Introduction

The combustion of fossil fuels such as oil and coal harms global climate conditions, with carbon dioxide (CO_2) being a primary contributing factor. The high production and combustion of CO_2 result in its atmospheric concentration exceeding the capacity of the carbon cycle to absorb it. Elevated levels of CO_2 exacerbate the greenhouse effect, a natural behavior of the Earth's atmosphere that retains certain gases, thereby preventing the planet's temperature from dropping to deficient levels. Consequently, the substantial emissions of carbon dioxide intensify the greenhouse effect, leading to an increase in global temperatures over time. The oil and gas industry has been continuously developing methods and technologies aimed at reducing CO_2 emissions. One promising alternative involves storing this gas in depleted oil and gas reservoirs at the end of their productive life, a process known as carbon capture, utilization, and storage (CCUS). Due to the nature of the problem, the CO2 stored in the reservoir mustn't migrate back to the surface, which could occur if operational conditions are improperly dimensioned, considering the geological and mechanical properties of both the reservoir rock and cap rock. Therefore, precise modeling of properties such as Elastic Modulus, Poisson's Ratio, friction angle, and cohesion is essential. This study employs a representative model incorporating faults and fractures from a real field in the Parnaíba Basin, Brazil, to inject and store CO_2, examining its behavior within the reservoir over time. Utilizing well-log data, a 1D geomechanical model was constructed to calculate mechanical properties, stresses, pore pressure, and the differential pressure approaching the cap rock fracture pressure. This facilitated the development of a 3D geomechanical model coupled with a porous media flow simulator to simulate initial fluid production, CO_2 injection, its behavior in the porous medium, and the variation of pressure and stresses over time. The methodology employed aids in understanding reservoir behavior during CO_2 storage and in analyzing operational parameters to optimize the storage process, identifying regions most susceptible to fracture reactivation and determining optimal injection rates and pressures to safely store the maximum volume of gas possible.

Method and/or Theory

The total stresses defined by Terzaghi (1925) represent the complete stress state, comprising the sum of effective stress and the pressure exerted by fluids within the rock, known as pore pressure. This study employed the three principal normal stresses: vertical stress, which accounts for the weight of overlying formations (Fjaer, 2008), represented by the column of material above the region of interest, z. This definition of vertical stress considers gravitational acceleration and the density of the material at point z. For the calculation of vertical, minimum horizontal, and maximum horizontal stresses, equations derived from Khan (2015) were utilized. Specifically, a custom equation for minimum horizontal stress was applied, tailored for basins with low tectonic activity, where the minimum horizontal stress is linked to a linear elastic relationship. In this context, the minimum horizontal stress is a function of Poisson's ratio, total vertical stress, and pore pressure. To assess potential reservoir ruptures due to deformation induced by CO_2 storage, the calculated stresses were subjected to differential pressure and differential temperature changes (Equation 1, equation obtained from Zoback, 2007). This approach allows for the observation of poroelastic effects resulting from applied pressure variations and thermal effects arising from temperature differentials between the reservoir and the injected fluid, in this case, CO_2.

$$\Delta\sigma x = \frac{\nu}{1-\nu}\alpha\Delta P + \frac{\alpha E}{1-\nu}\Delta T \quad (1)$$

A 3D geomechanical model with coupling aims to compute the mechanical properties of the reservoir while simulating the flow model. The flow-geomechanical coupling, where fluid flows in a deformable medium, was proposed by Maurice Biot (BIOT, 1941). Terzaghi (1925) defined that the load-bearing capacity of a rock saturated with fluid depends simultaneously on the properties of the fluid and the mechanical properties of the rock itself. Additionally, Terzaghi demonstrated that the deformations occurring within the rock due to fluid flow directly influence its load-bearing capacity, influenced by the rearrangement resulting from fluid movement. Moreover, the GEM© geomechanical simulator was utilized for this study. The primary focus of this work is to analyze the mechanical responses of a reservoir with faults and fractures subjected to CO_2 storage. Therefore, full coupling was chosen to comprehensively analyze the interaction between fluid flow and mechanical deformation. An analysis of the coupling between fluid flow, mechanical properties, and heat transfer was conducted to illustrate the differences in CO_2 behavior under these three factors.

