JFUE 9774
27 October 2015
ARTICLE IN PRESS
No. of Pages 8, Model 5G

Fuel xxx (2015) xxx–xxx

Contents lists available at ScienceDirect

Fuel

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

Influence of wettability and permeability heterogeneity on miscible CO_2 flooding efficiency

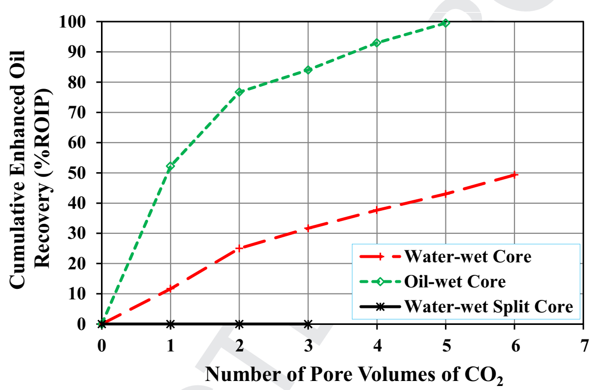
Prem Bikkina [1], Jiamin Wan *, Yongman Kim, Timothy J. Kneafsey, Tetsu K. Tokunaga

Earth Sciences Division, Lawrence Berkeley National Laboratory, 1 Cyclotron Road, Berkeley, CA 94720, United States

HIGHLIGHTS

- Significant influence of wettability on CO_2 enhanced oil recovery is revealed.
- High permeability streaks can make CO_2 flooding very inefficient.
- Huff & Puff method may produce significant CO_2 EOR from heterogeneous reservoirs.

GRAPHICAL ABSTRACT



ARTICLE INFO

Article history:
Received 24 July 2015
Received in revised form 19 October 2015
Accepted 20 October 2015
Available online xxxx

Keywords:
CO_2 enhanced oil recovery (EOR)
Reservoir wettability
Permeability heterogeneity
Miscible flooding
Core flooding

ABSTRACT

CO_2 flooding is a proven enhanced oil recovery (EOR) technique and is also considered as a potential method for CO_2 sequestration. Despite having successful field trials on CO_2 EOR, the effects of reservoir wettability and permeability heterogeneity on the efficiency of miscible CO_2 flooding are not well understood. In this work, laboratory investigations have been carried out to evaluate the influence of these properties on the miscible CO_2 EOR performance. The wettability of hydrophilic Berea core samples was altered to be oil-wet by vacuum saturation of the clean and dry core samples with n-hexadecane. The permeability heterogeneity was obtained by combining two half pieces of axially split water-wet core samples of different permeabilities. Core flooding experiments were conducted for n-hexadecane – synthetic brine – CO_2 systems at 1400 psig backpressure to achieve minimum miscibility pressure (MMP) of CO_2 in n-hexadecane at the test temperature (24 ± 1 °C). It was found that wettability strongly influences CO_2 EOR. For the alternate cases of previously brine flooded (to remaining oil saturation) oil-wet and water-wet core samples, five pore volumes (PVs) of CO_2 recovered 100% and only 43% of remaining oil in place (ROIP) respectively. Three PVs of CO_2 could recover only about 0–5% ROIP from the split core samples. The mechanisms underlying these results are discussed. This study sheds light on the significant influence of reservoir wettability and permeability heterogeneity on the performance of miscible CO_2 EOR.

1. Introduction

Wettability is the relative affinity of a fluid to an inert solid substrate in the presence of another immiscible or sparingly soluble fluid [1]. The wettability of petroleum reservoirs may range from

* Corresponding author. Tel.: +1 510 486 6004; fax: +1 510 486 7152.
E-mail addresses: prem.bikkina@okstate.edu (P. Bikkina), jwan@lbl.gov (J. Wan).
[1] Present address: School of Chemical Engineering, 224 Cordell North, Oklahoma State University, Stillwater, OK 74078, United States.

http://dx.doi.org/10.1016/j.fuel.2015.10.090
0016-2361/© 2015 Published by Elsevier Ltd.

strongly water-wet to strongly oil-wet, depending upon the reservoir rock mineralogy, chemistry of the fluids present, and the subsurface pressure and temperature. There are more oil-wet reservoirs in the world compared to water-wet reservoirs [2,3]. Wettability is a major factor that controls multiphase fluid flow, location and distribution of fluids in a reservoir [3]. It has been well recognized that reservoir wettability significantly influences oil production during primary, secondary, and tertiary recovery (enhanced oil recovery) stages [4–6].

The primary recovery stage occurs when the reservoir fluids (mostly oil) are produced using the natural pressure energy available in the reservoir. The secondary recovery stage starts when the pressure in the reservoir declines to such a level that can no longer produce reservoir fluids at the desired rate. Waterflooding is the most widely used secondary recovery method where water or brine is injected into the reservoir through injection wells in order to increase the reservoir pressure so that the reservoir fluids are produced at producing wells. Natural gas re-injection is another secondary recovery method in which the working principle is to increase the reservoir pressure and also to reduce the viscosity of the producing fluid. Gas lift is a commonly used artificial lift method (that may be used with any stage of the oil recovery methods) where the gas is injected into the tubing through tubing-casing annulus to lower the hydrostatic head of the fluids in the tubing so that they could be produced at the desired rate using the available reservoir pressure. Unlike in the gas re-injection method, in gas lift method the gas is not injected into the reservoir and hence the reservoir pressure is not increased.

