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Improving the fracturing fluid loss control for multistage fracturing by the precise gel breaking time design

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ABSTRACT

Tight gas and oil explorations have gained more and more attention across the world recently, and the hydraulic fracturing is considered the main approach to develop such resources. Previous fieldwork showed that in the micro-fracture reservoir development, serious liquid leakage would damage the formation dramatically. Furthermore, the situation can be aggravated due to the improper gel-breaking process. According to these problems, this study aims to improve the fluid loss control technology. In this paper, the Ammonium Persulfate (APS) releasing time of three encapsulated gel breakers were evaluated. A novel gel breaking formula was developed by combining APS and encapsulated breakers. The pilot case was conducted which exhibited a positive effect on the hydrocarbon production. Owing to the accurate fluid loss control, the formation damage was also relieved.

1. Introduction

Hydraulic fracturing fluid performance was considered a prevalent research topic since the late 1980s. The main goal of hydraulic fracturing for tight gas and oil reservoirs is to create a highly conductive fracture system that allows hydrocarbon flowing to the production well through the artificial fracture system. Hydraulic fracturing fluids are used to initiate and expand fractures and to transport proppant into the created hydraulic fractures. The viscosity of fracturing fluids is considered when they are formulated, for the efficient transport and placement of proppant into fractures. At the end of the hydraulic fracturing job, the injected fracturing fluids will be pumped out through wells as much as possible to relieve the contamination and damage to the formation.

Water-based fracturing fluids are predominant and usually employ an organic polymer that is some refined guar gum e.g., galactomannans or a derivative, as a viscosifier. Typically, the water-based system also uses a crosslinker to bind polymer molecules together so as to enhance the fluid viscosity. Although the high viscosity created by the polymer system is favorable during the fracturing process, the high viscosity and residue of the gelling agent will add a complication to the fracture fluid cleanup after the initialization of proppant placement. Gel breakers are essential to degrade the fluid for the entire fracture length, so that the fracturing fluid that is no longer required can be effectively removed from the fractures (El Shaari et al., 2005; Davidson et al., 1994; Ghassemi et al., 2010).

One of the key challenges in hydraulic fracturing is to maximize the fracture conductivity and formation permeability. To achieve this goal, the most important task is to optimize the fracture cleanup and control the fluid loss from the fracture to the formation. However, the fracturing fluid can invade the formation and leave gel residue or polymer filter cake in the fracture and formation during the shut-in period. The invasion will lead to severe impairment to the formation (Wrigth and Tanigawa, 1994; Ghassemi et al., 2008). The invasion depth of fracturing fluid depends on several factors, such as fracture surface, natural microfracture development, fluid volume, gel breaker (ammonium persulphate, APS) concentration, reservoir temperature and shut-in time. The improper gel breaking and cleanup of fracturing fluid will reduce the effective fracture length and cause serious formation damage, so as to affect the hydrocarbon production. This phenomenon is more pronounced for low-permeable reservoirs (Perkins and Kern, 1961; Khristianovic and Zheltov, 1955).

An oil reservoir located in the northern China was selected as a

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filed case study. As a tight sandstone formation, it was developed with partial natural microfracture. The reservoir was found with low porosity (7.2% on average) and ultralow permeability (0.4–1.2 mD). The main formation of the reservoir is located at an average depth of 2300 m with a geothermal gradient of 2.96 °C/100 m and a pressure coefficient of 0.91. Considering the poor permeability and natural energy, horizontal wells were employed, and consequently, the wells were stimulated with multistage fracturing treatment. The typical pattern of horizontal well is of 2200 m vertical depth and 800–1200 m horizontal length. For each stage interval of 100 m, there are approximately 8–12 stages for each well. After the well completion, the pay zone was fractured stage by stage, and then the well was open again for the fluid cleanup and oil production. The post-fracture production yields more than 200 wells in the oilfield with production rates ranged from 50 to 150 m^3 per day.

The result of the treatment seems profitable. However, based on the recent tracer detection test, the discharging efficiency varied greatly among these different stages. Proppant (natural sands) was injected into a testing well while the treatment of first three stages, and ceramic proppant was mainly used for all the stages. As a result, only ceramic was found in the discharged liquid, which implies a poor liquid flowback from the first three stages. The first a few fractures of the well exhibited extremely poor discharging efficiency and contribute little to the total oil/gas production because of the damage. Although a tight oil reservoir was adopted in this paper as a field application, the theory of improving fluid cleanup so as to reduce formation damage is also applicable in the development of shale gas reservoirs.

In this paper, a new treatment is introduced to improve breaker system of multistage fracturing so as to improve fluid loss control and alleviate the formation damage, and consequently, optimize the hydrocarbon production.

