Simulation Study Of The Effect Of Smart Water On Relative Permeability During WAG-CO_2 Injection For Light Oil Reservoir

by

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Dissertation submitted in partial fulfilment of
the requirements for the
Bachelor Of Engineering (Hons)
(Petroleum Engineering)

SEPTEMBER 2013

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CERTIFICATION OF APPROVAL

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A project dissertation submitted to the
Petroleum Engineering Programme
Universiti Teknologi PETRONAS
in partial fulfilment of the requirements for the
BACHELOR OF ENGINEERING (Hons)
(PETROLEUM ENGINEERING)

Approved by,

____

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September 2013

CERTIFICATE 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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YIP PUI MUN

ACKNOWLEDGEMENT

First and foremost, I must thank God the Almighty for giving me the strength to work on this Final Year Project and complete this report within the stipulated time. I could never have accomplished up to this mark without the faith I have in the Almighty.

I would like to extend my sincerest gratitude to my supervisor, Mr Ali Fikret Mangi Alta'ee for his excellent direction, invaluable feedback, constructive suggestions and detailed corrections which played enormous role resulting in the success of this project. He continually offered much advice and insight throughout this FYP. In many ways, I have learnt much from and because of him.

I can't imagine my current position without the love and constant source of emotional and moral support from my family. I thank my parents who are always my pillar and my guiding light.

ABSTRACT

Water alternating gas (WAG) injection with its first successful field pilot application on the North Pembina field in Alberta, Canada in 1957, is one of the most prominent EOR methods that substantially prolong the lives of the otherwise depleted and uneconomical oil fields. This technique is well established but the practical challenges are often of the occurrence of viscous fingering, gravity segregation and gas channeling or override and consequently, lower oil recovery rates. Previous researches have focused almost exclusively on modifying the salinity and the ionic composition of the injected water, also termed as smart water flooding which proved to further enhance the oil recovery obtained from water flooding. However, the use of smart water in WAG-CO_2 process has not been studied sufficiently and requires further detailed study. As such, the approach of fine tuning the salinity of the injection brine during WAG-CO_2 process is proposed in this project. This research aims to evaluate the impacts of smart water injection on the oil/ water relative permeability curves in comparison with the conventional brine during WAG-CO_2 injection for light oil reservoir using reservoir simulation. This research also intended to systematically investigate the effects of the composition of Ca^{2+} and Mg^{2+} ions in brine on the oil recovery factor and to determine the optimum brine salinity for maximum oil recovery. Crucially, the simulation results are to offer valuable insights into the two phase relative permeability functions important to predict the behaviour of the fractional flow, fluid distributions, residual fluid saturations and oil recovery.

List Of Figures

Figure 1 : Dependence of coreflood oil recovery on salinity--------------------------13
Figure 2 : How double layer worked---15
Figure 3 : The recovery of water flooding, WAG flooding and total as a function of salinity--16
Figure 4 : Research Methodology--20
Figure 5 : Relative permeability curves for the base case study ----------------------25
Figure 6 : Static reservoir simulation model---25
Figure 7 : Simulation design of three different injection scenarios ------------------26
Figure 8 : Relative permeability curves of k_{RO} and k_{RW} versus S_W -----------------34
Figure 9 : A Plot Of Cumulative Oil Produced Versus Ca^{2+} & Mg^{2+} Ions Composition--36
Figure 10 : A Plot Of Cumulative Oil Produced For 7 Different Injection Scenarios---38
Figure 11 : Comparison of the cumulative oil produced from 2005 to 2006---------39

List Of Tables And Charts

Table 1 : A summary of the Norne field and its reservoir rock and fluid properties--23
Table 2 : Reservoir simulation model input parameters ---------------------------------24
Table 3 : The Total Dissolved Solids (TDS) in the brine at different salinities----27
Table 4 : Key milestones for the project ---29
Table 5 : Tools used/ needed for the project ---32
Table 6 : Cumulative Oil Produced For 7 Different Injection Scenarios -------------37
Chart 1 : Gantt Chart for the FYP I---30
Chart 2 : Gantt Chart for the FYP II--31

Abbreviations And Nomenclatures

The abbreviations and nomenclatures that are used throughout this project dissertation are listed in alphabetical orders as below. Please refer to as below:-

1. API - American Petroleum Institute
2. BHP - Bottom Hole Pressure
3. B_{oi} - Initial oil formation volume factor
4. CCS - Carbon Capture And Sequestration
5. CMG - Compute Modeling Group
6. CO_2 - Carbon Dioxide
7. EOR - Enhanced Oil Recovery
8. E - Hydrocarbon recovery factor
9. E_A - Areal sweep efficiency
10. E_V - Vertical sweep efficiency
11. E_D - Microscopic displacement efficiency
12. FCM - First Contact Miscibility
13. FOE - Field Oil Efficiency
14. FYP I - Final Year Project I
15. GIIP - Gas Initially In Place
16. GOR - Gas-Oil Ratio
17. k - Permeability
18. k_r - Relative Permeability
19. k_{rw} - Relative Permeability to Oil
20. k_{rg} - Relative Permeability to Water
21. MIE - Multi-Ions Exchange
22. MCM - Multiple Contact Miscibility
23. MMP - Minimum Miscibility Pressure
24. OOIP - Original Oil In Place
25. PDO - Plan for Development and Operation
26. ppm - parts per million
27. P_R - Reservoir pressure
28. P_{Ri} - Initial reservoir pressure
29. RNB - Revised National Budget

30. RF - Recovery Factor
31. SACROC - Scurry Area Canyon Reef Operators Committee
32. SFW - Salinity Formation Water
33. STARS - Steam, Thermal and Advanced processes Reservoir Simulator
34. S_{or} - Residual Oil Saturation
35. S_w - Saturation of Water
36. TDS - Total Dissolved Solids
37. T_R - Reservoir temperature
38. WAG - Water Alternating Gas

<u>**TABLE OF CONTENTS**</u>

CERTIFICATE OF APPROVAL--i

CERTIFICATE OF ORIGINALITY---ii

ACKNOWLEDGMENT---iii

ABSTRACT--iv

LIST OF FIGURES---v

LIST OF TABLES AND CHARTS---v

ABBREVIATIONS AND NOMENCLATURES-------------------------------------vi

CHAPTER 1:- INTRODUCTION

1.1 Background Of Study---1

1.2 Problem Statement--4

1.2.1 Problem Identification---4

1.2.2 Significance Of The Project--4

1.3 Objectives and Scope of Study---5

1.3.1 Objectives---5

1.3.2 Scope of Study--5

1.4 Project relevance and feasibility---6

1.4.1 Project relevance---6

1.4.2 Project feasibility--7

CHAPTER 2:- LITERATURE REVIEW AND/ OR THEORY

2.1 Introduction--8

2.1.1 Basic Concepts In EOR---9

2.2 Water Alternating Gas (WAG) --10

2.2.1 WAG Process--10

2.2.2 Problems Associated With The WAG Process-------------------------10

2.2.3 Advantages Of CO_2 As Injectant In WAG------------------------------11

2.3 Smart Water Flooding---12

2.3.1 Mechanisms Of Smart Water Flooding----------------------------------13

2.3.2 Smart Water Applications In WAG--------------------------------------15

2.4 Relative Permeability--16

2.4.1 Calculations Of Relative Permeability-----------------------------------18

2.5 Literature Summary---19

CHAPTER 3:- METHODOLOGY/ PROJECT WORK

3.1 Research Methodology---20

3.2 Project activities---21
3.2.1 Problem Formulation---21
3.2.2 Project Research And Studies--21
3.2.3 Project Planning--21
3.2.4 Generation Of Input Rock And Fluid Properties Data------------------22
3.2.5 Construction Of The Reservoir Simulation Model----------------------23
3.2.6 Output Data Gathering And Analysis-------------------------------------28
3.2.7 Final Results And Discussion--28
3.2.8 Project Completion---28
3.3 Key milestones--29
3.4 Gantt Chart--30
3.5 Tools Used/ Needed For The Project--32

CHAPTER 4:- RESULTS AND DISCUSSION

4.1 Simulation results and discussion--33
4.1.1The Effects Of Smart Water Injection On The Relative Permeability-33
4.1.2 The Effects Of The Composition Of Ca^{2+} and Mg^{2+}Ions In Brine---35
4.1.3 The Optimum Brine Salinity for Maximum Oil Recovery------------37

CHAPTER 5:- CONCLUSION AND RECOMMENDATIONS

5.1 Conclusion --42
5.2 Recommendations---43

REFERENCES---44

CHAPTER 1:- INTRODUCTION

1.1 Background Of Study

The aging of oil fields and technology advances along with the concerns about forecasts of rising oil demand drives the need for squeezing more oil out of the matured fields. As oil is extracted, the unsustainable reservoir pressure declines and the level of water rises after the primary and secondary oil recovery, contributing to the unfavorable drop in rate of oil production. Yet up to 70% of the original oil in place is left behind once the conventional recovery methods have been exhausted (Terry, R.E., 2001). This thus creates a strong growth of opportunity for methods known as " Enhanced Oil Recovery " or EOR which target the remaining untapped significant quantities of oil. EOR techniques can significantly increase the oil recovery factors from reservoirs through several means, for instance, injecting miscible gases and chemicals, and heating of the reservoir to sweep the residual oil (Green and Willhite, 1998).

The wide implementation of EOR processes is attributable to the increase in overall oil displacement efficiency via the twin achievements of improved microscopic and macroscopic displacement efficiency (Green and Willhite, 1998 ; Christensen *et al.*, 2001). The microscopic sweep efficiency refers to the mobilization of oil at the pore scale. The macroscopic sweep efficiency represents the effectiveness of the volumetric sweep of the oil-bearing regions in the reservoir by the displacing fluid in contact (Ahmed, 2001). While the microscopic effeciency is affected by various governing factors including geometry, pore-to-throat diameter ratio, coordination number and wettability (Molina, 1980; Honarpour and Maloney, 1990; Sehbi *et al.*, 2001), the macroscopic sweep is primarily influenced by reservoir rock heterogeneities, mobility ratio, viscosity ratio, gravity forces as well as the injection or production well patterns (Sehbi *et al.*, 2001).

Gas injection or miscible flooding is ranked the second most commonly used commercial EOR methods for oil recovery from light oil reservoirs, after thermal recovery used in heavy oil reservoirs. Displacement fluids such as hydrocarbon solvents, CO_2 gas, flue gas and nitrogen play a role in enhancing the microscopic displacement efficiency. Ideally, CO_2 gas is more preferable than other EOR gas agents because of the abundance of CO_2 gas supply, lower injectivity problems and higher incremental oil recovery factor (Kulkarni, 2003). CO_2 gas has a low minimum miscibility pressure (MMP) in order to achieve first contact miscibility (FCM) and multiple contact miscibility (MCM), forming a zone of miscible CO_2 and light hydrocarbons (Martin and Taber, 1992). The CO_2 gas works to reduce the viscosity of oil, cause oil swelling and increase the relative permeability so the trapped oil is mobilized and can flow more easily through the rocks. Recently, the application of CO_2 gas is related to Carbon Capture and Sequestration (CCS) whereby waste CO_2 gas is collected from large point sources like fossil fuel power plants to be injected into the subsurface geologic structures, thus contributing to the reduction of harmful greenhouse gas emission into the atmosphere (Andrei *et al.*, 2010).

The poor sweep efficiencies during CO_2 gas injection caused by the high gas-oil mobility ratio led to the development of Water Alternating Gas (WAG) process for better mobility control or displacement stabilization. During WAG operations, the gas is injected intermittently with water as to increase the macroscopic sweep efficiency. Almost 40% of the total oil production by EOR methods in the United States are by the gas injection methods, most of which are WAG flooding projects (Christensen *et al.*, 2001). In spite of the broad application of WAG schemes, Christensen *et al.* (2001) demonstrated that the average increase in oil recovery was only a mere 5 to 10%. The limitations and operational problems such as viscous instabilities or fingering, gravity segregation, gas override and gas channeling through high permeability streaks or thief zones result in the unexpected low oil recovery.

