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Experimental Investigation of the Effects of Temperature and Oil Composition on CO_2-Crude Oil Swelling, Extraction Mechanisms, and Displacement Performance

Kartika Hartono[1]*, **Asep K. Permadi**[2], **Ucok W. R. Siagia**[2], **Andri L. Hakim**[2], **Sumadi Paryoto**[3], **Ahlul H. Resha**[4], **Syaeful A. Satya**[4], **Reno Pratiwi**[1], **Maman Djumantara**[1], **Dina A. Chusniah**[1]

[1] *Petroleum Engineering Department, Faculty of Earth Technology and Energy, Universitas Trisakti, West Jakarta 11440, Indonesia.*
[2] *Petroleum Engineering Department, Faculty of Mining and Petroleum Engineering (FTTM), Institut Teknologi Bandung, Bandung, West Java 40132, Indonesia.*
[3] *Upstream Research and Technology Innovation (URTI), PT. Pertamina, South Jakarta 12920, Indonesia.*
[4] *Laboratory Enhanced Oil Recovery, Research and Technology Innovation (RTI), PT. Pertamina, East Jakarta 13920, Indonesia.*

Abstract

CO_2 flooding has several advantages for enhancing oil recovery, including a reduction in crude oil viscosity, a decrease in interfacial tension, and an increase in oil volume through swelling. Although the mechanisms of oil swelling and extraction in CO_2–crude oil systems have been widely studied, the combined effects of temperature and oil composition on these mechanisms – and their influence on CO_2 displacement efficiency in porous media – remain insufficiently understood, especially under high reservoir temperatures. Therefore, this study investigates how temperature and crude oil composition affect swelling-extraction behaviour and CO_2 displacement efficiency. High-pressure and high-temperature (HPHT) PVT tests were conducted to evaluate swelling and extraction phenomena, while slim tube experiments were used to assess oil recovery performance. Tests were carried out at 70°C and 90°C using two light dead oils from an Indonesian field under varying injection pressures. Compositional analysis of produced oils was performed using Gas Chromatography (GC) and further interpreted through SARA fractions (saturates, aromatics, resins, and asphaltenes). Results show that lower temperatures enhance CO_2 extraction efficiency due to higher CO_2 density, leading to more pronounced swelling and miscibility effects. The miscibility was observed within the extraction region, emphasizing the role of hydrocarbon extraction in the miscibility mechanism. Higher temperatures were found to improve oil recovery, primarily due to viscosity reduction. Additionally, increasing CO_2 injection pressure reduced resin and asphaltene content, with evidence of asphaltene precipitation in the porous medium – particularly at lower temperatures. These findings provide valuable insight into how temperature and oil composition influence CO_2–oil interactions and support more effective implementation of CO_2 flooding at elevated reservoir temperatures.

Keywords:
CO_2 flooding, Swelling-extraction mechanisms, Miscibility, Asphaltene precipitation, Oil Recovery, SARA fractions

1. Introduction

CO_2 flooding is a promising Enhanced Oil Recovery (EOR) method that has successfully increased oil production (**Ghorbani et al., 2014; Hartono et al., 2021; Zhang et al., 2019**). The fundamental mechanism between CO_2 and crude oil interactions is shown in CO_2 solubility (**Rezk & Foroozesh, 2019**). During the interaction of CO_2 in hydrocarbon oils, the CO_2 will diffuse into these oils and cause the oils to swell (**Holm & Josendal, 1974; Wei et al., 2017; Yang & Gu, 2006**). The swelling phenomenon will help crude oil obtain several advantageous characteristics in oil recovery, such as lower viscosity, interfacial tension (IFT) reduction, and a larger volume. Furthermore, CO_2 has the ability to extract or vaporize light to intermediate hydrocarbons from crude oil. The extraction mechanism of CO_2-hydrocarbon becomes the principle in developing multi-contact miscibility (**Permadi et al., 2021; Siagian & Grigg, 1998; Yellig, 1982**). Therefore, the swelling and extraction phenomena in the CO_2 and crude oil interactions are the fundamental mechanisms for oil recovery. An increase in CO_2 injection pressure enhances both its solubility in oil and the oil swelling effect. Conversely, raising the temperature reduces CO_2 solubility, as CO_2 molecules become more active at elevated temperatures, which diminishes their interaction with crude oil (**Fakher & Imqam, 2020; Svrcek et al., 1982**). **Fakher & Imqam (2020)** concluded that oil swelling strongly

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* Corresponding author: Kartika Hartono
e-mail address: kartika@trisakti.ac.id

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depends on CO_2 injection pressures and reservoir temperatures. Many studies investigated the oil swelling and extraction mechanisms in the interactions of CO_2 and crude oil systems. Also, the swelling and extraction mechanisms have received attention from several researchers to determine the miscibility pressure of CO_2 and crude oil. However, most previous studies and experiments were conducted at relatively low temperatures. Only a few have focused on its application at high reservoir temperatures and the effects of oil composition on swelling extraction mechanisms and CO_2 displacement performance. Investigating the swelling and extraction mechanisms in high-temperatures environments is important for applying CO_2 flooding at high reservoir temperatures. For example, most of Indonesia's oil fields have reservoir temperatures above 90°C. **Fakher & Imqam (2020)**, based on their data analysis, showed that most swelling tests were conducted at the temperature range of 20 – 50°C. The interpretation of the swelling test data at 20 - 50°C might differ with the higher temperature. Therefore, more swelling test data for high reservoir temperatures is needed to understand the swelling and extraction mechanisms for applying CO_2 flooding in high reservoir temperatures.

Moreover, the extraction of hydrocarbons by dense CO_2 is also strongly influenced by crude oil compositions (**Orr & Silva, 1987; Silva et al., 1987**). As the principle of multi-contact miscibility in the interaction of CO_2 and crude oil system, the extraction mechanism will significantly affect CO_2 displacement performance, such as oil recovery. As previously mentioned, only a few studies have investigated the effects of temperatures and oil composition on swelling extraction mechanisms and CO_2 displacement performance. Therefore, the comprehensive study investigated the effect of temperature and crude oil compositions on swelling–extraction mechanisms and the impact on CO_2 displacement performance, particularly in high reservoir temperatures, are limited. Understanding the effect of temperatures and oil compositions on CO_2 EOR fundamental mechanisms such as swelling-extraction and CO_2 flow mechanisms in porous media is vital to optimizing CO_2 flooding process implementation. **Siagian & Grigg (1998)** studied the capacity of CO_2 in extracting hydrocarbons from crude oil as a function of pressure at relatively low temperatures of 35°C and 59°C and compared the results with the slim tube experiments. The findings showed that the CO_2 extraction capacity increased with increasing pressure and formed a sharp transition pressure range which corresponded effectively with the slim tube breakpoint or Minimum Miscibility Pressure (MMP). They considered that the sharp transition pressure range could be used to estimate the MMP reasonably. However, their study did not investigate the effect of change in crude oil composition due to the extraction of light–intermediate hydrocarbon on CO_2 displacement performance. **Tsau et al. (2010)** investigated the effect of temperature on swelling and extraction at 37°C – 52°C with a small sample size of 3-14 cc. They showed that at a given pressure, the swelling factor of oil decreases with an increase in temperature. The results also showed that the pressure at which extraction starts by CO_2 depends on the initial volume of oil and temperatures. They concluded that the intersection of significant extraction lines could determine the miscibility at these temperature conditions. Abdurrahman et al., investigated the swelling phenomena at 60°C and 66°C using light crude oil samples (**Abdurrahman et al., 2015 & 2019**). They proposed three stages in swelling factor versus pressure plot: condensation stage, condensation and extraction stage, and extraction stage. They also estimated the MMP using the slim tube but did not investigate the effect of oil composition on the CO_2 displacement performance.

