Simulation Study on Improved Oil Recovery for Thin Oil Rims

by

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14308

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CERTIFICATION OF APPROVAL

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A project dissertation submitted to

Petroleum Engineering Programme

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Approved by,

____

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UNIVERSITI TEKNOLOGI PETRONAS

TRONOH, PERAK

December 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.

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CHANG YEE LING

Abstract

Most oil reservoirs contain aquifer and gas cap. For every oil reservoir, the decrease in oil or gas production and increased operating expenses cause less profits. With limited technology and narrowed thin oil rims, reservoir management and improved oil recovery methods are facing challenges. The main problem for economic is because both water and gas coning could minimize oil production and hinder recovery of the thin oil rim. Thus, the objectives of this study is to overcome the challenges in thin oil rims reservoir and to produce a simulation model which thin oil rims reservoir is producing with improved oil recovery methods. To generate the similar simulation model in order to meet the objectives, model of thin oil rim was generated using ECLIPSE E100. By creating uncertainties and six cases with different injected fluid rate, well spacing and injection fluid properties, cases are compared with base case by generating total oil production vs time, gas-oil ratio vs time and total water produced vs time graph. The main scenarios generated are the horizontal well, the combination of horizontal well and peripheral and fencing water injection, horizontal well and down dip gas injection and up dip water injection, and lastly, horizontal well and polymer flooding. The best scenario will be the case with best total oil produced with lesser produced water and gas. Overall, polymer flooding provides the highest oil production with relatively lesser water and gas production due to its properties in increasing water viscosity to sweep away oil in regions. Future work could be recommended on fluid properties of polymer and its optimal injection rate.

Acknowledgment

My final year project would not have been possible without the kind support and help of many individuals and organization. With this, I would like to extend my sincere thanks to all of them.

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Chapter 1

Introduction

1.1 Background Study

Kromah and Dawe (2008) stated that majority oil reservoirs have water beneath oil layer or a gas-cap. The reservoir structure is further elaborated by Silva and Dawe (2010) as dome shaped with gas cap and water; and sloping shape with water at edge (see **Figure 1**). Since viscosity of gas and water is lower than that of oil, both of them tend to flow easily and cause the well to produce gas and water simultaneously with oil. At high production rate well in thin oil rims, the gravity effects are smaller than effects of viscosity ratio, thus causing the well to produce excessive gas or water than oil.

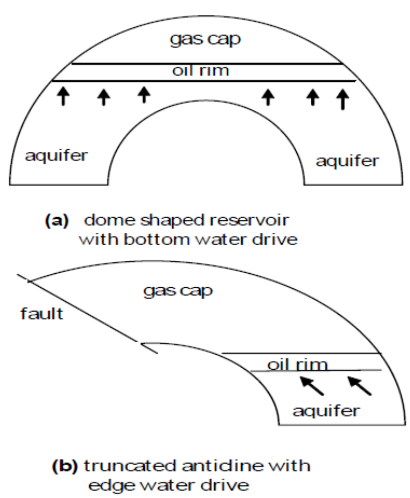

Figure 1: Dome shaped and sloping edge oil rim (Silva and Dawe, 2010)

For every reservoir with oil, the valuable resource, reduction of oil or gas production and increased operating expenses lead to less revenue. With the exploitation of these reservoirs with thin oil-bearing layers and sandwiched between gas cap and water drive, reservoir management and improved oil recovery methods face great challenges. (Silva & Dawe, 2010)

1.2 Problem Statement

For thin oil column (particularly in Malaysia), which the reservoir thickness varies from 10 to 70m (Razak, Chan, & Darman, 2010); field development and oil production present extra challenges. Maximizing oil recovery factor in thin oil rims has always been tough because of coning of underlying water and overlain gas (Silva & Dawe, 2010). The main problem is economic and optimal operations since both water and gas coning could cut short oil production and obstruct recovery (Vo, Waryan, Dharmawan, Susilo, & Wicaksana, 2000).

This study investigates the gas and water coning problems in thin oil rim reservoir and determines the improved oil recovery method to maximize both cumulative oil produced and oil production rate.

1.3 Objectives

The objectives of this project are as below:

i. To improve oil production in thin oil rims by generating different improved oil recovery method scenarios.
ii. To maximize total cumulative oil produced and oil production rate of thin oil rims.
iii. To determine best improved oil recovery methods.

The objectives above will seek the opportunity to overcome the challenges in thin oil rims reservoir. The final outcome of the simulation is to produce a reservoir model which thin oil rims reservoir is producing using improved oil recovery methods.

1.4 Scope of Study

The scope of study for the project entitled "Simulation of Improved Oil Recovery Methods for Thin Oil Rims" is as stated as below:

i. Gas and water coning problems in thin oil rims reservoir.
ii. Total oil production, total water produced and gas-oil ratio in thin oil rims.
iii. Horizontal well in thin oil rims reservoir.
iv. Improved Oil Recovery by fencing water injection (up dip) and peripheral water injection (down dip).
v. Improved Oil Recovery by gas-alternating-water injection (GASWAG)
vi. Polymer flooding.

Chapter 2

Literature Review

2.1 Thin Oil Rims

A typical thin oil rims have several reservoir layers with gas cap and aquifer. The total oil and gas reserve were in thin form of layers with porosity range of 24-30%, with possible permeability range of 200 mD to 2 D. To balance the forces which aquifer drive, expansion of gas cap and fluid production, thin oil rim is recommended to be in contact with production wells (Razak, Chan, & Darman, 2010). Other than that, WOC and GOC are equally important to maintain thin oil rims production. (Razak, Chan, & Darman, 2010; Chan, Kifli, & Darman, 2011). In short, production well must be in accurate distance between WOC and GOC to have an optimal fluid production.

2.2 Gas and Water Coning

The main reason for low oil recovery of thin oil rim are high water cut, fast gas and water coning (Kolbikov, 2012). Coning behavior prediction is significant in evaluating thin oil rims development and forecasting performance for reservoir depletion (Gallagher, Prado, & Pieters, 1993). Gas and water coning can limit the potential production of thin oil rims. Early gas breakthrough and production at high gas-oil ratio (GOR) led to well shut-in in many reservoirs (Olamigoke & Peacock, 2009).

Generally, coning is a system where gas or water or both moving towards the production perforation of oil well in a form of cone caused by pressure drawdown within the oil column close to wellbore (Kromah & Dawe, 2008). The pressure drawdown is large to overcome viscous and gravity forces and hence, causing gas dipping and water cresting in the reservoir, in other words, gas and water coning (see **Figure 2**).

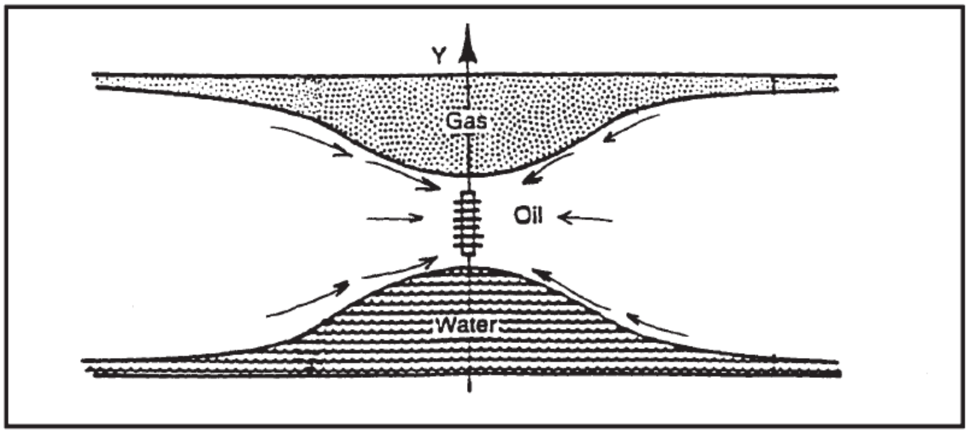

Figure 2: Gas and water coning in oil reservoirs (Ahmed, 2010)

Ahmed (2010) further divided gas and water coning into three concepts which are stable cone and unstable cone. It is stated that a steady-state condition is achieved if a well is producing at a constant production rate and the pressure drop is stable. If viscous forces of water and gas cap do not overcome the gravity forces, then the cone formed will remain and not reach to the well. However, provided if the pressure in the oil reservoir system is not stable, which is also known as unsteady-state condition, the cone formed will be an unstable cone. Unlikely stable cone, unstable cone will continuously been drawn towards the production interval in the wellbore until steady-state is achieved. When the viscous forces at the wellbore surpass gravitational forces, the unstable cone will break into the well. This phenomenon is known as gas or water breakthrough. This signifies the premature water or gas breakthrough involves production of gas and water simultaneously with oil.

To predict gas and water breakthrough time in every oil reservoir, critical production rate, optimum length and position of perforating interval are important. Critical production rate is defined as “the maximum rate of oil production without concurrent production of displacing phase by coning” (Ahmed, 2010).

2.3 Horizontal Wells

Horizontal drilled wells are proven to increase the oil recovery factor in mature reservoirs. This can be shown in Pennsylvanian Bartleville sand, where the Flatrock Field is located at a depth of 1400 feet, with over 1000 conventional wells. A HD of 1050 feet horizontal well was completed in 10 feet thick Bartleville Sand. Water cut was substantially lessened from 75 percent (at vertical wells) to 14 percent (horizontal well). (Rougeot & Lauterbach, 1991).

In thin oil column, the main parameters affecting thin oil rims recovery factor are oil rim thickness, permeability, size of gas cap, aquifer strength, reservoir geometry, magnitude of bed dip and oil viscosity (Vo, Waryan, Dharmawan, Susilo, & Wicaksana, 2000). Horizontal wells are effective in minimizing water coning (see **Figure 3**). The pressure profile in horizontal wells is uniform along wellbore. Since horizontal wells have higher contact area (drainage area) than vertical wells, given the same production rates, horizontal wells provides lesser pressure drawdown, larger capacity and a longer breakthrough time than that of vertical wells. (Joshi, Production forecasting methods for horizontal wells, 1988; Joshi, Horizontal Well Technology, 1991; Ahmed, 2010). Horizontal wells in thin oil rims provide large drainage area, more reserves and better oil recovery factor compared to vertical wells. Based on the performance of 50 horizontal wells in Mahakam Delta, offshore East Kalimantan, Indonesia, horizontal wells are drilled to produce thin oil bands between gas cap and bottom aquifer. **Figure 4** statistics show horizontal wells in thin oil columns provide twice the contact volumes and reserves compared to conventional wells. (Vo, Waryan, Dharmawan, Susilo, & Wicaksana, 2000)

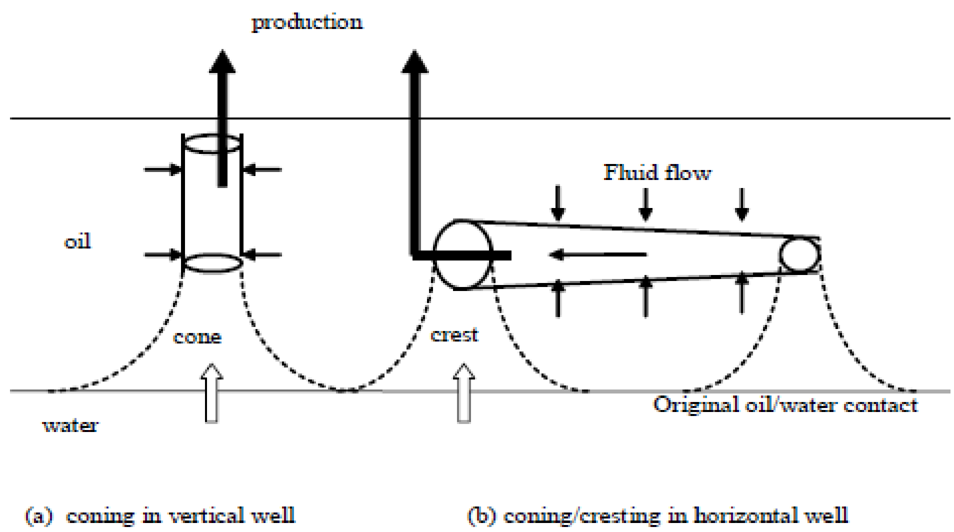

Figure 3: Coning in (a) Vertical and (b) Horizontal wells (Silva and Dawe, 2010)

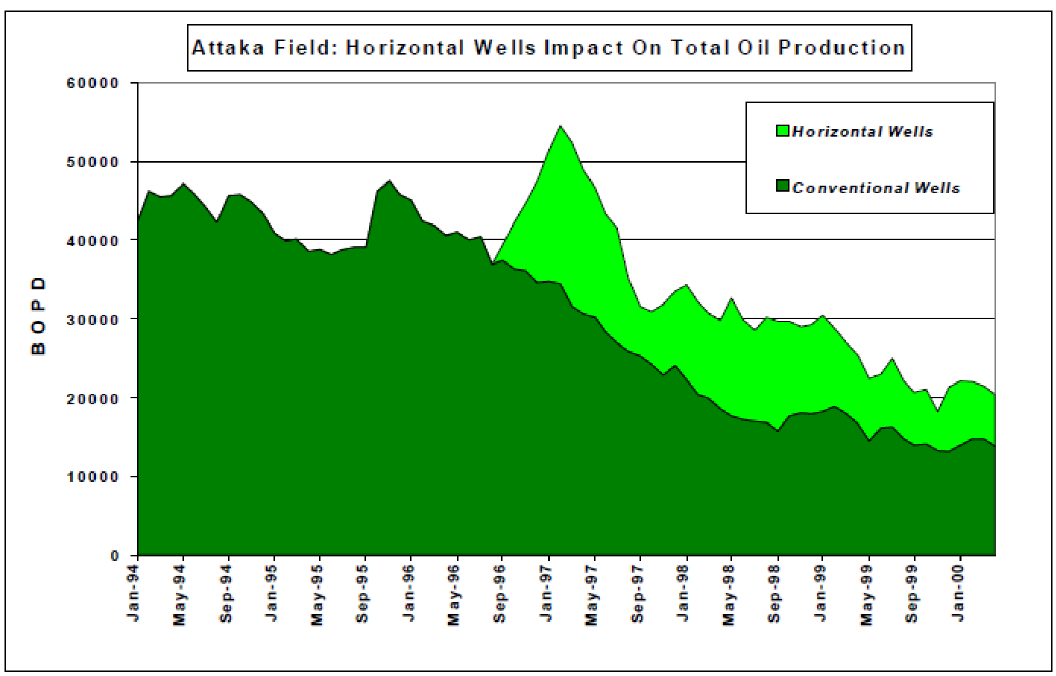

Figure 4: Contributions of horizontal wells to the total Attaka oil production (Vo et. al., 2000)

2.4 Water Injection

To maximize oil recovery of thin oil rims, the oil rim must be kept in contact with producing wells. By managing water injection either by down dip or injecting water up-dip, equilibrium of WOC and GOC can be achieved. For thin oil rims, these two techniques are equally significant (Dandona & Morse, August, 1975; Hegre, Dalen, & Strandenaes, 1994).

2.4.1 Peripheral Water Injection (Down-dip Water Injection)

Peripheral water injection is also known as the injection of water at and close to WOC (Dandona & Morse, August, 1975). The method is to enhance the bottom water drive to displace the oil rim up and toward producing wells (see **Figure 5** left). Ahmed (2010) elaborated peripheral flooding as the injection at the external boundary of the reservoir and the oil is displaced towards interior of reservoir. In other words, injection at external boundary means injection of water at or below WOC. It is also stated that as the peripheral flood involves injection at external boundary, this method usually yields maximum oil recovery with minimum produced water.

