The Influence of Low Salinity Waterflooding on Waxy Oil Recovery

By

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CERTIFICATION OF APPROVAL

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Approved by,

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TRONOH, PERAK
May 2013

CERTIFICATION OF ORIGINALITY

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

NUR SYAFFIQA BINTI MOHAMAD RUZLAN

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ABSTRACT

Waterflooding has been proven as the most popular and effective oil recovery methods through series of successful waterflooding project around the world. Today's conventional waterflooding however, only focus on the physical aspect of waterflooding mechanism with less attention given to the injection water itself especially its chemical composition. The high cost of conventional Enhanced Oil Recovery (EOR) methods such as Chemical and Thermal EOR limits its application in real field although many field tests show promising results. Therefore the main focus of the research is to investigate the influence of Low Salinity Waterflooding (LSW) on Waxy Oil recovery. This aim was achieved through simulation study using LOWSALT option in Eclipse 100 on a synthetic reservoir model. The study shows a significant increase in oil recovery as the salinity of the injected brine decreases. The research also demonstrates that LSW as tertiary imbibition is more effective and economical compared to secondary recovery as the incremental difference between two methods is small. Besides, the study also support the wettability as one of the proposed mechanism of LSW as being suggested in many literatures. With correct LSW design, the study demonstrates the importance of investigating the optimum LSW injection slug sizes in order to maximize the potential of LSW. As a conclusion, the study of LSW is very relevant as it helps to maximize the potential of waterflooding as an economic method of oil recovery.

TABLE OF CONTENT

LIST OF FIGURES

LIST OF TABLE

ABBREVIATIONS

API	American Petroleum Institute
CEC	Cation Exchange Capacity
IFT	Interfacial Tension
LSE	Low Salinity Effect
LSW	Low Salinity Waterflooding
MIE	Multi-Ion-Exchange
OIIP	Oil-Initially-In-Place
FOEW	Field Oil Recovery Efficiency
FSPC	Field Salt Production Concentration
FWCT	Field Water Cut
PPM	Unit of salinity (parts per million)
PV	Pore Volume
TDS	Total Dissolved Solids

NOMENCLATURE

°C	Degree Celsius
$\mathbf{Ca^{2+}}$	Calcium Ion
$\mathbf{H^{+}}$	Hydrogen Ion
$\mathbf{K^{+}}$	Potassium Ion
$\mathbf{Kg/m^3}$	Total mass of salts per cubic meter of sea water (Kilogram per cubic meter)
$\mathbf{Li^{+}}$	Lithium Ion
$\mathbf{Mg^{2+}}$	Magnesium Ion
$\mathbf{Na^{+}}$	Sodium Ion
$\mathbf{S_{or}}$	Residual Oil Saturation
$\mathbf{SO_4^{2-}}$	Sulphate ion
$\mathbf{K^{+}}$	Potassium ion

$\mathbf{Ba^{2+}}$	Barium ion
$\mathbf{Fe^{2+}}$	Ferum ion
$\mathbf{HCO_3^-}$	Hydrogen Carbonate
NaCl	Sodium Chloride
$\mathbf{CO_3^-}$	Carbonate ion
$\mathbf{NO_3^-}$	Nitrogen Trioxide
$\mathbf{Br^-}$	Bromine ion

CHAPTER 1
INTRODUCTION

1.1 Background Study

Since the first oil well - Drake Well was drilled in Pennsylvania late 1895 (The Paleontological Research Institution, 2013), oil has become a very important source of energy which drives the industrial revolution since the beginning of the 20^{th} century until today (Encyclopedia Britannica, Inc, 2013). A swift industrialization of China and India as well as a constant high usage from Europe and North America also contributed to the high global energy consumption especially crude oil (European Commision, 2012). According to the Short Term Energy Outlook published by the U.S Energy Information Administration (EIA), the agency forecasted that in year 2013, the global oil demand will increase by 1 million barrel per day (bpd) to an average of 90.1 million bpd (Zurich of North America Media, 2012). With exploration activities which are still being done around the world, the latest statistical review reported by BP for the last ten years, the world oil proved reserves has increased from 1267 billion barrel in 2001 to 1652 billion barrel in 2011 where 48% of the reserves come from the Middle East (BP, 2012). With the death of ‘easy oil’, enormous efforts have been done to explore the best possible recovery methods to extract the remaining oil while keeping the cost as economic as possible at the same time.

Primary recovery method is the first stage in oil and gas production. This method utilize the natural reservoir energies such as solution gas drive, gas cap drive, natural water influx, compressibility drive and combination drives processes to recover hydrocarbon from the reservoir. However, this method only helps to produce one-third or about 15 percent of oil from its Oil-Initially-In-Place (OIIP) (Schlumberger, 2013).

On the other hand, the secondary oil recovery method also known as Improved-Oil-Recovery (IOR). This method is based on the fluid flooding with objectives to further increase the oil recovery after primary depletion either through pressure restoration or pressure maintenance (Ahmad, 2007). In contrast to primary recovery method, more than one well bore is required where the reservoir pressure is supported or maintained artificially so that the oil production continues (US Oil & Gas Corp, 2008). Two techniques that are commonly used are waterflooding and gas injection.

Compared to gas injection, the most popular and successful secondary recovery method is waterflooding which involves the injection of water with objectives to renew a part of the original reservoir energy and displace oil towards the production wells when it spreads out from the flooding wells (Victory Energy Corporation, 2012). Refer Figure 1. With correct water LSW design, an increase of oil production up to 40% of OIIP can be achieved. Besides the abundant amount of water which are readily available and cheap, the success of water LSW also being contributed by the following factors:

- water has the capability to displace oil of light to medium gravity
- water is easy to handle and is relatively easy to inject into oil-bearing formations.
- waterflooding is economics as it requires relatively lower capital investment and operating costs.

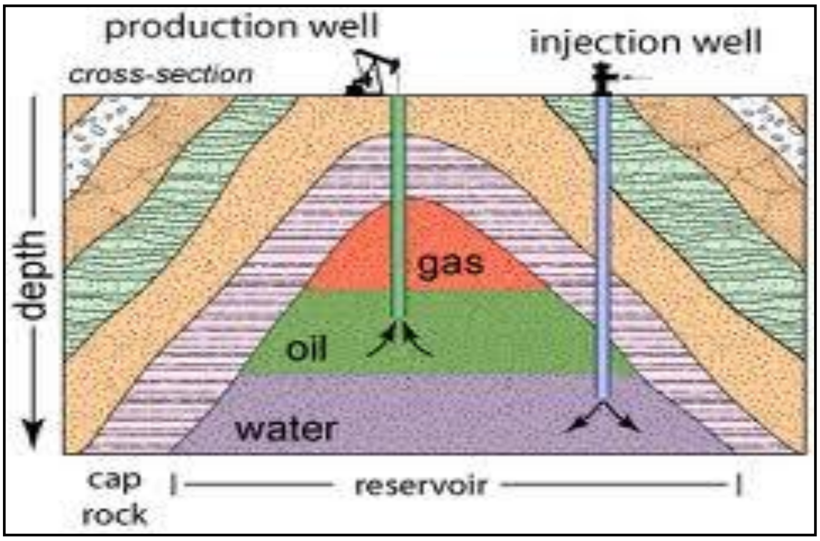


Figure 1 : Water injection mechanism (Victory Energy Corporation, 2012)

While secondary oil recovery method helps to produce up to 40% of OIIP, tertiary oil recovery method or also known as Enhanced Oil Recovery (EOR) assist in recovering the remaining oil in the reservoir which up to 75% of recovery. EOR techniques can be divided into two major types which are – thermal and non thermal. Thermal EOR aids in increasing oil recovery by reducing the viscosity of the oil when heat is being introduced to the reservoir. The non-thermal EOR consist of i) Chemical Flooding using surfactant, alkaline or polymer injection, ii) Gas Flooding using Carbon Dioxide, Nitrogen or Natural gas which when dissolve within the oil, the recovery will increase due to decreasing oil viscosity or by pushing the oil in the reservoir through gas expansion. (Rigzone, 2013). Refer Figure 2. Although many pilot projects have been carried out around the world, the applicability of EOR is still limited due to its high cost. A study done by Norwegian Petroleum Directorate (NPD) in April 2005 on Carbon Dioxide flooding support the statement that EOR is currently not an economic alternative to increase the production of oil although the technology is known to be successful in adding the oil recovery (Oil and Gas Journal, 2005).

1.2 Problem Statement

Conventional waterflooding involves the injection of water into the reservoir either for pressure maintenance or restoration has been proven as one of the most successful and economical ways of oil recovery. Commonly, the sources of water used are produced formation water, shallow groundwater or surface water sources such as lake, rivers and ocean.

Today's conventional waterflooding only focus on the physical aspect of waterflooding mechanism such as injection rate and type of injection pattern. However, less attention is given to the injection water itself especially the chemical composition of the injected water. Numerous studies have been done on the effect of injection water quality on the success of water flooding projects. However these studies mostly focused on the suspended solids and contaminants. These therefore, limit the true potential of waterflooding in increasing the oil recovery.

Another problem identified in maximizing oil recovery is the high cost of Enhanced Oil Recovery (EOR) method such as Chemical and Thermal EOR. This has become a huge limitation to its application in many oil fields although its effectiveness is proven in many pilot field tests. Therefore, a study must be done to maximize the potential of waterflooding as the most economic recovery methods.

Current literatures suggest an improved method of conventional waterflooding called Low Salinity Waterflooding (LSW) which could significantly increase the oil recovery by tuning the salinity of the injection brine. In this paper, the author will study the influence of Low Salinity Waterflooding (LSW) on Waxy Oil Recovery.

1.2.1 Problem Identification

The problems identified are:

1. The conventional waterflooding does not consider the effects of chemical composition of injected water in maximizing oil recovery.

2. The operating cost of conventional EOR methods such as Chemical and Thermal EOR as tertiary recovery mechanisms are too expensive and currently not economical to be done on many oil fields.

1.3 Objectives

The simulation project will be carried out on sandstone formations focusing on Waxy Oil Recovery have the following objectives:

1. To investigate the effect of brine salinity on Waxy Oil Recovery
2. To compare the influence of Low Salinity Waterflooding (LSW) as secondary and tertiary imbibition on Waxy Oil Recovery
3. To study the influence of low salinity injection slug sizes on Waxy Oil recovery

1.3 Project Relevance, Significance, Scope of Study and Feasibility

1.3.1 Relevance

- Waterflooding is the most widely used recovery methods in oil and gas industry with excellence record in increasing oil recovery
- Sources of water are abundant and readily available
- Involves lower capital investment and operating cost with assumptions that the field already have water injecting facilities
- The success in Low Salinity Waterflooding study will offer ‘cheap’ and economic alternatives of oil recovery since the application of Enhanced Oil Recovery (EOR) is still limited due to its high operational cost.

1.3.2 Significance of Project

Since most of the LSW studies were conducted experimentally, numerical simulation study of LSW performed in this project is important to study the effectiveness of LSW application in a bigger scale using synthetic reservoir model before considering its application in the real reservoir. Following that, optimization of LSW as secondary and tertiary imbibition was done. This provides a better understanding of LSW mechanisms and also as a justification of LSW as an economic recovery method.

1.3.3 Scope of Study

The research focused on the influence of LSW on waxy oil recovery on a sandstone formation where a synthetic reservoir model was being used. To apply LSW, the LOWSALT function in Eclipse E100 is turned on. Due to the limitation of the current software, the salinity of the injected water could not be defined according to the concentration of each salt component but were expressed as Total Dissolved Solids (TDS) in metric unit of Kg/m^3.

1.3.4 Feasibility

- The project can be finished within timeframe of FYP 1 and FYP 2
- The license of compositional simulator software needed is available in UTP

CHAPTER 2
LITERATURE REVIEW

2.1 Low Salinity Waterflooding

The success of Low Salinity Waterflooding (LSW) done by (Tang , 1999) in improving the oil recovery has become a stepping stone for many research works in exploring the potential of altering brine composition in improving oil recovery. Many literature review has been done on the modified waterflooding on both sandstone and carbonates reservoir, for example - 'Designer Waterflood' by Shell or 'Low Salinity Waterflood (LoSal ^{TM}) (Zhang and Sarma, 2012).

The interest in investigating the potential of LSW is increasing. Instead of injecting moderate to high saline water as defined by the US Geological Survey which contains about 10,000 ppm to 35,000 ppm of TDS, injecting slightly low saline seawater with the range of 1000-2000 ppm results in higher oil recovery (US Geological Survey, 2013). The accomplishment of many trials on LSW could be explained by the concept of wettability as being reported by Robertson (2007).

