Reservoir Engineering-EOR

Iranian Journal of Oil & Gas Science and Technology, Vol. 5 (2016), No. 4, pp. 18-24
http://ijogst.put.ac.ir

The Effect of Temperature and Injection Rate during Water Flooding Using Carbonate Core Samples: An Experimental Approach

Yaser Ahmadi[1], Mehdi Hassanbeygi[2], and Riyaz Kharrat[3*]

[1] M.S. Student, Department of Petroleum Engineering, Tehran Petroleum Research Center, Petroleum University of Technology, Tehran, Iran
[2] M.S. Student, Department of Petroleum Engineering, Tehran Petroleum Research Center, Petroleum University of Technology, Tehran, Iran
[3] Professor, Department of Petroleum Engineering, Tehran Petroleum Research Center, Petroleum University of Technology, Tehran, Iran

Received: December 12, 2013; *revised:* August 19, 2014; *accepted:* March 09, 2016

Abstract

In many reservoirs, after water flooding, a large volume of oil is still left behind. Hot water injection is the most basic type of thermal recovery which increase recovery by improved sweep efficiency and thermal expansion of crude. In the present work, the effects of injection rate and the temperature of the injected water were surveyed by using core flooding apparatus. Water flooding was performed at different rates (0.2, 0.3, and 0.4 cc/min) and temperatures (20 and 90 °C), and the reservoir temperature was about 63 °C. Oil recovery during hot water injection was more than water injection. Moreover, it was concluded that at injection rates of 0.2, 0.3, and 0.4 cc/min breakthrough time in hot water injection occurred 10 min later in comparison to water injection. The results showed that higher oil recovery and longer breakthrough time were obtained as a result of reducing injection rate. In the first 50 minutes, the oil recovery at injection rates of 0.2, 0.3 and 0.4 cc/min was 27.5, 34, and 46% respectively. It was found that at the beginning of injection, thermal and non-thermal injection recovery factors are approximately equal. Moreover, according to the results, recovery factor at the lowest rate in hot water (T=90 °C and q=0.2 cc/min) is the best condition to obtain the highest recovery.

Keywords: Water Flooding, Hot Water Injection, Core Flooding Apparatus, Breakthrough Time, Sweep Efficiency

1. Introduction

Water and hot water injection are common methods used to enhance oil recovery. In many reservoirs, after water flooding, a large volume of oil is still left behind. Hot water injection is the most basic type of thermal recovery which increases recovery by improving sweep efficiency and thermal expansion of crude. The primary function of thermal recovery methods is to reduce the viscosity of the in place oil. The capillary forces are affected by light fraction which become distilled and

* Corresponding Author:
Email: kharrat@put.ac.ir

mobilized. Elradi et al. (2013) surveyed low salinity hot water injection to enhance the recovery of heavy oil reservoirs, and the found that more than 25% additional oil would be recovered by low salinity as an additional mechanism to hot water flooding. Much attention has been paid to the direct use of geothermal energy by using hot fluids co-produced from oil and gas reservoirs (Li et al., 2007; Erdlac et al., 2007; Zhang et al., 2009; Sun and Li, 2010; Johnson and Walker, 2010). The improvement in the recovery of viscous crude oils by hot fluid injection is primarily due to the improved oil mobility and reduction in residual oil saturation. There are several works about sand stone, but few works are reported on carbonate samples (Sedaee, 2006). There are many questions about various effective parameters during this kind of flooding such as injection rate and temperature (Gong et al., 2010). In this study, water and hot water injection experiments were carried out to obtain the effect of temperature and injection rate during water flooding using carbonate core samples obtained from the oil zones of a heavy oil reservoir.

2. Experimental

2.1. Setup

Figure 1 depicts the schematic of core flooding apparatus. The core flooding apparatus contains a pressure gauge, transfer vessels, differential pressure, a core holder, overburden pressure, a gas metering system, a separator, HPLC pumps, a heating system, and a hand pump. The physical properties of the core samples and crude oil are shown in and Table 1 and 2 respectively.

