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Simulation Study of Miscible CO2 Flooding in Stratified Reservoirs

Ahmed I. Omar*,Abdulmoain M. Elhenshiri,Abdullah A. Elsherif
Petroleum Engineering Department, University of Alrefaq, Tripoli, Libya
*Corresponding Author: aioi.j85@gmail.com

Abstract

The production from underground petroleum reservoirs in early stage is totally accomplished by the reservoir natural energy. Ultimately, the production will decline, the secondary phase of oil started then followed by tertiary techniques when it becomes uneconomical feasible. The essential aim of this study is to examine the effects of vertical heterogeneity, by studying the layers' permeability order, degree of heterogeneity, injection rate and degree of communication effects on the performance of miscible gases flooding in reservoir experiencing vertical stratifications. The second scope of this research is optimizing WAG techniques in such reservoirs which implemented to control the negative effects of gravity forces that arise from the huge density and mobility's difference between the driving and in-situ reservoir fluid. The sensitivity analysis was designed to account the governing parameters for predicting efficient scenario of displacement such as slug size, WAG ratio, and WAG length and gas injection rate. Based on the result reported in this study, the performance of miscible CO_2 process was the preferable. The CO_2 flooding enhanced as the injection rate increased while the fining upward is the best permeability depth configuration for such EOR process. Virtually the communication between the layers lead this process of recovering more oil to limited value where the gravity force starts to act negatively. WAG CO_2 EOR performance was assessed based on the oil recovery factor and the amount of injected CO_2, for stratified reservoir with limited CO_2 sources the performance is getting better as the WAG ratio increased until critical ratio where the effect of miscibility is fully masked.

Keywords: Vertical heterogeneity; continuous CO_2 injection; miscible CO_2 WAG optimizing.

1. Introduction

Traditionally, Enhanced oil recovery (EOR) refers to a process implemented to modify the existing interaction properties either between the reservoir fluids or rock/fluids in order to optimize ultimate recovery factor, and this interaction might reduce the interfacial tension, oil swelling, reduce oil viscosity; also wetability modification. The gas flooding can be classified into miscible and immiscible, the miscible flood means no more interface between gas and in-situ hydrocarbon, interfacial tension (IFT (= 0, either at the front or back of the flood [1]).

Generally the miscible displacement process maintains reservoir pressure and improves oil displacement because the interfacial tension lowering. The fluid most commonly used for miscible displacement is carbon dioxide because it reduces the oil viscosity and is less expensive than liquefied petroleum gas. Oil displacement by carbon dioxide injection relies on the phase behavior of the mixtures of that gas and the crude, these behaviors are strongly dependent on reservoir temperature, pressure and crude oil composition. To get the miscibility should keep the pressure above minimum miscible pressure (MMP) and it's the lowest pressure at which the interfacial tension between a pair of fluids vanishes [1]).

WAGwater alternative miscible gas injection has proven its applicability to improve oil recovery compared to pure water injection or pure gas injection. WAG injection can improves oil recovery by bet-

ter sweep efficiency on both macroscopic and microscopic levels compared to gas injection or water flooding alone. In general the water alternative gas injection process it can be divided into miscible and immiscible displacement process [2]).
The efficiency is due to the advantages offered by this technique, including:

- Controls mobility (reduces Gas processing)
- Improves operation (less gas cycling)
- Improve residual oil recovery

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2. Material and Methods

Basically the research start with constructing a compositional reservoir simulation model based on *EOS* derived from *PVT* report of well (A-78) given by Melletah oil Company, the *PVT* laboratory data contain differential liberation (*DL*), constant composition expansion (*CCE*) and pressure saturation tests. Those results were used to tune the *EOS* to be capable of characterizing the CO_2-hydrocarbon system above the *MMP*. The reservoir oil is undersaturated light oil, see table 2.1, with stock tank gravity of 38.2 *API*, the CO_2 minimum miscibility pressure (*MMP*) was determined to approximately be 6040 *psia*.
The two-parameter Peng-Robinson *EOS* (Peng and Robinson, 1978) was selected to regenerate the fluid properties because it has proven to be suitable for low-temperature CO_2-oil mixtures). The Modified Pedersen 1987 selected as the best viscosity correlation match the oil viscosity test. As it is been depicted in figures 2.1a to 2.2a, final *EOS* yield good match with *DL* and *CCE* experiments results. In the meanwhile the viscosity of C1, C2 and C12+ are used as the regression variables to tune the viscosity correlation, the result demonstrated in figure 2.2b.
Three dimensions numerical reservoir simulation studies were conducted on a model shown in figure 2.3, with reservoir cross section equal to 66.632 acre and uniform reservoir thickness 100 *ft*. The model is constructed to be composed of 10 discrete layers and each layer has its own absolute horizontal and vertical permeability. The permeability variation is characterized by Log-Normal distribution, with $VDP = 0.3$ and the geometric permeability average is equal to 150 *md*. The other data are presented in following table 2.2:

