Simulation Study on Gravity Assisted Simultaneous Water and Gas (GASWAG) Injection for Thin Oil Rim

By

Yuhanis Fatihah Zainudain

(14500)

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Bandar Seri Iskandar

31750 Tronoh

Perak Darul Ridzuan

CERTIFICATION OF APPROVAL

SIMULATION STUDY ON GRAVITY ASSISTED SIMULTANEOUS WATER AND GAS (GASWAG) INJECTION FOR THIN OIL RIM

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YUHANIS FATIHAH BINTI ZAINUDAIN

14500

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(PETROLEUM)

Approved by,

Ali F. Mangi Alta'ee
Lecturer
Petroleum Engineering Department
Faculty of Geosciences and Petroleum Engineering
Universiti Teknologi PETRONAS
Bandar Seri Iskandar
31750 Tronoh Perak

(Mr Ali F. Mangi Alta'ee)

UNIVERSITI TEKNOLOGI PETRONAS
TRONOH, PERAK
SEPT 2014

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.

(YUHANIS FATIHAH ZAINUDAIN)

ABSTRACT

Thin oil rim is thin reservoir oil column that has an overlying gas cap and underlying aquifer. Oil rim reservoir is always associated with coning problem, gas smeared and oil lost into gas cap that will reduce the oil recovery factor. One of the effective solution for the thin oil rim problem is gravity assisted simultaneous water and gas (GASWAG) method. The objective of this study is to investigate GASWAG method by changing the possible parameters that affected the process of the GASWAG method in order to maximize the oil production from thin oil rim and to conduct an economic feasibility study. The study is related to gas flooding, water flooding and GASWAG method. A model of GASWAG will be generated using Black Oil Simulator in computer laboratory. The parameters that changed in the GASWAG process are type of well producer, location of the producer, salinity of brine injection, mobility ratio, injection rate of fluid injected and well spacing. The most suitable producer for GASWAG process is a horizontal well that located in the middle of the oil column. Low water injection rate and high gas injection rate give favorable result. Excellent result was presented by the existence of polymer in the water injection at the gas-cap. The salinity of brine injection is insignificant for GASWAG process.

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ABBREVIATIONS AND NOMENCLATURES

GASWAG	Gravity Assisted Simultaneous Water and Gas
WOC	Water- Oil-Contact
GOC	Gas-Oil-Contact
FGOR	Field-Gas-Oil Ratio
FGPT	Field-Gas-Production Total
FOPT	Field Oil Production Total
FOE	Field Oil Recovery
FWPT	Field Water Production Total
ANOVA	Analysis of Variance
FYP I	Final Year Project 1
FYP II	Final Year Project II

CHAPTER 1

1.0 INTRODUCTION

1.1 Background

There are three stages of oil recoveries, which is primary, secondary and tertiary. Primary recovery is done by using natural drives such as solution gas drive, water drive, and gas cap drive. Water injection in aquifer to maintain the reservoir pressure is also included in the primary recovery. After that, continue with water flooding at water-oil-contact (WOC) and gas injection at gas-oil-contact (GOC) respectively this step include in the secondary recovery. Later on, when the oil left is only residual oil saturation the tertiary oil recovery also known as enhanced oil recovery (EOR) is implied. This is the normal process occurring in the life of the reservoir.

However, reservoir condition is not uniform; it depends on the geological structure. One of them is the thin oil rim. A lot of challenges needed to face in order to produce the oil from the thin oil rim.

1.2 Problem Statement

When the oil production starts in the thin oil rim reservoir, the aquifer and gas cap starting to expand because of the oil start to lose its energy. This will lead to coning problem. According to Ahmed (2006), coning is the mechanism of downward movement of gas or/and movement of water toward perforation of a producing well. Gas smearing and oil loss into the gas cap also will occur. This will lead to low oil recovery. In order to prevent this problem happen a lot of methods was study, one of the methods is Gravity Assisted Simultaneous Water and Gas (GASWAG).

GASWAG is the best method to increase oil recovery for thin oil rim. However, a further study is needed in order to know the critical parameters that affect the recovery factor of GASWAG process.

1.3 Objectives and Scope of Study

1.3.1 Objective

1. To study GASWAG method and the parameters affected the process of GASWAG method.
2. To maximize oil production from thin oil rim
3. To conduct an economic feasibility study

1.3.2 Scope of study

There are 3 important keys for scope of study, they are 1) gas flooding and water flooding process 2) GASWAG study and 3) Simulation study.

To achieve the objective stated above, a study needs to conduct accordingly. Starting with understanding of gas and water flooding process, follow from GASWAG study. Which is by recognizing the parameter that affects the GASWAG process and give a high recovery factor. Later, proceed with simulation study. A result generated must be analyzed to know the effect of each parameter.

CHAPTER 2

2.0 LITERATURE REVIEW AND/OR THEORY

Thin oil rim are defined as a thin reservoir oil column that having overlying gas cap and an underlying aquifer by (Nagib, Ezuka, & Nasr, 2010). Satter, Iqbal, and Buchwalter (2008) stated that "primary production mechanism for thin oil rim is combination drive". Which is water drive (aquifer) and gas cap drive. The key force balance (Figure 2.1) of thin oil rim is between the gas cap expansion, aquifer drive and viscous withdrawal (Chan, Kifli, & Darman, 2011; Razak, Chan, & Darman, 2010a, 2010b).

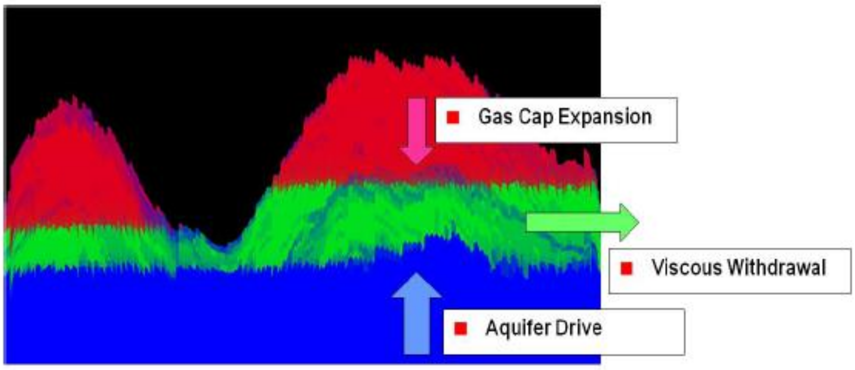

Figure 2.1 Key force balance of thin oil rim(Razak et al., 2010b)

However, this thin oil rim is not a good reservoir because it causes low oil recovery factor. Vo, Waryan, Dharmawan, Susilo, and Wicaksana (2000) mentioned that oil column thickness is important for oil and gas recovery of oil rim that having gas cap and also an aquifer. This has been supported later by research from Olamigoke and Peacock (2009) that mentioned the oil column thickness of oil rim give the major impact for oil recovery. As the thickness is low (thin) the recovery is low.

Range of thin oil rim thickness is different for each reservoir. For JZ25-IS oil field, the thin oil column thickness is considered to be 33 m (108.27 ft) to 98 m (321.52 ft) with gas column thickness of 65 m (213 ft) to 136 m (446 m) (Ge et al., 2013). Referring to Razak et al. (2010b), Malaysian thin oil rim field normally having a number of major heterogeneous and stratigraphic structural reservoirs per less complex reservoir. The oil thickness mentioned initially is about 10 m (32 ft) to 70 m (230 ft), the thickness has been decreasing to 10 m (32 ft) since 2 years of production. Meanwhile, oil column thickness of thin oil rim Seligi reservoir mention by Razak et al. (2010a) currently is less than 25 m (82 ft). Nagib et al. (2010) stated that the oil rim is considered thin when the thickness is less than 30 ft (9.144 m) and ultra-thin if the thickness is less than 20 ft (6.096 m). Whereas, in offshore Trinidad (Amhertia and Immortella) thin oil column thickness is around 31 ft (9.44 m) to 46 ft (14 m) (Bayley-Haynes & Shen, 2003). Evensen, Skaug, and Goodyear (1993) reported that the thin oil thickness for Troll Field is in the range of 22 m (72 ft) to 26 m (85 ft). Thin oil rim thickness from Ghaba North Shuaiba reservoir is approximately 30 m (98 ft) (Gallagher, Prado, & Pieters, 1993).

One of the major limitation of thin oil rim recovery is coning problem. When the oil is sandwiched by gas cap and aquifer, this inevitable fluid will flow onto perforation of producing tubing. The oil recovery process is a challenge because of this phenomenon (Olamigoke and Peacock (2009); Vo et al., 2000). Olamigoke and Peacock (2009) had list other problems that occur because of thin oil rim are because of gas production, oil rim move into the gas cap, the oil might loss into the gas cap due to gas cap re-saturation and early breakthrough. This problem will lead to poor performance. Putten Van and Naus (2008) also explained that, the movement of oil rim by aquifer and gas cap after the reservoir pressure decline when production is starting create “oil smearing” scenario. Oil is displacing gas in the gas cap as the oil rim moving into the gas cap and generate residual gas trapping. Further movement of this oil rim of aquifer drive leave the residual oil behind in the presence of trapped gas.

One of the solution to overcome this problem and increase oil recovery in thin oil rim is GASWAG. GASWAG is a method that used to maximize the oil recovery with the aid of gravity by water and gas injection. Water was injected into gas cap and gas was injected into the aquifer (Figure 2.2).

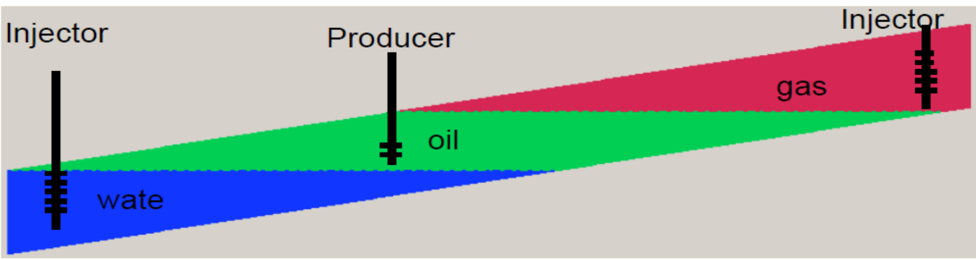

Figure 2.2 GASWAG, Gas injection in aquifer, water injection in gas cap (Bui, Forrest, Tewari, Henson, & Abu Bakar, 2010)

GASWAG is one of the efficient methods to use in thin oil rim. As presented by Abdul Razak, Chan, and Darman (2011), the ultimate oil recovery gain by GASWAG method was significant. This method also better compares to water injection in the aquifer, water injection in the gas cap and the combination of down-dip and up-dip water injection. This is because the sweep efficiency was improved due to gravity segregation and the oil was rezoning in the middle oil column and easy to be captured by additional infill drilling as shown in figure below (Figure 2.3).

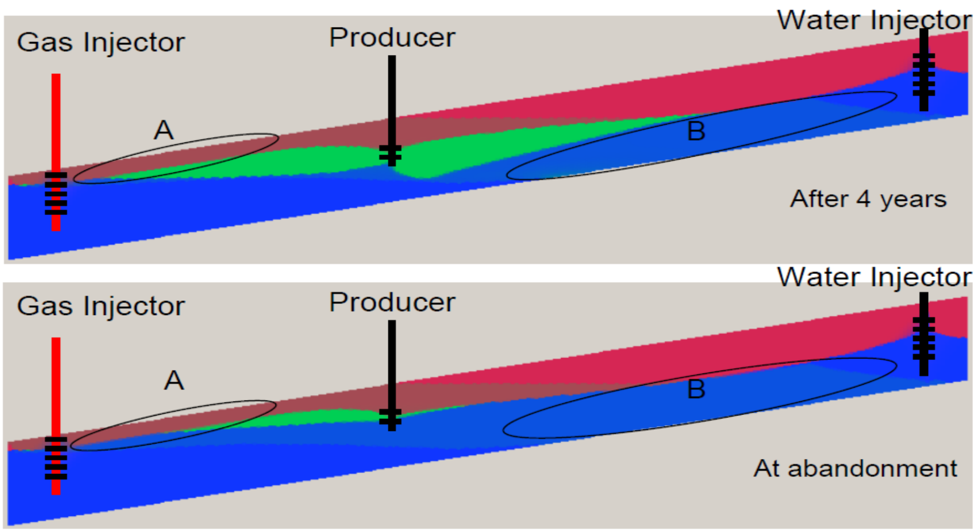

Figure 2.3 Fluid movement of GASWAG after 4 years (top) and at abandonment (bottom) (Bui et al., 2010)

They also listed another advantage of GASWAG is the reservoir pressure within the area was increased and lead to better productivity and higher cumulative recovery. Next, water fencing generated by GASWAG also protects gas cap from smeared. Gas injection in the aquifer can increase the pressure support at the gas cap when its make a way to the gas cap. This will prevent movement of water and oil into gas and even prevent the oil lost to the gas cap. In other word, GASWAG is not only good for oil production but also for gas recovery. This argument also supported by Bui et al. (2010) which is they stated that GASWAG gave better sweep efficiency and highest oil recovery.

However, a few parameters are needed in order to investigate which parameters that can produce maximize oil production.

2.1 Factor affecting the GASWAG

2.1.1 Type of Wells (Producer)

One of the solutions for coning problem is horizontal well drilling. Even though this is costly compare to vertical well drilling, but it is effective in the exploitation of the oil without worry about coning problem. Normally for the thin oil rim the infill horizontal well was located in the oil zone. Iyare and Marcelle-de Silva (2012) had proved that there is a significant effect of the infill horizontal well located to the oil production.

Their study was to determine the effect of well location and gas cap size on production performance. For the reservoir that having small gas cap but strong aquifer, the well was located at the gas cap in order to maximize the oil production. Meanwhile, for reservoir with large gas cap, the well at or below WOC can significantly increase ultimate oil recovery.

2.1.2 Salinity (solubility) of water

"Low salinity, high oil recovery factor" is a normal statement associates with salinity. This is because low salinity will reduce IFT between oil and injected brine. Shaker Shiran and Skauge (2012) concluded that the more oil wet core is significant for oil recovery by low salinity. In addition, low salinity concentration of water flooding in strongly water wet reservoir lead to no increase in oil recovery.

According to Nasralla and Nasr-El-Din (2011), the phenomenon of clay swelling by fresh water injection (low salinity) and block the pore throat and prevent fine migration is the reasons why the oil recovery is improved. They also founded that the oil recovery only will increase when the salinity of connate water is reduced. Next, they also stated that low salinity will alter rock wettability. The low salinity water leaches the cation from rock surface and creates a negative charge of the rock surface. As the oil/brine interface charge is negative, the repulsive force is produced.

Later, the oil is easily produced. Besides, other researchers said that salinity did not alter the wettability but cementing material dissolution. They also reported that the salinity is less significant on oil recovery compare to cation types. $MgCl_2$ showed the high recovery factor than NaCl and $CaCl_2$.

Meanwhile, Alotaibi and Nasr-El-Din (2009) reported that by reducing the salinity of the injected brine in the reservoir, IFT also decreasing. When IFT decreases the recovery factor also increase. The IFT will decrease with decreasing salinity until reach one point which is a critical point when the IFT will increase again.

However, Sharma and Filoco (2000) founded that the wettability give a significant effect to the salinity of the brine used. Drainage process recorded no change in the oil recovery factor when different brine concentration used. Meanwhile, imbibition process gives a different result which is low salinity of brine give high recovery factor. They also mentioned that, the salinity of connate water is a critical factor for oil recovery. Furthermore, composition of oil also contributes to the salinity of water to produce high recovery.

2.1.3 Mobility ratio

Mobility ratio is a ratio of mobility displacing fluid to the mobility of the displaced fluid. Mobility is favorable if it is less than one (Green & Willhite, 1998). Craft, Hawkins, and Terry (1959) stated that if the reservoir has high viscosity, the mobility will be greater than 1 and fingering phenomenon will occur and lead water to bypass the oil. A good mobility ratio for water flood is around 1.

Mobility ratio is related to fractional flow of water,f_w, viscosity and relative permeability.

