A SIMULATION STUDY OF MISCIBLE AND IMMISCIBLE CO_2 WAG INJECTION

by

JOACHIM WAN HAN YONG

Dissertation submitted in partial fulfillment of

requirement for the

Bachelor of Engineering (Hons)

Petroleum Engineering

MAY 2013

Universiti Teknologi PETRONAS

Bandar Seri Iskandar

31750 Tronoh

Perak Darul Ridzuan

CERTIFICATION OF APPROVAL

A SIMULATION STUDY OF MISCIBLE AND IMMISCIBLE CO_2 WAG INJECTION

by

JOACHIM WAN HAN YONG

A project dissertation submitted to

Petroleum Engineering Programme

Universiti Teknologi PETRONAS

in partial fulfillment of the requirement for the

Bachelor of Engineering (Hons)

Petroleum Engineering

Approved by,

____

(PROF DR MUSTAFA ONUR)

UNIVERSITI TEKNOLOGI PETRONAS

TRONOH, PERAK

MAY 2013

CERTIFICATION OF ORIGINALITY

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

JOACHIM WAN HAN YONG

ABSTRACT

As reservoir pressure continues to deplete leaving substantial unrecovered oil in the reservoir after secondary recovery, various enhanced oil recovery methods need to be evaluated to produce additional drive to increase the recovery factor of reservoir oil, among which is the water alternating gas (WAG) injection method. Choice has to be made whether to perform miscible or immiscible displacement, depending on reservoir conditions, incremental recovery, and cost-benefit analysis. In this project, several factors affecting miscible and immiscible displacement performance are reviewed, such as volumetric sweep efficiency and unit displacement efficiency. CO_2 gas is chosen to be the subject of research because of its favorable properties and behavior for miscible flooding, and its abundance in Malaysia (Samsudin, et al., 2005). This project focuses on studying the potential ways to achieve CO_2 miscibility with reservoir oil via increasing reservoir pressure via water flooding, or decreasing reservoir temperature via coolant flooding, by using a compositional model simulator with thermal option. Simulation results show that lowering reservoir temperature allows CO_2 to extract more heavy components from the oil phase, which increases oil recovery factor. This can be done by injecting cold water and/or cold CO_2 itself. However, if CO_2 temperature drops below its critical temperature, it condenses into liquid phase with extremely high viscosity, therefore it may take a longer time to cool down regions further away from the injector.

ACKNOWLEDGEMENTS

I would like to thank my supervisor, Prof Dr Mustafa Onur, for his guidance and supervision in completing this project. His constant support, assistance, and encouragement have motivated me to take up the challenge to explore this previously unfamiliar topic of miscible displacement. I truly appreciate the effort and time he spent on me throughout the course; in helping me to better understand the topic.

I would also like to thank my colleagues who have given me support and assistance in completing this project.

TABLE OF CONTENTS

ABSTRACT IV
ACKNOWLEDGEMENTS V
TABLE OF CONTENTS VI
LIST OF FIGURES VII
LIST OF TABLES VIII

CHAPTER 1: INTRODUCTION 1

1.1 BACKGROUND OF STUDY 1
1.2 PROBLEM STATEMENT 1
1.3 OBJECTIVES 2
1.4 SCOPE OF STUDY 2

CHAPTER 2: LITERATURE REVIEW AND/OR THEORY 3

2.1 EARLY DEVELOPMENT IN MISCIBLE DISPLACEMENT 3
2.2 MISCIBLE AND IMMISCIBLE DISPLACEMENT 4
2.3 MECHANISMS TO ACHIEVE MISCIBILITY 6
2.4 FACTORS AFFECTING MISCIBLE DISPLACEMENT 9
2.5 WAYS TO DETERMINE MINIMUM MISCIBILITY PRESSURE (MMP) 10
2.6 PROPERTIES OF CO_2 AS MISCIBLE SOLVENT 11
2.7 EFFECT OF COLD WATER FLOODING ON RESERVOIR TEMPERATURE 12
2.8 EFFECT OF RESERVOIR TEMPERATURE ON MMP 13
2.9 MOBILITY RATIO 15
2.10 WATER ALTERNATING GAS INJECTION 15
2.11 HYSTERESIS EFFECT DURING WAG INJECTION 17
2.12 SUBSURFACE ISSUES FOR CO_2 FLOODING 18
2.13 EOR REVIEW ON MALAYSIA'S OIL FIELDS 19
2.14 SUMMARY 19

CHAPTER 3: METHODOLOGY/PROJECT WORK 21

3.1 FLUID MODELING 22
3.2 STATIC MODELING 26
3.3 DYNAMIC MODELING 28
3.4 KEY MILESTONE 30
3.5 GANTT CHART 30

CHAPTER 4: RESULTS AND DISCUSSION 31

4.1 NATURAL DEPLETION – BASE 31
4.2 WATER FLOODING – WF 31
4.3 CONTINUOUS CO_2 GAS INJECTION – CGI 39
4.4 WATER ALTERNATING GAS MODE – WAG 49
4.5 FUTURE WORK 53

CHAPTER 5: CONCLUSIONS 52

REFERENCES 54

LIST OF FIGURES

Figure 2-1: Immiscibility of methane gas and oil liquid at reservoir temperature and pressure (Clark, et al., 1958). 4
Figure 2-2: Miscibility of methane gas and propane liquid at reservoir temperature and pressure (Clark, et al., 1958). 4
Figure 2-3: Miscibility of propane liquid and oil liquid at reservoir temperature and pressure (Clark, et al., 1958). 5
Figure 2-4: Gas displacement from high permeability channel (Clark, et al., 1958). 6
Figure 2-5: Water displacement from low permeability channel (Clark, et al., 1958). 6
Figure 2-6: Pseudo-ternary Diagram showing phase behavior of CO_2, pseudo-component C_6^-, and pseudo-component C_7^+ (Stalkup Jr., 1983). 7
Figure 2-7: Combined condensing/vaporizing drive mechanism. 9
Figure 2-8: MMP plot from slim tube experiment (Yellig, et al., 1978). 10
Figure 2-9: CO_2 Phase Diagram (Shakhashiri, 2008). 12
Figure 2-10: Effect of injection rate of cold water on average reservoir temperature reduction rate (Gong, et al., 2011). 13
Figure 2-11: CO_2 MMP at different PV of coolant injected (Shu, 1985). 14
Figure 2-12: Correlation between CO_2 MMP and reservoir temperature (Yellig, et al., 1978). 14
Figure 2-13: Partial completion of vertical injector and producer (Wu, et al., 2004). 17
Figure 2-14: Partial completion of horizontal injector and producer (Wu, et al., 2004). 17
Figure 3-1: Regression of saturation pressure. 24
Figure 3-2: Regression of swelling factor. 25
Figure 3-3: Plot of MMP against Temperature. 26
Figure 3-4: Water-Oil relative permeability curves. 27
Figure 3-5: Gas-Oil relative permeability curves. 27
Figure 3-6: Model viewed in FloViz 29
Figure 4-1: Water injection rate (WWIR) of the injector well 32
Figure 4-2: Field oil recovery factor (FOE) of WF cases and BASE case. 34
Figure 4-3: Block temperature (BTEMP) at different water injection temperature. 36
Figure 4-4: Viscosity (VOIL) and temperature distribution. 38
Figure 4-5: Plot of field recovery factor against volume of CO_2 injected 39
Figure 4-6: Effect of temperature on oil viscosity 41
Figure 4-7: Effect of temperature on gas viscosity. 42
Figure 4-8: Liquid mole fraction of components at 215˚F injection temperature. 43
Figure 4-9: Liquid mole fraction of components at 180˚F injection temperature. 43
Figure 4-10: Liquid mole fraction of components at 150˚F injection temperature. 44
Figure 4-11: Effect of injection temperature on field oil recovery factor 45
Figure 4-12: CO_2 injection at 40˚F. 46
Figure 4-13: Temperature profile of continuous gas injection at 150˚F. 47
Figure 4-14: Temperature profile of water flooding at 150˚F. 48
Figure 4-15: Effect of WAG ratio on field oil recovery factor of WAG schemes. 50
Figure 4-16: Effect of cycle size on field oil recovery factor of WAG schemes. 51

LIST OF TABLES

Table 3-1: Composition of reservoir fluid. 22
Table 3-2: Sat. pressures and swelling factors. 22
Table 3-3: Component properties after regression. 23
Table 3-4: Basic reservoir and fluid properties 27

CHAPTER 1: INTRODUCTION

1.1 BACKGROUND OF STUDY

The energy which initially drives reservoir oil during early stages of production often is depleted long before majority of oil is removed from it. Additional energy drive from outside sources is then used to drive the reservoir before or subsequent to the depletion of the native reservoir energy. Miscible phase displacement technique is a form of enhanced oil recovery technique where a fluid which is miscible with reservoir oil is introduced through injection wells to displace the oil from the pores of the reservoir and drive it to a production well. The effectiveness of miscible displacement is derived from the fact that the retentive forces of capillary and interfacial tension between solvent and reservoir oil is eliminated (Shu, 1985).

CO_2 has been recently used successfully as a miscible oil recovery agent because it is highly soluble in oil, and dissolution of CO_2 in oil causes a reduction in the viscosity of the oil and increase in oil volume through swelling, which enhances recovery efficiency. It is also able to achieve miscibility with reservoir oil at a larger range of reservoir pressure. In a review of EOR projects in Malaysia, Samsudin et al claimed that Malaysia is very fortunate because CO_2 is in abundance, which secures a long term supply of injection gas (Samsudin, et al., 2005). The change in CO_2 minimum miscibility pressure (MMP) is shown as a direct function of temperature by Yellig et al (Yellig, et al., 1978). It is shown that for every 50˚F drop in temperature, the CO_2 MMP decreases by about 600 to 700 psia. Therefore, if the CO_2 MMP can be substantially lowered without increasing reservoir pressure, significant energy can be saved by allowing injection pressure to be lowered in low pressure reservoirs.

1.2 PROBLEM STATEMENT

The amount of recoverable oil by primary and secondary recovery often consists of only a small portion of the oil originally in-place. Therefore, tertiary recovery methods are often conducted to increase the amount of recoverable oil from the reservoir, one of which is known as WAG injection method. WAG injection can be done either in miscible or immiscible manner, where the former usually gives a higher incremental recovery (Wu, et al., 2004). In Kulkarni’s study (Kulkarni, 2003), it was found that when oil recovery per unit volume of gas injected is used as a parameter to evaluate floods, miscible gas flooding were found to be more effective than immiscible floods, and WAG mode of injection out-performed continuous gas injection. At very shallow reservoirs, the relatively low reservoir pressure is often insufficient to allow miscible displacement by WAG injection. However, several methods can be used to increase the reservoir pressure, or to lower the minimum miscibility pressure (MMP) of injected gas, to allow miscible displacement, which will induce extra cost. The cost-benefit analysis need to be conducted based on the incremental recovery to gauge the feasibility of the methods.

1.3 OBJECTIVES

The objectives of this study are to evaluate the recovery performances of miscible and immiscible Water Alternating Gas (WAG) injection and to study the effects of various parameters (e.g. conditions of injection fluid and reservoir fluid) on the performances of miscible and immiscible Water Alternating Gas (WAG) injection.

1.4 SCOPE OF STUDY

The effects of injection temperature and pressure on miscible and immiscible WAG injection will be studied using a compositional simulator.

CHAPTER 2: LITERATURE REVIEW AND/OR THEORY

2.1 EARLY DEVELOPMENT IN MISCIBLE DISPLACEMENT

After discovery, most oil reservoirs typically undergo a period of production called primary recovery in which natural energy associated with a reservoir is used to recover a portion of the oil, such as liquid expansion, aquifer support and rock compaction. From the early days of the oil production up until the early 1930's, most reservoirs are abandoned as soon as production by primary recovery mechanisms reached an uneconomical oil rate. A typical range for recovery efficiency at this point is 5 to 20% original oil in place (OOIP). At this point, immiscible gas injection or water flooding into multiple wells gradually became accepted as a method to increase oil recovery from 20 to 40% OOIP (Stalkup Jr., 1992).

It is also mentioned in Stalkup's monograph that the ultimate recovery achievable by immiscible gas injection or water flooding is limited primarily by three factors: volumetric sweep out, displacement efficiency, and capture of the displaced oil at the producing wells. Volumetric sweep out of the reservoir volume is always less than 100% due to permeability stratification, viscous fingering, gravity segregation and incomplete areal sweep. Displacement efficiency is affected by the high residual oil saturation due to immiscibility between reservoir oil and the immiscible injection fluid. Moreover, some of the displaced oil near the injector might not be captured by (or in other words, reach) the producing wells because some go to re-saturate the pore spaces before reaching the producers.

To counter the problems faced by immiscible injection to improve recovery factor, considerable effort has been put to research on miscible drive processes which shows great promise in oil recovery. In the past, miscible displacement researches focus on the utilization of hydrocarbon materials such as propane, LPG, and hydrocarbon gas, to be injected into a reservoir under such conditions that fluid capillary forces are reduced to zero and unit displacement efficiency is increased in those pore spaces through which injected materials move (Clark, et al., 1958). These hydrocarbon solvents however, are expensive and, though efficient in miscible displacement, would be uneconomical due to the cost of the great quantity of materials required.

2.2 MISCIBLE AND IMMISCIBLE DISPLACEMENT

Two fluids are said to be miscible when they mix together in all proportions to form a single homogenous phase, having no interfacial tension between the two fluids (e.g. gasoline and kerosene). If the two fluids do not mix well and form two distinct phases separated by a sharp interface, the fluids are said to be immiscible (e.g. oil and water) (Stalkup Jr., 1992). Methane and oil tend to dissolve in each other; however they do not mix in all proportions and are thus considered as immiscible. The figures below (Figure 2-1, Figure 2-2, and Figure 2-3) show examples of miscible and immiscible mixtures:

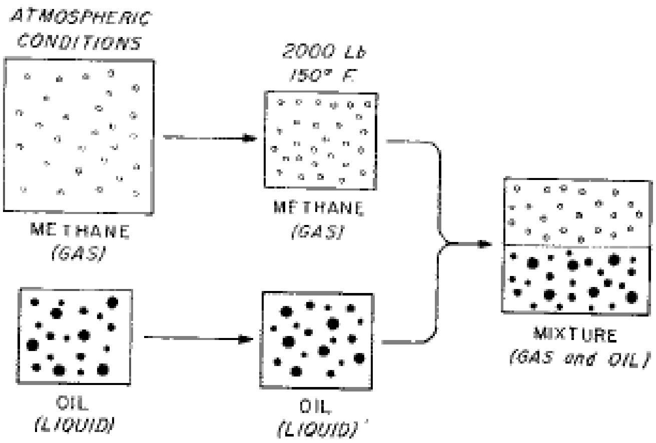


Figure 2-1: Immiscibility of methane gas and oil liquid at reservoir temperature and pressure (Clark, et al., 1958).

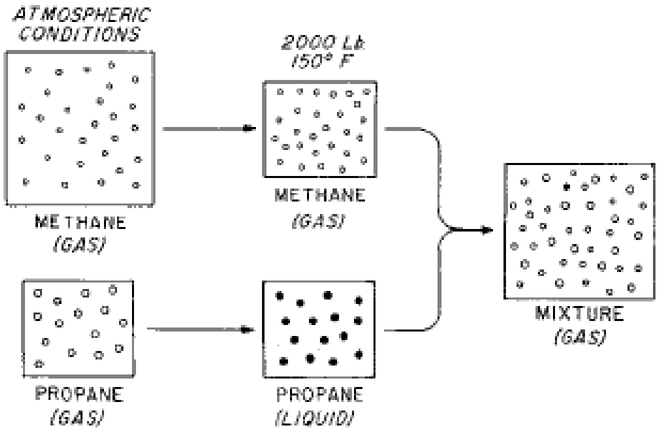


Figure 2-2: Miscibility of methane gas and propane liquid at reservoir temperature and pressure (Clark, et al., 1958).

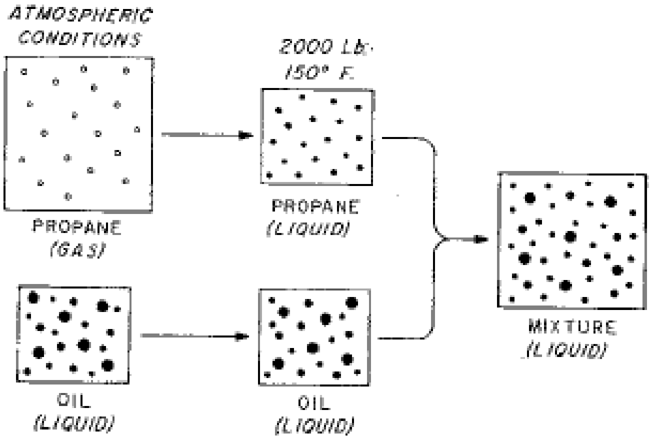


Figure 2-3: Miscibility of propane liquid and oil liquid at reservoir temperature and pressure (Clark, et al., 1958).

In reservoir context, miscible displacement eliminates the interfacial tension, as the capillary number becomes infinite, the residual oil saturation can be reduced to its lowest value. This is the ultimate objective of miscible displacement, where recovery is maximized by the effective removal of the influence of interfacial and capillary forces (Wu, et al., 2004). During miscible displacement, there is no effect of relative permeability between displacing fluid and reservoir oil on recovery factor. However, reservoir wettability has a significant effect on miscible flood oil recovery, with a trend of increasing incremental oil recovery with increasing oil-wetness. This means that the incremental oil recovery that can be obtained from miscible flooding is higher in oil-wet reservoirs than in water-wet reservoirs. Miscible flooding can alter in-situ rock wettability and can influence oil recovery (Rao, et al., 1991).

On the other hand, the flow behavior in immiscible displacement is determined by the relative permeability profile of the two fluids (Stalkup Jr., 1992). As oil saturation decreases, oil relative permeability also decreases. However, oil relative permeability decreases to zero while oil saturation is finite, known as the residual oil saturation which is the limiting saturation of oil in that unit volume. Residual oil saturation is affected by rock wettability and interfacial tension. Wettability is defined as the tendency of one fluid to spread on or to adhere to a solid surface in the presence of other immiscible fluids. Relative permeability for oil-wet rocks are more unfavorable for water flooding compared to water-wet rocks due to earlier water breakthrough in the oil-wet rocks.

Under immiscible gas displacement conditions, due to the high mobility and low viscosity, gas tends to flow through only the larger pore channels, leaving some residual oil in the low permeability pore channels. On the other hand, in immiscible water flooding, capillary forces tend to cause water to move faster into the smaller low permeability channels in water-wet conditions, leaving residual oil trapped in the larger pore spaces by the interfacial forces inherent between water and oil (Clark, et al., 1958). This is because in a water-wet reservoir, water preferentially wets the surface of the rock, thus it will flow through the narrower pore spaces with the highest capillary pressure, leaving oil residuals trapped in the larger pores. If the interfacial tension exhibited in the interface between the droplets of oil and the injected fluid can be sufficiently reduced, these droplets of oil conceivably could be displaced easily along the pore channel with the injected fluid. Figure 2-4 and Figure 2-5 show the illustrations of the above situation:

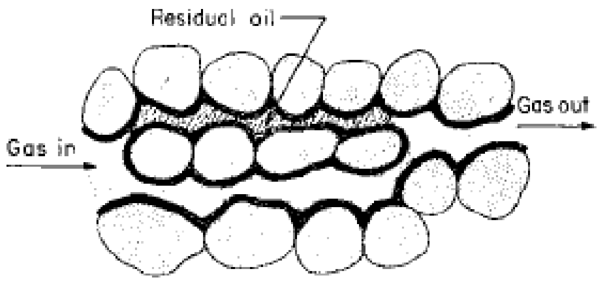


Figure 2-4: Gas displacement from high permeability channel (Clark, et al., 1958).

