Compositional Analysis and Screening for Enhanced Oil Recovery Processes in Different Reservoir and Operating Conditions

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Abstract

The feasibility of different gases (CO2, N2, or Enriched Gas) and Water-Alternating-Gas (WAG) to maintain pressure and optimize oil recovery have been examined on a simple mechanistic reservoir model of considerably depleted saturated oil reservoir. The simulation study was conducted on 3-phase - 2D finely gridded compositional simulation model. A compositional model is necessary to account for mass transfer and changes in composition of a saturated oil system because the miscibility takes place through inter-phase mass transfer during the miscible solvent injection. Also the compositional study is indispensable to design the surface facilities to deal not only with the reservoir hydrocarbon fluid but also the solvents and water after their break-through. These surface facility operations include the separation of injected solvent, water and reservoir hydrocarbon fluids, and the treatment of solvent & produced water and their reinjection into the reservoir. Due to better mobility control WAG injection was found to be significantly more efficient than the gas injection. For more optimization a sensitivity study was conducted on the injection cycling and component ratios. A sensitivity study was also conducted on the following parameters to study its effect on the overall field's recovery the composition of the produced oil. Some of these parameters include the completion of the injector well and the presence of a thief zone and its level of permeability For the good reservoir management a reliable prediction of oil and gas rates are to be simulated. This in turn requires a sound understanding of the displacement processes which take place in the reservoir. The oil recovery depends not only on the fluid to fluid displacement but also on compositional phase behavior.

Keywords: EOR, Simulation, EOR Screening, Gas and WAGInjection

Introduction

Enhanced Oil Recovery (EOR) is a collection of some advanced oil recovery methods, each with its own unique capability to extract the most of the oil from a particular reservoir. Each has been investigated previously, rather thoroughly both from a theoretical and practical perspective, as well as in the actual oil field[1, 2]. EOR is generally being considered.EOR is generally being considered as the third or the last phase of the useful oil production and sometimes is it is to be known as the tertiary oil production. EOR is a general term referring to efforts to recover more oil from reservoirs then can be obtained by using the conventional and routine technology of petroleum production under the prevailing economic conditions[1- 4]. These are the artificial techniques that are to be applied to recover the residual oil that left behind into the reservoir after its primary and secondary production by mean of injecting some external fluid into the reservoir. EOR processes are generally classified into Miscible or Immiscible gas injection, Thermal and Chemical EOR[3]. In this paper we are only emphasizing the performance ofCO_2, N_2, H.C and WAG-CO_2injection EOR processes.

CO_2 Injection

This technique of CO_2 injection is readily being adopted for the medium oil reservoirs, containing high percentage of C_5 to C_{12} components at significantly shallow depth.

It is applicable in both the Sandstone and Carbonate reservoirs[5, 6]. CO_2 makes the oil easier to flow by means of getting miscible into the oil and causes to swell it to increase its relative oil permeability and hence reduces the amount of Residual Oil Saturation (S_{or}). CO_2Injection may results up to 35% of more oil recovery of OOIP[7, 8]. Carbon dioxide is a supercritical fluid that exhibits different pressure and temperature dependent properties. Under high pressure and temperature range and favorable native fluid composition it mixes with oil to form a low viscosity, single-phase fluid[9].

N_2 Injection

The nitrogen injection can be used as a substitute for CO_2 in deep light to medium oil reservoirs mainly containing C_1 to C_7 components. It is applicable in both the Sandstone and Carbonate reservoirs[3, 6]. Nitrogen itself an inert gas that gets miscible at very high pressure and efficiently reduces the oil viscosity and provides efficient miscible displacement[6].

Hydrocarbon Enriched Gas Injection

The hydrocarbon (HC) miscible is similar to the CO_2 flooding, with that the solvent is composed of a mixture of hydrocarbon components (usually C_2 to C_5). The injected HC solvent is usually displaced with cheaper chase leaner or inert gas like Methane or Nitrogen[10]. At reservoir conditions the most usual problem occurs with the hydrocarbon miscible flood is the gravity over-ride because of its lighter density then the oil and water. So that into any miscible flood the Minimum Miscibility Pressure (MMP) plays the most major role to overcome this problem. As a remedial factor the solvent is to be injected at or above the MMP of the reservoir fluid. Once it becomes miscible then it improves the sweep efficiency and fallouts in optimum recovery[7, 11, 12].

Water Alternating Gas Injection

Water Alternating Gas (WAG) injection is a combination of two conventional EOR techniques; water flooding and gas injection[11]. In 1957, it was very first time applied on North Pembina field in Alberta, Canada by Mobil[13]. The WAG was adopted by keeping this point of consideration into the mind that the traditional gas and water floods usually leave at least 20-50% of the residual oil in place[14]. From the laboratory analysis it was calculated that simultaneous water/gas injection could have sweep efficiency up to 90% and only gas alone results in about 60%[14]. But later on this fact came in front that simultaneous injection of gas and water is impractical because of Mobility instabilities, then after alternate injection method of gas and water (WAG) was adopted. Also it was found to be quite economical. The initial proposed ratio of water and gas was 0.5:4 in frequencies of 0.1 to 2% Pore Volume slugs of each fluid, that was been adopted according to the reservoir conditions[15].

Model Description

We prepared a 2 dimensional 3 Phase mechanistic reservoir model, containing oil, gas and water. The reservoir has a width (y-direction) of 1000 feet and a length (x-direction) of 4000 feet. Twenty (20) equal spaced (constant dx) grid blocks are used in the x-direction, and 5 layers are considered (z-direction). The reservoir is made to be dipping to analyze the effect of viscous forces; the top depth is changing from 6100 feet to 6195 feet from first to the last column.

Table 1: Grid Cells Properties

Layer	Thickness (ft)	Perm kx (mD)	Perm kv (mD)
1	32	50	10
2	5	0.01	2 E -3
3	20	20	4
4	41	80	16
5	32	150	30

Table 2: Rock and Fluid Properties

Reservoir Temperature	100 ‘F
Bubble point of the Initial Oil	482 Psia
Rock Compressibility @ Ref. 3000 Psia	4 E -6 1/Psia
Water Compressibility @ 14.7 Psia	5 E -6 1/Psia
Surface density @ 14.7 Psia	64.00 lb/cu.ft
Average Porosity	18%
Net to Gross Ratio	1.0
Kv	20% of Kh

Table 3: Initialization Data

Parameters	Temperature (‘F)	Pressure (Pisa)
First Stage	100	815
Second Stage	70	500
Third Stage	60	14.7
Water Oil Contact (WOC)	8000 feet SSL	
Gas Oil Contact (GOC)	3000 feet SSL	
Datum Depth	6100 feet	
Pressure at Datum Depth	3000 Pisa	
Initial Surface Volume of Oil in Place	13.3964 MMstb	

Table 4: Schedule Data

Production Wells Specifications	Well 01 (P1)	Well 02 (P2)
Allocation (Columns)	10	20
Completed in layers	4 - 5	3 - 5
Min. field oil rate (stb/day)	200	200
Max. Gas Rate (MScf/day)	3000	3000
Min. BHP (Psia)	200	200
Max GOR (Mscf/stb)	6.0	6.0
Required Oil Rate (stb/day)	1500	1500
Max. Water Cut	95 %	95 %

The operating conditions are set on GOR, WC, or minimum oil rate limits, any of the producer violate these limits, it will be shut automatically. An injection well (named IN) is drilled in the up-dip location (1,1) and completed in layer 1, above the low permeability layer. The maximum injection BHP is 5000 Pisa. The injection well may inject CO_2,N_2, Enriched Gas Mixture (60% C1 and 40% C3), 100% Methane or WAG at the injection rate of 7000 Mscf/day. The simulation is set to run for 20 years or till the last producer is shut in as the result of the violation of the fixed operating limits.

Miscible &Immiscible Displacement of Oil by Gas Injection and WAG

Several EOR methods are applied to this model such asCO_2, N_2, Enriched Hydrocarbon Gas and WAG. The recovery of oil will be, also, determined using these techniques. The base case for the amount of gas to be injected is 7000 Mscf/Day and the pressure decline is low. Also we test the recovery performances by injecting gases through an injector, completing it into only up to 1st and 2nd layer from the top. Also the recovery parameters are compared by means of injecting WAG (CO_2) and find out the best water injection rate with the CO_2 injection at 7000 Mscf/Day to maintain the field pressure level. Lastly, all the results being obtained through the different scenarios listed above are compared. Additionally we checked the recovery by setting up the producer BHP limit at 3000 Pisa while injecting enriched gas and also found that, what if only 10% of C3 with 90% of the methane is injected. Complete study is designed to compare the performance of all the above said scenarios while injecting any of the injectant with 2 cases; while considering layer 2 as a thief or the tight permeability layer. In both the cases we made 2 further assumptions for injecting only in layer 1 or in both the layers 1 and 2 to study the effect of permeability on injecting different gases and WAG.

Results and Discussion

After running the base case of the model as shown in figure 1, we noticed the cross sectional grid structure of the reservoir is very homogeneous in two dimensional. Therefore, several cases were necessary to be considered in order to understand the behavior of the enhanced oil recovery processes injection. Also, we have three wells are drilled (one injector and two producers) as shown in figure 2. To better understand and evaluate the EOR processes, we need to perform some sensitivity analysis (will be described later in the report). The main idea is to determine the best filed performance under different conditions (in terms of pressure and composition).

