DEVELOPMENT OF SCALING CRITERIA FOR WATERFLOODING AND IMMISCIBLE CO₂ FLOODING IN UNCONVENTIONAL RESERVOIRS

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By
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Deyue Zhou, candidate for the degree of Master of Applied Science in Petroleum Systems Engineering, has presented a thesis titled, *Development of Scaling Criteria for Waterflooding and Immiscible CO$_2$ Flooding in Unconventional Reservoirs*, in an oral examination held on January 22, 2015. 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

As conventional oil reserves are depleting, the rising energy demand as well as advancements in well drilling and stimulation technologies have attracted increasingly interests in exploiting the unconventional oil resources (e.g., tight oil and heavy oil). Tight oil resources in Canada are mainly located in Cardium and Viking pools in Alberta, Bakken formation in Saskatchewan, and Western Canada Shale plays, respectively. Also, tremendous heavy oil resources accounting for almost half of the total world heavy oil reserves are mainly found in Western Canada, though they are contained in thin and depleted reservoirs. Such unconventional oil resources either have been deposited in extremely unfavourable environments or possess high carbon intensity, requiring more efforts and energy to recover than conventional oils. In practice, three-dimensional (3D) displacement models show unique advantages for designing appropriate well configurations, though their physical constraints make it impossible to duplicate the real reservoirs under certain conditions. Therefore, it is of fundamental and practical importance to develop scaling criteria for describing fluid flow behaviour in unconventional reservoirs.

Scaling criteria have been developed and validated to evaluate the performance of both waterflooding and immiscible CO₂ flooding in tight formations. Experimentally, saturation pressures of the CO₂-light oil systems are determined with a versatile PVT system and then used to tune the binary interaction parameter (BIP) correlations between CO₂ and the lumped pseudo-components. Subsequently, waterflooding and immiscible CO₂ flooding have been respectively conducted with light oil in the 3D physical model. Theoretically, mathematical formulae have been derived to reveal fluid flow of
immiscible displacements in tight oil reservoir by performing dimensional and inspectional analyses. Since not all of the scaling groups can be satisfied, relaxation of the scaling groups will be made to neglect capillary pressure force. Scaling criteria have been validated by history matching the experimental measurements, and then extended for field applications. Geometric factor is demonstrated to be negligible while gravitational and viscous forces have been considered for scaling up waterflooding and immiscible CO\textsubscript{2} flooding. Since capillary pressure and relative permeability have a negligible effect on general movement of the displacing fluid, sacrificing these two parameters has been proved permissible.

Scaling criteria have then been modified and validated to evaluate performance of waterflooding and immiscible CO\textsubscript{2} flooding in heavy oil reservoirs by using the 3D sandpacked displacement model. Experimentally, waterflooding and immiscible CO\textsubscript{2} flooding of heavy oil have been conducted with 3D sandpacked models. Theoretically, scaling criteria have been relaxed by neglecting the ratio of gravitational force to viscous force while other scaling groups including geometric factor, diffusion groups, and ratio of capillary forces to viscous forces can be satisfied. The relaxed scaling criteria are validated by comparing the simulation results of synthetic reservoirs with experimental measurements, and then extended for field applications. There exists a reasonably good agreement between the laboratory measurements and the simulation results of the synthetic models. This is consistent with the findings from literature that, as for thin heavy oil reservoirs (i.e., ratio of well spacing to thickness and mobility ratio larger than 50) gravity effect is negligible.
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DEDICATION

To my beloved parents, Mrs. Guilan Gong and Mr. Yiyin Zhou, my brother, Dexiang Zhou for their continuous support and unconditional love.
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<th>Description</th>
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<tbody>
<tr>
<td>$B$</td>
<td>Formation volume factor, m$^3$/sm$^3$</td>
</tr>
<tr>
<td>$c_p$</td>
<td>Pressure coefficient defined in Eq. 3-16</td>
</tr>
<tr>
<td>$c_t$</td>
<td>Temperature coefficient defined in Eq. 3-16</td>
</tr>
<tr>
<td>$C_{go}$</td>
<td>CO$_2$ concentration in oil phase, sm$^3$/m$^3$</td>
</tr>
<tr>
<td>$D$</td>
<td>Diffusion coefficient, m$^2$/s</td>
</tr>
<tr>
<td>$f$</td>
<td>Normalized velocities</td>
</tr>
<tr>
<td>$F$</td>
<td>Coefficients defined in Eqs. 3-6a to 3-6c</td>
</tr>
<tr>
<td>$g$</td>
<td>Gravitational acceleration constant, m/s$^2$</td>
</tr>
<tr>
<td>$H$</td>
<td>Reservoir or model height, m</td>
</tr>
<tr>
<td>$J(S)$</td>
<td>Leverett $J$-functions of saturations</td>
</tr>
<tr>
<td>$k$</td>
<td>Specific permeability, mD</td>
</tr>
<tr>
<td>$k_r$</td>
<td>Relative permeability</td>
</tr>
<tr>
<td>$K$</td>
<td>Dispersion coefficient, m$^2$/s</td>
</tr>
<tr>
<td>$\overline{K}$</td>
<td>Diagonal tensor of dispersion coefficient</td>
</tr>
<tr>
<td>$L$</td>
<td>Reservoir or model length, m</td>
</tr>
<tr>
<td>$M$</td>
<td>Formation morphology factor</td>
</tr>
</tbody>
</table>
\( n \)  
Coefficient defined in Eq. 3-17

\( p \)  
Pressure, kPa

\( P_c \)  
Capillary pressure, kPa

\( P^*_c \)  
Characteristic transverse capillary pressure, Pa

\( S \)  
Saturation

\( t \)  
Time, s

\( t_n \)  
Normalized time

\( T \)  
Temperature, ºC

\( T_c \)  
Critical temperature, ºC

\( u \)  
Darcy’s velocity, m/s

\( v \)  
Superficial velocity, m/s

\( W \)  
Reservoir or model width, m

\( x \)  
Relevant variables in a given problem

**Greek letters**

\( \alpha \)  
Reservoir dip angle, º

\( \varepsilon \)  
Measurement error

\( \theta \)  
Contact angle, º

\( \mu \)  
Viscosity, Pa·s
\( \rho \)  
Density, kg/m\(^3\)

\( \sigma \)  
Interfacial tension, mN/m

\( \phi \)  
Porosity, dimensionless

**Subscripts**

\( \text{av} \)  
Average vertical

\( \text{g} \)  
Gas phase

\( \text{go} \)  
Gas-oil system

\( \text{gox} \)  
Gas dispersion in oil in \( x \) direction

\( \text{goy} \)  
Gas dispersion in oil in \( y \) direction

\( \text{goz} \)  
Gas dispersion in oil in \( z \) direction

\( \text{M} \)  
Model

\( \text{o} \)  
Oil phase

\( \text{ow} \)  
Oil-water system

\( \text{R} \)  
Prototype

\( \text{s} \)  
Solvent

\( \text{t} \)  
Total

\( \text{w} \)  
Water phase
SI Metric Conversion Factors

cP × 1.0  E+03  =  Pa·s
{(°F−32)/1.8}  E+00  =  °C
{(K−273.15)}  E+00  =  °C
mD × 1.0132  E+03  =  µm²
psi × 1.4503  E−01  =  kPa
CHAPTER 1 INTRODUCTION

1.1 Unconventional Oil Resources and CO₂ EOR Techniques

As conventional oil reserves are depleting, the rising energy demand as well as advancements in well drilling and stimulation technologies combined with recently high oil prices have attracted increasingly interests in exploiting the unconventional oil resources (e.g., tight oil and heavy oil) and developing them to the maximum potential. Unconventional light oil has been classified into three categories, i.e., halo oil, tight oil, and shale oil, which are mainly discovered from low-permeability areas of the Cardium and Viking pools in Alberta, Bakken formation in Saskatchewan, and Western Canada shale oil plays, respectively (Clarkson and Pedersen, 2011). Meanwhile, the Canadian heavy oil reserves, which are mainly located in Western Canada, i.e., Saskatchewan and Alberta, account for almost half of the total world heavy oil reserves.

As for unconventional light oil recovery, it is a challenging task to recover oil from a tight formation due to its inherent low permeability and low injectivity, leading to a low recovery with the conventional waterflooding processes. Higher injectivity is expected to be achieved by injecting low-viscosity injectants such as gas (Jarrell et al., 2002; Song, 2013). CO₂ has been used as an enhanced oil recovery (EOR) agent for many years from both laboratory studies and field tests (e.g., Beeson and Ortloff, 1959; Holm and O’Brien, 1971; Holm and Josendal, 1982; Ghaderi et al., 2012; Song and Yang, 2012; Liu et al., 2014). According to a survey conducted in 2008, the number of CO₂ flooding projects in the USA has been increasing steadily from less than 10 to more than 100 since 1980s due
to the availability of affordable and sufficient CO₂ from natural sources (Manrique et al., 2010). However, limited efforts have been made to evaluate CO₂ flooding performances in tight formations.

Heavy oil resources in Western Canada account for a major part of energy resources in Canada with the estimated average recovery of as low as 15% of the original oil-in-place (OOIP) after primary depletion (Canada National Energy Board, 2005). In addition to its high carbon intensity, such heavy oil requires more efforts and energy to recover than conventional oils, resulting in adverse environmental consequences during exploitation. The major challenge is to develop techniques for recovering these heavy oil resources while minimizing greenhouse gas emissions (mainly CO₂) and thus reducing the carbon footprint. Physically, thermal methods, e.g., steam-assisted gravity drainage (SAGD) and vapor extraction (VAPEX), have seen their limitations on heavy oil recovery from the low pressure and thin formations, while CO₂ has been adopted as an efficient agent to increase oil recovery through its superiority in viscosity reduction and oil swelling effect during an immiscible displacement process.

Extensive laboratory studies have been conducted to identify the flooding mechanisms and performance of immiscible CO₂ flooding processes. As for heavy oil, the experimental displacements are commonly conducted with either core samples from targeted formations or 3D sandpacked models. When it comes to tight oil, the laboratory studies are usually limited to coreflooding experiments with real cores due to the fact that the permeability of the sandpacked models cannot reach as low as that of tight formations. However, one-dimensional (1D) coreflooding might have limitations on both designing well configurations (Ammer et al., 1991) and up-scaling process compared
with 3D model displacements. In addition, 3D model has been considered to be reasonably representative of the production performance of corresponding reservoirs if it is properly scaled (Geertsma et al., 1956; Loomis and Crowell, 1964; Rojas et al., 1991).

1.2 Importance of Scaling Criteria

Scaling model studies on petroleum reservoirs can be traced back to 1950s when Leverett et al. (1942) firstly proposed the basic theories for evaluating reservoir performance with properly dimensional models. A limited number of “scaling ratios” were then derived from the continuity equations of water and oil flow. By comparing the experimental measurements, the scaled models are found to be superior to unscaled models in describing the reservoir behaviour.

After developing the theories associated with dimensionally scaled models for cold-water drive, hot-water drive, and solvent injection processes, Geertsma et al. (1956) pointed out that it is necessary and practical to neglect some scaling groups (e.g., Reynolds group). However, the question of whether deletion of the Reynolds group and possibly other groups is permissible has not been answered. Lozada and Farouq Ali (1987) derived the scaling criteria for the immiscible CO₂ flooding process for heavy oil recovery by using both dimensional and inspectional analyses. A relaxation process has then been made to the complete set of scaling groups by neglecting the ratio of capillary forces to the viscous forces, though the relaxed scaling criteria have not been validated experimentally as of yet.
1.3 Objectives of This Thesis Study

The purpose of this thesis study is to systematically develop the scaling techniques for the experimental displacements of unconventional oil reservoirs associated with waterflooding and immiscible CO₂ flooding processes. The primary objectives of this thesis study are listed as follows.

(1). To develop scaling groups for the processes of waterflooding and immiscible CO₂ flooding by using dimensional and inspectional analyses.

(2). To examine effects of the scaling groups on the scaling process with respect to tight oil and heavy oil reservoirs.

(3). To conduct waterflooding and immiscible CO₂ displacement experiments of light oil and heavy oil by using a 3D sandpacked model.

(4). To validate the scaling criteria by history matching the experimental displacements and simulation results of the synthetic reservoirs, and extend them for field applications.

1.4 Outline of The Thesis

This thesis is composed of five chapters. Chapter 1 introduces the thesis research topic together with the major research objectives and scope. Chapter 2 provides an updated literature review on waterflooding and immiscible CO₂ flooding processes for the tight oil formations and heavy oil reservoirs as well as the corresponding studies on the scaled models. Chapter 3 develops the scaling criteria for waterflooding and immiscible CO₂ flooding processes by using both dimensional and inspectional analyses. A relaxation
process is made to the scaling groups with respect to oil displacement in tight formations. This chapter also includes the validation of the relaxed scaling criteria by using experimental measurements. Chapter 4 presents the development and validation of scaling criteria for waterflooding and immiscible CO₂ flooding processes for heavy oil reservoirs, including the theoretical formulations and experimental measurements. Chapter 5 summarizes the major scientific findings of this study and provides recommendations for future research.
CHAPTER 2 LITERATURE REVIEW

2.1 Unconventional Oil Resources

Unconventional oil resources, e.g., tight oil and heavy oil, have been increasingly recovered as conventional oil reserves are depleting and the energy consumptions are escalating. In North America, unconventional oil resources including tight oil, heavy oil, oil shale, and oil sands are estimated to be 3.5 trillion barrels, nearly two times larger than the world’s recoverable conventional oils (Forrest et al., 2011). The majorities of unconventional oil supplies are coming from the Canadian oil sands as well as tight oil.

Unconventional tight oils in North America are mainly discovered from low-permeability areas of the Cardium play in Alberta, the Bakken play in Williston Basin, the Eagle Ford play in Texas, and the Miocene Monterey play in California’s San Joaquin Basin (Clarkson and Pedersen, 2011). The total estimated tight oil reserves, mainly contributed by Bakken play, range from 5.6 to 10 billion barrels which include 3.65 to 4.3 billion barrels of recoverable resources (U.S. Geological Survey, 2008). The recoverable oil resources could be more when new enhanced oil recovery (EOR) techniques are applied to developing these deposits (Forrest et al., 2011). Early exploitation of tight oil in Bakken Formation in 1950s via vertical wells was hindered by the quick depleting production. After first implementation of horizontal wells in Bakken play in 1980s, improvements in well drilling, completion, and stimulation technologies combined with high oil prices have attracted increasing interest in Bakken play exploitation since 2005 (Lolon et al., 2009; Canada National Energy Board, 2011).
In addition to unconventional tight oil, there are vast heavy oil and oil sands resources in Canada which are mainly located in northeastern Alberta and western Saskatchewan. These abundant resources are estimated to be more than 2.2 trillion barrels of oil in place (Dusseault, 2002). OOIP of heavy oil resources in Canada is over 35 billion barrels while only 8–12% of OOIP has been recovered by using primary depletion and cold production methods (Forrest et al., 2011).

2.2 Waterflooding

Waterflooding has been considered as one of the cheapest and most profitable secondary oil recovery (SOR) methods on conventional oil productions (Morsy et al., 2013). As for unconventional tight oil recovery, waterflooding has been widely implemented by Lightstream Resources, Crescent Point Energy, and Tundra Oil and Gas Partnership (Canada) in the Bakken fields, South Saskatchewan (AccuMap, version 2014, IHS Inc.). However, it is a challenging task to recover oil from a tight formation due to its low injectivity of waterflooding, leading to low recovery with the conventional waterflooding processes.

Since 1990s, water has also been injected to recover conventional heavy oil resources. The combined heavy oil production from Alberta and Saskatchewan reached its peak in 1997 due to the advancements of progressive cavity pump and horizontal drilling technology (Dusseault, 2002). As for unconventional heavy oil exploitation, high oil viscosity leads to unfavourable mobility ratio of water displacement, resulting in poor sweep efficiency and low oil recovery factor. Usually, waterflooding is combined with polymer flooding and gas flooding processes to improve the sweep efficiency and
mobility ratio, resulting in a better recovery factor in those unconventional heavy oil reservoirs (e.g., presence of an aquifer in communication with the payzone and narrow payzone thickness) where thermal recovery methods are inapplicable.

2.3 CO$_2$ EOR

CO$_2$ injection has been used as an EOR approach in tight oil productions, especially in the USA, due to the availability of affordable and sufficient CO$_2$ from natural sources (Manrique et al., 2010). Most of the tight oil reservoirs in Saskatchewan, Canada, have reached their economic limit of recovery by waterflooding (Srivastava et al., 1999) and are considered to be good candidates for miscible/near miscible CO$_2$ flooding (Huang and Dyer, 1992). In a miscible and near miscible CO$_2$ flooding process, dispersion is considered to be a dominant phenomenon (Dullien, 1992) because of the rock heterogeneity and viscous fingering, results in an immiscible displacement region (Zekri et al., 2006).

Thermal recovery processes (e.g., SAGD) have been extensively adopted since oil viscosity can be significantly reduced by steam injection. However, thermal methods become inefficient when it comes to thin payzones and/or reservoirs with bottom aquifers because large heat losses to the overburden and underburden formations may occur (Butler, 2001; Zheng and Yang, 2013). In addition, there are many unresolved issues (e.g., artificial lift) for low pressure SAGD operations for those heavy oil formations with upper thief layers (Kisman, 2003). Also, water supply and treatment can impose severe constraints for successful SAGD applications (Butler, 2001). Compared with waterflooding and thermal methods, CO$_2$ injection has been adopted as a more
efficient approach to enhance heavy oil recovery from these low pressure and thin formations. As for heavy oil reservoirs exploited in Western Canada, although miscible CO₂ displacement cannot be achieved due to the low reservoir pressure (e.g., initial reservoir pressure for Lloydminster heavy oil reservoir, Canada, is about 3,500 kPa (Adams, 1982)). CO₂ has been found, through worldwide applications in heavy oil reservoirs, to be an efficient agent for recovering low pressure and thin heavy oil reservoirs through an immiscible displacement process (Thomas and Harvey, 1981; Mohammed-Singh and Singhal, 2005; Sahin et al., 2008).

During an immiscible CO₂ flooding process, CO₂ is injected into the formation, mobilizing the contacted oil and displacing it towards the production wells. Major mechanisms related in the immiscible flooding process include oil swelling effect, viscosity reduction, Interfacial tension (IFT) reduction, and light-component extraction (Schechter and Guo, 1996). To obtain a better utilization of CO₂ and improve sweep efficiency, in general, continuous CO₂ flooding is alternated by water injection which is usually named as a water-alternating-CO₂ (CO₂-WAG) process.

