Evaluating Different CO_2-EOR Methods for Coupled Emission Reduction in the Oropouche Field, Trinidad

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Abstract- Declining petroleum reserves and issues relating to climate change are receiving national attention in Trinidad and Tobago (T&T). Different CO_2 enhanced oil recovery (CO_2-EOR) techniques were evaluated to determine its feasibility to act as a sink and to boost oil production in the EOR44 reserve in the Oropouche Field in southwest Trinidad. The Computer Modelling Group (CMG) software was used to evaluate the EOR injection methods of CO_2, CO_2+N_2, and WAG injections. The findings showed that WAG was the best injection method, producing the most oil (3.5 MMBBL) at 200 MScf/day of CO_2 injection, with the greatest recovery factor of the scenarios at 40% and the maximum storage efficiency of 38%, storing roughly 100,000 tCO_2. The environmental performance utilized a CCUS system characterized by a cradle to grave boundary which represented CO_2 capture, CO_2 compression, CO_2 transportation by truck, and the EOR operation as well as injection possibilities for the EOR process. The results indicated that the CO_2 capture facility unit generating between 33,000 and 37,000 Mt of CO_2, has higher emission output than the compression and transportation units. The scenario performing the least in terms of storage performance was CO_2-N_2, with just 8% of CO_2 being stored. The WAG injection had the largest sequestration capability with a projection of 35%. This study demonstrated the feasibility of the use of CO_2-EOR as a net sink in the EOR 44 area, an appropriate step to aid in T&T's efforts to mitigate climate change and improve oil production.

Keywords- CO_2-EOR, Life Cycle Analysis, CO_2 injection, CO_2-N_2 injection, WAG.

1. Introduction

The need to reduce Green House Gas (GHG) emissions has increased the demand for emission reduction solutions and has become a priority in the global climate agenda [1]. Trinidad and Tobago (T&T), an energy-dependent nation, has long led the Caribbean as a significant petroleum producer, playing an essential role in the country's economy. However, throughout the years, energy challenges such as dwindling reserves, falling production rates, and particularly increased emissions have occurred. According to research conducted in T&T for the year 2018, 80% of emissions were being directly ascribed to the energy sector through power generation and heat (54%), industrial processes (16%) and transportation (11%) [2]. T&T is ranked fourth worldwide for registering high levels of CO_2 emissions on a per capita basis [3-4].

T&T ratified the Paris Climate Change Agreement in 2018, affirming its commitment to finding ways to reduce emissions, setting a goal of decreasing overall carbon emissions by 15% by 2030 through power generation, transportation, and industrial sectors [5]. Reducing emissions to the atmosphere can be accomplished by switching to low carbon energy sources, developing renewable energy sources, and increasing energy efficiency of processes consistent with strategic decisions and policies adopted by other countries around the world [6-12]. One technology of note in the energy sector is Carbon Capture, Utilization, and Storage (CCUS) through enhanced oil recovery (EOR) [13] which will be the focus of this study.

Although T&T has been involved in carbon dioxide enhanced oil recovery (CO_2-EOR) operations since the 1970's to improve oil recovery [14], the use CCUS though CO_2-EOR provides an additional emission mitigation strategy since it may be able to maintain the usage of fossil fuels while lowering CO_2 concentrations in the atmosphere. However, the debate over whether the CO_2-EOR as the CCUS technique in T&T is sufficient to fulfill climate objectives leads to a need to assess viability in order to achieve sustainability.

The use of Life Cycle Analysis (LCA) can address the environmental implications of a product system over the course of its entire life cycle whereas described by Müller et al. [15], the entire life cycle of a product system spans from a series of processes that begin with the extraction of raw materials and processing, manufacturing, distribution, consumption, re-use, recycling, and eventually disposal. The application of LCAs to evaluate the environmental implications of CO_2-EOR operations examining different aspects of a CCUS-EOR system have received considerable attention. Work done by Nuñez-López et al. [16] created a unique carbon life cycle study to better understand the environmental effect of CO_2 emissions and CO_2 storage linked with an extended CCUS EOR system. An operational and environmental performance model was developed to capture reservoir behaviors such as incremental oil recovery, CO_2 storage, and CO_2 use rates as well as GHG emissions associated with the system boundary. Four injection scenarios were simulated (water alternating gas (WAG), water curtain injection (WCI), continuous gas injection (CGI), and a combination WAG and CGI) and WAG was determined to offer the most ability to co-optimize EOR and carbon storage goals. Azzolina et al. [17] evaluated GHG emissions related to CO_2-EOR when the source of CO_2 is harvested from a coal power station and showed that the oil generated via this strategy is a lower carbon fuel with a low emission component and demonstrated that CO_2-EOR operations may be structured to increase oil output while lowering GHG emissions.

This study will investigate LCA methodologies for CO_2-EOR for the Oropouche field (EOR 44) located in Trinidad. This investigation aims to quantify how much carbon dioxide this field is producing in order to ensure that there is enough storage to regulate the quantity of carbon dioxide that is produced from the reservoir. The methodology involves a subsurface operational model involving map digitization of the field, reservoir development to conduct a sensitivity and history matching analysis, and simulations analyzing the reservoir reactions of different CO_2 injection strategies using the CMG-GEM as outlined by previous studies [18-25]. A surface environmental model will be developed and utilized to evaluate the required energy and material consumption for the capture, transport, and injection phases of the CCUS system.

2. Methodology

The methodical strategy and workflow for data collecting and analysis is shown in Figure 1. The study was conducted using field data from the Oropouche field. All the publicly available information for the location of Trinidad's CO_2 Project and the Structure Contour Map of EOR-44 and what was required for the geological modelling were obtained from a previous study [14].

