Petroleum and Coal

Article **Open Access**

Enhanced Recovery of Natural Gas Condensate Reservoir Using Carbon-Dioxide: A Simulation Study

Shadrach O. Ogiriki, Hezekiah O. Agogo and Nuradeen L. Tanko*

Department of Petroleum and Gas Engineering, Baze University, Abuja, Nigeria

Received July 21, 2021; Accepted January 14, 2022

Abstract

This study is aimed at improving the recovery of Natural Gas Condensate from a Niger-Delta Reservoir in Nigeria, with 35.1 million stock tank barrel (MMSTB) and a 6879 pounds per square inch (psi) reservoir pressure. ECLIPSE 300, a compositional reservoir simulator, was employed to simulate (mimic) the candidate reservoir conditions so as to understand the performance of Carbon-dioxide (CO_2) as the injecting fluid, while enhancing the recovery of the natural gas condensate from the reservoir. Nine case studies with different CO2 injection rates were considered to determine the optimum CO_2 injection rate. These were compared with the recovery from the natural energy drive of the reservoir. Using the natural energy (drive) of the reservoir, only 11.04MMSTB of natural gas condensates was recovered, which indicated a 32% recovery factor for the natural drive system. Case 6 with CO_2 injection rate of 4000 stock tank barrel per day (STB/D) recorded the optimum recovery factor for this natural gas condensate reservoir. This case 6 yielded an ultimate recovery of 21.65MMSTB with a recovery factor of 62%. This simulation results, precisely considering the reservoir conditions, indicated that CO_2 can be used to enhance natural gas condensate recovery from Niger-Delta reservoirs as demonstrated in this study. Another significance of this study is that CO_2 with its adverse effects to the atmosphere and environment can be gainfully used for enhanced natural gas recovery as well as stored in hydrocarbon reservoirs so as to reduce its volume in the atmosphere.

***Keywords**: Natural gas condensate; Carbon-dioxide; CO_2 injection; Enhanced gas recovery; Reservoir simulation.*

1. Introduction

The world is incessantly experiencing a growing demand for energy resources to meet the ever-increasing energy consumption due to rising population [1-2]. Also, there has been a shift of focus from liquid fossil fuels to a more environmentally friendly and cheap energy sources such as natural gas. This shift however, is consequent upon the fact that natural gas emits less greenhouse gasses like CO_2 thus limiting the current hazardous environmental energy impacts due to global warming – about 34 Gigatons of CO_2 as reported by the International Energy Agency [3]. In 2019, Ajayi *et al.* [4] proposed that fossil fuels reservoirs offer a stochastic approach for the sequestration of Carbon (IV) oxide. Moreover, this translates to the fact that CO_2 which is deemed a nuisance to the environment, can be re-used as a means for enhanced gas recovery (EGR) instead of discharging it irresponsibly to the environment. Even so, Amin *et al.* also demonstrated in their research that similar approach can be applied to gas shale reservoirs [5]. Consequently, depleted gas reservoirs become rejuvenated or energised through CO_2 injection [6]. Moreover, Morsy *et al.* [7] highlighted the concern that gas condensate reservoir requires an effective CO2 injection method to bypass the condition of "condensate banking" during enhanced recovery. Gas condensate reservoirs offer excellent storage capabilities for CO_2 plus an extra merit of improved gas recovery through re-injection to the reservoir to augment the inherent drive mechanism of the concerned reservoir [8-9].

Condensates are usually formed from the gas stream upon production from gas condensate reservoirs [10]. This happens when pressure suddenly declines below the dew point pressure of the natural gas, thereby reducing mobility to the surface during production. In addition, Jo [11] opined that the fall of pressure below dew point in gas condensate reservoirs is the reason for "condensate blockage" in the wellbore which in turn, causes decline in gas flow rate and productivity. Also, retrograde condensation is another concern that needs to be looked into considering its negative impacts on natural gas production from condensate reservoirs. This concern is attributed to reduced reservoir capacity emanating from the coalescing of liquid in the reservoir. The unwanted liquid accumulation causes high liquid dropout that reduces gas relative permeability. Nevertheless, the role of CO_2 injection in this scenario is to re-vaporize the condensed flow and increase mobility for optimum gas recovery [12]. With respects to the afore-stated challenges, it is obvious that production enhancement from condensate reservoirs is a necessity for optimum gas recovery. However, this paper seeks to demonstrate how CO_2 injection can be used for the enhancement of gas condensate reservoirs in the Niger Delta region of Nigeria through Enhanced Gas Recovery (EGR). A simulation approach using Eclipse 300 modeling toolkit will be presented and discussed in subsequent sections.

2. Theories and definitions

Enhanced oil recovery through Carbon (IV) oxide injection have long been practiced in the oil and gas industry to primarily displace oil to the wellbore for increased productivity, especially for depleted oil reservoirs [13]. Recent research works have demonstrated the efficacy of using CO_2 injection as a means of enhancing hydrocarbon recovery from gas condensate reservoirs [14-17]. According to literature, there are two basic methods of CO_2 injection. They are; miscible and immiscible gas injection (CO_2) [18]. Basically, miscible CO_2 injection enhances oil production by reducing crude oil viscosity thus elevating oil displacement efficiency. In same fashion, CO_2 injection is employed to gas reservoirs to foster optimum gas recovery. Notwithstanding, the procedure is more complicated than that of oil reservoirs due to the following factors [19];

1) Adsorption of gases within reservoir rocks.
2) The chemical affiliation between CO_2 and natural gas

Depleted gas reservoirs provide a larger volumetric capacity to house CO_2 when compared to oil reservoirs. Invariably, CO_2 is mostly stored at critical conditions (i.e. >32°C and 7.4Mpa). Under reservoir conditions, CO_2 is completely miscible with natural gas thus making it constitute nuisance to the natural gas resource. Carbon (IV) oxide is anti-combustive in nature, when completely mixed with natural gas; it increases the sweetening requirements of natural gas which are usually expensive. Hence, practical CO_2-EGR procedures are somewhat challenging especially when specifying the right quantity of CO_2 to be injected into the reservoir [1]. Consistent simulation modeling is subject to parameters like dispersion coefficient and tortuosity – as mixing take place by the process of diffusion in many reservoirs [20]. Superfluous amount of CO_2 leads to early breakthrough in production wells. More so, subsurface reservoir temperature modelling is often needed to describe the behavior of the fluid during injection, production and shut-in [21]. It also creates a medium to determine other parameters like production height and location [22]. In practice, there is need for CO2 injection to be optimized using appropriate simulation methods to circumvent the condition of produced gas contamination that increases the treatment costs of the produced gas [19].

