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Prospects of Supercritical CO_2 Injection for Niger Delta Heavy Oil-Fields Recovery

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Abstract

This study assesses the potential of supercritical CO_2 injection for the recovery of heavy oil in the Niger Delta Z-field, characterized by high viscosity crude with an API gravity of 18.6 API. Given the challenges posed by the viscosity of the reservoir fluid, conventional primary and secondary production schemes were deemed impractical. As a solution, hot supercritical CO_2, was chosen as an enhanced oil recovery (EOR) method due to its miscibility properties with oil and the environmental benefit of reducing atmospheric CO_2 concentrations. In the EOR process, supercritical CO_2 with a viscosity of 0.095 cP was injected at a pressure of 3500 psia and a temperature of 200°F, above the Minimum Miscibility Pressure (MMP) to ensure miscibility with the reservoir fluids and mobilization of residual oil. The CO_2 was heated at the surface and injected as hot CO_2 to achieve viscosity reduction by heating up the reservoir fluid. The injected CO_2, meeting the reservoir oil at miscible conditions, reduces the interfacial tension between the oil and the injected CO_2, leading to oil phase swelling. The study employed a compositional simulator for the simulation of CO_2 flooding, comparing two cases: natural depletion and supercritical (hot) CO_2 injection. The simulation results after 5000 days of recovery indicate a recovery efficiency of 3.3% for the natural depletion case. In contrast, the supercritical CO_2 EOR case demonstrates a remarkable recovery efficiency of 73%. Additionally, the analysis of gas recovery shows no significant difference between the two cases. These results show that natural depletion is not feasible for heavy oil recovery due to the low energy (dissolved gas) present in the oil at reservoir conditions and the inhibiting high viscous forces of the reservoir fluid that impede flow to the surface. In contrast, the deployment of hot CO_2 injection emerges as a highly promising and substantial prospect for the recovery of heavy oil in the Z-field. The study suggests that this process should be considered for application in the recovery of other non-conventional heavy oil fields in the Niger Delta, particularly those that are not extractable through primary and secondary drive mechanisms. The success of hot CO_2 injection, with its ability to reduce viscosity, achieve miscibility, and enhance recovery efficiency, positions it as a viable and environmentally beneficial EOR strategy for heavy oil reservoirs.

Keywords: *Supercritical; Hot CO_2; Recovery efficiency; Injection; Minimum miscibility pressure.*

1. Introduction

Production from oil reservoirs is accompanied by pressure decline. The primary and secondary energy at a point may not be sufficient to maintain profitable recovery from the reservoir [1]. Primary means of recovery uses energy inherent in the reservoir at discovery and are supplemented by secondary recovery means which majorly involves gas or waterflooding. Sufficient volume of oil is still left unrecovered even after primary and secondary recovery means [2]. This residual oil can only be recovered by more robust and sophisticated technology offered by enhanced oil recovery methods. Enhanced oil recovery (EOR) methods provide means for the recovery of oil that otherwise cannot be recovered by primary and secondary methods [3-4]. Amongst the several EOR methods available, CO_2-EOR has attracted positive and renewed attentions. Due to its availability, relative low cost and environmental concerns, CO_2-EOR has been used as the choice EOR technique by most operators [5]. CO_2-EOR has dual advantage of environmental CO_2 emission reduction and oil recovery in its implementation in

EOR processes. It has become more preferred to hydrocarbon gases in solvent EOR techniques because in addition to improved oil recovery, there is significant reduction in greenhouse gases due to increased volumes of CO_2 usage [6].

In light oil recovery, CO_2 has found extensive application. Its high solubility in light oil is a remarkable feature. CO_2 achieves miscibility in light oils in first contact or multiple contacts improving volumetric and displacement efficiencies. The miscibility depends on pressure, temperature and oil properties. Miscible flooding comprises mobilizing the oil light components, viscosity reduction, oil swelling, and interfacial tension reduction [7-9].

In recent years, heavy oil resources have gained prominence as a significant unconventional resource globally, notably in countries such as Canada, Venezuela, Kazakhstan, and Russia [10-11]. Nigeria, too, possesses widespread heavy oil reservoirs, with onshore and offshore heavy oil and bitumen constituting approximately a good percentage of Nigeria's total oil reserve [12]. The inherent challenge in developing heavy oil lies in its high viscosity compared to light oil. Various methods have been proposed to address this challenge, including in-situ combustion, steam stimulation, steam flooding, and steam-assisted gravity drainage (SAGD) [13]. The first three methods achieve oil viscosity reduction by injecting steam at high temperatures (>250°C) to raise the temperature of the heavy oil [14-15]. In-situ combustion involves injecting oxygen gas into the hydrocarbon reservoir, initiating crude oil combustion to generate heat and increase the temperature of the heavy oil [16]. As heavy oil viscosity is temperature-dependent, these methods effectively enhance production. However, a drawback of these approaches is the increase in CO_2 emissions which contributes to air pollution [17-19]. Additionally, these conventional methods often incur low economic profitability.

Non-condensing gases have been widely applied to thermal oil recoveries with notable performances. Non-condensate gases utilized in thermal oil recovery include N_2, CO_2, CH_4, and CO [20-22]. N_2 injection efficiently reduces steam injection and minimizes heat transfer between the steam chamber and the cap rock. However, due to the low solubility of N_2 in heavy oil, its impact on the PVT behaviour of heavy oil is limited. CH_4 and CO exhibit better solubility than N_2 and enhances oil recovery (EOR) in heavy-oil reservoirs [23]. Nevertheless, these processes are intricate, sensitive, and face limitations related to pollution, recycling, security, and economic viability, particularly considering fluctuations in crude oil prices.

CO_2, being widely available and cost-effective, proves beneficial for EOR due to its high solubility in oil, leading to a significant reduction in viscosity and an increase in volume [24]. Furthermore, considering environmental concerns, CO_2-enhanced oil recovery (CO_2-EOR) emerges as a potentially more suitable method for heavy oil production. CO_2-EOR not only addresses heavy oil viscosity but also aligns with environmental protection goals by minimizing CO_2 emissions [25-27]. Literature reports remarkable decrease in oil viscosity with CO_2 injection, and its solubility in heavy crude oil at moderate pressure (1.0–6.0 MPa) can reach about 50–100 m^3/m^3. This results in a 10–20% increase in oil volume and over an 80% reduction in viscosity [28]. The dissolution of CO_2 enhances the elastic energy of oil, converting remaining oil into movable oil [22]. CO_2 dissolution also reduces interfacial properties of the oil-CO_2 system, increasing oil-relative permeability [56]. Additionally, CO_2 extraction facilitates the extraction of light and intermediate hydrocarbon components, further aiding oil recovery [29]. Injected CO_2 primarily occupies the pore volume previously filled by oil, and about 60% of the injected CO_2 remains in the formation, representing an environmentally friendly approach [30].

Many scholars have investigated the application of steam-assisted and CO_2 methods in heavy oil reservoirs. Al-Quraini *et al.* [31] utilized numerical simulation to compare CO_2 flooding, water flooding, and alternative injection of a CO_2 and steam mixture in a heavy-oil reservoir, revealing that CO_2 gas displacement outperformed water flooding. Parracello *et al.* [32] conducted core-flooding tests, demonstrating the effective increase in oil recovery with CO_2 injection in a heavy-oil reservoir. Zheng *et al.* [33] studied the effects of well configurations on pressure maintenance and oil recovery with CO_2 injection in heavy-oil reservoirs, highlighting the benefits of pressure maintenance with CO_2 injection.