The initial works by Jadhunandan and Morrow (1995) and Yildiz and Morrow (1996) show that tuning of the ion composition and salinity of the injected fluid may further enhance oil recovery which is also evidenced from various successful field applications in the literature. This chemically altered water is termed as " smart water ". The wettability alteration mechanisms for the improvement of the oil displacement is still unclear but the possible mechanisms which have been proposed up to now are migration of fines or clay fragments (Morrow et al., 1998), pH increase (McGuire et al., 2005), and the multi-ions exchange (MIE) between the clay mineral surfaces and the injected brine (Lager et al., 2006) triggered by the expansion of the electrical double layer (Lighthelm et al., 2009).

It is therefore interesting to research on the effect of the employment of smart water replacing the conventional brine during WAG-CO_2 injection to explore the potential of this combination method. Reliable prediction of the performance of this method which is attainable by accurately determining the relative permeability while accounting for the effects of the composition of Ca^{2+} and Mg^{2+} ions in the brine is definitely an area of research that adds value in the related researches.

1.2 Problem Statement

Reduced water injectivity and early gas breakthrough caused by high mobility ratio as well as low viscosity gas channeling during WAG-CO_2 injection are critical because these unfavorable conditions lead to poor oil sweep efficiency and thus low additional oil recovery in most of the WAG-CO_2 field operations.

Focusing on this, this research project attempts to propose the use of smart water replacing the normal injected water during WAG-CO_2 injection as to complement some of these shortcomings. Smart water is generally water with its salinity and ionic composition adjusted aiming to alter the wettability of the porous media. This work also presents a comprehensive simulation study to demonstrate the influences of the smart water injection on the salinity dependent oil/ water relative permeability curves through wettability modification of the reservoir rock during WAG-CO_2 injection for light oil reservoir.

1.2.1 Problem Identification

Only a mere 5 to 10 % incremental recovery of the OOIP is achieved when utilizing the WAG injection because of the various operational problems. The effects of modifying the salinity and ionic composition of the injection water or the use of smart water in WAG-CO_2 process have not yet been studied extensively.

1.2.2 Significance Of The Project

The outcomes obtained from this project are significant because:-

1. The accurate determination of relative permeability is needed to describe and predict the behaviour of the fractional flow, fluid distributions, residual fluid saturations and oil recovery during multi-phase flow conditions. Hence the relative permeability model deployed in this study is vital to analyze or evaluate the change in the relative permeability.
2. To provide better understanding of the impacts of the composition of Ca^{2+} and Mg^{2+} ions in brine on the oil recovery factor. These divalent ions are found to be among the determining ions which reduce the ion binding between the crude oil

and the clay particles during smart water flooding.

3. To highlight the impact of the change in wettability induced by the smart water injection on the crude-brine-rock (CBR) interaction which is characterized by the relative permeability curves as well as to determine the optimum brine salinity for maximum total oil recovery or production. Better understanding of these effects is crucial as wettability primarily dictates the distribution of fluids such as oil and water in the porous media which affects the displacement and production from oil bearing reservoirs.

1.3 Objectives and Scope of Study

1.3.1 Objectives

This project aims to accomplish the following key objectives:-

1. To evaluate the impacts of smart water injection on the oil/ water relative permeability curves in comparison with the conventional brine during WAG-CO_2 injection for light oil reservoir using reservoir simulation.
2. To investigate the effects of the composition of Ca^{2+} and Mg^{2+} ions in brine on the oil recovery factor.
3. To determine the optimum brine salinity for maximum oil recovery.

1.3.2 Scope of Study

The initial project work involves literature review on the past researches in the related area of the project to gain basic understanding of the research topic. Extensive readings have been made on the three key terms in this project which are relative permeability, smart water and water alternating gas (WAG).

Prior to the construction of the simulation model, the required reservoir rock and fluid properties data are identified and collected as input parameters into the reservoir simulation software. In building the reservoir simulation model, the geometry of the simulation grid and various rock properties like porosity and permeability, as well as initial reservoir conditions are first well-defined. The data will be applied on three field case studies, one reference or base case which employs normal WAG-CO_2 injection while the others utilizes the proposed smart water assisted WAG-CO_2 injection and smart WAG-$CO2_2$ injection.

The results obtained from the simulation runs are systematically studied to reach the various objectives set. The scope of study covers the following:-

1. Conducting a simulation study for the integration of smart water flooding and WAG-CO_2 injection applied to a light oil reservoir.
2. Performing a comparative analysis of the effects of smart water injection on the two-phase relative permeability models as compared to that of conventional brine during WAG-CO_2 injection.
3. Identifying the relationship between the composition of the Ca^{2+} and Mg^{2+} ions in brine and the oil recovery factor (RF).
4. Determining the optimum brine salinity for maximum oil recovery.

1.4 Project relevance and feasibility

1.4.1 Project relevance

Decades of research and successful field applications of smart water flooding proved its potential as a technique used for reaching higher oil recovery efficiency. Amongst the added values of lowering the salinity of the injected water is that it is an inexpensive EOR technique that may also reduce the damage in the injection and production facilities caused by corrosion and scaling. Smart water flooding is, therefore, one of the future research areas with huge priority to meet the ever growing energy demand in the coming years. However, previous researches have focused almost exclusively on the application of smart water in water flooding. Obscurity exists on whether the deployment of smart water during WAG-CO_2 injection will be successful. Thus a detailed study of the impacts of the implementation of a technique which combines smart water flooding and WAG-CO_2 injection on the relative permeability and the optimum conditions to achieve the greatest oil recovery factor are extremely relevant. This project is essential as understanding the concept of relative permeability is crucial in analyzing the effectiveness of the displacement process during EOR processes.

1.4.2 Project feasibility

This project is highly feasible after assessing the project viability in terms of time frame, technical factor and tools availability:-

1. **Time frame**

   The scope of the study of this research project is outlined by taking into consideration the time frame of both FYP I and II. A Gantt Chart is used as a guideline to manage the project schedule, start and finish dates. There is sufficient time to complete the project.

2. **Technical factor**

   The input data collection as well as the development of simulation model can be completed within time frame by accounting the author's experience with reservoir simulation software and background knowledge of the relative permeability concept.

2. **Tools availability**

   The CMG software required to perform the simulations study is available in UTP.

CHAPTER 2:- LITERATURE REVIEW AND/ OR THEORY

2.1 Introduction

As the world's thirst for oil continue to rise, researchers and practitioners are devoted to squeeze as many barrels of oil as possible out of the reservoirs. In the BP Statistical Review Of World Energy (2013), it is stated that currently, the oil remains the world's leading fuel, at 33.1% of global energy consumption. Thus maximizing oil recovery is very critical to meet the growing energy demand in the coming years.

The extraction of oil primarily encompasses three main stages which are the primary, secondary and tertiary recovery or Enhanced Oil Recovery (EOR). Most of the reviews show that the amount of oil that can be extracted with primary recovery depending on natural drive mechanisms is about 10 – 30%. Thereafter, during the secondary oil recovery phase, water flooding or gas injection is used to boost declining pressure and sweep the oil from the reservoir which eventually contributes to an additional recovery of 10- 20%. Owing to the fact that the decline in hydrocarbon recovery after the primary and secondary oil recovery processes is attributed to the uneconomical production plus the unfavorable reservoir pressure drop, the residual oil in the reservoir may then be extracted by utilizing EOR approaches. About 35 % up to 50 % of Oil Initially In Place (OOIP) is achievable through EOR processes which is being the reason why recent focus areas have been on EOR techniques.

In the broadest definition, the term " Enhanced Oil Recovery " refers to any processes that further improve the total oil production after the secondary recovery becomes ineffective exceeding the economic limit (Green and Willhite, 1998). EOR processes may be classified into four main categories including miscible gases, chemicals, thermal and microbial flooding (Terry, 2001). The ultimate goal of EOR processes is to increase the overall oil displacement efficiency, which is a function of microscopic and macroscopic displacement efficiency (Christensen *et al.*, 2001).

2.1.1 Basic Concepts In EOR

The optimization of the EOR or reservoir displacement efficiency requires a good understanding of the three key factors affecting the hydrocarbon recovery factor, E. The parameters mentioned are the areal sweep efficiency, E_A, vertical sweep efficiency, E_V and microscopic displacement efficiency, E_D (Ahmed, 2001). The overall recovery efficiency can be significantly increased if any of these factors are maximized. The product of E_A and E_V is also called the macroscopic or volumetric displacement efficiency. The mathematical form of the recovery factor equation can be expressed as:-

$$E = E_A E_V E_D$$

As pointed out by Sehbi *et al.* (2001), the macroscopic displacement efficiency is primarily a function of the reservoir rock heterogeneities, mobility ratio, viscosity ratio, gravity forces as well as the injection or production well patterns. It represents how effective is the volumetric sweep of the oil-bearing regions in the reservoir by the displacing fluid in contact. The mobilization of the trapped oil at microscale greatly relies on the microscopic displacement efficiency. The major governing factors of the microscopic displacement efficiency include pore geometry, pore-to-throat diameter ratio and coordination number (Honarpour and Maloney, 1990). His statement is supported by other authors (Molina, 1980; Sehbi *et al.*, 2001) who claimed that the characteristics of the pore system and interactions between the fluids and rock such as wettability affects the microscopic displacement efficiency. Clerke (2009) provided a focus review of the pore systems of the Ghawar Arab D limestone, a major oil reservoir in Saudi Arabia and introduced a new pore system classification based on the maximum pore throat diameter. The coordination number is a dimensionless parameter which translates the average number of pore throat connecting the pores. Melrose and Brandner (1974) highlighted that the improved recovery efficiency is induced by the high coordination number.

2.2 Water Alternating Gas (WAG)

2.2.1 WAG Process

This method is a combination of the two conventional secondary recovery techniques, waterflooding and gas injection. It is a conventional EOR process in which slugs of water and gas are injected alternately to sweep the residual oil not recovered by the primary and the secondary phases of production (Christensen *et al*., 2001). This cyclical process begins with the injection of miscible CO_2 gas forming a zone of miscible CO_2 and light hydrocarbons. The CO_2 gas works to reduce the viscosity of oil, cause oil swelling and increase the relative permeability so the trapped oil is mobilized and can flow more easily through the rock. Due to the low gas density, the unfavorable high mobility ratio leads to poor sweep efficiencies. Thus, after a period of time, the injection switches to water to improve the macroscopic sweep efficiency and these alternate CO_2 gas and water injection repeats until the oil production drops below a profitable level. An inclusive performance review of the large scale CO_2-WAG EOR project conducted at the SACROC (Scurry Area Canyon Reef Operators Committee) Unit in Kelly-Synder Field by Kane (1979) proposed that a WAG ratio of above 2:1 may result in less displacement efficiency since higher water saturation cause the water to bypass the gas. Feng *et al.* (2004) presented their study on the micro-mechanisms by WAG injection observed via the use of glass micro-models which imitates the pore size and geometry structure of the reservoir rock. They concluded that WAG injection contributes to higher oil recovery as compared to water or gas flooding alone.

2.2.2 Problems Associated With The WAG Process

The ultimate recovery from WAG is relatively low with about incremental recovery of 5% to 10% (Christensen *et al.*, 2001). Christensen *et al.* (2001) presented a comprehensive literature of the WAG processes in about 59 fields and commented on several severe problems which caused the decrease in displacement efficiency when performing WAG-CO_2 injection.

The major problems of WAG injection are the water and gas breakthrough and decrease in injectivity (Gorell, 1990; Christensen *et al.*, 2001) due to the following challenges:-

1. Viscous instabilities/ fingering

   The high mobility ratio between gas and oil causes the less viscous fluid, in this case, the CO_2 gas to displace the more viscous oil. This may results in early gas breakthrough and poor sweep efficiencies.