2.1.3.1 Fractional flow of water, f_w

$$f_w = \frac{1}{1 + {}^{1}/_{M}}$$

2.1.3.2 Viscosity

Viscosity is one of important parameter for the water flooding method. Viscosity also related to mobility ratio. As the viscosity of water increase, the mobility ratio is decreasing. Hence, the recovery factor is increasing.

$$\downarrow M = \frac{M_{displacing\,fluid(water)}}{\uparrow M_{displace\,fluid(oil)}} = \frac{\frac{kr_w}{\mu_w}}{\frac{kr_o}{\mu_o}} = \frac{kr_w}{kr_o} \cdot \frac{\mu_o}{\uparrow \mu_w}$$

2.1.3.3 Relative Permeability

Relative permeability of water and gas are important variables for mobility ratio (Thomas, Mahoney, & Winter, 1987). When the relative permeability of water/gas is high the mobility ratio is decreasing.

$$\downarrow M = \frac{\downarrow M_{displacing\,fluid(water/gas)}}{M_{displace\,fluid(oil)}} = \frac{\frac{kr_{w/g}}{\mu_{w/g}}}{\frac{kr_o}{\mu_o}} = \frac{\downarrow kr_{w/g}}{\uparrow kr_o} \cdot \frac{\mu_o}{\mu_{w/g}}$$

As mentioned by Green and Willhite (1998), there are four parameters that affects the areal displacement efficiency including relative permeability. Other parameters are injection/production well pattern, mobility ratio and gravity and viscous force.

2.1.4 Water/gas injection rate

Referring to Billiter and Dandona (1999), high water injection rate can overcome gravity effect and displacement components and consequently displacing gas above GOC. High water injection not a good parameter for GASWAG as it will prevent water to move downward toward aquifer and gravity will not be assisting this method anymore.

The effect of CO_2 injection rate on carbonate reservoir experiment was conducted by Mohamed, He, and Nasr-El-Din (2011). Injection rate has played an important role in permeability enhancement. As the injection rate is high, the duration of CO_2, brine and rock in contact is reduced and the amount of rock dissolves decrease. Hence, the permeability increases.

2.1.5 Well spacing

When the well spacing is reduced, the recovery factor is increasing (Gallagher et al., 1993; Razak et al. (2010a)). They also discussed that by increasing well spacing the maximum oil recovery factor will decrease.

CHAPTER 3

3.0 METHODOLOGY/PROJECT WORK

3.1 Methodology

To achieve the above-mentioned objective literature review was thoroughly conducted. Research paper, journal and petroleum engineering handbook are gathered for research purposes. Then, a simulation study was conducted.

The Black Oil Simulator available in computer laboratory was used to model GASWAG experimental. The initial reservoir conditions are input into selected model. The parameters that were considered in the simulation are; Type of wells (producer), location of the horizontal producer well, salinity, mobility ratio, water/gas injection rate, and well spacing.

Simulation Run

The base case for the model was initialized; GASWAG, with 1 vertical water injector in the gas-cap, 1 vertical gas injector in the aquifer and 1 vertical producer in the oil column. The simulation of the model was divided into 6 items.

1. Type of wells (producer)
2. Location of the horizontal producer well
3. Salinity of brine injection
4. Mobility ratio (polymer)
5. Injection rate
6. Cases

The result obtains were shown how this parameter affects the recovery factor.

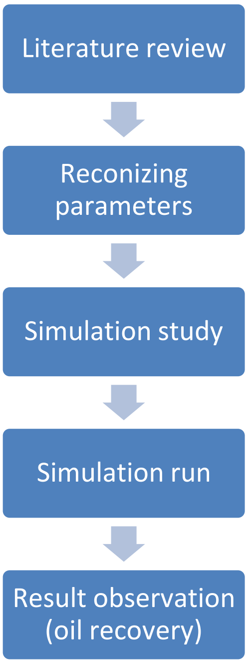

Figure 3.1 Methodology of the project

3.2 Gantt Chart and Milestone

3.2.1 FYP I

Gantt chart of FYP I (Figure 7.1)

Key project Milestone FYP I (Table 7.1)

Milestone of FYP I by Microsoft Project (Figure 7.2)

3.2.2 FYP II

Gantt chart of FYP II (Figure 7.3)

Key project Milestone FYP II (Table 7.2)

Milestone of FYP II by Microsoft Project (Figure 7.4)

CHAPTER 4

4.0 RESULT AND DISCUSSION

4.1 Data Analysis

4.1.1 Data Collection

Table 4.1 Reservoir Data

Parameters	**Values**
Porosity	20%
Permeability	30mD
Gas-Oil-Contact	3645.7 ft
Water-Oil-Contact	3710 ft
^{o} API	45 ^{o} API (light)

4.2 Model Structure

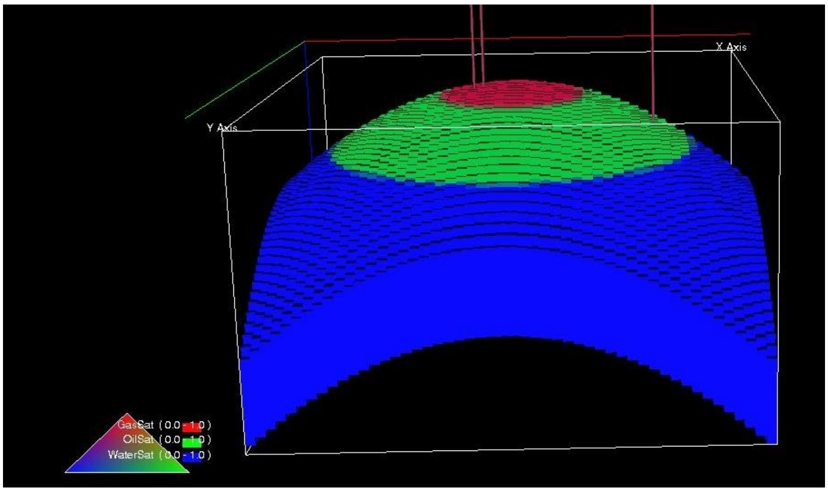

Figure 4.1 3D views of reservoir Structure

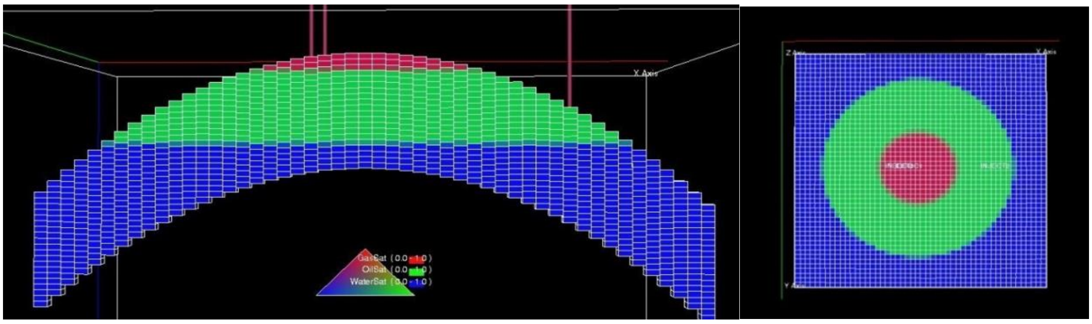

Figure 4.2 Reservoir Model Side view and Topview

4.3 GASWAG

4.3.1 Base Case

Initialization of GASWAG process; 1 water injection in the gas cap, 1 gas injection in the aquifer and vertical producing well.

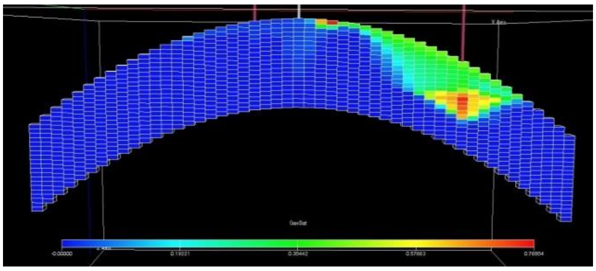

Figure 4.3 Gas injection in the aquifer

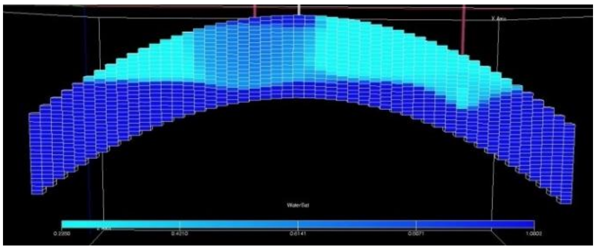

Figure 4.4 Water injection in the Gas Cap

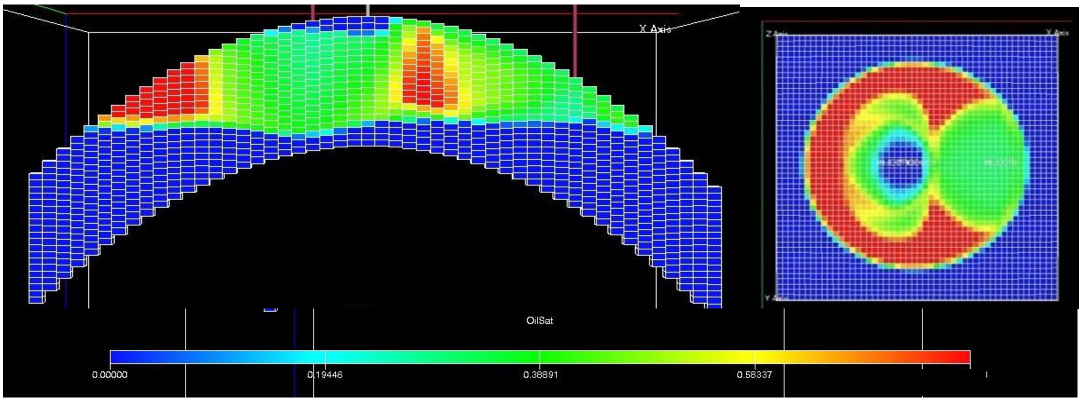

Figure 4.5 Oil Saturation after GASWAG Process; Top view and Side View (GASWAG Base Case)

4.3.2 GASWAG Horizontal

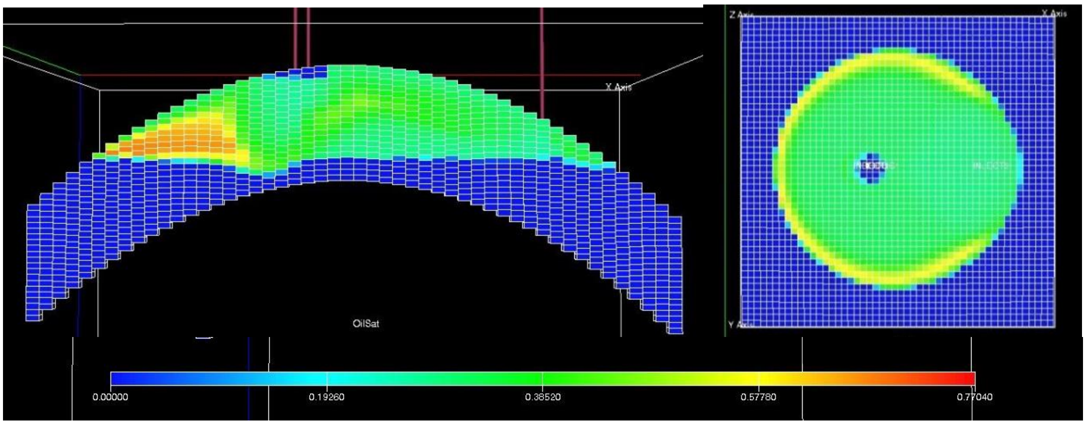

Figure 4.6 Oil Saturation after GASWAG Process; Top view and Side View (GASWAG Horizontal)

4.3.3 GASWAG Slanting

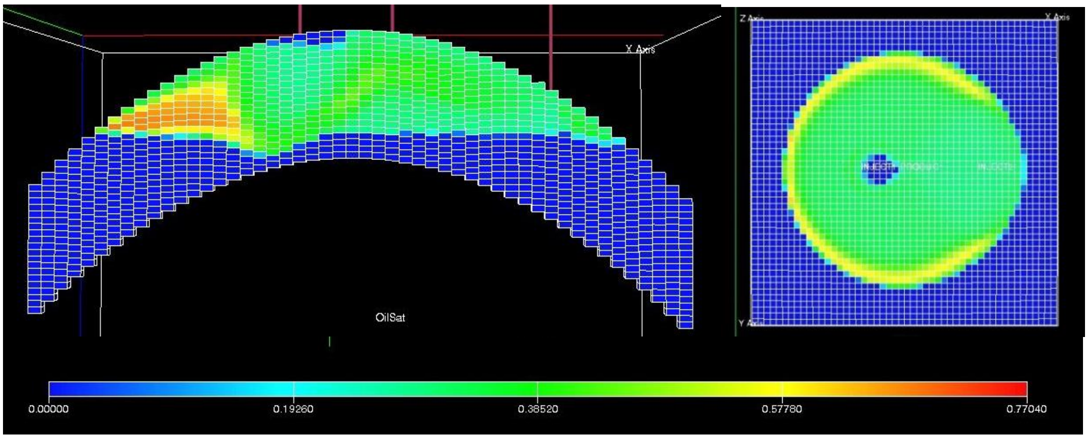

Figure 4.7 Oil Saturation after GASWAG Process; Top view and Side View (GASWAG Slanting)

4.3.4 Result Comparison of the type of producing well

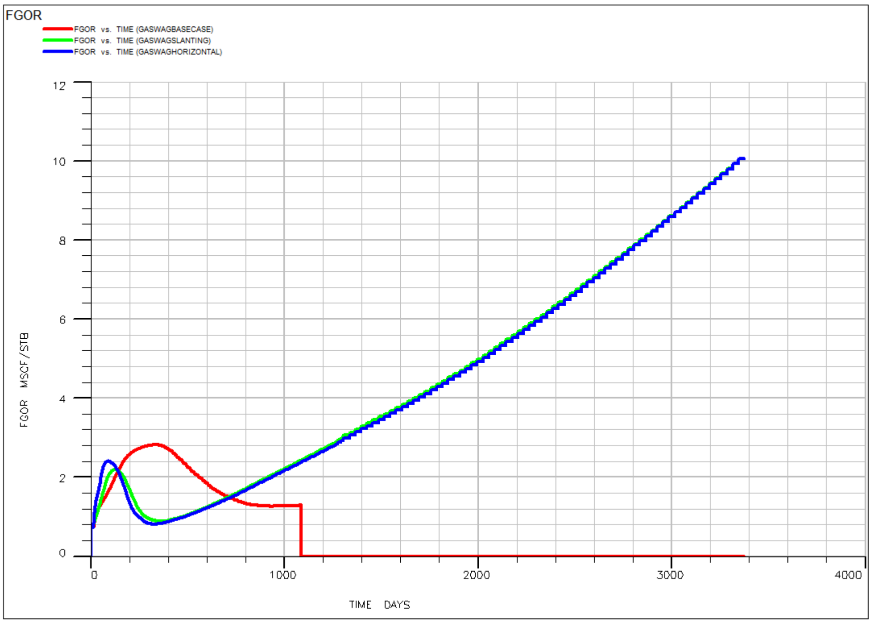

Figure 4.8 FGOR (Type of wells (producer))

