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Very High Temperature Laboratory CO_2 Injection

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Abstract

Carbon dioxide (CO_2) injection is the most promising technique to enhance the recovery of high gravity oil with the existing oil price situation. Even though, challenges still exist for thick and heterogeneous reservoirs at very high temperature. The problems faced in such reservoirs are low displacement efficiency and very high injection pressure requirement for a miscible displacement. The effort being done by researchers to overcome the situations is the use of silica nanoparticle as an agent to form CO_2-silica nanoparticle foam. Currently, the related literature shows that CO_2 miscible displacement is rarely performed at very high temperature and consequently no relevant effort has been made to investigate the stability of CO_2-silica nanoparticle foam, while there are many oil reservoirs with temperature of higher than 250 ^{o}F. Therefore, related studies on such situations are needed. The present work consists of two stages. First, slimtube and coreflood experiments of CO_2 injection are conducted at about 270 ^{o}F, respectively, to both determine the Minimum Miscibility Pressure (MMP) of the selected live oil system and the oil recovery. Secondly, CO_2-silica nanoparticle foam stability in various brine salinity at such high temperature will be investigated and effectiveness of the selected stable foam will be tested through an oil displacement using native cores.

In this paper, the results of both slimtube and coreflood experiments are first presented. A live paraffinic oil with 34 ^{o}API is used. The standard slimtube apparatus is employed. Stacked core composing of three native core plugs of different permeability ranging from 75 to 503 milidarcies are used to represent rock heterogeneity. At a temperature of 270 ^{o}F, MMP of the oil obtained from the slimtube experiment is 2960 psi, about 100 psi higher than that obtained from the coreflood experiment. The slimtube test gives oil recovery 94.2% and the coreflood as expected yields lower recovery, 84% of the initial oil in place. The importance of the tests is two folds that the MMP of the oil system is firmly known while the existing empirical correlations estimate the values ranging from 2718 to 5578 psi and a relatively low coreflood oil recovery suggests further investigation of stability of CO_2-silica nanoparticle foam at that temperature in an attempt for enhancing the oil recovery.

Keywords: CO_2 injection experiment, high temperature, minimum miscibility pressure

1. Introduction

Proven CO_2 injection as an Enhanced Oil Recovery (EOR) technique has been implemented successfully in many oil fields worldwide. The use of CO_2 to recover more oil from the reservoirs has been investigated since early 1950's (Stalkup, 1978; Mungan, 1981; Orr Jr. & Jensen, 1984). Principally, CO_2 at certain conditions can dissolve into oil, make the oil swelling, and thus reduce both oil viscosity and interfacial tension. Such oil property changes result in easier oil removal from rock pore spaces. At a given reservoir temperature, the degree of the oil property changes depends mainly on CO_2 injection pressure, the purity of CO_2 injected, and chemical composition of the live oil. The higher all CO_2 injection pressure, purity and hydrocarbon intermediate content, the larger the oil property changes. Conversely, lower both injection and CO_2 purity and higher content of heavy hydrocarbon components or lower oil gravity, the lesser the oil property changes.

For a given both oil and CO_2 purity, the effectiveness of the use of CO_2 is commonly tested by employing a standard slimtube apparatus (Holm & Josendal, 1974; Yelligh & Metcalfe, 1980; Mungan, 1981; Johnson & Pollin, 1982). The testing is a displacement process, CO_2 displacing the oil. At least four testing runs, each at a constant injection pressure, should be carried out to identify the oil recovery at each pressure. Plotting the oil recovery obtained against the injection pressure provides information about a pressure, termed as minimum miscibility pressure (MMP), above which the additional recovery is insignificant. As a guide to run the testing, since MMP is usually several hundred psi above bubble point pressure P_b of the oil, several injection pressures below and above the P_b should be selected. The purposes of determining MMP are to design the bottom hole injection pressure in order not to exceed the formation fracturing pressure and obtain an idea of its implication to effectiveness of CO_2 injection.

Determination of MMP in implementing CO_2 injection is therefore of important. As laboratory experiments for obtaining MMP are time consuming and quite expensive, many researchers had conducted a large number of laboratory experiments to determine MMP of various reservoir oils at varied temperature and arrived at empirical correlations. The correlations may help engineers in estimating MMP needed. Specifically, some correlations relate MMP to oil gravity and temperature (Holm & Josendal, 1974; National Petroleum Council [NPC], 1976; Yellig & Metcalfe, 1980) and another one takes molecular weight of C5+ into account in addition to oil gravity and temperature (Cronquist, 1978; Mungan, 1981; Johnson & Pollin, 1982). It is identified in the literature that the highest temperature used in their experiments is 250 °F or 121 °C. While, there are many oil reservoirs exist with temperature of higher than 250 °F or 121 °C. Applying such available correlations to higher temperature should therefore be taken with care in order to avoid an implementation of CO_2 injection from failure.

