EXPERIMENTAL STUDY ON IMPROVING THE WATERFLOODING POTENTIAL IN DIFFERENT HEAVY OIL-SOLVENT SYSTEMS

A Thesis
Submitted to the Faculty of Graduate Studies and Research in Partial Fulfillment of the Requirements for the Degree of Master of Applied Science in Petroleum Systems Engineering University of Regina

By
Xiaolong Peng
Regina, Saskatchewan
September, 2016

© Copyright 2016: X. Peng
Xiaolong Peng, candidate for the degree of Master of Applied Science in Petroleum Systems Engineering, has presented a thesis titled, *Experimental Study on Improving the Waterflooding Potential in Different Heavy Oil-Solvent Systems*, in an oral examination held on August 26, 2016. The following committee members have found the thesis acceptable in form and content, and that the candidate demonstrated satisfactory knowledge of the subject material.

External Examiner: Mr. Muhammad Imran, Saskatchewan Research Council

Supervisor: Dr. Fanhua Zeng, Petroleum Systems Engineering

Committee Member: Dr. Farshid Torabi, Petroleum Systems Engineering

Committee Member: Dr. Yongan Gu, Petroleum Systems Engineering

Chair of Defense: Dr. Raman Paranjape, Electronic Systems Engineering
ABSTRACT

Due to the unfavourable mobility ratio of heavy oil and water, waterflooding cannot be used successfully without the support of natural energies (such as solution gas drive, foamy oil effect, expansion effect, etc.) in heavy oil reservoirs. In previous studies, the parameters related to the pressure change, such as the injection rate, the start time of waterflooding, the voidage replacement ratio (VRR) control, etc., have been studied to take full advantage of the nature energies in heavy oil waterflooding processes. However, few researchers have directly studied the pressure control strategies to improve the waterflooding potential in heavy oil reservoirs. Meanwhile, previous studies investigated the heavy oil waterflooding mainly in heavy oil-methane systems or heavy oil-mixed solvent (methane and CO₂) systems. Heavy oil-mixed solvent (methane and propane) systems, which often existed during cyclic solvent injection (CSI) processes, are rarely examined in heavy oil waterflooding processes. Therefore, it is of importance to study pressure control strategies to improve the waterflooding potential in different heavy oil-solvent systems.

Two different heavy oil-solvent systems are included in this study: (1) a heavy oil-methane system and (2) a heavy oil-mixed solvent (methane and propane) system. For the heavy oil-methane system, four pressure control patterns are firstly investigated to screen out the optimal waterflooding pattern. Secondly, effects of pressure depletion rate are studied in the selected pressure control pattern to get the optimal control strategy. Finally, a history match is conducted for a test to further understand the heavy oil waterflooding process. For the heavy oil-mixed solvent system, one pure pressure
depletion test and two waterflooding tests are carried out to understand the production behaviors in this system.

For experimental study in heavy oil-solvent systems, it is found that the primary-plus waterflooding, an operational pattern that conduct the waterflooding and pressure depletion simultaneously, is the optimal pressure control pattern for heavy oil waterflooding processes. However, the pressure depletion rate in that pattern should be set properly in order to make full use of natural energies and water drive energy for both heavy oil-solvent systems. In this study, it is also understood that the interactive effect between water drive and foamy oil effect/solution gas drive at different waterflooding stages. Moreover, the optimal VRRs for different production objectives are recommended for heavy oil-methane system.

For the numerical study, the results indicate that the theoretical methods can be used to provide an initial relative permeability curves for heavy oil waterflooding processes. However, due to the foamy oil effect and solution gas drive, the gas production in the heavy oil waterflooding is difficult to be matched well even by tuning the relative permeability curves. Therefore, it is suggested to consider the foamy oil module into the simulation model to get a better history match.
ACKNOWLEDGEMENTS

Firstly, I would like to express my sincere and deepest gratitude to my supervisor, Dr. Fanhua (Bill) Zeng, for his continuous encouragement and excellent guidance in my graduate study period at the University of Regina.

Secondly, I would like to express my special appreciation to all the thesis committee members: Mr. Muhammad Imran, Dr. Farshid Torabi and Dr. Yongan (Peter) Gu for their valuable suggestions and comments.

Thirdly, I would like to thank Mr. Zhongwei (David) Du, Mr. Hao (Jason) Yang, Mr. Xiang (Michael) Zhou in Dr. Fanhua Zeng’s group for their kindness support in the experimental period. I also appreciate the experimental discussions and guidance from Mr. Yanbin Gong in Dr. Yongan Gu’s group. I would also like to thank Mr. Farrell Baird in Saskatchewan Research Council, for his technique support in the LabView system setup.

Finally, I would like to extend my gratitude to my friends and other members in Dr. Fanhua Zeng’s group for their inspiration and friendship during these years in Canada.
DEDICATION

To loving memory of my grandmother,

for I deeply miss her and the warm hugs that she gave to me.

To my beloved and honourable parents,

for their encouragement and generous support throughout my life.

To my lovely wife,

for her inspirations and endless love.
# TABLE OF CONTENTS

ABSTRACT .............................................................................................................................................. I

ACKNOWLEDGEMENTS .......................................................................................................................... III

DEDICATION ............................................................................................................................................... IV

TABLE OF CONTENTS ............................................................................................................................ V

LIST OF TABLES ...................................................................................................................................... VIII

LIST OF FIGURES ................................................................................................................................... IX

NOMENCLATURE .................................................................................................................................... XIII

CHAPTER 1 INTRODUCTION .................................................................................................................. 1

1.1 Waterflooding in heavy oil reservoirs ................................................................................................. 1

1.2 Methodologies and objectives .......................................................................................................... 5

1.3 Thesis outline .................................................................................................................................... 5

CHAPTER 2 LITERATURE REVIEW ...................................................................................................... 7

2.1 The recovery mechanisms for heavy oil waterflooding .................................................................... 7

2.1.1 Favourable mechanisms for heavy oil waterflooding .................................................................. 7

2.1.2 Unfavourable mechanisms for heavy oil waterflooding ............................................................... 12

2.2 Parameters that affect performances of heavy oil waterflooding ................................................... 13

2.3 Effects of operating parameters on heavy oil waterflooding ......................................................... 14

2.2.1 Water injection rate .................................................................................................................... 14

2.2.2 Voidage Replacement Ratio (VRR) ............................................................................................. 16

2.2.3 The starting time of waterflooding .............................................................................................. 17

2.4 Effects of reservoir parameters on heavy oil waterflooding ............................................................. 19

2.3.1 Rock permeability ...................................................................................................................... 19
2.3.2 Rock wettability ................................................................. 19
2.3.3 Heterogeneity ........................................................................ 20
2.3.4 Oil-water mobility ratio .......................................................... 20
2.5 Chapter Summary ...................................................................... 23

CHAPTER 3  WATERFLOODING PERFORMANCES IN A HEAVY OIL-
METHANE SYSTEM ......................................................................... 24

3.1 Introduction ................................................................................ 24
3.2 Experimental Section ................................................................. 26
  3.2.1 Experimental setup ................................................................. 26
  3.2.2 Experimental preparation ......................................................... 29
  3.2.3 Experimental procedures ......................................................... 39
3.3 Experimental Results and Discussion ............................................ 43
  3.3.1 Reproducibility of tests ............................................................ 43
  3.3.2 The discussion of different pressure control patterns ................. 43
  3.3.3 The discussion of different depletion rates in Pattern 2 ............... 58
  3.3.4 The interactive effects between water drive and foamy oil effect/solution gas drive ................................................................. 68
  3.3.5 Effects of aging time on waterflooding performances .................. 74
3.4 Theory-Assisted History Matching .............................................. 77
  3.4.1 Reservoir model grid ............................................................... 77
  3.4.2 Reservoir properties ............................................................... 79
  3.4.3 PVT model ............................................................................. 79
  3.4.4 Relative permeability curves .................................................... 80
LIST OF TABLES

Table 3.1. Heavy oil sample properties and estimated components. .......................... 30
Table 3.2. Live oil properties for the heavy oil-methane system. .............................. 31
Table 3.3. Physical properties of cores for the heavy oil-methane system. ............... 32
Table 3.4. Comparison between the experimental conditions and the properties of typical heavy oil reservoirs in Lloydminster area. ............................................. 33
Table 3.5. Operational details of each pressure control Pattern. ............................. 42
Table 4.1. Live oil properties for the heavy oil-mixture system. ............................. 100
Table 4.2. Physical properties of cores for the heavy oil-mixed solvent system. .... 101
LIST OF FIGURES

Figure 1.1. Distribution of the original heavy oil in place by region (Meyer et al., 2007). ................................................................. 3

Figure 1.2. The distribution of the incremental oil recovery by waterflooding in Saskatchewan and Albert provinces. (Renouf & Nakutnyy, 2009). .......... 4

Figure 2.1. Proposed heavy oil waterflooding type curve (Vittoratos & West, 2010). 9

Figure 2.2. Comparison of volume factor behaviours in conventional oil and foamy oil (Yrigoyen & Carvajal, 2001). ............................................. 11

Figure 2.3. Incremental oil recovery by waterflooding vs. pore volume injected for four Saskatchewan projects (Kumar et al., 2008) .............................. 22

Figure 3.1. Schematic diagram of the waterflooding setup for the heavy oil-methane system ........................................................................ 28

Figure 3.2. Photos of the produced liquids: (a) the form of produced liquid and (b) the oil ring phenomenon. ..................................................... 36

Figure 3.3. Schematic diagram of the new method for separating heavy oil and water. ............................................................................ 37

Figure 3.4. The mass error of the produced liquid for each tube (Test CM#1). ....... 38

Figure 3.5. Reproducibility of heavy oil waterflooding tests: (a) oil recovery factor; (b) water cut; (c) produced GOR. ......................................................... 45

Figure 3.6. Results of coreflooding in Test CM#3 (Pattern 1): (a) oil recovery and outlet pressure as a function of production time; and (b) water cut and produced GOR as a function of production time. .............................................. 46
Figure 3.7. Results of coreflooding in Test CM#1 (Pattern 2): (a) oil recovery and outlet pressure as a function of production time; and (b) water cut and produced GOR as a function of production time. ................................................................. 49

Figure 3.8. Results of coreflooding in Test CM#4 (Pattern 3): (a) oil recovery and outlet pressure as a function of production time; and (b) water cut and produced GOR as a function of production time. ................................................................. 51

Figure 3.9. Results of coreflooding in Test CM#5 (Pattern 4): (a) oil recovery and outlet pressure as a function of production time; and (b) water cut and produced GOR as a function of production time. ................................................................. 54

Figure 3.10. Comparison of four different pressure control patterns in two aspects: (a) oil recovery factor; (b) overall average production rate. ................................................................. 57

Figure 3.11. The outlet pressure records for tests with the depletion rates of 0.45 kPa/min, 1 kPa/min, 2 kPa/min, and 3 kPa/min .................................................................................. 59

Figure 3.12. Comparison of oil recovery factors in Pattern 2 under four different depletion rates. .............................................................................................................. 60

Figure 3.13. Comparison of the water cuts for four different pressure depletion rates in Pattern 2. .............................................................................................................. 61

Figure 3.14. Comparison of the produced GOR for four different pressure depletion rates in Pattern 2 .............................................................................................................. 62

Figure 3.15. Comparison of the effects of the pressure depletion rate on primary production and primary-plus waterflooding processes. ........................................ 65

Figure 3.16. Comparison of cumulative VRR for four different depletion rates in Pattern 2. .............................................................................................................. 66
Figure 3.17. The overall average production rates for four different depletion rates in Pattern 2 ................................................................. 67

Figure 3.18. Comparison of the results of Test 1 (Zhou et al., 2016) and Test CM#8. ................................................................................................................. 71

Figure 3.19. Comparison of the results of Test 2 (Zhou et al., 2016) and Test CM#1. ................................................................................................................. 72

Figure 3.20. Comparison of the results of Test 3 (Zhou et al., 2016) and Test CM#6. ................................................................................................................. 73

Figure 3.21. Comparison of Test CM#1 (72 hrs aging) and Test CM#2 (288 hrs aging) in the oil recovery, water cut, and produced GOR. ......................... 76

Figure 3.22. Model shapes used in the experiments and the numerical simulation. .. 78

Figure 3.23. The PVT model build-up for Test CM#4. ........................................... 81

Figure 3.24. Water-oil relative permeability curves calculated by the JBN method for Test CM#4 .................................................................................................. 85

Figure 3.25. Oil-gas relative permeability curves calculated by Tang’s method for Test CM#4 .................................................................................................. 87

Figure 3.26. Comparison of the simulation and the experimental results for Test CM#4: (a) Inlet pressure vs. time, (b) Cumulative oil production vs. time, (c) Cumulative gas production vs. time, and (d) Cumulative water production vs. time. ................................................................................................ 91

Figure 3.27. Comparison of the history matching errors in cumulative oil, cumulative gas, cumulative water, injection pressure, and global errors. ............... 92
Figure 3.28. Comparison of the initial and tuned water-oil relative permeability curves for Test CM#4. ................................................................. 93

Figure 3.29. Comparison of the initial and tuned oil-gas relative permeability curves for Test CM#4. ................................................................. 94

Figure 4.1. Outlet pressure records of Test CMS#1. ................................................................. 103

Figure 4.2. Production profiles (the pressure difference, oil recovery, and cumulative GOR) of Test CMS#1. ................................................................. 104

Figure 4.3. Pressure records (the outlet pressure and pressure difference) of Test CMS#2. ................................................................. 106

Figure 4.4. Production profiles (the oil recovery, cumulative GOR, and water cuts) of Test CMS#2. ................................................................. 107

Figure 4.5. Pressure records (the outlet pressure and pressure difference) of Test CMS#3. ................................................................. 110

Figure 4.6. Production profiles (the oil recovery, cumulative GOR, and water cuts) of Test CMS#3. ................................................................. 111

Figure 4.7. Comparison of production profiles (the oil recovery, cumulative GOR, and water cut) for Test CMS#2 and Test CMS#3. ........................................... 114

Figure 4.8. Comparison of oil recovery factors for Tests CMS#1 and CMS#3. ...... 117
NOMENCLATURE

Notations

A  The section area of model, cm²
Bo  The formation volume factor, res m³/stock-tank m³
Errₘ  The tolerated errors for satisfied simulation results
fₒ  The fraction of the oil phase in produced liquid
fₜ  The fraction of the water phase in produced liquid
g  The gravitational constant, N/kg
i  The value at sampling time
kᵢ  The relative permeability of component i, fraction
Kᵣₒ, Kᵣₙ  The relative permeability of the oil phase and gas phase, respectively, fraction
k  The absolute permeability, D
L  The length of model, cm
NT  The total number of samples
ΔP  The pressure drop between the inlet and outlet of the coreholder, kPa
q  The volumetric production rate of oil or gas, cm³/sec
Q  The history matching errors, i.e. the data quality of the simulation results
(Sₘ)₂  The water saturation at the production outlet, fraction
Wᵢ  The injected pore volume
X  The evaluated values, which could be cumulative productions of oil, gas, and water

