The Effect of Different Hysteresis Models
On Water-Alternating-Gas (WAG) Process

by

Amandeep Kaur Jusvir Singh

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

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CERTIFICATION OF APPROVAL

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Approved by,

(Pn. Faiza Mohamed Nasir)

UNIVERSITI TEKNOLOGI PETRONAS

TRONOH, PERAK

April 2009

CERTIFICATION OF ORIGINALITY

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

AMANDEEP KAUR JUSVIR SINGH

ABSTRACT

Enhanced oil recovery (EOR) or tertiary recovery is vastly applied to mostly mature and depleted oil reservoirs nowadays. One of the many EOR techniques is the Water-Alternating-Gas (WAG) process whereby water and gas are alternately injected for periods of time to provide better sweep efficiency hence improve oil recovery. It is well known that whenever the fluid saturations undergo a cyclic process, relative permeability display hysteresis effects. Recent studies have been done on establishing the effect of hysteresis on WAG process. However, different hysteresis models will have different assumption and methods which eventually affects the production profile and recovery of an oil field. The main objective of this project is to quantify the effect of different hysteresis models (Carlson and Killough's model) on a conceptual model using black oil simulation. In addition to the main objective, sensitivities studies on the model without hysteresis were done to obtain optimum values prior to running the model with hysteresis. Hysteresis effect always results in higher oil recovery and oil production rate compared to the model without hysteresis. The quantification of both the hysteresis models shows that Killough's model results in higher oil recovery compared to Carlson's model. This is due to the fact that Killough uses particular equations to produce the scanning curve where else Carlson's scanning curve is produced by shifting the imbibitions curve horizontally until it cuts the drainage curve at the maximum non-wetting phase saturation. The way the scanning curve (intermediate imbibiton curves) is generated differs in both the models. This quantification of different hysteresis models can help in obtaining more precise prediction of forecasting oil recovery in the future.

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LIST OF ABBREVIATIONS

Abbreviations	**Full Name**
EOR	Enhanced Oil Recovery
FGPT	Total Field Gas Production
FOE	Oil recovery efficiencies
FOIP	Oil In place
FOPT	Total Field Oil Production
GOR	Gas-Oil Ratio
HCPV	Hydrocarbon pore volume
IFT	Interfacial tension
MMSTB	Million stock tank barrel
MSCF	Million standard cubic feet
OOIP	Original Oil-In-Place
PSIA	Pounds per square inch absolute
PVT	Pressure, volume and temperature
STB	Stock tank barrel
STOIIP	Stock tank oil initially in place
WAG	Water-Alternating-Gas

CHAPTER 1

INTRODUCTION

1.1 Background of Study

The life of an oil well goes through three distinct phases where various techniques are employed to maintain crude oil production at maximum levels. The primary importance of these techniques is to force oil into the wellhead where it can be pumped to the surface. Techniques employed at the third phase, commonly known as Enhanced Oil Recovery (EOR), can substantially improve extraction efficiency. Laboratory and simulation development of these techniques involves setups that duplicate well and reservoir conditions.

Primary recovery typically provides access to only a small fraction of a reservoir's total oil capacity. Secondary recovery techniques can increase productivity to a third or more. Tertiary Recovery (EOR) enables producers to extract up to over half of a reservoir's original oil content, depending on the reservoir and the EOR process applied.

Even though petroleum and natural gas resources are finite, they remain among the most important sources of energy in the world. With the decline of hydrocarbon reserves, improved recovery of these resources to boost production is becoming increasingly important. Most improved oil recovery which is the enhanced oil recovery (EOR) or tertiary recovery is vastly applied to mature and mostly depleted oil reservoirs.

The EOR technique called the water-alternating-gas (WAG) is a process where water and gas are alternately injected for period of time to provide better sweep efficiency and reduce gas channeling from injector to producer. Here, gas can occupy part of the pore space that otherwise would be occupied by oil, thereby mobilising the remaining oil. Water, injected subsequently, will displace some of the remaining oil and gas, further reducing the residual oil saturation. Repetition of the WAG injection process will squeeze more oil out of a reservoir and hence can further improve the recovery of oil.

WAG injection is a cyclic process and it is well known that, whenever the fluid saturations undergo a cyclic process, relative permeabilities display hysteresis effect.

1.2 Problem Statement

Water alternating gas (WAG) injection process has been implemented to increase oil recovery percentage. In reality, WAG process consists of the injection of water and gas as alternate slugs by cycles. Whenever fluid saturations undergo a cyclic process, relative permeabilities will display hysteresis effects. It is believed that hysteresis will affect the recovery of oil whenever WAG process is performed. Recent studies have been done on establishing the effect of hysteresis on WAG process. However, different hysteresis models will have different assumption and methods which eventually affects the production profile and recovery of an oil field. Thus, to further advance the study, two different hysteresis models are used to model, quantify and compare the performance and production profile of a conceptual model. The two-phase hysteresis models that are typically used in reservoir simulators are by Carlson and Killough.

1.3 Objective and Scope of Study

The main objective of this project is to quantify the effect of different hysteresis models (Carlson and Killough's model) on a conceptual model using black oil simulation. The black oil simulation software that would be used for this project is Eclipse 100. In addition to the main objective, sensitivities studies on the model without hysteresis will be done to obtain optimum values prior to running the model with hysteresis.

Due to time constraint, only a conceptual model would be run since there was no model being run to quantify the performance of these two hysteresis models. Prior to running the simulation with hysteresis, correlation of relative permeability data for two-phase relative permeability is done to be input into the data file.

To achieve the objectives stated above, basic knowledge on reservoir engineering and WAG is essential. Therefore, detailed literature review is researched on and the black oil simulation software is learnt in order to simulate the WAG process and run the sensitivities.

CHAPTER 2
LITERATURE REVIEW

2.1 WATER-ALTERNATING-GAS (WAG)

The WAG process is an enhanced oil recovery process whereby water and gas are alternately injected for periods of time to provide better sweep efficiency and reduce gas channeling from injector to producer. This process aims to squeeze more oil out of a reservoir. It was originally intended to improve sweep efficiency during gas flooding, with intermittent slugs of water and gas designed by and large to follow the same route through the reservoir.

During an initial waterflood, water advances in pores by the process of 'corner filament flow'. The water filaments, that surround the oil present in the larger bodies, thicken progressively and leave oil filaments in the middle of pores and finally cause oil snap off at the pore throats. During gas injection, gas preferentially enters the oil filled pores, because gas has lower IFT with oil than it has with water. The invasion of oil filled pores by gas causes a small bank of oil to move ahead of gas front causing an increase in local oil saturation in some patches of pores. This in turn increases the mobility of oil in the pores and eventually results in improved oil recovery. (D.H.Tehrani, EOR by WAG Injection)

It is well known that remaining (residual) oil in the flooded rock may be lowest when three phases – oil, water and gas – have been achieved in this volume. Water injection alone tends to sweep the lower parts of a reservoir, while gas injected alone sweeps more of the upper parts of a reservoir owing to gravitational forces. By injecting oil and gas alternately, more oil can be produced than would otherwise be produced by water or gas injection alone.

Three-phase gas, oil and water flow is better at displacing residual oil in the pore system than two-phase flow. WAG thus improves the efficiency of both microscopic and macroscopic displacement. The challenge is to achieve sufficient sweep in the reservoirs. Carbon dioxide is usually injected in a WAG mode. Although carbon injection is treated as a separate technology in this strategy work, all the above-mentioned challenges are also relevant for the greenhouse gas. These technologies are key to optimising WAG injection procedures and to improving forecasts, and thereby to creating value by improving oil recovery.

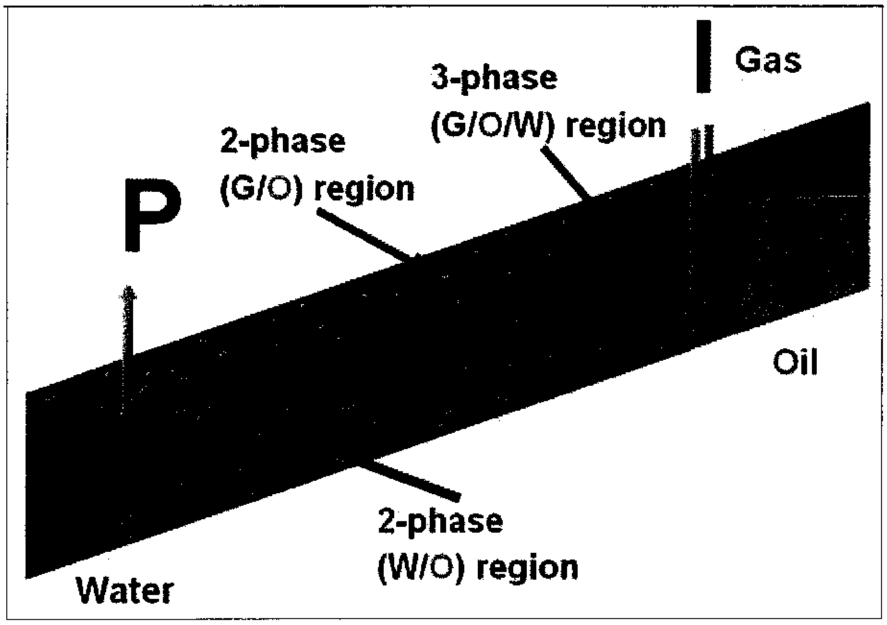

Figure 2.1: Segregated flow during up-dip WAG injection.

2.2 RELATIVE PERMEABILITY

The absolute or specific permeability is a property of the porous medium and it is independent of the saturating fluid, provided that there is no reaction between the rock and the fluid.

When more than one fluid is present in the pore spaces, as it is the case in petroleum reservoirs, the concept of permeability must be applied to each phase separately, because it depends upon the quantity and distribution of the particular fluid phase within the pore system. On this basis, we can define effective permeability to a specified fluid, which, like absolute permeability, can still be determined from the application of Darcy's law (under the assumption that the fluids are immiscible, incompressible and that no gravity forces are affecting the steady flow of each phase).