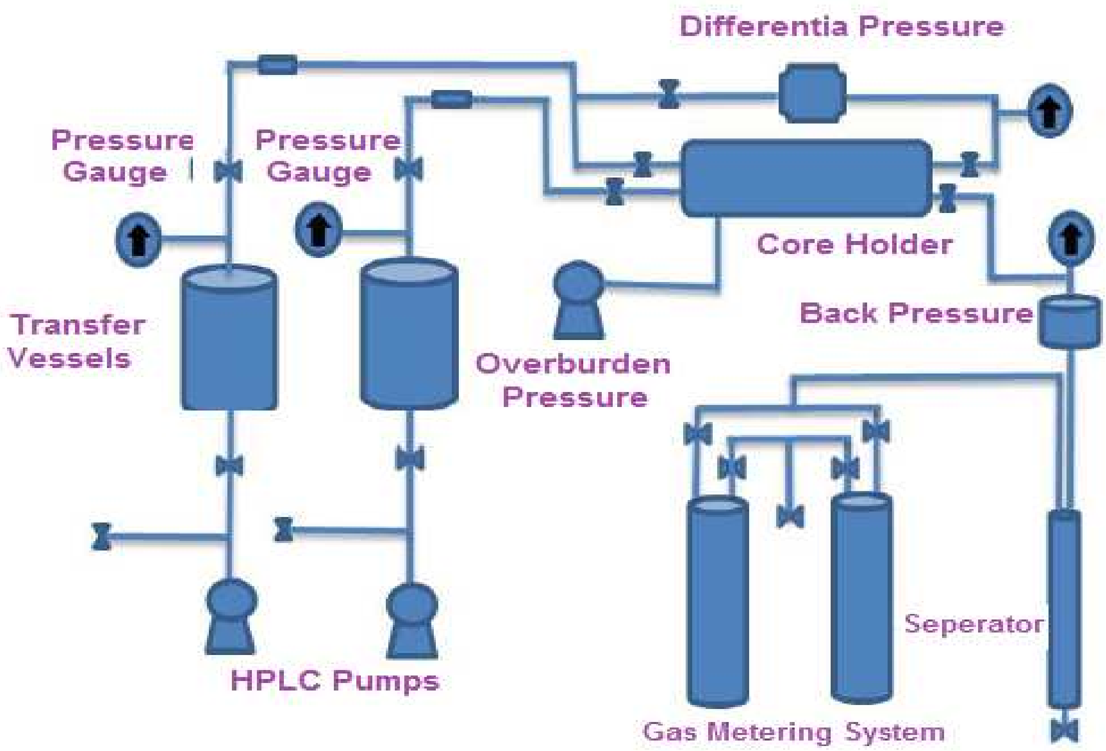

Figure 1
A schematic of core flooding setup.

Table 1
Properties of crude oil.

API	17.71
Asphaltene content (%)	14.6
GOR	448.42
Reservoir pressure(psi)	4650
Saturation pressure(psi)	2030-2035.7
Reservoir temperature(°F)	205
Molecular weight	354

Table2
Properties of core samples.

Properties	**Amount**
Length (cm)	12
Diameter (cm)	3.8-3.82
Porosity	0.23-0.25
Permeability (mD)	13.8-14
S_{wi}	0.185-0.2
Pore column (cc)	35.00
Core type	Carbonate

2.2. Procedure

Six samples of the carbonate core samples obtained from the oil zones of a heavy oil reservoir were selected. These samples have the same characteristic of connate water saturation, porosity, and permeability, and the pore volume of these samples is 35 cc. The samples were cleaned, dried, and then vacuumed for almost 24 hours, and they were saturated with water formation (200,000 ppm). The formation water was displaced by stock tank oil (STO) at a constant rate of 0.2 cc/min and the effects of injection rate and the temperature of injected water were studied using an experimental approach. The reservoir temperature was 63 °C. In this study, water flooding was performed at different rates, namely 0.2, 0.3, and 0.4 cc/min, and temperatures, i.e. 20 and 90 °C.

