

A STUDY OF CO<sub>2</sub> AND WAG INJECTION  
INDUCED ASPHALTENE PRECIPITATION

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by

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the requirements for the  
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CERTIFICATION OF APPROVAL

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## CERTIFICATION OF ORIGINALITY

This is to certify that I am responsible for the work submitted in this project, that the original work is my own except as specified in the references and acknowledgements, and that the original work contained herein have not been undertaken or done by unspecified sources or persons.

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ONG SHEAU HUN

## **ABSTRACT**

Asphaltene is high molecular weight component of crude oil that exists in the oil as colloidal suspension, and is peptized or stabilized by resin that absorbed on its surface. Asphaltene might loss its stability during different phases of production and specially during carbon dioxide flooding. The precipitation of asphaltene during CO<sub>2</sub> injection might lead to formation damage, wellbore plugging and recovery reduction. Water-alternating-gas (WAG) injection is the mobility enhancement method of CO<sub>2</sub> injection and it is believed that the presence of water could reduce the asphaltene precipitation.

In this work, dynamic core flooding experiments were conducted to study the effect of CO<sub>2</sub> injection and WAG injection on the amount of asphaltene precipitated. Core properties after displacement were inspected for any porosity, permeability and wettability alteration to study the effect of asphaltene precipitation on rock properties. The recovered oil is collected over a time interval and the change in asphaltene content was reported against pore volume of injection. The reduction of the asphaltene content in the effluent oil indicates the amount of asphaltene precipitated inside the core.

The laboratory data had justified that WAG injection gives less asphaltene precipitation compared to CO<sub>2</sub> injection. Higher porosity and permeability reduction were observed with CO<sub>2</sub> injection. It was also found out that during CO<sub>2</sub> injection, the presence of asphaltene would altered the rock wettability to more oil wet. However, in the presence of water film during WAG injection, the initial water wet condition of the rock remained and contributed to higher oil recovery. Overall, WAG injection gives less asphaltene precipitation, less formation damage, and higher oil recovery compare to CO<sub>2</sub> injection.

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# CHAPTER 1

## INTRODUCTION

### 1.1 Project Background

Carbon dioxide injection is one of the efficient Enhanced Oil Recovery methods, but it may induce asphaltene precipitation problem. During CO<sub>2</sub> gas injection, the miscibility of the CO<sub>2</sub> gas with the reservoir oil will contribute to oil composition change which alters the asphaltene-to-resin ratio and favour the precipitation of asphaltene (Kokal & Sayegh, 1995; Hammami *et al.*, 2000; Oskui & Abuhaimed, 2009). The precipitated asphaltene might lead to formation damage, wellbore plugging and recovery reduction. (Sima *et al.*, 2011; Ghedan, 2009; Srivastava *et al.*, 1997

Water-alternating-gas (WAG) injection is the enhancement of CO<sub>2</sub> injection in providing mobility control over fingering problem. A reduction in mobility would improve the sweep efficiency and leads to higher oil recovery (Caudle & Dynes, 1957). Okwen (2006), Sarma (2003), Walcott *et al.* (1989) and Srivastava *et al.*, (1997) are researchers who reported that the presence of water could minimize the asphaltene precipitation (Sarma, 2003; Srivastava *et al.*, 1997, Wolcott *et al.*, 1989; Okwen, 2006). In this paper, the effect of CO<sub>2</sub> and WAG injection on asphaltene precipitation was investigated to further determine the role of water in minimizes the amount of asphaltene precipitated.

### 1.2 Problem Statement

#### 1.2.1 Problem Identification

Asphaltene precipitation is a common problem during natural depletion, and especially during CO<sub>2</sub> injection. The precipitation of asphaltene might lead to formation damage, wellbore plugging and recovery reduction. In dealing with the asphaltene problem, most studies were focus

on determining the optimum CO<sub>2</sub> injection condition which could minimize the asphaltene precipitation. For example, the concentration of CO<sub>2</sub> gas, injection pressure, injection rate and etc.

Another approach that can be carrying out to deal with asphaltene precipitation problem is by investigating the role of water in minimizing asphaltene precipitation. It is believed that the presence of water could minimize the asphaltene precipitation. Thus, it is inquisitive to determine if WAG injection could give less asphaltene precipitation, less formation damage, and higher oil recovery compare to CO<sub>2</sub> injection.

### **1.2.2 Significant of the project**

The findings from this research are significant in support of the role of water in reducing asphaltene precipitation. This will further highlight the beneficial of WAG injection over CO<sub>2</sub> injection in providing mobility control, giving higher sweep efficiency, higher oil recovery and lower asphaltene precipitation. The findings would further provide the data on the amount of asphaltene precipitation and the formation damage induced by WAG and CO<sub>2</sub> injection.

### **1.3 Objectives**

1. To investigate and compare the asphaltene precipitation induced by CO<sub>2</sub> injection and Water-Alternating-CO<sub>2</sub> (WAG) injection.
2. To investigate the effects of asphaltene precipitation during CO<sub>2</sub> and WAG injection on rock properties.

### **1.4 Scope of Work**

In this project, two Barea sandstone core were used as formation representative. A light crude oil sample with API gravity of 36° and asphaltene

content of 0.12% were used. Dynamic core flooding test were taken out with two runs, one with continuous CO<sub>2</sub> injection and another one with WAG injection under 1:1 WAG ratio. Both runs of experiments were fixed under 3000 Psi and 100oC with an injection rate of 0.2cc/min and 2000 Psi injection pressure.

Both CO<sub>2</sub> and WAG injection were injected as tertiary oil recovery after water flooding. With known initial asphaltene content, the effluent oil was collected every 25 minutes and the asphaltene content changes were determined and studied. The effect of asphaltene precipitation on formation properties were only focused on effective porosity, absolute permeability and wettability. From the results, the changes of formation properties after the precipitation of asphaltene were related to the type of injection scheme and the amount of asphaltene precipitation. Lastly, the amount of oil recovery was obtained and study.

### **1.5 The relevancy of the project**

The study on CO<sub>2</sub> injection and WAG injection is relevant because miscible hydrocarbon and CO<sub>2</sub> WAG injection is the most favourable process in Malaysia field as presented by Hamdan *et al.* (2005) in their report. Malaysia field are having oil with low asphaltene content which have higher possibility of having asphaltene precipitation problems (Khanifar *et al.*, 2011). Thus, it is relevant to have a study on the asphaltene induced by light oil in Malaysia using CO<sub>2</sub> and WAG injection.

### **1.6 Feasibility of the project within the scope and time frame**

With careful planning and full dedication in conducting this research, all the experimental works will be manage to complete in time. All the materials and equipments needs to conduct the experiments were readily available; and with the assistance of the technicians in operating the equipments, this research will be successfully conduct and all the objectives set for this research will be achieve.

## **CHAPTER 2**

### **LITERATURE REVIEW**

#### **2.1 CO<sub>2</sub> INJECTION AND WAG INJECTION**

CO<sub>2</sub> (Carbon dioxide gas injection) and WAG (Water-Alternating-Gas injection) are one of the efficient Enhanced Oil Recovery (EOR) methods. EOR refers to processes that could increase the amount of oil removed from a reservoir, typically by injecting a liquid (e.g., water, surfactant) or gas (e.g., nitrogen, carbon dioxide) (Green & Willhite, 1998). Most of the fields in Malaysia have entered mature state for primary or secondary recovery. The declining production and increasing water cut and gas oil ratio (GOR) trend have give rise to the need for timely implementation of EOR. The Dulang field is the first pilot EOR development project in Malaysia implementing immiscible WAG recovery. EOR Screening study on 72 wells in Malaysia by PETRONAS on year 2000 stated that miscible hydrocarbon and CO<sub>2</sub> WAG injection is the most favourable process (Hamdan *et al.*, 2005). Malaysia field are having oil with low asphaltene content which have higher possibility of having asphaltene precipitation problems (Khanifar *et al.*, 2011).

CO<sub>2</sub> injection can be classified as miscible or immiscible and are applicable in both secondary and tertiary recovery. CO<sub>2</sub> miscible flooding improves oil recovery through gas drive, oil swelling and viscosity reduction (Sima *et al.*, 2011; Ghedan, 2009; Srivastava *et al.*, 1999; Al-Qasim, 2011). However, miscibility of the CO<sub>2</sub> gas with the reservoir oil will contribute to compositional change, and alter the asphaltene resin ratio which favors the precipitation of asphaltenes (Ghedan, 2009; Kokal & Sayegh, 1995).

WAG injection is the mobility enhancement method for CO<sub>2</sub> injection. During CO<sub>2</sub> injection, as gas injected is less viscous than the reservoir oil, the gas will tend to displace the oil causing instability in the displacement front. The instability will then induce an initially sharp displacement front which will further convolute and develop “fingers” which will cause undesired early breakthrough

(Green & Willhite, 1998). Water alternating gas injection has been used as mobility control methods which result in sweep efficiency improvement and oil recovery increment (Ghedan, 2009; Berenblyum et al., 2009; Sarma, 2003; Green & Willhite, 1998). The presence of water in WAG injection is believed to reduce the asphaltene precipitation. (Al-Qasim, 2011; Sarma, 2003; Srivastava *et al.*, 1997, Walcot *et al.*, 1989; Shedid *et al.*, 2008),

## **2.2 ASPHALTENE**

Asphaltenes is non-volatile, polar and high molecular weight fraction of crude oil that is insoluble in n-alkenes. Asphaltene is insoluble in nonpolar solvent with a surface tension lower than 25 dynes/cm at 25°C (77F) such as methane, ethane and propane and have no defined melting point (Alta'ee *et al.*, 2010). The definition of asphaltene is quite controversial as different solvents and extraction method used producing different asphaltene. Thus, the asphaltene should defined based on its solubility class rather than molecular structure (Sima *et al.*, 2011; Khanifar *et al.*, 2011).

