IMPROVED HYDROCARBON RECOVERY OF A LEAN RETROGRADE GAS RESERVOIR UNDER PROPANE INJECTION

By

IQMAL IRSYAD BIN MOHAMMAD FUAD

14796

Dissertation submitted in partial fulfilment of

The requirements for the

Bachelor of Engineering (Hons) Petroleum

JANUARY 2015

Universiti Teknologi PETRONAS

Bandar Seri Iskandar

31750 Tronoh

Perak Darul Ridzuan

CERTIFICATION OF APPROVAL

Improved Hydrocarbon Recovery of a Lean Retrograde Gas Reservoir under Propane Injection

By

Iqmal Irsyad Bin Mohammad Fuad

14796

A project dissertation submitted to the

Petroleum Engineering Programme

Universiti Teknologi PETRONAS

in partial fulfilment of the requirements for the

BACHELOR OF ENGINEERING (Hons)

(PETROLEUM)

Approved by,

____

(MUHAMMAD ASLAM MD YUSOF)

UNIVERSITI TEKNOLOGI PETRONAS

TRONOH, PERAK

January 2015

CERTIFICATION OF ORIGINALITY

This is to certify that I am responsible for the work submitted in this project, that the original work is my own except as specified in the references and acknowledgements, and that the original work contained herein have not been undertaken or done by unspecified sources or persons.

(IQMAL IRSYAD BIN MOHAMMAD FUAD)

ABSTRACT

In most cases, retrograde gas reservoir in N Field which is located at the north of Malay Basin achieved 40-70% of recovery factor (RF) compared to dry gas reservoir, 80-90% of RF. Reservoir K, a lean retrograde gas reservoir of the N Field drained by Well 5 experience reduction in recovery (about 60% of RF) that is caused by a significant productivity loss, suspected due to condensate banking effect. Condensate banking phenomenon (observed as skin) around the perforation zone restrict the flow of gas after the flowing bottom hole pressure falls below the dew point pressure. Therefore, the reduction in gas Inflow Performance Relationship (IPR) limits the Estimated Ultimate Recovery (EUR) of Reservoir K that is produced from 2008 to 2013. Miscible propane stimulated injection is proposed at mid of 2012 (where skin start increasing) to improve the IPR, well deliverability and hence reservoir recovery. The retrograde gas reservoir model is integrated between E300, IPM PROSPER (well model) and IPM MBAL (reservoir model) software in reservoir performance prediction and forecasting study. Results show that there is 4% increment in gas recovery and 6% increment in condensate recovery after injection of propane to Reservoir K. There are about 4.2 million USD increment in revenue upon propane injection development. As conclusion, propane injection could minimize the condensate saturation that improves reservoir IPR and hydrocarbon recovery for both gas and condensate.

ACKNOWLEDGEMENTS

I would like to express my deepest appreciation to all those who supported, believed, and provided me the possibility to complete this report. First of all, I would like to thank my supportive supervisor, Mr. Muhammad Aslam Bin Md Yusof for his guidance and advice throughout the completion of Final Year Project. The supervision and encouragement are truly help the progression and smoothness in completion of this project.

A special gratitude I give to my industrial supervisor, Mr. Awangku Alizul, a reservoir engineer from Nippon Oil Exploration (Malaysia) Limited in assisting me along this project period, guidance and providing direction that provide me confidence in completing the project. His depth industry-technical knowledge helps in sharpening my understanding especially in reservoir study.

I am also wanted to take this opportunity to extend the gratitude to Mr. Najib Ramli, Reservoir Engineer from Talisman (Malaysia) Limited and Mrs. Mariam Abdul Aziz, Principal Reservoir Engineer from Onyx IES Sdn Bhd in providing me a non-stop guidance in reservoir engineering understanding. In addition, I would like to thank Mr. Faiz H. Hussin, Director of Dyna Segmen Sdn Bhd who improve my engineering senses and Mr. Muhammad Zuhaili Bin Kashim, graduate student for his information and advices to proceed with the condensate reservoir study.

Not to forget my appreciation to my external examiners, lecturers, and friends, your advices really motivated me.

Finally, I dedicated this dissertation work to my lovely family for their understanding and trust me throughout the period of completing the project.

TABLE OF CONTENTS

LIST OF FIGURES

LIST OF TABLES

ABBREVIATIONS AND NOMENCLATURES

EUR	Estimated Ultimate Recovery
RF	Recovery Factor
IPR	Inflow Performance Relationship
WOC	Water- Oil-Contact
GOC	Gas-Oil-Contact
CGR	Condensate-Gas-Ratio
GIIP	Gas-Initial-In-Place
FGOR	Field-Gas-Oil Ratio
FGPT	Field-Gas-Production Total
FOPT	Field Oil Production Total
FOE	Field Oil Recovery
Bscf	Billion Standard Cubic Feet
MMscf	Million Standard Cubic Feet
STB	Stock Tank Barrel
IFT	Interfacial Tension
FYP I	Final Year Project 1
FYP II	Final Year Project II

CHAPTER 1

INTRODUCTION

1.1 Background

The N Field is located at the north of Malay Basin as shown in Figure 1. Geologically, N Field consists of a series of low relief anticlines with enhanced rollover features along a major system of northwest-southeast trending faults. The reservoirs have similar stratigraphy to the neighbouring field and are Oligo-Miocene in age and consist of fluvial to shallow water deltaic sandstones, which vary greatly in thickness and areal distribution. In addition, the N Field is still a Green Field and predominantly a Gas Development Field currently undergo production to re-development phase of petroleum life cycle. The gross gas production of the N Field is approximately 400MMscf/D (depend on market demand) with averaged 5000 STB/D of condensate liquid (by-product) that contribute about 28% of the N Field net liquid production. The condensate liquid production gives a lot of impact to the net liquid production of N Field. Therefore, a strategic production development of gas wells in N Field is crucial in optimizing production of not only to the gas, but also condensate liquid.

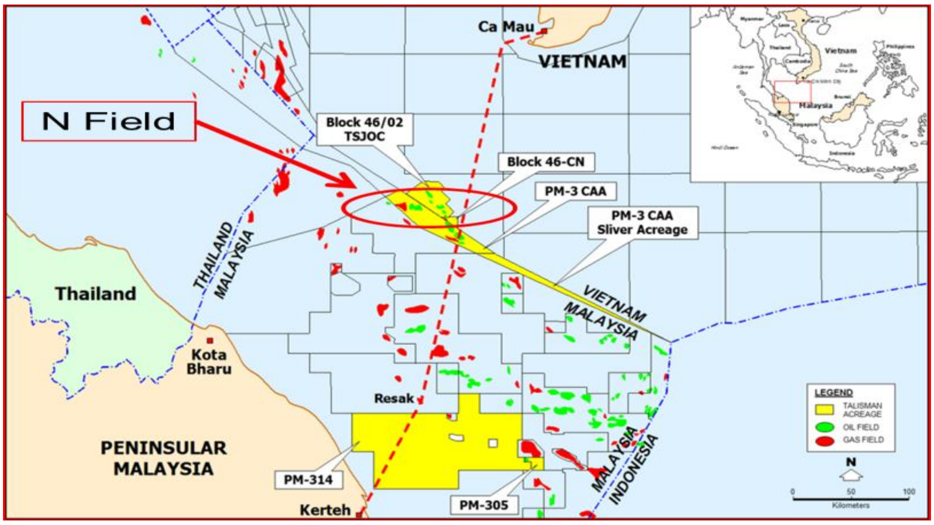


Figure 1: Location of the N Field in Malay Basin (FRMR 2013)

Condensate liquid is the by-product of gas producer well and is produced from the retrograde gas typed reservoir. Retrograde gases are also known as gas condensates. As stated by William D. Mc.Cain, (1990) stock-tank liquid produced from retrograde gas reservoirs often is called as condensate and the liquid referred in the reservoir is called retrograde liquid. In general, retrograde fluid is mostly consist of fewer heavy hydrocarbon components and much richer in the intermediate components. Therefore, retrograde gas reservoirs behaved differently from other conventional gas reservoirs (dry and wet gas reservoir) (Olaberinjo & Oyewola, 2006).

The retrograde reservoir is a compositionally dynamic system as depletion performance is highly affected by changes in fluid composition. The reservoir is mostly modelled by the compositional numerical simulation, to further study on retrograde phenomenon with respect to pressure, saturation and composition (Ayala, Ertekin, & Adewumi, 2006). In most known retrograde gas reservoir, they are probably could occur at any higher fluid pressures and temperatures within reach of the drill and are in the range of 3000 to 8000 psia and 200 to 400 F. These high pressure and temperature profile are part of a deep reservoir formation (more than 1000ft) characteristic. As most of the retrograde gas reservoirs of N Field are mostly located in a range of 8000 – 10,000 ft of True Vertical Depth Subsea (TVDSS), this will influence the composition and behaviour of the reservoir fluid in the N Field.

In most production cases of the retrograde gas reservoir, the pressure falls below the dew point within a short production period, increases the saturation of retrograde fluid (condensate blockage) around the wellbore that cause loss in productivity (Thomas, Andersen, & Bennion, 2009). They also added that the phenomenon cause reduction in the permeability around the perforated zone, thus limit the gas deliverability. This reduction in productivity is observed as skin where skin is an unknown reduction or increment in productivity during production operation. Based on this complex phenomenon, a lot of studies have been approached to study on the best method in enhancing the hydrocarbon recovery, theoretically by reducing the skin such as gas cycling, hydraulic fracturing, horizontal well, acidizing, and chemical treatment.

The project focuses on Reservoir K study to represent the retrograde reservoir performance in the N field. Reservoir K is selected based on selection criteria from the industry Field Reservoir Management Review (FRMR 2013) report in gas well prioritization for intervention program. Reservoir K starts producing in 2008 and had been depleted and abandoned in 2013 due to low productivity of the well which is not economic to keep producing that zone. Poor performance of Reservoir K was investigated and most of Reservoir K field data had been utilized to develop a simulation approach study of retrograde gas reservoir performance. Reservoir K is drained by gas producer, Well 5C for about 5 years of production under natural depletion and recovers approximately 60-70% of recovery factor. A study on Reservoir K was conducted and engineers found out that condensate banking phenomenon is one of the main factor to the retrograde gas recovery problem of the Reservoir K.

1.2 Problem Statement

Gas wells producing with high condensate gas ratio (CGR) reservoir zone decline in productivity when the bottom hole flowing pressure drops below the dew point pressure of the liquid. The condensate liquid banking around the perforation zone restricts the flow of gas and affects the gas Inflow Performance Relationship

(IPR). Reduction in gas IPR (reservoir potential) lower the well productivity or known as gas well deliverability.

According to the field experience, poor management of retrograde gas reservoir could cause reduction in hydrocarbon recovery. Figure 2 shows Reservoir K performance, presenting the reservoir pressure depletion trend (at bottom) and production history profile with deliverability curve trend. It is observed that decline in productivity starts at the mid of 2012 (circle in red). This period was investigated by deliverability curve analysis from IPM PROSPER model. In the deliverability curve, high skin value alters the shape of the curve that shows reduction in well productivity. Based on previous study, Reservoir K skin value has a range of 30 – 90 from the mid of 2012 onward that reduce the productivity index (PI). Petrowiki source summarized that the decline in productivity index observed in many fields is by a factor 2 to 4 because of liquid build-up. This skin increment may due to micro-scale reservoir effect (2 phase fluid flow challenges) such as capillary forces, interfacial tension (IFT), and relative permeability.

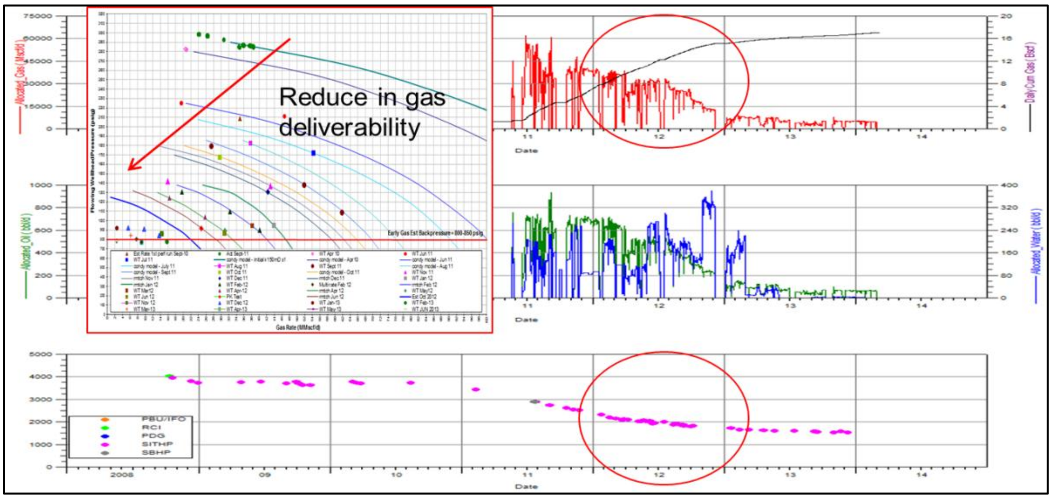


Figure 2: Reservoir K performance and effect of condensate banking to gas deliverability and production (FRMR 2013)

The reduction in well deliverability represents poor performance IPR at the bottom hole. This reduction in gas IPR limits the Estimated Ultimate Recovery (EUR) and hence lowering the hydrocarbon recovery (Al-Shawaf, Kelkar, & Sharifi, 2013). Figure 3 proves low gas recovery of Reservoir K which EUR is about 16.88 Bscf and RF of 73% from 22.87 Bscf of Gas-Initial-In-Place (GIIP).

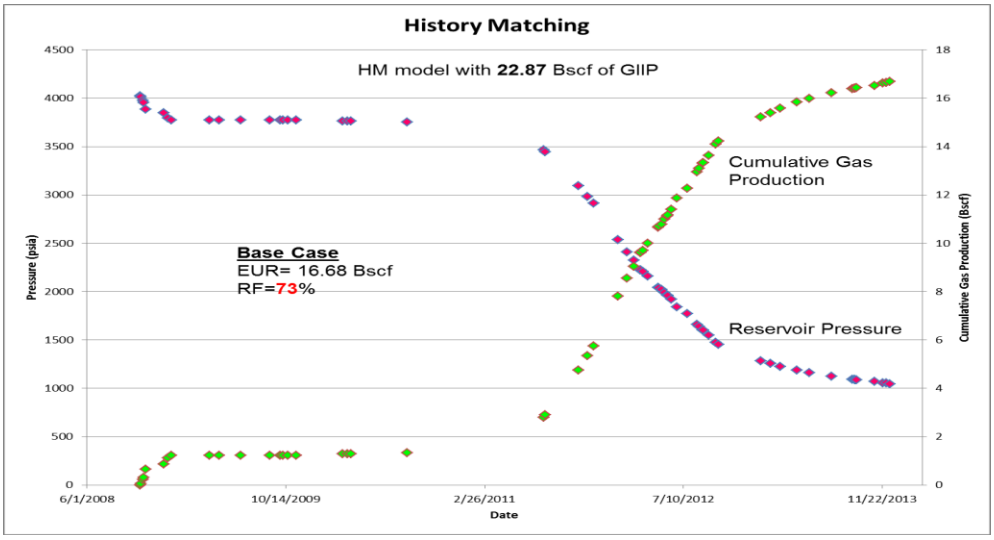


Figure 3: Simulated Reservoir K model under natural depletion (FRMR 2013)

Figure 3 also demonstrates a history matched performance with actual Reservoir K performance. Based on the study, Reservoir K recovers 73% of gas recovery factor that is lower than other conventional gas reservoir. Low gas recovery of Reservoir K is due to productivity loss once Reservoir K faced two phase fluid flow into the wellbore. This will limit the EUR and hence gas recovery. As the condensate is the by-product of the gas reservoir, low gas recovery also would affect the condensate recovery.