2. Gravity segregation

   Gravity segregation happens because of the tendency of the CO_2 gas to rise to the formation top while water migrates to the bottom. Therefore, miscible flood occurs only in a layer at the formation top and the remainder is water flooded.

3. Gas override

   The huge density difference between gas and oil causes the gas flows to bottom and oil to the bottom. Not only there is less gas to sweep the oil to the wellbore, but there will also be early gas breakthrough.

4. Gas channeling through high permeability streaks/ thief zone

   Gas channeling through high permeability streaks, also described as the thief zone is caused by the presence of heterogeneities of the reservoir like fracture, which consequently lead to reduced injectivity and early breakthrough.

2.2.3 Advantages Of CO_2 As Injectant In WAG

Displacement fluids such as hydrocarbon solvents, CO_2 gas, flue gas and nitrogen play a role in enhancing the microscopic displacement efficiency. Ideally, CO_2 gas is more preferable than other EOR gas agents because of the abundance of CO_2 gas supply, lower injectivity problems and higher incremental oil recovery factor (Kulkarni, 2003). CO_2 gas has a low minimum miscibility pressure (MMP) in order to achieve first contact miscibility (FCM) and multiple contact miscibility (MCM), forming a zone of miscible CO_2 and light hydrocarbons (Martin and Taber, 1992). The CO_2 gas works to reduce the viscosity of oil, cause oil swelling and increase the relative permeability so the trapped oil is mobilized and can flow more easily through the rocks. Recently, the application of CO_2 gas is related to Carbon Capture and Sequestration (CCS) whereby waste CO_2 gas is collected from large point sources like fossil fuel power plants to be injected into the subsurface geologic structures, thus contributing to the reduction of harmful greenhouse gas emission into the atmosphere (Andrei *et al.*, 2010).

2.3 Smart Water Flooding

For over 100 years, water flooding has been widely implemented to accomplish the dual objectives of reservoir pressure maintenance as well as a water drive to displace oil from the injector wells to the producer wells. In the 90's, the idea of the influences of brine composition on the oil recovery as introduced in the papers published by Jadhunandan and Morrow (1995) and Yildiz and Morrow (1996) began to shift the industry's focus to adjusting or optimizing the ion composition and salinity of the injected fluid. This chemically altered water is termed as " smart water ". Since then, there have been numerous researches done to advance the concept of smart water flooding and to demonstrate the tremendous potential of this technology.

There is increasing evidence from the laboratory that reduction in the concentration of salinity leads to higher oil recovery factor than conventional waterflooding in sandstone reservoirs (Tang and Morrow, 1997) as well as in carbonate reservoirs (Yousef *et al*., 2010). Research done by Tang and Morrow (1999) indicated an improvement in the oil recovery efficiency when the salinity of the injection brine was reduced from 15,000 to 1,500 ppm. Apart from corefloods, several field single well tests and field trials demonstrated the potential of low-salinity waterflooding to improve oil recovery (McGuire *et al.*, 2005; Lager *et al.* 2008; Seccombe *et al.*, 2008). Webb et al. (2005) reported decrease in the residual oil saturation, S_{or} as the salinity of the injection brine is varied from 100 % to 20 % and finally 5 % of the salinity formation water (SFW) as shown in Figure 1.

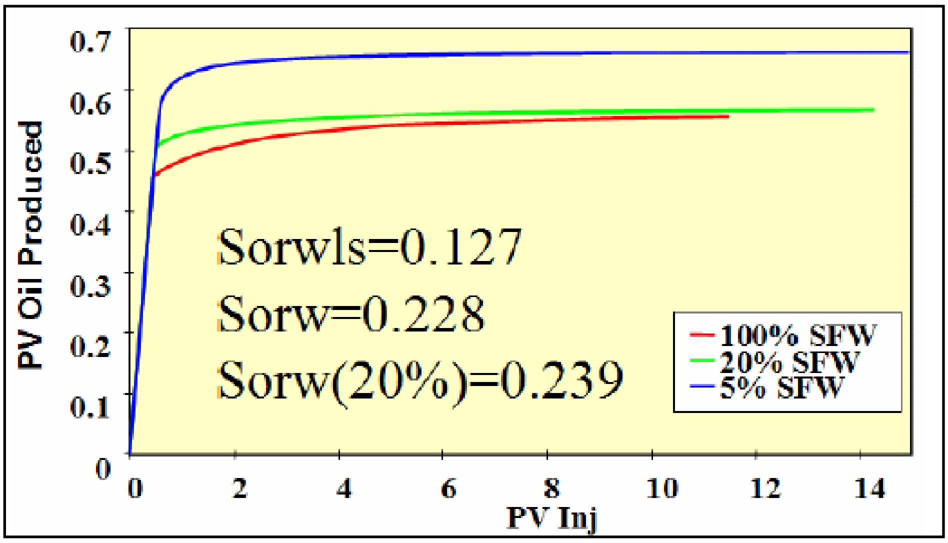

Figure 1:- Dependence of coreflood oil recovery on salinity. Adopted from Webb *et al.* (2005).

2.3.1 Mechanisms Of Smart Water Flooding

The low salinity effect is believed to significantly impact the ultimate oil recovery as a result of different mechanisms acting together. Although there is still no consistent mechanistic explanation of the low salinity water flooding phenomenon in sandstone reservoirs, the possible mechanisms which have been proposed up to now are migration of fines or clay fragments (Morrow *et al.*, 1998), pH increase (McGuire *et al.*, 2005), and the multi-ions exchange (MIE) between the clay mineral surfaces and the injected brine (Lager *et al.*, 2006) triggered by the expansion of the electrical double layer (Lighthelm *et al.*, 2009).

(i) Migration of fines or clay fragments

The mechanism of migration of fines or clay fragments is proposed by Morrow *et al.* (1998). It is suggested that the low salinity water could detach fines which were initially attached to the oil. The mobilized fines are transported along the oil-water interface together with the flowing fluid. Subsequently, the released of clay particles block the pore throats or pore constrictions, causing the diversion of the flow of water into the unswept pores to increase the microscopic sweep efficiency.

(ii) pH increase

The mechanism of rise in pH functions as one of the contributors of the increased oil recovery during low salinity flooding of McGuire *et al.* (2005). (RezaeiDoust *et al.*, 2009) mentioned that the pH increase is a consequent of two reactions which are the clay acting as active cation exchangers because of the presence of permanent negative charges on its surface, and pH change in the solution in which McGuire *et al.* (2005) describe the process as similar to alkaline flooding. These ultimately ease the desorption of oil components from the clay surfaces.

(iii) Multi-ions exchange (MIE) between the clay mineral surfaces and the injected brine

Lager et al. (2006) suggested that the oil recovery increase is caused by the multi-ions exchange (MIE) between the clay minerals and the injected brine which reduces the ion binding between the crude oil and rock surface. He performed the experiments with the North Slope core sample and the results indicated that LSW raise the oil recovery in the core that contain calcium, Ca^{2+} and magnesium, Mg^{2+} ions but no changes in the oil recovery was observed for the core without Ca^{2+} and Mg^{2+} ions on the surface.

(iv) Expansion of the electrical double layer

One mechanism was proposed by Lighthelm *et al.* (2009) which involves the expansion of the electrical double layer low salinity brines are used. This mechanism results in wettability manipulation to become a more water wet system. An electrical double layer is formed around the negatively charged clay particles when the clay in the porous media is immersed in water. The double layers consist of an inner adsorbed layer of positive ions and an outer diffuse layer of negative ions. The ion concentration in the surrounding water determines the thickness of the double layers. During high salinity waterflooding containing more ions, the double layer is more compact while during the low salinity waterflooding, the double layers tend to expand. The layer of positive ions contains divalent calcium, Ca^{2+} or magnesium, Mg^{2+} ions. The injection of low salinity water breaks open the outer layer, enabling monovalent ions such as sodium Na^{+} ions to penetrate into the double layer. The monovalent ions displace the divalent ions causing an increase in the electrostatic repulsion between clay particles and oil. Once the repulsive forces surpasses the binding forces via the formation of a multivalent cations layer, the oil particles may be desorbed from clay surfaces to be swept out of the reservoir.

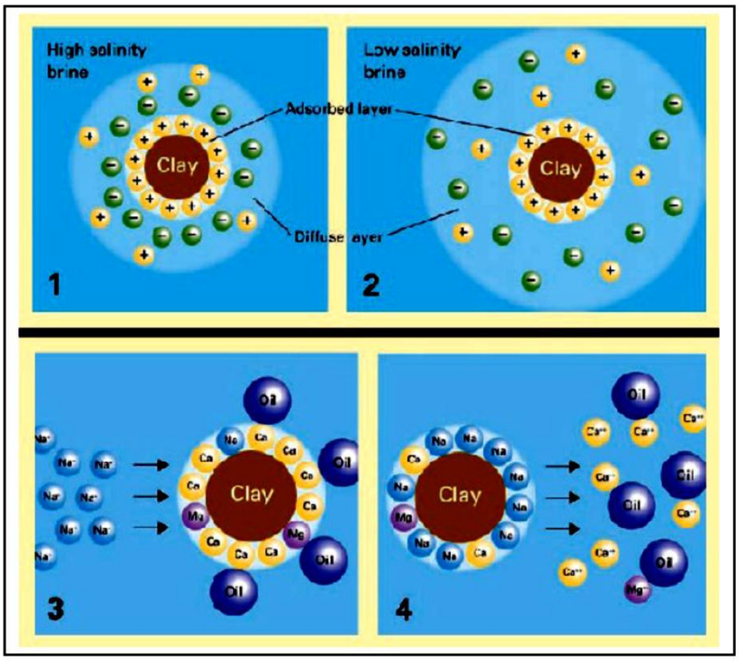

Figure 2:- How double layer worked. Adopted from Knott *et al.* (2009).

2.3.2 Smart Water Applications In WAG

To the best of our knowledge, there are two only two prior researches concerning the applications of smart water in WAG. Kulkarni and Rao (2004) published their work on the impacts of brine composition on the tertiary oil recovery through an experimental study using 5 % NaCl brine 0.5815 % NaCl reservoir brine during WAG . They concluded that the WAG recoveries are highly dependent on the brine composition and the explanation for the decrease in oil recovery at lower brine salinity is because of the rise in the solubility of the gas in the brine.

Jiang *et al.* (2010) progressed the research on the impact of salinity of the injection brine by conducting experiments using two oil models, one of which is a mixture of 50 wt% n-decane and 50 wt% n-hexadecane, and the other is a crude oil from the Cottonwood Creek. According to Jiang *et al.* (2010), an increase in the salinity of the injection brine is accompanied by an increase in the tertiary recovery and oil recovery factor of both model oil and crude oil as illustrated in Figure 3. Their reasoning was similar to that of Kulkarni and Rao (2004) which is when the salinity of the brine increases, the solubility of CO_2 gas in the brine decreases thus more CO_2 gas are available for the miscible flooding followed by an increase in the WAG recoveries.

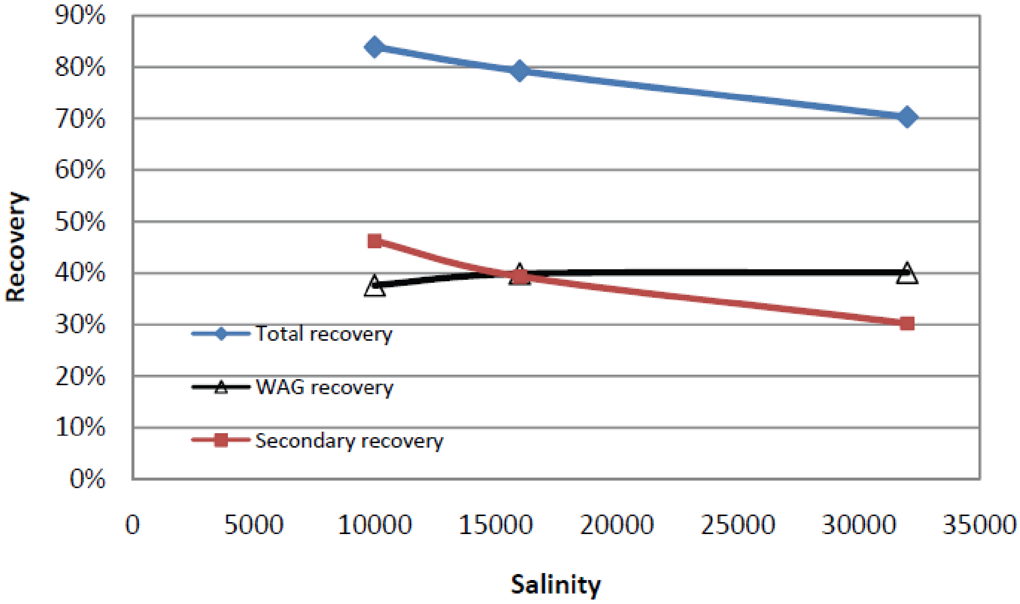

Figure 3:- The recovery of water flooding, WAG flooding and total as a function of salinity.

