Simulation Study on IWAG Assisted by Low Salinity Water Injection for Light Oil Reservoirs

by

Mohamed Yousry Ahmed Hussien

Dissertation submitted in partial fulfilment of

the requirements for the

Bachelor of Engineering (Hons)

(Petroleum Engineering)

MAY 2013

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CERTIFICATION OF APPROVAL

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A project dissertation submitted to the

Petroleum Engineering Programme

Universiti Teknologi PETRONAS

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BACHELOR OF ENGINEERING (Hons)

(PETROLEUM ENGINEERING)

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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.

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MOHAMED YOUSRY AHMED

ABSTRACT

Water alternating gas (WAG) injection is a widely practiced Enhanced Oil Recovery (EOR) technique for light oil reservoirs. On the other hand, various researches have documented that using the Smart water concept can further enhance the oil recovery obtained from water-flooding. Although, there was extensive researches conducted on each of the WAG and the smart water techniques separately, yet there are a very few researches conducted on using the smart water concept as the injection water in WAG technique. Previous laboratory core flooding researches have shown that reducing the salinity of the injection water in miscible WAG process would decrease the ultimate oil recovery. The published literature attributed that to the fact that reducing the salinity of the injection water would increase the solubility of the injected gas in water and thus reducing the amount of available gas to be soluble in oil.

Reservoir simulation processes were utilized in order to study the effect of using the smart water as the injection water in IWAG technique for light oil reservoirs. A synthetic model with 7,500 grid cells was used to evaluate the performance of several injection scenarios involving low salinity water and WAG techniques under the conditions of light oil reservoir at the depth of -6,000 ft. with oil API of 45°. The thickness of the reservoir is 30 ft.

The simulated results showed that using low salinity water as the injection water in immiscible WAG process would increase the oil recovery by 3.5% of the original oil in place (OOIP) than when using conventional high salinity water for light oil reservoirs. The results obtained from the simulation processes do not contradict the laboratory experiments results because of two main reasons. The first reason is that the simulation operations were based on immiscible WAG processes while the core flooding experiments were based on miscible WAG processes, and the second one is due to the gravity effects. During core flooding operations, gravity effects are minimal, while it was taken in consideration during the simulation processes.

Another important discovery by the reservoir simulation operations is that using a slug of low salinity water followed by high salinity drive water has much higher recoveries than conventional high salinity water flooding, and that adjusting the slug size can obtain recoveries almost as high as continuous low salinity water injection.

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ABBREVIATIONS AND NOMENCLATURE

Name	**Abbreviation**
Carbon Dioxide	CO_2
Enhanced Oil Recovery	EOR
Water-Alternating-Gas	WAG
Sodium Chloride	NaCl
Final Year Project	FYP
Hydrocarbon Pore Volume	HCPV
Minimum Miscibility Pressure	MMP
Multiple-contact miscibility	MCM
Nitrogen	N_2
Macroscopic or volumetric displacement efficiency	E_V
Microscopic displacement efficiency	E_D
Recovery Factor	RF
Multi-ion exchange	MIE
Magnesium Chloride	$MgCl_2$
Pore Volume	PV
Reservoir Barrel	RB
Stock Tank Barrel	STB
Pound per square inch	psi
Part per million	ppm
Pound per cubic feet	lb/ft3

CHAPTER 1

INTRODUCTION

1.1 Background of Study

When an oil field is first discovered, oil will usually flow into the producing wells under the natural pressure of the fluids present in the reservoir. With continuous production, the reservoir pressure will decline to a point where production is no longer economic, thus gas or water injection is used to restore the driving force of the reservoir to flow the fluids through the reservoir pores.

Although water-flooding has become the standard secondary recovery method for recovering oil left by primary production methods, yet conventional water-flooding cannot recover more oil beyond the residual oil saturation (Ezekwe, 2010; Orr, et al., 1982). Recently, various researches have documented that tuning the salinity and the ionic composition of the injected water can further enhance the oil recovery obtained from water-flooding. This chemically tuned water is usually termed as “Smart water”. (Jadhunandan, et al., 1995; Lager, et al., 2008; Yousef, et al., May, 2011; Yousef, et al., September, 2011)

On the other hand, tertiary oil recovery techniques, also known as Enhanced oil recovery techniques (EOR), aim to recover the oil that is initially unrecoverable by water-flooding. Water-alternating-gas (WAG) is a tertiary oil recovery process that is typically defined as, an enhanced oil recovery process whereby water injection and gas injection are alternately injected in the reservoir. WAG has been implemented successfully in a number of oilfields around the world. (Chen, *et al*., 2010)

The combination of the smart water injection and the WAG technique has not been studied sufficiently and requires further detailed study as it may hold the key to an ultimate EOR technique that would achieve the highest oil recovery possible from the reservoir. Although the utilization of the smart water concept as the injection water in the WAG technique should be tested for all kinds of reservoirs, yet the focus of this study is on Light oil reservoirs.

1.2 Problem Statement

Although, there was extensive researches conducted on each of the water-alternating-gas and the smart water techniques separately, yet there are a very few researches conducted on the combined use of the smart water concept and the Water-alternating-gas (WAG) technique. On the same time, all the studies conducted on the combined use of the smart water concept and the Water-alternating-gas (WAG) technique has been based on Core flooding laboratory experiments and does not take into account other important reservoir effects on WAG process which could be studied and accounted for only during reservoir simulation processes and pilot tests. The effect of smart water in WAG process could have a great effect on the oil recovery efficiency.

In conclusion, the utilization of the smart water concept in the WAG process requires extensive research in order to fully understand the process and fully optimize it for light oil reservoirs.

1.2.1 Problem Identification:

The problem identified is:

- The effect of tuning the salinity of the injection water in WAG process has not been sufficiently studied and requires further analysis and studies.

1.3 Objectives and Scope of Study

1.3.1 Objectives

1. To study the integration of WAG technique with the smart water injection concept, in light oil reservoirs, by using reservoir simulation processes.
2. To determine and analyze the factors having the greatest influence on the oil recovery efficiency when the smart water is used as the injection water in the WAG technique in light oil reservoirs.

1.3.2 Scope of Study:

This study aims to study the use of the smart water as the injection water in the Water-alternating-gas technique, in order to increase the ultimate oil recovery from the light oil reservoirs, as a result the ever growing global oil needs could be eventually met. The research will be conducted by using reservoir simulation processes.

1.4 Project relevancy and feasibility

1.4.1 Project Relevancy:

- With the ever increasing global oil demand, Enhanced oil recovery methods (EOR) hold promise for a better oil recovery efficiency.
- WAG and smart water techniques have proven that each of them separately has a great potential in oil recovery, so the employment of both techniques together requires detailed study in order to determine the impact of this combination, and its ultimate design parameters for achieving the highest oil recovery possible.

1.4.2 Project feasibility:

- Project can be finished within the timeframe of FYP 1 and FYP 2.
- Equipment and software needed are available in University of Technology PETRONAS.

CHAPTER 2

LITERATURE REVIEW

2.1 Introduction

The life cycle of any typical oil field spans through three main stages; Primary recovery by using the natural energy of the reservoir, secondary recovery mainly by water-flooding, and tertiary recovery or enhanced oil recovery (EOR) techniques (Yousef, *et al.*, May, 2011). The utilization, the duration, and the optimization of these three stages aim to increase the ultimate oil recovery and economic benefits from the reservoir. Primary and secondary oil recovery mechanisms are coming short in meeting the ever increasing oil demand. In most oilfields, using primary and secondary recovery mechanisms only 20 to 40 % of the reservoir's original oil in place (OOIP) can be extracted (EPRI, 1999). Feeding our ever growing oil demand lies in the future of enhanced oil recovery (EOR) techniques.

With the ever increasing global oil demand, Enhanced oil recovery methods (EOR) hold promise for recovering the oil remaining after conventional water-flooding. After the secondary recovery with water-flooding, the EOR technique implemented must have high microscopic displacement efficiency in order to mobilize the residual oil left behind by the water-flooding (Orr, *et al.*, 1982). Much of the new enhanced oil recovery techniques expansion is coming from the injection of non-hydrocarbon gases such as Nitrogen (N_2) and Carbon dioxide (CO_2) (Martin and Taber, 1992).

One of the most famous and successful EOR methods is Water-alternating-gas (WAG) method. WAG is a tertiary oil recovery process that is typically defined as, an enhanced oil recovery process whereby water and gas are alternately injected in the reservoir (Chen, *et al.*, 2010). Since it was first introduced in the late 1950s, WAG has been implemented successfully in a number of oilfields around the world (Christensen, *et al.*, 2001). More than half of the total oil production by enhanced oil recovery (EOR) methods in the United States is from gas injection methods, most of which are WAG processes (Chen, *et al*., 2010). In recent years, there has been great interest in WAG as it encompasses both favorable aspects of water-flooding and gas-flooding.

Since WAG was first proposed to improve the sweep efficiency of gas injection (Namani and Kleppe, 2011), its essential to understand the theory and the development of the gas injection process in order to fully understand the mechanisms behind the WAG process. Kulkarni and Rao (2004) also identified continuous gas injection as a type of WAG processes with a 0:1 WAG ratio. In this paper, Carbon Dioxide (CO_2) gas was chosen to be studied as the injection gas in the WAG process for various reasons. First of all, practical field applications show that using CO_2 gas in the WAG process has higher ultimate oil recovery than hydrocarbon gas (Christensen, *et al.*, 2001). The use of CO_2 for injection releases hydrocarbon gas for alternative uses (Ghedan, 2009). Last but not least, the recent enthusiastic move of Carbon Capture and Storage (CCS), where CO_2 is collected from large point sources, such as fossil fuel power plants, and then injecting it into subsurface geologic structures, which could contribute significantly in controlling the global problem of Greenhouse gases (GHG) emissions (Qi, *et al.*, 2008).

On the other hand and as basic as it may seem, yet the water component in the WAG process presented itself as a development opportunity for the WAG process in the recent years with the introduction of the "Smart water" concept. The smart water concept is the idea of injecting chemically-optimized water in terms of the salinity and the ionic composition into the reservoir in order to enhance the microscopic displacement efficiency of the water-flooding process (Youssef, *et al.*, October, 2012). The utilization of the smart water concept as the injection water in the WAG process presents itself as a promising future development opportunity for the WAG technique.

2.1.2 Basic Concepts in EOR

Oil recovery, in any Flooding process, depends on the volume of the oil reservoir contacted by the injected fluid. Oil recovery factor (RF) can be defined as the product of macroscopic or volumetric displacement efficiency, E_V, and microscopic displacement efficiency, E_D. Macroscopic displacement efficiency is a measure of the effectiveness of the displacing fluid in sweeping the oil of a reservoir both areally and vertically, while on the other hand, microscopic displacement efficiency is a measure of the effectiveness of the injected fluid to mobilize the oil at the pore scale in the invaded region. (Ghedan, 2009; Ezekwe, 2010)

Mobility ratio is the ratio of the mobility of the displacing phase, such as water, to the mobility of the displaced fluid, such as oil, at a specific saturation. It is very clear from the mobility ratio definition that it is most favorable to have the mobility ratio to be less than one, because the displaced fluid (Oil) will be more mobile than the displacing fluid, thus achieving the target of increasing the oil recovery. (Ezekwe, 2010)

Hence most artificial oil recovery mechanisms involve a fluid, or more, being injected into the reservoir, the process can be classified, based on the miscibility between oil and the injected fluid, as either miscible displacement process, or immiscible displacement process. Immiscible displacement occurs in a displacement process where a distinct boundary exists between oil and the injected fluid, while miscible displacement process is defined as fluid displacement where there is no interface between the two fluids (Ezekwe, 2010).

