Assessment of I-WAG for Optimum Recovery from a Heterogeneous Reservoir Offshore Terengganu, Malaysia.

by

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Dissertation submitted in partial fulfilment of
the requirement for the
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CERTIFICATION OF APPROVAL

Assessment on Immiscible Water Alternating Gas Implementation for Optimum Recovery from an Identified Heterogeneous, Non-Apparent Fluid Contact Reservoir

by

Muhammad Hafiz Bin Khairul Azmi

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Approved by,

(AP Dr Ismail M Saaid)

UNIVERSITI TEKNOLOGI PETRONAS

TRONOH, PERAK

January 2011

CERTIFICATION OF ORIGINALITY

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

M HAFIZ KHAIRUL AZMI

ABSTRACT

Water alternating gas, WAG seems to be the most practical EOR for Malaysian fields considering the abundance of CO_2 gas and the availability of treated seawater for injection. The injected seawater is used to increase the macroscopic displacement whereas the injected CO_2 gas is used to mobilize the residual oil to further enhance the sweep at microscopic level. The present study evaluates the influence of voidage replacement ratio (VRR) and WAG cycles to the incremental recovery factor. A dynamic model was developed by using Eclipse 100 to assess the incremental recovery from the implementation of WAG on a heterogeneous, non-apparent fluid contact oil reservoir offshore Terengganu. The study found that the predicted incremental recovery of 7% was insensitive to both VRR and WAG cycles. This incremental recovery was almost the same with the one obtained from the secondary recovery. This could be due to the complexity of the reservoir structure itself which requires further refinement on the locations of the injectors' perforation. Early gas breakthrough was observed in almost all simulated WAG cycles cases that ranged from 3 to 12 months and VRR cases that ranged from 50% to 150%. Therefore, the present study recommends WAG optimization involving assessment of the individual producing well performance.

ACKNOWLEDGEMENT

First and foremost, I would like to praise Allah s.w.t. for His guidance. Though difficulties occurred, His guidance gave me the chance and strength for me to pursue and strive for excellence especially in the Final Year Project (FYP).

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ABBREVIATIONS AND NOMENCLATURES

μg	: Gas Viscosity
μo	: Oil Viscosity
CO_2	: Carbon Dioxide
EDX	: Engineering Design Exhibition
Eh	: Horizontal Displacement Efficiency
Em	: Microscopic Displacement Efficiency
Ev	: Vertical Displacement Efficiency
FVDG	: Field Voidage
GI	: Gas Injection
GOR	: Gas Oil Ratio
IOR/EOR	: Improved Oil Recovery/Enhanced Oil Recovery
krg	: Gas Relative Permeability
kro	: Oil Relative Permeability
LRAT	: Liquid Rate
M	: Mobility Ratio
NFA	: No Further Activity
PermX	: Horizontal Permeability in X Direction
PermZ	: Vertical Permeability in Z Direction
RESV	: Reservoir Rate
Rf	: Recovery Factor
VRR	: Voidage Replacement Ratio
WAG	: Water Alternating Gas
WI	: Water Injection

CHAPTER 1

INTRODUCTION

With the abundance of CO_2 gas in Malaysian fields for gas injection and the availability of treated sea water for, it is evaluated that Immiscible Water Alternating Gas is the most suitable to be implemented in the maturing Malaysian Oil Fields. Miscible WAG is also suitable to be implemented in the maturing oil fields; however it is essential that the reservoir pressure do not drop below the miscibility pressure. If this were the case, then miscibility cannot be achieved.

Initially, Water Alternating Gas process is implemented to improve sweep efficiency during gas injection. The unswept hydrocarbon zones, especially attic and cellar oil can be recovered by exploiting the segregation of gas to the top or the accumulating of water towards the bottom. The residual oil after gasflooding is normally lower than the residual oil after waterflooding translates into lower remaining oil saturation in the three-phase zones. Therefore, it is concluded that WAG implementation can be used to recover more hydrocarbon by combining better mobility control and contacting unswept zones, and by leading to improved microscopic displacement (Christensen *et al*, 1998).

This report concentrates around the literature review on secondary recovery, tertiary recovery, Enhanced Oil Recovery concepts, and design factor of WAG process. A dynamic model is developed by using Schlumberger Eclipse to run evaluations on each recovery methods on the identified Malaysian Field.

1.1 PROBLEM STATEMENT

1.1.1 Problem Identification

Some of the identified maturing fields in Malaysia have reached the stage whereby declining production rate and reservoir pressure as well as increasing GOR and watercut trending can be observed. At this point, the recovery can be further improved by implementing secondary recovery such as water injection and gas injection for pressure maintenance, macroscopic and microscopic displacement.

Sometime after secondary recovery is implemented, further increase in either watercut or GOR can be observed, indicating that the initiative is no longer efficient to be used. At this moment, tertiary recovery should be implemented to further enhance the recovery.

The macroscopic displacement efficiency is characterized by horizontal displacement efficiency and vertical displacement efficiency by the injected water. The microscopic displacement efficiency is characterized by the relatively low viscosity of the injected gas. Relatively low viscosity gas causes unstable displacement efficiency, which eventually fingers into the oil column and causing early gas breakthrough.

Therefore, WAG is implemented to compensate the unfavorable mobility ratio since the viscosity of the injected water is relatively high, which causes favorable mobility ratio. The combined mobility ratio of the two phases is less than that of the injected gas alone, improving the displacement efficiency. The injected gas dissolves into the residual oil, mobilizing the oil towards the producing wells.

1.1.2 Significant of the Project

The findings from the research and project will provide a better understanding of Water Alternating Gas mechanism to improve recovery from a matured reservoir. The main factors affecting the recovery mechanism will be evaluated through numerical computer simulation in order to come up with the key parameter to ensure the success of Water Alternating Gas project in the future.

1.2 OBJECTIVE AND SCOPE OF STUDIES

The objectives of the study are:

- To evaluate the effectiveness between water injection, gas injection and Water Alternating Gas in terms of the incremental recovery
- To assess important parameters affecting Water Alternating Gas such as WAG cycle, and injected voidage replacement ratio

This project focuses on a Dynamic Black Oil Model of an identified brown field in Malaysia, where the following analysis will be conducted:

1. Case 1: Primary Recovery with No Further Activity
2. Case 2: Primary Recovery with Infill Drilling
3. Case 3: Secondary Recovery
    a. Case 3A: Water Injection
    b. Case 3B: Gas Injection
4. Case 4: Sensitivity Analysis on WAG
    a. Case 4A: WAG Cycle
    b. Case 4B: Injected Voidage Replacement Ratio

1.3 FEASIBILITY OF THE PROJECT

The author is confident that based on the scope of study and the time frame set for research; all the objectives will be achieved in providing scientific findings and observations to explain the principle behind the Water Alternating Gas to further improve recovery.

CHAPTER 2

LITERATURE REVIEW AND THEORY

2.1 Primary Recovery / No Further Activity (NFA)

Initially, hydrocarbon is stored under very high pressure inside a reservoir, and this provides a depletion energy known as natural drive. There are several types of primary recovery, which are Solution-Gas Drive, Water Drive, Gas Cap Drive, and Gravity Drainage.

2.1.1 Solution-Gas Drive

Normally, an oil reservoir contains some dissolved gas in its liquid hydrocarbon. The solution gas breaks out from the solution to provide drive energy, which assist the oil to flow up to the surface.

2.1.2 Water Drive

Water drive is a predominant source of producing energy, which comes from water encroachment from adjoining aquifer. The drive energy is provided by an aquifer that interfaces with the oil in the reservoir at the oil-water contact.

2.1.3 Gas Cap Drive

Gas cap drive derives its main source of energy from the expansion of the gas cap already existing above the reservoir. This expansion of gas cap reduces the reservoir pressure's tendency to decrease during production. The actual rate of pressure reduction is related to the gas cap size.

2.1.4 Gravity Drainage Drive

The natural segregation of oil, gas and water in the reservoir results from the density differences. This process is a relatively weak drive mechanism and only be used in combination with other drive mechanism. The best conditions for gravity drainage are thick oil zones and high vertical permeability. This mechanism is often used in addition to the other drive mechanism due to the very low rate of production.

2.2 SECONDARY RECOVERY

Secondary recovery is an initiative to improve recovery when the natural drives have diminished to unreasonably low efficiencies. Basically, there are two techniques that can be used, which are water injection and gas injection.

2.2.1 Water Injection

Water injection is implemented for pressure maintenance in order to maintain reservoir energy. This method is also known as waterflooding and is considered as secondary recovery method. The purpose is to increase oil recovery from reservoirs after the natural drive mechanisms become ineffective. Waterflooding is considered as an effective method, considering the availability of water, the relative ease of which water is injected, the ability of which water spreads through oil-bearing formations and the efficiency of water in displacing oil.

2.2.2 Gas Injection

When waterflooding application leads to poor recovery factor and low injectivity, gas injection can be very valuable. Due to the low value of interfacial tension between oil and gas phases, gas injection is implemented because it has higher microscopic displacement efficiency. Interfacial tension tends towards zero when miscibility is reached, which means it is possible that total oil recovery can be recovered in the swept area. Even if miscibility is not reached, the mass transfer mechanisms that occur between oil and gas phases lead to low interfacial tension values compared to water injection

2.3 TERTIARY RECOVERY (ENHANCED OIL RECOVERY)

Normally, primary and secondary recovery only recovers about 35% of the oil-in-place. Therefore, there is a need to further increase the recovery factor; many Enhanced Oil Recovery methods have been designed to do this. However, for this project, only Water Alternating Gas will be discussed.

2.3.1 Water Alternating Gas

Water Alternating Gas injection is an Enhanced Oil Recovery method which initially conducted to improve sweep efficiency during gas injection on top of pressure maintenance. This method is implemented by implementing water injection and gas injection alternately for a period of time. This process usually uses CO_2 for gas injection. Alternating slugs of water and gas can improve oil recovery from formation better than secondary recovery means, such as waterflooding.

Water Alternating Gas injection has the potential for increased both microscopic efficiency and macroscopic efficiencies. Macroscopic displacement is attributed to enhanced sweep efficiencies in the reservoir. Microscopic displacement by gas is generally better than water; therefore Water Alternating Gas method utilizes this characteristic in addition to improved macroscopic sweep by water injection which in return increases the recovery.

Gas injection in WAG develops a miscible front at pressure close to the minimum miscibility pressure (MMP) due to the mass transfer between the injected gas and the reservoir oil. This in return enhances recovery. Other than that, immiscible gasflooding can also increase recovery through swelling, viscosity reduction, and extraction.

WAG injection process are affected by the reservoir heterogeneity (stratification and anisotropy), rock wettability, injection technique and WAG parameters such as cycling frequency, slug size, WAG ratio and injection rate.

2.3.2 Miscible WAG Injection

A miscible WAG injection is the situation where miscibility is developed along the gas slug as gas displaces the oil. However, due to an uncertainty of the actual displacement process, it is very difficult to distinguish between miscible and immiscible WAG injection. In a miscible WAG injection, the reservoirs are usually repressurized to a pressure above the minimum miscibility pressure (MMP) of the fluid. If the minimum miscibility pressure is not achieved, it will cause the project to suffer from oscillating between miscible and immiscible gas during the life of the production.

2.3.3 Immiscible WAG Injection

An immiscible WAG injection is the situation where the injected gas could not develop miscibility with oil. This type of WAG is usually conducted in a reservoir that has limited gas resource or reservoir properties. The condition of the reservoir makes it impossible to implement gravity-stable gas injection. Immiscible WAG is aimed to improve frontal stability or contact unswept zones on top of improved microscopic displacement efficiency. Sometimes, the first gas slug dissolves to some degree into the oil, causing mass exchange (swelling and stripping) and a favorable change in the fluid viscosity/density relations at the displacement front. This in return changes the behavior of immiscible WAG injection to become near-miscible.

2.4 ENHANCED OIL RECOVERY CONCEPT

The purpose of implementing Enhanced Oil Recovery is to obtain higher recovery factor. The recovery factor obtained from EOR is a product of the macroscopic (or volumetric) displacement efficiency and the microscopic displacement efficiency, which can be described by three contributions, as follows:

$$R_f = E_v \,.\, E_h \,.\, E_m \tag{2.1}$$

Where E_v is vertical sweep, E_h is horizontal sweep, and E_m is microscopic displacement efficiency. Maximizing any or all of the three factors will optimize the recovery factor.

In a miscible displacement operation, the residual oil saturation in the flooded area tends to go toward zero whereas in an immiscible displacement operation, the residual oil saturation in the flooded area do not go towards zero. However, the remaining oil saturation after gasflooding is usually lower than after waterflooding, which indicates that gas has better microscopic displacement efficiency than water.

2.4.1 Macroscopic Displacement Efficiency

Macroscopic displacement efficiency is defined as a measure of how well the displacing fluid has contacted the oil-bearing parts of the reservoir. The macroscopic displacement efficiency is subdivided into two other terms namely vertical sweep efficiency and horizontal sweep efficiency.

2.4.1.1 Horizontal Displacement Efficiency

The horizontal displacement efficiency is related to the stability of the front, which can be described by the mobility of the fluids. The mobility ratio M is defined as follows:

$$M = \frac{k_{rg}/\mu_g}{k_{ro}/\mu_o} \tag{2.2}$$

Where k_{rg} and k_{ro} are the relative permeabilites and μ_g and μ_o are the viscosities for gas and oil, respectively. Unfavorable mobility ratio causes the gas to finger (or channel), resulting in early gas breakthrough and decreasing the sweep efficiency.

2.4.1.2 Vertical Displacement Efficiency

The vertical sweep efficiency is related to the viscous and gravitational forces, which can be expressed as follows:

$$R = \left(\frac{v\mu_o}{kg\Delta\rho}\right)\left(\frac{L}{h}\right) \tag{2.3}$$

Where vI = Darcy velocity, μ_o = oil viscosity, L = distance between the wells, k = permeability to oil, g = gravitational force, $\Delta\rho$ = density difference between fluids, and h = height of the displacement zone.