Adopted from Jiang *et al.* (2010).

2.4 Relative Permeability

The computation of relative permeability is necessary for understanding the Crude-Brine-Rock (CBR) interactions, reservoir performance prediction, finding out the factors contributing to low productivity and reducing formation damage (Honarpour *et al.*, 1990). The relative permeability can be generally defined as the property of the porous media which can be estimated from the ratio of the effective permeability of a fluid at a given saturation to the permeability of the fluid at 100 % saturation (Amyx *et al.*, 1960; Ahmed, 2001). It corresponds to the ability of the porous media to transmit one fluid when one or more fluids are present (Anderson, 1987). The relative permeability curves are representative of flow characteristics through the formation in the reservoir which is affected by the mechanism by which the reservoir is depleted (Osoba *et al.*, 1951).

The relative permeability can be expressed as:-

$$k_{Rp} = \frac{k_p}{k}$$

where subscript p = Oil, water or gas phase (o, w or g)

k_{Rp} = Relative permeability to phase p

k_p = Effective permeability to phase p , Darcy

k = Absolute permeability , Darcy

The famous Darcy law first defined mathematically by Darcy (1856) which relates the flow rate to the absolute permeability can be represented by the equation (Ahmed, 2001):-

$$q = \frac{kA}{\mu} \left(\frac{\Delta P}{L} \right)$$

where q = Flow rate through the porous medium, cm^3/s

μ = Viscosity of the flowing fluid, cp

L = Length of the porous medium, cm

A = Cross-sectional area, cm^2

ΔP = Pressure change, atm

When there is more than a fluid present in the porous medium, the Darcy's law can also be denoted in the form of:-

$$q_p = \frac{k k_{Rp} A}{\mu_p} \left(\frac{\Delta P}{L} \right)$$

Relative permeability is a reservoir dynamic property that is largely affected by several factors including the pore geometry, saturation history and wettability. The changes in the shape of the relative permeability can be justified due to the uncertainties in rock wettability, saturation history, pore geometry and fluid distribution in the reservoir (Molina, 1980; Anderson, 1987). From the curves of relative permeability, the wettability of the reservoir system, whether oil wet or water wet can be determined. Most of the studies suggested that the oil recoveries from oil wet reservoirs are generally less than from water wet reservoirs. Hysteresis refers to the irreversible change in the relative permeability inherently dependent on the saturation path or history. As a consequence of the trapping of the non-wetting phase by the wetting phase (Killough, 1976), the non-wetting phase relative permeability increases whilst the wetting-phase relative permeability decreases during drainage process as compared to imbibition. This behavior indicates that the relative permeability to a fluid at a given saturation depends on whether that saturation is obtained by approaching it from a higher or a lower value (Osoba *et al.*, 1951).

2.4.1 Calculations Of Relative Permeability

The literature on relative permeability shows a variety of approaches used to determine the relative permeability through experiments. Among them are the steady state and unsteady state or displacement method. The steady state method requires both the incompressible fluids injected simultaneously whereas the unsteady state requires only one fluid injected into the core to displace another fluid. Toth *et al.* (2001) discussed in their paper the determination of relative permeability from the unsteady state constant pressure and rate displacements. They correlated the total mobility and mobility ratio of the fluids to the characteristic parameters of the displacement process and cumulative pore volume of the injected fluid by a least-squares linear regression function. As opposed to the usual experimental approach, Jones and Roszell (1978) presented graphical constructions that are equivalent to the Welge and Johnson *et al.* equations to develop the required point functions of saturation history and pressure gradient per injection rate to compute the relative permeability. The constructions apply to constant rate, constant pressure and variable rate-pressure displacements. The difference between the equations used and the graphical method is that the permeabilities calculated by the graphical technique are relative to absolute water permeability, instead of the effective permeability at prewaterflood saturation. Regardless of the approaches used, the capillary end effects and gravity are often neglected.

Apart from experiments, correlations for two phase system are also frequently used to calculate the relative permeability. Corey (1954) proposed an approximation of relative permeability of the gas oil system. The estimation of the relative permeability is also possible with the use of well production data (Al-Yazeri, 2010). He extended the Toth *et* al. method and determined the relative permeability functions considering the effects of formation heterogeneity and skin factor on the well production data. The low salinity relative permeability functions can also be found via correlations with the high salinity permeability functions which are largely determined by the salt concentration factors (Hasanov, 2010).

2.5 Literature Summary

In view of the literature review conducted, the oil recovery factor is primarily a function of the macroscopic sweep efficiency as well as the microscopic sweep efficiency. One of the major EOR techniques which are widely implemented is the miscible gas injection. CO_2 gas is more desirable than other EOR gas agents like N_2 and flue gas because of its high availability, low MMP, low cost as well as role to reduce greenhouse gas emanation via Carbon Capture and Sequestration.

Due to the poor sweep efficiencies during gas flooding, Water Alternating Gas (WAG) WAG injection was initially proposed to provide better the gas mobility control. WAG schemes improve the microscopic and macroscopic sweep efficiency through the alternate injection of slugs of water and gas into the oil reservoirs. However, most of the existing literature highlights a variety of operational problems leading to the oil recovery during WAG injection. These include viscous instabilities, gravity segregation, gas override and gas channeling through high permeability streaks or thief zones. Recently, tuning the salinity and ionic composition of the injection brine has been the prime focus. Successful applications of the altered injection brine, also termed as " Smart Water " evidenced that the utilization of smart water could increase the oil recovery from reservoir. Various possible mechanisms have been proposed to explain the reasons for the increase in oil recovery ranging from migration of fines or clay fragments, pH increase,

There are limited researches on using smart water as the injection brine in WAG technique. The performance of such technique can be evaluated using relative permeability models taking into consideration the effects of the composition of Ca^{2+} and Mg^{2+} ions in brine during the WAG process.

CHAPTER 3:- METHODOLOGY/ PROJECT WORK

This section outlines the key milestones in completing this thorough and sound simulation study as well as the simulation framework applied in developing the reservoir simulation model.

3.1 Research Methodology

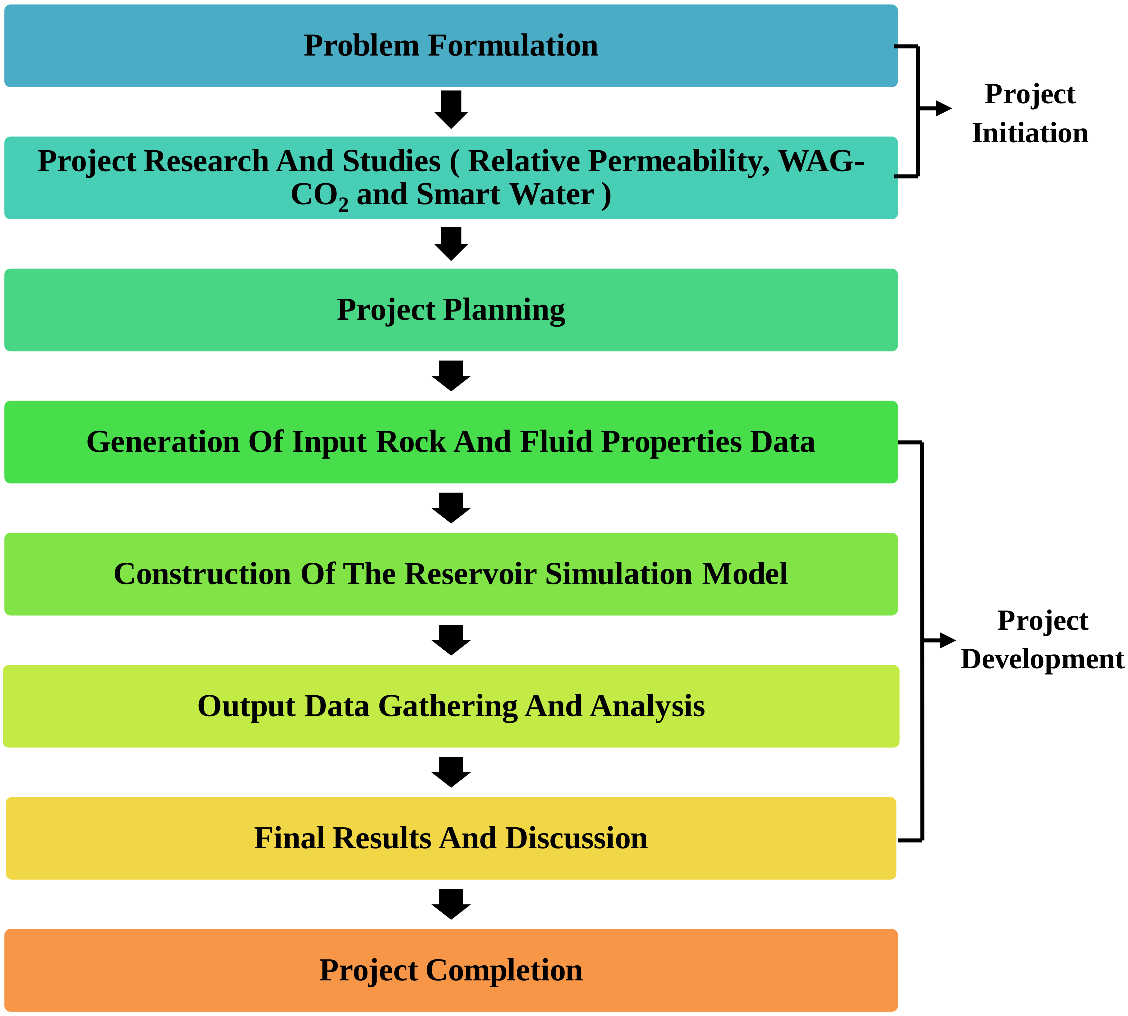

Figure 4:- Research Methodology.

3.2 Project activities

3.2.1 Problem Formulation

In the project initiation stage, the focus is on solving the various operational problems which occur during WAG-CO_2 injection contributing to the low incremental oil recovery. There are insufficient studies on the effect of tuning the salinity and ionic composition of the injection brine. Therefore, in this project, a simulation study is to be conducted aiming to analyze and interpret the effects of the use of smart water on the relative permeability during the WAG-CO_2 injection. This project also seeks to find out the relationship between the composition of Ca^{2+} and Mg^{2+} ions in brine and oil recovery as well as to determine the optimum brine salinity at which maximum oil recovery factor can be achieved. The outcomes from this research may offer better understanding of the concept of chemical alteration of the injection brine used during WAG-CO_2 injection for optimization of oil recovery from light oil reservoirs.

3.2.2 Project Research And Studies

Before proceeding to the project development, it is important to gain basic understanding of the research topic and make review on the past researched in the related area of the project. Extensive readings have been made on the three key terms in this project which are relative permeability, WAG-CO_2 and smart water.