Zolghadr *et al.*, [34] worked on temperature and composition effect on CO_2 miscibility by interfacial tension measurement. They produced results for various pure and mixtures of hydrocarbons fluids. Their results show that for pressures up to 5.2 MPa, the measured interfacial tension decreased with increase in temperature. But for pressures higher than 5.2 MPa, increase in temperature led to an increase in the interfacial tension between the injected CO_2 and the reservoir crude oil. They also investigated the effect of paraffin on the CO_2-crude oil MMP. They realize that the heavier paraffin was, the higher was the MMP noticed. They conclude that paraffin groups pose significant effect on multi-component interfacial tension characteristics

Kavousi *et al.* [35] explored CO_2 solubility and molecular diffusion in a heavy crude oil system, emphasizing the increased CO_2 solubility and diffusion achieved through a thermal process followed by CO_2 injection.

Cao and Gu [36] studied the mechanisms of oil recovery from immiscible CO_2 flooding process in core samples of tight sandstone reservoirs. They reported that oil recovery increases with injection pressure increase and oil recovery increase was owing to the reductions of oil viscosity and interfacial tension, and the increase of CO_2 solubility.

Hemmati-Sarapardeh *et al.* [37] studied the IFT of CO_2 and crude oil using an axisymmetric drop shape analysis (ADSA) at different temperatures and pressures. Their result revealed that for a lower pressure region, IFT decreases with increase in temperature while at higher pressure region, IFT increases with increase in temperature. Furthermore, they realized that MMP and maximum pressure increased linearly with temperature. They also found out that paraffin has a critical effect on the crude oil/CO_2 IFT behavior. They observed also that the lower the ratio of resin-to-asphaltene the greater the possibility of asphaltene precipitation. They further observed that the higher the molecular weight of heavier components of the crude oil, the higher will be the MMP obtained.

Bikkina *et al.* [38] conducted laboratory experiments to investigate the effect of reservoir wettability on the efficiency of CO_2 -EOR process. He discovered that oil recovery was considerably higher in oil-wet core samples than in water-wet ones. Mansour *et al.* [44] studied the effects of injectant CO_2 density on the performance of crude oils. They found that as the CO_2 density increases, the higher the heavier hydrocarbons extractable by the CO_2 in the reservoir. Thus, dense CO_2 extracts more and heavier hydrocarbons than light CO_2

Dong *et al.* [39] compared SAGD, SAGP, and multiple thermal fluid-assisted gravity drainage (MFAGD) processes, showing that MFAGD processes with CO_2 had higher oil recovery and lower steam injecting volumes. Seyyedsar and Sohrabi [40] investigated intermittent CO_2 and viscosity-reducing gas (VRG) injection for enhanced heavy-oil recovery (EHOR), demonstrating the importance of CO_2 in extracting hydrocarbons and achieving higher recovery.

While these studies have investigated the main EOR mechanisms of CO_2 injection and demonstrated its corresponding performance in SAGD processes, there is still limited quantitative research on CO_2 solubility in heavy-oil reservoirs and its effects on the density and viscosity of heavy oil [41]. Many scholars have studied the application of CO_2-EOR to heavy oil.

Few researchers have attempted the use of CO_2 on heavy oil. Among the literatures in this area are: Kok and Bagci [42] worked on the effect of CO_2-EOR and injection rate on heavy oil. They noticed CO_2 breakthrough shortly after the commencement of the experiment. They related this effect to viscous force and mass transfer between CO_2 and the oil. They generally discovered that oil recovery was improved on higher injection rates of CO_2. Torabi [43] experimentally studied on the effect of oil viscosity, injection rates, and permeability on the performance of heavy oil water flooding. Mansour *et al.* [44] studied the effect of CO_2 on the viscosity of heavy crudes. He observed that the viscosity of the CO_2-oil system was decreased greatly on addition of CO_2. This is as a result of the addition of less viscous and lighter CO_2 to the more viscous oil phase. Of course, the reduction in the crude oil viscosity will increase the mobility ratio and increase recovery efficiency.

Huang *et al.* [6] used CO_2 flooding strategy to enhance oil recovery in heavy oil reservoirs. He applied experimental and numerical simulation approach. He suggested an optimisation of pressure control scheme in CO_2 injection so as to maximize the CO_2 injection performance for higher heavy oil recovery.

2. Supercritical CO_2-EOR

CO_2 is termed supercritical when it is in a state above its critical properties (temperature and pressure). The critical point of CO_2 is at 87.8°F and 1,070 psi. Supercritical CO_2 can be achieved by increasing the temperature and pressure of the CO_2 fluid. Hot CO_2 flooding is an EOR means where supercritical CO_2 is injected to mobilize residual oil. In hot injection, CO_2 is heated, pressurized and injected into the reservoir through the injection wells. CO_2 is heated at the surface and injected into the reservoir. The CO_2 on its own is a non-hydrocarbon gas, it functions under two principle which are miscible CO_2 flooding and immiscible CO_2 flooding. The disparity between the two mechanisms is the injection pressure. CO_2 will usually not mix with oil at the first contact in the reservoir – there is not distinct CO_2-flood front, and CO_2 saturation changes with distance from injection well [45].

Minimum miscibility pressure (MMP) is the main prerequisite for miscible CO_2-EOR. If the injection pressure is greater than the minimum miscibility pressure (MMP) of the CO_2 and the reservoir oil, then the injected CO_2 mixes with the oil at that reservoir condition. But if the CO_2 injection pressure is less than the MMP, then the injected CO_2 will not mix with the reservoir oil and the injected CO_2 will only achieve 'piston-like displacement' when it comes in contact with the oil [46]. Hot CO_2 includes combination of thermal and solvent techniques where miscibility and viscosity reduction are primary concern. In the hot method, CO_2 will be superheated above the reservoir temperature to reduce the oil viscosities at the same time partially mix with crude oil which improves oil mobility [47].

2.1 Screening criteria for Hot CO_2 flooding

The screening criteria help to understand the range of applicability of EOR means. This work considered the following screening criteria for the Hot CO_2 injection as presented in Table1.

Table 1. Screening criteria for some EOR methods [46,48].

Screening Parameter	Steam injection	CO_2 miscible	CO_2 Immiscible	Hot CO_2
Oil gravity °API	10° - 34°	>25	10° -25°	10°-45°
Depth (ft)	<15000	>3000	>2300	2300-15000
Oil viscosity (cP) at reservoir condition	Not Critical	<12	100-1000	>12
Fraction of oil remaining in area to be flooded (before EOR), % PV	50	25	50	>25
Net pay, ft	>20	N.C	N.C	>10
Permeability, mD	>10	N.C	N.C	>10
Porosity, %	>10	N.C	N.C	>10

2.2. Concept in designing CO_2-EOR

Due to the high corrosiveness of CO_2 gas, materials that are highly resistive to corrosion must be used during injection into the wellbore from the surface. Also, heat transfer calculations must be done to make sure the CO_2 heated at the surface supplies the required thermal energy to heat up the viscous oil in the reservoir. Although, there will be losses along the well from the surface to the reservoir, however insulation of the wellbore ensures minimal heat loss [49]. First, CO_2 is sourced either externally or internally (onsite). CO_2 must be treated to remove contaminants before it can be used for EOR. The pretreated CO_2 will undergo heating at the surface. The temperature of the hot CO_2 will usually be higher than the reservoir temperature so that it can achieve viscosity reduction of the reservoir crude. The CO_2 will then undergo compression with a compressor to the desired pressure and injected into the well [50].

2.3. Minimum miscibility pressure (MMP)

The CO_2-EOR method relies on the Minimum Miscibility Pressure (MMP) which is defined as the pressure at which injected gas achieves dynamic miscibility at reservoir temperature [49, 51].

