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Water Dumpflood Alternating Gas Injection from Underlying Aquifer

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Abstract: In this paper, water dumpflood alternating gas injection (WDAG) is proposed as an alternative to conventional water alternating gas injection (WAG) to enhance oil recovery. Instead of injecting water from surface, the water dumping well is completed in both oil and water reservoirs to allow water to flow from the aquifer into the oil zone. A numerical simulation model was built using ECLIPSE100 reservoir simulator to evaluate the performance of WDAG compared to conventional WAG. Different gas injection rates and water-gas injection cycles were varied to study their effects on conventional WAG and WDAG. Furthermore, size of underlying aquifer was also varied to evaluate the performances of WDAG. Simulation results show that WDAG yields slightly lower recovery factor than conventional WAG when gas is injected at high rates at water-gas injection cycle of 1:1 month for all aquifer sizes but requires no water injection while conventional WAG requires a large amount of water injection. The results indicate that WDAG is a feasible alternative to conventional WAG as the cost of water injection is eliminated.

Keywords: *Water dumpflood, water dumpflood alternating gas injection, water alternating gas injection*

1. Introduction

Water alternating gas injection (WAG) is one of EOR techniques that has been proved for its successful potential and applications for oil recovery in laboratory [1, 2, 3] and in the field [4, 5, 6]. In this method, water and gas are injected alternately into the oil reservoir. The process combines the benefits of microscopic gas displacement and macroscopic water flooding. As water is injected alternatively with gas, it helps prevent an early gas breakthrough.

Besides the advantages of WAG, the implementation of WAG obliges oil companies to pay for costly surface facility for both water and gas injection. However, water is generally readily available from an underground aquifer. The water can be dumped into the oil reservoir directly via a dumping well. The development of water dumpflood alternating gas injection (WDAG) is proposed in this paper to save the capital and fixed costs for water injection. In WDAG, the dumper well is perforated to allow high-pressure water from an aquifer underneath the reservoir to flow into the oil zone, and immiscible gas is injected from the surface.

The purposes of this work are to compare the performance between conventional WAG injection and WDAG in terms of oil recovery, cumulative gas injection, and cumulative water injection under different producing conditions and to evaluate the effect of ratio of aquifer volume to oil reservoir volume on the performance of water dumpflood alternating gas injection.

2. Literature review

Christensen, Stenby & Skauge [7] reviewed performance of 59 oil fields in which WAG had been implemented from 1957 to 1996. Immiscible WAG and miscible WAG had been performed in sandstone, limestone, and dolomite. The injected gas was CO_2, N_2, and hydrocarbon gas. The average increase in oil recovery (over water flooding) was from 5 to 10%.

Osharode et al. [8] reviewed the oil production of a pilot water dumpflood scheme started in 1997 in the Egbema West field. A reservoir model was built to evaluate the effectiveness of water dumpfood for full field development by drilling six dumper wells and re-opening six shut-in oil wells. The result showed that there is 400% increase in production rate and the recovery factor increases to 62% from 33%.

In 2011, Anansupak [9] investigated the effect of water dumpflood method by varying well location, size and depth of aquifer. The study used finite difference, three-dimensional numerical black oil model from Chervon's in-house simulator named CHEARS. According to the study, a larger aquifer size which can provide more cumulative amount of water injection gives better recovery factor. However, too large aquifer causes high water cut and low amount of recovered oil. The injector locations had strong effect on oil production. Edge well injections yield better recovery factor. In addition, the oil that has API gravity ranging from 30 to 40 was seen to be the best candidate for water dumpflood.

Helaly et al. [10] discussed the application of water dumpflood at an onshore oil field in Egyptian Western Desert which is 10 km away from the water source. There were a lot of problems for operation activity when performing conventional water injection such as surface leakages, casing leakages and ESP's maintenance. To eliminate the problems and reduce operation cost, water dumpflood has been implemented in this field. The paper also gave a typical cost of initiating conventional water injection project compared to water dumpflood project. The cost for installing 10 km of pipe may be 263% higher for capital cost in case of conventional water injection. Furthermore, expensive operational cost can be eliminated if water dumpflood is performed at this field.

