14th International Conference on Greenhouse Gas Control Technologies, GHGT-14

21st -25th October 2018, Melbourne, Australia

Impact of Injecting CO_2 and Light Hydrocarbon Fractions in a Condensate Reservoir

David Alexander[a]*, Jonathan Narinesingh[a], Donnie Boodlal[a], Sarim Al-Zubaidy[a]

[a]*University of Trinidad and Tobago,Esperanza Road, Brechin Castle, Couva, Trinidad and Tobago*

Abstract

Greenhouse gas emissions have grown significantly in recent times globally. One of the most prevalent greenhouse gases is carbon dioxide (CO_2). Over the years, pilot projects along with reservoir simulations have sought to strengthen our confidence in the use of geologic storage as a mitigation strategy, but a lot more related research still has to be done.

One of the key issues when producing condensate reservoirs is that of liquid dropout as the reservoir drops below the dew point pressure. Condensate can therefore become trapped in the reservoir due to the effect of capillary pressure. As a result, flow within porous media can become restricted, thus reducing the efficiency of condensate and gas recovery.

CO_2 injection can assist with both these challenges, *i.e.* pressure maintenance and the sequestering of the CO_2. The depleted hydrocarbon pore spaces in the reservoir provide suitable storage sites for the injected CO_2.

Current technologies involve injecting produced natural gas from source wells into other wells to help increase reservoir pressure and improve recovery efficiency. This paper examined the effects of injecting both CO_2 and light hydrocarbon fractions (C1 - C2) into condensate reservoirs to optimize condensate recovery and CO_2 sequestration.

The results from the associated simulation studies show that the use of CO_2 to increase condensate recovery from the reservoir is feasible with the additional benefit of CO_2 sequestration. It also demonstrated that it is highly possible to increase condensate production by injecting CO_2 with some percentages of lighter fractions (C1 - C2), with these lighter fractions assisting to increase condensate recovery. It is possible to store between 11 and 15% of injected CO_2 using the different injection compositions.

The injection of CO_2 had a positive effect on the re-vaporization of condensate dropout in the reservoir. Increasing the injection pressure yielded higher condensate recoveries. More than 95% of the injected CO_2 stored in the reservoir was trapped in the supercritical phase, whilst 3-5% was stored due to hysteresis. As the injection pressure increased, the amount of CO_2 stored by hysteresis decreased in all cases. Once the reservoir seals were not breached, the CO_2 will remain trapped for over 1000 years.

Keywords: CO_2 Enhanced Gas Recovery; Condensate Reservoir; Geologic Sequestration; Natural Gas Injection

* Corresponding author. Tel.: 1-868-370-3800; fax: 1-868-642-8888. *E-mail address:* david.alexander@utt.edu.tt

1. Introduction

A gas condensate reservoir can choke its most valuable component which is the condensate [1]. One of the greatest problems currently in the oil industry is the difficulty in reaching a high hydrocarbon recovery in gas condensate fields [2, 18]. Condensate loss is therefore one of the major challenges in the gas condensate reservoirs. Gas condensate reservoirs usually exhibit reduced well productivity because of condensate dropout that occurs below the dew point pressure [3, 12, 22]. Different methods have been proposed to mitigate the condensate dropout and increase gas and condensate productivity. When the gas is very lean, condensate blocking can even cause a large decline in well productivity [4, 5, 6, 7]. Depleted gas condensate reservoirs like other geologic formations that have stored oil and gas for millions of years are important sites for CO_2 sequestration [8, 9]. CO_2 injection into depleted gas condensate reservoirs can potentially enhance gas recovery by liquid re-vaporization and/or pressure maintenance [10]. Repressurization of retrograde gas reservoirs fundamentally reduces the limit entrance into retrograde region during the production of the reservoir [11, 12].

Carbon Dioxide can be an impactful injection solvent for gas condensate reservoirs due to its large density and viscosity difference between gas condensate (resident gas) and CO_2 (injection fluid) that effectively will help to enhance gas recovery Moreover, it is relatively higher viscosity relative to resident gas makes a favorable mobility ratio for displacement and a less tendency to fingering, a main concern for displacement of injection fluid [13].

Depletion of gas/condensate reservoirs initiates a decline in reservoir pressure below the dew point pressure of the retrograde gas. This leaves valuable amount of condensate in the reservoirs which is not only lost but results in a condensate blockage near the wellbore region and decrease in the productivity. Thus, it is very essential and economical to find applicable ways to increase the recovery of this lost condensate from the reservoirs [14, 15]. Methane injection or gas cycling is the recovery process of choice for gas-condensate reservoirs. For economic reasons however, this process can often not be implemented [16]. The injected gas could be natural gas, methane, nitrogen or carbon dioxide. Historically, globally and over the years, operators used to cycle natural gas after it had been produced. The increase in demand, however, makes gas cycling a less attractive option [16, 17].