Accurate determination of MMP is crucial for effective CO_2 injection. Various studies have proposed empirical correlations, neural network, and genetic algorithm-based methods for MMP determination [50]. A novel approach utilizes an acoustically monitored separator to determine MMP by observing the disappearance of the phase boundary between CO_2 and oil as pressure increases at a fixed temperature [52]. This method, based on fast, reliable, and non-invasive principles, stands out compared to other techniques. Another technique involves a rapid pressure increase to explore phase behaviour and determine MMP [52]. This method is rapid, cost-effective, and reliable, also accommodating asphaltene precipitation.

The miscibility of injected gases is determined by the reservoir pressure. If reservoir pressure is below MMP, an immiscible displacement occurs. Above MMP, miscible displacement occurs through first-contact, vaporizing, and condensing gas drives [47]. First-contact miscibility involves the injected gas mixing with reservoir fluid in all proportions, resulting in a single phase. Hydrocarbon gas mixtures exhibit first-contact miscibility with crude oil, whereas CO_2, N_2, and flue gases require multiple contacts for miscibility.

Miscible displacement, particularly dynamic miscibility, yields greater oil recovery compared to immiscible processes due to stronger CO_2-oil interactions [53]. Reservoir pressure above MMP leads to dynamic miscibility, where lighter and intermediate crude oil fractions vaporize and mix with the injected gas phase. The MMP depends on factors like reservoir temperature, permeability, gas composition, and crude oil characteristics [54]. Increasing temperature raises MMP as higher pressure is required for CO_2 miscibility. The C_1 and N_2 content increases MMP, while C_2-C_6 content decreases it. For heavy oil reservoirs, CO_2-crude oil MMP is often higher than reservoir pressure, limiting the use of miscible flooding [55-56]. Hydrocarbon extraction correlates with the molecular size difference between injected gas and reservoir fluid.

Heterogeneity plays a significant role in oil recovery, impacting flow and recovery rates. Nano-confined spaces and capillary pressure changes have a negligible effect on MMP, especially in ultralow permeability reservoirs. The impact of nanopore confinement on CO_2-hydrocarbons in tight reservoirs showed minimal effects on bubble point pressure [54,57]. Reservoir conditions, fluid properties, and techniques influence MMP determination. While miscible displacement is generally more efficient, some reservoirs may face challenges due to higher MMP than reservoir pressure or technical constraints. In such cases, reducing MMP using surfactants and miscible solvents becomes crucial [49,58].

3. Methods

Simulation study of hot CO_2 flooding was conducted using ECLIPSE 300 compositional simulator. Well, reservoir data and various operating conditions are given. The reservoir fluid data are in the Table 2.

Table 2. Reservoir data used in this work.

Parameter	Values
Porosity	0.28
Permeability	600 - 800mD
Wellbore ID	5.921 inches
Compressibility factor	5.07E-6 psi^{-1}
Reservoir thickness	100 ft
Reservoir depth	7466ft
Reservoir acreage	278 acres

3.1. Case study

Z-field in the Niger Delta is used as case study. Z-field is a heavy oil field of high viscosity, low API gravity and underlying weak aquifer. Because of the high viscous nature of the reservoir fluid, the reservoir was unable to be produced by primary and secondary recovery methods. Thus, the reservoirs in Z-field were left off from production since 1998 after PVT analysis was performed on the reservoir fluid samples. Owing to this, it is suggested that the only means of producing Z-field is through EOR means. The choice EOR means would be one that would achieve significant viscosity reduction and high microscopic and macroscopic sweep efficiencies. It is suggested that Hot CO_2-EOR means be used as the choice EOR in producing the reservoir.

The theory behind the flooding pattern considered in this work is thermal and miscibility effects. The hot CO_2 achieves both thermal and miscibility effects on the reservoir fluids. The heat in the CO_2 reduces the oil viscosity causing oil swelling and viscosity reduction while the CO_2 itself mixes intimately with the heavy oil when injected above the miscibility pressure of the system. The CO_2 achieves miscibility with the reservoir oil through interfacial tension reduction at the CO_2-oil interface and increasing oil mobility to the production interval. The Assumptions used in this study are:

i. The reservoir is homogenous;
ii. Reservoir Uniformity and Pay Continuity;
iii. The reservoir has constant porosity across all grid;
iv. Constant permeability and thickness among layers;
v. The injected gas is miscible with the reservoir fluid;
vi. Injection and production rate were constant in the various injection scenario.

3.2. PVT parameters

PVT data for this work was obtained from analyses conducted on fluid samples from Z-field in the Niger Delta. The data for PVT as obtained from laboratory sampling already conducted on fluid samples from Z-field is given in Table 4. Table 3 shows the composition of the reservoir fluid sample from Z-field.

Table 3. Composition of reservoir fluid used in this study.

Component	Symbol	Mol %
Carbon dioxide	CO_2	0.36
Nitrogen	N2	0.12
Methane	C1	28.02
Ethane	C2	0.24
propane	C3	0.09
iso- Butane	i-C4	0.15
n- Butane	n-C4	0.03
iso- pentane	i-C5	0.13
n- pentane	n-C5	0.16
Hexane	C6	0.33
Heptane plus	C7+	70.36
Reservoir temp = 136°F		

Table 4. PVT data.

Parameter	Values
Initial Reservoir pressure	3118psia
Formation volume factor at Reservoir pressure	1.0686 rb/stb
Formation volume factor at Bubble point pressure	1.0785 rb/stb
Oil density	58.87lb/ft^3
API gravity	18.6 API
Water density	62.4 lb/ft^3
Gas density	0.269 lb/ft^3
Gas viscosity	14.225 cP
Reservoir temperature	136 °F

3.3. Reservoir and well models

The reservoir is 5-spot pattern with 1 producer and 4 injectors located on coordinates of:

Table 5. Reservoir model showing well location and configurations.

Configurations	
Producers	Injectors
(6, 6)	(1,1)
	(11,1)
	(1,11)
	(11,11)

A wide variety of injection-production well arrangements have been used in injection projects. The 5-spot pattern used in this work is an example of regular spot pattern. 5-spot is a special case of the staggered line drive in which the distance between all like wells is constant, i.e., a = 2d. The four injection wells thus form a square with a production well at the center.

3.4. Grid

The Cartesian model used in this model has total of 1210 grids-11, 11 and 10 grids in x, y and z directions respectively. The reservoir pay thickness is 100 ft thick. Each cell is 316.44 ft x 316.44 ft x 10 ft (x, y and z) direction respectively. The layers are homogeneous and have constant porosity of 28%, the permeability (along X, Y and Z) respectively is the same in the whole 11 layers and thickness are same among layers. Table 6 below gives the permeability and thickness of each layer.

Table 6: Permeability and thicknesses of layers.

GRID	X-Permeability (mD)	Y-Permeability (mD)
1-11	800 per layer	800 per layer
LAYERS	Z-Permeability (mD)	Thickness (ft)
1-10	600 per layer	10 ft per layer

The initial reservoir pressure is 3118 psia at the depth of 7,466 ft. The grid arrangement and the well location of this reservoir model are shown in Figure1. As shown in the Figure 1, there are 4 injection wells. The injection fluid is CO_2. Four Injection wells were scheduled for injecting the hot CO_2 using the eclipse simulation tool. Each of the injection well has same properties. The hot CO_2 injection rate is 188 Mscf/day with Group well control injection/limit of 5000Mscf/day.