Ideally, when a potential reservoir has quite different from those used for generating the existing empirical correlations in terms of oil characteristics and reservoir temperature, it would be desired to specifically run laboratory experiments to both determine the MMP by using a standard slimtube apparatus and observe the effectiveness of CO_2 injection by employing the native cores. The advantage of using native cores may provide information about the effect of rock heterogeneity combined with CO_2-to-oil mobility ratio on the displacement efficiency, although at core scale.

It is realized that some problems faced in the field implementation of CO_2 injection is CO_2 fingering due to high mobility ratio and bypassed oil due to reservoir heterogeneity. These result in a low displacement efficiency. Recently, instead of using conventional surfactants to generate CO_2 foam for reducing its mobility, many researchers have investigated the benefit of silica nanoparticles to form CO_2-in-brine foam (Dickson, Binks, & Johnston, 2004; Espinosa, Caldelas, Johnston, Bryant, & Huh, 2010; Worthen, Bagaria, Chen, Bryant, Huh, & Johnston, 2012; Yu, Liu, Li, & Lee, 2012; Yu, An, Mo, Liu, & Lee, 2012). The use of such nanoparticles is considered more stable than conventional surfactants in generating CO2-in-brine foam at high temperature. Unfortunately, the previous research employed water-wet silica nanoparticles with temperature of not higher than 140 °F or 60 °C. While, hydrophobic silica nanoparticles are known can adsorb at the CO_2-water interface and stabilize foams with extremely high adsorption energies, act as mobility control agent and can improves vertical and areal sweep efficiency (Binks & Horozov, 2006; Adkins, Gohil, Dickson, Webber, & Johnston, 2007; Yu et al., 2012; Yu, Mo, Liu, & Lee, 2013; Mo, Yu, Liu, & Lee, 2012; Mo, Jia, Yu, Liu, & Lee, 2014).

The objectives of the present research are to determine MMP at a typical high temperature, perform oil displacement by CO_2 using a heterogeneous porous medium, investigate the stability of CO_2-hydrophobic silica nanoparticle foam at a very high temperature, and gain information of the effectiveness of the stable foam from an oil displacement in the same porous medium. The tasks are divided into two stages. First stage is to perform slimtube experiments of CO_2 injection at a typical very high reservoir temperature to determine MMP of the selected live oil system and carry out CO_2 injection on heterogeneous native cores. The second stage is to investigate stability of CO_2-in-brine foam by use of hydrophobic silica nanoparticles at a very high temperature and test the effectiveness of the foam through a similar oil displacement done in the first stage.

Regarding with the laboratory experiments of CO_2 injection at a very high temperature, the present work is not the first one. A previous experiment of MMP determination using a conventional slimtube apparatus was conducted at a temperature of 285 °F (140.5 °C) for a very light oil, 51 °API (Christian, Shirer, Kimbel, & Blackwell, 1981). Differently, the present study carries out the laboratory tests at a reservoir temperature of 270 °F (132 °C) employing a paraffinic crude oil with an oil gravity of 34 °API and a relatively high pour point of 94 °F (34 °C). Such a situation is a challenge particularly in conducting the experiment.

This paper focuses on presenting the results of CO_2 injection obtained from both slimtube tests and native coreflood tests. A comparison of the results of the two test types will determine the need for further work on the use of CO_2-silica nanoparticle foam.

2. Experimental Description

2.1 Materials

Reservoir fluids and rock samples used in this research were obtained from Gemah Field located in Jambi Province, Sumatra, Indonesia. The reservoir of interest is a sandstone laying down at a vertical depth of 6100 feet sub-sea. The initial reservoir pressure was 2600 psi and the temperature is 270 °F or 132 °C. The type of oil produced is paraffinic one with a gravity of 34 °API, a high pour point of 94 °F, and a bubble point pressure of 2427 psi (see Table 1). The composition of reservoir hydrocarbon is presented in Table 2 showing a relatively high CO_2 content. The initial oil in place (IOIP) estimated is 105.9 MMSTB. The recovery factor (RF) is currently 6% with a reservoir pressure of 2300 psi and an average Water Cut of 65%. Since the surrounding oil and gas fields are producing a large volume of CO_2 gas, CO_2 injection is considered the most potential EOR method for Gemah Field. A need of implementing CO_2 injection in this Field is very urgent because the current recovery factor is low and the reservoir pressure cannot lift up the liquid to the surface in some of the wells.