3.2.3 Project Planning

In the project planning phase, schedules such as Gantt Charts which list the project's milestones, activities and deliverables, with the intended start and finish dates are outlined as a guide to ensure this project is completed on time. The project scope of this project is firstly defined and then the appropriate techniques for completing the project are determined. The durations for the tasks necessary to complete the project is clearly listed and then grouped into a work breakdown structure. The necessary resources and time allocated for each activity are estimated. The progress of this project is measured against this baseline schedule throughout the whole project.

3.2.4 Generation Of Input Rock And Fluid Properties Data

This stage is important as to identify and collect the input data required for the reservoir simulation model. The variables and range of the values are considered and defined. The input rock and fluid properties data needed include porosity, OOIP, reservoir temperature, reservoir pressure, oil API gravity, brine salinity and etcetera.

The input data were gathered and analyzed during the literature review. A comprehensive study was done to understand the reservoir rock and fluid behaviors of the selected field which is the Norne oil field. During this stage, there are several considerations that have been taken during the selection of the oil field for reservoir simulation, particularly the API gravity and the availability of the relative permeability data. Since the simulation study is performed on light oil reservoir thus the API gravity has to be higher than about 31.1. In this case, the oil API Gravity for the Norne oil field is 32.7 which indicates that it is a type of light oil. The summary of the Norne oil field and its reservoir rock and fluid properties are as shown in Table 1:-

1.	Discovered	December 1991
2.	Coverage	9 km x 3 km
3.	Location	80 km north of the Heidrun field in the Norwegian Sea
4.	1^{ST} Oil production	6^{TH} November 1997
5.	Sea depth	380 m
6.	Formation	Sandstone (Lower to Middle Jurassic)
7.	Depth	2500 – 2700 m
8.	Oil zone thickness	110 m
9.	Temperature	98.3 ^{o} C
10.	API Gravity	32.7
11.	Porosity, Ø	0.25 – 0.30
12.	Permeability, k	20 – 2500 mD
13.	Saturation of oil, S_o	0.35 – 0.92
14.	Viscosity of oil, μ_o	< 1.2

15.	Density of oil, ρ_o	859.5 kg/ m^3
16.	OOIP	164.2 $MMSm^3$ (PDO)/ 157.0 $MMSm^3$ (RNB)
17.	GIIP	29.9 $MMMSm^3$ (PDO)/ 29.8 $MMMSm^3$ (RNB)
18.	Estimated recoverable reserve	94.9 $MMSm^3$ (Oil)/ 11.0 $MMMSm^3$ (Gas)
19.	Gas cap thickness	25 m
20.	Wettability	Mixed

Table 1:- A summary of the Norne field and its reservoir rock and fluid properties. Adapted from Hasanov, B. (2010) and Maheshwari, Y. K. (2011).

3.2.5 Construction Of The Reservoir Simulation Model

The tasks and activities that are carried out in this stage are simulation process design as well as simulation runs for three different injection scenarios comprising of conventional WAG-CO_2 injection, proposed smart water assisted WAG-CO_2 injection and smart WAG-CO_2 injection.

The data gathered were first input using the CMG Builder and Winprop to be simulated or modeled by CMG STARS. Due to the data availability constraints and processing time considerations, only a sector model of the formation with sufficient data is simulated. However, the static model is adequate to model the effects of smart water injection during WAG CO_2 on the relative permeability and oil recovery factor.

The reservoir simulation model has a dimension of 11 X 11 X 6 with a total of 726 grid blocks with the Norne oil field reservoir rock and fluid properties. The length, width and height of the reservoir simulation model is 550 m, 550 m and 60 m respectively. A quarter five spot injection pattern between the injector and the producer wells is employed. The water and CO_2 injector is located at the same position to enable alternate injection of high salinity water or smart water and CO_2 gas. The reservoir simulation model input parameters are as illustrated in Table 2:-

1.	Grids (DX x DY x DZ)	11 * 11 * 6
2.	Number of active cells	726
3.	Viscosity of oil, μ_o	0.318 cp
4.	Initial formation volume factor, B_{oi}	1.038 Rm^3/ Sm^3
5.	GOR	111 Sm^3/ Sm^3
6.	Bubble point pressure, P_b	251 bar
7.	Initial oil density, ρ_{oi}	859.5 kg/ m^3
8.	Density of water, ρ_w	1033 kg/ m^3
9.	Reservoir temperature, T_R	98 ^{o} C
10.	Initial reservoir pressure, P_{Ri}	277 bar
11.	BHP	260 bar
12.	Compressibility of water, C_w	4.67 x 10^{-5} / bar at 277 bar
13.	Water formation volume factor, B_w	1.0328 Rm^3/ Sm^3
14.	Rock compressibility, C_r	4.84 x 10^{-5} / bar at 277 bar
15.	Oil formation volume factor, B_o	1.32 Rm^3/ Sm^3
16.	Gas formation volume factor, B_g	0.0047
17.	Density of gas, ρ_g	0.8545 kg/ m^3
18.	Reservoir pressure, P_R	273.2 bar at 2639 m TVD

Table 2:- Reservoir simulation model input parameters.
Adapted from Awolola, K. A. (2012).

The conventional WAG-CO_2 injection is set to be the base case study whereby water of 35 000 ppm is used during the WAG-CO_2 injection. The relative permeability curves for the base case are as shown in Figure 5:-

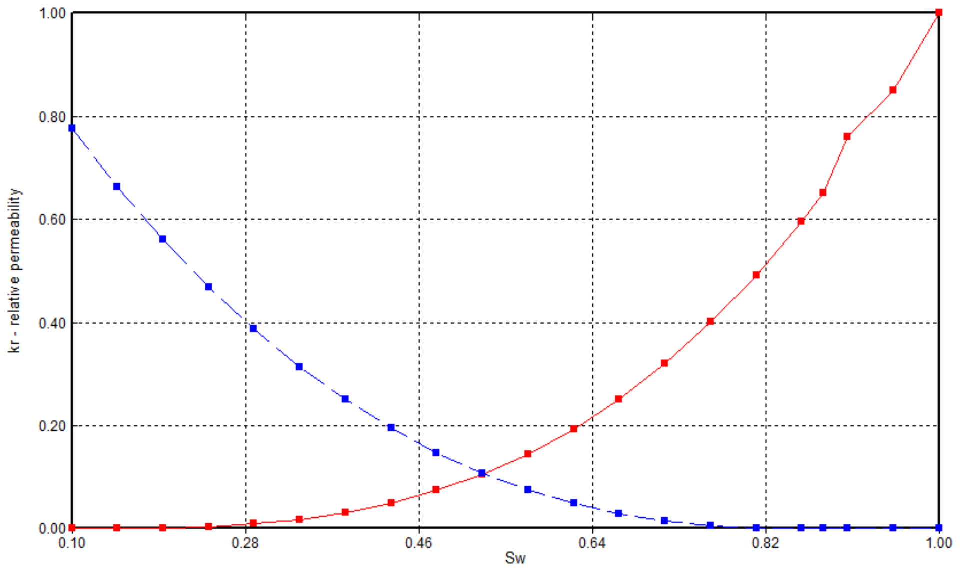

Figure 5:- Relative permeability curves for the base case study.

The mixed wettability nature of the reservoir is as indicated in Figure 5 with an intersection point of higher than 0.5 which is about 0.52 and the end points for the relative permeability to water is higher than that of the relative permeability to oil. This type of wettability eases the interpretation of the change in wettability to a more water wet system caused by the smart water injection.

The static reservoir simulation model with 1 oil producer well and 1 well for alternating gas and water injection is as shown in Figure 6:-

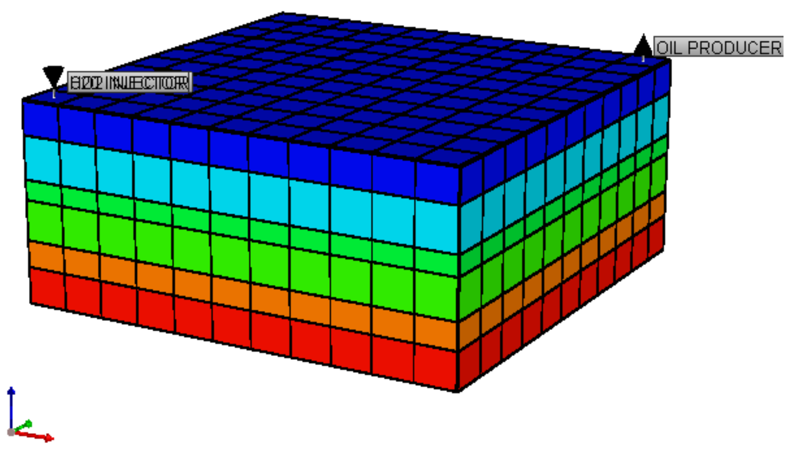

Figure 6:- Static reservoir simulation model.

Simulation runs are performed for three different injection scenarios comprising of conventional WAG-CO_2 injection, proposed smart water assisted WAG-CO_2 injection and smart WAG-CO_2 injection as follow:-

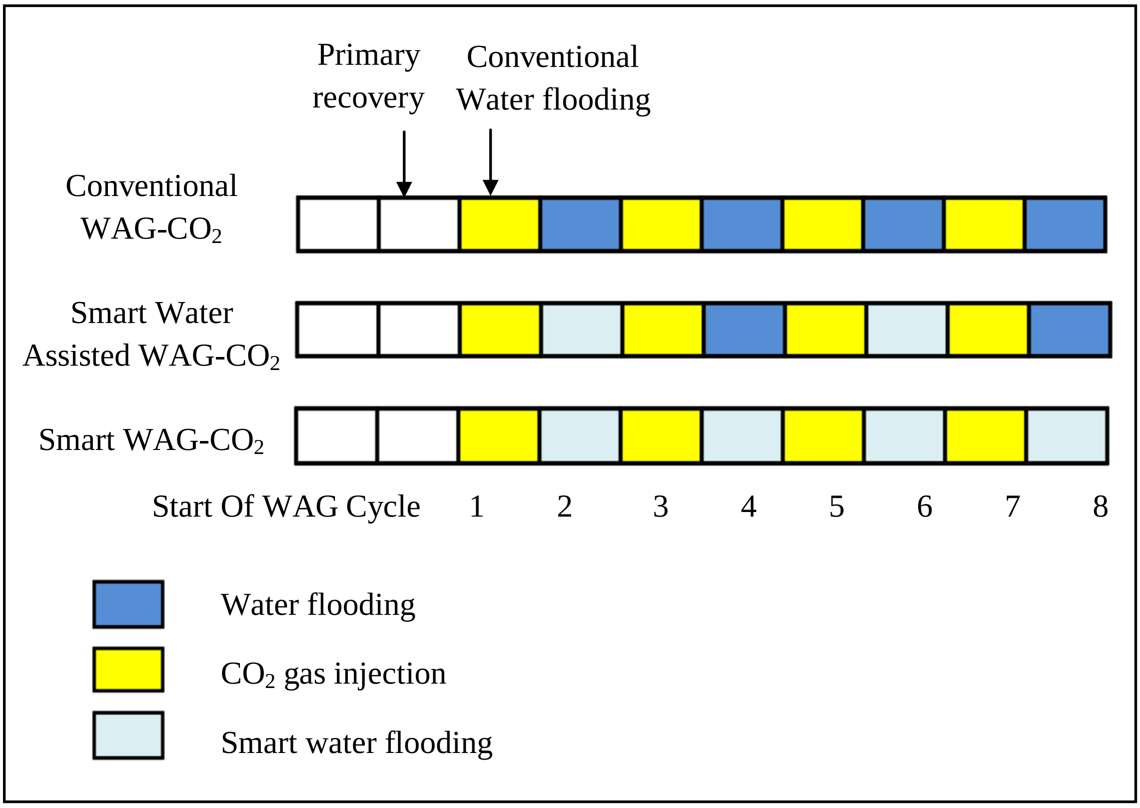

Figure 7:- Simulation design of three different injection scenarios.