2.2 CO_2 Flooding

Carbon dioxide flooding appeared in 1930's and had a great development in 1970's. Over 40 years of production practice, carbon dioxide flooding has become a leading EOR technique for light and medium oils (Dong, *et al.*, 1999; Yongmao, *et al.*, 2004; Ghedan, 2009). Today, CO_2 flooding contributes to an oil production of approximately 180,000 STB/day (McKean *et al.*, 1999; Ghedan, 2009).

Carbon dioxide flooding is considered more favorable over other gases because of the following reasons:

a) Miscibility is achieved at lower pressures than with hydrocarbon gas and Nitrogen gas ((Martin and Taber, 1992),
b) The use of CO_2 for injection releases hydrocarbon gas for alternative uses, e.g. sales (Ghedan, 2009),
c) The utilization of CO_2 in EOR projects could aid significantly in controlling the global warming problem (Asghari and Al-Dliwe, 2005; Ghedan, 2009).

According to Ghedan (2009) there are three main sources of Carbon dioxide for EOR projects:

a) Natural sources of CO_2 such as those in the subsurface reservoirs.
b) CO_2 separated during the manufacture of hydrogen or ammonia.
c) CO_2 produced from combustion processes.

2.2.1 CO_2 solubility in oil mechanisms:

Carbon dioxide flooding can be classified as immiscible or miscible, even though carbon dioxide and oil are not miscible upon first contact in the reservoir (Martin and Taber, 1992). First contact miscibility can be defined as the process in which the injection gas and reservoir oil, mixed in any ratio, form a single phase (Parra-Ramirez, *et al.*, 2001). Recent researches and studies have focused on miscible CO_2 flooding as it has been found to have higher oil recoveries (Martin and Taber, 1992). The experiments of Kulkarni and Rao (2004) have shown that, after water-flooding, miscible gas floods recover 60 to 70% more oil than immiscible gas floods.

Unlike liquid propane, CO_2 is not miscible with oil upon first contact in the reservoir, yet it does achieve miscibility by a mechanism called "multiple contact miscibility (MCM) mechanisms" (Ezekwe, 2010). Multiple-contact miscibility is achieved as the result of repeated contacts in the reservoir between the reservoir oil and the injected fluid, and also fluids generated in-situ by the interactions between the injected fluid and the reservoir oil, Multiple-contact miscibility is of two mechanistic types: vaporizing-gas drive and condensing-gas drive (Benham, *et al.*, 1960; Holm, 1986; Ezekwe, 2010). CO_2 utilizes the MCM mechanism of vaporizing-gas drive in order to achieve miscibility with crude oil (Parra-Ramirez, *et al.*, 2001; Ezekwe, 2010).

In order for Carbon Dioxide to achieve miscibility or multi-contact miscibility a minimum pressure is required which will vary depending on Oil composition, and reservoir temperature, this pressure is known as "the minimum miscibility pressure (MMP)" (Sahin, *et al.*, 2007). Martin and Taber (1992) defined the minimum miscibility pressure for Carbon Dioxide as the pressure required to compress Carbon dioxide to a density at which it becomes a good solvent for the lighter hydrocarbons in the crude oil, while Parra-Ramirez *et al*. (2001) defined it as the minimum pressure required to achieve the vaporizing-gas drive multi-contact miscibility. Many studies have reached empirical equations that can be used to calculate the MMP, such as Glaso correlation (Glass, 1985), yet MMP calculated from empirical equations can have large errors and should not replace those obtained from experimental or simulation methods (Ezekwe, 2010).

2.2.2 CO_2 solubility in Water:

One important factor affecting the process of CO_2 flooding is the presence and the properties of the water phase. Compared to hydrocarbon gas, CO_2 has a much higher solubility in water (Taber, 1983), yet the effect of dissolved CO_2 in water on the viscosity of the water phase is very small (Sayegh, *et al.*, 1987; Chang, *et al.*, 1998). The solubility of CO_2 in water is a function of pressure, temperature, and water salinity (Taber, 1983; Klins, 1984). Researchers have found that CO_2 solubility in water increases with pressure, and decreases with temperature and salinity increase of water (Chang, *et al.*, 1998).

Pollack *et al*. (1988) found that the presence of aqueous phase reduces the amount of CO_2 available for mixing with the hydrocarbons. Chang, *et al*. (1998) simulation results also agreed with the findings of Pollack *et al*. (1988) and concluded that about 10% of the CO_2 injected is dissolved in water and is unavailable for mixing with oil, and can be considered as "lost" to the aqueous phase. The solubility of CO_2 in water not only delays the oil recovery but also reduces the final oil recovery (Chang *et al*., 1998). On the other hand, Martin and Taber (1992) argued that the solubility of CO_2 in the water phase, could improve the overall flooding process efficiency. During laboratory experiments, CO_2 has been observed to diffuse through the water phase to swell bypassed oil until the oil is mobile (Martin and Taber, 1992).

2.2.3 CO_2 flooding screening criteria:

There are some basic conditions that are required in order for CO_2 flooding to be most beneficial and achieve the required miscibility. Because of the minimum pressure requirement, reservoir depth is an important factor, and CO_2 floods are normally carried out in reservoirs that are more than 2,500 ft. deep (Taber, 1983; Moritis, 1990; Martin and Taber, 1992). The oil composition is also an important factor, and the API gravity exceeds 30^o for most of the active CO_2 floods (Taber, 1983; Moritis, 1990; Martin and Taber, 1992). A decrease in API oil gravity generally increases miscibility pressure, reflecting the reduced content of extractable hydrocarbons which would obstacle vaporizing-gas drive MCM (Stalkup, 1978). On the other hand, Merchant (2010) argued that the previous conditions may not be necessarily correct and that today some successful CO_2 flooding projects operate below or near the minimum miscibility conditions.

Even with low API oil (low percentage of Intermediate components) or with the depth condition violated, immiscible CO_2 flooding could still achieve remarkable results (Merchant, 2010). Merchant (2010) reported that with immiscible CO_2 flooding in the Wilmington field in California, which produces 14 API Gravity crude from the Ranger formation, a good number of wells increased oil rate from 30 BOPD to over 300 BOPD after CO_2 was injected.

If miscibility is required, either for the overall effeciency of the process or economically, and the MMP is relatively high and hard to achieve by CO_2 floodig only, then hydrocarbon gases such as propane, butane can be added to the CO_2 injection stream to lower the minimum miscibility pressure (Merchant, 2010).

2.2.4 CO_2 Oil recovery mechanisms:

When the MMP is reached, both the oil phase and the CO_2 phase (which due to the vaporizing-gas drive MCM contains many of the oil's intermediate components) can flow together because of the low interfacial tension (IFT) and the relative increase in the total volume of the combined CO_2 and oil phase when compared with the water phase. At such conditions, CO_2 becomes a good solvent for oil, and it swells the net volume of oil and reduces its viscosity. (Taber, 1983; Orr, *et al*., 1982) Even below the MMP -immiscible flooding process-, the remaining oil saturation after gas flooding is normally lower than after water-flooding (Christensen, *et al*., 2001).

In general Carbon dioxide recovers crude oil by (Martin and Taber, 1992; Ghedan, 2009):

a) Generation of Miscibility,
b) Swelling the crude oil,
c) Lowering the oil viscosity,
d) Lowering the IFT.

2.2.5 CO_2 flooding Mobility control issue:

Stalkup (1978), as well as Ezekwe (2010), stated that a major disadvantage of carbon dioxide flooding, and gas flooding in general, compared with water-flooding results from the low viscosity of CO_2 relative to that of oil which causes the displacement front to be unstable which develops "viscous fingers". Viscous fingering is a manifestation of finger shaped interface occurring between displaced and displacing fluid (Benham and Olson, 1963). Viscous fingering phenomenon in gas flooding causes poor sweep efficiency and lower extra oil recovery (Ghedan, 2009).

In order to reduce the effects of the viscous fingering phenomenon, the concept of mobility control was introduced. Mobility control methods typically aim to reduce the mobility ratio between the injected fluid and the reservoir oil thus controlling the viscous fingering phenomenon. The mobility ratio can be reduced by reducing the fluid mobility in a porous medium which can be achieved by either reducing the relative permeability of the matrix to that fluid, or increasing the viscosities of the fluids in the region, or both (Caudle and Dyes, 1958). To help minimize fingering, Caudle and Dyes (1958) proposed simultaneous injection of water and natural gas following propane slug to lower the mobility of the displacing fluids. Although it was later on found impractical in field application, yet their idea triggered one of the most common enhanced oil recovery techniques today which is Water-Alternating-Gas (WAG). (Christensen, *et al*., 2001; Rogers and Grigg, 2001).

2.3 Water-alternating-gas (WAG)

Water-alternating-gas (WAG) is a tertiary oil recovery process that is typically defined as, an enhanced oil recovery process whereby water injection and gas injection are alternately conducted in the reservoir (Chen, *et al*., 2010). Christensen *et al.* (2001) gave a more general definition of WAG as any process where both gas and water are injected into the same well. WAG has been implemented successfully in a number of oilfields around the world since the 1960's (Christensen, *et al*., 2001). In recent years, there has been great interest in Water Alternating Gas (WAG) as a method to improve the sweep efficiency of gas injection in Enhanced Oil Recovery (EOR) by using water to control gas mobility (Jiang, *et al*., 2010). The utilization of the high microscopic efficiency of gas together with the high macroscopic efficiency of water help significantly in increasing the oil recovery over conventional water-flooding and gas-flooding (Kulkarni, and Rao, 2004). Injecting water with the miscible gas reduces the relative permeability of the matrix to the injected gas and so it reduces the relative mobility ratio, thus improving the macroscopic sweep efficiency of the injection gas (Al-Shuraiqi, *et al.*, 2003). Chen *et al*. (2010) compared the oil recovery by WAG-CO_2, Continuous

CO_2 flooding, and water-flooding, and found that the highest oil recovery is obtained from the WAG process.

Similar with the case of gas injection, WAG process can also be classified as miscible or immiscible WAG injection (Christensen, *et al.*, 2001). In practical field application, miscible WAG injection is more dominant as 79% of the WAG projects employed are miscible (Kulkarni, and Rao, 2004).

There are some important WAG parameters such as cycling WAG ratio and slug size which need to be defined. The WAG ratio can be defined as the volume of water versus the volume of gas injected and it is affected by various factors such as; gas availability and the wetting state of the reservoir rock (Jackson, *et al.*, 1985; Kulkarni and Rao, 2004). A WAG ratio of 1:1 is the most popular for field applications (Christensen, *et al*., 2001; Kulkarni and Rao, 2004). According to Kulkarni and Rao (2004), the WAG recovery efficiency is also a direct function of the total gas slug size, a 0.6 pore volume (PV) slug size gives maximum recovery. The slug sizes of the gas volume are mostly in the range of 0.1 to 3 PV (Christensen, *et al*., 2001).