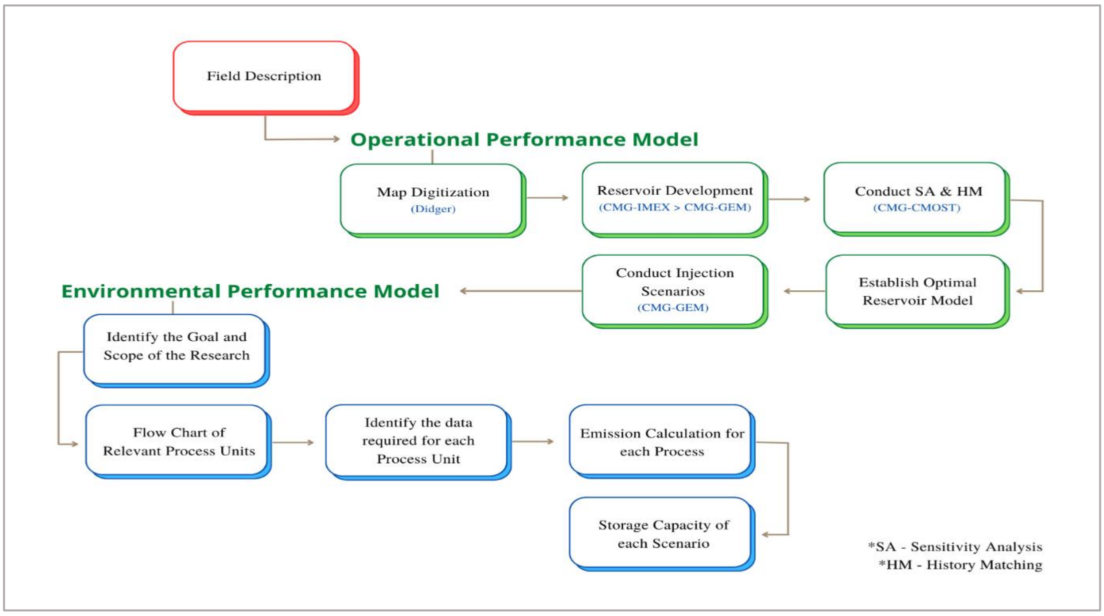

Figure 1. Flowchart of General Steps Conducted for this Research.

2.1. *Operational Performance Model*

The methodology utilized for development of the model was consistent to that used in previous studies [18-25]. These studies demonstrated the successful use of Didger for digitizing map data, and found it to be versatile, high precision with sophisticated editing options and an intuitive user interface. They also successfully utilized the CMG reservoir modeling and simulation tool for CO_2 injection along with the associated GEM-GHG module that accurately predicted the interactions of CO_2 in the reservoir. Didger was used to digitize the Oropouche field EOR 44 structure map that was provided by Mohammed-Singh & Singhal [14] and exported for use in creating a static model in CMG.

Table 1 shows the rock properties for the Oropouche Field - EOR 44 which was obtained in the literature [14]. Table 1 also shows the suitability of the field for implementation as the actual properties fell within the prescribed ranges described by Taber et. al., (1997) [26]. The black oil model was created using CMG's Builder IMEX simulator function and the reservoir grid was established. Specifying reservoir data and log data from Table 1 were incorporated creating the static model to establish the geological structure. The black oil model was generated, the IMEX file was then converted to the CMG-GEM simulator in order to create the compositional and numerical models for the scenarios to be identified.

The CMG program WINPROP was used to create PVT data using the reservoir's component information obtained from previous research which is shown in Table 2 [25]. The fluid model consisted of 15 different components including CO2. Prior to the modelling of the injection scenarios, the model was calibrated using sensitivity analysis and history matching for cumulative oil production utilizing the CMG-CMOST tool.

Table 1. Reservoir Rock and Fluid Properties [14, 26]

Oropouche Field - EOR 44		Screening Range (Taber et. al., 1997)
Rock Properties		
Area (acres)	175	
Pay Zone	AO-8	
Depth (ft)	2160	>1800
Thickness (ft)	35	
Porosity (%)	30	
Permeability (md)	2-36	Not critical
Oil Saturation (%)	70	15 to 70
Temperature (°F)	120	
Transmissibility(md-ft/cp)	111	
Fluid Properties - Initial Conditions		
Reservoir Pressure (psi)	1584	
Solution Gas Oil Ratio (scf/bbl)	260	
Oil Formation Volume Factor (bbl/bbl)	1.13	
Oil Gravity (°API)	29	27 to 44
Oil Viscosity (cp)	5	0.3 to 6

Because cumulative oil production data for this reservoir was not available, theoretical data for this reservoir was constructed utilizing an exponential decline curve analysis. The sensitivity analysis method is used to assess how sensitive an Objective Function is to various parameters and their value ranges. The parameters identified for this simulation were porosity, permeability, K_v/K_h ratios, and production well BHP values. The model was tuned to match the historical production results and history matching was followed using the results from the sensitivity analysis. The theoretical cumulative oil produced was the measured data that was matched, and the optimal experiment identified.

Table 2. Fluid Composition [25]

Component	Mole Fraction
CO_2	0.0091
N_2	0.0016
C1	0.3647
C2	0.0967
C3	0.0695
IC4	0.0144
NC4	0.0393
IC5	0.0144
NC5	0.0141
FC6	0.0433
FC9	0.1320
FC15	0.0757
FC16	0.0150
FC30	0.0315
FC45	0.0427

2.2. Simulation Scenarios

The model included three injection wells and five producing wells (offtakes). The simulation started on 1st June 1990 and ended on 1st June 2022 with a production period of 32 years in total. The model was run without injection to identify the OOIP and the primary production to be used as the base case of the study. There are three injection scenarios that were chosen for this study which are shown in Table 3.

Table 3. Fluid Composition [20]

Scenario	Injection Strategy
1	CO_2 Injection
2	CO_2+N_2 Injection
3	CO_2-WAG Injection

As described by Cheraghian et. al. [27], CO_2 injection for EOR is a commonly used technique that works to displace the oil in the flooded reservoir by injection of carbon dioxide. This technique achieves a higher oil displacement ratio than other CO_2 technologies. The CO_2 with N_2 injection displaces oil in flooded reservoirs much like CO_2 injection does, however this approach has the advantage of using cost effective flue gases like nitrogen. With CO_2 water alternating gas (CO_2-WAG) injection, CO_2 is injected in cycles alternated with quantities of water to regulate CO_2 mobility and stabilize the gas front. This technique helps to enhance sweep efficiency during CO_2 injection.

2.2.1 Optimization Properties for Reservoir Simulations

Scenario 1: CO_2 Injection

The injection rate was optimized for this scenario as it impacts the quantity of carbon dioxide stored but also the amount of oil recovered. In this study, 4 injection rates ranging from 100,000 ft^3/day to 300,000 ft^3/day were applied, while keeping other variables such as Injection BHP constant at 2000 psi.

Scenario 2: CO_2-N_2 Injection

The impact of variations in composition of the component was used to select the optimized scenario. Four variations were applied: 15% CO_2 and 85% N_2, 10% CO_2 and 90% N_2, 20% CO_2 and 80% N_2 and 50% CO_2 and 50% N_2. The injection BHP was kept constant at 2000 psi and the injection rate for the first scenario was 100,000 ft^3/day while the other scenarios utilized 200,000 ft^3/day.

