The Effect of Different Carbon Dioxide Injection Modes on Oil Recovery

Faiza M. Nasir and Yeap Y. Chong

Abstract—This paper presents a study of the effect of various CO₂ injection modes on miscible flood performance for a reservoir in Malaysia. Using a black oil numerical simulator, four injection techniques namely continuous, simultaneous water and gas (SWAG), water alternate gas (WAG) and hybrid WAG; were simulated on the reservoir. From the results of the simulations, the respective optimum injection modes for this case study reservoir were established. Comparing all the various optimum CO₂ injection modes, SWAG injection with a CO₂ injection rate of 15,000 Mscf/d and a SWAG ratio of 1:1 is the most efficient recovery method for the reservoir. This is because it yields the highest recovery factor of 54.8% OOIP, a water cut that is below the limit of 0.9 and a relatively low CO₂ breakthrough.

Index Term—Carbon Dioxide, Enhanced Oil Recovery, Miscible Injection, Simulation

I. INTRODUCTION

A large number of producing fields in Malaysia are entering the maturing stage for primary and/or secondary depletion with declining oil rates and increasing water cut and GOR trend. The average oil recovery factor for the producing fields is 37%. This means that there is still a substantial amount of the remaining-oil-in place that could potentially be recovered through tertiary recovery or EOR. Carbon dioxide (CO₂) miscible flooding has been identified to be the most amenable EOR process for these fields [1]. However, to fully optimize the oil recovery from the process, the most effective injection mode must be determined.

The increasing oil price and the burgeoning demand for petroleum products as a source of energy as well as the limited oil reserves have accelerated the effort to further extend the production life of reservoirs. Traditional primary recovery methods as well as secondary recovery techniques can only recover around one third of the Original Oil In Place (OOIP) [2]. Enhanced Oil Recovery (EOR) has been employed to further extract oil from the reservoir thus increasing the ultimate recovery in a reservoir with relatively economical costs. EOR is widely practised by many oil producing nations especially those having aging oil fields with reserves declining faster than the discovery of new oil reserves.

A screening study conducted by PETRONAS has identified that 52 out of 72 Malaysian reservoirs are technically feasible for the application of new EOR processes [3]. An additional 1 billion barrels of crude oil is estimated to be potentially recoverable from Malaysian oil fields through the application of these EOR processes [1].

CO₂ flooding can either be miscible or immiscible depending on the Minimum Miscible Pressure (MMP). Immiscible flooding occurs when the pressure is below the MMP where CO₂ does not form a single phase solution with the hydrocarbons in the reservoir. Miscible flooding on the other hand forms a single phase solution with the hydrocarbon reservoir when injected and in contact with the hydrocarbon at a pressure above the MMP.

II. CO₂ INJECTION TECHNIQUES

A. Continuous CO₂ Injection

This technique involves injecting a certain amount of CO₂ continuously until the required slug size is reached. In a simulation study performed by Rached Hindi, C.T. Cheng and Ben Wang [4] to assist in the design of CO₂ flood process for Roberts Unit, Wasson Field, Yoakum County, Texas, the ultimate recovery of oil was observed to be proportional to the total CO₂ injected. Ewon [5] conducted a study on the Means CO₂ flooding project to determine the effects of varying solvent bank sizes on oil recovery and similar results were obtained. The conclusion drawn by the study was that the larger the bank size the greater the ultimate recovery, but the increment gets smaller and smaller. One major problem faced by this technique is the formation of viscous fingers that propagates through the displaced fluid leaving much of the hydrocarbon not contacted. This is due to the fact that CO₂ has a lower viscosity compared to oil and it results in an adverse mobility ratio. Significant cross-flow of mobilized oil occurs as a result of fluid pressure gradients and the effects of buoyant and capillary forces between porous layers in a reservoir where vertical permeability exists.

B. WAG

The WAG or Water-Alternate-Gas technique is a combination of two traditional improved hydrocarbon recovery
techniques; waterflooding and gas injection. Waterflooding and the gas flooding cycles are alternated with the design parameters being the cycle timing and the ratio of water to gas. The main objective is to reduce CO₂ channeling by filling the highly permeable channels with water to improve sweep efficiency during CO₂ injection. Optimum conditions of oil displacement by WAG processes are achieved when the velocities of the gas and water are the same in the reservoir. The optimum WAG design varies from reservoir to reservoir and for a specific reservoir, it needs to be determined and possibly fine tuned for patterns within the reservoir. In an experiment on WAG performed by Chevron [5], the WAG ratio was increased from 1:1 to 3:1 and with each successive increase in the water to gas ratio, the oil recovery factor increased. Some advantages of the WAG process include higher CO₂ utilization, reduced CO₂ production and greater ultimate recovery. Some of the complications faced by WAG are slower oil response, gravity segregation due to density difference between CO₂ and water, interruption by water on the continuity of the extraction process by the CO₂ slug and loss of injectivity.

