**Simulation Studies on the Effect of Asphaltene Precipitation on Oil Recovery during $CO_2$ Injection for Light Oil Reservoir**

By

LIM HWEI SHAN

Dissertation submitted in partial fulfillment of

the requirements for the

Bachelor of Engineering (Hons)

(Petroleum Engineering)

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# CERTIFICATION OF APPROVAL

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BACHELOR OF ENGINEERING (Hons)

(PETROLEUM ENGINEERING)

Approved by,

________________________

Mr.Ali F.Mangi Alta'ee

UNIVERSITI TEKNOLOGI PETRONAS

TRONOH, PERAK

MAY 2011

# 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.

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## ABSTRACT

Enhanced Oil Recovery (EOR) is method widely use in many company for production. Gas injection is one of the oldest and most popular methods used in EOR. EOR is used to increase oil recovery. Gas is injected inside the reservoir and is stored in the geological formation. $CO_2$ injection is one type of gas injection and is preferred to use in light oil reservoir as the gas and oil can be mix forming a miscible phase reducing the interfacial tension of crude oil and flowing together to the surface. Unfortunately, in wells that has asphaltene, precipitation tends to exist even though the percentage of asphaltene is small. Once precipitation occurs, the asphaltene will clump together forming a flock of asphaltene and deposit in the reservoir when it is too heavy to be carried out by the flow causing formation damage such as porosity and permeability reduction and wettability alteration. Asphaltene precipitation will also cause the wellbore, tubing and facilities equipments to break down due to the accumulation in it. All these will lead to decrease in production. The author will continue doing research work reading more to understand the effect of asphaltene. Then, the author will use CMG software to simulate light oil reservoir under $CO_2$ injection to anticipate the outcome before it actually happens as when precipitation occurs, the cost to clean it mechanically and chemically is time consuming, expensive and unsafe. The author will use the Builder, WinProp and GEM to do the simulation work. The findings that the author found was consistent which the experimental work done by many experts in the industry and the author had proven that asphaltene precipitation causes formation damaged which in turn reduces the permeability and porosity of the formation.

## ACKNOWLEDGMENT

Many thanks to my Final Year Project supervisor Mr. Ali F. Mangi Alta'ee for all his support and guidance throughout the whole eight months of Final Year Project I and Final Year Project II. His guidance extended more than just being a lecturer to my final year project but he also became my friend and gave me many lifelong lessons.

Though his busy schedule, he would always find time to advise me on my problems I encountered through my project. His patience is remarkable being such a high established man he never fails to share his knowledge to me and repeats them to me no matter how many times I needed them.

Lastly, I would like to thank my simulation partner, Mr. Chiew Kwang Chian for all his support, help and guidance in figuring out the simulation together. I would also like to thank all my FYP team members who have the same supervisor as me for all their guidance.

## TABLE OF CONTENTS

## LIST OF FIGURES

## LIST OF TABLES

# CHAPTER 1

# INTRODUCTION

## 1.1 Background of Study

There are 3 stages of oil field recovery which is the primary, secondary and tertiary recovery which is also known as the Enhanced Oil Recovery (EOR). EOR is used only when the primary and secondary recovery failed to produce desired outcome of oil. Carbon Dioxide ($CO_2$) gas injection is a common method use in EOR and it widely used in light oil reservoir as it reduced the interfacial tension and the crude oil can flow together with the $CO_2$ to increase production. However, in light oil reservoir asphaltene is a crucial problem as it precipitates when $CO_2$ is injected. This is a serious problem as the precipitation causes reduction in permeability of reservoirs near the wellbore region and able to plug the wellbores and well tubings due to the deposition of asphaltene on the solid surfaces (Sarma, 2003; Cuiec, 1984; Kokal, 1995).

## 1.2 Problem Statement

In the process to clarify the purpose of the research was being carried out, the problem statement are divided into two sections:

### 1.2.1 Problem Identification

$CO_2$ injection causes the precipitation of asphaltene which will lead to bigger problems such as flocculation and deposition of asphaltene. These will cause the reduction in permeability of the reservoir leading to formation damaged. The presence of asphaltene also alters the wettability of the reservoir from water wet which is the ideal case into oil wet as well as plugging the wellbore and tubing causing reduction in the production.

### 1.2.2 Significant of the Project

The simulation will help to give a clearer and better view on what is happening in the reservoir as it will simulate as close as possible to condition of a real reservoir.

## 1.3 Objectives

The objectives of this research are:

i. To simulate the precipitation of asphaltene in light oil reservoir.
ii. To evaluate the importance of preventing asphaltene precipitation before it occurs.

## 1.4 Scope of Study

This project focuses on the Enhanced Oil Recovery using the $CO_2$ injection to increase production in a reservoir. It also helps to understand the behavior and characteristics of the asphaltene as till now it still remains a mystery due to its complex nature. Lastly on how the gas injection method used affects the rate of precipitation of asphaltene.

## 1.5 The Relevancy of the Project

Asphaltene removal techniques such as mechanical methods, chemical methods, pressure, temperature and flow rate manipulations and resinous additives has disadvantages such as time consuming, expensive, safety considerations, limited application and sometimes unsuccessful. Thus, it is good to do more research by simulating the real conditions of the reservoir to give us better understanding in how to prevent the asphaltene precipitation from happening.

## 1.6 Feasibility of the Project within the Scope and Time frame

The project is divided into two sections which are known as the FYP I and FYP II. Currently, the author has completed the course FYP I. During FYP I, the author researched more on the topic by reading journals, SPE paper, technical papers, books and also online reading. Then the author will focus on the simulation program on how to operate it by spending time to be familiar with the interface. The author will also ply round with the software to be able to master it for the next phase of FYP II. The second section which is FYP II will be more on simulation (Computer Modelling Group, CMG) of the real condition of a reservoir with data to see more clearly on how asphaltene precipitation takes place. The author will use three different parts which is known as the Builder to stimulate the reservoir modeling of a conventional reservoir. Then the author is using WinProp to stimulate the fluid properties in the reservoir (data obtain from supervisor) and lastly, the author is going to use GEM to stimulate the EOR recovery method which is $CO_2$ injection. According to the scope of work the author is going to accomplish, the time frame is within FYP I and FYP II, thus making it feasible. The CMG software will be provided by UTP making the project cost really low and feasible.

# CHAPTER 2

# LITERATURE REVIEW

## 2.1 Enhanced Oil Recovery (EOR)

Oil recoveries are divided into three types which is the primary, secondary and tertiary oil recovery which is also known as the EOR. Primary recovery according to the Schlumberger Oilfield Glossary is defined as the first stage of hydrocarbon recovery which uses the natural reservoir energy, such as gravity drainage, water drive and gas drive as for secondary recovery is define as the second stage of hydrocarbon recovery which uses external fluid such as water or gas injected into the reservoir to maintain the pressure of the reservoir to displace the hydrocarbon. (Larry *et al*., 1992).

The tertiary recovery is the third stage of hydrocarbon recovery and uses sophisticated method. It is divided into two major categories which is the thermal (steam injection, hot water flooding and in situ combustion) and non-thermal methods (chemical flood, waterflood and gas drive). It is also oil recovery enhancement method using sophisticated techniques that alter the original properties of oil. It restores the formation pressure and also improves the displacement of the reservoir fluid. EOR increases the mobility of the displacement medium by increasing the viscosity of the either oil or water or it can be both, extract the oil with a solvent and reduce the interfacial tension between oil and water (Larry *et al*., 1992).

The first and secondary recovery typically recovers only one third of the original oil in place and will lead to cost of production being more expensive then recovered oil causing the reservoir to be abandon which 70% of oil left behind (Larry *et al*., 1992). More and more mature fields are unable to be produce and this is where EOR comes in handy. The first two methods can recovery around 10-20% of the original oil in the reservoir and more sophisticated methods like the EOR needs to be used.

EOR is also preferable to be used as the implementation does not require drilling and completion costs as most of the existing infrastructure can be used. The design and implementation of an EOR project require a systematic integration from a multidisciplinary team (Bai, 2010).

### 2.1.1 Gas Injection ($CO_2$ Injection)

Gas injection is one of the oldest methods used in EOR and is divided into two which is the miscible and immiscible gas injection. In miscible gas injection, the gas is injected at or above minimum miscibility pressure (MMP) which causes the gas to be miscible with the oil, moving together as one. As for the immiscible gas injection, flooding by the gas is conducted below MMP, causing one fluid as the displacing fluid and the other as the displaced fluid. This is to maintain the reservoir pressure to prevent production cut-off and to also increase the production rate (Al-Anazi, 2007). It is important to know the value of MMP if want to achieve miscibility during a flood (Mungan, 1991).

$CO_2$ injection has been the leading enhanced oil recovery technique for light and medium oils as it helps to prolong the production lives of light and medium oil fields which are nearing depletion under waterflood by 15 to 20 years. $CO_2$ is a diatomic molecule and have high solubility in both aqueous and hydrocarbon solutions. This is the contribution where $CO_2$ has a potential used as an enhanced recovery agent (Bennion, 1993). $CO_2$ injection also recovers 15-20% of the original oil in place. Though $CO_2$ injection is normally used in the light oil reservoir, it is also currently used in heavier oil reservoir immiscibly to displace the oil. The reason why $CO_2$ injection is popular in light oil reservoirs is because at relatively high pressure which is around 17 MPa or more, it is extremely efficient as the process of miscibility can be established with $CO_2$ as it vaporizes. For the heavier crude oil, the reservoir pressure is very low thus making $CO_2$ injection immiscible. (Bennion, 1993).

According to Stalkup, (1983) several researches have emphasized that miscible process are able to recover more oil than immiscible process. $CO_2$ injection reduces oil viscosity by swelling up the oil which causes vaporization of the oil. This will cause miscibility and reduction in the interfacial tension of the oil enabling it to flow out easily.

Experiments have been carried out which resulted in the conclusion of $CO_2$ is miscible with light oil and immiscible with heavy oil. Oil swelling is greater in light oil reservoirs. This greater efficiency of $CO_2$ flooding is due mostly to the fourfold reduction in the oil viscosity and also the effects of 35% swelling of the oil (Mungan, 1991). After approaching the miscibility state, $CO_2$ and crude oil are able to flow together. The interfacial tension between their two phases will decrease which results in a good oil recovery. Based on the survey results, the API of more than $30^{o}$ is presentable for the most active $CO_2$ floods (David & Taber and Taber, 1992).

$CO_2$ gas is an inert, non flammable gas which is non-toxic to humans and can easily be transported in a liquid form at relatively low pressures. It has higher viscosity and density than other gas injection agents thus reducing problems associated with gravity override and viscous fingering effects. This makes $CO_2$ so preferable to use compared to other gas. Though how good $CO_2$ can be there is always room for disadvantages. $CO_2$ is limited in some areas of the world. $CO_2$ also causes the asphaltene to precipitation in the light oil reservoirs as injected $CO_2$ when it is in contact with the crude oil, it can cause several changes in fluid behavior and equilibrium conditions which favor precipitation of asphaltene (Kokal and Sayegh, 1995).

## 2.2. Asphaltene Precipitation and Deposition

**Figure 1 : n-C7 Asphaltene & n-C5 Asphaltene**

*Reference : NMT Reference FAQ*

French scientist, Boussingault, (1837) started to use the term "asphaltene" because they match in the appearance with the parent asphalt in order to stand for their origin. Thus, it is understand that asphaltene is a constituent of asphalt. Even after 166 years from Boussingault's qualitative definition of asphaltene, there are no correct definitions of asphaltene in terms of chemistry. This is due to the difficulties in the determination of asphaltene actual structure (Boussingault, 1837). However, there exist many definitions of asphaltene. Nellensteyn, (1924) states that asphaltene is a fraction insoluble in low boiling point paraffin hydrocarbons, but soluble in carbon tetrachloride and benzene. Mitchell and Speight, (1973) have defined asphaltene as the part precipitated by addition of low boiling paraffin solvents such as n-heptane. Marcussan, (1945) defined asphaltene as an insoluble fraction in light gasolines and petroleum ether while it is a fraction insoluble in n-heptane but soluble in toluene (Pfeiffer, 1950; Mansoori, 1997).

The physical appearances of asphaltene are dark brown to black friable solids with no definite melting point, and they are decomposed on heating leaving a carbonaceous residue and volatile products (Sarma, 2003; Speight, 2004). The amount of asphaltene in petroleum varies with sources, depth of burial, API gravity of the crude oil, the sulphur content as well as the non-asphaltene sulphur (Koots and Speight, 1975). Though the subject of asphaltene has been studied for more than half a century, there are still disagreements among the researchers about the nature of asphaltene in crude oil. It is believe to be two models to describe the nature of asphaltene in crude oil which is the solubility mode and the colloidal model.

Solubility model is a model that describes the asphaltene to be dissolved in a true liquid state. In this model, the asphaltene precipitation is considered as a thermodynamically reversible process as the composition is not altered. It is based on the amount of saturates and aromatics that is contain in the crude oil. Asphaltene is known to be soluble in aromatics and insoluble in saturates which are normally lighter hydrocarbon. The second model is the colloidal model. Asphaltene is said to be solid particles which are suspended colloidally in the crude oil and are stabilized by large resin molecules (Ashoori *et al*., 2006).

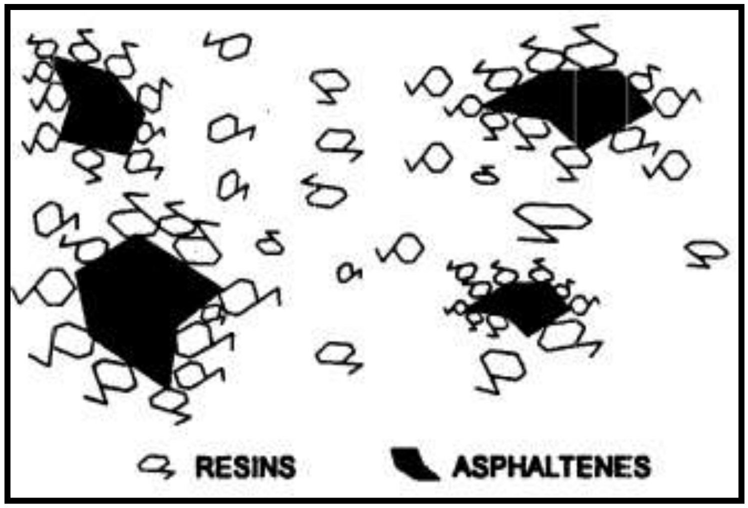


**Figure 2: Asphaltene & Resin Colloidal Model**

*Reference : Kokal & Sayegh*

When asphaltene and resins are together, they can be called as micelles (Leontaritis *et al*., 1987; Leontaritis, 1989). They are attracted to each other due to the polarity and the charges of substance. Asphaltene contain intrinsic charges where it can be positive or negative which rely on the oil composition. That is why for some reasons, highly polar resins are able to act as peptizing agent for asphaltene and act as a protective layer when adsorbed by the asphaltene(Leontaritis and Mansoori, 1987; Leontaritis, 1989). The mole percentage of resins must be larger than asphaltene. There are experimental evidence which suggested that for an oil mixture, there is a critical concentration of resins to avoid asphaltene from precipitating out of the crude oil. This is in the conditions with disregarded how much the oil mixture is agitated, heated, or pressurized, sort of changing its composition (Lichaa, 1977; Swanson, 1942).

Asphaltene precipitation is a serious problem as once the asphaltene precipitate out from the crude oil, it will flocculate and deposit. Flocculation is a process where the asphaltene which is precipitated out from the crude oil will be attracted to each other and will clump up to form bigger lump of asphaltene. Deposition happens when the clumps of asphaltene gets heavier and is unable to flow with the crude oil anymore, it will deposit down on the rock surface. Deposition can reduce permeability, causing formation damage and also altering the wettability of the reservoir from water wet to oil wet (Kokal and Sayegh, 1995).

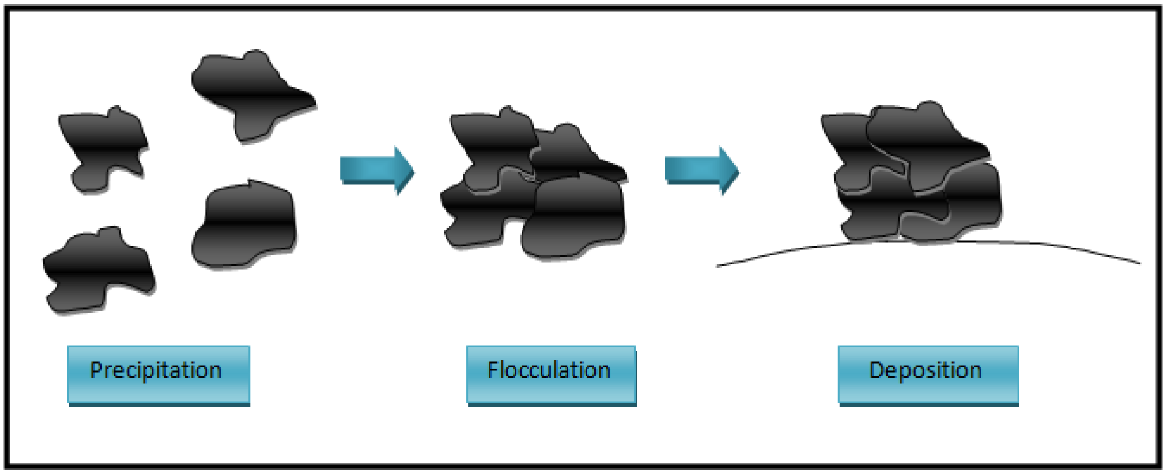


**Figure 3 : Asphaltene Precipitation Stages**

Asphaltene percentage of weight doesn't affect the precipitation in the reservoir. It depends on what kind of crude oil is in the reservoir. They are Venezuelan Boscan crude with 17 weight % asphaltene that was almost having nearly trouble free, while, Algerian Hassi Messaoud crude with 0.15 weight % asphaltene were having serious precipitation problem during production (Leontaritis and Mansoori, 1988). This is because heavy crude oil dissolves the asphaltene. This leads to the overlooked of the seriousness of asphaltene precipitation problem by the operators and as a consequence, when the precipitation problem occurs severe permeability reduction and wettability alteration in reservoir which will decrease the production (Cuiec, 1984). This shows that asphaltene precipitates in light crude reservoir rather than heavy crude reservoir because heavier crudes can dissolve more asphaltene compare to the lighter crudes.

The precipitated asphaltene can reduce porosity, permeability, alter rock wettability, affect well injectivity and productivity and cause plugging of wellbores, pipes and processing equipment (De Pedroza *et al*., 1996; Minnssieux, 1997). Asphaltene precipitation also are a mojor problem in the production and processing phase. Many cases have shown that the deposits can be formed in the reservoir, in the well tubing, can be carried through the flow lines and into the separators and other downstream equipment. The cost of remediation of this problems is expensive and significantly affect the economics of a project (Kokal and Sayegh, 1995).

The important parameters that affect asphaltene deposition is the compositional change. During production, pressure depletes causes the crude oil to lose it's lighter components. This will then reduce the asphaltene precipitation as asphaltene is soluble in the heavier crude. Thus, as the field gets older, there will be less asphaltene problems since the oil is heavier. Gas injection will also cause the asphaltene to precipitate as it alters the equilibrium of the crude oil. The greater the amount of injected solvents, the tendency of asphaltene problem is greater. Lastly, the electro-kinetic effects also causes the asphaltene precipitation problem as when the oil flow through the reservoir pores and well tubing, a streaming potential is generated. This will cause the flocculation of asphaltene. The region near the wellbore have high velocity of flow which gives higher tendency of asphaltene problem. (Lichaa, 1977; Lichaa and Harrera, 1975; Leontaritis and Mansoori, 1987; Leontaritis, 1989; Hirshberg *et al.*, 1984; Leontaritis and Mansoori, 1988; Tuttle, 1983; Hasket and Tartera, 1965).

Asphaltene precipitation is caused by changes in thermodynamic conditions of temperature, pressure and oil composition. There are also other operational factors that contributes to the precipitation and deposition of asphaltene such as high pressure drawdown, synergistic changes in conditions of temperature and pressure, mixture of fluids with varying density within the production and transportation facilities, during acidizing and the most important one, during gas injection (Sarma, 2003).

### 2.2.1 Asphaltene Precipitation during $CO_2$ Injection in Light Oil Reservoir.

It is not common that asphaltene precipitation in a light oil reservoir is overlooked by the operators. This may be due to the fact that the asphaltene content in the reservoir is very low in percentage. It might also be due to the fact that the reservoir has no pripor experience with asphatene problems in the first two stages of recovery. As a consequence, the fields will experiences several problems because the precipitation of asphaltene will cause severe permeability reduction and wettability alteration in reservoir which will decrease the production (Cuiec, 1984). The methods to treat asphaltene such s chemical cleaning and mechanical cleaning is time consuming and has a lot of safety issues.

