PROCEEDINGS
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The Effect of WAG's Starting Injection Time to Oil Recovery in Inverted-5 Spot Simulation Model

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Abstract

Water Alternate Gas (WAG) method have been used to enhance the displacement effectiveness of CO_2 injection mechanism. CO_2 injection was used to increase additional oil recovery by swelling the volume of oil and reducing its viscosity. By adding water after CO_2 injection phase, it will increase the volumetric displacement efficiency thus improving mobility ratio and increasing oil recovery. In this study, the determination of water injection start time after CO_2 injection will be further investigated to improve oil recovery of simulation results.

This simulation was using analogue 3D model from X Field with the wells used in this study are existing wells. It will be simulated by using CMG GEM commercial simulation software. The reservoir target layer for CO2 injection is at Y Layer, Talang Akar Formation. Current reservoir pressure of Y Layer is at 2500 psia with the MMP of the oil is at 2900 psia. The inverted 5 spot pattern injection scenario will be done for 15 years with WAG injection is conducted after the primary recovery. Several scenarios which consist of injecting water before CO_2 breakthrough, slightly after CO_2 breakthrough, and after CO_2 breakthrough were done with using same injection rate of CO_2 and water. CO_2 rate was at 3.6 MMSCFD and water rate is equivalent with the CO_2 injection rate. The effect of the water injection starting time then was analyzed.

The result of the study is that injection water after CO_2 breakthrough is giving the best result with RF of 40.13%, compared with the water injection before CO2 breakthrough (RF 39.47%) and injecting water slightly after breakthrough (RF 39.68%). By injecting water after CO_2 breakthrough will give more time for the microscopic displacement take effect and CO_2 phase can contact more oil before water displace the leftover oil which cannot be swept using CO_2 injection.

Introduction

CO_2 Flooding have been implemented around the world due to the abundant source of CO_2 and can be used for reducing emission in the atmosphere. The main reason of using CO_2 gas for tertiary recovery is because its capability to reduce oil viscosity and to make crude oil swell, hence improving oil mobility (Holm 1986; Bon, 2009). By injecting CO_2, it will provide a good microscopic sweep efficiency by swelling the crude oil and reduce its viscosity by several degrees. However, CO_2 flooding have several disadvantages such as viscous fingering that apparently can happen in the reservoir and also gravity segregation (CO_2 has less viscosity and density than oil and water). (Nasir, 2009; Bon, 2009)

There are several improvements for the CO_2 flooding technique with adding water as chase water or doing CO_2 injection alternating with water injection and repeated with several cycles (Water-Alternating Gas Injection). The purpose of adding water into CO_2 injection is to add mobility control to the injection system and improve the macroscopic sweep efficiency of the injection. (Christensen, 2001; Valeev, 2017). However, adding water also imposes water blocking effect which will make some CO_2 soluble into water than into oil. (Yan, 2010)

In this study, the determination of water injection starting time after CO_2 injection will be further investigated to improve oil recovery of simulation results.

Data and Method

The simulation was done by using CMG GEM compositional simulation. The input used in the simulation based on the X Field wells' actual data. Reservoir target for CO_2 injection is at Talang Akar Formation, Y Layer.

Current reservoir pressure of Y Layer is at 2500 psia with Minimum Miscible Pressure (MMP) calculated from slimtube experiment is at 2900 psia. The PVT used in this study and the PVT match results can be seen at Figure 1.

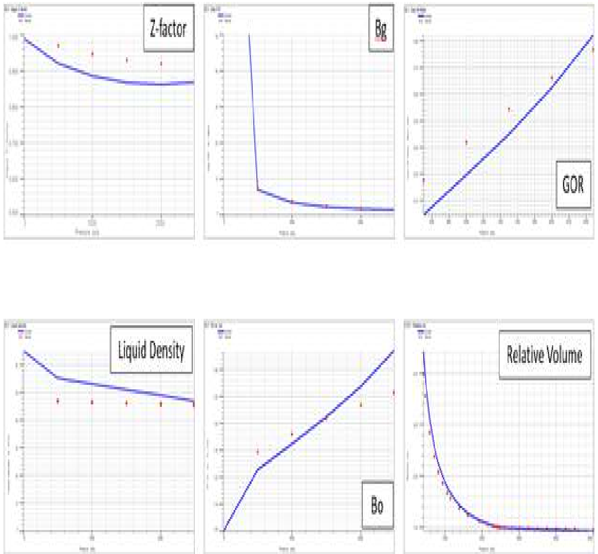

Figure 1: PVT Match Results for each matching parameters

Swelling and viscosity reduction results from the simulation can be seen at Figure 2. Reservoir model in this study used 7 tables of rock type (Figure 3). These relative permeability curve inputs were constructed based on existing history match results.