Representation of the live oil is made by recombining the oil produced and the separator gas. The previous PVT analysis data, particularly the bubble point pressure, are used as a reference in recombining the fluid samples. CO_2 gas with a purity of 99.5% employed for determining the MMP is bought from a commercial company.

Table 1. Properties of crude oil

Oil sample	Reservoir temperature		Initial reservoir pressure	Bubble point pressure	Pour point	
	Deg. F	Deg. C	Psi	Psi	Deg. F	Deg. C
Gemah	270	132	2600	2412	94	34

Table 2. Crude oil composition

Component	Separator Liquid	Separator Gas		Well Stream	
	Mol %	Mol %	GPM	Mol %	Weight %
Hydrogen Sulfide	0.00	0.00		0.00	0.00
Carbon Dioxide	7.64	58.56		33.03	12.31
Nitrogen	0.01	1.38		0.69	0.16
Methane	1.36	27.30		14.29	1.94
Ethane	1.55	5.66	1.514	3.60	0.92
Propane	4.09	4.46	1.229	4.27	1.60
Iso-Butane	1.57	0.74	0.242	1.16	0.57
N-Butane	2.46	1.06	0.334	1.76	0.87
Iso-Pentane	1.88	0.29	0.106	1.09	0.66
N-Pentane	1.76	0.22	0.080	0.99	0.61
Hexanes	3.42	0.16	0.062	1.80	1.28
Heptanes	5.73	0.11	0.046	2.93	2.38
Octanes	8.43	0.05	0.023	4.25	3.85
Nonanes	5.92	0.01	0.005	2.97	3.05
Decanes	4.87	0.00	0.000	2.44	2.77
Undecanes plus	49.31	0.00	0.000	24.73	67.03
Total	100.00	100.00	3.641	100.00	100.00

The rock samples available for coreflooding are sandstone cores with porosity and air permeability ranging from 16 to 21% and 73 to 205 millidarcies, respectively. All the cores are very consolidated, coming from a depth interval of 6848 – 6883 feet subsea and the properties of all the cores used are presented in the Table 3.

Table 3. Properties of native core data

L, (cm)	D, (cm)	WT, (gr)	BV, (cc)	GV, (cc)	PV,(cc)	GD, (Gr/cc)	Por, (%)	K, mD	Lithology Descriptions	Name	L, (cm)	PV, (cc)	K, mD	Injection pressure
6.778	3.793	168.706	76.62	61.83	12.79	2.643	16.69	83	SS : Brn, med.hrd, mgr, sb.ang - sb.rdd, mod.srtd, qz, plag	Stacked-1	20.448	38.97	86	2635
6.579	3.790	162.440	74.25	61.53	12.72	2.640	17.13	85	SS : Brn, med.hrd, mgr, sb.ang - sb.rdd, mod.srtd, qz, plag					
7.091	3.792	176.034	80.11	66.65	13.46	2.641	16.80	89	SS : Brn, med.hrd, mgr - fgr, sb.ang - sb.rdd, mod.srtd, qz, plag					
7.155	3.797	175.958	81.05	66.47	14.58	2.647	17.99	99.6	SS : Brn, med.hrd, mgr - fgr, sb.ang - sb.rdd, mod.srtd, qz, plag	Stacked-2	21.126	44.72	136	2830
7.407	3.801	184.401	84.08	69.61	14.47	2.649	17.21	104	SS : Brn, med.hrd, mgr - fgr, sb.ang - sb.rdd, mod.srtd, qz, plag					
6.564	3.787	155.019	73.96	58.29	15.67	2.659	21.18	205	SS : Brn, hrd, mgr - cgr, sb.ang - sb.rdd, p.srtd, qz, plag					
7.194	3.793	178.823	81.32	67.63	13.69	2.644	16.83	73	SS : Brn, med.hrd, mgr - fgr, sb.ang - sb.rdd, mod.srtd, qz, plag	Stacked-3	21.060	39.16	75	3250
6.965	3.792	174.846	78.69	66.10	12.59	2.645	16.00	74	SS : Brn, med.hrd, mgr, sb.ang - sb.rdd, mod.srtd, qz, plag					
6.901	3.790	172.812	77.89	65.01	12.88	2.658	16.54	79	SS : Brn, hrd, mgr - cgr, sb.ang - sb.rdd, p.srtd, qz, plag					

2.2 Laboratory Experiments

2.2.1 Slimtube experiments

The slimtube is a porous medium commonly used for determining MMP of reservoir oils. The slim-tube displacement is a simple experiment that eliminates effects of viscous fingering, gravity segregation, and rock heterogeneity and can give immediate information about potential operating pressures. It should be performed early in the evaluation of a field prospect for CO_2 flooding (Orr Jr. & Jensen, 1984). The slimtube employed in the present work is a coiled tubing having an inside diameter of 6.4 mm and the length of 18.9 meters and containing fully clean 200 - 240 mesh quartz sands. The grain sands are firmly packed inside the tubing, giving pore volume, porosity, and permeability of 156 cm^3, 25%, and 11.36 darcies, respectively. A schematic diagram of the apparatus arrangement used for MMP determination is shown in Figure 1. The purpose of installing a back pressure regulator (BPR) at the outlet of the slimtube is to control and maintain an estimated pressure required within the slimtube. In this experiment, since pour point of the oil is 94 °F or 34 °C, the separator of produced fluids is placed inside a separate air bath oven.

