Comparative Study of Different CO2 Injection Modes for Baronia RV2 Reservoir

by

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the requirements for the
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CERTIFICATION OF APPROVAL

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A project dissertation submitted to the
Mechanical Engineering Programme
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Approved by,

____
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UNIVERSITI TEKNOLOGI PETRONAS

TRONOH, PERAK

December 2008

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.

SITI FATIMAH BINTI MAZALAN

ABSTRACT

CO_2 flooding can be executed using several modes of injection technique such as continuous injection, simultaneous water and gas (SWAG) injection, water alternate gas (GAS) injection and hybrid WAG. Each of these injection modes will give certain amount of recovery based on their capability to restore formation pressure and also to improve oil displacement or fluid flow in the reservoir. Therefore, experiments or simulations may need to be conducted to determine the most effective injection mode which gives the most optimum recovery for a given reservoir. This project presents an experimental study of comparing different CO_2 injection mode for Baronia RV2 reservoir. It is the main objective to determine the most optimum CO_2 injection mode for this field. Using a coreflood equipment, CO_2 displacements were conducted on four core plugs saturated with Baronia RV2 crude oil. From the results of total oil recovered, it was found that SWAG is the most technically feasible mode for the field with over 60% recovery factor.

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CHAPTER 1

INTRODUCTION

1.1 BACKGROUND OF STUDY

1.1.1 Improve Oil Recovery

As of 1st January 2003, the Malaysian oil reserves figure stands at 3.5 Billion Stock Tank Barrel (Bstb) and the cumulative oil production is 4.9 Bstb and original oil in place (OOIP) of 24.9 Bstb [1]. These figures translate to an average oil recovery factor of 34%. This means that there is still a substantial amount of remaining petroleum resources in the ground that could potentially be recovered through other means such as improved oil recovery (IOR) or enhanced oil recovery (EOR).

Enhanced Oil Recovery (EOR) may be defined as any of several techniques that make it possible to recover more oil than can be obtained by natural pressure, such as the injection of fluid or gas into an oil reservoir to force more oil to the service. This is considered the third stage of hydrocarbon production. EOR can begin after a secondary recovery process or at any time during the productive life of an oil reservoir. Its purpose is not only to restore formation pressure but also to improve oil displacement or fluid flow in the reservoir. The three major types of enhanced oil recovery operations are chemical flooding (alkaline flooding or micellar-polymer flooding), miscible displacement (carbon dioxide [CO2] injection or hydrocarbon injection), and thermal recovery (steamflood). The optimal application of each type depends on reservoir temperature, pressure, depth, net pay, permeability, remaining oil and water saturations, porosity and fluid properties such as oil API gravity and viscosity [2].

Oil recovery by solvent flooding, particularly CO_2 as a flooding medium is finding increasing application in the field because it can prolong the production lives by 15 to

20 years and may recover 15 to 25% of OOIP [1]. CO_2 miscible flooding is expected to improve reservoir recovery and performance of Baronia RV2.

1.1.2 Baronia RV2 Reservoir

Baronia RV2 field is located about 40km offshore Baram Delta Province, Sarawak, and is one of the largest reservoirs in Baronia oil field. The field is a simple unfaulted domal structure discovered in 1967. It has no internal faulting and is located between major east west trending growth faults with water depth about 76 meters [1].

Stratigraphically, the field consists of alternations of sands, silts and shales of Cycle VI and VII. The main lithology of the field is sandstone interbedded with siltstones and shale of Late Miocene age at depth between 1,615 to 2,410 m. The standstone's thickness ranges from 3 to 75 m whereas the shale's thickness ranges from 1.5 to 90 m. In poorly developed sandstones, the porosity of the formation range from 13 to 25% and range from 26 to 30% in the better developed sandstones. Most of the standstones are fine grained with permeability varies from 100 to 350mD [1].

Currently there are seven producing wells and four water injection wells with current reservoir pressure about 3,300 psia and reservoir temperature is about 194 ^{0}F. the producers namely BN-6, BN-10, BN-31, BN-32, BN-41, BN-65 and BN-66 while the injectors are BN-51, BN-52, BN-58 and BN-60 wells. Production from the Baronia field peaked about 9,600 stb/d and currently is about 4,600 stb/d since initiated in 1972. The estimated OOIP is 148 MMstb and water cut is about 34%. Cumulative production to date is about 34 MMstb (about 24% OOIP) [1].

The hydrocarbons in Baronia are found in staked reservoirs. The main reserves are distributed over ten sandstone reservoirs with at least eight separate oil-water contacts (OWC). The oil gravity is around 42 ^{o}API with oil formation volume factor of 1.55 rb/stb. The initial dissolved gas-to-oil ratio is 1,038 scf/stb and oil viscosity is 0.3 cP. Since no gas was seen on logs, RV2 was assumed to be an undersaturated reservoir at initial reservoir pressure of 3,420 psi [1]. The average reservoir parameters for Baronia RV2 reservoir are shown in Table 1.1

Table 1.1: average reservoir parameters for Baronia RV2 [1].

Reservoir Parameters	**Average value**
Depth	7,830 ft
Thickness	128 ft
Porosity	17.50 %
Permeability	70 mD
Initial Reservoir Temperature	202 ^{o}F
Temperature	194 ^{o}F
Initial Reservoir Pressure	3,420 psi
Oil Gravity	42 ^{o}API
Oil Viscosity	0.3 cP
Initial Oil Formation Volume Factor	1.55

1.2 PROBLEM STATEMENT

CO_2 injection has been identified to be the most feasible EOR process for Malaysian field. There are many strategies on how the CO_2 injection can be executed, which includes continuous, SWAG, WAG and hybrid WAG injection. Continuous injection can produce high oil produced to CO_2 injection ration, early production response, but accompanied by viscous fingering problem. On the other hand, utilizing SWAG mode would reduce viscous fingering and provide better mobility control compared to WAG. However, one of the complications of this mode is the insufficient CO_2 availability at the flood front to maintain continuous oil viscosity reduction. WAG process would reduce viscous fingering effect and gives higher CO_2 utilization, hence less CO_2 breakthrough but its main disadvantages is the loss of injectivity, giving slower oil production response. The last mode of study, hybrid WAG has the same advantages as the conventional WAG process and it would give early production response and better injectivity. Each of the injection modes has their own advantages and disadvantages. Therefore careful selection of the injection mode must be made, either by simulation or by lab experiments before any pilot evaluation of field implementation.

1.3 SIGNIFICANT OF STUDY

This project is to conduct comparative experimental study for Baronia RV2 reservoir.

Miscibility can be achieved at current Baronia RV2 reservoir temperature and pressure hence this study is focused on miscible carbon dioxide displacement. Miscible fluids have no interfaces and consequently have no interfacial tension therefore it can reduce residual oil saturation to its lowest possible value and maximize the recovery. The chosen of carbon dioxide gas instead of nitrogen gas is because the carbon dioxide gas has smaller differential in viscosity with Baronia crude oil and will gives lower interfacial tension thus make it easier to achieve miscibility.

The result of this study will enhance our understanding on the benefits of CO_2 injection/ flooding for Baronia oil fields and will assist decision making in the further development of the field.

1.4 OBJECTIVE AND SCOPE OF STUDY

The main objective of this project is to determine the most optimum injection mode of CO_2 flooding for the Baronia RV2 reservoir, by means of coreflood displacements.

The scope of study for this project are:

1) Perform literature review on Enhanced Oil Recovery (EOR) techniques and specifically study on injection modes selected to be experimented for this project which are:
    i. Continuous injection
    ii. Simultaneous water and gas (SWAG) injection
    iii. Water alternate gas (WAG) injection
    iv. Hybrid WAG injection

2) Study on the background of Baronia RV2 reservoir.
3) Design of experiments for each mode of CO_2 injection.
4) Design of modification to the core flood equipment to suit the specific need of this project.
5) Running experiments for each mode of injection.
6) Analyze and compare results from the experiment.

CHAPTER 2

LITERATURE REVIEW

Enhanced oil recovery (EOR) basically a tertiary oil recover technique to recover remaining oil after the primary and secondary methods have run their courses. EOR is a generic term for techniques for increasing the amount of oil that can be extracted from and oil field. Using EOR, 30-60% or more of the reservoir's original oil can be extracted compared with 20-40% using primary and secondary recovery [3]. Primary recovery produces oil and gas using the natural pressure of the reservoir as the driving force to push the material to the surface. Secondary recovery uses other mechanisms such as gas re-injection and water flooding to produce residual oil and gas remaining after the primary recovery phases. While tertiary recovery (EOR) involves injecting other gases (such as carbon dioxide) or heat (steam or hot water) to stimulate oil and gas flow to produce remaining fluids that were not extracted during primary or secondary phase [4]. The EOR technique is achieved by either gas injection, thermal recovery or chemical injection [3]. Gas injection is the most commonly used in EOR technique. The most commonly used gasses in gas injection technique are nitrogen gasses, CO_2, hydrocarbon gasses because of they are cheap and readily available as waste material. Here, gas such as carbon dioxide (CO_2), natural gas, or nitrogen is injected into the reservoir whereupon it expands and thereby pushes additional oil to a production wellbore, and moreover dissolves in the oil to its lower viscosity and improves the flow rate of the oil [3].

2.1 CO_2 FLOODING

CO_2 flooding has been identified as one of the most feasible EOR technique in Malaysia [3]. Oil displacement by CO_2 injection relies on the phase behavior of CO_2 and crude oil mixtures that are strongly dependent on reservoir temperature, pressure and crude oil composition. These mechanisms range from oil swelling and viscosity reduction for injection of immiscible fluids (at low pressures) to completely miscible displacement in high-pressure applications. In these applications, more than half and up to two-thirds of the injected CO_2 returns with the produced oil and is usually re-injected into the reservoir to minimize operating costs. The remainder is trapped in the oil reservoir by various means [3].

Although the CO_2 flooding has been selected as the most feasible technique, the most effective injection technique is yet to be determined. Several types of injections that can be implemented by CO_2 flooding are Continuous injection, Water Alternating Gas (WAG), Simultaneous Water and Gas (SWAG) injection as well as Hybrid WAG. Each of the injection type has it owns advantages and disadvantages.

CO_2 flooding can be an ideal tertiary recovery method. It is particularly effective in reservoirs deeper than 2,000 ft with API oil gravity greater than 22^0 and remaining oil saturation greater than 20%. The viscosity of the reservoirs should be less than 15 cP (preferably less than 10 cP). CO_2 can dissolve in water; thus it can lower the interfacial tension between oil and water. CO_2 is uniquely solvent which potential to perform either as an immiscible or a miscible EOR agent. The nature of its behavior is dependent upon the composition of the oil and the reservoir pressure and temperature. Whether the process is carried out as a miscible or as an immiscible displacement and regardless of the method it applied in the field, the reduction of oil viscosity, swelling of oil, vaporization of oil, miscibility effects and reduction of interfacial tension mechanism play an important role in increasing the oil recovery by CO_2 flooding. These mechanisms are more or less important depending on whether the CO_2 displacement is miscible or immiscible. For example, with the miscible CO_2 process, the vaporization of the crude oil, development of miscibility and reduction of interfacial tension are very important whereas with immiscible CO_2 displacement, reduction of crude oil viscosity and swelling of oil are important effects [1].

The disadvantage of CO_2 flooding compared with waterflooding results from the low viscosity of CO_2 relative to that of oil [1]. For example, at a reservoir temperature of 110^oF, CO_2 viscosity is about 0.03 cP at 1,500 psi, whereas at 2,500 psi, the viscosity is about 0.06 cP. The low viscosity of CO_2 causes the mobility ratio in most CO_2 floods to be unfavorable; and unfavorable mobility ratio affect sweepout adversely [1].

The densities of oil and CO_2 are similar at many reservoir conditions, which tend to minimize, although not necessary eliminate, segregation between these fluids in reservoirs that have not been waterflooded. In reservoir that have been waterflooded or have had water injected with CO_2 to counteract the effects of viscosity ratio and permeability stratification, the density contrast between water and CO_2 may cause segregation [1].

2.1.1 The CO_2 Miscible Process

In general, miscibility between fluids can be achieved through two mechanisms; first-contact miscibility and multiple-contact miscibility. When two fluids become completely miscible, they form a single phase, one fluid can completely displace the other fluid, leaving no residual saturation. A minimum pressure is required for two fluids to be miscible [5].

A clear example of first-contact miscibility is ethanol and water. Regardless of the proportions of the two fluids, they immediately form one phase with no observable interface. Butane and crude oil also are first-contact miscible, and butane might make an ideal solvent for oil were it not for its high cost. In the multiple-contact miscible process that takes place with CO_2 and crude oil, CO_2 and oil are not miscible on first contact, but require many contacts in which components of the oil and CO_2 transfer back and forth until the oil-enriched CO_2 cannot be distinguished from the CO_2-enriched oil. This process is called condensing/ vaporizing mechanism. Multiple-contact miscibility between CO_2 and oil starts with dense-phase CO_2 and hydrocarbon liquid. The CO_2 first condenses into the oil, making it lighter and often driving methane out ahead of the “oil bank.” The lighter components of the oil then vaporize into the CO_2-rich phase, making it denser, more like the oil, and thus more easily soluble in the oil. Mass transfer continues between the CO_2 and oil until the resulting two mixtures become indistinguishable in terms of fluid properties. At that point, there is no interface between the CO_2 and oil, and one hydrocarbon phase results [5].

