Article

Minimum Miscibility Pressure and Swelling Factor Determinations of Carbondioxide Gas Injection Application in the KHL Oil Field

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Abstract: Minimum miscibility pressure (MMP) and oil swelling are two important factors of carbondioxide (CO_2) gas displacement mechanism occurred in the reservoir relate to application of CO_2 injection in the field to enhance oil recovery. In this paper determination of minimum miscibility pressure (MMP) between crude oil samples with carbondioxide gas conducted using two methods, i.e. correlation methods and laboratory experiment using slimtube. While, determination of swelling factor was conducted using PVT cell, where recombined fluid injected and conditionally at the reservoir temperature. The results of MMP using empirical equation (2807 Psig) and Holm & Josendal correlation (2750 Psig) is more approximate to the result of laboratory analysis (2805 Psig). The result of swelling test during injection CO_2 gas processes until 46.82% mole, shows that bubble point pressure is increasing gradually from 410 psig through 2200 psig, and swelling factor was also increase from 1.0 through 1.442. Based on the value of fracture pressure of Layer F in the KHL Field is 2200 Psig and MMP is 2805 Psig, hence the application of CO_2 gas injection in the field only could be conducted as immiscible flooding.

Keywords: minimum miscibility pressure (MMP); swelling factor; carbondioxide (CO_2); slimtube.

1. Introduction

The injection of carbon dioxide (CO_2) is very effective for increasing oil recovery and it is a proven technology in the enhanced oil recovery (EOR). The success of this CO_2 injection depends heavily on several parameters, such as the injection pressure, oil swelling, wettability, interface tension, rock permeability, viscosity ratio, °API of oil, fluid saturation, and reservoir heterogeneity [1]. Some research about CO_2 has been done by previous researchers both in terms of feasibility studies, [2,3,4,5,6], technical studies [7,8] and laboratory experiments [9]. From those studies, it can be concluded that the main factors causing success in CO_2-EOR include the decrease in oil viscosity [8,9,10,11], oil volume expansion [1,12,13,14], oil extraction and evaporation [9,15,16], injection pressure [1,16,17,18,19], and solution gas drive [17,20].

Based on reservoir characteristic parameters in the initial screening criteria and CO_2 source availability in the field, it is recommended for Layer F of KHL Field be chosen for CO_2 injection implementation [2]. In order to support the feasibility of applying CO_2 gas injection, it is necessary to determine the minimum miscible pressure (MMP) and swelling factor between oil samples from Layer F with CO_2 gas as the fluid to be injected. If the miscibility condition is achieved in the injection or pressurization process above minimum miscibility pressure, then the pressurization will be efficient and an optimal increase of oil recovery is obtained, however, pressurization below the minimum miscibility pressure can still increase oil recovery significantly.

The study presented in this paper is a laboratory study related to the application of CO_2 flooding in Layer F of KHL Oil Field, including determination of the minimum miscible pressure (MMP), swelling test analysis to determine the swelling factor and observation of oil recovery increase at several injection pressures below and above MMP using continuous CO_2 gas injection method. This laboratory study was conducted at PPPTMGB "Lemigas" Jakarta.

2. Basic Concept and Methods

The CO_2 injection (well known as miscible CO_2 injection) is performed by injecting CO_2 into a reservoir through injection well to displaced oil in the reservoir to the production wells. CO_2 is a stable molecule where one carbon atom binds two oxygen atoms. The molecular weight of CO_2 is 44.01, with 87.8 ^{0}F of critical temperature and 1071 Psia of critical pressure [12]. There are several reason why CO_2 is used as injected gas: easy to obtained and relatively affordable compared to other gas; CO_2 is miscible in oil and water; CO_2 injection could produce 60 - 90 % of OOIP [1], and CO_2 can act as "flooding agent" - a miscible substance that can act as displacing fluid [9,21].

Stalkup, Jr., [1] states that the mechanism of CO_2 injection in the reservoir is that oil swelling (since CO_2 is very easy to miscible in oil), reduces oil viscosity (more effective than N_2 or CH_4), reduces the interfacial tension between oil and CO_2/oil phase at the miscible area, and create miscibility when the injection pressure is high enough (greater than minimum miscibility pressure/MMP).

CO_2 source used in the injection process is an important parameter to be considered regarding the injection volume required for the CO_2 injection program. The available CO_2 source must be relatively pure since some gas component such as methane can increase the minimum miscible pressure, and the other gas component such as hydrogen sulfide is dangerous, smells, and causes a serious environmental problem. The best CO_2 source can be the CO_2 that is produced from a production well or the CO_2 that is produced from a gas factory. The other sources are the stock gas from coal-fired; acid gas separation of oil fields - as exhaust gas from power plants; limestone calcination facilities; and waste products from cement factories. The gas released from an ammonia plant can be the other alternative [1,9].

