COMPARING COMPOSITONAL AND BLACK OIL MODELS FOR SIMULATING MISCIBLE CO_2 INJECTION

by

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CERTIFICATION OF APPROVAL

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A project dissertation submitted to the

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Approved by,

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TRONOH, PERAK

September 2012

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.

Sermphon Klaiseengern

ABSTRACT

The miscible displacement in CO_2 injection is a process where the oil in the reservoir completely mixes with the injected CO_2. To see and understand the process of the CO_2 miscible injection, the simulator is the essential tool for engineering design. Normally, a compositional simulator is used for a detailed simulation by solving the equation of states for fluids and calculating the partitioning fluid between phases. However, the method is time consuming that the Black Oil Model would take a greater advantage as a simpler method for simulation.

In this study, the simulation of Black Oil Model for CO_2 Miscible Injection using the Water Alternating Gas Injection Technique, was carried out to investigate its ability and accuracy compared with the compositional simulator with the range of models and scenarios. All reservoir characteristics were kept constant in order to pay an attention on the PVT Properties of the fluids in the Black Oil and Peng-Robinson fluid characterization in Compositional Simulator. Schlumberger ECLIPSE 100 and ECLIPSE 300 were the main tools used for comparing the two simulations.

It is found that the Black Oil simulator is capable to predict the similar trends of Oil Recovery Factor, Total Oil Production and Reservoir Pressure to the Compositional Simulator in certain cases, however, there are the obvious differences in values between two simulators depending on the reservoir models and WAG scenarios examined. The gas injection rate is found to be an important parameter in determining the accuracy of Black Oil comparing to Compositional simulators.

In agreement with other studies, Black Oil simulator is found to have 6.45 speed up factor comparing to the Compositional simulator.

Keywords: Miscible CO_2 WAG Injection, Black Oil Model, Compositional Model

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CHAPTER 1

INTRODUCTION

1.1 BACKGROUND OF STUDY

Carbon Dioxide Injection is one of the proven methods in enhanced oil recovery. The technique is preferably done as the tertiary recovery mechanism after water flooding. Compared to other tertiary recovery methods, CO_2 has the potential, in its supercritical status, to enter into zones not previously invaded by water and thus releasing the trapped oil not extracted by traditional methods (Andrei *et al.*).

CO_2 injection has direct benefit in providing a pressure support for subsidence prevention and intrusion of water which will lead to better oil recovery, extension of field life and the increase in profitability of the fields (Al-Hashmi *et al.,* 2005). Additionally, the CO_2 is greenhouse gas and in recent years, the topic of CO_2 injection to the reservoir has received an increased attention as the successful method in reducing the greenhouse gas emission to the atmosphere in order to meet with the Kyoto Protocal (December, 1997) (Shariatipour *et.al.,*2012).

The great advantage of CO_2 injection compared to the other gas is its capability to extract heavier components up to C_{30}. The solubility of CO_2 in hydrocarbon oil can promote the swelling as the CO_2 expands to oil greater than methane. The usage of CO_2 will also benefit in oil viscosity reduction, increase in oil density, its solubility in water, ability to achieve miscibility at pressures of only 100 to 300 bars, reduction in water density, etc (Mathiassen *et al.*, 2003).

According to Andrei *et al.* , the Enhanced Oil Recovery through CO_2 injection can be achieved by two main processes which are miscible and immiscible displacement. The processes depend on reservoir pressure, temperature and oil characteristics. The miscible displacement processes are used under the suitable reservoir conditions (1,200m) and oil density (> 22 °API) where the oil in the reservoir completely mixes with the injected CO_2 resulting in effectively decreasing interfacial tension; the physical forces holding two phases apart, between the two substances to almost zero in order to create a fluid with low viscosity that can be easily displaced and produced. On the other hand, the immiscible displacement processes are applied when reservoir pressure is too low and the oil density is too high. The CO_2 injected does not mix with the oil within the reservoir, but causes the swelling of the oil, reducing its density, improving mobility and, consequently, increasing the oil recovery.

The simulator is essential to aid in the engineering design of a CO_2 injection project. A compositional simulator is normally used for a detailed simulation by solving the equation of states for fluids and calculating the partitioning fluid between phases (Shariatipour *et.al.,*2012). However the method is time consuming. CPU-time becomes the limiting factor when we make the simulation model (Fevang *et al,* 2000). From this aspect, it is the great advantage to use the black-oil simulator as the simpler method for simulation.

1.2 PROBLEM DESCRIPTION

The detailed simulation for CO_2 Miscible Injection for Enhanced Oil Recovery using the Compositional Simulator is a time consuming method. The simpler method as Black Oil simulator is used to compare its accuracy in different simulation cases with the Compositional Simulator.

1.3 OBJECTIVES

The two main objectives to be achieved in this study are:

- To conduct the simulation of CO_2 Miscible Injection for Black Oil and Compositional Simulators for range of models
- To investigate the ability and accuracy of the Black Oil Model Simulator to simulate Miscible CO_2 injection process for enhanced oil recovery in comparison with Compositional Model.

1.4 SCOPES OF STUDY

In this study, the Schlumberger ECLIPSE 100 and ECLIPSE 300 were the main instruments used for the comparison of Black Oil and Compositional Simulators. The CO_2 Water Alternating Gas injection into 3D Homogeneous Model was used as the base case for the study. Then, the base case model was adjusted to see the response of the simulators when there were the effect of heterogeneity, WAG cycle time, injection rate and vertical to horizontal permeability ratio. The other parameters are kept constant to investigate and compare the response of each simulator.

CHAPTER 2

LITERATURE REVIEW

2.1 CO_2 PROPERTIES

Carbon Dioxide becomes the effective agent for miscible flooding in improving oil recovery because of its density and viscosity. The critical temperature of CO_2 is 88 degree F and critical pressure is 1070 psia where it stays as pure component. Since most reservoir lies above the critical value, the CO_2 is still considered as a dense gas with liquid properties but low viscosity in the reservoir conditions. Dense phase CO_2 is capable to extract hydrocarbon from oil more easily than if it were in the gaseous phase. The viscosity of CO_2 can improve the recovery by reducing oil viscosity (Shariatipour *et al.*,2006; Fevang *et al.*,2000).

2.2 MECHANISM FOR CO2 MISCIBILITY WITH OIL

According to Jarrell *et al.* (2002) , miscibility between fluids can be achieved through two mechanisms which are the first contact miscibility and multiple contact miscibility. When two fluids become completely miscible, they establish a single phase; one fluid can completely displace the other fluid, leaving no residual saturation. For two fluids to be miscible, a minimum pressure is required. The example of the first-contact miscibility is ethanol and water. The two fluids can immediately form one phase with no observable interface, regardless of the proportions.

For CO_2 and crude oils, they are in the multiple contact miscible process. Both of them are not miscible on first contact, but require many contacts in which components of the CO_2 and oil transfer back and forth until the oil-enriched CO_2 cannot be distinguished from the CO_2-enriched oil (Holm *et al.*,1982; Rathmell *et al.*, 1971; Holm *et al.*, 1974). According to Zick (1986), the process is called a condensing/vaporizing mechanism. Multiple-contact miscibility between CO_2 and oil starts with dense phase CO_2 and hydrocarbon liquid. The CO_2 first condenses into the oil, making the oil lighter and often driving methane out ahead of the "oil bank". The lighter components of the oil and then vaporize into the CO_2-rich phase, making it denser, more like the oil, and thus more easily soluble in the oil. Between CO_2 and oil, the mass transfer continues to occur until the resulting two mixtures become indistinguishable in terms of fluid properties, where there is no interface between CO_2 and oil, and one hydrocarbon phase results.

2.3 EFFECT OF PRESSURE ON CO_2 OIL RECOVERY

Miscibility between Carbon Dioxide and oil is a function of both pressure and temperature. However, for the isothermal reservoir, the only factor is pressure. When the pressure increases, more CO_2 will be dissolved in oil and CO_2 will vaporize more oil. Being intimate contact at certain pressure, Oil and CO_2 will become miscible. When this contact happens with little or no reservoir mixing, the pressure that the miscibility occurs is called *Thermodynamic Minimum Miscibility Pressure* (Thermodynamic MMP). The displacement efficiency of CO_2 can be decreased by the effects of small scale reservoir mixing which will also result in higher required pressure for miscibility (*Wijaya*, 2006).

2.4 MINIMUM MISCIBILTY PRESSURE CORRELATION

Glass, O. (1985) proposed the correlation to generate the minimum miscibility pressure required for multicontact miscible displacement of reservoir fluids. The equations are derived from graphical correlations given by Benhem et al. and give MMP as a function of reservoir temperature, C_{7+} molecular weight of the oil, mole percent methane in the injection gas and the molecular weight of the intermediates (C_2-C_6) in the gas. CO_2 is represented in the correlation by equivalent methane/propane. The pressure required for CO_2 to achieve miscibility is significantly lower than requirement for hydrocarbon and nitrogen. CO_2 gas was found equivalent to 58 mol% methane and 42 mol% propane. The equation developed for CO_2 in predicting MMP is given by.

$$(p_m)_{min} = 810.0 - 3.404 M_{C7+} + \left(1.700 \times 10^{-9} M_{C7+}^{3.730} e^{786.7 M_{C7+}^{-1.058}}\right) T$$

Where M_{C7+} is the molecular weight of C_{7+} and T is the temperature of the reservoir in Farenheit. (Glass, 1985; Benham *et al.*, 1960)

2.5 WATER ALTERNATING GAS INJECTION

Caudle and Dyes (1958) proposed the water-alternating gas process (WAG) in order to improve the sweep efficiency of the gas injection process through water injection. The water injection is used to control the displacement efficiency and stabilize the gas front as the gas mobility control is one of the most important factors to achieve the oil recovery through gas injection. The viscosity of CO_2 can usually be 1/10 time lower than oil viscosity in reservoir conditions (Rao *et al.,*2004). The favorable aspects of gas injection and water flooding are combined. The gas injection provides the better oil displacement whereas water flooding gives better macroscopic sweep (Christensen *et al.,* 2001). WAG process has several advantages, especially in WAG-CO2 Process, where it gives the best corresponded oil recovery factor comparing to CO_2 continuous injection and water flooding (Chen *et al.*, 2010).

WAG injection causes a complex saturation pattern. This is owing to the saturations of gas and water which increase and decrease alternatingly. This requires special demands for the relative permeability description for oil, gas and water phases. Several correlations are available for calculating three phase relative permeability however only recently that the approach designed for WAG injection using cycle dependant relative permeability has been developed (Christensen, 1998).

For the Miscible WAG, it is actually quite hard to differentiate between miscible and immiscible WAG. It is found that in many cases, the miscibility of multi-contact gas oil may have been obtained, however, the actual displacement process is still uncertain. Real field cases may oscillate between miscible and immiscible gas during the life of the oil production owing to the failure in maintaining sufficient pressure (Christensen, 1998).

Numerical simulation of WAG Process is not simple procedure though it is not a new process and many projects have been accomplished before. The fundamental in compositional simulation as proposed by Chen et al.(2010) and Almeida et.al (2010), is a right fluid modeling in order to represent the phenomenon associated to CO_2 dissolution in the oil.

2.6 GENERAL DESCRIPTION RELATED TO WAG

According to Christensen (1998), some simple relations are useful to help in understanding the advantages of the WAG injections. The Oil recovery is described by three factors:

$$REC = E_v \, . \, E_h \, . \, E_m$$

Where REC is oil recovery, E_v is vertical sweep, E_h is horizontal sweep and E_m is the microscopic displacement efficiency. In order to optimize the recovery, one of these factors is maximized. For E_h and E_v, they are considered as macroscopic displacement efficiency.

For the horizontal displacement efficiency, E_h is strongly affected by the stability of the front defined by the mobility (M) of the fluids given by this equation:

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

k_{rg} and k_{ro} are the relative permeability of gas and oil, whereas μ_g and μ_o are the gas and oil viscosity respectively. The decrease in sweep efficiency and early gas breakthrough can happen owing to the unfavorable mobility. The other factors include a reservoir heterogeneity and high permeable layers.

The WAG displacement can be optimized when the mobility ratio is favorable, which should be less than 1. This can be obtained by increasing the velocity of the gas or decreasing the fluids relative permeability. The gas mobility reduction can be achieved through injecting water and gas alternately.

On the other hand, for vertical displacement efficiency, E_v is affected by by viscosity and gravitational forces.

$$R_{v/g} = \left(\frac{v\mu_o}{kg\Delta\rho}\right)(\frac{L}{h})$$

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

2.7 SIMULATION STUDY

Simulating multiphase fluid flow in porous media relates to solving a system of coupled non-linear partial differential equations. Developing a computer model for these types of systems requires the use of finite-difference approximation to discretize these equations which is similar to the case of single-phase flow models. The various solution techniques differ with respect to how we manipulate the governing partial differential equations.

2.8 BLACK OIL MODEL

The components of Black Oil Model consist of Oil, Gas and Water, existing in Oil, Gas and Water phases. According to Kleppe (2001), the oil density is described as;

$$\rho = \frac{\rho_{os} + \rho_{gs} \cdot R_{so}}{B_o}$$

Where Bo, Bg, Rs, rs ~ f(Po,Pb). These parameters can be determined from PVT experiments.

$$\frac{\partial}{\partial x}\left(\frac{kk_{ro}}{B_o\mu_o}\frac{\partial P_o}{\partial x}\right) - q_o = \frac{\partial}{\partial t}\left(\frac{\emptyset S_o}{B_o}\right)$$

$$\frac{\partial}{\partial x}\left(\frac{kk_{rg}}{B_g\mu_g}\frac{\partial P_g}{\partial x} + \frac{kk_{ro}}{B_o\mu_o}\frac{\partial P_o}{\partial x}\right) - q_g - Rs_o \cdot q_o = \frac{\partial}{\partial t}[\emptyset\left(\frac{S_g}{B_g} + \frac{S_g\ Rs_o}{B_g}\right)]$$

Black Oil Model typically used fluid flow equations that conserve surface oil, surface gas and water. The use of a single gas is limiting when attempting to model processes in which the nature of the injection gas and its equilibrium behavior in the presence if reservoir oil is different from that of the original reservoir gas (Peaceman, 1977).

2.9 COMPOSTIONAL MODEL

A compositional simulator is used in a variety of situations in which a black oil simulator does not adequately describe the fluid behavior. In reservoir containing light oil, the hydrocarbon composition as well as pressure affects fluid properties. The components of compositional model consists of Methane, ethane, propane … N, in Oil, Gas and Water phases. Equilibrium flash calculation using K values or and equation of state (EOS) must be used to determine hydrocarbon phase compositions

In a compositional model, we in principle make mass balance for each hydrocarbon component, such as methane, ethane, propane etc. In practice, we limit the number of components included and group components into pseudo components. Then, we define C_{kg} as a mass fraction of component k present in the gas phase, and C_{ko} as a mass fraction of component k present in the oil phase. Thus, we have conditions that for a system of N_c components:

$$\sum_{k=1}^{N_c} C_{kg} = 1 \ , \sum_{k=1}^{N_c} C_{ko} = 1$$

Then, a mass balance of component k may be written (in one dimension for simplicity):

$$-\frac{\partial}{\partial x}\left(C_{kg}\rho_g u_g + C_{ko}\rho_o u_o\right) = \frac{\partial}{\partial t}[\emptyset(C_{kg}\rho_g S_g + C_{ko}\rho_o S_o)]$$

Darcy's equations for each flowing phase are identical to the Black Oil equations:

$$u_o = -\frac{kk_{ro}}{\mu_o}\frac{\partial P_o}{\partial x}, u_g = -\frac{kk_{rg}}{\mu_g}\frac{\partial P_g}{\partial x}$$

Where: $P_{cog} = P_g - P_o$, $P_{cow} = P_o - P_w$, and $S_o + S_g = 1$. Thus, we may write flow equations for Nc components as:

$$\frac{\partial}{\partial x}\left(C_{kg}\rho_g\frac{kk_{rg}}{B_g\mu_g}\frac{\partial P_g}{\partial x} + C_{ko}\rho_o\frac{kk_{ro}}{B_o\mu_o}\frac{\partial P_o}{\partial x}\right) = \frac{\partial}{\partial t}[\emptyset(C_{kg}\rho_g S_g + C_{ko}\rho_o S_o)]$$

$k=1, Nc$

The properties of oil and gas phases depend on pressure and composition, so that the functional dependencies may be written:

$\rho_g(P_g, C_{1g}, C_{2g}, ..)$

$\rho_o(P_o, C_{1o}, C_{2o}, ..)$

$\mu_g(P_g, C_{1g}, C_{2g}, ..)$

$\mu_o(P_o, C_{1o}, C_{2o}, ..)$

The equilibrium K values may be used to determine component ratios:

$$\frac{C_{ig}}{C_{io}} = K_{igo}(T, P, C_{ig}, C_{io})$$

The numbers of equations that must be solved in compositional simulation depend on the number of components modeled. Often, we model the lighter components individually and group heavier components into a pseudo component. If non hydrocarbons are involved, these may have to also be modeled separately (Kleppe, 2001; Al-Awami *et al.*, 2003).