As the first run, CO_2 Injection is implemented with 100% of its concentration as well as to the N_2 injection. Whereas, for the Enriched Gas injection, we selected to inject 40% of propane and the remaining fraction is methane. Also, Water Alternating CO_2in injected for recovering oil, and an optimum WAG ratio first required to be selected (described more in WAG sensitivity) whose ratio 1:4 is found to be the most appropriate .

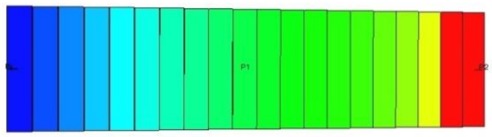

Figure 1. Grid Formation (top view)

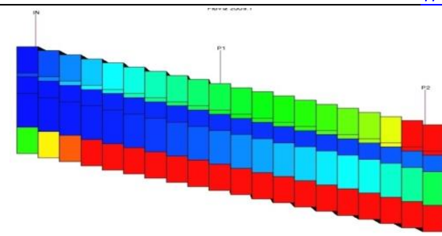

Figure 2. Grid Formation; (Front View)

The injection rate of 7000 Mscf/day is selected for all the methods, the bottom hole pressure for both the oil producers is set at 200 psi. Following are the saturation profile that we got at the early, middle and late time periods of the model as shown in figures 3-8. From the saturation maps, we noticed that theCO_2 has the best oil displacement process. Also, we found that N_2 had fair displacement in the upper four layers and poor displacement in the fifth layer, hence less oil recovery is encountered.

Layer two had the worst displacement process due to the very low permeability value. However, WAG (CO_2) injection provided, again, better displacement among all other methods due to mobility enhancement. Also, the thickness of this layer contributed even more in lowering the oil recovery due to its low flow capacity. In addition, the low vertical permeability value of layer 2 made the vertical communication between the layers above and below this layer very hard for the fluid to flow. Further investigation on this layer is made to see the effect of thief zones. Layer 5 has the highest permeability value although the oil displacement is not so efficient. This behavior is due to the injector well completion since we are injecting solvent in layer 1 only, and layer 2 is acting as a burrier and avoiding the injected solvent to displace oil in the lower layers. Producer 1 is, also, affecting the displacement of the fluid to the second producer sine it is located in the middle of the reservoir; therefore, decreasing the pressure in the area between producer 1 and 2. Both wells were completed in layers 1, 2, and 3; and they are 2000 feet apart.

Total Recovery Analysis

For evaluating any EOR process, we always require a recovery factor estimation to compare the processes. Figure 15 is showing the recovery comparison for all the four applied EOR methods to our model. WAG is recovering up to 86% of the OOIP and the project is lasting for 17 years. Whereas, CO_2 injection has the second highest recovery factor of around 84% for 19 years, and the Enriched Gas (60% of C1 and 40% of C3) injection is recovering up to 82% for the same period. While the Nitrogen injection is found as the least oil recovering process, and it recovered about 53% of oil for 19 years.

Whereas in the case for considering layer 2 as an thief zone by changing its permeability from 0.01 to 300 md.Figure 16 shows that enriched gas and CO_2injection become the most efficient EOR process with the highest recovery or more than 90%.