An alternative way to define permeability of a particular fluid phase is to normalise it to the value of absolute permeability. This is the widely used concept of relative permeability (relative to the absolute), which can be expressed as:

$$kr_o = \frac{k_o}{k} \qquad kr_g = \frac{k_g}{k} \qquad kr_w = \frac{k_w}{k}$$

where k is the absolute permeability and k_o, k_g, k_w refer to the effective permeability to oil, gas and water, respectively.

The concept of relative permeability is fundamental in the simulation of the dynamic behaviour of the reservoir, since it expresses the relative contribution of each phase to the total multiphase flow. The correct definition of a set of relative permeability functions is one of the most and difficult and at the same time, one of the most important steps in the construction of a reliable simulation model and for this reason, great deal of attention must be paid to this phase of the study.

2.3 TWO-PHASE RELATIVE PERMEABILITY

When a wetting and a non-wetting phase flow together in a reservoir rock, each phase follows separate and distinct paths. The distribution of the two phases according to their wetting characteristics results in characteristic wetting and non-wetting phase relative permeabilities. Since the wetting phase occupies the smaller pore openings at small saturations, and these pore openings do not contribute materially to flow, it follows that the presence of small wetting phase saturation will affect the non-wetting phase permeability only to a limited extent. Since the non-wetting phase occupies the central or larger pore openings which contribute materially to fluid flow through the reservoir, however, small non-wetting phase saturation will drastically reduce the wetting phase permeability. Figure 2 presents a typical set of relative permeability curves for a water-oil system with the water being considered the wetting phase.

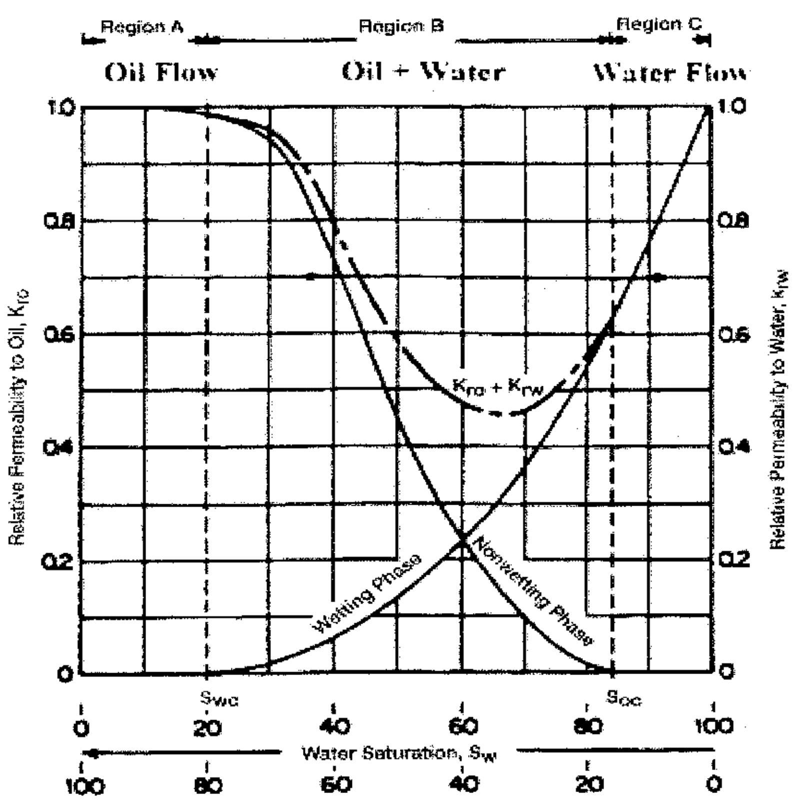

Figure 2.2: Typical two-phase (water-oil) flow behaviour.

Relative permeability curves are also subjected to hysteresis. Figure 2.3 shows a typical two-phase relative permeability curves. From the figure, it is noticeable that the wetting phase relative permeabilities exhibit smaller hysteresis effect. On the other hand, the non-wetting phase relative permeability displays a considerable reduction due to the hysteresis effect.

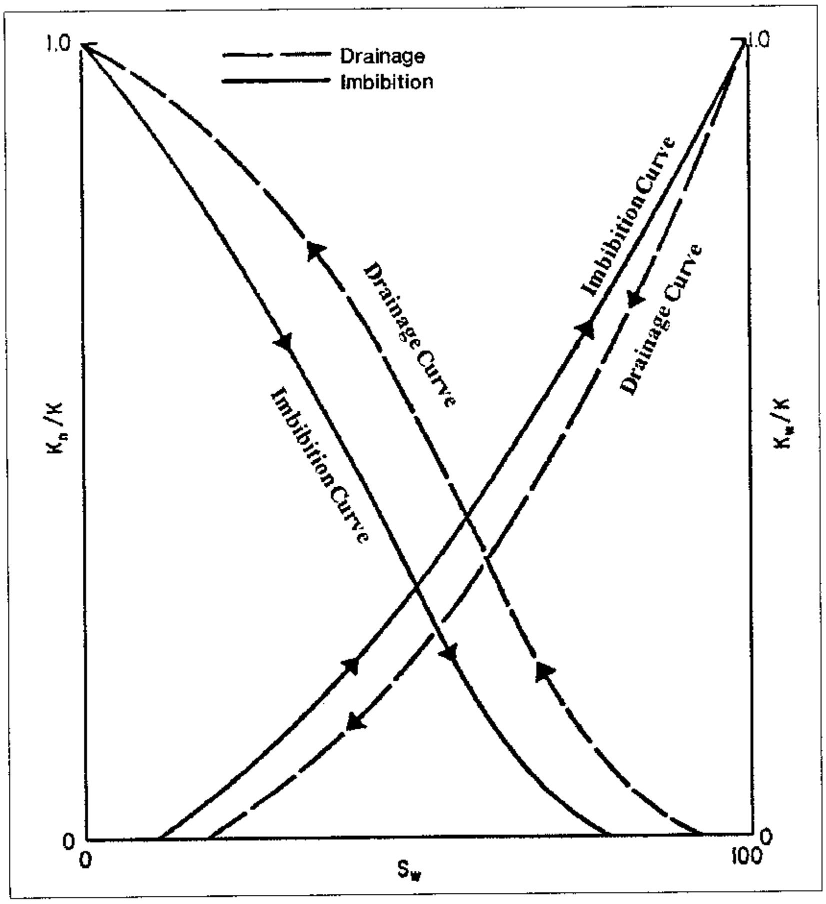

Figure 2.3: Hysteresis effect in two-phase relative permeability

2.4 HYSTERESIS

Multiphase fluid flow is in general an irreversible process and, therefore, is path-dependent. One consequent is that the distribution of the fluid phases in the porous network depends not only on the level of saturation but also on the direction of saturation change. When the saturation of the wetting phase increases, we refer to an imbibition cycle, otherwise to a drainage cycle. These two cycles, in general, are different and this phenomenon is called hysteresis of the saturation functions.

Both capillary pressure and relative permeability curves are subject to a drainage or an imbibition cycle and it is therefore important to access which is the predominant direction of saturation change in the reservoir under study and to observe whether or not a saturation reversal happens. From the view point of pore-scale processes, hysteresis is divided into two factors that can create hysteresis phenomenon which are contact angle hysteresis and trapping of non-wetting phase.

2.4.1 Drainage and Imbibition

Depending on the wetting properties of the fluids there are essentially two different types of displacement in two-phase flow in porous media. A drainage displacement is where a non-wetting invading fluid displaces a wetting fluid. The opposite case, imbibition, occurs when a wetting fluid displaces a non-wetting fluid. The mechanisms of the displacements in drainage and imbibition are quite different and the two cases should not be confused.

The flow properties of the drainage and imbibition systems differ because of the entrapment of the nonwetting phase during imbibition. As drainage occurs, the nonwetting phase occupies the most favourable flow channels. During imbibitions, part of the nonwetting phase is bypassed by the increasing wetting phase, leaving a portion of the nonwetting phase in an immobile condition. This trapped part of the nonwetting phase saturation does not contribute to the flow of that phase, and at a given saturation, the relative permeability to the nonwetting phase is always less in the imbibition direction than in the drainage direction. (Carlson. S. Land)

2.5 HYSTERESIS DESCRIPTION IN ECLIPSE

This description consists of the principal features that are to be used while running Eclipse. A brief theory on each feature is given and specific keywords that are to be used to input into the simulator are also explained.

2.5.1 Relative permeability hysteresis in the non-wetting phase

A typical pair of relative permeability curves for a non-wetting phase is shown in Figure 2.4. The curve 1 to 2 represents the user-supplied drainage relative permeability table, and the curve 2 to 3 represents the user-supplied imbibition relative permeability table. (Note that non-wetting phase saturation increases from right to left in this diagram). The critical saturation of the imbibition curve (S_{ncri}) is greater than that of the drainage curve (S_{ncrd}). The two curves must meet at the maximum saturation value (S_{nmax}).

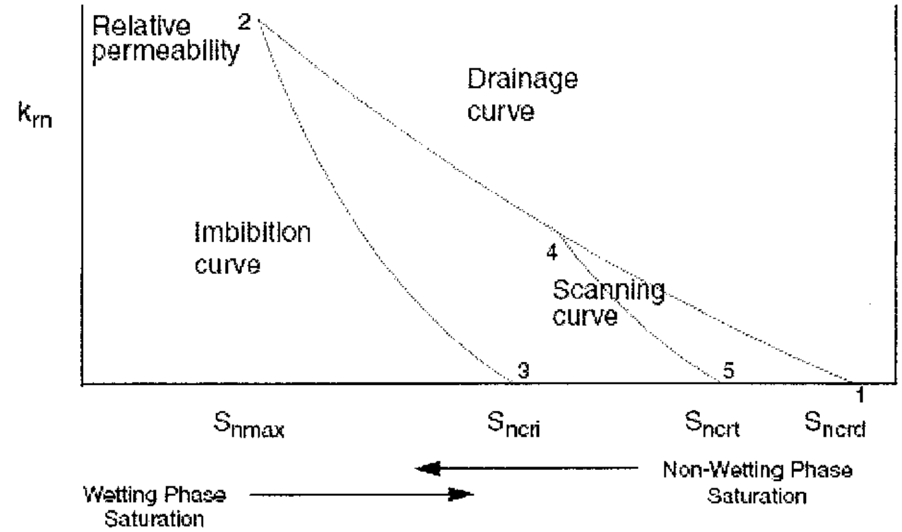

Figure 2.4: A typical pair of relative permeability curves for a non-wetting phase

The primary drainage curve is for a process which starts at the maximum possible wetting phase saturation, S_{wmaxd}. (This value will depend upon the end points of the saturation tables specified using the SATNUM keyword.) If the wetting phase saturation decreases to S_{wmin}, this primary drainage curve is used.