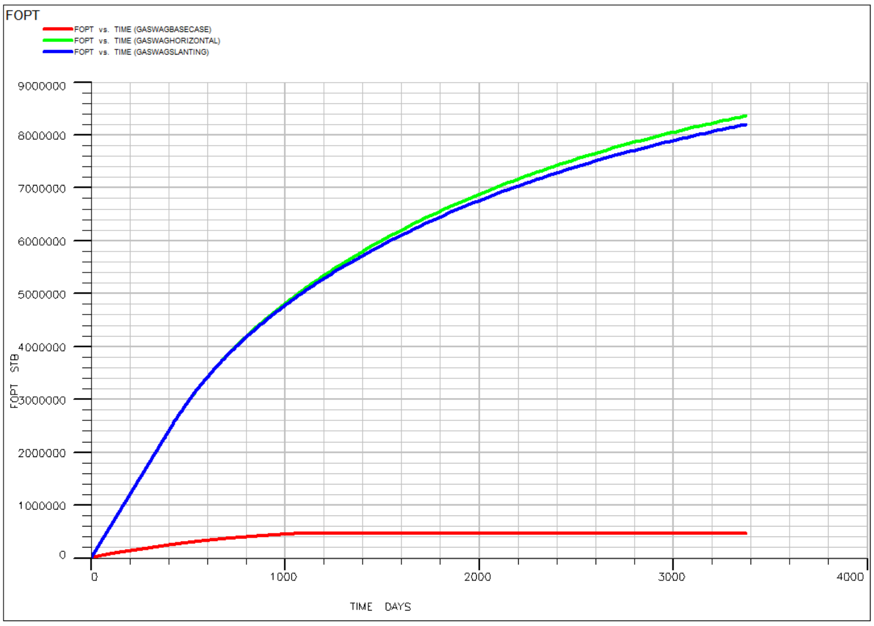

Figure 4.9 FOPT (Type of wells (producer))

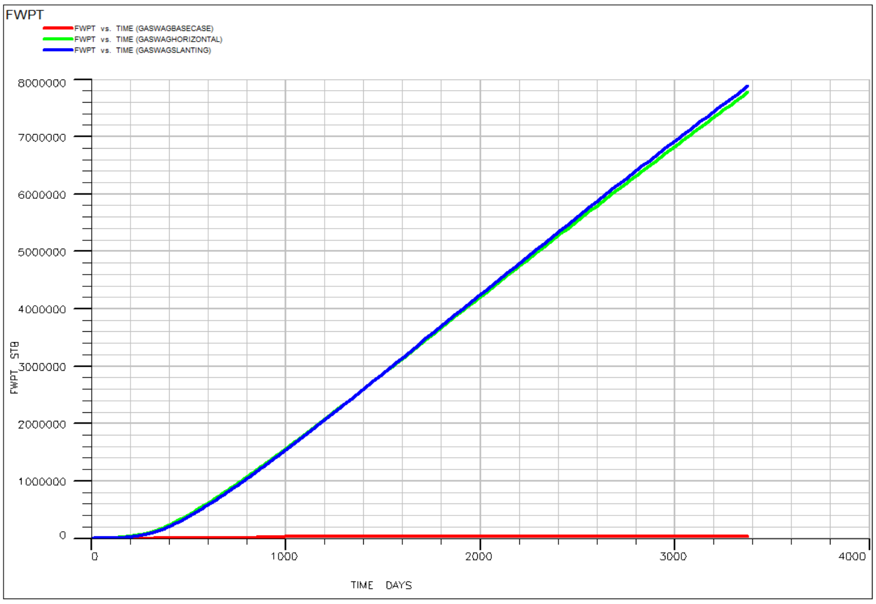

Figure 4.10 FWPT (Type of wells (producer))

Table 4.2 Table of Comparison (FGOR, FOPT, FWPT)

Type of GASWAG producer	FGOR (MSCF/STB)	FOPT (STB)	FWPT (STB)
Vertical (Basecase)	0	450000	0
Horizontal	10	8400000	7800000
Slanting	10	8200000	7900000

Table 4.3 Table of Analysis of Variance (ANOVA)

ANOVA : Single Factor

Summary

Groups	*Count*	*Sum*	*Average*	*Variance*	*Stn. Dev*	*maximum*	*minimum*
FGOR (MSCF/STB)	3	20	6.666667	33.33333	5.773503	12.44017	0.893164
FOPT (STB)	3	17050000	5683333	2.06E+13	4533303	10216636	1150031
FWPT (STB)	3	15700000	5233333	2.05E+13	4532475	9765809	700857.9

ANOVA

Source of Variation	*SS*	*df*	*MS*	*F*	*P-value*	*F crit*
Between Groups	5.99E+13	2	2.99E+13	2.186092	0.193572	2.129928
Within Groups	8.22E+13	6	1.37E+13			
Total	1.42E+14	8				

ANOVA analysis given the optimum value of FGOR, FOPT, FWPT to type of wells (producer) parameter.

From Figure 4.11, FGOR from horizontal and Slanting wells is the same and both of them below the maximum value of FGOR and above the minimum value of FGOR. Whereas, FGOR for vertical is 0.

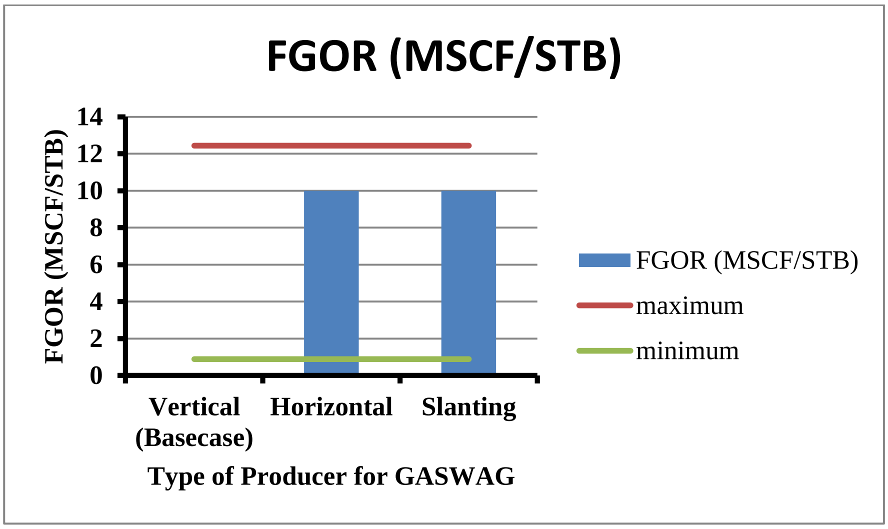

Figure 4.11 Analysis FGOR (Type of Well (producer))

Furthermore, FOPT for horizontal is higher 200000 STB than slanting well and both are in the optimum condition. Both of them have also been higher than vertical producing well (Figure 4.12)

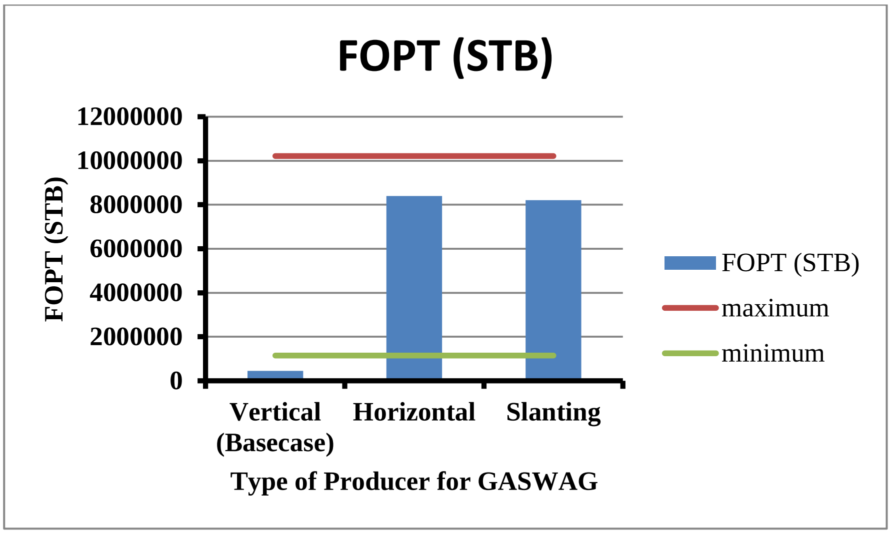

Figure 4.12 Analysis FOPT (Type of Well (producer))

In addition, Figure 4.13 shows the bar chart diagram for FWPT. FWPT for slanting producer well is worst compare that horizontal well, even though both of them in the optimum FWPT condition.

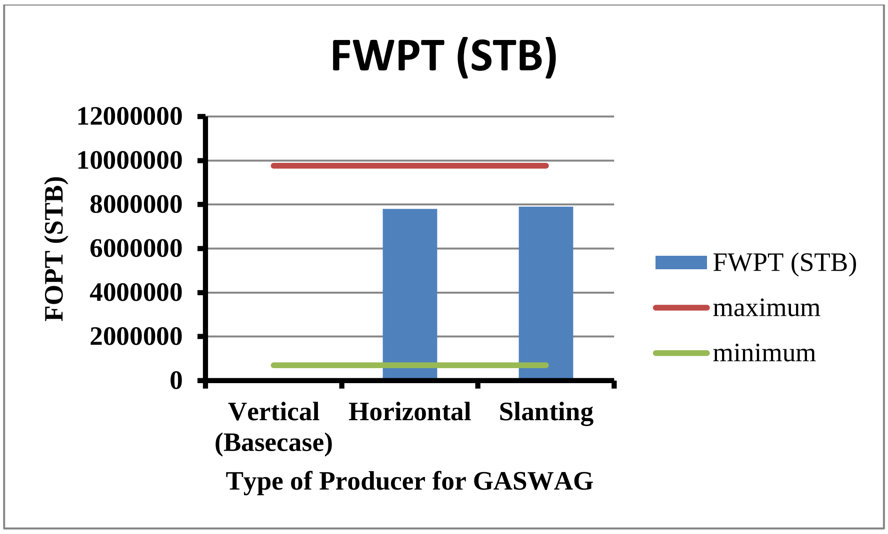

Figure 4.13 Analysis of FWPT (Type of Well (producer))

As a conclusion, GASWAG is preferable using horizontal producing well. This is because total oil production is higher and lower water coning.

4.4 Location Horizontal Well Producer

Table 4.4 Location of Horizontal Well Producer

Reservoir Model Layer	Indicators
4	Near Gas – Oil Contact (GOC)
7	Near Middle of Oil Column
8	Middle of Oil Column
9	Middle of Oil Column
10	Near Middle of Oil Column
11	Near Water – Oil Contact (WOC)

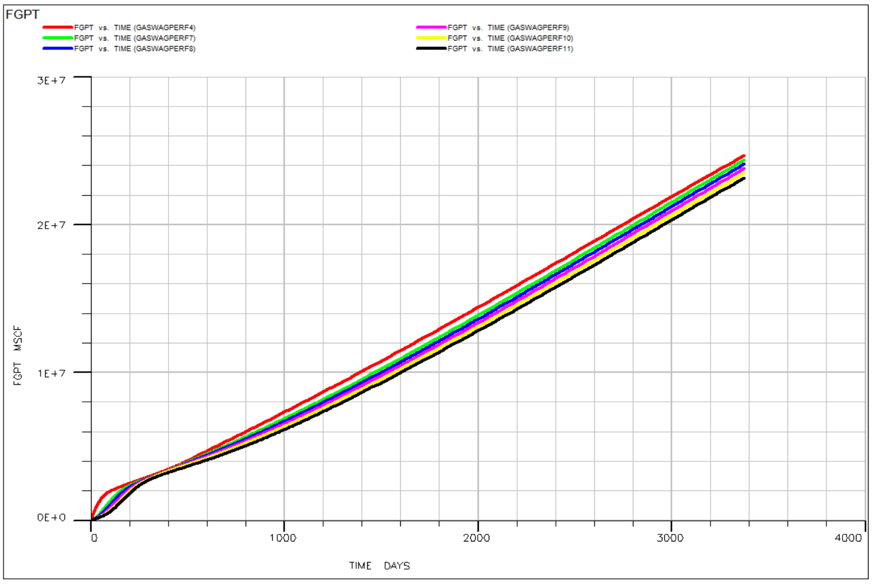

Figure 4.14 FGPT (Location of Horizontal Producer Well)

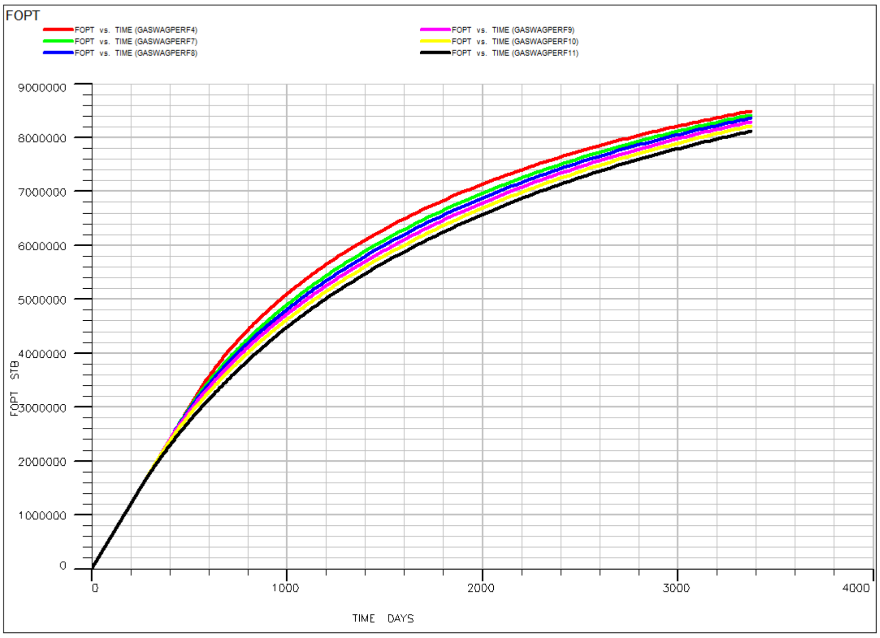

Figure 4.15 FOPT (Location of Horizontal Producer Well)

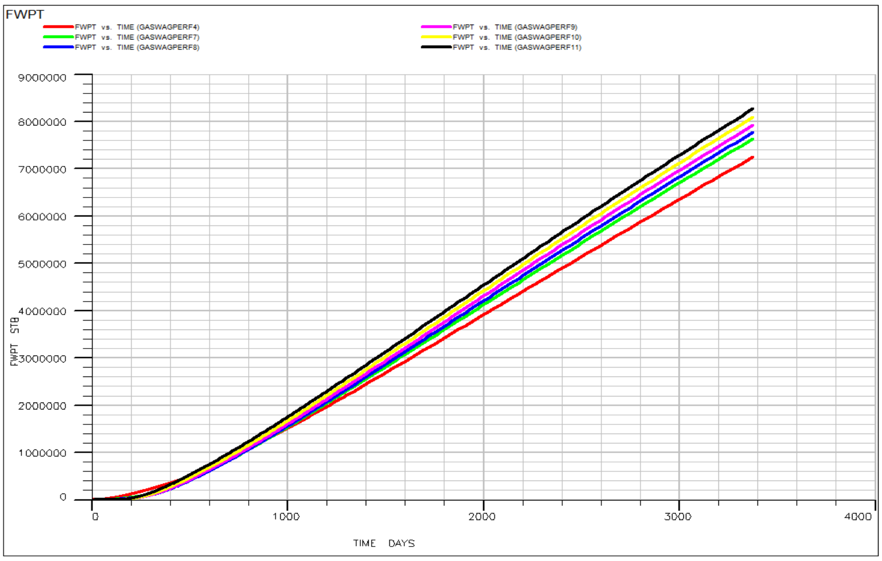

Figure 4.16 FWPT (Location of Horizontal Producer Well)

Table 4.5 Summary of Location of horizontal producing well

Location of horizontal producing well	FGPT (MSCF)	FOPT (STB)	FWPT (STB)
4 (Near Gas – Oil Contact (GOC))	24766978	8485372	7228723.5
7 (Near Middle of Oil Column)	24367510	8401596	7623670
8 (Middle of Oil Column)	24127830	8365691.5	7767287
9 (Middle of Oil Column)	23848202	8293883	7910904.5
10 (Near Middle of Oil Column)	23448736	8198138.5	8078457.5
11 (Near Water – Oil Contact (WOC))	23209054	8126330	8269947

Anova: Single Factor

SUMMARY

Table 4.6 ANOVA (location of horizontal producer well)

Groups	*Count*	*Sum*	*Average*	*Variance*	*Stnd. Dev.*	*Maximum*	*Minimum*
FGPT (MSCF)	6	1.44E +08	2396138 5	3.37E+11	5802 14.2	24541599	23381171
FOPT (STB)	6	49871 011	8311835	1.77E+10	1332 17.1	8445052	8178618
FWPT (STB)	6	46878 990	7813165	1.34E+11	3655 59.3	8178724	7447606

