

https://dspace.org/

Evaluation of reservoir fluid viscosity models applicable for heavy oil conditions using empirical data analysis

Tsubella, Sechaba Mpho

2019

https://hdl.handle.net/10539/28259

Downloaded from a DSpace repository. https://dspace.org/



Evaluation of reservoir fluid viscosity models applicable for heavy oil conditions using empirical data analysis

MSc (50/50) RESEARCH THESIS

Prepared by

Sechaba Mpho Tsubella

1414697

Submitted to

School of Chemical and Metallurgical Engineering, University of the Witwatersrand

Supervisor(s): Prof Jean Mulopo

January 2019

ABSTRACT

The viscosity of crude oils remains a key factor in the simulation of reservoir flow behaviour. It is particularly necessary to ascertain production potential and the recovery of the crude oil. Experimental determination of viscosity is expensive, cumbersome and not always feasible due to time and financial constraints.

Linked to the above, is the interesting emergence of the recovery of heavy oil recovery technology. This has been as a result of various circumstances including depleting light oil reserves. The simulation of heavy oil viscosity remains a very important area of relevance. In this regard, this Research Report explores, from a theoretical basis, the conventional models used in oil exploration with the aim of evaluating the viscosity of heavy oils, evaluating other viscosity-related properties (such as bubble point pressure) of heavy oil and developing a framework in the development and/or selection of viscosity models applicable to heavy oils.

Various models that are commonly used were explored from data available in literature. Two main themes were identified, namely Black Oil type and Corresponding states type. Three models were identified, namely Beal, Beggs-Robinson and Labedi. These models were evaluated using experimental data of Egyptian Oil under dead and undersaturated oil conditions. It was found that the Beggs-Robinson displayed the best correlation behaviour to the measured samples.

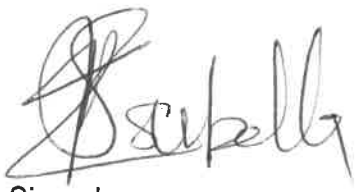
Various trends were observed from the overview of viscosity behaviour trends of the conventional models. It was found that the Beal's model under-predicts viscosity at high temperatures, while the Beggs-Robinson model tend to over-predict viscosity at lower temperatures.

The relationship between heavy oils and viscosity was expanded upon extensively. In this regard, various other properties of heavy oil including the bubble point pressure were explored. The constant composition expansion test was used for the Egyptian oil samples. Various properties like the relative volume, oil compression and pressure were briefly examined. Furthermore, reservoir performance was evaluated in order to obtain PVT data. PVT data is important for the development of viscosity models. The differential liberation expansion and multistage separator test was used to undertake this evaluation.

In our comparison between the experimental and simulated viscosity, all of the models under observation generally displayed good correlation in their estimation across both oil conditions. In conclusion, a theoretical framework is proposed for the selection of a viscosity model for heavy oils.

DECLARATION:

I, Sechaba Tsubella, student number 1414697 declare that this is my own work and, to my knowledge, has not been submitted for the awarding of any degree to any other University.



Signed

17 January 2018

Date

ACKNOWLEDGEMENT

This Research Report represents humble efforts that have been generously encouraged by love, overwhelming support and sheer tenacity.

In this regard, I would like to acknowledge the following people:

Prof Jean Mulopo for his patient and insightful guidance throughout this journey, I remain sincerely grateful.

My wife, Anita Tsubella, who continues to believe that I can do anything.

My son, Leloko Tsubella, who continues to be my inspiration.

To my employer, the Department of Science and Technology for affording me space and time to complete this mammoth tasks amidst the demands of public servanthood.

To my friends and family for the well wishes and support.

Thank You Jesus!, may this be yet another testimony of your greatness in my life!.

CONTENTS

Declaration	I
Abstract	II
Acknowledgement	IV
Table of Contents	V
List of tables and abbreviations	VI
List of figures	VIII
Chapter 1: Introduction	Page 9
1.1 Definition of key concepts	Page 19
1.2 Aims and objectives	Page 20
Chapter 2: Literature Survey	Page 25
2.1 Introduction	Page 25
2.2 Heavy Oil Exploration	Page 28
2.3 Oil recovery methods	Page 33
2.4 Viscosity models	Page 39
2.5 Conclusion	Page 46
Chapter 3: Theoretical Assessment of conventional models	Page 47

3.1 Introduction Page 47

3.2 Classification of models used in this research report Page 49

Chapter 4: Modelling, Results and Discussion Page 63

4.1 Introduction Page 63

4.2 Constant Composition Expansion Page 69

4.3 Differential Liberation Expansion and Multistate Separator Test Page 79

4.4 Viscosity Modelling (Experimental Data) Page 88

4.5 Proposed Framework for the selection/development of heavy oil models Page 95

Chapter 5: Conclusion Page 96

LIST OF TABLES AND ABBREVIATIONS

List of Tables

Table 1: Viscosity models for unsaturated oil conditions -

Table 2: Viscosity models for dead oil conditions -

Table 3: Bubble point viscosities ranges for several models. (Source: Journal of Petroleum Exploration and Production Technology)

Table 4: Constant Composition Expansion data for an Egyptian reservoir oil -

Table 5: Experimental data-Oil Properties -

Table 6: Experimental data-Vapour properties -

Table 7: Experimental (measured) viscosity data for the Egyptian oil samples.

List of abbreviations

API: American Petroleum Institute

CHOPS: Cold Heavy Production with Sand

LSSVM: Least square supported vector machine

GOR: Gas-oil ratio

BP: British Petroleum

LSVVM: Least square volumetric vector machine

DL: Differential Liberation

CSS: Cyclic Steam Simulation

SST: Significant Structure Theory

SAGD: Steam assisted gravity drainage

ANN: Artificial Neural Networks

cP: Centipoise, a unit of viscosity

VAPEX: Vapour Extraction Method

MBE: Material Balance Equation

AAD: Average Absolute Deviation

EOS: Equation of State

LBC: Lohrenz-Bay Clarke model

Mo: Molecular Weight

P: Pressure

V: Volume

T: Temperature

LIST OF FIGURES

Figure 1: Production Process of oil recovery

Figure 2: Shear stress diagram

Figure 3: Velocity gradient diagram

Figure 4: Pressure vs Temperature curve conditions of production and injection based on the different processing stages

Figure 5: Illustration of the SAGD Process

Figure 6: Viscosity curve as a function of pressure

Figure 7: Temperature vs Pressure trend for various viscosity models

Figure 8: Area of applicability of the Andrade model

Figure 9: Relationship between reservoir depth and temperature

Figure 10:Illustration of the different oil and gas PVT properties

Figure 11: Relative Volume vs Pressure Graph

Figure 12: Pressure vs Y-Function of the relative volume

Figure 13: Pressure vs Oil Compression

Figure 14: Differential Liberation Test results

Figure 15: DL #1 Pressure vs Oil Compression

Figure 16: DL #1 Pressure vapour gravity

Figure 17: DL #1 Pressure –formation volume factor

Figure 18: Viscosity reservoir fluid vs Pressure

Figure 19: Beggs-Robinson model trend for unsaturated and dead oil viscosities

Figure 20: Relationship between calculated and measured viscosity (Beggs-Robinson model)

Figure 22: Viscosity vs Oil density (Beal model)

Figure 22: Relationship between calculated and measured viscosity (Beal model)

Figure 23: Viscosity vs Oil density (Labedi model)

Figure 24: Relationship between measured and calculated viscosity (Labedi model)

CHAPTER 1 INTRODUCTION

In order to mitigate the high costs of exploration, scientists and engineers have had to rely on simulations that help to assist in providing information that can maximise exploration activities. The use of models is particularly important in predicting the key flow behaviour-viscosity. Viscosity modelling or simulation is not particularly unique in heavy oil exploration. However conventional models have performed poorly in predicting the behaviour of heavy crude oil. There is no standard approach in the development of these models, the selection thereof and the validation of information provided by these models, this challenge is what forms the aim of this research work. The objectives of this work is to:

- Provide a theoretical assessment of conventional models used in oil exploration
- Assess these models in the context of heavy oils;
- Perform a high level comparison of three different models and validate their effectiveness in the prediction of oil viscosity for both undersaturated and dead oil conditions ; and
- Develop a framework to assist in the development and/or selection of useful viscosity models with particular focus on heavy oils.

Crude oil viscosity is a very important aspect in petroleum engineering, it is often considered in the evaluation of hydrocarbon exploration, methods of oil recovery, design and efficiency of production systems for the manufacture of petroleum

products as shown in Figure 1. Viscosity is also an important part in the assessment of material properties, its quantification is particularly important in many petroleum engineering disciplines, ranging from the assessment of equipment used to transport hydrocarbon materials to the design of storage facilities. Viscosity is required in the a) calculation of two-phase flow, b) gas-lift and pipeline design, c) fluid flow in the reservoir, and d) selection of oil production strategy. Petroleum and reservoir fluids all possess viscosity and it is important that these viscosity values are known and understood.

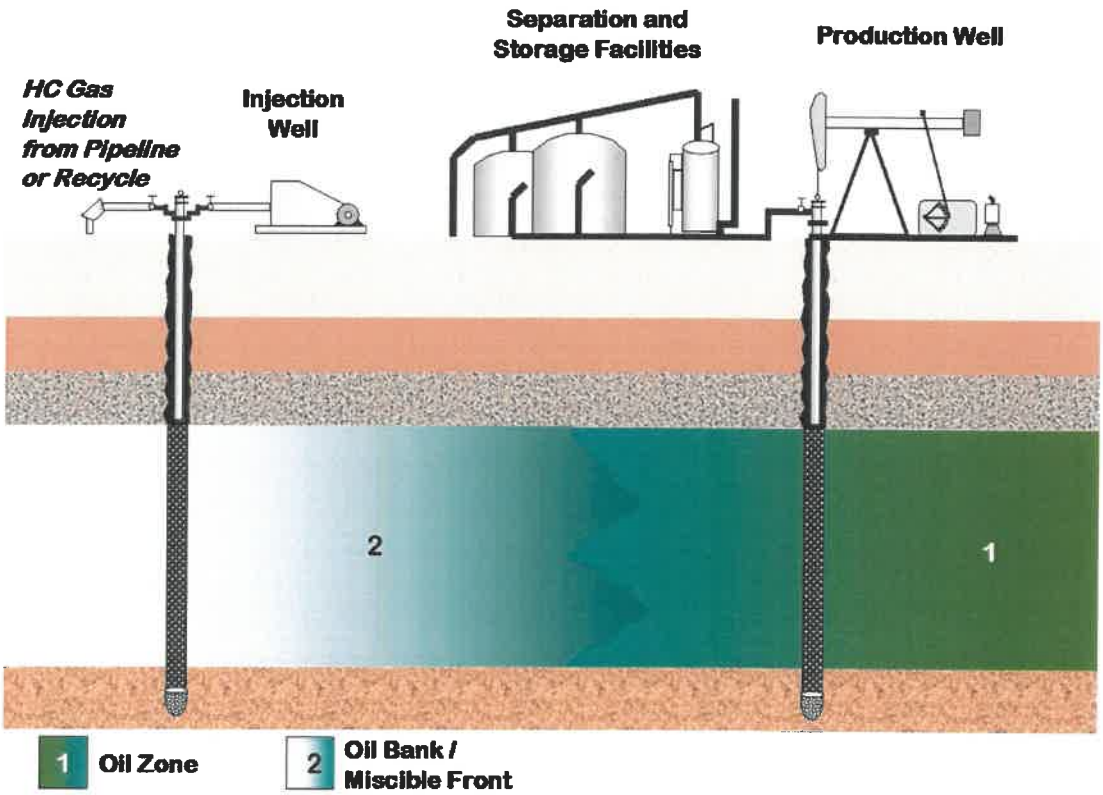


Figure 1: The various production processes of oil recovery

There are mainly two ways to measure the viscosity of a fluid. These are (a) experimental measurements and (b) estimation using a viscosity model. Whilst

the experimental method is likely to be the most accurate, it is improbable and not feasible to measure the viscosity of all fluids across all temperature ranges, pressure ranges and compositional levels. The time required for this to occur or the expenses associated with this would be too onerous. Realistically, properly defined flow quantification using models are the most feasible option available.

1.1 Definition of key concepts

Heavy Crude Oil

Like light crude, the definition of heavy crude varies by region and by the organization making the determination. In general, if it has an API gravity of less than 20, it is considered heavy, at an API gravity of 10, crude oil will have the same density as water. Any API below 10 and the crude sinks in water rather than floating. Oils with an API in this range are often called extra heavy oils (AAPG [1987]). It is estimated that there is twice the amount of heavy crude in reserves than light crude (Oilfield Review [2006]). When it comes to general properties, heavy crude is thicker, more resistant to flow, and usually contains higher levels of sulphur and other contaminants than light oil. For heavy oil to be made into gasoline, it has to be refined, cracked to make large hydrocarbons smaller, and treated to remove contaminants like sulphur. All of this extra refining requires more energy input for the same energy output, which reduces the energy returned on energy invested (EROEI) ratio.

Energy returned on energy invested (EROEI)

EROEI is a measure of a systems efficiency in the utilisation of energy. In this context, EROEI helps to determine how valuable a barrel of crude is because crude that requires more energy input is more expensive to refine, which reduces profit. Beyond the need for additional refinement, heavy crude also pose extraction and transportation issues that are not present with light crude.

Viscosity

Viscosity is defined as a measure of a material's resistance to flow (Elsharkawy et al [1999]). The internal viscosity of a fluid is thus related to the mobility of the flow properties of a material. Consider the following illustration as the measure of viscosity:

Two large parallel plates of area A with distance H between them as shown in the figure below, at a given time = 0. When a force is applied to the upper plate resulting in a shear stress on the fluid defined as $\tau=F/A$. The upper plate will start moving until it reaches a steady state velocity of U, whereas the velocity of the fluid in contact with the lower plate will be zero. If the distance between the plates decreases, the velocity distribution from the lower to the upper plate will increase. For many fluids, the force required in order to maintain the motion of the upper plate is proportional to the area A and the velocity V_x and inversely proportional to the thickness Y.

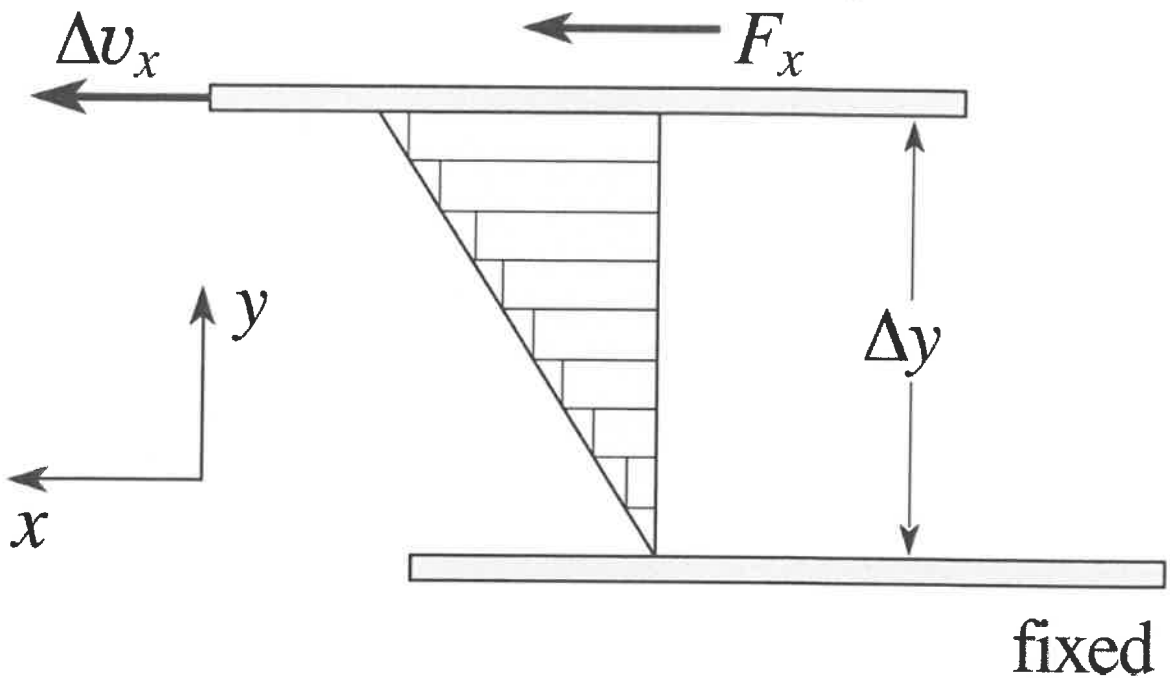


Figure 2: A fluid between two plates under a shear stress. F_x is the force acting on the top plate, V_X is the speed at which the top plate is moving as a result of the force applied and Y is the thickness between the top plate and the bottom plate.

Newtonian Fluids

Newtonian fluids include gases and simple liquids including hydrocarbons. The viscosity of Newtonian fluids is independent of shear stress and shear rate but depend on conditions of pressure (P), volume (V) and temperature (T).

Non-Newtonian fluids

Non-Newtonian fluids do not obey Newton's law and the viscosity of these fluids depends on shear stress and shear rate. Non-Newtonian fluids can further be classified into Bingham plastic, dilatant and pseudo plastic fluids. Bingham plastic

fluids require constant application of force in order to flow, this is because the shear stress must exceed a certain minimum force in Bingham plastic fluids. Pseudo-plastic fluids become less viscous as shear rate increases. This occurs, because as the stress increases, the molecular chains are oriented in a certain direction and start sliding over each other, which results in a reduction in viscosity. In the case of dilatant fluids, as the shear rate increases, the fluid becomes more viscous. Dilatant fluids have a lubricating effect at low shear rates however and when shear rate begins to increase, the friction between the particles is increased.

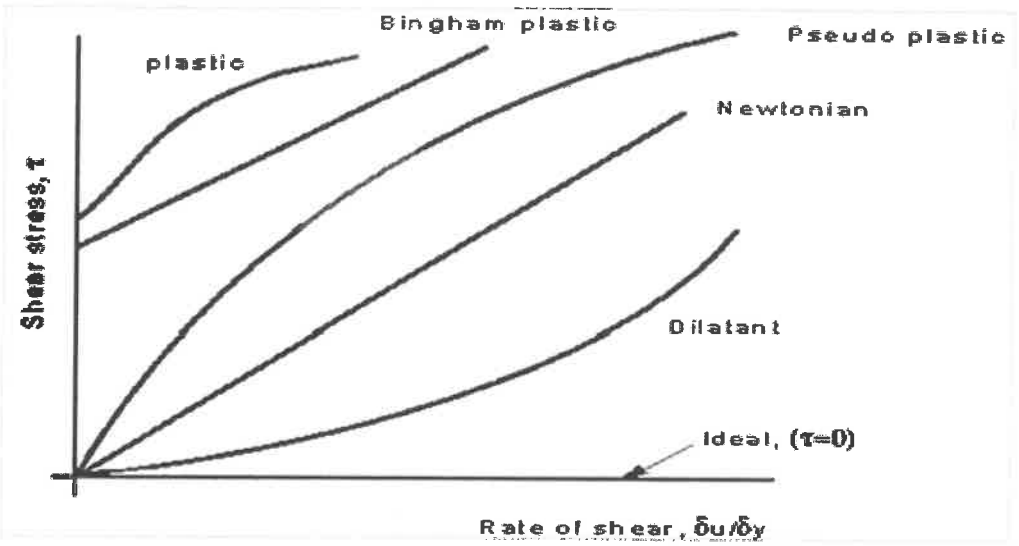


Figure 3: Velocity gradient diagram (shear stress versus shear rate) for Newtonian and non - Newtonian fluids .