In a similar way, if the initial saturation is S_{wmin}, and the wetting phase saturation increases to S_{wmaxi}, the imbibition table data will be used. (The maximum wetting phase saturation which can be reached, S_{wmaxi} , is determined from the endpoints of the tables specified using the IMBNUM keyword, and will generally be less than S_{wmaxd}). If the drainage or imbibition process is reversed at some point, the data used does not simply run back over its previous values but runs along a scanning curve.

Consider a drainage process starting at point 1. If a full drainage process is carried out, the bounding drainage curve is followed to point 2. If an imbibition process then occurs, the water saturation increasing, the bounding imbibition curve is followed to point 3, the imbibition critical saturation.

But suppose that the drainage process is reversed at some intermediate point 4. A scanning curve results (curve 4 to 5 in the diagram). The critical saturation remaining at point 5 is the trapped critical saturation (S_{ncr}), which is a function of the maximum non-wetting phase saturation reached in the run (S_{hy}).

If a further drainage process begins from any point on the scanning curve 5 to 4, the same scanning curve is retraced until S_{hy} is reached, at which point the drainage curve is rejoined. S_{hy} is updated during the run, so that further imbibition processes would occur along the appropriate scanning curves.

There is a choice of two methods for the generation of scanning curves from a given value of S_{hy} using Carlson's method or Killough's method. The choice of method is governed by Item 2 in keyword EHYSTR.

2.5.1.1 Carlson's method for generating scanning curve

Carlson's method produces a scanning curve that is parallel to the imbibition curve. It can be visualized by shifting the imbibition curve horizontally until it cuts the drainage curve at the saturation S_{hy}. When this method is chosen, it is important to ensure that the imbibition curve is always steeper than the drainage curve at the same value. If this is not the case, the scanning curve could cross to the right of the drainage curve, which may produce a negative value of S_{ncrt}.

2.5.1.2 Killough's method for generating scanning curve

Killough's method does not have such a simple geometric interpretation. For a given value of S_{hy} the trapped critical saturation is calculated as:

$$S_{ncrt} = S_{ncrd} + \frac{S_{hy} - S_{ncrd}}{1 + C(S_{hy} - S_{ncrd})}$$

where

$$C = \frac{1}{S_{ncri} - S_{ncrd}} - \frac{1}{S_{n\,\max} - S_{ncrd}}$$

(Killough's formulae have been adapted to allow for non-zero values of S_{ncrd})

The relative permeability for a particular saturation S_n on the scanning curve is

$$K_{rn}(S_n) = \frac{K_{rni}(S_{norm})K_{rnd}(S_{hy})}{K_{rnd}(S_{n\,\max})}$$

Where K_{rni} and K_{rnd} represent the relative permeability values on the bounding imbibition and drainage curves respectively, and

$$S_{norm} = S_{ncri} + \frac{(S_n - S_{ncrt})(S_{n\,\max} - S_{ncri})}{S_{hy} - S_{ncrt}}$$

With Killough's method S_{ncrt} will always lie between S_{ncrd} and S_{ncri}. But if the drainage and imbibition curves are made to coincide, the scanning curve will not necessarily follow this combined curve, except at its end points. The difference of the both the models are summarized in the table below:

Table 2.1: Difference in Carlson's and Killough's model for relative permeability hysteresis in the non-wetting phase

CARLSON	KILLOUGH
• Scanning curve parallel to imbibition curve • Scanning curve is produced by shifting imbibition curve horizontally until it cuts the drainage curve	• Not simple geometric interpretation as Carlson's model • There are particular equations to calculate trapped critical saturation, S_{ncrt} and relative permeabilities on the bounding drainage and imbibition curves.

2.5.2 Relative permeability hysteresis in the wetting phase

There is an option to use only the Killough's model for wetting phase hysteresis. Otherwise the same curve will be used to obtain the wetting phase relative permeability in both drainage and imbibition processes (can select either the drainage curve or the imbibition curve).

The option is selected in Item 2 of the EHYSTR keyword. A typical pair of wetting phase relative permeability curves suitable for the Killough model is shown in Figure 2.5. The curve 1 to 2 represents the user-supplied drainage relative permeability table, and the curve 2 to 3 represents the user-supplied imbibitions relative permeability table. The two curves must meet at the connate saturation (S_{wco} = 1 - S_{nmax}). The maximum saturation on the imbibition curve is 1 - S_{ncri}.

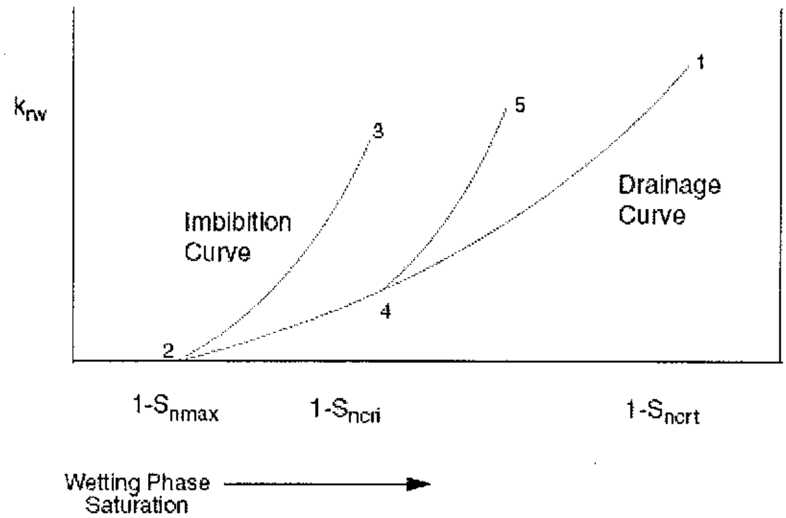

Figure 2.5: A typical pair of relative permeability curves for a wetting phase

An initial drainage process would follow the drainage curve (point 1 to point 2). An imbibition process starting at point 2 (S_w = S_{wco} = 1 - S_{nmax}) follows the bounding imbibition curve (point 2 to point 3). Point 3 (S_w = 1 - S_{ncri}) is the maximum wetting phase saturation that can be reached starting from S_{wco}, since the trapped non-wetting phase saturation is S_{ncri}. An imbibition process that starts from an intermediate saturation (point 4) will follow a scanning curve (point 4 to point 5). The saturation at point 4 is S_w = 1 - S_{hy}, where S_{hy} is the maximum non-wetting phase saturation reached. The maximum saturation that can be reached on the scanning curve (point 5) is S_w = 1 - S_{ncrt}, where S_{ncrt} is the trapped critical saturation of the non-wetting phase, as defined in the previous section.

If a further drainage process begins from any point on the scanning curve, the same scanning curve is retraced until point 4 is reached, where the drainage curve is rejoined.

Killough's method for calculating the scanning curves uses some of the quantities derived in the previous section for the non-wetting phase. The trapped critical nonwetting phase saturation S_{ncrt} is determined for the particular value of S_{hy}. The wetting phase relative permeability at the complementary saturation is calculated, thus fixing the position of point 5,

$$K_{rw}(1-S_{ncrt}) = K_{rwd}(1-S_{ncrt}) + (K_{rwi}(1-S_{ncri}) - K_{rwd}(1-S_{ncri}))\left(\frac{S_{ncrt}-S_{ncrd}}{S_{ncri}-S_{ncrd}}\right)^{A}$$

where the exponent A is a curvature parameter entered in Item 3 of the keyword EHYSTR. K_{rwd} and K_{rwi} represent the wetting phase relative permeability values on the bounding drainage and imbibition curves respectively. The relative permeability for a particular saturation S_w on the scanning curve is

$$K_{rw}(S_w) = K_{rwd}(1-S_{hy}) + \frac{(K_{rw}(1-S_{ncrt}) - K_{rwd}(1-S_{hy}))K_{rwi}(1-S_{norm})}{K_{rwi}(1-S_{ncri})}$$

where S_{norm} is the function of S_n (= 1 - S_w) defined in the non-wetting phase hysteresis section. As with Killough's non-wetting phase hysteresis model, if the drainage and imbibition curves are made to coincide the scanning curve will in general only meet this combined curve at its end points (points 4 and 5).

CHAPTER 3
METHODOLOGY

3.1 PROCEDURE

The following methodology has been design to have a view of the conduct and flow of the project for the duration of 2 semesters.

Preliminary Research Work

- Familiarize with relative permeabilities, hysteresis, hysteresis effects, drainage, imbibitions and etc.
- Read on journals regarding to the topic i.e. relative permeability hysteresis, WAG injection

↓

Preparation for simulation

- Black oil simulation training (familiarization of the Eclipse software) is done to get a hands-on training of using the software

↓

Model without Hysteresis Simulation

- **Base Case:** Conceptual model is run without hysteresis
- Sensitivity studies on injection rate, WAG cycle and WAG ratio are done and results are analysed

↓

Correlation of Relative Permeability data

- Two-phase relative permeability data are correlated using different correlations such as by Wylie and Gardner, Pirson's, Corey's and analytical method
- The correlation that best suited was chosen and used in the subsequent simulation

Model with Hysteresis Simulation

Conceptual model is run with hysteresis with the optimum values obtained from base case using different hysteresis models:

- Case 0 : Carlson's Hysteresis Model for non-wetting phase(s), drainage (*SATNUM*) curve for wetting phase
- Case 1 : Carlson's Hysteresis Model for non-wetting phase(s), imbibition (*IMBNUM*) curve for wetting phase
- Case 2 : Killough's Hysteresis Model for non-wetting phase(s), drainage (*SATNUM*) curve for wetting phase
- Case 3 : Killough's Hysteresis Model for non-wetting phase(s), imbibition (*IMBNUM*) curve for wetting phase
- Case 4 : Killough's Hysteresis Model for both wetting and non-wetting phases

Analysis of Results

- Results from all cases are graphed and analysed
- Results of hysteresis on both models (Carlson and Killough) are analysed and quantified

- Conclusion
- Final Report and Oral Presentation

3.1.1 Sensitivity Study of Conceptual Model

The sensitivity study of the conceptual model was done based on the injection rate, WAG cycle and WAG ratio. The comparison of each variation was based on the total oil production for 12 years (4320 days)

Sensitivity study on injection rate

- Injection rate was varied from 5000 rb/day to 18,000 rb/day for water and gas

Sensitivity study on WAG cycle

- Optimum injection rate determined earlier was used
- WAG cycle was varied from 2,3,4,5,6,8,10 and 12 months

Sensitivity study WAG ratio

- Optimum injection rate and WAG cycle determined earlier were used. WAG ratio was based on injection rate.

