Introduction

Deepwater fields in the Offshore Brazil Campos Basin are situated about 260 km from the coast. Gas fields in this ultra-deep-water region contain high CO2 levels, with deeper reservoirs reaching depths of 6,000 meters. As a result, assessing Carbon Capture and Storage (CCS) options is essential for identifying suitable nearby storage sites, helping to reduce CO2 emissions during the production of these high-CO2 fields. These hydrocarbon fields are characterized by CO2 concentrations ranging from 15% to 30%, equating to an estimated storage capacity of 0.6 to 3.8 Tcf. Potential CO2 storage options include various geological formations such as coalbeds, saline aquifers, and depleted hydrocarbon reservoirs can be targeted for CO2 storage.

This study evaluates CCS options for two CO2 source fields, Field X and Field Y, located in the same deepwater concession block with water depths of 2,500 to 3,000 meters. The screening area includes two regions: the Nearby Region (R1) and the Nearshore Region (R2) (Figure 1). R1, positioned 30 to 80 kilometers from Fields X and Y, has potential for CO2 storage within a saline aquifer, while R2, located 100 to 200 kilometers away, consists of major hydrocarbon fields that are expected to be depleted and repurposed as storage sites. Various CCS studies have highlighted opportunities for potential CO2 storage in depleted reservoirs and saline aquifers within the Campos Basin [1], [2], [3]

Saline aquifers may provide a better storage option due to their large pore space and favorable geological conditions, but they must be sufficiently large to store CO2 cost-effectively [4] and have low containment risks, with minimal reservoir containment risk. Depleted reservoirs are another potential storage solution; however, further evaluation of existing wells and infrastructure is needed, as they could be repurposed for CO2 injection, potentially lowering overall CCS project costs.

The basin has a complex geology, including sub-salt and post-salt carbonate and clastic reservoirs, covering an area of approximately 115,000 km² and situated 75 to 150 km from the coastline. The thickness of the sub-salt sequence suggests a folded terrain with synclines and anticlines oriented in an NNE-SSW direction (Figure 2). Basin depocenters align with synclines, while paleogeographic highs are in the anticlines (Bruhn et al., 2017) [4], [5]. Main reservoirs in R1 exhibited by pre-salt Aptian Macabu Carbonate and Coquina Rock of Lagoa Feia formation. Over time, diagenetic processes have enhanced its porosity and permeability, particularly in porous coquina rock and microbial carbonates, which contain the hydrocarbon at depth 6,000 to 7,000 meters. This pre-salt carbonate formations in deepwater formed as isolated platforms on basement highs and sealed by 1,000 to 2,000 meters thick of salt body of Retiro Formation. The reservoirs in R2, are dominant by post-salt Albian Carbonate known as Quissama Carbonate Formation and Cretaceous to Miocene Turbidite sand packages of Namorado, Santonian, Turonian and Eocene Sands at shallower depth within 1,000 to 2,500 meters of water depth. These post-salt clastic and carbonate formations are well-positioned in stratigraphic and structural traps, sealed by salt and turbidite shale, making them as low-risk containment targets for CO2 storage.

CCS screening have focused on identifying and evaluating potential storage sites within various formations across Campos basin, using detailed geological, geophysical, and petrophysical analyses to ensure their suitability and safety. Storage capacity estimates consider factors such as porosity, permeability, and injectivity integrity. Additionally, geomechanical analysis is highly recommended for future detailed CCS studies to ensure long-term storage security by predicting subsidence impacts on the reservoir after fluid injection or extraction. Trapping risk assessments typically evaluate cap rock integrity, fault reactivation potential, and geochemical interactions between CO2 and reservoir rocks. However, this feasibility study does not include an analysis of geochemical CO2 trapping.

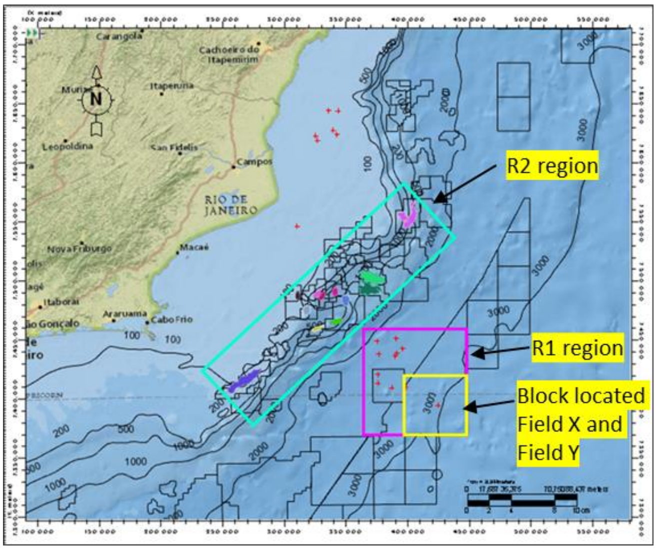

Figure 1. Study location for CCS screening in saline aquifer fields (R1 region) and Nearshore (R2 region) nearby CO2 fields of Field X and Field Y located in yellow box in the same concession block

