CO_2 Miscible Flooding For Enhanced Oil Recovery

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***Abstract*—Enhanced Oil Recovery (EOR) is a technique applied for the recovery of oil from a petroleum reservoir beyond what is recoverable by primary and secondary approaches. The key aim of all EOR methods is to increase the macroscopic (volumetric) sweep efficiency as well as enhance the microscopic (displacement) efficiency, in comparison to an ordinary water flooding. One mechanism utilized is to reduce the mobility ratio between the displacing and displaced fluids thereby increasing the volumetric sweep. CO_2 flooding has remained an effective and widely used technique for enhanced oil recovery (EOR) methods. Compositional simulation is usually required for the evaluation of CO_2 flooding in EOR projects, especially when miscibility is of great concern (miscible flooding). The simulation technique proposed is the multi-dimensional, compositional modeling approach, generally applicable to porous reservoirs.**

This study tends to investigate the injection pressure conditions necessary to achieve miscibility, various injection patterns and how they affect miscibility as well as Well Placements and their effect on Oil Recovery. Six case scenarios were studied. Results from simulations show that the reservoir pressure is below the minimum miscibility pressure (MMP) of the CO_2. As such, for miscibility conditions to be established and maintained, the pressure conditions must be kept above the MMP. Injection pressure was also identified as a key parameter that influences oil recovery. Increase in injection pressure of CO_2 resulted to an increase in the performance of the flood project. The optimum injection rate was attained at 5000 Mscf/day above which any further increase in rate would not result to increased recovery. The effect of different well placements resulted in different oil productions. The case "F" well arrangement pattern gave the highest recovery.

Keywords—Enhance Oil Recovery, CO_2 Flooding, Minimum miscibility pressure, production, Optimum Injection, Simulation.

Introduction

Enhanced oil recovery (EOR) is a type of oil recovery which involves the injection of materials not originally present in the reservoir. Enhanced oil recovery processes are targeted at recovering oil which was unrecoverable by conventional approach. In the past 40 years Carbon dioxide (CO_2) flooding has been used as a commercial process for enhanced oil recovery (EOR) and has been reported to be the second most applied EOR process in the world (Jarrell *et al.*, 2002; Di *et al*., 2011). Field applications as well as laboratory studies have proved that CO_2 can be an efficient oil-displacing agent. It is been considered that the injection of CO_2 in mature hydrocarbon fields remains a favorable option to reduce atmospheric CO_2 accumulation and thus alleviate the effect of greenhouse on climate (Bradshaw and Cook, 2001; Di *et al*., 2011; Tian *et al.*, 2015).

Natural production is dependent on a reservoir's internal energy and arises due to the existence of a higher pressure in the rock pores than the bottom of the well. All other recovery metods depend completely on the provision of extra energy to improve the recovery of the remaining reserves. Most enhanced oil recovery methods provide the extra energy in mechanical form, by the injection a fluid which thus displaces those already in existence. This artificial sweep takes place under isothermal conditions. There are other recovery techniques in which only a small part of the energy supplied to the reservoir is mechanical. In thermal recovery method, the injected fluid in the form of mechanical energy has the capacity of supplying thermal energy to the reservoir. The thermal energy may be latent for example in the case of in-situ combustion, when the heat is generated by the reaction of oxygen in the injected air with part of the oil in place. The interaction that exists between the displaced fluid and the displacing fluid is greatly affected by temperature variations (Latil *et al.*, 1980). The chemical recovery method itself involves alkaline injection or caustic solutions into the reservoir with oils that contain naturally organic acids which will result in soap production that lowers the interfacial tension so much thereby increasing production. It also involves the injection of water soluble polymer to increase the amount of oil recovered in the formations. Microbial injection is another form of enhanced oil recovery but at the moment rarely used. The main intent of enhanced oil recovery techniques is to improve sweep efficiency through the reduction of the mobility ratio between injected and in-place fluids and also to get rid of or reduce the capillary and interfacial forces; thereby improving displacement efficiency and as well act on both phenomena simultaneously (Teknica, 2001)