Reservoir dip angle and variation in permeability and porosity affects the vertical sweep efficiency. Normally, porosity and permeability increasing downward trends will be an advantage for WAG injection because this combination increases the stability of the front.

2.4.2 Microscopic Displacement Efficiency

The microscopic displacement efficiency is defined as a measure of how well the displacing fluid mobilizes the residual oil once the fluid has contacted the oil. Microscopic displacement efficiency can be characterized by the interfacial tension, rock wettability, capillary pressure and relative permeability.

2.5 DESIGN FACTORS OF WAG PROCESS

2.5.1 Vertical Well Completions

Considering the density of gas and liquid, a gas injector well should be located at the lower part of the formation and a water injector well should be located at the upper part of the reservoir. The injected gas will flow upwards, expanding the contact area with oil in-situ, while the injected water will flow downwards, sweeping oil to the producing well. This is known as gravity segregation effect. However, the gravity segregation effect may vary with the heterogeneity of the reservoir. Injected fluids will tend to flow in the higher permeability section of the reservoir. Therefore, production well must not be completed in a high permeability region as this will cause the gas to channel between injector and producer.

2.5.2 Horizontal Well Configuration

Another way to increase volumetric sweep efficiency is by drilling horizontal wells. This well enhances the volumetric sweep efficiency and the miscible gas storage in the reservoir. It has been proven that the longer the horizontal well section length, the higher the oil recovery.

2.5.3 WAG Ratio

Water injection is aimed for pressure maintenance. At times, the reservoir is repressurized to a higher reservoir pressure. The gas injection at the same time will dissolve in the oil, enhancing miscibility and reducing the oil viscosity. If the WAG ratio is high whereby too much water is injected, then the production performance will behave like a waterflooded reservoir. If the WAG ratio it low whereby too much gas is injected, the production performance like a gasflooded reservoir. This will result in rapid pressure decline, early gas breakthrough and production decline.

2.5.4 Injection Front Stability

Injection front stability has an impact to the ultimate recovery. It is related to the mobility ratio, where a lower mobility ratio gives better displacement stability. Instable displacement usually happens when the injected gas is very low in viscosity, which results in gas segregation and fingering. The same condition goes to water injection, whereby low injected water viscosity may cause fingering, results in lower recovery. In order to overcome this problem, solvent can be added to the injected water to increase the viscosity of the injected water.

2.5.5 Injected Voidage Replacement Ratio

The voidage replacement ratio works by balancing the reservoir voidage. In other words, the objective is to obtain pressure maintenance by injecting the same volume of fluids produced from the reservoir. The ratio is defined as the injected reservoir volume to the produced reservoir volume, which is given by the following formula:

$$VRR = \frac{Injected\ reservoir\ volume}{Produced\ reservoir\ volume} \quad (2.4)$$

If the ratio exceeds the value of 1.0, which means the injected fluid volume exceeds the produced fluid volume; then the reservoir is pressurized. Else, the reservoir pressure declines at a lower rate.

Other than maintaining the reservoir pressure, VRR is used to displace the oil towards the producing wells or to achieve miscibility with the oil in the case of miscible gas injection.

2.6 DYNAMIC MODELLING BY USING ECLIPSE

Basically, six (6) important keywords will be used in the SCHEDULE section for this project, which are WELSPECS, COMPDAT, GCONINJE, WCONINJE, WCYCLE, and WELOPEN.

2.6.1 Schedule Section

The SCHEDULE section specifies the operations to be simulated (production and injection control and constraints) and the times at which output reports are required (Eclipse Reference Manual, 2009).

2.6.2 WELSPECS Keyword – General Specification Data for Wells

The purpose of including the keyword in the data file is to introduce a new well, defining its name, the position of the wellhead, its bottom hole reference depth and other specification data.

2.6.3 COMPDAT Keyword – Well Completion Specification Data

The purpose of including the keyword in the data file is to specify the position and properties of one or more well completions. This is where the location of the perforation is defined.

2.6.4 GCONINJE Keyword – Injection Rate Controls/Limits for Field

The purpose of including the keyword in the data file is to specify the targets and limits for groups. The injection rate control modes available are as follows:

- NONE : No immediate control of injection rate
- RATE : The field surface injection rate of the phase is controlled to meet the target defined
- RESV : The field reservoir volume injection rate of the phase will be controlled to meet the target defined
- REIN : The field reservoir volume injection rate of the phase will be controlled so that the total volume injection rate of the field meets the target defined

- VREP : The field reservoir volume injection rate of the phase will be controlled so that the total reservoir volume injection rate of the field equals its production voidage rate times the voidage replacement fraction defined

2.6.5 WCONINJE Keyword – Control Data for Injection Wells

The purpose of the keyword in the data file is to specify the targets and limits for the injection wells. The injection rate control modes available are as follows:

- RATE : Controlled by surface flow rate target
- RESV : Controlled by reservoir volume target rate
- BHP : Controlled by BHP target
- THP : Controlled by THP target

2.6.6 WCYCLE Keyword – Automatic Cycling of Wells On and Off

The purpose of the keyword in the data file is to provide the means of automatically cycling wells on and off for specified intervals of time. This keyword is used to simulate a WAG process, where the injection well is represented by separate water and gas injectors that are cycles on and off alternately. The WELOPEN keyword is used to define the initial status of the injection well, either open or shut at the moment. The cycling duration in the WCYCLE keyword will take care for the rest of the cycle.

CHAPTER 3

RESEARCH METHODOLOGY

3.1 PROJECT ACTIVITIES

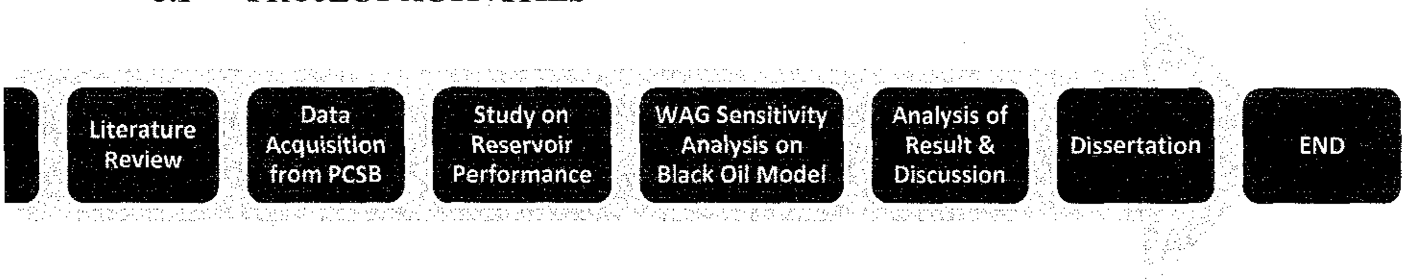

Figure 3.1: Project activities throughout Final Year Project II

The Final Year Project 2 consists of six (6) phases, which are Literature Review, Data Acquisition from PCSB, Study on Reservoir Performance, WAG Sensitivity Analysis on Black Oil Model, Analysis of Results & Discussion, and Dissertation. During Final Year Project 1, Material Balance Model has been covered, where the findings from the analysis are as follows:

1. Water injection with 100% VRR gives higher ultimate recovery and pressure maintenance compared to gas injection with 100% VRR
2. Water Alternating Gas (with 100% VRR) gives the highest recoveries and incremental recovery after gas injection (with 100% VRR)

The recommendation from the Final Year Project 1 analysis is to run the study by using dynamic simulator with real field data to simulate the actual incremental field production after tertiary recovery.

The real field data was acquired from PETRONAS Carigali Sdn Bhd with respective approvals from Vice President Office, PETRONAS Management Unit (PMU) and Dulang Resource Study team. Next, the author allocated approximately one (1) month to study on the field and reservoir performance. The author allocates another two (2) months for WAG Sensitivity Analysis on Black Oil Model in order to find the incremental recovery from each of the initiatives. At the end of the project, the sensitivity analysis will be discussed and written in the report for future references.

3.2 PROJECT METHODOLOGY

Figure 3.2: Project methodology

The objective of the project is to investigate the most suitable secondary and tertiary recovery initiatives to be implemented in order to obtain the highest incremental recovery. Sensitivity analysis on injected voidage replacement ratio and WAG cycle will be conducted in order to further increase incremental recovery. An identified brown field offshore Terengganu, Malaysia is selected for the case study.

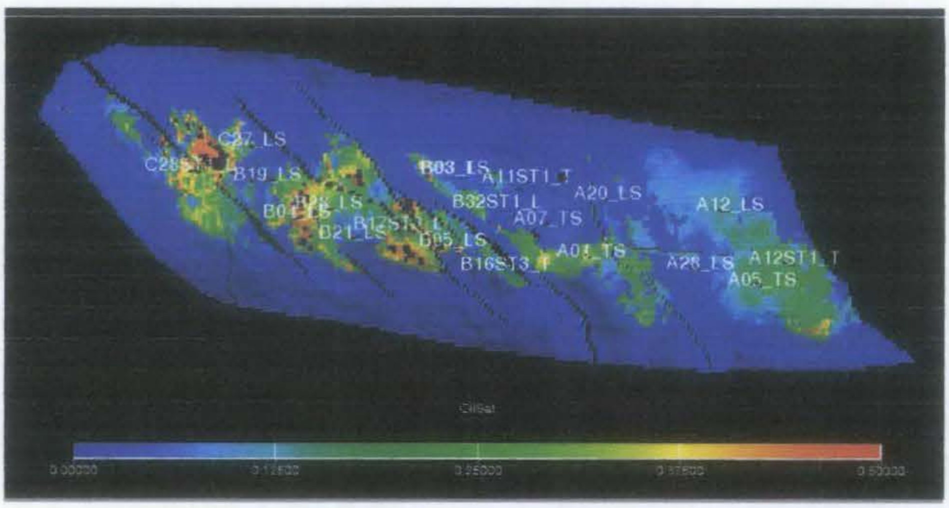

Figure 3.3: Oil saturation map at 1st November 2008

The reservoir of interest has Oil Initially In Place of 103.22 MMstb. It has 12 fault blocks; however there are only five (5) fault blocks with the potential to produce additional reserves from the reservoir of interest, namely N1, S2, SE1, SE2 and N3C. The reservoir has been in production since 1st March 1991 with a cumulative production total of 17.77 MMstb at 1st November 2008. This indicates that the reservoir still has the potential to produce more oil through the implementation of secondary and tertiary recovery initiatives. The economic constraints defined are minimum oil flow rate of 30 bbl/d, maximum watercut of 0.96, and maximum GOR of 8 Mscf/day for each individual well due to the capacity constraint by the surface facilities.

3.2.1 RESERVOIR SIMULATION VIA ECLIPSE E100

Several production predictions are generated from Eclipse E100 simulation runs to assess the most suitable initiative to be implemented in this reservoir.

The reservoir simulation data file consists of 8 sections, namely Runspec, Grid, Edit, Props, Regions, Solution, Summary and Schedule sections. For this project, the author concentrates on the Schedule section as the remaining section of the data file has been prepared by the engineers from PETRONAS Carigali Sdn Bhd. The major keywords used in the Schedule section which the author wishes to highlight are WCONPROD, WCONINJ, WCYCLE, and WELOPEN. These are the keywords required in order to simulate the WAG implementation.

The following shows a portion of the Schedule section related to production control definition:

```
WCONPROD

A07_TS              OPEN   LRAT   3*    400.00   600 /
A12ST1_TS           OPEN   LRAT   3*    600.00   600 /
A20_LS              OPEN   LRAT   3*    900.00   600 /
B04_LS              OPEN   LRAT   3*    800.00   600 /
B05_LS              OPEN   LRAT   3*    200.00   600 /
B19_LS              OPEN   LRAT   3*    500.00   600 /
B21_LS              OPEN   LRAT   3*    500.00   600 /
B32ST1_LS           OPEN   LRAT   3*    100.00   600 /
B03_LS              OPEN   LRAT   3*    1600.00  600 /
C27_LS              OPEN   LRAT   3*    500.00   600 /
AX_N3C_1            OPEN   LRAT   3*    900.00   600 /
AX_SE2_3&N3E_1      OPEN   LRAT   3*    900.00   600 /
AX_N3C_2_E3236      OPEN   LRAT   3*    900.00   600 /
AX_SE2_1            OPEN   LRAT   3*    900.00   600 /
B_S2_2&S2_1         OPEN   LRAT   3*    500.00   600 /
/
```

WCONPROD is the well control production keyword, used to control the production in terms of the production rate and bottomhole pressure.

WCONINJ is the well control injection, used to control the injection in terms of the voidage replacement ratio, injection rate constraint and bottomhole pressure. WCYCLE and WELOPEN are the keywords as specifically defined for WAG implementation. The WCYCLE keyword determines the injection duration for each phase while the WELOPEN keyword determines the well that should be flowing and shut.

