FEDERAL UNIVERSITY OF TECHNOLOGY, AKURE
JOURNAL OF ENGINEERING AND ENGINEERING TECHNOLOGY

PRODUCTION ANALYSIS OF FIVE-SPOT MISCIBLE DISPLACEMENT SCHEMES IN GAS CONDENSATE RESERVOIRS

[1]Adeyanju, O. A.* and [2]Adeosun, T. A.

[1]Department of Petroleum and Gas Engineering, University of Lagos, Akoka Lagos State, Nigeria
[2]Department of Mineral and Petroleum Engineering, Yaba College of Technology, Akoka, Lagos State, Nigeria

**Correspondence: adebaba2001@yahoo.com*

Adeyanju, O. A. and Adeosun, T. A. (2025): Production Analysis of Five-Spot Miscible Displacement Schemes in Gas Condensate Reservoirs. *FUTA Journal of Engineering and Engineering Technology /19(1), 114-125*

Received Date: 10.1.25 **Accepted Date: 15.4.25**

Abstract
Production from gas condensate reservoirs has been of great concern to the petroleum industry. This is due to the complex flow behaviours in response to pressure drops across the reservoirs towards the wellbores. Valuable condensate liquid is lost due to reservoir pressure drops below the dew point pressure. The condensate bank formed by the accumulations of the immobile condensate liquids restricts the flow of gas in the vicinity of the wellbore into the wellbore thereby reducing the recovery factor of the gas in place in this study, the application of a pressure maintenance scheme with the objective of keeping the reservoir fluid very close to the dew point pressure to alleviate such drastic loss in non-renewable resources is investigated. A carbon dioxide (CO_2) gas miscible displacement injection scheme was implemented to optimally produce gas condensate reservoir. Additionally, the CO_2 injection process into the subsurface reservoir serves as an avenue for the reduction of greenhouse gases in the environment. A compositional model was implemented to simulate the different homogeneous gas condensate depletion schemes. The simulated model was used to determine the performance of other production approaches, with and without gas injection. A five-spot injection pattern with fine grids near the producer was employed to further investigate the condensate oil saturation profile. Results show that among the investigated schemes, purely CO_2 injection process returned both the highest profit margin and maximum fractional recovery of \$176.65 million (USD) with 86.35% respectively, while complete natural depletion produced the least profit margin and minimum fractional recovery of \$69.63 million (USD) with 34.17% respectively. The result shows that the profit and the fractional recovery of different production schemes reduces as natural depletion prior to the CO_2 gas injection increases.

Keywords: *Condensate banks, retrograde condensation, re-vaporization, miscible displacement, condensate oil*

Introduction

Petroleum reservoirs can be classified into five categories, these are: black oil, volatile oil, condensate gas, wet gas, and dry gas reservoir. Janiga *et al.* (2019) proposed that condensate gas reservoirs have similar properties to the volatile oil reservoir in terms of the produced oil, and the major difference is that condensate gas reservoir has a temperature higher than the critical temperature of the composing fluid. At reservoir conditions of temperature and pressure whereas the volatile oil is liquefied, and the condensate reservoir is in the gaseous state. Unique reservoir properties and flow characteristics of the condensate gas reservoirs (as they exhibit both characteristics of oil and gas reservoirs) differentiate them from either oil or gas reservoirs. Isothermal production of the gas condensate results in the reservoir pressure falling below the gas dew point pressure, then the heavier fractions of the gas condense out, resulting in a two-phase fluid near the wellbore region. The retrograde condensation would continue until the liquid drop-out reaches its maximum (Kerunwa and Uchebuakor, 2015). Continuous drop in pressure at constant temperature as a result of continuous production results in re-vaporization of the heavy fractions in the condensed liquid. This process allows more molecules to leave the liquid surface than the amount that enter the liquid surface. The process continues until the pressure falls below the lower dew point line when all liquid formed from condensed heavy fraction must have vapourized, as only vapour exists at the dew point (Elsharkawy, 2002). When the flowing bottom hole of a producing condensate gas reservoir is below the dew point and the reservoir pressure is above the dew point pressure. The condensate reservoir can be categorized into three flow regions (as shown in Figure 1).

In Figure 1, Region 1, which is the near wellbore region where there is simultaneous flow of gas and condensate liquid the saturation of both gas and condensate liquid are high enough for them to be mobile, then both have enough permeability to move; Region 2 is where condensate liquid is building up, it's only the gaseous phase that have enough saturation and the permeability to move, note here that the condensate liquid is immobile due to its low saturation and capillary forces; Region 3 is innermost part of the gas condensate reservoir, it contain only gaseous phase, the pressure is above the gas bubble point pressure and condensate liquid has not started condensing out of the gas phase (Mindek, 2005).

It is more desirable to produce more condensate liquid than gas as the condensate liquid has more economic value than the gas, but when the determine the phase behavior of the gas condensate reservoir.

Many gas condensate reservoirs have been having challenges due to the near-wellbore condensate blockage problem. Mobil and Shell Oil recorded over 50% and 67% loss in their productivity in different gas condensate fields due to the near-wellbore condensate blockage problems (Hamid Behmanesh *et al.*, 2017; Mohammadhossein *et al.,* 2016; Smith *et al.*, 2001). Presently, there are two basic methods of improving productivity from condensate gas reservoirs, these are: continuous depletion development and pressure maintenance through gas injection. Although different classes of these two methods have been implemented to remediate damages caused by retrograde condensate formations with the injection of various gases to maintain the reservoir pressure above the dew point line (Janiga *et al.*, 2018; Wu *et al.,* 2021).