As discussed earlier, the extraction mechanism is a key principles of CO_2 - enhanced oil recovery and will impact displacement performance in porous media. This study aims to provide a comprehensive assessment of the effects of temperature and crude oil composition on swelling–extraction mechanisms and their subsequent impact on displacement performance efficiency. To achieve this, a series of high-pressure, high temperature (HPHT) visual PVT experiments were performed using light oil crude from an Indonesian oil field to obtain swelling data. The observation of CO_2 displacement performance was performed using a slim tube apparatus. The experiments were conducted at 90°C, representing the reservoir temperature. Then, it was re-conducted at 70°C, approximately the average of wellbore temperature condition. This study is expected to provide more data on the swelling and extraction mechanisms for implementing CO_2 flooding at high reservoir temperatures. Moreover, this study is also expected to provide insight into understanding the effect of different parameters such as, temperatures and oil compositions, on CO_2 flow mechanisms in porous media and optimizing CO_2 flooding process implementation.

2. Materials and Experimental Methods

The materials or crude samples in this study were taken from Indonesian oilfield. This experimental was conducted at different crude samples, pressures, and temperatures.

Table 1. Properties of Dead Oil Samples

Properties	JTB	RDG
API Gravity (°API)	36.4	42.6
Oil density (kg/m^3)	837	787
Oil viscosity (cp)	0.195	0.17
Molecular weight (g/mol)	187.7	174.8
Reservoir temperature (°C)	90	90
Average porosity (%)	16-33	15-23
Average permeability (mD)	22	37

Table 2. Compositions of Dead Oil Samples

JTB Oil				**RDG Oil**			
Component	**%Mole fraction**	**Component**	**%Mole Fraction**	**Component**	**%Mole fraction**	**Component**	**%Mole fraction**
nC_6	0.00	nC_{24}	3.42	nC_6	0.00	nC_{24}	2.43
nC_7	2.26	nC_{25}	3.24	nC_7	3.10	nC_{25}	2.13
nC_8	3.85	nC_{26}	2.77	nC_8	3.21	nC_{26}	1.72
nC_9	7.28	nC_{27}	2.63	nC_9	5.06	nC_{27}	1.57
nC_{10}	9.13	nC_{28}	1.87	nC_{10}	6.53	nC_{28}	1.11
nC_{11}	6.58	nC_{29}	1.69	nC_{11}	5.25	nC_{29}	1.00
nC_{12}	5.30	nC_{30}	1.02	nC_{12}	5.65	nC_{30}	0.63
nC_{13}	4.75	nC_{31}	0.90	nC_{13}	6.09	nC_{31}	0.52
nC_{14}	4.62	nC_{32}	0.50	nC_{14}	7.45	nC_{32}	0.31
nC_{15}	4.57	nC_{33}	0.42	nC_{15}	8.42	nC_{33}	0.26
nC_{16}	4.10	nC_{34}	0.16	nC_{16}	8.15	nC_{34}	0.10
nC_{17}	3.97	nC_{35}	0.11	nC_{17}	6.67	nC_{35}	0.07
nC_{18}	3.95	nC_{36}	0.00	nC_{18}	5.45	nC_{36}	0.00
nC_{19}	4.23	nC_{37}	0.00	nC_{19}	4.23	nC_{37}	0.00
nC_{20}	4.04	nC_{38}	0.00	nC_{20}	3.42	nC_{38}	0.00
nC_{21}	4.25	nC_{39}	0.00	nC_{21}	3.34	nC_{39}	0.00
nC_{22}	4.31	nC_{40}	0.00	nC_{22}	3.20	nC_{40}	0.00
nC_{23}	4.10	Total	100.00	nC_{23}	2.94	Total	100.00

Table 3. The Composition of SARA Components

SARA Contents	**JTB Crude Oil**	**RDG Crude Oil**
Saturates	61.6%	58.2%
Aromatics	26.4%	36.1%
Resins	6.9%	3.9%
Asphaltenes	5.1%	1.8%

2.1. *Materials*

Crude oil samples used in this study were dead crude oil with 42°API and 36°API obtained from the RDG and JTB Indonesian oilfield, respectively. The fluid reservoir properties and compositions of the crude oil samples are shown in **Table 1** and **Table 2**, respectively. Meanwhile, **Table 3** shows the composition of the crude oil measured based on the fractions of saturates, aromatics, resins, and asphaltenes (SARA). Moreover, the CO_2 used for gas injection was ultra-high pure (99.9%). The field's average reservoir temperature was found to be 90°C which was set as a temperature condition during experiments. The experiment was repeated at 70°C, which approximates the average of wellbore temperature condition, to observe the influence of temperature on oil swelling, extraction behaviour, and the effectiveness of CO_2 displacement.

2.2. *Experimental Apparatus*

The experiments were carried out using two main high-pressure and high-temperature (HPHT) systems. The PVT apparatus was utilized to analyze the swelling and extraction behaviour, while the slim tube apparatus was employed to evaluate oil recovery and CO_2 displacement efficiency. Additionally, fluid composition analysis was performed using the Agilent 7890B Gas Chromatography (GC) system.

2.2.1. PVT Set-up

A visual PVT cell was employed to examine CO_2–crude oil interactions under varying conditions. The cell, equipped with a sight glass and magnetic stirrer, allows real-time observation and mixing of fluids. A rotating mechanism was incorporated to accelerate phase equilibrium, while pressure control was achieved through an internal moving piston. Temperature was maintained using a thermostatically controlled oven with a circulating bath. The gas–oil interface was monitored using a high-resolution camera, and key parameters – pressure, temperature, volume, and visual data – were recorded via an integrated data acquisition system. The simplified diagram of visual PVT system is presented in **Figure 1**.

2.2.2. Slim tube Apparatus

The slim tube apparatus system used in this study was STS 700 with the specifications of high pressure and high temperature measurement. The detail specifications of the slim tube are as stated in **Table 4**. In general, the slim tube consist of a coil tube with sand pack and includes several components: high-pressure floating pis-