**Figure 4 : Asphaltene Precipitation in Pipe**

*Reference : http://www.bakerhughes.com*

Injected $CO_2$ when it is in contact with the crude oil, it can cause several changes in fluid behavior and equilibrium conditions which favor precipitation of asphaltene (Kokal and Sayegh, 1995; Sarma, 2003; Srivastava *et al*., 1997). Alta'ee *et al*. (2009) reported about their study on asphaltene precipitation using light oil sample (41.5°) at constant pressure and temperature. The results were that asphaltene precipitation increases with increasing in the concentration of $CO_2$. They observed that asphaltene starts to precipitate at the concentration of 22mol% of $CO_2$ and increases slowly until 40mol% $CO_2$ and after 40mol% of $CO_2$ injection, the asphaltene precipitation starts to increase linearly. Injected $CO_2$ when it is in contact with the crude oil, it can cause several changes in fluid behavior and equilibrium conditions which favor precipitation of asphaltene (Kokal and Sayegh, 1995; Sarma, 2003; Srivastava *et al*., 1997).

For injected $CO_2$ and crude oil mix in any ratio to be in contact for the first time is said to be the first contact miscible. However, the first contact miscibility only can be achieved by highly hydrocarbon rich gases, or at very high pressure for lean system. $CO_2$ can develop miscibility through multiple contacts under specific conditions of pressure and temperature and specific oil compositions (Jai Ying *et al*., 2006). Parra-Ramirez *et al*. (2001), conducted an experimental study on the effect of first and multiple contact for

34° API crude oil from Rangely field, Colorado. The crude contained about 1.5wt% asphaltene. It was determined that first contact precipitation at different $CO_2$ concentration does not exist. Multiple contact experiments showed that multiple contact precipitation amounts were 3-5 times the first contact precipitation values (Parra-Ramirez *et al,* 2001). The existance of miscibility between $CO_2$ and crude oil reduces the interfacial tension and the capillary pressure as well. This will give very good recovery to the production.

Many experiments have been conducted to study asphaltene precipitation. Srivastava *et al*. (1999) have investigated that based on dynamic and static tests on Weyburn crude oil for $CO_2$ injection, the concentration of $CO_2$ during injection is vary directly with the precipitation of asphaltene. The graph plotted shower linear relationship of concentration of $CO_2$ and asphaltene precepitation. At the operating conditions of 16MPa and 59-61°C, the relationship between the $CO_2$ concentration and asphaltene flocculated for Weyburn oil samples where increasing linearly. Flocculated asphaltene from oil may be suspended in oil and may be adsorbed onto pore surface and captured by pore throats. Asphaltene in soluble state will flow with oil flow in porous media (Srivastava and Huang, 1997).

Beliveau and Payne (1991) have conducted experimental work of laboratory and field data which affirmed that gradual diffusion of $CO_2$ into the oil, which was being produced at a low rate of about 100BPD had led to the precipitation of asphaltenes from the parent oil. Next, Huang (1992) observed that when asphaltene content in the oil exceeded 4.6-wt%, resulting to a lower oil recovery for higher asphaltene content (>5%), the minimum miscibility pressure (MMP) determined by slim tube test is less reliable. The sample used was based on $CO_2$ oil system in Permian Basin, West Texas. Studies has also shown that asphaltene precipitation started even within the reservoir because of changes in oil composition caused by multiple contacts of $CO_2$ and the crude oil from Rangely Field, Colorado which is having mature $CO_2$ flood. The operator of the field was only concerned about the asphaltene precipitation around the well perforations and surface facilities (Parra-Ramirez *et al.*, 2001).

Undersaturated reservoir with no presents of gas, pressure well above bubble point pressure are prone to have more asphaltene precipitation problem. This is because as the pressure slowly decreases to the bubble point pressure, the pressure of the reservoir decreases causing asphaltene to precipitate out from the crude oil. However, once the pressure hits below the bubble point, gas will start to be produce. This is a good thing as the lighter hydrocarbon will vaporize leaving behind the heavier crude. Asphaltene is more soluble in the heavier crude. Ventura oil field having a reservoir pressure above bubble point experienced heavy asphaltene precipitation in the tubing. However when the well reached bubble point, there are no more asphaltene problems occurred (Tuttle, 1983). Pressure decreasing above bubble point will reduce asphaltene solubility which increasing the precipitation problems. But the change in composition at below bubble point which cause by gas liberation will result in enhanced solubility upon pressure decrease (Hirschberg, *et al.,* 1984).

Injected $CO_2$ when it is in contact with the crude oil, causes several changes in the fluid behavior and equilibrium conditions which favor precipitation of asphaltene (Kokal and Sayegh, 1995; Sarma, 2003;Srivastava and Huang, 1997). The contact of injected $CO_2$ and formation oil may induce multiple phase coexistence. The asphaltene that precipitated are black and dark brown in colour causing it to be unable to be distinguish compared to the oil. This has cause the difficulty for the equipment to accurately determine asphaltene precipitation onset point and asphaltene precipitation quantity. Multiphase equilibrium thermodynamic model for asphaltic oil and $CO_2$ system is used to overcome the problem.

$CO_2$ injections will give a much better recovery if it was used as the tertiary recovery compared to secondary recovery. Water would be a much better recovery in the secondary recovery because water is better in displacing fluid. As stated, $CO_2$ injections will give a much better recovery as tertiary recovery is due to the fact that $CO_2$ is soluble in both water and crude oil (Okwen, 2006).

## 2.3 Summary

Asphaltene is complex in nature causing it to be very difficult to be analyzed. The assumption and conclusion to understand asphaltene better is given by so many researchers till today. The complex nature also cause a lot of operators to neglect the problem that might exist from a wellbore with little concentrations of asphaltene. Unfortunately, the precipitation and deposition of asphaltene is a major problem. It causes formation damage such as porosity and permeability reduction as well as alteration of wettability. In the surface, asphaltene will cause plugging of the surface equipments. Since EOR methods are very popular to be used to the successful rate in the light oil reservoir, asphaltene precipitation problem will definitely occur. It is always wise to anticipate asphaltene precipitation problem before it occurs as the cleaning methods such as chemical cleaning and mechanical cleaning are very time consuming and expensive. To anticipate the problem, simulation can be run to stimulate the production and anticipate the outcome in order for the operator to be ready with solutions to be implemented before the precipitation of asphaltene occurs.

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# CHAPTER 3

# METHODOLOGY / PROJECT WORK

## 3.1 Research Methodology

This section consists of project analysis which involves data and information gathering, experimental analysis and findings and lastly simulation work. Plenty of research is conducted to gain a good understanding on the subject such as EOR techniques which focuses on the $CO_2$ injection method. The author also focuses on what asphaltene is and the precipitation that is caused by $CO_2$ injection. The author also does a lot of reading on the effects of asphaltene precipitation, flocculation and deposition. Then the author read on how the injection method affects the asphaltene precipitation especially in the light oil reservoir which causes formation damage, wettability alteration and also damage of the surface equipments. Apart of the research also consist of exploring and reading the manuals for the software which the author is going to use (CMG). The author then starts to familiarize the CMG software and the interface. After that the author is going to start working on the simulation. This will be from then end of FYP I to the whole time frame for FYP II. Finally, after much understanding, questions and knowledge, the author compiles in the project's final report.

Some of the planned processes for the project are as follow:

i. Literature Review.
ii. Software exploration.

### 3.2 Project Activities

The project activities flow for FYP II is shown in Figure 5.

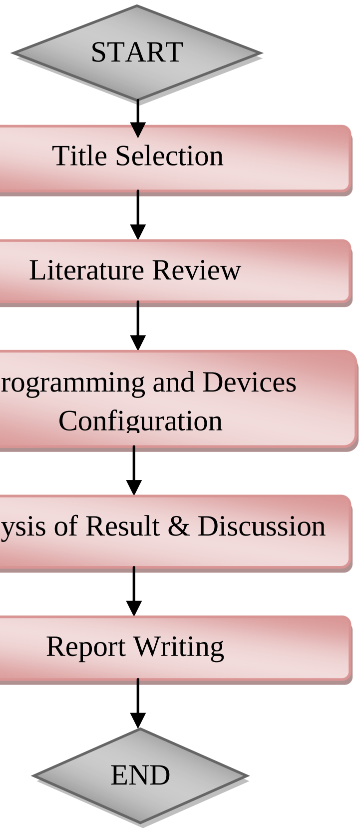



**Figure 5: Project Activities Flow Chart**

### 3.3 Software Required

**Figure 6 : CMG**

Numerical Simulator- Computer Modelling Group (CMG) which the author will be using three parts which is the builder, winprop and GEM.

i. Builder - An application used in the preparation of reservoir simulation models by designing and preparing the reservoir models. (shown in Figure 7 – example of how it would look like for understanding)

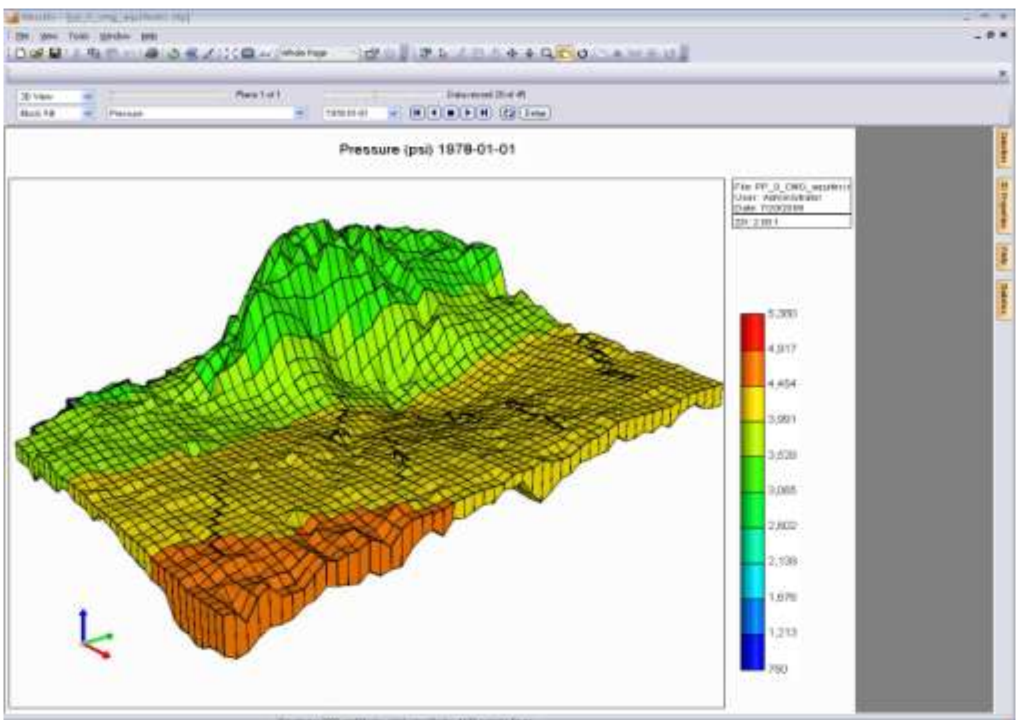



**Figure 7 : Builder – Simulate the reservoir (example)**

*Reference : CMG Builder showing a reservoir from Dr Anuj Gupta's visualization project "Visualization of Petroleum Reservoir Recovery Processes"*

ii. WinProp – Modeling of the phase behavior and properties of reservoir fluids. Can easily and accurately characterize the reservoir fluid system thorough matching of laboratory PVT experiments, miscibility studies, prediction of wax and asphaltene deposition and simulation of surface separation facilities.

iii. GEM (Generalized Equation-of-State Model Compositional Reservoir Simulator) - Simulates a variety of structurally complex and varying fluid combinations. GEM can do the modeling of $CO_2$ injection as well as asphaltene modeling.

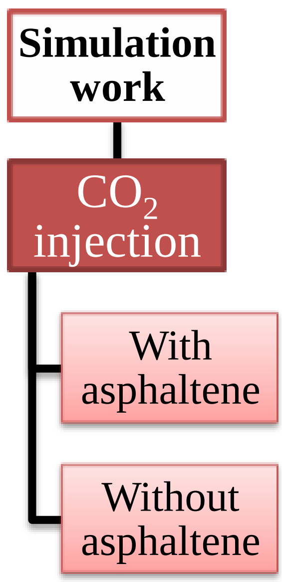



**Figure 8: Main simulations for this project**

### 3.4 Project Planning – Gantt Chart for FYP II

| No | Details/Week | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | 13 | 14 | 15 | 16 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Briefing and Update on Student Progress | | | | | | | | | | | | | | | | |
| 2 | Project work commences | | | | | | | **B** | | | | | | | | | |
| 3 | Submission of Progress Report | | | | | | | **R** | | | | | | | | | |
| 4 | PRE-EDX combined with seminar/ Poster Exhibition/ **Submission of Final Report (CD Softcopy & Softbound)** | | | | | | | **E** | | | | | | | | | |
| 5 | EDX | | | | | | | **A** | | | | | | | | | |
| 6 | Delivery of Final Report to External Examiner / Marking by External Examiner | | | | | | | **K** | | | | | | | | | |
| 7 | Final Oral Presentation | | | | | | | | | | | | | | | | |
| **8** | Submission of hardbound copies | | | | | | | | | | | | | | | | |

| | |
|---|---|
| Key Milestone | |
| Process | |

# CHAPTER 4

# RESULTS & DISCUSSION

The license used here for the author's final year project is CMG which is installed in the Academic Block 15, in the computer lab. The version of the CMG is version 2009.10. The license installed in the computer lab is an academic license and due to his, the author is limited to only a 20,000 grid blocks reservoir as this is the number of grid blocks permitted for the academic license by CMG. Due to this limitation as well, the maximum number of grid blocks the author is able to proceed with is 17,600 grids. Thus, this will make the author's reservoir a 2D reservoir instead of a 3D one.

## 4.1 Asphaltene Precipitation Model

The precipitation of asphaltene and wax phases is modelled using a multiphase flash calculation in which the fluid phases are described with an equation of state and the fugacities of components in the solid phase are predicted using the solid model described below**.** The precipitated phase is represented as an ideal mixture of solid components**.** The fugacity of a precipitating component in the solid phase is:

$$\ln f_s = \ln f_s^* + \frac{v_s}{R}\left[\frac{p - p_{tp}}{T} - \frac{p^* - p_{tp}}{T^*}\right] - \frac{\Delta H_{tp}}{R}\left[\frac{1}{T} - \frac{1}{T^*}\right] - \frac{\Delta C_p}{R}\left[\ln\left(\frac{T^*}{T}\right) - T_{tp}\left(\frac{1}{T} - \frac{1}{T^*}\right)\right]$$

where $f_s$ is the fugacity at pressure p and temperature T, $f_s^*$ is the fugacity at pressure $p^*$ and temperature $T^*$, $v_s$ is the solid phase molar volume of the component, $\Delta C_p$ is the solid-liquid heat capacity difference, $\Delta H_{tp}$ is the heat of fusion at the triple point, $p_{tp}$ and $T_{tp}$ are the triple point pressure and temperature, and R is the universal gas constant.

For isothermal predictions, this equation can be simplified to give:

$$\ln f_s = \ln f_s^* + v_s (p - p^*) / RT$$

The equation is based on the therrmodynamic equilibrium conditions which means that the process is reversible. Any precipitated solid will go back into solution when the system is returned to a state outside the asphaltene precipitation envelope.

## 4.2 Asphaltene Flocculation Model

Irreversibility of solid precipitates is modelled by allowing the thermodynamic asphaltene precipitate (solid $s_1$) to be transformed via a simple reversible chemical reaction into another solid, $s_2$. This can be viewed as the flocculation of smaller asphaltene particles into larger aggregates. The reaction may be written as follows:

$$s_1 \leftrightarrow s_2$$

The reaction rate for the formation of $s_2$ is:

$$r = k_{12} C_{s_1,o} - k_{21} C_{s_2,o}$$

where

| | | |
|---|---|---|
| $k_{12}$ | = | forward rate of formation of solid $s_2$ from $s_1$ [$day^{-1}$] |
| $k_{21}$ | = | reverse rate of formation of solid $s_1$ from $s_2$ [$day^{-1}$] |
| $r$ | = | reaction rate [$mol/(m^3\ day)$] |
| $C_{s1,o}$ | = | concentration of suspended solid $s_1$ in oil phase [$mol/m^3$] |
| $C_{s2,o}$ | = | concentration of suspended solid $s_2$ in oil phase [$mol/m^3$] |

If $k_{21}$ is zero, the reaction is irreversible and $s_2$ will not go back into solution. If $k_{21} << k_{12}$, the precipitation of $s_2$ is reversible, but may take a long time to complete. The above chemical reaction allows the modelling of irreversible precipitation or a slow redissolution of the precipitated asphaltene.

## 4.3 Asphaltene Depositon Model

An equation relating asphaltene deposition rate to the primary physical deposition processes was presented by Wang and Civan (2001). In the implementation of the deposition model, only the flocculated particles (solid $s_2$) are considered to deposit. Physically, this implies that the small asphaltene precipitate particles are more likely to flow with the oil phase, while the larger aggregates which are formed according to the irreversible asphaltene rate equation are more likely to deposit on the reservoir rock. The discretized form of the deposition rate equation is:

$$\frac{V_{s_2^d}^{n+1} - V_{s_2^d}^{n}}{\Delta t} - \alpha C_{s_2^f}^{n+1} \phi^{n+1} + \beta V_{s_2^d}^{n+1} \left(v_o^n - v_{cr,o}\right) - \gamma u_o^n C_{s_2^f}^{n+1} = 0$$

where

| | | |
|---|---|---|
| $V_{s_2^d}$ | = | volume of deposited solid $s_2$ per gridblock volume |
| $C_{s_2^f}$ | = | volumetric concentration of flowing solid $s_2$ per volume of oil |
| $v_o$ | = | oil phase interstitial velocity |
| $v_{cr,o}$ | = | critical oil phase interstitial velocity |
| $u_o$ | = | oil phase Darcy velocity |
| $\alpha$ | = | surface deposition rate coefficient |
| b | = | entrainment rate coefficient |
| $\gamma$ | = | pore throat plugging rate coefficient |

The surface deposition rate coefficient $\alpha$ is a positive constant and is dependent on the rock type. The entrainment rate coefficient is set to zero when the interstitial velocity is less than the critical interstitial velocity, and may be set to a positive constant otherwise. The pore-throat plugging coefficient is set to zero if the average pore throat diameter is larger than some critical value. If it is smaller, the coefficient is calculated as:

$$\gamma = \gamma_i \left(1 + \sigma V_{s_2^d}\right)$$

| | | |
|---|---|---|
| $\gamma_i$ | = | instantaneous pore throat plugging rate coefficient |
| $\sigma$ | = | snowball-effect deposition constant |

### 4.4 Asphaltenic Oil Modeling using WinProp.

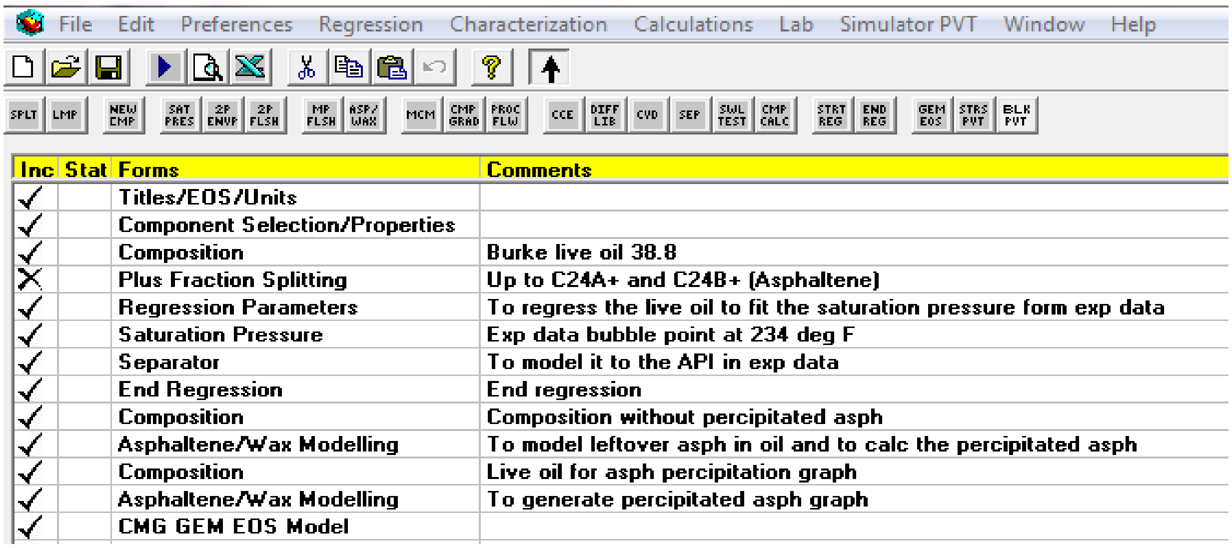
WinProp is CMG's equation of state (EOS) multiphase equilibrium and properties determination program. WinProp features techniques for characterizing the heavy end of a petroleum fluid, lumping of components, matching laboratory PVT data through regression, simulation of first and multiple contact miscibility, phase diagrams generation, asphaltene and wax precipitation modelling, compositional grading calculations as well as process flow simulation as stated in the WinProp manual for version 2009.10.