$\Delta Y^m$  The measured maximum change of the evaluated value

**Greek Symbols**

$\rho$  The density of oil or gas, g/cm$^3$

$\alpha$  The unit conversion constant

$\mu$  The viscosity of oil or gas, cp

$\mu_o(P_{avg})$  The oil viscosity at certain model pressure ($P_{avg}$), cp

**Subscripts**

s  The simulation results

m  The measured results

avg  The average values

ro  The oil phase

o  The oil phase

rg  The gas phase

g  The gas phase

w  The water phase

i  The component i

**Acronyms**

CMG  Computer Modelling Group

CHOPS  Cold heavy oil production with sand

CSI  Cyclic solvent injection

GOR  Gas oil ratio
<table>
<thead>
<tr>
<th>Abbreviation</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>IPV</td>
<td>Injected pore volume</td>
</tr>
<tr>
<td>JBN</td>
<td>Johnson-Bossler-Naumann</td>
</tr>
<tr>
<td>NMR</td>
<td>Nuclear magnetic resonance</td>
</tr>
<tr>
<td>OHOIP-Disc</td>
<td>Original heavy oil in place-discovered</td>
</tr>
<tr>
<td>OOIP</td>
<td>Original oil in place</td>
</tr>
<tr>
<td>VRR</td>
<td>Voidage replacement ratio</td>
</tr>
</tbody>
</table>
CHAPTER 1  INTRODUCTION

1.1 Waterflooding in heavy oil reservoirs

The original heavy oil in place-discovered (OHOIP-Disc) was 3396 billion barrels in the world (see Figure 1.1) and was mainly distributed in North America, South America, and the Middle East (Meyer et al., 2007). However, based on the U.S. geological survey, only less than 3% of the OHOIP-Disc has been recovered worldwide (Meyer et al., 2007). For short term and long term need, this insufficiently utilized resource is a considerable source of alternative energy for conventional oil resources.

Heavy oil waterflooding, a secondary oil recovery method, has been operated in western Canada for more than 50 years. The huge range of incremental oil recoveries by waterflooding was observed in Saskatchewan and Alberta, which is from 0.3% to 44% as shown in Figure 1.2. Although waterflooding performances were conflicting in different operations, many great potentials of the waterflooding were still observed in the field: 24% of OHOIP-Disc has been recovered by waterflooding in western Canada (Renouf, 2007); much more oil was recovered at high water cuts (Kumar et al., 2008); the produced oil higher than that predicted by conventional waterflooding theory (Alvarez & Sawatzky, 2013); a remarkable amount of oil was recovered even at a reservoir with the dead oil viscosity of 2000 cp (Beliveau, 2009). In addition, due to the low cost and little environmental pollution, waterflooding may be a better choice for thin reservoirs than thermal based methods (e.g. SAGD, steam injection, etc.).
Therefore, two challenges exist here for heavy oil waterflooding processes: how to understand the conflicting performance and how to improve the waterflooding potential to avoid poor performances occurring. A statistical study (Ahmadloo, Asghari, & Renouf, 2010) provided a view to understand the first challenge faced by waterflooding. It is suggested that the performances of heavy oil waterflooding were more sensitive to operating parameters than reservoir properties. In order to solve the second challenge, it was found that some of the operating parameters, such as water injection rate, the starting time of waterflooding (conversion pressure) and voidage displacement ratio (VRR), were highly studied in numerical and experimental studies. The suggestions of previous studies were as following: the slow water injection rate can enhance the imbibition effect (Lu et al., 2016; Mai, 2008); the conversion pressure should be optimized to make full use of water drive and solution gas drive (Lu et al., 2016); the VRR control less than one may amplify solution gas drive (Alvarez & Sawatzky, 2013). It can be easily found that the above three operating parameters are all related to the pressure change. However, the pressure control strategy has not been directly studied yet. Moreover, it is still unclear that the relative importance of waterflooding mechanisms, such as foamy oil effect and solution gas drive, at different waterflooding stages and the optimal VRR strategy in the field (Alvarez & Sawatzky, 2013). Therefore, more studies should be further conducted to answer those key questions to improve waterflooding performances in heavy oil reservoirs.
Figure 1.1. Distribution of the original heavy oil in place by region (Meyer et al., 2007).
Figure 1.2. The distribution of the incremental oil recovery by waterflooding in Saskatchewan and Albert provinces. (Renouf & Nakutnyy, 2009).
1.2 Methodologies and objectives

The detailed objectives and methodologies are list as follow:

1. To study different pressure control patterns and depletion rates in a heavy oil-methane system through coreflooding tests to get the optimal pressure control strategy;

2. Through numerical study to further understand the heavy oil waterflooding process.

3. To investigate effects of three main mechanisms (water drive, foamy oil effect, solution gas drive) at different waterflooding stages through comparing the results in this study with those in a previous study on foamy oil flow;

4. To understand production behaviors of waterflooding in different heavy oil-solvent system.

1.3 Thesis outline

There are five chapters in this thesis. Chapter 1 introduces the heavy oil waterflooding development together with the research methodology and objectives. Chapter 2 structurally reviews research achievements in waterflooding mechanisms and effects of operating and reservoir parameters on heavy oil waterflooding. Chapter 3 presents the experimental results together with the simulation results of waterflooding in a heavy oil-methane system. Chapter 4 presents the experimental results in a heavy oil-mixed solvent system (CH$_4$ and C$_3$H$_8$) and discusses the different production behaviors of waterflooding in different heavy oil-solvent systems. Finally,
the conclusions and recommendations based on the current study are provided in Chapter 5.
CHAPTER 2   LITERATURE REVIEW

2.1 The recovery mechanisms for heavy oil waterflooding

In principle, the recovery mechanisms proposed for heavy oil waterflooding have two categories: favourable and unfavourable mechanisms. The favourable mechanisms include imbibition effect, viscosity drag, emulsion effect, foamy oil effect, and solution gas drive before free gas phase largely generated, etc. The unfavourable mechanisms include unstable displacement and viscous fingering, solution gas drive after the free gas phase largely generated, etc.

2.1.1 Favourable mechanisms for heavy oil waterflooding

2.1.1.1 Imbibition effect

Due to the heavy oil (non-wetting phase) was less mobile than water (the wetting phase), water imbibition was a very slow process in heavy oil waterflooding processes (Mei et al., 2012). However, Smith (1992) and Mei et al. (2012) identified that this mechanism was benefit to the performance of heavy oil waterflooding when a low water injection rate was implemented. Mei et al. (2012) observed that, after water breakthrough, the water in the water channels tended to imbibe to the regions around the water channels with relatively high oil saturations. Through a series of sandpack experiments, Mai (2008) proved that the capillary imbibition effect was the dominant mechanism after water breakthrough for gas-free heavy oil reservoirs. Lu et al. (2016) also found that the lower injection rate could reach higher ultimate oil recovery.

2.1.1.2 Viscosity drag

The viscosity drag was also a potential mechanism for heavy oil waterflooding (Smith, 1992; Renouf, 2007; Brice & Renouf., 2008). The viscosity drag at the oil-
water interface forced the oil around the water paths to move out with the injected water (Smith, 1992; Alvarez & Sawatzky, 2013). The oil usually moved in the form of a thin film on top of the water.

2.1.1.3 Emulsion effect

Emulsion was also a favourable mechanism for heavy oil waterflooding (Smith, 1992; Vittoratos & West, 2010; Mei, 2012). Four potential conditions were more likely to form emulsions (Kokal, S., 2008):

1. A heavy oil density of lower than 25 API;
2. A reservoir pressure of lower than 65.6 °C;
3. A reservoir with relatively low porosity and permeability;
4. Heavy oil with a high content of asphaltenes.

Normally, there were two types of emulsion in heavy oil waterflooding processes: (1) water-in-oil (W/O) emulsion and (2) oil-in-water (O/W) emulsion (Vittoratos & West, 2010). Water-in-oil emulsion often occurs when the water cut is less than 50%. However, oil-in-water emulsion usually happens when the water cut is larger than 50%, as shown in Figure 2.1.
Figure 2.1. Proposed heavy oil waterflooding type curve (Vittoratos & West, 2010).
Water-in-oil emulsion was the commonly recognized mechanism for the heavy oil waterflooding process (Mei et al., 2012). Through signals measured by nuclear magnetic resonance (NMR), Mai (2008) identified W/O emulsion in heavy oil waterflooding experiments. This kind of emulsion was helpful to the re-distribution of fluids during the heavy oil waterflooding process (Mai, 2008). After W/O emulsion was formed, it tended to block the previous water paths, which helped the injected water to flow into the previously upsweeping pores to recover more oil (Alvarez & Sawatzky, 2013). Another type of emulsion, O/W emulsion, was mentioned in Vittoratos & West’s (2010) study. This kind of emulsion flowed like a water-phase, which can improve the oil mobility to some extent (Alvarez & Sawatzky, 2013).

2.1.1.4 Foamy oil effect

Due to the heavy oil properties, the solution gas drive in heavy oil reservoirs was different from that in conventional ones at a certain pressure range (between the bubble point pressure and the pseudo-bubble point pressure). In that pressure range, the released solution gas did not form the free gas directly, but instead dispersed in the heavy oil in the form of small gas bubbles. The dispersed small gas bubbles made the volume of heavy oil increase several times in a short period. A typical heavy oil volume changing behaviour as a function of pressure was illustrated in Figure 2.2. This mechanism, foamy oil effect, can significantly increase heavy oil recoveries in primary productions.
Figure 2.2. Comparison of volume factor behaviours in conventional oil and foamy oil
(Yrigoyen & Carvajal, 2001).
In the waterflooding, the foamy oil effect do benefit to oil recovery when the reservoir pressure decline to a certain pressure range. Adams (1982) once mentioned that the solution gas drive could contribute to the better-than-predicted waterflooding projects in Lloydminster area. However, the mechanism that how the waterflooding will affect the foamy oil flow has not been discussed in the literature. How to make full use of this mechanism is still unclear in heavy oil waterflooding processes.

2.1.1.5 Solution gas drive before free gas largely generated

When the pressure decreased lower than the pseudo-bubble point pressure in a waterflooding process, the gas bubbles coalesced in the foamy oil. The gas saturation increased in water channels and the continuous gas phase began to generate. The fluids system began to go into the three-phase flow region. Before the large continuous gas phase formed, the relative permeability was not that high. Moreover, due to the Jamin effect, the relative permeability of water phase was significantly reduced by gas phase. It is a good signal for the improvement of oil-water mobility ratio in heavy oil waterflooding processes (Alvarez & Sawatzky 2013; Lu et al., 2016). In other words, water injection hindered the development and flow of the free gas phase, which saved the solution gas drive energy for heavy oil production (Smith, 1992).

2.1.2 Unfavourable mechanisms for heavy oil waterflooding

2.1.2.1 Viscous fingering

Due to the unfavourable oil-water ratio, viscous fingering commonly existed in heavy oil waterflooding processes. This kind of non-piston displacing process made the water sweep efficiency decrease. The water injection rate and recovery at
breakthrough are related to the viscous fingering. The larger water injection rate is, the severer viscous fingering occurs, the less recovery at breakthrough is obtained.

2.1.2.2 Solution gas drive after free gas largely generated

After free gas largely generated in reservoirs, the gas phase can quickly take over the previous water/oil flowing paths due to its high mobility. The relative permeability of oil became much lower than before. What’s worse, as the solution gas released from heavy oil, the heavy oil viscosity increased significantly, which was even adverse for water to displace heavy oil.

2.2 Parameters that affect performances of heavy oil waterflooding

Due to the complex mechanisms of heavy oil waterflooding, researchers not only conducted laboratory or numerical studies to investigate mechanisms in waterflooding, but also used statistical methods to study the field parameters to screen out parameters that affect performances of heavy oil waterflooding. In previous researches (Forth et al., 1997 Renouf, 2007; Brice & Renouf, 2008; Mai, 2008; Ahmadloo et al., 2010; Lu et al., 2016), the influencing parameters on heavy oil waterflooding were divided into two groups: (1) operating parameters and (2) reservoir properties.

Operating parameters that listed in statistical studies included the water injection rate, the starting time of waterflooding, the VRR, the ratio of converted producers to injectors, the number of vertical producers in primary recovery, well spacing, etc. However, the first three parameters, which were often discussed in experimental and numerical studies, are specifically reviewed in Section 2.3.
The mostly discussed reservoir parameters were permeability, wettability, heterogeneity, oil-water parameters, formation volume factor, initial oil-gas ratio, initial reservoir pressure, initial water saturation, oil density, oil viscosity, porosity, net pay, reservoir temperature, etc. However, based on the statistical study on 44 heavy oil waterflooding operations in Western Canada, Ahmadloo et al. (2010) suggested that reservoir parameters were less sensitive to the performance of heavy oil waterflooding than operating parameters. Therefore, only some of reservoir parameters are reviewed in Section 2.4 but are not studied in this work.

2.3 Effects of operating parameters on heavy oil waterflooding

2.2.1 Water injection rate

The water injection rate, an operating parameter, was a highly important parameter to be considered regarding enhancing the heavy oil waterflooding process (Renouf et al., 2004; Renouf, 2007; Mai, 2008; Singhal, 2009a and 2009b; Ahmadloo et al., 2010; Lu et al., 2016). Before water breakthrough, the oil production rate was usually proportional to the water injection rate (Mai, 2008). It has been indicated in the literature that a faster injection rate led to a faster production rate. However, due to the high oil-water mobility ratio, a faster injection rate also indicated a larger viscous force, severer viscous fingering, and a lower oil recovery factor at breakthrough. After breakthrough, the injected water flowed through the previous water channels instead of the regions surrounding water channels with relative high oil saturations, which made the viscous force become a less important mechanism to displace the heavy oil (Mai, 2008; Lu et al., 2016).
In order to enhance the performance of heavy oil waterflooding after water breakthrough, researchers have conducted many studies on the water injection rate. They found that a low water injection rate was beneficial to heavy oil waterflooding processes (Mai, 2008, Lu et al., 2016). In the experimental studies of Mai (2008) and Lu et al. (2016), the results indicated that when the water injection rate decreased, the ultimate oil recovery under the same pore volume injection increased. This was because the imbibition effect helped the injected water swept into the regions with relative high oil saturations under the low injection rate. The 3-D simulation results of Vittoratos & Zhu (2014) also found that with a decrease of the water injection rate, the heavy oil recovery increased. Additionally, the water injection rate also related to the emulsion effects. Vittoratos’ (2011) found that there existed a minimum water injection rate for emulsion development, and this rate was smaller in water-wet systems.

