ABSTRACT

The SECARB offshore partnership project seeks to screen deep saline aquifers and hydrocarbon reservoirs in the central Gulf of Mexico (GOM) for CO₂ sequestration and CO₂-driven enhanced oil and gas recovery and estimate the corresponding CO₂ storage resources for select reservoirs. To this end, three major objectives have been completed: managing geological data from different sources, building a reservoir screening platform for CO₂ storage, and ranking the reservoirs based on the estimated storage potential. First, the major geological characteristics of both shelf and deep-water areas of the central GOM were examined and compared to define the appropriate reservoir screening criteria. Consequently, the CO₂ storage resources of the screened reservoirs were calculated and reported at the BOEM field level to identify fields with the highest storage potential. In the project's current phase, the assessment is being expanded to saline formations. Correlations are being identified, tested, and developed for a broad range of rock and fluid properties, including thickness, porosity, permeability, fluid saturation, and fluid chemistry. These correlations are developed for interfacial tension and CO₂ saturated brine viscosity to improve the storage estimates and consider the capillary trapping and solubility of CO₂ in reservoir fluids. SAS® Viya software is used to make visualizations of these properties of the offshore reservoir and make comparisons and draw similarities between the experimental and estimated correlated measures. Using interactive plots, different conditions could be screened, making the analysis more attractive from a user's point of view.

INTRODUCTION

The substantial CO₂ storage potential of the hydrocarbon reservoirs and saline formations in the central Gulf of Mexico (continental shelf and continental slope offshore of Louisiana) makes future development of CO₂ storage projects in those areas promising for a large-scale, long-term, and secure storage of CO₂. However, subsurface storage of CO₂ is always more complicated than merely locking the gas in a sealed container, hence requires assessing the geological properties of the underground formations and the thermophysical properties of the formation fluids (e.g., CO₂, brine).

The formation fluids and the underground formations need to qualify in several aspects to ensure safe and long-term storage of CO₂ (Piaudier-Cabot and Pereira, 2013). For example, the formation fluid needs to have high CO₂ solubility to favor the solubility trapping, one of the major mechanisms of CO₂ getting trapped in the subsurface formation; the sealing capillary pressure, which is a function of CO₂-brine interfacial tension, needs to be higher than the buoyancy forces exerted by the fluids underlying the caprock to prevent the upward migration and escape of stored CO₂; the viscosity contrast between CO₂ and CO₂ saturated brine needs to be sufficiently high to prevent the displacement of stored CO₂ by brine; the storage unit should be sufficiently porous and permeable to hold the gas; the reservoirs should have enough headroom to inject the CO₂. Designing and optimizing subsurface CO₂ storage thus requires a good understanding of the thermo-physical properties of the CO₂ and formation brine as well as the geological properties of the target formation.

This study is part of the SECARB Offshore Partnership Project (DE-FE0031557) to evaluate the CO₂ storage potentials of the hydrocarbon reservoirs and saline formations in the central Gulf of Mexico (GOM). The study estimates a few significantly important thermophysical properties of CO₂ and brine for the central GOM sands. These include the interfacial tension between CO₂ and brine, the solubility of CO₂ in brine, and the viscosity of CO₂ and CO₂ saturated brine. In addition to understanding the fluid behaviors in those formations, this study will help estimate the trapping and solubility potential of the reservoirs.
STUDY AREA AND DATA OVERVIEW

The study uses the Bureau of Ocean Energy Management’s (BOEM) 2019 Sands Atlas dataset (www.data.boem.gov). The dataset includes detailed information on the location, reservoir properties, well log measurements, core measurements, and production history at individual wells and their productive sand levels. The data here was segregated into the shelf and slope areas based on the protractions of the individual fields, but for this study, the information present is from the slope area only. The minimum, maximum, and average initial reservoir temperatures of the studied reservoirs were 21.1˚C, 164.4˚C, and 76.8˚C, respectively. The pressures of the fields have a minimum initial reservoir pressure of 26.96 bar, a maximum of 1489.88 bar, and an average of 385.13 bar.

