Chen Shen, candidate for the degree of Master of Applied Science in Petroleum Systems Engineering, has presented a thesis titled, *Experimental Study of Foamy Oil Characteristics and Post-CHOPS CSI Processes Based on CO$_2$-C$_3$H$_8$ Mixture Solvent*, in an oral examination held on November 28, 2019. The following committee members have found the thesis acceptable in form and content, and that the candidate demonstrated satisfactory knowledge of the subject material.

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Supervisor: Dr. Fanhua Zeng, Petroleum Systems Engineering

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ABSTRACT

As the demand of crude oil increases sharply nowadays, heavy oil, an unconventional liquid hydrocarbon representing more than 70% of the world’s total oil, needs to be further produced in the coming decades. Although some laboratory experiments have been conducted to find out the mechanism of foamy oil during pressure depletion processes. There are still some difficulties in understanding the characteristics of foamy oil flow in Cold Heavy Oil Production (CHOP). Large amounts of heavy oil samples used in previous studies were mixed with methane, carbon dioxide and butane. Only several studies were conducted under heavy oil-mixture solvent systems. Therefore, it is of great significance to carry out some experiments to perceive the foamy oil flow characteristics with its influencing factors in heavy oil-mixture solvent (CO₂-C₃H₈) systems so as to get better recovery factors in primary production.

In this study, four pressure depletion tests were conducted in 1D sand pack model to find out factors affecting the duration of foamy oil flow and recovery factors were obtained as the result. Firstly, all the conditions were the same except for the decline rate (-1, -2, -6, -12 kPa/min). Secondly, the optimized depletion rate was applied into the next stage experiments which was used to understand the length effect on foamy oil flow characteristics. Once all the depletion tests had been completed, another four post-CHOPS
CSI tests were conducted to find out whether gravity can take effect on the oil recovery factors. Results show that in CO$_2$-C$_3$H$_8$ mixture solvent-heavy oil system, oil recovery factor increases as the depletion rate becomes larger. Furthermore, compared with pure solvent heavy oil system, mixture solvent shows better during depletion tests. Besides, results show that there is a positive correlation between oil recovery factor and gravity. Last but not least, results from the pressure depletion tests indicate that pressure gradient will become smaller at the end as the model length increases. In the oil field, pressure gradient remains a low level when it is far away from the well bore and that is one reason for low cumulative oil production.
ACKNOWLEDGEMENT

First of all, I would like to greatly appreciate Dr. Fanhua (Bill) Zeng for his patience, guidance, and encouragement during my graduate studies at the University of Regina. It is his generous support that the work has been completed properly.

Secondly, thanks to all the committee members in my thesis defense for their valuable comments, questions, and suggestions.

Last but not least, I would like to thank all the members of Dr. Zeng’s research group for their assistance, support, and guidance. Thanks to Dr. Zhongwei Du, Dr. Xiang Zhou, Dr. Shanshan Yao, Mr. Xiaolong Peng, Mrs. Xinqian Lu, Mr. Jun Yang, Mr. Lilong Yang, Mr. Kewei Zhang, Mr. Mingyi Wu, Mr. Di Pu, Mr. Zixi Guo, Mr. Bingyang Zou, Miss. Xiao Hu, Mr. Haoran Hu, Mr. Zeyu Lin, and Miss. Xuan Yu for their advice and suggestions during my research.
DEDICATION

To

My beloved parents.
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Nomenclature

Notations

A \quad \text{cross section area of the sandpack, cm}^2

cP \quad \text{centipoise, units of viscosity}

L \quad \text{length of 1D sandpack model, cm}

M_{\text{dead oil}} \quad \text{mole weight of dead oil, g/mol}

n_{\text{CO}_2} \quad \text{mole of carbon dioxide, mol}

n_{\text{C}_3\text{H}_8} \quad \text{mole of propane, mol}

n_{\text{dead oil}} \quad \text{mole of dead oil, mol}

n_{\text{mix}} \quad \text{mole of mixture solvent, mol}

P_b \quad \text{pressure of mixture solvent, kPa}

P_{\text{CO}_2} \quad \text{pressure of carbon dioxide, kPa}

P_{\text{C}_3\text{H}_8} \quad \text{pressure of propane, kPa}

P_{\text{mix}} \quad \text{pressure of mixture solvent, kPa}

P_{\text{sat}} \quad \text{saturation pressure of live oil, kPa}

Q \quad \text{flow rate, cc/s}

R \quad \text{universal gas constant, J/mol\cdot{}K}

RF \quad \text{oil recovery factor, \%}

S_{\text{oi}} \quad \text{initial oil saturation, \%}
\( S_{wc} \)  connate water saturation, \% \\
\( T \)  temperature, K \\
\( V_{mix} \)  mole volume of mixture solvent, ml \\
\( V_{TC1} \)  volume of transfer cell 1, ml \\
\( V_{TC2} \)  volume of transfer cell 2, ml \\
\( V_{TC3} \)  volume of transfer cell 3, ml \\

Greek Symbols \\
\( \rho \)  dead oil density of dead oil, g/ml \\
\( \mu \)  viscosity, cP \\
\( \Delta P \)  pressure difference in the 1D sand pack model, kPa \\

Abbreviations \\
CMG  Computer Modeling Group \\
OOIP  Original oil in place \\
SARA  Saturates, Aromatics, Resins, Asphaltenes \\
SRC  Saskatchewan Research Council
Chapter 1 Introduction

1.1 Background

According to the *International Energy Outlook 2017* published by the United States (US) Energy Information Administration (EIA), the global energy consumption of petroleum will increase to 225 quadrillion Btu (38700 million barrels) by the end of 2040; in 2015 the number was about 190. With increasing demand of crude oil, heavy oil, an unconventional liquid hydrocarbon standing for more than 70% of the world’s total oil (Alboudwarej, 2006), needs to be produced in the next few decades. Heavy oil is defined as crude with a viscosity above 100 cP and a gravity below 22.3° API (“Heavy Crude Oil” n.d.). The challenge in recovering heavy oil mainly has to do with high viscosity. Actually, heavy oil viscosity decreases rapidly when the temperature gets higher. In order to get more heavy oil produced, much research has been conducted on thermal methods of heavy oil recovery. However, all of these thermal recovery methods need heating which can be a large expenditure in field application. At this time, for heavy oil with not-too-high viscosity, non-thermal recovery methods become preferable and economical in heavy oil production.

Heavy oil production mainly includes primary and secondary production. Primary production consists of open pit mining, cold heavy oil production (CHOP), cold heavy oil production with sands (CHOPS) and primary production under solution gas drive. Open-
pit mining, the original non-thermal method, has been proved to be practical and successful in heavy oil recovery in Canada. However, only when the reservoir depth is lower than 70 meters can this method be applied into field production, which means no more than 5% of the OOIP can be produced (Jiang, 1997). Meanwhile, CHOP and CHOPS processes are used in heavy oil recovery as these methods can approximately produce from 5 to 10% of the OOIP, but they are not economical because of pressure decline and water intrusion (Ivory, et al., 2010). From the past several decades research and field application, the solution gas drive method gets good performance in oil recovery factor and the final result is beyond the prediction by using conventional two-phase flow. Thus, a new mechanism has been taken into assumption that it is foamy oil flow, a non-Darcy form of conventional gas-oil two-phase flow, which contributes to such high recovery factor (Brij B. Mani, 1999). Therefore, the study of foamy oil flow with its characteristics becomes more and more important.

When it comes to the secondary production, flooding methods and cyclic solvent injection (CSI) play an important role. Although water flooding seems to be a preferable methods theoretically. Field application shows that it is very difficult to avoid viscous fingering due to the huge different viscosities between fluids. Meanwhile, chemical flooding is usually used in those relatively lighter heavy oil reservoirs with a viscosity less than 1000 cP (Kishore K. Mohanty, 2012) and only limited oil pools can this process be applied into. At this time, CSI, a solvent-based EOR technique shows its advantages over
the former two methods as this process generates foamy oil flow during production stage and can be used to most heavy oil reservoirs.

In general, among all the non-thermal EHOR methods, foamy oil flow drive and cyclic solvent injection are worth more attention. In this study, both methods will be discussed for the future improvement and field application.

1.2 Foamy oil flow

Foamy oil flow is originally observed in the form of stable foams in Canadian and Venezuelan heavy-oil wells. This non-Darcy form of two-phase flow usually shows up during production stage under solution gas drive (Brij B. Mani, 1999). After that, anomalous production happens and high oil recovery factors have been obtained. Heavy oil produced from the reservoir is in the form of continuous oil foam which looks like mousse in shiny black color. At the same time, foamy oil occupies huge volume of the samplers when produced while it can collapse few days later. Why this happens is that unlike the conventional gas-oil two phase flow of which the fluid phase always flows continuously, foamy oil flow is a combination of heavy-oil flow and dispersed gas bubbles.

Although 60 years has passed since the first primary production began in Lloydminster and many researchers have made their efforts to understand the mechanism of foamy oil flow. Most research was focused on foamy oil flow in pure solvent heavy oil system regarding the primary production condition. However, more and more different
kinds of mixture solvent have been used during CSI processes recently which means gas saturation in the heavy oil reservoir has already changed. Thus it is worthy of attention that more studies should be conducted to focus on foamy oil behaviors in mixture solvent heavy oil systems.

1.3 Cyclic solvent injection

CSI is a follow-up process of CHOPS. This non-thermal method includes three stages: solvent injection, soaking and production. Firstly, a specific solvent is injected into a cold heavy oil reservoir under a designed pressure. After that, the injection well will be shut down for a number of days when the solvent can be dissolved into heavy crudes. Finally, the diluted heavy oil will be produced from the same well. These three stages build up one cycle and then performed repeatedly to obtain higher oil recovery factor after primary production. Numerous experimental and mathematical studies have been conducted into this area in the past 40 years. All the results show that there is a bright future to use CSI to enhance heavy oil recovery (Du, 2017).