Saturation Profiles at Early Time Step

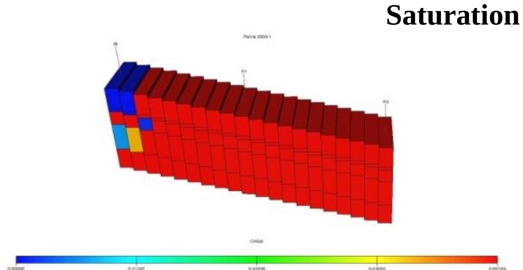

Figure 3. CO_2 at early time step

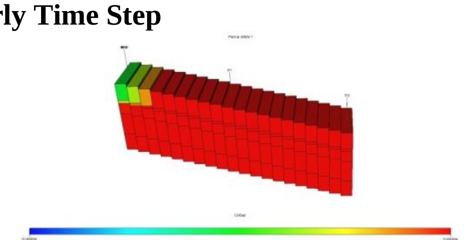

Figure 4. WAG (CO_2) at early time step

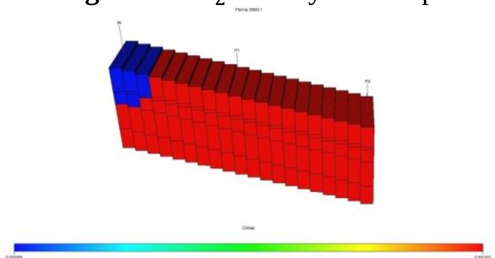

Figure 5. Enriched Gas at early time step

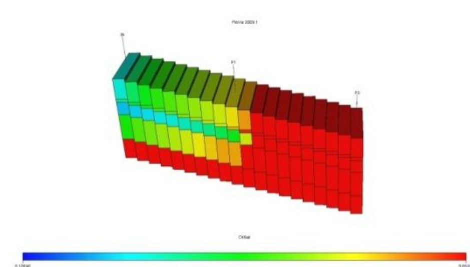

Figure 6. N_2 at early time step

Saturation Profiles at Middle Time Step

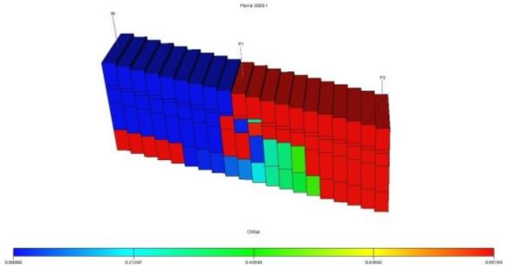

Figure 7. CO_2 at middle time step

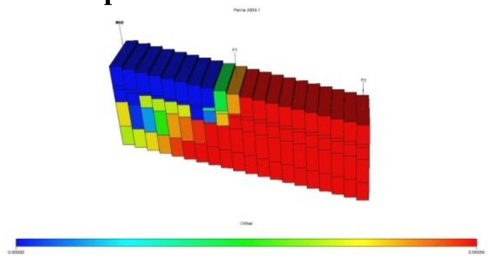

Figure 8. WAG (CO_2) at middle time step

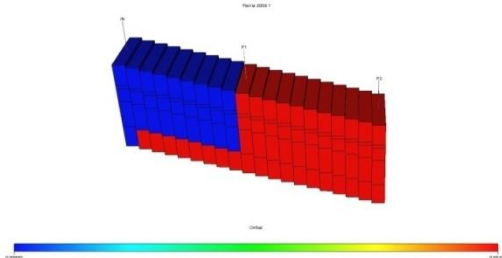

Figure 9. Enriched Gas at middle time step

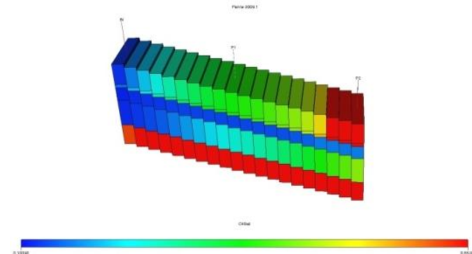

Figure 10. N_2 at middle time step

Saturation Profiles at Late Time Step

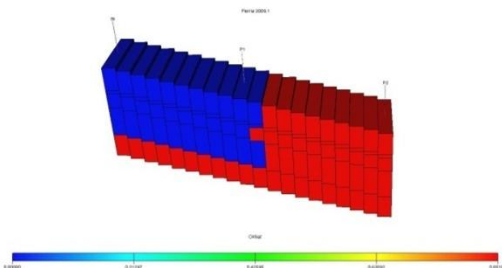

Figure 11. CO_2 at late time step

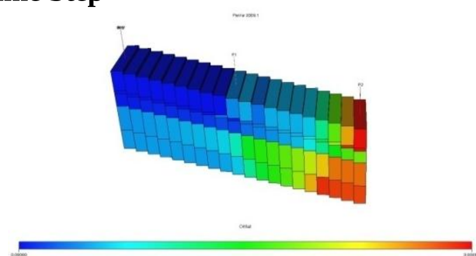

Figure 12. WAG (CO_2) at late time step

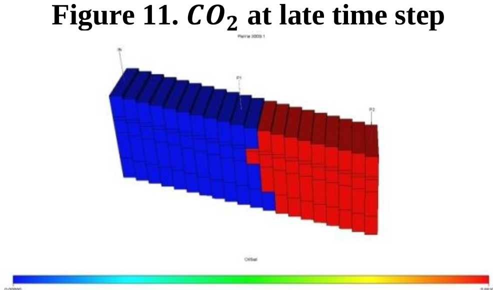

Figure 13. Enriched Gas at late time step

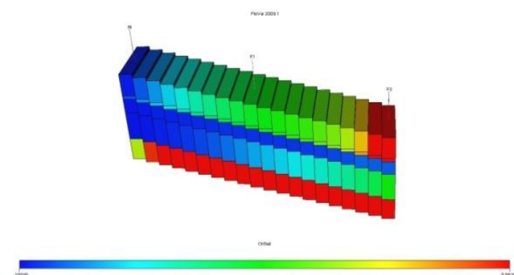

Figure 14. N_2 at late time step

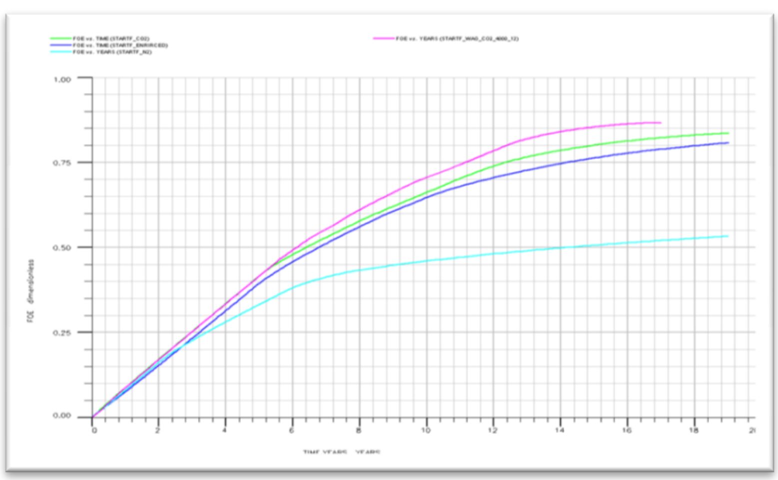

Figure 15. Field Oil Recovery; Injector Completed in only Layer 1

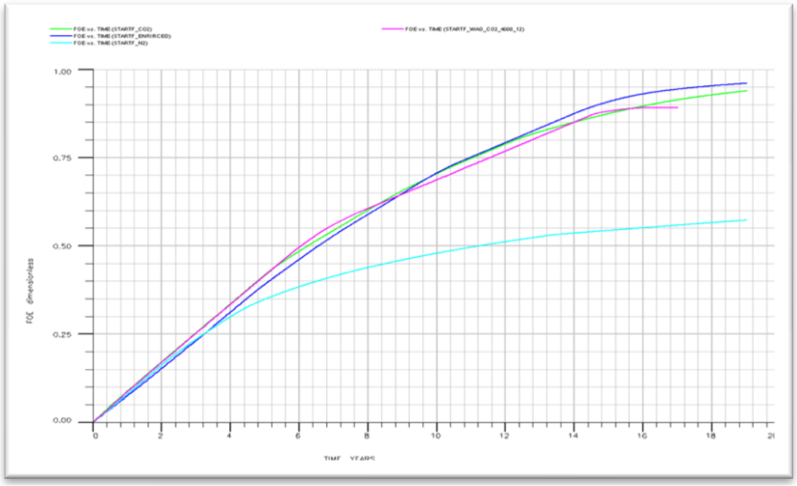

Figure 16. Field Oil Recovery; Injector Completed in only Layer 1 (layer 2 is acting as a thief zone)

In another scenario by changing the injector's completion to layer 1 & 2, we found an enormous change in the oil recovery factors (figure17), for example WAG contributed to produce more than 90% of oil while CO_2 and enriched gas injection produced up between 80 to 85%.There was an unexpected recovery was obtained while injecting water alternating CO_2 when considering the layer 2 as a thief zone of permeability 300 md, shown in figure 18. The model recovered up to 91% of OOIP but due to heavy water cut its production stopped at 16th year. On the other hand enriched gas, CO_2 and N_2 are were lasting up to 19 years but recovered only 96, 93 and 56% respectively.

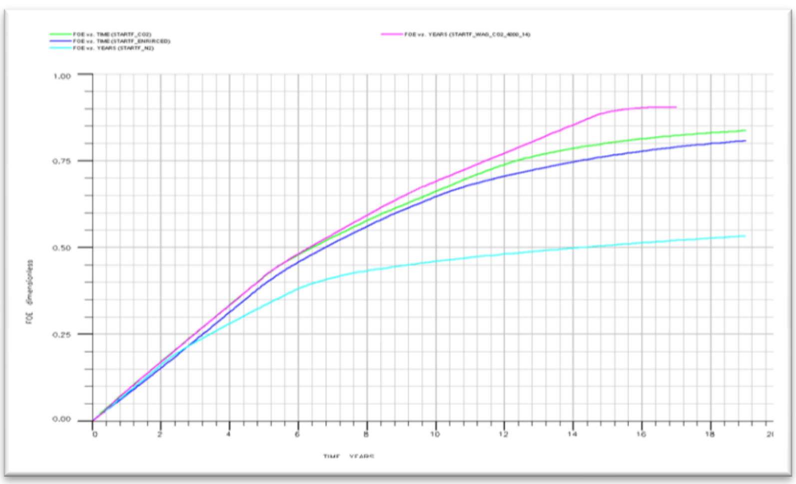

Figure 17. Field Oil Recovery; Injector Completed in Layer 1 & 2

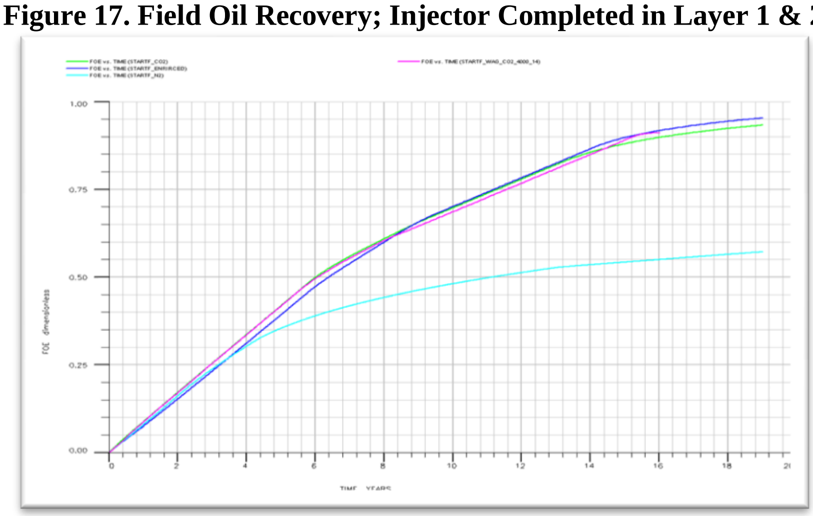

Figure 18. Field Oil Recovery; Injector Completed in Layer 1 & 2 (Layer 2 acting as a thief zone)

Compositional Analysis

Following figures 19 and 20 are showing the composition of the first component i.e. CO_2 while injecting all the four solvents into the model individually through only layer 1 and through both the layers 1 & 2, respectively. Almost all the solvents were break throwing at the production wells within 5 to 6 years. CO_2fraction was reached up to 99% in both the cases of injection at the end of year 19 through rapid viscous fingering where as CO_2 fraction was only raised up to 68% when injecting water alternating CO_2 through layer 1 only; the reason of this stabilization is the mobility control by the alternating injected solvent by water. When the same scenario was compared through injecting WAG through both the top 2 layers, CO_2 fraction was produced up to 96% and the model was shut from production because of heavy water cut after 16 years. The production of CO_2 was considerably very low while injecting nitrogen and enriched gas.

The injected nitrogen component was observed, that reached up to 98% at the end of the model life at P2. Nitrogen component behaved same in both the cases while injecting it through layer 1 only and layers 1 & 2. Figures 21 and 22 better illustrates the behavior of nitrogen injection when completing the injector in layer 1 and in layers 1 and 2.

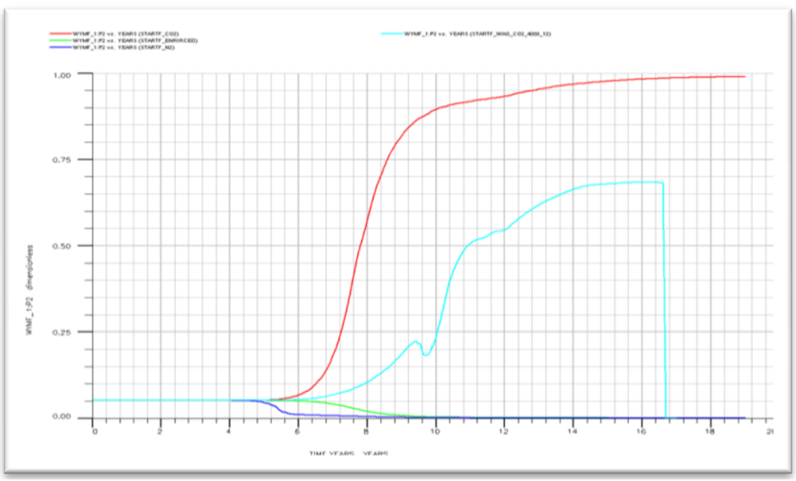

Figure 19. Composition of CO_2 at P2 while injecting solvents through layer 1

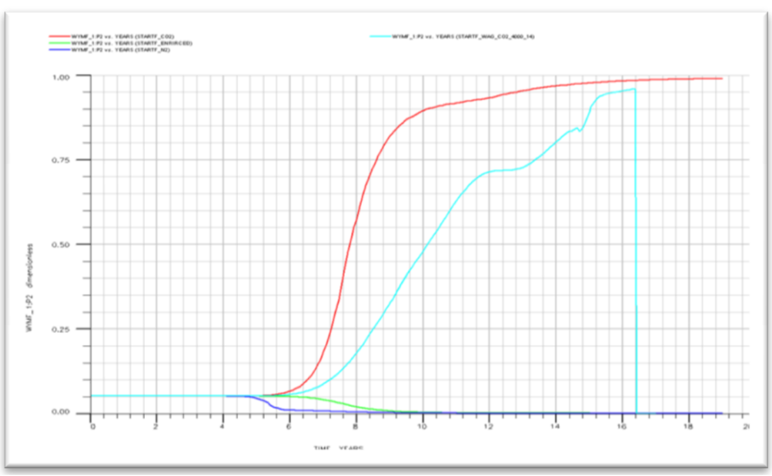

Figure 20. Composition of CO_2 at P2 while injecting solvents through layer 1&2

Figure 23 & 24 is depicting the fraction composition of component 3 (methane) while injecting all the four solvents individually. The highest mole fraction of methane was produced while injecting hydrocarbon enriched gas in both the cases of injecting the solvent through layer 1 or through layers 1 and 2. WAG injection was on gave the highest methane recovery after enrichedgas injection. There was a gradual decrease in methane fraction up to year nine, but there was asudden rise observed up to 10% in methane content because of sudden pressure drop from 2600 to 2200 psi. Whereas, it showed a smooth decline while injecting WAG through both layers 1 and 2.