Wettability is a rock property which influences the efficiency of oil displacement by controlling the microscopic distribution of oil and water in pore spaces. In addition to that, Rivet *et al.* (2010) reported that that injecting low saline brine promotes wettability changes of some core from mixed-wet conditions to more water-wet conditions thus improving the oil recovery.

This hypothesis is supported by a test done by Lager *et. al.*(2008) on different sandstone reservoir resulting an average increase in recovery of 14% using the LSW method. In addition to the success of LSW done by Lager on sandstone, Saudi Aramco through its upstream research centre (EXPEC ARC) has conduct an experiment on carbonate formation with all experimental parameters and procedures were well designed to represent the reservoir conditions and current field flooding practices. Three sets of diluted seawater were used – twice, 10 times and 20 times of diluted seawater with additional of oil recovery 7% to 5%, 9% to10% and 1% to 1.6% respectively (Yousef *et al.,* 2011). This experiment has contributed to another significant finding in LSW which prove that the increase in oil recovery in terms of Oil Originally in Cores (OOIC) is due to the optimum brine salinity not the lowest brine salinity.

Based on the systematic experimental work done by Tang and Morrow (1999) as well as the researchers from BP Lager *et al*. (2007); Lager *et al*. (2008) , eight conditions for low salinity effect to take place has been outlined (Austad *et al*. ,2010). The presences of clay in the porous medium as well as the presence of divalent cations such as Ca^{2+} and Mg^{2+} in the formation water were marked as important conditions.

2.2 Wettability

Wettability alteration is known to be the mechanisms involved in the application of LSW Razeidoust *et al*. (2009). Wettability of reservoir rock can be defined as the tendency of one fluid to spread on or adhere to a solid surface in the presence of other immiscible fluids. The preference of a solid to contact one liquid or gas is known as the wetting phase. The wetting phase will tend to spread in the solid surface and porous solid will tend to imbibe the wetting phase, in both cases displacing the non-wetting phase (Schlumberger, 2013). Rocks can be water-wet, oil-wet, or intermediate-wet where water wet conditions is desirable for efficient oil transport. Treatments that change the wettability of the formation from oil-wet to water-wet can significantly improve productivity

Wettability can be measured by the contact angle of the fluid with the solid phase. In reservoir, the rock is considered to be water-wet if the contact angle is less than 90° and to be an oil-wet if the contact angle is more than 90°. Refer Figure 3. Another convenient parameter for characterization of wettability is the wettability index. W. Lighthlem, *et al.* (2009) reported the correlations between the wettability index and relative permeability. In circumstances of increasing oil-wetness, oil prefer to stick to the rock and flow less easy relative to water thus resulting in less efficiency for microscopic sweep efficiency. Initially, in an oil reservoir a thermodynamic equilibrium has been established between rock, formation water and oil through millions of years. In many cases, the wetting condition for oil displacement is not optimal with the available source of flooding water (Razeidoust *et al*., 2009).

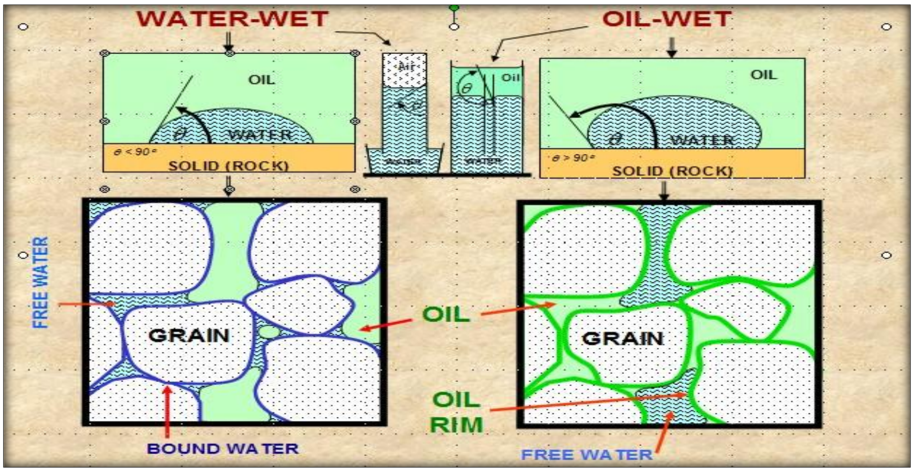


Figure 2 : Comparison between Water-Wet and Oil-Wet.
(Craig, 2013)

2.3 Low Salinity Waterflooding for Sandstones

Aloitaibi and Nasr-El-Din (2009) reported the idea of varying the composition of flooding water has been addressed by Smith (1942) when he conducted several lab tests on sandstone cores using calcium chloride solution and fresh water. The study shows injection using brine water produced more oil than fresh water. In order to explain this, Smith suggested the swelling of the clays was to be the main reason for lowering oil recovery than that in fresh water. On the other hand, a study done by Bernard (1967) demonstrated the opposite results when the flooding of fresh water both in secondary and tertiary modes on sandstone cores containing clays shows an increase in oil production compared to NaCl brine. Bernard observed the increased in oil recovery was also accompanied by development of a relatively high pressure drop. Aloitaibi and Nasr-El-Din (2009) attempted to describe the work done by Bernard (1967) in two scenarios- they suggested that fresh water contributes to the swelling of the clay in the rock which lead to the reduction in the pore space available to oil and water, and eventually increase in the oil recovery. The second explanation was related to the clay dispersion to very fine particles after using fresh water. These particles moved along the established flow channels and eventually plugged them up. As a result, new flow channels were established and additional oil was then recovered. They also stated that all clay types are capable of migrating when contacted by foreign water which alters the ionic environment. Unfortunately, his work does not capture the attention of the petroleum industry at that time. However, Yousef *et al*. (2011) stated that LSW has became a new research trend initiated by the extensive research works done by Jadhunandan (1990) ,Jadhunandan and Morrow (1995), Yildiz and Morrow (1996), Tang and Morrow (1997) , Tang and Morrow (1999), Zhang and Morrow (2006), and Zhang, *et al.* (2007) which show positive results of a significant increase in oil recovery.

2.3.1 Low Salinity Effect and Role of Ions in Sandstone

Zeta Potential is a method to estimate the charges at the interfaces of oil/brine and rock/brine. The measurement of Zeta Potential helps in understanding the relation between electric double charge layer and oil recovery (Nasralla and Nasr-El-Din, 2011). The surface charges are regarded as the main factor that controls the stability of water film surrounding the rock and also the rock wettability. The flooding of water with different salinity than the formation would cause the changes of charges at both interfaces of oil/brine and rock/brine. As a result, the electric double layer thickness would change, which could improve or suppress the oil recovery.

A study carried out by Nasralla and Nasr-El-Din (2011) exhibits the importance of clay in determining the surface charge of the sandstone. The results shows NaCl contributed in higher negative charge compared to the $CaCl_2$ and $MgCl_2$ of the same salinity. Besides they also proved the relationship between the role of ions and salinity by conducting two core LSW experiments by injecting different concentrations of NaCl and $CaCl_2$. Refer to Figure 4. The test using $CaCl_2$ show the lowest oil recovery at all concentrations compared to NaCl. Besides, it is important to note that the flooding using the highest salinity of NaCl 5wt% resulting higher recovery compared to the lowest salinity of $CalCl_2$ 0.2 wt%. This finding is important as a verification that the application of LSW is not merely about injecting the lowest salinity of water but the types of ions also play an important role in optimizing the recovery factor.

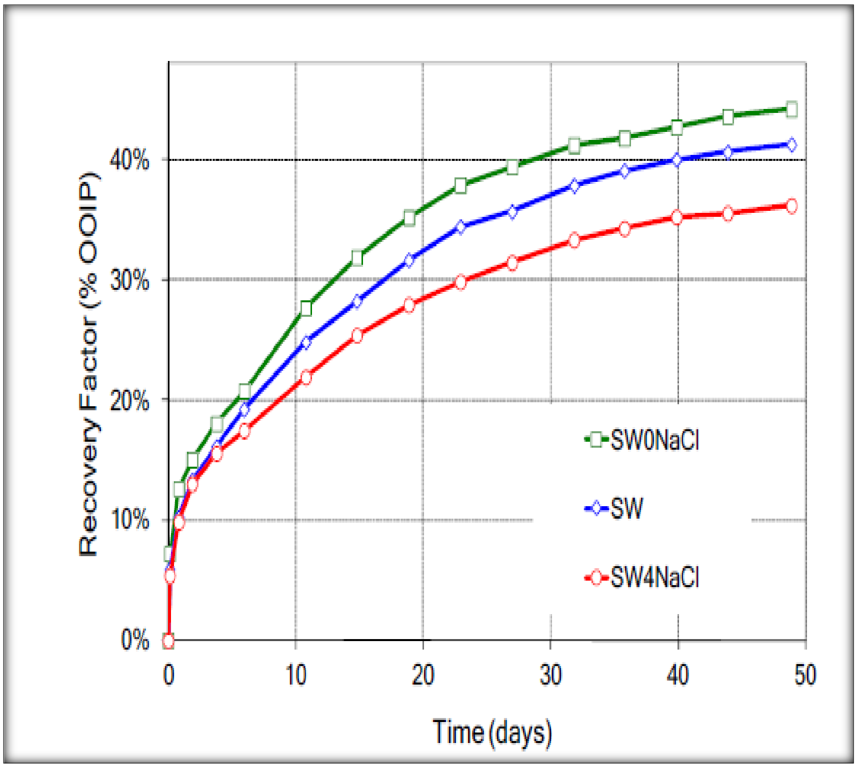


Figure 3 : Spontaneous imbibitions into oil saturated chalk core at 100 °C using different imbibing fluids (Nasralla and Nasr-El-Din ,2011)

2.3.2 Chemical Mechanisms of LSW in Sandstone

The efforts in the past two decades have been devoted to understand recovery mechanisms of low salinity waterflooding. Although different mechanism have been proposed, many questions and uncertainties remain. However, it is generally accepted that the effect is caused by wettability alteration of the rock.

2.3.2.1 Migration of fines

The proposed mechanisms of fines migration was supported by numerous studies done by Tang and Morrow since 1990's. An experimental work done on Berea sandstone by Tang and Morrow (1999) concludes that fines migration contributes to the increase in oil recovery during LSW. Fines, mainly kaolinite, were detached from the cores during LSW.

Zhang *et al*. (2012) reported the release of these particles would improve the water-wetness, and transportation of these movable particles would block some pore-throats, which would divert the fluid flow and increase the sweep efficiency. Refer to Figure 5. However Doust *et. al.* (2009) suggested the diversion of original flow path would is more important than wettability modification by fines release.

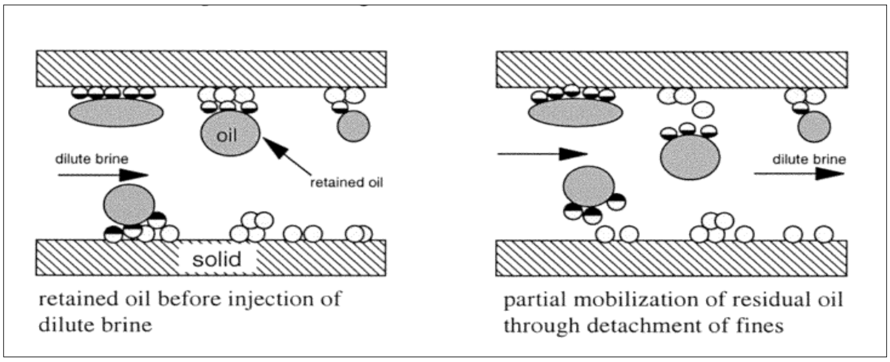


Figure 4: Role of mobile fines in crude oil/brine/rock interactions and increase in oil recovery with decrease salinity. Zhang et al. (2012)

There are numerous cases, in which fines production were not been observed during LSW, but the change of location for submicron-sized particles was witnessed (Morrow and Buckley, 2011). Moreover, the increase in pressure drop during LSW in both sandstones and carbonates was repeatedly reported in literature (Zhang and Morrow, 2006; Zhang *et al.*, 2007). On the other hand, Lager *et al*, (2008b) claimed that fines migration is not a mechanism, but a phenomenon of Multi-Ion-Exchange (MIE). These assumptions were made based on low salinity core flooding work done by BP at reduced and full reservoir conditions where an increase in oil recovery was identified without any observation of fines migration or significant permeability reductions. Nevertheless, from some published experimental results for LSW in carbonates, this mechanism may be also in play in carbonates (Pu, 2010).