Fig. 2.1 illustrates the condensing/ vaporizing mechanism for miscibility. During the oil displacement, there is a gradation in composition from pure CO_2 on the left (injection side) to virgin oil on the right (production side). The vaporizing region occurs upstream of the condensing region. Every contact in the process involves a miscible displacement, even though pure CO_2 is not miscible with original oil [5].

Miscibility development between CO_2 and oil is a function of both temperature and pressure, but for an isothermal reservoir, the only concern is pressure. As pressure increases, the oil can dissolve more CO_2, and more oil components can be vaporized by the CO_2. At some pressure, when the CO_2 and oil are in intimate contact, they will become miscible. When the contact between CO_2 and oil occurs with little or no reservoir mixing, the pressure at which miscibility happens is defined as the thermodynamic minimum miscibility pressure (thermodynamic MMP). The effect of small-scale reservoir mixing can decrease the displacement efficiency of CO_2 and increase the pressure required for miscibility [5].

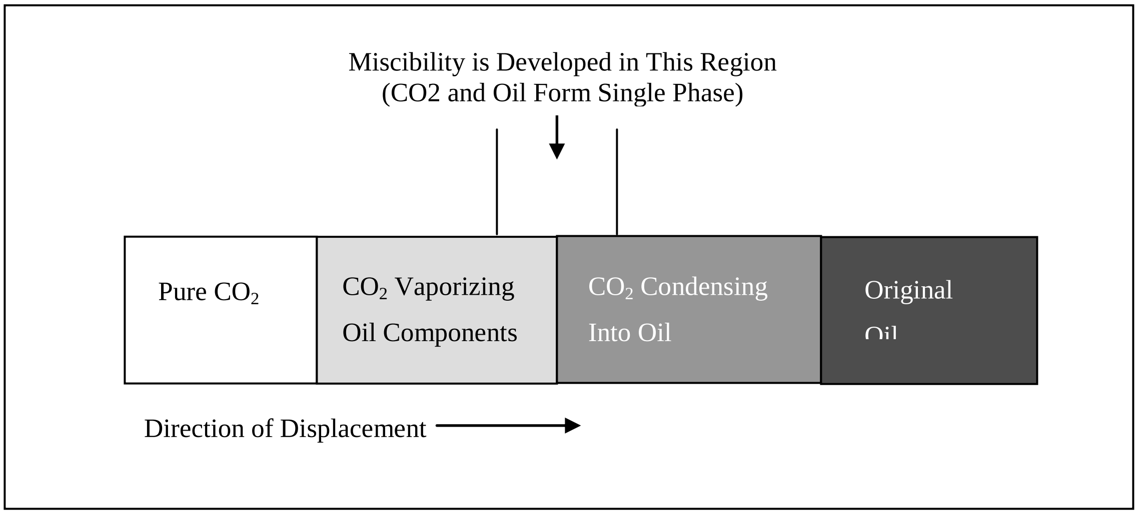


Fig. 2.1: Condensing/ vaporizing mechanism

Even though CO_2 is not miscible with reservoir oil on first contact, when it is forced into a reservoir a miscible front is generated by a gradual transfer of smaller, lighter hydrocarbon molecules from the oil to the CO_2. This miscible front is in essence a bank of enriched gas that consists of CO_2 and light hydrocarbons. Under favorable conditions of pressure and temperature, this front will be soluble with the oil, making it easier to move toward production wells. CO_2 vaporizes or extract hydrocarbon from the crude as heavy as the gasoline and gas/oil fractions. Vaporization occurs at temperature where the fluid at the displacement front is CO_2-rich gas, and the extraction occurs at temperatures where the fluid at the displacement front is CO_2-rich liquid. According to the pseudoternary diagram concept of CO_2 /reservoir oil phase behaviour, no tie lines pass through the reservoir oil composition above the MMP; and because of this, vaporization/ extraction can proceed to such and extent and so alter the composition of displacing fluid at the displacement front that dynamic miscibility result after sufficient contacting has occurred between the CO_2 and the reservoir oil [6].

The pressure required for achieving dynamic miscibility with CO_2 is usually significantly lower than the pressure required for dynamic miscibility with either natural gas, flue gas, or nitrogen. This is a major advantage of the CO_2 miscible process because dynamic miscibility can be attainable pressures in a broad spectrum of reservoirs [6].

2.1.2 The Estimation of Miscibility Pressure

Based on experimental study of factors affecting CO_2 miscibility pressure, following conclusion were made: [7]

1. Dynamic miscibility occurs when the CO_2 density is sufficiently great that the dense gas CO_2 or liquid CO_2 solubilizes the C_5-through-C_{30} hydrocarbons contained in the reservoir oil. For the particularly oils examined in their study, Holm and Josendal observed that the miscible displacement occurred at CO_2 densities ranging from 0.4 to 0.65 g/cm3 depending on both the total amount of

C_5-through-C_{30} hydrocarbon in the C_5^+ fraction of the reservoir oil and the distribution of hydrocarbons in this carbon range [7].

2. Reservoir temperature is an important variable affecting MMP because of its effect on the pressure required or achieve the CO_2 density required for miscible displacement. A higher temperature results in a higher miscibility pressure requirement, other factors being equal [7].
3. MMP is inversely related to the total amount of C_5-through-C_{30} hydrocarbons present in the crude oil. The more of these hydrocarbons contained in the crude oil, the lower the miscibility pressure [7].
4. MMP is affected by the molecular weight distribution of the individual C_5-through-C_{30} hydrocarbons in the reservoir oil. Low-molecular-weight gasoline-range hydrocarbons are particularly effective in promoting miscibility and the result in a lower miscibility pressure requirement, other factors being equal [7].
5. MMP also is affected but to a much lesser degree by the type of hydrocarbons present in the C_5-through-C_{30} fraction. For example, aromatics result in lower miscibility pressure [7].
6. Properties of the heavy fraction (i.e., $> C_{30}$ hydrocarbons) also influence MMP, although they are not as important as the total quality of C_{30}^+ material [7].
7. Development of dynamic miscibility does not require the presence of C_2-through-C_4 hydrocarbons [7].
8. The presence of methane in the reservoir does not change the MMP appreciably [7].

2.1.3 Characteristic of CO_2

Recent activity in miscible flooding has focused on the CO_2 miscible process. CO_2 has a low viscosity, similar to that of hydrocarbon miscible solvents. As in hydrocarbon miscible flooding, volumetric sweepout in CO_2 flooding is affected by an unfavourable viscosity ratio. CO_2 density is similar to that of oil in many reservoirs, which minimizes CO_2/oil segregation, but there is enough density contrast with brine for gravity segregation to occur when there is mobile reservoir brine.

Despite its low viscosity, CO_2 can be attractive injection fluid. Dynamic miscibility can be achieved in many reservoirs because of a relatively low operating pressure requirement. In addition, both supply and cost of CO_2 for miscible flooding may be more favourable in the future than for hydrocarbon-miscible solvents. This is because large quantities of CO_2 are available from natural deposits and from manufacturing and power generating plants as by-products. CO_2 from some of these sources, particularly natural deposits, potentially may be developed and transported to favourably located oil fields at acceptable cost [6].

2.2 CO_2 INJECTION MODES

2.2.1 Continuous Injection

For continuous CO_2 injection, a predetermined CO_2 slug volume is injected continuously with no other injected fluid or chase fluid to the end of recovery. This approach usually is applied in gravity-drainage reservoir or nonwaterfloodable reservoir directly following primary depletion [5]. Continuous injection can produce high oil produced to CO_2 injection ration, early production response, but accompanied by viscous fingering problem. It has disadvantages of high mobility of the gas that limits the vertical and the area sweep efficiencies of the gas injection [1].

2.2.2 Water alternating Gas (WAG) Injection

The WAG process involves injecting alternating cycles of gas and water. The significant of this process is to increase the sweep efficiency during gas injection mainly by utilizing the water to control the mobility of the displacement and stabilize the front thus reducing the impact viscous fingering. The process fundamental principle is based on the experimental fact that the total mobility of a two phase system is less than single phase mobility by proper selection of ratio of the volumes injected [1].

2.2.3 Hybrid WAG Injection

Hybrid WAG is referred to a process where large slugs of gas are injected into the reservoir and subsequently followed by a relatively small number of slugs of water and gas [1]. The water serving to improve sweep efficiency and to minimize the amount of CO2 required for the flood.

2.2.4 Simultaneous Water and Gas (SWAG) Injection

SWAG has been suggested as a means to reduce the capillary entrapment of oil in small scale reservoir heterogeneity, reduce viscous fingering and providing better mobility control of the gas compared to WAG and continuous injection processes. However, one of the complications of this mode is the insufficient CO_2 availability at the flood front to maintain continuous oil viscosity reduction. The process consists of mixing the gas with water at a pressure sufficient to maintain bubble flow of a gas dispersed in a water flow stream. The mixing occurred at the wellhead resulted in a two phase well stream from the wellhead down to the perforations to avoid segregation in the surface system [1].

2.3 LITERATURE REVIEW ON OTHER PEOPLE’S WORK

Previous study has been made on “Numerical Evaluation of Single-Slug, WAG, and Hybrid WAG CO_2 Injection Processes, Dollarhide Devonian Unit, Andrews Country, Texas” by E.C Lin and E.S Poole. This paper summarizes a numerical evaluation of the effectiveness of applying the conventional single-slug (continuous injection), water-alternating-gas (WAG) CO_2 injection processes and an innovative hybrid WAG process at the Dollarhide Devonian Unit, Andrews Country, Texas [8].

Dollarhide crude is a relatively light fluid with a 40^{o}API gravity. Initial bubblepoint pressure was about 2,830 psi, which is lower than the initial reservoir pressure of 3,300 psi. Initial solution GOR was about 1,270 scf/bb [8]l

Under the most likely reservoir conditions during CO_2 flooding (TR=120^oF and an average reservoir pressure of 3,200 psi), the density of Dollarhide crude is only slightly greater than that of CO_2 (0.8 vs. 0.76 g/cm^3). This small difference significantly reduces the adverse effect if gravity override of CO_2 during injection. The viscosity ratio of crude to CO_2 at such conditions is <10, which implies that only moderate viscous fingering will occur [8].

The minimum miscibility pressure was measured to be about 1,650 psi. This pressure is several hundred psi lower than the average reservoir pressure during CO_2 flooding. As a result, a miscible process is to be expected for CO_2 flooding at the Dollarhide field [8].

2.3.1 Continuous CO_2 Injection Prediction Runs.

Five slug sizes (8.8, 20, 30, 40, and 50% HCPV CO_2 injection) were investigated for the continuous injection process to determine the optimal slug size to be used for the Dollarhide field application [8].

It was found that the incremental oil recovery was increased and the solvent efficiency (i.e., the ratio of incremental oil recovery to the amount of CO_2 injected) decreased with increasing CO_2 slug size. Beyond a slug size of 30% HCPV CO_2, the solvent efficiency dropped below 0.1bbl/Mcf. With such low solvent efficiencies, a CO_2 flood project is not likely to be economical. As a result, a CO_2 slug size of 20% HCPV was selected and used in this study for comparing oil recovery from various CO_2 injection processes [8].

2.3.2 CO_2-WAG-Injection Prediction Runs.

During WAG injection studies, the total volume of CO_2 injected was kept at 30% HCPV. A sensitivity study indicated that different WAG ratios from 0.5 to 2 did not affect oil recovery significantly as long as the total volume of CO_2 injected was identical. A WAG ratio of 1:1 was selected for comparison with the continuous process [8].

Incremental oil recovery for the WAG process was 1.9% OOIP higher than the comparable continuous injection case. Further study indicates an acceleration of oil production for the continuous injection, while the WAG case gained advantage in cumulative oil recovery [8].

2.3.3 Hybrid-CO_2-Injection Prediction Runs.

In light of favorable early response by the continuous process and the overall higher oil recovery by the WAG process, an innovative hybrid CO_2 injection process was investigated. This hybrid process begins with an 8.8% HCPV pre-WAG initial slug CO_2 injection followed by injection of 42.4% HCPV of 1:1 WAG CO_2. This makes a total of 30% HCPV CO_2 injection before water injection to the economic limits. It was anticipated that this hybrid operation effectively would create an oil bank during initial slug injection and maintain higher oil production rates through improved mobility control during WAG injection. The selection of an initial CO_2 slug of 8.8% HCPV was reasonable because CO_2 is about to break through at the end of this injection [8].

