## 4.2 Simulation Work Results and Discussion

### *4.2.1 Line Drive Injection with Three Injection wells*

The first results of the simulation with ECLIPSE100 are obtained simulating three water injection wells and fifteen production wells at a simulation time of about 3500 days or about 10 years. Figure 4.1 shows the injectors rates of the three injection wells which are WI1, WI2 and WI3. The Properties of the Gelama Merah reservoir Model are given in APPENDIX C.

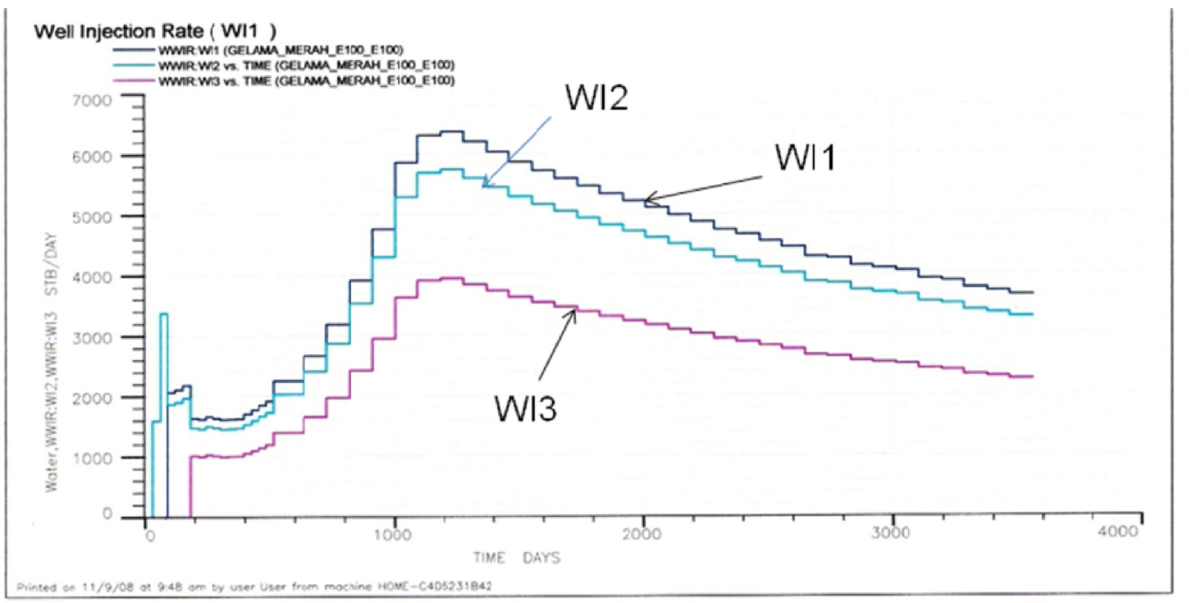


**Figure 4.1: Wells Injection rates for three Injection wells Vs. Time**

We see that the maximum rate in Figure 4.1, is 6,600 STB/Day of water for the well number one (WI1) and minimum injection rate is about 3,800 STB/Day for well number three (WI3). The Water injection performed for this first simulation is not at constant rate for all the wells. The reason for this is due to the requirement of each location of the wells in the field. Each location on the field requires different rate of injection. The injection rate decreases as the life of the reservoir growth. Only three was used because the idea was to analyze the reservoir behaviour when we have more production wells than the water injection wells.

### *4.2.2 Wells Borehole pressure Profile for Injectors and producers*

Wells borehole pressure profile for the injectors is shown Figure 4.2. The WBHP is consistent to all the three wells. From this figure, we see that the pressure changes from 2,200psi to 1,800psi. The Maximum pressure of model for the field is 2,200psia therefore the WBHP must not exceed this pressure limit in order to avoid overpressures in the reservoir. The pressure profiles for the three wells are almost the same, which appear to follow a linear trend throughout the injection process for all the wells.

