ANALYZING THE EFFECT OF INJECTION RATES ON OIL PRODUCTION DURING FAWAG PROCESS

By

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(10972)

Dissertation submitted to Petroleum Engineering Programme
in Partial Fulfilment of the Requirements
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CERTIFICATION OF APPROVAL

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Approved,

....

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Project Supervisor

UNIVERSITI TEKNOLOGI PETRONAS

TRONOH, PERAK

August 2011

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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Thank you,

RAHIMAH BINTI ABD HALIM
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ABSTRACT

Foam Assisted Water Alternating Gas (FAWAG) is one of Enhanced Oil Recovery method to increase oil production. It can only be implemented to reservoir already using water alternating gas (WAG) injection[1,3,11].It can be placed in the reservoir by either co-injection of liquid and gas at fixed quality, or surfactant-alternating-gas (SAG) injection. Studies confirmed that the use of foams for mobility control successful in reducing problems like early gas breakthrough and poor sweep efficiency.

This study is important as the aim of all EOR's process is to increase the oil production. The purpose of this research is to analyse the effect of injection rates on oil production during FAWAG process. It will focus on process and mechanism involved during FAWAG process and also the SAG method.

The results shows high injection rates of surfactant are stronger than the gas injection rates. However, injecting constantly high injection rates throughout the production life might affect reservoir pressure. The water productions will also increase as high surfactant slug injection rate is used.

By doing this study, it proves that FAWAG process can be implemented commercially. The simulation works has been done to using ECLIPSE 100.

CHAPTER 1

INTRODUCTION

1.1 BACKGROUND OF STUDY

The National Energy Technology Laboratory (NETL)[24], owned and operated by the U.S. Department of Energy (DOE) defines EOR as "…something is added to the reservoir after secondary recovery in order to increase production. This can be gases, chemicals, microbes, heat, or even the addition of energy, such as the stimulation of the oil through vibration energy".

The main purpose of any EOR method is to increase oil production by increasing the capillary number and providing favourable mobility ratio which is M<1.0.

a) Capillary number is defined as the ratio of viscous forces to capillary forces.

$$N_c = \frac{Viscous\ Forces}{Capillary\ Forces} = \frac{v\mu}{\sigma cos\theta} \ldots (1)$$

Where v is the velocity and μ is the viscosity of the displacing fluid, σ is the water-oil interfacial tension and θ is the contact angle between oil-water interface and the rock surface.

b) Mobility ratio, MR is defined as the ratio of mobility of the displacing phase to the displaced phase.

$$MR = \frac{M_D}{M_d} = \frac{\left(k/\mu\right)_{Displacing\ phase}}{\left(k/\mu\right)_{Displaced\ phace}} \ldots (2)$$

Where k and μ are the relative or effective permeability and viscosity, respectively.

CHAPTER 2

LITERATURE REVIEW

2.1 BACKGROUND OF FAWAG

There are five EOR technologies that have been initiated in North Sea. There are hydrocarbon (HC) miscible gas injection, water-alternating-gas (WAG) injection, simultaneous water-and-gas (SWAG) injection, foam-assisted WAG (FAWAG) injection, and microbial EOR (MEOR). In North Sea, WAG has been used to improve oil recovery by increasing the macroscopic and microscopic sweep efficiency. This is because residual oil to WAG is less than water or gas(1).

FAWAG technology was founded on Snorre by Saga Petroleum and was first implemented on the field in 1997(1,2,3,11). It was initiated at Snorre Field to delay gas breakthrough and to increase gas storage in the reservoir (1,2,3). FAWAG can only be introduced in reservoirs on which water alternating gas (WAG) injection is already in use(1,3,11). In WAG, the water displaces the lower part of the oil-bearing sands, and gas fills the upper part and attics. Although WAG is proven as a means of enhancing oil recovery, it has been observed that the gas often rises to the top of the reservoir relatively quickly, and its presence can be detected in the oil produced from this zone. FAWAG at WFB Snorre Field has been conducted successfully and around 33% free back-produced gas was reduced. This is because FAWAG technology has the potential for plugging selected zones or layers with foam while the reservoir remains under WAG flood.(2,3)

For WAG, the optimum ratio is influenced by the wetting state of the rock. Ratio of 1:1 of water and gas is the most popular for field applications. However, gravity forces dominate water-wet tertiary floods while viscous fingering controls oil-wet tertiary floods. High WAG ratios have a large effect on oil recovery in water-wet rocks resulting in lower oil recoveries.

For water-wet rocks, 0:1 WAG ratio (continuous gas injection) is suggested for secondary as well as tertiary floods. For a partially oil-wet rock, tertiary gas injection with 1:1 WAG ratio is suggested. [16]

When HC gas volumes are limited and uneconomical to export, then Surfactant WAG (SWAG) injection can be used. Using SWAG, Statoil has reported and increased recovery of 6% compared to water injection scheme at North Sea field. Some concerns using SWAG are potential of gas and water to separate if there are any branches in the injection pipe network, hydrate formation during the injection and backpressure valve is needed to prevent flow of the opposite medium into the respective compression system. That is one of the reason why Statoil introduced FAWAG.[1]

2.2 FOAM GENERATION

From the literature, most data suggest that oil may limit the efficiency of foams in reducing gas mobility. Some define foam does not form above a critical oil saturation while some show that it is possible to generate strong foams at relatively high oil saturation. Another suggests that a high concentration of light hydrocarbons in the oil appears to be the main reason for reduced foam stability.[25]

The presence of a surfactant in a porous medium can also have some negative effects like reducing the magnitude of capillary forces. For flow dominated by capillary forces, this may increase channelling and gravity segregation. The effect can reduce both vertical and area coverage if the surfactant slug is not well designed. The surfactant slug may also cause in-situ emulsification in the reservoir when in contact with oil and gas which could leave more residual oil behind. The flow of gas and water in the presence of surfactants is complex, since these fluids can generate foam whose behaviour is non-Newtonian. Foam generation is uncertain on operating conditions and it may sometimes be delayed or may never occur.

To characterize the strength of the generated foam, the mobility reduction factor (MRF) is often defined as

$$MRF = \frac{\Delta P_{foam}}{\Delta P_{no-foam}} \ldots (3)$$

ΔP_{foam} and $\Delta P_{no\text{-}foam}$ are the measured differential pressure across the porous medium with and without foam respectively. A high MRF corresponds to strong foam. Other methods used to describe foam strength in porous media include reporting the differential pressure of the full core and in parts of the core or to observe the time needed for foam to propagate throughout the core.(25,26)

2.3 FOAM CHARACTERISTIC

Foam has unique physical properties. The apparent viscosity of the foam is usually higher than the viscosities of either of its constituents, and thus it has a lower mobility ratio than gas and water. From the lab experiment, foam confirms that it can block the displacement or selectively block flow through the gas zone, making it useful driving fluid. Lower mobility ratio from using foam can reduce the fingering problem and improve channelling in high permeability reservoir (18, 24).

There are many arguments in which parameters are important and how they affect the foam rheology. The two parameters which are widely believed to affect the foam behaviour arc the surfactant quality and the concentration. However, how they affect it, or why they affect it, is not clearly described in the literature.

The theories about foam characteristics sometimes differ slightly, but basically it can be represented by the following seven behavioural patterns.(27)

1. Bubble Flow:

   Foam flows as a homogeneous fluid with gas uniformly dispersed in the surfactant solution.

2. Intermittent Flow:

   Foam flows in such a way that liquid is transported through a continuous network of liquid membranes acting as a free phase, while gas flows as a discontinuous phase through breaking and reforming of bubbles.

3. Plug Flow:

   Foam flows as plugs characterized by high shear rates near the boundary between the foam and the conduit.

4. Trapped-Gas Flow:

   Foam flows in such a manner that it traps some gas in the porous medium while the remainder flows as a free phase following Darcy's law.

5. Segregated Flow:

   Foam flows only through gas channels carrying a small amount of surfactant solution with it.

6. Membrane Flow:

   Foam is generated as lamellae at specific locations in a porous medium which have specific pore constrictions that help in its generation.

7. Tubular-Channel Flow:

   Foam flows through channels consisting of tubular bubbles moving along and extending over several pore spaces.

2.4 EFFECT OF FOAM

Presence of foam will increase the apparent viscosity of the gas phase thus will reduce the mobility of the gas in the higher permeability zone. It will then force more gas to the less permeable zones and increase sweep efficiency of the gas(5,6,9). Foam greatly reduces gas mobility by trapping some bubbles which means reducing the gas relative permeability and resisting the movement of flowing gas bubbles. Smaller bubbles reduce gas mobility more than large bubbles as gas mobility in the presence of foam is dominated by foam texture, or bubble size.(6,10)

Premature gas breakthrough can occur at producing wells because of gravity segregation of the lighter injected gas toward the top of the reservoir, fingering of the lower viscosity gas through the connate oil and water phases or preferential channelling through a high-permeability rock horizon(8). Foams are also used to divert acid flow in matrix well stimulation treatments and to divert liquid or gas flow in environment remediation processes.

Several experimental results indicate the existence of a minimum velocity or pressure gradient which must be exceeded for foam generation(8). Foam generation in this context means an abrupt change of state from weak foam to strong foam. Several studies confirmed that foam generation is more effective with alternating slugs of gas and liquid rather than continuous co-injection of gas and liquid(8,17).

Foam can be placed in the reservoir by Surfactant-Alternating-Gas (SAG) or co-injection of surfactant solution and gas. Aarra et. al(2,3) reported that the reduction in gas breakthrough time between the first and second gas injection can be due to establishment of trapped gas saturation after the first injection. Simulation studies showed that the period after the first injection of surfactant matched the Mobility Ratio Factor (MRF) for gas ranging from 10 to 50.

Gas Oil Ratio (GOR) behaviour was observed after the second surfactant injection. Foam also becomes stronger after the second injection[2,3]. The second FAWAG injection was simulated with the same volumes, rates and concentrations for the surfactant injection and with almost the same gas volumes as the first FAWAG injection. The effect of foam has been shown to last over a long duration and the breakdown of foam is captured in the simulations.[8]

The concern in FAWAG is that high mobility gas near the well may finger through or override lower mobility foam during gas injection. In homogeneous, gravity override represents worst case of fingering. Simulation studies suggest that at fixed injection rates, high mobility near the injection well promotes gravity override in SAG process[4,6]. However, both gas and liquid should be injected at maximum allowable injection pressure to minimize segregation and reduce surfactant slumping [4,14].

Foam simulation confirming a reduced GOR and additional oil recovery as a result of FAWAG[3,4]. Microscopic displacement efficiency of foam also proves that capillary number can be increased, as foam can help to reduce the IFT. In conclusion, foams were sufficiently stable and persistent at extremely dry conditions for a successful SAG process[3,4,5,6]

2.5 SURFACTANT-ALTERNATING-GAS

Surfactant-Alternating-Gas (SAG) is when foam formed in the reservoir after slug of surfactant solution is injected and followed by gas injection. Co-injection is when foam formed in the well when gas and surfactant solution are injected simultaneously. It was found that SAG injection has advantages over co-injection which are minimizing contact between water and gas in the surface, promote foam generation in the near well region, and improve injectivity by increase of gas mobility as foam weakens there, gas mobility rises and injectivity increases.[1,4,6] The concept of SAG process is relatively new, with limited experimental and theoretical work available on the subject.