CO_2 injection into these reservoirs offer a promising solution, however accurate fluid modeling is crucial in reservoir modeling of such reservoirs [18]. In this paper we analyse the impact of injecting CO_2 to increase the condensate recovery. As the injection of lighter fractions such as C1 and C2 as fractions of the injected solvent will also be analysed.

Nomenclature

CO_2	Carbon Dioxide
MEEI	Ministry of Energy and Energy Industries
WHP	Well Head Pressure

Geology of the Columbus Basin

In this paper, we model an analogous reservoir in the Columbus basin since many of the condensate reservoirs in Trinidad and Tobago reside in this area. The Columbus Basin is a prolific hydrocarbon basin situated on the eastern shelf of Trinidad with more than 1 billion barrels of oil produced, and natural gas resources exceeding 25 trillion cubic feet [19]. The basin was filled during late Moecene to Holocene time with sediments deposited by an ancestral Orinoco River draining a hinterland to the southwest. The Pliocene-Pleistocene section, which contains the hydrocarbon accumulations in the Columbus basin, was deposited in three coarsening-upward sedimentary sequences followed by a late Pliestocene transgressive sequence [20]. The basin is a detached extensional basin in a transpressional foreland setting. Giant oil fields have been discovered since 1968 but today’s major production comes from several gas and condensate fields which feed Trinidad’s bourgeoning downstream gas industries. Much of the deep potential of the Columbus Basin shelf remains untested. The continental slope and ultra-deep areas of the Columbus Basin are also areas with great untapped potential [19].

Simulation Model Conceptual Design

The compositional reservoir simulator CMG-GEM was used to create a simple 2D model of a gas condensate reservoir analogous to those that exist in the Columbus Basin. The model's geometry was kept simple in order to more accurately focus on the effects of the various injection parameters. However, in order to account for reservoir heterogeneity, similar data published by Narinesingh and Alexander [21] to create flow units in the model was utilised. CMG-WINPROP was used to develop the fluid model for this simulation which was also outlined by Narinesingh and Alexander [21]. Seven different cases studies were designed and analysed to see the impact of injecting lighter fractions of hydrocarbon along with CO_2 into the reservoir. For the analysis, the model was allowed to solve, simulating primary production initially (Case 1). This was used to obtain benchmark statistics with respect to condensate-gas ratios (CGRs) and recovery factors. Another simulation run was conducted (Case 2) which involved injecting only CO_2 into the reservoir at the end of the primary production period. This simulation gave benchmark statistics for additional gas and condensate recovery factors, percentages of CO_2 sequestered and CO_2 breakthrough times. Cases 3 to 6 outlined the parameters for a sensitivity analysis to model CO_2 injection into the reservoir together with varying percentages of the light hydrocarbon fractions (C1-C2) as outlined in **Table 1** below:

Table 1: Case Studies

	CO_2 (%)	C_1 (%)	C_2 (%)
Case 1	100	0	0
Case 2	90	10	0
Case 3	90	5	5
Case 4	80	20	0
Case 5	80	10	10
Case 6	80	0	20

The injection pressure for each case was varied from 2000 to 6000 psi to observe the impact of varying pressure on the cumulative condensate recovery and the amount of CO_2 stored. The additional recovery factors and the percentages of sequestered CO_2 were analysed and compared for all simulation runs to determine the impacts of these various injection scenarios on EGR and CO_2 sequestration.

1.1. Static Reservoir Model

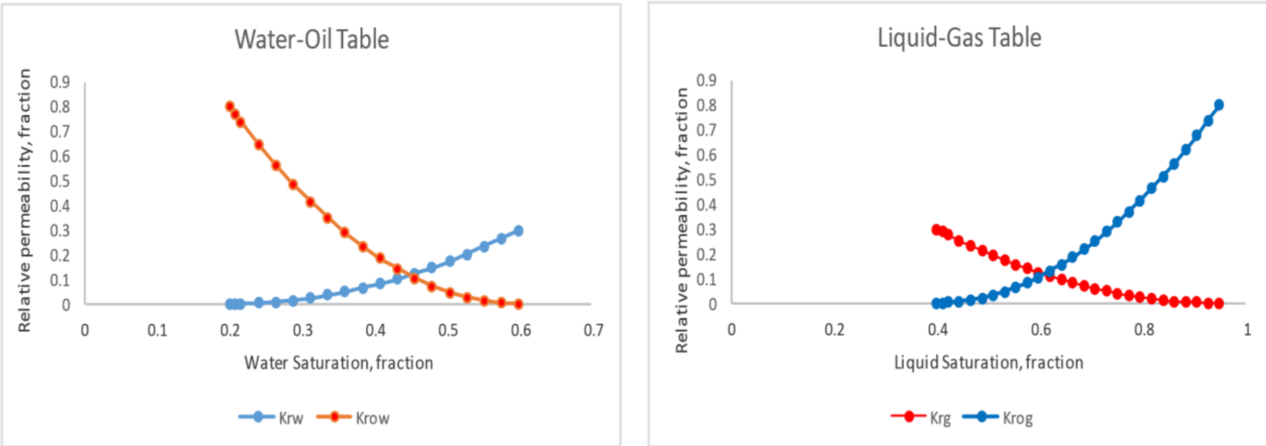
A simple 2D slice of the reservoir model was built. This 2D model was 150 ft. wide, 8000 ft. long and 150 ft. thick. For the vertical thickness, 3 layers were used (each was 50 ft. thick) to simulate 3 sandstone flow packages which were analogous to real field data from the Columbus Basin. The table below contains the main properties for each layer (flow package).