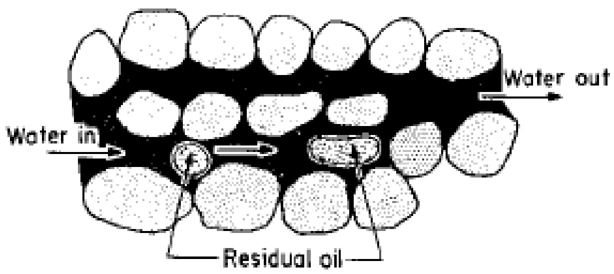


Figure 2-5: Water displacement from low permeability channel (Clark, et al., 1958).

2.3 MECHANISMS TO ACHIEVE MISCIBILITY

There are originally three types of ways to achieve miscibility (Stalkup Jr., 1992), which are first contact miscibility, multiple-contact condensing gas drive, and multiple-contact vaporizing gas drive. The phase behavior of a multi-component mixture can be shown on a pseudo-ternary diagram, where components are grouped into three pseudo-components. In first contact miscibility, injected fluid mixes with reservoir oil completely in all proportions at first contact. Otherwise, if the injected fluid contains enough intermediate hydrocarbon, multiple contact condensing gas drive might occur, where intermediate hydrocarbon from injected fluid condenses into reservoir oil multiple times to form a mixture which is miscible with the injected fluid. Another mechanism of multiple contact miscibility is the vaporizing gas drive, where intermediate hydrocarbon in the reservoir oil is vaporized and causes the injected fluid to be miscible with the reservoir oil. Figure 2-6 shows a typical pseudo-ternary diagram used to evaluate the miscibility of CO_2 with reservoir oil:

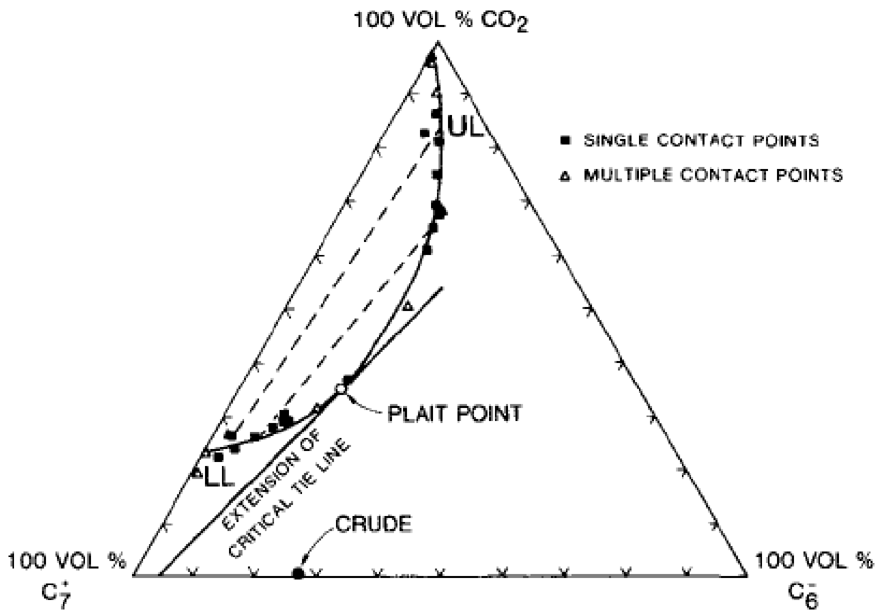


Figure 2-6: Pseudo-ternary Diagram showing phase behavior of CO_2, pseudo-component C_6^-, and pseudo-component C_7^+ (Stalkup Jr., 1983).

In the above diagram, plait point is the point where the upper line (UL) meets the lower line (LL). The vapor line is the line at which compositions will exhibit single vapor phase, whereas the liquid line is the line at which compositions will exhibit single liquid phase. The region enclosed by the vapor line and the liquid line will be the region at which compositions will exhibit 2 phases, with the vapor composition determined by the point where the tie line (the dotted line) meets the vapor line, and liquid composition determined by the point where the tie line meets the liquid line. A straight line which is the tangent to the curve formed by vapor line and liquid line is called the critical tie line.

However, Zick claimed that there exists a combined condensing/vaporizing gas drive mechanism, where both mechanisms are observed (Zick, 1986). Consider a hydrocarbon system composed essentially of four groups of components: very light components such as C_1 and N_2, light intermediates which are able to enrich reservoir oil via condensation, middle intermediates which can be vaporized to enrich the injection gas, and the heavy components which are usually difficult to vaporize.

When injected enriched gas comes into contact with reservoir oil, light intermediates condense into oil, making oil lighter. The gas then moves on ahead and is replaced with fresh injected gas, and the condensing process continues. However, at the same time, middle intermediates are being vaporized into the gas, making the oil heavier. After a few contacts with the fresh injected gas, the oil will eventually become saturated with light intermediates, ending the process of condensation. Unlike injected gas which is constantly replaced, the middle intermediates will continue to be vaporized from the same oil by fresh injected gas, causing net vaporization which makes the oil heavier. Ultimately all the middle intermediates will be removed, leaving residual oil which is very heavy, containing only the heaviest components.

Consider the fresh reservoir oil which is further downstream from the injection point, the first gas that will be encountered here is gas which has lost some of its light intermediates and gained some middle intermediates. There will be very little mass transfer between this gas and the fresh reservoir oil. However, the next gas that follows will have as much light intermediates as fresh injected gas, and small amount of middle intermediates. The reservoir oil that sees this gas will receive more net condensed light intermediates, before the net vaporization process takes over again when it encounters fresh injected gas later.

Even further downstream, the injected gas that will be encountered is probably enriched with an increasing amount of middle intermediates. However, the gas will not be enriched enough to be fully miscible with the fresh reservoir oil. The condensing of light intermediates continues, and eventually a vaporization process results in a small saturation of residual oil being left behind. Therefore, the condensing region will be at the leading edge of the gas displacement, and the vaporizing region will be at the trailing end, leaving small saturation of residual oil. In between is the sharp, two-phase transition zone, where the two phases are near-miscible. This results in a very efficient "apparently" miscible displacement, caused by combined condensing/vaporizing mechanism. This mechanism can be illustrated in Figure 2-7:

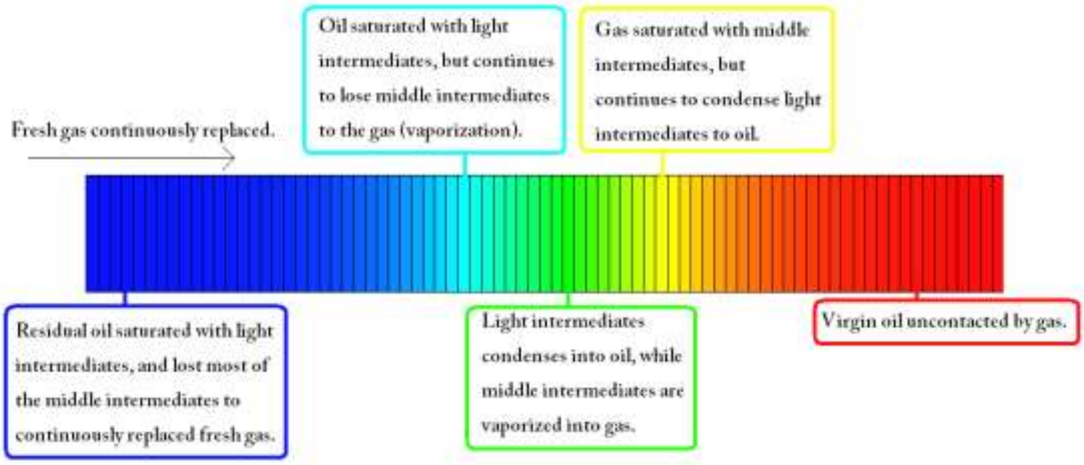


Figure 2-7: Combined condensing/vaporizing drive mechanism.

2.4 FACTORS AFFECTING MISCIBLE DISPLACEMENT

There are several factors affecting the efficiency of miscible displacement, among which are the conditions of reservoir temperature and pressure, and the composition of the injected fluid. For miscible drive to occur, a certain pressure for a given temperature must prevail to maintain miscible conditions between oil and injected fluid, known as the minimum miscibility pressure (MMP). If the reservoir pressure is below the MMP, miscibility will not occur. In that case, proper requirement for pressure control of the reservoir must be conducted to induce miscible displacement. Next, the composition of injected fluid can be controlled as to content such that the composition can allow miscible drive to be achieved. This can be done by increasing the amount of intermediate hydrocarbon in the injected hydrocarbon gas, which may lower the MMP needed for miscibility. The minimum amount of secondary solvent (which is the fluid that is to be added to the primary solvent, e.g. ethane) required allowing miscible displacement at a particular pressure and temperature is termed the minimum miscibility enrichment (MME). For example, if at least 20% ethane is to be added to carbon dioxide to achieve miscibility with reservoir fluid at 2000 psia and 130˚F, then MME of ethane to carbon dioxide at 2000 psia and 130˚F is 0.2 (i.e. 20%). However, relatively small amount of methane or nitrogen gas in CO_2 will increase its MMP substantially. 15 mol% methane increased CO_2 MMP from about

1250 psig (pure CO_2) to 2000 psig (Stalkup, 1978). Jiang et al also showed that 10 mol% O_2 can increase CO_2 MMP up to 60% (Jiang, et al., 2012).

2.5 WAYS TO DETERMINE MINIMUM MISCIBILITY PRESSURE (MMP)

There are a number of ways to determine the MMP between two fluids, which includes slim tube experiments, core flooding, rising bubble apparatus, and the use of pseudo-ternary diagrams (Thomas, et al., 1994). In slim tube experiments, displacement efficiency is used to determine the pressure in which miscibility happens. Figure 2-8 shows a typical plot to determine MMP using slim tube experiments:

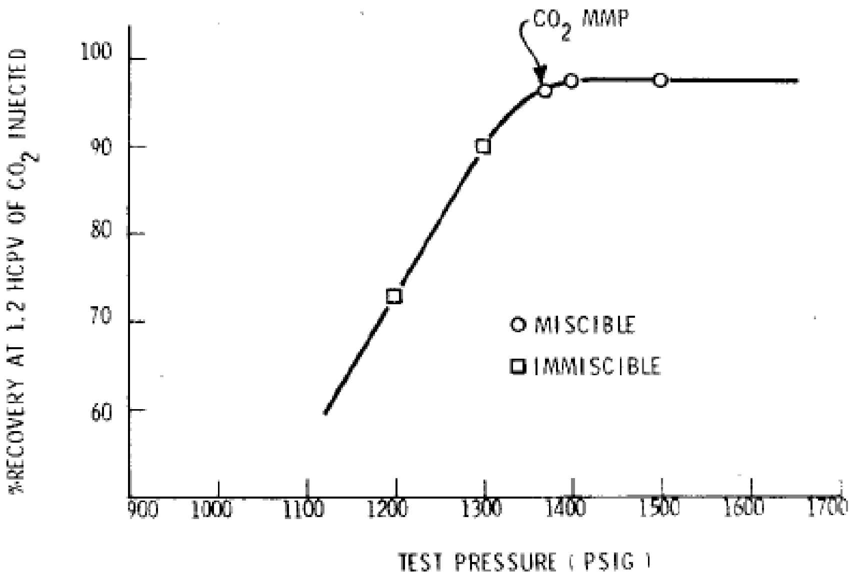


Figure 2-8: MMP plot from slim tube experiment (Yellig, et al., 1978).

However, the capillary pressure phenomena within the slim tube might not be representative of the reservoir rock, thus induces a certain amount of uncertainty in the MMP obtained. The procedure of conducting core flooding experiments is similar to slim tube experiments, but it uses cores instead of slim tube filled with glass beads. In this way, core flooding experiments are the most accurate because it uses actual core which is more reliable, but to generate at least four points on the MMP plot is far more costly than to explicitly calculate MMP. A semi-analytical way of calculating MMP is the use of pseudo-ternary diagrams, but Zick (Zick, 1986) showed that ternary diagram tie-line extrapolation techniques are often erroneous in their estimation of MMP. It is not recommended to use pseudo-ternary diagrams when multiple contact procedure is involved. Lastly, the observation from rising bubble apparatus technique is very subjective as the disappearance of bubble is difficult to see.

2.6 PROPERTIES OF CO_2 AS MISCIBLE SOLVENT

CO_2 has a low viscosity similar to that of hydrocarbon miscible solvents. As in hydrocarbon miscible flooding, volumetric sweep out in CO_2 flooding is affected by an unfavorable viscosity ratio. CO_2 density is similar to that of reservoir oil in many reservoirs, which minimizes the effect of gravity segregation with reservoir oil, but may cause segregation with mobile reservoir brine. CO_2 is not first-contact miscible with reservoir oils generally. However, CO_2 is able to achieve miscibility with reservoir oil through multiple contacts vaporizing gas drive mechanism if the reservoir oil contains sufficient intermediate hydrocarbon. Usually, the MMP of CO_2 is substantially lower than miscibility pressure for dry hydrocarbon gas, such as methane (Stalkup Jr., 1992). CO_2 generally yields higher incremental compared to hydrocarbon gases through oil swelling (Bakar, et al., 2011).

CO_2 behaves as a super critical fluid above critical temperature of 31.1˚C and critical pressure of 1070 psia (73 atm), where a distinct liquid and gas phase does not exist. If CO_2 is to be injected under low reservoir temperature (below CO_2 liquid line), up to five distinct phases can co-exist in the reservoir, which includes aqueous phase, liquid hydrocarbon, liquid CO_2, gaseous CO_2, and solid precipitation such as asphaltene, wax, hydrates, or scales (Goodyear, et al., 2003). It is also important to note that CO_2 is highly soluble in water (aqueous phase). Figure 2-9 shows the phase diagram of CO_2:

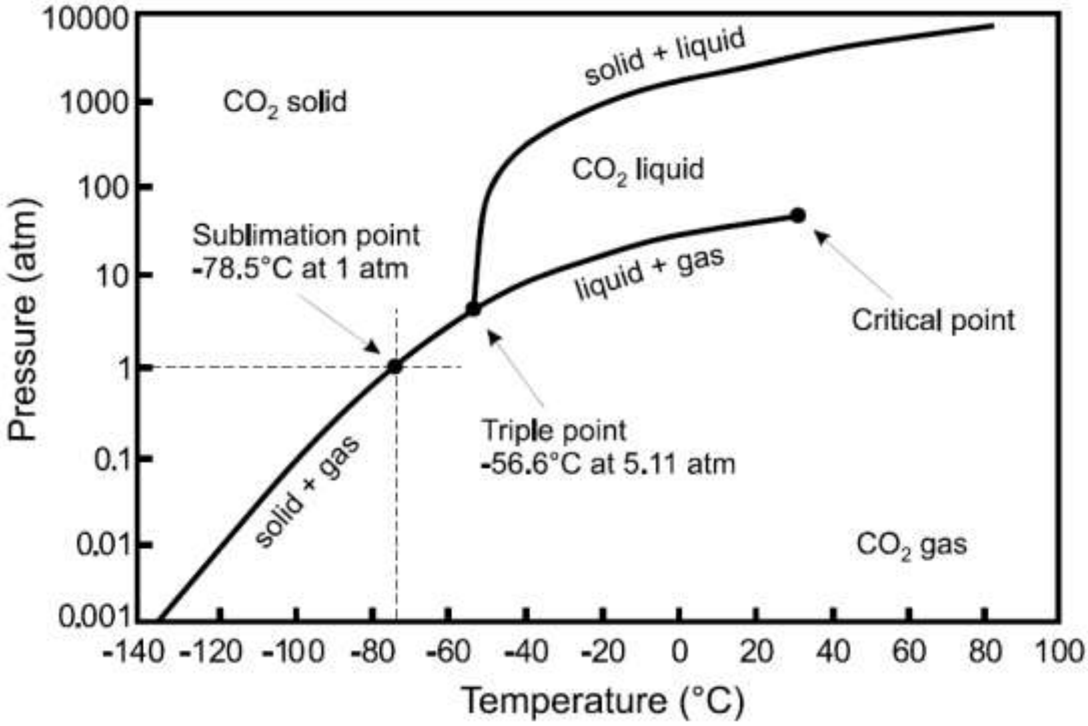


Figure 2-9: CO_2 Phase Diagram (Shakhashiri, 2008).

The use of CO_2 for enhanced oil recovery started as early as 1950s, when Whorton and Brownscombe received a patent for oil recovery using CO_2 (Stalkup, 1978). CO_2 miscible flooding is known for its high displacement efficiency and relatively low cost. However, a candidate reservoir must be able to withstand an average reservoir pressure greater than the MMP of CO_2 with reservoir oil. Otherwise, other methods have to be used to lower the MMP of CO_2 to achieve miscibility, such as injection of alcohol mix (Djabbarah, 1990).