2.3.1 WAG advantages:

WAG process has many advantages when compared with the conventional water-flooding or miscible gas injection, as WAG encompasses the favorable aspects of both of them. Besides the gas mobility control, other important aspects are associated to the WAG process: oil swelling, composition variation and viscosity reduction caused by the gas dissolution in oil, and decrease of the residual oil saturation resulted from the flow of three phases and effects associated to relative permeability hysteresis (Christensen, *et al*., 2001; Namani and Kleppe, 2011; Ligero, *et al*., 2012). Kuuskraa (1983) carried out an experiment in order to compare the WAG and the Continuous CO_2 injection and the experiments showed that the WAG provided higher recovery efficiency and lower CO_2/oil ratios than using continuous CO_2.

From an economic point of view gas injection is an expensive operation, the reduction in the amount of gas injected in the reservoir, when compared with continuous gas injection, could be considered an advantage of WAG. In order to further reduce the amount of gas needed during the WAG process a new concept, known as WAG tapering, was introduced. We refer to WAG tapering as the progressive reduction of CO_2 injection volumes so that more water and less CO_2

are injected during any complete WAG cycle (Attanucci, *et al.,* 1993). The process of WAG tapering was adopted by the industry during the late 1980s to improve the overall recovery process and economic benefits (Merchant, 2010). For further demonstration, Hadlow (1992) has reported a case in which Chevron is utilizing a tapered WAG process in which they used a 1:1 WAG ratio until 30% Hydrocarbon Pore Volume (HCPV) of CO_2 was injected. Then, Chevron would switch to a 2:1 WAG ratio until 40% of HCPV of CO_2 was injected. From 40 to 50% HCPV, a 3:1 WAG ratio was utilized, after which chase water would be injected.

2.3.2 WAG practical Field Applications:

Christensen, *et al*. (2001) have reviewed 59 field applications of WAG technique and have concluded that the average improved recovery is calculated to be 9.7% for miscible WAG injection and, 6.4% for immiscible WAG, but in general it can be up to 20%. The review have also studied the usage of different types of injection gases and the results showed that CO_2 has higher recovery factor over hydrocarbon gas and nitrogen, with an average improved oil recovery of 10%. Christensen, *et al.* (2001) attributed the higher recoveries of WAG process from CO_2 to the fact that most CO_2 injections are miscible, while the hydrocarbon gas and nitrogen gas WAG field tests are mostly immiscible.

Until today, most WAG projects have been applied for onshore fields, but it has been proven applicable for a wide range of reservoir types, from very low permeability chalk to very high permeability sandstones. It is also worth noting that the leader WAG injection gas is CO_2 as 47% of WAG projects utilized CO_2 as the injection gas. (Christensen, *et al*., 2001; Kulkarni, and Rao, 2004)

2.3.3 WAG Design Parameters:

In the design of a Water-alternating-gas (WAG) process, there are several factors that must be taken in consideration in order to fully optimize the process and obtain the ultimate oil recoveries. These important factors affecting WAG injection include reservoir heterogeneity, rock wettability condition, fluids properties, miscibility conditions, injection technique and WAG parameters such as cycling frequency, slug size, WAG ratio, and injection rate (Surguchev, *et al.,* 1992; Sanchez, 1999). Christensen *et al.* (2001) has reported some of the common operational problems in WAG process, which include; early breakthrough in the production wells, reduced injectivity in the reservoir, and Asphaltene and Hydrate formation.

The presence of reservoir heterogeneities makes the WAG process vulnerable to premature breakthrough of one of the phases (Gas or Water). Optimum conditions of oil displacement by WAG would be achieved, if gas and water were travelling in the reservoir at equal speed (Surguchev, *et al*., 1992). In order to achieve this uniform sweeping of oil towards the producing wells, Chen, *et al*. (2010) emphasized that it is essential to determine specific WAG injection and production parameters for each injector and producer taking in consideration the reservoir heterogeneity and the formation flow capacity, which could be achieved by accurate reservoir simulation processes.

The rock wettability conditions and the fluid properties also play an important in the efficiency and the effectiveness of the WAG process. Various laboratory studies have concluded that rock wettability strongly affects the trapping mechanism of oil by the water injected during the WAG process, as the saturation changes are cyclic during any WAG process. As a result, a comprehensive analysis and study of the wettability conditions, the saturation history of the reservoir, and the performance and the properties of the three phases flowing in the reservoir are always essential for a successful WAG process. (Surguchev, *et al*., 1992; Ghedan, 2009)

In terms of WAG parameters, the review conducted by Christensen, *et al*. (2001) shows that the most successful field application of WAG technique so far comes from the 5-spot injection pattern with close well spacing, yet other injection patterns have also proven successful in some fields. A WAG ratio of 1:1 is the most popular for field applications, yet the WAG ratio specification is controlled by the availability of the gas, and the wetting state of the reservoir (Christensen, *et al*., 2001; Kulkarni and Rao, 2004). Another important WAG parameter is the Slug size. According to Kulkarni and Rao (2004), 0.6 PV slug size gives the highest oil recoveries, but due to economic constraints sometimes the slug size of 0.2 to 0.4 PV is used. In terms of the injection gas, Abed and Zekri (2009) carried out a study on various EOR projects and found that using the CO_2 as the injection gas in WAG process could yield a recovery factor up to 60 to 70% which is higher than that obtained with hydrocarbon gases and Nitrogen gas.

Although it was given less importance though the literature, yet the properties and the chemistry of the drive fluid (Water) may be an important factor in the WAG process. Kuuskraa (1983) carried out a very unique experiment trying to compare the effect of the viscosity of the drive fluid (Water) in the WAG process. His experiments concluded that using a fluid with higher viscosity, 8 cp, increased the recoveries, from 32% with normal 1 cp water, to 46%.

2.4 The Smart Water Concept:

Typically water-flooding had always been regarded as a physical displacement process to maintain reservoir pressure and push the oil towards the producing wells, until Jadhunandan *et al*. (1995) has published his research on the influence of brine composition on oil recovery. In recent years, various researches have shown that tuning the salinity and the ionic composition of the injected water can enhance the microscopic displacement efficiency of water-flooding process. Filoco and Sharma's (1998) experiments on water flooding showed strong salinity dependence such that higher oil recoveries were obtained for lower connate brine salinities. The chemically altered water in terms or salinity and ionic composition is usually referred to as "Smart Water". Many researches have shown that the efficiency of the water-flooding process can be enhanced significantly by lowering the salinity of the injected water. (Lager, *et al*., 2008; Yousef, *et al*., May, 2011; Yousef, *et al*., September, 2011)

There are various proposed theories on the mechanisms behind smart water, yet until today none of them have been generally accepted to be the true mechanism (Austad, *et al*., 2010; Lager, *et al*., 2008a). Austad *et al.* (2010) also listed down some of the suggested mechanisms which include; fines migration, pH increase, Multi-ion exchange (MIE), and salting in effects. On the other hand, the experiments of Larger *et al*. (2008) refuted two of the proposed explanations for the effects of smart water, which are; fines migration, and high pH associated with the injection of low salinity water. Due to the conflict between the results, Austad *et al.* (2010) suggested that the effect of smart water is a result of different mechanisms acting together, and that these mechanisms will vary from one case to another.

2.4.1 Smart water as the injection water in WAG

To the best of our knowledge there are only two researches conducted to test the combination of Smart water concept and WAG technique. The first work was done by Kulkarni and Rao (2004), but they investigated only for model oil (n-Decane). They found that a change in brine composition from 5% Sodium Chloride (NaCl) to 0.926% multivalent brine showed an adverse effect on oil recovery due to the increased solubility of CO_2 in brine.

The second research was conducted by Jiang, *et al*. (2010), in which they used two oil models to be studied; a mixture of 50 wt% n-decane and 50 wt% n-hexadecane, and a crude oil from Cottonwood Creek. The research was based on an experimental study of core flooding in which six alternate cycles of brine and CO_2 with a half-cycle slug size of 0.25 pore volumes (PV) and a WAG ratio of 1:1 are injected in every core flood test. The research concluded that the tertiary oil recovery and the recovery factor of both model oil and crude oil are found to increase slightly with the increase of the salinity of the injection brine as shown in Figure 1.

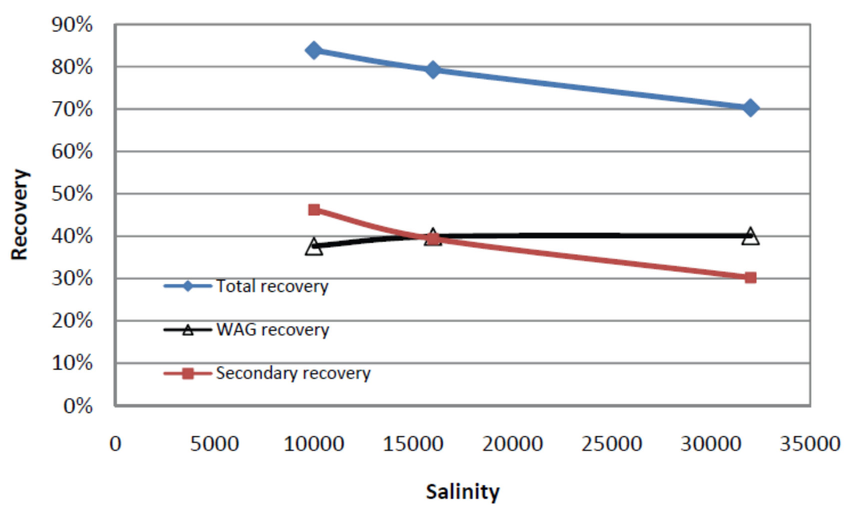

Figure 1: the recovery of water flooding, WAG flooding, and total as a function of salinity

Adopted from Jiang *et al.* (2010)

Jiang et al. (2010) concluded that when the salinity of the injected was increased the only changed property is the solubility of CO2 in brines. The solubility of CO_2 in brine water decreased with the increase of the water salinity, which means that when the salinity of brine increases, there will be more CO_2 available for miscible flooding, and thus the WAG recovery increases.

2.5 Literature Review Summary

In the recovery factor of any oil recovery operation depends on its macroscopic displacement efficiency, and microscopic displacement efficiency. Since conventional water-flooding has effective macroscopic displacement efficiency but poor microscopic displacement efficiency, thus the EOR technique implemented, after the water-flooding operation, must have high microscopic displacement efficiency in order to mobilize the residual oil left behind by the water-flooding. One of the leading EOR techniques for light and medium oil reservoirs is CO_2 flooding. One major disadvantage for CO_2 flooding is the viscous fingering phenomenon which causes poor sweep efficiency and lower oil recovery. In other words CO_2 flooding has effective microscopic displacement efficiency but poor macroscopic displacement efficiency.

As a method to control the viscous fingering phenomenon of CO_2 flooding, water was used to control the mobility of CO_2, thus the concept of WAG was introduced. WAG is a tertiary oil recovery process that is defined as, an enhanced oil recovery process whereby water injection and gas injection are alternately injected in the reservoir. There are important factors affecting WAG technique which include reservoir heterogeneity, rock wettability condition, fluids properties, miscibility conditions, and WAG parameters such as cycling frequency, slug size, WAG ratio, and injection rate. On the other hand, recent researches and studies have concluded that tuning the salinity and ionic composition of the injection water (Smart Water) in water-flooding process could increase the oil recovery from the reservoir. There are various proposed mechanisms behind the effect of the smart water injection such as; fines migration, pH increase, Multi-ion exchange (MIE), and salting in effects.