### 2.3.1 Oil swelling effect

When CO₂ contacts with crude oil, it promotes oil expansion (i.e., the volume of CO₂-saturated crude oil is larger than that of crude oil alone). Oil swelling effect is an important factor during CO₂ EOR processes since it provides information on the extent to which crude oil is driven out of pore by such an expansion (Mulliken and Sandler, 1980).
Comparing with the effect of viscosity reduction, oil swelling is recognized to be a more important mechanism by which light oil is recovered in the immiscible CO₂ flooding processes (Thomas and Monger-McClure, 1991). With low permeability matrix in tight formations where gravity drainage is negligible, oil swelling and expulsion from matrix to fractures are resulted from CO₂ dissolution in light oil phase (Ravel and Anterion, 1985). The magnitude of swelling factor for heavy oil is not as high as for light oil, which can be expanded to more than twice its original volume. As for heavy oil, swelling factor is increased linearly with CO₂ solubility (Chung et al., 1988).

2.3.2 Viscosity reduction

Viscosity reduction is the major recovering mechanism for immiscible CO₂ flooding of heavy oil. The viscosity of the heavy oil can be significantly reduced as a result of dissolution of CO₂ in low-API-gravity oil. For example, at reservoir temperature of 63ºC, the viscosity of Bati Raman oil with 12 °API is reduced from 600 cP to 60 cP with the pressure increasing from atmosphere pressure to the reservoir pressure of 2,000 psi (Sahin et al., 2008).

The viscosity reduction of heavy oil with CO₂ saturation depends on temperature, pressure, and contact time. Jacobs et al. (1980) pointed out that CO₂ has a dramatic effect on bitumen viscosity at the temperature less than 100ºC. Contact time is also an important factor to allow CO₂-oil system to achieve an equilibrium state because of the slow dissolution process of CO₂ into the oil system. The heavy oil recovery rate with which immiscible CO₂ contacted and displaced is limited by the diffusion rate of CO₂ in oil phase (Hara and Christman, 1993). Both laboratory experiments and field
applications support that enough contact time is required to maximize ultimate oil recovery in a CO₂ huff-n-puff process (Monger and Coma, 1988).

2.3.3 IFT reduction

Large quantities of residual oil remain in the reservoir rocks after waterflooding due to the fact that driving force is inadequate to expel oil trapped by capillary forces, resulting from IFT between any two immiscible phases in porous media. Extensive studies show that displacement efficiency under both oil-wet and water-wet conditions can be significantly improved by sufficiently reducing IFT (Mungan, 1964; Wagner and Leach, 1966).

The effect of low IFT as one of the CO₂ displacement mechanisms can be experimentally determined. The residual oil saturation was reduced from 37.4% to 25.0% of the total pore volume while the IFT was reduced from 24.8 to 0.105 dynes/cm by replacing waterflooding with CO₂ flooding (Rosman and Zana, 1977). In a CO₂ flooding process, IFT reduction is a function of CO₂ dissolution in the oil phase. In general, the equilibrium IFT is decreased as the pressure increases, whereas it is decreased with temperature. This is ascribed to the fact that dissolution of CO₂ in oil phase is increased with pressure and decreased with temperature, respectively (Yang et al., 2005). As for CO₂ injection, IFT reduction is more profound in light oil than heavy oil.
2.3.4 Light-components extraction

Hydrocarbon vaporization and diffusion in the CO\textsubscript{2} gas phase result in the well-known condensate recovery (Ravel and Anterion, 1985). Theoretical studies on increasing recovery in low permeability and naturally fractured reservoirs by CO\textsubscript{2} injection indicated the possibility of significant oil production by light-components extraction (Schechter and Guo, 1996). This phenomenon was further manifested by laboratory studies with the PVT cell system (Hand and val Pinczewski, 1990), semi-batch extraction system (Siagian and Grigg, 1998), and pendant drop system (Yang et al., 2005).

During CO\textsubscript{2} injection processes, the light-component extraction is dependent on pressure, temperature, and oil composition. Usually it is increased with an increase in pressure, whereas it is strongly affected by extraction temperature reversely (Siagian and Grigg, 1998). Lighter components (from propane to pentane) are more likely extracted than the heavier ones. In addition, the mole ratio of the CO\textsubscript{2} to oil also has an effect on the extraction capacity. Hand and val Pinczewski (1990) pointed out that the actual amount of extraction increases with increasing CO\textsubscript{2} volume and decreasing oil volume.

2.4 Scaled Model Studies

It is very difficult to bridge between theoretical multiphase flow systems and field applications for any given hydrocarbon reservoirs without introducing greatly simplifying assumptions, resulting in questionable conclusions (Rapoport, 1954). Laboratory investigations could compensate the deficiencies of analytical solutions,
though difficulties still remain that such measurements could be entirely misleading with respect to field applications, unless certain relationships must be satisfied between physical and geometric properties of the reservoir and laboratory systems (Nielsen and Tek, 1963; Loomis and Crowell, 1964).

Laboratory coreflooding is one of the most common methods to investigate certain EOR methods (e.g., solvent injection and polymer flooding) before they are implemented in the oilfields. Used as a small replica of the real reservoir, the core has many limitations on representing the properties of the reservoir (e.g., reservoir heterogeneity and lithology). In addition, accuracy of the displacement experiments (e.g., gas displacing oil) conducted within cores is often seriously affected by the capillary end effect (Huang and Honarpour, 1996). Also, many experimental issues associated with coreflooding tests including composite core-samples and high dead volume limit its capacity (Saeedi, 2012).

As for a tight oil reservoir, laboratory displacing tests on CO₂ flooding are limited to one-dimensional (1D) coreflooding, though 3D model may have unique advantages to be adopted to design well configurations (Ammer et al., 1991; Zheng and Yang, 2013). In addition, 3D model has been considered to be reasonably representative of the production behaviour of corresponding reservoirs if it is properly scaled (Geertsma et al., 1956; Loomis and Crowell, 1964; Rojas et al., 1991). However, the permeability of a 3D displacement model packed with sand cannot reach as low as that in a tight formation. As such, it is essential that scaling criteria be developed to design proper physical models that can represent a tight formation in a reasonable and scalable way.
As reservoir permeability of a heavy oil reservoir can be satisfied in 3D sandpacked models, displacing experiments of heavy oil by water, solvents, and polymer are conducted with sandpacked models to optimize the injection strategy and well configurations (Rojas, 1985; Wu et al., 2011; Zheng and Yang, 2013). However, whether the displacements performed with these 3D sandpacked models are capable of representing the reservoir fluid behaviours has yet to be answered.

Scaled model studies on petroleum reservoirs can be traced back to 1950s when Leverett et al. (1942) firstly published the basic theories for dimensional-model studies to investigate immiscible displacement of oil by water. Concerns of the scaled model technique have been focused on the fact that very coarse sand might limit the capacity of the sandpacked model to represent the relative permeability-saturation relations.

Rapoport (1954) developed the scaling laws for an incompressible, immiscible, and two-phase flow in a water-oil displacement process. Scaling groups have been derived from inspectional analysis. Difficulties have been raised on reproducing identical relative permeability and similar capillary pressure curves. Various model tests performed with different materials might be capable of studying waterflooding processes for a wide range of reservoir conditions. In turn, given a specific reservoir, its behaviour could be evaluated by interpolating the characteristics of this reservoir into the ranges covered by the scaled model studies.

Geertsma et al. (1956) extended the scaling theory to hot-water drive and solvent injection by using dimensional and inspectional analyses. Uniform porosity and permeability, and isotropic permeability have been assumed. Since not all the scaling groups can be satisfied in building a model, comprehensive discussions on which scaling
groups are negligible have been conducted. However, experimental studies need to be performed to verify the feasibility of neglecting some scaling groups. Van Daalen and van Domslaar (1972) derived the scaling groups by applying inspectional analysis to macroscopic displacement processes and pointed out that geometric factor (length to thickness ratio) can usually be neglected if no cross flow occurs.

Rojas (1985) performed scaled model studies for immiscible CO₂ flooding of heavy oil. A complete set of scaling groups has been derived by using dimensional and inspectional analyses, through selection of the scaling groups has yet to be made. In general, scaling groups are derived by using dimensional and inspectional analyses.

2.4.1 Dimensional analysis

Dimensional analysis was firstly adopted in developing dimensionless groups for the investigation of reservoir behaviour by Leverett et al. (1942). The first step in the dimensional analysis is to ascertain all the relevant variables that affect the flow behaviour. These variables can be arranged in a set of independent dimensionless groups by using the Buckingham’s π-theorem (Buckingham, 1914). This theorem states that dimensional variables that are relevant in a given problem can be grouped in a functional relationship which is equal to zero, i.e.,

\[ F(x_1, x_2, x_3, \ldots, x_n) = 0 \]  

[2-1]

where \( x_1 \) to \( x_n \) are \( n \) relevant variables in a given problem.

Proper usage of dimensional analysis requires that all the related variables are included. According to the Buckingham’s π-theorem, the number of the independent
dimensionless groups is equal to the total number of the variables minus the number of the basic dimensions (i.e., mass, length, time, and temperature).

2.4.2 Inspectional analysis

Inspectional analysis is based on the differential equations that govern the displacement. As such, all equations that describe the process of interest are combined to form a single differential equation of which the parameters form the dimensionless scaling groups (Loomis and Crowell, 1964). The equations describing flow behaviour in porous media are listed as follows (Geertsma et al., 1956):

(1). Conservation of basic quantities such as continuity equation, Darcy’s law, and thermal balance equation;

(2). Properties of single components which are dependent on pressure and temperature.

One advantage of the inspectional analysis is that the derived scaling groups have physical meanings comparing with those from dimensional analysis. Inspectional analysis was firstly adopted by Rapoport (1954) to derive a scaling relationship of immiscible displacement of oil by cold water. This work was extended by Geertsma et al. (1956) to hot waterflooding and miscible solvent injection processes, assuming that there is no cross flow between layers which simplified the derivation process. By following the procedure of inspectional analysis, Rojas et al. (1991) presented a set of scaling groups for immiscible CO₂ flooding of heavy oil. Mass transfer shall be taken into account due to dissolution, diffusion, and dispersion of CO₂ in oil and water phase.
2.4.3 Relaxation of scaling criteria

It is expected that all of the scaling groups from dimensional and inspectional analyses should be satisfied to obtain similarity between a model and its prototype. In practice, it is a challenging task to satisfy all scaling groups for designing a scaled model of a hydrocarbon reservoir (Geertsma et al., 1956; Craig et al., 1957; Doscher and Gharib, 1983). It is necessary and practical to neglect some scaling groups (e.g., Reynolds’ group) whenever possible. Many discussions have been made on which scaling group should be met while neglecting other unimportant ones (e.g., Geertsma et al., 1956; Loomis and Crowell, 1964).

(1) Geometric factor

To be capable of representing the flow behaviour of the prototype, a model must be firstly geometrically similar, requiring the scaling groups of \( \frac{L}{H} \) (length/thickness) and \( \frac{L}{W} \) (length/width) should be satisfied (Langhaar, 1951; Geertsma et al., 1956; Doscher and Gharib, 1983). Van Daalen and van Domslaar (1972) stated that geometrical similarity can be violated if no cross flow occurs in an immiscible displacement; otherwise, the aspect ratio becomes important and needs to be met.

(2) Driven forces

All the forces that affect the flow behaviour in the prototype should be known and scaling groups related to those forces should be satisfied, though this requirement has been extensively recognized to be unlikely satisfied (e.g., Geertsma et al., 1956; Craig et
A properly scaled model cannot be built unless those more important scaling groups are recognized and satisfied.

**Gravity force and viscous force:** Particularly in a post waterflooding process of recovering the residual oil by solvent gas injection, residual oil is recovered after mobile water is firstly displaced out (Doscher and Gharib, 1983). During this process, the applied pressure and innate buoyancy gradients (i.e., viscous force and gravity force) play an important role. Therefore, the scaling group of the ratio of gravity force to viscous force should be equal between a model and its prototype. However, Pozzi and Blackwell (1963) presented that the ratio of viscous force to gravity force need not be scaled if it falls in the range of lower and upper limits determined experimentally. Otherwise, the ratio must be identical between a model and its prototype.

**Capillary pressure:** Pujol and Boberg (1972) stated that, for highly viscous oil (viscosity higher than 100,000 cP), capillary pressure levels can be left unscaled because the ratio of capillary to viscous forces is so small that the unscaled capillary pressure imposes a negligible effect on the measured oil recovery. Neglecting capillary force unscaled for medium-viscous oil (viscosity less than 10,000 cP) might then lead to optimistic oil recovery values. Perkins and Collins (1960) demonstrated that it is possible to design unconsolidated models in which relative permeability and capillary pressure are different functions of saturation from the consolidated prototype.

Doscher and Gharib (1983) suggested that capillary pressure presents a serious problem in scaling of multiphase flow in porous media. This is because satisfying capillary pressure requires sacrificing the scaling of other important viscous and gravity forces. After quantifying the effect of capillary force on fluid flow in a simple
heterogeneous reservoir, Zhou et al. (1997) found that, for an immiscible displacement process, fluid flow transfers from viscous-dominated to capillary-dominated in the following range:

\[
0.35 \leq \left( \frac{\mu_w}{\mu_o} \frac{L P^* k_{sv}}{H^2 u_t \mu_o} \right) \left( 1 + \frac{\mu_w}{\mu_o} \right) < 4.1
\]  

[2-2]

where \( \mu_w \) and \( \mu_o \) are water and oil viscosity, respectively, Pa\( \cdot \)s; \( L \) and \( H \) are reservoir length and thickness, respectively, m; \( P^*_c \) is characteristic transverse capillary pressure, N/m\(^2\); \( k_{av} \) is average vertical permeability, m\(^2\); \( u_t \) is total Darcy flow velocity, m/s. Since it is difficult to determine the capillary pressure, the bound set by Eq. 2-2 for immiscible displacement may have a relative large uncertainty.

(3) Relative permeability

The relative permeability curves are usually quite different between unconsolidated sandpacks and consolidated reservoirs and violation of the necessary relationships could lead to significant deviations between reservoir and model performance (Nielsen and Tek, 1963). Bentsen (1976) suggested that mobility ratio is a more useful scaling group than relative permeability because using mobility ratio would result in the same end-points of the relative permeability functions between a model and its prototype, weakening the scaling requirement of unique relative permeability curves.
(4) Rock wettability

Rock wettability is another requirement that the laboratory model should have the same wettability as the consolidated reservoir. For the laboratory model packed with silica sand, Demetre et al. (1982) found that the silica sand is preferentially water wet if it is firstly contacted by water. If the sandpacked model is allowed to contact with reservoir fluids for a reasonable long period, it is expected to have similar wettability to that of the prototype (Rojas, 1985).

2.5 Summary

This chapter summarizes previous studies on unconventional resources together with waterflooding and CO₂ flooding to recover crude oil from both tight oil and heavy oil reservoirs. Due to limitations of coreflooding, the performance of 3D models on CO₂ EOR has been widely conducted through scaled models and its importance has been demonstrated. However, a comprehensive scaling theory needs to be developed for laboratory studies of waterflooding and immiscible CO₂ flooding in tight and heavy oil formations. Extensively attentions have been previously focused on scaled model studies in order to reveal fluid flow behaviours in a real reservoir by using the properly scaled models. The scaling groups derived from dimensional and inspectional analyses need to be relaxed because of difficulties on satisfying them simultaneously. The reliability of the scaled model according to the relaxed scaling criteria has been discussed in the literature, though many uncertainties of scaled model studies still need to be experimentally validated.
CHAPTER 3 DEVELOPMENT OF SCALING CRITERIA FOR FLUID FLOW IN TIGHT FORMATIONS

In this chapter, techniques have been developed to evaluate performance of waterflooding and CO₂ flooding in tight formations by using a 3D sandpacked displacement model. Experimentally, saturation pressures of the CO₂-light oil systems are determined with a versatile PVT system and then used to tune the binary interaction parameter (BIP) correlations between CO₂ and the lumped pseudo-components. Waterflooding and immiscible CO₂ flooding have been respectively conducted with light oil in the 3D physical model. Three major parameters including oil production rate, water-cut, and pressure drop are measured during the displacements. Theoretically, scaling criteria have been developed for waterflooding and immiscible CO₂ flooding by performing dimensional and inspectional analyses and then used for building the synthetic reservoir models with CMG GEM (version 2011.10, Computer Modelling Group Ltd.). The scaling criteria are validated by history matching the experimental measurements and simulation results of the synthetic reservoir, and then extended for field applications.
3.1 Mathematical Formulations

3.1.1 Dimensional analysis

In the dimensional analysis approach, all parameters involved in the waterflooding and immiscible CO₂ flooding should be considered (Buckingham, 1914). The following variables control the immiscible displacements of oil:

1. Geometrical dimensions: \( L, W, \) and \( H \) are length, width, and thickness of the formation, respectively; \( \alpha \) is the angle of dip, dimensionless (Loomis and Crowell, 1964);

2. Sand characteristics: \( k \) is the specific permeability; \( \phi \) is porosity; and \( M \) is the formation morphology factor (Rojas, 1985);

3. Fluid properties: \( \mu_o, \mu_w, \mu_g \) are viscosities of oil, water, and gas, respectively; \( g\Delta \rho_{ow} \) and \( g\Delta \rho_{og} \) are density differences between the displacing and displaced fluids multiplied by the force of gravity; \( \sigma_{go} \) and \( \sigma_{ow} \) are interfacial tensions for gas-oil and oil-water systems, respectively; usually, interfacial tension and the contact angle of wetting, \( \theta \), are combined as \( \sigma \cos \theta \) (Loomis and Crowell, 1964);

4. Variables to describe the mixing or microscopic dispersion: \( K_{gox}, K_{goy}, \) and \( K_{goz} \) are dispersion coefficients of gas in oil in \( x, y, \) and \( z \) directions, respectively (Rojas, 1985);

5. Variables which depend upon the interactions between reservoir fluids and rocks: \( k_{rg}, k_{ro}, \) and \( k_{rw} \) are relative permeability for gas, oil, and water phases,
respectively; \( J(S_g) \) and \( J(S_w) \) are Leverett \( J \)-functions of dimensionless gas and water saturations, respectively (Geertsma et al., 1956);

(6). Other variables: \( v \) is total or superficial velocity; \( \Delta p \) is pressure difference; according to Darcy’s law, \( v \) or \( \Delta p \) will be selected (Geertsma et al., 1956); \( t \) is time; \( T \) is temperature.