- WAG ratio was varied with following:
    - Water to Gas ratio (Gas varied) 1:1, 1:2, 1:3, 1:4 and 1:5
    - Water to Gas ratio (Water varied) 2:1, 3:1, 4:1 and 5:1

3.2 GANTT CHART

The Gantt chart for the project timeline of two semesters is attached in Appendix A.

3.3 TOOLS / EQUIPMENTS

This project basically requires a workstation which has the black oil simulation software. The black oil simulation software that is available in the laboratory in Universiti Teknologi PETRONAS is Eclipse 100.

CHAPTER 4

RESULTS AND DISCUSSION

4.1 SENSITIVITY STUDY OF CONCEPTUAL MODEL WITHOUT HYSTERESIS

4.1.1 Injection rate Sensitivity study

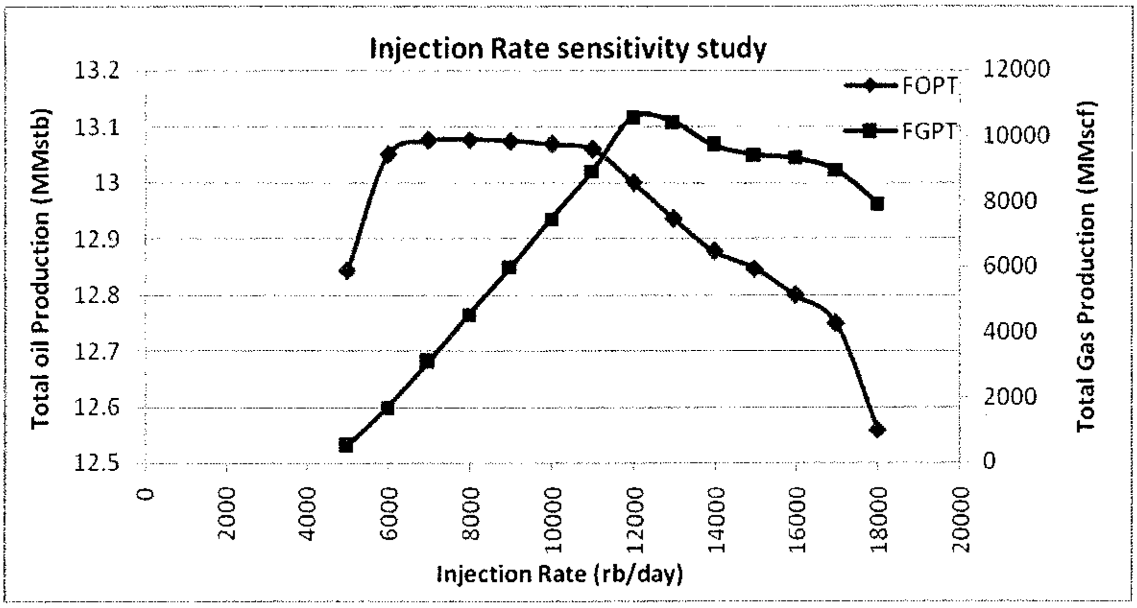

Figure 4.1: FOPT and FGPT for Injection Rate Sensitivity Study

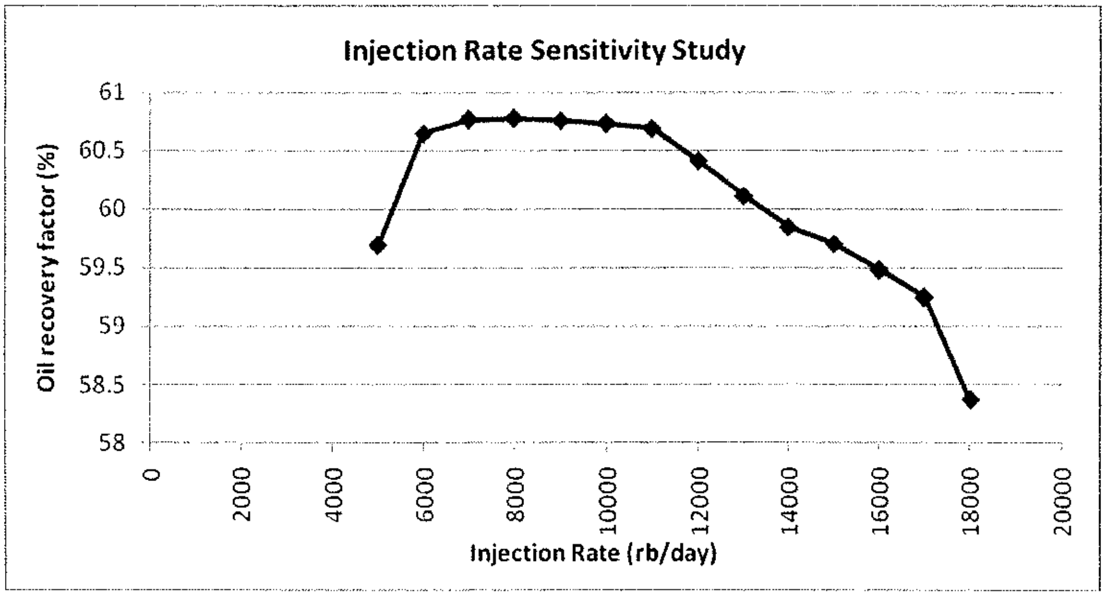

Figure 4.2: Oil Recovery Rate for Injection Rate Sensitivity Study

The base case set for running sensitivity throughout the conceptual model for 4320 days (12 years) are at an injection rate of 10,000 rb/day with Water to Gas ratio of 1:1 and a WAG cycle of 6 months.

The injection rate for water and gas were varied from 5,000 rb/day to 18, 000 rb/day. From Figure 4.1, the total oil production increases from injection rate of 5000 rb/day until 8000 rb/day. Then the trend drops slightly in terms of total oil production until 11,000 rb/day. Starting from that point, there is a significant drop in total oil production.

The injection rate chosen must be higher than the pore volume of the reservoir. For this case, the pore volume is 33.39 MMRB. Therefore, an injection rate of 10, 000 rb/day is chosen as the most optimum rate as it will inject 36 MMRB in 4320days. Referring to Figure 4.2, the oil recovery factor for 8000 rb/day and 9000 rb/day is higher than 10,000 rb/day. However, by injecting 9000 rb/day, the total injection rate will be lesser than the pore volume, which is not suitable.

The injection rate of 10,000 rb/day was chosen as the injection rate with total oil production of 13.06711 MMSTB and recovery rate of 60.728%. This rate would be used in the subsequent simulation. The selection of the injection rate disregards the cost of the volume injected.