Scenario 3: CO_2-WAG Injection

The WAG injection cycle was varied for four CO_2-WAG simulations to measure the effects on oil production and CO_2 sequestered. The cumulative injection rate was 200,000 ft^3/day for CO_2 injection periods and 10000 bbl/day for periods of water injection for each case. The duration of each fluid injection (CO_2 then H_2O) varied from 120 days – 120 days, 120 days – 240 days, 240 days – 120 days, and 240 days – 240 days. The production BHP for the first case had a pressure of 2500 psi while the other cases remained constant at 2000 psi. The optimum injection strategy for each scenario was selected based on performance parameters of recovery factor, utilization rates, CO_2 stored and CO_2 storage efficiency.

2.3. Environmental Performance Model

Development of the Environmental Performance Model for the LCA of CO_2-EOR operations for the EOR-44 Oropouche field was consistent with previous work conducted by Nuñez-López et al. [16] and Azzolina et al. [17]. The approach involved conducting an LCA using a spreadsheet to determine net volume of CO_2 emission reduction by estimating the difference between the amount of volume of CO_2 stored and what has been injected. In order to address the surface environmental performance of CO_2 generated, this inquiry required a simple yet effective template, which is why a spreadsheet approach was chosen. Focus is on the energy and material consumption involved with CO_2-EOR processes, such as capture, compression, and truck transportation. The energy necessary for consumption was determined using literature data and corresponding emissions were calculated via the Cradle-to-Grave system boundary. A comparison of CO_2 storage for the various injection scenarios was studies also. The CO_2 for the process units for the complete CCUS system, as well as the CO_2 stored at the end step, will be considered in the findings. The general components of the CCUS system are defined in Figure 2.

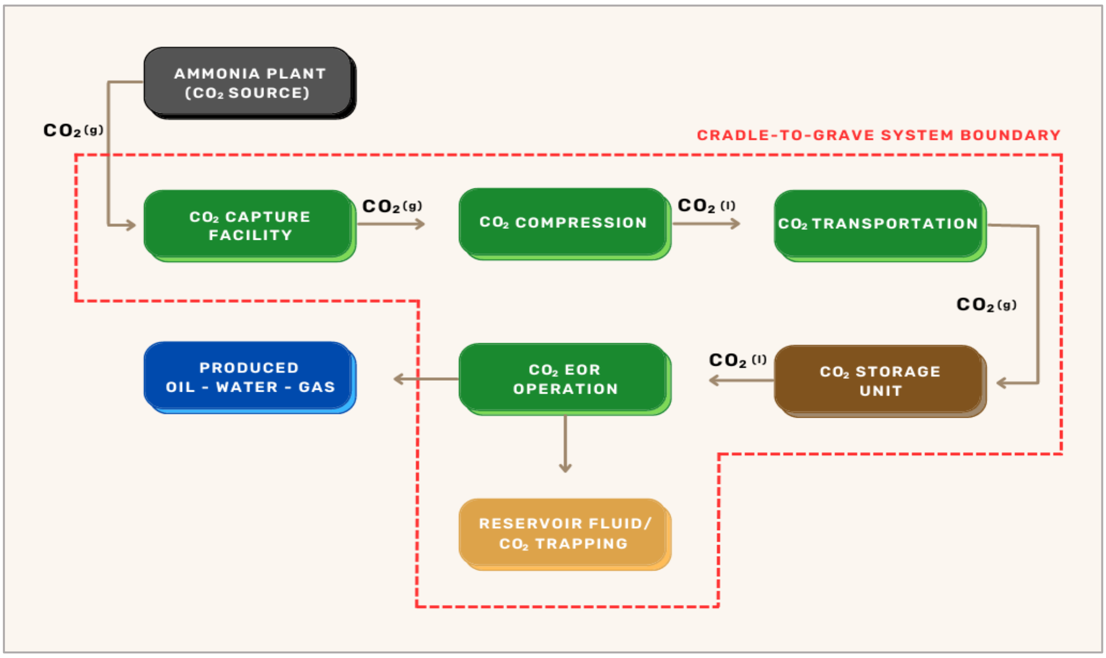

Figure 2. CCUS System Components and Boundary Defined.

2.4. CCUS System Emission Estimates

CCUS System Emission Estimates was conducted as described by Azzolina et al., [17]. The cradle to grave system boundary for the CCUS system includes emissions upstream of the CO_2-EOR operation and factors capturing, compressing, and transporting CO_2. In the gate-to-grave system boundary, the gate is the point where CO_2 is injected into the reservoir and the grave represents storage or the trapping of CO_2 as the product is being produced.

For a CO_2 capture system, the required data to estimate emissions (energy to capture CO_2 available * average emission rate) include CO_2 available for EOR operations, energy required to capture 1tonne of CO_2, energy to capture CO_2 available, and average emission rate. Estimations for the CO_2 compression system, ecom (energy to compress CO_2 available * average emission rate) include data inputs such as energy required to compress 1tonne of CO_2, energy to compress CO_2, average emission rate, and emission from compressor. The CO_2 emissions associated with transport via trucking required information such as fuel requirements for trucks and fuel consumed (liters), distance travelled, CO_2 released per liter of fuel, total liters consumed by truck, and CO_2 emissions per liter diesel engines and leakage.

3. Results & Discussion

3.1. Oropouche Field EOR-44 Field Description

The EOR 44 located in the Oropouche field in the southwest peninsula of the island of Trinidad and is shown in Figure 3.

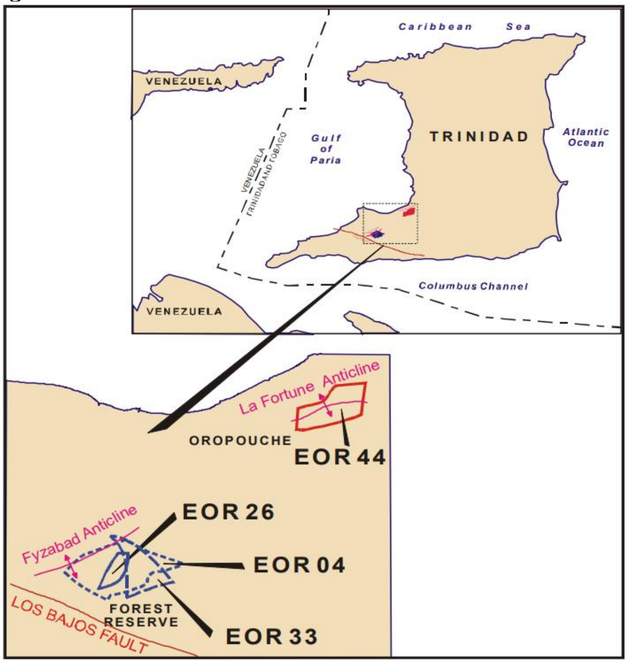

Figure 3. Location of EOR 44 [14].