Table 2: Layer Properties

Layer/Flow Package	Thickness (*ft.*)	Porosity (*%*)	Average Permeability (*mD*)
Layer 1	50	28	180
Layer 2	50	25	150

Layer 3	50	22	90

The top of sand layer 1 was 13100 ft, the initial reservoir pressure was 6400 psi with a reservoir temperature of 256 ^{o}F. The relative permeability curves for the oil-water and liquid-gas components are shown in **Figure 1** below.



(a) Water-oil relative permeability curve

(b) Liquid-gas relative permeability curve

Figure 1: Relative permeability curves for field X

1.2. Fluid Properties

The main aim of this paper was to observe and quantify the effects of CO_2 injection pressures on the liquid dropout in condensate reservoirs, thus an accurate fluid model was essential. The table below lists the components and their respective mole percentages for the condensate used in this model.

Table 3: Fluid Composition

Component	Mole Percent
CO2	0.03
N2	0.11
C1	68.93
C2	8.63 5.34
C3	1.15 2.33
IC4	0.93 0.85
NC4	1.73
IC5	9.97
NC5	
C6	
C7+	

Dew point pressure was calculated as 6025 psia at 256 ^{0}F. Because initial pressure is close to dew point pressure and a while followed by production, reservoir pressure reaches dew point pressure. As a result, the percentage of condensate that can be produced would be far less than what is possible.

2. Dynamic Reservoir Model

A model utilising 160 grids in the x-direction, 1 grid in the y-direction with three distinct layers (480 grids) to represent a 2D slice of the reservoir was constructed; see **Figure 2**. After all the required data were entered in the model, model initialization was performed.

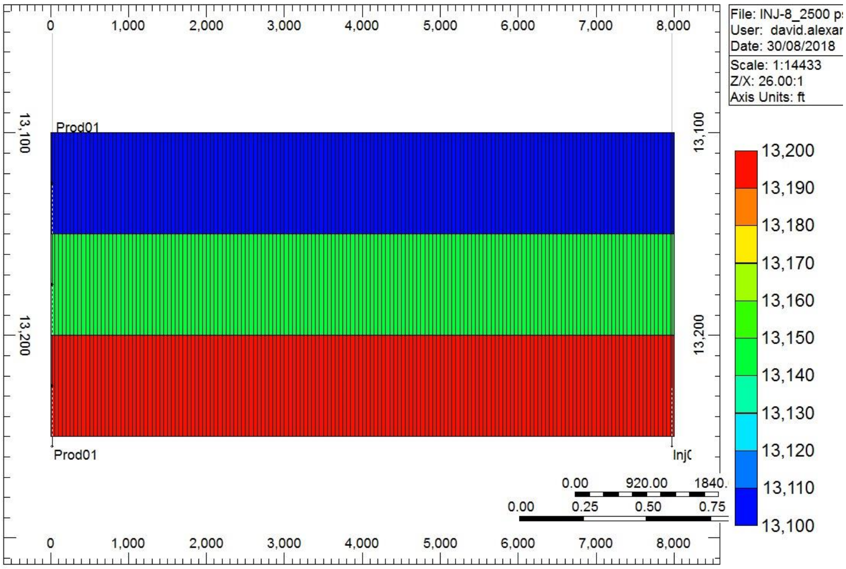


Figure 2: Reservoir Slab (IK 2D Cross Section)

A single producer was placed at one end of the reservoir slab as seen in **Figure 2**. The production well was perforated in all three sand packages and completed with 4 ½" OD tubing to a depth of 13100 ft. The producer well was set to shut in once a well head pressure (WHP) of 1200 psi wasn't maintained. This base model was run, and the primary production phase (i.e. 3 years) of this slice of the reservoir was analyzed. The total recoveries and remaining in place hydrocarbons were analyzed along with pressures and condensate dropout in the reservoir. The models in this paper are designed specifically to investigating any effects of CO_2 injection pressures on condensate recovery and CO_2 storage.