2.10 EQUATIONS OF STATE

An equation-of-state (EOS) is an equation which expresses the relationship between pressure, temperature and volume of a gas or liquid. These equations are usually of cubic form. Peng-Robinson EOS is among the widely EOS used in the petroleum industry. The EOS proposed by Peng and Robinson is described below:

$$\left[p + \frac{a_T}{V_M(V_M + b) + b(V_M - b)}\right](V_M - b) = RT$$

The coefficients for the equation are calculated by:

$$a_T = a_c \alpha$$

$$A_C = 0.45724 \frac{R^2 T_C^2}{P_C}$$

$$\alpha^{1/2} = 1 + m(1 - T_r^{1/2}$$

$$b = 0.07780 \frac{RT_c}{p_c}$$

$$m = 0.37464 + 1.54226\omega - 0.26992\omega^2$$

2.11 RESERVOIR SCREENING

There are the preliminary technical evaluations proposed by different authors for selecting the suitable oil reservoir for CO_2 Enhanced Oil Recovery from the facts that not all reservoirs is appropriate to apply the technique owing to technical and economic reasons. The screening criteria for application of CO2 miscible flood suggested by different authors are shown in the table below.

Reservoir Parameter	[20] Carcona (1982)	[23] Taber & Martin (1983)	[21] Klins (1984)	[22] Taber et al. (1997)
Depth (m)	< 3000	> 700	> 914	i) > 1219; ii) > 1006 iii) > 853; iv) > 762
Temperature(°C)	< 90			
Pressure (Mpa)	>83		>103	
Permeability (mD)	>1			
Oil gravity (°API)	>40	>26	>30	i) 22-27.9; ii) 28-31.9 iii) 32-39.9; iv) > 40
Viscosity	<2	<15	<12	< 10
Fraction of oil remaining	>0.30	>0.30	>0.25	> 0.20

Table 1: Screening criteria for application of CO_2 miscible flood

The stated criteria are based on the optimizing reservoir performance for better enhanced oil recovery. Nevertheless, we can ignore certain criteria such ad reservoir depth and oil viscosity as they are affected by other parameters such as oil gravity and reservoir temperature.

In addition Rivas et al. (1992) used the reservoir simulators to investigate the effect of many reservoir parameters to CO_2 EOR performance. The set of optimum values of reservoir and oil properties best suitable for CO_2 EOR Operation is shown in the following table.

Reservoir parameters	Optimum values	Parametric weight
API Gravity (°API)	37	0.24
Remaining oil saturation	60%	0.20
Pressure over MMP (MPa)	1.4	0.19
Temperature (°C)	71	0.14
Net oil thickness (m)	15	0.11
Permeability (mD)	300	0.07
Reservoir dip	20	0.03
Porosity	20%	0.02

Table 2: Reservoir and oil properties best suitable for CO_2 EOR Operation

2.12 BASE MODELS CHARACTERISTICS

2.12.1 Fluid Properties

Fluid data for the base model is taken from Crude Oil Data from Table 10-1,"The Properties of Petroleum Fluids", Second Edition by McCain W.D. (1990). The results of laboratory from main procedures which are composition measurement, flash vaporization, differential vaporization, separator test and oil viscosity measurement, are shown in the following tables.

Compositions	ZI	MW
CO_2	0.0091	44.010
N_2	0.0016	28.013
C_1	0.3647	16.043
C_2	0.0967	30.070
C_3	0.0695	44.097
IC_4	0.0144	58.124
NC_4	0.0393	58.124
IC_5	0.0144	72.151
NC_5	0.0141	72.151
C_6	0.0433	84.000
C_{7+}	0.3329	218.000

Table 3: Fluid Composition Data

Pressure	Rel. Volume	Y
5000	0.9639	
4500	0.9703	
4000	0.9771	
3500	0.9846	
3000	0.9929	
2900	0.9946	
2800	0.9964	
2700	0.9983	
2620	1	
2605	1.0022	2.574
2591	1.0041	2.688
2516	1.0154	2.673
2401	1.035	2.593
2253	1.0645	2.51
2090	1.104	2.422
1897	1.1633	2.316
1698	1.2426	2.219
1477	1.3618	2.118
1292	1.5012	2.028
1040	1.7802	1.92
830	2.1623	1.823
640	2.7513	1.727
472	3.7226	1.621

Table 4: Flash Vaporization Data

Pressure (psig)	Solution Gas Oil Ratio	Relative Oil Volume	Relative Total Volume	Oil Density (gm/cc)	Deviation Factor	Gas Formation Volume Factor	Incremental Gas Gravity
2620	854	1.6	1.6	0.6562			
2350	763	1.554	1.665	0.6655	0.846	0.00685	0.825
2100	684	1.515	1.748	0.6731	0.851	0.00771	0.818
1850	612	1.479	1.859	0.6808	0.859	0.00882	0.797
1600	544	1.445	2.016	0.6889	0.872	0.01034	0.791
1350	479	1.412	2.244	0.6969	0.887	0.01245	0.794
1100	416	1.382	2.593	0.7044	0.903	0.01552	0.809
850	354	1.351	3.169	0.7121	0.922	0.02042	0.831
600	292	1.32	4.254	0.7198	0.941	0.02931	0.881
350	223	1.283	6.975	0.7291	0.965	0.5065	0.988
159	157	1.244	14.693	0.7382	0.984	0.10834	1.213
0	0	1.075		0.7892			2.039

Table 5: Differential Vaporization Data

Pressure (psig)	Oil Viscosity	Calculated Gas Viscosity	Oil/Gas Viscosity Ratio
5000	0.45		
4500	0.434		
4000	0.418		

3500	0.401		
3000	0.385		
2800	0.379		
2620	0.373		
2350	0.396	0.0191	20.8
2100	0.417	0.018	23.2
1850	0.442	0.0169	26.2
1600	0.469	0.016	29.4
1350	0.502	0.0151	33.2
1100	0.542	0.0143	37.9
850	0.592	0.0135	43.9
600	0.654	0.0126	51.8
350	0.738	0.0121	60.9
159	0.855	0.0114	75.3
0	1.286	0.0095	137.9

Table 6: Oil Viscosity Measurement Data

GOR	GOR @ STB	Stock Tank Gravity	Formation Vol. Factor	Seperator Vol. Factor	Specific Gravity of Flashed Gas
715 to 41	737 41	40.5	1.481	1.031 1.007	0.84 1.338
	778				
637 to 91	676 92	40.7	1.474	1.062 1.007	0.786 1.363
	768				
542 to 177	602 178	40.4	1.483	1.112 1.007	0.732 1.329
	780				
478 to 245	549 246	40.1	1.495	1.148 1.007	0.704 1.286
	795				

Table 7: Separator Test Data

2.12.2 Relative Permeability

The relative permeability data in this study is obtained from the SPE Paper "Fifth Comparative Solution Project: Evaluation of Miscible Flood Simulator" (Killoug *et al.*, 1987). The following shows the relative permeability table data corresponding to the water saturation and relative permeability curve.

S_w	K_{rw}	K_{row}	K_{rog}
0.2	0	1	1
0.2899	0.0022	0.6769	0.7023

0.3778	0.018	0.4153	0.4705
0.4667	0.0607	0.2178	0.2963
0.5556	0.1438	0.0835	0.1715
0.6444	0.2809	0.0123	0.0878
0.7	0.4089	0	0.056
0.7333	0.4855	0	0.037
0.8222	0.7709	0	0.011
0.9111	1	0	0
1	1	0	0

Table 8: Relative Permeability Data from SPE "Fifth Comparative Solution Project: evaluation of Miscible Flood Simulator

2.12.3 Reservoir Model

The reservoir model data is to be taken from the SPE "Fifth Comparative Solution Project: Evaluation of Miscible Flood Simulator". The 3D reservoir model is 7 x 7 areally with 3 layers. The reservoir data by layers is given below (Killoug *et al.,* 1987).

Layer	Horizontal Perm. (md)	Vertical Perm. (md)	Porosity	Thickness (ft)
1	500.0	50.0	0.30	20.0
2	50.0	50.0	0.30	30.0
3	200.0	25.0	0.30	50.0

Table 9: Reservoir Data by Layers from SPE "Fifth Comparative Solution Project: Evaluation of Miscible Flood Simulator"

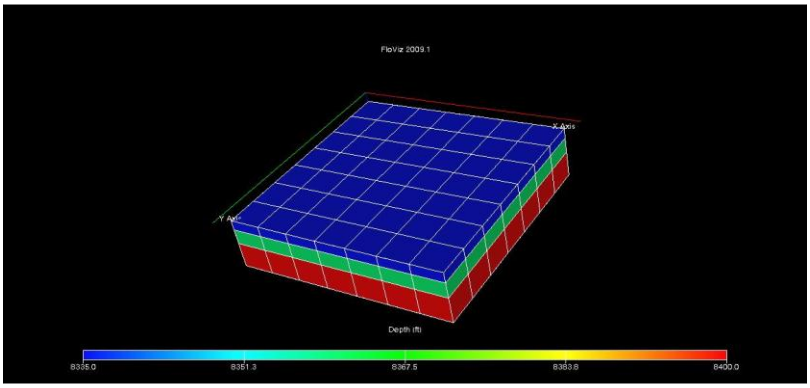

Figure 1: Reservoir Grid simulated by FloViz

2.12.4 WAG Injection Parameters

The base model for CO_2 WAG injection in this study follows the Scenario One of the SPE "Fifth Comparative Solution Project: Evaluation of Miscible Flood Simulator". The injection well is located in the grid block with i=1, j=1and k=1 and one production well located in grid block i=7, j=7, and k=3. The production well is constrained to produce at maximum rate oil rate of 12000 STB/Day with a minimum bottomhole pressure of 1000 psia for two years with no injection. After two years, the WAG injection begins with a one year cycle. A maximum injection bottomhole pressure stays at 10000 psia. The gas injection rate is at 12000 Mscf/Day and the oil injection rate is 12000 STB/Day (Killoug *et al.*, 1987).

Year	Day	Injectant
1	365.25	No
2	730.5	No
3	1095.75	Water
4	1461	Gas
5	1826.25	Water
6	2191.5	Gas
7	2556.75	Water
8	2922	Gas
9	3287.25	Water
10	3652.5	Gas
11	4017.75	Water
12	4383	Gas
13	4748.25	Water
14	5113.5	Gas
15	5478.75	Water
16	5844	Gas
17	6209.25	Water
18	6574.5	Gas
19	6939.75	Water
20	7305	Gas

Table 10: Water Alternating Gas Cycle

2.13 SIMULATION USING ECLIPSE

2.13.1 ECLIPSE 100: Black Oil

In order to enable modeling of miscible flooding in which injected fluids are miscible with the hydro-carbons in the reservoir, the ECLIPSE 100 Solvent model also provides a 4-component extension of the black oil model. This function can model gas injection projects without going to the complexity and expense of using a compositional model.

According to Schlumberger ECLIPSE Reference Technical Description (2009), the model is empirical treatment suggested by M. Todd and W. Longstaff. This empirical treatment takes into account the effects of physical dispersion between the miscible components in the hydrocarbon phase. The model introduces an empirical parameter, ω, whose value lies between 0 and 1, to represent the size of the dispersed zone each grid cell. The value of ω thus controls the degree of fluid mixing within each grid cell.

Section/Data	Keywords	Descriptions
RUNSPEC	SOLVENT	Activates the Separate Solvent component
	MISCIBLE	Initiates the mixing calculation.
PROPS	SDENSITY	Surface density of the Solvent
	PVDS	Pressure dependent data for each PVT region
	TLMIXPAR	The mixing parameter, ω, a value in the range 0 to 1 must be supplied for each miscible region.
Relative Permeability Data (under PROPS section)	SWFN	relative permeability and water-hydrocarbon capillary pressure
	SOF2	the relative permeability of the hydrocarbon phase with respect to hydrocarbon phase saturation

Table 11: Keywords for Black Oil Simulation in ECLIPSE 100

2.13.2 ECIPSE 300: Compositional Modeling

The components and their properties shall be input into the system through following keywords.

NCOMPS	Number of Components
EOS	Type of Equation of States
RTEMP	Reservoir Temperature
STCOND	Standard Temperature and Pressure
CNAMES	Component Names
TCRIT	Critical Temperature
PCRIT	Critical Pressure
ACF	Accentric Factor
MW	Molecular Weight
TBOILS	Boiling Points
VCRIT	Critical Volume
ZCRIT	Critical z factors
PARACHOR	Parachors
BIC	Binary Coefficients

Table 12: Keywords for Compositional Simulation in ECLIPSE 300

2.13.3 Water Alternating Gas Injection

The water alternating gas injection shall be controlled in the SCHEDULE section. The followings are the significant keywords to control gas and water injection.

RPTSCHED	Data being written to the Restart file at every timestep
WELSPECS	Well Specification Data
COMPDAT	Completion Specification Data
WCONPROD	Production Well Controls
WECON	Minimum Economic Production Rate for a Well
WCONINJE	Set Control Limit for a well
WSOLVENT	Specify Gas Flow Fraction of Injected Solvent
TUNING	Control Max. Length of Time Setup
WELOPEN	Control Well Open and Shut
TSTEP	Time Steps
WELLSTRE*	Set Composition of Injection Gas Steam
WELLINJE*	Specify well injection targets
WELLWAG*	Specify WAG well injection targets.\

Table 13: Keywords in SCHEDULE Section

(*The Keyword is only valid for ECLIPSE 300)

2.14 EFFECTS OF SOME PARAMETERS IN WAG PROCESS

There is a study investigated the effect of some parameters in Miscible WAG Process. The results show that the changes in WAG cycle time did not affect oil recovery factor of the WAG Process. The sensitivity in half cycle time has some effects to the recovery factor. The vertical permeability has an impact toward the oil distribution and segregation and the oil recovery in the WAG process. The increase or decrease in vertical permeability does not always help a stable advancing front which results in maximized sweep efficiency and oil recovery. There is the optimum value for the ratio of vertical to horizontal permeability which favors the oil recovery (Namani *et al.*,2011).

CHAPTER 3

METHODOLOGY

3.1 RESEARCH METHODOLOGY

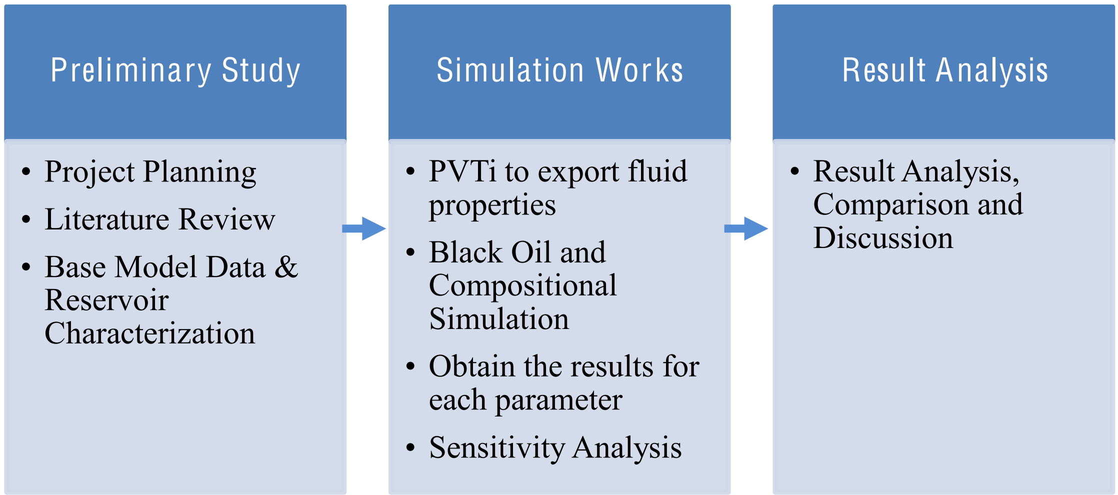

Figure 2: Research Methodology Workflow

3.1.1 Preliminary Study

On the first phase, the preliminary study was conducted. The process in this phase included project planning, literature review and determination of the base model and reservoir rock & fluid properties. The objectives and frameworks of the project were identified clearly during the project planning. The background of the study and the theories involved with the topic were reviewed to ensure the scope and understanding toward the project in the literature review part.