2.3.2.2 Increase in pH

Tang and Morrow (1999) and Zekri *et al.* (2011) reported a conclusion made by Valdya and Fogler (1992) which relates the fines migration to low salinity and pH of the injected water. A change in permeability was observed at pH higher than 9 and a significant reduction in permeability was reported at a pH higher than 11. The results give an indication that severe damage due to contact with the high pH fluid and in the absence of salts in the solution (Alotaibi & Nasr-El-Din, 2009). In addition, Zekri *et al*. (2011) also presented a conclusion done by Bain and Ladbrin (1991) where the cation exchange capacity (CEC) of clay sandstones a big effect on fine migration. They concluded that high CEC sandstone will result in a high potential for permeability reduction. It is also reported that Kia (1987) and Khilar *et al*.(1990) explained that the permeability reduction will take place if the ionic strength of the injected water is equal to or less than, the critical flocculation concentration (CFC). The CFC is strongly dependent on the relative concentration of divalent cations such as Ca^{2+} and $Mg^{2+.}$ Divalent cations lower the Zeta potential resulting in the lowering of the repulsive force and that leads to clay stabilization. A laboratory work done by Lager et al (2006) demonstrated a rise in pH of produced water as a function of pore volume injected.

On the basis of the fact that pH usually increases in a low salinity flood, McGuire *et al.* (2005) reported , in many cases, the increase in pH is not more than 1 pH unit and cause the water to become slightly basic. Therefore, Lager *et al*. (2008) stated that the small increase in pH could not contribute much to the reduction of the interfacial tension (IFT) and thus not strong enough to promote low salinity effects.

Razeidoust *et al*. (2009) stated that clay will act as a cation exchanger in sandstone. Supporting this statement, the relationship between the clay type and brine composition of both original formation water and extraneous water on the dispersion of clay were explained by Aloitaibi and Nasr-El-Din (2009) which also supported by Austad et al. (2010) by concluding that the types of clay which in order of kaolinite < illite/mica/cholorite < montmorillionite contributes to the Low Salinity Effect (LSE). Besides, at normal to high pH, the negative charges exist on clay surfaces promotes clay dispersion which leads to a reduction permeability. Austad *et al.* (2010) also mentioned in low salinity solutions the effect of pH are significant compared to high salinity solution as being reported by Zekri *et al*. (2011) when dissolution of silica were observed at pH value higher than 9 thus initiate the fine migration by Khilar *et al.* (1990).

2.3.2.3 Multi-ion Exchange

The Multi-Ion-Exchange (MIE) mechanisms on sandstone were suggested by Lager *et al*. (2008) involves cationic exchange at the surface. According to the conditions of LSE outlined based on the experimental works done by Tang and Morrow (1999) and Lager (2008) it was suggested that the presence of Mg^{2+} and Ca^{2+} plays an important role in the interaction between the clay minerals and surface active components in the crude oil. Austad *et al.* (2010) reported that an adsorption model was suggested where Ca^{2+} acts as a bridge between the negatively charged clay surface and carboxylic material. Through the cation exchange at the surface, the organic material will be removed. Besides, the salinity effect as the proposed mechanisms of MIE in sandstone is different from carbonates Tang and Morrow (1999). They reported that in contrast to carbonates, original seawater is regarded as high salinity water. Therefore, injection of original seawater in sandstone will not portray any low salinity effect.

2.3.2.4 Salting-in Mechanism

When the salinity of water is changing, the thermodynamic equilibrium between the phases (water/oil/rock), which has been established during geological time, will be disturbed. The ionic composition and salinity of the water will affect the solubility of polar organic components in water. Based on this, Tang and Morrow (1999) proposed a mechanism called Salting-in-Mechanism where the solubility of the organic material in the aqueous phase is increasing due to the decrease in salinity below a critical ionic strength as a result of injecting low salinity water. An experimental work done by Webb *et al.* (2005) supported the suggested mechanisms where a significant low salinity effects on oil recovery can only be observed at salinities below a certain value, usually at salinities in the range of 2000-3000 ppm . Since clay act as a cation exchanger, Tang and Morrow (1990) suggested the replacement of cation will follow the flowing order: $Li^{+} < Na^{+} < K^{+} < Mg^{2+} < Ca^{2+} < H^{+}$. It is therefore, exchanging Na^{+} by Ca^{2+} in the low salinity water will decrease the efficiency of the low salinity flood which is proven by a work done by (Nasralla & Nasr-El-Din, 2011).

2.4 Effect of Salinity and brine composition in Carbonates formation

The early stages of SmartWater research mostly focusing its potential on sandstone (Lager *et al*., 2006, Doust *et al*., 2009). A team of researchers from Saudi Aramco lead by Yousef through its upstream research arm initiated a research program called Smart Waterflooding to explore the potential of increasing oil recovery by tuning the flooding water properties (Yousef, et al., 2012). Based on the research done by Razeidoust *et al.* (2009); (Alotaibi & Nasr-El-Din, 2009); (Yousef, Al-Saleh, & Al-Jawfi, 2011) ; (Yousef, et al., 2012) ; Zhang and Sarma (2012) and other researchers a few mechanisms of Smart Waterflooding in carbonates has been proposed. The MIE theory in carbonates suggested by Austad and his co-workers (Austad *et al.*, 2005; Strand *et al.*, 2005; Zhang and Austad, 2006; Zhang *et al.*, 2007; Austad *et al.*, 2008; Austad *et al.*, 2011) were related to anion exchange as being proposed by Tang and Morrow (1999).The MIE mechanism in carbonates is opposite to the exchange of cation proposed by Lager et al (2008) on sandstone.

The surface charge ions on carbonates are said to be positive while the carboxylic acid have negative charge which make carbonates an originally oil-wet (Gaurav Sharma, 2011). In carbonates, $Ca^{2+,}$ SO_4^{2-} and Mg^{2+} are the active ions in the wettability alteration process. SO_4^{2-} which is the potential determining ions will act as a catalyst that undergo adsorption onto the positively charged carbonates. Refer to Figure 6. As the temperature increase, Mg^{2+} ions have the ability to displace the Ca^{2+} bonded to the carboxylic group and contributed to the release of negatively charge carboxylic acid from the rock surface that makes the rock to be less oil-wet.

Zhang (2012) has done a study to investigate the importance of sulphate ions in promoting wettability alteration. The increase in oil recovery was compared based on three different types of flooding fluids - SW, CaMg0S, and CaMg4S. It was observed that there was no or negligible wettability change when CaMg0S was used, whereas obvious wettability change was observed when core plate was exposed to SW The results, illustrated by Appendix 1, Appendix 2, and Appendix 3 proves that the role of Sulphate in brine in promoting wettability alteration towards less oil-wetness at 90°C. The experiment was done at temperature of 90°C, based on the fact that 90°C is known as the lowest temperature for activating the potential determining ions - $Ca^{2+,}$ $Mg^{2+,}$ and SO_4^{2-} (Doust *et al.*, 2009; Strand *et al.*, 2008; Zhang *et al.*, 2007) . Thus, it can be concluded that the conditions for 'SmartWater' to take place on carbonate are – the potential determining ions (SO_4^{2-}) as well as divalent ions such as Ca^{2+} and Mg^{2+} must be present and better take place at higher temperature (above 90 °C).

Another study done by Zekri *et al.* (2011) lead to a conclusion that at high salinity water, the presence of sulphate could alter the wettability of the rock towards water-wet. The wettability measurements can be made by investigating the contact angle. The contact angle between the actual crude oil and three different brine composition and concentration has been compared – i) FW (salinity of 140,000 ppm, sulphate concentration of 378 ppm), saline water (salinity of 50,000 ppm , sulphate concentration of 0.0 ppm and sea water (salinity of 49000 ppm, sulphate concentration of 4048ppm) on chalk limestone disk. A water-wet system was presented by contact angle less than 90° while the oil-wet system was indicated by contact angle of more than 90°. Results are illustrated in Figure 8. The investigation proves the effect of di-valent ion (sulphate) in wettability alteration and indicates that salinity is not the only critical factor in wettability alteration.

Fathi *et al*. (2012) reported that the concentration of active ions $Ca^{2+,}$ SO_4^{2-} and Mg^{2+} is not the only factor for wettability alteration of carbonates to take place. While the LSW in sandstone display an increase in oil recovery as the salinity of the flooding water decrease, the LSW in carbonates demonstrates the effect of mono-valent which is supported by a study done by Fathi *et al*. (2010a) and Fathi *et* *al.* (2011b) . An investigation has been done by adjusting the concentration of NaCl (0,1, and 4 SW salinity), while keeping the concentration of the active potential determining ions, $Ca^{2+,}$ SO_4^{2-} and Mg^{2+}, constant and equal to the concentration in seawater. The effects of mono-valents were studied by comparing the imbibitions of original SW, SW with depleted NaCl (SW0NaCl) SW with 4 times higher concentration of NaCl (SW4NaCl) at temperature of 100 °C. Refer to Figure 4 ,the oil recovery using original SW days was in the range of 41%. While SW0NaCl recorded the highest oil recovery for about 45% of OOIP, the imbibition of SW4NaCl gave an ultimate recovery of 35% of OOIP.

CHAPTER 3
METHODOLOGY

3.1 Research Methodology

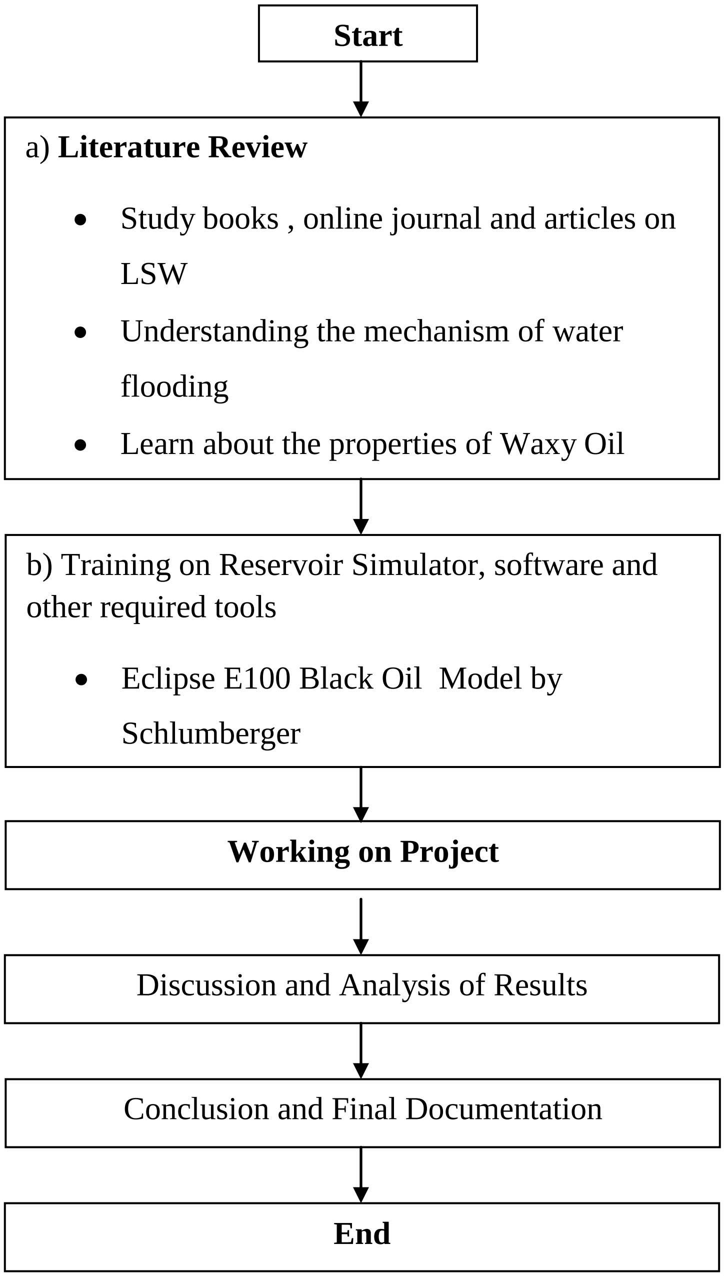
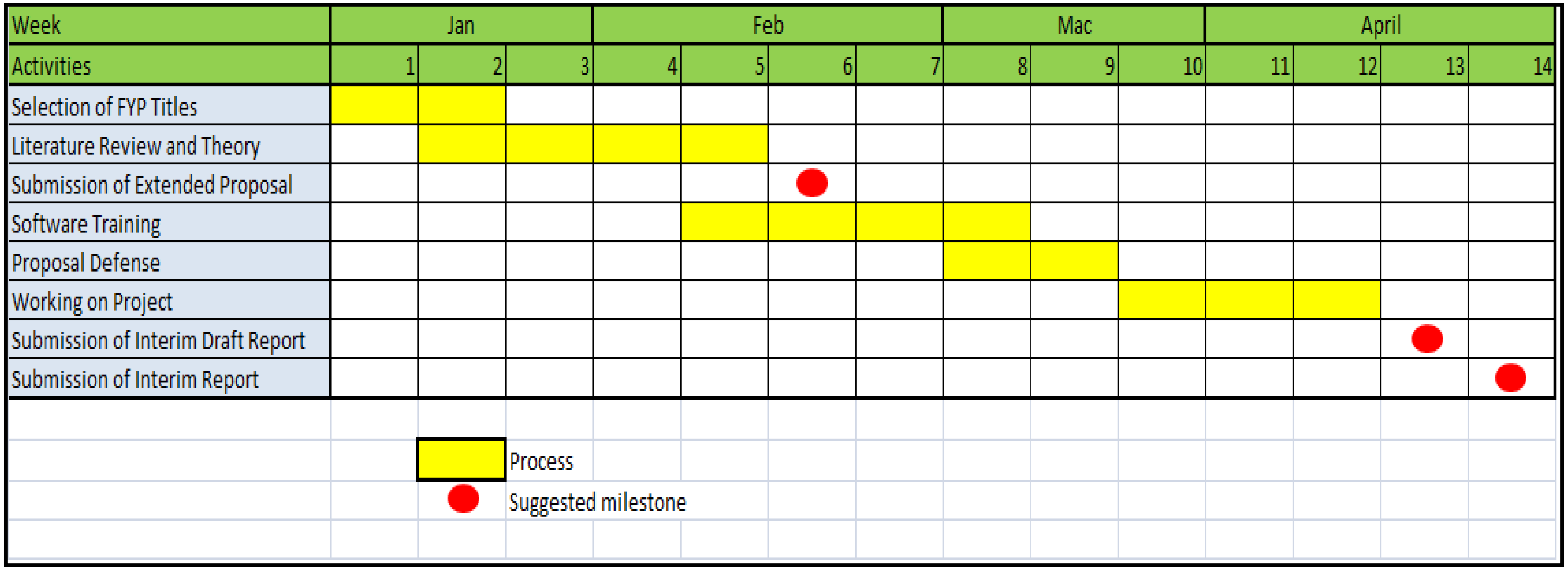


