

Investigating Petrophysics Effect of CO₂ Injection and Sequestration in Carbonate Reservoir Rocks - A Reservoir Engineering/ Petroleum Geology Approach

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Abstract

The interactions between brine and carbon dioxide (CO₂) at the fluid–rock interface play a critical role in controlling the distribution and migration of fluids within porous geological formations. These interactions—dominated by interfacial tension, wettability, capillary forces, and mass transfer—largely determine the efficiency and security of CO₂ sequestration in deep saline aquifers. Although considerable research has addressed CO₂ behavior in oil and gas reservoirs, limited experimental data exist on the interfacial properties specific to saline aquifer systems under reservoir conditions. In particular, reliable laboratory measurements of interfacial tension and wettability evolution are required to improve understanding of how pressure, temperature, and salinity influence CO₂–brine systems. Such data are essential for predicting multiphase flow behavior, assessing residual and structural trapping mechanisms, and ultimately evaluating the long-term storage capacity and stability of saline formations. This study provides experimental insights into brine–CO₂ interfacial properties under conditions representative of deep aquifers, with emphasis on the implications for reservoir petro physical behavior and carbon storage performance.

Keywords: Brine, CO₂, Interfacial tension, Wettability, Reservoir properties, Saline aquifers.

Introduction

Compressed petroleum gas (CPG), derived from crude oil processing, is among the most common hydrocarbon products generated during secondary recovery operations. The continuous reliance on fossil fuels for power and industrial processes, however, has significantly increased atmospheric concentrations of greenhouse gases, particularly CO₂, which is widely recognized as the primary driver of global warming and climate instability. Carbon capture and geological storage (CCS) has therefore emerged as a promising mitigation strategy to reduce anthropogenic CO₂ emissions and support global climate goals (Bachu, 2000; Benson et al., 2005; IEA, 2015; Skov et al., 2002).

Among the proposed storage options, deep saline aquifers offer substantial potential due to their widespread occurrence, vast storage capacity, and suitability for long-term containment (Bennion & Bachu, 2005). Several global demonstration projects have investigated the fate of injected CO₂ in subsurface systems, highlighting the importance of secure trapping mechanisms. These mechanisms include structural and stratigraphic trapping, solubility trapping, residual trapping, and mineral trapping, each contributing to the permanence of storage (Firoozabadi & Cheng, 2010; Zhang & Song, 2014).

Residual trapping, in particular, is of high interest in this work as it directly relates to the petrophysical properties of the host formation. Using the Lower Benue Trough as a case study, this research

investigates how CO₂ injection alters interfacial tension and wettability of carbonate rocks—two parameters that strongly influence multiphase flow and storage efficiency. Ensuring that CO₂ plumes remain immobilized within the reservoir is critical, as excessive pressure buildup could compromise caprock integrity, trigger fault reactivation, or result in leakage pathways. Monitoring technologies, particularly seismic methods, have proven effective in tracking CO₂ plume migration in notable projects such as Sleipner in the North Sea and In Salah in Algeria (Arts et al., 2004; Ringrose et al., 2013). These approaches rely on changes in seismic responses governed by both rock frame and pore fluid properties (Avseth et al., 2010; Mavko et al., 2009).

The hydrodynamic and geomechanical behavior of a storage reservoir is fundamentally controlled by parameters such as porosity, absolute and relative permeability, and wettability. While porosity and absolute permeability are intrinsic rock properties, they can be significantly altered by fluid pressure changes during injection. Relative permeability hysteresis, caused by successive displacement cycles of brine and CO₂, plays a decisive role in determining the extent of residual trapping and hence the long-term security of storage (Juanes et al., 2006). Experimental studies that couple rock mechanics with fluid–fluid interactions provide valuable insights into these processes.

The present research therefore aims to examine the effect of CO₂ injection on the petrophysical characteristics of carbonate rock samples obtained from the Lower Benue Trough. The specific objectives include:

- i) Preparing cylindrical core samples of 4 cm by 2 cm using a coring machine.
- ii) Determining interfacial tension and wettability of the carbonate samples prior to CO₂ injection.
- iii) Measuring the same parameters after CO₂ exposure under reservoir conditions.
- iii) Comparing pre- and post-injection results to evaluate changes induced by supercritical CO₂.

The study is restricted to laboratory-scale evaluation of supercritical CO₂ injection into carbonate cores, with emphasis on interfacial tension and wettability as controlling factors of rock–fluid interactions. The findings are expected to contribute to a deeper understanding of fluid behavior in saline aquifers, ultimately improving storage capacity estimates and supporting safer implementation of CCS projects.

Materials and Methods

This research followed established reservoir engineering protocols to evaluate the effect of supercritical CO₂ injection on the petrophysical characteristics of carbonate rocks. The workflow comprised sample preparation, experimental testing, and data collection using specialized equipment.

Core Sampling and Preparation and Coring Procedure

Cylindrical core samples were extracted from carbonate formations in the Lower Benue Trough. Two sets of cores were prepared:

50 × 100 mm cylindrical cores (20 samples).

200 × 200 mm cylindrical cores (20 samples).

Coring was conducted at the Department of Petroleum Resources Engineering, Federal Polytechnic Ado-Ekiti. To minimize alteration of porosity and wettability, careful handling and preservation techniques were applied. Core handling included cutting, preservation, transportation, and sampling. All procedures were designed to avoid contamination and mechanical damage.