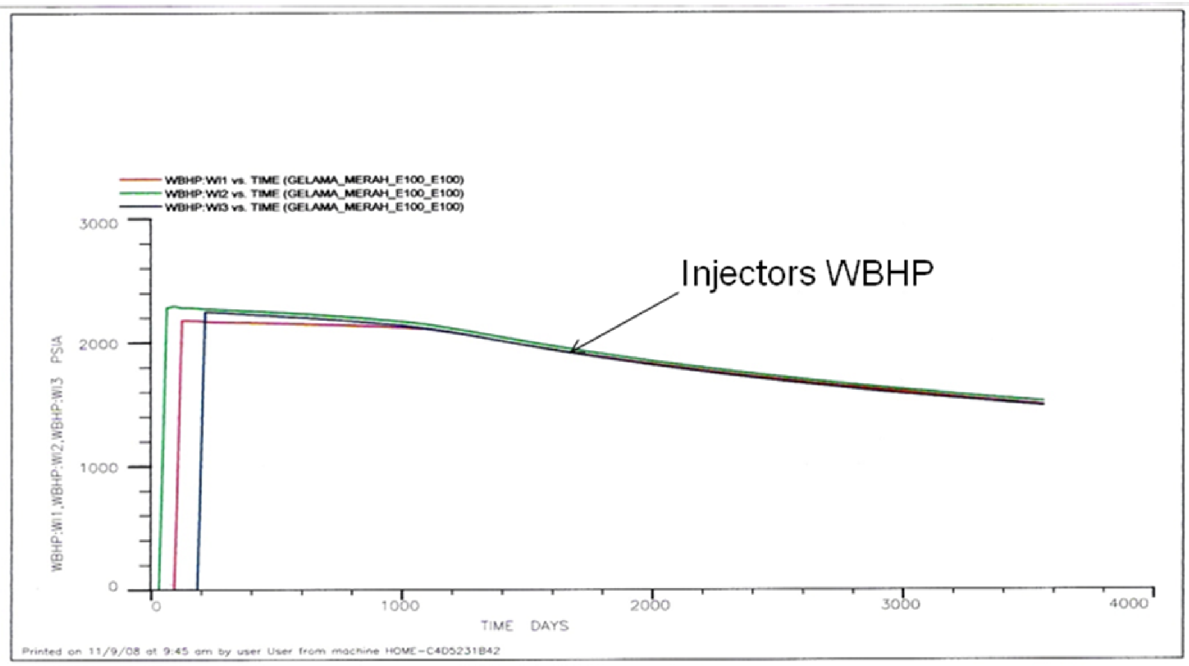


**Figure 4.2: Injectors wells borehole pressure Profile**

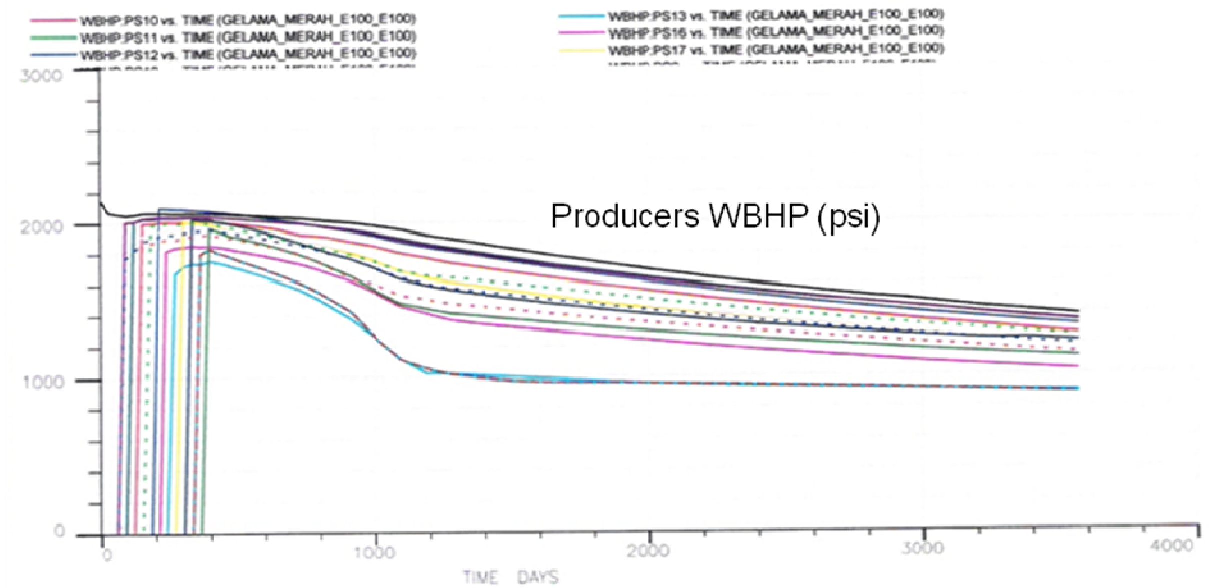


**Figure 4.3: Production wells borehole pressure Profile (for 15 wells)**

In figure 4.3, we have the production wells borehole pressure profile for fifteen wells. The WBHP profile shows a consistency for all the wells for about 40 days of production. The pressure of the wells starts to decrease after of about 200 days. Pressure drop in some wells is faster than others due to the different fluids migration in different locations in the reservoir. The overall pressure drop ranges from 2200psi to 1,600psi at the top part of the profile and from 1600psi to about 1000psi to the lowest part of the profile. The pressure drop of the wells appears to follow a nonlinear trend at the beginning of production and a linear trend by the end of production.

### *4.2.3 Wells Oil Production Rate*

The wells Oil Production rate for the fifteen wells are shown in figure 4.4. In this figure the maximum production rate is 3,150 STB/Day, of “PS19” well. Different wells produce at the different rates due to the location of the wells in the reservoir. The trend shows that, the production profiles drops at the beginning of the production. The high production of the wells at the early days is related to high pressure of the reservoir at the production. The pressure of most of the wells decrease as the year of the reservoir increases as show at after 1,200 days of production.