The fluids considered in this work are classified as Newtonian fluids.

Viscosity Modelling

Petroleum fluids are highly complex fluids with differing and sometimes complicated thermodynamic and flow behaviour. These fluids are usually multicomponent, and consist of varying amounts of hydrocarbons. The varying nature of these hydrocarbons is responsible for the compositional and phase changes that these fluids undergo during extraction, refining and transportation. Viscosity models are important tools that are used to describe the viscosity of a fluid as a function of several properties i.e. temperature and pressure. Many viscosity models are available from literature, these include highly theoretical and empirical correlation based models. The challenge however is that these models do not always adequately explain fluid behaviour across all oil reservoir conditions (Macias-Salina et al [1987]) or instances where the pressure and temperature levels are usually higher than the normal onshore reservoirs (Baled [2003]) as shown in Figure 4

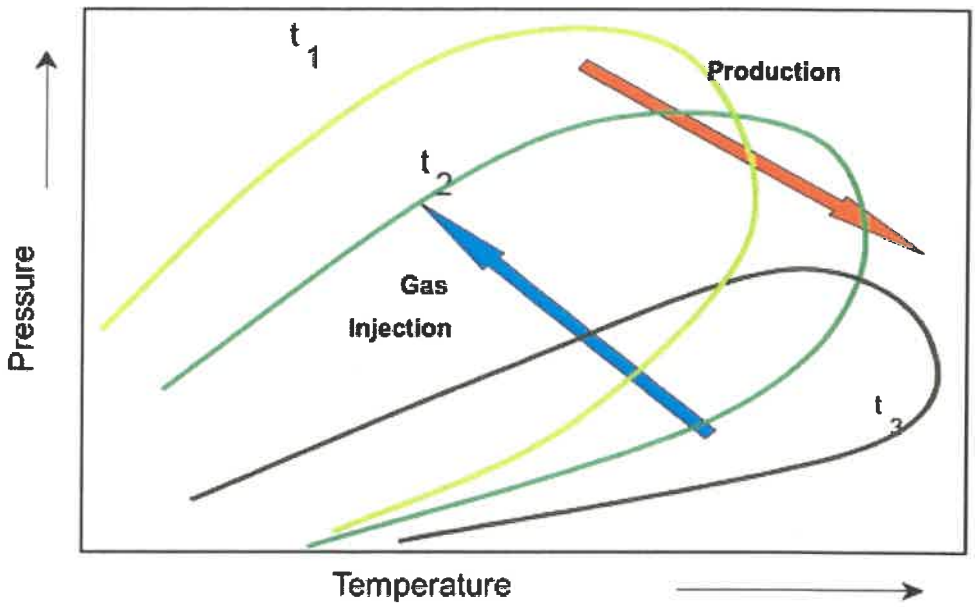


Figure 4: Pressure vs temperature during production and injection based on the different processing stages as shown in figure 1

American Petroleum Institute (API)

The API gravity is determined by using the specific gravity of an oil in a set equation. API = [141.5/specific gravity of oil] – 131.5. The API is used to classify the category of the crude.

Cold Heavy Production with Sand (CHOPS)

CHOPS is primarily used in heavy oil production. It involves the deliberate initiation of sand influx into a perforated oil well, and the continued production of substantial quantities of sand along with the oil.

Gas –oil constant (GOC)

A bounding surface in a reservoir above which gas occurs and below which oil occurs.

Pressure, Volume, Temperature (PVT)

PVT is the main and most critical grouping of data conventionally used in the analysis of oil and gas behaviour. It is responsible for providing the foreground data upon which many viscosity properties can be determined and studied.

Constant Composition Expansion (CCE)

A constant composition expansion test is used to determine the bubble point pressure, under saturated oil density, isothermal oil compressibility and two phase volumetric behaviour at pressures below the bubble point.

Energy return on energy invested (EROEI)

The EROEI is a measure of the system's efficiency in the utilisation of energy during production process. A high EROEI means a production system is efficient as it the energy output is lower than the energy input.

Differential liberation expansion (DLE)

The DLE test is one of the PVT experiments that are used to determine the bubble point pressure. The primary results that can be extracted from a DLE test include oil formation factor, solution gas/oil ratio, oil density, gas formation factor, z-factor gas and gas gravity.

Drag reducing agents (DRA)

DRA's reduce the frictional pressure within the flow of a pipeline or conduit. They act as buffers along the pipe wall and decrease the amount of energy lost during turbulent formation.

Least square supported vector machine (LSSVM)

LSSVM is a statistical learning theory which makes use of a least square linear system as loss functions instead of the conventional quadratic programme.

Gas-oil ratio (GOR)

Gas oil ratio is a comparative ratio of the amount of gas dissolved in the oil during production Generally heavy oil have a lower GOR because they have an lower capacity to dissolve gases as compared to lighter oils.

Cyclic steam simulation (CSS)

CSS is a method of thermal recovery usually used in heavy oil production in which a wall is injected with steam. The method consists of 3 stages, stage 1 is injection of steam. Stage 2 is the soak phase wherein the well is shut to allow uniform heat distribution, and stage 3 is where the oil is produced.

Significant Structure Theory (SST)

The SST visualizes a solid liquid as having both solid and gaseous degrees of freedom, with fluidized vacancies of molecular size randomly distributed throughout the lattice structure.

Steam-assisted gravity drainage (SAGD)

SAGD makes use of steam to recover to recover bitumen from oil sands. In SAGD, a pair of horizontal wells are drilled into the reservoir at a certain distance beneath the surface. The top well injects the steam to heat the bitumen, which then separates from the sand and collects with the produced water in the lower well. The bitumen is then pumped to the surface, where it is separated from the water. The figure below depicts the SAGD process.

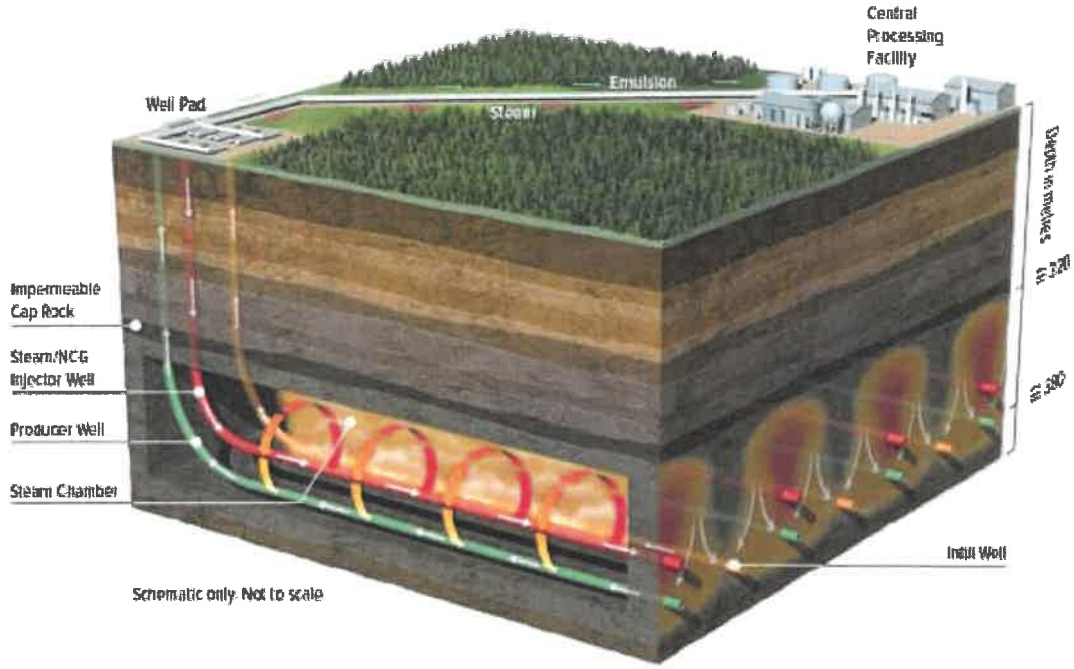


Figure 5: Illustration of the SAGD Process (source: https://www.megenergy.com/operations/steam-assisted-gravity-drainage-sagd)

Artificial Neuron Networks (ANN)

ANN is a machine learning tool used to replicate the process of producing intelligence. Neural Networks typically consist of input and output layers with a hidden layer that transforms the inputs into something that can be utilised by the output layer. In the oil and gas industry, ANN is applied to develop models that can predict processing properties like flow behaviour i.e. viscosity.

Vapour extraction method (VAPEX)

The VAPEX is a non-thermal heavy oil production method. Similar to SAGD, a solvent is used to reduce the viscosity of the heavy oil. The injected solvent vapour expands and dilutes the heavy oil by contact. The (diluted) heavy oil will drain by gravity to the lower horizontal well, where it is produced.

1.2 Aim and Objectives

The overall aim of this research is to evaluate three conventional models and assess their applicability to heavy oils. The overall objective of this research is to develop a framework to be considered in the design of viscosity models for heavy oils.

The aim and objective will be fulfilled by:

- Providing a theoretical assessment of conventional oil models for viscosity;
- Assess these models in the context of heavy oils;
- Perform a high level analysis of three different models using real data to validate the effectiveness of the models in the production of oil viscosity for both undersaturated and dead oil conditions; and
- Develop a framework to assist in the development and/or selection of accurate viscosity models with particular focus on heavy oils.

CHAPTER 2 LITERATURE SURVEY

2.1 Introduction

In addition to the fact that the extraction of heavy crude requires higher energy input. Heavy crude does not flow like light crude. In fact, its consistency is often compared to that of molasses at room temperature and it is even occasionally solid if not heated (Benniston [1998]). The field of petroleum chemistry has its origins in the attempts to make crude easy to extract and transport. Current methods of extraction include open- pit mining, steam stimulation (to make it less viscous), the addition of sand to the oil, and the injection of air into wells to create fires that burn heavier hydrocarbons and degrade them into lighter, more easily pumped varieties. Transporting heavy crude often requires the addition of diluting agents, particularly in pipeline transport. These diluents are referred to as Heavy Oil Drag Reducing Agents or DRAs. Most pipelines were initially designed for light crude and thus cannot accommodate heavy crude unless it is modified. Often times, heavy and light crude are mixed to promote transport through pipeline. This, of course, results in contamination of the light crude and a reduction in its value. The other major drawback to heavy crude is its environmental impact. Two specific aspects of heavy crude contribute to this. Firstly, it is contaminated with sulphur and heavy metals, both of which must be removed. Heavy metals are often toxic and their removal from crude presents disposal and environmental issues. The sulphur content of heavy oil may be as high as 4.5% as reported by Ghanavat et al (2013). Sulphur contributes to acid rain and in combination with hydrogen,

produces hydrogen sulphide, which can be deadly. Sulphur is corrosive to pipeline metal and refinery components.

The other environmental impact of heavy crude is carbon dioxide output, which can be as much as three times that of light crude of the same quantity (Ghanavat et al [2013]). There are two reasons for this, firstly, more energy must be supplied as an input to generate the same quantity of useable material from heavy crude compared to light. This means more carbon dioxide is released for the same amount of useable energy produced. In addition, heavy crude has a higher carbon to hydrogen ratio than light crude. In other words, it contains less hydrogen per carbon than does light crude, which means that when it is burned, more carbon dioxide is created. Most heavy crude reserves are found in Canada and Venezuela, though there are deposits throughout the world. It is generally divided into two categories based on sulphur content. Low sulphur heavy crude has less than 1% sulphur and is primarily found in Africa. High sulphur crude is found throughout the rest of the globe, with Venezuela having the largest single recorded deposit. In fact, the deposit of heavy crude in Venezuela is greater than any recoverable deposit in the world, including Saudi Arabia and Canada (BP [2011]).

The complications described above have necessitated a deviation from a "one size fits all" approach to the development of new and accurate viscosity models that are also able to simulate and interpret data associated with high pressure and compositional changes over a wide range. Therefore, there is a legitimate need to understand the application of viscosity models. In addition to this, a framework

needs to be developed that assists in the selection or development of the most suitable viscosity model in relation to a particular reservoir oil profile. This will assist in the decision making process in order to enable the selection of a particular model in an efficient and expeditious manner.

Globally the exploitation of heavy oil is gaining momentum in light of increased scarcity in conventional resources. However, it remains challenging to produce, mainly due to physical factors such as high viscosities encountered resulting in low mobility and economic factors related to the more expensive methods required to reduce in-situ viscosity i.e. the thermal recovery methods namely cyclic steam simulation (CSS), steam assisted gravity drainage (SAGD), vapour extraction (VAPEX), in-situ combustion etc. Generally, oil reserve estimates are based on appropriate field development plans and production predictions, obtained mainly from numerical modelling. Thermal composition simulation is used to model the thermally enhanced production methods and predict the production rates of oil, gas, water/steam and steam injection rates required to reach economical oil rates and field recovery factors. Due to the sensitivity of the economic numbers related to the recovery rates, as well as the amount of steam or heat required, and taking into account that the production rates are a direct inverse function of oil viscosity meaning that a higher level of accuracy is required in the oil viscosity predictions as a function of reservoir temperatures. Knowledge of viscosity is thus essential for reservoir exploitation and development of new technologies, especially as management decisions and production strategies are frequently based on the results of the reservoir simulations.

2.2 Heavy Oil Exploration

Dwindling oil supplies, high energy prices and the need to replenish reserves are encouraging oil companies to invest in heavy oil operations. Heavy and viscous oil present challenges in fluid flow analysis and modelling, and obstacles to recovery that are being surmounted by new technology and modifications developed for conventional oils. Most of the world's oil resources are heavy viscous hydrocarbons that are difficult and costly to produce and refine. As a general rule, the heavier or denser the crude oil, the lower its economic value. Less dense, lighter ends of crude oil derived from simple refining distillation are most valuable. Heavy crude oils tend to have higher concentrations of metals and other elements, requiring more effort and expensive processing to extract useable products and dispose of waste. High oil demands and rising prices associated with declining productions in conventional oil reservoirs has led the petroleum industry to shift their focus to the exploitation of heavy oil. Heavy oil is typically defined as having and API of 22.3° or less according to Conaway C (1999). Oils of 10° API or less are known as extra heavy, ultra-heavy or super heavy because they are significantly denser than water. In contrast, conventional oils usually have crude densities ranging between 38° API and 40° API. While oil densities are important for evaluating for resource value and estimating refining output and costs, the fluid property that most affects producibility and recovery is oil viscosity. The more viscous the oil, the more difficult it is to produce. There is no standard relationship available or prescribed in literature between density and viscosity however "heavy" and "viscous" tend to be used interchangeably to describe heavy

oils. It is a well-established fact that heavy oil is more viscous than conventional oils. Conventional oils viscosity may range from 1cP, the viscosity of water to about 10 cP. Viscosity of heavy and extra heavy oil may range from less than 20 cP to more than 1 000 000 cP (Ghanavat [2013]). The most viscous hydrocarbon, bitumen is a solid at room temperature, and softens readily when heated (Ghanavat [2013]). Since heavy oil is usually less valuable and more difficult to refine than conventional oil, the question arises as to why should oil companies be interested in devoting time and money to its exploitation. The answer to this question is twofold; firstly, in today's technology age, many reservoirs can now be economically exploited. Secondly, the reported reserves of heavy crudes are becoming increasingly abundant in comparison to their light counterparts. The world's total oil reserves are reported to be approximately 1 482,77 billion barrels (Opec Annual Statistical Bulletin 2018). Conventional oils make up only 30% of that amount with the remainder consisting of mainly heavy oil, extra heavy oil and bitumen.

Heavy oil promises to play a major role in the future of the oil industry, and many countries are now moving to increase their production, revise reserve estimates, test new technologies and invest in infrastructure to ensure that their heavy oil reserves are not left unexploited. In order to understand the complexity associated with the extraction of heavy oil, perhaps it is useful to reflect on how heavy oil hydrocarbons are formed.

There are various considerations in how heavy hydrocarbon deposits are formed and produced. Important methods include the selection of the recovery method, downhole and laboratory analysis of fluid samples, well testing and completion and monitoring of the heavy oil recovery process. The largest accumulations of the world's heavy, extra heavy and bitumen oil reserves occur in similar geographical settings. These are typically large shallow deposits trapped on the flanks of foreland basins (AAPG Study 25,1987). Foreland basins are described as huge depressions formed by the warping downwards of the Earth's crust during mountain formation. Marine sediments in the basin become the source rock of hydrocarbons that migrate into sediments eroded from the newly formed mountains. In these shallow, cool sediments, the hydrocarbon is degraded. This biodegradation is the main cause of the heavy formation according to Head et al (2003). Over geological time scales, microorganisms degrade light and medium hydrocarbons. The effect of biodegradation is to cause oxidation oil, decreasing gas/oil and increasing density, acidity, viscosity and sulphur and other metal content.

The term heavy refers to crude oil density. Classic crudes usually have high density naphthene-aromatics and heteroatom-containing compounds and are poor in low density alkenes. They are commonly either immature or degraded high crudes which have low densities (high API gravities), and are rich in alkanes. The complexity of the petroleum chain increases rapidly with increasing boiling point, as a result of the increasing number of atoms in a molecule and the immense

number of possible structural arrangements. It has been long recognised that compositional analysis of high boiling petroleum fractions by isolation of individual compounds is a practical impossibility. Numerous separation methods and schemes have been developed over the years. Petroleum components can be viewed as two major groups of compounds, namely hydrocarbons and nonhydrocarbons. Hydrocarbons include acyclic alkanes and cycloalkanes, both commonly referred to as saturates. The third group is known as aromatics. Molecular structure is a more accurate determination of the boiling point distribution and density of the crude oil than molecular weight.

Research has been undertaken by Boduszynskil et al (1998) to describe the complexity of petroleum material and develop better means of crude oil differentiation. Heavy crudes are usually evaluated by comparing bulk properties such as gravity. This method however does not reveal important compositional differences which determine the intrinsic value of crude oil. The API gravity scale is commonly used for ranking crudes. API is defined by the formula:

Gravity = 141.5÷ (Density – 131.5[°API])……(1) (Alomair et al [2016]

World reserves of heavy crudes are reported to have API gravities between 10° API to 20° API. (Alomair et al [2016]).

Bouszynski (1998) collected data to illustrate the relationship between crude oil gravity and viscosity. The data shows that crude oil viscosity increases rapidly with decreasing gravity. Heavy low-gravity crudes, are very viscous. The term "heavy" frequently refers to high boiling petroleum fractions. Distillation is the primary refinery operation that separates crude oil into fractions which are then used as feedstock to various conversion and upgrading processes. The low-value residue which comprises of high molecular weight petroleum molecules are referred to as heavy ends. Alomair et al (2018) performed a sensitivity analyses in order to understand the relationship between viscosity of heavy oil and other related input variables used in oil modelling. They concluded that viscosity is directly related to the density and specific gravity of the oil.

Through biodegradation, oils also lose a significant fraction of their original mass. Other mechanisms such as water washing and phase fractionation contribute to the formation of heavy oil, separating light ends from heavy ones by physical means. Optimal conditions for microbial degradation of hydrocarbons occur in petroleum reservoirs at temperatures less than 80° C, the process is usually restricted to shallow reservoirs (AAPG Study 25,1987). The largest known individual petroleum accumulation is the Orinoco heavy oil belt in Venezuela with 1.2 trillion barrels of extra heavy 6 - 12° API oil (AAPG Study 25,1987). The American Association of Petroleum Geologists reported that, the regional exploration and evaluation programme of the 53 000 Km^2 of the Orinoco Heavy Belt resulted in an estimation of $1{,}2 \times 10^{12}$ barrels of oil in place. This confirms

the existence in South eastern Venezuela, of one of the largest oil accumulation in the world. The oil discovered has an average gravity of 9.5° API, with an average viscosity of 1500 cP, 3.6% sulphur content, 420 ppm vanadium content and 95 ppm nickel. One of the fundamental parts of the evaluation of the basin was the construction of sedimentary models to support the geological interpretation and estimation of oil in place. The stratigraphy of the area was established, permitting sedimentary models to be constructed, based on a well-to-well correlation and analysis of 3290 m of conventional cores. The physical and chemical properties of the oil are probably due to long distance migration and the consequent loss of volatiles and oxidation during migration. The sources of these oils are not completely understood but it is agreed that the oil reserves derived from severely biodegraded marine oils. The depositional environment, the original oil composition, the degree to which it has been degraded, the influx of or charging with, lighter oils and the final pressure and temperature conditions make every heavy oil reservoir unique requiring different methods of recovery. This will be discussed briefly in the next section.