From the simulation, it is predicted that WAG process is the most attractive process for the Dollarhide application as it gives the highest cumulative oil recover, 66%

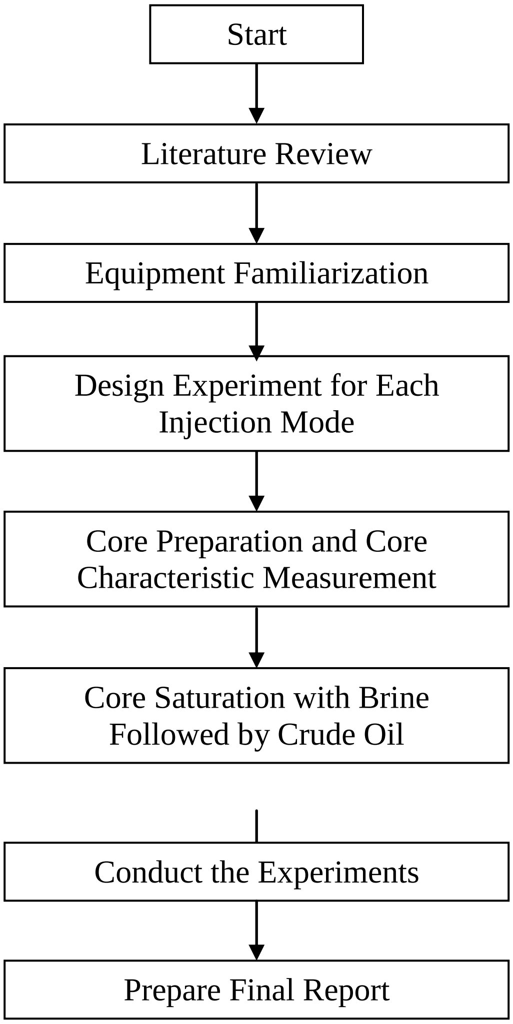
Table 2.1: Summary of Simulation Prediction Result for the Dollarhide Field Study [8].

	30% HCPV CO2 Continuous	30% HCPV CO2 1:1 WAG	30% HCPV CO2 hybrid WAG
Cumulative oil recovery, % OOIP	64.1	66.0	64.8

CHAPTER 3

METHODOLOGY

The methodology of conducting this project work is summarized in the following flowchart.



3.1 EQUIPMENT

Experiments on CO2 flooding were conducted on a core flood equipment called "Relative Permeability Test System" (RPS). This system can accommodate gas injection by means of gas mass flow controllers. The system is provided with precision metering pumps for constant pressure or constant flow rate injection. The produced phases are collected in either a fraction collector or phase separator depending upon the option chosen.

Figure 3.1: Relative Permeability Test System (RPS)

The fluid injected will be accumulated in the accumulator until it built up to required pressure before injected through the core. The core sample is placed inside the horizontal core holder with overburden pressure holding the core. Overburden pressure must be greater than injection pressure to ensure the injection fluid completely go through the core.

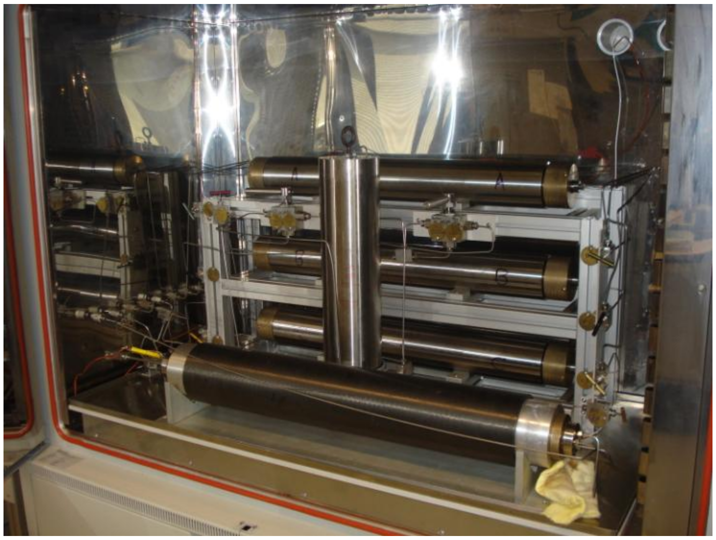


Figure 3.2: Accumulators and Core holder inside the sytem

Several parameters of the core are required prior to the start of experiments:

1. Density of the Gas
2. Viscosity of the Gas
3. Temperature and Pressure
4. Injection Flowrate

Item 1 and 2 are obtained from PVT data for CO_2

Item 3 relates to the prevailing reservoir temperature and MMP.

Item 4 is dictated by the actual velocity of the injected fluid front.

3.2 DESIGN THE EXPERIMENT FOR EACH INJECTION MODES

3.2.1 Calculate the value of viscosity and density of CO_2

Value of viscosity and density of CO_2 were obtained from PVT data-CO_2 Properties at Various Temperature, ^oF tables as shown in Appendix 11. The data for 800 psi properties are summarized in the Table 3.1.

Table 3.1: The summary of CO_2 properties at 800psi

Temperature, ^oF	**Viscosity, cP**	**Density, lbm/ft^3**
70	0.01909	10.28
77	**0.0189**	**9.671**
80	0.01882	9.41

3.2.2 Determine the injection flowrate for each injection modes.

The injection flowrate of each mode was designed in such that the velocity of the fluid injected will be 2 ft/day subsequently gives the flowarate value of 0.162cc/min. However, the coreflood equipment is unable to read flowrate value less than 0.5cc/min. Therefore, the velocity injected was set to be <u>15 ft/day.</u>

According to Buckley Leveret theorem, the velocity of the fluid front can be found by;

$$\left(\frac{\partial x}{\partial t}\right)_S = \frac{q}{\Phi A}\left(\frac{dF_S}{dS}\right) \quad \text{(Eq. 3.1)}$$

Where;

$\left(\frac{\partial x}{\partial t}\right)_S$: Velocity of the fluid injected

q: The flowrate of injection

Φ: Porosity of core samples

A: Area of core samples

$\left(\frac{dF_S}{dS}\right)$: The slope of the graph plotted between Fs vs. S

This equation however applies to 1-D waterflooding process. In order to manipulate this equation to describe movement of miscible fluid front, Koval's modifications to the Buckley Leveret theorem are required. In Koval method, F_S can be found by;

$$F_S = \frac{1}{1+\left(\frac{1-S}{S}\right)\left(\frac{1}{H}\right)\left(\frac{1}{E}\right)} \qquad \text{(Eq. 3.2)}$$

Where E is defined as;

$$E = \left(0.78 + 0.22\left(\frac{\mu_o}{\mu_g}\right)^{1/4}\right)^4 \qquad \text{(Eq. 3.3)}$$

Where;

Fs: Fractional Flow

S: Solvent saturation

H: Heterogeneity factor

E: Effective viscosity ratio

μ_o: Viscosity of oil

μ_g: Viscosity of gas (CO_2)

H: 1 (the fluid is homogenous)

μ_o: 0.3 cP

μ_g: 0.0189 cP

$$E = \left(0.78 + 0.22\left(\frac{0.3cP}{0.0189cP}\right)^{1/4}\right)^4$$

$$E = 2.2089$$

$$F_S = \frac{1}{1 + \left(\frac{1-S}{S}\right)\left(\frac{1}{1}\right)\left(\frac{1}{2.2089}\right)}$$

Using the Buckley-Leverett equation, the value of Fractional Flow, F_s for Solvent Saturation, S were obtained and shown in the table below:

Table 3.2: Value of Fractional Flow, Fs in corresponds with Solvent Saturation, S

S	F_s
0.1	0.197069431
0.2	0.355767578
0.3	0.48630707
0.4	0.595571703
0.5	0.688370546
0.6	0.768164805
0.7	0.837509123
0.8	0.898330145
0.9	0.95210832

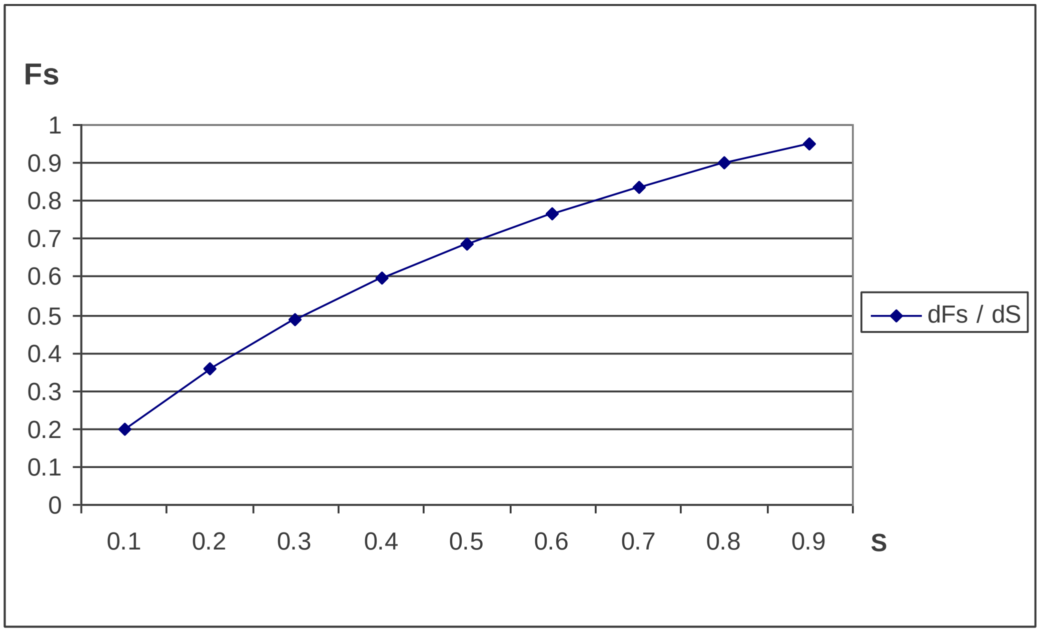


Figure 3.3: Graph of Fractional Flow, Fs vs. Solvent Saturation, S

From the graph, the value of slope which represent the $\frac{dF_S}{dS}$ is approximately 0.5378.

V= 15 ft/d

d= 0.125 ft

A= 0.01227 ft^2

Φ= 18%

Rearrange Equation 3.1;

$$q = \frac{\left(\frac{\partial x}{\partial t}\right)_S \times \Phi \times A}{\left(\frac{dF_S}{dS}\right)} \quad \text{(Eq. 3.4)}$$

The result of the calculation is shown in Table 3.3.

Table 3.3: Fluid injection flowrate for each of injection mode.

Core sample	Injection mode	Ratio	q_{water} (cc/min)	q_{CO2} (cc/min)
A	Continuous	0 : 1	0	1.1848
B	WAG	1 : 1	1.1935	1.1935
C	Hybrid WAG	1 : 1	1.1934	1.1934
C	SWAG	1 : 1	0.574	0.574

The calculations will be further discussed in Appendix 7.

3.2.3 Determine the time taken to complete the experiment.

The total time for injection is determined to control the pore volume injected through core. It can be computed as

$$Time(\min) = \frac{VolumeInjected\,(cc)}{Flowrate(cc/\min)} \quad \text{(Eq. 3.5)}$$

$$PV = BulkVolume \times AveragePorosity \quad \text{(Eq. 3.6)}$$

Table 3.4: Average Pore Volume for individual core

Core sample	Bulk Vol. (cc)	Average Porosity	Pore Vol. (cc)
A	87.05	0.1777	15.47
B	87.14	0.1793	15.62
C	87.05	0.1787	15.56
D	87.26	0.1712	15.00

Table 3.5: Total time taken to complete each of the injection modes.

Injection mode	Water			CO_2			Total time (min)
	q_{water} (cc/min)	PV injected	Time (min)	q_{CO2} (cc/min)	PV Injected	Time (min)	
Continuous	0	0	0	1.1848	4 PV	52.23	52.23
WAG	1.1935	4 PV	52.35	1.1935	4 PV	52.35	104.70
Hybrid WAG	1.1934	3 PV	39.12	1.1934	4 PV	52.15	91.27
SWAG	0.574	4 PV	104.53	0.574	4 PV	104.53	104.53

The calculation for overall experiment is shown in the Appendix 8

3.2.4 Determine the temperature and pressure to satisfy MMP

The most critical detailed constraint for the applicability of miscible CO_2 injection is the MMP. Minimum miscibility pressure is a function of oil properties, reservoir temperature, reservoir pressure, and the purity of the injected CO_2. The pressure applied during the injection must be slightly higher than the MMP in order to achieve miscibility of gas and crude oil. The major factors that affect the MMP directly are temperature and the molecular weight of C_5^+ component in the crude oil.

A two-step approach has been taken to estimate the Baronia RV2 reservoir's MMP. First, the molecular weight of C_5^+ components of the reservoir oil must be determined. A correlation between oil API gravity and C_5^+ oil molecular weight should be made (Figure 3.4) [7].