Although CSI studies have been conducted for more than 40 years, there are still some influencing factors needing to be discovered. Meanwhile, upscaling criteria from the laboratory to field application has not been fully understood yet. Therefore, it is important to investigate factors affecting the cyclic solvent injection and then improve the dynamic performance of CSI processes.
1.4 Research objectives

The author conducted six pressure depletion tests as well as six post-CHOP cyclic solvent injection processes to achieve the goals as follows:

1) To understand the effects of pressure depletion rates on foamy oil flow characteristics in mixture solvent-heavy oil system.

2) To study the effects of model length on foamy oil flow characteristics in mixture solvent-heavy oil system.

3) To study the effects of gravity on heavy oil recovery for the post-CHOP cyclic solvent injection processes.
1.5 Outline of the dissertation

In this thesis, five chapters are included in total. Chapter 1 gives introduction to the research topic combined with its main objectives. Chapter 2 focuses on the experimental studies on the effect of different pressure decline rate on foamy oil flow characteristics in mixture solvent heavy oil system. Chapter 3 provides the experimental studies on the effect of model length on the foamy oil flow behavior. Chapter 4 discusses the post-CHOP cyclic solvent injection process and results show that gravity can take a huge effect on the oil recovery factor. Finally, conclusions are presented in Chapter 5 as well as some recommendations.
Chapter 2 Experimental studies on the effect of pressure decline rate on foamy oil flow characteristics in CO2-C3H8 heavy oil system.

Abstract

Foamy oil flow has been found in heavy oil reservoirs in Canada and Venezuela for several decades. Research shows that this non-Darcy two phase flow is sensitive to pressure declination. Also, it is believed that foamy oil flow is an important mechanism leading to high recovery factors in heavy oil productions. In this study, CO2 and C3H8 were chose to be mixed with a typical heavy oil sample collected from the Manatoken oil field for live oil preparation. After that, four pressure depletion tests were conducted to investigate the effect of decline rate as well as production behaviors under foamy oil flow. Meanwhile, other factors including gas oil ratio (GOR), bubble point, pseudo-bubble point and solution gas were studied as well. Results show that foamy oil flow contributes to 70% at least of total oil production in CO2-C3H8 mixture solvent heavy oil system. What’s more, higher pressure decline rates lead to better performance of foamy oil flow thus more oil was produced when the BPR dropped to barometric pressure. Additionally, compared with other solvent heavy oil systems, it can be found that the foamy oil flow in CO2-C3H8 mixture solvent is less pressure sensitive than other solvents such as pure methane, pure propane and CH4-C3H8 mixture solvent.
2.1 Introduction

Heavy oil consists more than 70% of total crudes in the world. It is important to enhance heavy oil recovery to meet the increasing demand of petroleum. Foamy oil flow, a non-Darcy form of two phase flow, is one of the most significant mechanism leading to the anomalous production behaviors. Therefore, it is of great importance to investigate the foamy oil characteristics to enhance heavy oil recovery.

Foamy oil flow, first officially defined as a non-Darcy gas and oil phase flow that involves the flow of dispersed gas bubbles (Maini, B. B., & Busahmin, B., 2010). A lot of studies have been conducted to investigate the foamy oil flow behaviors through the observation of relatively higher primary production performances including a high cumulative oil production rate, a high oil recovery factor as well as low gas oil ratio (Chen, J. Z., & Maini, B., 2005). Heavy oil samplers were installed on the wellhead in early years when the researchers found that the heavy oil produced was like foam instead of a conventional liquid flow. That is because all the heavy oil collected is in the form of continuous phase with dispersed gas bubbles. It is the existing of this dispersed gas bubbles that tell the difference between conventional solution-gas drive and foamy solution-gas drive. Maini has taken both two kinds of solution-gas drive into comparison in Table 2-1. Meanwhile, the lifespan and amount of dispersed gas bubbles are also significant aspects to distinguish between these two kinds of solution gas drive (Xu, S., 2007). To investigate
foamy oil flow, it is important to understand its dynamic processes first. The mechanism of foamy oil flow can be divided into three stages which are (Bora, 1998; Kumar, 1999; Zhang, 1999; Albartamani, 2000; Xu, 2007; Maini, 2010): bubble nucleation, bubble growth and bubble coalescence. Process of bubble nucleation is necessary to study as it is the first stage of the whole dynamic processes. Two types including homogeneous nucleation and heterogeneous nucleation are presented in the literature mostly (Sheng et al., 1999). However, different theories (instantaneous nucleation (IN), published by (Firoozabadi & Kashchiev, 1996), and progressive nucleation (PN) are presented (Li and Yortsos, 1995) on the duration of nucleation processes are waiting for further investigation. When it comes to the influential factors, it is reported that the pressure depletion rate is one of the main factors controlling the bubble nucleation (Xu, 2007). This is because pressure decline rate takes great effect on the level and amount of nucleation in appositive proportional relationship. Therefore, it is necessary to investigate the effect of pressure decline rate on foamy oil flow characteristics.

Although large amount of research have been conducted to understand the effect of pressure depletion rate on foamy oil flow behavior during the production period. Most of them are based on pure solvent heavy oil systems. Even if the studies are aiming at understanding foamy oil flow characteristics in mixture solvent heavy oil systems, researchers prefer to investigating methane-propane, methane-CO₂ mixture solvent.

However, more different mixture solvent are chose for CSI processes recently as the
higher oil recovery factor can be obtained. It is reported that using CO$_2$-C$_3$H$_8$ mixture solvent for CSI process is practical for field application as the saturation pressure is higher than pure propane (Du, et al., 2018). According to the former study (Jia, 2014), foamy oil flow is also one of the mechanisms in VAPEX and CSI processes. Therefore, it is of great importance to conduct studies on the foamy oil behavior in the CO$_2$-C$_3$H$_8$ heavy oil system.

In this study, 4 pressure depletion tests were conducted through the 1D sandpack model with different pressure depletion rates to investigate the effect of pressure decline rate on foamy oil flow characteristics in CO$_2$-C$_3$H$_8$ heavy oil system. Production behavior and foamy oil characteristics are discussed. An optimized pressure decline rate for foamy oil stability and higher oil recovery factor is obtained as well. The results can be useful to understand the dynamic processes of foamy oil flow in CO$_2$-C$_3$H$_8$ heavy oil system.
Table 2-1: Comparison between Conventional and Foamy Oil Solution Gas Drive (Maini, 2001)

<table>
<thead>
<tr>
<th>Conventional Solution-Gas Drive</th>
<th>Foamy Solution-Gas Drive</th>
</tr>
</thead>
<tbody>
<tr>
<td>Pressure depletion creates supersaturation.</td>
<td></td>
</tr>
<tr>
<td>Bubbles nucleate in rough cavities of pore walls.</td>
<td></td>
</tr>
<tr>
<td>Some bubbles detach and start growing in pore bodies.</td>
<td></td>
</tr>
<tr>
<td>Bubbles continue to grow in place without vacating the pore in which they originated.</td>
<td>Bubbles start migrating with the oil after growing to a certain size.</td>
</tr>
<tr>
<td>Different bubbles originating in different pores grow large enough to contact each other.</td>
<td>Migrating bubbles stop growing in a certain size</td>
</tr>
<tr>
<td>Bubbles coalesce to form a continuous gas phase.</td>
<td>Dispersed flow is achieved by breakup of large bubbles into smaller bubbles.</td>
</tr>
<tr>
<td>Producing GOR increases rapidly once the gas starts to flow as a continuous phase.</td>
<td>Producing GOR remains low.</td>
</tr>
<tr>
<td>Reservoir energy is depleted at a low recovery factor.</td>
<td>High recovery factors are obtained.</td>
</tr>
</tbody>
</table>
2.2 Experimental Section

2.2.1 Experimental Materials

Heavy Oil sample has been collected from Manatoken oil field. Oil properties and SARA analysis were tested by Saskatchewan Research Council and are shown in Table 2-2 and 2-3 respectively. Carbon dioxide, propane and nitrogen were provided by Praxair, both with purities of 99.99%. Propane and carbon dioxide were used for mixture solvent preparation while nitrogen was used for pressure test.

2.2.1.1 1D sandpack model

1D sandpack model is used to mimic porous media for heavy oil reservoir. The sandpack used in the laboratory is a 95 cm long steel tube with the inner diameter of 3.8 cm. The model will be filled with glass beads during the lab experiment and the undertake pressure can reach to 10 mPa to meet the needs. Table 2-4 summarized the model size, type of sand used, grain sizes, porosity, permeability, initial oil saturation, connate water saturation and other parameters in each test.

2.2.1.2 Packing methods

In this study, dry packing method was used to fill the model with glass beads. During the packing period, no water or any other liquid was needed. However, a vibrator was used
for 2-hour vibration as the sand should be packed in the model compactly and uniformly.

2.2.1.3 Live oil preparation

Different from the pure solvent heavy oil system, CO\textsubscript{2}-C\textsubscript{3}H\textsubscript{8} mixture solvent should be prepared ahead. All the steps for live oil preparation are shown as the follows:

1) Calculate the P\textsubscript{sat} of the live oil by using CMGWinprop\textsuperscript{®} according to the mole ratio (70% CO\textsubscript{2}:30% C\textsubscript{3}H\textsubscript{8}) of the mixture solvent.

2) Fill the transfer cell 1 with dead oil and the volume will be V\textsubscript{TC1}.

3) Then determine the mole of dead oil.

\[ n_{\text{dead oil}} = \frac{\rho_{\text{dead oil}} \times V_{\text{TC1}}}{M_{\text{dead oil}}} \]

Where the \( n_{\text{dead oil}} \) is the amount of oil used for preparation, mol; \( \rho_{\text{dead oil}} \) is the density of the heavy oil, g/cm\textsuperscript{3}; \( M_{\text{dead oil}} \) is the mole weight of dead oil, g/mol; \( V_{\text{TC1}} \) is the volume of transfer cell 1, ml.

4) Determine the mole of each solvent according to the mole ratio of (70%:30%) of CO\textsubscript{2} and C\textsubscript{3}H\textsubscript{8}.

\[ n_{\text{CO2}} = n_{\text{dead oil}} \times 70\% \]

\[ n_{\text{C3H8}} = n_{\text{dead oil}} \times 30\% \]

Where the \( n_{\text{CO2}} \) and \( n_{\text{C3H8}} \) are the amount of mixture solvent, mol.