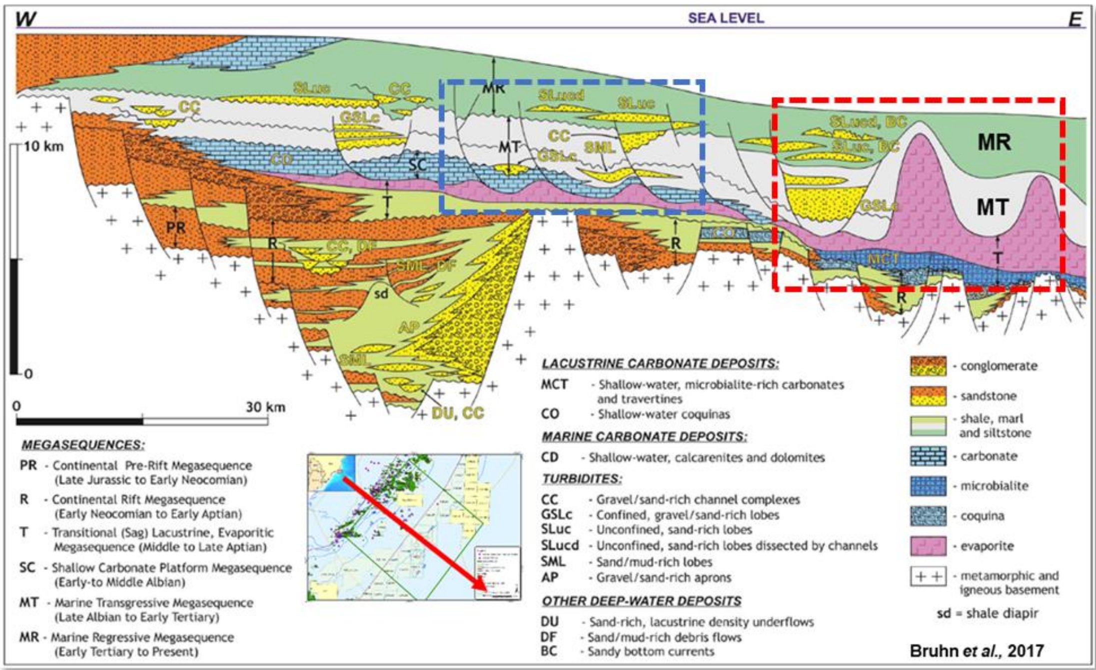

Figure 2. *Generalized geological section across Brazil offshore eastern Campos Basin (Bruhn et. al, 2017). Red box, represent region 1 and blue box is screening coverage area at nearshore (region 2)*

Methodology

A new screening criteria chart and workflow (Figure-3) was developed based on geological and petrophysical characteristics and production information (for depleted reservoirs) to categorize storage site potential and assess risk levels. It also includes volumetric capacity screening for each storage site. The initial screening criteria focus on the site's location and distance from the CO2 source, followed by cumulative production and recovery factor (RF) status. Greater distances will lead to higher transportation and facility costs, along with increased risks during transit, as well as if the reservoir exist in multiple stacking layers.

The evaluation of seal and trap criteria differs for depleted reservoirs and saline aquifers. A proven hydrocarbon reservoir already confirms the presence of an effective seal and trap, whereas saline aquifers require further investigation to assess their seal and trap effectiveness. The storage criteria were mainly screened based on reservoir net thickness and quality in term of porosity and permeability where total porosity derived from shale volume cutoff at 30% and 6% for clastic and carbonate respectively and permeability obtained from available report or forecasted from nearby field data.

