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A review of CO_2-injection projects in the Brazilian Pre-Salt — Storage capacity and geomechanical constraints

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ABSTRACT

This review describes the main geological and geomechanical aspects of CO_2-injection projects in the Brazilian Pre-Salt reservoirs, focusing on the storage potential and geomechanical aspects of CO_2 injection. The Pre-Salt reservoirs in the Santos Basin offer favorable conditions for CCS due to their geological characteristics and existing infrastructure. The thick evaporite caprock, primarily composed of halite, acts as an efficient seal against CO_2 migration. The CO_2-injection in the Pre-Salt has been active since 2010, with significant amounts of CO_2 already stored in the reservoirs. The volumetric assessment estimates the static storage capacity of the Pre-Salt reservoirs to be over 3.3 Gt of CO_2, considering only the four fields currently undergoing injection. Geomechanical constraints, including the maximum injection pressure and caprock integrity, are crucial considerations for safe CCS operations. The high stress regime and the hydrostatic state of the caprock minimize the risk of fracturing during injection. Furthermore, dynamic storage capacity calculations indicate the feasibility of injecting CO_2 into Pre-Salt reservoirs. This review provides insights into the current state and future prospects of CO_2-injection projects in the Brazilian Pre-Salt, contributing to the development of sustainable carbon mitigation strategies in the region.

1. Introduction

As the world moves towards a low-carbon energy future, the demand for carbon capture and storage (CCS) projects is increasing. One of the most promising alternatives for geological storage is in abandoned or depleted petroleum reservoirs. In comparison to deep saline aquifers, hydrocarbon reservoirs have a number of advantages for CCS, in terms of both their geological characteristics and operational aspects. From the geological standpoint, oil and gas reservoirs have a proven capability of trapping fluids for prolonged periods of time, which is not necessarily the case for saline deep saline aquifers. In terms of the operation of a CCS project, producing reservoirs undergo extensive petrophysical and geological characterization campaigns, which reduce the uncertainty regarding containment and injectivity. Furthermore, the availability of fluid processing plants and injection facilities is an advantage in comparison to aquifer injection and can accelerate in years the starting date of a future CCS project.

The Brazilian Pre-Salt is a relatively new oil-producing area, that was discovered in 2006. It is located in the Santos Basin, in the southeast coast of Brazil. Its petroleum system hosts a unique combination of lacustrine carbonate rocks overlaid with a thick layer of salt, which has been deposited across the South Atlantic Margin during the Aptian age. These carbonate reservoirs, formed during rift to drift transition of the South Atlantic, are characterized by their significant depth, high porosity, high Young's modulus and high productivity (Gomes et al., 2020; de Almeida et al., 2010; Pizarro and Branco, 2012). The presence of the caprock salt layer provides an exceptional seal, which has preserved good quality oil (average 29 API), and maintained high pressures within the reservoirs.

From the geomechanical perspective, the Pre-Salt behavior is controlled by the complex interplay between the salt topography and the carbonate mechanical heterogeneity. This is exemplified in Fig. 1, which illustrates both the varying salt depths and the strong presence of intercalations in the reservoir. The salt ductility influences the entire stress regime, and, by consequence, the maximum CO_2 injection pressure. Geological time has allowed the salt to flow plastically, redistributing stresses in the subsurface and controlling the drilling and production properties. Understanding the stress dynamics, which controls the fracture gradients and injectivity, is vital for a safe operation and containment of the reservoirs. Bose and Sullivan (2022) discuss in length the structural complexity and distribution of the salt layer across the Santos basin, providing a detailed analysis of the Aptian evaporite sequence, including its extent and internal deformation patterns.

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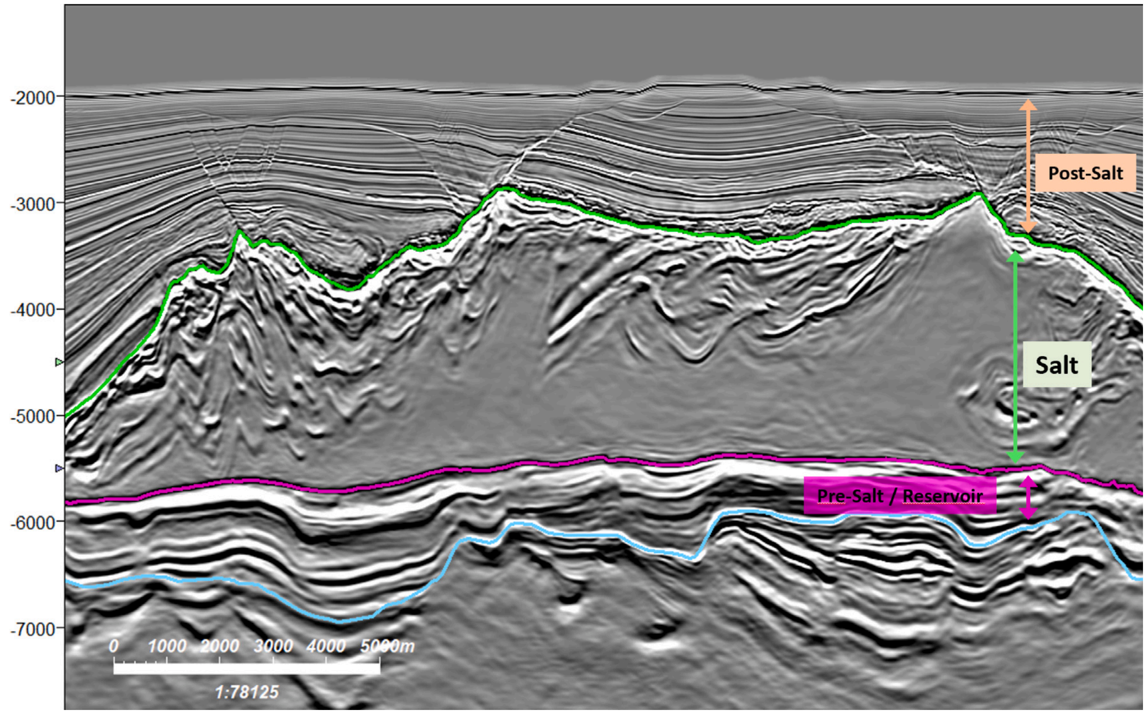