Sample Location

Five representative carbonate rock samples were collected from the study area. Their geographic coordinates were recorded using GPS, as shown below:

Geographic coordinates of sampling locations

Samples	Locations	Easting	Northing	Depth
AD1	One	005 ⁰ 15.433'	007 ⁰ 28.208'	454m
AD2	Two	005 ⁰ 18.664'	007 ⁰ 30.024'	388m
AD3	Three	005 ⁰ 16,222'	007 ⁰ 28.886'	460m
AD4	Four	005 ⁰ 12.002'	007 ⁰ 30.202'	454m
AD5	Five	005 ⁰ 12.888'	007 ⁰ 26.676'	445m

Samples were selected based on mineralogy, porosity, pore structure, and degree of homogeneity. To ensure representativeness, CT scanning was used to avoid cores with fractures or inclusions that could bias measurements.

Cleaning and Conditioning

Collected cores were cleaned using alternating toluene and methanol flushing to remove residual hydrocarbons. In cases where clay preservation was critical, miscible fluids and supercritical drying were applied. After cleaning, cores were conditioned by saturating with formation brine and aging in formation oil to restore near-reservoir wettability. Prepared cores were cut into 50 × 100 mm cylindrical plugs for laboratory analysis.

Equipment and Experimental Techniques

2.2.1 Mercury Injection Capillary Pressure (MICP)

MICP analysis was performed to determine pore throat distribution, porosity, and permeability. The process involved:

- i) Placing core samples in a penetrometer pre-filled with mercury.
- ii) Subjecting the system to incremental pressures from ~26 psia up to 60,000 psia.
- iii) Measuring mercury intrusion into pore spaces under increasing pressure.

The method provided:

- Drainage capillary pressure curves.
- Pore throat size distributions.
- Porosity and grain density at high pressure.
- Empirically derived permeability estimates.

CO₂ Injection and Saturation Measurement

CO₂ injection tests were conducted under controlled laboratory conditions to simulate reservoir environments. Fluid saturations of CO₂ and brine were determined using X-ray CT tomography, enabling non-destructive measurement of saturation profiles during relative permeability experiments.

Wettability Determination

Wettability was assessed using the Amott test method, which quantifies spontaneous imbibition and forced displacement of fluids. The procedure involved:

- i) Saturating a core sample with oil.
- ii) Placing the core in an imbibition cell surrounded by water, allowing spontaneous water imbibition to displace oil until equilibrium.

- iii) Forcing remaining oil out by centrifugation or displacement pumping.
 - iv) Measuring the volumes of imbibed and displaced fluids to calculate the wettability index.
- This index provided a quantitative measure of rock–fluid interactions before and after CO₂ exposure.

Sample Handling Considerations

During cutting and transportation, kerosene and water were used as coolants to prevent overheating and contamination. Exposure to air was minimized to preserve native wettability. Once in the laboratory, cores were labeled, stored in airtight sample bags, and prepared for testing.

Results and discussion

Interfacial Tension and Solubility Behavior

The experiments examined the interaction between CO₂ and brine systems under different thermodynamic conditions. The measured interfacial tension (IFT) and solubility data revealed distinct patterns when CO₂ was pre-saturated compared with when it was not pre-saturated before drop formation.

In Table 1, when CO₂ was pre-saturated at 120 bars, the IFT initially decreased with rising solubility but eventually reached a plateau between 8–10 minutes. At this stage, the IFT stabilized at approximately 26.5 mN/m, indicating a state of equilibrium between the aqueous phase and CO₂. Conversely, in Table 2, where pre-saturation was not achieved, IFT values continued to decline without a stable plateau, suggesting dynamic changes at the interface and incomplete equilibration. This finding demonstrates that pre-saturation plays a critical role in controlling equilibrium at reservoir conditions, and omitting this step may result in underestimation of long-term interfacial stability.

Effect of Brine Concentration on Interfacial Tension

Data in Table 3 highlight the influence of salinity on CO₂–brine IFT. At 28°C, IFT values increased progressively with rising molar concentration of NaCl, from 27.50 mN/m at 0.085 mol/dm³ to 30.01 mN/m at 3.69 mol/dm³. This linear relationship aligns with previously reported findings (Kiepe et al., 2002; Iglauer, 2011), where the presence of salts reduces CO₂ solubility, thereby increasing interfacial tension. From a storage perspective, this means that brine-rich formations with higher salinity may reduce CO₂ dissolution trapping potential but enhance structural and residual trapping through higher capillary entry pressures.

Pressure Dependence of Interfacial Tension

Tables 4a–4c present the variation of IFT with pressure across different brine molarities. At 0.085 M NaCl, IFT decreased sharply as pressure increased from 50 bars to ~120 bars, after which it stabilized around 25 mN/m. Similar stabilization was observed at 0.87 M and 1.7 M concentrations, although the exact pressure at which equilibrium was reached varied slightly.

The plateau indicates that once CO₂ reaches supercritical conditions, further increases in pressure exert minimal influence on IFT. This is consistent with earlier studies (Bachu, 2000; Bennion & Bachu, 2005) suggesting that beyond a threshold pressure, interfacial properties are primarily governed by fluid–fluid interactions rather than external stress. Importantly, underestimating this plateau effect could lead to erroneous calculations of storage capacity and capillary entry pressures.