Presently, slimtube technique is the most accepted approach in the industry. Slimtube is a small diameter tube (<0.25") with length up to 75 ft, packed with sand or glass beads that represents a one dimensional reservoir (Amao *et al*., 2012). For controlling the temperature of the slimtube, oven or water bath is normally used. Slimtube is saturated with crude oil and by gas flooding; then, the miscibility conditions are determined by applying different injection pressures. Each pressure of injection corresponds to a recovery factor resulted by 1.2 Pore Volume (PV) of injected gas. Finally, the oil recovery vs. pressure is plotted and interpretation is conducted to determine the MMP. MMP is determined as the breakthrough point in the recovery vs. pressure plot (Hamdi and Awang, 2014). Accurate estimation of the minimum miscibility pressure is important in conducting numerous simulation runs. MMP is the minimum miscibility pressure which defines whether the displacement mechanism in the reservoir is miscible or immiscible (Farzad and Amani, 2012). Miscible displacement is a process in which the injected and displaced phases mix in all proportions such that they do not form interfaces or two phases. The single-phase condition implies that all resident oil are displaced by the solvent from the pore space that it invades. Some fluids, like propane fulfill this definition, majority of the solvents available for oilfield use when combined with reservoir oils form two distinct phases over a wide range of mixtures and pressures (Mathiasson, 2003). Displacement fluids such as hydrocarbon solvents, CO_2 flue gas or nitrogen could be used as miscible fluid displacement methods. We have first contact miscible (FCM) and multiple contact miscible (MCM) on the basis of the manner in which miscibility is developed. First contact miscible fluids (FCM) form only a single phase upon first contact as the injected fluid is directly miscible with the reservoir oil at conditions of pressure and temperature existing in the reservoir. An example of FCM process is where liquefied petroleum gas (LPG) is injected to displace the oil. Conversely, in the case of MCM fluids, the injected fluid is not miscible with the reservoir at first contact. Miscible conditions are developed in-situ through composition alteration of the injected fluid or crude oil as the fluids move through the reservoir. The CO_2 miscible process is a type of MCM process. There are two classical mechanisms that have been identified for achieving multiple contact miscibility, which include the condensing gas drive and the vaporizing gas drive. CO_2 as injection gas for oil has been mentioned as early as 1916 in the literature but was dismissed as laboratory curiosity due to the absence of large and economically priced supplies. The first recorded CO_2 injection project was carried out in 1964 at the Ritchie field which was at small scale and later CO_2 was used as an immiscible secondary recovery mechanism in 1972 in the Permian basin (Mathiasson, 2003). CO_2 flooding now has wide usage in many countries of the world like-the US, Canada, Hungary, Turkey, Trinidad and Brazil. The US has the highest number of CO_2 flood projects probably due to the availability of CO_2 (Lui, 2013). Industrial experience has shown that CO2 injection is an effective EOR method for variable conventional reservoir (Gao and Towler, 2010; Liu, 2013). According to results of successful injections, CO2 miscible flooding worldwide indicates that using CO_2 as injection gas could yield an extra 7-15% of OOIP as incremental recovery (Crolet and Bonis, 1991; Mathiasson, 2003; Gao and Towler; 2012).

3.0 METHODOLOGY

The work targeted at increasing oil recovery when CO_2 is injected at various pressures in the reservoir. This will be carried out by simulation of the slim-tube experiment. It will also study the effect of well placement on the recovery. Both cases involved a dynamic modeling package, ECLIPSE. The implication of injecting the CO_2 above the minimum miscibility pressure (MMP) is thus to achieve miscibility with the reservoir fluid. When CO_2 is injected at pressures below the (<MMP), immiscible conditions exist in the reservoir. Dynamic miscibility of the CO_2 is generated as a vaporizing gas drive mechanism. CO_2 is not first contact miscible with the reservoir oil but develops miscibility under specific conditions of pressure and temperature. This work tries to study the injection pressure conditions necessary to achieve miscibility and also the effects of various injection patterns on miscibility.

3.1 Overview Reservoir

The reservoir under study (UCH-209) is situated in the Niger Delta in the South-South part of Nigeria. The reservoir is under-saturated and has bubble point pressure of 3616psia. The reservoir has an API gravity of 22.62 and oil density of 57.26 lb/ft^3 and rock compressibility of 1.053112E-6. Just like other nearby reservoirs in the same field, UCH-209 has a high permeability.

