CO2 Enhanced Oil Recovery in Reservoirs with Advanced Wells: Simulations and Sensitivity Analysis

Isu Uchechukwu Agha, Nora C.I. Furuvik, Soheila Taghavi *

Department of Process, Energy and Environmental Technology, University of South-Eastern Norway.

**Corresponding author: soheila.t.hosnaroudi@usn.no*

Abstract: Injection of CO2 for enhanced oil recovery (CO2-EOR) is used in fields with high amount of residual oil. CO2-EOR refers to a technology where supercritical CO2 is injected into an oil reservoir to increase the oil production. CO2-EOR in combination with CO2-storage is an attractive method to increase the oil production from mature oilfields, and at the same time reduce the carbon footprint from industrial sources. Utilizing autonomous inflow control valves (AICVs) in CO2-EOR projects contributes to a better distribution of CO2 in the reservoir, reduction in production of water and CO2 mixture, and thereby increased storage capacity of CO2. The main objective of this study is modelling and simulation of oil production from an oil reservoir using CO2 water alternating gas (CO2 WAG) injection in combination with advanced wells that are completed with AICVs. Furthermore, performance evaluation of the AICV technology and sensitivity analysis of parameters affecting the WAG process are completed. The results from the simulations indicate that well completion with AICV can maintain good oil production while the production of water is decreased from 3e+06 m3 to 9.8e+04 m3 which corresponds to 97% reduction in water production. The sensitivity analysis of the simulation results affirms that permeability, well placement, and well spacing have impact on productivity in terms of both oil recovery and water production in the WAG EOR method. The results indicate that permeability increase has a slight increment effect on oil recovery. The well spacing analysis shows that increasing the distance between the wells will increase the oil recovery and delay the water breakthrough. Lastly the well placement analysis shows that vertical injection of miscible CO2 produces more oil than horizontal injection of miscible CO2. AICVs restrict the production of mixture of CO2 and water, and thereby cause a better distribution of CO2 in the reservoir.

Keywords: Miscible CO_2, Enhanced Oil Recovery, Autonomous Inflow Control Valve, Water Alternating Gas, Computer Modelling Group, Minimum Miscible Pressure

1. INTRODUCTION

The oil and gas industry has played a pivotal role for the world energy production for decades. The oil and gas will remain important sources of energy in the future. Hence, improving oil recovery with reduced carbon footprint is necessary to meet the future energy demands. The CO_2 water alternating gas enhanced oil recovery (WAG EOR) is one of the methods used in the tertiary stage of oil production. WAG is a process of injecting CO_2 in alternating sequence with water into the oil field formation (Bahagio, 2013).

Studies suggest that the injection of CO_2 into the oil field reservoirs is beneficial for both the oil recovery and the greenhouse gas emissions (Safi et al., 2020). One example of the application of WAG EOR, is the commercial project at Lula offshore oil field, Brazil. Compared with CO_2-EOR, the CO_2-WAG EOR gives improved oil displacement and sweep efficiencies (Bahagio, 2013). Norway has technical potential for CO_2-WAG EOR on the North Sea oil fields. However, one problem is that the CO_2 injected can be recirculated into the producer well leading to poor distribution of CO_2 in the reservoir and thereby damage the process equipment due to the corrosive mixture of CO_2 and water (E. K. Halland et al., 2019). Advanced wells or smart wells are used to avoid the problems with recirculation of CO_2, thus forcing CO_2 to distribute over a larger area in the reservoir. Examples of advanced well completion technologies are the autonomous inflow control valve (AICV) developed by InflowControl AS and the passive inflow control device (ICD) (Aakre et al., 2018). Restricting CO_2 recirculated using AICV may potentially lead to higher drawdown in high-oil saturation zones. There is also a broader contact between CO_2 and the residual oil in the reservoir, all of which will boost oil production and recovery. CO_2-WAG can be either miscible or immiscible depending on the minimum miscibility pressure, however this study will solely investigate the miscible process. The producer and injector wells can either be vertical or horizontal. The CO_2-WAG performance depends on well spacing, well placing, CO_2 and water injection rates, permeability, and porosity differences in the reservoir (Taghavi et al., 2023).