Sample section

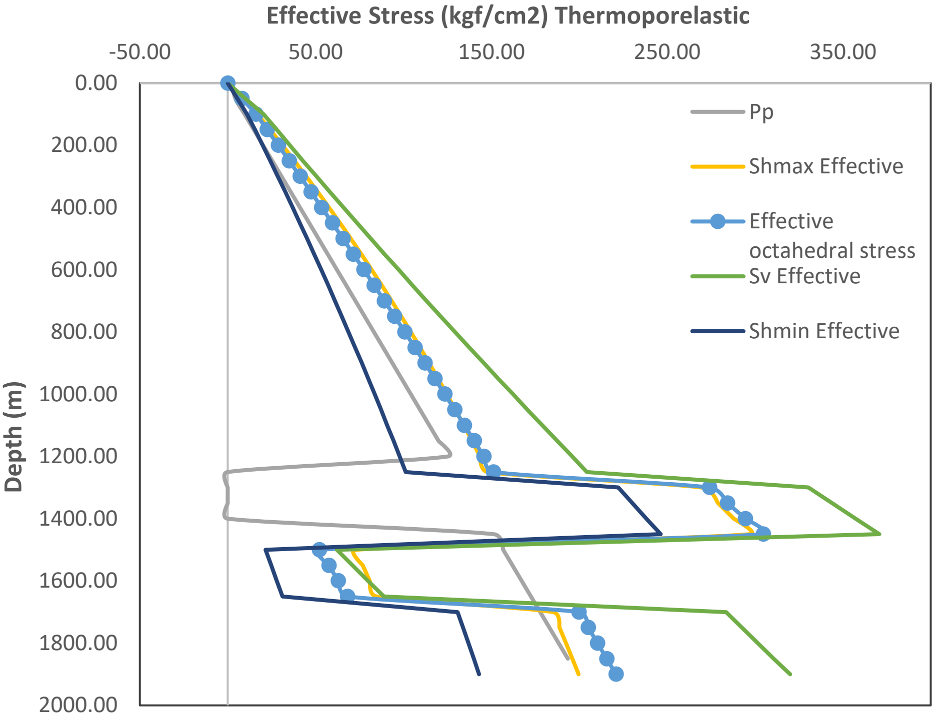

Figure 1 *In this graph, the application of the thermoporoelastic effect in the reservoir region in contact with the cap rock is illustrated. This area is particularly prone to leakage, as it is where fluid pressure first increases, exerting stress on the cap rock and potentially causing fractures and subsequent gas leakage. Applying the thermoporoelastic effect results in a pressure differential within this region. From this pressure differential, it becomes possible to identify the injection pressure at which fractures and potential leaks may occur.*

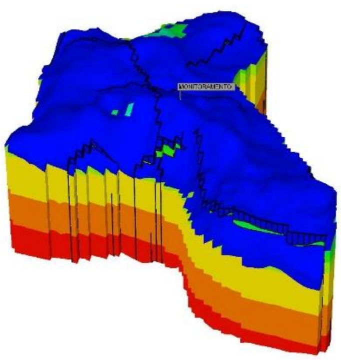

Figure 2 *In this figure, the 3D model constructed for coupled simulation is depicted. The model is designed to represent each significant formation essential for the simulation. The blue region represents the cap rock, composed of diabase. The yellow region is where the depleted gas reservoir is located, predominantly composed of sandstone. The orange region represents a region composed of shale. Lastly, the red region is a region which includes an aquifer and is predominantly composed of sandstone.*

Figure 3 *In this image, the arrangement of faults that comprise the model can be observed. One of the main parameters to be analyzed in this study is fault reactivation.*