2.1. Screening Criteria

Screening criteria for selecting the best EOR method for an oil field is based on the "Implemented Technology Case", which is the current implied technology or at least has been proven applicable in an oil field [22]. The technology includes thermal methods, chemical injection, and miscible displacement as shown in **Table 1**.

When **Table 1** is used, there will be several EOR methods that are applicable in one oil reservoir. To determine which one is the best method to be performed (the method that economically gives the optimum oil recovery), further research of laboratory study, mathematical model (simulation), and pilot test on the field is required. **Table 1** will give options on the homogenous reservoir [22]. For a heterogenous reservoir with fractures, faults, lateral discontinuity, or an oil reservoir with a gas cap; further study is required to find the impact of the reservoir heterogeneity on each EOR method [9].

According to Taber, J.J., Martin, F.D., and Seright, R.S., [22], the parameters that influence the selection of the EOR method can be divided into 2 (two) groups: oil physical properties (oil gravity, oil viscosity, and oil composition) and reservoir characteristic (oil saturation, reservoir lithology, net sand thickness, porosity, permeability, reservoir depth, and reservoir temperature). Meanwhile, the reservoir water brine properties such as salinity and solids content are used as a supportive parameter.

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Table 1. Screening Criteria of EOR Methods [22]

		Oil Properties			Reservoir Characteristics					
Detail Table in Ref. 16	EOR Method	Gravity (°API)	Viscosity (cp)	Composition	Oil Saturation (% PV)	Formation Type	Net Thickness (ft)	Average Permeability (md)	Depth (ft)	Temperature (°F)
Gas Injection Methods (Miscible)										
1	Nitrogen and flue gas	> 35 ↗ 48 ↗	< 0.4 ↘ 0.2 ↘	High percent of C_1 to C_7	> 40 ↗ 75 ↗	Sandstone or carbonate	Thin unless dipping	NC	> 6,000	NC
2	Hydrocarbon	>23 ↗ 41 ↗	< 3 ↘ 0.5 ↘	High percent of C_2 to C_7	> 30 ↗ 80 ↗	Sandstone or carbonate	Thin unless dipping	NC	> 4,000	NC
3	CO_2	> 22 ↗ 36 ↗ [a]	< 10 ↘ 1.5 ↘	High percent of C_5 to C_{12}	> 20 ↗ 55 ↗	Sandstone or carbonate	Wide range	NC	> 2,500[a]	NC
1–3	Immiscible gases	> 12	< 600	NC	> 35 ↗ 70 ↗	NC	NC if dipping and/or good vertical permeability	NC	> 1,800	NC
(Enhanced) Waterflooding										
4	Micellar/ Polymer, ASP, and Alkaline Flooding	> 20 ↗ 35 ↗	< 35 ↘ 13 ↘	Light, intermediate, some organic acids for alkaline floods	> 35 ↗ 53 ↗	Sandstone preferred	NC	> 10 ↗ 450 ↗	> 9,000 ↘ 3,250	> 200 ↘ 80
5	Polymer Flooding	> 15	< 150, > 10	NC	> 50 ↗ 80 ↗	Sandstone preferred	NC	> 10 ↗ 800 ↗ [b]	< 9,000	> 200 ↘ 140
Thermal/Mechanical										
6	Combustion	> 10 ↗ 16 → ?	< 5,000 ↓ 1,200	Some asphaltic components	> 50 ↗ 72 ↗	High-porosity sand/ sandstone	> 10	> 50[c]	<11,500 ↘ 3,500	> 100 ↗ 135
7	Steam	> 8 to 13.5 → ?	< 200,000 ↓ 4,700	NC	> 40 ↗ 66 ↗	High-porosity sand/ sandstone	> 20	>200 ↗ 2,540 ↗ [d]	< 4,500 ↘ 1,500	NC
—	Surface mining	7 to 11	Zero cold flow	NC	>8 wt% sand	Mineable tar sand	> 10[e]	NC	> 3:1 overburden to sand ratio	NC

NC = not critical.
Underlined values represent the approximate mean or average for current field projects.
[a]See Table 3 of Ref. 16.
[b]> 3md from some carbonate reservoirs if the intent is to sweep only the fracture system.
[c]Transmissibility > 20 md-ft/cp
[d]Transmissibility > 50 md-ft/cp
[e]See depth.