SAG is an immiscible gas injection process used to control the mobility and improve sweep efficiency. The main reasons which contribute to the high displacement efficiency are gas entrapment in the reservoir due to hysteresis and the effect of the 3 phase flow; oil, water and gas. SAG injection lead to improve oil recovery through various factors such as mobility control, contact of unswept zones, improved microscopic displacement efficiency and oil vaporization due to mass transfer between reservoir oil and injected gas due to vaporization process.

The optimal injection strategy for overcoming gravity override with foam in a homogeneous reservoir is alternating injection of large slugs between gas and surfactant solution at fixed, maximum-allowable injection pressure(4,6). This strategy minimizes both gravity override and time of injection, with minimal rise in injection-well pressure. Injection of gas at maximum pressure can partially reverse the effects of gravity slumping of surfactant during injection of liquid(14).

CHAPTER 3

RESEARCH METHODOLOGY

3.1 GANTT CHART

In order to achieve the objectives of the project, researches have been made on abundant resources including books, journal, internet and also the simulator's manual

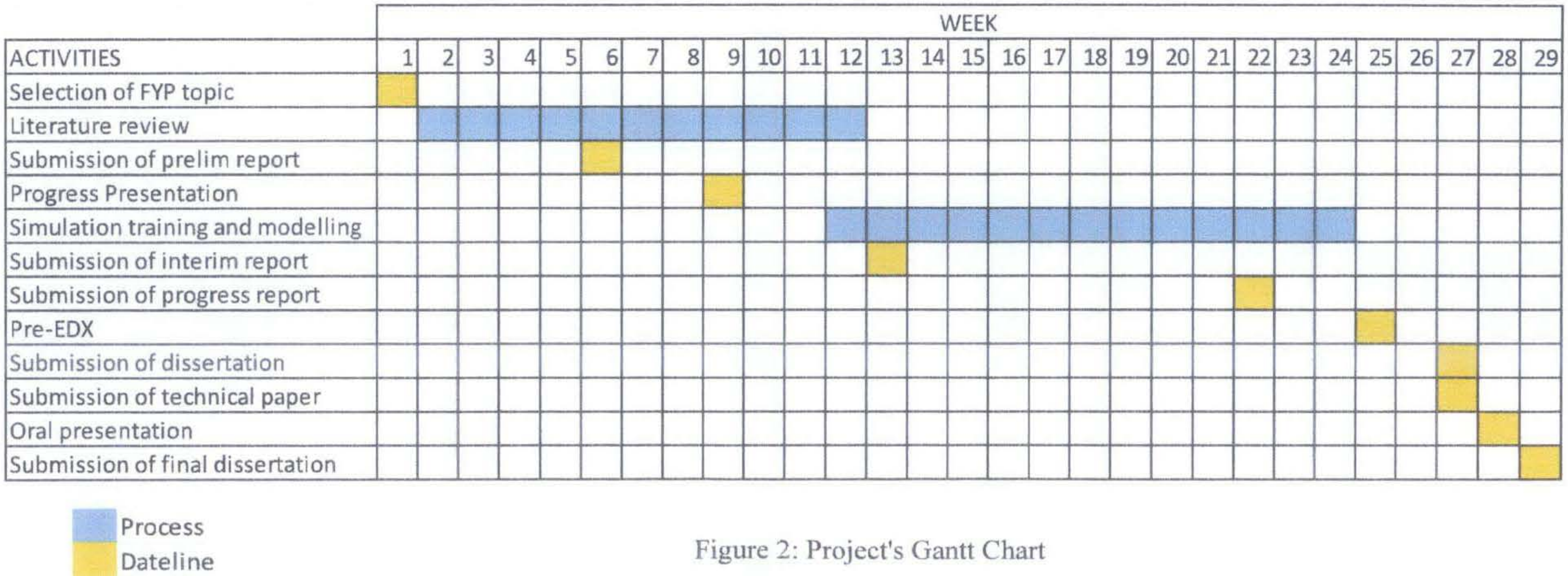

Figure 2: Project's Gantt Chart

Figure 2 shows the Gantt Chart throughout the project.

As for saturation set, the data that should be available are gas saturation functions with the corresponding gas relative permeability (SGFN), oil saturation functions for three phase fluid (SOF3) and also water saturation functions (SWFN).

The inputs of injected surfactant are specified by concentration of the surfactant in the injected water and occur only in the water phase. Concentration of surfactant used is 10.3 kg/m3. Table 2 shows the keywords to activate the surfactant model in Eclipse 100.

Table 2: Keywords to activate Surfactant Model in Eclipse 100

Keyword		
SURFST	Water-oil surface tension in the presence of surfactant	Obligatory
SURFVISC	Modified water viscosity	Obligatory
SURFCAPD	Capillary de-saturation data	Obligatory
SURFADS	Adsorption isotherm	Optional
SURFROCK	Rock properties and adsorption model indicator	Obligatory if SURFADS is present

The data set for surfactant is also taken from another's researcher data.

To analyse the effect of injection rates on oil production, there are 16 cases that have been modelled for this project which are:

1. Case 1: base case
2. Case 2-6: Cases with constant surfactant injection rate and different gas injection rate
3. Case 7-11: Cases with different surfactant injection rates and constant gas injection rates
4. Case 12-16: Cases with both surfactant and gas injection rates are changed

Table 3 shows the value of injection rates that have been modelled in this project. The reason for doing 16 cases is to make the results more accurate.

For this project, below are the lists of assumptions made:

1) FAWAG process using surfactant-alternating-gas (SAG) method

4) Gravity is neglected

5) The fluids (oil and gas) are immiscible

Table 3: Injection Rates for Each Case

<table>
<tr><th>Case</th><th>Surfactant Injection Rate (stb/day)</th><th>Gas Injection Rate (Mscf/day)</th></tr>
<tr><td>1</td><td>100</td><td>100</td></tr>
<tr><td>2</td><td rowspan="5">100</td><td>200</td></tr>
<tr><td>3</td><td>300</td></tr>
<tr><td>4</td><td>400</td></tr>
<tr><td>5</td><td>500</td></tr>
<tr><td>6</td><td>600</td></tr>
<tr><td>7</td><td>200</td><td rowspan="5">100</td></tr>
<tr><td>8</td><td>300</td></tr>
<tr><td>9</td><td>400</td></tr>
<tr><td>10</td><td>500</td></tr>
<tr><td>11</td><td>600</td></tr>
<tr><td>12</td><td>200</td><td>200</td></tr>
<tr><td>13</td><td>300</td><td>300</td></tr>
<tr><td>14</td><td>400</td><td>400</td></tr>
<tr><td>15</td><td>500</td><td>500</td></tr>
<tr><td>16</td><td>600</td><td>600</td></tr>
</table>

CHAPTER 4
RESULTS AND DISCUSSION

4.1 RESULTS

The surfactant model was applied to the synthetic case described in Chapter 3. Different injection rates have been applied to the base case to analyse the oil production during FAWAG process. The list of cases can be found in Table 3 in Chapter 3. All cases were simulated for 3200 days with the first 1600 days are for surfactant slug injections followed by 1600 days of gas injection.

The results will take into account the recovery factor, the oil production rate together with the reservoir management parameters (water production and field pressure) and the gas oil ratio over time. Since there are 16 cases with three different scenarios; (i) constant surfactant injection rates while manipulating gas injection rates, (ii) manipulating surfactant injection rates while constant gas injection rates and (iii) changing both fluid injection rates, we will also analyse these three scenarios.

4.1.1 Comparison of oil saturation model after FAWAG process

Figure 5, 6, 7 and 8 shows the oil saturation at the end of injection time for only Case 1, 6, 11 and 16.

Case 11 shows that most of the oil is recovered, only few of them were left unswept.

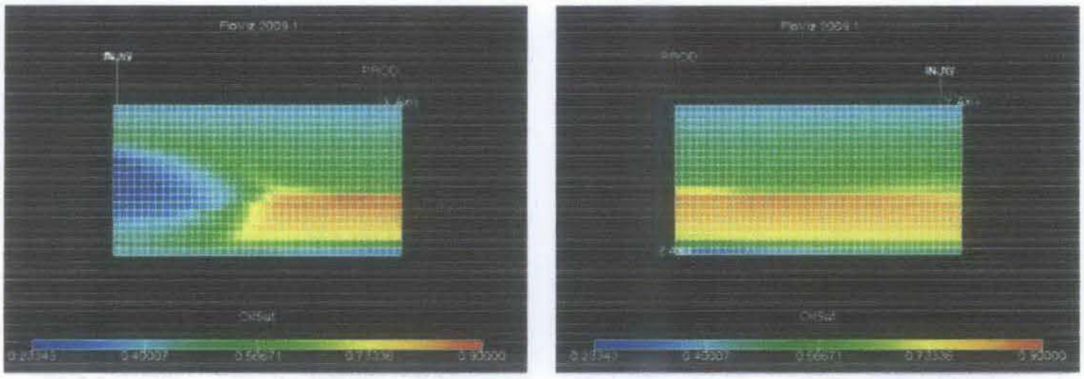

Figure 5: Oil saturation at the end of 3200 days for Case 1 a) Left view b) Right view

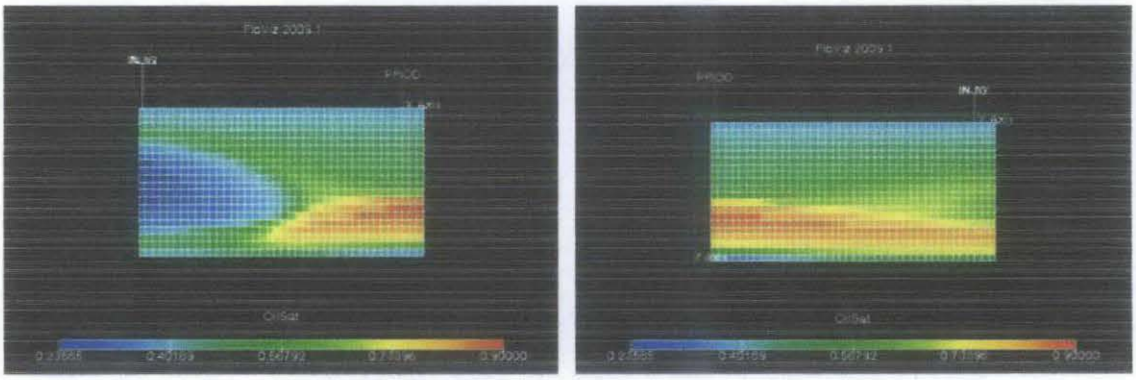

Figure 6: Oil saturation at the end of 3200 days for Case 6 a) Left view b) Right view