METHODOLOGY AND MODELLING

INTERFACIAL TENSION

Interfacial tension (IFT) is the force of attraction between the molecules at the interface of two fluids. IFT determines the separation potential to mix between two fluids or phases in contact, which in the case of subsurface CO₂ storage would be the brine/oil and the CO₂ inside the rock (Moghadasi, Rostami et al. 2018). This intrinsic property of the interaction primarily affects the amounts of CO₂ that can be stored in the reservoir due to structural trapping. The IFT between the brine and the CO₂ can be affected by several parameters, including the cation valence molality of the brine, reservoir temperature, pressure, and the concentrations of the brine.

This study used the correlation developed by Jerauld & Kazemi (Jerauld and Kazemi 2022) to estimate the CO₂-brine IFT for the BOEM reservoirs mentioned in the introduction section. The execution of this correlation was expressed as a function of the density difference between water-saturated CO₂ and CO₂-saturated brine, temperature, and valence-weighted molality of cations (e.g., Na⁺).

CO₂ density was estimated as a function of temperature and pressure using the Spycher et al. CO₂ density prediction method (Spycher, Pruess et al. 2003), modified by Bikkina et al. to evaluate the saturated CO₂ phase densities (Bikkina, Shoham et al. 2011). The density of CO₂-saturated brine was estimated as a function of temperature, pressure, and mass fraction of CO₂ in brine using the model developed by Bachu and Adams (Bachu and Adams 2003), with the corresponding CO₂ solubility data estimated using the solubility model developed by Duan and Sun (Duan and Sun 2003).

A total of 1717 experimental data on CO₂-brine IFT was collected from previous studies (Ren, Chen et al. 2000, Yan, Zhao et al. 2001, Hebach, Oberhof et al. 2002, Chiquet, Daridon et al. 2007, Kvamme, Kuznetsova et al. 2007, Bachu and Bennion 2009, Chalbaud, Robin et al. 2009, Aggelopoulos, Robin et al. 2010, Georgiadis, Maitland et al. 2010, Bikkina, Shoham et al. 2011, Li, Boek et al. 2012, Li, Boek et al. 2012) that include the IFT between pure/impure CO₂ and pure water/brine of different composition and salinities, and were used to validate the estimations from the model used in this study. The set of equations used to estimate IFT between CO₂ and brine are as follows:

Interfacial Tension Estimation (Jerauld and Kazemi, 2022)

\[
\begin{align*}
Y &= cn + df\sqrt{\Delta \rho} + pf(\Delta \rho)^{ex} + a \text{[m}^+\text{]} \quad (1) \\
cn &= cn_0 + cn_1T_r \quad (2) \\
df &= df_0 + df_1T_r + df_2T_r^2 \quad (3) \\
ex &= ex_0 + ex_1T_r + ex_2T_r^2 \quad (4) \\
pf &= pf_0 + pf_1T_r + pf_2T_r^2 \quad (5) \\
a &= a_0 + a_1T_r + a_2T_r^{-1} \quad (6)
\end{align*}
\]

Where, \(Y\) stands for the IFT between the CO₂ and brine, mN/m; \(\Delta \rho\) is the density difference, kg/m³; \(T_r\) is the reduced temperature; \(m^+\) is the valence-weighted molality of the cations, mol/kg.
Table 1. Parameters and their values for Eqs. 2-6

| Parameter | Values | Parameter | Values | Parameter | Values | Parameter | Values |
|-----------|--------|-----------|--------|-----------|--------|-----------|--------|
| $cn_1$    | -41.146| $df_0$    | -147.856| $pf_3$    | 259.490| $a_2$     | -0.9311|
| $cn_0$    |  68.790| $ex_2$    |  15.071| $pf_2$    | -930.066| $a_1$     |  0.4753|
| $df_2$    | -91.281| $ex_1$    | -52.516| $pf_1$    | 1083.514| $a_0$     |  2.0181|
| $df_1$    |  245.472| $ex_0$    |  49.239| $pf_0$    | -374.117|           |        |