Figure 2.1

(a) . Comparison of the predicted (PR EOS) and observed valued for relative volume

(b) Comparison of the predicted (PR EOS) and observed valued for oil volume factor

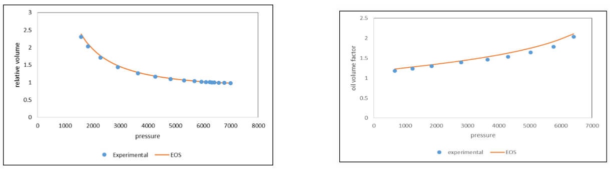


Figure 2.2

(a) Comparison of the predicted (PR EOS) and observed valued for oil viscosity

(b) Comparison of the predicted (PR EOS) and observed valued for gas volume factor

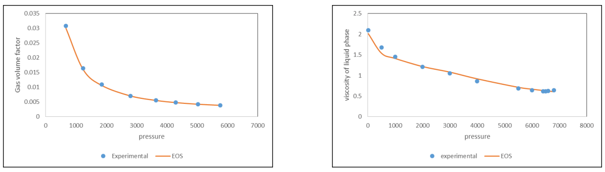


Table 2.2: Reservoir properties

Property	Value
Length, ft	2150
Width, ft	1,350
Thickness, ft	100
Depth at the top of formation, ft	14055
Initial reservoir pressure, psi	7000
Initial water saturation, %	20
Initial oil saturation, %	80
Reservoir temperature, °F	298
Average porosity, %	25
Average horizontal permeability, mD	150
Vertical to horizontal permeability ratio	0.1
Rock compressibility at Pi, psi^{-1}	2.1528751810320E-06
Number of grids ($N_x \times N_y \times N_z$)	43×27×10
Grid size ($D_x \times D_y \times D_z$), ft	50×50×10
Well diameter, ft	0.6
Duration of primary recovery, year	0.5
Duration of water flooding stage, year	5.5
The crude oil API	38.2
The bubble point pressure psi	6406

Table 2.1: Semi-detailed composition of monophasic fluid

Component	CO_2	N_2	C_1	C_2	C_3	I-C_4	N-C_4	I-C_5
Composition	4.83	0.19	60.21	10.83	3.21	0.69	0.99	0.47
Component	N-C_5	I-C_6	C_7	C_8	C_9	C_{10}	C_{11}	C_{12+}
Composition	0.55	1.18	1.54	1.74	1.17	1.01	0.89	10.5

Figure 2.3: Three dimensional synthetic model

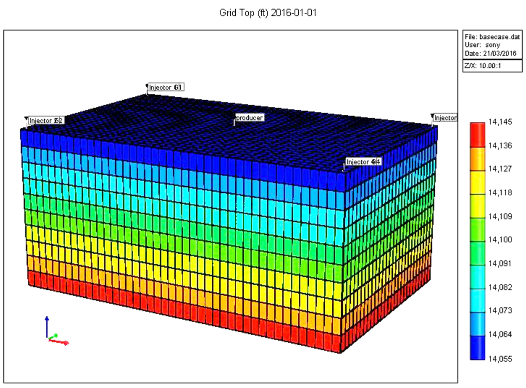
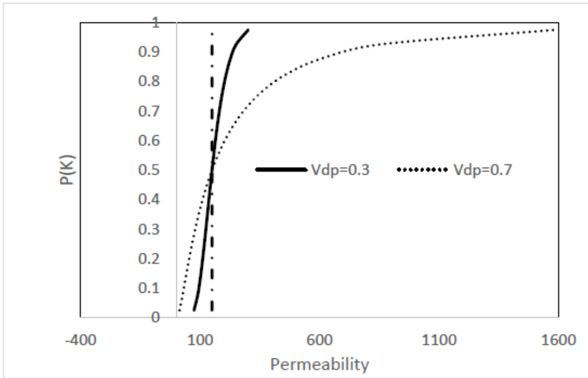