Fig. 1. Seismic section from the Buzios field illustrating the Pre-Salt's geological context. The reservoirs lie under a very thick layer of salt (green horizon) and under a depth of over 5000 m. There are no discernible faults crossing the salt section and the reservoirs are very heterogeneous.

Today, the Pre-Salt cluster is the major hydrocarbon producing area in the country, and one of the most prolific offshore provinces in the world. After the first commercial Pre-Salt discovery in 2006, and the start of production of the Tupi field in 2010, several adjacent fields also proved highly productive, culminating with the Búzios field in 2018, which is the largest offshore field in the world, with an estimated original volume of oil in-place of over 4.5 billion m^3. Today (May 2023), the daily production of the Pre-Salt fields is of 1.8 MMbbl (290 Mm^3) of oil, and the cumulative production reached over 5000 MMboe. The province is not mature, and the area is still target of heavy investments in exploration and production.

Compared to the Pre-Salt, the deployment of CO_2-injection projects worldwide faces different challenges and offers another perspective on the application and safety of this technology. The United States holds the lead in the application of CO_2-EOR, particularly in the Permian Basin of Texas. There, CO_2-EOR has become one of the most common strategies in tertiary oil recovery, contributing significantly to the national oil output. Since the inception of the first large-scale project in 1972 by Chevron, the U.S. has seen a substantial increase in CO_2-EOR application, with around 280,000 barrels per day contributed by this method as of 2013, making up about 3.7% of its total oil production. This success is attributed to the extensive infrastructure and experience in optimizing CO_2 injection techniques across multiple sites (Hill et al., 2020; Matsushita and Raven, 2016). The United States has also developed a comprehensive strategy for CCS deployment, including financial incentives such as the 45Q tax credit, which has significantly stimulated CCS projects across the country. This approach, combined with extensive experience in CO_2-EOR, positions the US as a leader in CCS technology and implementation (Jones and Marples, 2023).

In contrast, the chinese approach to CO_2-EOR is part of a broader carbon capture, utilization, and storage (CCUS) strategy, aiming to reduce China's heavy reliance on coal. Despite facing challenges to operate in deep, tight reservoirs, and the lack of extensive infrastructure such that in the U.S., China has been advancing its CO_2-EOR techniques. This has the advantage of both enhancing oil recovery while also contributing to carbon emission reduction goals. Pilot projects and significant investment in CCUS highlight China's commitment to evolving its CO_2-EOR capabilities as part of its larger environmental and energy strategy (Hill et al., 2020).

Another approach has been prioritized in Canada, where CO_2 -injection, particularly in Alberta, is focused on research and development. Projects such as the Quest, Boundary Dam, and the Alberta Carbon Trunk Line exemplify the successful integration of CO_2-EOR and storage solutions. These projects not only emphasize oil recovery, but also underline the importance of safe and efficient CO_2 storage, reflecting a balanced approach to resource utilization and environmental conservation (Macquet et al., 2022).

In Europe, the Sleipner project, in the North Sea, was the first large-scale offshore CO_2 storage project. Since its start in 1996, the Sleipner project serves as a benchmark for CCS, demonstrating long-term storage and monitoring solutions in deep saline aquifers. This project illustrates the feasibility of long-term storage in offshore environments and the potential of deploying CCS projects to mitigate the impact of producing CO_2-rich hydrocarbons (Ringrose and Meckel, 2019).

The CO_2 storage capacity is estimated early in the planning phase of a CCS project. To this end, there are several approaches, depending on the level of knowledge about the area and risk tolerance. The most basic approach is to perform volumetric assessments that estimate the volume of porous rocks potentially available to receive the CO_2, assuming average properties for the reservoir rocks. This is often the first choice when analyzing the storage potential of deep saline aquifers (Bachu et al., 2007), which typically suffer form a scarcity of data when compared with oil and gas fields. Despite of its practicality and widespread use, this approach is of pedagogical value only, since it should never be used in actual projects. The main reason for this is that in closed (or semi-closed) reservoirs, the continuous injection of CO_2, for either EOR or CCS, causes pressure buildup that limits the CO_2 storage capacity (Rutqvist, 2012; Ringrose and Meckel, 2019; Zhang et al., 2022). For the safe operation of CO_2–injection projects, it is crucial to consider the geomechanical limits of the injection pressure. This precaution is necessary to avoid potential damage to the caprock, which could lead to leakage into the surrounding rock formations or to the surface. This study provides a comprehensive review of CO_2–injection projects in the Brazilian Pre-Salt over the past decade, emphasizing the static and dynamic storage potential of the area, in contrast with more conventional geological settings. We also highlight how the geomechanical aspects impact the safety of the operation. With this study we bring attention to the significance and potential of the Brazilian Pre-Salt as a major hub for carbon capture and storage (CCS) initiatives. The paper starts with an overview of the CO_2–injection operations in the Brazilian Pre-salt (Section 2), followed by an assessment of the static (volumetric) storage potential of the area (Section 3). Then we proceed to discuss the advantages of injection CO_2 in pre-salt reservoirs, from the containment and geomechanical perspectives (Section 4).