3. Results and discussion

3.1. Effect of injection rate

Figures 1-3 show the variation of recovery factor versus time at a constant temperature of 20 °C and different injection rates of 0.2, 0.3, and 0.4 cc/min. These figures show that the breakthrough time depends on injection rate. Accordingly, higher oil recovery and a longer breakthrough time were obtained at a lower injection rate. Three tests were designed to study the effect of injection rate on oil recovery. The results show that at injection rates of 0.2, 0.3, and 0.4 oil recovery factors are 27.5, 34, and 46% respectively.

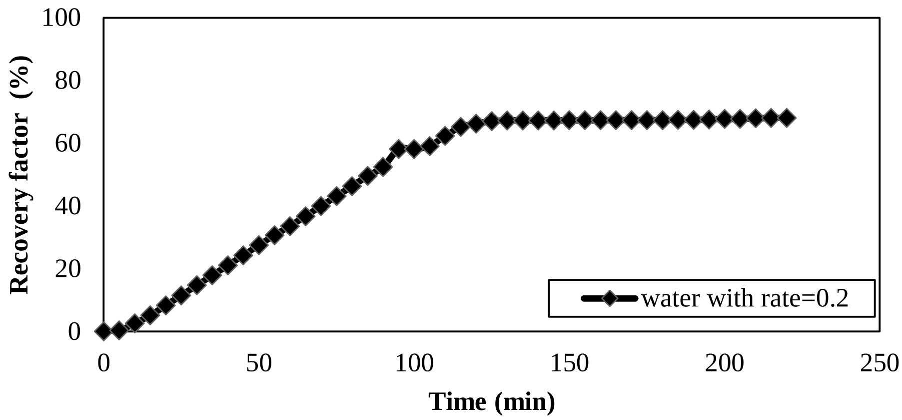

Figure 2
Recovery factor versus time at q= 0.2 cc/min and T= 20 °C.

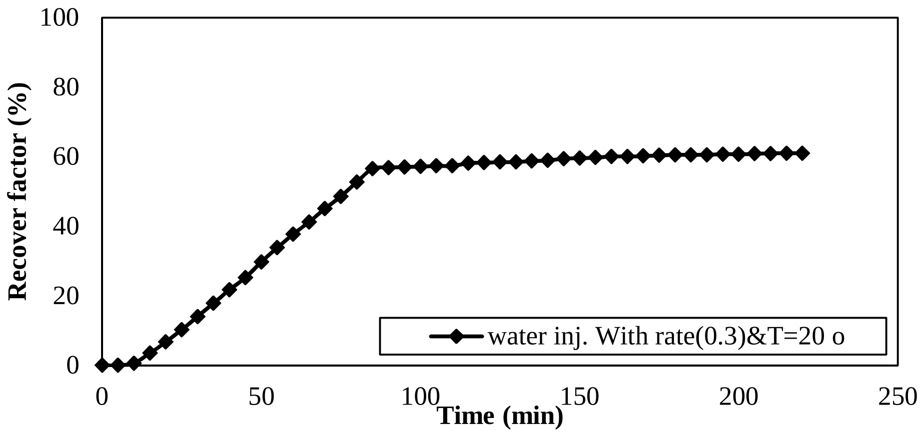

Figure 3
Recovery factor versus time at q= 0.3 cc/min and T= 20 °C.

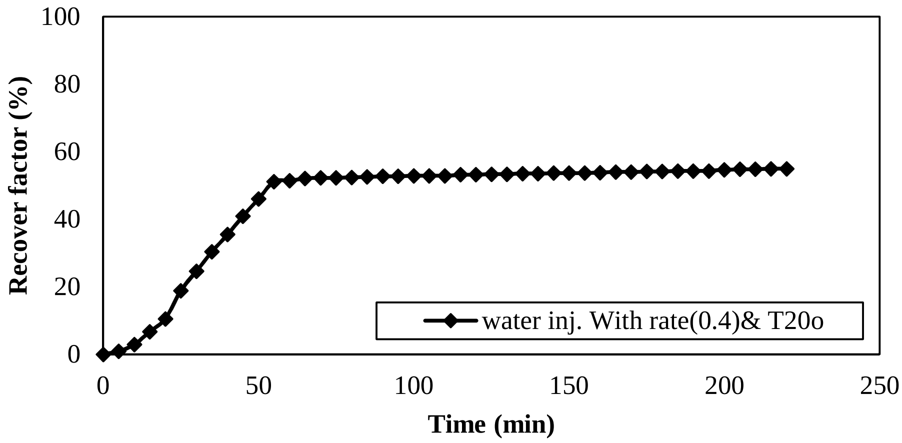

Figure4
Recovery factor versus time at q= 0.4 cc/min and T= 20 °C.