C. SWAG

SWAG injection involves injecting both water and CO₂ simultaneously into the reservoir. The mixing of CO₂ and water in a SWAG injection can be at the downhole or on the surface. Surface mixing usually occurs at the well, drill site or at the central processing facility (CPF). The objective of this technique is to reduce capital and operating cost and at the same time, improve the sweep efficiency of waterflooding and miscible CO₂ flooding. This will reduce the impact of viscous fingering and will result in an improvement in gas handling and oil recovery [6, 7]. SWAG can improve the profile control relative to WAG injection and continuous injection. SWAG is a means to reduce the capillary entrapment of oil in small scale reservoir heterogeneity, providing a better mobility control of gas compared to WAG. However, one of its short-comings is insufficient CO₂ availability at the flood front to saturate the oil and reduce its viscosity. Hence a substantial volume of carbonated water is required to saturate the residual oil and to reduce its viscosity and cause it to flow. The use of carbonated waterflood has been proposed in low permeability and naturally fractured reservoirs [7]. Injection of water with dissolved gas may reach and recover oil from places where it otherwise is trapped.

D. Hybrid WAG

In light of the early favorable single slug injection and the overall higher recovery by the WAG technique, the hybrid WAG was introduced. In this process, a large fraction of the pore volume of the CO₂ is continuously injected to about 20% to 40% HCPV and the remaining fraction is then injected using WAG technique at a specific WAG ratio [5]. In a simulation study performed by Rachel Hindi et al, a lower initial CO₂ slug size was preferred [4]. Their findings showed little effects on the recovery factor when the initial CO₂ slug size increased from 10% to 16% HCPV. The lower initial slug size of 10% was chosen as the optimum injection strategy. The advantages of hybrid processes are the early production response associated with continuous injection methods, better injectivity, minimization of water blocking, greater ultimate recovery and higher CO₂ utilization as compared to that for the WAG process [5].

III. RESERVOIR DESCRIPTION

Reservoir A, the case study area, is located offshore Sarawak in Malaysia. It has no primary gas cap and the original pressure of the reservoir is assumed as the bubble point pressure. The primary drive mechanism of the reservoir is depletion drive accompanied by weak aquifer. At the later stage of the reservoir life, drive by the aquifer becomes more prominent as water injection scheme is implemented. The average reservoir parameters are shown in Table I.

| Table I |
| Reservoir A averaged parameters |
| Reservoir Parameters | Average Value |
| Depth | 7,830 ft ss |
| Thickness | 128 ft |
| Porosity | 17.50% |
| Permeability | 70 mD |
| Initial Reservoir Temperature | 202 °F |
| Temperature | 176 °F |
| Initial Reservoir Pressure | 3,420 psi |
| Oil Gravity | 42 °API |
| Oil Viscosity | 0.3 cP |
| Initial Oil Formation Volume Factor | 1.55 |

The reservoir has an estimated Stock Tank Oil in Place (STOIIP) of 92.8 MMstb and the Ultimate Recovery (UR) is expected to be 62.2 MMstb. To date, cumulative production is about 24% of STOIIP with a daily production of 4600 stb of oil and water cut stands at 34%. Production in this reservoir started in 1972 under natural drive and in 1994, it underwent a water injection scheme. There are altogether 16 producer wells and 4 injector wells.

IV. SIMULATION MODEL

The base 3D model for reservoir A was constructed using 500x500 ft grid size with 12 vertical layers. The optimized dimension is 33x29x12 yielding a total number of 11,484 gridblocks. It has been history-matched from 1972 to 2000. The model was run for 16 years using a numerical black-oil simulator. The solvent gas injected is pure CO₂ with a Todd-Longstaff mixing parameter of 0.667.