The average porosity of the field is 30%, while the permeability ranges from 2 to 36md. With an API gravity of 29° and a viscosity of 6cp at 375psi and 120 °F, the crude is classified as light oil. This field is defined as deep-water sands formed on a continental slope with two discrete units, with a net thickness of 35 feet, with shale-outs and faults that restrict the reservoir as seen in the structural map (Figure 4) and occurs at an average depth of 2160 ft.

The commercially available software Didger was used to digitize the Oropouche field EOR 44 structure map that was provided by Mohammed-Singh & Singhal [14] and shown in Figure 4 and exported for use in creating a static model in CMG. The black oil model was created using CMG's Builder IMEX simulator function where the reservoir grid was established using the Non-orthogonal Corner Point (Figure 5).

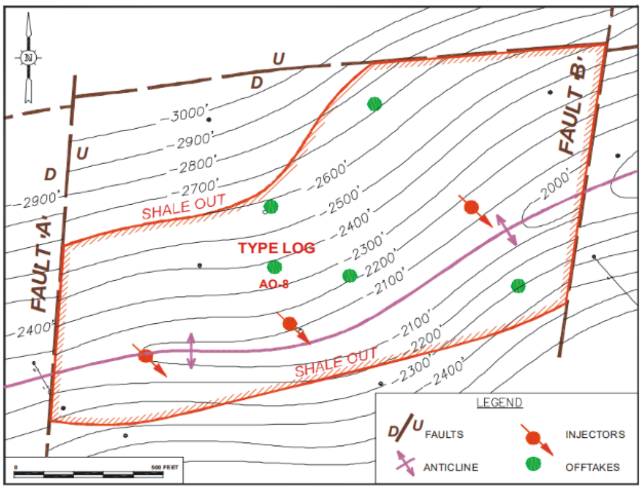

Figure 4. Structure Contour Map of EOR-44 [14].

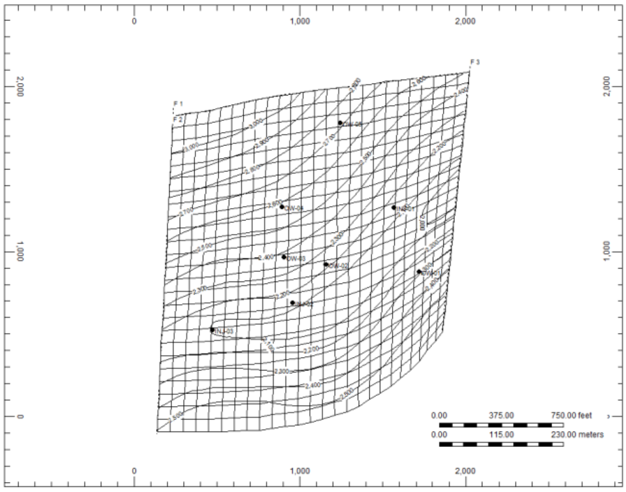

Figure 5. Non-orthogonal Corner Plot.

Specifying reservoir data and log data from Table 1 were incorporated creating the static model. The established geological structure and location of injection (INJ) and offtake (OW) wells are depicted in Figure 6.

The black oil model was generated, the IMEX file was then converted to the CMG-GEM simulator in order to create the compositional and numerical models for the scenarios to be identified.

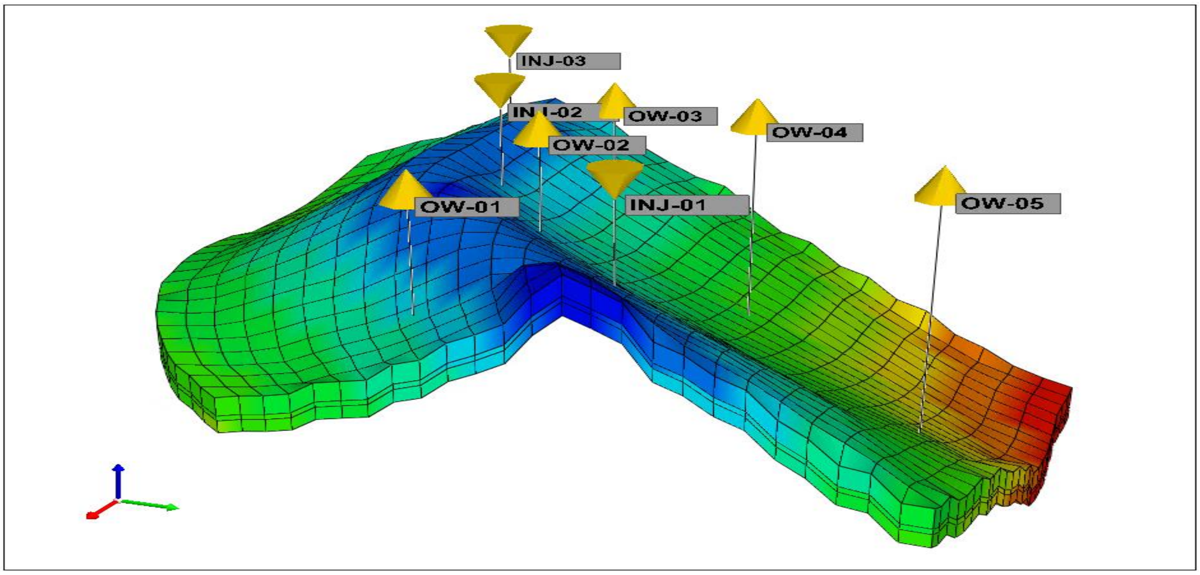

Figure 6. 3D Structure and Location of injection (INJ) and offtake (OW) well.

3.2. Optimal Reservoir Base Model

A history match was performed using the CMG-CMOST optimization software. BHP pressures, porosity data, and permeability data were used to match the theoretical field production statistics, i.e. calculating the average of the errors of each well and parameter (Figure 7). The simulation's ideal scenario has a global history match error of 28% which suggests that there is a close match between the historical production data and parameters analyzed for the field. Scenario 1: CO_2 Injection Four injection rates ranging from 100000 ft^3/day to 300000 ft^3/day were applied, while keeping other variables such as Injection BHP constant at 2000 psi. The performance of the CO_2 Injection scenario is summarized in Table 4.