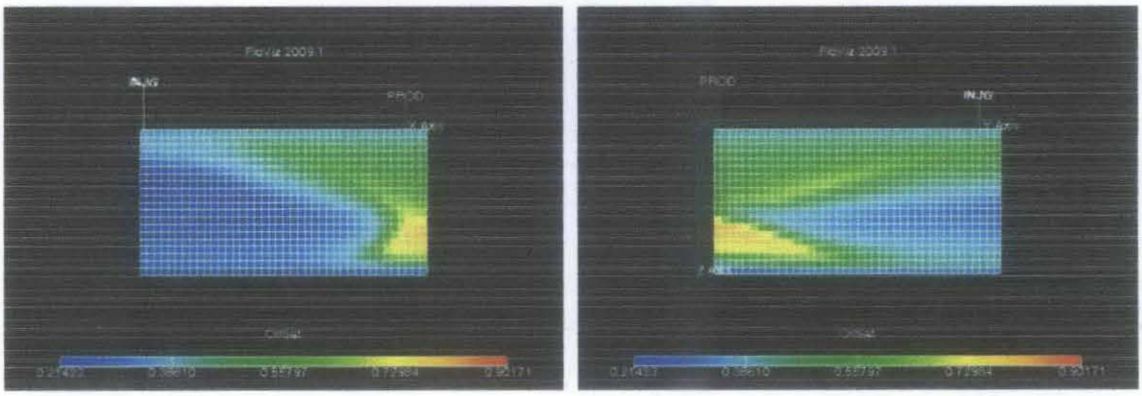

Figure 7: Oil saturation at the end of 3200 days for Case 11 a) Left view b) Right view

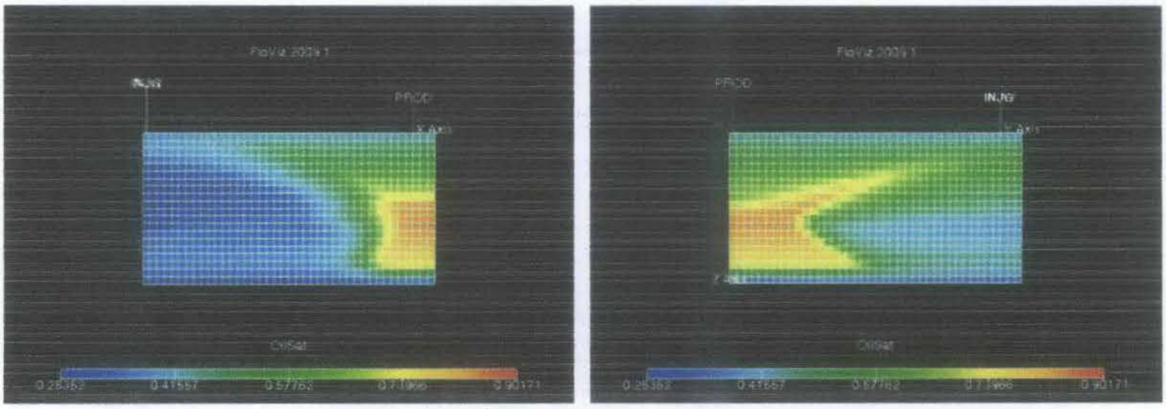

Figure 8: Oil saturation at the end of 3200 days for Case 16 a) Left view b) Right view

4.1.2 Field Oil Efficiency (Oil Recovery)

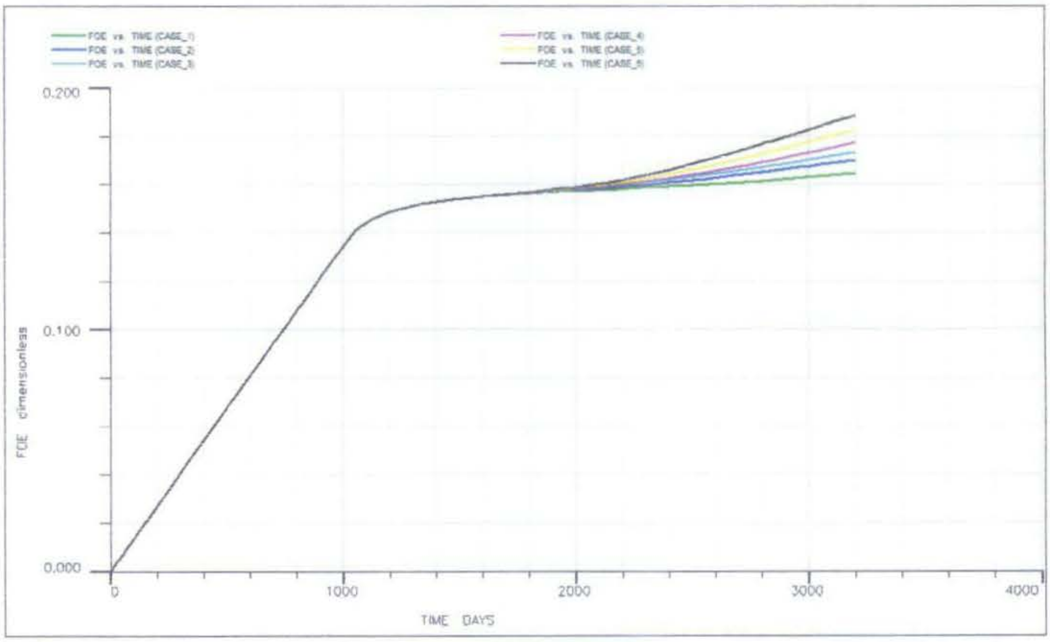

Figure 9: Recovery Factor for Constant Surfactant Injection Rates

Figure 9 shows the oil recovery factor (or FOE) for constant surfactant injection rates while manipulating gas injection rates. Recovery factor was observed to increase with increase of gas injection rate.

The highest oil recovery factor is 18.8% when injecting 600Mscf/d of gas. The lowest oil recovery factor is 16.4% when injecting 100 Mscf/d of gas. However, the increased factor is really small; around 0.4% with increase of 100 Mscf/d gas. The difference in gas injection also only appears starting at time 2000 days which is 400 days after gas injection started to inject.

Figure 10 shows the FOE when manipulating surfactant injection rates while having constant gas injection rates. The recovery factor seems to increase clearly from 16.4% to 40.1% from injecting 100 stb/day surfactant to 600 stb/day, respectively.

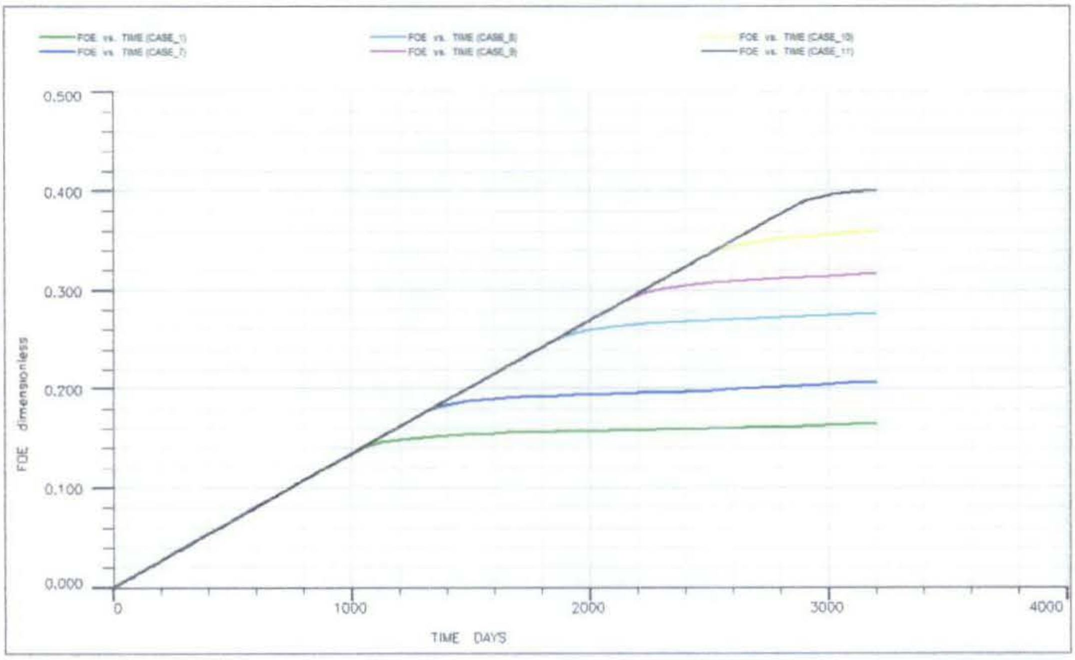

Figure 10: Recovery Factor for Constant Gas Injection Rates

Figure 11 shows the oil recovery factor when both surfactant slug and gas injection rates are increased. The highest FOE is for Case 16 with 43.1% while the lowest FOE is for Case 1 with 16.4% at the end of simulation.

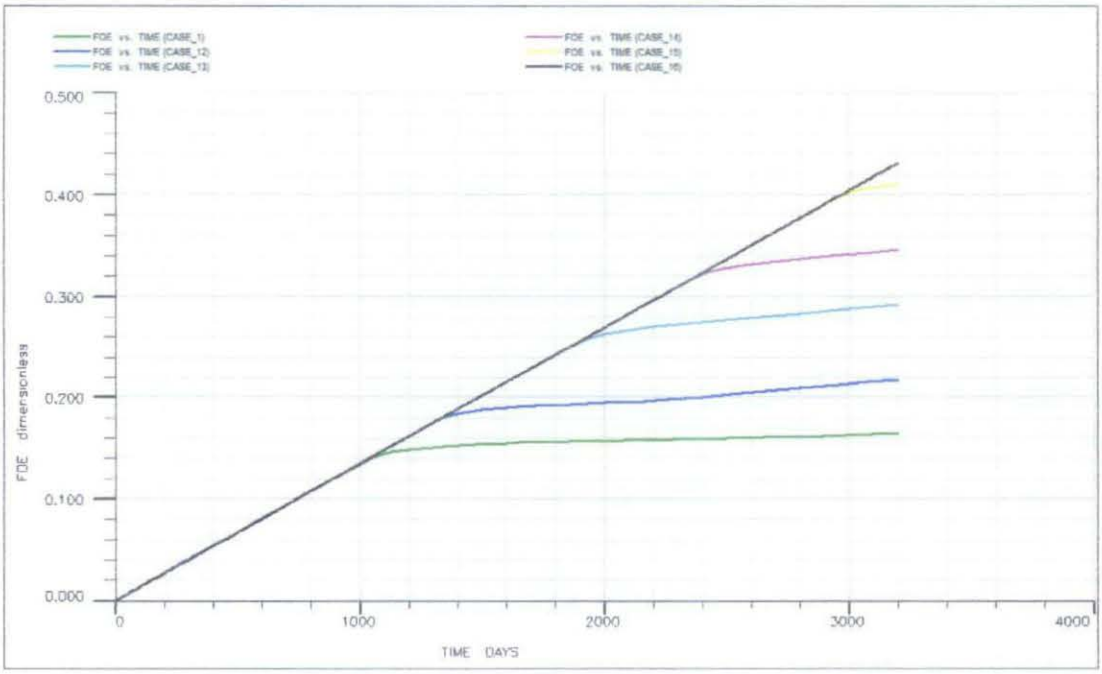

Figure 11: Recovery Factor for Changing Surfactant Slug and Gas Injection Rates

Figure 12 shows the combination results for all 16 cases. From the figure, we can say that increase in surfactant injection means more surfactant slug will be injected and more foam will be formed in the reservoir. As foam is confirmed to delay gas breakthrough and reduced the Gas-Oil-Ratio, the higher surfactant injection can produce more oil compare to lower surfactant injection rates. Case 11 has the highest recovery factor from all the cases.