2. CO_2 injection in the Brazilian pre-salt – The first decade

The pre-salt reservoirs consist of lacustrine carbonates (Gomes et al., 2020), bearing a light oil of average 29 API and rich in dissolved gas (the solubility ratio is typically greater than 300). The caprock is a very thick sequence of Aptian evaporites which extends throughout the entire Santos Basin (Jackson et al., 2015), Fig. 1. The Pre-Salt exhibits a significant geomechanical heterogeneity due to its lithological diversity. The sequence of microbial carbonates, followed by deeper water carbonates, indicates a high degree of depositional variability, which translates into varying mechanical properties. This lithological diversity must be considered in any geomechanical evaluation, especially when assessing the capacity and integrity of CO_2 storage within these reservoirs.

Most of the production activity in the area is concentrated in a cluster of four fields – Tupi, Búzios, Mero and Sapinhoá – located at a large distance from the coast (over 100 Km), and under very deep water-depths, typically around 2000 m, Fig. 2. These circumstances, combined with environmental requirements, propelled a field development strategy based on Floating Production Storage and Offloading (FPSO) vessels and the reinjection of the total amount of the produced CO_2, and part of the produced hydrocarbon gas (de Almeida et al., 2010).

Since the drilling of the appraisal wells, it became clear that the associated gas of some pre-salt fields was rich in CO_2. The operator (Petrobras) decided not to ventilate the CO_2 – a decision motivated by both the necessity of implementing enhanced oil recovery (EOR) and in anticipation of a stricter environmental legislation – and began reinjecting the produced CO_2 into the reservoirs in the very early stages of production (Pizarro and Branco, 2012). Pre-Salt reservoirs also offer favorable conditions for capillary and solubility trapping. The lacustrine carbonates and Aptian evaporites serve as fitting host rocks for CO_2, providing pore-space for storage and promoting its dissolution in formation fluids.

Currently, there are four fields undergoing CO_2 injection in the pre-salt: Búzios, Mero, Tupi and Sapinhoá. The Tupi field alone injected more than 14 Mton CO_2 since 2010, and the cumulative injection in these four fields of the Santos Basin is over 40 Mton CO_2, and the current annual combined injection capacity is over 8 Mtpa, Fig. 3. This amount is larger than industry-operated CCS projects, surpassing the capture capacities of projects such as Sleipner and Snohvit in the North Sea. Additionally, the pre-salt CCS initiatives have demonstrated remarkable progress compared to industry-led projects such as Gorgon and Quest, which faced technical challenges and injection rate limitations. This track record highlight the pre-salt region's emergence as a leading offshore CCS area, making significant strides in large-scale CO_2 storage (Zhang et al., 2022).

3. Static storage capacity of the pre-salt reservoirs

Early storage capacity estimates for CCS projects concentrated on estimating the volumetric capacity of the reservoir, an approach very similar to the one adopted by the industry to quantify resource volumes and, in later stages of development, to book reserves (Bachu et al., 2007).

In its simplest form, the volumetric approach calculates the reservoir volume available to store CO_2 using average reservoir properties (Bachu et al., 2007):

$$V_{CO_2} = V_{trap}\phi(1 - S_{wi}) \tag{1}$$

where $V_{trap}\,[\mathrm{m}^3]$ is the volume of the trap (reservoir formation), $\phi\,[.]$ is the average porosity, and $S_{wi}\,[.]$ is the irreducible water saturation. Eq. (1) expresses what is considered to be the maximum theoretical capacity, never reached in practice, since it does not account for multiphase flow characteristics, and operational limits. In practice, the effective capacity (in mass units) is commonly written as (Ringrose and Meckel, 2019):

$$M_{CO_2} = V_{trap}\phi\rho_{CO_2}\epsilon \tag{2}$$

where $\rho_{CO_2}\,[\mathrm{kg/m^3}]$ is the CO_2 density at *in situ* conditions, and ϵ is a storage efficiency factor commonly defined within the range of 1%–5% (Gorecki et al., 2009) that account for losses due to multiphase dynamics and operational constraints.

When considering CO_2 storage in depleted oil reservoirs, Eq. (2) can be further refined and made more rigorous by incorporating the known characteristics of the reservoir, which are routinely assessed by the field operator. These are the original volume of oil in place (VOIP[m^3 std]), the recovery factor (R_f [.]), and the reservoir volume formation factor (B_f [$\mathrm{m^3/m^3}$std]) (Callas et al., 2022):

$$M_{CO_2} = \rho_{CO_2}\left[R_f.VOIP.B_f - \Delta V_w\right] \tag{3}$$

where $\Delta V_w = V_{inj} - V_{prod}$ is the balance between injected and produced water, thus removing the water injected for EOR from the available volume for storage. Considering the balance of water injected until May 2023 (the last public available date), and assuming typical values for the pre-salt fluids – $B_f = 2$ and $\rho_{CO_2} = 910\ \mathrm{kg/m^3}$ (CO_2 density at reservoir conditions) – and a reference recovery factor of R_f = 20%, typical of carbonate reservoirs, we can estimate the total storage capacity for the pre-salt reservoirs, Table 1. While estimates conducted using Eq. (3) do not take into account the CO_2 already injected, this is not relevant to our particular case. The total amount injected (approximately 30 Mt) corresponds to only 1% of the total practical storage, Table 1.