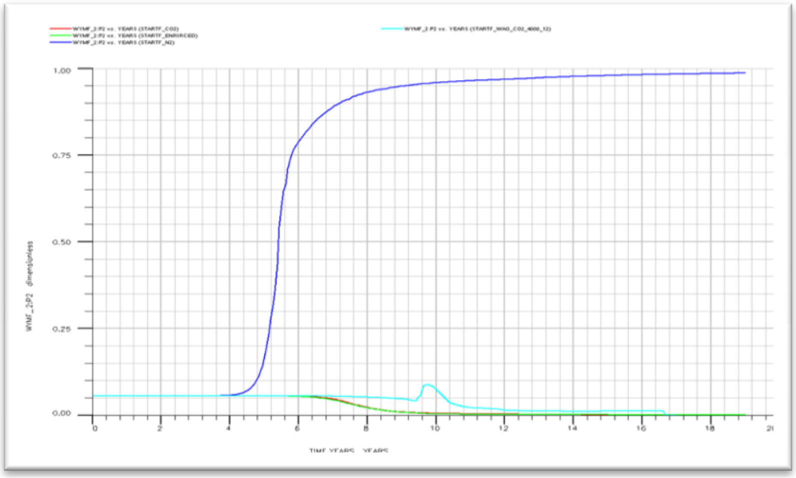

Figure 21. Composition of N_2at P2 while injecting solvents through layer 1

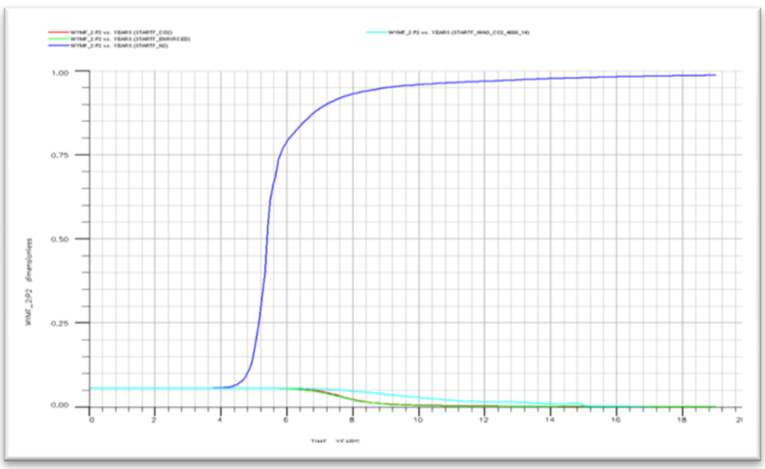

Figure 22. Composition of N_2 at P2 while injecting solvents through layer 1&2

Figure 25 is presenting the mole fraction of CO_2, nitrogen, and methane at the producer well-2 when injecting CO_2 through layers 1 & 2. $CO_2$was initially produced up to only 5% for about six years then suddenly its fraction increased up to 99% by the end of the model life. This happened dueto CO_2 breakthrough at year 6. While the second fraction i.e. nitrogen decreased and almost vanished when the CO_2 fraction just increased. On the other hand, methane fraction was the highest among the other two compositions mentioned above where its initial fraction was about 55%. The methane fraction started to decline suddenly when theCO_2 was sharply increasing.

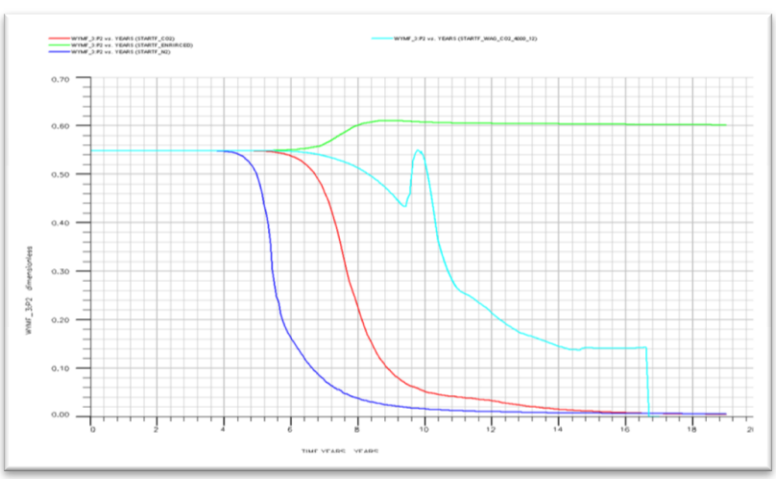

Figure 23. Composition of CH_4at P2 while injecting solvents through layer 1

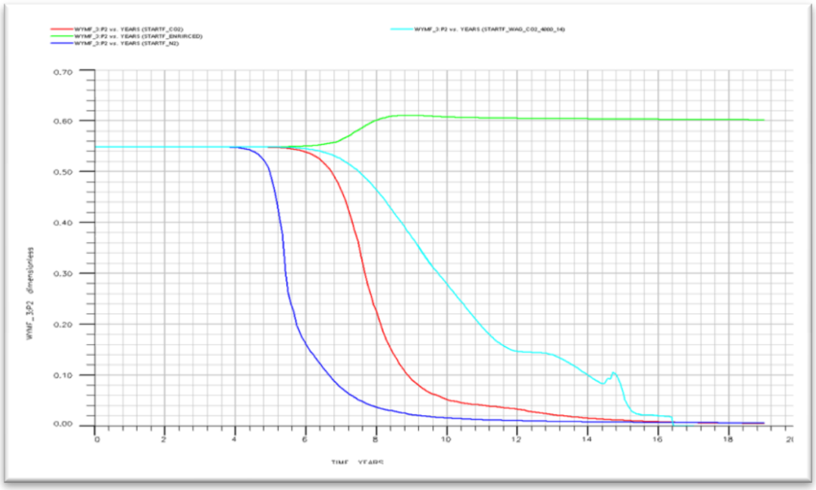

Figure 24. Composition of CH_4 at P2 while injecting solvents through layer 1 & 2

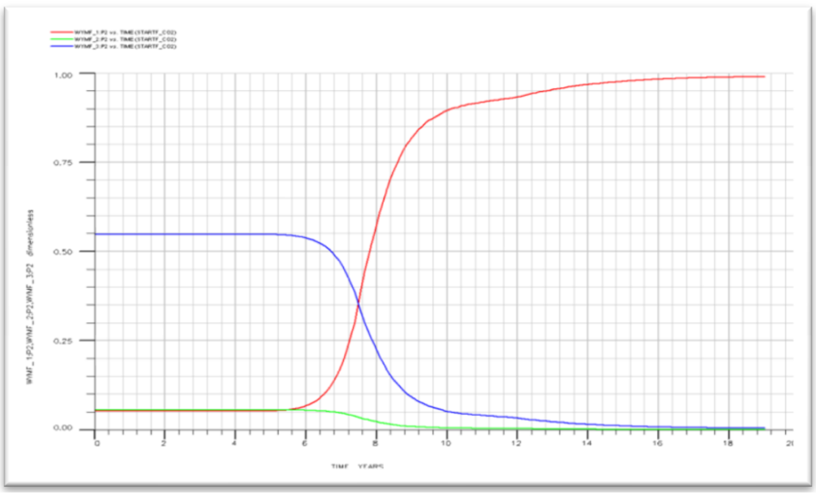

Figure 25. Composition of all 3 components while injecting only CO_2 through layer 1&2

Pressure, Production Rate & GOR vs. Time

One of the most vital outputs to monitor and evaluate an EOR process where simulation engineer need to look for the reservoir pressure, production rate, and the gas-oil ratio. These results give a clear picture of what the reservoir is experiencing during an EOR process, and these results need to be analyzed very carefully. Figures 26-29 shows the difference of pressure, GOR, and production rate while injecting the four different EOR solvents. The first figure shows that how the reservoir is responding when injecting 100% CO_2 where the field production rate is constant at3000 stb/d for five years. Then, the production starts to the CO_2 breakthrough at the two producers, therefore, GOR started to increase. The pressure, first, declined due to the decline near the wellbores, and then started to increase after eight years making the production rate to stabilize for about two years, but the rate started to decrease since the GOR increased dramatically.

For the N_2 injection, the process results are different from CO_2. Figure 27 better explains the behavior of N_2 injection. The production rate seemed to be constant at 3000 stb/d for only two years and then started to decline sharply due to the increase of GOR. The pressure performance was odd, and was affected with the behavior of the individual wells. Same scenario took place with the GOR performance due to the distance between the two producers. Whereas, the enriched gas injection had, again, a different performance from the previous mentioned methods as shown in figure 28. The production profile for the enriched gas followed the CO_2 profile, but the pressure profile was most likely closer to the N_2 profile. Also, the solvent breakthrough was almost the same as the CO_2, this is due to the miscibility of N_2 was harder to reach than enriched and CO_2.The WAG (CO_2) process showed a better control on the GOR. However, the pressure performance was irregular and hard to maintain.