In the oil and gas fields, dry gases (mostly methane)

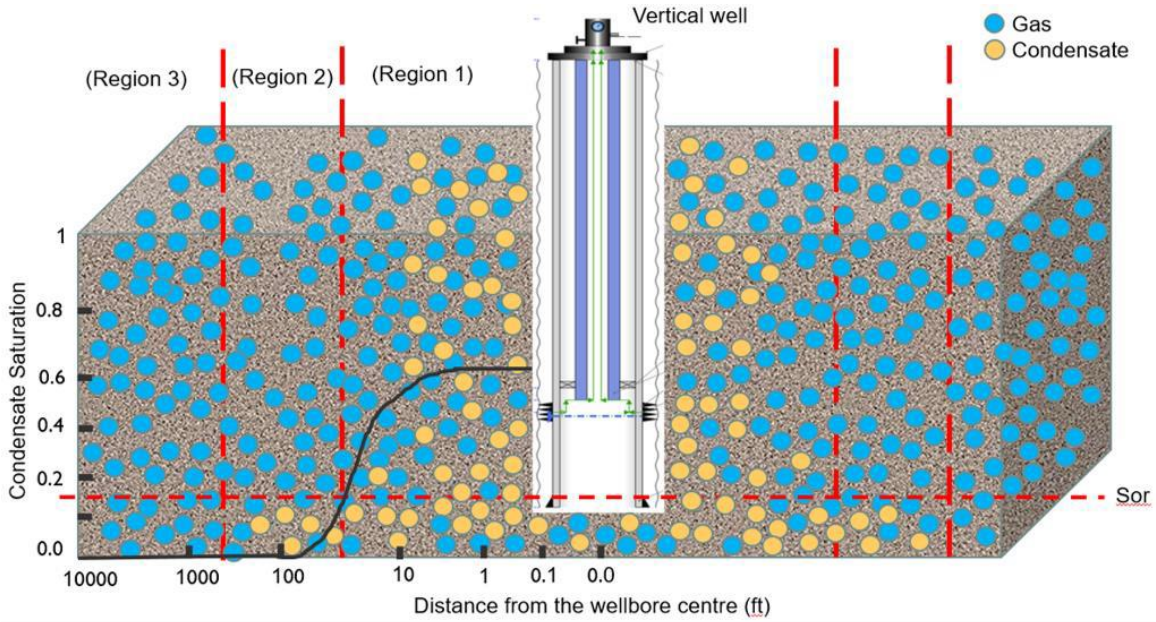

Figure 1: Gas condensate flow in three regions

condensate liquid has a very low concentration, the permeability of the rock to the condensate fluid becomes very low, causing them to form liquid banks close to the wellbore. The presence of immobile liquid banks in the vicinity of the wellbore affects gas deliverability and productivity from the reservoir as the liquid banks obstruct the free movement of gas condensate into the wellbore (App *et al.,* 2007). Also, the microscopic condensate droplets that are trapped at the near wellbore region create additional pressure drops, thereby reducing the reservoir's productivity. The phase envelope and thermodynamic properties of the reservoir fluids have been used as injection gas for reservoir pressure maintenance (Janiga *et al.,* 2018; Huerta Quinones *et al.*, 2010). The method is also common in gas condensate reservoir pressure maintenance (Johnson and Jamiolahmady, 2018; Jingsong *et al.,* 2004; Li *et al*., 2008; Lu, 2019; Lu *et al.,* 2019). However, some researchers proposed the use of easily available gases such as carbon dioxide, nitrogen, butane-pentane gases, air, rich gas injection (Fasesan *et al.,* 2003; Kaydani *et al.,* 2016; Rahimzadeh *et al.,* 2016; Janiga *et al.,* 2017). However, some modifications needed to be implemented due to mixing of most of these gases with the reservoir fluids in order to prevent significant formation of condensate liquid above the dew point pressure as a result of modification in the thermodynamic properties of the gas mixtures (Safari and Hashemi, 2016; Sadooni *et al.,* 2015; Nastriani *et al.,* 2015; Su *et al.,* 2017). The gas cycling method was introduced in order to overcome the challenges of gas mixtures (Mohsen Safari *et al.,* 2021). In this method, the gas condensate reservoir pressure is maintained very close to the dew point pressure so as to recover the maximum amount of wet gas characterized by maximum condensate yield. Some researchers attempted to enhance condensate gas productivity through wettability alterations. Results showed that gas injection techniques in gas condensate reservoirs leads to higher productivity than water injection methods (Sakhaei *et el.,* 2017: Su *et al.,* 2017). Several studies had also been performed to optimize condensate productivity from gas condensate reservoirs (Dong *et al.*, 2007; Huerta Quinones *et al*., 2010; Mahdiyar and Jamiolahmady, 2014; Kalugin *et al.,* 2015; Zhou *et al.,* 2016; Kaydani *et al.,* 2016; Ghorbani *et al.,* 2017; Lu *et al.,* 2019).

Mahdiyar and Jamiolahmady, (2014) developed an optimization method for fractured condensate reservoirs. Kalugin *et al.* (2015) optimized condensate gas productivity using the steepest descent method with fractional steps. Zhou *et al.* (2016) optimize the condensate reservoir productivity by the determination of the critical gas flow rate needed to prevent liquid drop out in a deep condensate gas well. Kaydani *et al.* (2016) proposed a multi gene genetic programming model that can determine the dew point of the reservoir fluids at different reservoir conditions in order to optimize the reservoir productivity. Ghorbani *et al.* (2017) developed firefly optimization algorithm for prediction of critical gas flow rate needed to supress the formation of near wellbore condensate liquid banks that reduces reservoir productivity.

Materials and Methods

In this present study, a Computer Model Group (CMG) Simulation Software was used to simulate the injection of CO_2 into a gas condensate reservoir in a Nigerian Niger Delta field with the objective of maintaining the flowing bottom hole pressure very close to the reservoir dew point pressure so as to maximize the production of liquid condensate thereby enhancing the gas condensate reservoir productivity.

Table 1: Composition Analyses of Reservoir Fluid

Component	Mole fraction
N_2	1.08
CO_2	0.01
C_1	77.13
C_2	6.53
C_3	5.33
i-C_4	1.82
n-C_4	1.79
i-C_5	0.78
n-C_5	0.59
C_6	0.70
C_{7+}	4.24

Properties of the C7+ fractions

Density of C_{7+}, g/cm^3	0.7845
Molecular weight of C_{7+}, g/mol	139.07

Experimental Study

The Constant Volume Depletion (CVD) test was carried out on the reservoir fluid solvent containing 30% carbon dioxide on a PVT cell. The gas condensate reservoir has an initial pressure of 5640 psia and a temperature of 184.6°F. The dew point pressure is 4061 psia. The initial composition of the reservoir fluid used for the study is shown in Table 1.