Using this as the base model, the optimum injection mode for continuous, WAG, hybrid WAG and SWAG were determined and compared to yield the most effective CO₂ injection mode.
V. SIMULATION STUDIES
A. Study 1: Continuous CO₂ injection (varying injection rate)

The focus of this study is to analyze the effects of CO₂ injection rate on the recovery factor and to determine the optimum CO₂ injection rate for the reservoir. CO₂ was injected continuously into the reservoir. Five cases with different injection rates, 10,000 Mscf/d, 15,000 Mscf/d, 20,000 Mscf/d, 25,000 Mscf/d, 30,000 Mscf/d and 35,000 Mscf/d were simulated.

B. Study 2: CO₂ WAG injection (varying WAG ratio)

Using the model as defined for the continuous injection, the effects of varying WAG ratio on the recovery factor were studied and the optimum WAG ratio was determined. The optimum CO₂ injection rate determined in Study 1 was used as the injection rate for this study. Injection of water and CO₂ were implemented alternately through the same injectors at their respective intervals. Five cases with different WAG ratios were simulated and evaluated. They were 1:1, 1.2, 1.3, 1.5:1 and 2:1. The CO₂ injection rate remained constant but the water injection rate was varied for all the five cases according to their water to oil WAG ratio. The water injection rate required to make up to the WAG ratio was determined using the equation below.

\[
\text{Water Injection Rate} = \frac{Q_{\text{CO}_2} \times B_{\text{CO}_2} \times \text{WAG ratio}}{B_w} \quad \text{[Equation 1]}
\]

The cycle time for the WAG injections for all the five cases was set for a year.

C. Study 3: CO₂ WAG injection (varying cycle time)

Using the optimum WAG ratio model from Study 2, the effects of varying cycle time on the recovery factor were studied and the optimum cycle time for reservoir A were determined. With the WAG ratio and CO₂ injection rate fixed, five cases with varying cycle time of 6 months, 1 year, 1.5 years, 2 years and 3 years were simulated.

D. Study 4: CO₂ hybrid WAG injection (varying CO₂ initial slug size)

Using the optimum WAG injection mode for the WAG portion of the hybrid WAG and the optimum injection rate for the initial CO₂ injection rate, the effects of varying CO₂ initial slug size on the recovery factor for hybrid WAG were studied and the optimum hybrid WAG strategy for the reservoir was determined. Five cases with varying CO₂ initial slug size; 10% HCPV, 20% HCPV, 30% HCPV, 40% HCPV and 50% HCPV were simulated. The initial slug size was defined by prolonging the cycle time of the initial CO₂ injection until the required initial slug size was met.

E. Study 5: CO₂ SWAG injection (varying injection rate)

The focus of this study was to analyze the effects of CO₂ injection rate for SWAG injection on the recovery factor and to determine the optimum SWAG CO₂ injection rate. Using the base model, the injectors at respective locations were duplicated as both CO₂ and water were injected simultaneously into the reservoir. Five CO₂ injection rates were modeled. They were 5,000 Mscf/d, 7,500 Mscf/d, 10,000 Mscf/d, 12,500 Mscf/d and 15,000 Mscf/d. The SWAG ratio was fixed at 1:1 and the accompanying water injection rates were determined using Equation 1.

F. Study 6: CO₂ SWAG injection (varying SWAG ratio)

Using the optimum SWAG CO₂ injection rate, the effects of varying SWAG ratio on the recovery factor were studied. Five SWAG ratios were simulated and evaluated. They were 1:1, 1:2, 1:3, 1:5.1 and 2:1. The CO₂ injection rate remained constant but the water injection rate varied for all the five cases according to their water to oil SWAG ratio. Calculations for the required water injection rate to make up the SWAG ratio were determined using Equation 1.

VI. RESULTS & DISCUSSION

A. Study 1: Continuous CO₂ injection (varying injection rate)

Fig. 1 shows the oil recovery factor (or FOE) for various CO₂ injection rate. Recovery factor was observed to increase with increasing injection rate. Increasing the injection rate increased the injected volume of CO₂. Due to the fact the model was assumed to be miscible at first contact in this simulation, residence time did not affect the degree of miscibility. Therefore, the recovery factor was dependent on the volumetric sweep provided by the injection rate and was not significantly affected by the residence time. The incremental increase in recovery factor decreased with increasing injection rate as observed in Fig. 1. This was because the higher the injection rate of CO₂, the earlier water and CO₂ breakthrough would be and a higher value of water cut and CO₂ production was yielded.