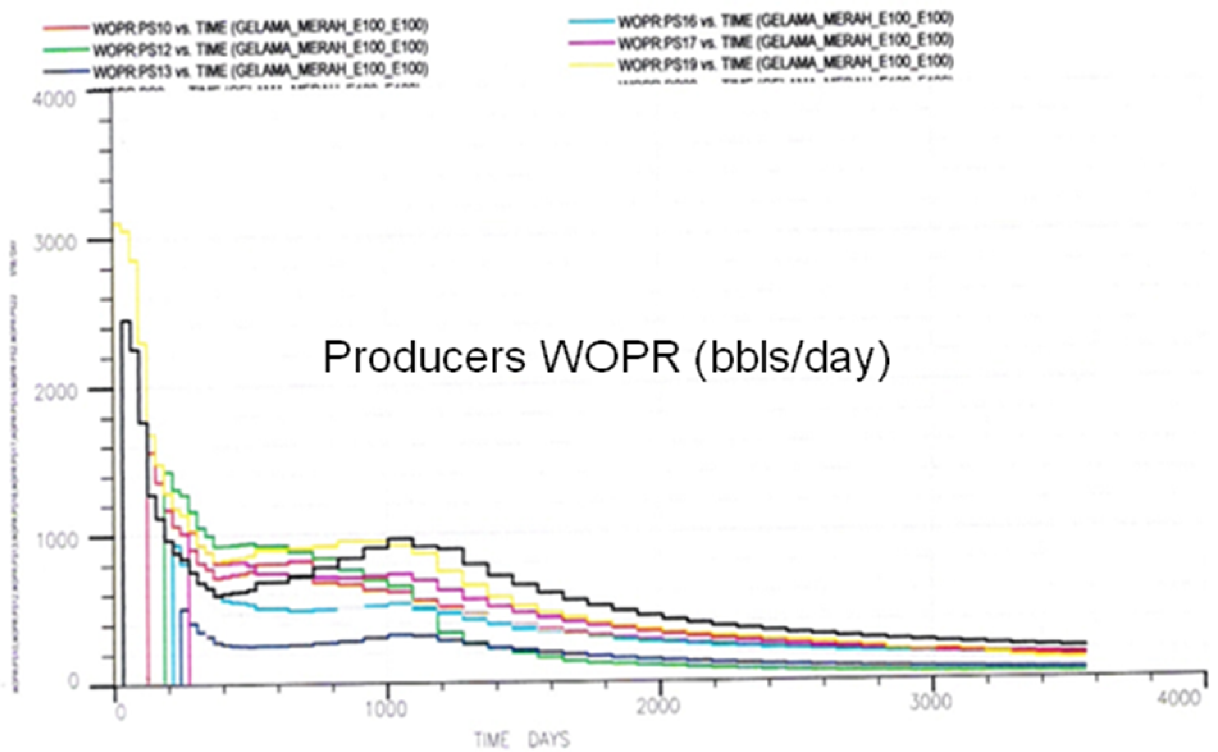


**Figure 4.4: wells Oil Production rate profile**

### *4.2.4 Field Oil Production Rate (FOPR)*

Figure 4.5, shows the Field Oil Production Rate (FOPR), Field Gas Production Rate (FGPR) and Field Water injection rate plotted against the time. In Figure 4.5 the field Oil production rate has a constant rate 10,000 STB/Day for the first 3 years, then it start to decline until it ends with a production of 2,000 STB/Day. The Field Production declines as the Injection rate declines.. The water injection rate reaches to maximum of 16,000 STB/day of water while the field gas production rate reaches to about 30,000 MSCF/day. This high production of gas could lead to high depletion of the field pressure.

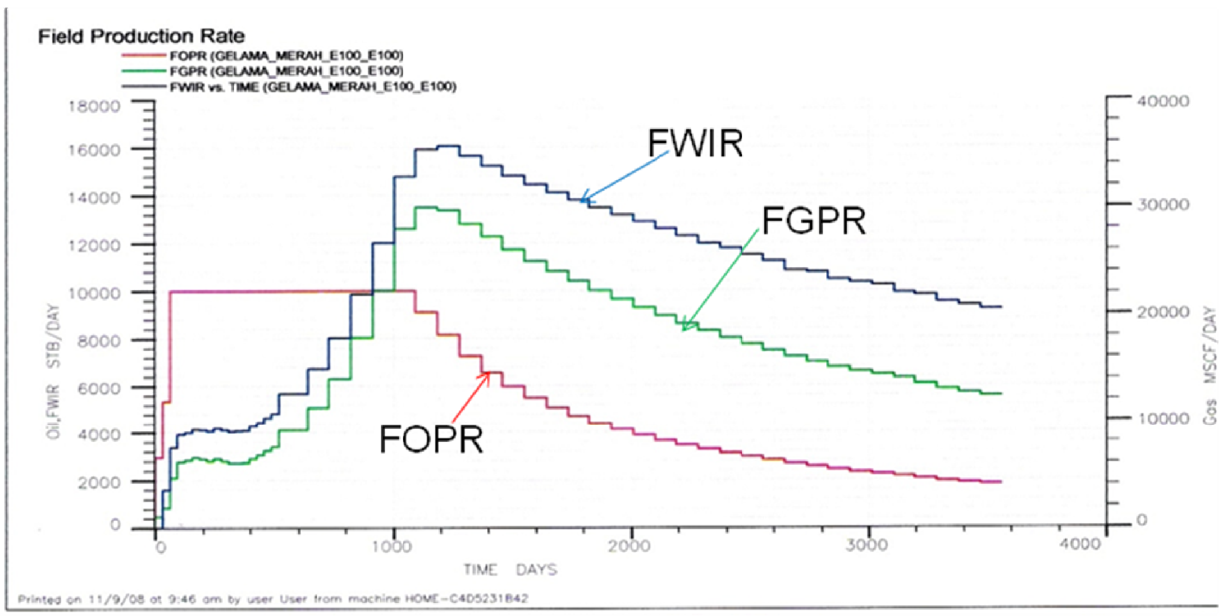


**Figure 4.5: FOPR-FGPR and FWIR vs. TIME**

### *4.2.5 Water Injection with Nine Injection wells*

The Second Simulation work was done with nine production wells and Nine Injection wells. Figure 4.6 shows the wells injection rate profile for a period of more than sixteen years. The maximum rate is about 2,800 STB/Day of water by the WI1 and WI5 wells. The injection rates decrease as the reservoir life increases.