4.1.2 WAG cycle Sensitivity Study

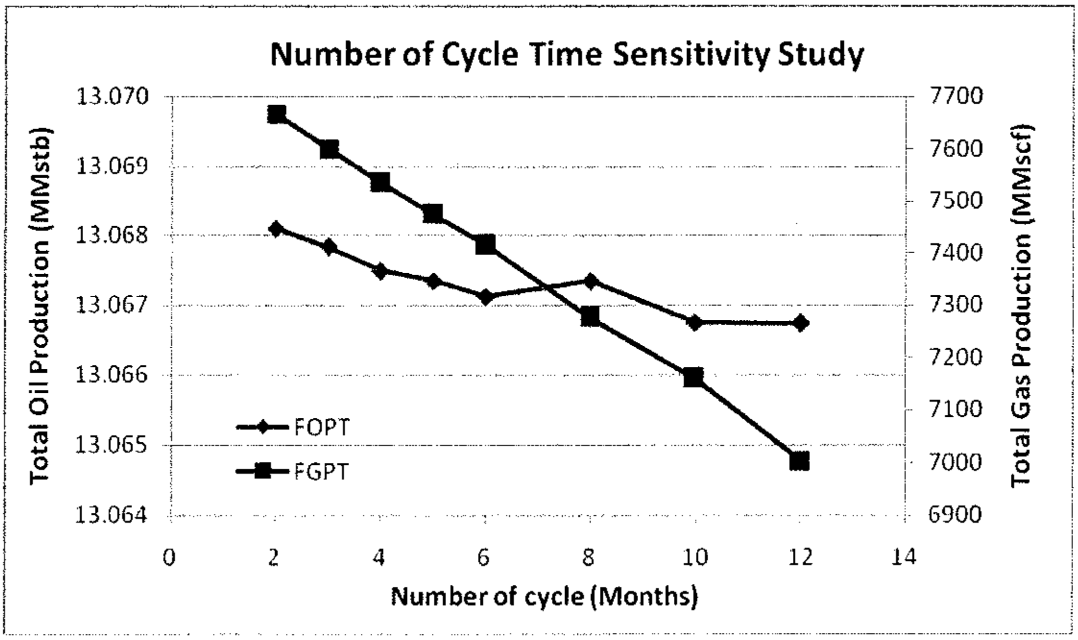

Figure 4.3: FOPT and FGPT for Number of Cycle Time Sensitivity Study

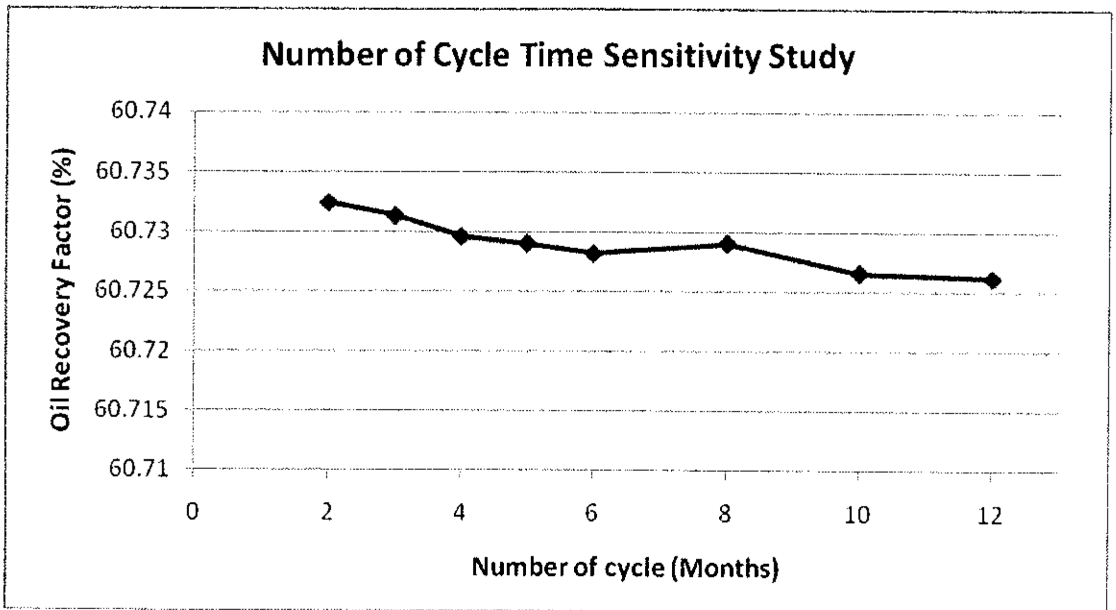

Figure 4.4: Oil Recovery Rate for Number of Cycle Time Sensitivity Study

For the WAG cycle time, the WAG cycle which is per month was simulated from 2 months to 12 months for each cycle using the preferred injection rate of 10,000 rb/day of water and gas. Referring to Figure 4.3, the total oil production is decreasing as the number of cycle increases except from 6 to 8 months where the total oil production increases slightly and subsequently decreases thereafter. Likewise, the total gas production is decreasing throughout as the number of cycle time increases.

The high recovery rates are for WAG cycles of 2, 3, 4 and 8 months. However, the difference in oil recovery factor (Refer Figure 4.4) is very small, only around 0.003% (~760 STB in 4320 days). Therefore, 8 months is chosen instead of 2, 3 or 4 months because lower frequency is always preferred as there will be less number of time to change the phase injected thus reduces the probability of mistakes and machine failure.

The cycle time of 8 months gives total oil production of 13.06733 MMSTB and a recovery rate of 60.729%. This cycle time would be used in the subsequent simulation.

4.1.3 WAG Ratio Sensitivity Study

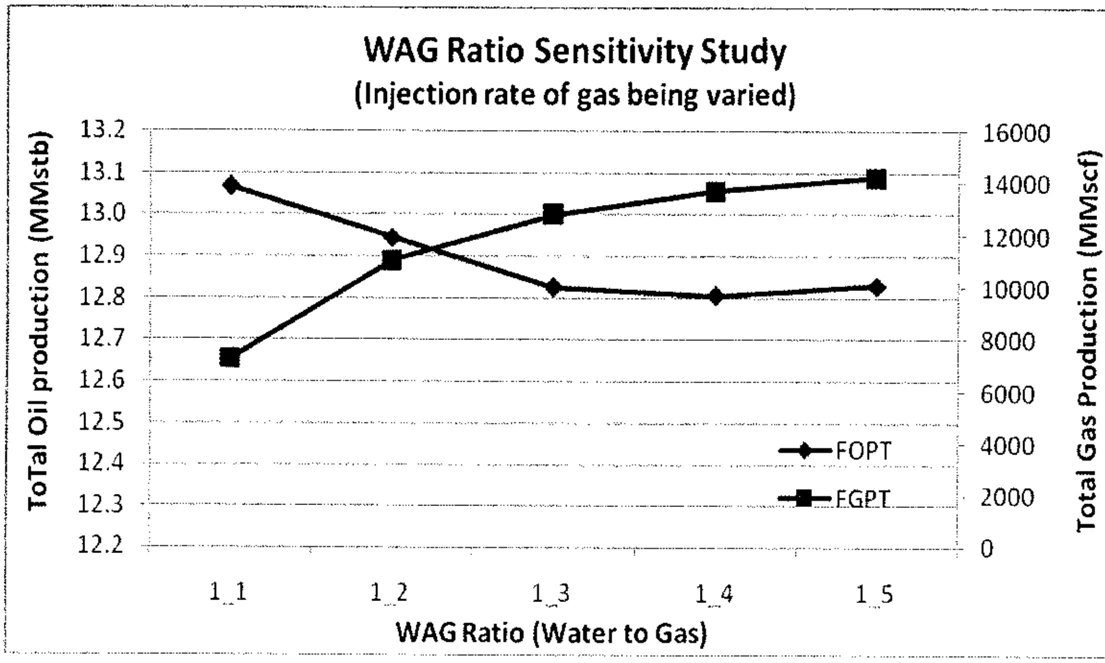

Figure 4.5: FOPT and FGPT for WAG Ratio Sensitivity Study
(Injection rate of gas being varied)

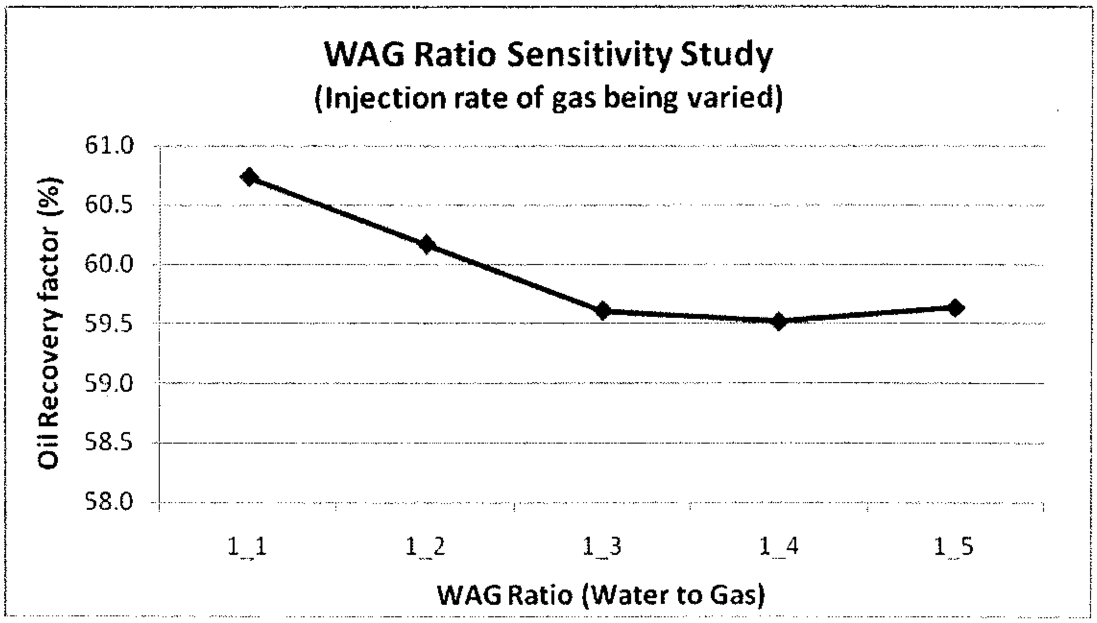

Figure 4.6: Oil Recovery rate for WAG Ratio Sensitivity Study
(Injection rate of gas being varied)

For the WAG ratio sensitivity study, the water to gas ratio was varied by varying the gas injection rate and thereafter the water injection rate. In this case, the injection rate used was 10, 000 rb/day with 8 months cycle time.

Referring to Figure 4.5, as the injection rate of gas is being increased, the total oil production is decreasing and on the other hand, the total gas production increases rapidly. The most optimum WAG ratio that would result in the highest oil recovery factor is 1:1 (Refer Figure 4.6) which gives total oil production of 13.06733 MMSTB and an oil recovery factor of 60.729%.

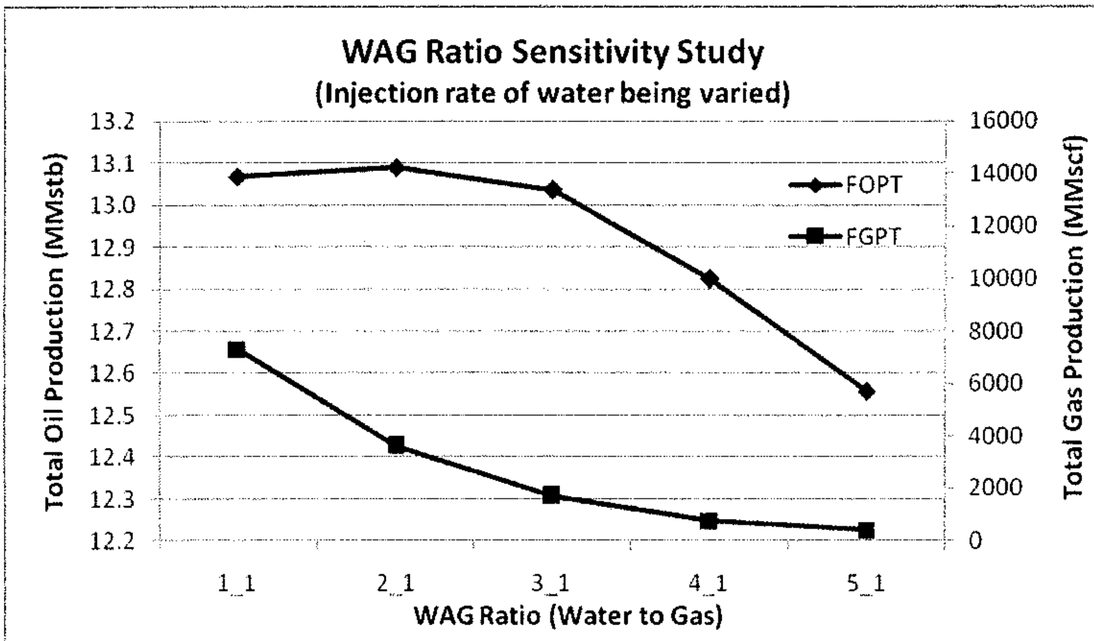

Figure 4.7: FOPT and FGPT for WAG Ratio Sensitivity Study

(Injection rate of water being varied)