The oil sample used in the author's final year project is taken from Burke, Hobbs and Kashou, "Measurement and Modeling of Asphaltene Precipitation", Journal of Petroleum Technology, November 1990, pp. 1440-1446. The author here used the oil sample which contains the API of 38.8 (light oil). This is the main API gravity for the author's project. The components of the oil are listed as below in table 1.

| **Component** | **Burke Oil 38.8** |
|---|---|
| Nitrogen | 0.25 |
| $CO_2$ | 2.03 |
| Methane | 32.44 |
| Ethane | 15.50 |
| Propane | 6.54 |
| i-Butane | 0.81 |
| n-Butane | 3.20 |
| i-Pentane | 1.15 |
| n-Pentane | 2.13 |
| Hexanes | 2.46 |
| Hexanes plus | 33.49 |
| **Total** | **100** |
| $C_{7+}$ molecular weight | 223 |
| $C_{7+}$ specific gravity | 0.8423 |
| Live-oil molecular weight | 95.2 |
| API gravity, stock tank oil | **38.8** |
| Asphaltene content in stock tank oil, wt% | 1.7 |
| Reservoir temperature, °F | 234 |
| Saturation pressure, psia | 2492 |

**Table 1: Burke Oil 38.8 (light oil) properties**

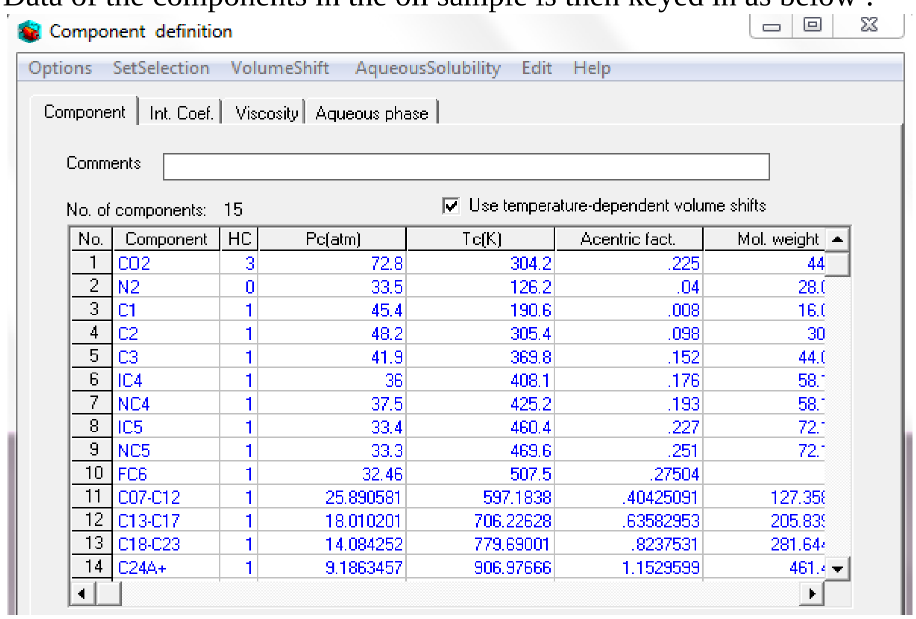
As the author's objective here is to simulate the asphaltene precipitation, it is really crucial to first characterization the asphaltene components of the solid forming components, both in solution and in the solid phase. The author did this by splitting the heaviest components into two components, a non-precipitating and a precipitating fraction. The mole fraction of the asphaltene component can be determined from the relation: $x_{Asph}\ MW_{Asph} = w_{Asph}\ MW_{Oil}$. From the output of the regression run, the molecular weight of the oil is calculated as 223. The asphaltene content of the stock tank oil is given as 1.7 wt%. From the component table, the molecular weight of the **$C_{24B+}$** component is 461.442.




| Inc | Stat | Forms | Comments |
|---|---|---|---|
| ✓ | | Titles/EOS/Units | |
| ✓ | | Component Selection/Properties | |
| ✓ | | Composition | Burke live oil 38.8 |
| ✗ | | Plus Fraction Splitting | Up to C24A+ and C24B+ (Asphaltene) |
| ✓ | | Regression Parameters | To regress the live oil to fit the saturation pressure form exp data |
| ✓ | | Saturation Pressure | Exp data bubble point at 234 deg F |
| ✓ | | Separator | To model it to the API in exp data |
| ✓ | | End Regression | End regression |
| ✓ | | Composition | Composition without percipitated asph |
| ✓ | | Asphaltene/Wax Modelling | To model leftover asph in oil and to calc the percipitated asph |
| ✓ | | Composition | Live oil for asph percipitation graph |
| ✓ | | Asphaltene/Wax Modelling | To generate percipitated asph graph |
| ✓ | | CMG GEM EOS Model | |

**Figure 9 : WinProp Data**

Data of the components in the oil sample is then keyed in as below :




| No. | Component | HC | Pc(atm) | Tc(K) | Acentric fact. | Mol. weight |
|---|---|---|---|---|---|---|
| 1 | CO2 | 3 | 72.8 | 304.2 | .225 | 44 |
| 2 | N2 | 0 | 33.5 | 126.2 | .04 | 28. |
| 3 | C1 | 1 | 45.4 | 190.6 | .008 | 16. |
| 4 | C2 | 1 | 48.2 | 305.4 | .098 | 30 |
| 5 | C3 | 1 | 41.9 | 369.8 | .152 | 44. |
| 6 | IC4 | 1 | 36 | 408.1 | .176 | 58. |
| 7 | NC4 | 1 | 37.5 | 425.2 | .193 | 58. |
| 8 | IC5 | 1 | 33.4 | 460.4 | .227 | 72. |
| 9 | NC5 | 1 | 33.3 | 469.6 | .251 | 72. |
| 10 | FC6 | 1 | 32.46 | 507.5 | .27504 | |
| 11 | C07-C12 | 1 | 25.890581 | 597.1838 | .40425091 | 127.35 |
| 12 | C13-C17 | 1 | 18.010201 | 706.22628 | .63582953 | 205.83 |
| 13 | C18-C23 | 1 | 14.084252 | 779.69001 | .8237531 | 281.64 |
| 14 | C24A+ | 1 | 9.1863457 | 906.97666 | 1.1529599 | 461. |

**Figure 10 : Components in Winprop**

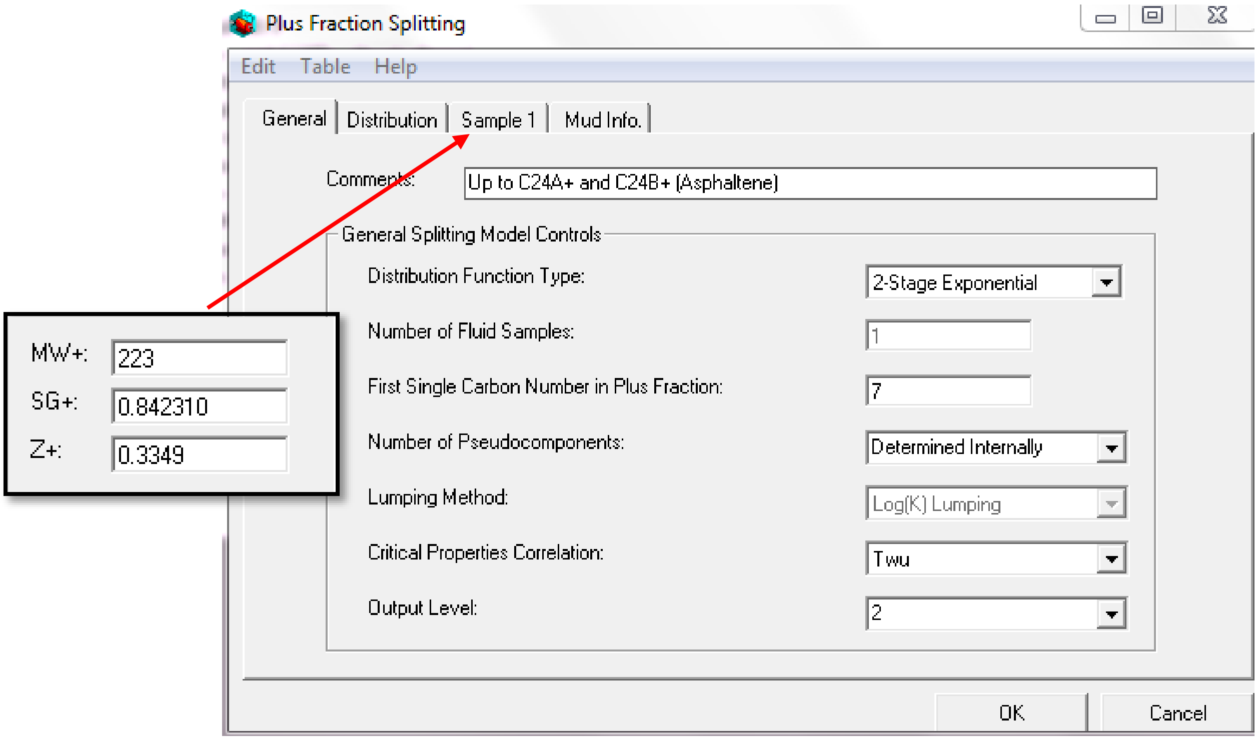



**Figure 11 : Plus Fraction Splitting**

In order to split the components into fractions to better define the asphaltene deposition, the mole fraction, specific gravity and molecular weight of the oil sample is keyed into Winprop to generate the fraction splitting as shown in Figure 10. The data is extracted from the literature review. Log(K) lumping is available when characterizing a single sample with any of the distribution functions. Gaussian quadrature lumping may be used with the gamma distribution, and is required for characterizing multiple samples. Log(K) lumping defines pseudo-components as having equal ranges of log(K). Gaussian quadrature lumping defines pseudo-components via analytical integration of the gamma distribution.

The modeled components extracted from CMG after the calculation of the splitting has been done is as shown in Table 2 :

| Burke Oil 38.3 | | |
|---|---|---|
| Component | **Mole %** | **Molecular Weight** |
| CO2 | 2.03 | 44.01 |
| N2 | 0.25 | 28.013 |
| C1 | 32.44 | 16.043 |
| C2 | 15.5 | 30.07 |
| C3 | 6.54 | 44.097 |
| i-C4 | 0.81 | 58.124 |
| n-C4 | 3.2 | 58.124 |
| i-C5 | 1.15 | 72.151 |
| n-C5 | 2.13 | 72.151 |
| FC6 | 2.46 | 86.000 |
| C7-C12 | 15.6754 | 127.35883 |
| C13-C17 | 7.28706 | 205.83943 |
| C18-C23 | 4.92755 | 281.64483 |
| C24A+ | 5.24928 | 461.442 |
| C24B+ | 0.350756 | 461.442 |

**Table 2 : Modeled fluid composition for Burke Oil 38.8**

The precipitated asphaltene is modeled as a pure solid and is described by splitting the heaviest pseudo component in the oil characterization into a non-precipitating component and a precipitating component. The non-precipitating component is the C24A+ fraction while the precipitating component is C24B+ fraction. Both the components have identical critical properties and acentric factors, but different interaction parameters with the light components in the system. The B component has much higher interaction parameters with the light components compared to the A component.

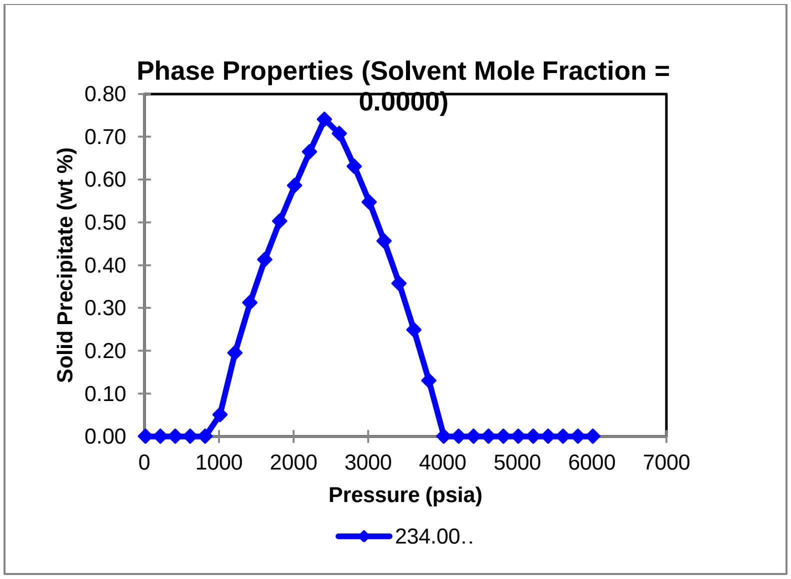



**Figure 12 : Modeled asphaltene precipitation as a function of pressure**

As seen in figure 12, the asphaltene onset pressure for Burke Oil 38.8 is 4000 psia. The maximum precipitation normally for any light oil reservoir occurs around their saturation pressure. Thus, making our result accurate as see above, the maximum asphaltene precipitation occured around 2500 psia and our saturation pressure is 2492 psia. As pressure decreases the number of asphaltene precipitation increases and as it reaches the bubble point pressure the asphaltene precipitation is maximum due to the compositional change. However as the pressure decreases after the bubble point pressure, the asphaltene precipitation decreases due to the lighter components in the oil evaporated leaving behind heavier components which then solutes the asphaltene back in to the crude oil.

### 4.5 Main Simulation using Builder and GEM

In this part, the author will discuss about her results on the simulation the author had ran. Firstly, the author built her WinProp and finalizes her results in the WinProp she then needs to built her reservoir by using another part of CMG software which is the Builder. Builder is a MS-Windows based software tool that can be use to create simulation input files (datasets) for CMG simulators. All three CMG simulators, IMEX, GEM and STARS, are supported by Builder. Builder covers all areas of data input, including creating and importing grids and grid properties, locating wells, importing well production data, importing or creating fluid models, rock-fluid properties, and initial conditions. Builder contains a number of tools for data manipulation, creating tables from correlations, and data checking. It allows the author to visualize and check your data before running a simulation. Builder can create or import the simulation grid and grid properties describing the volume of a reservoir. Builder has tools for the creation of 3D models from 2D maps of top of structure, gross thickness, and other properties. Once the grid structure has been created or imported, there are a number of grid editing operations that Builder can perform. Refined grids can be added to a grid. Builder can split grid blocks in each of the I, J, or K directions. A sub-section of a grid can be extracted from a model. Finally, grid layers may be combined, to reduce the number of vertical layers.

Additional simulation will be discussed in this chapter but it would be insignificant to the results which will be focus mainly on the $CO_2$ injection in the light oil reservoir. All the main simulation discussed here is ran on a heterogeneous formation. The results of the asphaltene deposition in the formation with and without asphaltene will be discussed and compared in this chapter. Asphaltene modelling is a tricky subject here. In WinProp, the author had modelled the asphaltene precipitation. However, WinProp does not have the ability to model asphaltene flocculation and deposition. The author would have to resort to modelling asphaltene precipitation in Builder. To do so, the author must manually keyed in specific keywords to be put in GEM to model the asphaltene. The keywords are to control the deposition of flocculated solid particles. The conversion of precipitated to flocculated asphaltene particles is controlled with the *SOLID-CONV-RATE keyword. The formats are :

| | |
|---|---|
| *SOLID_ALPHA | alpha |
| *SOLID_BETA | beta |
| *SOLID_CRITVEL | critvel |
| *SOLID_GAMMA | gamma |
| *SOLID_SIGMA | sigma |
| *RF_EXPONENT | Rfexp |

What these key words mean are discussed briefly below:

i) Alpha - Surface deposition rate constant (1/day).
ii) Beta - Entrainment rate constant (1/m|1/ft).
iii) Critvel - Critical interstitial velocity (m/day|ft/day).
iv) Gamma - Instantaneous pore throat plugging deposition rate constant (1/m|1/ft)
v) Sigma- Snowball effect deposition constant (dimensionless).
vi) Rfexp - Exponent for calculation of permeability reduction due to solid deposition (dimensionless).

Viscous fingering was simulated in two types of formation which is formation with asphaltene deposition and formation without asphaltene deposition during CO2 injection. Earlier simulations were done is less refined grid blocks but the fingering effect was unable to be observed well. Thus, the author refined her grid blocks and managed to view the effect of viscous fingering and compared the severity of asphaltene precipitation in heterogeneous reservoir. Tchelepi & Orr. Jr. (1993), presented various comparisons of viscous fingering at the same amount of pore volume injected for several cases. Same pore volume was use in this project to show the comparison between the amounts of time taken to displace the oil out from the reservoir. The comparison is done based on the oil saturation in the formation. The reasons of comparing the two different types of formation at the same pore volume of injected fluid are to show whether asphaltene deposition affects the shape and size of the fingering. The more effect is observed the more severe the fingering is and the more severe the asphaltene deposition is happening in the reservoir. The speed and effect of asphaltene will be observed and recorded.

Below is the 2D view of the reservoir built:

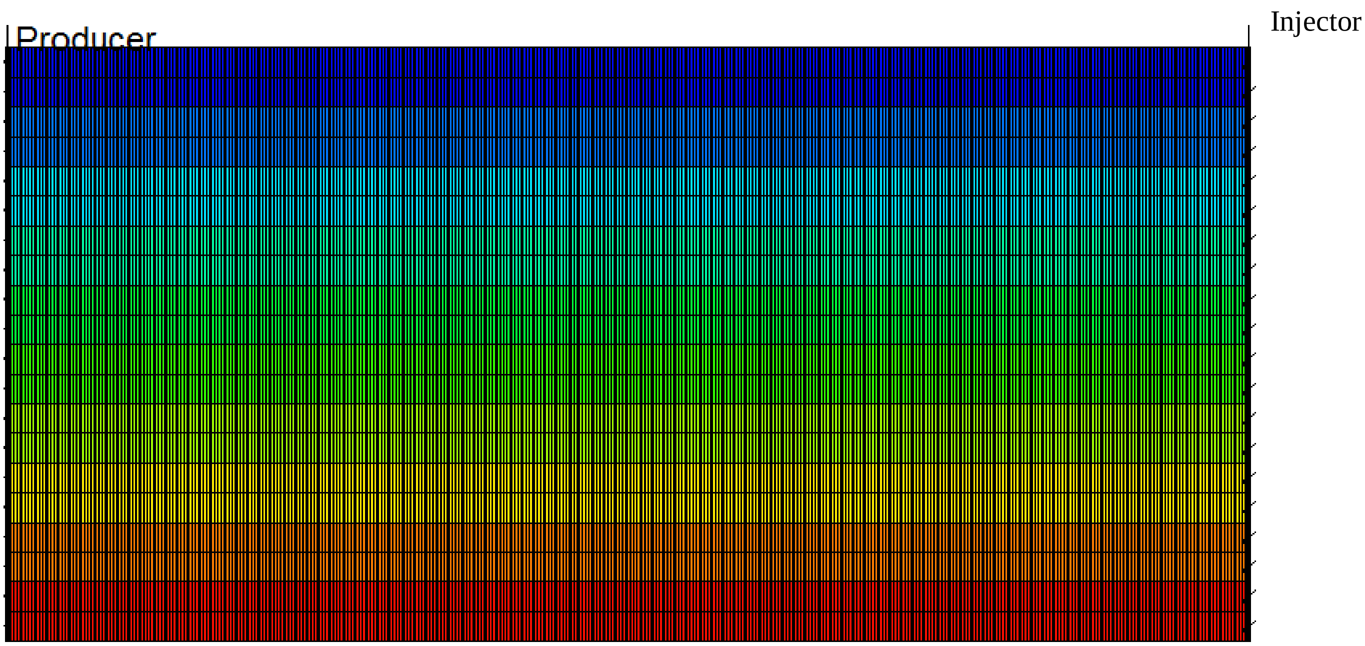



**Figure 13: 440 x 1 x 20 grid block configuration**

The injector is placed at the right end of the reservoir while the producer is placed on the left end of the reservoir. The reservoir is 440 x 10ft, 1 x 10 ft and 20 x 1 ft and has been modeled with 17,600 grid blocks. Permeability distribution of the homogeneous and heterogeneous reservoir is as placed in appendix.