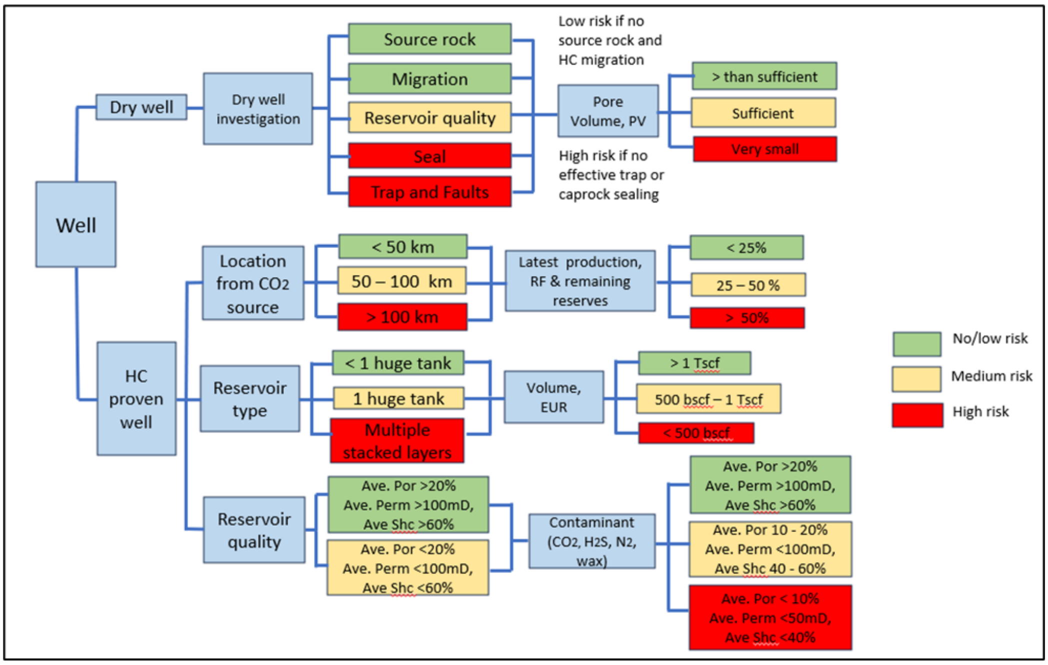

Figure 3. *Screening workflow of each reservoir containment target in each field (newly built screening criteria)*

Risk Assessment Result

The containment targets are defined within three main reservoir intervals: (1) pre-salt silicified Macabu Carbonate and Coquina Rock, (2) post-salt Quissama Carbonate, and (3) post-salt Cretaceous sand formations. The reservoir characteristics vary between R1 and R2. In R1, the primary reservoirs consist of pre-salt Coquina Rock and silicified Macabu Carbonate, with carbonate platform thicknesses reaching up to 500 meters, developed over basement structural highs. It is played as major oil province at deepwater region, with approximately 12 to 15% porosity. Although thick salt body provides effective sealing for pre-salt reservoirs, their classification as medium to high-risk containment targets is based on their generally low to medium porosity characteristic. Upper Cretaceous intervals in R1 is water-bearing or saline aquifers zones, with limited evidence of hydrocarbon migration into shallower zones. However, the area features well-defined structural and stratigraphic traps that can be considered for CO2 storage. Late Cretaceous faulting, differential compaction, and salt growth have shaped these formations into elongated dome structures, partially confined by faults within compacted shale beds.

Post-salt Carapebus turbidite sandstone succession is the major prolific reservoir in Nearshore oil field in R2 area with approximately 27% of porosity and net thickness ranging from 30 to 250 meters. Quissama Carbonate averaging 100 meters in thickness was an oil reservoir in R2 with approximately 20% porosity and up to 150 meters thickness. However, in deeper saline aquifer, Quissama Carbonate is often characterized by tight carbonate due to overburden and low permeability. Both Macabu and

Quissama carbonate formations developed as isolated platforms at top of basement highs (pre-salt) and positioned up-dip of salt bodies (post-salt), rendering them well-preserved within suitable stratigraphic and structural traps with turbidite shale and salt as effective seal rock, resulting in their classification as low risk containment targets. In R2, Miocene sand has higher risk due to absence of seal rock as observed across regional area. A summary of reservoir and containment characteristics in R1 and R2 is provided in Table 1 and Table 2.

Table 1 Reservoir containment characteristics, seal type and trapping style summary in R1 area

No	Reservoir Containment	Facies Criteria	Petrophysical Criteria	Seal / trapping
1	Post-salt Oligocene to Miocene Sand	Thick sand, coarse to fine-grain quartz	Excellent porosity, >30%	Turbidite shale
2	Post-salt Namorado Sand (Createceous)	Deepwater turbidite sand fan channel	Porosity 12 - 23%	Quteiro shale as seal
3	Post-salt Turonian Sand (Cretaceous)	Deepwater turbidite sand channel	Porosity 17 - 21%	Quteiro shale as seal
4	Post-salt Quissama Carbonate	Pure Limestone, tight isolated carbonate body	Porosity 9 - 13%. Poor permeability	Upper Cretaceous turbidite shale as seal. Carbonate appeared as isolated build-up mound over salt body
5	Pre-salt Silicified Macabu Carbonate	Shallow water carbonate platform with contain of Marlstone, claystone interbedded wackstone to packstone	Porosity 10 - 15%. Permeability up to 160 mD (P well)	Salt. Carbonate platform as trapping
6	Pre-salt Coqueiros (coquina) Rock	Resedimented of argiliceous lime-mudstone, chert and wackstone.	Porosity ~10%.	Salt. Carbonate platform as trapping