The static storage capacity for the Brazilian pre-salt totalizes around 3.3 Gt of CO_2, if we consider only the four fields already undergoing CO_2 injection. Our estimates are on the sub-basin scale. We are dealing with individual oil fields for which reliable estimates rock and fluid characteristics are already available. Thus, care must be taken when comparing our results with capacity estimates reported in the literature (Table 2). Basin-scale estimates tend to be highly optimistic, in the sense that they overestimate the volume of potential targets and assume lateral continuity and homogeneity of the reservoir rocks (Szulczewski et al., 2012; Gorecki et al., 2009; Ranaee et al., 2022).

A word of caution is also needed when interpreting estimates for producing or depleted hydrocarbon fields that follow a similar approach as Eq. (3) for the capacity estimate. A few studies calculate the storage capacity by dividing the in-place oil volume (VOIP [std m^3]) by B_f (the volume formation factor [m^3/std m^3]). See, for instance equation 5 in Bachu et al. (2007), quoted in Rockett et al. (2013), Ciotta et al. (2021). There is clearly a unit inconsistency in doing so. Hence, the correct expression is given by Eq. (3), also correctly stated in Ranaee et al. (2022) and Karvounis and Blunt (2021). This mistake could help explain part of the discrepancy in the reported storage capacity for the Santos Basin from Ciotta et al. (2021) and the value we report in this work.

Fig. 2. The CO_2 injection activity in Brazil is concentrated in the Santos Basin (blue polygon), on the southeast coast, where there are four large Pre-Salt fields (Tupi, Búzios, Mero and Sapinhoá) injecting CO_2 (gray polygons) since 2010.

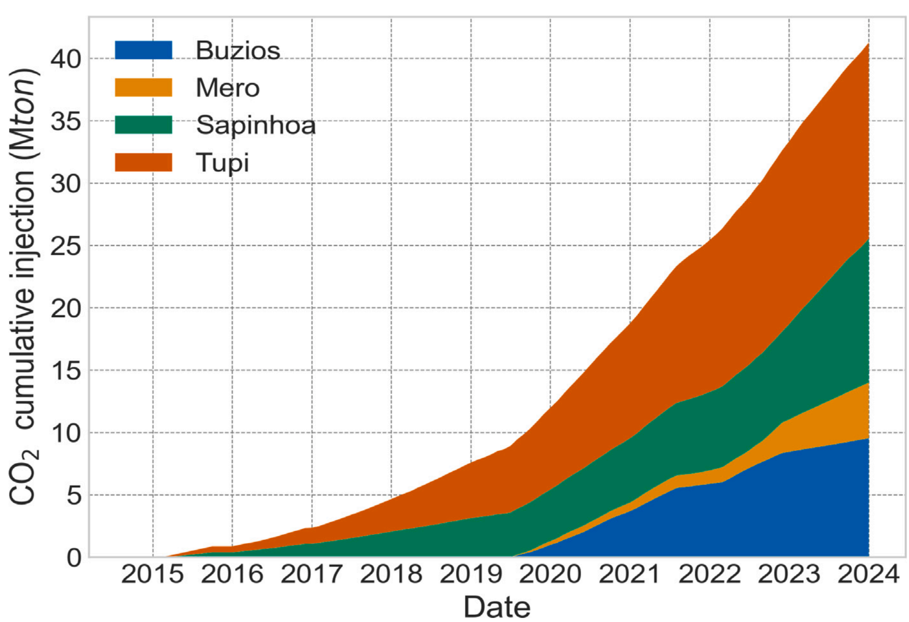

Fig. 3. Cumulative injection of CO_2 (in Mton) in the four main producing reservoirs of the Brazilian pre-salt. CO_2 injection in the Tupi field started in 2010, but the publicly available date starts in 2015.

Table 1
Storage capacity (Eq. (3)) and the amount of CO_2 injected until May (2023) for the four main presalt fields.

Field	VOIP (m^3)	CO_2 Injected (Mton)	Practical storage capacity CO_2 (Mton)	Start date
Búzios	4,582,731,822	8.4	1668.6	2019
Mero	1,555,955,014	2.4	572.6	2019
Sapinhoá	628,892,228	7.3	148.6	2015
Tupi	3,306,780,948	14.5	908.1	2010
Total	*10,074,360,012*	*32.7*	*3297.9*	

Table 2
Storage capacity estimated using a volumetric approach of different basins and plays. The reported volumetric storage capacity far surpasses the current CO_2 worldwide offer.

Location	Type	Storage capacity (Gt)	Reference
Campos basin	Oil fields	0.95	Rockett et al. (2013)
Santos basin	Oil fields	0.32–0.98	Ciotta et al. (2021)
Operating Pre-Salt fields	**Oil fields**	**3.3**	**This work**
USA	Deep saline aquifers	200	Szulczewski et al. (2012)
Norwegian North sea	Oil fields	>100	Ringrose and Meckel (2019)
North sea	Deep saline aquifers	440	Karvounis and Blunt (2021)
China	Deep saline aquifers	1350	Ranaee et al. (2022)

4. Storage safety and geomechanical constraints in the pre-salt

In this section, we examine the safety aspects and the geomechanical constraints associated with CO_2 storage in the Pre-Salt reservoirs. The role of salt as a caprock in geological CO_2 storage is investigated, highlighting its function as a robust and efficient seal. We also describe the stress regime of the caprock, analyzing how the injection pressure and the properties of the reservoir interact and affect the dynamic storage capacity, emphasizing the need to account for geomechanical constraints to prevent caprock fracturing.

The geological containment of CO_2 depends on four primary mechanisms: structural trapping, capillary trapping, solubility trapping, and mineralization. Structural and capillary trapping are particularly critical in the short and medium terms as they effectively restrict the upward movement of CO_2. They immobilize it in ganglia before facilitating its subsequent dissolution in the formation fluids (Krevor et al., 2015). Solubility is a process associated with medium term containment (years after injection) and fundamentally controlled by the formation fluids chemistry. Mineralization is not significant for short and medium terms, and should play a small role even after centuries of injection.