In table 3 and 4 below will be listed the main reservoir properties which is keyed in.

| RESERVOIR | |
|---|---|
| **Reservoir pressure** | 3000 psia |
| **Reservoir temperature** | 234°F |
| **Porosity** | 0.20 |
| **Oil saturation** | 0.78 |
| **Connate water saturation** | 0.22 |
| **Grid block dimension (X x Y x Z)** | 440 x 1 x 20 with refinement (X=4400 ft, Y=10 ft, Z=20 ft) |
| **Initial condition** | Oil and water only present. Reservoir is undersaturated. |
| **BURKE OIL** | |
| **API gravity** | 38.8 |
| **Saturation pressure** | 2492 psia |
| **WELL** | |
| **$CO_2$ injector constraint** | Maximum bottomhole pressure = 3000 psia |
| **Producer constraint** | Minimum bottomhole pressure = 2500 psia |
| **Injector fluid** | $CO_2$ |
| **EOR process** | $CO_2$ |
| **Perforation** | 20 ft (all layers) |

**Table 3 : Main Reservoir Properties**

| | |
|---|---|
| Total bulk reservoir volume, res $ft^3$ | $8.8 \times 10^6$ |
| Total pore volume, res $ft^3$ | $1.76 \times 10^6$ |
| Total hydrocarbon pore volume, res $ft^3$ | $1.37 \times 10^6$ |
| Original oil in place, std bbl | $2.44 \times 10^5$ |

**Table 4 : Reservoir Data**

Below are the saturation diagram in the reservoir and the relative permeability curves plotted in the simulation:

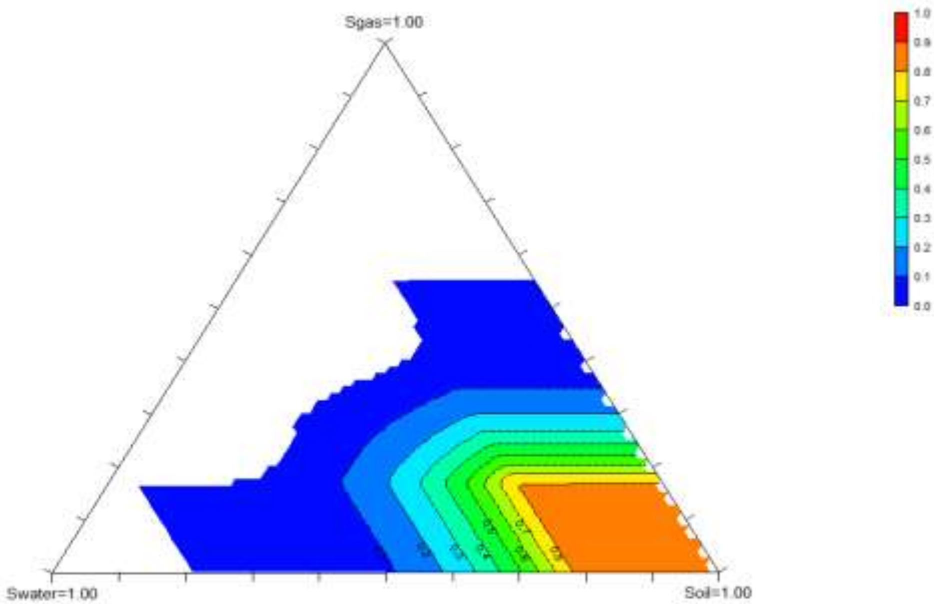



**Figure 14 : Saturation Diagram**

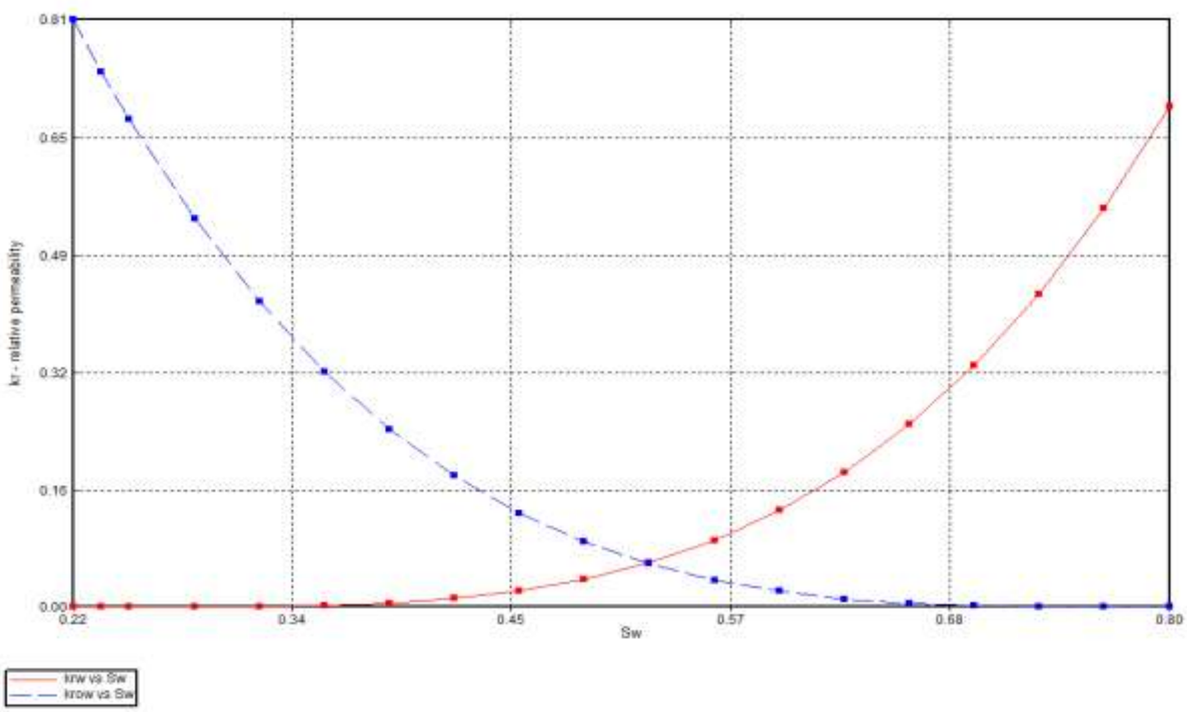



**Figure 15 : Relative Permeability Curve**

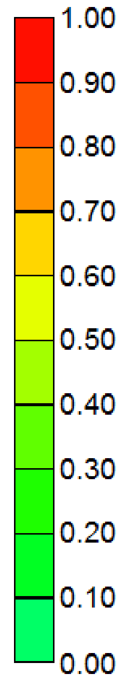



**Figure 16: Colour scale used in showing $CO_2$ distribution across formation**

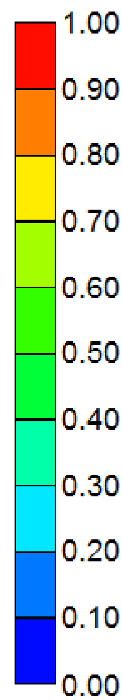



**Figure 17: Colour scale used in showing oil saturation across formation**

#### 4.5.1 Viscous Fingering Simulation during $CO_2$ Injection

Below are the results :