However, some other researchers believed that to simply set the low water injection rate was not an optimal or economical strategy to improve heavy oil recovery. Through the observations of three heavy oil waterflooding projects in Southern Alberta, Singhal (2009b) reported that a lower water injection rate led to a higher ultimate oil recovery, but lower oil production rate. Through a field statistical study, Renouf & Nakutnyy (2009) also mentioned that a low injection rate might not be suitable for field cases due to the low oil production rate. Those researchers did not deny the positive effects of imbibition on waterflooding. However, they prefer to believe that the water injection rate should be optimized to get the balance between the high production rate and the high oil recovery factor. Singhal (2009b) suggested that variable injection rates,
which mean periodically changing the injection rate from a high level to a low level, might stimulate the waterflooding performance more efficiently. Instead of using variable injection rated, Mei et al. (2012) suggested that using an intermediate injection rate not sacrificed so much ultimate oil recovery, but significantly increased the oil production rate.

Therefore, based on the experience from both laboratory and field, the best injection rate should be the one that can obtain a balance between high ultimate oil recovery and the high oil production rate.

### 2.2.2 Voidage Replacement Ratio (VRR)

The voidage replacement ratio (VRR) can be assumed as an operating strategy or an evaluation metric for heavy oil waterflooding systems. It is expressed as follows:

\[
VRR = \frac{\text{Injected water volume}}{\text{Produced liquid volume}}
\]  

From the previous statistical, experimental, and numerical studies on heavy oil waterflooding processes (Smith, 1992; Renouf, 2007; Brice & Renouf, 2008; Beliveau, 2009; Vittoratos and West, 2010, 2011; Vittoratos, 2013; Vittoratos & Zhu 2014; Delgado, 2013 Vidal & Alvarado, 2014; Kim, Vittoratos, & Kovscek, 2016), it is widely recognised that the VRR less than one benefit to heavy oil waterflooding processes. During the production period of VRR less than one, it is indicated that the injected volume is less than the produced volume, which means that the reservoir pressure is declining during the operating practices. When VRR less than one, some favourable mechanisms, such as solution gas drive (Smith, 1992; Vittoratos et al, 2014), foamy oil effect (Brice & Renouf, 2008) and emulsion (Brice et al, 2008; Vittoratos,
might be amplified to improve the heavy oil recovery. Therefore, the VRR control was significant for heavy oil waterflooding and fundamentally was a reservoir pressure control strategy (Shirlkar & Stephenson, 1994).

As the VRR control was previously controlled via the control of the injected and produced volume. Usually a constant VRR was set to evaluate waterflooding performances. The VRR has been suggested by researchers were different, which ranged from 0.7 to 1.11. However, for improving heavy oil waterflooding performances, the optimal VRR was not always a constant in whole waterflooding processes. Based on statistical study, Brice (2008) recommended that, for the oil API gravity larger than 17°, cycling reduce the VRR from 0.95 for a certain time followed by overall VRR controlled around 0.93 to 1.11 can be economical for heavy oil waterflooding. Based on the results of numerical simulations, Vittoratos et al. (2014) found that heavy oil waterflooding can achieve initial benefit when VRR equal to 0.7, but to achieve the better final recovery the VRR should be raised to 1. However, those suggestions for optimize VRR strategy were ambiguous, which needed some experimental studies to further investigate it.

2.2.3 The starting time of waterflooding

The optimal starting time of waterflooding strongly affects the waterflooding performances. With pressure declining in waterflooding processes, the free gas is generated in reservoirs, which establishes high mobility channels for water/gas phase and reduces oil mobility with oil viscosity increasing. Therefore, it is usually recommended to conduct the waterflooding at early stage of primary production. This
is because the continuous gas phase was not largely formed at early stage. However, the “early stage” for the starting time of waterflooding is an ambiguous concept in previous studies. In the literature, the early stage is identified by oil recoveries or reservoir pressures.

From the field experiences reported by Adams (1982), it was observed that the starting times of waterflooding were based on how much oil had been recovered from the OOIP. The recommended starting time of waterflooding was after no more than 8% or 1.5~2.5% of the OHOIP was recovered from the primary production processes for heavy oil with a density less than 17 API or 17~23 API, respectively (Brice & Renouf, 2008).

Another starting time of waterflooding was selected based on the model/reservoir pressure. In Lu et al.’s (2016) experimental study, the conversion pressure, at which the pressure level was chosen to start the waterflooding, was studied in six tests. Six conversion pressures, which were 0%, 25%, 36.7%, 58.3%, 76.7%, and 108.3% of the bubble point pressure, were examined under the same water injection rate. The experimental results showed that the optimal time to start the waterflooding was at the pseudo-bubble point pressure (Lu et al., 2016). However, the starting time of waterflooding existed some conflicting opinions. According to the field-scale numerical simulation results, Kumar et al. (2008) suggested that the optimal starting time of waterflooding should be above the bubble point pressure.
2.4 Effects of reservoir parameters on heavy oil waterflooding

2.3.1 Rock permeability

Rock permeability was not a significant parameter that will affect the heavy oil waterflooding performances (Derakhshanfar, Jia, Jiang, Zeng, & Gu, 2011; Renouf, 2007). In general, effects of permeability on the heavy oil waterflooding process was described below.

For the low rock permeability, the capillary pressure was relatively high, which was not favourable for oil to flow. However, due to the relative high capillary pressure, the water imbibition effect was strong in the low water injection rate. Especially when the water cut was high, the imbibition effect was more efficient in low rock permeability for heavy oil waterflooding processes (Mai, 2008). Through the field experiences and laboratory tests, it was also found that more than half of the final oil recovery was produced during the high water cut (Alvarez & Sawatzky, 2013). For the high rock permeability, the mobility of oil phase was better than that in low rock permeability systems. However, the water channeling was also severer in high rock permeability too. Therefore, it is still unclear how much the rock permeability will affect the heavy oil waterflooding.

2.3.2 Rock wettability

The effects of rock wettability on heavy oil waterflooding systems might be affected by foamy oil or emulsion effect with pressure declining. Few researchers have studied the wettability effect on heavy oil waterflooding. In the literature, there are three opinions.
1. Harley (1966) pointed out that the performance of heavy oil waterflooding does not depend on rock wettability.

2. Mai (2008) stated that the water-wet wettability was essential to heavy oil waterflooding as the positive effect of imbibition effect. The field-scale simulation results obtained by Kumar et al. (2008) also supported this opinion.

3. Based on the statistical study conducted by Ahmadloo et al. (2010), it was found that wettability was not an important parameter in the field.

2.3.3 Heterogeneity

The effects of heterogeneity on fluid re-distribution and the three-phase flow system were not fully understood. Renouf (2007) pointed out that the effect of heterogeneity on heavy oil waterflooding was not as significant as that on medium oil waterflooding. However, Kumar et al. (2008) believed that heterogeneity was a significant factor for waterflooding performance. In Kumar et al.’s (2008) study, a field-scale simulation model with an oil-water ratio of 600 and 6000 was studied. The results indicated that, if the waterflooding was conducted with primary production, the heterogeneity had no effect on the low oil-water ratio system (600), but it had a positive impact on the high oil-water ratio system (6000). However, if waterflooding was conducted after the primary production, the low heterogeneity benefited to oil production in both oil-water ratio systems.

2.3.4 Oil-water mobility ratio

The oil-water mobility ratio was one of the most important reasons that caused the difference between light and heavy oil waterflooding processes. Although the viscous
fingering in the heavy oil waterflooding was severer than that in conventional light oil waterflooding, both field and laboratory studies reported that a remarkable amount of heavy oil still can be recovered under the unfavourable oil-water mobility ratio.

Another surprising finding was that the ultimate oil recovery in heavy waterflooding processes was not always inverse with the oil-water ratio. Figure 2.3 illustrated the relationship between the incremental waterflooding oil recovery and oil-water ratio for four Saskatchewan projects. The figure showed that even when a similar oil-water ratio was shown in the project of Court Bakken and Marsden South, the difference in the incremental oil recovery was large. It is indicated that other parameters existed, which are more important than the mobility ratio to affect the performances of heavy oil waterflooding.
Figure 2.3. Incremental oil recovery by waterflooding vs. pore volume injected for four Saskatchewan projects (Kumar et al., 2008).
2.5 Chapter Summary

From the literature review in this chapter, it is found that extensive laboratory experiments, numerical simulations, and field-scale statistical studies have been conducted to investigate the waterflooding mechanisms and the influencing parameters for heavy oil waterflooding.

For waterflooding mechanisms, effects of favourable and unfavourable mechanisms have been discussed respectively. To improve the waterflooding potential, favourable mechanisms, such as foamy oil effect, solution gas drive, etc., should be utilized properly. However, how to enhance favourable mechanisms in heavy oil waterflooding were not fully discussed in previous studies.

For influencing parameters, operating parameters and reservoir properties are discussed respectively. Based on statistical studies, it was found that operating parameters were more sensitive to waterflooding performances than reservoir properties. For those operating parameters, water injection rate, the starting time of waterflooding, and VRR control were highly discussed in the literature. However, their related parameter, pressure change, are rarely directly discussed in heavy oil waterflooding processes.
CHAPTER 3 WATERFLOODING PERFORMANCES IN A HEAVY OIL-METHANE SYSTEM

3.1 Introduction

As a relatively inexpensive secondary oil recovery technique, heavy oil waterflooding has been applied in Western Canada for more than 50 years (Miller, 2006). However, the incremental heavy oil recovered by waterflooding varied from 1% to 20% of the OOIP (Kumar et al., 2008). To better support field practices, many studies have been conducted to understand the conflicting performances of waterflooding in Western Canada. Those studies can be divided into two groups. One group focused on statistical studies for selecting the key parameters for waterflooding performance in the field-scale. The other group investigated the key parameters to enhance heavy oil waterflooding processes in the lab-scale.

The statistical studies conducted by Renouf et al. (2004) and Ahmadloo et al. (2010) have investigated 57 and 44 heavy oil waterflooding operations in Western Canada, respectively. Both of the studies concluded that waterflooding performances were more sensitive to operating parameters than reservoir properties. The significant operating parameters listed in those two statistical studies were the water injection rate, the starting time of waterflooding, the voidage replacement ratio (VRR) control strategy, the ratio of converted producers to injectors, well spacing, etc. As the above parameters were selected based on field data, only part of them have been specifically discussed by scholars at the laboratory level to understand the mechanisms of heavy oil waterflooding processes. The top three parameters studied in the literature are the...
water injection rate, the starting time of waterflooding, and the VRR control strategy. Regarding the water injection rate, the literature indicated that a relatively low injection rate should be chosen to reach a balance between the ultimate oil recovery and the oil recovery rate (Lu et al., 2016; Mai, 2008; Mei et al., 2012). Concerning the start time of waterflooding, most research studies suggested that waterflooding should be conducted at the early stage of primary production (Adams, 1982; Brice & Renouf, 2008; Kumar et al., 2008; Lu et al., 2016). Regarding the VRR control, a widely recognition for heavy oil waterflooding was the VRR should be less than one (Beliveau, 2009; Brice & Renouf, 2008; Delgado, 2013; Kim et al., 2016; Renouf, 2007; Smith, 1992; Vidal & Alvarado, 2014; Vittoratos et al., 2011; Vittoratos & West, 2010; Vittoratos & Zhu, 2014).

It can be easily found that the top three parameters mentioned above are all related to the pressure change. For instance, the VRR less than one indicated reservoir pressure decline (Kim et al., 2016; Vittoratos, 2013); varied injection rates meant pressure fluctuation (Singhal, 2009b). Therefore, pressure change is a significant parameter in heavy oil waterflooding processes. It was because pressure change may stimulate the nature energies, such as solution gas drive, foamy oil effect, compaction effect, to enhance heavy oil waterflooding performances (Smith, 1992). However, effects of pressure change on waterflooding performances has not been directly studied yet.

In this work, to better understand and utilize pressure change to improve waterflooding potentials in heavy oil reservoirs, a series of one-dimensional coreflooding tests are conducted in a heavy oil-methane system. More specifically,
four different pressure control patterns and four pressure depletion rates are studied. The four pressure control patterns are (1) primary production followed by waterflooding, (2) primary-plus waterflooding, (3) cyclic water injection with continuous pressure depletion, and (4) cyclic injection with cyclic production. The four depletion rates are (1) 0.45 kPa/min, (2) 1 kPa/min, (3) 2 kPa/min, and (4) 3 kPa/min.

Through experimental results, it is found that primary-plus waterflooding (i.e. the waterflooding conducted with primary production simultaneously) with a proper depletion rate can make full use of water drive and nature energies. In addition, it is found that the pressure depletion rate strongly affects the contributions of different mechanisms at different stages of waterflooding.

For numerical study, the Johnson-Bossler-Naumann (JBN) method (Johnson, Bossler, & Naumann, 1959) and the method of Tang et al. (2006) are employed to provide initial relative permeability curves for history match experimental data. The results of the numerical simulations indicates that the theory-assisted method can provide good initial relative permeability curves for tuning, but it is still not enough for the numerical model to match the gas production very well. The foamy oil module is needed for history matching the heavy oil waterflooding processes if solution gas drive or foamy oil effect involved.

3.2 Experimental Section

3.2.1 Experimental setup

Figure 3.1 shows the schematic diagram of the waterflooding setup for the heavy oil-methane system. The experimental setup consists four systems: (1) the
multifunctional control system, (2) the coreholder system, (3) the producing and sampling system, and (4) the data acquisition system.

3.2.1.1 Multifunctional Control System

The multifunctional control system consists of a brine cylinder, an oil-gas mixer, three syringe pumps, a back pressure regulator (BPR), and a pressure transducer with an accuracy of ± 0.08% FS (full scale), which is labeled “P4.” Four main functions of this control system are listed as follows,

- Control the outlet pressure in the producing and sampling system by using Pump #3.
- Control the water injection for the coreholder system by using Pump #2.
- Supply the confining pressure by using Pump #3.
- Make heavy oil-solvent systems in the oil-gas mixer by using Pump #2, Pump #3, and the BPR.

3.2.1.2 Coreholder System

The coreholder system consists of a coreholder with a maximum working pressure of 5,000 psi and three pressure transducers (“P1,” “P3,” and “P5”). The transducer P1 is used to record the inlet pressure. The transducer P5 is used to record the outlet pressure. The transducer P3 is used to monitor the confining pressure.
Figure 3.1. Schematic diagram of the waterflooding setup for the heavy oil-methane system.
3.2.1.3 Producing and Sampling System

The producing and sampling system consists of an automatic 4-way valve, an electronic balance with an accuracy of 0.01g, a Milligas counter with an accuracy of ± 3% of reading, and two BPRs.