3. Methodology

In order to evaluate performances of WDAG, a reservoir model was constructed in ECLIPSE100 reservoir simulation software to simulate the flow of gas, oil, and water in the oil reservoir, water aquifer, and wellbores. Several production conditions such as gas injection rates, water-gas injection cycles were varied to determine their effects on oil recovery for both conventional WAG and WDAG scenarios. As the strength of water aquifer is significant in WDAG, its size was varied from 5 times the reservoir pore volume (5 PV) to 20 times the reservoir pore volume (20PV) to determine its effects.

3.1. Reservoir Model

The model consists of 50-ft oil reservoir, 1000-ft thick impermeable layer, and 500-ft thick water aquifer, having the length and width of 4,500 and 1,900 ft, respectively. The top depth of the oil reservoir is 4500 ft deep. The number of grid blocks is 45x19x11 in the x-, y- and z-directions, respectively. The reservoir initial pressure, temperature, permeability and porosity are 2020 psi, 216^{o}F, 126 mD and 21.5%, respectively.

3.2. Fluid Properties

The reservoir contains oil having a density of 30 ^{o}API and initial solution gas oil ratio of 350 SCF/STB with gas specific gravity of 0.8. Oil formation volume factor and oil viscosity at initial conditions is 1.12 RB/STB and 1.392 cP, respectively.

3.3. Well location

The model contains three wells: two production wells located on both sides of the reservoir and one injection well (or dumping well in the case of WDAG) in the middle of reservoir as depicted in Figure 1.

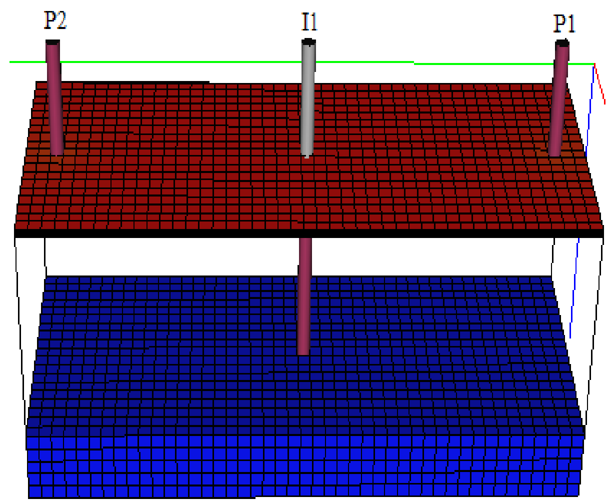

Figure 1: *Well locations (P1, P2 = production well and I1 = water injector for WAG, dumping well for WDAG)*

3.4. Operating conditions

3.4.1. Conventional water alternating gas injection

For conventional WAG, water and gas are injected alternately at well *I1*. The target water injection rate was set at 6,000 STB/D while the target gas injection rate was varied as 2, 4, 8 and 16 MMSCF/D. In addition, water-gas injection cycles were varied as 1:1, 2:1, 2:2, 3:1, 3:2 and 3:3 (month: month) to find the most suitable operating conditions. The maximum bottomhole pressure for injection well was set at 2700 psi to avoid fracturing. Wells *P1* and *P2* were used to produce oil with the target liquid production rate of 3000 STB/D/well.

3.4.2. Water dumpflood alternating gas injection

In this study, water was allowed to flow naturally from the aquifer into the oil reservoir without any downhole rate control device while gas was injected alternatively from surface. Apart from water dumpflood, other operating conditions were the same as those specified in the case of conventional WAG.

3.5. Abandonment Conditions

The production wells are produced until the economic rate of 50 STB/D/well or or the gas-oil ratio exceeds 50 MSCF/STB or the production time reaches the concession period of 30 years.