3.2 Effect of Temperature

Figures 5-7 show the variations of recovery factor versus time at temperatures of 20 and 90 °C respectively at different injection rates of 0.2, 0.3, and 0.4 cc/min). The results show that higher oil recovery and a longer breakthrough time were obtained as a result of reducing the injection rate. Moreover, a 10-min-difference in breakthrough time is seen when water and hot water are used at different injection rates. According to the results, oil recovery by hot water was higher than the one by water injection after breakthrough time.

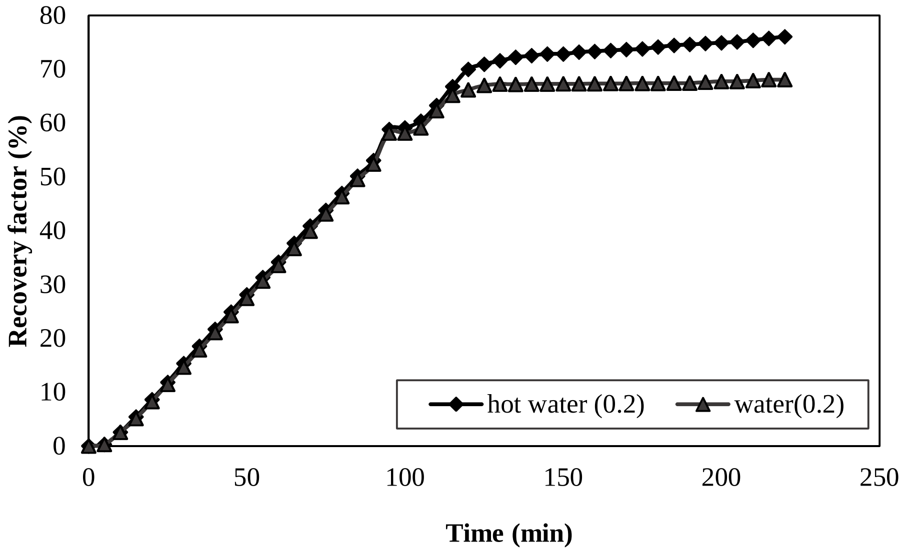

Figure 5
Recovery factor versus time at a constant injection rate of 0.2 cc/min and different temperatures of 20 and 40 °C.

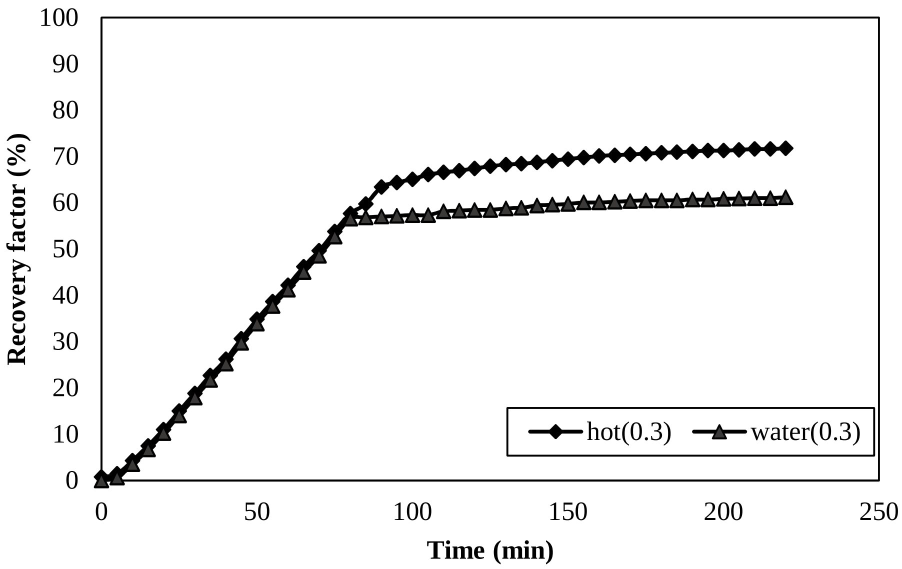

Figure 6
Recovery factor versus time at a constant injection rate of 0.3 cc/min and different temperatures of 20 and 40 °C.