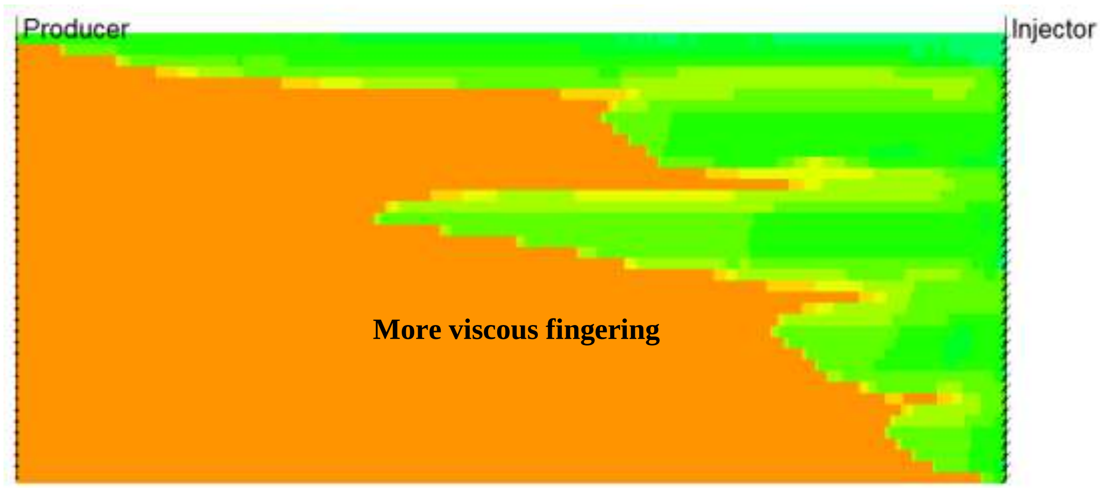



**Figure 18 : Oil saturation after 730 days (Without Asphaltene)**

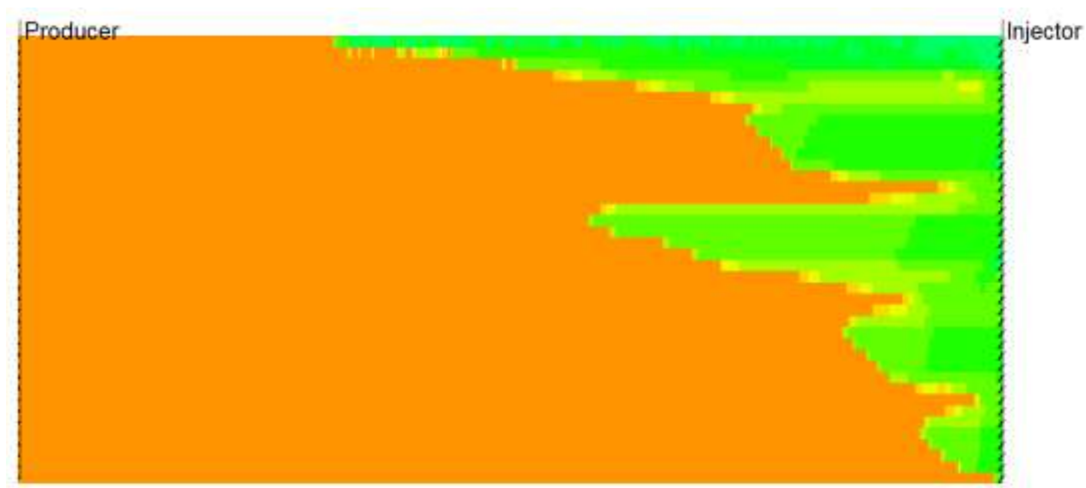



**Figure 19 : Oil saturation after 730 days (With Asphaltene)**

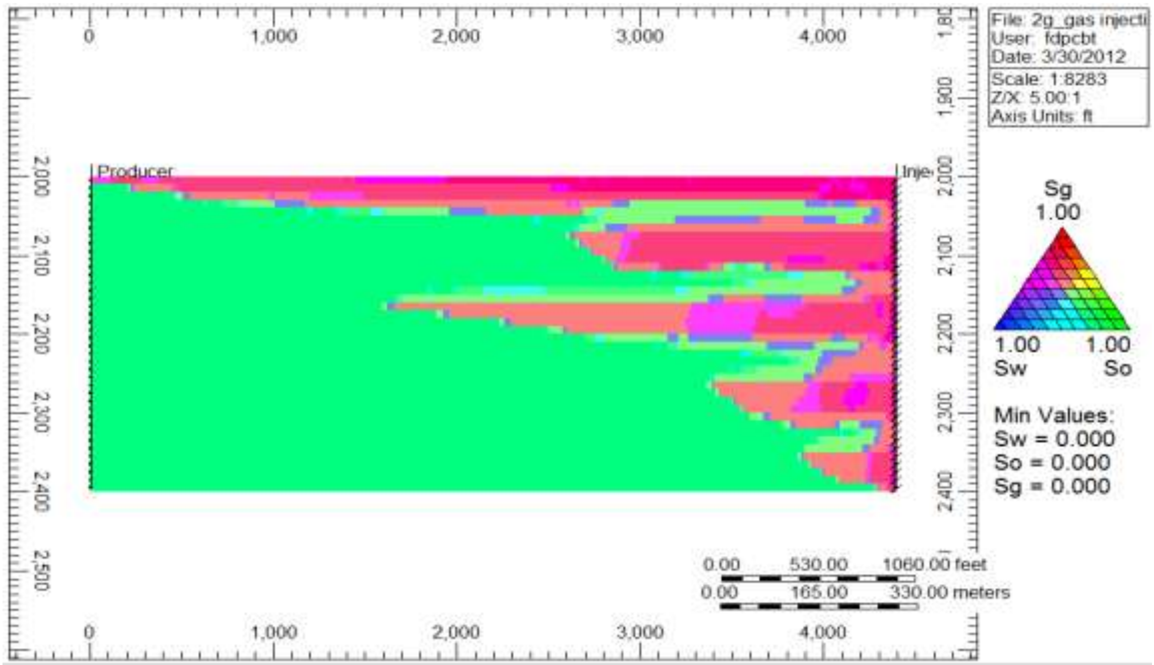



**Figure 20 : Ternary Diagram after 730 days (Without Asphaltene)**

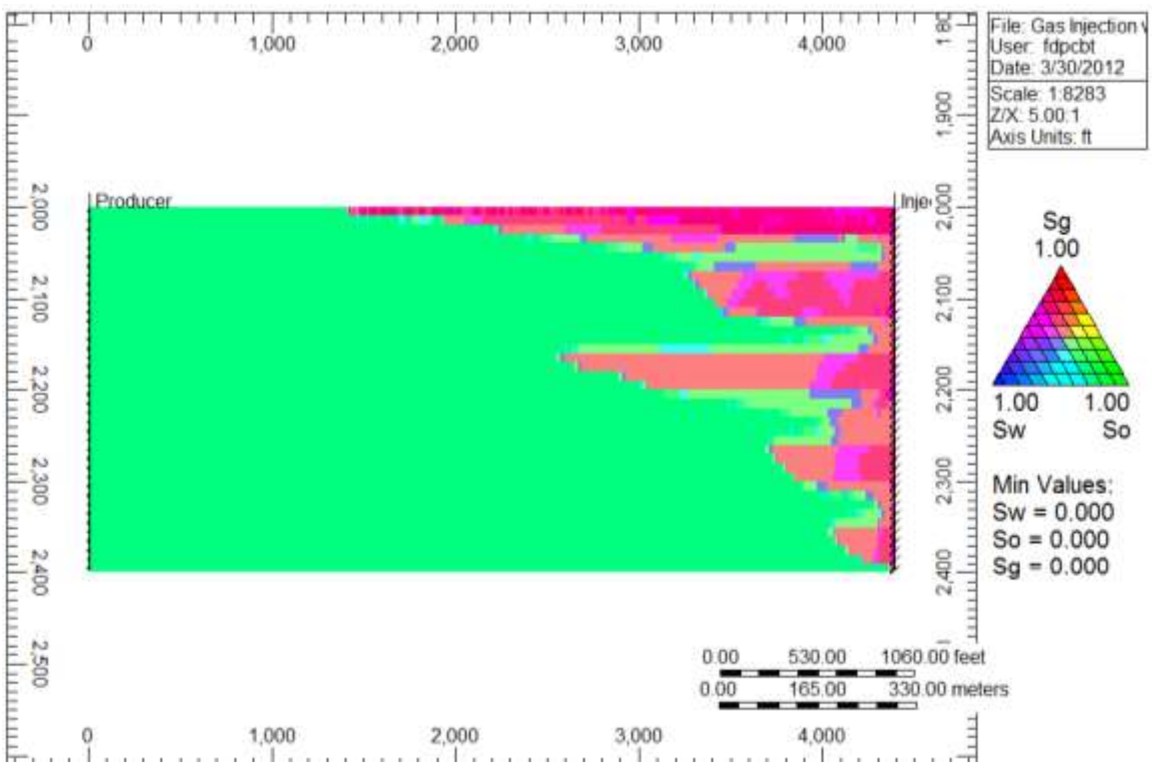



**Figure 21 : Ternary Diagram after 730 days (With Asphaltene)**

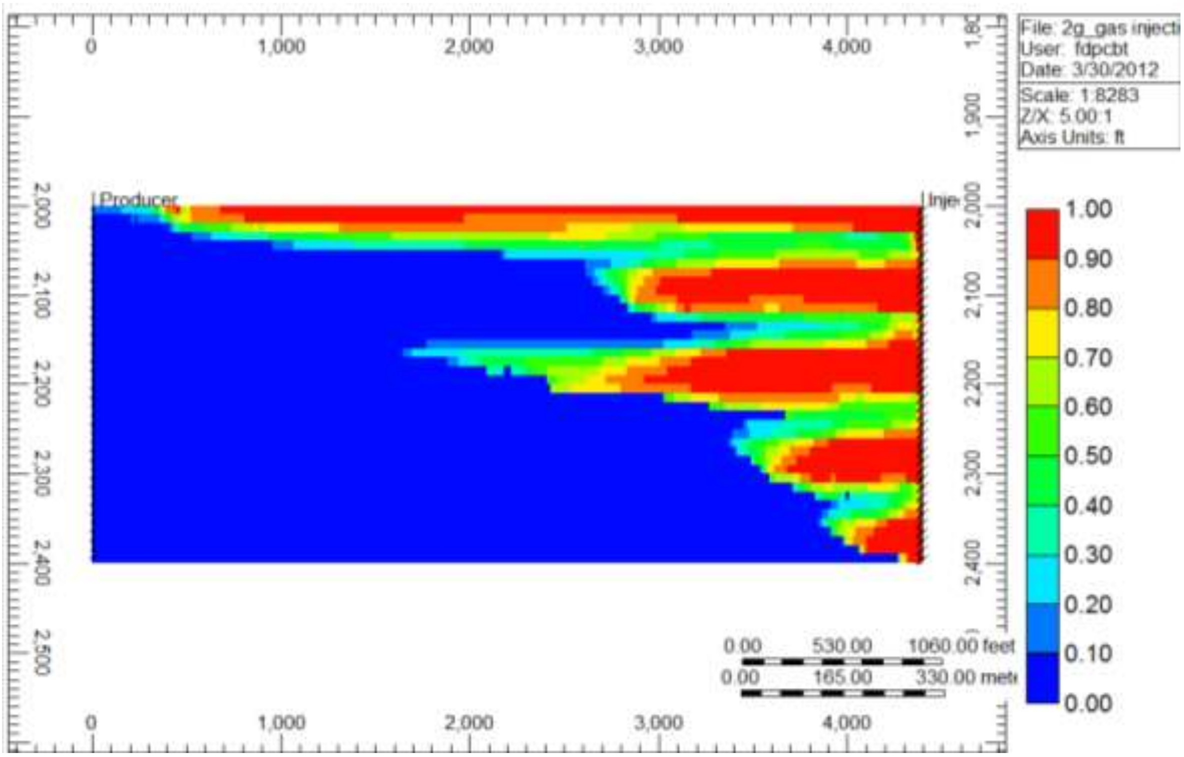



**Figure 22 : Gas Mole Fraction (CO2) after 730 days (Without Asphaltene)**

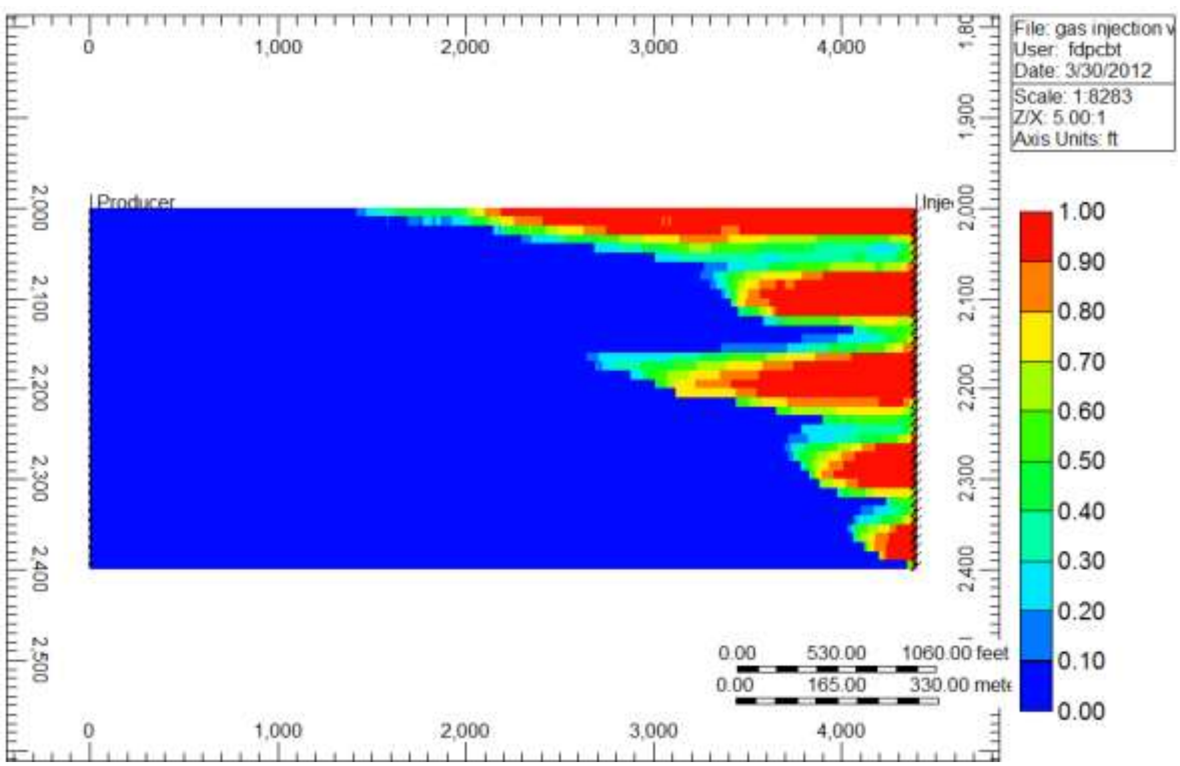



**Figure 23 : Gas Mole Fraction (CO2) after 730 days (With Asphaltene)**

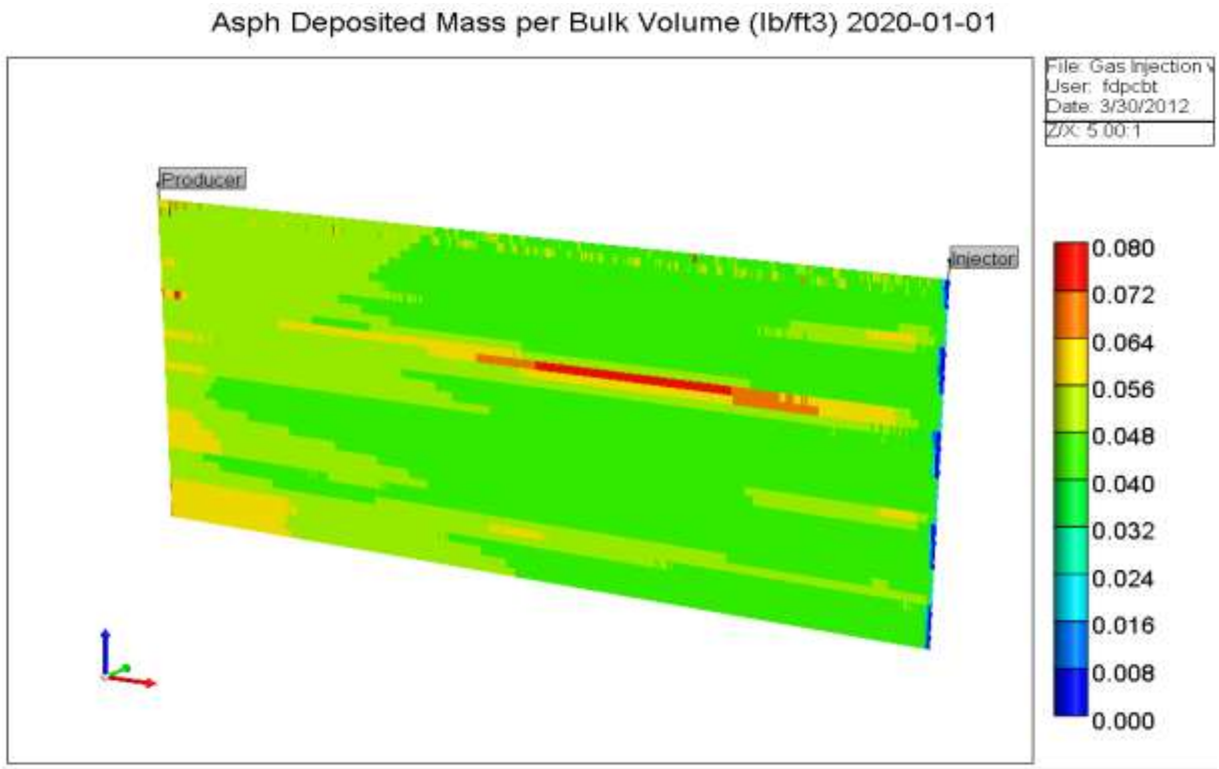



**Figure 24 : Asphaltene Deposited Mass per Bulk Volume**

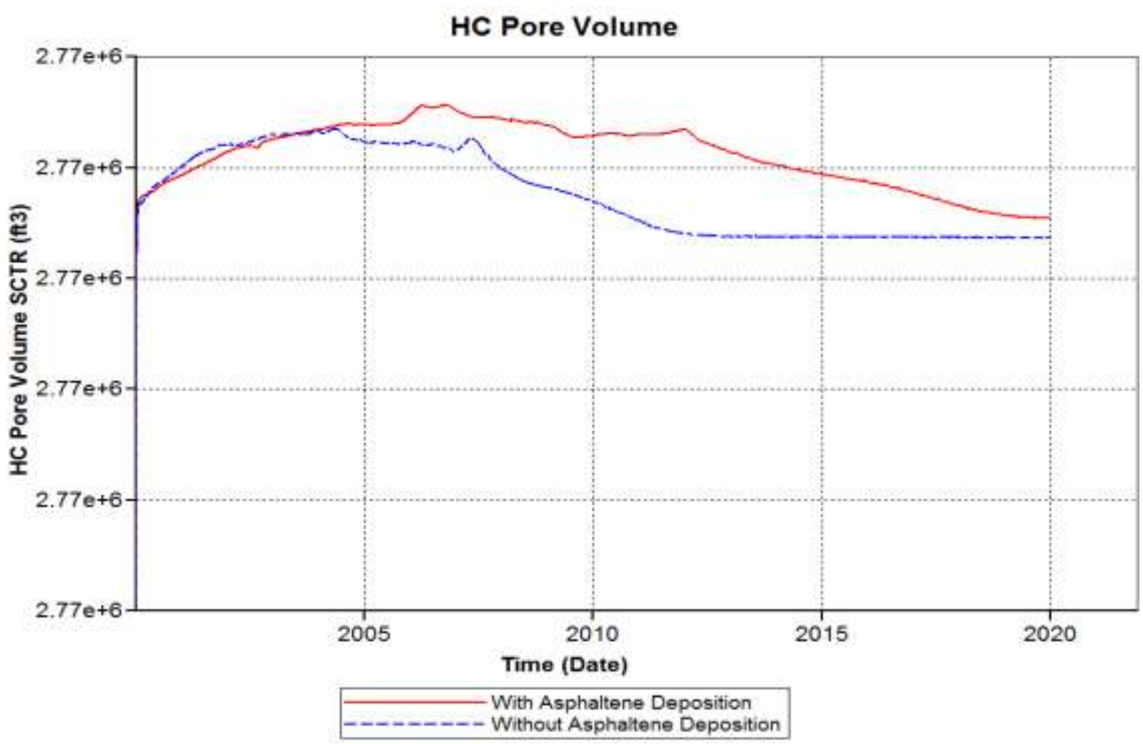



**Figure 25 : Hydrocarbon Pore Volume vs Time**

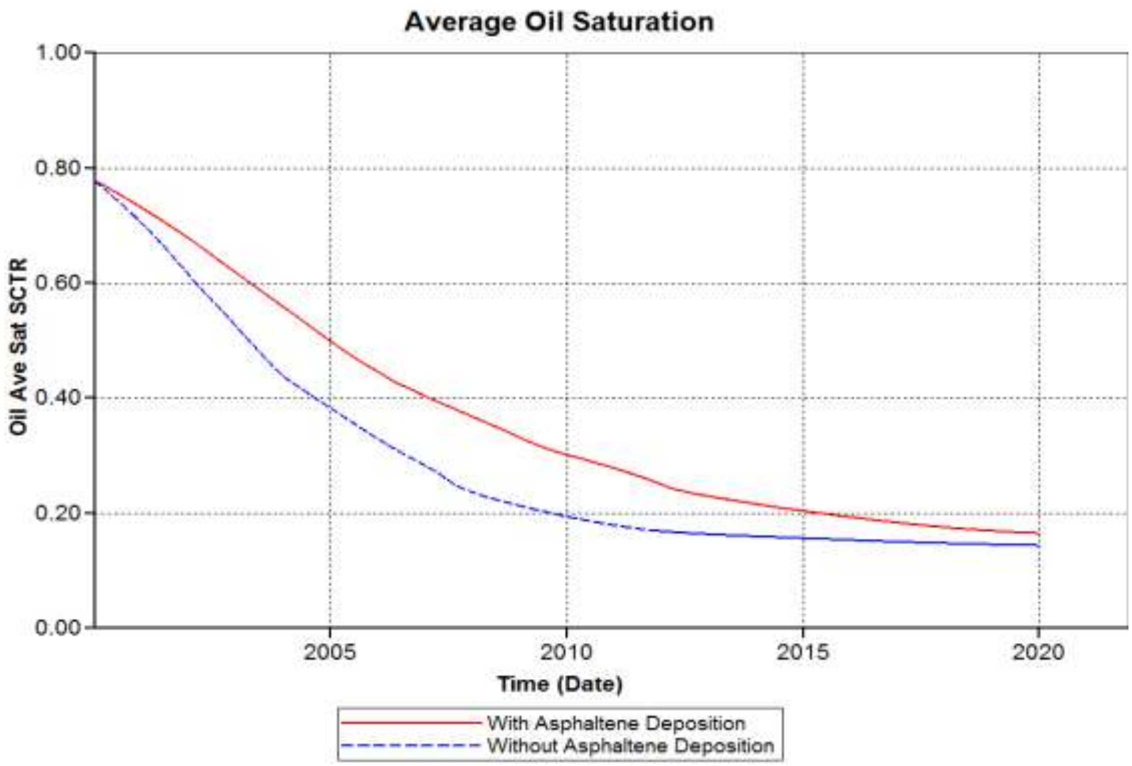



**Figure 26 : Oil Average Saturation vs Time**

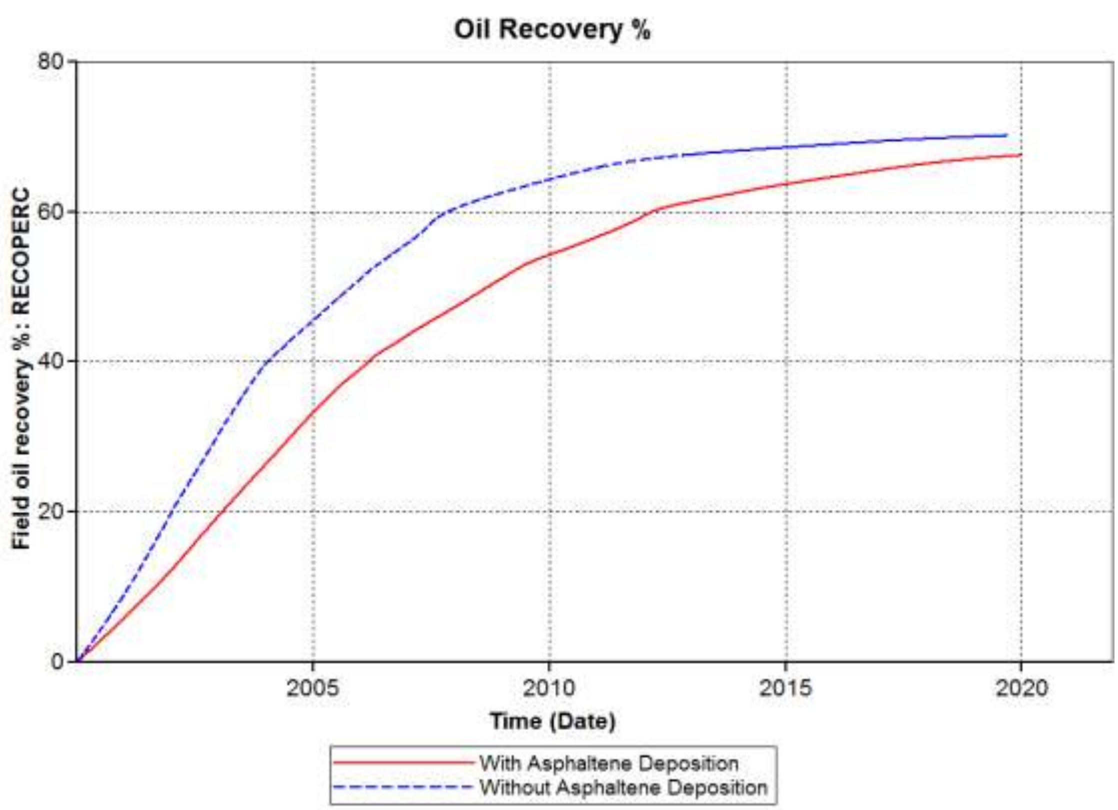



**Figure 27 : Oil Recovery % vs Time**

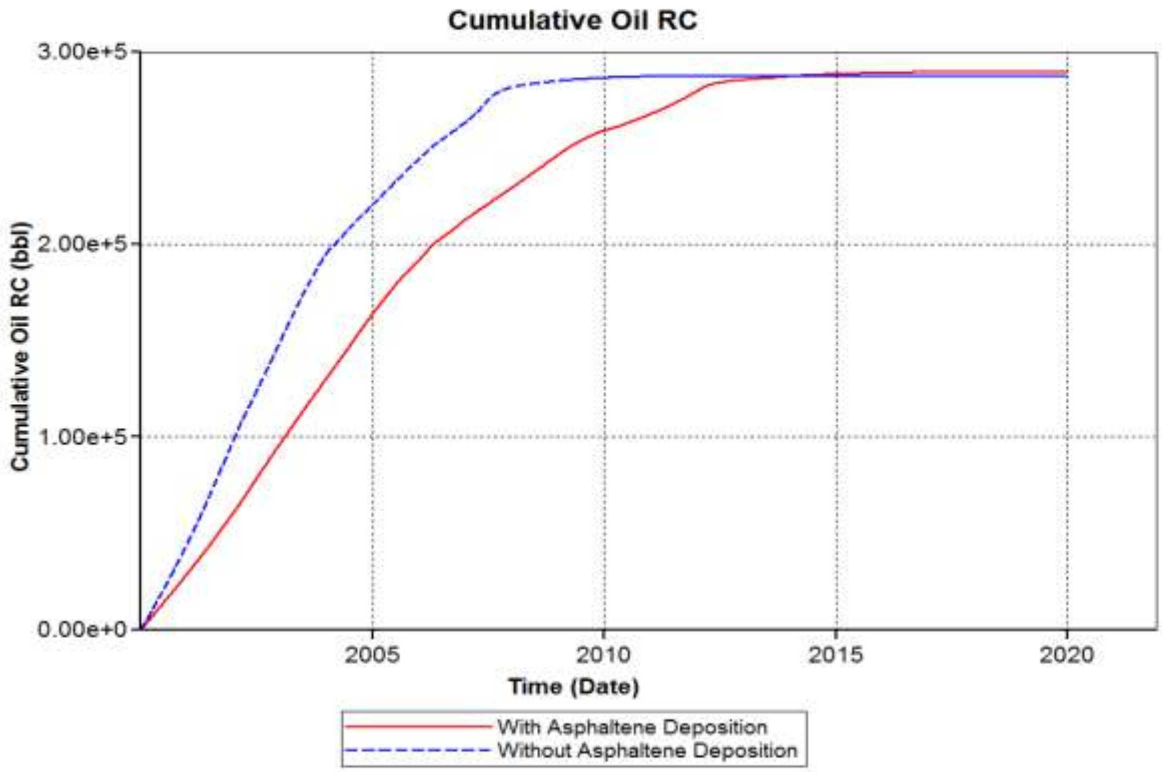



**Figure 28 : Cumulative Oil Reservoir Condition % vs Time**

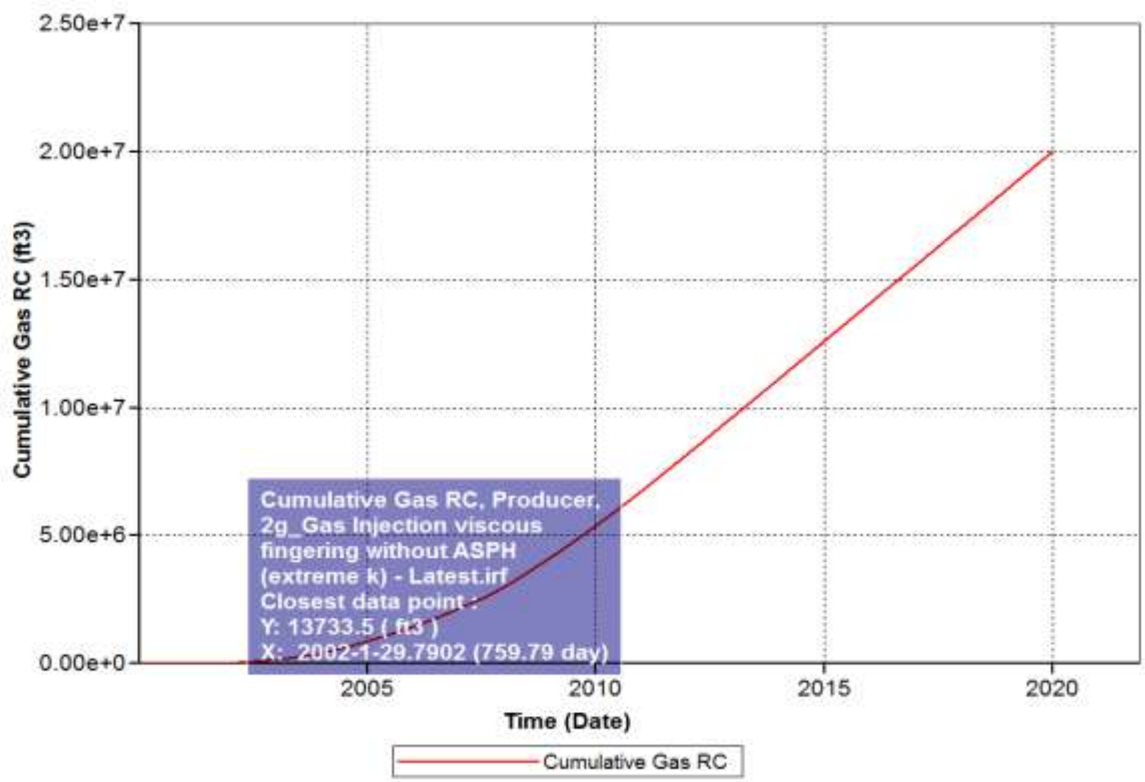



**Figure 29 : Cumulative Gas Reservoir Condition vs Time (Without Asphaltene)**

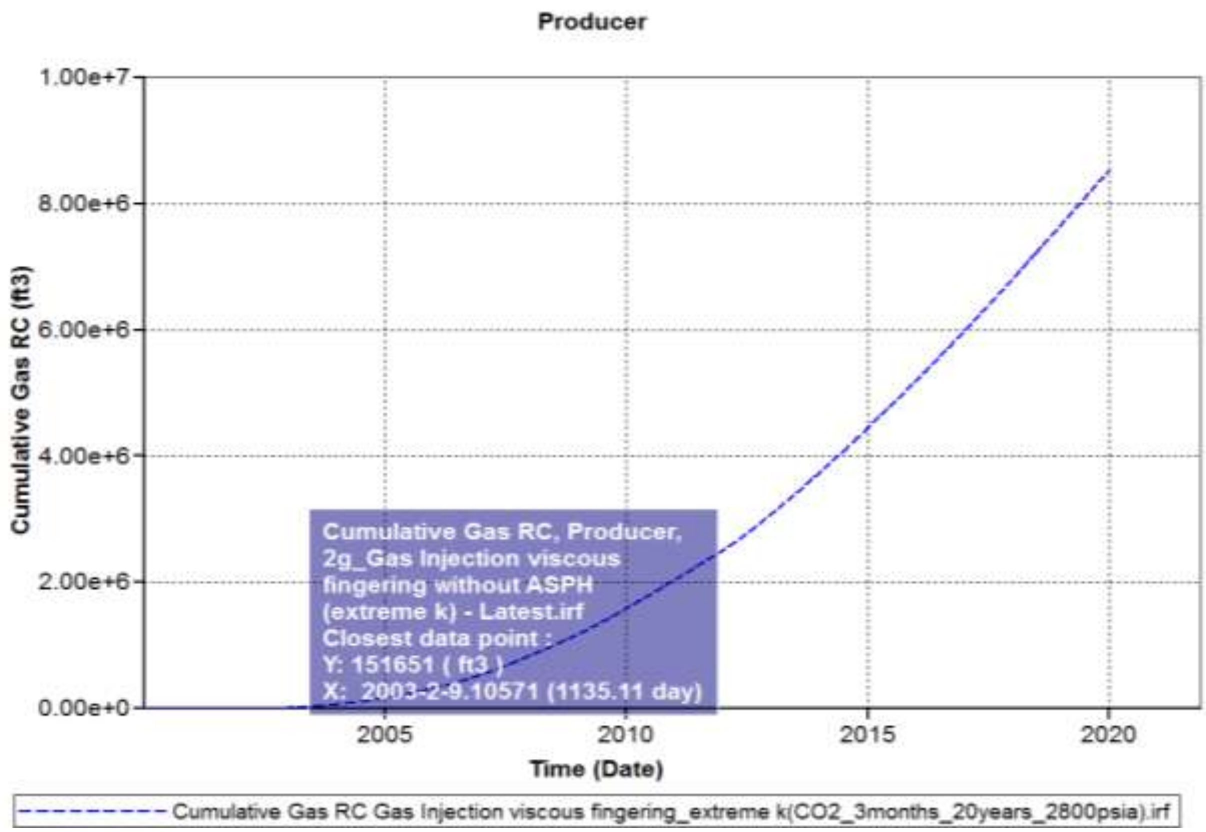



**Figure 30 : Cumulative Gas Reservoir Condition vs Time (With Asphaltene)**

A number of comparisons between the formation with asphaltene and formation without asphaltene have been shown above from Figure 18 till Figure 28. The objective of all the comparison made is to show that asphaltene precipitation caused formation damaged which are permeability reduction and porosity reduction. Based on figure 18 and figure 19, the viscous fingering effect can be clearly seen that with the presence of asphaltene deposition, the fingering is slower. The reason why the fingering is slower is because the asphaltene deposition has cause the pore throat of the reservoir to be clog and this reduces the mobility of oil to be pushed out as formation damage is present in the reservoir. This is modeled by CMG GEM with some specific key words for permeability and porosity reduction. CMG GEM uses a simple model for these phenomena based on a resistance factor. The resistance factor relates the original permeability, k0 to the instantaneous permeability, k as a function of the ratio of the original porosity to the instantaneous porosity.