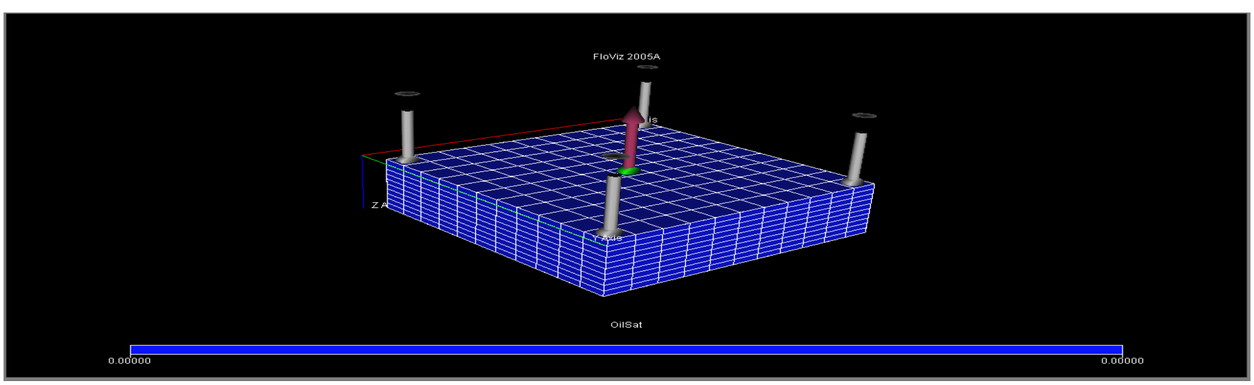

Figure 1. Reservoir model of hot CO_2 flooding using 5-spot pattern showing injectors and producer.

The 4 injector wells share same properties. The nature of Injected Gas is GRUP. GRUP is Eclipse injected Gas nature that enable each of the injection well to be immediately under group control, to inject its share of a group or field target/limit set. A key property of Eclipse is that fluid specified as Injection fluid type is only as water or gas. If the injected fluid is gas, Eclipse relies on nature of injected gas and its composition to know the kind of gas which in this case is CO_2 at high temperature (Hot CO_2). The density of the injected CO_2 is 47.13 lb/ft3 at 136 ^oF reservoir temperature and 3118psia reservoir pressure. The molar mass of the CO_2 used for the simulation is 44.01g/mol.

3.5. MPP determination

The MMP for the miscible Hot CO_2 flooding was determined using correlations. The Lasater (1958) correlation does not estimate MMP but rather is used to estimate the molecular weight of the C_5+ components of the reservoir oil as a function of oil gravity in degree API (fig below) and can be used in conjunction with the Holm and Josendal (1974) correlation for MMP. Considering the Crude API gravity of 18.6, the Lasater correlation will give an effective molecular weight of 44.0g/mol. Using the Mungan_Holm_Josendal MMP chart, the MMP is 3300psia. This can also justify the increase in reservoir Field pressure for Hot CO_2 miscible gas flooding. Hot CO_2 was injected at 200^0F (93.3^oC) and 3500 psia downhole into the formation. The viscosity of the injected CO_2 is 0.095cP.

4. Results and discussions

The results of the Eclipse 300 compositional simulator are presented for both the natural depletion case and the hot CO_2 injection. Oil and gas recoveries and efficiencies are presented and discussed.

4.1. Results

The results of the simulations performed in Eclipse 300 compositional simulator are given in this section. Discussion of results is given in section 4.2

4.1.1. Description of the heavy oil from Z-field

Figure 2 shows the composition diagram of the heavy oil from the reservoir indicating the carbon contents. The reservoir oil is predominantly composed of C_1 and the C_{12}+ components. This shows that the oil has complex functional groups and slightly high relative molecular weight. The mole fraction of C_1~C_{11} in heavy oil distribution is about 37%. Accordingly, the content of oil in C_{12}+ distribution is higher. Due to the macromolecules, main functional groups and intermolecular forces in crude oil, the mobility of heavy oil will vary with temperature, pressure, and the content of injected gas. The phase plot from the CVD experiment is given in the Figure 3.

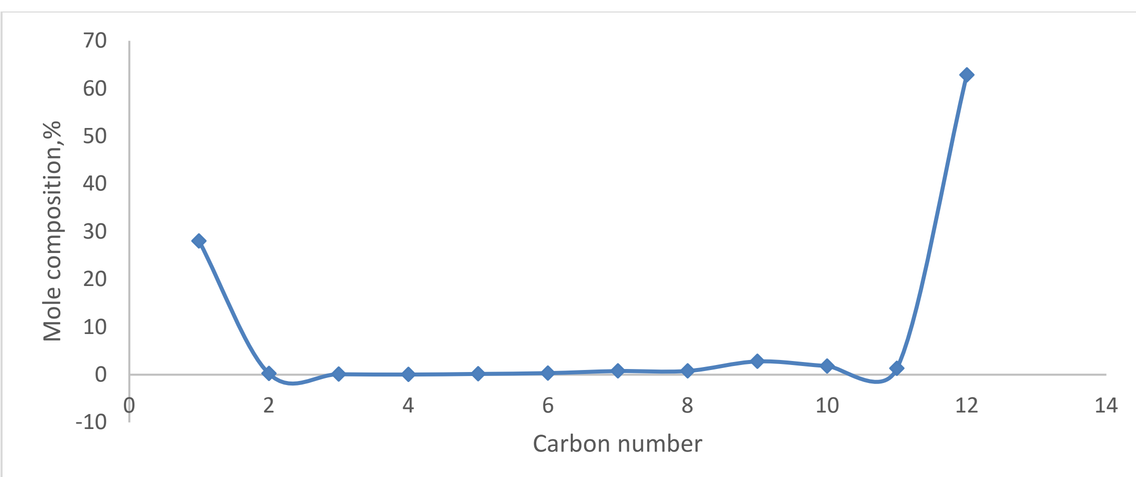

Figure 2. Hydrocarbon composition diagram of the reservoir oil.

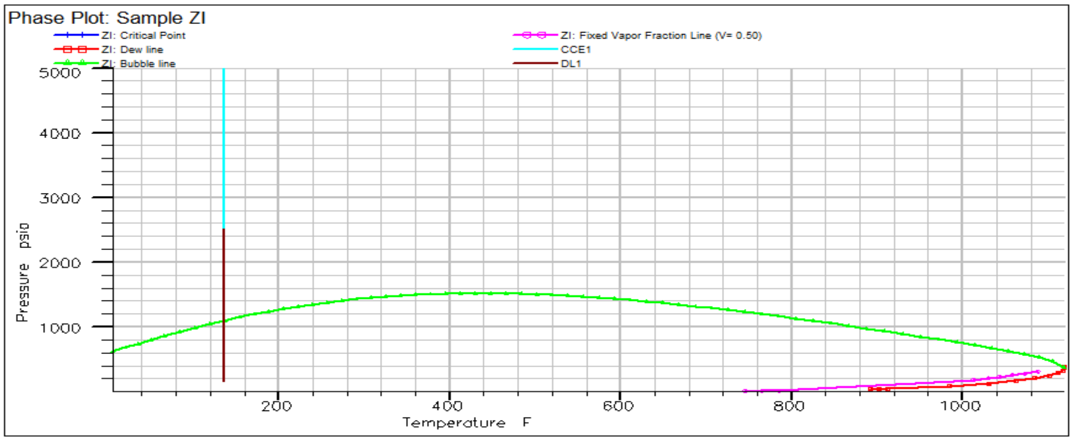

Figure 3. Phase plot from CVD.

Figure 3 shows the phase diagram of the reservoir oil. The heavy nature of the oil can be easily observed from the critical point and the coverage of the bubble point line. Maximum reservoir pressure is at 5015 psia, the reservoir exists at 3118 psia. Isothermal depletion occurs from initial reservoir pressure to the bubble point pressure. At the bubble point pressure, i.e., at 1169 psia. At the bubble point, the first vapour comes out the oil. The CCE plot for relative volume and pressure is given in Figure 3.