ANOVA

Source of Variation	*SS*	*df*	*MS*	*F*	*P-value*	*F crit*
Between Groups	1.01184E+15	2	5.06E+14	3109.992	2.29E-20	1.79516 8
Within Groups	2.44014E+12	15	1.63E+11			
Total	1.01428E+15	17				

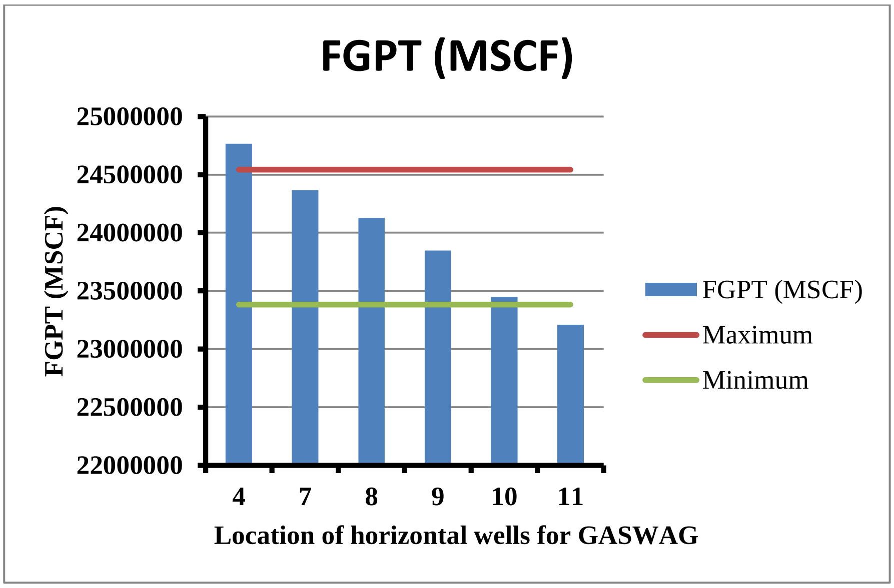

Figure 4.17 Analysis FGPT (location of horizontal producer well)

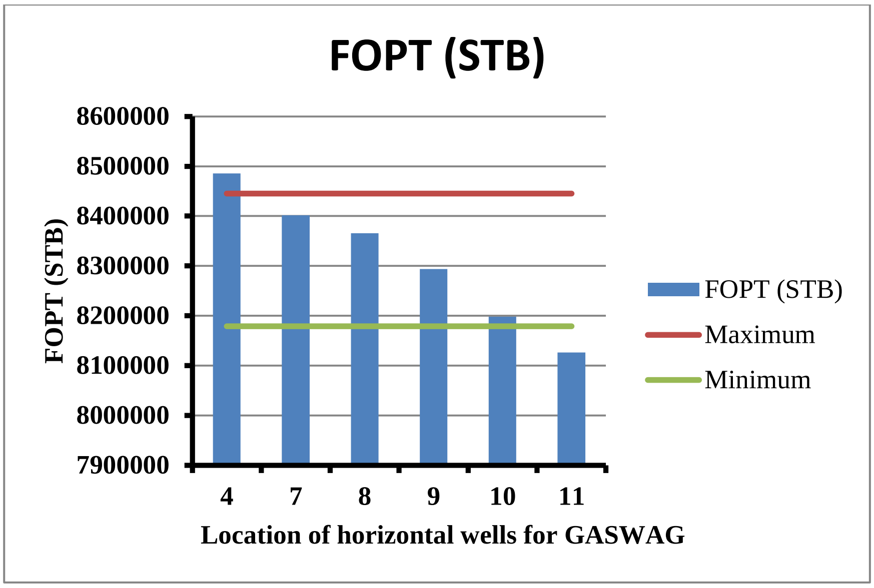

Figure 4.18 Analysis FOPT (location of horizontal producer well)

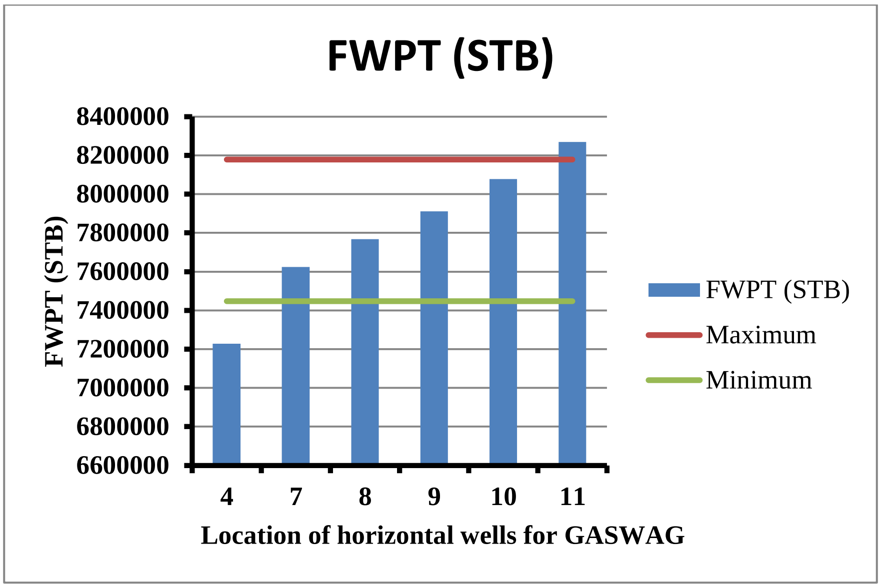

Figure 4.19 Analysis FWPT (location of horizontal producer well)

The graphs (Figure 4.17, Figure 4.18, Figure 4.19) show that the horizontal producer placed near the gas-oil-contact having maximum oil recovery and minimum water production. However, the gas production also maximum.

Meanwhile, the location of horizontal producer that placed near the water-oil-contact had minimum gas and oil production but give maximum water production.

The most favorable location is layer 8 for this model, which is in the middle of oil zone that can avoid early water and gas coning. In layer 8, gas, oil and water production is optimum.

4.5 Salinity

We assume that the model having 35 000 ppm (12.47 lb/STB) which is the same as sea water. A few different brine salinity was injected in the gas cap; 0.1 lb/STB, 0.5 lb/STB, 1 lb/STB, 5 lb/STB, 10 lb/STB, 12.47 lb/STB, 15 lb/STB and 20 lb/STB

Graph FGOR (Figure 4.20),FOPT (Figure 4.21), FWPT (Figure 4.22) show that the salinity did increase the oil production, but Gas – Oil ratio and water production also increased.

However, the increased FOE and FOPT is only a small value and FWPT is higher, so this parameter is insignificant, but if we consider the injection rate (increase the injection rate). The FOE and FOPT change will be increased.

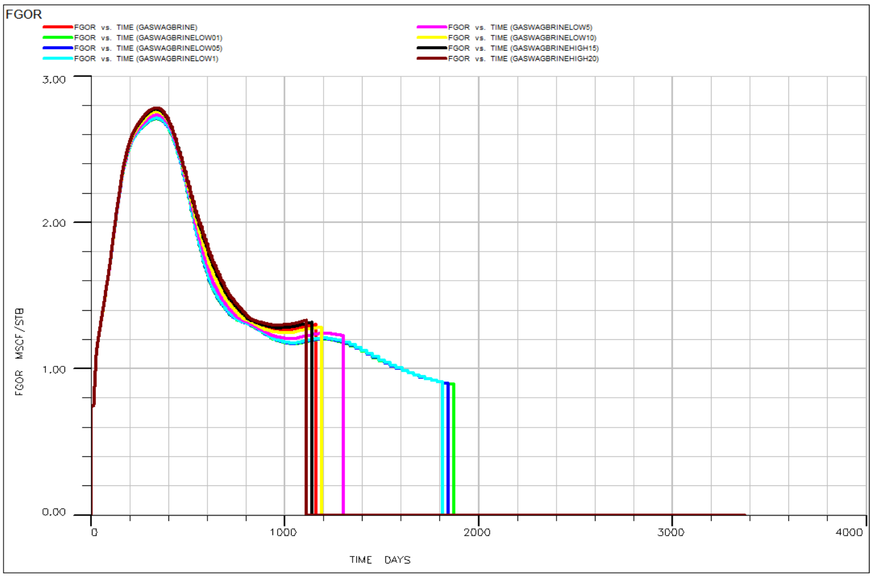

Figure 4.20 FGOR (Salinity)

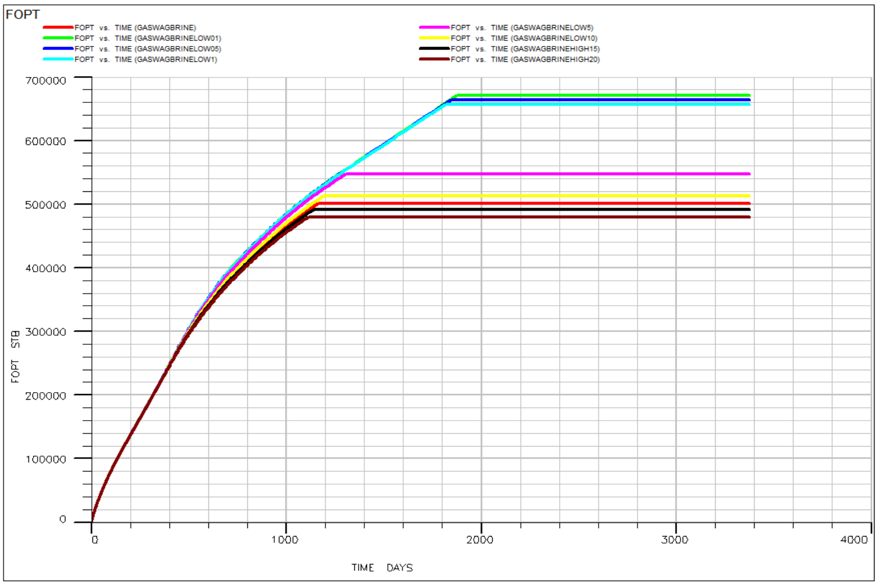

Figure 4.21 FOPT (Salinity)

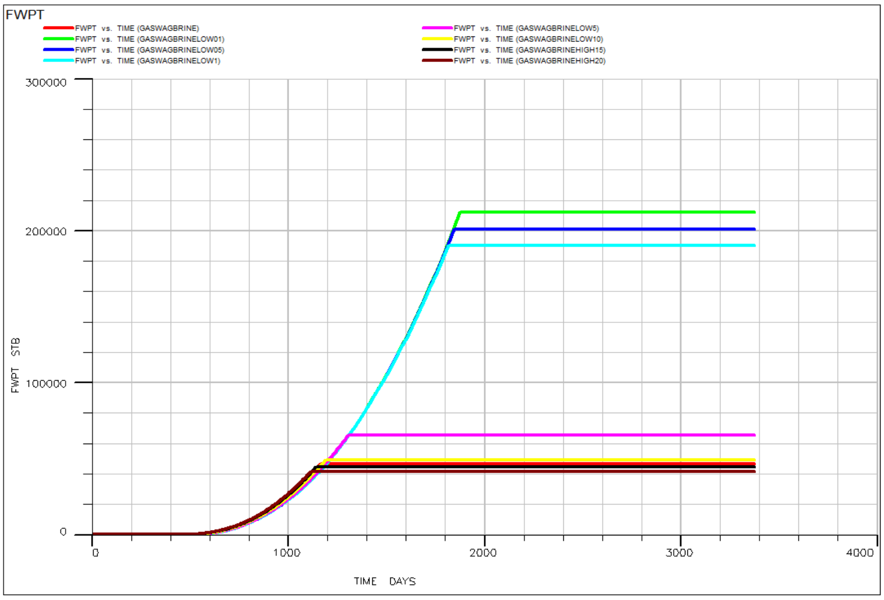

Figure 4.22 FWPT (Salinity)

4.5.1 Recovery factors

Lowering the salinity of brine injection, increased the oil recovery factor for the GASWAG process. The table below (Table 4.7) shows the result of increase FOE. Then, next table (Table 4.8) is explained how fit the data to the model. R^2 = 0.866037 nearest to 1. It shows that all the FOE data is around its average mean and generated nearest fit plot.

Table 4.7 Table of FIT FOE

Salinity of Brine Injection (lb/STB)	FOE	FOE fit
0.1	1.90	1.833729
0.5	1.88	1.821945
1	1.86	1.807216
5	1.55	1.689383
10	1.46	1.542092
12.26775 (Sea water)	1.42	1.475288
15	1.39	1.3948
20	1.36	1.247509

Table 4.8 Table of LINEST Analysis

Slope	-0.02946	Intercept	1.836674
Error of slope ∓	0.00473	Error of intercept ∓	0.050218
Uncertainty in the Slope	16.06%	Uncertainty in the intercept	2.73%
r2	0.866037	s(y)	0.093633
F	38.78839	Degree of freedom	6
Regression ss	0.340062	residual ss	0.052603

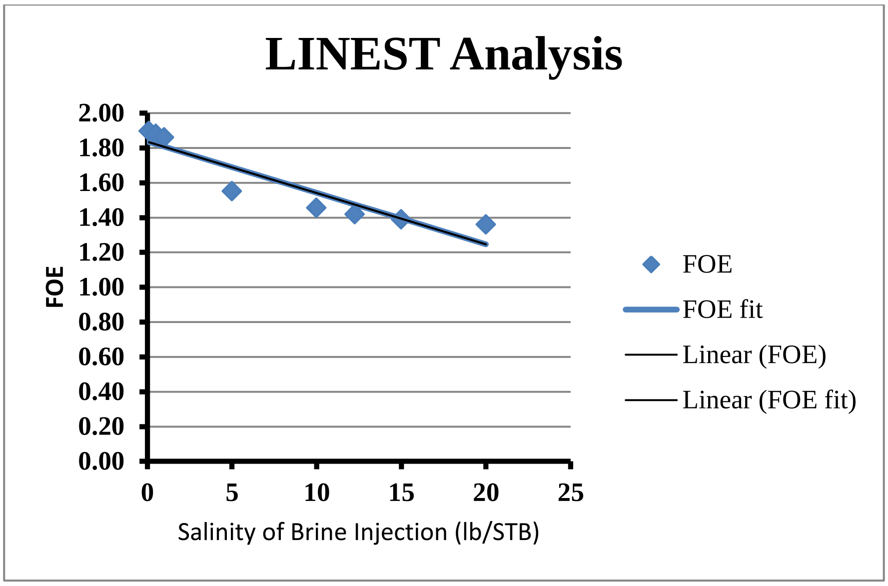

Figure 4.23 Graph of Fit FOE (Salinity)

4.6 Mobility Ratio (Polymer)

Alteration of mobility ratio was made in term of water viscosity. By increasing the viscosity of water the mobility ratio is reduced. Low mobility ratio is favorable. By adding polymer to water injection, the viscosity of water will increase. Diagram below (Figure 4.24) shows that the oil was totally swept away by polymer water injection in the gas-cap compared to the base case.