5) Use PV=ZnRT to calculate the pressure of two solvents in transfer cell 2 and transfer cell 3
\[ P_{\text{CO}_2} = \frac{n_{\text{CO}_2} \times RT}{V_{\text{TC}_2} \times 10^{-3}} \]

\[ P_{\text{C}_3\text{H}_8} = \frac{n_{\text{C}_3\text{H}_8} \times RT}{V_{\text{TC}_3} \times 10^{-3}} \]

Where the \( P_{\text{CO}_2} \) is the pressure of carbon dioxide in transfer cell 2, kPa. \( P_{\text{C}_3\text{H}_8} \) is the pressure of propane in transfer cell 3, kPa. \( V_{\text{TC}_2} \) is the volume of transfer cell 2, ml. \( V_{\text{TC}_3} \) is the volume of transfer cell 3, ml.

6) The mole of mixture solvent will be:

\[ n_{\text{mix}} = n_{\text{CO}_2} + n_{\text{C}_3\text{H}_8} \]

7) Determine the mole volume of mixture solvent.

\[ V_{\text{mix}} = \frac{V_{\text{TC}_2} \times 10^{-3}}{n_{\text{mix}}} \]

Where the \( V_{\text{mix}} \) is the mole volume of mixture solvent, L/mol.

8) Using CMGWinprop® to find the solvent mixing pressure \( P_{\text{mix}} \) in transfer cell 2 and the unit will be in the form of kPa.

9) Inject \( \text{CO}_2 \) and \( \text{C}_3\text{H}_8 \) to the transfer cell 2 and 3 separately as the pressure shown in step 5.

10) Connect two transfer cells and use syringe pump to inject de-ionized water to move the piston all way in TC3 in order to mix solvents completely.

11) Check the final pressure and make sure that the pressure equals \( P_{\text{mix}} \) calculated in step 8.

12) Pump the mixture solvent into Transfer cell 1 for live oil preparation.
Table 2-2: Manatoken Heavy Oil Properties. (Tested by SRC)

<table>
<thead>
<tr>
<th>Temperature (°C)</th>
<th>Density (kg/m³)</th>
<th>Viscosity (mPa.S)</th>
<th>Compressibility (1/(kPa))</th>
<th>Pressure Coefficient of Viscosity (1/(mPa))</th>
</tr>
</thead>
<tbody>
<tr>
<td>15</td>
<td>967.9</td>
<td>4330</td>
<td>5.2*10^{-7}</td>
<td>0.056</td>
</tr>
<tr>
<td>21</td>
<td>964.3</td>
<td>2200</td>
<td>5.5*10^{-7}</td>
<td>0.031</td>
</tr>
<tr>
<td>25</td>
<td>961.8</td>
<td>1830</td>
<td>5.7*10^{-7}</td>
<td>0.027</td>
</tr>
<tr>
<td>75</td>
<td>929.5</td>
<td>72.3</td>
<td>6.6*10^{-7}</td>
<td>0.026</td>
</tr>
</tbody>
</table>
Table 2-3: SARA analysis results (Tested SRC)

<table>
<thead>
<tr>
<th>Property</th>
<th>Measured</th>
</tr>
</thead>
<tbody>
<tr>
<td>Saturates</td>
<td>28.4 %</td>
</tr>
<tr>
<td>Aromatics</td>
<td>27.0 %</td>
</tr>
<tr>
<td>Resins</td>
<td>22.5 %</td>
</tr>
<tr>
<td>Asphaltenes</td>
<td>14.8 %</td>
</tr>
<tr>
<td>Uncovered</td>
<td>7.3 %</td>
</tr>
<tr>
<td>Parameters</td>
<td>Test 2.1</td>
</tr>
<tr>
<td>-----------------------------</td>
<td>----------</td>
</tr>
<tr>
<td>Depletion Rate kPa/min</td>
<td>-12</td>
</tr>
<tr>
<td>Length (cm)</td>
<td></td>
</tr>
<tr>
<td>Inner Diameter (cm)</td>
<td></td>
</tr>
<tr>
<td>Cross Section Area (cm²)</td>
<td></td>
</tr>
<tr>
<td>Porosity Φ (%)</td>
<td>34.82</td>
</tr>
<tr>
<td>Permeability K (D)</td>
<td>6.47</td>
</tr>
<tr>
<td>Initial Oil Saturation (%)</td>
<td>89.33</td>
</tr>
<tr>
<td>Connate Water Saturation (%)</td>
<td>10.67</td>
</tr>
<tr>
<td>Type of Sands</td>
<td>Glass Beads</td>
</tr>
<tr>
<td>Grain Size</td>
<td>90-150 µm</td>
</tr>
</tbody>
</table>
2.2.2 Experimental Procedures

1D sand pack model preparation and pressure depletion tests are involved in this part as the following steps:

1) Pack the model with glass beads.

2) Use nitrogen to perform the leak test on the model.

3) Gas in the sandpack model is evacuated by a vacuum pump until the negative pressure became stable (-93 kPa).

4) Water is then be imbibed into the sandpack model for porosity calculation.

5) Permeability is measured by using syringe pump to inject water under different rate. Inlet and outlet pressure are recorded to calculate the pressure difference in the model. Darcy’s law is then applied to calculate the model permeability.

6) 4 pressure transducers (PXM409-070BG10V, OMEGA Engineering INC., Canada) were evenly distributed in the 1D sand pack model and one BPR (EB1ZF1-SS316, EquiliBAR, USA), controlled by syringe pump, is installed at the outlet to make sure the live oil injection pressure is 1.5 times of the $P_{\text{sat}}$ (1547 kPa) calculated in CMGWinprop®.

7) Signals of pressure ports on the model are collected and transformed by the LabView device and software LabVIEW 2012 (NI CompactDAQ, Nation Instruments Corporation, Canada) as pressure data which would be stored in the
computer.

8) The production unit included two parts: oil collection part and gas detection part.

   An Erlenmeyer combined with an electronic balance is used for oil collection.

   Gas produced will be transferred into gas flow meter (Rigamo, Germany), the data is collected and recorded in the computer.

9) Once the live oil has been injected into sandpack completely, a syringe pump is then used to control the decline rate in each test. All the data is recorded and stored in the computer.

   All the setup of pressure depletion tests were shown in the Fig. 2-1.
Fig. 2-1: Schematic of Pressure Depletion Test
2.3 Results and discussion

2.3.1 Heavy oil-mixture solvent system

Results of four pressure depletion tests are shown in the Table 2-5. All the tests are analyzed in this part along with the comparison between mixture solvent heavy oil system and pure solvent heavy oil system. Due to the former research on heavy oil-propane, heavy oil-methane and heavy oil-mixture solvent (propane and methane) system, results discussion in this study mainly focus on the pressure decline rate effect on the foamy oil characteristics.
<table>
<thead>
<tr>
<th>Experiment No.</th>
<th>Solvent Type</th>
<th>Pressure Decline Rate</th>
<th>Oil Recovery Factor</th>
<th>Gas Recovery Factor</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>kPa/min</td>
<td>%</td>
<td>%</td>
</tr>
<tr>
<td>Test 2.1</td>
<td>CO₂-C₃H₈</td>
<td>-12</td>
<td>23.44</td>
<td>48.7</td>
</tr>
<tr>
<td>Test 2.2</td>
<td>CO₂-C₃H₈</td>
<td>-6</td>
<td>21.67</td>
<td>52.4</td>
</tr>
<tr>
<td>Test 2.3</td>
<td>CO₂-C₃H₈</td>
<td>-2</td>
<td>20.62</td>
<td>49.2</td>
</tr>
<tr>
<td>Test 2.4</td>
<td>CO₂-C₃H₈</td>
<td>-1</td>
<td>18.11</td>
<td>50.9</td>
</tr>
</tbody>
</table>
2.3.2 Single phase flow region

Depletion tests are shown from Fig. 2-2 to 2-4 as the example. Pressure curves of Test 2.4 is omitted due to the data loss during the test. However, the oil production was recorded properly and can be used for comparison and discussion. The red dash lines are shown in these figures respectively to separate the single phase flow from two phase flow. On the left of the dash line, the pressure in the model drops from the initial pressure to the pseudo-bubble point pressure (1500 kPa) and the cumulative oil production was around zero. Pressure recorded by transducers evenly distributed in the sandpack model shows that there is no pressure difference in the single phase flow region and they equal the pressure of BPR controlled by the syringe pump. The reason why this happened and no oil was produced in this period is that only single phase flow took place at that time and there was no free gas existing in the model when the pressure was above bubble point. Meanwhile, as the pressure dropped continuously, the volume of live oil would increase. So, the oil produced at that moment was due to the live oil expansion instead of any other mechanism.
Fig. 2-2: Production behavior of Test 2.1
Fig. 2-3: Production behavior of Test 2.2
Fig. 2-4: Production behavior of Test 2.3
2.3.3 Foamy oil flow region

When the system pressure dropped below pseudo-bubble point pressure (1488 kPa in Test 2.2), foamy oil flow appeared as the mixture solvent gas bubbles evolved from the heavy oil system. However, these gas bubbles could only disperse on the surface of the heavy oil instead of escaping into the form of free gas. This process is defined as bubble nucleation (Firoozabadi and Kashchiev, 1996). At this time, hardly could the free gas be caught and the cGOR is relatively low.

Shortly after the bubble nucleation, two phases including gas and oil showed up in the sandpack, resulting in the higher compressibility as larger volume had been created by evolved gas bubbles. Meanwhile these tiny bubbles were still trapped because of the capillary force of high viscosity heavy oil. Therefore, oil could be produced more easily when the foamy oil flow took place as the gas bubbles can increase the relative permeability of the oil phase.