1.3 Objectives

Based on Reservoir K analysis and available field data, the objectives of the study are mainly;

- To study the effect of propane injection to reservoir IPR and hydrocarbon recovery that include both gas and condensate liquid (by-product)
- To propose propane injection (stimulation approach) as part of retrograde gas reservoir development in N Field by preparing Reservoir K study

1.4 Scope of Study

There are two main analysis in this study which are study on Reservoir K under actual/natural depletion performance (base case) and under propane injection development at proposed date. The timeframe of both analysis are the same which is within the actual production performance of Reservoir K from 2008 to 2013.

Study was limited to availability of actual field data that cover only macro-scale analysis. In addition, reservoir and well model was integrated by using compositional Eclipse model E300, IPM PROSPER, and IPM MBAL software due to geology model and micro-scale laboratory data limitation. Therefore, there are several assumptions and limitations being set depend on subsurface data quality and availability;

- A homogeneous and isotropy single tank reservoir with history matched properties (not considering the geologic geometry of the reservoir)
- Isothermal reservoir system
- The zone produce at a high rate (>10MMscf/D – abandonment rate), therefore capillary pressure is set as zero (neglected)
- Assume an ideal completion set up and hence Non-Darcy flow is neglected
- No/minor water production
- Gravity effect is neglected
- Dispersive flux is neglected
- In an isothermal system, the molar energy is also could be neglected

CHAPTER 2

LITERATURE REVIEW

This chapter presents critical review of the literature as the conceptual guideline for Retrograde Gas Reservoir K study and technical analysis. The main focus of the study would be emphasis on the phase and flow behaviour, deliverability and performance, and condensate banking phenomena of the Retrograde Gas Reservoir K in understanding of the reservoir complex system.

2.1 Retrograde Gas Reservoir

During the discovery phase, retrograde gas reservoirs are mostly found consist of a single-phase gas vapor (based on the “butterfly effect” in the well log). Upon production phase, condensate liquid could be observed at the surface. The retrograde gas reservoir could be characterized as the transition between volatile oil and wet gas reservoir with having a critical temperature less than reservoir temperature and a cricondentherm greater than reservoir temperature (Dumkwu, 2013). These behaviour are the effect of retrograde gases consist of small amount of heavy (long-chain) hydrocarbon than the crude oils (McCain, 1990). Figure 4 shows the phase diagram of retrograde gas reservoir where liquid condensate was developed upon isothermal depletion (Grigg & Lingane, 1983). In contrast, dry gas and wet gases do not undergo phase changes upon reservoir depletion, as their phase envelope’s cricondentherm are found to the left of the reservoir temperature isobar line (Ayala et al., 2006).

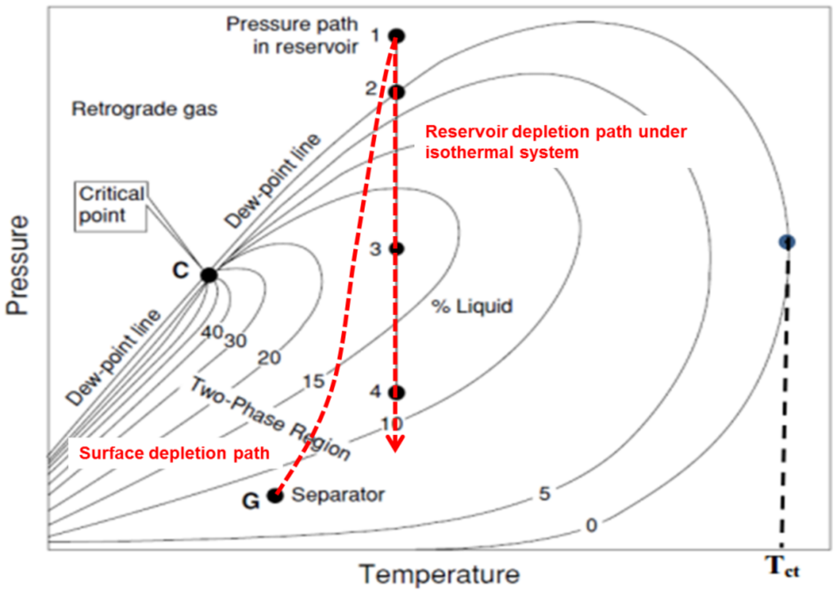


Figure 4: Phase Diagram of Retrograde Gas (McCain, 1990)

The gas condensate is usually light-coloured (straw colour), more volatile than crude oil, compose a huge portion of gasoline and other volatile petroleum components, and typically consist API gravity of above 50 degrees (Thornton, 1946). In addition, a rich retrograde gas can produce gas-oil ratio (GOR) of 3300 to 5000 scf/STB initially. These characteristics and behaviours are crucial to be studied and understand on the complex system behaviour that could effect on later production performance.

Based on the Reservoir K Drill Stem Tester (DST) evaluation, the fluid composed 46.63 API and GOR range from 45000 to 65000 scf/STB during the exploration phase. Based on Kamath in 2007, Reservoir K fluid could be categorized as a lean condensate gas since the CGR is ranged between 15-22 bbl/MMscf (lower than 100 bbl/MMscf) and is in between the wet gas reservoir and rich retrograde gas reservoir characteristic. Figure 5 shows the phase diagram for a lean gas condensate and the comparison between the rich and lean retrograde reservoir could be observed in Figure 6 to see the different in liquid drop out versus pressure.

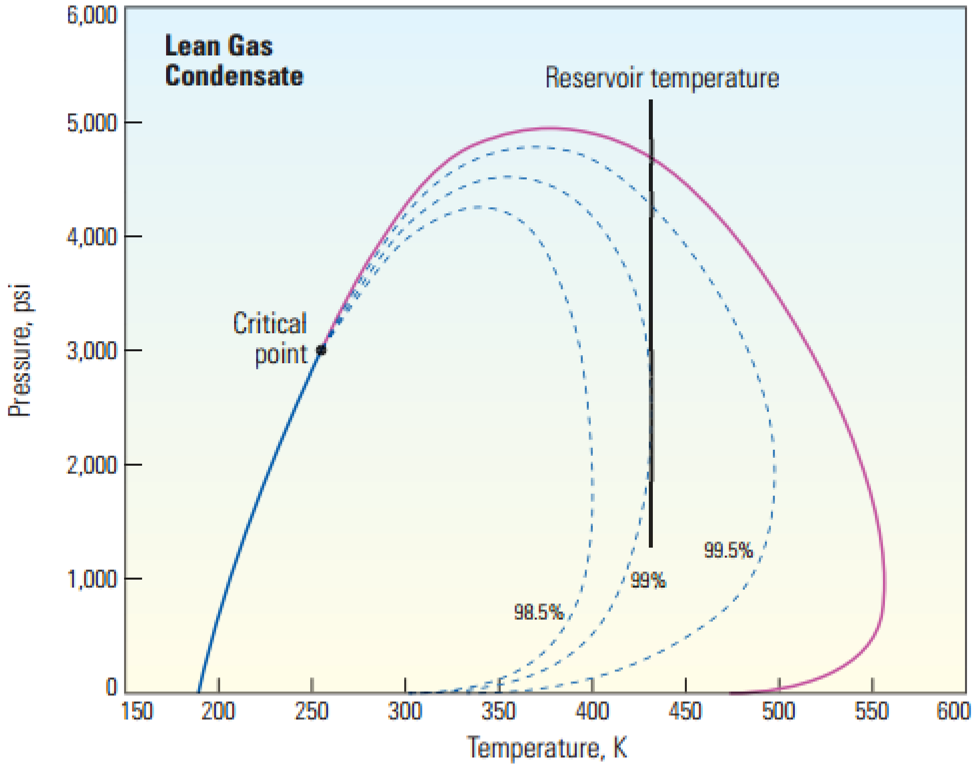


Figure 5: Phase diagram of a Lean Gas Condensate Reservoir (Fan et al., 1998)

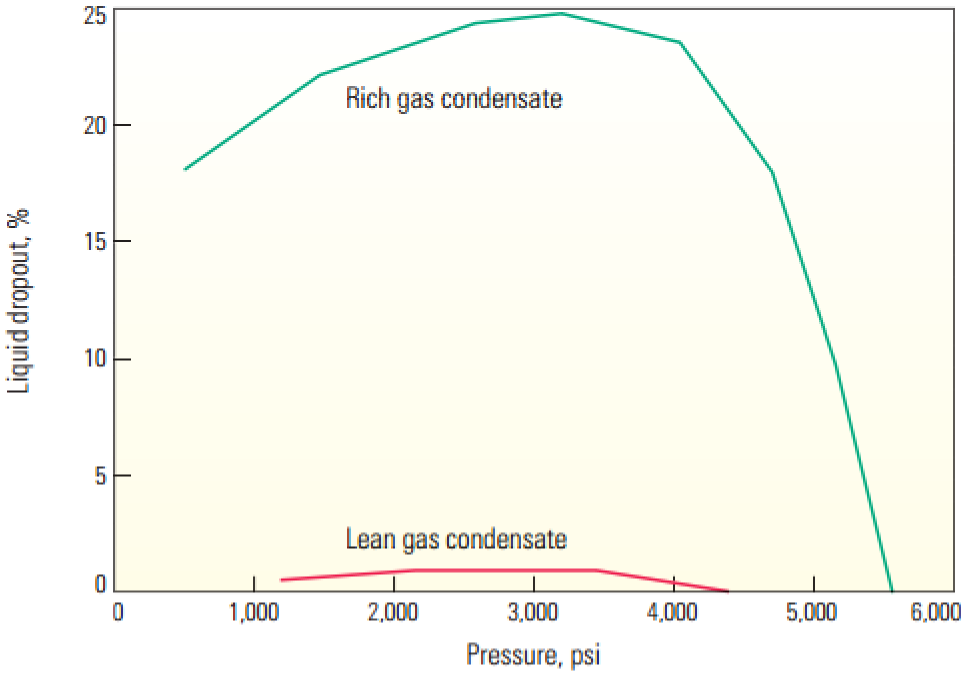


Figure 6: Comparison between Rich Gas Condensate and Lean Gas Condensate liquid dropout vs pressure (Fan et al., 1998)

2.1.1 Composition of Retrograde/Condensate Fluid

The composition indices for retrograde gas systems are the gas-liquid ratio (GLR) of produced fluids (could also indicate as gas-oil ratio, GOR or condensate-gas ratio, (CGR) (Moses and Donohoe ,1987). However, the knowledge of the gas-liquid ratio and gravity of the liquid in not enough to describe the composition of gas condensate for all purposes, since the gas-liquid ratio and the gravity of condensate are functions of the pressure and temperature at which the separation are made (Thornton, 1946). Therefore, it is important to represent the fluid composition in fraction or percentage in every state of fluid (gas, condensate, and gas-condensate mixture) (Dumkwu, 2013).

Methane and ethane with few quantities of propane, butanes, pentanes, hexanes, and heptane plus is mostly composed in gas produced from retrograde gas reservoir. While the heptane and heavier fractions, with reducing fraction of hexanes, pentanes, butanes, and fewer amounts of propane, ethane, and methane are composed in the condensate fluid (Dumkwu, 2013).

As the phase diagram depends on fluid composition, the ternary diagram concept for more than one component in a mixture is used in developing the petroleum mixture diagram as shown in Figure 7. The compositional phase diagram for three component mixture plotted in terms of mole fraction/percentage. The ternary diagram is mostly used in analysis of miscible displacement (McCain, 1990).

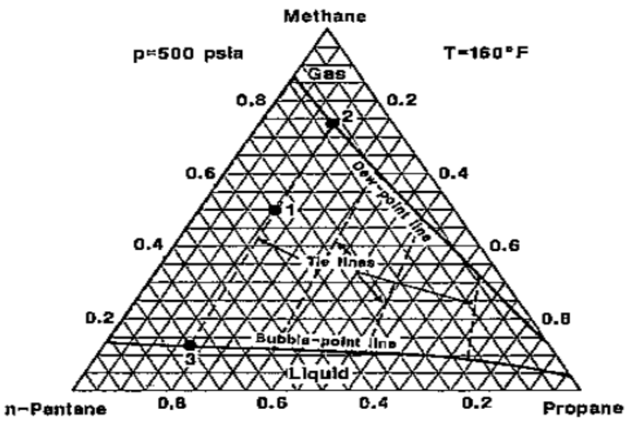


Figure 7: Ternary Diagram of gas mixture of Methane, Propane, and n-Pentane (McCain, 1990)

2.1.2 Retrograde Gas Reservoir Performance

In this part, retrograde gas reservoir performance of Reservoir K will be discussed to study the effect of condensate banking to reservoir performance. Reservoir K could be classified as a lean gas condensate as it generates small volume of the liquid phase (typically less than 100bbl per million ft^3) compared to a rich gas condensate (generally more than 150bbl per million ft^3). The production of Reservoir K by pressure depletion method results in low recovery (approximately 60-70%) of the gas-initially-in-place (GIIP) especially the liquid phase. This supported by (Kolbikov, 2010), where for a typical retrograde gas reservoir, 85% of the dry gas-in-place is normally recovered, while 40-70% of original condensate element of the gas is remain in the reservoir due to retrograde condensation. He added that the hydrocarbon recovery factor of retrograde gas reservoir do rely on the initial gas-oil ratio (GOR), filtration properties, well spacing, and completion, development plan, economical indexes, and abandon reservoir pressure.

At reservoir pressure above the dew point pressure, the gas deliverability rely on the reservoir thickness, permeability, and viscosity (Lal, 2003). While at pressure below the dew point, the gas deliverability is controlled by the critical condensate saturation and the shape of the gas and condensate relative permeability curves. However, Dumkwu (2013) stated that for a lean retrograde gas reservoir, the cumulative production is mainly caused by pressure gradient and not by high relative permeability reduction. Other factors that might reduce the well deliverability are non-Darcy flow, critical condensate saturation, and high capillary number effects (Hashemi, Nicolas, & Gringarten, 2006).

2.2 Condensate Banking

Condensate banking phenomenon is the main problem in managing the retrograde gas reservoir that engineers need to understand on its dynamic system. Retrograde gas reservoirs are normally single-phase gas at discovery and the initial reservoir pressure is above or close to the critical pressure. Once production is initiated, isothermal pressure decline and at the saturation pressure (dew point pressure), retrograde liquid saturation start to build up near the perforated zone due to drawdown below the dew point pressure, that restrict the flow of gas (A. S. Al-Abri, 2011; Fan et al., 1998). Fan et al. (1998) also conclude that the phenomenon is caused by fluid phase properties, formation flow characteristic and pressure in the formation and in the wellbore.