![Fig. 1. Recovery Factor (FOE) trend with varying CO₂ injection rate](image-url)
Two of the highest recovery factors were yielded by injection rates 35,000 Mscf/d and the 30,000 Mscf/d with the recovery factor of 51.6 and 51.4% respectively. Taking the water cut limit to be 0.9 and since the incremental recovery factor between the two injection rates was not very significant, the injection rate of 30,000 Mscf/d was taken to be the optimum injection rate. It yielded a lower CO₂ as well as water production.

B. Study 2: CO₂ WAG injection (varying WAG ratio)

The recovery factor as observed in Fig. 2 increase with increasing water to CO₂ WAG ratio. The WAG process affected the cyclic accelerations in the oil recovery resulting from the improved mobility ratio. Taking a WAG ratio of 1:1 as the base case, the incremental increase of recovery factor decreased with increasing CO₂ portions as seen in Fig. 4. Well water cut increased with increasing WAG ratio. The reason is because at higher WAG ratio, the amount of water injected into the well increased while the CO₂ injected remained constant. Taking the water cut limit as 0.9, the 1:1 WAG ratio was the most optimum WAG ratio as it gave a high recovery factor very close to that of 1.5:1 and 2:1 and yet with water cut below 0.9.

C. Study 3: CO₂ WAG injection (varying cycle time)

From the results of the simulation, the recovery factor was not significantly affected by the cycle time. This could be seen by the insignificant difference in the recovery factor yielded by all the different cycle times in Fig. 3.

One of the reasons for the small deviations is that even though the time cycle varied, the injected volume of each fluid remained quite the same. However, there was a small increase in recovery factor with decreasing cycle time. One of the deductions that can be made is that in having a long cycle time, the occurrence of gravity segregation of water was greater as compared to the gravity segregation of water in a shorter time cycle as the very close alternating nature of WAG reduced the severity and potential occurrence of gravity segregation.

D. Study 4: CO₂ hybrid WAG injection (varying CO₂ initial slug size)

From Fig. 5, the recovery factor is seen to increase with smaller initial CO₂ slug size. One of the reasons for the application of hybrid WAG is the higher initial response yielded by the initial CO₂ slug flooding. It was observed that the initial production rate was highest for the 50% initial slug size. On the other hand, the recovery factor yielded by the 50% initial slug size was the lowest compared to the 10% initial slug size which yielded the highest recovery factor of 53.3%. The lower initial slug size of 10% which was lower than the 16% was later chosen as the optimum injection strategy. Thus for reservoir A, the optimum CO₂ hybrid WAG injection strategy is to apply 10% initial slug size with a 1:1 WAG ratio and an
injection rate of 30,000 Mscf/d with a time cycle of 6 months yielding a recovery factor of 53.9%.

**E. Study 5: CO₂ SWAG injection (varying injection rate)**

The SWAG simulation performed here was of 1:1 SWAG ratio. From Fig. 6, recovery factor is observed to increase with increasing injection rates. This is because the higher the injection rate, the higher the total amount of CO₂ was injected leading to higher ultimate recovery [4]. Taking a CO₂ injection rate of 15,000 Mscf/d as the base case, the incremental increase in recovery factor decreased with increasing flow rate as can be seen in Fig. 8. The highest recovery factor of 54.8% was yielded by an injection rate of 15,000 Mscf/d. CO₂ injection at a rate 15,000 Mscf/d is the most optimum injection rate as it yielded the highest recovery factor of 54.8% and at the same time below the water cut limit of 0.9.

**F. Study 6: CO₂ SWAG injection (varying SWAG ratio)**

In Fig. 7, recovery factor is seen to increase with increasing SWAG ratio. The incremental increase of recovery factor was observed to decrease with increasing water volume fractions. At higher SWAG ratio, the amount of water injected into the well increased due to the increase in injection rate to meet up to the SWAG ratio. Eventhough a SWAG ratio of 2:1 and 1.5:1 yielded a very high recovery factor, the water cut experienced was very high, both exceeding the limit of 0.9. Hence, the SWAG injection at a CO₂ injection rate of 15,000 Mscf/d with a 1:1 SWAG ratio is chosen as the most optimum SWAG injection strategy as it yields a high recovery factor very near to that of 1.5:1 and 2:1 and yet with water cut below 0.9.