4.1. The role of salt as a caprock in geological CO_2 storage

The effectivity of the structural trapping mechanism in the Pre-Salt is credited to the thick evaporite caprock, predominantly composed of halite. Given the negligible permeability of salt (Warren, 2010), which is a result of its unique crystalline structure and exceptionally high capillary entry pressure, salt is deemed the most efficient geological seal. In the Santos basin the sealing capability of the salt layer has been documented for hydrocarbon accumulations under both near-normal fluid pressure (as shown in Fig. 5) and overpressure conditions, such as the one found in the Bacalhau field (Equinor, 2023). Such natural validation of the hydraulic and structural integrity of the evaporite caprock provides confidence in the safe injection of fluids into the pre-salt reservoirs. Therefore, the caprock serves as an efficient seal against CO_2 migration. In the long term, the dissolved CO_2 may also interact with the host rock to form stable carbonates, thus enhancing the safety and security of CO_2 storage in Pre-Salt reservoirs.

While the Brazilian Pre-Salt represents a unique case of large-scale CO_2 injection into a salt-sealed reservoir, the effectiveness of salt formations as caprocks is widely recognized in the geological storage literature. Recent studies have further reinforced this understanding, demonstrating the sealing properties of salt formations due to their negligible permeability and high capillary entry pressure (Kim and Makhnenko, 2023). These findings from other geological contexts support the observed effectiveness of the evaporite caprock in the Pre-Salt reservoirs, providing additional confidence in the long-term safety of CO_2 storage in these formations.

Moreover, concerns regarding fault reactivation are minimal due to the absence of visible or mapped faults intersecting the caprock. As a result, any induced seismicity potential is localized within the reservoir formation, which is situated hundreds of kilometers away from the coastline. This leaves fracture propagation as the main geomechanical issue requiring attention.

4.2. Stress regime, injection pressure, and 3D geomechanical modeling

In most Brazilian pre-salt reservoirs, the evaporite caprock – with a thickness of at least hundreds of meters (de Almeida et al., 2010; Jackson et al., 2015) – exhibits a significant creep behavior. This contributes to higher stresses in the salt rock, which tends to be in a hydrostatic regime, where all the principal stresses are equal: $S_1 = S_2 = S_3$. This has been tested and documented through a series of well fracturing tests, see for instance (Azevedo et al., 2019; Thompson et al., 2022). This behavior is expected to occur on the time scale typical of geological process, the salt behaves as a viscous fluid and tends to be in a hydrostatic stress condition.

The maximum injection pressure (P_{max} [Pa]) is defined to guarantee the integrity of the caprock, thus imposing a limit on the pressure buildup during injection. The maximum pressure increase before tensile failure (ΔP_{max}) is:

$$\Delta P_{max} = T_0 + S_3 - P_0 \tag{4}$$

where T_0 [Pa] is the tensile strength of the rock (usually assumed zero in geological materials), S_3 [Pa] is the minimum principal stress and P_0 [Pa] is the initial pressure. In practice, it is recommended to define a safety factor (SF) that accounts for uncertainties in the estimation of stresses and pressures and reduces the maximum pressure build-up. Thus, assuming $T_0 = 0$, Eq. (4) is rewritten as:

$$P_{max} = P_0 + (1 - SF)(S_3 - P_0) \tag{5}$$

and both S_3 and P_0 are calculated at the caprock. Industry practice imposes $SF = 0.1 - 0.2$, depending on the level of uncertainty, regulatory requirements, and well monitoring devices in place.

The Pre-Salt is located in a passive margin, where the maximum stress component (S_1) is vertical, Thus, in the case of a saline caprock that is in the hydrostatic regime, the injection pressure is limited by the overburden stress, since $S_1 = S_v$ and $S_3 = S_1$. The vertical stress is high in the case of the deep pre-salt reservoirs (Azevedo et al., 2019). This scenario has been analyzed through computational simulations employing a finite-element geomechanics simulator, which utilizes a two-step approach to tackle the complexity of the problem. The first step formulates the governing equations for mass and momentum conservation, considering factors such as stress, strain, pore pressure, and rock strength. The second step focuses on the efficient computational implementation and parallelization strategies, leveraging high-performance computing architectures such as distributed memory systems using MPI for parallelization (Figueiredo et al., 2023).

Stresses in the subsurface are routinely estimated using numerical geomechanical models (do Amaral et al.; Rutqvist, 2012), this is performed for all Pre-Salt reservoirs. Fig. 4 illustrates the minimum stress gradient resulting from a 3D geomechanical finite-element model of a Pre-Salt reservoir. This kind of model captures the remarkable stress complexity induced by salt tectonics, such as the presence of compressional (high stress) regions in salt valleys (mini-basins), low confining zones in the crests, and lateral stress variations at the reservoir level due to mechanical heterogeneity. A typical stress profile along a well is presented in Fig. 5, which illustrates the difference between the reservoir pore-pressure and the minimum stress at the base of salt,