2.2. Minimum Miscible Pressure

Minimum miscible pressure (MMP) is the minimum displacement pressure where gas can be dissolved in the displaced oil through a multi-contact mechanism or dynamic miscibility process. In the dynamic miscibility process, the injected gas will vapourize the intermediate component of hydrocarbon in the crude oil based on vaporizing gas drive mechanism [1].

The minimum miscible pressure can be obtained in three ways, i.e. using the equation of state, correlations, and performing laboratory experiments [1]. The MMP can be determined empirically with the equation presented by Stalkup, Jr., [1] as follows:

$$MMP = -329.558 + (7.727 \times MW \times 1.005^{T}) - (4.377 \times MW) \quad (1)$$

where:

$$T = 0.015\ Depth + 77.45 \quad (2)$$

MW = Molecule Weight of C_{5+}

$$MW = \left(\frac{7864.9}{G}\right)^{\frac{1}{1.0386}} \quad (3)$$

G = Oil Gravity (°API)

The correlations between oil and gas in MMP determination has been developed by several researchers such as Holm and Josendal [17], Yellig and Metcalfe [18], Mungan [19], Yellig [16] also Stalkup, Jr., [1]. The MMP determination using correlations are shown in **Figure 1** through **Figure 4**.

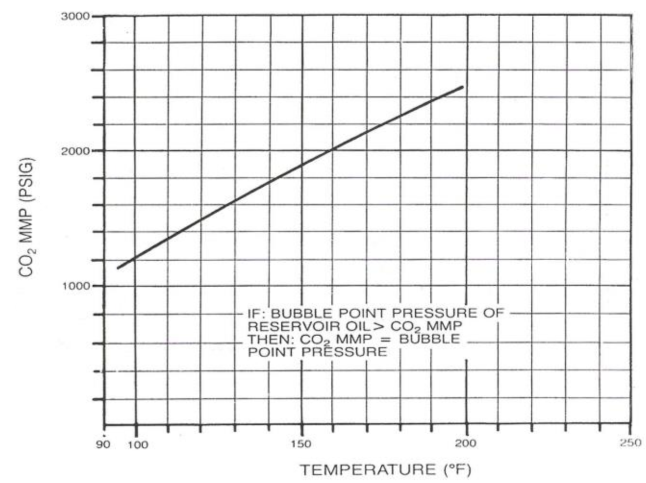

Figure 1. Temperature vs minimum miscible pressure correlation of Yellig and Metcalfe [18]

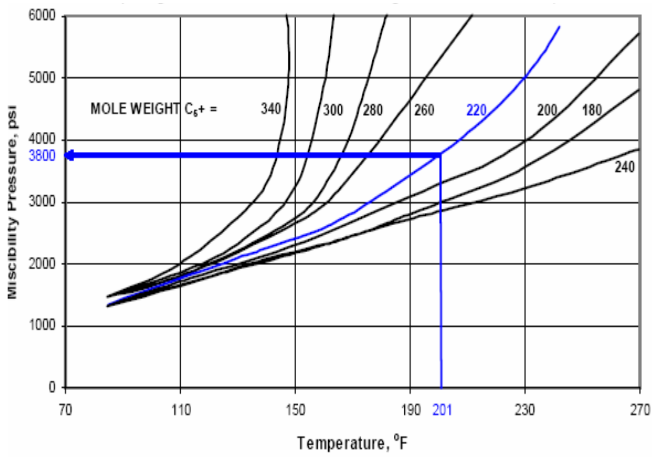

Figure 2. Minimum miscible pressure correlation of CO_2 injection as a function of temperatur from Mungan [19]

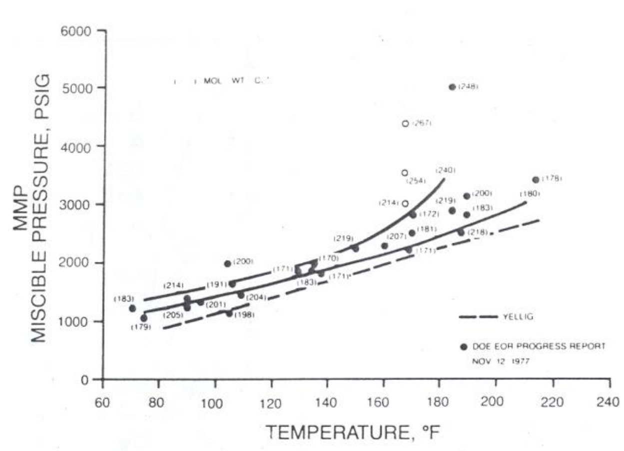

Figure 3. Minimum miscible pressure correlation of CO_2 injection from Holm & Josendal [17] and Yellig [16]

