OPTIMUM WATER-ALTERNATING-GAS (CO$_2$-WAG) INJECTION
IN THE BAKKEN FORMATION

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Submitted to the Faculty of Graduate Studies and Research
In Partial Fulfillment of the Requirements for the
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by
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Longyu Han, candidate for the degree of Master of Applied Science in Petroleum Systems Engineering, has presented a thesis titled, *Optimum Water-Alternating-Gas (CO₂-WAG) Injection in the Bakken Formation*, in an oral examination held on December 10, 2014. The following committee members have found the thesis acceptable in form and content, and that the candidate demonstrated satisfactory knowledge of the subject material.

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ABSTRACT

In this thesis, miscible CO₂ water-alternating-gas (CO₂-WAG) injection in the tight Bakken formation and the effectiveness of CO₂-enhanced oil recovery (CO₂-EOR) methods in the fractured Bakken formation were experimentally studied. First, the saturation pressure $P_{\text{sat}}$, oil-swelling factor (SF), oil density, and CO₂ solubility of CO₂-saturated Bakken light crude oil were measured by using a PVT system. Second, the viscosities of CO₂-saturated Bakken light crude oils with different CO₂ concentrations were measured by using a capillary viscometer. Third, the vanishing interfacial tension (VIT) technique was applied to determine the minimum miscibility pressure (MMP) of the Bakken light crude oil and CO₂ at the actual reservoir temperature. In addition, a total of nine coreflood tests were conducted through respective waterflooding, continuous miscible CO₂ flooding, and miscible CO₂-WAG injection in the tight Bakken formation. In the miscible CO₂-WAG injection, different WAG slug sizes of 0.125, 0.250, and 0.500 pore volumes (PVs) and different WAG slug ratios of 2:1, 1:1, and 1:2 were used to examine their specific effects on the oil recovery factor (RF), cumulative water production ($Q_w$), and average gas production rate ($q_g$) in the tight Bakken formation. Last, four more coreflood tests were carried out to evaluate CO₂-EOR processes in the fractured Bakken formation. Specifically, the first two tests were performed to examine CO₂-soaking effect on miscible CO₂ secondary flooding and the last two tests were undertaken to study the fracture effect on CO₂-WAG injection in the fractured Bakken formation.
The experimental results showed that saturation pressure $P_{\text{sat}}$ and oil SF of CO$_2$-saturated Bakken light crude oil were increased respectively in the ranges of 2.01–9.29 MPa and 1.05–1.62 when CO$_2$ concentration was increased in the range of 18.64–70.11 mol.%. The density was increased marginally at low CO$_2$ concentrations and did not change appreciably by dissolving more CO$_2$ into the Bakken light crude oil. The measured CO$_2$ solubility was increased from 30.0 to 313.6 cm$^3$ CO$_2$/cm$^3$ oil as the saturation pressure was increased from 2.01 to 9.29 MPa. The viscosities of CO$_2$-saturated Bakken light crude oils with 18.64 and 70.11 mol.% CO$_2$ concentrations were reduced to 56% and 28% of the original dead Bakken light crude oil viscosity at the same reservoir temperature. The measured equilibrium interfacial tension (IFT) was reduced almost linearly with the equilibrium pressure and the MMP was determined to be 10.0 MPa. The miscible CO$_2$-WAG injection had the highest oil RF (78.8% in Test #3), in comparison with waterflooding (43.2% in Test #1), continuous miscible CO$_2$ flooding (63.4% in Test #2), and miscible CO$_2$ gas-alternating-water (CO$_2$-GAW) injection (66.2% in Test #8). Furthermore, a smaller WAG slug size of CO$_2$-WAG injection led to a higher oil RF and the optimum WAG slug ratio was approximately 1:1 for the tight Bakken formation. Over 60% of the light crude oil was produced in the first two cycles of the miscible CO$_2$-WAG injection. The CO$_2$ consumption in the optimum miscible CO$_2$-WAG injection was much less than that in the continuous miscible CO$_2$ flooding. The final oil RF of CO$_2$ injection with a CO$_2$-soaking period of 24 h was 9.7% higher than that of CO$_2$ injection without CO$_2$ soaking in the fractured Bakken formation. The CO$_2$-WAG injection was less effective in the fractured Bakken formation than in the tight Bakken formation.
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To my parents, Yanyi Han and Genlan Wei, for their unconditional love and support.

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NOMENCLATURE

Notations

\( k \) \hspace{1cm} \text{Permeability, mD}

\( L \) \hspace{1cm} \text{Length of the capillary viscometer, cm}

\( m_{\text{CO}_2} \) \hspace{1cm} \text{Mass of CO}_2, \text{ g}

\( m_{\text{mix}} \) \hspace{1cm} \text{Mass of the mixture of the Bakken light crude oil and CO}_2, \text{ g}

\( m_{\text{oil}} \) \hspace{1cm} \text{Mass of the dead light crude oil, g}

\( N_{\text{ca}} \) \hspace{1cm} \text{Capillary number}

\( P_c \) \hspace{1cm} \text{Capillary pressure, MPa}

\( P_{\text{cell}} \) \hspace{1cm} \text{Pressure of PVT cell, MPa}

\( P_{\text{eq}} \) \hspace{1cm} \text{Equilibrium pressure, MPa}

\( P_{\text{prod}} \) \hspace{1cm} \text{Production pressure, MPa}

\( P_{\text{res}} \) \hspace{1cm} \text{Reservoir pressure, MPa}

\( P_{\text{sat}} \) \hspace{1cm} \text{Saturation pressure, MPa}

\( P_{\text{sc}} \) \hspace{1cm} \text{Pressure at the standard conditions, kPa}

\( q_{\text{brine}} \) \hspace{1cm} \text{Brine injection rate, cm}^3/\text{min}

\( q_{\text{CO}_2} \) \hspace{1cm} \text{CO}_2 \text{ volume injection rate, cm}^3/\text{min}

\( q_{\text{avg}} \) \hspace{1cm} \text{Average gas production rate, cm}^3/\text{min}

\( q_{\text{mix}} \) \hspace{1cm} \text{Volume flow rate of CO}_2\text{-saturated Bakken light crude oil, cm}^3/\text{min}

\( q_{\text{oil}} \) \hspace{1cm} \text{Oil volume injection rate, cm}^3/\text{min}

\( q_{\text{w}} \) \hspace{1cm} \text{Water volume flow rate, cm}^3/\text{min}

\( Q_{\text{w}} \) \hspace{1cm} \text{Cumulative water production, cm}^3
\( r \) Radius of the capillary tubing, cm
\( r_{\text{eff}} \) Effective radius of the capillary tubing, cm
\( R^2 \) Correlation coefficient
\( S_{\text{oil}} \) Initial oil saturation, %
\( S_{\text{wc}} \) Connate water saturation, %
\( T_{\text{lab}} \) Laboratory temperature, °C
\( T_{\text{res}} \) Reservoir temperature, °C
\( v \) Linear flow velocity, cm/s
\( v_{\text{mix}} \) Mass-based specific volume of the Bakken light crude oil–CO\(_2\) mixture, cm\(^3\)/g
\( V_{\text{CO}_2} \) Volume of CO\(_2\) at the atmospheric pressure and laboratory temperature, cm\(^3\)
\( V_{\text{mix}} \) Volume of the Bakken light crude oil–CO\(_2\) mixture, cm\(^3\)
\( V_{\text{oil}} \) Volume of the dead Bakken light crude oil, cm\(^3\)
\( w_{\text{asp}} \) Asphaltene content of the dead Bakken light crude oil, wt.%
\( z_{\text{CO}_2} \) Mole percentage of CO\(_2\) in the Bakken light crude oil–CO\(_2\) system, mol.%
\( z_{\text{oil}} \) Mole percentage of the light crude oil in the Bakken light crude oil–CO\(_2\) system, mol.%

**Greek letters**

\( \gamma \) Interfacial tension, mJ/m\(^2\)
\( \gamma_{eq} \)  \hspace{1cm} \text{Equilibrium interfacial tension between the Bakken light crude oil and \( \text{CO}_2 \), mJ/m}^2

\( \theta \)  \hspace{1cm} \text{Contact angle, degree}

\( \mu \)  \hspace{1cm} \text{Viscosity, cP}

\( \mu_{\text{CO}_2} \)  \hspace{1cm} \text{Viscosity of \( \text{CO}_2 \), cP}

\( \mu_{\text{mix}} \)  \hspace{1cm} \text{Viscosity of the Bakken light crude oil–\( \text{CO}_2 \) mixture, cP}

\( \mu_{\text{oil}} \)  \hspace{1cm} \text{Viscosity of the Bakken light crude oil, cP}

\( \mu_{w} \)  \hspace{1cm} \text{Viscosity of distilled water, cP}

\( \rho_{\text{brine}} \)  \hspace{1cm} \text{Density of brine, g/cm}^3

\( \rho_{\text{CO}_2} \)  \hspace{1cm} \text{Density of \( \text{CO}_2 \), g/cm}^3

\( \rho_{\text{mix}} \)  \hspace{1cm} \text{Density of the Bakken light crude oil–\( \text{CO}_2 \) mixture, g/cm}^3

\( \rho_{\text{oil}} \)  \hspace{1cm} \text{Density of the dead Bakken light crude oil, g/cm}^3

\( \phi \)  \hspace{1cm} \text{Porosity, %}

\( \chi_{\text{CO}_2} \)  \hspace{1cm} \text{\( \text{CO}_2 \) solubility in the Bakken light crude oil, cm}^3 \text{CO}_2/\text{cm}^3 \text{ oil}

\text{Subscripts}

\( \text{asp} \)  \hspace{1cm} \text{Asphaltene}

\( \text{brine} \)  \hspace{1cm} \text{Brine}

\( c \)  \hspace{1cm} \text{Capillary}

\( \text{ca} \)  \hspace{1cm} \text{Capillary}

\( \text{CO}_2 \)  \hspace{1cm} \text{CO}_2

\( \text{cell} \)  \hspace{1cm} \text{PVT cell}
eff  Effective
eq  Equilibrium
g  Gas
lab  Laboratory
mix  Mixture
oi  Initial oil
oil  Oil
prod  Production
res  Reservoir
sat  Saturation
sc  The standard condition
w  Water
water  Water
wc  Connate water

**Acronyms**

atm  Atmospheric pressure
ADSA  Axisymmetric drop shape analysis
ASP  Alkali/surfactant/polymer
ASTM  American Society for Testing and Materials
BOPD  Barrels of oil per day
BPR  Back-pressure regulator
BT  Breakthrough
<table>
<thead>
<tr>
<th>Abbreviation</th>
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<tbody>
<tr>
<td>CAG</td>
<td>Chemical-alternating-gas</td>
</tr>
<tr>
<td>CMG</td>
<td>Computer Modelling Group</td>
</tr>
<tr>
<td>EOR</td>
<td>Enhanced oil recovery</td>
</tr>
<tr>
<td>EOS</td>
<td>Equation of state</td>
</tr>
<tr>
<td>EWF</td>
<td>Extended waterflooding</td>
</tr>
<tr>
<td>FCM</td>
<td>First-contact miscibility</td>
</tr>
<tr>
<td>GAW</td>
<td>Gas-alternating-water</td>
</tr>
<tr>
<td>GOR</td>
<td>Gas–oil ratio</td>
</tr>
<tr>
<td>HCPV</td>
<td>Hydrocarbon pore volume</td>
</tr>
<tr>
<td>HPHT</td>
<td>High-pressure high-temperature</td>
</tr>
<tr>
<td>IFT</td>
<td>Interfacial tension</td>
</tr>
<tr>
<td>MCM</td>
<td>Multi-contact miscibility</td>
</tr>
<tr>
<td>MI</td>
<td>Miscible injectant</td>
</tr>
<tr>
<td>MMC</td>
<td>Minimum miscibility composition</td>
</tr>
<tr>
<td>MME</td>
<td>Minimum miscibility enrichment</td>
</tr>
<tr>
<td>MMP</td>
<td>Minimum miscibility pressure</td>
</tr>
<tr>
<td>NSERC</td>
<td>Natural Sciences and Engineering Research Council</td>
</tr>
<tr>
<td>OD</td>
<td>Outer diameter</td>
</tr>
<tr>
<td>OOIP</td>
<td>Original-oil-in-place</td>
</tr>
<tr>
<td>P–R</td>
<td>Peng–Robinson</td>
</tr>
<tr>
<td>RF</td>
<td>Recovery factor</td>
</tr>
<tr>
<td>ROS</td>
<td>Residual oil saturation</td>
</tr>
<tr>
<td>PTRC</td>
<td>Petroleum Technology Research Centre</td>
</tr>
<tr>
<td>Abbreviation</td>
<td>Description</td>
</tr>
<tr>
<td>--------------</td>
<td>---------------------------------------</td>
</tr>
<tr>
<td>PV</td>
<td>Pore volume</td>
</tr>
<tr>
<td>PVT</td>
<td>Pressure–volume–temperature</td>
</tr>
<tr>
<td>RBA</td>
<td>Rising-bubble apparatus</td>
</tr>
<tr>
<td>SF</td>
<td>Swelling factor</td>
</tr>
<tr>
<td>SWAG</td>
<td>Simultaneous water-and-gas</td>
</tr>
<tr>
<td>TDS</td>
<td>Total dissolved solids</td>
</tr>
<tr>
<td>VIT</td>
<td>Vanishing interfacial tension</td>
</tr>
<tr>
<td>WAG</td>
<td>Water-alternating-gas</td>
</tr>
<tr>
<td>WCSB</td>
<td>Western Canada Sedimentary Basin</td>
</tr>
<tr>
<td>WOR</td>
<td>Water–oil ratio</td>
</tr>
<tr>
<td>XRD</td>
<td>X-Ray diffraction</td>
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CHAPTER 1  INTRODUCTION

1.1  Tight Oil Reservoirs

Tight light oil reservoirs can be roughly defined as the light oil reservoirs that require the horizontal drilling, infill drilling, and multi-stage hydraulic fracturing in order to stimulate and produce the light crude oil [National Energy Board, 2011]. They are usually characterized by extremely low permeabilities and low porosities [Miller et al., 2008]. There are two types of tight light oil reservoirs: (1) The original shale source-rocks; and (2) The tight sandstones, siltstones, limestones, or dolostones. In North America, tight oil development began from the Bakken Play in 1953 [Breit et al., 1992], which is a vast and vital unconventional oil resource in Western Canada and the adjacent U.S. states with the extremely low permeabilities of 0.01–1 mD. It has approximately 271–503 billion barrels of the original-oil-in-place (OOIP) [National Energy Board, 2011]. Bakken production has increased quickly in Canada since the 2004 discovery of the Viewfield Oilfield in Saskatchewan. In December 2012, 2,357 Bakken wells in Saskatchewan produced a record high amount of 71,000 barrels oil per day [Kohlruss et al., 2013].

Tight oil development in Canada started in the Bakken Formation of southeast Saskatchewan and southwest Manitoba in 2005 and by 2010 had spread extensively to other plays in the Western Canada Sedimentary Basin (WCSB) as shown in Figure 1.1. The Bakken Play and Pembina Cardium Formation are the two largest tight formations in Canada.
Figure 1.1  Oil production from tight oil plays in Western Canada Sedimentary Basin (WCSB) [National Energy Board, 2011].
The major oil production problem associated with the development of a tight reservoir is its sharp decrease in the oil production rate. Figure 1.2 shows the typical well production profiles from four major tight plays in WCSB, which can be characterized as three major production stages: an initial high oil production rate stage, a significant oil production decline stage, and a final stabilized low oil production rate stage. The first two stages are very short, usually within 9–12 months. Take the Bakken play as an example, Figure 1.2 indicates that the oil production rate of one well decreases from 28 to 5 m³/d within one year, which is a reduction of 82%. This can be explained by the poor reservoir characteristics, i.e., low porosity and permeability. In the first oil production stage, the near-wellbore oil can easily flow into the wellbore by the existing pressure gradient, leading to an initial high oil production rate. After the oil in the near-wellbore area has been produced, the oil in the far areas of the reservoir is difficult to flow into the wellbore due to the limited flowing conductivity, which is caused by a low permeability and a low pressure gradient. This fact results in the final stabilized low oil production stage. The sharp decrease in the oil production rate adversely and significantly affects tight oil producer’s profits. Therefore, how to reduce the oil production rate decline and maintain the well productivity becomes a key technical challenge to the development of these tight oil reservoirs for the petroleum industry.
Figure 1.2  Tight oil well production profiles of four major tight oil plays in Western Canada Sedimentary Basin (WCSB) [National Energy Board, 2011].
1.2 Techniques for Unlocking Tight Oil Reservoirs

Certain oil reservoirs have been classified as tight oil reservoirs because of their poor reservoir characteristics, i.e., low porosities and permeabilities [Arshad et al., 2009]. The oil production from these reservoirs is not economical because of the low oil production rate. Two efforts are required to develop these tight reservoirs commercially and economically. The first effort is to find ways to increase the oil production rate. This can be achieved by drilling extended wells and multilaterals wells or increasing the reservoir contact areas by employing stimulation techniques (e.g., hydraulic fracturing and/or infill drilling). The second task is to increase the oil recovery factor (RF) by using appropriate enhanced oil recovery (EOR) techniques.

Primary oil production from a tight light oil reservoir is a pressure-depletion process, which relies on the isothermal compressibilities of the formation rock and reservoir fluids. The combination of multi-stage hydraulic fracturing and horizontal drilling enlarges the contact area between the wellbore and reservoir. Infill drilling has also been identified to play an important role in increasing oil recovery from tight reservoirs [Guan et al., 2004]. This technology has been successfully applied in several oil fields [Hudson et al., 2000, Kyte and Meehan, 1996]. Because of the large capital cost required for drilling new wells and operating the additional wells as well as the variability of the oil price, however, it is unclear whether infill drilling could produce enough incremental oil to recover the huge capital and operating investments.

Waterflooding is a much more economical secondary oil recovery method to improve the oil RF and maintain the reservoir pressure after the primary oil recovery stage. Nevertheless, the microscopic displacement efficiency of waterflooding is rather
low, the oil production rate decreases sharply and the water-cut increases quickly once water starts to break through (BT). Another serious problem is that water injectivity is very low in the tight oil reservoirs. Thus it is too difficult for waterflooding to be widely applied to improve the oil RF in the tight oil reservoirs [Iwere et al., 2012].

Recently, CO₂-EOR has played an important role in the petroleum industry due to its high displacement efficiency in enhancing or improving an oil RF and its apparent environmental benefits of mitigating greenhouse gas emissions [Aycaguer et al., 2001]. In 2012, a total of 122 miscible and 16 immiscible CO₂-EOR projects were conducted in the world and the total CO₂-enhanced oil production was 304,206 barrels per day (BOPD) [Kuuskraa, 2012]. Most CO₂-EOR projects have been applied in the light oil reservoirs with high API gravities of above 35° and oil viscosities lower than 3 cP. There are large amounts of light and intermediate hydrocarbons in the light crude oil so that the injected CO₂ can strongly extract them and easily achieve the so-called dynamic or multi-contact miscibility (MCM) with the light crude oil under the actual reservoir conditions. The crude oil in the tight reservoirs is usually very light and also the CO₂ has a much higher injectivity due to its extremely lower viscosity [Jarrel et al., 2002]. Therefore, CO₂-EOR method has been applied to recover crude oil from many tight oil reservoirs worldwide [Arshad et al., 2009; Bon and Sarma, 2004; 2009; Svec and Grigg, 2000; Toelle et al., 2008; van Vark et al., 2004]. Several major CO₂-EOR methods are developed, such as continuous CO₂ flooding, CO₂ huff-n-puff process, and CO₂ water-alternating-gas (CO₂-WAG) injection under the immiscible or miscible condition.