### **2.2.1 Colloidal Model**

Asphaltene is believed to exist as colloidal suspension in oil phase and is stabilized by a protective layer formed by the peptized of highly polar resin on its surface. The combination of these resin and asphaltenes are called micelles. Micelles would not flocculate due to the presence of repulsive force in between the resin molecules absorbed on asphaltene surface. (Thou et al., 2002) The concept of asphaltene stabilization by resin is well recognized; however, the exact mechanism in behind still remains not well known for light oil reservoir (Alta'ee *et al.*, 2010; Srivastava *et al.*, 1999). Figure 1 shows the illustration of resin and asphaltene in crude oil. Resin and asphaltene have similar molecular structure but resins are less polar, less aromatic and lower molecular mass compared to asphaltene.

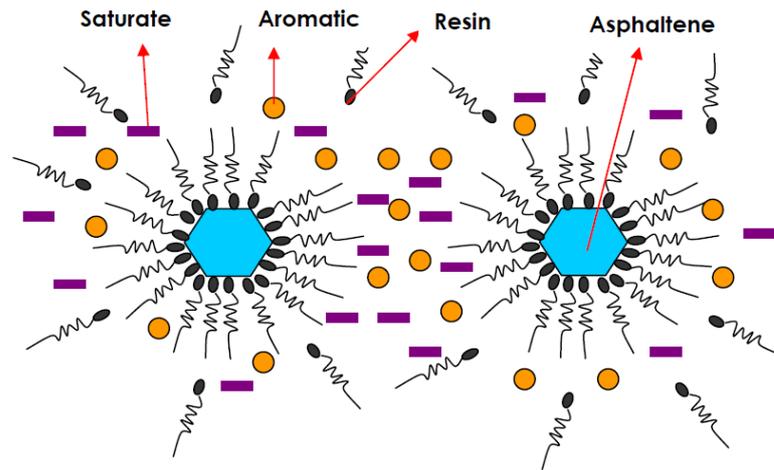


Figure 1: Resin and Asphaltene in Crude Oil (Miftachul, 2010).

### 2.2.2 Asphaltene fraction in Crude Oil

SARA analysis is a laboratory method used to quantify the asphaltene fraction in the crude oil. This analysis separates the crude oil into SARA (Saturates, Aromatics, Resin, and Asphaltene). The amount of asphaltene in crude oil varies with sources, depth of burial, API gravity of the crude oil (Thou *et al.*, 2002; Khanifar *et al.*, 2011).

Less asphaltene fraction in crude oil did not indicate less possibility of having less asphaltene precipitate problem (Sima *et al.*, 2011; Alta'ee *et al.*, 2010). Field observation indicates that lower asphaltene content in crude oil contributes to higher possibility of asphaltene destabilization. For example, the Boscan field in Venezuela with 17wt% asphaltene was observed to have no asphaltene problem but the Hassi-Masoud in Algeria with only 0.15wt% asphaltene has an asphaltene problem (Khanifar *et al.*, 2011; Sima *et al.*, 2011; Alta'ee *et al.*, 2010).

Many field and laboratory data have justified that the lighter oil which consists largely of paraffinic materials, has lower asphaltene solubility (Sima *et al.*, 2011). On the other hand, the heavier oil contains plenty of intermediate components which are good asphaltene solvents (Khanifar *et al.*, 2011). The stability of asphaltene is influenced by the ratio of aromatics to saturates and the ratio of resin to asphaltene. This ratio reduction of these will

lead to higher asphaltene precipitation possibility (Donnez, 2007; Kamath *et al.*, 1993).

### **2.2.3 Mechanism of Asphaltene Precipitation**

Asphaltene itself is not problematic but the asphaltene precipitation is the major operational concern (Sima *et al.*, 2011). The precipitation and deposition of asphaltene can cause severe reservoir and production problems arises from permeability and porosity reduction, wettability alteration, plugging of wellbore and surface facilities (Ghedan, 2009; Srivastava *et al.*, 1999).

The terminologies for both precipitation and deposition are different (Miftachul, 2010; Hammami & Ratulowski, 2007). The asphaltene precipitation involved three steps, which are precipitation, floccuration, and deposition. Precipitation is defined as the solid phase (solid particle) coming out from the liquid phase. The flocculation is when the fines particles aggregate into larger particles. Deposition is a point at which the particles are too large to be supported by the liquid and therefore settle out on the solid surfaces or absorb onto rock surface (Khanifar *et al.*, 2011; Alta'ee *et al.*, 2010). Figure 2 shows the process of asphaltene precipitation, flocculation and deposition.

Asphaltene precipitation problems are usually firstly observed in production facilities, and then tubing move towards formation (Sima *et al.*, 2011; Ghedan, 2009; Srivastava *et al.*, 1999; Kokal & Sayegh, 1995). The asphaltene precipitation induced formation damage would start from the wellbore and extend over large distance from the origin. This is in contrast with the reservoir damage induced by organic deposit which is normally restricted to the wellbore zone only (Khanifar *et al.*, 2011).

## **2.3 ASPHALTENE DESTABILIZES FACTORS**

The asphaltene stabilized by resin, remain in thermodynamics equilibrium under colloidal state at normal reservoir condition. Asphaltene will loss it stability when the initial equilibrium state disturbed. Asphaltene stability depends on a number of factors including pressure and temperature alteration, changes in chemical composition, asphaltene and resin content in reservoir oil and the nature of injected fluids. The composition and pressure are believed to have greater effect on asphaltene precipitation than temperature (Kokal & Sayegh, 1995; Hammami *et al.*, 2000; Oskui & Abuhaimed, 2009).

### **2.3.1 Temperature Drop**

The studies conducted by Verdier *et al.* (2005) on pressure and temperature effect on asphaltene stability indicate that asphaltene less stable when temperature decreases; however, in the presence of CO<sub>2</sub>, asphaltene more stable when temperature decreases (Verdier *et al.*, 2005). Under low temperature, the asphaltene is unstable due to the energy difference between asphaltene and crude oil molecules. The temperature may alter the solubility of maltenes and resin. Temperature drop may cause the precipitation of paraffin that traps some asphaltene during solidification (Verdier *et al.*, 2005; Mohammed *et al.*, 1998).

### **2.3.2 Pressure Drop**

Pressure effect is likely to be the major reason in destabilizing asphaltene. It is believed that the lower the reservoir pressure, the lower is the asphaltene solubility (Verdier *et al.*, 2005; Sima *et al.*, 2011; Khosravi *et al.*, 2009). The effect of pressure on asphaltene precipitation is more intense when the crude oil is rich in light ends just above bubble point pressure. Laboratory data indicated that the maximum asphaltene precipitation occurred at bubble point (Alta'ee *et al.*, 2010; Khanifar, *et al.*, 2011).

When pressure is depleting from above bubble point, the crude oil density reduce while the molar mass increases. The minimum asphaltene solubility occurred at bubble point when there is a maximum difference in molar mass between asphaltene and bulk oil (Hammami *et al.*, 2000; Oskui & Abuhaimed, 2009). With the lighter hydrocarbon increasing with pressure drop, the solubility parameter between resin and lighter ends decreases, which induces resin solve constantly causing asphaltene to precipitate (Alta'ee *et al.*, 2010; Kokal & Sayegh, 1995; Mohammed *et al.*, 1998).

With further pressure drop below the bubble point, some lighter hydrocarbons vaporize from reservoir fluid leaving the heavier reservoir fluid with higher resin fraction and the resin reestablishes some of its lost asphaltene stability. This is shown by Ventura field, Hassi-Messaoud Field and Lake Maracaibo where the asphaltene problem diminished after bottom hole pressure drop below bubble point (Kokal & Sayegh, 1995).

### **2.3.3 Compositional Change**

The addition of compound may alter the existing resin-asphaltene solubility parameter and phase equilibrium in crude oil (Ghedan, 2009; Kokal & Sayegh, 1995; Sima *et al.*, 2011; Khosravi *et al.*, 2009). For example mixing of hydrocarbon fluids, miscible flooding, CO<sub>2</sub> injection, gas lift operation using gases and/or acidizing jobs (Hammami & Ratulowski, 2007).

The injection of gas into reservoir either in miscible or immiscible may lower the resin ratio or reduce the amount of the peptizing agent absorb on asphaltene surface (Mohammed *et al.*, 1998). When the resin ratio drops to a point which the absorbed amount were not enough to cover the asphaltene, the asphaltene particles will deposit. It is also reported that the increase of alkane carbon number decrease the amount of asphaltene precipitate (Chukwudeme & Hamouda, 2009). Most miscible solvents have the potential to cause asphaltene instability. Gholoum *et al.* (2003) reported that the CO<sub>2</sub>

is the most effective asphaltene precipitant followed by alkanes (C1 to C7) (Gholoum *et al.*, 2003; Shedid & Zekri, 2004).

## **2.4 EFFECT OF CO<sub>2</sub> INJECTION ON ASPHALTENE PRECIPITATION**

During gas flooding of CO<sub>2</sub>, the miscibility between the CO<sub>2</sub> gas with the reservoir oil will contribute to the change of phase behaviour and compositional, which cause asphaltene to precipitate (Ghedan, 2009; Kokal & Sayegh, 1995; Sima *et al.*, 2011; Khosravi *et al.*, 2009; Mousavi Dehghani *et al.*, 2007).