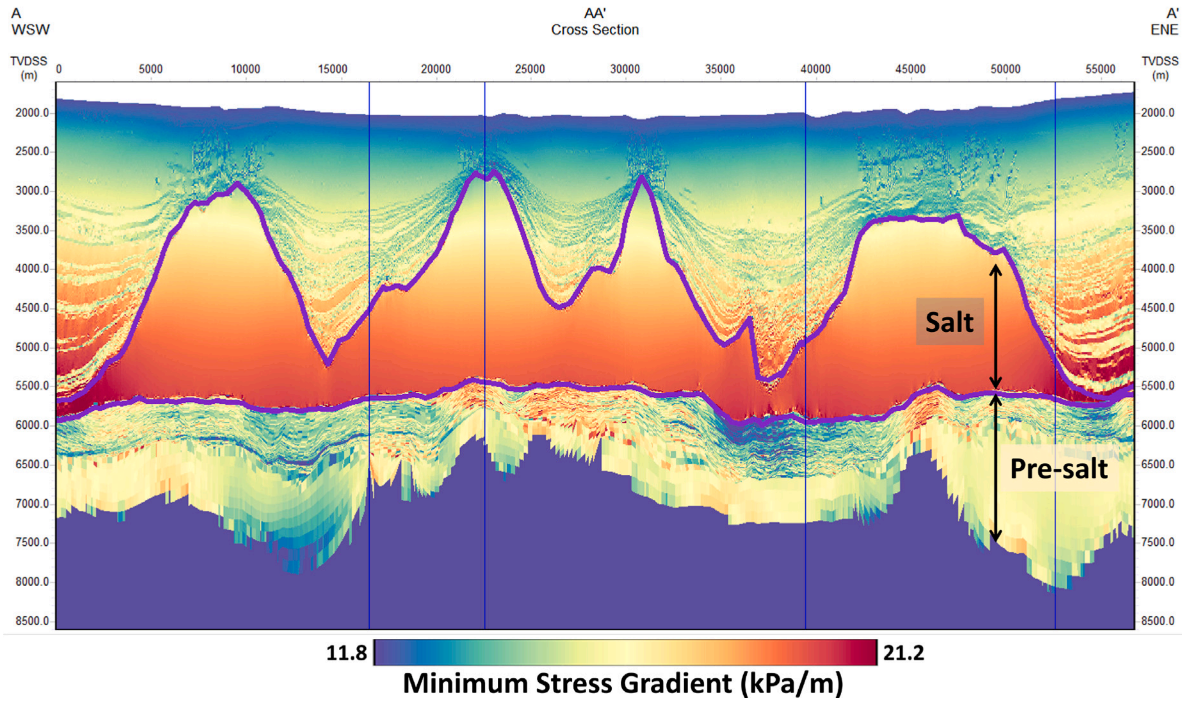

Fig. 4. Minimum Stress gradient resulting from a 3D geomechanical finite-element model of a Pre-Salt reservoir. The model captures the stress variations induced by the salt topography, the hydrostatic state in the salt and the stress contrast between the salt and the carbonate reservoir.

which serves as safety barrier. The minimum stress is calibrated using a microfrac test (Azevedo et al., 2019). This high stress contrast severely constrains the possibility of fracturing the caprock during injection and is a key to assert the safety of the typical pre-salt reservoirs as CCS targets.

As the cold CO_2 is injected into the reservoir, the adjacent formations are cooled, and as the thermal front advances in the reservoir, the caprock is also cooled. The mechanical effect of this thermal phenomenon is the stress reduction in the rock and major favorability to rock fracturing, depending on the injection pressure (Perkins et al., 1985). This effect is also enhanced by carbonate and salt high elastic stiffness, which are one order of magnitude larger than that of soft sandstones. In the context of cold fluid injection in the Pre-Salt, these phenomena have been numerically studied, considering that creeps occur faster than heat diffusion in the salt rock. The results show that thermal effects are not a significant factor to define the maximum injection pressure. Salt creeping relieves the thermal stresses induced by cooling, thus the saline caprock integrity is not impacted by cold fluid injection. Thus, any thermal effects are relevant only to the reservoir itself, and do not influence the maximum injection pressure, which is limited by the stress in the caprock. The use of a multiscale approach combined with efficient parallelization strategies, allows for accurate and computationally efficient solutions to these complex thermal and geomechanical interactions (do Amaral et al.).

4.3. Dynamic storage capacity

The volumetric approach to storage quantification is useful for scenario screening and preliminary area selection, but it does not provide estimations for maximum injection rates, which are critical to design realistic CCS projects. In project-specific studies, geomechanical constraints must be taken into account, most obviously through the definition of a maximum injection pressure that does not exceed the tensile fracture pressure in the caprock, this has been emphasized by several studies (Ringrose and Meckel, 2019; Szulczewski et al., 2012; Ranaee et al., 2022; Rutqvist, 2012). The maximum injection pressure, as defined in Eq. (5), establishes a safety limit for the operation a CCS project, but it does not calculate the pressure buildup in the reservoir. This is done either using field-scale simulators (do Amaral et al.), or using analytical solutions based on simplifying assumptions on the reservoir geometry and petrophysical properties (Mathias et al., 2009, 2011; Simone and Krevor, 2021). In this section, apply the analytical solution of Mathias et al. (2009) to calculate the pressure-limited injection rate of both a pre-salt reservoir and a tertiary turbidite sandstone in the Campos Basin (Brazil) using representative properties for these two areas. This analysis intends to highlight the dynamic storage capacity of the pre-salt play in comparison to more conventional geological settings (shallow reservoirs under shaly caprocks) currently under consideration for large-scale CCS projects.

Table 3
Representative properties used for dynamic storage capacity estimation. The data do not represent a specific reservoir, but rather specific hydraulic compartments located in Post- and Pre-Salt fields.

