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Experimental study on microscopic formation damage of low permeability reservoir caused by HPG fracturing fluid

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ABSTRACT

Hydraulic fracturing has become an important stimulation technique for low/ultra-low permeability reservoirs. Research on formation damage caused by fracturing fluid has mainly focused on permeability, sensitivity, fracturing fluid and clay minerals. However, little attention has been devoted to the microscopic changes in pore structure and properties. In this paper, nitrogen gas-adsorption techniques were introduced to characterize the microscopic changes in pore structure. Meanwhile, contact angle testing and Scanning Electron Microscope (SEM) observations were also used to show the changes in wettability and surface morphology of cores, respectively. The results showed that the pore size distributions (PSDs) of low permeability cores were wide, with approximately 75% macropore volume. The obvious changes in PSDs of damaged samples occurred in the range of 2–5 nm and 30–80 nm. The specific surface area decreased, and the adsorbability of damaged samples declined, as well. Concentrated gel and solid residues were confirmed to be the main damage mechanisms for gel breaking liquids, which resulted in changes in composition and roughness, making the cores more hydrophilic. Based on the results of the analysis, the N_2 adsorption technique is deemed appropriate for the study of reservoir formation damage when a certain amount of mesopores are present. Additionally, a new method of determining contact angles for porous media is also recommended.

1. Introduction

Hydroxypropyl Gum (HPG) cross-lined with borax (HPG gel) is widely used in hydraulic fracturing operations due to the following advantages: high cross-linking velocity, good rheological properties, strong sand-carrying capacity and low price. However, in the flow-back process, due to factors such as incomplete gel breaking, a low flow-back rate and high residue retention, the fracturing effect is often lower than expected, causing reservoir damage. Although new types of fracturing fluids such as viscoelastic surfactant (VES) and CO_2 has been introduced to boost hydrocarbon production and decrease formation damage (Lv et al., 2015; Ribeiro et al., 2015; Chen et al., 2014), liner or cross-linked guars are still the most commonly used method in fracturing operations (Barati and Liang, 2014). Additionally, it is worth noting that low permeability reservoirs with low formation pressure and small pore throat radius usually contain a high concentration of clay minerals and are more sensitive to water-based fracturing fluids. Therefore, it is essential to investigate formation damage with an emphasis on the microscopic changes that occur in small pores as a result of the invasion of fracturing fluids.

The main causes of formation damage and their remediation measures are well understood and documented. The primary mechanism of formation damage is fluid loss during fracturing operations. To mitigate this problem, fluid-loss agents (Yoshimura et al., 2015) and fluid loss control technologies (Lin et al., 2015; Kang et al., 2014b) have been suggested in hydraulic fracturing operation. Another mechanism that leads to formation damage is retention of fracturing fluids during the flow-back process. Zhou et al. (2016) reported that fracturing fluids caused serious reduction in both matrix and open fracture permeabilities but increased the permeability of micro-fractures due to lubrication effect. Wang et al. (2012) noted that fracture fluid cleanup was affected by static yield stress, flowing yield stress, the amount of polymer residue, filter cake on the walls of the fracture, proppant crushing as well as

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non-Darcy flow effects. Lastly, the surfactants added to fracturing fluids could have different effects on the adsorption capacity and wettability (You et al., 2015).

Most scholars studied the degree of formation damage by testing and calculating permeability recovery. (Tang et al., 2015; Kang et al., 2014a; Jin-Gang et al., 2013; Cheng et al., 2012; Potter et al., 2011). Rapid-Gel-Damage (RGD) and API conductivity cell methods were used to obtain similar regained permeability for gel breaking liquids with different break-times (Weaver et al., 2015). Fang et al. (2016) proposed the use of nuclear magnetic resonance (NMR) as a new experimental method for quantitative evaluation of sensitive clay minerals. Meanwhile, some other scholars have investigated formation damage microscopically and recommended improvements in working fluids design. Guo and He (2012) studied the gel breaking process of HPG gel and noted that the oxide gel breaker could effectively reduce the viscosity of the fracturing fluid but contributed little to the degradation of molecular size and weight. Additionally, the degradation rate of galactose in the side chain of the HPG molecule was much higher than that of the mannose in the main chain, which led to lower water solubility. These two attributes were the main reasons for the production of residues in the gel breaking process. Chen et al. (2010) studied the filtrate of gel breaking liquids cross-linked in different pH conditions by atomic force microscope (AFM). They noted that dense network structures could be observed in the filtrate that cross-linked in conventional alkaline conditions while no residue and a loose gathering of particles were observed in the filtrate that cross-linked in acidic conditions. This, according to the authors, implied that HPG/Borate gel, which is commonly used in alkaline conditions, caused greater damage to reservoirs. Wilson et al. (2014) reviewed the various mechanisms involved in formation damage as well as the physicochemical properties of individual clay minerals. They concluded that the swelling of smectitic clays, dispersion and migration of a variety of clay minerals and transformation of clay minerals into other mineral phases were responsible for formation damage in sandstones. To facilitate a better understanding of the factors involved in the above processes, the diffuse double electric layer (DDL) and hydration pressure, which varied with solution salinity and pH, were also discussed for each mineral.