Temperature Effects on Interfacial Properties

Temperature was also found to exert a significant influence on CO₂–brine interactions. In Tables 5a–5c, results for 0.87 M NaCl brine showed that at 28°C, IFT values decreased with pressure before stabilizing at ~26 mN/m beyond 240 bars. At 72°C, stabilization occurred earlier, around 20 bars, with

lower IFT values than at 28°C. At 100°C, IFT values dropped even more sharply, reaching 25 mN/m at 260 bars.

These results indicate that increasing temperature lowers interfacial tension and accelerates the approach to equilibrium. This has important implications: higher reservoir temperatures promote CO₂ dissolution into brine and enhance solubility trapping, though they may also increase the risk of CO₂ mobility and leakage if caprock integrity is compromised.

Implications for CO₂ Storage in the Lower Benue Trough

The interplay of pressure, salinity, and temperature on interfacial tension directly influences the efficiency of CO₂ trapping in deep saline aquifers. Three major insights emerge:

Capillary Pressure and Residual Trapping:

Capillary pressure, expressed as:

$$P_c = P_{CO_2} - P_{brine} = 2 \cdot \gamma_{brine,CO_2} \cos \theta / R.$$

Depends strongly on interfacial tension (γ) and pore throat radius (R). If IFT is underestimated, capillary pressure and CO₂ column height will also be underestimated, leading to miscalculations of storage capacity.

Salinity Effects:

High salinity enhances structural and residual trapping by increasing IFT, though it reduces solubility trapping. For the Lower Benue Trough, where brine concentrations vary, this means site-specific evaluations are critical before large-scale injection.

Thermal Influence:

Elevated temperatures, typical of deep aquifers, accelerate CO₂ solubility and lower IFT. This supports solubility trapping but raises the need for robust caprock integrity to contain buoyant CO₂.

These findings align with observations from international CO₂ storage projects such as Sleipner (Arts et al., 2004) and In Salah (Ringrose et al., 2013), where the balance between trapping mechanisms and reservoir integrity determined long-term success.

Sample collection

Five samples were carefully collected from the geological carbonate formation and sent to Federal Polytechnic Ado Ekiti. The samples are collected at regular intervals. The most homogeneous samples are selected. Such a bias likely imposes an undesirable bias on the results. The samples were kept in a sample bag and well labeled for laboratory analysis.

Computerized tomography (CT) scanning help the selection of samples easier without internal pebbles or fractures that might drastically affect the outcome of measurements. In general, the characteristics of a collected sample represent a significant portion of the reservoir. Collecting a core sample from the rock sample entails a cutting action with diamond-coated saws and boring tools. The coolant for these cutting processes is a source of contamination. To reduce contamination and preserve water saturation in the samples, kerosene and water is used as a coolant. During sample collection, the core sample is less exposed to air in order not to foster a shift of wettability from its native condition.

Sample cleaning and preparation

After collection from the core, rock samples are thoroughly cleaned in preparation for contact angle, wettability index and capillary measurement. Cleaning is done by flushing the sample alternately with toluene and methanol. To preserve delicate clay structures in some samples, a cleaning process with miscible fluids and supercritical drying is used.

The rock samples obtained were finished into six cylindrical core slides, 50 by 100mm cylindrical core samples. The core samples are cut from collected rock sample from the reservoir formation using

specialized coring machine. When cutting a core, all phases of the coring process are considered to ensure that the porosity is not altered prior to its usage in the laboratory. These phases include core cutting, core handling, core preservation, core sampling and core testing. Coring is carried out at Mineral and Petroleum Resources Engineering Technology department of Federal Polytechnic Ado Ekiti where there is a coring machine.

After suitable cleaning, the condition of the samples can be returned to near reservoir condition by processes of flooding with brine and oil from the formation and aging in formation oil. The restored-state samples are used for contact angle, wettability index and capillary measurement.

Results and Discussion

Results

Table 1: Showing when CO₂ is pre - saturated before the drop formation at 120 bars

Time(min)	Dissolution rate or solubility	IFT (mN/m)	Salinity(ppm)	Pressure(bars)	Temperatures(⁰ C)
0	0.5	29.0	5000	120	28
2	0.75	28.5	5000	120	28
4	1.00	27.5	5000	120	28
6	1.25	27.0	5000	120	28
8	1.50	26.5	5000	120	28
10	1.75	26.5	5000	120	28
12	2.00	26.5	5000	120	28
14	2.25	26.5	5000	120	28

Table 2: Showing Solubility vs. IFT (mN/m)

Dissolution rate or solubility	IFT (mN/m)
0.5	29.0
0.75	28.5
1.00	27.5
1.25	27.0
1.50	26.5
1.75	26.5
2.00	26.5
2.25	26.5