The production rate was constant at 3,000 stb/d for about five years (similar to CO_2) but it reached again a stabilized rate of 1,500 stb/day for about five years. The rate decline was less sharp than all other methods. The GOR performed the best among all other methods due to water injection (1:4 cycling ratio). Figure 29 better illustrates the behavior of the WAG injection. In conclusion, the selected method should always be aligned with the surface rate constraints and potentials (oil and gas rates).

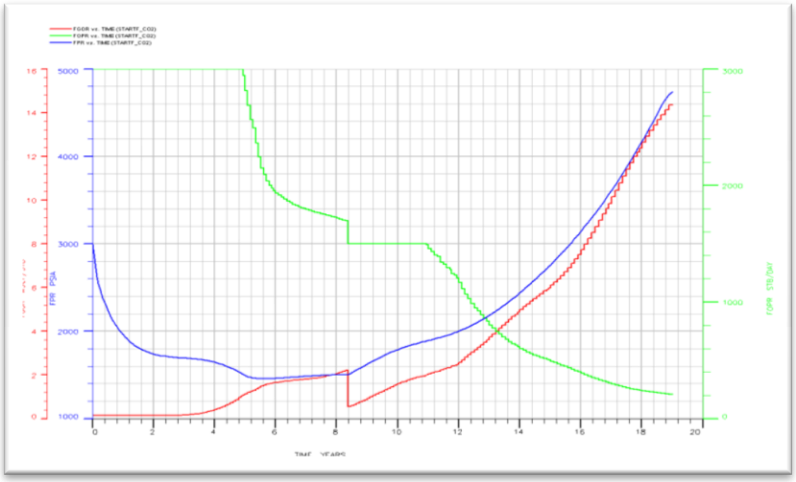

Figure 26. Pressure, Production Rate & GOR vs. Time, while injecting pure CO_2

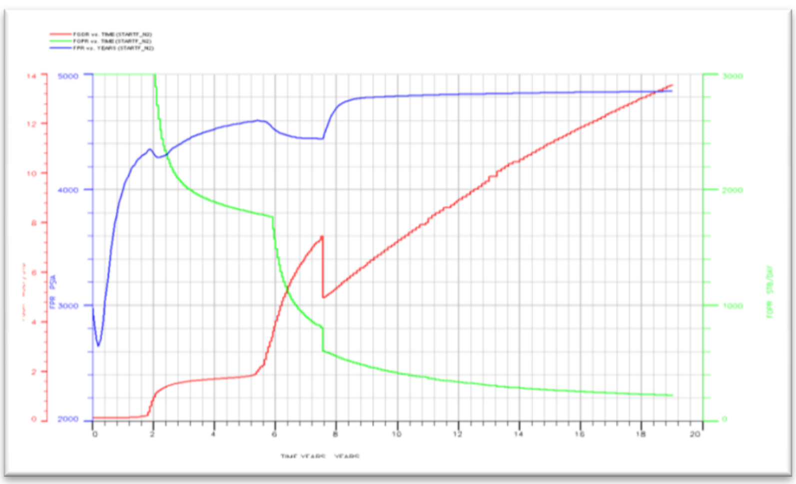

Figure 27. Pressure, Production Rate & GOR vs. Time, while injecting pure N_2

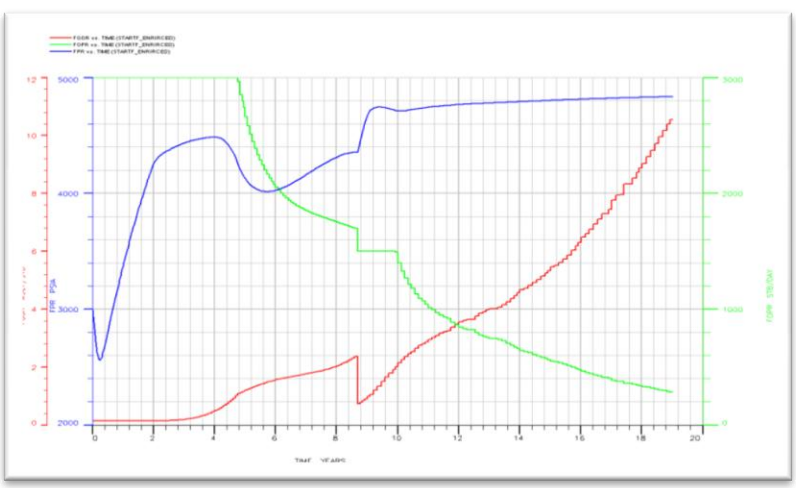

Figure 28. Pressure, Production Rate & GOR vs. Time, while injecting Enriched Gas

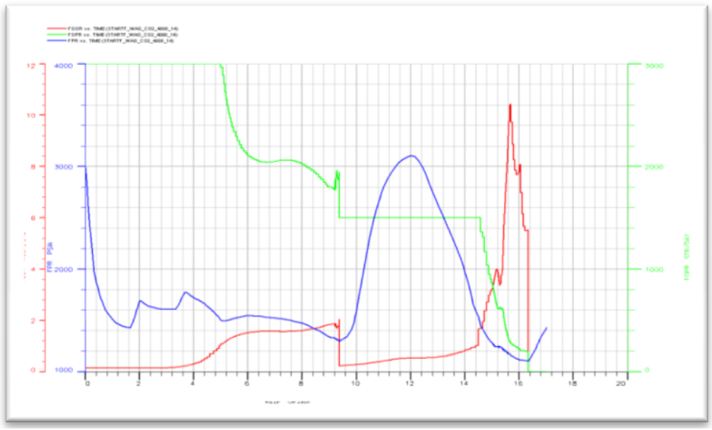

Figure 29. Pressure, Production Rate & GOR vs. Time, while injecting WAG (CO_2)

Thief Zone Effects on Oil Recovery while injecting CO_2 and WAG

The overall recovery of the model was enhanced from 86 to 94% while considering layer 2 as a thief zone of very high permeability (300md) when injecting CO_2 into the formation, this recovery performance is shown in figure 30. The most possible reason of such performance is that, in our conventional model layer 2 has got very low permeability of 0.01 md such that it would be acting like a burier for the fluid flow across the layers when the CO_2 was only injected solvent through layer 1 only.

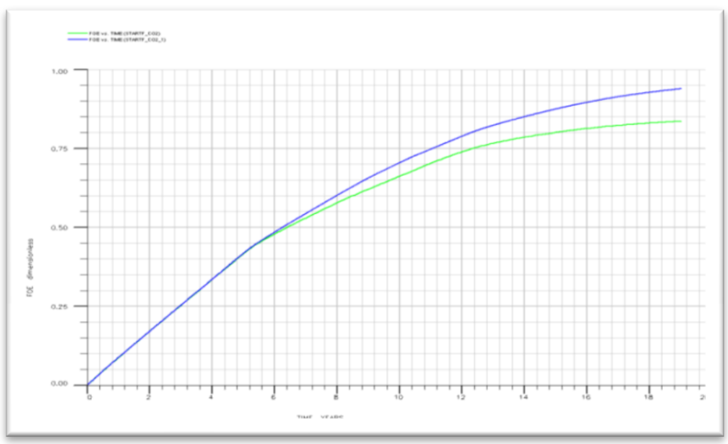

Figure 30. Effects of Thief zone on Recovery Factors while injecting CO_2

On the other hand, in the case of WAG injection the performance of the model was decreased by 1% and it got early water break through as well as due to huge water cut the production was stopped at 16th year when the 2nd layer was supposed to be taken as a thief zone of high permeability. Otherwise the conventional model was producing up to 91% for 17 years, as show in figure 31.

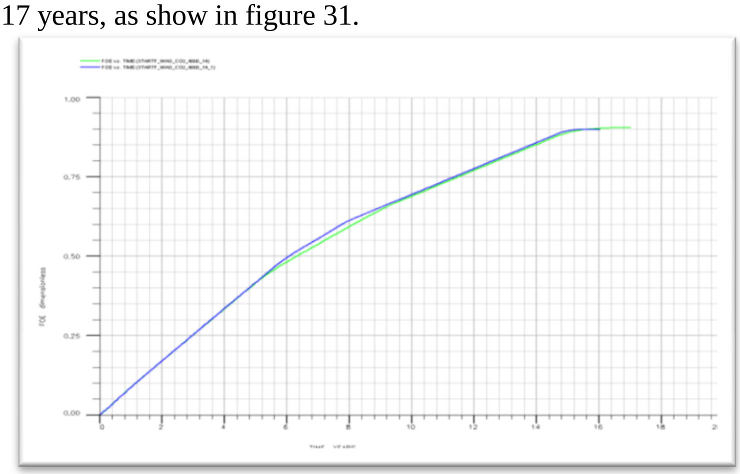

Figure 31. Effects of Thief zone on Recovery Factors while injecting WAG (CO_2)

Completion Effects on EOR Performance while injection CO_2 and WAG

There was exactly no difference found into the overall model performance by changing the competition profile of the injector well. Even we didn't observe any minute effect in figure 32 and 33 neither on flow period nor on the fluid recovery efficiency.