4. Results and Discussions

4.1. Conventional Water Alternating Gas Injection

The oil recovery factor, cumulative gas injection, cumulative water injection and production time for different gas injection rates and water-gas injection cycles are depicted in Figures 2-5. The simulation results show that higher gas injection rates yield higher recovery factors. As gas is injected at high rates, it helps maintain the reservoir pressure and improve microscopic displacement of the oil better than injecting at low rates, thus increasing the recovery factor. Injecting gas at high rates also needs less cumulative water injection and shorter times to produce but higher amounts of injected gas.

For the same gas injection rate, water-gas injection cycles of 3:1 month shows slightly higher recovery factors than other ratios as a shorter period of gas injection helps delay gas breakthrough, thus improving volumetric sweep efficiency. This 3:1 ratio requires the least amount of injected gas but the highest amount of injected water.

In locations where limited amount of gas is available, injecting gas at 2 MMSCF/D at 3:1 water-gas injection cycle may be the best choice as the recovery factor is as high as 75.70% while the requirement for gas is only 3.61 BCF. If there is unlimited amount of gas, gas injection rate of 16 MMSCF/D at 3:1 water-gas injection cycle may be the most appropriate since we can achieve up to 77.71% recovery factor. In any case, economic conditions need to be considered when making the decision as injection and production costs varies with location.