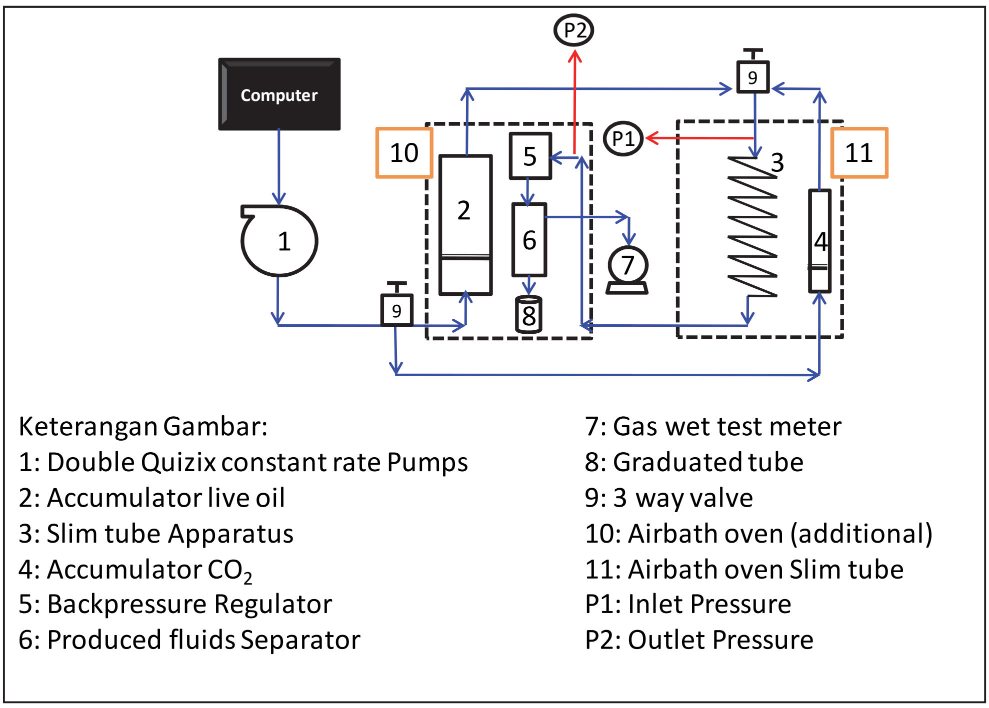

Figure 1. Slimtube Apparatus diagram

The slimtube is vacuumed prior to saturating the slimtube with the live oil. A Double Quizix constant rate pump is connected to the live oil accumulator during the process of saturating the slimtube with the oil. A pressure slightly above the bubble point pressure is finally maintained in the slimtube to avoid free gas inside the slimtube before injecting the CO_2 gas. CO_2 gas at a desired pressure is then injected into the slimtube by using another Double Quizix constant rate pump connected to the CO_2 accumulator. An automatic pressure transducer is set to control pressures at the inlet and outlet of the slimtube. Injection rate of CO_2 gas was 0.3 cm^3/min and CO_2 injected was 1.2 PV (pore volume) to complete each run. The liquid effluent passing through the separator was collected in the graduated tube and the gas effluent is recorded by using wet gas meter. By considering the bubble point of the oil, 2427 psi, six slimtube experimental runs were conducted above the bubble point pressure to avoid earlier CO_2 gas breakthrough. The injection pressure used were 2619, 2742, 2917, 3235, 3451, and 3623 psig.

2.2.2 Coreflood Experiments

Although CO_2 injection into the rock samples containing oil and water would not represent oil displacement at much larger scale such as in an oil reservoir, at least one could gain knowledge about effects of both the existence of water within the rock pores and injection pressure on oil recovery. This situation may exist in water-out zones at the end of either a primary or secondary recovery stage. The knowledge derived from coreflood tests may inspire us whether or not an improved CO_2 injection technique would be needed for a better oil displacement, such as the use of CO_2-nanoparticle foam (Yu et al., 2013; Mo et al., 2014). The present study is focused first on oil displacement by CO_2 at a very high temperature condition before investigating the stability of CO_2-nanoparticle foam at such a condition. The schematic diagram of the arrangement of equipments employed for coreflooding is shown in Figure 2. The arrangement slightly differs from that of the slimtube test. Coreflood tests here employed a Hassler type core holder covered with a heating mantle and placed outside of the airbath oven for easier experimental operations.