Figure 2.4: Different degree of heterogeneity



Four injections wells (G1, G2, G3and G4) were drilled in locations at cell (1, 1), (1, 27), (43, 1), (43, 27) respectively. The injection wells were drilled and start to operate after six months from the beginning of the production. They firstly used to inject water for 5.5 years under constant injection rate equal to 765 bbl/day for each injection well, then were exploited to inject gas (Co_2) with constant injection rates equal to 1250000 ft^3/day for each injection well, the reservoir was depleted using on production well drill at (22,13), And it was operate under constrains of withdrawing at constant production rate equal to 1400 STB/day, total fluid production rate cannot exceed 2000 bbl/day And bottom hole pressure in well limited to 2000 psi. The perforation thickness for the all wells were equal to the reservoir thickness. The production was started at 1 JAN 2016. These operation constrains were applied to keep depleting the reservoir above its saturation pressure and sustaining miscibility as long as possible. The model was running for 15 years.

Firstly the model was used to find the optimum EOR process to continues the study with which was miscible CO_2 flood. Simulation studies were deigned to examine the effects of vertical heterogeneity on such process, the parameters control the gravity dimensionless number, cross flow between the adjacent layers, the layers permeability order were sensitized.

2.1. Degree of heterogeneity

The horizontal permeability variation in the vertical direction has significant effect on the performance of the Co_2 flooding. To investigate this effect and since the permeability is represented by log-normal distribution, The degree of heterogeneity modified by using log-normal distribution function with VDP equal to 0 and 0.7 in addition to the base case, as depicted in figure 2.4.

2.2. Gas injection rate

The injection rate considered as one of the main factors control any flooding performance and have huge effect on the gravity forces. The values of injection rates used in this study are varied in manner of ± 25 of base case model.

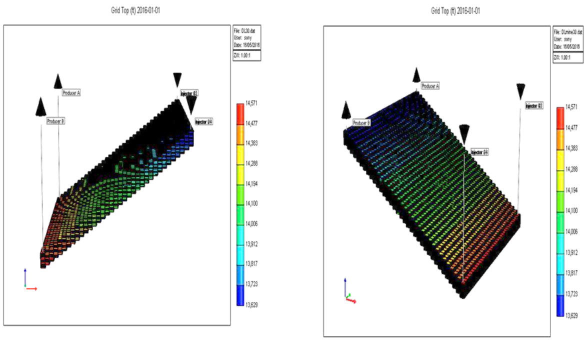
2.3. Dipping angle

The base case of this study has (dipping angle equal to zero), the effects is examined by changing the inclination angle of models in X direction to be 30 and

Figure 2.5

(a) Reservoir shape of dipping angle 30

(b) Reservoir shape of dipping angle -30



-30. In order to examine the effect of the reservoir inclination angle effect on this EOR process a direct flood pattern was used with 2 injections and 2 production wells. The injection constrains kept as the ones used in the rest of the study while the production wells was set to produces around 800 bbl/day as bulk and they was restricted with well bottom hole pressure can fall up to 2000 psi.

2.4. well bottom hole pressure

In order to study withdrawing rate effect while keeping the reservoir pressure above the minimum miscibility pressure, the bottom hole pressure was put in two constant scenarios 6000 and 6500 psi.

2.5. Kv/Kh ratio

This study investigate the impact of the cross flow between the adjacent layers on the oil recovery. The vertical permeability for the layers is set to zero for preventing the cross flow and the communications between the layers increased by set Kv/Kh to 0.3 and 0.5.

2.6. Permeability Ordering

The purpose of this study is examination the gravity cross flow which depend on the actual ordering of the layers in the reservoir. The evaluation of the bouncy effect can be achieved by randomly assigning the layers permeability without any order. Table 2.3 show the designed cases

2.7. Continuous Co_2 injection and miscible Co_2 WAG optimizing

The above mentioned studies are followed by optimizing WAG technique. The sensitivity analysis was designed to include wide range of parameters to predict the best scenario of displacement such as slug size, WAG ratio, WAG length and gas injection rate

In typical gas injection processes, the mobility ratio between injected gas and the displaced oil bank is very unfavorable because of low viscosity of the injected fluids. This lead to viscous fingering (abridged breakthrough) and reduced sweep efficiency. To overcome these problems, alternating injection of gas and water with specified volume, known as the WAG process, has been developed [3].