2.7 EFFECT OF COLD WATER FLOODING ON RESERVOIR TEMPERATURE

In January 2011, Gong et al presented their study on the effect of cold water and injection rate on average reservoir temperature in Huabei oil field (Gong, et al., 2011). They conducted their study using numerical reservoir models at different injection temperature and injection rate. After that, the study is further extended to see the effect of reservoir rock's thermal conductivity on the reduction of average reservoir temperature. Their study shows that a lower injection temperature and a higher injection rate will lower the average reservoir temperature significantly faster. Their extended study also shows that the rock's thermal conductivity does not have a significant impact on the reduction of average reservoir temperature. It is reported that the reduction in average reservoir temperature can be up to 1.2˚C per year. Figure 2-10 shows the results for 20˚C water injection at different rates, where temperature decreases faster at higher injection rate:

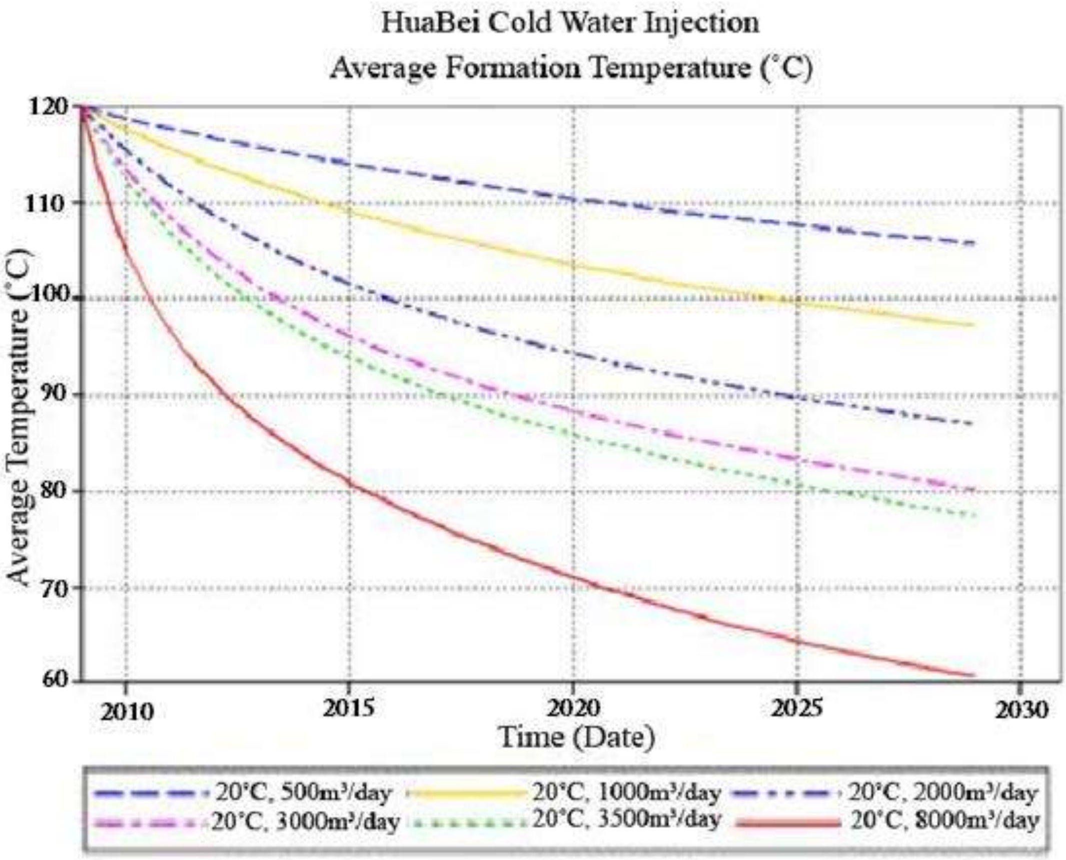


Figure 2-10: Effect of injection rate of cold water on average reservoir temperature reduction rate (Gong, et al., 2011).

2.8 EFFECT OF RESERVOIR TEMPERATURE ON MMP

Research on the effect of temperature on CO_2 MMP with reservoir oil also showed that MMP decreases with reservoir temperature (Yellig, et al., 1978). In that research, oil recovery factor is plotted against test pressure at different reservoir temperature, at a fixed amount of CO_2 injected. In other words, CO_2 MMP can be potentially lowered by lowering the temperature of the reservoir. Figure 2-11 shows the amount of CO2 MMP reduction at different pore volume of injected coolant, and Figure 2-12 shows the correlation between CO2 MMP and reservoir temperature:

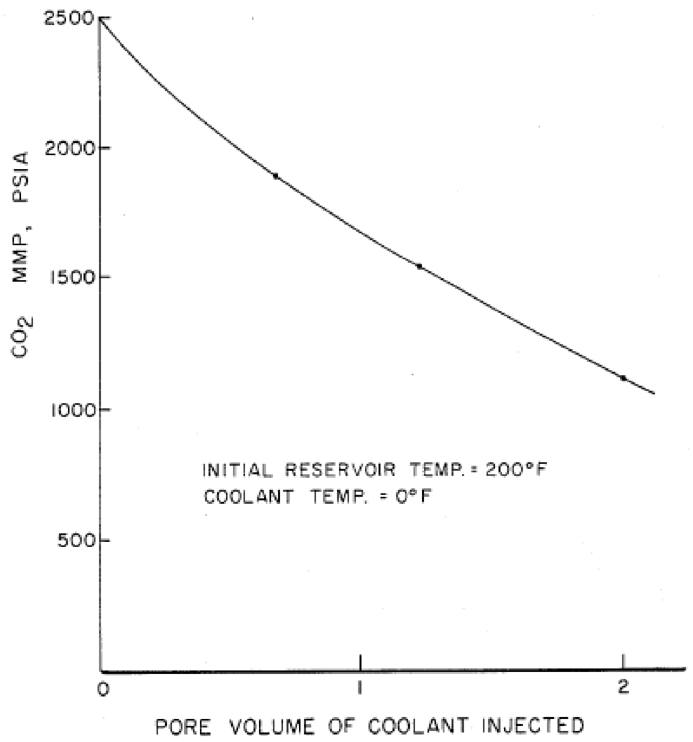


Figure 2-11: CO_2 MMP at different PV of coolant injected (Shu, 1985).

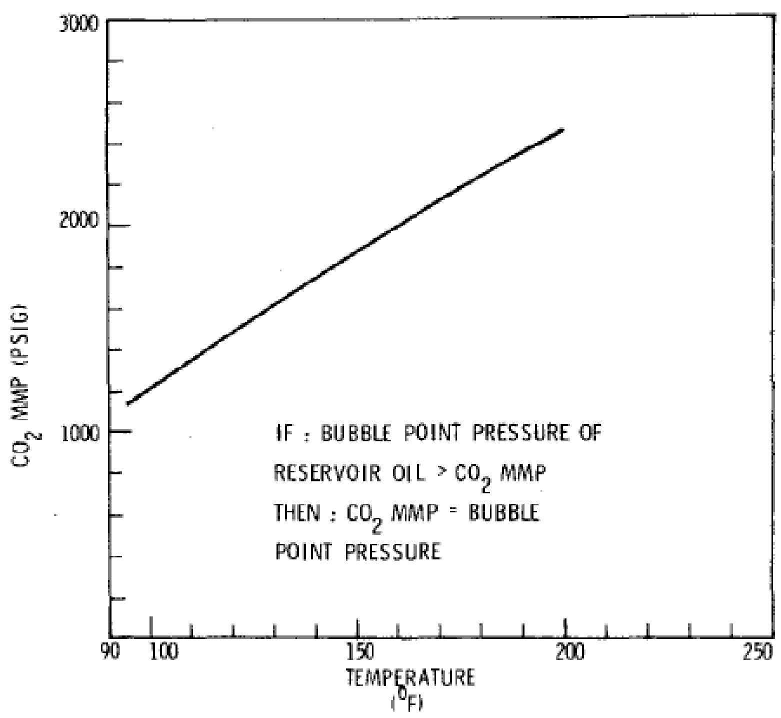


Figure 2-12: Correlation between CO_2 MMP and reservoir temperature (Yellig, et al., 1978).

CO_2 is able to vaporize hydrocarbons as heavy as gasoline in the CO_2 front in addition to the intermediates, thus able to develop vaporizing gas drive miscibility with minimal intermediate components in the oil. However, at temperature lower than 120˚F, the situation becomes more complex (Stalkup Jr., 1983). At higher pressure, two distinct liquid phases (liquid hydrocarbon and liquid CO_2) coexist in the multi-phase region rather than the typical vaporizing gas drive system where there are only gas and oil phase. At lower pressure, three phases might occur, which are two liquid phases, and one gas phase.

2.9 MOBILITY RATIO

The Darcy equation, which describes the flow of fluids in a porous medium, relates the velocity of a fluid to the pressure gradient by a proportionality factor. The proportionality factor (permeability divided by viscosity) is known as the mobility of the fluid and is a measure of the facility with which the fluid flows through the rock. When one fluid displaces another fluid, the mobility ratio is defined as the mobility of the displacing fluid divided by the mobility of the displaced fluid. Mobility ratio has a profound influence on the volumetric sweep out efficiency of the fluid. Mobility ratio which is greater than unity is unfavorable as the displacing fluid is travelling faster than the displaced fluid, causing viscous fingering to occur (Stalkup Jr., 1992).

As CO_2 has a high mobility, its mobility ratio with reservoir oil is often unfavorable. In one method to reduce the mobility of CO_2, CO_2 slug is followed by continuous water injection to drive the slug through the reservoir. The water immiscibly displaces CO_2, leaving a residual CO_2 saturation instead of oil saturation (Stalkup Jr., 1992), which is normally left behind after immiscible water flooding. The alternate injection of CO_2 slugs and water is to reduce the mobility of the displacing fluid and promote greater volumetric conformance (Wu, et al., 2004). After alternating cycles of CO_2 slugs and water is injected, continuous injection of water begins as the driving mechanism to displace fluid. By reducing CO_2 mobility, water injection can improve areal sweep out efficiency. However, water injection may cause residual oil to be trapped and gravity segregation of CO_2. Thus, the injection WAG ratio for mobility ratio improvement must be evaluated for each flood.

2.10 WATER ALTERNATING GAS INJECTION

Water alternating gas (WAG) injection technology is a method which improves oil recovery efficiency by combining the effects of two traditional technologies, which are water flooding and gas flooding. Water slugs and gas slugs are injected alternately under certain WAG ratio and cycle size to improve both microscopic oil displacement and sweep efficiency, by improving the mobility ratio of injected gas (Wu, et al., 2004).

There are several main factors that will impact the performance of miscible WAG injection, which includes gravity segregation effect, injection schemes, and well completion constraints. Gravity segregation effect is affected by the density difference between the displacing fluid and the displaced fluid. As gas density is usually much lower than liquid density, injected gas tends to invade the upper portion of the reservoir, and water tends to flood the lower portion of the reservoir. This affects the vertical sweep efficiency.

Important WAG injection schemes include WAG ratio, cycle size, and injection rates. In a conventional WAG injection, water keeps the reservoir pressure high and controls the mobility of injected fluid, while gas achieves miscibility with reservoir fluid, causes swelling and lowers the viscosity of reservoir fluid. In practice, an excess volume of injected gas is desired preceding the water bank, so that the volume of injected gas is high enough to create sufficient gas saturation prior to the next water injection cycle (Surguchev, et al., 1992). Higher gas ratio (more gas than water) generally gives better WAG performance (Christensen, et al., 1998). WAG cycle size is often optimized so that injected gas and water travel at equal speed. Higher injection rates generally gives better recovery. However, the effects of these parameters are different in stratified reservoirs containing high permeability and low permeability layers. Depending on the proportion of oil reserves in high and low permeability layers, increasing injection rate may even decrease total oil recovery (Surguchev, et al., 1992).

To increase volumetric sweep efficiency of miscible gas injection, partial well completion for injector and producer can be applied. In the presence of buoyancy and mobility effects, partial completion of injection well at the lower section may improve sweep efficiency. On the other hand, the producer well should be completed at the upper section of the reservoir. If horizontal wells are economically viable, it should also be considered for maximizing oil recovery. This is because horizontal wells provide more contact area for injected solvent to mix with reservoir fluid, compared to vertical wells. Within economic and technical limits, longer horizontal wells are recommended for both producer and injection wells (Wu, et al., 2004). Figure 2-13 and Figure 2-14 shows the two partial completion schemes mentioned above:

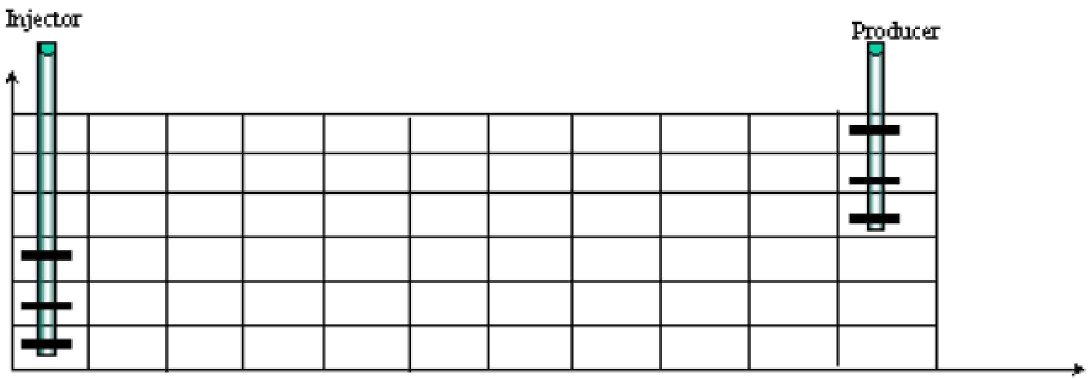


Figure 2-13: Partial completion of vertical injector and producer (Wu, et al., 2004).

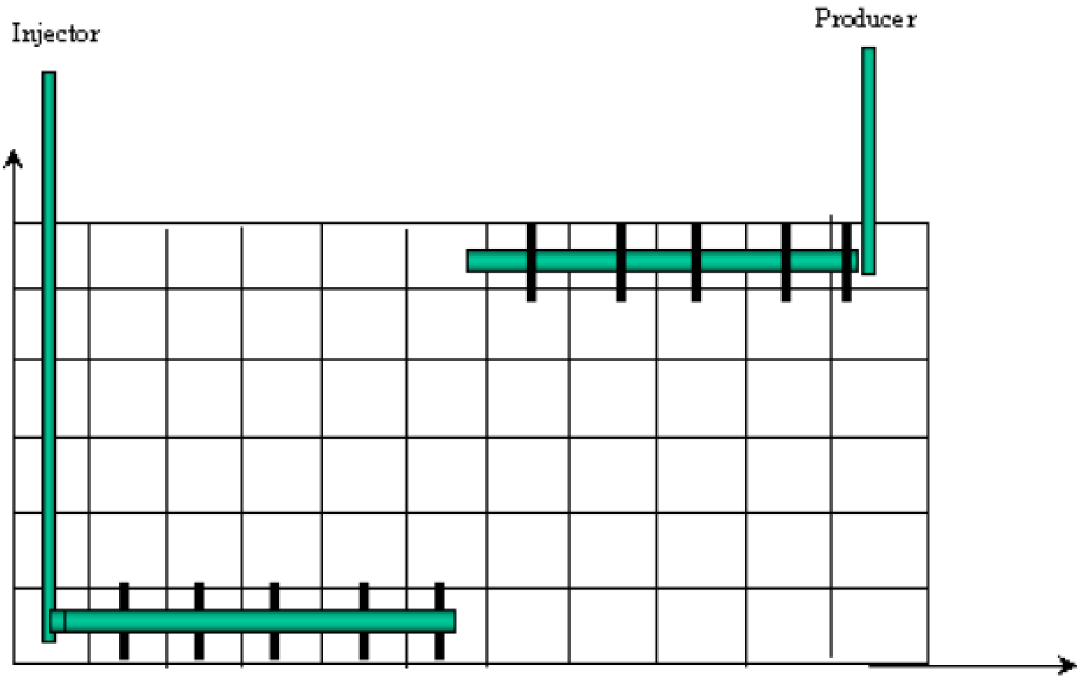


Figure 2-14: Partial completion of horizontal injector and producer (Wu, et al., 2004).

2.11 HYSTERESIS EFFECT DURING WAG INJECTION

Oil displacement by WAG injection is a combination of imbibitions and drainage processes taking place sequentially. Depending on which process is occurring, the relative permeability profile of the phases present may differ. In a water-wet reservoir, gas injected might be trapped by capillary pressure after water is displaced. In the presence of gas phase, the residual oil saturation may be significantly reduced, effectively changing the relative permeability profile as well. If hysteresis effect is modeled, the model will show a principal difference in gas saturation distribution after WAG injection, where certain amount of gas saturation can be found at the lower layer of the reservoir (Surguchev, et al., 1992). This is because gas trapping process prevented a certain amount of gas from segregating to the upper layers. Models with hysteresis effect also shows a lower produced gas-oil ratio due to gas being trapped in the pore spaces, and a delayed gas breakthrough, compared to models without hysteresis effect (Christensen, et al., 1998).

In a study conducted by Shahverdi et al (2011), it was concluded that relative permeability of a 3-phase flow conditions are functions of the other 2 independent fluid saturations, which contradicts with the oversimplifying assumptions made in most of the widely used empirical 3-phase relative permeability models (Shahverdi, et al., 2011).

2.12 SUBSURFACE ISSUES FOR CO_2 FLOODING

Temperature has a significant impact on CO_2 WAG injection, and needs to be assessed if CO_2 is to be injected in a reservoir cooled by cold water flooding. Subsurface issues caused by cold CO_2 flooding include thermally induced fractures, dissolution of minerals, and flow assurance issues.

Firstly, injecting cold water into a reservoir can potentially cause thermally induced fractures (Goodyear, et al., 2003). These fractures could be detrimental if it led to shortfall in void replacement that reduces reservoir pressure, which is needed to induce miscibility between CO_2 and reservoir fluid. Thus, geo-mechanical studies should be done to study the effects of thermal stress on the reservoir rocks.

Next, CO_2 has the ability to dissolve minerals (e.g. calcite and siderite) from sandstone and carbonate reservoirs, increasing permeability. This is particularly significant in sandstone reservoirs, as those minerals made up the cementation of the rock. In carbonate reservoirs, CO_2 injection can potentially worsen the $CaCO_3$ scaling issue especially due to the increased bicarbonate concentration in the produced water, which in turns increases the acidity of produced water. Nonetheless, dissolution of calcium from the limestone rock may increase the permeability of the reservoir, improving recovery. CO_2 hydrates will also form at low temperature, approximately 50˚F over the pressure range expected in UK Continental Shelf

(UKCS) reservoirs and upstream of the separators (Goodyear, et al., 2003). This usually occurs in wells with high CO_2 cuts, and could pose serious flow assurance issues.

Liquid CO_2 have a density close to that of pure water, therefore it can be injected using pumps, instead of compressors. Furthermore, gravity segregation effects will be reduced due to small density difference between liquid CO_2 and reservoir fluid. When cold water is injected into the reservoir, it reduces the temperature of the reservoir, and will potentially cause precipitation of paraffin/asphaltene which is generally caused by reduction in temperature (Bennion, et al., 1995).

As CO_2 enters the producer, it expands and cools, reducing bottom-hole temperature of the well (Goodyear, et al., 2003). As it continues to expand, the temperature at the choke could be lowered, potentially causing increased scaling, paraffin/asphaltene deposition, and well head freezing.

2.13 EOR REVIEW ON MALAYSIA'S OIL FIELDS

In year 2000, PETRONAS, Malaysia's national oil company, conducted a screening study to identify EOR potential in Malaysia oil reserves (Samsudin, et al., 2005). The study identified CO_2 flooding as potential EOR in most of the top candidate reservoirs, including Dulang field and West Lutong field. CO_2 miscible flooding was found to be the most favorable process, although miscibility might not be achieved due to insufficient reservoir pressure. CO_2 constitutes nearly 50% of the gas composition in Dulang field, which is the source of CO_2 to be used as injection fluid. However, miscibility could not be achieved in Dulang field due to insufficient reservoir pressure. On the other hand, miscibility can be achieved in West Lutong field. A generator will be installed to supply high purity CO_2 to be used as injection gas at miscible conditions. In this review, it is claimed that Malaysia has an abundance of CO_2 supply to be used for EOR purposes.

2.14 SUMMARY

The fundamentals of miscible displacement and the mechanisms have been reviewed, which includes the advantages of miscible displacement, i.e. to reduce the residual oil saturation. CO_2 miscible flooding has been generally identified to achieve miscibility through multiple contacts with reservoir fluid via vaporizing gas drive or potentially a combined drive mechanism. Favorable properties of CO_2 in miscible flooding includes the ability to reduce viscosity of oil, causes oil swelling, relatively low MMP, having density near to oil, and is relatively low cost.