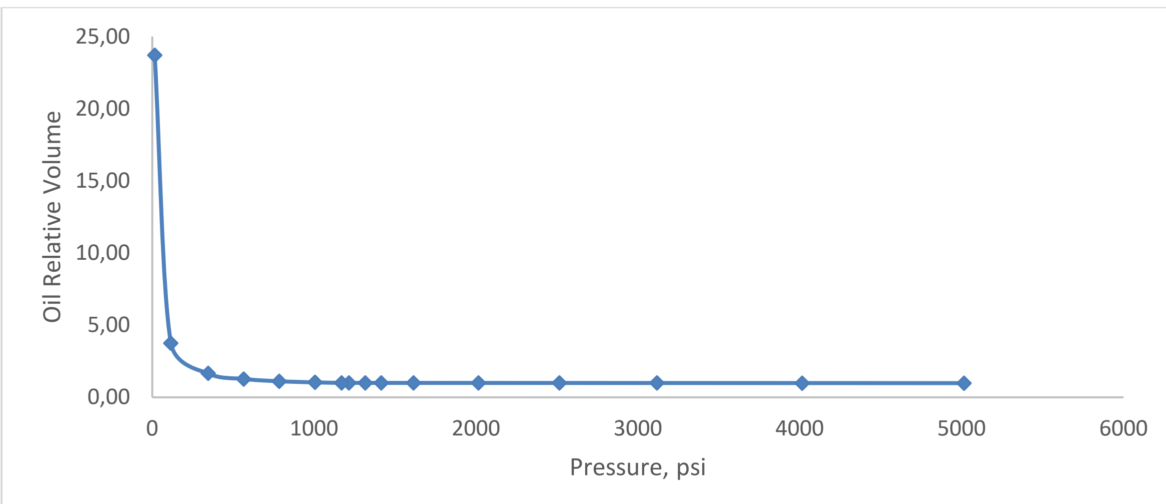

Figure 4. Regressed fluid model using relative fluid volume.

From Figure 4, the oil relative volume increases with decreasing reservoir pressure as pressure is depleted up to the bubble point pressure at 1069 psi and then began to increase as reservoir pressure is further depleted lower than the bubble point pressure. Thus, two regions were identified, the region before the bubble point pressure wherein the relative volume of the oil decreased as pressure is depleted and the saturated region below the bubble point in which the oil relative volume increased as pressure is depleted.

From Figure 5, a plot of gas formation volume factor and pressure is given. The gas formation volume factor (Gas FVF) varies decreases with increasing pressure until the bubble point is reached. Thus, at lower pressure, there is higher gas FVF as within the two-phase region of the phase envelope.

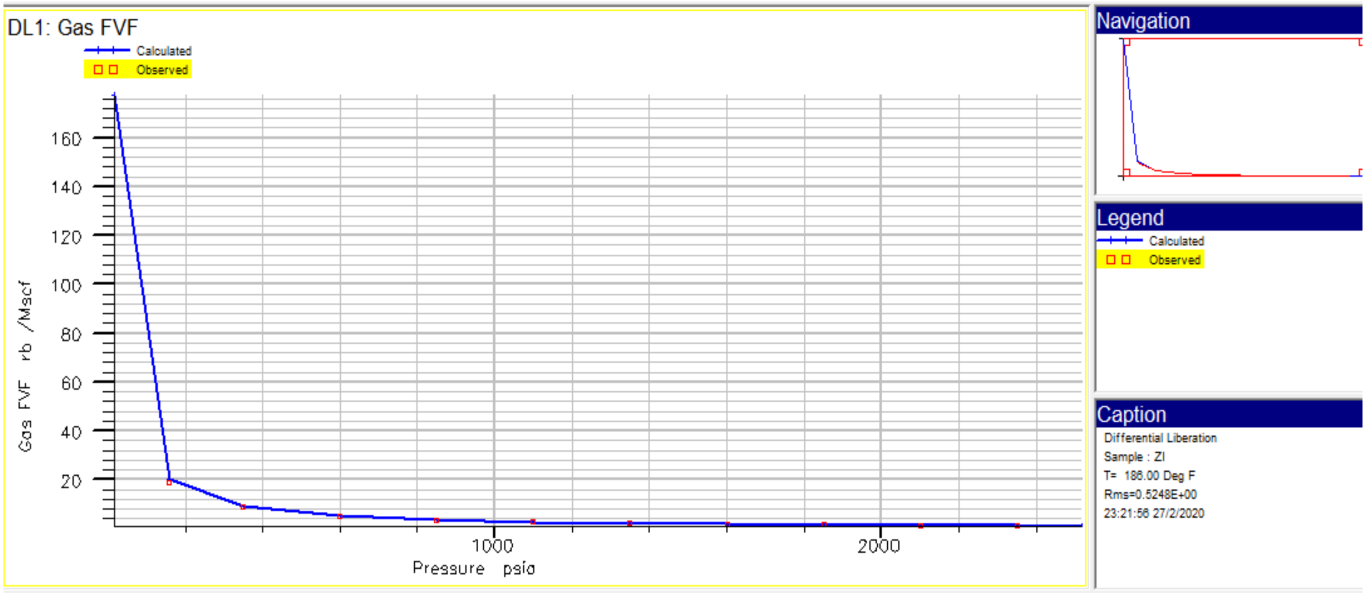

Figure 5. Regressed fluid model using gas FVF of DL experiment.

The viscosity variation of the reservoir heavy oil with pressure with and without injected CO_2 is given in Figure 6.

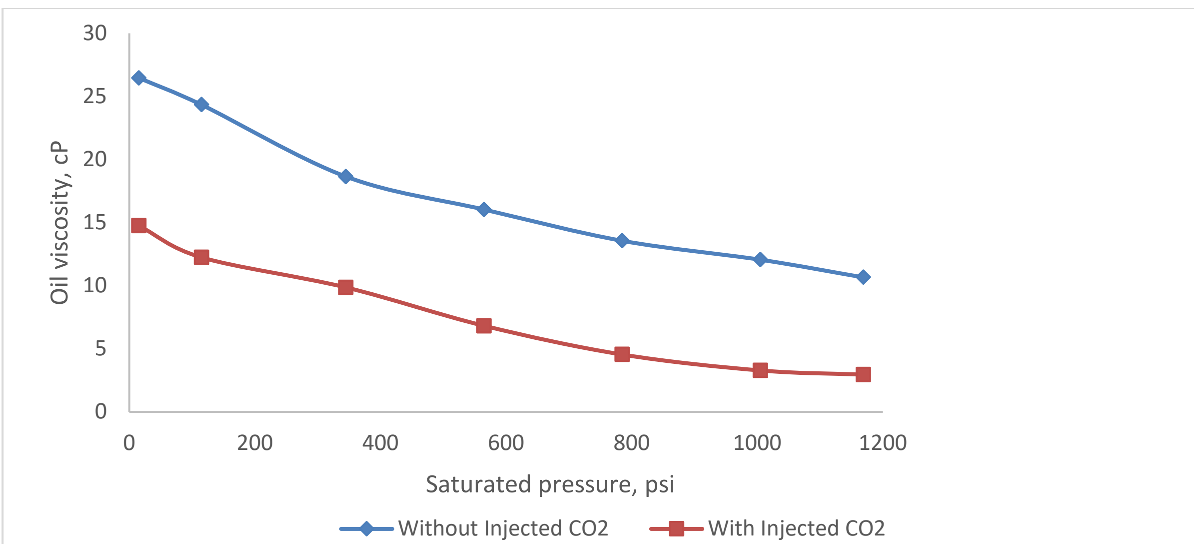

Figure 6. Oil viscosity variation with and without hot CO_2 injection.