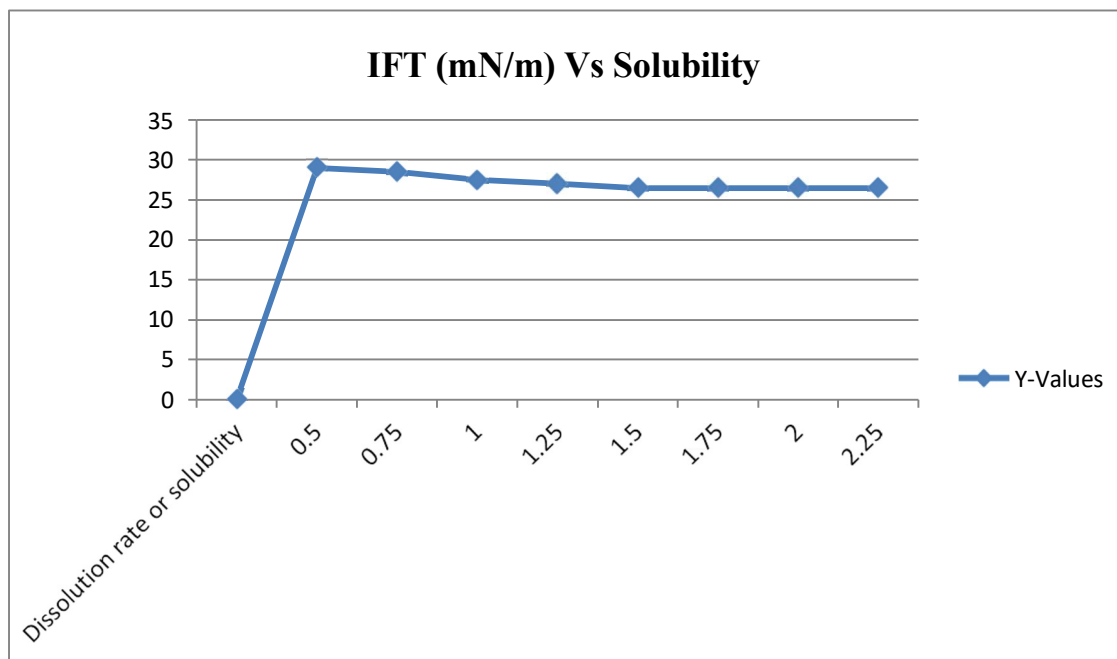


Fig1: Showing Solubility vs. IFT(mN/m)

Table 3: When CO₂ is not Pre saturated before the drop formation or CO₂ ceiling is not present in the visualization cell.

Time(s)	Dissolution rate or solubility	IFT (mN/m)	Salinity(ppm)	Pressure(bars)	Temperatures(⁰ C)
0	0.5	29.0	5000	120	28
2	0.75	28.5	5000	120	28
4	1.00	27.5	5000	120	28
6	1.25	27.0	5000	120	28
8	1.50	26.5	5000	120	28
10	1.75	26.0	5000	120	28
12	2.00	25.5	5000	120	28
14	2.25	25.0	5000	120	28

Table 4: Showing Solubility vs, IFT (mN/m)

Dissolution rate or solubility	IFT(mN/m)
0.5	29.0
0.75	28.5
1.00	27.5
1.25	27.0
1.50	26.5
1.75	26.0
2.00	25.5
2.25	25.0

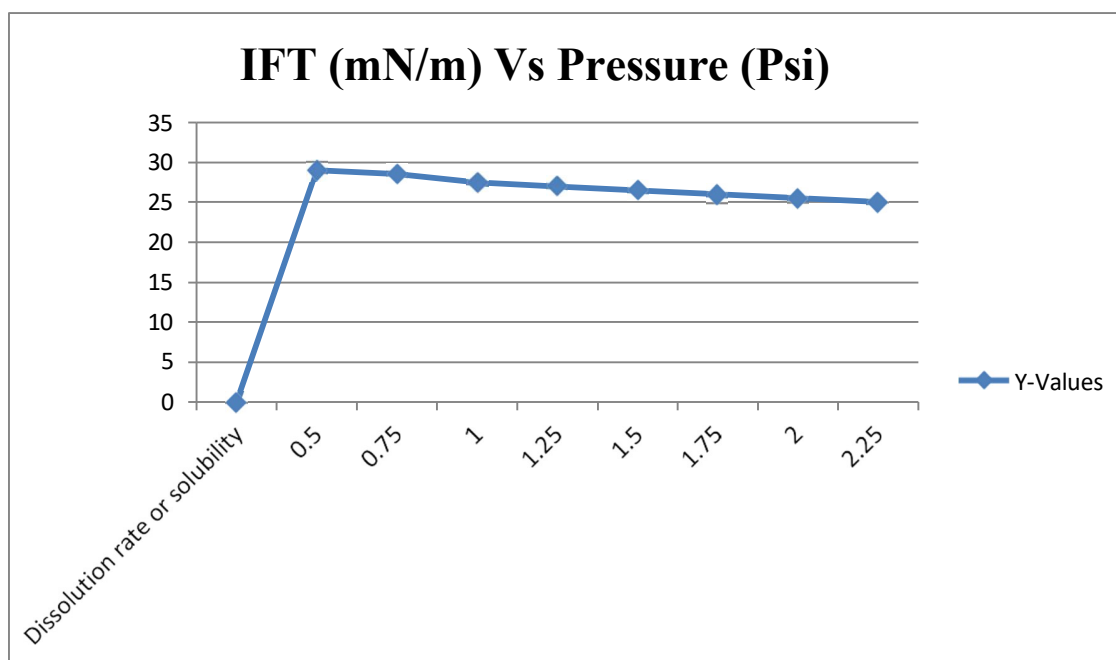


Fig 2: Showing Solubility vs. IFT(mN/m) for table 2

Table 5: Showing Interfacial Tension Increase with Increase in Molar Concentration of brine at 28°C.