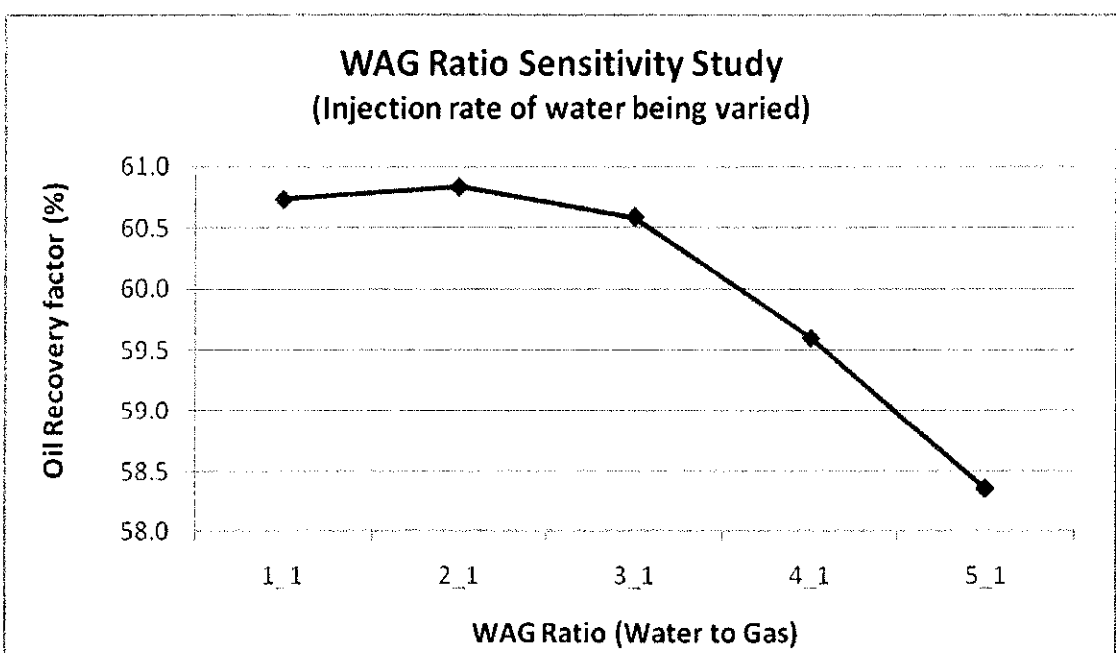

Figure 4.8: Oil Recovery rate for WAG Ratio Sensitivity Study(Injection rate of water being varied)

In Figure 4.7, the injection rate of water is being varied by increasing the injection rate of water in every run. It can be seen that the total oil production increases from a ratio of 1:1 to 2:1 and subsequently decreases thereafter. In addition, the total gas production decreases as the water injection rate increases. For this case, the most optimum WAG ratio that would result in the highest oil recovery factor is 2:1 (Refer Figure 4.8) which gives total oil production of 13.08928 MMSTB and an oil recovery factor of 60.8303%. The selection of the WAG ratio disregards the water cut value.

Table 4.1: Total Oil Production and Oil recovery factor for WAG Ratio sensitivity study

Water to Gas Ratio	FOPT (MMSTB)	Oil RF (%)
1:1	13.06733	60.729
2:1	13.08928	60.8303

Comparing both the WAG ratios from the table above, a WAG ratio of 2:1 gives higher total oil production and oil recovery factor. Therefore, this ratio is chosen as the most optimum WAG ratio.

In conclusion, the most optimum values for the conceptual model for 12 years are at an injection rate of 10,000 rb/day with a WAG cycle of 8 months and Water to Gas ratio of 2:1. The difference of the new case from the base case is tabulated below.

Table 4.2: Difference in Base Case and New Case after sensitivity study

Sensitivity	Base Case	New Case
Injection Rate (rb/day)	10,000	10,000
WAG cycle (months)	6	8
WAG ratio	1:1	2:1

4.2 CONCEPTUAL MODEL WITH HYSTERESIS

The optimum values from the sensitivity studies done earlier in section 4.1 are used to run the model with hysteresis. The section that follows discusses the results of using different hysteresis models. The legends on the graphs represent:

Base : Model without hysteresis

Case 0 : Carlson's Hysteresis Model for non-wetting phase(s), drainage (*SATNUM*) curve for wetting phase

Case 1 : Carlson's Hysteresis Model for non-wetting phase(s), imbibition (*IMBNUM*) curve for wetting phase

Case 2 : Killough's Hysteresis Model for non-wetting phase(s), drainage (*SATNUM*) curve for wetting phase

Case 3 : Killough's Hysteresis Model for non-wetting phase(s), imbibition (*IMBNUM*) curve for wetting phase