Figure 5 : FYP flow chart on research methodology

3.2 Gantt Chart and Key milestone

3.2.1 Final Year Project I

Table 1: Gantt chart and Key Milestone of Final Year Project I



3.2.2 Final Year Project II

Table 2 : Gantt Chart and Key Milestone of Final Year Project 2

Week	MAY			JUNE				JULY			AUGUST			
Activities	1	2	3	4	5	6	7	8	9	10	11	12	13	14
Data Gathering (Final)												Hari Raya Break		
Reservoir Simulation (Objective 1)														
Reservoir Simulation (Objective 1)														
Reservoir Simulation (Objective 1)														
Analysis of Results														
Submission of Final Draft Report														
Submission of Technical Paper														
Pre-SEDEX														
Oral Presentation (VIVA)														
Submission of project disseration (Hardbound)														

Process

Suggested Milestones

3.3 Project Activities

The reservoir was set to produce for 20 years by setting the simulation time step. Within this period, the flooding brine salinity as well as the time to start LSW was varied in order to achieve the objectives outlined. It also important to note that all the work done in Eclipse was in Metric unit where the salinity is expressed in Kg/m3.

3.3.1 Activity 1: Base Case Study

In order to simulate the real field condition, initially, the reservoir was allowed to produce using natural depletion strategy which contributes to an oil recovery of 0.04 %. Following that, secondary recovery was performed after the oil production reach plateau stage. Injection brine of 35 kg/m^3 TDS was used to simulate the conventional waterflooding process was set as a **base case**.

3.3.1 Activity 2 : To investigate the effect of brine salinity on Waxy Oil Recovery

In order to see the effect of LSW as secondary Imbibition, brines of different salinities were injected. The wettability was set to be initially oil-wet, and the more water-wet set of saturation and relative permeability profiles were applied during LSW. The steps of the process are shown in the flow chart below:

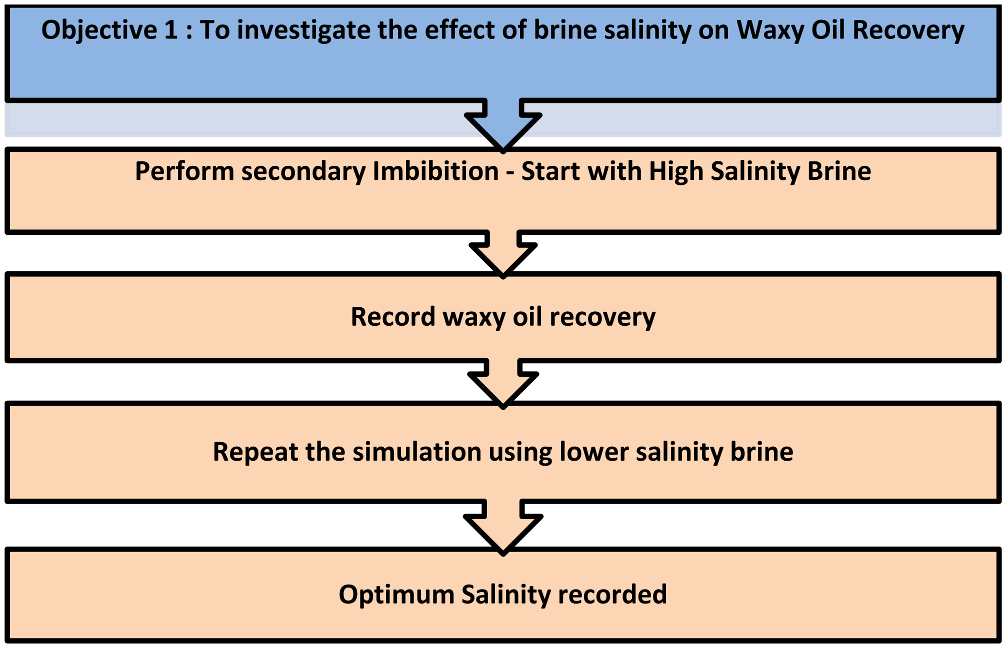


Figure 6: Flow Chart on steps to investigate the effect of brine salinity on waxy oil recovery

Table 3 : Range of Brine Salinity Investigated

Run #	***1***	***2***	***3***	***4***	***5***	***6***	***7***
Salinity (kg/m^3)	35.00	10.00	5.00	4.00	3.00	2.00	1.00

3.3.2 Activity 3 : To compare the influence of secondary and tertiary imbibition on waxy oil recovery

Prior to tertiary LSW, brine with high salinity of 35 Kg/m^3 TDS or equal to the initial connate water salinity was injected. After 4 years of conventional waterflooding, LSW tertiary recovery was performed by injecting brine with salinities of 10 Kg/m^3, 5 Kg/m^3, Kg/m^3, 4 Kg/m^3, 3 Kg/m^3, 2 Kg/m^3, and 1 Kg/m^3 TDS. Refer Figure 8. Wettability for these cases ranged from initially oil-wet to water-wet.

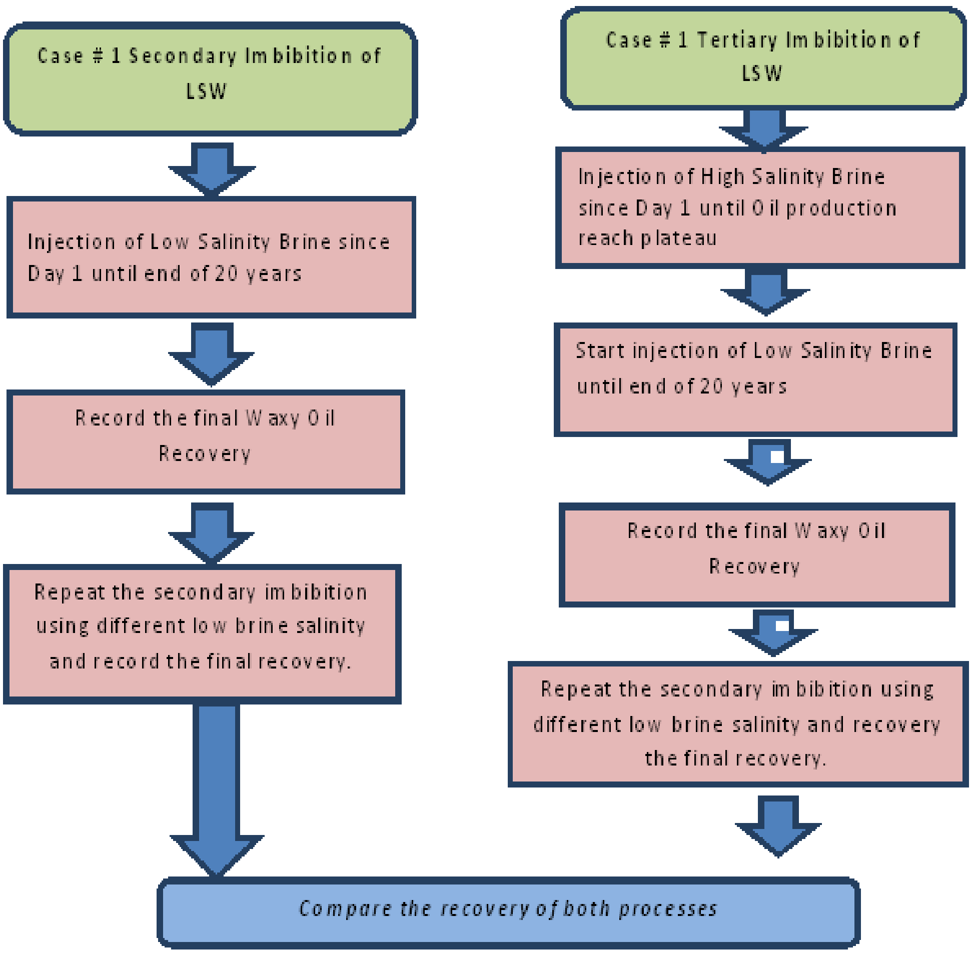


Figure 7: Flow Chart of Steps to Compare Secondary and Tertiary Imbibition of LSW

3.3.3 Activity 4 : To measure the impact LSW slug sizes on Waxy Oil recovery

The study of slug size is important as a part of optimization process. Since the process of getting low salinity water involved extra cost, the study helps to justify the potential LSW as an economic recovery method. The study was carried out on tertiary Imbibition using brine salinity of 1 Kg/m^3 which started after 4 years of conventional secondary flooding. Since the injection slug size increase as the injection period increases, low saline slug sizes were varied by varying the flooding period to be 13 years, 10 years, 8 years, 6 years, 5 years, 4 years, 3 years, 2 years, 1 years, 0 years. For each case, high salinity brine of 35 Kg/m^3 was injected before and after the LSW to make up the total simulation run time of 20 years.

3.4 Low Salinity Waterflooooding : Options in ECLIPSE E100

Eclipse E100 provides Brine Tracking facility which enables Eclipse to model the mixing of waters with different salinities, as well as the effect of low salinity versus high salinity on the flow performance. This facility is done under Eclipse Low Salinity option.

The Brine Tracking facility is activated by the keyword BRINE and Low Salinity option is activated by the LOWSALT both in the RUNSPEC section. In this model, a mass conservation equation for the new phase is solved for each grid block in the reservoir model. The brine is also assumed to only exist in the water phase.

To activate the low salinity option in ECLIPSE, keyword LOWSALT is introduced in the RUNSPEC section of the model. This automatically activates the BRINE option and allows the user to introduce two separate salinity dependent sets of saturation, relative permeability and capillary pressure curves for the already existing phased. The option works such that it is possible to change the set of curves when switching the flooding brine from high salinity to low salinity. In addition to these salinity dependent curves, an interpolation between the curves might also be added.

The LSALTFNC keyword in the PROPS section opens up this opportunity. This keyword is set to input two weighting factors controlling and calculating the saturation end points, the water and oil relative permeability and the water-oil capillary pressure when the LOWSALT option is active.

In the REGIONS section it is possible to define which of the profiles that belongs to either the high salinity or low salinity flooding brine. This is done by adding the two keywords SATNUM and LWSLTNUM. Both keywords determine the high salinity saturation functions and low salinity table number to each grid block, respectively.

In addition to what has already been described it is necessary to have input for the low salinity PVT. This is done in the PROPS section by adding the keyword PVTWSALT followed by two recorded tables. The first table includes reference pressure and salt concentration. The second input table contains salt concentration, water formation volume factor, water compressibility, water viscosity and water viscosibility. The parameters should vary slightly from the water containing no salt due to a difference in water composition.

To set the initial salt concentration for the connate water, the keywords SALTVD or SALT should be added in the SOLUTION section. SALTVD comprise a table of salt concentration versus depth. The keyword SALT, however, should be followed by one real number for every grid block specifying the initial salt concentration. For setting the wanted flooding brine salinity, input in the SCHEDULE section is necessary. The keyword WSALT after the name of the flooding wells sets the salt concentration in the brines for the flooding wells (Schlumberger, 2011).