3.2 Reservoir Fluid Characterization

Precise and accurate characterization of a reservoir fluid is an imperative factor in reservoir simulation studies. The starting point was a 7-component equation of state (EOS) model for the original reservoir fluid, tuned to key experimental data including Differential Liberation and Constant Volume Depletion tests. The tuning procedure for the EOS parameters to match the available experimental PVT data was used to represent a more realistic fluid. The modified Peng-Robinson EOS was used for tuning (matching) the PVT data obtained from Differential Liberation and Constant Volume Depletion tests. The data tuned includes the liquid saturation, relative volume and gas compressibility factor and saturation pressure. The fluid used for the simulation was obtained from a Niger delta oil reservoir with an API gravity of 22.62 and a reservoir temperature of 163ºF. Laboratory results and data obtained from a slim tube experiment were used for the simulation. ECLIPSE's PVTi package (Schlumberger, 2001b) was used for fluid characterization and was used to develop the

PVT properties and the results were exported to ECLIPSE compositional simulator (Schlumberger, (2001a).

3.3 Special Core Analysis (SCAL) Input

The Corey correlation was used for the special core analysis. The necessary data like oil relative permeability, gas relative permeability (at minimum water saturation) and initial oil and gas saturations were utilized for the analysis as required. The input data was entered into the SCAL section as shown below.

Corey Correlations

Table entries: 11

Water		Gas		Oil	
Corey Water	4	Corey Gas	3	Corey Oil/Water	3
Swmin	0.2	Sgmin	0	Corey Oil/Gas	3
Swcr	0.24	Sgcr	0.02	Sorg	0.12
Swi	0.2	Sgi	0.67	Sorw	0.12
Swmax	1	Krg(Sorg)	0.78	Kro(Swmin)	0.9
Krw(Sorw)	0.433	Krg(Sgmax)	0.9	Kro(Sgmin)	0.9
Krw(Swmax)	1				

Fig. 1: SCAL input data

Row	Rs (MSCF/STB)	Pbub (PSIA)	FVF (rb /stb)	Visc (CPOISE)
1	0.048601066	500	1.0655951	5.9953073
2		736.84211	1.0615639	6.140326
3		973.68421	1.0595001	6.3405056
4		1210.5263	1.0582458	6.5871644
5		1447.3684	1.0574029	6.8753589
6		1684.2105	1.0567974	7.2020977
7		1921.0526	1.0563415	7.56551
8		2157.8947	1.0559858	7.9644017
9		2394.7368	1.0557005	8.3979959
10		2631.5789	1.0554667	8.865769
11		2868.4211	1.0552715	9.3673411
12		3105.2632	1.0551061	9.9023988

Fig. 2: Gas properties generated in SCAL

Row	Press (psia)	FVF (rb /Mscf)	Visc (cp)
1	500	6.0094058	0.013388697
2	736.84211	4.0016564	0.013693913
3	973.68421	2.9759909	0.014057535
4	1210.5263	2.3566172	0.014477439
5	1447.3684	1.9446327	0.014951856
6	1684.2105	1.6529841	0.01547826
7	1921.0526	1.4374796	0.016052789
8	2157.8947	1.2732331	0.016670057
9	2394.7368	1.145095	0.01732332
10	2631.5789	1.0432645	0.01800494
11	2868.4211	0.96108967	0.018707
12	3105.2632	0.89388404	0.019421922

Fig. 3: Oil properties generated in SCAL

The full table of the oil and gas saturations and relative permeabilities was generated and plotted as shown in the tables below.