The Constant Volume Depletion (CVD) test experimental procedure is performed as presented by (Johnson *et al.,* 2018). The reservoir fluid solvents containing 30% carbon dioxide were prepared and transferred into a PVT cell. The attached oven to the PVT cell was used to adjust the reservoir fluid solvent temperature to the prevailing reservoir temperature (approximately 200°F). The constant volume depletions were performed to simulate an actual reservoir scenario. The pressure was reduced at different time steps, while the produced liquid volumes based on the percentage of cell volume were determined. The CVD test was divided into at least six (6) pressure drops from the dew point pressure to the abandonment pressure.

Due to high miscibility of carbon dioxide (CO_2) gas with the gas condensate reservoir fluids at a pressure of 1878.5 psia and temperature of 184.6°F from the minimum miscibility pressure (MMP) test in (Table 3); the injected carbon dioxide gas is expected to mix with the reservoir fluids at the operating pressures.

Reservoir Model Description

The production model is design with four (4) injection wells set around a centred production well in the reservoir. The producer is set at a distance of 1422 ft from every injector. The injectors are located at each corner of the reservoir and are 2715ft laterally apart from each other. Using the CMG simulation software, the field was modelled using a five-spot pattern with four CO_2 injection wells and a producer. The reservoir was modelled as 54×54×1 in the compositional simulator GEM of the computer modelling group (CMG). The reservoir has an area equivalent to a square of length 2845ft and a 95 ft thick pay-zone. The reservoir model is constructed with grid sizes of 52.68 ft in both I and J directions, and the pay zone is 95 ft thick (K direction). The effect of reservoir heterogeneity on productivity was not considered in the study. The reservoir rock and fluid properties of the field were used in the model. The reservoir fluid components were lumped into eleven (11) pseudo-components (Table 1). The properties of each pseudo-component were determined for input into the Peng-Robinson equation of state (PREOS) calculations used in the model. Since the reservoir pressure of 1500 – 2500 psia is characterized to have maximum condensate oil yield from the CVD test. The producer is subjected to a limiting bottom-hole pressure between 1500 psia and 2500 psia. Each injection well was subjected to a maximum injection pressure of 5650 psia (lower than the reservoir fracture pressure). Due to the size of the gas condensate reservoir under study, an injection time of ten (10) years is set for this simulation study, though the production from the reservoir would have stopped before the ten-year period. The further injection of the carbon dioxide (CO_2) gas after production has stopped was to store the carbon dioxide gas in the depleted gas condensate reservoir.

Results and Discussion

The results of the simulation of CO2 injection carried out on the Computer Modelling Group (CMG) simulation software were analysed. The objective was to investigate how CO_2 injection affects the condensate oil (wet gas) saturation in a five-spot injection pattern inside the gas condensate reservoir. Four injection wells, injecting CO_2 at the rate of 5.7 MMSCF/D of gas and a producer. This gives a total of 22.8MMSCF/D, equivalent to 7.2 tonnes of CO_2 per day The project was set to run for a minimum period of twenty years, injecting CO2 at a rate of 2,628 Metric tonnes (Mt) CO_2 per annum. The injection rates in different units are presented in the Table 2.

Table 2: CO_2 gas Injection rate in Different Units

zDays	Injection Rate (ft3/d)	Injection Rate (MMSCF/d)	Tonnage (Metric-Tonnes/d)	TOTAL Metric Tonnes
3,650	141,259	5.7	7.2	26,280

Thus 26,280 tonnes of CO_2 were injected into the Reservoir over a period of 10 years, equivalent to 2,628 Mt/annum. The profile of the injection rate in

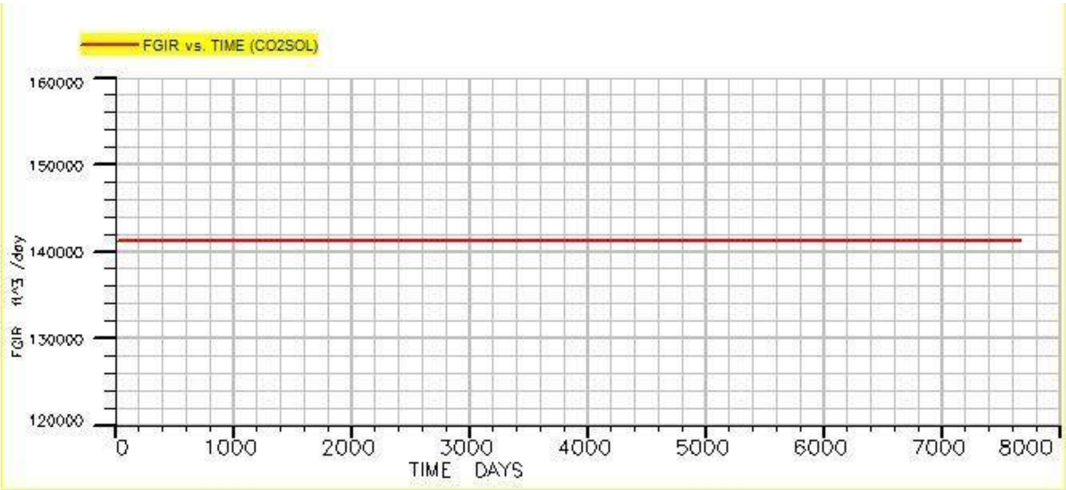

Figure 2: Plot of Injection Rate vs Time

cubic-feet per day (ft^3/d) with time is as shown in Figure 2. This is a way of ensuring continuation of the process by maintaining the injection rate to an acceptable level. From simulations run, higher injection rates may lead to the shutting down of some wells, bringing the project to an abrupt end. A constant injection rate of 141,259ft3/day, indicates that reservoir pressures are below formation fracture pressure and so injection process continues. Any increase or decrease in injection pressure creates an abnormality, usually in terms of high bottom-hole pressure.

Fluid Model

The fluid model was characterized using the CMG Winprop tool. It was used to develop the equation of state for the gas condensate reservoir and the equation was tuned to match with experimental data of Constant Composition Expansion (CCE) and percentage (9.6%) was achieved and it gradually reduces to 7% condensate oil at a pressure of 500 psia due to liquid re-vaporization. Similarly, the Constant Composition Expansion (CCE) simulated results are in closed form agreements with the experimental results with average percentage error of 2.15%.