Previous researches on the usage of smart water as the injection water in WAG technique are limited. The available researches conducted on this combination have concluded that the oil recovery was found to increase with the increase of the salinity of the injection water. This increase in oil recovery was attributed to the decrease of solubility of CO_2 in water, thus more CO_2 will be available for miscible contact with the reservoir oil.

CHAPTER 3

METHODOLOGY

3.1 Research Methodology Flow chart

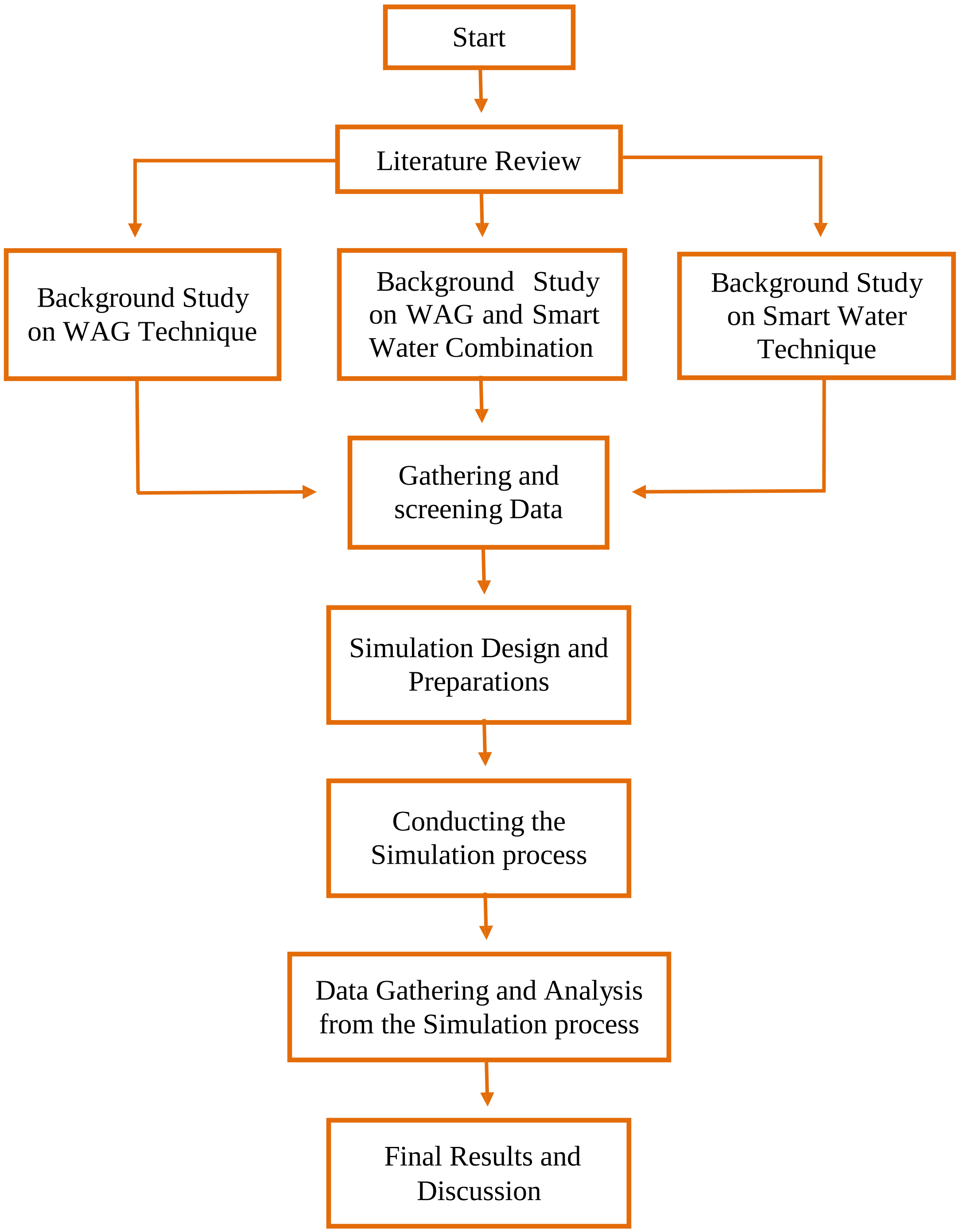

Figure 2: FYP flow chart on research methodology

3.2 Project Gantt Charts

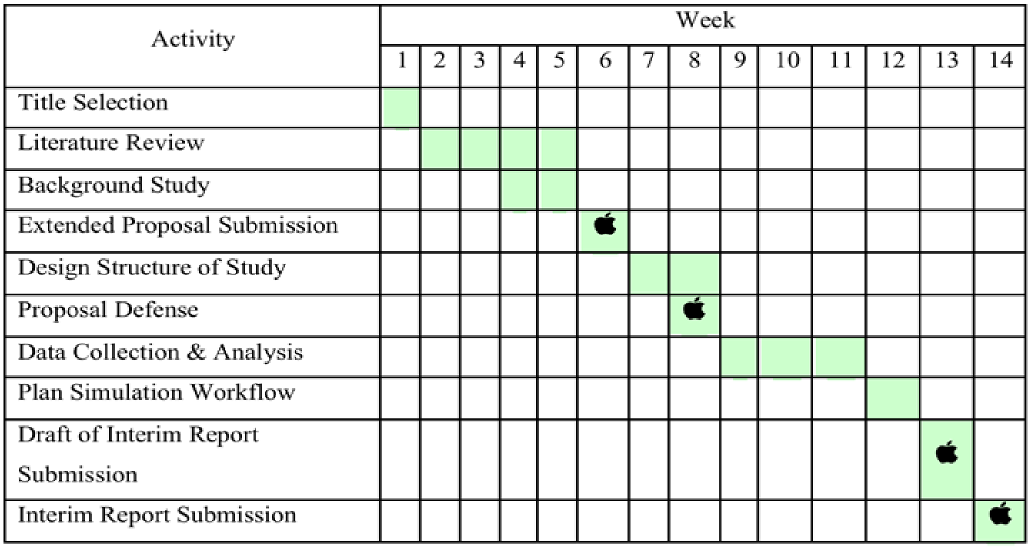

Figure 3: FYP I Gantt chart

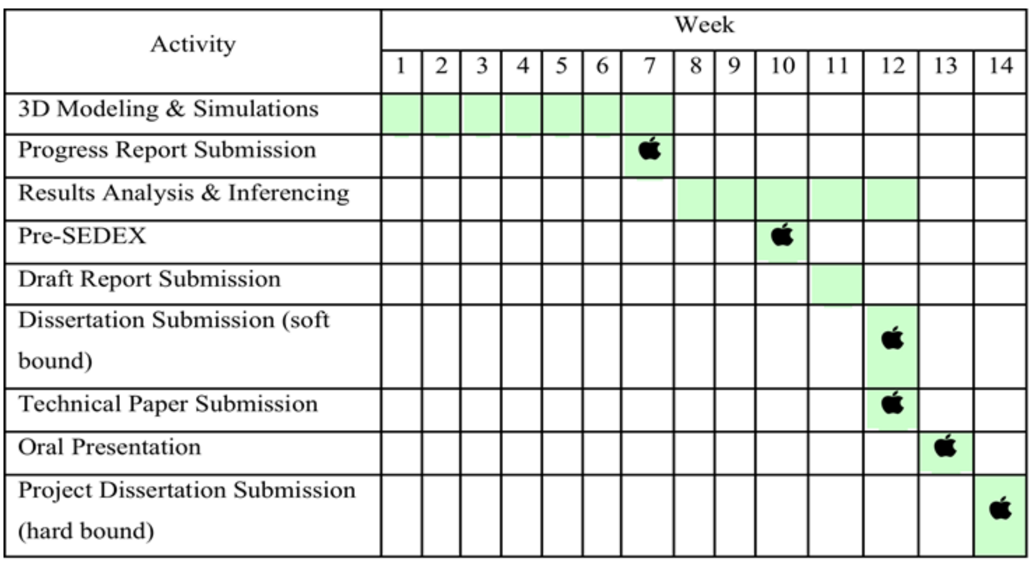

Figure 4: FYP II Gantt chart

3.3 Softwares used in the research

There are two main softwares used in this research, which are Schlumberger PETREL and Schlumberger ECLIPSE.

Schlumberger *PETREL* software:

PETREL is a Schlumberger owned Windows software application which is used as a pre and post processor for the simulator engine (Schlumberger ECLIPSE). It allows the user to interpret seismic data and build a geological model, perform well correlation, build reservoir models suitable for simulation, submit and visualize simulation results, calculate volumes, produce maps and design development strategies to maximize reservoir recovery and economic benefits.

Schlumberger *ECLIPSE* software:

ECLIPSE is a Schlumberger owned Windows software application which is used as simulation engine software. ECLIPSE software covers the entire spectrum of reservoir simulation, specializing in black oil, compositional and thermal finite-volume reservoir simulation, and streamline reservoir simulation. ECLIPSE has two main versions: E100 and E300; E100 solves the black oil equations, while E300 solves the reservoir flow equations for compositional hydrocarbon descriptions and thermal simulation. In this research ECLIPSE 300 will be utilized.

3.4 Project Activities

Task	Objective
Data research and gathering	To understand the operational advantages and disadvantages, and the science behind both the WAG technique and the smart water technique.
Simulation process design	To define the main simulation process Input data, and determine which parameters to be held constant and which needs to be tuned and tested.
Reservoir geologic model and fluid model construction	To construct a reliable geological model that encompasses various kinds of heterogeneities, and permeability distributions. To construct a realistic fluid model that is representative for light oil.
Simulation runs and predictions	To conduct the simulation process and predict the effect of tuning the predefined parameters on the ultimate oil recovery, and analyze the effect of the different reservoir heterogeneities on the process.
Simulation process results analysis	To analyze the results and predictions obtained from the simulation process.

Table 1: Summary of Project Activities

CHAPTER 4

RESULTS AND DISCSSUION

4.1 Synthetic Model, Fluid Properties, and ECLIPSE input Data

4.1.1 Synthetic Model and Fluid Properties

In this study, a synthetic model of dimension 500 feet, 500 feet and 30 feet in I, J and K directions, respectively, was created. The model was created to be 50, 50 and 3 grids blocks. The property details of the reservoir model are as follows:

Property	Value	Unit
Depth (Top Layer)	-6000.00	Feet
Total Volume	7,500,000.00	Cubic Feet
Permeability in X-Direction	300.00	md
Permeability in Y-Direction	300.00	md
Permeability in Z-Direction	30.00	md
Porosity	0.25	Unit-less
Net To Gross	0.90	Unit-less
Initial Water Saturation	0.20	Unit-less
Initial Gas Saturation	0.00	Unit-less
Initial reservoir pressure	2550.00	psia
Reservoir Temperature	220.00	Degree Fahrenheit

Table 2: Properties of the synthetic model

The model was created to be homogenous in order to isolate the various effects of reservoir heterogeneities on the processes conducted and in order to focus the study on the effects of tuning the salinity and ionic composition on WAG process.

In the created model, the fluid properties utilized were based on the fluid properties of Gullfaks reservoir. The reservoir is under-saturated and the following tables summarize the main parameters of the oil, and water phases in the reservoir.