Case 4 : Killough's Hysteresis Model for both wetting and non-wetting phases

4.2.1 Results

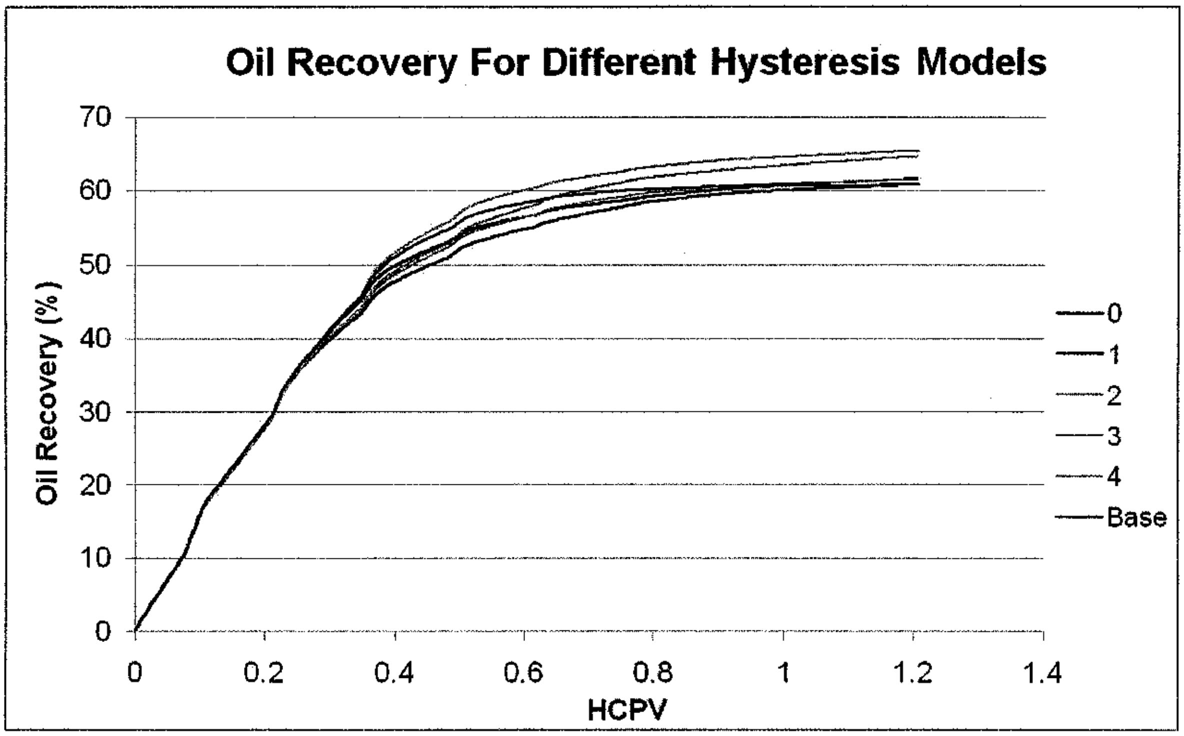

Figure 4.9: Oil Recovery for Different Hysteresis Models

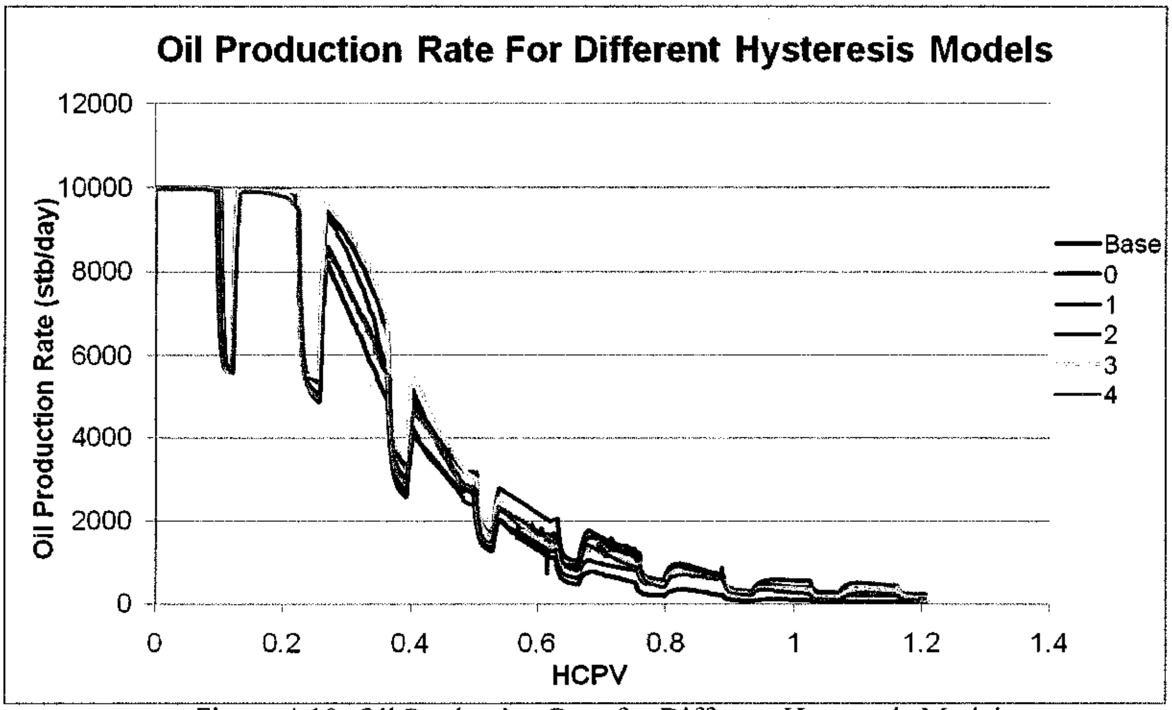

Figure 4.10: Oil Production Rate for Different Hysteresis Models

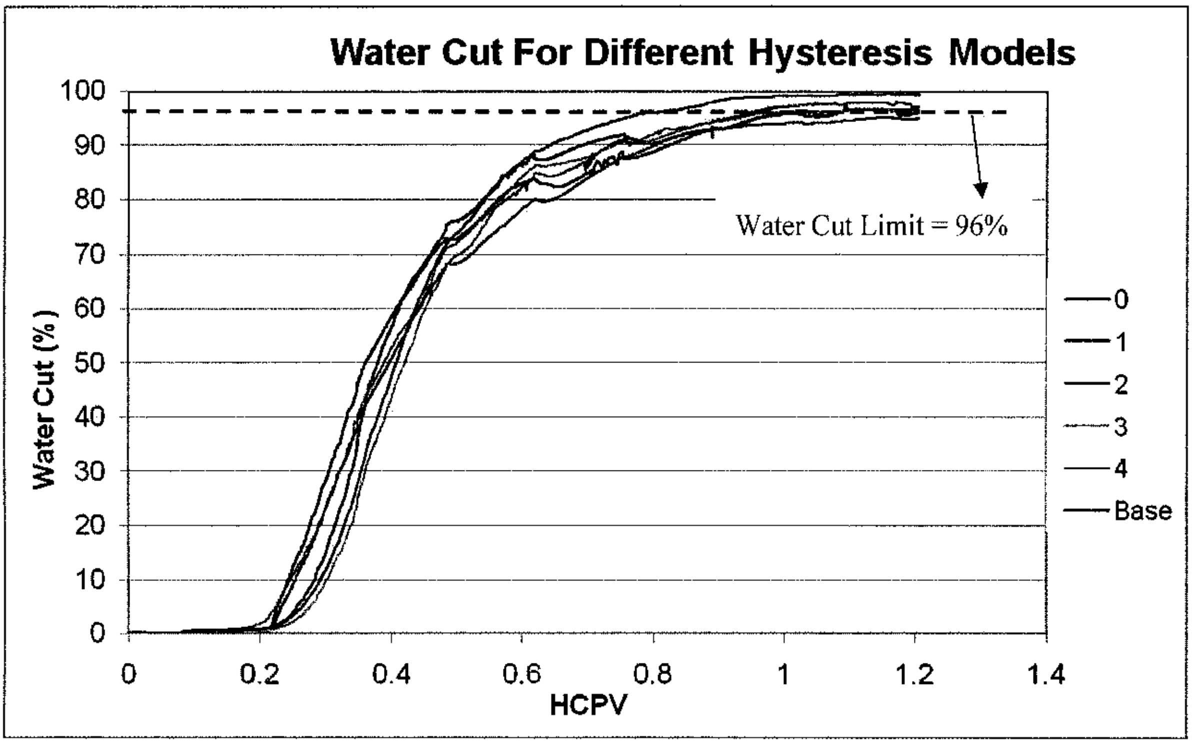

Figure 4.11: Water Cut for Different Hysteresis Models

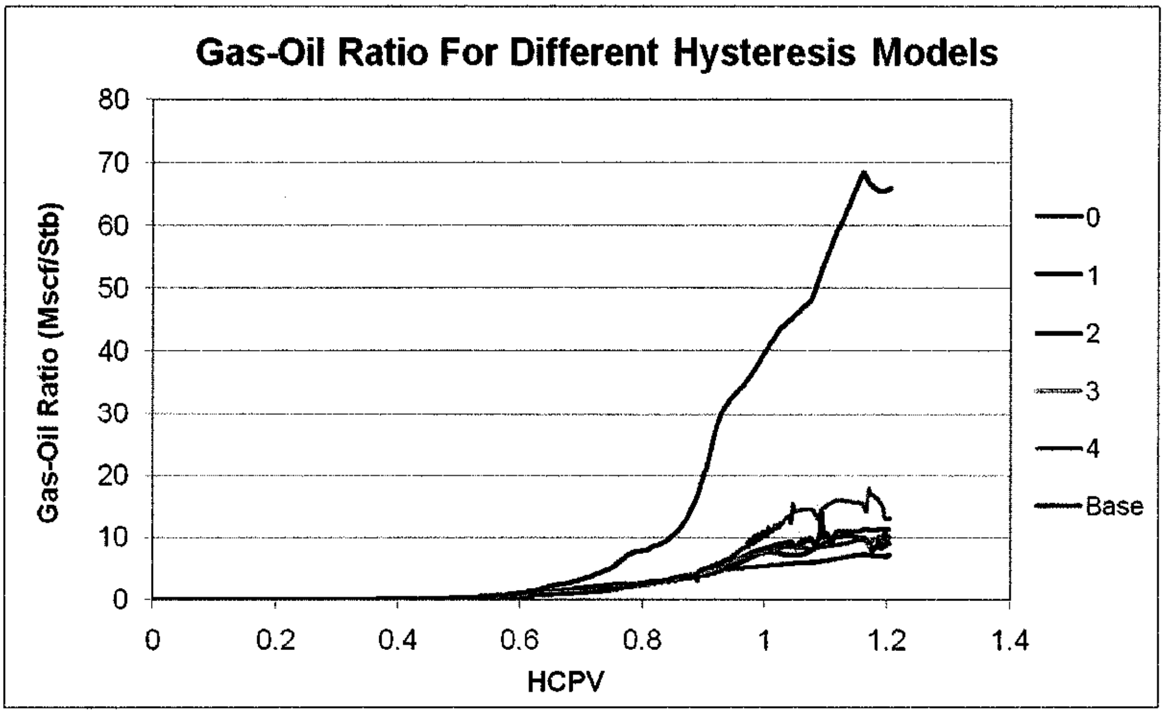

Figure 4.12: Gas-Oil Ratio for Different Hysteresis Models

4.2.2 Discussion

As it can be seen from Figure 4.9, Case 3 gives the highest oil recovery rate from all the cases. On the other hand, the base case gives the lowest recovery rate. However, the difference in oil recovery for all the cases varies slightly (less than 5%).

Referring to Figure 4.10, a definite declining pattern is seen in the oil production rate for all the cases. The decline in this rate is due to the lesser amount of oil left in the reservoir after production for some time. The base case here has the lowest oil production and case 2 has the highest oil production rate after 12 years.

The water cut values increases with increase in hydrocarbon pore volume (HCPV). This is due to the high amount of water injected into the reservoir (6666 rb of water/day). The optimum amount of water cut allowed when injecting water into the reservoir is 96%. By referring to Figure 4.11, the base case and Case 4 exceeds the maximum water cut value after 8 years and 9.4 years respectively. All the other 3 cases are below the maximum allowable water cut.

Since the amount of gas injected is much lesser compared to water (water to gas ratio is 2:1), the Gas-Oil ratio is seen to be very low for all the cases (Refer Figure 4.12). However, the base case here has the highest gas-oil ratio. This is probably due to the fact that hysteresis effect is not taken into account for this case. The cases with hysteresis have a very fluctuating trend of this Gas-Oil ratio especially after HCPV exceeds the value of 1 which could be due to gas breakthrough.

Table 4.3: Average Difference of Models from base Case

Case	Difference from Base Case		After 12 years,	
	Oil Recovery (%)	**Oil Production Rate (stb/day)**	**Oil Recovery (%)**	**Oil Production Rate (stb/day)**
Base	-	-	60.83	27.8
0	1.59	488.37	60.88	151.63
1	0.77	358.26	61.61	183.13
2	1.54	441.67	64.66	230.07
3	2.03	266.49	65.42	164.01
4	0.94	374.30	61.52	126.22

The table above quantifies the differences of the five different hysteresis models with the base case model (without hysteresis) with respect to the oil recovery and oil production rate. As it can be seen for the oil recovery, Case 3 has the biggest difference (2.03%) while Case 1 has the smallest difference (0.07%). For the oil production rate, Case 0 has the biggest difference (488.37 stb/day) and Case 3 the smallest difference, (266.49 stb/day).

After producing for 12 years, Case 2 gives the highest oil production rate and Case 3 gives the highest oil recovery. Case 2 and 3 are both using Killough's model for the non-wetting phases. This shows that by using Killough's model, it results in higher oil recovery compared to when using Carlson's model. This is due to the fact that Killough uses particular equations to produce the scanning curve where else Carlson's scanning curve is produced by shifting the imbibitions curve horizontally until it cuts the drainage curve at the maximum non-wetting phase saturation. The way the scanning curve (intermediate imbibiton curves) is generated differs in both the models. In addition, Carlson only uses a minimum of one point on the imbibition curve to calculate intermediate imbibition relative permeability curve (scanning curve) to the non-wetting phase where else Killough uses a parametric interpolation method to calculate the intermediate imbibition non-wetting phase relative permeability to produce the scanning curve.

The difference of oil recovery for the case where Carlson's model is used such as Case 0 and Case 1 is because of the user-input data for the drainage and imbibition curve respectively. However, since the user-input curves are calculated analytically for this conceptual model, the results may differ when using a real field with different input of drainage and imbibition curves.

The difference in Killough's Case 2 and 3 where the model is used for non-wetting phase can also be due to the user-input data for the drainage and imbibition curve respectively. However, Case 4 where Killough's model is used for both wetting and non-wetting phases has quite low oil recovery because the wetting phase exhibits a far smaller dependence on the trapped non-wetting saturation. Since the trapping on the non-wetting phase are one of the factors of hysteresis, this wetting phase relative permeability does not actually contribute much to material flow.