**VISCOSITY OF CO₂ AND CO₂-SATURATED BRINE**

For any system incorporating a multiphase flow system, there exists the importance of modeling the viscosity of the fluid phases (Peter, Yang et al. 2022). The viscosity of CO₂ and brine affect the mobility of the fluids and may cause issues such as viscous fingering and low volumetric efficiency if the injected CO₂ has low viscosity (Yu, Lashgari et al. 2015). The viscosity of the injected CO₂ phase must be adequate to maintain the balance that seeks to keep the CO₂/brine phase immovable. CO₂ viscosity also determines the energy and economic feasibility of CO₂ transportation through pipelines, one of the major ways of transporting CO₂ to storage sites in the USA and Canada (Cole and Itani 2013).

Brine viscosity is directly related to its density which may vary depending on the dissolution of CO₂ (Duan and Sun 2003). In the case of storing CO₂ underground, dissolution of CO₂ in brine is expected; hence the viscosity estimation of brine should take CO₂ solubility into account. In this study, we estimated the viscosity of CO₂ and CO₂ saturated NaCl brine using a combination of equations of states (EOS). CO₂ viscosity was estimated using a recent empirical model developed by Nait Amar et al. (Amar, Ghriga et al. 2020). The model is applicable in the temperature and pressure ranges from 220–673 K and 0.1 MPa to 7960 MPa.

Estimating CO₂ saturated NaCl brine required estimating pure water density, the viscosity of brine (NaCl+H₂O), and the mole fraction of CO₂ in brine. The density of the water is obtained from the formulation developed by the International Association for the Properties of Water and Steam (Wagner and Kretzschmar 2008). The viscosity of the H₂O+NaCl system was estimated using the dynamic viscosity model developed by Mao and Duan (Mao and Duan 2009). The CO₂ mole fraction is calculated using the Duan and Sun model for CO₂ solubility in brine (Duan and Sun 2003). The model developed was valid up to 273 to 533 K, 0–200 MPa, and 0–6.5 m NaCl. Finally, the viscosity of CO₂ saturated NaCl brine is estimated with the empirical correlation developed by Islam and Carlson (Islam and Carlson 2012).

The models were selected based on their performance in accurately estimating the experimental values of CO₂ viscosity (Li, Wilhelmsen et al. 2011, Laesecke and Muzny 2017), NaCl+H₂O (Kestin, Khalifa et al. 1977, Ozbek, Fair et al. 1977, Semenyuk, Zarembo et al. 1977, Kestin, Khalifa et al. 1978, Kestin, Khalifa et al. 1981, Kestin and Shankland 1984), CO₂ mole fraction (Rumpf, Nicolaisen et al. 1994, Bando, Takemura et al. 2004, Messabeb, Contamine et al. 2016, Mohammadian, Liu et al. 2022), and CO₂-saturated brine viscosity (Bando, Takemura et al. 2004) over the temperature and pressure range of the BOEM fields.

The summary of the equations used in the model development is shown below:

**CO₂ Viscosity (Amar, Ghriga et al. 2020)**

\[
\mu_{CO₂} = [0.5703 + 0.01033\sqrt{T} - 11.69 - 0.0001304 \times A + 0.134 \times B + 10^{-5} \times \sqrt{\rho \times C}]^{10} \tag{7}
\]

In this equation, T and ρ are temperature and CO₂ density, respectively. CO₂ density is estimated using NIST Chemistry WebBook (Laesecke and Muzny 2017). The constants A, B, and C are defined as follows:

\[
A = \rho + T + \ln(\rho) \tag{8}
\]

\[
B = \tanh\left(\frac{T}{\rho}\right) - 0.271194 \times \tanh\left(\frac{\rho}{T}\right) - 0.063664 \times \tanh(T - \rho) \tag{9}
\]
\[ C = 1.624 \times (T + \rho) - 2.363 \times \sqrt{T \times \rho} - 480.8 \]  

(10)

T and \( \rho \) should be expressed in units of K and kg/m\(^3\), respectively, to obtain viscosity, \( \mu_{\text{CO}_2} \) in mPa.s.