CO<sub>2</sub> gas and the crude can be miscible through first contact or multiple contacts (Alta'ee *et al.*, 2010; Srivastava *et al.*, 1999). In the experimental studies presented by Srivastava *et al.* (1999) on the effect of operating pressure effects on asphaltene precipitation, they indicated that the asphaltene precipitated from multiple contact miscibility were more than the first contact miscibility. The vapor-liquid separation during the miscible injection process strips away the light components which increase the asphaltene precipitation (Srivastava *et al.*, 1999).

Based on the experimental investigation conducted by Sima *et al.* (2011) on the effect of CO<sub>2</sub> injection on asphaltene precipitation, more pore volume of CO<sub>2</sub> gas injected would cause more asphaltene to precipitate. At pressure of 2000 Psi, the asphaltene start to precipitate at 0.43 pore volume. Then, the asphaltene content is increases from 0.11 wt% to 0.31 wt% until the end of the flooding process. However, as the injected pressure increase, the asphaltene precipitation decreases due to lower asphaltene solubility at low pressure. At lower pressure, the distance between the asphaltene particle and the surrounding fluid is large therefore causing more precipitation. Observation from their studies indicated that at pressure 2300 Psi, the asphaltene precipitation at 1.26 pore volume is 0.23 wt%; while at 2600 Psi, the asphaltene precipitation at 1.27 pore volume is 0.19 wt% (Sima *et al.*, 2011).

Srivastava *et al.* (1999) studied on the effect of oil properties and CO<sub>2</sub> gas concentration on asphaltene precipitation by means of static and dynamic test. Their studies on asphaltene onset pressure have indicated that the amount of asphaltene precipitation at bubble point was maximum. They also concluded that the asphaltene

precipitation is dependent on the concentration and pore volume of CO<sub>2</sub> gas injected. CO<sub>2</sub> gas concentration is the most important parameter which affects the asphaltene precipitation (Srivastava *et al.*, 1999). This is agreed by Chukwudeme & Hamouda (2009) who reported that the asphaltene deposition is proportional to the injected CO<sub>2</sub> concentration, and will rise rapidly when the injected CO<sub>2</sub> gas exceed its critical value. They suggested that higher recovery may be obtained if the injected CO<sub>2</sub> gas is remained below the critical content point (Chukwudeme & Hamouda, 2009; Al-Qasim, 2011; Alta'ee *et al.*, 2010; Khosravi *et al.*, 2009).

Khosravi *et al.* (2009) reported in his studies that the presence of CO<sub>2</sub> gas increases the oil density through withdrawing the light components, but asphaltene precipitation decreases the oil density. A reduction in oil density and viscosity are favoured in oil recovery. The mass transfer which takes place during miscibility development would enhance the asphaltene precipitation (Khosravi *et al.*, 2009).

According to Bagheri (2011), who investigated the effect of injection rate on asphaltene precipitation under natural depletion. The observations from the studies show that the increase of flow rate will increase asphaltene precipitation due to larger pressure drop along the core. They concluded that the increase of production rate from the wells causes more serious formation damage problems far from the well (Bagheri *et al.*, 2011). This is also supported by Shedid & Zekri (2004) who reported that the increase of flow rate will increase the formation damage due to more asphaltene deposited (Shedid & Zekri, 2004).

## 2.5 EFFECT OF WAG INJECTION ON ASPHALTENE PRECIPITATION

Based on the studies by Srivastava *et al.* (1999) on the effect of brine on asphaltene flocculation, it is observed that the effect of the brine on asphaltene flocculation seemed to be negligible. However, an increase in the brine concentration appears to reduce the asphaltene precipitation (Srivastava *et al.*, 1999). This finding is further supported by Wolcot *et al.* (1989) who presented that the presence of brine could reduce the deposition but could not eliminate it at all (Wolcot *et al.*, 1989).

According to Okwen (2006), the formation water would act as a CO<sub>2</sub> buffer during CO<sub>2</sub> injection. When the injected CO<sub>2</sub> gas concentration reduces, the amount of asphaltene precipitation reduces too. Other than this, the laboratory data indicated that the presence of water film on rock surface in water wet rock can reduce or delay the asphaltene deposition process as asphaltene are preferentially deposited on the less water wet surface than the water surface. Water is believed to act as a shield to rock surface which shield it from direct interaction with asphaltene. This explains why there are more asphaltene deposited on sandstone core than limestone core which is more water wet (Mousavi Dehghani *et al.*, 2007; Okwen, 2006). This paper also recommended further researches to be carried out on the optimum concentrations of CO<sub>2</sub> and formation water which can minimize the asphaltene deposition (Okwen, 2006).

Wang & Civan (2005) conducted investigation on water injection scheme for prevention of asphaltene deposition by means of simulation. This paper concluded that the application of water injection can increase the oil recovery through asphaltene deposition prevention (Wang & Civan, 2005). The issue of the role of brine on the precipitation and its effect on asphaltene precipitation has been raised up by Sarma (2003) too (Sarma, 2003),

## **2.6 EFFECT OF ASPHALTENE PRECIPITATION ON FORMATION PROPERTIES**

Hayashi & Okabe (2010) performed experimental investigation on asphaltene induced permeability reduction and the results indicate a 20% permeability reduction during CO<sub>2</sub> injection due to asphaltene precipitation. The permeability reduction is presented as a function of asphaltene precipitation increment (Hayashi & Okabe, 2010). The effect of asphaltene precipitation on porosity and permeability reduction are depends on few factors. For instant, the pore size distribution, the degree of asphaltene deposition and the intial permeability of the formation (Kamath *et al.*, 1993).

Some researchers reported that core with lower permeability show more intense formation damage effect than the core with higher permeability (Zekri *et al.*, 2007; Shedid & Zekri, 2004). The reduction of injection flow rate may decrease the formation damage due to less asphaltene precipitate (Shedid & Zekri, 2004). A study of asphaltene induced formation damage by Sima *et al.* (2011) has demonstrated that the porosity and permeability reduction is more intense at lower injection pressure due to more asphaltene deposited (Sima *et al.*, 2011). The permeability reduction is consider to due to the larger size asphaltene particles block the smaller pore throat or the smaller size asphaltene accumulate or absorb in large pore throat causing reduction in pore throat radii (Kamath *et al.*, 1993).

Asphaltene precipitation is the major cause of the wettability change in oil reservoir. The understanding of role of asphaltene in wettability reversal will help in more efficient enhanced oil recovery planning (Kim & Mansoori., 1990; Yeh & Emanuel, 1992). The wettability change of the core is due to the potential of asphaltene adsorb onto high energy mineral surface (Al-Maamari & Buckley, 2000; Kamath *et al.*, 1993). Huang and Holm (1988) used asphaltene dissolved in toluene to effect reverse the rock wettability. This indicates the role of asphaltene in wettability alteration (Huang & Holm, 1988). However, Al-Maarmari and Buckley (2000) reported that in the presence of stable water film, the water wet rock will remain water wet (Al-Maarmari & Buckley, 2000). When wettability change from

water wet to oil wet, it can cause a higher water cut profile which may possibly reduce oil recovery (Al-Qasim, 2011).

Another possible effect from asphaltene precipitation is the flow diversion effect, where when the high permeability zone plugged; the fluid will flow to the low permeability zone. This may be a positive result from asphaltene precipitation as improved sweep efficiency may be obtained. Other than this, the increase in asphaltene precipitation can lead to an increase in water breakthrough time (Kamath *et al.*, 1993).

## **2.7 LITERATURE SUMMARY**

Light oil is having higher possibility of having asphaltene precipitation than heavy oil. The common factors causing asphaltene precipitation are pressure drop, temperature drop and compositional change. The composition and pressure have higher effect on asphaltene precipitation than temperature. The asphaltenes precipitated could cause reservoir damage, change of wettability of the rock matrix and affect the flood performance.

The addition of CO<sub>2</sub> gas can destabilize the asphaltene colloidal model and possibly causes the asphaltene to precipitate, flocculate and deposit. The amount of asphaltene precipitated during CO<sub>2</sub> injection are depending on the injected CO<sub>2</sub> concentration and pore volume, injection pressure, flowrate, and miscibility development. The maximum asphaltene precipitation is believed to occur at bubble point.

The presence of water is believed could reduce the asphaltene precipitation. Water is act as a CO<sub>2</sub> buffer in CO<sub>2</sub> injection and an increase in the brine concentration appears to reduce the asphaltene precipitation. The investigations of the optimum conditions that could reduce or avoid the asphaltene to precipitate are one of the good efforts in dealing with asphaltene precipitation problem. There are further researches require in investigate the optimum concentration of brine and CO<sub>2</sub> gas in WAG injection that can reduce the asphaltene precipitation.

## CHAPTER 3

### METHODOLOGY

#### 3.1 Research Methodology

Core flooding experiment was conducted under operation conditions of 3000 Psi and 100°C. Berea sandstone cores were used as formation representative. Below are the outlines of the works.