Table 4 : Summary of Low Salinity Keyword in Eclipse E100 (Schlumberger, 2011).

RUNSPEC	
BRINE	This is to activate Brine Tracking option
LOWSALT	The activation keyword for the low salinity functions of the eclipse simulator. This keyword also activates the BRINE keyword if it has not been written.
PROPS	
LOWSALTFNC	Specify the low salinity fraction as function of the salt concentration in the grid block. The concentration of salt is specified either low salinity, high salinity or in the interpolated area of the flow functions.
PVTWSALT	Specify PVT data of water with salt
SWOF	Input tables of water and oil relative permeability and water-oil capillary pressure as functions of the water saturations.
REGIONS	
SATNUM	Defines which table of saturation function (SWOF) represent high salinity
LWSLTNUM	To associate low salinity number to each grid block
SOLUTION	
SALTVD	Salt concentration versus depth table
SCHEDULE	
WSALT	Salt concentration for injection well

3.5 Properties of Injection water

3.5.1 Composition of formation/ seawater

Basically, all formation water contains dissolved solids – primarily sodium chloride NaCl. The types of cations and anions are listed below:

- Cations : Na^{+}, Ca^{2+}, Mg^{2+}, K^{+}, Ba^{2+}, Li^{+}, Fe^{2+}
- Anions : Cl^{-}, SO_4^{2-}, HCO_3^{-}, CO_3^{-}, NO_3^{-}, Br^{-}

3.5.2 Salinity common units

The understandings of water salinity common units are important so that accurate measurement and analysis of salinity effect can be made especially for the input and output for reservoir simulator (Schlumberger, 2012).

Table 5 : Salinity common units

Term	Symbol	Definition
Weight percent solids	C_w	gram solid/ 100 gram brine
Parts per million	C_{pm}	gram solid / 10^6 gram brine
Milligrams per liter	$C_{mg/l}$	gram solid/ 10^6 ml brine
Grains per gallon	$C_{gr/gal}$	grains solid/ gallon brine

Example :

The total mass of salts per kilogram of sea water averages 35 grams: this is known as salinity.

- 35 g dissolved salt / kg sea water equivalent to :
- 35 g/L
- 35 ppt
- 35 kg/m3 (Metric Unit)
- 35,000 ppm (Field Unit)

Sodium chloride is the major salt in sea water which accounts for 78 % of sea water salinity, or an average of 27 grams per liter (g/l) of sea water.

Therefore, composition of common sea water of 35kg/m^3 is listed below:

Table 6 : Composition of common seawater

Salt	$NaCl$	$MgCl_2$	$MgSO_4$	$CaSO_4$	K_2SO_4
Wt (%)	27	3.8	1.7	1.4	1.1
Total : 35 wt%					

3.5.3 Limits of Salinity

Below are common the ranges of salinity value for different types of water as guidelines for the project work to be conducted (Schlumberger, 2012).

- Fresh water < 1 ppm
- Drinking Water
  - 0 ppm – 100ppm : Soft
  - 100 ppm – 200 ppm : Moderate
  - 300 ppm -500 ppm : Hard
  - 500 ppm– 1000 ppm : Extremely Hard
- Sea Water : more than 35, 000 ppm
- Aquifers/oilfield Saturated : Around 300,000 ppm

3.5.4 Properties of Waxy Oil

The properties of Waxy Oil (Sulaiman, 2003) :

API Gravity : 38

Pour Point : 34 °C

Table 7 : Waxy Oil properties at initial reservoir condition (**Sulaiman, 2003)**

Reservoir and fluid properties	Value
Saturation pressure	91.84 bar /1332 psia
Reservoir temperature	101 ºC / 215 ^{o}F
Initial reservoir pressure	128 bar / 1854 psia
Initial oil formation volume factor	1.437 bbl/stb
Initial solution gas oil ratio	1400 scf/stb
Reservoir oil viscosity	1.76 cp

3.5.5 Initialization of the Synthetic Model

Table 8 : Reservoir rock properties of Synthetic Model

Layer	#1	#2	#3	Unit (Metric)
Number of blocks	50	50	50	-
Depth	2600	2605	2610	m
Width (X & Y)	300	300	300	m
PERMX	1172	1172	1050	mD
PERMY	1143	1143	1800	mD
PERMZ	1162	1162	500	mD
Porosity (%)	30	30	30	-

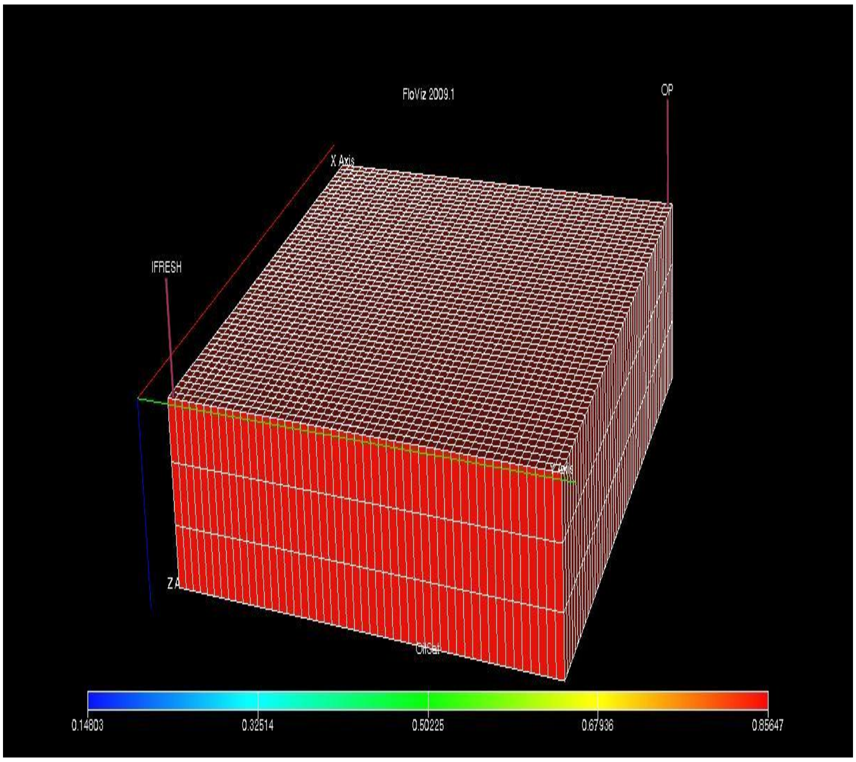


Figure 8 : 3D View of the synthetic reservoir model showing initial oil saturation

Figure 9 shows the 3D view of the synthetic model of the reservoir. The well placements are also illustrated. INJ is the water injector located at (1,1) and OP is the oil producer located at (50,50).

The low salinity options in ECLIPSE 100 are very dependent on relative permeability and saturation profiles, and hence strongly dependent on wettability. The reservoir could be classified as oil-wet and water-wet before and after LSW. In this project, 2 sets of relative permeability and saturation profiles from Eclipse Low Salinity sample data set are being used.

The LOWSALT option in Eclipse allow the user to have two inputs for relative permeability and saturation profiles where one of the profiles is to be used during conventional water flooding and another set to be used during LSW. The reservoir for base case study was initially considered slightly oil-wet and then reconsidered to be slightly water-wet after LSW as being suggested by many researchers (Vledder *et al.*, 2010).

Table 9 : Saturation and Relative Permeability End Point for Oil-Wet and Water-Wet reservoir

End Point	Water wet	Oil Wet
Swi	0.15	0.15
Sor	0.15	0.3
Ew=Krw(Sor)	0.4	0.3
Eo=Kro(Swi)	0.9	0.75

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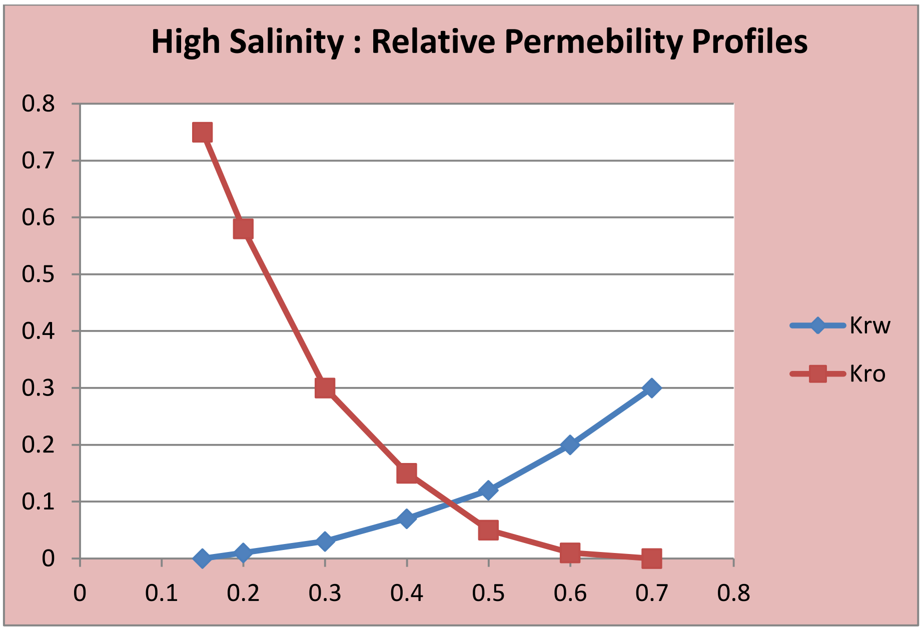

Figure 9 : Relative Permeability Profiles for High Salinity Brine

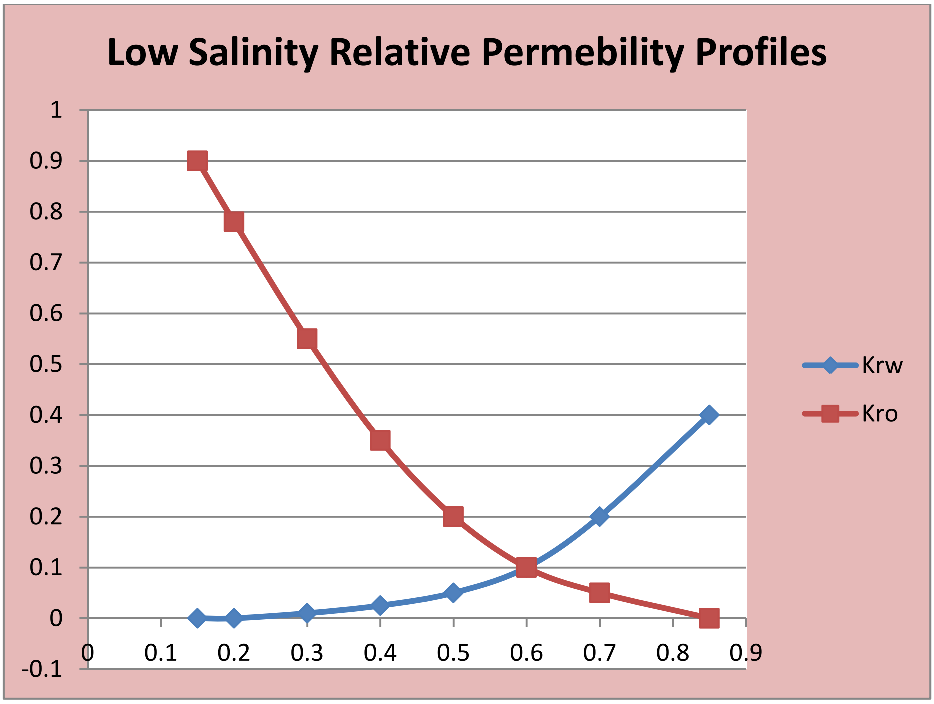

Figure 10 : Relative Permeability Profiles for Low Salinity Brine

The different wettability profiles were mainly generated to yield a difference in residual oil saturation during water flooding because the oil recovery is highly dependent on this variable. The slightly oil-wet case has a high S_{or} and is predicted to yield the lowest ultimate recovery. An oil-wet recovery is characterized by low relative permeability, high water relative permeability and high S_{or} has been proven to have a low potential for conventional water flooding.

Crossover point for an oil-wet reservoir, where the water and oil relative permeability are equal, should as a rule of thumb occur below water saturation of 50% PV (Ahmad, 2006). Refer Figure 10. A water-wet reservoir is characterized by low $S_{or,}$ low water relative permeability and high oil relative permeability. The water-wet case applied in this model however has a relatively high water relative permeability at maximum water saturation.

This is on the other side not expected to influence the recovery as much as the low residual oil saturation. Crossover over point for a water-wet reservoir, where the water and oil relative permeability are equal, should as rule of thumb occur above water saturation of 50 % PV (Ahmad, 2006). Refer Figure 11.