Typical primary recovery ranges from 5% to 20% of the initial oil in place (IOIP) and secondary recovery adds an additional 10–20% IOIP [7]. Normally, the end point of the secondary recovery would be determined by the economics of the project. About 60–70% of the IOIP is usually left in the reservoir after the secondary recovery. Most of the remaining oil after the secondary recovery is primarily trapped by capillary forces [8]. The capillary forces arise from the fact that oil and water phases present in the reservoir are immiscible and hence an interface forms between the fluid phases. The capillary pressure is controlled by the interfacial tension between the oil and aqueous phases, relative wettability of the reservoir rock to the fluids, and the pore size (distribution) of the rock formation. The effect of capillary forces on oil trapping can be characterized by the Capillary number (N_{Ca}), which is defined as the ratio of viscous to capillary forces [9].

$N_{Ca} = \frac{v\mu}{\sigma \cos\theta}$, where, v and μ are the velocity and viscosity of the displacing fluid respectively, σ is the interfacial tension between the oil and water, and θ is the contact angle that quantifies wettability. Significant improvement in oil recovery after the secondary recovery requires the Capillary number to be increased by a factor of 4–6 orders of magnitude [9]. That may be achieved by one or more of the following ways: significantly increasing the velocity and/or viscosity of the displacing fluid; significantly decreasing the oil–water interfacial tension and/or by significantly altering the reservoir wettability. Tertiary recovery methods, for example thermal enhanced oil recovery (TEOR) and chemical enhanced oil recovery (CEOR), target to influence one or more of the above parameters for improved oil recovery. Steam assisted gravity drainage (SAGD) and in-situ combustion are typical TEOR methods and they mainly target to lower the viscosity of the producing oil (displaced fluid) [10,11]. Alkaline–surfactant–polymer (ASP) flooding is a CEOR method that aims to improve the interfacial properties to reduce the capillary barrier and also to increase the viscosity of the displacing fluid for mobility control [12,13].

In the recent decades CO_2 flooding has gained substantial attention as a tertiary recovery method that also simultaneously allows sequestering a portion of the injected CO_2. CO_2 enhanced oil recovery (CO_2 EOR) aims to improve the interfacial properties as well as to reduce the oil viscosity by swelling it. A major disadvantage of CO_2 EOR comes from the very low viscosity of CO_2. The low viscosity promotes viscous fingering and hence very low sweep efficiency. In general, higher sweep efficiencies can be obtained by reducing the mobility ratio (M) which may be defined as,

$$M = \left(\frac{k}{\mu}\right)_{displacing\ \ phase} \Bigg/ \left(\frac{k}{\mu}\right)_{displaced\ \ phase}$$

where k is the end point relative permeability to the fluid and μ is the fluid viscosity. To avoid viscous fingering and early breakthrough of the displacing fluid, viscosity of the displacing fluid phase should be sufficiently high.

In recent years considerable research efforts have also been devoted to develop CO_2 foams for EOR and hydraulic fracturing applications [14–18]. CO_2 foam flooding has all the advantages of CO_2 flooding and in addition the low viscosity problem is mostly solved as the stable CO_2 foams have few orders of magnitude higher viscosities. Nonetheless, obtaining stable CO_2 foams at reservoir conditions is a real challenge. Therefore, for reasonably homogeneous and low viscosity crude oil reservoirs CO_2 flooding may be a viable option for EOR. Various aspects of CO_2 flooding efficiency have been addressed using laboratory, field scale, and computer simulation studies [18–23].

The flooded CO_2 can be immiscible or miscible with the oil in the reservoir. The CO_2 miscibility with the oil would be primarily determined by the reservoir pressure, temperature, and physicochemical properties of the oil. The minimum pressure at which CO_2 is miscible in all proportions with the oil at reservoir temperature is referred as the minimum miscibility pressure (MMP). In general, immiscible CO_2 flooding is inefficient in obtaining significant EOR compared to miscible CO_2 flooding [24]. The CO_2 miscibility with oil helps in two primary ways: one, the interface between displacing fluid (CO_2) and displaced fluid (oil) would vanish and hence the corresponding capillary force would become zero; two, due to CO_2 dissolution the oil swells and its viscosity is considerably reduced.

Both the miscible and immiscible CO_2 flooding could be conducted either as a continuous gas injection (CGI) mode or water alternating gas (WAG) injection mode [25]. As the names suggest, in CGI mode CO_2 is continuously injected, whereas in WAG mode water (or brine) and CO_2 are alternately injected. The advantages of WAG injection mode are to reduce the usage of expensive CO_2, and also to limit the viscous fingering of CO_2 through thin high permeability zones ('thief zones') and gravity override issues that are usually encountered in the CGI mode flooding. However, the negative aspect of WAG flooding is that water could make some of the oil unavailable to be contacted by CO_2 (this phenomenon is referred as water blocking) that would reduce the efficiency of the flooding process. Loss of injectivity and corrosion problems are also some other concerns associated with the WAG injection process [26,27].

The wettability of a petroleum reservoir might be anywhere between strongly water-wet to strongly oil-wet, depending upon its mineralogy and physicochemical properties of the fluids. Even an initially strongly water-wet reservoir may become mixed-wet (different wetting preferences at different locations in the reservoir), intermediate-wet (equal preference to oil and water) or oil-wet, during the production period, due to the injected solvents and/or surface active components [4]. The wettability alteration can also result from deposition of natural surface active components such as asphaltenes and resins as a consequence of the reduction in reservoir pressure and/or the decrease in lower

Please cite this article in press as: Bikkina P et al. Influence of wettability and permeability heterogeneity on miscible CO_2 flooding efficiency. Fuel (2015), http://dx.doi.org/10.1016/j.fuel.2015.10.090