Molar Concentration (Mol/dm ³)	Isotherm IFT(mN/m)	Temperature condition(°C)
0.085	27.50	28.00
0.87	28.20	28.00
1.79	28.90	28.00
2.75	29.50	28.00
3.69	30.01	28.00

Table 6, 7 & 8,; Showing IFT as a function of pressure for different Molar Concentration of Nacl (Brine) at T = 28⁰C

Table 6: Showing Pressure vs IFT at 28⁰C for 0.085Molar of brine

IFT(mN/m)	Pressure(bars)
37	50
33	60
28	70
28	80
29	110
26	120
25	175
25	210
25	240

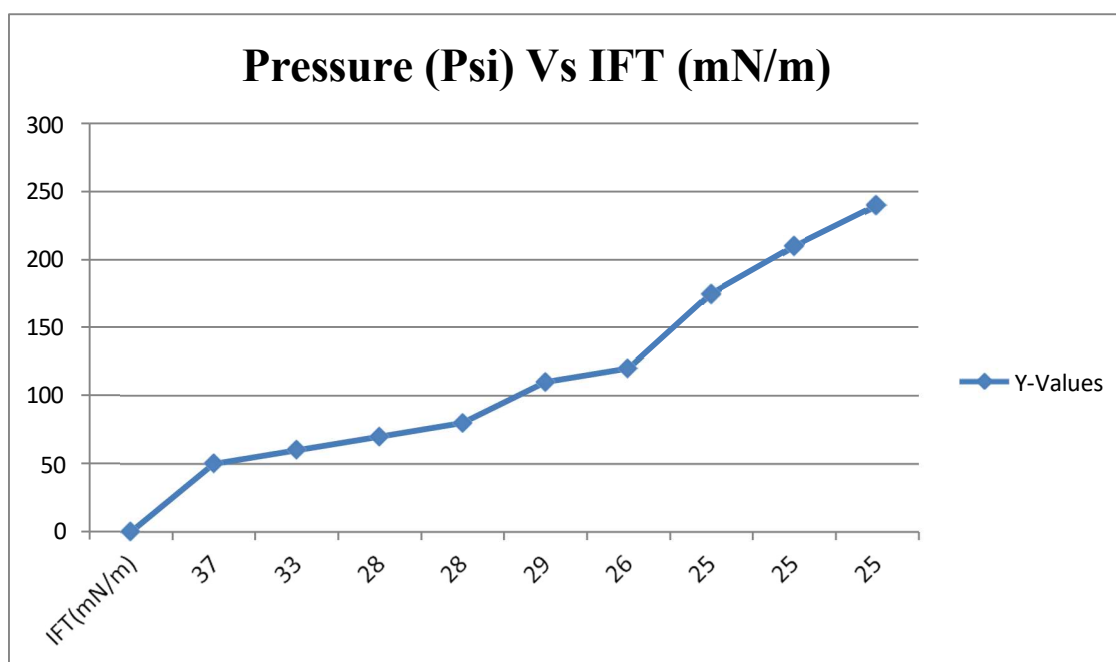


Fig. 3: Showing Pressure vs IFT at 28⁰C for 0.085Molar of brine

Table 7: Showing Pressure VS IFT at 28⁰C for 0.87Molar of brine

IFT (mN/m)	Pressure(bars)
38.0	60
36.0	63
28.0	70

29.0	80
29.5	100
30.0	120
27.5	135
28.0	170
26.0	200
27.0	252

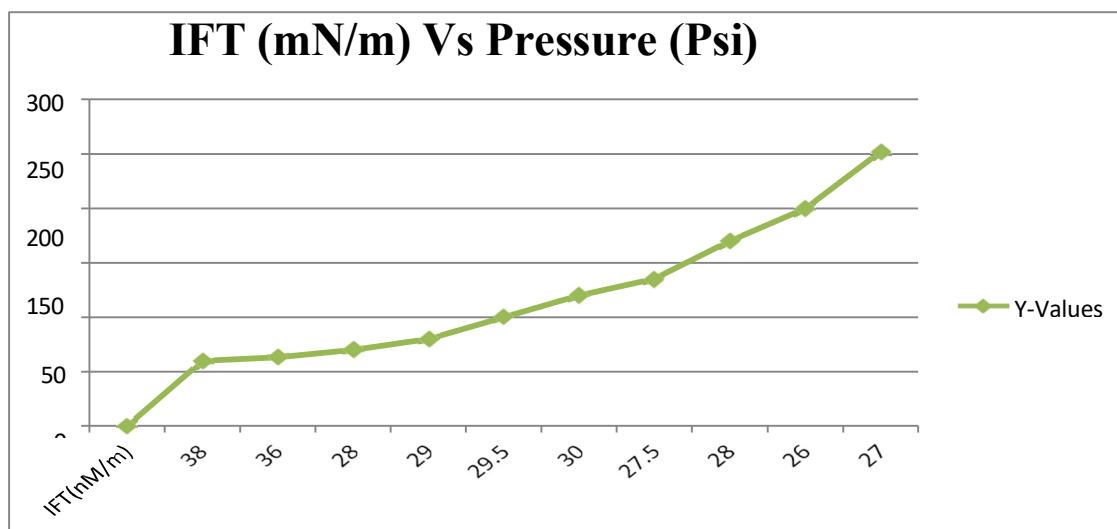


Fig. 4: Showing Pressure VS IFT at 28°C for 0.87Molar of brine

Table 8: Showing Pressure VS IFT at 28°C for 1.7Molar of brine

IFT (mN/m)	Pressure(bars)
39.0	50
36.5	60
31.0	70
27.0	85
28.5	90
30.0	110
27.0	130
27.5	150
28.0	210
28.5	225