Property	Value	Unit
Bubble point pressure	2516.00	psia
Formation Volume Factor	1.10	RB/STB
Solution Gas oil Ratio	1.13	SCF/STB
Viscosity at reservoir conditions	1.33	Centipoise
Oil Density	45.11	Pound per cubic feet
Oil API	45	Unit-less

Table 3: Properties of the Oil phase

Property	Value	Unit
Salinity	30,000.00	Part per million
Density at reservoir conditions	63.69	Pound per cubic feet
Viscosity at reservoir conditions	0.3293	Centipoise
Compressibility at reservoir conditions	2.86E-6	RB/STB

Table 4: Properties of the water phase

In the created synthetic model, there were two well; an injector, and a producer which were placed in grid number 1, 1, 1-6 and 50, 50, 1-6 respectively, such that the producer is in one corner while the producer is in the other corner. The following 3D figure visualizes the location of the two wells within the reservoir.

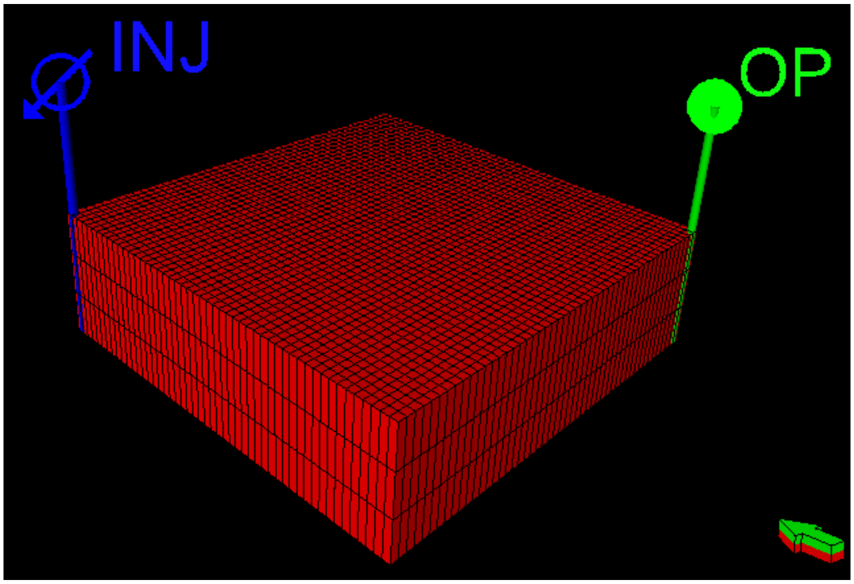

Figure 5: The wells locations in the synthetic model

4.1.2 Low Salinity Water Flooding Model's ECLIPSE Input Data

In order to activate the low salinity water flooding process in ECLIPSE E100 software, the keyword LOWSALT must be included in the RUNSPEC section. According to ECLIPSE software's manual, the keyword LOWSALT allows the user to modify the saturation and relative permeability end points for water and oil phases as a function of the salt concentration. Therefore as two sets of saturation functions; one for low salinity (around 1000pm) and another for high salinity, must be provided once the LOWSALT model is activated.

Under the SWOF keyword in the PROPS section two saturation functions have been defined; one for the low salinity water and another for the high salinity water. The saturation functions data were based on the low salinity sample provided with ECLIPSE software. A low salinity water flooding changes the shape of the relative permeability curve due to wettability changes toward more water wet rock as shown in the next figure.

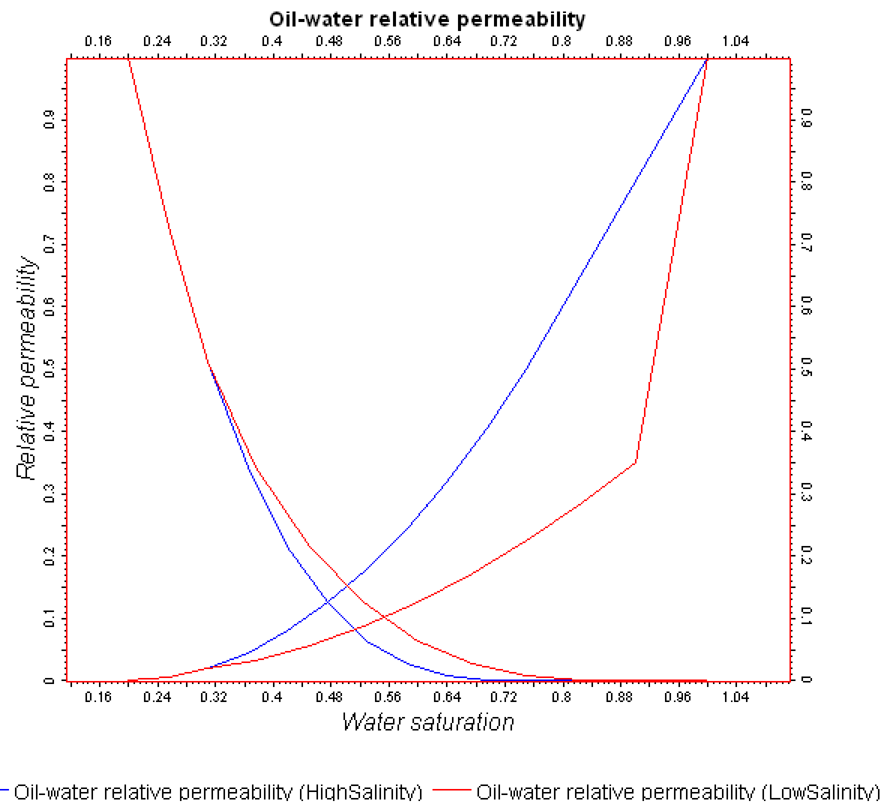

Figure 6: The oil and water relative permeability curves for high and low salinity water

After the low salinity and high salinity saturation functions have been defined under the props section, the keyword SATNUM in the REGIONS section defines which table of saturation function (SWOF) represents the high salinity saturation and the keyword LWSLTNUM must then be used in REGIONS section to associate low salinity table number to each grid block. As a the result the keywords SATNUM and LWSLTNUM were defined in ECLIPSE as,

SATNUM

15000*1/

LWSATNUM

15000*2/

where 15000 is the total number of grid blocks in the synthetic model.

In order for ECLIPSE to interpolate the end points of the saturation curves and the oil-water relative permeabilities as a function of the salt concentration, the keyword LSALTFNC must be included. The keyword LSALTFNC, which is activated in the PROPS section, is set to modify the saturation end points and the relative permeabilities by using the following equations:

$$S_{wco} = F_1 S_{wco}^L + (1 - F_1) S_{wco}^H$$

$$S_{wcr} = F_1 S_{wcr}^L + (1 - F_1) S_{wcor}^H$$

$$S_{wmax} = F_1 S_{wmax}^L + (1 - F_1) S_{wmax}^H$$

$$S_{owcr} = F_1 S_{owcr}^L + (1 - F_1) S_{owcr}^H$$

and,

$$k_{rw} = F_1 k_{rw}^L + (1 - F_1) k_{rw}^H$$

$$k_{ro} = F_1 k_{ro}^L + (1 - F_1) k_{ro}^H$$

$$P_{cow} = F_1 P_{cow}^L + (1 - F_2) P_{cow}^H$$

Where,

F_1 is the weighting factor for the low-salinity saturation endpoints and the relative permeability interpolation

F_2 is the weighting factor for the low-salinity capillary pressure interpolation

S_{wco} is the connate water saturation

S_{wcr} is the critical water saturation

S_{wmax} is the maximum water saturation

S_{owcr} is the critical oil saturation in water

H is index for high salinity

L is index for low salinity

Under the LSALTFNC and by using the previous equations, the F1 factor value of 0 means that the high salinity saturation functions will be used while the value of 1 means low salinity saturation functions will be used. The LSALTFNC data used in this study is as follows.

Water Salinity (ppm)	**F1**	**F2**
0	1	1*
10,000	0.8	1*
20,000	0.3	1*
30,000	0	1*

Table 5: The LSALTFNC (F1, F2) table

When low salinity option is active, keyword PVTWSALT in PROPS section is used, instead of PVTW, to supply the water PVT data as a function of salt concentration. Also the keyword SALTVD must be defined when the LOWSALT model is utilized. The keyword SALTVD, is used to define the reservoir water salinity as a function of depth for this study it was assumed the reservoir water saturation has a constant salinity with depth of 30,000 ppm below 5000 feet depth.

4.2 The Studied cases:

Various simulation runs were conducted in order to reach the ultimate production and injection strategies. Since the average initial reservoir pressure is very close to the bubble point pressure, water flooding was decided to be conducted from the first day of production. After getting the best case to oil recovery from secondary recovery, it was found that the optimum recovery was obtained when both wells were controlled by a reservoir volume rate (RESV) of 100 RB/D (reservoir barrels per day) whether in production or injection. It was also found that the simulation runs must continue for 10 years to clearly show the various effects of Salinity. The formation water salinity was kept constant in all cases as 30,000 ppm.

In this report, the results for three selected water flooding cases are shown. The first case is a continuous high salinity (30,000 ppm) water flooding, the second one is a low salinity (0.0 ppm) water flooding, and the last one is a process of injecting a 0.7 HCPV slug of 0.0 ppm water followed by 30,000 ppm drive water. The third case was mainly studied based on typical chemical EOR processes strategy in which the chemical is injected first then followed by drive water. Because the cost of fresh water is very expensive, as its main source is water distillation which is a very expensive operation, the idea of injecting a slug of fresh water followed by high salinity water might recover significantly more oil than typical high salinity water flooding and still be more cost efficient compared to continuous low salinity water flooding.

Unfortunately the LOWSALT function cannot be activated in E300 compositional simulator. Thus the research was limited for an immiscible WAG process. Carbon Dioxide was used as the injection gas in the immiscible WAG process. For the Water Alternating gas process, various simulation runs were conducted in order to determine the operational factors such as the optimum time at which the WAG process starts after water flooding and the WAG ratio. After the sensitivity studies, it was found that the optimum recovery that can be obtained from the immiscible WAG processes can be achieved if the WAG process started after three years of water flooding. In terms of the WAG ratio, it was found that the best recovery can be obtained with a WAG ratio of 1:1 and a slug size of 0.2 HCPV.

In this report, the results for four selected immiscible WAG cases are shown. In the first two cases water flooding was conducted for three years with a water salinity of 30,000 ppm, then immiscible WAG processes were started. While in the second two cases, water flooding was also conducted for three years but with a water salinity of 0.0 ppm before the WAG processes were started.

4.2.1 Water Flooding Simulation Cases:

In all three cases, water flooding started from the first day of production through field's production life that is 10 years. The simulation results for all three water flooding cases are shown in this section of the report. In the following figures, figure 7 and figure 8, comparisons are displayed between both the three water flooding simulation cases.