Gas injection did not have much effect to the oil recovery when surfactant injection is low because gas may have early breakthrough and move to the production well faster and bypass the foam and oil. However, since increase in gas injection rates shows increase in recovery factor, it proves that high injection rates can increase sweep efficiency of oil.

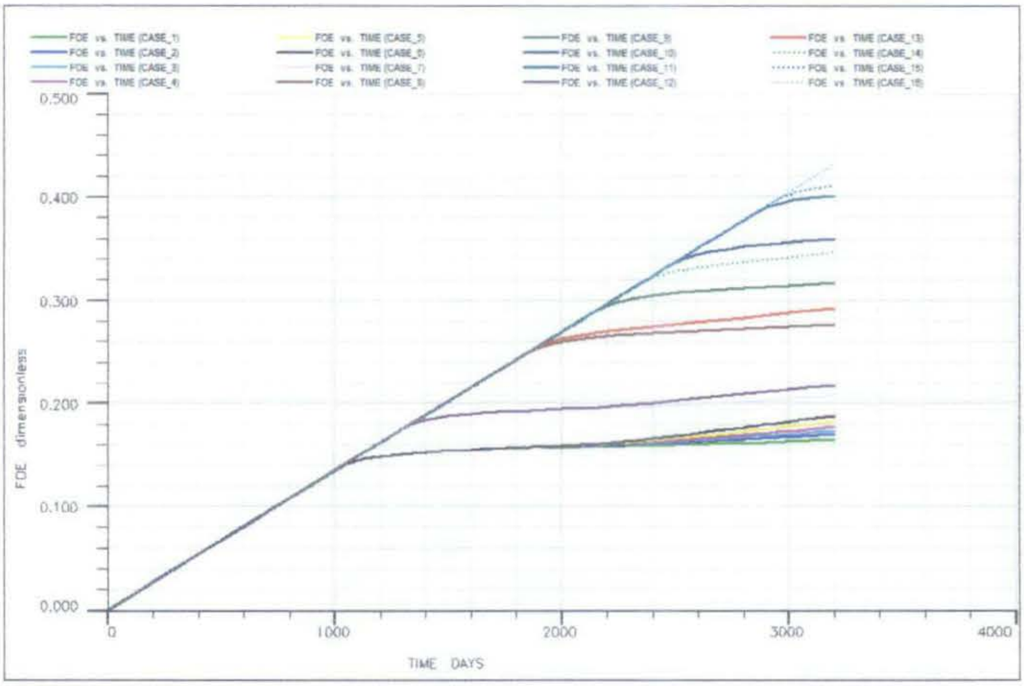

Figure 12: Recovery Factor for all Cases

4.1.3 Field Oil Production Rate

Figure 13 shows at early time, oil production is constant at 350 stb/d and there have sudden drop during 1000 days for all cases. The reason that can be conclude is at early time the surfactant slug acts like strong aquiver pushing the oil to the production well, however sudden drop during 1000 days is because surfactant slug effect is declining with the oil production.

The gas injection seems to have no effect in increasing the oil production rate. This is due to early gas breakthrough from gas to the surfactant slug as the injection rate of surfactant slug is only100 stb/day.

Figure 14 shows that with high surfactant injection rate, oil production rate can be maintained at maximum (350 stb/day) for a long time compared to the lower surfactant injection rate. The time for the production to decline is elongated and it indicates the highest surfactant injection rates can acts like strong aquifer and produce more oil compared to the lowest injection rates.

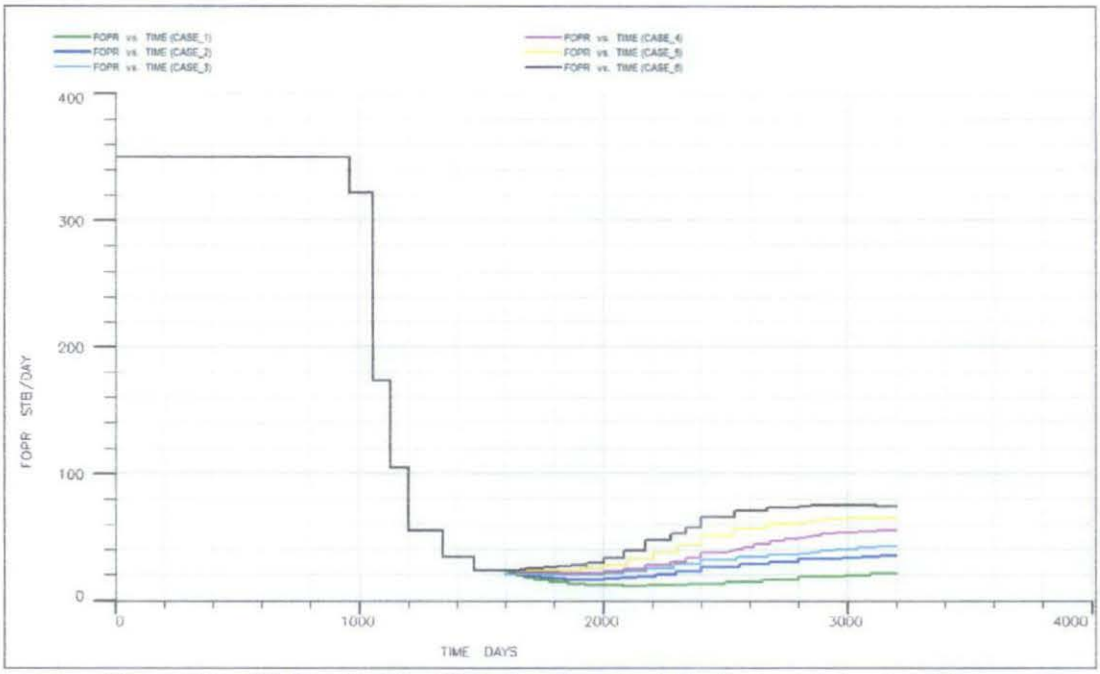

Figure 13: Oil Production Rate for Constant Surfactant Injection Rates

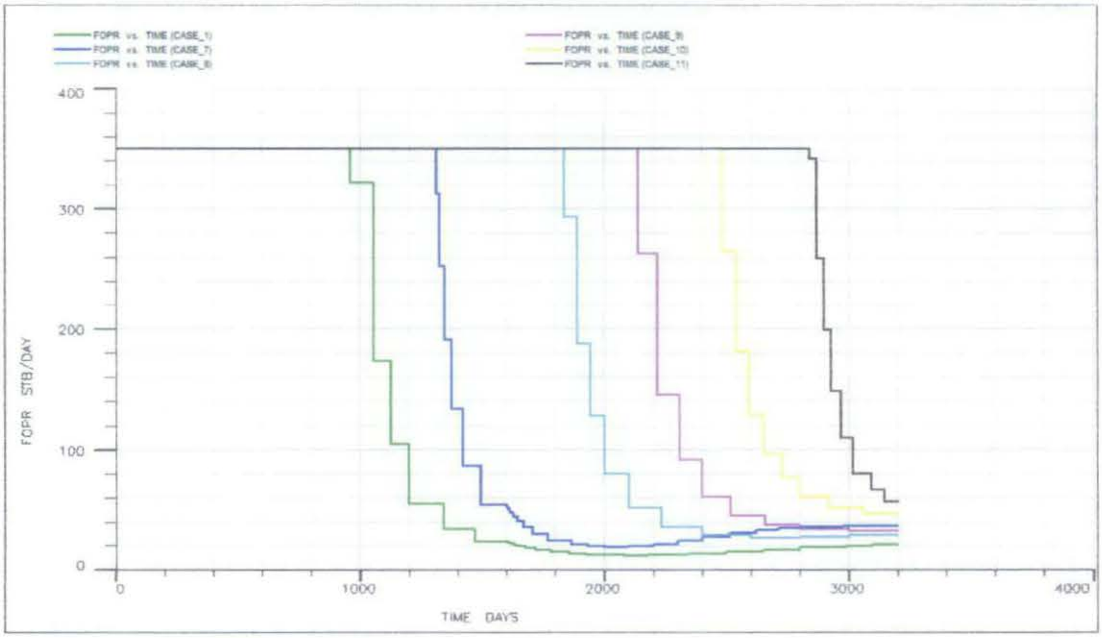

Figure 14: Oil Production Rate for Constant Gas Injection Rates

Figure 15 shows that the higher injection rates of both fluids, the higher the oil production rate. For Case 16, the oil production rate did not declining; production rate maintain at 350 stb/day while for Case 1, the production start to decline on 1000 days. It means that surfactant slug that injected have become strong foam in the reservoir and delaying the gas breakthrough. Thus, it will increase the sweep efficiency of the gas.

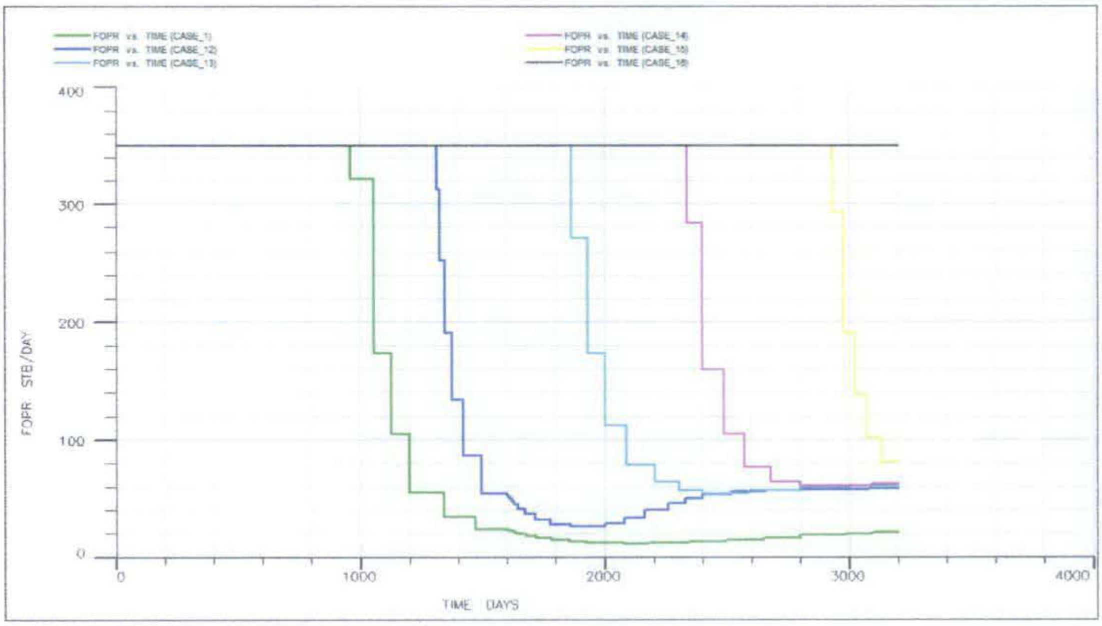

Figure 15: Oil Production Rate for Changing Surfactant Slug and Gas Injection Rates

Figure 16 shows the combination oil production rate for all cases and the more consistent production are from Case 16 with high oil production throughout the simulation period. We can say that high injection rate of gas did not help much in oil production as the effect is barely seen, unless we use the high surfactant injection rates.