Take Test 2.2 as an example, Fig. 2-5 shows that cumulative oil production rate increases sharply when foamy oil flow happens in the sandpack model. Meanwhile, as the gas bubbles are still trapped, the gas production rate does not change a lot. The average oil production rate in foamy oil flow region is 0.36 g/min, while the production rate of solution gas drive is only 0.13 g/min. Fig. 2-6 shows the foamy oil flow region (between two dash lines) in the test 2.2. In this region, pressure dropped from bubble point to the pseudo-
bubble point pressure. High oil production rate and low cumulative gas oil ratio were obtained simultaneously. Once the pressure dropped below the pseudo-bubble point, the oil production rate curve and gas oil ratio curve switched their positions. Table 2-6 summarized foamy oil flow contribution in different tests. We can easily draw a conclusion that in heavy oil-CO\textsubscript{2}-C\textsubscript{3}H\textsubscript{8} mixture solvent system, foamy oil flow can at least bring 70% of total oil production.
Fig. 2-5: Oil and gas production rate in Test 2.2
Fig. 2-6: Foamy oil flow region in Test 2.2
Table 2-6: Foamy oil flow contribution in all tests

<table>
<thead>
<tr>
<th>Test No.</th>
<th>Pressure depletion rate</th>
<th>Foamy Production Contribution</th>
</tr>
</thead>
<tbody>
<tr>
<td>Test 2.1</td>
<td>12.5</td>
<td>80%</td>
</tr>
<tr>
<td>Test 2.2</td>
<td>6</td>
<td>78%</td>
</tr>
<tr>
<td>Test 2.3</td>
<td>2</td>
<td>71%</td>
</tr>
<tr>
<td>Test 2.4</td>
<td>1</td>
<td>79%</td>
</tr>
</tbody>
</table>
2.3.4 Pressure difference and gradient in the sandpack model

Fig. 2-7 and 2-8 are the pressure difference and gradient curves of heavy oil-CO₂-C₃H₈ mixture solvent system and the depletion rate in this test is 2 kPa/min.

As is shown in the Fig. 2-7, two dash lines divide the pressure difference curves into three regions. The horizontal axis represents the production pressure controlled by BPR. Pressure in region 1 ranges from 1800 kPa to 1488 kPa. During this period, pressure difference in the 1D sandpack model was as low as 5 kPa, which means sand pack was dominated by single phase flow and no gas phase appeared during this period. When it comes to the region 2 of which the pressure is from 1488 kPa to 680 kPa, a sharp increase of pressure difference took place in the sand pack model. The reason why it happened is that when the pressure dropped below the pseudo-bubble point pressure (1488 kPa in this test), mixture solvent gas bubbles nucleation started. Tinier gas bubbles were formed then dispersed on the surface of the oil phase. At the same time, pressure decline in the sand pack model also contributed to the expansion of those small gas bubbles. This stage is called bubble growth which has been observed and studied by (Wong et al., 1999). Foamy oil flow was then formed and oil production started immediately. Therefore, we can see that the Pg1 curve representing the nearest pressure port to the BPR is at the bottom in the figure while the Pg3 curve (pressure ports located at the end of the sandpack model) stands on the top as the gas bubbles are still on the way to move forward. Meanwhile, gas bubbles
coalescence began after nucleation and growth in the sandpack model. At the same time, two different zones in the foamy oil flow region are divided by a solid line in this figure. In Zone 1 where the system pressure is below pseudo-bubble point, gas bubbles were formed and dispersed in the oil phase. Meanwhile, gas bubbles entrapped in the oil phase would increase the foamy oil viscosity and pressure difference kept increasing. A special point with pressure of 1100 kPa can be found from Fig. 2-7. Before the system pressure dropped to 1100 kPa, gas production stayed at a low level while pressure difference in the 1D sandpack model increased sharply. This was due to the major processes of bubble nucleation and growth instead of bubble coalescence. When the pressure dropped below 1100 kPa (Zone 2 in this figure), bubble coalescence began to play the main role in the sandpack and gas production rate started growing. Although the pressure difference kept going up, small bubbles coalesce to become larger bubbles then been produced along with the oil phase. The slope of pressure difference curve falls slightly. Once the system pressure dropped below 680 kPa, which is also known as pseudo-bubble point, these gas bubbles began coalescing together to form the continuous gas phase. As the result, cumulative gas production rose fast to the peak in a short time and pressure difference in the sand pack decreased corresponding to the decline rate.

Pressure gradient is also calculated in this study, of which the equation is using pressure difference divided by the distance (25 cm fixed) between two pressure transducers. Same trends can also be found in the Fig. 2-8. The pressure gradient remained a low level
(0.3 kPa/cm) during single phase flow region. When the system pressure dropped below the foamy oil formation pressure, the pressure gradient started growing as the gas bubbles nucleation and growth dominated the process in the model. The peak showed up at the pressure of pseudo-bubble point as gas bubbles shall coalesce together to form the continuous gas phase.

Different from the other curves in Fig. 2-8, the curve of Pg3 (pressure gradient between two ports at the head of sand pack model close to the BPR) is at the top in the figure while the Pg1 curve sits at the bottom. This means pressure depletion effect is firstly propagated to the area close to the production port thus gas bubble nucleation and growth start immediately. However, for the potential gas bubbles trapped in the heavy oil at the back of the model, they will not appear instantly since the pressure decline could not transfer to the back while as the gas bubbles evolves at the front compensate the pressure drop in the model to certain extent.
Fig. 2-7: Pressure difference in the sandpack during Test 2.3
Fig. 2-8: Pressure gradient in the sandpack during Test 2.3
2.3.5 Comparison of heavy oil-\text{CO}_2-\text{C}_3\text{H}_8 \ mixture \ solvent \ system

It is obviously shown in the figure that oil recovery factor increases as the pressure
decline rate rises. \textbf{Fig. 2-6} has already proved that foamy oil production plays the main role
(Contributing to more than 70\% of total oil recovery) in the tests. Therefore, more attention
should be paid to the foamy production behaviors during the depletion tests. At this time,
the average foamy production rate can be applied to explain why the higher oil recovery
factor can be obtained when the pressure decline rate rises.

\textbf{Fig. 2-9} presents the average foamy production rates in 4 tests. From the figure we
can know that the higher pressure decline rates used, the larger foamy production rates
perform in the sand pack model. Foamy production equals to the average production rate
times the duration of foamy oil flow region. In \text{CO}_2-\text{C}_3\text{H}_8 \ heavy \ oil \ pressure \ depletion \ tests,
bubble-point pressure difference caused by decline rates variation is relative small. And it
can hardly affect the duration of foamy production. So, the dominant factor that influence
the foamy production time is pressure decline rate. Compared with Test 2.3 (-2 kPa/min,
foamy oil flow region: 1488-680 kPa, foamy production time: 404 min), Test 2.2 (-6
kPa/min, foamy oil flow region: 1475-600 kPa foamy production time: 145 min) has
shorter time for foamy oil flow contribution. But the average production rate can make
compensation and results show that foamy production in higher pressure decline rate is
larger than that in lower pressure decline rate.
Fig. 2-9: Relationship between depletion rate and average foamy production rate
2.4.6 Comparison between this study and former researches

Table 2-8 shows that all the experiment conditions including the heavy oil sample and 1D sand pack model are the same as the former study (Zhou, 2015). However, different oil recovery factors are obtained because of various solvent types and pressure depletion rates. In the former study, we can find the relatively poor stabilities of oil recovery factors is in different solvent heavy oil systems especially when the solvent is propane. This means foamy oil behaviors in heavy oil propane system is sensitive to the pressure decline rate. The methane-propane mixture solvent used did enhance the stability of the foamy oil. However, stability of foamy oil characteristic in this study is much higher than that in the former, which means foamy oil in CO$_2$-C$_3$H$_8$ heavy oil system is not as much sensitive as in other solvent heavy oil systems.

Fig. 2-10 presents the average oil recovery factors in different solvent heavy oil systems. It is obviously shown in the figure that oil production behavior in CO$_2$-C$_3$H$_8$ heavy oil system is relatively better. More attention can be paid into this area and more heavy crudes can be produced hopefully when this mixture solvent taken into field application.
<table>
<thead>
<tr>
<th>Test Comparison</th>
<th>Solvent Type</th>
<th>Pressure Decline Rate kPa/min</th>
<th>Oil Recovery Factor %</th>
</tr>
</thead>
<tbody>
<tr>
<td>This Study</td>
<td>CO$_2$-C$_3$H$_8$</td>
<td>1</td>
<td>18.11</td>
</tr>
<tr>
<td></td>
<td>CO$_2$-C$_3$H$_8$</td>
<td>2</td>
<td>20.62</td>
</tr>
<tr>
<td></td>
<td>CO$_2$-C$_3$H$_8$</td>
<td>6</td>
<td>21.67</td>
</tr>
<tr>
<td></td>
<td>CO$_2$-C$_3$H$_8$</td>
<td>12</td>
<td>23.44</td>
</tr>
<tr>
<td>Zhou, 2015</td>
<td>CH$_4$</td>
<td>0.97</td>
<td>20.12</td>
</tr>
<tr>
<td></td>
<td>CH$_4$</td>
<td>1.7</td>
<td>22.13</td>
</tr>
<tr>
<td></td>
<td>CH$_4$</td>
<td>4.02</td>
<td>12.11</td>
</tr>
<tr>
<td></td>
<td>C$_3$H$_8$</td>
<td>0.76</td>
<td>24.17</td>
</tr>
<tr>
<td></td>
<td>C$_3$H$_8$</td>
<td>1.92</td>
<td>19.19</td>
</tr>
<tr>
<td></td>
<td>C$_3$H$_8$</td>
<td>4.52</td>
<td>11.85</td>
</tr>
<tr>
<td></td>
<td>CH$_4$-C$_3$H$_8$</td>
<td>0.86</td>
<td>9.09</td>
</tr>
<tr>
<td></td>
<td>CH$_4$-C$_3$H$_8$</td>
<td>1.84</td>
<td>15.61</td>
</tr>
<tr>
<td></td>
<td>CH$_4$-C$_3$H$_8$</td>
<td>3.97</td>
<td>21.8</td>
</tr>
<tr>
<td></td>
<td>CH$_4$-C$_3$H$_8$</td>
<td>6.66</td>
<td>20.44</td>
</tr>
</tbody>
</table>
Table 2-8: Experimental conditions in this study and former one.