This case is proposed to give the highest ultimate recovery. There is no clear relationship between the different wettability profiles and they are created to test the low salinity options in ECLIPSE E100 and to see if there is a potential for LSW as an EOR mechanism. The high reduction in S_{or} is applied to illustrate the high dependency of this variable during waterflooding.

The reservoir model was a two phase model, containing only oil and water for simplicity. Capillary pressures were neglected due to lack of data. The initial connate water salinity was set to 35 kg/m3 TDS, approximately the same salinity as regular seawater. From the literature, the effect of LSW was only observed after a significant below 5kg/m^3 (Mc Guire, 2005). Therefore the effect of LSW was decided to start after flooding of brines with salinities below 5kg/m3 TDS.

This was set in LSALTFNC. In the LSALTFNC it could be also decided how much of either the high salinity or low salinity saturation and relative permeability profiles that were used during flooding of brines with different salinities. The initial LSALTFNC is found in Table below

Table 10 : Initial LSALTFNC according to Brine Salinity

Salt Concentration (kg/m3)	**F1**	**F2**
0	1.0	1.0
1	0.8	1.0
4	0.2	1.0
5	0.0	0.0
35	0.0	0.0

3.6 Tools

Table 11 : List of Tools

Tasks	**Tools**	**Provided by**
Reservoir Simulator	Eclipse E 100 Black Oil Model Simulator	Schlumberger
3D Viewer	Eclipse Office and Floviz	Schlumberger
Data Processing and Management	Microsoft Word 2007 Microsoft Excel 2007 Microsoft Power Point 2007	Microsoft

CHAPTER 4

RESULT AND DISCUSSION

The aim of this research is to determine the influence of Low Salinity Waterflooding (LSW) on Waxy Oil recovery through reservoir simulation. The main objectives are : i) to investigate the influence of brine salinities on Waxy Oil recovery, ii) to compare the LSW as secondary and tertiary Imbibition on Waxy Oil recovery and iii) to study the impact of low saline slug sizes on waxy oil recovery. In this chapter the simulation results will be presented and discussed.

4.1 Effect of brine salinities on waxy oil recovery

Secondary Imbibition was performed using brine salinity of 35 Kg/m^3, 10 Kg/m^3, 5 Kg/m^3, 4 Kg/m^3, 3 Kg/m^3, 2 Kg/m^3, and 1 Kg/m^3 TDS. The results are presented graphically in Figure 12 and Table 13 below:

Graph Colour Legend :

35 Kg/m^3 10 Kg/m^3 5 Kg/m^3 4 Kg/m^3

3 Kg/m^3 2 Kg/m^3 1 Kg/m^3 Primary Recovery

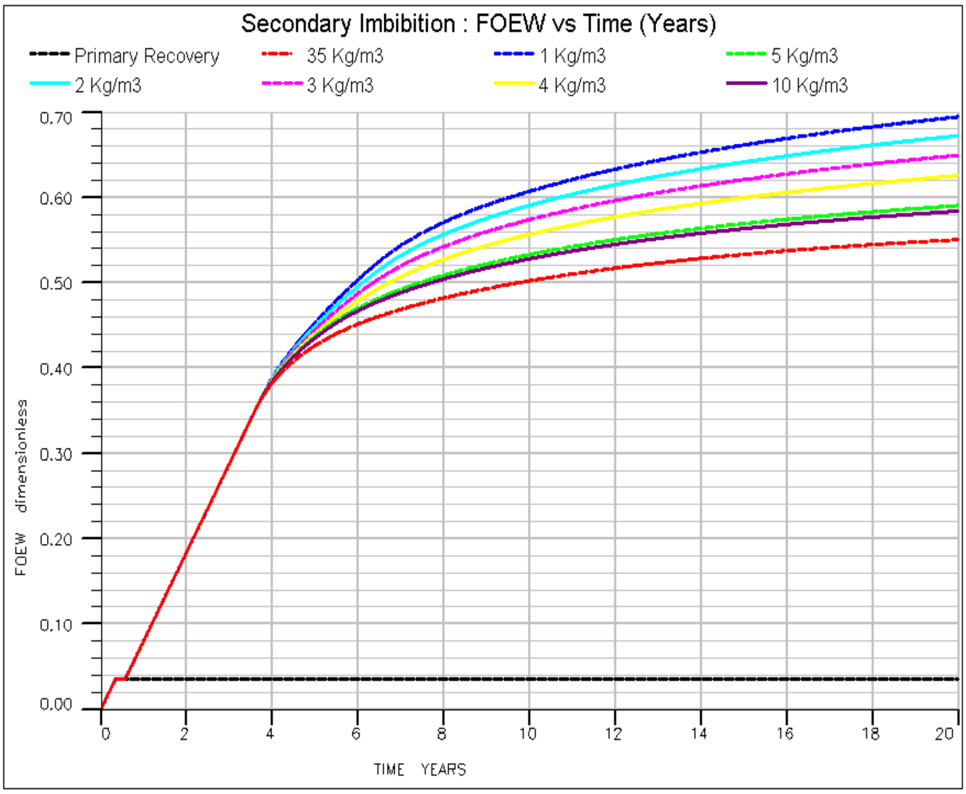

Figure 11: Graph of Recovery (FOEW) vs Time (Years)

Figure 12 shows the Field Oil Recovery Efficiency (FOEW) versus Time in years for brine of different salinity of 35 Kg/m^3, 10 Kg/m^3, 5 Kg/m^3, 4 Kg/m^3, 3 Kg/m^3 , 2 Kg/m^3 and 1 Kg/m^3. Waterflooding of 35 Kg/m^3 represents the conventional waterflooding using normal seawater.

Table 12 : Percentage of Oil Recovery for different brine salinity

Brine Salinity (kg/m^3)	***Oil recovery (%OIIP)***	***Increase in Oil Recovery from conventional waterflooding (%)***
Primary Recovery	3.5	-
35 (conventional waterflooding)	55.05	0.00
10	58.38	3.33
5	59.04	3.99
4	62.55	7.50
3	64.93	9.88
2	67.22	12.17
1	69.43	14.38

Initially, the reservoir was made to produce using primary depletion. In this case the recovery is very low since there is no natural aquifer or gas cap. In order to increase the recovery, conventional waterflooding using normal seawater of 35 Kg/m^3 salinity has been applied. Refer to Figure 12 and Table 12, the oil production using conventional waterflooding results in more than 50% of oil recovery compared to the primary recovery using natural depletion. The success of conventional waterflooding shows the potential of exploring LSW to further improve the recovery factor before using other chemical based EOR method.

Brines with different salinity, lower than the normal seawater were used in order to observe the impact of brine salinity on oil recovery. The results are consistent with the experimental studies done by Morrow (1999). Refer Figure 11. The graph of Field Oil Recovery Efficiency (FOEW) versus Time (years) shows an increase in oil recovery as the flooding brine salinity decreases. Table 12 shows a comparison in incremental percentage of oil recovery between conventional and low salinity waterflooding.

It is observed that a significant increase in recovery only occur if brine salinity lower than 5 Kg/m^3 were used and brine salinity of 1 Kg/m^3 gives the highest recovery up to 14.38 %. These observations supports the experimental work done by Webb *et.al* (2005) where a significant oil salinity effects on oil recovery can only be seen at brine salinity below a certain value. Brine salinity of 0 Kg/m^3 is equivalent to fresh water have not been used in this study although based on the trends of results obtained it may increase the recovery as its application in sandstone reservoir may lead to clay swelling in real field application.

Wettability changes in the formation are known to be one of the factors that contribute to the increase in oil recovery. Initially, during the conventional waterflooding using high salinity brine, the formation was set to be oil-wet. In an oil-wet reservoir the oil prefers to stick to the rock surface which makes the flow of oil to be less easy thus, resulting in less microscopic sweep efficiency.

However, the injection of low salinity water caused the wettability of the rock to change from oil-wet to be water-wet. This condition makes water to be a more preferred phase to stick to the rock surface compared to the oil phase. When the oil relative permeability is high, the oil flows easily through the largest pores thus contribute to the increase in oil recovery.

The results are also being supported through the reduction in the field water cut (FWCT). To further investigate the low salinity water flooding behaviour, the field water cut (FWCT) versus time was plotted in Figure 12.

Refer to Figure 12, after LSW started at early year 4, the reservoir is observed to have significant lower field water cut (FWCT). Water cut is the ratio of water produced compared to the volume of total liquids produced. The red line shows field water cut when conventional waterflooding is used and the blue line represents the field water cut when the lowest brine salinity of 1Kg/m^3 is used.

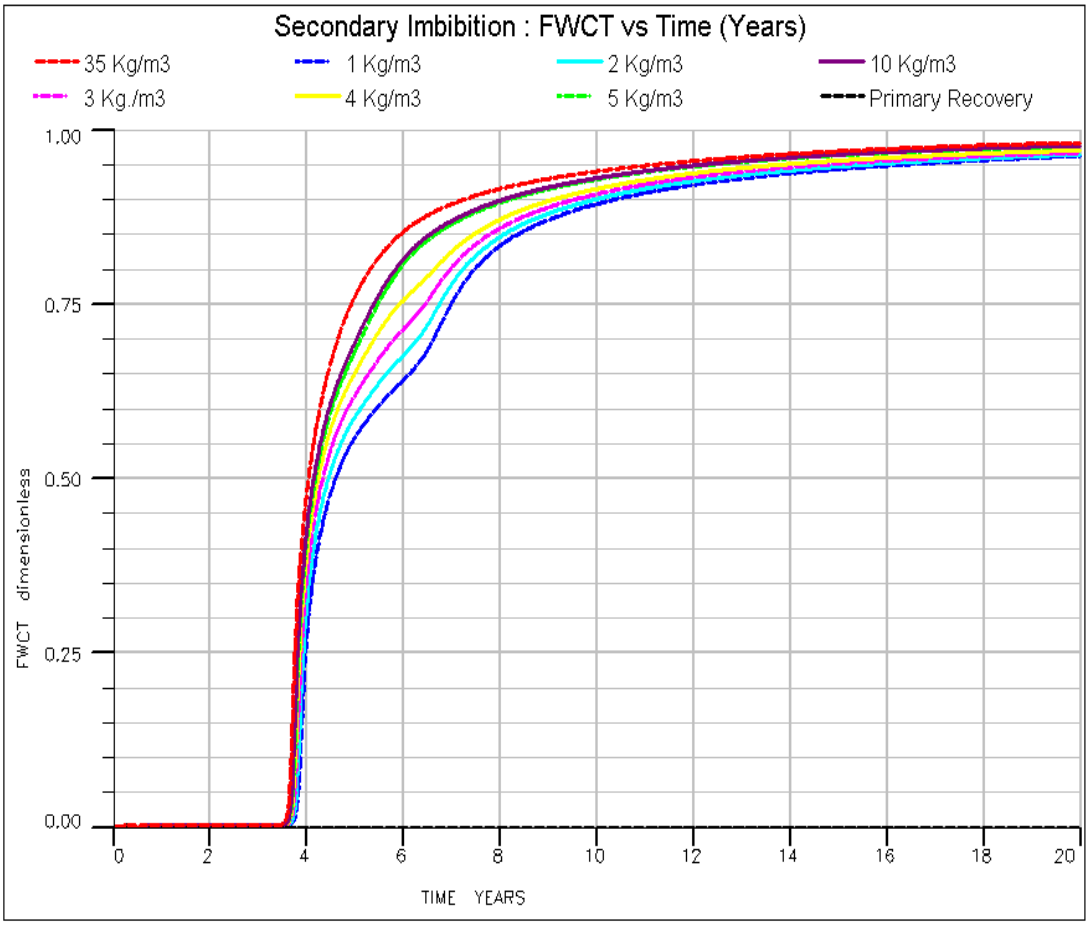

Figure 12 : Field Water Cut (FWCT) vs Time (Years)

4.2 Comparison between LSW as secondary and tertiary imbibition

The oil recovery is expected to flatten out (plateau) sometimes after secondary water flooding and usually tertiary recovery method will be carried out in order increase the production. This activity is a part of LSW optimization as well as to gain economic justification of LSW on waxy oil recovery by comparing secondary and tertiary Imbibition of LSW.

LSW as tertiary Imbibition process started at Year 5 after oil production start to flatten until the end of simulation at Year 20. Prior to tertiary imbibition using low saline water, secondary imbibition using high salinity brine of 35 Kg/m^3 was conducted which represent conventional waterflooding using normal sea water. The tertiary imbibition was done by using brine with salinities of 10 Kg/m^3, 5 Kg/m^3, 4 Kg/m^3, 3 Kg/m^3, 2 Kg/m^3, and 1 Kg/m^3 TDS. The results from the imbibition of different brine salinities in tertiary flooding are presented in Figure 15 and tabulated in Table 14.