Data Preparation

The simulation required reservoir rock and fluid properties as well as the Water Alternating Gas Control Input. The base model and reservoir rock and fluid properties were obtained from the literature. The fluid properties were retrieved from Table 10-1 from the properties of Petroleum Fluids", Second Edition by McCain W.D. The rock properties, 3D reservoir model and WAG injection base case scenario was applied from the SPE paper “Fifth Comparative Solution Project: evaluation of Miscible Flood Simulator”. The summary of required input is summarized in the following graph.

Input	Source	E100		E300	
		Keyword	Description	Keyword	Description
Fluid Properties	McCain W.D.	PVTO	Live Oil PVT Properties	EOS	Equation of States
		PVDG	Dry Gas PVT Properties	NCOMPS	No. of Components
		PVTW	Water PVT Properties	CNAMES	Component Names
		DENSITY	Density of Oil, Water, Gas	MW	Molecular Weight
		SDENSITY	Density of Injectant	OMEGAA	Omega A
		TXMIXPAR	Todd Longstaff mixing Parameter	OMEGAB	Omega B
				TCRIT	Critical Temperature
				VCRIT	Critical Volume
				PCRIT	Critical Pressue
				ZCRIT	Critical Z-Factor
				SSHIFT	EOS Volume Shift
				ACF	Accentric Factors
				BIC	Binary coefficients
				PARACHOR	Component Parachors
				VCRITVIS	Critical Volumes for Viscosity Calculation
				ZCRITVIS	Critical Z-Factors for Viscosity Calc
				LBCCOEF	Lorentz-Bray-Clark Viscosity Correlation Coefficients
				ZI	Overall Composition
				DENSITY	Density of Water
				PVTW	Water PVT Properties
Rock Properties	SPE 5th	ROCK	Rock Compressibility	ROCK	Rock Compressibility
		SWFN	Water Saturation Functions	SWFN	Water Saturation Functions
		SGFN	Gas Saturation Functions	SGFN	Gas Saturation Functions
		SOF2	2 Phase Oil Saturation Functions	SOF3	3 Phase Oil Saturation Functions

		SOF3	3 Phase Oil Saturation Functions		
Reservoir Grid	SPE 5th	DX,DY,DZ	Grid Block Sizes	DX,DY,DZ	Grid Block Sizes
		PERMX,PERMY, PERMZ	Permeabilities	PERMX,PERMY, PERMZ	Permeabilities
		PORO	Porosity	PORO	Porosity
WAG Injection Scenario	SPE 5th	WELSPECS	Well Data	WELSPECS	Well Data
		COMPDAT	Well Completion	COMPDAT	Well Completion
		WCONPROD	Production Well Control Data	WCONPROD	Production Well Control Data
		WCONINJE	Injetion Well Control Data	WCONINJE	Injetion Well Control Data
		WELOPEN	Shut or Open Well Connection	WELLSTRE	Compostions of Injection Gas Stream
		TSTEP	Time Step Control	WELLINJE	Well Injection Targets
				WELLWAG	WAG Injection Targets
				TSTEP	Time Step Control

Table 14: Data Requirement for Reservoir Simulation

3.1.2 Simulation Works

PVTi

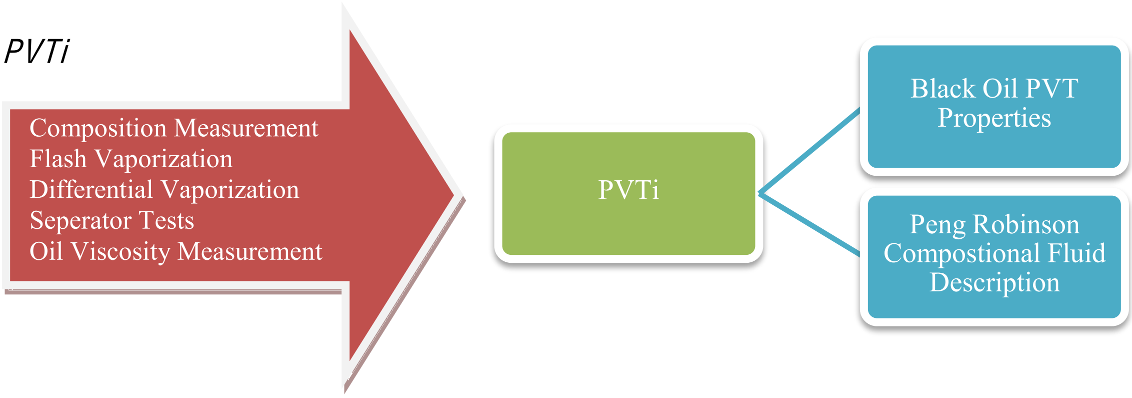

Figure 3: PVTi Work Flow

The data of composition measurement, flash vaporization, differential vaporization, separator tests and viscosity measurement obtained from the literature, were processed in the PVTi program in order to come up with the Black Oil PVT properties, particularly the Live Oil and Dry Gas properties, as well as the compositional fluid description characterized by Peng-Robinson Equation of States.

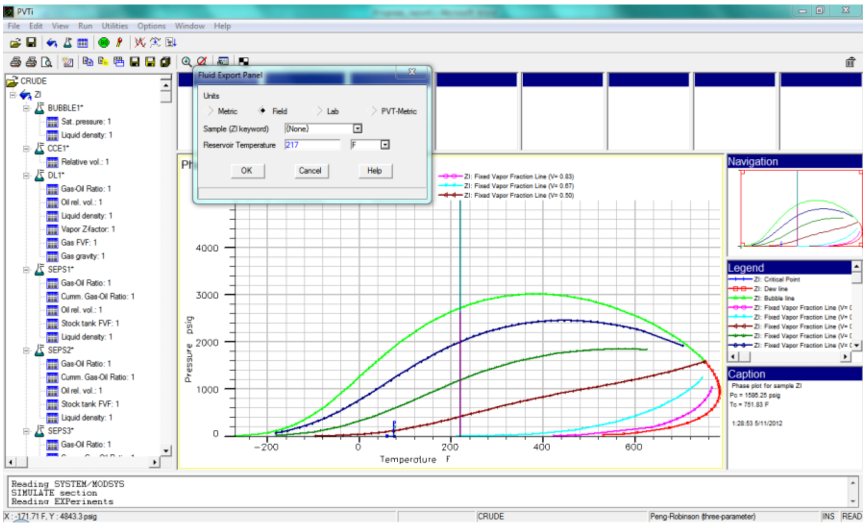

Figure 4: Exporting Fluid Properties from PVTi

MMP Correlation

The Minimum Miscibility Pressure correlation proposed by Glass, O. (1985), was calculated to ensure that the injection pressure stayed above the minimum miscibility pressure.

ECLIPSE 100 & ECLIPSE 300

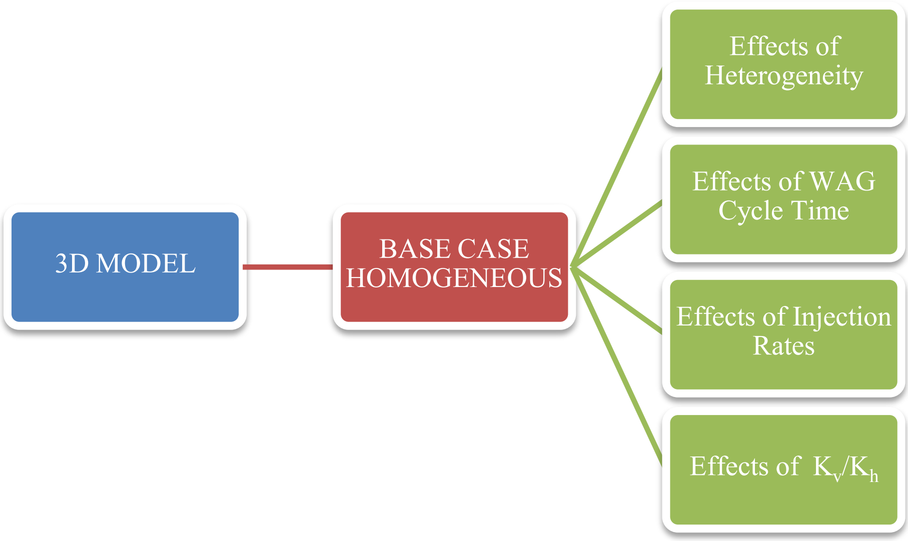

Figure 5: Simulation Work Flow

The two set of fluid properties generated by the PVTi were used in simulating the reservoir models. The ECLIPSE 100 was used for Black Oil Simulation and ECLIPSE 300 was to simulate the Compositional Model. In this study, CO_2 was injected using Water Alternating Gas Technique into 3D homogeneous model. Then, from the base model, the base case model was adjusted to see the response of the simulators when there were the effect of heterogeneity, WAG cycle time, injection rate and K_v/K_h ratio.

a) *Effect of Heterogeneity*

Case	Layer	K_v (md)	K_h (md)	Porosity	Thickness (ft)
Homogeneous Case (Base Case)	1	500	50	0.3	20
	2	500	50	0.3	30
	3	500	50	0.3	50
Heterogeneous Case	1	500	50	0.3	20
	2	50	50	0.3	30
	3	200	25	0.3	50

Table 15: Data for Effect of Heterogeneity

b) *Effect of WAG Cycle Time*

Case	WAG Cycle Time (Year)
Base Case	1
Scenario 1	2
Scenario 2	3

Table 16: Data for Effect of WAG Cycle Time

c) *Effect of Injection Rate*

Case	Gas Injection (Mscf/Day)	Water Injection (STB/Day)
Base Case	12000	12000
Scenario 1	24000	12000
Scenario 2	12000	24000
Scenario 3	24000	24000

Table 16: Data for Effect of Injection Rate

d) *Effect of K_v/K_h*

Case	Kv (md)	Kh (md)	Kv/Kh
Base Case	50	500	0.1
Scenario 1	500	500	1
Scenario 2	5	500	0.01

Table 17: Data for Effect of K_v/K_h

The other reservoir properties and WAG injection parameters were remained unchanged in both simulations so that we could pay attention on the PVT Properties of the fluids in the Black Oil and Compositional Simulations to achieve the main objectives of the project. The results of the simulations were evaluated by comparing the Oil Recovery Factor (FOE), Total Oil Production (FOPT) and Reservoir Pressure (FPR).

3.1.3 Result Analysis

Lastly, on the third phase, the results from each simulation case the simulation were discussed, compared and analyzed. The results of simulation for all cases for each parameter will be plotted against time. The comparison of the result revealed how close the two models provide the results in response with each parameter. The graphs were discussed in the ability of the two models in different scenarios. Lastly, the percentage of errors for Oil Recovery Factor and Total Oil Production for all cases in both simulators were analyzed to see how much deviation Black Oil model predicted the result comparing to the compositional model.

In addition, for all simulation runs, the CPU time for different models and simulators will also be recorded to analyze the running time comparison.

3.2 RESEARCH ACTIVITIES AND TOOLS

The project activities were largely involved with the literature review and simulation. Society of Petroleum Engineer research papers, journals, petroleum engineering books and Ms.C. thesis are the main sources for understanding the background theories and principles of miscible CO_2 injection for enhanced oil recovery. Schlumberger PVTi was utilized to export the fluid properties for PVT Black Oil and compositional equation of states description. Schlumberger ECLIPSE 100 and ECLIPSE 300 were the main tools used for the simulations.

3.3 GANTT CHART

Tasks & Activities / Weeks	Final Year Project I														Final Year Project II													
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28
Topic Selection / Proposal	■	■																										
Project Planning			■																									
Preliminary Research Work/Literature Review				■	■	■																						
Extended Proposal Submission							■																					
Project Defence								■	■																			
Determination of Base Model Data & Reservoir Characterization										■	■																	
Interim Draft Report Submission												■																
Interim Report Preparation& Submission													■	■														
Execute Simulation Works															■	■	■	■										
Sensitivity Analysis																			■	■								
Results Discussion & Conclusion																					■	■						
Report Preparation																							■	■	■			
Submission of Draft Report																										■		
Submission of Dissertation (soft bound)																											■	
Submission of Technical Paper																											■	
Oral Presentation																												■
Submission of Dissertation (hard bound)																												■

Table 18: Gantt Chart

CHAPTER 4

RESULTS & DISCUSSION

4.1. PVTi - FLUID PROPERTIES GENERATION

PVTi program is used to generate the fluid properties from the crude oil laboratory data. The experimental data input includes fluid compositions, Pressure-Volume Relations, Differential Vaporization, Viscosity Data and Oil Viscosity Measurement.

4.1.1 Component Properties

Comps.	ZI	MW	Tc	Pc	Vc	Zc
CO_2	0.0091	44.010	548.4600045	1071.33111	1.505747298	0.27408
N_2	0.0016	28.013	227.159996	492.31265	1.441654368	0.29115
C_1	0.3647	16.043	343.0799991	667.7817	1.569811895	0.28473
C_2	0.0967	30.070	549.7740046	708.34238	2.370692075	0.28463
C_3	0.0695	44.097	665.6399976	618.69739	3.203659218	0.27748
IC_4	0.0144	58.124	734.5799995	529.0524	4.212900139	0.28274
NC_4	0.0393	58.124	765.3600003	550.65537	4.084773563	0.27386
IC_5	0.0144	72.151	828.720002	483.49511	4.933743704	0.26823
NC_5	0.0141	72.151	845.2800024	489.52043	4.981695292	0.26884
C_6	0.0433	84.000	921.6000044	484.37686	5.622496655	0.27537
C_{7+}	0.3329	218.000	1340.864436	247.58441	13.61427998	0.23425

Table 19: Fluid Component Properties I

Comps.	OMEGA A	OMEGA B	ACF	Parachors
CO_2	0.457236	0.077796074	0.225	78
N_2	0.457236	0.077796074	0.04	41
C_1	0.457236	0.077796074	0.013	77
C_2	0.457236	0.077796074	0.0986	108
C_3	0.457236	0.077796074	0.1524	150.3
IC_4	0.457236	0.077796074	0.1848	181.5
NC_4	0.457236	0.077796074	0.201	189.8999
IC_5	0.457236	0.077796074	0.2223	225
NC_5	0.457236	0.077796074	0.2539	231.5
C_6	0.457236	0.077796074	0.25	271
C_{7+}	0.457236	0.077796074	0.70397	564.40006

Table 20: Fluid Component Properties II

4.1.2 Binary Interaction Coefficients

	CO2	N_2	C_1	C_2	C_3	IC_4	NC_4	IC_5	NC_5	C_6	C_{7+}
CO_2	0										
N_2	-0.01	0									
C_1	0.1	0.1	0								

C_2	0.1	0.1	0.002108	0							
C_3	0.1	0.1	0.006214	0.00113	0						
IC_4	0.1	0.1	0.01165	0.00407	0.00093	0					
NC_4	0.1	0.1	0.010962	0.00365	0.00074	1.20E-05	0				
IC_5	0.1	0.1	0.015439	0.00655	0.00231	0.00031	0.000445	0			
NC_5	0.1	0.1	0.015686	0.00672	0.00241	0.00035	0.000492	1.00E-06	0		
C_6	0.1	0.1	0.018894	0.00901	0.0039	0.00104	0.00127	0.000213	0.00018	0	
C_{7+}	0.1	0.1	0.047496	0.03331	0.0238	0.01615	0.016958	0.01228	0.01206	0.00943	0