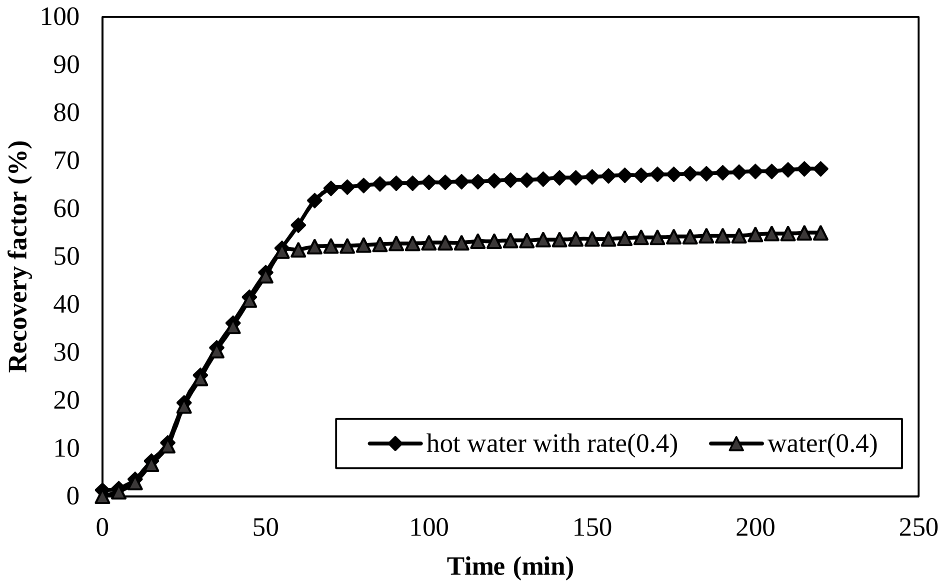

Figure 7
Recovery factor versus time at a constant injection rate of 0.4 cc/min and different temperatures of 20 and 40 °C.

3.3. Parameter optimization

Figure 8 shows the changes in recovery factor versus time while changing the injection rate and temperature. Equal recovery factors were obtained at the beginning of the process for thermal and non-thermal injections. In addition, the recovery process by hot water at the lowest rate, namely T= 90 °C and q= 0.2 cc/min, provides the optimum condition to obtain the maximum recovery factor.