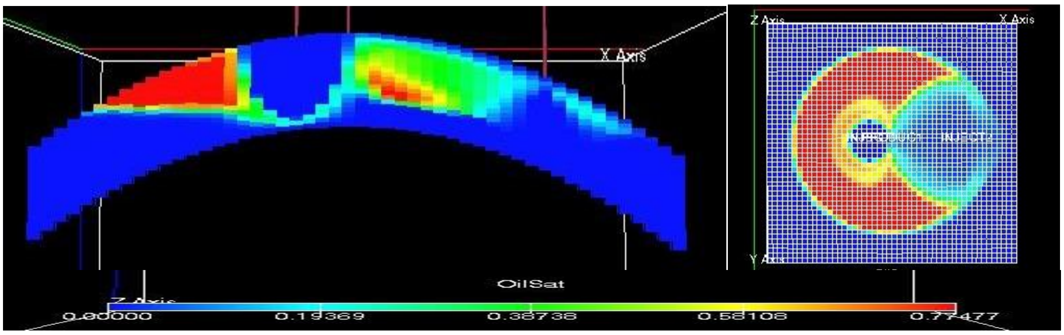

Figure 4.24 Oil recovery by water injection with polymer (Topview and Sideview)

The figures below (Figure 4.25, Figure 4.26, Figure 4.27) show the difference of FGOR, FOPT, FWPT respectively, for water injection without polymer and water injection with polymer in the gas-cap in GASWAG process

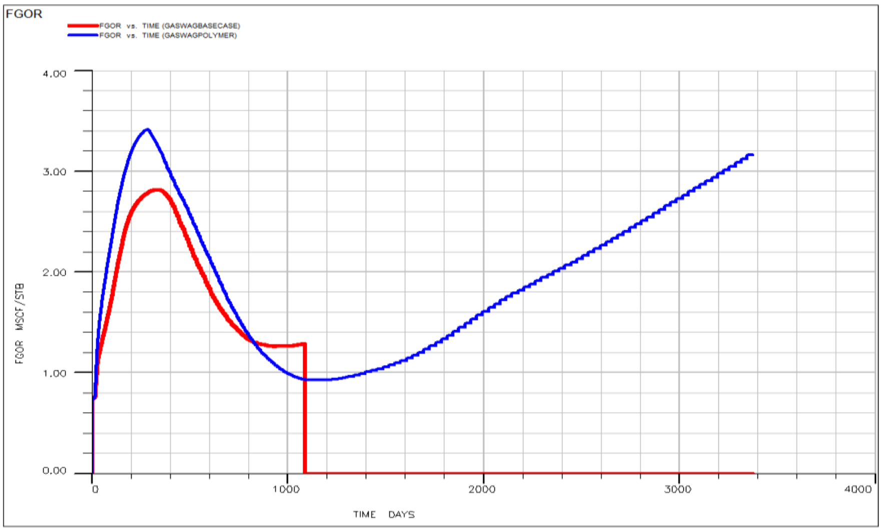

Figure 4.25 FGOR (Polymer)

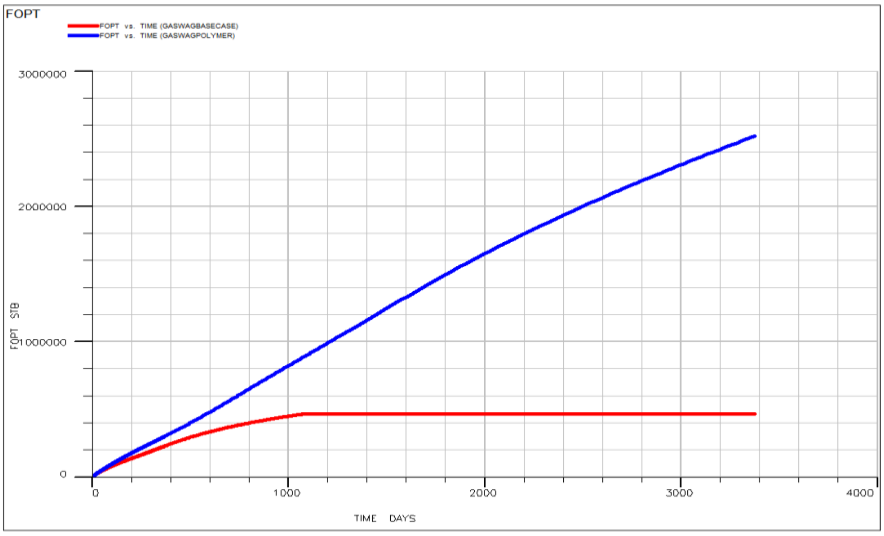

Figure 4.26 FOPT (Polymer)

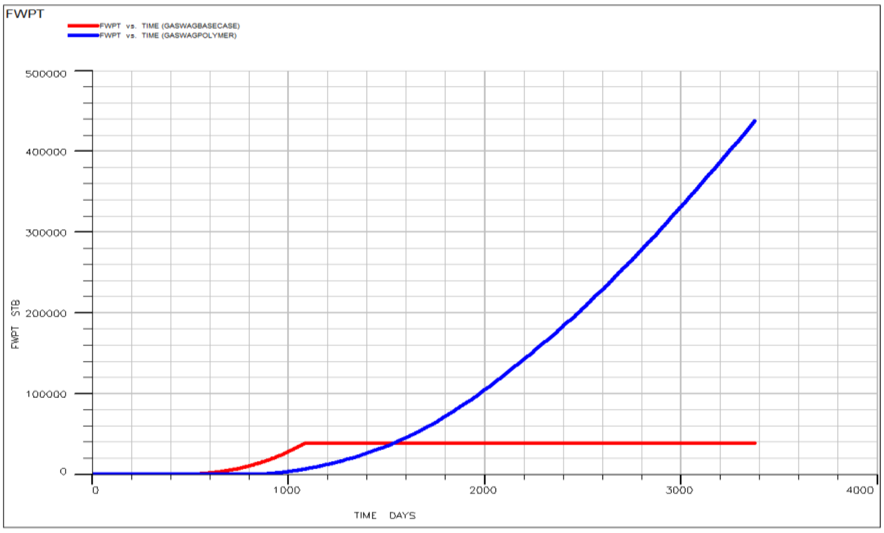

Figure 4.27 FWPT (Polymer)

Table 4.9 Summary table of water injection in the gas-cap with and without polymer

Water Injection	Without Polymer	With Polymer
FGOR (MSCF/STB)	0	3.2
FOPT (STB)	450000	2500000
FWPT (STB)	40000	440000

The generated result shown that there is a significant increase in the oil production (Table 4.9)

4.7 Injection Rate

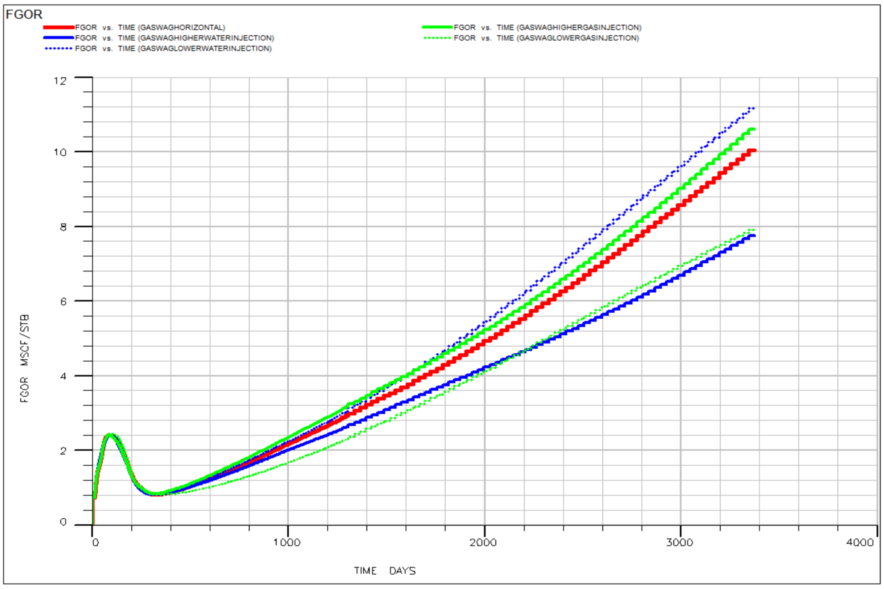

Figure 4.28 FGOR (Injection Rate)

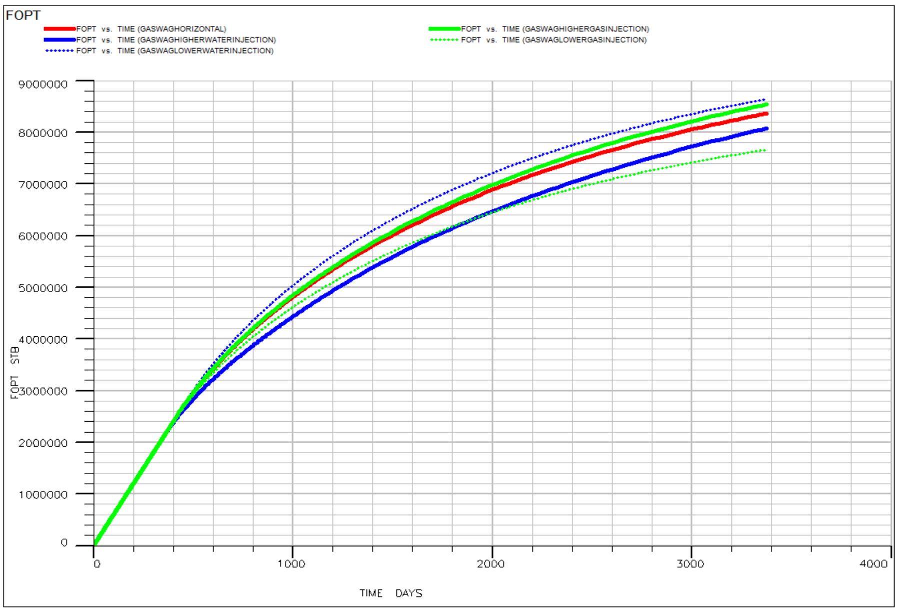

Figure 4.29 FOPT (Injection Rate)

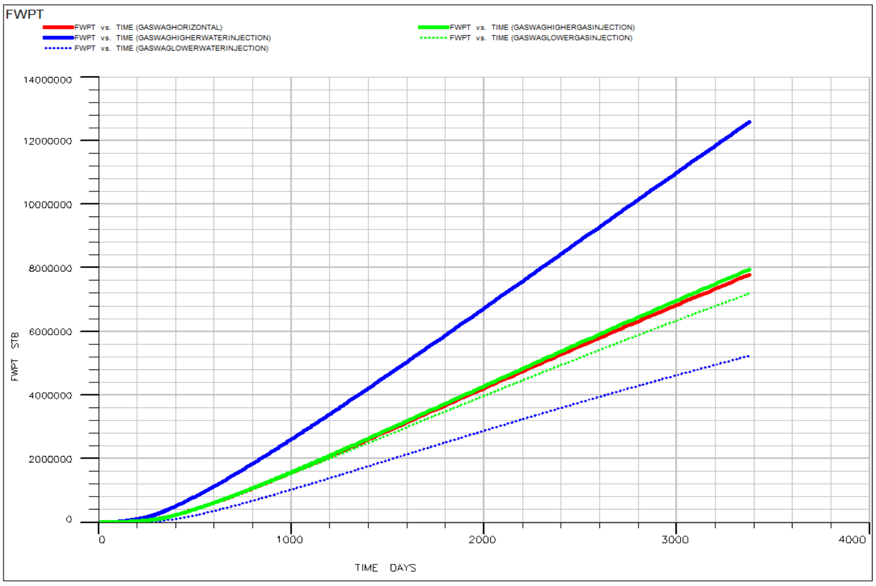

Figure 4.30 FWPT (Injection Rate)

Table 4.10 Summary table of water injection rate in the gas-cap

	Base Case (Horizontal producer well)	Water Injection Rate (STB/Day)		Gas Injection Rate (MSCF/Day)	
		Lower	Higher	Lower	Higher
FGOR (MSCF/STB)	10	11.2	7.8	8	10.8
FOPT (STB)	8400000	8600000	8100000	7600000	8500000
FWPT (STB)	7800000	5200000	12600000	6200000	8000000

Result shown that, for water injection, lower water injection is preferable. This is because the lower water injection rate gives higher oil production and also lower water production. The reasons are higher injection rate can overcome the gravity effect and displaces the gas in the gas-cap. In GASWAG, We need that gravity. Hence, the result of the low water injection is more favorable.

This is different to the gas injection case. The result proved that the higher gas injection rate is better that lower gas injection in term of oil production. The explanation is because of the higher injection rate of gas will reduce the time contact between water, rock and gas. Thus, it reduced the rock dissolution and have high reservoir permeability. However, gas-oil-ratio and water production also higher.

4.8 Case Study

Water Injector		Oil Producer		Gas Injector	

Figure 4.31 Indicators

i) Case 1

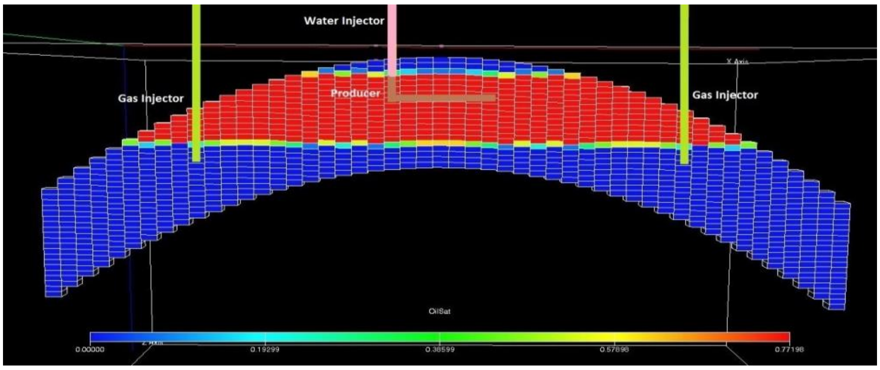

Figure 4.32 2 gas injectors in aquifer. 1 well as water injector in gas cap and as horizontal production well. (3 wells)

ii) Case 2

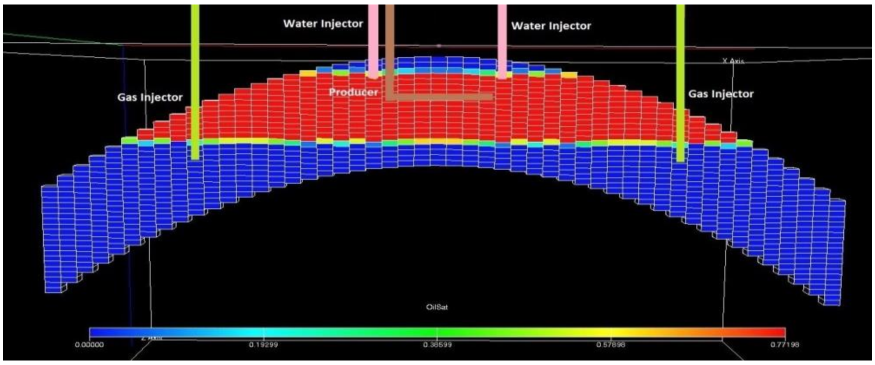

Figure 4.33 2 gas injectors in aquifer, 2 water injectors in gas cap and 1 horizontal production well. (5 wells)

iii) Case 3

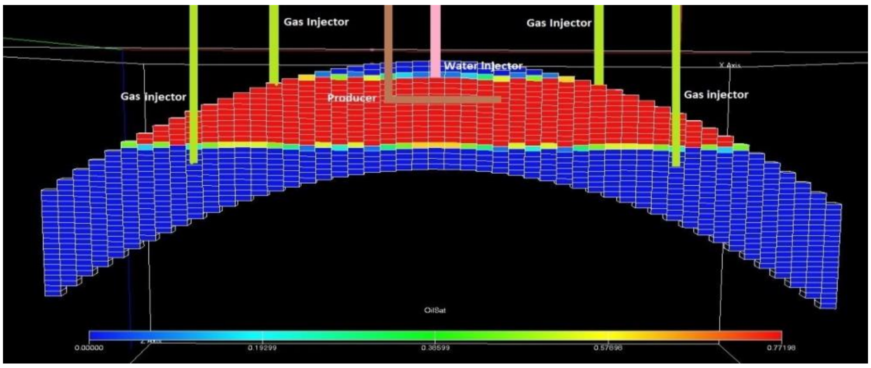

Figure 4.34 4 gas injectors in aquifer, 1 water injection in the middle of gas cap and 1 horizontal production well (6 wells)