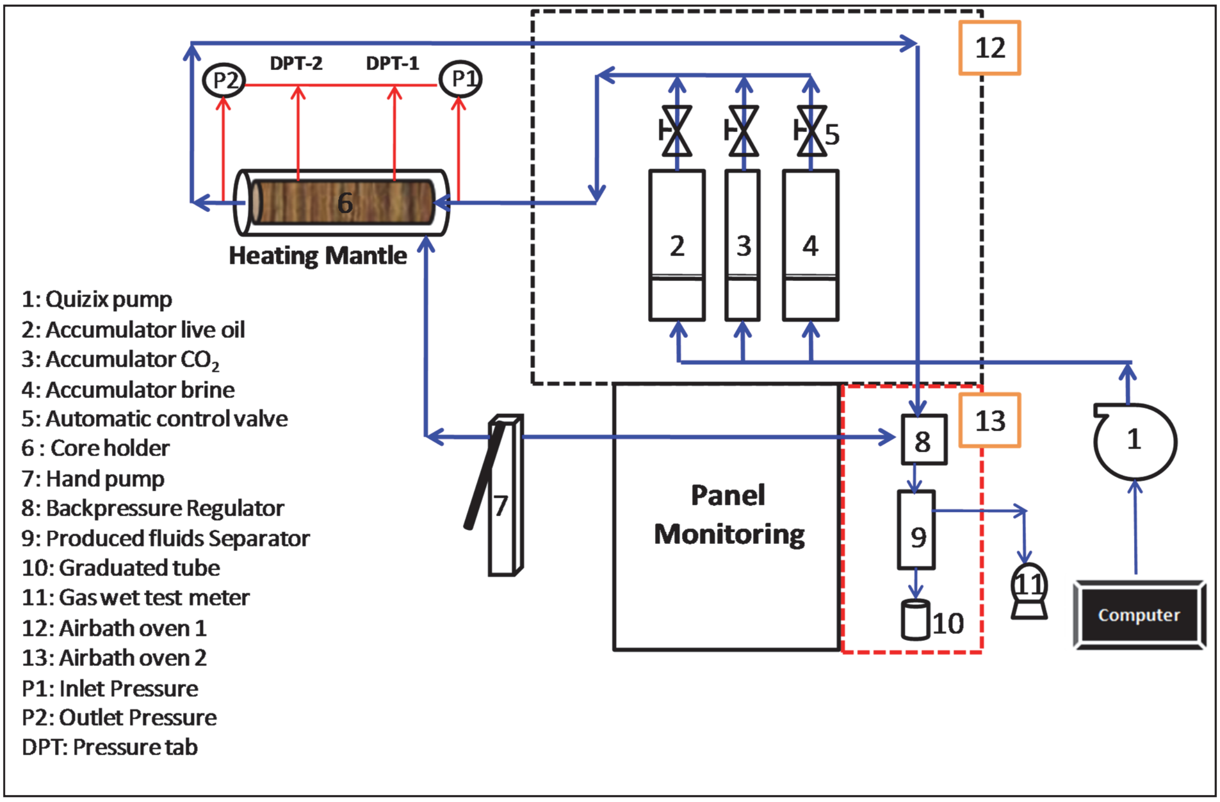

Figure 2. Coreflooding Rig Apparatus diagram

Properties of core plugs employed can be seen in Table 3. Since the number of the cores was limited, coreflood runs of CO_2 injection were planned for only three pressure levels. Two runs were for injection pressure between the oil bubble point pressure and the MMP and another run was scheduled for pressure above the MMP. Each run used one core set of three core plugs stacked inside the rubber sleeve. The plugs to be stacked for one set were selected to have all about the same permeability to avoid the effect of horizontal heterogeneity on oil recovery. Unfortunately, we had only two sets with an average permeability of 75 and 86 millidarcies, respectively. One core set left consists of three core plugs having permeability of 99.6, 107, and 205 millidarcies with the average permeability of 136 millidarcies (see Table 3). This situation was just taken to be an advantage to study further the effect of horizontal heterogeneity on oil recovery. It was decided then to use this core set for one of the two CO_2 injection runs below MMP that will be obtained from the slimtube experiment to see whether the oil recovery performance would deviate from what will be obtained from another core set.

