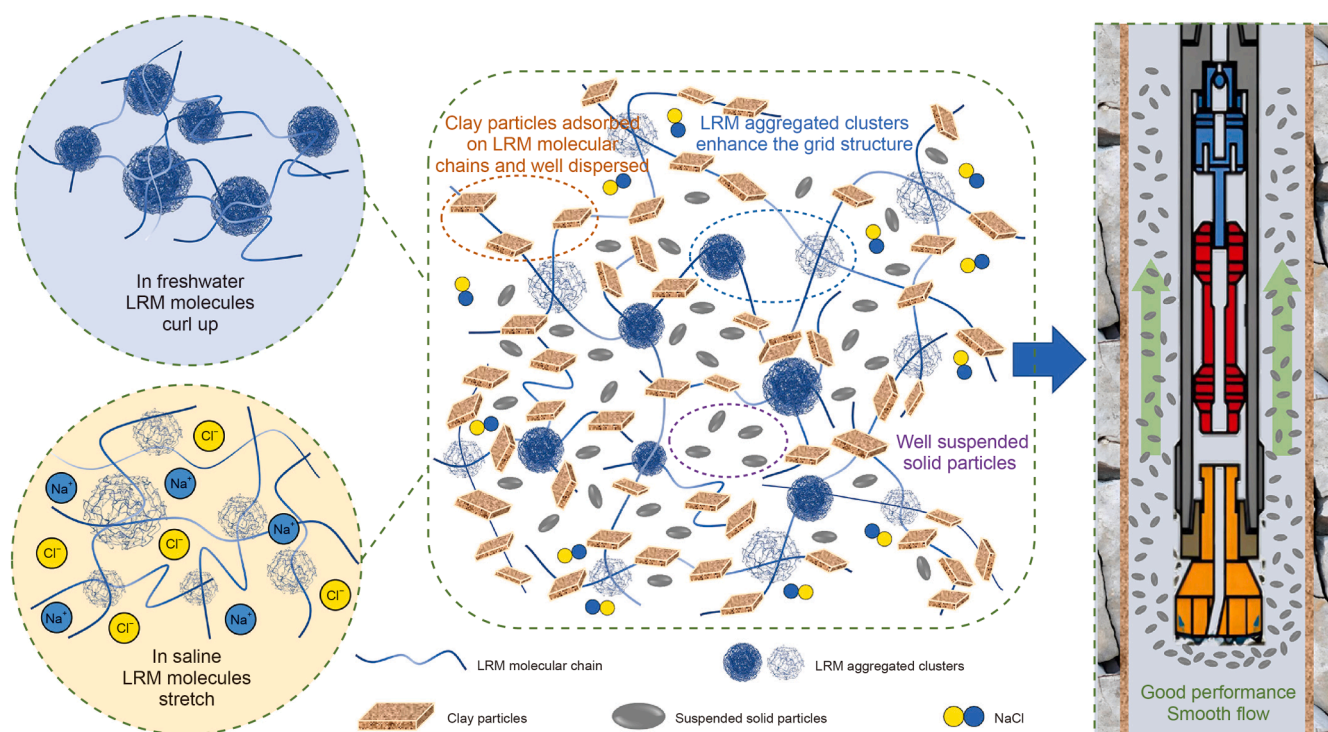


Fig. 11. Schematic diagram of LRM's mechanism for enhancing drilling fluid performance.

buffer local stress. The recoverable microstructure formed by LRM molecules through multipoint adsorption and aggregation exhibits strong viscoelasticity. When the external shear force increases, these microclusters partially dissociate but do not fully break, maintaining structural viscosity and displaying enhanced initial resistance to flow. As the shear rate further increases, the entire network framework moves, showing an approximately linear decrease in viscosity, which imparts the drilling fluid with relatively low viscosity and high yield point characteristics.

Through the combined action of the above three mechanisms, macroscopically, LRM imparts high-temperature, high-salinity, high-density water-based drilling fluids with improved rheological properties, reduced fluid loss, and enhanced settling stability, thereby improving their practical performance.