This study aims at modelling and simulation of enhanced oil recovery for miscible CO_2 injection with advanced wells completed with AICV. Further performance evaluation of the AICV technology and sensitivity analysis of parameters affecting the WAG process are completed. The Miscible CO_2-WAG with advanced wells model was developed using the commercial software Computer Modelling Group (CMG). In this study, different available modules such as Builder, FlexWell, and STARS are used to achieve the modelling and simulations. The collected data from different simulation cases are used to perform sensitivity analysis on parameters that impact the EOR process.

2. CO_2 EOR

2.1 EOR method of CO_2 water alternating gas (WAG)

CO_2-WAG is an improvement of the gas injection methods. CO_2, when dissolved in oil, reduces the oil viscosity which helps to increase the mobility of the oil hence improving the oil recovery. The CO_2 injection alone often results in low sweep efficiency because of unstable displacement due to gravity segregation and viscous fingering caused by early gas breakthrough. (Cherian et al., 2012)

Figure 1 illustrates the principle of the CO2-WAG EOR process and shows how the miscibility between CO_2 and oil happens in the miscible zones after flooding.

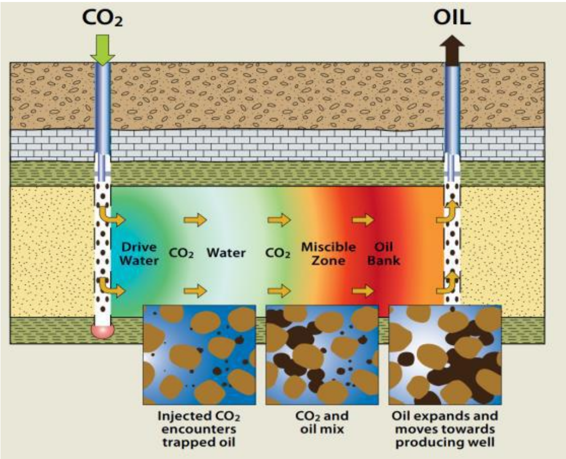

Fig. 1. The diagram of CO_2 WAG process (E. Halland et al., 2012).

When CO_2 EOR takes place at a pressure equal to or higher than the minimum miscibility pressure (MMP) it is called miscible CO_2 EOR, while CO_2 EOR at pressures lower than MMP is called immiscible CO_2 EOR. The advantage of the miscible CO_2 EOR process is that the oil volume is increased, and the oil viscosity is lowered causing oil to travel easier towards the producing wells (Chathurangani and Halvorsen, 2015). The MMP is the reservoir pressure above which CO_2 and oil can combine into a single-phase fluid.

CO_2-WAG can help to control the mobility of the gas because the water will limit fractional flow of gas which will lead to improved sweep efficiency as well as displacement efficiency. The parameters which can affect the result of CO_2-WAG are injection rates and WAG cycle length for each injection phases (Bahagio, 2013).

A problem with CO_2-WAG is that CO_2 dissolved in water can form corrosive acid with calcite component presence in the rock (Oomole and Osoba, 1983):

$$H_2O + CO_2 + CaCO_3 \rightarrow Ca(HCO_3)_2$$

This phenomenon can lead to economic challenges after breakthrough if this corrosive mixture reaches the producer wells.

2.2 Advanced wells and their impact on increased EOR

Advanced well completion might be necessary in maximizing the efficiency of the EOR process in order to avoid the common challenge of early CO_2 and water breakthrough. Presently in the oil and gas industry advanced wells can be achieved with flow control devices, annular flow isolation, and sand control screens (Moradi et al., 2022).

The ICD (Fig. 2) is an example of a passive flow control device with no moving parts inside. ICD was innovated to solve the phenomena of the heel-to-toe effect along the well because it can provide additional pressure drop, and by that balance the pressure variation from the toe to the heel along the well. The installation of ICD in the wells can delay gas and water breakthrough in an EOR process, but it cannot restrict the flow of unwanted effluents once a breakthrough of these fluids occurs (Kais et al., 2016).

Fig. 2. The picture of the nozzle type ICD technology (Kais et al., 2016).

The AICV (Fig. 3) is an example of a reactive flow control device. The AICV responds with a contrary course of action without direct human control when present in the well. It is a modern technology with a movable piston which acts after water breakthrough in EOR. The operating procedure of the AICV device is governed by viscosity and density differences which determines the pressure drop for different reservoir fluids (Aakre et al., 2018).

Fig. 3. The picture of the modern AICV technology (*InflowControl*, 2024).