In WAG process, injection of water as a slightly incompressible fluid can maintain the reservoir pressure level, which is necessary for developing the miscibility between gas and oil with acceleration of gas solubility in oil (and therefore oil viscosity reduction). Because of the density contrast, the injected gas and water usually tend to sweep different portions of the reservoir. The upper portion of the pore space will tend to be swept by gas while water will push the oil in the lower parts. In order to optimize the WAG process, there are several parameters that should be designed carefully such as WAG Ratio, cycle length and slug size. To study the effect of WAG ratio on recovery for this specific reservoir model, four cases with WAG ratio of 0.5, 1.0, 2.0 and 0 (continuous CO_2 injection) were considered. Each injection scenario will be continued until the $HCPV$ of injected CO_2 reaches 1.0. To consider the effect of cycle length, an additional two cases for the WAG ratio of 0.5 will be provided. Table 2.4 provides a summary of the injection scheme in each case. The injection rate of fluids is however fixed at 1400 $rbbl/day$ except for all scenarios.

Table 2.3: Distribution of permeability on reservoir layers

Permeability md	Fining down-ward	Fining upward	Random 1	Random 2	Random 3	Random 4	Random 5
301.782	1	10	3	6	5	9	8
226.091	2	9	7	5	10	1	3
196.384	3	8	5	7	9	10	4
176.352	4	7	2	10	6	5	9
160.467	5	6	9	8	2	7	1
146.682	6	5	10	4	1	3	2
133.885	7	4	1	9	8	6	10
121.198	8	3	4	1	7	2	6
107.478	9	2	6	3	4	8	7
89.7646	10	1	8	2	3	4	5

Table 2.4: Summary of WAG injection scheme in each case

	WAG ratio [fraction]	WAG cycle length [months]	CO2 inj. length [months]	Water inj. length [months]
1	0	NA	NA	NA
2	0.5	18	12	6
3	1.0	18	9	9
4	2.0	18	6	12
5	0.5	12	8	4
6	0.5	9	6	3

3. Results and Discussion

Compositional simulation model was used to simulate some enhanced oil recovery methods, examining their mechanisms of improving the ultimate oil recovery and studying the effects of the degree of heterogeneity on these techniques performance. The results are classified based on purpose of study to:

3.1. Result of degree of heterogeneity

The effect of the degree of heterogeneity is obvious on recovery factor, depicted in figure 3.1a, the less recovery factor that we get it when the VDP is equal to 0 and the highest recovery factor when the VDP is equal to 0.7, this mean the performance of reservoir is getting better as the heterogeneity increase. The strange response is established due to the reservoir is layered with coarsen upward permeability-depth configurations with vertical permeability being set as 10% of the perm J values.

Figure 3.1

(a) . Sensitivity for degree of heterogeneity on the recovery factor

(b) Sensitivity for degree of heterogeneity on the reservoir pressure

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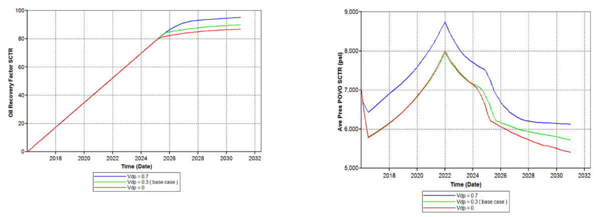


3.2. Result of gas injection rate

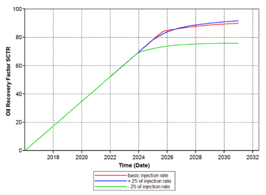
The recovery factor with base case injection rate doesn't have that much difference than when it is added by 25% while the recovery factor dropped clearly when the injection rate decreased by 25 %. In the case where the injection rate was declined with 25% the reservoir energy was depleted very quickly and we lose the miscibility after only 2 years of injection operation taking place.