The flowing bottom hole pressure of the producer is set between 1500 – 2500 psia where the liquid drops out is at the highest from the constant volume depletion (CVD) experiment as seen in Figure 4. Outside this pressure range the production well (producer) will shut down. This is to enable more condensate oil to drop out of the reservoir fluid there-by increasing the amount of condensate oil produced from the gas condensate reservoir.

Figure 5 shows matched simulation and laboratory

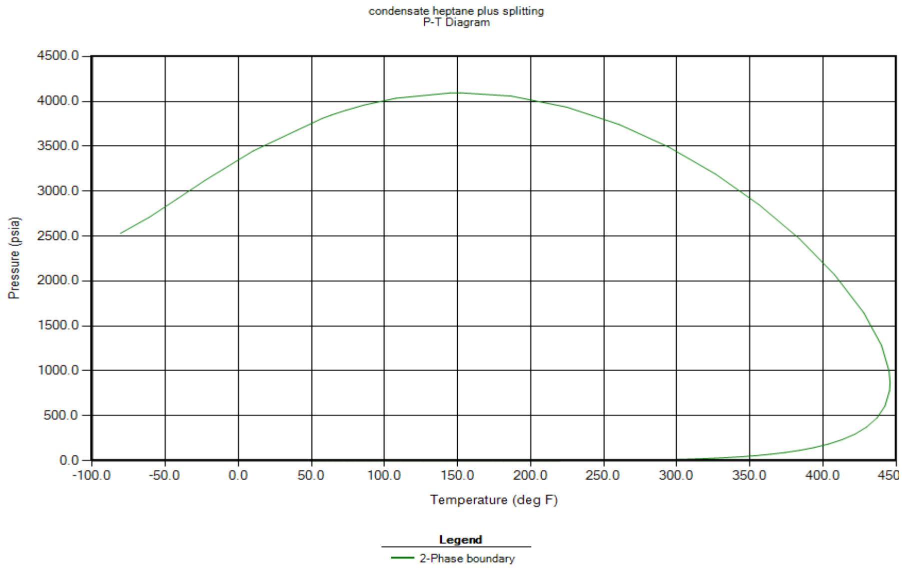

Figure 3: Phase diagram of the gas condensate reservoir fluid

Constant Volume Depletion (CVD) from laboratory measurements. The CMG Winprop tool was able to simulate the experiment and determined CCE tests and the CVD tests to acceptable degrees of accuracy, with percentage error of 1.05%. The CMG Winprop was also used to construct the phase diagram of the gas condensate reservoir fluid shown in Figure 3.

The Constant Volume Depletion and Constant Composition Expansion Test Results

Figure 4 shows that the Constant Volume Depletion (CVD) test result and the simulated results (continuous lines) are in very good agreement with the experimental results (dotted points). The condensate oil starts to form when the reservoir fluid is below the dew-point pressure (4016 psia). Figure 4 shows that the condensate oil volume continues to increase until the pressure reduces to 2000 psia, when the maximum amount of condensate oil plots of the constant composition expansion (CCE) test that shows the produced gas profile against the producer bottom hole pressure and the percentage of the produced gas increases as the bottom hole pressure reduces due to reduction in the resistance to gas outflow from the reservoir through the producer.

The limiting bottom-hole pressure at the producer was set at between 1500 to 2500 psia very close to the pressure of 2000 psia, characterized to have maximum condensate oil yield (9.5%) from the CVD test results. This is to prevent the re-vaporization of condensate oil that occurs when the pressure decreases below the lower dew point lines on the gas condensate phase diagram. Figure 6 shows the amount of carbon dioxide to be injected during the project. The 26,280 tonnes of carbon dioxide is relatively high and in addition to assisting in the recovery of more condensate oil from the

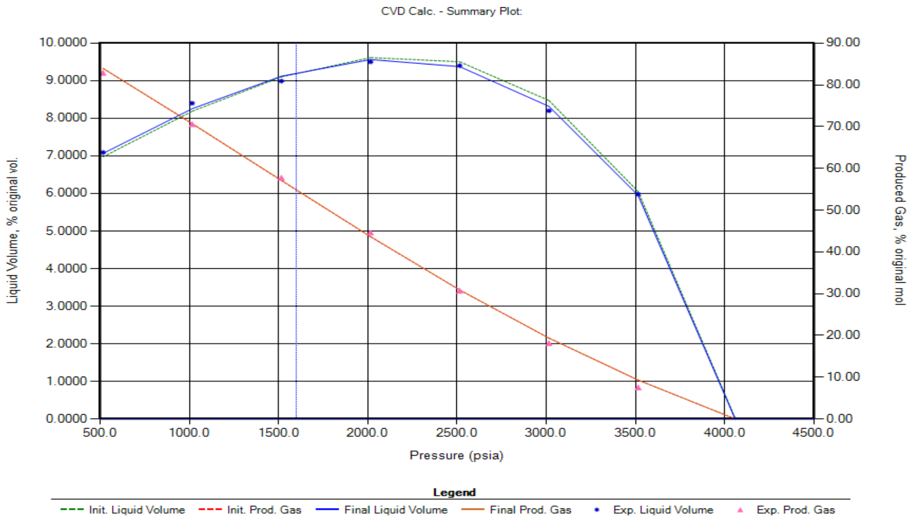

Figure 4: Liquid dropout curve for CVD experiment at 184.6°F of the gas condensate mixture

reservoir. It also serves as a mean of storage for captured carbon dioxide in the subsurface formation, keeping them away from the atmosphere. This will greatly reduce the amount of greenhouse gases in the atmosphere thereby reducing global warming (Carbon Captured and Sequestration, CCS process).

Minimum Miscibility Pressure (MMP) Determination

Minimum miscibility pressure (MMP) being the pressure at which miscibility between injection gas and reservoir fluid will be achieved was numerically determined using the CMG software. The result as shown in Table 3 confirmed that minimum miscibility pressure (MMP) between the injected CO_2 gas and the reservoir condensate fluid was achieved at a pressure of 1,878.5 psia. The dew point was also determined to be 4,125 psia (multiple contact miscibility pressure value).

Experimentally, the minimum miscibility pressure (MMP) of the carbon dioxide (CO2) gas in the reservoir condensate fluid was determined in the laboratory using the rising bubble apparatus (RBA). The MMP of the reservoir fluid and CO2 gas is measured as 1900psia. This is in a reasonable agreement with numerical solution (1878.5psia) determined from the CMG software. Hence, the MMP which determines the minimum injection pressure (MIP) used in the simulations study was approximated to 2000psia.