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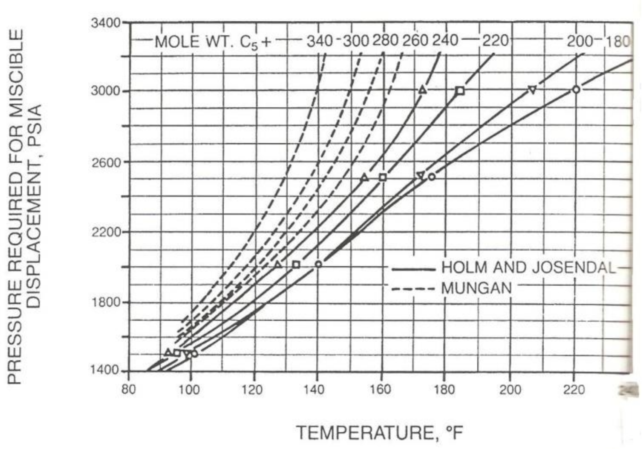

Figure 4. Minimum miscible pressure correlation of CO_2 injection from Holm, Josendal, and Mungan [1]

These correlations describe the relationship between the MMP with the temperature, light fluid components (C_1, N_2, CO_2), intermediate components (C_2-C_6), C_5-C_{30} contain, impurities (N_2 and H_2S), C_{7+} molecule weight, oil molecule weight, oil density, and the oil type (aromatic, naphthenic, paraffinic). It can be concluded that every correlation has a different variable. Therefore, to choose the correlation used, its better use the same oil composition and the oil type as used in the correlation.

The MMP can also be determined by performing laboratory experiments using Slimtube [1]. The Slimtube as shows in **Figure 5**, describes a stable and low dispersion displacement process, where the oil displacement is rely on phase behavior. The crude oil is put in the Slimtube and then displaced by gas at a certain pressure. After the displaced volume reaches 1.2 of the gas pore volume, the oil production is calculated as the recovery factor. If the addition of higher-pressure results in a relatively very small increase in oil production, then the pressure can be defined as the minimum miscible pressure.

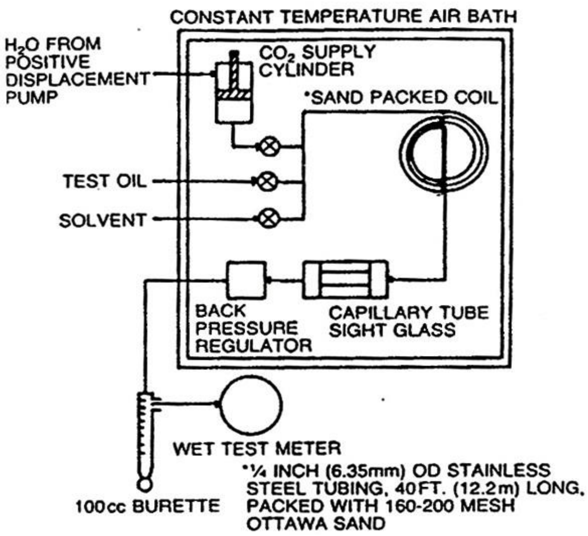

Figure 5. Schematic of Slimtube apparatus [1]

This research uses a slimtube containing quartz sand with a length of 1890 cm, tube diameter of 0.639 cm, porosity of 25.7%, a permeability of 15.803 darcy, and a pore volume of 155.838 cc at 120 ºC. Furthermore, the Slimtube is filled with crude oil with the composition of H_2S, CO_2, N_2, C_1, C_2, C_3, i-C_4, n-C_5, C_6, and C_{7+}, with variations of displacement pressure is 1200, 1300, 1380, 1400, 1500 Psig. The result of oil recovery from CO_2-oil displacement at each pressure is shown in **Figure 6**.