iv) Case 4

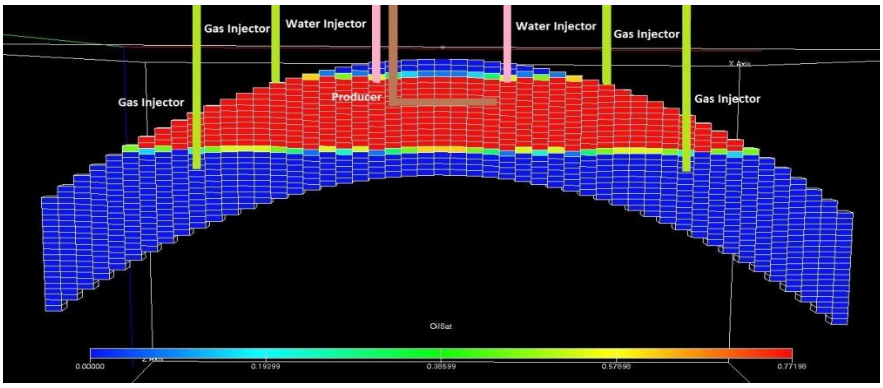

Figure 4.35 4 gas injectors in aquifer, 2 water injectors in the gas cap and 1 horizontal production well. (7 wells)

v) Case 5

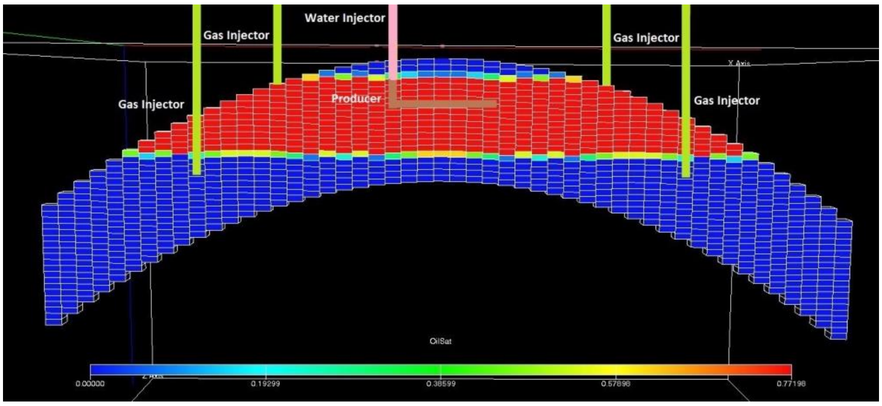

Figure 4.36 4 gas injectors in aquifer, 1 well as water injector in the gas cap and as horizontal production well (5 wells)

vi) Case 6

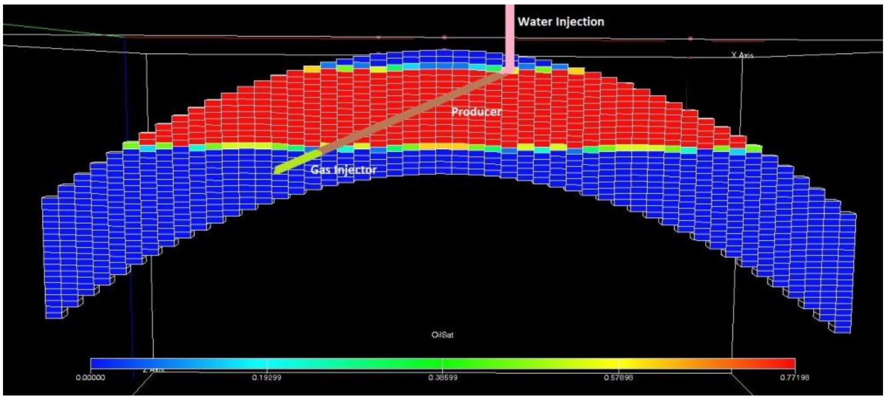

Figure 4.37 Injector and producer in 1 well (Slanting Well)

vii) Case 7

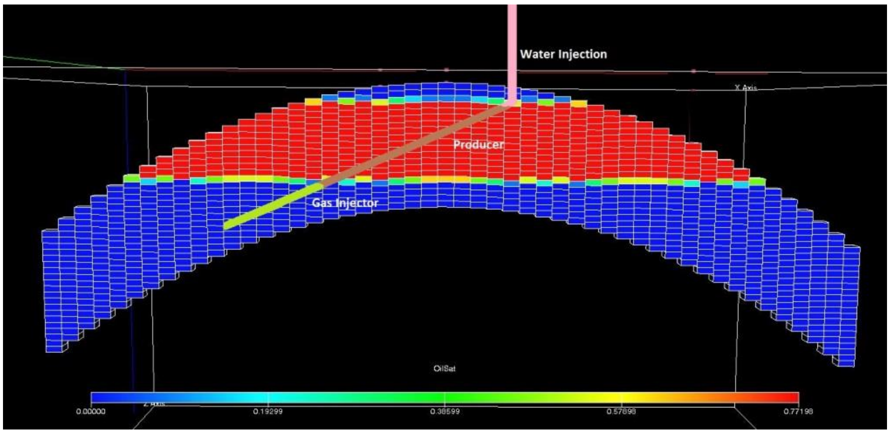

Figure 4.38 Case 7 : Extended Slanting Well

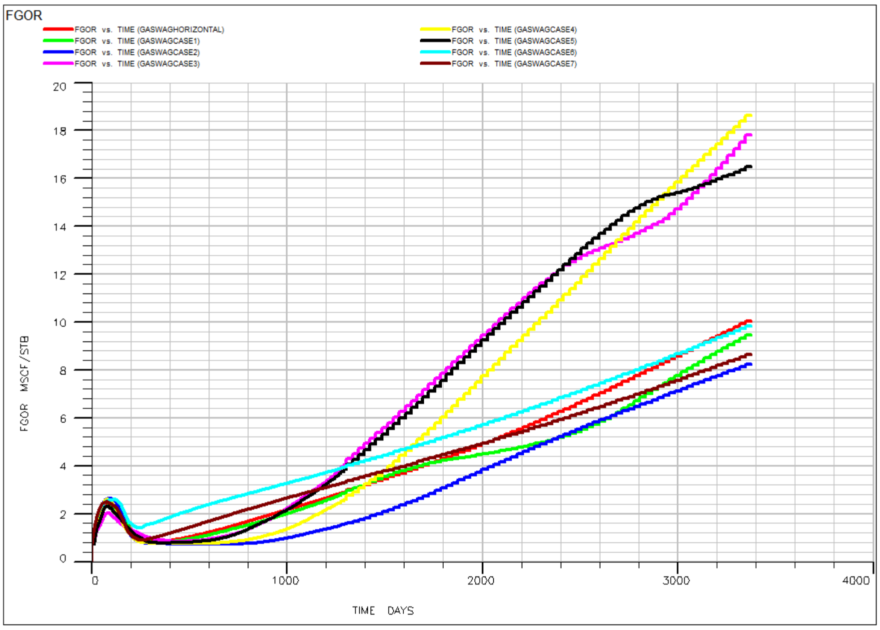

Figure 4.39 FGOR (Case Study)

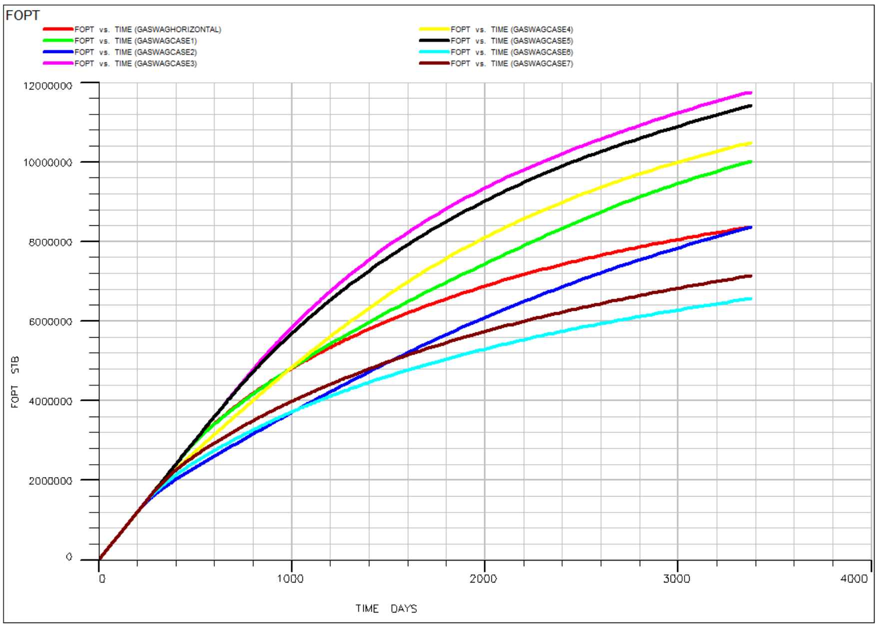

Figure 4.40 FOPT (Case Study)

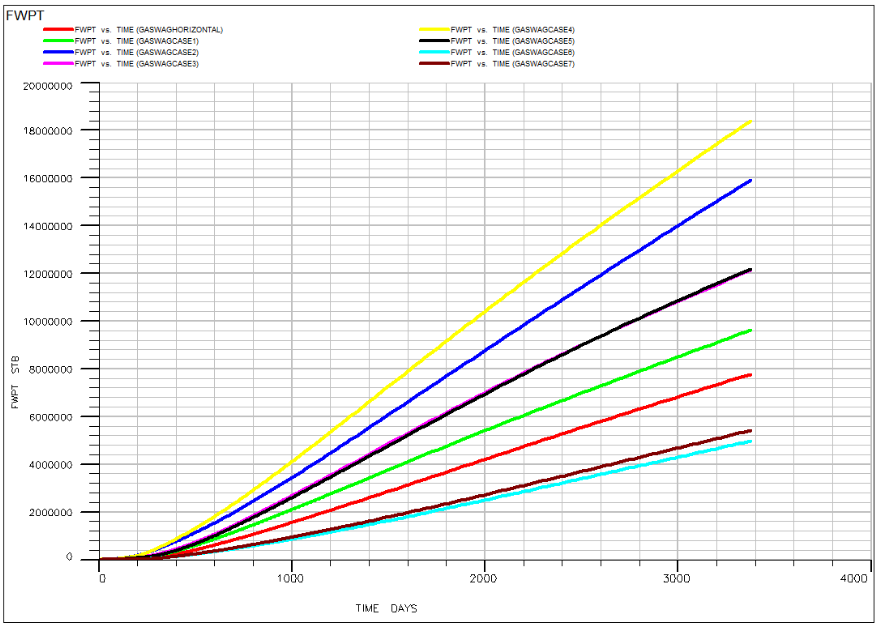

Figure 4.41 FWPT (Case Study)

Table 4.11 Summary of Cases

Cases	FGOR (MSCF/STB)	FOPT (STB)	FWPT (STB)
1	9.5	1.00E+07	9.67E+06
2	8.27	8.37E+06	1.60E+07
3	17.9	1.18E+07	1.20E+07
4	18.7	1.04E+07	1.85E+07
5	16.5	1.13E+07	1.23E+07
6	9.83	6.54E+06	4.97E+06
7	8.63	7.14E+06	5.47E+06

ANOVA : Single Factor

Summary

Table 4.12 ANOVA Analysis (Cases)

Groups	*Count*	*Sum*	*Average*	*Variance*	*Stnd. Dev*	*Maximum*	*Minimum*
FGOR (MSCF/STB)	7	89.33	12.76143	22.02005	4.692552	17.45398	8.068876
FOPT (STB)	7	65550000	9364286	4.18E+12	2044063	11408349	7320222
FWPT (STB)	7	78910000	11272857	2.54E+13	5035367	16308224	6237490

ANOVA

Source of Variation	*SS*	*df*	*MS*	*F*	*P-value*	*F crit*
Between Groups	5.1E+14	2	2.55E+14	25.88391	5.06E-06	1.762319
Within Groups	1.77E+14	18	9.84E+12			
Total	6.87E+14	20				

Figure 4.42 indicates that all of the cases above the minimum value of FGOR. Only case 3 and case 4 is above maximum FGOR.

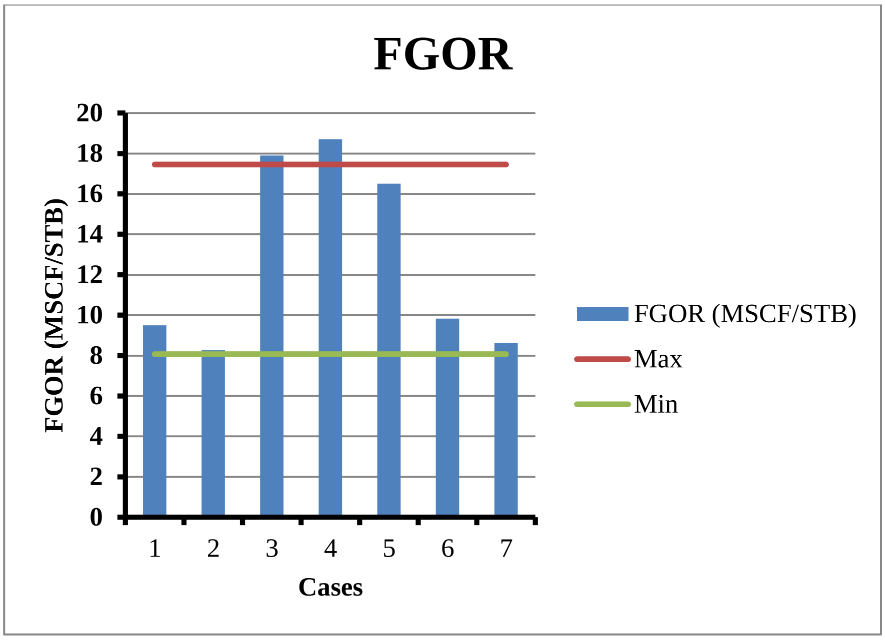

Figure 4.42 Analysis FGOR (Cases)

However, Figure 4.43 shows that only case 3 having maximum oil production and case 5 is closest to the maximum oil production where as, case 6 and 7 having lowest oil recovery.

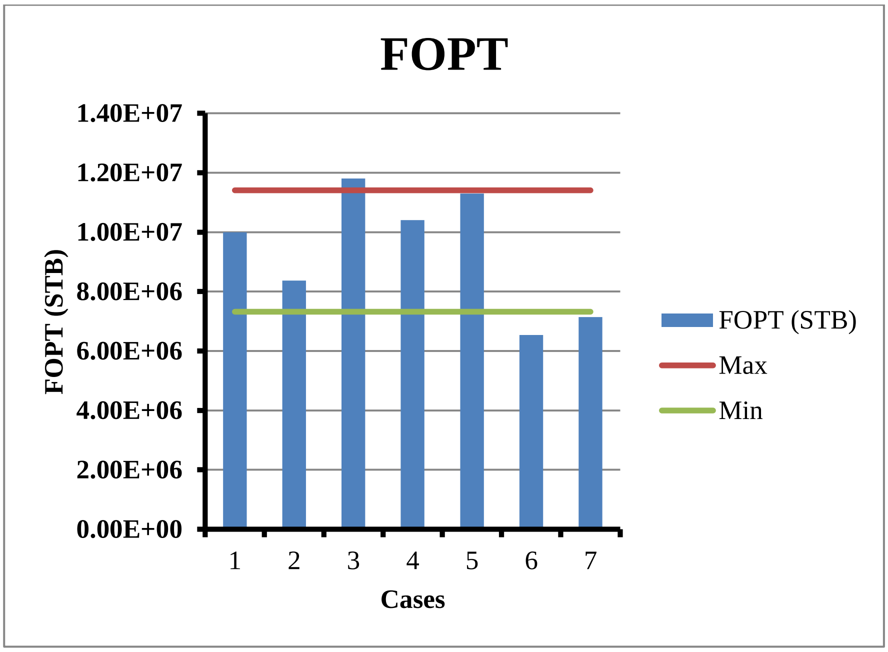

Figure 4.43 Analysis FOPT (Cases)

Next, for water production, Case 4 having highest water production followed by case 2. Case 6 and case 7 is produced minimum water production. Meanwhile, case 1, 2 and 5 is produced optimum water production (Figure 4.44).