Fig. 5: Showing Pressure VS IFT at 28°C for 1.7Molar of brine

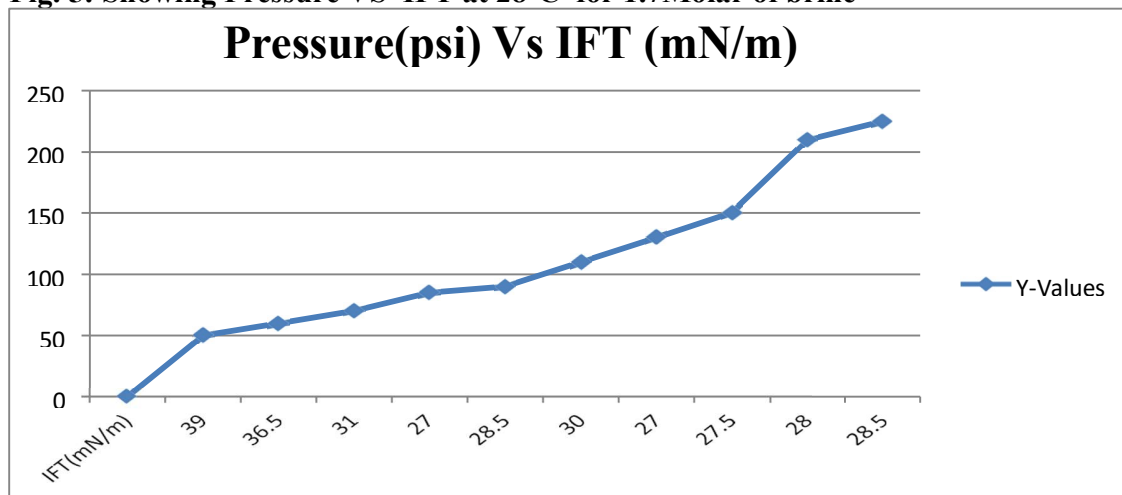


Table 9, 10 & 11: Showing IFT as a function of pressure for different temperatures at same molar concentration.

Table 9: Showing IFT VS Pressure @ 28°C for 0.87M Brine

IFT(mN/m)	Pressure(bar)
38.0	60
36.0	63
27.0	70
28.0	80
28.5	90
29.0	115
27.0	125
28.0	160
26.0	240

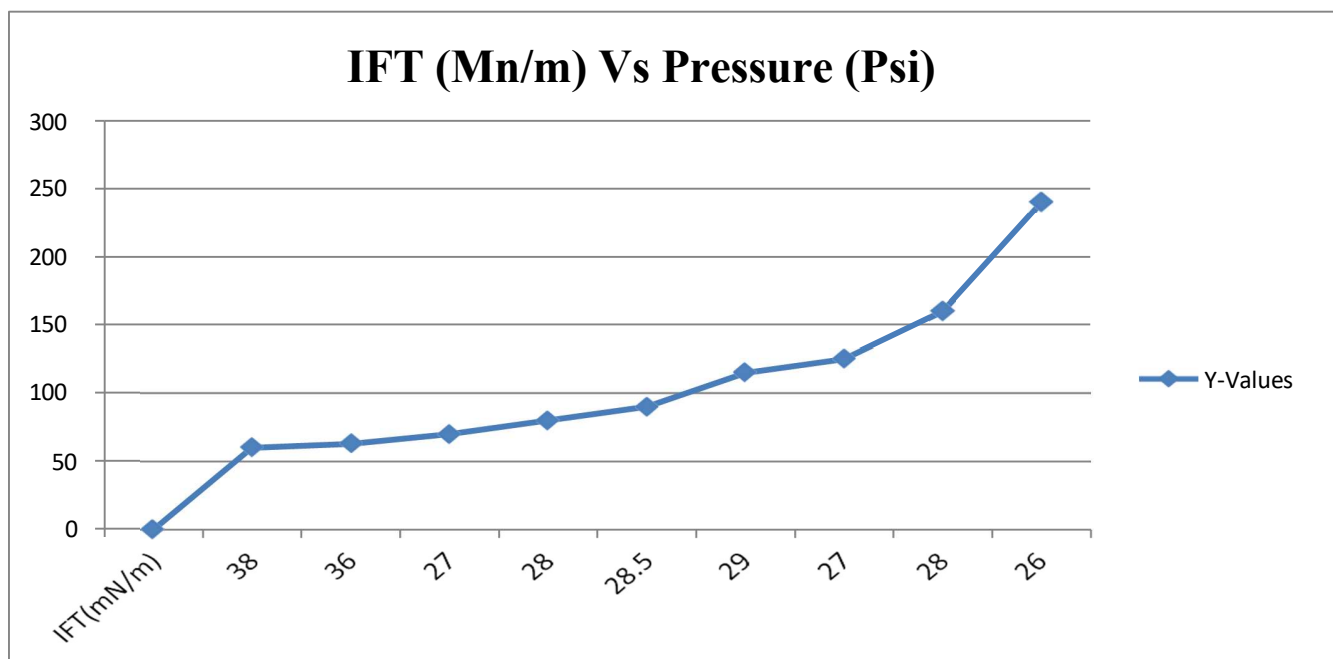


Fig 6: Showing IFT VS Pressure @ 28⁰C for 0.87M Brine

Table 10: Showing IFT VS Pressure @ 72⁰C for 0.87 Molar Brine

IFT(mN/m)	Pressure(bar)
42.0	60
41.0	62
37.0	70
32.0	80
27.0	115
28.0	130
27.5	165
28.0	195
27.4	225
26.0	250

