Journal of Petroleum Science and Engineering 168 (2018) 390–399

Contents lists available at ScienceDirect

Journal of Petroleum Science and Engineering

journal homepage: www.elsevier.com/locate/petrol

Evaluation of liquid nanofluid as fracturing fluid additive on enhanced oil recovery from low-permeability reservoirs

Tianbo Liang[a,b], Qingguang Li[a,b], Xingyuan Liang[a,b], Erdong Yao[a,b], Yanqing Wang[c], Yuan Li[a,b], Mai Chen[c], Fujian Zhou[a,b,**], Jun Lu[c,*]

[a] State Key Laboratory of Petroleum Resources and Prospecting, China University of Petroleum at Beijing, China
[b] The Unconventional Natural Gas Institute, China University of Petroleum at Beijing, China
[c] McDougall School of Petroleum Engineering, University of Tulsa, USA

ARTICLE INFO

Keywords:
Fracturing fluid additive
EOR
Tight oil
Wettability alteration

ABSTRACT

Hydraulic fracturing creates a complex fracture network that makes the oil production from low-permeability reservoirs economical. However, significant amount of water is likely lost into the rock matrix during hydraulic fracturing. This can cause formation damage due to multiphase flow, thus hindering the oil production rate. Surfactants can alter rock wettability and/or reduce oil-water interfacial tension (IFT), and it has been proposed to be used to mitigate such water blockage and enhance oil recovery. Among different approaches of using surfactants, forming liquid nanofluid (LNF) can minimize the adsorption of surfactants on rock surface, and it is likely to be one of the best options for low-permeability rocks with extensive surface area. In this study, the key properties of a well-screened LNF are evaluated, and then compared with a commercial flowback surfactant (CFS) that is widely used in the field. Pressure transmission test is further applied, which can determine the change of rock permeability due to different fluids and the potential formation damage due to multiphase flow. A systematic evaluation method is thus established to screen fracturing fluid additives to enhance oil production from low-permeability reservoirs both effectively and efficiently.

1. Introduction

To economically recover oil from shales or other tight reservoirs, horizontal drilling and hydraulic fracturing need to be applied to create a complex fracture network that maximizes the contact area with the formation. During hydraulic fracturing, a significant amount of water is pumped into the formation, while only 5–50% of it can be recovered as “flowback” (Asadi et al., 2008; Zelenev and Ellena, 2009; King, 2012; Wasylishen and Fulton, 2012). The majority of lost water is likely trapped within the induced unpropped fractures and the rock matrix adjacent to the created fractures (Sharma and Manchanda, 2015). Water remaining in the fracture network can reduce fracture conductivity (Sharma and Agrawal, 2013; Zhang et al., 2016), while water invading the rock matrix can create water blockage that also hinders the flow of hydrocarbon (Liang et al., 2017d, 2017b). In order to enhance oil recovery from tight reservoirs where the ultimate oil recovery rate is likely less than 5% (Patzek et al., 2013; EIA, 2015), a new technique is needed to mitigate water blockage and increase the relative permeability to oil.

Surfactants have been successfully developed for enhancing oil recovery from conventional reservoirs (Hirasaki et al., 2011; Lake et al., 2014; Lu et al., 2014c), and similar ideas have been introduced in the unconventional reservoirs. Currently, surfactants can be applied to enhance oil recovery from low-permeability reservoirs through the following three approaches: (1) to alter rock wettability into water-wet and promote spontaneous imbibition (Wang et al., 2012; Alvarez and Schechter, 2015; Morsy and Sheng, 2015; Kim et al., 2016; Neog and Schechter, 2016); (2) to generate weak *in-situ* emulsions to enhance oil displacement efficiency (Xu and Fu, 2012; He et al., 2015; He and Xu, 2015); (3) to achieve low to ultralow oil-water IFT to remove the invaded water and increase the relative permeability to oil (Kim et al., 2016; Shuler et al., 2016; Liang et al., 2017c, 2017a, 2017e). Studies have also shown that assembling surfactants into liquid nanofluid (LNF), which consists of thermodynamically stable nano-micelles, can effectively minimize surfactant adsorption on rock surface (Paktinat et al., 2005; Penny et al., 2005; Penny and Pursley, 2007). Low-permeability rocks have small pores and pore throats, which results in the extensive specific surface area. Minimizing the adsorption loss allows