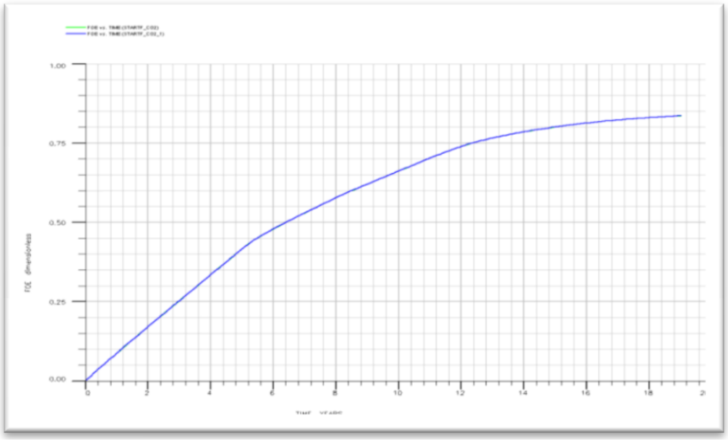

Figure 32. Effects of injecting CO_2 through different layers (layer 1 only and 1&2 both)

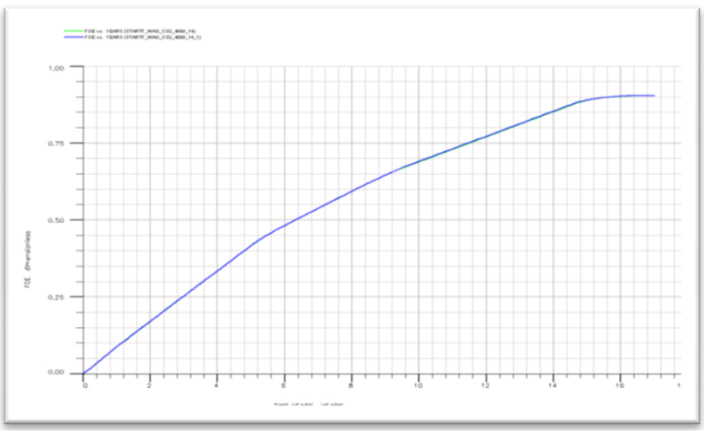

Figure 33. Effects of injecting WAG (CO_2) through different layers (layer 1 and 1 & 2 both)

Sensitivity Analysis

It includes the number of scenarios for the Water Alternating Gas (CO_2) EOR process to select the best recovery giving process in terms of WAG ratio and WAG cycling. Also the sensitivity is done to study the injection rates, Bottom Hole Flowing pressures and the injection gas composition. In all the scenarios the CO_2 injection rate is kept constant at 7000 MScf/D; while the water rate is varying, except one scenario in which we compared the recovery while injecting CO_2 at 5000, 6000 and 7000 MScf/D.

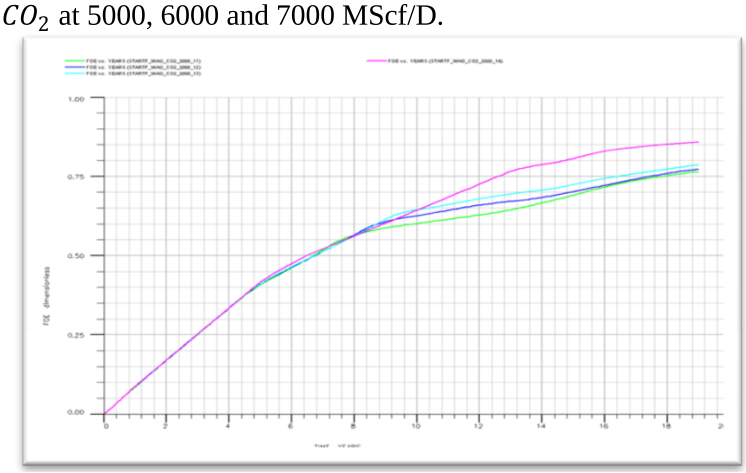

Figure 34. Water to CO_2 Ratio for WAG sensitivity at water injection of 2000 MScf/D

i. WAG Ratios and Cycling Sensitivity (Without thief Zone)

Figures 34-37 are showing the results of recovery while injecting water at 2000, 4000, 6000 & 8000 MScf/D with alternative CO_2 injection at a fixed rate of 7000 MScf/D with the ratio of 1:1,2,3 & 4 injection cycles. Among all the 4 selected sensitivity cases for the cycle and injection rate ratios water injection with 4000 MScf/D was found with best recovery for long lasting at the injection cycle of 1:4.

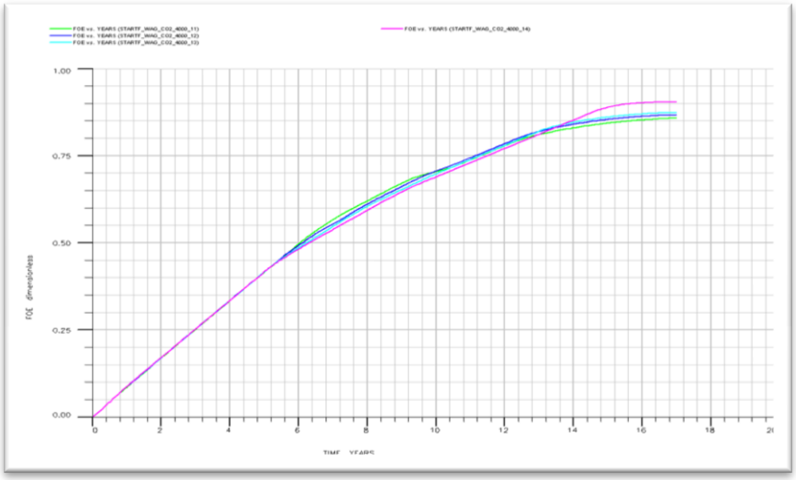

Figure 35. Water to CO_2 Ratio for WAG sensitivity at water injection of 4000 MScf/D

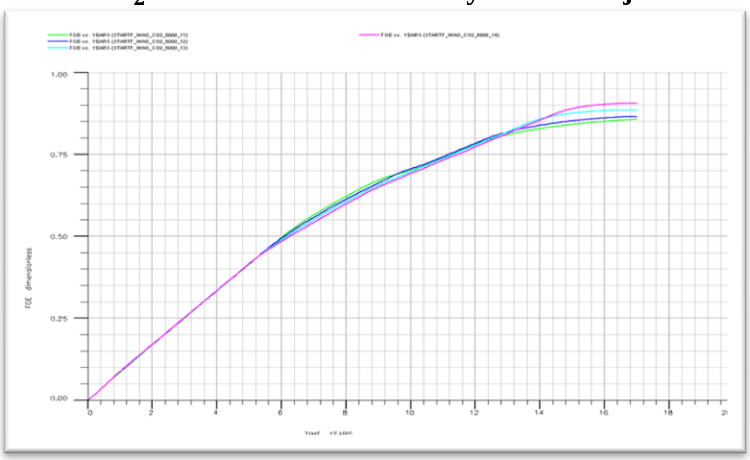

Figure 36. Water to CO_2 Ratio for WAG sensitivity at water injection of 6000 MScf/D

i. WAG Ratios and Cycling Sensitivity (With thief Zone)

The similar simulation runs were taken with the assumption of layer 2 as a thief zone (permeability 300 md). In these scenarios 6,000 and 8,000 stb/day injection of water gave the optimum recovery of about 91% in least time duration of the model life at the cycling ratio of 1:4.

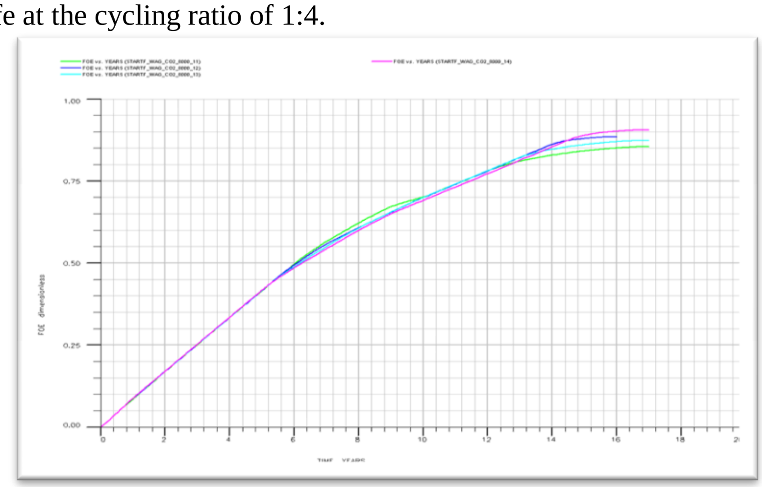

Figure 37. Water to CO_2 Ratio for WAG sensitivity at water injection of 8000 MScf/D

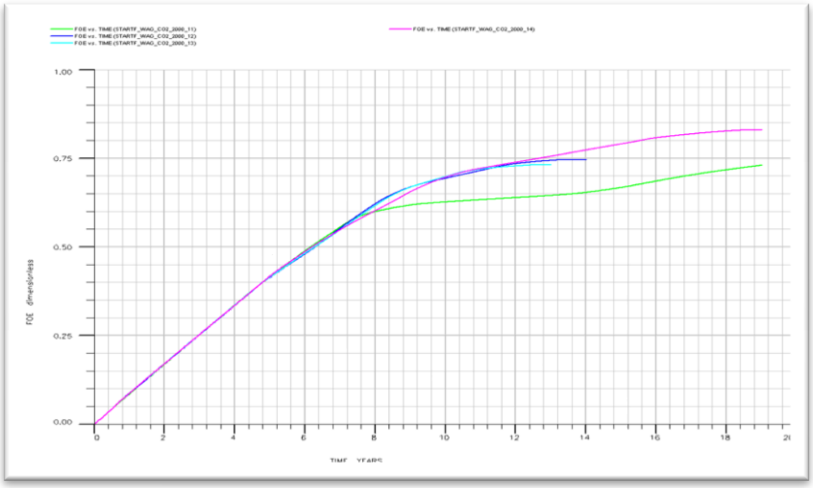

Figure 38. Water to CO_2 Ratio for WAG sensitivity at water injection of 2000 MScf/D