SCAL Keywords - SCAL Section - Data Manager Module - ECLIPSE Office

SGOF (Gas/Oil Saturation Functions)

Row	Sg	Krg	Kro	Pc (psia)
1	0	0	0.9	0
2	0.02	0	0.82290098	0
3	0.1025	0.0015234375	0.55127937	0
4	0.185	0.0121875	0.34716135	0
5	0.2675	0.041132813	0.20090356	0
6	0.35	0.0975	0.10286262	0

Fig. 4: Gas relative permeability table and oil

SCAL Keywords - SCAL Section - Data Manager Module - ECLIPSE Office

SWOF (Water/Oil Saturation Functions)

Row	Sw	Krw	Kro	Pc (psia)
1	0.2	0	0.9	0
2	0.24	0	0.75033584	0
3	0.32	0.00010571289	0.5026664	0
4	0.4	0.0016914063	0.31654793	0
5	0.48	0.0085627441	0.18318746	0
6	0.56	0.0270625	0.09379198	0

Fig. 5: Water and oil relative permeability table.

3.4 Simulation Model Description

The model was built for the representation of the whole field. The model has Cartesian coordinates with block-centered geometry having length of 100 ft. in the X and Y directions. The number of grids selected was 10 ×10×7 and the top of the reservoir was 7000ft with a reference reservoir pressure of 3616psia while its reference depth is 7100ft. The reservoir is a consolidated sandstone type. The model consists of 1 injector and 1 producer at the boundaries. The Water Oil Contact (WOC) was 7230ft while Gas Oil Contact (GOC) 7050ft. The rock compressibility was 1.053112E-6 per psi. This well placement patterns was focused on sensitivity runs. Injection was performed for a period of 162.845days while simulation runs lasted for 15 years.

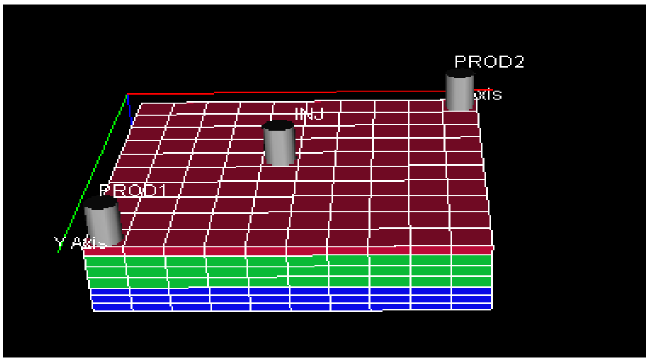

Fig. 6: Reservoir model showing 2 Producer wells and 1 Injector well.

The factors (input variables) which were sensitized in this work include- injection pressures, injection rates and well placement forms. The injected CO_2 is only miscible when it is injected at pressures above the MMP. The response variables were oil production and recovery factor. The results of simulation runs (as the response variables) were obtained after several runs while keeping some variables constant at optimized conditions.

3.5 Study of the Effects of Well Placements on Oil Recovery

It is important to account for the placement of wells in order to achieve optimal recovery and hence maximize recovery. In this study, well placement was considered. The wells were arranged in various forms along **I** & **J** grids and the effects on recovery were noted. Running sensitivity on well placement patterns during injection is important, bearing in mind the possibility of drilling new wells in the future. The well placement and arrangement is dependent on a lot of variable factors which includes availability of drilling sites for new wells. 6 different well placement patterns were investigated by ascertaining and comparing their various oil productions with the view of determining the well placement pattern that will maximize oil recovery. Basically the well placement format consisted of 2 producers and 1 injector. The injector well was kept static while the 2 producers were varied in terms of location for the sensitivity runs. The various placement patterns studied were divided into 6 cases and denoted as cases: **A, B, C, D, E, and F.**

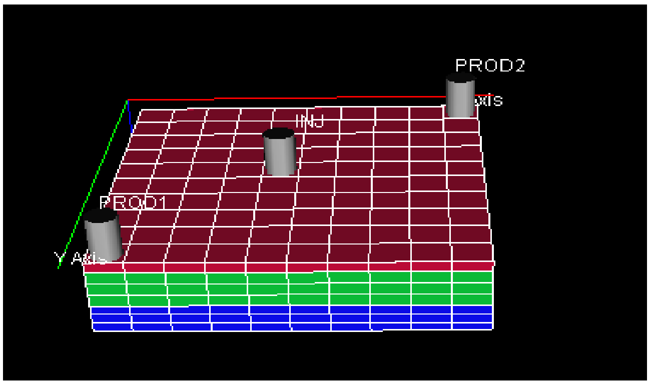

Fig. 7: **Case "A"** well arrangement.