2.1. Gas reservoirs

Gas reservoirs are basically grouped into condensates, wet and dry gas reservoirs [23]]. In short, gas reservoirs are generally best described using phase diagrams [24]. The phase diagram showing different types of gas reservoirs is illustrated in Figure 1. It is paramount to address the effect of CO_2 injection on the gas phase behavior. PVT laboratory experimentations have shown that CO_2 has a drying impact on condensate and wet reservoirs. Conversely, CO_2 has a wetting effect on dry gas reservoirs. Conventionally, upon the addition of CO_2 in the reservoir, compressibility of gas declines and provides a high storage capacity in the process [25]. In depleted retrograde gas condensate reservoirs, liquid condenses from the gas stream at conditions below the dew point. This drop below dew-point has two major effects; firstly, gas production decrease due to near-well blockage, and secondly, reduced mobility of fluid flow to the wellbore. Although it is no longer a controversy that gas recovery factors are generally higher than those of oil fields, some challenges are usually encountered [26]. A number of productivity losses have been recounted for wells in gas-condensate fields. In Arun field, which was operated by ExxonMobil, the loss in some wells was greater than 50%. There was also another case where two wells from a field operated by ExxonMobil were reported to have died due to condensate blockage.

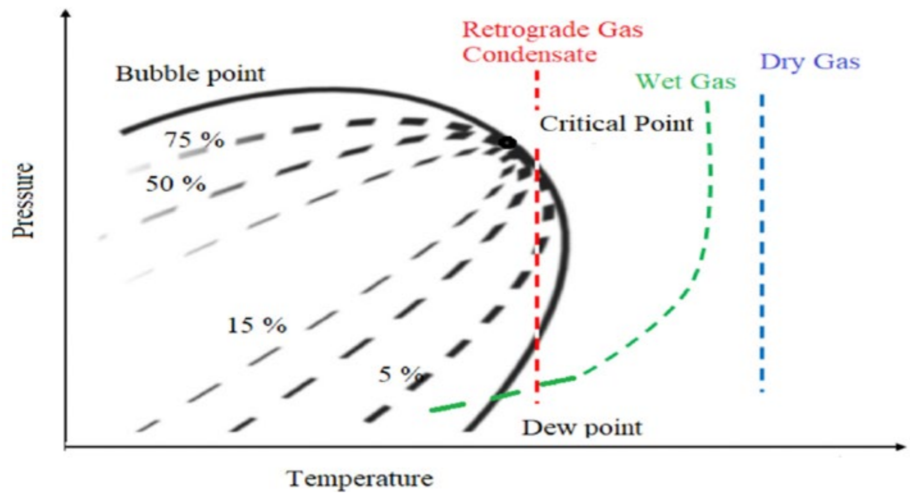

Figure 1. Phase diagram of different gas reservoirs [1]

Gas condensate reservoirs are mostly affected by near-wellbore condensate blockage. However, the extent to which condensate dropout constitute a production problem is dependent on the ratio of pressure drop within the reservoir to the total pressure drop from distant areas of the reservoir. At a relatively high pressure drop, condensate blockage issues need to be addressed for well deliverability. This condition typically applies in a formation with a low reservoir capacity (kh) [11]. Condensate blockage can be assumed to double the pressure drop in the reservoir for the same flow rate. Also, it is possible to increase the temperature of the accumulated liquid in the gas wellbore through methanol injection – so as to curb the problem of condensate blocking [27]. Another, approach to this problem is to perform hydraulic fracturing of the reservoir to the liquid bank thereby temporarily improving gas productivity [28]. Theoretically, flow in gas condensate fields can be subdivided into three reservoir regions, although in some scenarios not all three are present. Figure 2. illustrates the regions encountered during gas production from condensate reservoirs. The two regions nearest to the wellbore can exist at bottom hole pressures lower than the dew point of the gas stream. The third region, distant from the producing well, exists only when the reservoir pressure is above the dew point. Above the dew point pressure of gas, only one phase of fluid can exist – gas. The interior periphery of this region occurs where the pressure equals the dew point pressure of the original reservoir gas. This boundary is not stationary, but moves outward as hydrocarbon are produced from the well and the formation pressure drops, eventually disappearing as the outer-boundary pressure drops below the dew-point.

In the second region which is the condensate-buildup region, liquid condenses out from the gas phase, but its saturation remains small and immobile. The amount of liquid that drops out is determined by the gas phase characteristics, as described by its PVT diagram. The liquid saturation increases and the gas phase become slimmer as gas flows to the wellbore.

In the first region, closest to producing well, both gas and condensate phases flow. The condensate saturation here is greater than the critical condensate saturation. This region ranges in size from tens of feet to lean condensates to hundreds of feet for rich condensates. Its size is proportional to the volume of gas drained and the percentage of liquid dropout. It extends farther from the well for layers with higher permeability than average since a larger volume of gas has flowed through these layers.