2.2.1 Flowing Bottom Hole Pressure Decline below the Dew Point Pressure

Upon gas production, the flowing bottom hole pressure (FBHP) falls below the dew point within short period of the production. Therefore, saturation condensate build up around the wellbore area and create the condensate bank as stated by Sayed and Al-Muntasheri in 2014. This may affect the well deliverability loss for both gas and condensate for more than 50% based on the industry literature (Kamath , 2007). Even in lean gas condensate reservoirs, where the maximum liquid dropout in the constant composition expansion (CCE) experiment is low as 1%, the condensate liquid build up close the wellbore may effect a significant reduction in productivity (Al-Shawaf et al., 2013).

2.2.2 Condensate Saturation Regions

The condensate saturation region ranges in size from tens of feet for lean condensates to hundreds of feet for rich condensates depend on the volume of gas being drained and the percentage of liquid dropout (directly proportional) (A. S. Al-Abri, 2011).

Theoretically, flow in retrograde gas reservoir could be divided into three reservoir regions with different liquid saturation (Gringarten, Al-Lamki, Daungkaew, Mott, & Whittle, 2000). These regions are shown in Figure 8 as follows:

- Region 3: Far from the production wells and the pressure is above the dew point pressure. Therefore, there is single gas phase present.
- Region 2: A rapid increase in liquid saturation and corresponding reduction in gas relative permeability. The trapped condensate liquid in the small pore cause the capillary forces act on it, those make them difficult to flow.

- Region 1: Close to the wellbore where condensate saturation reaches a critical value. That cause two-phase flow in porous medium.

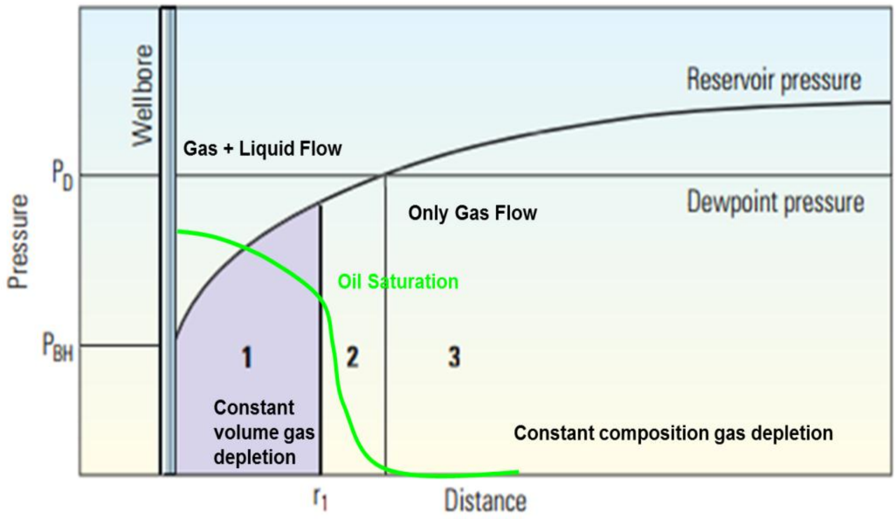


Figure 8: Pressure vs distance of Retrograde Gas Reservoir liquid build up analysis

2.2.3 Gas Relative Permeability

The amount of liquid phase saturated rely not only on the pressure, temperature, and composition, but also on the fluid properties and relative permeability (Hinchman & Barree, 1985; Sognesand, 1991). Upon pressure depletion, high amount of liquid can be condensed, resulting in high liquid saturations in the formation pores (Moses and Donohoe , 1987). Therefore, the possibility of hydrocarbon fluid to flow through and out of the reservoir should be examined. They also recommend that the combination of relative permeability relationship (Krg/Kro vs. saturation) and viscosity data (μ_o/μ_g) could be used in the volumetric proportion of liquid (in the flowing stream) estimation that would also affect the remaining reservoir phase compositions at every stage of pressure depletion. The condensate build up near the wellbore not only reduces the productivity of condensate, but also reduce the gas effective relative permeability with consequent reduction in well deliverability of gas at surface facilities (Dumkwu, 2013). This phenomenon could be observed as the skin in reduction of well deliverability.

2.3 Production Schemes: Well Stimulation Approach

After the dynamic behaviour of retrograde gas reservoir and the mechanism of condensate banking effect have been studied, an appropriate production schemes can be investigated. The methods such as gas cycling, drilling horizontal wells, hydraulic fracturing, injection of super critical CO2, huff ‘n’ puff gas injection, use of solvents, and the use of wettability alteration chemicals have been widely studied to mitigate condensate banking problem (Sayed and Al-Muntasheri , 2014). In this part, latest technologies and methods in mitigating condensate banking will be reviewed and one method will be selected to be applied in Reservoir K. Each method has their pros and cons under certain field application. In N Field, well stimulation techniques will be prioritized as the technique improves well performance from drainage area into the wellbore (around the perforated zone) that require a well intervention program. Well stimulation technique does not require to drill additional well that is suitable to be applied in multi stake reservoir development.

The horizontal wells and hydraulic fracturing both are effectively improve the flow area and thus production rates. However, the limitation of hydraulic fracturing is the well with bottom water. In 2011, France’s constitutional court upheld a ban on hydraulic fracturing, ruling that the law against the energy-exploration techniques that brings consequences to the environment. Plus, condensate liquid will still builds up around fractured well or horizontal wells although it takes a longer time for the bank to form. The benefit also must be compared to increased cost. Thus, this study will focus in stimulating well around the perforated zone instead of drilling other additional producer/injection well.

There are several stimulation techniques would be discussed in this section for Reservoir K case study, depending on the cost, solution availability, and political issues. Thornton (1946) stated the basic principles in field particular operating method selection as follows;

- Selection of operating method on the basis of reservoir fluid character
- Pressure maintenance in those reservoir where a decrease would result in loss of valuable products at the surface
- Efficient handling of produced fluids at the surface to extract the maximum amount of liquid

- Optimum spacing of wells to ensure maximum highest hydrocarbon recovery
- Unitization of interest to assure equity to all parties with vested interests in the reservoirs, and to enable the application of the afore-mentioned principles

Well stimulation processes could divide into two parts which are miscible gas and chemical approach. Both processes is discussed and compared in simulation study on which approach require minimum volume to be injected in order to dissolve the condensate bank.

2.3.1 Miscible Injection Approach

The gas flooding method normally can be achieved by two process, miscible or immiscible based on minimum miscibility pressure (MMP) (Ghedan, 2009). At constant temperature and composition, MMP is the least pressure at which first or multiple contact miscibility can be achieved. Miscible flooding is more efficient and common in Enhanced Oil Recovery, EOR application, yet immiscible flooding may become important where the reservoir conditions are not suitable for miscible flooding. Immiscible process is one method to assist in maintaining the reservoir pressure. Sometime, additional injector well also is required which means add another additional cost of drilling a well.

Gas Cycling is one of the techniques applied by the industry for a long time and provides an immiscible approach. The main objective of gas cycling approach is to maintain the reservoir pressure above the dew point pressure that keep the fluid in gas phase and prevent more condensation to formed at the same time (Sayed and Al-Muntasheri ,2014). The stripped gas is compressed and re-injected into the reservoir through the injection wells to displace further wet gas and keep the reservoir pressure in minimizing the retrograde condensation (Dumkwu, 2013). However, sweep efficiencies (both areal and vertical) and re-vaporization of the formed liquid condensate bank may reduce the effectiveness of this method (Havlena, Griffith, Pot, & Kiel, 1967). Plus, from the operational perspective, the profit from gas sales is deferred and requires big initial capital expenditure for compression and injection. Gas cycling allows the pressure to be maintained above the dew point but may not be economical, especially late in the life of the reservoir when large quantities of injected gas are required to maintain the pressure above dew point. In this part, miscible process will be further discussed; (1) the techniques of super critical CO2 injection, (2) CO2 huff ‘n’ puff method, and (3) Propane injection.

2.3.1.1 Super Critical Carbon Dioxide Injection

The N field produces approximately 20–30% of carbon dioxide from gross gas production that makes engineer start to consider carbon dioxide injection into depleted gas reservoirs. Carbon dioxide could be utilized for the field use application in this hydrocarbon recovery effort. This method also is a good practice to store carbon dioxide, instead of released to the atmosphere (Oldenburg and Benson ,2002). The carbon dioxide injection capable to reduce the dew-point pressure of oil and gas system (U. O. ODI, 2013). Plus, Mamora and Seo (2002) found that carbon dioxide improve sweep efficiency and re-pressurization of depleted gas fields, in a laboratory study to displace methane in a carbonate rocks. Lino (2000) performed an experiment approach study and concludes that the carbon dioxide was the only solvent that developed miscibility by vaporization of rich gas condensate mechanism. On the other hand, Monger and Khakoo (1981) also noted that carbon dioxide capable to reduce the miscibility pressure for paraffin fluids and enhance miscibility mechanism of carbon dioxide injection. Thus, these show some of benefit of carbon dioxide as the injection agent to provide miscibility mechanism.

The condensate liquid recovery also can be enhanced with carbon dioxide injection in the depleted retrograde reservoirs (Jessen & Orr, 2004). In the other study, Seto, Jessen, and Orr (2007) stated that the factors that affect the recovery efficiency of carbon dioxide injection are local displacement efficiency, that is controlled by phase behaviour of fluids mixture in the reservoir and the fluid flow at which controlled by the reservoir heterogeneities.

The injection of supercritical carbon dioxide could improve the relative permeability to gas and enhanced the recovery of the condensate liquids (A. Al-Abri & Amin, 2010). They also found that the capacity (volume injected before breakthrough take place) of supercritical carbon dioxide was 62% of PV compared to methanol-supercritical carbon dioxide mixture (55% PV) and methane only (27%

PV). A modelling approach of a different scenarios comparative study of methane injection, nitrogen injection, gas recycling, and carbon dioxide injection by Moradi, Tangsiri Fard, Rasaei, Momeni, and Bagheri (2010) figure out that ability of carbon dioxide injection recovered more liquid and gas than other scenarios. In a laboratory scale study, Gachuz-Muro, Gonzalez Valtierra, Luna, and Aguilar Lopez (2011) showed that carbon dioxide achieved higher recovery factor than nitrogen but less than natural gas in a study to evaluate the effectiveness of gases in displacing condensate from the reservoirs. Soroush, Hoier, and Kleppe (2012) investigate the injection of carbon dioxide, methane, and mixture of methane and carbon dioxide in dipping gas condensate reservoir for enhance condensate liquid recovery. Based on the findings, the carbon dioxide injection attained the highest recoveries than other injections. Another numerical simulation study of Kurdi, Xiao, and Liu (2012) on the effect of super critical carbon dioxide injection, resulting that the method increases the density of gas, decrease the viscosity, and density of condensate and lowers the surface tension between the two phases that lowering the capillary pressure. Thus, the condensate liquid recovery is improved with reducing the residual (critical) condensate saturation.

Numerical simulation study conducted by Taheri, Hoier, and Torsaeter (2013), investigate the miscible and immiscible gas injection performance in condensate banking elimination process for a fractured gas condensate reservoirs. Gases such as carbon dioxide, methane, and nitrogen are tested in the study. As the result, carbon dioxide able to lowered the minimum miscibility pressure (MMP) and hence recover more condensate liquid. Zaitsev et al. (1996) also conclude that carbon dioxide flooding is one of the effective methods for removing the condensate plug.

However, the challenges of implementing carbon dioxide injection are carbon dioxide is easily to react with produced water that could cause corrosion and make the application is costly and risky. Surface facilities need to be enhanced to implement this approach. Therefore an appropriate plan should be strategized in order to embark the carbon dioxide injection method to K Reservoir.

2.3.1.2 Carbon Dioxide Huff 'n' Puff Method

Other technique of carbon dioxide injection is the huff 'n' puff method which uses the same producer well as injector well alternatively. Ahmed, Evans, Kwan, and Vivian (1998) investigated the performance of lean gas, nitrogen, and carbon dioxide huff 'n' puff method in condensate liquid elimination near the wellbore. They found that pure carbon dioxide is the most effective gas in minimizing the condensate liquid dropout than the other gases at the same pressure system. The huff 'n' puff injection of gases also able to enhance the condensate liquid recovery by reducing near wellbore damage due to condensate blocking.

U. Odi (2012) also studied the performance of carbon dioxide huff 'n' puff approach to eliminate gas-condensate around the wellbore. The method approaches miscibility between the displacing natural gas and condensate by decreasing the dew point pressure of the fluid mixture. He also found that the ability of carbon dioxide to diffuse into the retrograde phase as the concentration of the carbon dioxide is increased. However, the method is very sensitive to time once the process is executed that should take consideration in field application.

2.3.1.3 Propane Injection

Propane injection is among the new technology had been approached and studied in recovering a heavy oil reservoir. Yarranton, Badamchi-Zadeh, Satyro, and Maini (2008) conducted a study on Anthabasca bitumen by diluting the bitumen using propane and carbon dioxide to reduce the fluid viscosity, so that the fluid is mobile enough to be drained. Plus, they found out that propane and butane have higher solubility and provide greater viscosity reduction than carbon dioxide.

An experimental study by Ferguson, Mamora, and Goite (2001) on the effectiveness of steam-propane injection in heavy oil recovery found out that the light components of the hydrocarbon are miscible with the injected propane gas and 'carried' by the propane ahead of the steam front. The miscibility mechanism provides a no 'boundary' between the fluid (heavy and lighter components) lower the viscosity and hence accelerate the oil production. Study in mobilizing the heavy oil could be used to recover the immobilize condensate near well-bore of gas well producer.

Jamaluddin, Thomas, D'Cruz, Nighswander, and Oilphase (2001) assess the condensate behaviour near-wellbore zone by adding light hydrocarbon gases which is propane in their study. The vaporization of condensate liquid capable to improves the liquid extraction of gas producer well. The use of propane alters the system conditions to be in supercritical conditions for most typical reservoir fluids at reservoir pressure and temperature. Plus, the CCE test by Jamaluddin et al. (2001) shows propane decrease both dew point pressure and total liquid dropout. Author believes that propane as the vaporizer agent potential to improve the gas producer well productivity.

The investigation of propane gas as the vaporizer agent could be further study as propane potential to:

- Dilute (miscible) the condensate liquid
- Reduce condensate viscosity and hence mobility
- Improve gas relative permeability and hence productivity
- Decrease the dew point pressure of the hydrocarbon mixture

2.3.2 Chemical (Solvent) Treatment

Another possible approach than miscible injection is the chemical or solvent treatment. This method apply injection of high molecular weight alcohols, such as methanol, other mutual solvents, and surfactant to reduce the interfacial tension of the immobilize condensate liquid and reservoir gas that enhance recovery of the residual condensate (Dumkwu, 2013). In addition, the gas relative permeability can also be increased from the alcohols and solvents treatment (Sayed and Al-Muntasheri , 2014). They added that the mechanism of increased gas relative permeability from solvent treatment could be presented into two ways which are the solvent able to minimize the interfacial tension between the condensate and gas and solvent able to dissolve some of the condensate into the gas stream.

A lot of literature studies on chemical (solvent) treatment effectiveness to enhance the hydrocarbon recovery of retrograde gas reservoir system by reducing the impairment effects of condensate build up near the wellbore (Kamath ,2007). For example methanol application could enhance productivity but it does not give a long-term effect because the condensate liquid will reform back upon reservoir depletion.

