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Waterless fracturing technologies for unconventional reservoirs-opportunities for liquid nitrogen

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ABSTRACT

During the past two decades, hydraulic fracturing has significantly improved oil and gas production from shale and tight sandstone reservoirs in the United States and elsewhere. Considering formation damage, water consumption, and environmental impacts associated with water-based fracturing fluids, efforts have been devoted to developing waterless fracturing technologies because of their potential to alleviate these issues. Herein, key theories and features of waterless fracturing technologies, including Oil-based and CO_2 energized oil fracturing, explosive and propellant fracturing, gelled LPG and alcohol fracturing, gas fracturing, CO_2 fracturing, and cryogenic fracturing, are reviewed. We then experimentally elaborate on the efficacy of liquid nitrogen in enhancing fracture initiation and propagation in concrete samples, and shale and sandstone reservoir rocks. In our laboratory study, cryogenic fractures generated were qualitatively and quantitatively characterized by pressure decay tests, acoustic measurements, gas fracturing, and CT scans. The capacity and applicability of cryogenic fracturing using liquid nitrogen are demonstrated and examined. By properly formulating the technical procedures for field implementation, cryogenic fracturing using liquid nitrogen could be an advantageous option for fracturing unconventional reservoirs.

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1. Introduction

Without a doubt hydraulic fracturing has revolutionized the exploitation of unconventional oil and gas resources in the United States and around the world. Hydraulic fracturing for developing reservoirs of micro- and nano-Darcy permeability entails pumping highly pressurized fracturing fluids at high flow rates into the reservoir to create fractures in this rock. Hydraulic fractures predominantly propagate perpendicular to the minimum horizontal stress in a single plane around the perforations. As pumping stops and the fracture closes, the proppants suspended in the fracturing fluid prop open the complex network of fractures. These fracture networks increase the contact area between the reservoir and the wellbore and serve as highly conductive pathways for reservoir fluids to flow into the wellbore for production, controlling a region surrounding the wellbore known as the stimulated reservoir volume (Mayerhofer et al., 2010; Yuan et al., 2015). Hydraulic fracturing and its associating technologies have drastically increased the oil and gas production in the United States (Steward, 2013).

Modern hydraulic fracturing technology is being applied worldwide in the field; more than 90% of gas wells and 70% of oil wells drilled in recent years have been hydraulically fractured (Brannon, 2010). Hydraulic fracturing typically relies on water-based fracturing fluids, including the popular slick water, due to the general availability and low cost of water as well as its ability for proppant transport; however, a dependence upon water presents several major shortcomings. First, water can cause significant formation damage, which is manifested as capillary end effects, effective permeability decreases, and clay swelling stemming from water imbibition and mineral hydration, respectively (e.g. Sinal and Lancaster, 1987). Formation damage mechanisms inhibit hydrocarbon flow from rock matrix into fracture network and thus impair production rates and recovery efficiency. Second, water use in large

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quantities may place significant stress upon local water resources, especially for areas experiencing droughts, as well as local environments. Based on statistics from thousands of wells drilled in unconventional reservoirs across the United States in 2014, the median annual water volume of hydraulically fracturing horizontal oil and gas wells are 15,275 and 19,425 m^3, respectively (Gallegos et al., 2015). Third, improper disposal or treatment of large amounts of flow back fluids with contaminants could lead to contentious public concerns and political issues. Several cases of felt seismicity that are below the damage threshold of modern building codes were probably induced by injecting flow back fluids into disposal wells (Davies et al., 2013; Ellsworth, 2013). Unless being re-injected into deep formations, flow back fluids containing chemical additives, high concentrations of suspended solids, salts, and hydrocarbons, etc. needs to be properly treated in order to avoid environmental pollution, lifting the cost of implementing hydraulic fracturing treatments (Hayes et al., 2014). All of these water related issues necessitate the research and development of waterless fracturing technologies.

Foams, by stabilizing CO_2, N_2 or their combination in liquid with the aid of surfactants, have been introduced for fracturing to reduce water usage and formation damage over 40 years (Blauer and Kohlhaas, 1974). The volume of gas in the foam system can amount to as much as 95%, and its subsequent expansion during flow back would assist and accelerate the cleaning up of the liquid phase from rock matrix (Gupta et al., 2005). Generally, the higher the density and viscosity of foam, the better it carries proppants and the deeper they can be transported. However, foam is sensitive and fragile to high temperature, high salinity, and oil/condensate presence, therefore its efficacy is restrained by the reservoir conditions. In foam formulas, water still remains as an important constituent thus the water related issues cannot be completely eliminated.

2. Waterless fracturing technologies

A few waterless fracturing technologies have been developed and tested in the field during the past several decades. In the following section, we review mechanisms, case studies, advantages and disadvantages of commonly used waterless fracturing technologies, including oil-based and CO_2 energized oil fracturing, explosive and propellant fracturing, gelled alcohol and LPG fracturing, gas fracturing, liquid/supercritical CO_2 fracturing, and cryogenic fracturing using liquid nitrogen (LN_2).