Figure 20 and figure 21 shows that the saturation of gas is increasing as oil is being displaced out. This effect is cause by injection $CO_2$ into the reservoir. But the same effect of fingering is seen which is the formation without asphaltene deposition gives a much better oil displacement is observed making the result consistent. As discussed earlier in part 4.1, part 4.2 and part 4.3, based on the equation, by increasing in volume of deposited solid s2 per grid block volume, this will cause an increase in the value of resistance factor as well. The permeability reduction by adsorption of asphaltene on rock surface causes an increase in permeability resistance factor for all the flowing phases which in turn decreasing their mobilities. This explains the asphaltene deposition phenomena.

Figure 25, figure 26, figure 27 and figure 28 shows the comparison of the asphaltene deposition and without asphaltene deposition effect in different occasions. Figure 25 shows that the formation without asphaltene deposition gives us less hydrocarbon pore volume left behind in the reservoir compared to the formation with asphaltene deposition. Figure 26 shows that the oil saturation for the formation without asphaltene gives us less oil saturation left behind in the reservoir due to higher recovery of oil. Figure 27 shows that the formation without asphaltene gives higher recovery compared the formation with asphaltene. This finding is really consistent as here it all shows that the formation with asphaltene causes formation damage and this reduces the permeability and porosity in the reservoir. The gas break through for the reservoir without asphaltene in figure 29 is also faster which is 759 days than figure 30 which is 1041 days because there is no asphaltene deposition to clog the reservoir.

# CONCLUSION & RECOMMENDATIONS

## 5.1 CONCLUSION

In conclusion, $CO_2$ injection in light crude oil causes asphaltene to precipitate, flocculate and be deposited in the reservoir. This statement is proven by an experiment done by Alta'ee (2010) where his findings was that asphaltene content in the recovered oil is decreasing as the increasing of $CO_2$ injected in the pore volume of the core sample. This is due to the precipitation and deposition of apshaltene in the core sample induced by $CO_2$ injection. Alta'ee *et al* (2011) also has experimentally proven that as the injection pressure increases, the asphaltene precipitation and deposition is decreasing due to asphaltene being more soluble in crude oil at high pressure. Thus, $CO_2$ injection decreases the important properties of the reservoir such as porosity and permeability reduction. It also causes the wettability to be altered.

Asphaltene deposition slows down the effect of viscous fingering due to the asphaltene plugging the pore throat and causes permeability reduction which is also known as formation damage. Asphaltene deposition also slows down the mobility of the injected fluid in the reservoir. No viscous fingering is observed in homogeneous formation thus making the simulation results all focusing on heterogeneous formation. Thus, asphaltene deposition is an unpreferable situation in the reservoir as it causes formation damaged which induces permeability reduction and porosity reduction and in more severe cases wettability alteration.

The process will save a lot of time and money if simulation of the reservoir is done early to anticipate the damaged that will be done once the precipitation of asphaltene occurs.

## 5.2 RECOMMENDATION

Asphaltene precipitation is true enough causes a lot of problems during production of oil from the reservoir. Once the asphaltene precipitate, it causes formation damaged such as porosity reduction, permeability reduction and also wettability alteration if it is really severe. Mechanical and chemical methods can be used but due to the safety and money factor is it not preferable. Thus, it is good to be able to anticipate the problem before hand and work on the measurements to prevent it from happening.

The simulation done by the author is only a 2D simulation due to limitation of the academic license. It would be clearer to simulate in 3D as it would be able to simulate the real reservoir conditions better. It would be great to be able to get a license more than the academic one.

The author would also like to suggest that if possible to use real complete data from a field as it would give a better simulation if the data is complete as the data from literature review does not reveal most of the data needed and has to be estimated.

Lastly, the author would like to suggest if the time permits to use other software to compare the results to the asphaltene simulation. As CMG might has its own limitation to model the asphaltene model and other software such as ECLIPSE can be used to compare the results. Due to time limitation the author is only able to simulate the asphaltene precipitation using CMG and not other softwares.

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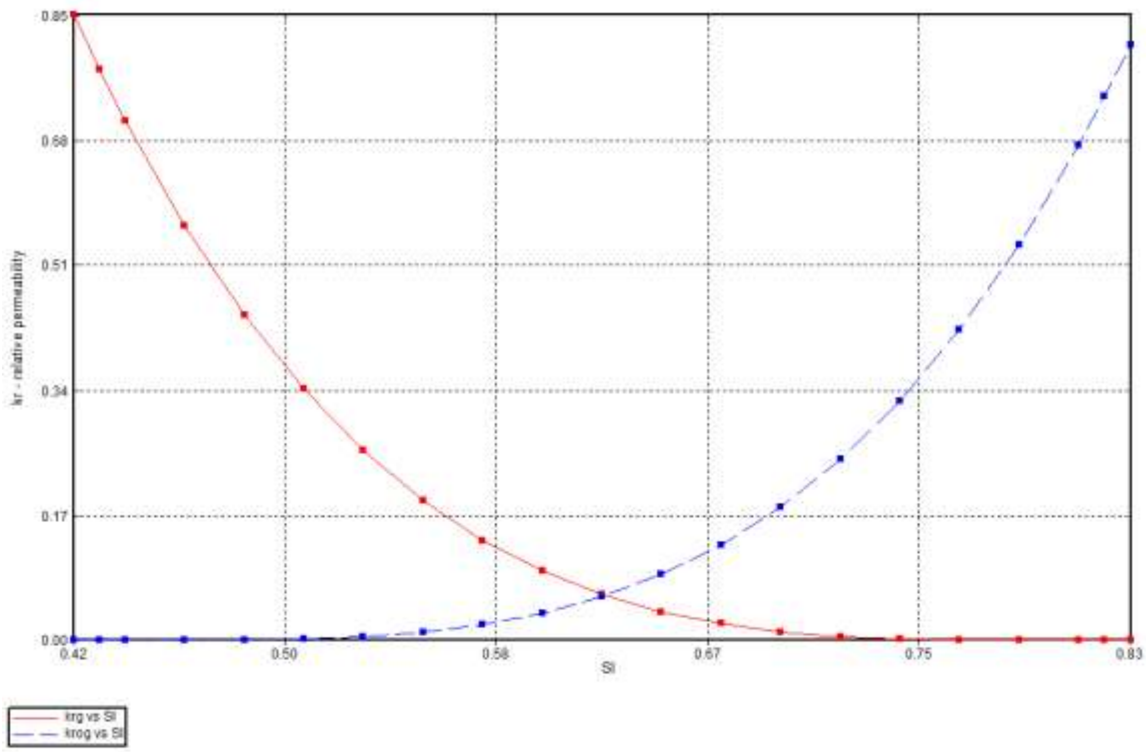
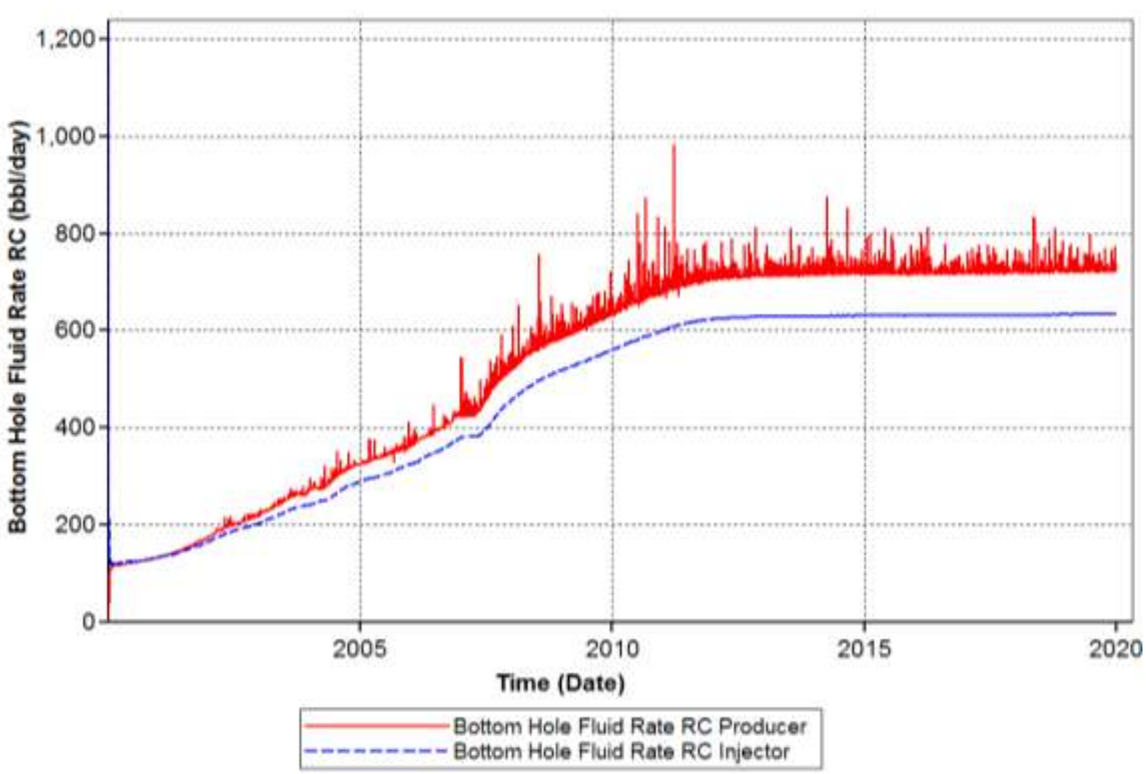
# APPENDIX

| | Permeability I | Permeability J | Permeability K |
|---|---|---|---|
| UNITS: | md | md | md |
| SPECIFIED: | X | X | X |
| HAS VALUES: | X | X | X |
| Whole Grid | | | |
| Layer 1 | 120.216 | 120.917 | 121.667 |
| Layer 2 | 121.165 | 121.805 | 122.418 |
| Layer 3 | 122.065 | 122.791 | 123.238 |
| Layer 4 | 5.8798 | 6.4487 | 5.6971 |
| Layer 5 | 5.61881 | 4.2658 | 5.47798 |
| Layer 6 | 4.1487 | 5.271 | 4.26598 |
| Layer 7 | 5.746 | 6.518 | 5.7812 |
| Layer 8 | 129.871 | 128.361 | 127.447 |
| Layer 9 | 128.606 | 127.377 | 126.701 |
| Layer 10 | 126.713 | 125.962 | 125.658 |
| Layer 11 | 124.305 | 124.205 | 124.39 |
| Layer 12 | 129.871 | 128.361 | 222.996 |
| Layer 13 | 5.045 | 4.5951 | 6.5112 |
| Layer 14 | 5.1022 | 5.6921 | 5.89812 |
| Layer 15 | 5.6981 | 6.2655 | 5.6367 |
| Layer 16 | 6.25815 | 6.2851 | 5.32638 |
| Layer 17 | 218.746 | 220.248 | 221.604 |
| Layer 18 | 216.113 | 218.417 | 220.35 |
| Layer 19 | 215.251 | 220.681 | 221.355 |
| Layer 20 | 215.558 | 216.51 | 226.151 |
| Layer 21 | 254.022 | 260.155 | 245.266 |
| Layer 22 | 5.62618 | 6.2149 | 4.2651 |
| Layer 23 | 5.21584 | 6.2154 | 5.06165 |
| Layer 24 | 6.51654 | 6.2654 | 5.26498 |
| Layer 25 | 5.15984 | 5.198 | 6.96498 |
| Layer 26 | 4.61694 | 5.32164 | 6.65468 |
| Layer 27 | 127.447 | 129.871 | 128.361 |
| Layer 28 | 126.701 | 128.606 | 127.377 |
| Layer 29 | 125.658 | 126.713 | 125.962 |
| Layer 30 | 124.39 | 124.305 | 124.205 |
| Layer 31 | 122.689 | 129.871 | 128.361 |
| Layer 32 | 5.89812 | 5.045 | 4.5951 |
| Layer 33 | 5.6367 | 5.1022 | 5.6921 |
| Layer 34 | 5.32638 | 5.6981 | 6.2655 |
| Layer 35 | 6.5112 | 6.25815 | 6.2851 |
| Layer 36 | 121.667 | 120.216 | 120.917 |
| Layer 37 | 122.418 | 121.165 | 121.805 |
| Layer 38 | 123.238 | 122.065 | 122.791 |
| Layer 39 | 121.646 | 122.546 | 150.065 |
| Layer 40 | 125.065 | 132.065 | 140.265 |

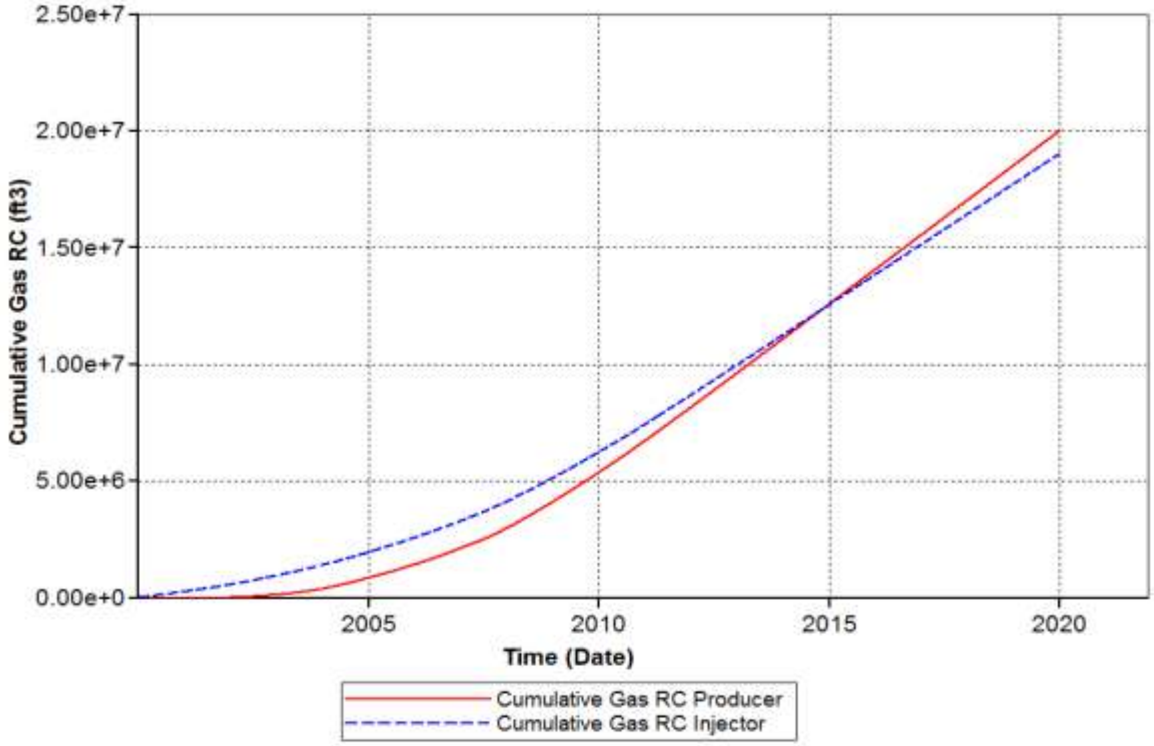
1) Permeability for Heterogeneous Formation



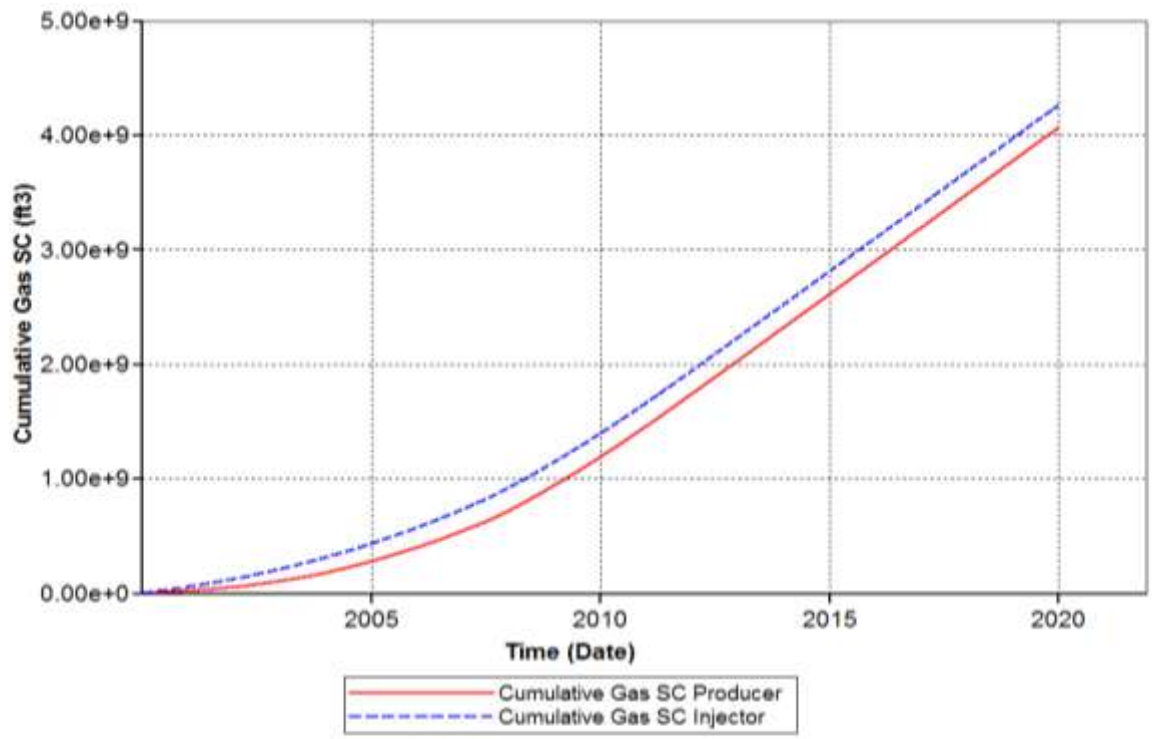

2) Relative Permeability Curve



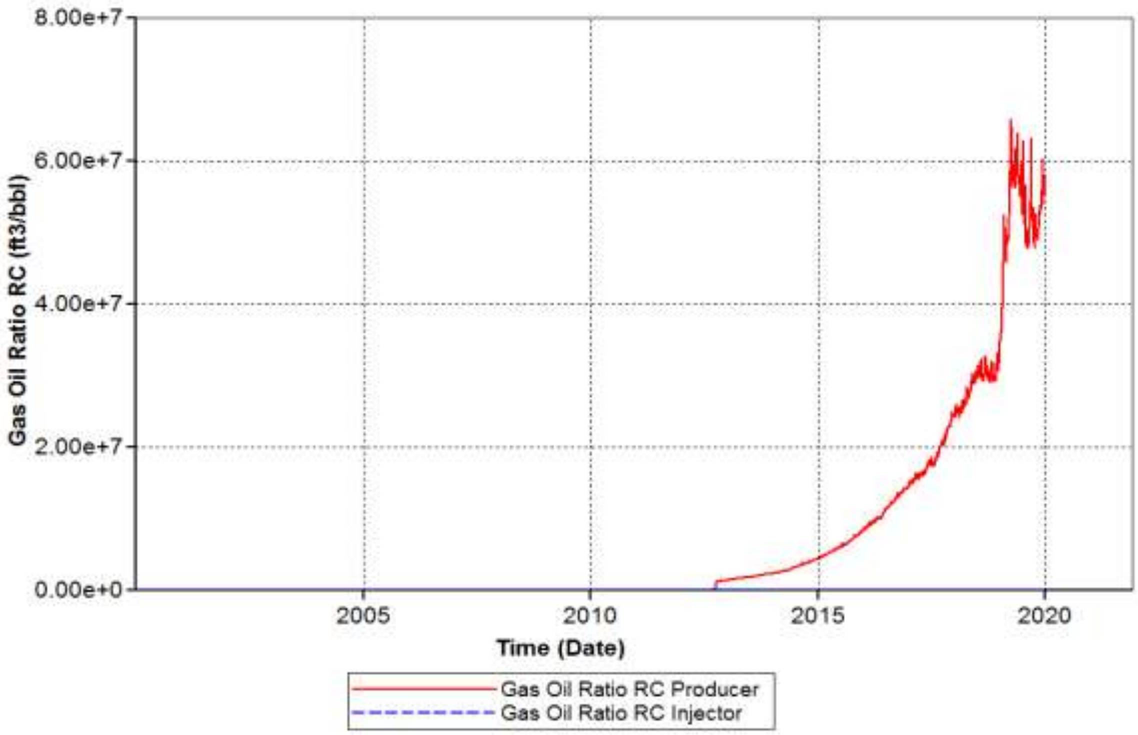

3) Bottom Hole Fluid Rate vs Time (Without Asphaltene)