If high viscous fluids like oil is around the valve, the piston acts downwards which opens the valve. If low viscous fluids like CO_2 or water is around the valve, the piston acts upwards which closes the valve.

Taghavi et al. (2023) compared the ICD with the AICV performance. With both devices having the same oil flow rate at a specific differential pressure, the results from the study showed that there is a significant gas and water reduction by using AICV under the same conditions, see Fig. 4.

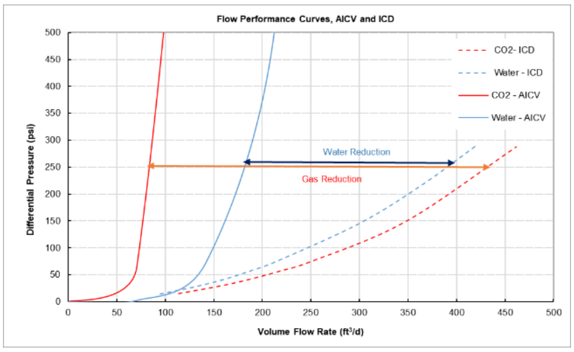

Fig. 4. The performance curves of pressure and volumetric flow rate for AICV and ICD (Taghavi et al., 2023).

3. MODEL DEVELOPMENT ON CMG

3.1 Reservoir fluid components and characterization

The WinProp package is capable of fluid characterization, matching experimental data, and constructing phase diagrams. WinProp uses equation of states such as Peng-Robinson combined with data obtained from laboratory analysis of reservoir samples. However, the aim of the created fluid model in this work is to calculate the MMP required to achieve miscibility between oil and CO_2 injected. It was determined to be 15284 kPa at reservoir temperature of 85.5°C. Figure 5 shows the pressure-temperature phase envelope of CO_2 generated by WinProp. The two-phase boundary is the green curve, and the critical temperature and pressure are approximately 6500kPa and 425°C.

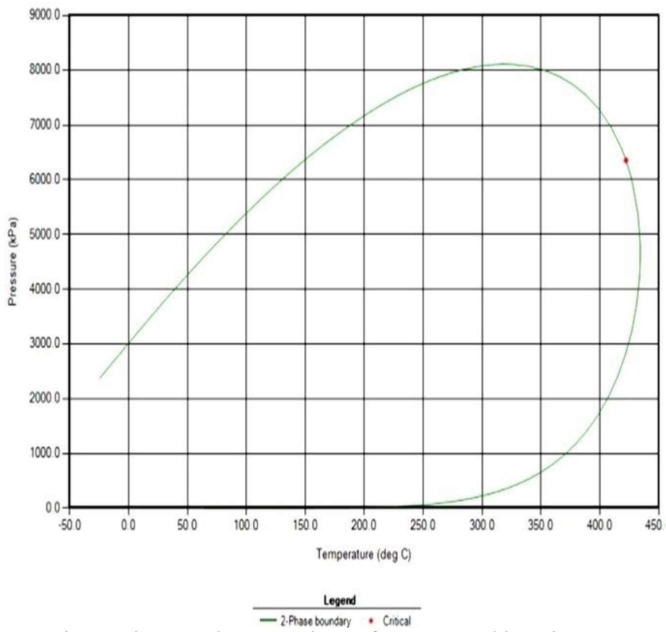

Fig. 5. The P-T phase envelope of CO_2 created in WinProp.

3.2 The reservoir

One homogeneous reservoir and one heterogeneous reservoir were built in builder suite package with cartesian plane. For both reservoirs, there are ten grids in the I-J direction, and fifteen in the K direction. The length, width and height dimensions of the reservoir are 300 m, 500 m, and 150 m, respectively. The top of the reservoir is at a depth of 1000 m and the bottom of the reservoir is at depth 1150 m. Most properties of the reservoirs were left in the original preset initial values specified by CMG, however both reservoirs porosity was modified to 0.35. The initial reservoir temperature is constant at 85.5°C. The reference pressure is 20684.3 kPa, which is much higher than the MMP, to ensure the process remains a miscible CO_2 process. The surface pressure condition was 101 kPa and the surface temperature condition was 16.85°C.