The following shows a portion of the Schedule section related to WAG implementation:

```
WCONINJ
W_A01_TS            WAT   OPEN   RESV   1*    0    0.2    FVDG   2200   /
W_B06               WAT   OPEN   RESV   1*    0    0.2    FVDG   2200   /
W_B15               WAT   OPEN   RESV   1*    0    0.2    FVDG   2200   /
W_SE2_INJ1          WAT   OPEN   RESV   1*    0    0.2    FVDG   2200   /
W_N3C_INJ1          WAT   OPEN   RESV   1*    0    0.2    FVDG   2200   /
G_A01_TS            GAS   OPEN   RESV   1*    0    0.2    FVDG   3000   /
G_B06               GAS   OPEN   RESV   1*    0    0.2    FVDG   3000   /
G_B15               GAS   OPEN   RESV   1*    0    0.2    FVDG   3000   /
G_SE2_INJ1          GAS   OPEN   RESV   1*    0    0.2    FVDG   3000   /
G_N3C_INJ1          GAS   OPEN   RESV   1*    0    0.2    FVDG   3000   /
/

WCYCLE
W_A01_TS     91.2   91.2   1*    10    YES   /
W_B06        91.2   91.2   1*    10    YES   /
W_B15        91.2   91.2   1*    10    YES   /
W_SE2_INJ1   91.2   91.2   1*    10    YES   /
W_N3C_INJ1   91.2   91.2   1*    10    YES   /
G_A01_TS     91.2   91.2   1*    10    YES   /
G_B06        91.2   91.2   1*    10    YES   /
G_B15        91.2   91.2   1*    10    YES   /
G_SE2_INJ1   91.2   91.2   1*    10    YES   /
G_N3C_INJ1   91.2   91.2   1*    10    YES   /
/

DATES
1 JAN 2021 /
1 FEB 2021 /
1 MAR 2021 /
/

WELOPEN
W_A01_TS     OPEN   /
W_B06        OPEN   /
W_B15        OPEN   /
W_SE2_INJ1   OPEN   /
W_N3C_INJ1   OPEN   /
/
```

Sensitivity analysis on voidage replacement ratio and WAG cycle is done by manipulating the defined items in the WCONINJ and WCYCLE keywords.

3.2.2 N1 Fault Block Background

There are three (3) producers in N1 Fault Block, which are B19_LS, C27_LS and C28ST1_LS. Currently two producers are flowing namely C27_LS and B19, however both are showing high watercut trending. The injector well is B06, which is located at the boundary of the oil, with the objective to displace oil to C27_LS and B1.

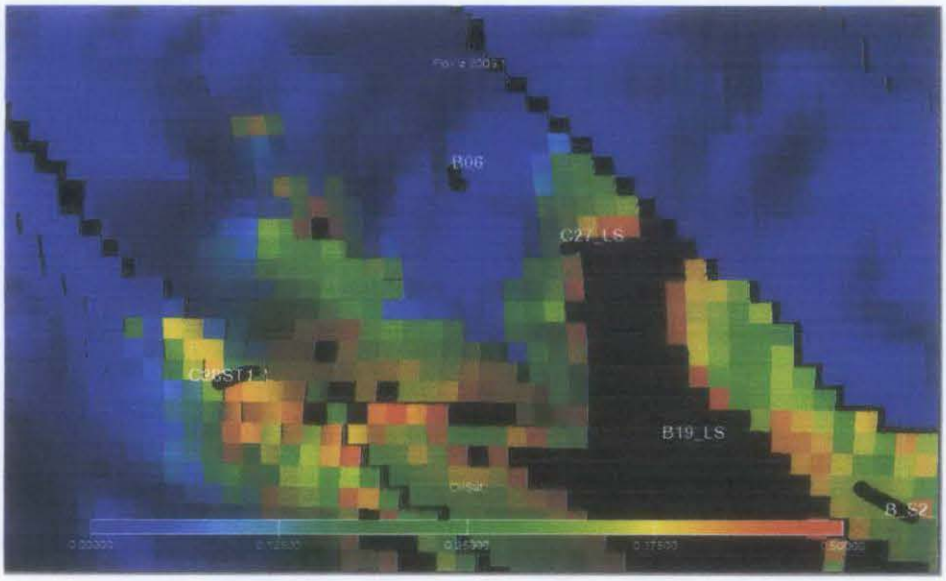

Figure 3.4: Oil saturation map at N1 Fault Block layer K-4

Looking at the oil saturation map in Figure 3, a considerable amount of oil saturation can be seen around B19_LS and C27_LS. B19_LS and C27_LS wells recorded a value of 0.66 and 0.51 of oil saturation, respectively. However, C28ST1_LS has been shut-in due to low oil saturation value around the well.

The horizontal permeability (PermX) at this location is excellent, with an average of 1000 mDarcy around C27_LS and B19_LS. However, the horizontal permeability at B06 injector is relatively lower, which is 208.60 mDarcy.

The vertical permeability (PermZ) at this location is good, with an average of 100 mDarcy around C27_LS and B19_LS. However, the vertical permeability at B06 injector is only 20.860 mDarcy. The acceptable value of vertical permeability in this region might suggest that gravity segregation effect might take place when WAG is implemented.

3.2.3 S2 Fault Block Background

There are three (3) producers in S2 Fault Block, which are B_S2_2&S, B28_LS and B04_LS. Currently two producers are flowing namely B_S2_2&S and B04_LS, however both are showing high watercut trending. The injector well is B15, which is located at the boundary of the oil, with the objective to displace oil to B04_LS and B_S2_2&S.

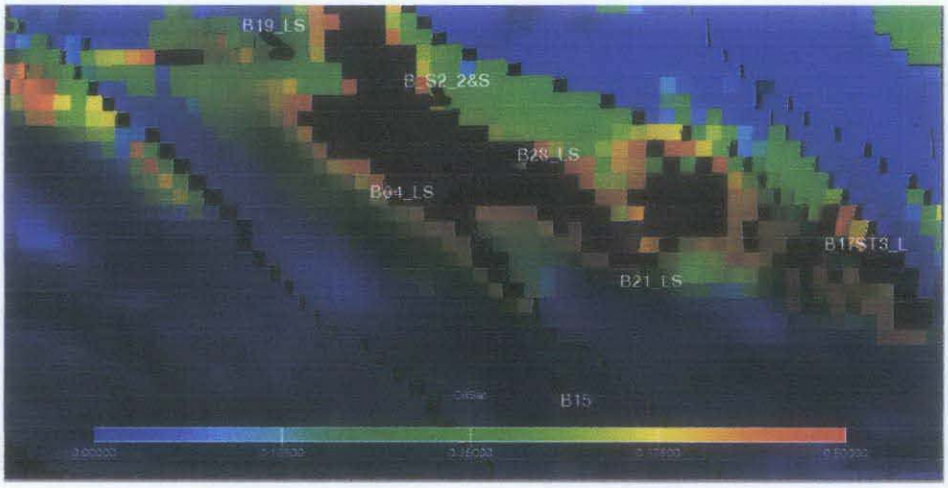

Figure 3.5: Oil saturation map at S2 Fault Block layer K-9

Looking at the oil saturation map in Figure 3, a considerable amount of oil saturation can be seen around B04_LS, B28_LS and B_S2_2&S. B04_LS, B28_LS and B_S2_2&S wells recorded a value of 0.65, 0.63 and 0.64 of oil saturation, respectively.

The horizontal permeability (PermX) at this location is excellent, varying from 300 mDarcy at B_S2_2&S to 500 mDarcy at B04_LS. The horizontal permeability at B15 injector is also excellent, which is 287.84 mDarcy.

The vertical permeability (PermZ) at this location is generally good, with an average of 50 mDarcy around B04_LS, B28_LS and B_S2_2&S. However, the vertical permeability at B15 injector is only 28.725 mDarcy. The relatively lower vertical permeability might suggest that gravity segregation effect might not be significant in this region.

3.2.4 SE1 Fault Block Background

In this fault block, there is only one producer and one injector. The producer is A07_TS and the injector is A01_TS.

Figure 3.6: Oil saturation map at SE1 Fault Block layer K-8

Looking at the oil saturation map, there is significant amount of oil saturation in the region. There is 0.52 of oil saturation around A07_TS and 0.23 of oil saturation around A01_TS. The objective of A01_TS is to displace oil towards A07_TS.

The horizontal permeability in this region is excellent, varying from approximately 900 mDarcy at A01_TS to 300 mDarcy at A07_TS.

The vertical permeability in this region is relatively lower, varying from 30.86 mDarcy at A07_TS to 81.710 mDarcy at A01_TS. This might suggest that gravity segregation effect might take place, however the results might not be significant.

3.2.5 SE2 Fault Block Background

There are five (5) producers in SE2 Fault Block, which are A05, A12ST1_TS, A28_LS, AX_SE1, and AX_SE2_3. The injector well is E_SE2_INJ, which is located at the boundary of the oil, with the objective to displace oil to A12ST1_TS and AX_SE2_1.

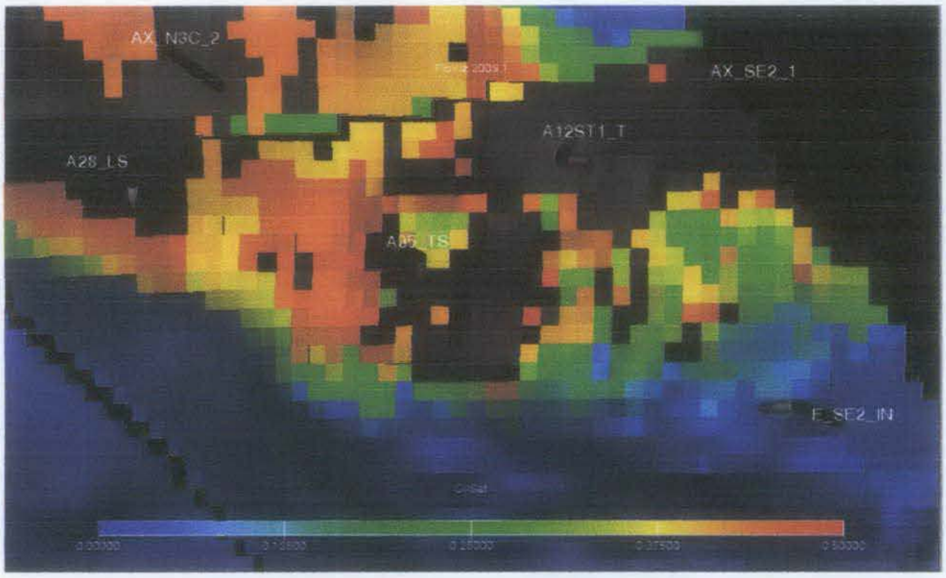

Figure 3.7: Oil saturation map at SE2 Fault Block layer K-8

Looking at the oil saturation map, there is significant amount of oil saturation in the region. There is 0.50 of oil saturation around A05_TS, 0.7 of oil saturation around A1ST1_TS and 0.70 of oil saturation around AX_SE2_1.

The horizontal permeability in this region is good, varying from 40.69 mDarcy at A05_TS to 152.79 mDarcy at A12ST1_TS. The horizontal permeability for the injection well in this region is excellent, which is 145.38 mDarcy.

The vertical permeability in this region is rather poor. All the producers have low vertical permeability, ranging from 4 mDarcy to 20 mDarcy. However, the vertical permeability of the injector is slightly higher, which is 32 mDarcy, which might suggest that gravity segregation effect may take place, though the results may not be significant.

3.2.6 N3C Fault Block Background

There are four (4) producers in N3C Fault Block, which are A12_LS, A20_LS, AX_N3C_1 and AX_N3C_2. The injector well is AX_N3C_INJ, which is located at the boundary of the oil, with the objective to displace oil to A12_LS, AX_N3C1 and AX_N3C_2.

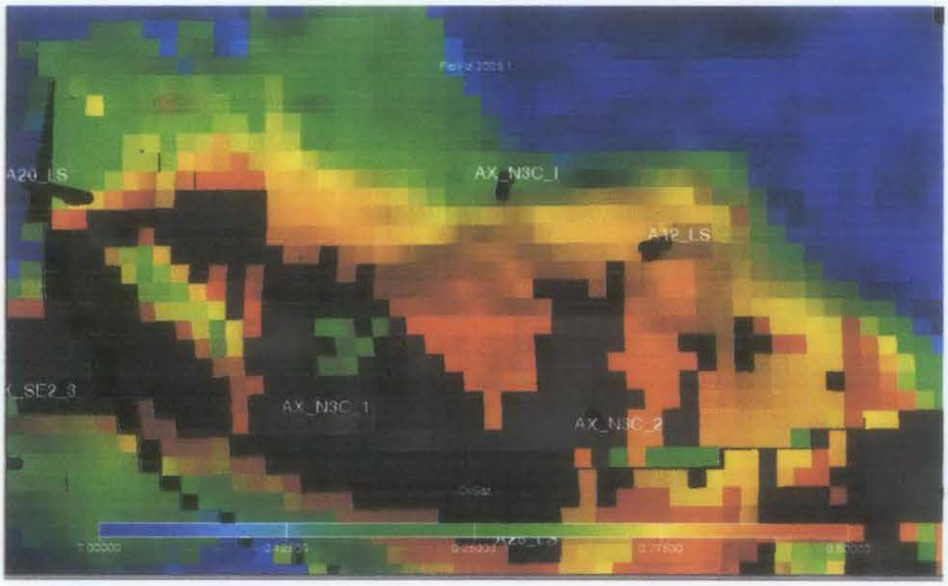

Figure 3.8: Oil saturation map at N3C Fault Block layer K-8

Looking at the oil saturation map, there is significant amount of oil saturation in the region. There is 0.57 of oil saturation around AX_N3C_1, 0.55 of oil saturation around AX_N3C_2 and 0.52 of oil saturation around A28_LS.

The horizontal permeability in this region is good, varying from 147.28 mDarcy at AX_N3C_2 to 186.66 mDarcy at AX_N3C_1. The horizontal permeability for the injection well in this region is good, which is 52.67 mDarcy.

The vertical permeability in this region is rather poor. All the producers and the injector have low vertical permeability of approximately 20 mDarcy. This suggests that gravity segregation effect will not take place in this region.