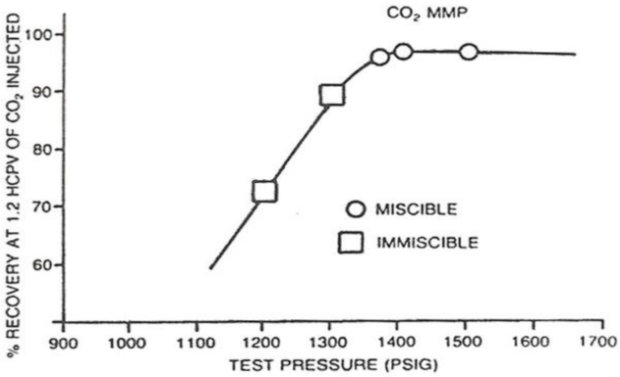

Figure 6. MMP determination on CO_2-Oil displacement [1]

Figure 6 shows that the oil recovery when the displacement pressure is below MMP will increase along with the increase of displacement pressure. The phenomena occurs both in the oil recovery at breakthrough, displacement of 1.2 pore volume (PV) and blowdown. Furthermore, for displacement at and above TTM, the increase in displacement only resulted in a relatively small increase in oil recovery. This occurs at breakthrough, 1.2 pore volume, and at blowdown. Therefore, it can be decided that the magnitude of TTM is 1380 Psig. After this pressure, the addition of pressure only increases the oil recovery slightly.

2.3. Swelling Factor

The presence of CO_2 gas dissolved in oil will increase the volume of oil. This increase in volume is expressed by a quantity called the swelling factor, which is "The ratio of the volume of oil that has been filled with CO_2 to the initial oil volume before being filled with CO_2, if the magnitude of this swelling factor is more than one, it indicates the presence of expansion". Simon and Graue [13] said that the swelling factor is influenced by the mole fraction of CO_2 dissolved in the oil (XCO_2) and the size of the oil molecules formulated by the ratio of molecular weight density (M/ρ). Particularly, the results of Wellker and Dunlop [12] showed that the swelling factor is also influenced by pressure and temperature as shows in **Figure 7**.

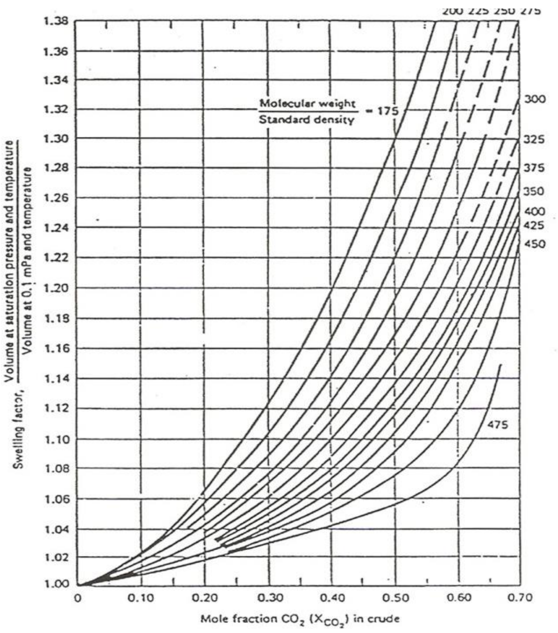

Figure 7. Swelling factor vs CO_2 mole fraction [12]

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3. Results and Discussion

3.1. Screening Criteria of F Layer

The mapping of Layer F of KHL Field is carried out to evaluate the feasibility of the CO_2 flooding application. The crucial part is reservoir characterization of reservoir rock physics, reservoir fluid physics and chemistry, and reservoir conditions. This characterization served as a discretion and input for laboratory studies and reservoir simulation of applied CO_2 injection in Layer F, either during pilot project and full-scale application [2].

Based on EOR screening criteria Taber, J. J., Martin, F. D., and Seright, R.S. [22] in **Table 1**, for Layer F of KHL Field, when adjusted with the most affecting factors and parameters in EOR method screening (oil characteristics and reservoir characteristics), then EOR method using CO_2 gas injection is appropriate, or considered to be feasible for field application. Screening results of Layer F is shown in **Table 2.**

Table 2. Screening criteria result of CO_2 flooding in Layer F of KHL Field based on Taber, J. J., Martin, F. D., dan Seright, R.S. [22]