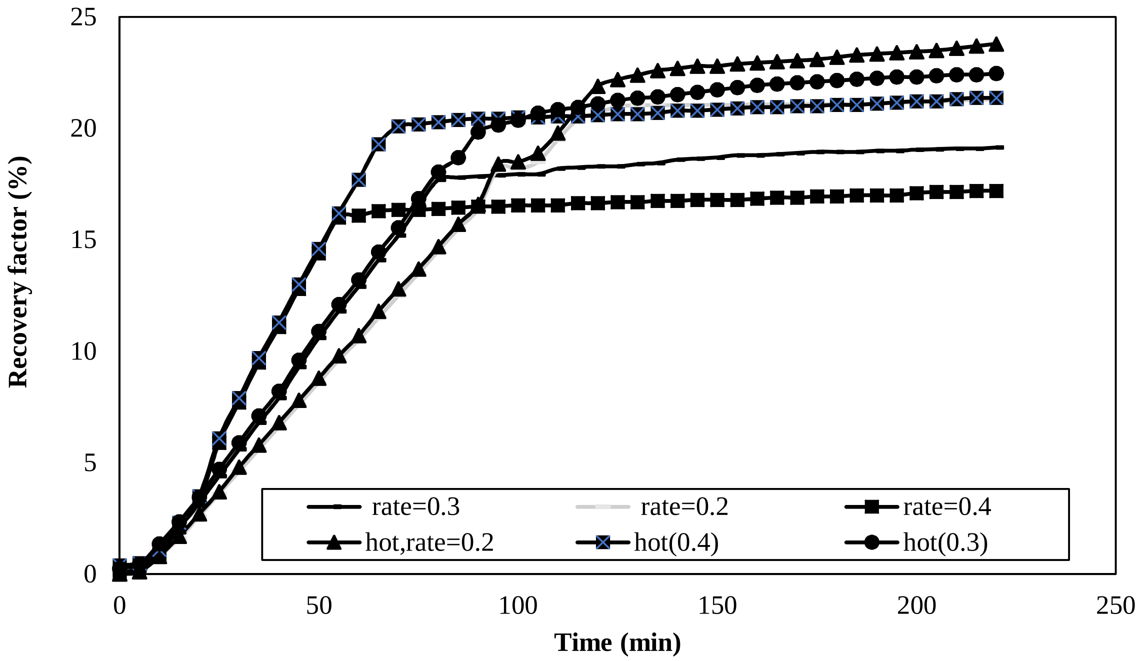

Figure 8
Recovery factor versus time while changing the injection rate and temperature.

Conclusions

According to the results of the current work, the following conclusions can be reached:

1. Hot water injection resulted in higher oil recovery compared to water injection;
2. Breakthrough time in hot water injection occurred 10 min later in comparison to the one in water injection; the same results were obtained at different injection rates of 0.2, 0.3, and 0.4 cc/min;
3. Higher oil recovery and a longer breakthrough time were obtained as a result of reducing injection rate;
4. At the beginning of the injection process, thermal and non-thermal injection recovery factors were approximately equal;
5. Using hot water at the lowest injection rate, namely T= 90 °C and q= 0.2 cc/min, provided the optimum condition to obtain the highest recovery.

Nomenclature

mD	: MilliDarcy
GOR	: Gas oil ratio
HPLC	: High performance liquid chromatography
q	: Injection rate (cc/min)
STO	: Stock tank oil
T	: Fluid temperature (°C)

References

Gong, B., Liang, H., Xin, S., and Li, K., Effect of Water Injection on Reservoir Temperature during Power Generation Oil Fields, Proceedings, Thirty-sixth Workshop on Geothermal Reservoir Engineering Stanford University, Stanford, California, Vol. 2, January 31-February 02, 2011.

Elradi, A. and Fahmi, A., Experimental Investigation of Low Salinity Hot Water Injection to Enhance the Recovery of Heavy Oil Reservoirs, SPE 164768, April 15-17, 2013.

Erdlac, Jr., R. J., Armour, L., Lee, R., Snyder, S., Sorensen, M., Matteucci, M., and Horton, J., Ongoing Resource Assessment of Geothermal Energy from Sedimentary Basins in Texas, Proceedings of Thirty-second Workshop on Geothermal Reservoir Engineering, Stanford University, Stanford, California, January 22-24, 2007, SGP-TR-183.

Li, K., Zhang, L., Ma, Q., Liu, M., Ma, J., and Dong, F., Low Temperature Geothermal Resources at Huabei Oilfield, China, Geothermal Resources Council Transactions, Vol. 31, 2007.

Lyle, A., Johnson, P.E., and Everett, D., Oil Production Waste Stream, A Source of Electrical Power, Proceedings of Thirty-fifth Workshop on Geothermal Reservoir Engineering Stanford University, Stanford, California, February 1-3, 2010.

Sedaee Sola, B., Investigation of Temperature Effect on Carbonate Reservoir Water/oil Relative Permeabilities Thermal EOR, Ph.D. Thesis, Amirkabir University, Tehran, Iran, 2007.

Sun, W. and Li, K., Effects of Fluid Saturation and Porosity on the Estimation of Geothermal Resources in Oil and Gas Reservoirs, Proceedings of World Geothermal Congress 2010, Bali, Indonesia, 25-29 April, 2007.

Zhang, L., Liu, M., and Li, K., Estimation of Geothermal Reserves in Oil and Gas Reservoirs, SPE 120031, SPE Western Regional Meeting Held in San Jose, California, USA, 24-26 March, 2009.