According to the theory of dimensional analysis, all the independent variables mentioned above could be grouped in a functional relationship equal to zero (Buckingham, 1914):

\[
\frac{f\left(L, W, H, \phi, M, k, \kappa_{rg}, \kappa_{rw}, \kappa_{rg}, \mu_g, \mu_w, g \Delta \rho_{tg}, g \Delta \rho_{tw}, \sigma_{go} \cos \theta, \sigma_{ow} \cos \theta, J(S_g), J(S_w), K_{gox}, K_{goy}, K_{gox}, \nu \text{ or } \Delta p, t, T\right)}{0}
\]

[3-1]

By applying the Buckingham’s \( \pi \)-theorem, 17 scaling groups are derived: \( \frac{L}{W}, \frac{L}{H}, \frac{k \Delta \rho_{wg}}{v \mu_w}, \frac{k \Delta \rho_{wg}}{v \mu_g}, \frac{\sqrt{k \phi \sigma_{go} \cos \theta}}{L \mu_g v}, \frac{\sqrt{k \phi \sigma_{ow} \cos \theta}}{L \mu_w v}, \frac{K_{gox}}{L v}, \frac{K_{goy}}{W v}, \frac{K_{gox}}{H v}, \phi, M, M_{wo}, M_{go}, J(S_g), J(S_w), T, \text{ and } \frac{\Delta pk}{\mu L^2}. \) Detailed derivations can be found elsewhere (Loomis and Crowell, 1964).

### 3.1.2 Inspectional analysis

As for inspectional analysis, all equations describing the behaviour of the process are combined to form a single equation. The coefficients of these equations are then combined to form the dimensionless scaling groups. In the immiscible displacements of oil by water and \( \text{CO}_2 \), the three phases are immiscible; however, \( \text{CO}_2 \) may exist as free or
solution gas. During the displacement processes, the reservoir is assumed to be at constant temperature, and the fluids are assumed to be in thermodynamic equilibrium throughout the reservoir. The continuity equations for the two immiscible phases of oil and water can be written as (Ertekin et al., 2001):

\[ \nabla \cdot \left( \frac{\bar{u}_o}{B_o} \right) = -\frac{\partial}{\partial t} \left( \frac{\phi S_o}{B_o} \right) \]  

for oil, and

\[ \nabla \cdot \left( \frac{\bar{u}_w}{B_w} \right) = -\frac{\partial}{\partial t} \left( \frac{\phi S_w}{B_w} \right) \]  

for water, where \( \bar{u}_o \) and \( \bar{u}_w \) are phase velocities of oil and water from Darcy’s law. \( B_o \) and \( B_w \) are formation volume factors (FVF) of oil and water.

If taking into account mass transfer between CO₂ and oil by molecular diffusion, dispersion, and solution, the equation of continuity of CO₂ is expressed as below (Rojas et al., 1991; Ertekin et al., 2001):

\[ \nabla \cdot \left[ \frac{\bar{u}_g}{B_g} + \frac{C_{go} \bar{u}_o}{B_o} - \frac{K_{go} \nabla C_{go}}{B_g} \right] = -\frac{\partial}{\partial t} \phi \left( \frac{S_g}{B_g} + \frac{C_{go} S_o}{B_g} \right) \]  

where \( \bar{u}_g \) is gas velocity from Darcy’s law; \( B_g \) is the FVF of gas; \( \overline{K}_{go} \) is the diagonal tensor of dispersion coefficient of CO₂ in oil phase; \( C_{go} \) is CO₂ concentration in oil phase.

The total saturation of the three phases is equal to one:

\[ S_o + S_w + S_g = 1 \]
Generally, water is wetting phase, gas is nonwetting phase, and oil is an intermediate wetting phase (Perkins and Johnston, 1963). Therefore, oil-water capillary pressure can be written as:

\[ P_{cw} = p_o - p_w \]  \[ 3-4a \]

and gas-oil capillary pressure is:

\[ P_{go} = p_g - p_o \]  \[ 3-4b \]

In order to normalize Eqs. 3-2a to 3-2c, normalized fluid saturations (Stone, 1970; Perkins and Collins, 1960), and time (Perkins and Collins, 1960), given by Eqs. 3-5a to 3-5d, will be adopted.

\[ S_{on} = \frac{S_o - S_{or}}{1 - S_{wi} - S_{or}} \]  \[ 3-5a \]

\[ S_{wn} = \frac{S_w - S_{wi}}{1 - S_{wi} - S_{or}} \]  \[ 3-5b \]

\[ S_{gn} = \frac{S_g - S_{gc}}{1 - S_{wi} - S_{or}} \]  \[ 3-5c \]

\[ t_n = \frac{v_t}{L\phi(1 - S_{wi} - S_{or})} \]  \[ 3-5d \]

Likewise, normalizing the total velocities along the three principal axes can be made possible by dividing the total velocity: \( f_x = v_x / v_t, f_y = v_y / v_t \), and \( f_z = v_z / v_t \).

To simplify the continuity equation, the derivatives of the reciprocal FVF (i.e., \( B_o, B_w \), and \( B_g \)) versus pressure are not expressed. Then, the continuity equations, i.e., Eqs 3-2a
to 3-2c, of oil, water, and gas could be rewritten as dimensionless forms (The detailed
derivation can be found in APPENDIX):

\[-\left( f_x \frac{\partial S_{\text{wn}}}{\partial \xi} + \frac{L}{W} f_y \frac{\partial S_{\text{wn}}}{\partial \eta} + \frac{L}{H} f_z \frac{\partial S_{\text{wn}}}{\partial \zeta} \right) \frac{d}{d S_{\text{wn}} \left( \frac{1}{F_o} \right)} - \frac{\sqrt{k \phi \sigma_{\text{ov}} \cos \theta}}{\mu_w v_t L} \]

\[\left[ \frac{\partial}{\partial \xi} \left( \frac{k_{\text{rw}} dJ}{F_o} \frac{\partial S_{\text{wn}}}{\partial \xi} \right) + \left( \frac{L}{W} \right)^2 \frac{\partial}{\partial \eta} \left( \frac{k_{\text{rw}} dJ}{F_o} \frac{\partial S_{\text{wn}}}{\partial \eta} \right) + \left( \frac{L}{H} \right)^2 \frac{\partial}{\partial \zeta} \left( \frac{k_{\text{rw}} dJ}{F_o} \frac{\partial S_{\text{wn}}}{\partial \zeta} \right) \right] \]

\[\frac{k_{rg} \sqrt{k \phi \sigma_{\text{go}} \cos \theta}}{\mu_g v_t L} \left[ \frac{\partial}{\partial \xi} \left( \frac{k_{\text{rg}} dJ}{F_o} \frac{\partial S_{\text{gn}}}{\partial \xi} \right) + \left( \frac{L}{W} \right)^2 \frac{\partial}{\partial \eta} \left( \frac{k_{\text{rg}} dJ}{F_o} \frac{\partial S_{\text{gn}}}{\partial \eta} \right) \right] + \left( \frac{L}{H} \right)^2 \frac{\partial}{\partial \zeta} \left( \frac{k_{\text{rg}} dJ}{F_o} \frac{\partial S_{\text{gn}}}{\partial \zeta} \right) \]

\[\frac{K_{\text{gux}}}{L v_t} \frac{\partial}{\partial \xi} \left( \frac{1}{F_o} \frac{\partial C_{\text{go}}}{\partial \xi} \right) + \frac{L}{W} \frac{K_{\text{guy}}}{W v_t} \frac{\partial}{\partial \eta} \left( \frac{1}{F_o} \frac{\partial C_{\text{go}}}{\partial \eta} \right) + \frac{L}{H} \frac{K_{\text{guz}}}{H v_t} \frac{\partial}{\partial \zeta} \left( \frac{1}{F_o} \frac{\partial C_{\text{go}}}{\partial \zeta} \right) = - \frac{\partial S_{\text{m}}}{\partial t_n} \]

for oil phase;

\[-\left( f_x \frac{\partial S_{\text{wn}}}{\partial \xi} + \frac{L}{W} f_y \frac{\partial S_{\text{wn}}}{\partial \eta} + \frac{L}{H} f_z \frac{\partial S_{\text{wn}}}{\partial \zeta} \right) \frac{d}{d S_{\text{wn}} \left( \frac{1}{F_w} \right)} + \frac{\sqrt{k \phi \sigma_{\text{ow}} \cos \theta}}{\mu_w v_t L} \]

\[\left[ \frac{\partial}{\partial \xi} \left( \frac{\mu_w}{F_w} \left( \frac{k_{\text{ro}}}{\mu_o} + \frac{k_{\text{rg}}}{\mu_g} \right) dJ \frac{\partial S_{\text{wn}}}{\partial \xi} \right) + \left( \frac{L}{W} \right)^2 \frac{\partial}{\partial \eta} \left( \frac{\mu_w}{F_w} \left( \frac{k_{\text{ro}}}{\mu_o} + \frac{k_{\text{rg}}}{\mu_g} \right) dJ \frac{\partial S_{\text{wn}}}{\partial \eta} \right) \right] \]

\[\frac{\sqrt{k \phi \sigma_{\text{go}} \cos \theta}}{\mu_g v_t L} \left[ \frac{\partial}{\partial \xi} \left( \frac{k_{\text{rg}} dJ}{F_w} \frac{\partial S_{\text{gn}}}{\partial \xi} \right) + \left( \frac{L}{W} \right)^2 \frac{\partial}{\partial \eta} \left( \frac{k_{\text{rg}} dJ}{F_w} \frac{\partial S_{\text{gn}}}{\partial \eta} \right) \right] + \left( \frac{L}{H} \right)^2 \frac{\partial}{\partial \zeta} \left( \frac{k_{\text{rg}} dJ}{F_w} \frac{\partial S_{\text{gn}}}{\partial \zeta} \right) \]

\[-\frac{k \Delta \rho_{\text{wog}}}{v_w \mu_w} \frac{\partial}{\partial \xi} \left( \frac{\mu_w}{F_w} \left( \frac{k_{\text{ro}}}{\mu_o} + \frac{k_{\text{rg}}}{\mu_g} \right) \frac{dJ}{F_w} \frac{\partial S_{\text{gn}}}{\partial \xi} \right) - \frac{k \Delta \rho_{\text{og}}}{v_g \mu_g} \frac{\partial}{\partial \xi} \left( \frac{k_{\text{rg}}}{F_w} \frac{\partial S_{\text{gn}}}{\partial \xi} \right) + \frac{K_{\text{gux}}}{L v_t} \frac{\partial}{\partial \xi} \left( \frac{1}{F_w} \frac{\partial C_{\text{go}}}{\partial \xi} \right) \]

\[\frac{L}{W} \frac{K_{\text{guy}}}{W v_t} \frac{\partial}{\partial \eta} \left( \frac{1}{F_w} \frac{\partial C_{\text{go}}}{\partial \eta} \right) + \frac{L}{H} \frac{K_{\text{guz}}}{H v_t} \frac{\partial}{\partial \zeta} \left( \frac{1}{F_w} \frac{\partial C_{\text{go}}}{\partial \zeta} \right) = - \frac{\partial S_{\text{wn}}}{\partial t_n} \]

for water phase; and
\[
- \left( f_x \frac{\partial S_{yn}}{\partial x} + \frac{L}{W} f_y \frac{\partial S_{yn}}{\partial y} + \frac{L}{H} f_z \frac{\partial S_{yn}}{\partial z} \right) \frac{d}{dS_{yn}} \left( \frac{1}{F_g} \right) \\
+ \left( \frac{k_{rw}}{\mu_w v_L} \right)^2 \frac{\partial \left( k_{rw} \frac{dJ}{\partial S_{yn}} \right)}{\partial x} + \left( \frac{L}{W} \right)^2 \frac{\partial \left( k_{rw} \frac{dJ}{\partial S_{yn}} \right)}{\partial y} + \left( \frac{L}{H} \right)^2 \frac{\partial \left( k_{rw} \frac{dJ}{\partial S_{yn}} \right)}{\partial z}
\]

\[
= \frac{\sqrt{k_0 \sigma_{ow}} \cos \theta}{\mu_o v_L} - \frac{\sqrt{k_0 \sigma_{go}} \cos \theta}{\mu_o v_L} - \frac{\sqrt{k_0 \sigma_{ow}} \cos \theta}{\mu_o v_L} - \frac{\sqrt{k_0 \sigma_{go}} \cos \theta}{\mu_o v_L}
\]

for gas phase,

where

\[
F_o = 1 + \frac{k_{rw} \mu_o}{k_{ro} \mu_w} + \frac{k_{rg} \mu_o}{k_{ro} \mu_g} ;
F_w = 1 + \frac{k_{ro} \mu_w}{k_{rw} \mu_o} + \frac{k_{rg} \mu_w}{k_{rw} \mu_g} ;
\]

and

\[
F_g = 1 + \frac{k_{ro} \mu_g}{k_{rg} \mu_o} + \frac{k_{rw} \mu_g}{k_{rg} \mu_w} .
\]

From the normalized fractional flow equation, the following dimensionless groups can be obtained:

\[
\frac{L}{W}, \frac{L}{H}, M_{wo}, M_{go}, \frac{k_{ro} \mu_o}{\mu_w}, \frac{k_{rg} \mu_o}{\mu_g}, \frac{k_{ro} \mu_w}{v_L L} + \frac{k_{rg} \mu_w}{v_L L}, \frac{\sqrt{k_0 \sigma_{ow}} \cos \theta}{\mu_o v_L}, \frac{\sqrt{k_0 \sigma_{go}} \cos \theta}{\mu_o v_L}, K_{gox}, K_{gov}, K_{gor}, \frac{dJ(S_{yn})}{dS_{yn}}, \frac{dJ(S_{gn})}{dS_{gn}}, v_I \frac{F_g}{F_g}, \frac{v_I}{v_L L} \frac{1}{L \phi (1 - S_{wi} - S_{or})}.
\]

A complete set of scaling groups could be obtained by combining the scaling groups from dimensional analysis and inspectional analysis, as shown in Table 3-1.
Table 3-1 A complete set of scaling groups derived by dimensional and inspectional analyses

<table>
<thead>
<tr>
<th>Scaling groups</th>
<th>Name</th>
<th>References</th>
</tr>
</thead>
<tbody>
<tr>
<td>$L/W$, $L/H$</td>
<td>Geometric factor</td>
<td>Geertsma et al., 1956</td>
</tr>
<tr>
<td>$M_{wo}$, $M_{go}$</td>
<td>Mobility ratio of water-oil and gas-oil systems</td>
<td>Bentsen, 1976</td>
</tr>
<tr>
<td>$k\Delta\rho_{wo}g/\nu_{w}\mu_{w}$</td>
<td>Gravitational to viscous forces of oil-water system</td>
<td>Geertsma et al., 1956</td>
</tr>
<tr>
<td>$k\Delta\rho_{og}g/\nu_{g}\mu_{g}$</td>
<td>Gravitational to viscous forces of gas-oil system</td>
<td>Geertsma et al., 1956</td>
</tr>
<tr>
<td>$\sqrt{k\phi}\sigma_{go}\cos\theta/L\mu_{g}\nu_{g}$</td>
<td>Capillary to viscous forces of gas-oil system</td>
<td>Geertsma et al., 1956</td>
</tr>
<tr>
<td>$\sqrt{k\phi}\sigma_{ow}\cos\theta/L\mu_{w}\nu_{w}$</td>
<td>Capillary to viscous forces of water-oil system</td>
<td>Geertsma et al., 1956</td>
</tr>
<tr>
<td>$K_{gox}/L\nu_{g}, K_{goy}/W_{g}, K_{goz}/H_{g}$</td>
<td>Dispersion groups of gas in oil phase</td>
<td>This study</td>
</tr>
<tr>
<td>$\phi$</td>
<td>Porosity</td>
<td>Geertsma et al., 1956</td>
</tr>
<tr>
<td>$M$</td>
<td>Morphology factor</td>
<td>Rojas and Farouq Ali, 1986</td>
</tr>
<tr>
<td>$k_{ro}$, $k_{rg}$, $k_{rw}$</td>
<td>Relative permeabilities</td>
<td>Geertsma et al., 1956</td>
</tr>
<tr>
<td>$j(S_{gn})$</td>
<td>Leverett $J$-function for gas-oil systems</td>
<td>Geertsma et al., 1956</td>
</tr>
<tr>
<td>$j(S_{wn})$</td>
<td>Leverett $J$-function for oil-water systems</td>
<td>Geertsma et al., 1956</td>
</tr>
<tr>
<td>$dJ(S_{wn})/dS_{wn}$</td>
<td>Slope of Leverett $J$-function for gas-oil systems</td>
<td>Geertsma et al., 1956</td>
</tr>
<tr>
<td>$dJ(S_{gw})/dS_{gw}$</td>
<td>Slope of Leverett $J$-function for oil-water systems</td>
<td>Geertsma et al., 1956</td>
</tr>
<tr>
<td>$T$</td>
<td>System temperature</td>
<td>This study</td>
</tr>
<tr>
<td>$t\Delta p k/\mu L^2$</td>
<td>Ratio of pressure forces to viscous forces</td>
<td>Geertsma et al., 1956</td>
</tr>
<tr>
<td>$\nu_{t}/L\phi(1-S_{wi}-S_{sw})$</td>
<td>Dimensionless time</td>
<td>Perkins and Collins, 1960</td>
</tr>
</tbody>
</table>
3.2 Relaxation of the Scaling Criteria

In general, models designed with the scaling criteria must be a replica in every necessary way of a real reservoir; however, the main problem encountered is that all the scaling criteria shall be satisfied simultaneously (Geertsma et al., 1956; Craig et al., 1957; Perkins and Johnston, 1963). In practice, it is necessary to eliminate one or more of the scaling groups if such groups are less important when comparing with those involved ones. This process is usually called the relaxation of scaling criteria. The relaxation of scaling criteria has been extensively discussed elsewhere (Geertsma et al., 1956; Bentsen, 1976; Doscher and Gharib, 1983). In this study, a similar procedure is followed for the relaxation of scaling criteria, provided that the following assumptions have been made:

(1). The reservoir is assumed to be homogeneous and bounded by impermeable layers.

(2). Molecular dispersion can be neglected when the fluid flow falls into a laminar flow region by injecting the fluid at a moderate flow rate (Perkins and Johnston, 1963).