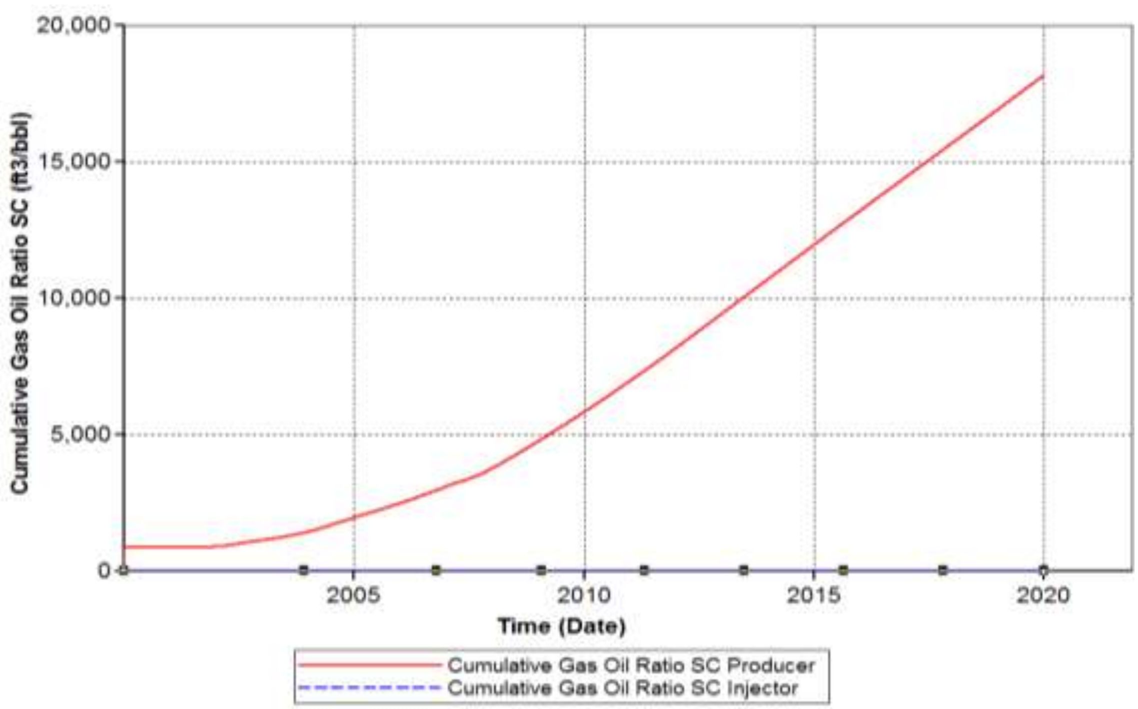

4) Cumulative Gas Reservoir Condition vs Time (Without Asphaltene)



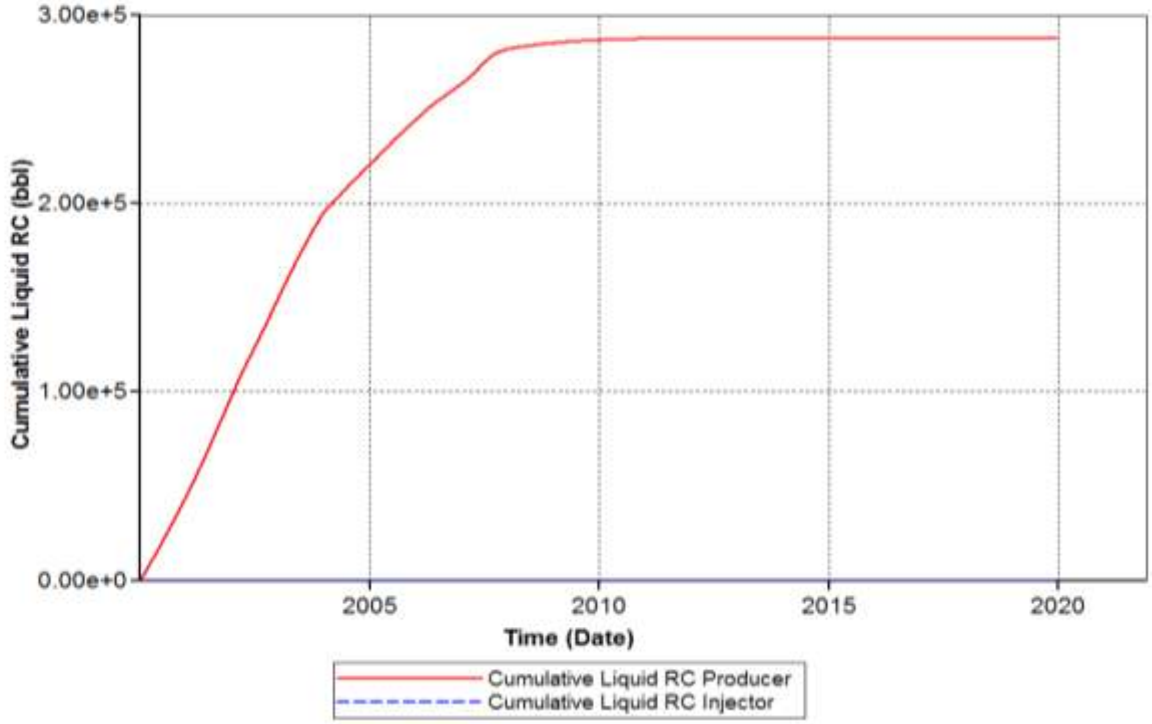

5) Cumulative Gas Standard Condition vs Time (Without Asphaltene)



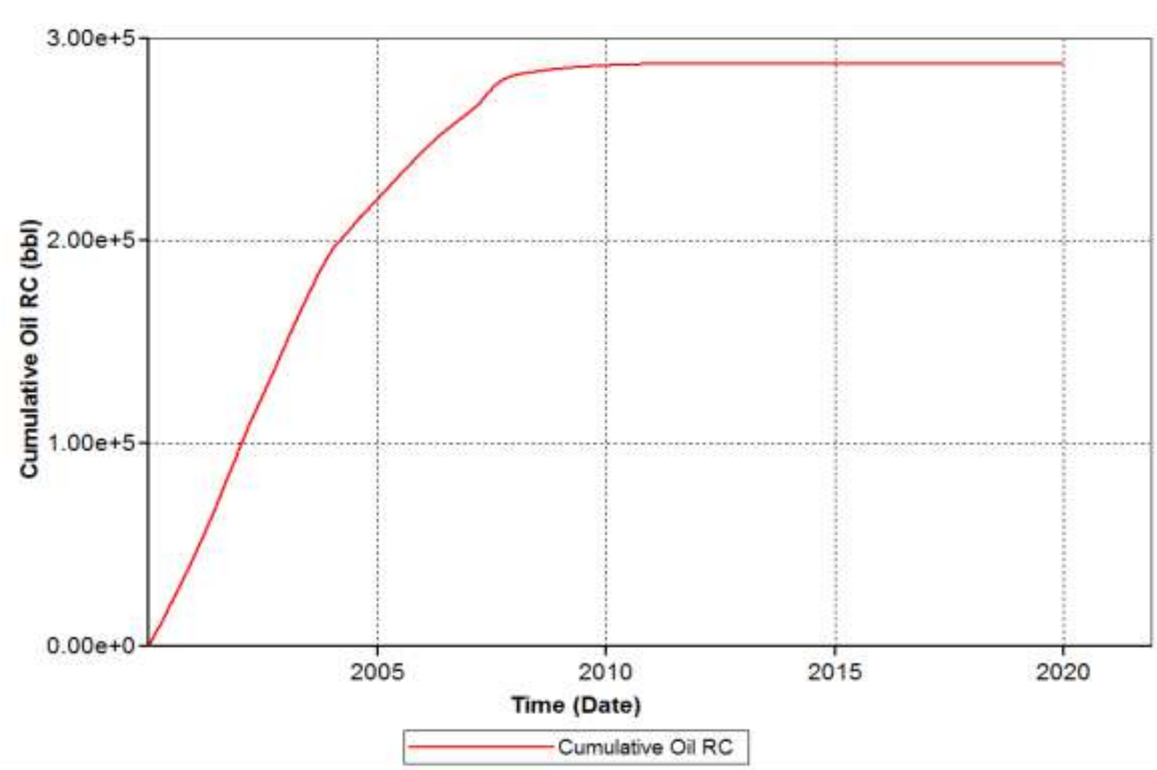

6) Cumulative Gas Oil Ratio Reservoir Condition vs Time (Without Asphaltene)



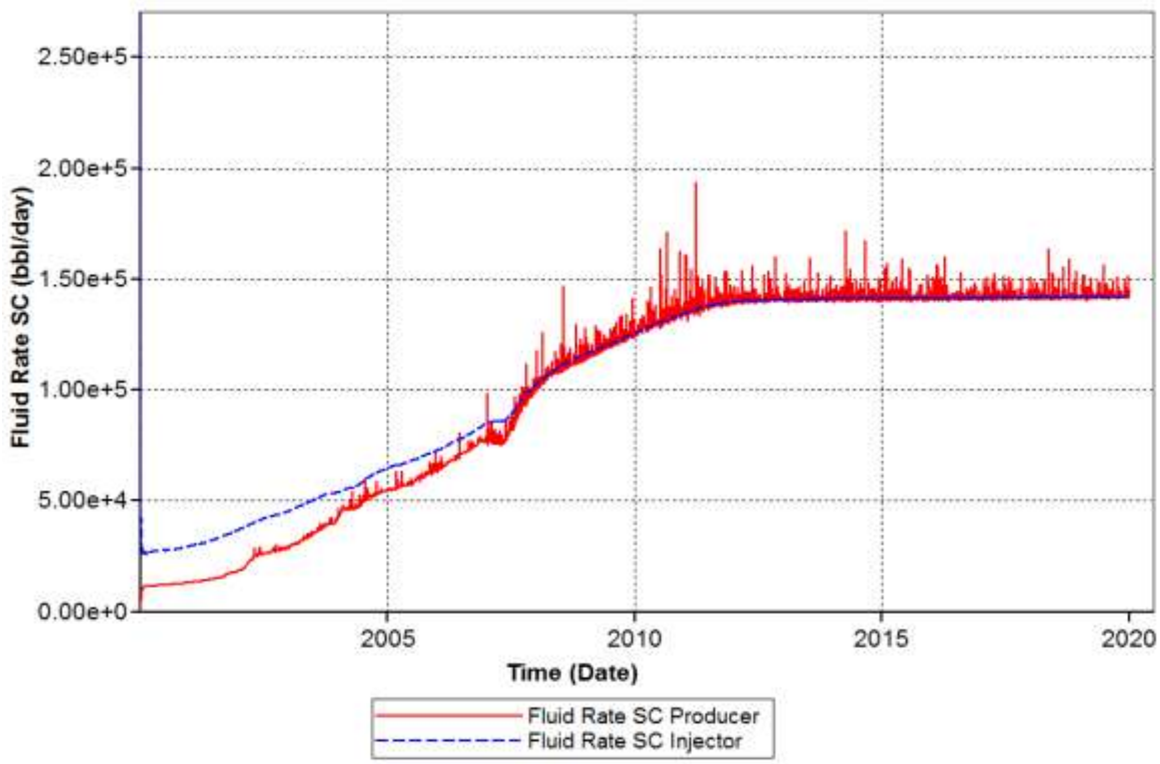

7) Cumulative Gas Oil Ratio Standard Condition vs Time (Without Asphaltene)



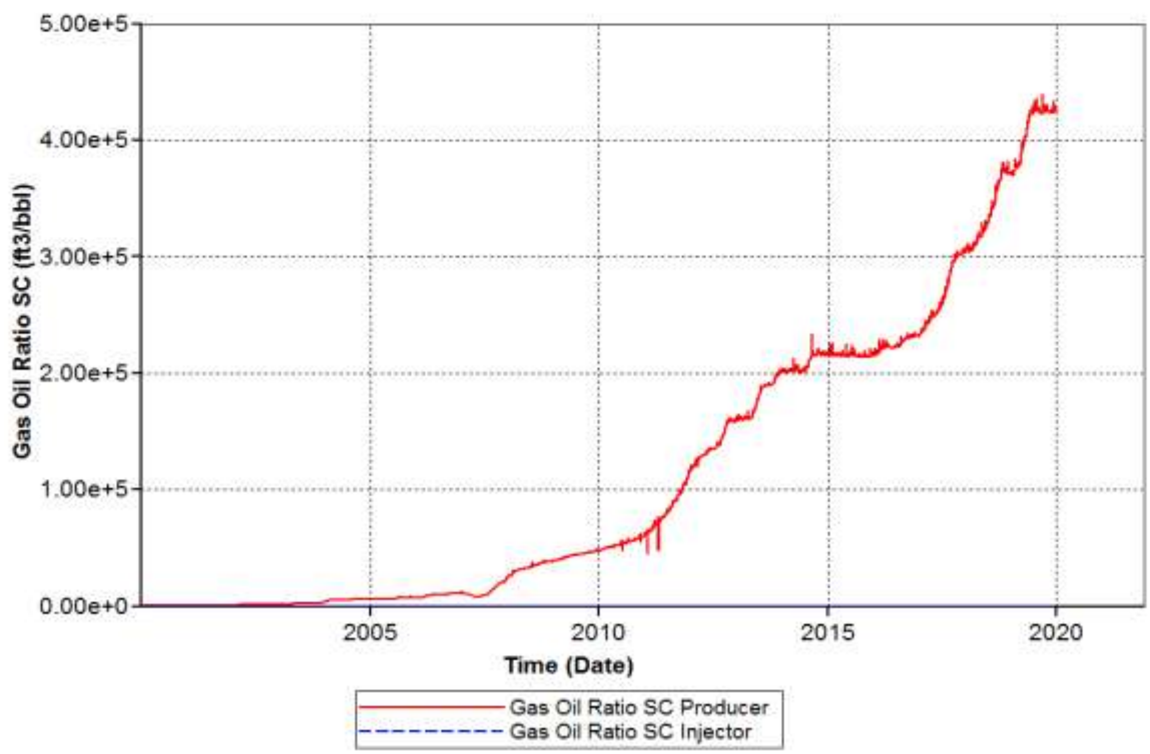

8) Cumulative Liquid Reservoir Condition vs Time (Without Asphaltene)



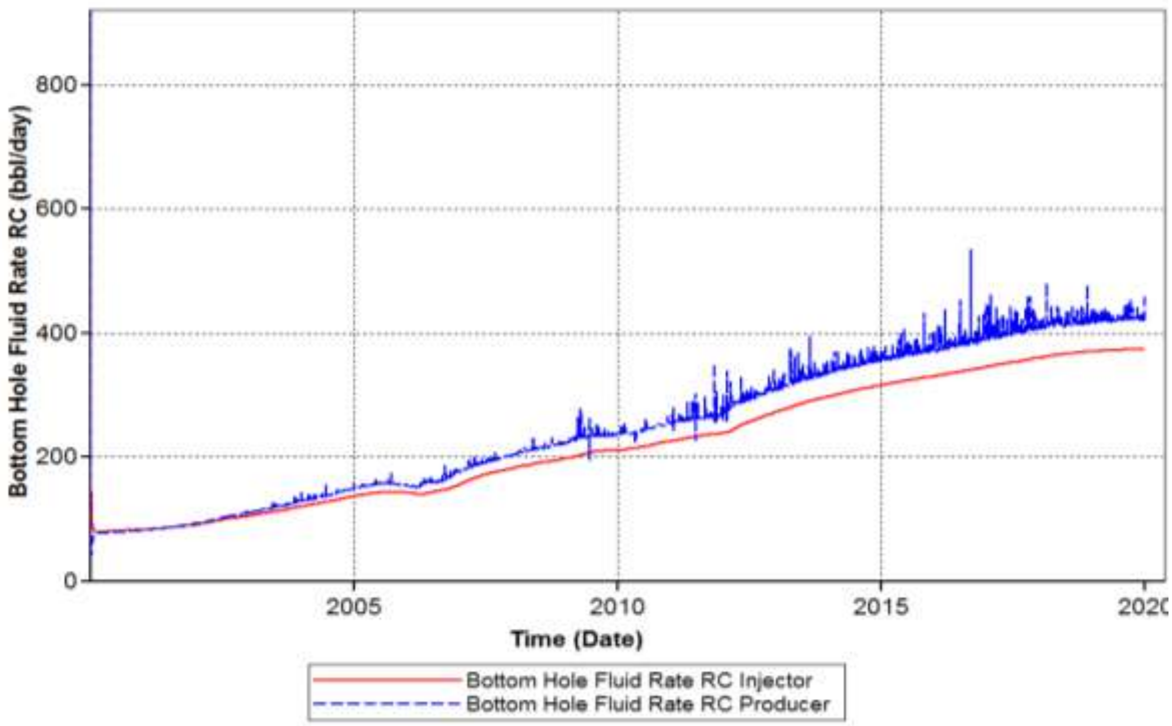

9) Cumulative Oil Reservoir Condition vs Time (Without Asphaltene)



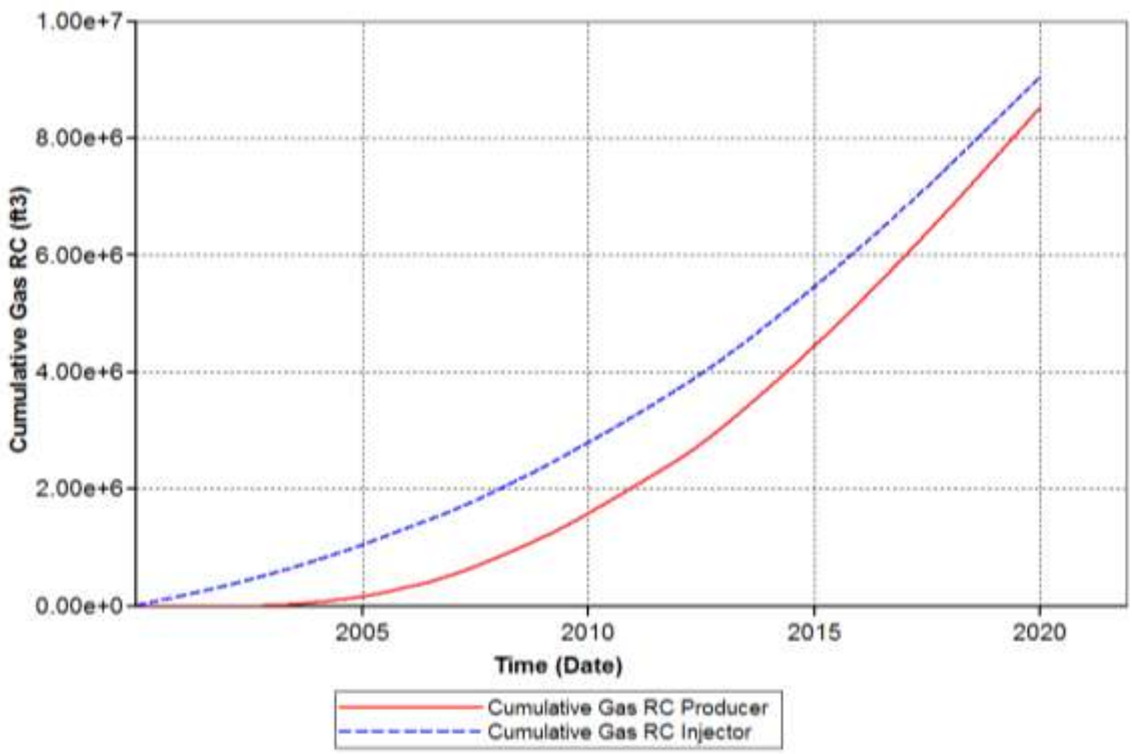

10) Fluid Rate Standard Condition vs Time (Without Asphaltene)