* Corresponding author.
** Corresponding author. State Key Laboratory of Petroleum Resources and Prospecting, China University of Petroleum at Beijing, China.
E-mail addresses: zhoufj@cup.edu.cn (F. Zhou), jun-lu@utulsa.edu (J. Lu).

https://doi.org/10.1016/j.petrol.2018.04.073
Received 21 October 2017; Received in revised form 27 April 2018; Accepted 28 April 2018
0920-4105/

surfactants to travel further into the formation and interact longer with the oil. This type of additives has been proved to be effective in shale gas reservoirs because of its mitigation on water blockage (Penny et al., 2006; Howard et al., 2010; Zelenev et al., 2010; Champagne et al., 2011; Penny et al., 2012; Rostami and Nasr-El-Din, 2014), and it might be effective as well in tight oil reservoirs (Bui et al., 2016; King et al., 2017). However, since LNF can influence the stimulation and production in a completely different way, its mechanism needs to be elucidated to tailor its properties for enhanced oil recovery from tight oil reservoirs. Current evaluations are all conducted through imbibition cells, sandpack columns or corefloods with intermediate-permeability rocks. Therefore, flow experiments on low-permeability rocks are imperative to evaluate the effectiveness of LNF on stimulating tight oil reservoirs.

Unlike LNF, solid nanoparticles have been widely studied for enhanced oil recovery (Bennetzen and Mogensen, 2014; El-Diasty and Aly, 2015). They can either stabilize the interface between different phases and improve the swept efficiency (Yu et al., 2010; Aminzadeh-goharrizi et al., 2012; Li et al., 2015; Yuan et al., 2016), or alter the wettability of rock surface (Ogolo et al., 2012; Idogun et al., 2016). However, the sizes of pore throats in shales and other tight reservoir rocks can be as low as nanometers, which is of the same order of magnitude as the sizes of solid nanoparticles. This can result in agglomeration of nanoparticles and/or plugging of nanoparticles in the pore throats (Kanj et al., 2009; Alaskar et al., 2012; Li and Torsæter, 2015). LNF may be able to deform and squeeze through tiny pore throats without introducing additional formation damage. However, no study has been done to test this hypothesis.

In this study, a type of LNF is firstly synthesized with well-screened surfactants. Its key properties that may affect the fracturing design are then evaluated and compared with a commercial flowback surfactant (CFS) that is widely used in the field. To further evaluate its effectiveness in enhancing oil recovery from low-permeability rocks, pressure transmission test is applied that can determine the potential formation damage due to blockage of pores by LNF and/or multiphase flow. A systematic evaluation method is thus established to screen fracturing fluid additives to enhance oil production from low-permeability reservoirs both effectively and efficiently.

2. Target reservoir and core samples

The target reservoir locates in Jimsar depression, eastern Junggar Basin in China. At a depth of 2300–4000 m, the reservoir rock consists of fine-grained sandstone and siltstone, with clay minerals less than 5%. Imaging logging results indicate that natural fractures are not developed within an averaged reservoir thickness of 5–15 m, and the fracture density is less than 0.5 f/m. Well logging and core analysis results show that the average porosity is around 11% and the average permeability is around 0.012 mD.

Four reservoir rock samples (Cores R1—R4) are tested in this work to evaluate and further compare two types of fracturing fluid additives (CFS and LNF). Key information of these samples is listed in Table 1. Besides, one tight sandstone outcrop (Core O1) is tested in the preliminary study of this work to evaluate the newly developed liquid nanofluid (LNF) before it is evaluated on the reservoir rock samples. More information on their permeability measurements and their experimental schemes is detailed in the **Materials and Methods** section.