Table 21: Binary Interaction Coefficients

4.1.3 Live Oil PVT Properties

GOR (Mscf/stb)	PSAT (psia)	OIL FVF (rb/stb)	OIL VISC (cp)	GOR (Mscf/stb)	PSAT (psia)	OIL FVF (rb/stb)	OIL VISC (cp)
0.0000	14.6959	1.0939	1.0777	0.2622	864.6959	1.2553	0.3235
	173.6959	1.0931	1.0865		1114.6959	1.2507	0.3328
	364.6959	1.0922	1.0970		1364.6959	1.2463	0.3419
	614.6959	1.0910	1.1105		1614.6959	1.2422	0.3510
	864.6959	1.0899	1.1237		1864.6959	1.2382	0.3599
	1114.6959	1.0888	1.1368		2114.6959	1.2345	0.3687
	1364.6959	1.0877	1.1496		2364.6959	1.2309	0.3773
	1614.6959	1.0867	1.1622		2634.6959	1.2273	0.3865
	1864.6959	1.0857	1.1746		2724.0220	1.2261	0.3896
	2114.6959	1.0847	1.1868	0.3317	1114.6959	1.2929	0.3045
	2364.6959	1.0838	1.1988		1364.6959	1.2878	0.3134
	2634.6959	1.0828	1.2116		1614.6959	1.2831	0.3222
	2724.0220	1.0825	1.2158		1864.6959	1.2786	0.3309
0.0485	173.6959	1.1305	0.3902		2114.6959	1.2744	0.3394
	364.6959	1.1279	0.3979		2364.6959	1.2704	0.3479
	614.6959	1.1246	0.4078		2634.6959	1.2662	0.3569
	864.6959	1.1215	0.4175		2724.0220	1.2649	0.3598
	1114.6959	1.1186	0.4270	0.4022	1364.6959	1.3302	0.2867
	1364.6959	1.1158	0.4364		1614.6959	1.3248	0.2953
	1614.6959	1.1131	0.4457		1864.6959	1.3197	0.3037
	1864.6959	1.1105	0.4548		2114.6959	1.3149	0.3120
	2114.6959	1.1081	0.4637		2364.6959	1.3103	0.3202
	2364.6959	1.1057	0.4726		2634.6959	1.3057	0.3289
	2634.6959	1.1033	0.4819		2724.0220	1.3042	0.3318
	2724.0220	1.1025	0.4850	0.4747	1614.6959	1.3680	0.2701
0.1169	364.6959	1.1728	0.3675		1864.6959	1.3622	0.2783
	614.6959	1.1690	0.3774		2114.6959	1.3568	0.2863
	864.6959	1.1654	0.3871		2364.6959	1.3517	0.2942
	1114.6959	1.1619	0.3967		2634.6959	1.3464	0.3027
	1364.6959	1.1587	0.4062		2724.0220	1.3447	0.3055
	1614.6959	1.1556	0.4155	0.5499	1864.6959	1.4068	0.2546
	1864.6959	1.1526	0.4246		2114.6959	1.4007	0.2623
	2114.6959	1.1498	0.4336		2364.6959	1.3949	0.2699
	2364.6959	1.1471	0.4425		2634.6959	1.3889	0.2781
	2634.6959	1.1443	0.4520		2724.0220	1.3871	0.2808
	2724.0220	1.1434	0.4551	0.6286	2114.6959	1.4470	0.2400
0.1921	614.6959	1.2164	0.3441		2364.6959	1.4405	0.2473
	864.6959	1.2121	0.3537		2634.6959	1.4338	0.2551
	1114.6959	1.2081	0.3632		2724.0220	1.4317	0.2577
	1364.6959	1.2043	0.3726	0.7113	2364.6959	1.4890	0.2263
	1614.6959	1.2007	0.3818		2634.6959	1.4814	0.2338

	1864.6959	1.1972	0.3908		2724.0220	1.4791	0.2363
	2114.6959	1.1940	0.3998	0.8060	2634.6959	1.5367	0.2124
	2364.6959	1.1909	0.4086		2724.0220	1.5340	0.2148
	2634.6959	1.1876	0.4180	0.8387	2724.0220	1.5531	0.2081
	2724.0220	1.1866	0.4211		2826.8933	1.5500	0.2107

Table 22: Live Oil PVT Properties

4.1.4 Dry Gas PVT Properties

Pressure (psia)	Gas FVF (rb/Mscf)	Gas Visc (cp)
14.6959	230.4205	0.0103
173.6959	18.6136	0.0118
364.6959	8.6957	0.0126
614.6959	5.0590	0.0132
864.6959	3.5384	0.0138
1114.6959	2.7084	0.0144
1364.6959	2.1895	0.0150
1614.6959	1.8372	0.0157
1864.6959	1.5847	0.0166
2114.6959	1.3964	0.0174
2364.6959	1.2518	0.0184
2634.6959	1.1303	0.0195
2724.0220	1.0961	0.0199

Table 23: Dry Gas PVT Properties

4.1.5 Fluid Densities

Oil Density (lb/ft^3)	Water Density (lb/ft^3)	Gas Density (lb/ft^3)
50.9323	62.4280	0.0718

Table 24: Fluid Densities

4.2 MINIMUM MISCIBILITY PRESSURE CORRELATION

According the Minimum Miscibility Pressure Correlation proposed by Glass, O. (1985), the MMP for the crude oil with CO_2 is calculated below

$$(p_m)_{min} = 810.0 - 3.404M_{C7+} + \left(1.700 \times 10^{-9} M_{C7+}^{3.730} e^{786.7 M_{C7+}^{-1.058}}\right) T$$

$$(p_m)_{min} = 810.0 - 3.404(218) + \left(1.700 \times 10^{-9} 218^{3.730} e^{786.7(218)^{-1.058}}\right)(217)$$

$$(p_m)_{min} = 2798.17 \text{ psia}$$

Thus, the injection pressure is much greater than Minimum Miscibility Pressure, which ensures the miscibility condition of the fluids in the reservoir.

4.3 RESERVOIR SIMULATION

4.3.1 Base Model

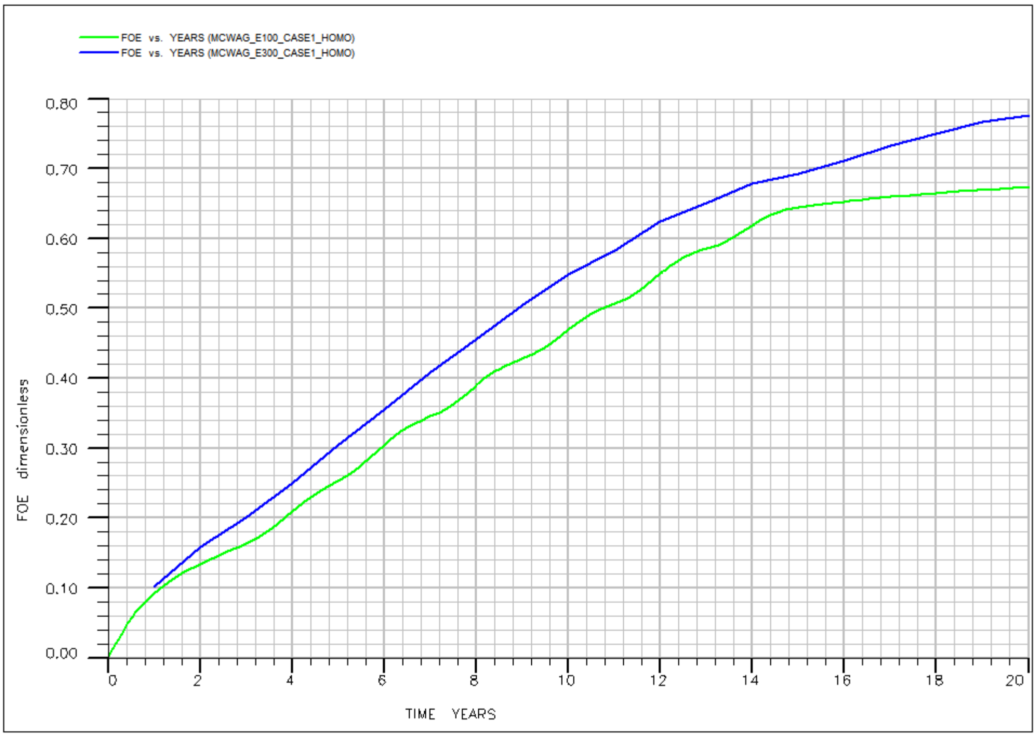

Figure 6: Oil Recovery Factor for Homogeneous Case

Figure 6 gives a comparison on Oil Recovery Factor of CO_2 WAG Miscible Injection for base case predicted by Black Oil and Compositional simulators. The compositional simulator prediction is higher than the Black Oil throughout the graph. The prediction is closer at early years and becomes more different as the time goes by. The recovery factors after 20 years estimated by the former are 0.675 and the latter 0.782. The percentage of difference between two models is at 13.68 percent. The difference in the result is caused by the inability of the four-component Black Oil Simulator to account for the evolution of dissolved gas owing to the assumption that Black Oil Simulator may not be able to carry oil component on the gas phase and the interaction of the injected gas and oil in the reservoir was accounted only by the Todd-Longstaff Mixing Parameter.

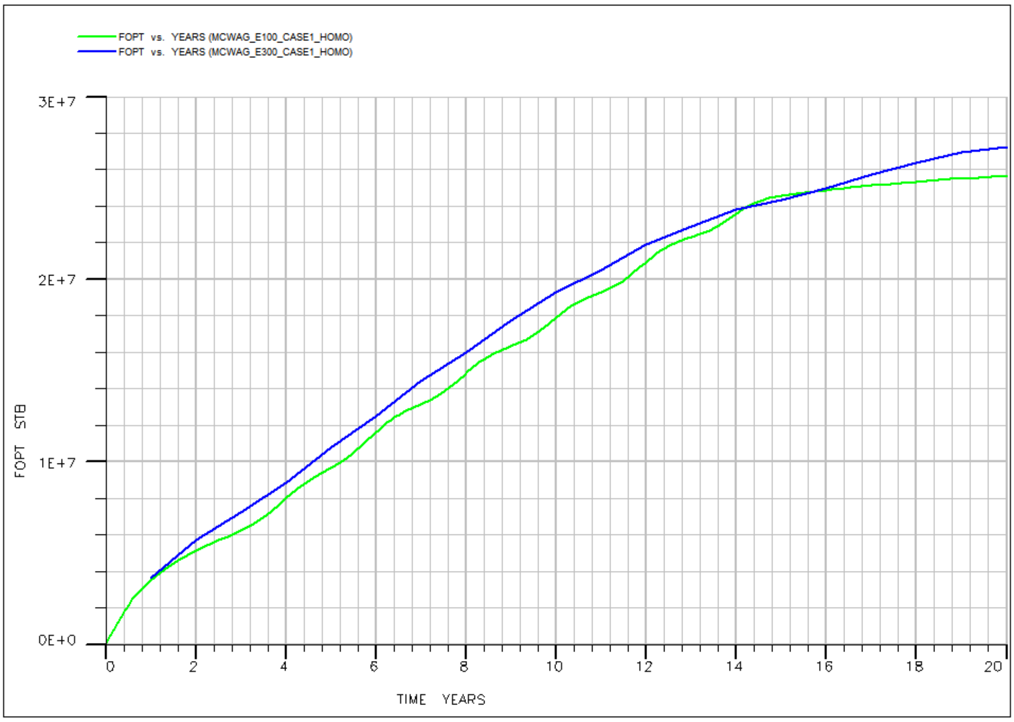

Figure 7: Oil Production Total for Homogeneous Case

The Total Oil Productions forecasted by both simulators are shown on Figure 7. After twenty years the compositional simulator shows a higher result of total oil produced at 27.46 MMSTB, where the black oil model predicts at 25.65 MMSTB.

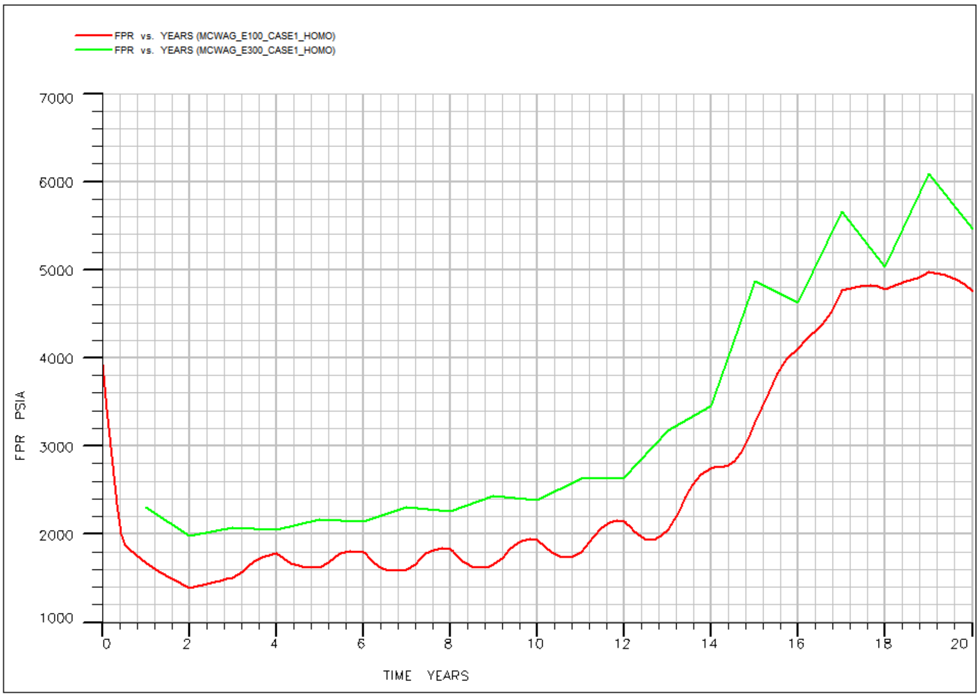

Figure 8: Reservoir Pressure for Homogeneous Case

The tendency of reservoir pressure throughout twenty years predicted by both models shows a good agreement among each other as shown in Figure 8. The graph exhibits humps in pressure for each WAG Cycle. However, compositional simulator still predicts a higher reservoir pressure since before the WAG injection occurred.

4.3.2 Effects of Heterogeneity

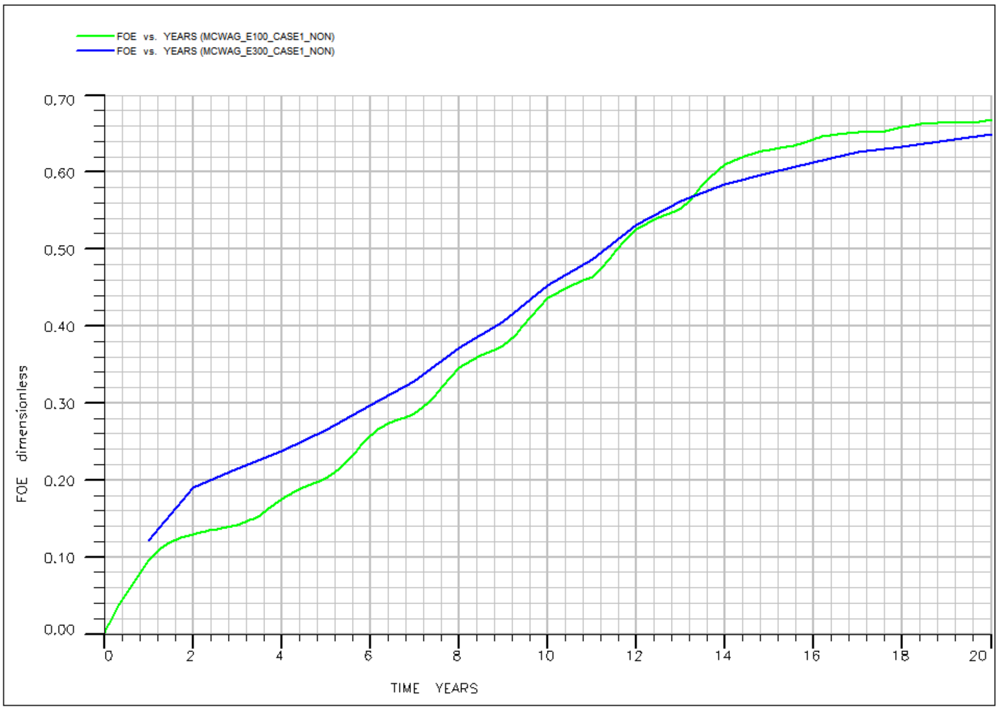

Figure 9: Oil Recovery Factor for Heterogeneous Case

Figure 9 shows the result of oil recovery prediction by both simulators in the heterogeneous model. Initially, compositional simulator shows a higher oil recovery prediction until year 13 in which the black oil simulator starts to give greater forecast. The ultimate recovery yielded from black oil and compositional simulators are at 0.67 and 0.65 percent respectively. However, this difference is dependent on the nature of heterogeneity.