The ability of cold water flooding in reducing the reservoir temperature was shown in one of the reviews, where the reservoir temperature dropped by 1.2˚C per year. The effects of reduced temperature on several factors have also been reviewed, which include the effects on MMP, wettability, and the formation of paraffin/asphaltene. Decreasing reservoir temperature will reduce the MMP by about 600 psi for every 50˚F decrease. On the other hand, heavy polar constituents tend to physically desorbed from the surface of the rock when the reservoir temperature is increased.

Water alternating gas (WAG) injection is used in miscible CO_2 flooding to control the mobility of the miscible CO_2 slug. CO_2 injection and water flooding is performed alternately, allowing water slugs to drive the CO_2 slug to improve sweep efficiency. Factors affecting WAG performance includes gravity segregation effects, injection schemes, and completion constraints. The importance of hysteresis effect in modeling is also reviewed, which involves the gas trapping mechanism. Subsurface issues regarding WAG injection using cold water and CO_2 have been analyzed as well. Lastly, the potential of CO_2 miscible flooding in Malaysia is reviewed.

CHAPTER 3: METHODOLOGY/PROJECT WORK

In this research, a synthetic reservoir model is used as a base case for various simulation runs. Continuous gas injection using CO_2 and various WAG injection schemes will be analyzed. Parameters such as injection water temperature and pressure are altered to investigate their effects on the incremental recovery. The obtained incremental recoveries will be evaluated and cost-benefit analysis will be conducted to gauge the feasibility of the methods.

The reservoir fluid composition that is used in this study is taken from Dulang oil field, with 45.88 lb/ft^3 liquid density and saturation pressure of 1525 psia. Fluid analysis software, such as CMG's WinProp and ECLIPSE's PVTi, are used to define the component properties and the composition, and fine-tuned to match the properties reported. Preliminary study on effects of low temperature on MMP between pure CO_2 and reservoir fluid is simulated using semi-analytical method in WinProp.

The reservoir model is built and simulated using reservoir modeling software, i.e. ECLIPSE 300. It is built as 1D model, and the reservoir properties are taken from Dulang field, with an initial reservoir pressure of 1800 psia and average reservoir temperature of 215˚F. The reservoir model contains one producer well and one injector well. Various cases will be simulated, which includes natural depletion, water flooding, continuous CO_2 injection, and CO_2 WAG injection. The recovery factor of each flood will be compared and analyzed.

3.1 FLUID MODELING

CMG's WinProp and ECLIPSE's PVTi have been used to define the component and compositions of the reservoir fluid. The composition is taken from SPE 72106 (Md. Zain, et al., 2001) as shown in Table 3-1:

Table 3-1: Composition of reservoir fluid.

Component	Molecular Weight	Wellstream (mol%)
CO2	44.010	20.743
N2	28.013	0.109
C1	16.043	15.062
C2	30.070	3.007
C3	44.097	2.710
iC4	58.124	1.032
nC4	58.124	0.854
iC5	72.151	0.415
nC5	72.151	0.283
C6	86.000	2.917
C7	96.000	2.833
C8	107.000	1.285
C9	121.000	2.470
C10	134.000	2.357
C11+	215.200	43.923
Total		100.000

The reservoir fluid is tuned to match a saturation pressure of 1525 psia and liquid density of 45.88 lb/ft^3 at 215˚F, and the swelling factors obtained. The swelling factors and saturation pressures are tabulated in Table 3-2:

Table 3-2: Sat. pressures and swelling factors.

CO2 Added (mol%)	Sat. Pressure (psig)	Swelling Factor
0	1525	1.00
20	2015	1.13
40	2570	1.25
60	3210	1.50
80	4250	2.25

The regression parameter used is mainly the properties of C_{11}^{+} component. The result of the regression is shown in Table 3-3, Figure 3-1 and Figure 3-2 below:

Table 3-3: Component properties after regression.

Comp	Pc (psia)	Tc (F)	Omega A	Omega B	Acentric Factor	Parachors	V Crit (ft3/lb-mole)	Z Crit	Boil Temp (F)	Ref Dens (lb-mole/ft3)	Ref Temp (F)
CO2	1071.30	88.79	0.45724	0.077796	0.225	78	1.5057	0.27408	-109.2	48.507	67.73
N2	492.31	-232.51	0.45724	0.077796	0.040	41	1.4417	0.29115	-320.4	50.192	-319.09
C1	667.78	-116.59	0.45724	0.077796	0.013	77	1.5698	0.28473	-258.8	26.532	-258.61
C2	708.34	90.10	0.45724	0.077796	0.099	108	2.3707	0.28463	-127.4	34.211	-130.27
C3	615.76	205.97	0.45724	0.077796	0.152	150.3	3.2037	0.27616	-43.7	36.333	-43.87
IC4	529.05	274.91	0.45724	0.077796	0.185	181.5	4.2129	0.28274	10.7	34.772	67.73
NC4	550.66	305.69	0.45724	0.077796	0.201	189.9	4.0847	0.27386	31.2	36.146	67.73
IC5	491.58	369.05	0.45724	0.077796	0.227	225	4.9337	0.27271	82.1	38.705	67.73
NC5	488.79	385.61	0.45724	0.077796	0.251	231.5	4.9817	0.26844	96.9	39.08	67.73
C6	436.62	453.83	0.45724	0.077796	0.299	271	5.6225	0.25042	147.0	42.763	60.53
C7	426.18	526.73	0.45724	0.077796	0.300	312.5	6.2792	0.25281	197.4	45.073	60.53
C8	417.66	575.33	0.45724	0.077796	0.312	351.5	6.936	0.26082	242.1	46.509	60.53
C9	381.51	625.73	0.45724	0.077796	0.348	380	7.7529	0.25394	288.0	47.695	60.53
C10	350.94	667.13	0.45724	0.077796	0.385	404.9	8.5539	0.24825	330.4	48.569	60.53
C11+	253.92	889.49	0.44548	0.081386	0.827	557.49	13.312	0.23345	561.6	53.938	60

P_c and T_c are critical pressure and critical temperature respectively, and is used in equation of states such as viscosity calculation and generating k-value tables. Omega A and Omega B are also constants used in equation of states. Acentric factor is used in generating k-value tables; parachors is used in surface tension calculation. V_{crit} is the critical molar volume and Z_{crit} is the critical z-factors, both used in viscosity and phase density calculation.

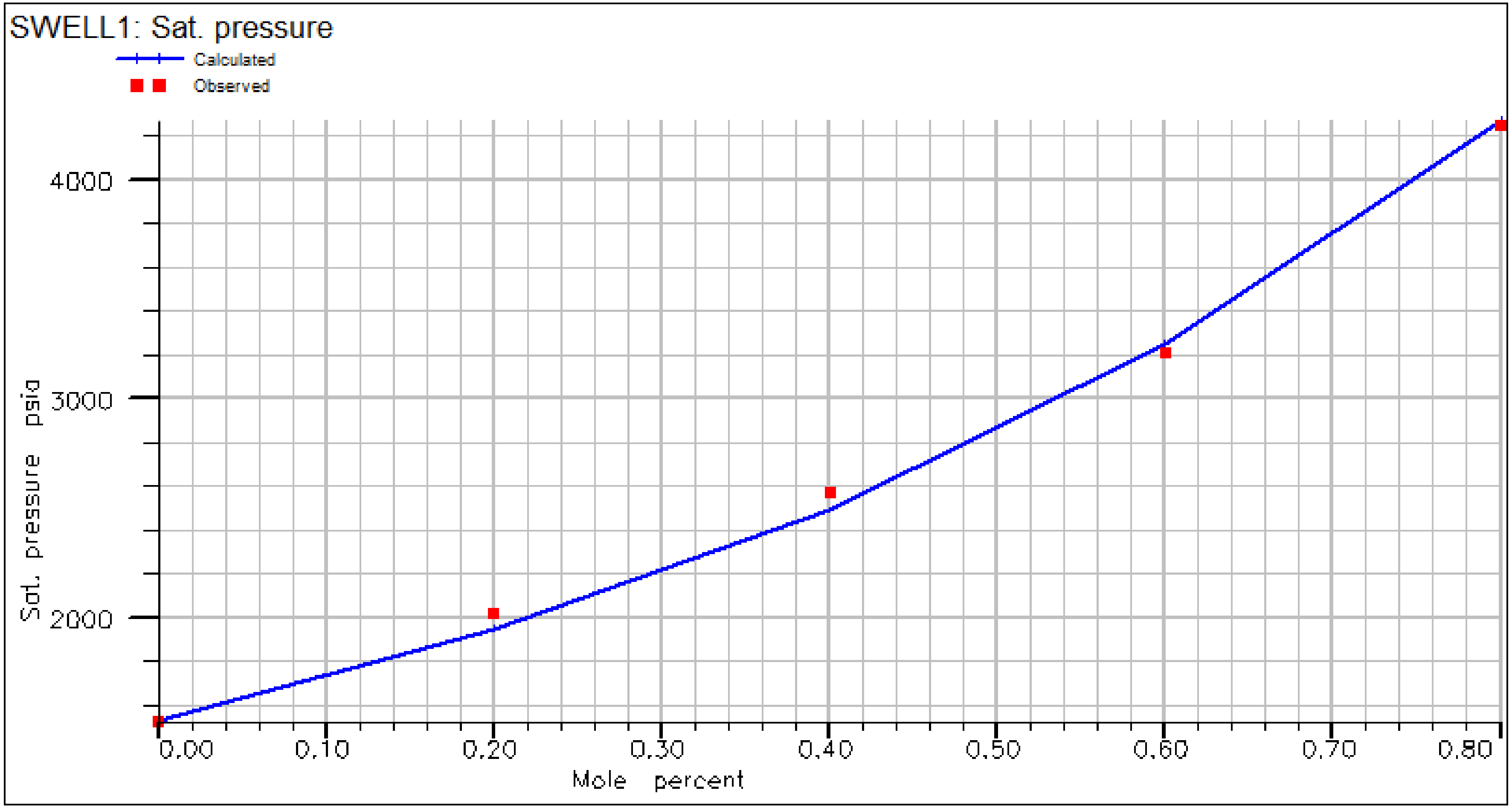


Figure 3-1: Regression of saturation pressure.

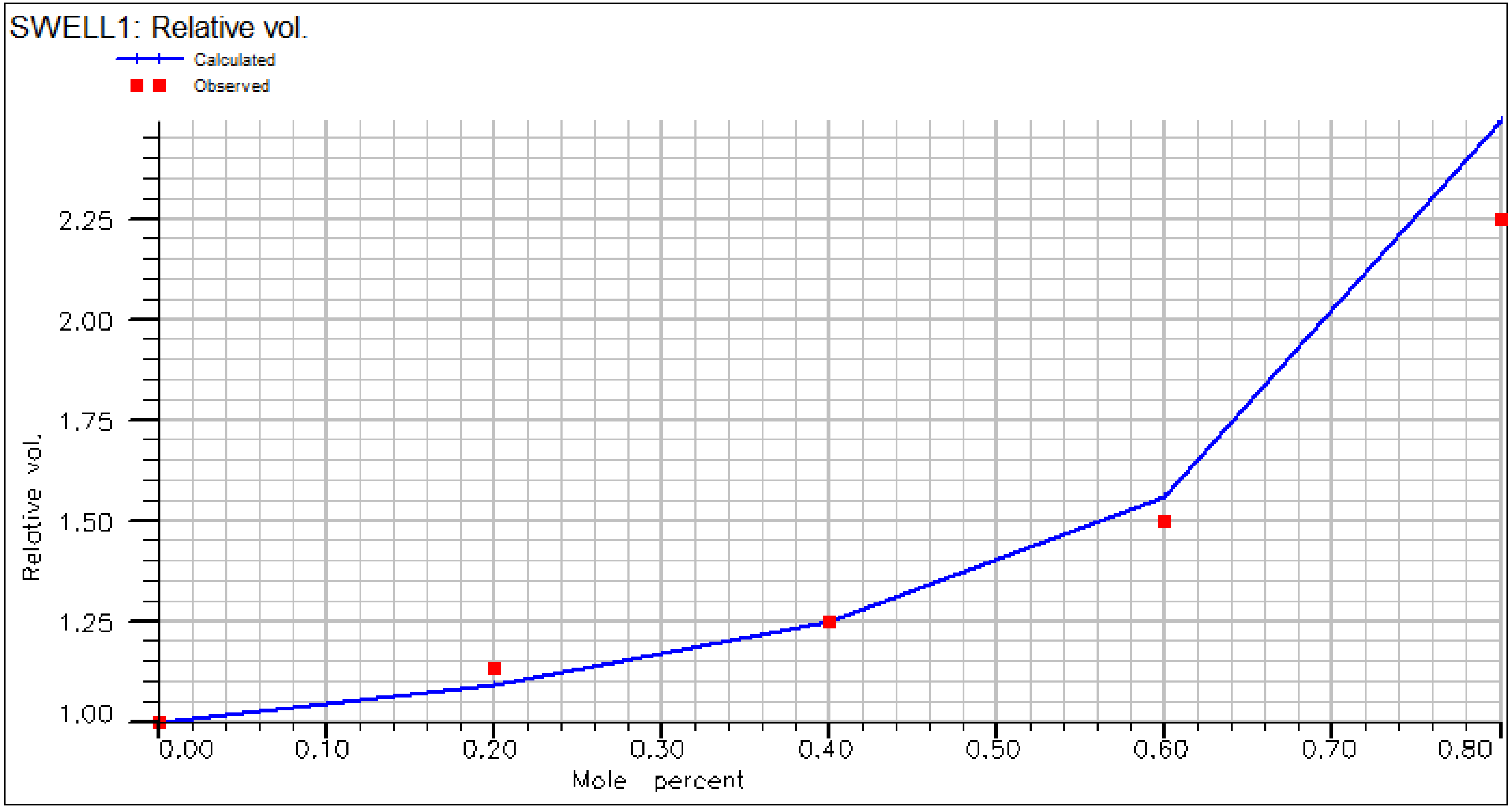


Figure 3-2: Regression of swelling factor.

At the moment the tuning of reservoir fluid is satisfactory as the other lab measurements are unavailable. Therefore, the regressed properties are updated, and the multiple contact miscibility (MCM) tests are conducted, using semi-analytical method in WinProp. MCM test is conducted at several reservoir temperatures, to study how reservoir temperatures affect the MMP of CO_2 and reservoir fluid. The compiled result of the effects of reservoir temperature on MMP is shown in Figure 3-3:

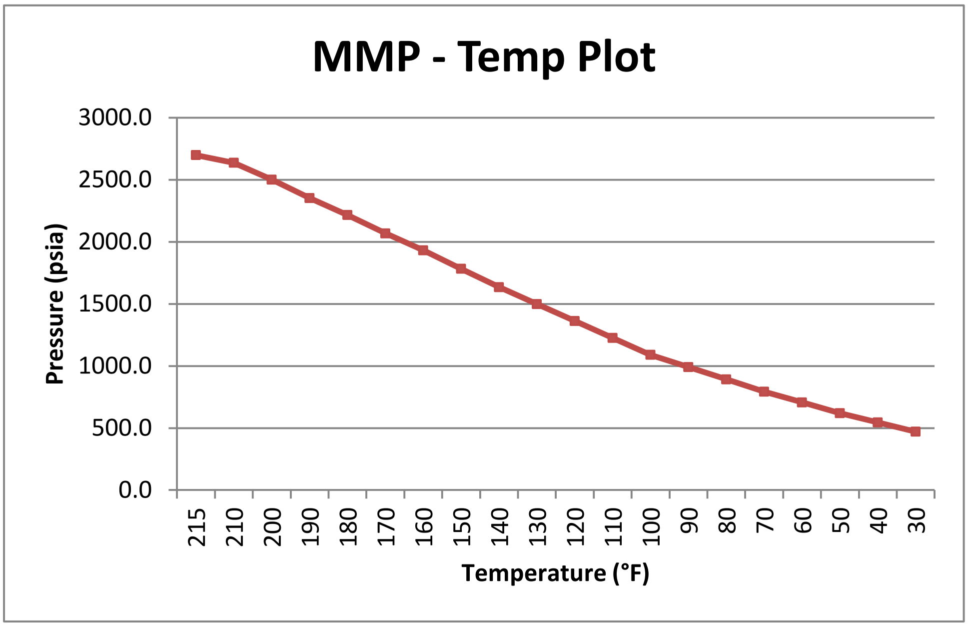


Figure 3-3: Plot of MMP against Temperature.

It can be seen that the results of this simulation matched the results from Yellig and Metcalf's claim, which is a reduction of 600 psi for every 50˚F reduction in reservoir temperature.

Fluid properties (i.e. constants used in equation of state calculations) data is then exported from PVTi as an input for ECLIPSE 300.

3.2 STATIC MODELING

The synthetic model contains 300 x 1 x 1 grids, each measuring 10' x 10' x 10', giving a total of 3000' in the *x*-direction. The reservoir properties are extracted and estimated from literatures (i.e. SPE 88499, SPE 72106, and SPE 25012), rock thermal conductivity and rock specific heat capacity are arbitrary values, and are summarized in Table 3-4 below:

Table 3-4: Basic reservoir and fluid properties

Porosity	0.3	
Horizontal Permeability	200	mD
Verticle Permeability	20	mD
Top	3000	feet
Rock Thermal Conductivity	24	BTU/ft.day.F
Rock Specific Heat Capacity	35	BTU/ft.F
Pressure	1800	psia
Temperature	215	F
Initial Water Saturation	0.33	
Initial Gas Saturation	0	

The relative permeability curves are generated using Corey's method with end points obtained from literatures, as shown in Figure 3-4 and Figure 3-5:

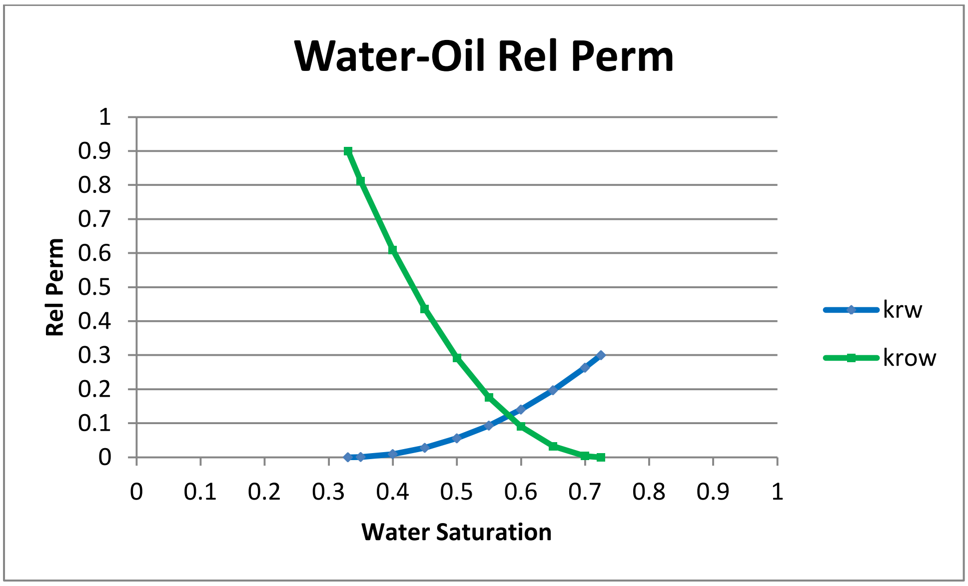


Figure 3-4: Water-Oil relative permeability curves.