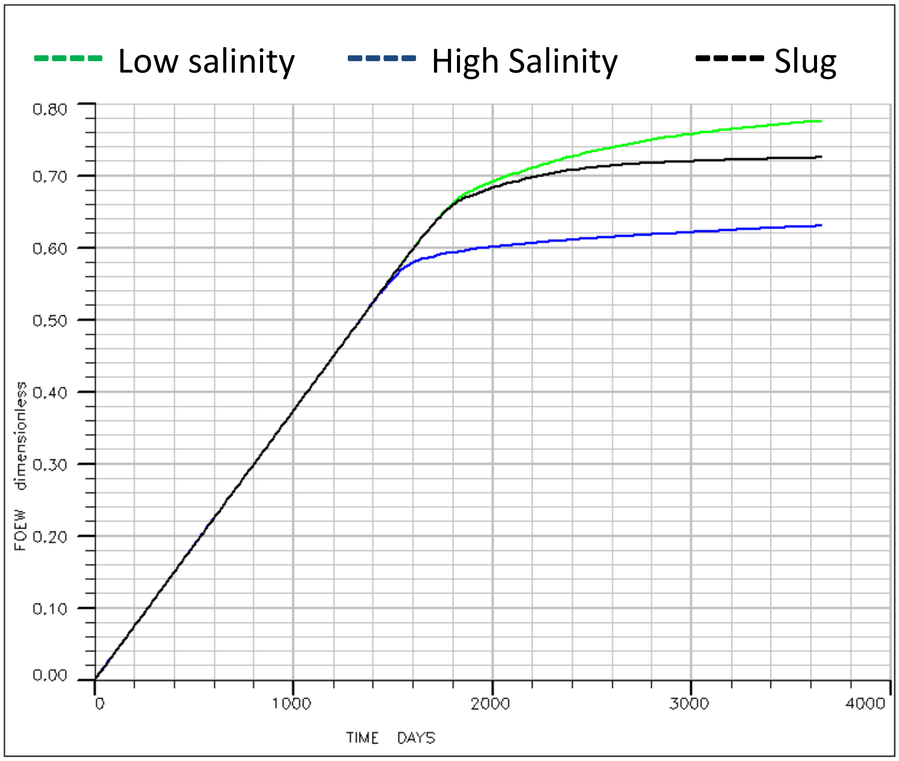

Figure 7: Oil Recovery percentage for water flooding simulation cases

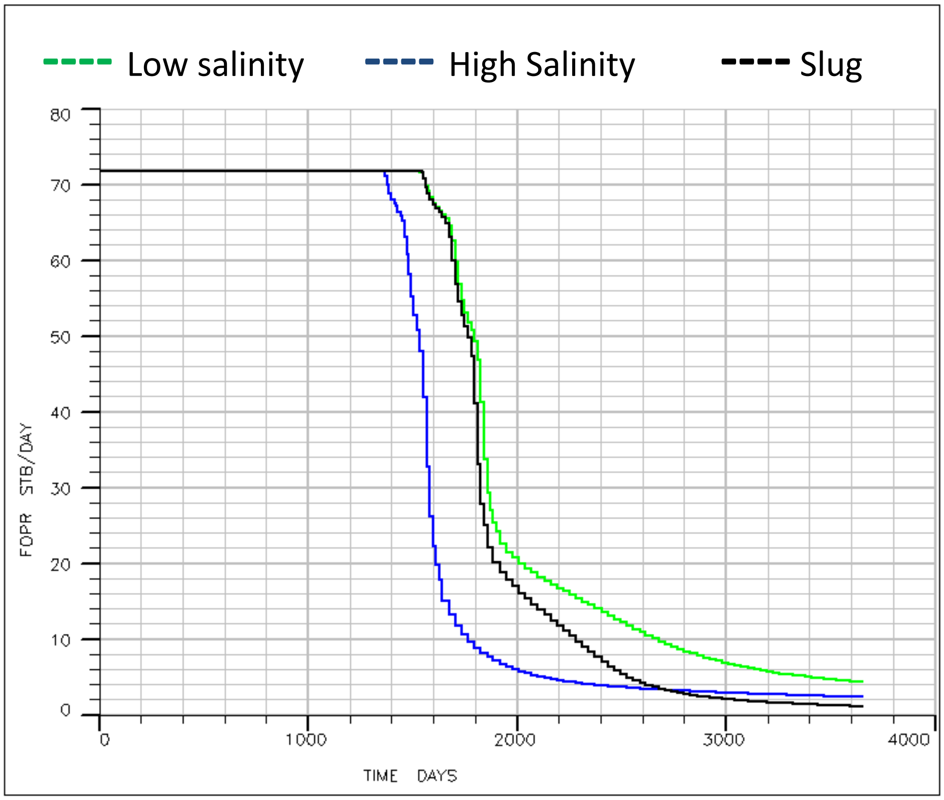

Figure 8: Oil Production rate for water flooding simulation cases

The following table, table 6, summarizes the most important simulation results, which includes, total oil recovery percentage and time to water breakthrough.

Case	Total Oil recovery percentage	Time to water breakthrough (Days)
0.0 ppm salinity Continuous water flooding	77.5%	1550
30,000 ppm salinity continuous water flooding	63.1%	1350
0.0 ppm salinity slug follows by 30,000 ppm drive water	72.7%	1550

Table 6: Water flooding cases simulation results summary

From the figures above, it can be concluded that the utilization of Low salinity water as the injection water has an oil recovery increment of 14.4% over the conventional high salinity water. The oil production rate keeps running at100 RB/day as imposed by the controlling factor, but due to gas liberation along the wellbore as of the pressure drop only 72 STB/day is produced before water breakthrough then the oil production rate starts to drop as shown in the following figure, where oil production rate is shown in green colour and water cut is in the blue colour.

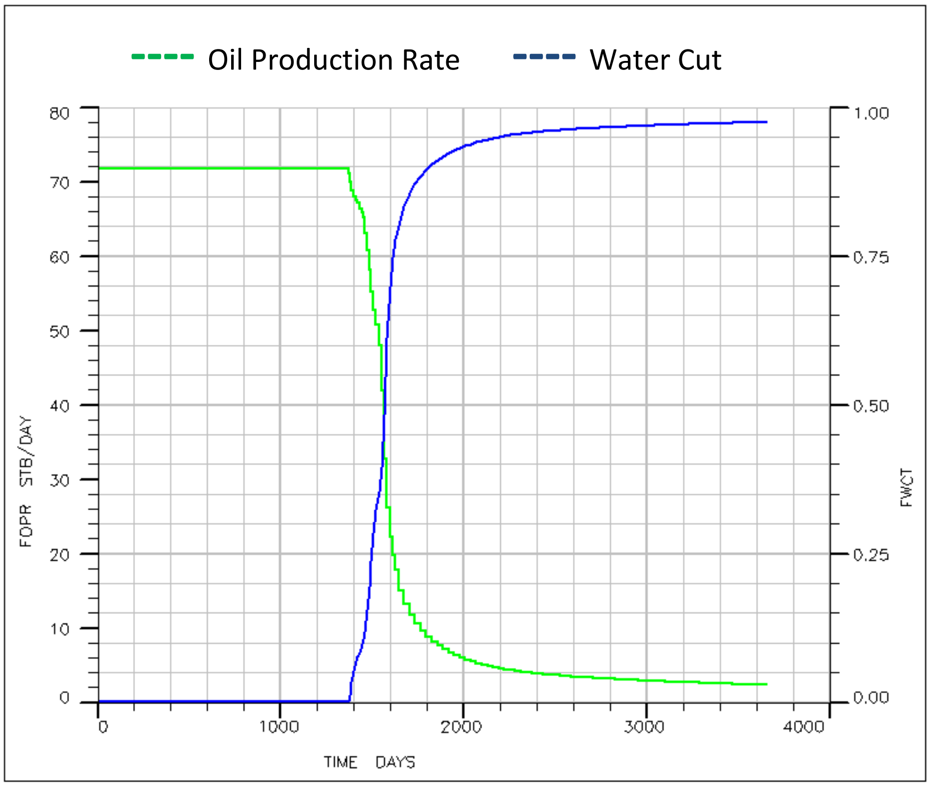

Figure 9: Oil Production rate and water cut for 30,000 ppm salinity water flooding simulation case

The time required for water breakthrough is 1350 days of production for the high salinity water flooding case and 1550 days of production for the low salinity water flooding case. Even after water breakthrough, low salinity water flooding maintains a higher production rate than that of high salinity water flooding.

This can be attributed to the fact that the wettability changing to more water-wet has played a significant role in the effectiveness of low salinity water flooding because of the changing of relative permeability in the simulation case to a more favourable situation.

While extremely efficient in terms of oil recovery, the continuous injection of fresh water is very expensive; this in return reduces the overall efficiency of the whole process. Following the standard procedure of most chemical EOR processes a slug of fresh water is inject first then followed by high salinity water drive. The following figure visually explains the salt concentration changes inside the reservoir for the continuous low salinity water flooding case and the low salinity slug flooded by high salinity water drive case.

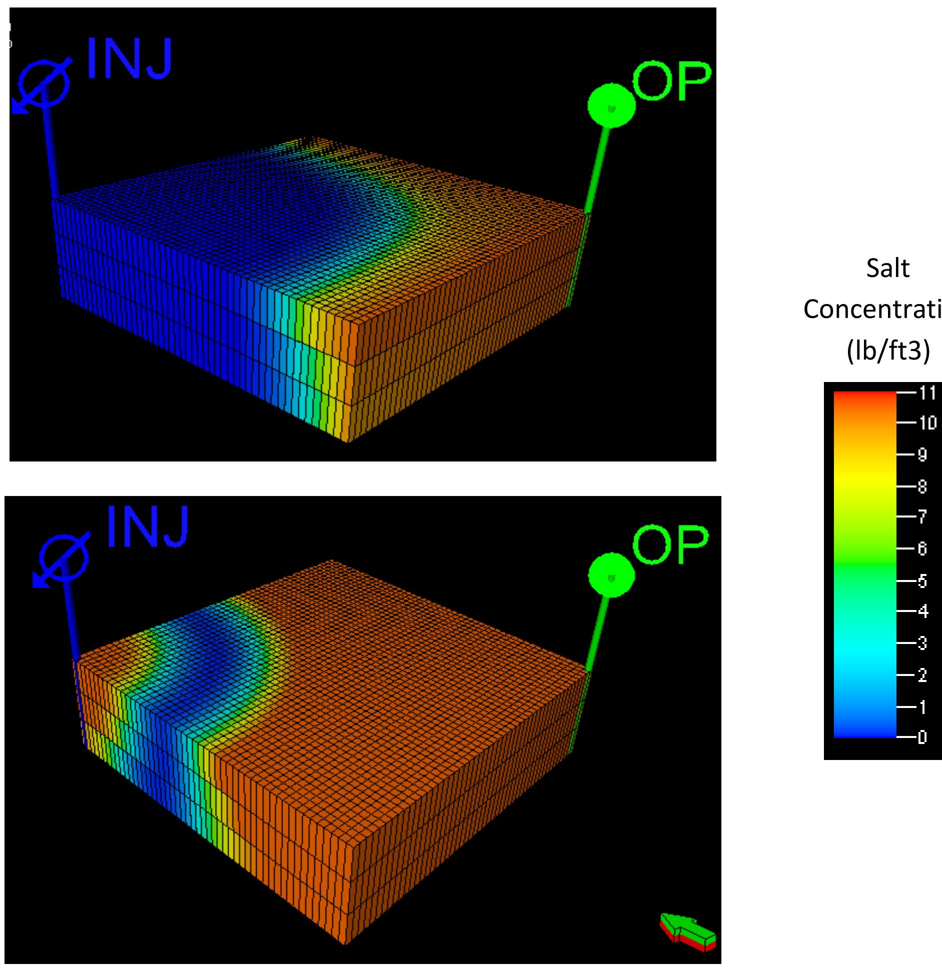

Figure 10: Reservoir Salt concentration comparison in low salt water flooding cases.