3.3 KEY MILESTONE

Table 3.1: Key milestone of Final Year Project II

Date	Activity
16th March 2011	Progress Report Submission
4th April 2011	PRE-EDX
11th April 2011	EDX
20th April 2011	Final Oral Presentation
20th April 2011	Submission of Final Report to External Examiner
4th May 2011	Submission of Hardbound Copies

3.4 GHANTT CHART

Table 3.2: Gantt Chart of Final Year Project II

Task	2	3	4	5	6	7	8	9	10	11	12	13	14
Briefing & updates	X												
Data Acquisition	X												
Project Work Commences	X												
Study on Reservoir Performance		X	X	X	X								
WAG Sensitivity Analysis				X	X	X	X	X	X	X			
Progress Report Submission							X						
Pre-EDX										X			
EDX											X		
Final Oral Presentation												X	
Delivery of Final Report to External Examiners													X
Submission of Hardbound Copies													X

3.5 TOOLS REQUIRED

Throughout the Final Year Project period, the PetroleumExpert MBal was required for Final Year Project I while the Black Oil Simulator Schlumberger's Eclipse is required for Final Year Project II.

The PetroleumExpert MBal is a material balance software that calculates the production prediction data from PVT and history-matched production and pressure data. Sensitivity analysis can be done on the model in order to further enhance the recovery.

The Black Oil Simulator Schlumberger's Eclipse can model extensive well controls and support efficient field operations planning, including water and miscible-solvent gas injection. The blackoil model assumes that the reservoir fluids consist of three phases – oil, water, and gas, with gas dissolving in oil and oil vaporizing in gas.

CHAPTER 4

RESULTS & DISCUSSION

4.1 HISTORY MATCHING

Figure 4.1 shows the amount of oil produced with respect to time from 1st March 1991 to 1st November 2008. The blue line indicates the historical production total and the green line indicates the calculated production total. From the plot, we can conclude that the model matches the historical production data.

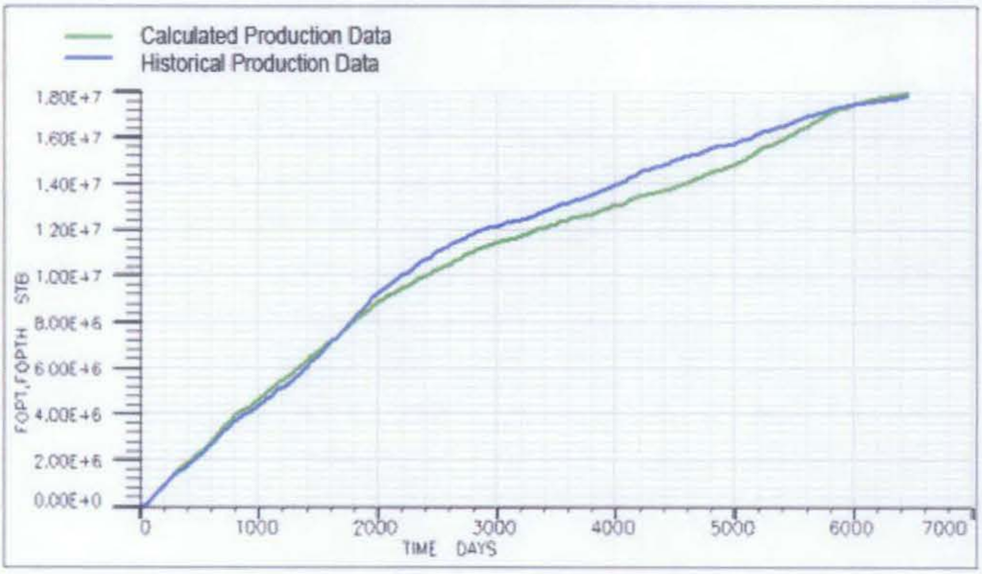

Figure 4.1: Field oil production total versus time

The cumulative oil production at 1st November 2008 is 17.7746 MMstb, which gives a recovery factor of 17.22%. The formula for the calculation of recovery factor is as follows:

$$RF = \frac{NP}{OIIP}$$

Where NP is cumulative oil produced and OIIP is Oil-Initially-In-Place. Therefore, the recovery factor is calculated as follows:

$$RF = \frac{17.7746\ MMstb}{103.22\ MMstb} = 17.22\%$$

This indicates that the field is able to produce more oil via other recovery methods such as drilling infill wells, introducing secondary and tertiary recovery methods.

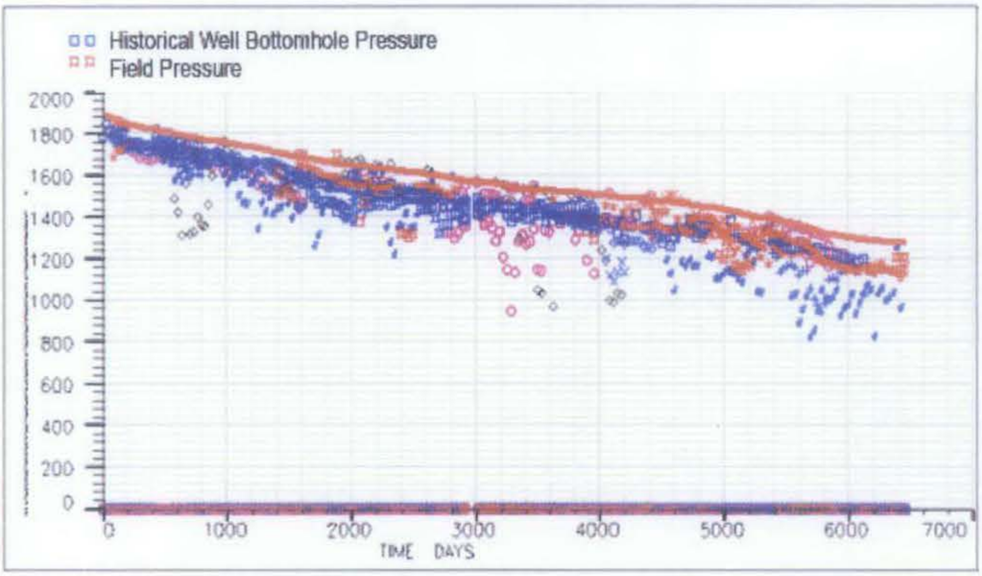

Figure 4.2: Field pressure and well bottomhole pressure versus time

Figure 4.2 shows the average field pressure and respective bottomhole pressure with respect to time. From the plot, it can be seen that the matching is acceptable. As time passes by, the reservoir pressure declines from 1885.20 psia to 1272.80 psia.

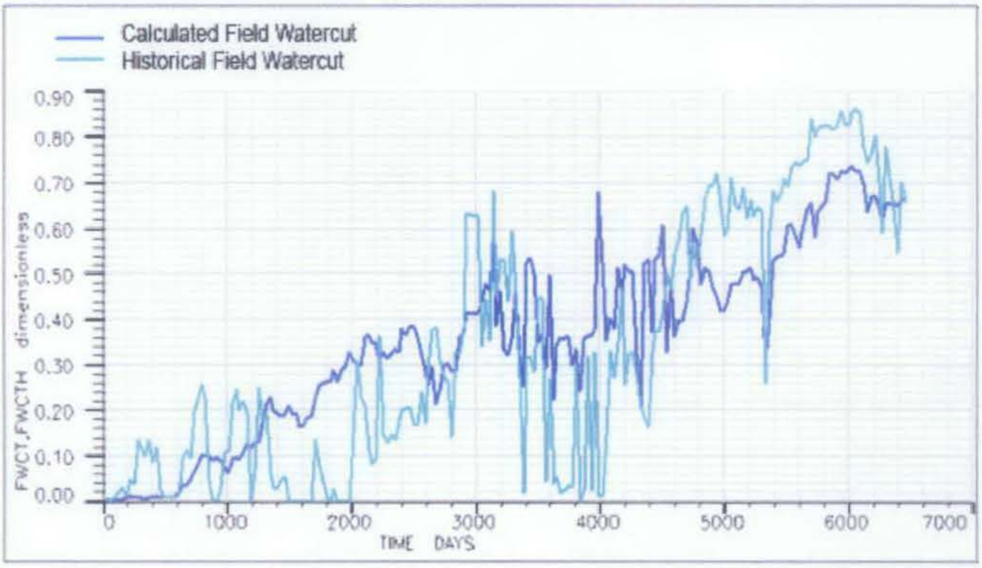

Figure 4.3: Field watercut versus time

Increasing trending of watercut can be observed from Figure 4.3, which indicates that natural drive mechanism is no longer efficient to be used to recover more oil. Therefore, there is a need for either water injection or gas injection for pressure maintenance; otherwise the pressure will continue to deplete, which consequently causes the reservoir to lose its energy.

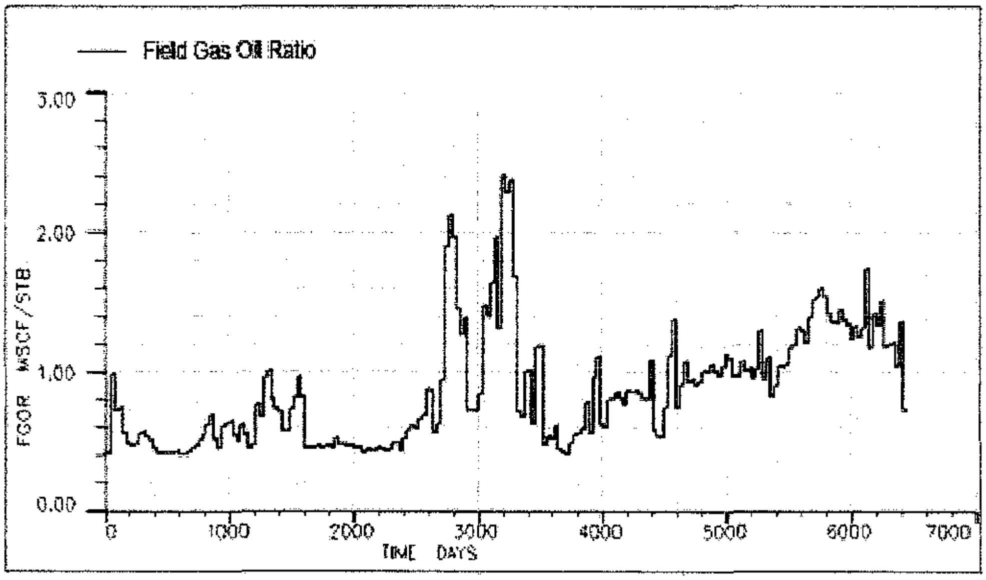

Figure 4.4: Field Gas Oil Ratio vs time

Figure 4.4 shows the field gas oil ratio plot versus time. It can be seen that the GOR is still within the acceptable range and the increase in GOR is negligible.

4.2 PRIMARY RECOVERY

Production prediction is conducted without any further initiatives on the reservoir until 1st December 2031. The predicted total oil cumulative production at 1st December 2031 is 20.92 MMstb, which translates into 20.27% of recovery factor and incremental recovery factor of 3.05%.

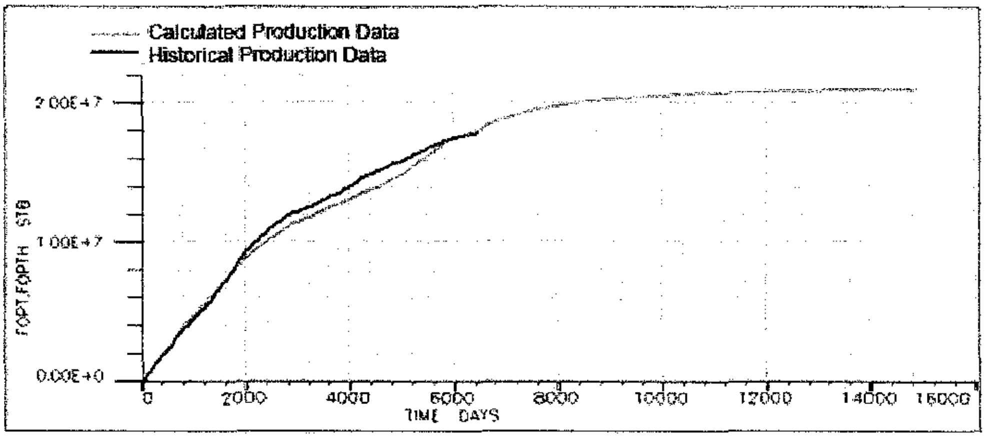

Figure 4.5: Field oil production total versus time

Figure 4.6 also indicates that if the reservoir were to continue production without any further initiatives, an increasing watercut trending can be observed.

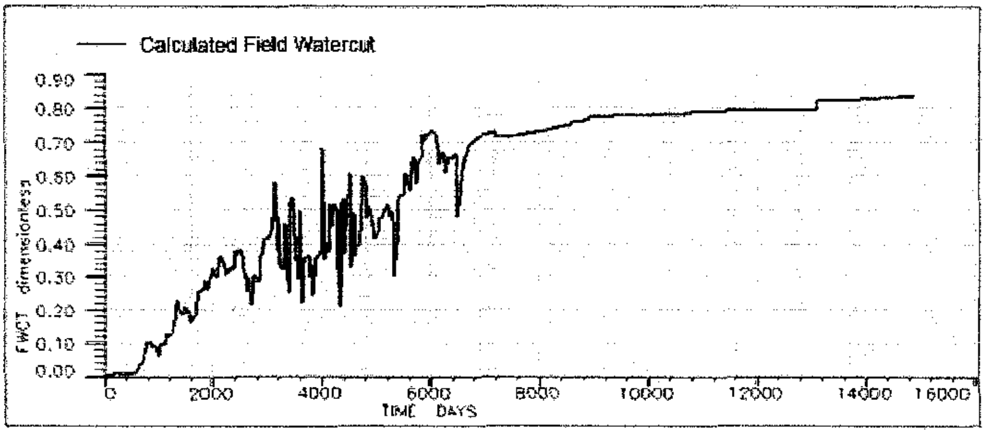

Figure 4.6: Field watercut versus time

4.3 INFILL CASE

In this case, five (5) infill wells were introduce to three (3) fault blocks with considerably high oil saturation left. The identified fault blocks with high oil saturation are N3C, SE2, and S2. The infill wells introduced are AX_N3C_1, AX_N3C_2, AX_SE2_1, AX_SE2_3, and B_S2_2&S.