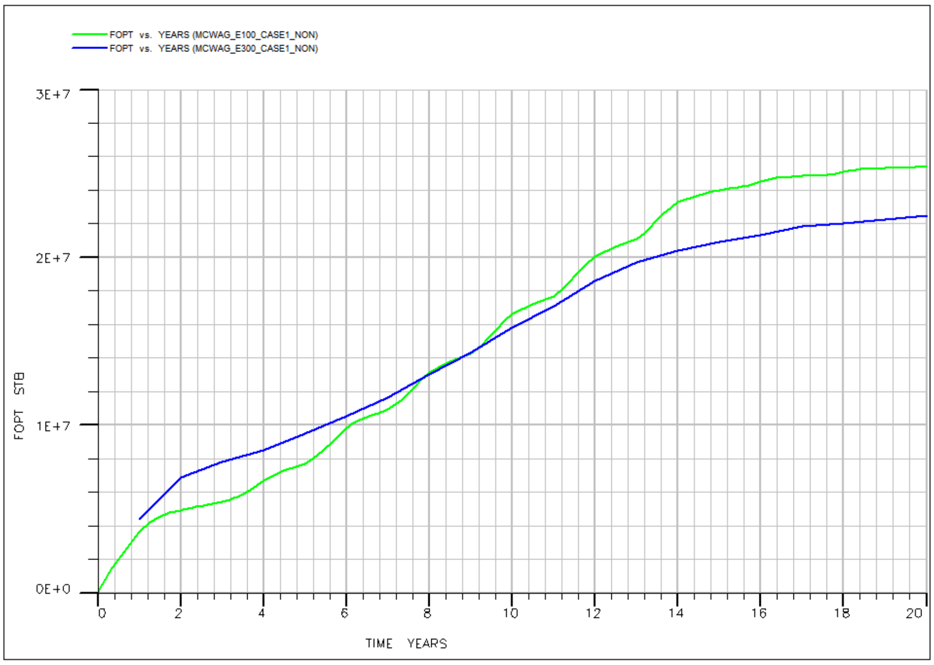

Figure 10: Oil Production Total for Heterogeneous Case

Black Oil Simulator shows a higher total oil production forecast after 20 years to be greater than the compositional simulator at 25.82 and 22.67 MMSTB respectively with the percentage of difference at 13.90%. The result is quite obvious as shown in Figure 10 caused by the effect of heterogeneity.

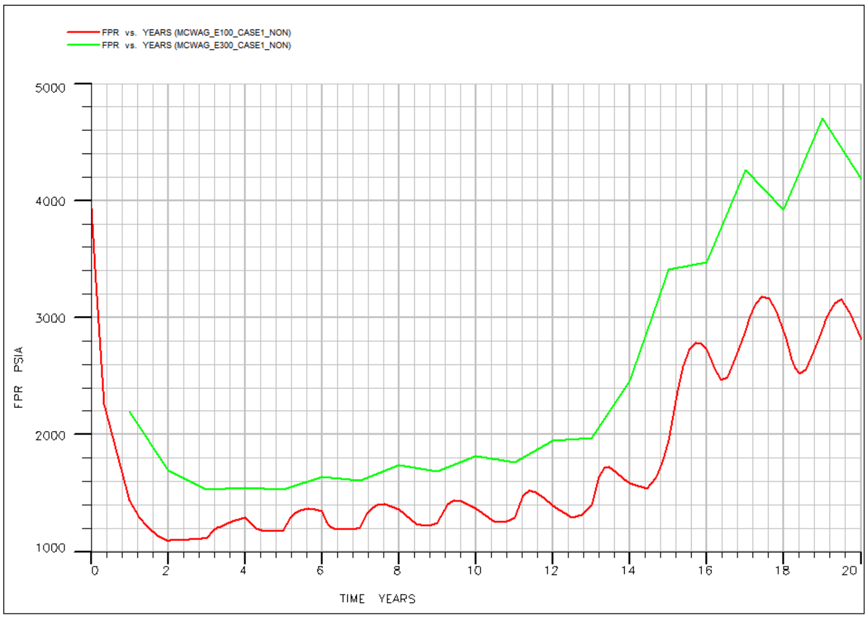

Figure 11: Reservoir Pressure for Heterogeneous Case

The reservoir pressure for both simulators in heterogeneous case still shows a reasonable agreement among each other as in the homogeneous case. The upward and downward trends of reservoir pressure are in similar manner following the WAG cycle, presented in Figure 11.

4.3.3 Effects of WAG Cycle Time

The WAG cycle time of the base model was determined at one year. After 2 years of natural production, the water and gas were injected in equal cycles of one year for 18 years. The effect of WAG time cycle has been studied by increasing the time of each injection to 2 and 3 years equally. The results are presented in the below graphs.

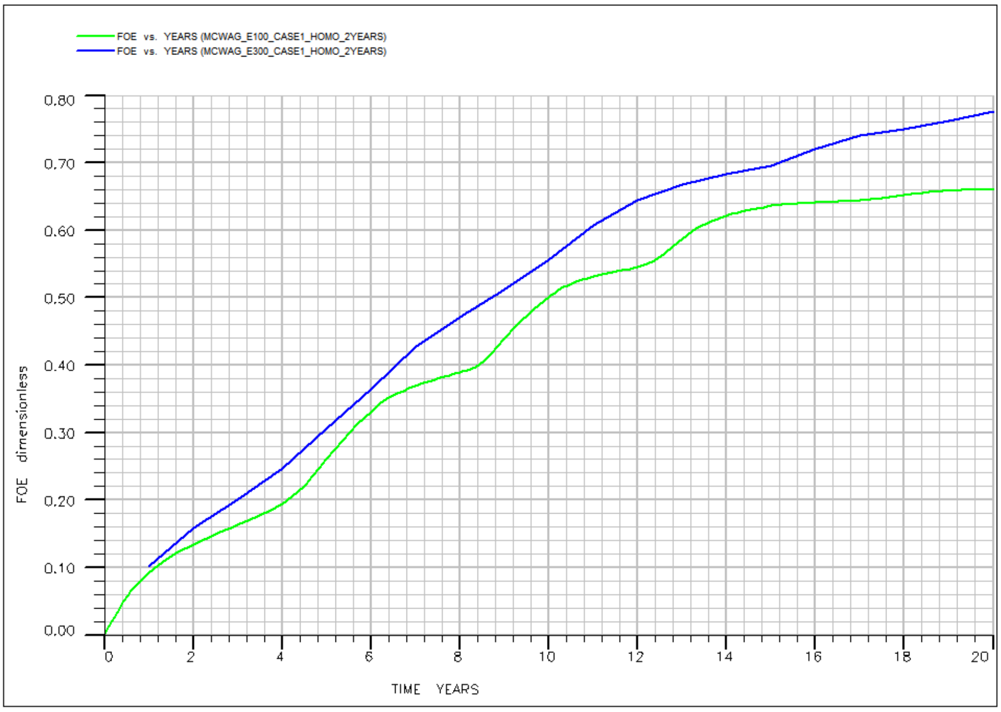

Figure 12: Oil Recovery Factor for 2 Years WAG Cycle

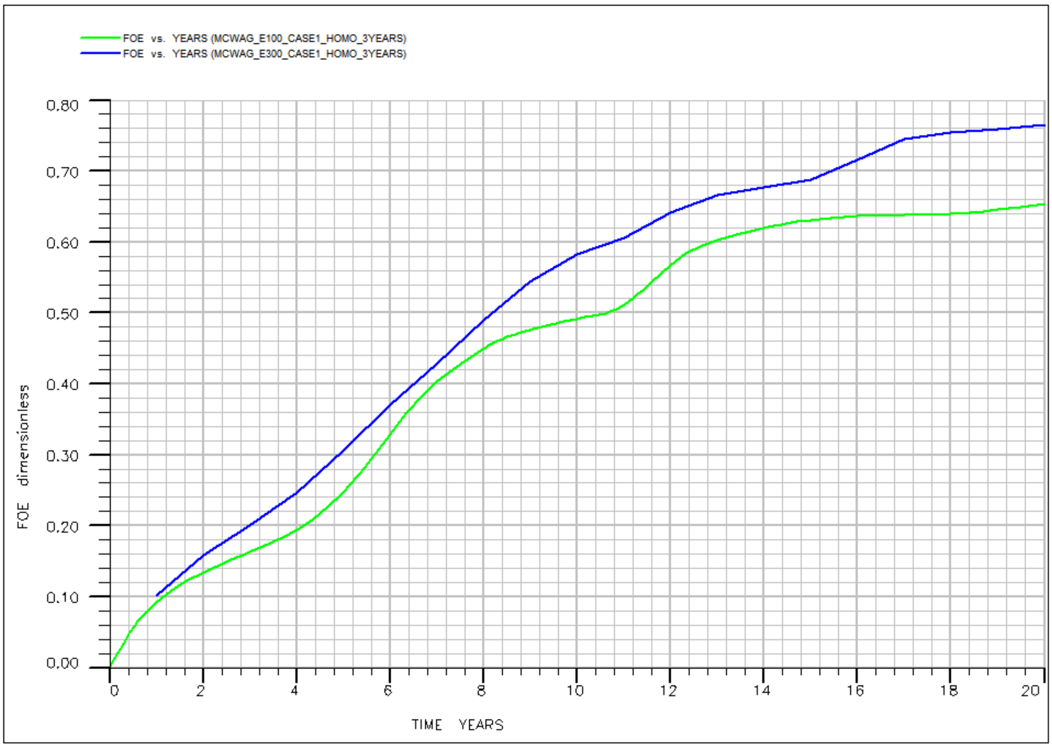

Figure 13: Oil Recovery Factor for 3 Years WAG Cycle

The recovery factors after 20 years for both black oil and compositional simulators become less when the WAG Cycle time is greater. Black oil simulator predicts the recovery factors at 0.675, 0.66 and 0.658 and compositional simulator yields the values at 0.782, 0.78 and 0.65 for 1 (base case), 2 and 3 years WAG Cycle time. The prediction in values between two simulators is still apparently different as presented in figure 12-13.

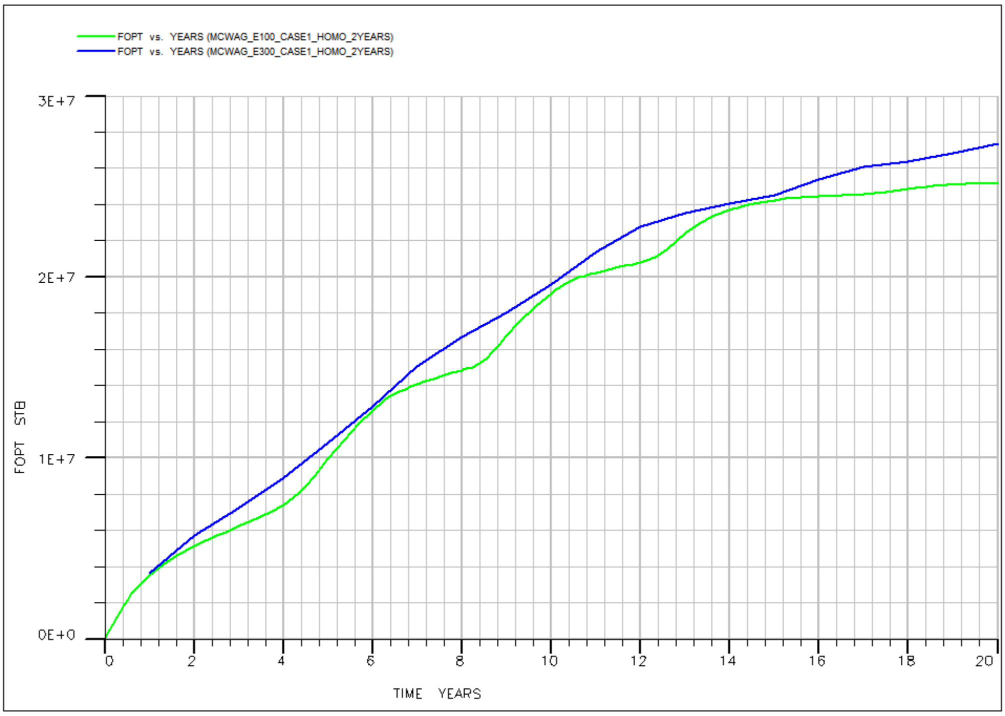

Figure 14: Oil Production Total for 2 Years WAG Cycle

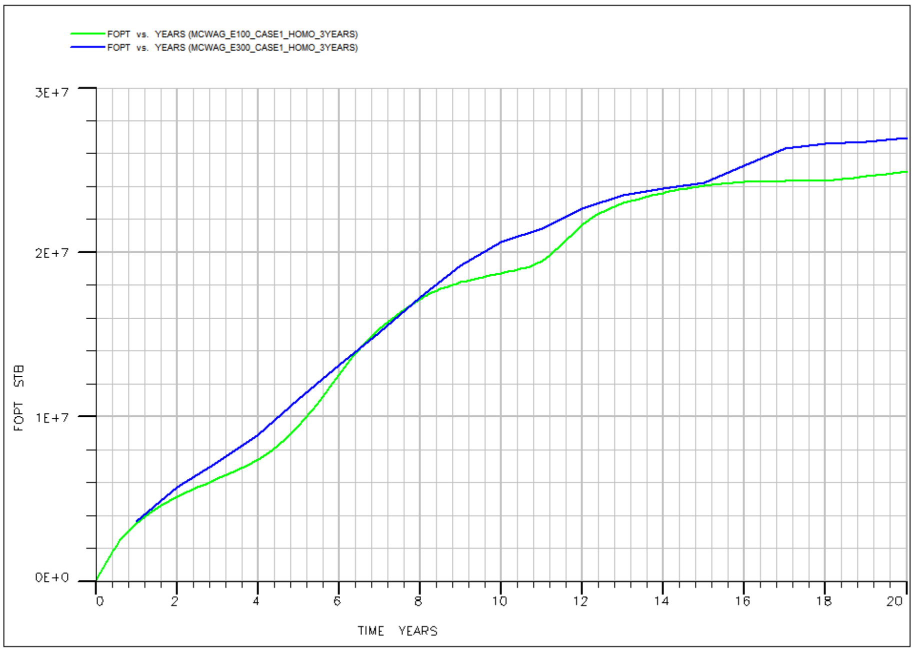

Figure 15: Oil Production Total for 3 Years WAG Cycle

From Figure 14-15, the tendency for the total oil production exhibits similar comparison results to the oil recovery factor. Nevertheless, there is no appreciable change in total oil production prediction after 20 years for both compositional and black oil simulators when the WAG Cycle time increases. Total Oil Productions forecasted by Black Oil Model are 25.65, 25.82 and 25.24 MMSTB and by

Compositional Model are 27.46, 27.39 and 27.08 MMSTB for 1, 2 and 3 years respectively.