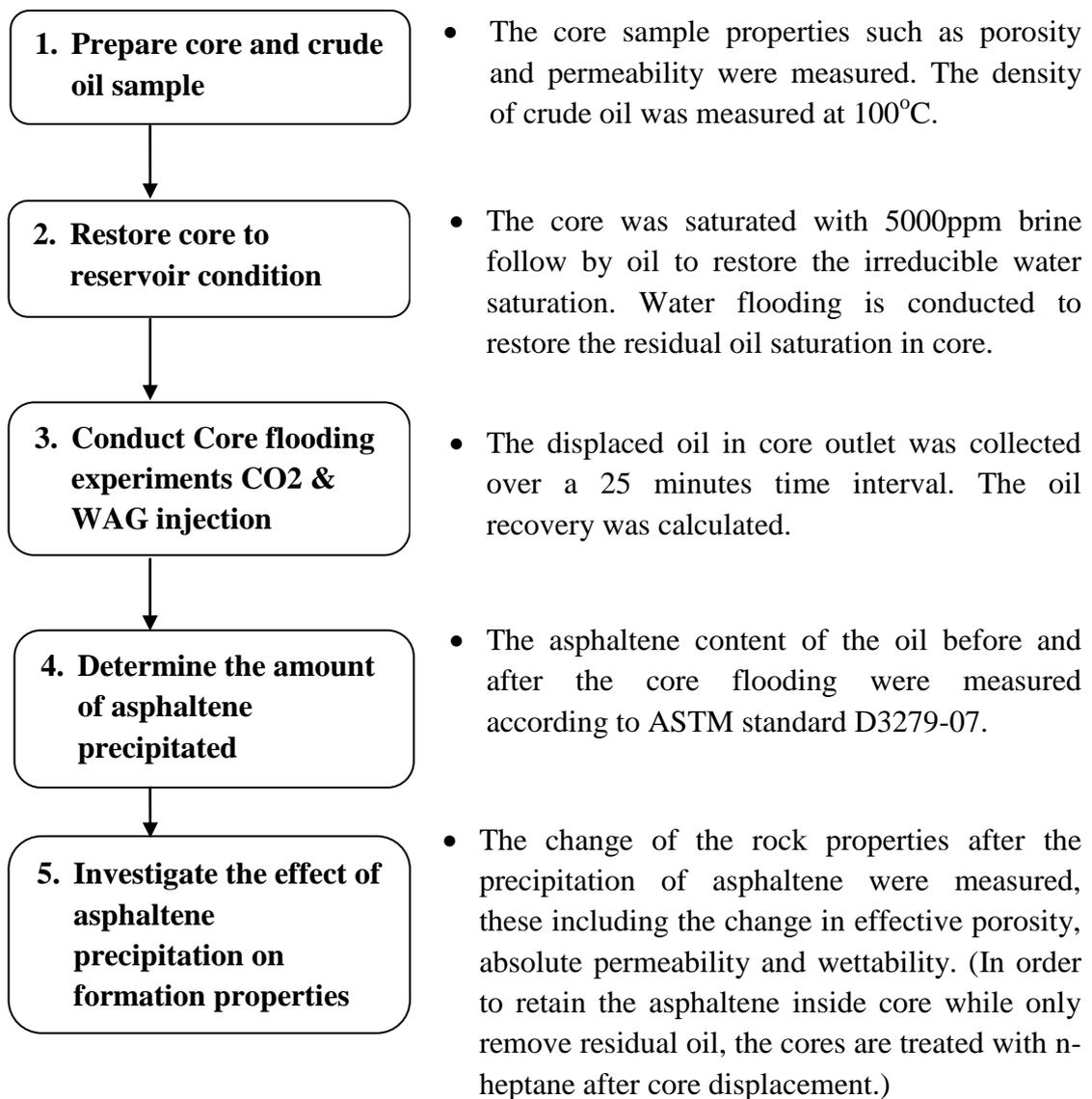


Figure 2: Methodology Outline

### 3.1.1 Core Properties Measurement

Porosimetry System is a permeameter and porosimeter used in determine the properties of core samples at ambient confining pressure.

#### Chemical and Apparatus

Oven, Poro-Perm System,  
Nitrogen Gas



Figure 3: Poro-Perm System

#### Procedure:

- The core samples were cleaned using toluene and dry in oven before loaded into the core holder.
- The length and diameter of samples were measured with digital caliper and subsequently bulk volume was determined automatically from system.
- Nitrogen gas was filled into core chamber to fully saturate the samples.
- Using suitable confining pressure of 300 Psia, the effective porosity and gas absolute permeability can be obtained.
- The Klinkenberg gas slippage effect is corrected using the built-in Klinkenberg correction software.

#### Bulk Volume:

$$V_b = \pi r^2 L \quad (1)$$

$r$  = radius of the core

$L$  = length of the core

**Porosity:**

$$\phi = \frac{V_p}{V_b} \times 100\% \quad (2)$$

$V_b$  = bulk volume of the core

$V_p$  = pore volume of the core

**3.1.2 Crude Oil Properties Measurement**

**Density Measurement**

**Chemical and Apparatus**

Densitometer  
Crude Oil Sample,  
syringe



Figure 4: Densitometer

**Procedure:**

- About 3 ml of crude oil sample was drawn into a syringe and injected into the air tube.
- The crude oil was injected continuously and slowly to decrease the possibility of having air bubble forming inside the air tube.
- The injected crude oil was then heated up from 40 °C to 89 °C.
- Then the option to start recording the density was selected. The equipment provided the density value once the reading had stabilized.
- The results were then extrapolated to obtain the density at temperature of 100 °C.

### 3.1.3 Asphaltene Content Measurement

ASTM D3279-07 Standard Test Method for n-Heptane Insoluble is used to measure the mass percent of asphaltene in crude oil sample. This test determines the mass percent of asphaltene as defined by insolubility of asphaltene in normal heptane solvent.

#### Chemical and Apparatus

Gooch Crucible,  
n-Heptane, Filter Paper,  
Heating Flask,  
Suction Flask, Reflux  
Condenser, Hot Plate,  
Magnetic Stirrer,  
Desiccator, Hood, Oven



Figure 5: ASTM D3279-07 Standard Test Method for n-Heptane

#### Procedure:

- The sample was weighted to the nearest 1.0 g (B) and 100 ml of solvent per 1.0 g of sample was added into the heating flask.
- With the magnetic stirrer added, the flask was heated on the hot plate at 70 °C under the reflux condenser for about 20 minutes and cool down.
- The filter paper was placed into the gooch crucible and put into oven at about 107 °C for 15 minutes. The gooch crucible was allowed to cool down in desiccator and the weight was measured.
- The gooch crucible was pre-filtered with n-heptane and the mixture in the heating flask was poured into the suction flask through the gooch crucible.
- The gooch crucible was put into oven at about 107 °C for 15 minutes. The gooch crucible was then allowed to cool down in desiccator and the weight was measured. The amount of insoluble inside is denoted as (A).
- The weight percentage of asphaltene content,  $wt\% = \frac{A}{B} \times 100\%$  (3)

### 3.1.4 Core Flooding

Relative Permeability Test System is used to conduct core flooding experiment. Brine, oil and CO<sub>2</sub> gas are injected simultaneously into the core sample for CO<sub>2</sub> injection and WAG injection experiment.

#### Chemical and Apparatus

Relative Permeability System, Brine water (5000 ppm), 99.99% Pure CO<sub>2</sub> Gas, Crude Oil Sample



Figure 6: Relative Permeability Test System

#### Procedure:

- The core sample was flooded with brine follow by dead oil for irreducible water saturation restoration.
- It was assuming that the core was 100% saturated with water, where the initial volume of water should be equal to the pore volume. The original oil in place was determined through the amount of water dispersed.
- The core was then flooded with brine and the amount of produced oil was measured to obtain the residual oil saturation. The process was conducted until a stable residual oil was established. This is when only water is being produced at the outlet.
- To determine the CO<sub>2</sub> gas effect on the asphaltene precipitation, CO<sub>2</sub> gas is injected into the core 2 cc/min injection rate. The amount effluent oil were collected every 25 minutes to obtain the recovery factor and phase saturation change.
- The above step was repeated for WAG injection (1:1 ratio) under same injection rate. The injection length for brine and CO<sub>2</sub> gas injected were 10 minutes each.

**Initial Oil Saturation:**

The amount of brine displaced by oil from the brine saturated core is the volume of oil saturated in the core. Initial oil saturation was determined by dividing the amount of brine produced to the pore volume of the core.

$$S_{oi} = \frac{V_o}{V_p} \quad (4)$$

$S_{oi}$  = initial oil saturation

$V_o$  = volume of oil

$V_p$  = pore volume of the core

**Residual Oil Saturation:**

The amount of oil remains in the core after water flooding over the pore volume of the core.

$$S_{or} = \frac{V_{oi} - V_o}{V_p} \quad (5)$$

$S_{or}$  = residual oil saturation

$V_{oi}$  = Initial oil volume in the core

$V_o$  = volume of oil produced from water flooding

$V_p$  = pore volume of the core

**Oil Recovery Factor:**

Oil Recovery can be estimated from the amount of oil recovered by amount of residual oil after water flood.

$$\text{Oil recovery factor} = \frac{V_o}{V_{or}} \quad (6)$$

$V_o$  = volume of oil produced

$S_{or}$  = residual oil saturation

### 3.1.5 Post Flooding Evaluation

#### IFT Measurement

In determining the effect of asphaltene precipitation on wettability alteration, Sessil Drop method is applied using IFT 700 equipment.

#### Chemical and Apparatus

IFT 700 Equipment, Core Sample, Crude Oil Sample, Brine water (5% NaCl)



Figure 7: IFT 700 System

#### Procedure:

- A degreaser and air-blower were used to clean the chamber cell to remove any impurities.
- A small piece of core sample was inserted into the sample holder and load into the chamber cell.
- The cell was then pressurized to 3000 Psi at constant temperature of 100°C to resemble the core flooding conditions.
- By slowly controlling the inlet/ outlet pressure of the oil tank, a single droplet of oil was injected into the pressure cell.
- The oil droplet image adhere on the core surface was observed from the computer through the microscopic camera.
- The position and the resolution of camera were adjusted to give clear image.
- The results with low contact angle (0 to 90°C) indicate water wet properties while the large contact angle (90 °C to 180 °C) represent oil wet properties.

### 3.1.6 Core Cleaning

Cores were cleaned using toluene before displacement test. After the displacement test, cores were cleaned using n-heptane to dissolve and extract oil and brine from core sample with core flooding apparatus. The use of n-heptane enables the asphaltene precipitated to retain inside the cores for porosity and permeability reduction analysis.

