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Implementation of Mechanical Earth Model in Predicting the Maximum Water Injection Flow Rate in Mature Field

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ABSTRACT

Fracture can occur at shale zone, when fluid injection pressure to reservoir sand target exceeds fracture pressure. Consequence, fluid injected to reservoir target will not be optimum. Therefore, we must determine the fracture pressure that will apply. This study was performed in order to build fit purpose 1D mechanical earth model which will be used to determine or predict injection pressure and maximum injection flow rate, in order to prevent fracture growth from targeted reservoir sand to the enclosing shale interval. Required data to build 1D mechanical earth model in this study namely gamma ray log, density, sonic compression, sonic shear and repeat formation test (RFT). Then, mohr stress diagram applied to determine the safety factor and reservoir simulation done to predict flow rate maximum of water injection at inverted five spot pattern and inverted seven spot patterns with three scenarios. Based on calculation, then obtained vertical stress (S_v) > Maximum Horizontal Stress (SH_{max}) > Minimum Horizontal Stress (Sh_{min}), with average value of S_v, SH_{max}, Sh_{min} is 0.827 psi/ft, 0.731 psi/ft, 0.696 psi/ft, which mean normal stress regime. Fracture pressure that obtained at intact reservoir (cap rock) is 1521.19 psi, and safety factor obtained is 12% or maximum injection pressure is 1460.7 psi. The result of reservoir simulation performed with three scenarios at inverted five spot pattern and inverted seven spot patterns show that second scenario provide the best result with apply flow rate water injection is 53000 STB/D pressure reached is 1453 psi and at inverted seven spot patterns with apply flow rate water injection is 56000 STB/D pressure reached is 1458 psi.

Keywords: *Mechanical Earth Model, Fracture Pressure, Water Injection*

INTRODUCTION

Mario Field is one of the largest waterflood fields in South East Asia, which is located in the Riau Province of Indonesia. This field has been in production for more than 59 years since its discovery in 1944 (Hao et al., 2011). It is planned that water injection will be carried out in this field at injection well X, zone Mr 2 (2276–2390 ft). Before carrying out water injection, an important step that must be prepared in advance is to build a 1D mechanical earth model to determine the maximum injection pressure from the waterflood to prevent fracture of the shale interval in the target reservoir (PT. CPI, 2011).

Most water injection wells in water flooded reservoirs have fractured over time. These fractures have a significant effect on reservoir performance (oil production rate, oil-water ratio, and ultimate recovery). If the injection pressure increases beyond the minimum horizontal (fracture pressure) or vertical stress in the formation around the borehole, fractures will form (Gadde, & Sharma, 2001). Oil recovery and reservoir sweep are affected by a fracture because the injected fluid enters the fractured layer, then water breakthrough will occur quickly which causes little oil recovery to be achieved (Kyunghaeng, Chun, & Sharma, 2011).

To build a 1D mechanical earth model, data logging and field test data are needed such as gamma-ray, density, sonic compression, sonic shear, and repeat formation tests. The mechanical earth model that has been generated, including fracture pressure, will be used as a constraint to perform injection simulation on Petrel 2009 software which will be used to predict the maximum flow rate of water injection in the inverted five spots and inverted seven-spot patterns.

DATA AND METHOD

Water injection planned to be done at injection well X, zone Mr 2 (2276–2390 ft). before doing water injection, important step that must be done is to determine the pressure gradient fracture by building 1D mechanical earth model (MEM). Value of fracture pressure previously obtained at depth critical (Mr 1) shale zone will be used as a limitation in the application of water injection, then a simulation is carried out by building an appropriate reservoir model on the Mario Field depth structure map, then three field scenarios are made to predict the maximum flow rate when water injection is done on pattern inverted five spots and inverted seven spots with limitations fracture pressure. If the injection pressure increases beyond the minimum horizontal (fracture pressure) or vertical stress in the formation around the borehole, the fracture will occur (Gadde, & Sharma, 2001). Oil recovery and reservoir sweep are affected by a fracture because the fluid injected enters the fractured layer, then water breakthrough will occur quickly which causes little oil recovery to be achieved. (Kyunghaeng, Chun, & Sharma, 2011). The flow chart of this research can be seen in Figure 1.

1D Mechanical Earth Model Construction

Analysis of 1D Mechanical Earth Model Construction begins by calculating the vertical stress by integrating bulk density (RHOB) at all depths and regressing to ground level. Then, combined with the log data. It was found that the vertical stress was 2402.56 psi or the gradient overburden stress was 0.877 psi/ft. And then, determine the normal compaction trend using log sonic data in the shale interval with a Vshale value of 0.6. Then, the normal compaction trend is used as input into the pore pressure calculation. The pore pressure value obtained is calibrated against field tests such as the repeat formation test (Setiawan, & Vera, 2016).