2.4.2 Fencing Water Injection (Up-dip Water Injection)

Up-dip water injection (or fencing water injection) at and close to GOC can suppress the oil rims movement towards the gas cap (see **Figure 5** right). By optimizing water injection rate at an optimum viscous/gravity ratio, water fence can be built mainly on top of oil rim and thus, producing remaining oil reserve. Combination of down-dip and up-dip water injection could improve oil recovery in thin oil rims significantly (Chan, Kifli, & Darman, 2011).

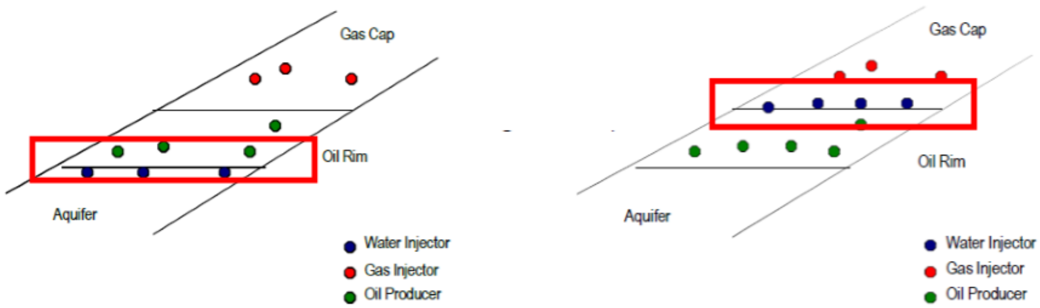

Figure 5: Peripheral water injection scheme (Left) and Fencing water injection scheme (Right) (Chan, Kifli, & Darman, 2011)

2.5 Gas Injection

Since the sweep efficiency of gas is lower than that of water, it signifies that the mobility ratio, M is less than 1 (Cosse, 1993). According to Cosse (1993) as well, gas injection is often performed either in the gas cap (also known as local injection), or directly into the oil (also known as dispersed injection). The aim of gas injection is to reduce the drop in pressure as well as maintaining reservoir pressure.

Mereenie Field in Australia was discovered in 1964 and started production in 1984. After primary recovery, most of the oil is within a 200-300 m wide narrow rim. The studies proved by re-injecting gas into gas cap increases 2-3% of the oil recovery factor. Another studies by same research paper also shows that by injecting gas directly into oil rims, this technique displaces the inaccessible oil as well as maintaining pressure, thus resulting in 10-14% of oil recovery (Kabir, McKenzie, Connell, & Sullivan, 1998). As the case study above suggested, produced gas re-injection method is an effective way of improving oil recovery.

2.5.1 Simultaneous Down-dip Gas Injection and Up-dip Water Injection

The application of down-dip gas injection and up-dip water injection (also known as DDGI UDWI method) can cause the oil to re-zone and move to the central of the reservoir. This combination of re-injecting gas into aquifer and injecting water at gas cap or near to gas oil contact can result in increase in reservoir pressure, better productivity and higher recovery (Razak, Chan, & Darman, 2011). By fencing water injection, this approach can protect the gas in the gas cap from smearing and preventing oil from moving towards gas cap rapidly. (Razak, Chan, & Darman, 2011; Chan, Kifli, & Darman, 2011)

2.6 Comparison between peripheral and fencing water injection and DDGI UDWI

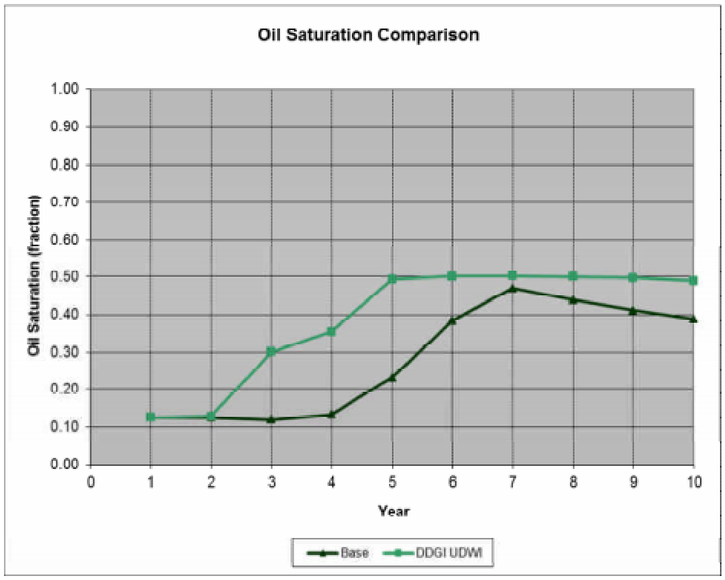

Figure 6: Comparison of oil saturation (Razak, Chan, & Darman, 2011)

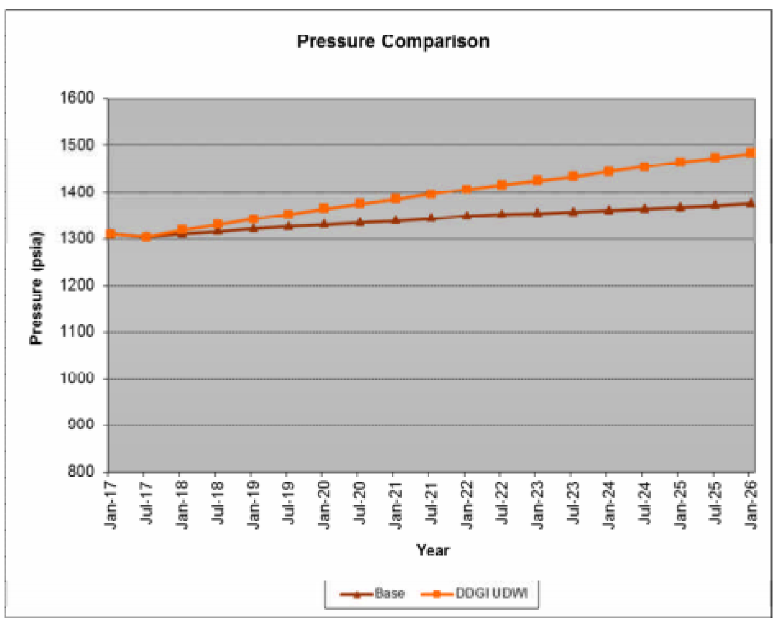

Figure 7: Comparison of pressure between base case and DDGI UDWI (Razak, Chan, & Darman, 2011)

Based on figures above, a combination of horizontal well and down dip gas injection and up dip water injection is predicted to be the best improved oil recovery method. If compare solely by **Figure 7**, it is clearly seen that even though water injection improves reservoir pressure, nevertheless, this method does not increase as much the reservoir pressure as the DDGI UDWI. The base case in both **Figure 6** and **Figure 7** signifies the peripheral and fencing water injection. This method is also supported by the statement of "Estimated ultimate oil recovery gain was significant when compared to base case of peripheral and fencing water injecting" (Razak, Chan, & Darman, 2011).

2.7 Polymer Flooding

Water-soluble polymer is added with water during process of polymer flooding to increase water viscosity. Effective permeability to water is reduced while polymer flooding allow well to produce to residual oil saturation quickly by reducing water/oil mobility ratio (Needham & Doe, 1987). The equation for mobility ratio is:

$$M = \frac{k_w \mu_o}{\mu_o k_o} \qquad (1)$$

M is the mobility ratio, k_w is water permeability, μ_o is oil viscosity and k_o is oil permeability. Polymers can improve mobility ratio of flood by reducing water permeability or increasing water viscosity. This signifies the lower the water permeability, the lower the mobility ratio, and thus, the higher the oil recovery of the reservoir.

Needham and Doe (1987) further concluded that polymer flooding can improved areal sweep efficiency by improving mobility ratio. In water flooding areas, oil recovery may be efficient due to water entry into preferential permeable zones to sweepout. Moreover, reduction in mobility ratio can reduce in fingering problems, as much as improving sweep efficiency (San Blas & Vittoratos, 2014).

2.8 Summary of Literature Review

In short, thin oil rim reservoirs are reservoirs with large gas cap, huge aquifer supporting system and oil column thickness of 10-70m (in Malaysia). To achieve best oil recovery factor, producing wells are best to be in contact with oil reserve and WOC and GOC are important to avoid gas and water coning problems in thin oil rim reservoirs. To obtain best oil recovery factor and critical production rate of the oil rims, horizontal wells are proposed for production since the structure of horizontal wells allows large drainage contact area, less pressure drawdown, large capacity and a long gas and water breakthrough time. In addition for horizontal wells, water injection, both down-dip and up-dip, is also best way for exploiting thin oil rim reserves. Down-dip water injection supported bottom and edge aquifer for better water drive, while up-dip water injection provides water fencing to prevent oil reserves from ascending into gas region. Other than that, simultaneous down dip gas injection and up dip water injection can as well as improve oil recovery factor and centralizing oil in reservoir. However, if comparison is made between peripheral and fencing water injection and DDGI UDWI, the expected result between this two would favor the latter method to yield the best oil recovery. Lastly, for polymer flooding, with increase of water viscosity and presence of water-soluble polymer, the mobility ratio of water and fingering effect are reduced, thus increasing the oil recovery.

Chapter 3

Methodology

3.1 Simulation

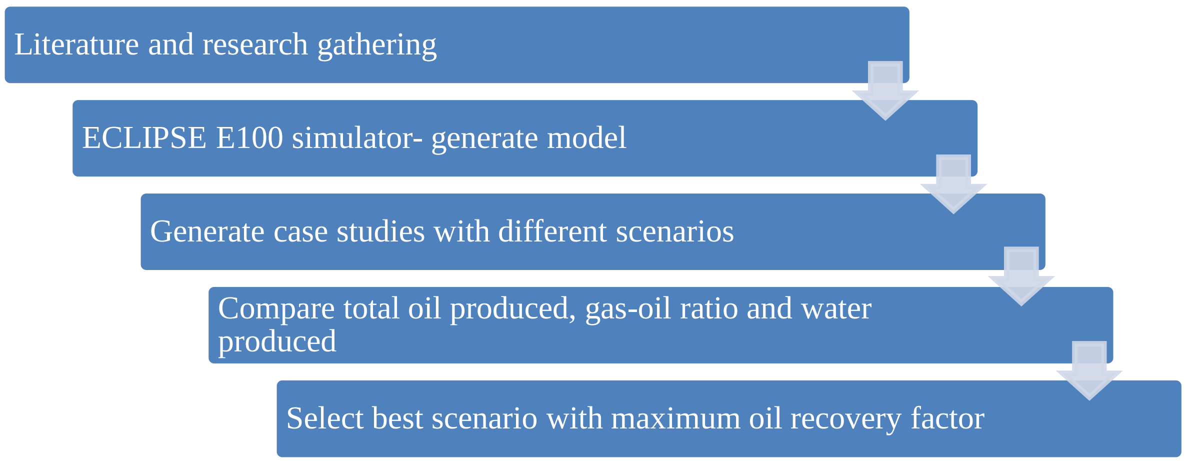

Figure 8: Methodology

Before proceed with simulations, research papers, journal articles and reservoir engineering books regarding thin oil rim reservoirs and improved oil recovery were referred and gathered for better research purposes. Different cases on thin oil rim were decided based on research and was input in ECLIPSE E100 simulator for generating model and determining best scenario in future. The reservoir selected was determined to be anticline reservoir with light oil, gas cap and strong aquifer for better simulation purpose.

In this project, an anticline thin oil rims reservoir model was provided by LEAP Energy Sdn. Bhd. By using Eclipse E100 simulator, the model was generated and case studies of different scenarios were tried. Initial reservoir conditions such as WOC, GOC, oil viscosity, height of oil rim, porosity and permeability were input into selected model. By creating uncertainties and cases with different wells trajectory, water injection and gas injection, cases are compared with base case by comparing parameters of **total oil produced**, **gas-oil ratio** and **total water produced**. Horizontal well can be combined with water injection and gas injection as producer to study the improved oil recovery method.

The best scenario will be the case with best total oil produced.

The case studies are as below:

- Case 1: Horizontal well vs. vertical well (1 producer, natural depletion)
- Case 2: Water injection in aquifer with different injection rate (5 spots water injection – 1 producer 4 injectors)
- Case 3: Water injection in gas cap and water injection in aquifer (1 producer, 2 injectors in gas cap and 4 injectors in aquifer)
- Case 4: Gas injection in gas cap and water injection in aquifer (1 producers, 2 injectors in gas cap and 4 injectors in aquifer)
- Case 5: Water injection in gas cap and gas injection in aquifer (1 producers, 2 injectors in gas cap and 4 injectors in aquifer)
- Case 6: Polymer flooding (1 producers, 4 injectors)

Case 1 was conducted first prior in choosing production well trajectories. This case was created based on comparative analysis table between horizontal, vertical and slanted wells as referred in **Figure 9**. Based on the well type and oil production rate, by comparing different fields of Agua Fria, Cantarell and Abkatun, horizontal well had an overall more oil production rate than that of vertical well. Hence, by using previous research analysis, both horizontal and vertical wells were generated and used as case 1 to compare total oil produced by natural depletion. The highest total oil produced by the well trajectories was used as producer for case 2 to case 6 to ensure constant in case studies.

FIELD	WELL TYPE	Qo (BPD)	Δp (kg/cm²)	J (BPD /Kg/ cm²)	L (m)	J_H/J_V
AGUA FRIA	Fractured vertical	921.5	21.9	42.0	80	2.4
	Vertical without fracture	245.0	100.7	2.43	-	
	Horizontal	409.0	71.7	5.70	150	
CANTARELL	Slanted (2094)	7071	1.14	6203	-	2.0
	Horizontal (2074)	8800	116.6	75.5	290	
ABKATUN	Vertical (212-A)	1234	39	31.6	-	
	Horizontal (221)	2599	20	129.9	365	4.1
	Horizontal (223)	2432	31	78.6	100	2.5

Figure 9: Comparison of Horizontal and Vertical Wells Productivity (Leon-Ventura, Gonzalez-G, & Leyna-G., 2000)

As for case 2, Ahmed (2010) provides theory for regular injection patterns. A regular five spot injection pattern was used in this case for water injection as shown in **Figure 10**, which consisted of one producer and four injectors at WOC. The injection at WOC was to increase bottom water drive to displace oil rim towards oil producer (Chan, Kifli, & Darman, 2011). Similar patterns, best water injection rate and injection well placement were referred and used from case 3 to 6.

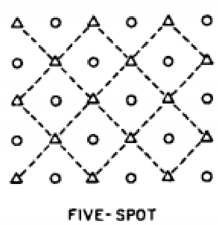

Figure 10: 5 spot flood pattern (Ahmed, 2010)

3.2 Key Project Milestone

In align with the objectives above, key milestones are projected and marked when achieved. The key milestones are as shown in figure below. Each milestone had been submitted accordingly on time.