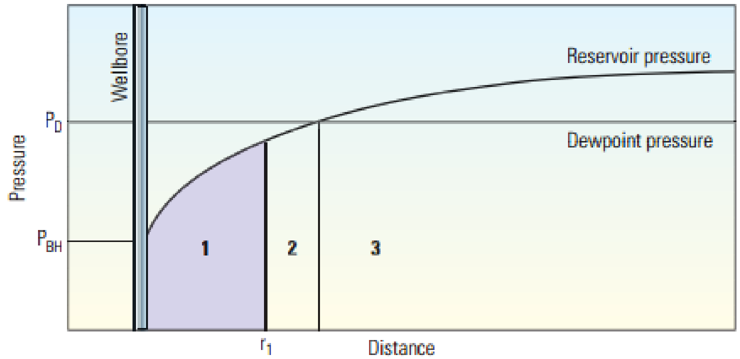

Figure 2. Three regions in gas condensate reservoirs

2.2. Concepts of reservoir simulation

Reservoir simulation – using commercial tools – is usually conducted to monitor the impact of *CO2* injection on the deliverability of gas wells and condensate rates enhancement. The simulation envisages a systematic application of numerical modelling through discretization method used for spatial gridding of radial mesh. In short, the resulting simulator incorporates concise implicit time functions and diverse point schemes based on finite difference approximations or appropriate linearization schemes as demonstrated in recent literatures [29-31]. These schemes mimic unstructured grids and packed tensor permeability precisely while employing "equation of state" (EoS) for the fluid model.

3. Methodology

This section discusses the implementation of dynamic reservoir simulation tool ECLIPSE 300 specialized in compositional modeling to account for the following effects:

i. Condensate production and saturation
ii. CO_2 injection under pressure depletion

For this purpose, the software used with basic features of the reservoir are delineated to characterize fluid properties such as viscosity, density, API gravity, and rock properties (porosity, relative permeability, compressibility) gas production rate, pressure of reservoir, depth of the reservoir, area of the field of operation. Following this, simulations of the gas condensate reservoir was performed for the gas condensate reservoir under pressure depletion for the hypothetical reservoir with one producer well.

3.1. Simulator work flow and case runs

A typical Eclipse Simulator Workflow consists of defining the Cases (Runs Specification) and this step is critical and the objective is clearly defined here. Then the collected data is reviewed followed by building of the model and property modeling - 3D grid modeling (Import, editing etc.), initialization, scheduling. History matching (optimization) is then performed in which the pressure and production match are established. Finally, forecasting or prediction of future production outcomes under varying operating strategies.

For the purpose of this paper, case runs were carried out involving simulated scenarios, prior to changing the reservoir geological features in the grid tab, petrophysical properties and well production conditions. Individual cases were reported on the run manager tool in the ECLIPSE 300 to avoid bugs. Careful set of input rules was followed to avoid errors in which case the run manager hangs and becomes inappropriate to generate the output file and data. The hypothetical reservoir was modelled with some permeability and porosity values generated from the pseudo pressure integral function method. For the purpose of clarity, a producer well system (AD_1) was assumed to be operating at a producing rate of 4000MScf/day with an equidistant injector well.

3.2. Data gathering and presentation

The data used for this study include
1) 3D static modelled grid and property data,
2) well data for one relative permeability data.

Table 1 shows the PVT Fluid Composition versus depth for DAMA Reservoir. Table 3 also shows the correlations Endpoints used in generation Special Core Analysis (SCAL).

3.3. Model description

For the purpose of model simulation, a Niger delta gas condensate field consisting of one proposed producing well (Well-01) was used for this study. The simulation models a 6800acres gas condensate field. The constructed model is in grid unit of feet with the following grid axis with respect to map coordinates and dimensions :79 x 19 x 12. The reservoirs fluid properties with respect to depth have been tabulated in the Table 1.

3.4. Case definition

The Eclipse simulation has been built with inputs from the static model, and other engineering data. Simulation start date was defined for the cases. Grid dimensions (in x, y and z directions) were specified as illustrated by Table 2. Cartesian grid and corner point grid geometry options were chosen for more accurate reservoir modeling. Reservoir fluid phases (water, oil, gas, dissolved gas and vaporized oil) were defined. A fully implicit solution method was used for all the runs to guarantee convergence of the solution type.

Table 1. PVT Fluid Composition vs depth

Depth (ft)	Z1	Z2	Z3	Z4	Z5	Z6	Z7
15257	0.016	0.669	0.178	0.029	0.071	0.032	0.005
15506.7	0.016	0.664	0.178	0.03	0.073	0.034	0.005
15510.64	0.016	0.664	0.178	0.03	0.073	0.034	0.005
15514.58	0.016	0.664	0.178	0.03	0.073	0.034	0.005
15518.52	0.016	0.664	0.178	0.03	0.073	0.034	0.005
15522.47	0.016	0.664	0.178	0.03	0.073	0.034	0.005
15526.41	0.016	0.664	0.178	0.03	0.073	0.034	0.005
15530.35	0.016	0.664	0.178	0.03	0.073	0.034	0.005
15534.29	0.016	0.664	0.178	0.03	0.073	0.034	0.005
15538.23	0.016	0.664	0.178	0.03	0.073	0.034	0.005
15542.17	0.016	0.664	0.178	0.03	0.073	0.034	0.005
15546.11	0.016	0.664	0.178	0.03	0.073	0.034	0.005
15550.06	0.016	0.664	0.178	0.03	0.073	0.034	0.005
15554	0.016	0.664	0.178	0.03	0.073	0.034	0.005
15557.94	0.016	0.664	0.178	0.03	0.073	0.034	0.005
15561.88	0.016	0.663	0.178	0.03	0.073	0.034	0.005
15565.82	0.016	0.663	0.178	0.03	0.073	0.034	0.005
15569.76	0.016	0.663	0.178	0.03	0.073	0.034	0.005
15573.7	0.016	0.663	0.178	0.03	0.073	0.034	0.005
15577.65	0.016	0.663	0.178	0.03	0.073	0.034	0.005
15581.59	0.016	0.663	0.178	0.03	0.073	0.034	0.005
15585.53	0.016	0.663	0.178	0.03	0.073	0.034	0.005
15589.47	0.016	0.663	0.178	0.03	0.073	0.034	0.005
15593.41	0.016	0.663	0.178	0.03	0.073	0.034	0.005
15597.35	0.016	0.663	0.178	0.03	0.073	0.034	0.005
15601.29	0.016	0.663	0.178	0.03	0.073	0.034	0.005
15605.24	0.016	0.663	0.178	0.03	0.073	0.034	0.005
15609.18	0.016	0.663	0.178	0.03	0.073	0.034	0.005
15613.12	0.016	0.663	0.178	0.03	0.073	0.034	0.005
15617.06	0.016	0.663	0.178	0.03	0.073	0.034	0.005
15621	0.016	0.662	0.178	0.03	0.073	0.034	0.005