At the end of the primary production phase, an injector well was placed 1800 ft. away from the producer as seen in **Figure 2** above. The injector well was perforated only in the deepest sand package with the lowest permeability to reduce early CO_2 breakthrough. CO_2 was injected for a total of 10 years. During this time, the producer was opened again and allowed to flow using a WHP constraint of 1200 psi. Again, once this WHP could no longer be maintained, the well was shut in. The injector and the producer were shut in at the end of the 10-year injection period and the model allowed to run to a total of 1000 years to observe the amount of CO_2 stored in the different phases over the said timeframe.

3. Results and Discussion

Compared to Narinesingh and Alexander [21], this paper investigated a broader range of injection pressures, injection solvents and started injection 3 years after primary production to determine the optimum pressure and injection solvent composition that would increase the condensate yield from these types of reservoirs. While some researchers have investigated CO_2 or gas recycling (which would be predominantly C1 - C2 fractions) that paper analyses the impact of combining different injection compositions (see **Table 1**) to see which would give the best result.

Figure 2 below shows the results for the total condensate recoveries from the reservoir model for the various scenarios. It should be noted that the well was choked to produce at a fixed rate of 5 MMSCF/day to observe the change in condensate production at a constant wet gas rate.

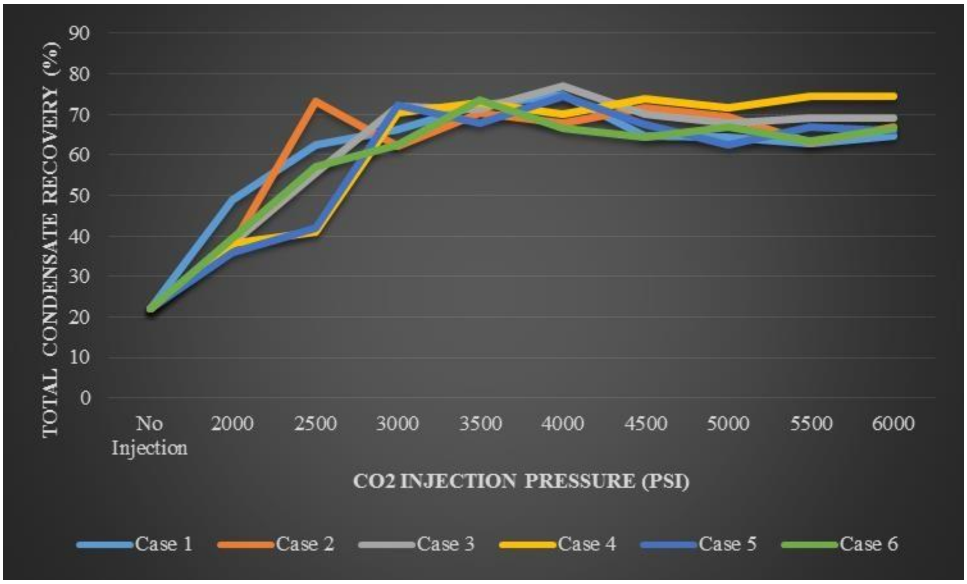


Figure 2: Condensate Recovery Results

The 2D slice of the reservoir had 1.23 MMSTB of condensate originally in place. **Figure 2** shows the total condensate recovery from the reservoir with increasing pressure for the cases mentioned in **Table 1**.

From the graph, at the end of primary production, the oil recovery values for the condensate gas was 21%. From **Figure 2**, generally as the injection pressure increased from 2000 psi to 4000 psi, the total condensate recovery increased significantly i.e. from 21 to 70%. When 100% CO_2 was injected as the injection solvent, it generally gave the higher condensate recoveries up to 3000 psi injection pressure. As the pressure increased between 3000 and 4000 psi, Case 3 gave the best recovery overall in all the cases (i.e. injection fluid composition of 90% CO_2, 5% C1 and 5% C2). Injection pressures greater than 4000 psi generally caused the condensate recovery to decrease again except for Case 4 (*i.e.* Injection fluid composition of 80% CO_2, 20% C1) which continued the general trend of increased recovery but only incrementally (*i.e.* from 70 to 75%).

These results show that the solvent injection re-pressurized the reservoir and allowed some of the liquid dropout to re-vaporize and be produced at surface. As in the case of Case 3, the added C1 assisted in increasing the condensate recovery when compared to injecting pure CO_2 only. In general, when analyzing the reservoir saturation of condensate, as the injection solvents re-pressurized parts of the reservoir, the condensate saturation decreased implying the condensate was re-vaporized and mobilized. This was reflected in the CGRs observed after injection.

Figure 3 below shows the increase in CGR when the producer was opened during the CO_2 injection phase. It can be observed that the injection of injection solvents described in **Table 1** improved the recovery of condensate from the reservoir. These results showed the general improvements possible by injection CO_2/CO_2 combined with lighter fractions. To observe the effects of this and to get better field scale estimates, a full-scale model has to be developed.