3.3. Compatibility of LRM with different types of water-based drilling fluid systems

In drilling engineering, drilling fluids are used as complex systems. Investigating the performance of LRM in different types of water-based drilling fluid systems is of practical significance for its wider application (Zhang Z. et al., 2022). According to the formulations listed in Table 1, three common and representative water-based drilling fluid systems—namely, a 2.0 g/cm³ density sulfonated drilling fluid, a polymer drilling fluid, and a clay-free drilling fluid—were prepared. Subsequently, 2% LRM was added to each system. After high-temperature aging, the rheological properties, fluid loss, and settling stability of each test fluid were measured and compared with their original base fluid counterparts to explore the effects of LRM on these three drilling fluid systems.

The sulfonated water-based drilling fluid system is mainly constructed using sulfonated natural organic materials (such as

sulfonated lignite, sulfonated asphalt, and sulfonated asphalt resin) as primary additives. Sulfonation imparts these organics with good hydrophilicity, dispersibility, and thermal stability, enabling them to maintain a certain degree of dispersion and rheological control ability under high-temperature and high-salinity conditions (Wang B. et al., 2023). Due to their cost advantages, sulfonated materials are widely applied in complex well conditions such as deep wells and high-temperature wells (Cheng et al., 2024). However, most sulfonated materials are small molecules or low molecular weight polymers, lacking sufficient network framework support, resulting in relatively low yield points and inadequate fluid loss control (Su et al., 2022). Fig. 12(a) presents the performance of the sulfonated drilling fluid after aging at 200 °C for 16 h. The radar chart's right half represents rheological properties, where moderate increases in viscosity and yield point contribute to improved overall rheological behavior. The left half shows fluid loss and sedimentation factor data, where smaller values within an appropriate range indicate better fluid loss control and settling stability. It can be observed that the addition of LRM causes only a slight increase in viscosity but significantly enhances the yield point of the system. Combined with the aforementioned mechanism analysis, this indicates that the network framework of the system has been strengthened. Additionally, the initial and final yield points of the system have increased, demonstrating improved thixotropic behavior; the high-strength network framework can effectively recover after shear destruction. Such a reinforced network improves the settling stability of the drilling fluid, with the sedimentation factor after 72 h of static standing decreasing from 0.542 to 0.517. The fluid loss performance of the sulfonated drilling fluid system has also been enhanced by network reinforcement. Both the API fluid loss and the high-temperature, high-pressure fluid loss at 200 °C and differential pressure of 3.5 MPa have decreased by more than 20%. This improvement is attributed to the effective suspension of particles in the drilling fluid, resulting in a denser mud cake. The