Table 2. Simulation Grid Dimensions Reservoir Specifications

GRID options	Geometry options	Grid dimensions			PVT considerations
		I	J	K	
Cartesian	Corner point	79	19	12	Water-Oil-Gas

Table 3. Corey Endpoints values

Corey Water	4	Corey Oil Gas	3
Corey Gas	3	Sgmin	0
Corey Oil Water	3	Sgcr	0.05
Swmin	0.25	Sgi	0
Swi	0.25	Krg (Sorg)	0.7
Swmax	1	Krg (Sgmax)	0.7
Sorw	0.1	Sorg	0.1
Kro(Sgmin)	0.9	Kro (Swmin)	0.9

Some of the basic reservoir properties can be seen in Table 4. All the data gathered were integrated and quality checked, and were further used to archive a fit for purpose dynamic model for DAMA reservoir.

Table 4. Reservoir properties

Reservoir description	Values
Total field area, acres	6800
Average thickness, ft	100
Average reservoir depth, ft	8920
Datum depth, ft	15527
GOW depth, ft	15593.8
Initial reservoir pressure, psia	6879
Reservoir temperature, oF	227
Average porosity, %	14
Average water saturation, %	25
Dew point pressure, psia	4700

4. Results and discussion

Model was initialized under hydrostatic equilibrations, the contact used were carried forward from the static modeling. The equilibration data is shown in Table 5.

Table 5. Equilibration data

Reservoir_ A	Pi (Psia)	Datum depth (Ft)	Gwc (Ft)
Dama	6879	15527	15593.8

Table 6. Initialized volume

Static volumes (MMSTB)	Oil dynamic volumes (rb) (reservoir volume)	Gas dynamic volumes (MMSTB)	Gas (reservoir volume) (MMSCF)
35.1	0	34.85	195.65

Table 6 show the Initialized volume from the dynamic initialization, the oil reservoir volume is zero (0) showing that the fluid exists as gas condensate in the reservoir but the condensate drops out at the separator with a volume of 34.85MMSTB which is quite reflective that very reasonable quantity can be recovered if properly managed.

Also, Carter-Tracy analytical aquifer was attached as bottom drive to sustain the energy of the reservoir as shown in Table 7.

Table 7. Carter-Tracy's Aquifer Data

Aquifer perm (Md)	100
Aquifer Angle	177°
Compresibility	4.20e-06

Figure 3 presents the oil saturation map, the map proves that there was no liquid formed at the initial state of the reservoir life. The oil saturation is zero (0) as seen from the map. Also, figure 4 shows the condensate saturation map at the initial stage of the reservoir.

To achieve the objectives of this paper, different case runs have been carried out on the simulated model. To start with, the reservoir was firstly investigated under natural gas depletion. Furthermore, other cases where then run, which considered the duration of the injection of CO_2 and varying the rates of injection to determine the optimal injection pressure.