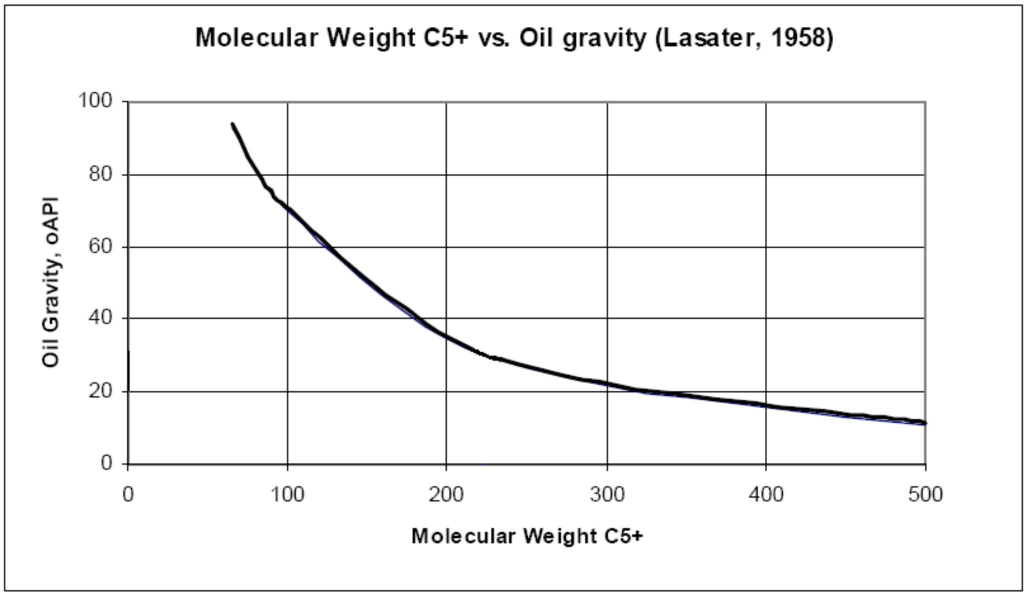


Figure 3.4: Correlation between oil gravity and the molecular weight of an oil's C_5^+ components [7].

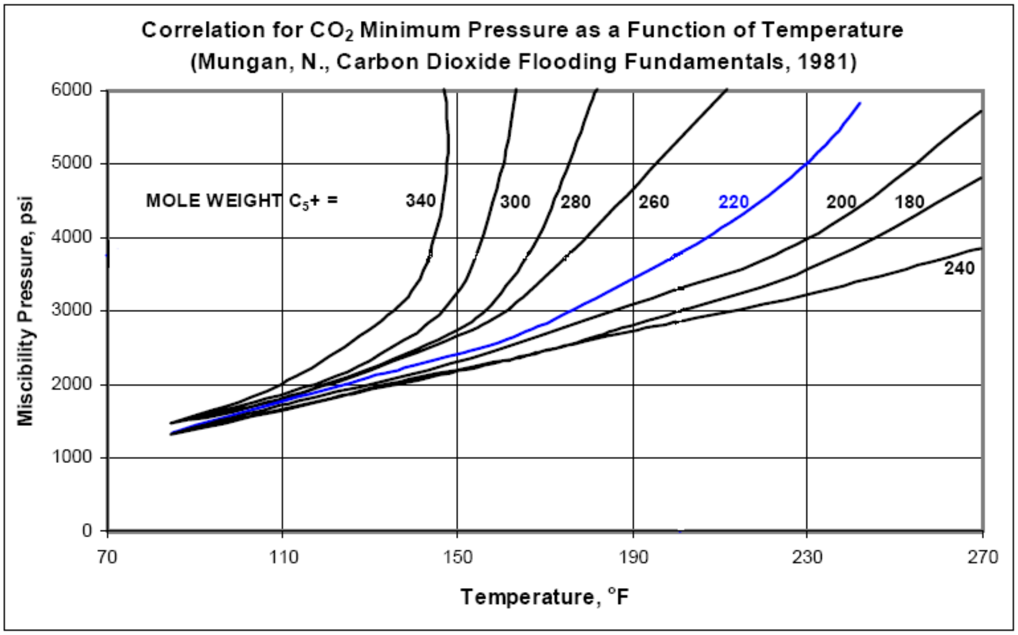


Figure 3.5: Nonlinear relationship between temperature and C_5^+ oil molecular weight and minimum miscibility pressure [7].

This correlation can be empirically determined by applying Equation 3.7.

$$MW = \left(\frac{7864.9}{G}\right)^{\frac{1}{1.0386}} \qquad \text{(Eq. 3.7)}$$

Where;

MW: Molecular weight of C_5^+ component in the crude oil

G: API oil gravity

G for Baronia crude oil is 42^0 API, therefore the molecular weight of C_5^+ component in the crude oil (MW) is 154.1656.

Second, MMP from reservoir temperature and $C5^+$ oil molecular weight must be determined. A relationship is extended, which estimates MMP from molecular weight of the $C5^+$ components of reservoir oil and reservoir temperature (Figure 3.5), was applied. This relationship was used by developing an equation through nonlinear multiple regression that allowed us to estimate MMP (Equation 3.8) [7].

$$MMP = -329.558 + (7.727 \times MW \times 1.005^T) - (4.377 \times MW) \qquad \text{(Eq. 3.8)}$$

Where;

MMP: Minimum Miscibility Pressure estimated

T: Temperature (^oF)

Temperature for these experiments were set to be 77 ^oF, hence gives MMP value of 744.64 psi. The pressure set for the experiment will be 800 psi which is slightly higher than MMP calculated to ensure the fluids will be fully miscible. The calculation is shown in Appendix 9

3.3 CORE PREPARATION

3.31 Core Cutting

Two Berea core samples obtained were:

a. 1 ft in length and 1.5 inch in diameter
b. 3.5 inch in length and 2 inch in diameter

The experiments have been designed to inject the CO_2 into 3inch x 1.5 inch core plug. Therefore, the Berea core samples obtained have to be cut into required size using several equipments from the laboratory. The detail of this procedure is provided in Appendix 1.

3.3.2 Core Cleaning

The core samples need to be clean to remove contaminants. The cleaning processes were conducted using Soxhlet Extractor. Using solvent (Toluene), the core samples were left in the Soxhlet Extractor for about one day to fully removed the unnecessary particles inside the core samples. Subsequently, they were left in an oven for about 1 day with temperature 77.5^0C to make them dry. The detail of this procedure is provided in Appendix 2.

3.3.3 Core characteristic measurement

The important characteristic of the core samples to be measured are:

a. Porosity
b. Permeability
c. Hydrocarbon Pore Volume (HCPV)

These properties were measured using “Poroperm” instrument. The results are summarized in the following table;

Table 3.6: Average properties of individual core

Core sample	Bulk Vol. (cc)	Pore Vol. (cc)	Grain density (g/cc)	Effective Core Porosity (%)	Permeability (mD)
A	87.22	15.50	2.62	17.77	188.158
B	87.15	15.63	2.62	17.93	205.626
C	87.41	15.62	2.61	17.87	211.880
D	87.30	115.01	2.64	17.19	199.271

The detail of this procedure is provided in Appendix 3.

3.3.4 Preparation of brine water

In this experiment, 10 liters of 30 ppm concentration of brine water was prepared to saturate the core samples prior to crude oil saturation. 30 g of salt was added into 1liter of distilled water to produce 1 liter of 30 ppm brine water. The step was repeated for 10 times to produce 10 liters of brine. The detail of this procedure is provided in Appendix 4

3.3.5 Core Saturation

The core samples are placed inside the manual saturator cylinder which filled with 30 ppm of brine water. The cylinder is pressurized using a hand pump until it achieved 1000 psi pressure. The core samples then left inside the cylinder for about one day to ensure that they are fully saturated with brine water. The detail of this procedure is provided in Appendix 5.

The core samples that are fully saturated with brine are then placed inside a vacuum pump which filled with 1 liter of Baronia crude oil. The core samples then left inside the cylinder for about one day to ensure that they are fully saturated with Baronia crude oil. The detail of this procedure is provided in Appendix 6.

3.4 DESIGN OF MODIFICATION OF EQUIPMENT

The gas mass flow controller in Relative Permeability Test System is calibrated for nitrogen gas instead of CO_2 which are used in this project. During several test runs, using CO_2 injection, gas mass flow controller has been damaged. It was found that at high pressure, CO_2 tends to form hydrates with moisture in the line, which in turns damage the gas mass flow controller.

To prevent the gas mass flow controller from malfunction, steps must be taken to ensure only dry gas flowing through it. Therefore dehumidifier is added into the system to absorb the moisture caused by liquefaction of CO_2 gas in the tube before flowing into the gas mass flow controller. Silica gel is used as dehumidifier as it has great ability to absorb the moisture surround it.

In this case, silica gel is placed in the High Pressure High Temperature (HPHT) cylinder and mounted to the system such that the gas will be passing through it prior to enter the gas mass flow controller. The schematic diagram is shown in Fig 3.7.