Figure 6 shows the pictorial view of the homogeneous reservoir (left-hand-side) and the heterogeneous reservoir (right-hand-side). The homogeneous reservoir permeability is constant all through the layers at 2500 mD. The heterogeneous reservoir permeability varies from 2500 mD (blue color) to 10000 mD (red color). The highest permeability region for the heterogeneous reservoir was placed at the heel section of the producer wells.

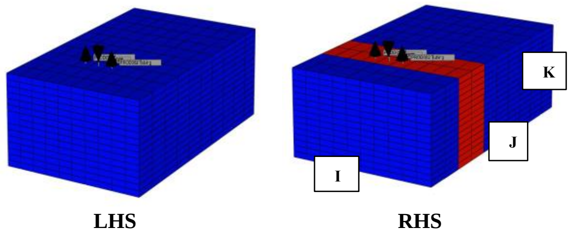

Fig. 6. The 3-D view of the homogeneous (LHS) and heterogeneous reservoir (RHS).

The wettability state of the rock is water wet. The relative permeability curves datasets were calculated based on the Stone II model for two-phase. The oil is immobile below 0.25 saturation, and the water maximum saturation is 0.78.

3.3 The simulation cases

The developed simulation cases were based on the homogeneous reservoir labelled Case-A and the heterogeneous reservoir labelled Case-B. The simulation cases were investigated with different injection methods (water-EOR and WAG-EOR), different wellbore placement (horizontal and vertical wells), and different wellbore completion (with AICV and without AICV). Additional simulations were performed in order to investigate the effect of parameters such as well spacing and permeability.

The timeline of the simulated cases was for 10 years from the period of 2024-01-01 to 2034-01-01. The base case is defined as the water injection mode with two producer wells open for continuous production all year, and one injector well perforated in the middle between the two producer wells. The injector well is open all year during these periods to inject water into the reservoirs. The WAG-EOR case involves the same wells and the same perforation location as the base case, but the injection cycle period was modified to injection period for both water and CO_2. Figure 7 shows an illustration of the timeline for the water injected alternately with CO_2 with all year continuous production. The annulus of the producer well is shut, but the tubing is open.

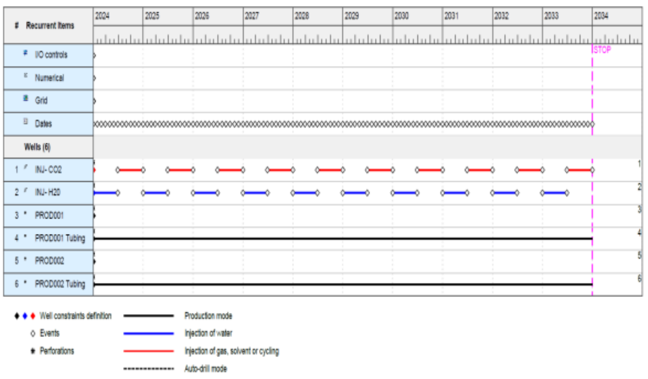

Fig. 7. The timeline of the WAG cycle periods.

The wall inner and outer diameters were modified to 0.3 m and 0.35 m respectively. Table 1 shows the type of constraint and the specified values for the simulations. Both the injector well, the producer well-1 and the producer well-2 which are installed in the horizontal and vertical perforations have the same constraints values specified, except STL surface liquid rate.

Table 1. The constraint specification for both the injector well and producer wells

Constraint Type	Limit	Value
BHP bottom hole pressure	MAX	22000 kPa
BHP bottom hole pressure	MIN	15000 kPa
STG surface gas rate	MAX	50000 m3/day
STW surface water rate	MAX	10000 m3/day
STL surface liquid rate	MAX	840 m3/day

Figure 8 shows the picture of the horizontally placement producer well-1 from the J-k direction view.

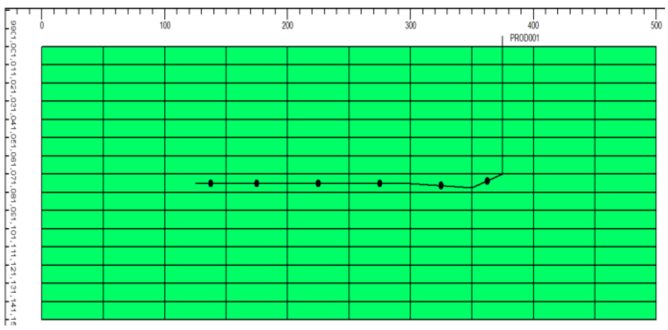

Fig. 8. The J-K direction view of the horizontal producer well-1.