2.3 Oil Recovery methods

Heavy oil recovery methods are divided into two main types with the first recovery method being linked to temperature. This is because the key fluid property, viscosity is highly temperature dependent. At an elemental level, when heavy oil is warmed, it becomes less viscous. The second main type is classified as cold production methods. These methods can only be used when heavy oil viscosity is

low enough to allow the oil to flow at what is typically termed as economic rates (Alomair et al, 2016). This requirement is not a factor in the alternate thermally assisted method. An example of the cold oil recovery method is the one employed in the Canadian Oil Sands operations, where oil sands are recovered by truck and shovel then transported to the processing plants where warm water is used to separate bitumen from sand (Motahhari, 2013). The bitumen is then diluted with a lighter hydrocarbon and upgraded to form a synthetic crude oil. Cold heavy-oil production with sand (CHOPS) is another cold production method that found applicability in many heavy oil reservoirs. Sand cuts, up to 10% by volume are produced along with the oil. Sand and oil are separated by gravity at surface and disposed of into a permeable stratum. Vapour assisted petroleum extraction (VAPEX) involves the injection of a miscible solvent, which reduces the viscosity of heavy oil. VAPEX has been studied in the laboratory and in simulations and is currently reported to be undergoing pilot testing in several heavy oil fields but the technique is yet to be deployed in large scale operations at the writing of this work. Steam-assisted gravity drainage has been proven to work for extra heavy oil (BP 2011). Steam injected into the upper well heats the heavy oil, reducing the viscosity of the oil. Gravity causes the moving oil to flow downward toward the lower horizontal producer. Fire flooding also known as in-situ combustion is another method used for the recovery of highly viscous oil. This is a multi-well process in which a combustion front is initiated at an air injection well which propagates to a producing well. The in-situ combustion technique burns some of

the oil and the heat sufficiently reduces the viscosity of the rest of the oil to enable production.

The selection of a particular recovery method usually requires a comprehensive study of factors such as fluid properties, formation continuity, rock mechanisms, drilling technology, completion options, production simulation and available infrastructure. The importance of having accurate viscosity data and the associated modelling is of particular significance in this regard. The team undertaking this particular assessment should also carefully consider other factors such as trade-offs between reserves, expected recovery rates, and production rates. Other important factors include the cost of energy generation and environmental sustainability. Reservoir pressure, volume and temperature (PVT) properties especially fluid viscosity and its variation with temperature in particular are crucial factors in the selection of a recovery technique.

In the case study of the exploration of the Ugnu sand, screening studies undertaken by BP and Schlumberger, measured oil viscosity data limited to two production samples with dead oil viscosities of 200 °C and 2500 cP at 270 ℃, these samples are definitely wholly inadequate nor were they meant to be representative of the entire range of viscosities present in the Ugnu sands. Geochemical transforms were used to predict oil viscosity from sidewall core samples, the only constraint with this technique was that it relied on extrapolation beyond the range of measured viscosities. Although the model did serve as a good starting point,

further optimisation of this model for prediction of oil viscosity and collection of additional samples would have led to more accurate results.

Boduszynski et al (1998) advised that a critical step in determining the best (heavy) oil recovery method is to characterise the reservoir fluid properties. The current trend towards processing petroleum residues or whole "heavy" crudes requires adequate compositional and processing information to understand the chemistry of reactions that are involved in heavy crude oil. Monitoring compositional changes by a mere comparison of operationally defined fractions or by a determination of "average structures" for feedstock and product components provides inadequate and frequently misleading information. Much more detailed compositional data is needed to unravel the structural transformation which occur during processing or to explain product properties. Knowledge of viscosity throughout the reservoir is vital for simulating production and predicting with better certainty, the rate of reserves recovery. The added complication is that heavy oil viscosity can exhibit large variations, even within the same formation. Building a viscosity map often requires adequate sampling and logging-derived information of in-situ viscosity. Nuclear Magnetic Resonance (NMR) has been used successfully to determine in-situ viscosity of conventional oils, but current commercial methods have limitations when it comes to the measurement of heavy or viscous oils. This is because as fluid viscosity increases, NMR relaxation time decreases. When relaxation times are extremely short, NMR logging tools tend to be unable to detect them. When viscosity is greater than about 100 00 Cp, NMR tools detect most of the heavy oil

or bitumen as part of the rock matrix. To improve understanding of the correlation between viscosity and NMR response, researchers at the University of Calgary acquired and interpreted laboratory NMR measurements on a large selection of Canadian heavy oils. Measured viscosities showed a correlation with two NMR parameters, but with differing sensitivities. An increase in viscosity resulted in a decrease in relaxation time, however at high viscosities, these increases became less sensitive to changes in viscosity. The increasing viscosities did however cause the decreasing relative hydrogen index to become more sensitive to viscosity changes. The Calgary researchers therefore concluded that on the basis of these findings, a new empirical relationship between NMR parameters and fluid viscosity can be developed, however more research will still need to be conducted in this field to strengthen this conclusion. It should of course be noted that translating this laboratory NMR-viscosity relationship to one that can be effectively applied as an NMR logging tool is not as clear cut and straightforward. Heavy oils in rocks are mixed with other fluids and exhibit behaviours that differ from bulk fluids in the laboratory. The right combination of laboratory and logging measurements can however provide the information necessary to fine tune the viscosity relationship and produce a continuous viscosity log for viscosity behaviour prediction.

Evaluating the productivity of potential heavy oil reservoirs has been and continues to be a challenge because of the high fluid viscosity associated with heavy oils. The high fluid viscosity makes it difficult to acquire representative fluid samples

and test the reservoir dynamics. There is currently no unique technology to offer a solution to the difficulty of collecting heavy oil samples. A reported methodology that has enjoyed some success in the collection of high viscosity oil samples starts with the simulation of the multiphase flow around the well bore to model the decrease in drilling fluid contamination with time as fluid is pumped into the wellbore. In one case, Cana et al (2014) reported that a technique using Modular Dynamics Tester dual packer module and a flow rate less than $1\,cm^3$/s successfully sampled oil viscosity greater than 3200 cP. Other examples are cited in the case study examining the exploration of the Bhagyam field in the Barmer basin of India (AAPG Study 25, 1987). Compared with conventional oils, viscous heavy oil samples present several challenges in laboratory fluid analysis. Traditional techniques used for analysing key fluid properties can fail to fully characterise heavy crude samples.

Most heavy oils are produced along with water, whether water occurs naturally in the reservoir or has been injected in the form of water or steam. During the production process, more shear forces resulting from the high flow rate through pumps or flow constriction may be great enough to cause water to become emulsified in the heavy oil leading to a rise in viscosity, this may also lead to a dramatic increase in the energy required to transport the heavy oil. In addition, wells present a variety of well construction challenges and complexities. These include drilling stable boreholes in weak formations, accurately landing horizontal wells, designing tubular systems and durable cements for wells that undergo

temperature extremes, installing complicated sand control and lifting equipment that must operate efficiently under the harshest conditions. Understanding fluid flow in heavy oil reservoirs is important for optimising recovery methods particularly when heat is required to reduce viscosity and mobilise fluids. The development of models is thus an important consideration to enable the acquiring of this understanding.

2.4 Viscosity Models

Accurate determination of the viscosity parameter is crucial for the petroleum industry. The common approach to determine the viscosity is laboratory analysis of bottomhole samples or recombined liquids and gases collected from the separators at the surface. However, when the pressure, volume and temperature (PVT) data is not available, and also to save time, fluid properties can be determined by using models that simulate flow behaviour. Empirical correlations and equations of state are one such mechanisms. Depending on the input variables, it is possible to divide correlations used for determining oil viscosity into two categories. The first category relates to the use of oil field data such as temperature of the reservoir, saturation pressure, oil API gravity and solution gas ratio. The second category relates to the use of empirical and semi-empirical models that factor characteristics such as reservoir oil composition, critical temperature, acentric factor, pour point temperature, molar mass and normal boiling point. Hemmatti-Sarapardeh et al (2014) reports that several correlations have been developed to predict the viscosity of crude oils. Most of these are

specific to certain regions and generally perform poorly in other regions due to differences in crude oil nature and compositions. The correlations developed in Hemmati-Sarapardeh et al (2014) were developed for three conditions, namely under-saturated, saturated and dead oil. A typical viscosity curve at reservoir temperature as function of pressure is shown below:

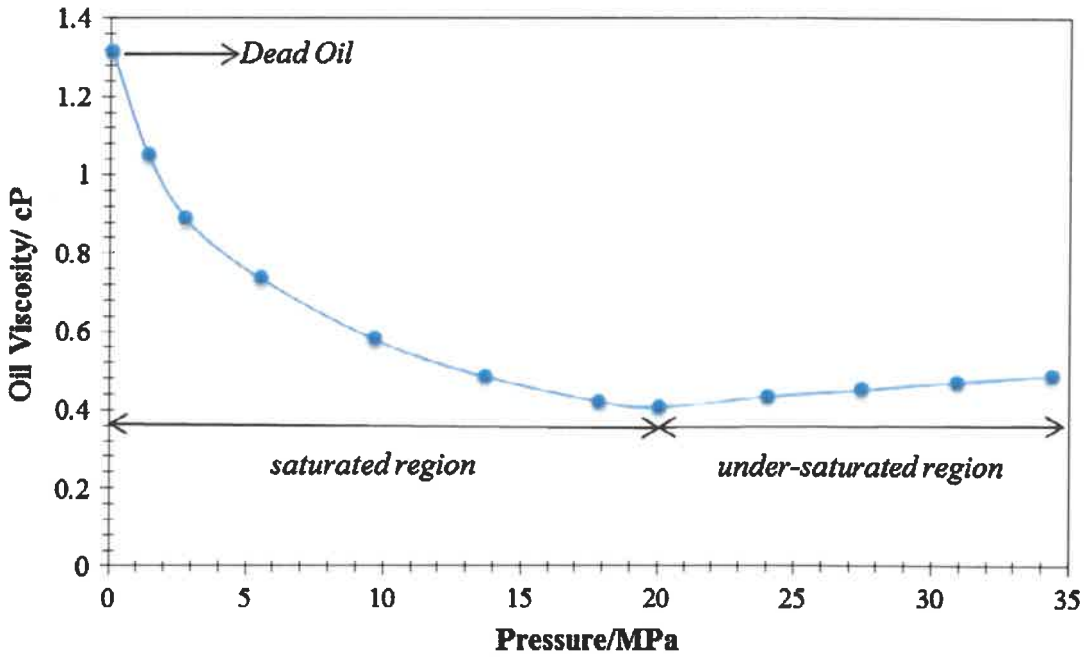


Figure 6: Viscosity curve as a function of pressure (Hemmati-Sarapardeh et al [2014])

In the study referred to above, several well-known oil viscosity correlations were collected to comprehensively investigate the performance of existing empirical correlations on Iranian crude oil reservoir data. The most well-known correlations for oil viscosity were developed by Beal, Beggs and Robinson, Glaso, Kaye, Al-Khafail et al, Petrosky, Egbogah and Ng, Labedi, Karatoatmodjo and Schmidt,

Bennison, Elsharkawy and Alikhan Hossain et al etc. The reliability of any of these models for the prediction of properties and phase behaviour of fluids generally depend on the comprehensiveness of available data. A review of literature reveals that most of reservoir oil viscosity correlations make use of reservoir temperature and reservoir oil API gravity to predict oil viscosity. In addition, pressure, bubble point pressure and oil viscosity at bubble point are also employed depending on the level of saturation of the oil. These parameters were also used by Hemmati-Sarapardeh et al (2014) to develop three models for the prediction of viscosity of dead oil, saturated oil and under-saturated oil. These Least Square Supported Vector Machine (LSSVM) model developed by Hemmati-Sarapardeh et al (2014) was compared with experimental data results, in the case of trend analysis, the behaviour of the model is in good agreement with the experimental data surveyed. The efficiency of the LSVVM model was also reportedly the best when compared to existing models. While the LSSVM model developed in the Hemmati-Sarapardeh et al (2014) study was fairly accurate in the prediction of Iranian oil reservoirs, the applications of these model in other regions has reportedly met with very little success, particularly less successful in prediction heavy oil viscosity behaviour. It is however notable that the LSVVM model is capable of simulating the actual physical trend of oil viscosity with variation of oil API gravity, temperature and pressure.

Another commonly used model is based on the significant structure theory (SST) (Cruz-Reyes et al (2005). Marcias-Salinas et al (2013) improved this model by including modifications that would assist in accurate correlation and/or prediction

of reservoir fluids across wide molar mass pressures and temperature ranges. Although viscosity modelling was conducted for certain reservoir fluids, the applicability of this particular model to heavy oil reservoir cannot be determined from the available information. The modelling approach used by Marcias-Salinas et al (2013) is based on a theory which visualizes a liquid as having both solid and gaseous degrees of freedom (Eyring et al [2005]) with "fluidized" vacancies of molecular size randomly distributed throughout a quasi-lattice structure. The criticism that can be levied against this theory is that it is only applicable to pure fluids and light petroleum fluids. The advantage is that it does predict fluid viscosity behaviour over a wide temperature and pressure range, it is also reasonably computationally efficient. It can thus be incorporated easily into a model or reservoir simulator.

In the work of AM Elsharkwy et al (2000), a detailed comparison was undertaken between classical and neural regression techniques in modelling crude oil viscosity. Earlier on, there were certain studies alluded to, that involved the development of empirical correlations capable of predicting crude oil viscosity as a function of reservoir temperature, oil API gravity, and solution gas ratio, much of these correlations are developed for a given area or region using local viscosity data – this means they are inherently limited in predicting viscosity in areas outside of the region of locality. Since one of the objectives of this work is to develop a framework to aid the development and selection of a viscosity model for heavy oil in particular, due consideration must be given to this "locality" challenge that most

models possess. One approach that has been introduced in the petroleum industry is the use of artificial neural networks (ANN). ANNs are computing tools that mainly comprise of interconnected processors referred to as neurons. These neurons process an input vector by applying a transfer function to give an output, which can serve as input to other neurons (Elshwarkwy et al 2000). It is reported that the comparison between classical regression and neural regression revealed that viscosity models developed using ANN, simulate viscosity behaviour of crude oil better than those developed using classical regression techniques. The ANN models are especially useful in the absence of measured samples, at temperatures either than the reservoir temperature for optimum design of production facilities and improved oil recovery methods

As mentioned before, the viscosity of a fluid changes with temperature, pressure and composition. In the gaseous state, the viscosity is much lower than in the liquid state. The reason lies in the fact that the distance between the molecules in the gas phase is greater than in the in liquid phase. The transfer of momentum in the liquid phase relies mainly on the intermolecular effects between the densely packed molecules. In contrast, the momentum in the gaseous phase is transferred by collisions of the freely moving molecules. Kheirabadi et al (2014) reported on the use of material balance equations (MBE) as an analytical tool for assessing flow behaviour in non-volumetric reservoirs. Material balance has been usually used in reservoir engineering as a tool to determine hydrocarbon in place during exploration phase. The MBE technique relies on the use of pseudo-time. The

definition of pseudo-time has evolved over time according to literature. Agawal (1979) used viscosity and compressibility at the wellbore conditions to define pseudo-time. Palacio and Blasingame (1993) went on to introduce a new definition of pseudo-time that would factor depletion effects using average reservoir pressure rather than wellbore pressure as used by Agarwal. Ander and Mattar (2007) later proved that it is more appropriate to use average pressure in the mathematical definition of pseudo-time rather than applying reservoir pressure. During the validation of this model using numerical models, key observations were made. Chief amongst them was that the difference in the prediction of flow behaviour between the analytical and numerical modes in non-volumetric gas reservoirs is larger than in oil reservoirs. This is due to the fact that gas properties vary sharply as pressure changes. The MBE showed a very slight potential as a tool for oil viscosity prediction in oil reservoirs. In general, the viscosity of a fluid in the gaseous phase increases with increasing temperature, whereas the viscosity of liquids decreases with increasing temperature. When the pressure in the oil reservoir decreases due to oil depletion, the viscosity will decrease until such time that the saturation pressure is reached, temperature on the other end remains constant. From there onwards, pressure continues to decrease and eventually drops below saturation point, the viscosity of the oil is increased which will equate to lower production. Coincidentally, this phenomenon also explains the oil recovery challenges usually associated with heavy oil reservoirs. The reason for this observation is fairly simple yet its implications are problematic for oil viscosity modelling, the oil tends to separate into a liquid and a gaseous phase

below the saturation point. This results in changes in the composition of both the gas and the liquid as the pressure lowers.

A further review of existing viscosity models suitable for practical engineering applications is found in Monnery et al (1905), Mehrotra et al (1996) and Reid et al (1987). The available viscosity models range from highly theoretical models to simple empirical correlations. These models are only suitable for predicting either the liquid or the gas phase viscosity. The kinetic theory of gases and the Chapman-Enskog theory have formed the basis of achieving accurate semi-theoretical models for predicting the viscosity of gases at low pressure. Viscosity models based on the equation state of state (EOS) have also been introduced by Gutto et al (1997). These models are also suitable for estimating gases and liquids. Most of the viscosity available in literature have been derived for hydrocarbon fluids due to their importance in the petroleum industry. Most models in the petroleum industry are based on either the corresponding state principle or the empirical residual concept such as the Lohrenz-Bay- Clarkc(LBC) model (Lohrenz et al 1964). The calculated viscosities predicted by the LBC model strongly depend on how accurate the associated density measures are estimated. This is because parameters that form part of the LBC model rely on density data. An alteration of the LBC model by Tahir (1997) which he achieved by readjusting the equation of the LBC model led to what is referred to as the LABO model. The LABO model also relies heavily on density data estimations for the modelling of viscosity behaviour. It therefore offers no particular advantage over LBC model.

Viscosity models based on the corresponding states principle are common and are generally based on reference fluids. The basic idea of the corresponding states principle is that the same functional behaviour for a given reduced property, eg viscosity, is expressed in terms of other reduced properties.

2.5 Conclusion

It is clear that the modelling of viscosity using any particular model can be greatly enhanced if the parameters closely resemble the natural environment as much as possible. Furthermore, it is a common feature of most if not all the models discussed that regional and other differences linked to the local environment greatly affect the output of the model, this should be accommodated in the selection and design of a particular model. Most models currently in use are very particular and cannot be considered as general models. The viscosity modelling of heavy oil has not enjoyed much interest as a stand-alone area of research and literature on the subject has been rather limited. There is therefore greater scope for research in this field, particularly given the challenges associated with heavy oil exploration and recoveries. It is however expected that as more heavy oil exploration and recovery happens, a greater body of knowledge will be developed. It is thus envisaged that this work will make a modest contribution to that knowledge. The remainder of this work is as follows. Chapter 3 will focus on the theoretical assessment of conventional viscosity models, followed by chapter 4 which presents the results and discussions of the viscosity modelling experiments and chapter 5 which presents concluding remarks.