Most of the research available focused on fracturing fluids, clay minerals, changes in core sensitivity and permeability; but very little research has been conducted on the changes in pore structure and properties of the pore wall. Four problems were investigated and discussed in this paper: (1) microscopic properties of undamaged samples, including pore shape, pore volume, pore size distributions (PSDs), specific surface area (SSA) and adsorbability; (2) changes in the aforementioned properties after damage by HPG fracturing fluid; (3) changes in wettability and surface morphology of core samples; and (4) improved methods in data processing and analysis.

2. Experimental fluids

Mineralized water was prepared according to the fracturing fluid composition as used in the field. This same mineralized water was used to prepare the HPG gel and the gel breaking liquids with different break-times of 1 h, 2 h, 4 h, 8 h and 12 h. The viscosity of the base fluid was 45 mPa s, and the HPG gel was a pseudoplastic fluid with a smooth appearance and suitable viscoelasticity (Fig. 1). It performed well as a static sand-carrying agent (the average settlement rate was 0.0032 cm/min in 12 h with proppant concentration of 25%). At 60 °C and for over 2 h the gel breaking liquids had a low stable viscosity and showed no elasticity (Fig. 2). These properties met the requirements for field operation applications.

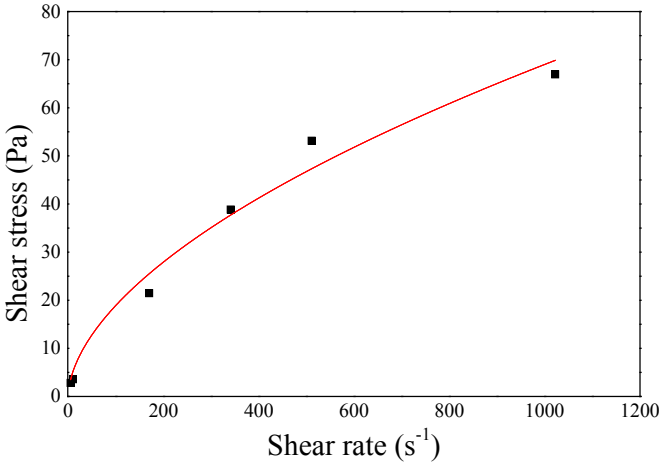

Fig. 1. Pseudoplastic characteristic of HPG gel (25 °C).

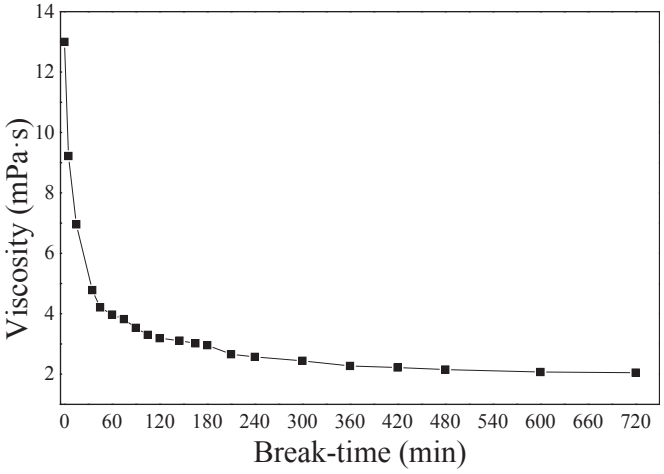

Fig. 2. Viscosity decrement during gel breaking process (60 °C).

3. Methods

3.1. N_2 adsorption measurements

The experimental cores came from a typical low-permeability sandstone reservoir in Y oilfield.

Parts of the cores were crushed into 20–60 mesh particles. The particles were then separated into 7 groups. Each sample was measured by an N_2 adsorption-desorption analysis instrument. Since this was performed before damage was effected, these samples are referred to as undamaged. The damage process was then carried out by placing each sample into mineralized water and HPG gel for 12 h. The remaining 5 samples were each placed into gel breaking liquids over different break times of 1 h, 2 h, 4 h, 8 h and 12 h, respectively. N_2 adsorption-desorption analysis was then carried out again on these damaged samples to investigate the degree of damage.

The static volumetric method was used to represent the changes in microscopic parameters of samples damaged by HPG fracturing fluid. The adsorbance was measured at different relative pressures and at a temperature of 77 K by N_2 to obtain the adsorption–desorption isotherms. Parameters such as SSA, PSDs and pore volume were calculated on the basis of reasonable models and theories. Isotherm characteristics were used to describe the morphology of pores qualitatively. The SSA was analyzed by the BET