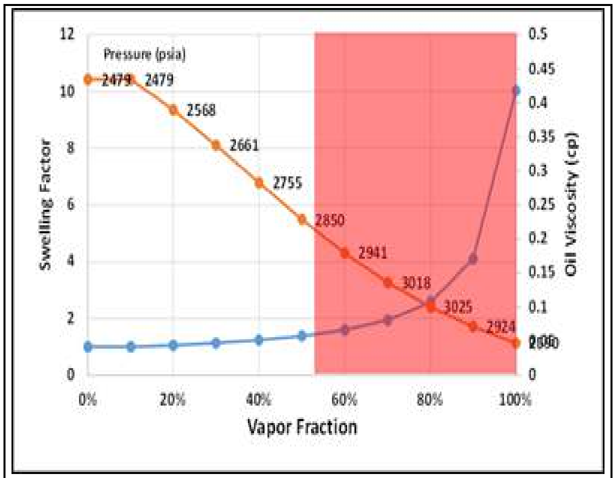

Figure 2: Viscosity Reduction Results

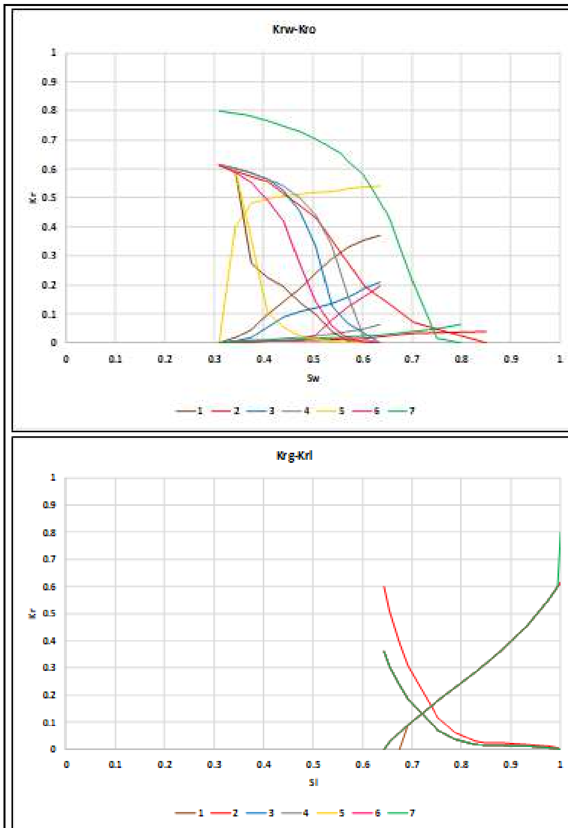

Figure 3: Relative permeability table for each rock types: a) Kwo-Krw; b) Krg-Krl

The history matching conducted for X Field which started on production since 1991 until present day. The CO_2 simulation scenario then was conducted with using inverted 5 spot pattern injection scenario with WAG injection conducted after primary recovery for 15 years. Several scenarios which consist of injecting water before CO_2 breakthrough, slightly after CO_2 breakthrough, and after CO_2 breakthrough were done with using same injection rate of CO_2 and water. CO_2 rate was at 3.6 MMSCFD and water rate is equivalent with the CO_2 injection rate. The effect of the water injection starting time to the recovery factor then was analyzed. The location of the injection well and production well in the pattern could be seen at Figure 4. Also, the CO_2 WAG injection scenario using sensitivity of water injection starting time could be seen at Figure 5.

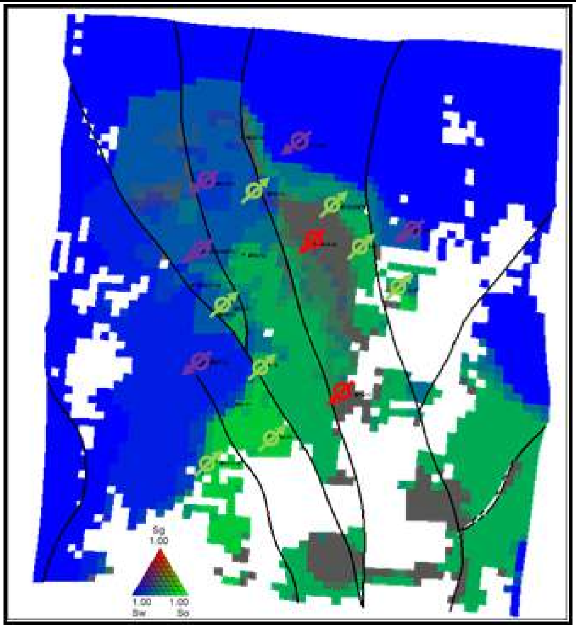

Figure 4: Injection and Production Well Pattern in Y Layer

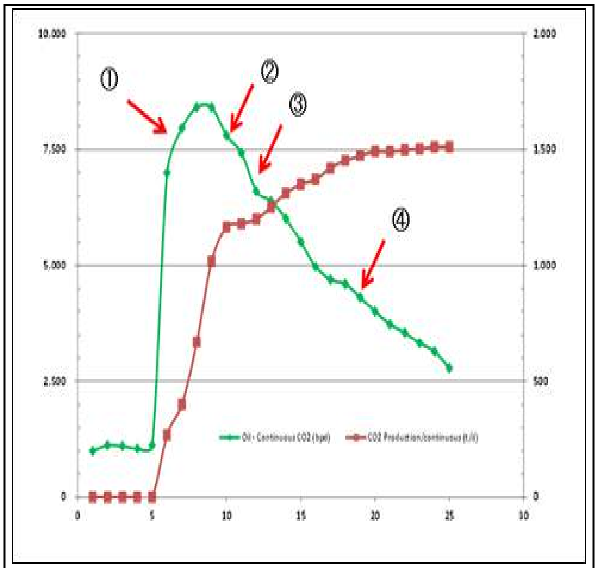

Figure 5: WAG starts timing scenario after Waterflood: 1) Before Breakthrough; 2) Slightly After Breakthrough; 3) After Breakthrough; 4) Late After Breakthrough

Result and Discussion

History matching results which was conducted to match the actual production of this zone can be seen at Figure 6.