The overall oil recovery obtained from the low salinity slug flooded by high salinity water drive case is 72.7% with an increment of 9.6% over conventional high salinity water flooding case. Although the 0.7 HCPV low salinity slug case yielded a 4.8% lower oil recovery than continuous low salinity water flooding case, yet economically this is a much justifiable case. The amount of expensive fresh water required is approximately 87% less than the continuous water flooding case. The simulation mentioned previously have proven that using a slug of fresh water or low salinity water followed by a high salinity drive water would yield a much better recovery than conventional high salinity water and the slug size could be adjusted based on the economics.

4.2.2 High salinity water flooding followed by immiscible WAG Simulation Cases:

In the following simulation results, the water flooding process conducted prior to the WAG process is done by using High salinity water of the same salinity as the reservoir water salinity of 30,000 ppm.

In the following figures, comparisons are displayed between both the low salinity WAG, the high salinity WAG, and High salinity water flooding.

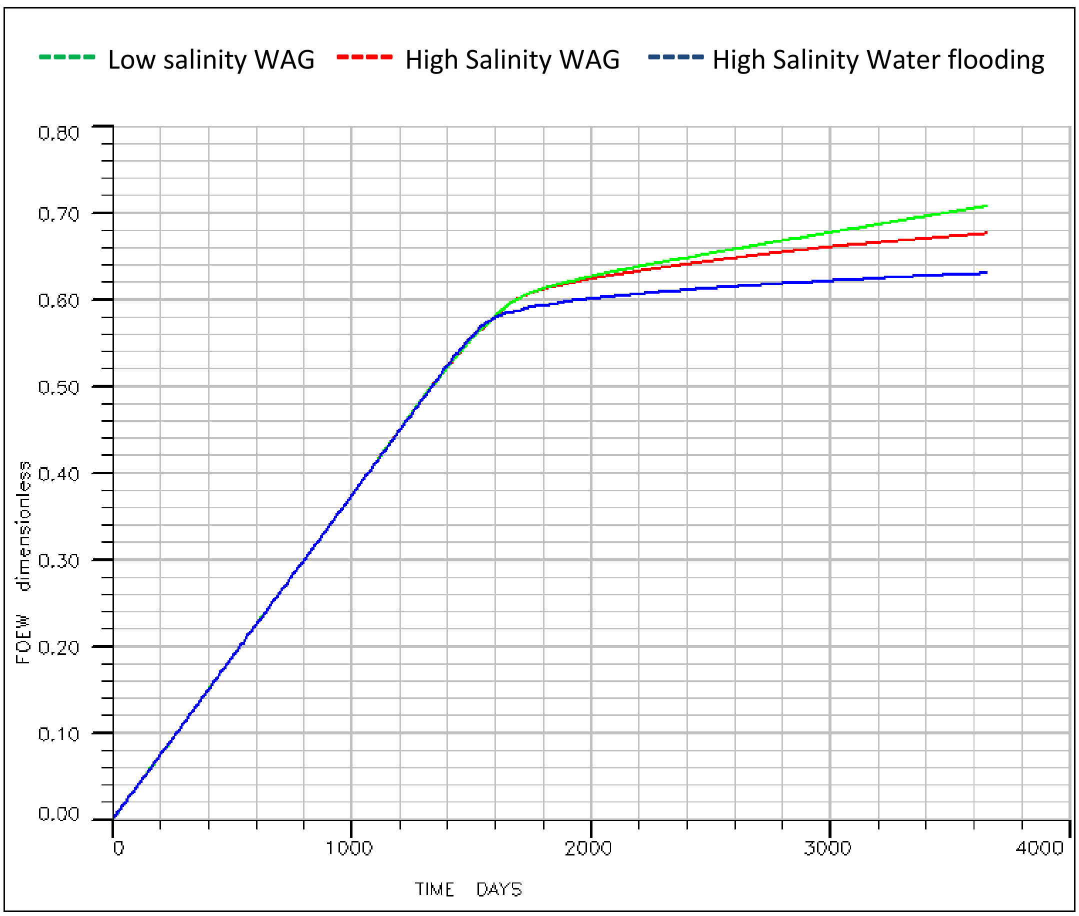

Figure 11: Oil Recovery Factor for high salinity water flooding, high salinity WAG and low salinity WAG

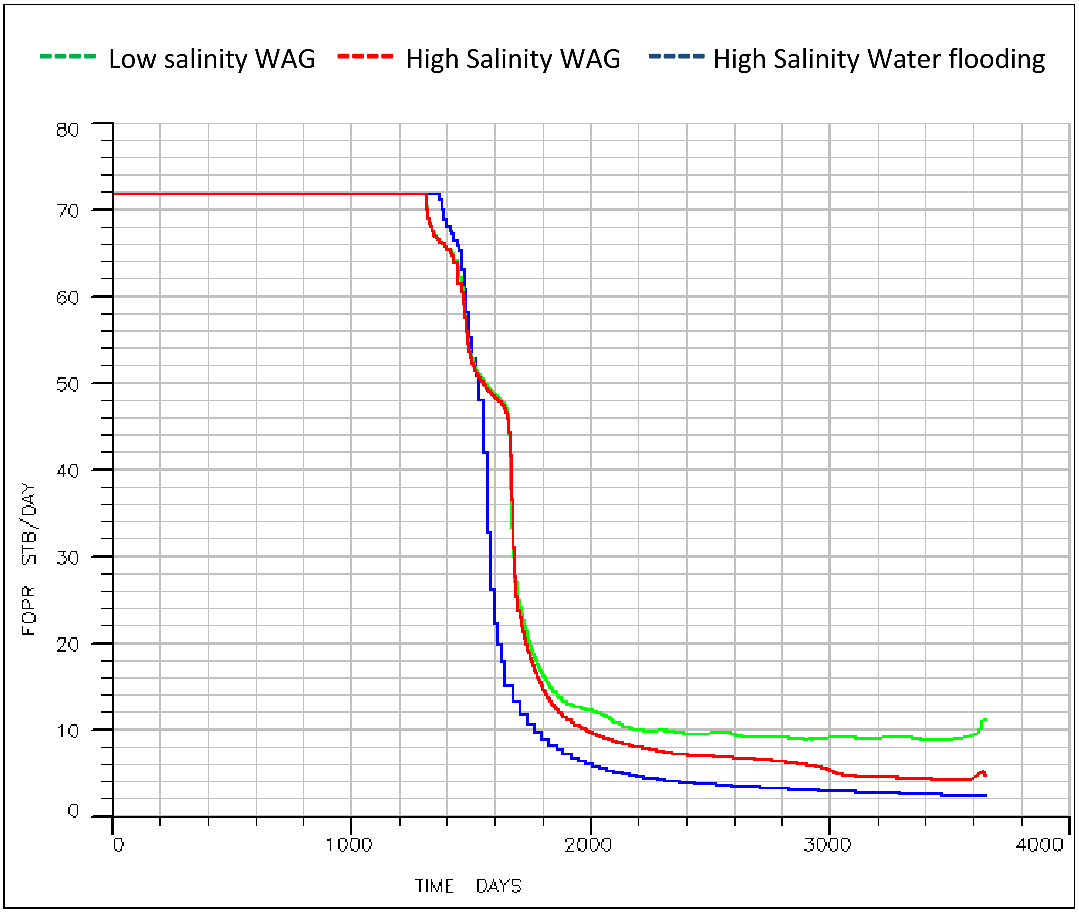

Figure 12: Oil Production rate for high salinity water flooding and low salinity WAG

The following table, table 7, summarizes the most important simulation results, which includes, total oil recovery percentage and time to water or gas breakthrough.

Case	Total Oil recovery percentage	Time to water or gas breakthrough (Days)
30,000 ppm salinity water flooding	63.1%	1350
High Salinity WAG	67.5%	1300
Low Salinity WAG	71.0%	1300

Table 7: WAG cases simulation results summary

From the figures above, it is concluded that Low salinity WAG have an oil recovery factor of 71.0% while the high salinity WAG have an oil recovery of 67.5%. The utilization of Low salinity water as the injection water in the WAG process has an oil recovery increment of 3.5% over the conventional high salinity water WAG process. Although the oil production rate started to drop after 1300 days in both WAG cases due to gas breakthrough, yet the utilization of low salinity water as the injection water in the WAG process helped to maintain the oil production rate at a higher production rate compared with the high salinity WAG process.

Although Kulkarni and Rao (2004) and Jiang *et al.* (2010) predicted that utilizing low salinity water as the injection water in WAG processes should yield lower recovery when compared with high salinity injection water, yet the 3D simulation of WAG processes shows otherwise. This can be attributed to the fact that the simulation results were based on immiscible WAG processes in which the injected Carbon Dioxide does not dissolve in neither oil nor water. Another possible explanation is that both researches conducted by Kulkarni and Rao (2004) and Jiang *et al.* (2010) were based on core flooding laboratory experiments which does not account for the gravity effects while the model used in this study is 30 feet thick which clearly shows the gravity segregation effects.