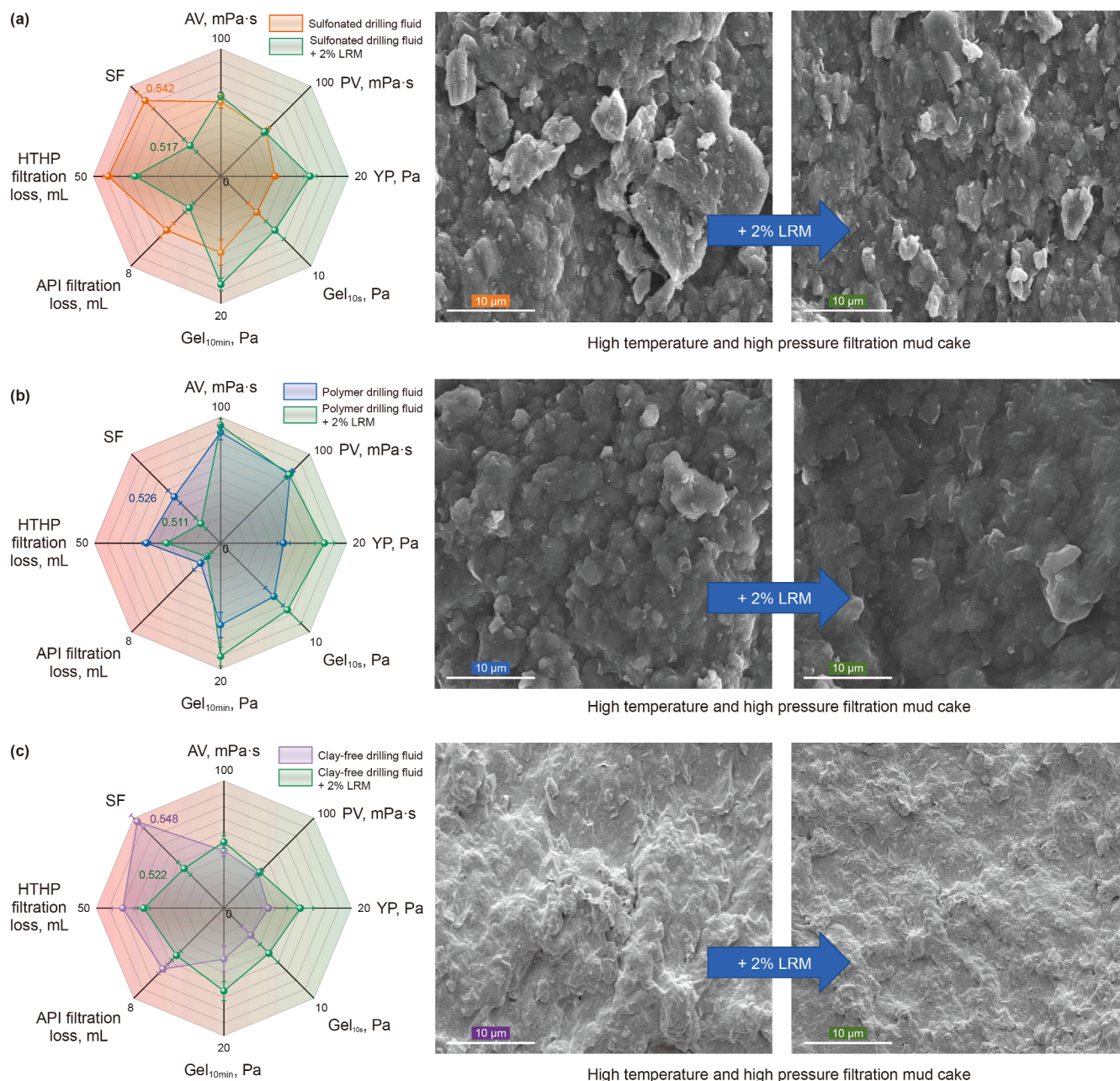


Fig. 12. Effect of LRM on different types of water-based drilling fluid systems: (a) sulfonated drilling fluid, (b) polymer drilling fluid, (c) clay-free drilling fluid.

microscopic morphology of the high-temperature, high-pressure mud cake on the right side visually confirms this, showing significantly fewer pores on the mud cake surface after LRM addition. The above analysis indicates that LRM is well compatible with sulfonated drilling fluid systems and can effectively improve their performance.

Polymer water-based drilling fluid systems utilize high molecular weight polymers as the primary functional materials (He Y.B. et al., 2023). Through swelling, entanglement, or bridging actions, these polymers form a certain spatial network framework within the aqueous phase, enabling functions such as suspension, lubrication, and fluid loss control. Compared to sulfonated systems, polymer systems generally exhibit better potential for improvement in temperature and salt resistance and possess relatively lower toxicity, making them suitable for

environmentally sensitive areas (Alafnan, 2022). However, the performance of polymer drilling fluids heavily depends on the polymer additives, and changes in polymer conformation and configuration can significantly affect the overall system properties (Lyu et al., 2019). Moreover, common polymer rheology modifiers tend to substantially increase the viscosity of drilling fluids while enhancing yield point, which imposes considerable challenges in rheological control under high-density conditions. Fig. 12(b) presents the performance of the polymer drilling fluid system after aging at 200 °C for 16 h. Due to the denser network framework formed by high molecular polymers and clay particles, its viscosity is higher compared to the sulfonated system, and the high-temperature, high-pressure mud cake is correspondingly more compact. However, under high-temperature and high-salinity conditions, partial chain scission, degradation, or curling and

desorption of the polymer additives can occur, resulting in less pronounced yield point advantages over the sulfonated system. The mud cake still shows some large clay particles exposed outside the network framework, indicating room for further improvement in fluid loss control. The addition of LRM synergistically entangles with the original polymers to reinforce the backbone structure under high-temperature and high-salinity conditions. The aggregated cluster structures themselves act as localized “supports”—network nodes within the system—enhancing the overall structural strength of the fluid. This effectively suspends solid particles and improves the settling stability of the drilling fluid, with the sedimentation factor reduced to 0.511. With only a slight increase in viscosity, the yield point and thixotropy of the drilling fluid are significantly maintained. The high-temperature, high-pressure mud cake also shows that the polymer network framework nearly envelops all drilling fluid particles, with virtually no visible pores or cracks. The high-temperature, high-pressure (200 °C, 3.5 MPa) fluid loss is reduced by more than 15%. The above analysis demonstrates that LRM is also well compatible with polymer drilling fluid systems. LRM can synergistically enhance the existing polymers, jointly improving the system's performance.