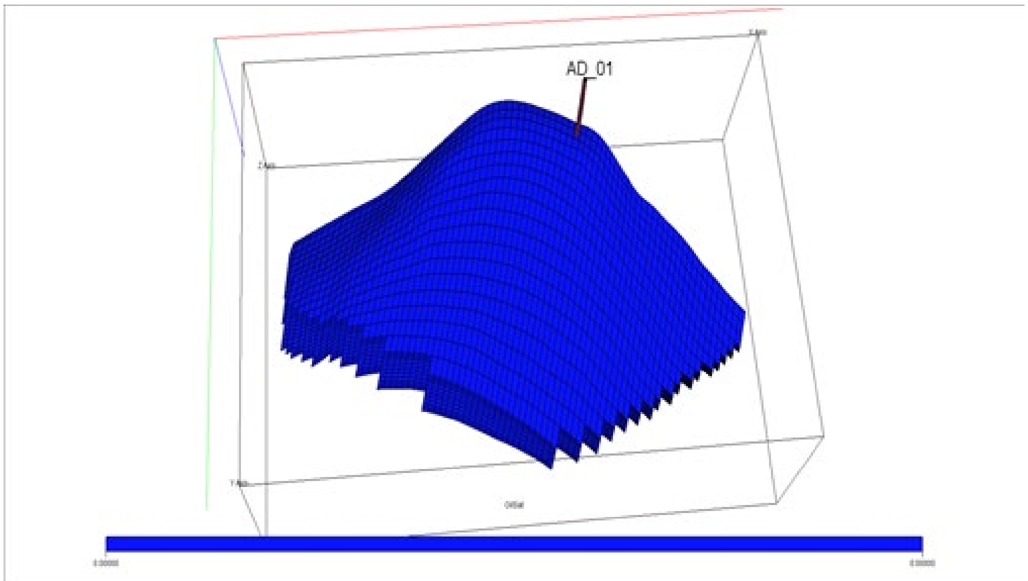

Figure 3. Initial oil saturation map

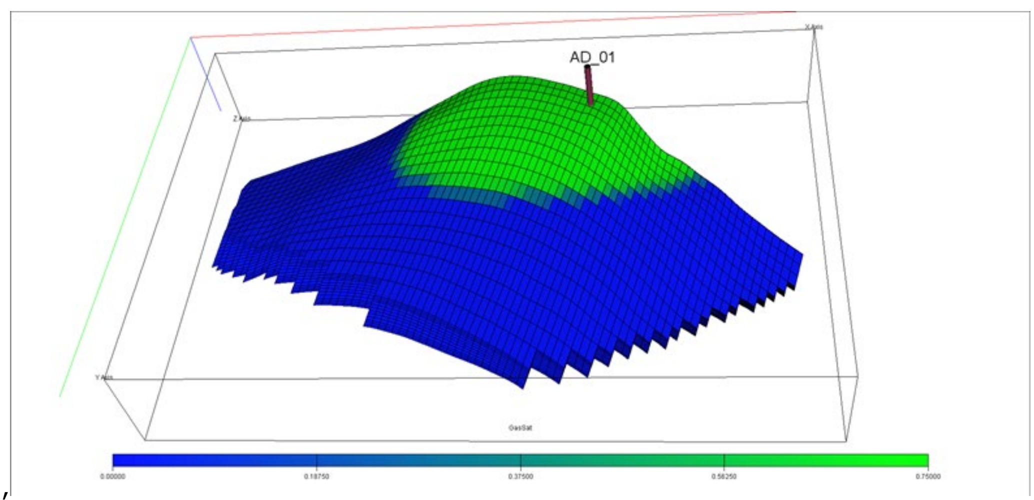

Figure 4. Condensate saturation map

4.1. Case 1 (Base case)

In this case the reservoir was subjected to natural depletion, and well AD_01 was opened to production. The predicted production period is for 25 years from (2017 to 2041) with a maximum reservoir liquid production rate of 4000Mstb/day. This was done to investigate the efficiency of the natural depletion and to determine the recovery factor on natural depletion. Figure 5 illustrates the production profile of the base case simulation runs. Also figure 6 shows the gas condensate saturation map and the oil (oil drop out due to attending due point at the reservoir) saturation map at the end of prediction while Table 8 shows the summary results. Until the year of 2020, field oil production is increasing at a constant rate, but subsequently, the field faces the reduction of oil production as shown in figure 5. In other words, the field's production potential is not attained. Therefore, in order to increase production, we need to apply the CO_2 injection.