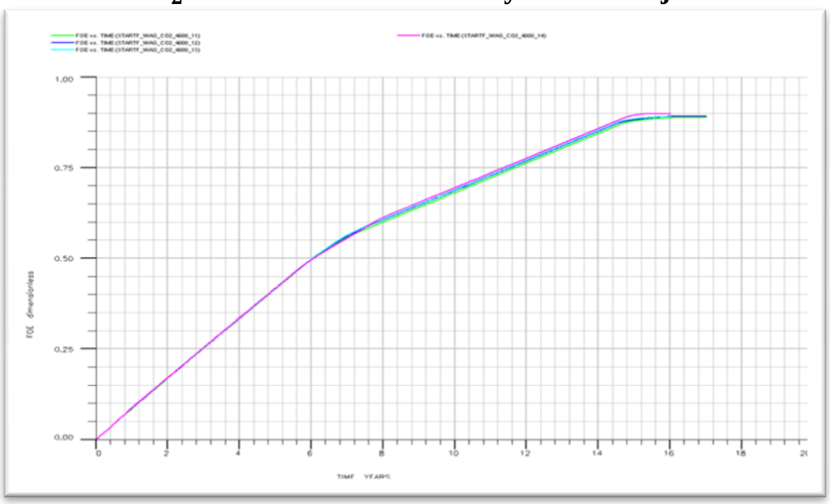

Figure 39. Water to CO_2 Ratio for WAG sensitivity at water injection of 4000 MScf/D

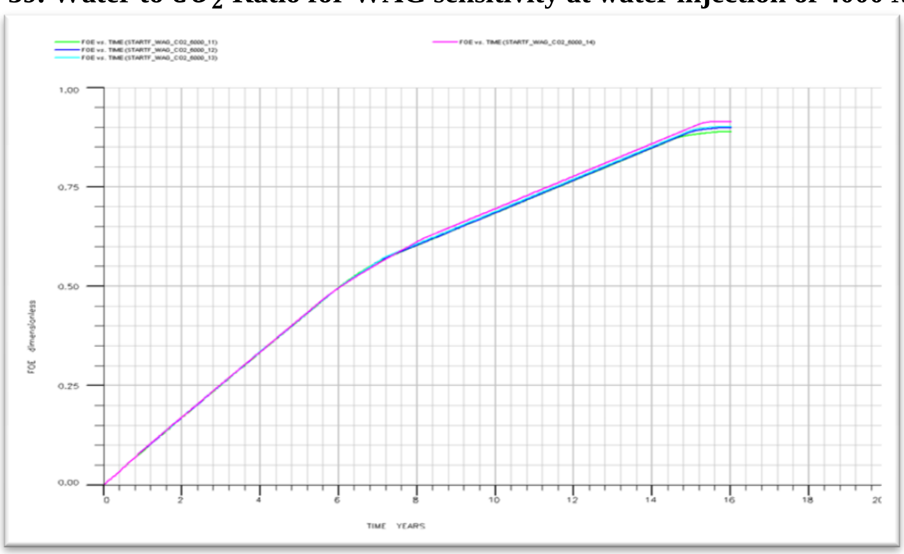

Figure 40. Water to CO_2 Ratio for WAG sensitivity at water injection of 6000 MScf/D

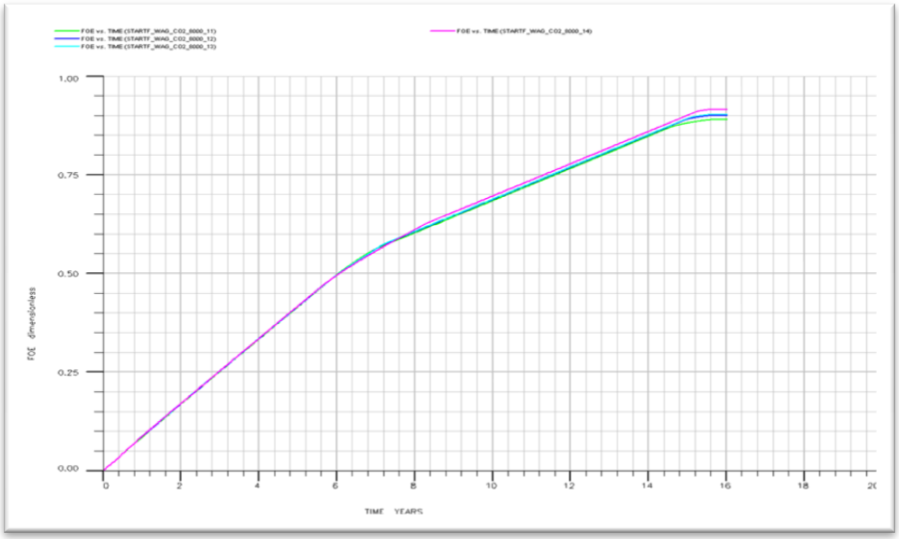

Figure 41. Water to CO_2 Ratio for WAG sensitivity at water injection of 8000 MScf/D

ii. WAG (CO_2) Injection Cycling Duration

Figures 42-44 show the reservoir behavior change to the change of the WAG cycling. Three different cycling durations were selected to compare which is the optimum duration. Figure 42 shows the recovery factor change while keeping the cycling duration up to 5, 10, and 15 years. And, 10 years of duration is found out to be the optimum (maximum) time where the recovery factor was found to be around 94% for a life time of 19 years. While, cycling the WAG for 5 and 15 years gave almost the same recovery factor of 90%. However, the only difference between 5 and 15 years cycling was the life time of process where 5 years cycling tended to reach its maximum recovery in 17 years, and 15 years cycling reach its maximum recovery in 19 years.

In addition, the pressure was plotted to compare the behavior in terms of pressure maintenance. As a result, 10 years cycling duration better maintained at around 3,000 psi and for a longer time. Figure 43 shows the behavior of pressure with the three selected cycling durations. For the 5 years cycling, the pressure increased at year ten and then declined at year twelve. On the other hand, the 15 years cycling behaved differently where it started to increase at year ten and did not decline again or maintained at 3,000 psi. Another comparison parameter was selected to compare the between the three cycling durations which was the CO_2 composition at well 2. It confirmed that CO_2 composition will be the highest when more CO_2 is injected which was the case of 15 years of cycling duration, and the vice versa was also verified by figure 44.