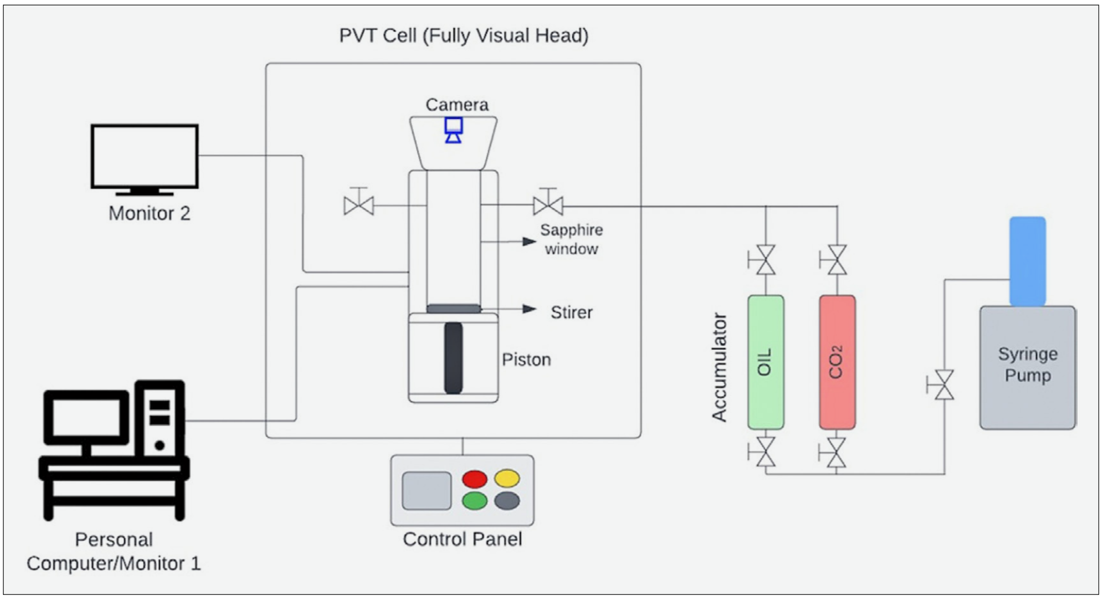

Figure 1. Schematic Diagram of Visual Fluid Eval PVT System

Table 4. The Specifications of Slim Tube Apparatus

Specification	Parameters (Units)	Values
Overall System	Maximum Pressure (Psi)	10000
	Temperature Range (°C)	Room temperature to 150°C
	Multiple Fluids	Up to 3 different fluids
	Wetted Material	Hastelloy
Injection pump	Flow Range (mL/min)	0.01 to 100 mL/min
	Delivery Mode	Constant-Flow or Constant-Pressure
	Wetted Material	Stainless Steel 316
	Dimension	25 cm x 41 cm x 97 cm
Slim tube	Length (m)	24
	Inner Diameter (mm)	4
	Porous media (µm)	Calibrated 230 – 310 µm Silica
	Average Porosity (%)	35
	Pore volume (mL)	120
Visual Cell	Material	Titanium
	Sapphire Inside Diameter (mm)	1.5
	Sapphire Outside Diameter (mm)	20
	Sapphire Length (cm)	7

ton accumulators for oil, gas, and solvent; oven with a temperature-controller; a back-pressure pump; a gasometer; a remote-control panel; and visual cell. Additionally, a densitometer is installed to monitor the density of fluids exiting the slim tube. The system is illustrated in **Figure 2**.

2.3. *Experimental Procedures*

The experiments were categorized into three main parts, which include (1) swelling/extraction using Visual Fluid Eval PVT; (2) the CO_2 displacement process using a slim tube apparatus system; and (3) compositional analysis of the effluent oils in the CO_2 flooding process which was analyzed by Gas Chromatography. Subsequently, the residual oil samples were examined to determine their SARA (Saturates, Aromatics, Resins, and Asphaltenes) fractions, following the ASTM D6560 standard method (**Ashoori et al., 2017; Santos et al., 2019**).

2.3.1. Swelling and Extraction Experimental Procedures

The swelling and extraction experiments were performed in a visual PVT cell, which was tested for any leakage using nitrogen, cleaned, vacuumed, and made ready to be filled. The cell was initially charged with a crude oil sample at atmospheric pressure, corresponding to 10% of the total cell volume, in accordance with the suggestion of **Hand & Pinczewski (1990)** recommendation that the maximum initial oil volume for swelling and shrinkage curve should not exceed 30% of the total cell capacity. The cell temperature was then elevated to the experimental reservoir condition of 90°C. Once the PVT cell reached the desired temperature stability, this was followed by an increase in the pressure in discrete steps by injecting CO_2 into the cell until it reached 4000 Psi. The cell was sealed, stirred by a magnetic stirrer, and rotated to accelerate the CO_2 and oil sample dissolution. After the oil became fully saturated with CO_2, the oil and gas volume were determined through visual digital imaging, with measurements recorded using an integrated computer system. The Swelling Factor (SF) was calculated as the ratio between the oil volume fully satu-

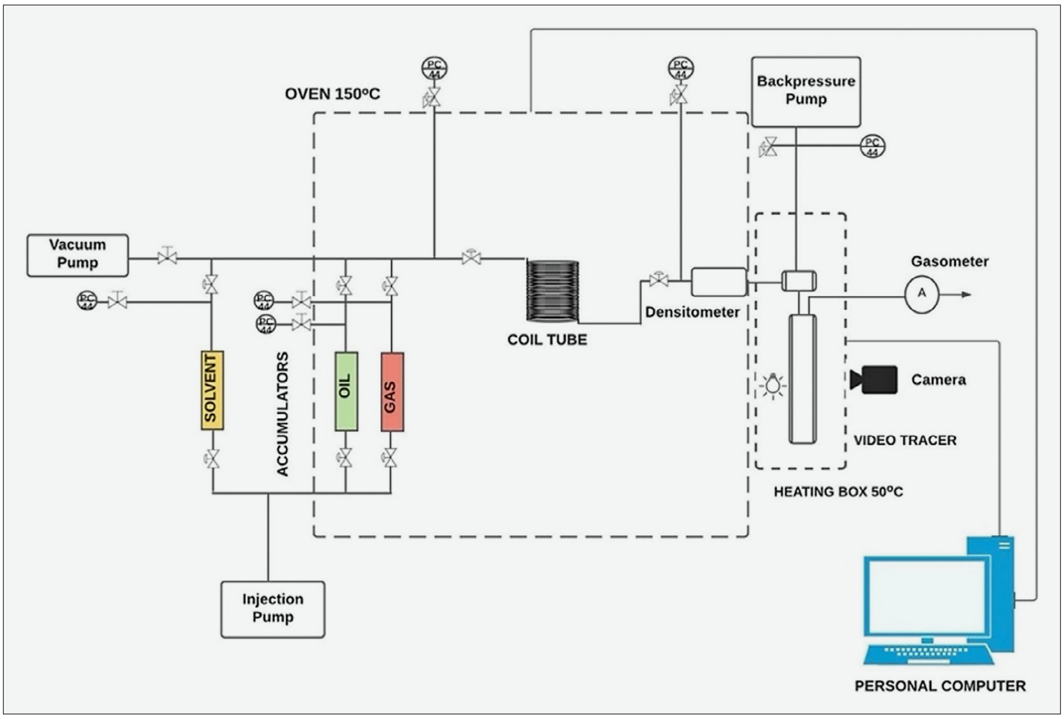

Figure 2. Schematic Diagram of Slim Tube System

rated with CO_2 at the test pressure and temperature, and the initial oil volume at atmospheric pressure under the same temperature (**Welker, 1963; Simon & Graue, 1964**). These swelling/extraction experimental procedures were repeated at the temperature of 70°C to investigate the influence of decreasing temperature on swelling and extraction mechanism.

2.3.2. Slim tube Experiment

The slim tube experiment procedure in this study was adopted from the previous work of **Hartono et al. (2024)**. Generally, the experiment was carried out into three main steps: preparation, cleaning, and coil tube saturated by the oil until reaching 1.5 pore volumes (PV), then continued with CO_2 injection. The pressure is maintained to be constant by back-pressure regulator. Subsequently, CO_2 was injected into the slim tube at a rate of 0.06 mL/min, and the effluent fluids were monitored visually through a separator equipped with a visual cell. The recovery factor of oil for each pressure condition was calculated and plotted to determine the MMP. The MMP was identified from the inflection point of the recovery curve at 1.2 PV of injected gas (**Glaso, 1990; Hudgins et al., 1990**). These experimental steps were also repeated under reservoir conditions of 70°C. In addition, the composition of the effluent oil was evaluated by gas chromatography to examine the extraction of hydrocarbon components at various pressures.