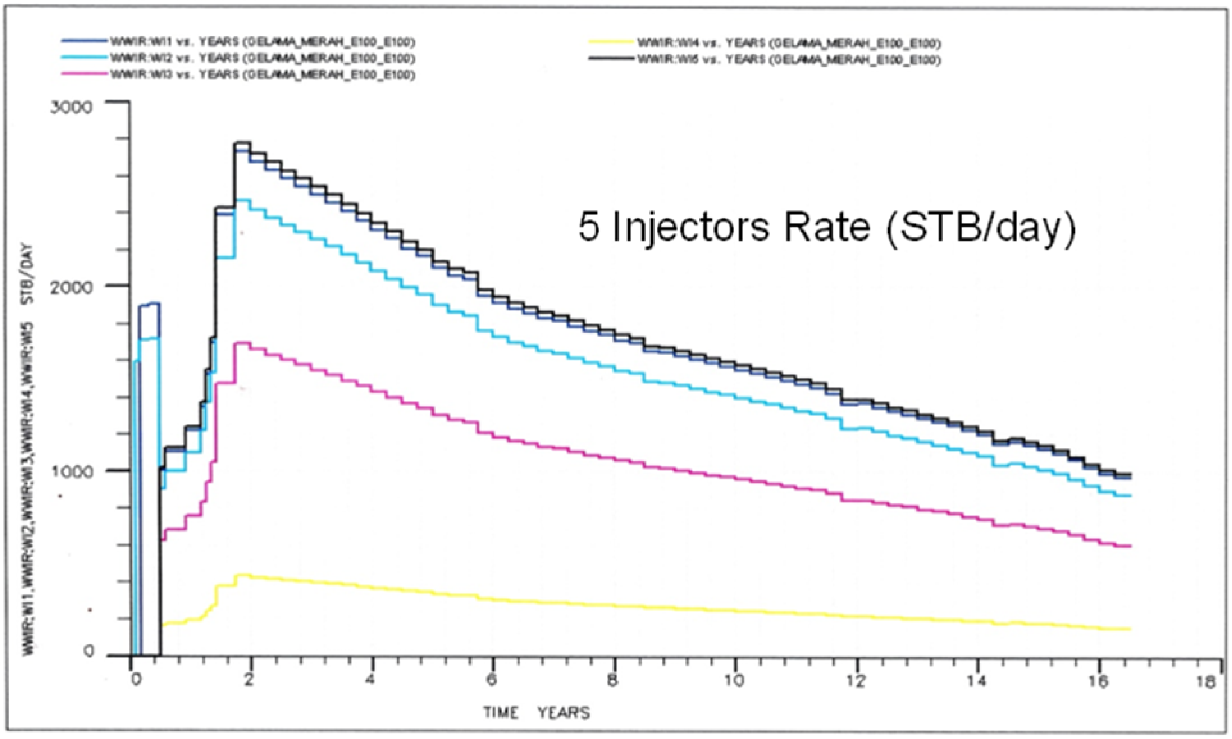


**Figure 4.6: wells Injection rate Profile1 (five wells)**

Figure 4.7 and Figure 4.8 also show the injection rate profile of the remaining injection wells. WI6 well in Figure 4.7 (blue plot) has the lowest rate of the simulation, about 100 STB/Day of water. In Figure 4.6, shows the Wells Water injection Rate (WWIR) profile for WI1, WI2, W13, WI4 and WI5 injection wells.

Figure 4.7, shows the WWIR profile of WI6, WI7, and WI8 injection wells at a simulation time of about 16 years.