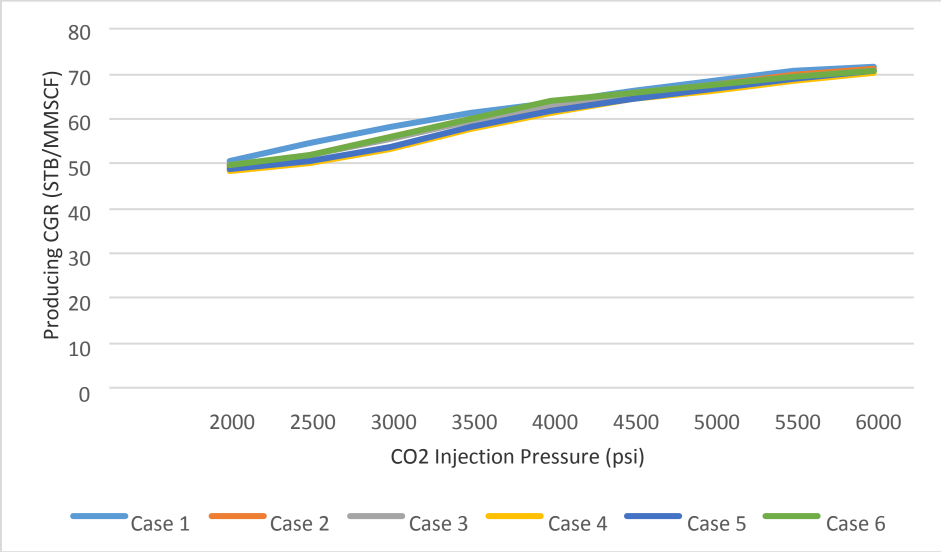


Figure 3: CGR at Start of CO_2 Injection

CO_2 Storage Results

Appendix A.1. to **A.6**. show the results for the total amounts of CO_2 stored for Case 1 to Case 6 with varying injection pressures ranging from 2000 to 6000 psi. Each table in these **Appendix A** presents the total cumulative CO_2 injecting, how much CO_2 remained trapped into the reservoir and the percentage of cumulative CO_2 stored. Cases 1 to 6 demonstrate that it is possible to store between 11 and 15% of injected CO_2.

Appendix B.1. to **B.6.** gives a breakdown of how the CO_2 was stored in the reservoir. In all the cases, it was observed that the CO_2 was either stored in the supercritical phase or trapped by hysteresis. From the tables in **Appendix B** most of the trapped CO_2 remains in the supercritical phase in the reservoir. The most notable point from this table is as injection pressure increased, the volume of CO_2 trapped in the reservoir by hysteresis decreased.

4. Conclusions

Some of the key points from this research include:

- The results from these simulation studies showed that the use of CO_2 to increase condensate recovery from the reservoir is feasible with the additional benefit of CO_2 sequestration. It also demonstrated that it is highly possible to increase condensate production by injecting CO_2 with some percentages of lighter fractions (C1 and C2). It is possible to store between 11 and 15% of injected CO_2 using the different injection compositions.
- The injection of CO_2 had a positive effect on the re-vaporization of condensate dropout in the reservoir. Increasing the injection pressure yielded higher condensate recoveries.
- More than 95% of the injected CO_2 stored in the reservoir was trapped in the supercritical phase whilst 3-5% was stored due to hysteresis.
- As the injection pressure increase, the amount of CO_2 stored by hysteresis decreased for all cases.

Acknowledgements

The authors would like to thank CMG Ltd for the use of their software for this research. They would also like to thank staff at the University of Trinidad and Tobago who supported this research.

5. Appendix A: Cumulative CO_2 injected, produced and stored at varying injection pressures

Table A.1.: Cumulative CO_2 injected, produced and stored for Case 1 at varying injection pressures

CO_2 Injection Pressure (*psi*)	Cumulative CO_2 Injection (MMSCF)	Cumulative CO_2 Produced (MMSCF)	Cumulative CO_2 Stored (MMSCF)	% CO_2 Stored (MMSCF)
2000	10235	8,697	1,538	15.0%
2500	11556	9,858	1,698	14.7%
3000	12179	10,400	1,779	14.6%
3500	12906	11,020	1,886	14.6%
4000	13776	11,810	1,966	14.3%
4500	13042	11,135	1,907	14.6%
5000	13363	11,409	1,954	14.6%
5500	13610	11,627	1,983	14.6%
6000	14060	12,009	2,051	14.6%

Table A.2.: Cumulative CO_2 injected, produced and stored for Case 2 at varying injection pressures