Reservoir Production Model

In order to critically analysed the condensate oil saturation around the production well. The vicinity of the producer is model as 44×44×1 compositional simulator GEM of computer modelling group (CMG). The grid size was reduced to 5 ft in both I and J direction and the 95ft grid size was retained for

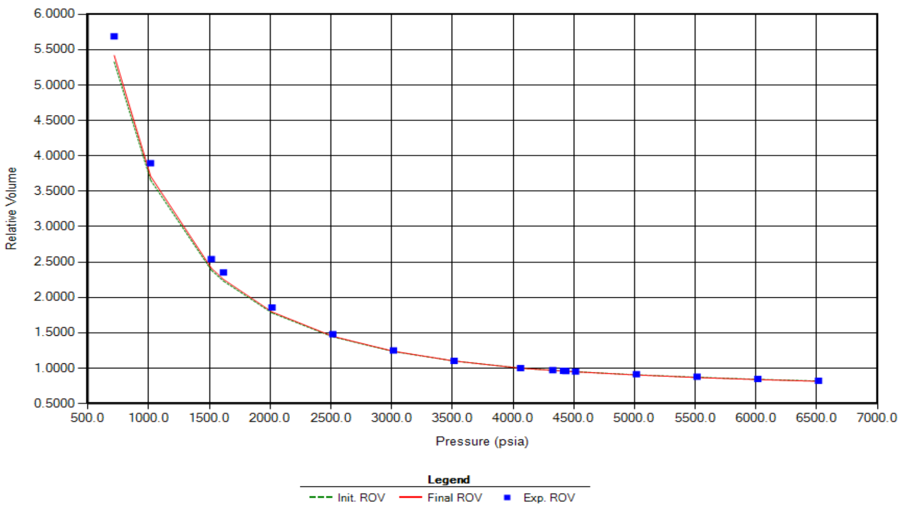

Figure 5: Matched Simulation and Laboratory plots of the Constant Composition Expansion (CCE) Test

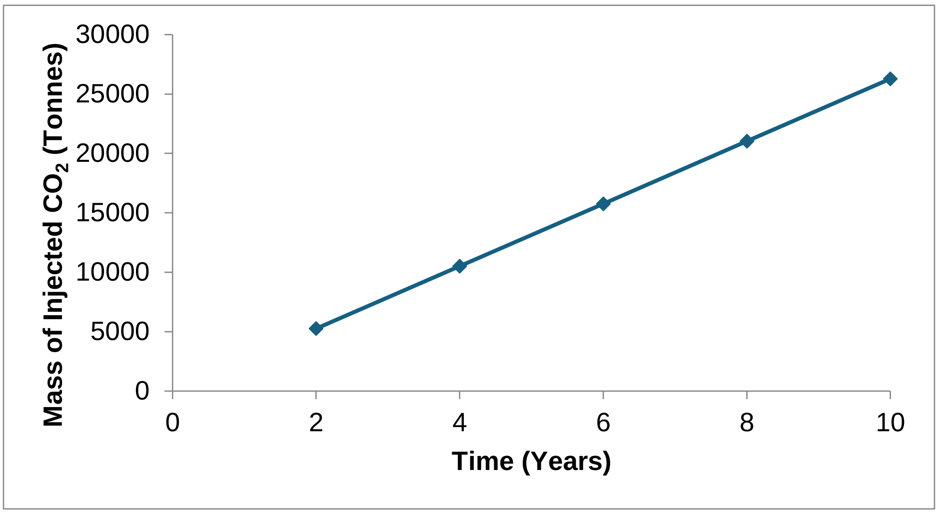

Figure 6: Graph of cumulative CO_2 injected

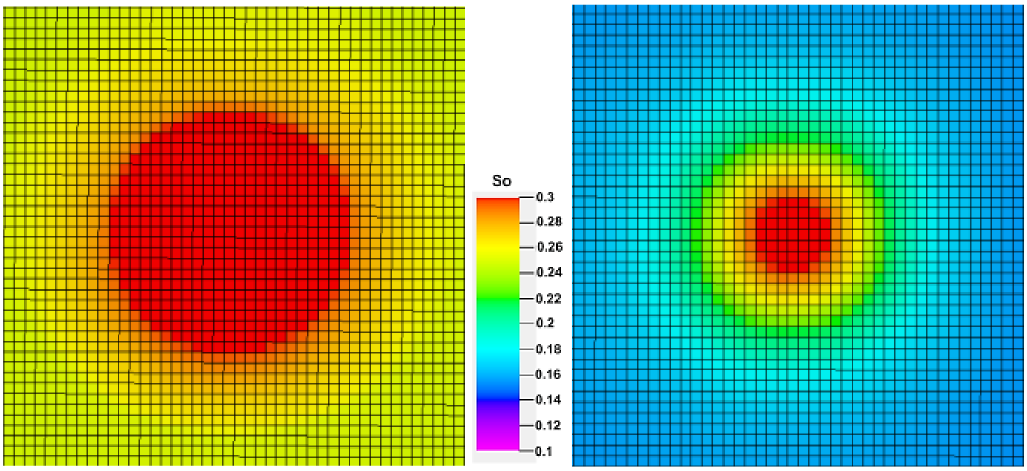

Figure 7: Profile of Condensate Oil Saturation around the Producer initially and after 3 years of Production

the K direction. This was to perform a detail study of how the condensate oil saturation around the producer changes with time.

Figure 7 shows that, as the reservoir is produced, the average condensate oil saturation within the reservoir reduces and there is noticeable difference in the change of condensate oil saturation around the producer during the first three years. This is expected judging by the rate at which the average reservoir pressure decreases in the first three years as shown in Figure 9. As the percentage of carbon dioxide gas in the reservoir fluid increases due to continuous its injection, the reservoir average pressure increases. The increase in average reservoir pressure improves the mechanisms of miscibility, condensation and re-vaporization between the reservoir gas and trapped liquid condensate. These ultimately lead to increase in gas and condensate oil productivity from the reservoir.