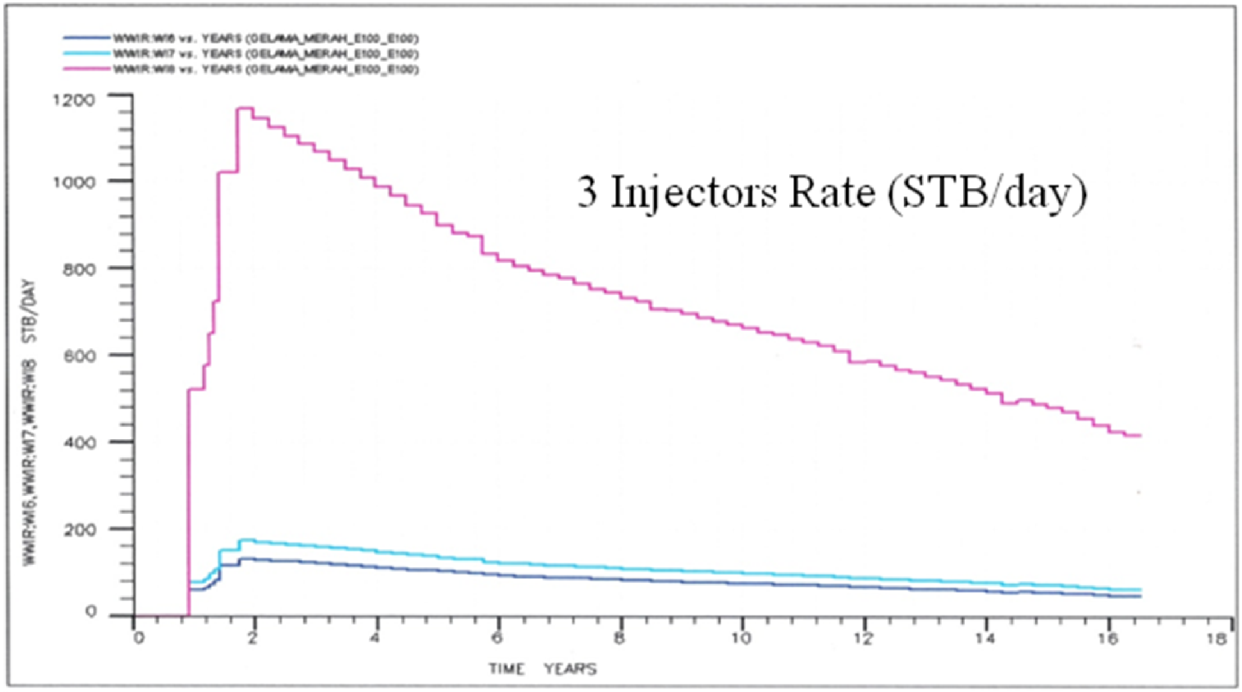


**Figure 4.7: wells Injection rate Profile2 (3 wells)**

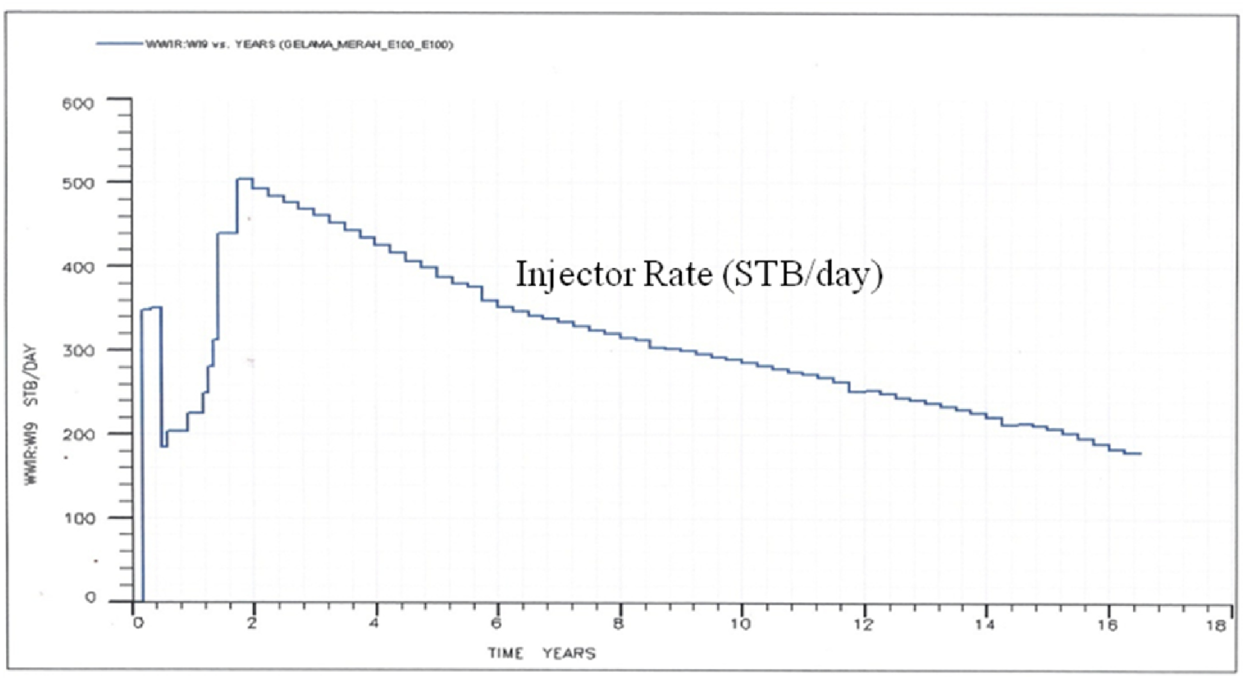


**Figure 4.8: wells Injection rate Profile3 (one well)**

### *4.2.6 WBHP for Nine production wells*

The wells borehole pressure profile for four production wells is shown in Figure 4.9, three production wells in Figure 4.10 and two production wells in Figure 4.11. The borehole pressure depletion for the nine wells ranges from 2,200 psia of the maximum pressure of the field until it reaches about 1,200 psia. Meaning that the pressure profile of all the wells is consistent to one trend. If we compared it with Figure 4.2 for pressure profiles for fifteen production wells, we see that the decline is lower than the previous simulation, which reflects the influence of the injection fluids by the injectors in the field.

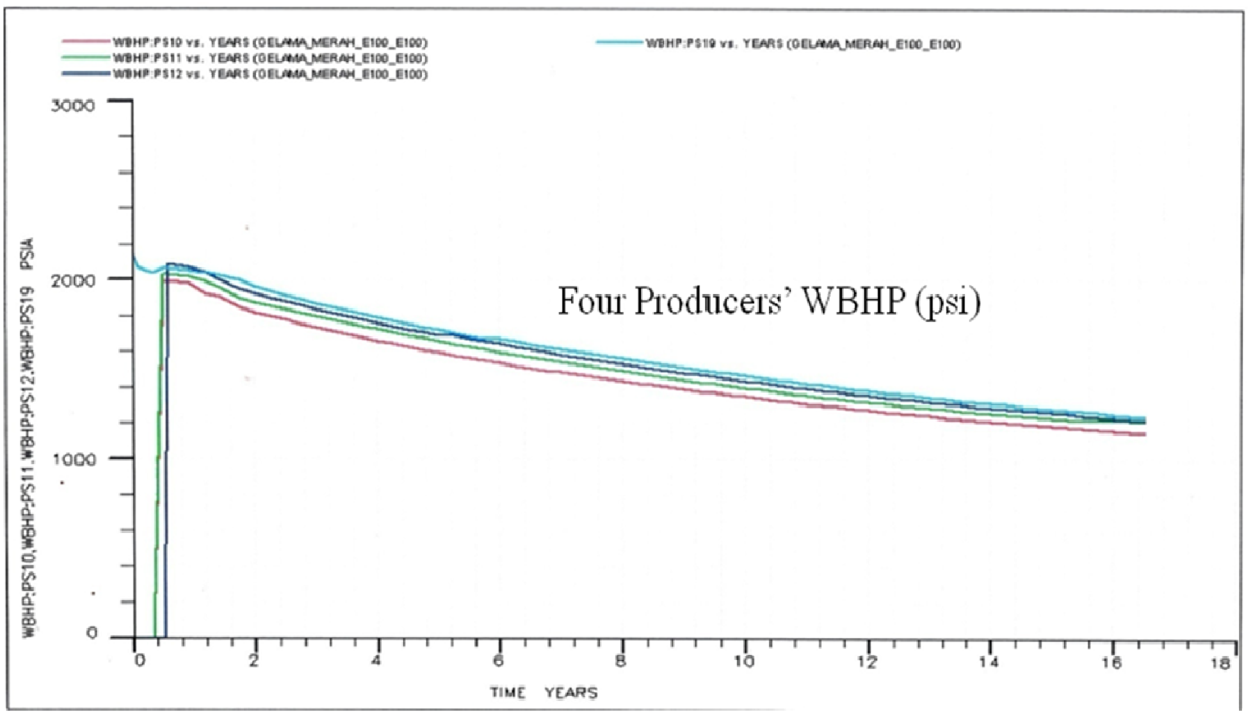


**Figure 4.9: Production wells Pressure profile1 (four wells)**

Figure 4.10, shows the well borehole pressure profile for three production wells (PS2, PS4 and PS6).