Figure 9 shows the picture of the vertically placement wells from the I-k direction view of the producer well-1 to the left, the injector well in the middle, and the producer well-2 to the right.

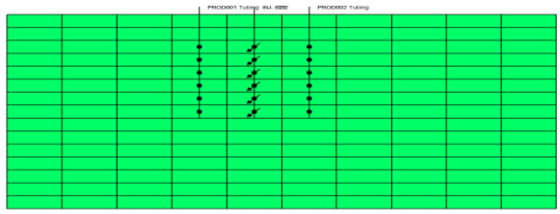

Fig. 9. The I-K direction view of the vertical placement of the injector and producer wells.

4. RESULTS AND DISCUSSION

4.1 Comparison of WAG and water injection

Figure 10 shows the field oil rate of the two producer wells at standard condition. The thick green line represents the oil rate for water injection, and the dash green line represents Case-A-1 which is the WAG.

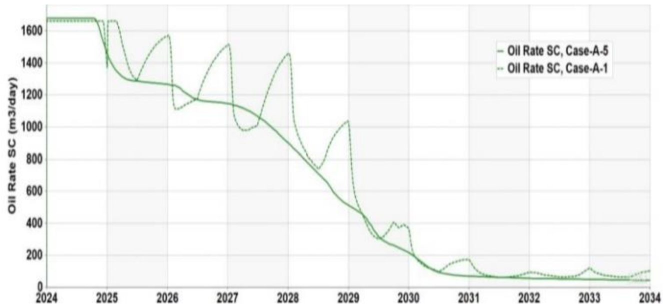

Fig. 10. The field oil rate of the two producer wells at standard condition for case-A-1 and case-A5.

The field oil rate in the figure illustrates that both WAG and water injection can promote oil productivity. The case-A-1 has an oscillating curve because the highest peaks in the oil production appear during the CO_2 injection period. This is because if CO_2 is well circulated around the reservoir region of high oil saturation, the mobility of the oil toward the producer wells increases.

In year 2034, the cumulative oil production for the WAG is 2.7e+06 m^3, represented with the thin green line in Fig. 11. This is approximately 12.5 % more oil than the cumulative oil production for water injection (Thick green line in Fig. 11), of which the oil cumulative production is 2.4e+06 m^3.

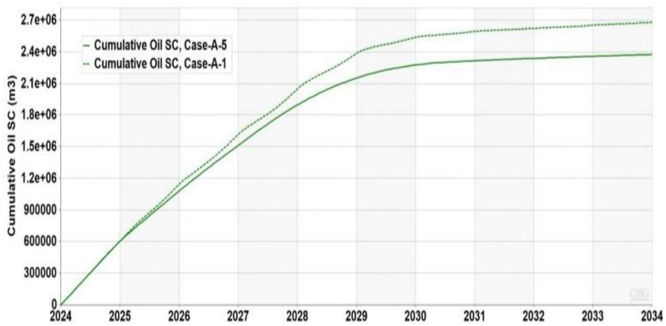

Fig. 11. The field cumulative oil of the two producer wells at standard condition for case-A-1 and case-A-5.

Oil saturation is an important parameter to observe when comparing WAG and water injection. Figure 12 indicates that WAG produces more oil than water injection. In Fig. 12 the green color zones in the reservoir are where oil has been produced and replaced with water. The scaling shows that the red color zone is the high oil saturation zone and has a mole fraction of 1 which means oil is the only component present. The orange and yellow color indicates two-phase zone of oil and water.

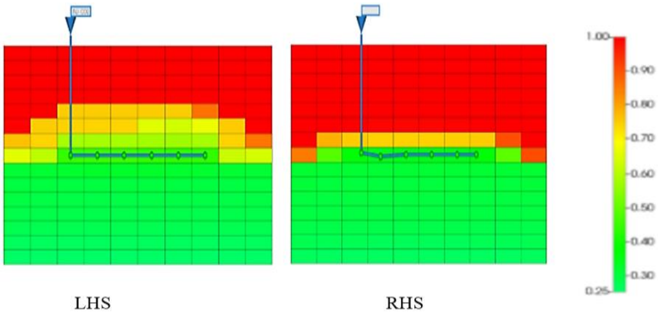

Fig. 12. The reservoir oil saturation for the WAG (LHS) and the water injection (RHS).