#### Chemical and Apparatus

Soxhlet Extractor,  
Toluene, n-heptane



Figure 8: Soxhlet Extractor

#### Procedure:

- Core to clean was inserted into the core chamber. The solvent was filled in the boiling flask and the condenser was connected to water supply source.
- Upon heating the boiling flask, the solvent will vaporized and then cool in the condenser and flow back into the core chamber.
- The cleaned solvent filled the chamber and soaked the core sample.
- When the chamber was full, the condensed solvent was abosorb back into the boiling flask and was redistilled.
- The colour of the solvent was observed from the siphons to determine the cleanliness of the core sample.
- The core sample was dry in the oven to make sure it is clear from any impurities.

### 3.2 Project Activities

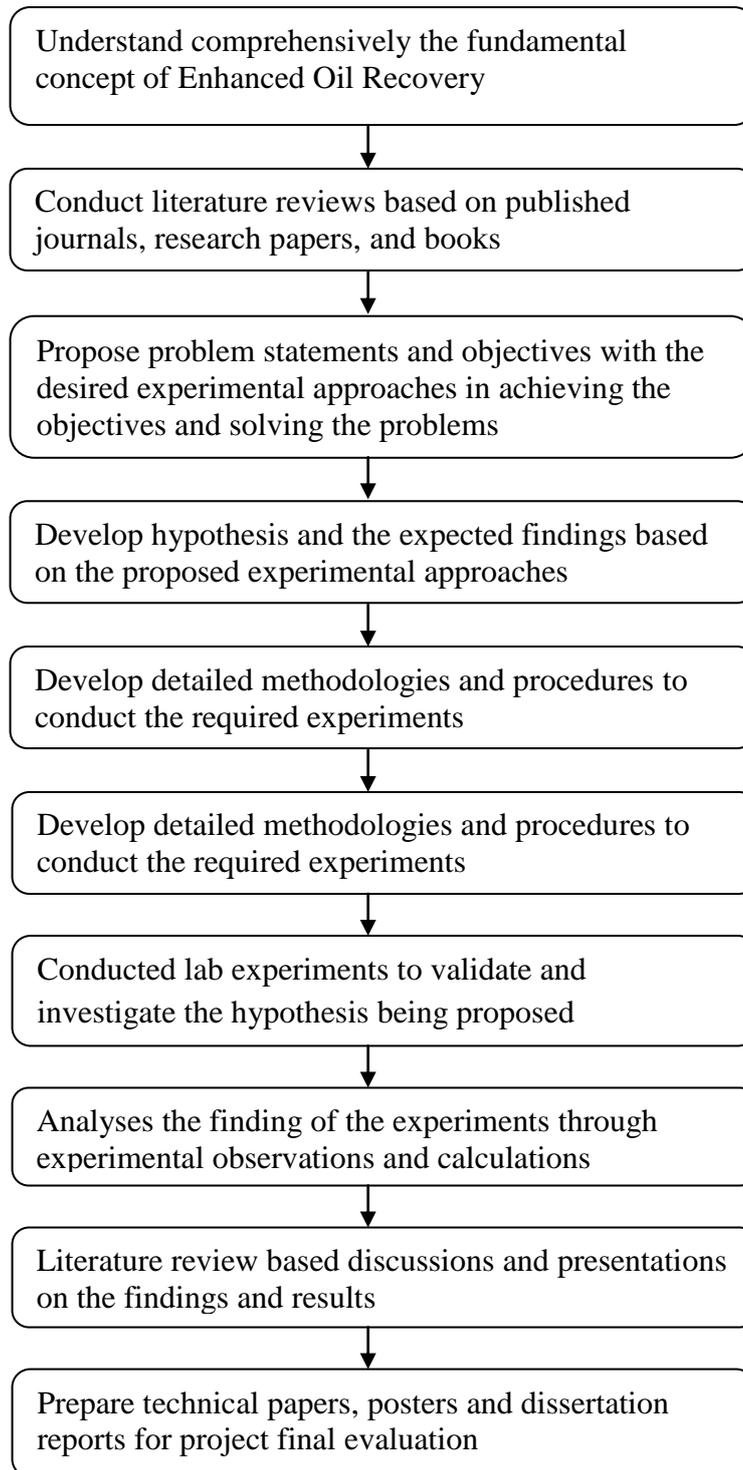


Figure 9: Project Activities

### 3.3 Gantt Chart and Key Milestones

Table 1: Project Gantt Chart and Key Milestones

Final Year Project I																
Details/Week	1	2	3	4	5	6		7	8	9	10	11	12	13	14	
Topic Selection & Confirmation	█	█					Mid Semester Break									
Preliminary Research Work		█	█	█	█											
Preliminary Report submission						█										
Proposal Defense (Oral Presentation)									█	█						
Project Work Continues											█	█	█			
Interim Draft Report submission															█	
Submission of Interim Report																█



Final Year Project II																
Details/Week	1	2	3	4	5	6		7	8	9	10	11	12	13	14	
Materials Preparation & Lab Booking	█	█	█				Mid Semester Break									
Pre-test Analysis			█	█	█											
1 <sup>st</sup> Project Run									█	█						
Progress Report Submission										█						
2 <sup>nd</sup> Project Run											█	█				
Post-test Analysis												█				
Pre-EDX													█			
Draft Report Submission														█		
Dissertation Submission (Softbound)															█	
Technical Paper Submission															█	
Oral Presentation																█
Dissertation Submission (Hardbound)																█

### 3.4 Tools, Material and Equipment

Below is the summary of tools and equipment that used throughout the project.

Table 2: List of Chemicals/ Materials Use in Project

<b>Chemicals/ Materials</b>	<b>Experiment</b>
<b>Sample core plug</b>	Core flooding
<b>Sample crude oil</b>	Core flooding
<b>99.99% pure CO<sub>2</sub> gas</b>	CO <sub>2</sub> & WAG injection
<b>Brine</b>	Core restoration/ WAG injection
<b>Toulene</b>	Core cleaning
<b>n-heptanes</b>	Core cleaning, Asphaltene content measurement
<b>Distilled water</b>	Brine preparation

Table 3: List of Equipments Use in Project

<b>Equipments</b>	<b>Experiment</b>
<b>Soxhlet Extractor</b>	Core cleaning
<b>Drying oven</b>	Core cleaning, Asphaltene content measurement
<b>Poro-perm system</b>	Core properties measurement
<b>Dessicator</b>	Asphaltene content measurement
<b>Densitometer</b>	Crude oil density measurement
<b>IFT 700</b>	Interfacial Tension measurement

## CHAPTER 4

### RESULTS AND DISCUSSION

Below are the summaries of results obtained from each experimental phases. Details results from each experiment are presented in Appendix for reference.

#### 4.1 Sample properties

Table 4 presents the initial asphaltene content and the density of sample used. Knowing the initial asphaltene content of the oil sample used enables us to study the variation in amount of asphaltene precipitation during CO<sub>2</sub> and WAG injection.

Table 4: Crude Oil Properties

<b>Asphaltene content (wt %)</b>	<b>0.12</b>
<b>Density @ 100°C (g/cc)</b>	<b>0.7939</b>
<b>API gravity</b>	<b>36.04</b>

Before running the core flooding test, the core properties such as porosity, permeability and bulk volume are determined. Table 5 shows the initial core properties before the displacement test measured using Poroperm System.

Table 5: Original Core Samples Properties

<b>Parameter</b>	<b>Core 1 (CO<sub>2</sub> injection)</b>	<b>Core 2 (WAG injection)</b>
Diameter (mm)	37.01	36.94
Length (mm)	77.18	77.76
Weight (g)	180.43	182.55
Bulk volume (cc)	80.03	83.337
Pore volume (cc)	15.087	15.473
K <sub>air</sub> (mD)	89.148	95.762
K <sub>∞</sub> (mD)	78.028	80.359
Porosity (%)	18.170	18.566

## 4.2 Core Displacement Test

Dynamic displacement experiments were conducted to determine the effect of CO<sub>2</sub> and WAG injection on asphaltene precipitation. Table 6 shows the parameters used in the displacement. Operation condition of the equipment was fixed at 3000 Psi and 100 °C with an injection rate of 0.2 cc/min under 2000 Psi injection pressure. The WAG injection was conducted with 10 minute injection length for gas followed by water continuously until no oil production was obtained. In order to measure the change of asphaltene content, the effluent were collected every 25 minutes interval for both CO<sub>2</sub> and WAG injection. The simple schematic of the core flooding equipment is illustrated in figure 10.

Table 6: Core Displacement Test Parameters

Injection rate (cc/min)	0.2
Inlet Pressure (Psia)	2000
Confining Pressure (Psia)	3000
Temperature (°C)	100
CO <sub>2</sub> injection length	continuous
WAG injection length	
Water injection length (min)	10
Gas injection length (min)	10
Effluent collection interval (min)	25
Brine concentration (ppm)	5000

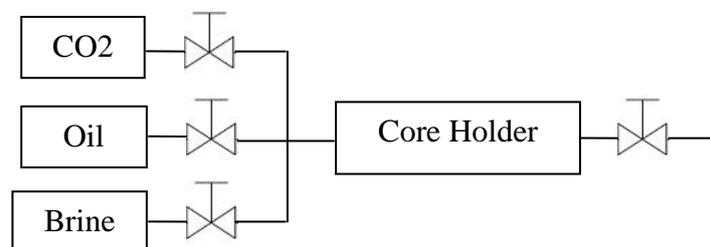


Figure 10: Simple Schematic of Core Flooding Equipment

### 4.3 CO<sub>2</sub> and WAG Injection Induced Asphaltene Precipitation

During CO<sub>2</sub> and WAG injection, the injected gas might dissolve into the oil during the displacement process. The change of oil composition would further alter the asphaltene-resin ratio which favors the precipitation of asphaltene. Asphaltene would start to flocculate when the fraction of resin drops to a concentration where it absorbed amount is insufficient in covering the entire surface of asphaltene particles. The flocculation of asphaltene particle may follow by precipitation and deposition.