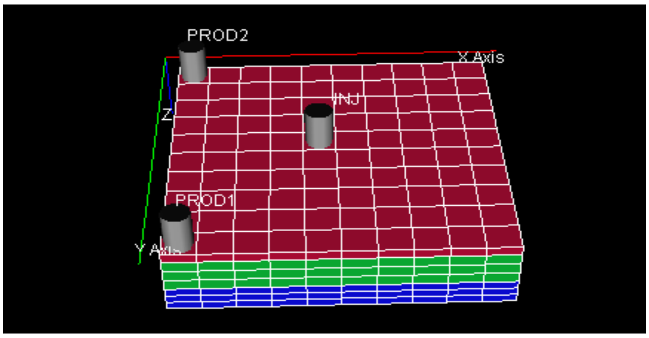

Fig. 8: **Case "B"** well arrangement

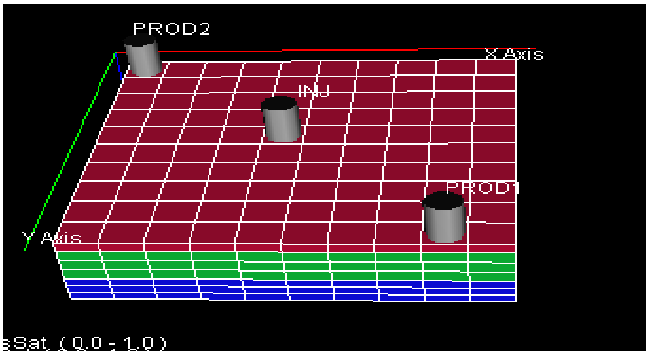

Fig. 9: **Case "C"** well arrangement

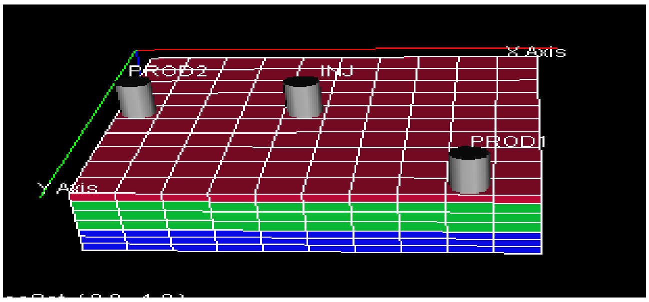

Fig. 10: **Case "D"** well arrangement

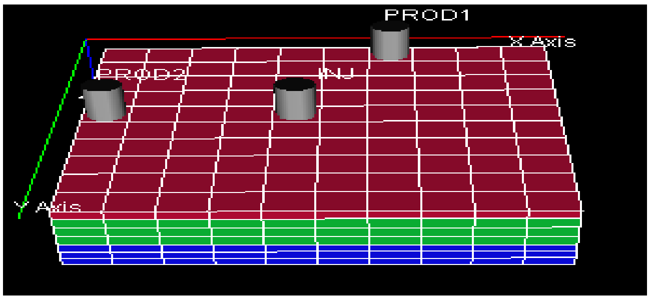

Fig. 11: **Case "E"** well arrangement

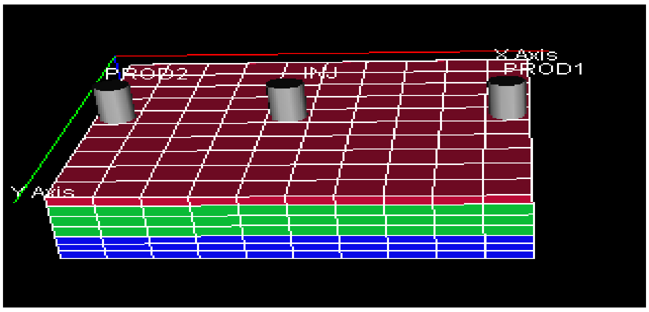

Fig. 12: **Case "F"** well arrangement

RESULTS AND ANALYSIS

The incremental oil recovery is largely dependent on the injection pressure. The effect of injection rate and various well placements patterns on oil recovery are analyzed below.