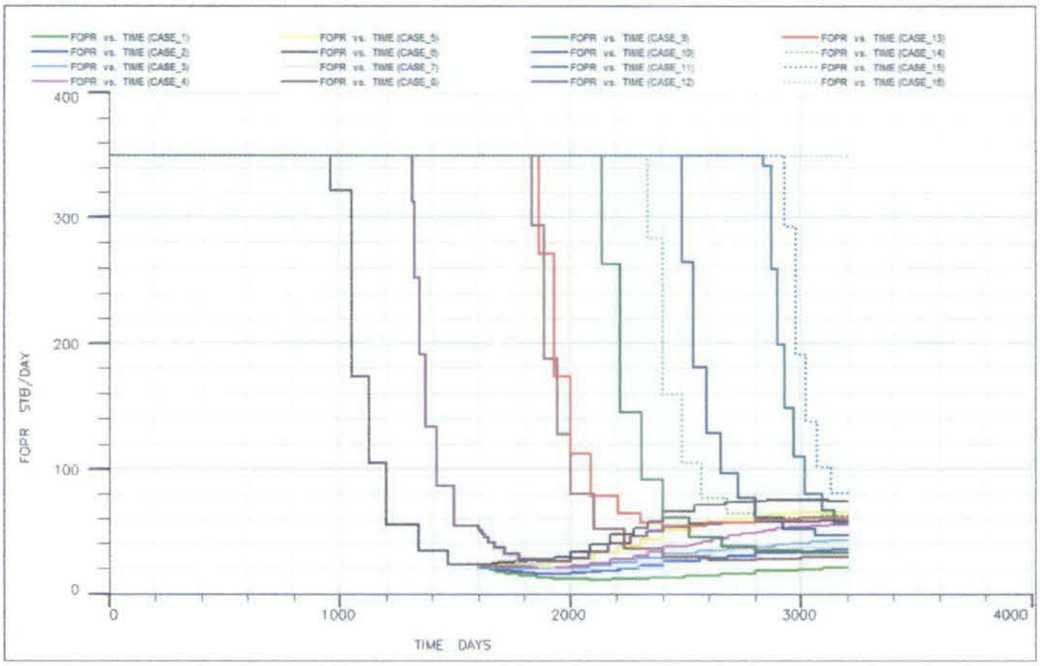

Figure 16: Oil Production Rate for all Cases

4.1.4 Field Oil Production Total

Figure 17 shows that with increased of any fluid injection rates, the cumulative oil production will increase too. However, injection rates of surfactant slug effect are more dominant because:

i) For case 1 to 6, the highest cumulative oil production is Case 6; 488573.6 stb
ii) For case 1, 7-11, the highest cumulative oil production is Case 11; 1041663.1stb
iii) For case 12-16, the highest cumulative oil production is Case 16; 1119999.4stb

From the values above, it shows that for FAWAG to be effective, the injection of surfactant slug should be higher as it can delay the gas breakthrough. The difference between cumulative production of Case 11 and Case 16 is only by 7.5%. This proves that high gas injection rates are not necessary as it will only bring more cost during the production time.