Figure 6 shows the change of variation of oil viscosity with saturation pressures for the initial reservoir oil (without injection of hot CO_2) and when hot CO_2 was injected. It is evident that the injection of hot CO_2 to the reservoir oil, changed the physical properties of the oil especially its viscosity which is the principal factor affecting the flow of the oil

4.1.2. Production results for natural depletion

The result for the Eclipse 300 simulation is presented in this chapter. Two cases are considered. Case 1 is the natural depletion while case 2 is the Hot CO_2 flooding. Natural depletion was done to investigate the performance of the reservoir under natural driving energy. The result of the simulation for natural depletion is given in Figure 7.

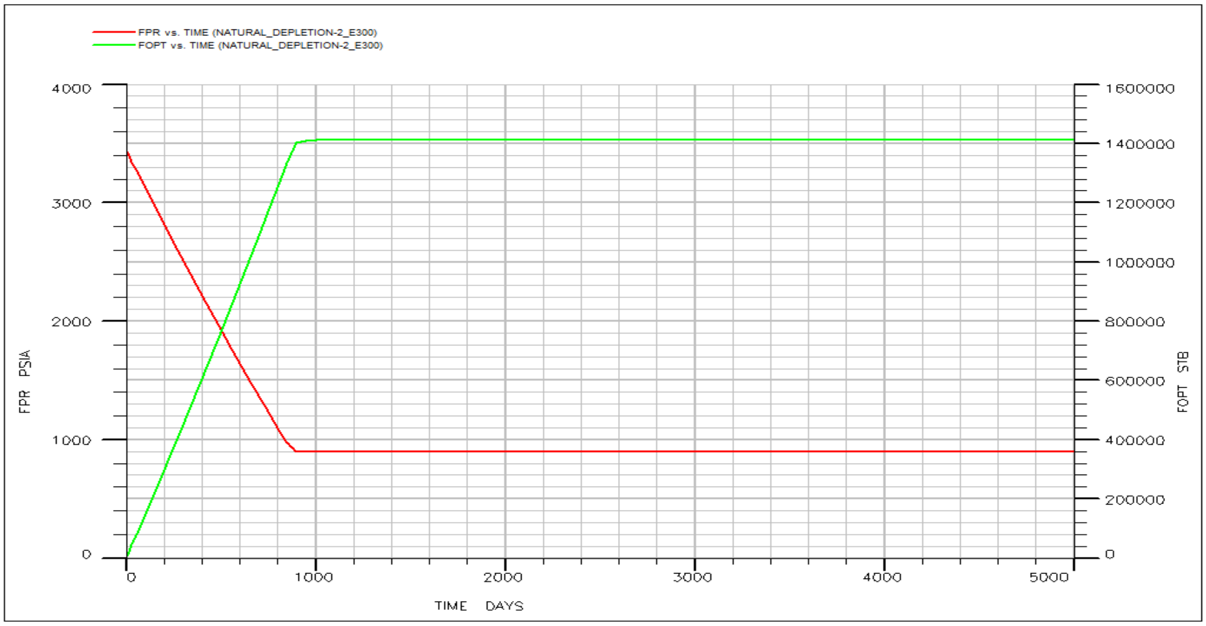

Figure 7. FOPT vs. FPR plot of the recovery using natural depletion mechanism.

The reservoir pressure declined from 3118psia to 897psia after 950days of production before remaining constant for remaining production cycle, with total oil recovery (FOPT) of 1.4MMstb as shown in green line. This clearly showed that using natural depletion with the reservoir pressure, there was little recovery compared to Oil Initially in place of 42.41 MMstb justifying the heavy crude nature. The Overall Field Oil Recovery Efficiency for Natural depletion is 3.3%. Thus, there is need for better recovery mechanism for which Hot CO_2Flooding was considered.

4.1.3. Field pressure (FPR)

When the reservoir pressure for Natural depletion and Hot CO_2flooding are compared, it is observed that the reservoir pressure declined progressively for the Natural depletion with little improved pressure maintenance for Hot CO_2Flooding. The increase in pressure can be attributed to miscible gas flooding EOR method implored in the Hot CO_2 flooding (For miscibility, the pressure should be greater than or equal to minimum miscibility pressure, MMP).

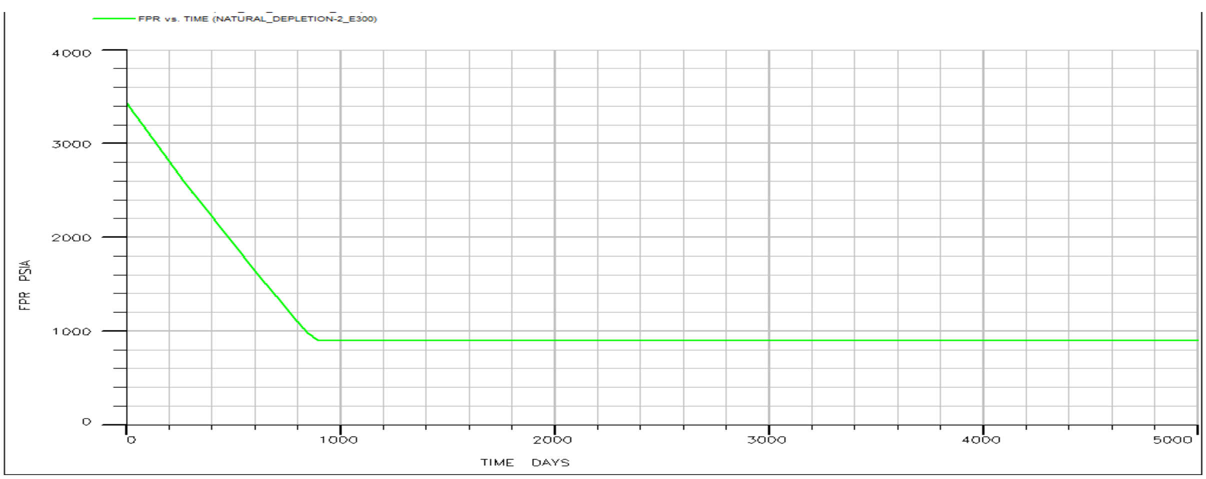

Figure 8. Field pressure for natural depletion.

4.1.4. Field oil production total (FOPT)

The Eclipse simulation summary result showed that there was substantial Oil recovery represented by the Field Oil Production Total for hot CO_2 flooding. The plot for FOPT for Hot CO_2 flooding is shown in the Figure9.

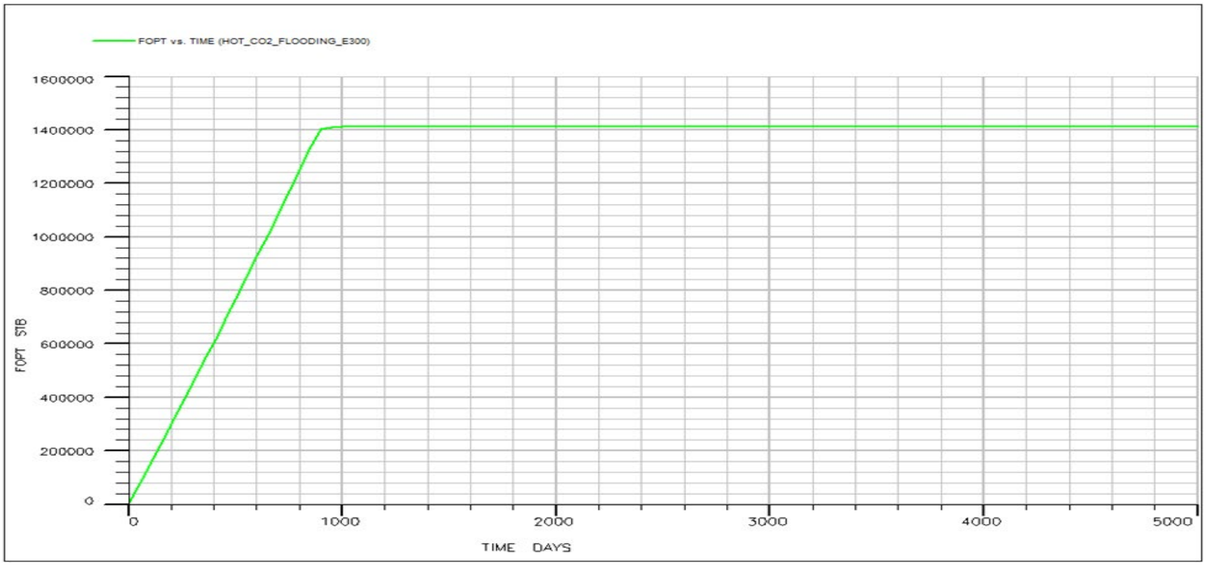

Figure 9. FOPT for hot CO_2 flooding showing oil recovery.