Figure 4.7: Oil saturation map at S2 Fault Block layer K-9

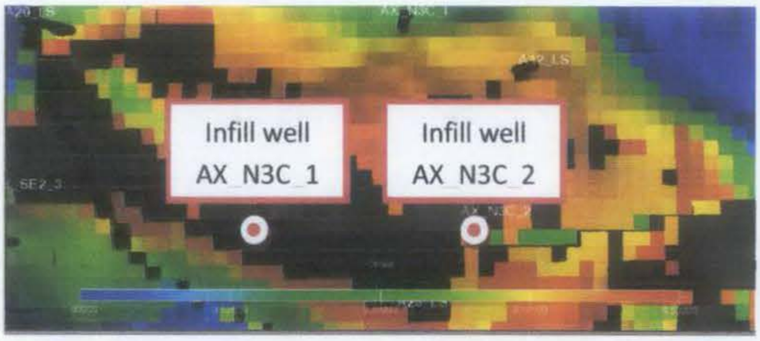

Figure 4.8: Oil saturation map at N3C Fault Block layer K-8

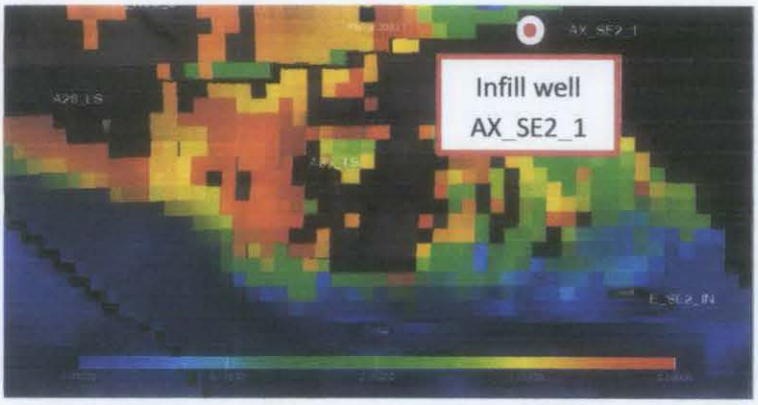

Figure 4.9: Oil saturation map at SE2 Fault Block layer K-8

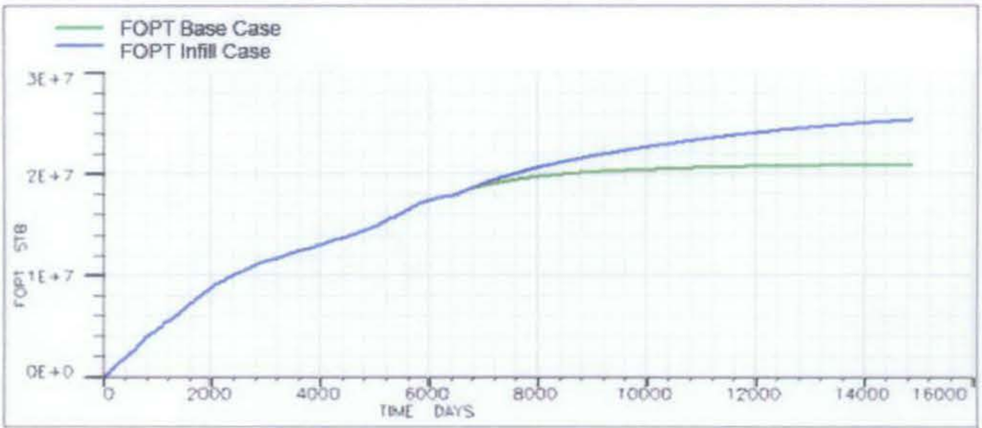

Figure 4.10: Field oil production total versus time

Figure 4.10 indicates an increase in recovery when infill wells are introduced to the reservoir. In this case, the total cumulative oil production at 1st November 2031 is 25.26 MMstb, which translates into 24.47% of recovery factor. This indicates that with the introduction of infill wells, the incremental recovery is 4.20% with respect to the case without infill wells.

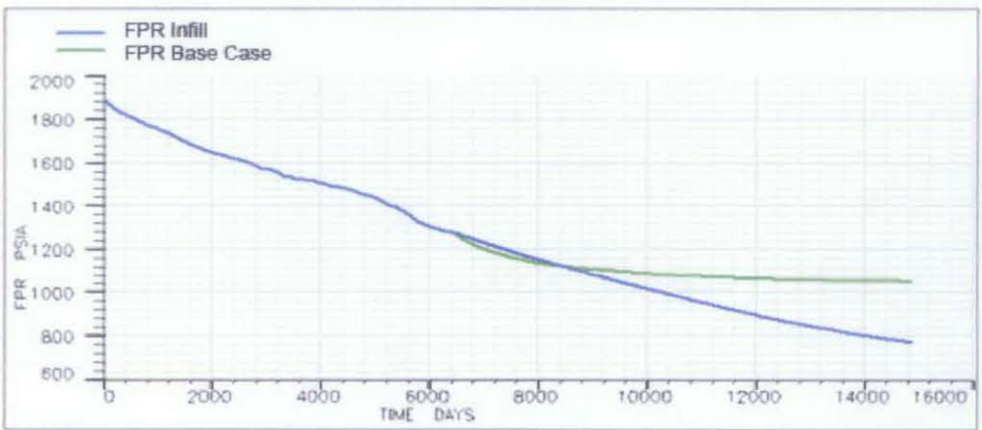

Figure 4.11: Field pressure versus time

Figure 4.11 shows the field pressure decline with respect to time. The figure shows that the case with infill wells has greater production decline compared to the case without infill wells. This is because the additional five (5) wells continued to produce, causing the pressure to deplete.

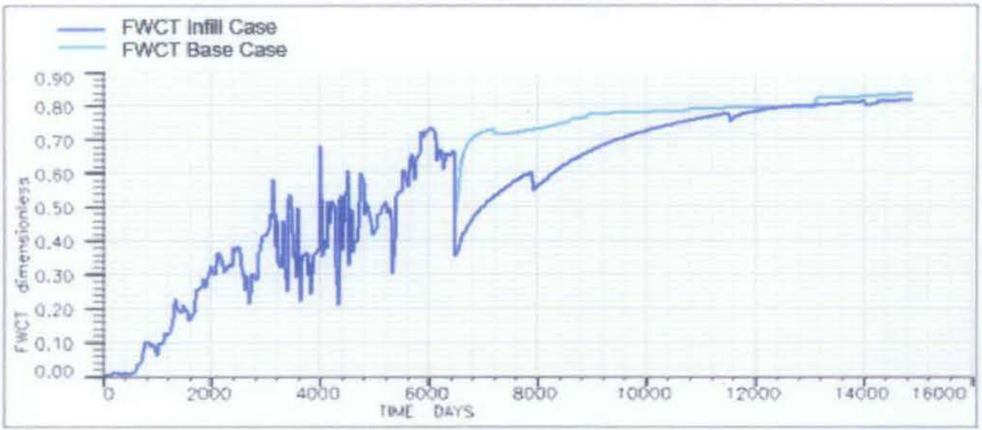

Figure 4.12: Field watercut versus time

Other than that, the field average watercut is reduced when the additional wells are introduced, because these infill wells produce with low watercut.

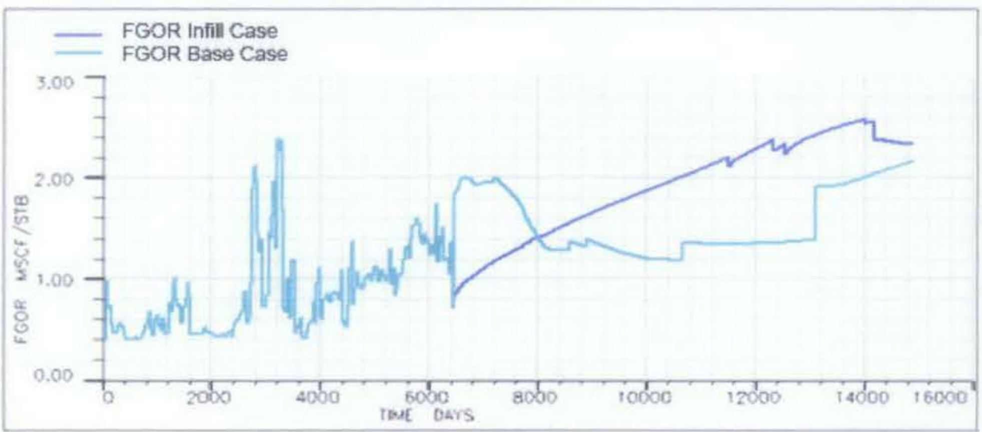

Figure 4.13: Field Gas Oil Ratio versus time

From Figure 4.13, it can be seen that GOR increases as time passes by, with the infill case producing more gas compared to the case without infill. Therefore, water injection is required to reduce GOR.

4.4 WATER INJECTION AND GAS INJECTION CASE

In this case, five (5) injection wells were introduced to five (5) fault blocks with considerably high oil saturation left. The identified fault blocks are N1, S2, SE1, SE2, and N3C. The injectors introduced are B06, B15, A01_TS, E_SE2_INJ and AX_N3C_INJ.

Figure 4.14: Oil saturation map at N1 Fault Block layer K-4

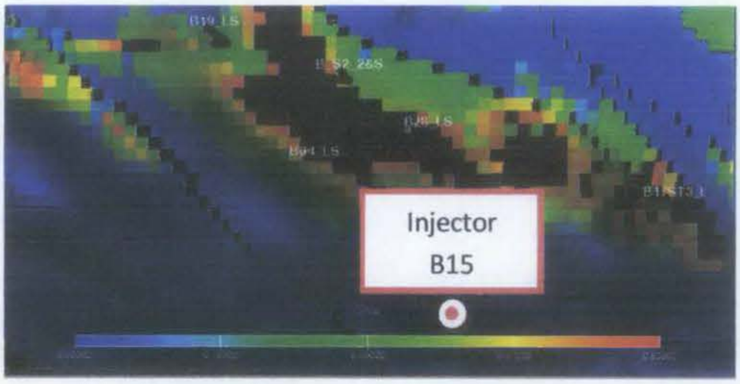

Figure 4.15: Oil saturation map at S2 Fault Block layer K-9

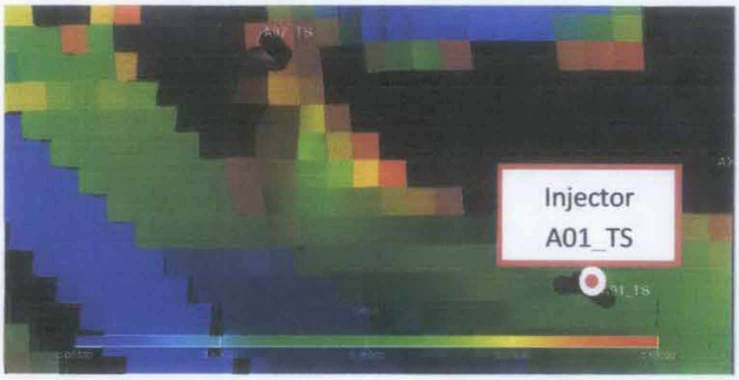

Figure 4.16: Oil saturation map at SE1 Fault Block layer K-8

Figure 4.17: Oil saturation map at N3C Fault Block layer K-8

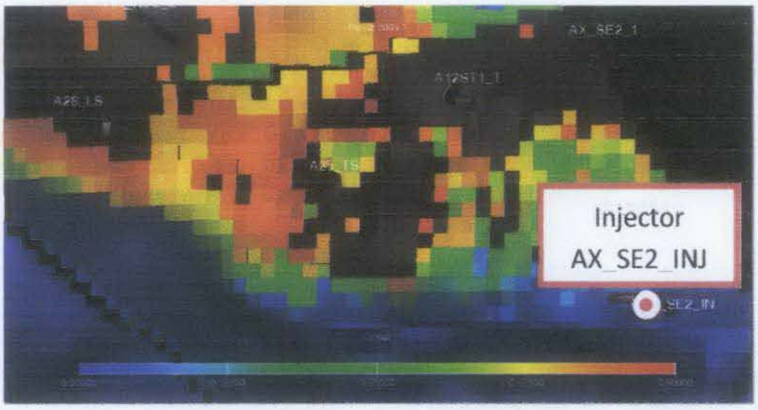

Figure 4.18: Oil saturation map at SE2 Fault Block layer K-8

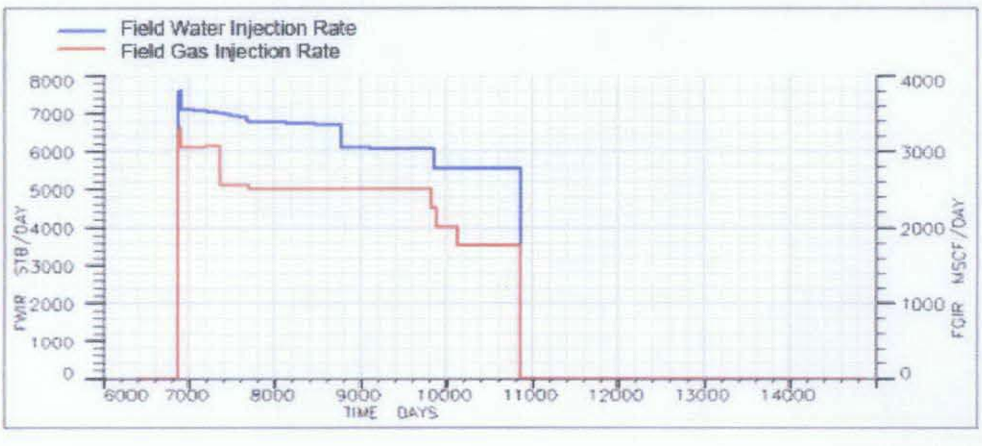

Figure 4.19: Field gas injection rate and water injection rate versus time

In this water injection and gas injection case, a voidage replacement ratio of 0.20 has been defined to each of the five injectors, making a cumulative of 1.00 voidage replacement ratio. By defining voidage replacement ratio of 1.00, the simulator injects the same voidage volume produced from the field.