<table>
<thead>
<tr>
<th>Experiment Conditions</th>
<th>This Study</th>
<th>(Zhou, 2015)</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Heavy oil Properties</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Density</td>
<td>0.964 g/ml</td>
<td>0.964 g/ml</td>
</tr>
<tr>
<td>Viscosity @ 21°C</td>
<td>2200 cP</td>
<td>2200 cP</td>
</tr>
<tr>
<td><strong>Sand Pack Model</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>properties</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Length</td>
<td>95 cm</td>
<td>95 cm</td>
</tr>
<tr>
<td>Inner diameter</td>
<td>3.81 cm</td>
<td>3.81 cm</td>
</tr>
<tr>
<td>Porosity (avg)</td>
<td>34.84%</td>
<td>35.99%</td>
</tr>
<tr>
<td>Permeability (avg)</td>
<td>6.44 D</td>
<td>6.03 D</td>
</tr>
<tr>
<td>Soi (avg)</td>
<td>89.90%</td>
<td>96.70%</td>
</tr>
<tr>
<td>Swc (avg)</td>
<td>10.10%</td>
<td>3.30%</td>
</tr>
<tr>
<td><strong>Other Conditions</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Temperature</td>
<td>21°C</td>
<td>21°C</td>
</tr>
</tbody>
</table>
Fig. 2-10: Average oil recovery factor in different solvents-heavy oil systems
2.4 Conclusions

According to the four pressure depletion tests in this study, some conclusions can be drawn as follows:

- It is shown that foamy oil flow is the main mechanism for high production which can at least bring 70% of total oil production in heavy oil-CO$_2$-C$_3$H$_8$ mixture solvent system.

- A special pressure has been found in the foamy oil flow region. Bubble nucleation and growth dominate the processes when the pressure is higher than the point, while bubble coalescence tends to play the main role as the system pressure drops below.

- Larger pressure depletion rate leads to a better performance on the foamy oil characteristics especially on the average foamy production rate. However, this only happens on the CO$_2$-C$_3$H$_8$ mixture solvent heavy oil system. For other solvents, more studies need to be conducted for further discussion.

- CO$_2$-C$_3$H$_8$ mixture solvent shows better than methane, propane, methane-propane in the stability of oil recovery factor as it is less sensitive to the pressure decline rate than other solvents.
Chapter 3 Experimental investigation of the model length effect on foamy oil behaviors by using CO$_2$-C$_3$H$_8$ heavy oil mixture solvent system

Abstract

Foamy oil flow has been playing an important role in heavy oil production since the last century. Large amounts of experimental investigation is conducted by researchers in this area to understand the mechanism of this non-Darcy two-phase flow. However, most studies mainly focus on the major influencing factors including pressure decline rate, temperature, and solvent type and so on. Hardly have the tests been done to discuss the model length effect on the foamy oil flow characteristic. In this study, three pressure depletion tests were carried out by using 1D sand pack models with a length of 1 m, 2 m, and 4 m respectively to find out the model length effect on the foamy oil behavior. Oil recovery factors were calculated separately when BPR stopped working and the system pressure dropped to zero. Results show that total oil recovery decreases when the model length becomes larger. However, oil production behaved similarly during the free energy release period (After BPR stopped working). Besides, tail pressure recorded by transducers located at the end of 1D sand pack models with different length proves that pressure differences and gradients become harder to form when the model becomes longer. Thus, the lack of enough driving force and longer migration distance result in the lower oil
recovery factor in the longer models.

3.1 Introduction

Heavy oil is proved to be a promising source to meet the increasing demand of crude oil supply at present. Different methods for enhance heavy oil recovery have been created in the laboratory and then used for pilot tests. All these methods can be classified into 2 categories which are non-thermal and thermal recoveries according to the operating temperature. Compared with thermal recovery, Non-thermal methods are usually more economic and ecological by taking the advantages of no heat utilization. Thus, many efforts have been made into this area to find out the mechanism to enhance heavy oil recovery.

Foamy oil flow is the main mechanism of these non-thermal recovery methods. The dynamic process of this flow be divided into three stages (Bora, 1998; Kumar, 1999; Zhang, 1999; Albartamani, 2000; Xu, 2007; Maini, 2010): 1. Bubble nucleation; 2. Bubble growth; 3. Bubble coalescence.

Bubble nucleation is the first process of the foamy oil flow. During this period, bubbles start to form under the pseudo-bubble point pressure. A number of influential factors have been studied such as pressure decline rate, Asphaltenes content, connate water saturation, and capillary pressure and so on. Among these factors, it has been proved that pressure depletion rate brings a huge effect on the bubble nucleation extent and scale (Xu, 2007). It is widely confirmed that larger pressure decline rate do contributes to faster
nucleation and larger amounts of the gas bubbles. Thus, foamy oil behaves better in the heavy oil system with the larger pressure decline rate and recovery factor is relatively higher.

Bubble growth is the second stage comes after bubble nucleation process. Former study (Zhou, 2015) shows that bubble growth is mainly affected by the pore structure and geometry in porous media. Three main routes for bubble growing are pointed out (Wong et al., 1999). Firstly, the volume expansion of gas bubbles as the pressure drops during depletion tests of heavy oil system. Secondly, some tiny bubbles can coalesce together to form a bigger one. Thirdly, some gas diffused from the closed bubble nucleation site may aggregate to form bigger bubbles as well.

Bubble coalescence comes the last when the concentration and density reach a certain level. Several steps can be drawn into conclusion to describe this process. First, gas bubbles can be brought together as pressure gradient takes place in the reservoir during field production. At this time, some bubbles are still in the processes of nucleation and growth as the pressure decline effect cannot transfer to the end immediately. Secondly, the liquid film on each bubble must be thinned and drained to coalesce the bubbles. Whether these bubbles can coalesce together or not depends on the fluid dynamics. Although bubble coalescence is the last stage of foamy oil flow, it is still very important as the process brings effect on the continuous gas flow formation. Once the continuous gas flow was built up, free gas will release from the reservoir and gas-oil ratio is to increase immediately.
Meanwhile, cumulative oil production rate will experience a sharp decrease during the solution gas drive period.

Therefore, pressure difference and gradient need to be pay more attention to in foamy oil behavior studies. Numerous studies have been already conducted to investigate these two factors. However, little work has been done to take model length into consideration. In this study, three pressure depletion tests were performed by using 1D sand pack models with different length (1 m, 2 m, and 4 m) to discuss the model length effect on the foamy oil flow characteristics. Experimental parts including materials and set up procedures are included. After that, results discussion and conclusions will be provided.

3.2 Experimental section

3.2.1 Experimental Materials

Heavy Oil sample has been collected from Manatoken oil field and then sent to the lab for this experimental study. Oil properties and SARA analysis are shown in Table 2-1 and 2-2 respectively. Carbon dioxide, propane and nitrogen were provided by Praxair, both with purities of 99.99%. Propane and carbon dioxide were used for mixture solvent preparation while nitrogen was used for pressure test. The average pore size for glass beads packed in 1D sandpack model ranges from 90-150 µm.
3.2.1.1 Live oil preparation

For the information of live oil preparation, please take steps in Chapter 2 as a reference and all the oil properties are proved to be the same as that in the former chapter.

3.2.1.2 1D sand pack models preparation

In this study, 1D sand pack models with different length (1 m, 2 m, 4 m) are prepared separately. Due to the limited room space for the experiment, 1-meter-long 1D sandpack model was used as one unit in the three tests. Thus, in Test 3.2 and 3.3, two and four 1D sandpack models were connected together to create the different models. Fig. 3-1 provides schematic for Test 3.3.

For the packing methods, dry packing was used to fulfill the model with glass beads. During the packing period, no water or any other liquid was needed. However, a vibrator is needed as the sand should be packed in the model compactly and uniformly.
Fig. 3-1: 4-meter-long 1D sand pack model used in Test 3.3
3.2.1.3 Leaking Test

As all the experiments in this study are pressure sensitive, no leak was allowed throughout the whole process. Thus, it is necessary to perform the leak test every time before the start to make sure the whole system is isolated from the outside.

In this test, one pressure gauge was installed at the head of the sand pack model for pressure measurement. Purified nitrogen (> 99.99%) was utilized as the ideal gas to conduct the leaking test because nitrogen is neither reactive nor corrosive to the experimental system. Considering that the pressure ranges from 0-3000 kPa, BPR was set to 3500 kPa to seal the whole system. Criteria for passing the test is that pressure drop must less than 5 kPa in 24 hours.

3.2.1.4 Porosity Measurement

Due to the length change among the three tests in this study, porosity have to be measured accurately for the reference. The method to perform the porosity test is using water imbibition to fill the entire pore space of the system. All the steps are shown as the following:

1) Using end caps to seal all the outlets of the model except the one used for vacuuming and water inhaling.

2) A vacuum pump was connected to the model through the inlet port to take out the
air. Pressure gauge installed at the head should drop below -90.0~93.0 KPA.

3) Deionized water was filled into a glass graduate for later measurement.

4) After the vacuum process was finished, disconnect the vacuum pump and connect the model to the graduate.

5) Tense the valve and water would be inhaled into the system.

6) Measure the volume of inhaled water.

7) Open the outlet at the end of the 1D sand pack model and inject deionized water by the pump.

8) Calculate the volume loss of the water injection.

9) Calculate the porosity by using the following equation:

\[ \phi = \frac{V_{inhaled} + V_{injected}}{V_{bulk}} \]
3.2.1.5 Absolute Permeability Measurement

Sandpack models with different length were used in the experiments. Thus, permeability is necessary to measure as a parameter. In this part, Darcy’s law is used to perform the test.

The model waiting for test was water saturated and fixed flow rate is set allow water flow through the model. Upon the time when the pressure gets stable, record the pressure on the inlet and outlet pressure gauge.

Taking 4-meter-long sandpack as an example, all the details are shown in the Table 3-1 and 3-2 and Fig. 3-2.
Table 3-1: Permeability of 4-meter-long 1D sandpack model.