4.1 Slime-Tube Simulation

The slim tube simulation was carried out to determine the MMP**.** Injection of CO_2 was carried out at various pressures. A series of simulation runs was conducted at specified pressures. The CO_2 was injected at a constant rate while the injection pressures were varied ranging from 1000 psia to

10,000 psia. The corresponding oil productions were also recorded for simulation run for a period of 15years, from 2002 to 2016. The estimated MMP is about 4000 psia. Above this injection pressure, a significant increase in oil recovery as much as 17.02% higher than that from natural depletion was noticed at an injection pressure of 10,000 psia. From the simulation runs, the MMP of the CO_2 is above the reservoir reference pressure (3616 psia). Hence the CO_2 must be injected at pressures above the MMP in order to attain miscibility with the reservoir oil at reservoir conditions. At reservoir pressures above 4000 Psia, there was a substantive chance for increased oil production.

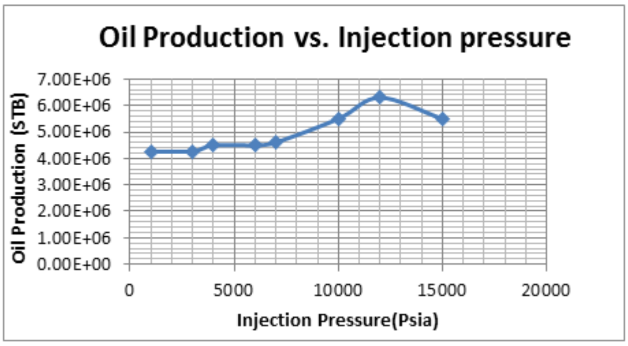

Fig. 13: Oil production vs. Injection rate plot

From fig. 13 above, when there was no injection of CO_2 (i.e. a case of natural depletion), the oil production was just 3.44954E6 STB which translates to a recovery of just 28.62%. Oil recovery could be as high as 45.65% at injection pressure of 10000 psia and could increase at higher injection pressures. This shows that the CO_2 injection project is worthwhile and should be embarked upon. The CO_2 injection gave an incremental recovery of about 17.02% (@injection pressure of 10,000 psia). The recovery could still increase with an increase in the injection pressure.

4.2 Effect of Injection Rates on Oil Recovery

Sensitivity studies were run with 7 injection rates ranging from 500 to 9000 Mscf/day and the effect of each rate on oil production was analyzed. The injection pressure was kept constant at 4000 Psia throughout the sensitivity run.

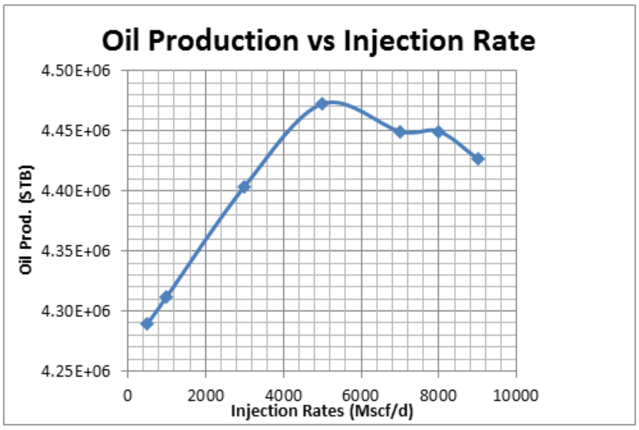

Fig. 14: plot of Oil production vs. Injection rates

From the above graph, it can be seen that the optimum injection rate was attained at 5000 Mscf/day. Increased oil production up to the optimum injection rate is almost linear. Further increase in the injection rate above this value does not result to any incremental oil recovery and hence not economical. It is important to note that increase in injection rates does not automatically translate to increase in income because of the cost of the injected CO_2. As such, a balance must be struck which is the optimum injection rate which should be considered alongside with varying economic conditions. The optimum injection rate will depend on the prevailing economic conditions of the operating environment.