3.2.1.4 Data Acquisition System

The data acquisition system includes a computer, a set of LabView devices, and three data acquisition software.

3.2.2 Experimental preparation

3.2.2.1 Oil Sample and Brine

A typical heavy oil sample from Lloydminster area, is compounded with methane that has a purity of 99.99% (supplied by Praxair) to synthesize the live oil sample for this study. The heavy oil properties and the estimated components are listed in Table 3.1. For the live oil sample, the mole factions of heavy oil and methane are 84% and 16%, respectively. The specific live oil properties for all tests are listed in Table 3.2. Moreover, the typical brine sample from the oil field is used in the experiments to conduct the waterflooding.

3.2.2.2 Core Sample

The cores (L: 12 in, D: 1.5 in) made by Bentheimer sandstone are used in the coreflooding tests. In this study, the physical properties of the cores, such as the porosity, permeability, and initial oil saturation, etc., are measured, and they are listed in Table 3.3.
Table 3.1. Heavy oil sample properties and estimated components.

<table>
<thead>
<tr>
<th>Heavy oil properties</th>
<th>SARA compositions</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Component</td>
</tr>
<tr>
<td>Temperature °C</td>
<td>Density kg/m³</td>
</tr>
<tr>
<td>20</td>
<td>28.4</td>
</tr>
<tr>
<td></td>
<td>27.0</td>
</tr>
<tr>
<td></td>
<td>22.5</td>
</tr>
<tr>
<td></td>
<td>14.8</td>
</tr>
<tr>
<td></td>
<td>7.30</td>
</tr>
</tbody>
</table>

* After correction for vaporization losses and solvent content of recovered fractions.
Table 3.2. Live oil properties for the heavy oil-methane system.

<table>
<thead>
<tr>
<th>Test #</th>
<th>Live Oil System</th>
<th>Live oil viscosity* (cp)</th>
<th>GOR Vol/Vol</th>
<th>$B_o$**</th>
<th>Saturation pressure kPa</th>
</tr>
</thead>
<tbody>
<tr>
<td>CM#1</td>
<td>Heavy Oil-Methane</td>
<td>686</td>
<td>10.38</td>
<td>NA</td>
<td>3000</td>
</tr>
<tr>
<td>CM#2</td>
<td>Heavy Oil-Methane</td>
<td>777</td>
<td>10.23</td>
<td>NA</td>
<td></td>
</tr>
<tr>
<td>CM#3</td>
<td>Heavy Oil-Methane</td>
<td>776</td>
<td>10.2</td>
<td>NA</td>
<td></td>
</tr>
<tr>
<td>CM#4</td>
<td>Heavy Oil-Methane</td>
<td>795</td>
<td>10.13</td>
<td>1.41</td>
<td></td>
</tr>
<tr>
<td>CM#5</td>
<td>Heavy Oil-Methane</td>
<td>753</td>
<td>10.18</td>
<td>NA</td>
<td></td>
</tr>
<tr>
<td>CM#6</td>
<td>Heavy Oil-Methane</td>
<td>837</td>
<td>10.06</td>
<td>NA</td>
<td></td>
</tr>
<tr>
<td>CM#7</td>
<td>Heavy Oil-Methane</td>
<td>747</td>
<td>10.29</td>
<td>1.50</td>
<td></td>
</tr>
<tr>
<td>CM#8</td>
<td>Heavy Oil-Methane</td>
<td>647</td>
<td>10.46</td>
<td>1.45</td>
<td></td>
</tr>
</tbody>
</table>

Notes:
- GOR: Gas oil ratio
- $B_o$: Formation volume factor
- CM#: The number of the coreflooding test for the heavy oil-methane system.
- NA: The data is not measured in this study.
- *: Live oil viscosities are estimated by using Darcy’s Law.
- **: The values are estimated by reading the changing volumes of oil during the GOR measurements.
Table 3.3. Physical properties of cores for the heavy oil-methane system.

<table>
<thead>
<tr>
<th>Test #</th>
<th>Porosity</th>
<th>Permeability (± 200) mD</th>
<th>Rock compressibility (± 3E-08) 1/kPa</th>
<th>Initial water saturation %</th>
<th>Temp. (± 1) °C</th>
<th>Aging time (± 0.1) days</th>
<th>OOIP cm³</th>
</tr>
</thead>
<tbody>
<tr>
<td>CM#1</td>
<td>23</td>
<td>1380</td>
<td>9.00E-07</td>
<td>12</td>
<td>19</td>
<td>3</td>
<td>70.6</td>
</tr>
<tr>
<td>CM#2</td>
<td>24</td>
<td>1280</td>
<td>NA</td>
<td>12</td>
<td>19</td>
<td>12</td>
<td>72.3</td>
</tr>
<tr>
<td>CM#3</td>
<td>23</td>
<td>1080</td>
<td>9.35E-07</td>
<td>8</td>
<td>19</td>
<td>4</td>
<td>75.4</td>
</tr>
<tr>
<td>CM#4</td>
<td>24</td>
<td>1080</td>
<td>NA</td>
<td>7</td>
<td>19</td>
<td>4</td>
<td>77.3</td>
</tr>
<tr>
<td>CM#5</td>
<td>23</td>
<td>1050</td>
<td>NA</td>
<td>12</td>
<td>19</td>
<td>3</td>
<td>72.2</td>
</tr>
<tr>
<td>CM#6</td>
<td>24</td>
<td>1200</td>
<td>NA</td>
<td>10</td>
<td>19</td>
<td>3</td>
<td>72.4</td>
</tr>
<tr>
<td>CM#7</td>
<td>23</td>
<td>1080</td>
<td>NA</td>
<td>9</td>
<td>19</td>
<td>3.5</td>
<td>74.9</td>
</tr>
<tr>
<td>CM#8</td>
<td>24</td>
<td>1180</td>
<td>NA</td>
<td>12</td>
<td>19</td>
<td>3</td>
<td>73.0</td>
</tr>
</tbody>
</table>

Note:
CM# The number of the coreflooding test for the heavy oil-methane system.
NA The data is not measured in this study.
Table 3.4. Comparison between the experimental conditions and the properties of typical heavy oil reservoirs in Lloydminster area.

<table>
<thead>
<tr>
<th>Reservoir properties</th>
<th>Lloydminster (Adams, 1982)</th>
<th>Experimental conditions</th>
</tr>
</thead>
<tbody>
<tr>
<td>Porosity, %</td>
<td>29 to 35</td>
<td>23 to 24</td>
</tr>
<tr>
<td>Permeability, mD</td>
<td>Avg. 2000</td>
<td>1080 to 1380</td>
</tr>
<tr>
<td>Initial water saturation,%</td>
<td>10 to 25</td>
<td>7 to 12</td>
</tr>
<tr>
<td>Oil gravity, g/cm³</td>
<td>0.95 to 0.98</td>
<td>0.9454</td>
</tr>
<tr>
<td>Tank oil viscosity, cp</td>
<td>950 to 6500</td>
<td>2760</td>
</tr>
<tr>
<td>Initial solution GOR, std m³/m³</td>
<td>10</td>
<td>≈10</td>
</tr>
<tr>
<td>Initial reservoir pressure, kPa</td>
<td>3500</td>
<td>4000</td>
</tr>
<tr>
<td>Bubble-point pressure, kPa</td>
<td>3500</td>
<td>3000</td>
</tr>
<tr>
<td>Initial formation volume factor, res m³/stock-tank m³</td>
<td>1.02</td>
<td>NA</td>
</tr>
<tr>
<td>Reservoir temperature, °C</td>
<td>22</td>
<td>19</td>
</tr>
<tr>
<td>Initial reservoir oil viscosity, cp</td>
<td>400 to 1500</td>
<td>647 to 837</td>
</tr>
</tbody>
</table>

Note:

NA  This data is not measured in this study.
In principle, the experimental conditions in this study are similar to the typical reservoir properties of heavy oil reservoirs in Lloydminster area, which are summarized in Table 3.4.

3.2.2.3 Produced fluids volume measurement

For the heavy oil waterflooding process, the samples of the produced liquid at different waterflooding stages are shown in Figure 3.2 (a). It is found that the produced water and oil are not automatically separate with each other, which makes the volume reading not be directly conducted. The centrifuge process is needed to read the volumes of water and oil accurately. However, if oil ring phenomenon shown in Figure 3.2 (b), happens after centrifuge process, it is still impossible to read the volumes of water and oil accurately. Based on experimental data, it is found that the oil ring phenomenon often occurs when water cuts are above 85%. However, it is known that a remarkable amount of heavy oil could be recovered at high water cuts (Beliveau, 2009; Kumar et al., 2008; Mei et al., 2012). Therefore, reading the volumes accurately at high water cuts is significant for heavy oil waterflooding processes.

A new oil-water separation method is introduced to solve the volume reading accuracy when oil ring occurs. This new method can separate the water from heavy oil quickly without sacrificing much accuracy (usually less than 0.5% volume of liquid loss). The schematic plot of this method is shown in Figure 3.3. The separating procedure is simple. By using high air injection pressure, the produced liquid, which includes water and oil, is sprayed out of the tube in the form of small liquid drops. When heavy oil drops are adsorbed on the surface of strong oil-wet wax papers, the
ejected water drops flow through wax papers and are collected in a precisely graduated centrifuge tube. Finally, the water is separated with heavy oil and read in the centrifuge tube.

After the volumes of the water and oil are determined for each tube, Eq. 3.1 is used to evaluate the reading errors. Figure 3.4 shows the mass error of each tube in Test CM#1. It is observed that expect the error in tube #25, the absolute errors in other tubes are controlled less than 0.6%.

\[
\text{Error} = \frac{\rho_{\text{oil}}(V_{\text{liquid}} - V_{\text{water}}) + \rho_{\text{water}}V_{\text{Water}} - \text{Mass}_{\text{liquid measured}}}{\text{Mass}_{\text{liquid measured}}} \quad (3.1)
\]
Figure 3.2. Photos of the produced liquids: (a) the form of produced liquid and (b) the oil ring phenomenon.
Figure 3.3. Schematic diagram of the new method for separating heavy oil and water.
Figure 3.4. The mass error of the produced liquid for each tube (Test CM#1).
3.2.3 Experimental procedures

To improve waterflooding potentials for heavy oil reservoirs, four different pressure control patterns are evaluated. In this univariate analysis of pressure control patterns, injection rate and depletion rate are set as constant values. For injection rate, it was known that a slow injection rate does not only reduce the severe water channeling, but also increase the oil recovery due to the imbibition effect (Lu et al., 2016; Mai, 2008; Mai & Kantzas, 2008). Based on the experiments conducted by Lu et al. (2016), 0.05 cc/min is selected as the injection rate for all tests in this study. For depletion rate, 1 kPa/min is selected as the pressure depletion rate based on the foamy oil study conducted by Zhou et al. (2016) in a heavy oil-methane system. The specific procedures of each pressure control pattern, which can be quickly reviewed in Table 3.5, are discussed in Sections 3.2.3.1–3.2.3.4.

3.2.3.1 Pattern 1: Primary production followed by waterflooding

The primary production is firstly conducted with a constant depletion rate (1 kPa/min). When the outlet pressure declines to 350 kPa, waterflooding is carried out under a fixed injection rate (0.05 cc/min) until the water cut reached above 95%.

3.2.3.2 Pattern 2: Primary-plus waterflooding

Pattern 2, which was called primary-plus waterflooding by Kasraie, Sammon, and Jespersen (1993), is the technique that conduct waterflooding simultaneously with primary production. It has been used in the Batrun Unit 4 of Saskatchewan (Kasraie et al., 1993). In this study, the injection rate and depletion rate are 0.05 cc/min and 1
kPa/min, respectively. When water cuts of the produced liquid reach above 95% or the outlet pressure drops to the atmosphere pressure, the experiment will be terminated.

3.2.3.3 Pattern 3: Cyclic water injection with cyclic pressure depletion

In the literature, it was found that many proposed techniques for enhancing heavy oil recovery, such as cyclic solvent injection (CSI), pressure pulsing, and water-alternating-gas (WAG) process, have periods of pressure build-up and draw-down (i.e. pressure cycling). It was believed that the pressure cycling could break the equilibrium states of the reservoir fluid systems to stimulate heavy oil recovery (Singhal, 2009). Therefore, based on the same idea, Pattern 3 is proposed to investigate whether pressure cycling can take full advantage of natural energies in waterflooding processes. This Pattern is similar to Pattern 2 except for the pressure cycling parts. For one pressure cycle, there are four steps:

1. Production period: Both the injector and producer are opened to conduct waterflooding with pressure declining. This period is terminated when the outlet pressure reaches roughly 2,000 kPa.

2. Injection period: The producer is shut to let the pressure build up with the continuous water injection until the model reaches the bubble point pressure (3,000 kPa) again.

3. Soaking period: The injector is shut for approximately 10 hours for soak.

4. Another production period is started for the next pressure cycle.

3.2.3.4 Pattern 4: Cyclic injection with cyclic production
Cyclic injection with cyclic production was first introduced into heavy oil waterfloods as a VRR control method by Brice et al. (2014). The field results in Alaska were encouraging as the oil recovery rate was increased while the water production significantly decreased (Brice et al., 2014). However, the performance of this Pattern remained unclear as only one injection/production cycle was reported by Brice et al. (2014). Therefore, Pattern 4 is included in this study to understand the characteristics of cyclic injection with cyclic production further. The procedures are:

1. Production period: The injector is shut. The producer is opened to conduct the pressure depletion process.
2. Injection period: The producer is shut. The injector is opened to inject the fixed water volume, which equals 90% of the volume of the previous produced liquid in a slow injection rate.
3. Another production period is started for the next pressure cycle.

At first glance, it is difficult to distinguish between Pattern 3 and Pattern 4. However, there are three main differences between those two patterns. First, Pattern 4 does not exist a period that both the producer and injector are opened. Second, the pressure control in Pattern 4 is passive in the injection period. In other words, it is unclear about the target of the build-up pressure before the designed volume of water is injected. However, for Pattern 3, the pressure control is active in the injection period, as the target of the build-up pressure was pre-designed for each pressure cycle. Third, Pattern 4 does not have a soaking period while there is one in Pattern 3.
Table 3.5. Operational details of each pressure control Pattern.