4.2 The performance of AICV

Figure 13 shows the graph of the field cumulative oil of the two producer wells at standard condition. The solid green line represents Case-A-1 i.e. with AICV completion, and the dash green line represents Case-A-2 which is without AICV completion. From the figure it is seen that the cumulative oil production without AICV corresponds to around 3.3e+06 m^3 for the entire production period, while the cumulative oil production with AICV corresponds to 2.7e+06 m^3.

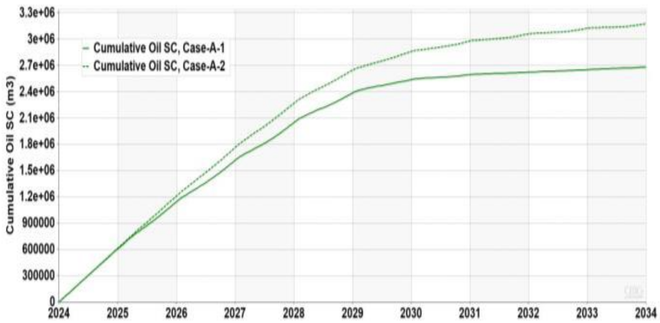

Fig. 13. The field cumulative oil of the two producer wells at standard condition for case-A-1 and case-A-2.

As water can form corrosive mixture with CO_2 (Oomole and Osoba, 1983), the goal is to produce as little water as possible. This is, among other things, to prevent the corrosive mixture from entering the top side facilities where it can cause major damage. Figure 14 compares the cumulative water production with and without AICV completion in the wells. The figure shows that by installing AICVs in the well, the cumulative water production can be reduced from 3e+06 m^3 to 9.8e+04 m^3 during the production period, which corresponds to approximately 97% less water production with AICV.

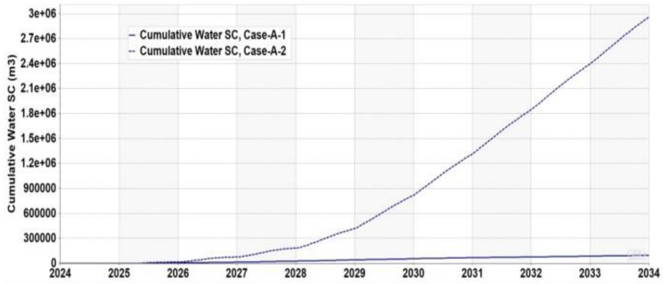

Fig. 14. The field cumulative water of the two producer wells at standard condition for case-A-1 and case-A-2.

4.2 Comparison of homogeneous and heterogeneous reservoir

Figure 15 and Figure 16 illustrate that permeability of the reservoir plays an important role in oil and water production. In Fig. 15 the heterogeneous reservoir is represented by the thin green line, while the homogenous reservoir is represented by the thick green line. The heterogenous reservoir, which has a higher permeability (10000 mD) around the heel section of the well has a slightly higher cumulative oil production in the year 2034 compared to the homogenous reservoir, of which the oil production has increased from 2.65e+06 m^3 to 2.7e+06 m^3 respectively.

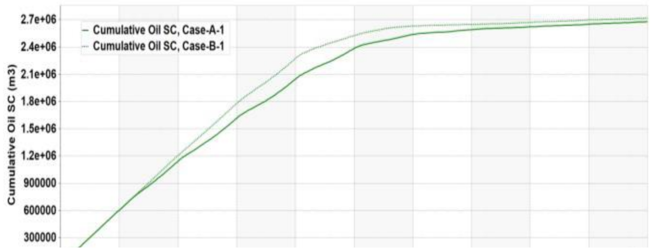

Fig. 15. The field cumulative oil at standard condition for case-A-1 (homogeneous) and case-B-1(heterogeneous).

However, the heterogeneous reservoir produces considerably less water than the homogenous reservoir. During the entire production period the heterogenous reservoir produces 5.2e+04 m^3, which is around 50% reduction compared to the homogeneous reservoir that produces 9.8e+04 m^3.

