Research Journal of Applied Sciences, Engineering and Technology 8(10): 1239-1243, 2014
DOI:10.19026/rjaset.8.1089
ISSN: 2040-7459; e-ISSN: 2040-7467

Submitted: April 12, 2014 Accepted: July 01, 2014 Published: September 15, 2014

Research Article

# Introducing New Slug Size Method in Water Alternating $CO_2$ for Enhanced Oil Recovery

Zakaria Hamdi and Mariyamni Awang
Department of Petroleum Engineering, Universiti Teknologi PETRONAS, Perak 31750, Malaysia

**Abstract:** Reduction of hydrocarbon reserves and optimum production is one of major concerns about future of petroleum industry. In the recent years, several enhanced oil recovery methods have been introduced, tested and modified. With increasing methods of improving oil recovery and production techniques, it will be necessary to perform further studies and research to check their feasibility and displacement efficiency. The aim of this research is to study the effect of slug size variation of injection on the displacement efficiency in different scenarios of water alternating $CO_2$ injection method in a hypothetical reservoir by performing numerical simulations. The results indicate that varying slug size method can yield better performance than fixed water alternating gas ratio, both in terms of recovery factor as well as $CO_2$ storage. This can open a new look for calculating optimum water alternating gas ratios.

**Keywords:** CO2 Injection, enhanced oil recovery, reservoir simulation, sequestration, water alternating gas, water slug size

## INTRODUCTION

By increasing oil consumption and depletion of conventional oil reservoirs around the world Enhanced Oil Recovery (EOR) techniques have been developed vastly. The major EOR techniques are thermal flooding, chemical flooding and gas flooding. Thermal flooding, such as steam flooding and cyclic steam stimulation are effective for heavy oil displacement since viscosity of the oil is sensitive to the temperature. Chemical techniques on the other hand, are considered one of the most effective flooding technique in EOR (Thomas *et al*., 2001). But due to their high consumption of chemical reactants and also safe transportation to the injection well, their usage will be limited (Flaaten *et al*., 2009; Stoll *et al*., 2010). Among gas flooding techniques, the most general gas flooding technique is $CO_2$ flooding. Comparing with air and natural gas, $CO_2$ has higher solubility in various crudes that makes it more favorable technique. Different mechanisms are associated in $CO_2$ flooding including viscosity reduction, oil swelling, extraction, gas solution drive and interfacial tension reduction (Beecher and Parkhurst, 1926; Holm and Josendal, 1974; Simon *et al*., 1978; Miller and Jones, 1981; Mungan, 1981; Klins, 1984; Jha, 1986; Rojas and Farouq Ali, 1988).

The Water Alternating Gas (WAG) process is consisting of injection of gas and water slugs in cyclic form. The main aim of WAG is to improve sweeping efficiency in water flooding as well as gas flooding while decreasing gas overriding and viscous fingering. Recent studies have shown that WAG technique can be used in secondary and tertiary flooding of reservoirs. Recently, WAG is found to be more effective than gas flooding or water flooding alone. The WAG process increases microscopic displacement by gas flooding and macroscopic sweeping efficiency by water flooding (Christensen *et al*., 2001).

Factors controlling the efficiency of WAG project include reservoir rock properties, their wettability and heterogeneity. Also, fluids inside the reservoir and injection fluids have great impact on displacement efficiency of the project. The WAG ratio, slug size and injection techniques have to be considered too (Sanchez, 1999).

There are numerous miscible and immiscible WAG processes have been described in different reservoirs (Asghari *et al*., 2007; Righi and Pascual, 2007; Shi *et al*., 2008; Chen *et al*., 2010), yet few attempts have been made to study WAG process under varying slug size condition i.e., different injection duration of $CO_2$ and water during a project.

In this study we attempt to run high recovery oriented WAG simulations using $CO_2$ as the gas and see the effect of injection duration on displacement efficiency, leading to prove that the best recovery factor can be made when duration of fluid injection is dependent on real-time $CO_2$ and water production rates as well as minimum amount of oil production.