<table>
<thead>
<tr>
<th>Pattern type</th>
<th>Test</th>
<th>Water injection rate</th>
<th>Pressure depletion rate</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>cm³/min</td>
<td>kPa/min</td>
</tr>
<tr>
<td>Pattern 1</td>
<td>CM#3</td>
<td>(\text{① }0^a) (\text{② }0.05^b)</td>
<td>(1^a,b)</td>
</tr>
<tr>
<td></td>
<td>CM#1</td>
<td>(\text{② }0.05^b)</td>
<td>(1^b)</td>
</tr>
<tr>
<td></td>
<td>CM#2</td>
<td>(\text{② }0.05^b)</td>
<td>(1^b)</td>
</tr>
<tr>
<td>Pattern 2</td>
<td>CM#6</td>
<td>(0.05^b)</td>
<td>(2^b)</td>
</tr>
<tr>
<td></td>
<td>CM#7</td>
<td>(0.05^b)</td>
<td>(3^b)</td>
</tr>
<tr>
<td></td>
<td>CM#8</td>
<td>(0.45^b)</td>
<td></td>
</tr>
<tr>
<td>Pattern 3</td>
<td>CM#4</td>
<td>(\text{① }0.05^b) (\text{② }0.05^c) (\text{③ }0^d)</td>
<td>(\text{Repeat ① to ③ for another pressure cycle}) (\text{Repeat ① to ③ for another pressure cycle})</td>
</tr>
<tr>
<td>Pattern 4</td>
<td>CM#5</td>
<td>(\text{① }0^b) (\text{② }0.05^c)</td>
<td>(\text{Repeat ① to ② for another pressure cycle}) (\text{Repeat ① to ② for another pressure cycle})</td>
</tr>
</tbody>
</table>

Note:

- **a** Primary production period
- **b** Production period in waterflooding process
- **c** Injection period
- **d** Soaking period
3.3 Experimental Results and Discussion

3.3.1 Reproducibility of tests

Test CM#1 and CM#4 are conducted to investigate the reproducibility of the test. The production profiles of those tests are shown in Figure 3.5. From Figure 3.5, it can be observed that the production profiles of oil recovery, water cut and produced GOR are all overlapped with each other for Test CM#1 and CM#4. It is indicated that the tests of this study are repeatable.

3.3.2 The discussion of different pressure control patterns

Test CM#1, CM#3, CM#4 and CM#5 are carried out to investigate waterflooding performances under different pressure control patterns. The detailed model properties and operating parameters can be checked in Section 3.2.2 and 3.2.3, respectively. The experimental results for each pattern are specifically discussed as follow.

3.3.2.1 Primary production followed by waterflooding (Pattern 1)

Test CM#3 is conducted to investigate the waterflooding performance after the primary production is terminated. Figure 3.5 (a) and (b) shows the experimental results in the oil recovery, water cut, produced GOR, and outlet pressure.

The primary production is conducted from 0 to 60 hours with depletion rate of 1 kPa/min. In this production region, 18.5% of OOIP is recovered. As the research topic of this study is not in this part, the production behavior of primary production is not discussed here.
The subsequent waterflooding is conducted from 60 hours and terminated when water cut reaches above 95%. The oil recovery contributed by waterflooding is 51.3% of OOIP.
Figure 3.5. Reproducibility of heavy oil waterflooding tests: (a) oil recovery factor; (b) water cut; (c) produced GOR.
Figure 3.6. Results of coreflooding in Test CM#3 (Pattern 1): (a) oil recovery and outlet pressure as a function of production time; and (b) water cut and produced GOR as a function of production time.
For waterflooding period, two regions can be divided: the region before breakthrough and the region after breakthrough. The region before breakthrough ranges from 60 to 68 hours. During this 8 hours’ production, only 3.1% of OOIP is recovered by waterflooding. It is because the produced GOR reaches as high as 155 vol/vol before waterflooding starts, which indicates that the high mobility channels for gas flowing has been existed in the model. The injected water tends to flow through the high mobility channels generated by gas flowing instead of sweeping the oil around those channels. Therefore, only small amount of oil has been recovered. For the produced GOR, it slightly increases and then significantly decreases during this period. The first increase of the produced GOR is because of the injected water pushes trapped free gas out of the model. However, with water injection, two phases flowing system change into a three-phase flowing system, which indicates that the relative permeability of gas becomes lower than before. Therefore, the sharp drop in the produced GOR is observed.

After water breakthrough, the production profile can be divide into another two regions. The first region is between 68 to 90 hours, where the water cut is lower than 80%. In this region, water cut and oil producion all increases rapidly. However, the produced GOR maintains in an extremely low level, which means that the continuous gas phase is not existed. The high water cuts after water breakthrough are mainly because of the unfavorable mobility ratio of oil and water. The reasons for the rapidly increasing oil recovery rate can be summarized in two aspects: (1) the gas bubbles in relative high oil saturation regions pushes the trapped oil into the water paths due to
the pressure gradient; and (2) the injected water tends to sweep the channels around
the water paths due to the Jamin effect. The second region after breakthrough is
between 90 to 119 hours, where water cuts maintain around 90%. In this region, oil
recovery rate gradually declines. It is because the separated gas phase beginning to
form the continuous gas phase again as that is observed in high produced GOR. The
relative permeability of oil becomes lower than before. The water tends to flow through
the high mobility channels. Therefore, the water cut finally reaches above 95%.

3.3.2.2 Primary-plus waterflooding (Pattern 2)

Test CM#1 is conducted to investigate the waterflooding performance in primary-
plus waterflooding process. Figure 3.7 (a) and (b) represents the oil recovery, water
cut, and produced GOR as a function of production time for Tests CM#1.

Based on water cuts shown in Figure 3.7 (b), the production profiles can be divided
into two regions: before breakthrough and after breakthrough. The region before water
breakthrough ranges from 0 to 6.4 hours. During this period, the outlet pressure is
above saturation pressure of the heavy oil-methane system. Therefore, no gas phase
exists in the model. Water drive is the main mechanism for the oil production. Finally,
20.8% of OOIP is contributed by pure water drive in this region.

After water breakthrough, the oil recovery rate decreases slightly than that before
breakthrough. It is because the injected water tends to flow through the water channels
created before breakthrough instead of sweep the areas around the channels. Moreover,
with the pressure declining, the mobility ratio of oil and water begins to increase as
solution gas begins to release from oil.
Figure 3.7. Results of coreflooding in Test CM#1 (Pattern 2): (a) oil recovery and outlet pressure as a function of production time; and (b) water cut and produced GOR as a function of production time.
However, for the most part of this region after breakthrough, the oil recovery rate maintains at a certain level even if water cuts are as high as 85%. It is indicated that there must have some other mechanisms involved into the waterflooding process to keep the relative high oil production rate. Between 36 to 47 hours, it is clearly observed in Figure 3.7 (a) and (b): the oil recovery rate increases slightly; the produced GOR lower than the initial GOR and water cut decreases sharply. Moreover, the model pressure of this region is around the pseudo-bubble point pressure of the heavy oil-methane system under depletion rate of 1 kPa/min. Therefore, it can be concluded that solution gas drive must be existed in this region and play an important role in oil recovery.

After water breakthrough, 42.7% of OOIP is recovered by waterflooding. 74.9% of the recovery after breakthrough obtained when water cuts above 80%. This observation is consistent with previous studies (Lu et al., 2016).

3.3.2.3 Cyclic water injection with continuous pressure depletion (Pattern 3)

Test CM#4 is conducted to evaluate the performance of Pattern 3.

Figure 3.8 (a) and (b) represents the oil recovery, water cut, and produced GOR as a function of production time for Tests CM#4. Based on the pressure control pattern, the production profiles are divided into three regions: (1) the primary-plus waterflooding region (Region I), (2) the pressure-cycling region (Region II), and (3) the post-pressure-cycling region (Region III).
Figure 3.8. Results of coreflooding in Test CM#4 (Pattern 3): (a) oil recovery and outlet pressure as a function of production time; and (b) water cut and produced GOR as a function of production time.
Region I is from 0 to 30.3 hours, where the outlet pressure declines linearly from 4,000 to 2,000 kPa with a fixed water injection rate of 0.05 cc/min. As the pressure control strategy of Pattern 3 is the same as that in Pattern 1, the production characteristics for Test CM#4 are not discussed here again.

Region II is from 30.3 to 94.4 hours. Three pressure cycles are conducted in this region. For the first two pressure cycles, the model pressure is built up from 2000 to 3000 kPa and then declined linearly to 2000 kPa. For the third pressure cycle, the model pressure is pressurized from 2000 to 2500 kPa and then declined linearly to 2000 kPa. By comparing oil recovery rates (i.e. the slopes the oil recovery curve) at the same pressure range in Region I and II, it is found that except the performance of cycle 1, the performances of other two cycles are much lower than that shows in Region I. It implies that the pressure cycling process has some positive effects on stimulating the favourable mechanisms, such as foamy oil effect. However, those positive effects decrease with the number of pressure cycle increasing. In other words, the positive effects of pressure cycling are limited in heavy oil waterflooding processes. It is because with the pressure cycling continuing, the small gas bubbles separated in the foamy oil tend to be compressed to form the continuous free gas slugs instead of dissolving into the heavy oil again. Therefore, the abnormal GOR profiles and high water cuts are observed in Region II as that shown in

Figure 3.8 (b).

Region III is from 94.4 to 117.3 hours. At first 8.6 hours of Region III, there is no oil production. It is because the injected water takes main flowing paths and forces the
separated gas bubbles into a continuous phase. Therefore, water cuts and produced GOR are extremely high in this period. After that, the solution gas from the relative high oil saturation areas involves again with pressure declining, which pushes more oil into the waterflooding paths. The decreasing water cuts and increasing oil recovery rate shows again. However, the region of high oil production cannot last long as free gas phase is largely and continuously formed in the model. From

Figure 3.8 (b), it can be observed that water cuts and produced GOR increase quickly. It indicates the gas and water takes over the main flowing paths. And, no more oil will be produced shortly. Finally, 60.9% of OOIP is recovered from Pattern 3.

3.3.2.4 Cyclic injection with cyclic production (Pattern 4)

Test CM#5 is conducted to evaluate the waterflooding performance in Pattern 4. Figure 3.9 (a) and (b) represents the oil recovery, water cut, and produced GOR as a function of production time for Tests CM#5. The production profiles of Test CM#5 are divided into two regions based on water cuts shown in Figure 3.9 (b): the region before breakthrough (Region I) and the region after breakthrough (Region II).

Region I is from 0 to 92.97 hours. As the producer and injector are not opened at the same time, the effects of pressure decline in producer on the viscous fingering is not severe. Therefore, the water breakthrough time has been delayed significantly. In this region, 29.63% of OOIP is recovered without any water production. This high recovery factor at breakthrough is mainly because of the incomplete VRR control stimulated the foamy oil effect in the waterflooding process.
Figure 3.9. Results of coreflooding in Test CM#5 (Pattern 4): (a) oil recovery and outlet pressure as a function of production time; and (b) water cut and produced GOR as a function of production time.
Region II is from 92.97 to 204.08 hours. Due to the VRR control and the control method of the producer and injector, the oil is produced with water cuts below 80% 70% of the production time after breakthrough. However, once the water increases higher than 80%, the oil recovery rate is reduced rapidly, which is different from the general understanding that a large amount of heavy oil could be recovered at high water cuts (above 80%).

For Pattern 4, when producer is opened, no water is injected to seize the high mobility channels that generated by previous water flow. Therefore, oil recovery rate of some pressure ranges in Patter 4 are higher than that in other patterns. However, Pattern 4 takes more than 200 hours to produce 62% of OOIP, which takes much longer time to get the same oil recovery when is compared with other patterns. Therefore, whether this pattern is economic technique needs more studies.

3.3.2.5 The comparison of different pressure control patterns

Based on two criteria (i.e. ultimate oil recovery and overall average production rate), Figure 3.10 (a) is plotted to compare oil recovery factors in different stages for different patterns. Figure 3.10 (b) is plotted to compare overall average production rates for different patterns. In this study, the overall average production rate is defined as the ultimate oil recovery factor divided by total flood life.

The ultimate oil recoveries of the four patterns (see Figure 3.10 (a)) are ranked in order: Pattern 1 (69.8% of OOIP, which includes the oil recoveries of primary production and waterflooding), Pattern 2 (63.5% of OOIP), Pattern 4 (62% of OOIP), and Pattern 3 (60.91% of OOIP). For Pattern 1, 51 more hours waterflooding are
conducted when pressure drops to the atmosphere pressure. However, for other three patterns, they are terminated when the outlet pressures decline to the atmosphere pressure. The Pattern 1 is only 6.3% of OOIP higher than the Pattern 2. Therefore, it is hardly to say the Pattern 1 is better than Pattern 2. Moreover, from Figure 3.10 (b), it is observed that the overall average production rate of Pattern 2 is almost twice higher than that in other patterns. It indicates that Pattern 2 is better choice for heavy oil reservoirs to improve the waterflooding potentials.

Through the comparison, another interesting observation is found. If the oil recovery in primary production is looked as the oil recovery before the breakthrough, it can be easily found in Figure 3.10 (a), that the oil recovery at breakthrough is not significantly influenced by the start time of waterflooding in heavy oil systems. However, for the similar oil recoveries at breakthrough, it takes 68, 6.38, and 6.67 hours to produce for Pattern 1, 2 and 3, respectively. It indicates that the early waterflooding is important to improve waterflooding potentials.
Figure 3.10. Comparison of four different pressure control patterns in two aspects: (a) oil recovery factor; (b) overall average production rate.
3.3.3 The discussion of different depletion rates in Pattern 2

Given the fixed water injection rate (0.05 cc/min), four waterflooding tests, such as Test CM#1 (1 kPa/min), CM#6 (2 kPa/min), CM#7 (3 kPa/min) and CM#8 (0.45 kPa/min), are conducted to further evaluate the potentials of Pattern 2.

3.3.3.1 The comparison of experimental results

The record of outlet pressure for each test is plotted in Figure 3.11. For those depletion rates, Figure 3.12 to Figure 3.14 are respectively plotted to compare oil recovery factors, water cuts and produced GOR for four waterflooding tests.