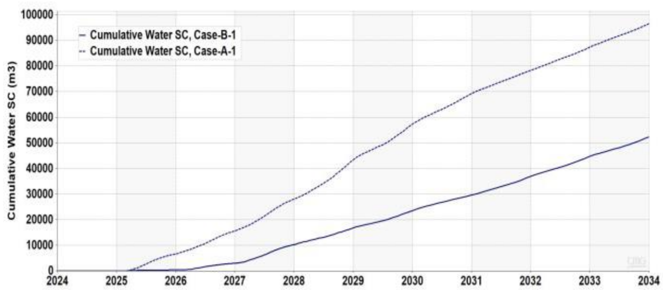

Fig. 16. The field cumulative water at standard condition for case A-1 (homogeneous) and case-B-1(heterogeneous).

4.2 The impact of well spacing and position on production

To investigate the impact of well spacing and position on the oil and water production, the producer wells were modified to have a shorter distance from the injector well, as shown in Fig. 17.

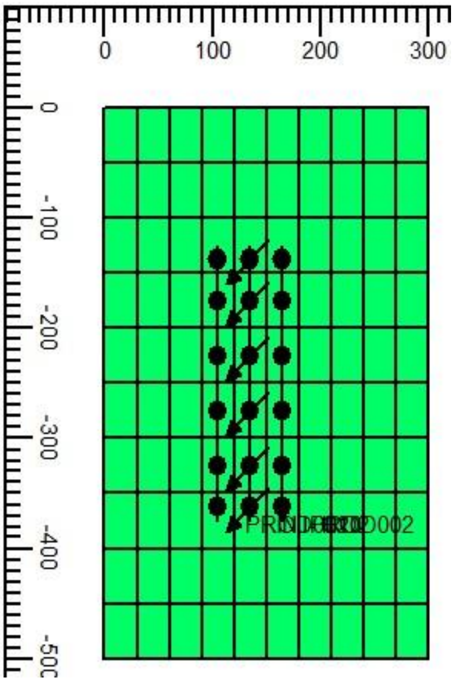

Fig. 17. The modified case-A-2 with less well spacing distances.

It is important to avoid that the producer wells are too close to the injector well, this is because an early water breakthrough at the start of the WAG is observed. Possibly because the injected fluid (water) at the start of every year is produced directly in the producer well instead of being distributed in the reservoir. This effect reduces the oil rate, as shown in Fig. 18 where the production drops towards zero at the start of the years which corresponds to the periods when water was injected.

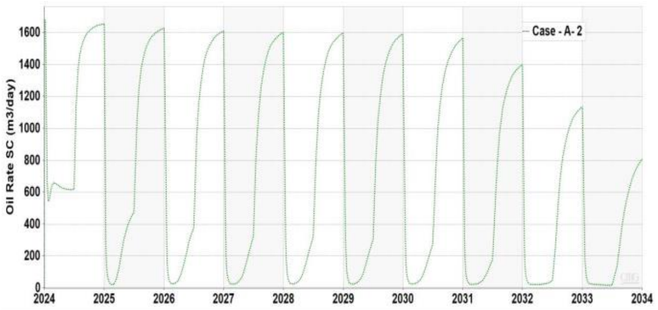

Fig. 18. The field oil rate for the modified case-A-2 with less well spacing distance.

At year 2034, the cumulative water production has increased from 3e+06 m^3 (Fig. 14) to 3.5e+06 m^3, this is because of early breakthrough at the beginning of year 2024, see Fig. 19.

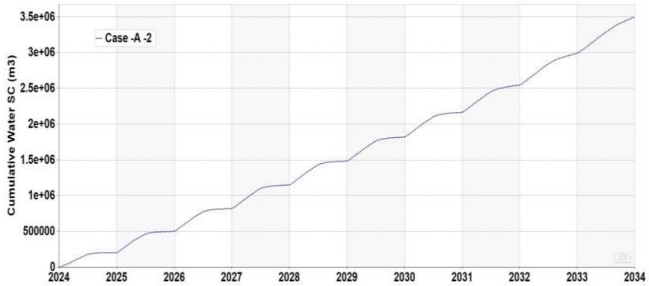

Fig. 19. The field cumulative water volume for the modified case-A-2 with less well spacing distance.

4.5 Comparison of horizontal and vertical wells

The impact of well placement on miscible CO_2 injection was investigated by comparing a vertical injector well with vertical producer wells, to a horizontal injector well with horizontal producer wells. This comparison was done for cases with AICV and cases without AICV.