Reservoir Characteristics	Layer F of KHL Field	Immiscible Flood		Miscible Flood		Chemical Injection			Thermal Injection	
		Water Flooding	Gas Flooding	CO2	N2 (Inert Gas)	Surfactant	Alkaline	Polymer	Steam Flooding	Insitu Combustion
Reservoir Characteristics										
Type of Lithology	Limestone	Sandstone and Limestone	Sandstone and Limestone	Sandstone or Limestone with minimum	Sandstone or Limestone with minimum	Sandstone (more prefer)	Sandstone (more prefer)	Sandstone (more prefer)	Sandstone	Sandstone
Porosity, %	16 - 23	>10	>10	NC	NC	>15	NC	>15	High Porosity	High Porosity
Oil Saturation (%PV)	55.8	>30	>20	>20	>40	>35	>35	>50	>40	>50
Permeability, mD	5 - 42	>10	NC	NC	NC	>10	>10	>100	>200	>50
Thicknes, ft	6	NC	NC	Relatively thin, unless formation dip is low	Relatively thin, unless if formation dip is high	NC	NC	NC	>20	>10
Well Depth, ft	3927	NC	>1800	>2500	>6000	<8000	<9000	<9000	<11500	>4500
Temperature, °F	201	NC	NC	NC	NC	<175	<200	<200	NC	>100
Reservoir Fluids Properties										
Oil Gravity, °API	34.29	>20	>12	>22	>35	>20	>20	>15	8-13.5	>10
Oil Viscosity, cp	2.24	<35	<600	<10	<0.4	<35	<35	<150	<20000	<5000
Oil Composition	C1 - C7+	NC	NC	High percent of C5 to C12	High percent of C1 to C7	Light to Intermediate	Light to Intermediate	NC	NC	Some Asphaltic Component
Total Score		30	29	30	22	24	23	19	16	14

Noted: Red = 1; Yellow = 2; Green = 3

CO_2 injection is commonly carried out with injecting a certain amount of CO_2 (30% or more than hydrocarbon PV) into the reservoir. CO_2 is not instantly mixed with oil during the first contact, but after going through gradual contacts or multiple contacts. CO_2 extracts light-to-medium hydrocarbon components; and if the pressure is high enough, it would form a mixture to displace oil films from the rocks. Over the depths less than 1,800 ft, reservoir is considered not qualified to meet the technical screening criteria of miscible CO_2 injection.

Furthermore, oil reservoirs with API gravity greater than 22 °API, is qualified to meet the technical screening criteria of immiscible CO_2 injection with the injection pressure is set to be less than minimum miscible pressure (MMP). Immiscible CO_2 flooding is commonly less effective, yet it would still gain more oil recovery than water injection. Besides, CO_2 gas source with exceptional quality is paramount, which has minimal-to-no content of water (H_2O) nor dry gas.

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3.2. Minimum Miscibility Pressure Determination (MMP)

Minimum Miscibility Pressure (MMP) is referred as the lowest pressure where gas is soluble with oil. Minimum miscibility pressure determination of Well J-108 using CO_2 gas is carried out with 3 (three) methods, namely using empirical equation, correlation, and laboratory experiments using slimtubes. Oil samples are taken from Well J-108, operating at Layer F (depth: 3927 ft) which has reservoir pressure of 1706 psig, temperature of 201 ^{0}F, formation fracture pressure of 2200 psig, with API gravity of 34.29 ^{0}API.

Minimum miscibility pressure determined from empirical equation (Equation 1) obtained a value of 2807 psig, whereas the one determined from several correlations, namely Cronquist's correlation [1], Yellig and Metcalfe correlation [18], and Holm and Josendal correlation [17] is shown in **Table 3**.

Tabel 3. MMP determination results based on correlations

Correlations	Minimum Miscibility Ptessure, Psig
Cronquist (Stalkup, 1983)	2301
Yellig & Metcalfe (1980)	2490
Holm & Josendal (1974)	2750

The next step is an experimentation of MMP determination in PPPTMGB "Lemigas" laboratory carried out by using a slimtubes with 1890 cm in length and 0.64 cm in diameter, filled to the brim with quartz sands which has a permeability around 1 Darcy, then put inside a heater oven. MMP determination using slimtubes in a laboratory is shown in **Figure 8** and carried out with procedures as follows:

- Saturating slimtubes with 160 cc of dead oil at similar pressure conditions as when determining MMP.
- Slimtubes then injected with recombined fluids from the oil sample from Well J-108 at the pressure above bubble-point pressure.
- Then, injecting CO_2 at similar pressure into the slimtubes. Write down or measure all crucial parameters that occurred during the experiment.
- Injection then stopped after 1.2 PV of injected CO_2 is achieved.
- Next step is cleaning out the slimtubes, then all procedures above is repeated with higher injection pressure, and write down or measure all crucial parameters that occurred during the experiment.
- The experiment is concluded when adding more injection pressure does not result in a significant increase of incremental oil recovery.
- Pressure where it does not result in a significant increase of incremental oil recovery can be determined as Minimum Miscibility Pressure (MMP).
- In this experiment, CO_2 gas injection is carried out at reservoir temperature of 94^{0}C for a variety of injection pressure, which are 2300, 2650, 2750, and 3250 psig.

Figure 8. MMP determination apparatus in laboratory using slimtubes

From this laboratory experiment using slimtubes, we obtained CO_2 gas MMP value of 2805 psig with the oil sample from Well J-108. Summary of oil recovery measurement results

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using slimtubes for a variety of CO_2 injection pressure is shown in **Table 4** and graphically shown in **Figure 9**.