For oil recovery curves in Figure 3.12, the turning points for each test are defined as the point where the oil recovery rate changes significantly. Two turning points exist for all waterflooding tests. One turning point is the water breakthrough point. It is known that the produced oil and water in heavy oil waterflooding processes cannot be automatically separated with each other as that in light oil waterflooding processes. It is difficult to identify the actual breakthrough time for heavy oil waterflooding. Therefore, only the possible time range of the breakthrough point can be read from Figure 3.13. In this study, the last record point that has 0% water cut is assumed as the breakthrough point. From Figure 3.13, it is observed that the water breakthrough time for different depletion rates are quite close. This observation is also supported by the similar oil production profiles shown in Figure 3.12.
Figure 3.11. The outlet pressure records for tests with the depletion rates of 0.45 kPa/min, 1 kPa/min, 2 kPa/min, and 3 kPa/min.
Figure 3.12. Comparison of oil recovery factors in Pattern 2 under four different depletion rates.
Figure 3.13. Comparison of the water cuts for four different pressure depletion rates in Pattern 2.
Figure 3.14. Comparison of the produced GOR for four different pressure depletion rates in Pattern 2.
The second turning points for each test are shown in Figure 3.12. For the waterflooding with the depletion rate of 1 kPa/min, 2 kPa/min and 3 kPa/min, the oil recovery rates show climbs after the second turning points. And, this phenomenon must company with a fall of water cuts when depletion rate higher than 1 kPa/min. It indicates that solution gas drive or foamy oil effect contribute to the waterflooding performances. However, for the waterflooding with the depletion rate of 0.45 kPa/min, the oil recovery rate declines with water cuts increasing after the second turning point. The produced GOR is much higher than initial GOR in the test with depletion rate of 0.45 kPa/min. It means that the free gas is largely formed after the second turning point in Test CM#8 (0.45 kPa/min). The positive effect of solution gas drive is not as strong as that in other three depletion rates.

For the production period between those two turning points, it is observed that the trends of the production profiles (oil recovery, water cuts, produced GOR) are all similar as that shown in Figure 3.12 to Figure 3.14. Moreover, the phenomenon of the produced GOR lower than initial GOR is not obvious especially for relative low depletion rates. Therefore, it is difficult to identify when foamy oil flow or solution gas drive begin to affect waterflooding performances. However, it can be concluded that the effects of depletion rate on this production period are similar for each test.

3.3.3.2 The optimal depletion rate for heavy oil waterflooding

The ultimate oil recoveries of waterflooding tests under different depletion rates are compared with the results of primary production in Zhou et al. (2016), as shown in Figure 3.15. For waterflooding results, it is found that the ultimate oil recoveries
declines with depletion rate increasing. The optimal range of the depletion rate, 0.45 to 1 kPa/min, in waterflooding is existed. However, when compares with this rate with Zhou et al.’s result, it is found that the optimal rate in waterflooding is smaller than that in primary production.

For the waterflooding in the heavy oil-methane system, 0.45 to 1 kPa/min is the optimal range for depletion rate as those two rates have the similar ultimate oil recovery factors. However, based on the overall average production rates shown in Figure 3.17, the 1 kPa/min can produce twice faster than that in 0.45 kPa/min. Therefore, 1 kPa/min is the optimal depletion rate for heavy oil waterflooding.

3.3.3.3 The optimal VRR strategy for heavy oil waterflooding

Figure 3.16 shows the cumulative VRRs recorded in the tests. From the figure, it can be observed that the cumulative VRR ranges from 0.7 to 1.1, which is similar to the recommend VRR range proposed by Brice et al. (2008) and Vittoratos et al. (2014).

From Figure 3.15 and Figure 3.16, it is found that the ultimate oil recovery is not proportionally change with the cumulative VRR. In other words, with cumulative VRR decreasing, the ultimate oil recovery not always decreases. However, by comparing Figure 3.16 and Figure 3.17, it is observed that the overall average production rate is inversely proportional to cumulative VRR. Based on the relationship of cumulative VRR with ultimate oil recovery and overall average production rate, it recommends to use the VRR around 0.9 to get the balance between ultimate oil recovery and production rate and to use VRR around 0.7 to increase the production rate with some sacrifice of ultimate oil recovery.
Figure 3.15. Comparison of the effects of the pressure depletion rate on primary production and primary-plus waterflooding processes.
Figure 3.16. Comparison of cumulative VRR for four different depletion rates in Pattern 2.
Figure 3.17. The overall average production rates for four different depletion rates in Pattern 2.
3.3.4 The interactive effects between water drive and foamy oil effect/solution gas drive

In the literature (Adams, 1982; Alvarez & Sawatzky, 2013; Lu et al., 2016; Smith, 1992), solution gas drive/foamy oil effect was mentioned as the significant mechanism in heavy oil waterflooding processes. Moreover, it was known that performances of solution gas drive/foamy oil effect, which can significantly enhance heavy oil recovery, varied with different pressure depletion rates in primary production processes (Zhou et al., 2016). However, how the water drive will affect the performance of solution gas drive/foamy oil effect at different waterflooding stages has not been discussed directly yet. In this part, the solution gas drive and foamy oil effect will be identified in waterflooding processes by comparing with experimental results in a previous study. The interactive effects between water drive and foamy oil effect/solution gas drive will be discussed.

As the heavy oil-methane system and operating patterns are similar, three tests (Tests CM#8, CM#1, and CM#6) in Pattern 2 are selected to compare with the primary production tests (Tests 1, 2, and 3) from the study by Zhou et al. (2016). The dimensionless pressure is introduced to eliminate influences of different bubble point pressures to compare those studies in the same scale. It is defined by Eq. (3.2).

\[
P_D = \frac{\text{Outlet Pressure}}{\text{Bubble Point Pressure}}
\]  

(3.2)

Figure 3.18 to Figure 3.20 are plotted to compare the oil production profiles of primary-plus waterflooding and primary production. The dimensionless values of critical pressure for foamy oil flow and pseudo-bubble point pressure are calculated
for waterflooding processes. Therefore, the waterflooding production profiles are divided into three stages: Stage I, the pure water drive stage, is from the initial pressure to the critical pressure for foamy oil flow. Stage II, the foamy oil flow stage, is from the critical pressure for foamy oil flow to the pseudo-bubble point pressure. Stage III, the solution-gas drive stage, is from the pseudo-bubble point pressure to terminated pressure. The three stages of waterflooding are respectively marked in Figure 3.18, Figure 3.19 and Figure 3.20.

In order to understand interactive effects between water drive and solution gas drive/foamy oil effect in Stage II and III, the oil recovery differences between the waterflooding process and pure pressure depletion production are introduced, which are shown in the blue curves in Figure 3.18, Figure 3.19 and Figure 3.20. If the blue curve shows the uptrend with pressure declining, it means the oil recovery rate in waterflooding is larger than that in pure pressure depletion. In other words, positive effects between water drive and solution gas drive/foamy oil effect exist. If the blue curve shows the horizontal trend with pressure declining, it means the oil recovery rate in waterflooding equals to that in primary production with the same depletion rate. In other words, neutral effects between water drive and solution gas drive/foamy oil effect exist. If the blue curve shows the downtrend with pressure declining, it means the oil recovery rate in waterflooding is smaller than that in pure pressure depletion. In other words, negative effects between water drive and solution gas drive/foamy oil effect exist.
Take Test CM#8 as an example. As the pressure is above the critical pressure for foamy oil flow in Stage I, the oil production in this stage depend mainly on the water drive. Therefore, from Figure 3.18, it is observed that the blue curve is overlapped with oil production in the waterfloodig process. In Stage II, an uptrend of the blue cure with pressure declining is observed. It is indicated that the waterflooding has a positive effect in foamy oil flow stage. In Stage III, the blue cure shows up-down trend. It indicates that interactive effects between water drive and solution gas drive are unstable in Stage III.

By using the same analysis method, interactive effects of water drive and solution gas drive/foamy oil effect in Test CM#1 and CM#6 can be obtained. Through the comparison of waterfloodig performances under different depletion rates, several conclusions can be obtained. First, pure water drive is important in heavy oil waterflooding processes as it can recovery more than 50% of OOIP in Pattern 2. Second, with depletion rate increasing, interactive effects between water drive and foamy oil effect have a negative trend in Stage II. Third, with depletion rate increasing, interactive effects between water drive and solution gas drive have a positive trend in Stage III. Fourth, the operating strategies in Stage I and Stage III are significant for waterfloodig processes as those two stages take 92.2%, 84.6%, and 89.5% of the ultimate oil recovery for Tests CM#8, CM#1, and CM#6, respectively.
Figure 3.18. Comparison of the results of Test 1 (Zhou et al., 2016) and Test CM#8.
Figure 3.19. Comparison of the results of Test 2 (Zhou et al., 2016) and Test CM#1.
Figure 3.20. Comparison of the results of Test 3 (Zhou et al., 2016) and Test CM#6.
3.3.5 Effects of aging time on waterflooding performances

Test CM#2 is conducted to compare with Test CM#1 to study effects of aging time on waterflooding performances. For those two tests, the only difference is the aging time. The aging time of Test CM#1 is about 72 hours while it is 288 hours for Test CM#2. Figure 3.21 represents the oil recovery, water cut, and produced GOR as a function of the injected pore volume (IPV) for Tests CM#1 and CM#2. As shown in Figure 3.21, the production profiles of these two tests were divided into three stages: Stage I, the pure water drive stage; Stage II, the foamy oil flow stage; Stage III, the solution gas drive stage.

From Figure 3.21, it can be observed that the production profiles in Stage I and Stage II are similar. The main difference happens in Stage II. In Stage II, Test CM#2 has the higher oil recovery rate, lower water cuts and lower produced GOR than those in Test CM#1. Based on the discussion in Section 3.3.4, it can be concluded that the positive effect between water drive and foamy oil effect in Test CM#2 (288 hr aging) is more stronger than that in Test CM#1 (72 hr aging). Moreover, for produced GORs in Test CM#2, it is obviously observed that they are lower than initial GOR in Stage II, which is an important signal for foamy oil flow in primary production. Therefore, it can be concluded that the longer aging time is benefit to waterflooding processes as strong foamy oil effect will be involved.

In summary, the aging time can significantly affect production behaviors of oil, water and gas in waterflooding processes. Based on experimental results in this study, the difference of oil recovery factors with different aging times could reach as high as
13 % of OOIP. Moreover, the main differences in oil recovery factor happens in the foamy oil flow stage.
Figure 3.21. Comparison of Test CM#1 (72 hrs aging) and Test CM#2 (288 hrs aging) in the oil recovery, water cut, and produced GOR.
3.4 Theory-Assisted History Matching

History matches were sensitive to relative permeability curves (Kim et al., 2016). A proper setting of initial relative permeability curves may accelerate the history match process. Through the data collected from the displacing experiments, the proper relative permeability curves are calculated by using the Johnson-Bossler-Naumann method (Johnson et al., 1959) and the method of Tang et al. (2006). Then STARS (CMG, 2014) is used to conduct the history match.

3.4.1 Reservoir model grid

Figure 3.22 compares the model shapes used in the experiments and the numerical simulation. The cartesian grid type is used to build up the simulation model. Obviously, the shape of the numerical model used in this work is different from the shape of the core shown in Figure 3.22, because cartesian grids cannot build the curved shape. However, it is found that the difference of bulk volume and initial oil volume between those two models can be negligible without much influence on the simulation results if the geometric dimensions and compressibility of the numerical model are set properly. In this work, the model section area and length are selected to match the real core dimensions. The rock compressibility of the numerical model is set around 9.00E-07 1/kPa, as measured in Section 3.2.2.2.
Figure 3.22. Model shapes used in the experiments and the numerical simulation.
3.4.2 Reservoir properties

To make sure the simulation model can reflect the physical model, the reservoir properties are set the same values as that measured in experiments. As for rock compressibility, the estimated value of 9.00E-07 is selected, which is listed in Table 3.3, to run history matches. The oil volume calculated in STARS (CMG, 2014) is compared with the measured oil volume in the test to validate the feasibility of the numerical model. The OOIP calculated in STARS (CMG, 2014) is only 1.5 cm$^3$ larger than that measure in Test CM#4. It means that the settings of reservoir properties in CMG is acceptable.

3.4.3 PVT model

Through the analysis of experimental results, it is known that the production behaviours of the fluids are strongly influenced by the model pressure changing. Therefore, in order to history match the experimental results through the numerical model; the PVT model should be developed reliably. The measured properties of the dead and live oil (see Table 3.1 and Table 3.2) are used to generate the live oil PVT model by using WinProp. WinProp is a fluid property characterization application in CMG.

Two things need to be mentioned about the quality of the PVT model in this work. First, as WinProp (CMG, 2014) cannot generate the non-equilibrium PVT, the equilibrium PVT model is built to conduct the history match. Second, the four parameters, such as dead oil density (@101 kPa, 20 °C), dead oil viscosity (@101 kPa,
20 °C) and live oil viscosity (@4000 kPa, 20 °C), are used to build the PVT model for the heavy-oil methane system.

Take Test CM#4 as an example. Figure 3.23 shows the live oil density, viscosity, and GOR as a function of pressure for Test CM#4. It is obvious that the oil properties correlated by WinProp are similar to the values listed in Table 3.1 and 3.2. Therefore, the PVT models shown in Figure 3.23 are used in STARS (CMG, 2014) to conduct the history match for Test CM#4.

3.4.4 Relative permeability curves

All experiments in heavy oil-methane systems are experienced from a two-phase flow system to a three-phase flow system. In order to match the production behaviours of oil, water, and gas, the reliable relative permeability curves are crucial parameters to decide the quality of a history match. Compared with two-phase relative permeability curves, three-phase relative permeability curves have two main characteristics: (1) the relative permeabilities of water, oil, and gas were much lower than those in the corresponding two-phase flow system (Vittoratos, 2013), and (2) the relative permeability of the gas phase in the three-phase flow system can be the order of magnitude reduced from that in the two-phase flow system (Vittoratos, 2013). As the three-phase relative permeability curves significantly affect the production behaviours of the simulation results, the blind set of the initial relative permeabilities would make it difficult to conduct the history match. Therefore, the setting of the initial relative permeabilities is crucial to conduct the history match for the three-phase flow system.
Figure 3.23. The PVT model build-up for Test CM#4.
Basically, two ways exist to obtain the relative permeability curves for a three-phase flow system: (1) experimental measurement and (2) theoretical calculation. For the experimental measurement method, the exsolved solution gas flow and foamy oil effect in this study make the measurement of relative permeability difficult. Therefore, based on Kim et al.’s (2016) experience, the mathematical algorithms, such as the JBN method and the method of Tang et al. (2006), are used to generate the relative permeability curves for the numerical simulation study.

3.4.4.1 Water-oil relative permeability curves

The JBN method can be used to calculate incompressible waterflooding when the capillary end effect was negligible (Johnson et al., 1959). Although the small measurement errors may be amplified when the JBN method is used to derivate the experimental data, it still can be used to provide an initial value of relative permeability curves. It has been proved in Kim et al.’s (2016) research on the interpretation of the relative permeability behaviour in numerical simulations. Although the live oil viscosity in our tests (around 640 cp @ saturation pressure) are larger than that used in Kim et al.’s (2016) experiment (29.2 cp @ saturation pressure), the relative permeability curves still can be calculated by using the JBN method. This is because the viscosity ratio did not affect the calculation accuracy much based on the error analysis conducted by Tao & Watson (1984).