**Corresponding Author:** Zakaria Hamdi, Department of Petroleum Engineering, Universiti Teknologi PETRONAS, Perak 31750, Malaysia

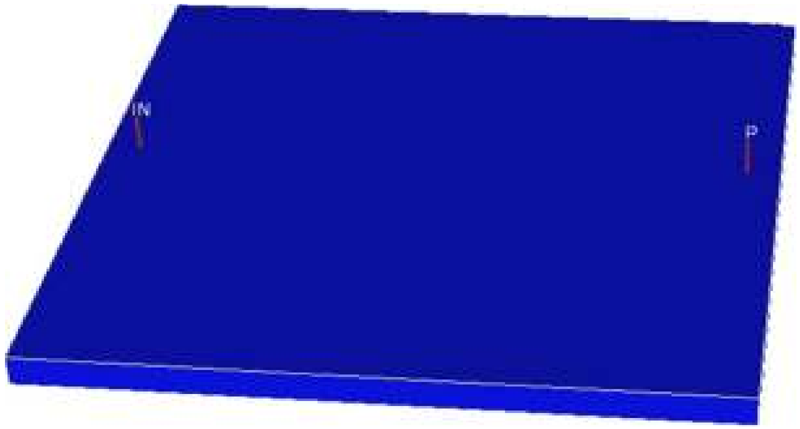


Fig. 1: Reservoir shape and position of the Injection (IN) and Production (P) wells

Table 1: Reservoir data by layers

| Layer | Horizontal permeability (mD) | Vertical permeability (mD) | Porosity (%) | Thickness (ft) |
|---|---|---|---|---|
| 1 | 500 | 50 | 30 | 20 |
| 2 | 50 | 50 | 30 | 30 |
| 3 | 200 | 25 | 30 | 50 |

Table 2: Reservoir well properties

| Name of the well | IN (injection) | P (production) |
|---|---|---|
| Location (x, y, z) | 25, 1, 1 | 25, 50, 1 |
| Reference depth (ft) | 8400 | 8400 |
| Wellbore diameter (ft) | 0.5 | 0.5 |
| Minimum bottomhole pressure (psi) | - | 1000 |
| Maximum oil/water rate (bbl/d) | 12000 | 12000 |
| Maximum gas rate (MMSCF) | 12000 | 12000 |

Table 3: Oil sample properties

| | Component name | Mole fraction (%) |
|---|---|---|
| 1 | C1 | 36.47 |
| 2 | C2 | 9.67 |
| 3 | C3 | 6.95 |
| 4 | iC4 | 1.44 |
| 5 | nC4 | 3.93 |
| 6 | iC5 | 1.44 |
| 7 | nC5 | 1.41 |
| 8 | C6 | 4.33 |
| 9 | C7+ | 34.36 |
| C7+ molecular weight: 218 | | |

## RESERVOIR SIMULATION MODEL

The reservoir model used in this study is a in a form of a box, which has heterogeneous geology and the crude oil lies at the depth of 8325 ft. It contains non-uniform geological characteristics (different permeabilities) in form of 3 layers with different permeabilities in x, y and z axis as shown in Table 1.

Reservoir dimensions are 3500×3500×100 ft. The vertical wells drilled in this model are one injection well and one production well, each located on one end of the x axis and middle of y axis of the model as shown in Fig. 1. The perforations are similar since we don't want to allow for gravity effect from injection of $CO_2$ (in that case production well would be shallower). The properties of the wells are shown in Table 2.

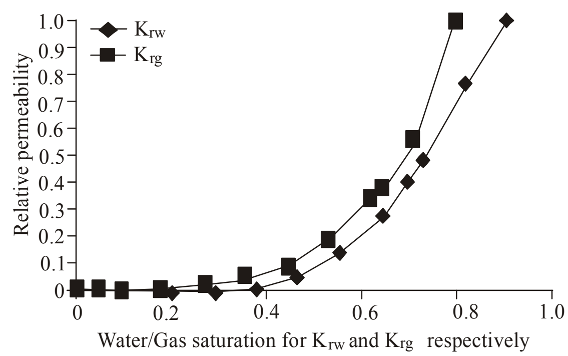


Fig. 2: Relative permeability curves of water and gas based on their saturation

The Gas/Oil Contact (GOC) and Water/Oil Contact (WOC) are situated at depth of 4000 and 9000 ft, respectively. The wells are completed between GOC and WOC.