3.2.1 Geometric factor

To be capable of representing the behaviour of a large prototype (R), the model (M) must first be geometrically similar (Langhaar, 1951):

\[
\left( \frac{L}{H} \right)_R = \left( \frac{L}{H} \right)_M \tag{3-7a}
\]

\[
\left( \frac{L}{W} \right)_R = \left( \frac{L}{W} \right)_M \tag{3-7b}
\]
where $L$ is length; $H$ is height; and $W$ is width.

Craig et al. (1957) stated that geometric similarity is negligible in frontal driven where mixing is unimportant since the displacements are dominated by viscous and gravitational forces. Pozzi and Blackwell (1963) suggested that geometric factor ($L/H$) be not required when mixing is important. In this study, geometric factor is included for scaling up CO$_2$ flooding processes, but excluded for waterflooding.

### 3.2.2 Gravitational force to viscous force ratio

The forces related to viscosity of the fluid and gravity control the displacement of oil. The two forces can be termed as viscous force and gravitational force, respectively. The ratio of gravitational force to viscous force which is defined as the gravity number (Sharma and Rao, 2008) should be the same between the prototype and the model:

$$
\left( \frac{k \Delta \rho g}{v \mu} \right)_R = \left( \frac{k \Delta \rho g}{v \mu} \right)_M
$$

[3-8]

In this study, the oil, water, and CO$_2$ used in the experiments are the same as those in the prototype. As such, Eq. 3-8 can be simplified to

$$\frac{v_M}{v_R} = \frac{k_M}{k_R}$$

[3-9]

From Eq. 3-9, it can be seen that when the gravity and viscous forces are considered as important ones, a perfectly scaled model of immiscible displacement requires fluid velocity increased in the model over that of the prototype by the same ratio as the permeability is increased in the model.
3.2.3 Capillary pressure and relative permeability

Since unconsolidated sands may have connate water and residual oil saturations are quite different from the consolidated reservoirs, scaling criteria pertaining to relative permeability and capillary pressure usually cannot be met (Loomis and Crowell, 1964). It has been experimentally demonstrated that capillary force has a negligible effect upon the gross movement of the displacing fluid (gas or water) and that flow behaviour in terms of sweep efficiency is only dependent on mobility ratio in the unconsolidated formations (Craig et al., 1957). Perkins and Collins (1960) demonstrated that it is possible to design unconsolidated models in which relative permeability and capillary pressure are different functions of saturation from the consolidated prototype. Doscher and Gharib (1983) stated that an inability of the scaled capillary pressure does not detract from the capability of the scaled model to reveal basic information about the displacement mechanism.

In this study, if the capillary force was taken into account, the ratio of capillary pressure to viscous force should be equal for a model and its prototype,

$$\left(\frac{\sqrt{k\phi\sigma \cos \theta}}{L\mu
u}\right)_M = \left(\frac{\sqrt{k\phi\sigma \cos \theta}}{L\mu
u}\right)_R$$ \[3-10\]

As the fluids used in the model are the same as that of the prototype, the requirement in Eq. 3-10 can be simplified to

$$\left(\frac{\sqrt{k\phi}}{L\nu}\right)_M = \left(\frac{\sqrt{k\phi}}{L\nu}\right)_R$$ \[3-11\]
The flow rate could be calculated with Stalkup’s suggestion (1983) that the proper width for average velocity is one-fifth of the distance between wells:

\[ q = \frac{\sqrt{2}}{5} LHv \]  

[3-12]

Substituting Eqs. 3-9 and 3-11 into Eq. 3-12, the relations of the flow rate between a model and its prototype could be expressed as

\[ q_M = \frac{\phi_M}{\phi_R} q_R \]  

[3-13]

As can be seen from Eq. 3-13, the injection rate will be the same magnitude as the flow rate of the prototype which is too large to be practically performed for laboratory measurements. Therefore, scaling criteria related to capillary forces has not been satisfied in the up-scaling process.

3.2.4 Diffusion and dispersion

Diffusion occurs as two immiscible fluids are in contact and diffuse into one another because of random motion of the molecules (Perkins and Johnston, 1963). Simultaneously, dispersion occurs in the porous media when additional mixing is caused by uneven fluids flow or concentration gradients. In a CO₂ flooding process, diffusion and dispersion may occur when CO₂ is made in contact with oil so that the forces related to diffusion and dispersion must be considered. The longitudinal and transverse dispersion coefficients can be calculated with the Perkins and Johnston equation (Perkins and Johnston, 1963). If the solvent is injected at a moderate flow rate, transverse
dispersion is characterized by a region in which transverse diffusion dominates (Perkins and Johnston, 1963). In this study, water and CO\textsubscript{2} injection rates are set to be 2.0 cm\textsuperscript{3}/min and 200.0 Scm\textsuperscript{3}/min, respectively. The calculated Reynolds numbers are 1.05\times10^{-4}, 2.90\times10^{-4}, and 3.56\times10^{-3} for light oil, brine, and CO\textsubscript{2}, respectively, ensuring that the flow falls into the diffusion-dominated region in this study, as shown in Figure 3-1. Thus the dispersion coefficient could be represented by the molecular diffusion coefficient \( D \). The dispersion groups of the gas in oil phase are replaced with \( D_{gxy}/Lv_t, D_{gxy}/Wv_t, D_{gxy}/Hv_t \). As diffusion coefficient is independent of direction, these foregoing groups could be simplified into

\[
\left( \frac{D}{v_tL} \right)_M = \left( \frac{D}{v_tL} \right)_R \tag{3-14}
\]

The diffusion coefficient is considered to be dependent on pressure, temperature and the concentrations of the solvents involved (Grogan \textit{et al.}, 1988; Yang and Gu, 2008). In this study, the diffusion coefficient is regarded as identical for the model and prototype when the fluids, pressure, and temperature are the same. When Eq. 3-14 is combined with Eq. 3-9, the requirements for scaling become

\[
\frac{v_M}{v_R} = \frac{k_M}{k_R} = \frac{L_R}{L_M} \tag{3-15}
\]
Figure 3-1 Flow regime characterizations for (a) Aqueous system, and (b) Gaseous system (Perkins and Johnston, 1963)
3.3 Experimental

3.3.1 Materials

The light oil and reservoir brine used in this study are collected from the Viewfield area of Bakken formation, Saskatchewan, Canada. As shown in Table 3-2, the density and viscosity of the dead oil at 20°C and atmospheric pressure are 801.2 kg/m³ and 2.17 cP, respectively. Compositional analysis results of the dead oil are tabulated in Table 3-3. As can be seen, the major components of the oil sample are lighter than \( C_{20+} \), which account for 75.33 wt% of the oil sample. In this study, synthetic brine is prepared according to the measured composition of reservoir brine as shown in Table 3-4.

In this study, research grade CO₂ with a purity of 99.998 mol% is purchased from the Praxair, Canada. To minimize the permeability of the sandpack model, the Ottawa sand #710 (Bell & Mackenzie, Canada) and glassbeads #13 (Potters Industries LLC, USA) are combined to pack the 3D physical model and their screen analyses are listed in Tables 3-5 and 3-6, respectively.

3.3.2 Experimental setup

(1) PVT system

To measure saturation pressure for the CO₂-light oil system, a mercury-free DBR PVT system (PVT-0150-100-200-316-155, DBR, Canada) is used to perform the pressure-volume-temperature (PVT) measurements. The schematic diagram of the DBR PVT system (see Figure 3-2) is mainly comprised of a visual high-pressure PVT cell that has an inner diameter and length of 3.177 and 20.320 cm, respectively. The PVT cell is
**Table 3-2** Physical properties of light oil sample

<table>
<thead>
<tr>
<th>Property</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Density, kg/m(^3)</td>
<td></td>
</tr>
<tr>
<td>at 15°C</td>
<td>805.0</td>
</tr>
<tr>
<td>at 20°C</td>
<td>801.2</td>
</tr>
<tr>
<td>at 30°C</td>
<td>793.1</td>
</tr>
<tr>
<td>Viscosity, cP</td>
<td></td>
</tr>
<tr>
<td>at 15°C</td>
<td>2.54</td>
</tr>
<tr>
<td>at 20°C</td>
<td>2.17</td>
</tr>
<tr>
<td>at 30°C</td>
<td>2.22</td>
</tr>
<tr>
<td>Acid number, mg-KOH/g</td>
<td>0.4</td>
</tr>
<tr>
<td>Molecular weight, g/mol</td>
<td>162</td>
</tr>
</tbody>
</table>

Note: Measured by the Saskatchewan Research Council (SRC), Canada.
### Table 3-3 Compositional analysis of the light oil sample

<table>
<thead>
<tr>
<th>Components</th>
<th>wt%</th>
<th>mol%</th>
<th>Components</th>
<th>wt%</th>
<th>mol%</th>
<th>Components</th>
<th>wt%</th>
<th>mol%</th>
</tr>
</thead>
<tbody>
<tr>
<td>C1</td>
<td>0.00</td>
<td>0.00</td>
<td>C8</td>
<td>11.96</td>
<td>16.16</td>
<td>C20</td>
<td>2.22</td>
<td>1.21</td>
</tr>
<tr>
<td>C2</td>
<td>0.48</td>
<td>2.46</td>
<td>C9</td>
<td>4.55</td>
<td>5.47</td>
<td>C21</td>
<td>2.42</td>
<td>1.26</td>
</tr>
<tr>
<td>C3</td>
<td>0.31</td>
<td>1.09</td>
<td>C10</td>
<td>5.60</td>
<td>6.07</td>
<td>C22</td>
<td>1.43</td>
<td>0.71</td>
</tr>
<tr>
<td>i-C4</td>
<td>0.00</td>
<td>0.00</td>
<td>C11</td>
<td>4.89</td>
<td>4.83</td>
<td>C23</td>
<td>1.79</td>
<td>0.85</td>
</tr>
<tr>
<td>n-C4</td>
<td>1.72</td>
<td>4.57</td>
<td>C12</td>
<td>4.59</td>
<td>4.16</td>
<td>C24</td>
<td>1.53</td>
<td>0.70</td>
</tr>
<tr>
<td>i-C5</td>
<td>1.08</td>
<td>2.31</td>
<td>C13</td>
<td>4.39</td>
<td>3.67</td>
<td>C25</td>
<td>1.46</td>
<td>0.64</td>
</tr>
<tr>
<td>n-C5</td>
<td>2.02</td>
<td>4.32</td>
<td>C14</td>
<td>3.77</td>
<td>2.93</td>
<td>C26</td>
<td>1.31</td>
<td>0.55</td>
</tr>
<tr>
<td>other C5</td>
<td>0.24</td>
<td>0.51</td>
<td>C15</td>
<td>3.91</td>
<td>2.84</td>
<td>C27</td>
<td>1.19</td>
<td>0.48</td>
</tr>
<tr>
<td>i-C6</td>
<td>1.74</td>
<td>3.12</td>
<td>C16</td>
<td>3.22</td>
<td>2.19</td>
<td>C28</td>
<td>1.11</td>
<td>0.43</td>
</tr>
<tr>
<td>n-C6</td>
<td>1.70</td>
<td>3.04</td>
<td>C17</td>
<td>3.01</td>
<td>1.93</td>
<td>C29</td>
<td>0.92</td>
<td>0.35</td>
</tr>
<tr>
<td>Other C6</td>
<td>1.91</td>
<td>3.42</td>
<td>C18</td>
<td>2.93</td>
<td>1.78</td>
<td>C30</td>
<td>0.79</td>
<td>0.29</td>
</tr>
<tr>
<td>C7</td>
<td>7.63</td>
<td>11.75</td>
<td>C19</td>
<td>2.48</td>
<td>1.43</td>
<td>C30+</td>
<td>10.51</td>
<td>2.48</td>
</tr>
</tbody>
</table>

**Total** | 100.00 | 100.00

Note: Measured by the Saskatchewan Research Council (SRC), Canada.
**Table 3-4** Properties of reservoir brine

<table>
<thead>
<tr>
<th>Property</th>
<th>Value</th>
<th>Major components</th>
<th>mg/l</th>
</tr>
</thead>
<tbody>
<tr>
<td>Density, kg/m³</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>at 15°C</td>
<td>1,110.2</td>
<td>Chloride</td>
<td>94,340</td>
</tr>
<tr>
<td>at 20°C</td>
<td>1,108.7</td>
<td>Sulphate</td>
<td>4,100</td>
</tr>
<tr>
<td>at 40°C</td>
<td>1,099.6</td>
<td>Sodium</td>
<td>56,200</td>
</tr>
<tr>
<td>Viscosity, cP</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>at 15°C</td>
<td>1.41</td>
<td>Potassium</td>
<td>1,500</td>
</tr>
<tr>
<td>at 20°C</td>
<td>1.24</td>
<td>Magnesium</td>
<td>460</td>
</tr>
<tr>
<td>at 40°C</td>
<td>0.85</td>
<td>Calcium</td>
<td>1,900</td>
</tr>
<tr>
<td>Refractive index</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>at 25°C</td>
<td>1.359</td>
<td>Iron</td>
<td>1</td>
</tr>
<tr>
<td>Conductivity, mS/m</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>at 25°C</td>
<td>125.4</td>
<td>Barium</td>
<td>0.25</td>
</tr>
<tr>
<td>pH</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>at 25°C</td>
<td>6.87</td>
<td>Manganese</td>
<td>0.61</td>
</tr>
</tbody>
</table>

Note: Measured by the Saskatchewan Research Council (SRC), Canada.
## Table 3-5 Typical screen analysis of #710 silica sand

<table>
<thead>
<tr>
<th>U.S. sieve, mesh</th>
<th>% retained</th>
</tr>
</thead>
<tbody>
<tr>
<td>40</td>
<td>Trace</td>
</tr>
<tr>
<td>50</td>
<td>0.30</td>
</tr>
<tr>
<td>70</td>
<td>7.00</td>
</tr>
<tr>
<td>100</td>
<td>52.00</td>
</tr>
<tr>
<td>140</td>
<td>32.00</td>
</tr>
<tr>
<td>200</td>
<td>8.00</td>
</tr>
<tr>
<td>270</td>
<td>0.70</td>
</tr>
</tbody>
</table>
Table 3-6 Typical screen analysis of #13 glassbeads

<table>
<thead>
<tr>
<th>U.S. sieve, mesh</th>
<th>% retained</th>
</tr>
</thead>
<tbody>
<tr>
<td>140</td>
<td>0.00</td>
</tr>
<tr>
<td>170</td>
<td>4.70</td>
</tr>
<tr>
<td>325</td>
<td>91.61</td>
</tr>
<tr>
<td>400</td>
<td>3.05</td>
</tr>
<tr>
<td>400+</td>
<td>0.64</td>
</tr>
</tbody>
</table>
Figure 3-2 Schematic of the PVT setup
capable of operating at a maximum pressure of 69 MPa and a temperature range of 283.15-473.15 K. Inside the PVT cell, a floating piston is used to isolate the testing mixture from the hydraulic oil which can be driven downward and upward by a high-pressure automatic positive displacement pump (PMP-0500-1-10-MB-316-M4-C0, DBR, Canada). A magnetic mixer is equipped at the bottom of the PVT cell to stir the CO₂-light oil mixture for sufficient mixing. Meanwhile, a video-based digital cathetometer with a measuring resolution of 0.002 cm is used to measure the volume of the fluids. A pressure gauge (2089, Ashcroft, USA) with an accuracy of 0.05% of full scale of 13,790 kPa is installed at the inlet of the PVT cell to measure the system pressure. The air bath temperature is controlled by a microprocessor-based controller and a resistance temperature device sensor at an accuracy of within ±0.1 K.

(2) 3D displacement model

The schematic diagram and its digital image of the 3D displacement model is shown in Figure 3-3. This setup mainly includes three subsystems, i.e., injection subsystem, displacement subsystem, and production subsystem. The fluid injection subsystem is used to supply CO₂ and brine, respectively. The CO₂ injection system includes a CO₂ cylinder, a gas regulator, a CO₂ flow meter (XFM17S, Aalborg, USA) and a digital pressure gauge, while the displacement subsystem contains a high pressure syringe pump (500 HP, Teledyne ISCO Inc., USA) and a transfer cylinder (500 cm³ and 5,000 psi). The CO₂ cylinder is used to provide continuous CO₂ supply, while the synthetic brine is introduced from the transfer cylinder to the physical model by using the syringe pump at a constant flow rate. The accuracy of the CO₂ flow meter can be calculated by using Eq.
Figure 3-3 3D experimental setup: (a) Schematic diagram; and (b) Digital image.

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\[ \epsilon_{\text{total}} = \pm (c_p \cdot p + c_T \cdot T) \]  

where \( \epsilon_{\text{total}} \) is the total error coefficient, \% of full scale (FS); \( c_p \) is pressure coefficient, 0.01\% of FS/psia; \( c_T \) is temperature coefficient, 0.015\% of FS/°C; \( p \) is CO\(_2\) pressure at the flow meter, psi; and \( T \) is test temperature, °C. The accuracy of CO\(_2\) flowrate in this study is calculated to be \( \pm 3.19\% \) of FS under the experimental temperature and pressure of 19.5°C and 2,000 kPa, respectively.

The 3D displacement subsystem consists of five vertical wells and three horizontal wells with an inside dimension of 30.4 cm × 30.4 cm × 12.7 cm. The maximum operational pressure for the 3D physical model is 6 MPa at room temperature. All the wells with a diameter of 0.635 cm are perforated to allow fluids flow, while they are wrapped with a 400 × 400 mesh wire-screen (Ferrier Wire Goods, Canada) to prevent sand production during the displacements. During the displacements, the pressure drop is measured by two digital pressure gauges (DPG 8001-500, Omega, USA) with an accuracy of \( \pm 0.1\% \) of test gauge.

The production subsystem is comprised of two digital pressure gauges, a back pressure regulator (BPR) (EB1HP1, Equilibar, USA), an oil-gas separator, and a CO\(_2\) flow meter. The BPR is used to maintain a pre-specified pressure inside the physical model during each displacement on which the reference pressure is exerted with a syringe pump. The separated gas is measured by using the gas flow meter before being exhausted to the atmosphere, while the produced liquids are collected with conical-bottom glass centrifuge tubes (Kimble, USA). During each test, the injected and
produced CO$_2$ flow rate can be recorded and stored in a desktop computer, while the total produced gas volume is read directly from the CO$_2$ flow meter (XFM17S, Aalborg, USA).