3. Results and Discussions

The discussion begins by examining how temperature and oil composition influence the swelling and extraction mechanisms. This is followed by an analysis of how these same factors affect CO_2 flow behaviour and displacement efficiency within porous media. Additionally, changes in oil composition, specifically the SARA (Saturates, Aromatics, Resins, and Asphaltenes) fractions, resulting from CO_2 injection are also evaluated to understand their impact on the overall displacement performance.

3.1. Effect of Temperature on Swelling – Extraction Mechanisms

The swelling and extraction phenomena of CO_2 and crude oil were observed at different pressures and temperatures. The results of swelling factor versus pressure at temperatures of 70°C and 90°C for JTB and RDG crude samples are shown in **Figures 3** and **4**, respectively. The swelling curves are divided into three stages, as suggested by **Abdurrahman et al. (2015) and Siagian & Grigg (1998)**. The first stage, known as the condensation region, is characterized by an increase in the swelling factor as pressure rises. The second stage represents the condensation and extraction region, where the oil phase volume drops sharply. The third stage, the extraction region, shows a more gradual decrease in oil phase volume with increasing pressure. The data indicate that the rate of oil swelling declines as temperature increases. **Figure 3** for JTB oil shows that the peak of the swelling factor at 90°C is slightly higher than 70°C. Then, the oil volume starts to decrease rapidly at 2500 Psi, indicating that some hydrocarbon components are extracted by dense CO_2. The condensation and extraction regions also show that the oil phase volume of JTB at 70°C decreases sharper than at 90°C. It indicates that CO_2 has a higher capacity to extract hydrocarbon com-

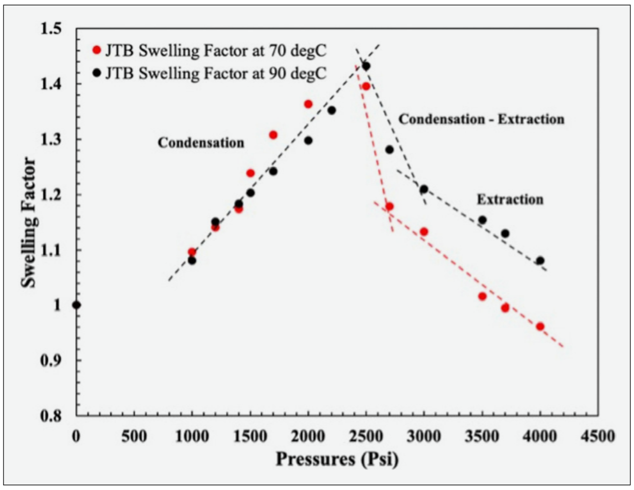

Figure 3. Swelling Factor curves of CO_2 – JTB oil sample at 70°C and 90°C with various pressures

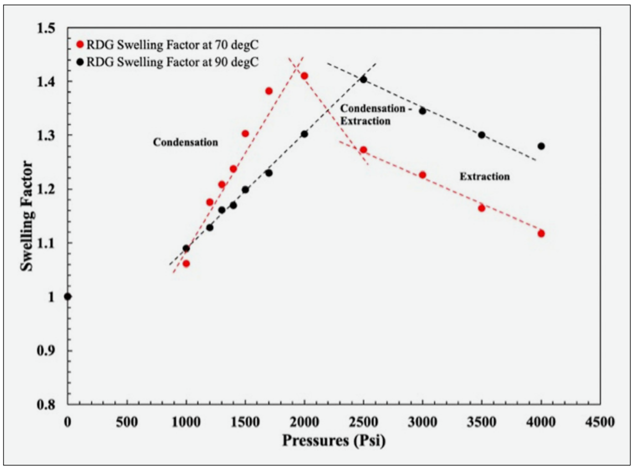

Figure 4. Swelling Factor curves of CO_2 – RDG oil sample at 70°C and 90°C with various pressures

ponents at lower temperatures than at higher temperatures at the given pressures.

Figure 4 presents the swelling factor as a function of pressure for RDG crude oil. Similar to the trend observed in JTB oil, the swelling rate at 70°C is greater than at 90°C. For the RDG sample, the maximum swollen oil volume reached almost one and half times the initial volume at both 70°C and 90°C. It was found from the figures that the rate of oil swelling decreased as the temperature increased for both samples and a similar trend was observed to have been reported by **Hand & Pinczewski (1990) and Rezk & Foroozesh (2019)**. The influence of crude oil composition on the CO_2 flooding flow mechanisms within porous media will be explained detail in the subsequent chapter.

3.2. Effect of Oil Composition on Swelling – Extraction Mechanisms

The influence of oil composition on swelling and extraction mechanisms is shown by comparing the swelling and extraction curves of JTB and RDG crude oil samples, as presented in **Figures 3** and **4**, respectively. Even though JTB oil has a higher Molecular Weight (MW) than RDG oil, the pressure required to achieve maximum swell is similar at 90°C. However, at a temperature of 70°C, the pressure required to achieve maximum swell for RDG crude samples was lower than that for JTB oil. Interestingly, JTB oil has a more significant decrease in the condensation-extraction region than RDG oil, although JTB has a higher molecular weight or is heavier than RDG oil. It should be noted that the extraction of hydrocarbon components from oil increases as the gas density increases with the pressure (**Dindoruk et al, 2020**). However, the amount of extraction also depends on the composition of the oil, particularly the fraction of the oil that includes components that are soluble in dense CO_2. Hence, it requires to be observed the compositions of oil samples.

The extraction phenomena occurred in JTB and RDG oil samples can be seen from the changes of hydrocarbon compositional of the original oil sample and the characterization of the residue oil with various CO_2 injection pressures at a temperature of 90°C, as shown in **Figures 5** and **6**, respectively. **Figures 5** and **6** show that the mole percentage of intermediate components (C_6-C_9) reduces with increasing CO_2 injection pressures. On the other hand, the heavier components (C_{23}-C_{30}) showed a relatively higher mole percentage with increasing CO_2 injection pressures. The depletion of light - intermediate hydrocarbon fractions results in an increase in the bulk fluid density. This compositional shift can also enhance asphaltene solubility, as the removal of volatile components alters the thermodynamic equilibrium and promotes the incorporation of higher-molecular-weight asphaltenes into the crude oil phase (**Kokal & Sayegh, 1995; Rezk & Foroozesh, 2019**). During CO_2 flooding, the properties of both produced and residual oils can be altered through mutual interaction between CO_2 and crude oil. A reduction in the mole fraction of light to intermediate components – primarily within the saturates fraction – can compromise crude oil stability, leading to the precipitation of heavier hydrocarbon constituents such as asphaltenes (**Wang et al., 2016**).

Hagedorn & Orr (1994) reported that ring structures of components generally reduce solubility, especially for multi-ring aromatics. As indicated by the SARA analysis in **Table 3**, the RDG crude oil sample contains a higher fraction of aromatics compared to JTB oil. Aromatics are hydrocarbon components that are generally nonpolar, distinguished by their unsaturated ring structures containing multiple carbon–carbon double bonds (**Fakher et al., 2020**).