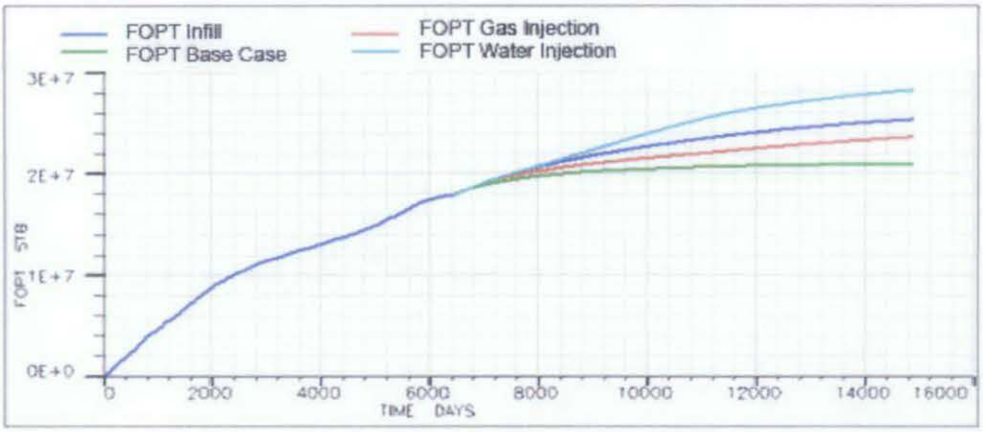

Figure 4.20: Field oil production total versus time

From Figure 4.20, it can be seen that there is an increment in recovery for the water injection case, where the total cumulative production is 28.07 MMstb. This translates into 27.20% of recovery factor, an increment of 6.93% in recovery with respect to prediction without infill. However, in the case of gas injection, it can be seen that less oil can be recovered compared to the infill case, where the cumulative oil production total is 23.59 MMstb. The recovery factor for gas injection case is 22.58%, which is 1.62% less compared to the infill well case. This is probably because of the gas break-through in each of the individual producing wells, causing some of the wells to shut-in.

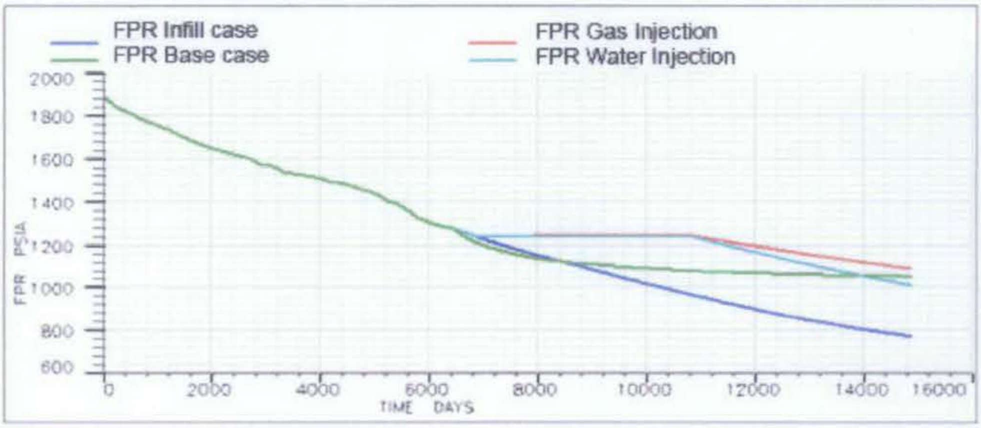

Figure 4.21: Field pressure versus time

Figure 4.21 shows the field pressure versus time for the no infill case, infill case, water injection case and gas injection case. The plot indicates that without any pressure maintenance initiatives, the infill case pressure continues to decline below 1000 psia. For the case of water injection and gas injection, the pressure is maintained at 1241.50 psia during the injection. This is because for both cases, the injected voidage replacement ratio of 1.00 injects the same voidage volume produced from the field, thus maintaining the reservoir pressure.

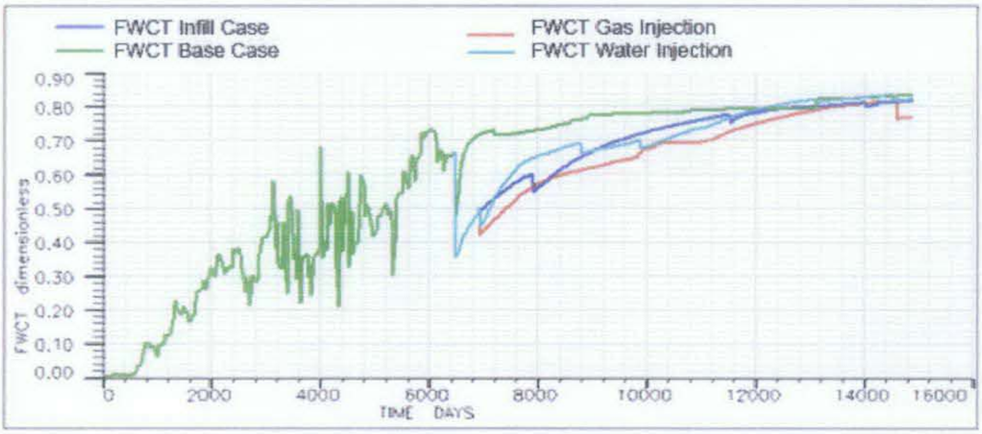

Figure 4.22: Field watercut versus time

Figure 4.22 shows the watercut versus time plot. It can be observed that throughout the production period, the watercut for the four cases are almost similar. Therefore, it is concluded that the injected water fills up the void spaces in the reservoir and no injected water were produced at the surface, thus making it an effective pressure maintenance initiatives.

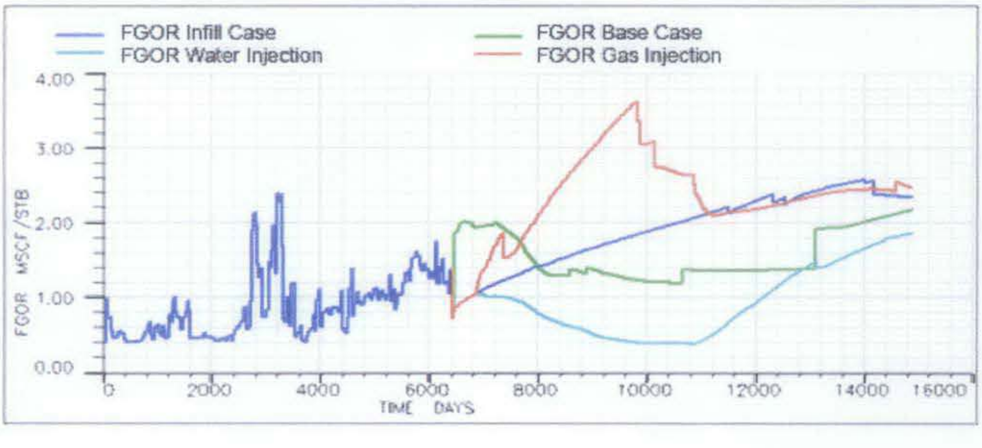

Figure 4.23: Field gas oil ratio versus time

Figure 4.23 shows the field gas oil ratio versus time. From the plot, it can be observed that gas injection case gives higher average field GOR compared to infill case. This supports the fact that some of the wells were shut-in due to early gas breakthrough. The water injection case shows lower GOR value compared to infill case, which indicates that more oil is produced from the well compared to the infill case.

4.5 WATER ALTERNATING GAS

4.5.1 Voidage Replacement Ratio Sensitivity Analysis on Gas Injectors

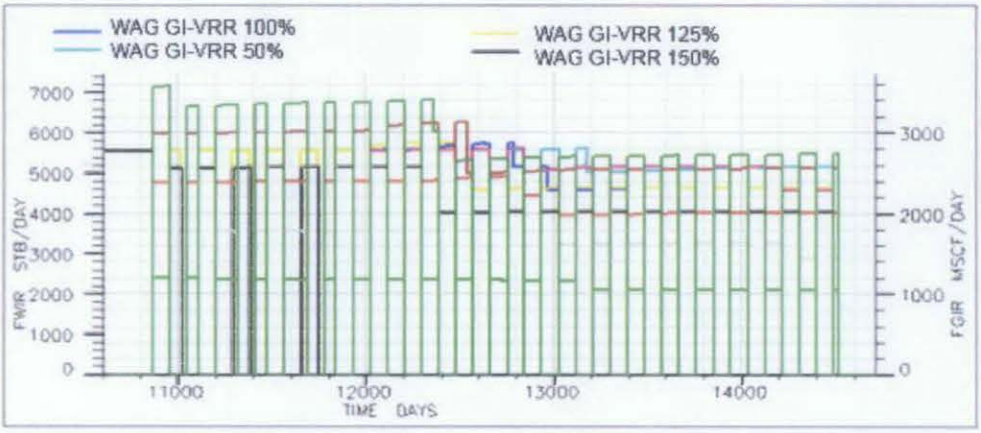

Figure 4.24: Field water injection rate and gas injection rate versus time

Five (5) voidage replacement ratio (VRR) sensitivity analysis were conducted on the gas injectors, ranging from 50% to 150%, with the water injector VRR held constant at 100%. Figure 32 shows the water injection rate and gas injection rate for each sensitivity analysis.

Figure 4.25: Field oil production total versus time

Figure 4.25 shows the field oil production total versus time for each of the VRR sensitivity analysis on gas injectors. The results are tabulated as follows:

Table 4.1: Recovery factor and incremental recovery for each sensitivity analysis

WAG VRR	RECOVERY FACTOR, %	INCREMENTAL RECOVERY, %
GI 50%	27.60	7.33
GI 75%	27.47	7.20
GI 100%	27.34	7.07
GI 125%	27.17	6.90
GI 150%	26.93	6.66

From the results obtained, it can be seen that from WAG implementation, there is an approximately 7% of incremental recovery. However, the incremental recovery is insensitive to the voidage replacement ratio sensitivity. In the table, the 50% VRR scheme gives the highest incremental recovery of 7.33% whereas the 150% VRR scheme gives the lowest incremental recovery of 6.66%. This suggests that gas injection is not efficient in displacing the oil.

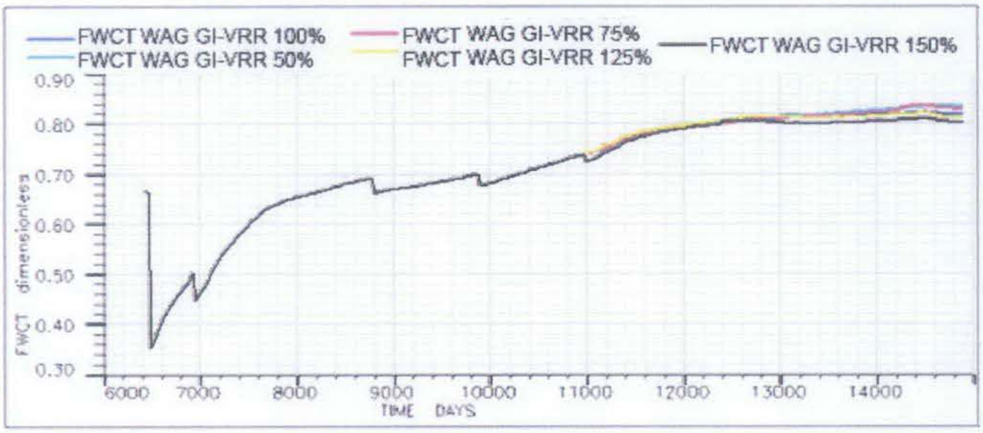

Figure 4.26: Field watercut versus time

Figure 4.26 shows the field watercut versus time. It can be seen from the plot that for each schemes, the watercut has a small variation. Thus, we can conclude that the field watercut is insensitive to VRR sensitivity on gas injectors. This may suggest that all the injected water fills the voids in the reservoir and none are produced.

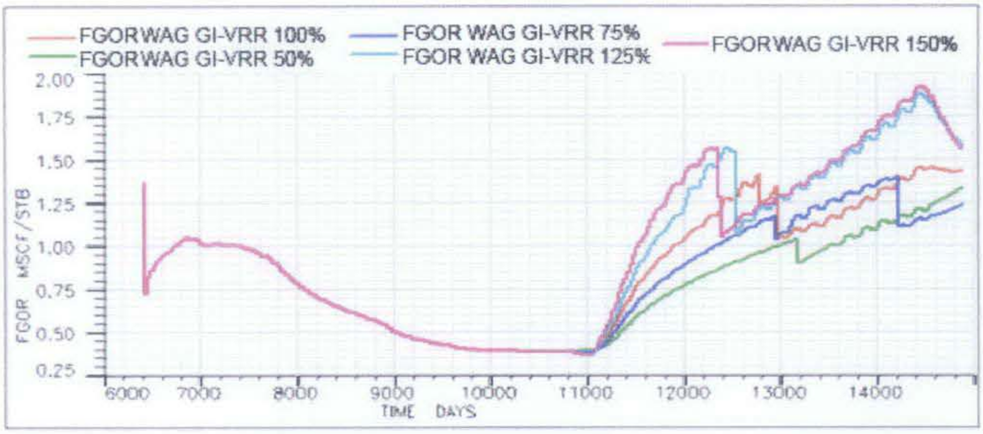

Figure 4.27: Field gas oil ratio versus time

Figure 4.27 shows the field gas oil ratio versus time. From the plot, it can be seen that the case with 150% VRR on gas injectors gives the highest GOR of 1.9 Mscf/stb, whereas the case with 50% VRR on gas injectors gives the lowest GOR of 1.0 Mscf/stb. This suggests that there might be early gas breakthrough at individual wells, causing less oil to be produced. This supports the early fact that gas might not be efficient to displace the oil, as suggested earlier. Gas fingering might have occurred due to the nature of low viscosity of the gas relative to the viscosity of the oil.