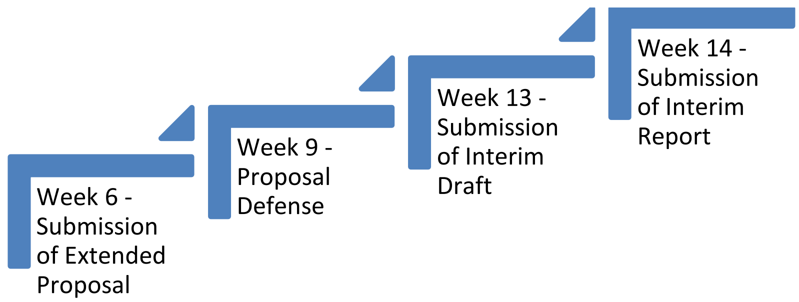

Figure 11: Key milestones of FYP 1

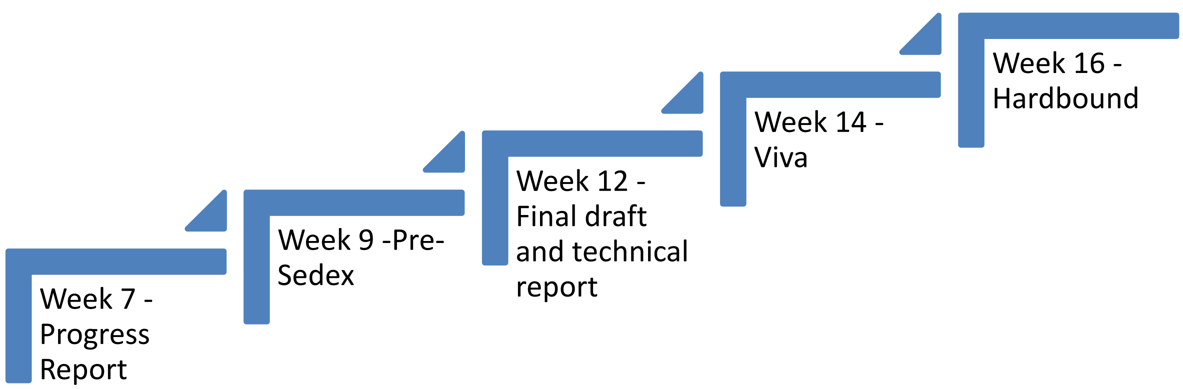

Figure 12: Key Milestone of FYP 2

3.3 Project Activities

Table 1: FYP 1 Gantt chart

Project Activities/Week	1	2	3	4	5	6	7	8	9	10	11	12	13	14
Selection of Topic														
Preliminary Research Work														
Submission of Extended Proposal														
Proposal Defense														
Project Work Continues														
Submission of Interim Draft Report														
Submission of Interim Report														

Table 2: FYP 2 Gantt Chart

Project Activities/Week	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
Project Work Continues															
Submission of Progress Report															
Project Work Continues															
Pre-SEDEX															
Submission of Draft Final Report															
Submission of Dissertation (soft bound)															
Submission of Technical Paper															
VIVA															
Submission of Project Dissertation (hard bound)															

3.4 Summary of Project Progress and Future Work

Up to FYP 1, the key milestones were set and successfully achieved. In this semester, proposal defense had been done on week 9. Throughout the semester, the main focus was on literature review on the main problems of thin oil rims and methods of solution. This solution method was tested in FYP 2. The scenarios to be concerned were listed out in section **3.1 Simulation**. A combination of horizontal well and water injection, DDGI UPWI and polymer flooding is yet to be tested and parameters will be taken into account to measure the best outcome of the simulation. The case studies as shown in methodology as well for better reference purposes.

For FYP 2, the best reservoir model for simulation purpose was determined as light oil and anticline reservoir with gas cap and aquifer. The thin oil rim reservoir model was requested from LEAP Energy Sdn. Bhd. for real case simulation. More studies on literature reviews and methodology were carried out. Scenarios were generated based on literature review to determine the best improved oil recovery method and were discussed in section below. In this semester, findings, result and discussion were the main attention.

Further research can be done with different water injection salinity and injection fluid properties in down-dip gas injection and up-dip water injection and polymer flooding in prior to determine the best improved oil recovery method.

Chapter 4

Result and Discussion

4.1 Findings

4.1.1 Reservoir Modelling

The reservoir model was obtained from LEAP Energy Sdn. Bhd. with anticline thin oil layer structure and light oil properties. Figure provided below is the image of anticline reservoir with gas cap on above and aquifer. The porosity was 0.20 for whole reservoir, assuming the reservoir is homogeneous, while the permeability was set 30 mD for both X, Y and Z direction. Oil API for this thin oil rim reservoir was calculated based on density of oil and density of water given, which is 48.8 ^{o}API. Since API gravities for light crude oil ranges from 47 ^{o}API (Ahmed, 2010), the oil in this particular thin oil rim reservoirs was considered very light crude oil.

Main parameters concerned for simulation of thin oil rim were tabulated in **Table 3.**

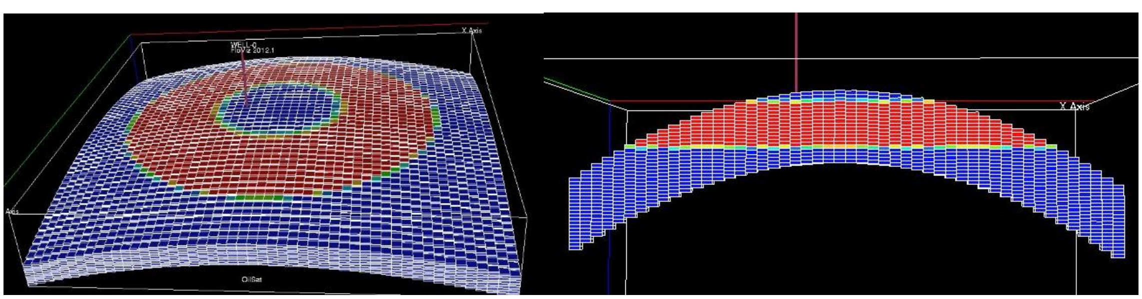

Figure 13: Anticline thin oil rim reservoir

Table 3: Main parameters of reservoir model

Parameters	
Porosity, fraction	0.2
Horizontal permeability, mD	30
Vertical permeability, mD	30
Thickness, ft	65
Gas oil contact, ft	3645
Water oil contact, ft	3710
Oil API	48.8
Oil viscosity, cP	1.01
Oil formation volume factor	1.08
Dimension	50 x 50 x 20
Cell Size, ft x ft x ft	200 x 200 x 5
Rock compressibility, psi	3.14×10^{-6}
Density of oil, lb/ft^3	49.99
Density of water, lb/ft^3	63.698
Density of gas, lb/ft^3	0.050674

4.2 Discussions

4.2.1 Case 1: Horizontal well vs. vertical well (1 producer, natural depletion)

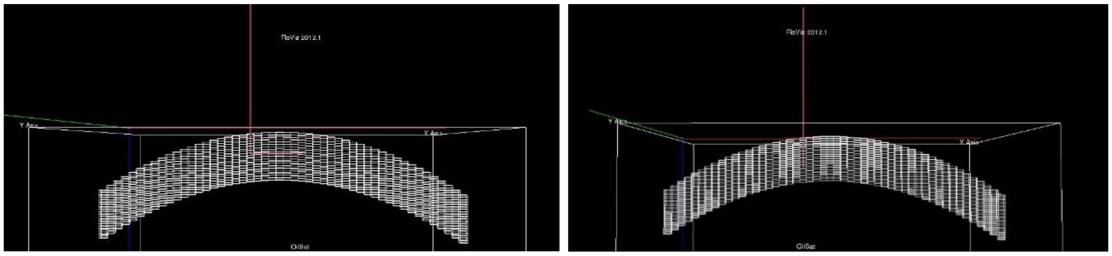

Figure 14: Horizontal well (left) vs. vertical well (right) in reservoir model

Two data files of horizontal well and vertical well (see **Appendix**) were generated for the selected case. To ensure consistency in data, the coordinate of both horizontal well and vertical well were input as same and both wells would be producing up to March 2018. Graphs of **total oil produced (FOPT) vs time**, **GOR (FGOR) vs time**, and **total water produced (FWPT) vs time** were generated using ECLIPSE E100 after creating the wells. The results were tabulated as below.

Table 4: Comparison between horizontal well and vertical well

Parameters	**Well Trajectories**	
	Horizontal well	*Vertical well*
Total oil produced, STB	7587893	7041927.5
Gas-oil ratio, Mscf/STB	8.0955038	7.8141766
Total water produced, STB	2143935.3	2993064.8

For case 1, the indication of all **three graphs** is as below:

Horizontal well

Vertical well

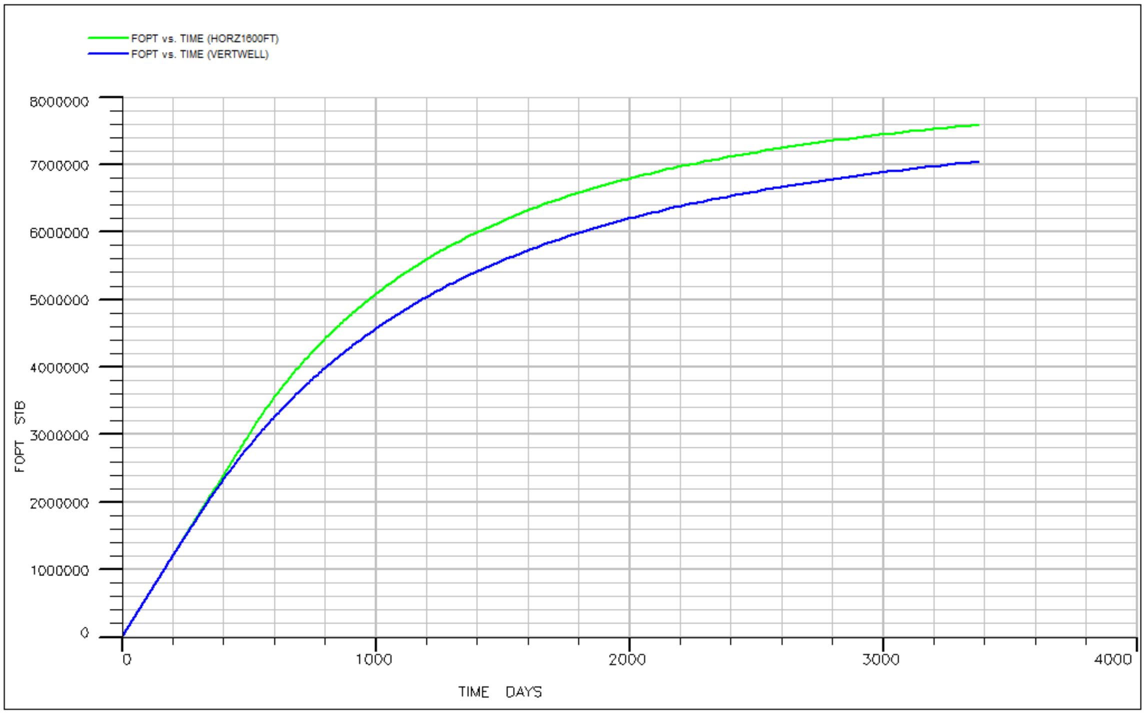

Figure 15: Total oil produced (FOPT) vs. time of horizontal well and vertical well

From **Figure 15**, the oil production of both wells were similar at first until it reached 195 days. At the end of production which is 3375 days, data showed that horizontal well produced up to 7587893 STB, while vertical well only produced 7041927.5 STB, which is 545966 STB in difference. The difference in oil production can be supported by literature review in section **2.3 Horizontal Wells**. Horizontal well is effective in reservoirs of small thickness and with problems of water and gas coning due to its capability in increasing contact area. (Leon-Ventura, Gonzalez-G, & Leyna-G., 2000; Vo, Waryan, Dharmawan, Susilo, & Wicaksana, 2000). By using horizontal well in thin oil rims, the drainage area was increased, thus resulting in more oil production.

After comparing FOPT, gas-oil ratio of two cases were compared as graph below.

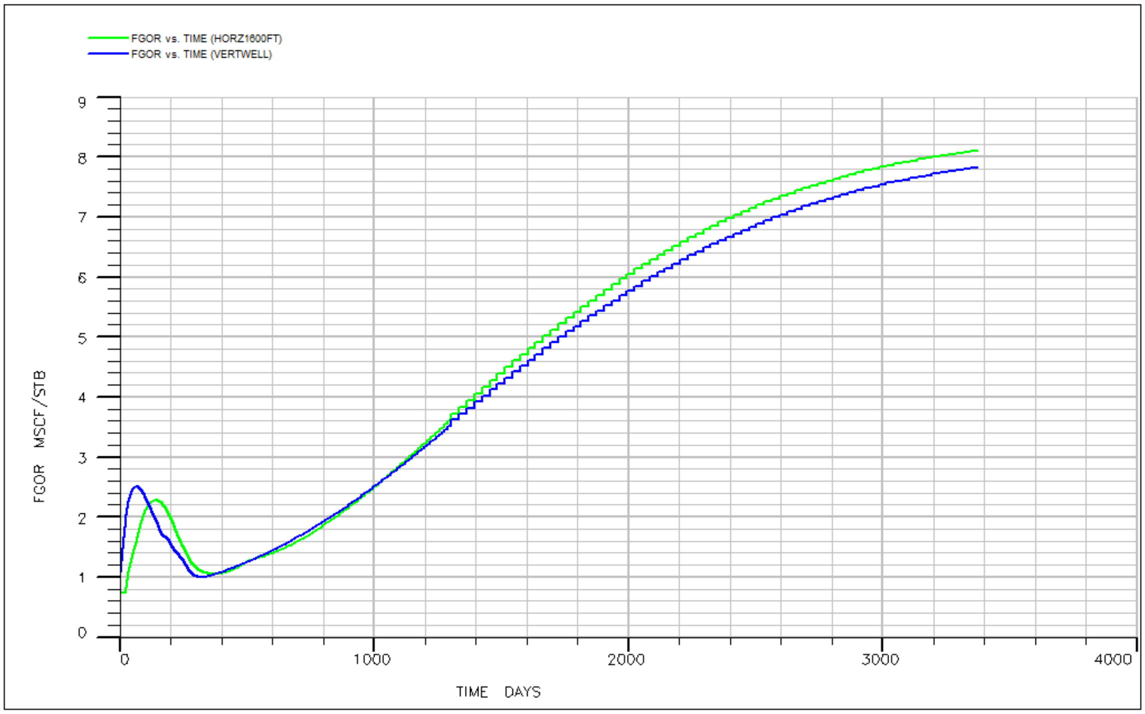

Figure 16: Gas-oil ratio (FGOR) vs. time of horizontal well and vertical well

The equation of GOR was defined as total gas flow rate, both free gas and solution gas, divided by total oil flow rate (Ahmed, 2010). The statement above provided information that the more the total gas produced, the higher the value of GOR. The high GOR value in graph indicated there was gas coning in reservoir with production of gas and water simultaneously with oil. In this case, vertical well and horizontal well produced 7.8141766 Mscf/STB and 8.0955038 Mscf/STB correspondingly, which were roughly only 0.2 Mscf/STB in difference.