3. Materials and methods

3.1. Mimicked oil, mimicked fracturing fluid, and fracturing fluid additives

Kerosene is used in this work to mimic the crude oil in the reservoir and to evaluate the formation damage due to water blockage. Its viscosity is 1.8 mPa s measured by Ubbelohde viscometer at 25 °C.

2 wt% potassium chloride (KCl) solution is used to mimic the formation brine and the basic fracturing fluid, of which viscosity is 1.1 mPa s at 25 °C. To promote flowback and reduce formation damage due to the invaded fracturing fluid, surfactants are typically used as fracturing fluid additives. In this work, one commonly-used commercial flowback surfactant system (CFS), a mixture of anionic surfactants, is chosen for comparing with LNF. In the mimicked CFS-aided fracturing fluid, 0.5 wt% CFS is mixed with 2 wt% KCl in distilled water.

The selected liquid nanofluid (LNF) is a diluted suspension of the nanoscaled oil-droplets (i.e., nano-micelles) in brine. The stock solution of LNF consists of approximately 10 wt% alkanes and/or olefins as the oil cores of micelles, 30–50 wt% nonionic surfactants (e.g., alcohol ethoxylates) to stabilize the micelles, and 20–40 wt% alcohols as co-solvents. To prepare the LNF-aided fracturing fluid, the stock solution is diluted to 0.1 wt% and mixed with 2 wt% KCl in the distilled water. As shown in Figs. 1 and 2, the average particle size of this mimicked fracturing fluid is 19.5 nm, and the fluid is transparent and well-dispersed without any agglomeration.

3.2. Adsorption test

Dynamic adsorption of CFS or LNF on rock surface during fracturing fluid invasion is evaluated through a packed-column flood test. To conduct this test, a stainless-steel column is packed with the ground reservoir rock (70/120 mesh in size) and saturated with 2 wt% KCl solution. Then, the mimicked CFS-aided or LNF-aided fracturing fluid is injected into the column at a constant flow rate; meanwhile, the effluent is separately collected at different times for analysis. Interfacial tension (IFT) between kerosene and the effluent at each time is measured through Du Noüy ring method, and results are plotted with respect to the flooded pore volumes (PVs). From the change of IFT over time, the loss of fracturing fluid additives on rock surface during fracturing fluid invasion can be quantified.

3.3. Contact angle measurement

To evaluate how CFS or LNF affects the wettability of the oil-wet surface, contact angle measurement is conducted to observe the morphology change of oil droplet on the oil-wet glass within the CFS-aided or LNF-aided fracturing fluid environment.

Before conducting the contact angle measurement, the natively water-wet glass is altered to oil-wet through silanization (Salter and Mohanty, 1982; Arsalan and Nguyen, 2016). After a glass slide is cleaned with detergents and completely dried, it is soaked in a mixture of sulfuric acid and hydrogen peroxide (with a volume ratio of 7:3) for 2 h to remove organic contamination on its surface and thus expose

Table 1
Information of rock samples used in this work.

Sample Name	Rock Description	Diameter (cm)	Length (cm)	Permeability (mD)	Experimental Schemes
#1	Tight Sandstone (Core O1)	2.54 (± 0.02)	9.53 (± 0.02)	3.0	Coreflood Test (4 Steps)
#2	Reservoir Rock (Core R1)	2.54 (± 0.02)	0.65 (± 0.02)	0.051	Single-Phase PTT (KCl→CFS→KCl)
#3	Reservoir Rock (Core R2)	2.54 (± 0.02)	0.63 (± 0.02)	0.038	Single-Phase PTT (KCl→LNF→KCl)
#4	Reservoir Rock (Core R3)	2.54 (± 0.02)	0.72 (± 0.02)	0.060	Multiphase PTT (Oil→CFS→Oil)
#5	Reservoir Rock (Core R4)	2.54 (± 0.02)	0.76 (± 0.02)	0.048	Multiphase PTT (Oil→LNF→Oil)