The tensile strength of the formation is used to evaluate the tensile failure of boreholes due to stress concentration. Tensile strength usually ranges from 1/12 to 1/8 of the UCS (Rafieepour, & Jalalifar, 2014). In this study, the tensile strength applied is 1/10 of UCS to determine the rock strength properties of the injection well X. In determining the minimum horizontal stress (Sh_{min}) there are two methods used, namely the eaton method (in sand and shale lithology using a combination of pore profiles pressure), and matthew & kelly method (only on shale lithology), assuming hydrostatic (shale pore pressure). The Matthew & Kelly curves were adjusted to the Eaton curves for the shale fracture, by adjusting the value of the coefficients of the stress matrix. In determining the maximum horizontal stress (Sh_{max}) in the Mario Field, it is assumed that it is based on analog data from the nearest field.

A previous study from Kotabatak Field stating that the calibration borehole enlargements by comparing the difference between collapse mud weight and mud weight used during drilling indicate that the difference between the minimum and maximum horizontal stress, using a comparison σ_H/σ_h with a value of 1.05 resulted in a calibration consistent (Yi, Goodman, Williams, & Hilarides, 2008).

The ratio of these values will be used in this field. Based on the results of calculations and analysis of vertical stress, pore pressure, minimum horizontal stress, and maximum horizontal stress. Based on Anderson's (1951) classification, this Mario field is in the normal fault stress regime where $S_v > SH_{max} > Sh_{min}$. Figure 2 shows the geomechanics model of the injection well X.

Maximum Injection Pressure

Determination of the maximum injection pressure aims to prevent the occurrence of debris in the reservoir to the caprock. As long as there is sufficient stress contrast between the reservoir and the caprock, the applied pressure will always seek the least resistance into the reservoir section. (Setiawan, & Vera, 2016). Determination of maximum injection pressure is divided into two parts, in the intact reservoir and in the fault area. Based on the results of the calculations that have been carried out, the maximum injection pressure in the intact reservoir at a critical depth is 1661.38 psi. Then by applying the Mohr stress diagram, we get a safety factor of 12% or a maximum injection pressure of 1460.7 psi. Then, from the results of calculations that have been carried out, it is found that the maximum injection pressure in the fault area is 1521.19 psi. Then by applying the Mohr stress diagram, we get a safety factor of 20% or a maximum injection pressure of 1220.7 psi.

Prediction of Maximum Flow Rate of Water Injection

After knowing the fracture pressure and establishing reservoir modelling, the next step is to predict the maximum flow rate of water injection in the inverted five-spot and inverted seven-spot pattern by simulating the reservoir for three years, and making several field scenarios by adjusting the injection flow rate to see if the injection flow rate whether the fracture pressure reaches the fracture pressure or not because if the fracture pressure is reached, the fluid injected into the target zone that has been determined will spread to other zones and of course something like this is not desirable to happen.

Inverted Five Spot Pattern Field Development Scenario

Figure 3.a is inverted five-spot patterns in the Mario field using one existing well, namely an injection well and 4 additional production wells. And the following picture below is an illustration of the inverted five-spot patterns on the Mario field.

Inverted Five Spot Pattern Scenario 1

In this scenario (Figure 3.b), the strategy for field development is to set the water injection rate of 40000 STB/D. The pressure is reached at 1263 psi, which indicates that there is no fracture, so it is still at a safe level in the application of the injection rate. The cumulative oil production in this scenario is 23.4 MMSTB, the cumulative water produced is 23 MMSTB and the water cut reaches 80% after producing for 3 years.

Inverted Five Spot Pattern Scenario 2

In this scenario (Figure 3.c), the strategy for field development is to set the water injection rate to 53000 STB/D. The pressure is reached at 1453 psi, which indicates that there is no fracture, so it is still at a safe level in the application of the injection rate. The cumulative oil production in this scenario is 24.6 MMSTB, the cumulative water produced is 33.6 MMSTB and the water cut reaches 84.1% after producing for 3 years.

Inverted Five Spot Pattern Scenario 3

In this scenario (Figure 3.d), the strategy for field development is to set the water injection rate of 60000 STB/D. The pressure is reached at 1560 psi, which indicates that a fracture has occurred because it has exceeded the maximum injection pressure so that the rate is not feasible to apply. The cumulative oil production in this scenario is 25.6 MMSTB, the cumulative water produced is 39 MMSTB and the water cut reaches 86% after producing for 3 years.