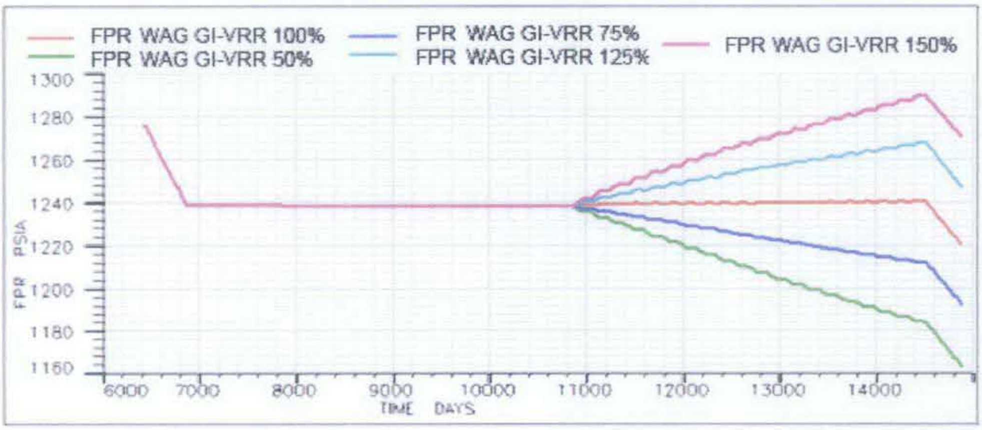

Figure 4.28: Field pressure versus time

Figure 4.28 shows the field pressure versus time. It can be seen that the case with 150% VRR on gas injectors gives the highest pressure of 1289.70 psia whereas the case with 50% VRR on gas injectors gives the lowest pressure 1184.20 psia. This holds the fact that the case with 150% VRR injects an additional 50% of voidage volume into the reservoir, thus increasing the pressure of the reservoir whereas the case of 50% VRR injects 50% of the produced voidage volume, thus the reservoir pressure decreases.

4.5.2 Voidage Replacement Ratio Sensitivity Analysis on Water Injectors

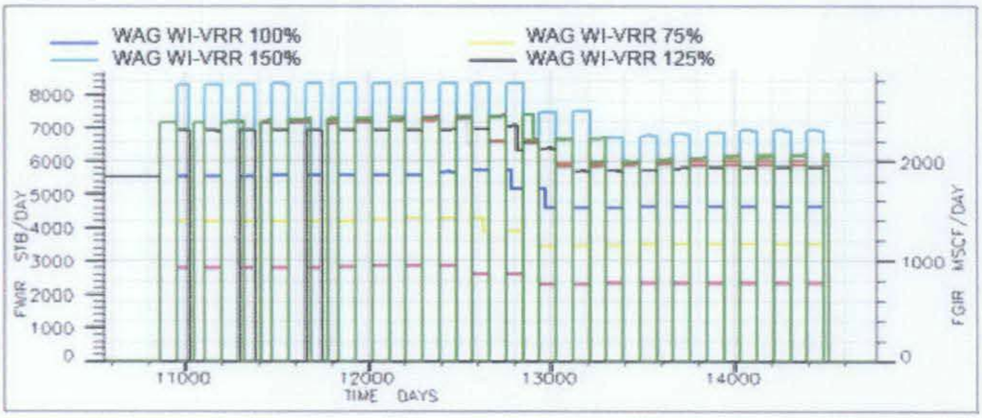

Figure 4.29: Field water injection rate and gas injection rate versus time

Five (5) voidage replacement ratio (VRR) sensitivity analysis were conducted on the water injectors, ranging from 50% to 150%, with the gas injector VRR held constant at 100%. Figure 36 shows the water injection rate and gas injection rate for each sensitivity analysis.

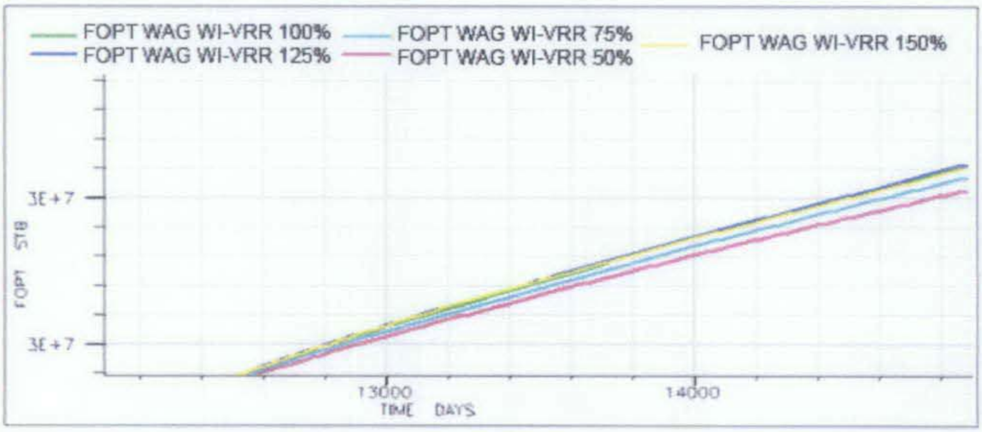

Figure 4.30: Field oil production total versus time

Figure 4.30 shows the field oil production total versus time for each of the VRR sensitivity analysis on water injectors. The results are tabulated as follows:

Table 4.2: Recovery factor and incremental recovery for each sensitivity analysis

WAG VRR	RECOVERY FACTOR, %	INCREMENTAL RECOVERY, %
WI 50%	27.18	6.91
WI 75%	27.27	7.00
WI 100%	27.34	7.07
WI 125%	27.35	7.08
WI 150%	27.33	7.06

From the results obtained, it can be seen that from WAG implementation, there is an approximately 7% of incremental recovery. However, the incremental recovery is insensitive to the voidage replacement ratio sensitivity. In the table, the 50% VRR scheme gives the lowest incremental recovery of 6.91% whereas the 125% VRR scheme gives the highest incremental recovery of 7.08%. This suggests that for this reservoir, voidage replacement ratio does not play an important role in increasing the incremental recovery. This is probably due to the nature of the heterogeneity of the reservoir, whereby the injected water is unable to mobilize the residual oil.

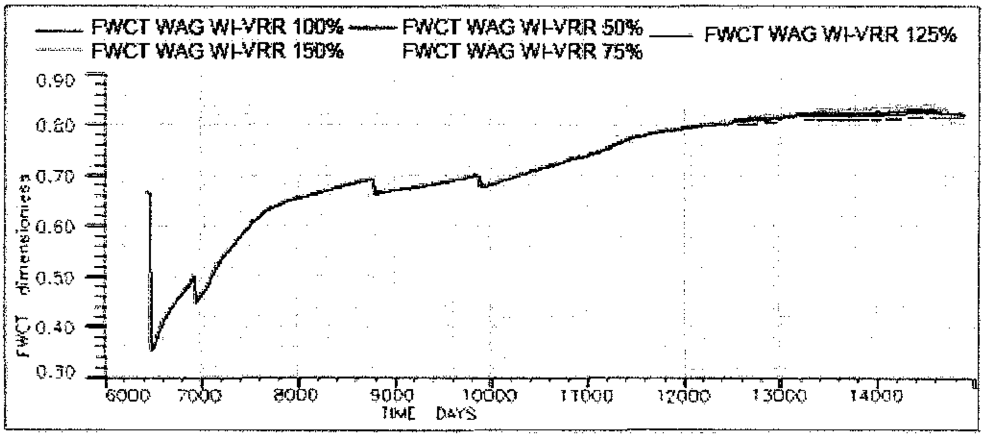

Figure 4.31: Field watercut versus time

From Figure 4.31, it can be seen that the field watercut is insensitive to the injected water voidage replacement ratio. This suggests that all the injected water fills the pore spaces and none are produced in the producers.

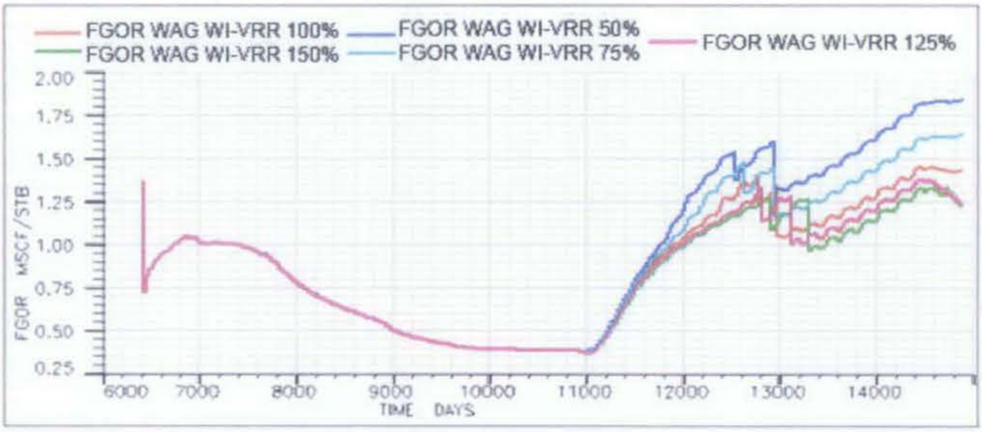

Figure 4.32: Field Gas Oil Ratio versus time

From Figure 4.32, it can be seen that the injected water voidage replacement ratio of 150% gives the lowest GOR while the injected water VRR of 50% gives the highest GOR. This supports the fact that the higher the volume of water injected, the lesser the amount of gas produced. The injected water somehow inhibits the production of gas from the reservoir.

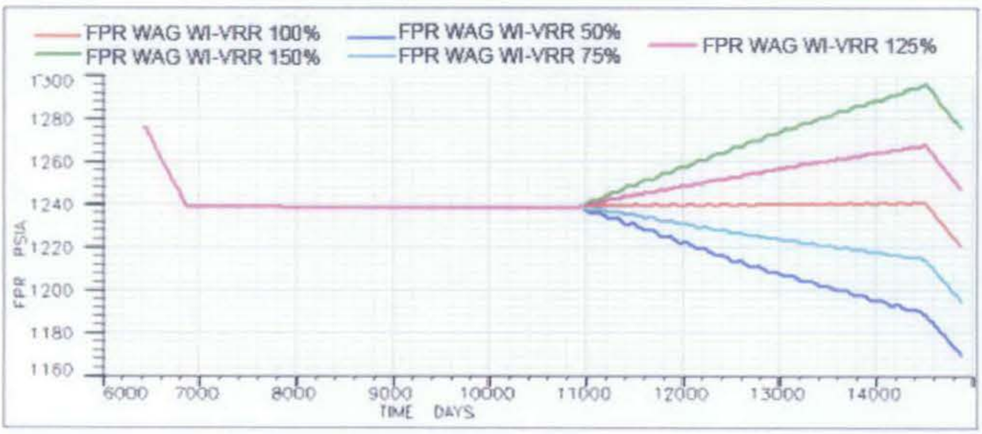

Figure 4.33: Field pressure versus time

From Figure 4.33, it can be seen that the case of 150% injected water VRR gives the highest pressure of 1297.60 psia while the case of 50% injected water VRR gives the lowest pressure of 1189.10 psia. This holds the fact that the case with 150% VRR injects an additional 50% of voidage volume into the reservoir, thus increasing the pressure of the reservoir whereas the case of 50% VRR injects 50% of the produced voidage volume, thus the reservoir pressure decreases.

4.5.3 WAG Cycle Sensitivity Analysis on Gas Injectors

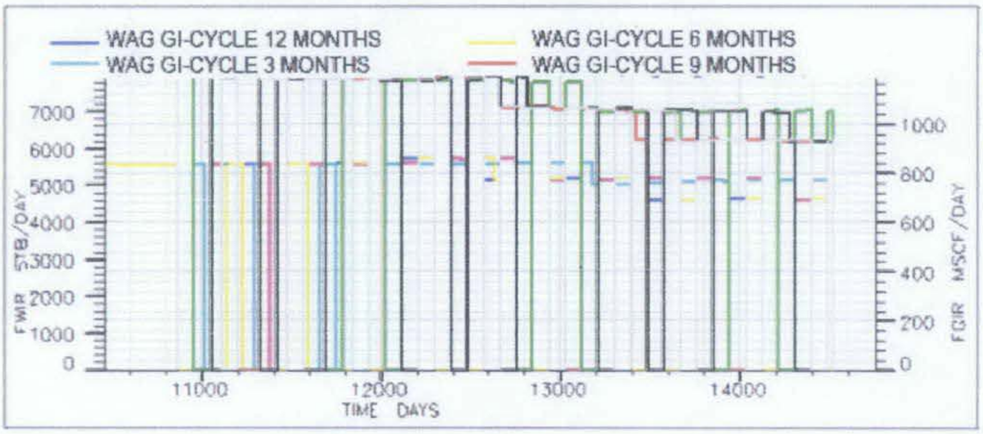

Figure 4.34: Field water injection rate and gas injection rate versus time

Figure 4.34 shows the field water injection rate and gas injection rate versus time for WAG cycle sensitivity analysis on gas injectors. The gas injector cycle in WAG is variate to 3 months, 6 months, 9 months and 12 months while the water injector cycle is held at 3 months.