Continuous CO₂ flooding has been proven to be a highly effective EOR method by the petroleum industry [Alquriaishi and Shokir, 2011]. The major CO₂-EOR
mechanisms include CO₂ miscible or immiscible displacement, CO₂-induced interfacial tension (IFT) reduction, oil viscosity reduction, oil-swelling effect, light and intermediate hydrocarbons extraction by CO₂ [Blunt et al., 1993; Cao and Gu, 2013a]. However, continuous CO₂ flooding also has some obvious limitations. Technically, a low volumetric sweep efficiency and an early CO₂ BT are often caused by both viscous fingering due to an unfavourable mobility ratio of the injected CO₂ (i.e., the displacing phase) to the residual crude oil (i.e., the displaced phase) and gravity overriding due to a relatively low density of CO₂ under the actual reservoir conditions [Dellinger et al., 1984]. Economically, an extremely large amount of CO₂ is required in the continuous CO₂ flooding. Relatively high capital and operating costs of CO₂ acquisition, transportation, storage, compression, and injection may seriously limit many field applications of the continuous CO₂ flooding in practice [Holt et al., 2009].

CO₂ huff-n-puff process starts by injecting a slug of CO₂ into a single well at certain reservoir pressure and finally produces CO₂-diluted crude oil from the same well after a shut-in or soaking period, during which CO₂ is further dissolved into the crude oil to reduce its viscosity and increase its volume. Haskin and Alston [1989] summarized the detailed results of 28 CO₂ huff-n-puff projects in Texas, USA. They indicated that the incremental oil production from this CO₂-EOR process was mainly attributed to the oil viscosity reduction and oil-swelling mechanisms. In general, CO₂ huff-n-puff process can be successfully applied in an oil reservoir with a relatively small pool size and poor connectivities among wells [Monger et al., 1991]. It can also be used as an initial and inexpensive process before another major CO₂-EOR process is applied, such as continuous CO₂ flooding or CO₂-WAG injection.
The CO₂-WAG injection is applied to greatly improve the volumetric sweep efficiency and reduce CO₂ consumption, in comparison with continuous CO₂ flooding and CO₂ huff-n-puff process. The CO₂-WAG injection has several technical advantages, especially when it is applied in the light oil reservoirs under the miscible condition. First, the injected CO₂ and the light crude oil can easily become miscible under the actual reservoir conditions because of a low minimum miscibility pressure (MMP) between them. Second, the miscible CO₂-WAG injection usually leads to a higher oil RF than waterflooding or continuous miscible CO₂ flooding alone because it combines the improved volumetric sweep efficiency of waterflooding and the enhanced microscopic displacement efficiency of CO₂ flooding. Third, the injected water can quickly increase and maintain the reservoir pressure above the MMP so as to effectively control the mobility of the injected CO₂ by reducing its relative permeability. Lastly, CO₂-WAG injection can considerably reduce CO₂ consumption and the associated capital and operating costs, in comparison with continuous miscible CO₂ flooding. Therefore, the miscible CO₂-WAG injection is widely applied in the North America. In the literature, a total of 59 WAG injection field applications were reviewed, 24 of which were miscible CO₂-WAG injection projects [Christensen et al., 2001]. Most CO₂-WAG injection projects had larger oil RFs than waterflooding projects by at least 5–10%.

There are a number of laboratory studies [Wang, 1980; Kulkarni and Rao, 2005; Fatemi and Sohrabi, 2013a] and numerical simulations [Spiteri and Juanes, 2006; Fatemi et al., 2012] to examine some key parameters that determine the performance of WAG injection. These parameters include WAG slug size, WAG slug ratio, and fluid injection sequence in each cycle. First, the WAG slug size strongly affects the oil RF of
WAG injection. In general, the WAG injection has poor performance if too much water is injected in one WAG cycle, largely because the injected water prevents the subsequently injected gas from further contacting the residual oil. The oil RF is also low if too much gas is injected in one WAG cycle, which causes a gas tongue at the top of an oil reservoir due to the gravity segregation, especially if its vertical permeability is high enough. The gas overriding leads to a reduced volumetric sweep efficiency. Second, the WAG slug ratio is another key parameter that has a strong effect on the oil RF. If the WAG slug ratio is too high, the residual oil is trapped in the reservoir and surrounded by the injected mobile water so that it becomes difficult to access and recover, which is referred to as waterblocking effect [Bedrikovetsky, 2003]. If the WAG slug ratio is too low, the injected excessive gas will flow much faster than the injected water, which results in an early gas BT and a low volumetric sweep efficiency [Rao and Girard, 2002]. The fluid injection sequence (water-alternating-gas injection versus gas-alternating-water injection) is the third important factor in the WAG injection [Wang, 1980]. Therefore, it is important to determine the optimum operating parameters of WAG injection in a given oil reservoir, such as the WAG slug size, WAG slug ratio, and fluid injection sequence of each WAG cycle.

1.3 Purpose and Scope of the Thesis Study

The purpose of this thesis study is to examine the three flooding schemes (i.e., waterflooding, continuous CO₂ flooding, and CO₂-WAG injection), optimize the CO₂-WAG injection in the tight Bakken formation, and evaluate the effectiveness of CO₂-EOR methods in the fractured Bakken formation. The specific research objectives of this thesis are listed as follows:
1. To analyze the phase behaviour of the Bakken light crude oil–CO₂ system by measuring its saturation pressure ($P_{sat}$), oil-swelling factor (SF), oil density, and CO₂ solubility of CO₂-saturated Bakken light crude oil;

2. To study the oil viscosity reduction effect by measuring the viscosities of CO₂-saturated Bakken light crude oils with six different CO₂ concentrations;

3. To measure the equilibrium IFTs between the Bakken light crude oil and CO₂ at eight equilibrium pressures and the actual reservoir temperature of $T_{res} = 56$ °C and determine the MMP between the Bakken light crude oil and CO₂ at the actual reservoir temperature by applying the vanishing interfacial tension (VIT) technique;

4. To conduct a series of comprehensive coreflood tests at the actual reservoir condition, evaluate the oil recovery performance of waterflooding, continuous miscible CO₂ flooding, and miscible CO₂-WAG injection, and optimize the miscible CO₂-WAG injection in the tight Bakken formation; and

5. To examine CO₂-soaking effect in the fractured Bakken formation and compare the miscible CO₂-WAG injection process in the tight and fractured Bakken formations.

1.4 Outline of the Thesis

This thesis is composed of five chapters. More specifically, Chapter 1 is an introduction to the thesis research topic, together with its research objectives. Chapter 2 provides an up-to-date literature review on the mutual interactions between different crude oils and CO₂, the laboratory, numerical, and field studies of the WAG injection. Chapter 3 describes the experimental setups and detailed experimental procedures for PVT tests, viscosity measurements, IFT measurements, and coreflood tests. In Chapter 4, the PVT data, viscosities, and the MMP of the Bakken light crude oil–CO₂ systems at
the reservoir temperature are first discussed. Second, three flooding schemes (i.e., waterflooding, continuous CO₂ flooding, and CO₂-WAG injection) are analyzed and the miscible CO₂-WAG injection is optimized in the tight Bakken formation. At last, the CO₂-soaking effect is examined in the fractured Bakken formation and the miscible CO₂-WAG injection process is compared in the tight and fractured Bakken formations. Chapter 5 summarizes some major scientific findings of this study and makes several technical recommendations for future studies.
CHAPTER 2       LITERATURE REVIEW

2.1   Mutual Interactions between Crude Oil and CO₂

2.1.1   CO₂ solubility

In the petroleum industry, the maximum amount of gas dissolved into an oil at reservoir conditions is called solution gas–oil ratio (solution GOR) or gas solubility. Simon and Graue [1965] conducted several experimental studies to measure CO₂ solubilities in a variety of different crude oil types in a temperature range from 110 to 250 °F and at pressures up to 2,300 Pisa. The CO₂ solubility correlations with the saturation pressure, fugacity, and temperature were obtained based on their experimental results. With these correlations, the CO₂ solubility can be easily determined if the reservoir conditions and oil composition are known.

CO₂ solubility is a strong function of the saturation pressure, reservoir temperature, and oil composition [Nguyen and Farouq Ali, 1998]. It increases with pressure but decreases with temperature and the reduced API gravity. Miller and Jones [1981] showed that a sharp change in CO₂ solubility occurs in the PVT curve at the carbon dioxide condensation pressure. However, further increase in the pressure above the liquid-point conditions (6.9 MPa at 24 °C) results in only a small amount of liquid carbon dioxide dissolved into the crude oil. At reservoir conditions, nevertheless, the dissolved amount of carbon dioxide in a crude oil increases gradually as more and more carbon dioxide is injected [Chung and Burchfield, 1987]. CO₂ is highly soluble in and has strong interactions with the light crude oil [Han and Gu, 2014]. The CO₂ solubility affects the oil RF in the CO₂-EOR process too. Doscher and El-Arabi [1981] found that
an increased oil RF by increasing the injection pressure is partially because of an increased CO₂ solubility in the crude oil during an immiscible CO₂ flooding process.

Carbon dioxide is much less soluble in water than in a crude oil. The CO₂ solubility in brine is a function of brine salinity, pressure, and temperature. Li and Gu [2014a] measured the CO₂ solubilities in the Pembina Cardium light crude oil and brine at the reservoir temperature of 53 °C and different equilibrium pressures. They found that in general, the measured CO₂ solubility in the light crude oil was about six times of that in the reservoir brine at the same equilibrium pressure and temperature. Hence, much more CO₂ was dissolved into the light crude oil than that into the reservoir brine under the same reservoir condition.

2.1.2 Oil-swelling effect

The oil-swelling factor (SF) was defined as the ratio of the volume of the carbon dioxide saturated crude oil at the given test temperature and pressure to the volume of the dead crude oil at the same temperature and the standard pressure (1 atm) [Chung et al., 1988].

Oil-swelling or expanding effect is an important effect in an oil recovery process because the amount of the residual oil left in an oil reservoir after CO₂ flooding is inversely proportional to the oil SF, i.e., the larger the oil SF, the less volume of the residual oil left in the oil reservoir [Simon and Graue, 1965; Rojas, 1985]. The increased oil volume results in an increase in the oil saturation, thus allowing the discontinuous oil droplets previously trapped in the pores to merge with the flowing oil phase [Prosper, 1992]. Also, the reservoir brine can be displaced by the swollen oil [Jha, 1986], which
contributes to improving the oil phase relative permeability and eventually lowers the residual oil saturation in the porous medium.

Hand and Pinczewski [1990] found that the oil-swelling rate decreases with the increasing temperature as the CO\textsubscript{2} solubility in the oil decreases. The oil-swelling effect is more pronounced in the lower-molecular-weight crude oil, such as a light or medium crude oil. Miller and Jones [1981] also showed that the crude oil expansion increases with the increasing saturation pressure.

### 2.1.3 Viscosity reduction

The viscosity of carbon dioxide is extremely low, depending on the temperature and pressure. For example, the viscosities of CO\textsubscript{2} at $P_{\text{res}} = 10–20$ MPa and $T_{\text{res}} = 56.0$ °C are in the ranges of 0.0266–0.0598 cP, which are calculated by using the CMG WinProp module (Version 2013.20, Computer Modelling Group Limited, Canada) with the Peng–Robinson equation of state (PR-EOS) [Peng and Robinson, 1976]. The viscosity of a CO\textsubscript{2}-saturated crude oil sample mainly depends on the oil and CO\textsubscript{2} concentrations, temperature, and pressure. Holm [1982] stated that because of a high CO\textsubscript{2} solubility in crude oil at certain reservoir conditions, CO\textsubscript{2} can easily be dissolved into the crude oil to reduce its viscosity by 5–10 times. If a CO\textsubscript{2} slug is injected prior to water, the crude oil–CO\textsubscript{2} mixture with a lower viscosity flows more easily to production wells and thus leads to a higher final oil RF.

A larger percentage reduction in oil viscosity occurs at a lower operating temperature due to an increased CO\textsubscript{2} solubility [Prosper, 1992]. Rojas and Farouq Ali [1988] indicated that the higher the initial oil viscosity, the larger the percentage reduction in oil viscosity when the oil phase is saturated with the subcritical carbon
dioxide. Simon and Graue [1965] also found that viscosity reduction reaches 10 times in an oil sample with the viscosity of 5 cP, whereas viscosity reduction of a 1000 cP oil sample can be more than 50 times.

One way to estimate the viscosity of CO$_2$-saturated oil is from correlations and charts given by Beal [1946]. These correlations were developed for an oil containing dissolved hydrocarbon gases and therefore are not expected to hold well for a crude oil containing a large quantity of dissolved CO$_2$. However, in the absence of any information, they could provide useful estimates as a first approximation [Mungan, 1981].

2.1.4 IFT reduction

In CO$_2$ flooding, a large amount of CO$_2$ can be dissolved into crude oil, which results in a significant decreased IFT in the crude oil–CO$_2$ mixture [Ghedan, 2009]. The IFT reduction increases the capillary number by reducing the capillary force, and thus increases the oil RF [Nobakht et al., 2008a]. The IFT plays an important role in a miscible flooding process because it is the most sensitive variable to determine the capillary number. The capillary number can be expressed as follows:

$$N_{ca} = \frac{\mu \nu}{\gamma},$$

where $\mu$ is the viscosity of the liquid, $\nu$ is the linear characteristic velocity, and $\gamma$ is the IFT. The enlargement in the capillary number by altering these three variables can give a significant increase in the oil RF. In a CO$_2$-EOR process, one can obtain a remarkable reduction in the IFT by injecting CO$_2$ into an oil reservoir under the so-called multi-
contact miscible conditions. A substantially increased capillary number by decreasing the IFT at a relatively low cost is one of several major technical benefits of CO₂-EOR.

At the equilibrium state, the capillary pressure can be expressed in terms of the IFT, contact angle, and capillary radius:

\[ P_c = \frac{2\gamma \cos \theta}{r} \]

where \( \gamma \) is the IFT, \( \theta \) is the contact angle, and \( r \) is the capillary radius. The decreased capillary pressure due to the reduction in the IFT makes the injected CO₂ more easily access the crude oil inside smaller pores, which results in improving the volumetric sweep efficiency and reducing the residual oil saturation.

The dynamic IFT between the light crude oil and CO₂ will be reduced gradually and finally an equilibrium IFT is reached at a given pressure and temperature [Yang et al., 2005]. The equilibrium IFT between the light crude oil and CO₂ reduces with the increased equilibrium pressure at a given temperature [Gu et al., 2013].

2.1.5 Miscibility

One technical advantage of using miscible CO₂ to displace crude oil is to achieve an enhanced microscopic displacement efficiency, which means that once the CO₂ front has moved through a volume of the porous medium containing the original crude oil, little to no residual crude oil is left behind [Lewis, 2008].

Two fluid phases can develop the first-contact miscibility (FCM) if they can form a single phase immediately after they are mixed together in any proportion at given conditions [Stalkup, 1983]. A high oil recovery efficiency and a low residual oil saturation are observed in the FCM displacements. However, the actual reservoir
conditions (i.e., the reservoir pressure and temperature) are seldom good enough to achieve the FCM between the crude oil and injected CO$_2$. In general, an increased pressure tends to help injected CO$_2$ to achieve the FCM with the crude oil. But the high pressures required for the FCM development in the oil formations are typically higher than the rock fracture pressures [Lewis, 2008].

Even if the injected CO$_2$ cannot achieve the FCM with the crude oil at the given operating conditions, a high oil RF can still be obtained if the fluids can develop miscibility through multiple contacts [Stalkup, 1983]. This process is referred to as the dynamic or multi-contact miscibility (MCM). Two mechanisms were identified in the dynamic miscibility development: condensing gas-drive and vapourizing gas-drive [Stalkup, 1987; Johns et al., 1993; 1994]. In a condensing gas-drive, components in the injected CO$_2$ are condensed and then dissolved into the crude oil, gradually increasing the CO$_2$ composition in the crude oil until it becomes miscible with CO$_2$. In a vapourizing gas-drive, hydrocarbon components in the crude oil are vapourized or extracted into the solvent phase to enrich it until it becomes miscible with the crude oil.

The pressure at which a miscible displacement occurs depends on the temperature of the reservoir and the composition of the crude oil. With adequate amounts of light to intermediate hydrocarbon components in the crude oil, the miscible displacement occurs with CO$_2$ injection at low pressures [Holm and Josendal, 1982]. At higher temperatures or for heavier oils with less amounts of light to intermediate hydrocarbon components, a higher pressure is required to achieve the miscible displacement during CO$_2$ injection process [Holm, 1982].
The minimum pressure under which CO\textsubscript{2} can achieve the MCM with the crude oil is called the minimum miscibility pressure (MMP). In order to achieve miscibility during CO\textsubscript{2}-EOR process, the MMP of a crude oil–CO\textsubscript{2} system needs to be determined in the design of a field CO\textsubscript{2}-EOR application.

Generally, there are two commonly used methods to measure the MMP between a crude oil and CO\textsubscript{2}:

1. Slim-tube method: In this method, CO\textsubscript{2} is injected into a long sandpacked slim tube at different injection pressures and the actual reservoir temperature to recover the oil from the slim tube. The measured oil RF is then plotted versus the injection pressure. The MMP is determined as the pressure at which the measured oil RF versus injection pressure curve has a sudden change in slope [Flock and Nouar, 1984]. Alternatively, the MMP for the crude oil–CO\textsubscript{2} system is defined as the pressure at which the oil RF can reach 90 or 95% after 1.2 pore volumes (PVs) CO\textsubscript{2} is injected into the slim tube. The slim-tube method is the most accurate way to determine the MMP but is very time-consuming and expensive.

2. Rising-bubble apparatus (RBA): In this method, a small CO\textsubscript{2} bubble is injected into a thin transparent column of the crude oil inside the RBA at a different pressure each time. The MMP is assumed to be reached when the rising CO\textsubscript{2} bubble ultimately disappears in the oil column under a certain pressure [Christiansen and Kim, 1987]. The RBA method is much cheaper and faster and requires much smaller amounts of crude oil and CO\textsubscript{2}, in comparison with the slim-tube method [Dong et al., 2001].
Recently, a new experimental approach, named the vanishing interfacial tension (VIT) technique, has been developed and utilized to determine the MMPs of different crude oil–CO$_2$ systems [Rao, 1997; Rao and Lee, 2002; 2003]. The VIT technique is based on the concept that the interfacial tension between the gas and crude oil phases at reservoir temperature must reduce to zero as these two phases approach the point of miscibility. The concept of zero-interfacial tension at miscibility is based on a well-accepted fact that the interface between the two phases must vanish as they become miscible with one another. Thus the MMP and minimum miscibility composition (MMC) can be determined precisely by measuring oil–gas interfacial tension as a function of pressure and gas composition to as low as an experimental technique can measure and then extrapolating the data to zero-interfacial tension [Rao and Lee, 2002]. Because the smallest amounts of oil and time are required, the VIT technique is the cheapest and fastest among the three experimental methods for determining the MMP. Its reliability and accuracy have been discussed in the literature [Nobakht *et al.*, 2008a; 2008b].

In addition, some useful empirical correlations based on the experimental data of the gas and crude oil compositions during the CO$_2$ extraction process are also available in the literature for determining the MMPs of the crude oil–CO$_2$ systems [Holm and Josendal, 1982].

### 2.2 Laboratory-Scale WAG Injection

Huang and Holm [1988] presented laboratory results of Devonian crude oil displacement from water-wet Berea core and reservoir cores by using three different injection techniques, i.e. continuous CO$_2$ flooding, single-slug CO$_2$ injection followed by water, and CO$_2$-WAG injection at the miscible reservoir conditions of 120 °F and
2,500 psig (i.e., 49 °C and 17.0 MPa). The effects of the WAG injection and rock wettability on the oil RF were investigated in their study. They also provided a method to alter the wettability of Berea core artificially and simulate different wettability conditions of reservoir cores. They concluded that during CO₂-WAG injection process, a significant oil trapping occurs in water-wet cores, whereas less oil trapping occurs in oil-wet cores.