2.1. Oil-based and CO_2 energized oil fracturing

Oil-based fracturing field tests were first implemented in Colorado, Kansas, Texas, and Wyoming in the late 1940s (Clark, 1949). In these tests 11 out of the 23 stimulated wells experienced increased productivity, while productivity decreased at 3 wells in Rangely, Colorado. In these field tests, gasoline was gelled to form high-viscosity fracturing fluid enabling sand transport by adding Napalm. Oil-based fracturing fluids are preferable in cold regions where water-freezing can be a problem, e.g. the North Slope of Alaska and Canada in winter (McCabe et al., 1990). Fluids including condensate, kerosene, diesel, or even crude oil can be used alone as or mixed to form the base fluid (Maberry et al., 1997). Usage of gasoline was initially thought to avoid most of the water-related formation damage. Oil-based fracturing fluids can however impair the effective permeability of gas reservoirs (Smith, 1973). Considering the confinement effect in small pores (~10 nm and smaller) in shale and tight reservoirs as well as the heavy hydrocarbon components introduced by oil (Wang et al., 2014), effective permeability decreases could get worse and capillary end effects could become much more significant than those in conventional reservoirs. Moreover, oil-based fracturing fluids are expensive and hard to dispose of.

To aid with the flow back of fracturing fluid and reduce the amount of oil required, gas (CO_2 or N_2) has been used to "energize" the oil-based fracturing fluids (e.g. Vezza et al., 2001; Gupta and Leshchyshyn, 2005). Due to the good miscibility with hydrocarbons, CO_2 is often selected as the energizing gas. Experiments on Montney cores with average permeability of 6.6 μD demonstrated that a 50/50 vol% miscible CO_2/C_{7-11} fracturing fluid regained 99.9% methane permeability after a 7-day exposure under representative reservoir conditions, as is comparable to gelled propane, a 95-quality foam, and an 80-quality foam formed by a biopolymer gel (Taylor et al., 2010). Vezza et al. (2001) implemented CO_2 energized oil fracturing in a well in Morrow formation in Oklahoma, which is a water-sensitive fine sandstone reservoir with measured core permeability of 1.26 mD. The target well was stimulated by energized diesel gel containing 30–40 vol% CO_2. Comparison to two offset wells with similar formation properties that were treated by non-energized gelled diesel showed that initial production rate of the target well was 140% higher and its estimated ultimate recovery was estimated to be increased by 110%. Additionally, pressure build-up analyses obtained a fracture half-length of 65 ft and a total skin of −3 for the target well; superior to 35 ft half-length and −1 skin of the two offset wells. Gupta and Leshchyshyn (2005) compared short-term gas production data for 55 wells completed in the Rock Creek gas formation in Alberta, which has a typical porosity range of 10–14% and a permeability range of 1–5 mD (Stepic and Strobl, 1996). Of these wells, 7, 16, and 32 were stimulated by CO_2 energized, N_2 energized, and non-energized oil gel, respectively. Although different proppant types and concentrations were used, on whole CO_2 energized fracturing approximately doubled the average cumulative gas production achieved by N_2 energized and non-energized oil fracturing. Recently, in the Karr field of the Montney gas play, Hlidek et al. (2012) investigated the performance of energized oil gel and energized water gel in fracturing 6 horizontal wells. The pay zone is characterized by fine sandstone, and has an average porosity of 7% and an average gas permeability of 0.28 mD. Initial production rate data showed that three wells stimulated with 20 vol% CO_2 energized oil outperformed the other three stimulated with 25 vol% CO_2 energized water by 107%, even though the slurry volume of the oil-based fluid used was much smaller. Furthermore, flow back of oil-based fluid occurred 8 times faster than that for water-based fluid, with 75% more recovery. It is obvious that CO_2 significantly improves the compatibility of conventional oil-based fracturing fluid with unconventional reservoirs.

Nowadays, flow back that accounts for about 40–50% of the fracturing fluid is cleaned and recycled for subsequent fracturing, reducing the fluid cost and environmental impacts (Edwards, 2009; Hlidek et al., 2012). Spent oil is generally returned with produced oil to refinery for processing (Fyten et al., 2007). Still there are a few concerns associated with CO_2 energized oil fracturing, such as permeability damage due to residual fluid (Vezza et al., 2001), CO_2/hydrocarbon vapor separation, possible produced water separation from recovered flow back, and safety risks.

2.2. Explosive and propellant fracturing

One of those earliest explosive fracturing technologies started in 1964 (Miller and Johansen, 1976), nitroglycerin and TNT were detonated in small 5-spot wells that were 60–100 feet deep to fragment oil shale formations in Wyoming. Extensive fractures were formed to a radius of 90 feet and significant airflow enhancement up to 800% was measured from different oil shale

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