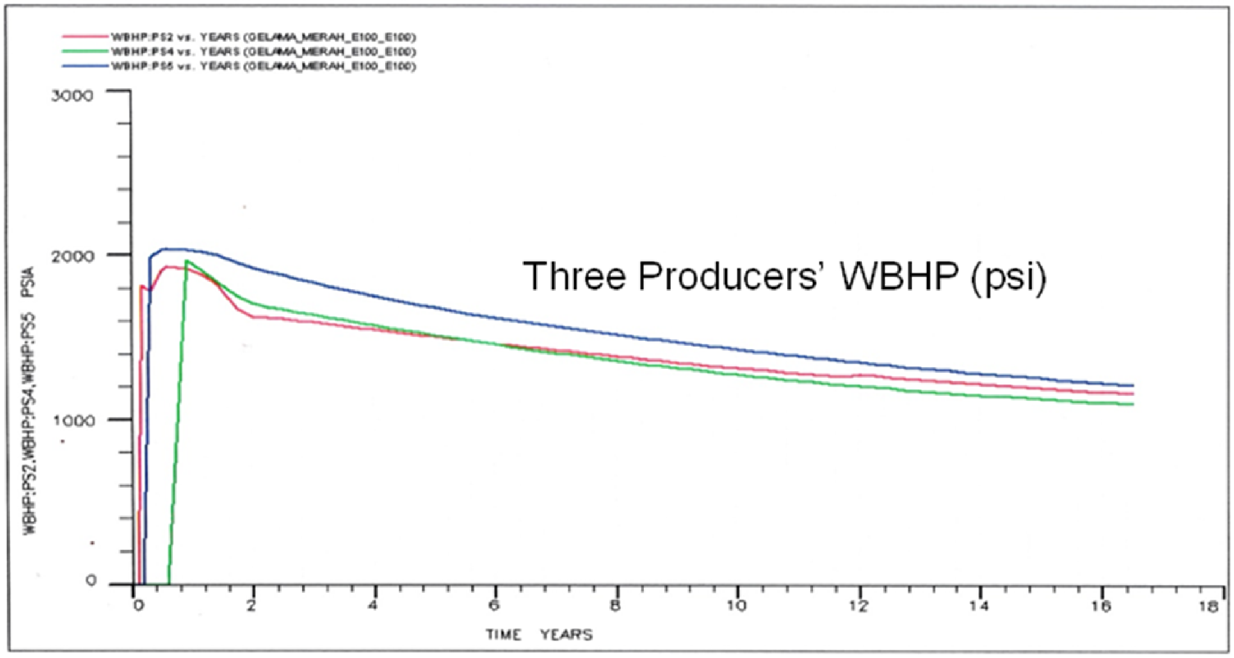


**Figure 4.10: Production wells Pressure profile2 (three wells)**

Figure 4.11, shows the well borehole pressure profile for two production wells (PS8 andPS9)

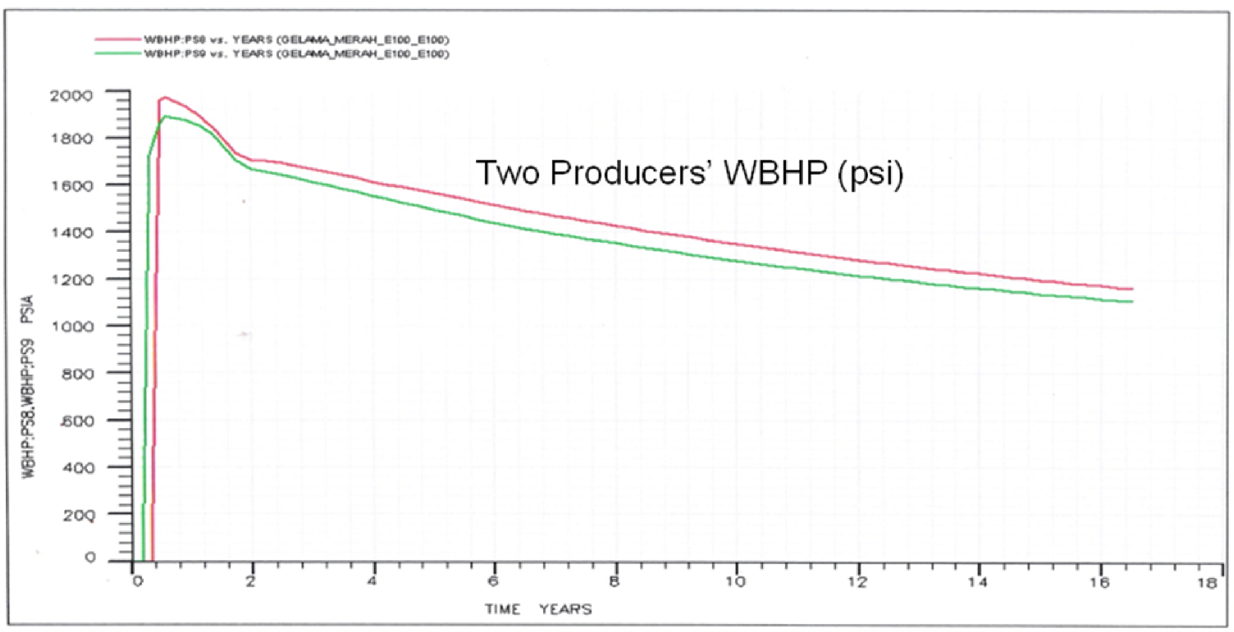


**Figure 4.11: Production wells Pressure profile3 (2 wells)**

### *4.2.7 Field Oil Production Rate*

The field Oil Production Profile rate is shown in Figure 4.12 of the production rate and Injection rate. In Figure 4.12 the FOPR reaches at a maximum value of 10,000 STB/day of oil, while the FWIR reaches at a maximum of 12,000 STB/Day of water. This values shows that the injected at the end of second year is higher than the FOPR. We see that the trend of FOPR is constant for the first two years of injection before drop at the end of the second year. The FOPR declines faster as the FWIR declines as well. This fast decline of the FOPR could be due to the distance between the injection wells and the production wells in the reservoir. This distance will influence in order to obtain front drive of the Injection wells to the production wells.