3.3.3 Experimental preparation

(1) Sand-packing

After the wells being prepared and located at designated positions, the physical model is placed horizontally prior to filling the void space with Ottawa #710 sand and/or glassbeads #13. In the water flooding, a combination of Ottawa #710 and glassbeads #13 (volume ratio is 2:1) has been used to get a lower permeability. In the CO$_2$ flooding process, only Ottawa #710 is used. Once being fully packed, the physical model is shaken with a pneumatic vibrator (NP 35, Northern Vibrator, USA) for at least 12 h. During the vibration, more sands will be added into the void space wherever necessary. Once fully and tightly packed, the lid is covered and tightened with 28 bolts so that the 3D physical model is ready for experimental displacements.

(2) Porosity measurement

Two different methods are used to calculate the porosity of the 3D physical model. The first method is called the imbibition method. Firstly, the physical model is connected to a vacuum pump (M12C, Fisher Scientific, Canada) through one of the wells. The pressure in the physical model will be evacuated to as low as −92.0 kPa for 12 h via a valve. Secondly, once completed, the valve is closed so that the physical model is disconnected...
from the vacuum pump. Then, the physical model is connected to a tube which is submerged into a container filled with certain volume of the synthetic brine. Once the valve is turned on, the brine imbibes into the model. Subsequently, the volume of the remaining brine in the container is measured. As such, the volume of brine imbibed into the model can be considered as the pore volume which is used to calculate the porosity. On the other hand, porosity of the physical model can also be calculated once the model is packed with the sand when its density and volume has been measured. Usually, the latter is more accurate for the existence of trace air within the pore. The porosities are determined to be 33.20%, 34.94%, and 36.90% of pore volume (PV) for waterflooding, CO₂ flooding and CO₂-WAG, respectively.

(3) Permeability measurement

The 3D physical model is placed horizontally while two diagonally opposite vertical wells are chosen as an injector and a producer to measure absolute permeability. The 3D sandpacked model was initially saturated with the synthetic brine. Then, the water bucket is set at a certain height and the brine is allowed to flow from the injector to the producer by the potential energy. The volume flowrate of the brine is measured using a centrifuge tube (100 cm³) and a stop watch after the flowrate is stable, while the height difference between the brine surface in the bucket and the producing outlet is recorded. During the test, usually three different flow rates under three heights are measured so that the flowrate and height difference are averaged to minimize the error of measurement. Then, the CMG IMEX module (version 2011.10) is used to determine absolute permeability by history matching the production profile. The simulated absolute permeabilities for
waterflooding, CO₂ flooding, and CO₂-WAG flooding are 910, 1,070, and 1,150 mD, respectively.

(4) Saturating oil

After absolute permeability has been determined, the light oil sample is introduced to the physical model through the wells from a transfer cylinder with a syringe pump. The saturating process is terminated when no more water is displaced out. This means that the model has been saturated with light oil sample to ensure reasonable initial oil saturation under immobile water saturation. The initial oil saturation is calculated as the volume of oil divided by the pore volume of the physical model. After oil saturating process, the model is aged for 24 h to equilibrate the distribution of fluids (Zheng and Yang, 2013).

3.3.4 Experimental procedures

(1) Saturation pressure measurement

Prior to each test, the PVT cell and fluid handling tubing are thoroughly cleaned with kerosene, flushed with air and finally evacuated by using a vacuum pump (M12C, Fisher Scientific, Canada) to remove all traces of kerosene and air. In addition, the temperature of the air bath is set to the desired value for 12 h to ensure the sample cylinders and the PVT cell are able to reach the preset constant pressure prior to any measurements. As for CO₂-light oil system, the experimental procedures are briefly described as follows.
The density of the liquid CO₂ in the PVT cell can be determined from correlations in the following form (Yaws, 2003).

\[
\log_{10} \left( \frac{\rho_s}{1000} \right) = \log_{10}(h) - \log_{10}(l) \left( 1 - \frac{T}{T_c} \right)^n
\]  

[3-17]

where \( \rho_s \) is density of the liquid solvent in kg/m³; \( T \) is temperature, K; \( T_c \) is the critical temperature of the solvent, K; and \( h, l, n \) are the coefficients with the corresponding values of 0.4638, 0.2616, and 0.2903 for CO₂, respectively. At the experimental temperature of 19.5 ºC and pressure of 1,100 psi, the density of liquid CO₂ is calculated to be 779.20 kg/m³.

The volume of the liquid CO₂ is measured by using the cathetometer, and thus the mass of the CO₂ can be obtained. The magnetic mixer is switched on after CO₂ is injected into the PVT cell. A certain amount of light oil is then added into the PVT cell by maintaining a constant pressure in the PVT cell, ensuring the mixture is in the liquid phase. The volume of light oil added is determined to be the total volume reading from the cathetometer minus the CO₂ volume, assuming that there is no volume change due to mixing of CO₂ and light oil since the volume measurement is conducted right after the light oil injection. The mass of the added light oil can be then determined after its density is measured. The CO₂-light oil mixture is vigorously stirred for 6 h prior to any further measurements.

In this study, continuous depressurization method (Badamchi-Zadeh et al., 2009; Memon et al., 2010) has been adopted for determining the saturation pressure of CO₂-light oil system. By continuously depressurizing the pressure of PVT cell and recording
the corresponding volume, a pressure-volume relationship curve can be obtained. In this study, a withdrawal rate of 3 cm$^3$/h is used (Li et al., 2013). The saturation pressure is determined by locating the transitioning point on the pressure-volume curve. It is worthwhile noting that, the magnetic stirrer is always kept on to rigorously stir the CO$_2$-light oil mixture in order to significantly shorten the time for the mixture to reach its equilibrium state. After the measurement of one concentration of CO$_2$ to light oil is completed, a certain amount of additional oil is injected into the PVT cell and the measurement of saturation pressure is repeated. In this study, saturation pressures of three different concentrations of CO$_2$ to light oil (mol% of CO$_2$ are 39.89, 32.33, and 25.48, respectively) at 19.5ºC are experimentally measured.

(2) Displacement experiments

Waterflooding: The synthetic brine is injected into the 3D physical model at a constant rate of 2 cm$^3$/min, while water injection is terminated once no more oil is produced. For waterflooding, the system pressure is maintained at 2.0 MPa. The produced liquids are collected and measured with conical-bottom glass centrifuge tubes (Kimble, USA). The injection and production pressures are measured by two digital pressure gauges (DPG 8001-500, Omega, USA) with an accuracy of ±0.1% of test gauge.

CO$_2$ flooding: CO$_2$ is introduced into the physical model from a CO$_2$ cylinder where a gas regulator is used to control the flow rate at a relatively stable value of 200 Scm$^3$/min by using the regulator. Similarly, once there is no more oil production, the flooding process is terminated. The system pressure is maintained at 2.0 MPa. As mentioned
previously, the separated gas is measured by using the gas flow meter before being exhausted to the atmosphere, while the produced liquids are collected and measured with conical-bottom glass centrifuge tubes (Kimble, USA). During test, the injected and produced CO₂ flow rate can be recorded and stored in a desktop computer, while the total produced gas volume is read directly from the CO₂ flow meter (XFM17S, Aalborg, USA).

**CO₂-WAG flooding**: To examine the effects of interrupting continuous CO₂ injection by waterflooding, CO₂-WAG flooding has been conducted with the 3D sandpacked model. In the experiment, CO₂-WAG flooding was followed after waterflooding. Similar to the waterflooding and continuous CO₂ flooding, the system pressure is maintained at 2.0 MPa and the injection rates of water and CO₂ are controlled at 2.0 cm³/min and 200 Scm³/min, respectively.

### 3.4 Numerical Simulation

To validate the scaling criteria and obtain a better understanding on the mechanisms governing waterflooding and immiscible CO₂ flooding in tight formations, history matching technique has been used to obtain relative permeability and capillary pressure curves of the sandpack displacements. Subsequently, CMG GEM module (version 2011.10) is used to build synthetic models for validating the relaxed scaling criteria, and then applied to a field case.
3.4.1 History matching

To simulate the experimental displacement of tight oil via waterflooding and immiscible CO₂ flooding processes, a compositional reservoir simulator CMG GEM module is used for simulation while history matching technique is selected to tune the relative permeability curves. A grid system of $11 \times 11 \times 4$ gridblock is applied for both waterflooding and CO₂ flooding. Meanwhile, homogeneous distribution of oil saturation, porosity, and absolute permeability are assigned to each model.

The CMG WinProp module (version 2011.10) is used to lump the light oil components into 7 pseudo-components. The measured saturation pressures of the CO₂-light oil systems are used to tune the binary interaction parameter (BIP) correlations between CO₂ and the lumped pseudo-components. Finally, a PVT model compatible with GEM compositional simulator is generated and incorporated into the displacement model.

3.4.2 Validation of scaling criteria

To validate the scaling criteria for waterflooding and immiscible CO₂ flooding, synthetic reservoir models are built with the CMG GEM module by correspondingly scaling up the experimental models. Table 3-7 tabulates the comparison of the experimental and synthetic reservoir models. By using the CMG GEM simulator, a grid system of $11 \times 11 \times 4$ gridblock is applied throughout the simulations, though the dimension of each model varies for two scenarios (i.e., $276.6 \times 276.6 \times 115.6$ m for waterflooding and $325.3 \times 325.3 \times 135.9$ m for CO₂ flooding). Meanwhile, the homogeneous distribution of oil
Table 3-7 Properties of the scaled theoretical reservoir and physical model for waterflooding and CO₂ flooding

<table>
<thead>
<tr>
<th>Properties</th>
<th>Waterflooding</th>
<th>CO₂ flooding</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Synthetic reservoir</td>
<td>Sandpack #1</td>
</tr>
<tr>
<td>Well radius, m</td>
<td>0.0762</td>
<td>0.0032</td>
</tr>
<tr>
<td>Length (=width), m</td>
<td>276.64</td>
<td>0.304</td>
</tr>
<tr>
<td>Thickness, m</td>
<td>115.57</td>
<td>0.127</td>
</tr>
<tr>
<td>Permeability, mD</td>
<td>1</td>
<td>910</td>
</tr>
<tr>
<td>Porosity</td>
<td>0.1400</td>
<td>0.3320</td>
</tr>
<tr>
<td>Angle of dip</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Viscosity of oil, cP</td>
<td>2.5</td>
<td>2.5</td>
</tr>
<tr>
<td>Viscosity of water, cP</td>
<td>1.24</td>
<td>1.24</td>
</tr>
<tr>
<td>Density of oil, g/cm³</td>
<td>0.804</td>
<td>0.804</td>
</tr>
<tr>
<td>Density of water, g/cm³</td>
<td>1.108</td>
<td>1.108</td>
</tr>
<tr>
<td>Water injection rate</td>
<td>2.6 m³/day</td>
<td>2.0 cm³/min</td>
</tr>
<tr>
<td>CO₂ injection rate, SC</td>
<td>N/A</td>
<td>N/A</td>
</tr>
<tr>
<td>Temperatures, ºC</td>
<td>19.5</td>
<td>19.5</td>
</tr>
</tbody>
</table>
saturation, porosity, and absolute permeability are assigned to each model. A synthetic reservoir model for CO₂ flooding is shown in Figure 3-4. The relative permeability curves tuned in history matching process are used for the synthetic reservoir model. Since the permeability is down scaled for synthetic reservoir model, the capillary pressure curves are tuned to history match the experimental measurements.

### 3.4.3 Field application

To further apply the scaling criteria for immiscible displacement of light oil in tight formations, a real reservoir model is employed to perform the simulation task. The prototype model selected is a tight oil formation in the Bakken field located in the south Saskatchewan, Canada (Song, 2013). Usually in numerical simulation process, the study area could be a well pattern within a reservoir (Memon et al., 2010). A region with 600 × 600 m with a net pay thickness of 9.24-9.34 m is used for the numerical simulation. The permeability of the formation matrix ranges from 0.12 to 0.66 mD, while the porosity has a range of 4.0-5.0%. The initial water saturation is 20%, with initial reservoir pressure and temperature of 27.7 MPa and 63°C, respectively. The physical properties and compositional analysis of reservoir oil and brine can be referred to Tables 3-2 to 3-4.

As the reservoir pressure and temperature varying far from the experimental conditions, field application has been conducted for waterflooding of tight oil to alleviate the pressure and temperature effects on fluid phase behaviours. Table 3-8 shows the comparison of the experimental and field models. Pozzi and Blackwell (1963) stated that geometric similarity is negligible if the ratio of gravitational to viscous forces
Figure 3-4 A 3D view of synthetic reservoir model for CO₂ flooding
Table 3-8 Properties of the field model and sandpacked model for waterflooding

<table>
<thead>
<tr>
<th>Properties</th>
<th>Sandpack</th>
<th>Reservoir</th>
</tr>
</thead>
<tbody>
<tr>
<td>Well radius, m</td>
<td>0.0032</td>
<td>0.0762</td>
</tr>
<tr>
<td>Length (=width), m</td>
<td>0.3</td>
<td>600.0</td>
</tr>
<tr>
<td>Thickness, m</td>
<td>0.1</td>
<td>9.3</td>
</tr>
<tr>
<td>Permeability, mD</td>
<td>910.0</td>
<td>0.5</td>
</tr>
<tr>
<td>Porosity</td>
<td>0.33</td>
<td>0.05</td>
</tr>
<tr>
<td>Angle of dip</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Viscosity of oil, cP</td>
<td>2.5</td>
<td>2.2</td>
</tr>
<tr>
<td>Viscosity of water, cP</td>
<td>1.24</td>
<td>1.24</td>
</tr>
<tr>
<td>Density of oil, g/cm³</td>
<td>0.804</td>
<td>0.801</td>
</tr>
<tr>
<td>Density of water, g/cm³</td>
<td>1.108</td>
<td>1.108</td>
</tr>
<tr>
<td>Rate of water injection</td>
<td>2.0 cm³/min</td>
<td>5.2 m³/day</td>
</tr>
<tr>
<td>Temperatures, °C</td>
<td>19.5</td>
<td>63.0</td>
</tr>
</tbody>
</table>
is scaled. In this study, the geometric factor \((L/H)\) is not satisfied in the field application and its impact on the capability of the scaling criteria will be discussed.

By using the CMG GEM module, a grid system of \(30 \times 30 \times 1\) gridblock is employed for the field model. Meanwhile, homogeneous distribution of oil saturation is assigned to the model. Figure 3-5 shows a 3D view of the field model. Similar to the experiment, an injector and a producer are drilled at the two corners to simulate a quarter of five-spot flooding pattern. The injection rate and operation time are scaled up accordingly with the scaling criteria determined previously are listed in Table 3-8.

3.5 Results and Discussion

3.5.1 Saturation pressure

Three CO\(_2\)-light oil systems have been tested in this study. Figure 3-6 shows the measured \(P-V\) relations by using continuous depressurization method for (a) Feed #1 (60.11 mol\% light oil, 39.89 mol\% CO\(_2\)); (b) Feed #2 (67.67 mol\% light oil, 32.33 mol\% CO\(_2\)); and (c) Feed #3 (74.52 mol\% light oil, 25.48 mol\% CO\(_2\)) at temperature of 292.65 K. The measured saturation pressures for these three feeds are 371.27, 359.66, and 275.55 psi, respectively. As can be seen, saturation pressure increases with CO\(_2\) solubility in light oil. The measured saturation pressures are incorporated into WinProp simulator to regress the BIPs between CO\(_2\) and 7 lumped pseudo-components. The regressed BIPs are tabulated in Table 3-9.
Figure 3-5 A 3D view of real reservoir model
### Table 3-9 Lumped pseudo-components and the BIPs with CO₂

<table>
<thead>
<tr>
<th>No.</th>
<th>Pseudo-components</th>
<th>$p_c$, atm</th>
<th>$T_c$, K</th>
<th>BIPs with CO₂</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>C₁ – C₄</td>
<td>41.2044</td>
<td>385.6539</td>
<td>0.130673</td>
</tr>
<tr>
<td>2</td>
<td>C₅ – C₆</td>
<td>32.2255</td>
<td>490.5220</td>
<td>0.134766</td>
</tr>
<tr>
<td>3</td>
<td>C₇ – C₁₀</td>
<td>28.6421</td>
<td>575.3447</td>
<td>0.229173</td>
</tr>
<tr>
<td>4</td>
<td>C₁₁ – C₁₅</td>
<td>20.8138</td>
<td>677.6815</td>
<td>0.000123</td>
</tr>
<tr>
<td>5</td>
<td>C₁₆ – C₂₀</td>
<td>15.8736</td>
<td>756.6887</td>
<td>0.150000</td>
</tr>
<tr>
<td>6</td>
<td>C₂₁ – C₂₆</td>
<td>12.7803</td>
<td>814.3992</td>
<td>0.150020</td>
</tr>
<tr>
<td>7</td>
<td>C₂₇ – C₃₀⁺</td>
<td>7.8835</td>
<td>949.0099</td>
<td>0.000002</td>
</tr>
</tbody>
</table>
Figure 3-6 $P-V$ relations measured by the continuous depressurization method for (a) Feed #1 (60.11 mol% light oil, 39.89 mol% CO$_2$); (b) Feed #2 (67.67 mol% light oil, 32.33 mol% CO$_2$); and (c) Feed #3 (74.52 mol% light oil, 25.48 mol% CO$_2$) at 292.65 K
3.5.2 Experimental displacements

(1) Waterflooding

Figure 3-7 shows the measured oil recovery and water-cut, respectively. As can be seen, at the beginning of the displacement, oil is displaced continuously, while no water is produced for the first 0.30 pore volume (PV) of water injected. Once water breakthrough occurs, water-cut increases rapidly while oil production rate starts to decline. After water breaks through, little incremental oil is produced as the water bypasses the oil. A total of 0.41 PV water is injected, resulting in an ultimate recovery of 42.9% of OOIP.

(2) CO₂ flooding

Figure 3-8 shows the measured oil recovery versus CO₂ injection volume. The oil recovery increases gradually with the continuous injection of CO₂ and then reaches to a plateau of 33.8% of OOIP at the injection volume of 1.20 PV. During this process, water production is reduced. This is consistent with the findings in the literature (Thomas and Monger-McClure, 1991).