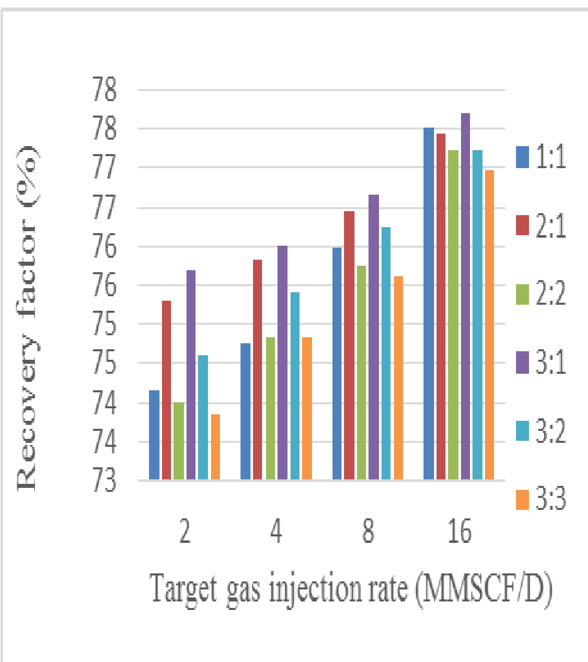

Figure 2: *Oil recovery factor for WAG.*

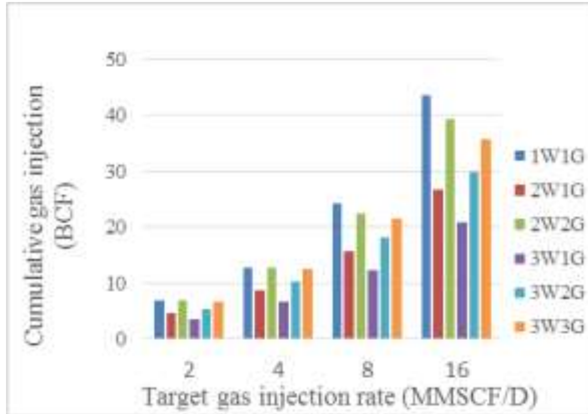

Figure 3: *Cumulative gas injection for WAG*

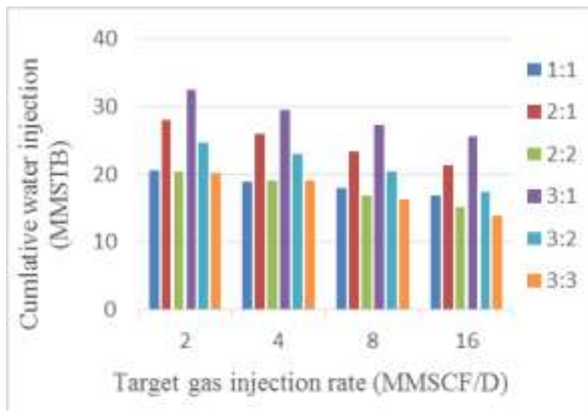

Figure 4: *Cumulative water injection for WAG*

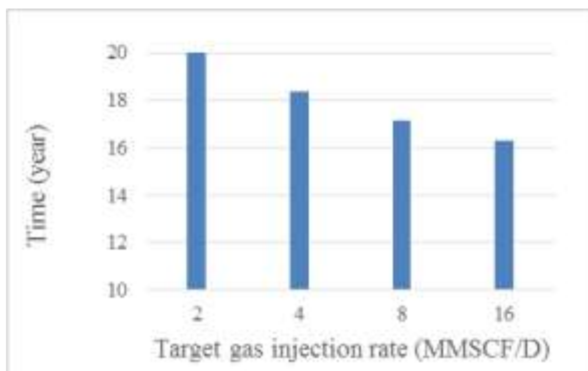

Figure 5: *Production time for WAG.*

4.2. Water dump Flood Alternating gas Injection

4.2.1. Aquifer is 5 times the reservoir pore volume

For WDAG, recovery factors are significantly different between low and high gas injection rates as illustrated in Figure 6. Higher gas injection rates give much better recovery factor while requiring much higher amounts of injected gas (see Figure 7). Note that the amount of cumulative water injection is zero because water was dumped from an aquifer instead of injecting from surface. As water was dumped from the aquifer that is 5 times the reservoir pore volume located 1000 feet below the reservoir, a small cumulative amount of water had entered the oil reservoir. If the gas injection rate is also small, the total amount of displacing fluids is then small. Thus, there is insufficient amount of fluids to efficiently displace the oil in the reservoir.

Water-gas injection cycle moderately affects the recovery factor. The ratios 1:1, 2:2, 3:3 show better results than 2:1 and 3:1. As there is limited amount of water flowing from the aquifer into the oil reservoir, it is better to dump water and inject gas at lower water-gas injection cycle to utilize the benefits of gas displacement.

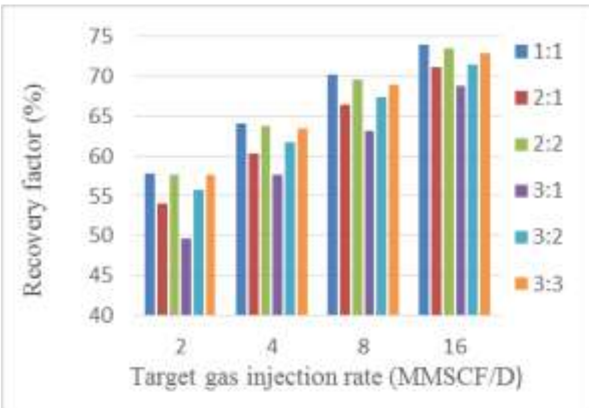

Figure 6: *Recovery factor for WDAG (5PV aquifer).*

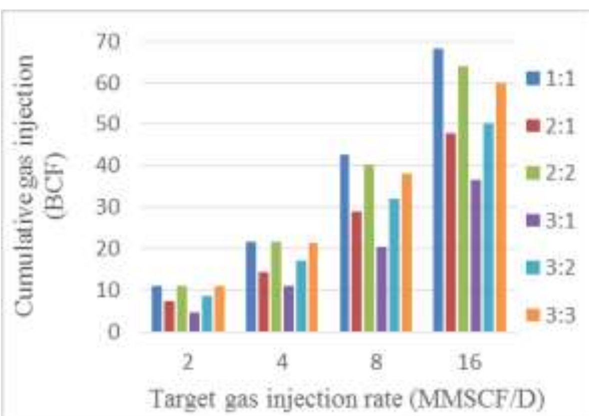

Figure 7: *Cumulative gas injection for WDAG (5PV aquifer).*

4.2.2. Aquifer is 10 times the reservoir pore volume

When increasing the pore volume ratio of aquifer to oil reservoir to 10PV, the trends in the recovery factor and cumulative gas injection are the same as the ones for 5PV cases as depicted in Figures 8 and 9. However, the performances of the 10PV cases are better as their recovery factors are slightly higher while requiring lower amounts of injected gas.