Figure 8 shows the profiles of average reservoir pressure against time during complete natural depletion (without CO_2 injection), it can be observed that the average reservoir pressure dropped by more than 70 % (from 5640 psia to about 4000 psia) within the first one year of complete natural depletion of the reservoir. The volumetric reservoir is sharply depleting at a factor of 18.44% within the first 60 days. The drop in reservoir pressure leads to more re-vaporization of the condensed liquid. The reduction in the condensate liquid concentration reduces its relative permeability, which eventually leads to the formation of immobile condensate bank in the vicinity of the well-bore. This results in reduction in well productivity as the formed immobile condensate bank in the vicinity of the wellbore prevents the flow of condensate gas into the well.

Table 6: Multiple Contact Miscibility Results from CMG Software

SUMMARY OF MULTIPLE CONTACT MISCIBILITY	
CALCULATIONS AT TEMPERATURE OF 65°C	
PARAMETERS	**VALUES**
Multiple Contact Miscibility Pressure (MMP)	4,125 Psia
Make Up Gas Mole Fraction	1.000
The MMP from Correlation	1878.5 Psia

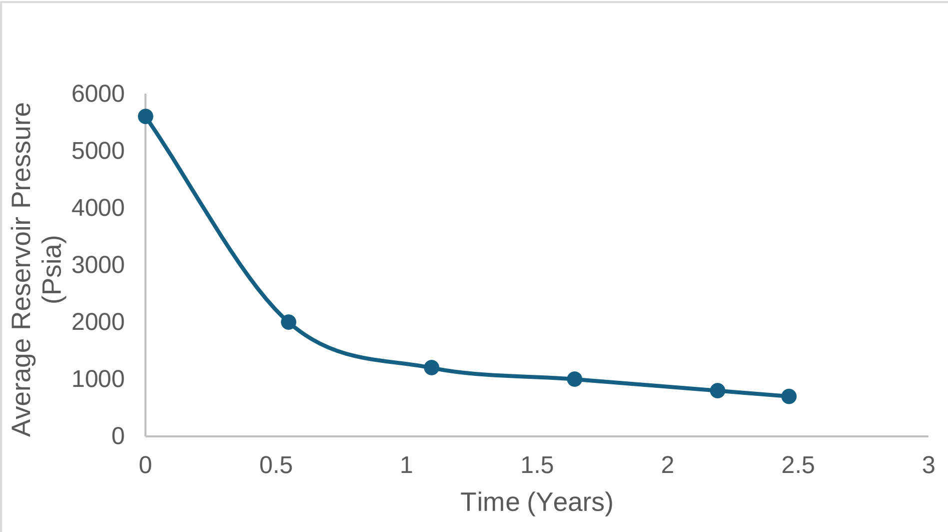

Figure 8: Average Reservoir Pressure against time during Complete Primary Depletion

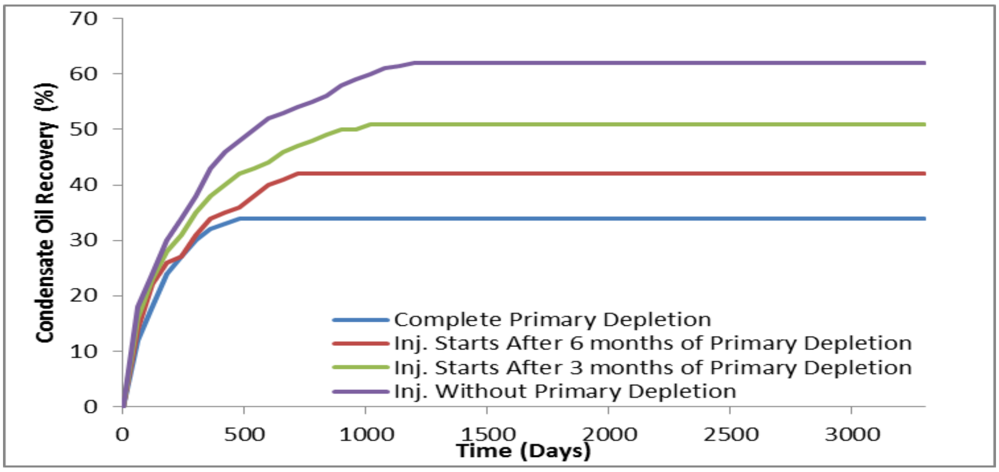

Figure 9: Condensate Oil Recovery Profile of Sensitivity Study of Gas Injection Period

Figure 9 shows the results of sensitivity analyses of the effect of injection starting time on condensate oil recovery. Due to the high average reservoir pressure depletion rate within the first one year of natural depletion, a delay in the injection starting time resulted in drastic drop in condensate oil recovery from the gas condensate reservoir. From the simulation results the highest condensate oil recovery of 86.35% was observed during complete CO_2 gas injection process without any natural depletion. This is due to early average reservoir pressure maintenance, which prevents the high drop rate in reservoir pressure which encourages the formation of immobile condensate liquid bank as a result re-vapourization of condensate oil in the vicinity of the wellbore.

The injection of carbon dioxide (CO_2) gas after three (3) months of natural depletion returned the condensate recovery factor of 69.13%. The lower percentage of fractional recovery during this process when compare with complete CO_2 gas injection is due to the lower average reservoir pressure at the start of the injection process some substantial

Table 4: The Project Expenses

		Description	Quantity	Total
1.	Cost of injection Well	$10M/well	4 wells	$40M
2.	Total cost of Treatment Facility			$6M
3.	Cost of Injection	$7/ton	26,280 tons	$183,960
4.	TOTAL			$46.184

amount of the reservoir pressure had been lost during the three (3) months of natural depletion. The injected CO_2 gas will take some time to create effective miscibility contact with the lost condensate liquid components resulting in lower condensate liquid fractional recovery. The start of the CO_2 gas injection after six (6) months of natural depletion will result in only about 62.27% of the condensate oil being recovered. More of the reservoir pressure has been expended during the six (6) of natural depletion hence greater time will be needed to create effective miscibility contact with the lost liquid condensate components. More injection rate is needed for the reservoir to recover its loss pressure and if the injection rate is increased beyond the formation fracture pressure, the injection wells will shut down and the project will be brought to an abrupt end. Hence the initial injection rate has to be maintained.

Producing the reservoir completely using the natural depletion yields as little as only 34.17% of the condensate oil recovery. This is due to uncontrollable drop in reservoir pressure (Figure 8). The failure to engage in reservoir pressure maintenance will result in low condensate oil fractional recovery (34.17%) from the gas condensate reservoir.