<table>
<thead>
<tr>
<th>Flowrate (cc/s)</th>
<th>Inlet Pressure (atm)</th>
<th>Outlet Pressure (atm)</th>
<th>Δ P (atm)</th>
</tr>
</thead>
<tbody>
<tr>
<td>0.167</td>
<td>0.94</td>
<td>0.01</td>
<td>0.93</td>
</tr>
<tr>
<td>0.333</td>
<td>2.00</td>
<td>0.80</td>
<td>1.20</td>
</tr>
<tr>
<td>0.500</td>
<td>3.00</td>
<td>1.20</td>
<td>1.80</td>
</tr>
<tr>
<td>0.667</td>
<td>4.00</td>
<td>1.70</td>
<td>2.30</td>
</tr>
<tr>
<td>0.833</td>
<td>5.10</td>
<td>2.10</td>
<td>3.00</td>
</tr>
<tr>
<td>1.000</td>
<td>7.38</td>
<td>3.70</td>
<td>3.68</td>
</tr>
<tr>
<td>1.167</td>
<td>8.60</td>
<td>4.30</td>
<td>4.30</td>
</tr>
<tr>
<td>1.500</td>
<td>11.00</td>
<td>5.50</td>
<td>5.50</td>
</tr>
<tr>
<td>2.000</td>
<td>15.00</td>
<td>7.80</td>
<td>7.20</td>
</tr>
</tbody>
</table>
Fig. 3-2: Relationship between flow rate and pressure difference in the 4-meter-long 1D sandpack model
Table 3-2: Final calculation of 4-meter-long 1D sandpack model

<table>
<thead>
<tr>
<th>Parameters</th>
<th>Value</th>
<th>Unit</th>
</tr>
</thead>
<tbody>
<tr>
<td>Length</td>
<td>400</td>
<td>cm</td>
</tr>
<tr>
<td>Inner Diameter</td>
<td>3.81</td>
<td>cm</td>
</tr>
<tr>
<td>Volume</td>
<td>4534.16</td>
<td>ml</td>
</tr>
<tr>
<td>Area</td>
<td>11.345</td>
<td>cm²</td>
</tr>
<tr>
<td>Porosity $\Phi$</td>
<td>36.57</td>
<td>%</td>
</tr>
<tr>
<td>Permeability</td>
<td>10.06</td>
<td>D</td>
</tr>
<tr>
<td>Soi</td>
<td>97.13</td>
<td>%</td>
</tr>
<tr>
<td>Swc</td>
<td>2.87</td>
<td>%</td>
</tr>
</tbody>
</table>
3.2.2 Experimental Procedures

3.2.2.1 Experiment Setup

Once the live oil and 1D sand pack models were ready for tests, the experiment set up can be started. Among all the pressure depletion tests conducted in this study, Test 3.3 (4-meter-long) was the most complex one and it would be taken as an example in this part. **Fig. 3-1** presents the schematic of the Test 3.3. In this test, two syringe pumps (1000D, 260D) were used for different functions. The first pump (1000D) took the responsibility of live oil injection as the total pore volume was 1415 ml while the second pump (260D) was used to control the BPR so that the system pressure would be assured and pressure depletion test would go on properly. During the live oil injection period, constant flow mode was used on the first pump and flow rate was chose to be 0.05 ml/min to prevent the viscous fingering and wall effect in the model. Pressure ports were installed on the chosen outlets of the 4-meter-long sand pack model to record the pressure change in the model. All the data were stored in the computer. When it comes to the production module, one BPR was controlled by the second pump to ensure the depletion rate and an erlenmeyer was located on the electric balance to measure the oil production. Gas flow meter provided by Rigamo was connected behind.

The 260D pump would start working by the end of live oil injection, which means the start of the test. In this study, -6 kPa/min was chose for the decline rate of all tests.
3.3 Results and discussion

3.3.1 Oil production behavior

Table 3-3 summarizes the oil recovery factors in the three tests. In this section, oil recovery factors will be divided into 2 stages: pressure depletion stage and residual pressure production stage. During the pressure depletion stage, the production was measured until the BPR stopped working. Oil produced afterwards would be calculated as the second stage production. Results show that as the model length became longer, oil recovery factor decreased sharply in the pressure depletion stage. However, due to the pressure gradient in the sandpack, longer models contributed to a relatively higher oil recovery factor during the residual pressure production stage. Total recovery factors of the three tests indicates that although longer models behaves better in the second stage, more oil can be obtained in the shorter sand pack models.

3.3.1.1 First stage oil production behavior

Production behavior of three tests are shown in the Fig. 3-3. It can be obviously observed from the figure that less oil was produced in the first stage as the model length became larger. It has been widely accepted that foamy oil flow dominates the primary production processes in the heavy oil reservoir. In this study, as the pressure dropped below the bubble-point pressure, foamy oil flow appeared in the sandpack models and a sharp
increase of oil production took place. Absolute production was recorded and compared. Although there were some difference in absolute production between these tests, it is believed that the doubled and quadrupled OOIP in Test 3.2 and 3.3 is the main reason for lower oil recovery factors in these two tests.

3.3.1.2 Second stage oil production behavior

It can be obviously drawn from the Table 3-3 that oil recovery factor of second stage production increased when the model length became larger. This may attribute to the pressure preservation during the first stage production.

It is known to us all that foamy oil flow includes three parts: bubble nucleation, bubble growth and bubble coalescence. During the first stage production, gas bubbles appeared when the pressure dropped below pseudo-bubble point pressure. As the pressure kept decreasing, those tiny bubbles started growing into bigger ones. Meanwhile, bigger bubbles would flow with the oil phase to the outlet of the sandpack. However, flow rate was limited due to the fixed size of the tube. Therefore, a part of the bigger bubbles would stay at the head of the sandpack and create a relative hermetic space. At the same time, more and more gas bubbles formed and enlarged in the hermetic space. So the pressure maintenance happened in the models and pressure difference and gradients were built up.

Fig. 3-4, 3-5 and 3-6 are used to show the pressure during the second stage production period. It can be obviously drawn in to conclusion that the production time in 2-meter-long
model (2592 min) is much larger than that in 1-meter-long sandpack (1081 min).

Meanwhile, the oil production rate in the longer model was slight higher than that in the shorter one (0.029 g/min in Test 3.1 and 0.034 g/min in Test 3.2). This may mainly due to the better performance of pressure preservation in longer models.
Table 3-3: Oil recovery in different stages during Test 3.1, 3.2 and 3.3

<table>
<thead>
<tr>
<th>Test</th>
<th>Length (m)</th>
<th>Ro in Stage 1</th>
<th>Ro in Stage 2</th>
<th>Total Ro</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>1</td>
<td>20.60%</td>
<td>9.85%</td>
<td>30.45%</td>
</tr>
<tr>
<td>2</td>
<td>2</td>
<td>11.96%</td>
<td>10.11%</td>
<td>22.07%</td>
</tr>
<tr>
<td>3</td>
<td>4</td>
<td>3.60%</td>
<td>14.65%</td>
<td>18.25%</td>
</tr>
</tbody>
</table>

Stage 1: pressure depletion production stage

Stage 2: residual pressure production stage

Ro: Recovery Factor
Fig. 3-3: Oil recovery factors in stage 1 for each test

Test Number
Test 3.1 (1m) Test 3.2 (2m) Test 3.3 (4m)
Oil Recovery Factor in Stage 1 (%)
20.60% 11.96% 3.60%
Average production rate in second stage : 0.04 g/min
\( R_{oT} = R_{o1} + R_{o2} = 30.45\% \)

Fig. 3-4: Pressure decline curves in Test 3.1
Fig. 3-5: Pressure decline curves in Test 3.2
Fig. 3-6: Pressure decline curves in second stage production of Test 3.3
3.3.2 Pressure difference and gradient

Pressure difference and gradient were also calculated in this study to talk about the foamy oil flow behavior in the sandpack with different length. Fig. 3-7 and 3-8 are presented to show the pressure difference in the 1 and 2 meters long models.

In these sandpack models, pressure difference appeared when the pressure drops below the pseudo-bubble point pressure and increased sharply in a short time. Same phenomenon happened in other two models in the tests. This is mainly because upon the pseudo-bubble point pressure was reached, bubble nucleation started in the model and bubble volume expansion created pressure difference in the model. After that, the tiny bubbles had already grown into bigger ones and coalesced together to form the free gas flow. At this time, gas production rate increased immediately and continuous gas phase was brought out of the model and pressure difference grew at a lower rate until the BPR stopped working. When the BPR stopped working, residual pressure created by remained gas bubbles began to drop down and pressure difference started to decrease. Compared with Test 3.1, it can be observed that pressure curve recorded by 3 pressure ports installed at the end of the 2-meter-long model are overlapped. This means pressure difference at the end did not show up even if the longer model was in the second stage production. It can be proved that longer models have poorer oil production behaviors in the lab and length effect may bring disadvantages in the field application.
Fig. 3-7: Pressure difference in Test 3.1
Fig. 3-8: Pressure difference in Test 3.2
Pressure gradient in the three tests are shown respectively in Fig. 3-9, 3-10 and 3-11. When the system pressure drops below the pseudo-bubble point, gas bubbles nucleation began and pressure difference and gradient showed up. As is shown in Fig. 3-9, Pg4 (P3-BPR) increased immediately, which is because the system pressure decay transfer from the BPR to the far end of the sandpack model (BPR-P3-P2-P1-P0) consequently. When the free gas was formed in the model, Pg4 remained at the certain level or experienced a slight increase until the BPR stopped working. When the BPR pressure dropped to atmosphere, pressure gradient started decreasing and residual pressure production began. In the longer models, higher pressure difference and gradient contributes to larger oil recovery factor during the second stage production.