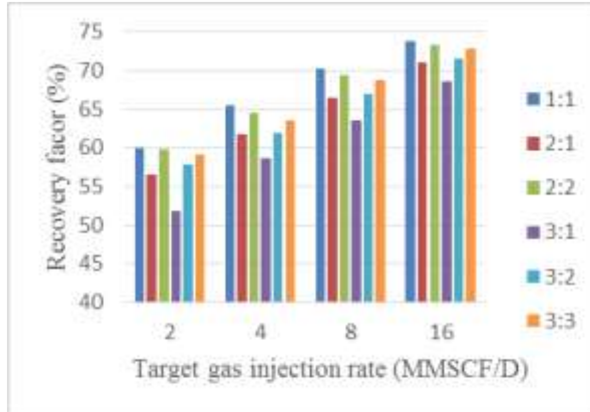

Figure 8: *Recovery factor for WDAG (10PV aquifer).*

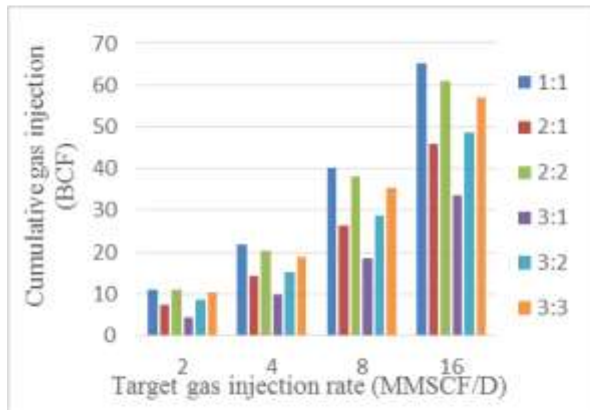

Figure 9: *Cumulative gas injection for WDAG (10PV aquifer).*

4.2.3. Aquifer is 20 times the reservoir pore volume

For 20PV cases, the trends in the recovery factor and cumulative gas injection are the same as the ones for 5PV and 10PV cases as shown in Figures 10 and 11. Nevertheless, the performances of the 20PV cases are better as their recovery factors are slightly higher while requiring lower amounts of injected gas.