The initial pressure of the reservoir is 5900 psia and temperature of 160°F. Since it is an isothermal simulation, so $CO_2$ is above supercritical condition. Also it is assumed that based on the initial data, the flooding is in miscible condition. A live oil sample is generated by PVTi and its mole fraction and component properties are shown in Table 3. PVTi generates all needed PVT data for this simulation. Also, the permeability curves of water and gas are considered as Fig. 2. Figure 3 shows the corresponding oil relative permeability for two regions. First is where only oil and water are present ($K_{row}$) and second is where only oil, gas and connate water are present ($K_{rog}$).

To determine the optimum number of grids used in this study, a base case is considered. The grids are taken in form of 7×7×3 and a parameter such as recovery is calculated. Then by increasing the number of grids (while decreasing each grid size) the before mentioned parameter is calculated until after a specific grid set, no major change is detected. In this case of study, the optimum value of the grids is obtained as 50×50×3. The size of each grid is 70 ft in length, 70 ft in width and for

Table 4: Varying slug size scenario

| Step No. | Injection status | Duration with significant production (days from start) | Recovery of the injection section | Total recovery on stoppage point | Total recovery after 15000 days |
|---|---|---|---|---|---|
| 1 | Natural depletion | 2410 | 23.72 | 23.72 | 26.30 |
| 2 | Water#0 (secondary) | 5760 | 35.75 | 59.47 | 59.95 |
| 3 | $CO_2$ #1 | 8545 | 5.77 | 65.24 | 70.22 |
| 4 | Water #1 | 10190 | 6.54 | 71.78 | 72.61 |
| 5 | $CO_2$ #2 | 10890 | 0.52 | 72.30 | 74.02 |
| 6 | Water #2 | 11640 | 1.55 | 73.85 | 74.73 |
| 7 | $CO_2$/water | 100/100 from 11640 until the end | | | 77.60 |

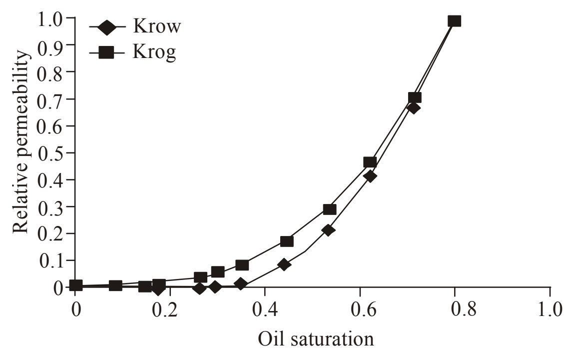


Fig. 3: Oil relative permeability curves versus oil saturation

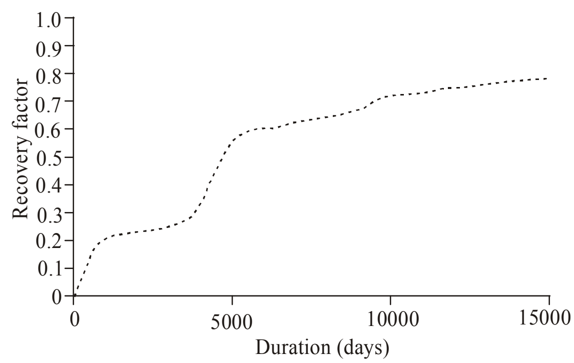


Fig. 4: Recovery factor during variable slug size injection

depth is 20, 30 and 50 ft, respectively from top to bottom.

Different scenarios have been put into consideration for this study subject that as shown in Table 4 and 5. The maximum duration of production is 15000 days. The first scenario is a natural depletion of the reservoir until no significant oil production is detected. Then several scenarios of water injection are considered as secondary recovery, each one with a specific duration of injection.