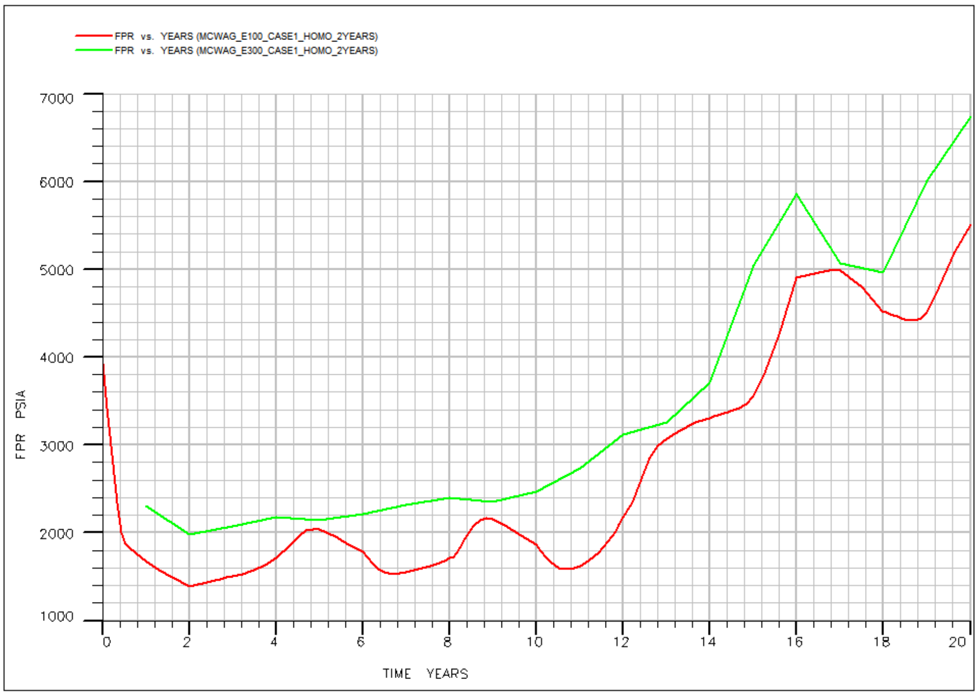

Figure 16: Reservoir Pressure for 2 Years WAG Cycle

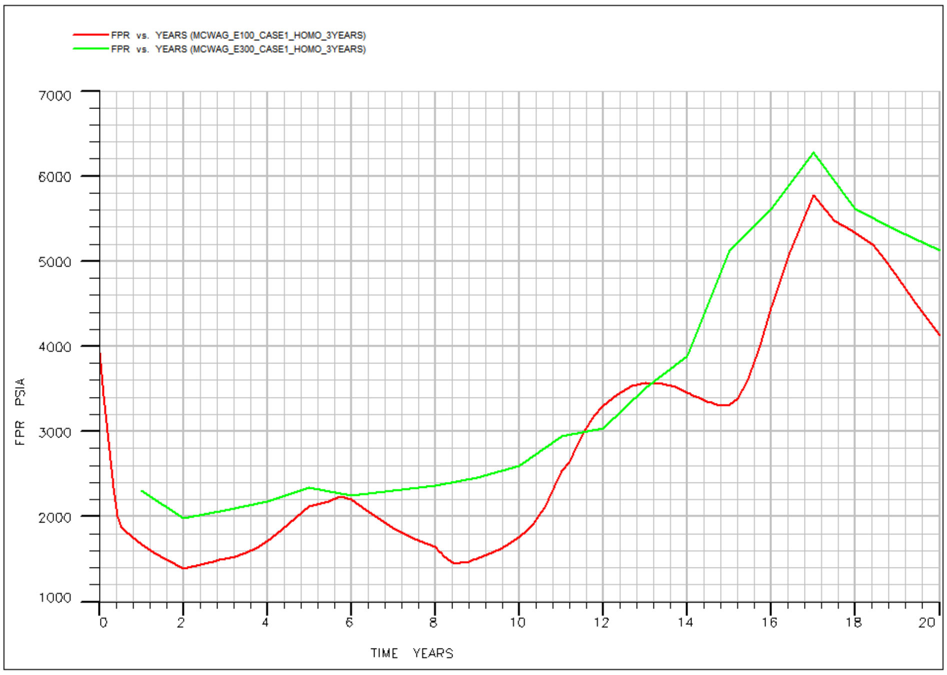

Figure 17: Reservoir Pressure for 3 Years WAG Cycle

The estimation for reservoir pressure throughout twenty years for three different WAG Cycle time scenarios for Black Oil and Compositional simulators yield similar overall rising trends. The humps in reservoir pressure become larger as the WAG Cycle time increases. The black oil model exhibits the obvious rise in reservoir pressure during each water injection period whereas the compositional model predicts the gradual increase in reservoir pressure in all cases. The rises in pressure occur during the water injection periods. The results for average reservoir prediction are shown in Figure 16-17.

4.3.4 Effects of Field Injection Rates

The gas and water injection rates for base case have been set at 12000 Mscf/Day and 12000 STB/Day respectively. The effect of the injection rates has been studied by doubling the gas injection rate, water injection rate and both gas and water injection rates. The WAG cycle time and the rest of the parameters have been remained the same to see the response of the two models when the injection rates become double. The results for each case are shown in following graphs.

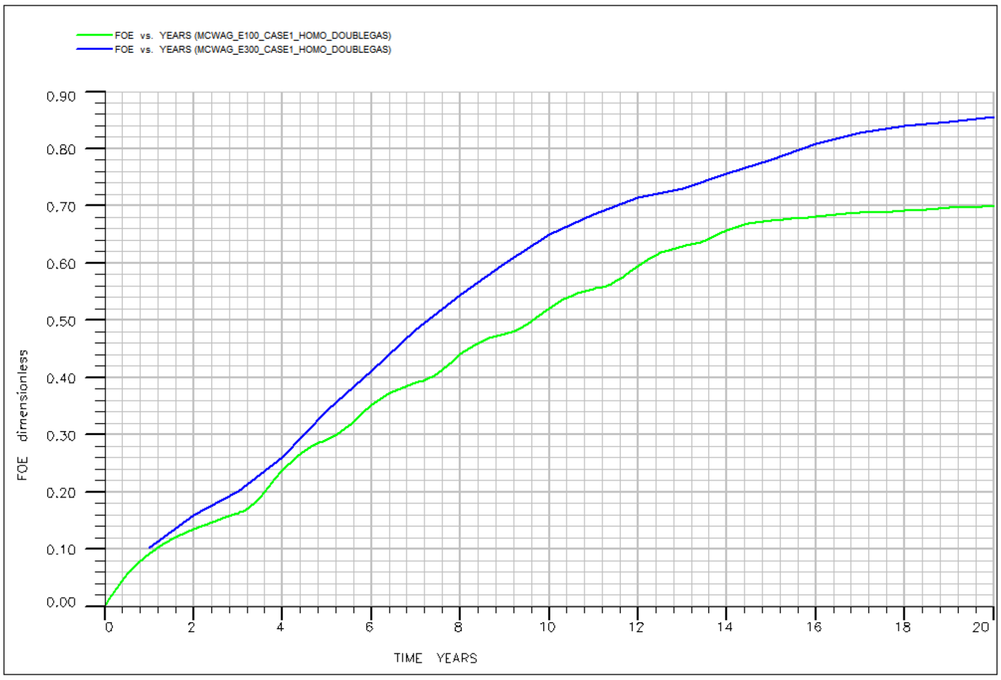

Figure 18: Oil Recovery Factor for Double Gas Injection Case

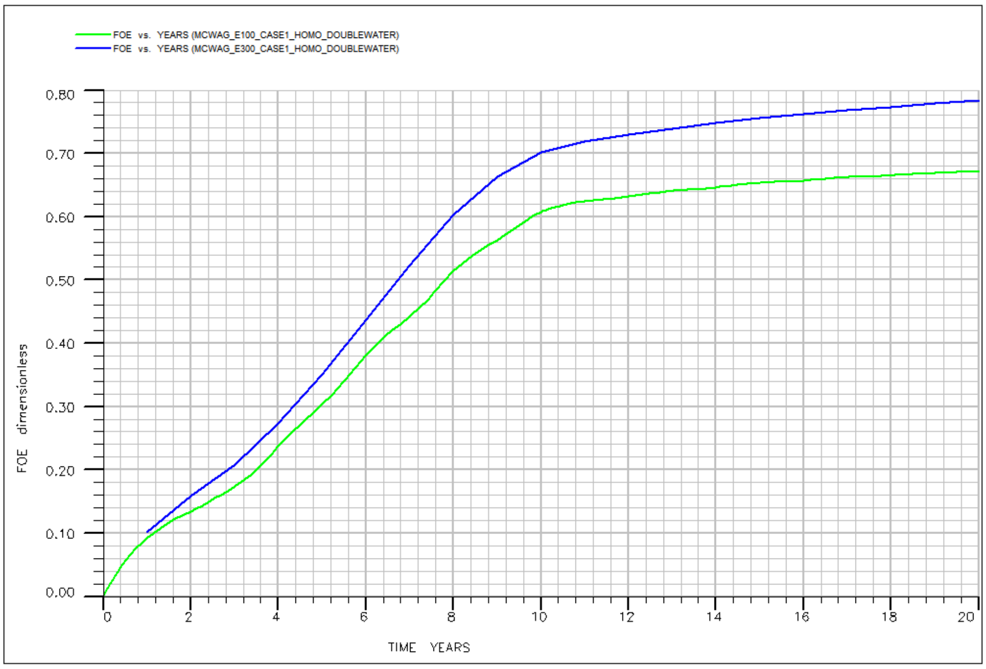

Figure 19: Oil Recovery Factor for Double Water Injection Case

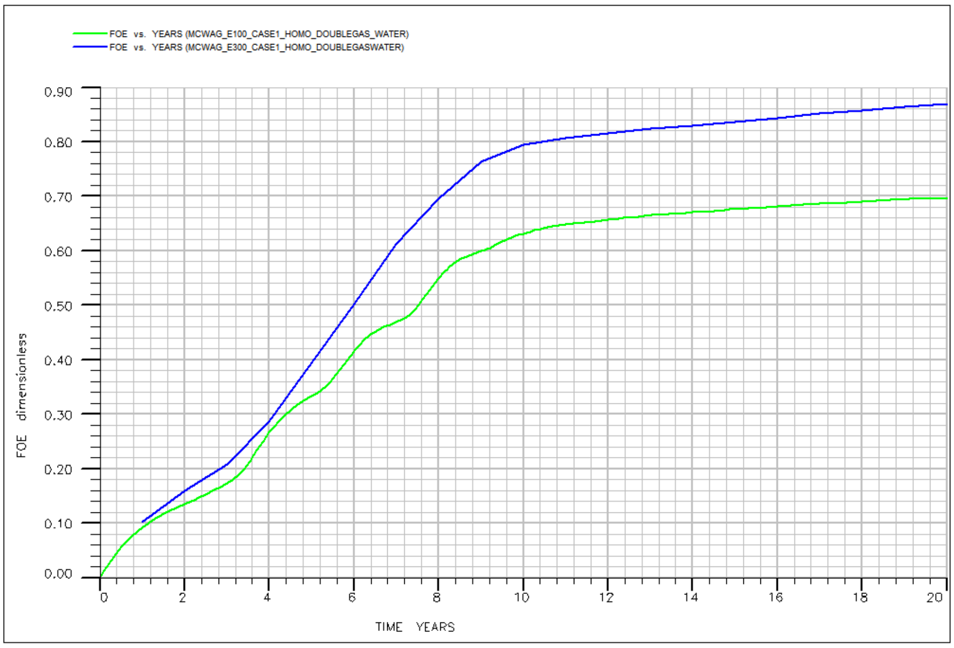

Figure 20: Oil Recovery Factor for Double Gas & Water Injection Case

From Figures 18-20, the Oil Recovery Factor in all scenarios exhibits the higher prediction of Compositional Model comparing to Black Oil Model. After 20 years, in scenarios 1 & 3 when the gas injection is double, the Oil Recovery Factor becomes 0.86 and 0.70 for Compositional and Black Oil Models. The estimation yields 0.78 and 0.67 when water injection rate is increased twice. And on the last case where both injection rates are doubled, the Compositional Simulator sees the value at 0.87 and Black Oil Simulator predicts at 0.695.

It should be noted that percent difference between the two models become apparently greater in scenario 1 and 3 when the gas injection rates become twice which yield the values at 18.60% and 20.11% respectively, comparing to the base case and the scenario 2 at 13.68 and 14.10%. This is caused by the difference in assumptions between the two fluid models where the black oil model has limitation in describing the condensing and vaporizing processes in miscibility process.

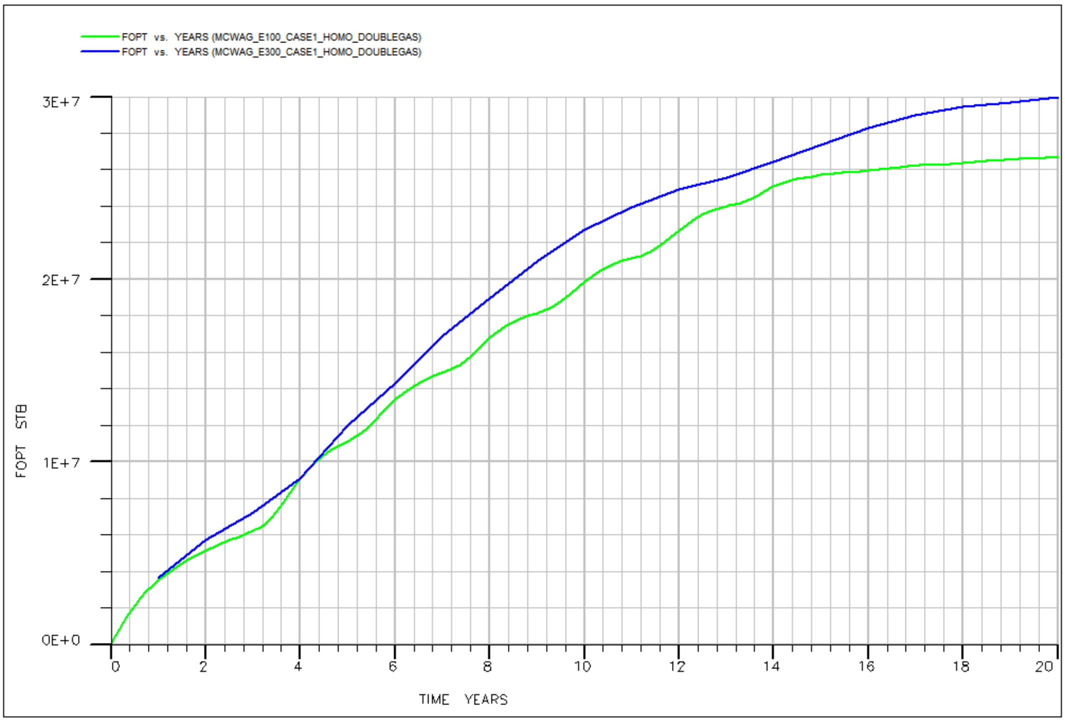

Figure 21: Oil Production Total for Double Gas Injection Case

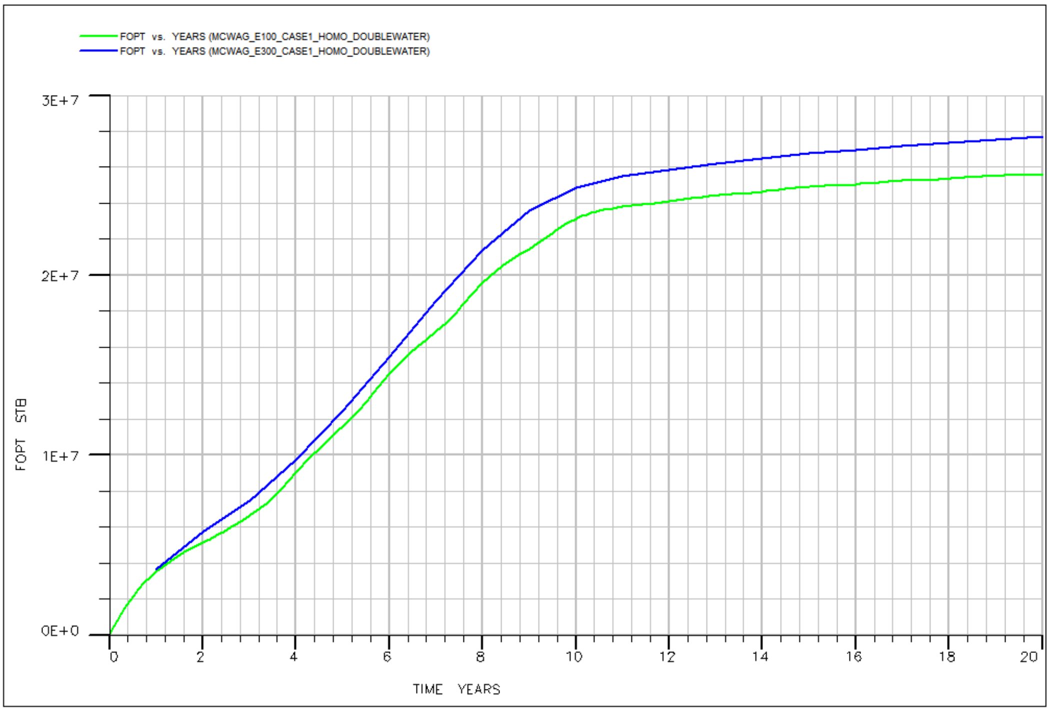

Figure 22: Oil Production Total for Double Water Injection Case

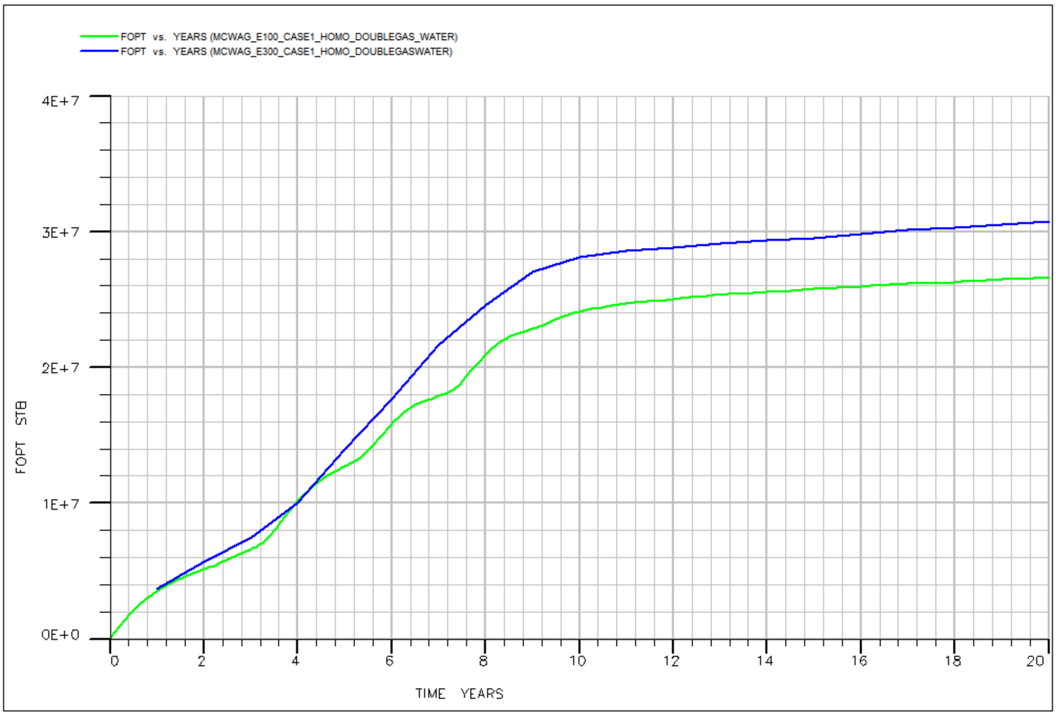

Figure 23: Oil Production Total for Double Gas & Water Injection Case

The Total Oil Production in all scenarios shows the greater values of prediction of Compositional Model comparing to Black Oil Model as shown in Figures 21-23. When the gas injection is double, the Total Oil Production after 20 years yields 30.1 and 26.75 MM STB for Compositional and Black Oil Models. Water injection rate increased twice, the estimation yields 27.54 and 25.42 MM STB. In last scenario where both injection rates are doubled, the Compositional Simulator predicts the value at 30.87 and Black Oil Simulator sees at 26.46 MMSTB.