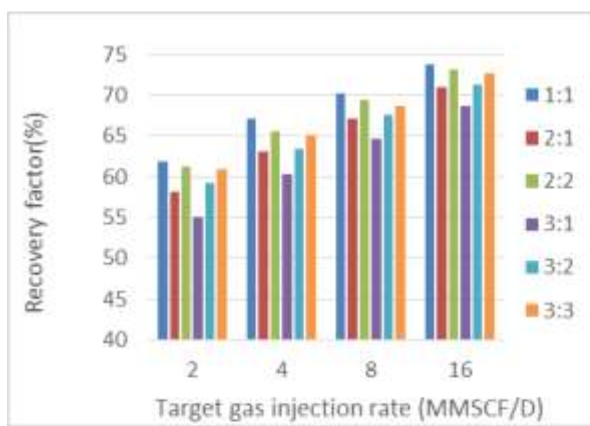

Figure 10: *Recovery factor for WDAG (20PV aquifer).*

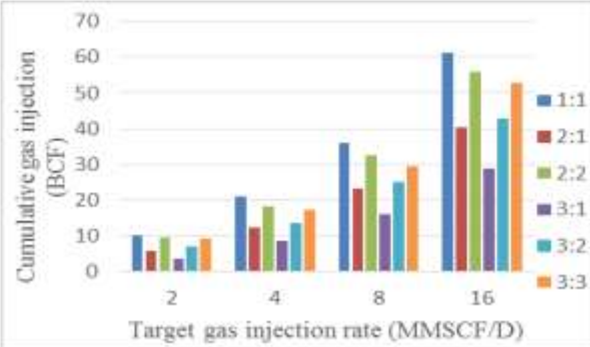

Figure 11: *Cumulative gas injection for WDAG (20PV aquifer).*

4.3. Comparison between conventional WAG and WDAG

As illustrated in Figures 12-17, at gas injection rate of 2 MMSCF/D, the recovery factors for WDAG are much lower than the ones for conventional WAG for all aquifer sizes and water-gas injection cycles. As the gas injection rate is increased, the difference in recovery factors for the two processes becomes significantly smaller. The smallest difference happens at gas injection rate of 16 MMSCF/D and water-gas injection cycle of 1:1 month (see Figure 12) for all three aquifer sizes. For this particular case, the amount of cumulative water injection for conventional WAG is 16.80 MMSTB while WDAG requires none.

From the comparison, we can conclude that WDAG is not suitable for cases in which there is limitation on gas injection as its recovery is much lower than conventional WAG. However, WDAG is an attractive alternative to WAG in cases where there is unlimited amount of gas available as its recovery factor is slight lower but the process requires no water injection facility.

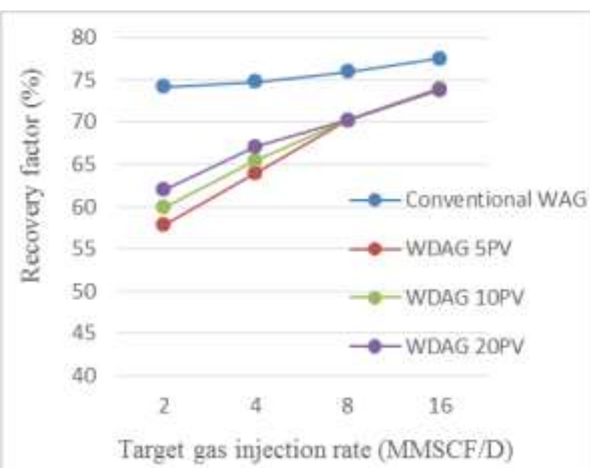

Figure 12: *WAG and WDAG recovery factors in the case of water-gas injection cycle of 1:1 month.*

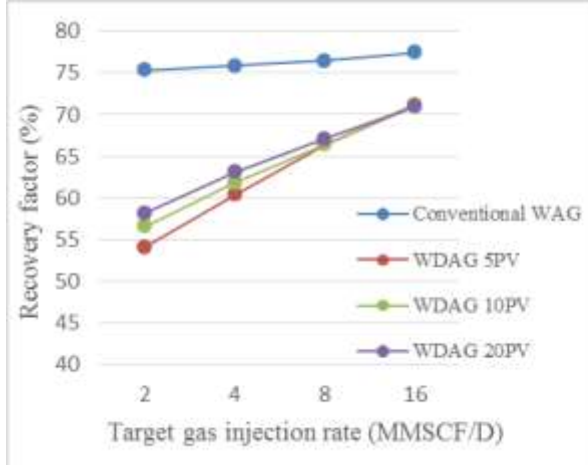

Figure 13: *WAG and WDAG recovery factors in the case of water-gas injection cycle of 2:1 month*

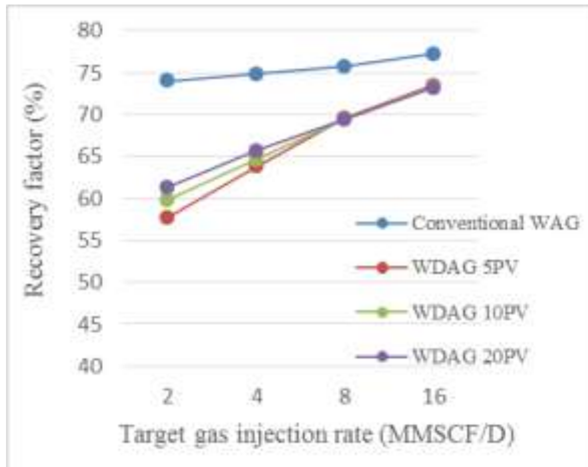

Figure 14: *WAG and WDAG recovery factors in the case of water-gas injection cycle of 2:2 month.*