## SIMULATION RESULTS AND DISCUSSION

The main goal of this simulation is to study the effect of slug size of injection on the displacement efficiency in different scenarios.

In WAG scenarios, it is common that they take a constant ratio of water/gas injection. But in this study, we also check every slug size based of recovery of each step.

The first step is to run the simulator for obtaining primary recovery. After the recovery is almost stopped, then the secondary recovery is simulated using water. After reaching a point where no major production is detected, the tertiary recovery begins with the other phase that is $CO_2$.

Different scenarios are used either fixed or varying duration of water and $CO_2$ injection. In varying slug injection, we use next phase injections start point as the points where recovery by previous phase is not economical. These stoppage points happen when oil production falls below 500 bbl/day or production exceeds 11000 bbl/day or mole percentage of $CO_2$ in production well exceeds 90%. Then the results are determined based on duration and amount of injection and different scenarios are compared.

**Results and discussion:** The simulation is started with primary recovery. For this matter we leave the injection well in shut mode in order to let the pressure of reservoir be the only agent forcing the crudes to be produced. After 2410 days of production the recovery factor is almost became steady on 23.72%.

Then, simulation continues for secondary recovery. Water injection is used as secondary recovery agent worldwide. In this scenario we start by water flooding after primary recovery of 2410 days. After 5760 days since the start of production, the production rate dropped rapidly and the water cut increased exponentially. In this point the recovery is recorded 59.47%.

In this step, varying scenario is examined. The $CO_2$ injection and water injection are performed using before mentioned stoppage conditions. The simulation results are summarized in Table 4.

As shown, after 6 steps, no major recovery is detected and since the stoppage points are determined manually, it is better to switch to a fixed slug size. Therefore, a 7$^{th}$ step is considered that is a fixed duration injection of 100 days in each phase after 11640 days from start. An overall recovery trend can be observed as Fig. 4.

Then the results have to be compared with fixed slug size injection. Different injection ratio of 50/100, 100/100, 150/100, 200/100, 100/50 and 100/150 for $CO_2$/water injection days are examined after the

Table 5: Fixed slug size scenarios

| Scenario No. | Slug size ratios ($CO_2$/water injection days) | Total recovery (%) |
|---|---|---|
| 1 | 50/100 | 74.12 |
| 2 | 100/100 | 77.17 |
| 3 | 150/100 | 77.38 |
| 4 | 200/100 | 76.35 |
| 5 | 100/50 | 76.54 |
| 6 | 100/150 | 75.10 |

Table 6: Comparing different factors between varying method and fixed method

| Parameter | Varying method | Fixed method |
|---|---|---|
| Total water injection (STB) | 88,900,000 | 95,400,000 |
| Total water production (STB) | 55,600,000 | 61,700,000 |
| Total water in place (STB) | 46,500,000 | 47,000,000 |
| Total $CO_2$ injection (MSCF) | 62,200,000 | 55,700,000 |
| Total $CO_2$ production (LB-M) | 103,000,000 | 99,200,000 |
| Total $CO_2$ stored (LB-M) | 60,600,000 | 47,500,000 |

secondary recovery at 5760 days, respectively. The recovery factors are recorded as Table 5.

Comparing the results from different scenarios show that varying slug size injection based on economic factors can increase the recovery factor slightly. Also, other factors can be compared between the varying slug size method and best fixed method (scenario 3) as shown in Table 6.

The values in Table 6 show that in fixed method, the injection, production and also storage of water is more than varying method. This can be put in an advantage of using variable method. On the other hand, $CO_2$ injection in variable method is higher and the production is a little higher than of fixed method. But the remaining $CO_2$ is stored inside the reservoir. Therefore again, the variable method has an advantage in $CO_2$ consumption too. One more reason to use varying method is the much less need to change the injection modes from one phase to another.

## CONCLUSION

Several simulations are done in a hypothetical reservoir and crude oil sample in order to study the effect of slug size on the recovery factor.

Using varying slug size based on oil production and maximum water/$CO_2$ production rate, will increase the recovery factor slightly in compare with a fixed WAG ratio.