The simulated reservoir is first depleted and waterflooded for 6 years before WAG is applied for 9 years. The secondary recovery using waterflooding stops beginning of the year of 1997 because of the economical limit set using the percentage of water cut of higher than 80%. The duration of the simulation run is for 15 years from 1^{ST} of January 1991 up to 1^{st} of January 2006.

For optimized production, a WAG ratio of 1:1 is used. The conventional brine is set to have water components of 35000 ppm whereas the smart water are of different salinities of about 1000 ppm, 3000 ppm and 7000 ppm. This is because low salinity effects take place when the injected concentration is below 25% of the salinity of the connate water with approximate values of 1000 to 7000 ppm for the lower and upper salinity threshold as suggested in the literature (Jerauld *et al.*, 2008). The ion components dissolved in the water are Na^+, K^+, Ca^{2+}, Mg^{2+}, Cl^-, HCO_3^{2-} and SO_4^{2-}. The composition of the Na^+ cations and the Cl^- anions defines the salinities of the injection water. The Total Dissolved Solids (TDS) in the water at different salinities are as summarized in Table 3:-

TDS	35000 ppm brine/ mol/ L	7000 ppm brine/ mol/ L	3000 ppm brine/ mol/ L	1000 ppm brine/ mol/ L
Na^+	0.4703	0.1117	0.0408	0.01596
K^+	0.009873	0.0008440	0.0008696	0.0001279
Ca^{2+}	0.01003	0.005240	0.0008484	0.0001248
Mg^{2+}	0.05205	0.008640	0.004526	0.0001646
Cl^-	0.5349	0.1085	0.04632	0.01551
HCO_3^{2-}	0.002409	0.007523	0.0001967	0.001082
SO_4^{2-}	0.02753	0.0002498	0.002394	0.00003123

Table 3:- The Total Dissolved Solids (TDS) in the brine at different salinities. Adapted from McGuire, P. L. *et al.* (2005).

For the base case which is the conventional WAG-CO_2, alternate injection of high salinity water of 35000 ppm and CO_2 gas are used. Then the second injection scenario which is smart assisted WAG-CO_2 involving the alternate injection of high salinity and smart water flooding with CO_2 gas are simulated. There are 3 simulation runs which are conducted for this smart water assisted WAG-CO_2 injection whereby 3 different salinities of smart water including 1000 ppm, 3000 ppm and 7000 ppm are deployed. The next injection scenario is the smart WAG-CO_2 injection in which smart water flooding follows every CO_2 gas injection, also run at 3 different salinities similar to the smart assisted WAG-CO_2 case studies.

The effects of the composition of Ca^{2+} and Mg^{2+} ions in brine on the oil recovery during WAG-CO_2 injection are simulated by varying the mole fractions of these divalent ions contained in the brine ranging from 0 ppm up to 300 ppm at 50 ppm intervals.

3.2.6 Output Data Gathering And Analysis

The output data generated for further analysis in this project are the two phase relative permeabilities curves and the oil recoveries for the 7 different case studies which were then analyzed using the CMG Results Graph and CMG Results 3-D. The 7 cases studies are comprised of the base case conventional WAG-CO_2, smart assisted WAG-CO_2 using 1000 ppm, 3000 ppm and 7000 ppm brine, and smart WAG-CO_2 injection using 1000 ppm, 3000 ppm and 7000 ppm brine. The oil recoveries when applying smart WAG-CO_2 with different composition of Ca^{2+} and Mg^{2+} ions in the brine are also being compared.

These output data are used to draw inferences from the data obtained from each of the simulation runs.

3.2.7 Final Results And Discussion

Data analysis and interpretation of the output data assists in summarizing the effects of the use of smart water on the water/ oil relative permeability curves during WAG-CO_2 injection for light oil reservoir, how the composition of the Ca^{2+} and Mg^{2+} ions in the brine may affects the oil recovery factor and the determination of optimum brine salinity for ultimate oil recovery.

3.2.8 Project Completion

This is the final phase of this project. The main task is to plan an effective project closure to ensure that all the project activities have been completed, all the outcomes and deliverables are accomplished, and all the goals initially set during the earlier stage of this project have been achieved. The deliverable in this project which is the two phase relative permeability curves should be able to illuminate the effects of adjustment of brine salinity and ionic composition during WAG-CO_2 injection for light oil reservoir. This project should be officially concluded by taking note of the recommendations for the further improvements of this project.

3.3 Key milestones

The key milestones of this FYP are as shown in the Table 4:-

Activities	June 2013	July 2013	August 2013	Sept 2013	October 2013	Nov 2013	Dec 2013
1. Problem Formulation							
2. Project Research And Studies							
3. Project Planning							
4. Generation Of Input Rock And Fluid Properties Data							
5. Construction Of The Reservoir Simulation Model							
6. Output Data Gathering And Analysis							
7. Final Results And Discussion							
8. Project Completion							

Table 4:- Key milestones for the project.

3.4 Gantt Chart

There are two Gantt Charts which are produced to facilitate the project planning and scheduling in this FYP. Chart 1 is the Gantt Chart for the FYP I while Chart 2 is the Gantt Chart for the FYP II.

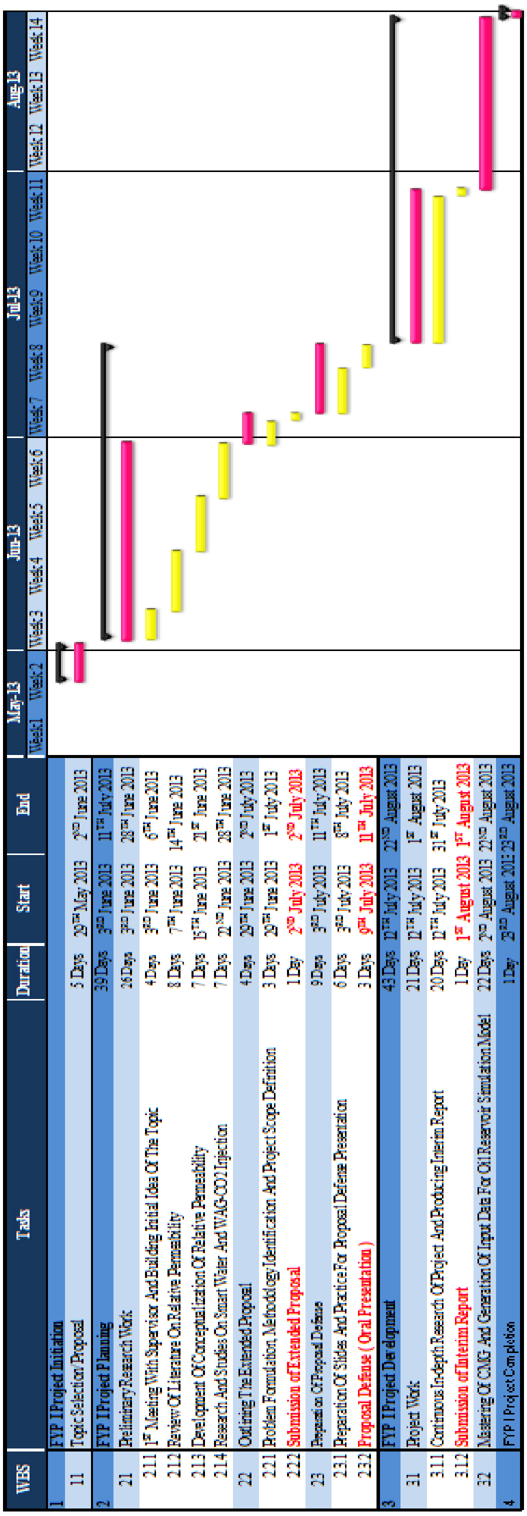

Chart 1:- Gantt Chart for the FYP I.

WBS	Tasks	Duration	Start	End
1	**FYP II Project Initiation**	12 Days	23RD September 2013	4TH October 2013
1.1	Mastering Of CMG	12 Days	23RD September 2013	4TH October 2013
2	**FYP II Project Development**	51 Days	5TH October 2013	24TH November 2013
2.1	Simulation Design And Results Interpretation	26 Days	5TH October 2013	24TH November 2013
2.1.1	Generation Of Input Data For Oil Reservoir Simulation Model	8 Days	5TH October 2013	12TH October 2013
2.1.2	Construction Of Reservoir Simulation Model	31 Days	13TH October 2013	12TH November 2013
2.1.3	Results Analysis And Discussion	12 Days	13TH November 2013	24TH November 2013
3	**FYP II Project Documentation**	37 Days	25TH November 2013	31ST December 2013
3.1	Preparation Of Progress Report	4 Days	25TH November 2013	28TH November 2013
3.1.1	**Submission of Progress Report**	1 Day	29TH November 2013	29TH November 2013
3.2	Preparation Of Pre-SEDEX And SEDEX	4 Days	30TH November 2013	3RD December 2013
3.2.1	**Pre-SEDEX**	1 Day	4TH December 2013	4TH December 2013
3.2.2	**SEDEX**	2 Days	11TH December 2013	12TH December 2013
3.3	Preparation Of Final Dissertation And Technical Paper	12 Day	27TH November 2013	8TH December 2013
3.3.1	**Submission of Final Dissertation And Technical Paper**	3 Days	9TH December 2013	11TH December 2013
3.4	Preparation Of Final Oral Presentation	21 Days	12TH December 2013	22ND December 2013
3.4.1	**Final Oral Presentation**	2 Days	23RD December 2013	24TH December 2013
3.5	Preparation Of Hardbound	6 Days	25TH December 2013	30TH December 2013
3.5.1	**Submission Of Hardbound**	1 Day	31ST December 2013	31ST December 2013
4	**FYP II Project Completion**	1 Day	31ST December 2013	31ST December 2013

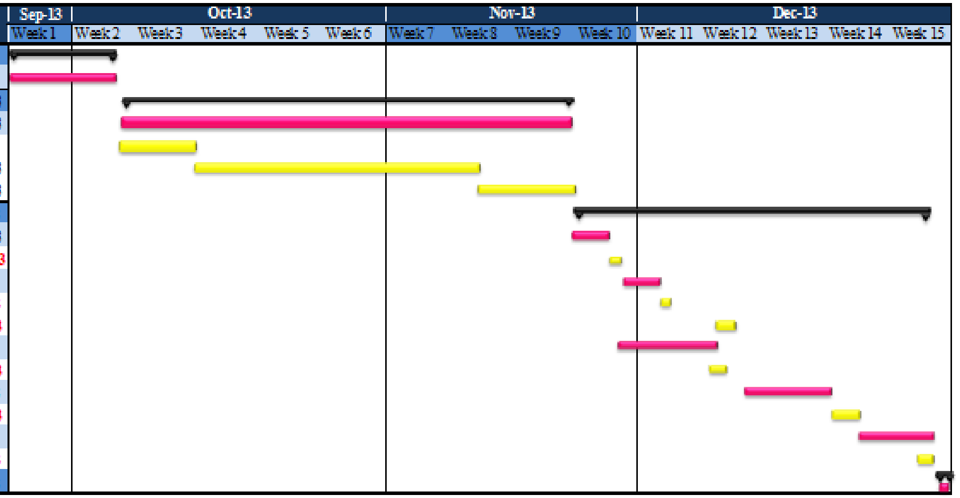

Chart 2:- Gantt Chart for the FYP II.

3.5 Tools used/ needed for the project

The main software used in this simulation study is the Computer Modeling Group (CMG) reservoir simulation software available at Universiti Teknologi PETRONAS (UTP).

Tool	Descriptions
1. CMG software	The CMG simulation software is used to build the relative permeability models to analyze the impact of the smart water injection during WAG-CO_2 flooding for light oil reservoir as compared to that of when conventional brine injected is used. There are 3 main CMG applications utilized to construct the reservoir simulation model which are the CMG Builder for inputting the simulation data, WinProp for fluid modeling and STARS for modeling the effects of smart water during WAG-CO_2 injection. The CMG Results Graph and Results 3D are used to analyze the output data such as the oil recovery factor.

Table 5:- Tools used/ needed for the project.