Figure 3.6: Dehumidifier: HPHT with Silica Gel inside

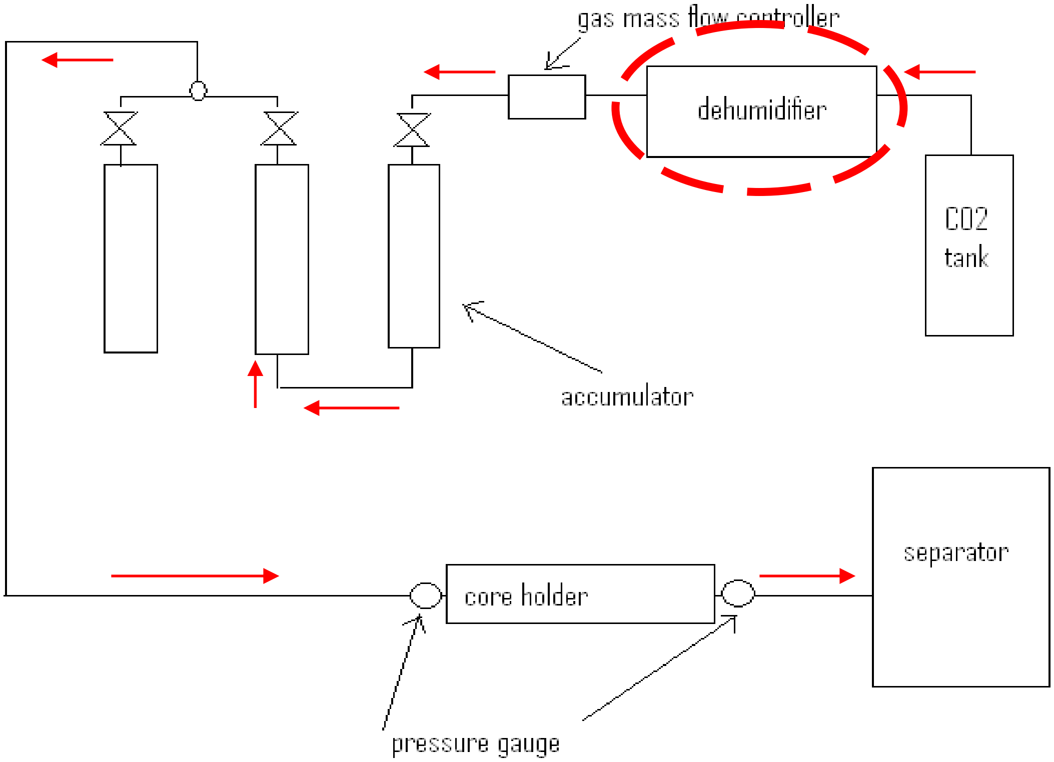


Figure 3.7: The flow diagram of the system after modification

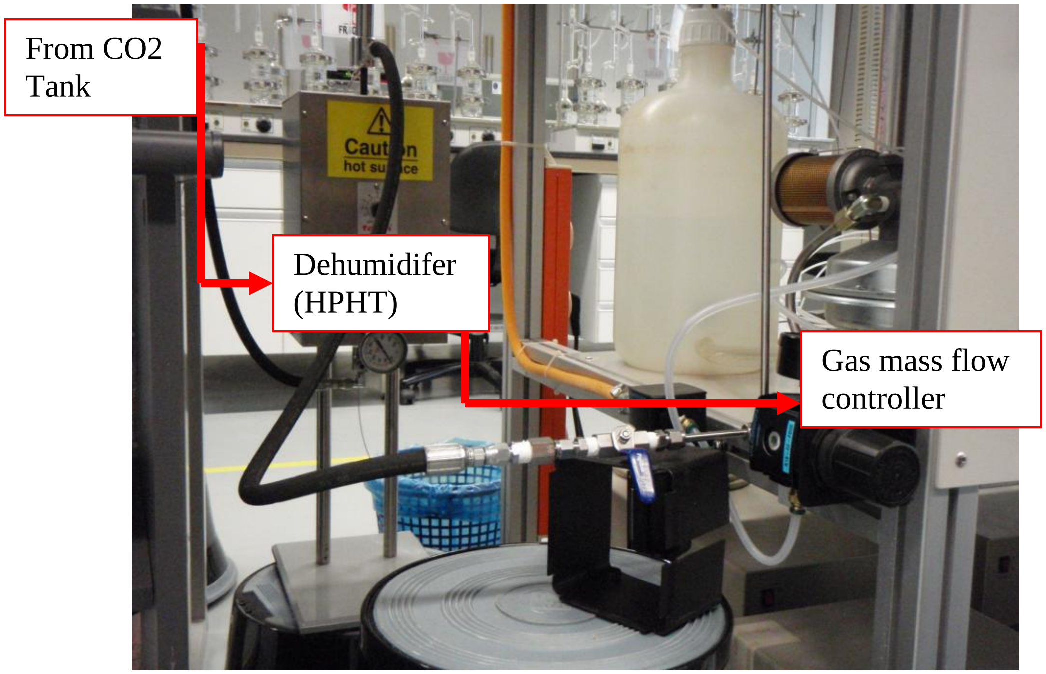


Figure 3.8: Sequence of Flowing to through Dehumidifier

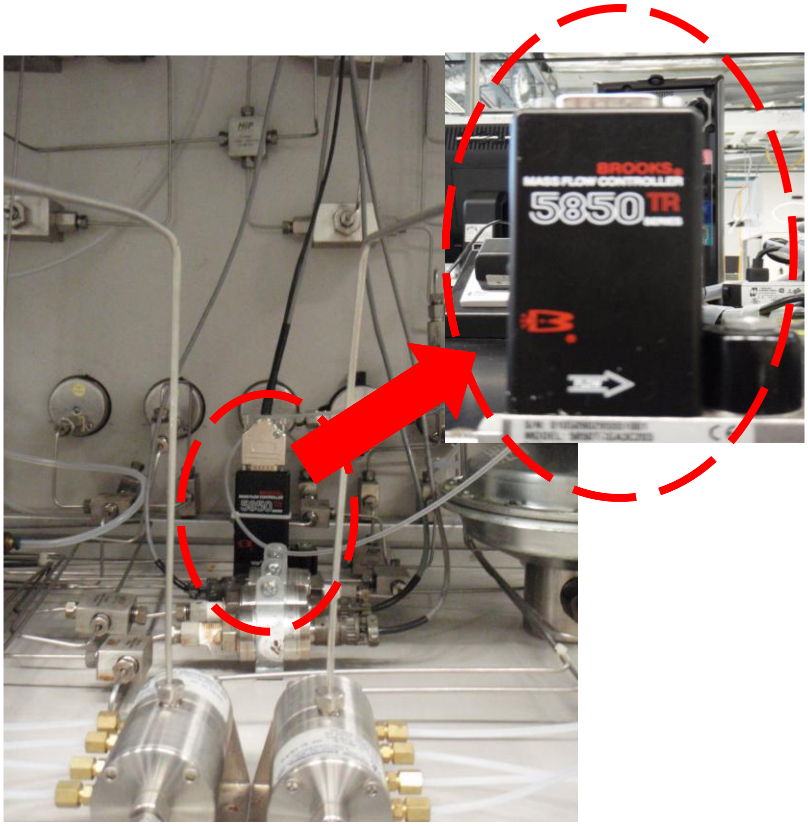


Figure 3.9: Gas mass flow controller

3.5 TEST RUN

Test run is made after modification of equipment. During test run, the core sample used is not the core prepared before and the crude oil used is not from Baronia. The main objective of this test run is only to ensure the modification made can encounter the problem faced which is liquefaction of carbon dioxide gas. CO_2 gas is expected to flowing through the system without any problem.

CHAPTER 4

RESULT AND DISCUSSION

From the experiment, the main parameters to be measured are Oil Recovery Factor and injection cycle time to achieve ultimate recovery. From these parameters, it can conclude which method leads to highest recovery and can find the most optimum injection mode of CO2 flooding for the Baronia RV2 reservoir.

4.1 EXPERIMENT RESULT

Table 4.1: Result of recovery for each injection modes

Injection modes	% Recovery
Continuous Injection	40.00
WAG Injection	41.61
Hybrid WAG Injection	42.89
SWAG Injection	67.95

4.1.1 Continuous Injection

The experiment is run by injecting 4 PV CO_2 through the core. The time taken to inject 4 PV of CO2 is 52.33 minutes with flowrate of 1.1848 cc/min. The recovery for continuous injection is 40.0%. It is found that the recovery for continuous injection is rapidly accelerate during first 15 minutes and very slowly producing for the next few minutes.

4.1.2 WAG Injection

During the WAG injection studies, the total volume of CO2 injected was kept at 4 PV. The total volume injected including water is 8 PV. A WAG ratio of 1:1 is selected for comparison with the continuous injection. The time taken to inject 8 PV of CO2 and water is 104.70 minutes with flowrate of 1.1935 cc/min.

The oil recovery for the WAG process is 41.619% which is 1.61% higher than continuous injection case. It is maybe due to an acceleration of oil recovery for continuous case at early injection, while the WAG case gained an advantage in cumulative oil recovery at longer time.

4.1.3 Hybrid WAG Injection

In light of the favorable early oil response by the continuous injection and the overall higher oil recovery by the WAG injection, an innovative hybrid WAG injection process is investigated. This process begins with 1 PV initial slug of CO_2 injection followed by injection of 3 PV of 1:1 WAG CO_2. This makes a total of 4 PV CO2 injection and total of 7 PV including water injection. The time taken for initial slug of CO2 is 13.09 min and the total time taken to inject 7 PV 1:1 hybrid WAG injection is 91.63 minutes.

The recovery for hybrid WAG is 42.89% which is 1.28% higher than continuous injection and 1.28% higher than WAG injection. It was anticipated that this hybrid WAG injection effectively would create an oil bank during initial slug of CO2 injection and maintain higher oil production rates through improved mobility control during WAG injection.

4.1.4 SWAG Injection

This method is involves the simultaneous injection of 4 PV of water and 4 PV of CO2 through core. The time taken to complete injecting 8 PV of water and CO2 simultaneously with flowrate of 0.574cc/min is 104.60 minutes. The recovery for this injection is 67.95% which is the highest oil recovery obtained compared to other three methods (Continuous Injection, WAG Injection, and hybrid WAG Injection).

From the result, it can be concluded that the SWAG injection is the most effective injection modes for Baronia RV2 reservoir by the means of highest oil recovery. The coreflood equipment does not have a wet gas meter or any kind of gas production measurement. Therefore, in this work, only oil production can be measured.

The oil was flowing out from the core through the tubing and collected in a beaker. The amount of oil collected in the beaker is not the maximum recovery as there was still remaining oil left in the tubing. Therefore, the volume inside the tubing was calculated and added with the volume of oil recovered in the beaker to obtain maximum oil recovery.

$$VolumeTubing = \frac{\Pi \times d^2 \times L}{4}$$

Where;

d: diameter of tubing

L= Length of tubing

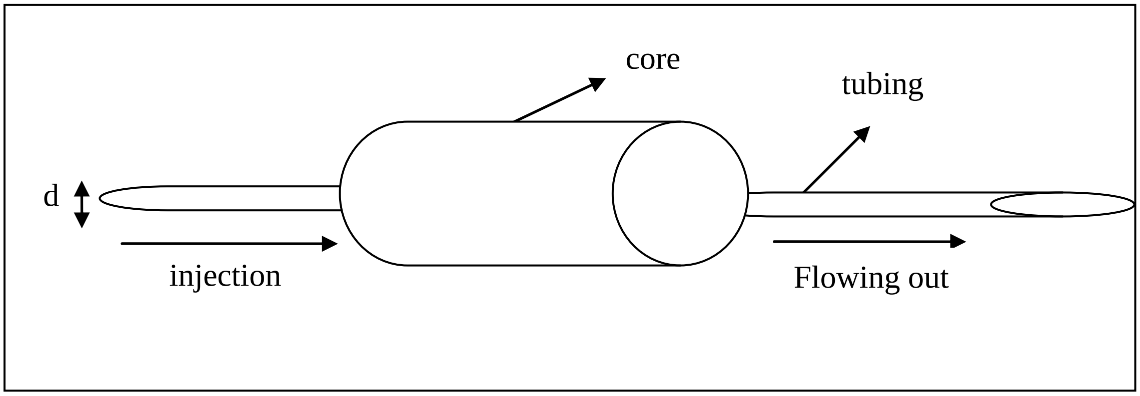


Figure 4.1: Oil flowing through the core and tubing

4.2 PROJECT'S CONSTRAINTS AND LIMITATIONS

1. As been planned from the beginning, this project is to run the experiment using Baronia crude oil and Baronia core. However, due to logistic and availability problem, the Baronia core is not available. Therefore, as alternative, Berea core

is chosen to replace Baronia core because it has almost the same characteristic as the real core from Baronia which is around 17.5% porosity.

2. The equipment used to run the core flooding is Relative Permeability Test System. This equipment is design ideally for nitrogen gas. If CO_2 gas is used, it will damage the mass flow controller because carbon dioxide gas produced liquid at high temperature and high pressure. Therefore, the equipment is modified by adding dehumifier system before carbon dioxide flow into mass flow controller. Silica gels are added into HPHT to adsorb the liquid produced by $CO_{2.}$

3. Based on the initial design, the velocity to inject the carbon dioxide and brine water is 2ft/day and subsequently the injection flowrate will be 0.162cc/min. The equipment cannot read less than 0.5cc/min so the velocity has to be increased and become 15ft/day.

4. The Baronia RV2 reservoir temperature is 194^0F, subsequently gives MMP of 2130.49 psi. However, maximum pressure of available CO_2 tank is only 850 psi and sometimes the pressure fluctuates and getting lower during the experiment. Therefore these experiments were run under temperature of 77^0F to ensure fully miscibility between CO_2 and crude oil is achieved. The MMP for 77^0F is 744.64 psi.

5. The coreflood equipment does not have a wet gas meter or any kind of gas production measurement. Therefore, in this work, only oil production can be measured.

CHAPTER 5
CONCLUSION

1. After running the experiment, it can be concluded that SWAG injection is the most efficient injection modes for Baronia RV2 reservoir.
2. SWAG injection mode yield 67.95% oil recovery.
3. It is 27.95% higher than continuous injection, 26.34% higher than WAG injection and 25.06% higher than hybrid WAG injection.
4. This result due to SWAG was injected with the highest total PV which is 8 PV.
5. SWAG injection also has great ability to improved sweep efficiency hence increase the recovery.

CHAPTER 6

RECOMMENDATION

1. For further work, it is recommended to maintain the total PV between each of injection mode to evaluate the performance of injection modes at specified PV.
2. The reading of oil recovery should be taken at every 1 PV fluid injected to study the effect of different injection technique with function of time.
3. It is believed that with proper design of WAG ratio and initial slug size, the hybrid WAG injection process has the potential to recover more oil than other injection modes.

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APPENDIX 1

Objective:

To obtain 4 core samples with 3 inch in length and 1.5 inch in diameter

Apparatus / Equipment:

1. Coring Machine
2. Trimming Machine
3. Cutting Saw
4. Transparent Container
5. Cement
6. Core 1 (1 ft length and 1.5 inch diameter)
7. Core 2 (3.5 inch length and 2 inch diameter)

Method:

1. The 3.5 inch length and 2 inch diameter core is cemented in the transparent container to avoid the core from fractured during reducing its diameter size.

Fig 1: Core 1 is cemented in transparent container

2. The core 1 then left until the cement solidifies before doing the cutting.
3. The second core with 1 ft length and 1.5 inch diameter is cut using Cutting Saw Machine to obtain 3 core samples with required size.

Fig 2: Core 2 is cut using Cutting Saw Machine

4. The core samples obtained then trimmed by Trimming Machine to finish the core surface.

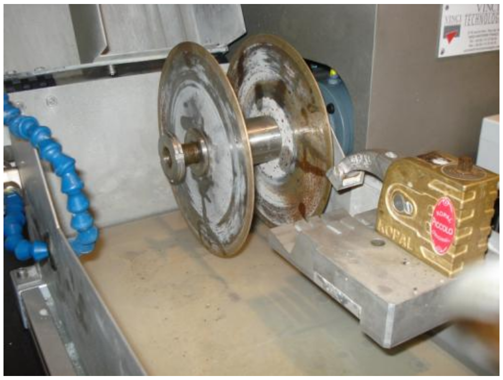

Fig 3: Core samples trimmed by Trimming Machine

5. After the cement has solidified, the core 1 is cut by Coring Machine to reduce the size of its diameter.
6. Then the core 2 is cut by Cutting Saw Machine and trimmed by trimming machine to obtain another core sample with 3 inch length and 1.5 inch diameter.

Fig 4: Core 1 is being reduced in diameter by Coring Machine

Result:

4 core samples are obtained with length of 3 inch and diameter of 1.5 inch.