A confining pressure of 300 psi above pore pressure at any respective step of the experiment, saturating and injecting, was used outside of the rubber sleeve and a temperature of 270 °F was maintained. Saturating the core set with brine was first made and the core was aged inside the core holder for one day to equilibrate the rock-brine system. The core permeability to brine was measured. The next step was to inject the recombined oil at a rate of 0.25 cm^3/min into the core and the injection was ceased when a high water saturation as expected, about 60%, was obtained by measuring the brine produced. The core was then aged for a day before conducting CO_2 injection. Establishment of a high water saturation was to imitate a condition of the start of a tertiary recovery stage.

Three CO_2 coreflood runs were conducted at an injection pressure of 2635, 2830, and 3250 psig, respectively. The CO_2 injection rate implemented was increased gradually from 0.1 cc/min initially to 1.0 cc/min, corresponding to a maximum velocity of about 1 ft/day. For each of the first two runs, a total of 1.2 pore volume injected (PVI) of CO_2 was used. For the last run with injection pressure of 3250 psi, however, CO_2 breakthrough occurred much earlier than expected and much of the oil was produced after the breakthrough. The run was ceased after 2.5 PV of CO_2 was injected when no more oil at the first time was detectable.

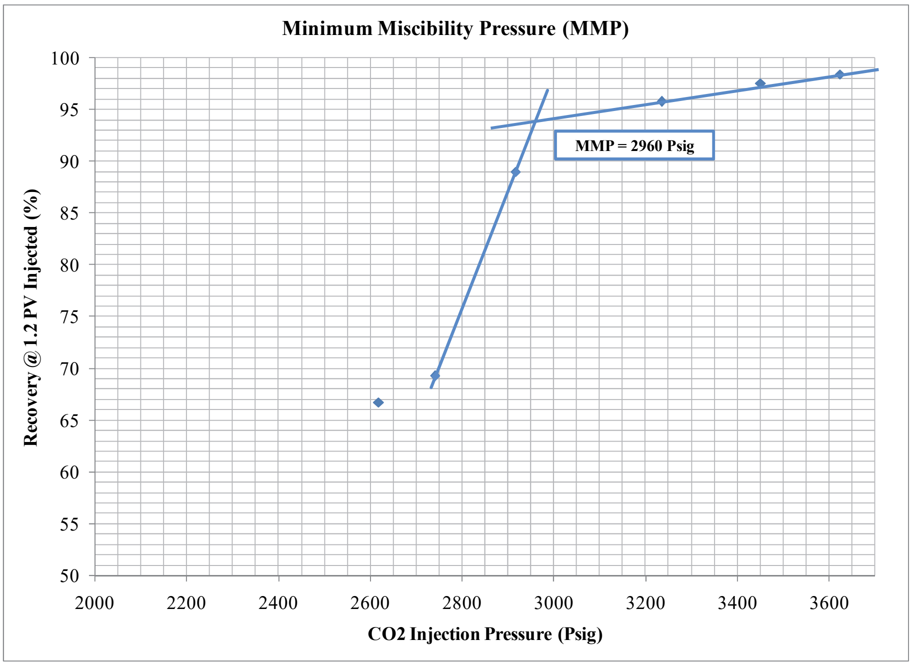

Figure 3. MMP determination by slimtube experiment at high temperature 270 °F

3. Results and Discussion

The need of this laboratory study was decided after realizing that the use of the existing empirical correlations in predicting MMP of the oil system under the study results in a wide range of the values, 2718 to 5578 psi (Table 4). Moreover, consideration of relatively low formation fracturing pressure of about 3400 psi (Rauf, Edwin, & Made, 2007) for the Field gave even a more push to carry out laboratory tests. Results of the slimtube test are presented in Figure 3, oil recovery at 1.2 PVI versus CO_2 injection pressure. Here, oil recovery is the percentage of the initial oil in place within the slimtube. The oil recovered at 1.2 PVI for estimating MMP is commonly adopted in slimtube tests. Figure 3 shows that the data points distribute into two parts, exhibiting an abrupt change in the increase of oil recovery between pressure below and above approximately 2960 psig. This pressure is obtained by intersecting two linear trend lines as shown in the figure. The point of intersection is taken for estimating the MMP, which is 2960 psig. Since oil displacement by CO_2 involves a dynamic miscibility process, the abrupt change in oil recovery indicates that the MMP was an optimum condition for the dynamic miscibility process to occur between CO_2 and the oil (Yellig & Metcalfe, 1980). MMP of the oil employed here is about 500 psig above the bubble point pressure of 2412 psig (see Table 1). The present experimental results provide very important information concerning with the limitation of CO_2 injection pressure when the formation fracturing pressure of 3400 psig is considered in order to avoid the formation from fracturing. In continuous CO_2 injection, fracturing may cause a low displacement efficiency as CO_2 injected would go channeling through the fractures and bypassing most of the reservoir oil.