CHAPTER 3: THEORETICAL ASSESSMENT OF CONVENTIONAL MODELS IN THE CONTEXT OF HEAVY OILS

3.1 Introduction

In an attempt to better understand the use of models, it is useful to explore two main themes that forms the basis of conventional viscosity modelling in the petroleum industry. For the purposes of this section, the term, Black Oil models covers modelling that relates to the use of the oil field derived variables as temperature of the reservoir, saturation pressure, oil API gravity and solution gas ratio and therefore is geographically dependent. The second theme termed corresponding states models relates to the use of compositional data such as reservoir oil composition, critical temperature etc. The two categories depend on the input variables used to develop the model. Furthermore, it is possible to divide models or correlations used for determining oil viscosity into two main subsections depending on the choice of input variables employed in the development of the model. The first subsection makes use of variables such as pour point temperature, molar mass and boiling point while the second model can be derived from a sample of representative PVT data in a given or similar oilfield. Although complex, the latter method is often more accurate.

During course of oil and reservoir compositional simulation, the task of calculating crude oil viscosity is usually required at each pressure step. This process begins by estimating dead oil (gas free) viscosity atmospheric pressure and reservoir temperature. The dead oil is actually taken up as input for the estimation of the

gas-saturated crude oil viscosity; which in turn is taken up as an input for estimation of unsaturated crude oil viscosity. There are other models that make use of the Watzen factor, this factor is introduced as an additional parameter. The Watzen factor provides a means for identifying the paraffinicity or character of the crude oil. It is also reasonably consistent for chemically similar hydrocarbons. It is reported that the Watzen factor and the boiling point are related together through the API gravity (Elsarkway and Alikhan, 1999). Revisiting figure 6 earlier on, the viscosity starts at the dead oil viscosity condition where it is evaluated at atmospheric pressure and system temperature. As the pressure increases, associated with underground conditions, the free gas get into contact with the oil and is dissolved until all gas is dissolved. The pressure increases until it gets to what is commonly referred to as the bubble point pressure. At bubble point pressure, it is often assumed that there is no more gas available that can be dissolved into the oil (Hemmati-Sarapardeh et al, 2014). This is the region of saturation. The under-saturation is attained when pressure increases above the bubble point pressure, usually accompanied by a viscosity increase. As mentioned in the prior sections of this work, the more applicable viscosity correlations are to a wider range of parameters like temperature for example, the more useful they are to the petroleum industry. Such correlations and modelling often require the composition of the hydrocarbon mixture in order to enhance the usefulness of the model. This presents a significant challenge because, generally, the hydrocarbon composition will be different for each region making it impossible to use an exact model of a particular region to accurately predict the viscosity behaviour of another

region. We shall reflect on this point again in later sections when we review the research in context of heavy oils.

3.2 Classification of models used in this research

3.2.1 Beal Model

The Beal model was developed in 1946 to determine dead oil viscosity, as a function of API gravity and temperature. Beal used different temperatures using 492 fields in the United States. Beal also presented a correlation to predict viscosity of undersaturated oil using 52 data points from 26 different crude oils. The study is often criticised on its lack of analytical expression corresponding to the graphical correlation.

3.2.2 Beggs and Robinson

Beggs and Robinson developed two models to predict viscosity from dead and saturated viscosity as a function temperature and API gravity. The dead oil viscosity model is based on 460 data points obtained from 93 samples. The unsaturated oil viscosity model was developed from 2073 samples. The authors modified the concept of Chew and Connally to provide a linear relationship, where each line represents different oil densities. However, this method demonstrates a considerable error when tested against samples either than the reference samples. The authors never clarified the source of the error, but advised that an extrapolation of the method outside the range of data used in the study should be approached with caution.

3.2.3 Labedi

In 1992, Labedi introduced a set of new correlations for dead, saturated and undersaturated oil viscosity. The model is created through the use of multiple regression analysis of 100 oil samples from Libya. The correlation of dead oil viscosity revealed an average error of -2.61% while the unsaturated oil viscosity presented an average error of -2.38%. Even though the Labedi model is developed based on samples from a relatively small region, the author claims the correlation to be valid for other areas such as the Middle East. The model is however not suitable for oils with an API gravity of less than 32. This important factor renders it without use for heavy oils unless it is appropriately modified.

The three models selected were chosen because of their extensive use in both industry and literature and their apparent ability to be modified in order to produce more accurate results, this modification is however, beyond the scope of this research. The following table shows the 3 viscosity models. For the purposes of this work, we evaluated the chosen models, for dead oil conditions and for unsaturated oil conditions. Table 1 and 2 below show the models for each of the conditions. These models will be validated and discussed using real data (Egyptian oil) in chapter 4.

Models for unsaturated oil conditions

Authors	Model Correlation
Beal (1946)	$\mu_o = \mu_{ob} + 0.001(P - P_b)(0.024\mu_{ob}^{1.6} + 0.038\mu_{ob}^{0.56})$
Beggs and Robinson (1975)	$\mu_O = \mu_{Ob}(\frac{P}{P_b})^n$
Labedi (1982)	$\mu_o = \mu_{0b} + \left(\frac{P}{P_b} - 1\right)\left(\frac{10^{-2.488} \times \mu^{0.9036} \times P_b^{0.6151}}{10^{0.0197 \times API^\circ}}\right)$

Table 1:Viscosity models for unsaturated oil conditions

Models for dead oil conditions

Authors	Model Correlation
Beal (1946)	$\mu_{od} = 0.32 + \left(\frac{1.8*10^7}{API^{\circ 4.53}}\right)\left(\frac{360}{((T+460)-260)}\right)^a \quad a = 10^{0.42+\left(\frac{8.33}{API^\circ}\right)}$
Beggs and Robinson (1975)	$\mu_{od} = \mu_{os} 10^C - 1$ $C = 10^{3.0324 - 0.02023 * {}^\circ API} * T^{-1.163}$
Labedi (1982)	$\mu_{od} = \frac{a}{b}$ where $a = 10^{9.224}, b = API^{\circ 4.7013} \times T^{0.6739}$

Table 2: Viscosity models for dead oil conditions

The tables above summarise the main equations of the viscosity models that have been identified for experimental evaluation. As mentioned before, dead oil viscosity correlations that offer increased accuracy in calculating viscosity require the inclusion of Watson characterisation factor as an extra parameter. This factor provides a means of identifying the paraffin composition or character of the crude oil. It stays reasonably constant for chemically similar hydrocarbons. Bergman and Sutton (2003) reportedly used non-linear regression techniques to update the correlation for the Watson characterisation. In the equation proposed by Bergmann and Sutton, the molecular weight of the crude oil (Mo) is often measured from the oil itself if this is practical or derived from the fractional values reported in the PVT report of the crude oil. If the chemical nature of the crude oil is known, it is defined as a function of API gravity. If the chemical nature of the crude oil is unknown, industry can make use of the plot presented by Bergman and Sutton where the Watson factor is plotted against the API gravity for a database of oils compiled from all over the world including 3000 crude oil assays, conventional PVT reports and literature data. It is worth noting that the graph is only used as a guidance for typical values for Watson factors as a function of API gravity. The focus of this work involves the analysis of viscosity models with particular reference to heavy oil suitability. Available literature as revealed early in the survey clearly concluded that it is not possible nor is there any scientific evidence to suggest that a general model for heavy oil viscosity using oil field data (Bennistion,1998). However several models have been advanced with small enough relative errors to increase the correlation between experimental data and predicted data using

certain oil field parameters. Measuring the viscosity and density of dead oil is easier using empirical correlations at temperatures either than reservoir temperatures (Ahrabi et al 1987). These measurements can be used as the starting point for live oil viscosity and density predictions. It is very difficult and expensive to measure viscosity at reservoir temperatures, which explains the lack of data available on this particular parameter. However viscosity and density for that matter are important for creating numerical simulations to determine the economics of oil recovery. Knowledge of oil viscosity is therefore vital to most areas of the petroleum industry, especially in the production of heavy oil. Stable crude oil emulsions are an interesting concept that can also employed in the analysis of crude oil viscosity.

Oil emulsions are generally prevalent in the many stages of heavy oil production, processing and transportation. The challenge however is as viscosity increases, conventional methods become less accurate and more difficult to obtain. In heavy oil and bitumen, oil viscosity is often correlated directly to reserve estimates and can determine the success or failure of a chosen oil recovery scheme (Al-Rawahi et al, 2012). The development of viscosity models require a fundamental understanding of viscosity principles. We shall briefly reflect on these principles. Newton's law of viscosity is given as:

$$\acute{E} = \eta\gamma \ldots\ldots\ldots\ldots\ldots\ldots (2)$$

Where ´E is the shear stress, γ is the shear rate and η is the viscosity

In context of the above equation, viscosity calculations usually require a multi-step process that may involve separate correlations for each step of the process. Dead or gas free oil viscosity is typically determined as a function of crude oil API gravity and temperature. The viscosity of saturated oil is determined as a function of dead oil viscosity and solution gas ratio. Unsaturated oil viscosity is determined as a function of saturated oil viscosity and pressure above saturation pressure.

3.2.4 General viscosity trends for different models

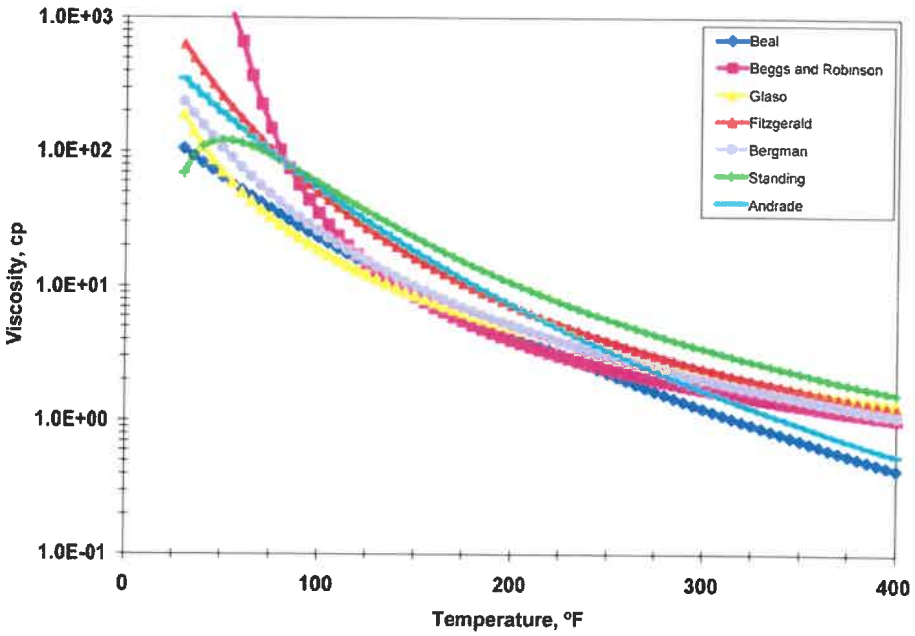


Figure 7: Viscosity models as a function of temperature (Macias-Salinas et al [2013]).

Several trends for oil viscosity and temperature have been observed on some of the more commonly used models. For example at temperatures below 24 °C, the model of Beggs and Robinson tends to over-predict viscosity quite severely. This exact tendency is part of the characteristic that render models such as these unsuitable for use in other temperature ranges. Beal's model, as observed from the graph above was initially developed from observations of dead oil viscosity at temperatures ranging between 38° C and 93° C. Contrary to the model developed by Beggs and Robinson, Beal's model under-predicts viscosity at high temperatures. Dead oil viscosity correlations are somewhat inaccurate because they fail to take into account the chemical nature of crude oil as previously alluded to in this work and as previously introduced, models that make use of the Watson characterisation factor are better able to address this technical shortfall. It is reported in the API technical data book of Petroleum Refining 2015 that the Fitzgerald model was developed for a wide range of conditions and is probably one of the more versatile viscosity correlation methods.

A model that could possibly be proposed as the most apt for dead oil viscosity is the one developed by Andrade. This model is based on the observation that the logarithm of dead oil viscosity is directly proportional to the reciprocal of absolute temperature from somewhere around the boiling point to the freezing point of the oil. The following figure shows how Andrade's model is applied through the use of measured dead oil viscosity points taken at low pressure and two or more temperatures in comparison to other commonly used models.

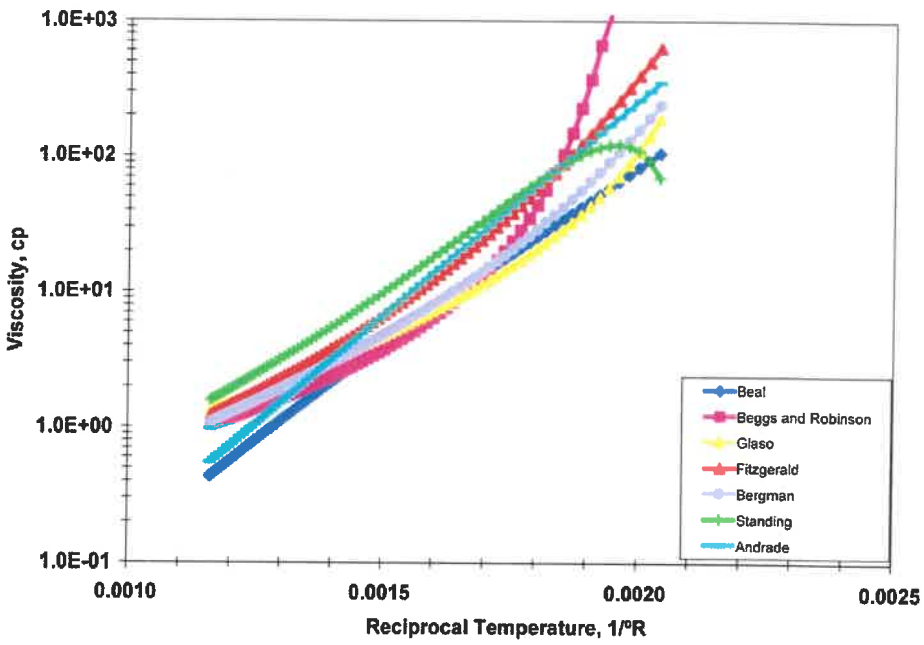


Figure 8: Area of applicability of the Andrade model in compared to other models (Macias-Salinas et al [2013]).

The table below provides a summary of the ranges of what is referred to as bubble point viscosity correlation methods. The bubble point is the point where the bubble comes out of solution as the pressure is so great, the crude oil can no longer hold gas. Correlations of the bubble point viscosity take the form of

$$\gamma_{ob} = A\,\gamma_{od} \ldots\ldots\ldots (3)$$ (Marcias-Salinas et al [2013])

As proposed by Chew and Connally

When pressure increases above the bubble point, the oil becomes unsaturated. Oil viscosity increases almost proportionally with an increase in pressure Above the bubble point, the oil acts as a single phase and is known as saturated oil.

Model	Nr of data points	Range	R_S Range (scf/STB)	Average Error	Average Absolute Error	Standard deviation
Chew and Connolly	2257	N/A	51-3544	N/A	N/A	N/A
Beggs and Robinson	2073	N/A	20-2070	-1.83	27.25	N/A
Labedi	91	0.115-3.72	N/A	-2.36	22.81	N/A
Khan	1841	0.13-77.4	24-1901	0.941	7.201	5.157
Al-Khafaji	72	N/A	0-2100	1.8	2.7	2.8
Petrosky	864	0.21-7.40	21-1885	-3.12	14.47	19.66
Kartoatmodjo and Schmidt	5321	0.096-586	0-2890	0.08	16.08	N/A
De Ghetto	195	0.07-295.9	9-3299			N/A
Almehaideb	57	N/A	128-3871	N/A	13	16.26
Elsharakawy	254	0.05-20.89	0.05-20.89	2.8	18.6	25.7
Dinodruk and Christman	95	0.161-87	0.161-87	-3.05	13.2	17.29

Table 3: Bubble point viscosities ranges for several models (Source: Journal of Petroleum Exploration and Production Technology)

There is still no conclusive practical evidence for the calculation of viscosity at heavy oil conditions with absolute accuracy across multiple regions and processing/environmental parameters. This difficulty becomes further amplified in particularly high temperatures. This is notable given that the harvesting of oil is becoming deeper and heavier. Alomair et al. (2016) attempted to obtain exact models to accurately predict the viscosity and density of heavy oils by predicting heavy oil density from API and temperature, and then the predicted values of the densities were used in the second step to develop the viscosity correlation. A total of 30 heavy oil samples were used with differing API's. Viscosity and density were measured at ranges between 20 ℃ and 160 ℃. The investigation then used the Standing and Katz method to test the accuracy of the proposed model. A comparison between the experimental data and the predicted values indicated that the model proposed by Alomair et al. has a 80% accuracy rate. However when tested on heavy oil samples, it was once again confirmed that it is not possible to derive a general correlation for heavy oil viscosity modelling using only API and temperature, this is a particularly important observation. The figure below also illustrates that the temperature may have a limited impact on the viscosity in reservoir depth except for a particular geology.

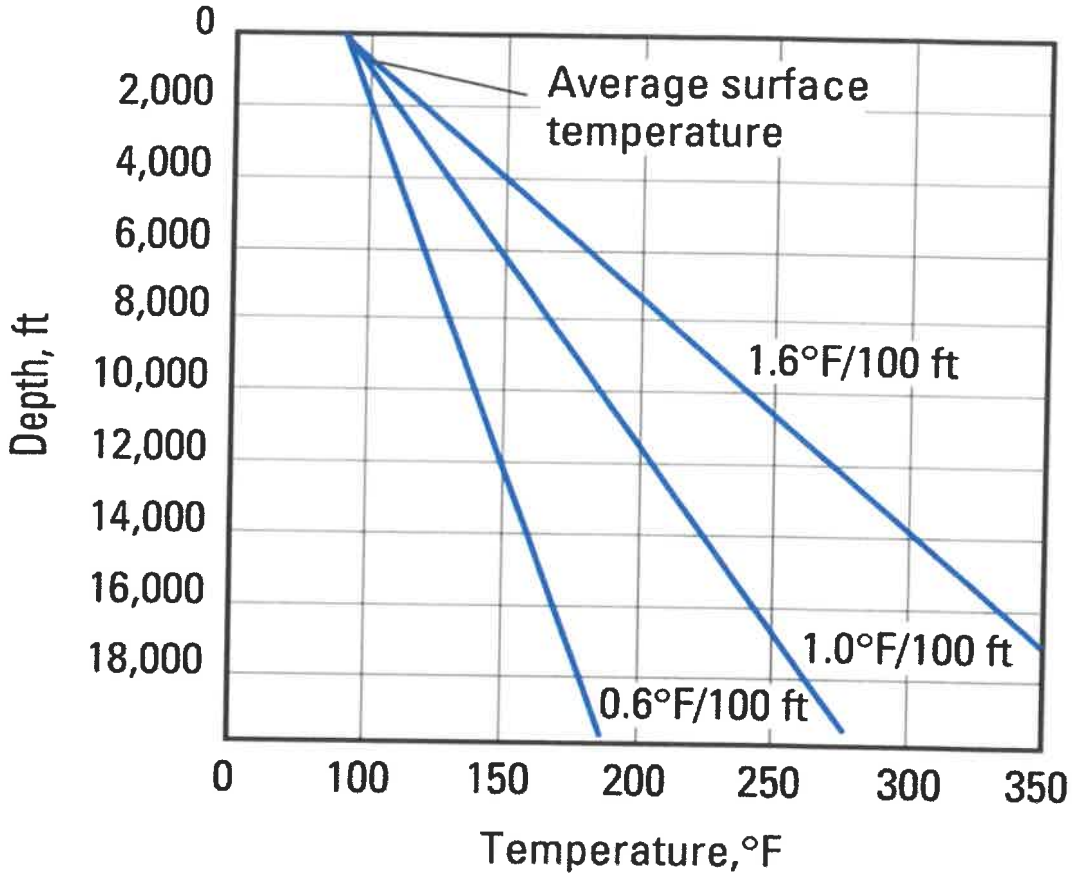


Figure 9: The relationship between reservoir depth and temperature

Owing to the relative usefulness of the proposed model, it would be of interest to briefly reflect on its experimental derivation. The experimental data of the viscosity and the 30 heavy oil samples were measured. These values were subjected to a statistical analysis to determine and assess the distribution and relationship between the data points. In line with ASTM guidelines, the model of the dead oil viscosity was labelled according to its standard API at 15.5 ℃, referred to as the first parameter for any viscosity model. The second parameter of the proposed model was the measured temperature. An analysis of the literature indicates that

most of the models are based on the intermediate parameter or two parameters like API and temperature to calculate the viscosity. In the model under discussion, a real physical property was selected as the intermediate parameter. Density was modelled using API and temperature. This density was then used to predict the viscosity. Some observations can also be made about the density model and the viscosity model.