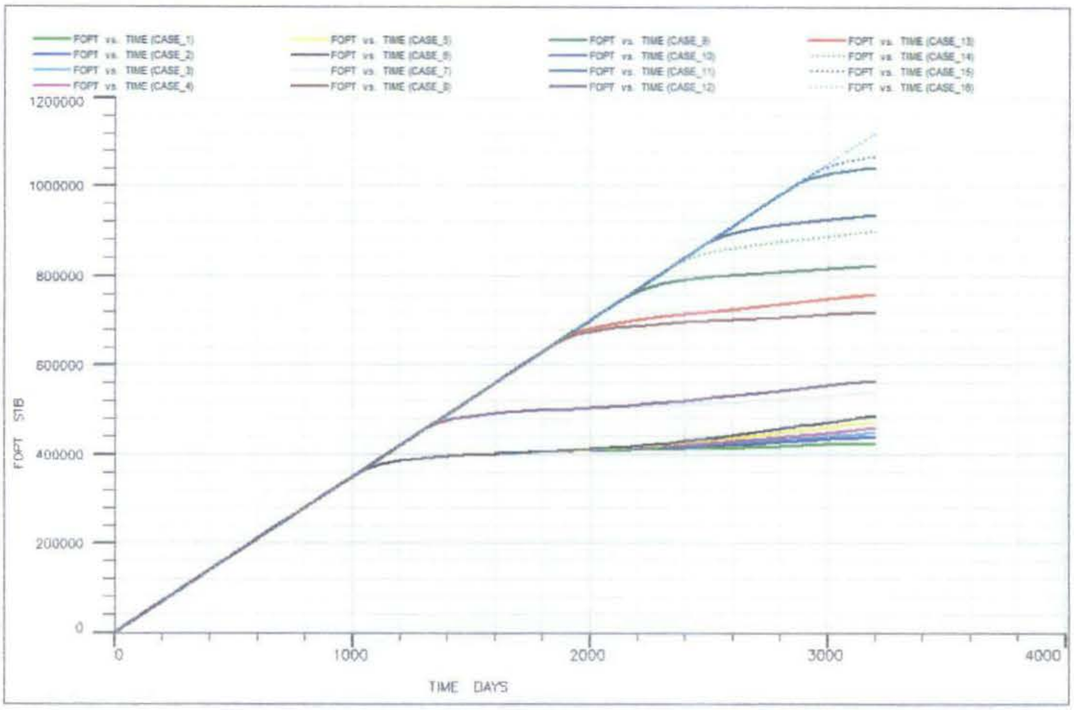

Figure 17: Cumulative Oil Production for all Cases

4.1.5 Field Gas Oil Ratio

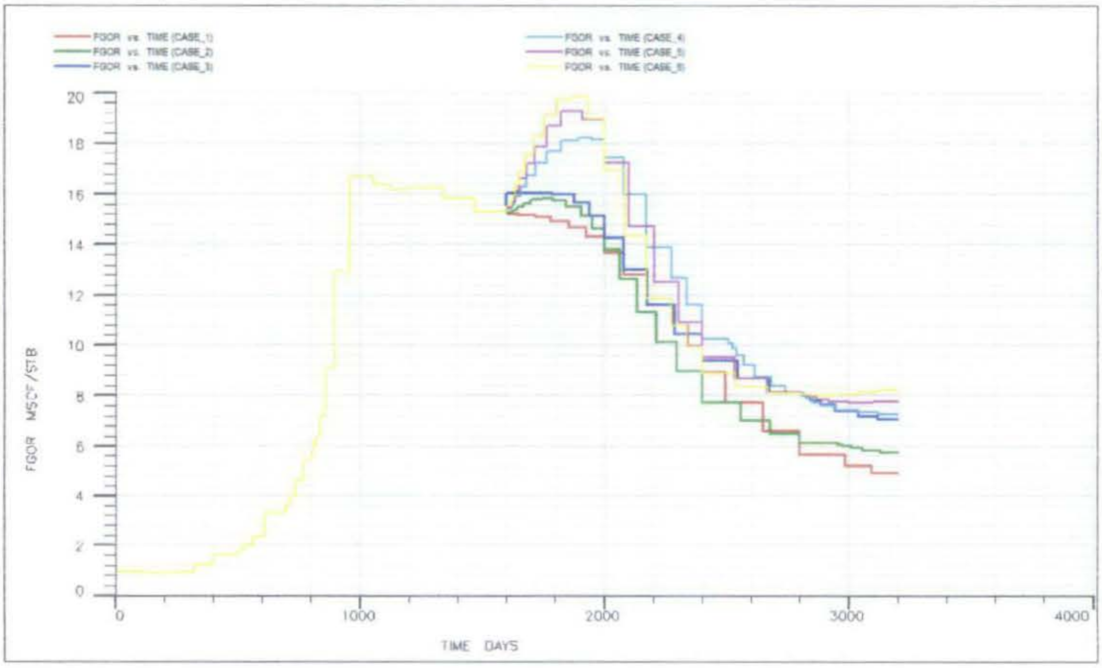

Figure 18: Gas Oil Ratio for Constant Surfactant Injection Rates

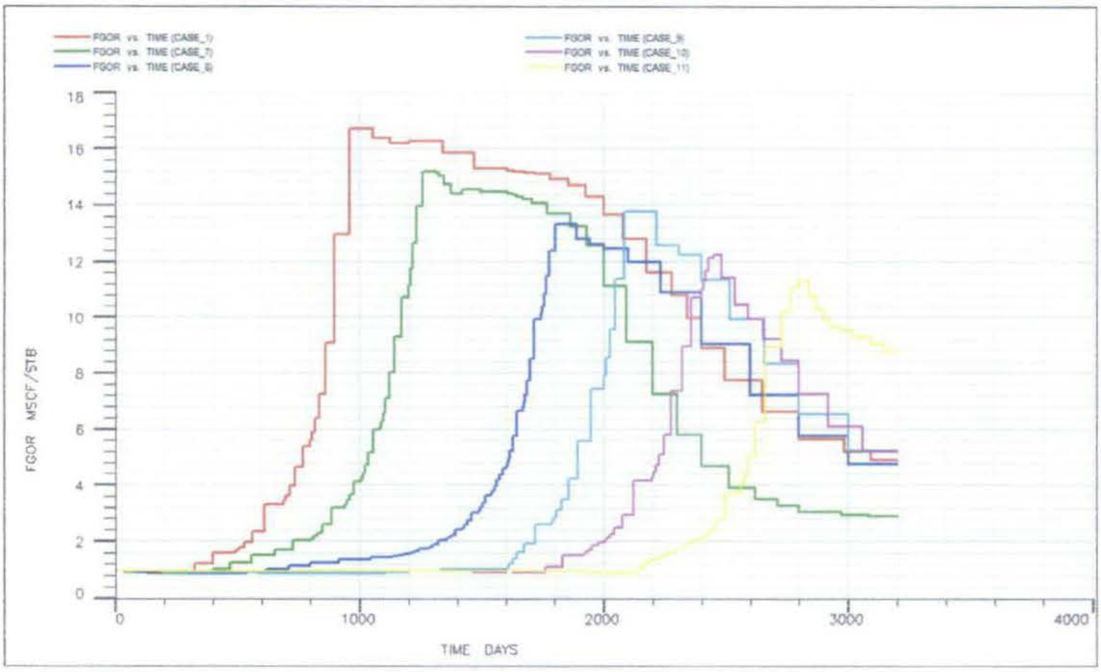

Figure 59: Gas Oil Ratio for Constant Gas Injection Rates

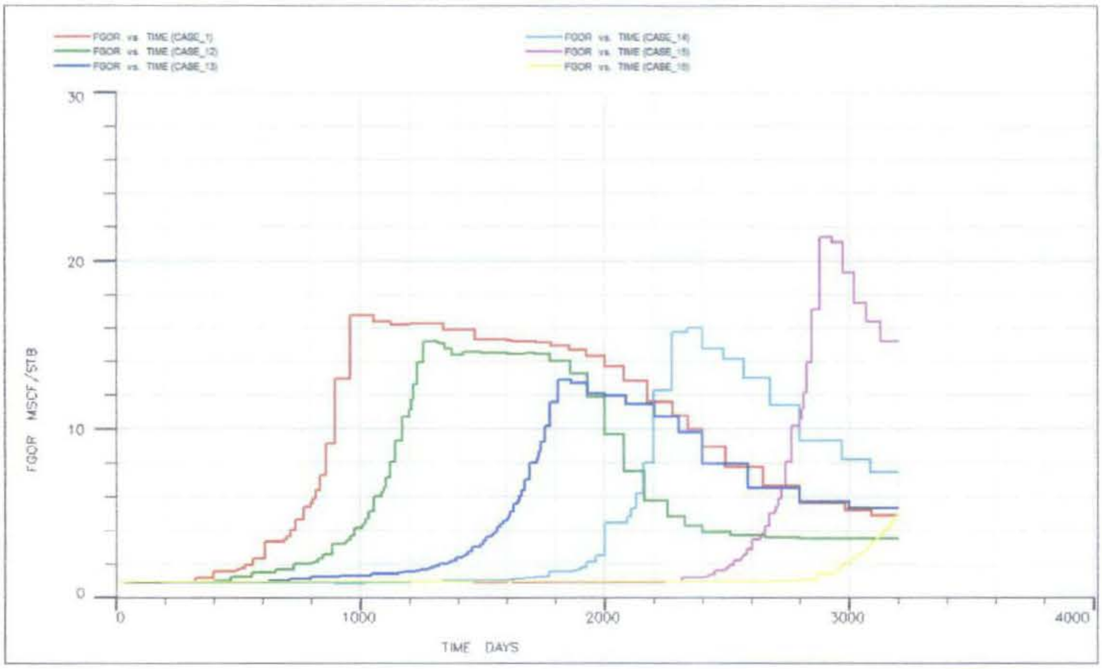

Figure 20: Gas Oil Ratio for Changing Surfactant Slug and Gas Injection Rates

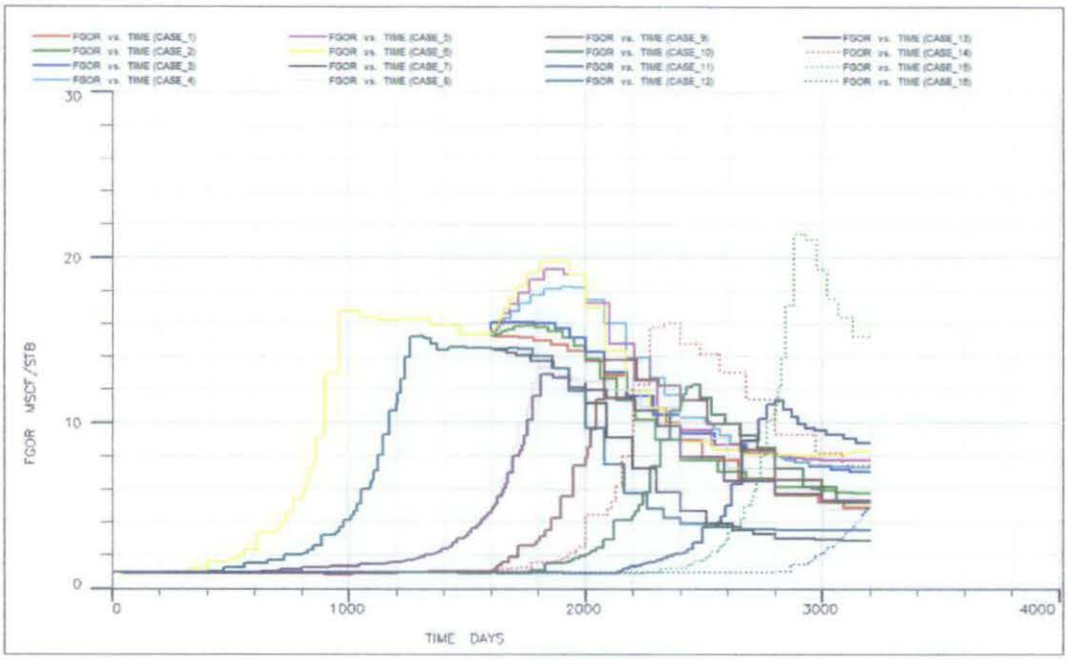

Figure 21: Gas Oil Ratio for all Cases

4.1.6 Field Pressure

Figure 22 shows the field pressure for Case 1 to 6. The trend is almost similar until the gas start to inject on 1600 days. The curve indicates that the pressure loss in the reservoir is high during injection of surfactant slug.

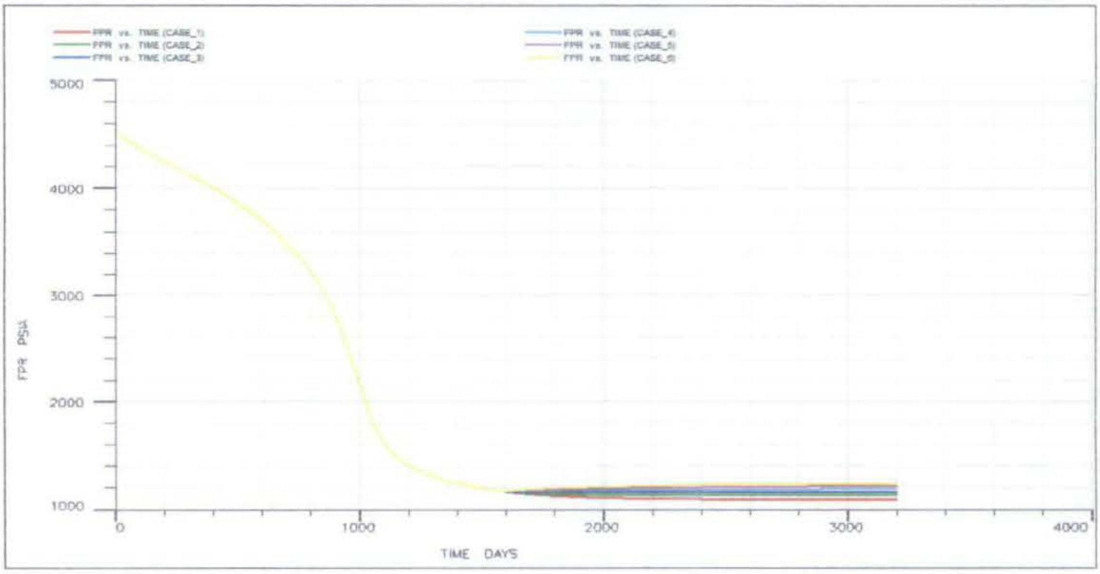

Figure 6: Field Pressure for Constant Surfactant Injection Rates

Figure 23 shows that reservoir pressures are declining better than Figure 22 except for Case 11. Case 11 illustrate that reservoir pressure is increasing during the injection of surfactant slug and then decrease abruptly during gas injection. This situation might affect the reservoir properties.

For Figure 24, Case 16 experiences the same pressure change like Case 11. Case 15 has very small pressure change but at the end of simulation time, the pressure drop drastically and it is not a good change for the reservoir.

Figure 25 shows all the cases pressure changes during the simulation. It is confirmed that high injection rates of surfactant slug may risk the reservoir properties. The moderate pressure drops can be seen from Case 8 and 13.