Figure 4.35: Field oil production total versus time

Figure 4.35 shows the results of the sensitivity analysis on WAG cycle, and is tabulated as in the following table.

Table 4.3: Recovery factor and incremental recovery for each sensitivity analysis

WAG CYCLE	RECOVERY FACTOR, %	INCREMENTAL RECOVERY, %
GI 3 MONTH	27.60	7.33
GI 6 MONTH	27.39	7.12
GI 9 MONTH	27.28	7.01
GI 12 MONTH	27.20	6.93

From the table, it can be seen that from WAG implementation, there is an increase of approximately 7% in incremental recovery. However, the results is insensitive to the WAG cycle. The 3 months gas injection cycle case gives the highest recovery, which is 27.60% while the 12 months gas injection cycle gives the lowest recovery, which is 6.93%. This supports the fact that more stable displacement is achieved with less gas injected.

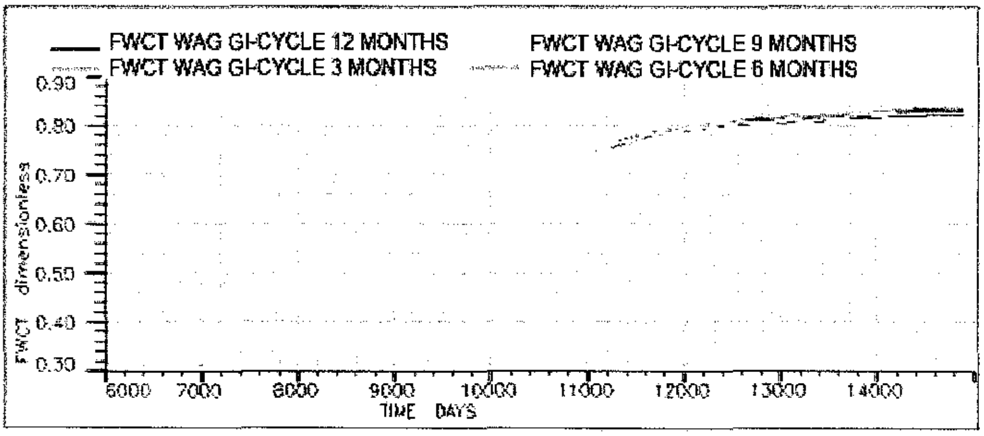

Figure 4.36: Field watercut versus time

Figure 4.36 shows the field watercut versus time. From the plot, it can be seen that the field watercut is insensitive to the sensitivity analysis on gas injection cycle. This is because the volume and cycle of the water injection is held constant and gas injection plays no role in contributing to higher water production.

Figure 4.37: Field Gas Oil Ratio versus time

Figure 4.37 shows the field gas oil ratio versus time. From the plot, it can be seen that the 12 months gas injection cycle case gives the highest rise in GOR while the 3 months gas injection case gives the lowest rise in GOR. This supports the fact that the more gas is injected, the less stable the displacement is; thus contributing to gas breakthrough and more gas is produced with respect to oil.

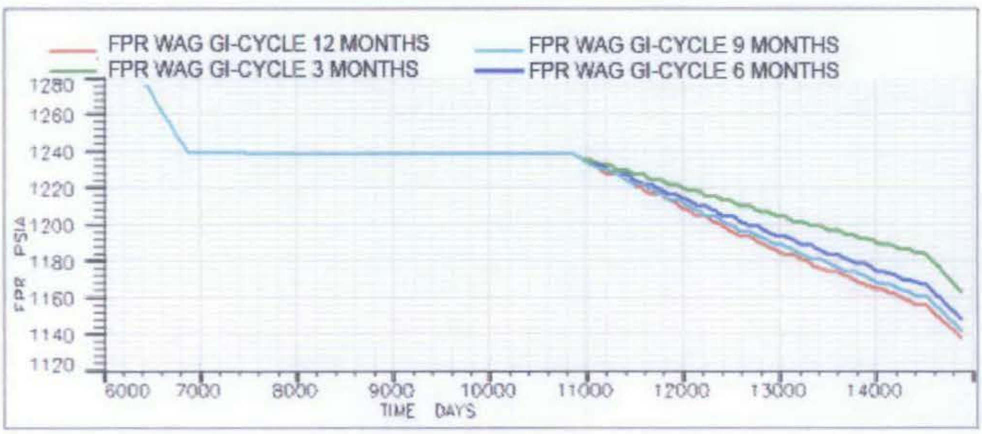

Figure 4.38: Field pressure versus time

Figure 4.38 shows the field pressure versus time. It can be seen that after the implementation of WAG, the field pressure starts to decline. This is because the 50% voidage replacement ratio on gas injector was selected for this WAG cycle sensitivity. 50% voidage replacement ratio is not sufficient to maintain the reservoir pressure. From the plot, it can be seen that the 3 months gas injection cycle gives the highest pressure after WAG implementation and the 12 months gas injection cycle gives the lowest pressure after WAG implementation, even the voidage replacement ratio defined is the same. This supports the fact that displacement by gas is inefficient and gas-fingering could have happened, contributing to lower efficiency in pressure maintenance.

4.5.4 WAG Cycle Sensitivity on Water Injectors

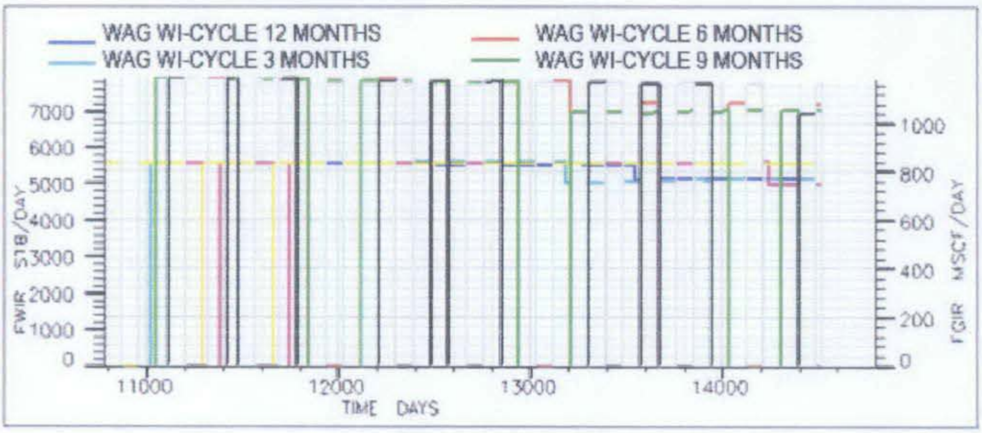

Figure 4.39: Field water injection rate and gas injection rate versus time

Figure 4.39 shows the field water injection rate and gas injection rate with respect to time. WAG cycle sensitivity on water injector is conducted in this case study by varying the water injection duration ranging from 3 months to 12 months, with the duration of gas injection held constant. The injected water VRR for this case is 100% while the injected gas VRR for this case is 50%.

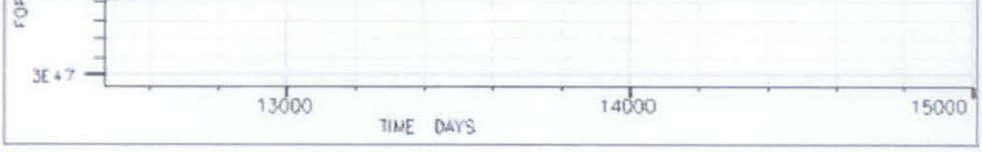

Figure 4.40: Field oil production total versus time

Figure 4.40 shows the field oil production total versus time. The results of the sensitivity are tabulated in the following table.

Table 4.4 – Recovery factor and incremental recovery for each sensitivity cases

WAG CYCLE	RECOVERY FACTOR, %	INCREMENTAL RECOVERY, %
WI 3 MONTH	27.60	7.33
WI 6 MONTH	27.81	7.54
WI 9 MONTH	27.90	7.63
WI 12 MONTH	27.90	7.63

From the table, it can be seen that the 3 months water injection cycle gives the lowest incremental recovery of 7.33% while the 12 months water injection cycle gives the highest incremental recovery of 7.63%. Thus, it can be concluded that the incremental recovery is insensitive to the sensitivity analysis on water injection cycle. Water injection in particular provides the most stable displacement relative to gas injection, supporting the results where the longer the duration of water injection, the higher the recovery factor.

Figure 4.41: Field watercut versus time

Figure 4.41 shows the watercut versus time plot. The WAG case watercut does not vary much from the base case watercut. From the plot, we can conclude that the incremental recovery is insensitive to the WAG cycle on water injection. Thus, we can conclude that no injected water is produced in the producing wells, in a way explained that water injection is successful in displacing the oil towards the producing wells.

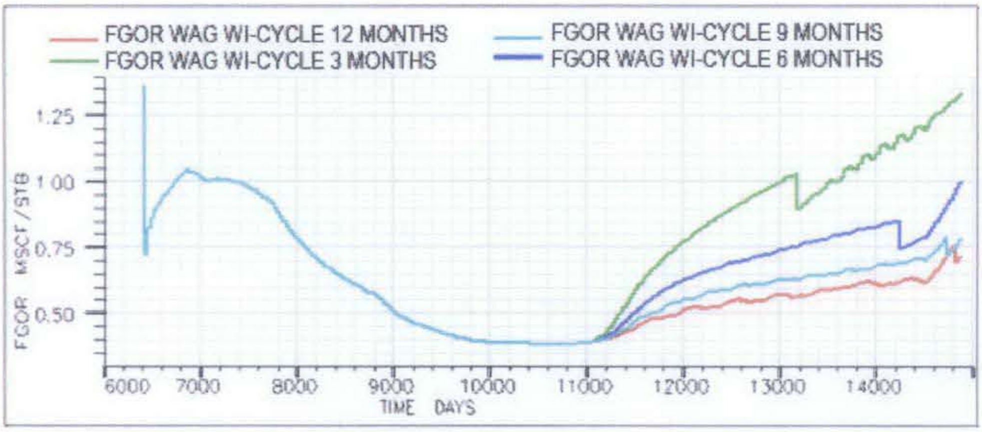

Figure 4.42: Field Gas Oil Ratio versus time

Figure 4.42 shows the field gas oil ratio versus time. From the plot, it can be seen that the 3 months water injection cycle gives the highest GOR rise, while the 12 months water injection cycle gives the lowest GOR rise. This supports the fact that water injection reduces the amount of gas production.

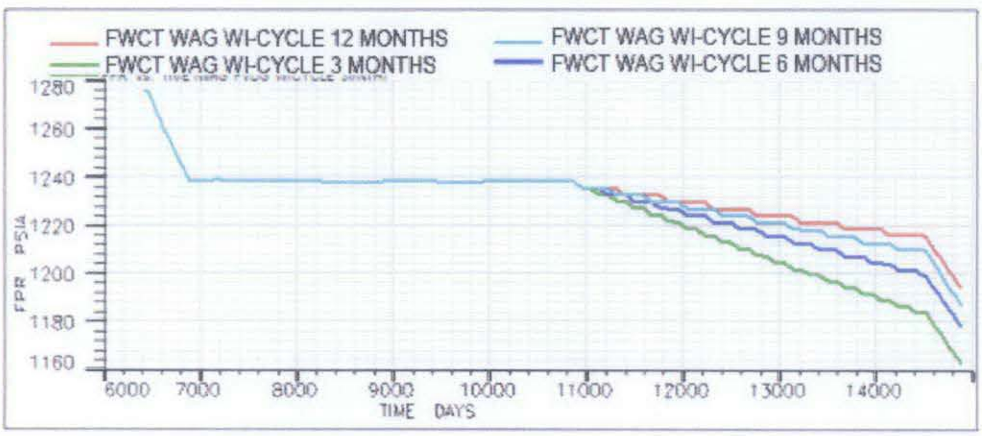

Figure 4.43: Field pressure versus time

Figure 4.43 shows the field pressure versus time. After WAG is implemented, the pressure starts to decline. This is because voidage replacement ratio for gas injector has been defined as 50% as from the previous case study, this voidage replacement ratio in WAG gives the highest incremental recovery. The 3 months water injection cycle in particular gives the lowest pressure and the 12 months water injection cycle gives the highest pressure. This supports the fact that the displacement by water is efficient and water is able to maintain reservoir pressure efficiently compared to gas. The more the volume of water injected, the higher the pressure maintenance and the higher the amount of incremental recovery.

CHAPTER 5

CONCLUSIONS AND RECOMMENDATIONS

5.1 CONCLUSIONS

Based on the results and discussion, it can be concluded that for this type of reservoir;

- History matching case provides recovery factor of 17.22%, indicating that more oil can be recovered by other initiatives.
- Base case prediction provides recovery factor of 20.27%, with incremental recovery of 3.05% with respect to the history matching case while the infill case prediction provides recovery factor of 24.47%, with incremental recovery of 4.20% with respect to the base case
- Water injection case provides recovery factor of 27.20%, with incremental recovery of 6.93% with respect to the base case while the gas injection case provides recovery factor of 22.85%, with incremental recovery of 2.58%
- WAG case provides recovery factor ranging from 26.93% to 27.90% with incremental recovery ranging from 6.66% to 7.63% with respect to the base case
- Sensitivity on WAG voidage replacement ratio and WAG cycle both concludes that the recovery factor is insensitive to the two WAG parameters in this case study
- From the study, it can be concluded that stable displacement is achieved by injecting water; however not for the case of gas injection where gas breakthrough can be seen

5.2 RECOMMENDATIONS

The author recommends the following initiatives to further increase recovery from the field:

- WAG Optimization including revising the injection perforation interval and the injection rates for individual blocks
- Miscible WAG where the field pressure must be repressurized to above the Minimum Miscibility Pressure (MMP)
- E300 Compositional model for an accurate evaluation in incremental recovery from WAG implementation

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