Density model

The following equation was derived by curve fitting regression methods using experimental density data with respect to the standard API gravity and temperature.

$$\rho_{od} = a + b\left(API_{60°F} - 60°F\right) + c\,(T) \quad \text{.....(4) (Alomair et al 2014)}$$

Where ρ_{od} is the density of the dead oil in kg/m³ measured at the temperature and API of the dead oil measure at 16 ℃. The values of a, b and c are 1,0724088, -0,0065265 and -0,0006639 respectively. The regression coefficient (r) is 0,98. What is of interest to this work is the viscosity model.

Viscosity model

Any model usually makes use of input and output variables. A viscosity model is no exception, it is therefore important to understand the relationship between different variables and how each variable affects the viscosity. In the proposed model, Alomair O performed a sensitivity analysis for the main parameters, namely viscosity, density and temperature. Two equations were derived, these are

$$\gamma_{od} / T_b^{-1} \ldots\ldots\ldots\ldots\ldots\ldots (5)$$ (Alomair et al 2014)

This equation describes the relationship between viscosity and temperature. The relationship depicted is that whenever the temperature is increased, the viscosity decreases (inversely proportionality).

$$\gamma_{od} / \mathrm{cln}\rho_{od} \ldots\ldots\ldots\ldots\ldots (6)$$ (Alomair et al 2014)

This equation suggests that there is a direct correlation between viscosity and density.

After multiple regression analysis of the experimental viscosity data, the following function was developed:

$$\mathrm{Ln}\ (\gamma_{od} = a + (b/T^2) + c(\rho_{od}{}^2)\mathrm{ln}\ \rho_{od} \ldots\ldots\ldots\ldots\ldots\ldots (7)$$ (Alomair et al 2014)

The evaluation of the proposed viscosity model showed that the results for the low temperature region were in good agreement. The relationship between the predicted viscosity and the experimental viscosity is directly proportional. The

model data was subjected to conventional models developed by Beal (1946); Beggs and Robinson (1975); Elsharkwag and Alikhan (1999); Glaso (1980); Elossain et al (2005); Kartoatmodjo and Schmidt (1994), Labedi (1992), Naseri et al (2005), Petrosky and Farshed (1992), Standing (1947) in order to test the capability of the model. In the assessment of the proposed model, it was found that Stander model results had the highest correlation with the model. The proposed model was also compared with other theoretical models available in literature using crude oil samples from North America. It was found that it is not possible or at least not a simple task to generalize dead oil viscosity modelling using API and temperature as the determining factors.

CHAPTER 4: RESULTS AND DISCUSSIONS

4.1 Introduction

Heavy oil properties are distinctly unique from light oils, this may affect how they are extracted, refined and processed. These properties include the following.

- Heavy oil wells produce at lower rates than is the case in light oils due to slow reservoir flow.
- Heavy oil extraction requires more well development
- Water flooding is not viable.
- It also presents energy balance difficulties during the recovery process.
- Heavy oil is depleted in hydrogen when compared to light oil.
- Fewer refined products can be derived from heavy oil as a result of its composition.
- Currently heavy oil is priced at a lower value than light oil

For the purpose of this work, we will explore viscosity as it relates to heavy oils, later on when we explore modelling techniques using oil viscosity samples and discuss their validity, we will then attempt to derive a set of principles that can be considered in the selection or development of viscosity models for heavy oil. The term heavy oil is usually used to refer to the high density of the chain molecules. We have already observed that there is a direct correlation between gravity and viscosity, however this relationship is considered to be generally weak. The consensus in literature is that any quantitative transformation from gravity to viscosity is merely a rough estimation rather than a scientific certainty. Heavy oils

are believed to be residues formed from light oils that do not contain any light molecules, meaning only heavy ones are present. These form long hydrocarbon chains characterized by long, complex molecular chains. Since the hydrogen are usually in the light oil ends, heavy oils are generally hydrogen depleted. The long and complex chains of heavy oils causes intermolecular friction which results in high viscosity.

When reflecting on the use of conventional technologies for heavy oil depletion, we observe that the highest economic recovery rates are achieved in open pit harvesting of heavy oil reserves, this however is not feasible in most instances. The use of high density vertical wells, horizontal wells, cold heavy oil production with sand (CHOPS) and water flooding only has recovery hovering around 10% (BP 2011) Other notable conventional technologies such as EOR have recovery rates that are better, standing at around 20% (BP, 2011). Clearly there is scope to either develop technologies for higher recovery of heavy oil or improve the recovery of heavy oil using conventional technologies. A key component of these improvement efforts lies in the modelling of viscosity.

When fluids flow from the reservoir to the surface, pressure and temperature decrease. This affects the gas/liquid equilibrium and the properties of the gas and liquid phases. The black-oil model enables estimation of these, from a minimum of input data.

The black-oil model employs 2 pseudo components.

1) Oil which is usually defined as the produced oil, at stock tank conditions.

2) Gas which then is defined as the produced gas at atmospheric standard conditions.

The basic modeling assumption is that the gas may dissolve in the liquid hydrocarbon phase, but no oil will dissolve in the gaseous phase. This implies that the composition of the gaseous phase is assumed the same at all pressure and temperatures.

The black-oil model assumption is reasonable for mixtures of heavy and light components, like many reservoir oils. The assumption gets worse for mixtures containing much of intermediate components (propane, butane), and is directly misleading for mixtures of light and intermediate components typically found in condensate reservoirs. The basic modeling assumptions lead to the following relationships for fluid volumes at flowing conditions:

$$Q_L = q_o B_o + q_w B_w = q_o \left(B_o + F_w B_w\right) \tag{8}$$

$$Q_G = \left(q_g - R_s q_o\right) B_g = q_o \left(R_t - R_s\right) B_g \tag{9}$$

where:

q_o : surface oil production rate (Sm^3/s)

q_g : surface gas production rate (Sm^3/s)

q_w : surface water production rate (Sm^3/s)

R_t : producing gas/oil ratio (Sm^3/Sm^3)

R_s : gas solubility (Sm^3/Sm^3)

F_w : producing water/oil ratio (Sm^3/Sm^3)

B_o : oil formation volume factor (m^3/Sm^3)

B_g : gas formation volume factor (m^3/Sm^3)

B_w : water formation volume factor (m^3/Sm^3)

In Eq. (8), the water is added to the liquid phase. Although some water will vaporize to the gas phase, this is usually neglected. The surface densities of oil, water and gas are usually available from measurements.

The fluid densities at flowing conditions can be derived from the volume relationships above

$$\rho_G = \frac{\rho_g (q_g - R_s q_o)}{Q_G} = \frac{\rho_g}{B_g} \tag{10}$$

$$\rho_L = \frac{(\rho_o + \rho_g R_s) q_o + \rho_w q_w}{Q_L} = \frac{\rho_o + \rho_g R_s + \rho_w F_w}{B_o + B_w F_w} \tag{11}$$

where:

ρ_o : surface oil density (kg/Sm^3)

ρ_g : surface gas density (kg/Sm^3)

ρ_w : surface water density (kg/Sm^3)

As long as liquid and gas are in contact and in thermodynamic equilibrium, the liquid will be gas saturated at the actual pressure and temperature. The saturation pressure for a gas-oil system is the pressure at which the gas solubility equals the producing gas/oil ratio, R_t

$$R_s(p_b, T) = R_t \tag{12}$$

where:

p_b : saturation pressure

T : fluid temperature

Thus correlations for the gas solubility can be used to estimate the saturation pressure for a given R_t, and vice versa. From basic thermodynamics the following solubility behaviour may be expected.

a) Solubility proportional to pressure (Henry's law)

b) Solubility inversely proportional to the exponential of 1/T (after Clausius - Clapeyron's law)

c) Heavy gas more soluble than light gas. Heavy oil dissolves less gas than light oil (molecular similarity). Actually most gas solubility correlations have originally been presented as methods for saturation pressure estimation.

The volumetric behaviour of reservoir fluid due to changes in temperature and pressure is influenced by the physical properties of the fluid such as composition, density, viscosity, etc. This behaviour is easily understood through analysis of results obtained from either controlled PVT (Pressure-Volume-Temperature) experiments on crude oil samples, or field test (or induction data). Observation has shown that PVT parameters measured from bottom-hole samples taken from saturated reservoir, do not always represent the true condition in the reservoir due to the effects of excessive drawdown pressure (that is, the difference between the bottom-hole flowing pressure and the initial reservoir pressure),gas saturation. It is therefore becoming a normal practice for PVT data on saturated black oil reservoir to be evaluated before use. The evaluation procedure involves using the gas-oil contact (GOC) to estimate the bubble-point pressure of the oil; where the data is found to be wrong due to the drawdown pressure, the PVT parameters have to be re-determined starting from the sampling stage to the data –report stage or validated and corrected using standard correlations.

There are five types of reservoir fluids: Black oil, volatile oil, retrograde gas, wet gas and dry gas. It is important that the field engineer determines the type of fluid in the early life of a reservoir so as to enable him or her decide the method of sampling, the type and size of surface equipment to be used, the causational procedures for determining oil and gas in a place, the techniques of predicting oil and gas reserves, the plan of depletion, and selection of enhanced recovery method. Three properties that are readily available as rules of thumb for identifying each of the five types of reservoir fluids are the initial producing gas-oil ratio, API

gravity of the stock-tank liquid, and the colour of the stock-tank liquid, but the initial producing gas-oil ratio is by far the most important indicator of the type of fluid. Note that stock-tank-oil means dead oil (i.e. oil with zero gas at atmospheric pressure) corrected to 60°F. The name black-oil is misnomer since the colour of this type of oil is not always black. This type of reservoir fluid has also been called low-shrinkage crude oil or ordinary oil. Black oils consist of a wide variety of chemical species including large, heavy, non-volatile molecules. The phase diagram predictably covers a wide temperature range. Black oils exhibit initial producing gas-oil ratios of above 2000scf/stb (standard cubic feet per stock-tank barrel) or less. Producing gas-oil ratio will increase during production. When reservoir pressure falls below the bubble-point pressure of the oil, the stock-tank oil usually will have gravity below 45°API which decreases slightly with time until late in the life of the reservoir when it will increase. The stock-tank oil is very dark, often black, indicating the presence of heavy hydrocarbons, sometimes with a green or brown cast. Laboratory analysis will indicate an initial oil formation-volume factor of 2.0 reservoir barrels per stock-tank barrels (res bbl/ stb) or less.

4.2 Constant Composition Expansion (CCE) test

For an oil sample, the CCE experiment is used to determine bubble point pressure, under saturated-oil density, isothermal oil compressibility, and two-phase volumetric behaviour at pressures below the bubble point. Table 4 presents data from the CCE experiment data for an Egyptian reservoir oil and which will be

assessed in this study. Typically to conduct a CCE experiment, a blind cell (i.e., a cell without a window) is filled with a known mass of reservoir fluid. Reservoir temperature is held constant during the experiment. The sample is initially brought to a condition somewhat above initial reservoir pressure, ensuring that the fluid is single phase. As the pressure is lowered, oil volume expands and is recorded. The fluid is agitated at each pressure by rotating the cell. This avoids the phenomenon of super-saturation, or metastable equilibrium, where a mixture remains as a single phase even though it should exist as two phases. Just below the bubble point, the measured volume will increase more rapidly because gas evolves from the oil, yielding a higher system compressibility. The total volume is recorded after the two phase mixture is brought to equilibrium. Pressure is lowered and equilibrium is obtained at each pressure. For a black oil (far from its critical temperature), the discontinuity in volume at the bubble point is sharp and the bubble point pressure and volume are easily read from the intersection of the p-V trends in the single- and two-phase regions. Volatile oils do not exhibit the same clear discontinuity in volumetric behaviours at the bubble point pressure. Instead, the p-V curve is practically continuous in the region of the bubble point because the under saturated-oil compressibility is similar to the effective two-phase compressibility. Laboratory inaccuracies in measuring the total hydrocarbon volume just below the saturation pressure frequently require correction by smoothing the relative volume data. The Y - function is used to smooth the values of the relative volume by plotting the Y-function as a function of pressure on a Cartesian scale and by using the coefficients of it to correct the relative volume.

Generally, the Y - function when plotted, forms a straight line and has only a small curvature at pressures close to the bubble point pressure, as in Figure 11. The Y-function is linear with pressure and is related to the two phase volume (Vp (scf)), bubble-point volume (Vb (scf)), bubble-point pressure (Pb (psia)) and pressure (P (psia)) as follows:

$$Y = \frac{P_b - P}{P\left(\frac{V_p}{V} - 1\right)} \tag{13}$$

The Y - function, which is dimensionless, is applied to CCE data below the bubble-point from black oil PVT studies (Standing, 1952) but has also been extended to determine the bubble-point pressures for black oils and volatile oils.

As far as the oil compressibility is concerned, its value for pressures above bubble point can be derived from CCE by counting the derivative of volume to the pressure change. It is expected that, as pressure increases, the oil compressibility decreases linearly (Figure 12). A small error in relative volume leads to huge deviation of the derivative of the volume, so the isothermal compressibility would deviate from linearity with pressure. Traditionally, isothermal compressibility data are reported for pressure intervals above the bubble point. In fact, the under saturated-oil compressibility varies continuously with pressure, and, because Vt =Vo (Vrt= Vro) for p >pb, oil compressibility can be expressed as:

$$c = \frac{1}{V_{rt}}\left(\frac{\delta V_{rt}}{\delta P}\right)_T = \frac{1}{V_{To}}\left(\frac{\delta V_{To}}{\delta P}\right)_T \qquad (14)$$

Pb; bubble point density, $V_{ob}\left(V = \frac{1}{\rho}\right)$ is the specific volume and Vt is the total volume and where $V_{rt} = \frac{V_t}{Vob}$

When gas dissolves in the oil, the mass contained in oil phase increases. This makes the pressure-volume behavior of liquid below the saturation pressure fundamentally different than from above the saturation pressure.

Below the saturation pressure:

Both liquid and gaseous phases will be present, and the following effects may be expected:

a) Expansion of the liquid volume by the dissolved gas. This should be roughly proportional to amount of gas dissolved and increase by increasing molecular size (mol volume) of the gas.

b) Expansion of liquid volume by increased temperature. However, increased temperature will also reduce gas solubility.

c) Compression by increased pressure.

The overall effect of pressure increase at constant temperature will be increased liquid volume. Temperature increase at constant pressure will result in reduced liquid volume, caused by vaporization.

Above the saturation pressure, all gas will be in solution, and only a liquid oil phase present. This liquid will compress with increasing pressure. The compressibility factor is generally defined as

$$c = -\frac{1}{V}\frac{dV}{dp} = -\frac{1}{B_o}\frac{dB_o}{dp} \tag{15}$$

For ideal liquids, the compressibility factor is constant. Assuming constant compressibility, the volume behavior above saturation pressure may be expressed by integrating (18). This gives

$$B_o = B_{ob}\, e^{-c(p-p_b)} \tag{16}$$

where:

c : constant compressibility factor (1/bar)

p_b : saturation pressure (bubble point pressure)

B_{ob}: formation volume factor at saturation pressure

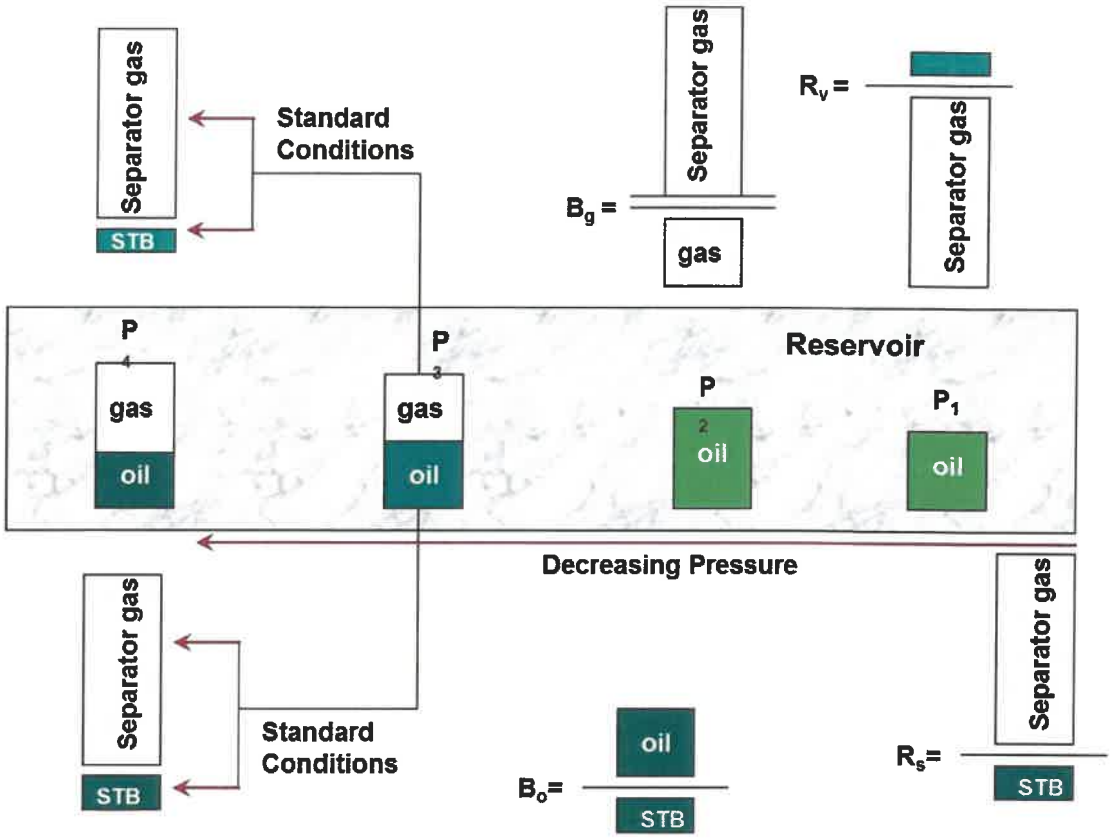


Figure 10: Illustration of the different Oil & Gas PVT Properties

Table 4: Constant Composition Expansion data for an Egyptian reservoir oil

CCE #1 Experimental Data			
Pressure	**Relative Volume**	**Oil Compress.**	**Y Function**
Psia	V/Vsat	1/psi	
5015	0.9626	1.020E-05	
4515	0.9679	1.07E-05	
4015	0.9730	1.15E-05	
3597	0.9777	1.24E-05	
3015	0.9848	1.38E-05	
2515	0.9917	1.65E-05	
2346	0.9941	2.01E-05	
2162	0.9969	2.98E-05	
2067	1.0000		
1913	1.0309		2.618
1653	1.1003		2.520
1323	1.2397		2.372
1118	1.3796		2.266
973	1.5200		2.196
864	1.6604		2.146
781	1.8008		2.096
713	1.9401		2.063