Observation of simulation results (Figure 9) shows that the condensate oil ultimate fractional recoveries in all the production mechanisms were achieved before the first three (3) years of production. Hence, producer will only produce gas after the third year, very little additional condensate oil will be produced after the third year of production. Further injection of carbon dioxide CO_2 gas after the third year should be solely for gas production and the storage of the injected CO_2 gas in the depleted subsurface gas condensate reservoir. The percentage of the CO_2 gas in the produced gas is expected to increase with time. The production well should be shut when the percentage of CO_2 in the produced gas is excessive (i.e. if CO_2 gas is 65% of the produced gas). The injection should be continued for carbon dioxide gas storage in the depleted subsurface reservoir.

Effects of Injected CO_2 on Climate Change

With increased threat on biotic life caused by the emission of greenhouse gases from the flaring of gases, this project is a huge success. The storing away 2628 Mt/annum of CO_2 means keeping away the emissions from an average of 1052 cars every year. The project, being small scale, means it could be easily replicated in many oil fields.

Economics of the Project

The carbon dioxide gas (CO_2) injection is an expensive project. Usually, a Gas Treatment plant is necessary to convert the Methane gas produced from the oil and gas field to CO_2. Also, large industrial plant exists around the facility would also have their carbon waste treated and converted to pure CO_2 for injection into the formation. The major financial challenge of these project is summarized below.

Table 4 shows the capital expenses (CAPEX) account for the bulk of the project expenses ($46 million out of the total $46.184 million) of the 3650 days (10 years) project period. The operating expenses (OPEX) account for only $183,960 which is less than 1% of the total expenses. Excluding the production well's capital and operating expenses (CAPEX and OPEX). The profits for different cases were investigated.

Table 5 shows the economic analysis for a ten years' period of CO_2 gas injection into the gas condensate reservoir. If the condensate oil price is set at $60 (USD)/BBL and gas price is set at $2.5 (USD)/MSCF.

It can be shown from Table 5 that complete primary depletion method of gas condensate reservoir returned the least profit of $69.63 million (USD) compared to the three injection methods. The process where injection was started after six (6) months of natural depletion increases the profit margin to $92.195 million (USD). The profit margin would be further increase to $119.41 (USD) when the pre-injection depletion time is reduced to three (3) months. The highest returned on investments ($176.65 (USD)) was when a complete injection process was implemented without prior natural depletion of the gas condensate reservoir.

Table 5: Economic Analysis of CO_2 Gas Injection into Gas Condensate Reservoir

Production Method	Injection Time (days)	Produced Gas (BSCF)	Injected Gas (BSCF)	Condensate Oil Produced (MBBL)	Condensate Recovery Factor (%)	Revenue (million $, USD)	Injector Expenses (CAPEX + OPEX) (million$)	Profit Margin (million $ USD)
Complete Primary Depletion	-	7.634	-	842.974	34.17	69.63	-	69.63
Inj. Starts After 6 months of Primary Depletion	3,464	18.481	19.745	1536.201	62.27	138.37	46.175	92.195
Inj. Starts After 3 months of Primary Depletion	3,557	25.305	20.275	1705.437	69.13	165.59	46.179	119.41
Inj. Without Primary Depletion	3,650	38.127	20.805	2130.255	86.35	222.83	46.184	176.65

Application of the CO_2 gas injection for longer time with bottom hole pressure (BHP) constraints assist in the recovery of both natural gas and condensate oil from a gas condensate reservoir.

Hence, injection of captured carbon dioxide (CO_2) gas into gas condensate reservoir will provide a win-win situation in term of profit margin and protection of the environment. Since gas flaring attracts heavy fines depending on the amount of gas flared, CO_2 injection will be very profitable for both in term of profit for the oil company and the protection of the environment. The project has the capability to be extended beyond the ten years' simulation period in this study. Hence implementation of similar scheme in many hydro-carbon reservoirs will be of much incentive both in term of return on investment to the investors and an avenue for the reduction of greenhouse gases from the environment thereby reducing global warming.

Conclusion

i. Production of volumetric gas condensate reservoir through a natural depletion process results in immobile condensate oil saturation whose saturation is less than the critical condensate saturation thereby reducing productivity of both natural gas and condensate oil.

ii. Injection of the carbon dioxide gas above the dew point pressure through the injector and constraining the flowing bottom hole pressure at the producer for high yield of condensate oil help in maximizing the gas and condensate oil productivity.

iii. The carbon dioxide injection into a gas condensate reservoir help to create miscibility, condensation and re-vapourization mechanisms between the gas and lost condensate, which enhances gas and condensate oil recoveries.

iv. The sensitivity analyses of the effect of natural depletion periods of condensate recovery factors shows the negative effect of the natural depletion time on the condensate oil fractional recovery. The natural depletion time of 0, 3, 6 and 36 months returned recovery factors of 86.35%, 69.13%, 62.27% and 34.17% respectively.

v. Complete carbon dioxide (CO_2) gas injection without prior natural depletion of the gas condensate reservoir generates highest return on investment with a profit margin of $176.65 (USD) and complete production through natural depletion returned the least profit margin value of $69.63 million (USD).

vi. A substantial reduction in the amount of greenhouse gas in the atmosphere through subsurface storage of the captured carbon dioxide (CO_2) gas was achieved in addition to the optimal profit margin returned when CO_2 was injected into the gas condensate reservoir.

References

App, J. F. and Burger, J. E. (2007): Experimental determination of relative permeability for a rich gas condensate system using live fluid. In: SPE annual technical conference and exhibition. Society of Petroleum Engineers.

Dong, P. C. Jiang, T. W. Tang, M. L. and Xie, W. (2007): Optimization of Yaha-5 Condensate Gas Reservoir Development Method," *Daqing Petroleum Geology and Development*. 26(3): 51–54.

Elsharkawy, A. M. (2002): Predicting the Properties of Sour Gases and Condensates',in *2002 SPE International Petroleum Conference and Exhibition*. Society of Petroleum Engineers.

Fasesan, S., Olukini, O. and Adewumi, O. (2003): Characteristics of Gas Condensate. *Petroleum Science and Technology*. 21(1–2):81–90.