4.3 Effects of Well Placement on Oil Production

It has been stated that the arrangement of wells along the grid could affect the oil production. The injection pattern considered is the 5spot pattern. During the sensitivity runs, the position of the injector was kept constant (at a cell location of 5, 5 for the I & J location) while that of the 4 producers were varied and were shown as the results for the various cases of well locations. The injection pressure and rate of 4000 Psia and 5000 Mscf/day respectively was kept constant throughout the sensitivity runs. The CO_2 injection was carried out for a period of 6years as recorded in the table below which also shows the performance of each of the 4 producers throughout the injection years.

Table 1: Oil production for the various grid arrangements for the injection period.

Well arrangements	Injection time (Years)	Oil Production for the various 4 producers				Oil Production for (STB)	Oil recovery (%)
		Prod1	Prod2	Prod3	Prod4		
Case **"A"**	1	1.104E6	1.144E6	1.114E6	1.134E6	4.49541E6	37.06
Case **"B"**	2	1.087E6	1.057E6	1.084E6	1.060E6	4.28899E6	35.60
Case **"C"**	3	1.090E6	1.112E6	1.113E6	1.090E6	4.40367E6	36.51
Case **"D"**	4	1.321E6	1.293E6	1.319E6	1.295E6	5.22936E6	43.35
Case **"E"**	5	1.261E6	1.239E6	1.263E6	1.237E6	5.00000E6	41.74
Case **"F"**	6	1.361E6	1.337E6	1.365E6	1.333E6	5.3945E6	44.50

The result of the investigation shows that the well placement/arrangement that performed best was that of case "**F"** which shows a recovery of 44.5% followed by case "**D"**, case "**E"**, case "**A"**, case "**C"** and finally case "**B"** in that other. The results are shown in the chat below.

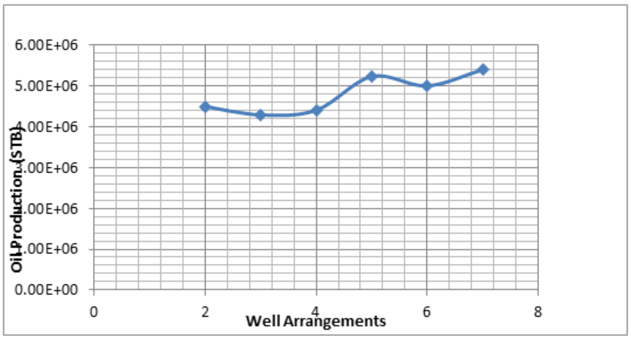

Fig. 15: A chat of oil recovery for different well placements.

. CONCLUSION

A methodology to assess CO_2 miscible flooding for enhanced oil recovery in one of the Niger-delta fields has been established in this work. A model was built for predicting the performance of CO_2 injection for the reservoir under study.

Results from slim-tube simulations show that the reservoir pressure is below the MMP of the CO_2. Thus, for miscibility conditions to be established and maintained, the pressure conditions must be kept above the MMP. Increase in injection pressure of CO_2 resulted to an increase in the performance of the flood project. In the same vein, an increase in the injection rate also resulted to a higher performance of the flood project. The optimum injection rate was attained at 5000 Mscf/day above which any further increase in rate would not result to increased recovery. The effect of different well placements resulted in different oil productions. The case **"F"** well arrangement pattern showed the highest recovery. Optimized scenario for the miscible CO_2 injection could yield an incremental recovery as high as 22.29% compared with natural depletion, which shows prospect of the project.

In spite of the predictions from this model, it is important to note that results generated in this study largely depend on prevailing economic conditions and operators' discretion

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Nomenclature/Abbreviations

(EOR) Enhanced oil recovery

(Kro) Oil relative permeability

(Krw) Water relative permeability

(MMP) Minimum miscibility pressure.

(IFT) Interfacial tension

(PVT) Pressure volume and temperature

(SCAL) Special core analysis

(GOC) Gas oil contact

(WOC) Water oil contact

(STB) Stock tank barrel

(Mscf) Thousand standard cubic feet

(FCM) First contact miscible

(MCM) Multiple contact miscible

(EOS) Equation of state

(LPG) Liquefied petroleum gas

(P—X) Pressure-Composition

(P—T) Pressure-Temperature