Du, Walker, Pope, Sharma, and Wang (2000) and Al-Anazi, Al-Otaibi, Al-Faifi, and Hilab studied the application of methanol to treat damage caused by condensate and water plugging. The authors presented that the condensate precipitation could be delayed from the methanol injection by improving the gas-oil relative permeability (achieved 1.2 to 2.5 times increase in the endpoints of gas relative permeability). Plus, the methanol treatments eliminate both water and condensate by a multi-contact miscible displacement if enough methanol are injected. Bang, Pope, and Sharma (2006) also stated that the condensate liquid drop out could be retarded by reducing the dew point pressure from the methanol treatment to the mixture of water and condensate. Methanol treatments resulted in a significant but temporary enhancement in productivity.

It is found that a lot of alcohol have sludge and emulsion problems with condensates; hence, it is recommended to apply compatibility test between the suggested injection alcohols and reservoir condensate before embarking the project (Dumkwu, 2013). He also added that in most cases, the real reduction in condensate-gas interfacial tension is relatively small, and hence, the stimulating effect might be somehow insignificant.

Another study by Sayed and Al-Muntasheri (2014), summarized that isopropyl alcohol (IPA) and methanol mixture could be an effective technique to eliminate the condensate liquid and water bank near the wellbore in carbonate reservoirs, as well as sandstone reservoirs. Although this technique is not last for a long period (liquid can be accumulated again), but by a well-organized scheduling of the well treatment activity could be an effective technique to be implemented. However, chemical/solvent treatment is more recommended to be applied in rich retrograde gas reservoir that having high CGR content and water production problem. This is due to the high cost of chemical to be prepared in a huge (field) scale. Economic wise, costly chemical is worth to recover the valuable high condensate content in gas reservoir.

Figure 9 summarizes the latest technologies in mitigating condensate banking problem occurred in retrograde gas reservoir. The summary explains on the limitation of each application that should be considered. These methods are generally having the same objective which is to dissolve/delay the condensate bank near wellbore. In this study, the effectiveness of propane injection to dissolve condensate bank in Reservoir K is investigated as propane shows potential in mobilizing the condensate saturation with the lowest volume of injection required based on simulation result.

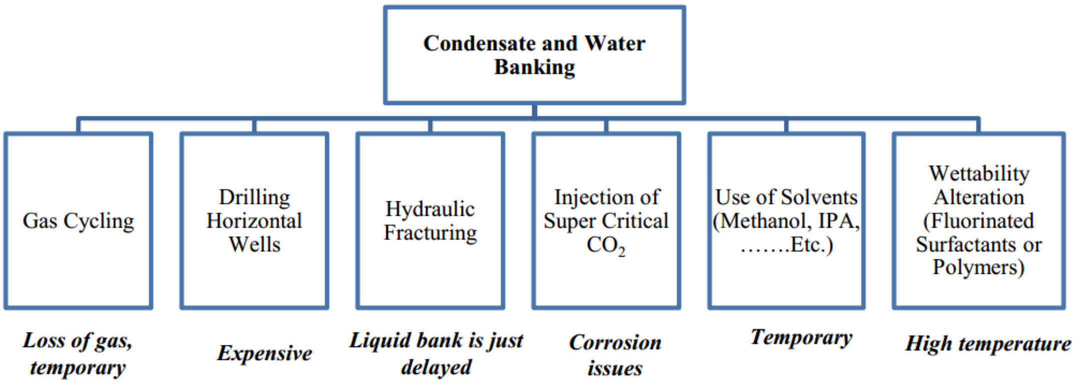


Figure 9: Summary of applicable technique in mitigating condensate banking

2.4 Compositional Modelling: Retrograde Gas Reservoir

Previous literature study has presented on dynamic system of retrograde gas reservoir, challenge in managing retrograde gas reservoir, and several stimulation methods in mitigating condensate bank problem. By available field data, Reservoir K system could be evaluated under the compositional model to investigate the dissolve-ness of propane injection to Reservoir K fluid. The composition model allows changes in the phases, therefore each component will be calculated in addition to the pressures and saturations (Abou-Kassem, Farouq-Ali, & Islam, 2013). Reservoir modelling been done to predict the fluid flow in porous media and a quick decision could be made if the workflow is properly followed. Reservoir simulation is an area of reservoir engineering in which computer models are used to assemble governed equation in representing the mechanism of the reservoir.

Mathematical description of the compositional model for the fluid flow and heat transfer in a permeable medium is obtained from:

- Conservation of mass
- Conservation of momentum
- Conservation of energy
- Equation of state and constitutive equations

The governing equation of the compositional model is essential to be understood as they relate the phase behaviour to fluid flow and material balance concept. This concept could describe on the relationship between IPR and hydrocarbon recovery.

2.4.1 Mass Transport in Porous Media

The Conservation of Mass or continuity equation applies the conservation of mass concept. The net mass flux for a three-dimensional Cartesian system (x,y,z) can be simplified as;

$$\frac{\partial(\emptyset\rho)}{\partial t} = -\nabla(\rho v) \tag{1}$$

Where;

Ø = porosity, ρ = fluid density, t = time, and v = velocity

The continuity equation is the fundamental physic concept in developing the diffusivity/diffusion equation for the fluid flow in porous medium. Therefore, understanding in the continuity equation is essential before applying the simulation work.

The Conservation of Momentum (Motion Equation) apply on multi-mechanistic fluid flow, a combination of a Darcian flow component (macroscopic flow due to pressure or gravity gradient) and a Fickian-like or diffusive flow component (diffusion flow from high concentration of molecules to a low concentration region) (Ayala et al., 2006). The diffusivity equation was developed by inserting the Darcy' law in the continuity equation, illustrated by;

$$\frac{\partial^2 P}{\partial t^2} = \frac{\emptyset \mu ct}{k} \frac{\partial P}{\partial t} \tag{2}$$

Where;

P = pressure, t = time, $\emptyset$ = porosity, μ = viscosity, c_t = total compressibility, and k = permeability

Ayala et al. (2006) assumed that the multi-mechanistic phenomenon only take place in the gas phase, while the flow of the liquid phase is only due to pressure gradient. For the diffusion equation (developed from Fick's law and continuity equation) can be shown as;

$$\frac{\partial \emptyset}{\partial t} = D \frac{\partial^2 \emptyset}{\partial x^2} \tag{3}$$

Where;

$\emptyset$ = porosity, t = time, D = diffusion coefficient and x = distance

The combination of both mass balance and motion equation result in mass transport equation. This reservoir pressure-rate behaviour of an individual well also could be known as reservoir inflow performance (IPR). The governed equation is the basic of fluid flow equation in porous media as the equation also has been used in the Black Oil Simulator (E100). As the compositional simulator (E300) is considering the fluid phase behaviour, component, and thermodynamic parameters, additional equation of state (EOS) algorithm is inserted in the mass transport equation.

2.4.2 Conservation of Energy

The first law of thermodynamic states that energy is conserved and neither created nor destroyed and it is only transferred and converted to other types of energy. The laws of conservation of energy for an arbitrary volume of the reservoir fluid indicate that:

"Flux of energy through the boundary of an arbitrary volume + Energy input from a source = Gain in internal energy"

The arbitrary volume may be considered as an infinitesimal rectangular parallelepiped of lengths *dx, dy* and *dz* along x-, y-, and z- axis in a Cartesian coordinate system. The total energy, transferring through the representative elementary volume (REV) boundaries, consists of:

1. A part that is transferred through the mass transfer, convective term;
2. A part due to the heat transferred by conduction and radiation; and
3. The shear work, due to viscous stresses, occurs at the boundaries of the REV

This study focus on the miscible mechanism in an isothermal reservoir system and thus, this equation could be neglected and is recommended to be investigated in future work.

2.4.3 Cubic Equation of State: Peng Robinson

Peng Robinson Equation Of State is the one of the accepted method in petroleum industry, improved the prediction of liquid density (physical properties) and been used for phase equilibrium and gas-liquid equilibrium of hydrocarbon mixture (McCain, 1990). The Fugacity factor also should be considered in Peng Robinson EOS to study on the thermodynamic effect. In order to estimate the phase and volumetric behaviour of mixtures using the Peng Robinson EOR, the critical properties (Tc, Pc, ω) for each component in the mixture must be prepared. The Peng Robinson equations;

$$P = \frac{RT}{V-b} - \frac{a\alpha}{V(V+b)+b(V-b)} \quad (4)$$

$$a_T = a_c\alpha \quad (5)$$

$$a_c = 0.457235\frac{R^2Tc^2}{Pc} \ (6) \qquad \& \qquad b = 0.0778\frac{RTc}{Pc} \ (7)$$

$$\alpha = [1 + m(1 - \sqrt{Tr})]^2 \quad (8)$$

$$m = 0.37464 + 1.54226\omega - 0.26992\omega^2 \quad (9)$$

Where;

P = pressure, R = universal gas constant, T = temperature, V = Volume, a = internal pressure term, b = co-volume term, α = temperature dependent parameter, a_T = dependent a term to temperature, a_c = a_T at critical temperature, and ω = Pitzer accentric factor

The Peng-Robinson EOS was developed to simulate the depletion process, characterize the fluid from well data and predict the reservoir behaviour upon the isothermal depletion. After EOS has been tuned in phase diagram development of the fluid, the model could be used for further fluid analysis study such as gas liquid equilibrium, fluid properties, and phase stability study.

Gas Liquid Equilibrium is the area bounded by the bubble point and dew point curve on the phase diagram of a multicomponent mixture define the conditions for gas and liquid to exist in equilibrium (McCain, 1990). McCain also added that the quantities and composition of the two phases varies different points within the limits of the phase envelope. Gas liquid equilibrium is generally a condition in which a liquid and its vapor are in equilibrium with each other. The equilibrium gas liquid distribution ratio (K-value) is the ratio of composition in the vapor phase to that of the liquid phase, developed from the combination of Raolt's and Dalton's law;

$$\frac{y_j}{x_j} = K_j = \frac{P_{vj}}{P} \tag{10}$$

Where;

y_j = mole fraction of j^{th} component in the gas, x_j = mole fraction of j^{th} component in the liquid, P_{vj} = vapor pressure of component j^{th}, and P = pressure

Since Raolt's and Dalton's law is only applicable for ideal solution, K-value needs to be correlated in gas liquid equilibrium calculation for the industry practice where hydrocarbon mixtures are mostly having non-ideal solution behaviour. The most widely used empirical correlation for K-value estimation is Wilson's correlation (Mohammed S.A., Cairo U., and Wattenbarger R.A., 1991). They also found that the equation correlates pressure, temperature, critical properties, and acentric factors of the system into a simple expression for K-values. Other than K-value correlation, EOS also could be used to calculate gas liquid equilibrium as alternative (McCain, 1990). He added that the main use of equilibrium ratios is to predict compositional changes in the reservoir fluids where the K-value is the function of pressure, temperature, and composition.

In this study, Peng Robinson Equation of State model had been used in Eclipse E300, IPM PROSPER, and IPM MBAL software for fluid characterization and PVT model. This model would describe fluid behaviour of Reservoir K upon production of Well 5C.

Based on the governed equation, the EOS could be relates to the algorithm of compositional simulation;

$$\frac{d}{dt}\left(\emptyset\, S_j\, \rho_j\, x_{ij}\right) + \nabla\left(u_j\, \rho_j\, x_{ij}\right) \pm source = 0 \qquad (11)$$

Where, $\rho_j = \frac{P}{z_j RT}$ & $u_j = \frac{k k_r}{\mu_j}\Phi$

And Ø = porosity, S_j = Phase j saturation, ρ_j = Phase j density, x_{ij} = mole fraction of component i in phase j.

This equation describes each component flow mechanism correspond to the phases. This fundamental equation is then been further developed to predict changes of reservoir pressure, saturation, and compositions. As propane intermediate component is injected to the condensate liquid which is mostly heavy component, propane dilute the mixture and fluid flow performance would be close to single phase fluid flow performance. This shows on how the fluid phase behaviour would affect the fluid flow performance. The algorithm of the compositional simulator could describe on how the propane affect the fluid behaviour by lowering the dew point once propane dissolved in Reservoir K fluid that contribute to a better performance in fluid flow after condensate liquid is mobilized and relative permeability is altered.

CHAPTER 3

METHODOLOGY

3.1 Project Workflow

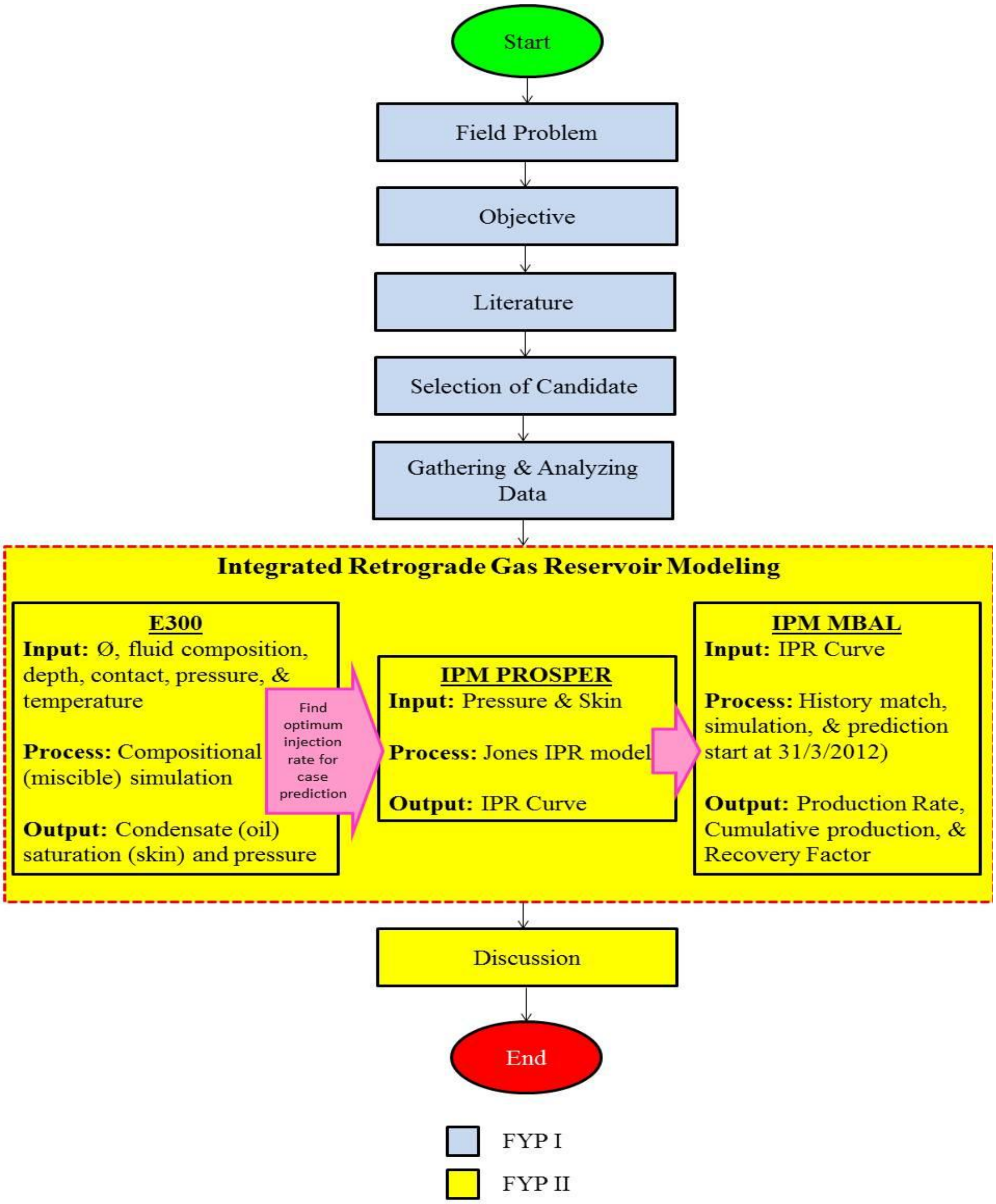


Figure 10: Final Year Project Workflow

The project workflow above in Figure 10 presents the overview of FYP methodology. The study is developed from problem faced in managing retrograde gas reservoir during field experience. Therefore, the case study is selected and been developed in order to investigate a more economical production scheme in producing retrograde gas reservoir. Literature study is conducted to obtain the idea and understand the complex mechanism of the reservoir and get updated with latest technology been approached in mitigating the problem. The literature review are mainly focusing on:

- Understanding complex mechanism of retrograde gas reservoir
- Understand typical problem in managing retrograde gas reservoir; condensate banking phenomenon
- Review of updated technology approached by the industry and evaluate the advantages and limitation of different production scheme (focus on well stimulation approach)
- Investigate capability of propane injection

3.1.1 Reservoir Candidate Selection

In order to improve the hydrocarbon recovery in N Field, K Reservoir is selected to be the candidate/representative of retrograde gas reservoir of N Field. There are several criteria evaluated in selection of the retrograde gas reservoir which are:

- Reservoir consist of more than 10 stb/MMscf condensate gas ratio (CGR)
- Moderate to good reservoir permeability (k>100mD)
- Surface composition data availability
- Single layer reservoir (Not commingle and no production allocation issue)
- No/minor water production

The criteria are determined from typical characteristic of retrograde gas reservoir that suspected facing condensate banking phenomenon referred to the N Field Reservoir Management Review (FRMR 2013) report. And for simplicity, single layer and reservoir with no water production is selected. As shown in Table 1, K Reservoir was selected to be evaluated in order to study the best strategy of producing that zone.