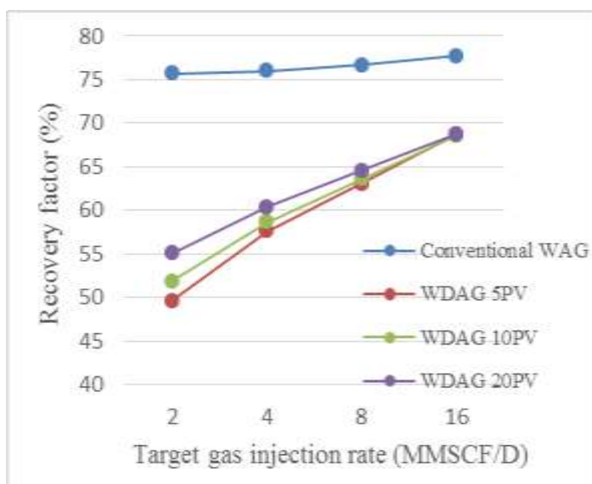

Figure 15: *WAG and WDAG recovery factors in the case of water-gas injection cycle of 3:1month.*

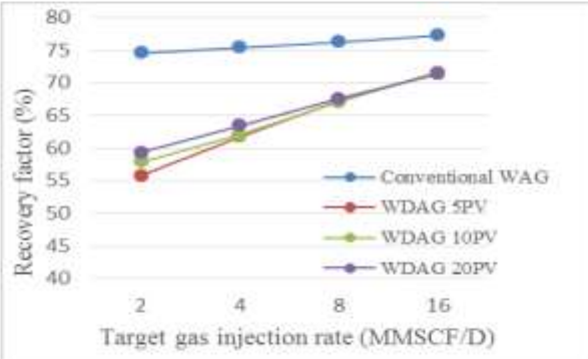

Figure 16: *WAG and WDAG recovery factors in the case of water-gas injection cycle of 3:2 month.*

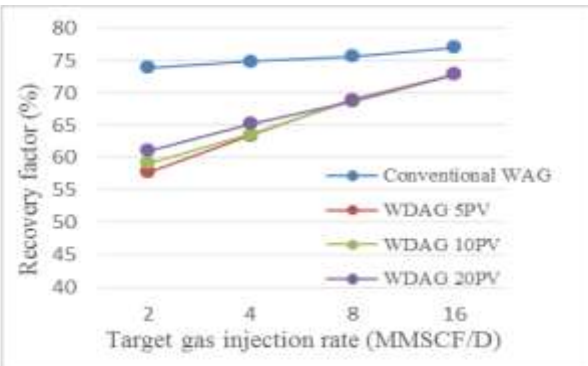

Figure 17: *WAG and WDAG recovery factors in the case of water-gas injection cycle of 3:3 month*

5. Conclusions

Based on the results of this study, the following conclusions can be drawn:

(i) Conventional WAG gives higher recovery factor than WDAG. However, it requires large amount of water injection while WDAG method does not require any water injection.
(ii) Recovery factor for WDAG is much lower than the ones for WAG at low gas injection rate but becomes slightly lower at high gas injection rate.
(iii) Water-gas injection cycles of 3:1 yields the highest recovery factor in the case of conventional WAG while water-gas injection cycle of 1:1 yields the highest recovery factor in the case of WDAG.
(iv) For WDAG, larger aquifers yield slightly higher recovery factors when injecting gas at low rates but no improvement when injecting gas at high rates.

6. Nomenclature

WAG: water alternating gas injection
WDAG: water dumpflood alternating gas injection
MMSCF/D: million standard cubic feet per day
MMSTB: million stock tank barrels
BCF: billion cubic feet
PV: pore volume ratio of aquifer to oil reservoir

7. Acknowledgements

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