It can be seen that oil produced with a smaller rate at the beginning of the CO₂ displacement and then with an increasing rate till gas breakthrough. This is attributed to the fact that a large amount of CO₂ firstly contacts with oil and dissolves into it to form a CO₂-rich phase on the upper layer of the reservoir (Orr et al., 1982). Within the CO₂-rich phase, the dissolved CO₂ swells the oil, reduces oil viscosity, and mobilizes the light oil, resulting in a higher recovery rate after it reaches the producer. The oil production rate begins to decrease after gas breakthrough occurs at the 0.66 PV of CO₂ injection.
Figure 3-7 Measured oil recovery and water-cut versus water injection volume for waterflooding
Figure 3-8 Measured oil recovery versus CO₂ injection volume for CO₂ flooding
(3) CO$_2$-WAG

Figure 3-9 shows the measured oil recovery and water-cut versus injection volume of the CO$_2$-WAG flooding process. CO$_2$ injection was started after 0.45 PV of water injection during which 46.3% of OOIP oil has been displaced out and water-cut reached 70%. The CO$_2$ injection rate was controlled at a moderate rate of 200 Scm$^3$/min and the total injection volume for this cycle was measured to be 0.20 PV. As can be seen, cumulative oil recovery slightly increased from 46.3% to 49.6%. After CO$_2$ injection, 0.1 PV of water was injected resulting in an incremental oil recovery of 3.8% of OOIP. Subsequently, one more cycle of CO$_2$ (0.15 PV) and water (0.11 PV) has been injected, resulting in an incremental recovery of 2.7% and 3.7% of OOIP, respectively. During the displacement, water-cut decreased with each cycle of CO$_2$ injection and rose up quickly when switching back to waterflooding.

Comparing the CO$_2$-WAG flooding (Figure 3-9) with continuous CO$_2$ flooding (Figure 3-8), one can conclude that, a higher oil recovery can be expected from CO$_2$-WAG processes. This can be explained by the fact that CO$_2$ can dissolve into oil phase to swell the oil, reduce oil density and IFT; the diluted oil was displaced out by the following water flooding process. This is consistent with the experimental results in the literature (Song, 2013).
Figure 3-9 Measured oil recovery and pressure drop versus CO\textsubscript{2} injection volume for CO\textsubscript{2}-WAG flooding
3.5.3 Validation of scaling criteria

(1) Waterflooding

Figure 3-10 shows the tuned water and oil relative permeability curves for history matching the experimental waterflooding process. As can be seen, the water relative permeability is rather low (less than 0.10) in the water saturation ranging from 0.16 to 0.40, while the oil phase relative permeability has low values (less than 0.10) in the water saturation range of 0.50-0.68. With such determined relative permeability curves, the simulation results obtained from the synthetic reservoir model are compared in Figure 3-11. As can be seen, the experimental oil recovery and water-cut have been well matched. As such, one can conclude that relative permeability and capillary pressure curves for the unconsolidated sandpacked model can be applied to the synthetic reservoir which is consolidated and has low permeability. This is a similar finding from the literature that relative permeability and capillary pressure curves have negligible effect on the measured oil recovery (Pujol and Boberg, 1972).

(2) CO₂ flooding

Similar to waterflooding, the tuned water-oil relative permeability, gas-liquid relative permeability, and capillary pressure curves for CO₂ flooding are depicted in Figure 3-12. As can be seen, gas phase relative permeability increases slightly when the gas saturation is lower than 0.20, and increases sharply to high values with gas saturation. Correspondingly, relative permeability for liquid phase decreases sharply when gas saturation is larger than 0.20, and then maintains to a significantly low level (less than
Figure 3-10 Water-oil relative permeability and capillary pressure curves for waterflooding
Figure 3-11 Comparison of the measured and simulated oil production and water-cut for waterflooding
Figure 3-12 Relative permeability and capillary pressure curves for (a) Water-oil system; and (b) Gas-liquid system during CO$_2$ flooding
0.05) in the gas saturation range of 0.30-0.68. Figure 3-13 compares the measured and simulated oil recovery. As can be seen, measured oil recovery has been well matched except for the small deviation at the end of the displacements. This is probably due to the non-uniform distribution of oil and water saturations in the sandpack (Zhang et al., 2012).

3.5.4 Field application

As aforementioned, the relative permeability curves and capillary pressure curves for the reservoir model have been obtained by history matching the production data, as shown in Figure 3-14 (Song, 2013). As can be seen, the relative permeability of water at the maximum water saturation is lower than 0.30, while the oil phase relative permeability and capillary pressure have low values (less than 0.20) in the water saturation range of 0.40-0.90. It can be seen from the liquid-gas systems that the relative permeability of liquid has low values (less than 0.10) when the gas saturation is higher than 0.50, while the gas relative permeability increases to its high level (larger than 0.30). The capillary pressure of liquid-gas phase increases with gas saturation which has a maximum value of 370.7 kPa. Figure 3-15 shows that the experimental oil recovery and water-cut curves have been well matched.
Figure 3-13 Comparison of the measured and simulated oil recovery for CO₂ flooding
Figure 3-14 Relative permeability curves and capillary pressure curves for the real reservoir model: (a) Oil-water systems; (b) Liquid-gas systems (Song, 2013)
Figure 3-15 Comparison of the measured and simulated oil production and water-cut for waterflooding
3.6 Summary

Scaling criteria have been developed and validated to evaluate performance of waterflooding and immiscible CO₂ flooding in tight formations by using a 3D sandpacked displacement model. Geometric factor is demonstrated to be negligible while gravitational and viscous forces have been considered for scaling up waterflooding and immiscible CO₂ flooding. This is because the immiscible displacement processes of light oil by water and CO₂ are controlled by gravity and viscosity of the fluids rather than by the geometric factors (i.e. ratio of length to thickness). Since capillary pressure and relative permeability have a negligible effect on movement of the displacing fluid, sacrificing these two parameters have been proved permissible. This can be attributed to the fact that in a uniform reservoir influences of capillary forces and permeability variation on fluids flow are much less than that of gravity and viscous forces (if viscosity ratio of displacing and displaced fluid is far from unity).

Continuous CO₂ injection results in an early gas breakthrough and low ultimate recovery rate. This is mainly ascribed to the fact that CO₂-rich phase flows more quickly than oil phase due to the unfavourable mobility ratio of gas and oil. Once gas breakthroughs, gas phase tends to flow through gas channels while less oil is contacted with CO₂, thus the displacement efficiency is limited. A higher oil recovery can be expected from CO₂-WAG process comparing with continuous CO₂ flooding. It is attributed to the fact that CO₂ can dissolve into oil phase to swell the oil, reduce oil density, and IFT; the diluted oil was displaced out by the following water flooding process by which gas breakthrough is delayed.
CHAPTER 4 DEVELOPMENT OF SCALING CRITERIA FOR IMMISCIBLE DISPLACEMENTS IN HEAVY OIL RESERVOIRS

In this chapter, scaling criteria developed in Chapter 3 by using dimensional and inspectional analyses has been modified for waterflooding and immiscible CO₂ flooding in heavy oil reservoirs. The scaling group of the gravitational force to viscous force is chosen to be neglected while other scaling groups including geometric factor, diffusion groups, and ratio of capillary forces to viscous forces can be satisfied. Since the fluids, pressure-temperature conditions, and initial water and oil saturations used in the sandpacked model are the same as in the synthetic reservoir model, similarities of chemical properties and relative permeabilities are also expected to be satisfied. Experimentally, a set of waterflooding and immiscible CO₂ flooding of heavy oil is performed with the 3D sandpacked model. The relaxed scaling criteria are validated by comparing the simulation results of synthetic reservoirs with experimental measurements, and then extended for a field application.

4.1 Relaxation of the Scaling Criteria

Similar to relaxation of the scaling criteria for immiscible displacements in tight formations in Chapter 3, discussions have been made on which scaling groups are more important to be satisfied while neglecting the less important ones.
4.1.1 Geometric factor

Van Daalen and van Domslaar (1972) stated that geometrical similar can be violated if no cross flow occurs or the component of flow across the layers is negligible compared with that of parallel flow in immiscible displacement. However, in the waterflooding and immiscible CO₂ flooding of heavy oil processes, vertical flow is common due to the density difference between the displacing fluids and oil. To be capable of representing the behaviour of a large prototype, therefore, the model must first be geometrically similar.

4.1.2 Gravitational force to viscous force ratio

If the scaling group of gravitational force to viscous force ratio (Eq. 3-8) is considered, it can be simplified to Eq. 3-9 since the heavy oil sample, brine, and gas (CO₂) used in the experiments are the same as those in the reservoir. As can be seen from Eq. 3-9, if the ratio of gravitational force to viscous force was scaled, the fluid velocity in the model will be scaled by the same ratio as the permeability changes.

4.1.3 Diffusion and dispersion

As discussed in Section 3.2.4, the forces related to dispersion and molecular diffusion must be taken into account with respect to waterflooding and immiscible CO₂ flooding. In the experimental displacements of heavy oil, water and CO₂ injection rates are set to be 2.0 cm³/min and 8.0 cm³/min (at the pressure of 3,000 kPa), respectively. Correspondingly, the Reynolds number are calculated to be $9.16 \times 10^{-8}$, $4.73 \times 10^{-4}$, and
1.09 \times 10^{-2} for heavy oil sample, brine, and CO\textsubscript{2}, respectively, ensuring that the flow falls into the diffusion-dominated region (see \textbf{Figure 3-1}). Thus, the dispersion coefficient can be represented by diffusion coefficient only. As for diffusion, the dimensionless group that relates diffusion to the pressure gradient can be written as Eq. 3-14.

In this study, diffusion coefficient is regarded as identical for the model and its prototype because the fluids and the system temperature are the same between each other. Although the system pressure of the prototype is slightly different from that of the sandpack, difference on diffusion coefficients can be negligible (Perkins and Johnston, 1963; Song \textit{et al.}, 2010). When Eq. 3-9 is combined with Eq. 3-14, the requirements for scaling become to be the relations shown in Eq. 3-15.

The permeability of the Lloydminster heavy oil reservoir ranges from 100 to 5,000 mD, with typical reservoir averaging about 2,000 mD (Adams, 1982). Since permeability for the sandpacked model used in this study is from 1,500 to 4,000 mD, the ratio of $k_M$ to $k_R$ has a range of 0.7 to 2.0 if the typical average reservoir permeability 2,000 mD is used. From Eq. 3-15, it can be seen that $L_R/L_M$ equals to $k_M/k_R$ which ranges from 0.7 to 2.0. This result is obviously impractical since the prototype is much larger in size than the sandpacked model. As such, scaling groups in Eqs. 3-8 and 3-14 cannot be satisfied simultaneously and one of them needs to be sacrificed. In this study, the ratio of gravitational force to viscous force is neglected and the feasibility of which needs to be further justified in the validation part.
4.1.4 Capillary force to viscous force ratio

As aforementioned, the scaling group that represents the ratio of capillary force to viscous force should be the same in the sandpacked model and the prototype, as expressed in Eq. 3-10. Since the heavy oil sample, brine, and CO\(_2\) in the sandpacked model and the prototype are the same, thus, \(\sigma \cos \theta\) and \(\mu\) can be cancelled out. Rearrange Eq. 3-10 to get Eq. 3-11. Since, from Eq. 3-14, the term \(\nu L\) is identical for the sandpacked model and the prototype, Eq. 3-11 can be met if

\[
\left(\sqrt{k\phi}\right)_M = \left(\sqrt{k\phi}\right)_R \quad [4-1]
\]

For the sandpacked models used in this study, there exists a reasonably good linear relationship between the natural logarithm of permeability (i.e., \(\ln(k)\)) and the porosity, as following:

\[
\ln(k) = 16.297\phi + 1.948 \quad [4-2]
\]

where \(k\) is permeability, mD; and \(\phi\) is porosity.

It is assumed that the prototype reservoir has a similar characteristic to the sandpacked models for the relationship of \(\ln(k)\) and porosity. As such, if an absolute permeability of 3,000 mD was used for the prototype reservoir, the porosity was calculated with Eq. 4-2 to be 37.18\%, correspondingly. The measured absolute permeability and porosity for the water and immiscible CO\(_2\) flooding are 4,000 mD and 38.72\%, respectively. Thus, the ratio of the left-hand side to the right-hand side in Eq. 4-1 will be 1.18, which is very close to unity. In this way, the ratio of capillary force to the viscous force can be met between the sandpacked model and the real reservoir.
4.2 Experimental

4.2.1 Materials

The heavy oil sample and reservoir brine used in this study are collected from the Lloydminster area, Canada. The initial reservoir temperature and pressure are 21.0°C and 3,500 kPa, respectively. The compositional analysis of the Lloydminster heavy oil is tabulated in Table 4-1. As can be seen, no hydrocarbon components are lighter than C₈. The density and viscosity of the Lloydminster heavy oil are measured to be 988.3 kg/m³ at 15.6°C and atmosphere pressure and 4,543 cP at 25°C and atmosphere pressure, respectively. The density and viscosity of reservoir brine are measured to be 1,051.7 kg/m³ and 1.03 cP at 20°C and atmosphere pressure, respectively. The dominant components of the reservoir brine are chloride, sodium, calcium and magnesium ions. In this study, synthetic brine is prepared and used as a proxy for reservoir brine, the compositions of which are shown in Table 4-2. The CO₂ (Praxair, Canada) used in the measurements has a purity of 99.998 mol%. The Ottawa sand #710 (Bell & Mackenzie, Canada) is used to pack the 3D physical model and the screen analysis is listed in Table 3-5.

4.2.2 Experimental setup

The schematic diagram of the 3D displacement model for heavy oil displacements is shown in Figure 4-1. This setup mainly includes three subsystems, i.e., injection subsystem, displacement subsystem, and production subsystem. The fluid injection
Table 4-1 Compositional analysis of the Lloydminster heavy oil

<table>
<thead>
<tr>
<th>Carbon No.</th>
<th>wt%</th>
<th>mol%</th>
<th>Carbon No.</th>
<th>wt%</th>
<th>mol%</th>
<th>Carbon No.</th>
<th>wt%</th>
<th>mol%</th>
</tr>
</thead>
<tbody>
<tr>
<td>C1</td>
<td>0.55</td>
<td>2.63</td>
<td>C21</td>
<td>1.45</td>
<td>2.66</td>
<td>C41</td>
<td>0.67</td>
<td>0.63</td>
</tr>
<tr>
<td>C2</td>
<td>0.62</td>
<td>2.63</td>
<td>C22</td>
<td>0.93</td>
<td>1.63</td>
<td>C42</td>
<td>0.49</td>
<td>0.45</td>
</tr>
<tr>
<td>C3</td>
<td>0.62</td>
<td>2.37</td>
<td>C23</td>
<td>1.22</td>
<td>2.04</td>
<td>C43</td>
<td>0.77</td>
<td>0.69</td>
</tr>
<tr>
<td>C4</td>
<td>0.81</td>
<td>2.80</td>
<td>C24</td>
<td>1.03</td>
<td>1.65</td>
<td>C44</td>
<td>0.77</td>
<td>0.67</td>
</tr>
<tr>
<td>C5</td>
<td>0.99</td>
<td>3.15</td>
<td>C25</td>
<td>1.16</td>
<td>1.79</td>
<td>C45</td>
<td>0.47</td>
<td>0.40</td>
</tr>
<tr>
<td>C6</td>
<td>1.21</td>
<td>3.57</td>
<td>C26</td>
<td>1.09</td>
<td>1.56</td>
<td>C46</td>
<td>0.47</td>
<td>0.39</td>
</tr>
<tr>
<td>C7</td>
<td>1.38</td>
<td>3.78</td>
<td>C27</td>
<td>0.71</td>
<td>0.81</td>
<td>C47</td>
<td>0.56</td>
<td>0.46</td>
</tr>
<tr>
<td>C8</td>
<td>1.48</td>
<td>4.19</td>
<td>C28</td>
<td>0.71</td>
<td>0.78</td>
<td>C48</td>
<td>0.56</td>
<td>0.45</td>
</tr>
<tr>
<td>C9</td>
<td>1.50</td>
<td>3.39</td>
<td>C29</td>
<td>0.82</td>
<td>0.88</td>
<td>C49</td>
<td>0.50</td>
<td>0.39</td>
</tr>
<tr>
<td>C10</td>
<td>1.53</td>
<td>3.27</td>
<td>C30</td>
<td>0.55</td>
<td>0.55</td>
<td>C50</td>
<td>0.49</td>
<td>0.38</td>
</tr>
<tr>
<td>C11</td>
<td>1.47</td>
<td>2.97</td>
<td>C31</td>
<td>0.81</td>
<td>0.80</td>
<td>C51</td>
<td>0.50</td>
<td>0.37</td>
</tr>
<tr>
<td>C12</td>
<td>1.47</td>
<td>2.50</td>
<td>C32</td>
<td>0.81</td>
<td>0.80</td>
<td>C52</td>
<td>0.49</td>
<td>0.37</td>
</tr>
<tr>
<td>C13</td>
<td>1.47</td>
<td>2.50</td>
<td>C33</td>
<td>0.67</td>
<td>0.64</td>
<td>C53</td>
<td>0.42</td>
<td>0.31</td>
</tr>
<tr>
<td>C14</td>
<td>1.47</td>
<td>2.50</td>
<td>C34</td>
<td>0.67</td>
<td>0.64</td>
<td>C54</td>
<td>0.42</td>
<td>0.30</td>
</tr>
<tr>
<td>C15</td>
<td>1.47</td>
<td>2.50</td>
<td>C35</td>
<td>0.67</td>
<td>0.64</td>
<td>C55</td>
<td>0.42</td>
<td>0.30</td>
</tr>
<tr>
<td>C16</td>
<td>1.47</td>
<td>2.50</td>
<td>C36</td>
<td>0.67</td>
<td>0.64</td>
<td>C56</td>
<td>0.42</td>
<td>0.30</td>
</tr>
<tr>
<td>C17</td>
<td>1.47</td>
<td>2.50</td>
<td>C37</td>
<td>0.67</td>
<td>0.64</td>
<td>C57</td>
<td>0.42</td>
<td>0.30</td>
</tr>
<tr>
<td>C18</td>
<td>1.47</td>
<td>2.50</td>
<td>C38</td>
<td>0.67</td>
<td>0.64</td>
<td>C58</td>
<td>0.42</td>
<td>0.30</td>
</tr>
<tr>
<td>C19</td>
<td>1.47</td>
<td>2.50</td>
<td>C39</td>
<td>0.67</td>
<td>0.64</td>
<td>C59</td>
<td>0.42</td>
<td>0.30</td>
</tr>
<tr>
<td>C20</td>
<td>1.47</td>
<td>2.50</td>
<td>C40</td>
<td>0.67</td>
<td>0.64</td>
<td>C60+</td>
<td>56.00</td>
<td>26.03</td>
</tr>
</tbody>
</table>

Total 100.00 100.00
<table>
<thead>
<tr>
<th>Component</th>
<th>Concentration (mg/L)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Chloride, Cl⁻</td>
<td>43,677</td>
</tr>
<tr>
<td>Sodium, Na⁺</td>
<td>24,700</td>
</tr>
<tr>
<td>Calcium, Ca²⁺</td>
<td>1,500</td>
</tr>
<tr>
<td>Magnesium, Mg²⁺</td>
<td>850</td>
</tr>
<tr>
<td>Potassium, K⁺</td>
<td>413</td>
</tr>
</tbody>
</table>
**Figure 4-1** Schematic diagram of the 3D displacement experimental setup
subsystem is used to supply CO\textsubscript{2} and brine, respectively. The CO\textsubscript{2} injection system includes a CO\textsubscript{2} supply cylinder with a pressure regulator, a high pressure syringe pump (500 HP, Teledyne ISCO Inc., USA) and a transfer cylinder (1,000 cm\textsuperscript{3} and 5,000 psi). To improve the accuracy and operability of the CO\textsubscript{2} injection process, CO\textsubscript{2} is introduced from the transfer cylinder to the physical model by using the syringe pump at constant flow rates. The injection volume of CO\textsubscript{2} is calculated with CMG WinProp (version 2011.10).