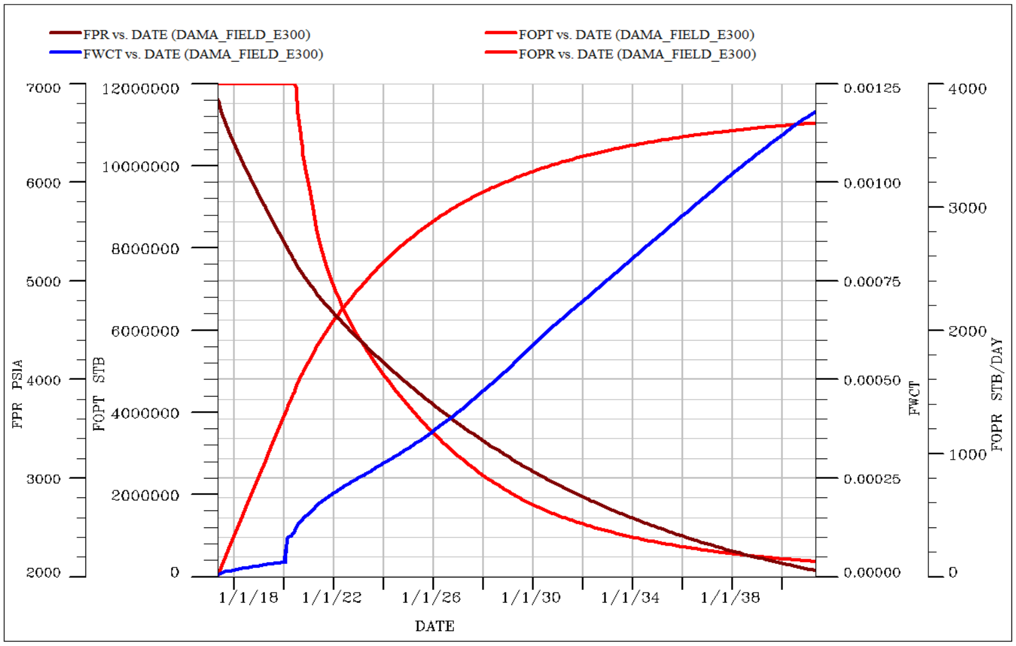

Figure 5. Production Profile of the base case simulation

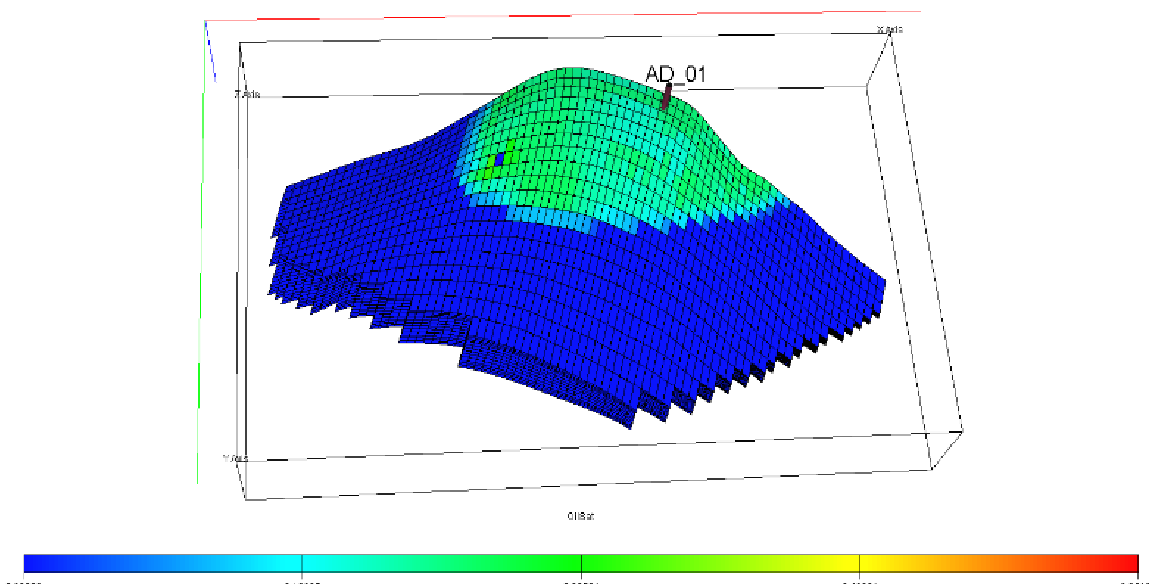

Figure 6. EOP gas condensate saturation map

Table 8. Summary results for base case

Oil dynamic volumes (MMSTB) (wrt separator)	Dynamic ultimate recovery (MMSTB)	R.F @ end of history (%)	Oil rate @ end of prediction STB/day	BHP @ end of history (PSIA)
34.85	11.04	31.67	123	2064

4.2. Case 2 (CO_2 injection)

CO_2 injection has been carried out. The reservoir pressure is being maintained by the injection of CO_2. DAMA reservoir has been observed under natural depletion to have started declining in rate after the year 2020 hence pressure maintenance with CO_2 injection had been kick started just at the time of production rate decline. The injection well has been set to BHP control. It was observed that under natural depletion, the reservoir BHP attained a minimum pressure of 2064psia. Therefore, the injection BHP target has been set to a pressure above the minimum reservoir pressure after natural depletion prediction. Based on these, further sensitivity analysis have been carried out by running different simulation scenarios using different injection BHP target starting from a target minimum of 2500psia to a target maximum of 7500psia to achieve an optimum injection pressure that will yield maximum recovery. The maximum injection pressure 7500 psia was used in other to stay within the pressure regime as observed in the reservoir to avoid over pressuring the system which could lead to fracturing.

The injection well coordinate is represented in Table 9. The CO_2 injection gas composition is also represented in Table 10

Table 9. Injection well coordinates

Well Name	i coordinate	J	K upper	K lower
INJ	37	7	8	11

Table 10. Injection gas composition

Component	Mole%	Component	Mole%
H_2	1.8	C3	14.16
CO_2	32.92	iC4	7.77
C1	23.37	nC4	5
C2	14.98		

Table 11 shows the summary of results obtained from the injection BHP targets that was considered. Table 11 presents the summary of all the cases that have been considered. It shows the BHP target that was used for each case, their respective ultimate recovery (UR) and recovery factor (R.F). It can be observed that the BHP target for Case 1 and 2 had no effect on condensate recovery, therefore they have a uniform ultimate recovery and recovery factor with the base case. Figure 7 represents the incremental field oil production total for all case scenarios.

The pressure profile for all case is illustrated in Fig. 4.6. Case 9 pressure profile looks to be over pressured. In other to determine the maximum CO_2 injection pressure (BHP target) that is best for the reservoir and also, to avoid having over pressured system, an analytical plot of R.F vs Injection BHP target has been made to properly ascertain the maximum injection pressure. This could be seen in Figure 9.

Table 11. BHP injection cases

Cases	CO_2 BHP injection (psi)	CO_2 injected volume (STB/D)	Ultimate recovery (MMSTB)	Recovery factor (%)
Base Case	0	0	11.04	32
Case 1	3000	4000	11.04	32
Case 2	4000	4000	11.04	32
Case 3	5000	4000	15.99	46
Case 4	5500	4000	17.61	50
Case 5	6000	4000	19.45	56
Case 6	6500	4000	21.65	62
Case 7	7500	4000	24.02	69
Case 8	9000	4000	26.12	75
Case 9	15000	4000	27.4	79