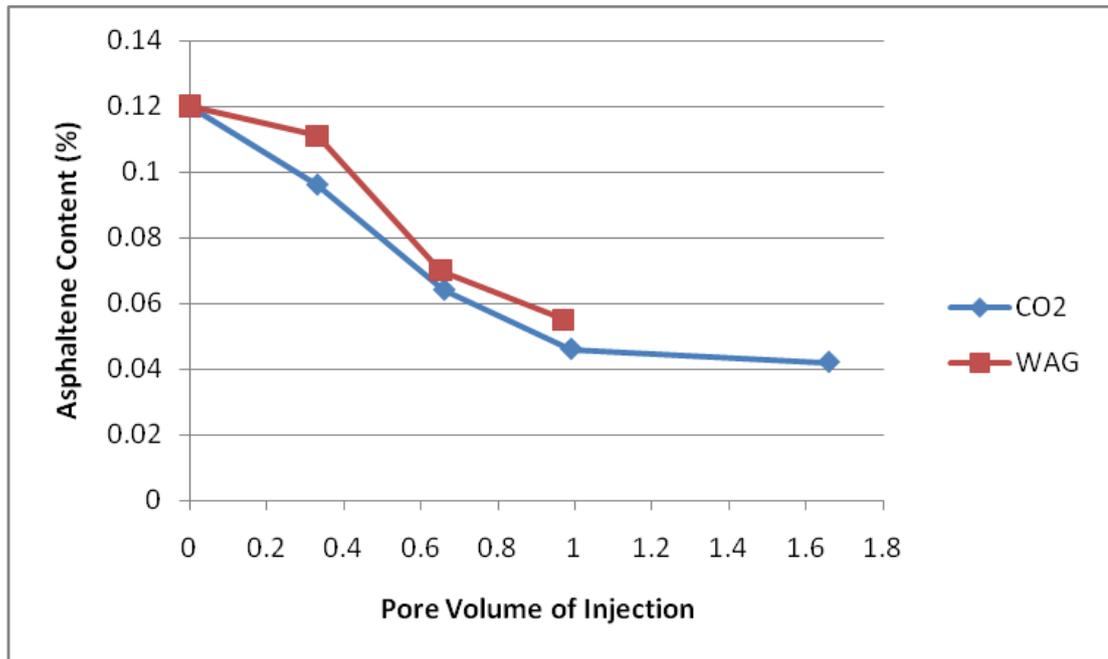


Figure 11: Asphaltene Content of the effluent versus Pore Volume of Injection

Figure 11 shows the asphaltene content of the effluent oil during CO<sub>2</sub> and WAG injection over the pore volume of injection. The weight percentage of asphaltene in the effluent oil were measured based on ASTM D3279-07 Standard Test Method. The original asphaltene content of the oil is 0.12%. At the end of the displacement test where oil production stopped, the asphaltene content of the effluent oil from CO<sub>2</sub> injection is 0.042%, while for WAG injection is 0.055%. The reduction of the asphaltene content in the effluent oil indicates the precipitation of asphaltene inside the core. The results show that the asphaltene content of the effluent oil from CO<sub>2</sub> injection is lower than WAG injection.

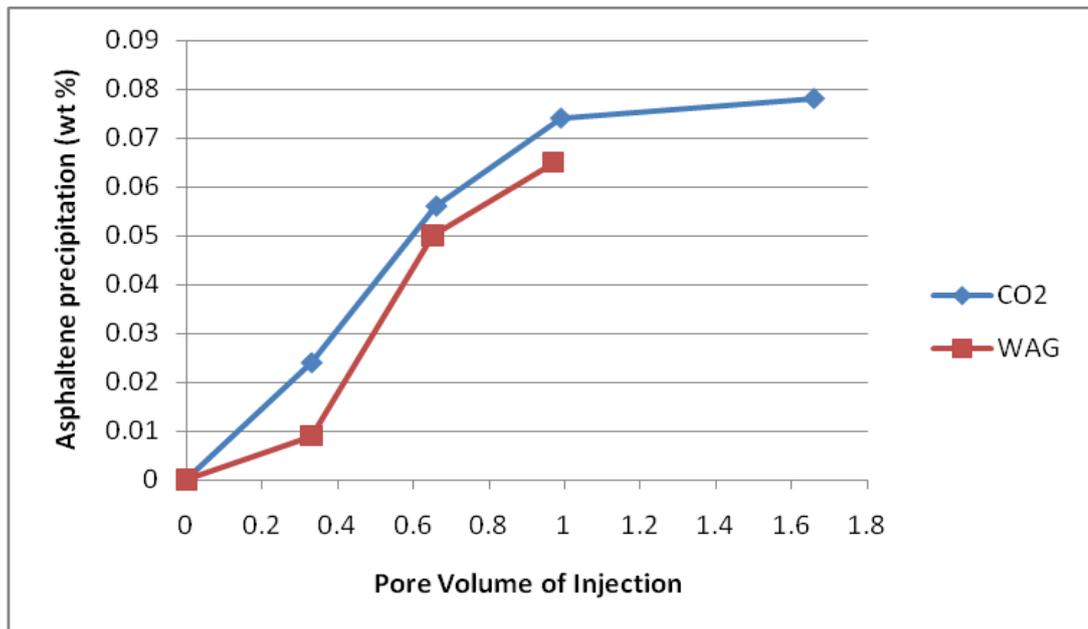


Figure 12: Asphaltene Precipitation inside the core versus Pore Volume of Injection

Figure 12 shows the weight percentage of asphaltene deposited inside the core during CO<sub>2</sub> and WAG injection. In run 1 of core flooding using CO<sub>2</sub> injection, the amount of asphaltene precipitate inside the core at 0.33 pore volumes was 0.024 wt%. When the CO<sub>2</sub> injection reaches 0.66 pore volume, the asphaltene precipitated was 0.056 wt%. At 0.99 pore volumes, the amount of asphaltene precipitation was 0.074 wt%. After that, the asphaltene precipitated inside the core was continued to increase as the injected pore volume increase. It reaches to a final value of 0.078 wt % at 1.66 pore volumes.

In run 2 of using WAG injection, the asphaltene precipitation was 0.009 wt% at 0.33 pore volumes of injection. In compare with the same pore volumes of injection from previous run, the asphaltene precipitation from the CO<sub>2</sub> injection is much higher. At 0.65 pore volumes of injection, the asphaltene precipitation was 0.05 wt% and then the asphaltene precipitation continue to increase and rise to 0.065 wt% at 0.97 pore volume of injection.

Figure 12 clearly shows that asphaltene precipitation is a function of pore volume of injection. As pore volume of gas injected increase, the asphaltene precipitated inside the core increase. Based on the results, it is also observed that the asphaltene precipitated from CO<sub>2</sub> injection is more than that of WAG injection. This is due to the fact that CO<sub>2</sub> is soluble in both water and crude oil. During WAG

injection, CO<sub>2</sub> gas will dissolve in brine and reduces its concentration. The reduction in CO<sub>2</sub> available to precipitate the asphaltene had minimizes the asphaltene precipitation.

#### 4.4 Effect of Asphaltene Precipitation on porosity and permeability

Once asphaltene is destabilizes, it may flow as suspended particles and may deposit on the rock surface causing changes to the rock properties. The effects of asphaltene precipitation on rock sample are indicated by the porosity and permeability reduction. In order to indicate the change of rock properties due to the presence of asphaltene, each core was treated with n-heptane after displacement test. The n-heptane will removes the residual oil while only leave asphaltene fraction inside the core. Table 7 present the original core properties and properties after the asphaltene precipitate. The change of the porosity and permeability from the original indicate the extent of asphaltene precipitation induced formation damage.

Table 7: Core Properties Before and After Displacement Test

		Porosity (%)	Difference %	Permeability (mD)	Difference %	Pore Volume (cc)
<b>Run 1 (CO<sub>2</sub>)</b>	Before Displacement	18.170	7.01	78.028	75.85	15.087
	After Displacement	16.896		17.753		13.469
<b>Run 2 (WAG)</b>	Before Displacement	18.566	6.66	80.359	71.92	15.473
	After Displacement	17.330		22.560		13.679

Figure 13 and 14 shows the percentage of porosity and permeability reduction during CO<sub>2</sub> and WAG injection. Results show an obvious reduction in porosity and permeability for both runs. It is justified that the precipitation of asphaltene would cause reduction in porosity and permeability. The permeability reduction is considered to due to the larger size asphaltene particles block the smaller pore throat

or the smaller size asphaltene accumulate or absorb in large pore throat causing reduction in pore throat radii.