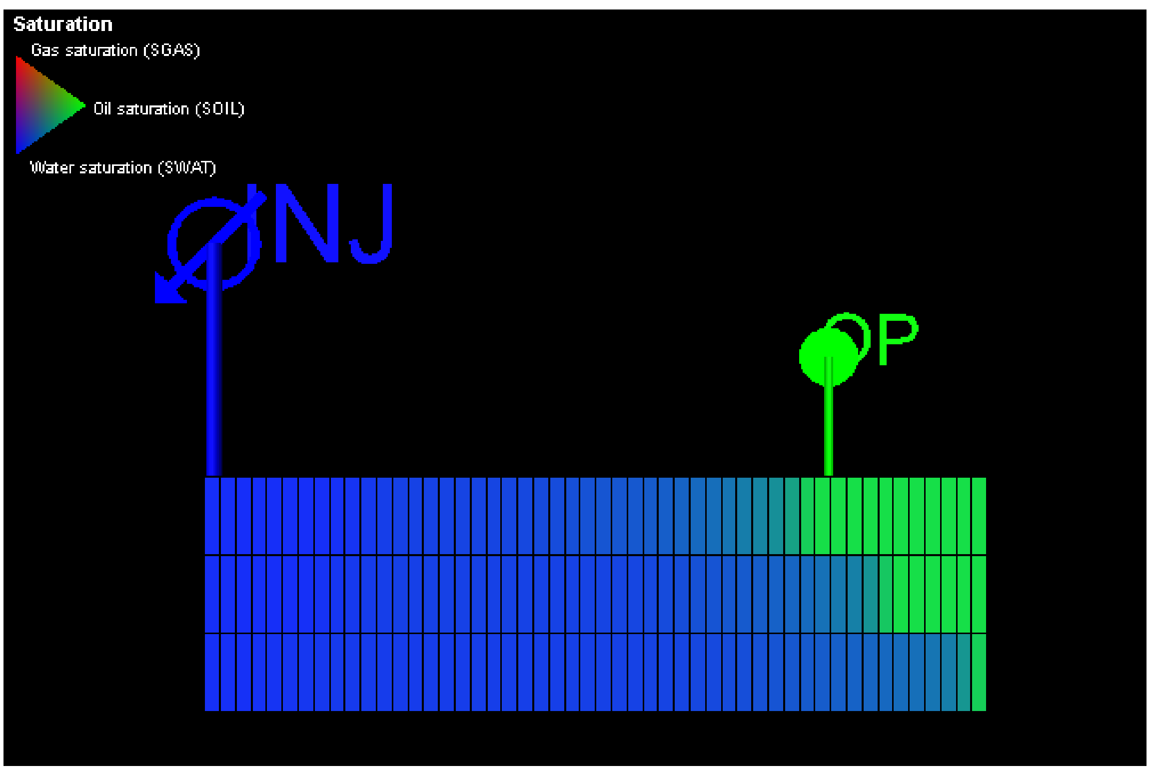

Figure 13: Gravity effect on water propagation in the reservoir

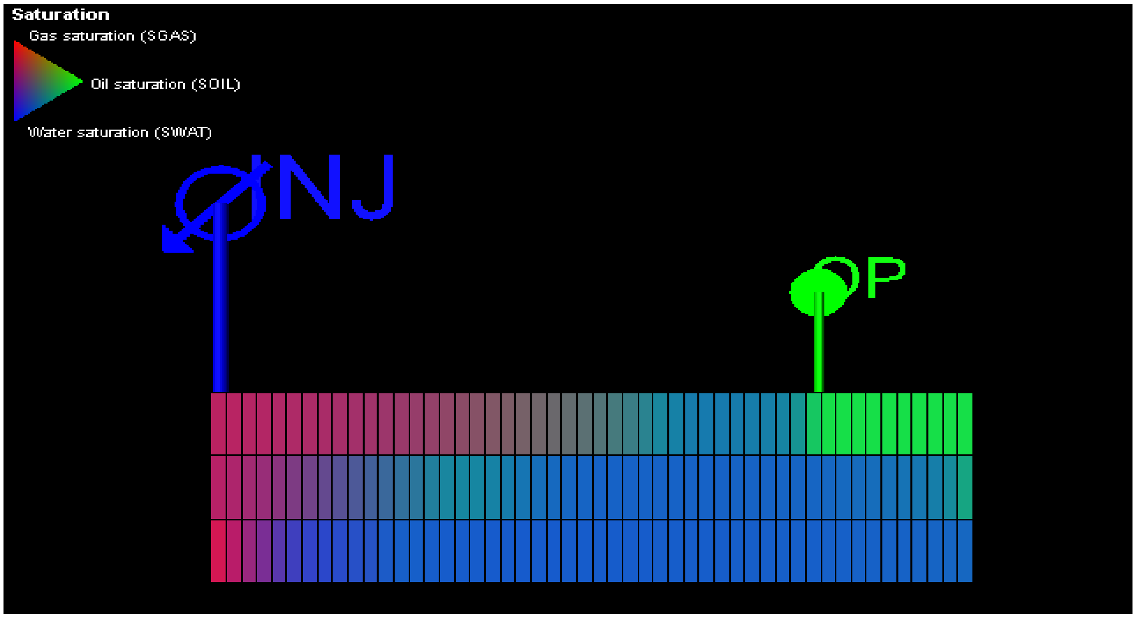

Figure 14: Saturations of the three phases; gas, oil and water after the first slug of gas has been completely injected.

While it is true that reducing the salinity of the injection water in the WAG process increases the amount of the Carbon dioxide that dissolves in the water phase, yet it can be seen from figure 12 that water propagation in the formation is not uniform due to gravity segregation similarly also gas propagation is not uniform as shown in figure 13. As a result, the increase of recovery obtained by low salt immiscible WAG compared with high salt immiscible WAG can be attributed to the fact that as the higher parts of the reservoir is being efficiently swept by gas in both cases, yet in the lower parts, which gas cannot invade efficiently, the low salinity water is sweeping the oil more efficiently than high salinity water.

4.2.3 Low salinity water flooding followed by immiscible WAG Simulation Cases:

In the following simulation results, the water flooding process conducted prior to the WAG process is done by using low salinity (0.0 ppm) water.

In the following figures, comparisons are displayed between both the low salinity WAG, the high salinity WAG, and low salinity water flooding.

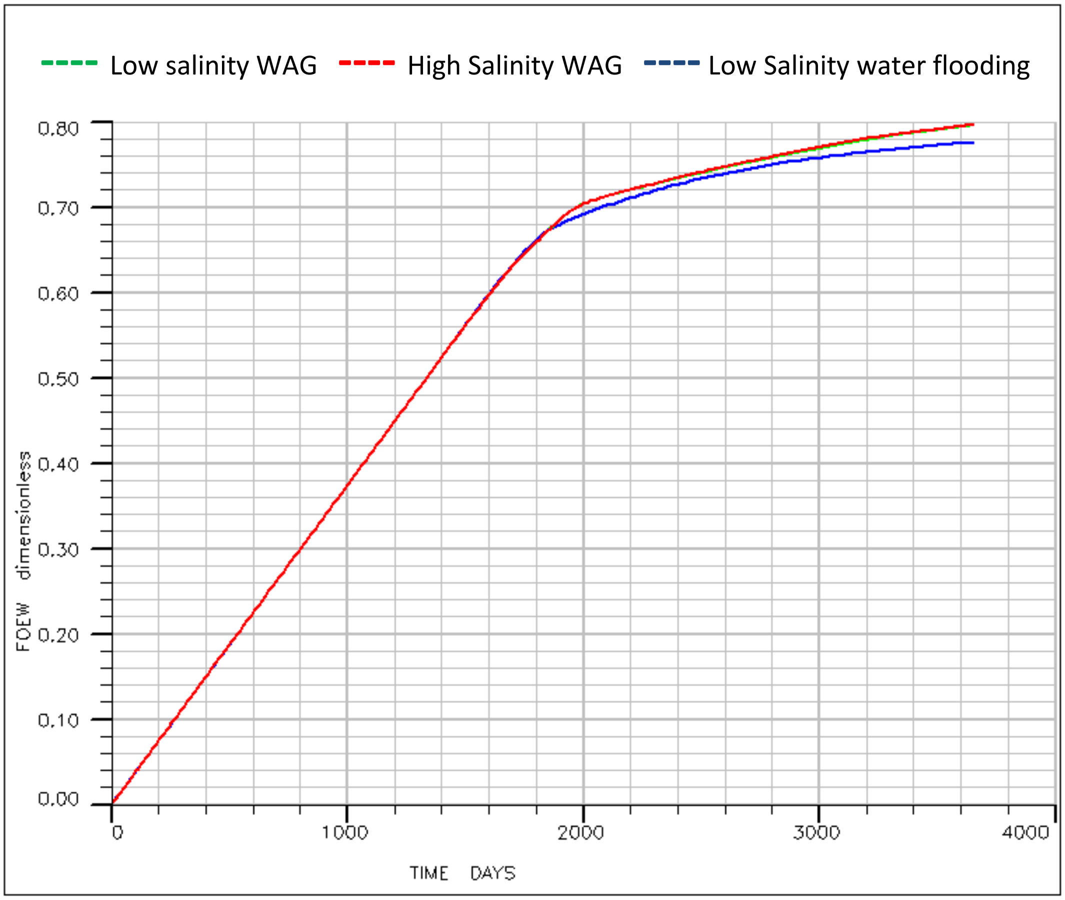

Figure 15: Oil Recovery Factor for low salinity water flooding, high salinity WAG and low salinity WAG

From the figure above, it was concluded that when low salinity water flooding is followed by an immiscible WAG process, the salinity of the injection water during the WAG process does not have an effect on the overall recovery obtained from the WAG process. Both the high salinity WAG and the low salinity WAG had the same overall oil recovery of 79.9% with an increment of 2.4% over continuous low salinity water flooding.

The main reason for same results obtained from Low salinity and high salinity WAG processes could be concluded from the previous low salinity slug injection simulation. Previously it was shown that injecting a 0.7 HCPV slug of low salinity water followed by high salinity water should yield a much higher recovery factor than conventional water flooding. In the low salinity water flooding followed by WAG processes, the total fresh water injected was 1.8 HCPV. The 1.8 HCPV slug of low salinity water that was injected in both case was enough to efficiently sweep most of the reservoir especially the lower parts of the reservoir, as a result injecting low salinity water or high salinity water during the WAG process did not have any effect on the overall recovery efficiency.

In order to test this theory a simulation case was conducted in which a 1.8 HCPV of fresh water was injected in order to compare its results with the continuous low salinity water flooding. It was found that a slug of 1.8 HCPV of 0.0 ppm water salinity followed by 30,000 ppm salinity drive water would yield a recovery of 76.9 % which is only 0.6% lower than continuous low salinity water flooding.

The results obtained from the last simulation run confirms that the 1.8 HCPV slug of low salinity water that was injected in both case; low salinity WAG and high salinity WAG, was enough to efficiently sweep most of the reservoir especially the lower parts of the reservoir due to gravity effects, as a result injecting low salinity water or high salinity water during the WAG process did not have any effect on the overall recovery efficiency, and as a result the change of the salinity of water during the WAG process would not have any effect on the overall recovery and the 2.4% increment in recovery can be attributed to the gas injection.

4.4 Research Limitations:

Due to computational limitations, further research opportunities were limited. The most important limitation was using immiscible WAG process instead of the miscible one. Also another major drawback was the inability of simulating the effect of ionic composition of the injection water on the oil recovery.

E300 compositional simulator does not support the LOWSALT function which is required for studying the low salinity water injection technique, on the other hand E100 does not account for turning on the MISCIBLE option and the LOWSALT option on the same time as the error message shown in figure 18. Thus the research was limited for simulating immiscible WAG process.

```
<eclipse>
<error date="1/1/2012" time="0.00000000000000">
 THE LOW SALINITY OPTION CANNOT BE USED WITH THE
 MISCIBLE FLOOD OPTION IN THIS VERSION OF ECLIPSE
</error>
```

Figure 18: E100 MISCIBLE and LOWSALT options error

With the continuous development of the reservoir simulators, the research opportunities still lies ahead to study the effect of low salinity water as the injection water in miscible WAG processes as well as the ionic composition of the injection water.

CHAPTER 5

CONCLUSION AND RECOMMENDATIONS

This paper strives to evaluate the expected gain in light oil recovery by using smart water as the injection water in immiscible WAG processes. A synthetic model was used to evaluate several scenarios with a combination between low salinity water flooding, and water alternating gas techniques.

1. The results presented in this paper show that, after a conventional high salinity water flooding, using smart water as the injection water in immiscible WAG processes could increase ultimate recovery by approximately 3.5% of OOIP, over conventional high salinity WAG, for light oil reservoirs. The main reason for the higher efficiency of smart water compared with conventional high salinity water in WAG processes can be attributed to the gravity effects inside the reservoir. While gas typically tends to channel through the higher parts of the reservoir in both cases, low salinity water tends to sweep the lower parts, through which gas invasion is limited, more efficiently than high salinity water.
2. On the other hand, if the reservoir has undergone low salinity water flooding for a long time, adjusting the salinity of the injection water in the WAG process would not have any effect on the overall recovery of the WAG process. Following the same principle as the low salinity slug injection, if the reservoir has undergone a long time low salinity water flooding then the reservoir has already been swept by the low salinity water and the drive water or the water injected during WAG processes would not affect the recovery and the increment of recovery obtained by the WAG process over continuous low salinity water flooding is due to the gas injection only.
3. The main factor that has the greatest influence on oil recovery when low salinity water is utilized is the slug size of low salinity water injected whether during secondary or tertiary recovery stages.

For using smart water as the injection water during WAG processes, it is recommended to investigate its effects on oil recovery for different types of oil, such as heavy oil, as well as taking into consideration other factors such as asphaltene disposition.

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