Table 1: Reservoir Candidate Selection Criteria from N Field Reservoir Management Review (FRMR 2013) of Gas Well Prioritization for Intervention Plan

Criteria/Candidates	Reservoir I	Reservoir J	Reservoir K
CGR (stb/MMscf)	14.43	18.48	14
Permeability	HIGH	MODERATE	MODERATE
Composition Data	YES	YES	YES
Allocation Issues	YES	YES	NO/MINOR
Data Quality	GOOD	POOR	GOOD
Water Production	YES	NO/MINOR	NO/MINOR

After candidate selection, Reservoir K field data was gathered and initial analysis was conducted. Data also had been checked to eliminate outliers and this process required experience judgement in selecting representative reservoir data. From this process also, assumptions could be made and need to be clearly justified. Available field data provided for the composition model study are:

- Production History Data (shown in Figure 11)
- Pressure Survey Data (shown in Figure 12)
- Production Rate Test (Well Test) Data
- Surface Composition Data
- Petrophysic Log Data (shown in Figure 13)
- Drill Stem Test Data
- Fluid Properties Correlation Data

And the field data of Reservoir K had been compiled as in Table 2. Compiled reservoir parameters presented both the rock and fluid properties of Reservoir K at a field scale measurement. The table data are then used as the main input for all the integrated software.

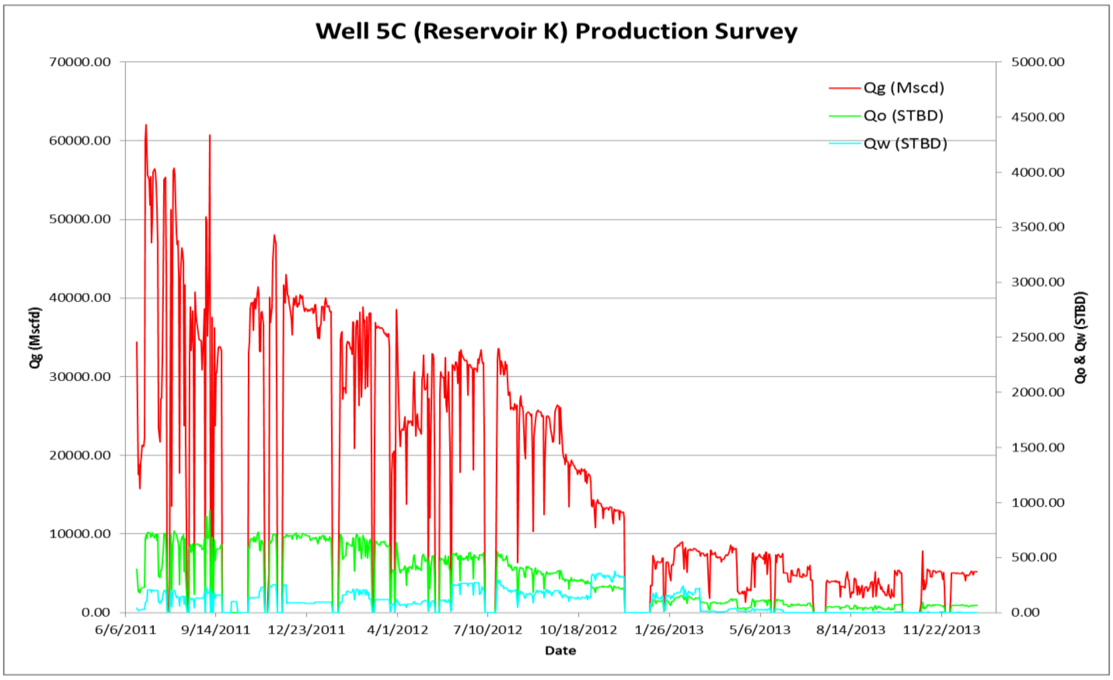


Figure 11: Well 5C (Reservoir K) Production Survey Data

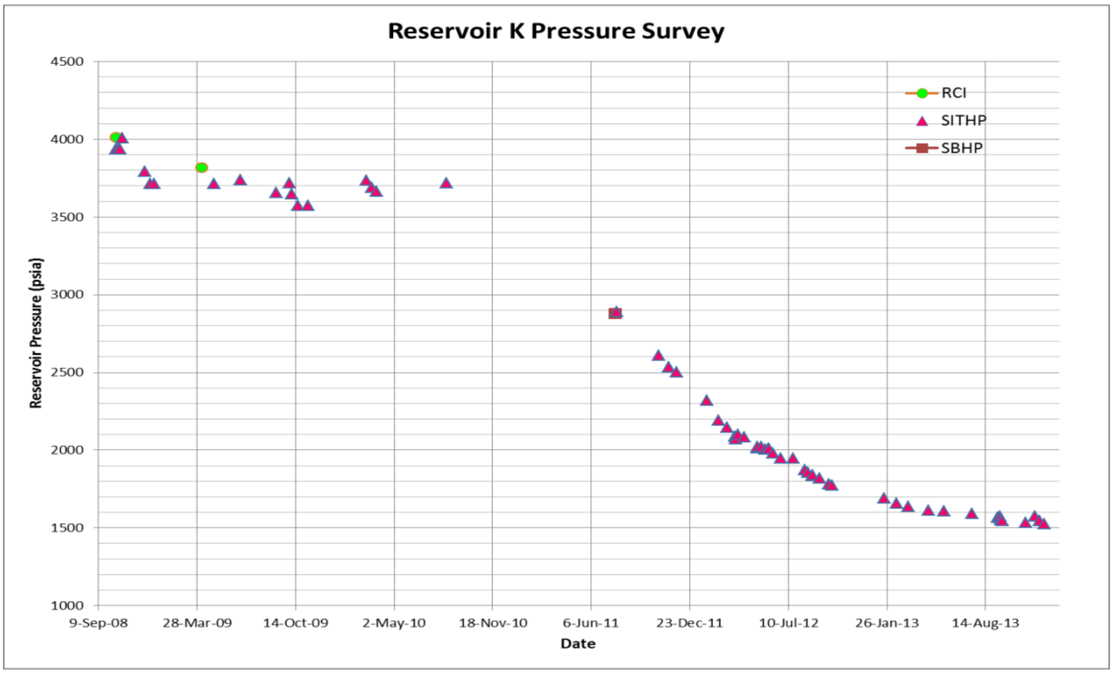


Figure 12: K Reservoir Pressure Survey Data

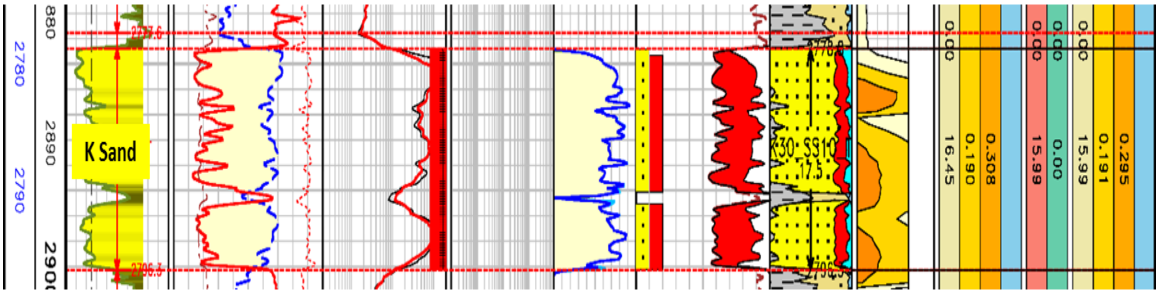


Figure 13: Petrophysic Log Data of K Reservoir

Table 2: Reservoir input parameters

PARAMETERS	RESERVOIR K
Avg. Net Thickness (ft)	52.5
Avg. Porosity	0.191
Avg. Permeability (mD)	138
Pi @ MPP (psia)	4021
Ti @ MPP (F)	286
Depth (ft)	9114
CGR (STB/MMscf)	15.4 – 16.3
GOR (scf/STB)	65000 - 61350
SG	0.8
API (Condensate)	50.2

3.1.2 Integrated Reservoir Modelling

In this study, the retrograde gas reservoir model is integrated by using E300, IPM PROSPER, and IPM MBAL software due to limitation of data such as geological model and microscopic scale data (i.e. relative permeability). If these data could be obtained, a full simulation study can be done in compositional model, E300 only. The model is integrated to achieve the objective of the study to investigate the effect of propane injection to well deliverability and reservoir recovery. Compositional model, E300 is used to study the dissolve-ness of propane injection to the condensate liquid bank and the effect on reservoir pressure. Reduction in condensate saturation near wellbore could minimize the skin and therefore changes in reservoir pressure and skin are captured as the input for IPM PROSPER model.

SPE 12778 is used and modified to represent the actual rock and fluid properties of Reservoir K. The parameters changed are;

1. Porosity
2. Fluid composition
3. Reservoir Pressure and Temperature
4. Depth
5. Fluid contacts

IPM PROSPER model been used to develop well model of Well 5C. Plus, the model has been matched with actual production rate test result to represent the actual well performance. Jones IPR model was used in IPM PROSPER since the main input required are reservoir pressure and skin to construct the IPR curve.

The IPR curve from the IPM PROSPER is then been used to IPM MBAL for production forecasting. But first, the IPM MBAL model needs to be history match to represent actual reservoir performance. Simulated (calculate from IPM MBAL based on input data) output need to be calibrated with the actual measured result as shown in Figure 14. After the model has been matched, cases prediction could be proceed with different IPR curves.

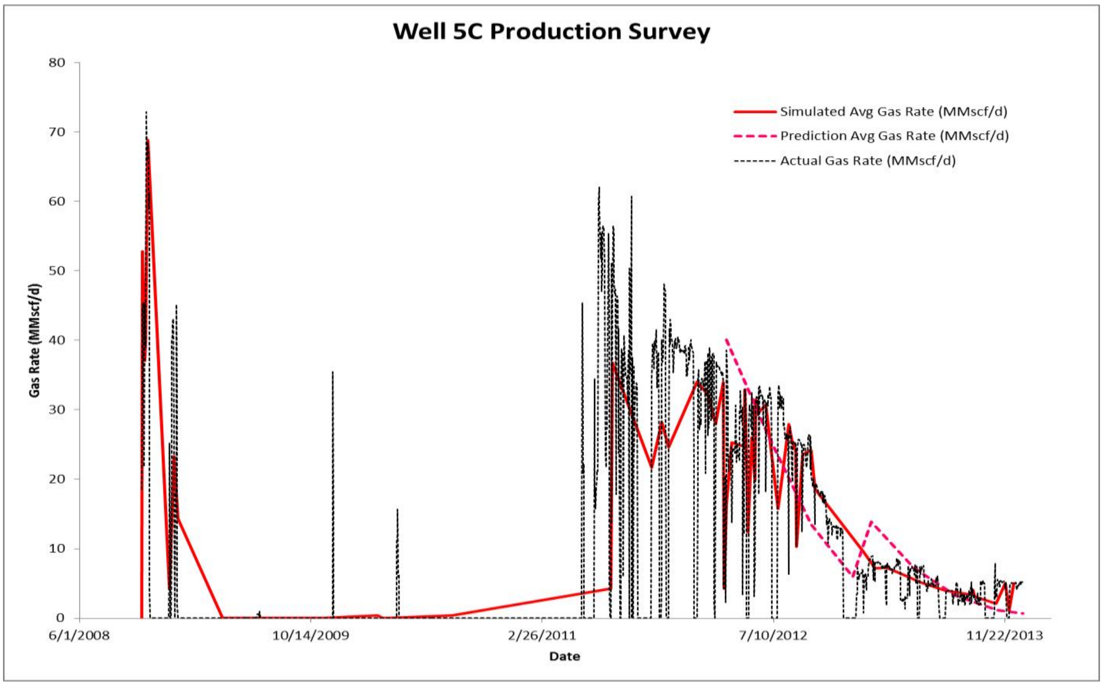


Figure 14: History matched, simulated, and prediction of gas production from IPM MBAL

The cases prediction is run under natural depletion of Reservoir K (base case) and under propane injection. Propane injection is proposed to starts from 31/3/2012 where the skin starts to increase, based on Figure 15. The injection schemes would be a miscible well stimulation approach within 3 days of injection operation. Then the reservoir performance of K Reservoir is evaluated and reserve recovery is recorded. The study is expected to increase well productivity and hence recover more hydrocarbons from the retrograde gas reservoir. A quick economic evaluation was then been reviewed in order to oversee the implementation of propane (stimulation) injection as part of retrograde gas reservoir development.