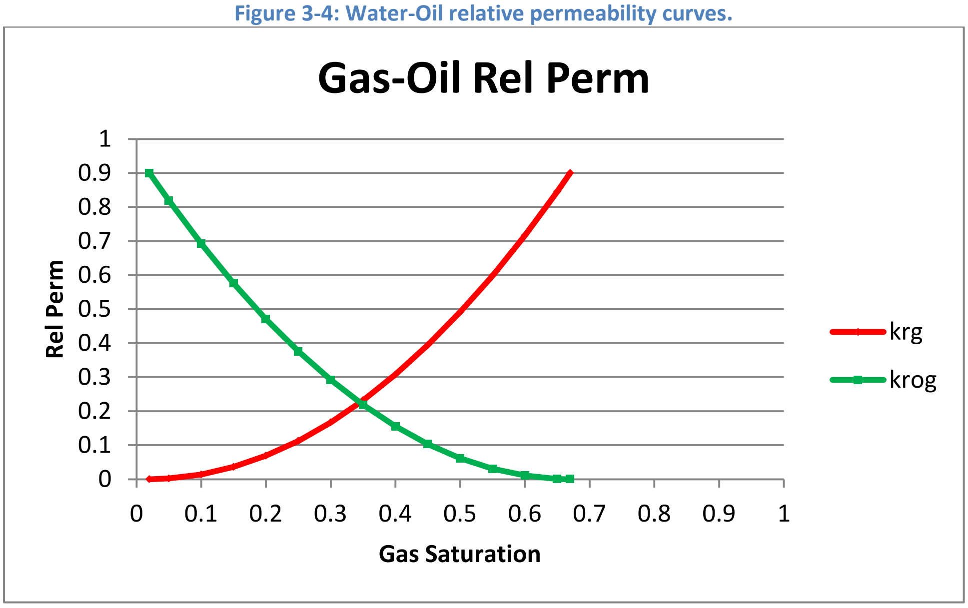


Figure 3-5: Gas-Oil relative permeability curves.

3.3 DYNAMIC MODELING

The model contains only 1 injector (1 1 1) and 1 oil producer (300 1 1). The producer is constantly producing at a bottom-hole pressure of 1200 psia, while the injector is controlled at a bottom-hole pressure of 2000 psia. Cases which are analyzed include natural depletion (BASE case), water flooding (WF) at various injection temperatures, continuous gas injection (CGI) at various injection temperatures, and WAG mode. The gas that is injected is pure CO_2 in all cases. All cases are simulated for a total of 10 years. The model as viewed in FloViz is as shown in Figure 3-6:

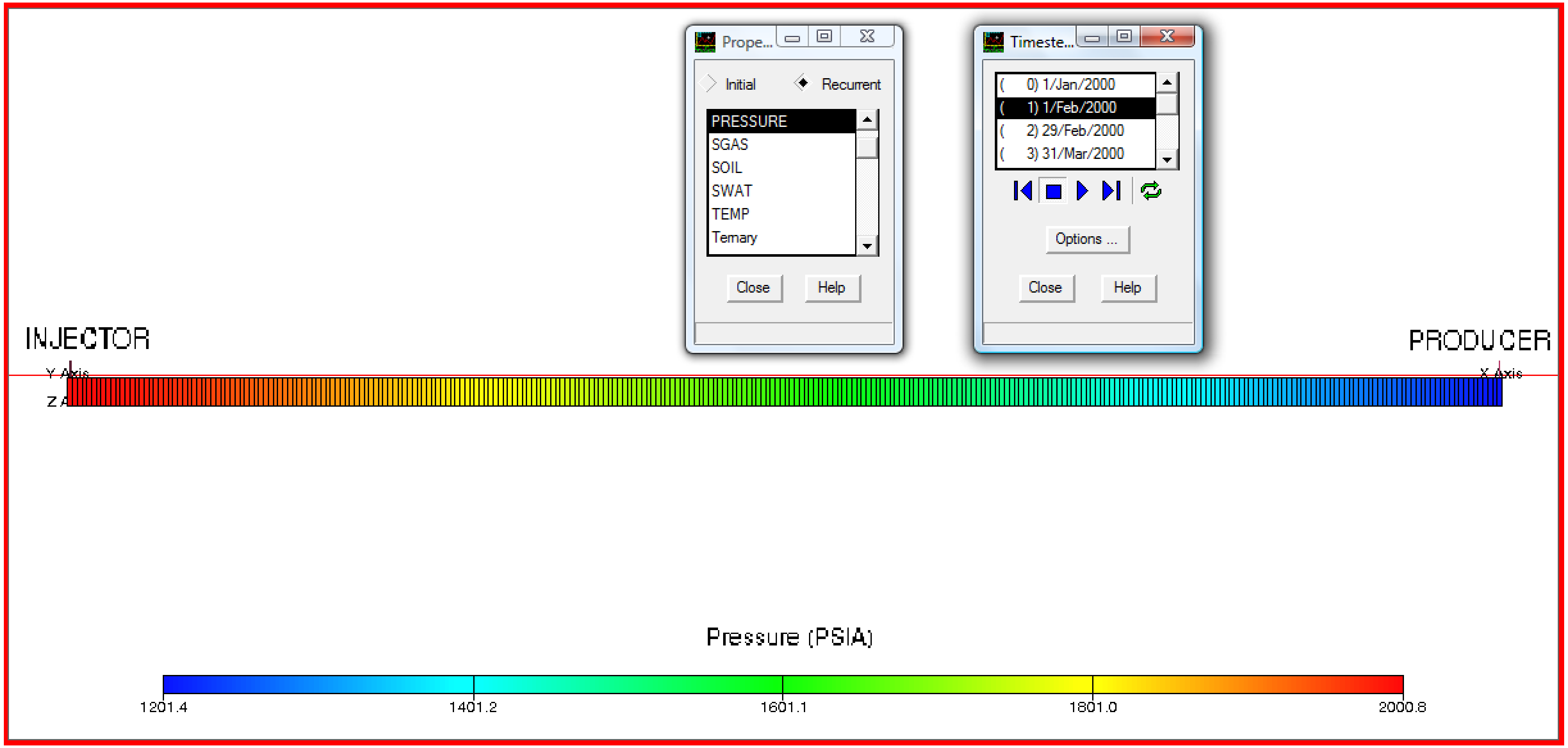
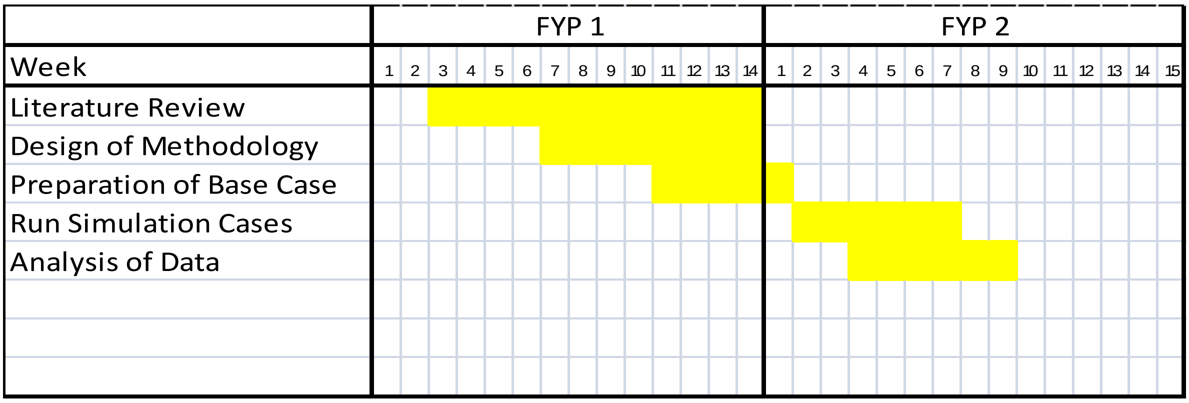


Figure 3-6: Model viewed in FloViz

3.4 KEY MILESTONE

FYP 1	Week 7	Submission of Extended Proposal
	Week 8	Proposal Defense
	Week 13	Submission of Draft Interim Report
	Week 14	Submission of Interim Report
FYP 2	Week 7	Submission of Progress Report
	Week 10	Pre-SEDEX
	Week 11	Submission of Draft Report
	Week 12	Submission of Dissertation and Technical Paper
	Week 13	Oral Presentation
	Week 15	Submission of Dissertation Hard-Bound

3.5 GANTT CHART



CHAPTER 4: RESULTS AND DISCUSSION

4.1 NATURAL DEPLETION – BASE

In the base case run, injector is shut and producer is allowed to produce under natural depletion with a bottom-hole pressure of 1200 psia. The base case run is also used to check for technical errors with the input data and to check if the assumptions made are realistic (e.g. bottom-hole pressure constraint).

Initially, the major error encountered was in the calculation of CO_2 density in oil phase, which is computed using a single point reference including reference density, pressure, temperature, compressibility factor, and thermal expansion coefficient. The reference density and compressibility factor exported from PVTi do not allow CO_2 to have a positive component density, which is believed to be an error. Thus, these two parameters were manually changed, where reference density is changed to match that in PVTi library, and compressibility is changed to be very small.

Time stepping criteria has also been added to all simulation runs, limiting the minimum time step to one day. However, this has caused some problems with simulation runs where CO_2 condenses into liquid under extremely low temperature.

Under natural depletion, the model can only achieve a field oil recovery factor of 0.084 very early during production. The pressure within the model depletes until it reaches the bottom-hole pressure of the producer. Gas saturation increases as pressure depletes below bubble point pressure. Oil saturation decreases but do not reach residual oil saturation. There is no temperature change within the model.

4.2 WATER FLOODING – WF

In these cases, water flooding started on day one at an injector bottom-hole pressure of 2000 psia, to provide additional energy and to displace the oil to the producer. The bottom-hole pressure limit of 2000 psia is set as the constraint so that the injection pressure doesn't exceed initial reservoir pressure too much as to fracture the reservoir. As this is a one dimensional study, gravity segregation effect is not present. Water flooding cases are repeated at different injection temperature which ranges from reservoir temperature (i.e. 215˚F) to 40˚F. Figure 4-1 shows the water injection rate of water flooding case at 215˚F:

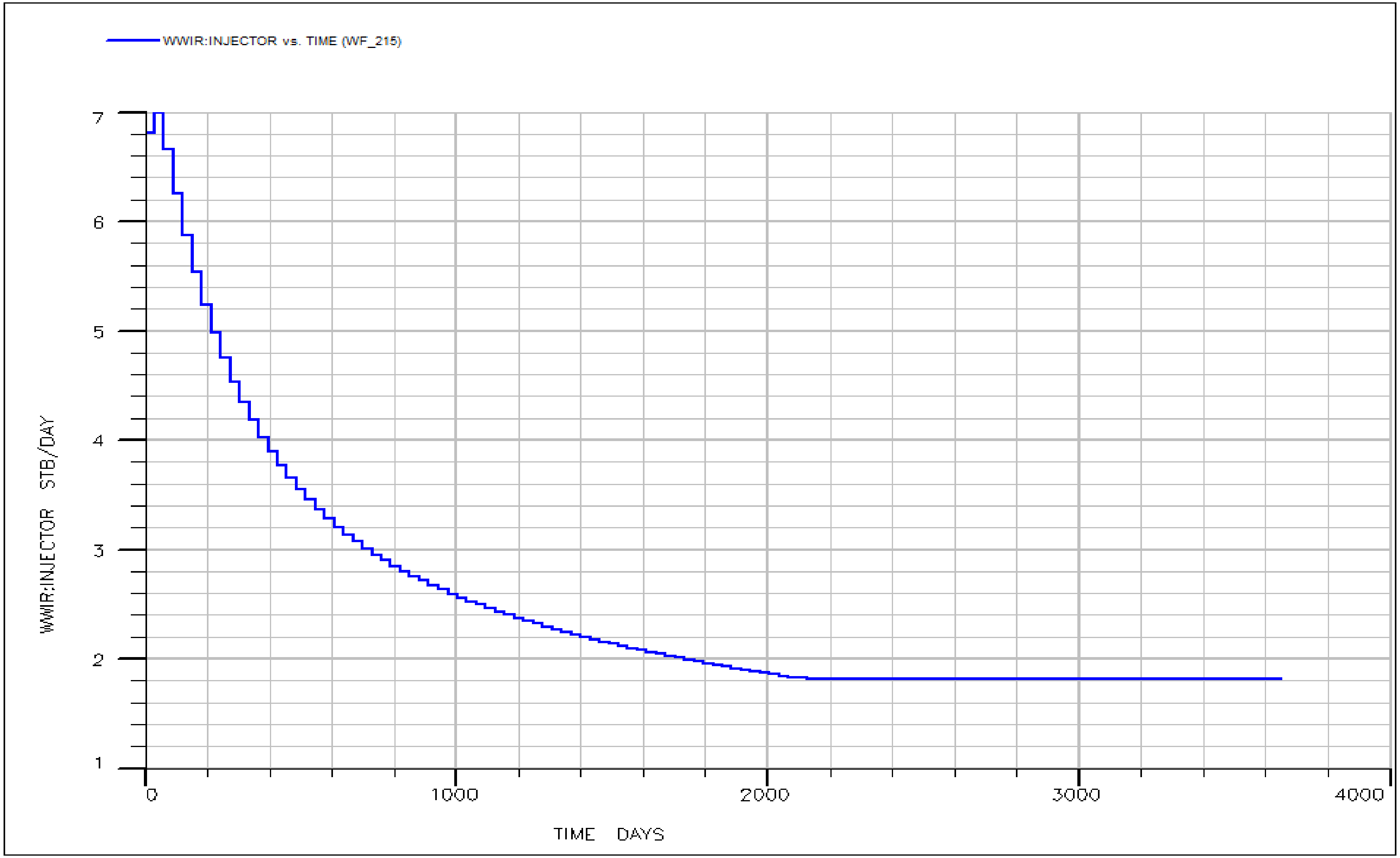


Figure 4-1: Water injection rate (WWIR) of the injector well.

With water flooding, the model is able to achieve a field oil recovery factor of 0.576 after extending the life of the reservoir by about 5 years compared to base case run. Figure 4-2 shows the field oil recovery factor of 4 water flooding schemes (i.e. 215˚F, 150˚F, 80˚F and 40˚F) and that of base case:

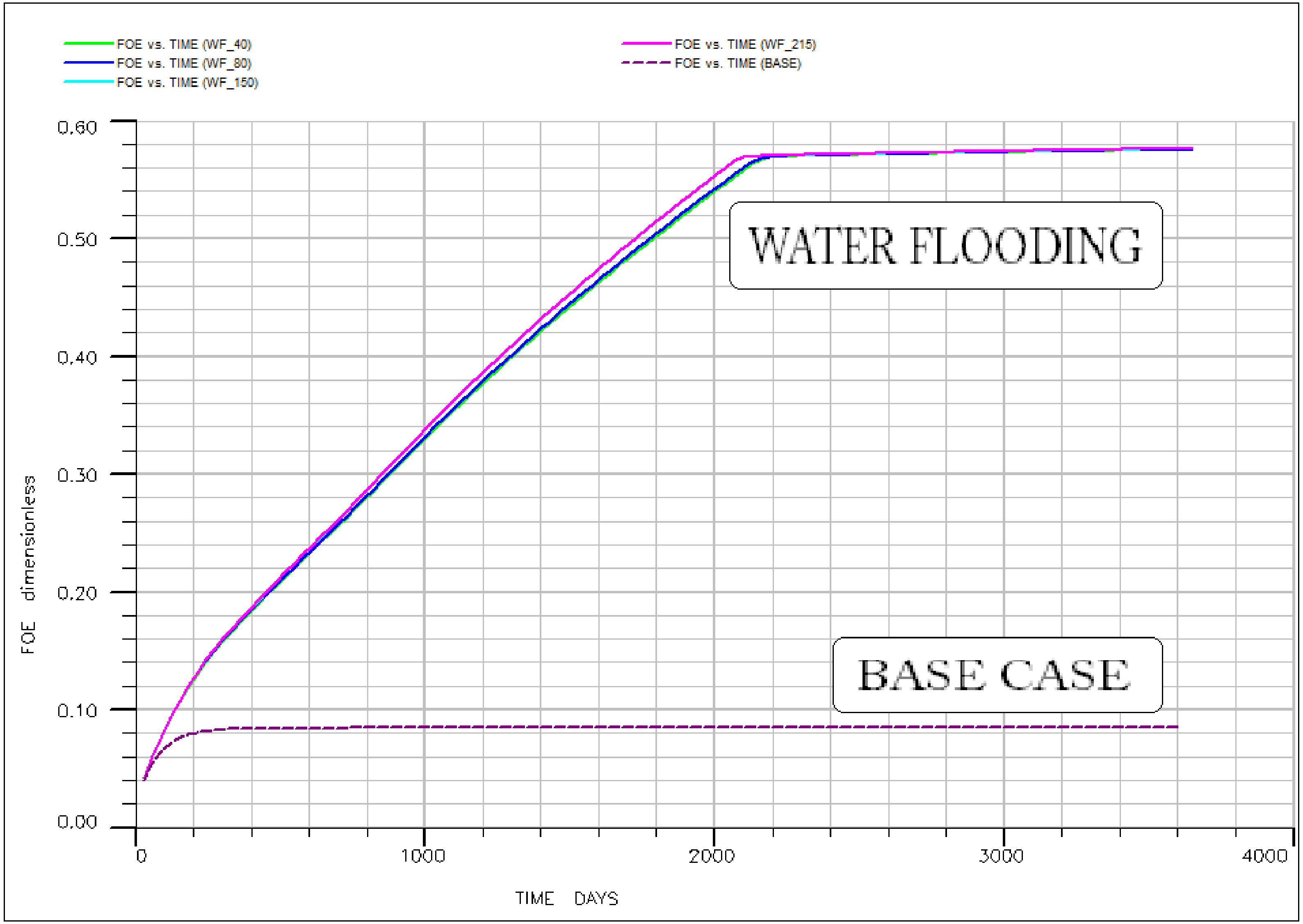


Figure 4-2: Field oil recovery factor (FOE) of WF cases and BASE case.

Water is able to sweep oil to the producer as oil saturation is highest at the water front, and only residual oil saturation is left at region swept by water. At water breakthrough, oil production rate fell drastically.