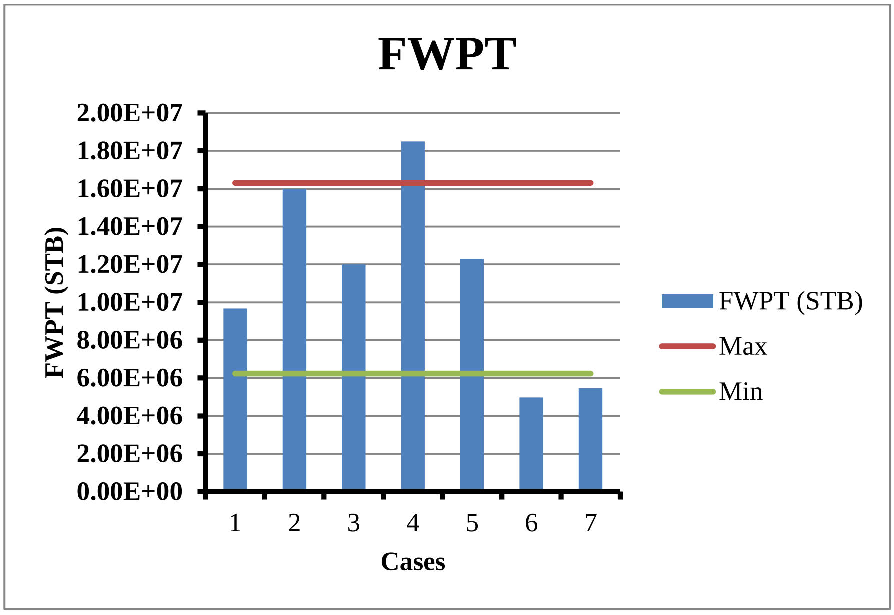

Figure 4.44 Analysis FWPT (Cases)

In a nutshell, case 3 and case 5 was chosen as the best case. The difference between these two cases is the location of water injector in the gas-cap. Case 3 water injector was placed in the middle of the gas-cap, thus the water displacement is uniform compare to case five where the water injector at the left-side of the gas-cap which is the water movement is unbalance.(Figure 4.45 and Figure 4.46)

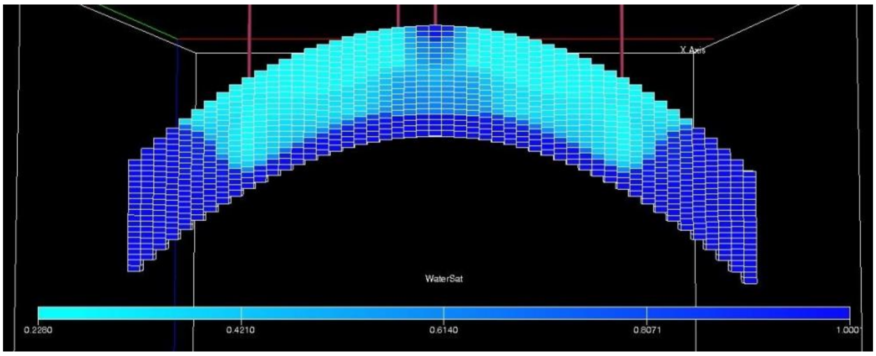

Figure 4.45 Movement water saturation (Case 3)

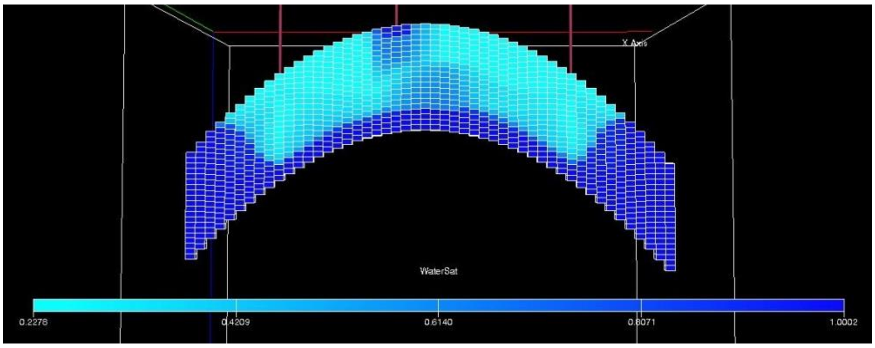

Figure 4.46 Movement water saturation (Case 5)

4.8.1 Economy Analysis

Meanwhile case 3 having 6 wells and case 5 having 5 wells. According to oil price nowadays, which is approximately around $66 per barrel, the different of oil production between case 3 and case 5 is 0.5M STB. 0.5M STB x $66 = $33,000,000.00 ($33M). If the price for vertical water injector well ≅ $1M – $15M. $33M-$15M = **$18M**. Case 3 profit still $18M higher that case 5. Hence, Case 3 is most favorable.

4.8.2 Case 3

Case 3 was selected to undergo further simulation for the salinity and water-polymer injection.

4.8.2.1 Case 3: Salinity

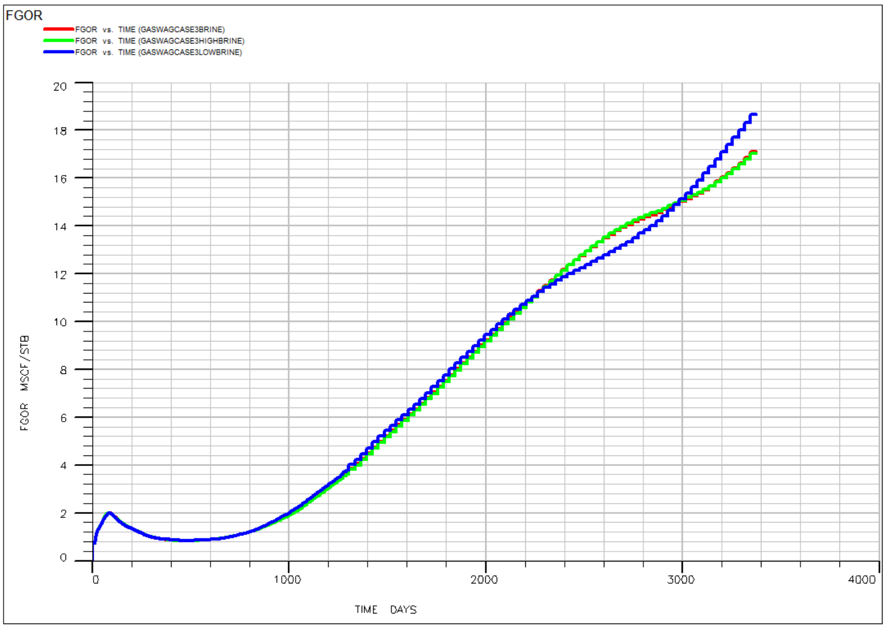

Figure 4.47 FGOR (Case 3: Salinity)

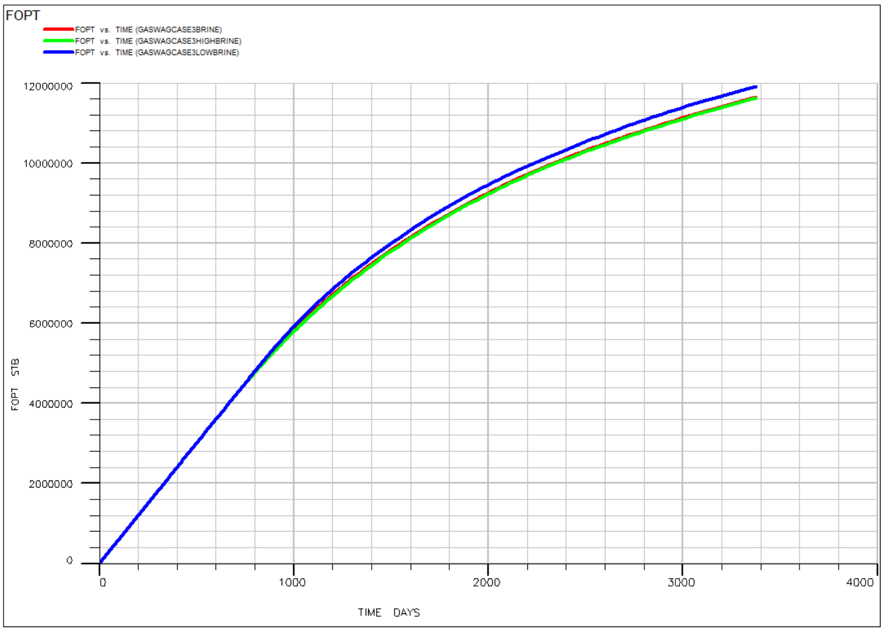

Figure 4.48 FOPT (Case 3: Salinity)

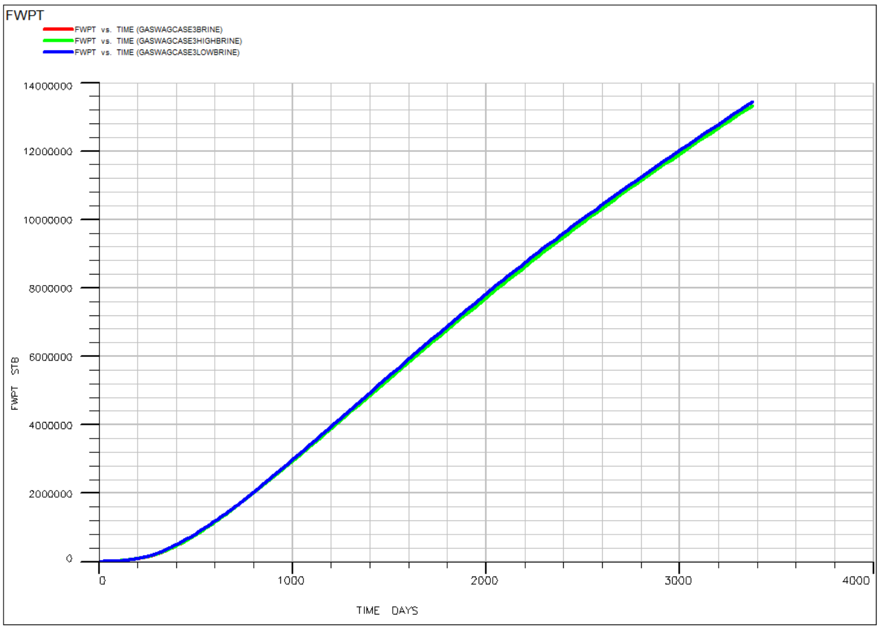

Figure 4.49 FWPT (Case 3: Salinity)

According to Figure 4.47, Figure 4.48 and Figure 4.49 the salinity changes for case 3 is insignificant.

4.8.2.2 Case 3 : Polymer

The presence of polymer in the case 3 give the excellent effect. The FGOR was decreased (Figure 4.50). Significantly increased the oil production (Figure 4.51). Declining of water production (Figure 4.52).

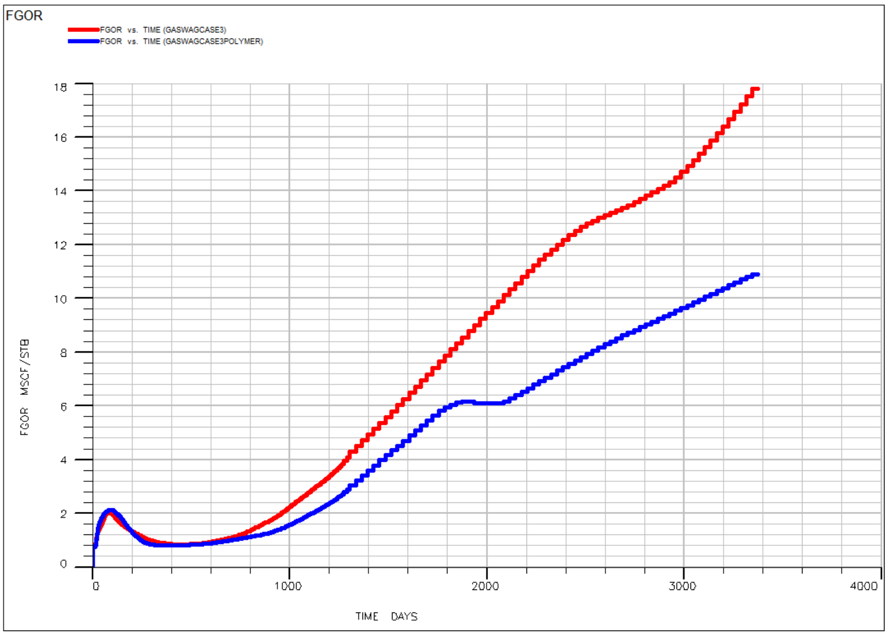

Figure 4.50 FGOR (Case 3 : Polymer)

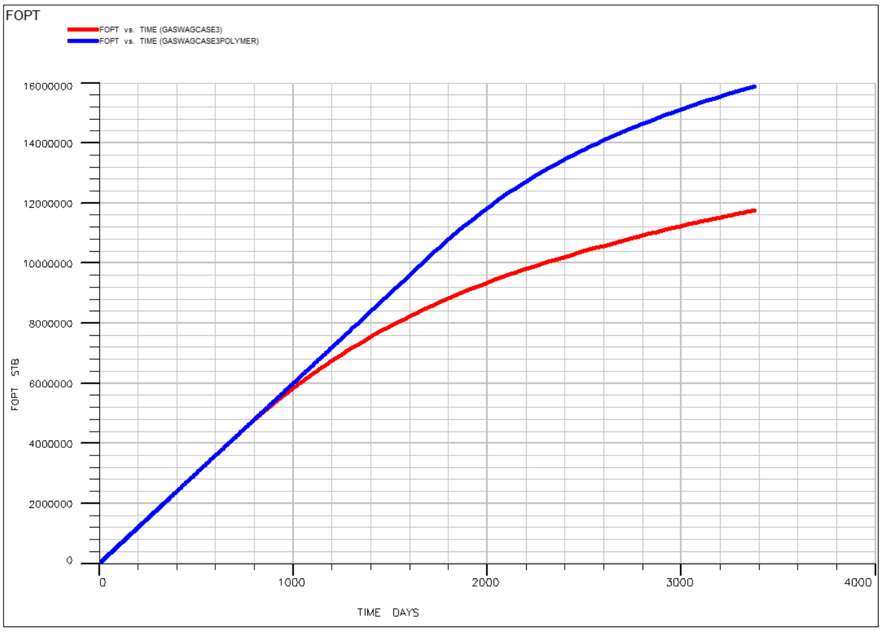

Figure 4.51 FOPT (Case 3 : Polymer)

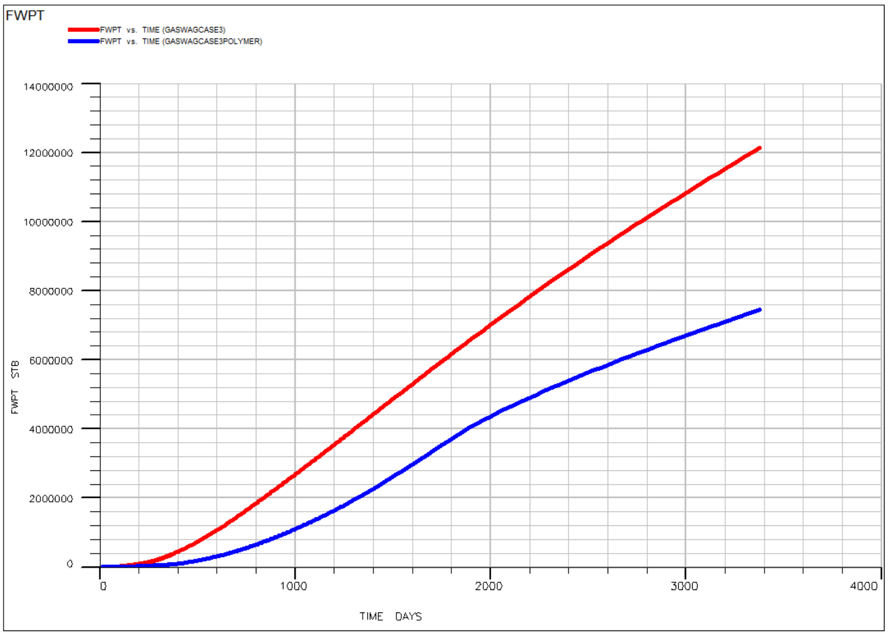

Figure 4.52 FWPT (Case 3 : Polymer)

Figure 4.53 shows the oil saturation after nine years of production without and with polymer in water injection in the gas-cap respectively.