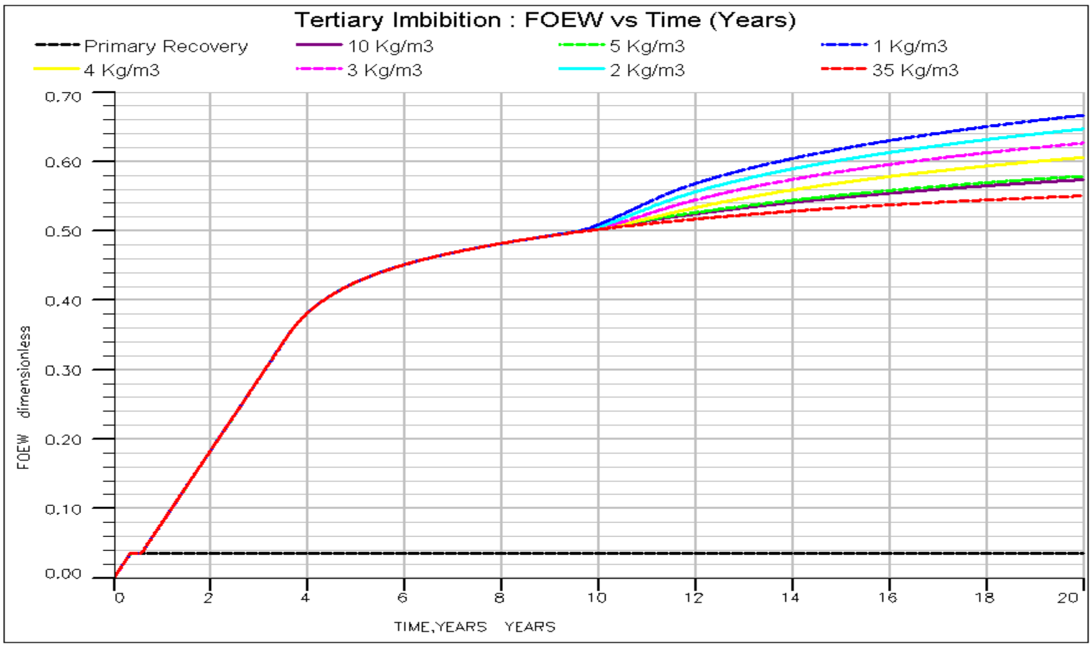

Figure 12 : Field Oil Recovery (FOEW) vs Time (Years) of Tertiary Imbibition for all Salinity

Table 13: Comparison of oil recovery between secondary and tertiary LSW Imbibition

Brine Salinity (kg/m^3)	**Secondary Oil recovery (%OIIP)**	**Tertiary Oil recovery (%OIIP)**	**Absolute Difference in recovery (% OIIP)**
10	58.38	57.37	1.01
5	59.04	57.88	1.16
4	62.55	60.06	2.49
3	64.93	62.64	2.29
2	67.22	64.67	2.55
1	69.43	66.67	2.76

As predicted, a significant increase in recovery can only be seen when brine salinity lower than 5 Kg/m^3 are used. Similar to secondary imbibition, the oil recovery increased as the brine salinity decreased. Nevertheless, comparison between secondary and tertiary imbibition of LSW shows a very interesting result. Refer to table 14, LSW as tertiary imbibition of lowest brine salinity of 1 Kg/m^3 have lesser recovery than LSW as secondary imbibition of the same salinity. However, the less in recovery is just around 2.76 %. The small difference between secondary and tertiary LSW water flooding maybe be due to the same sets of permeability and saturation profiles being applied for both cases thus giving almost same reduction in residual oil saturation appeared in LSW. Besides, since secondary imbibition of low saline water started at earlier time than tertiary imbibition, more low saline water being injected in secondary imbibition thus, contributes to higher oil recovery.

Despite some argument of high cost in producing low saline or fresh water, in terms of economic advantages, the results gives a good indication that the application of LSW as tertiary imbibition has more potential to be an economic solution in increasing oil recovery since the required amount of low salinity water to be injected is less than LSW as secondary imbibition. Figure 16 shows a better picture in comparing the oil recovery between secondary and tertiary imbibition using the lowest brine salinity of $1Kg/m^{3.}$

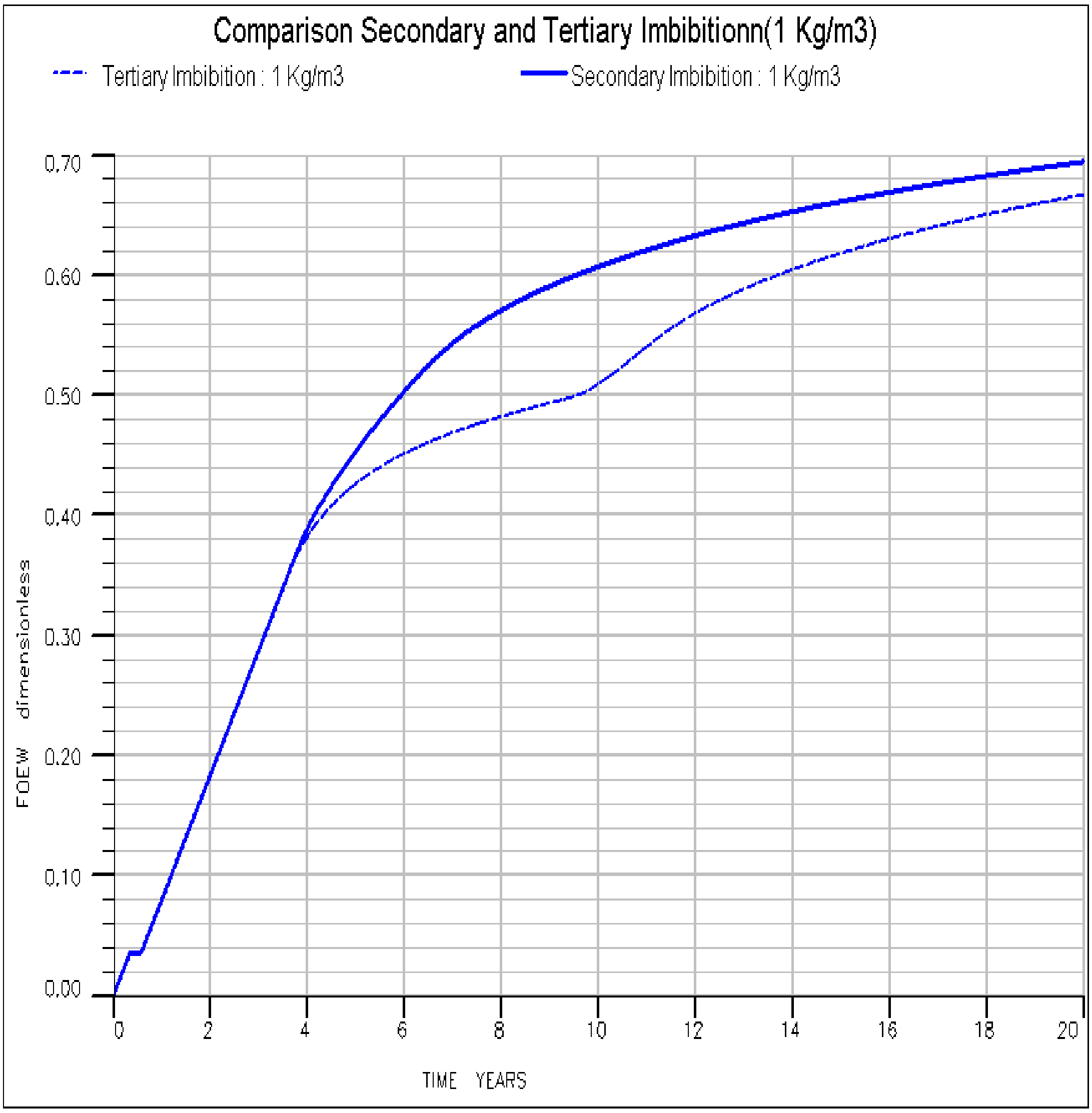

Figure 13 : Comparison of LSW as secondary and tertiary imbibition using 1Kg/m3 brine

4.3 Effect of Slug size

While evaluating EOR, the amount of fluids injected should be carefully considered. This is the case especially when the economically aspects are to be evaluated. If this is not properly done, extra amount of cash earned from the incremental oil recovered might be less than the cost of the injecting fluids.

In this is sensitivity analysis, a short evaluation of the recovery as an effect of different volumes of injected low salinity brines has been conducted. The different cases includes flooding of low salinity brines with a salinity of 1Kg/m^3 TDS for 1 year, 2 years, 3 years, 4 years, 5 years, 6 years, 8 years, 10 years, and 13 years. Since the total simulation run time is 20 years, waterflooding of 35 Kg/m^3 were done before and after the flooding of low salinity brine. The results are presented in Figure 17 below:

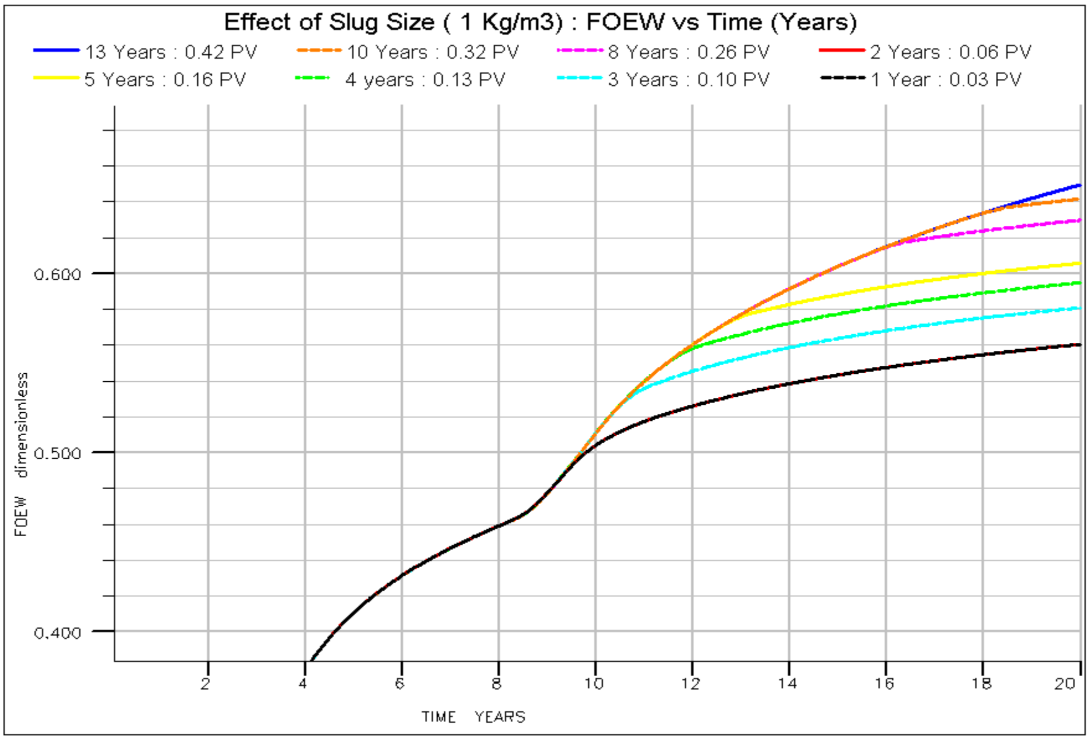

Figure 14 : Field Oil Recovery (FOEW) vs Time (Years) for different LSW slug sizes

Refer to Figure 17. As expected, the recovery increases as the slug size increases. A more detailed analysis was done in terms of volume calculations. The amount of fluid injected and total recovery is shown in Table 16.

Table 14 : Analysis on effect of different LSW slug size on Oil recovery

Total PV : 1,125,000 (Rsm3) Brine Salinity 1Kg/m^3						
LSW	**LSW**	**LSW**	**Injection Rate**	**Injection Volume**	**Injection PV**	**Total Recovery**
(Start Year)	**(End Year)**	**Period (Year)**	**(Rm3/day)**	**(Rm3)**		**%**
4	20	16	100	584,000	0.52	64.93
4	17	13	100	474,500	0.42	64.93
4	14	10	100	365,000	0.32	64.16
4	12	8	100	292,000	0.26	62.96
4	10	6	100	219,000	0.20	61.47
4	9	5	100	182,500	0.16	60.56
4	8	4	100	146,000	0.13	59.47
4	7	3	100	109,500	0.10	58.08
4	6	2	100	73,000	0.07	56.04
4	5	1	100	36,500	0.03	56.04

Table 16 shows an increase in recovery as the size of the low saline slugs were controlled by the imbibition time. Refer to Table 16, the slug sizes that give high oil recovery which are around 64% are 0.3 PV, 0.4 PV and 0.5 PV. Since the difference between the oil recovery are less than 1% thus the optimum low saline slug size for this study is 0.32 PV. Slug size of 0.4 PV and 0.5 PV are not economical to be used since the increase in recovery is small compared to the large volume of water required to be injected.