3.3. Effect of Temperature on CO_2 Displacement Performance

The performance of CO_2 displacement was examined using a slim tube through seven experimental runs con-

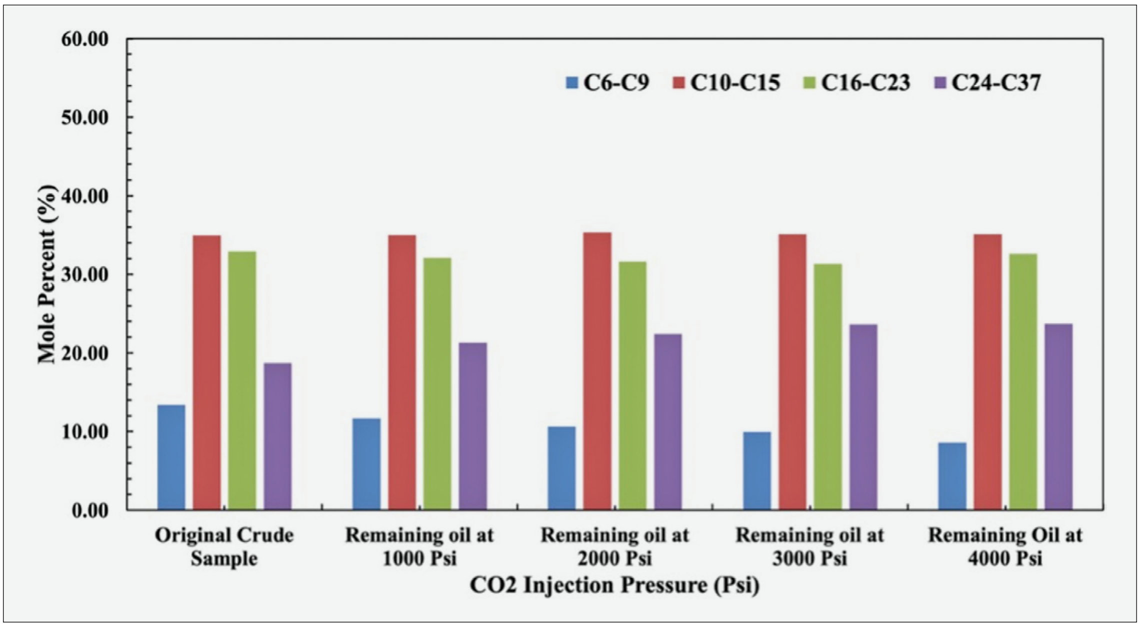

Figure 5. Hydrocarbon compositions of the original JTB sample and the residual oil after the swelling test at 90°C

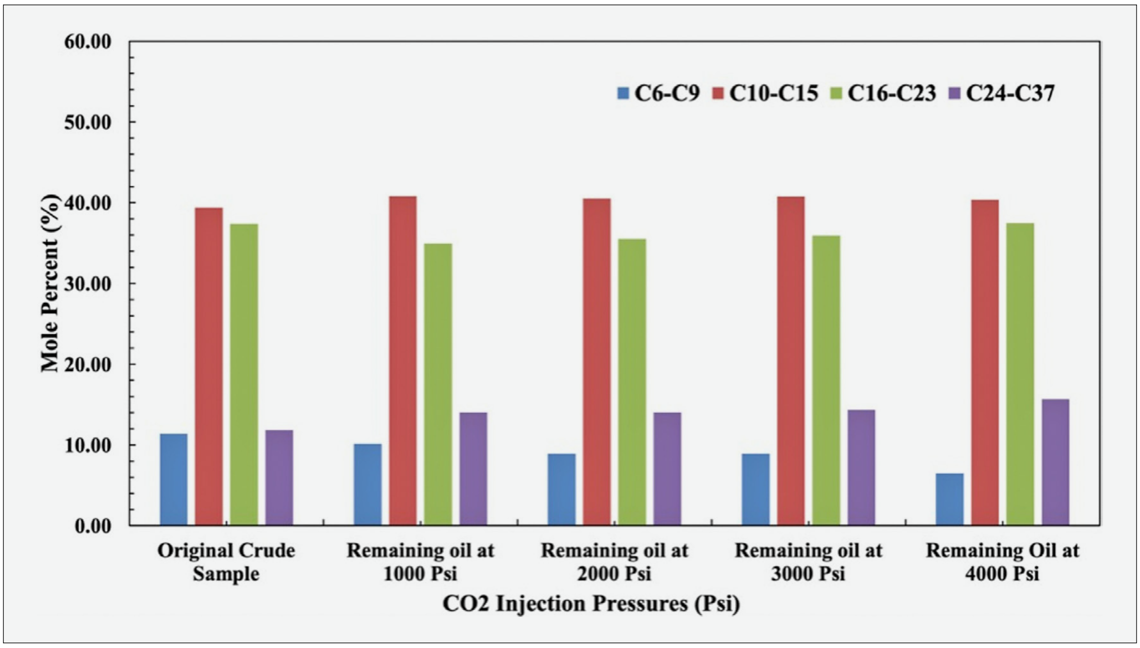

Figure 6. Hydrocarbon compositions of the original RDG sample and the residual oil after the swelling test at 90°C

ducted at varying pressures and temperatures. The experiments were carried out at high pressures of 1000 to 5000 Psi and the oil recovery outcomes from the CO_2 flooding process are shown in **Table 5**. Each displacement test was initially conducted at 90°C, representing the average reservoir temperature, and then repeated at 70°C, which reflects the wellbore temperature condition. As shown in **Table 5**, oil recovery at 70°C is lower compared to 90°C for both RDG and JTB crude oil samples. Specifically, the maximum recovery at 70°C reached 85.7% for RDG and 89% for JTB, while at 90°C, the recoveries increased to 93.5% and 94.5%, respectively. These results suggest that higher temperatures enhance oil recovery, which is likely due to the reduction in oil viscosity with increasing temperature (**Maqbool et al., 2011**). Therefore, the oil recovery results from the CO_2 displacement tests are crucial for determining the MMP.

MMP values for JTB and RDG samples are presented in **Figure 7** and **8**, respectively. The MMP was determined by plotting recovery factor (%) values against the corresponding injection pressures, as described by **Glaso (1990)** and **Hudgins et al. (1990)**. **Figure 7** shows that the MMP for JTB oil is higher at a higher temperature. Additionally, the figure suggests that miscibility

Table 5. Recovery Factor (%) obtained from slim tube experiments at 70°C and 90°C

Injection Pressure (Psi)	RF (%) RDG 70°C	RF (%) RDG 90°C	RF (%) JTB 70°C	RF (%) JTB 90°C
1000	51	51.6	47.5	46
2000	61.7	79	64.2	64
2500	-	-	-	76.3
3000	78.5	93.5	86.5	90.6
3500	85.7	-	88	-
4000	84.6	93.5	89	93.5
5000	83	93.5	82	94.5