CHAPTER 4:- RESULTS AND DISCUSSION

4.1 Simulation Results And Discussion

The objectives of this FYP initially set are to evaluate the impacts of smart water injection on the oil/ water relative permeability curves in comparison with the conventional brine during WAG-CO_2 injection for light oil reservoir using reservoir simulation, to investigate the effects of the composition of Ca^{2+} and Mg^{2+} ions in brine on the oil recovery factor and finally, to determine the optimum brine salinity for maximum oil recovery. Therefore, in this chapter, the results of the simulations run using WAG-CO_2 schemes with different salinities and ionic compositions are presented and discussed.

4.1.1 The Effects Of Smart Water Injection On The Relative Permeability

Smart water injection is a well-known EOR method due to its capability to modify the rock wettability towards a more water wet system which corresponds to a change in the relative permeability and the oil recovery. Therefore, an analysis of the relative permeability curves is very vital and effective in evaluating the performance or the potential and the effects of the smart water injection during WAG-CO_2 flooding. The relative permeability curves dictate the fluid distribution, wettability and the residual oil saturation.

The relative permeability curves during WAG-CO_2 flooding, smart WAG-CO_2 injection using 7000 ppm, 3000 ppm and 1000 ppm are compared to verify the effects of the smart water injection during WAG-CO_2 flooding. The effects of the smart water injection during WAG-CO_2 flooding is evident from the results of the relative permeability curves of k_{RO} and k_{RW} versus S_W as shown in Figure 8:-

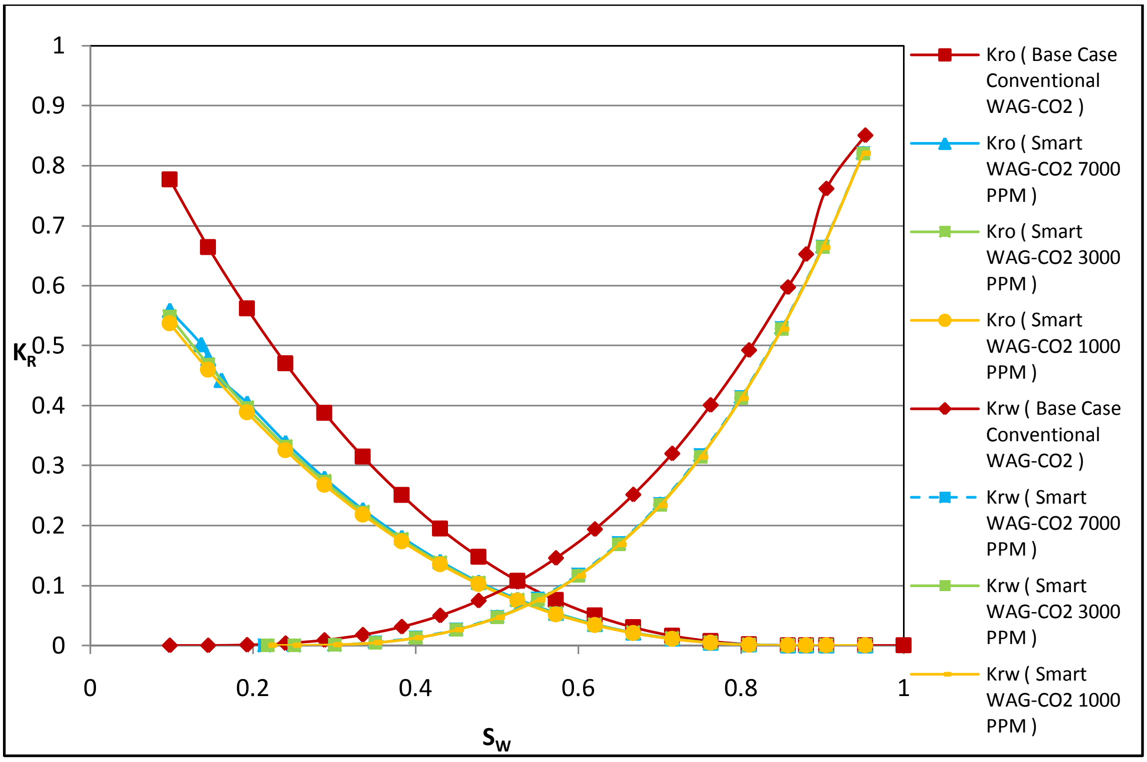

Figure 8:- Relative permeability curves of k_{RO} and k_{RW} versus S_W.

Interpretations:-

It is obvious from Figure 8 that the relative permeability curves are shifted to the right when smart WAG-CO_2 injection with lower salinity from 35000 ppm to 7000 ppm, 3000 ppm and 1000 ppm is applied on the sandstone reservoir with light oil. Unlike waterflooding, the relative permeability to oil during smart WAG-CO_2 injection decreases instead of increases in relative to the relative permeability to oil during the base case conventional WAG-CO_2 injection when lower salinity brine is used. This explains why lower incremental oil recovery is achieved when the salinity is reduced during smart WAG-CO_2 injection. The lower relative permeability to oil also implies that smart water injection during WAG-CO_2 flooding delays the oil displacement process and results in higher residual oil saturation.

At the same time, the relative permeability to water during smart WAG-CO_2 also decreases in relative to the relative permeability to water during base case conventional WAG-CO_2 injection when lower salinity brine is utilized. This is evident by the fact that solubility of CO_2 gas in brine increases with a decrease in the salinity of the brine (Chang *et al.*, 1998) causing an increase in the viscosity of the water. Subsequently, the mobility of the water decreases and less percentage of water cut because of the reduction in the relative permeability to water during smart WAG-CO_2 injection. However, the effects of the dissolved CO_2 gas in water on the viscosity of the water are not very drastic (Sayegh, *et al.*, 1987) which clarifies the small reduction in the relative permeability to water as compared to the larger reduction in the relative permeability to oil during smart WAG-CO_2 injection.

The gradual shifting of the intersection point between the relative permeability to oil and relative permeability to water curves to the right when lower salinity brine is used signifies the change in the wettability towards a more water wet system induced by the smart water injection. The influence of the smart water injection on the relative permeability is related to the few smart waterflooding mechanisms earlier proposed including the Multi-Ions Exchange (MIE) mechanism and expansion of the electrical double layer (Lager *et al.*, 2006; Lighthelm *et al.*, 2009). The formation of a layer of multivalent cations during smart water injection increases the electrostatic repulsion thus eases the desorption of oil components from the negatively charged clay surfaces.

4.1.2 The Effects Of The Composition Of Ca^{2+} and Mg^{2+} Ions In Brine

The interactions between the crude, oil and brine are sensitive to the ionic compositions. Tuning the composition of divalent ions, specifically Ca^{2+} and Mg^{2+} ions in brine during smart WAG-CO_2 injection plays an essential role in escalating the oil recovery factor. The concentration of these divalent ions appears to be the driving force which enhances the multi-ions exchange (MIE) and double layer expansion mechanisms responsible for reducing the residual oil saturation during smart water injection.

There are 7 simulation runs conducted in order to simulate the effects of the composition of these divalent cations on the oil recovery during smart WAG-CO_2 injection. The results are represented as a plot of the cumulative oil produced versus Ca^{2+} & Mg^{2+} ions composition in brine is as shown in Figure 9.

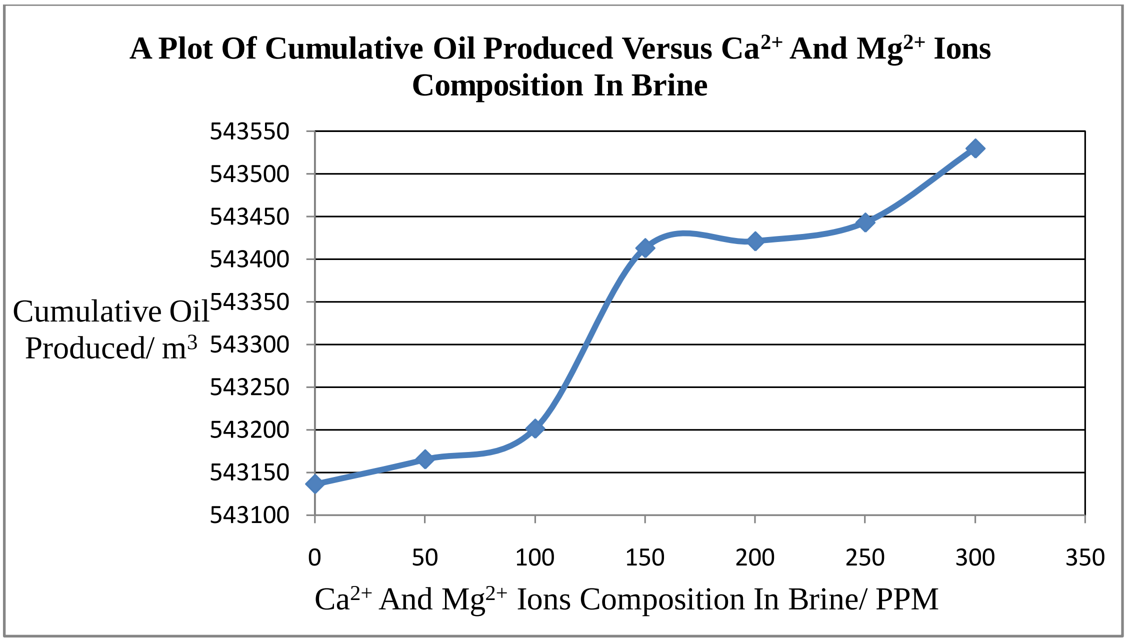

Figure 9- A Plot Of Cumulative Oil Produced Versus Ca^{2+} & Mg^{2+} Ions Composition.

Interpretations:-

An increase in the composition of the Ca^{2+} and Mg^{2+} ions in the brine yields a higher oil recovery as shown in Figure 9. The observed incremental recovery behavior as the concentration of Ca^{2+} and Mg^{2+} ions in the brine increases from 0 ppm up to 300 ppm is ascribed to the presence of more divalent ions available for the cations exchange reaction between the clay minerals and the injected brine which further reduces the ion binding between the crude oil and rock surface. Flooding of the reservoir through smart water injection that has a higher concentration of the Ca^{2+} and Mg^{2+} ions in the brine releases the molecules oil stuck at the adsorbed layer at the rock surface. These divalent ions act as potential determining ions that are reactive and have the capability of changing the rock surface charges thus allows the release of the negative carboxylic oil component from the rock surface. This eventually alters the rock wettability towards a more water wet system and further improves the ultimate oil recovery.

4.1.3 The Optimum Brine Salinity for Maximum Oil Recovery

In this simulation study, 7 different WAG-CO_2 injection schemes with the same injection rate are simulated for a sandstone reservoir with light oil. The injection period for each alternating water and gas injection is set as 1 year. The resulting oil recoveries for the 7 different injection schemes are as shown in Table 6:-

Case Studies	Injection scenarios	Cumulative Oil Produced/ m^3	Cumulative Oil Produced/ MMbbl	WAG Recoveries/ m^3	WAG Recoveries/ MMbbl	WAG Recoveries/ %
1	**Base Case: Conventional WAG-CO_2**	556 554	3.5006	99 612	0.6265	2.944
2	**Smart Assisted WAG-CO_2 Using 35 000 PPM & 7000 PPM Brine**	551 745	3.4703	94 803	0.5963	2.802
3	**Smart Assisted WAG-CO_2 Using 35 000 PPM & 3000 PPM Brine**	551 662	3.4698	94 720	0.5958	2.800
4	**Smart Assisted WAG-CO_2 Using 35 000 PPM & 1000 PPM Brine**	551 483	3.4687	94 541	0.5946	2.795
5	**Smart WAG-CO_2 Using 7000 PPM Brine**	543 428	3.4180	86 486	0.5440	2.556
6	**Smart WAG-CO_2 Using 3000 PPM Brine**	542 895	3.4146	85 953	0.5406	2.541
7	**Smart WAG-CO_2 Using 1000 PPM Brine**	542 346	3.4112	85 404	0.5372	2.525

Table 6:- Cumulative Oil Produced For 7 Different Injection Scenarios.