When water is injected at a lower temperature, it is able to reduce the temperature around the injector. However, the temperature of regions further away from the injector remains high even when water front have reached further. This is because the higher temperature in the reservoir is able to heat up the injected cold water as it flows further away from the injector. The colder the water injected, the faster the temperature of the reservoir reduces. Figure 4-3 shows the temperature of the block 100 feet away from the injector when water is injected at different temperature:

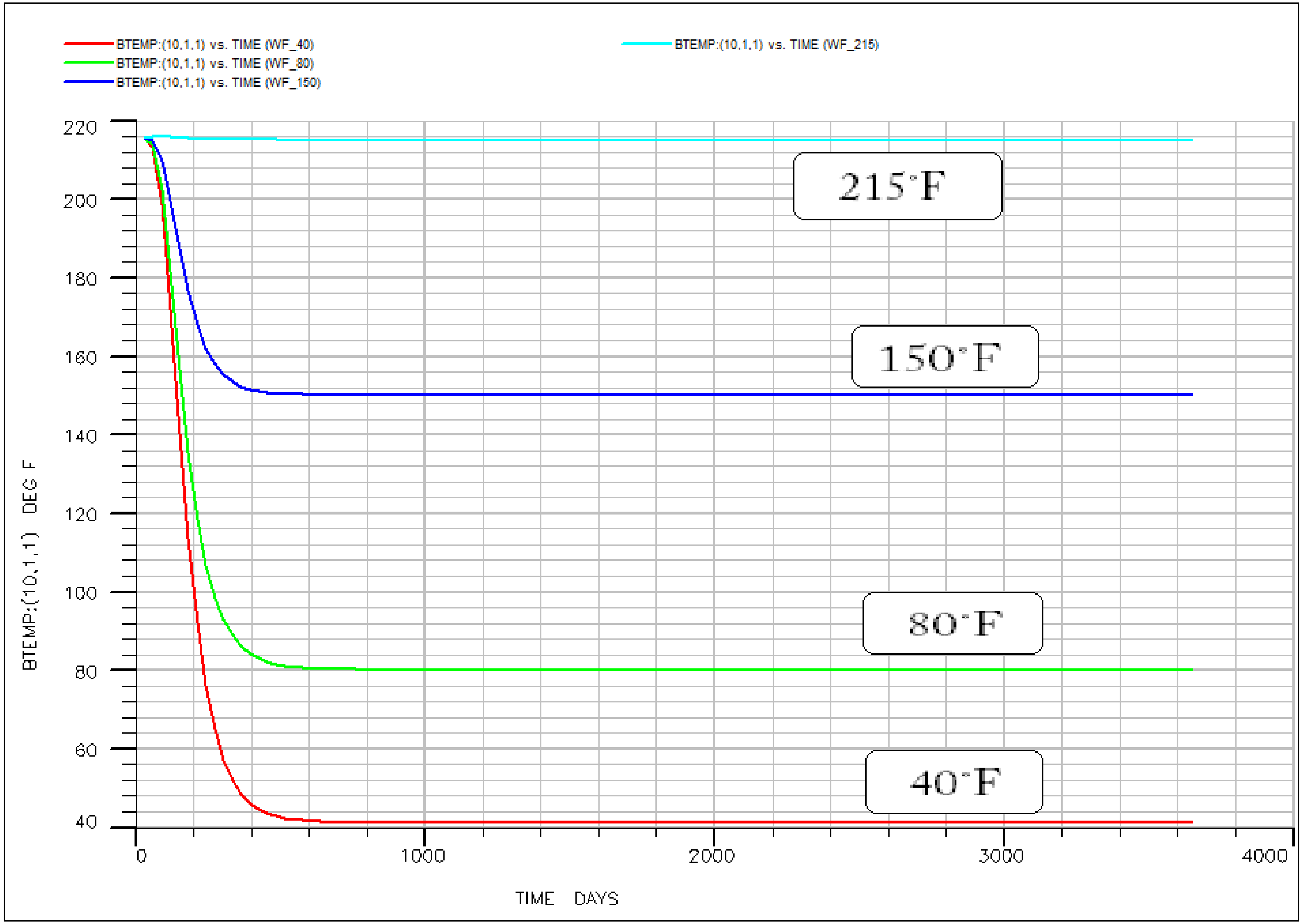


Figure 4-3: Block temperature (BTEMP) at different water injection temperature.

Another point worth noticing is that temperature does not significantly affect the field oil recovery factor of water flooding operations, as shown in Figure 4-2 above. The viscosity distribution and the temperature distribution at water breakthrough are as shown in Figure 4-4:

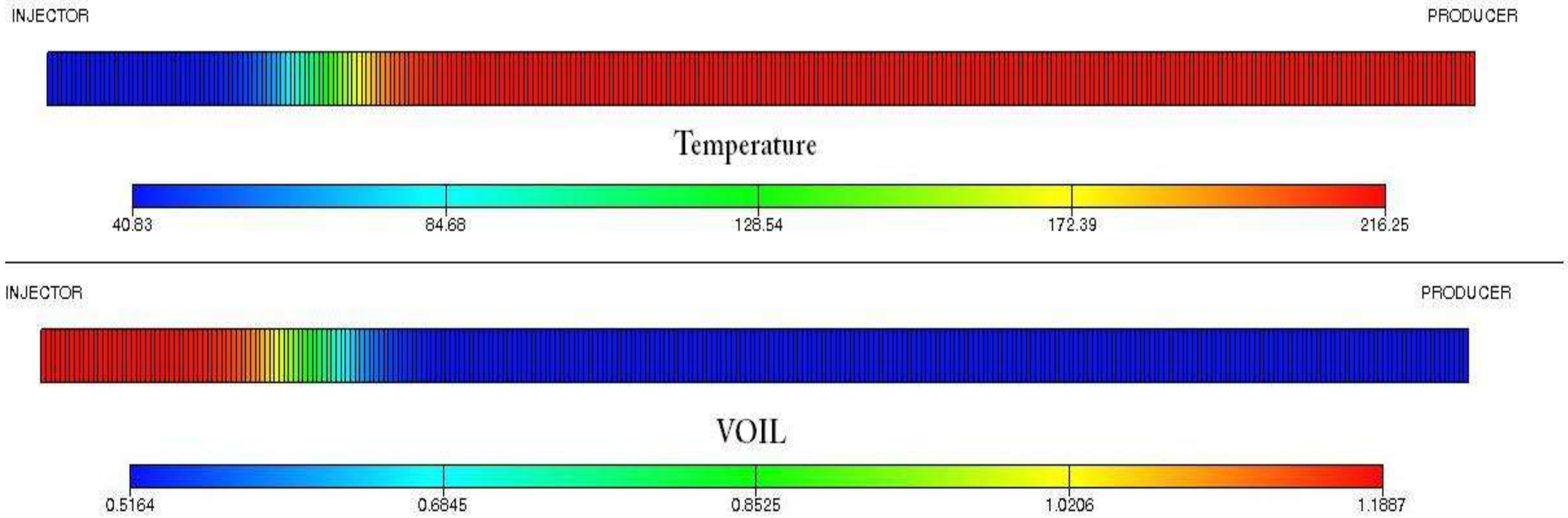


Figure 4-4: Viscosity (VOIL) and temperature distribution.

4.3 CONTINUOUS CO_2 GAS INJECTION – CGI

In continuous gas injection, CO_2 gas is first injected at increasing bottom-hole pressure (i.e. 2000 psia to 3200 psia) to study the effect of pressure on recovery factor, then it is injected at a constant injector bottom-hole pressure of 2000 psia for 10 years at different temperature. CO_2 gas is injected at a different temperature for each case so that the effect of temperature on CO_2 injection can be studied (i.e. 215˚F to 150˚F).

As injection pressure increases, the injection rate required to achieve that certain pressure also increases, thus it is not appropriate to compare the field recovery factor of different injection pressure at the same injection duration, where the total injected volume is not the same. Therefore, the field recovery factor is plotted against total volume injected to study the effect of pressure on recovery, as shown in Figure 4-5:

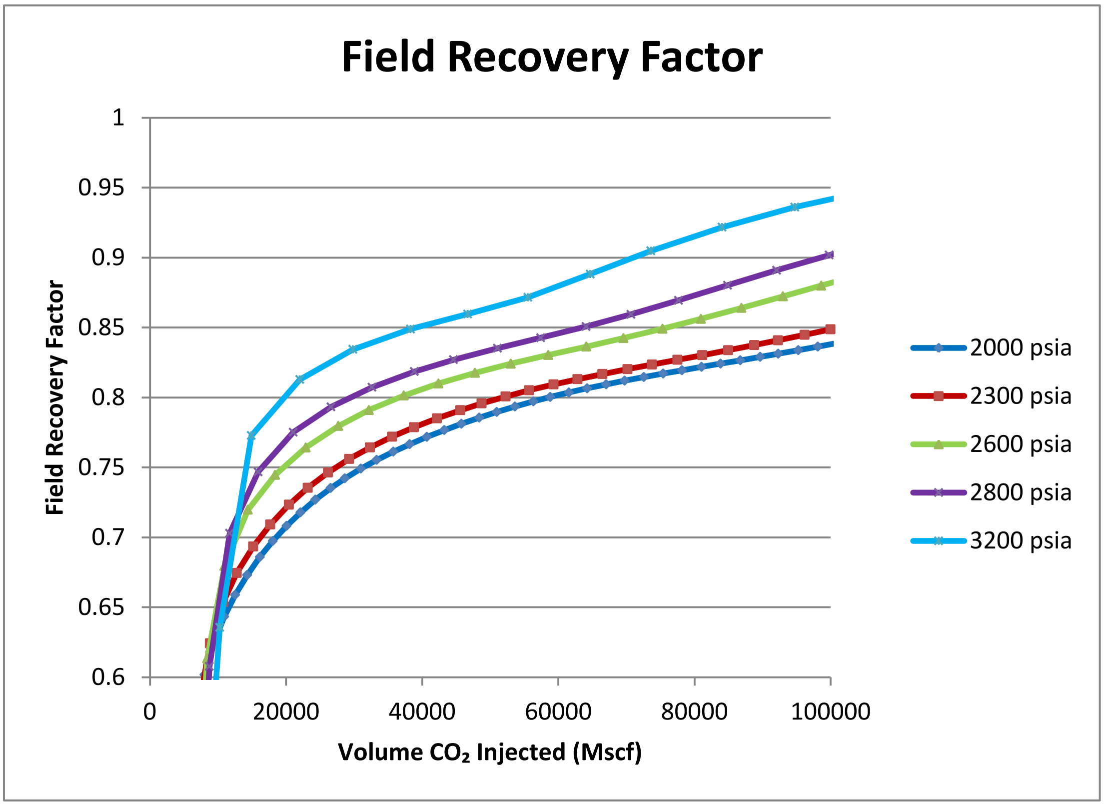


Figure 4-5: Plot of field recovery factor against volume of CO_2 injected

At higher injection pressure, CO_2 is able to vaporize more heavy components, thus reducing oil saturation. Simulation results show that at 3200 psia injection pressure, oil saturation near injector is reduced to 0, completely vaporizing all oil into a single phase, achieving miscible displacement. Therefore, when the same volume of CO_2 is injected at higher pressure, field oil recovery will increase.

Temperature affects CO_2 injection in many ways which then affects the field oil recovery factor, which includes phase behavior, vaporizing power of oil, and viscosity of oil and gas. As temperature decreases, oil phase viscosity increases causing it to be more viscous. On the other hand, gas viscosity decreases as temperature decreases due to less frictional force. Generally, if other parameters stay unchanged, more viscous liquid will flow slower than less viscous liquid due to the resistance to flow. Figure 4-6 and Figure 4-7 show the oil viscosity and gas viscosity respectively, of the block 100 feet away from the injector as temperature decreases:

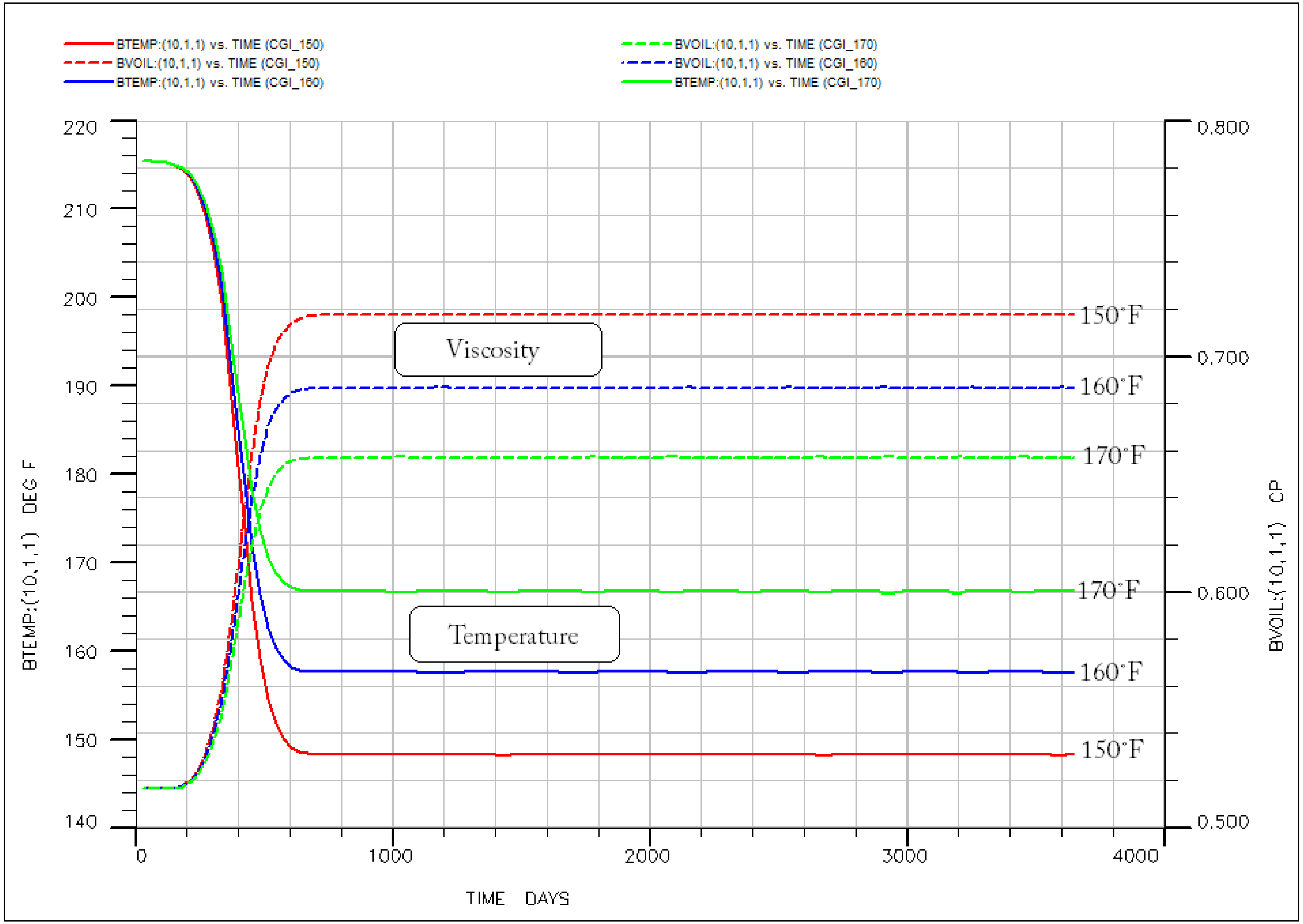


Figure 4-6: Effect of temperature on oil viscosity.

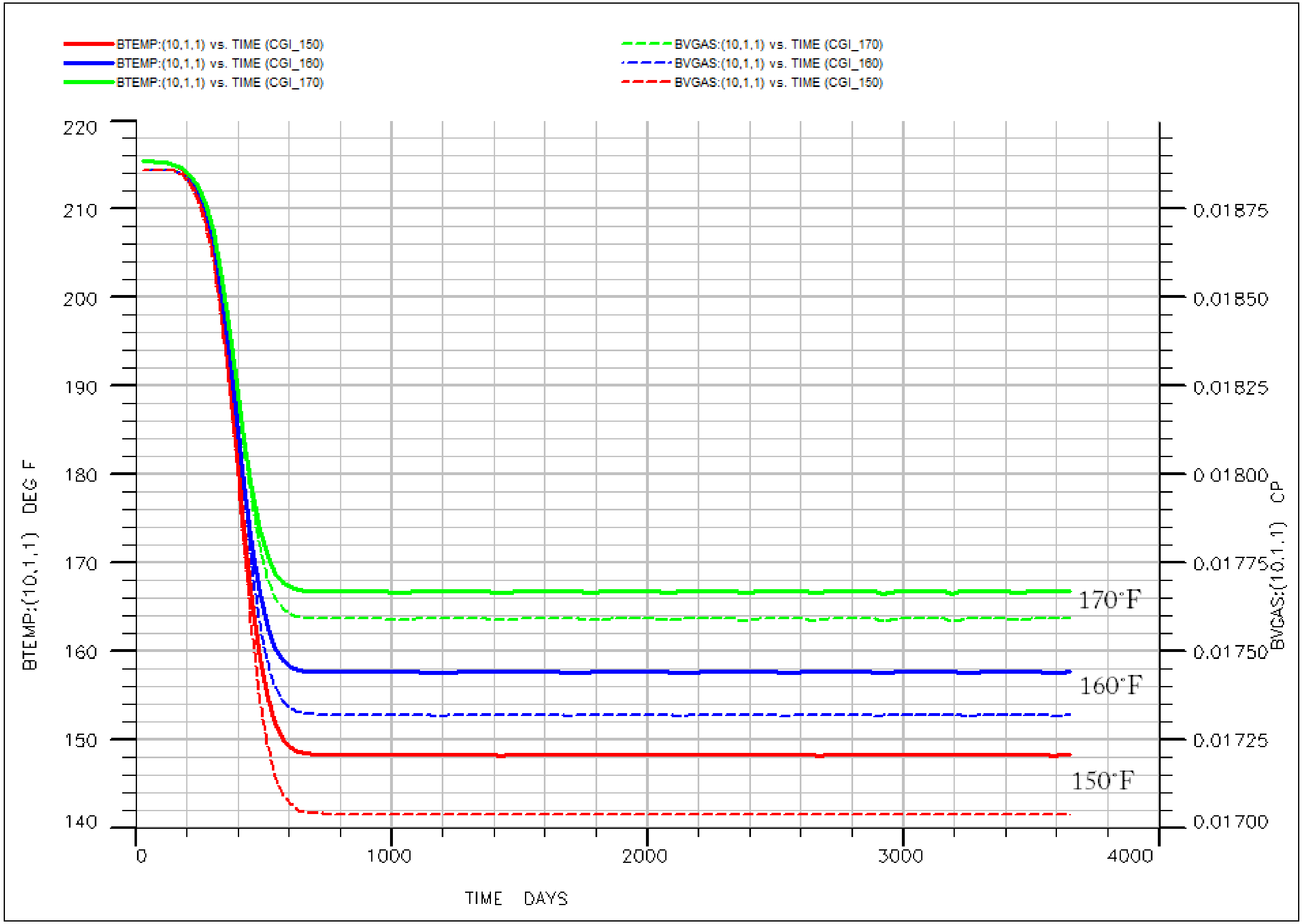


Figure 4-7: Effect of temperature on gas viscosity.