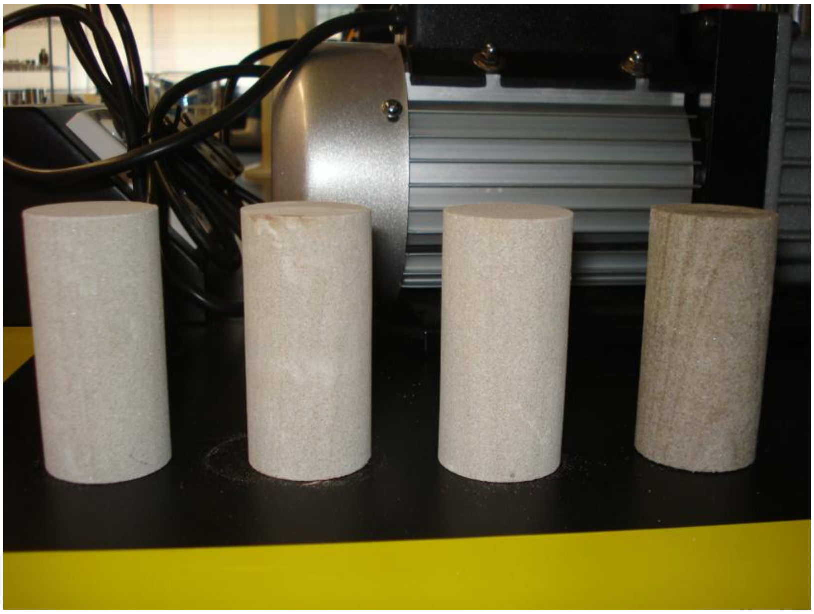

Fig 5: 4 core samples obtained

APPENDIX 2

Objective:

To clean the core sample from oil, water and any other materials.

Apparatus:

1. Soxhlet Extractor
2. Solvent (Toluene)

Method:

1. The core sample is first placed into the sample chamber.
2. The solvent is heated and vaporized. The solvent vapors travel through a lateral way and rise to the top of the glass tube where the cold trap is. At this place, the vapors condense and fall into the sample chamber. The solvent fills the chamber and removes soluble components from the core.
3. Then, the spoiled solvent is evacuated from the chamber through a siphon and goes back to the flask where it will be redistilled.
4. The core sample is left for about 8 hours inside the sample chamber to ensure the core is fully cleaned.
5. After brought out, the core sample is left in oven for about 1 day with temperature 77.5^0C to make it dry.

Figure 1: Sample Chamber

APPENDIX 3

Objective:

To determine the porosity and permeability of core samples.

Apparatus / Equipment:

1. 4 core samples labeled A, B, C and D.
2. Electronic Balance
3. Digital Caliper
4. Poroperm Machine

Method:

1. The core samples have to be cleaned and dried before start the porosity and permeability test.
2. Weights of core samples are measured using Electronic Balance.

Figure 1: Electronic Scale

Figure 2: Digital caliper

3. Diameter and length of core samples are measured using Digital Caliper.
4. All information required has to be filled in the Excel file such as:
    - i. Sample ID
    - ii. Diameter of the core
    - iii. Length of the core
    - iv. Weight
    - v. Atmospheric pressure

5. Inlet pressure is set to be 100 psi and confining pressure must be greater than 200 psi.
6. Core sample A is plugged into the core holder.
7. “Calibration” button is clicked on to start the calibration after the core sample has been identified.
8. Step 6 and 7 are repeated for the rest of core samples.
9. The report will be available in active file (Excel file).
10. The Poroperm machine is switched off after finish measure all the samples.

Figure 3: Poroperm Machine

Data:

Atmospheric pressure: 14.7 psi

Room temperature: 24.7 ^{0}C

Core information:

Core sample ID	Diameter (mm)	Length (mm)	Weight (g)
A	37.91	77.27	187.721
B	37.90	77.25	187.637
C	37.95	77.28	187.273
D	37.96	77.14	190.815

Result:

1st run

Table 4.2: Porosity of core (1st run)

Core sample	Bulk Vol. (cc)	Vol. Grain (cc)	Pore Vol. (cc)	Grain density (g/cc)	Effective Core Porosity (%)
A	87.22	71.90	15.32	2.61	17.56
B	87.15	71.50	15.64	2.62	17.95
C	87.41	71.80	15.61	2.61	17.86
D	87.30	72.30	15.00	2.64	17.18

Table 4.3: Permeability of core (1st run)

Core sample	Permeability K_{air} (mD)	Permeability $K_{klinkenberg}$ (mD)
A	185.171	158.689
B	204.294	182.398
C	209.577	176.341
D	192.213	161.045

2nd run

Table 4.4: Porosity of core (2nd run)

Core sample	Bulk Vol. (cc)	Vol. Grain (cc)	Pore Vol. (cc)	Grain density (g/cc)	Effective Core Porosity (%)
A	87.22	71.66	15.56	2.62	17.84
B	87.15	71.50	15.65	2.62	17.96
C	87.41	71.80	15.61	2.61	17.86
D	87.30	72.32	14.98	2.64	17.16

Table 4.5: Permeability of core (2nd run)

Core sample	Permeability K_{air} (mD)	Permeability $K_{klinkenberg}$ (mD)
A	189.893	167.311
B	210.541	194.526

C	208.010	174.872
D	207.877	194.068

3rd run

Table 4.6: Porosity of core (3rd run)

Core sample	Bulk Vol. (cc)	Vol. Grain (cc)	Pore Vol. (cc)	Grain density (g/cc)	Effective Core Porosity (%)
A	87.22	71.75	15.47	2.62	17.74
B	87.15	71.56	15.59	2.62	17.89
C	87.41	71.78	15.63	2.61	17.88
D	87.30	72.22	15.08	2.64	17.27

Table 4.7: Permeability of core (3rd run)

Core sample	Permeability K_{air} (mD)	Permeability $K_{klinkenberg}$ (mD)
A	191.734	170.841
B	205.447	183.255
C	215.242	190.440
D	199.084	177.051

4th run

Table 4.8: Porosity of core (4th run)

Core sample	Bulk Vol. (cc)	Vol. Grain (cc)	Pore Vol. (cc)	Grain density (g/cc)	Effective Core Porosity (%)
A	87.22	71.59	15.63	2.62	17.92
B	87.15	71.55	15.60	2.62	17.90
C	87.41	71.79	15.62	2.61	17.87
D	87.30	72.34	14.96	2.64	17.14

Table 4.9: Permeability of core (4th run)

Core sample	Permeability K_{air} (mD)	Permeability $K_{klinkenberg}$ (mD)
A	185.835	159.742
B	202.423	179.623
C	214.691	189.913
D	197.909	176.347

Calculation:

Core sample A

Bulk Volume $= \dfrac{\pi \times d^2 \times L}{4}$

$= \dfrac{\pi \times (37.9mm)^2 \times 77.16mm}{4}$

= 87048.35 mm

= 87.05 cc

Pore Volume = Bulk Volume x Porosity

= 87.05 cc x 0.1777

= 15.47 cc

Core sample B

Bulk Volume $= \dfrac{\pi \times d^2 \times L}{4}$

$= \dfrac{\pi \times (37.9mm)^2 \times 77.24mm}{4}$

= 87138.60 mm

= 87.14 cc

Pore Volume = Bulk Volume x Porosity

= 87.14 cc x 0.1793

= <u>15.62 cc</u>

<u>Core sample C</u>

Bulk Volume $= \dfrac{\pi \times d^2 \times L}{4}$

$= \dfrac{\pi \times (37.9mm)^2 \times 77.16mm}{4}$

= 87048.35 mm

= <u>87.05 cc</u>

Pore Volume = Bulk Volume x Porosity

= 87.05 cc x 0.1787

= <u>15.56 cc</u>

<u>Core sample D</u>

Bulk Volume $= \dfrac{\pi \times d^2 \times L}{4}$

$= \dfrac{\pi \times (37.9mm)^2 \times 77.35mm}{4}$

= 87262.69 mm

= <u>87.26 cc</u>

Pore Volume = Bulk Volume x Porosity

= 87.26 cc x 0.1719

= <u>15.00 cc</u>

APPENDIX 4

Objective:

To prepare 10 liters of 30ppm brine water.

Apparatus:

3. Distilled water
4. 300g of salt

Method:

6. 1 liter of distilled water is pumped into the cylinder.
7. 30 g of salts is weighted and is put into the distilled water.
8. The mixture of 1 liter of distilled water and 30 g of salt is stirred until the salt dissolved.
9. Step 1 until 3 are repeated for another 10 times to prepare 10 liters of 30 ppm brine water.

Objective:

To saturate the core samples with brine water

Apparatus:

5. Manual Saturator
6. 5 liters of 30 ppm brine water

Method:

10. The reservoir tank is filled with 30 ppm brine water to saturate with core.
11. The core is placed inside the cylinder.
12. The cylinder is closed.
13. The vacuum valve is opened while the pressure gauge valve is closed.
14. The cylinder is vacuumed.
15. The main valve is opened.
16. The brine is started pumped with hand pump to fill the cell with the fluid in the reservoir to pressurize it.
17. The pressure is increased until 1000 psi.
18. The core samples are left in the cylinder for one day until they are fully saturated.

Result:

The core samples were saturated with 30 ppm of brine water.

Objective:

To saturate the core samples with Baronia crude oil

Apparatus:

7. Vacuum Pump
8. 1 liters of Baronia crude oil

Method:

19. The gas ballast valve is closed.
20. The reservoir is filled with oil.
21. Switch is turned on.
22. The cap on the inlet ports is replaced when the pumps run smoothly.
23. The vacuum pump is run for at least 30 minutes. Then the oil level is check. The oil level must be at the oil level line.
24. The manifold valve between pump and the system is closed.
25. The hose from the pump inlet is moved.
26. Cap the inlet port to prevent any contamination or loose particles from entering the port.

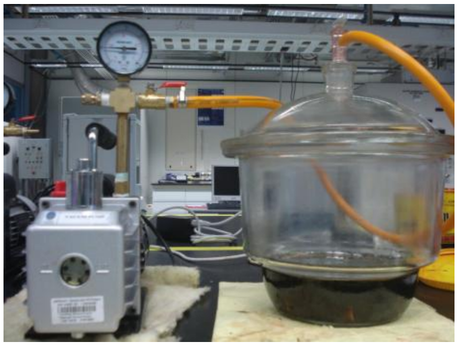

Figure 1: Vacuum Pump

Result:

The core samples were saturated with Baronia crude oil.

CALCULATE THE FLOWRATE FOR EACH INJECTION

Buckley-Leverett Equation and Koval method

$$F_S = \frac{1}{1+\left(\frac{1-S}{S}\right)\left(\frac{1}{H}\right)\left(\frac{1}{E}\right)}$$

and,

$$E = \left(0.78 + 0.22\left(\frac{\mu_o}{\mu_g}\right)^{1/4}\right)^4$$

Where;

Fs: Fractional Flow

S: Solvent saturation

H: Heterogeneity factor

E: Effective viscosity ratio

μ_o: Viscosity of oil

μ_g: Viscosity of gas (Carbon Dioxide)

H: 1 (the fluid is homogenous)

μ_o: 0.3 cP

μ_g: 0.0189 cP

$$E = \left(0.78 + 0.22\left(\frac{0.3cP}{0.0189cP}\right)^{1/4}\right)^4$$

$$E = 2.2089$$

$$F_S = \frac{1}{1+\left(\frac{1-S}{S}\right)\left(\frac{1}{1}\right)\left(\frac{1}{2.2089}\right)}$$

Using the Buckley-Leverett equation, the value of Fractional Flow, F_s for Solvent Saturation, S are obtained and shown in the table below:

Table 1: Value of Fractional Flow, Fs in corresponds with Solvent Saturation, S

S	F_s
0.1	0.197069431
0.2	0.355767578
0.3	0.48630707
0.4	0.595571703
0.5	0.688370546
0.6	0.768164805
0.7	0.837509123
0.8	0.898330145
0.9	0.95210832

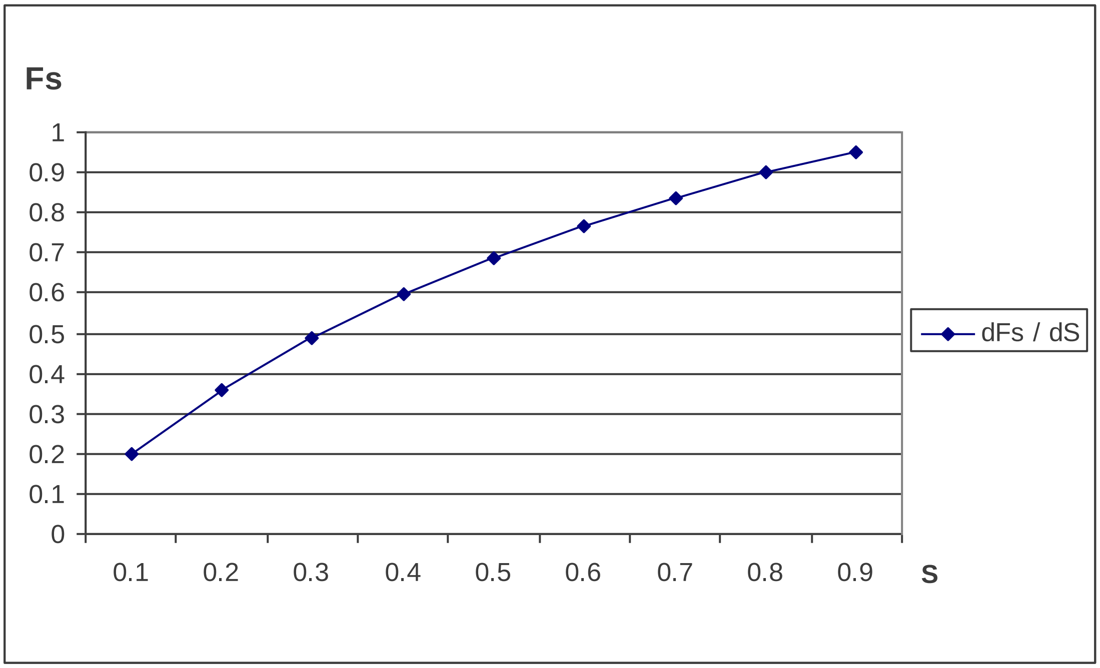

Figure 1: Graph of Fractional Flow, Fs vs. Solvent Saturation, S

From the graph, the value of slope which represent the $\frac{dF_S}{dS}$ is approximately 0.5378.