3.3.3 Field application of the model length effect

Fig. 3-12 shows the effective oil production time of the three tests in this study. 0.01 g/min has been chosen to be the minimum effective oil production rate and the effective oil production time was calculated for each test. It can be easily drawn from the figure that as the model length becomes larger, a retention time (1100, 1600, 6000 min in three tests respectively) can be found obviously for effective oil production. In the 1-meter-long sandpack model, the effective oil production rate was obtained through the whole process (100% of total production time) while the effective production time percentage was proved to be only 50% (6000 min/12000 min). In the site production period, many enhance heavy
oil recovery methods like CSI processes have to take time consumption into consideration. Under such circumstance, production time optimization can be applied into CSI processes based on different well spacing and the pay zone condition. Test 3.3 can be used for explanation, 4-meter-long sandpack model represents a horizontal pay zone in CSI processes. In each cycle of CSI, solvent will be injected through the upper horizontal well and oil will be produced from the lower horizontal well after the soaking period. During the production period, well shut down can be adjusted in each cycle to obtain less time consumption and economic oil recovery as the result.
Fig. 3-9: Pressure gradient in Test 3.1
Fig. 3-10: Pressure gradient in Test 3.2
Fig. 3-11: Pressure gradient in Test 3.3
Fig. 3-12: Effective production time in each test
3.4 Conclusions

According to the pressure depletion tests conducted by using models with different length in this study and conclusions can be drawn as the follows:

- In 1D sandpack pressure depletion tests, oil recovery factors decrease as the model length becomes longer.
- Strong foamy production and relative lower OOIP contribute to the high oil recovery in the first stage production (Cumulative production calculation stopped as the BPR stopped working).
- Due to the pressure preservation in the hermetic space of the 1D sandpack model, larger amount of time will be consumed for production in the longer model.
- The disappearance of pressure difference and gradient at the end of longer models leads to the lower production, which indicates that the model length effect is shown to be disadvantageous in those wells in a distance.
- More gas bubbles generated in the longer model led to larger volume expansion so that more oil will be produced from the central well in heavy oil reservoir with larger OOIP.
Chapter 4 Experimental study on the gravity effect on the post-CHOPS CSI processes.

Abstract

Cyclic Solvent injection has been used as a follow-up oil recovery process to CHOPS recently. Some pilot tests have already been performed in the site production. Meanwhile, a lot of research has been conducted in the laboratory to understand the mechanism of the CSI processes and influencing factors. However, most studies focus on the wormhole and soaking time optimization. Few studies were carried out to discuss the gravity effect on the post-CHOPS CSI processes. In order to investigate this influencing factor, experiments were conducted under four different inclination (0°, 20°, 30°, 90°) to find out the relationship between gravity and production behaviors in the post-CHOPS CSI processes. In this study, 1D sandpack model (Length: 95 cm; Inner diameter: 3.8 cm) was used to mimic the heavy oil reservoir in the lab. Meanwhile, a typical heavy oil (Viscosity 2260 cP @ 21°C) from the Manatoken oil field was used. Furthermore, pressure depletion tests were conducted ahead to simulate the reservoir condition after primary production. After that, some pads were used to raise the end of the sandpack model to create dips with different degree. Mixture solvent was chosen to be the composition of 70%CO₂ and 30%C₃H₈ to compare with former studies in the research group. Dew point was calculated as 2865 kPa by using CMG Winprop® and injection pressure was decided to be 2850 kPa.
as a result. Soaking time was also optimized to be six and a half hours in the pretest. Results shows that gravity do take effects on the production behavior when a higher inclination was created. Through analyzing the experimental data, a relationship of oil recovery factor to dip degree is also obtained and verified.

4.1 Introduction

It has been proved to be successful that using Cold Heavy Oil Production with sand (CHOPS) as the primary production method can bring 5 - 15% heavy oil recovered in Alberta and Saskatchewan, Canada. The average oil recovery factor under CHOPS is usually lower than 10%, which means over 90% heavy oil was still trapped in the reservoir waiting for further production. Under such circumstance, it is of great significance to find effective ways for post-CHOPS EOR processes (Du, 2017). Due to the high percentage of heavy oil was remained in the reservoir, water flooding, a typical secondary oil recovery (SOR) method used in conventional reservoir production was applied into enhance heavy oil recovery area (Zhang, 2018). However, huge difference took place between conventional and unconventional reservoir production because of the unique oil properties and sedimentary environment. Therefore, a number of other “post-CHOPS” techniques are developed to match field productions in the last several decades and most of them are summarized in the Table 4-1.
Although all these methods are applied into field application, some disadvantages show up. Firstly, thermal methods always require heating for heavy oil viscosity reduction. The cost for heating during thermal production occupies the major share of the budget. What is worse, due to the low thermal conductivity of the rocks underground, the heat transfer efficiency is relatively low thus additional heat is needed and higher cost was brought. Secondly, chemical flooding includes two main components which are chemicals and water. In such case, large amount of water will be used as injecting fluid. Besides, some chemicals could also be expensive and result in a huge expense to oil companies. Meanwhile, large consumption of water and energy leads to the greenhouse gas emissions as well (Luhning et al., 2003).

Therefore, the Cyclic Solvent Injection (CSI) process, a solvent based method is developed as an alternative way for EHOR (Enhance Heavy Oil Recovery). The mechanism is that solvent dissolved in the heavy oil can decrease the viscosity so that higher mobility will be obtained and more oil will be produced as a result. According to the research carried out recently (James et al., 2007), solvent based methods have some obvious advantages than other recovery methods in terms of energy consumption and efficiency, cost value, oil production quality and environmental friendliness. Thus, more attention should be paid to the development of CSI. Cyclic Solvent Injection process has been built up and brought into field application for over several decades and a lot of
experimental investigation has been carried out. CSI process has been optimized by many researchers in these years and they focus on the relative permeability (John Ivory, 2010), wormhole effect (Du, 2017), pressure decline rate and solvent types. Although these research are meaningful, there is one parameter ignored which is gravity.

It is well known that the CSI process includes three stages: injection, soaking and production. Solvent is injected from the well head to the bottom hole and dissolved in the heavy oil reservoir during the soaking time. In this two stages, gravity effect is also worth attention as it may contributes to the additional oil production in the third stage. In order to investigate the gravity effect, four CSI tests were conducted in this study by using 1D sandpack model. Since the CSI process is developed as a post-CHOPS EHOR method, 4 pressure depletion tests had been carried out to mimic the reservoir condition after primary production. Four formation dips (0°, 20°, 30°, and 90°) were created by using pads with different heights. Experimental and analytical results will also be presented in this study to show the gravity effect in the CSI processes.
Table 4-1: Different methods of post-CHOPS processes (Ma, 2017)

<table>
<thead>
<tr>
<th>Post-CHOPS Oil Recovery Methods</th>
<th>Thermal</th>
<th>Solvent</th>
<th>Chemical</th>
<th>Hybrid</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>THAI</td>
<td>VAPEX</td>
<td>Alkaline Flooding</td>
<td>SAP</td>
</tr>
<tr>
<td></td>
<td>Air Injection</td>
<td>CSI</td>
<td>Surfactant Flooding</td>
<td>LASER</td>
</tr>
<tr>
<td></td>
<td>Electromagnetic Heating</td>
<td></td>
<td>Polymer Flooding</td>
<td>ES-SAGD</td>
</tr>
<tr>
<td></td>
<td>Cyclic Steam Stimulation</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Steam Flooding</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>SAGD</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
4.2 Experimental Section

4.2.1 Experimental Materials and Pre-tests

A typical heavy oil sample was taken from the Manatoken oil field and then sent to the lab for composition analysis. All the results are the same as that in former chapters. Praxair provided the gas needed for the experiment such as CO\textsubscript{2}, N\textsubscript{2} and C\textsubscript{3}H\textsubscript{8} with the purity of 99.99%. Nitrogen was used for the leak test to make sure that the whole system is sealed properly. CO\textsubscript{2} and N\textsubscript{2} were chosen to be the mixture solvent used in these tests. Besides, glass beads of which the average pore size ranges from 90 - 150 µm was dry packed in the sandpack models.

Since the CSI tests are post-CHOPS processes, pre-CISI pressure depletion tests were conducted to simulate the reservoir condition before the cyclic solvent injection. Thus live oil was supposed to be prepared ahead. Saturation pressure was calculated as 1547 kPa by using CMGWinprop® firstly. Two transfer cells were then used to fill the mixture solvent and dead oil respectively. After that, a syringe pump (ISCO 1000D) was used to move the gas into the oil phase by injecting the deionized water. Once all the gas had been moved, valve was closed and two transfer cell was disconnected. The transfer cell was then rotated in order to fully mix the oil and gas. It is suggested that the rotation time should be 24 hours at least, or the gas may not dissolve into the oil phase properly.
Meanwhile, sandpack models were injected with water for porosity and absolute permeability measurement. Upon two measurements was finished, deionized water would be injected by the syringe pump to raise the system pressure and a BPR was installed at the outlet for pressure maintenance.

Once the live oil was ready to inject, the transfer cell would be connected to the 1D sandpack model. Constant flow mode was used during the oil injection period and the flow rate was set to be 0.08 ml/min to prevent viscous fingering and wall effect.

Pressure depletion tests would not started until all the system were prepared properly. All the reservoir condition for the CSI tests are summarized in Table 4-2.
<table>
<thead>
<tr>
<th>No</th>
<th>Dip</th>
<th>Porosity</th>
<th>Permeability</th>
<th>Residual Oil Saturation</th>
<th>Residual Oil</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>0°</td>
<td>34.82%</td>
<td>6.47 D</td>
<td>69.90%</td>
<td>226.6 g</td>
</tr>
<tr>
<td>2</td>
<td>20°</td>
<td>36.57%</td>
<td>6.42 D</td>
<td>77.84%</td>
<td>292.3 g</td>
</tr>
<tr>
<td>3</td>
<td>30°</td>
<td>35.35%</td>
<td>6.45 D</td>
<td>80.90%</td>
<td>274.2 g</td>
</tr>
<tr>
<td>4</td>
<td>90°</td>
<td>36.07%</td>
<td>6.43 D</td>
<td>74.30%</td>
<td>289.4 g</td>
</tr>
</tbody>
</table>
4.2.2 Experimental procedure

The schematic of post-CHOPS CSI processes is shown in the Fig.4-1 and the experiment is divided into three parts in each cycle: Gas injection, Well Soaking and Oil production.