The optimum injection mode for each of the CO₂ injection techniques for the reservoir is as summarized in Table II.
TABLE II

<table>
<thead>
<tr>
<th>CO₂ Injection Mode</th>
<th>Injection Strategy Design</th>
<th>Recovery Factor</th>
</tr>
</thead>
<tbody>
<tr>
<td>Continuous Injection</td>
<td>CO₂ Injection Rate at 30,000 Mscf/d</td>
<td>0.493</td>
</tr>
</tbody>
</table>
| WAG Injection | • CO₂ Injection Rate at 30,000 Mscf/d  
• WAG Ratio of 1:1  
• Cycle Time of 6 months | 0.547 |
| Hybrid WAG Injection | • CO₂ Injection Rate at 30,000 Mscf/d  
• WAG Ratio of 1:1  
• Cycle Time of 6 months  
• Initial CO₂ Slug Size of 10% HCPV | 0.539 |
| SWAG Injection | • CO₂ Injection Rate at 15,000 Mscf/d  
• SWAG Ratio of 1:1 | 0.548 |

In Table II, the SWAG injection yielded the highest recovery factor followed by WAG, Hybrid WAG and finally continuous injection. The difference in efficiency of the SWAG, WAG and hybrid WAG was not profound. However, the CO₂ continuous injection yielded a relative low recovery factor as compared to the other techniques. The hybrid WAG on the other hand exhibited the highest initial production response compared to the other CO₂ injection techniques. However, the initial high production response period was short and was soon taken over by SWAG injection in around August 2002. The production rate on the other hand was still higher than that of WAG until early 2003. Though the initial production response was high for Hybrid WAG, the final recovery factor was still lower compared to the WAG and SWAG.

The cumulative gas production as seen in Fig. 9 denotes insignificant difference in values compared to WAG, Hybrid WAG and SWAG injection. Continuous injection yielded the highest gas production total of 212,248 MMscf. This is because CO₂ was injected throughout the time of study with no other fluid injected at 30,000 Mscf/d. The water cut of continuous injection on the other hand is the lowest of all the injection strategies as CO₂ continuous injection did not inject any water into the reservoir. The water recovered from the reservoir was purely from the aquifer of the reservoir for continuous injection. For the SWAG, WAG and Hybrid WAG technique, high water cut was experienced as the techniques involved water injection. The water cut trend for all the CO₂ injection technique can be referred to in Fig. 10.

![Fig. 9. Cumulative gas production (FGPT) for different CO₂ injection modes](image)

![Fig. 10. Water cut (WWCT) for different CO₂ injection modes](image)

After evaluating the recovery factor, gas production rate and total as well as the water cut, SWAG injection with a CO₂ injection rate of 15,000 Mscf/d and SWAG ratio of 1:1 is proposed for reservoir A as it yields the highest final recovery and at the same time, a water cut that is below the limit of 0.9 and a relatively low CO₂ breakthrough.

VII. CONCLUSION

- Recovery factor increased with increasing injection rate. Recovery factor increment however decreased with increasing injection rate.
- The optimum continuous injection rate for our case study reservoir is 30,000 Mscf/d yielding a recovery factor of 49.3%.
- For WAG, the recovery factor increased with increasing WAG ratio. The recovery factor however is not very sensitive to the WAG time cycle. The optimum WAG injection strategy for reservoir A is CO₂ injection at a rate of 30,000 Mscf/d at 1:1 WAG ratio with a time cycle of 6 months. The resulting recovery factor is 54.7%.
- Hybrid WAG yields high initial production response and also increases the ultimate recovery. The recovery factor was seen to increase with decreasing initial CO₂ slug size. For the reservoir, an initial slug size of 10% HCPV is the optimum injection strategy yielding a recovery factor of 53.9%.
- For SWAG, the recovery factor increased with increasing CO₂ injection rate and increasing SWAG ratio. The optimum SWAG injection technique is set at an injection...
rate of 15,000 Mscf/d with a SWAG ratio of 1:1, yielding a recovery factor of 54.38%.

• Comparing all the various optimum CO₂ injection modes, SWAG injection with a CO₂ injection rate of 15,000 Mscf/d and SWAG ratio of 1:1 is the most efficient recovery method for reservoir A. This is because it yields the highest recovery factor of 54.8% and at the same time, water cut that is below the limit of 0.9 and a relatively low CO₂ breakthrough.

It is important to note that different reservoirs require different injection techniques because of the unique reservoir characteristics and not that any one technique can be applied to any reservoir. Hence it is important to identify the optimum flooding mode prior to implementing the flood in the actual field.

ACKNOWLEDGMENT

We would like to acknowledge the support from Dr Nasir Darman, PMU and Assoc Prof Dr Anwar Raja to this work. Thanks are also due to Assoc Prof Dr Chow Weng Sum for proofreading this manuscript.

REFERENCES