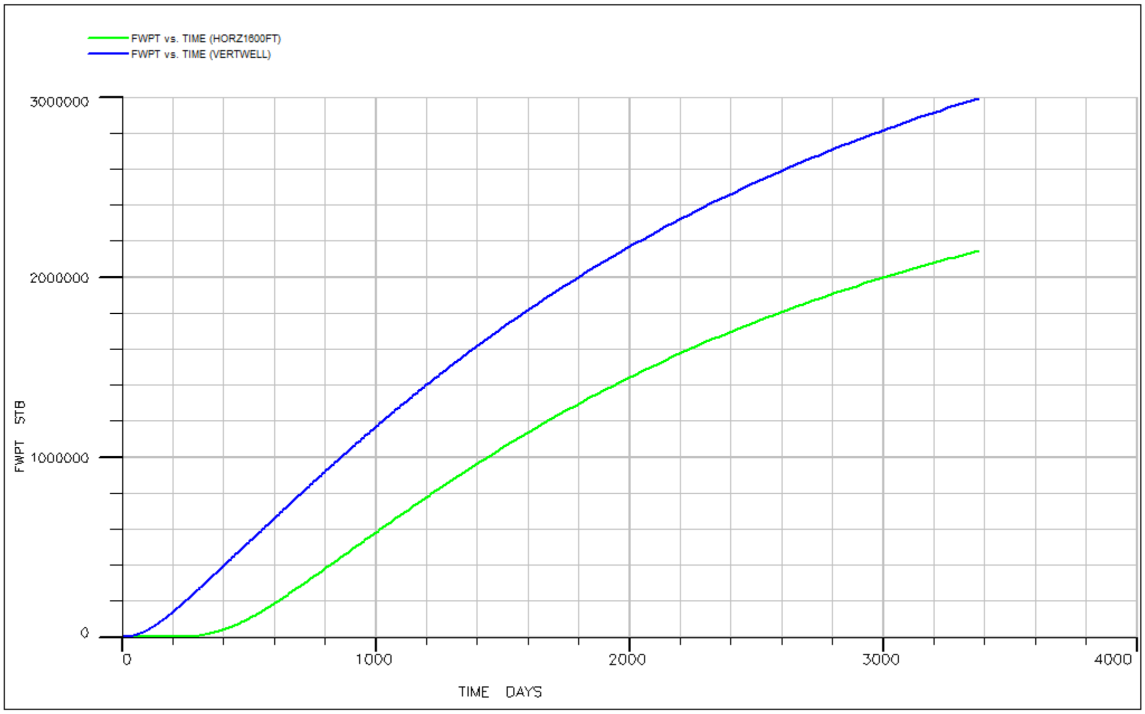

Figure 17: Total water produced (FWPT) vs. time of horizontal vertical well

According to **Figure 17**, total water produced by vertical well, which is the blue curve was higher than horizontal well (green curve). At the end of production, the water produced from vertical well is 2993064.8 STB, while for horizontal well, the same parameter was 2143935.3 STB, signifying water coning in vertical well is severe than that in horizontal well.

By comparing graph of **Figure 15** to **Figure 17**, with higher simultaneous total water production and slight lesser gas-oil ratio than horizontal well, vertical well has lesser oil production. Hence, horizontal well was proven a better oil producer well comparing to vertical well. For case studies below, horizontal well was used as producer to ensure better oil production.

4.2.2 Case 2: Water injection in aquifer with different injection rate (5 spots water injection – 1 producer 4 injectors)

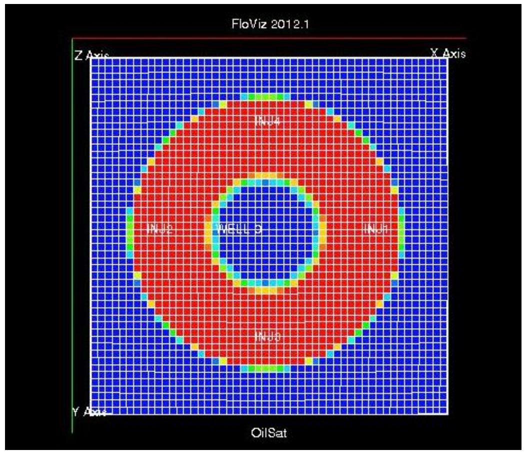

Figure 18: Water injection pattern in reservoir model

As discussed in methodology, 5 spot regular flooding pattern was applied and used in this case (see **Figure 10** and **Figure 18**). The injection wells were placed near WOC and surrounding one horizontal producer to provide better bottom drive and increase oil production. The results of different water injection rate were tabulated.

Table 5: Comparison between different rates of water injection

Parameters	**Water Injection Rate (STB/day)**		
	500	*2000*	*6000*
Total oil produced, STB	8639369	14001270	13323523
Gas-oil ratio, Mscf/STB	6.4105368	0.82843238	0.79504412
Total water produced, STB	2572298.3	7316131	48714692

For case 2, the indication of three graphs is shown as below:

Water injection in aquifer with injection rate of 500 STB/day

Water injection in aquifer with injection rate of 2000 STB/day

Water injection in aquifer with injection rate of 6000 STB/day

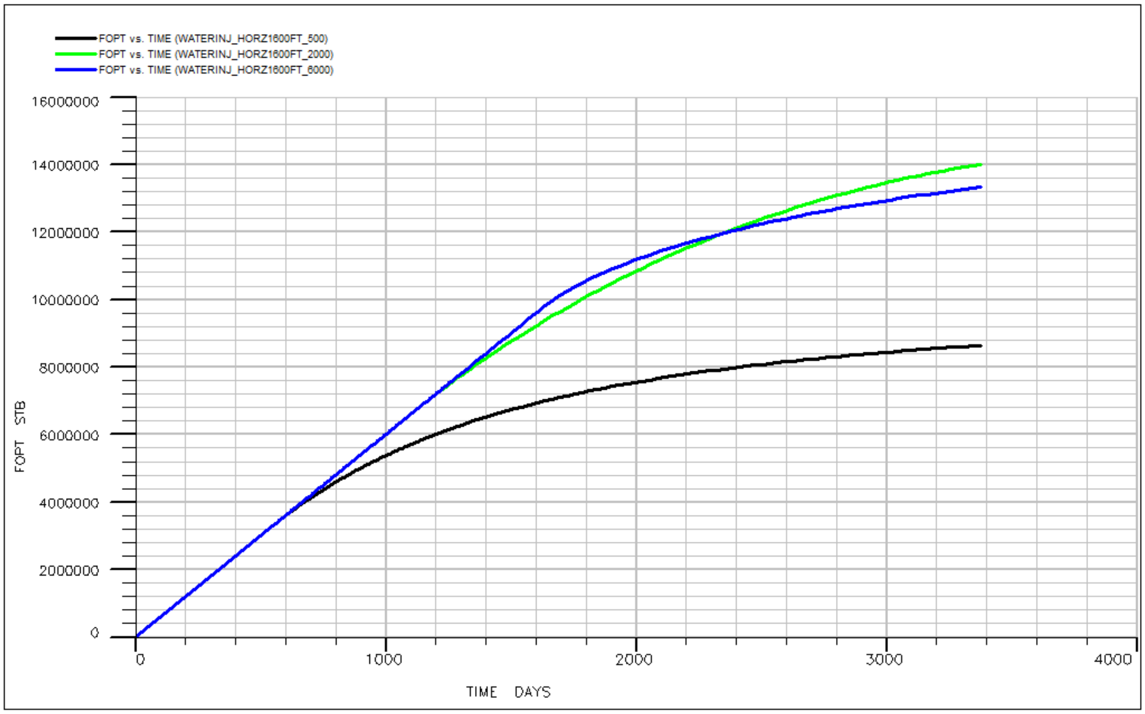

Figure 19: Total oil produced (FOPT) vs. time of water injection with different rates

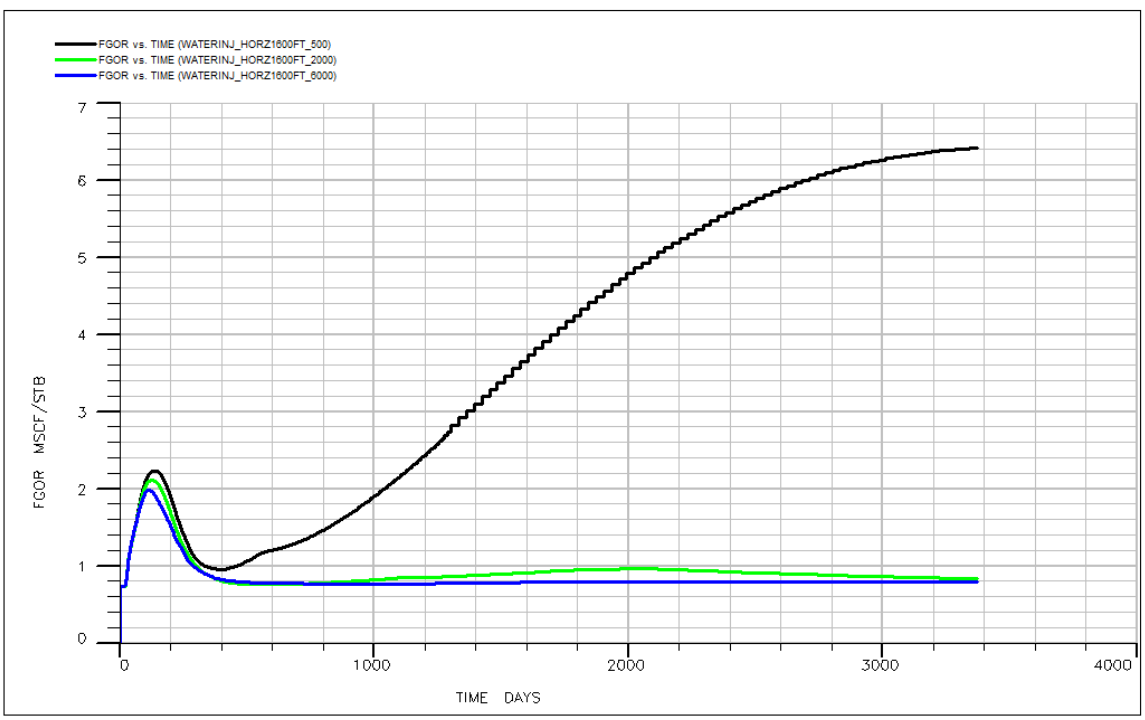

Figure 20: GOR (FGOR) vs. time of water injection with different rates

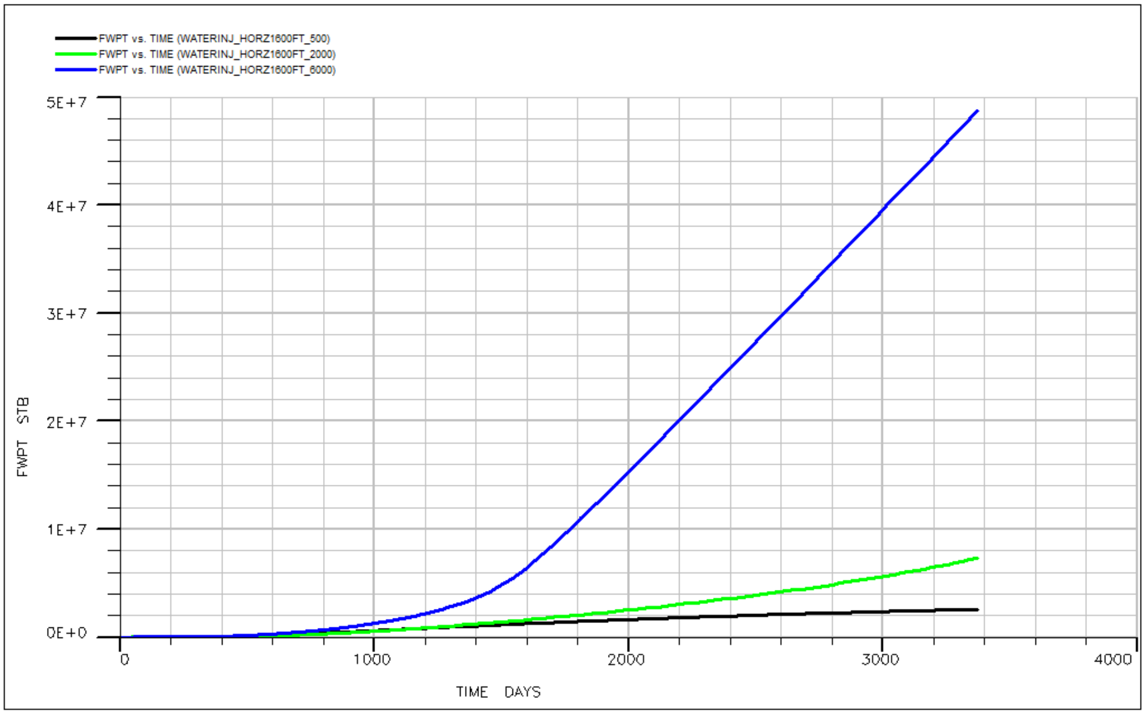

Figure 21: Total water produced (FWPT) vs. time of water injection with different rates

Increased rates of water injection can result in increase of in oil production rate (Dickey, et al., 1946). This theory can be proven in **Figure 19** as it shows increase in oil production comparing 500 STB/day injection, 2000 STB/day injection rate and 6000 STB/day injection rate. The trend of three curves in FOPT graph generally increase when there is increase in injection rate. However, at 2300 days of production, oil production of 6000 STB/day water injection rate started to decrease and result in lower cumulative oil production. At the same time of oil production, total water produced by 6000 STB/day water injection rate increased steadily and steeply to 48714692 STB, while the oil production is 13323523 STB. Dickey et al. (1946) evaluated this phenomenon by the effect of too large increase in water injection rates can cause well to produce more water than can be lifted economically. This will lead to ineffective of water injection due to high water production. Other reason could be during high rate injection, water fingers were created and this caused water to produce rather than oil. While for slower water injection rate, water were laterally spread and able to sweep region with oil. (Singhai, 2009)

In this scenario, water injection rate of 2000 STB/day was concluded as the best injection rate comparing 500 and 6000 STB/day. This value was used as best water injection rate for cases generated after.