**NaCl+H\(_2\)O Viscosity (Mao and Duan 2009)**

\[
\mu_{\text{brine}} = \mu_{\text{relative}} \times \mu_{\text{pw}} 
\]

(11)

\[
\mu_{\text{relative}} = e^{(A x n + B x m^2 + C x m^3)} 
\]

(12)

\[
\log_{10} \mu_{\text{pw}} = \frac{d_1 [1] \times (T + 273.15)^{1-3} + d_2 [2] \times (T + 273.15)^{2-3} + d_3 [3] \times (T + 273.15)^{3-3} + d_4 [4] \times (T + 273.15)^{4-3} + d_5 [5] \times (T + 273.15)^{5-3} + d_6 [6] \times \left( \frac{\mu_{\text{pw}}}{1000} \right) \times (T + 273.15)^{6-8} + d_7 [7] \times \left( \frac{\mu_{\text{pw}}}{1000} \right) \times (T + 273.15)^{7-8} + d_8 [8] \times \left( \frac{\mu_{\text{pw}}}{1000} \right) \times (T + 273.15)^{8-8} + d_9 [9] \times \left( \frac{\mu_{\text{pw}}}{1000} \right) \times (T + 273.15)^{9-8} + d_10 [10] \times \left( \frac{\mu_{\text{pw}}}{1000} \right) \times (T + 273.15)^{10-8}}{\mu_{\text{pw}}}
\]

(13)

In equation 11, \( \mu_{\text{relative}} \) is the relative viscosity of brine to pure water; \( m \) in equation 12 is the molality of brine. Other constants can be calculated as follows:

\[
A = a[0] + a[1] \times (T + 273.15) + a[2] \times (T + 273.15)^2 
\]

(14)

\[
B = b[0] + b[1] \times (T + 273.15) + b[2] \times (T + 273.15)^2 
\]

(15)

\[
C = c[0] + c[1] \times (T + 273.15) 
\]

(16)

The values for constants \( a, b, c, \) and \( d_i \) in equations 13 to 16 are listed in table 1. The temperature should be expressed in °C, pressure in bar, density in g/cc, molality in mol/kg, and viscosity in mPa.s.

| Par. | Values | Par. | Values | Par. | Values | Par. | Values | Par. | Values |
|------|--------|------|--------|------|--------|------|--------|------|--------|
| \( a_0 \) | -0.21 | \( a_1 \) | \( b_1 \) | 0.27 \times 10^{-3} | \( d_0 \) | 0 | \( d_4 \) | \( -0.31 \times 10^{-1} \) | \( d_7 \) | \( 0.56 \times 10^{4} \) |
| \( a_1 \) | 0.17 \times 10^{-2} | \( a_2 \) | \( b_2 \) | 0.21 \times 10^{-6} | \( d_1 \) | 0.28 \times 10^{-7} | \( d_5 \) | \( -0.27 \times 10^{-4} \) | \( d_8 \) | \( 0.14 \times 10^{8} \) |
| \( b_0 \) | 0.69 \times 10^{-1} | \( b_1 \) | \( c_1 \) | 0.78 \times 10^{-5} | \( d_2 \) | \( -0.91 \times 10^{-1} \) | \( d_6 \) | \( -0.19 \times 10^{-7} \) | \( d_9 \) | \( 0.48 \times 10^{1} \) |

**Table 2. Parameters and their values for Eqs. 14-16**

**Viscosity of H\(_2\)O+NaCl+CO\(_2\) (Islam and Carlson 2012)**

\[
\mu_{\text{H}_2\text{O}+\text{NaCl}+\text{CO}_2} = \mu_{\text{brine}} (1 + 4.65 \times m_{\text{CO}_2}^{1.0134}) 
\]

(17)

\( \mu_{\text{brine}} \), in equation (17), is the viscosity of the H\(_2\)O+NaCl system, estimated using equation (11). \( m_{\text{CO}_2} \) is the mole fraction of CO\(_2\) in brine, calculated using the solubility model developed by Duan and Sun (Duan and Sun 2003).