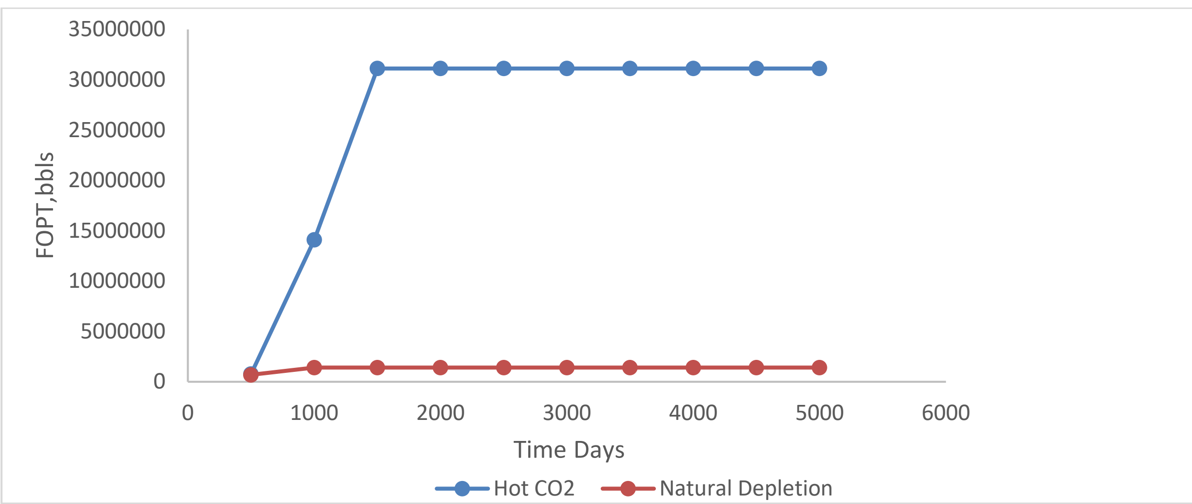

Figure 10. FOPT for hot CO_2 flooding showing oil recovery and natural depletion.

From Figure10, it can be observed that using hot CO_2 substantially increased the FOPT from that gotten for natural depletion. Because of very low dissolved gas owing to high crude viscosity, natural depletion produced minimal amount of oil after 5000 days as compared to hot CO_2

4.1.5. Field gas production total

For the natural depletion, the cumulative gas recovery after production cycle of 5000 days is 197.969 MMscf. Field Gas Initial in place is 5,947.5MMscf. Thus, the Field Gas Recovery Efficiency is 3.3%. The result of the simulation showed little amount of Field Gas recovery from Natural depletion to Hot CO_2 flooding. The cumulative gas recovery after production cycle of 5000 days is 198 MMscf. The Field Gas Recovery Efficiency is. 3.3%. The difference in cumulative gas recovery for hot CO_2 and natural depletion after 5000days is 35.18 Mscf. Because of the Heavy nature of the crude, much gas was not produced even when hot CO_2

flooding was applied. This is because of the absence of dissolved gas in the oil at reservoir conditions

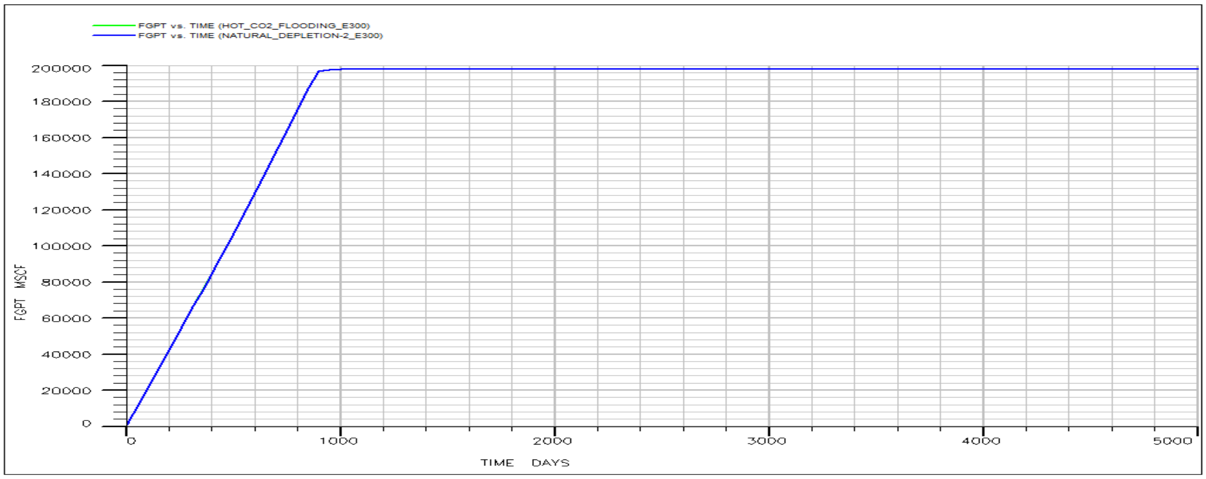

Figure 11. FGPT for hot CO_2 flooding and natural depletion showing gas recovery.

From Figure11, the FGPT for natural depletion and hot CO_2 flooding lie together on the same curve. This signifies that the use of hot CO_2 flooding does not have appreciable impact on gas production from the heavy oil reservoir

4.1.6. Field oil and Field Gas Recovery Efficiencies

The Field oil and field gas recovery efficiencies for the two cases are given below. Recovery efficiency indicates the fraction of fluids recovered to that left in the reservoir after the prevailing drive mechanism has been deployed. The recovery efficiency for the natural depletion case is given Figure 12.

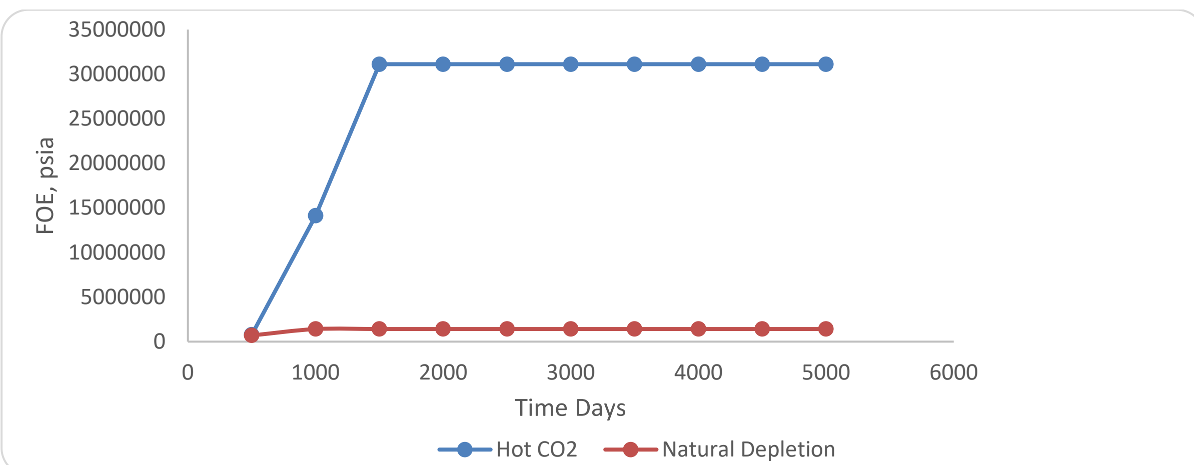

Figure 12: FOE for natural depletion and hot CO_2 flooding

Analysis of Figure 12 reveals that the Field oil production total after 5000 days is 1,411,684 stb of oil using natural depletion while the field oil production total using hot CO_2 is 31,119,347 stb of oil. The field oil recovery efficiency improved from natural depletion to hot CO_2flooding as shown Figure 12. The overall Oil Recovery efficiency for the production cycle is 73%. The high percentage recovery was due to miscible Hot CO_2 flooding.