The vertical injection (thick green line) of miscible CO_2 injection gives a higher cumulative oil production than the horizontal injection (thin green line), producing 3.3e+06 m^3 and 3e+06 m^3 respectively, see Fig. 20.

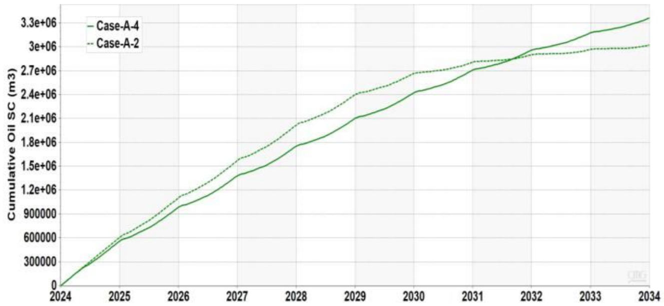

Fig. 20. Cumulative oil production without AICV for the horizontal case (A-2) and the vertical case (A-4).

The vertical injection (thick blue line) of miscible CO_2 injection gives less cumulative water production than the horizontal injection (thin blue line), producing around 2.7e+06 m^3 and 3e+06 m^3 respectively, see Fig. 21.

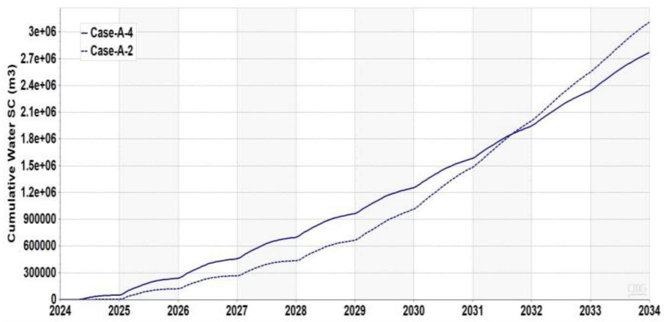

Fig. 21. Cumulative water production without AICV for the horizontal case (A-2) and the vertical case (A-4).

Another important observation is the oil saturation from the injector for both vertical and horizontal well with time. Figure

22 illustrates the sweeping of oil because of the miscible CO_2 injection at the end of the production period (year 2034).
The figure shows that at the end of the production period at year 2034, the vertical miscible CO_2 injection has better sweep of the oil resulting in less oil saturation (light green) compared to horizontal miscible CO_2 injection.

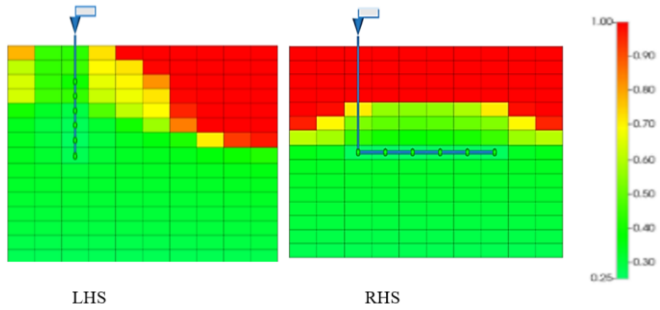

Fig. 22. The oil saturation at year 2034 of case-A-4 and case-A-1 for the vertical (LHS) and horizontal (RHS) CO_2 injection.

6. CONCLUSIONS

The objective of this study was modelling of the miscible CO_2 injection for WAG process and evaluation of the performance of the AICV including sensitivity analysis of the parameters affecting the EOR process.

The results show that the production wells completed with AICVs maintain good oil production while the production of water is decreased from 3e+06 m^3 to 9.8e+04 m^3 which corresponds to 97% reduction in water production.
The sensitivity analysis of the simulation results affirms that permeability, well placement, and well spacing have impact on productivity in terms of both oil recovery and water production in the WAG EOR method. The results indicate that permeability increase has a slight increment effect on oil recovery and 50% decrease in water production. The well spacing analysis shows that increasing the distance between the wells will increase the oil recovery and delay the water breakthrough. Also, if the wells are too close, recirculation of injected water and CO_2 in the producer wells occurs at the start date. Lastly the well placement analysis shows that vertical injection of miscible CO_2 produces more oil than horizontal injection of miscible CO_2.

As future study, it is recommended to investigate the optimum perforation location and distance for the CO_2 injector from the producer well which favors maximum oil recovery, reduced operational cost and economic challenges.

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