3.3. Result of dipping angle

As the gas being injected up dip the gravity force will improve its percentage of flow which drive gas production rate in increase drastically and pressure to fall very fast and eventually lead to very bad per-

Figure 3.2

(a) Sensitivity for gas injection rate on the recovery factor



(b) Sensitivity for gas injection rate on the reservoir pressure

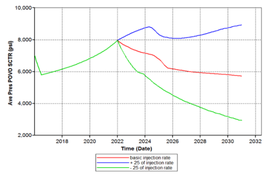
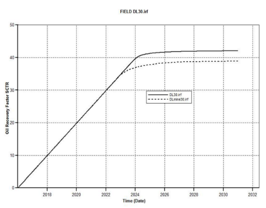


Figure 3.3

(a) Sensitivity for dipping angle on the recovery factor



(b) Sensitivity for dipping angle on the reservoir pressure

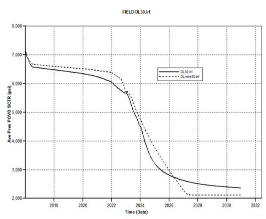
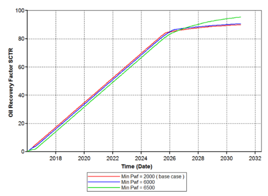


Figure 3.4

(a) Sensitivity for Production well bottom hole pressure on the recovery factor



(b) Sensitivity for Production well bottom hole pressure on the reservoir pressure

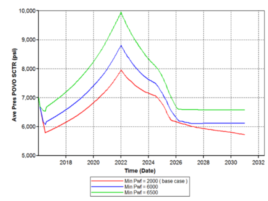
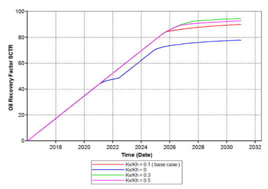
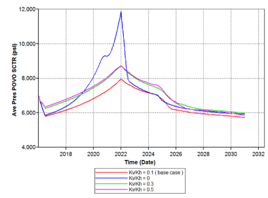


Figure 3.5

(a) Sensitivity for Kv/Kh ratio on the recovery factor



(b) Sensitivity for Kv/Kh ratio on the reservoir pressure



formance as can be seen in figures 3.3a3.3b. During secondary techniques phase the result were pretty match the same due to the very favourable mobility conditions.

3.4. Result of Production well bottom hole pressure

The variation of minimum bottom hole pressure associated with constant flowrate equal to 1400 bbl/day was 6000 and 6500 Psi. When bottom hole lower limit increase the recovery factor increase especially when lowest bottom hole pressure set to be above MMP. This happen because the operation conditions ensure the miscibility to be attained throughout the flooding and from the reservoir energy conservation point of view.

3.5. Result of Kv/Kh ratio

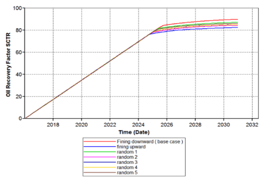
The vertical permeability for the layers is set to zero for permanently preventing the cross flow between the layers and increased by modifying Kv/Kh to 0.1, 0.3 and 0.5 for communication scenarios. For the communicating system, as the vertical permeability increased the recovery factor enhanced to certain limit because of the effect of cross flow either due to gravity or viscous force being positively maximized. Obviously when Kv/Kh ratio increased to half, the cross flow acting negatively cause it permit the gas to reach the top of the reservoir very rapidly hence premature breakthrough occurred and GOR increased drastically.

3.6. Result of permeability ordering

In the case where the permeability is kept decreasing with depth the front advancing slower in the top and bottom layers due to drainage the water down and the gas upward respectively. This effect will sharpen the front and enhance the performance, for the opposite permeability configuration the performance will get worse since the gravity effect will improve the water velocity in bottom layers and gas velocity in the top layers which will accelerate the water and gas breakthrough. In the case where the permeability is randomly distributed with depth (i.e. permeability alternately increase and decrease with depth) the cross flow between the layers due to the bouncy effect may be greater than in the fining downward case. As the result of this compensation the random permeability distribution tend to have minor effect on the performance. The fining upward case ending

Figure 3.6

(a) Sensitivity for permeability ordering on the recovery factor



(b) Sensitivity for permeability ordering on the reservoir pressure

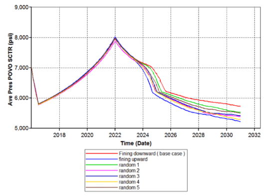
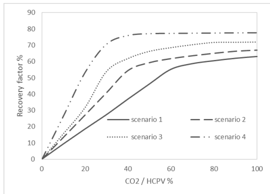
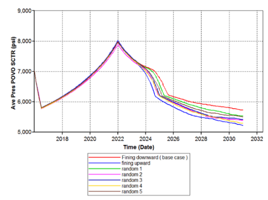


Figure 3.7

(a) Co_2 pore volume injected versus recovery factor for different WAG ratios



(b) Co_2 pore volume injected versus average reservoir pressure for different WAG ratios