From the development scenario that has been carried out, it can be concluded that the best scenario is scenario 2, because with the application of a flow rate of 53000 STB/D the pressure achieved is still below the fracture pressure (1460,7 psi) which is 1453 psi and is still at a safe level to apply.

Inverted Seven Spot Pattern Field Development Scenario

Figure 4.a is the inverted seven-spot patterns in the Mario field using one existing well, namely an injection well and 6 additional production wells. And the following picture below is an illustration of the seven-spot pattern on the Mario field.

Inverted Seven Spot Pattern Scenario 1

In this scenario (Figure 4.b), the strategy for field development is to set the water injection rate to 45,000 STB/D. The pressure is reached at 1295 psi, which indicates that there is still no fracture, so it is still at a safe level in the application of the injection rate. The cumulative oil production in this scenario is 25 MMSTB, the cumulative water produced is 27.4 MMSTB and the water cut reaches 84% after producing for 3 years.

Inverted Seven Spot Pattern Scenario 2

In this scenario (Figure 4.c), the strategy for field development is to set the water injection rate to 56,000 STB/D. The pressure is reached at 1458 psi, which indicates that there is still no fracture, so it is still at a safe level in the application of the injection rate. The cumulative oil production in this scenario is 26 MMSTB, the cumulative water produced is 37 MMSTB and the water cut reaches 86.4% after producing for 3 years.

Inverted Seven Spot Pattern Scenario 3

In this scenario (Figure 4.d), the strategy for field development is to set the water injection rate to 60,000 STB/D. The pressure is reached at 1520 psi, which indicates that there is still no fracture, so it is still at a safe level in the application of the injection rate. The cumulative oil production in this scenario is 26.35 MMSTB, the cumulative water produced is 40.8 MMSTB and the water cut reaches 87% after producing for 3 years.

From the development scenario that has been carried out, it can be concluded that the best scenario is scenario 2, because with the application of a flow rate of 56,000 STB/D the pressure achieved is still below the fracture pressure (1460,7 psi) which is 1458 psi and is still at a safe level to apply.

RESULT AND DISCUSSION

From the three field scenarios that have been carried out in predicting the maximum flow rate. In the five-spot pattern, the second scenario is the best by applying an injection flow rate of 53,000 STB/D and the pressure achieved is 1453 psi. in the seven spot pattern, the second scenario is the best by applying an injection flow rate of 56,000 STB/D and the pressure achieved is 1458 psi, where the pressure is close to fracture pressure by applying a safety factor of 12% which is 1460,7 psi.

CONCLUSIONS

The conclusions obtained from this study are as follows:

1. Based on the calculation and analysis of the 1D mechanical earth model, the Mario Field is currently in the normal fault stress regime where $S_v > SH_{max} > Sh_{min}$.
2. Using log data to identify pore pressure trends that can be used to estimate pore pressure. Where the pore pressure is part of geomechanic properties.
3. Fracture pressure prediction is calculated using 2 methods, namely the Eaton method (on sand and shale lithology), using a combination (profile pore pressure), and the Matthew & Kelly method (only on shale lithology), assuming hydrostatic (shale pore pressure).
4. The maximum injection pressure in the intact reservoir is 1661.38 psi and at the fault area is 1521.19 psi.
5. The safety factor obtained from the Mohr stress diagram at the intact reservoir is 12% or 1460,7 psi and at the fault area is 26% or 1220.7 psi.
6. In the five spot pattern, the second scenario is the best by applying an injection flow rate of 53,000 STB/D and the pressure achieved is 1453 psi.
7. In the seven spot pattern, the second scenario is the best by applying an injection flow rate of 56,000 STB/D and the pressure achieved is 1458 psi.

There are several things that are suggested for further research, namely as follows:

1. Determine wellbore stability, in directional or horizontal wells.
2. Determine the stable mud weight window.
3. Comparing the economics of the five spot pattern and seven spot pattern cases in a water injection project.

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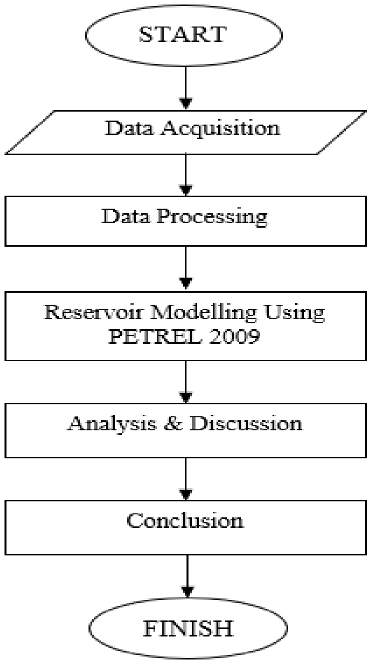