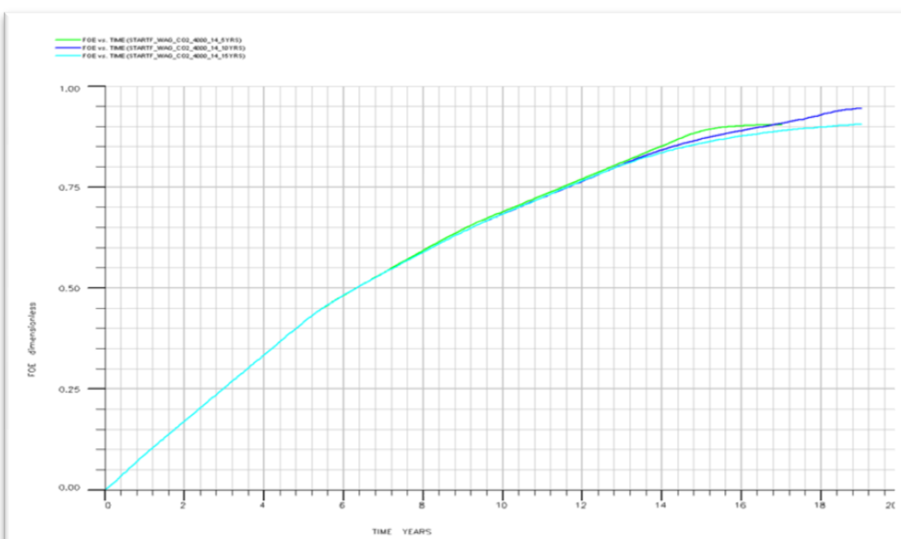

Figure 42. Recovery Factor Analysis of WAG injection for 5, 10 & 15 years

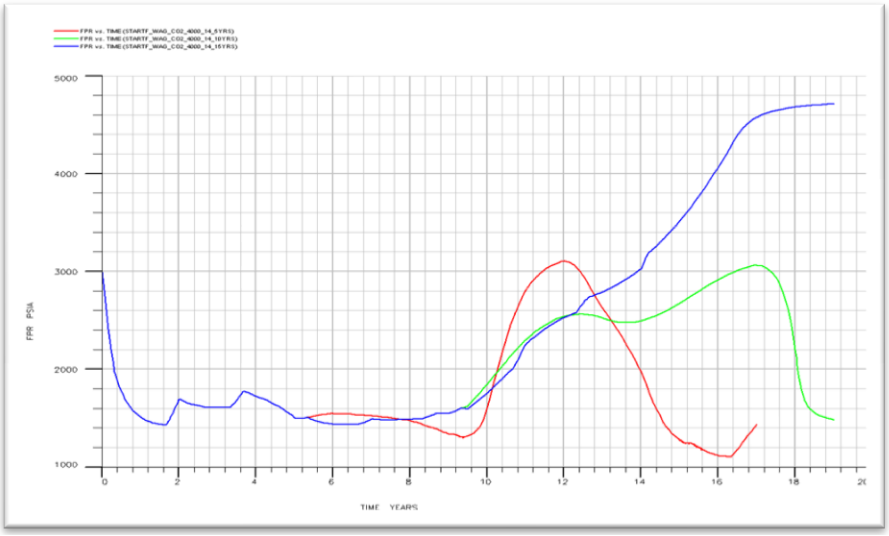

Figure 43. Field Pressure Analysis of WAG injection for 5, 10 & 15 years

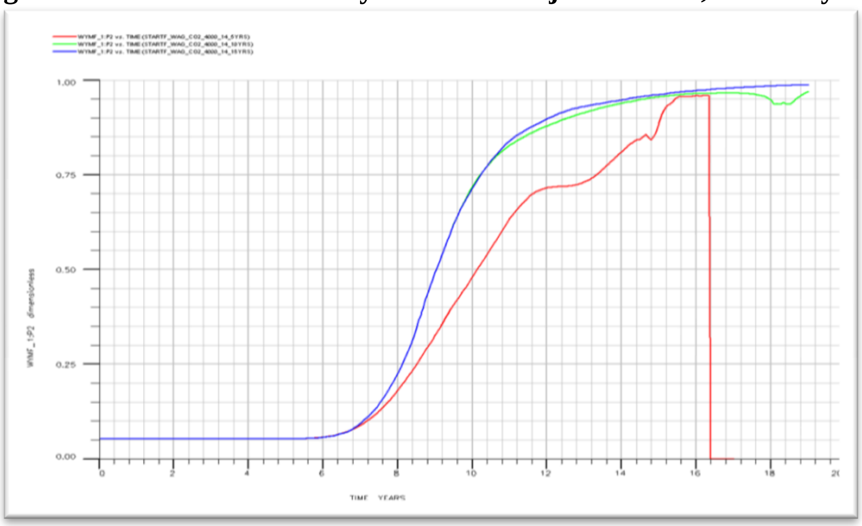

Figure 44. Producing Fluid Composition Analysis for WAG injection for 5, 10 & 15 years

iii. Injection Rate Sensitivity

Injection rate is usually set based on the field surface potentials. Yet, the need to investigate the optimum value from reservoir engineering prospective is very important. In this project, the solvent surface injection rate was set to be 7,000 scf/day for all EOR methods. Then, the injection rate was changed to 5,000 and 6,000 scf/day for CO_2 injection to find the optimum surface injection pressure. Figure 45 shows how the injection rate affected the recovery of the oil. Increasing the injection rate did not increase the recovery factor. In fact, the optimum injection rate was found to be 6,000 scf/day which resulted a recovery factor of 85%. Whereas, the 7,000 scf/day resulted a recovery factor of 84%, and 5,000 scf/day gave the least recovery factor value of 82%. This sensitivity proved that less injection rate than given in default model can be used to recover more oil which will, also, reflect in better surface power consumption!

iv. Bottom Hole Pressure Sensitivity

Bottom hole pressure is one of the most important factors on well productivity estimation. As the BHP increase, the production rate decreases. This fact indicates an inversely proportional relationship between the production rate and the BHP. In the default model, the BHP was set to be 200 psi for the both producers, and it resulted a recovery factor of 81%. Then, the BHP was changed to 2,000 psi for the both producers, and the recovery factor result was 48%. The difference was too high due to the huge difference in the BHP value for the two cases. Figure 46 better illustrates the mentioned results above. Note that this sensitivity was done only for the enriched gas method.

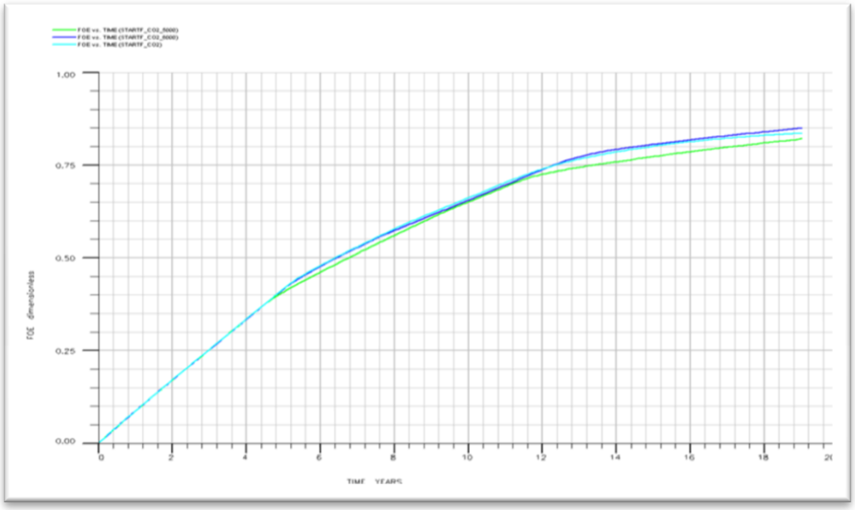

Figure 45. Recovery Factor at 5000, 6000 & 7000 MScf/D Injection Rate for CO_2

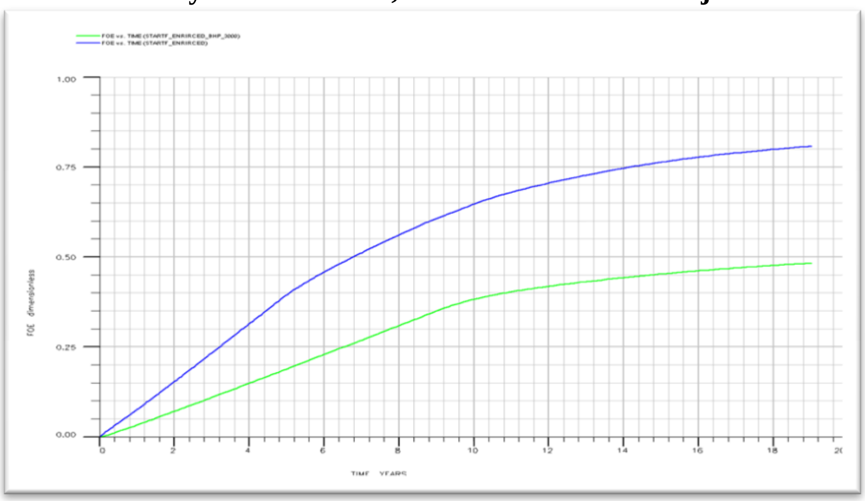

Figure 46. Recovery Factor at 200 & 3000 psi BHP for Enriched Gas Injection

v. Injection Gas Composition Sensitivity Analysis

The last sensitivity performed in this project was on the composition of the enriched gas. The default composition for the enriched gas was 40% of C3 (propane) and 60% of C1 (propane) injection. This proportion resulted in a recovery factor of 81%. Then, the enriched gas composition proportion was changed to 10% of C3 and 90% of C1, and it resulted in a little bit higher recovery factor which was 82%.

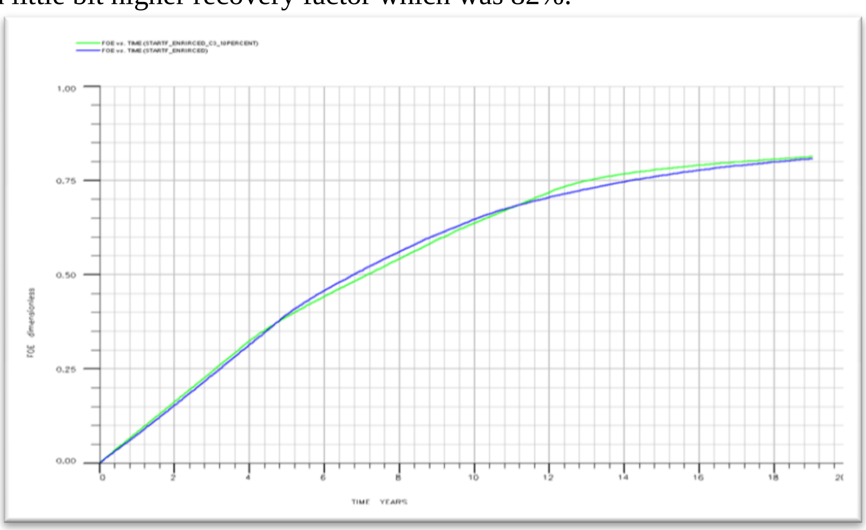

Figure 47. Recovery Factor for Enriched Gas Injection at 10% and 40% C3 Composition

Findings and Conclusions

- Water alternating CO_2 gives the highest recovery due to mobility control between the solvent and the reservoir fluid.
- Completing the injector in layers 1 and 2 gave WAG process the highest recovery, again.
- The enriched gas injection gives the highest recovery factor in the presence of thief zones (layer 2 acting as the thief zone) either completing the injector in layer 1 or layers 1 and 2.
- The injected solvent always gives its composition as the highest fraction at producers.
- WAG gives high methane recovery when completing and injecting WAG in layers 1 and 2.
- WAG injection controls gas oil ratio, and maintains it at the lowest values. And, it provides a stabilized oil production rate.
- Nitrogen injection has the best pressure maintenance while CO_2 injection has the least pressure maintenance control.
- The presence of thief zone in CO_2 injection gives higher recovery, while in WAG injection; thief zone has no effect on the recovery factor.
- Well completion shows no effect on recovery if injector is completed in either layer 1 or in layers 1 and 2 when injecting CO_2 or WAG.
- The optimum WAG ratio is found to be 4,000 stb/day of water and 7,000 Mscf/day of CO_2, with a cycling ratio of 1:4 without having a thief zone.
- Thief zone increases the optimum water injection rate for the WAG process and the cycling ratio is not affected.
- The optimum cycling duration for the WAG is 10 years to get the highest recovery factor.
- For the enriched gas, the optimum injection rate is found to be 6,000 Mscf/day.

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