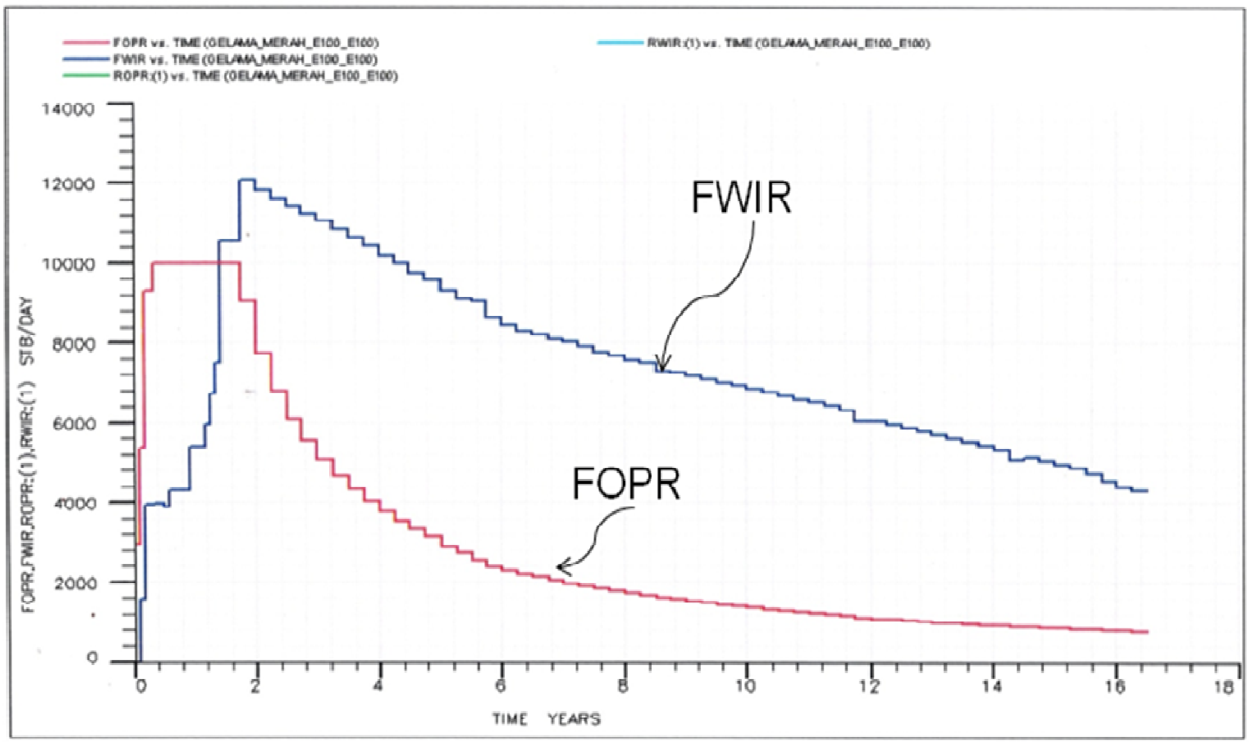


**Figure 4.12: Field Oil Production rate and Injection rate Profile**

Figure 4.13 Shows the FOPR and Field gas Production rate (FGPR) for nine production wells and nine Water injection wells.

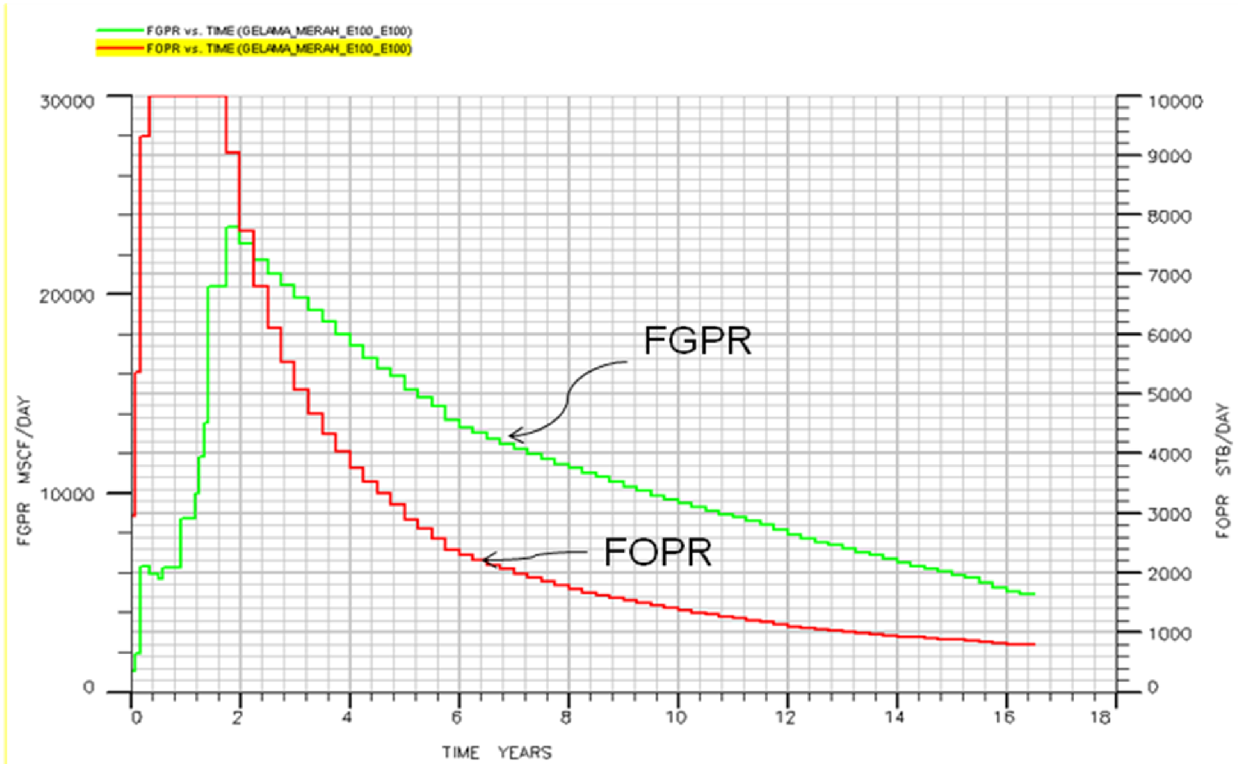


**Figure 4.13: FGPR -FOPR- vs. TIME**

In Figure 4.13 of FGPR and FOPR, the two plots show a fast decline after two years of production. The maximum FGPR is 7,800MSCF/day while the FOPR reaches a maximum of 10,000 STB/day. The FGPR increases for the first two years up to the maximum value before declining at the beginning of year three of production.

In Figure 4.14 we can see the FOPR, Field Gas oil ratio (FGOR) and Field Pressure rate (FPR).The FRP declines as the FORP declines, meaning that the withdrawal of this reservoir fluids influence directly for the pressure depletion of the reservoir. The field needed more fluids to replace the rock voidage created by the produced fluids. Increasing the number of the injection wells is one option, but we can maintain the pressure longer by injecting gas and water at the same time. Because getting back to Figure 4.12, the Water injection rate is higher than the oil production rate at all the times of the years of production.