Svec and Grigg [2001] conducted an experimental study on the injectivity abnormalities during WAG injection process. In their study, two different core samples were used in coreflood tests, i.e., Indiana limestone and Seminole San Andres dolomite. Pre-flood and post-flood microscopic images obtained by using Backscatter electron imaging were compared to determine the mineral changes during WAG injection process. They concluded that mineral dissolution occurred in both types of carbonate rocks.

Sohrabi et al. [2004] reported experimental results of a series of WAG tests conducted in glass micromodels with three different wettability states, i.e., water-wet, mixed-wet, and oil-wet. The objective of their study is to improve the understanding of oil recovery mechanisms of WAG injection process in oil reservoirs. A high-definition optical equipment for image capture and analysis was used to record the experimental data. Their experimental results indicated that more oil can be recovered in WAG injection test than that in either water or gas injection alone. The main mechanism for incremental oil recovery during WAG injection is the redistribution of the fluids, which results in more pores being touched or invaded by gas. The oil RF of WAG injection
was generally higher for the oil-wet or mixed-wet models than that for the water-wet model.

Dong et al. [2005] presented an experiment study of immiscible WAG Injection in a water-wet micromodel. The mechanism of gas, oil, and water flow during immiscible WAG injection was analyzed in their study. They found that during immiscible gas injection after an initial waterflood, gas moved through the residual oil paths and the residual oil was pushed either toward the production end of the model or into previously waterflooded channels. When water was injected after gas injection, however, it flowed through channels that were created in the initial waterflood.

An experimental study of two different injection schemes of gas injection, i.e., continuous gas flooding and WAG injection, on the oil RF was conducted by Kulkarni and Rao [2005]. The effects of brine composition and miscibility state on the final oil RF were investigated in their experiments. They suggested that the optimum injection scheme is 0.7 PV continuous gas injection followed by a 1:1 WAG injection. They also found that miscible flooding is more efficient than immiscible flooding and that WAG injection is more successful than continuous gas injection. Also, WAG injection showed a large dependence on the brine composition because of different CO₂ solubilities in different brines.

Torabi et al. [2012] presented an experimental evaluation of three oil recovery methods, i.e., waterflooding, immiscible CO₂ flooding, and CO₂-WAG injection, to recover heavy oil in a sandpacked model. A total of 11 tests were conducted to investigate the effect of the oil viscosity and model permeability, the effect of injection rate on waterflooding, and the effect of slug ratio on CO₂-WAG injection. They
concluded that waterflooding gave a higher final oil RF than CO₂ flooding or CO₂-WAG injection. The oil viscosity effect is more significant than the model permeability effect on these three oil recovery methods.

A series of high-pressure high-temperature (HPHT) coreflood tests were conducted to evaluate the performance of WAG injection in carbonate cores at the reservoir temperature of 115 °F and different pressures [Nematzadeh et al., 2012]. The fluid system included reservoir dead and live crude oil, CO₂, and synthetic brine, while the chosen porous media were core samples with the permeabilities of 0.6–1.0 mD and the porosities of 12–14%. The oil RF, water and oil production rates, and pressure drop along the core samples were recorded in each test. The experimental results indicated that increasing pressure improved the oil RF but this improvement above the MMP was not as significant as it was below the MMP. The oil RFs of the dead and live oils showed different values at the same pressure due to their differences in miscibility development.

Dehghan et al. [2012] presented an experimental study of investigating the WAG injection in a fractured system. A micromodel that comprised of four matrix blocks surrounded by fractures was used to study the effects of different injection scenarios, such as waterflooding, gas flooding, and WAG injection with different slug arrangements on the oil RF. Kerosene and brine were used as the hydrocarbon and aqueous phases, and N₂ was the injected gas. They found that the WAG injection could lead to a larger oil RF in the fractured model, compared with either waterflooding or gas flooding alone at its optimum injection rate. The optimum slug sequence in their experiments was 0.08 PV water injection followed by 0.35 PV gas slug injection. In this
way, the matrix sweep efficiency was increased and gas/water production was reduced at the outlet.

Fatemi and Sohrabi [2013b] reported laboratory results of a comprehensive series of coreflood tests carried out under water-wet and mixed-wet conditions. Waterflooding, gas flooding, and WAG injection were conducted by using sandstone core samples in their study. The wettability of core sample can be changed into mixed-wet by using an appropriate crude oil to age the core. Also, in their experiments, X-Ray scanner was used to measure the distributions and saturations of different phases (e.g., water, oil, and gas) along the core sample. The experimental results indicated that in both the water-wet and mixed-wet cores, WAG injection gave the best performance in the three injection schemes. Waterflooding had a higher oil RF in mixed-wet condition. The oil RFs of water, gas, and WAG injection processes were strongly affected by the wettability of core sample.

A laboratory investigation of the effects of WAG ratio and fluid flow rate on the miscible WAG injection was conducted by Kootiani and Samsuri [2013]. Glass beads were used to pack the 2-D physical model, whose dimensions were 23 cm × 10 cm × 0.6 cm. The use of bead-packed model enabled the in-situ visualization of the WAG displacement process in a real time. They concluded that the optimum WAG ratio was about 1:1 and that the optimum fluid flow rate was approximately 3 ml/min.

Luo et al. [2013] reported a laboratory feasibility study of an improved WAG injection to recover heavy oil. Chemicals (alkali/surfactant/polymer) were added into the injected water and this process was referred to as the CAG (i.e., chemical-alternating-gas) injection. Four sandpacked coreflood tests were conducted through CO₂-WAG
injection, flue gas (30 mol.% CO₂ + 70 mol.% N₂) WAG, ASP/CO₂ CAG, and ASP/flue gas (30 mol.% CO₂ + 70 mol.% N₂) WAG, at the pressure of 3.5 MPa and temperature of 27 °C. They concluded that CO₂ recovered more oil than flue gas (9.43% of the OOIP versus 3.58% of the OOIP) in the WAG injection because a large portion of CO₂ was dissolved into the oil phase to reduce the oil viscosity. The final oil RF was greatly enhanced when the WAG process was augmented with chemicals. The total incremental oil RF in the CO₂-CAG injection was 27.4% of the OOIP, which was almost three times of that in CO₂-WAG injection.

A laboratory study of waterflooding, gas flooding, and WAG injection was conducted by Jafari [2014]. A series of coreflood tests were carried out at the reservoir pressure (3,100–3,400 psi) and reservoir temperature (200 °F). Carbonate cores with the permeability of 8 mD and porosity of 12.5% were used in this study. Injection rates of 0.1, 0.2, and 0.5 cc/min were used in waterflooding, continuous gas flooding, and WAG injection under the immiscible condition. The experimental results showed that the oil RF in the WAG injection process appeared to be better than those in waterflooding and immiscible methane flooding. Also, the optimum injection rate for WAG process was 0.2 cm³/min and the corresponding oil RF was 51.9% of the OOIP.

2.3 Numerical Simulations of WAG Injection

Claridge [1982] reported a simulation study of the effectiveness of different CO₂ flooding strategies in a communicating layered reservoir. The subject of this investigation was the southeast Seminole San Andres Unit. Different WAG ratios of 2:1, 1:1, and 1:2, were evaluated in this study. The simulation results showed that WAG injection did reduce the extent of crossflow and thus mitigated the adverse effects in
continuous CO₂ flooding. The optimum WAG ratio depends on the waterblocking curve (trapped oil saturation vs. water saturation). This curve can be determined experimentally for a given reservoir rock. From the curve used in this study, the optimum WAG ratio was 1:1.

Lin and Poole [1991] summarized a numerical evaluation of the effectiveness of continuous CO₂ flooding, CO₂-WAG injection, and an innovative hybrid process at the Dollarhid Devonian Unit, Texas, USA. The hybrid process consisted of the injection of an initial slug of CO₂ followed by CO₂-WAG injection and waterflooding. The simulation studies included history matching of both primary and waterflooding production data and predictions of various CO₂ injection processes. The simulation results showed that the incremental oil RF for the WAG injection was 1.2% of the OOIP more than that for the hybrid injection. However, a detailed economic analysis indicated that the hybrid injection process was the most attractive process for the Dollarhide application. With proper design of the CO₂-WAG slug size, the hybrid injection process had the potential to recover more oil than either continuous CO₂ flooding or CO₂-WAG injection.

Pritchard and Nieman [1992] conducted a simulation study on the Judy Creek Field to identify the potential to increase the oil RF by using WAG injection process. The Judy Creek ‘A’ pool is located about 200 km to the northwest of Edmonton and its OOIP was estimated to be 800 MMSTB. Its total thickness of 111 feet (34 m) was divided into 2 layers. A reservoir simulator was used to optimize WAG cycle parameters, such as the slug size, injection rate, and WAG ratio. The simulation results indicated that properly chosen slug size and injection rate enhance the oil RF and injectant
utilization factor. The optimum solvent slug size depends on the volumetric sweep efficiency of a given pattern. The tapered WAG ratios could enhance the oil RF of Judy Creek pattern by up to 16%.

Sim et al. [1996] reported laboratory experiments and reservoir simulation studies to support a CO₂ injection project in Mattoon Field, Illinois, USA. An integrated geological reservoir simulation approach was used to model the pilot study area. A 3-D geological model was constructed by using SGM computer software. A continuous CO₂ injection program and a WAG injection program were simulated and compared in both the A-sandstone of the Pinnell Unit and E-sandstone interval of the Sawyer Unit. In the Pinnell Unit, the simulated results showed that neither of the two methods produced the crude oil economically because of the poor inter-well connectivity. On the contrary, simulated results showed that a significant amount of additional oil was produced from the Sawyer Unit. A CO₂-WAG injection program yielded more oil than waterflooding or continuous CO₂ flooding alone. The model predictions also showed that 10% hydrocarbon pore volume (HCPV) was the optimum slug size. The optimum WAG ratio for the project depends on economics.

A 2-D model with a random permeability distribution was set up by using a compositional stimulator to study the effects of well placements and well completions on the oil RF [Wu et al., 2004]. Three injection methods, i.e., waterflooding, miscible gas flooding, and WAG injection, were studied. The parameters studied included the injection solvent type, optimal bottom-hole pressure, WAG ratio, cycle length, and WAG timing. The simulation results showed that WAG injection gives the best displacement efficiency among all three injection methods. The heterogeneity of the
porous media was a major factor that affects the oil RF and needed to be considered in the field development. The injector should be completed in a lower portion of reservoir while the producer should be completed in an upper portion of the reservoir to avoid an early gas BT. The optimal bottom-hole pressure for a producer was near the bubble-point pressure to avoid an early gas BT. A small WAG slug size was preferred in order to maximize the cumulative oil RF.

Bermudez et al. [2007] reported a simulation investigation of WAG injection above the minimum miscibility enrichment (MME) composition. Numerical simulations were performed by using the numerical code UT COMP, a fully compositional simulator developed in the University of Texas at Austin. The effects of WAG parameters, numerical dispersion, enrichment level, and reservoir heterogeneity on the local displacement efficiency and sweep efficiency were investigated. The simulation results indicated that the richer the gas above the MME, the fewer the number of WAG cycles were required to achieve the maximum oil RF at a given WAG ratio. The over-enrichment above the MME enhanced the oil RF to the largest extent when the largest permeability layers were at the bottom of the reservoir. Continuous slug injection performed better than WAG injection when the largest permeability layers were at the bottom of the reservoir, richer gases were used, and the vertical-to-horizontal permeability ratio was small.

Panda et al. [2009] presented a simulation study on optimizing WAG injection in the Eileen West End area, Greater Prudhoe Bay. The OOIP in Eileen West End was estimated to be 750 MMSTB. They selected several major design parameters of WAG injection, i.e., slug size, injection rate, WAG ratio, and WAG sequence to optimize the
oil RF in Eileen West End area. A fine-grid and fully compositional numerical simulator called VIP was used to determine the optimal design parameters. They concluded that multiple WAG cycles with an overall WAG ratio of 1:1 provided the highest oil RF. The optimal WAG sequence was 15% HCPV miscible injectant (MI) followed by 10% HCPV of waterflooding, then by 10% HCPV of MI, followed by 100% HCPV of waterflooding, 5% MI, and continuous waterflooding.

A simulation study was conducted by Aghdam et al. [2013] to compare the performance of waterflooding, gas flooding, WAG injection, and simultaneous water and gas injection (SWAG) in an Iranian oil reservoir. A synthetic model with dimensions that had 2,000 ft in length, 1,000 ft in width, and 150 ft in thickness was chosen in their study. They found that WAG injection had a higher oil RF than gas flooding or waterflooding alone. WAG injection controlled and reduced mobility of displacing fluids in an oil reservoir. Although SWAG injection had a higher oil RF than WAG injection, higher water production in SWAG injection made this process economically unacceptable.

Zuo et al. [2014] studied the effect of three-phase relative permeability model on the simulation of WAG injection under various conditions. In their study, immiscible and miscible WAG injection processes were simulated by using black-oil and compositional models in both 2-D homogeneous cases and actual 3-D field sector models. They found that three-phase relative permeability model had stronger effect on immiscible WAG injection (black-oil simulations) because the size of three-phase flow region in the immiscible case is typically larger. For near-miscible cases, the choice of an appropriate three-phase relative permeability model substantially affected the final oil RF. When the
miscibility was fully developed, the effect of the three-phase relative permeability models could be negligible.

2.4 Field-Scale WAG Injection

Reid and Robinson [1981] reviewed the performance of an immiscible CO$_2$-WAG injection project conducted at Lick Creek Meakin Sand Unit. The project was implemented in four distinct phases by using 16 injectors and 38 producers on 1,640 acres area. These phases included: (1) Cycling all wells with CO$_2$ for one year to raise the reservoir pressure and produce the oil in the near-wellbore area; (2) Injecting a large amount of CO$_2$ into permanent injectors for several months to displace oil by CO$_2$ flooding; (3) Conducting CO$_2$-WAG injection in permanent injectors for three years with the WAG ratio of about 1.5 bbl water/MSDCF CO$_2$; and (4) Displacing the residual oil with water. After 5 years of operation, 7.6 BSCF of source CO$_2$ and 6.5 BSCF of recycled CO$_2$ had been injected, and more than 1 MMbbl of oil had been produced. About 755 Mbbl of oil was considered as additional oil due to WAG injection. Hence, CO$_2$-WAG injection project was successful in the Lick Creek Meakin Sand Unit.

Hsie and Moore [1988] summarized the performance of a miscible CO$_2$-WAG injection project in a U.S. gulf coast reservoir. This project was conducted at a 75-acre pilot area, which consisted of one injection well, two monitor wells, and five production wells. The pilot area contained an estimated 1.11 MMbbl of the OOIP, and the estimated residual oil saturation (ROS) was about 38% before CO$_2$ injection. In the field injection, only 18.9% HCPV slug of CO$_2$ was injected with a WAG ratio of 2:1. The project was conducted for 16 months and a total of 187.9 Mbbl of oil (or 16.9% of the OOIP) was produced. The results indicated that the small slug size of 18.9% HCPV was sufficient
to obtain a substantial amount of the incremental oil RF with the CO\textsubscript{2} utilization factor as low as 2.57 MSCF/bbl. This project demonstrated that a miscible CO\textsubscript{2}-WAG injection process was applied successfully to recover a considerable amount of the residual oil from a water-out Miocene reservoir in the gulf coast.

The performance of an early CO\textsubscript{2} flood at the South Wasson Clearfork Unit was described by Burbank [1992]. In January 1986, CO\textsubscript{2}-WAG injection with the WAG ratio of 8:1 and slug size of 8\% HCPV was implemented at the South Wasson Clearfork Unit. The five-spot injection pattern was used to maximize the oil RF in this project. Three years later, the oil production rate was increased to over 500 BOPD, or 9\% of the Unit’s oil production rate. Then WAG injection with the WAG ratio of 2:1 was implemented in April 1990. In the CO\textsubscript{2}-WAG injection area, the cumulative oil production was 0.3\% of the OOIP after 3\% HCPV CO\textsubscript{2} was injected. During CO\textsubscript{2}-WAG injection process, water injectivity was not significantly reduced after CO\textsubscript{2} injection.

Tanner et al. [1992] reviewed the production performance of a CO\textsubscript{2}-EOR project at the Wasson Denver Unit. The Denver Unit is the largest CO\textsubscript{2} EOR project in the world. The project was originally implemented with both a continuous CO\textsubscript{2} flooding area and a CO\textsubscript{2}-WAG injection area. In the continuous CO\textsubscript{2} flooding area, within four years of CO\textsubscript{2} injection, oil production had increased by 8,000 BOPD. In the CO\textsubscript{2}-WAG injection area, the oil production response was disappointing due to a lower WAG injectivity. Several questions needed to be answered before CO\textsubscript{2}-WAG injection was applied in Denver Unit: (1) The best time to switch from continuous CO\textsubscript{2} flooding to WAG injection; (2) The optimum CO\textsubscript{2} slug size; (3) The best WAG ratio; and (4) The optimum number of the WAG cycles.
Stephenson et al. [1993] reported the Canada’s first miscible CO$_2$ flood in the Joffre Viking pool, northeast of Red Deer, Alberta. The field was discovered in July 1953, 42% of the OOIP was recovered at the primary and secondary recovery stages. The commercial field development by applying CO$_2$-EOR method started in October 1991. Different injection strategies were tested to maximize the oil RF, including continuous CO$_2$ injection, WAG injection, and SWAG injection. The test results indicated that SWAG injection at water–CO$_2$ ratio approaching 1:1 enhanced CO$_2$ sweep efficiency significantly in the reservoir. Continuous CO$_2$ injection established a high CO$_2$ saturation flow path at the top of the formation, which significantly reduced CO$_2$ vertical sweep efficiency.

Masoner and Wackowski [1995] presented a review of one CO$_2$-EOR project in Rangely Weber Sand Unit, in which the OOIP was estimated to be 1.9 billion bbl of oil. In 1995, there were 372 active producers and 300 active injectors, 250 of which were CO$_2$-WAG injection wells. CO$_2$-WAG injection with a WAG ratio of 1:1 started in October 1986. At that time, the cumulative oil RF was estimated to be 37.0% of the OOIP and the producing water–oil ratio (WOR) was 17:1. The CO$_2$ project extended the life of the Unit significantly. In April 1995, the cumulative incremental oil production was 50% of the Unit’s remaining recoverable reserves, which was attributed to the CO$_2$-EOR project. During the CO$_2$-WAG injection, the WAG slug size was reduced from 1.5% to 0.25% HCPV to control gas production. The small WAG slug size technique was applied in over 90% of the Unit’s WAG injectors and had proven to be an effective tool in controlling gas production.
Instefjord and Todnem [2002] reviewed a 10-year CO₂-WAG injection project in Lower Brent at the Gullfaks Field. A WAG injection pilot in Lower Brent was initiated in March 1991. The main objectives of WAG injection were: (1) Avoiding oil production reduction; (2) Reducing storage cost and CO₂ tax; (3) Reducing the residual oil saturation (ROS); and (4) Reaching areas that waterflooding could not touch. The water and gas cycles were optimized for WAG injection from March 1991 to August 1996. From August 1996 to September 2000, the gas cycles were shorter and a lower injection rate was used. Three methods were developed to quantify the increased oil RF in WAG injection. The results indicated that CO₂-WAG injection was a significant contributor to enhance the oil RF at the Gullfaks Field with a low cost.