4.2.3 Case 3: Water injection in gas cap and water injection in aquifer (1 producer, 2 injectors in gas cap and 4 injectors in aquifer)

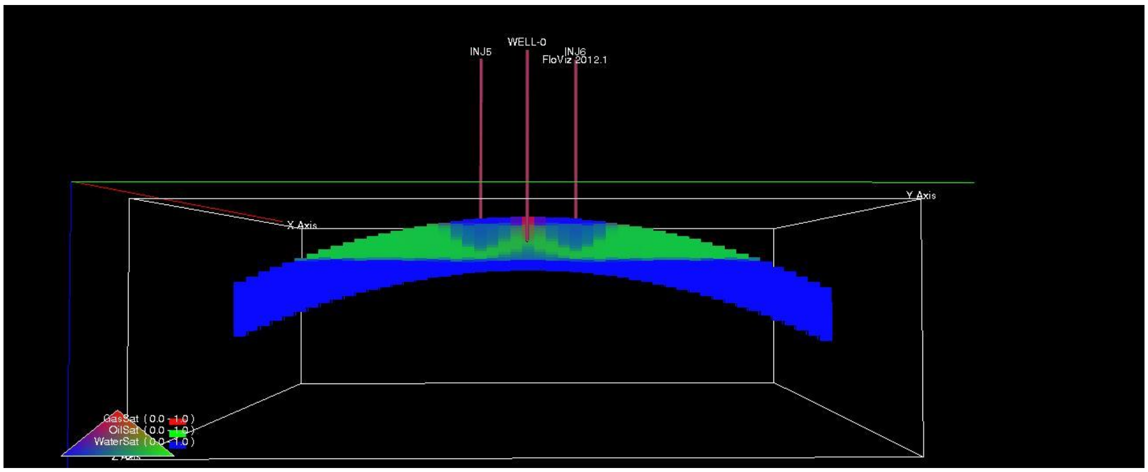

Figure 22: Fencing water injection in reservoir model

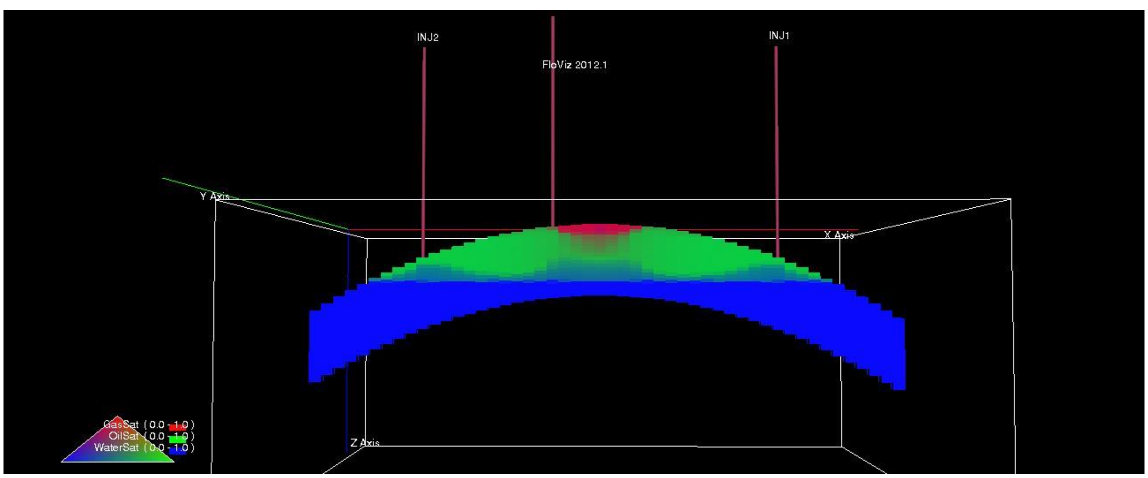

Figure 23: Fencing and peripheral water injection in reservoir model

An illustration of fencing and peripheral water injection was shown in **Figure 23** to provide better picture of up dip and down dip simultaneous water injection. 4 injectors were placed in previous case 2 well placement with same coordinates and latitude, while for 2 injectors in gas cap, the wells were placed near to GOC.

Table 6: Comparison between fencing water injection and simultaneous fencing and peripheral water injection

Parameters	**Water Injection Method**	
	Fencing	*Fencing and peripheral*
Total oil produced, STB	7193760	11163191
Gas-oil ratio, Mscf/STB	4.3115978	0.75154668
Total water produced, STB	10628851	20019478

For case 3, the indication of three graphs is shown as below:

Water injection in gas cap with injection rate of 2000 STB/day

Water injection in both aquifer and gas cap with injection rate of 2000 STB/day

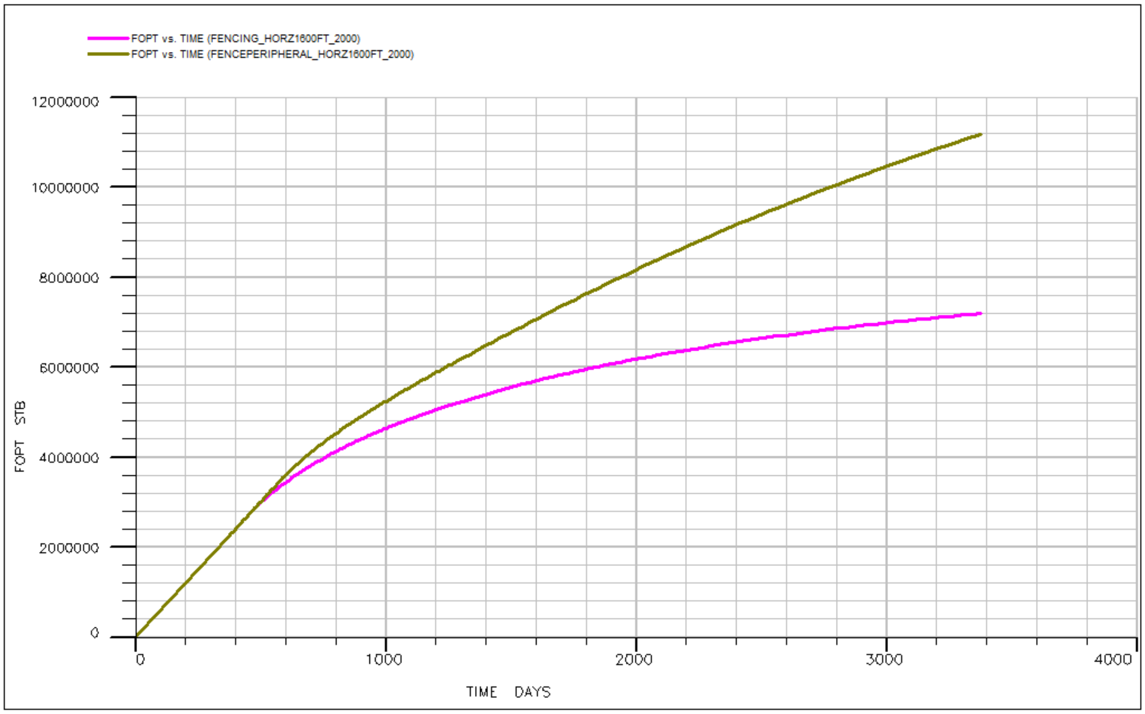

Figure 24: Total oil produced (FOPT) vs. time of fencing water injection and simultaneous fencing and peripheral water injection

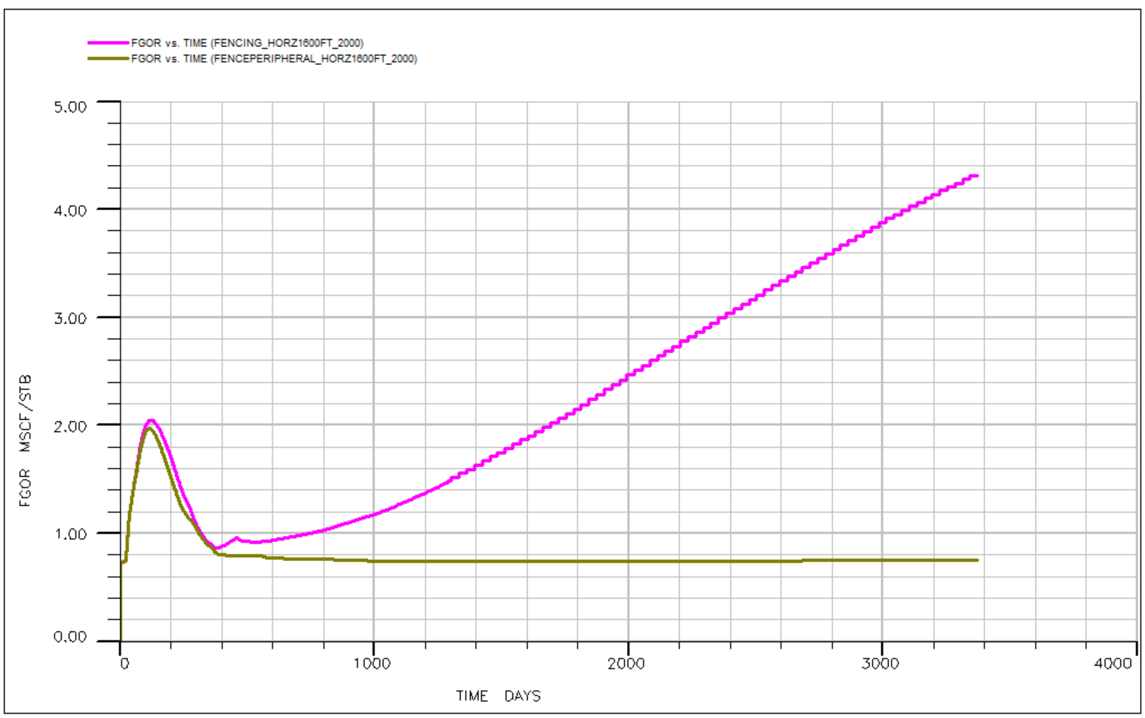

Figure 25: GOR (FGOR) vs. time of fencing water injection and simultaneous fencing and peripheral water injection

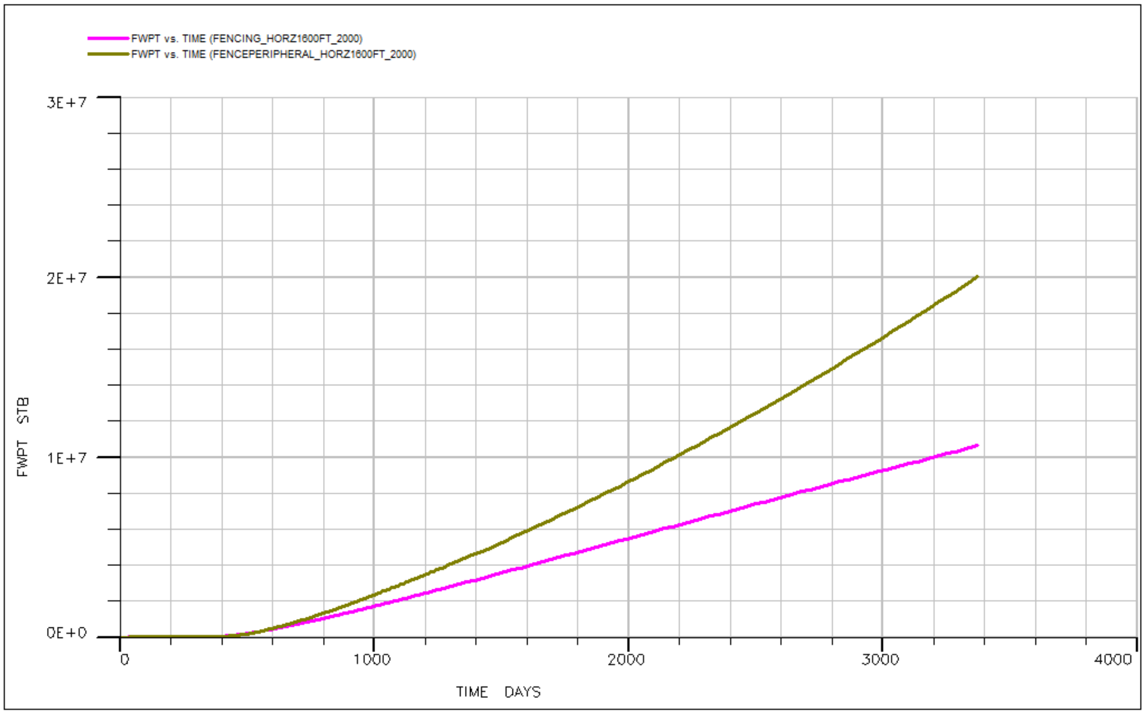

Figure 26: Total water produced (FWPT) vs. time of fencing water injection and simultaneous fencing and peripheral water injection

Comparing up-dip water injection and simultaneous up-dip and down-dip water injection, the cumulative oil produced were 7193760 STB and 11163191 STB correspondingly. The difference between this two cases was 3969431 STB (~3.9 MSTB). Simultaneous up-dip and down-dip water injection produced higher oil than only up-dip water injection. Combining both fencing and peripheral water injection, while peripheral water injection maintained reservoir pressure, fencing water injection suppressed oil rim movement towards gas cap (Chan, Kifli, & Darman, 2011; Razak, Chan, & Darman, 2011). Figure 25 showed combination of fencing and peripheral water injection significantly reduced gas production by decreasing gas-oil ratio. As for **Figure 26**, since this combination involved injection of water both ways up-dip and down-dip at the same time, there were an increase in water production up to 9390627 STB (~9.4 MSTB).

By comparing three parameters above, it can be determined that simultaneous fencing and peripheral water injection has better oil recovery compared to solely fencing water injection.

4.2.4 Case 4: Gas injection in gas cap and water injection in aquifer (1 producers, 2 injectors in gas cap and 4 injectors in aquifer)

Using same coordinates as case 3, water was injected in aquifer and gas injection was performed in gas cap instead of water. 50 MMscf of gas was injected in gas cap in line with research paper SPE 128392. Gas injection was performed in Samarang field for 50MMscf/day with similar reservoir properties and yielded an additional 33.5MMSTB of oil production (Bui, Forrest, Tewari, Henson, & Abu Bakar, 2010). The results were tabulated and compared to water injection as base case for analysis.

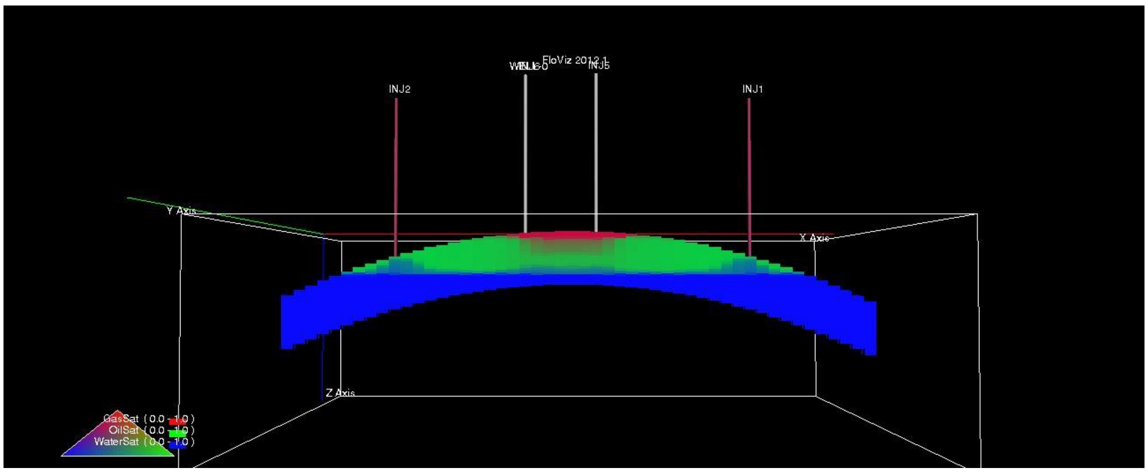

Figure 27: Water injection in aquifer and gas injection in gas cap

Table 7: Comparison between simultaneous water injection in aquifer and gas injection in gas cap and base case

Parameters	**Comparison with base case**	
	Water injection in aquifer	*Water injection in aquifer and gas injection in gas cap*
Total oil produced, STB	14001270	11005061
Gas-oil ratio, Mscf/STB	0.82843238	53.306168
Total water produced, STB	7316131	7390289.5

For case 4, the indication of three graphs is shown as below:

Water injection in aquifer with injection rate of 2000 STB/day

Water injection in aquifer with injection rate of 2000 STB/day and gas injection in gas cap with injection rate of 50 MMscf/day