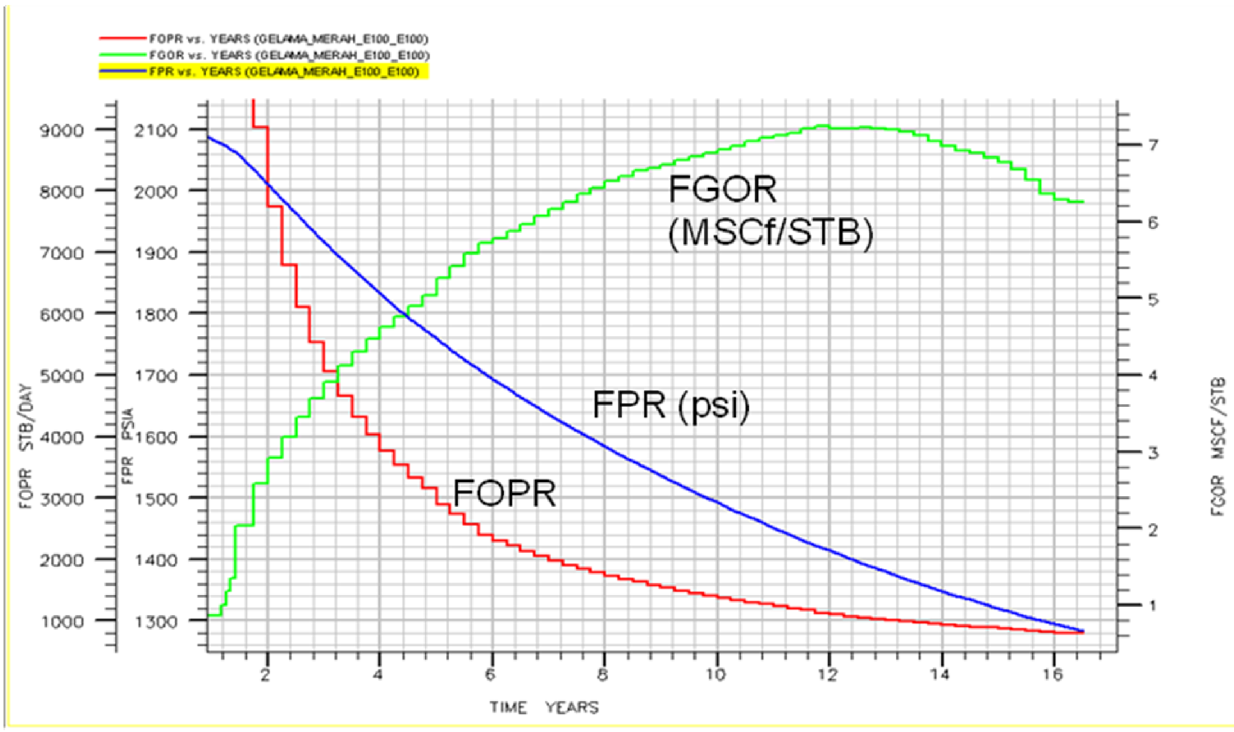


**Figure 4.14: FOPR-FGOR-FPR- vs. TIME**

The FGOR increases as the production declines over the years. This rising of the FGOR is due to the expansion of the gas in the field and leads to high production of this solution gas as the oil production rate declines. High Production of solution gas leads to fast decline of the FPR. The FPR in Figure 4.14 shows a linear drop as the FGOR increases with a negative slope of 55.55psi/year approximately.

Normally for black oil reservoir, reservoir pressure decreases as liquid is removed from the reservoir. At pressures above the bubble point, the oil, water and reservoir rock must expand to fill the void created by the removal of liquid. The rock and remaining liquids are not very compressible. So a large decrease in pressure is necessary to allow the rock and remaining liquids to expand enough replace a relatively small amount of oil produced. Thus as long as the reservoir pressure is above bubble point, pressure decreases rapidly during production. At Pressures below bubble point, gas forms in the pore space. This free gas occupies considerably more space as a gas than it did as a liquid. Also, the gas readily expands as pressure decreases further. The forming and expanding gas replaces most of the void created by production. Reservoir pressure does not decrease as rapidly as it does when pressure is above the bubble point [18].

Figure 4.15 shows the Field water injection total and field oil production total for nine producers and nine water injectors. From these graphs we can see that the water injected in the field is more than the oil produced for a period of sixteen years. Though the water injected is more than the oil produced by the producers, but the expansion of the liquids is not sufficient enough to boost up the production of the field. Figure 4.15 shows that the FWIT by beginning of year seventeen is about 54MMSTB of water, while the FOPT is 28MMSTB of oil. This shows that the ratio between the water injected and the oil produced is about 1.93 or 2 barrels of water per one produced barrel of oil on the field.

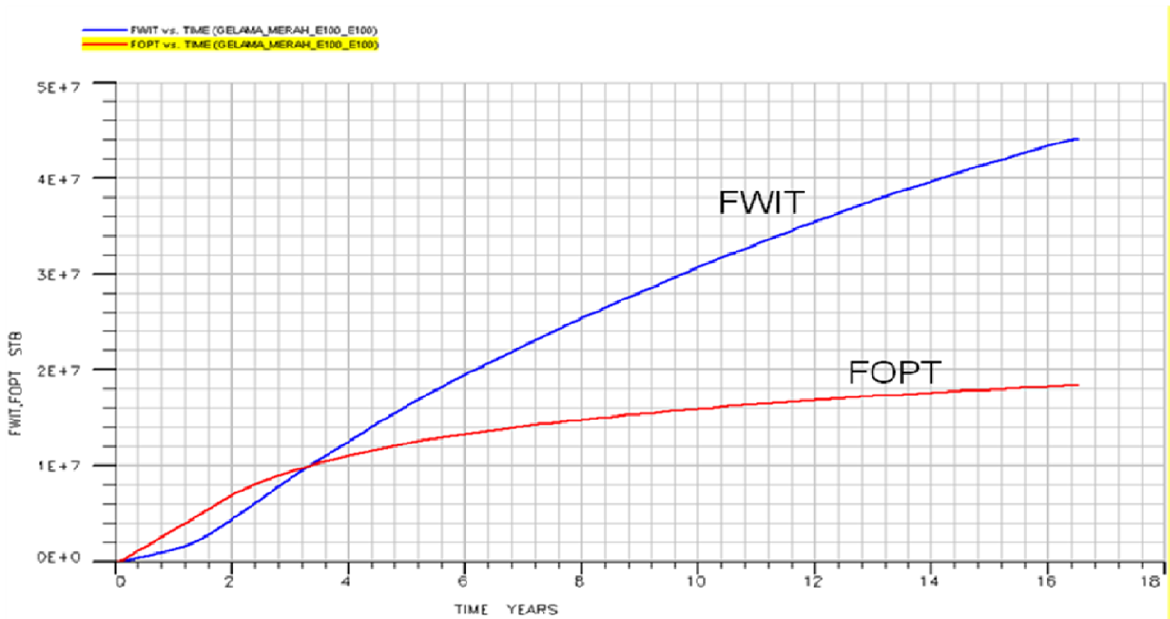


Figure 4.15 Field Water injection total and Field Oil Production total