Crogh et al. [2002] reviewed a field performance of WAG injection in a pilot area at the Statfjord Field. The Statfjord Field was discovered in the North Sea in 1973 and is the biggest oil discovery to date in Europe. CO₂-WAG injection was initiated in 1997 and the results were encouraging. As of May 2002, the estimated total incremental oil production due to CO₂-WAG injection was almost 3.5 million Sm³. All the WAG injectors had incremental oil production in their respective response wells. In general, the first WAG cycle was the most efficient. And the CO₂-WAG injection potential in Statfjord Field was estimated to be significant based on the reservoir simulation and the historical data for 5 years of WAG experience in the field.

### 2.5 Problem Statement

As the global energy demand is increasing and conventional oil resources are depleting, it is of practical importance to produce the light crude oil from the tight formations. The Bakken formation is the largest tight formation in North America with
the approximately 271–503 billion barrels of the OOIP [National Energy Board of Canada, 2011]. However, a major oil production problem associated with the development of the Bakken formation is its sharp decrease in the oil production rate due to its low permeabilities and porosities. The CO$_2$-WAG injection has been proven to be an effective method to recover the crude oil from the conventional oil formations. In the literature, although numerous experimental tests, numerical simulations, and field studies have been conducted to study and optimize the CO$_2$-WAG injection processes in various oil reservoirs, there have been fewer studies of the miscible CO$_2$-WAG injection processes in the tight oil formations [Song and Yang, 2012; Ghaderi, 2012]. Therefore, the main objective of this thesis study is to evaluate the oil recovery performance of CO$_2$-WAG injection in the Bakken formation.

In this study, a number of tight sandstone reservoir rock samples are collected from the Bakken formation in Canada and thoroughly characterized. The PVT studies of six Bakken light crude oil–CO$_2$ systems with different CO$_2$ concentrations at the actual reservoir temperature are performed. The equilibrium IFTs between the Bakken light crude oil and CO$_2$ are measured at different equilibrium pressures and the actual reservoir temperature. Then, the MMP is determined by applying the so-called VIT technique. A total of nine coreflood tests are conducted to measure the oil RFs, cumulative water production data, and average gas production rates of different CO$_2$-based oil recovery methods. More specifically, the following CO$_2$-EOR processes are tested and compared: three different flooding schemes, i.e., waterflooding, continuous miscible CO$_2$ flooding, and miscible CO$_2$-WAG injection; three different WAG slug sizes, i.e., 0.125, 0.250, and 0.500 PV; three different WAG slug ratios, i.e., 2:1, 1:1,
and 1:2; and two different fluid injection sequences, i.e., WAG or gas-alternating-water (GAW) injection. Last, four coreflood tests were further conducted to study CO₂-EOR processes in the fractured Bakken formation. Specifically, the first two tests were conducted to study CO₂-soaking effect on miscible CO₂ secondary flooding and the last two tests were carried out to study the fracture effect on CO₂-WAG injection processes and its oil RFs in the fractured Bakken formation.
CHAPTER 3  EXPERIMENTAL

3.1  Materials

In this study, a number of tight sandstone reservoir rock samples were collected from several wells located in the Viewfield region inside the Bakken formation, Saskatchewan, Canada, at the reservoir depths of 1,565–1,626 m. The thin-section analysis and the X-Ray diffraction (XRD) method were used to qualitatively and quantitatively identify the elements of the rock samples, respectively. The thin-section digital image of one rock sample (Well No.: 08-03-008-08W2) is shown in Figure 3.1 and the detailed compositional analysis result and petrographic properties are given in Tables 3.1a and 3.1b, respectively. According to the thin-section image and XRD analysis, one lithofacies was found and categorized as the Dolomitic Arkosic Sandstones. The thin-section image (Figure 3.1) also depicts various minerals in the Bakken rock sample. More specifically, the golden coloured material is the dolomite, which is the main component. The white grains are sand-sized quartz and the black opaque mineral is pyrite. The blue colour represents the porosity as a blue epoxy was used to mount the thin section.

In addition, the compositional analysis results of the XRD method show 48.0 wt.% dolomite, 31.5 wt.% quartz, 10.7 wt.% k-feldspar, 7.9 wt.% plagioclase, 1.2 wt.% illite, and 0.7 wt.% pyrite in the Bakken rock sample. The framework grains within this lithofacies are mainly monocrystalline quartz with smaller amounts of k-feldspar and plagioclase. This lithofacies contains cements, which consist of a large amount of ferroan dolomite and an extremely small amount of pyrite. There is also a relatively small amount of clays found within this lithofacies. The total estimated porosities of this
Figure 3.1  Thin-section micrograph of the Bakken rock sample (Well No.: 08-03-008-08W2).
Table 3.1a  Compositional Analysis Result of One Tight Rock Sample from the Viewfield Region (Well No.: 08-03-008-08W2).

<table>
<thead>
<tr>
<th>Component</th>
<th>Density (g/cm$^3$)</th>
<th>Composition (wt.%)</th>
<th>Composition (vol.%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Quartz</td>
<td>2.65</td>
<td>31.5</td>
<td>32.6</td>
</tr>
<tr>
<td>K-feldspar</td>
<td>2.58</td>
<td>10.7</td>
<td>11.3</td>
</tr>
<tr>
<td>Plagioclase</td>
<td>2.63</td>
<td>7.9</td>
<td>8.2</td>
</tr>
<tr>
<td>Dolomite</td>
<td>2.84</td>
<td>48.0</td>
<td>46.4</td>
</tr>
<tr>
<td>Pyrite</td>
<td>5.00</td>
<td>0.7</td>
<td>0.3</td>
</tr>
<tr>
<td>Illite</td>
<td>2.75</td>
<td>1.2</td>
<td>1.2</td>
</tr>
<tr>
<td>Total</td>
<td>2.75*</td>
<td>100.0</td>
<td>100.0</td>
</tr>
</tbody>
</table>

*The calculated grain density of the bulk rock sample.

Table 3.1b  Petrographic Properties of One Tight Rock Sample from the Viewfield Region (Well No.: 08-03-008-08W2).

<table>
<thead>
<tr>
<th>Property</th>
<th>Characteristics</th>
</tr>
</thead>
<tbody>
<tr>
<td>Grain size</td>
<td>Fine sand to coarse silt</td>
</tr>
<tr>
<td>Sorting</td>
<td>Poor</td>
</tr>
<tr>
<td>Roundness</td>
<td>Angular–subangular</td>
</tr>
<tr>
<td>Intergranular</td>
<td>Abundant</td>
</tr>
<tr>
<td>Microporosity</td>
<td>Trace</td>
</tr>
<tr>
<td>Estimated $\phi$ (%)</td>
<td>8–16</td>
</tr>
<tr>
<td>Estimated $k_{max}$ (mD)</td>
<td>0.1–1.0</td>
</tr>
<tr>
<td>Reservoir quality</td>
<td>Fair–good</td>
</tr>
</tbody>
</table>
lithofacies are in the range of 8–16%, which are close to the measured porosities prior to the coreflood tests in this study. The estimated permeabilities range from 0.1 to 1.0 mD, which are approximately one order higher than the measured permeabilities prior to the coreflood tests. Both measured porosity and permeability are extremely low as this lithofacies is rich in carbonate cement, which significantly reduces its porosity and permeability. Furthermore, a small amount of clay reduces the sizes of pore-throats, leading to low porosity and permeability. Clay XRD method was also conducted to find that most of the clay mineral is illite, which is a swelling clay. A small concentration of swelling clay causes this rock sample to have a strong sensitivity to freshwater. If freshwater is used to displace the light crude oil in the Bakken formation, this clay might swell and potentially plug pore-throats.

The original light crude oil was collected from the Viewfield region in Saskatchewan, Canada. The obtained original light crude oil was cleaned by using a centrifuge (Allegra X-30 Series, Beckman Coulter, USA) to remove any sands and brine. Also, an inline filter (SS-2TF-0.5, Swagelok, Canada) with a pore size of 0.5 µm was used to further remove any fine solids from the Bakken light crude oil. The densities and viscosities of the cleaned Bakken light crude oil were measured to be \( \rho_{\text{oil}} = 0.805 \text{ g/cm}^3 \) by using a densitometer (DMA 512P, Anton Paar, USA) and \( \mu_{\text{oil}} = 2.43 \text{ cP} \) by using a viscometer (DV-II+, Brookfield, USA) at the atmospheric pressure and \( T_{\text{lab}} = 22.0 ^\circ\text{C} \), \( \rho_{\text{oil}} = 0.745 \text{ g/cm}^3 \) and \( \mu_{\text{oil}} = 1.48 \text{ cP} \) at the atmospheric pressure and \( T_{\text{res}} = 56.0 ^\circ\text{C} \), respectively. The molecular weight of the Bakken light crude oil was measured to be 162.0 g/mol by using an automatic high-sensitivity wide-range cryoscropy (Model 5009, Precision Systems Inc., USA). The asphaltene content of the cleaned Bakken light crude
oil was measured to be \( w_{\text{asp}} = 0.16 \text{ wt.\% (n-pentane insoluble)} \) by using the standard ASTM D2007–03 method and filter papers (Whatman No. 5, England) with a pore size of 2.5 \( \mu \text{m} \). The compositional analysis result of the Bakken light crude oil was obtained by using the standard ASTM D86, and is given in Table 3.2 and shown in Figure 3.2. The total molar percentages of \( \text{C}_1–10, \text{C}_{11–20}, \text{C}_{21–30}, \) and \( \text{C}_{31+} \) are equal to 64.19, 26.94, 6.26, and 2.61 mol.\%, respectively. These data show that the light crude oil used in this study contains a large amount of light to intermediate hydrocarbons and is thus especially suitable for \( \text{CO}_2\)-EOR.

The reservoir brine samples were collected from the same region, cleaned, and analyzed. Its detailed physicochemical properties are listed in Table 3.3. However, a synthetic brine was prepared and used in this work. The sandstone reservoir core plugs were found to be completely blocked by the fine solids in the reservoir brine after it was tested and used in the coreflood tests. The synthetic brine contained 149,800 mg/L NaCl, which was equal to the total dissolved solids (TDS) of the reservoir brine at 110.0°C. Its viscosity was measured to be \( \mu_{\text{brine}} = 1.24 \text{ cP} \) by using the viscometer at the atmospheric pressure and \( T_{\text{lab}} = 22.0 ^\circ \text{C} \).

The purity of carbon dioxide (Praxair, Canada) used in this study was equal to 99.998 mol.\%. The densities and viscosities of \( \text{CO}_2 \) at \( P_{\text{res}} = 10–20 \text{ MPa and } T_{\text{res}} = 56.0 ^\circ \text{C} \) were in the ranges of \( \rho_{\text{CO}_2} = 0.318–0.722 \text{ g/cm}^3 \) and \( \mu_{\text{CO}_2} = 0.0266–0.0598 \text{ cP} \). These data were obtained by using the CMG WinProp module (Version 2013.20, Computer Modelling Group Limited, Canada) with Jossi-Stiel-Thodos correlation [Jossi \textit{et al.}, 1962].
Table 3.2  Compositional Analysis Result of the Original Light Crude Oil from the Viewfield Region (Well No.: 16-17-9-8W2) (GC analyses were conducted by Saskatchewan Research Council).

<table>
<thead>
<tr>
<th>Carbon No.</th>
<th>mol.%</th>
<th>Carbon No.</th>
<th>mol.%</th>
</tr>
</thead>
<tbody>
<tr>
<td>$C_1$</td>
<td>0.00</td>
<td>$C_{27}$</td>
<td>0.48</td>
</tr>
<tr>
<td>$C_2$</td>
<td>2.46</td>
<td>$C_{28}$</td>
<td>0.43</td>
</tr>
<tr>
<td>$C_3$</td>
<td>1.09</td>
<td>$C_{29}$</td>
<td>0.35</td>
</tr>
<tr>
<td>$C_4$</td>
<td>4.55</td>
<td>$C_{30}$</td>
<td>0.29</td>
</tr>
<tr>
<td>$C_5$</td>
<td>7.13</td>
<td>$C_{31}$</td>
<td>0.28</td>
</tr>
<tr>
<td>$C_6$</td>
<td>9.56</td>
<td>$C_{32}$</td>
<td>0.27</td>
</tr>
<tr>
<td>$C_7$</td>
<td>11.73</td>
<td>$C_{33}$</td>
<td>0.17</td>
</tr>
<tr>
<td>$C_8$</td>
<td>16.14</td>
<td>$C_{34}$</td>
<td>0.17</td>
</tr>
<tr>
<td>$C_9$</td>
<td>5.46</td>
<td>$C_{35}$</td>
<td>0.19</td>
</tr>
<tr>
<td>$C_{10}$</td>
<td>6.07</td>
<td>$C_{36}$</td>
<td>0.13</td>
</tr>
<tr>
<td>$C_{11}$</td>
<td>4.82</td>
<td>$C_{37}$</td>
<td>0.12</td>
</tr>
<tr>
<td>$C_{12}$</td>
<td>4.16</td>
<td>$C_{38}$</td>
<td>0.12</td>
</tr>
<tr>
<td>$C_{13}$</td>
<td>3.67</td>
<td>$C_{39}$</td>
<td>0.11</td>
</tr>
<tr>
<td>$C_{14}$</td>
<td>2.93</td>
<td>$C_{40}$</td>
<td>0.11</td>
</tr>
<tr>
<td>$C_{15}$</td>
<td>2.83</td>
<td>$C_{41}$</td>
<td>0.10</td>
</tr>
<tr>
<td>$C_{16}$</td>
<td>2.19</td>
<td>$C_{42}$</td>
<td>0.06</td>
</tr>
<tr>
<td>$C_{17}$</td>
<td>1.93</td>
<td>$C_{43}$</td>
<td>0.06</td>
</tr>
<tr>
<td>$C_{18}$</td>
<td>1.78</td>
<td>$C_{44}$</td>
<td>0.06</td>
</tr>
<tr>
<td>$C_{19}$</td>
<td>1.42</td>
<td>$C_{45}$</td>
<td>0.06</td>
</tr>
<tr>
<td>$C_{20}$</td>
<td>1.21</td>
<td>$C_{46}$</td>
<td>0.04</td>
</tr>
<tr>
<td>$C_{21}$</td>
<td>1.26</td>
<td>$C_{47}$</td>
<td>0.04</td>
</tr>
<tr>
<td>$C_{22}$</td>
<td>0.71</td>
<td>$C_{48}$</td>
<td>0.04</td>
</tr>
<tr>
<td>$C_{23}$</td>
<td>0.85</td>
<td>$C_{49}$</td>
<td>0.03</td>
</tr>
<tr>
<td>$C_{24}$</td>
<td>0.70</td>
<td>$C_{50}$</td>
<td>0.03</td>
</tr>
<tr>
<td>$C_{25}$</td>
<td>0.64</td>
<td>$C_{51^+}$</td>
<td>0.42</td>
</tr>
<tr>
<td>$C_{26}$</td>
<td>0.55</td>
<td>Total</td>
<td>100.00</td>
</tr>
</tbody>
</table>
Viewfield oil \( (C_{31+} = 2.61 \text{mol} \%) \) and \( \text{MW}_{\text{oil}} = 162.0 \text{ g/mol} \)

**Figure 3.2** Compositional analysis result of the Viewfield light crude oil.
Table 3.3  Physical and Chemical Properties of the Cleaned Reservoir Brine Sample from the Viewfield Region (Well No.: 16-17-9-8W2) at $P = 1$ atm (The properties and ionic concentrations were measured by Saskatchewan Research Council).

<table>
<thead>
<tr>
<th>Property</th>
<th>15</th>
<th>20</th>
<th>40</th>
</tr>
</thead>
<tbody>
<tr>
<td>Temperature ($^\circ$C)</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Density (g/cm$^3$)</td>
<td>1.107</td>
<td>1.102</td>
<td>1.091</td>
</tr>
<tr>
<td>Viscosity (cP)</td>
<td>1.49</td>
<td>1.33</td>
<td>0.89</td>
</tr>
<tr>
<td>pH @ 20 $^\circ$C</td>
<td></td>
<td></td>
<td>6.82</td>
</tr>
<tr>
<td>Specific conductivity @ 25 $^\circ$C (μS/cm)</td>
<td>160,000</td>
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<tr>
<td>Refractive index @ 20 $^\circ$C</td>
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<td></td>
<td>1.3566</td>
</tr>
<tr>
<td>Chloride (mg/L)</td>
<td></td>
<td>81,500</td>
<td></td>
</tr>
<tr>
<td>Sulphate (mg/L)</td>
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</tr>
<tr>
<td>Potassium (mg/L)</td>
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</tr>
<tr>
<td>Sodium (mg/L)</td>
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<td>55,300</td>
<td></td>
</tr>
<tr>
<td>Calcium (mg/L)</td>
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</tr>
<tr>
<td>Magnesium (mg/L)</td>
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</tr>
<tr>
<td>Iron (mg/L)</td>
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<td>21</td>
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</tr>
<tr>
<td>Manganese (mg/L)</td>
<td></td>
<td>0.69</td>
<td></td>
</tr>
<tr>
<td>Barium (mg/L)</td>
<td></td>
<td>0.15</td>
<td></td>
</tr>
<tr>
<td>Total dissolved solids @ 110 $^\circ$C (mg/L)</td>
<td>149,800</td>
<td></td>
<td></td>
</tr>
<tr>
<td>@ 180 $^\circ$C (mg/L)</td>
<td></td>
<td>148,600</td>
<td></td>
</tr>
</tbody>
</table>
3.2 PVT Tests

In the literature, it can be found that there are large variations in properties of Bakken light crude oil. More specifically, oil gravities were 39 to 44 °API, bubble-point pressures changed from 2,450 to 2,900 Psia, solution GORs ranged from 750 to 1,050 SCF/STB, and oil viscosities varied from 0.27 to 0.40 cP [Breit et al., 1992].