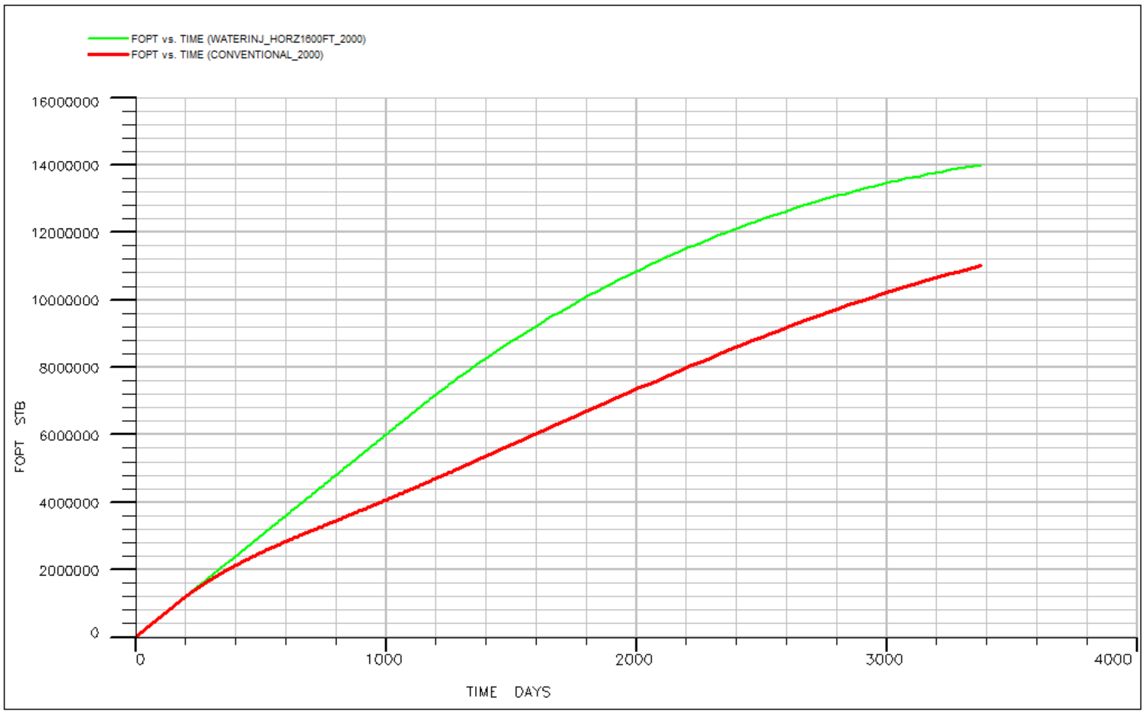

Figure 28: Total oil produced (FOPT) vs. time for water injection and simultaneous water injection in aquifer and gas injection in gas cap

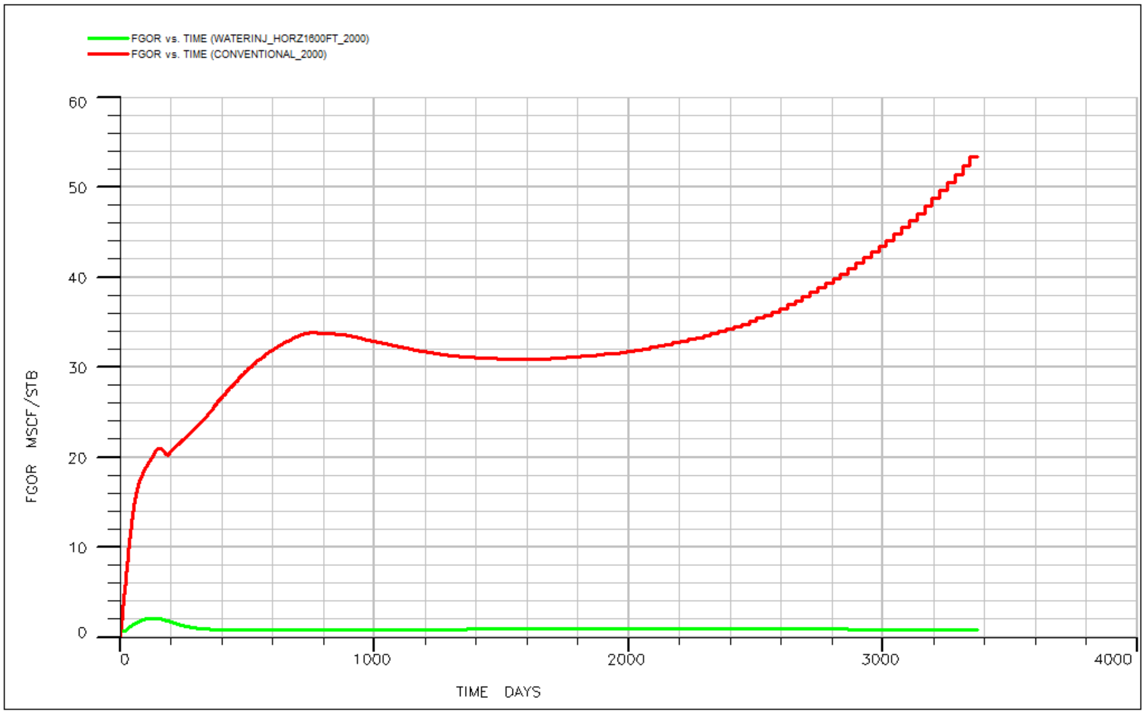

Figure 29: GOR (FGOR) vs. time for water injection and simultaneous water injection in aquifer and gas injection in gas cap

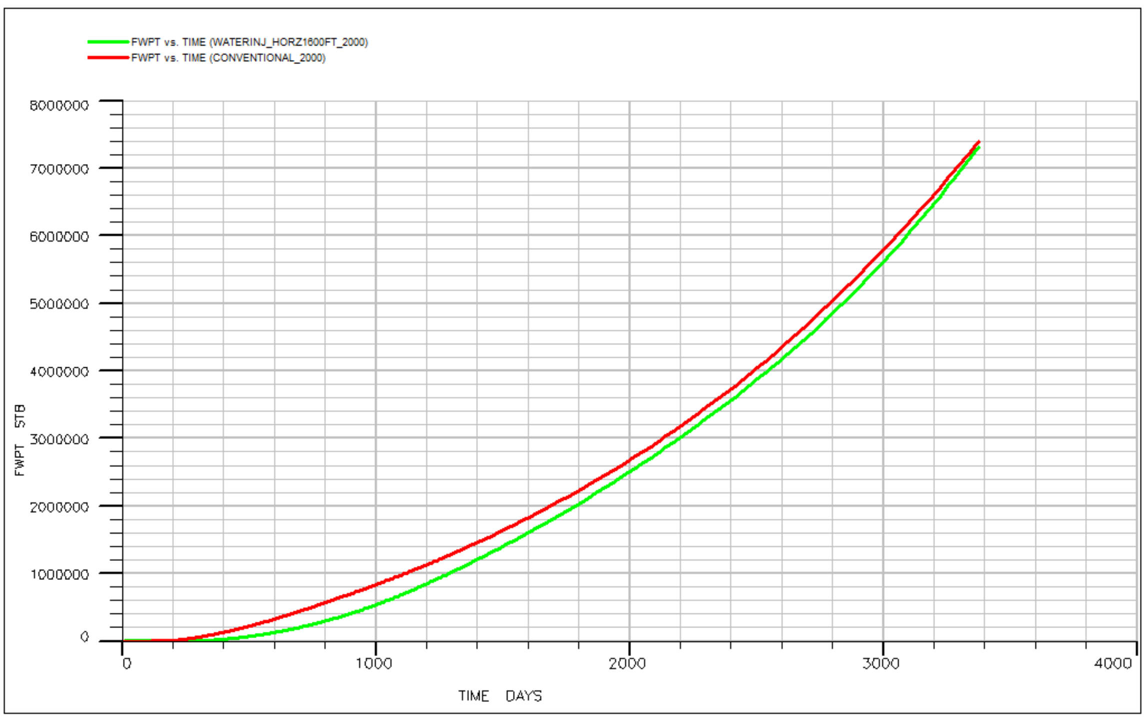

Figure 30: Total water produced (FWPT) vs. time for water injection and simultaneous water injection in aquifer and gas injection in gas cap

Gas injected is assumed to be discharged gas from reservoir with 0.050674 lb/ft^3 and its properties. Since gas is very mobile and has small critical gas saturation, gas produces faster than that of oil (Ahmed, 2010). From **Figure 28** to **Figure 30**, it is concluded that gas produced more in simultaneous water and gas injection than that of base case water injection. Due to higher production in gas, oil production is significantly lower than oil production of base case. This can be justified by Ahmed (2010) which we assumed oil is the wetting phase while gas is the non-wetting phase. Given non-wetting phase resides the larger pores, a small non-wetting phase saturation can affect much on wetting phase permeability. Future work is recommended to improve this method by correcting well spacing and injection gas rate and properties.

4.2.5 Case 5: Water injection in gas cap and gas injection in aquifer (1 producers, 2 injectors in gas cap and 4 injectors in aquifer)

This technique also known as GASWAG, simultaneous down-dip gas injection and up-dip water injection, which the gas was injected at or near WOC and water was injected at or near GOC. The injection rate was referred to case 2 and case 4 for better oil recovery purposes. The results were tabulated and analysis were done based on results and graphs.

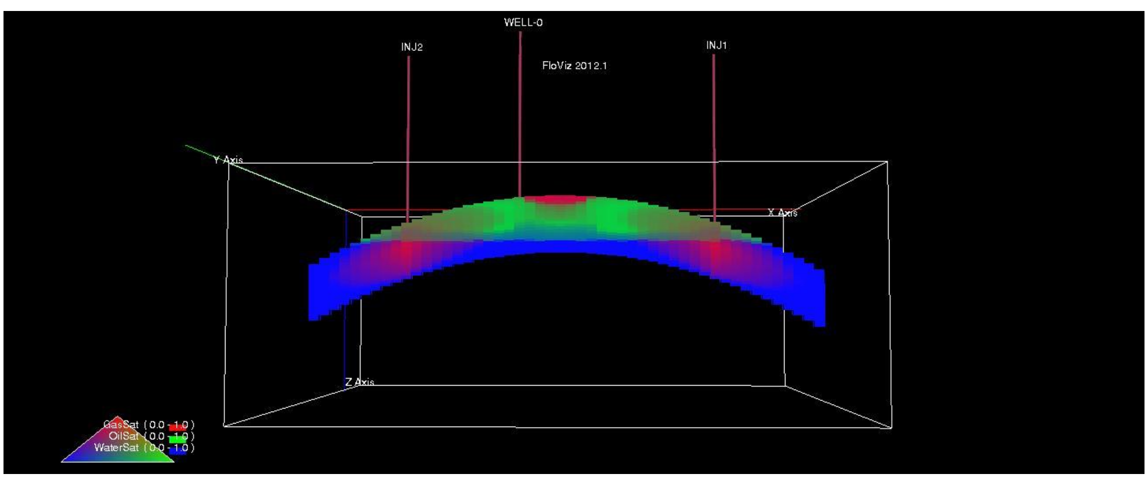

Figure 31: Simultaneous water injection in gas cap and gas injection in aquifer in reservoir model

Table 8: Comparison between fencing and peripheral water injection and simultaneous water injection in gas cap and gas injection in aquifer

Parameters	**Comparison**	
	Fencing and peripheral water injection	*Water injection in gas cap and gas injection in aquifer*
Total oil produced, STB	11163191	14129820
Gas-oil ratio, Mscf/STB	0.75154668	145.659
Total water produced, STB	20019478	32476530

For case 5, the indication of three graphs is shown as below:

Water injection in gas cap with injection rate of 2000 STB/day and gas injection in aquifer with injection rate of 50 MMscf/day

Water injection in both aquifer and gas cap with injection rate of 2000 STB/day

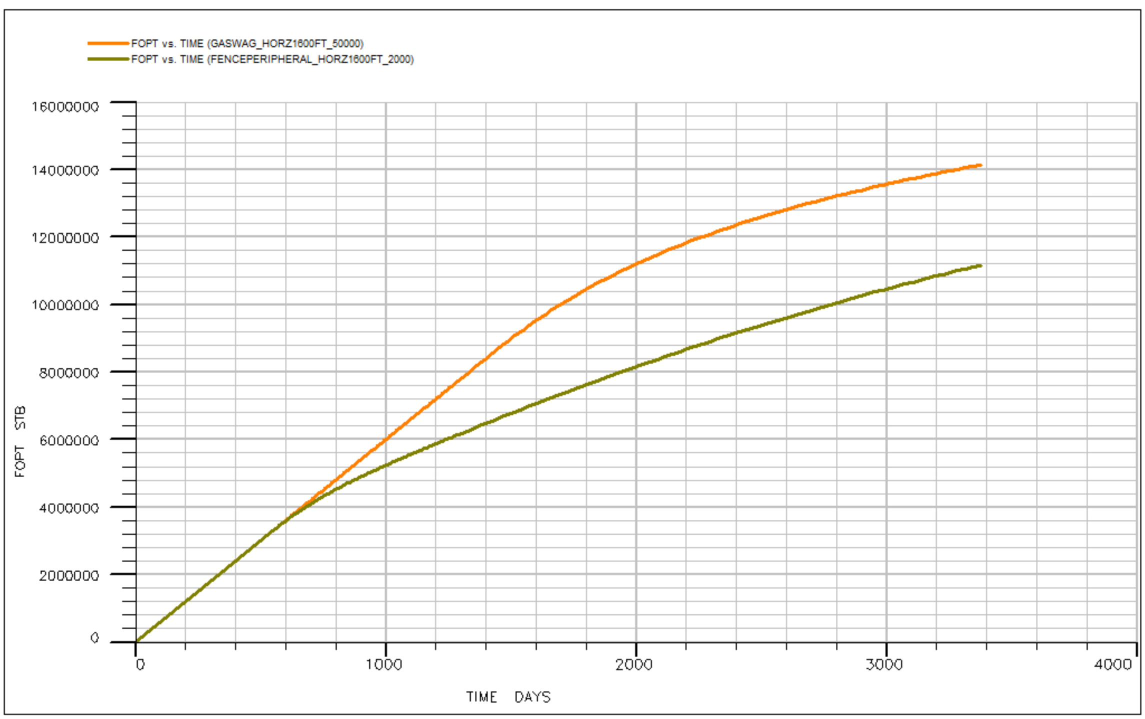

Figure 32: Total oil produced (FOPT) vs. time for fencing and peripheral water injection and simultaneous water injection in gas cap and gas injection in aquifer

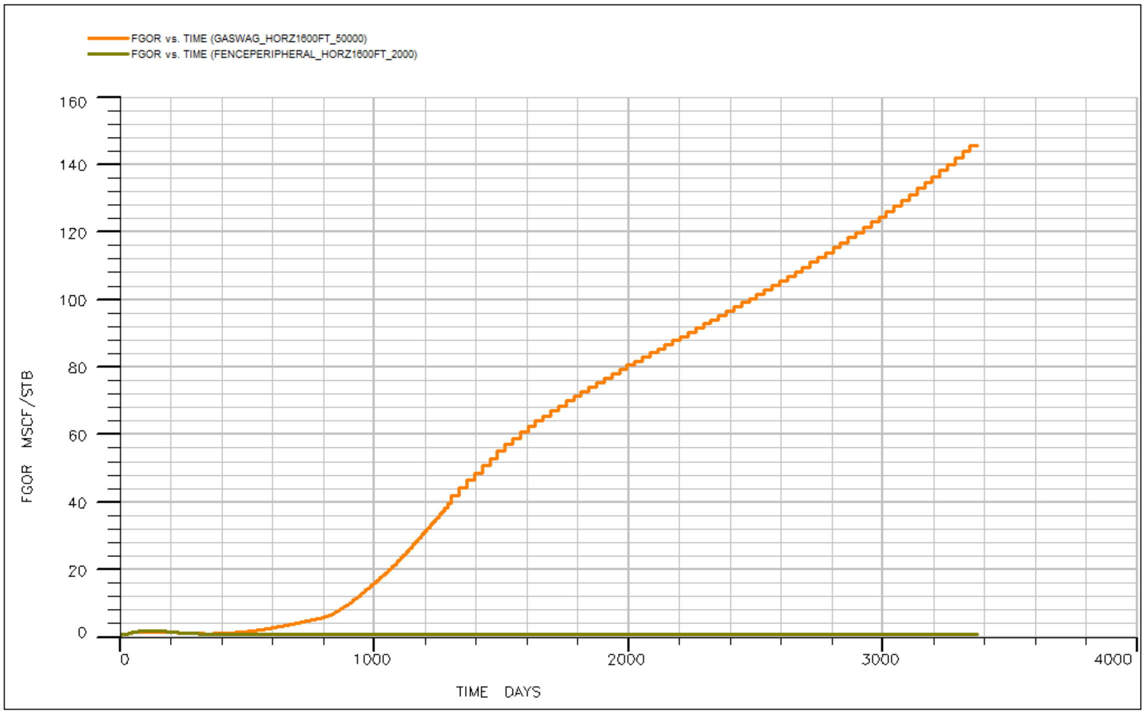

Figure 33: GOR (FGOR) vs. time for fencing and peripheral water injection and simultaneous water injection in gas cap and gas injection in aquifer