However, the ability of CO_2 gas to vaporize heavier components from oil improves as temperature decreases. As more oil is vaporized, residual oil saturation decreases, thus resulting in more oil being produced. Figure 4-8, Figure 4-9, and Figure 4-10 show the liquid mole fraction of each component at the block 100 feet away from the injector when CO_2 is injected at different temperature:

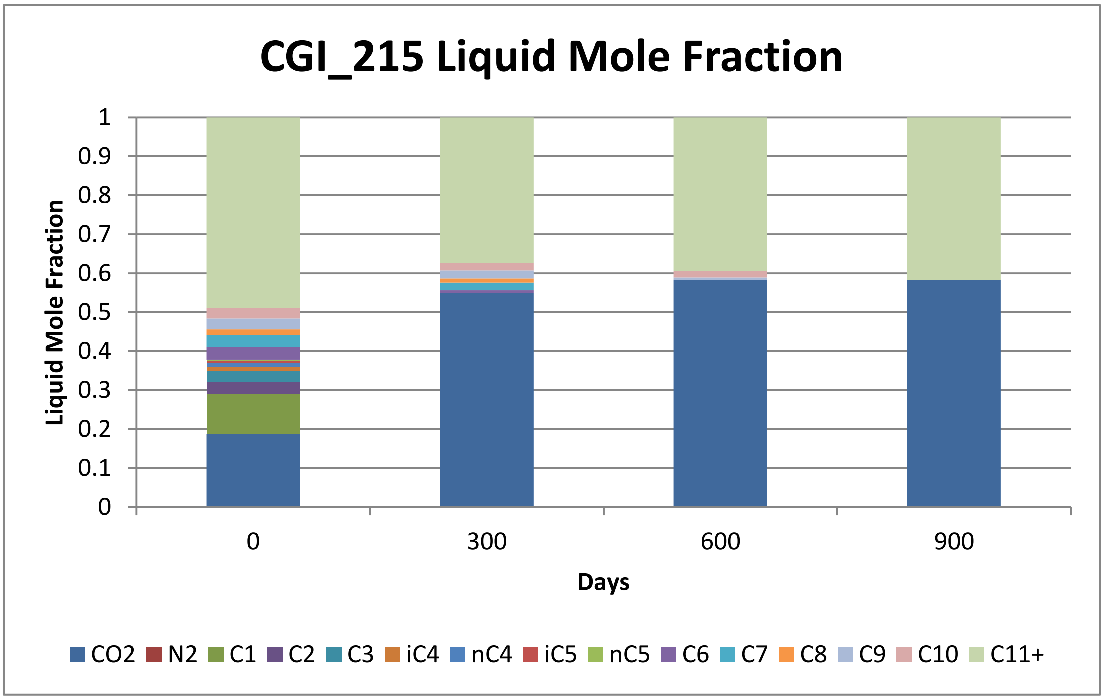


Figure 4-8: Liquid mole fraction of components at 215˚F injection temperature.

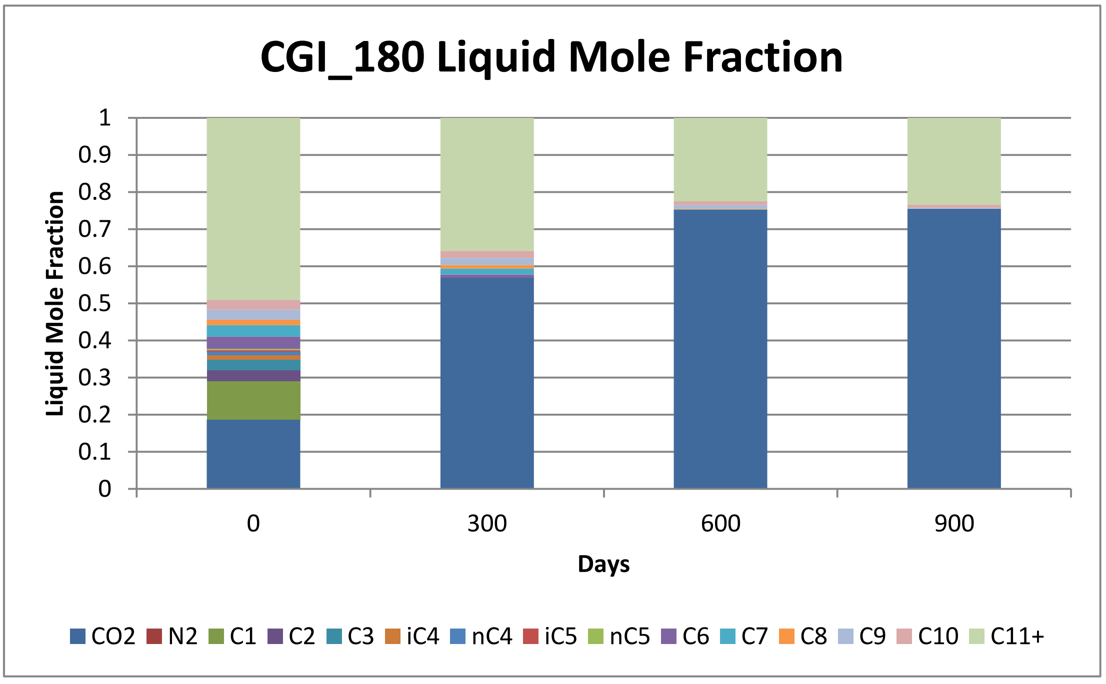


Figure 4-9: Liquid mole fraction of components at 180˚F injection temperature.

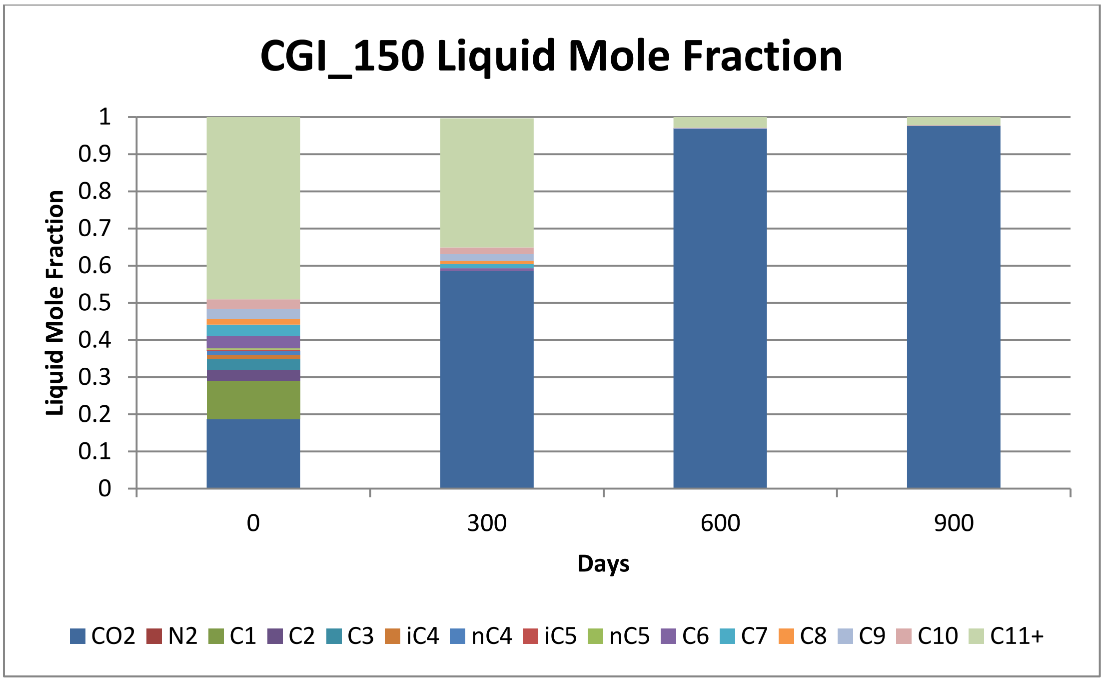


Figure 4-10: Liquid mole fraction of components at 150˚F injection temperature.

Results show that field oil recovery factor increases as injection temperature decreases, although oil viscosity increases. Figure 4-11 shows the field oil recovery factor of continuous gas injection schemes at different temperature:

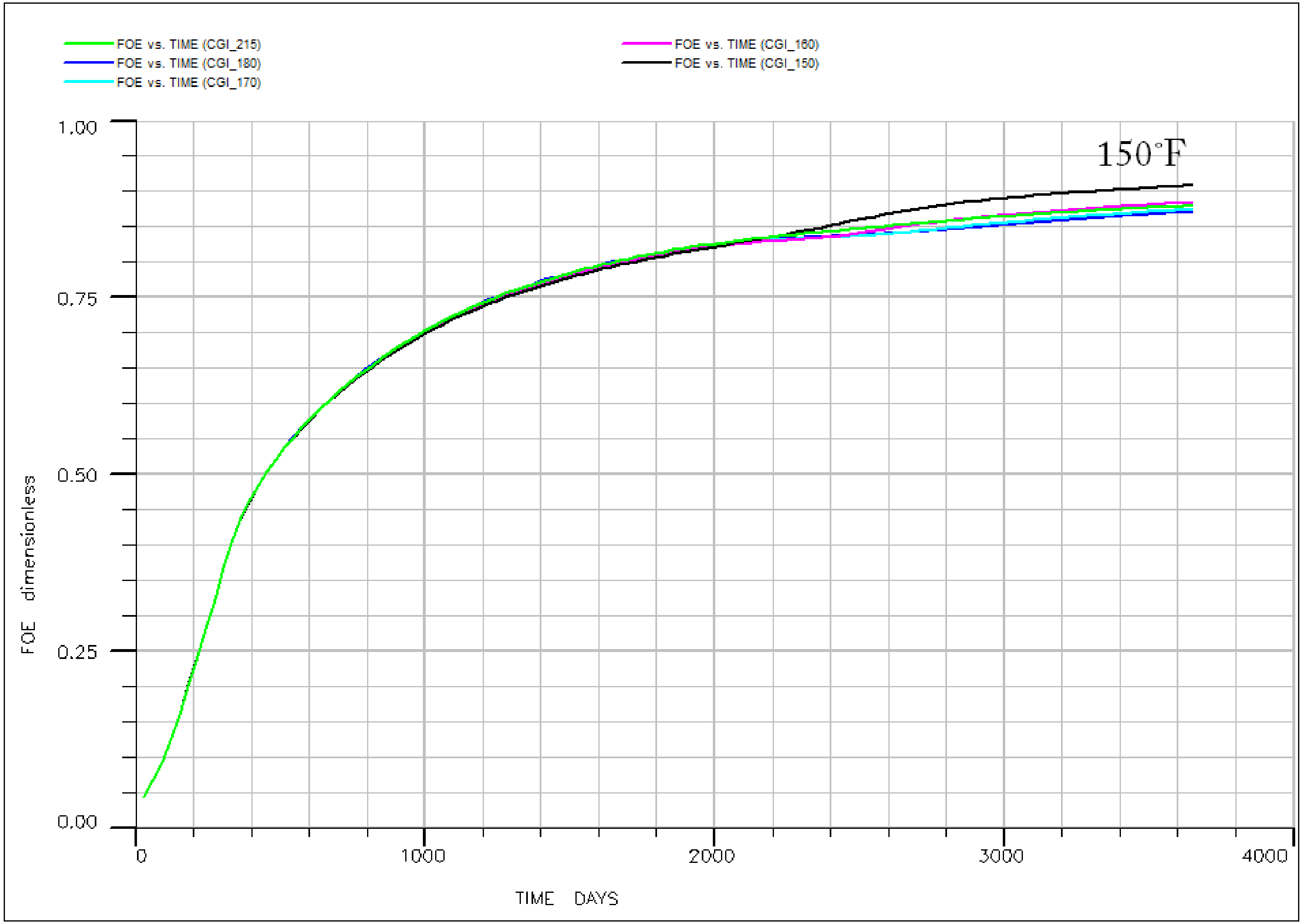


Figure 4-11: Effect of injection temperature on field oil recovery factor.

At lower temperature, CO_2 might condense into liquid form with higher viscosity. As all CO_2 turns into liquid, ECLIPSE treats it as being in oil phase (no gas saturation), that is to say that CO_2 is fully miscible with reservoir oil. When that happens, the mobility of CO_2 decreases (due lower temperature and higher viscosity), thus having higher resistance to flow. As flow rate of CO_2 decreases, it will take a longer time until liquid CO_2 is able to reach regions further from the injector and displaces oil towards the producer. Figure 4-12 shows the behavior of CO_2 in liquid form:

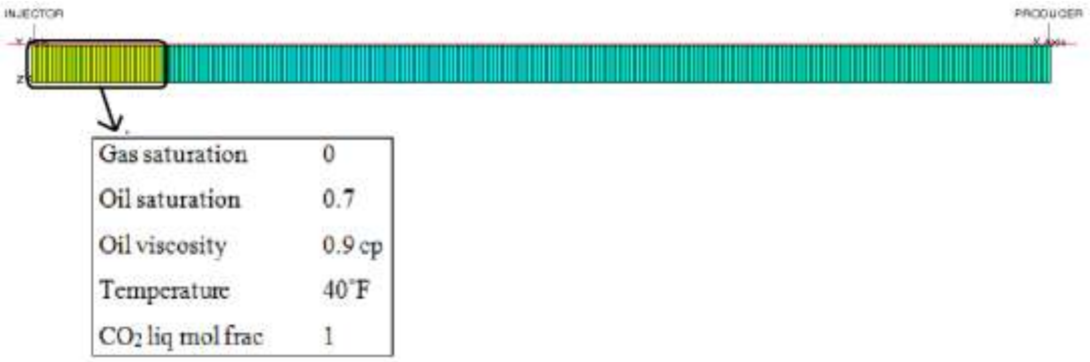


Figure 4-12: CO_2 injection at 40˚F.

In the attempt to lower reservoir temperature, cold water or cold CO_2 gas can be injected into the reservoir. The better option is to inject the fluid which will cool the reservoir furthest and fastest. Therefore, temperature gradient in both cases is analyzed to decide which fluid is better used to cool the reservoir. Both fluids are injected at a constant injector bottom-hole pressure of 2000 psia. Results show that continuous gas injection can cool region further away from the injector faster. The result of the simulations is shown in Figure 4-13 and Figure 4-14:

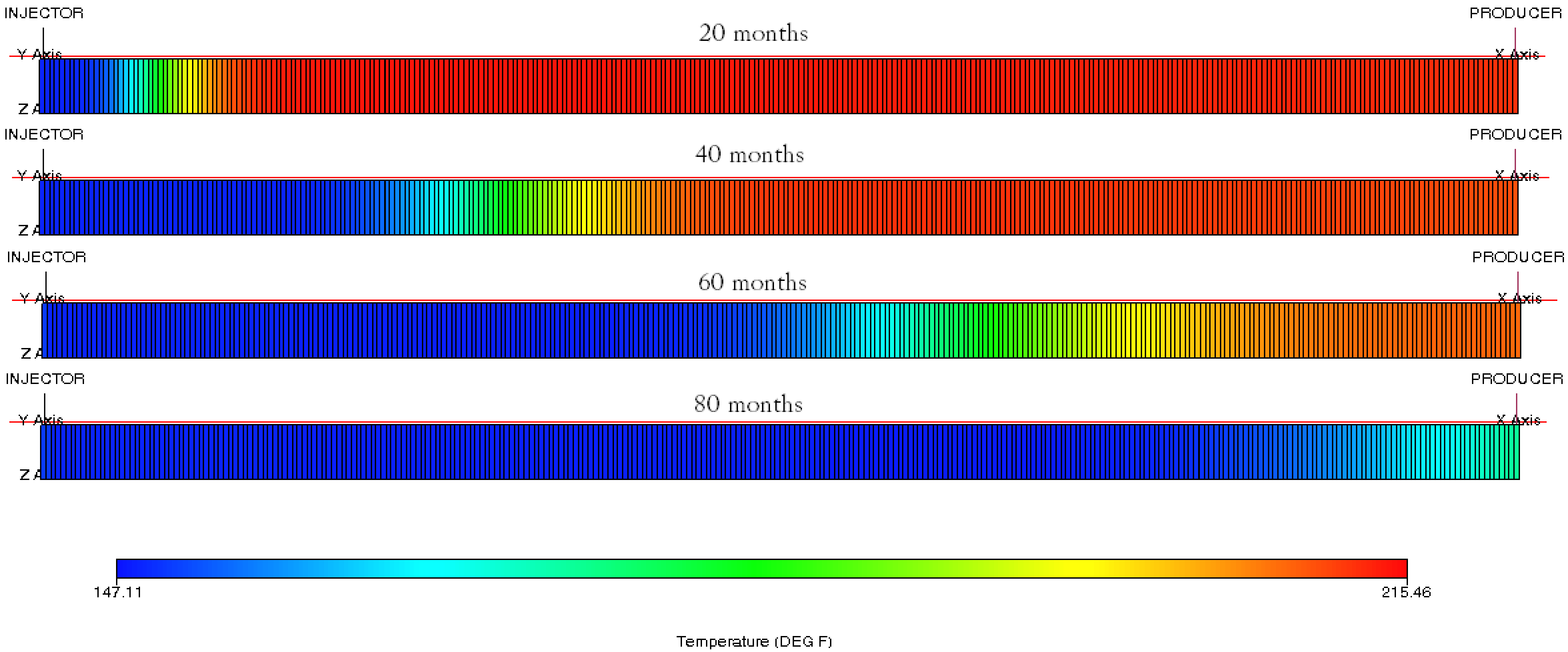


Figure 4-13: Temperature profile of continuous gas injection at 150˚F.

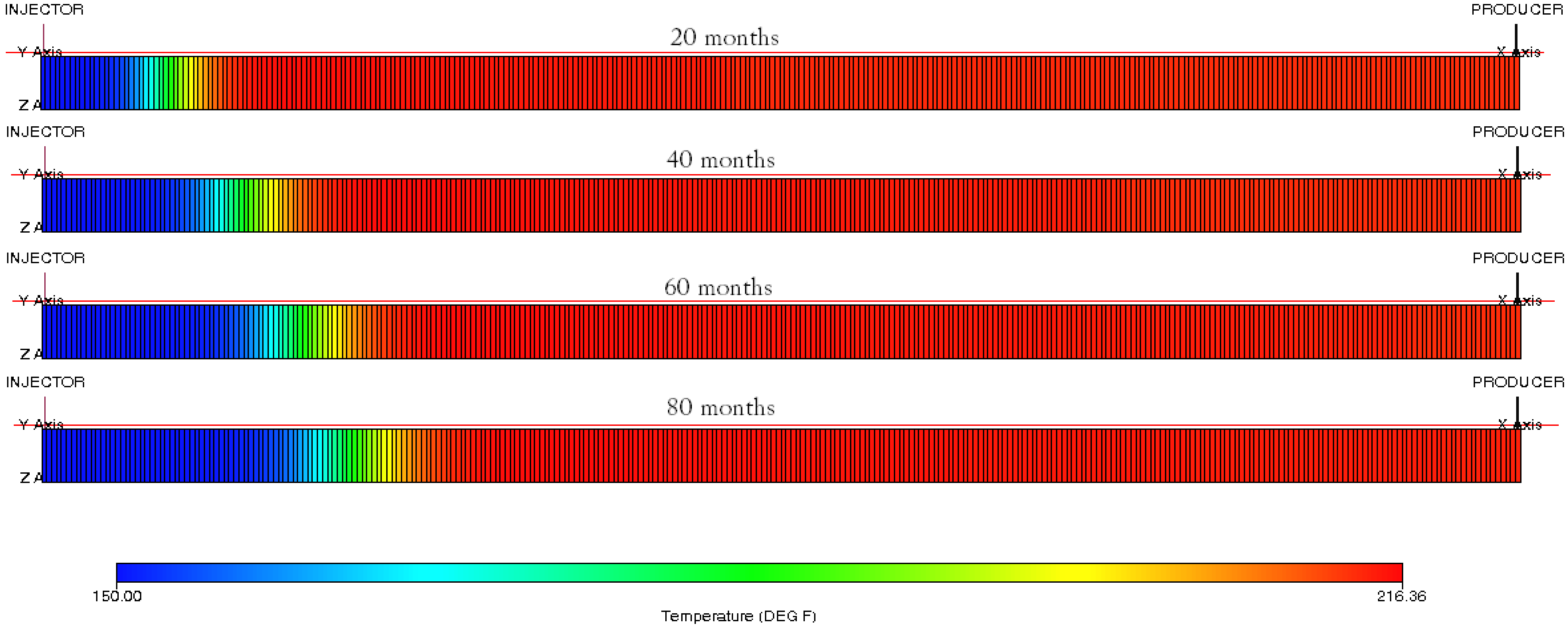


Figure 4-14: Temperature profile of water flooding at 150˚F.