V= 15 ft/d

d= 0.125 ft

A= 0.01227 ft^2

Φ= 18%

$$\left(\frac{\partial x}{\partial t}\right)_S = \frac{q}{\Phi A}\left(\frac{dF_S}{dS}\right)$$

Rearrange the equation;

$$q = \frac{\left(\frac{\partial x}{\partial t}\right)_S \times \Phi \times A}{\left(\frac{dF_S}{dS}\right)}$$

<u>Continuous Injection (Core sample A)</u>

$$q = \frac{15\, ft/d \times 0.1777 \times 0.01216\ ft^2}{0.5378}$$

$$q = 0.06025\, cuft/d$$

Conversion factor, 1 cuft = 28316.85 cc and 1day = 1440 minutes

$$q = 0.060256\, cuft/d \times \frac{28316.85cc}{1cuft} \times \frac{1d}{1440\min}$$

$$q = 1.1848 cc/\min$$

<u>WAG Injection (Core Sample B)</u>

For this calculation, consider WAG ratio of 1:1

$$q = \frac{15\, ft/d \times 0.1793 \times 0.01214\ ft^2}{0.5378}$$

$$q = 0.06070\, cuft/d$$

Conversion factor, 1 cuft = 28316.85 cc and 1day = 1440 minutes

$$q = 0.060706\,cuft/d \times \frac{28316.85cc}{1cuft} \times \frac{1d}{1440\min}$$

$$q = 1.1935\,cc/\min$$

$$q_{water} = q \times WAGratio$$

$$q_{water} = 1.1935\,cc/\min \times \left(\frac{1}{1}\right)$$

$$q_{water} = 1.1935\,cc/\min$$

$$q_{CO2} = q$$

$$q_{CO2} = 1.1935\,cc/\min$$

Hybrid WAG Injection (Core Sample C)

For this calculation, consider WAG ratio of 1:1

$$q = \frac{15\,ft/d \times 0.1787 \times 0.01218\,ft^2}{0.5378}$$

$$q = 0.06069\,cuft/d$$

Conversion factor, 1 cuft = 28316.85 cc and 1day = 1440 minutes

$$q = 0.06069\,cuft/d \times \frac{28316.85cc}{1cuft} \times \frac{1d}{1440\min}$$

$$q = 1.1934\,cc/\min$$

$$q_{water} = q \times WAGratio$$

$$q_{water} = 1.1934\,cc/\min \times \left(\frac{1}{1}\right)$$

$$q_{water} = 1.1934\,cc/\min$$

$$q_{CO2} = q$$

$$q_{CO2} = 1.1934 cc/\min$$

SWAG injection (Core sample D)

For this calculation, consider WAG ratio of 1:1

$$q = \frac{15\, ft/d \times 0.1719 \times 0.01218\ ft^2}{0.5378}$$

$$q = 0.0584 cuft/d$$

Conversion factor, 1 cuft = 28316.85 cc and 1day = 1440 minutes

$$q = 0.0584 cuft/d \times \frac{28316.85 cc}{1 cuft} \times \frac{1d}{1440\min}$$

$$q = 1.1480 cc/\min$$

$$q = q_{water} + q_{CO2}$$

$$q_{water} = q \times SWAGratio$$

$$q_{water} = 1.1480 cc/\min \times \left(\frac{1}{1+1}\right)$$

$$q_{water} = 0.574 cc/\min$$

$$q_{CO2} = q \times SWAGratio$$

$$q_{CO2} = 0.574 cc/\min \times \left(\frac{1}{1+1}\right)$$

$$q_{CO2} = 0.574 cc/\min$$

APPENDIX 8

ESTIMATE THE TIME TAKEN TO COMPLETE THE EXPERIMENT

Continuous Injection (Core sample A)

Average Pore Volume PV: 15.50 cc

Volume injected = 4PV

= 4 x 15.50 cc

= 62 cc

$$\text{Time taken to complete the experiment} = \frac{\text{Volume Injected}}{\text{Flowrate}}$$

$$= \frac{62\ \text{cc}}{1.1848\ \text{cc/min}}$$

$$= 52.23\ \text{min}$$

WAG Injection (Core Sample B)

Number of cycle (water alternate gas): 3

WAG ratio: 1 : 1

Average Pore Volume PV: 15.63 cc

Volume injected = 8 PV

= 8 x 15.63 cc

= 124.96 cc

$$\text{Volume injected in for carbon dioxide} = \frac{124.96 \times 1}{2}$$

$$= 62.48\ \text{cc}$$

$$\text{Time taken to inject carbon dioxide (for each cycle)} = \frac{\text{volume injected}}{\text{flowrate} \times 3}$$

$$= \frac{62.48 \text{ cc}}{1.1935 \text{ cc/min} \times 3}$$

$$= 17.45 \text{ min}$$

Volume injected in for water $= \frac{124.96 \times 1}{2}$

$$= 62.48 \text{ cc}$$

Time taken to inject water $= \frac{\text{volume injected}}{\text{Flowrate} \times 3}$
(for each cycle)

$$= \frac{62.48 \text{ cc}}{1.1935 \text{ cc/min} \times 3}$$

$$= 17.45 \text{ min}$$

Time taken to complete the experiment $= 17.45 \times 6$

$$= 104.70 \text{ min}$$

<u>Hybrid WAG Injection (Core Sample C)</u>

Number of cycle (water alternate gas): 3

WAG ratio: 1 : 1

Average Pore Volume PV: 7 cc

Initial slug of carbon dioxide injected= 1PV

Volume injected for initial slug of CO_2

$$= 1 \times 15.62 \text{ cc}$$

$$= 15.62 \text{ cc}$$

Time taken to inject intial slug of CO_2 $= \frac{\text{volume injected}}{\text{flowrate}}$

$$= \frac{15.62 \text{ cc}}{1.1934 \text{ cc/min}}$$

$= 13.12 \text{ min}$

Volume injected in for carbon dioxide= 3 PV x 15.62 cc

$= 46.86 \text{ cc}$

Time taken to inject carbon dioxide $= \frac{\text{volume injected}}{\text{flowrate x 3}}$
(for each cycle)

$$= \frac{46.86 \text{ cc}}{1.1934 \text{ cc/min x } 3}$$

$= 13.12 \text{ min}$

Volume injected in for water= 3 PV x 15.62 cc

$= 46.86 \text{ cc}$

Time taken to inject water$= \frac{\text{volume injected}}{\text{flowrate x 3}}$
(for each cycle)

$$= \frac{46.86 \text{ cc}}{1.1934\text{cc/min x } 3}$$

$= 13.12 \text{ min}$

Time taken to complete the experiment= 13.12 x 7 min

$= 91.27 \text{ min}$

SWAG Injection (Core Sample D)

SWAG ratio: 1 : 1
Average Pore Volume PV: 15.01 cc

Volume injected = 8 PV
= 8 x 15.01 cc
= 120.08 cc

$$\text{Time taken to complete the experiment} = \frac{\text{Volume Injected } (CO_2)}{\text{Flowrate } (CO_2)}$$

$$= \frac{60.04 \text{ cc}}{0.574 \text{ cc/min}}$$

$$= 104.53 \text{ min}$$

ESTIMATE THE MMP PRESSURE

Temperature: 77°F
API oil gravity: 42°

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

Where;
MW: Molecular weight of C_5^+ component in the crude oil
G: API oil gravity

$$MW = \left(\frac{7864.9}{42}\right)^{\frac{1}{1.0386}}$$

$$MW = 154.1656$$

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

Where;
T: Temperature (°F)

$$MMP = -329.558 + (7.727 \times 154.1656 \times 1.005^{77}) - (4.377 \times 154.1565)$$

$$MMP = 744.6407\ psi$$

Therefore the experiments are decided to be run under 77°F temperature and 800 psi pressure in order to achieve miscibility.