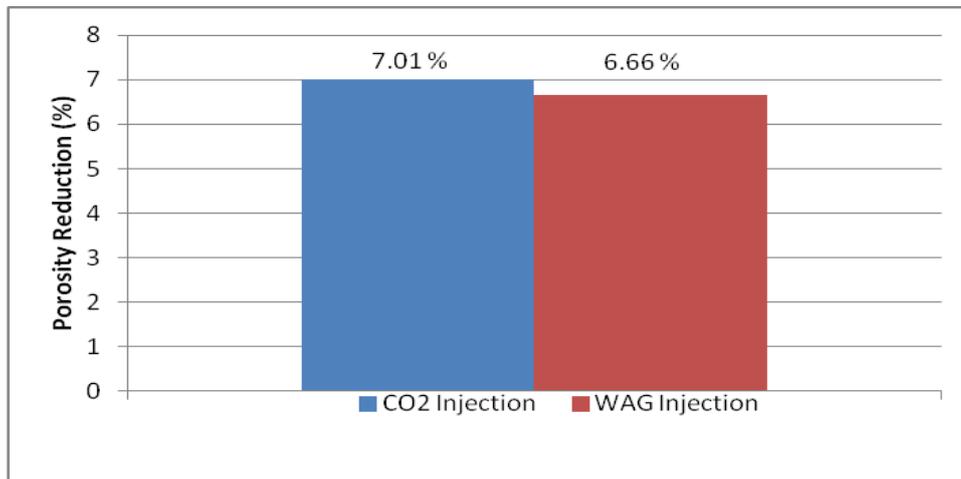


Figure 13: Porosity Reduction during CO2 and WAG Injection

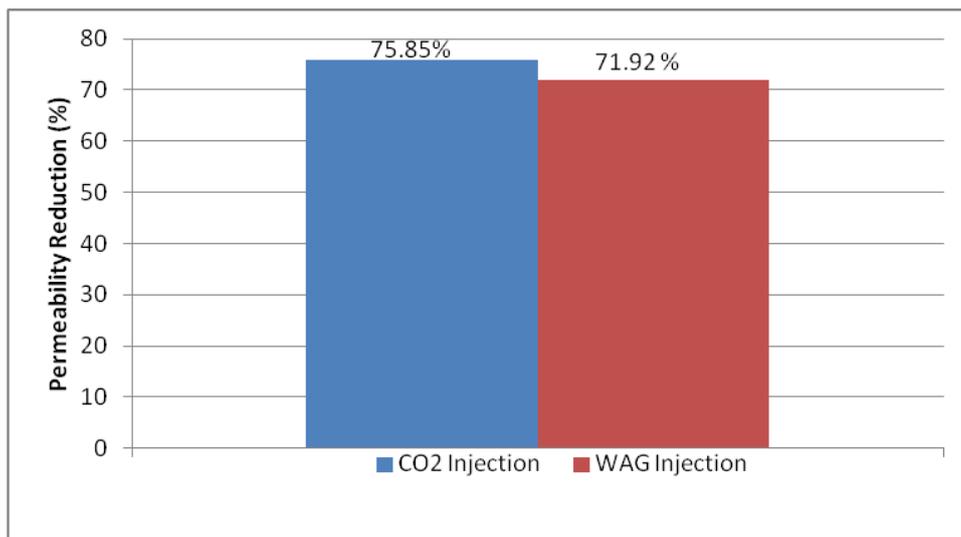


Figure 14: Permeability Reduction during CO2 and WAG Injection

A larger reduction in porosity and permeability are observed with core undergo CO2 flooding. In CO2 injection, permeability decline of 75.85% and porosity reduction of 7.01% was detected. In WAG injection, the permeability decline was 71.91% while porosity reduction is 6.66%. It is observed that the degree of porosity and permeability reduction is a function of the degree of asphaltene precipitation. This can explained why the permeability reduction of core undergo CO2 injection is more than WAG injection.

As discussed in the previous section, asphaltene precipitation increases with the time the CO<sub>2</sub> gas contacted the oil. Thus, with time, it is anticipated that the porosity and permeability reduction would be getting higher. More asphaltene may continue to deposit and accumulate resulting in severe core plugging problem. The effect of asphaltene precipitation on porosity and permeability reduction depends on few factors. For instance, the pore size distribution, the degree of asphaltene deposition and the initial permeability of the formation.

#### **4.5 Effect of Asphaltene Precipitation on Rock Wettability**

Once the asphaltene is destabilized, the highly polar and surface active asphaltene particles would adhere onto rock surface and change its wettability. The core wettability is determined through contact angle measurement using sessile drop method. The angle of the denser fluid (brine) to the rock surface of less than 90° indicates a water wet condition while an angle of more than 90° indicates an oil wet condition as illustrated in figure 15.

For run 1, the CO<sub>2</sub> gas injected changed the rock wettability from water wet (25°) toward more oil wet condition (70°). This signifies the role of asphaltene precipitation on wettability alteration to more oil wet. These findings should be placed high concern as wettability alteration governs the relative permeability curve, end point saturation and oil recovery. The change of rock oil wet may cause higher water cut that reduces the amount of oil recovered.

For run 2 under WAG injection, the original water wet condition (25°) of the rock remained, in which the wettability of the rock moved towards more water wet (27°) after displacement test. The presence of water film on the rock surface is believed to shield the rock surface from interaction with the asphaltene particles. This is also explained why during WAG injection, the asphaltene precipitation is less and the original wettability moved to more water wet. Table 8 summarizes the findings on the change of rock wettability before and after core displacement.

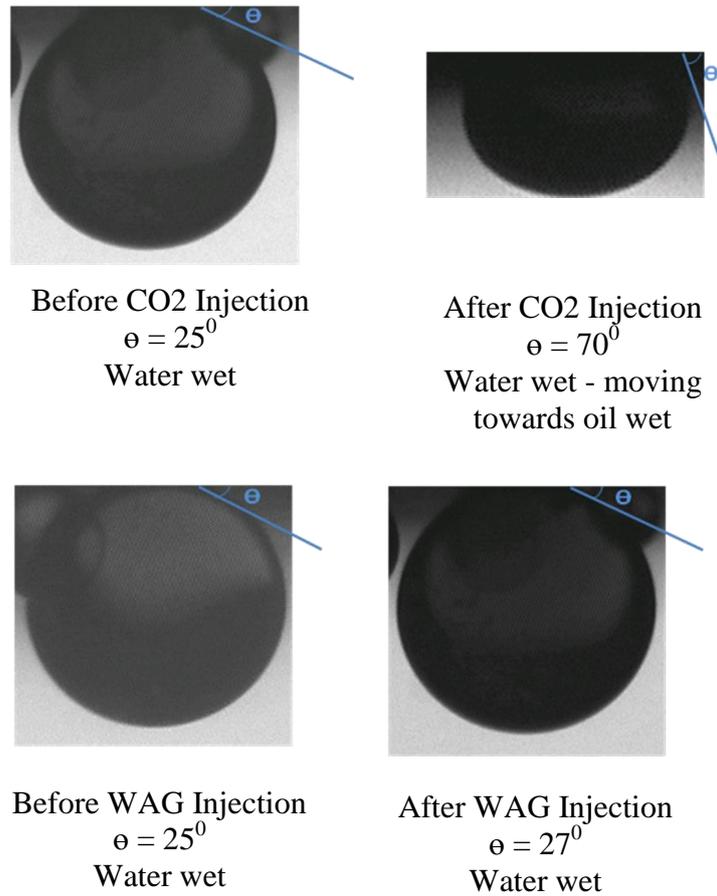


Figure 15: Contact Angle Measurement for CO<sub>2</sub> and WAG Injection Before and After Core Flooding

#### 4.6 CO<sub>2</sub> and WAG injection Oil Recovery Factor

Table 8 presents the oil recovery factor for CO<sub>2</sub> and WAG injection. During CO<sub>2</sub> injection, 17.18% of the original oil in place was displaced, while for WAG injection, a total of 24.72 % of water was produced. The results indicated that both CO<sub>2</sub> and WAG injection can improve the oil recovery after water flooding. It can be obviously distinguish that WAG injection shows a better performance in oil recovery. The residual oil saturation after CO<sub>2</sub> injection is 0.63, which is less than that of 0.39 after WAG injection. Detailed calculation of oil recovery factor is stated in the Appendix.

Table 8: Recovery Calculation from Displacement Test

	<b>Water Flooding (%OOIP)</b>	<b>EOR (%OOIP)</b>
<b>Run 1 (CO2 flooding)</b>	<b>17.18</b>	<b>18.92</b>
<b>Run 2 (WAG flooding)</b>	<b>24.72</b>	<b>47.05</b>

From the results, it is justified that gas injection during tertiary oil recovery can significantly increase oil recovery. The mechanisms behind the oil recovery increment are oil swelling, reduction of the reservoir fluid viscosity and interfacial tension (IFT). However, one problem encounters with CO2 flooding is the gas fingering problem. Gas fingering problem may cause early breakthrough and sweep efficiency reduction. As gas injected is less viscous than the reservoir oil, the gas will tend to displace the oil causing instability in the displacement front. The instability will then induce an initially sharp displacement front which will further convolute and develop “fingers” which will cause undesired early breakthrough.

WAG injection can be used as a main mobility control scenario for the fingering problem. It is working on the principle of decreasing the mobility behind the flood front to increase the sweep efficiency. Thus, the presence of water has reduces the relative permeability to gas, lower the mobility, and reduce the fingering phenomena which resulted in higher oil recovery.

Figure 16 illustrates the recovery factor of CO2 and WAG injection. Based on the results, WAG injection gave a recovery of about 47.05 % of residual oil in place (OOIP) while CO2 injection only gave a recovery of about 18.92% OOIP. During CO2 injection, the change of wettability to more oil may cause the increased of irreducible oil saturation, resulted in lower oil recovery which is not favorable in oil recovery.

It is also observed that during CO2 injection, the change of wettability to oil wet increases othe irreducible oil saturation. However, during WAG injection, the water wet condition of the rock retained. The presence of water film on rock surface had maintained the water wet condition of the rock, led to less amount of

asphaltene precipitated. The retention of rock initial water wet condition would increase the relative permeability to oil and increase oil recovery.