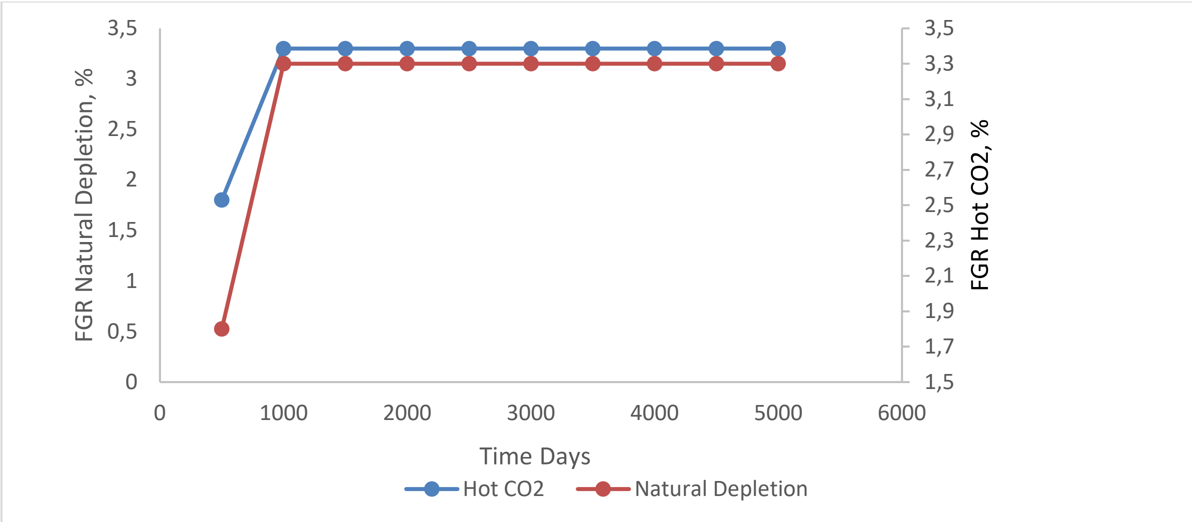

Figure 12. FPR for natural depletion and hot CO_2 flooding.

The Field gas production total (FGPT) after 5000 days is 197.97MMscf of gas for natural depletion while the field gas production total for hot CO_2 flooding after 5000 days is 198MMscf of gas. The field gas recovery efficiency for both natural depletion and Hot CO_2 Flooding are the same as shown in Figure 12 (FGR for natural depletion was plotted on the primary axis while the FGR for the hot CO2 was plotted on the secondary axis). The overall Gas Recovery efficiency for the production cycle is 3.3%.

Table 7. Summary of Production Results after 5000 days.

Cases	Natural depletion	Hot CO_2 flooding
FOIP	42.4 MMstb	42.4 MMstb
FGIP	5947.5 MMscf	5947.5 MMscf
FOPT	1.4 MMstb	31 MMstb
FGPT	197.97 MMscf	198MMscf
FOE	3.3	73
FGR	3.3	3.3

From Table7, it can be observed that using hot CO_2 substantially increased the FOE from 3.3% gotten from natural depletion to 73% after 5000 days. The increased recovery efficiency justifies the use of CO_2 flooding for the recovery of heavy oils in the Niger Delta.

4.2. Discussion

The simulation results presented in Figures 7 and 8 depict the performance of the reservoir under natural depletion and supercritical CO_2 injection, shedding light on the significant impact of enhanced oil recovery (EOR) methods.

In the case of natural depletion, a continuous decline in reservoir pressure is observed, dropping from the initial pressure of 3118 psia to 897 psia after the first 980 days of production. Subsequently, the pressure remains constant at 897 psia for the rest of the 5000-day operational period. The total oil production was 1.4 MMstb, with a corresponding recovery efficiency of 3.3% for both oil and gas. This low recovery efficiency is attributed to the heavy nature of the crude oil, lacking sufficient solution gas at reservoir conditions to provide the energy needed for fluid flow to the surface.

Contrastingly, in the case of supercritical CO_2 injection, where CO_2 is injected at 3500 psia and 200°F, a huge impact on recovery is evident. The injected hot CO_2 gas resulted in a reduction in oil viscosity and the lowering of interfacial tension, and facilitated increased oil recovery. The simulation showed a Final Oil Production Total (FOPT) of 31 MMstb of oil and a Final Gas Production Total (FGPT) of 198MMscf.

Comparing natural depletion with hot CO_2 injection, it becomes evident that natural depletion alone yields minimal oil production due to high viscous forces and low energy in the reservoir fluid. This limited recovery is deemed economically and technically unfeasible. However, with hot CO_2 injection, recovery efficiency experiences a remarkable increase, soaring from 3.3% in natural depletion to an impressive 73% after 5000 days of production. This substantial improvement is attributed to the combined effects of the thermal and miscible characteristics of the hot CO_2 fluid.

The cumulative gas recovery for hot CO_2 flooding exceeds natural depletion by 35.18 Mscf after 5000 days. The relatively low difference in the gas produced by the two methods highlights the heavy nature of the crude with minimal solution gas at reservoir conditions.

Summarily, the result highlight that natural depletion is impractical for very heavy oils due to the lack of solution gas to energize fluid flow. The introduction of hot CO_2, leveraging its unique properties, addresses this limitation. It reduces oil viscosity, induces oil swelling, achieves miscibility above the MMP, and lowers interfacial tension, altogether facilitating increased recovery efficiency.

5. Conclusion

Hot CO_2 increases the recovery efficiency from Z-field from 3.3% gotten for natural depletion to 73%. For the case of natural depletion and use of hot CO_2 flooding, there was no appreciable diffidence in the gas produced. This is due to the heavy nature of the crude oil at reservoir condition, having not much dissolved gas in it. Combination of thermal and miscible flooding holds great prospects in the recovery of heavy oil especially in the Niger Delta sandstone formation. Natural depletion is not feasible in heavy oil recovery due to the absence of dissolved gas and the high viscosity of the crude. Hot CO_2 flooding holds great potential as a means of heavy oil recovery because it possesses dual features of thermal and miscibility making it a good choice for heavy oil recovery. Poorly designed CO_2 injection will result in lower recovery efficiency and early breakthrough of CO_2 to producing wells. Also, significant heat losses may occur if there is no proper design.

Nomenclature

CCE	*Constant composition expansion*
CO_2-EOR	*CO_2 enhanced oil recovery*
cP	*Centipoise*
EoS	*Equation of state*
FVF	*formation volume factor*
mD	*Millidarcy*
MEOR	*Microbial enhanced oil recovery*
MMP	*Minimum miscibility pressure*
MMscf	*million standard cubic feet of gas*
MMstb	*million stock tank barrel of oil*
NC	*Not critical*
stb	*stock tank barrels*

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