CO_2 Injection Pressure (*psi*)	Cumulative CO_2 Injection (MMSCF)	Cumulative CO_2 Produced (MMSCF)	Cumulative CO_2 Stored (MMSCF)	% CO_2 Stored (MMSCF)
2000	8446.5	7,297	1,149	13.6%
2500	11127	9,664	1,463	13.1%
3000	11074	9,610	1,464	13.2%
3500	11904	10,332	1,572	13.2%
4000	12151	10,547	1,604	13.2%
4500	12745	11,066	1,679	13.2%
5000	13257	11,534	1,723	13.0%
5500	12884	11,183	1,701	13.2%
6000	13723	11,927	1,796	13.1%

Table A.3.: Cumulative CO_2 injected, produced and stored for Case 3 at varying injection pressures

CO_2 Injection Pressure (psi)	Cumulative CO_2 Injection (MMSCF)	Cumulative CO_2 Produced (MMSCF)	Cumulative CO_2 Stored (MMSCF)	% CO_2 Stored (MMSCF)
2000	8707.6	7,525	1,183	13.6%
2500	10338	8,939	1,399	13.5%
3000	11788	10,249	1,539	13.1%
3500	12204	10,612	1,592	13.0%
4000	13070	11,390	1,680	12.9%
4500	12792	11,121	1,671	13.1%
5000	12967	11,265	1,702	13.1%
5500	13408	11,653	1,755	13.1%
6000	13863	12,063	1,800	13.0%

Table A.4.: Cumulative CO_2 injected, produced and stored for Case 4 at varying injection pressures

CO_2 Injection Pressure (psi)	Cumulative CO_2 Injection (MMSCF)	Cumulative CO_2 Produced (MMSCF)	Cumulative CO_2 Stored (MMSCF)	% CO_2 Stored (MMSCF)
2000	7761.6	6,821	941	12.1%
2500	8360.6	7,350	1,010	12.1%
3000	10514	9269	1,245	11.8%
3500	11449	10,125	1,324	11.6%
4000	11685	10336	1,349	11.5%
4500	12296	10,870	1,426	11.6%
5000	12538	11071	1,467	11.7%
5500	13016	11491	1,525	11.7%
6000	13840	12258	1,582	11.4%

Table A.5.: Cumulative CO_2 injected, produced and stored for Case 5 at varying injection pressures

CO_2 Injection Pressure (psi)	Cumulative CO_2 Injection (MMSCF)	Cumulative CO_2 Produced (MMSCF)	Cumulative CO_2 Stored (MMSCF)	% CO_2 Stored (MMSCF)
2000	7833.5	6,886	947	12.1%
2500	8878.7	7,810	1,069	12.0%
3000	11083	9803	1,280	11.5%
3500	11462	10,154	1,308	11.4%
4000	12192	10798	1,394	11.4%
4500	11918	10,535	1,383	11.6%
5000	11990	10587	1,403	11.7%
5500	12911	11426	1,485	11.5%
6000	12842	11347	1,495	11.6%

Table A.6.: Cumulative CO_2 injected, produced and stored for Case 5 at varying injection pressures

CO_2 Injection Pressure (psi)	Cumulative CO_2 Injection (MMSCF)	Cumulative CO_2 Produced (MMSCF)	Cumulative CO_2 Stored (MMSCF)	% CO_2 Stored (MMSCF)
2000	8970.6	7,751	1,220	13.6%
2500	10427	9,028	1,399	13.4%
3000	11234	9,760	1,474	13.1%
3500	12292	10,689	1,603	13.0%
4000	12392	10,792	1,600	12.9%
4500	12371	10,748	1,623	13.1%
5000	12910	11,220	1,690	13.1%
5500	12824	11,141	1,683	13.1%
6000	13428	11,665	1,763	13.1%

6. Appendix B: Percentage Breakdown of Trapped CO_2

Table B.1.: Percentage Breakdown of Trapped CO_2 for Case 1

CO_2 Injection Pressure (*psi*)	Total CO_2 Trapped (MMSCF)	Cumulative CO_2 in Supercritical Phase (MMSCF)	CO_2 Trapped by hysteresis (MMSCF)	% CO_2 in Supercritical Phase (%)	% CO_2 in Trapped by hysteresis (%)
2000	1,538	1,458	81	94.7	5.3
2500	1,698	1,633	65	96.2	3.8
3000	1,779	1,718	61	96.6	3.4
3500	1,886	1,821	65	96.6	3.4
4000	1,966	1,901	65	96.7	3.3
4500	1,907	1,843	64	96.7	3.3
5000	1,954	1,893	62	96.8	3.2
5500	1,983	1,924	60	97.0	3.0
6000	2,051	1,985	66	96.8	3.2