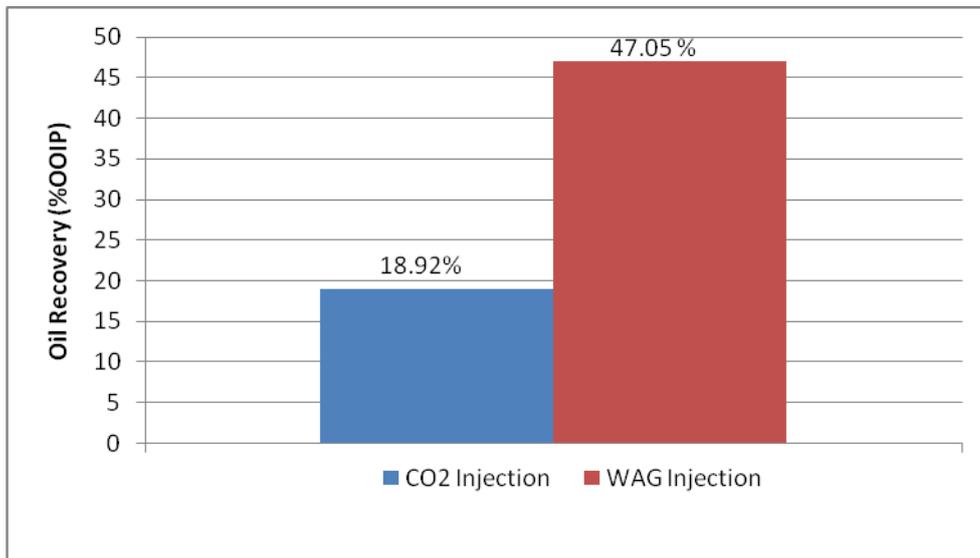


Figure 16: Recovery Factor of CO2 and WAG Injection

## **CHAPTER 5**

### **CONCLUSION AND RECOMMENDATION**

Both CO<sub>2</sub> and WAG injection would cause asphaltene instability. The precipitation of asphaltene may lead to reduction in porosity, permeability and alter the rock wettability. A smaller reduction in amount of asphaltene precipitation is observed with WAG injection. It is due to the tendency of CO<sub>2</sub> gas to dissolve in water, which reduces its concentration and minimizes the asphaltene precipitation. The porosity and permeability reduction is higher during CO<sub>2</sub> injection due to more asphaltene precipitated. Other than that, the presence of asphaltene was observed to alter the rock wettability to more oil wet. However, in the presence of water film, the initially water wet condition of the rock remains. This retention of water wet condition of the core during WAG injection has contributed to higher oil recovery.

Overall, it is justified that CO<sub>2</sub> injection causes more asphaltene problem than WAG injection in terms of the amount of asphaltene precipitated, porosity and permeability reduction and wettability change. This research has further highlighted the beneficial of WAG injection over CO<sub>2</sub> injection in providing mobility control, giving higher sweep efficiency, higher oil recovery and lower asphaltene precipitation.

Other than focusing on determining the optimum condition of CO<sub>2</sub> injection, it is recommended to place the research focus on WAG injection too. Further studies are suggested in determining the optimum concentration of CO<sub>2</sub> and brine, which can give less asphaltene precipitation. More studies are also recommended on optimum WAG ratio to have a better understanding of the role of water in reducing asphaltene precipitation.

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**APPENDIXES**

**Appendix 1: Core Flooding Results**

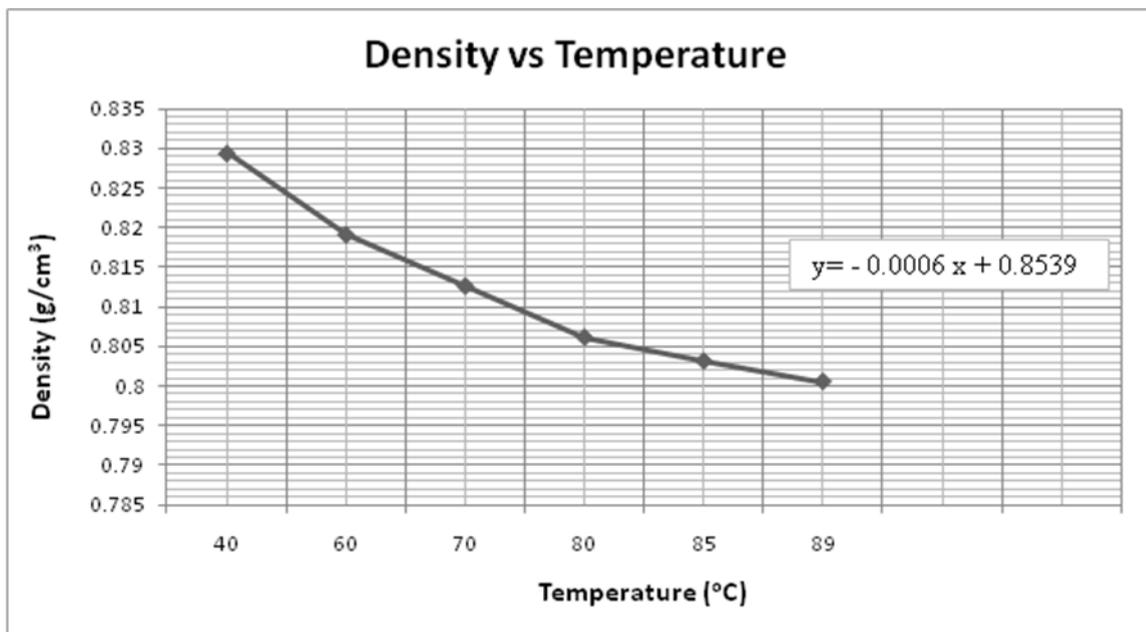
<b>Parameters</b>	<b>CO2 Flooding</b>	<b>WAG Flooding</b>
Pore Volume (ml)	15.087	15.473
Initial Oil Volume (ml)	11.47	7.97
Initial Oil Saturation	0.76	0.52
Initial Water Volume (ml)	3.617	7.503
Initial Water Saturation	0.24	0.48
<b>Water Flooding</b>		
Oil Produced (ml)	1.97	1.97
Residual Oil Volume (ml)	9.50	6.00
Residual Oil Saturation	0.63	0.39
Residual Water Volume (ml)	5.587	9.473
Residual Water Saturation	0.37	0.61
Oil Recovery Factor	17.18 %	24.72 %

**Appendix 2: Oil Recovery Factor**

<b>Time (min)</b>	<b>CO2 Flooding</b>		<b>WAG Flooding</b>	
	<b>Vp of injection</b>	<b>Oil Produced (ml)</b>	<b>Vp of injection</b>	<b>Oil Produced (ml)</b>
25	0.33	0.70	0.33	3.05
50	0.66	0.32	0.65	0.40
75	0.99	0.20	0.97	0.30
100	1.32	0.10	1.29	-
125	1.66	0.40	1.62	-
150	1.99	0.45	1.95	-
Total Oil Produced		2.17		3.75
Oil Recovery Factor (OOIP)		18.92 %		47.05 %

### Appendix 3: Oil Sample Density

Temperature ( $^{\circ}\text{C}$ )	Density (g/cc)
40	0.82940
60	0.8191
70	0.8126
80	0.8061
85	0.8031
89	0.8005



Given the above line equation  $Y = 0.0006x + 0.8539$  (7)

The density (Y) of crude at temperature (X) of  $100^{\circ}\text{C}$  is as below:

$$\begin{aligned} Y &= -0.0006(100) + 0.8539 \\ &= 0.7939 \text{ g/cc} \end{aligned}$$

#### Appendix 4: Oil Sample API Gravity

$$API\ Gravity = \frac{141.5}{SG} - 131.5 \quad (8)$$

SG = Specific Gravity

Equation to obtain the oil specific gravity,

$$SG = \frac{\rho\ oil}{\rho\ H20} \quad (9)$$

$\rho\ oil$  = Density of oil

$\rho\ H20$  = Density of water

\* The above equation is applied with reference to density of water at 15.55 °C or 60 °F, which is 1.0g/cc.

The density of oil sample at 15.55 °C is obtained from the line equation (7) in Appendix 3. The density (Y) of crude at temperature (X) of 15.55 °C is as below:

$$\begin{aligned} Y &= - 0.0006 (15.55) + 0.8539 \\ &= 0.84457\ g/cc \end{aligned}$$

Thus, the specific gravity,

$$SG = \frac{0.84457}{1.0} = 0.84457$$

The Oil API Gravity,

$$API\ Gravity = \frac{141.5}{0.84457} - 131.5 = 36.04$$

### Appendix 5: Asphaltene Content Measurement

Below is the asphaltene content (wt%) of the effluent oil measured after the core displacement experiment:

	<b>Pore Volume of Injection</b>	<b>Asphaltene content (%)</b>
<b>Run 1 (CO2)</b>	0	0.12
	0.33	0.096
	0.66	0.064
	0.99	0.046
	1.66	0.042
<b>Run 2 (WAG)</b>	0	0.12
	0.33	0.111
	0.65	0.070
	0.97	0.055

## **NOMENCLATURES**

EOR – Enhanced Oil Recovery

CO<sub>2</sub> – Carbon Dioxide

WAG – Water-Alternating-Gas

wt % – Weight Percentage Percent

ASTM – American Society for Testing and Materials

V<sub>oi</sub> – Initial Oil Volume

V<sub>o</sub> – Produced Oil Volume

V<sub>b</sub> – Bulk Volume

V<sub>p</sub> – Pore Volume

r – Radius of the core

L – Length of Core Sample

S<sub>oi</sub> – Initial Oil Saturation

S<sub>or</sub> – Residual Oil Saturation

K<sub>air</sub> – Air Permeability

K<sub>∞</sub> – Corrected Permeability for Klinkenberg Effect

ϕ – Porosity

OOIP – Original Oil in Place