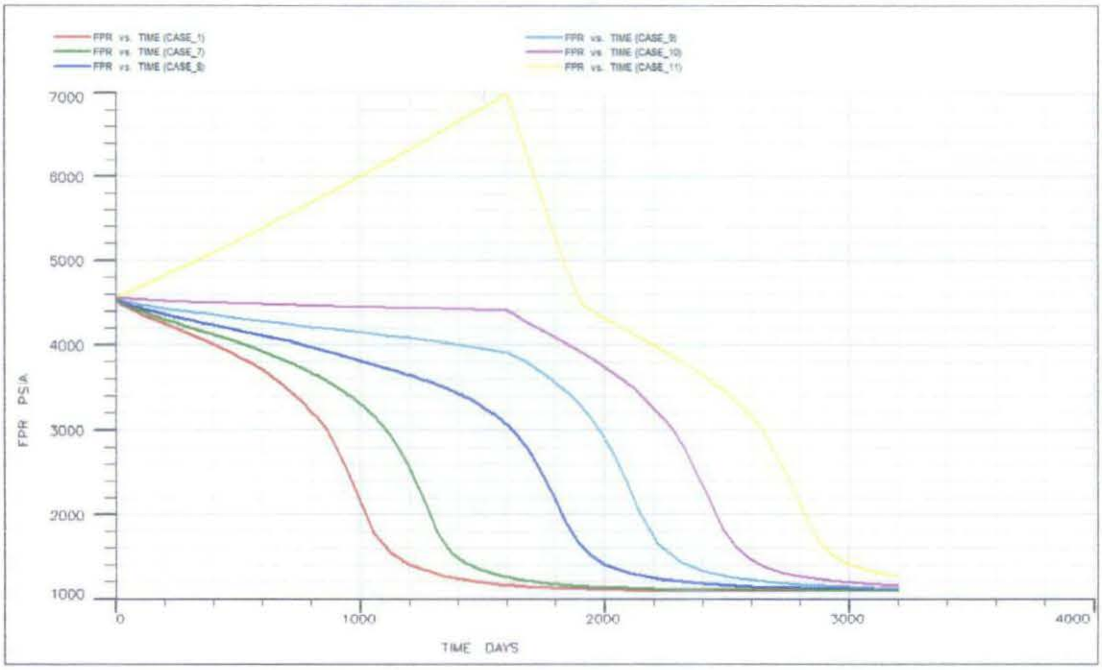

Figure 23: Field Pressure for Constant Gas Injection Rates

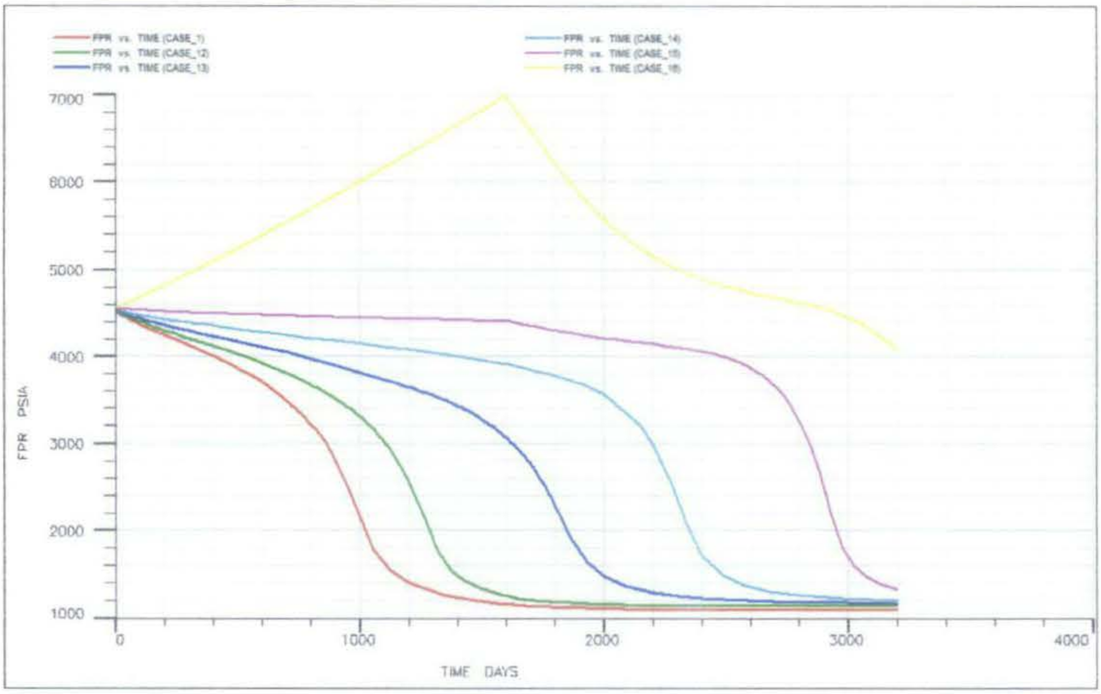

Figure 24: Field Pressure for Changing Surfactant Slug and Gas Injection Rates

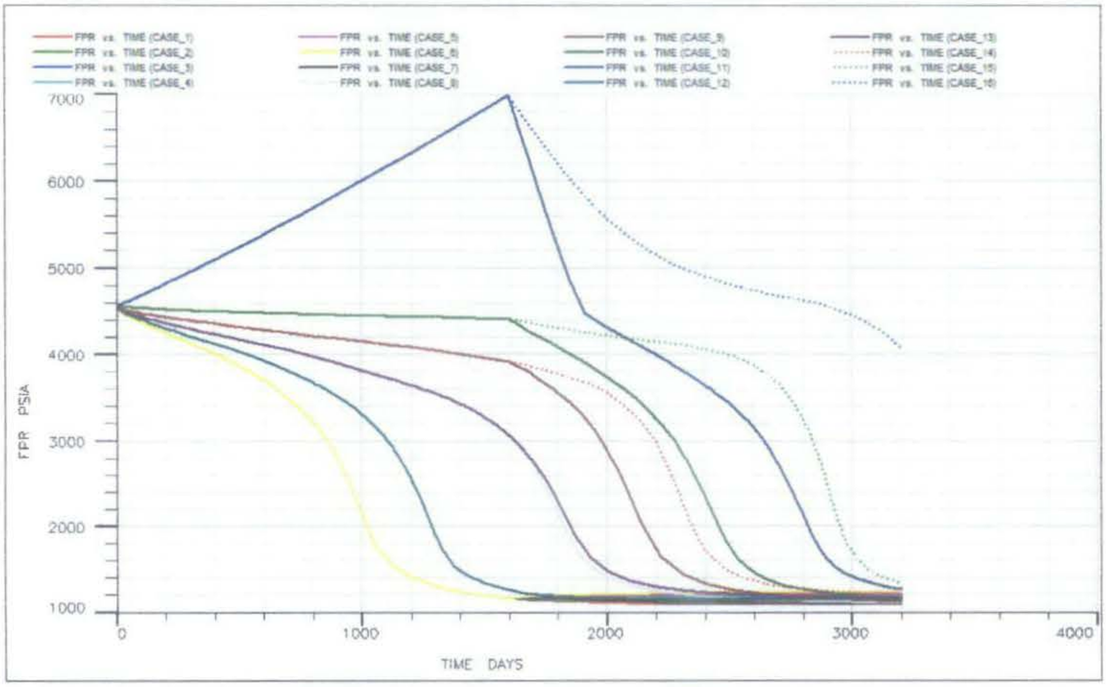

Figure 7: Field Pressure for all Cases

4.1.7 Field Water Production Total

Figure 26 shows the total water production of the field for case 1 to 6. The smallest amount of water production is obtained for case. The water breakthrough occurs at the same time for all 6 cases, 250 days after the production started.

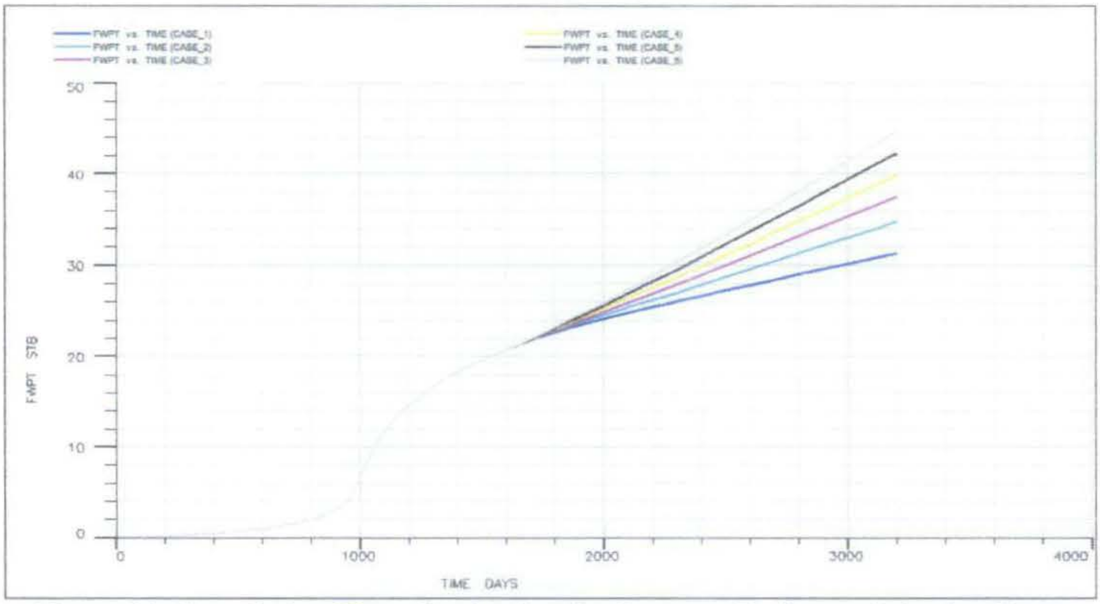

Figure 86: Cumulative Water Production for Constant Surfactant Injection Rates

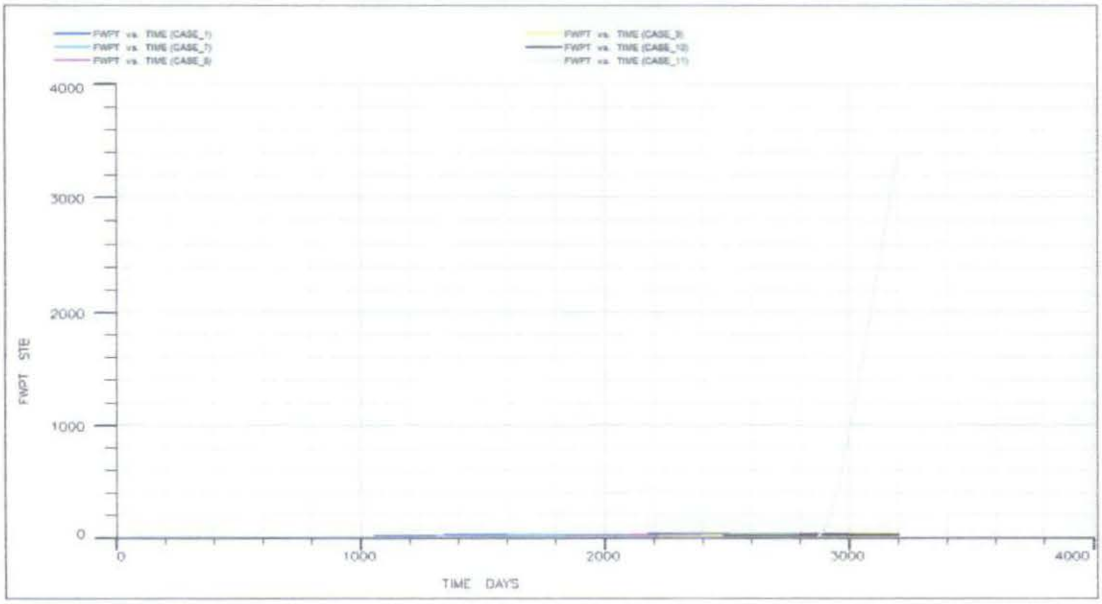

Figure 97: Cumulative Water Production for Constant Gas Injection Rates

Figure 27 shows that Case 11 is having extremely high water production which up to 3400 stb. There might be an error in this case as gas injection is not sufficient enough, i.e 100 mscf/d compared to high surfactant injection rate, i.e 600 stb/day.

Figure 28 shows that when injecting high surfactant slug rates followed by high gas injection rate, the water production is really small, around 0.58 stb only. This situation supports the high surfactant slug can increase the capillary number and high gas injection can reduce the mobility ratio.