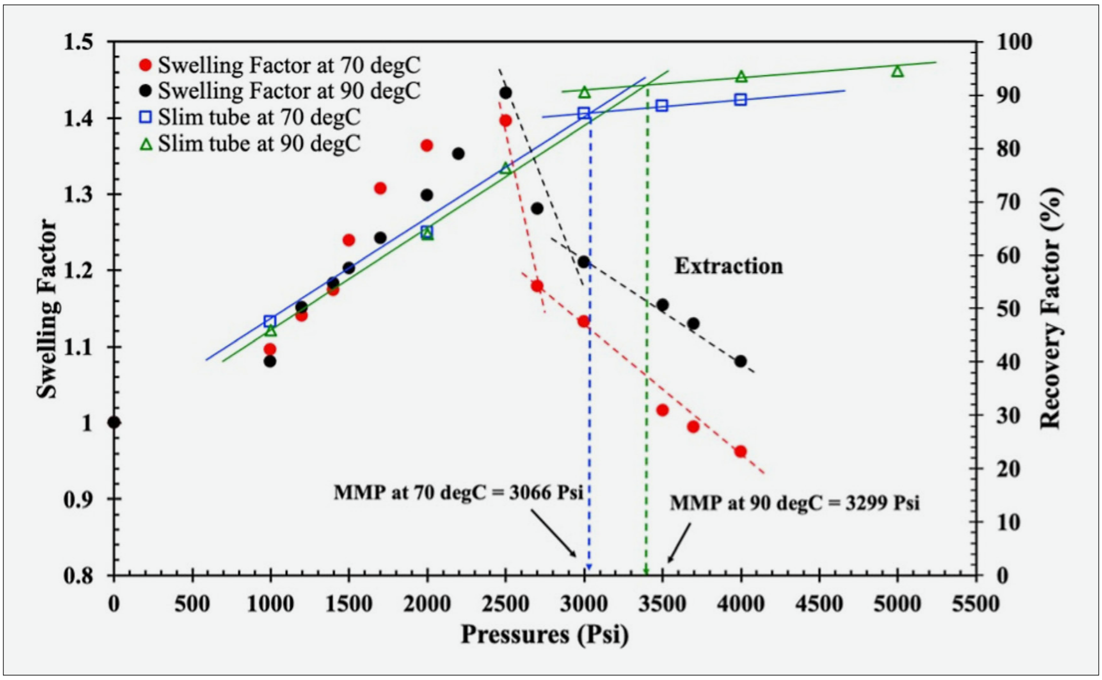

Figure 7. MMP Estimation from slim tube and Swelling Factor JTB oil at 70°C and 90°C

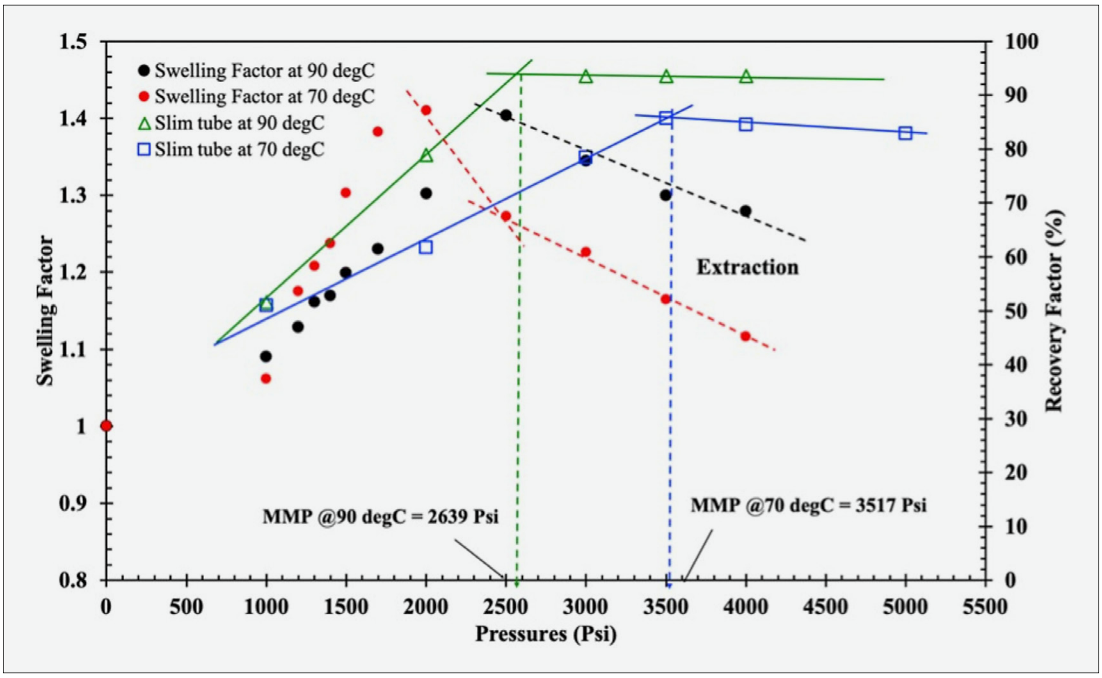

Figure 8. MMP Estimation from slim tube and Swelling Factor RDG oil at 70°C and 90°C

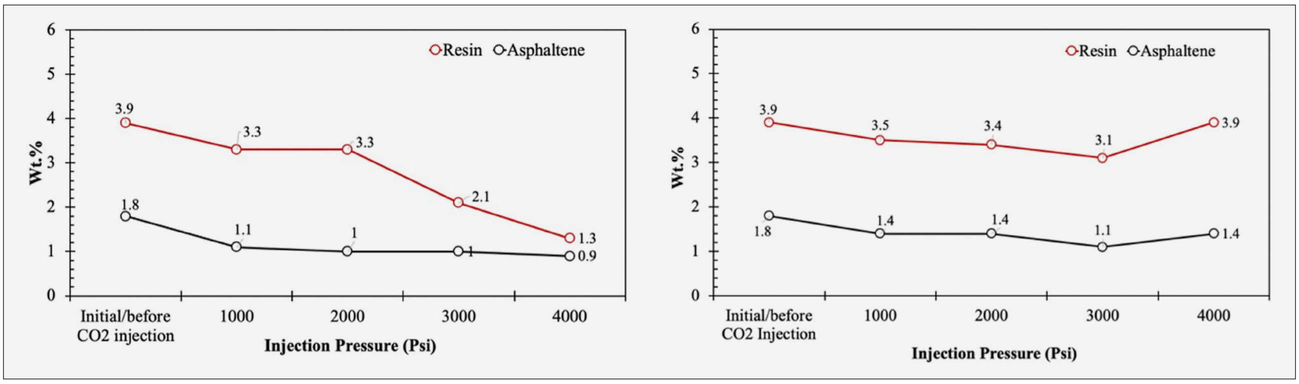

Figure 9. Resin and Asphaltene Fraction (wt.%) of RDG sample at (a) 70°C and (b) 90°C in varying injection pressures

between CO_2 and the crude oil occurs within the extraction region, indicating that the extraction of hydrocarbon components by CO_2 plays a significant role in achieving miscibility. On the other hand, for the RDG crude oil, **Figure 8** demonstrates that the MMP at 70°C is notably higher compared to that at 90°C. This phenomenon shows that the extraction of hydrocarbon components by CO_2 is one of the mechanisms of miscibility. In contrast to the MMP of the JTB oil sample, the RDG oil shows that the MMP at 70°C is much higher than at 90°C, as shown in **Figure 8**. According to **Lashkarbolooki & Ayatollahi (2018)** and **Yellig & Metcalfe (1980)**, an increase in temperature typically leads to a rise in MMP. However, some of the MMP data summarized from the literature showed that some oil fields with lower reservoir temperatures have higher MMP than those with higher reservoir temperatures, as shown in **Figure 11**. Therefore, the experimental results on the effect of temperature on displacement performance require further analysis to investigate the effect of oil compositions on the CO_2 displacement process in porous media. The effect of oil composition on displacement performance will be discussed in the subsequent section.