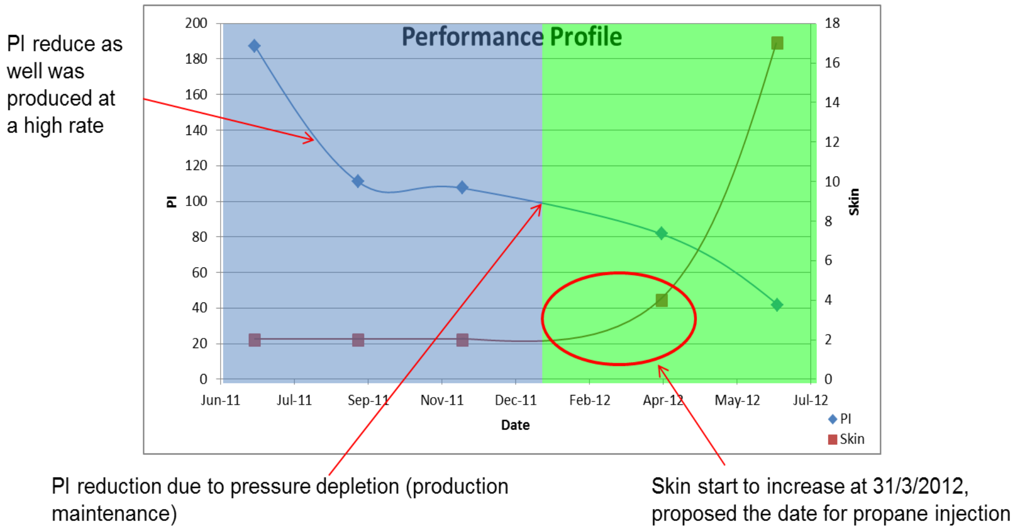
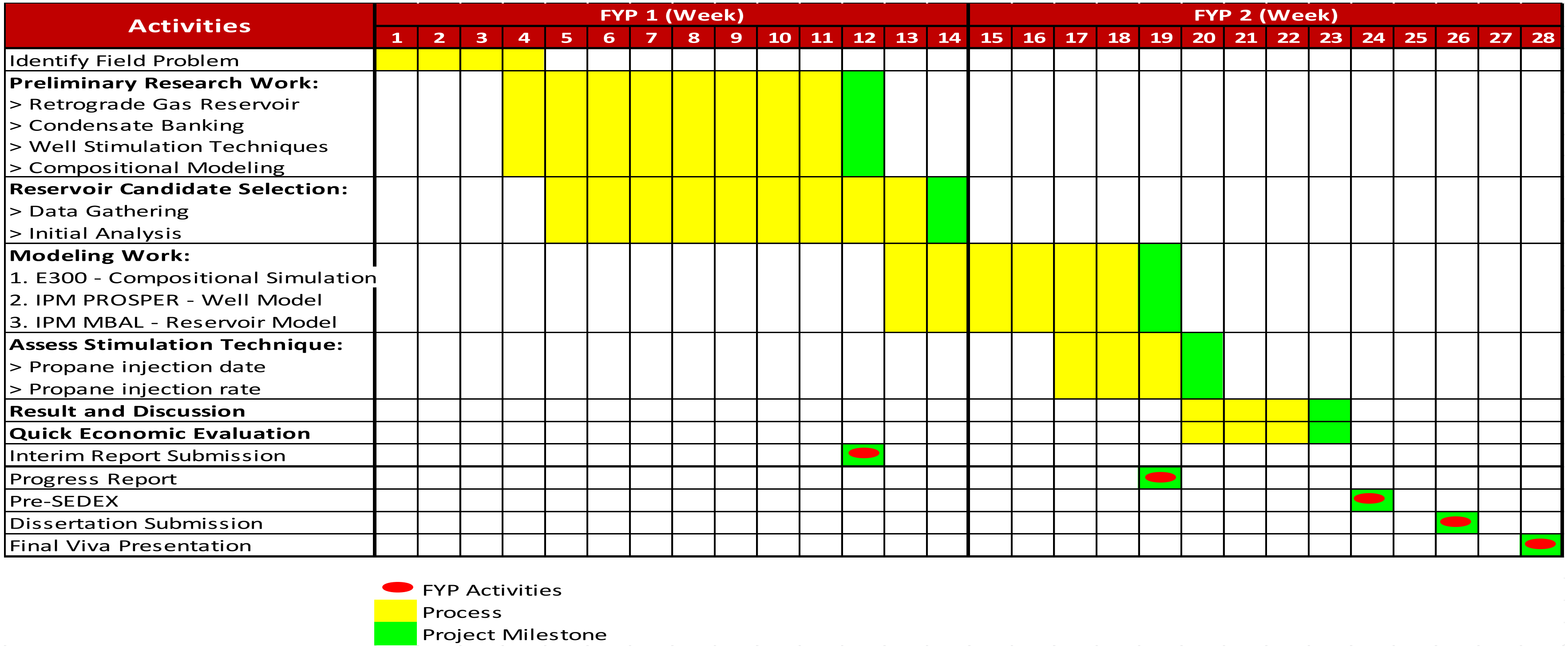


Figure 15: PI and skin throughout the time

3.2 Project Gantt Chart and Key Milestone

Table 3: Project Gantt Chart and Key Milestone



CHAPTER 4

RESULT AND DISCUSSION

This project aims to mitigate lean retrograde gas reservoir recovery problem of Reservoir K by proposing propane injection to increase reservoir pressure and reduce skin (condensate saturation near wellbore). The effect of propane injection to inflow performance relationship, IPR and it's improvement to reservoir recovery also are the main focus in this chapter.

4.1 Effect of Propane Injection to Condensate Saturation and Reservoir Pressure

The effect of propane injection to condensate saturation and reservoir pressure was investigated by using E300 software in order to study the dissolve-ness of injected propane to the condensate liquid bank near wellbore. Figure 16 shows on different propane injection rates affect the condensate saturation for the next 3 years;

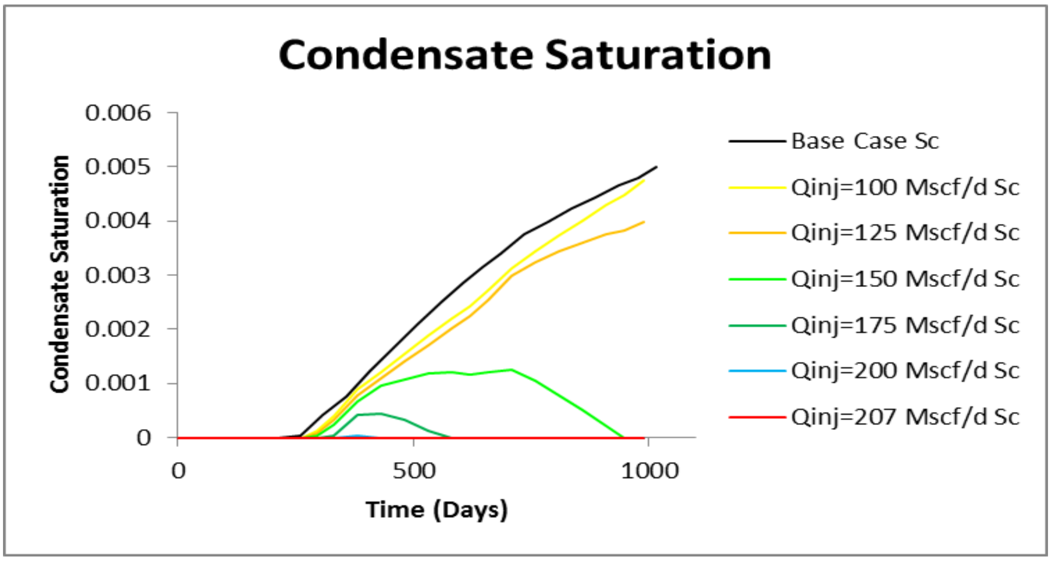


Figure 16: Condensate saturation result upon different rates of propane injection

Based on the propane injection rates sensitivities study, it could be observed that 207 Mscf/day of propane injection minimizes the condensate saturation for next 3 years. Therefore, 207 Mscf/day had been selected as the optimum rate to be injected in Reservoir K. Changes to condensate saturation and reservoir pressure had been captured to be the input for IPM PROSPER model. In this case, increase in the skin factor of Reservoir K is suspected mainly from the condensate bank effect. Therefore, it could be assumed that the skin in which inhibits gas deliverability had been reduced for approximately another three years of production with 207 Mscf/day of propane injection.

Figure 17 shows the effect of different propane injection rates to the reservoir pressure. Small changes to reservoir pressure are due to injection duration which is only for three days of operation and propane is injected from the producer well (stimulation approach). Since the main objective of this study is to reduce/eliminate the skin from condensate bank, changes in reservoir pressure would be the additional improvement toward the gas deliverability.

It could be concluded that there is 25 psia increases in reservoir pressure with 207 Mscf/day of propane injection and resulting of 2% increment to reservoir potential, Absolute Open Flow (AOF). This will contribute a better reservoir IPR as well as well deliverability. Plus, it could be observed that, there is 2% increase in reservoir pressure every 1 MMscf/day increase in propane injection rate. This information of reservoir pressure and skin been used as the main input for IPM PROSPER to find the reservoir potential IPR.

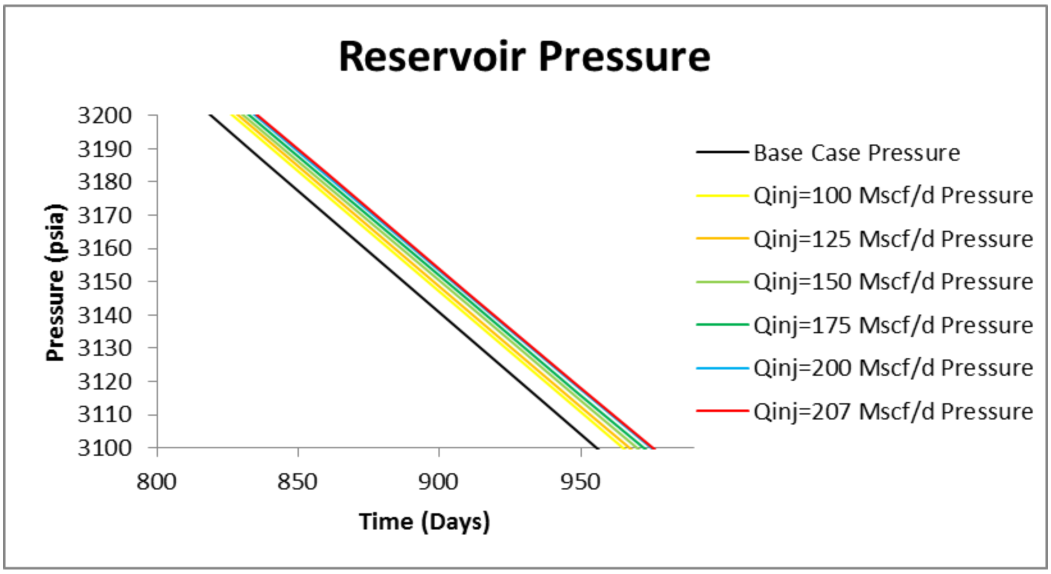


Figure 17: Effect of propane injection to reservoir pressure

The dissolve-ness of propane injection to condensate liquid of Reservoir K results a dilute mixture that having a lower viscosity and hence increase the condensate mobility. Propane as an intermediate components present in the injected gas condense with condensate bank, heavier component in reservoir to generate a modified fluid that become miscible with the injection fluid (Latil, 1980). A combination of condensing-vaporizing drives may occur once propane/enriched gas or known as the intermediate hydrocarbon is injected. Upon propane injection, at certain stage where the condensate saturation will have increased sufficiently that condensate become mobile. This is due to increase in critical condensate saturation that will increase the condensate relative permeability. In other word, the residual (critical) condensate saturation is lowered and more condensate is mobilize that would influence both condensate and gas productivity (Lal, 2003). These relationships between condensate effective permeability and viscosity in improving condensate mobility can be presented as;

$$Mobility = \frac{Krc\ (condensate\ relative\ permeability)}{\mu\ (condensate\ viscosity)} \qquad (12)$$

These condensate relative permeability and viscosity parameters could be further investigated in a laboratory scale for the condensate mobility study. In addition, other study in extracting unconventional heavy oil by Kariznovi, Nourozieh, and Abedi (2011), found that at high isothermal system, enriched propane injection capable to lower the viscosity of heavy oil that is usually immobilize. This analogy is close to immobilize condensate bank in bottom hole that is diluted and then drove by propane into the well bore. Their study also proves that propane as part of hydrocarbon component has potential and capability in improving the viscosity of heavier component.

The fluid flow performance and mobility have close relationship to fluid phase behaviour. In term of phase behaviour context, propane capable to reduce dew point pressure (Jamaluddin et al., 2001). Reduction in dew point pressure will delay the formation of condensate bank in the reservoir which single phase fluid flow could be maintained. Where, single phase fluid flow of gas will rely more to the reservoir permeability, thickness, and pressure gradient instead of high relative permeability reduction (Lal, 2003, Dumkwu, 2013). The improvement of the fluid flow performance can be observed from the IPR curve.

4.2 Effect of Propane Injection to Inflow Performance Relationship (IPR)

The results from E300 were then been used for IPM PROSPER IPR modelling to investigate the effect of changes in reservoir pressure and skin reduction contribution to IPR curve.

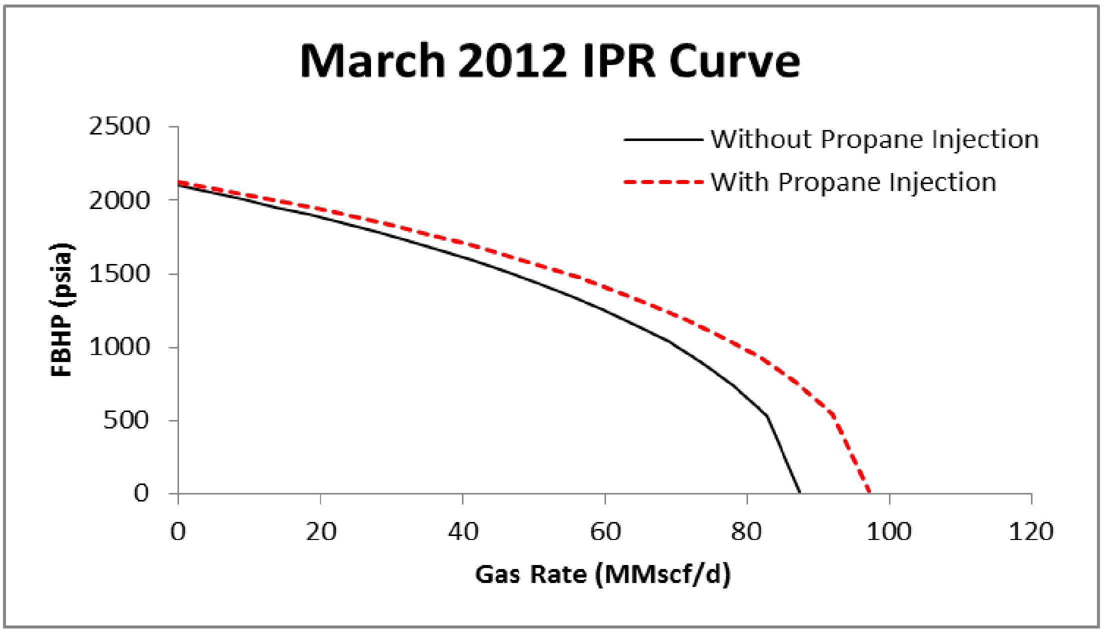


Figure 18: IPR Curve for March 2012 Model

Based on the IPR curve in Figure 18, there is an approximate 10 MMscf/day additional to Absolute Open Flow (AOF) after propane injection from 87 MMscf/day to 97 MMscf/day. This shows a significant improvement toward IPR curve of Reservoir K under propane injection. This study assumes that condensate saturation is minimized upon propane injection and hence lowering skin value as close as initial skin value which is at a factor of 2. Jones gas IPR model was used in IPM PROSPER software since the main inputs needed are reservoir pressure and skin. Jones, Blount, and Glaze (1976) derived the flow equation from the field data correlation to calculate the gas rate at constant flowing pressure that also considering the skin effect and turbulent flow (non-Darcy flow effect). The equation can be expressed as;

$$\frac{P_r^2 - P_{wf}^2}{q_g} = a + bq_g \tag{13}$$

Where;

P_r = Reservoir static pressure, P_{wf} = Sandface flowing pressure, q_g = Gas flow rate at standard condition, a = turbulent flow term, and b = Darcy flow term

If the a and b coefficient have been determined from multi-rate test result, deliverability can be estimated through;

$$q_g = \frac{-a + \sqrt{a^2 + 4b(P_r^2 - P_{wf}^2)}}{2b} \tag{14}$$

Once the coefficients of the deliverability equation have been determined, these relationships can be used to estimate production rates for various bottom hole flowing pressures. This could measure the ability of the reservoir to produce gas from the wellbore by determining the rate versus pressure relationship.