Table B.2.: Percentage Breakdown of Trapped CO_2 for Case 2

CO_2 Injection Pressure (psi)	Total CO_2 Trapped (MMSCF)	Cumulative CO_2 in Supercritical Phase (MMSCF)	CO_2 Trapped by hysteresis (MMSCF)	% CO_2 in Supercritical Phase (%)	% CO_2 in Trapped by hysteresis (%)
2000	1,149	1,082	68	94.1	5.9
2500	1,463	1,378	85	94.2	5.8
3000	1,464	1,403	61	95.8	4.2
3500	1,572	1,510	62	96.1	3.9
4000	1,604	1,539	65	95.9	4.1
4500	1,679	1,618	61	96.4	3.6
5000	1,723	1,659	63	96.3	3.7
5500	1,701	1,641	60	96.5	3.5
6000	1,796	1,731	65	96.4	3.6

Table B.3.: Percentage Breakdown of Trapped CO_2 for Case 3

CO_2 Injection Pressure (*psi*)	Trapped [2] Total CO (MMSCF)	Cumulative CO_2 in Supercritical Phase (MMSCF)	CO $_2$ Trapped by hysteresis (MMSCF)	% CO_2 in Supercritical Phase (%)	% CO_2 in Trapped by hysteresis (%)
2000	1,183	1,116	67	94.3	5.7
2500	1,399	1,327	72	94.9	5.1
3000	1,539	1,478	60	96.1	3.9
3500	1,592	1,537	55	96.5	3.5
4000	1,680	1,620	60	96.4	3.6
4500	1,671	1,615	57	96.6	3.4
5000	1,702	1,643	60	96.5	3.5
5500	1,755	1,699	56	96.8	3.2
6000	1,800	1,740	60	96.7	3.3

Table B.4.: Percentage Breakdown of Trapped CO_2 for Case 4

CO_2 Injection Pressure (*psi*)	Total CO_2 Trapped (MMSCF)	Cumulative CO_2 in Supercritical Phase (MMSCF)	CO_2 Trapped by hysteresis (MMSCF)	% CO_2 in Supercritical Phase (%)	% CO_2 in Trapped by hysteresis (%)
2000	941	885	56	94.1	5.9
2500	1,010	953	58	94.3	5.7
3000	1,245	1,173	72	94.2	5.8
3500	1,324	1,263	61	95.4	4.6
4000	1,349	1,291	58	95.7	4.3
4500	1,426	1,366	60	95.8	4.2
5000	1,467	1,405	62	95.8	4.2
5500	1,525	1,462	63	95.8	4.2
6000	1,582	1,515	67	95.8	4.2

Table B.5.: Percentage Breakdown of Trapped CO_2 for Case 5

CO_2 Injection Pressure (*psi*)	Total CO_2 Trapped (MMSCF)	Cumulative CO_2 in Supercritical Phase (MMSCF)	CO_2 Trapped by hysteresis (MMSCF)	% CO_2 in Supercritical Phase (%)	% CO_2 in Trapped by hysteresis (%)
2000	947	894	54	94.3	5.7
2500	1,069	1,013	56	94.8	5.2
3000	1,280	1,225	55	95.7	4.3
3500	1,308	1,261	47	96.4	3.6
4000	1,394	1,343	51	96.3	3.7
4500	1,383	1,337	45	96.7	3.3
5000	1,403	1,354	49	96.5	3.5
5500	1,485	1,432	53	96.4	3.6
6000	1,495	1,445	50	96.7	3.3

Table B.6.: Percentage Breakdown of Trapped CO_2 for Case 6

CO_2 Injection Pressure (*psi*)	Total CO_2 Trapped (MMSCF)	Cumulative CO_2 in Supercritical Phase (MMSCF)	CO_2 Trapped by hysteresis (MMSCF)	% CO_2 in Supercritical Phase (%)	% CO_2 in Trapped by hysteresis (%)
2000	1,220	1,150	70	94.3	5.7
2500	1,399	1,337	62	95.6	4.4
3000	1,474	1,422	52	96.5	3.5
3500	1,603	1,550	53	96.7	3.3
4000	1,600	1,557	43	97.3	2.7
4500	1,623	1,573	50	96.9	3.1

5000	1,690	1,635	54	96.8	3.2
5500	1,683	1,632	51	97.0	3.0
6000	1,763	1,710	53	97.0	3.0