Figure 1: Research Flowchart

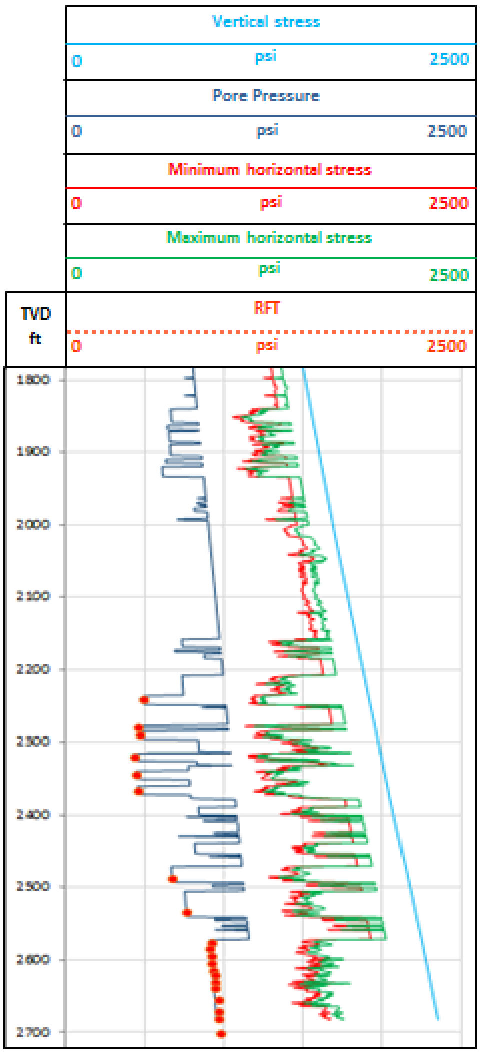

Figure 2: Geomechanic Model

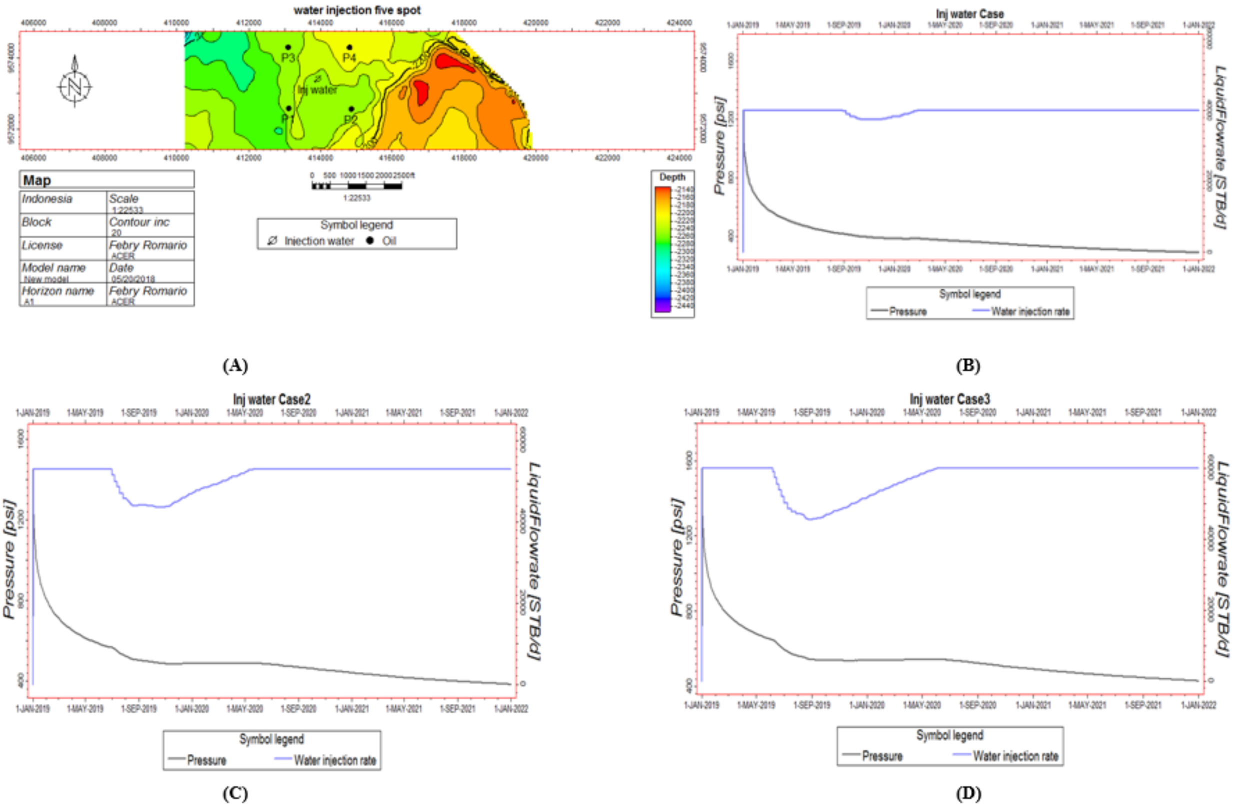

Figure 3: (a) Well Point on the Mario Field with Inverted Five-Spot Pattern; (b) Pressure Profile and Water Injection Rate Scenario 1 in Inverted Five-Spot Pattern; (c) Pressure Profile and Water Injection Rate Scenario 2 In Inverted Five-Spot Pattern; (d) Pressure Profile and Water Injection Rate Scenario 3 In Inverted Five-Spot Pattern.