However, for gas flow with condensate banking problem, which the gas flow is restricted, the deliverability and a and b coefficient might be affected from the Jones's correlated equation. Theoretically, skin or formation damage caused by condensate banking problem may reduce in permeability at the altered zone causes by an additional pressure drop, ΔP_S. The dimensionless skin factor, s, and the additional pressure drop across the altered zone are related by;

$$\Delta P_s = \frac{141.2\, q\beta\mu}{kh} s \quad (15)$$

Where;

ΔP_s = Pressure drop due to skin, q = production rate, β = formation volume factor, μ = viscosity, k = permeability, h = reservoir thickness, and s = dimensionless skin factor

The skin factor affects the pressure drop and hence limits reservoir performance. Therefore, propane injection could assist in mitigating condensate banking problem by minimizing the condensate saturation near well bore and reduce the skin factor.

Based on the Jones correlated equation, the IPR produced only represent the reservoir performance at a particular time. Thus, to investigate reservoir performance change in time, diffusivity equation (unsteady state fluid flow) is needed to be applied. Based on the literature review, diffusivity equation formed from combination of main equation of continuity equation and Darcy's fluid flow equation. IPM MBAL software applies this diffusivity equation in order to forecast reservoir performance. From the updated IPR Curve, Reservoir K performance under propane injection could be investigated as shown in Figure 19.

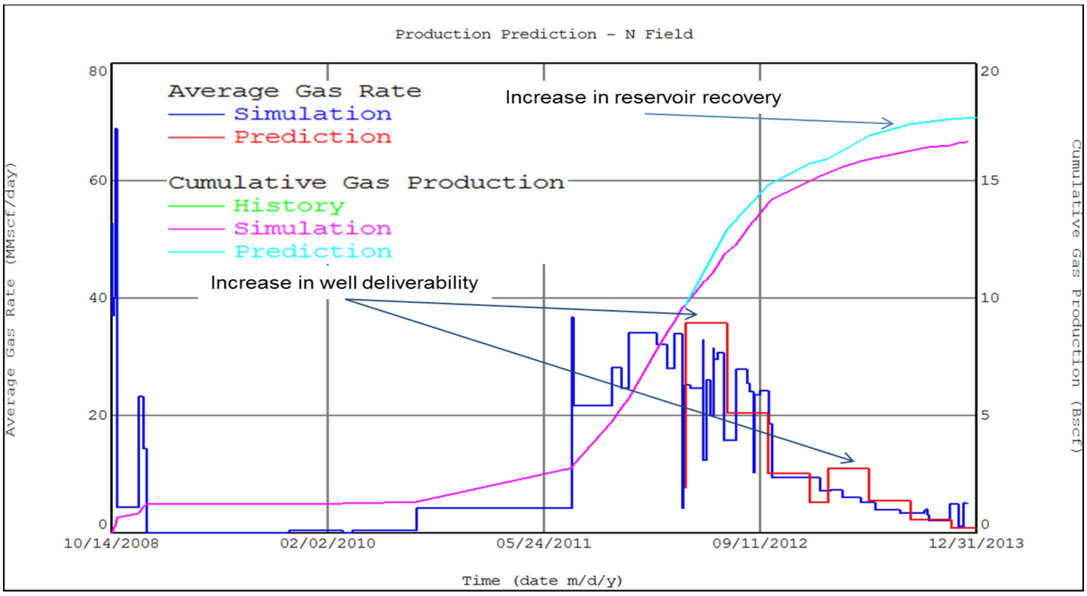


Figure 19: IPM MBAL results on average gas rate and cumulative gas production

Figure 19 shows Reservoir K performance after the updated IPR curve was imported to IPM MBAL model. The average gas rate is being simulated (blue line) from scheduled production constraint in IPM MBAL and predicted (red line) starts from 31/3/2012 to 31/12/2013. It could be observed increase in well deliverability and hence improve the gas recovery. Gas recovery improvement could be observed from additional to cumulative gas production after the propane injection. The model has been matched and this could be observed that historical (green line) and simulated (pink line) cumulative gas production are matched. The model is then been used to predict additional gas recovered (light blue) after propane injection.

It can be conclude that reduction in skin improves well deliverability that increase the average gas rate and more hydrocarbon gas can be recovered. As condensate is the by-product of produced gas, logically the condensate recovery also can be improved.

4.3 Effect of Propane Injection to Reservoir K Recovery

After Reservoir K, IPM MBAL model has been matched and equipped by improved IPR curve, hydrocarbon recovery prediction was conducted.

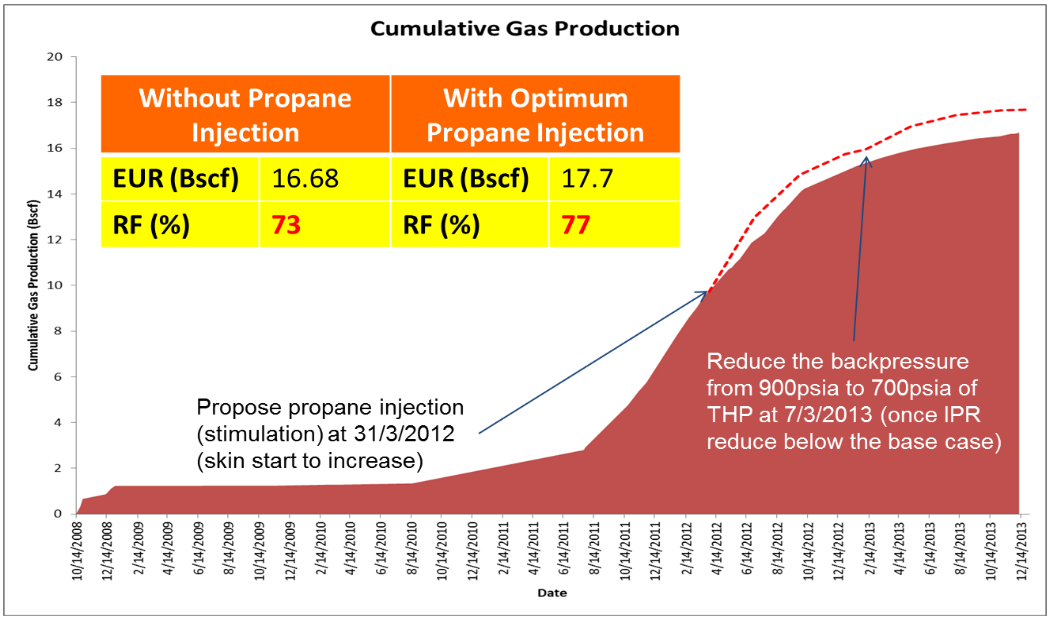


Figure 20: Cumulative Gas Production

There is an additional in gas cumulative production from the base case cumulative production after propane injection as shown in Figure 20. At 7/3/2013, backpressure was proposed to reduce from 900 psia to 700 psia that increase more the cumulative gas production. It is predicted gas reserve to recover up to 17.7 Bscf that brings 77% of recovery factor (increase 4% from the base case). On the other hand, the cumulative condensate production could be observed in Figure 21;

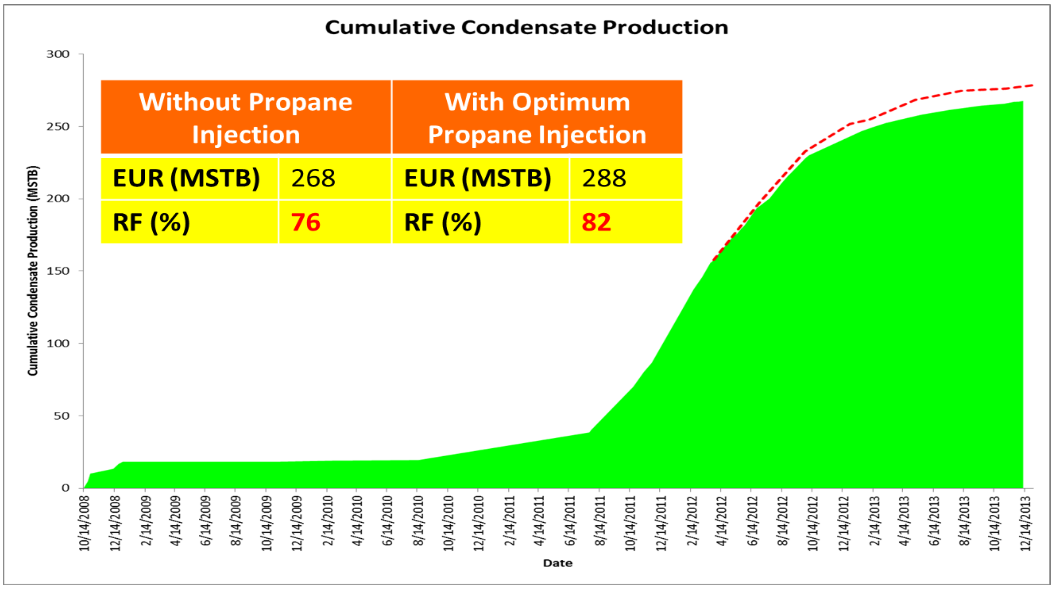


Figure 21: Cumulative Condensate Production

The cumulative condensate production shown in Figure 21 predicts Reservoir K to recover 288 MSTB of condensates that brings additional 6% of recovery factor from the base case. The condensate recovery could be proved by GOR result from E300;

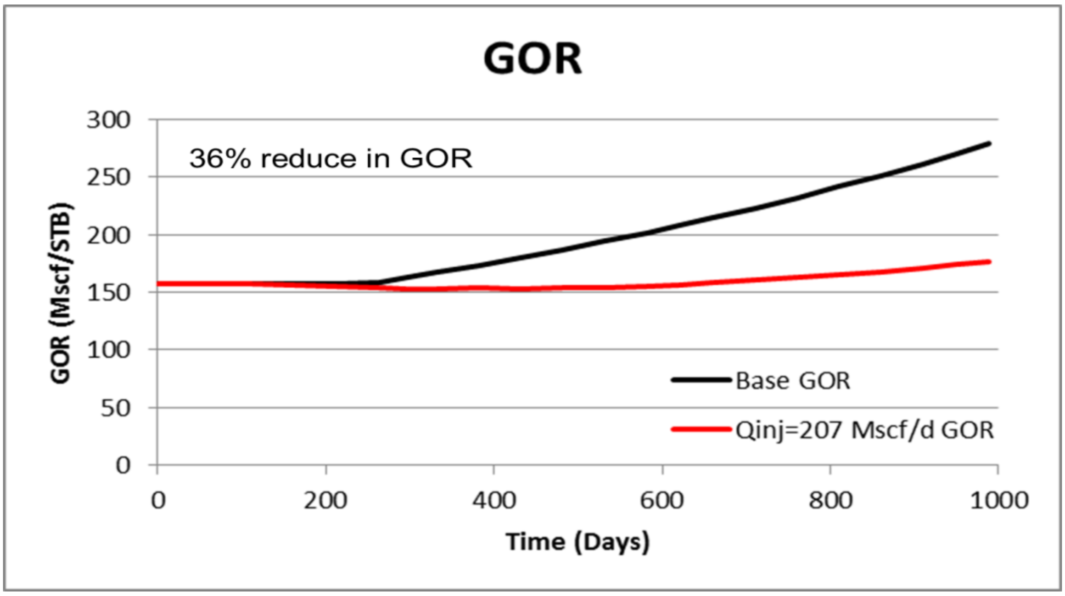


Figure 22: Gas Oil Ratio (GOR) changes upon propane injection

Based on the Figure 22, it is observed that propane injection reduce the GOR (approximate 36%) under 207 Mscf/d of propane injection. This shows that more condensate able to recover as the lower the GOR, the higher the CGR (condensate gas ratio). Therefore, propane injection not only recover more gas, but also capable to recover more condensate liquid at the surface. These results are then been collected to study on economic viability of this project to Reservoir K.

4.4 Quick Economic Evaluation

In economic perspective, production under propane injection could be predicted brings additional 4.2 Million USD of revenue based on the quick economic profile in Figure 23;

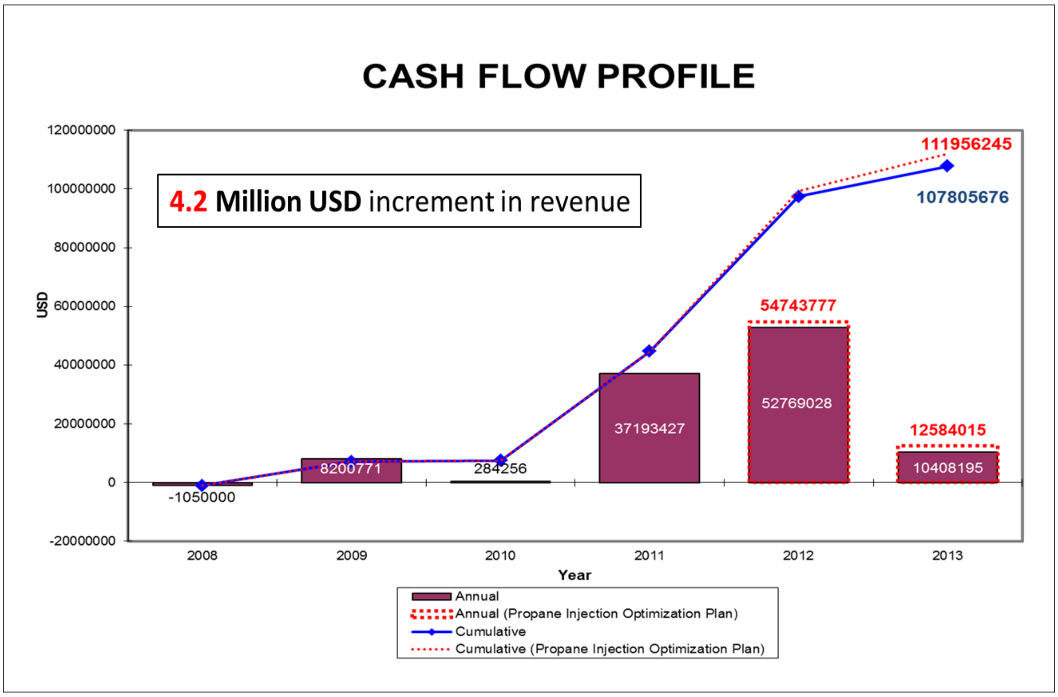


Figure 23: Quick Economic Evaluation

It is approximately 4% increase in the revenue after embarking propane injection development to Reservoir K. The value of the condensate is close to the crude oil that influence the total revenue. Therefore, by recovering more condensate could increase economic viability of the project. From this quick economic evaluation, it can be conclude that the economic viability of this project is depend on;

- Condensate recovery
- Cost of propane injection

Therefore, any effort in increasing the condensate recovery and optimizing the cost of propane injection would increase the benefit in implementing this project. For cost optimization, cheaper propane needs to be acquired. (Kallio, Pásztor, Thiel, Akhtar, and Jones (2014)) found an ideal way to produce cheaper propane from Escherichia coli (E.coli) bacteria. They interrupted the bacteria's natural process of creating cell membranes out of fatty acids by using three different enzymes with separate functions. It is found out that the cost of propane from bacteria could be as low as 0.67 USD per gallon that make there is possibility of utilizing propane from bacteria for this well stimulation program. However, a study on compatibility of propane from bacteria and reservoir fluid need to be investigated for the future work.