In this study, a mercury-free DBR PVT system (PVT-0150-100-200-316-155, DBR, Canada) was used to measure the PVT data of the Bakken light crude oil–CO₂ systems with six different CO₂ concentrations at \( T_{res} = 56.0 \, ^\circ C \). A schematic diagram of the DBR PVT system is shown in Figure 3.3. The key component of this system was a visual PVT cell, where fluid samples were encapsulated inside a glass tube. The maximum sample volume of this glass tube was 130 cm³. The maximum operating pressure and temperature of the PVT system were equal to 68 MPa and 200 °C. Inside the glass tube, a movable piston was used to separate the test fluids from the surrounding hydraulic oil. The test pressure of the PVT cell was changed by using an automatic positive-displacement pump (PMP-1-10-MB-316-M4-C0, DBR, Canada) to move the piston upward or downward. A magnetic stirrer was used to mix the test fluids inside the glass tube. A video-based digital cathetometer with a resolution of 0.0025 cm was used to accurately measure the sample heights or volumes inside the PVT cell. The test temperature was maintained by using a microprocessor-based temperature controller within the accuracy of 0.1 °C. The PVT cell and two respective sample cylinders filled with the Bakken light crude oil and pure CO₂ were kept inside the PVT system.
Figure 3.3  Schematic diagram of the DBR PVT system.
3.2.1 Saturation pressure measurements

Prior to each PVT test, the PVT cell and the fluids handling system were thoroughly cleaned with kerosene and methanol, flushed with air for several times, and finally vacuumed to remove any traces of the cleaning agents. The test temperature of the airbath was first set at $T_{\text{lab}} = 22.0 \, ^\circ\text{C}$ 12 h before each PVT test so that the fluid sample cylinders and the PVT cell would reach the pre-specified reservoir temperature at a later time. To measure the saturation pressure ($P_{\text{sat}}$) of CO$_2$-saturated Bakken light crude oil, first, the PVT cell was filled with CO$_2$ in a gaseous phase at an initial pressure below its vapour pressure at the laboratory temperature. The mass of CO$_2$ was determined by multiplying its predicted density from the P–R EOS modeling at the test pressure and temperature and measured volume read from the cathetometer. Second, the Bakken light crude oil was injected into the PVT cell. The volume of the injected Bakken light crude oil was read from the syringe pump. Third, the test temperature of the PVT cell was gradually increased to and maintained at $T_{\text{res}} = 56.0 \, ^\circ\text{C}$ by using an airbath for 24 h. At the same time, the magnetic stirrer was turned on to mix the Bakken light crude oil and CO$_2$. During the light crude oil injection process, the pressure inside the PVT cell was kept at a constant value to protect the glass tube inside the PVT cell. Fourth, the Bakken light crude oil–CO$_2$ system was compressed into one phase by injecting the hydraulic oil at an injection rate of 2 cm$^3$/h and slowly moving the piston downward. Finally, the continuous depressurization method with a constant withdrawal rate of 3 cm$^3$/h was used by slowly moving the piston upward to determine the saturation pressure of the Bakken light crude oil–CO$_2$ mixture at $T_{\text{res}} = 56.0 \, ^\circ\text{C}$.
After each PVT test was completed, the curve of the Bakken light crude oil–CO₂ mixture pressure \((P_{\text{cell}})\) in the PVT cell versus the specific volume \((v_{\text{mix}})\) was plotted. The sudden change point of the slope of \(P_{\text{cell}}\) versus \(v_{\text{mix}}\) curve was defined to be the saturation point, at which there was only one phase inside the PVT cell and CO₂ was completely dissolved into the Bakken light crude oil. Here, \(v_{\text{mix}}\) denotes the mass-based specific volume of the Bakken light crude oil–CO₂ system at a given \(P_{\text{cell}}\) and \(T_{\text{res}}\):

\[
v_{\text{mix}}(P_{\text{cell}}, T_{\text{res}}) = \frac{V_{\text{mix}}(P_{\text{cell}}, T_{\text{res}})}{m_{\text{mix}}},
\]

where, \(V_{\text{mix}}\) and \(m_{\text{mix}}\) (i.e., \(m_{\text{oil}} + m_{\text{CO₂}}\)) represent the measured total volume and mass of the Bakken light crude oil–CO₂ mixture. The pressure at the saturation point was called the saturation pressure \((P_{\text{sat}})\) of CO₂-saturated Bakken light crude oil.

### 3.2.2 Oil-swelling factor measurements

The oil SF of the Bakken light crude oil is defined as the ratio of the mixture volume at the saturation state to the volume of the crude oil at the atmospheric pressure and reservoir temperature:

\[
SF(P_{\text{sat}}, T_{\text{res}}) = \frac{V_{\text{mix}}(P_{\text{sat}}, T_{\text{res}})}{V_{\text{oil}}(1 \text{ atm}, T_{\text{res}})},
\]

where, \(V_{\text{mix}}\) is the measured volume of CO₂-saturated Bakken light crude oil at the saturation state and \(V_{\text{oil}}\) is the measured volume of the Bakken dead light crude oil at the atmospheric pressure and reservoir temperature of \(T_{\text{res}} = 56.0 \degree C\).

### 3.2.3 Oil density measurements

Accordingly, the density of CO₂-saturated Bakken light crude oil was defined as:
\[ \rho_{\text{mix}} (P_{\text{sat}}, T_{\text{res}}) = \frac{m_{\text{mix}} (P_{\text{sat}}, T_{\text{res}})}{V_{\text{mix}} (P_{\text{sat}}, T_{\text{res}})}, \] (3.3)

where, \( m_{\text{mix}} \) (i.e., \( m_{\text{oil}} + m_{\text{CO}_2} \)) represents the total mass of injected oil and \( \text{CO}_2 \). \( V_{\text{mix}} \) is the measured total volume of \( \text{CO}_2 \)-saturated Bakken light crude oil at the saturation state.

### 3.2.4 \( \text{CO}_2 \) solubility measurements

A flashing method was used to measure the \( \text{CO}_2 \) solubility in the Bakken light crude oil. A schematic diagram of the experimental setup used in the flashing method is also shown in Figure 3.3. First, a programmable syringe pump was used to apply a high pressure at the outlet of a back-pressure regulator (BPR) (BPR-50, Temco, USA) until its outlet pressure was above the saturation pressure. The positive-displacement pump was used to displace the \( \text{CO}_2 \)-saturated Bakken light crude oil through the BPR. A quick separation of the Bakken light crude oil–gas mixture occurred after the \( \text{CO}_2 \)-saturated Bakken light crude oil passed through the BPR. The separated crude oil was collected inside a graduated glass tube, where its volume was recorded. The flashed gas was collected in an air bubbler, where its volume was measured. The \( \text{CO}_2 \) solubility in the Bakken light crude oil at the saturation state was measured by using the above-mentioned flashing method:

\[ \chi_{\text{CO}_2} (P_{\text{sat}}, T_{\text{res}}) = \frac{V_{\text{CO}_2} (P_{\text{sc}}, T_{\text{lab}})}{V_{\text{oil}} (P_{\text{sc}}, T_{\text{lab}})}, \] (3.4)

where \( \chi_{\text{CO}_2} \) is the \( \text{CO}_2 \) solubility in the Bakken light crude oil at the saturation state, \( V_{\text{CO}_2} \) and \( V_{\text{oil}} \) are the volumes of \( \text{CO}_2 \) and dead Bakken light crude oil flashed from the \( \text{CO}_2 \)-saturated Bakken light crude oil at \( P_{\text{sc}} = 1 \) atm and \( T_{\text{lab}} = 22.0 \) °C.
3.3 Viscosity Measurements

To measure the viscosity of CO₂-saturated Bakken light crude oil at its saturation state, a capillary viscometer was constructed and connected to the PVT cell inside the airbath. Its schematic diagram is shown in Figure 3.4. A 35-foot long stainless steel tubing (SS-T1-S-020-20, Swagelok, Canada) was coiled onto two specially designed cylinders. The outer diameter (OD) of the capillary tubing was 1/16 inch and its wall thickness was 0.02 inch. The total interior void volume of the capillary tubing was calculated to be 2.737 cm³. This long and small capillary tubing was chosen to ensure that a pressure drop along it was large enough to accurately measure the low viscosity of CO₂-saturated Bakken light crude oil by using the Poiseuille equation. A programmable syringe pump (100DX, ISCO Inc., USA) was used to apply a high pressure at the outlet of a BPR until its outlet pressure was about 0.5 MPa above the saturation pressure ($P_{sat}$) to ensure that each CO₂-saturated Bakken light crude oil remained as one liquid phase inside the capillary tubing during the viscosity measurement. An automatic positive-displacement pump was used to inject the CO₂-saturated Bakken light crude oil through the capillary viscometer. The injection rate was controlled by using the automatic positive-displacement pump and three different constant volume flow rates ($q_{max} = 0.1, 0.2, \text{ and } 0.3 \text{ cm}^3/\text{min}$) were used to inject the mixture. When the CO₂-saturated Bakken light crude oil passed through the capillary tubing, the pressures at its two ends were measured and recorded by using a digital differential pressure indicator (PM, Heise, USA) at a preset time interval of 15 s.
Figure 3.4  Schematic diagram of the capillary viscometer.
Prior to CO₂-saturated Bakken light crude oil viscosity measurements, a distilled water with $\mu_w = 0.497$ cP at $T_{\text{res}} = 56.0$ °C was used as a standard viscosity liquid and injected through the capillary tubing at different constant volume flow rates ($q_w = 0.5$–15.0 cm³/min) to calibrate the capillary viscometer. The distilled water was chosen as the standard viscosity liquid because its viscosity is close to the low viscosity of CO₂-saturated Bakken light crude oil under the actual reservoir conditions. Then the Poiseuille equation was applied to determine the CO₂-saturated Bakken light crude oil viscosity:

$$
\mu_{\text{mix}}(P_{\text{sat}}, T_{\text{res}}) = \frac{\pi (r_{\text{eff}})^4 \Delta P}{8 q_{\text{mix}} L},
$$

(3.5)

where, $\mu_{\text{mix}}$ is the viscosity of CO₂-saturated Bakken light crude oil at the saturation state; $\Delta P$ and $q_{\text{mix}}$ are the measured pressure drop and preset constant volume flow rate; $r_{\text{eff}}$ and $L$ are the “effective radius” and the length of the capillary tubing. Three assumptions of the equation are that the fluid is Newtonian; the fluid flow is laminar and steady through circular tube, which is sufficiently long.

### 3.4 IFT Measurements

Figure 3.5 shows a schematic diagram of the experimental setup used for measuring the equilibrium IFT between the Bakken light crude oil and CO₂ by applying the axisymmetric drop shape analysis (ADSA) technique for the pendant drop case [Cheng et al., 1990]. The major component of this experimental setup was a see-through windowed high-pressure IFT cell (IFT-10, Temco, USA). A stainless steel syringe needle was installed at the top of the IFT cell and used to form a pendant oil drop.
Figure 3.5  Schematic diagram of the experimental setup used for measuring the equilibrium interfacial tension (IFT) between the Bakken light crude oil and CO$_2$ by applying the axisymmetric drop shape analysis (ADSA) technique for the pendant oil drop case.
The Bakken light crude oil was introduced from a transfer cylinder (500-10-P-316-2, DBR, Canada) to the syringe needle by using the programmable syringe pump. A light source and a glass diffuser were used to provide uniform illumination for the pendant oil drop. A microscope camera (KPM1U, Hitachi, Japan) was used to capture the sequential digital images of the dynamic pendant oil drops inside the IFT cell at different times. The high-pressure IFT cell was positioned horizontally between the light source and the microscope camera. The entire ADSA system and the high-pressure IFT cell were placed on a vibration-free table (RS4000, Newport, USA). The digital images of the dynamic pendant light crude oil at different times were acquired in tagged image file format (TIFF) by using the digital frame grabber (Ultra II, Coreco Imaging, Canada) and stored in a desktop computer.

The high-pressure IFT cell was first filled with CO₂ at a pre-specified pressure and a constant temperature. After the pressure and temperature inside the IFT cell reached their stable values, the Bakken light crude oil was introduced from the sample cylinder to the IFT cell to form a pendant oil drop at the tip of the syringe needle. Once a well-shaped pendant oil drop was formed and surrounded by CO₂, the sequential digital images of the dynamic pendant oil drop at different times were acquired and stored automatically in the computer. Then the ADSA program for the pendant drop case was executed to determine the dynamic IFT between the dynamic pendant oil drop and CO₂ phase at any time. The IFT measurement was repeated for at least three different pendant oil drops to ensure a satisfactory repeatability of ± 0.05 mJ/m² at each pre-specified pressure and constant temperature. In this study, the Bakken light crude oil–CO₂ dynamic and equilibrium IFTs were measured at a constant reservoir temperature.
of $T_{\text{res}} = 56.0^\circ \text{C}$ and eight different equilibrium pressures in the range of $P_{\text{eq}} = 1.6–5.6$ MPa. Then the VIT technique was applied to determine the MMP of the Bakken light crude oil–CO$_2$ system from the measured equilibrium IFT versus equilibrium pressure data.

### 3.5 Coreflood Tests

A schematic diagram of the high-pressure coreflood apparatus used in CO$_2$ coreflood tests is shown in Figure 3.6. Prior to each test, the sandstone reservoir core plugs were cleaned by using a Dean–Stark extractor (09-556D, Fisher Scientific, Canada) for 4–7 days. An automatic displacement pump (PMP-1000-1-10-MB, DBR, Canada) was used to displace the Bakken light crude oil, synthetic brine or CO$_2$ through the composite reservoir core plugs inside a coreholder (DCH-1.0, Temco, USA). The tap water was pumped by using a syringe pump to apply the so-called overburden pressure, which was always kept 3.0–5.0 MPa higher than the inlet pressure (i.e., the injection pressure) of the coreholder. The composite reservoir core plugs used in the CO$_2$ coreflood tests were 4–6 inches long and 1 inch in diameter. Four high-pressure cylinders (500-10-P-316-2, DBR, Canada) were used to store and deliver the Bakken light crude oil, synthetic brine, CO$_2$, and tap water, respectively. These four transfer cylinders and the high-pressure coreholder were placed inside an air bath. A thermocouple heating gun (HG 1100, Thankita, USA) and a temperature controller (Standard-89000-00, Cole–Parmer, Canada) were used to heat the air bath and keep it at the constant reservoir temperature of $T_{\text{res}} = 56.0^\circ \text{C}$. A BPR was used to maintain the outlet pressure (i.e., the production pressure). During the synthetic brine, original Bakken light crude oil, and CO$_2$ injection processes, the differential pressures between
Figure 3.6  Schematic diagram of the high-pressure CO$_2$ coreflood apparatus.
the inlet and outlet of the coreholder were measured, monitored, and recorded by using the digital differential pressure indicator. The instantaneous gas production rate and cumulative gas production from the outlet of the coreholder were measured every second by using a gas flow meter for CO₂ (XFM, Aalborg, USA). Then an average gas production rate was determined in every five minutes. The produced oil and water were separated by using a centrifuge. A digital video camera was used to record the respective cumulative volumes of the produced oil and water in the entire CO₂ coreflood test.

The general procedure for preparing each CO₂ coreflood test is briefly described as follows. Two sandstone reservoir core plugs were placed in series inside the Dean–Stark extractor and cleaned with toluene, methanol, and chloroform in sequence to remove hydrocarbons, salts, and clays, respectively. After the two sandstone reservoir core plugs were cleaned and dried, they were assembled in series in the horizontal coreholder and vacuumed for 24 h. Then the synthetic brine was injected to measure the porosity of the composite reservoir core plugs. Afterwards, the synthetic brine was injected at different volume flow rates \( q_{\text{brine}} = 0.01–0.05 \text{ cm}^3/\text{min} \) to measure the absolute permeability of the composite reservoir core plugs. As will be given in the next chapter, the measured porosity was in the range of \( \phi = 10.73–17.20\% \) and the measured absolute permeability was in the range of \( k = 0.016–0.132 \text{ mD} \), both of which show that the Bakken reservoir core plugs are extremely tight. Next, the Bakken light crude oil was injected at \( q_{\text{oil}} = 0.025 \text{ cm}^3/\text{min} \) through the synthetic brine-saturated composite reservoir core plugs until no more brine was produced so that the connate water saturation was achieved. The initial oil saturation process was purposely conducted at \( T_{\text{lab}} = 22.0 \text{ °C} \) in order to obtain
a high initial oil saturation close to the actual high oil saturation in a tight oil formation. As will be given in the next chapter, the initial oil saturation was in the range of $S_{oi} = 44.8–54.5\%$ and the connate water saturation was found to be $S_{wc} = 45.5–55.2\%$. After the initial oil saturation and the connate water saturation were reached, the heating gun and the temperature controller were used to increase the temperature inside the airbath to $T_{res} = 56.0 \, ^\circ\text{C}$ and maintain this temperature for at least two days. Finally, a total of 3.0–5.0 PV of the Bakken light crude oil was further injected to pressurize the composite reservoir core plugs to the production pressure of 10.0 MPa prior to each coreflood test. It is worthwhile to mention that the composite reservoir core plugs were pressurized by gradually increasing the operating pressure of the BPR to $P_{prod} = 10.0$ MPa at a rate of $\Delta P = 7 \, \text{kPa/min}$ for about 24 h.

In the waterflooding test (Test #1), after the composite reservoir core plugs were pressurized to $P_{prod} = 10.0 \, \text{MPa}$, the synthetic brine was injected at a constant volume flow rate of $q_{\text{brine}} = 0.025 \, \text{cm}^3/\text{min}$ to recover the light crude oil from the composite reservoir core plugs at $T_{res} = 56.0 \, ^\circ\text{C}$. The brine injection was terminated after 2.0 PV of the synthetic brine was injected and no more oil was produced.

In the continuous miscible CO$_2$ secondary flooding test (Test #2), the supercritical CO$_2$ was injected at a constant volume flow rate of $q_{\text{CO}_2} = 0.025 \, \text{cm}^3/\text{min}$, $P_{prod} = 10.0 \, \text{MPa}$, and $T_{res} = 56.0 \, ^\circ\text{C}$. The production pressure was chosen to be the MMP to ensure that the injected CO$_2$ could become miscible with the Bakken light crude oil through the so-called dynamic MCM process. The CO$_2$ injection was terminated after 2.0 PV of CO$_2$ was injected and no more oil was produced in this test. It is worthwhile to point out that no water was produced in any continuous miscible CO$_2$ secondary flooding test.
In the miscible CO2-WAG injection (Tests #3–7) and CO2-GAW injection (Tests #8 and #9), the synthetic brine and supercritical CO2 were injected into the composite reservoir core plugs alternately at the same volume flow rate of $q_{\text{brine}} = q_{\text{CO}_2} = 0.025$ cm$^3$/min, $P_{\text{prod}} = 10.0$ MPa, and $T_{\text{res}} = 56.0$ °C with different WAG slug sizes (Tests #3–5), different WAG slug ratios (Tests #4, #6, and #7), and different fluid injection sequences (Tests #4, #5, #8, and #9). More specifically, the WAG slug sizes of Tests #3–5 were equal to 0.500, 0.250, and 0.125 PV, respectively. The WAG slug ratios of Tests #4, #6, and #7 were equal to 1:1, 2:1, and 1:2, respectively. Tests #4 and #5 were two CO2-WAG injection tests, whereas Tests #8 and #9 were two CO2-GAW injection tests. The original light crude oil was displaced by the injected brine/CO2 or CO2/brine alternately in each CO2-WAG or GAW injection test, which was continued until no more oil was produced. At the end of each test, 1.0 PV of the synthetic brine was further injected to apply the so-called extended waterflooding (EWF). However, only small amounts of the remaining light crude oil were recovered in the EWF processes of Tests #5, #8, and #9.

Tests #10 and #11 were conducted to study the CO2-soaking effect on miscible CO2 secondary flooding in a fractured tight formation. The Bakken tight core plugs were fractured by using the Brazilian method to model the hydraulically fractured Bakken formation. In the Brazilian test, a cylindrical Bakken rock sample was compressed along two diametrically opposed generators. The loading pressure was applied gradually on the Bakken rock sample until it was fractured or split. The detailed fracturing procedure was provided by Dr. Christopher Hawkes from University of Saskatchewan. It was described below. To develop a single fracture along the core sample, a shallow groove
was cut along the core axis by using a circular rock saw with a 2.3 mm diamond blade. The core sample with the shallow groove was placed on the bottom loading platen of a Caver Laboratory Press (MINI–C, FRED S. CARVER Inc., USA) (Figure 3.7). The core sample was oriented and adjusted to make sure that the shallow groove was on the top. Then a 4-mm diameter stainless steel rod was placed in the groove. As such, the top loading platen’s load was localized within the groove. The load was applied by manually operating the bottom loading platen. A clear crack sound could be heard once the core sample was fractured. The loading was stopped immediately. In the test, the core samples were generally fractured or cracked when the applied load was approximately two tonnes.

In CO₂ secondary flooding test without CO₂ soaking period (Test #10), a total of 2.0 PV of CO₂ was injected continuously. In CO₂ secondary flooding with CO₂ soaking period (Test #11), the first PV of CO₂ was injected continuously. Then the fractured reservoir core plugs together with the residual light crude oil were soaked with the injected CO₂ for 24 h. It should be noted that there was no initial water saturation process before the coreflood test due to the existing fractures inside the core plug. The dry core plugs were used to do the coreflood test in the fractured tight formation.