Table 4. Oil recovery results using slimtubes in laboratory

Injection Pressure, Psig	Oil Recovery prior to Breakthrough, %	Total Oil Recovery, %
2451.02	78.45	85.64
2659.52	80.27	92.96
2947.55	96.62	98.47
3364.98	97.04	99.41

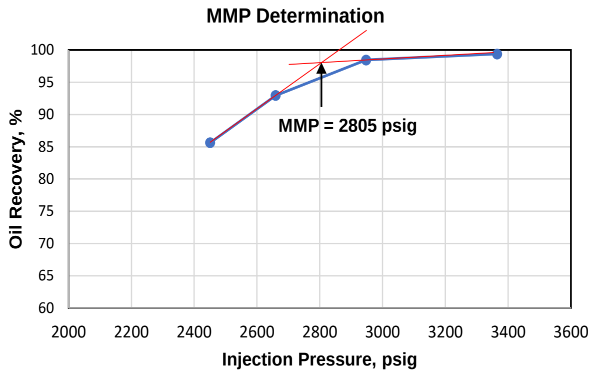

Figure 9. Plot of MMP tetermination results using slimtubes in laboratory

Based on **Table 4** and **Figure 9**, we observed that oil recovery when the injection pressure is below MMP, would increase along with the increase of injection pressure. This occurs either in oil recovery at breakthrough, and when injected up to 1.2 pore volume (PV). Then when the injection pressure is already at or above the MMP, adding more injection pressure would only result in relatively minor increase in oil recovery. Hence, in this case, we can conclude that the value of MMP is 2805 psig.

Furthermore, based on the results of MMP determination using empirical equation, it is found at the value of 2807 psig, and from Holm & Josendal Correlation (1974) is found at the value of 2750 psig. Then, it is concluded that the assumptions used in those 2 methods of determining MMP matched the reservoir characteristics of Layer F, since it has the exact same composition and oil type with the sample used in lab experiment. This can be observed from the results of MMP determination based on correlation and empirical equation mimicked the laboratory experiment using slimtubes which resulted in 2805 psig.

3.3. Swelling Test

Swelling test is carried out using PVT cell, where recombined fluids are injected and conditioned at reservoir temperature of 201°F. Then, an analysis of pressure-volume relationship is carried out to determine bubble-point pressure from various levels of pressure up until bubble-point pressure of 410 psig is achieved. Next step, a certain amount of CO_2 is injected into the PVT cell, CO_2 volume is then recorded, then repeating the same pressure-volume analysis to determine bubble-point pressure. This process is repeated 4 (four) times, with adding the amount of injected CO_2. Injected CO_2 volume increase surely would increase the oil swelling occurrence, as it would on bubble-point pressure. This injection process is then continued up to the point where the bubble-point pressure is on the verge of minimum miscible pressure. Results of this swelling test is tabulated in **Table 5** for swelling factor and CO_2 solubility. Changes in reservoir fluid composition during CO_2 injection is shown in **Table 6**. A correlation between swelling factor and saturation pressure is shown graphically in **Figure 10**, whereas a correlation between saturation pressure and injected CO_2 mole percentage is shown in **Figure 11**.

From **Table 5** its shows that during CO_2 injection up to 46.82% mole, bubble-point pressure increased gradually from 410 psig to 2200 psig, and swelling factor also increased from 1.0 to 1.442. With the increase of CO_2 injection and saturation pressure, followed by the increasing amount of CO_2 soluble in oil; would cause a decrease in oil density, so then oil volume expansion would occur more, indicated by the increase of swelling factor number, as shown in **Figure 10**. This also meant that the bigger the amount of CO_2 dissolved in hydrocarbon, would incur an increase of CO_2 concentration (% mol) and changes in fluid composition, mainly the amount of C_{7+} would decrease, as shown in **Table 6** and **Figure 11**.