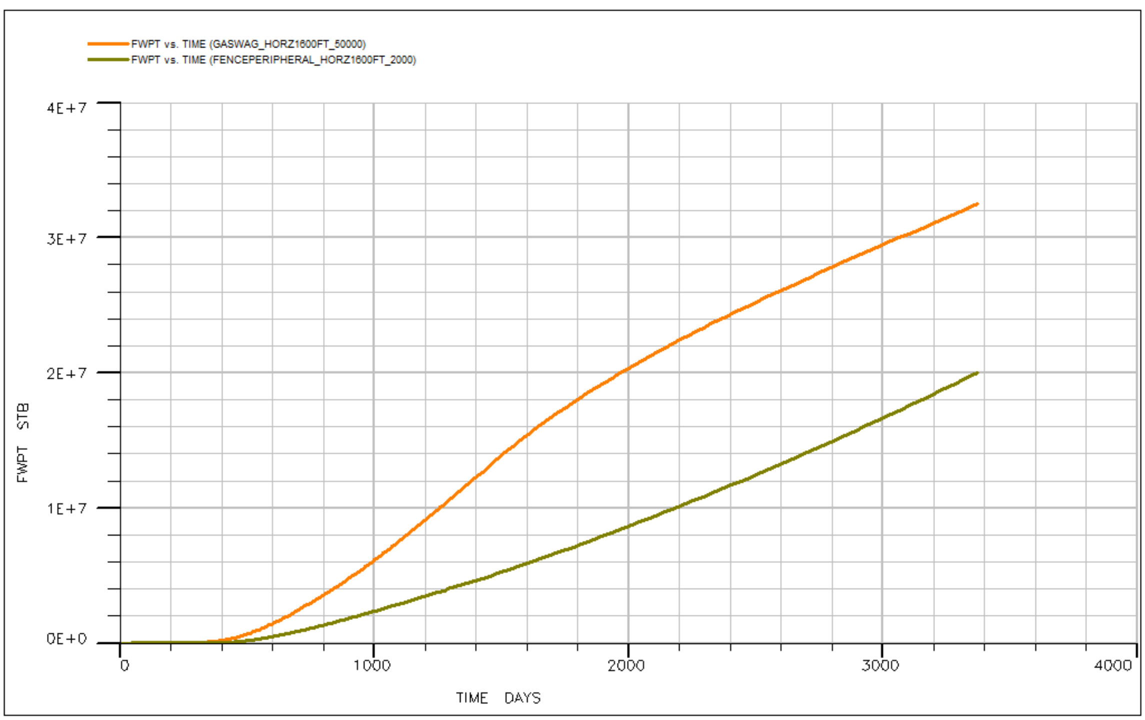

Figure 34: Total water produced (FWPT) vs. time for fencing and peripheral water injection and simultaneous water injection in gas cap and gas injection in aquifer

Similar to case 4, more gas was produced in comparison to oil production. While comparing to simultaneous fencing and peripheral water injection, GASWAG yielded a better oil recovery, which is 2966629 STB (~3 MMSTB). By injecting gas into aquifer and water into gas cap simultaneously, the application was expected to rezone oil to the center by injector well placement as gas would displaced oil in the reservoir upwards while water displaced oil in downwards movement, resulting in higher oil production (Bui, Forrest, Tewari, Henson, & Abu Bakar, 2010; Razak, Chan, & Darman, 2011). Combination of fencing water injection and down dip gas injection could result in lateral displacement of oil near to oil producer in reservoir to increase oil production.

4.2.6 Case 6: Polymer flooding (1 producers, 4 injectors)

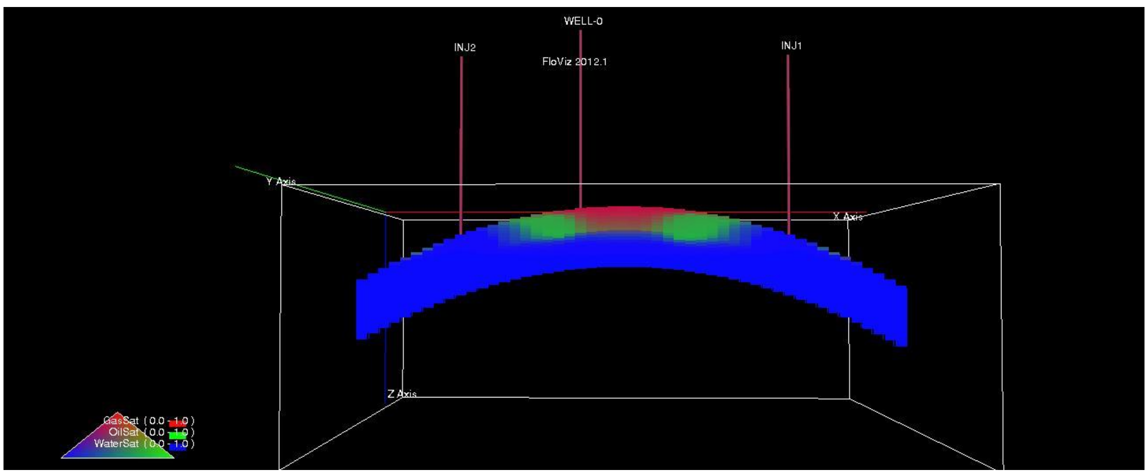

Figure 35: Polymer flooding in reservoir model

For case 6, the indication of three graphs is shown as below:

Water injection in aquifer with injection rate of 2000 STB/day

Water injection in gas cap with injection rate of 2000 STB/day

Water injection in both aquifer and gas cap with injection rate of 2000 STB/day

Water injection in aquifer with injection rate of 2000 STB/day and gas injection in gas cap with injection rate of 50 MMscf/day

Water injection in gas cap with injection rate of 2000 STB/day and gas injection in aquifer with injection rate of 50 MMscf/day

Water-soluble polymer injection in aquifer with injection rate of 2000 STB/day

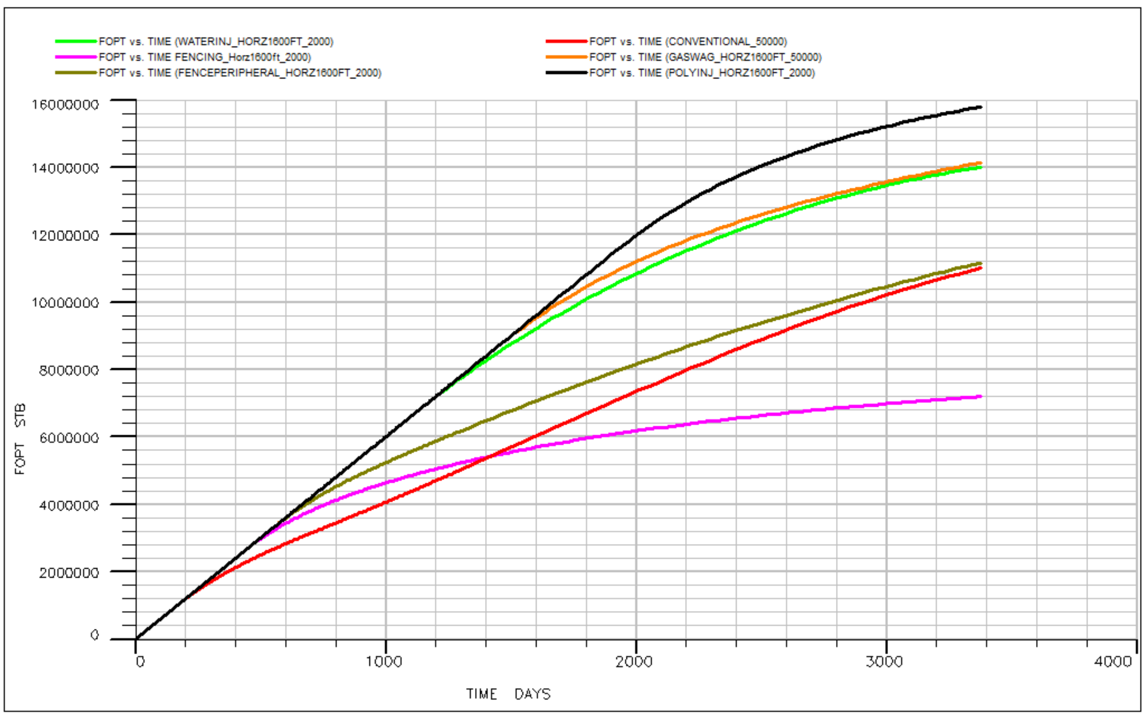

Figure 36: Total oil produced (FOPT) vs. time for all case studies

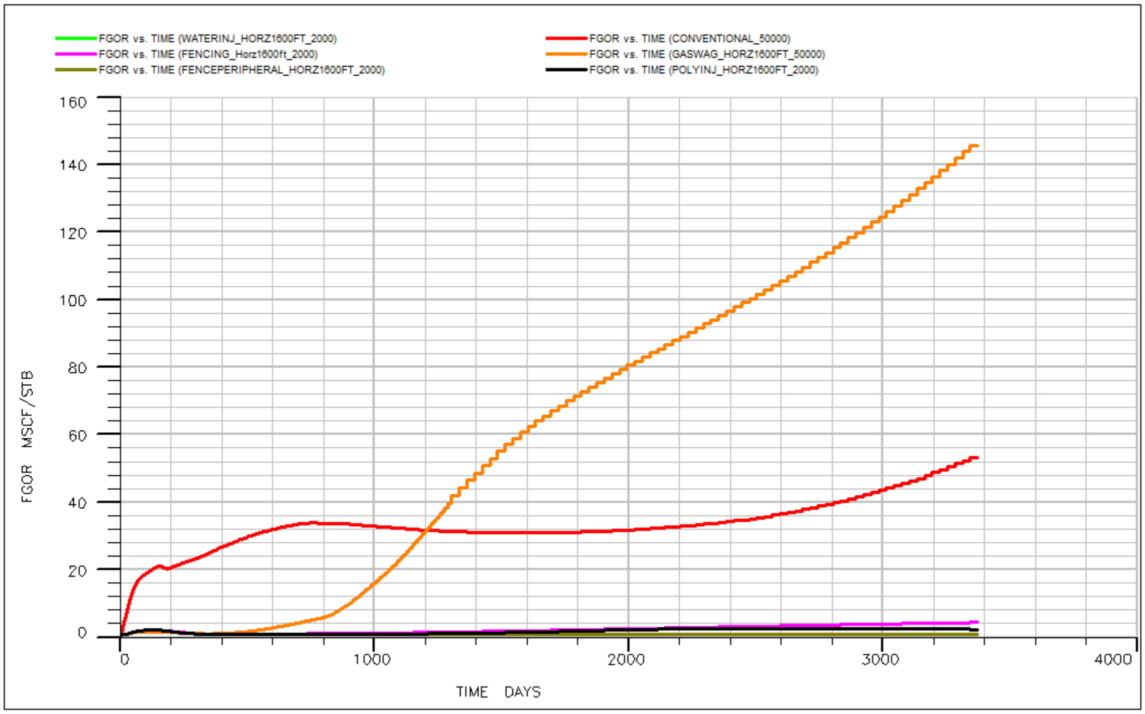

Figure 37: GOR (FGOR) vs. time for all case studies

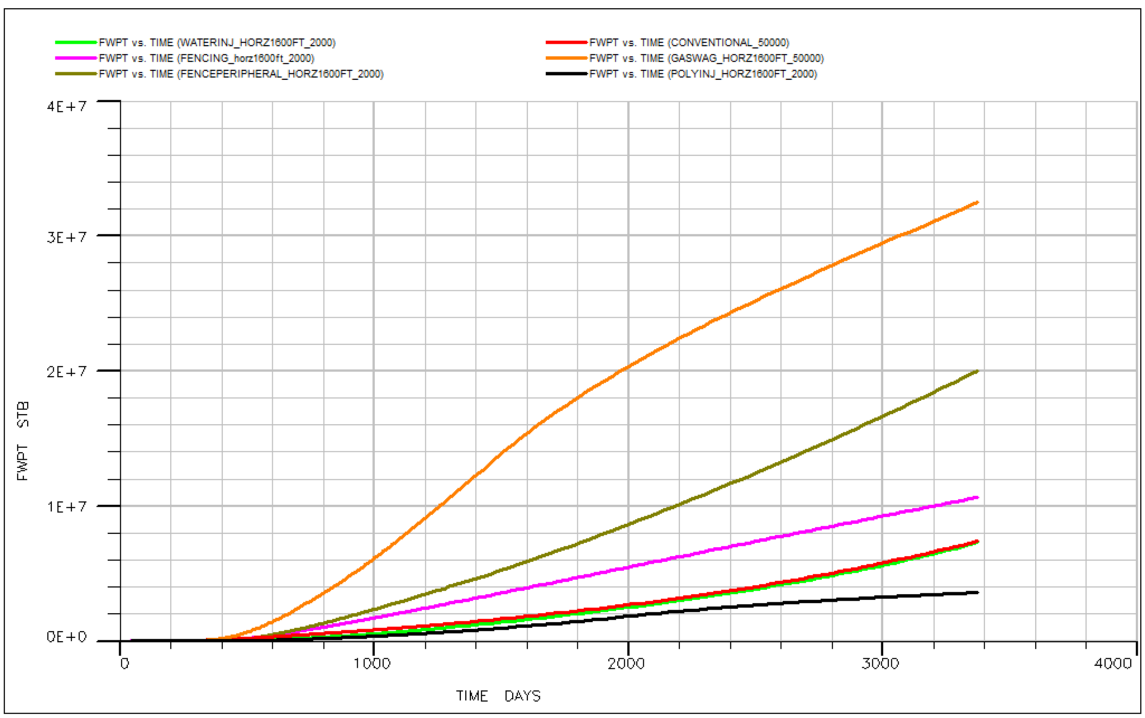

Figure 38: Total water produced (FWPT) vs. time for all case studies

Polymer flooding is usually used for heavy oil reservoirs production (San Blas & Vittoratos, 2014). For simulation purposes to discover best improved oil recovery methods, polymer flooding was taken into consideration for light oil reservoir model since polymer flooding is able to increase water viscosity and reduce water mobility ratio for the ease of oil production (Needham & Doe, 1987). Other than that, high oil prices provide economic advantages to applications of polymer flooding (San Blas & Vittoratos, 2014).