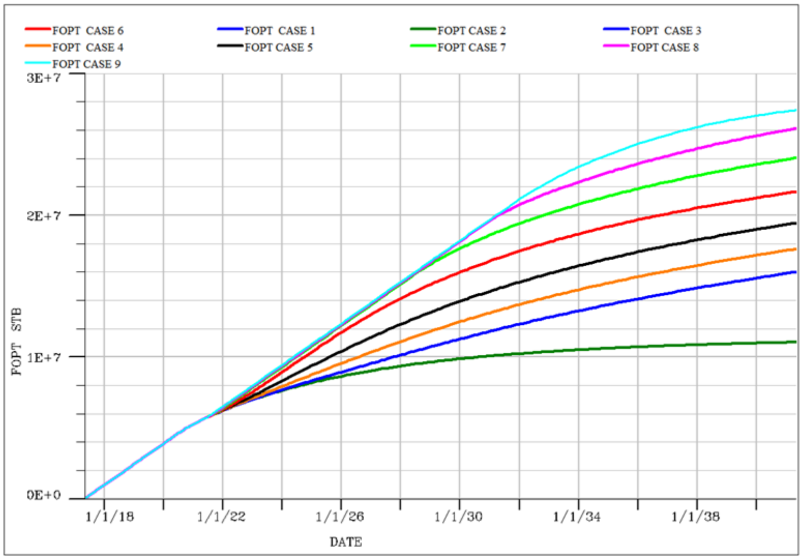

Figure 7. field oil production total (FOPT) for all cases

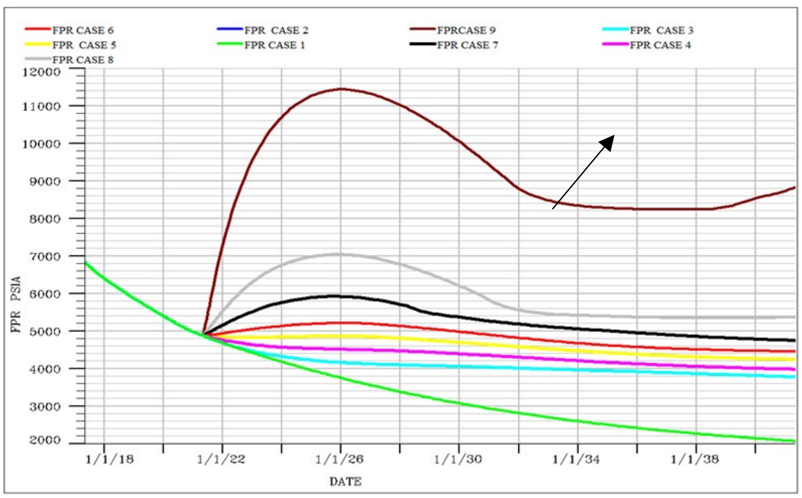

Figure 8. Field pressure for all cases

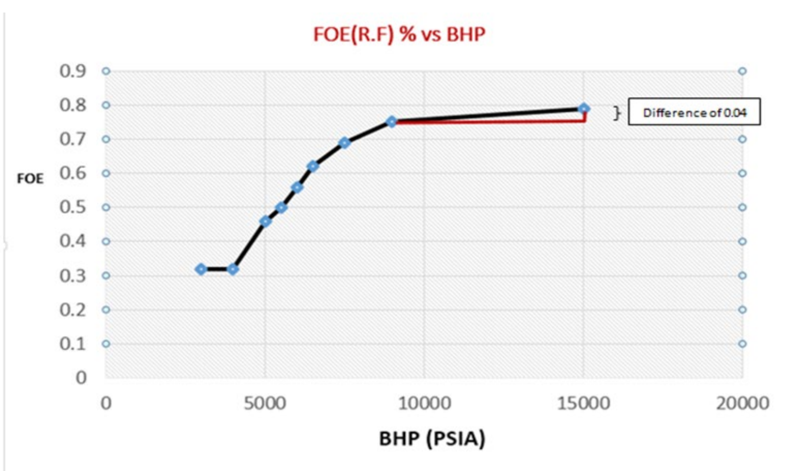

Figure 9. Plot of R.F Vs BHP

From the plot, the R.F seems to have attained a plateau between 9,000 psia and 15,000 psia, the difference in R.F at 15,000 psia is also insignificant compared to the pressure difference between the both cases.

5. Conclusion

It is an established fact that the total oil dynamic volume with respect to the separator is 34.85MMSTB. From the results obtained in chapter four, it was clearly seen that only a total of 11.04MMSTB (with a recovery factor of 0.32%) was able to be recovered using the natural drive system (i.e. without CO_2 injection) of the reservoir, this recovery can be considered quite insufficient compared to the total dynamic oil volume. Therefore, the purpose for CO_2 injection was considered in order to seek an incremental recovery of the total oil dynamic volume present in the reservoir. Nine (9) BHP target cases were simulated to obtain the best pressure at which the CO_2 gas can be injected for the optimal recovery of oil. Case 1 and 2 with injection pressures of 3000psia and 4000psia respectively gave exactly the same ultimate recovery and recovery factor as the base case. Furthermore, five BHP cases (Cases 3 to 7) that were below the reservoir pressure were simulated and it was observed that there was a significant progressive increase in the ultimate recovery and recovery factor. In addition, two extra BHP cases (Cases 8 and 9) whose injection pressures (9000psia and 15,000psia respectively) were above the reservoir pressure were simulated to see their impact in ultimate recovery and recovery factor. It was seen that there was no significant increment in the ultimate recovery and recovery factor of oil.

Conflict of interest

The authors declare that this paper has no conflict of interest whatsoever with any organization, individual or research works previously done anywhere else.

References

[1] Hamza A, Hussein I, Al-Marri M, Mahmoud M, Shawabkeh R, and Santiago A. CO_2 enhanced gas recovery and sequestration in depleted gas reservoirs: A review. Journal of Petroleum Science and Engineering, 2020; 196-200.

[2] Saad A, Murtada A, Fahad A, and Abdulaziz A. Enhanced Recovery from Gas Condensate Reservoirs through Renewable Energy Sources. Energy & Fuels, 2019; 33(10): 10115-10122.

[3] International Energy Agency (IEA), Global Energy Review, 2020.

[4] Ajayi T, Gomes J, and Bera A. A review of CO_2 storage in geological formations emphasizing modeling, monitoring and capacity estimation approaches. Pet. Sci., 2019; 16, 1028–1063.

[5] Amin D, Khalil S, Mahdi G, and Azam M. Simultaneous geological CO_2 sequestration and gas production from shale gas reservoirs: brief review on technology, feasibility, and numerical modeling. Energy Sources, Part A: Recovery, Utilization, and Environmental Effects, 2020; 1-10.

[6] Bourg ., Beckingham L, and de Paolo D."The Nanoscale Basis of CO_2 Trapping for Geologic Storage" Environ. Sci. Technol. 2015; 49, 17: 10265–10284.

[7] Morsy E, Mahmoud A, Samad G, Ann M and Peter F. CO^2 Injection for Improved Recovery in Tight Gas Condensate Reservoirs. Paper presented at the SPE Asia Pacific Oil & Gas Conference and Exhibition, Virtual, November 2020. doi: https://doi.org/10.2118/202363-MS.

[8] Jonathan N, and David A. CO_2 Enhanced Gas Recovery and Geologic Sequestration in Condensate Reservoir: A Simulation Study of the Effects of Injection Pressure on Condensate Recovery from Reservoir and CO_2 Storage Efficiency. Energy Procedia, 2014; 63: 3107-3115.