Thus, this clearly proves the importance of evaluating the amount of fluids that should be injected during EOR processes especially when dealing with expensive fluids. In real field industry application this type of economic evaluation could not be ignored.

To illustrate the effectiveness of different slug sizes, live 2D screenshots of the salt distribution at different time steps can be used. In Figure 18, 19, 20 and 21, the salt distributions after flooding of low salinity brine for small slug size of 0.032 PV and larger slug size of 0.324 PV can be seen. The screen shots were taken at time step of 7 and 11 years.

As being explained in section 4.1 the highest recovery was achieved at low salinity water which can be associated by low production of salt in the producer. When small slug size being injected, the salt concentration does not decrease significantly. In contrast to large slug size, a significant drop in salt concentration was achieved.

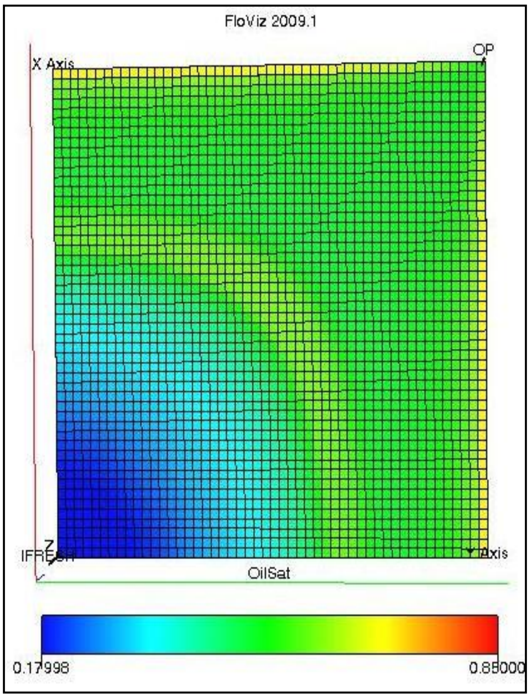

Figure 18 : Salt concentration at TSTEP (6) for small slug size

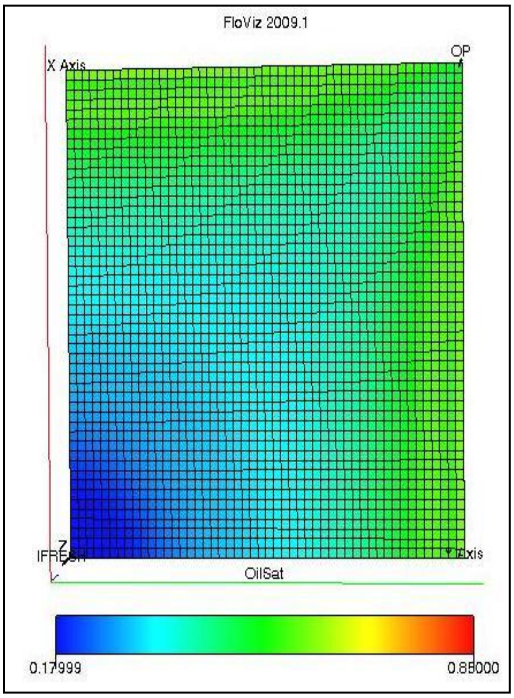

Figure 15 : Salt concentration at TSTEP (11) for small slug size

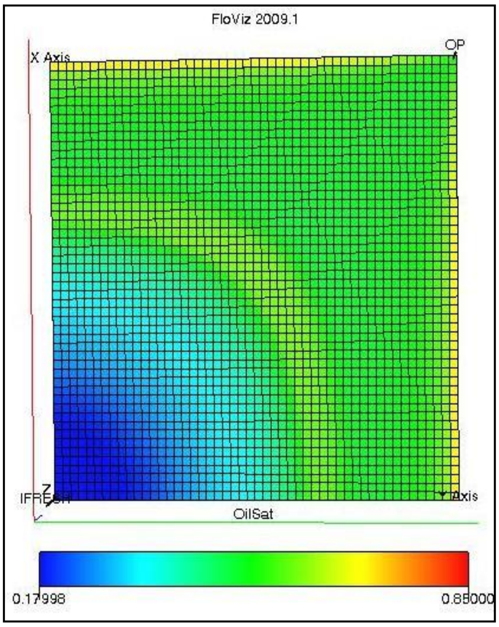

Figure 17 : Salt concentration at Year 6 for large slug size

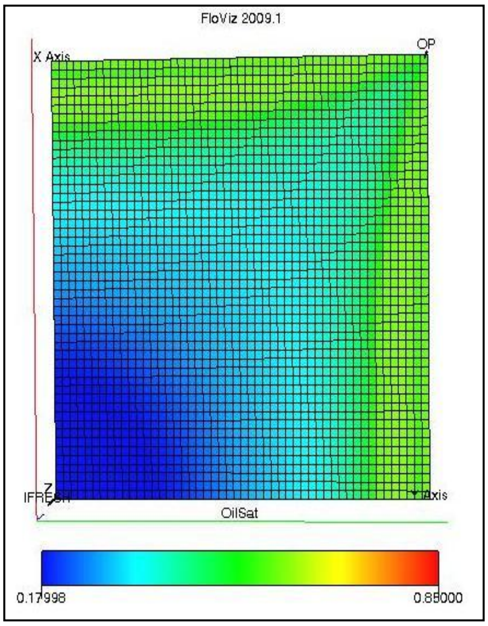

Figure 16 : Salt concentration at Year 6 for larger slug size

CHAPTER 5
CONCLUSION & RECOMMENDATION

5.1 Conclusion

From the simulation study conducted, following conclusion can be drawn:

1. As brine salinity decrease, the recovery of waxy oil also increases significantly up to an optimum salinity of 1 Kg/m^3. These findings show as the brine salinity decreases, the oil recovery increases. The observations from this study follow what have been suggested in the literature.

2. The success of LSW has been known to be its ability to control and change the wettability of the rock from an initially oil-wet reservoir to a water-wet reservoir. This is also proven by the water cut level since as the brine salinity decreases, the water cut also decreases which eventually helps in increasing the oil recovery.

3. Secondary Imbibition of low salinity yield higher recovery than tertiary imbibition since the volume of low saline water injected is more than tertiary imbibition. However the difference is less than just around 2% which makes tertiary imbibition of Low Salinity Waterflooding is more feasible and more economical to be done as tertiary Imbibition of low salinity requires smaller volume of low saline water.

4. The study of low salinity brine slug sizes is proven to be very important to economically justify the feasibility of LSW. The simulation study shows that any increase in the low salinity flooding pore volume (PV) above 0.32 or 365,000 Rsm^3 do not contribute to any significant increase in oil recovery.

In conclusion, the objective of the FYP is achieved. The influence of Low Salinity Water flooding on Waxy oil were thoroughly investigated and discussed. The results were summarized in the conclusion above. All these findings shall provide a good insight for LSW application in the industry.

5.2 Recommendation

Currently, the low salinity function build in Eclipse is only based on the modeling work of Jerauld et al. (2008). Due to the limitation of the software, the total TDS of the seawater is assumed to be a single salt which is NaCl. An improvement could be made by building LOWSALT function based on the modeling work done by Omekeh et al. (2012). With this, the interpolation of salinity curves will be based on ion exchange of certain ion. Thus, investigation on the impact of Multi-Component Salt which represents the actual composition of the seawater can be done.

Besides, it is recommended to get some of the actual field data from the oil company. This would add the credibility of this research aside from helping the companies to conduct researches. In fact, the actual field data can serve as good inputs for economic analysis of Low Salinity Waterflooding on Waxy Oil Recovery.

In addition, the work could also be expanded by using real reservoir model which include the reservoir heterogeneity and complexity in order to have a better understanding of the low salinity waterflooding behavior.

Last but not least, it is recommended to expand the Eclipse function capacity of Multi-Component salt (ECLMC keyword) and Low Salinity model using in both E100 and E300 simulator. This will give more flexibility in varying the component of waxy oil.

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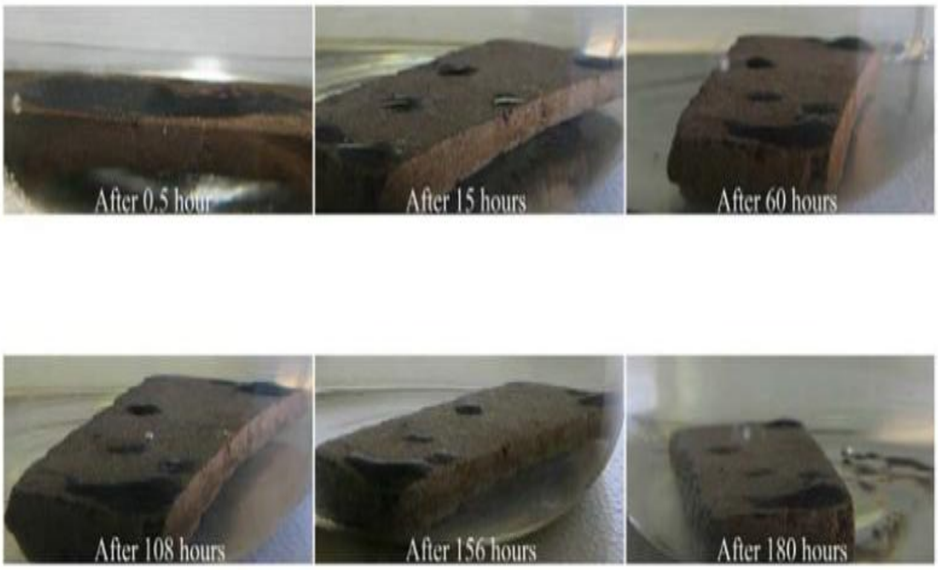
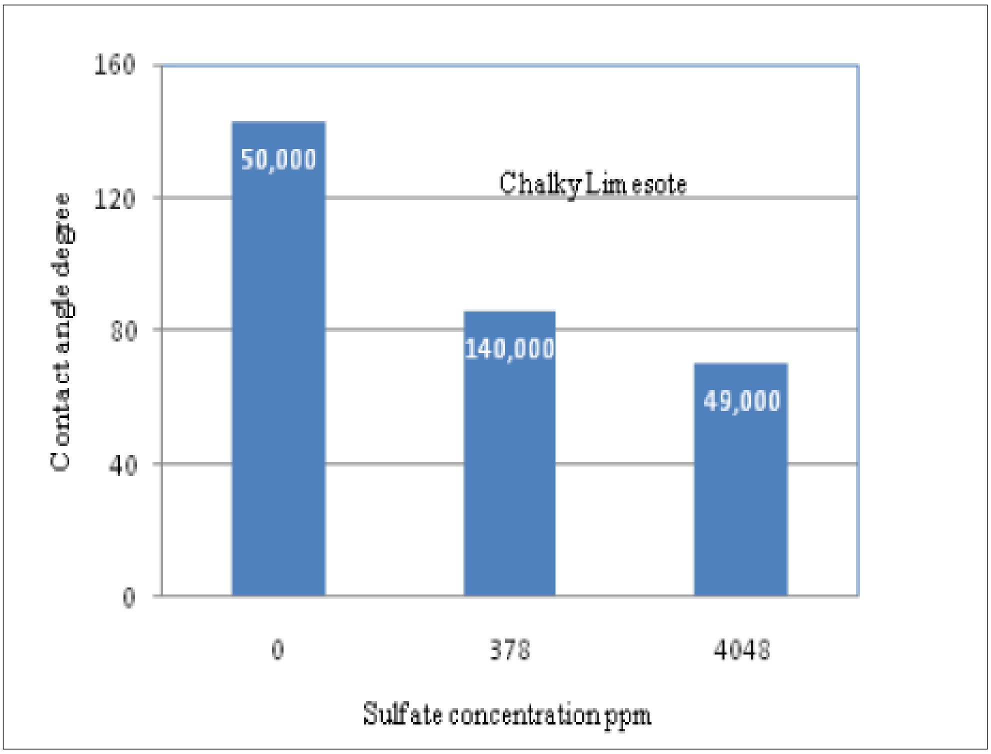
APPENDIX

Appendix 1 : Wettability monitoring results using SW. Zhang (2012)



Appendix 2 : Wettability monitoring using CaMg4S. Zhang (2012)



Appendix 3 : Contact angle as a function of sulphate concentration, Chalk LS. Zhang (2012)