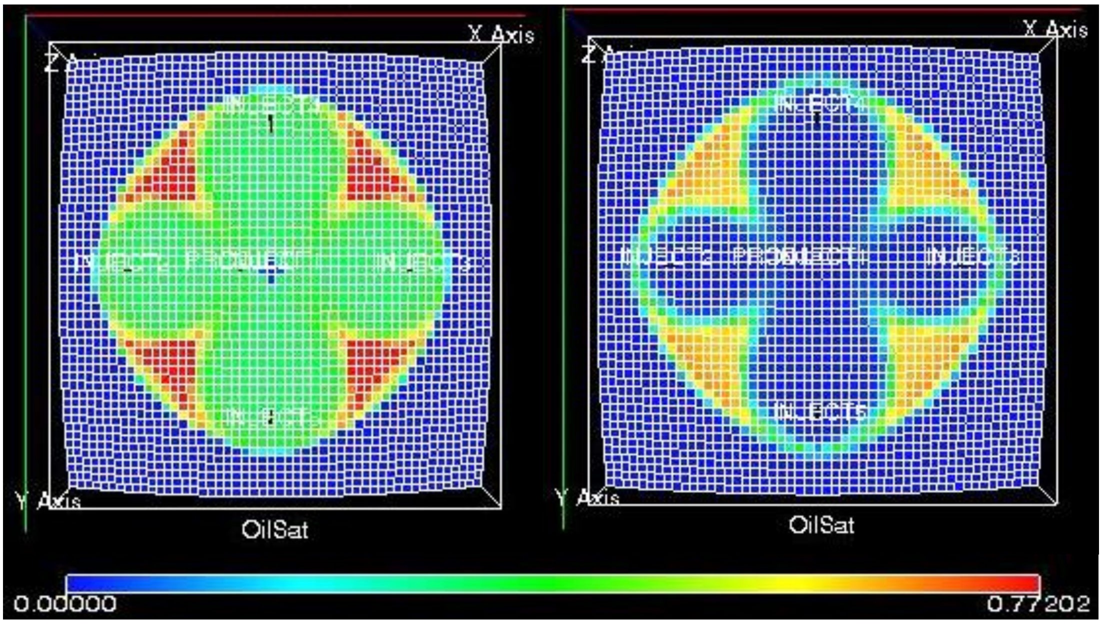

Figure 4.53 Oil displacement without (left) and with polymer (right)

CHAPTER 5

5.0 CONCLUSION AND RECOMMENDATION

5.1 Conclusions

GASWAG process required low water injection rate and high gas injection rate with horizontal producer well in the middle of the oil column. The presence of polymer in the water injection at the gas-cap give favorable result. Then, the salinity of brine injection did increase the oil production, but it is an insignificant change in GASWAG process.

As a conclusion, the objective (section 1.3.1) of this study is achieved.

5.2 Recommendations

This model is an anticline homogeneous model. Anticline and homogeneous reservoir literally difficult to obtain. As a recommendation, this study should continue with the heterogeneous reservoir model. Furthermore, Fluid properties study also important such as the composition of the water injection, oil and gas injection.

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7.0 APPENDICES

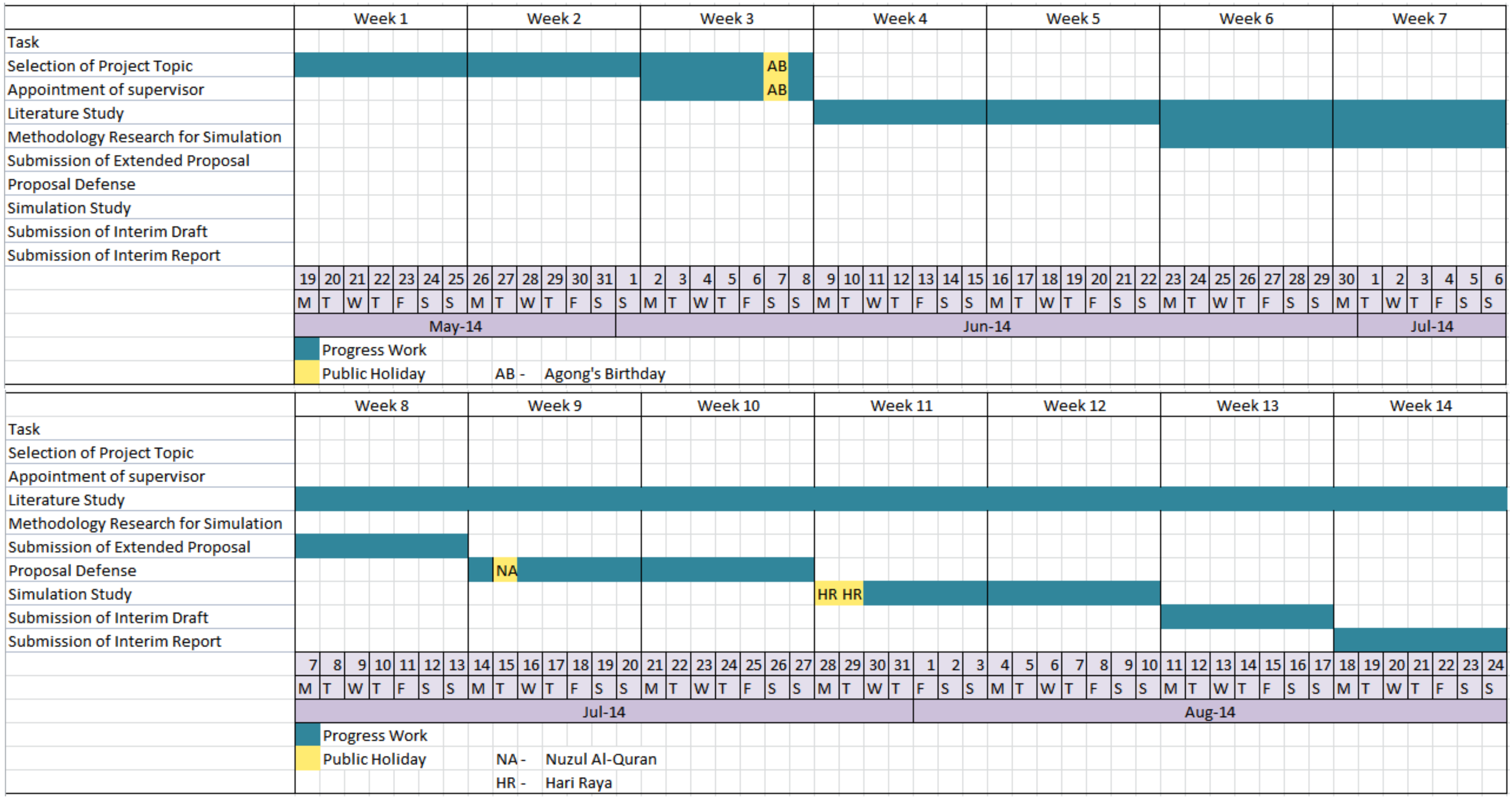

Figure 7.1 Gantt chart of FYP I

Table 7.1 Key Project Milestone FYP I

Key Project Milestone FYP I	
Title Selection	Week 2
Literature review	Week 4
Recognizing parameters	Week 5
Extended Proposal Submitted	Week 8
Proposal Defense	Week 10
Simulation study	Week 11
Submission of Interim Report	Week 14

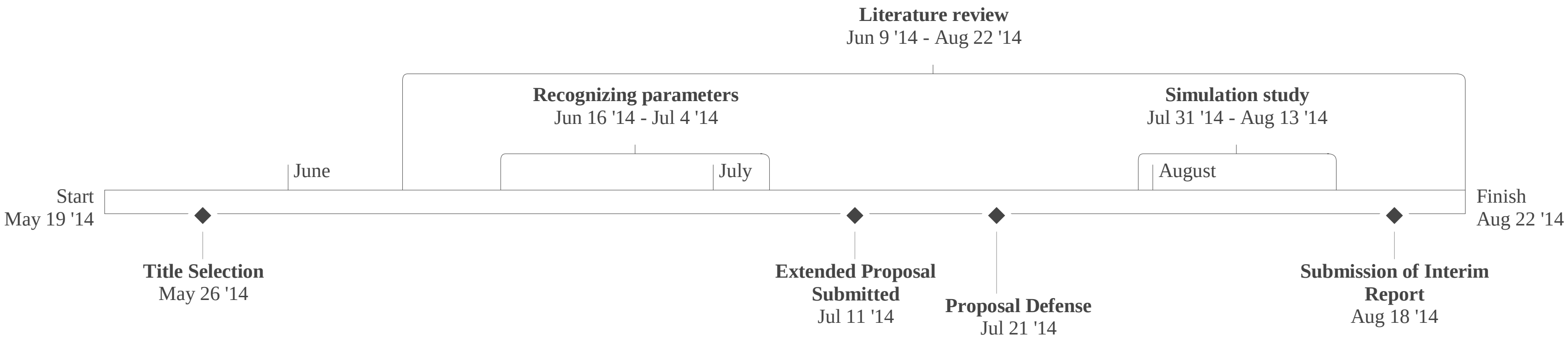

Figure 7.2 Milestone of FYP I by Microsoft Project

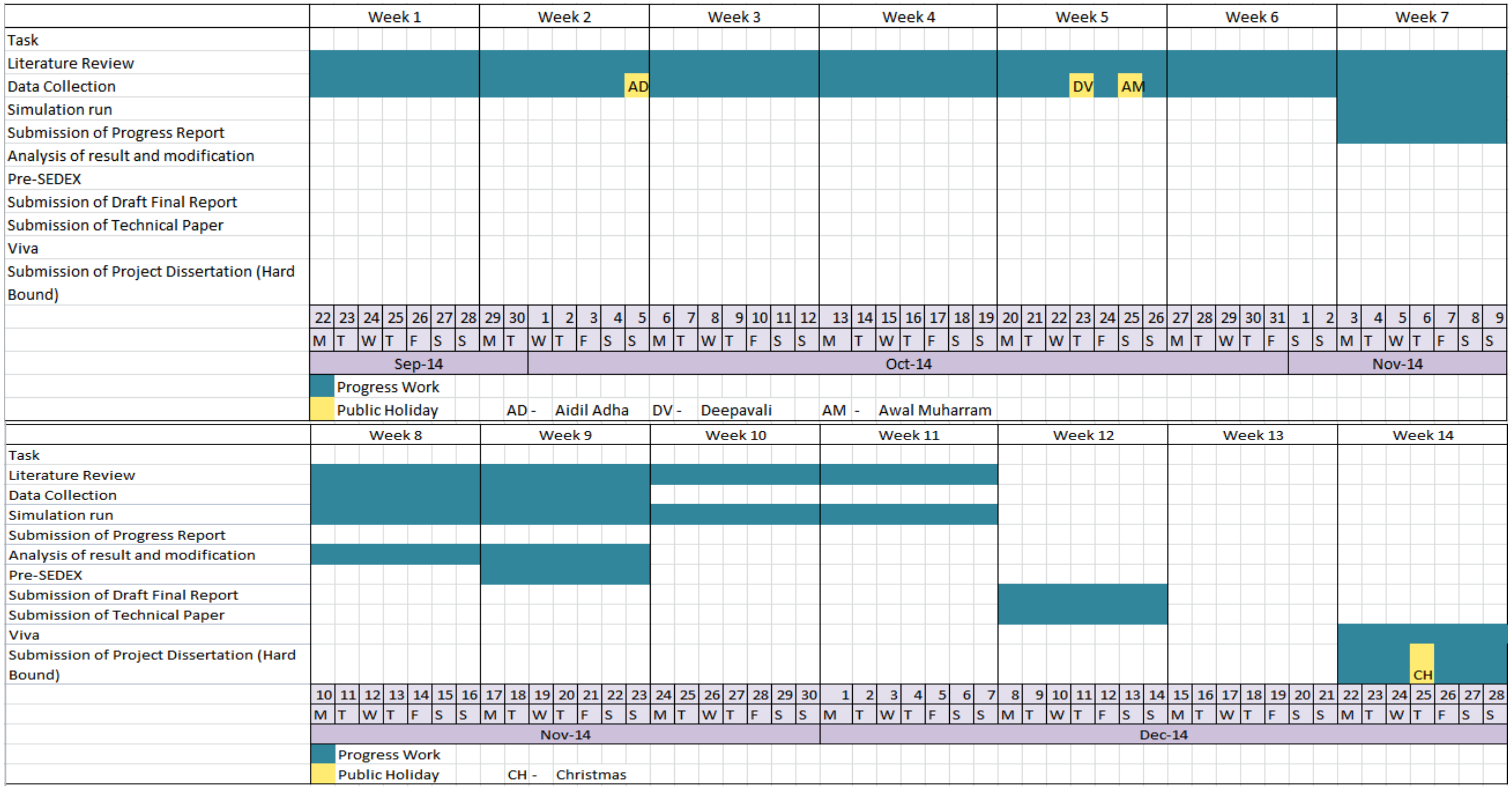

Figure 7.3 Gantt chart of FYP II

Table 7.2 Key Project Milestone FYP II

Key Project Milestone FYP II	
Literature Review	Week 1
Data Collection	Week 1
Simulation run	Week 7
Analysis of result and modification	Week 8
Submission of Progress Report	Week 7
Pre-SEDEX	Week 9
Submission of Draft Final Report / Technical Paper	Week 12
Viva	Week 14

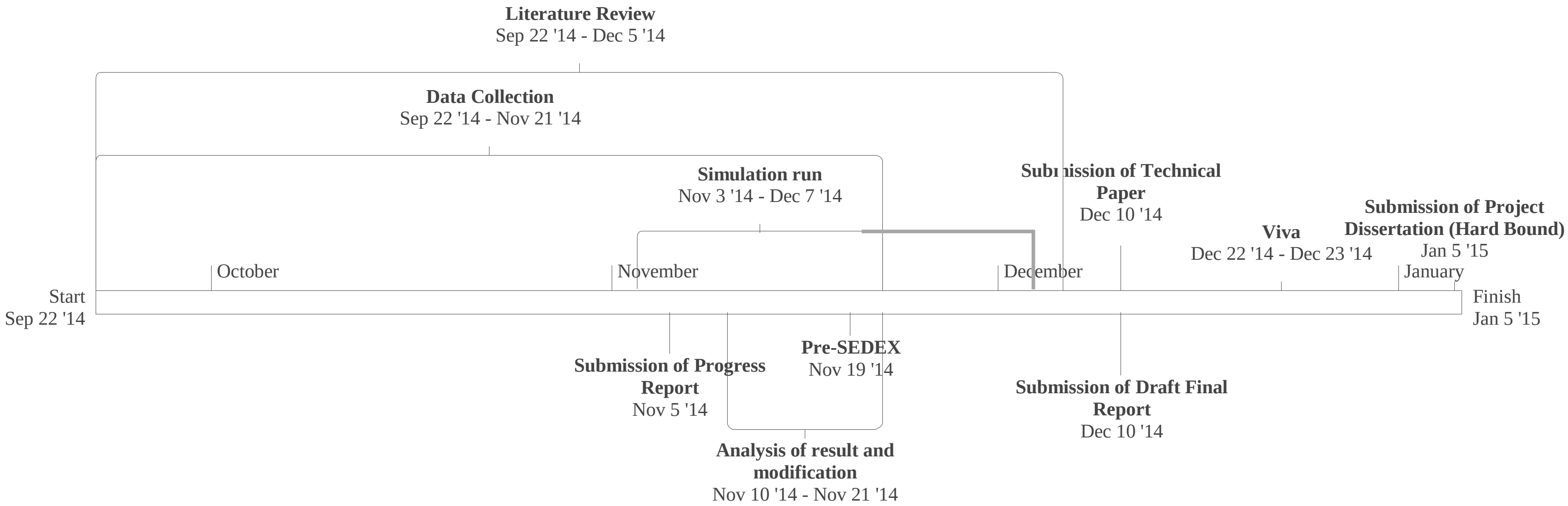

Figure 7.4 Milestone of FYP II by Microsoft Project