The equations to calculate the water-oil relative permeability curve are listed in Eqs. 3.3 to 3.8. As the live oil viscosity increases with model pressure decline, the $\mu_o$ in the original JBN method is replaced by $\mu_o(P_{avg})$ to improve the theoretical results.
The viscosity data with the pressure changing is provided by the correlation results obtained from WinProp (CMG, 2014).

\[
W_i = \frac{1}{\frac{dS_w}{dW_i}}
\]  
(3.3)

\[
(f_o)_2 = \frac{dS_{avg}}{dW_i}
\]  
(3.4)

\[
I_r = \frac{\frac{u}{\Delta P}}{\left(\frac{u}{\Delta P}\right)_{\text{start}}} = \frac{\Delta P_s}{\Delta P}
\]  
(3.5)

\[
\frac{f_o}{k_{ro}} = \frac{d(1/W_i I_r)}{d(1/W_i)}
\]  
(3.6)

\[
\frac{f_o}{f_w} = \frac{1-f_w}{f_w} = \frac{k_{rw}\mu_o(P_{avg})}{k_{ro}\mu_w}
\]  
(3.7)

\[
(S_w)_{avg} = (S_w)_2 + W_i(f_o)_2
\]  
(3.8)

where \(f_o\) is the fraction of the oil phase in produced liquid; \(f_w\) is the fraction of the water phase in the produced liquid; \(k_{ri}\) is the relative permeability of component \(i\); \((S_w)_2\) is the water saturation at the production outlet; \(W_i\) is the injected pore volume; and \(\mu_o(P_{avg})\) is the oil viscosity at a certain model pressure \((P_{avg})\).

For the water-oil relative permeability curve, two parts are divided to conduct the calculation. The first part is calculated from the initial pressure to the bubble point pressure, where the viscosity of the live oil is assumed as a constant. The second part is calculated from the bubble point pressure to atmosphere pressure, where the live oil viscosity is increased with decreasing pressure. According to the experimental results obtained in Test CM#4, the water-oil relative permeability curves are calculated.

However, the initial results calculated by this method, which are not monotonic curves for both water or oil, cannot be used directly for CMG to correlate the relative
permeability curves. Therefore, some initial calculated data for the relative permeability curves has to be eliminated to make the relative permeability curves reasonable. Figure 3.24 shows the modified relative permeability curves for Test CM#4.
Figure 3.24. Water-oil relative permeability curves calculated by the JBN method for Test CM#4.
3.4.4.2 Gas-oil relative permeability curves

For the relative permeability curve of oil and gas, Tang & Firoozabadi’s (2003) equation, which has been proved by Kim et al. (2016), is applied to provide relative permeability curves for numerical simulations.

\[
k_{ro} = \frac{\mu_0 q_0 L}{2 k A (\Delta P_o + \rho_o g L \sin \theta)} \tag{3.9}
\]

\[
k_{rg} = \frac{\mu g q_g L}{2 k A (\Delta P_o + \rho_g g L \sin \theta)} \tag{3.10}
\]

where \( K_{ro}, K_{rg} \) stands for the relative permeability for the oil phase and gas phase, respectively; \( k \) is the absolute permeability; \( A \) is the section area of model; \( \Delta P \) is the differential pressure; \( \rho \) is the density of oil or gas; \( g \) is the gravitational constant; \( L \) is the length of model; \( \alpha \) is the unit conversion constant; \( \mu \) the viscosity of oil or gas; and \( q \) is the volumetric production rate for oil or gas, respectively.

As Tang et al.’s equations (Eqs. 3.9 and 3.10) were derived based on the gas-oil flow system, they cannot be used in our waterflooding system to provide gas-liquid relative permeability curves. However, due to the difference of the relative permeability between oil and liquid being extremely large for heavy oil reservoirs, the relative permeability curves of gas-oil may be applied instead of the relative permeability curves of gas-liquid to provide the initial values. Therefore, instead of using the experimental results in Test CM#4 to calculate the gas-liquid table, the data from the primary production part of Test CM#3 is used to calculate the relative permeability curves of gas-oil. Figure 3.25 shows the modified relative permeability curves of gas and oil.
Figure 3.25. Oil-gas relative permeability curves calculated by Tang’s method for Test CM#4.
3.4.5 The discussion of history match results

3.4.5.1 The comparison of the numerical study and the experimental study

Figure 3.26 shows the comparison results between the simulation and the experiment, which include the injector bottom-hole pressure, cumulative oil production, cumulative gas production, and cumulative water production.

Before 10 hours of production, it is observed that the cumulative production of oil, gas, and water are all matched well in Figure 3.26. This is because the system is a two-phase flow system as the model pressure above the bubble point pressure. However, after 10 hours, it was found that the history matching errors in gas production began to increase. When the production time is between 10 to 30 hrs, the simulated gas production is larger than it is in the historical data. In the real case, foamy oil is formed in the experiment as the pressure declines lower than the bubble point pressure. Due to non-equilibrium PVT behaviour, the gas production volume is smaller than the simulation result as the equilibrium PVT model is used in the simulation. Therefore, during this production period, almost all the exsolved gas was released from the system in the simulation case. This conclusion can also be used to explain why the gas production in the simulation is lower than the experimental data during the subsequent two pressure cycles at a similar pressure range. After approximately 110 hours of production, another fast gas production rate is observed in the simulation case. This is because the free gas is continuously generated in the simulation case with pressure declining. And, the saturation of the gas phase passes the critical gas saturation point soon. Therefore, the high gas production rate is found in the simulation case as shown in Figure 3.26 (c). However, in the experiment, although the free gas is also generated
continuously at the low pressure arrange, the scenario is complex. The Jamin effect or emulsion effect may further hinder the gas production rate for the real case. Therefore, the gas production rate observed in the experiment is not as high as that in the simulation case.

3.4.5.2 The analysis of fitting errors

To evaluate the fitting quality of the history match, the history matching error is introduced, which can be expressed as,

\[ Q = \sqrt{\frac{\sum_{i=1}^{n} (x_i^s - x_i^m)^2}{NT \cdot \Delta Y^m + 4 \times Err^m}} \]  (3.11)

where \( Q \) represents the history matching errors (i.e. the data quality of the simulation results); \( X \) represents the evaluated values, which could be the cumulative productions of oil, gas, and water; \( NT \) represents the total number of samples; \( \Delta Y^m \) represents the measured maximum change of the evaluated value; \( Err^m \) represents tolerated errors for satisfied simulation results; \( ^s \) and \( ^m \) stand for simulation results and measured results; and \( ^i \) stands for the value at the sampling time.

The history matching errors calculated in the cumulative oil, water, gas, and injection pressure are shown in Figure 3.27. The global errors, which are also shown in Figure 3.27, are the average values of the errors in the cumulative oil, water, gas, and injection pressure for the initial and tuned case. The global error represents the comprehensive fitting quality of the history matching case. The initial global error is 9.745%, which indicates that the history match is acceptable with the initial relative permeability data. However, the errors in the cumulative oil and gas pressure are larger than 10%, which are 13.85% and 17.8%, respectively. By tuning the relative
permeability curves, the global error of the history match is reduced from 9.745% to 4.031%. Moreover, despite the 7.652% error in cumulative gas production, the errors of the other three indexes (cumulative oil, cumulative water and injection pressure) drop lower than 4%, which can be assumed as a good match.

Figure 3.28 and Figure 3.29 compare the permeability curves obtained from the theory-assist methods with the correlated curves in the best match case. By comparing the relative permeability data in the initial case and the tuned case, it can be observed that the order of magnitudes of the curves for each phase are the same. This indicates two things. First, the theory methods (the JBN method and Tang et al.’s method) can provide reliable orders of magnitude for permeability curves. Second, the history matching quality seems more sensitive to the order of magnitude of the permeability data than the shapes of the relative permeability curves. Therefore, using the theory methods to provide the initial permeability data is necessary and significant for the history match in the heavy oil waterflooding process.

Although the fitting errors can be reduced for cumulative oil, cumulative water, and injection pressure by tuning the permeability curves, it is difficult to match well the cumulative gas production. It is because of the foamy oil flow and solution gas drive involved into the waterflooding processes. Therefore, to better match the heavy oil waterflooding, the foamy oil module may be needed to add into the STARS (CMG, 2014).
Figure 3.26. Comparison of the simulation and the experimental results for Test CM#4:
(a) Inlet pressure vs. time, (b) Cumulative oil production vs. time, (c) Cumulative gas production vs. time, and (d) Cumulative water production vs. time.
Figure 3.27. Comparison of the history matching errors in cumulative oil, cumulative gas, cumulative water, injection pressure, and global errors.
Figure 3.28. Comparison of the initial and tuned water-oil relative permeability curves for Test CM#4.
Figure 3.29. Comparison of the initial and tuned oil-gas relative permeability curves for Test CM#4.
3.5 Chapter Summary

Through experimental and numerical simulation studies in this chapter, six conclusions are obtained:

1. Four pressure control patterns are evaluated in this study: (1) primary production followed by waterflooding, (2) primary-plus waterflooding, (3) cyclic water injection with continuous pressure depletion, and (4) cyclic injection with cyclic production. For the heavy oil-methane system, the experimental results suggest that primary-plus waterflooding is the best pressure control pattern in terms of both ultimate oil recovery and oil recovery rate.

2. The small cumulative VRR usually reflects the fast depletion rate of reservoir pressure and the fast overall average production rate. However, the cumulative VRR has not proportional relationship with the ultimate oil recovery. Therefore, to get the balance between ultimate oil recovery and overall average production rate, the cumulative VRR equaling to 0.9 is recommended. To get the better overall average production rate with less consideration of the ultimate oil recovery, the cumulative VRR equaling to 0.7 is recommended.

3. There exists the optimal depletion rate for waterflooding processes. To take full use of natural energies, such as solution gas drive and foamy oil effect, the depletion rate should be selected properly.

4. With depletion rate increasing, the interactive effect between water drive and foamy oil effect has a negative trend in foamy oil flow stage. However, with depletion rate increasing, the interactive effect between water drive and
solution gas drive has a positive trend in solution gas drive stage. As the water drive stage and solution gas drive stage can contribute most of the ultimate oil recovery in waterflooding processes, operating strategies in those two stages should be carefully designed.

5. The JBN method and the method of Tang et al (2006) can be used to provide the initial relative permeability curves for history matching waterflooding processes.

6. Without the foamy oil module in STARS (CMG, 2014), it is difficult to match the gas production in waterflooding processes only by tuning relative permeability curves.
CHAPTER 4  WATERFLOODING PERFORMANCE IN HEAVY OIL-MIXED SOLVENT SYSTEMS

4.1 Introduction

Through over the two decades of CHOPS (cold heavy oil production with sand) in the western Canadian, only 5% to 15% of the OOIP (original oil in place) has been recovered (Chang et al., 2015). In order to enhance the heavy oil recovery, the sequential cold production techniques, such as waterflooding, CSI (cyclic solvent injection), etc., are usually applied.

In the experimental study by Du et al. (Du, Zeng, & Chan, 2013, 2014) on CSI, it was found that the solution gas drive was stimulated in a heavy oil-mix solvent (CH$_4$-C$_3$H$_8$) system. As discussed in Chapter 3, the solution gas drive do benefit to primary-plus waterflooding processes in a heavy oil-methane system. Therefore, these two techniques might be combined to enhance heavy oil recovery. However, the characteristics of waterflooding on heavy oil-mixed solvent (CH$_4$-C$_3$H$_8$) systems should be first studied. In this study, three coreflooding experiments are conducted to investigate the waterflooding performances in a heavy oil-mixed solvent system.

The experimental results show that the characteristics of oil production in the foamy oil flow stage are unstable in the heavy oil-mixed solvent system when compared with those in the heavy oil-methane system. Moreover, the high depletion rate and high water injection rate are more suitable for the heavy oil-mixed solvent systems to recover more oil faster.
4.2 Experimental Section

4.2.1 Experimental setup

The experimental setup applied in the heavy oil-mixed solvent system is the same as that used in the heavy oil-methane system. The details of the experimental setup are given in Section 3.2.1.

4.2.2 Experimental preparation

A typical heavy oil sample, which is obtained from the Lloydminster area, is compounded with methane and propane to synthesize the live oil sample for this study. The live oil consists of 70 mol% of heavy oil, 12.25 mol% of methane, and 17.75 mol% of propane. The specific live oil properties in the heavy oil-mixed solvent system are listed in Table 4.1.

The other preparations for the tests in the heavy oil-mixed solvent system are the same as those in the heavy oil-methane system (see details in Section 3.2.2). The physical properties of the cores for the heavy oil-mixed solvent system, such as the porosity, permeability, initial oil saturation, etc., are listed in Table 4.2.

4.2.3 Experimental procedures

Before investigating the waterflooding performance in the heavy oil-mixed system, a pressure depletion test (Test CMS#1) is undertaken to test the quality of live oil. In order to identify the characteristics of live oil clearly, 3 kPa/min, which is a little less than the best depletion rate (4 kPa/min) measured in Zhou’s (2016) study, is selected for Test CMS#1.

Next, two coreflooding tests (Test CMS#2 and CMS#3) are conducted to investigate the waterflooding performances in heavy oil-mixed solvent systems. For
Test CMS#2, the pressure depletion rate and the water injection rate are 1 kPa/min and 0.05 cc/min, respectively. For Test CMS#3, the pressure depletion rate and the water injection rate are 3 kPa/min and 0.15 cc/min, respectively.
Table 4.1. Live oil properties for the heavy oil-mixture system.

<table>
<thead>
<tr>
<th>Composition</th>
<th>Density</th>
<th>Live oil viscosity</th>
<th>Initial GOR</th>
<th>Bubble point pressure</th>
</tr>
</thead>
<tbody>
<tr>
<td>Mole fraction</td>
<td>Kg/m³</td>
<td>cp</td>
<td>Vol/Vol</td>
<td>kPa</td>
</tr>
<tr>
<td>Dead oil: 70%</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Methane: 12.25%</td>
<td>939</td>
<td>592</td>
<td>27.3</td>
<td>2700</td>
</tr>
<tr>
<td>Propane: 17.75%</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

100
Table 4.2. Physical properties of cores for the heavy oil-mixed solvent system.

<table>
<thead>
<tr>
<th>Test #</th>
<th>Porosity %</th>
<th>Permeability (± 200) mD</th>
<th>Initial water Saturation %</th>
<th>Temp. (± 1) ºC</th>
<th>Aging time (± 0.1) days</th>
<th>OOIP cm³</th>
</tr>
</thead>
<tbody>
<tr>
<td>CMS#1</td>
<td>23</td>
<td>1086</td>
<td>11</td>
<td>19</td>
<td>3</td>
<td>73.3</td>
</tr>
<tr>
<td>CMS#2</td>
<td>23</td>
<td>1290</td>
<td>12</td>
<td>19</td>
<td>4</td>
<td>70.6</td>
</tr>
<tr>
<td>CMS#3</td>
<td>24</td>
<td>1000</td>
<td>8</td>
<td>19</td>
<td>4</td>
<td>77.1</td>
</tr>
</tbody>
</table>

Note:
CMS# The number of the coreflooding test for the heavy oil-mixed solvent system.
NA Not available.
4.3 Experimental Results and Discussion

4.3.1 Discussion on Test CMS#1

In order to understand the waterflooding performances in heavy oil-mixed solvent systems, Test CMS#1 is conducted firstly to investigate production behaviours in pure pressure depletion test for heavy oil-mixed solvent systems. Figure 4.1 shows the pressure control profile of a heavy oil-mixed solvent system. The experimental results of Test CMS#1 are shown in Figure 4.2.