4.4 WATER ALTERNATING GAS MODE – WAG

In WAG injection schemes, gas slugs and water slugs are injected alternately into the reservoir. To optimize WAG design, several schemes are simulated. Since all injections are controlled by bottom-hole pressure (i.e. 2000 psia), injection rate of each cycle need not to be designed. Simulations are run with different WAG ratio (i.e. 1:1, 1:2, 1:3, 2:1, and 3:1) and cycle size (i.e. 6 months, 12 months, and 24 months). In all these cases, water and gas are injected at 215˚F (i.e. reservoir temperature).

Results showed that WAG ratio of 1:3 and cycle size of 24 months (2 years) gives the highest field oil recovery factor over 10 years. This is because more CO_2 can be injected into the reservoir to vaporize lighter components of oil to reduce residual oil saturation. The results can be shown in Figure 4-15 and Figure 4-16 below:

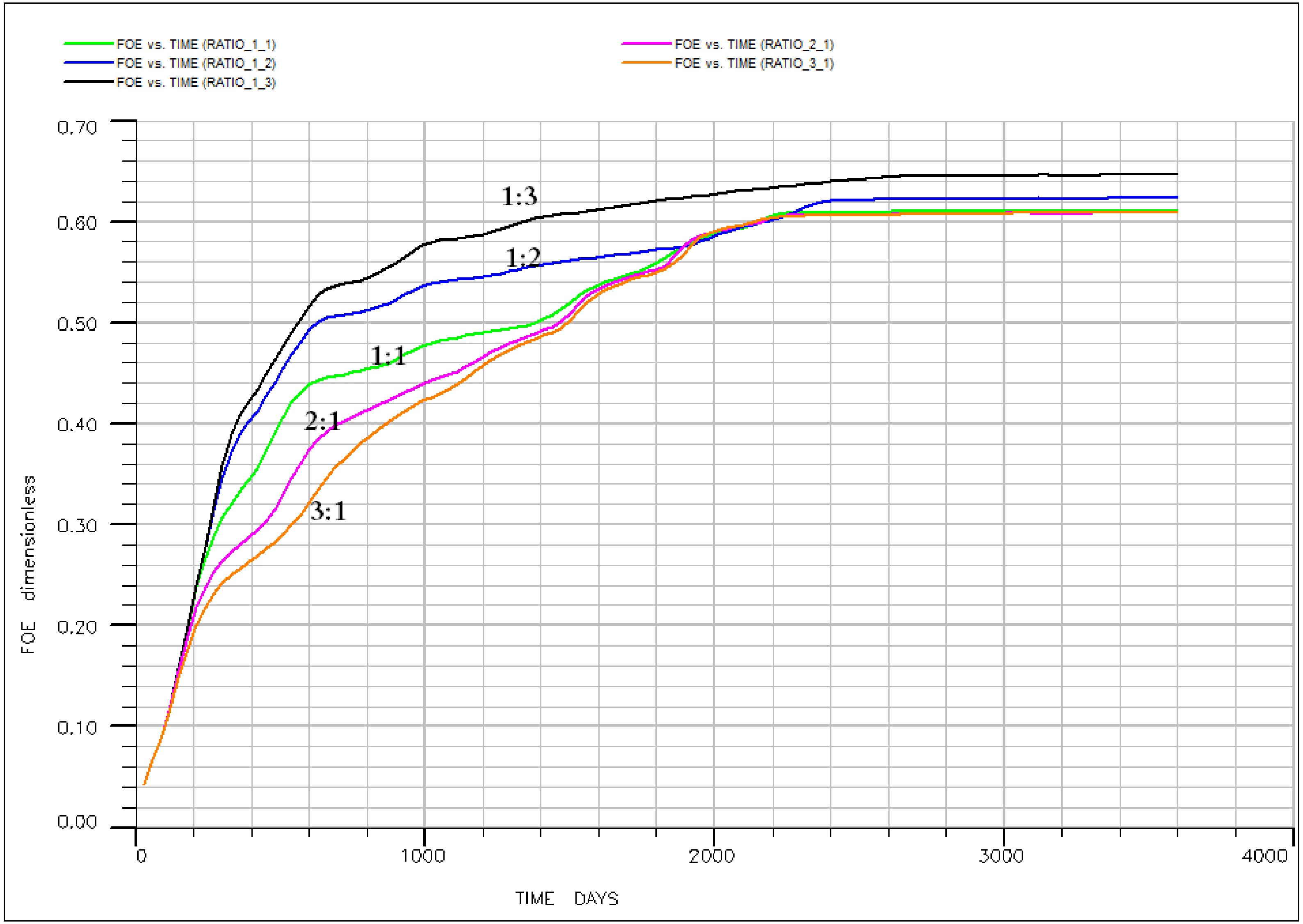


Figure 4-15: Effect of WAG ratio on field oil recovery factor of WAG schemes.

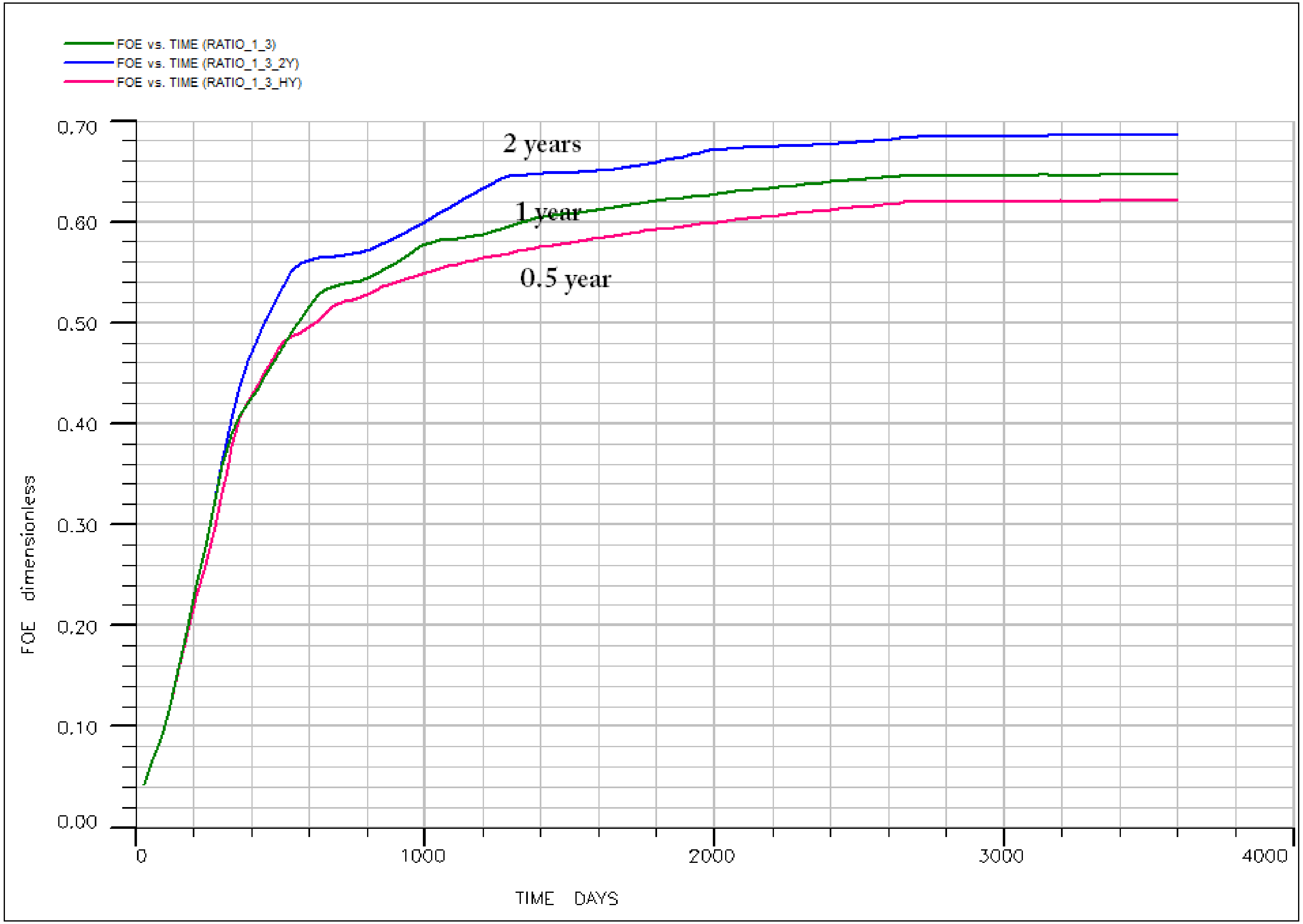


Figure 4-16: Effect of cycle size on field oil recovery factor of WAG schemes.

CHAPTER 5: CONCLUSIONS AND RECOMMENDATIONS

5.1 CONCLUSIONS

Simulation runs on continuous gas injection, water flooding, and WAG has been carried out on different injection temperature to study the feasibility of temperature induced miscibility. Several conclusions can be derived:

- At higher injection pressure, the vaporizing power of CO_2 on heavier components of oil increases, thus able to recover more oil. When compared at the same injection volume, the injection scheme with higher injection pressure produces a higher oil recovery factor.
- At lower temperature, the vaporizing power of CO_2 on heavier components of oil increases, thus able to improve oil recovery factor. Thus, if CO_2 is injected at lower temperature, it can improve oil recovery by displacing heavy components in the oil phase. This can be done by injecting cold water into the reservoir to cool the region prior to CO_2 injection, or by injecting cold CO_2 directly into the reservoir.
- While injecting solvent to achieve miscibility either from vaporizing or condensing drives, theoretical full miscibility does not need to be achieved to have the most economic recovery. This is because theoretical full miscibility can only be achieved when either all components in the oil phase can be vaporized, or when the solvent condenses completely into the oil phase. To achieve full miscibility in most cases require very high pressure or very low temperature, which can be costly. Injection pressure and temperature only need to be designed to vaporize the amount of oil in the most economical way.
- Water flooding represents completely immiscible flooding scheme. It is not able to perform vaporizing or condensing drives even at lower temperature, thus water flooding can only displace oil up to residual oil saturation. Therefore, injecting water at lower temperature does not improve field oil recovery factor. Incremental oil recovery decreases drastically at the point of water breakthrough.

- To reduce the temperature of the reservoir, continuous gas injection gives a better performance compared to water flooding, when injected at the same temperature and bottom-hole pressure.
- When CO_2 is injected at very low temperature, it may become liquid phase completely, and ECLIPSE model this as oil phase. When CO_2 is in oil phase, it is able to displace all oil components completely leaving CO_2 as the only component in oil phase in the swept region. This can be described as achieving miscibility because CO_2 completely mix with oil to form a single phase in all proportions (no gas saturation). However, at low temperature, oil phase viscosity increases which hinders the flow of liquid CO_2 through the reservoir, thus well spacing needs to be shorter for the displaced oil to reach the producer faster.
- In WAG design, WAG ratio of 1:3 and the longer cycle size gives the best field oil recovery factor as more CO_2 is injected to vaporize the oil components. However, economical factors (e.g. price of solvent and operational costs) need to be considered to design the optimized WAG scheme.

5.2 FUTURE WORK

Recommended future work includes expanding the model to 2-dimensional or 3-dimensional to study the effect of gravity segregation, which is also an important factor in WAG as well as CO_2 injection at low temperature, when it becomes liquid form with higher density (oil phase). The model can also be improved by introducing hysteresis model to see the effect of hysteresis on oil recovery, and asphaltene formation to predict the effect of asphaltene on displacement efficiency. The effects of clay swelling and the formation of wax or hydrates can also be analyzed. Next, geo-mechanic studies can be done to study the effect of cold water on the geo-mechanics of the reservoir rocks. Then, flow assurance studies can be done to check the feasibility of injecting cold water and CO_2 through the injection tubing into the formation.

REFERENCES

Bakar, M. A., Yeap, Y. C., Nasir, E., Din, A., Chan, C. F., Adamson, G., et al. (2011). SPE 144533 EOR Evaluation for Baram Delta Operations Fields, Malaysia. *SPE Enhanced Oil Recovery Conference.* Kuala Lumpur: SPE. 19-21 July 2011.

Bennion, D. B., Thomas, F. B., Bennion, D. W., & Bietz, R. F. (1995). SPE 30320 Mechanisms of Formation Damage and Permeability Impairment Associated With the Drilling, Completion and Production of Low API Gravity Oil Reservoirs. *SPE International Heavy Oil Symposium.* Calgary, Canada: SPE. 19-21 June 1995.

ChemicaLogic Corporation. (n.d.). Retrieved April 13, 2013, from CHEMICALOGIC: http://www.chemicalogic.com/Pages/DownloadPhaseDiagrams.aspx

Christensen, J. R., Stenby, E. H., & Skauge, A. (1998). SPE 39627 Compositional and Relative Permeability Hysteresis Effects on Near-Miscible WAG. *SPE Improved Oil Recovery Symposium.* Tulsa, Oklahoma: SPE. 19-22 April 1998.

Clark, N. J., Shearin, H. M., Schultz, W. P., Garms, K., & Moore, J. L. (1958). Miscible Drive - Its Theory and Application. *Journal of Petroleum Technology*, Volume 10, Number 6, 11-20.

Djabbarah, N. F. (1990). Miscible oil recovery process using carbon dioxide and alcohol. *Patent No. 4899817.* Texas.

Gong, B., Liang, H., Xin, S., & Li, K. (2011). Effect of Water Injection on Reservoir Temperature during Power Generation in Oil Fields. *Thirty-Sixth Workshop on Geothermal Reservoir Engineering.* California: Stanford Geothermal Program. 31–2 February 2011.

Goodyear, S. G., Hawkyard, I. R., Masters, J. H., Woods, C. L., & Jayasekera, A. J. (2003). Subsurface Issues for CO2 Flooding of UKCS Reservoirs. *81*. *Trans IChemE,* Vol 81, Issue 3, 315-325.

Jiang, H., Nuryaningsih, L., & Adidharma, H. (2012). SPE 154252 The Influence of O2 Contamination on MMP and Core Flood Performance in Miscible and Immiscible CO2 WAG. *Eighteenth SPE Improved Oil Recovery Symposium.* Tulsa: SPE. 14-18 April 2012.

Kulkarni, M. M. (2003). *Thesis: Immiscible and Miscible Gas-Oil Displacements in Porous Media.* The Craft and Hawkins Department of Petroleum Engineering.

Md. Zain, Z., Kechut, N. I., Nadeson, G., Ahmad, N., & Raja, D. A. (2001). SPE 72106 Evaluation of CO2 Gas Injection for Major Oil Production Fields in Malaysia - Experimental Approach Case Study: Dulang Field. *SPE Asia Pacific Improved Oil Recovery Conference.* Kuala Lumpur: SPE. 8-9 October 2001.

Rao, D. N., Girard, M., & Sayegh, S. G. (1991). SPE 20522 Impact of Miscible Flooding on Wettability, Relative Permeability, and Oil Recovery. *SPE Annual Technical Conference and Exhibition.* New Orleans: SPE. May 1992.

Samsudin, Y., Darman, N., Husain, D., & Hamdan, M. K. (2005). SPE 95931 Enhanced Oil Recovery in Malaysia: Making It a Reality (Part II). *SPE International Improved Oil Recovery Conference.* Kuala Lumpur: SPE. 5-6 December 2005.

Shahverdi, H., Sohrabi, M., Fatemi, M., & Jamiolahmady, M. (2011). Three-phase relative permeability and hyteresis effect during WAG process in mixed wet and low IFT systems. *Journal of Petroleum Science and Engineering* 78 (2011) 732–739.

Shakhashiri, B. Z. (2008, February 6). *Chemical of the Week: Carbon Dioxide.* Retrieved May 31, 2013, from http://scifun.chem.wisc.edu/chemweek/pdf/CarbonDioxide.pdf

Shu, W. R. (1985). Lowering CO_2 MMP and Recovering Oil Using Carbon Dioxide. *Patent No. 4513821.* Texas.

Stalkup Jr., F. I. (1992). *Monograph: Miscible Displacement.* Richardson, Texas: Society of Petroleum Engineers. 1-67, 137-162.

Stalkup Jr., F. I. (1983). Status of Miscible Displacement. *Journal of Petroleum Technology*, Volume 35, Number 4, 815-826.

Stalkup, F. I. (1978). Carbon Dioxide Miscible Flooding: Past, Present, And Outlook for the Future. *Journal of Petroleum Technology*, Volume 30, Number 8, 1102-1112.

Surguchev, L. M., Korbol, R., & Krakstad, O. S. (1992). SPE 24646 Optimum Water Alternate Gas Injection Schemes for Stratified Reservoirs. *57th Annual Technical Conference and Exhibition.* Washington DC: SPE. 4-7 October 1992.

Surguchev, L. M., Korbol, R., Haugen, S., & Krakstad, O. S. (1992). SPE 25075 Screening of WAG Injection Strategies for Heterogeneous Reservoirs. *European Petroleum Conference.* Cannes, France: SPE. 16-18 November 1992.

Thomas, F. B., Holowach, N., XueLong, Z., Bennion, D. B., & Bennion, D. W. (1994). SPE 27811 Miscible or Near-Miscible Gas Injection, Which is Better? *SPE Ninth Symposium on Improved Oil Recovery.* Tulsa, Oklahoma: SPE. 17-20 April 1994.

Wu, X., Ogbe, D. O., Zhu, T., & Khataniar, S. (2004). Critical Design Factors and Evaluation of Recovery Performance of Miscible Displacement and WAG Process. *5th Canadian International Petroleum Conference.* Calgary, Canada: Petroleum Society. 8 - 1 Jun, 2004.

Yellig, W. F., & Metcalfe, R. S. (1978). Determination and Prediction of CO2 Minimum Miscibility Pressure. *Journal of Petroleum Technology*, Volume 32, Number 1, 160-168.

Zick, A. A. (1986). SPE 15493 A Combined Condensing/Vaporizing Mechanism in the Displacement of Oil by Enriched Gases. *SPE 61st Annual Technical Conference and Exhibition.* New Orleans: SPE. 5-8 October 1986.