The percentage of difference of total oil production for the black oil model as compared to the compositional simulator when the gas injection is increased in scenario 1 and 3, also become larger as the oil recovery factor. Scenario 1 and 3 give results in the percentage difference at 11.13% and 14.29% where base case and scenario 2 give values at 6.59 and 7.70%.

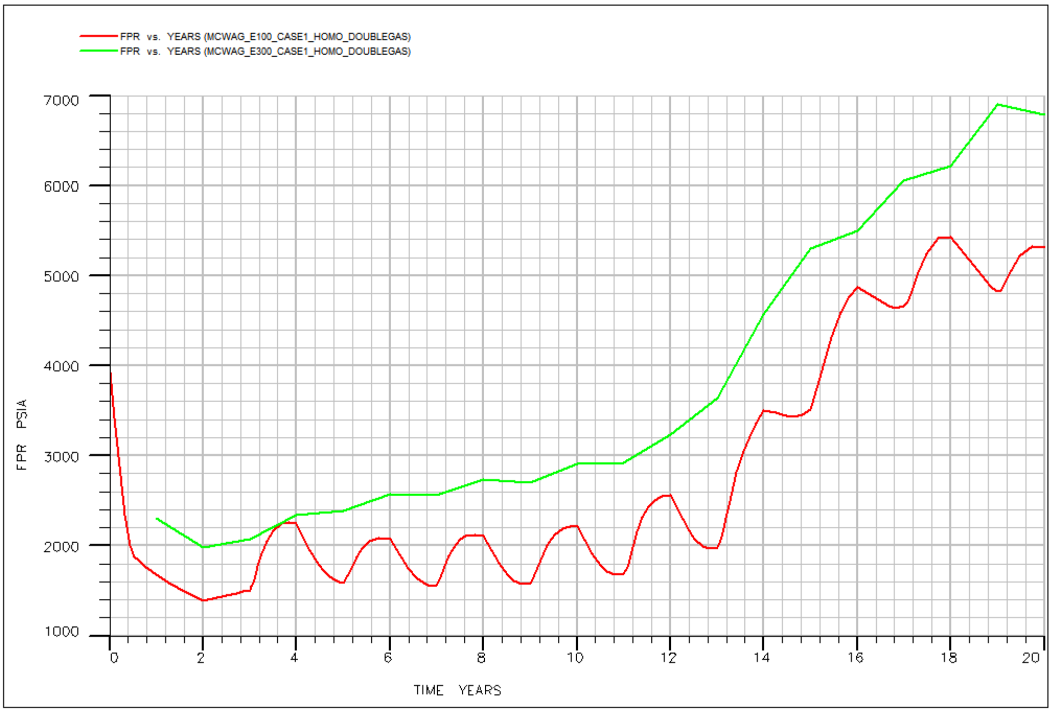

Figure 24: Reservoir Pressure for Double Gas Injection Case

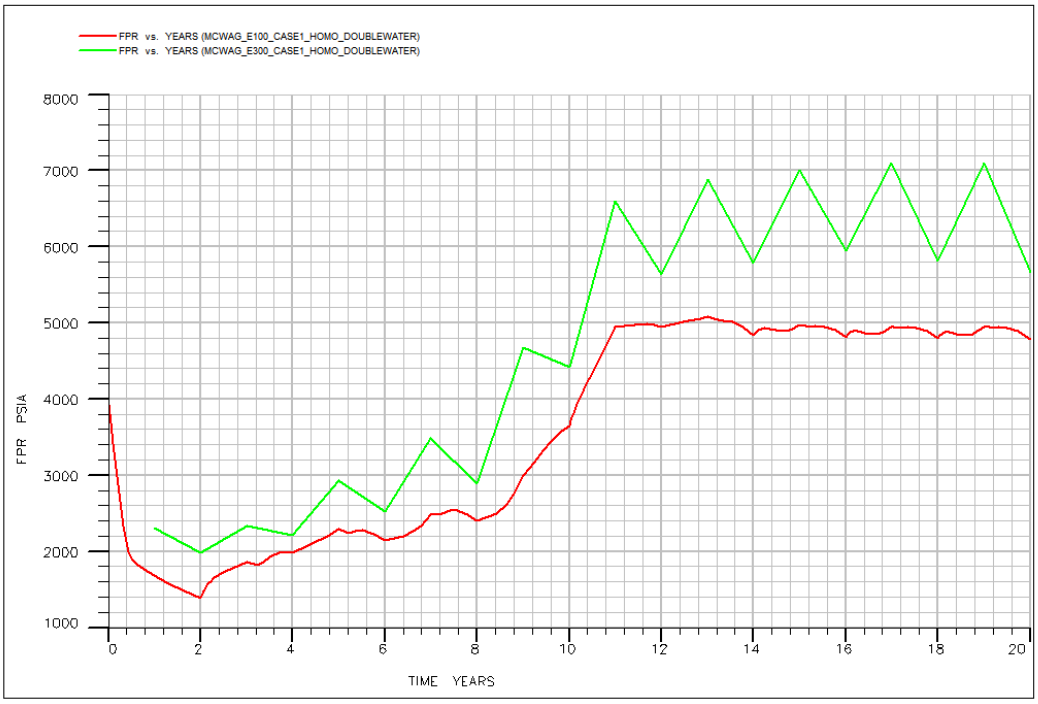

Figure 25: Reservoir Pressure for Double Water Injection Case

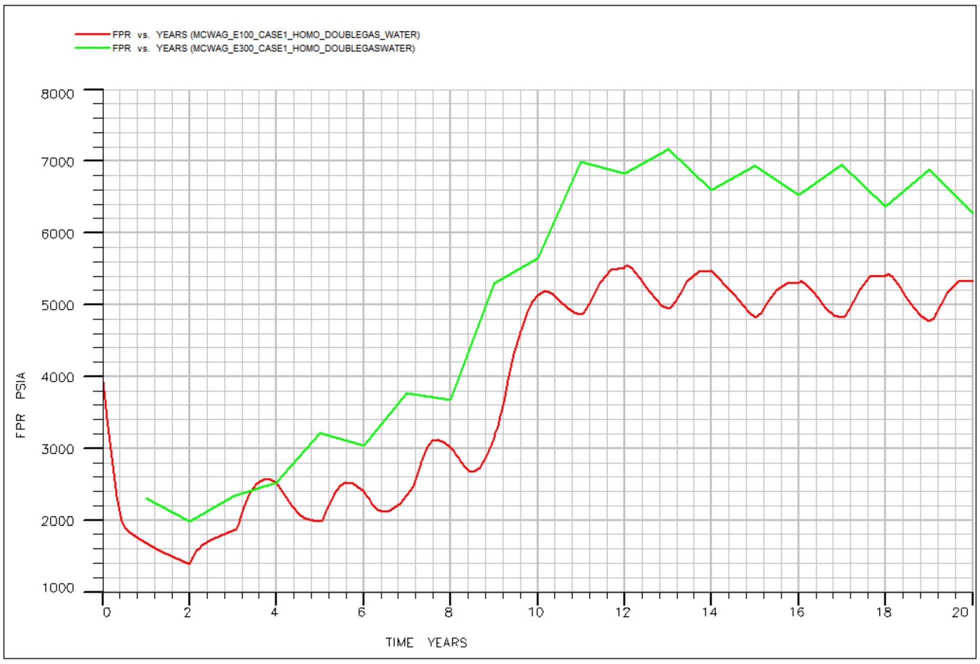

Figure 26: Reservoir Pressure for Double Gas & Water Injection Case

Figures 24-26 show the reservoir pressure prediction for both simulators in all injection cases. The reservoir pressure still exhibits the reasonable agreement in all cases. The general prediction from Black Oil simulator is in line with Compositional Simulator though there are the wide ranges in values between the two. When the injection rates become higher in all three scenarios from the base case study, the rising in reservoir pressure during injection period can be apparently observed from both simulators.

4.3.5 Effects of K_v/K_h

The permeability ratio for the base case is set at 0.1 where K_v is 50 md and K_h is at 500 md. The effect of K_v/K_h has been studied by adjusting the values of K_v to 500 and 5 md respectively, which yields the permeability ration at 1 and 0.01, whereas the horizontal permeability is set to be constant. The results were displayed in the following graphs.

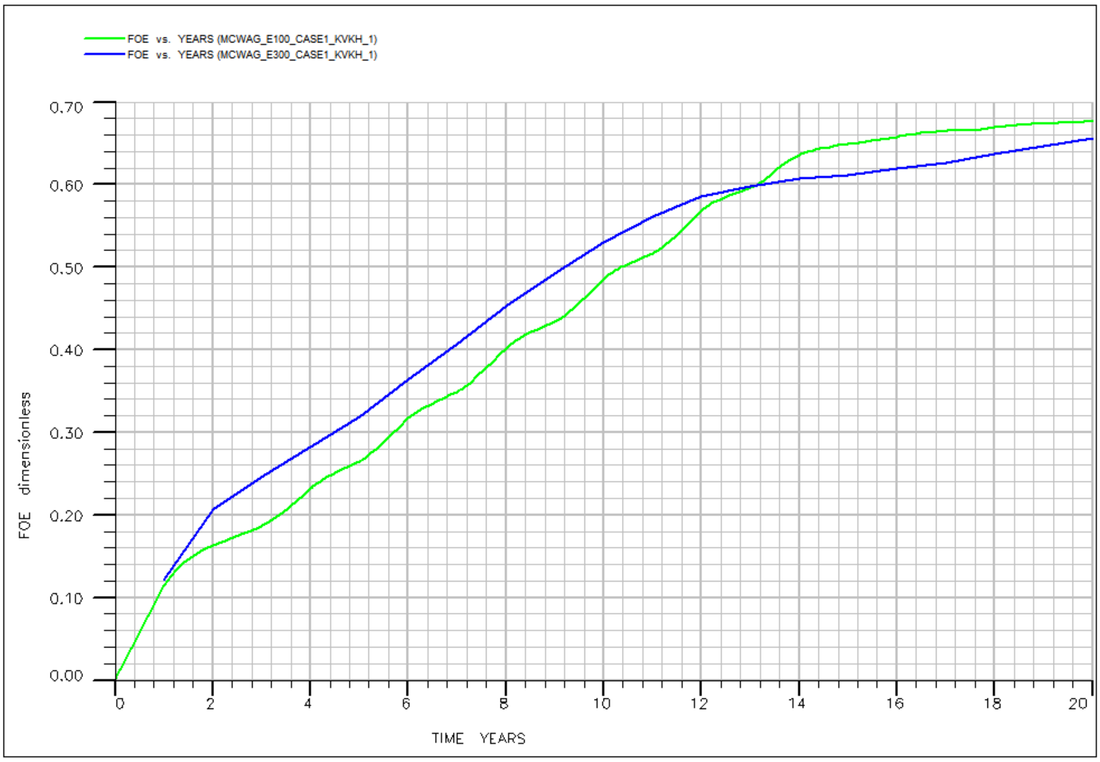

Figure 27: Oil Recovery Factor for K_v/K_h = 1 Case

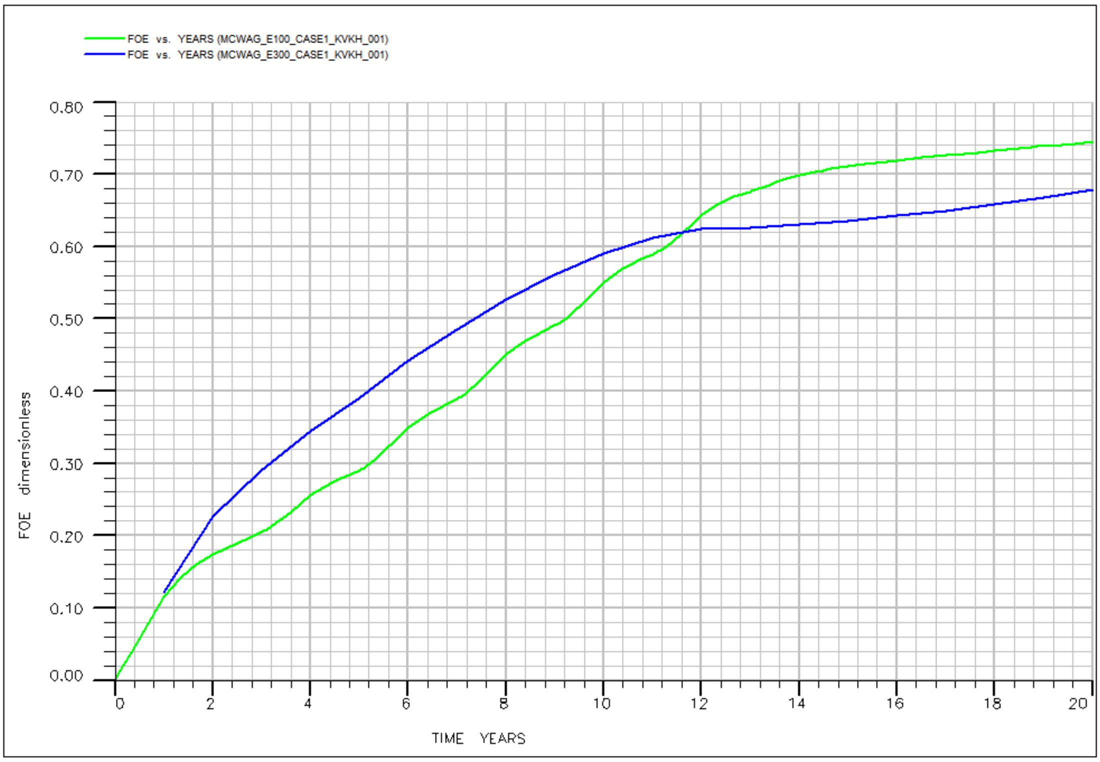

Figure 28: Oil Recovery Factor for $K_v/K_h = 0.01$ Case

Figures 27-28 shows the result of oil recovery prediction by both simulators in the different permeability ratio models. The compositional simulator shows a higher oil recovery prediction initially in both cases then black oil simulator generates greater results. The ultimate recoveries after 20 years by black oil and compositional simulators for first and second scenarios are equal to 0.68 & 0.658 and 0.744 &0.684 with the percent difference at 3.44% and 8.77% respectively.