As summary to the result and discussion part, it is found that propane injection project could be part of the retrograde gas reservoir development. Study shows that condensate banking problem can be removed by mobilizing the condensate saturation at the bottom hole. Propane capable to clear the restriction of gas to flow into the wellbore that increase well productivity and hence increases gas recovery. The condensate liquid can recovered from mobilized high saturation of condensate and produced along the gas flow. This could be observed from the improved CGR that is close to the initial CGR. In economic view, condensate recovery gives more contribution toward the project revenue compared to gas recovery. On the other note, plan of optimizing the project cost also should be considered. Thus, effort on both increases in condensate recovery and cost optimization would contribute to a high profit of this project.

CHAPTER 5

CONCLUSION & RECOMMENDATION

5.1 Conclusion

As conclusion, the study is mainly to investigate the potential propane injection to retrograde gas recovery compared to the normal industry practice under natural depletion. There are additional 4% of gas recovery factor and 6% increase in condensate recovery factor that brings 4.2 Million USD of revenue. In addition, study shows that propane injection improve both gas and condensate performance as propane capable to;

- Reduce the dew point pressure that delay condensate bank formation
- Dilute the condensate liquid at bottom hole that reduce condensate viscosity, hence mobilize the condensate liquid
- Theoretically maintain single phase fluid flow into the wellbore, increase gas relative permeability, ease gas to flow, thus increase gas inflow performance

This study also found that reservoir IPR and hydrocarbon recovery could be improved after the skin effect had been minimized. On the other hand, condensate recovery and cost of propane is the main factors that determine the economic viability of the project. Therefore, these factors could be improved and further studied as part of gas development strategy.

5.2 Recommendation

Project study was basically focus on the effect of propane injection to dissolve condensate saturation at bottom hole, influence of skin to reservoir IPR, and how it contribute to reservoir recovery. However, there are still a lot of areas that need to be covered as it is depending on what variables to study on for example saturation changes in time or location. In this area of study which relates skin from condensate bank, gas IPR, and hydrocarbon recovery, it is recommended to further study on;

- Micro-scale laboratory data such as relative permeability from Special Core Analysis (SCAL), Constant Volume Depletion (CVD) test data and Constant Composition Expansion (CCE) test data that could increase the quality of the study
- Reservoir actual geology model considering geology physical such as dipping, folded, and channelling
- Miscibility test to observe the minimum miscibility pressure (MMP) of propane for reservoir fluid in N field
- Cost optimization by using cheaper propane artificial produced from bacteria and surface facilities study

As summary, the area of retrograde gas reservoir study could be presented as shown in Figure 24;

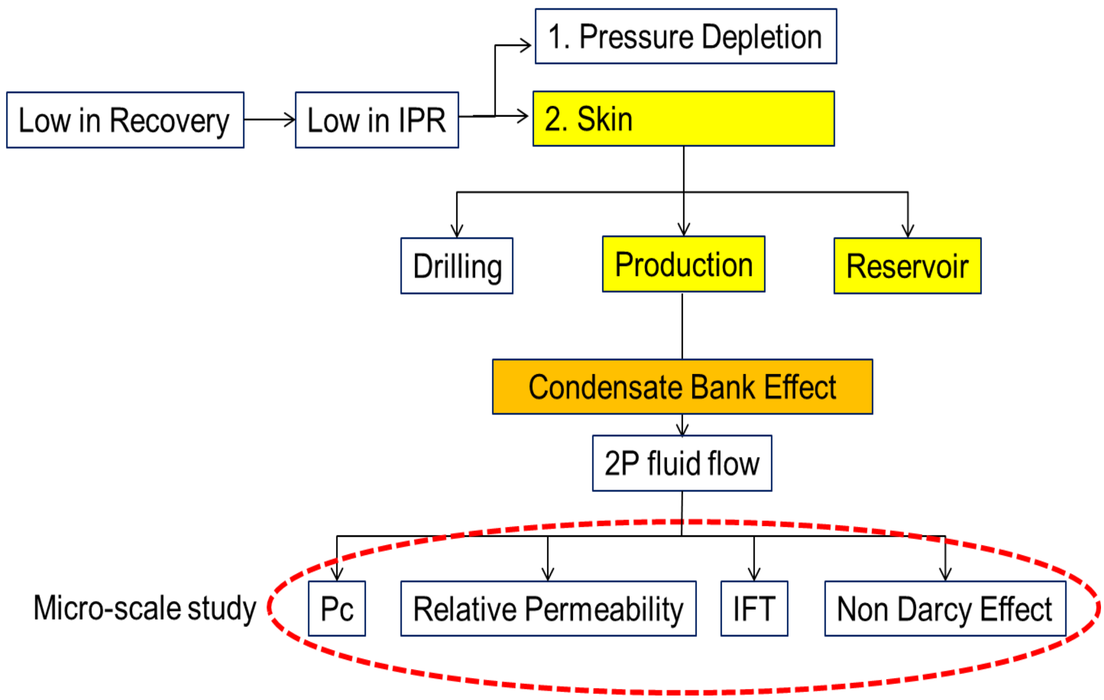


Figure 24: Retrograde Gas Reservoir study area in hydrocarbon recovery project

CHAPTER 6

REFERENCES

Abou-Kassem, J. H., Farouq-Ali, S., & Islam, M. R. (2013). *Petroleum Reservoir Simulations*: Elsevier.

Ahmed, T., Evans, J., Kwan, R., & Vivian, T. (1998). *Wellbore liquid blockage in gas-condensate reservoirs.* Paper presented at the SPE Eastern regional meeting.

Al-Abri, A., & Amin, R. (2010). Phase behaviour, fluid properties and recovery efficiency of immiscible and miscible condensate displacements by SCCO2 injection: experimental investigation. *Transport in porous media, 85*(3), 743-756.

Al-Abri, A. S. (2011). *Enhanced gas condensate recovery by CO2 injection*: Curtin University of Technology.

Al-Anazi, H. A., Al-Otaibi, M. A., Al-Faifi, M., & Hilab, V. V. *Enhancement of Gas Productivity Using Alcoholic Acids: Laboratory and Field Studies*.

Al-Shawaf, A. M., Kelkar, M., & Sharifi, M. (2013). A New Method to Predict Performance of Gas Condensate Reservoirs. *SAUDI ARAMCO JOURNAL OF TECHNOLOGY*, 23.

Ayala, L. F., Ertekin, T., & Adewumi, M. A. (2006). Compositional modeling of retrograde gas-condensate reservoirs in multimechanistic flow domains. *SPE Journal, 11*(04), 480-487.

Bang, V. S. S., Pope, G. A., & Sharma, M. M. (2006). *Phase Behavior Study of Hydrocarbon/Water/Methanol Mixtures at Reservoir Conditions.* Paper presented at the SPE Annual Technical Conference and Exhibition.

Du, L., Walker, J. G., Pope, G. A., Sharma, M. M., & Wang, P. (2000). Use of solvents to improve the productivity of gas condensate wells. *paper SPE, 62935*, 1-4.

Dumkwu, F. A. (2013). *Integrated Reservoir Characterization and Modeling for Enhanced Hydrocarbons Recovery from Mature Gas-condensate Reservoirs:*

A Case Study of Big Escambia Creek Field, Escambia County, Alabama, USA: University of Alabama Libraries.

Fan, L., Harris, B. W., Jamaluddin, A. J., Kamath, J., Mott, R., Pope, G. A., . . . Whitson, C. H. (1998). Understanding gas-condensate reservoirs. *Oilfield Review, 10*(3), 16-25.

Ferguson, M., Mamora, D., & Goite, J. (2001). *Steam-propane injection for production enhancement of heavy Morichal oil.* Paper presented at the SPE International Thermal Operations and Heavy Oil Symposium.

Gachuz-Muro, H., Gonzalez Valtierra, B. E., Luna, E. E., & Aguilar Lopez, B. (2011). *Laboratory Tests with CO2 N2 and Lean Natural Gas in a Naturally Fractured Gas-Condensate Reservoir under HP/HT Conditions.* Paper presented at the SPE Enhanced Oil Recovery Conference.

Ghedan, S. (2009). *Global laboratory experience of CO2-EOR flooding.* Paper presented at the SPE/EAGE Reservoir Characterization & Simulation Conference.

Grigg, R., & Lingane, P. (1983). *Predicting phase behavior of mixtures of reservoir fluids with carbon dioxide.* Paper presented at the SPE Annual Technical Conference and Exhibition.

Gringarten, A., Al-Lamki, A., Daungkaew, S., Mott, R., & Whittle, T. (2000). *Well test analysis in gas-condensate reservoirs.* Paper presented at the SPE annual technical conference.

Hashemi, A., Nicolas, L., & Gringarten, A. C. (2006). Well test analysis of horizontal wells in gas-condensate reservoirs. *SPE Reservoir Evaluation & Engineering, 9*(01), 86-99.

Havlena, Z., Griffith, J., Pot, R., & Kiel, O. (1967). *Condensate Recovery by Cycling at Declining Pressure.* Paper presented at the 7th World Petroleum Congress.

Hinchman, S., & Barree, R. (1985). *Productivity loss in gas condensate reservoirs.* Paper presented at the SPE Annual Technical Conference and Exhibition.

Jamaluddin, A., Thomas, S., D'Cruz, D., Nighswander, J., & Oilphase, S. (2001). Experimental and theoretical assessment of using propane to remediate liquid buildup in condensate reservoirs. *paper SPE, 71526*.

Jessen, K., & Orr, F. (2004). Gas cycling and the development of miscibility in condensate reservoirs. *SPE Reservoir Evaluation & Engineering, 7*(05), 334-341.

Jones, L. G., Blount, E., & Glaze, O. (1976). Use of short-term, multiple-rate flow tests to predict performance of wells having turbulence: Mobil Research and Development Corp.

Kallio, P., Pásztor, A., Thiel, K., Akhtar, M. K., & Jones, P. R. (2014). An engineered pathway for the biosynthesis of renewable propane. *Nature communications, 5*.

Kamath, J. Deliverability of Gas-Condensate Reservoirs — Field Experiences and Prediction Techniques. doi: 10.2118/103433-JPT

Kariznovi, M., Nourozieh, H., & Abedi, J. (2011). *Experimental and Modeling Study of Vapor-Liquid Equilibrium for Propane/Heavy Crude Systems at High Temperature Conditions.* Paper presented at the SPE annual technical conference and exhibition.

Kolbikov, S. V. (2010). *Gas-Condensate Recovery For The Low Permeable Sands Gas Cycling Efficiency.* Paper presented at the SPE Russian Oil and Gas Conference and Exhibition.

Kurdi, M., Xiao, J., & Liu, J. (2012). *Impact of CO2 Injection on Condensate Banking in Gas Condensate Reservoirs.* Paper presented at the SPE Saudi Arabia section Young Professionals Technical Symposium.

Lal, R. R. (2003). *Well Testing in Gas-Condensate Reservoirs.* STANFORD UNIVERSITY.

Latil, M. (1980). *Enhanced oil recovery*: Editions OPHRYS.

Mamora, D., & Seo, J. (2002). *Enhanced gas recovery by carbon dioxide sequestration in depleted gas reservoirs.* Paper presented at the SPE Annual Technical Conference and Exhibition.

McCain, W. D. (1990). *The properties of petroleum fluids*: PennWell Books.

Monger, T., & Khakoo, A. (1981). *The phase behavior of CO2-Appalachian oil systems.* Paper presented at the SPE Annual Technical Conference and Exhibition.

Moradi, B., Tangsiri Fard, J., Rasaei, M. R., Momeni, A., & Bagheri, M. B. (2010). *Effect of Gas Recycling on the Enhancement of Condensate Recovery in an Iranian Fractured Gas/Condensate Reservoir.* Paper presented at the Trinidad and Tobago Energy Resources Conference.

Moses, P. L., & Donohoe, C. W. Gas-Condensate Reservoirs (1987 PEH Chapter 39): Society of Petroleum Engineers.

Odi, U. *Analysis and Potential of CO2 Huff-n-Puff for Near Wellbore Condensate Removal and Enhanced Gas Recovery*.

ODI, U. O. (2013). *Optimal Process Design for Coupled CO2 Sequestration and Enhanced Gas Recovery in Carbonate Reservoirs.* Texas A&M University.

Olaberinjo, A., & Oyewola, O. (2006). Modelling the Effect of Compositional Changes in Transient Flow of Gas Condensate Reservoirs. *International Journal of Fluid Mechanics Research, 33*(6).

Oldenburg, C. M., & Benson, S. M. *CO2 Injection for Enhanced Gas Production and Carbon Sequestration*.

Sayed, M. A., & Al-Muntasheri, G. A. *Liquid Bank Removal in Production Wells Drilled in Gas-condensate Reservoirs: A Critical Review*.

Seto, C. J., Jessen, K., & Orr, F. M. (2007). Using analytical solutions in compositional streamline simulation of a field-scale CO2-injection project in a condensate reservoir. *SPE Reservoir Evaluation & Engineering, 10*(04), 393-405.

Sognesand, S. (1991). *Long-term testing of vertically fractured gas condensate wells.* Paper presented at the SPE Production Operations Symposium.

Soroush, M., Hoier, L., & Kleppe, J. (2012). *CO2 Injection and CO2 WAG in Dipping Gas Condensate and Oil Reservoirs.* Paper presented at the SPE Improved Oil Recovery Symposium.

Taheri, A., Hoier, L., & Torsaeter, O. *Miscible and Immiscible Gas Injection for Enhancing of Condensate Recovery in Fractured Gas Condensate Reservoirs*.

Thomas, F., Andersen, G., & Bennion, D. (2009). Gas condensate reservoir performance. *Journal of Canadian Petroleum Technology, 48*(7), 18-24.

Thornton, O. (1946). Gas-Condensate Reservoirs-A Review. *Drilling and Production Practice*.

Yarranton, H., Badamchi-Zadeh, A., Satyro, M., & Maini, B. (2008). *Phase Behaviour and Physical Properties of Athabasca Bitumen, Propane and CO.* Paper presented at the Canadian International Petroleum Conference.

Zaitsev, I., Dmitrievsky, S., Norvik, H., Yufin, P., Bolotnik, D., Sarkisov, G., & Schepkina, N. (1996). *Compositional modeling and PVT analysis of pressure maintenance effect in gas condensate field: Comparative study*. Paper presented at the EUROPEC: European petroleum conference.