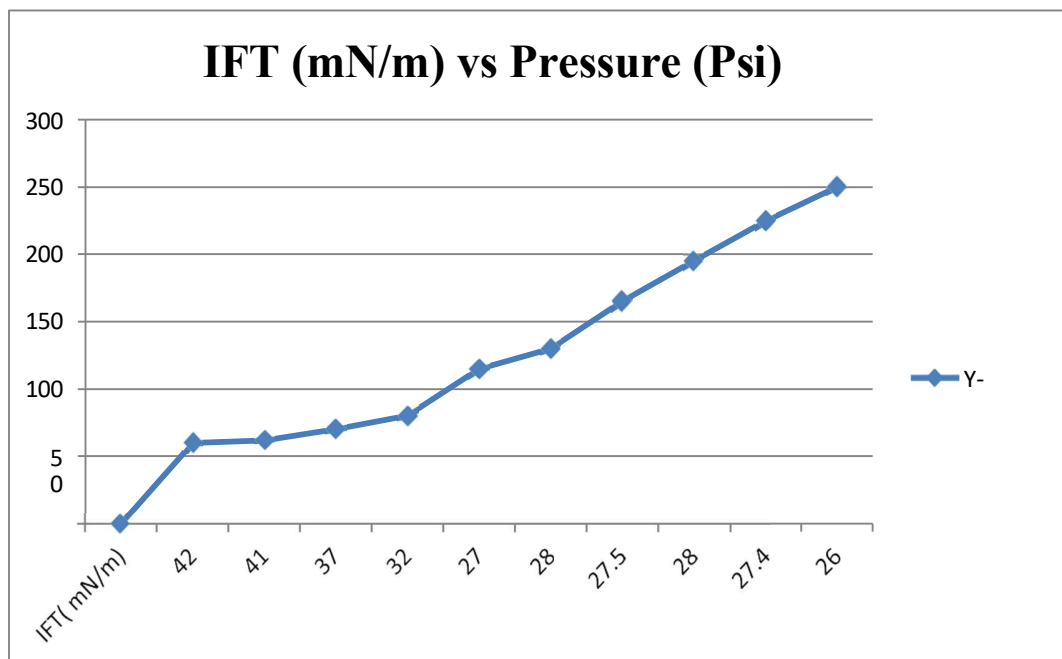


Fig 7: Showing IFT VS Pressure @ 72°C for 0.87 Molar Brine

Table 11: Showing IFT VS Pressure @ 100°C for 0.87M Brine

IFT(mN/m)	Pressure(bar)
42.0	70.0
38.0	80.0
34.0	100.0
32.5	120.0
29.0	150.0
28.0	160.0
27.0	220.0
25.0	260.0

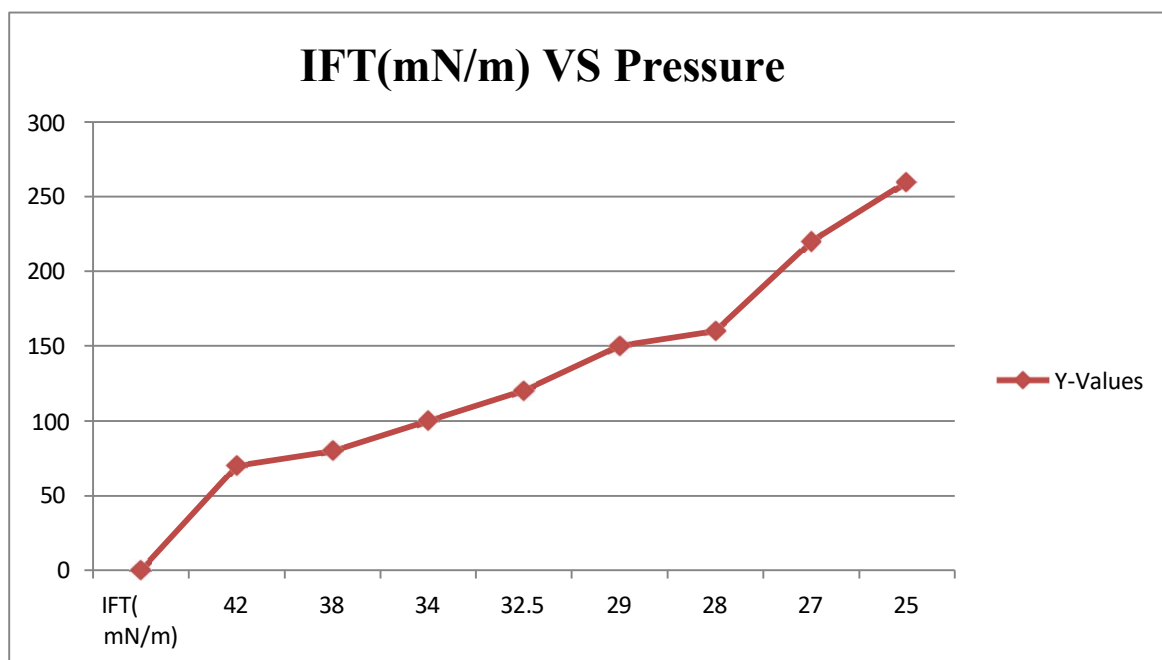


Fig 8: Showing IFT VS Pressure @ 100°C for 0.87M Brine

Discussion

This discussion explores the implications of interfacial tension (IFT) behavior in CO₂-brine systems for CO₂ storage in geological formations, considering effects of pre-saturation, salinity, pressure, and temperature.