3.4. Effect of Oil Composition on CO_2 Displacement Performance

As previously discussed, **Figure 8** shows that the MMP for the RDG sample at a temperature of 70°C is much higher than at 90°C, which contrasts with the JTB oil sample. Therefore, further investigation into the influence of oil composition on CO_2 displacement is important. In this study, the impact of oil composition was examined by analyzing changes in crude oil resulting from CO_2–oil interactions. This was achieved through SARA fraction analysis of produced oil obtained from slim tube experiments at each injection pressure. **Figures 9** and **10** present the changes in the wt.% of resins and asphaltene fractions from the produced oil of RDG and JTB samples, respectively. Notably, JTB crude oil is classified as heavier than the RDG and initially contains a higher concentration of asphaltenes. Interestingly, the MMP for RDG at 70°C is considerably higher than at 90°C. The data in both tables reveal a general trend of decreasing resin and asphaltene content with increasing CO_2 injection pressure. Although JTB oil exhibits a higher initial asphaltene content than RDG, it also possesses a higher resin fraction.

Asphaltenes are among the most complex constituents of crude oil, characterized by their insolubility in normal alkanes and composed of highly polar, structurally intricate molecules (**Fakher et al., 2020; Soleymanzadeh et al., 2019**). In contrast, resins contribute significantly to the stability of crude oil by exhibiting both polar and non-polar properties, enabling them to function as peptizing and bridging agents that connect polar asphaltenes with non-polar hydrocarbon components (**Miadonye & Evans, 2010**). The observed decline in asphaltene content with increasing injection pressure indicates potential asphaltene deposition within the porous media. This phenomenon is likely driven by a concurrent reduction in resin concentration, which weakens the peptizing effect necessary to maintain asphaltene dispersion. As reported by **Deo & Parra (2012)**, repeated between CO_2 - crude oil interactions can result in asphaltene precipitation within the reservoir. Such deposition may adversely affect both the efficiency of oil recovery and the MMP.

Figure 9 shows that the resin and asphaltene content of RDG oil at 70°C (see **Figure 9a**) decrease more significantly than at 90°C (see **Figure 9b**). The decreasing of resin and asphaltene also indicates that temperatures also affect the change of SARA composition during the CO_2 flooding process, which can cause the possibility of the asphaltene precipitation phenomenon in porous media. It can be seen that at 70°C, the resin reduces from 3.9 wt.% at initial composition (before CO_2 was injected) to 1.3 wt.% at a CO_2 injection pressure of 4000 Psi. The asphaltene fraction also reduces from 1.8 wt.% to 0.9 wt. % at 4000 Psi. The reduction in resin and asphaltene content at 70°C is more pronounced compared to 90°C, resulting in lower oil recovery at the lower temperature. A similar finding was also reported by **Hagedorn & Orr (1994)** that crude oils containing substantial amounts of multi-ring aromatic compounds face challenges in achieving miscibility with CO_2. These aro-

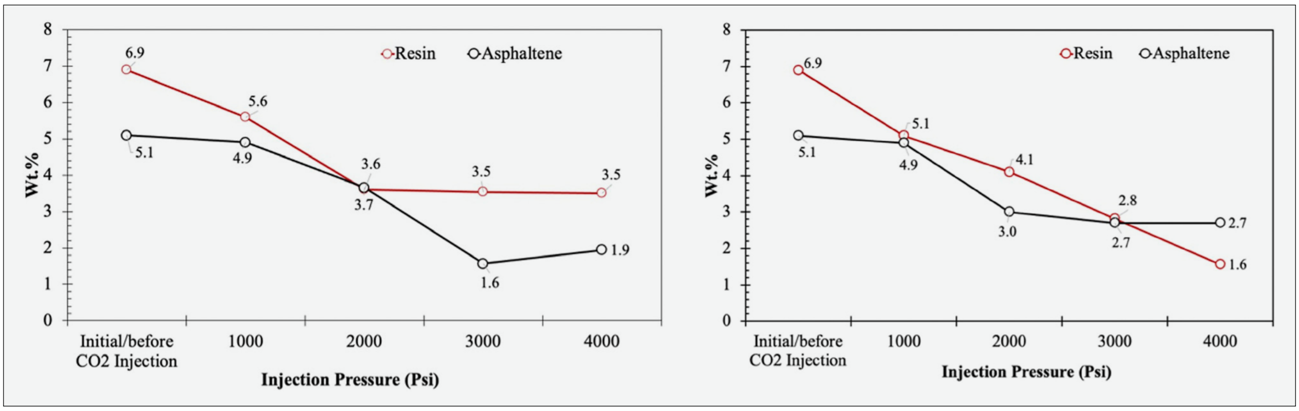

Figure 10. Resin and Asphaltene Fraction (wt.%) of RDG Sample at (a) 70°C and (b) 90°C in Varying Injection Pressures

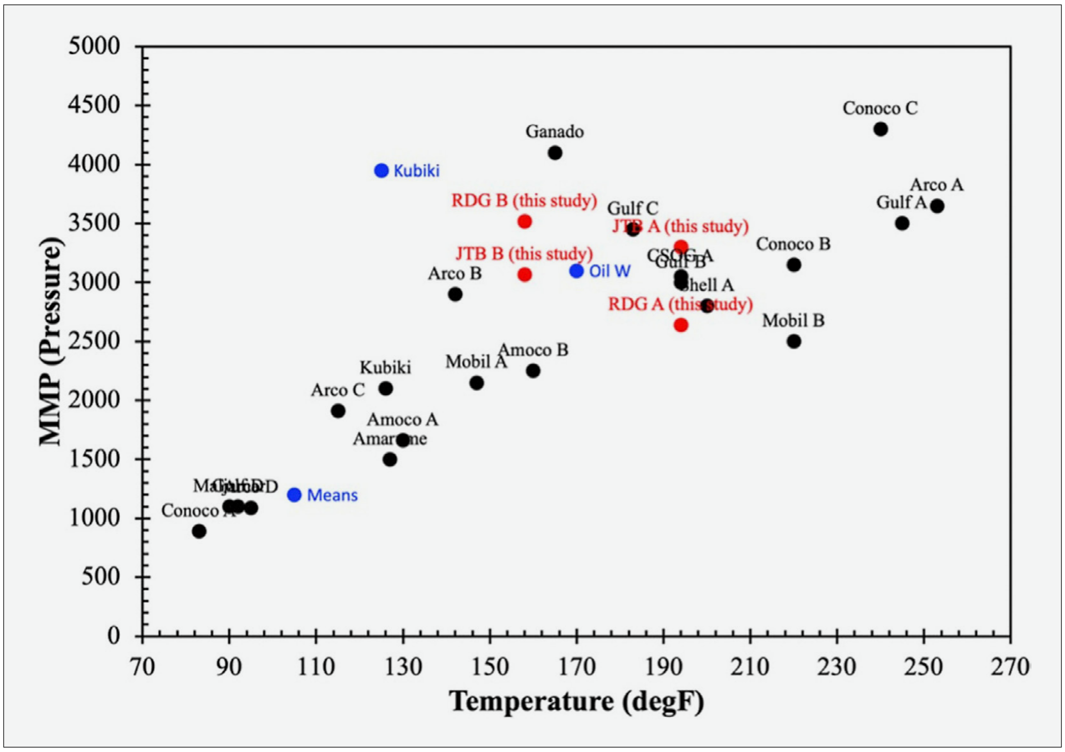

Figure 11. Minimum Miscibility Pressure (MMP) oil fields data vs. Reservoir Temperatures (summarized from **Hagedorn & Orr, 1994 and Orr & Silva, 1987**)

matic compounds are not easily extracted by dense CO_2, leading to decreased oil recovery in slim tube tests at a given pressure and consequently requiring a higher MMP. As shown in **Table 3**, RDG sample contains a higher proportion of aromatic components compared to JTB crude oil.