**CO\(_2\) SOLUBILITY IN NACL BRINE**

One of the major considerations for successful long-term safety of CO\(_2\) storage is to anticipate the spread of CO\(_2\) in the aquifer (Riaz and Cinar 2014). For that to be appropriately ascertained, the solubility of the CO\(_2\) in the formation water (brine) needs to be known. This is essential to identify the potential for free-phase CO\(_2\) or brine leakage through the fault fractures in the subsurface structures (Meguerdijian, Pawar et al. 2022). To arrive at that, the balance between the potential of the CO\(_2\) in the liquid phase and that in the gas phase would be needed to determine the CO\(_2\) solubility in aqueous solutions. This is represented as the calculation of fugacity (\( \phi_{\text{CO}_2} \)). From this approximation, the solubility (\( m_{\text{CO}_2} \)) can be estimated as follows:
\[
ln \frac{\gamma_{\text{CO}_2P}}{m_{\text{CO}_2}} = \frac{\mu_{\text{CO}_2}^{(0)}}{RT} - ln\phi_{\text{CO}_2} + \sum_c 2\lambda_{\text{CO}_2-c}m_c + \sum_a 2\lambda_{\text{CO}_2-a}m_a + \sum_c \sum_a \zeta_{\text{CO}_2-a-c}m_cm_a
\]  \hspace{1cm} (18)

In the equation (18), the \( \lambda \) and the \( \zeta \) are the second and third order interaction parameters. The \( \frac{\mu_{\text{CO}_2}^{(0)}}{RT} \) term is the dimensionless standard chemical potential (fugacity potential) and are dependent on the temperature and pressure of the system.

**RESULTS AND DISCUSSION**

**MODEL PERFORMANCE**

The section is a summary of the performance of the models with respect to the data that was fed into it. The model predictions and the experimental results are being compared here, and the results are shown below.

**CO\textsubscript{2}-Brine Interfacial Tension**

Fig 1a shows the comparison chart between the experimental and estimated IFTs. The selected model for IFT performed well on the experimental data. For the same density difference, experimental and estimated IFT values fell on top of each other, especially at higher density differences (>0.5 g/cc). There are some instances in the low-density difference region where the estimated values are not matching very well with the experimental values. That could be due to the phase change of the CO\textsubscript{2} when the temperature and pressure are above the critical region (Bikkina, Shoham et al. 2011). Nevertheless, the model estimated the IFTs with great accuracy as the mean absolute error (MAE) was only 1.29 mN/m.

**CO\textsubscript{2} Viscosity**

CO\textsubscript{2} viscosity was estimated as a function of T, P, and CO\textsubscript{2} density. The experimental CO\textsubscript{2} viscosity values are plotted against the estimated ones. The 45° reference line is drawn to show the deviation of estimated values from the experimental data (Fig. 1b). The estimated values fell very close to the experimental ones. The MAE was only 0.23 mPa.s, indicating an excellent accuracy of the model in estimating the viscosity of CO\textsubscript{2}.
Figure 1: Comparison between the experimental and estimated values of (a) IFT between CO$_2$ and NaCl brine, viscosities of (b) CO$_2$ and (c) CO$_2$ saturated NaCl brine and (d) solubility of CO$_2$ in NaCl brine

**Viscosity of H$_2$O+NaCl+CO$_2$**

Unlike the CO$_2$ viscosity, in the case of CO$_2$ saturated brine, there were not enough experimental data to validate the model. The only relevant data source we found covering the range of temperature and pressure usually encountered in the geological formations for CO$_2$ storage is from Bando et al. (Bando, Takemura et al. 2004). The comparison of the estimated viscosity with their data is shown in figure 1c. Even though it appears from the plot that the model is significantly overestimating the viscosities, the estimates are only slightly different from the experimental values, as the MAE was found to be only 0.06 mPa.s. Due to the representation of the units being in the tenths, a difference of 0.06 units of measurement shows a significant visual difference in the plot.