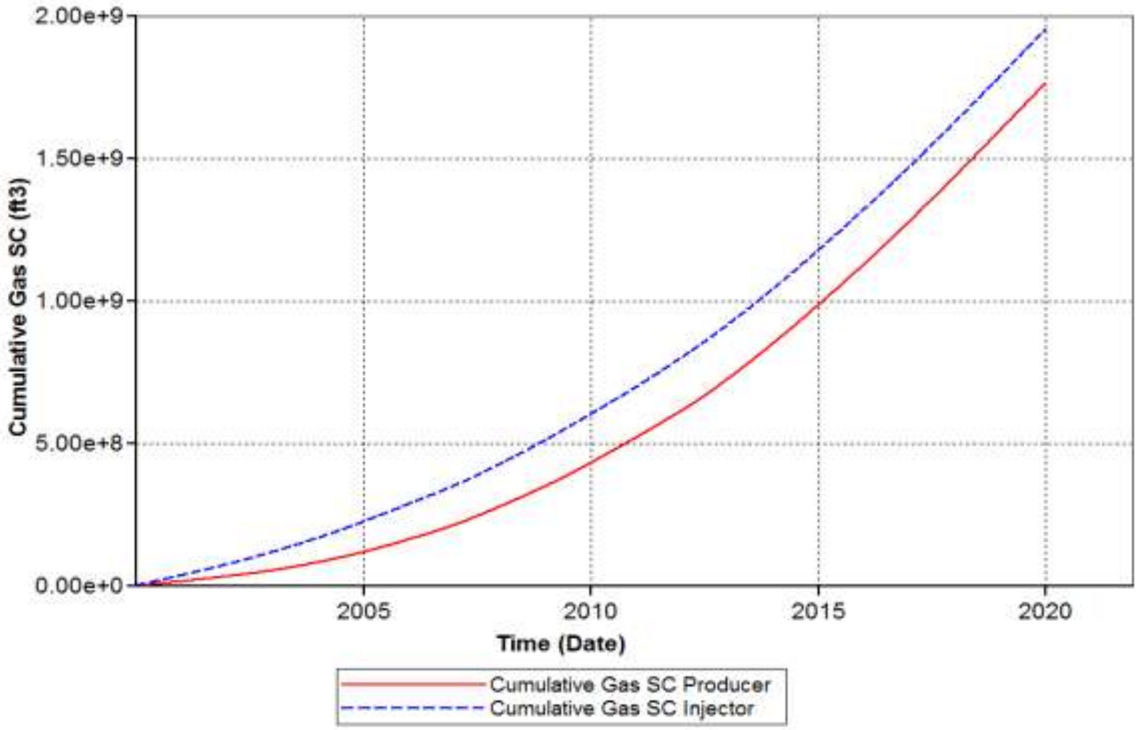

11) Gas Oil Ratio Standard Condition vs Time (Without Asphaltene)



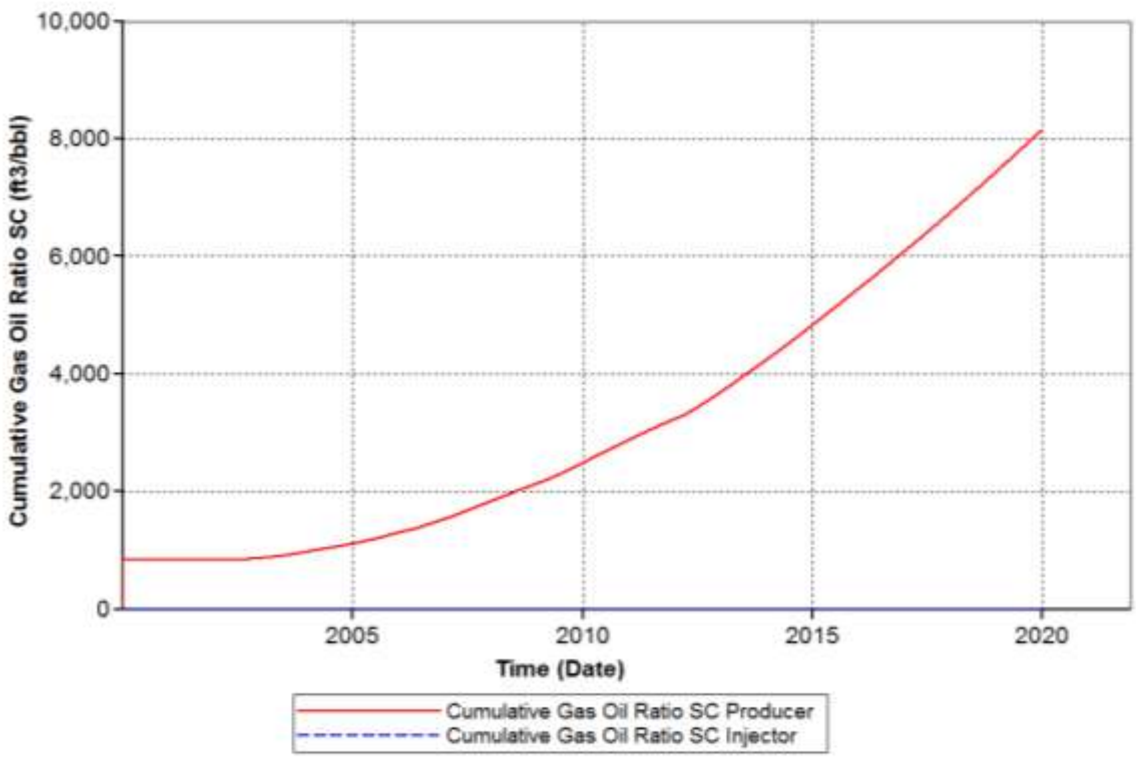

12) Bottom Hole Fluid Rate vs Time (WithAsphaltene)



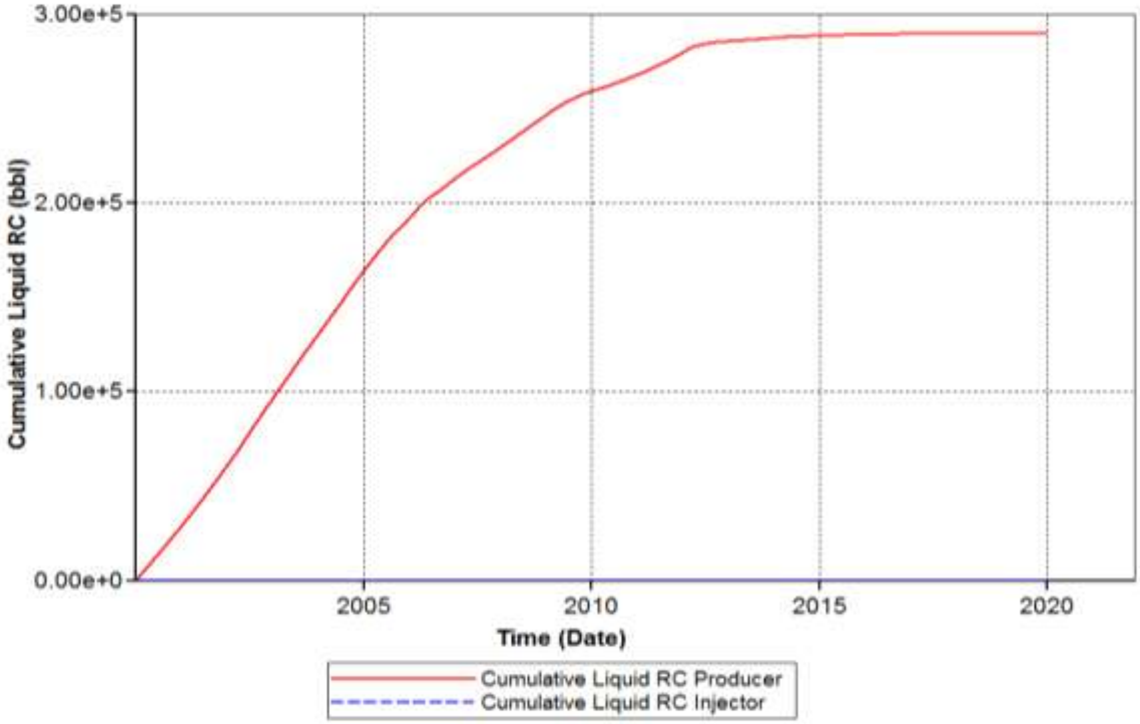

13) Cumulative Gas Reservoir Condition vs Time (With Asphaltene)



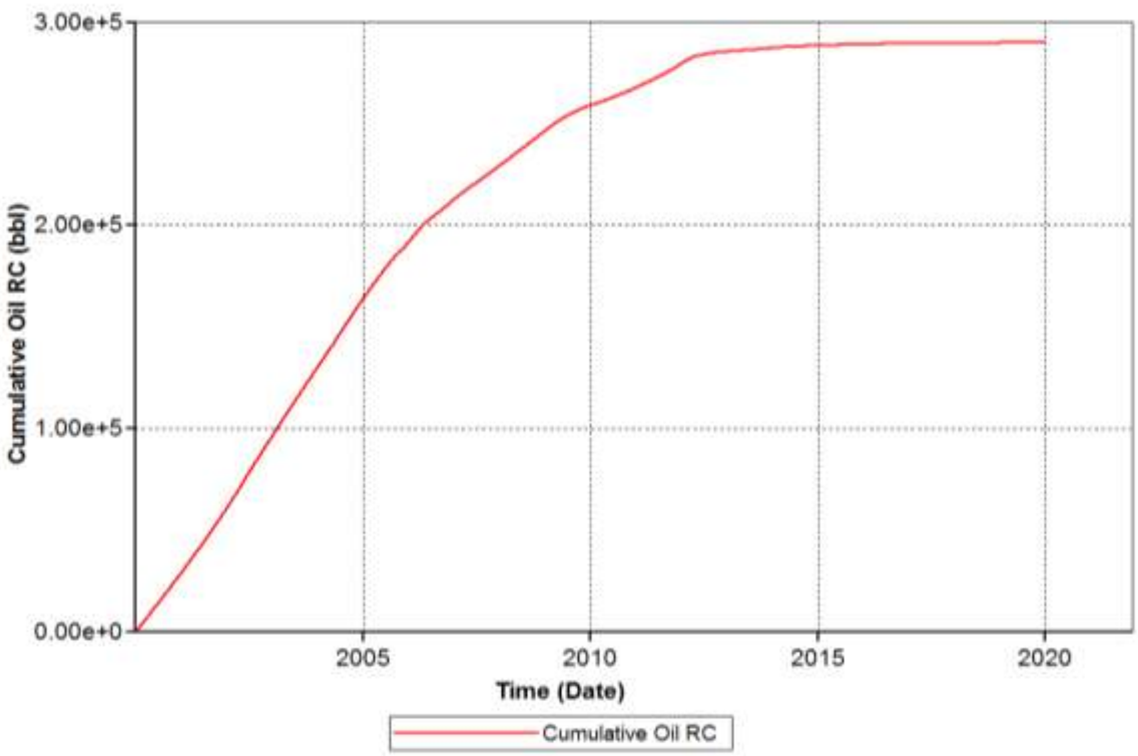

14) Cumulative Gas Standard Condition vs Time (With Asphaltene)



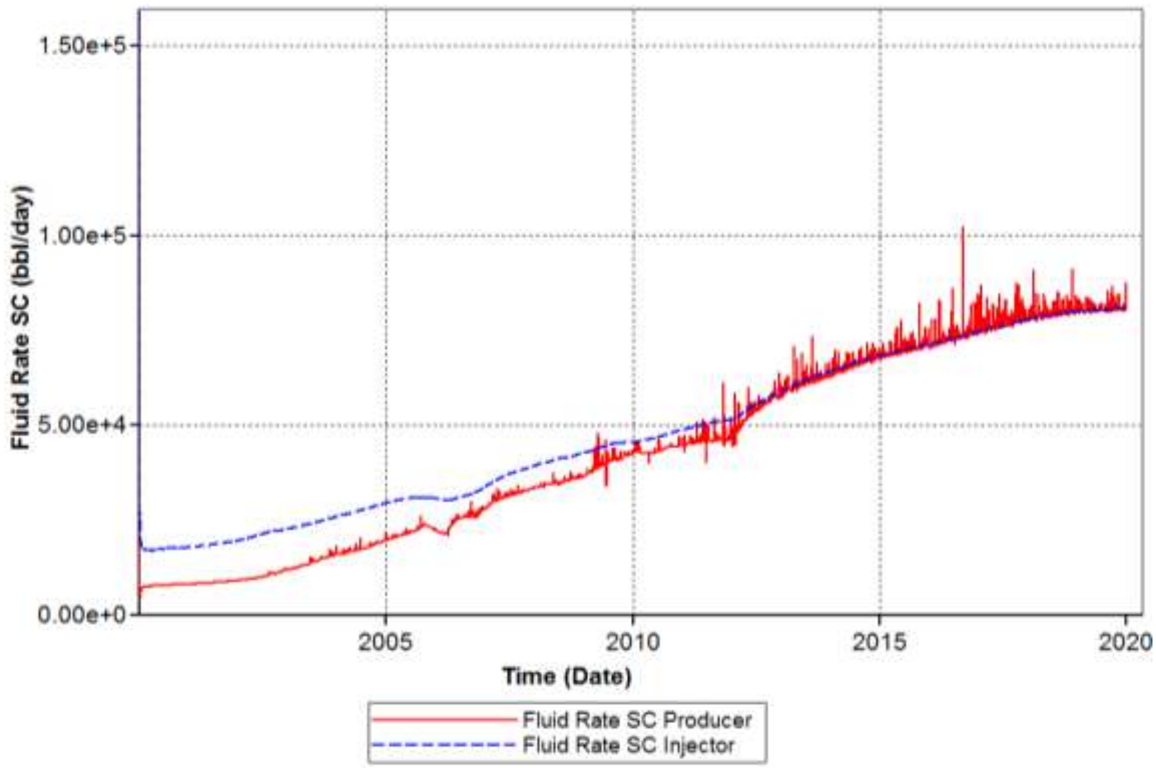

15) Cumulative Gas Oil Ratio Standard Condition vs Time (With Asphaltene)



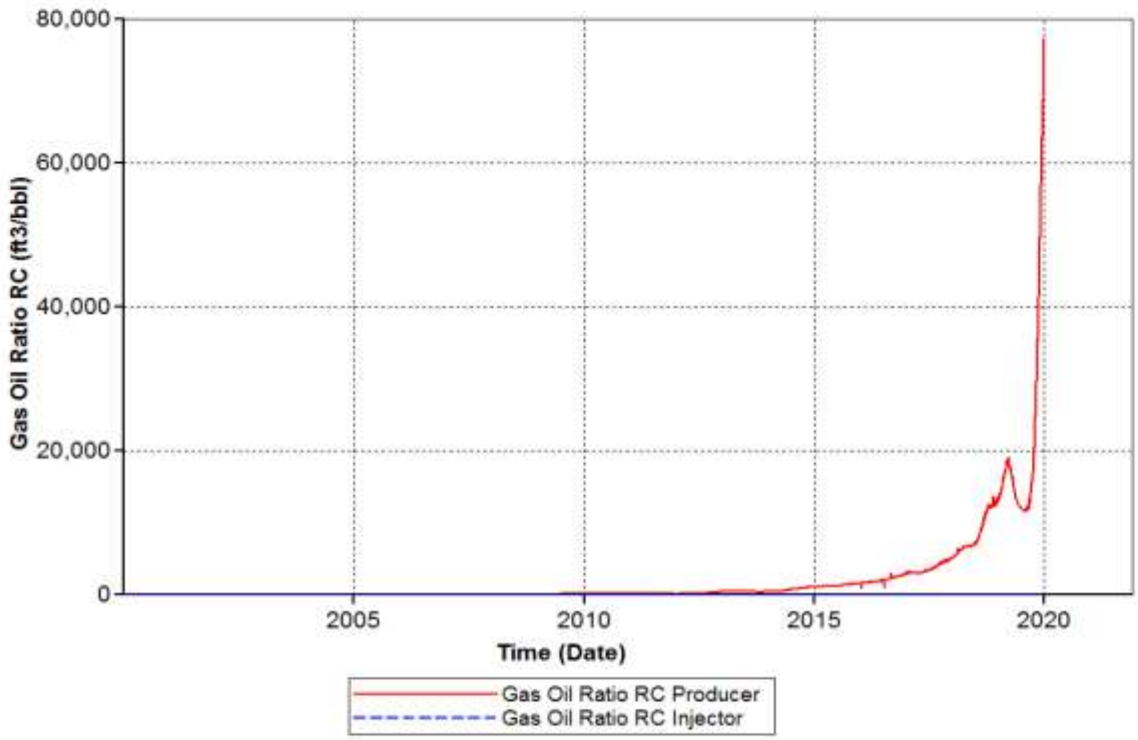

16) Cumulative Liquid Reservoir Condition vs Time (With Asphaltene)



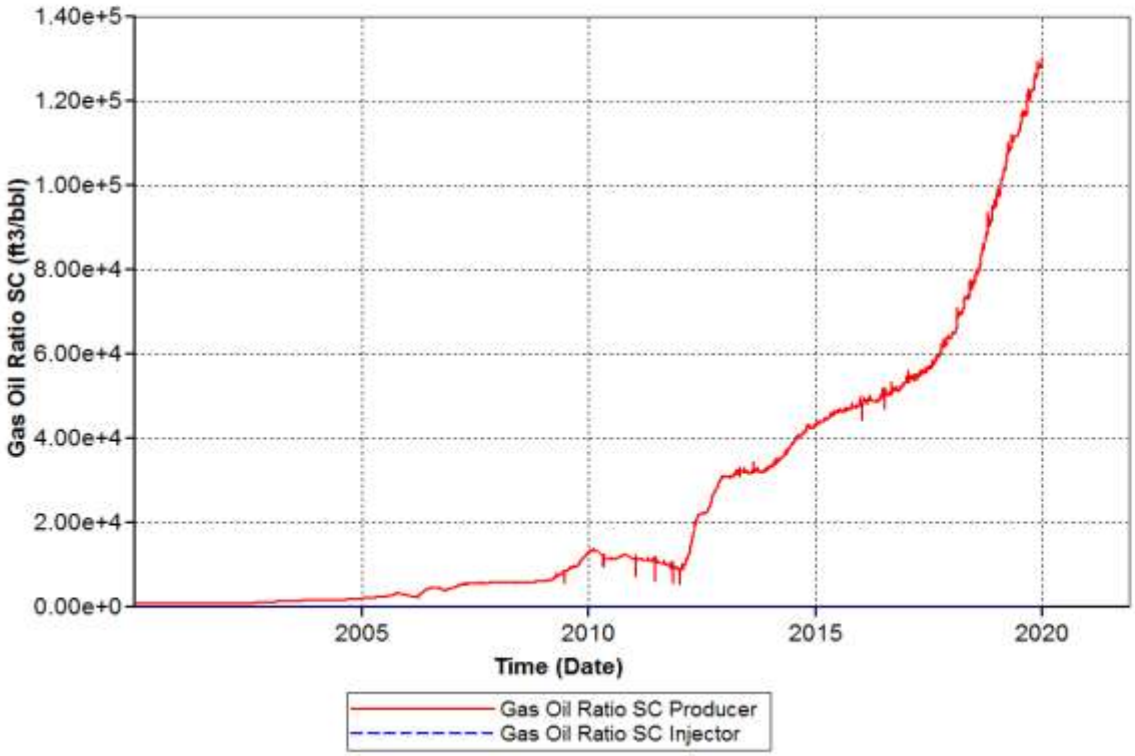

17) Cumulative Oil Reservoir Condition vs Time (With Asphaltene)




18) Fluid Rate Standard Condition vs Time (With Asphaltene)




19) Gas Oil Ratio Reservoir Condition vs Time (With Asphaltene)




20) Gas Oil Ratio Standard Condition vs Time (With Asphaltene)