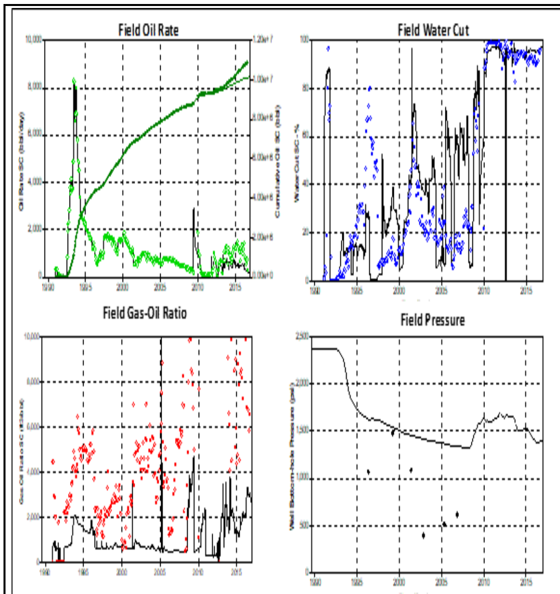

Figure 6: History Match Results

By using the cases from Figure 5, there are 3 cases which can be used to determine starting time injection effect on the production such as before CO_2 breakthrough, at the time of breakthrough, and after CO_2 breakthrough. The difference is shown in Figure 7 below.

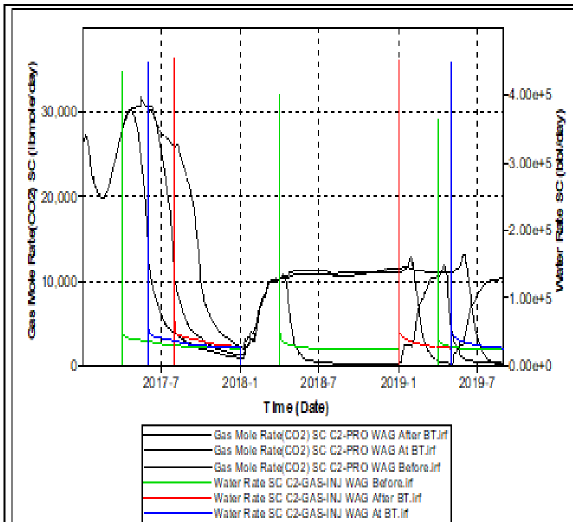

Figure 7: WAG start using timing scenario

Figure 7 shows a cycle for CO_2 WAG injection based on timing. The prediction performances for these cases can be seen in Figure 8.

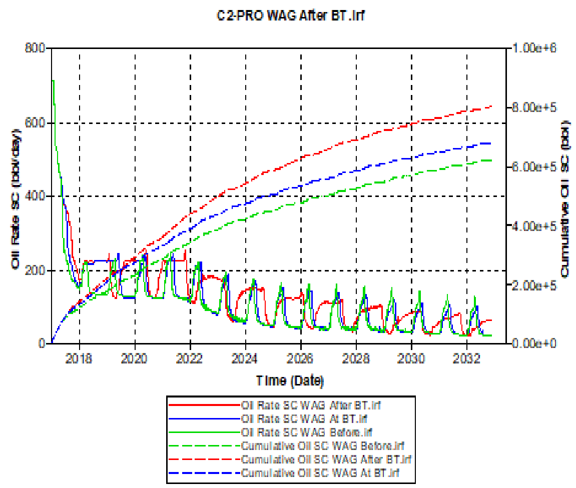

Figure 8: Simulation Results using WAG timing scenario

The result of the study is that injection water after CO_2 breakthrough is giving the best result with RF of 40.13%, compared with the water injection before CO_2 breakthrough (RF 39.47%) and injecting water slightly after breakthrough (RF 39.68%). By injecting water after CO2 breakthrough will give more time for the microscopic displacement take effect and CO_2 phase can contact more oil before water displace the leftover oil which cannot be swept using CO_2 injection.

The prediction gives highest recovery when we start injecting CO_2 after breakthrough of CO_2 produced. The high recoveries reflect when we inject CO_2 higher than other cases. In summary, we can conclude that WAG timing after breakthrough will give the highest recovery.

Conclusions

- From the simulation study, the highest recovery was gained from water injection after CO_2 breakthrough WAG scenario (RF 40.13%).
- Addition of water after CO_2 breakthrough will more efficiently improve mobility ratio and sweep efficiency.

References

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