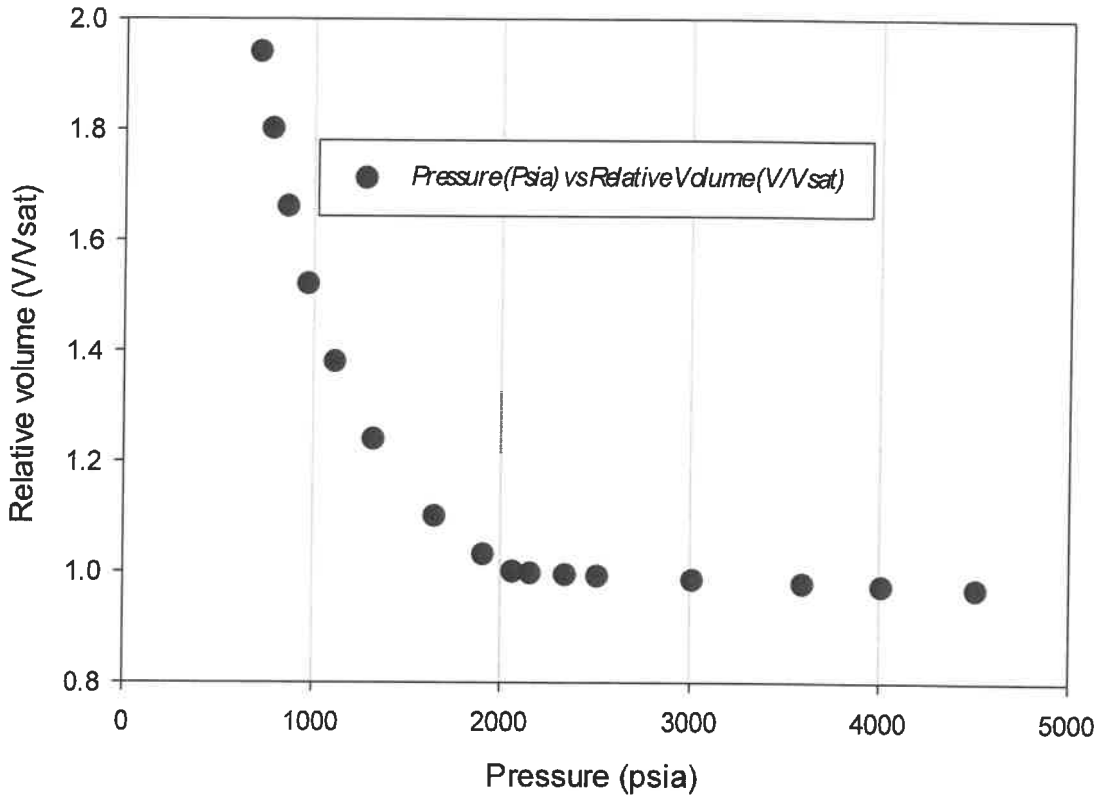


Figure 11: Illustration of the Relative Volume vs Pressure

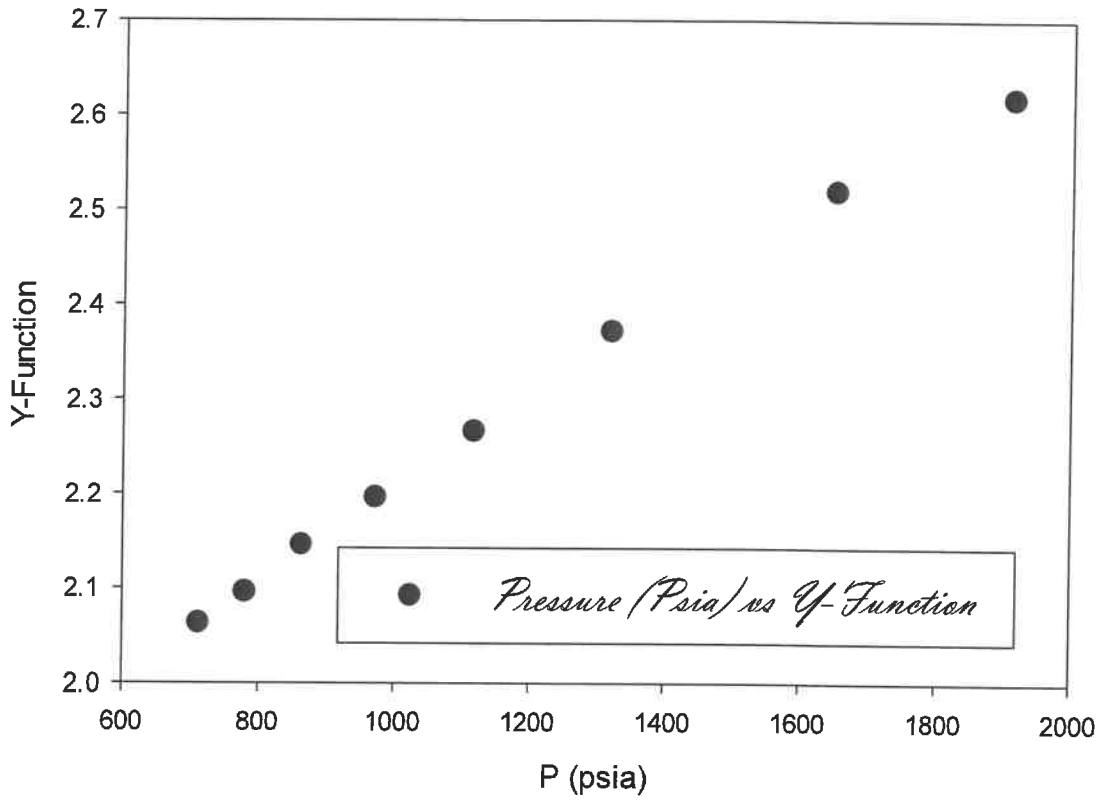


Figure 12: Illustration of the Pressure vs Y-function of relative volume

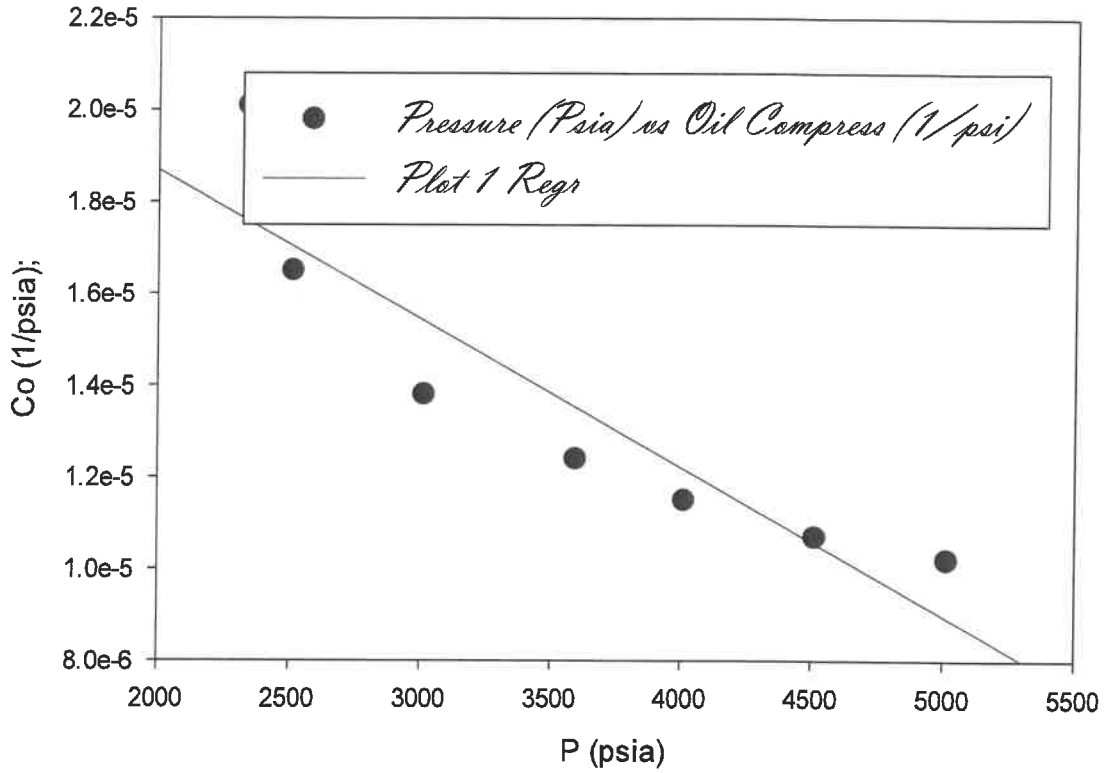


Figure 13: Illustration of the Pressure vs Oil compression

4.3 Differential Liberation Expansion (DLE) and Multistage-separator Test

This experiment is designed to approximate the depletion process of an oil reservoir and thereby providing suitable PVT data to calculate reservoir performance (Moses, 1986). A PVT cell is filled with the reservoir oil, which is brought to a single-phase (ie above reservoir pressure) at reservoir temperature. The pressure is decreased until the fluid reaches its bubble-point and the oil volume at this point, V_{ob} is recorded. Since the initial mass is known, the bubble-point density of the oil (ρ_{ob}) can be calculated. The pressure is decreased below the bubble-point in steps, and at each point, the cell is agitated until equilibrium is reached and the gas is removed at constant pressure before proceeding to the next step. The volume (ΔV_g), number of moles (Δn_g) and the specific gravity ($\Delta \gamma_g$), of the removed gas as well as the volume of the remaining oil (V_o) are measured at each pressure point. This procedure is repeated for not less than seven steps until it gets to atmospheric pressure where the residual-oil volume (V_{or}) and specific gravity (γ_{or}) are measured. Other properties that can be calculated for each step (or stage) based on the above measured data are the differential solution gas-oil ratio (R_{osd}), differential oil formation volume factor (B_{od}), oil density (ρ_o), and gas deviation factor (Z), for stage K, these properties may be determined as follows (Moses, 1986);

$$(R_{sd})_k = \frac{\sum_{j=1}^{k} 379(\Delta n_g)_j}{V_{or}} \qquad (16)$$

$$(B_{od})_k = \frac{V_R}{V_{or}} \tag{17}$$

$$(\rho_{ob})_k = \frac{350\gamma_o + \sum_{j=1}^{k} 0.0764(R_{sd})_j(\gamma_g)_j}{5.6158(B_{od})_k} \tag{18}$$

$$(z)_k = \left(\frac{1}{RT}\right)\left(\frac{\rho\Delta V_g}{\Delta n_g}\right)_k \tag{19}$$

Note that gas-oil ratio (R_s) and formation-volume factor (B_o) are calculated directly from results of the DLE experiment. For stock tank conditions using (Curtis and Michael, 2000) equation as follows:

$$R_s = (R_{sb} - R_{sd})\left(\frac{B_{ob}}{B_{odb}}\right) \tag{20}$$

$$B_o = B_{od}\left(\frac{B_{ob}}{B_{odb}}\right) \tag{21}$$

Furthermore, a multistage-separator test is performed on oil sample primarily to provide a basis for converting differential-liberation data from residual-oil to a stock-tank-oil basis. Occasionally, several separator tests are run to help choose separator conditions that maximize stock-oil-oil production. Usually, two or three stages of separation are used, with the last stage at atmospheric pressure and near-ambient temperature (60 to 80°F). Initially, the reservoir sample was at saturation conditions and the volume measured (V_{ob}). The sample was then brought to the pressure and temperature of the first-stage separator. All the gas was removed, and the oil volume at the separator stage (V_{osp}) was noted together with the volume of the removed gas (ΔV_g). The number of moles of the removed gas (Δn_g), and the specific gravity of the removed gas (γ_g). The oil remaining after

gas removal was brought to the conditions of the next separator stage. The gas was removed again and quantified by moles and specific gravity. The oil volume was noted, and the process was repeated until stock-tank conditions were reached. Final oil volume (V_o), and specific gravity (γ_o) were measured at 60°F. The total gas-oil ratio (GOR) was calculated by adding the stock-tank oil based GORs for each separator stage as

$$R_s = \sum_{k=1}^{Nsp} (\Delta R_s)_k \tag{22}$$

Where Nsp = number of stages in the multi-stage separator test, and ΔR_s is the stock-tank oil based GOR for each stage of the multi-stage separator test. From (Curtis and Michael 2000) equation for solution gas-oil ratios;

$$R_{sp} = \frac{V_g}{V_{osp}} \tag{23}$$

$$R_s = \frac{V_g}{V_{osp}} \tag{24}$$

Dividing the above two equations gives the formation volume factor for separator oil (B_{osp}) as

$$B_{osp} = \frac{R_s}{R_{sp}} \tag{25}$$

The average gas gravity for all the k-stage in the multistage separator test was calculated as

$$\gamma_g = \frac{\sum_{k=1}^{Nsp} (\gamma_g)_k (\Delta R_s)_k}{\sum_{k=1}^{Nsp} (\Delta R_s)_k} \tag{26}$$

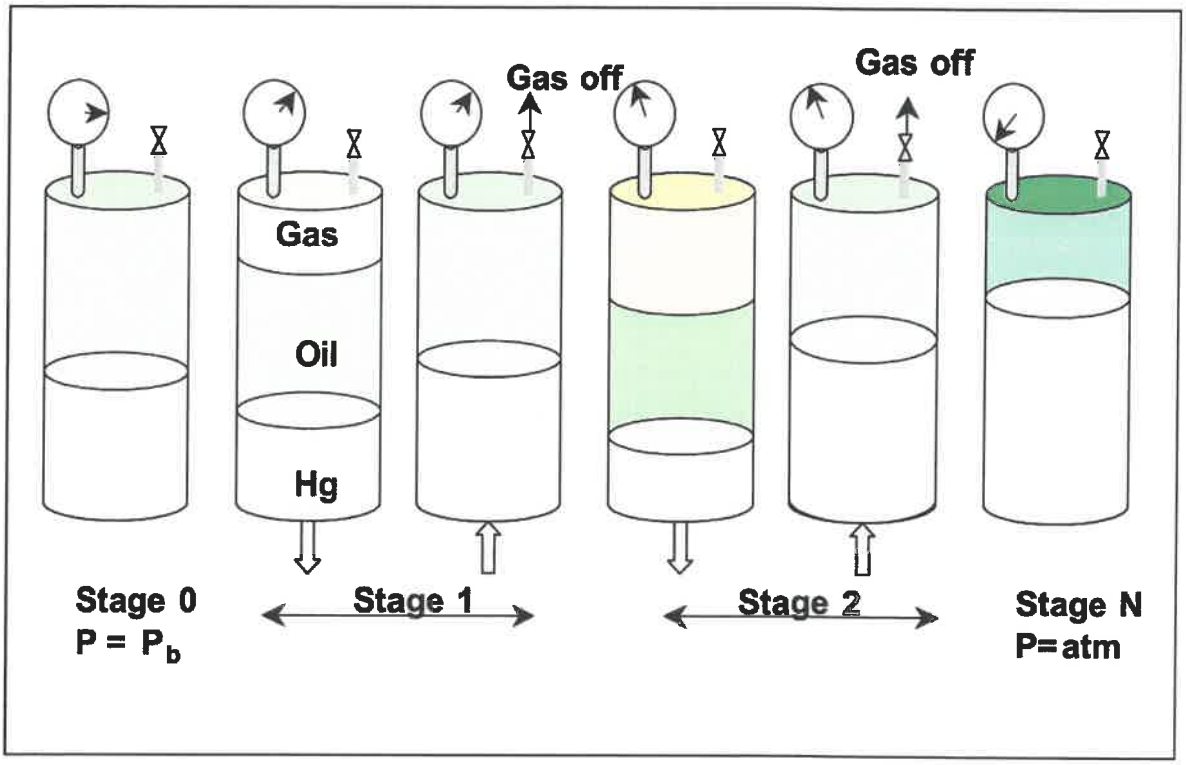


Figure 14: Illustration of the Differential Liberation Tests

The experimental results and calculated parameters for our study black oil is shown in the table 5 and 6 below:

Table 5: Experimental data-Oil Properties

Pressure	Oil Density	Oil Compress.	Oil FVF	Oil Viscosity	Liberated GOR	Solution GOR
psia	g/cm3	1/psi	vol/std vol	cP	scf/stb	scf/stb
5014.7	0.691	1.02E-05	1.344	0.640	0	563.1
4514.7	0.6873	1.07E-05	1.351	0.620	0	563.1
4014.7	0.6837	1.15E-05	1.358	0.590	0	563.1
3596.7	0.6804	1.24E-05	1.365	0.570	0	563.1
3014.7	0.6755	1.38E-05	1.375	0.550	0	563.1
2514.7	0.6708	1.65E-05	1.384	0.520	0	563.1
2345.7	0.6691	2.01E-05	1.388		0	563.1
2161.7	0.6673	2.98E-05	1.392		0	563.1
2066.7	0.6653		1.396	0.500	0	563.1
1514.7	0.6865		1.321	0.590	146	417.5
1014.7	0.7028		1.265	0.700	260	303
514.7	0.717		1.214	0.850	377	186.5
214.7	0.7276		1.174	0.990	457	106
114.7	0.736		1.150	1.110	491	72.6
14.7	0.7802		1.051	1.750	563	0

Table 6: Experimental data-Vapour properties

Pressure psia	Vapor Z Factor	Increment. Vap. Gravity Air = 1.0	Vapor FVF ft3/mscf	Total FVF vol/resid vol.	Vapor Viscosity cP
1515	0.905	0.691	0.00		0.015
1015	0.923	0.701	0.00		0.014
515	0.947	0.755	0.01		0.013
215	0.965	0.902	0.02		0.012
115	0.972	1.076	0.03		0.011
15	0.990	1.683	0.23		0.010

The experimental data above were used to determine the gas deviation factor (Z), solution gas-oil ratio and liberated gas-oil ratio. The obtained results were plotted graphically as shown in Figure 15 and Figure 16.