Table 4. Comparison of predicted MMP from correlations

Methods	MMP Correlations	MMP, Psi
Cronquist (1978)	MMP as a function of temperature and MW_{5+} and mol% of methane and nitrogen $MMP = 15.988\, T^{n}$ where: $n = 0.744206 + 0.0011038\, M_w(C_{5+}) + 0.0015279\, MFC$ T = Reservoir Temperature, °F MW_{5+} = Molecular weight of C_{5+} MFC = Molecular fraction of light components (C_1 and N_2)	2979
Yellig and Metcalfe (1980)	MMP as a function of Temperature $MMP = 1833.7171 + 2.2518055\, T + 0.01800674\, T^2 - 103949.93 / T$ T = Reservoir Temperature, °F	3369
Jhonson and Pollin (1981)	MMP as a function of Temperature and Oil Characterization Index (I) $P_{MDMP} - P_c, inj = \alpha_{inj}(T_{res} - T_c, inj) + I(\beta M - M_{inj})^2$ where: $\alpha_{inj} = 10.5\left(1.8 + \frac{10^3 y_2}{Tres - Tc, inj}\right)$ $I = -11.73 + (6.313\times10^{-2} M) + (-1.954\times10^{-4} M^2) + (2.502\times10^{-7} M^3) + [0.1362 + 1.138\times10^{-5} M]\rho + (-7.222\times10^{-5})\rho^2$ Pc,inj = Injection gas critical pressure, psia Tc,inj = Injection gas critical temperature, °K Tres = Reservoir Temperature, °K I = Oil Characterization Index $\beta = 0.285$ M = Number average Molecular Weight of the oil Minj = Molecular Weight of the injection gas y_2 = Mole fraction of diluting component ρ = API gravity	3044
Orr Jr. and Jensen (1984)	MMP as a function of Temperature (can be use if reservoir temperature below 120 °F) $P = 14.69235 \exp\left(\frac{-2015}{T} + 10.91\right)$ T = Reservoir Temperature, °K	5578
Glaso (1985)	MMP as a function of temperature and MW_{7+} $(P_m)_{\min} = 810.0 - 3.404\, Mc_{7+} + \left(1.700\times10^{-9}\, Mc_{7+}^{3.730}\, e^{786.8\, Mc_{7+}^{-1.058}}\right) T$ MW_{7+} = Molecular weight of C_{7+} T = Reservoir Temperature, °F	3208
Alston et. al. (1985)	MMP as a function of temperature and MW_{5+} and the ratio of volatile to intermediate mol% from live oil $MMP = 8.78\times10^{-4}(T_R)^{1.06}(Mc_{5+})^{1.78}(x_{vol}/x_{int})^{0.136}$ where: T_R = Reservoir Temperature, °F MW_{5+} = Molecular weight of C_{5+} $x_{vol} = mole\ \ fraction\ \ C_1, N_2$ $x_{int} = mole\ \ fraction\ \ C_2, C_3, C_4, CO_2, H_2S$	2718

Consideration of this situation leads to the attention that has to be paid for avoiding the formation from fracturing during CO_2 injection. Although information about the safety factor for injection operation is rarely available in the literature, a typical safety factor for is 500 psi below fracturing pressure (Justen & Hoenmans, 1958). As just mentioned above in this Section, the fracturing pressure of the Formation under the study is 3400 psi. Taking a maximum injection pressure of say 3000 psi for the Field under the present study and a reservoir flowing gradient of 0.85 psi/ft (Bickle, Kampman, Chapman, Ballentine, Dubacq, Galy, Sirikitputtisak, Warr, Wigley, & Zhou, 2017), the miscibility condition that could be attained would only be within a radius of about 50 feet from the injection well. The displacement mechanisms within the rest of the area affected by CO_2 would be a near miscible and/or immiscible process, depending on the distance between injection and producing wells. Interpreting the result of CO2 injection test as exhibited in Figure 3 (and also Figure 4 as will be discussed later) indicates that a near miscible condition may occur between pressures of 2750 and 2960 psig as demonstrated by a steep increase in oil recovery. It may be expected then that a near miscibility displacement could take place within radius of 50 to 235 feet from the injection well. For a larger radius, there would be an immiscible fashion. This is a very important point drawn from the laboratory CO_2 injection test and a critical one when formation fracturing pressure is considered.