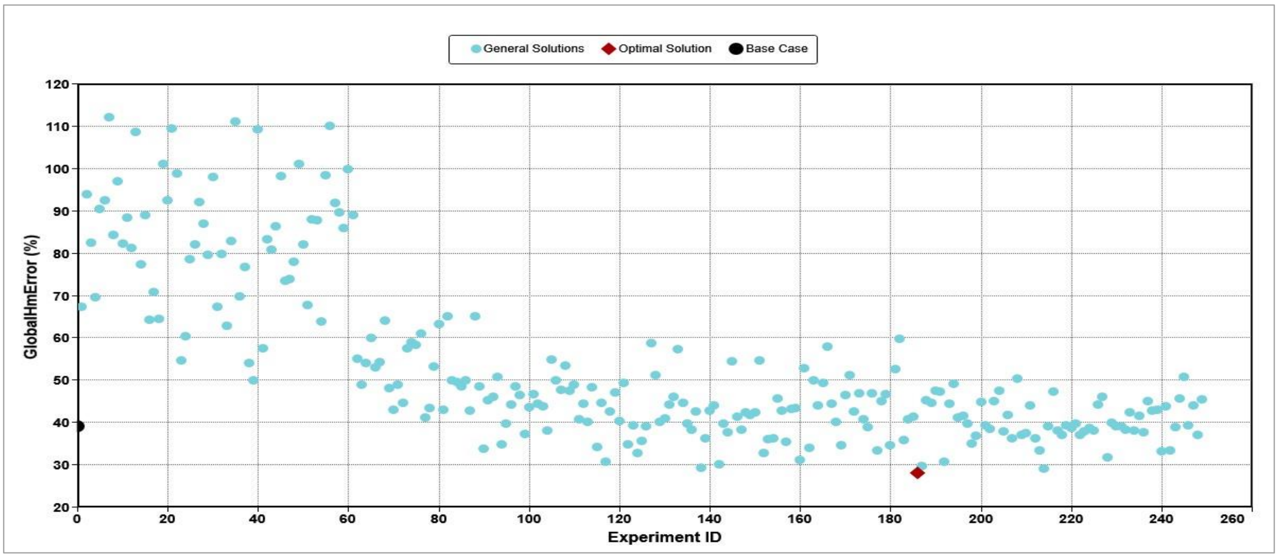

Figure 7. Global History Match Error Graph Representing Experiments.

Table 4. Summary of CO_2 Injection Simulation Outcomes

CO_2 INJECTION										
CASES	Optimization Property	Injection	Production			Results				
	Injection Rate	CO_2	Cumulative Oil	Cumulative Gas	CO_2	CO_2 Utilization Rate	Secondary Recovery Factor	CO_2 Stored	CO_2 Stored	CO_2 Storage Efficiency
	MSCF/day	BCF	MMBBL	BCF	BCF	MSCF/BBL	%	BCF	Million Tonnes	%
1	100	3.506	3.202	5.310	2.250	0.392	37.165	1.256	0.072	35.83
2	150	5.260	3.229	7.032	3.743	0.470	37.477	1.516	0.087	28.83
3	200	7.013	3.228	8.748	5.270	0.540	37.461	1.743	0.100	24.85
4	300	10.519	3.225	12.201	8.394	0.659	37.431	2.125	0.122	20.20

Increasing the injection rate from 100 MScf/day to 150 MScf/day enhanced the recovery factor and the amount of CO_2 being stored after which increases in injection rates resulted in a decrease for both parameters.

Increasing injection rates resulted in an increase in CO_2 utilization rates and cumulative gas production since as the volume of CO_2 delivered into the reservoir increases, so do CO_2 breakthrough and the reservoir's capacity to sweep. CO_2 storage efficiency decreased with higher injection rates due to a greater level of CO_2 breakthrough occurring at higher injection rates. Figure 8 shows the cumulative oil production for the various CO_2 injection rates compared to the base case over a 32-year period and shows that when the injection rates were increased, the cumulative oil also increased, plateauing at approximately 3.2 MMBBL. All scenarios had a higher cumulative oil compared to the base case. Based on the results, Case 4 is the best-case scenario as it fits the project's priority which focus on minimizing emissions while maintaining oil recovery. Scenario 2: CO_2-N_2 Injection:

The impacts of variations in composition of the component were studied using four variations: 15% CO_2 and 85% N_2, 10% CO_2 and 90% N_2, 20% CO_2 and 80% N_2 and 50% CO_2 and 50% N_2. The injection BHP was kept constant at 2000 psi and the injection rate for the first scenario was 100,000 ft^3/day while the other scenarios utilized 200,000 ft^3/day. The performance of the CO_2-N_2 injection scenario is summarized in Table 5.