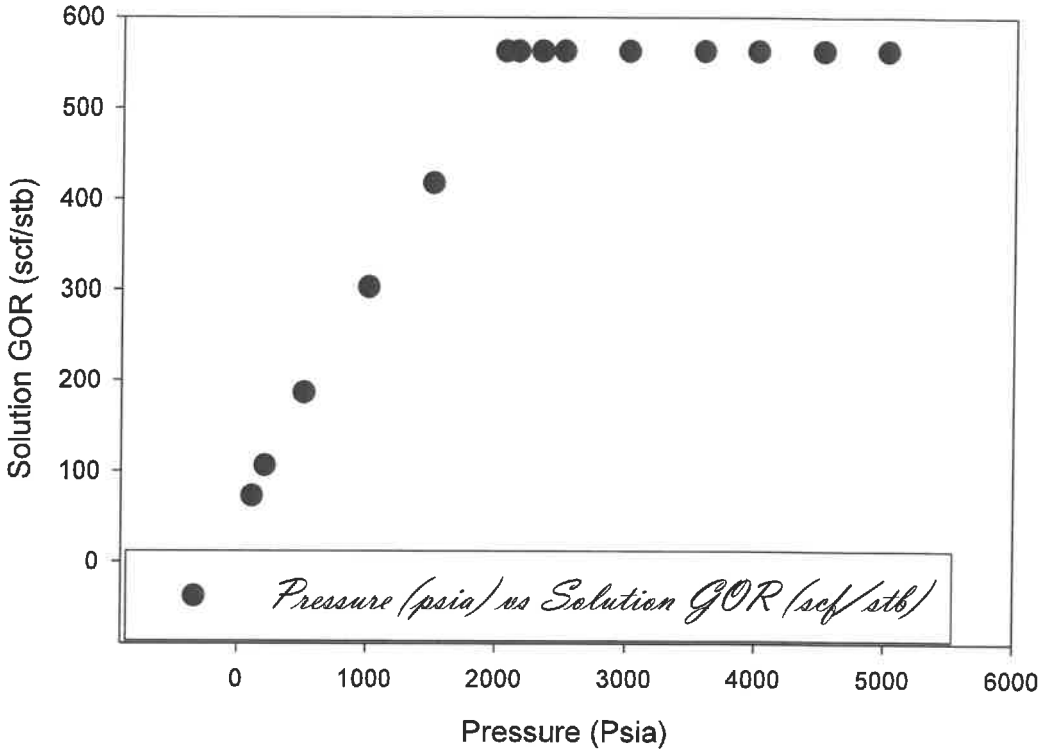


Figure 15: DL #1 Pressure - Oil Solution GOR

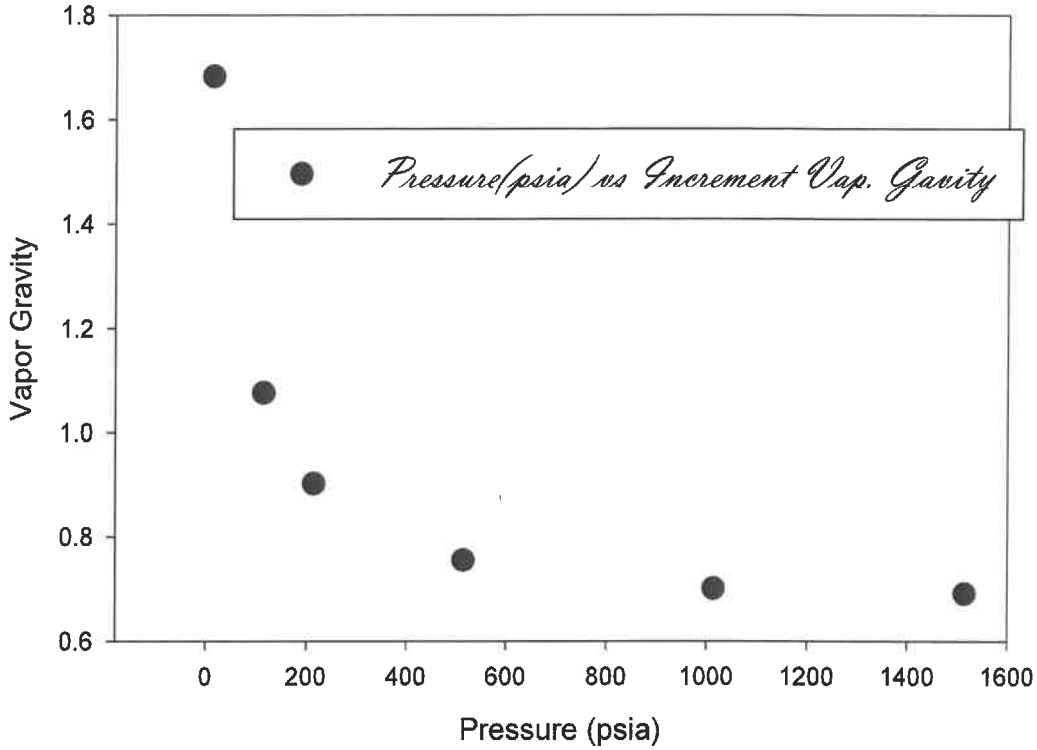


Figure 16: DL #1 Pressure Vapour Gravity

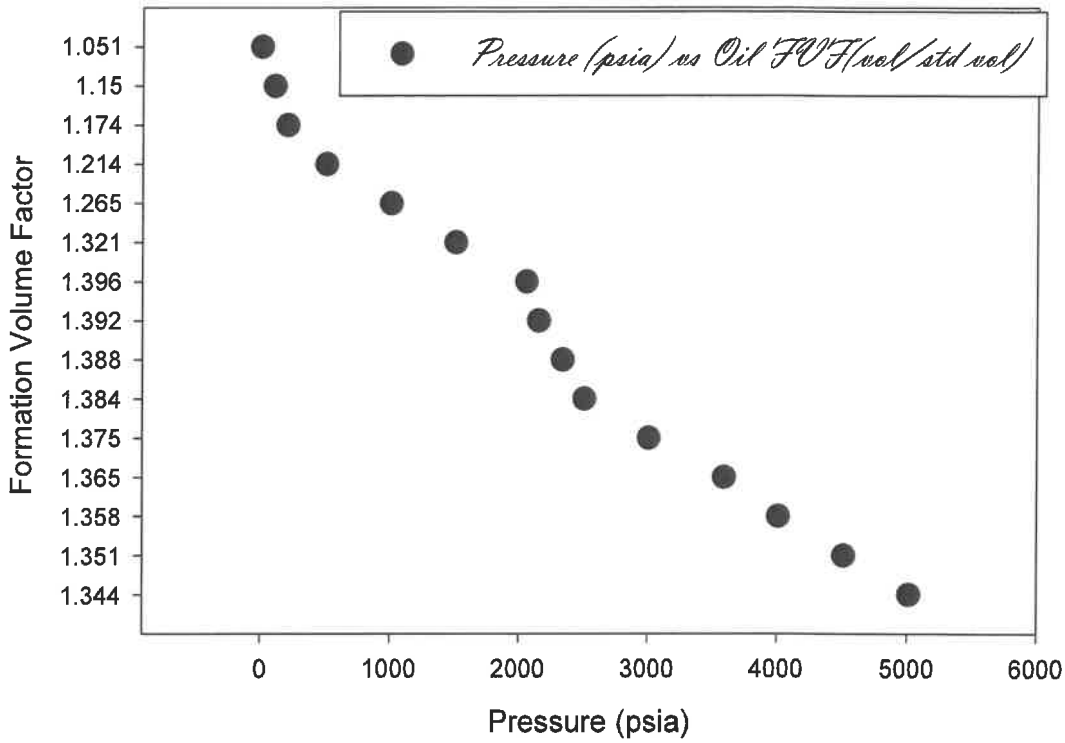


Figure 17: DL #1 Pressure – Formation Volume Factor

The PVT data obtained so far in the various experiments needed to be validated to ensure that there are no errors. Evaluation of PVT parameters before use in reservoir analysis has been proven to be of great importance to the reservoir engineer in the oil industry. The validation was done through pressure gradients obtained from the differential-liberation expansion experiment and multi-stage separator test. The oil viscosity from the DL test increase as pressure decreases, the densities vary smoothly with pressure and the solution gas oil ratios vary smoothly with pressure. Therefore, the PVT experimental data were deemed well enough for viscosity modelling.

4. Oil Viscosity Modelling

For pressures lower than the saturation pressure, the viscosity of the oil increases as pressure decreases due to the evaporation of the volatile components. On the other hand, the viscosity increases almost linearly as pressure increases for p>Pb. The viscosity test was satisfactory since the plot of the viscosity of the reservoir fluid versus pressure showed the anticipated behavior.

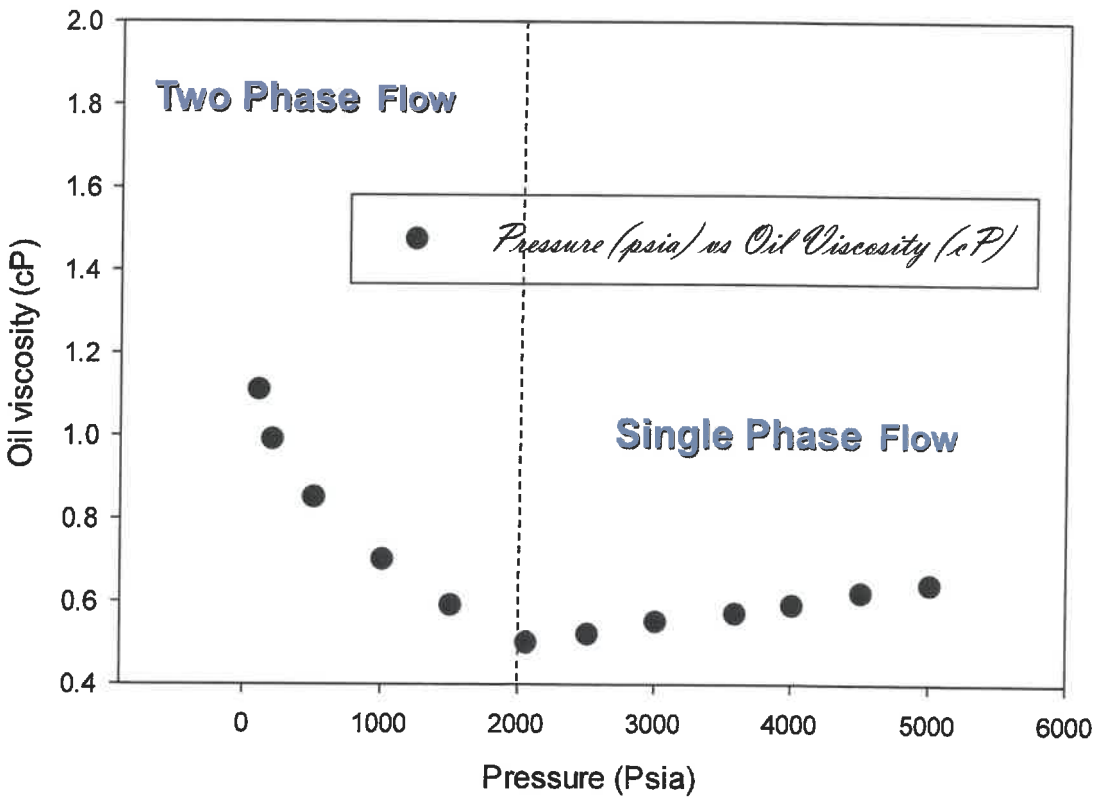


Figure 18: Viscosity of reservoir fluid vs Pressure

For the determination of oil viscosity, correlations are mostly used as far as EOS cannot predict viscosity well and PVT laboratories measure liquid viscosities to ±5% (Moffatt, n.d.). Oil viscosity is generally determined by first calculating the deal oil viscosity (no solution gas) and using that value to obtain the viscosity of the oil at the bubble point (Lang and Donohue, 1985). In this work we shall compare three commonly used models and discuss their validity, we shall attempt as much as possible to interpret the validity of the models with reference to heavy oil. The models will be evaluated using actual crude oil data. The Beal model is used extensively in literature, and relies on the measurements of bubble-point pressure and saturated oil viscosity. The Beggs-Robinson model is a widely used correlation in both academic and industry studies. The Labedi model has been particularly successful in the modelling of viscosity for North Sea heavy oils (Benniston 1998). Actual Oil samples of Egyptian Oil were used to validate the accuracy of the models by comparing the performance of the models in predicting viscosity. 12 oil samples were measured at 206 ℉ and different pressures as shown in Table 7 .

Table 7: Experimental (measured) viscosity data for the Egyptian oil samples.

Pressure	Oil Viscosity	Vapour Viscosity
psia	cP	Cp
5015	0.640	
4515	0.620	
4015	0.590	
3597	0.570	
3015	0.550	
2515	0.520	
2067	0.500	
1515	0.590	0.0153
1015	0.700	0.0140
515	0.850	0.0130
215	0.990	0.0121
115	1.110	0.0115
15	1.750	0.0100
2341-3232-=41		

The following graphs below are illustrated to examine the performance of the 3 selected models in comparison to measured data above. In each instance, the models were validated for both unsaturated- and dead oil viscosity conditions. The Matlab software was used to generate statistical data.

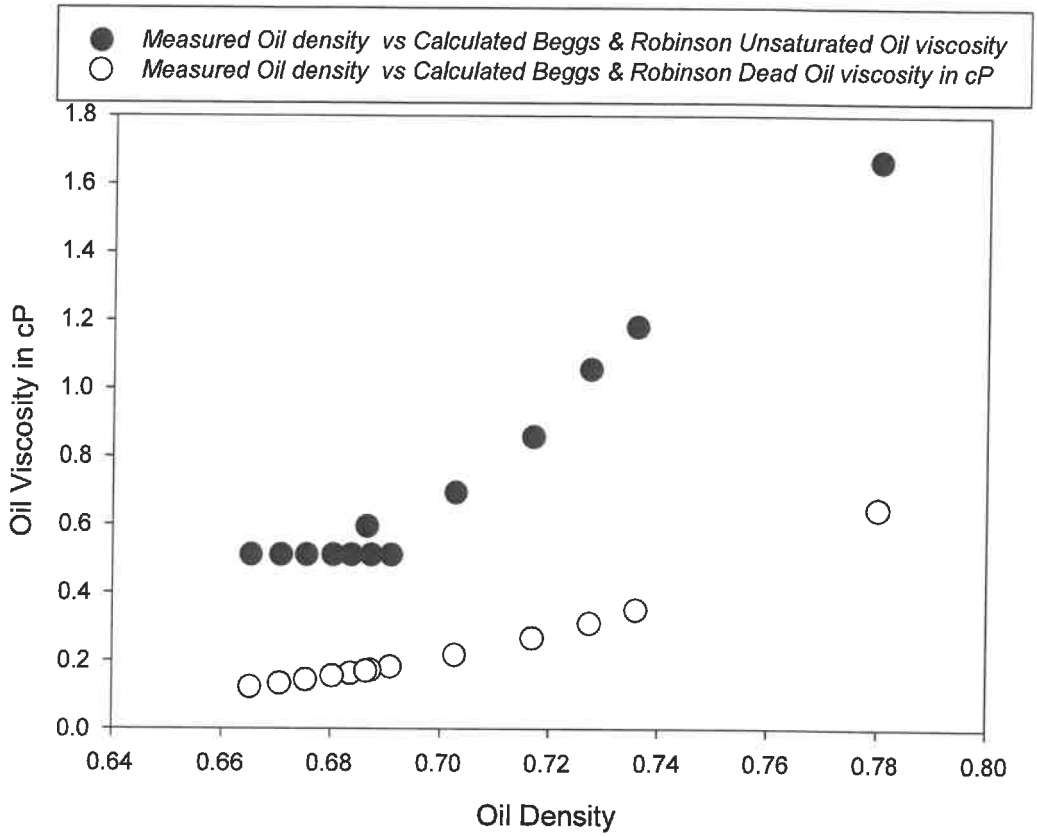


Figure 19: Trend analysis of the Beggs-Robinson model for both unsaturated and dead oil viscosities.

The figure above shows the consistency of the Beggs-Robinson model in predicting viscosity for both unsaturated and dead oil conditions. Both models have a similar trend, this is particularly important to note given the dead oil model makes use of the unsaturated oil viscosity value. The Beggs-Robinson model had a reported accuracy of -0.64% for dead oil conditions. In Sutton and Farshad (1984) a 13,53% error was recorded when making use of this model. Importantly, the model was consistent with the experimental values which clearly illustrated that lower density readings (both measured and predicted) are associated with higher

viscosity and vice versa. The reason for this has been extensively elaborated upon in both this work and elsewhere in literature, and thus requires no further explanation. The overall performance of the model was satisfactory across both oil conditions.

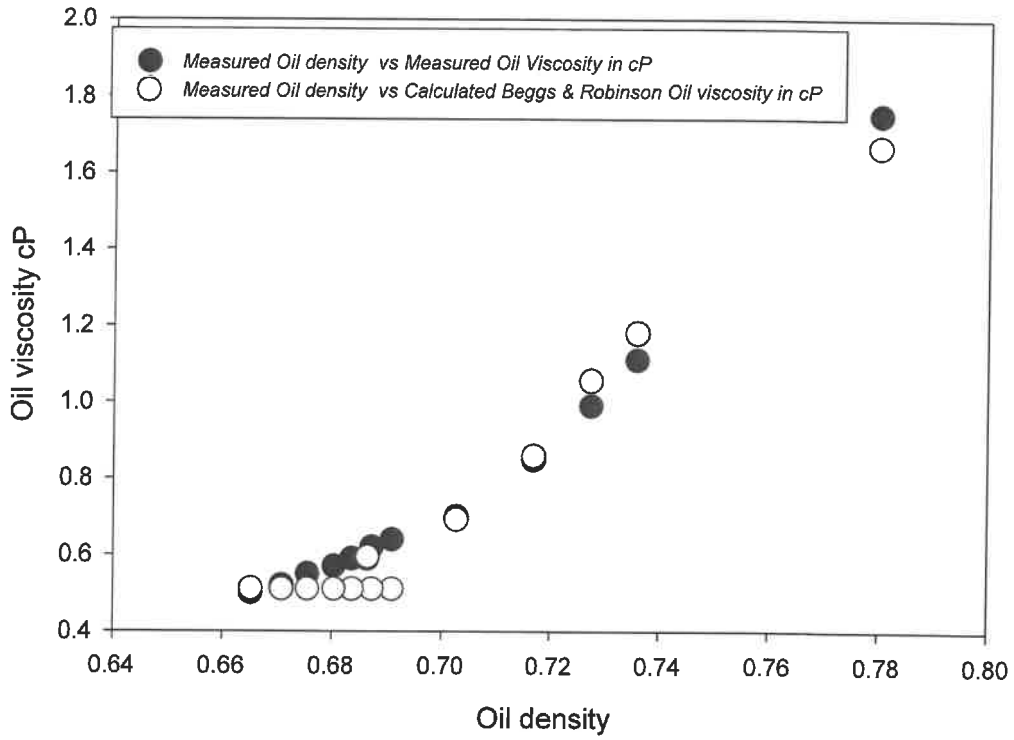


Figure 20: Relationship between Calculated Oil Viscosity and Measured Oil Viscosity.

Figure 20 shows the relationship between measured (experimental) oil viscosity and calculated (model prediction). There is a directly proportional relationship between the two measurements indicating the correlation strength of the Beggs-Robinson model. However, at low experimental viscosities, the model tends to slightly overstate the viscosity predictions. The relative accuracy of its predictions

at high viscosities make it a viable option for the prediction of heavy oil, which tends to possess high viscosity measurements.

We shall now move on to discuss the performance of the Beal model.

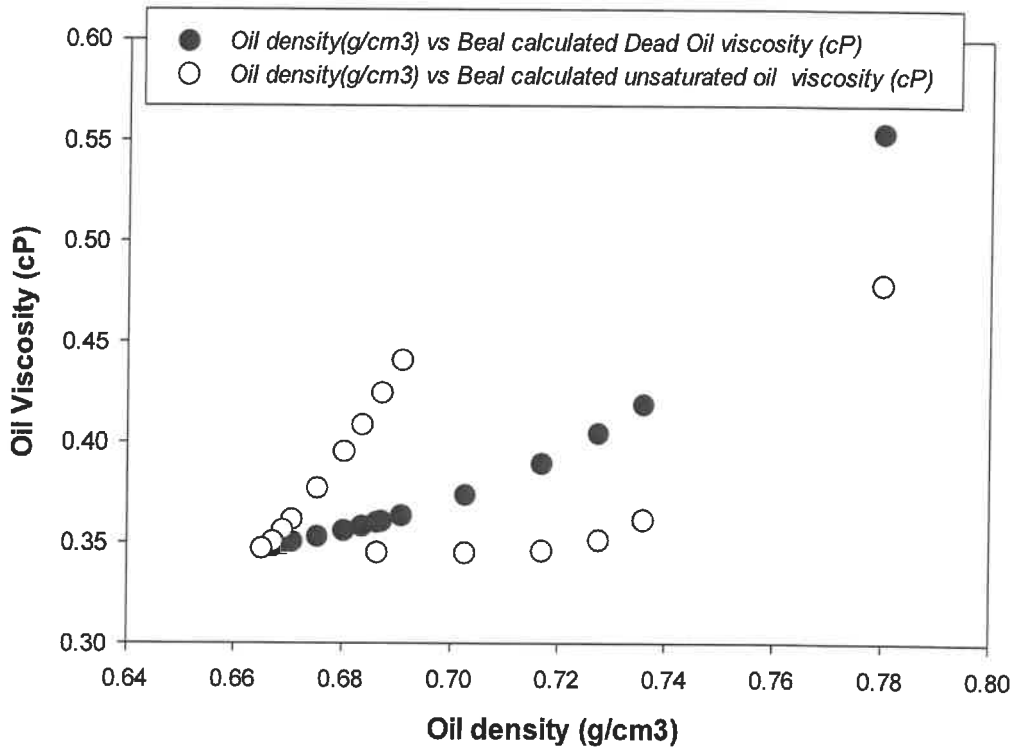


Figure 21: Trend graph (Viscosity vs Oil density) using the Beal model

The Beal model displayed good consistency across both unsaturated- and deal oil viscosity conditions. However the model tends to overestimate viscosity when comparing calculated values and experimental values. The Beal model reported an accuracy of 24% with a relative error of 5%.