A plot of the cumulative oil produced versus time for the 7 different injection schemes are as illustrated in Figure 10:-

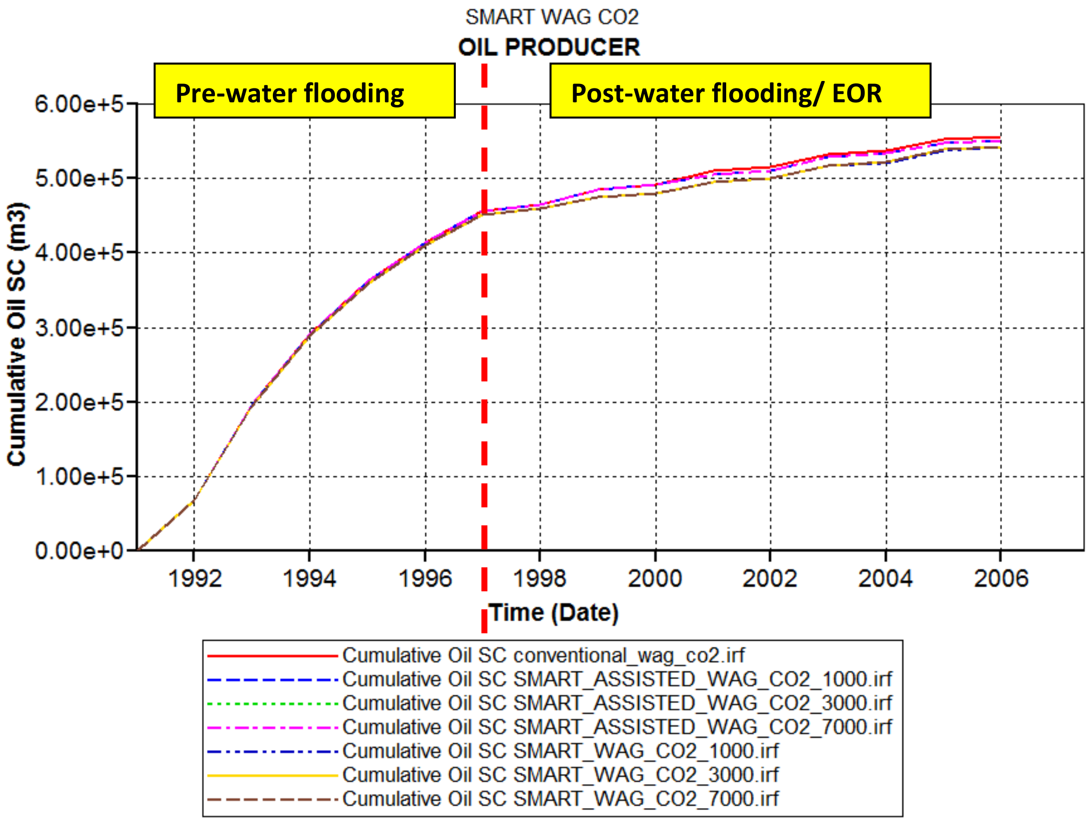

Figure 10:- A Plot Of Cumulative Oil Produced For 7 Different Injection Scenarios.

To obtain a clearer picture of the difference in oil recovery between the 7 injection scenarios, the cumulative oil recovery plot is magnified to the comparison plots from year 2005 to 2006 as in shown in Figure 11:-

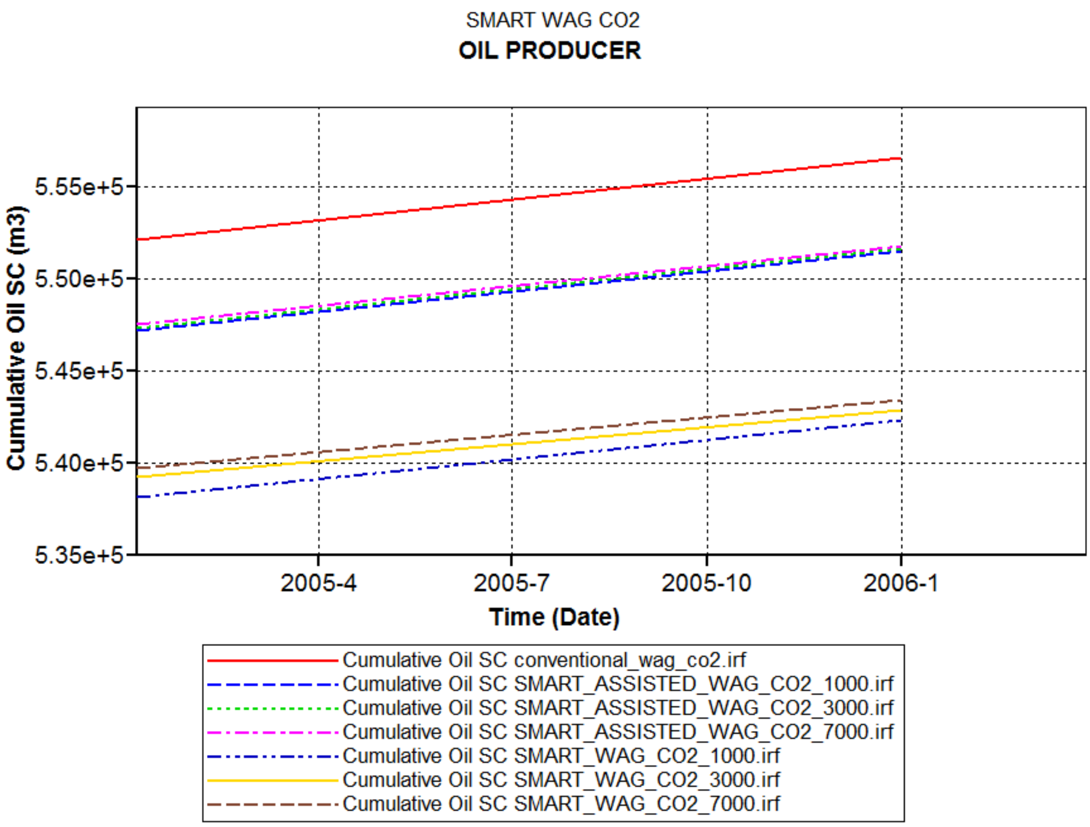

Figure 11:- Comparison of the cumulative oil produced from 2005 to 2006.

Interpretations:-

As illustrated in the Figure 10, the injection timeline of the oil reservoir is mainly divided into 2 stages which are the secondary recovery via pre-waterflooding and the post-waterflooding or EOR. During the pre-waterflooding, the injection rate and the injection period are constant for all the 7 different case studies. The oil recoveries from waterflooding are the same for all the case studies which is 456 942 m^3 or 2 874 029.81 bbl. The pre-waterflooding stops early year 1997 due to percentage of water cut of 81.5768 % exceeding the economic constraint of 80 %. Since the main interest is to evaluate the performance of smart water injection during WAG-CO_2, the focus of analysis lies on the oil recovery during the post-EOR stage.

From the Table 6 and the Figure 11, it is clear that the conventional WAG-CO_2 injection gives the highest oil recovery followed by smart assisted WAG-CO_2 using 7000 ppm, smart assisted WAG-CO_2 using 3000 ppm, smart assisted WAG-CO_2

using 1000 ppm, smart WAG-CO_2 using 7000 ppm, smart WAG-CO_2 using 3000 ppm and smart WAG-CO_2 using 1000 ppm.

Although there is a no very significant or slight difference in oil recovery in the various approaches, the correlation between salinity and oil recovery that can be observed is that as the salinity of the injected brines decreases, the oil recovery decreases. This means that the decrease in the salinity of the injection brine during WAG-CO_2 injection has adverse effects on the oil recovery. This is obviously very different from the smart water injection during waterfooding whereby a decrease in the salinity during secondary waterflooding contributes to a higher oil recovery (Lager, A. *et al.*, 2006; Tang and Morrow, 1997).

The proposed reason for the lower oil recovery during smart WAG-CO_2 injection is because of the decrease in solubility of CO_2 gas in oil but increase in solubility of CO_2 gas in water when the salinity of the brine decreases. The CO_2 gas solubility in water increases with pressure but decreases with a decrease in the temperature and salinity of water (Chang *et al.*, 1998). Thus there is less amount of CO_2 gas available for mixing with the hydrocarbons to form a zone of miscible CO_2 and light hydrocarbons which works to reduce the viscosity of oil and cause oil swelling (Jiang *et al.*, 2010). The increase in solubility of CO_2 gas in the smart water consequently hinders the oil displacement efficiency and reduces the ultimate oil recovery during WAG-CO_2 injection.

However, as compared to the smart WAG-CO_2 injection, the smart water assisted WAG-CO_2 injection achieves a higher oil recovery. Based on the Table 6 and Figure 11, it is also obvious that the smart water assisted WAG-CO_2 has higher oil recovery than the smart WAG-CO_2 but lower oil recovery than the conventional WAG-CO_2 injection. These occurrences may be due to the approach of alternate injection of conventional brines and smart water after each CO_2 gas injection. The first conventional brine injected after the first cycle of gas injection functions to increase the macroscopic efficiency through better gas-oil mobility control and stabilized displacement of oil. On the other hand, the smart water injection which follows the second cycle of gas injection aims to increase the microscopic sweep efficiency via altering the wettability of the reservoir rocks towards more water wet. Therefore, this combined approach makes a perfect scheme in increasing the overall sweep efficiency, yielding a lower water cut as well as higher oil recovery factor than the smart WAG-CO_2 injection. Besides that, the smart water assisted WAG-CO_2 injection may reduce the required expenses for the desalination of the brines.

All in all, the conventional WAG-CO_2 injection yields the highest oil recovery factor. Hence, the optimum brine salinity for maximum oil recovery in this simulation study is 35000 ppm. This suggests that the potential use of smart water injection is low during WAG-CO_2.

CHAPTER 5:- CONCLUSION AND RECOMMENDATIONS

5.1 Conclusion

From the simulation study conducted, the following can be deduced:-

1. During WAG-CO_2 injection, the smart water injection causes both the relative permeability to oil and relative permeability to water to decrease in relative to that of conventional brine injection. In another words, smart water injection during WAG-CO_2 hinders the flow of oil through the porous medium resulting in a lower oil recovery factor and also percentage of water cut. A slight shifting of the intersection point between the relative permeability to oil and to water curves to the right suggests that the smart water injection during WAG-CO_2 flooding modified the rock wettability towards a more water-wet system.
2. An increase in the composition of Ca^{2+} and Mg^{2+} ions in brine yields a higher oil recovery factor. The higher concentration of these divalent ions further reduces the ion binding between the negative carboxylic oil component and the rock surfaces.
3. A decrease in the brine salinity during WAG-CO_2 injection has unfavorable effects on the oil recovery factor. Therefore, the optimum brine salinity for maximum oil recovery during WAG-CO_2 injection in this simulation study is 35 000 ppm.

In conclusion, the objectives targeted in this FYP were achieved. The impacts of smart water injection on the oil/ water relative permeability curves in comparison with the conventional brine during WAG-CO_2 injection for light oil reservoir via reservoir simulation were evaluated using CMG software. This FYP also illuminated the effects of the composition of the Ca^{2+} and Mg^{2+} ions in brine on the oil recovery factor and the optimum brine salinity to achieve maximum oil recovery. All these findings are significant as to evaluate the performance of smart water injection applied during WAG-CO_2 injection which is mainly characterized by the relative permeability.

5.2 Recommendations

There are still many significant potential for further improvements and advancement of this research. It is recommended that further research be undertaken to examine the effects of smart water on the three phase relative permeability models which is much more complicated. Further works might explore or concentrate on experimental or laboratory works to compare and prove the results obtained from the simulation runs in this research. It is also imperative to determine the optimum WAG ratio to maximize oil recovery and optimize fluid injection.

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