CHAPTER 5
CONCLUSION AND RECOMMENDATION

5.1 CONCLUSION

WAG is a process where water and gas are alternately injected into the reservoir by cycles to provide better sweep efficiency which will then improve oil recovery. However, this process produces hysteresis effect. All studies done in this report were conducted on a conceptual model. Sensitivity studies were conducted for a model without hysteresis (base case) to obtain the optimum parameters of injection rate, WAG ratio and WAG cycle to be input into the subsequent models (Case 0,1,2,3 and 4) where hysteresis effects were taken into account. From the study, the optimum values for production in 12 years are at an injection rate of 10,000 rb/day with a WAG cycle of 8 months and Water to Gas ratio of 2:1.

In addition, the models with hysteresis were run and the results for oil recovery, oil production rate, water cut and gas-oil ratio were analyzed. From the results obtained, it can be seen that difference in oil recovery for all the cases varies slightly with the base case giving the lowest recovery rate. A definite declining trend is seen in the oil production rate for all the cases. The base case again produces the lowest oil production and Case 2 has the highest oil production rate after 12 years. For the water cut analysis, the base case and Case 4 exceeds the maximum water cut value of 96% after 8 years and 9.4 years respectively. The Gas-Oil ratio is seen to be very low for all the cases since the amount of gas injected is relatively low compared to water (water to gas ratio of 2:1). However, the base case has high gas-oil ratio compared to the cases with hysteresis. From all these analysis, it can be said that hysteresis effect has a significant effect on oil recovery, oil production rate, water cut and gas-oil ratio.

The quantification of the oil recovery and oil production rate for all the cases were done and from the results obtained, the simulaton when Killough's model is used results in higher oil recovery compared to when Carlson's model is applied. This is due to the fact that Killough uses particular equations to produce the scanning curve where else Carlson's scanning curve is produced by shifting the imbibitions curve horizontally until it cuts the drainage curve at the maximum non-wetting phase saturation. Carlson's model has a very simple interpretation where else on the other hand Killough's model has specific geometric interpretation where a parametric interpolation method is used to calculate the intermediate imbibition non-wetting phase relative permeability to produce the scanning curves. Therefore, it can be concluded that, from the quantification of the two different hysteresis models on a conceptual model, the simulation when Killough's model is used results in higher recovery and oil production rate compared to when applying Carlson's model. This quantification of different hysteresis models can help in obtaining more precise prediction of forecasting oil recovery.

For the conceptual model run in this study, simulation with Killough's model is preferred as it gives higher oil recovery and production rate. However, this analysis may differ when different fields are modeled as different fields exhibit different characteristics and properties. Therefore, further study should be done on several other conceptual models or on real field models with different characteristics and properties.

5.2 RECOMMENDATION

Due to time constrain the study of this project was done on a conceptual model only. In future, this same study could be done on a real field model where the reservoir would have different characteristics and user-input relative permeability curves. The real field model can then further quantify and verify the difference obtained here.

In addition, sensitivity studies on the model with hysteresis could be done on parameters that effect hysteresis such as Land's parameter, the secondary drainage factor and imbibition curve linear function.

Other than that, future work on wettability effect on hysteresis of WAG process could be done. Different reservoirs have different wetting phases; therefore by having different wetting phases, hysteresis on the WAG process could be affected.

A study could also be done on ways to include the gas phase (a third phase) into the two-phase hysteresis models available such as Killough and Carlson. The available models only take into account the liquid relative permeability. However, in the water-alternating-gas injection, there are three phases present and all these three phases need to undergo the hysteresis effect.

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APPENDIX A: GANTT CHART

Gantt Chart for First Semester of 2-semester Final Year Project

No.	Detail/ Week	1	2	3	4	5	6	7	8	9	10		11	12	13	14
1	Selection of Project Topic	●										Mid-Semester Break				
2	Preliminary Research Work - Journals research, Literature review - Understanding and familiarizing of terms such as WAG, permeability, drainage and imbibition		●	●	●											
3	Submission of Preliminary Report				●											
4	Project work - More literature review and deeper understanding on hysteresis, two-phase relative permeability and etc.					●	●	●	●							
5	Approval for lab access from Security Dept									●						
6	Submission of Progress Report										●					
7	Seminar 2												●			
8	Eclipse software training - Familiarizing with keywords in Eclipse - Practising on tutorials - Basic data file created												●	●	●	
9	Submission of Interim Report Final Draft														●	
10	Oral Presentation															●

Gantt Chart for Second Semester of 2-semester Final Year Project

No.	Detail/ Week	1	2	3	4	5	6	7	8	9		10	11	12	13	14	15	16	17	18	19	20
1	Conceptual Model without hysteresis Sensitivity studies - Injection Rate - WAG Cycle time - WAG Ratio	●	●	●							Mid-Semester Break											
2	Analysis of results from sensitivity studies				●	●																
3	Submission of Progress Report I					●																
4	Relative Permeability Correlations						●	●														
5	Running Conceptual model with hysteresis (Case 0)							●														
6	Running Conceptual model with hysteresis (Case 1)								●													
7	Running Conceptual model with hysteresis (Case 2)								●													
8	Running Conceptual model with hysteresis (Case 3)									●												
9	Running Conceptual model with hysteresis (Case 4)									●												
10	Running Conceptual model with hysteresis (Case 5)											●										
11	- Analysis of results - Compiling of all results											●	●	●								
12	Poster Exhibition / Pre EDX													●								
13	Submission of Dissertation (soft bound)															●						
14	Final Oral Presentation																			●	●	
15	Submission of Project Dissertation (Hard Bound)																					●

APPENDIX B: DATA FILE FOR CONCEPTUAL MODEL WITH HYSTERESIS

```
RUNSPEC

3D three-phase

DIMENS
15        15        9/

OIL
WATER
GAS

FIELD

SATOPTS
'HYSTER'  /

TABDIMS
2   1   3*  /

WELLDIMS
2       9       2       1 /

UNIFOUT

START
1 JAN 2002 /


--==================================================================
GRID

DX
2025*170 /


DY
2025*170  /


DZ
2025*17  /


BOX
         1    15     1   15      1   1  /


TOPS
225*8000  /


ENDBOX
```

```
PERMX
2025*400 /


PERMY
2025*400 /


PERMZ
2025*400 /


PORO
2025*0.2  /

INIT

--===================================================================
PROPS

EHYSTR
0.1  0  1.0  0.1  KR /


WAGHYSTR
2.0  1.0  YES  YES   NO /
/

STONE1

DENSITY
49        63        0.01 /

PVDO
         300         1.25        1.0
         800         1.20        1.1
        6000         1.15        2.0   /


PVDG
      300     1.25     1.0
      800     1.20     1.1
      6000     1.15     2.0 /


PVTW
          4500         1.02     3.0E-06        0.8                0.0  /


ROCK
         4500         4E-06 /
```

```
SWFN
      0.25      0.0            4.0
      0.5       0.2            0.8
      0.7       0.4            0.2
      0.8       0.55           0.1 /


      0.25     0.0          4.0
      0.4      0.07         2.9
      0.5      0.16         2.25
      0.7      0.4          0.0 /



SGFN
      0.0      0.0      0.1
      0.3      0.2      0.5
      0.5      0.4      0.8
     0.75      0.6      4.0 /


       0       0.0      0.0
     0.3       0.29     2.6
     0.5       0.53     3.37
     0.75      0.87     4.14 /



SOF3
      0.3      0.0      0.0
      0.5      0.2      1*
      0.6      0.3      1*
     0.75      1.0      1.0 /


    0.3       0       0
    0.5      0.25    1*
    0.6      0.4     1*
    0.75     0.7     0.7 /



RPTPROPS
 SGFN   SWFN   SOF3  /

--=============================================================
REGIONS

IMBNUM
2025*1  /

SATNUM
2025*2  /
```

```
--=================================================================
SOLUTION

EQUIL
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RPTSOL
    FIP=1   /

--=================================================================
SUMMARY

FPR

WBHP
/

FOPR

FWPR

FOPT

FWPT

WWCT
PROD /

FOIP
FGIP
FGPT
FGPR
FOE
FVIT
FGOR
FWCT


BGSAT
1   1   5 /
2   2   3 /
14  14  3 /
15  13  6 /
/

TCPU

EXCEL

--=================================================================
SCHEDULE

RPTRST
```

```
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DIMPES
1*  0.2  550 /

WELSPECS
         PROD    G1     2     2   8000    OIL /
         INJ     G2     14    14  8000  WATER /
/

COMPDAT
        PROD     2     2     1    9     OPEN    2*     0.6667 /
        INJ      14    14    1    9     OPEN    2*     0.6667 /
/

WCONPROD
   PROD    OPEN    LRAT             3*             10000    1*    2000 /
/

WCONINJ
    INJ 'WAT' 'OPEN' 'RESV' 1*  13334   2*   5000 /

/

TSTEP
24*10 /

WCONINJ
    INJ 'GAS' 'OPEN' 'RESV' 1*  6666  2*   5000 /

/

TSTEP
24*10 /

WCONINJ
    INJ 'WAT' 'OPEN' 'RESV' 1*  13334   2*   5000 /

/

TSTEP
24*10 /

WCONINJ
    INJ 'GAS' 'OPEN' 'RESV' 1*  6666  2*   5000 /
/

TSTEP
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```
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24*10 /


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/


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24*10 /


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/


TSTEP
24*10 /
```

```
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/


TSTEP
24*10 /


WCONINJ
    INJ 'GAS' 'OPEN' 'RESV' 1*  6666  2*   5000 /
/


TSTEP
24*10 /



WCONINJ
   INJ 'WAT' 'OPEN' 'RESV' 1*  13334   2*   5000 /
/


TSTEP
24*10 /


WCONINJ
    INJ 'GAS' 'OPEN' 'RESV' 1*  6666  2*   5000 /
/


TSTEP
24*10 /


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    INJ 'GAS' 'OPEN' 'RESV' 1*  6666  2*   5000 /
/


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/
```

```
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24*10 /

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/

TSTEP
24*10 /


END
```