The result of CO_2 gas injection conducted on the core sets is shown in Figure 4, demonstrating that, at the same 1.2 PV of CO_2 injected as used in the slimtube test, the oil recovery below MMP is closely the same as that obtained from the slimtube test. As mentioned above that the CO_2 coreflood test here was conducted with a relatively high water saturation. The results may suggest that oil displacement by CO_2 at high pressure within the range of near miscibility conditions is not significantly affected by the existence of water saturation in the cores. This performance is supported by a previous study conducted by Shyeh-Yung (1991) using mixed-wet carbonate cores. Even though, the present study shows that the oil recovery difference between those obtained from coreflood and the slimtube tests tends to be larger as injection pressure approaches the bubble point of the oil, 2412 psig, and thus toward immiscible situation. In this situation, a significant oil recovery difference is obviously due to gravity effect because the displacement was horizontal in the coreflood test vertical downward in the slimtube one. In addition, core scale heterogeneity might contribute to the difference.

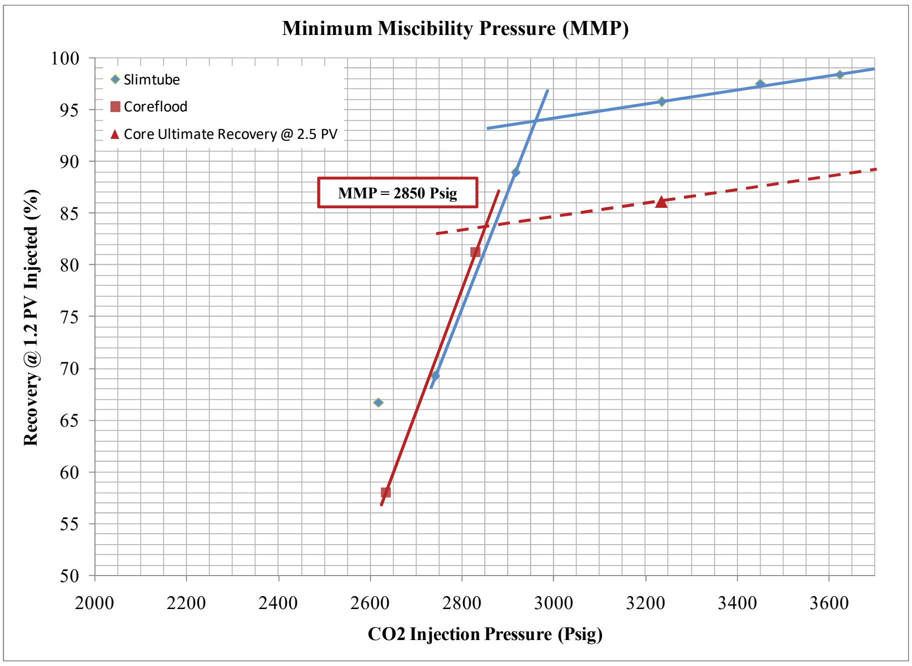

Figure 4. MMP determination by coreflood experiment (PVI = 1.2) at high temperature 270 °F

The coreflood recovery obtained at 3250 psig, which is above the MMP, is obtained only for 2.5 PVI and considerably lower than that recovered from the slimtube test at about the same pressure, 86.2% versus 95.6% of IOIP (see Figure 4). A similar coreflood result was also reported above MMP by Aleidan and Mamora (2011). Such a performance may be explained in that a stable displacement can be maintained in a slimtube at a miscible condition as the medium is homogeneous and the injection is vertically downward for which gravity effect is minimized; whereas a horizontal miscible displacement in the coreflood test may significantly be affected by core scale heterogeneity causing CO_2 fingering and gravity segregation. However, this needs a further investigation.

Therefore, this work will be continued with coreflood experiments using CO_2-silica nanoparticle foam. The advantage of using the foam is not only for increasing the displacement efficiency at macro scale but also at reservoir scale through conformable action of the foam. The next stage of this work is going to investigate first the stability of the foam at a very high temperature as no previous effort has been attempted for such a condition.

4. Conclusions

Very high temperature CO_2 flood recovery of a live paraffinic oil was investigated by conducting experiments on both a slimtube porous medium and real sandstones. The followings are withdrawn from the results:

1. The MMP obtained from slimtube tests is 2960 psig, which is about 500 psig above the bubble point pressure of the oil, 2427 psig.
2. The results of slimtube test conducted in the present study provide very important information and are critical when eventually it is found that the MMP is relatively close to fracturing pressure of the Formation.
3. Oil recoveries below the MMP obtained from the coreflood tests are not much different as compared with those of the slimtube tests at the same pressure.
4. The presence of high water saturation in the cores did not affect on CO_2 coreflood oil recovery at near miscibility conditions. This result supports the previous published investigation.
5. Considerable lower oil recovery above the MMP obtained from the coreflood tests, as compared with the slimtube results, provides information for further work on an investigation of CO_2-silica nanoparticle foam stability at a very high temperature to be used for further coreflood study.

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