Ghorbani, H., Moghadasi, J. and Wood, D.A. (2017): Prediction of Gas flow rates from Gas Condensate Reservoirs through Wellhead chokes using a Firefly Optimization Algorithm. *Journal of Natural Gas Science and Engineering*. 45:256–271.

Hamid, B., Hamidreza, H. and Christopher, R. C. (2017): Production of Data Analysis of Gas Condensate Reservoirs using two-phase viscosity and two-phase compressibility. *Journal of Natural Gas Science and Engineering*, 47(7): 47-58.

Huerta, Q.V.A., Lanchimba, A.F. and Colonomos, P. (2010): Gas Condensate Field Development Plan by means of Numerical Compositional Simulation. In: SPE Latin American and Caribbean Petroleum engineering conference. Society of Petroleum Engineers.

Janiga, D., Czarnota, R., Stopa, J., Wojnarowski, P. and Kosowski, P. (2017): Performance of Nature inspired Optimization Algorithms for Polymer Enhanced oil Recovery Process. *Journal of Petroleum Science and Engineering*. 154:354–366.

Janiga, D., Czarnota, R., Stopa, J., Wojnarowski, P. and Kosowski, P. (2019): Utilization of Nature-Inspire Algorithm for Gas Condensate Reservoir Optimization, *Soft Computing*. 23:5619-5631.

Jingsong, L., Xiangfang, L., Xiaodong, K., Min, T. and Yongyi, Z. (2004): New method of cyclic gas injection for condensate gas reservoirs, *Natural Gas Industry*, 24: 76–79.

Johnson, C. and Jamiolahmady, M. (2018): Production data analysis in Gas Condesate Reservoirs using Type Curves and the Equivalent Single-phase approach. *Journal of Petroleum Science and Engineering*. 171:592-604.

Kalugin, Y., Yakovlev, V. and Kalugin, A. (2015): Mathematical Modeling and Optimization of Gas-Condensate Field Development. Journal of Natural Gas Science and Engineering. 27(Part 2):1195–1204.

Kaydani, H., Mohebbi, A. and Hajizadeh, A. (2016): Dew-point Pressure Model for Gas Condensate Reservoirs based on Multi-Gene GeneticPprogramming Approach. *Applied Soft Computer* 47:168–178.

Kerunwa, A. and Uchebuakor, C. (2015): Optimization of Condensate recovery using using Gas Recycling Technique. *Petroleum and Coal*. 57(5): 565-572.

Li, S. L., Pan, Y. and Sun, L. (2008): New Ideas for Improving the Recovery Efficiency of Condensate Gas Reservoirs. *Natural Gas Industry*. 28(9). 145- 153.

Lu, F. (2019): Gas Injection Enhanced Oil Recovery Phase Behavior and Seepage Mechanism of Dalaoba Condensate Gas Reservoir, *Journal of Southwest Petroleum University*, Chengdu, 23(14), 18-26.

Lu, H., Ma, G., Cao, L. and Azimi, M. (2019): Optimization of Light Hydrocarbon Recovery System in Condensate Gas Field, *Energy Reports*, 5, 1209–1221.

Mahdiyar, H and Jamiolahmady, M. (2014): Optimization of hydraulic fracture geometry in gas condensate reservoirs. *Fue*l. 119:27–37.

Mindek, C. (2005): Production Optimization of Gas Condensate Reservoir Using a Black Oil Simulator and Nodal System Analysis: A Case Study. *A Thesis submitted to the Graduate School of Natural and Applied Sciences*, Middle East Technical University.

Mohammad, H. S., Mohmmad, H. and Reza, A. (2016): Production of Data Analysis in a Gas Condensate Field: Methodology, Challenges and Uncertainties, *Iranian Journal of Chemistry*. 35(2), 113-127.

Mohsen, S. B., Abdolnabi, H. and Reza, A., Hamed H. and Hamid E. (2021): Numerical Well Test Analysis of Condensate Dropout Effects in Dual-permeability Model of naturally Fractured Gas Condensate Reservoirs: Case Studies in the South of Iran. *Mathematical Problems in Engineering*. 53(21): 1-10.

Nasriani, H.R., Borazjani, A.A., Iraji, B. and Moradi, D. A. M. (2015): Investigation into the Effect of Capillary Number on Productivity of a Lean Gas Condensate Reservoir. *Journal of Petroleum Science and Engineering* 135:384–390.

Rahimzadeh, A., Bazargan, M., Darvishi, R. and Mohammadi, A. H. (2016): Condensate Blockage Study in Gas Condensate Reservoir. *Journal of Natural Gas Science and Engineering*. 33:634–643.

Sadooni, M. and Zonnouri, A. (2015): The effect of Nitrogen Injection on Production Improvement in an Iranian Rich Gas Condensate Reservoir. *Journal of Petroleum Science and Technology*, 33(4):422–429.

Safari, B. and Hashemi, A. (2016): Condensate Blockage Effects in Well Test Analysis of Dual-Porosity/Dual-Permeability, Naturally Fractured Gas Condensate Reservoirs: A Simulation Approach, *Iranian Journal of Chemistry*, 6: 729-742.

Sakhaei, Z., Mohamadi-Baghmolaei, M., Azin, R. and Osfouri, S. (2017): Study of Production Enhancement through Wettability Alteration in a Super-Giant Gas-Condensate Reservoir. *Journal of Molecular Liquids*, 233:64–74.

Smiths, R., Van der Post N. and Al Shaidi, S. (2001): Accurate Prediction of Well Requirements in Gas Condensate Fields. *In: SPE Middle East Oil Show.* Society of Petroleum Engineers.

Su, Z., Tang, Y., Ruan, H., Wang, Y. and Wei, X. (2017): Experimental and Modelling Study of CO_2-Improved Gas Recovery in Gas Condensate Reservoir. *Iranian Journal of Chemistry,* 6(1):87–95.

Wu, Y., Yao, K., Liu, Y., Li, X., Wu, M., Cheng, R. and Wang B. (2021): Experimental Study of Enhanced Condensate Recovery by Gas Injection in Yaha Condensate Gas Reservoir, *Geofluids*. 2021, 21-36.

Zhou, C., Wu, X., Li, H., Lin, H., Liu, X., Cao, M. (2016): Optimization of Methods for Liquid Loading Prediction in Deep Condensate Gas Wells, *Journal of Petroleum Science Engineering,* 146:71–80.