	Post-Salt	Pre-Salt
Water depth (m)	1325	2140
Overburden thickness (m)	1056	2732
Temperature (C)	52	62
Original pressure (Mpa)	25	58
Porosity (%)	27	10.6
Permeability (mD)	806	269
Netpay (m)	13	118
Rock compressibility (1/kPa)	0.00008	0.00003
Oil density (API)	19	28
Gas-oil Ratio (–)	70	263
Oil Viscosity (cP)	9.7	1.1
Formation volume factor (–)	1.2	1.7
Brine salinity (ppm)	82 000	220 000
Vertical stress (Mpa)	37.5	84.2
Fracture pressure (MPa) (Eq. (5))	25.1	81.6

During injection, the maximum pressure buildup is located at the well (ΔP_{well}). This can be estimated using an analytical solution for asymptotic times that assumes immiscible flow and accounts for rock and fluid compressibilities (Mathias et al., 2009), quoted here for

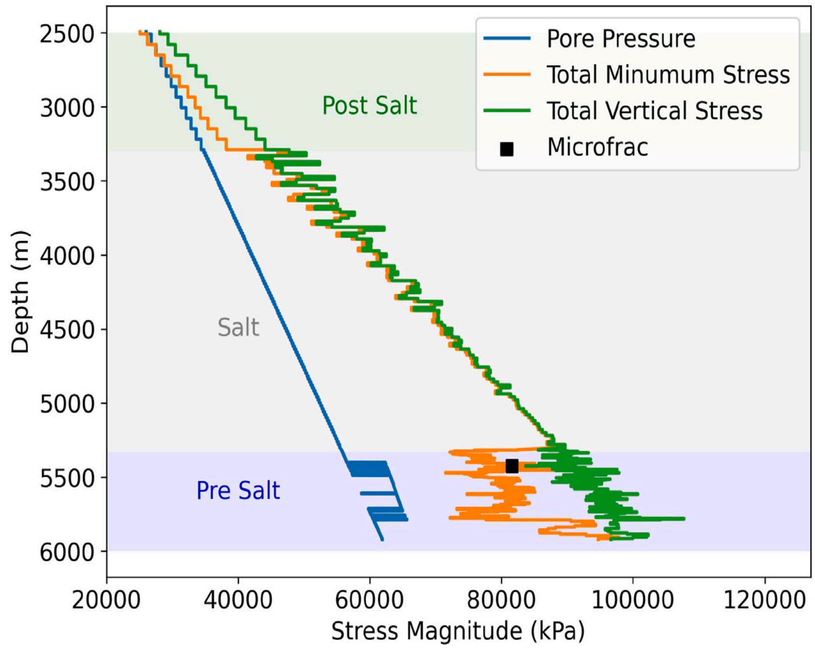

Fig. 5. Typical stress and pressure profiles along a pre-salt well. The pore pressure (blue line) is well below the minimum stress curve (orange line). Note the difference at the base of salt and the hydrostatic stress state inside the salt. The stress response is calibrated using a microfrac test (black dot).

completeness:

$$\Delta P_{well} = p_0\left\{-\frac{1}{2}\ln\left(\frac{t_0}{2\gamma t}\right) - 1 + \frac{1}{\gamma} - \frac{1}{2\gamma}\left[\ln\left(\frac{\alpha}{2\gamma^2}\right) + 0.5772\right] + \beta\right\} \quad (6)$$

which is written in terms of the CO_2 properties – ρ_0 density, viscosity μ_0 and compressibility c_0, calculated at *in situ* conditions. Together with the formation fluid properties, and the reservoir characteristics permeability (k), and porosity (ϕ), these terms are combined in dimensionless groups – $\alpha = \frac{M_0\mu_0(c_r+c_f)}{2\pi H\rho_0 k}$, $\beta = \frac{M_0 kb}{2\pi H r_w \mu_0}$, $\gamma = \frac{\mu_0}{\mu_f}$, $\epsilon = \frac{c_0-c_f}{c_r+c_f}$, $\sigma = \frac{\rho_0}{\rho_f}$ – and parameters $p_0 = \frac{M_0\mu_0}{2\pi H\rho_0 k}$ and $t_0 = \frac{2\pi\phi H r_w^2\rho_0}{M_0}$ that represent characteristic times and pressures in Eq. (6), and r_w is the well radius (typically a few centimeters). The Forchheimer parameter (b) in the expression for β is given by the correlation $b = 0.005\phi^{-5.5}k^{-0.5}$, Mathias et al. (2009).

The injection rate (M_0 in mass units per time) dictates the pressurization in the reservoir, and fracture propagation is then assumed to start when the pressure at the well exceeds the maximum injection pressure. The maximum pressure at the injection well is then $P_{well} = \Delta P_{well} + P_0$, and the maximum allowed injection rate is achieved when $P_{well} = P_{max}$, where P_{max} is given by Eq. (5), and $SF = 0.1$.

We illustrate the storage potential for typical injection wells in two distinct geological settings, a Tertiary Turbidite and a Pre-Salt carbonate by performing the previous analysis using the data shown in Table 3. The results (Fig. 6) show that, for practical applications, the injection of CO_2 in the Pre-Salt would not be pressure-limited. The combined injection of all the Pre-Salt wells is currently over 8 Mtpa of CO_2, and the pressure analysis indicates that a typical well does would reach the fracture pressure only with rates of over 5 Mtpa, which are not feasible due to operational constraints.

5. Final comments and conclusions

In this work we present a review of the CO_2 -injection projects operating in the Brazilian Pre-Salt in the last decade. We also discuss the storage capacity, and the geomechanical aspects of the CO_2 injection in Pre-Salt reservoirs. We show that the Pre-Salt has a storage potential in the gigatonne range and is already storing large amounts of CO_2 since the start of production in the area, in 2010. Furthermore, the combination of very permeable carbonate reservoir with a very thick evaporite caprock provides near perfect geological trapping characteristics.