References

[1] Fan, L., Harris, B.W., Jamalluddin, A., Kamath, J., Mott, R., Pope, G.A., Shandrygin, A., & Whitson, C. H. (1998). Understanding Gas-
Condensate Reservoirs. Retrieved from
https://www.slb.com/resources/publications/industry_articles/oilfield_review/2005/or2005win02_gascondensate_reservoirs.aspx
[2] Lopez, J. A. C. (2000). Gas Injection as a method for improved recovery in gas condensate reservoirs with active support. SPE 58981
[3] Izuwa, N., & Ogbunude, B. C. (2015). Parametric Study of Enhanced Condensate Recovery of Gas Condensate Reservoirs using Design of Experiment. Journal of Petroleum & Environmental Biotechnology 2015, 7:1
[4] Afidick, D., Kaczorowski, N.J., & Bette, S. (1994). Production Performance of a Retrograde Gas Reservoir: A Case Study of the Arun Field. Presented at the SPE Asia Pacific Oil and Gas Conference, Melbourne, Australia, 7-10 November 1994. SPE-28749-MS.
[5] Narayanaswamy, G., Pope, G.A., Sharma, M.M., Hwang, M.K., & Vaidya, R.N.1999. Predicting Gas Condensate Well Productivity Using Capillary Number and Non-Darcy Effects. Paper SPE51910 presented at the SPE Reservoir Simulation Symposium, Houston, 14-17
February. doi: 10.2118/51910-MS
[6] Boom, W., Wit, K., Schulte, A.M. et al. (1995). Experimental Evidence for Improved Condensate Mobility at Near-wellbore Flow Conditions. Presented at the SPE Annual Technical Conference and Exhibition, Dallas, Texas, 22-25 October 1995. SPE-30766
[7] Pope, G. A., Wu, W., Narayanaswamy, G., Delshad, M., Sharma, M. M., & Wang, P. (2000). Modeling relative permeability effects in gas/condensate reservoirs with a new trapping model. SPE Res. Eval. Eng. 2:171–178.
[8] Haszeldine, R.S. (2005). Deep Geological CO2 Storage: Principles, and Prospecting for Bioenergy Disposal Sites. Journal of Mitigation and Adaptation Strategies for Global Change (2006) 11: 377–401.
[9] Hartai, E. (2012). Carbon dioxide storage in geological reservoirs. Retrieved from http://fold1.ftt.uni-miskolc.hu/~foldshe/co2geol.pdf.
[10] Shtepani, E. (2006). CO2 Sequestration in Depleted Gas/Condensate Reservoirs. SPE 102284.
[11] Bedrickovetsky, P. (1997). Enhanced Gas-Condensate Recovery in Complex Reservoirs: Pilots and Models. SPE 39056. [12] Al-Abri, A. S. (2011). Enhanced Gas Condensate Recovery by CO2 Injection.
Retrieved from https://espace.curtin.edu.au/bitstream/handle/20.500.11937/1770/159514_Al-Abri2011.pdf?sequence=2.
[13] Flores. H. C. (2014). CO2 Sequestration in Depleted Gas-Condensate Reservoirs. Retrieved from https://brage.bibsys.no/xmlui/bitstream/handle/11250/227767/Hilda_CHOQUE.pdf?sequence=1
[14] Amini, Sh., Aminshahidy, B., Afshar, M., 2011. Simulation Study of Enhanced Condensate Recovery in a Gas-Condensate Reservoir. Iranian Journal of Chemical Engineering, Vol. 8, No. 1.
[15] El Aily, M., Desouky, S.S., Khalil, M. H., Badawi, A. M., & Abdelraheem, O. H. (2016). Effect of Dry Gases Injection into Egyptian Gas/Condensate Reservoirs on Condensate Recovery. International Journal of New Technology and Research (IJNTR) ISSN: 2454-4116, Volume-2, Issue-5, May 2016 Pages 119-121
[16] Sanger, P. J., & Hagoort, J. (1998). Recovery of Gas Condensate by Nitrogen Injection Compared with Methane Injection. SPE Journal, 3(1), 26-33.
[17] Manrique, E. J., Muci, V. E., & Gurfinkel, M. E. (2007). EOR Field Experiences in Carbonate Reservoirs in the United States. SPE REE, 10(6), 667-686.
[18] Khadar. R. H., Aminshahidy. B., Hashemi, A., & Ghadami. N. (2013). Application of Gas Injection and Recycling to Enhance Condensate Recovery. Journal of Petroleum Science and Technology, 31:10, 1057-1065
[19] MEEI (2018). Petroleum Geology. http://www.energy.gov.tt/wp-content/uploads/2014/02/petroleum_geo.pdf
[20] Leonard, R. Geology and hydrocarbon accumulations, Columbus Basin, Offshore Trinidad. United States: N. p., 1983. Web. doi: 10.1306/03B5B231-16D1-11D7-8645000102C1865D.
[21] Narinesingh. J., & Alexander, D. (2014). CO2 Enhanced Gas Recovery and Geologic Sequestration in Condensate Reservoir: A Simulation
Study of the Effects of Injection Pressure on Condensate Recovery from Reservoir and CO2 Storage Efficiency. Energy Procedia 63:3107-
3115
[22] Ahmed. T., Evans J., Kwan R., & Vivian T (1998). “Wellbore liquid blockage in gas condensate reservoirs”. Paper SPE 51050, Presented at the 1998 SPE Eastern Regional meeting, Pittsburgh.