Although $CO_2$ consumption was higher in varying method, more $CO_2$ remained in the reservoir that suggest higher possibility of $CO_2$ storage when using varying method which usually has a longer injection period for each phase. Also, by using varying method, less amount of water is needed for injection and also less water production is expected while lower water will remain in the reservoir.

## ACKNOWLEDGMENT

Authors would like to thank Universiti Teknologi PETRONAS for graduate research assistantship support and Eclipse software licensing.

## REFERENCES

Asghari, K., M. Dong, J. Shire, T.J. Coleridge, J. Nagrampa and J. Grassick, 2007. Development of a correl ation between performance of CO2 flooding and the past performance of waterflooding in weyburn oil field. SPE Prod. Oper., 22(2): 260-264.

Beecher, C.E. and I.P. Parkhurst, 1926. Effect of dissolved gas upon the viscosity and surface tension of crude oil. T. AIME, 1(26): 51-69.

Chen, S., H. Li and D. Yang, 2010. Optimization of production performance in a CO2 flooding reservoir under uncertainty. J. Can. Petrol. Technol., 49(2): 71-78.

Christensen, J.R., E.H. Stenby and A. Skauge, 2001. Review of WAG field experience. SPE Reserv. Eval. Eng., 4(2): 97-106.

Flaaten, A., Q.P. Nguyen, G.A. Pope and J. Zhang, 2009. A systematic laboratory approach to low-cost, high-performance chemical flooding. SPE Reserv. Eval. Eng., 12(5): 713-723.

Holm, L.W. and V.A. Josendal, 1974. Mechanisms of oil displacement by carbon dioxide. SPE J. Petrol. Technol., 26(12): 1427-1438.

Jha, K.N., 1986. A laboratory study of heavy oil recovery with carbon dioxide. J. Can. Petrol. Technol., 25(2).

Klins, M.A., 1984. Carbon Dioxide Flooding: Basic Mechanisms and Project Design. D. Reidel Publishing Co., Boston.

Miller, J.S. and R.A. Jones, 1981. A laboratory study to determine physical characteristics of heavy oil after CO2 saturation. Proceeding of SPE/DOE Enhanced Oil Recovery Symposium. Tulsa, Oklahoma.

Mungan, N., 1981. Carbon dioxide flooding-fundamentals. J. Can. Petrol. Technol., 20(1).

Righi, E.F. and M.R. Pascual, 2007. Water-alternating-gas pilot in the largest oil field in argentina: Chihuido de la Sierra Negra, Neuquen Basin. Proceeding of Latin American and Caribbean Petroleum Engineering Conference. Buenos Aires, Argentina.

Rojas, G.A. and S.M. Farouq Ali, 1988. Dynamics of subcritical CO2/brine floods for heavy-oil recovery. SPE Reservoir Eng., 3(1): 35-44.

Sanchez, N.L., 1999. Management of Water Alternating Gas (WAG) injection projects. Proceeding of Latin American and Caribbean Petroleum Engineering Conference. Caracas, Venezuela.

Shi, W., J.R. Corwith, A.J. Bouchard, R.L. Bone and E.W. Reinbold, 2008. Kuparuk MWAG project after 20 years. Proceeding of SPE/DOE Symposium on Improved Oil Recovery. Tulsa, Oklahoma, USA.

Simon, R., A. Rosman and E. Zana, 1978. Phase-behavior properties of CO2-reservoir oil systems. Soc. Petrol. Eng. J., 18(1): 20-26.

Stoll, M., H. Al-Shureqi, J. Finol, S.A. Al-Harthy, S.N. Oyemade, A.D. Kruijf, J.N.M.V. Wunnik, F. Arkesteijn, R. Bouwmeester and M.J. Faber, 2010. Alkaline-surfactant-polymer flood: From the laboratory to the field. Proceeding of SPE EOR Conference at Oil and Gas West Asia. Muscat, Oman.

Thomas, S., S.M.F. Ali, J.R. Scoular and B. Verkoczy, 2001. Chemical methods for heavy oil recovery. J. Can. Petrol. Technol., 40(3).