The 3D displacement and production subsystems are similar to the light oil displacement setup (see Section 3.3.2). As for heavy oil experiments, the produced fluid is collected with fluid collectors every 5 min and then heated in water bath at 60\textdegree{}C for 30 min; oil and water productions are read after oil and water are separated by using a centrifuge (Allegra X-30 Series, Beckman Coulter, USA) at a speed of 1,600 r/min for 10 min.

**4.2.3 Experimental preparation**

Before displacements, several experimental preparations need to be completed including sand-packing, porosity measurement, permeability determination, and saturating heavy oil sample into the sandpack. The detail procedure can be found in Section 3.3.3. The measured porosity, permeability, and oil saturation are 38.72\%, 3,500 mD, and 85.33\% respectively.
4.2.4 Experimental procedures

(1) Viscosity measurement

The viscosities of the heavy oil samples were measured at atmospheric pressure and a temperature range of 25 to 80ºC by using a cone-plate viscometer (DV-II+, Brookfield Engineering Laboratories, USA). The viscometer has a measurement accuracy of 1% of the full-scale range. During the measurements, constant temperature is maintained with a heated circulating water bath (Haake DC10, Thermo Electron Corporation, USA) with an accuracy of ±0.1ºC. In the measurement, spindle CP-51 which covers the viscosity range of 2.4 to 48,000 cP is used. Table 4-3 lists the measured viscosity at different temperatures for the heavy oil sample.

(2) Displacement experiments

In this study, waterflooding is followed by immiscible CO₂ flooding. As for waterflooding, the synthetic brine is injected into the 3D physical model at a constant rate of 2 cm³/min; while water injection is terminated once the water-cut reaches to 80%. The system pressure is maintained at 3,000 kPa by using a BPR at the producer. The produced liquids are collected and measured with a conical-bottom plastic centrifuge tube (15 ml, VWR, USA). The injection and production pressures are measured by two digital pressure gauges (DPG 8000-3k, Omega, USA) with an accuracy of 0.25% of full scale range.

As for immiscible CO₂ injection, gaseous CO₂ is introduced into the transfer cylinder (1,000 cm³ and 5,000 psi) from a CO₂ storage cylinder where a gas regulator is used to
Table 4-3 Measured viscosity of the Lloydminster heavy oil sample at different temperatures

<table>
<thead>
<tr>
<th>Temperature, ºC</th>
<th>Viscosity, cP</th>
</tr>
</thead>
<tbody>
<tr>
<td>25</td>
<td>4,543</td>
</tr>
<tr>
<td>30</td>
<td>2,873</td>
</tr>
<tr>
<td>35</td>
<td>1,877</td>
</tr>
<tr>
<td>40</td>
<td>1,274</td>
</tr>
<tr>
<td>45</td>
<td>882.3</td>
</tr>
<tr>
<td>50</td>
<td>666.8</td>
</tr>
<tr>
<td>55</td>
<td>481.1</td>
</tr>
<tr>
<td>60</td>
<td>357.9</td>
</tr>
<tr>
<td>65</td>
<td>266.9</td>
</tr>
<tr>
<td>70</td>
<td>205.1</td>
</tr>
<tr>
<td>75</td>
<td>158.7</td>
</tr>
<tr>
<td>80</td>
<td>125.9</td>
</tr>
</tbody>
</table>
control the pressure in the transfer cylinder. The pressure in the transfer cylinder is controlled at 3,000 kPa. A high pressure syringe pump (500 HP, Teledyne ISCO Inc., USA) is used to inject the compressed CO\textsubscript{2} into the physical model at a constant rate of 8 cm\textsuperscript{3}/min. In this study, CO\textsubscript{2} injection is terminated after 0.15 PV of CO\textsubscript{2} is injected. As aforementioned, the produced liquids are collected and measured with conical-bottom plastic centrifuge tubes (15 ml, VWR, USA).

4.3 Numerical Simulation

4.3.1 Fluid properties

Heavy oil characterization is performed by using the Peng-Robinson equation of state (PR EOS) multiphase equilibrium and properties determination program CMG WinProp (version 2011.10). Heavy oil is characterized as a single pseudocomponent. The measured viscosity data at a temperature range of 25 to 80ºC and the compositional analysis of the heavy oil are used as input data. The binary-interaction-parameter (BIP) correlation in the PR EOS method has been adopted for characterizing CO\textsubscript{2}-heavy oil binaries which can be used for predicting the saturation pressure and swelling factor of the CO\textsubscript{2}-heavy oil system with a good accuracy. The BIP correlation for CO\textsubscript{2}-heavy oil system obtained by Li et al. (2013) is:

\[ \delta = -0.5462 \frac{T}{T_c} - 0.4596SG - 0.0238\omega + 0.7523 \]  \[4-3\]

where \( T_c \), \( SG \), and \( \omega \) are the critical temperature in K, the specific gravity, and the acentric factor of heavy oil, respectively. The calculated BIP correlation for the CO\textsubscript{2}-heavy oil system at the experimental temperature of 294.15 K is 0.08364.
4.3.2 Validation of scaling criteria

To validate the scaling criteria for waterflooding and immiscible CO\textsubscript{2} flooding, synthetic reservoir models are built with CMG GEM module. Based on the theory of scaling criteria, the sandpacked model has been up scaled to a synthetic reservoir model. The comparison of these two models is shown in Table 4-4.

In this study, the dimension of the sandpacked model was scaled up with a ratio of 500 from 30.4 cm to 152.0 m and 12.7 cm to 63.5 m for length and thickness, respectively. Because the up scaling process is based on an already built sandpack, the thickness of the synthetic model is 63.5 m which is much higher than the real thickness of 3.5 to 6.5 m in the Lloydminster heavy oil reservoir (Adams, 1982). This inability to scale the reservoir thickness does not detract from the capability of the scale model to reveal basic information about the displacement mechanisms (Doscher et al., 1983). In addition, the main purpose of the up scaling process is to validate the relaxation of scaling criteria and to finally evaluate the impact of each scaling group. The permeability of the synthetic reservoir model was set to be 2,000 mD, which is the average value for the Lloydminster heavy oil reservoirs (Adams, 1982). Correspondingly, the porosity is assumed to be 0.35. As such, the ratio of the left-hand side to the right-hand side in Eq. 4-1 equals to 1.49, while the ratio of capillary force to viscous force is approximately satisfied.

As suggested by Stalkup (1983), Eq. 3-12 is used to calculate the flow rate. As such, the relations of the flow rates for sandpacked model and synthetic reservoir model is

\[
\frac{q_M}{q_R} = \frac{1}{500}
\]  

[4-4]
<table>
<thead>
<tr>
<th>Properties</th>
<th>Sandpacked model</th>
<th>Synthetic reservoir</th>
</tr>
</thead>
<tbody>
<tr>
<td>Well radius, m</td>
<td>0.00246</td>
<td>0.0762</td>
</tr>
<tr>
<td>Length (=width), m</td>
<td>0.304</td>
<td>152.0</td>
</tr>
<tr>
<td>Thickness, m</td>
<td>0.127</td>
<td>63.5</td>
</tr>
<tr>
<td>Permeability, mD</td>
<td>4,000</td>
<td>2,000</td>
</tr>
<tr>
<td>Porosity</td>
<td>0.3872</td>
<td>0.3500</td>
</tr>
<tr>
<td>Angle of dip</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Rate of water injection</td>
<td>2.0 cm³/min</td>
<td>1.44 m³/day</td>
</tr>
<tr>
<td>Rate of CO₂ injection, SC</td>
<td>283.68 cm³/min</td>
<td>204.25 m³/day</td>
</tr>
<tr>
<td>Operation time</td>
<td>1.0 s</td>
<td>2.6 day</td>
</tr>
<tr>
<td>Temperatures, °C</td>
<td>21</td>
<td>21</td>
</tr>
</tbody>
</table>
The calculated flow rates for water and CO₂ are tabulated in Table 4-4. From the scaling group, it can be obtained as

\[
\frac{v_i t}{L\phi(1 - S_{wi} - S_{or})_M} = \frac{v_i t}{L\phi(1 - S_{wi} - S_{or})_R}
\]  

[4-5]

Assuming that the initial water saturation and residual oil saturation are the same for the sandpack and reservoir, rearranging Eq. 4-5 yields

\[
\frac{t_R}{t_M} = \frac{v_M}{v_R} \frac{(L\phi)_R}{(L\phi)_M}
\]  

[4-6]

As can be seen from Eq. 4-6, with the same injection volume, the operation time consumed in the reservoir is proportional to the dimension and porosity, and reversely proportional to the velocity. In this case, the reservoir time is \(2.2 \times 10^5\) times longer than that of the model time.

A Cartesian 3D model with a grid system of 11×11×5 gridblocks is built. Figure 4-2 shows the 3D view of the synthetic reservoir model. Similar to the sandpacked model, both horizontal injector and producer are drilled in the 3rd layer and the well length has been scaled up from 11.0 cm to 55.0 m for the synthetic reservoir model. Homogeneous porosity and permeability are assigned for the synthetic reservoir model. Since heavy oil is saturated into the sandpacked model at a moderate flow rate, a uniform distribution of initial oil and water can be expected. Relative permeability and capillary pressure curves tuned in the history matching process are used for the synthetic reservoir model.
Figure 4-2 3D view of the synthetic reservoir model
4.3.3 Case studies

To further apply the scaling criteria for immiscible displacement of heavy oil, an experimental displacement conducted by Rojas (1985) and a heavy oil reservoir from Northminster Sparky pool, Saskatchewan, Canada (AccuMap, 2014) are selected to perform simulation tasks.

(1) Rojas’s waterflooding test (1985)

The experimental displacement selected was conducted by Rojas (1985). The 3D sandpacked model with dimensions of 46.0 cm × 46.0 cm × 2.2 cm was used to carry out the immiscible displacements of heavy oil by water and CO₂. One scenario of waterflooding in a quarter of five-spot pattern is chosen in this study. In the experiment, Ottawa silica sand was used to prepare the sandpacked model. The porosity and absolute permeability were measured to be 38.70% and 8,700 mD, respectively. The sandpack was initially saturated with reservoir brine and then saturated with crude oil sample from Aberfeldy field (Saskatchewan, Canada) while the initial oil saturation was measured to be 88.3%. The physical properties of Aberfeldy oil and brine are tabulated in Table 4-5.

During the waterflooding process, the producer pressure was controlled at a range of 40-100 kPag. A total volume of 1.52 PV of brine was injected at an injection rate of 1.73 cm³/min, resulting in an ultimate oil recovery of 32.4% of OOIP. Figure 4-3 shows the measured oil recovery, water-cut, and pressure drop. As can be seen, early water breakthrough occurred after 0.09 PV of water injection while injection pressure begins to decrease. This is attributed to the unfavourable mobility ratio (larger than 500) of
**Table 4-5** Properties of Aberfeldy oil and brine (Rojas, 1985)

<table>
<thead>
<tr>
<th>Properties</th>
<th>Crude oil</th>
<th>Brine</th>
</tr>
</thead>
<tbody>
<tr>
<td>Density, kg/m³ at 1 atm and 23°C</td>
<td>952.8</td>
<td>1,047.0</td>
</tr>
<tr>
<td>Viscosity, cP at 1 atm and 23°C</td>
<td>1,032</td>
<td>1.14</td>
</tr>
<tr>
<td>Molecular weight, g/mol</td>
<td>425</td>
<td>N/A</td>
</tr>
</tbody>
</table>
Figure 4-3 Waterflooding of heavy oil conducted by Rojas (1985)
injected brine and Aberfeldy heavy oil, resulting in water channels formed between the injector and producer. As waterflooding continues, water-cut is increased rapidly with the injection volume, while pressure drop decreases from 400 kPa to less than 50 kPa. The cumulative oil recovery reaches its plateau of 32.4% at the total injection volume of 1.52 PV.

To simulate the experimental waterflooding, CMG GEM module is used to build the numerical model with a gridblock of $23 \times 23 \times 3$ (see Figure 4-4). Homogeneous permeability, porosity, and initial oil saturation are assigned to the model with the measurements of 8,700 mD, 38.70%, and 88.3%, respectively. The reservoir fluid model has been regressed with CMG WinProp module (version 2011.10) by using the properties listed in Table 4-4.

The history matching technique has been used to tune the relative permeability and capillary pressure curves by matching the experimental measurements (see Figure 4-5). As can be seen, relative permeability curves change exponentially as a function of saturations. Oil relative permeability decreases to a low value range (less than 0.10) when water saturation is higher than 0.60. Capillary pressure for water-oil phase decreases with water saturation. Figure 4-6 shows the simulated oil recovery and pressure drop of the waterflooding. There exists an excellent agreement between simulation results and experimental measurements. Minor mismatch for oil recovery curve can be attributed to the experiment constraints and non-uniform of the oil saturation distributions of the sandpacked model (Zhang et al., 2012).
Figure 4-4 3D view of the sandpacked model (Rojas, 1985)
Figure 4-5 Relative permeability and capillary pressure curves for Rojas’s waterflooding:
(a) Water-oil system; (b) Liquid-gas system
Figure 4-6 Comparison of simulation results and experimental measurements for Rojas’s waterflooding (1985)
(2) Northminster Sparky pool

Northminster Sparky pool is a heavy oil reservoir located in Northminster field, Saskatchewan, Canada (see Figure 4-7). According to AccuMap (2014), this reservoir has been producing since July 1959, while the waterflooding was initiated in October 1970. Table 4-6 tabulates the rock and fluid properties of the reservoir.

To build a simulation model of the selected reservoir, a compositional reservoir simulator CMG GEM module has been selected. A gridblock size of 200 × 200 × 6 m is used when the net pay and porosity are homogeneously assigned to be 6.00 m and 34.0%, respectively (see Figure 4-8). History matching technique has been adopted by using the CMG CMOST module (version 2011.10) to simulate the production history from July 1959 to December 1974 of 66 producers and 6 injectors. During the history matching process relative permeability curves, capillary pressure curves, and absolute permeability are tuned. As can be seen from Figure 4-9, oil relative permeability and water-oil capillary pressure decrease with water saturation while water relative permeability increases with water saturation. Figure 4-10 plots the simulation results of the field production. A reasonable good history match has been obtained between the simulation results and field production profile.

(3) Procedure of field application

After obtained properties for the reservoir rock, fluid, and relative permeability, a section with dimensions of 125 × 125 × 6 m is selected when geometric similarity (L/H) could be satisfied. Similar to the experiment, a vertical injector and a vertical producer are
<table>
<thead>
<tr>
<th>Parameter</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Mean depth, m</td>
<td>541</td>
</tr>
<tr>
<td>Net pay, m</td>
<td>6</td>
</tr>
<tr>
<td>Porosity</td>
<td>0.340</td>
</tr>
<tr>
<td>Permeability, mD</td>
<td>1,000–6,000</td>
</tr>
<tr>
<td>Oil density, kg/m³</td>
<td>967.0</td>
</tr>
<tr>
<td>Oil saturation</td>
<td>0.85</td>
</tr>
<tr>
<td>Reservoir temperature, °C</td>
<td>21–23</td>
</tr>
</tbody>
</table>

**Table 4-6** Summary of Northminster Sparky pool (AccuMap, 2014)
Figure 4-7 Northminster Sparky pool (AccuMap, 2014)
Figure 4-8 A 3D view of the numerical simulation model of Northminster Sparky pool
Figure 4-9 Relative permeability curves and capillary pressure curves of field reservoir model: (a) Oil-water system; (b) Liquid-gas system
Figure 4-10 History matching results for the Northminster Sparky reservoir production
drilled at the two corners. A grid system of $25 \times 25 \times 1$ is built with CMG GEM module (version 2011.10). The Rojas’s experiment (1985) is scaled up and a comparison with the Northminster Sparky reservoir is tabulated in Table 4-7. As can be seen, water injection rate has been scaled up from 1.73 cm$^3$/min of the experiment to 0.68 m$^3$/day for the reservoir. The injection volume for the reservoir is set to be the experimental value of 1.52 PV. The simulation results of the field reservoir production will be compared with experimental measurement to validate the scaling criteria.