The discussion about the dynamic storage capacity highlights the crucial importance of understanding and managing geomechanical constraints to ensure the feasibility and safety of CCS projects. While the analysis presented here is based on a single base-case scenario, it provides a starting point to assess the storage capabilities of the Brazilian Pre-Salt. Each oilfield within the Pre-Salt has its own unique characteristics, including variations in porosity, permeability, and fluid and rock compositions, which can significantly influence the storage capacity and the injectivity. Therefore, each reservoir must undergo a comprehensive geological characterization and modeling specific to each field before the start of operations. This is routinely done by the Operator as part of field development plan and reserves assessment. In regards to CCUS, the continuous injection for over a decade of large amounts of CO_2 with no safety issues or loss of injectivity illustrates the good level of understanding of the pre-salt geological and flow characteristics. Also, the integrity of the caprock is paramount for the containment of injected CO_2. The experience of injecting in different fields and the stress and geomechanical tests performed in the salt caprock have provided strong evidence in favor of the integrity of the caprock and overall safety of the operation. No leakages or unexpected geological events have been recorded.

For the practical implementation of CCUS, operational uncertainties also present substantial challenges. Optimizing injection rates involves balancing several factors, including storage efficiency, economic viability, and safety considerations. This balancing act requires a precise understanding and monitoring of reservoir behavior, potential for induced seismicity, and interactions with reservoir fluids and rocks (de Azevedo Novaes et al., 2023).

In light of these considerations, while our base case scenario provides valuable insights, it is merely the tip of the iceberg. A robust, cautious, and informed approach is essential, incorporating continuous research, monitoring, and adaptation to address the wide spectrum of uncertainties. Such an approach will enhance the reliability, safety, and efficiency of CCS as a crucial component of carbon mitigation strategies in the Brazilian Pre-Salt and beyond. As Brazil continues to advance its CCS initiatives, lessons learned from both successes and challenges will be vital in optimizing strategies, ensuring environmental compliance, and enhancing economic viability in the face of an evolving energy landscape.

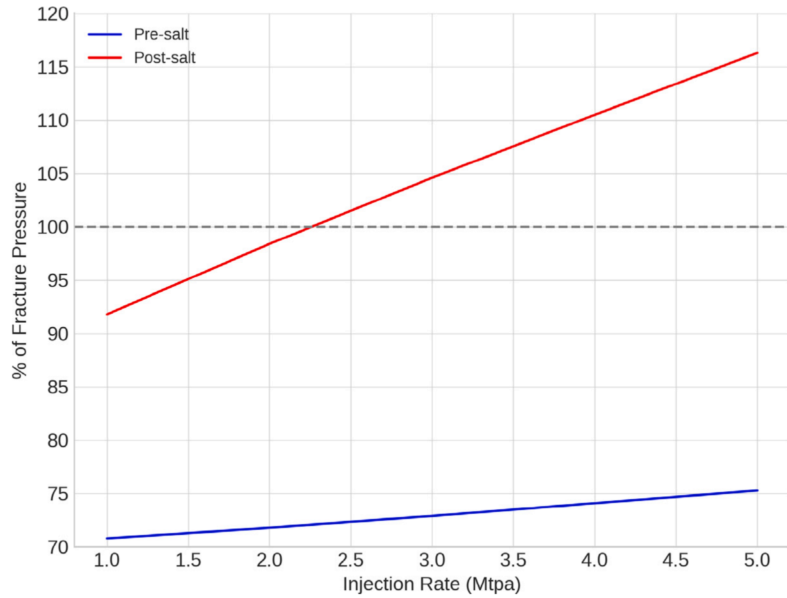

Fig. 6. Pressure buildup in percentage points of the fracture pressure (the maximum injection pressure, Eq. (5)) as a function of the CO_2 injection rate in Mtpa. This post-salt example has a lower dynamic capacity than the pre-salt, whose capacity is not pressure-limited in practical applications.

The geomechanical characteristics of the Pre-Salt also contribute to the safety of the operation. The evaporite caprock is in a high-stress state (near hydrostatic), well over the initial reservoir pressure, resulting in a very effective safety barrier. A thorough geomechanical modeling is critical to evaluate the maximum injection pressures and to assess the caprock integrity risks, particularly in areas of high structural complexity. Understanding these aspects is key to developing safe, efficient, and realistic carbon capture and storage (CCS) projects in Pre-Salt reservoirs. In the presence of a thick salt layer, the injection pressures are limited by the overburden stress and the leakage risks are negligible. We expect that the Pre-Salt has the potential to stay a very important hub for CCS in Brazil during the next decades.

In conclusion, the Brazilian Pre-Salt cluster provides a promising opportunity for CO_2 storage due to its favorable geological and operational characteristics. The CO_2 injection project in the Pre-Salt has been successful during the last decade, and the reservoirs have the capacity to store large amounts of CO_2. The structural trapping guaranteed by the salt caprock provides a mechanism for safe and secure storage of CO_2. Further research is needed to fully understand the long-term behavior of CO_2 in these reservoirs, but the Pre-Salt cluster in Brazil has the potential to play a significant role in the implementation of CCS projects.

CRediT authorship contribution statement

João Paulo Pereira Nunes: Writing – review & editing, Writing – original draft, Validation, Software, Methodology, Investigation, Formal analysis, Data curation, Conceptualization. **Gabriel S. Seabra:** Writing – review & editing, Writing – original draft, Formal analysis, Data curation, Conceptualization. **Luis Carlos de Sousa Jr.:** Writing – review & editing, Writing – original draft, Investigation, Formal analysis, Data curation, Conceptualization.

Declaration of competing interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

Data availability

Data will be made available on request.

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