The last two tests (Tests #12 and #13) were carried out and compared to study the fracture effect on these two CO₂-WAG injection processes and their oil RFs. In Test #12, four WAG cycles were injected into the tight core plugs with the WAG slug size of 0.250 PV and the WAG slug ratio of 1:1, which were followed by 1.0 PV EWF. In Test #13, two WAG cycles were injected into the fractured core plugs with the WAG slug size of 0.500 PV and the WAG slug ratio of 1:2, which were followed by 1.0 PV EWF.
Figure 3.7  Carver apparatus used for fracturing or splitting the tight core samples.
CHAPTER 4 RESULTS AND DISCUSSION

4.1 Reservoir Fluids Characterization

4.1.1 $P_{\text{sat}}$, oil SF, oil density, and CO₂ solubility

Saturation pressures ($P_{\text{sat}}$), oil SFs, oil densities, and CO₂ solubilities for six Bakken light crude oil–CO₂ mixtures were measured at $T_{\text{res}} = 56.0$ °C. The CO₂ concentrations in these mixtures ranged from 18.64 to 70.11 mol.%. The PVT results are summarized in Table 4.1.

In this study, the saturation pressure of each Bakken light crude oil–CO₂ system is determined from a sudden turning point of the slope of its $P_{\text{cell}}$ versus $v_{\text{mix}}$ curve, which is plotted in Figure 4.1. It is found from this figure that the measured cell pressure is reduced linearly with the mass-based specific volume in two distinct ranges: Range I and Range II. In Range I, $P_{\text{cell}}$ decreases drastically with a small increase of $v_{\text{mix}}$. This is because the Bakken light crude oil–CO₂ mixture is in a liquid phase at $P_{\text{cell}} \geq P_{\text{sat}}$, which is almost incompressible. In Range II, however, $P_{\text{cell}}$ decreases marginally with a substantial increase of $v_{\text{mix}}$. A large amount of dissolved CO₂ is released from the Bakken light crude oil–CO₂ mixture, which becomes highly compressible or expandable especially when $P_{\text{cell}}$ is slightly lower than $P_{\text{sat}}$.

A linear equation is obtained by applying the linear regression of the measured $P_{\text{cell}}$–$v_{\text{mix}}$ data points in each range. On the basis of the measured data points in Figure 4.1 for each Bakken light crude oil–CO₂ system at $T_{\text{res}} = 56.0$ °C, the cell pressure $P_{\text{cell}}$ (MPa) is correlated to the mass-based specific volume $v_{\text{mix}}$ (cm$^3$/g) by applying the linear regression:
Table 4.1  Measured Saturation Pressures ($P_{\text{sat}}$), Oil-Swelling Factors (SFs), Oil Densities ($\rho_{\text{mix}}$), CO$_2$ Solubilities ($\chi_{\text{CO}_2}$), and Viscosities ($\mu_{\text{mix}}$) of Six Bakken Light Crude Oil–CO$_2$ Systems with Six Different CO$_2$ Concentrations as well as the Density and Viscosity of the Dead Bakken Light Crude Oil at $T_{\text{res}} = 56.0$ °C.

<table>
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<th>Test no.</th>
<th>light oil–CO$_2$ system</th>
<th>$P_{\text{sat}}$ (MPa)</th>
<th>SF</th>
<th>$\rho_{\text{mix}}$ (g/cm$^3$)</th>
<th>$\chi_{\text{CO}_2}$ (cm$^3$/cm$^3$)</th>
<th>$\mu_{\text{mix}}$ (cP)</th>
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<td>6.29</td>
<td>1.26</td>
<td>0.811</td>
<td>148.2</td>
</tr>
<tr>
<td>6</td>
<td>40.01</td>
<td>59.99</td>
<td>8.01</td>
<td>1.41</td>
<td>0.803</td>
<td>190.0</td>
</tr>
<tr>
<td>7</td>
<td>29.89</td>
<td>70.11</td>
<td>9.29</td>
<td>1.62</td>
<td>0.807</td>
<td>313.6</td>
</tr>
</tbody>
</table>
Figure 4.1  $P_{\text{cell}}$–$v_{\text{mix}}$ diagrams of six Bakken light crude oil–CO$_2$ systems with six different CO$_2$ concentrations at $T_{\text{res}} = 56.0$ °C.
(1) 81.36 mol.% Bakken light crude oil + 18.64 mol.% CO\textsubscript{2}:

\[
\text{Range I: } P_{\text{cell}} = 333.38 - 271.65 \nu_{\text{mix}} \quad (R^2 = 1.000),
\]
\[
\text{Range II: } P_{\text{cell}} = 4.19 - 1.79 \nu_{\text{mix}} \quad (R^2 = 0.983),
\]

(2) 72.52 mol.% Bakken light crude oil + 27.48 mol.% CO\textsubscript{2}:

\[
\text{Range I: } P_{\text{cell}} = 723.91 - 575.81 \nu_{\text{mix}} \quad (R^2 = 0.992),
\]
\[
\text{Range II: } P_{\text{cell}} = 8.34 - 3.77 \nu_{\text{mix}} \quad (R^2 = 0.991),
\]

(3) 60.10 mol.% Bakken light crude oil + 39.90 mol.% CO\textsubscript{2}:

\[
\text{Range I: } P_{\text{cell}} = 586.88 - 470.96 \nu_{\text{mix}} \quad (R^2 = 0.998),
\]
\[
\text{Range II: } P_{\text{cell}} = 7.91 - 2.38 \nu_{\text{mix}} \quad (R^2 = 0.999),
\]

(4) 50.11 mol.% Bakken light crude oil + 49.89 mol.% CO\textsubscript{2}:

\[
\text{Range I: } P_{\text{cell}} = 564.44 - 452.82 \nu_{\text{mix}} \quad (R^2 = 0.999),
\]
\[
\text{Range II: } P_{\text{cell}} = 9.75 - 2.81 \nu_{\text{mix}} \quad (R^2 = 0.994),
\]

(5) 40.01 mol.% Bakken light crude oil 59.99 mol.% CO\textsubscript{2}:

\[
\text{Range I: } P_{\text{cell}} = 528.29 - 417.55 \nu_{\text{mix}} \quad (R^2 = 0.984),
\]
\[
\text{Range II: } P_{\text{cell}} = 12.38 - 3.51 \nu_{\text{mix}} \quad (R^2 = 0.994),
\]

(6) 29.89 mol.% Bakken light crude oil + 70.11 mol.% CO\textsubscript{2}:

\[
\text{Range I: } P_{\text{cell}} = 339.71 - 266.67 \nu_{\text{mix}} \quad (R^2 = 0.995),
\]
\[
\text{Range II: } P_{\text{cell}} = 13.53 - 3.42 \nu_{\text{mix}} \quad (R^2 = 0.985).
\]

Then the intersection point of the two linear equations for each Bakken light crude oil–CO\textsubscript{2} system is determined to be the saturation point, whose pressure is referred to as the saturation pressure, \( P_{\text{sat}} \). The obtained saturation pressures of six Bakken light crude oil–
CO₂ systems as a function of CO₂ concentration were listed in Table 4.1 and plotted in Figure 4.2. Figure 4.2 depicts an almost linear increase in the saturation pressure of the Bakken light crude oil–CO₂ system with addition of CO₂ into the Bakken light crude oil. The $P_{\text{sat}}$ of CO₂-saturated Bakken light crude oil increases from 2.01 to 9.29 MPa as CO₂ concentration in the Bakken light crude oil–CO₂ mixture increases from 18.64 to 70.11 mol.%). In this study, the production pressure in each coreflood test was chosen to be 10.0 MPa, which was equal to the MMP between the Bakken light crude oil and CO₂. Given the above measured saturation pressures of six different Bakken light crude oil–CO₂ systems at $T_{\text{res}} = 56.0 \, ^\circ\text{C}$, the Bakken light crude oil and CO₂ phases were likely miscible and in an under-saturated liquid state during each CO₂ coreflood test.

The variation of the SF of the Bakken light crude oil–CO₂ mixture is shown to increase with CO₂ concentration, as listed in Table 4.1 and depicted in Figure 4.3. The SF of CO₂-saturated Bakken light crude oil increases substantially from 1.05 to 1.62 in the same CO₂ concentration range. This means that CO₂ can greatly swell the Bakken light crude oil once the former is dissolved into the latter. This strong oil-swelling effect has three obvious benefits to CO₂-EOR [Li and Gu, 2014b]. First, a relatively large amount of oil can be produced from the reservoir as the oil volume increases. Second, the oil-swelling effect increases the residual oil saturation and thus the oil effective/relative permeability, which results in a higher oil production rate. Third, the oil-swelling effect helps the residual oil trapped by water to swell and displace the water so that the waterblocking effect can be weakened or overcome. As such, a favourable condition can be developed to mobilize and produce the residual light crude oil trapped by water.
Figure 4.2  Saturation pressure versus CO₂ concentration data for six Bakken light crude oil–CO₂ systems at $T_{res} = 56.0 \, ^{\circ}C$. 
Figure 4.3  Measured oil-swelling factor (SF) versus CO\textsubscript{2} concentration data for six CO\textsubscript{2}-saturated Bakken light crude oils at $T_{\text{res}} = 56.0$ °C.
Figure 4.4 depicts the variation of density of CO\(_2\)-saturated Bakken light crude oil with CO\(_2\) concentration. It shows that the density increases marginally at low CO\(_2\) concentrations and does not change appreciably by dissolving more CO\(_2\) into the Bakken light crude oil. This is because the oil-swelling effect is not strong at a lower CO\(_2\) concentration but becomes stronger at a higher CO\(_2\) concentration. Thus the mass increase of the Bakken light crude oil–CO\(_2\) mixture due to CO\(_2\) dissolution is proportional to its volume increase at a high CO\(_2\) concentration so that the density of CO\(_2\)-saturated light crude oil remains almost constant.

The CO\(_2\) solubility in the Bakken light crude oil at the saturation pressure of each Bakken light crude oil–CO\(_2\) system is plotted in Figure 4.5. As shown in Figure 4.5, the measured CO\(_2\) solubility increases from 30.0 to 313.6 cm\(^3\) CO\(_2\)/cm\(^3\) oil as the saturation pressure increases from 2.01 to 9.29 MPa. This fact indicates that CO\(_2\) is highly soluble in and has strong interactions with the Bakken light crude oil. This figure also indicates that CO\(_2\) solubility in the Bakken light crude oil exceeds 313.6 cm\(^3\) CO\(_2\)/cm\(^3\) oil (or CO\(_2\) concentration of higher than 70.11 mol.\%) at the production pressure of \(P_{\text{prod}} = 10.0\) MPa, which is equal to the MMP of the Bakken light crude oil–CO\(_2\) system and will be discussed later. A large amount of CO\(_2\) can be dissolved into the Bakken light crude oil at the production pressure around the MMP and thus can substantially enhance the microscopic displacement efficiency of CO\(_2\) flooding. Moreover, a tight reservoir with the light crude oil is especially suitable for carbon dioxide storage due to a high CO\(_2\) solubility in its light crude oil at its operating conditions.
Figure 4.4  Comparison of the live oil densities of six CO$_2$-saturated Bakken light crude oils with the density of the dead Bakken light crude oil at $T_{res} = 56.0$ °C.
Figure 4.5  CO₂ solubility in CO₂-saturated Bakken light crude oil as a function of the saturation pressure at $T_{\text{res}} = 56.0$ °C.
4.1.2 Viscosity

In this study, the viscosities of six CO$_2$-saturated Bakken light crude oils at six different CO$_2$ concentrations are tabulated in Table 4.1 and plotted in Figure 4.6. The measured viscosity of each Bakken light crude oil–CO$_2$ system is reduced by dissolving CO$_2$ into the Bakken light crude oil. This figure illustrates a quick reduction in viscosity of the CO$_2$-saturated Bakken light crude oil at a lower CO$_2$ concentration, followed by a gradual reduction at a higher CO$_2$ concentration. The CO$_2$-saturated Bakken light crude oil viscosities of $\mu_{\text{mix}} = 0.83$ and $0.41$ cP at the respective CO$_2$ concentrations of 18.64 and 70.11 mol.% and $T_{\text{res}} = 56.0$ °C are equal to 56% and 28% of the dead Bakken light crude oil viscosity of $\mu_{\text{oil}} = 1.48$ cP at the same reservoir temperature. The reduced oil viscosity contributes substantially to the oil RFs of the continuous CO$_2$ flooding and the CO$_2$-WAG injection. When CO$_2$ is injected into a light oil reservoir, a large amount of it is dissolved into the light crude oil. The CO$_2$-diluted light crude oil with a much lower viscosity becomes more mobile or has a much higher mobility. During the subsequent water injection process, the mobility ratio of the displacing phase (i.e., the injected water) to the displaced phase (i.e., the CO$_2$-diluted crude oil) is considerably reduced and becomes favourable, which results in an improved volumetric sweep efficiency or secondary oil RF.
Figure 4.6  Comparison of the live oil viscosities of six CO$_2$-saturated Bakken light crude oils with the viscosity of the dead Bakken light crude oil at $T_{res} = 56.0$ °C.
4.1.3 Equilibrium IFT and the MMP

In this study, the equilibrium IFTs between the Bakken light crude oil and CO\(_2\) at different equilibrium pressures were measured by applying the ADSA technique for the pendant drop case [Cheng et al., 1990]. For the Bakken light crude oil, the measured equilibrium IFTs between the crude oil and CO\(_2\) at eight different equilibrium pressures of \(P_{\text{eq}} = 1.6\)–7.5 MPa and \(T_{\text{res}} = 56.0\) °C are shown in Figure 4.7. It is found from this figure that the measured equilibrium IFT is reduced almost linearly with the increased equilibrium pressure. As the Bakken crude oil is a light oil and has large amounts of light and intermediate hydrocarbons, the measured equilibrium IFTs are low even in a relatively low equilibrium pressure range. The initial quick light-hydrocarbons extraction by CO\(_2\) was also observed prior to the equilibrium IFT measurements at high pressures. Based on the measured data (symbols) in Figure 4.7, the equilibrium IFT \(\gamma_{\text{eq}}\) (mJ/m\(^2\)) is correlated to the equilibrium pressure \(P_{\text{eq}}\) (MPa) by applying the linear regression:

\[
\gamma_{\text{eq}} = -2.10 P_{\text{eq}} + 21.05 \quad (1.6 \text{ MPa} \leq P_{\text{eq}} \leq 7.5 \text{ MPa}, \; R^2 = 0.987). \quad (4.7)
\]

For the Bakken light crude oil–CO\(_2\) system, the linear regression equation of the measured equilibrium IFT versus equilibrium pressure data intersects with the abscissa (i.e., \(\gamma_{\text{eq}} = 0\)) at \(P_{\text{eq}} = 10.0\) MPa. Therefore, the MMP of the Bakken light crude oil–CO\(_2\) system is determined to be 10.0 MPa at \(T_{\text{res}} = 56.0\) °C by applying the VIT technique.
Figure 4.7  Measured equilibrium interfacial tensions of the Bakken light crude oil–CO₂ system at eight different equilibrium pressures and $T_{res} = 56.0 \, ^\circ C$. 

\[
\gamma_{eq} = -2.10\, P_{eq} + 21.05 \quad (1.6 \, \text{MPa} \leq P_{eq} \leq 7.5 \, \text{MPa}, R^2 = 0.987)
\]

$\text{MMP} = 10.0 \, \text{MPa}$
4.2 CO₂-WAG Injection in the Tight Bakken Formation

4.2.1 Different flooding schemes

In this work, three different flooding schemes were applied to study the effect of a different flooding process on the oil RF in the tight formation, i.e., waterflooding, continuous miscible CO₂ flooding, and miscible CO₂-WAG injection. The detailed experimental data of Test #1 (waterflooding), Test #2 (continuous miscible CO₂ flooding), and Test #3 (miscible WAG injection with the WAG slug size of 0.500 PV and the WAG slug ratio of 1:1) in the tight Bakken Formation are listed in Table 4.2.

Figure 4.8a shows the measured oil RFs of waterflooding (Test #1) and the continuous miscible CO₂ flooding (Test #2), cumulative water production (Test #1) and average gas production rate (Test #2). It is seen from this figure that water BT occurred and water production started at 0.40 PV in Test #1. The oil RF was increased quickly prior to water BT. However, only a small amount of the light crude oil (3.7%) was produced and the cumulative water production was increased quickly after water BT. This is because the water channels were formed after water BT and the subsequently injected water followed the established water channels from the inlet to the outlet. Unlike waterflooding, the continuous miscible CO₂ flooding in Test #2 had a different trend after CO₂ BT. As shown in Figure 4.8a, CO₂ BT happened at 0.26 PV when the measured average gas production rate reached the highest value and the oil RF was 35.0%. A large amount of the residual oil (28.4%) was further recovered after CO₂ BT. Accordingly, the measured average gas production rate was reduced quickly and then reached a constant value. Similar experimental trends were reported for the continuous
Table 4.2  Basic Physical Properties and Oil Recovery Factors (RFs) of Nine Coreflood Tests in the Tight Bakken Formation at the Production Pressure of $P_{\text{prod}} = 10.0$ MPa and Reservoir Temperature of $T_{\text{res}} = 56.0$ °C.

<table>
<thead>
<tr>
<th>Test No.</th>
<th>Injection</th>
<th>Slug size (PV)</th>
<th>Slug ratio (W:G)</th>
<th>$\phi$ (%)</th>
<th>$k$ (mD)</th>
<th>$S_{\text{oi}}$ (%)</th>
<th>$RF_w$ (%)</th>
<th>$RF_{\text{CO}_2}$ (%)</th>
<th>Total RF (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Water</td>
<td>--</td>
<td>--</td>
<td>15.87</td>
<td>0.016</td>
<td>49.1</td>
<td>43.2</td>
<td>--</td>
<td>43.2</td>
</tr>
<tr>
<td>2</td>
<td>CO$_2$</td>
<td>--</td>
<td>--</td>
<td>11.38</td>
<td>0.125</td>
<td>48.7</td>
<td>--</td>
<td>63.4</td>
<td>63.4</td>
</tr>
<tr>
<td>3</td>
<td>WAG</td>
<td>0.500</td>
<td>1:1</td>
<td>10.73</td>
<td>0.025</td>
<td>47.2</td>
<td>32.5</td>
<td>46.3</td>
<td>78.8</td>
</tr>
<tr>
<td>4</td>
<td>WAG</td>
<td>0.250</td>
<td>1:1</td>
<td>16.30</td>
<td>0.091</td>
<td>53.0</td>
<td>45.6</td>
<td>42.6</td>
<td>88.2</td>
</tr>
<tr>
<td>5</td>
<td>WAG</td>
<td>0.125</td>
<td>1:1</td>
<td>15.25</td>
<td>0.078</td>
<td>50.0</td>
<td>59.3</td>
<td>33.6</td>
<td>92.9</td>
</tr>
<tr>
<td>6</td>
<td>WAG</td>
<td>0.250</td>
<td>2:1</td>
<td>15.55</td>
<td>0.077</td>
<td>51.0</td>
<td>56.3</td>
<td>22.5</td>
<td>78.8</td>
</tr>
<tr>
<td>7</td>
<td>WAG</td>
<td>0.250</td>
<td>1:2</td>
<td>15.00</td>
<td>0.131</td>
<td>54.5</td>
<td>39.2</td>
<td>52.8</td>
<td>92.0</td>
</tr>
<tr>
<td>8</td>
<td>GAW</td>
<td>0.250</td>
<td>1:1</td>
<td>17.20</td>
<td>0.132</td>
<td>49.5</td>
<td>48.1</td>
<td>18.1</td>
<td>66.2</td>
</tr>
<tr>
<td>9</td>
<td>GAW</td>
<td>0.125</td>
<td>1:1</td>
<td>16.10</td>
<td>0.109</td>
<td>44.8</td>
<td>43.6</td>
<td>31.4</td>
<td>75.0</td>
</tr>
</tbody>
</table>

Notes:

- **Slug size**: PVs of the first fluid (brine or CO$_2$) to be injected in each WAG or GAW cycle
- **Slug ratio**: ratio of the slug size (PV) of the first fluid to that of the second fluid to be injected in each WAG or GAW cycle (i.e., W:G for CO$_2$-WAG injection and G:W for CO$_2$-GAW injection)
- **$\phi$**: porosity of the composite reservoir core plugs
- **$k$**: absolute permeability of the composite reservoir core plugs
- **$S_{\text{oi}}$**: initial oil saturation
- **$RF_w$**: oil RF of waterflooding, including the extended waterflooding (EWF)
- **$RF_{\text{CO}_2}$**: oil RF of CO$_2$ flooding
- **Total RF**: total oil RF of waterflooding and CO$_2$ flooding
Figure 4.8a Measured oil RFs of waterflooding (Test #1) and continuous miscible CO₂ flooding (Test #2), cumulative water production ($Q_w$) of waterflooding (Test #1) and average gas production rate ($q_g$) of the continuous miscible CO₂ flooding (Test #2).
CO₂ flooding under the immiscible, near-miscible, and miscible conditions [Cao and Gu, 2013b].