4.4 Results and Discussion

4.4.1 Experimental measurements

(1) Waterflooding

As aforementioned, waterflooding is followed by the immiscible CO$_2$ flooding. The cumulative oil recovery factor, oil rate, water-cut, and well bottom-hole pressure of the injector are plotted versus injection volume, as shown in Figures 4-11 and 4-12. The water injection is conducted at a constant flow rate of 2 cm$^3$/min for 400 min, resulting in a total injection volume of 0.18 PV. As can be seen from Figure 4-12, the initial water-cut is nearly 40%, indicating relatively high water production in heavy oil reservoirs due to the high oil viscosity. At the injection volume of 0.05 PV, water-cut sharply increases from less than 50% to 60%, indicating water breakthrough. Meanwhile, oil rate drops from 1.1 to 0.8 cm$^3$/min (see Figure 4-11). After water breakthrough occurs, water-cut levels off to about 80% and well bottom-hole pressure of the injector is decreased with a gentle slope as well as of the oil rate.
Table 4-7 Properties of 3D sandpacked model (Rojas, 1985) and Northminster Sparky pool

<table>
<thead>
<tr>
<th>Properties</th>
<th>Sandpacked model</th>
<th>Field model</th>
</tr>
</thead>
<tbody>
<tr>
<td>Well radius</td>
<td>0.25 cm</td>
<td>7.62 cm</td>
</tr>
<tr>
<td>Length (=width)</td>
<td>46.0 cm</td>
<td>125 m</td>
</tr>
<tr>
<td>Thickness</td>
<td>2.2 cm</td>
<td>6 m</td>
</tr>
<tr>
<td>Permeability, mD</td>
<td>8,700</td>
<td>5,000</td>
</tr>
<tr>
<td>Porosity</td>
<td>0.387</td>
<td>0.340</td>
</tr>
<tr>
<td>Angle of dip</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Initial water saturation</td>
<td>0.117</td>
<td>0.150</td>
</tr>
<tr>
<td>Water injection rate</td>
<td>1.73 cm³/min</td>
<td>0.68 m³/day</td>
</tr>
<tr>
<td>Operation time</td>
<td>1.0 s</td>
<td>0.7 day</td>
</tr>
<tr>
<td>Temperatures, °C</td>
<td>23</td>
<td>23</td>
</tr>
</tbody>
</table>
Figure 4-11 Experimental measurements of the waterflooding and immiscible CO₂ flooding of heavy oil: Oil recovery and flow rate
Figure 4-12 Experimental measurements of the waterflooding and immiscible CO₂ flooding of heavy oil: Water-cut and injector bottom-hole pressure
(2) CO₂ flooding

After water injection, gaseous CO₂ was introduced by using a transfer cylinder at pressure of 3,000 kPa and a pump rate of 8 cm³/min. The CO₂ flooding lasted 80 min and was terminated due to the trace production of oil. Total amount of 0.14 PV of CO₂ was injected, leading to an incremental oil recovery of 1.1%. An obvious decline in water-cut was observed from the beginning of the CO₂ flooding process. The increased oil production rate might be ascribed to that CO₂ preferentially displaces heavy oil instead of water, though in a high water saturation formation (Rojas and Farouq Ali, 1986).

Because of the unfavorable mobility ratio of the CO₂-heavy oil system and slow dissolution rate of CO₂ in heavy oil, recovery mechanisms (oil swelling effect and IFT reduction) by CO₂ cannot be accomplished by single CO₂ injection (Rojas and Farouq Ali, 1986). As such, early CO₂ breakthrough was observed after 0.06 PV of CO₂ injection, resulting in a decline of both oil production rate and water-cut (see Figures 4-11 and 4-12). The CO₂ flooding process was terminated as oil production rate was as low as 0.15 cm³/min.

4.4.2 Validation of scaling criteria

Experimental waterflooding and CO₂ flooding processes are simulated with the CMG GEM simulator by using history matching technique. Figure 4-13 shows the tuned relative permeability and capillary curves. As can be seen, water relative permeability slightly increases when water saturation is less than 0.50, indicating a strong water-wet system. With an increase of water saturation, oil relative permeability decreases rapidly
Figure 4-13 Relative permeability and capillary pressure curves: (a) Water-oil system; (b) Liquid-gas system for experimental displacement of heavy oil by water and CO$_2$
and remains low (less than 0.05) when water saturation is higher than 0.50. Because waterflooding was terminated after 0.18 PV of water injection while water saturation is less than 0.30, the history matching process is very sensitive to the relative permeability curves where water saturation is lower than 0.30. As for liquid-gas curves, oil relative permeability decreases significantly to a low value range (less than 0.20) when gas saturation is higher than 0.20. Meanwhile, gas relative permeability increases to be higher than 0.60.

The tuned relative permeability and capillary curves are assigned to the synthetic reservoir model for simulation. The simulated results are plot together with experimental measurements for comparison. Figure 4-14 shows a satisfactory match in all parameters including cumulative oil recovery, water-cut, and well bottom-hole pressure of the injector. The minor mismatches are probably ascribed to the fact of the non-uniform distribution of oil and water saturations in the sandpack (Zhang et al., 2012).

Based on the excellent match to the experimental measurements, the displacement processes of heavy oil by waterflooding and immiscible CO₂ flooding can be scaled up from physical sandpacked model to a synthetic reservoir model with the relaxed scaling criteria. The neglect of the ratio of gravitational force to viscous force is demonstrated permissible when scaling up immiscible oil displacement in heavy oil reservoirs.

4.4.3 Case studies

The validated scaling criteria have been applied to the Northminster heavy oil reservoir.
Figure 4-14 History matching results of synthetic reservoir case: (a) Oil recovery and water cut; (b) Injector bottom-hole pressure
As can be seen from **Figure 4-15**, a reasonable good match has been obtained between Rojas’s experimental measurements and simulation results of the Northminster Sparky pool production. By using the experimental sandpack to perform immiscible displacements can be upscaled to a field reservoir. In this way, waterflooding and immiscible CO₂ flooding strategies can be optimized by performing experimental tests.

**4.5 Summary**

Scaling criteria have been modified and validated to evaluate performance of waterflooding and immiscible CO₂ flooding in heavy oil reservoirs by using a 3D sandpacked displacement model. The ratio of gravitational force to viscous force was neglected when scaling up experimental displacements to the field application. Validation of the relaxed scaling criteria demonstrates the negligible effect of the ratio of gravitational force to viscous force on immiscible displacing processes of heavy oil. This is consistent with the findings in the literature made by Craig *et al.* (1957) that gravity effect will be negligible in the reservoirs with a higher ratio of well distance to thickness and having higher mobility ratio \((M > 50)\).

The validated scaling criteria have been applied to a field reservoir by using a heavy oil displacement experiment performed by Rojas (1985). Based on the excellent matching results, the reliability of the relaxed scaling criteria is further justified. Enhanced heavy oil recovery by immiscible CO₂ injection is limited by early gas breakthrough mainly due to the unfavourable mobility ratio between CO₂ and heavy oil.
Figure 4-15 Comparison of experimental measurements and simulation results of the field reservoir
CHAPTER 5  CONCLUSIONS AND RECOMMENDATIONS

5.1 Conclusions

In this study, techniques have been developed and validated to evaluate performance of waterflooding and immiscible CO$_2$ flooding in both tight formations and heavy oil reservoirs by using a 3D sandpacked displacement model, respectively. Experimentally, a number of light oil and heavy oil displacements by waterflooding and immiscible CO$_2$ flooding have been conducted with a 3D sandpacked model. Theoretically, scaling criteria for waterflooding and immiscible CO$_2$ flooding have been developed by performing dimensional and inspectional analyses. Mass transfer from CO$_2$ to oil and water by solution and diffusion has been considered in the inspectional analysis, though all of the scaling groups cannot be satisfied simultaneously. Relaxations of scaling criteria for immiscible displacements in tight formations and heavy oil reservoirs have been performed, resulting in two set of scaling criteria for tight oil and heavy oil reservoirs, respectively. Scaling criteria have been validated by history matching the experimental measurements, and then extended for field applications.

The major conclusions that can be drawn from this thesis are summarized as follows:

(1). As for waterflooding and immiscible CO$_2$ flooding in tight oil formations:

   a) Geometric factor is demonstrated to be negligible while gravitational and viscous forces have been considered for scaling up waterflooding and immiscible CO$_2$ flooding. This is because the immiscible displacement processes of light oil by water and CO$_2$ are controlled by gravity and
viscosity of the fluids rather than by the geometric factors (i.e. ratio of length to thickness).

b) Since capillary pressure and relative permeability have negligible effect on general movement of the displacing fluid, sacrificing these two parameters have been proved permissible. This can be ascribed to the fact that, in a uniform reservoir, effects of capillary forces and permeability variation on fluids flow are much less than that of gravity and viscous forces if viscosity ratio of displacing and displaced fluid is far from unity.

(2). As for waterflooding and immiscible CO₂ flooding in heavy oil reservoirs:

a) The scaling group of the gravitational force to viscous force is chosen to be neglected while other scaling groups including geometric factor, diffusion groups, and ratio of capillary forces to viscous forces can be satisfied.

b) Validation of relaxed scaling criteria demonstrates the negligible effect of the ratio of gravitational force to viscous force on immiscible displacing processes of heavy oil. This conclusion is consistent with the findings in the literature made by Craig et al. (1957) that gravity effect is negligible in the reservoirs with a higher ratio of well distance to thickness and having higher mobility ratio (i.e., $M > 50$).

(3). The oil recovery factor by continuous CO₂ flooding is usually limited in unconventional reservoirs due mainly to the early gas breakthrough. By using CO₂-WAG flooding process, macro-sweep efficiency is enhanced, resulting in a higher ultimate oil recovery.
5.2 Recommendations

The following recommendations for future studies can be made:

(1). Further validation on the scaling group about relative permeability and capillary pressure curves, viscous force, and gravitational force should be performed by comparing fluid flow in real reservoirs and scaled models.

(2). CO\textsubscript{2} displacements experiments should be conducted under miscible and/or near-miscible conditions to further validate the newly developed scaling criteria for tight formations.

(3). 3D displacements experiments should be conducted with samples collected from the outcrops of a tight formation, if applicable, to examine the effects of the sandpacked models’ inability of representing real reservoirs on scaling processes.

(4). Given a real reservoir, production performance by immiscible CO\textsubscript{2} flooding could be further evaluated with the scaled models to optimize injection strategies and well configurations.
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APPENDIX: DERIVATION OF THE DIMENSIONLESS CONTINUITY EQUATIONS

As for the inspectional analysis, the continuity equations of oil, water, and gas phases are expressed in dimensionless forms by applying normalized parameters. The continuity equations for the two immiscible phases of oil and water can be written as (Ertekin et al., 2001):

\[ \nabla \left( \frac{\bar{u}_o}{B_o} \right) = -\frac{\partial}{\partial t} \left( \phi S_o \right) \]

As aforementioned, the derivatives of the reciprocal FVF (i.e., \( B_o, B_w, \) and \( B_g \)) versus pressure are not expressed. Thus, Eq. 3-2a is rewritten as

\[ \nabla \bar{u}_o = -\frac{\partial (\phi S_o)}{\partial t} \]  
\[ [A-1] \]

In \( x \) direction, superficial oil velocity can be expressed as

\[ v_{ox} = v_x - v_{wx} - v_{gx} \]  
\[ [A-2] \]

Water velocity \( v_{wx} \) equals to the Darcy’s velocity \( u_{wx} \). As such, according to Darcy’s law

\[ v_{wx} = -\frac{k k_{rw}}{\mu_w} \frac{\partial p_w}{\partial x} \]  
\[ [A-3] \]

By taking dispersion and diffusion effects on gas phase, the gas velocity \( v_{gx} \) can be expressed as (Rojas et al., 1991)
\[ v_{gx} = u_{gx} - K_{gox} \frac{\partial C_{go}}{\partial x} \]  

[A-4]

Substituting Darcy’s velocity into Eq. A-4, we have

\[ v_{gx} = -\frac{kk_{rg}}{\mu_g} \frac{\partial p_g}{\partial x} - K_{gox} \frac{\partial C_{go}}{\partial x} \]  

[A-5]

Substituting \( v_{wx} \) and \( v_{gx} \) into Eq. A-2, \( v_{ox} \) can be rewritten as

\[ v_{ox} = v_x + \frac{kk_{rw}}{\mu_w} \frac{\partial p_w}{\partial x} + \frac{kk_{rg}}{\mu_g} \frac{\partial p_g}{\partial x} + K_{gox} \frac{\partial C_{go}}{\partial x} \]  

[A-6]

From Eqs. 3-4a and 3-4b, pressures of water and gas phase can be expressed as

\[ p_w = p_o - P_{cow} \]  

[A-7a]

\[ p_g = p_o + P_{cg_o} \]  

[A-7b]

Substituting Eqs. A-7a and A-7b into Eq. A-6, we have

\[ v_{ox} = v_x + \frac{kk_{rw}}{\mu_w} \frac{\partial (p_o - P_{cow})}{\partial x} + \frac{kk_{rg}}{\mu_g} \frac{\partial (p_o + P_{cg_o})}{\partial x} + K_{gox} \frac{\partial C_{go}}{\partial x} \]  

[A-8]

Rearranging Eq. A-8 with respect to \( v_{ox} \), one may have

\[ v_{ox} = \frac{1}{F_o} \left[ v_x - \frac{kk_{rw}}{\mu_w} \frac{\partial P_{cow}}{\partial x} + \frac{kk_{rg}}{\mu_g} \frac{\partial P_{cg_o}}{\partial x} + K_{gox} \frac{\partial C_{go}}{\partial x} \right] \]  

[A-9a]

where \( F_o = 1 + \frac{k_{rw} \mu_o}{k_{ro} \mu_w} + \frac{k_{rg} \mu_o}{k_{to} \mu_g} \).

Similarly, \( v_{oy} \) and \( v_{oz} \) can be written as
According to the Leverett $J$-function (Leverett, 1941), capillary pressure can be described as a function of saturation:

$$J(S_w) = \frac{P_{cw}(S_w)}{\sigma_{cw} \cos \theta} \sqrt{k/\phi} \quad [A-10a]$$

for water phase, and

$$J(S_g) = \frac{P_{cg}(S_g)}{\sigma_{cg} \cos \theta} \sqrt{k/\phi} \quad [A-10b]$$

for gas phase.

By substituting oil velocities in $x$, $y$, and $z$ directions expressed in Eqs. A-9a to A-9c, and the normalized parameters expressed in Eqs. 3-5a to 3-5d into the continuity equation of oil phase described in Eq. A-1, the dimensionless form of continuity equation of oil can be written as:
Similarly, the dimensionless form of the following continuity equations of water and gas phase can be derived, respectively.

$$
-\left( f_\text{x} \frac{\partial S_{\text{sw}}}{\partial x} + \frac{L}{W} f_\text{y} \frac{\partial S_{\text{sw}}}{\partial y} + \frac{L}{H} f_\text{z} \frac{\partial S_{\text{sw}}}{\partial z} \right) \frac{d}{dS_{\text{sw}}} \left( \frac{1}{F_\text{w}} \right) + \frac{\sqrt{k_\phi \sigma_{\text{sw}} \cos \theta}}{\mu_\text{w} v_\text{t} L} \\
\left[ \frac{\partial}{\partial x} \left( \frac{k_{\text{rw}}}{F_\text{o}} \frac{dJ}{dS_{\text{sw}}} \right) + \left( \frac{L}{W} \right)^2 \frac{\partial}{\partial y} \left( \frac{k_{\text{rw}}}{F_\text{o}} \frac{dJ}{dS_{\text{sw}}} \right) + \left( \frac{L}{H} \right)^2 \frac{\partial}{\partial z} \left( \frac{k_{\text{rw}}}{F_\text{o}} \frac{dJ}{dS_{\text{sw}}} \right) \right] \\
+ \frac{k_\text{rg} \sqrt{k_\phi \sigma_{\text{go}} \cos \theta}}{\mu_\text{g} v_\text{t} L} \left[ \frac{\partial}{\partial x} \left( \frac{k_{\text{rg}}}{F_\text{o}} \frac{dJ}{dS_{\text{gn}}} \right) + \left( \frac{L}{W} \right)^2 \frac{\partial}{\partial y} \left( \frac{k_{\text{rg}}}{F_\text{o}} \frac{dJ}{dS_{\text{gn}}} \right) \right] - \frac{k_{\text{rg}}}{v_\text{y} \mu_\text{y}} \left[ \frac{\partial}{\partial z} \left( k_{\text{rg}} \right) \right] + \frac{k_\text{rg}}{v_\text{y} \mu_\text{y}} \left[ \frac{\partial}{\partial z} \left( k_{\text{rg}} \right) \right] \\
+ \frac{K_{\text{gox}}}{L \nu_\text{i}} \frac{\partial}{\partial x} \left( \frac{1}{F_\text{o}} \frac{\partial C_{\text{go}}}{\partial x} \right) + \frac{L K_{\text{goy}}}{W \nu_\text{j}} \frac{\partial}{\partial y} \left( \frac{1}{F_\text{o}} \frac{\partial C_{\text{go}}}{\partial y} \right) + \frac{L K_{\text{goz}}}{H \nu_\text{l}} \frac{\partial}{\partial z} \left( \frac{1}{F_\text{o}} \frac{\partial C_{\text{go}}}{\partial z} \right) = -\frac{\partial S_{\text{sw}}}{\partial t_\text{n}} \quad [3-6a]
$$

for water phase; and
\[-\left( f_x \frac{\partial S_{wn}}{\partial x} + \frac{L}{W} f_y \frac{\partial S_{wn}}{\partial y} + \frac{L}{H} f_z \frac{\partial S_{wn}}{\partial z} \right) dS_{wn} \left( \frac{1}{f_g} \right) \]

\[+ \sqrt{k \phi \sigma_{wn}} \cos \theta \mu_n v_L \left[ \frac{\partial}{\partial x} \left( \frac{k_{rw} \partial J}{F_g dS_{wn}} \frac{\partial S_{wn}}{\partial x} \right) \right] + \left( \frac{L}{W} \right)^2 \frac{\partial}{\partial y} \left( \frac{k_{rw} \partial J}{F_g dS_{wn}} \frac{\partial S_{wn}}{\partial y} \right) \]

\[+ \left( \frac{L}{H} \right)^2 \frac{\partial}{\partial z} \left( \frac{k_{rw} \partial J}{F_g dS_{wn}} \frac{\partial S_{wn}}{\partial z} \right) \]

\[+ \left( \frac{L}{W} \right)^2 \frac{\partial}{\partial y} \left( \frac{\mu_g \left( k_{ro} + k_{rw} \right) \partial J}{F_g dS_{gn}} \frac{\partial S_{gn}}{\partial y} \right) \]

\[+ \left( \frac{L}{H} \right)^2 \frac{\partial}{\partial z} \left( \frac{\mu_g \left( k_{ro} + k_{rw} \right) \partial J}{F_g dS_{gn}} \frac{\partial S_{gn}}{\partial z} \right) \]

\[- \frac{k \Delta \rho_{oo, g}}{v_i \mu_w} \frac{\partial}{\partial z} \left( \frac{k_{rw}}{F_g} \right) - \frac{k \Delta \rho_{og, g}}{v_i \mu_g} \frac{\partial}{\partial z} \left[ \mu_g \left( k_{ro} + k_{rw} \right) \right] = - \frac{\partial}{\partial t_n} \left( S_{gn} + C_{go, S_{on}} \right) \]

for gas phase.