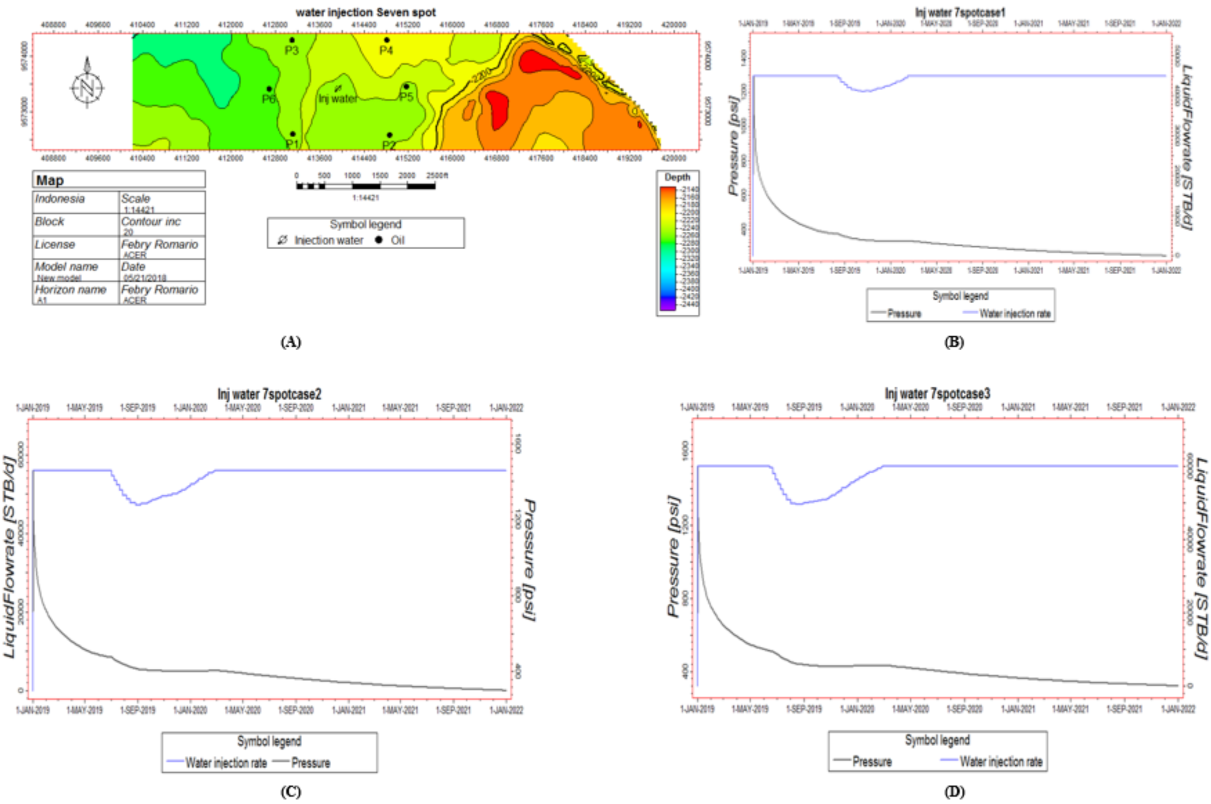

Figure 4: (a) Well Point on the Mario Field with Inverted Seven-Spot Pattern; (b) Pressure Profile and Water Injection Rate Scenario 1 in Inverted Seven-Spot Pattern; (c) Pressure Profile and Water Injection Rate Scenario 2 In Inverted Seven-Spot Pattern; (d) Pressure Profile and Water Injection Rate Scenario 3 In Inverted Seven-Spot Pattern.