Water-soluble polymer was mixed into injection water and was injected using well placement from case 2 and a horizontal oil producer. The result shown not only polymer was able to improve oil production to 15792995 STB (~15.8 MMSTB), this technique yielded relatively less gas and water comparing to other cases. This can be shown in all **Figure 36**, **Figure 37** and **Figure 38**.

Chapter 5
Conclusions and Recommendations

As the main goal of this study is to determine best improved oil recovery method for thin oil rim reservoir, seven case studies with different scenarios and fluid injection were created and generated based on the reservoir model. The case study with best oil production was selected to be the best in this study. In this case, polymer flooding is determined as the best improved oil recovery, followed by simultaneously water injection in gas cap and gas injection in aquifer. This is mainly because polymer flooding can increase water viscosity and allow more oil to be produced. Proper well placement of injector wells and injection rate of injector fluid are important in improving and maximizing oil recovery (Davis & Habib, 1999; Ahmed, 2010). Both techniques can be recommended to further improved by having proper well placement, improving fluid properties of polymer and its optimal injection rate in the future.

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Appendix

Eclipse program for base case (horizontal well)

```
RUNSPEC
TITLE
Oil Rim Simulation
START
1 Jan 2009/
FIELD
OIL
GAS
WATER
DISGAS
DIMENS
50 50 20 /
UNIFOUT
--NOSIM
EQLDIMS
1 100 1 1 20 /
REGDIMS
1 1 0 0 /
TABDIMS
1 1 50 50 5 50 50 /
WELLDIMS
5 300 50 5 /
NSTACK
 50/

GRID
INIT
INCLUDE tops.inc/ INCLUDE dz.inc/ INCLUDE dx.inc/ INCLUDE dy.inc/ INCLUDE
PV.inc/
EQUALS
ACTNUM 1 1 50 1 50 1 20/
NTG 1 1 50 1 50 1 20/
PERMX 30 1 50 1 50 1 20/
PORO 0.2 1 50 1 50 1 20/
/
MULTIPLY
 PERMX 1/
/
COPY
PERMX PERMY/
/
COPY
PERMX PERMZ/
```

```
/
MULTIPLY
 PERMZ 0.01/
/
EDIT
PROPS
SWOF
--  sw      krw     kr      pc
0.23    0    1.000    0
0.26    0.001    0.837    0
0.28    0.005    0.695    0
0.30    0.010    0.572    0
0.32    0.018    0.466    0
0.35    0.028    0.375    0
0.37    0.041    0.298    0
0.39    0.056    0.234    0
0.41    0.073    0.181    0
0.44    0.092    0.137    0
0.46    0.113    0.102    0
0.48    0.137    0.074    0
0.51    0.163    0.052    0
0.53    0.192    0.036    0
0.55    0.222    0.023    0
0.57    0.255    0.015    0
0.60    0.290    0.009    0
0.62    0.328    0.005    0
0.64    0.367    0.002    0
0.66    0.409    0.001    0
0.69    0.454    0.000    0
0.71    0.500    0.000    0
0.73    0.549    0.000    0
0.76    0.600    0.000    0
1.00    0.600    0.000    0  /

SGOF
--   Sg       krg    Kro      Pc
0    0.000    1.000    0
0.037    0.000    1.000    0
0.073    0.002    0.900    0
0.110    0.011    0.753    0
0.146    0.027    0.619    0
0.183    0.052    0.497    0
0.219    0.085    0.390    0
0.256    0.125    0.295    0
0.292    0.174    0.213    0
0.329    0.230    0.145    0
0.365    0.294    0.090    0
```

```
0.402   0.367   0.048   0
0.438   0.447   0.019   0
0.475   0.535   0.000   0
0.511   0.631   0.000   0
0.548   0.734   0.000   0
0.584   0.846   0.000   0
0.621   0.966   0.000   0
0.657   1.000   0.000   0
0.694   1.000   0.000   0
0.730   1.000   0.000   0
0.767   1.000   0.000   0 /


PVTW                          -- Generated : Petrel
     3118.3      1.0132  2.7438E-006     0.39851          0 /

PVTO                          -- Generated : Petrel
    0.038703      206.26      1.0806     0.58902
     450.08      1.0721      1.0121
     693.89      1.0696      1.0347
     937.71      1.0683      1.0457
     1181.5      1.0676      1.0523
     1425.3      1.0672      1.0566
     1669.2      1.0668      1.0597
       1913      1.0666       1.062
     2156.8      1.0664      1.0638
     2400.6      1.0663      1.0652
     2644.4      1.0661      1.0664
     3132.1      1.0659      1.0682
     3619.7      1.0658      1.0695
     4351.1      1.0657      1.0709 /
    0.099025      450.08      1.1055     0.50511
     693.89      1.0987     0.89393
     937.71      1.0954     0.91814
     1181.5      1.0935     0.93277
     1425.3      1.0922     0.94257
     1669.2      1.0914     0.94959
       1913      1.0907     0.95486
     2156.8      1.0902     0.95897
     2400.6      1.0898     0.96226
     2644.4      1.0894     0.96495
     2888.2      1.0892      0.9672
     3132.1      1.0889      0.9691
     3375.9      1.0887     0.97073
     3619.7      1.0886     0.97215
     3863.5      1.0884     0.97338
```

4107.3	1.0883	0.97448	
4351.1	1.0882	0.97545	
4838.8	1.088	0.9771 /	
0.16676	693.89	1.1338	0.44567
937.71	1.1276	0.79152	
1181.5	1.124	0.81374	
1425.3	1.1216	0.82881	
1669.2	1.1199	0.83971	
1913	1.1187	0.84796	
2156.8	1.1177	0.85442	
2400.6	1.117	0.85961	
2644.4	1.1163	0.86388	
2888.2	1.1158	0.86744	
3132.1	1.1154	0.87047	
3375.9	1.115	0.87307	
3619.7	1.1147	0.87533	
3863.5	1.1144	0.87731	
4107.3	1.1141	0.87906	
4351.1	1.1139	0.88062	
4594.9	1.1137	0.88202	
4838.8	1.1135	0.88328 /	
0.23964	937.71	1.1645	0.40168
1181.5	1.1586	0.70236	
1425.3	1.1547	0.72208	
1669.2	1.152	0.73649	
1913	1.1499	0.74748	
2156.8	1.1483	0.75614	
2400.6	1.1471	0.76314	
2644.4	1.1461	0.76891	
2888.2	1.1452	0.77375	
3132.1	1.1445	0.77788	
3375.9	1.1439	0.78143	
3619.7	1.1434	0.78452	
3863.5	1.1429	0.78723	
4107.3	1.1425	0.78963	
4351.1	1.1422	0.79177	
4594.9	1.1418	0.79369	
4838.8	1.1415	0.79542 /	
0.31653	1181.5	1.1971	0.36769
1425.3	1.1913	0.62524	
1669.2	1.1872	0.64257	
1913	1.1841	0.65591	
2156.8	1.1818	0.66649	
2400.6	1.1799	0.67509	
2644.4	1.1784	0.68223	
2888.2	1.1771	0.68823	
3132.1	1.176	0.69336	

3375.9	1.1751	0.69779	
3619.7	1.1743	0.70165	
3863.5	1.1736	0.70505	
4107.3	1.173	0.70806	
4351.1	1.1725	0.71075	
4594.9	1.172	0.71317	
4838.8	1.1716	0.71535 /	
0.39674	1425.3	1.2314	0.3405
1669.2	1.2255	0.55886	
1913	1.2212	0.57406	
2156.8	1.2179	0.58621	
2400.6	1.2152	0.59616	
2644.4	1.213	0.60444	
2888.2	1.2112	0.61145	
3132.1	1.2097	0.61746	
3375.9	1.2084	0.62266	
3619.7	1.2073	0.62721	
3863.5	1.2064	0.63123	
4107.3	1.2055	0.63479	
4351.1	1.2047	0.63798	
4594.9	1.2041	0.64086	
4838.8	1.2034	0.64345 /	
0.47982	1669.2	1.2671	0.31815
1913	1.2612	0.50187	
2156.8	1.2566	0.51521	
2400.6	1.253	0.52621	
2644.4	1.2501	0.53543	
2888.2	1.2476	0.54326	
3132.1	1.2456	0.55	
3375.9	1.2438	0.55586	
3619.7	1.2423	0.561	
3863.5	1.241	0.56554	
4107.3	1.2398	0.56959	
4351.1	1.2388	0.57322	
4594.9	1.2378	0.57649	
4838.8	1.237	0.57946 /	
0.56541	1913	1.3041	0.29939
2156.8	1.298	0.45296	
2400.6	1.2933	0.46472	
2644.4	1.2894	0.47464	
2888.2	1.2862	0.48311	
3132.1	1.2834	0.49044	
3375.9	1.2811	0.49683	
3619.7	1.2791	0.50245	
3863.5	1.2774	0.50744	
4107.3	1.2758	0.5119	
4351.1	1.2745	0.5159	

4594.9	1.2733	0.51952	
4838.8	1.2722	0.5228 /	
0.65327	2156.8	1.3422	0.28336
2400.6	1.336	0.41097	
2644.4	1.331	0.42137	
2888.2	1.3269	0.43031	
3132.1	1.3234	0.43807	
3375.9	1.3204	0.44488	
3619.7	1.3178	0.45088	
3863.5	1.3156	0.45623	
4107.3	1.3136	0.46102	
4351.1	1.3119	0.46533	
4594.9	1.3103	0.46923	
4838.8	1.3089	0.47278 /	
0.74318	2400.6	1.3814	0.26946
2644.4	1.3751	0.37485	
2888.2	1.3698	0.38409	
3132.1	1.3654	0.39216	
3375.9	1.3617	0.39926	
3619.7	1.3584	0.40556	
3863.5	1.3556	0.41118	
4107.3	1.3531	0.41623	
4351.1	1.3509	0.42078	
4594.9	1.3489	0.42492	
4838.8	1.3472	0.42869 /	
0.83498	2644.4	1.4216	0.25727
2888.2	1.4151	0.3437	
3132.1	1.4096	0.35196	
3375.9	1.4049	0.35925	
3619.7	1.4009	0.36575	
3863.5	1.3974	0.37157	
4107.3	1.3943	0.37681	
4351.1	1.3915	0.38156	
4594.9	1.3891	0.38588	
4838.8	1.3869	0.38982 /	
0.92852	2888.2	1.4626	0.24648
3132.1	1.4559	0.31678	
3375.9	1.4502	0.32418	
3619.7	1.4452	0.3308	
3863.5	1.4409	0.33676	
4107.3	1.4372	0.34214	
4351.1	1.4338	0.34702	
4594.9	1.4308	0.35148	
4838.8	1.4282	0.35556 /	
1.0237	3132.1	1.5044	0.23683
3375.9	1.4975	0.29342	
3619.7	1.4915	0.3001	

```
    3863.5   1.4863   0.30613
    4107.3   1.4818   0.3116
    4351.1   1.4777   0.31658
    4594.9   1.4741   0.32114
    4838.8   1.4709   0.32532 /
    1.1204   3375.9   1.5469   0.22814
    3619.7   1.5398   0.27311
    3863.5   1.5335   0.27917
    4107.3   1.5281   0.28468
    4351.1   1.5233   0.28972
    4594.9   1.519    0.29434
    4838.8   1.5151   0.29859 /
    1.2185   3619.7   1.59     0.22026
    3863.5   1.5827   0.25538
    4107.3   1.5762   0.2609
    4351.1   1.5705   0.26595
    4594.9   1.5654   0.27061
    4838.8   1.5608   0.2749 /
    1.318    3863.5   1.6337   0.21309
    4107.3   1.6261   0.23985
    4351.1   1.6194   0.2449
    4594.9   1.6134   0.24956
    4838.8   1.6081   0.25387 /
    1.4188   4107.3   1.6779   0.20651
    4351.1   1.6701   0.22621
    4594.9   1.6631   0.23086
    4838.8   1.6569   0.23517 /
    1.5208   4351.1   1.7226   0.20045
    4594.9   1.7145   0.21419
    4838.8   1.7072   0.21848 /
 /
PVDG                        -- Generated : Petrel
     200     15.54    0.012826
    443.82   6.8597   0.013129
    687.63   4.3418   0.013512
    931.45   3.1479   0.013968
    1175.3   2.4549   0.014494
    1419.1   2.005    0.015088
    1662.9   1.6919   0.015747
    1906.7   1.4635   0.016467
    2150.5   1.2911   0.017242
    2394.3   1.1578   0.018063
    2638.2   1.0525   0.018921
    2882     0.96805  0.019805
    3125.8   0.89934  0.020706
    3369.6   0.84271  0.021615
    3613.4   0.79548  0.022525
```

```
        3857.2      0.75564      0.02343
        4101.1       0.7217     0.024327
        4344.9      0.69248     0.025211
        4588.7      0.66711     0.026081
        4832.5      0.64488     0.026935
  /
DENSITY                              -- Generated : Petrel
        49.999       63.698     0.050674 /
FILEUNIT                             -- Generated : Petrel
  FIELD /
ROCK
  2949    0.00000314    /
REGIONS
SOLUTION
ECHO
EQUIL
3645.7 2500 3710 0 3645.7 0 /
RPTSOL
 PRESSURE SWAT SGAS SOIL  RESTART=2 /
RPTRST
 BASIC=2 /
SUMMARY
INCLUDE
summary.inc/
SCHEDULE
RPTSCHED
 PRESSURE SWAT SGAS SOIL SUMMARY=2 RESTART=2  WELLS   /
RPTRST
BASIC=2 /
DRSDT
0 /
WELSPECS
Well-0 G1 21 25 1*  Oil 5* AVG /
/
COMPDAT
Well-0 21 25 9 9 'OPEN'       2*  0.5  3* x/
Well-0 22 25 9 9 'OPEN'       2*  0.5  3* x/
Well-0 23 25 9 9 'OPEN'       2*  0.5  3* x/
Well-0 24 25 9 9 'OPEN'       2*  0.5  3* x/
Well-0 25 25 9 9 'OPEN'       2*  0.5  3* x/
Well-0 26 25 9 9 'OPEN'       2*  0.5  3* x/
Well-0 27 25 9 9 'OPEN'       2*  0.5  3* x/
Well-0 28 25 9 9 'OPEN'       2*  0.5  3* x/
/
WCONPROD
Well-0 OPEN  ORAT 6000 4* 250/
/
```

```
WECON
Well-0 200 6*/
/
--TUNING
--/
--/
--2* 50/
TSTEP
365*1/
TSTEP
30*7/
TSTEP
100*7/
TSTEP
70*30/
-- TSTEP
-- 100*7/

END
```

Table 9: Comparison of all cases

Parameters	**Comparison**						
	Horizontal producer	*Water injection (2000 STB/day)*	*Fencing water injection*	*Fencing and peripheral water injection*	*Water injection in aquifer and gas injection in gas cap*	*Water injection in gas cap and gas injection in aquifer*	*Polymer flooding*
Total oil produced, STB	7587893	14001270	7193760	11163191	11005061	14129820	15792995
Gas-oil ratio, Mscf/STB	8.0955038	0.82843238	4.3115978	0.75154668	53.306168	145.659	2.3050325
Total water produced, STB	2143935.3	7316131	10628851	20019478	7390289.5	32476530	10628851