The measured oil RF, cumulative water production, and average gas production rate of the miscible CO₂-WAG injection (Test #3) are plotted in Figure 4.8b. In this test, a total of three WAG cycles were conducted with the WAG slug size of 0.500 PV and the WAG slug ratio of 1:1, which was followed by the EWF of 1.0 PV. It can be seen from Figure 4.8b that there was still a large amount of light crude oil (37.6%) to be recovered after water BT at 0.38 PV in the first cycle of the miscible CO₂-WAG injection. In addition, 13.2% of the residual light crude oil was produced in the second WAG cycle but no more oil was produced in the third WAG cycle and the EWF. The cumulative water production was increased slowly in the first two WAG cycles and quickly in the third WAG cycle and in the EWF. This is because no more oil was produced after the first two WAG cycles. It is seen from this figure that CO₂ BT occurred at 0.45 PV in the first WAG cycle, which was substantially delayed in comparison with 0.26 PV in the continuous miscible CO₂ flooding. The previously injected water helped to considerably postpone the CO₂ BT. This was attributed to a much smaller mobility contrast between the injected reservoir brine and the subsequently injected CO₂ in CO₂-WAG injection than that between the residual light crude oil and the injected CO₂ in the continuous CO₂ secondary flooding. Also CO₂ BTs were delayed in the second and third WAG cycles.

The measured oil RFs of three different flooding schemes are plotted and compared in Figure 4.8c. This figure depicts that three flooding schemes had high oil production rates at the beginning. The oil RF of the waterflooding achieved its highest value of 43.2% at 0.6 PV, while the oil RFs of the other two tests were still increased until much
Figure 4.8b  Measured oil RF, cumulative water production ($Q_w$), and average gas production rate ($q_g$) of the miscible CO$_2$-WAG injection (Test #3) with the WAG slug size of 0.500 PV and the WAG slug ratio of 1:1.
**Figure 4.8c** Comparison of the measured oil RFs of the miscible CO$_2$-WAG injection (Test #3), the continuous miscible CO$_2$ flooding (Test #2), and waterflooding (Test #1).
higher values were reached. The final oil RF of the miscible CO$_2$-WAG injection was the highest (78.8% in Test #3) at a total of 2.5 PV of injected brine and 1.5 PV of injected CO$_2$, which was followed by the continuous miscible CO$_2$ flooding (63.4% in Test #2) and waterflooding (43.2% in Test #1) at a total of 2.0 PV of injected CO$_2$ and brine, respectively. Waterflooding is a commonly used secondary oil recovery method but its microscopic displacement efficiency is rather low. In the continuous CO$_2$ secondary flooding, both viscous fingering due to an unfavourable mobility ratio of the injected CO$_2$ to the residual crude oil and gravity overriding due to a relatively low density of CO$_2$ (e.g., $\rho_{CO_2} = 0.318$ g/cm$^3$ at $P_{res} = 10.0$ MPa and $T_{res} = 56.0$ °C) lead to a low volumetric sweep efficiency. In the miscible CO$_2$-WAG injection, water injection is used to control the mobility of CO$_2$ and stabilize its displacement front, which results in a high volumetric sweep efficiency. At the same time, the microscopic displacement efficiency of the residual oil by the injected CO$_2$ under the miscible condition is far higher than that by the injected water. This is why miscible CO$_2$-WAG injection has less residual oil trapped in the tight reservoir and enhances the hydrocarbon recovery, in comparison with water or CO$_2$ flooding alone.

### 4.2.2 WAG slug size

In this study, three miscible CO$_2$-WAG injection tests were carried out to investigate the effect of a different WAG slug size on the oil RF. These three tests were performed with different WAG slug sizes but at the same WAG slug ratio of 1:1. The WAG slug size represents the volume of the first fluid (i.e., water for CO$_2$-WAG injection) to be
injected in each cycle at the actual reservoir conditions and is expressed as a fraction of PV. Tests #3–5 had the WAG slug sizes of 0.500, 0.250, and 0.125 PV, respectively.

The measured oil RF as a function of the total injected PV of brine and CO₂ in each of the three miscible CO₂-WAG injection tests is plotted in Figure 4.9. The oil RFs and oil production rates (i.e., the slopes of the oil RF versus PV curves) of these three tests were similar before 0.30 PV. From 0.30 to 0.50 PV, the oil RF of Test #3 did not increase at all, while the oil RFs of the other two tests were increased continuously. This is because Test #3 had the largest WAG slug size of 0.500 PV and its water BT occurred at 0.30 PV. Almost no oil was produced in the remaining water injection period after water BT. However, a large amount of the residual oil was produced in the subsequent CO₂ injection process in Test #4 or #5. This fact indicates that there is still a great potential for CO₂-EOR process after waterflooding to recover the residual oil in the tight light oil reservoir.

Figure 4.9 also shows that Test #5 with the smallest WAG slug size of 0.125 PV reached the peak oil RF at 1.00 PV, which was followed by Test #4 at 1.25 PV and Test #3 at 1.75 PV. The final oil RFs of Tests #5–3 are equal to 92.9%, 88.2%, and 78.8%, respectively. Hence, the WAG slug size has a strong effect on the oil RF. More specifically, a higher oil RF of the miscible CO₂-WAG injection is achieved if a smaller WAG slug size is used. More injected water in one WAG cycle causes a more severe waterblocking effect and prevents a large amount of the residual oil from being contacted by the injected CO₂, which hinders the mutual interactions between the residual oil and the injected CO₂. The waterblocking effect was found to be strong in the water-wet oil reservoir during the WAG injection process [Huang and Holm, 1988]. On
Figure 4.9  Effect of the WAG slug size on the oil RF of the miscible CO$_2$-WAG injection with the same WAG slug ratio of 1:1 (Tests #3–5).
the other hand, implementing a smaller WAG slug size will increase the operating cost because the fluid injection has to be alternated or switched more frequently. Therefore, an optimum WAG slug size needs to be determined for a specific field application of WAG injection.

4.2.3 WAG slug ratio

In this study, three miscible CO$_2$-WAG injection tests with the same WAG slug size of 0.250 PV were conducted to study the effect of a different WAG slug ratio on the oil RF. The WAG slug ratio is defined as the ratio of the injected PV of brine to that of CO$_2$ in each WAG cycle at the actual reservoir conditions. Tests #6, #4, and #7 had three different WAG slug ratios of 2:1, 1:1, and 1:2, respectively.

The measured oil RFs versus the total injected PVs of brine and CO$_2$ of Tests #6, #4, and #7 are plotted and compared in Figure 4.10. These three tests had quite high oil RFs. The final oil RF of Test #7 was the highest (92.0%), which was followed by Test #4 (88.2%) and Test #6 (78.8%). This is because Test #7 had the largest amount of CO$_2$ injected into the reservoir core plugs in each WAG cycle. Apparently, CO$_2$ has a much higher microscopic displacement efficiency under the miscible condition than that of water. Figure 4.10 also shows that Test #6 had the highest oil production rate (i.e., the slope of the oil RF versus PV curve) at the beginning, which was followed by Tests #4 and #7. This trend was attributed to the largest WAG slug ratio of Test #6. The injected water is almost incompressible so that the oil RF is increased almost linearly with the injected PV of water during waterflooding because of its volumetric displacement. However, the light crude oil is produced in the miscible CO$_2$ flooding through different EOR mechanisms. The injected CO$_2$ contacts the light crude oil at the MMP and thus
Figure 4.10  Effect of the WAG slug ratio on the oil RF of the miscible CO₂-WAG injection with the same WAG slug size of 0.250 PV (Tests #4, #6, and #7).
strong two-way mass transfer occurs. The injected CO₂ is dissolved into the light crude oil, which reduces its viscosity and makes it swell. Meanwhile, some light to intermediate hydrocarbons are extracted by supercritical CO₂ from the light crude oil to CO₂ phase. The CO₂ phase becomes more and more enriched after it makes multiple contacts with the light crude oil. At the end, the CO₂-diluted light crude oil and the hydrocarbons-enriched CO₂ become one phase and the so-called MCM is achieved. The mutual interactions between the light crude oil and CO₂ take some time to occur so that the initial oil production rate is not high. This is why the miscible CO₂ flooding has the highest displacement efficiency and leads to the highest oil RF at a later time or near the end.

In summary, Test #7 had the highest oil RF but consumes the largest amount of CO₂. Test #6 had the lowest oil RF, though the largest amount of water was injected. Among the three miscible CO₂-WAG injection tests with the same WAG slug size of 0.250 PV (Tests #6, #4, and #7), Test #4 shows the best overall performance as its oil RF and oil production rate were rather high with a moderate consumption of CO₂. It can be concluded that the WAG slug ratio of 1:1 is particularly suitable for the miscible CO₂-WAG injection in this study. In this way, water can effectively control the CO₂ mobility in the tight oil formation, leading to a high oil RF and a moderate consumption of CO₂.

4.2.4 Fluid injection sequence

In this study, two miscible CO₂-WAG injection tests (Tests #4 and #5) and two CO₂-GAW injection tests (Tests #8 and #9) were performed and compared to examine the effect of a different fluid injection sequence on the oil RFs with two different slug sizes of 0.250 and 0.125 PV but the same slug ratio of 1:1. The fluid injection sequence
represents the orders of brine and CO₂ to be injected into the tight reservoir core plugs. The measured oil RF vs. injected PV of brine and CO₂ curves of the four tests are plotted and compared in Figure 4.11. This figure reveals that the final oil RFs of the two CO₂-WAG injection tests were obviously higher than those of the two CO₂-GAW injection tests. In the CO₂-WAG injection, the initial water injection has a higher volumetric sweep efficiency than the initial CO₂ injection due to a more favourable mobility ratio of the injected water to the light crude oil. After the initial water injection, CO₂ was injected into the reservoir core plugs and it preferentially moved through the residual oil zone due to its much higher solubility in the light crude oil than that in the brine at the reservoir conditions [Li and Gu, 2014a]. In the miscible CO₂-GAW injection, however, the supercritical CO₂ was injected into the reservoir core plugs first. Its severe viscous fingering occurred in the tight core plugs due to the ultra-low viscosity of the supercritical CO₂, resulting in a relatively low volumetric sweep efficiency. Based on the prediction from the CMG WinProp module, \( \mu_{\text{CO}_2} \) is equal to 0.0266 cP at \( P_{\text{res}} = 10.0 \) MPa and \( T_{\text{res}} = 56.0 \) °C. The subsequently injected water followed the gas channels that had already formed in the CO₂ injection process, which caused a lower oil RF of the miscible CO₂-GAW injection. Hence, it is suggested that water should be injected prior to solvent injection (i.e., WAG rather than GAW injection) in a tight oil formation in order to achieve a higher final oil RF.

4.2.5 Oil RF and CO₂ utilization

The oil RFs in each WAG/GAW cycle of five miscible CO₂-WAG injection tests (Tests #3–7) and two miscible CO₂-GAW injection tests (Tests #8 and #9) are
Figure 4.11  Effect of the fluid injection sequence on the oil RF of themiscible CO$_2$-WAG/GAW injection with the same WAG/GAW slug ratio of 1:1 (Tests #4, #5, #8, and #9).
summarized in Table 4.3. The oil RFs of all nine coreflood tests are plotted and compared in Figure 4.12. According to Table 4.3 and Figure 4.12, the oil RFs of the first two cycles of Tests #3–9 were 78.8%, 84.6%, 58.6%, 74.5%, 82.0%, 61.5%, and 62.3%, respectively. The percentages of the oil RFs of the first two cycles in the total oil RFs are even higher, i.e., 100.0%, 95.9%, 63.1%, 94.5%, 89.1%, 92.9%, and 83.1%, respectively. A large amount of the light crude oil is produced in the first two cycles in the miscible CO₂-WAG/GAW injection tests except in Test #5. The sub-total oil RF of the first two WAG cycles and its percentage in the total oil RF of Test #5 were the lowest because its WAG slug size was 0.125 PV. After the first two WAG cycles, only 0.500 PV of fluids was injected into the tight reservoir core plugs, which was too small to recover a large amount of the light crude oil. In this test, 34.3% of the light crude oil was recovered in the next two WAG cycles and the EWF. In summary, Test #5 had the highest total oil RF and was the most efficient CO₂-WAG injection scheme with the smallest WAG slug size of 0.125 PV and the moderate WAG slug ratio of 1:1. In this case, the injected water can effectively control the CO₂ mobility.

The injected CO₂ volumes in Tests #1–9 were equal to 0.00, 2.00, 1.50, 1.00, 0.50, 0.50, 1.50, 0.75, and 0.75 PV and the corresponding total oil RFs were equal to 43.2%, 63.4%, 78.8%, 88.2%, 92.9%, 78.8%, 92.0%, 66.2%, and 75.0%, respectively. Based on the above experimental data, the so-called gross CO₂ utilization factor for each test can be determined. In the literature, the gross CO₂ utilization factor is defined as the total amount of CO₂ injected in one thousand standard cubic feet (MSCF) divided by the total amount of the stock-tank oil produced in barrels (STB) at the end of each CO₂ injection process [Merchant, 2010]. The gross CO₂ utilization factors in Tests #1–9 were
Table 4.3  Oil Recovery Factors (RFs) of Different Cycles in Each Miscible CO₂-
WAG/GAW Injection Test.

<table>
<thead>
<tr>
<th>Test No.</th>
<th>1st cycle</th>
<th>2nd cycle</th>
<th>3rd cycle</th>
<th>4th cycle</th>
<th>EWF³</th>
</tr>
</thead>
<tbody>
<tr>
<td>WAG</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>(WAG)</td>
<td>RFw (%)</td>
<td>RFCO₂ (%)</td>
<td>RFw (%)</td>
<td>RFCO₂ (%)</td>
<td>RFw (%)</td>
</tr>
<tr>
<td>3</td>
<td>28.0</td>
<td>37.6</td>
<td>4.5</td>
<td>8.7</td>
<td>0.0</td>
</tr>
<tr>
<td>4</td>
<td>26.4</td>
<td>27.9</td>
<td>16.6</td>
<td>13.7</td>
<td>2.6</td>
</tr>
<tr>
<td>5</td>
<td>12.0</td>
<td>12.2</td>
<td>21.7</td>
<td>12.7</td>
<td>17.7</td>
</tr>
<tr>
<td>6</td>
<td>26.8</td>
<td>16.4</td>
<td>25.2</td>
<td>6.1</td>
<td>4.3</td>
</tr>
<tr>
<td>7</td>
<td>24.0</td>
<td>30.0</td>
<td>11.2</td>
<td>16.8</td>
<td>4.0</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Test No.</th>
<th>1st cycle</th>
<th>2nd cycle</th>
<th>3rd cycle</th>
<th>4th–6th cycles</th>
<th>EWF³</th>
</tr>
</thead>
<tbody>
<tr>
<td>GAW</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>(GAW)</td>
<td>RFCO₂ (%)</td>
<td>RFw (%)</td>
<td>RFCO₂ (%)</td>
<td>RFw (%)</td>
<td></td>
</tr>
<tr>
<td>8</td>
<td>34.6</td>
<td>9.6</td>
<td>13.5</td>
<td>3.8</td>
<td>0.0</td>
</tr>
<tr>
<td>9</td>
<td>32.3</td>
<td>13.2</td>
<td>7.7</td>
<td>9.1</td>
<td>3.6</td>
</tr>
</tbody>
</table>

³Extended waterflooding (EWF).
Figure 4.12  Comparison of the measured oil RFs of nine coreflood tests.
approximated to be 0.0, 18.5, 9.8, 6.3, 4.2, 6.2, 7.4, 11.9, and 7.6 MSCF/STB. The miscible CO$_2$-WAG/GAW injection significantly reduces the CO$_2$ consumption and enhances the oil RF, in comparison with the continuous miscible CO$_2$ flooding. In particular, Test #5 with the WAG slug size of 0.125 PV and the WAG slug ratio of 1:1 had the highest total oil RF (92.9%), the least amount of CO$_2$ consumption (0.50 PV), and the lowest gross CO$_2$ utilization factor (4.2 MSCF/STB). It is also worthwhile to note that the final oil RF of the miscible CO$_2$-WAG injection is not increased proportionally with the total amount of the injected CO$_2$. Therefore, the operating parameters of a CO$_2$-WAG injection process, such as its WAG slug size, WAG slug ratio, fluid injection rate and sequence, have to be optimized before it is applied in a given oil reservoir.

4.3 CO$_2$-EOR in the Fractured Bakken Formation

4.3.1 CO$_2$-soaking effect

In this work, two different flooding scenarios were designed to study CO$_2$-soaking effect on the oil RF in the fractured Bakken formation, which consists of one tight Bakken core plug and one fractured Bakken core plug. The detailed experimental data of Test #10 (miscible CO$_2$ secondary flooding without CO$_2$ soaking process) and Test #11 (miscible CO$_2$ secondary flooding with a CO$_2$ soaking period of 24 h between the first and second injected PVs of CO$_2$) are tabulated in Table 4.4.

Figure 4.13 compares the measured oil RFs and average gas production rates versus the injected PV of CO$_2$ in Tests #10 and #11. The oil RFs and oil production rates of
Table 4.4  Basic Physical Properties and Oil Recovery Factors of Three Coreflood Tests in the Fractured Bakken Formation and One Coreflood Test in the Tight Bakken Formation at the Production Pressure of $P_{\text{prod}} = 10.0$ MPa and Reservoir Temperature of $T_{\text{res}} = 56.0$ °C.