**CO$_2$ Solubility in Brine**

Fig 1d shows the comparison between the model estimated solubility compared with the experimental values obtained. The model estimated the CO$_2$ solubility as a function of T, P, brine composition (cation valence molality), and water-saturated CO$_2$ density. The estimated mean absolute error of this model was 0.01 mol/kg.

**ESTIMATIONS FOR THE STUDY AREA**

The section is a representation of the CO$_2$-brine IFT, viscosity of CO$_2$ and CO$_2$ saturated brine, and the solubility of CO$_2$ in brine estimated for the reservoirs from the central Gulf of Mexico (BOEM sands) using the models mentioned in section 3.

Figure 2 shows the spread of IFT values throughout the BOEM sands on the slope region. Red indicates less IFT, while blue indicates very high CO$_2$ brine interfacial tension. As can be seen, the IFT ranges from 14.15 to 68.08 mN/m, and very few fields have a very high CO$_2$-brine IFT. Figure 3 and figure 4 show the field spread of the viscosity of CO$_2$ and CO$_2$ saturated brine, respectively. While the CO$_2$ viscosity in the central GOM reservoirs ranges from 0.02 to 0.16 mPa.s, the brine viscosity ranges from 0.16 to 1.34 mPa.s.
However, in both cases, the Northern boundary sands (marked blue) are attributed to lower viscosities than the southern ones (marked red).

The CO$_2$ solubility potential of the reservoirs is shown in figure 5. The solubility ranges from 0.6 to 1.4 mol/kg in brine. Sands in the central, west and south-west regions (marked deep green) are estimated to have very high solubility potential, close to 1 mol/kg. Table 2 summarizes the findings of all the thermo-physical properties estimated in this study for the BOEM sands. It also includes the estimated values of the properties such as the density of H$_2$O, NaCl+H$_2$O, CO$_2$, and NaCl+H$_2$O+CO$_2$ that were used to estimate the other properties.
Table 3: Summary of the properties estimated for the study area in the central GOM

|               | Interfacial Tension (mN/m) | CO₂ Saturated Brine Viscosity (mPa.s) | CO₂ Viscosity (mPa.s) | CO₂ solubility (mol/kg) | Water Density (kg/m³) | CO₂ Brine Density (kg/m³) | CO₂ Density (kg/m³) |
|---------------|-----------------------------|---------------------------------------|-----------------------|-------------------------|------------------------|---------------------------|------------------------|
| Min           | 14.145                      | 0.1595                                | 0.0162                | 0.6133                  | 55.22                  | 1.0301                    | 0.0552                 |
| Max           | 68.081                      | 1.3446                                | 0.1642                | 1.4392                  | 1105.98                | 1.2559                    | 1.1059                 |
| Avg           | 29.984                      | 0.6442                                | 0.0731                | 0.8463                  | 756.52                 | 1.1090                    | 0.7565                 |

CONCLUSION

This paper was made to report on the importance of these thermo-physical properties of the CO₂ and the brine phases, along with their interactions with respect to geologic storage. The consolidated models were validated against the experimental values to be able to make profiles of the properties. These consolidated models built can make reasonable estimations of the IFT, CO₂ viscosity, CO₂ saturated brine viscosity, and CO₂ solubility in brine. IFT and CO₂ solubility data can be used to estimate the trapping and solubility potential of the reservoirs for CO₂ storage, respectively, while the viscosity data can help understand the displacement efficiency of CO₂ and brine in the reservoirs as well as the transport properties of CO₂ in the pipelines.

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