[9] Daryasafar A, Keykhosravi A, and Shahbazi S. Modeling CO_2 wettability behavior at the interface of brine/CO2/mineral: Application to CO2 geo-sequestration. Journal of Cleaner Production, 2019; 239: 118101.

[10] Shtepani E. CO_2 Sequestration in Depleted Gas/Condensate Reservoirs. Society Paper presented at the SPE Annual Technical Conference and Exhibition, San Antonio, Texas, USA, September 2006. doi: https://doi.org/10.2118/102284-MS.

[11] Tan AJ. Co-optimising CO_2 Storage and Enhanced Recovery in Gas and Gas Condensate Reservoirs. School of Petroleum Engineering, UNSW Australia, 2012.

[12] Zangeneh H, S Jamshidi, and Soltanieh M. Coupled optimization of enhanced gas recovery and carbon dioxide sequestration in natural gas reservoirs: Case study in a real gas field in the south of Iran. International Journal of Greenhouse Gas Control, 2013; 17: 515-522.

[13] Dai Z, Viswanathan H, Xiao T, Middleton R, Pan F, Ampomah W, Yang C, Zhou Y, Jia W, Lee S, Cather M, Balch R, and McPherson B. Sequestration and enhanced oil recovery at depleted oil/gas reservoirs. Energy Procedia, 2017; 6957–6967.

[14] Jia Y, Shi Y and Jin Y. The Feasibility Appraisal for CO_2 Enhanced Gas Recovery of Tight Gas Reservoir: Case Analysis and Economic Evaluation. Paper presented at the International Petroleum Technology Conference, March 2021. doi: https://doi.org/10.2523/IPTC-21291-MS.

[15] Baek SI, and Yucel A. Enhanced Recovery of Nanoconfined Oil in Tight Rocks Using Lean Gas (C_2H_6 and $_{CO2}$) Injection. SPE J. 2021; 26: 2018–2037.

[16] Mohsin A, Abd A, Salam A, and Abushaikha A. Modeling Condensate Banking Mitigation by Enhanced Gas Recovery Methods. Paper presented at the International Petroleum Technology Conference, Virtual, March 2021. doi: https://doi.org/10.2523/IPTC-21491-MS.

[17] Santiago S, Carla J, and Apostolos K."On the Role of Molecular Diffusion in Modelling Enhanced Recovery in Unconventional Condensate Reservoirs. Paper presented at the SPE Europec, Virtual, December 2020. doi: https://doi.org/10.2118/200596-MS.

[18] Tunio S, Tunio A, Ghirano N, Mohamed Z and Adawy E. Comparison of different enhanced oil recovery techniques for better oil productivity. International Journal of Applied Science and Technology, 2011; 1(5): 143 – 153.

[19] Patel M, May E, and Johns M."High-fidelity reservoir simulations of enhanced gas recovery with supercritical CO_2. Energy, 2016; 548-559.

[20] Hughes T, Honari A, Graham B, Chauhan A, Johns M, and May E. CO_2 sequestration for enhanced gas recovery: new measurements of supercritical CO_2-CH_4 dispersion in porous media and a review of recent research. International Journal of Greenhouse Gas Control, 2012; 457–468.

[21] Li X, and Zhu D. Temperature behavior during multistage fracture treatments in horizontal wells. SPE Prod & Oper, 2018; 33: 522–538. doi: https://doi.org/10.2118/181876-PA

[22] Yoshida N, Hill AD, and Zhu D. Comprehensive modeling of downhole temperature in a horizontal well with multiple fractures. SPE J., 2018; 23, 1580–1602.

[23] Raza A, Gholami R, Rezaee R, Rasouli V, Bhatti A, and Bing C. Suitability of depleted gas reservoirs for geological CO_2 storage: a simulation study. Greenhouse Gases Science Technology journal, 2018; 8: 876–897.

[24] Tu H, Guo P, Jia N, and Wang Z. Numerical evaluation of phase behavior properties for gas condensate under non-equilibrium conditions. Fuel, 2018; 226: 675−685.

[25] Sobers L, Frailey S, and Lawal A. Geological sequestration of carbon dioxide in depleted gas reservoirs. Paper presented at the SPE/DOE Symposium on Improved Oil Recovery, Tulsa, Oklahoma, April 2004. doi: https://doi.org/10.2118/89345-MS

[26] Massarweh O, and Abushaikha A. The use of surfactants in enhanced oil recovery: A review of recent advances. Energy Reports, 2020; 6: 3150–3178.

[27] Hassan A, Mahmoud M, Al-Majed A, Elkatatny S, Al-Nakhli A, and Bataweel M. Novel technique to eliminate gas condensation in gas condensate reservoirs using thermochemical fluids. Energy fuels, 2018; 32(12): 12843−12850.

[28] Sayed MA, and Al-Muntasheri GA. Mitigation of the effects of condensate banking: A critical review. SPE Production Operations, 2016; 31: 085−102.

[29] Abushaikha A, and Terekhov K. A fully implicit mimetic finite difference scheme for general purpose subsurface reservoir simulation with full tensor permeability. Journal of Computational Physics, 2020; 406.

[30] Al-Jundi A, Li L, and Abushaikhaa A. Investigation of the Accuracy and Efficiency of the Operator-based Linearization through an Advanced Reservoir Simulation Framework. in European Association of Geoscientists & Engineers Conference Proceedings, Conference Proceedings, ECMOR XVII, Sep 2020, Volume 2020, p.1 - 10

[31] Nardean S, Ferronato M, and Abushaikha A. A novel block non-symmetric preconditioner for mixed-hybrid finite-element-based flow simulations. J. of Comp. Physics, 2021; 442:110513.

To whom correspondence should be addressed: Eng. Shadrach O. Ogiriki, Department of Petroleum and Gas Engineering, Baze University, Abuja, Nigeria, E-mail: shadrach.ogiriki@bazeuniversity.edu.ng