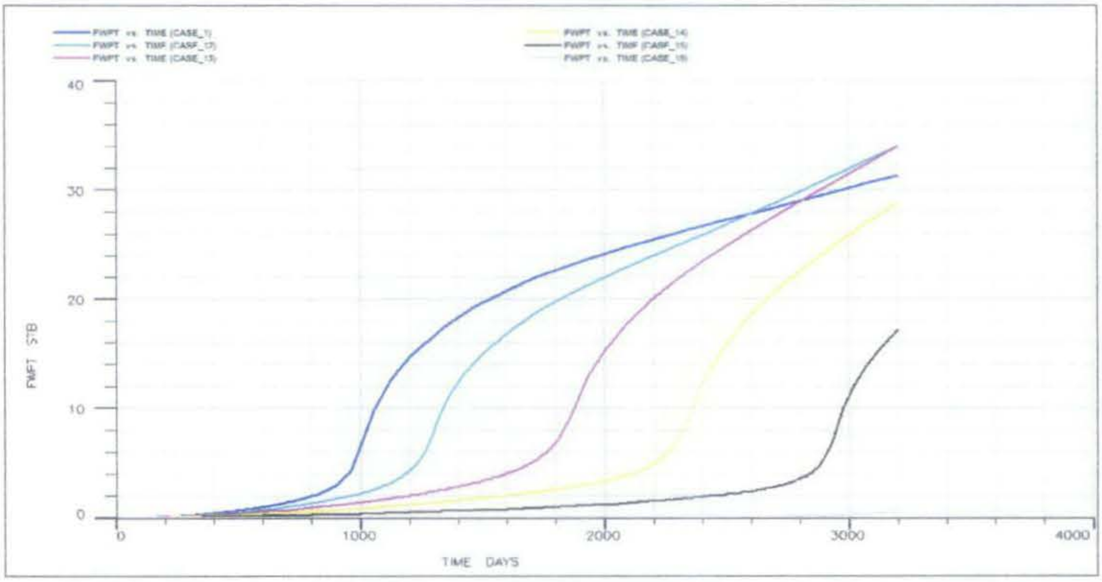

Figure 108: Cumulative Water Production for Changing Surfactant Slug and Gas Injection Rates

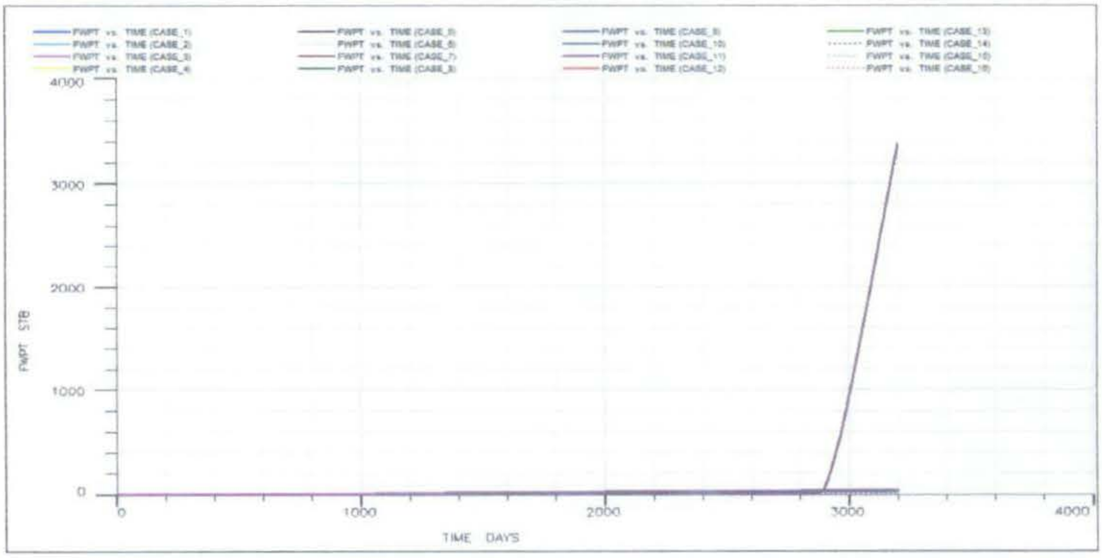

Figure 29: Cumulative Water Production for all Cases

Figure 29 shows the water production for all cases and case 11 has the highest water production. Figure 30 is the upscale of Figure 29. From there, it shows that average water production is around 25 to 45 stb.

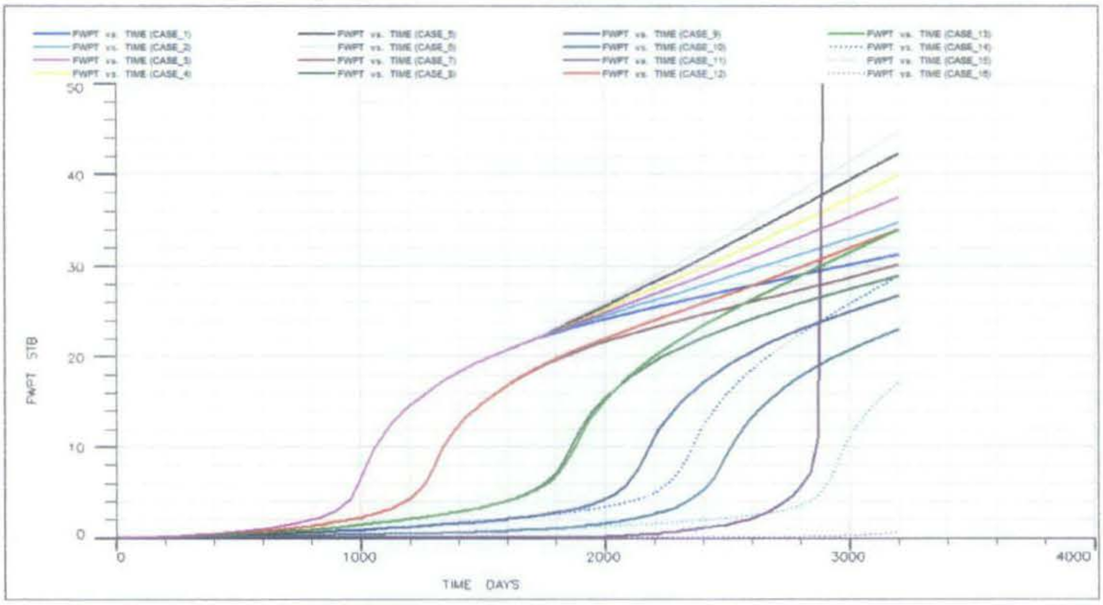

Figure 11: Cumulative Water Production for all Cases (Upscale)

4.2 DISCUSSIONS

The main objective of this study is to analyse the effect of injection rates on oil production during FAWAG process. It has been prove through experiments, simulations and pilot field that WAG process can be improved by adding surfactant solution so foam can be formed in reservoir. In this study, surfactant solution is injected alternately with gas with various injection rates.

Literature review shows that foam can improve mobility and increase sweep efficiency. Mobility ratio for a very sharp front displacement is given by:

$$MR = \frac{M_D}{M_d} = \frac{\left(k/\mu\right)_{Displacing\ phase}}{\left(k/\mu\right)_{Displaced\ phace}} \ldots (2)$$

Where M_D and $M_d$is the mobility of the displacing and displaced phase. Since the permeability values are functions of water saturation, it is very important to decide which saturation value must be used in estimation of mobility ratio. As mobility ratio is defined at the flood front, the saturation values to be used in determination of the relative permeabilities must be selected accordingly. So the average water saturation behind the front must be used in determination of relative permeability to water, and the interstitial water saturation ahead of the front must be used in determination of relative permeability to oil.

Oilfield Glossary[26] has defined sweep efficiency as, "A measure of the effectiveness of an enhanced oil recovery process that depends on the volume of the reservoir contacted by the injected fluid", while Oil and Gas Glossary[27] defined as, "The percentage of original oil in place displaced from a formation by a flooding fluid". Injected gas and surfactant solution doesn't wet the rock surfaces, but sweeps through the oil and tends to form a continuous gas phase throughout the reservoir. For a given rate of injected gas and surfactant solution, the greater the pressure gradient, the greater the produced oil will be achieved.

From Figure 31, we can see that high injection rates of both surfactant slug and gas have the highest oil production, and the lowest water production (Case 16). However, the reservoir pressure that act with these injection rates in Figure 11 is undesirable. Figure above also shows that Case 11 show a different trending of water production compared to others. The reason might be due to too much surfactant injection rate followed by too low gas injection rate.

The results confirm that surfactant can create foam in the reservoir and then the foam can delay gas breakthrough and increase the sweep efficiency of the gas. Thus, it will reduce the mobility ratio of the fluid.

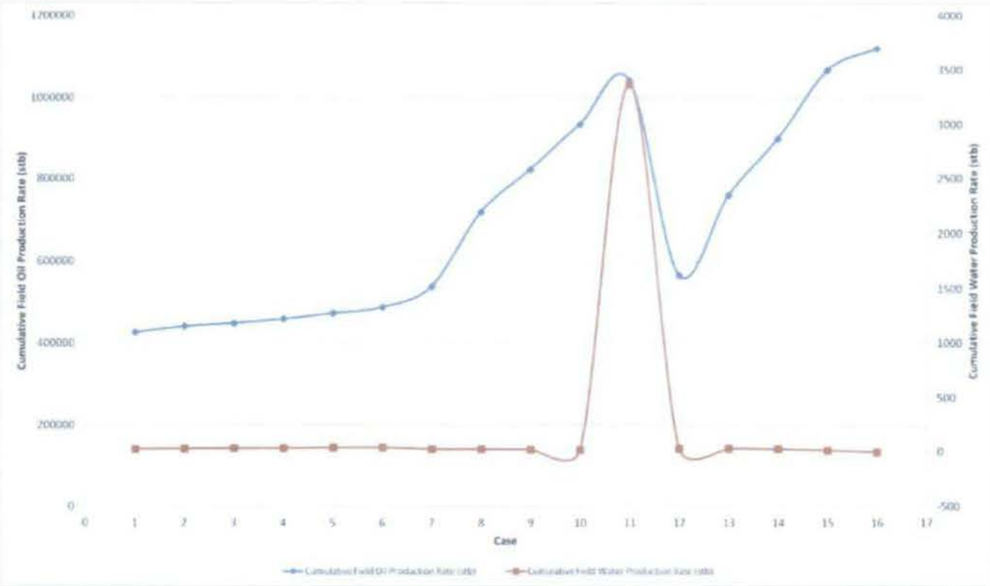

Figure 31: Oil and Water Production Comparison for Each Case

Due to high price of surfactant, this analysis is crucial prior to using FAWAG process. From the simulation; see Table 4, we can see that between Case 9, 10, 14 and 15, they have the most economical value as the oil production is high and water production is relatively small. However, for case 14 and 15, they have higher GOR than Case 9 and 10. Furthermore, the reservoir pressure also did not decrease normally.

Further investigation lead us that Case 9 is the best injection rates for these model. This is due to high oil production with low water production rate. In addition to that, the reservoir pressure is decrease quite smoothly and the GOR is low. Although cumulative production of Case 9 is much lesser than Case 10, 14 and 15, Case 9 might have a longer production period compared to others.

CHAPTER 5

CONCLUSIONS AND RECOMMENDATIONS

5.1 CONCLUSIONS

Injection rate of gas and surfactant solution during FAWAG process is important to the recovery. The injection rate will affect the propagation of foam in the reservoir. It is also confirm that foam can reduce the mobility of gas and increase the sweep efficiency. Thus, it will increase the recovery of oil.

Higher surfactant injection rate will be more effective for oil production but not too economic as it will jeopardize the reservoir condition; abrupt change of reservoir pressure. Moderate surfactant injection rates may not have high oil production but it can maintain the reservoir production for a long period.

Analyzing the injection rate of surfactant slug and gas is important for reservoir management as more oil can be produced while maintaining the reservoir condition.

With this thesis, it proves that FAWAG process can be implemented commercially and widely in any less efficiency WAG process field.

5.2 RECOMMENDATIONS

The recommendations from this study for future work are:

1. Experimental study should be done to confirm the simulation work.

2. Comparison between results from the surfactant model in Eclipse 100 should be made with other simulation tools that support surfactant model.

3. Real reservoir data should be used either in simulation or in experimental work.

4. Economic evaluation should be taken into account before FAWAG is used in any field.

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