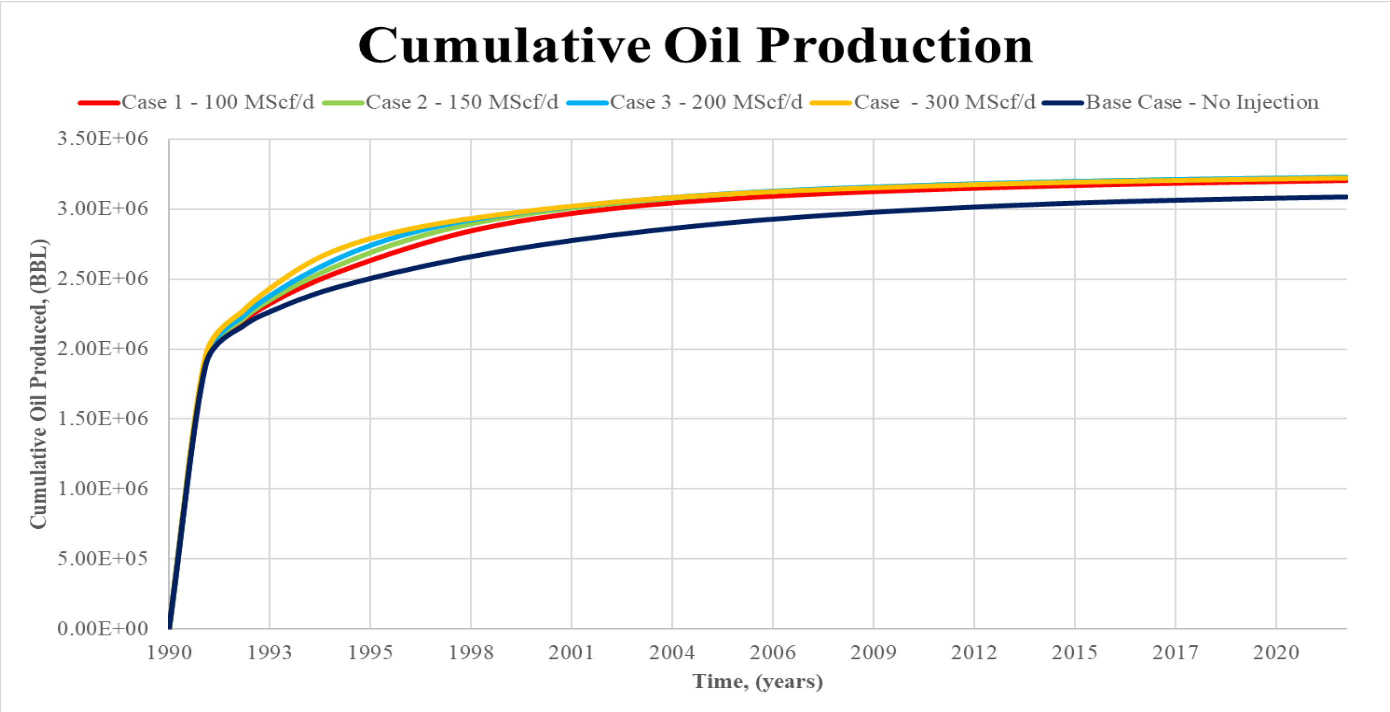

Figure 8. Cumulative Oil Production for the CO_2 Injection rates over a 32-year period.

Table 5. Summary of CO_2-N_2 Injection Simulation Outcomes

CO_2-N_2 INJECTION											
CASES	Optimization Property	Injection		Production			Results				
	Injection Composition	CO_2	N_2	Cumulative Oil	Cumulative Gas	CO_2	CO_2 Utilization Rate	Secondary Recovery Factor	CO_2 Stored	CO_2 Stored	CO_2 Storage Efficiency
	CO_2-N_2	BCF	SCF	MMBBL	BCF	BCF	SCF/BBL	%	BCF	Million Tonnes	%
1	15-85	0.48	3.04	3.202	5.83	0.40	0.03	37.162	0.08	0.005	17.04
2	10-90	0.65	6.44	3.206	9.38	0.59	0.02	37.207	0.05	0.003	8.33
3	20-80	1.29	5.73	3.206	9.33	1.13	0.05	37.213	0.16	0.009	12.42
4	50-50	3.23	3.58	3.213	9.18	2.73	0.16	37.295	0.50	0.029	15.51

The first case for this scenario, using a gas composition containing 15% CO_2 recorded the lowest recovery factor which can be attributed to the lower injection rate utilized. In cases 2-4, at a constant injection rate, when the concentration of CO_2 increased from 10% to 50%, the secondary oil recovery factor increased. It was also observed that there was an increase CO_2 storage and utilization rate in the reservoir. Case 1 (15% CO_2) recorded the highest CO_2 storage efficiency which can be attributed to the relative low injection rate associated with a low CO_2 breakthrough.

Figure 9 shows the results of cumulative oil production of the CO_2-N_2 injection strategies compared to the base case over a 32-year period. All scenarios had higher cumulative oil compared to the base case. The results show that for the cases 2-4, when the percentage of injected CO_2 was increased, the cumulative oil also increased, plateauing at approximately 3.2 MMBBL.

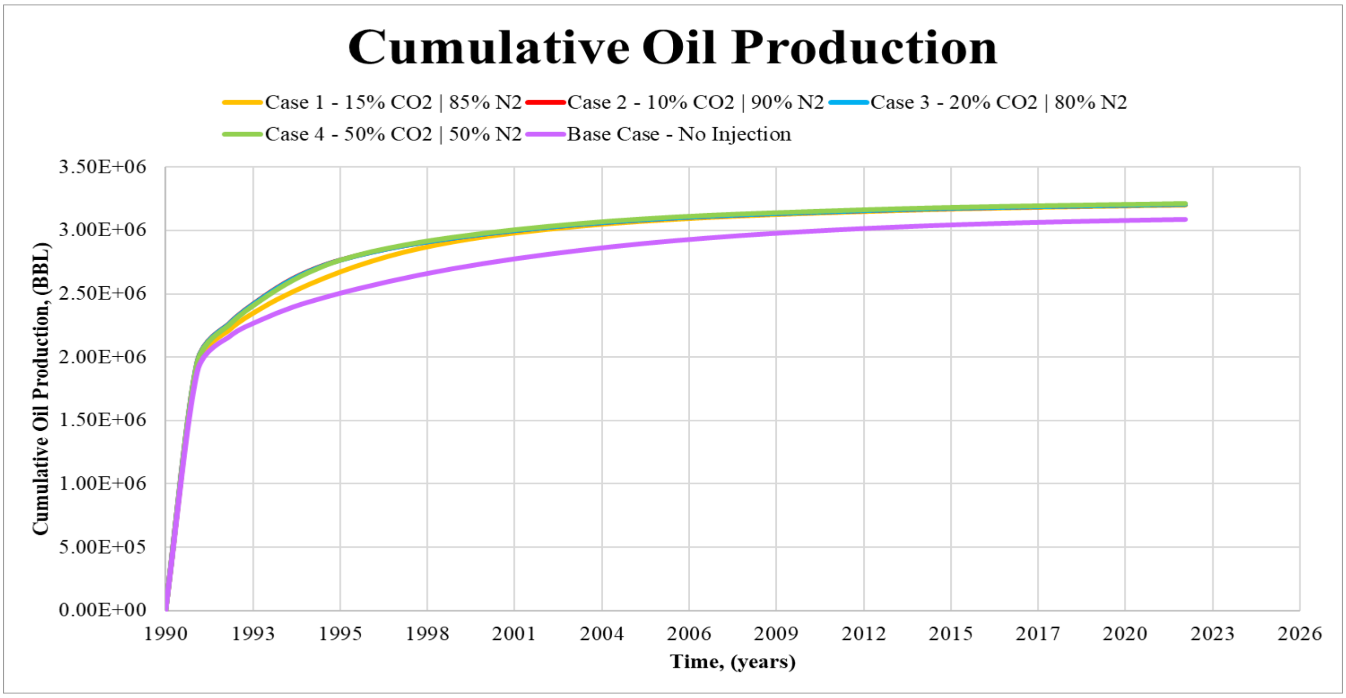

Figure 9. Cumulative Oil Production of the CO_2-N_2 Injection Strategies over a 32-year period.

Case 1 had a lower cumulative oil production compared to the other cases up to 1998 which can be associated with the lower injection rate, however the cumulative oil production was comparative to the other cases in the latter years of production.