Table 5. Experiment results of oil swelling test

Reservoir System	CO_2 Injection, SCF/STB	Saturation Pressure, psig	CO_2 Solubility, SCF/BBL Reservoir*)	Swelling Factor, fraction**)
Original Reservoir Oil	0.00	410	0.00	1.00
CO_2 / Oil System I	104.61	700	130.35	1.1215
CO_2 / Oil System II	219.39	1200	253.22	1.1755
CO_2 / Oil System III	556.74	1700	615.22	1.3446
CO_2 / Oil System IV	763.83	2200	836.77	1.4421

*) at current reservoir condition; **) Ratio of volume at saturation pressure

Table 6. Experiment results of changes in reservoir fluids composition

Components	Original Reservoir Oil Mol %	CO_2 / Oil System I Mol %	CO_2 / Oil System II Mol %	CO_2 / Oil System III Mol %	CO_2 / Oil System IV Mol %
Hydrogen Sulfide (H_2S)	0.0000	0.0000	0.0000	0.0000	0.0000
Carbon Dioxide (CO_2)	2.5947	7.9181	18.4611	38.7266	46.8176
Nitrogen (N_2)	0.2457	0.3793	0.3359	0.2524	0.2191
Methane (C_1)	4.8792	4.3542	3.8557	2.8974	2.5148
Ethane (C_2)	0.5293	0.4859	0.4303	0.3233	0.2806
Propane (C_3)	0.8971	1.5529	1.3751	1.0333	0.8969
Iso-Butane (i-C_4)	0.3658	0.6937	0.6142	0.4616	0.4006
n-Butane (n-C_4)	0.6585	1.6353	1.4480	1.0881	0.9445
Iso-Pentane (i-C_5)	0.6642	1.3658	1.2094	0.9088	0.7888
n-Pentane (n-C_5)	0.6722	1.7831	1.5790	1.1865	1.0299
Hexane (C_6)	2.2972	3.4126	3.0218	2.2708	1.9710
Heptane plus (C_{7+})	86.1961	76.4191	67.6695	50.8512	44.1362
Total	**100.0000**	**100.0000**	**100.0000**	**100.0000**	**100.0000**

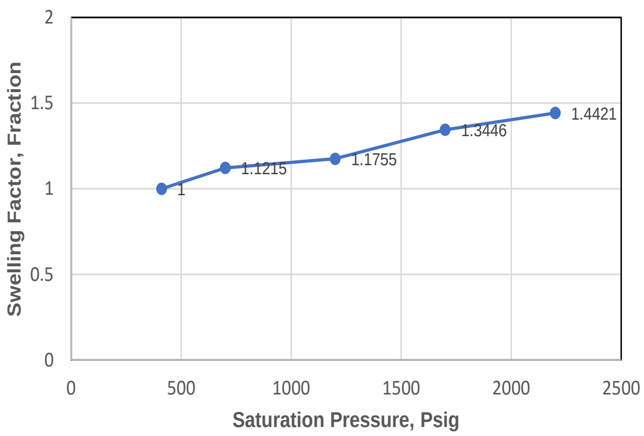

Figure 10. Correlation results of swelling factor to saturation pressure

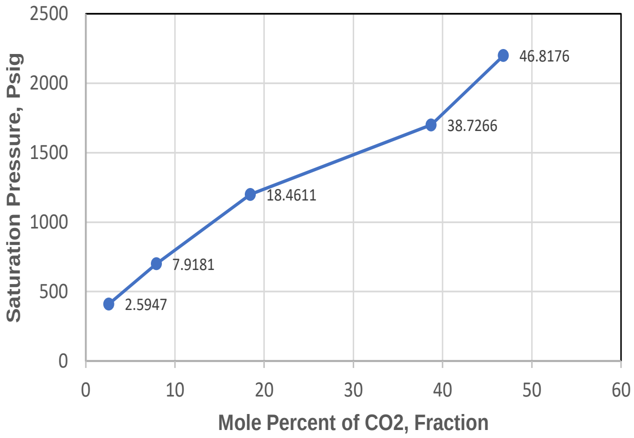

Figure 11. Correlation results of saturation pressure vs injected CO_2 mol %

4. Conclusions

Based on the results of the analysis and discussion that has been thoroughly executed, the conclusions can withdraw as follows:

1. The magnitude of the minimum miscible pressure (MMP) between J-108 oil and CO_2 gas based on the empirical equation is 2807 Psig; Cronquist correlation is 2301 Psig; Yellig and Metcalfe is 2490 Psig; Holm and Josendal is 2750 Psig, while based on measurements in the laboratory using a slimtube is 2805 Psig.
2. Factors that affect the miscibility of CO_2 gas with oil are CO_2 purity, oil composition, temperature, and depth.
3. The swelling test during the CO_2 gas injection process up to 46.82% mole and bubble pressure conditions increased gradually from 410 Psig to 2200 Psig, it was found that the swelling factor increased from 1.0 to 1.442.
4. Based on the magnitude of the formation fracture pressure in the Layer F of 2200 Psig and MMP of 2805 Psig, in its application in the Layer F of KHL Field, CO_2 gas injection can only be implemented in an immiscible flooding.

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