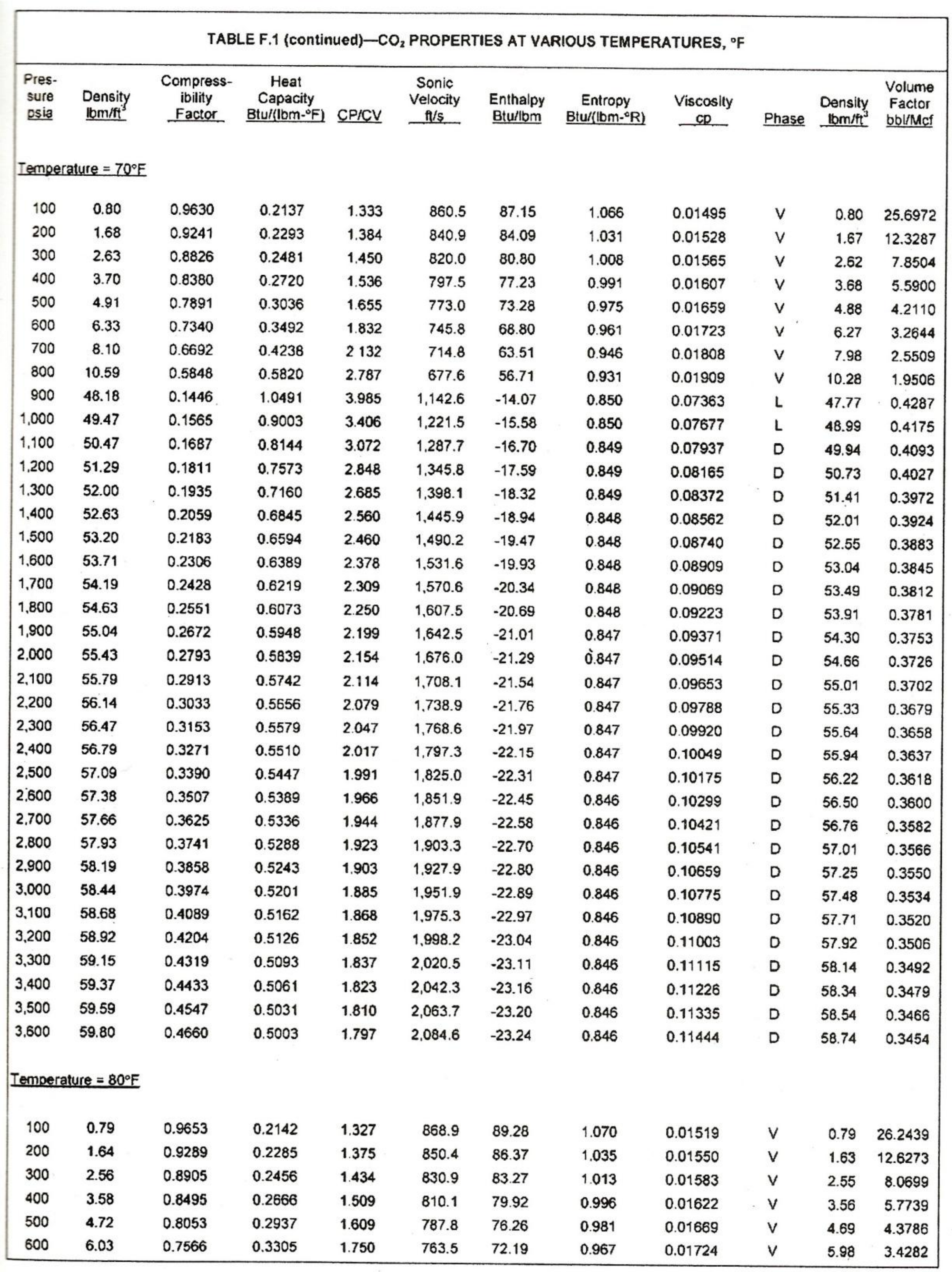

TABLE F.1 (continued)—CO_2 PROPERTIES AT VARIOUS TEMPERATURES, °F

Pressure psia	Density lbm/ft^3	Compressibility Factor	Heat Capacity Btu/(lbm-°F)	CP/CV	Sonic Velocity ft/s	Enthalpy Btu/lbm	Entropy Btu/(lbm-°R)	Viscosity cp	Phase	Density lbm/ft^3	Volume Factor bbl/Mcf
Temperature = 70°F											
100	0.80	0.9630	0.2137	1.333	860.5	87.15	1.066	0.01495	V	0.80	25.6972
200	1.68	0.9241	0.2293	1.384	840.9	84.09	1.031	0.01528	V	1.67	12.3287
300	2.63	0.8826	0.2481	1.450	820.0	80.80	1.008	0.01565	V	2.62	7.8504
400	3.70	0.8380	0.2720	1.536	797.5	77.23	0.991	0.01607	V	3.68	5.5900
500	4.91	0.7891	0.3036	1.655	773.0	73.28	0.975	0.01659	V	4.88	4.2110
600	6.33	0.7340	0.3492	1.832	745.8	68.80	0.961	0.01723	V	6.27	3.2644
700	8.10	0.6692	0.4238	2.132	714.8	63.51	0.946	0.01808	V	7.98	2.5509
800	10.59	0.5848	0.5820	2.787	677.6	56.71	0.931	0.01909	V	10.28	1.9506
900	48.18	0.1446	1.0491	3.985	1,142.6	-14.07	0.850	0.07363	L	47.77	0.4287
1,000	49.47	0.1565	0.9003	3.406	1,221.5	-15.58	0.850	0.07677	L	48.99	0.4175
1,100	50.47	0.1687	0.8144	3.072	1,287.7	-16.70	0.849	0.07937	D	49.94	0.4093
1,200	51.29	0.1811	0.7573	2.848	1,345.8	-17.59	0.849	0.08165	D	50.73	0.4027
1,300	52.00	0.1935	0.7160	2.685	1,398.1	-18.32	0.849	0.08372	D	51.41	0.3972
1,400	52.63	0.2059	0.6845	2.560	1,445.9	-18.94	0.848	0.08562	D	52.01	0.3924
1,500	53.20	0.2183	0.6594	2.460	1,490.2	-19.47	0.848	0.08740	D	52.55	0.3883
1,600	53.71	0.2306	0.6389	2.378	1,531.6	-19.93	0.848	0.08909	D	53.04	0.3845
1,700	54.19	0.2428	0.6219	2.309	1,570.6	-20.34	0.848	0.09069	D	53.49	0.3812
1,800	54.63	0.2551	0.6073	2.250	1,607.5	-20.69	0.848	0.09223	D	53.91	0.3781
1,900	55.04	0.2672	0.5948	2.199	1,642.5	-21.01	0.847	0.09371	D	54.30	0.3753
2,000	55.43	0.2793	0.5839	2.154	1,676.0	-21.29	0.847	0.09514	D	54.66	0.3726
2,100	55.79	0.2913	0.5742	2.114	1,708.1	-21.54	0.847	0.09653	D	55.01	0.3702
2,200	56.14	0.3033	0.5656	2.079	1,738.9	-21.76	0.847	0.09788	D	55.33	0.3679
2,300	56.47	0.3153	0.5579	2.047	1,768.6	-21.97	0.847	0.09920	D	55.64	0.3658
2,400	56.79	0.3271	0.5510	2.017	1,797.3	-22.15	0.847	0.10049	D	55.94	0.3637
2,500	57.09	0.3390	0.5447	1.991	1,825.0	-22.31	0.847	0.10175	D	56.22	0.3618
2,600	57.38	0.3507	0.5389	1.966	1,851.9	-22.45	0.846	0.10299	D	56.50	0.3600
2,700	57.66	0.3625	0.5336	1.944	1,877.9	-22.58	0.846	0.10421	D	56.76	0.3582
2,800	57.93	0.3741	0.5288	1.923	1,903.3	-22.70	0.846	0.10541	D	57.01	0.3566
2,900	58.19	0.3858	0.5243	1.903	1,927.9	-22.80	0.846	0.10659	D	57.25	0.3550
3,000	58.44	0.3974	0.5201	1.885	1,951.9	-22.89	0.846	0.10775	D	57.48	0.3534
3,100	58.68	0.4089	0.5162	1.868	1,975.3	-22.97	0.846	0.10890	D	57.71	0.3520
3,200	58.92	0.4204	0.5126	1.852	1,998.2	-23.04	0.846	0.11003	D	57.92	0.3506
3,300	59.15	0.4319	0.5093	1.837	2,020.5	-23.11	0.846	0.11115	D	58.14	0.3492
3,400	59.37	0.4433	0.5061	1.823	2,042.3	-23.16	0.846	0.11226	D	58.34	0.3479
3,500	59.59	0.4547	0.5031	1.810	2,063.7	-23.20	0.846	0.11335	D	58.54	0.3466
3,600	59.80	0.4660	0.5003	1.797	2,084.6	-23.24	0.846	0.11444	D	58.74	0.3454
Temperature = 80°F											
100	0.79	0.9653	0.2142	1.327	868.9	89.28	1.070	0.01519	V	0.79	26.2439
200	1.64	0.9289	0.2285	1.375	850.4	86.37	1.035	0.01550	V	1.63	12.6273
300	2.56	0.8905	0.2456	1.434	830.9	83.27	1.013	0.01583	V	2.55	8.0699
400	3.58	0.8495	0.2666	1.509	810.1	79.92	0.996	0.01622	V	3.56	5.7739
500	4.72	0.8053	0.2937	1.609	787.8	76.26	0.981	0.01669	V	4.69	4.3786
600	6.03	0.7566	0.3305	1.750	763.5	72.19	0.967	0.01724	V	5.98	3.4282

TABLE F.1 (continued)—CO_2 PROPERTIES AT VARIOUS TEMPERATURES, °F

Pressure psia	Density lbm/ft³	Compressibility Factor	Heat Capacity Btu/(lbm-°F)	CP/CV	Sonic Velocity ft/s	Enthalpy Btu/lbm	Entropy Btu/(lbm-°R)	Viscosity cp	Phase	Density lbm/ft³	Volume Factor bbl/Mcf
700	7.58	0.7015	0.3851	1.966	736.7	67.54	0.954	0.01795	V	7.51	2.7245
800	9.56	0.6359	0.4789	2.347	706.4	61.95	0.940	0.01882	V	9.41	2.1612
900	12.46	0.5488	0.6987	3.261	670.5	54.55	0.925	0.01992	V	12.07	1.6578
1,000	43.74	0.1737	1.7637	6.856	945.1	-3.85	0.858	0.06449	L	43.04	0.4722
1,100	46.14	0.1811	1.1595	4.486	1,061.8	-7.22	0.856	0.06915	D	45.53	0.4476
1,200	47.65	0.1913	0.9560	3.685	1,146.9	-9.19	0.855	0.07241	D	47.07	0.4335
1,300	48.78	0.2025	0.8477	3.257	1,217.1	-10.59	0.855	0.07507	D	48.21	0.4234
1,400	49.71	0.2140	0.7788	2.984	1,278.1	-11.68	0.854	0.07738	D	49.14	0.4155
1,500	50.50	0.2257	0.7303	2.790	1,332.7	-12.56	0.854	0.07946	D	49.92	0.4090
1,600	51.19	0.2375	0.6941	2.645	1,382.4	-13.29	0.854	0.08137	D	50.60	0.4035
1,700	51.81	0.2493	0.6657	2.531	1,428.2	-13.91	0.853	0.08314	D	51.21	0.3987
1,800	52.37	0.2611	0.6429	2.439	1,471.0	-14.45	0.853	0.08482	D	51.76	0.3944
1,900	52.88	0.2730	0.6240	2.362	1,511.2	-14.92	0.853	0.08641	D	52.26	0.3906
2,000	53.36	0.2848	0.6080	2.296	1,549.1	-15.34	0.853	0.08793	D	52.72	0.3871
2,100	53.80	0.2965	0.5943	2.240	1,585.2	-15.70	0.853	0.08939	D	53.15	0.3839
2,200	54.22	0.3083	0.5824	2.191	1,619.6	-16.03	0.852	0.09080	D	53.55	0.3810
2,300	54.61	0.3200	0.5720	2.148	1,652.5	-16.32	0.852	0.09217	D	53.92	0.3782
2,400	54.98	0.3316	0.5628	2.109	1,684.0	-16.58	0.852	0.09350	D	54.28	0.3757
2,500	55.34	0.3432	0.5546	2.074	1,714.4	-16.82	0.852	0.09479	D	54.61	0.3733
2,600	55.67	0.3548	0.5471	2.043	1,743.7	-17.03	0.852	0.09606	D	54.93	0.3710
2,700	55.99	0.3664	0.5404	2.015	1,772.0	-17.22	0.852	0.09729	D	55.23	0.3689
2,800	56.30	0.3778	0.5343	1.988	1,799.5	-17.39	0.852	0.09851	D	55.52	0.3669
2,900	56.60	0.3893	0.5287	1.964	1,826.1	-17.54	0.852	0.09970	D	55.80	0.3650
3,000	56.88	0.4007	0.5236	1.942	1,851.9	-17.68	0.851	0.10087	D	56.07	0.3631
3,100	57.15	0.4121	0.5189	1.922	1,877.0	-17.80	0.851	0.10202	D	56.33	0.3614
3,200	57.42	0.4234	0.5145	1.902	1,901.5	-17.91	0.851	0.10315	D	56.58	0.3597
3,300	57.67	0.4347	0.5105	1.884	1,925.3	-18.01	0.851	0.10427	D	56.82	0.3581
3,400	57.92	0.4460	0.5067	1.868	1,948.6	-18.10	0.851	0.10537	D	57.05	0.3566
3,500	58.16	0.4572	0.5031	1.852	1,971.3	-18.17	0.851	0.10646	D	57.27	0.3551
3,600	58.40	0.4684	0.4998	1.837	1,993.5	-18.24	0.851	0.10754	D	57.49	0.3537
Temperature = 90°F											
100	0.77	0.9674	0.2147	1.322	877.1	91.43	1.074	0.01530	D	0.77	26.7881
200	1.60	0.9333	0.2279	1.366	859.7	88.66	1.039	0.01552	D	1.60	12.9228
300	2.49	0.8976	0.2435	1.419	841.5	85.71	1.017	0.01596	D	2.49	8.2854
400	3.47	0.8599	0.2623	1.486	822.2	82.56	1.000	0.01635	D	3.46	5.9526
500	4.55	0.8195	0.2857	1.572	801.7	79.16	0.986	0.01678	D	4.53	4.5388
600	5.77	0.7759	0.3162	1.687	779.8	75.42	0.973	0.01728	D	5.74	3.5811
700	7.17	0.7279	0.3586	1.852	756.2	71.25	0.960	0.01791	D	7.12	2.8794
800	8.86	0.6734	0.4230	2.109	730.4	66.44	0.948	0.01877	D	8.77	2.3309
900	11.03	0.6085	0.5373	2.576	701.8	60.60	0.935	0.01944	D	10.87	1.8722
1,000	14.28	0.5223	0.8193	3.746	669.7	52.72	0.920	0.02128	D	13.88	1.4464
1,100	29.58	0.2774	4.4244	18.666	639.9	35.74	0.893	0.03416	D	21.30	0.6982
1,200	41.80	0.2141	1.7977	7.100	896.8	3.30	0.864	0.02925	D	40.60	0.4942
1,300	44.35	0.2187	1.1982	4.711	1,008.5	-0.70	0.862	0.03890	D	43.50	0.4658
1,400	45.98	0.2271	0.9805	3.841	1,092.9	-3.02	0.861	0.05346	D	45.27	0.4492

APPENDIX 12

First semester

No.	Detail/ Week	1	2	3	4	5	6	7		8	9	10	11	12	13	14
1	Selection of Project Topic	🟨	🟨						Mid-semester Break							
2	Preliminary Research Work		🟨	🟨	🟨											
3	Submission of Preliminary Report				🟨 √											
4	Literature Review	🟨	🟨	🟨	🟨	🟨	🟨	🟨		🟨	🟨	🟨	🟨	🟨	🟨	🟨
5	Study the core flood equipment and accessories.					🟨	🟨	🟨								
6	Design the experiment for each of injection mode							🟨		🟨	🟨					
7	Submission of Progress Report									🟨 √						
8	Seminar									🟨 √						
9	Consultancy regained from PRSB									🟨						
10	Design of modification to the core flood equipment									🟨	🟨	🟨	🟨	🟨	🟨	
11	Submission of Interim Report															🟨 √
12	Oral Presentation															🟨 √

√ Suggested milestone

🟨 Process

Second Semester

No.	Detail/ Week	1	2	3	4	5	6	7		8	9	10	11	12	13	14
1	Core Preparation	🟨							Mid-semester Break							
2	Experiment on each type of injections		🟨	🟨	🟨											
3	Submission of Progress Report 1				🟨 √											
4	Literature Review	🟨	🟨	🟨	🟨	🟨	🟨	🟨		🟨	🟨	🟨	🟨	🟨	🟨	🟨
5	Continue experiments					🟨	🟨	🟨								
6	Submission of Progress Report									🟨 √						
7	Seminar										🟨	🟨	🟨			
8	Continue experiments									🟨	🟨	🟨	🟨	🟨		
9	Poster Exhibition											🟨 √				
10	Result analysis and comparison												🟨	🟨		
11	Submission of Dissertation Report (softbound)													🟨 √		
12	Oral Presentation														🟨 √	
13	Submission of Dissertation Report (hardbound)															🟨 √

√ Suggested milestone

🟨 Process