The obtained results agree with the study by Namani M. & Kleppe J.(2011), that the vertical permeability has a significant impact to the WAG process but there is an optimum value for ratio of vertical to horizontal permeability which favors oil recovery.

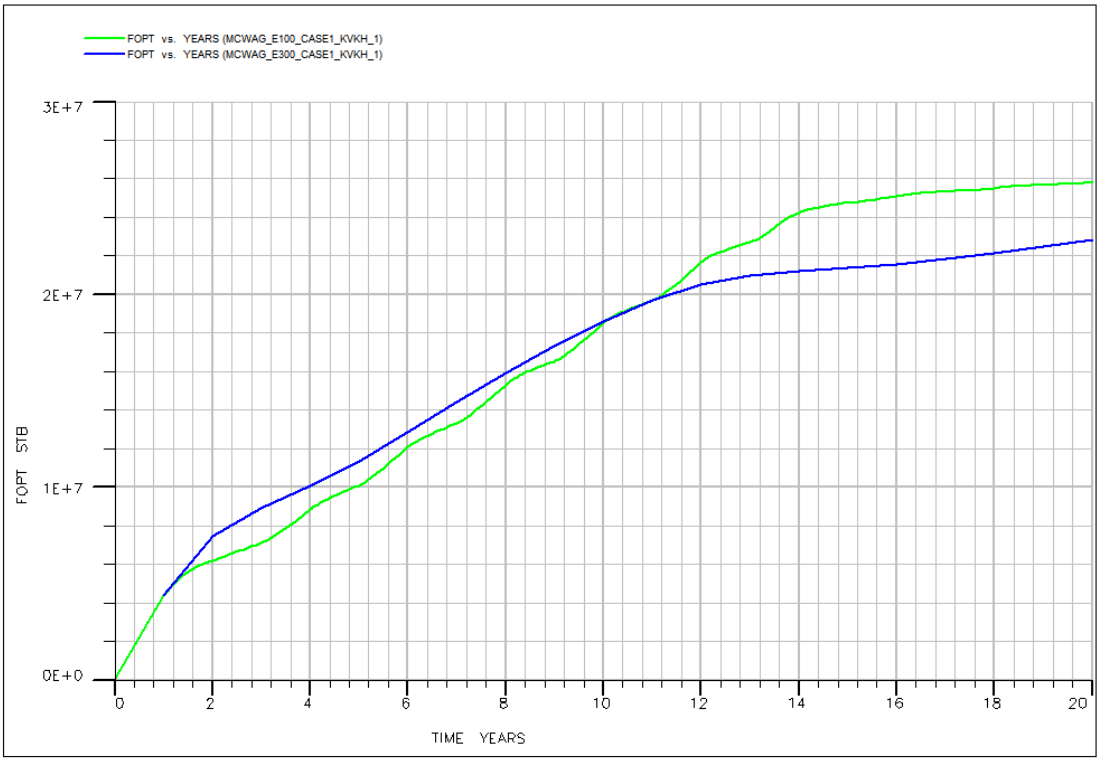

Figure 29: Oil Production Total for $K_v/K_h = 1$ Case

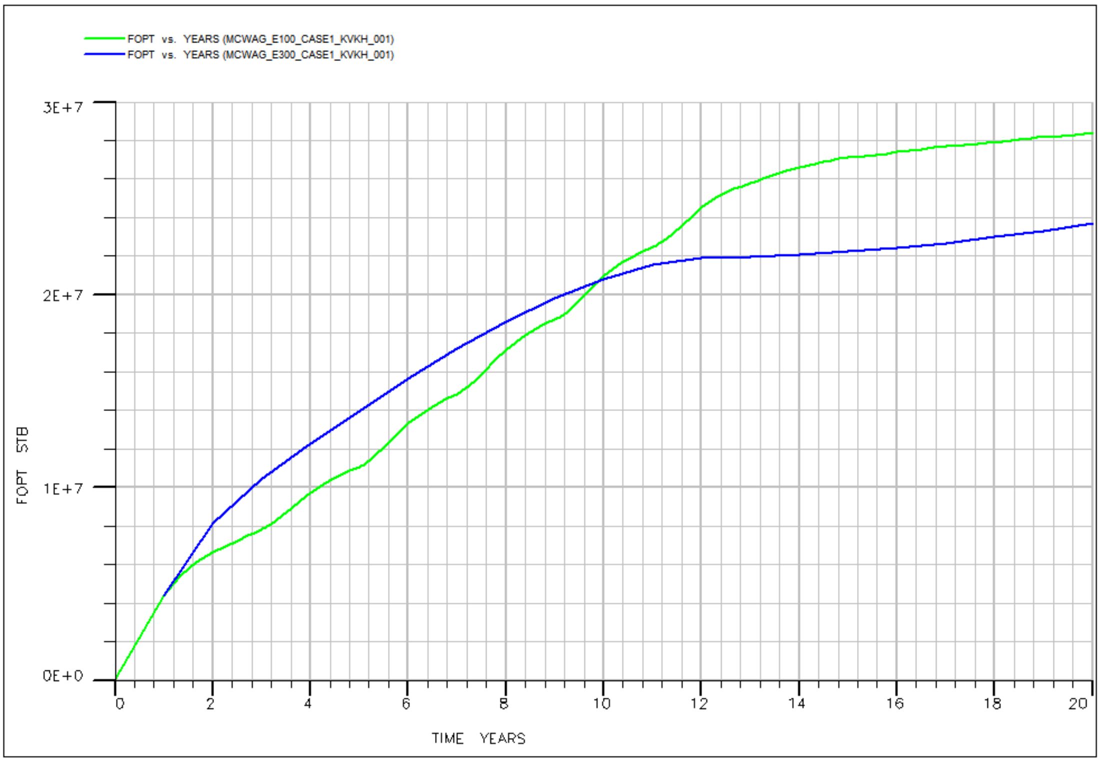

Figure 30: Oil Production Total for $K_v/K_h = 0.01$ Case

Referring to Figures 29-30, Black Oil and Compositional Simulators predict the similar trend of total oil production per time, with the oil recovery factor in which initially the compositional predicts higher result and later on black oil model become apparently higher for different vertical to horizontal permeability ratios. The total oil productions forecasted by Black Oil and Compositional simulators for scenario one are 26 and 22.63 MMSTB, while the results for the second scenario are at 28.73 and 23.79 respectively.

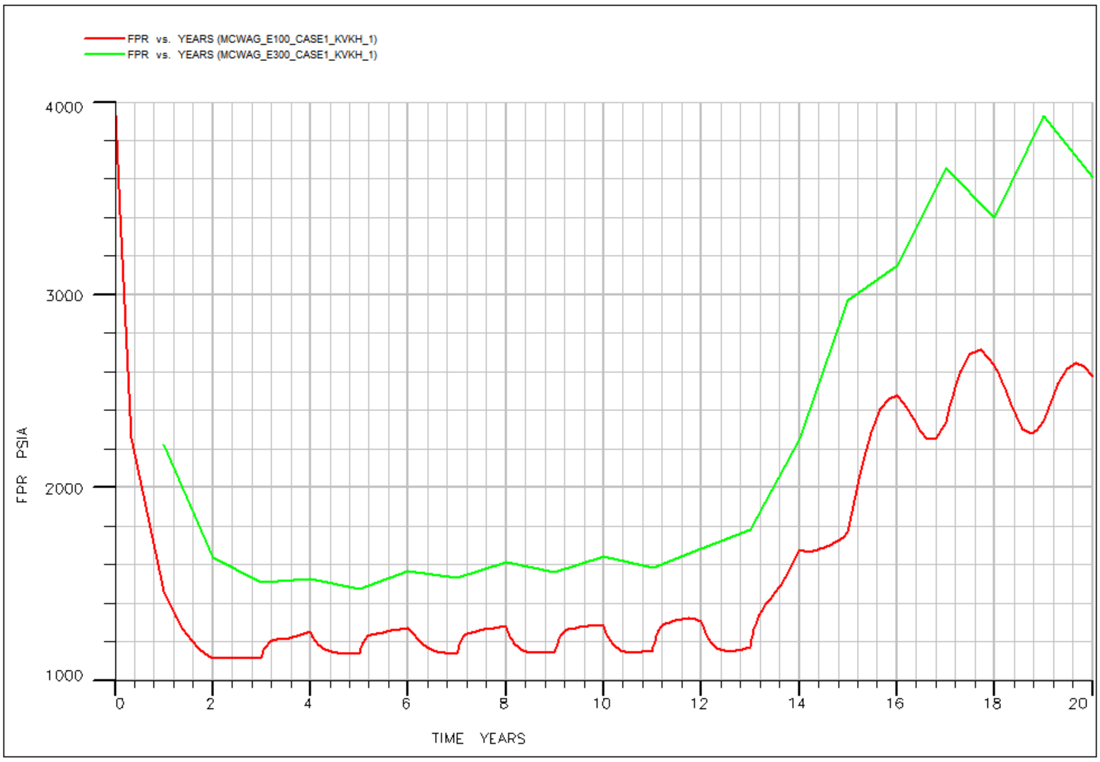

Figure 31: Reservoir Pressure for $K_v/K_h = 1$ Case

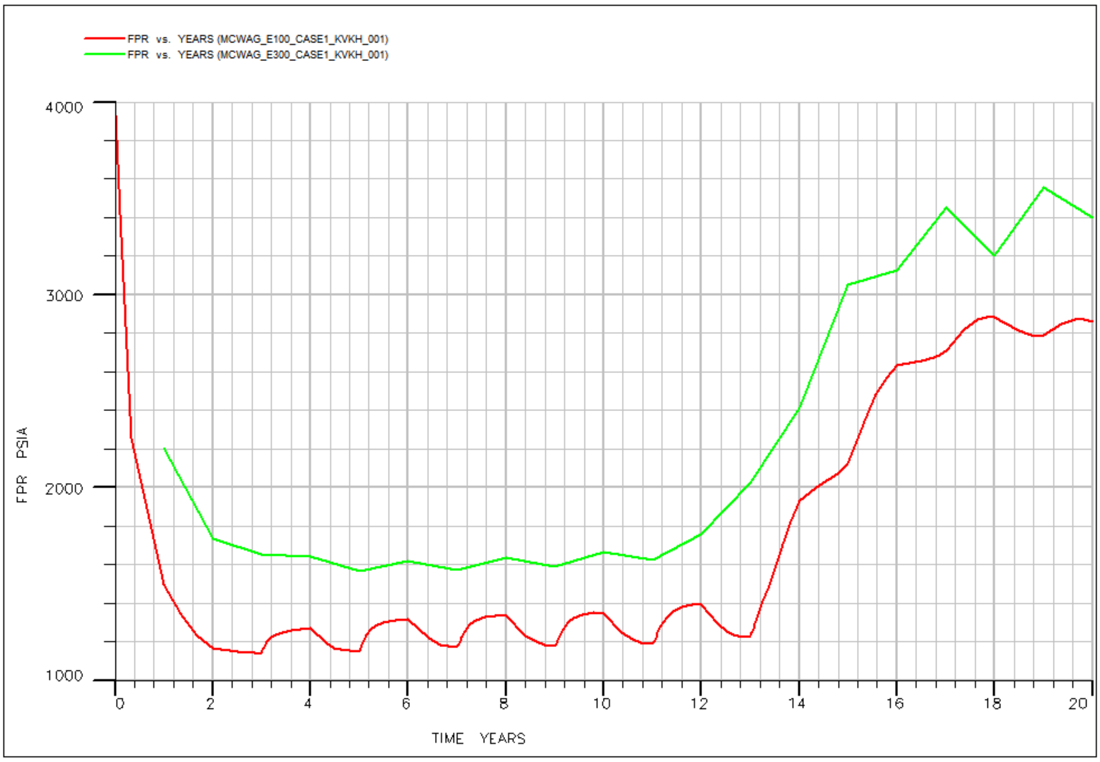

Figure 32: Reservoir Pressure for $K_v/K_h = 0.01$ Case

The reservoir pressure predictions by both simulators still yield the similar rising and declining trends with the discrepancy in values as shown in Figures 31-32. The changes in vertical to horizontal permeability ratios slightly affect the reservoir pressure.

4.4 PERCENTAGE OF DIFFERENCE

As shown in the previous parts, though the Black Oil managed to predict the similar trends to the Compositional Simulator in certain scenarios, there are obvious gaps in values in each observed parameters. The Oil Recovery Factors and Total Oil Productions from all scenarios predicted by Black Oil and Compositional Simulators are summarized in the Tables 21-22. The percent difference of Black Oil estimation as compared to the Compositional Simulator is calculated in each case and the averaging value is obtained. The percent difference for Oil Recovery Factor ranges from 3.08 to 20.11 with average difference of 12.72. For Total Oil Production estimation, the percent difference ranges from 4.87-19.50, which yields the average value at 11.19

Cases	Recovery Factor After 20 Years		Percent Difference
	E100	E300	
WAG 1 Year - Homogeneous (Base)	0.675	0.782	13.68
WAG 1 Year - Heterogeneous	0.67	0.65	3.08
WAG 2 Year - Homogeneous	0.66	0.78	15.38
WAG 3 Year - Homogeneous	0.658	0.76	13.42
WAG Double Gas Injection	0.7	0.86	18.60
WAG Double Water Injection	0.67	0.78	14.10
WAG Double GAS & Water Injection	0.695	0.87	20.11
WAG K_v/K_h = 1	0.68	0.658	3.34
WAG K_v/K_h = 0.01	0.744	0.684	8.77
Average Percent Difference			*12.72*

Table 25: Oil Recovery Factor for Black Oil and Compositional Simulations

Cases	Total Oil Production After 20 Years (MMSTB)		Percent Difference
	E100	E300	
WAG 1 Year - Homogeneous (Base)	25.65	27.46	6.59
WAG 1 Year - Heterogeneous	25.82	22.67	13.90
WAG 2 Year - Homogeneous	25.24	27.39	7.85
WAG 3 Year - Homogeneous	25.76	27.08	4.87
WAG Double Gas Injection	26.75	30.1	11.13
WAG Double Water Injection	25.42	27.54	7.70
WAG Double GAS & Water Injection	26.46	30.87	14.29
WAG K_v/K_h = 1	26	22.63	14.89
WAG K_v/K_h = 0.01	28.43	23.79	19.50
Average Percent Difference			*11.19*

Table 26: Total Oil Production for Black Oil and Compositional Simulations

4.5 SIMULATION RUN TIMES

The table below illustrates the CPU run times for both Black Oil and Compositional Simulators for all scenarios. It is found that the Black Oil Simulator is in average 6.45 times faster than the Compositional simulator. It should also be noted that the simulation in Homogeneous case is shown to be faster than the Heterogeneous case in both simulators.

Cases	E100	E300	Elapsed Time Ratio (E300:E100)
	Elapsed Time	Elapsed Time	
WAG 1 Year - Homogeneous (Base)	5	40	8.00

WAG 1 Year - Heterogeneous	6	46	7.67
WAG 2 Year - Homogeneous	5	39	7.80
WAG 3 Year - Homogeneous	6	40	6.67
WAG Double Gas Injection	7	42	6.00
WAG Double Water Injection	7	39	5.57
WAG Double GAS & Water Injection	7	54	7.71
WAG Kv/Kh = 1	9	38	4.22
WAG Kv/Kh = 0.01	9	40	4.44
	Average Time Ratio		6.45

Table 27: Run Times for Black Oil and Compositional Simulations

CHAPTER 5

CONCLUSION & RECOMMENDATIONS

A comparison for Black Oil and Compositional Simulations has been conducted for range of models and case studies. It is found that though the Black Oil simulator is capable to predict the similar trends of Oil Recovery Factor, Total Oil Production and Reservoir Pressure to the Compositional Simulator in certain cases, there are the obvious differences in values between two simulators depending on the reservoir models and WAG scenarios examined.

The gas injection rate shows the significant role in the accuracy of Black Oil comparing to Compositional Simulator. The greater the volume of gas injected, the greater the difference in the prediction of Oil Recovery Factor and Total Oil Production. This is a result of limitation of Black Oil model in describing the condensing and vaporizing processes in miscibility process which can only be done by determining the Todd-Longstaff mixing parameter.

On average, there is a speed up factor of 6.45 when using Black Oil Simulator comparing to Compositional Simulator. This supports the conclusion that the Black Oil Simulators take advantages in term of time for modeling and forecasting the general tendency of Miscible CO2 WAG Injection.

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