In terms of the optimum case and as shown in Table 5, Case 4 (50% CO_2 and 50% N_2) had the highest utilization rate, the highest recovery factor and the most amount of CO_2 stored in the reservoir and is considered the best-case scenario.

Scenario 3: WAG Injection

The WAG injection cycle was varied for four CO_2-WAG simulations to measure the effects on oil production and CO_2 sequestered and the results of the experiments are shown in Table 6.

The results demonstrate that the secondary recovery factor increased as the cycle time increased, with values in excess of 40% for cases 2-4. In terms of CO_2 storage, when looking at cases 1 and 3, as the period of CO_2 injection is extended (period of water injection was constant), more CO_2

is stored. A comparison of cases 1 and 2 shows that when the water injection is extended (and CO_2 period is held constant), the amount of CO_2 stored in the reservoir reduces. By injecting water at lower rates than CO_2, CO_2 sequestered can be stabilized and oil can be produced for a longer length of time. The data shows that Case 1 has the highest utilization rate while Case 2 has the lowest residual capacity for carbon storage. In Case 2, water is injected for a longer period of time compared to CO_2, and since water takes up a significant volume of space it results in a lower residual capacity for carbon storage.

Figure 10 shows the cumulative oil production of the WAG injection strategies over a 32-year period and compares them with the base case model with no injection strategy. The results show that Cases 2 to 4 resulted in higher cumulative oil output compared to the base case, which plateaued at approximately 3.5 MMB.

Table 6. Summary of CO_2-WAG Injection Simulation Outcomes

WAG INJECTION											
CASES	Optimization Property	Injection		Production			Results				
	Injection Cycles	CO_2	H_2O	Cumulative Oil	Cumulative Gas	CO_2	CO_2 Utilization Rate	Secondary Recovery Factor	CO_2 Stored	CO_2 Stored	CO_2 Storage Efficiency
	CO_2 (days) - WAG (days)	BCF	MMBBL	MMBBL	BCF	BCF	MSCF/BBL	%	BSCF	Million Tonnes	%
1	120 - 120	2.592	7.341	1.736	2.262	0.900	0.97	20.15	1.691	0.097	65.26
2	120 - 240	2.304	12.156	3.471	3.938	1.030	0.37	40.29	1.274	0.073	55.28
3	240 - 120	4.637	7.935	3.476	6.225	2.891	0.50	40.34	1.746	0.100	37.66
4	240 - 240	3.456	10.208	3.482	5.052	1.914	0.44	40.41	1.542	0.088	44.61

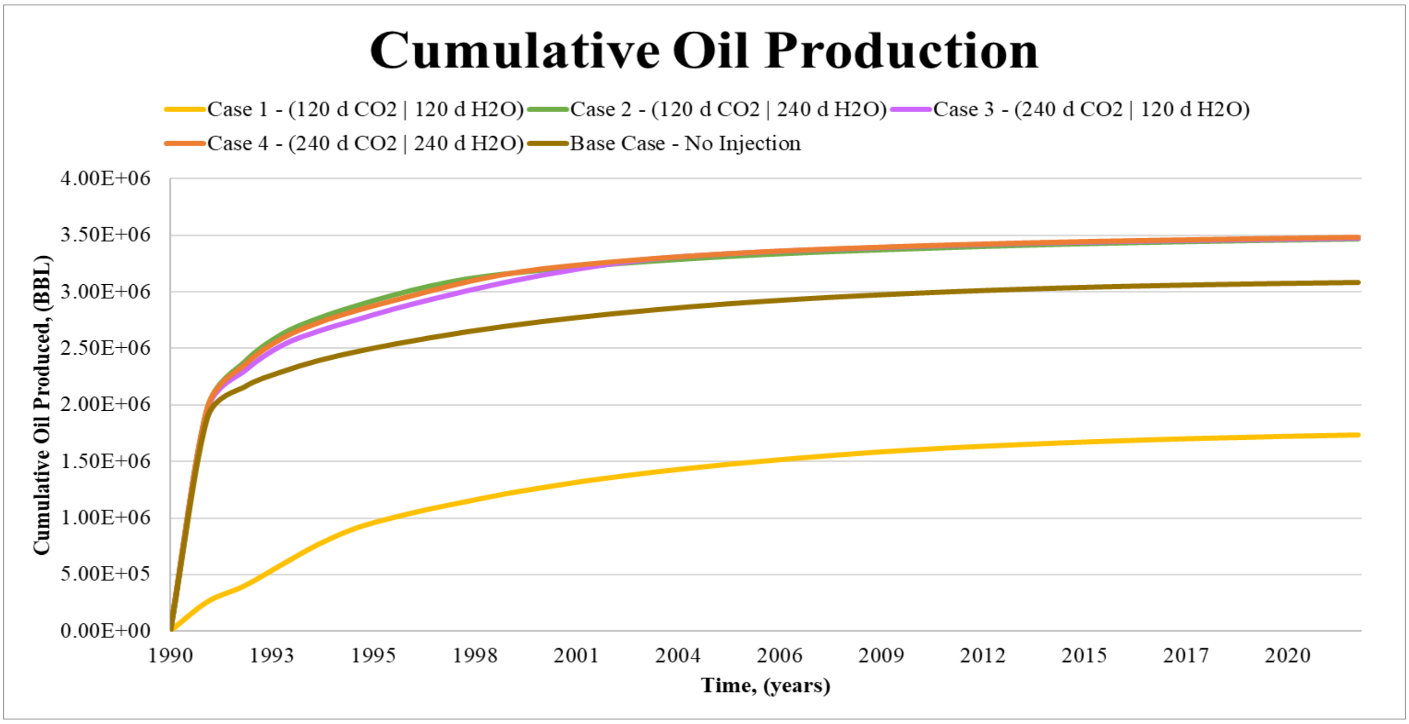

Figure 10. Cumulative Oil Production of the WAG Injection Strategies Over a 32-year period.

Case 1 had the lowest cumulative oil production compared to the other cases. The best case for this injection strategy would be Case 3, where CO2 was injected for 240 days and water for 120 days, which resulted in a superior recovery factor and volume of storage compared to the other cases.

3.3. *Optimal Injection Scenario*

A comparison of the performances of each of the optimal cases selected from each scenario is presented in Table 7 and the data clearly show that the best injection scenario is WAG. With an injection of 200 MScf/day of CO_2, it produced the highest cumulative oil (3.476 MMBBL) with the highest recovery factor (40.34%) as compared to the optimal scenario for CO_2 injection which uses 300 MScf/day of CO_2 producing (3.225 MMBBL). Despite WAG not having the highest stored volume of CO_2, it had the highest storage efficiency method. Even when compared to CO_2 injection, which can store equal amounts at a similar injection rate of 200 MScf/day as shown in Table 4, WAG has a substantially higher storage efficiency of 37.66% compared to CO_2 injection (24.85%).