Based on Zhou et al.’s (2016) pressure depletion tests in heavy oil-mixture systems, the production profiles of Test CMS#1 (see Figure 4.2) can be also divided into two flow regions, which are the single-phase flow region and the foamy oil flow region. The pressure range for the single-phase flow region is from 4000 to 1674 kPa. In this flow region, no oil or gas is produced due to the small driving force caused by the oil expansion effect. For the foamy oil flow region, the pressure ranged from 1674 kPa to atmosphere pressure. During this flow region, the pressure difference first increased for a short period. Then it decreased to a lower level (around 70 kPa) until another climb showed again after the pressure decreased lower than 500 kPa. This kind of up-down-up trend of the pressure difference for the depletion test in the heavy oil-mixed solvent system is also observed in Zhou et al.’s (2016) research. Moreover, the oil and gas production behaviours of the whole production period are similar to the results shown in Zhou et al.’s (2016). This result validates that the live oil and apparatus settings in this study are stable enough to conduct the waterflooding experiments in heavy oil-mixed solvent systems.
Figure 4.1. Outlet pressure records of Test CMS#1.
Figure 4.2. Production profiles (the pressure difference, oil recovery, and cumulative GOR) of Test CMS#1.
4.3.2 Discussion on Test CMS#2

Test CMS#2 is the primary-plus waterflooding test with the consideration of the soaking effect and pressure build-up effect. According to the optimal pressure control strategy in heavy oil-methane system, the pressure depletion rate and water injection rate in Test CMS#2 are set as 1 kPa/min and 0.05 cc/min, respectively. Figure 4.3 shows the records of the outlet pressure and pressure difference ($P_{\text{inlet}} - P_{\text{outlet}}$) of Test CMS#2. Figure 4.4 represents the production profiles of oil, gas, and water.

4.3.2.1 The primary-plus waterflooding process at the early stage

The primary-plus waterflooding process at the early stage is from 0 to 23 hours. The production behaviors of oil, water and gas are quite similar to the waterflooding processes in heavy oil-methane system. Therefore, this part will not be discussed here again.

4.3.2.2 Effects of the soaking period

The soak is conducted from 28 to 33 hours. After around the 5-hour soaking period, it is observed that water cuts have a slightly drop. It is indicated that water imbibition happens in the soaking period. However, the oil recovery rate is the same as that before soaking. It can be concluded that the soak at this pressure range can reduce the water cut but cannot improve the oil production rate. The imbibition effect is not the dominating mechanism in this pressure range.
Figure 4.3. Pressure records (the outlet pressure and pressure difference) of Test CMS#2.
Figure 4.4. Production profiles (the oil recovery, cumulative GOR, and water cuts) of Test CMS#2.
4.3.2.3 Effects of foamy oil and solution gas in the second production part

After 32 hours production, the water cut significantly decreases with the oil recovery rate increasing. As the gas bubbles largely exsolved into the fluid flow, the pressure difference between the inlet and outlet as well as the cumulative GOR began to rise, as shown in Figure 4.3. This indicates that the foamy oil and exsolved gas are formed. With the pressure decreasing, the expansion of the foamy oil and gas bubbles pushed more oil flow into the water flowing paths. Therefore, the oil production and the pressure difference between the inlet and outlet are all increased.

4.3.2.4 Effects of the pressure build-up

Based on the oil production after pressure build up, it can be observed that the pressure build-up at pressure 800 kPa has the negative effect on waterflooding performance. After pressure build-up, the water cut increases significantly and stays above 95% for 12 hours. It is indicated that the pressure build-up is not able to resolve the solvent to the oil to form the foamy oil again. On the contrary, using water to pressurize the model pushes the oil around the water paths away. It is worse that with the pressure slowly declining (1 kPa/min) for the heavy oil-mixed solvent system, the effect of the solution gas drive is not significant as that in the heavy oil-methane system. Therefore, it can be concluded that to conducted the pressure build-up process after the pressure difference reached the peak level will not help produce more oil in heavy oil-mixed solvent systems.
4.3.3 Discussion on Test CMS#3

Test CMS#3 is another primary-plus waterflooding test in the heavy oil-mixed solvent systems. Figure 4.5 and Figure 4.6 illustrate the pressure records and production performances for Test CMS#3, respectively. Based on the characteristics of the pressure difference shown in Figure 4.5, the profile of the production performance can be clearly divided into four regions, which are named as I, II, III, and IV.

Region I is from 0 to 2.4 hours. In this region, the pressure difference did not have many fluctuations as shown in Figure 4.5. The characteristics of the pressure difference are similar to those in the conventional waterflooding process. During this period, no water is produced. The oil is produced mainly by water drive.

Region II is from 2.4 to 12 hours. The outlet pressure, as shown in Figure 4.5, drops from around 3200 to 1674 kPa. The pressure difference fluctuates around the lowest level (50 kPa) in the test. By comparing Region II in Figure 4.5 and Figure 4.6, it can be observed that the pressure difference fluctuation starts after water breakthrough. This is because, with the pressure declining, the expansion of live oil now and then blocked the water paths and pushes the water to expand its flooding area. Therefore, the main mechanisms in this region are the water drive and the oil expansion effect.
Figure 4.5. Pressure records (the outlet pressure and pressure difference) of Test CMS#3.
Figure 4.6. Production profiles (the oil recovery, cumulative GOR, and water cuts) of Test CMS#3.
Region III is from 12 to 21 hours. The outlet pressure, as shown in Figure 4.5, decreases from 1674 kPa to atmosphere pressure. According to the pressure depletion results shown in Test CMS#1, it is believed that strong foamy oil shows up during this pressure range (1674 kPa to 1100 kPa) for Test CMS#3. Therefore, from Figure 4.6, it is observed that the water cut drops significantly from 93% to 78%. At the same time, the oil recovery rate also shows a significant increase when compared with the rate in Region II. However, after 2 hours’ high productive period in Region III, the oil production rate slow down again. Moreover, the fluctuation of the pressure difference during this period is extremely large. The maximum range of the fluctuation could reach 170 kPa as shown in Figure 4.5, which is almost three times larger than that in Region II. This is because the gas bubbles and free gas are involved into flowing system. The large fluctuation in pressure difference maybe caused by the combination effect of water drive, solution gas drive, Jamin effect, etc, which is needed further studies to validate it.

Region IV is from 21 to 25 hours. In this region the outlet pressure of the model has already be declined to the atmosphere pressure. From the continuous increasing of the cumulative GOR shown in Figure 4.6, it can be concluded that the free gas begins to take the high mobility channels. During this period, the water cut is high as 95%. Therefore, the experiment is terminated after 2 hours production in Region IV.
### 4.3.4 The comparison results of Test CMS#2 and Test CMS#3

Tests CMS#2 and CMS#3 are both waterflooding tests conducted in heavy oil-mixed solvent systems. Compared with Test CMS#2, Test CMS#3 has a faster water injection rate (0.15 cc/min) and pressure depletion rate (3 kPa/min). Figure 4.7 represents the oil recovery factor, water cut, and cumulative GOR.

From Figure 4.7, it can be observed that the injected pore volume before the water breakthrough is almost the same for both tests. It is indicated that enlarging or reducing the water injection rate and pressure depletion rate in the same proportion cannot significantly affect the injected water volume at water breakthrough. However, the water breakthrough time is inversely proportional to the water injection rate. Moreover, the higher oil recovery is obtained at breakthrough in Test CMS#2 as relative low injection rate, which consists with the observations in the study of Mai & Kantzas (2008). It is indicated that, before water breakthrough, viscous force and capillary forces are play a role in primary-plus waterflooding processes instead of oil expansion force.

After water breakthrough, the slope of the oil recovery factor Test CMS#2 is always larger than that in the fast test until the injected volume reaches around 1.3 PV. This is because, after water breakthrough, the main water paths have been developed. Due to the imbibition effect, the test with slow injection rate can sweeps more oil from the smaller pores than the test with high injection rate.
Figure 4.7. Comparison of production profiles (the oil recovery, cumulative GOR, and water cut) for Test CMS#2 and Test CMS#3.
However, after the injected volume rose above 1.3 PV, the oil recovery per IPV of Test CMS#3 starts to become larger than that in Test CMS#2. It is because of in this region the solution gas drive is the dominating mechanism. The test with strong solution gas drive can produce more oil.

Finally, the ultimate oil recovery of Test CMS#3 is higher than the test Test CMS#3, as the Test CMS#3 makes full use of the water drive energy and primary energies. There are two reasons for this phenomenon. First, for the heavy oil-mixed solvent system, the fast pressure depletion rate (3 kPa/min) tended to produce more foamy oil based on the Zhou et al.’s study (2016). Second, the larger amount of foamy oil formed by fast depletion rate can block more of the previous water paths and push the injected water to sweep a larger area.

Based on the above comparison, it can be concluded that for the primary-plus waterflooding process, the fast injection rate and depletion are the optimal operating strategy for heavy oil-mixed solvent system.

**4.3.4 The interactive effect between water drive and foamy oil effect/solution gas drive**

Tests CMS#1 and CMS#3 are compared with each other to investigate the interactive effect between water drive and foamy oil effect/solution gas drive for heavy oil-mixture solvent systems. Figure 4.8 illustrates the comparison results of the production performances for the above two tests.

Based on the analysis in Section 4.3.1, the pseudo-bubble point pressure of the heavy oil-mixed solvent system under the depletion rate of 3 kPa/min is around 1674 kPa. Therefore, the production profiles of the two tests can be divide into three stages.
Stage I is the pure water drive stage. Stage II is the foamy oil flow stage. Stage III is the solution gas drive stage.

Stage I is ended when dimensionless pressure decreased to 0.62, which is much lower than the 0.9 in heavy oil-methane system under the same depletion rate. Moreover, 44% of OOIP, which stands for the 69% of ultimate oil recovery, is recovered in this stage. Therefore, it is important to conducted the early waterflooding in heavy oil-mixed solvent system. Otherwise, a large range of pressure declining will not bring any profit.

For Stage II, it can be found that interactive effect between water drive and foamy oil flow has a negative trend. Moreover, the oil production rate is not as stable as that in heavy oil-methane system. It is because of methane and propane alternatively affect the foamy oil flow in this region.

For Stage III, the interactive effect between water drive and solution gas drive have a neutral or negative trend, which is different from that in heavy oil-methane system at this same stage. It is because the exsolved propane largely forms the free gas phase at the low pressure range and hinds the waterflooding performance.
Figure 4.8. Comparison of oil recovery factors for Tests CMS#1 and CMS#3.
4.4 Chapter Summary

In this chapter, three tests were conducted to investigate the waterflooding process in the heavy oil-mixed solvent system. The conclusions are summarized as follows:

1. A soaking process above pseudo-bubble point pressure can stimulate the imbibition effect in heavy oil-mixed solvent systems to reduce the water cut. But it has not effect on improving oil production rate.

2. The pressure build-up when free gas phase has been formed will not benefit to the waterflooding performances in heavy oil-mixed solvent system.

3. By increasing the pressure depletion rate and water injection rate proportionally, the water breakthrough time is reduced significantly, but the oil recovery factor and pore volume injected at breakthrough are not strongly influenced.

4. The fast depletion rate and injection rate can help the heavy oil-mixed solvent system to get high ultimate oil recovery factor.
CHAPTER 5 CONCLUSIONS AND RECOMMENDATIONS

5.1 Conclusions

In this thesis, a series of coreflooding tests are conducted to investigate and optimize the pressure control strategies for the heavy oil-methane and the heavy oil-mixed solvent system. Moreover, a numerical study is carried out in the heavy oil-methane system to further understand the heavy oil waterflooding process. The conclusions are obtained as follow,

1. For the heavy oil-methane system, the experimental results suggest that primary-plus waterflooding is the best pressure control strategy in terms of both ultimate oil recovery and oil recovery rate.

2. To get the balance between ultimate oil recovery and overall average production rate, the cumulative VRR equaling to 0.9 is recommended. To get the better overall average production rate with less consideration of the ultimate oil recovery, the cumulative VRR equaling to 0.7 is recommended.

3. In order to take full use of natural energies, such as solution gas drive and foamy oil effect, the depletion rate should be selected properly. There exists the optimal depletion rate for waterflooding processes, which is usually smaller than the optimal depletion rate in primary production processes.

4. For heavy oil-mixed solvent system, in order to match the optimal depletion rate, the higher injection rate may be needed to make full use of natural energies. Although with higher water injection rate, the oil recovery factor and pore volume injected at breakthrough are not strongly influenced.
5. The relative permeability curves calculated by JBN and Tang et al’s method can provide good initial values for tuning to get an acceptable history match. However, it is still difficult to match the gas production well without the foamy oil module in simulation model.

5.2 Recommendations

Based on this study, several recommendations are listed as follow,

1. To reduce the reading errors in recording the produced heavy oil and water, the new oil-water separation method introduced in this study are recommended especially when the oil ring phenomenon occurs.

2. Multiple pressure depletion rates should be designed based on the interactive effect between water drive and solution gas drive/foamy oil flow in a heavy oil-methane system.

3. To extend the foamy oil flow and solution gas drive in waterflooding processes, the pressure build-up process might be carried out by using gas injection at a certain pressure level.

4. The micromodel study should be conducted in heavy oil waterflooding processes to further investigate how water drive interactively affect the foamy oil effect/ solution gas drive.
REFERENCES


Ahmadloo, F., Asghari, K., & Renouf, G. (2010). A New Diagnostic Tool for Performance Evaluation of Heavy Oil Waterfloods: Case Study of Western Canadian Heavy Oil Reservoirs. SPE-133407. In *Western North America Regional Meeting*. Anaheim, California, USA.


Meyer, R., Attanasi, E., & Freeman, P. (2007). Heavy oil and natural bitumen resources