4.2.2.1 Solvent injection

Mixture solvent containing 70% CO₂ and 30% C₃H₈ had been prepared ahead. During the solvent injection period, mixed gas solvent was injected into the 1D sandpack model through the outlet of production side. Meanwhile, pressure port started working and system pressure was shown on the monitor. Constant flow mode was used in this step and solvent injection rate was set to be 30 ml/min. Upon the system pressure reached 2500 kPa, the injection rate was lowered to 5ml/min until the system pressure reached 2850 kPa. It is suggest that the injection pressure should not be higher than dew point of the gas mixture (Pₐ in study had been calculated as 2865 kPa) in case of liquefaction.

4.2.2.2 Soaking

Once the solvent injection had been finished, the valve installed at the outlet was shut down and the model was isolated. Soaking time was optimized to be 450 min as almost no pressure drop happened after 7.5 hours.
4.2.2.3 Production

In this step, the outlet valve was opened and the BPR was used to control the pressure depletion rate. According to the mixture solvent pressure depletion test conducted ahead, pressure decline rate was set to be 6 kPa/min in the CSI tests. At the same time, a water flask was used to collect produced oil and gas flow meter was also connected to measure the gas production during the test.

When a cycle was over, a new cycle would be started and all the processes would be repeated. The entire production procedure would not stop until three consecutive production was lower than 1g.
Fig. 4-1: Schematic of post-CHOPS CSI processes
4.3 Results and discussion

4.3.1 Production behaviors overview

Oil recovery factors is summarized in the Fig. 4-2. The horizontal reservoir in Test 4.1 owns the lowest oil recovery factor which is only 2.47%. However, using CSI as a follow-up process in the vertical reservoir can let us obtain the relatively high oil recovery factor (27.91%). Although the vertical reservoir of which the formation dip is 90° seems to be theoretical, Test 4.4 indicates that gravity effect did happen during the oil production time. Results in Test 4.2 and 4.3 are proved to be consistent with the conclusion as well.
Fig. 4-2: Oil recovery factor for each test
4.3.2 Production behaviors in each test

Results for the four tests in this study are shown respectively in Fig. 4-3, 4-4, 4-5 and 4-6. It can be easily drawn from the first figure that only 2 effective cycles took place in the test 4.1 of which the formation dip is 0º. In the test 4.1, the absolute production in cycle 1 was 0.72g which means only cycle 3 could we obtain the effective oil production (6.1g).

Gas production curve was also recorded in this test. Taking Cycle 3 as a typical cycle, a stepped descent curve circled in the Fig.4-7 presented the main production area in this cycle. The production area can be divided into 2 parts, the same as Du pointed out in 2017, which are Phase 1 and Phase 2. Under the pressure range of 2600-1653 kPa, foamy oil flow and solution gas drive played a main role and Phase 1 production contributed to 68.8% of total oil recovery and the average production rate was as high as 0.025 g/min. When the pressure dropped below 597 kPa, oil production started again. However, the second stage was mainly due to the pressure gradient instead of solution gas drive or foamy production. Therefore, the production rate decreased sharply and the average was only 0.003 g/min.

The same production behaviors happened in other test as well. Details of phase 1 and phase 2 production are summarized in the Table 4-3. It can be easily drawn from the table that, more phase 1 production showed up when the formation dip became larger so that the recovery factor increased as a result. Therefore, there is a positive relationship between gravity effect and foamy production in the post-CHOPS CSI processes.
Fig. 4-3: Oil recovery factor of each cycle in Test 4.1
Fig. 4-4: Oil recovery factor of each cycle in Test 4.2
Fig. 4-5: Oil recovery factor of each cycle in Test 4.3
Fig. 4-6: Oil recovery factor of each cycle in Test 4.4
Fig. 4-7: Two phases production of Cycle 3 in Test 4.1
<table>
<thead>
<tr>
<th>Test No</th>
<th>Foamy oil flow</th>
<th>Solution gas drive</th>
<th>Phase 2 Pressure gradient</th>
<th>Effective Cycles</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Cycle 3</td>
<td>Cycle 1,3</td>
<td>2</td>
<td></td>
</tr>
<tr>
<td>2</td>
<td>Cycle 2,4,5,8</td>
<td>Cycle 3,6,7,9</td>
<td>8</td>
<td></td>
</tr>
<tr>
<td>3</td>
<td>Cycle 1,2,3,4,5</td>
<td>Cycle 1,2,3,4,5,6</td>
<td>6</td>
<td></td>
</tr>
<tr>
<td>4</td>
<td>Cycle 1,2,3…12,13,14</td>
<td>Cycle 2</td>
<td>15</td>
<td></td>
</tr>
</tbody>
</table>
4.3.3 Gravity effect on the solvent chamber

Solvent chamber has also been studied in this study. Although 2-phase production has been discussed in the former section, solvent chamber is also taken into consideration according to the solvent dissolution mechanism in the CSI tests.

It is interesting to find that little production was obtained in the first cycle of each test except for the test 4.3. This mainly due to the thrust force in gas injection period. During the injection period, the gas phase was injected under a large flow rate of 50 ml/min. Meanwhile, no wormhole was built in the sandpack model ahead of time. These two factors resulted in the fact that once the gas was injected into the reservoir, the residual oil at the outlet of the sandpack would be driven away for a certain distance. Therefore, although the relatively stronger force took place in foamy production period, the residual oil which had been driven away would only be pushed back as a result.

Another phenomenon we can find from the results figures is that oil production experienced fluctuation through different cycles Fig. 4-8. It can be easily found that more fluctuation showed up as the formation dip became higher. This is because during the gas injection period, gravitational potential energy made the residual oil flew back to some extent. However, when it comes to the production period, gravity separation effect can help the oil phase flew back to the outlet and this phenomenon is more obvious in the sandpack models with larger dip angles.
One more phenomenon which worth attention is that almost all the production peak appeared in the middle cycle (among effective cycles). Some factors may lead to this result comprehensively. On the one hand, all the models in this tests had been conducted pressure depletion test ahead, which meant oil saturation was relatively lower at the outlet of each model. However, foamy oil flow during the primary production drove the oil from the end to the well head and the oil stopped moving as the system pressure dropped to zero. This lead to the fact that oil was pushed forward to the center of the model instead of being produced. On the other hand, because of the large flow rate during the gas injection stage, the oil phase was pushed back first and moved forward in the production stage. This greatly limited the production behavior in the first several cycles. However, dissolved oil in the solvent chamber would move step by step in each cycle. Once the driving force met the requirement, this potential oil recovery factor would be obtained as the result.
Fig. 4-8: Recovery factor fluctuation phenomenon in 4 tests
4.4 Conclusions

According to the pressure depletion tests under different formation dips in this study, some conclusions can be drawn as follows:

- There is a positive correlation between the gravity effect and oil recovery factor. Thus, gravity effect is ought to be taken into consideration in the site production period.
- Foamy oil flow and solution gas drive lead to the strong production (Phase 1) at the beginning of each cycle while pressure gradient contribute to the weak production (Phase 2) at the end.
- As the formation dip becomes higher, Phase 1 production appears more frequently and oil recovery factor increases as the result.
- Oil can be driven away for a certain distance during the gas injection period in the CSI processes, which may lead to the cut down on the oil recovery factor even if the strong foamy oil flow shows up.
Chapter 5 Conclusions and Recommendations

5.1 Conclusions

In this study, six pressure depletion tests were carried out to investigate the pressure decline rate and model length effect on the foamy oil flow behaviors in CO$_2$-C$_3$H$_8$ mixture solvent heavy oil system. Four post-CHOPS Cyclic Solvent Injection tests were conducted to discuss the gravity effect on the production behavior. Conclusions are shown as the following:

- When the oil production is calculated when BPR stopped working, there is a positive relationship between pressure decline rate and oil recovery factor. However, an optimized pressure decline rate has been found to be -6 kPa/min as the oil production (30.1%) was calculated when the system pressure dropped to atmospheric pressure.

- One special pressure has been found to determine the status of the foamy oil flow during the pressure depletion test. Bubble nucleation and growth will dominate the strong foamy production process while bubble coalescence will dominate the weak foamy production process.

- Larger pressure depletion rates do have a better performance on the foamy oil characteristics especially on the average foamy production rate in the CO$_2$-C$_3$H$_8$ mixture solvent heavy oil system. For other solvents, more studies need to be conducted for further discussion.
• CO₂-C₃H₈ mixture solvent show better than methane, propane, methane-propane in the stability of oil recovery factor as it is less sensitive to the pressure decline rate than other solvents.

• More gas bubbles generated in the longer model leaded to larger volume expansion and higher pressure gradient so that more oil will be produced. However, longer models may result in the larger blocked space for pressure preservation. Therefore, increasing time consumption will happen in longer sandpacks.

• The disappearance of pressure difference and gradient at the end of longer models leads to the lower production, which indicates that length effect is shown to be disadvantageous in those wells in a distance.

• There is a positive correlation between the gravity effect and oil recovery factor. Thus, gravity effect is ought to be taken into consideration in the site production period.

• Foamy oil flow and solution gas drive play the main role in the first stage production of Cyclic Solvent Injection (CSI) processes. However, the second stage production is mainly due to the pressure gradient.

• As the formation dip becomes higher, phase 1 production appears more frequently and oil recovery factor increases as the result. Meanwhile, the production rate of Phase 1 is much higher than that of Phase 2. Therefore, higher oil recovery will be obtained as the formation dip increases.
• Oil can be driven away for a certain distance during the gas injection period in the CSI processes, which may lead to the cut down on the oil recovery factor even if the strong foamy oil flow shows up. However, gravitational potential energy in this study makes the oil driven away flow back to some extent.

5.2 Recommendations

• According to the influential factors of foamy oil flow discussed in this study, more actions for Cold Heavy Oil Production (CHOP) can be taken for foam stability promotion.

• CO2-C3H8 mixture solvent heavy oil system has been proved to be successfully used in the lab tests and high oil recovery has been obtained. Therefore, it is worth attention to carry out pilot tests in the field to examine the efficient.

• As is discussed in Chapter 3, length effect has been proved to be a negative factor for heavy oil recovery. Thus, it should be taken into consideration when the well pattern is under design.

• Results show that gravity effect can be positive for higher oil production during the post-CHOP Cyclic Solvent Injection process. When it comes to the site production, well trajectory can be optimized to help increase the oil production.
Reference


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