Interfacial Tension and Solubility Behavior

The interaction between CO₂ and brine under various thermodynamic conditions significantly influences interfacial tension (IFT) and solubility. When CO₂ was pre-saturated at 120 bars (Table 1), IFT decreased with increasing solubility before stabilizing at approximately 26.5 mN/m between 8–10 minutes. This plateau indicates equilibrium between CO₂ and the aqueous phase. In contrast, without pre-saturation (Table 2), IFT continued to decline without stabilization, suggesting ongoing dynamic changes at the interface and incomplete equilibration. Pre-saturation plays a critical role in controlling equilibrium at reservoir conditions; omitting this step may lead to underestimation of long-term interfacial stability (Bennion & Bachu, 2005).

Effect of Brine Concentration on Interfacial Tension

Data in Table 5 highlight the influence of salinity on CO₂-brine IFT. At 28°C, IFT increased progressively with rising molar concentration of NaCl, from 27.50 mN/m at 0.085 mol/dm³ to 30.01 mN/m at 3.69 mol/dm³. This linear relationship aligns with findings by Kiepe et al. (2002) and Iglauer (2011), where increased salts reduce CO₂ solubility, thereby increasing IFT. For CO₂ storage in brine-rich formations, higher salinity may enhance structural and residual trapping via higher capillary pressures but reduce solubility trapping.

Pressure Dependence of Interfacial Tension

Tables 6–8 present the variation of IFT with pressure for different brine molarities at 28°C. IFT decreased sharply with increasing pressure before stabilizing once CO₂ reached supercritical conditions. This plateau effect indicates that beyond a threshold pressure, further increases in pressure exert minimal influence on IFT (Bachu, 2000; Bennion & Bachu, 2005).

Temperature Effects on Interfacial Properties

Tables 9–11 illustrate IFT behavior at varying temperatures (28°C, 72°C, 100°C) for 0.87 M NaCl. Elevated temperatures lowered IFT and accelerated approach to equilibrium, promoting CO₂ dissolution into brine and enhancing solubility trapping (Bennion & Bachu, 2008). At higher temperatures, the pressure at which the IFT plateau is reached may vary, but the IFT value at the plateau tends to be lower.

Implications for CO₂ Storage

The interplay of pressure, salinity, and temperature on IFT directly influences CO₂ trapping efficiency in deep saline aquifers. Capillary pressure $P_c = P_{CO_2} - P_{brine} = 2 \cdot \gamma_{brine,CO_2} \cos \theta / R$.

depends strongly on IFT $\gamma_{brine,CO_2} \cos \theta / R$ and pore throat radius (R). Underestimating IFT could lead to erroneous calculations of storage capacity and capillary entry pressures. High salinity enhances structural trapping but reduces solubility trapping. Elevated temperatures promote solubility trapping but require robust caprock integrity.

Detailed Analysis of CO₂-Brine Interactions

Further analysis of Tables 1–11 reveals nuanced effects of thermodynamic conditions on IFT. The evolution of IFT with pressure and temperature (Tables 9–11) underscores the importance of considering reservoir-specific conditions for CO₂ storage simulations. Accurate IFT data are essential for predicting fluid distribution in porous media and evaluating H₂O displacement by CO₂ injection.

Conclusion and Recommendations

Conclusion

This study evaluated the solubility and interfacial tension behavior of CO₂-brine systems under varying conditions of pressure, salinity, and temperature, with specific application to potential storage reservoirs in the Lower Benue Trough. Results demonstrated that:

Pressure dependence: Interfacial tension decreases sharply with pressure up to ~120 bars, beyond which it stabilizes, highlighting the significance of supercritical CO₂ conditions for storage calculations.

1. Salinity effects: Increasing NaCl concentration elevates interfacial tension and reduces CO₂ solubility. While this limits solubility trapping, it improves residual and structural trapping due to higher capillary entry pressures.

2. Thermal influence: Elevated reservoir temperatures accelerate CO₂-brine equilibration and lower interfacial tension, enhancing solubility trapping but raising concerns regarding buoyancy-driven migration.

Overall, the findings reinforce that the interplay of reservoir pressure, temperature, and salinity controls the efficiency and security of CO₂ trapping mechanisms. For the Lower Benue Trough, site-specific assessments that integrate these factors are crucial to ensure reliable capacity estimation and safe long-term sequestration.

Recommendations

1. Site-specific characterization: Future studies should couple laboratory IFT and solubility

measurements with numerical reservoir simulations to refine predictions of CO₂ plume migration and trapping efficiency.

2. Extended parameter ranges: Experiments should be conducted at pressures beyond 260 bars and temperatures above 100°C to mimic deeper formations and evaluate storage under more extreme conditions.

3. Caprock integrity studies: Since reduced IFT at high temperatures could increase buoyancy forces, geomechanical and geochemical analyses of caprock formations should be prioritized.

4. Comparative solvent testing: Beyond NaCl, the effects of other brine compositions (e.g., CaCl₂, MgCl₂) should be evaluated to capture realistic geochemical diversity in Nigerian reservoirs.

5. Pilot field projects: Small-scale injection pilots in the Lower Benue Trough should be initiated to validate laboratory findings under real reservoir conditions.

By addressing these recommendations, Nigeria can strengthen its capacity for carbon capture and storage (CCS) projects, contributing to global climate change mitigation efforts while supporting sustainable energy development.

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