Table 2 Reservoir containment characteristics, seal type and trapping style summary in R2 area

No	Reservoir Containment	Facies Criteria	Petrophysical Criteria	Seal / trapping
1	Post-salt Oligocene to Miocene Sand (Turbidite sandstone)	Variation in thickness, 16 to 130 m	High porosity, 25 - 30%	Uncertainty seal. Most of low-risk potential provide stratigraphic trap
2	Post-salt Santonian Sand (channel turbidite Sandstone)	Massive, medium to coarse-grained turbidites, gross thickness 250m	High porosity, 27%. Permeability 2500 mD	Sealed by thick deep marine mudstone (Ubatuba Fm.). Combination depositional pinch-out and tilted fault block
3	Post-salt Namorado Sand	Medium to high NTG, 30 to 70 m of thickness	Average porosity 27%	Quteiro shale as seal. Trapped by dome or 4-way dip closure structure with fault
4	Post-salt Quissama Carbonate	Thickness up to 130 m	Porosity 10 - 20%. Permeability range 27 to 800 mD. High perm at DF6 field (~4000mD)	Turbidite shale as seal. Apper as isolated carbonate build-up mound over salt body
5	Pre-salt Macabu Carbonate	Gross thickness ~170 m	Porosity 8 - 20%.	Sealed by thin salt (<100m). Carbonate platform at updip structure overlaid basement
6	Pre-salt Coqueiros (coquina) Rock - at DF6 field	Gross thickness ~240 m	Porosity 4 - 21%. Good connectivity from integrated primary and mouldic porosity	Sealed by mudstone and salt. Stratigraphic trap from (pinch-out and diagenetic cementation)

Storage Capacity Assessment

Field X and Field Y are expected to produce around 248 million tonnes (MT) of CO2, equivalent to 4.4 Tcf, throughout their development. Therefore, the analysis of potential storage sites must ensure a minimum total storage capacity of 4 Tcf. A high-level theoretical storage capacity has been estimated for both saline aquifers and future depleted hydrocarbon fields. However, the hydrocarbon fields under evaluation are still in production and are not yet depleted. These fields are expected to become available for CO2 storage only after they reach the end of their production life in the coming years.

The basic formula, assumptions, and methodology for estimating CO2 storage capacity in depleted hydrocarbon fields are as follows:

$$CO_2\ Storage\ Capacity\ (scf) = OIIP\ (bbl) \times RF_{oil} \times \frac{1}{Bgi_{CO2}\left(\frac{bbl}{scf}\right)}$$

With assumptions,

1. RF oil reservoirs. Low Case: 15%**, Most Likely: 30%*, High Case: 40%**
2. Max injection BHP is equal to initial reservoir pressure.
3. Permeate stream contains 100% CO_2.
4. Above $P_{bubblepoint}$, no gas liberation, oil volume only.
5. Aquifer drive and water encroachment is not accounted.
6. Injectivity related concerns is not accounted.

The total estimated storage capacity across R1 area is approximately 3.16 Tcf or equivalent to 161 MT, with the largest capacity found in single well around 1.4 Tcf or 72 MT. Standalone CO2 injection into saline aquifers is less feasible due to the limited storage capacity of each individual target. However, injection may be viable if aquifer pressure is managed through water production. CO2 injection into depleted fields is generally more practical compared to saline aquifers, as it does not require de-watering to maintain pressure. Two fields offer larger storage capacities of approximately 3.8 Tcf (~193 MT) and 2.5 Tcf (~130 MT), respectively, but have limited data availability for detailed development planning. Given PETRONAS' current accessibility into one of the fields in R2, it can be prioritized for preliminary development where proposed capacity of 0.8 Tcf (~43 MT), aligning with the storage requirements for Field Y.

Conclusions

Subsurface studies strongly recommend CO2 storage in low-risk reservoirs, specifically in post-salt Cretaceous sand in R1 and Quissama Carbonate in select fields in R2. The estimated CO2 storage capacity in future depleted reservoirs in R2 is approximately 12.6 Tcf (~640 million metric tons), assuming a 30% recovery factor. In the short term, an injection plan could be implemented in R1, which offers a storage capacity of 1.4 Tcf in one of the saline aquifer fields.

This high-level capacity assessment should be further refined as field development progresses. A comprehensive study on reservoir containment performance is recommended, including 3D static and dynamic reservoir modeling, geomechanical and geochemical assessments, and injectivity analysis.

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