Table 7. A Comparison of the Performances of each of the Optimal cases selected from each Scenario

BEST CASE											
Optimization Property	Injection Scenario	Injection	Production			Results					
		CO_2	Cumulative Oil	Cumulative Gas	CO_2	CO_2 Utilization Rate	Secondary Recovery Factor	CO_2 Stored	CO_2 Stored	CO_2 Storage Efficiency
		BCF	MMBBL	BCF	BCF	MSCF/BBL	%	BCF	Million Tonnes	%
300 Mscf/day	CO_2	10.5	3.225	12.201	8.394	0.659	37.431	2.125	0.122	20.20
50:50	CO_2-N_2	3.2	3.213	9.18	2.73	0.16	37.295	0.50	0.029	15.51
(2:1)	WAG	3.5	3.476	6.225	2.891	0.50	40.34	1.746	0.100	37.66

The results obtained were consistent with the findings obtained by Nuñez-López et. al. [16] who utilized an integrated model that quantitatively evaluated life cycle greenhouse gas (GHG) emissions associated with CO_2 enhanced oil recovery (EOR) investigating CO_2 is captured from a coal-fired power plant. In both studies, the quantities of injected CO_2 are reported to be largest in the CO_2 injection scenarios. This study showed that WAG produced more oil, generating roughly 8% more when just 33% of the injected CO_2 was used.

3.4. *Excel Based Life Cycle Analysis*

Environmental performance assesses the emissions associated with processes within the prescribed cradle-to-grave system boundaries. The CO_2 capture facility, CO_2 compression, CO_2 transportation through trucks, and the injection for CO2-EOR were all considered. The injection for CO_2 injection volume of CO_2 considered the optimal scenarios of each injection strategy simulated, and the case data for this LCA was reviewed with the purpose of determining the potential of using the field as a net sink for emissions. Data utilized for the required computations is shown in Table 8.
Table 9 shows the total CO_2 generated by each unit upstream of the EOR process. According to the estimates, the injection scenario creating the greatest amount of emissions for capturing, compressing, and transporting CO_2 is CO_2 injection. In all cases, the capture facility is shown to be the largest contributor to the quantity of CO_2 emitted. The WAG scenario sequestered the highest amount of CO_2 injected into the reservoir of the three techniques, accounting for 34% of the CO_2 stored.

Although pure CO_2 injection was shown to be the best alternative for environmental performance in the literature [17], it proved to be the worst-case scenario in terms of environmental performance for the Oropouche field (EOR 44) with WAG producing the best operational performance.

Table 8. Input Data for Calculations

Process Units	Parameter Description	Value	Unit
CO_2 Capture Facility	CO_2 available for EOR operation	0.300	Mt CO_2
	Energy required to capture 1t of CO_2	275.000	kWh_{el} / tCO_2
	Energy to capture of CO2 available	82500000.000	kWh_{el}
	Average emission rate	0.898	lbs CO_2 / kWh
	Emissions from capture facility (e_{cf})	0.037043	Mt
CO_2 Compression	Energy required to compress 1t of CO_2	100.000	kWh_{el} / tCO_2
	Energy to compress CO2 available	30000000.000	kWh_{el}
	Average emission rate	0.650	kg CO_2e/kWh
	Emissions from capture facility (e_{com})	0.021	Mt
Truck Transport of CO_2	Roadway distance	40.000	km
	CO_2 available for transport (in litres)	166,860,000,000.00	L
	Gross capacity of 1 truck	25000.000	L
	Nob. of trucks needed for transport	9143.014	
	Average diesel burnt per 100km	38.000	L
	Diesel burnt per trip (to and from)	15.200	L
	Total litres consumed	138973.808	L
	Diesel engines CO2 emissions per litre	0.0027	t
	CO_2 emissions per litre Diesel consumed	0.000375	Mt
	Leakage	3.500	%
	Leakage from transport	0.011	Mt
Injection for CO_2-EOR	CO2-EOR project duration	32.000	years
	Total CO_2 injected	0.290	Mt
	CO_2 produced	0.214	Mt
	CO_2 stored	0.075	Mt
	Total Emissions From Cradle-to-Grave	0.2720	Mt
	Percentage of Emissions Stored	26%	

Table 9. Associated CO_2 released, produced, and stored from the process unit of each strategy

Injection Strategy	CO_2 Capture	CO_2 Compression	CO_2 Transportation	EOR Inj.	EOR Prod.	CO_2 Stored	Percent of CO_2 Stored *(CO_2 Stored/CO_2 Inj.)*	Total Emissions
	(CO_2 Released), Mt	(CO_2 Released), Mt	(CO_2 Released), Mt	(CO_2 Injected), Mt	(CO_2 Produced), Mt	Mt	%	Mt
CO_2	0.037	0.021	0.0004	0.29	0.214	0.076	26	0.272
CO_2-N_2	0.022	0.013	0.0002	0.174	0.16	0.014	8	0.195
WAG	0.033	0.019	0.0003	0.256	0.17	0.086	34	0.222

4. Conclusion

CO_2 enhanced oil recovery (CO_2-EOR) was evaluated to determine its feasibility as a net sink and to boost oil production in the EOR44 reserve in the Oropouche Field in southwest Trinidad. This study's approach involved a dynamic carbon lifecycle analysis (LCA) that tied operational performance to corresponding greenhouse gas (GHG) emissions of a specific carbon capture, utilization, and storage (CCUS) system. The Computer Modelling Group (CMG) application evaluated the EOR injection methods of CO_2, CO_2+N_2, and WAG injections and found that WAG was the best injection method, producing the most oil (3.5 MMBBL) at 200 MScf/day of CO_2 injection with a recovery factor of 40% and a storage efficiency of 38%, storing roughly 100,000 tCO_2.

The environmental performance utilized a CCUS system characterized by a cradle to grave boundary that represented CO_2 capture, CO_2 compression, CO_2 transportation by truck, and EOR operations. Results indicated that the CO_2 capture facility unit, generating between 33,000 and 37,000 Mt of CO_2, has a higher emission output than the compression and transportation units. The scenario with the lowest storage performance was CO_2-N_2 (8% of CO_2 stored), while WAG injection had the largest sequestration capability with a projection of 34%. This study demonstrated the feasibility of the use of CO_2-EOR as a net sink in the EOR 44 area, an appropriate step to aid in T&T's efforts to mitigate climate change and improve oil production.

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