Clay-free water-based drilling fluid systems are those that contain little to no clay solid particles and mainly rely on polymers, salts, and micro- to nano-scale particle additives to achieve functions such as cuttings carrying, inhibition, and rheological control (Gautam et al., 2025). Clay-free systems do not require consideration of clay flocculation or colloidal instability-induced performance fluctuations, making them particularly suitable for complex formations and environmentally sensitive areas (Li and Xiang, 2024). However, lacking the network framework formed by bentonite, these systems exhibit weaker structural strength and are prone to settling. Additionally, due to the current limitations of supporting additives, their upper limits for temperature and salt resistance are temporarily lower than those of clay-containing drilling fluids (Zhang B.W. et al., 2022). Fig. 12(c) shows the performance of the clay-free drilling fluid after aging at 180 °C. It can be seen that LRM significantly improves the rheological properties and settling stability of the drilling fluid. While the viscosity slightly increases, the yield point, initial gel strength, and final gel strength (YP, Gel_{10s}, and Gel_{10min}) nearly double compared to the original system. This indicates that under clay-free conditions, the network framework formed solely by LRM aggregated clusters and their interactions with drilling fluid particles can effectively enhance internal friction and thereby improve rheological performance, compensating for the lack of a spatial backbone in the system. Furthermore, from the microstructure morphology of the high-temperature, high-pressure mud cake under 180 °C and differential pressure of 3.5 MPa, the LRM-enhanced drilling fluid structure more effectively supports and encapsulates the inorganic particles and weighting materials in the drilling fluid. This improvement in mud cake integrity leads to enhanced fluid loss control performance.

4. Conclusions

- (1) A zwitterionic polymer rheology modifier (LRM) with a unique aggregated cluster structure was synthesized via inverse emulsion polymerization. Its core innovation lies in the ability to significantly enhance the yield point of drilling fluids without substantially increasing the viscosity under extreme conditions of high temperature (200 °C), high salinity (30% NaCl), and high density (2.4 g/cm³). This results in an excellent “low viscosity, high yield point” effect, alongside improved filtration control and settling stability.

- (2) The distinctive performance of LRM stems from a unique structure–property relationship. On one hand, its partially curled cluster structures act as rigid anchoring points, embedding into and reinforcing the network framework of the drilling fluid, thereby enhancing the overall strength and solids suspension capacity. On the other hand, molecular chains extended via the anti-polyelectrolyte effect in high-salinity environments undergo multi-point adsorption and bridging with clay particles, increasing the internal friction within the network. This synergistic “anchoring–bridging” effect forms a tough and recoverable three-dimensional network. Under shear, the reversible micro-cluster structures within this network adaptively adjust (partially disintegrating without complete breakdown), manifesting macroscopically as high yield point and low viscosity characteristics.
- (3) LRM demonstrates excellent universality and compatibility in various water-based drilling fluid systems, including sulfonated, polymer, and clay-free types. It effectively enhances the overall performance of existing systems under demanding conditions. This work provides a novel and effective material strategy for designing high-performance water-based drilling fluids suitable for complex operations such as deep and ultra-deep well drilling, indicating significant potential for practical engineering applications.

CRediT authorship contribution statement

Yuan-Wei Sun: Writing – original draft, Formal analysis, Data curation. **Jin-Sheng Sun:** Investigation, Funding acquisition. **Kai-He Lv:** Supervision, Methodology. **Jing-Ping Liu:** Methodology, Funding acquisition, Formal analysis. **Lei Nie:** Data curation. **Tai-Feng Zhang:** Visualization. **Ning Huang:** Methodology. **Han Yan:** Validation. **Ye-Cheng Li:** Formal analysis. **Yu-Fan Zheng:** Resources. **Meng Li:** Visualization. **Wu-Shuo Liu:** Methodology.

Declaration of competing interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

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