2. Laboratory study

2.1. Gel preparation

The purpose of the experiment designed is to test the gel breaking process and find a solution to control fluid loss during the fracturing treatment. The slurry shared the same formula with those used in field application and was prepared in a Waring blender, which contained 0.42% hydroxypropyl guar gum, 1.0% potassium chloride, 0.1% biocide and 0.1 demulsifier. After a complete hydration, the pH value of slurry was adjusted to 8.0–8.5 with 0.05% sodium carbonate. Then a 5.0% (v/v) volume of 1.0% borax solution was added to the slurry to produce the viscous gel.

2.2. Dynamic gel break

The focus of breaker system is to maximize created fracture conductivity and allow the flowback of the fracturing fluids (after the treatment) in a proper manner (Sneddon, 1946; Geertsma and de Klerk, 1969). For this purpose, a series of gel breaking experiments were conducted using APS at various concentrations of 50, 100, 150, 250, 350, 550 and 750 mg/L. Each test was conducted using a small amount of fluid taken from the same stock slurry. The slurry was stored in a refrigerator until another test sample was required. For each test, the slurry was heated to the temperature of 20 °C and the gel was freshly produced before use. The rheological scans were collected at 170 sec^{-1} shear rate every 20–30 min on Thermo Haake RS6000 rheometer equipped with a PZ38 rotor. During the shut-in period after fracturing treatment, the rock dynamics and fluid movement occur. However, the flow rate and related shear rate especially at the tip of fracture are probably quite low. Therefore, a shear rate of 5.0 sec^{-1} was set between the scans to simulate the practical fluid movement. The gel breaking test was stopped until the apparent viscosity of the sample was below 20 mPa s. At a certain temperature, the rate of gel breaking process varied as a function of the APS concentration.

As indicated in Fig. 1, the gel breaking time decreases with the increase of the APS concentration. When APS was added at a concentration of 50 mg/L, it took about more than 240 min for the gel viscosity to drop below 40 mPa s. As the APS concentration got up to 100 mg/L, the time reduced to 120 min. At the APS concentration of 750 mg/L, it merely took 20 min for the guar gel to break.

Fig. 1 indicates the precise time that viscous fluid breaking down with various gel breaker concentrations. This result can help plan fluid APS concentration in each stage of fracturing. It can be inferred that in the case of certain condition, the concentration of breaker is the key factor for gel breaking time. In other words, the gel breaking time can be adjusted by changing the APS concentration. Although temperature is a big factor in gel breaking, at different stages of a particular horizontal well, it is reasonable to assume an isothermal condition. Considering the working pattern in the objective oilfield, it will take much longer time for gel break to discharge than observed in the laboratory. The loss of the gel broken fracturing fluid might not be well controlled in such circumstance (Siddiqui et al., 2004).

2.3. Fluid loss test

The fluid loss was further tested with the cores from the objective formation. The gel was freshly prepared and added with designated concentrations of APS as mentioned above. The fluid flow was driven by a diaphragm pump at a rate of 8.0 L/min through a 5.0 m long tube with an inner diameter of 2.00 mm. The fluid reached the temperature, 68 °C, for fluid loss testing after heated in an oil bath. The cells were prepared with cores and the differential pressure across the sandstone cores was 8.0 MPa. The fluid loss was recorded by measuring the collected mass of the effluent as a function of elapsed time every 36 min. The permeability reduction of the tested cores was estimated after 2-h pumping using the following equation.

$$D = [(k_o - k_s)/k_o] \times 100\% \quad (1)$$

where D represents damage rate (dimensionless), k_o and k_s denote the permeability before and after damage, respectively.

Table 1 indicates that more APS usage will result in more fracturing fluid loss in the formation, and so as to lower the retained permeability. In fact, as shown in Fig. 1, the higher APS concentration, the faster the fluid would break down, and the lower viscosity

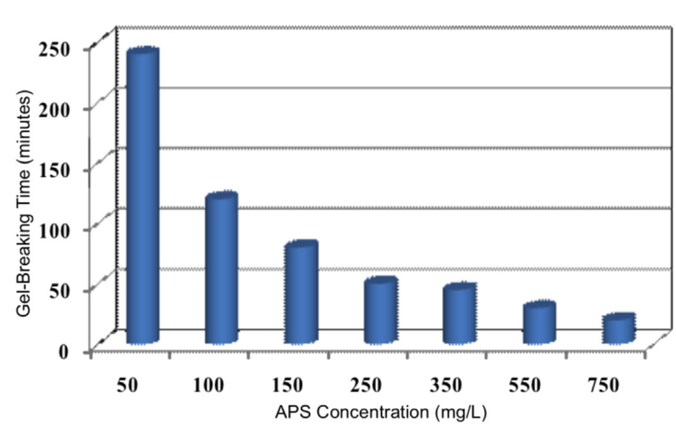

Fig. 1. Time for gel breaking at various APS concentrations.