<table>
<thead>
<tr>
<th>Test No.</th>
<th>Injection</th>
<th>Formation</th>
<th>Slug size (PV)</th>
<th>Slug ratio</th>
<th>$\phi$ (%)</th>
<th>$k$ (mD)</th>
<th>$RF_w$ (%)</th>
<th>$RF_{CO_2}$ (%)</th>
<th>$RF_{\text{total}}$ (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>10</td>
<td>CO$_2$</td>
<td>Fractured</td>
<td>–</td>
<td>–</td>
<td>18.53</td>
<td>0.478</td>
<td>–</td>
<td>40.0</td>
<td>40.0</td>
</tr>
<tr>
<td>11</td>
<td>CO$_2$-soaking</td>
<td>Fractured</td>
<td>–</td>
<td>–</td>
<td>15.53</td>
<td>0.130</td>
<td>–</td>
<td>49.7</td>
<td>49.7</td>
</tr>
<tr>
<td>12</td>
<td>WAG</td>
<td>Tight</td>
<td>0.250</td>
<td>1:1</td>
<td>14.20</td>
<td>0.086</td>
<td>34.7</td>
<td>29.3</td>
<td>64.0</td>
</tr>
<tr>
<td>13</td>
<td>WAG</td>
<td>Fractured</td>
<td>0.500</td>
<td>1:2</td>
<td>18.38</td>
<td>0.420</td>
<td>36.4</td>
<td>17.2</td>
<td>53.6</td>
</tr>
</tbody>
</table>
Figure 4.13 Measured oil RFs and average gas production rates of two CO₂ secondary flooding processes (Test #10 without CO₂ soaking and Test #11 with a CO₂ soaking period of 24 h) in the fractured Bakken formation.
these two tests were similar in the first PV of CO₂ injection. The oil RFs at the end of 1.0 PV were 38.7% of the OOIP in Test #10 and 39.3% of the OOIP in Test #11, respectively. However, the two tests showed rather different trends in the second PV of CO₂ injection. More specifically, the oil RF of Test #10 without soaking process increased marginally and only 0.7% of the OOIP was produced in the second PV of CO₂ injection. A similar experimental trend was found in the tight Bakken formation [Han and Gu, 2014]. A large amount of the residual oil (11.0% of the OOIP) was recovered in Test #11 with a soaking period of 24 h prior to the second PV of CO₂ injection. Obviously, CO₂-soaking process considerably increased the final oil RF of the miscible CO₂ secondary flooding in the fractured Bakken formation. Figure 4.13 also indicates the CO₂ BTs in Tests #10 and #11 if the average gas production rates of the two tests are compared. It is seen from this figure that CO₂ BT happened at 0.14 PV in Test #10 and at 0.17 PV in Test #11, when the measured average gas production rates reached their highest values. The respective oil RFs were 25.3% in Test #10 and 28.5% in Test #11 at the CO₂ BT. A large amount of the residual oil was further produced after CO₂ BT in each test with the fractured Bakken formation. But the continuous CO₂ flooding with a CO₂-soaking process had a higher oil RF than that by the continuous CO₂ flooding without a CO₂-soaking process in the fractured Bakken formation. This is because there were much stronger and longer mutual interactions between the Bakken light crude oil and the injected CO₂ in the soaking period. Therefore, the oil-swelling effect, oil viscosity reduction, IFT reduction, and other beneficial effects in CO₂-EOR were more pronounced in Test #11 with a CO₂ soaking period and led to a much higher oil RF.
4.3.2 Fracture effect

In this study, the fracture effect on the oil RF was evaluated by comparing the miscible CO\textsubscript{2}-WAG injection processes in the tight Bakken formation (Test #12) and in the fractured Bakken formation (Test #13). In Test #12, four WAG cycles were injected into the tight Bakken formation with the WAG slug size of 0.250 PV and the WAG slug ratio of 1:1, which were followed by 1.0 PV EWF. In Test #13, two WAG cycles were injected into the fractured Bakken formation with the WAG slug size of 0.500 PV and the WAG slug ratio of 1:2, which were followed by 1.0 PV EWF. The detailed experimental data of Tests #12 and #13 are listed in Table 4.4.

The measured oil RFs, cumulative water productions, and average gas production rates of the miscible CO\textsubscript{2}-WAG injection in the tight Bakken formation (Test #12) and in the fractured Bakken formation (Test #13) are plotted in Figure 4.14 and Figure 4.15, respectively. It is seen from these two figures that in Test #12, 21.1% of the OOIP was produced in the first cycle of the miscible CO\textsubscript{2}-WAG injection in the tight Bakken formation, 10.3% in the second WAG cycle, 15.8% in the third WAG cycle, 16.8% in the last WAG cycle, and no oil in the EWF. In Test #13, 22.3% of the OOIP was produced in the first WAG cycle of the miscible CO\textsubscript{2}-WAG cycle in the fractured Bakken formation, 31.3% in the second WAG cycle, and no more oil in the EWF. The final oil RF of Test #12 was 10.4% higher than that in Test #13. Apparently, miscible CO\textsubscript{2}-WAG injection performed much better in the tight Bakken formation than in the fractured Bakken formation. The water BT happened at 0.40 PV in the tight Bakken formation and at 0.15 PV in the fractured Bakken formation, respectively. This is because the injected water can easily flow through the fractures in the fractured Bakken formation.
Figure 4.14  Measured oil RFs, cumulative water production data ($Q_w$), and average gas production rates ($q_g$) of the miscible CO$_2$-WAG injection (Test #12) with the WAG slug size of 0.250 PV and the WAG slug ratio of 1:1 in the tight Bakken formation.
Figure 4.15  Measured oil RFs, cumulative water production data ($Q_w$), and average gas production rates ($q_g$) of the miscible CO$_2$-WAG injection (Test #13) with the WAG slug size of 0.500 PV and the WAG slug ratio of 1:2 in the fractured Bakken formation.
formation.

In addition, the cumulative water production was increased slowly during CO$_2$-WAG injection process in Test #12. In Test #13, however, it was increased quickly in the water injection period and almost terminated in the CO$_2$ injection period. The lower water production rate of Test #12 indicates that the injected water displaced the light crude oil more effectively in the tight Bakken formation than in the fractured Bakken formation. From Figure 4.15, CO$_2$ BT happened early and the period with a high CO$_2$ production rate lasted much longer, during which only a small amount of the light crude oil was recovered in the fractured Bakken formation. Due to the early CO$_2$ BT, there was not enough time for the injected CO$_2$ to contact the light crude oil and extract it from the matrix. This resulted in a lower microscopic displacement efficiency in the fractured Bakken formation. In addition, the volumetric sweep efficiency of WAG injection was also decreased due to the existence of fractures inside the fractured core plug. Only 17.2% of the OOIP was recovered in the CO$_2$ injection process in the fractured Bakken formation. In contrast, 29.3% of the OOIP was produced in the CO$_2$ injection process in the tight Bakken formation. Therefore, the final oil RF was much higher in the tight Bakken formation than that in the fractured Bakken formation.

Furthermore, the amount of CO$_2$ injected into the fractured Bakken formation was two times as much as that injected into the tight Bakken formation. The additionally injected CO$_2$ did not help to achieve a higher oil RF in the fractured formation. Moreover, the low oil RF of the CO$_2$-WAG injection may also be caused by inappropriate WAG injection parameters, such as the WAG slug size and the WAG slug ratio.
CHAPTER 5  CONCLUSIONS AND RECOMMENDATIONS

5.1 Conclusions

This study experimentally measured the PVT properties of the Bakken light crude oil–CO₂ systems at six different CO₂ concentrations, examined three flooding schemes, i.e., waterflooding, continuous miscible CO₂ flooding, and miscible water-alternating-gas (WAG) injection, and optimized the miscible CO₂-WAG injection in the tight Bakken formation. It also evaluated the CO₂-soaking effect in the fractured Bakken formation and compared the miscible CO₂-WAG injection process in the tight and fractured Bakken formations. The major conclusions that can be drawn from this study are listed as follows:

1) In the PVT study, the saturation pressure \( P_{\text{sat}} \) and oil-swelling factor (SF) of CO₂-saturated Bakken light crude oil were increased respectively in the ranges of 2.01–9.29 MPa and 1.05–1.62 when CO₂ concentration in the Bakken light crude oil–CO₂ system was increased in the range of 18.64–70.11 mol.%. The density increased marginally at low CO₂ concentrations and did not change appreciably if more CO₂ was dissolved into the Bakken light crude oil. The measured CO₂ solubility was increased from 30.0 to 313.6 cm³ CO₂/cm³ oil as the saturation pressure was increased from 2.01 to 9.29 MPa;

2) The viscosities of CO₂-saturated Bakken light crude oils with 18.64 and 70.11 mol.% CO₂ concentrations were reduced to 56% and 28% of the original dead Bakken light crude oil viscosity at the reservoir temperature of \( T_{\text{res}} = 56.0 \) °C. The reduced oil viscosity contributes substantially to the oil recovery factors (RFs) in the continuous CO₂ flooding and CO₂-WAG injection;
3) The measured equilibrium interfacial tension (IFT) was reduced almost linearly with the equilibrium pressure and the minimum miscibility pressure (MMP) of 10.0 MPa was determined by using the vanishing interfacial tension (VIT) technique;

4) The miscible CO$_2$-WAG injection had the highest oil RF (78.8% in Test #3), in comparison with waterflooding (43.2% in Test #1), continuous miscible CO$_2$ flooding (63.4% in Test #2), and miscible CO$_2$ gas-alternating-water (CO$_2$-GAW) injection (66.2% in Test #8). Miscible CO$_2$-WAG injection was considered to be the best CO$_2$-EOR process in the tight oil formations because the miscible CO$_2$-WAG injection combined the improved volumetric sweep efficiency of waterflooding and the enhanced microscopic displacement efficiency of CO$_2$ flooding;

5) Three tests were performed with different WAG slug sizes of 0.500, 0.250, and 0.125 but at the same WAG slug ratio of 1:1 to recover the light crude oil from the tight Bakken formation. The highest final oil RF was achieved in the miscible CO$_2$-WAG injection with the smallest WAG slug size of 0.125 pore volume (PV);

6) The optimum WAG slug ratio in this study was approximately 1:1. In this way, water can effectively control the CO$_2$ mobility in the tight Bakken formation, leading to a high oil RF and a moderate consumption of CO$_2$;

7) Water should be injected prior to solvent injection (i.e., WAG injection is better than GAW injection) in a tight oil formation. In the CO$_2$-WAG injection, the initial water injection had a higher volumetric sweep efficiency than the initial CO$_2$ injection and also forced the subsequently injected CO$_2$ to flow through the residual oil zone;

8) Over 60% of the original oil-in-place (OOIP) was produced in the first two WAG cycles in the tight Bakken formation. The miscible CO$_2$-WAG injection achieved a
higher oil RF and consumed a less amount of CO₂ than the continuous miscible CO₂ flooding. This means that the miscible CO₂-WAG injection has a lower gross CO₂ utilization factor than the continuous miscible CO₂ flooding;

9) CO₂ BTs happened earlier in two continuous CO₂ flooding processes in the fractured Bakken formation. However, a large amount of the residual light crude oil was still produced after CO₂ BT in the fractured Bakken formation.

10) The final oil RF of continuous CO₂ secondary flooding with a CO₂ soaking period of 24 h was 9.7% higher than that of continuous CO₂ secondary flooding without CO₂ soaking in the fractured Bakken formation. Much longer and stronger mutual interactions between the Bakken light crude oil and the injected CO₂ occurred in the soaking period, which resulted in a much higher oil RF;

11) During CO₂-WAG injection process in the fractured Bakken formation, water BT happened at 0.15 PV, which was smaller than 0.40 PV in the tight Bakken formation. The earlier water BT resulted in a lower volumetric sweep efficiency of water injection in the fractured Bakken formation; and

12) CO₂ BT occurred earlier and the period with a high CO₂ production rate lasted much longer in the fractured Bakken formation so that only a small amount of the light crude oil was recovered. There was not enough time for the injected CO₂ to contact the light crude oil and extract it from the matrix due to an earlier CO₂ BT. This also led to a lower microscopic displacement efficiency of CO₂ injection and a lower oil RF in the fractured Bakken formation.
5.2 Recommendations

Based on this thesis study, the following technical recommendations are made for future studies:

- The hydraulic fracturing method was commonly used to increase the productivity of the tight formations. The fracture effect needs to be fully studied in the coreflood tests. A series of high-pressure coreflood tests are to be conducted by using the fractured Bakken core plugs. The miscible CO₂-WAG injection is to be tested in the fractured Bakken formation in order to optimize the CO₂-WAG slug size and ratio.

- A comprehensive numerical modelling program can be undertaken by using CMG GEM module to simulate the CO₂-WAG coreflood tests conducted in this study and the CO₂-EOR methods in a fractured tight oil formation. Furthermore, the reservoir simulations of practical field-scale applications can be performed to study the best production scheme and operating conditions;

- In order to accurately monitor the fluids flow in the porous medium during the coreflood tests, X-Ray scanning method is recommended to visualize the distributions of fluids inside the core plugs.

- Three phases (i.e., oil, gas, and water) exist at the same time during the CO₂-WAG injection. The three-phase relative permeability of multi-phase fluid flow affects the oil RF due to the relative permeability hysteresis in the WAG injection process. Therefore, the effect of the relative permeability hysteresis on CO₂-WAG injection needs to be further investigated.
REFERENCES


Miller, J. S.; Jones, R. A. A Laboratory Study to Determine Physical Characteristics of Heavy Oil after CO₂ Saturation. Paper SPE 9789, presented at the SPE/DOE Enhanced Oil Recovery Symposium, Tulsa, OK, April 5–8, 1981.


APPENDIX A

Safe Operating Procedures for Laboratory Coreflood Tests

<table>
<thead>
<tr>
<th>Student Name: Longyu Han</th>
<th>Academic Supervisor: Dr. Yongan (Peter) Gu</th>
</tr>
</thead>
<tbody>
<tr>
<td>Activity/Experiment: High-Pressure Coreflood Test</td>
<td></td>
</tr>
</tbody>
</table>

**Equipment Specifications / Manufacturer Guidelines:**

**100 DX syringe pump:**
- **Capacity:** 100 ml
- **Flow range (ml/min):** 0.00001–50
- **Flow Accuracy:** 0.3% of set point
- **Pressure Range (psi):** 10–10,000
- **Standard Pressure Accuracy:** 0.5% FS
- **Standard Temperature Range:** 5–40 °C Ambient
- **Power:** 100 Vac, 117 Vac, 234 Vac, 50/60 Hz
- **Dimensions:** Height: 103 cm (40.5 in), Width: 27 cm (10.6 in), Depth: 47 cm (18.5 in)

**260 DX syringe pump:**
- **Capacity:** 260 ml
- **Flow range (ml/min):** 0.001–107
- **Flow Accuracy:** 0.5% of set point
- **Pressure Range (psi):** 10–7,500
- **Standard Pressure Accuracy:** 0.5% FS
- **Standard Temperature Range:** 5–40 °C Ambient
- **Power:** 100 Vac, 117 Vac, 234 Vac, 50/60 Hz
- **Dimensions:** Height: 103 cm (40.5 in), Width: 27 cm (10.6 in), Depth: 47 cm (18.5 in)

**High-pressure cylinder (500 ml):**
- **Capacity:** 500 ml
**Pressure Range (psi):** 10–10,000  
**Standard Temperature Range:** 5–200°C Ambient  
**Coreholder:**  
- **Maximum working Pressure (psi):** 20,000  
- **Maximum working Temperature:** 315 °C

<table>
<thead>
<tr>
<th>Steps:</th>
<th>Hazards:</th>
<th>Safe Work Practices/Mitigation Strategies:</th>
</tr>
</thead>
</table>
| 1. Clean core samples by using the Dean–Stark extractor for about one week | Three chemicals, i.e., toluene, methanol, and chloroform are used to clean the core plugs, They are highly toxic and volatile | • Do task inside a fume hood  
• Be careful when you pour these chemicals |
| 2. Dry the core samples at 120 °C inside a lab oven for 10 hours       | It might be a fire hazard due to the long-term heating                   | • Do it in the daytime and check it every hour  
• Always shut off the oven before leaving for the day |
| 3. Place the cool downed core samples together with two distributors in series inside a shrinkable tube, and put them back to the lab oven for 1h at 120 °C | It might be a fire hazard                                               | • Do it in the daytime and check it every hour  
• Always shut off the oven before leaving for the day |
| 4. Place the core plugs into a rubber sleeve                          | None                                                                    | • None                                                                                                    |
| 5. Assemble the rubber sleeve into a coreholder on a work bench       | Coreholder is too heavy and could cause physical injury                 | • Wear the heavy-duty gloves and safety boots  
• Ask your classmates to help you to assemble the coreholder, if needed. |
<p>| 6. Connect the tubings before and after the coreholder                | None                                                                    | • None                                                                                                    |</p>
<table>
<thead>
<tr>
<th>Step</th>
<th>Task Description</th>
<th>Materials/Notes</th>
<th>Safety Precautions</th>
</tr>
</thead>
<tbody>
<tr>
<td>7.</td>
<td>Apply the overburden pressure of 3–5 MPa to the core samples</td>
<td>None</td>
<td>• None</td>
</tr>
<tr>
<td>8.</td>
<td>Use the high pressure air to do the leakage test</td>
<td>High pressure air</td>
<td>• Keep you PPE on all the time in the lab</td>
</tr>
<tr>
<td>9.</td>
<td>Vacuum the coreholder by using a vacuum pump</td>
<td>Vacuum pump can produce a lot of heat during its working process, it might be a fire hazard</td>
<td>• Stop it for a while in every one hour &lt;br&gt;• Keep the flammable materials away from the vacuum pump</td>
</tr>
<tr>
<td>10.</td>
<td>Fill the oil, brine, and CO₂ into three transfer cylinders</td>
<td>Cylinders are very heavy and could cause physical injury</td>
<td>• Wear the heavy-duty gloves and safety boots &lt;br&gt;• Move any items away from your path before you move the transfer cylinders &lt;br&gt;• Cart may be used to deliver these heavy transfer cylinders</td>
</tr>
<tr>
<td>11.</td>
<td>Inject brine to measure the porosity and permeability of the core plugs</td>
<td>The whole system is under a high-pressure condition</td>
<td>• Keep you PPE on all the time in the lab &lt;br&gt;• Make sure that the overburden pressure is 3–5 MPa higher than the injection pressure</td>
</tr>
<tr>
<td>12.</td>
<td>Inject oil to achieve the connate water saturation</td>
<td>The whole system is under a high-pressure condition</td>
<td>• Keep you PPE on all the time in the lab &lt;br&gt;• Make sure that the overburden pressure is 3–5 MPa higher than the injection pressure</td>
</tr>
<tr>
<td>13.</td>
<td>Increase the BPR pressure to the preset production pressure</td>
<td>The whole system is under a high-pressure condition</td>
<td>• Keep you PPE in the lab &lt;br&gt;• Gradually increase the BPR pressure to protect the BPR</td>
</tr>
<tr>
<td>14.</td>
<td>Inject water or CO₂ to displace the crude oil inside the coreholder</td>
<td>The whole system is under a high-pressure condition</td>
<td>• Make sure that the overburden pressure is 3–5 MPa higher than the injection pressure</td>
</tr>
<tr>
<td>15.</td>
<td>Collect the produced oil by using an oil sample collector and measure the volume of produced gas by using a gas flow meter</td>
<td>Produced oil might spill</td>
<td>• Remember to change the oil sample collector before an overflow occur</td>
</tr>
<tr>
<td>16.</td>
<td>Use a centrifuge to separate the produced oil and water, and record their volumes</td>
<td>None</td>
<td>• Place the centrifuge on a flat surface</td>
</tr>
<tr>
<td>Step</td>
<td>Task Description</td>
<td>Safety Concern</td>
<td>Safety Precautions</td>
</tr>
<tr>
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<tr>
<td>17.</td>
<td>Reduce pressure of the coreflood system and carefully start a blowdown procedure or process</td>
<td>Gas and oil might produced too quick, which may cause the spill problem</td>
<td>Keep you PPE on all the time in the lab</td>
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</tbody>
</table>
| 18.  | Disassemble the Coreholder in the work bench and clean the tubings by using kerosene and methanol in sequence | Coreholder is too heavy and may cause the physical injury, if it is not handled properly | Wear the heavy-duty gloves and safety boots  
Move any items away from your path before you move the coreholder  
Ask your classmates to help you to disassemble the coreholder |
|      |                 |                |                   |
| 19.  | Pour the wasted oil into a container | Oil might spill and contaminate air | Put the container into a fume hood and seal it  
Dispose of the waste oil if the container is 80% full |

**PPE required:**
- Pair of Kevlar high temperature gloves
- Safety boots
- Safety Glasses
- Lab Coat
- Pair of heavy duty gloves
- Rubber gloves
- Lab Coat
- Heavy-duty gloves

**Materials/Tools Required:**
- Cart
- Wrench
- Hammer
- Vice
- Work bench
- Flask
- Paper towels