Figure 10 also presents the resin and asphaltene content of JTB oil at 70°C (see **Figure 10a**) and 90°C (see **Figure 10b**) under varying pressures. Although the initial asphaltene fraction in JTB is higher than in RDG, the resin content in JTB is also significantly greater. In contrast, the initial aromatic fraction in JTB oil is lower than in RDG oil. As previously discussed, dense CO_2 has limited ability to extract multi-ring aromatic compounds. Due to its high resin and lower aromatic content, JTB crude exhibits greater stability compared to RDG. Consequently, asphaltene precipitation is more likely to occur in RDG oil upon CO_2 injection, despite RDG having a higher API gravity. This difference results in lower oil recovery from CO_2 flooding process in the RDG crude than in the JTB crude.

The findings indicate that variations in pressure, temperature, and crude oil composition resulting from CO_2 injection significantly influence the efficiency of CO_2 displacement. These factors, in turn, affect both oil recovery and the determination of the MMP. The performance of the displacement process is closely linked to the collective behaviour and proportion of all crude oil components – saturates, aromatics, resins, and asphaltenes – as shown in **Table 3**, rather than being attributed to a single component alone. The findings are also aligned with the work by **Fan et al. (2024)** that investigated the effect of some complex components in the interaction of the CO_2 and crude oil by the insight of convolutional neural networks.

4. Conclusions

This study investigated the effect of temperature and oil compositions on swelling-extraction behaviour and CO_2 displacement mechanisms. Understanding the influence of temperatures and oil compositions on CO_2 EOR fundamental mechanisms such as swelling-extraction and CO_2 flow mechanisms in porous media is vital to optimizing CO_2 flooding process implementation. This study is expected to provide more data on the swelling and extraction mechanisms for implementing CO_2 flooding at high reservoir temperatures. Moreover, this study is also expected to provide insight into understanding the effect of different parameters such as, temperatures and oil compositions, on CO_2 flow mechanisms in porous media and optimizing CO_2 flooding process implementation. The main conclusions from the research that has been carried out are shown below.

1. An increase in temperature led to a reduction in the oil swelling rate. This effect is attributed to the decreased solubility of CO_2 at elevated temperatures, resulting from the increased kinetic energy of CO_2 molecules, which weakens the attractive interactions between the gas and crude oil molecules.
2. The pressure point at which the oil starts to shrink significantly is strongly affected by both the temperature and composition of the oil. At 70°C, the swelling factor indicates a more pronounced oil shrinkage compared to that at 90°C. This suggests that CO_2 exhibits greater efficiency in extracting hydrocarbon components at lower temperatures under the same pressure conditions. Generally, hydrocarbon extraction by CO_2 improves with increasing CO_2 density and pressure. Since lower temperatures typically result in higher CO_2 density, the extraction rate tends to increase more rapidly with pressure at cooler conditions. JTB oil has a more significant decrease in the condensation-extraction region than RDG oil, although JTB has a higher molecular weight or is heavier than RDG oil. It shows that the amount of extraction also depends on the composition of the oil, particularly the fraction of the oil that includes components that are soluble in dense CO_2.
3. The RDG crude oil contains a greater proportion of aromatic compounds compared to the JTB sample. Aromatics are typically nonpolar hydrocarbons characterized by ring structures with multiple carbon double bonds. These molecular features tend to reduce the solubility of CO_2 in crude oil.
4. Higher temperatures led to an improvement in oil recovery, primarily because increasing temperature causes a reduction in crude oil viscosity, thereby enhancing fluid mobility.
5. Alterations in crude oil composition resulting from interactions with CO_2 significantly influence displacement efficiency. As CO_2 injection pressure increases, the contents (wt.%) of resins and asphaltenes in the crude oil tend to decline. The observed reduction in asphaltene content with rising pressure suggests that asphaltene precipitation occurs within the porous medium. This precipitation is further linked to the decrease in resin content, which normally functions as a peptizing agent that maintains asphaltene stability in crude oil.

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SAŽETAK

Eksperimentalno ispitivanje utjecaja temperature i sastava nafte na bubrenje nafte izazvano istiskivanjem s CO_2, mehanizme ekstrakcije i karakteristike istiskivanja

Povećanje iscrpka nafte utiskvanjem CO_2 ima nekoliko prednosti, uključujući smanjenje viskoznosti sirove nafte, smanjenje međufazne napetosti i povećanje volumena nafte bubrenjem. Iako su mehanizmi bubrenja i istiskivanja nafte u sustavima CO_2-sirova nafta puno proučavani, kombinirani učinci temperature i sastava nafte na te mehanizme – i njihov utjecaj na učinkovitost istiskivanja CO_2 u poroznim medijima – još uvijek nisu dovoljno poznati, posebice pri visokim temperaturama ležišta. Stoga se u ovome radu istražuje kako temperatura i sastav sirove nafte utječu na ponašanje bubrenja i istiskivanje te učinkovitost istiskivanja s CO_2. Za procjenu fenomena bubrenja i istiskivanja provedeni su PVT testovi u uvjetima visokoga tlaka i visoke temperature (HPHT), dok je procjena iscrpka nafte napravljena ispitivanjem metodom istiskivanja nafte iz cijevi maloga promjera (engl. *slim tube experiments*). Ispitivanja su provedena na dvije lake otplinjene nafte s indonezijskoga polja pri temperaturi od 70 °C i 90 °C i različitim tlakovima utiskivanja. Analiza sastava proizvedenih nafti napravljena je plinskom kromatografijom (engl. *Gas Chromatography,* GC), a rezultati su interpretirani prema SARA klasifikaciji (zasićeni ugljikovodici, aromati, smole, asfalteni). Rezultati pokazuju da niže temperature povećavaju učinkovitost istiskivanja s CO_2 zbog veće gustoće CO_2, što dovodi do izraženijega efekta bubrenja i mješljivosti. Mješljivost je uočena unutar područja istiskivanja, što naglašava ulogu istiskivanja ugljikovodika u mehanizmu miješljivosti. Utvrđeno je da više temperature povećavaju iscrpak nafte, primarno zbog smanjenja viskoznosti. Osim toga, povećanje tlaka utiskivanja CO_2 smanjilo je sadržaj smole i asfaltena u proizvedenoj nafti, uz utvrđeno taloženje asfaltena u poroznome mediju, posebice na nižim temperaturama. Ovi rezultati daju vrijedan uvid u to kako temperatura i sastav nafte utječu na interakcije CO_2 i nafte te omogućuju učinkovitiju primjenu povećanja iscrpka nafte utiskivanjem CO_2 pri povišenim temperaturama ležišta.

Ključne riječi:
povećanje iscrpka nafte utiskivanjem CO_2, mehanizam bubrenja – istiskivanja, mješljivost, taloženje asfaltena, iscrpak nafte, SARA frakcije

Author’s contribution

Kartika F. Hartono (Dr.): conceptualization, methodology, validation, formal analysis, investigation, writing – original draft, and visualization. **Asep K. Permadi (Prof.)**: conceptualization, formal analysis, writing – review & editing, and supervision. **Utjok. W. R. Siagian (Dr.)**: conceptualization, formal analysis. **Andri, L. L. Hakim (Dr.)**: conceptualization, formal analysis, writing – review & editing. **Sumadi Paryoto**: resources, methodology, project administration. **Ahlul H. Resha:** resources, methodology, and project administration. **Syaeful A. Satya**: methodology, and project administration. **Reno Pratiwi (Dr.), Maman Djumantara, Dina A. Chusniah:** writing – review & editing.
All authors have read and agreed to the published version of the manuscript.