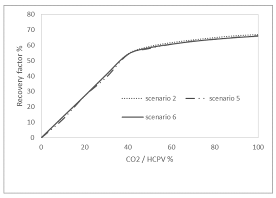
to be the worst case since it accelerates the water and gas and the fining downward is the otherwise.
Moreover this happen because in very early stage of injection process the water injection period was more effective depending on voidage replacement basis but this criteria was reversed as gas reaches to the producing interval and the amount of fluids being withdrawn from the reservoir is greater than the injected ones. the consequence of this material unbalanced, the reservoir pressure will decline to a point in time where the gas injected being more effective than water since it compressing will be hugely reduced and can replace more voilage in the reservoir. Noticeably as the average reservoir pressure being above or close to MMP the recovery factor will increased steeply with small incremental of Co_2 injected but it will flattered out as the pressure sink below MMP. Last but not least, the length of the slug cycle does not affect the reservoir performance of the WAG process.

3.7. Water alternative gas process optimization

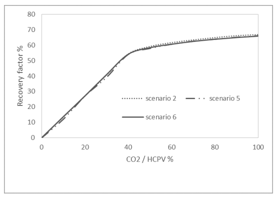
As predicted the recovery factor improved drastically as the WAG ratio increased which give an indication to major improvement in volumetric sweep efficacy. This incremental in ultimate oil recovery not solely due to gravity control but this case perfect for limited Co_2 resources. clearly the amount of Co_2 used, which equal to initial hydrocarbon pore volume, was only enough to sustain the injection for only 10.5 while it last to more than 40 years for WAG ratio 2 since we injected the gas for short discrete periods. Even though continues Co_2 injection case was very conservative, see figure 3.7b, and the pressure decline rate was very small in compare with other cases.
Moreover this happen because in very early stage of injection process the water injection period was

Figure 3.8

(a) Co_2 pore volume injected versus recovery factor for different WAG Cycle length



(b) Co_2 pore volume injected versus average reservoir pressure for different WAG cycle length



more effective depending on voidage replacement basis but this criteria was reversed as gas reaches to the producing interval and the amount of fluids being withdrawn from the reservoir is greater than the injected ones. the consequence of this material unbalanced, the reservoir pressure will decline to a point in time where the gas injected being more effective than water since it compressing will be hugely reduced and can replace more voilage in the reservoir. Noticeably as the average reservoir pressure being above or close to MMP the recovery factor will increased steeply with small incremental of Co_2 injected but it will flattered out as the pressure sink below MMP. Last but not least, the length of the slug cycle does not affect the reservoir performance of the WAG process.

4. Conclusion

1. For all cases were investigated the main conclusions based on the simulation results are: The highest recovery factor that we get when the VDP is equal to 0.7, this mean the performance of reservoir is getting better as the heterogeneity increase only for this special system.

2. The sweep efficiency of the water flooding enhanced when it is injected up dip. Where the density difference will be positive and lead to preferably gravity forces acting that at the end will reduce the fractional flow and improve the sweep efficiency, vice versa for the gas.

3. For permeability ordering, the fining upward case ending to be the worst case since it accelerates the water and gas breakthrough, while the fining downward was the best because it maximized the effect of cross flow between the layers.

4. As the average reservoir pressure being above or close to MMP, the recovery factor will increased steeply due to IFT in flood front is lowered to zero which lead to better sweep.

5. The length of the slug cycle does not affect the reservoir performance of the WAG process as demonstrated in the result.

6. The ultimate recovery factor was improved as the WAG ratio increased either due to the sustain of the miscibility and/or improvement of the volumetric sweep efficiency by preventing gas overriding and water under passing which lead to immature breakthrough. This direct relationship is logically continued to be presented to limit value where the WAG ratio is high enough to replicate the performance of the immiscible water flooding.

5. RECOMMENDATIONS

1. Collecting the vital lab data that used to characterize the interaction properties between Co_2 and the in situ reservoir fluids for more represented tuned EOS, i.e. slim tube test and swelling test.

2. Studying the effect of continues heterogeneity in the three dimension on these EOR process.

3. 3. Conducting an economical study to evaluate the feasibility of implementing such methods and optimizing the gas injection rate by studying net present values of total project

4. Gather more information to describe the multiphase flow more precisely by defining representing rock-fluid interaction properties in the each layer.

5. Studying the effect of capillary pressure by conducting the necessary laboratory work.

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