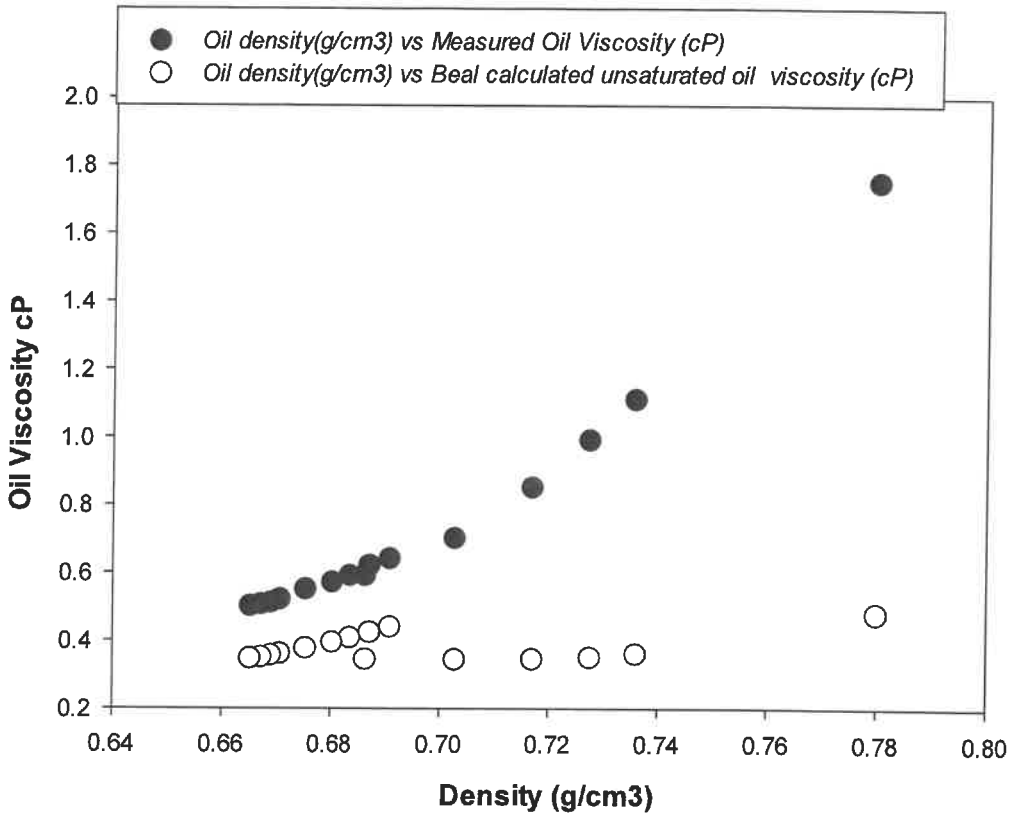


Figure 22: Relationship between Calculated Oil Viscosity and Measured Oil Viscosity.

The Beal model generally overestimated the viscosity of the oil samples. This may question the ability of the model to accurately predict viscosity behaviour across wide ranges. The model is therefore unsuitable for the prediction of Egyptian oil viscosity or any oil that displays the same viscosity behaviour.

The last model examined was the Labedi model, from figure 23 to 24 the viscosity behaviour of the experimental samples was almost identical for both unsaturated- and dead oil conditions according to the Labedi model. The viscosity behaviour across both the unsaturated- and dead oil conditions displayed strong correlation.

The model reported an accuracy of 2% when used to evaluate Libyan crude oils. McCain, Spivey and Lenn (2011) reported an average error of 58% and absolute error of 84% when using the model. The Labedi model also performed poorly in the prediction of the viscosity of the experimental samples as it also tended to over-estimate viscosity.

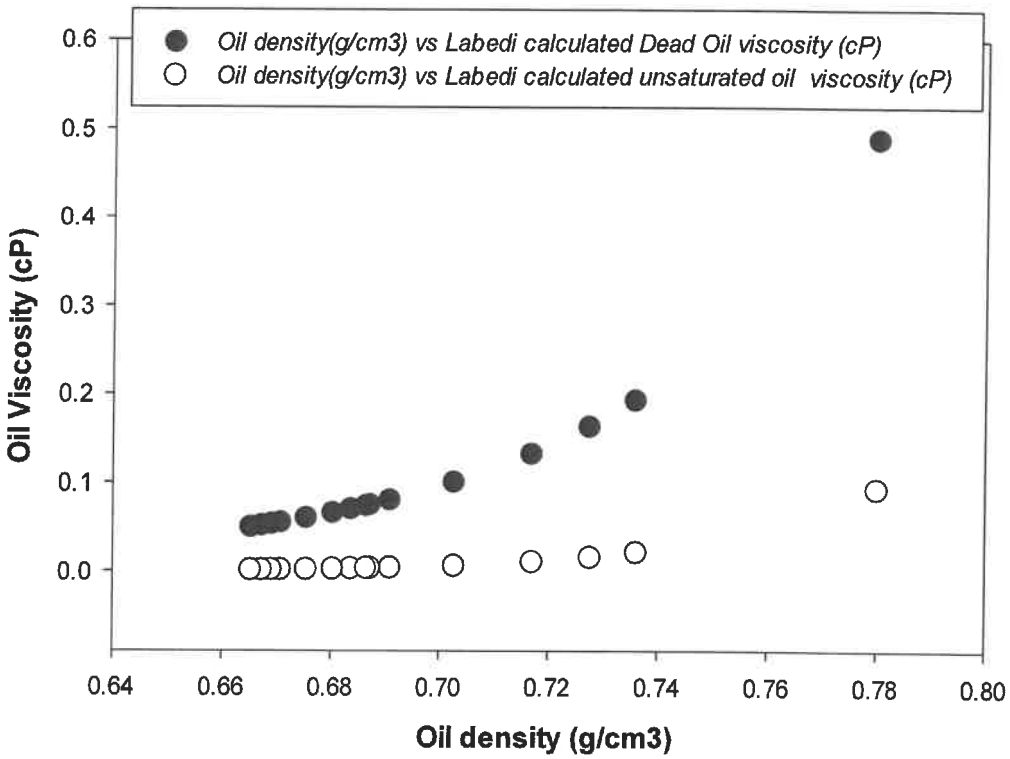


Figure 23: Trend graph (Viscosity vs Oil density) using the Labedi model

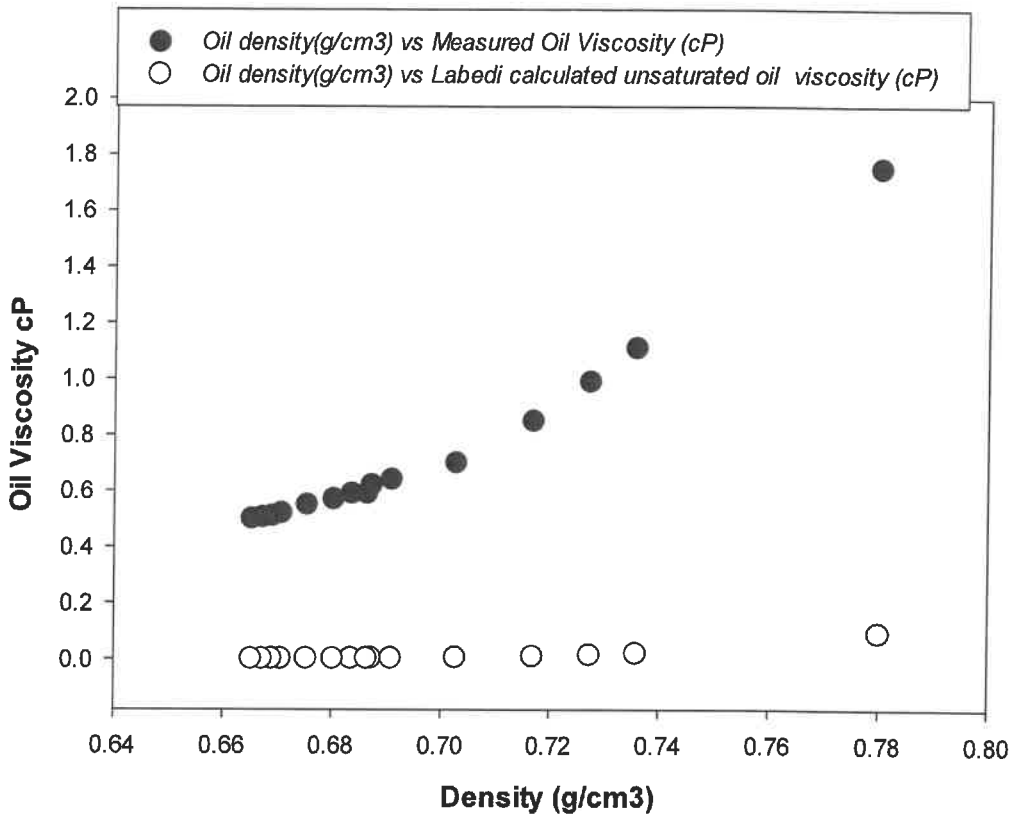


Figure 24: Relationship between Calculated Oil Viscosity and Measured Oil Viscosity.

It is clear from the figures above that the Beggs-Robinson model performed extremely well when compared to the other two models. However this does not mean that the model is necessarily superior to the other two, as we have come to appreciate throughout this study, the accuracy of a model can be affected by varying variables. It would seem to suggest, based on the results presented in this study that it would be difficult to codify a single model for all conditions, this challenge is further exacerbated somewhat by the unusual viscosity behaviour of heavy oil. Based on the results presented, the Beggs-Robinson model was the

most valid model in predicting Egyptian oil viscosity behaviour for both unsaturated and heavy oil conditions. It also must be noted that all models displayed good correlation in their estimation across both oil conditions, this generally means that the assumptions made in deriving the models were sound.

4.4 Proposed framework for the selection/development of heavy oil models

The concluding objective of this work is to create a theoretical framework that can be considered in the development of models for heavy oil viscosity In trying to codify this framework, this work explored several assumptions that are made in the design of viscosity models and attempted to evaluate to what extent do these assumptions hold for heavy oils. The framework is proposed as follows.

a) The measured fluid properties of a potential heavy oil model must be adjusted from those used in medium and light oils. Adjustment are made to cater for the unique characteristics of heavy oil. There are already several models that have since adopted this approach, examples include De Ghetto et al model, modified Egbogah-Jack model, Glaso model (which was originally developed for North Sea Heavy Oil) and modified Labedi for heavy oils.

b) Heavy Oils exhibit non-Newtonian shear thinning, in comparison to the Newtonian behaviour assumed in conventional models. Viscosity decreases with increasing shear frequency over several temperature ranges. This is important in considering the production, storage and transportation of heavy oil.

c) Most viscosity models assume steady-state flow, however the material flow behaviour of heavy oils is usually more dynamic and is thus subject to inconsistent mass flow rates and pressure. In this regard, any model should allow for a more transient or dynamic simulation of viscosity.

d) The effects of asphaltenic content of heavy crude of a particular area can lead to errors in the prediction of heavy oil viscosity. A satisfactory model for heavy oil should consider additional parameters such as asphaltenic content, oil density at operating temperatures and molecular weight. These are some of the factors that can lead to the mathematical adjustment of the model equation as pointed out in A.

e) It is difficult to develop a general model for heavy oils using only temperature and pressure because of the dramatic change in the flow behaviour of heavy oil across a wide range of temperatures.

f) Dead oil viscosity is an important input into the development of a heavy oil viscosity model. Therefore the dead oil viscosity data used to develop a particular model should be within the ranges of the data found in a particular region where the model is anticipated to be used.

g) The theoretical framework for the development of a heavy oil model should be sound and based on experimentally determined parameters.

h) In addition to the condition mentioned in g, the model should make use of equations already used in industry and any constant utilised within the model should be derived from experimental data.

i) Literature and experience suggest that the more customised a model is to a particular geographical location or region, the more accurate it is likely to be, whilst this should always be considered, it may limit the usefulness of the model. This is particularly true for heavy oils because of the nature of the complex composition, even within the same region.

j) Any model must always be validated with real environment data, an approximate model with an AAD of less than 20% is considered to be a good model.

k) The model must have the flexibility for modification to cope with the changing demands of oil production from extraction to refining right through to transport and storage.

CHAPTER 5: CONCLUSION

The importance of viscosity models for oil production continues to be an important topic for the petroleum industry. The difficulty and cost associated with extracting experimental data has necessitated a reliance on the use of simulation and models. Parallel to that situation, declining conventional oil reserves, has also meant that heavy oil becomes a more important option for petroleum firms today than it has have been historically. However the performance of conventional models in the prediction of heavy oil behaviour has often been sub optimal.

In this work, we briefly examined the composition of heavy crude oil to try and establish the associated challenges it faces in the modelling its viscosity behaviour. It was confirmed that the compositional differences between heavy oil and light or medium oil significantly affect the flow behaviour of the material which makes it difficult for conventional models to accurately predict the flow behaviour of heavy crude oil. It was also discussed that crude oil viscosity increases with decreasing gravity, in this regard, the API gravity scale and its relevance to prediction of viscosity using models or simulation was considered. The literature survey and analysis of empirical evidence unanimously confirmed that there is no general model for viscosity for either conventional or non-conventional crude oils. It also showed that current models are either related to the use of oil field data or related to the use of empirical/semi-empirical studies. It was found that models are

generally developed for three reservoir conditions, namely saturated, unsaturated and dead oil conditions.

A theoretical assessment was made of some of the more widely used models. The models were mainly distinguished into two main themes, the first theme was the Black Oil Type. The second theme was the corresponding states type. Four main models were discussed and the Watzen characterisation factor was explored. Several trends for oil viscosity as a function of temperature were observed and the applicability of the Fitzgerald, Andrade, Beal and Beggs-Robinson model were discussed. It was found that Beal's model under predicts viscosity at high temperature while Beggs-Robinson tends to over-predict viscosity.

The last section explored the properties of heavy oil in greater detail and how these affect viscosity models for heavy oils. Three models, namely the Beggs-Robinson, Beal and the Labedi models were evaluated using experimental data of Egyptian oil under dead oil and unsaturated oil conditions, the evaluation of the saturated oil conditions was not pursued in this section. While all three models exhibited correlation consistency across both dead and unsaturated oil conditions, only the Beggs-Robinson model displayed competent correlation between predicted viscosity and experimental viscosity for Egyptian oils. Even though no heavy oils were used in the validation experiment of the three models, it was however revealed from literature that the Beals equation fared the best amongst conventional models for the prediction of heavy oil viscosity. Finally a framework

was proposed that can be used in the selection and development of viscosity models for heavy oils. This framework can form the starting base for the assessment of any heavy oil model that can be developed in the future. In future, more research needs to be directed at optimising models for heavy oil viscosity as the exploration and extraction of these oil will become prevalent.

REFERENCES

1. Alomair, O. Jumma, M. Alkorien, A. Hamed, M. (2016) 'Heavy Oil viscosity and density prediction at normal and elevated temperatures' *Journal of Petroleum Exploration and Production Technology* 6:253 – 263.
2. Al-Rawah, N. Vakili–Nezhaard, G. Ashour, I. Fatemi, A. (2012) 'A new correlation for prediction of viscosities of Omani-Fahud field crude oils' Advances in modelling of fluid dynamics, Chapter 12. Downloaded from http://www.intechopen.com/books/advances-in-modeling-of-fluid-mechanics.
3. Baled, H (2012) 'Density and viscosity of hydrocarbons at extreme conditions associated with ultra-deep reservoir measurement and modelling, Phd Thesis. University of the Pittsburgh.
4. Benniston, T. (1998) 'Prediction of Heavy oil viscosity' IBC Heavy Oil Field Development Conference, London 2 – 4 Dec 1998.
5. Boduszynski, M. Rechsteiner, C. Shafizadeh, A. Carlson, R. (1998) 'Composition and Properties of heavy crudes'. Chevron Research and Technology
6. Elsharkawy, A. and Gharbi R (2001) 'Comparing classical and neural regression techniques in modelling crude oil viscosity' *Journal of Advances in Software Engineering* 32:215-224.
7. Elsharkawy, A. and Alikhan, A (1999) 'Models for predicting viscosity of Middle East crude oils' *Journal of Fuel* 78:891-903

8. Hemmati-Sarapardeh, A. Shokrollah, A. Tata, A. Gharagheizi, F. Mohammad, A. Naser,A. (2014) 'Reservoir oil viscosity determination using a rigorous approach' *Journal of Fuel* 116:39-48.
9. Ghanavat, M. Shojali, M. Ramazani, A. (2013) 'Effects of asphaltene content and temperature on viscosity of Iranian heavy crude oil: Experimental and Modeling study *Journal of Energy and Fuels* 27:7217-7232.
10. Kheirahadi,R. and Ghadami, N (2014) 'Analytical modelling of flow behaviour in non-volumetric reservoirs' *Journal of Petroleum Science and Engineering* 120:163-169.
11. Marcia-Salmas, R. Aquino-Olivos, M. Garcia-Sanchez, F (2013) 'Viscosity modelling of reservoir fluids over wide temperature and pressure ranges' *Chemical Engineering Transaction 23(32): 1573-1578.*
12. McCain, W. Spive, J. Lenn, C (2011) *'Petroleum Fluid Property Correlation'* PennWell Books.
13. Motahhari, H (2013) 'Development of a viscosity model for Petroleum Industrial Applications' Ph.D Thesis, University of Calgary, *Dissertation, Abstracts International* 74(4):351.
14. Naji, H. (2011) 'The dead oil viscosity correlations AC-sharp simulation approach' *JKAU Engineering Science* 22(2):61-87.
15. Naser, A. Nikazai, M. Deghan, S (2005) 'A correlation of crude oil viscosities' *Journal of Petroleum Science and Engineering* 47:163-174.
16. Petrosky, J and Farshad, F. (1997) 'Viscosity correlation for the Gulf of Mexico crude oil' 10.2118/29468-MS.

17. Rahum, K. (2016) 'Evaluation of oil viscosity using several empirical correlations for some Libyan Crude oils' *American Journal of Engineering and Technology Management* 1(4):55-58.
18. Zeberg-Mikkelson, C. Stenby, E (2001) 'Viscosity study of hydrocarbon fluids at reservoir conditions, modelling and measurements'. Technical University of Denmark.
19. American Society of Petroleum Geologists (AAPG) (1978) 'Exploration for heavy crude oil and natural bitumen' AAPG Study 25. Downloaded from GeoScience World with access at 1313.94.178 on 6 Dec 2016 5:40 am.
20. Highlighting Heavy Oil, Oilfield Review 2016.
21. Heavy Oil vs Light Oil. Legislative Brown Bag, British Petroleum Company, 2011