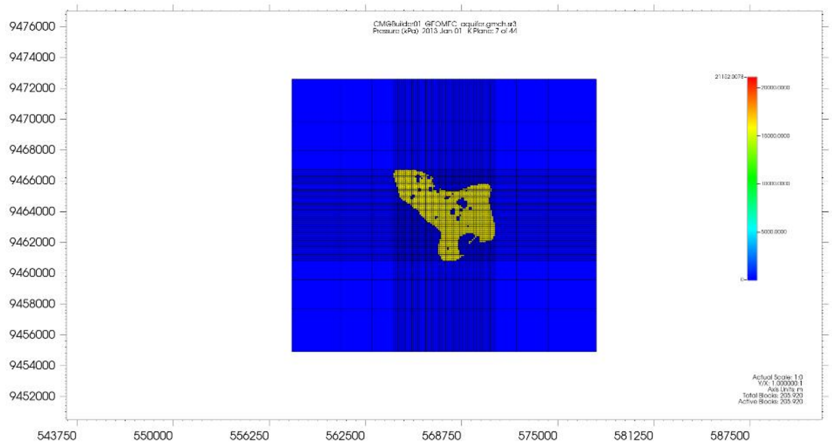

Figure 4 *The figure above displays an aerial view of the reservoir (at the center) surrounded by the extended region. Utilizing an extended geomechanical model is essential to observe the stress behavior in the area surrounding the reservoir. In this study, an extended model was employed not only to understand stress distribution within the reservoir but also in the neighboring regions. This approach facilitates the visualization of potential fault reactivations, ruptures, and CO_2 leaks.*

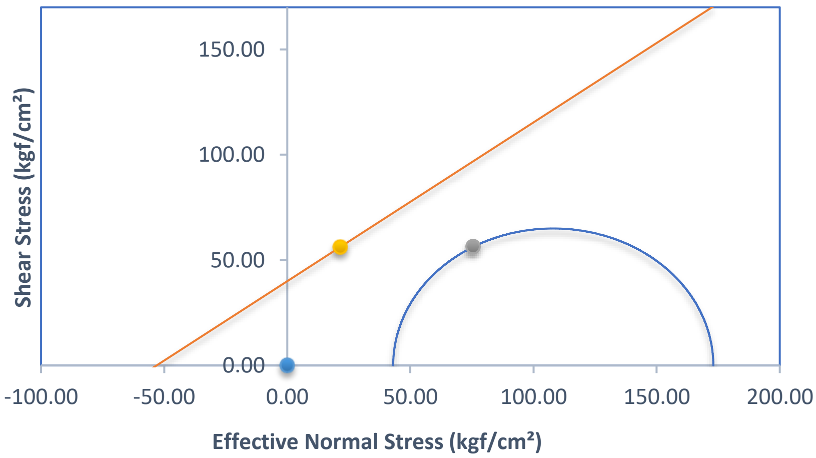

Figure 5 *The graph above represents the Mohr-Coulomb circle at the initial stage of the reservoir, indicating that initially, the reservoir exhibits a fault reactivation pressure greater than the current pressure of 257 kgf/cm².*

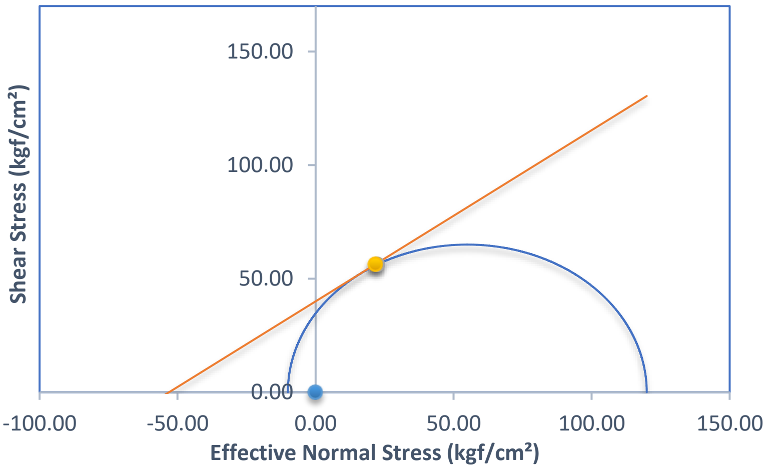

Figure 6 *In this instance, the reactivation pressure of reservoir faults is illustrated. When the Mohr-Coulomb circle contacts the failure envelope, fault reactivation due to shear will occur at a pressure of 322 kgf/cm², and fault reactivation due to tension will occur at a pressure of 344 kgf/cm².*

Conclusions

The study of geomechanics in the context of CO_2 storage primarily focuses on the safe operation of this process. Understanding how stresses vary as pore pressure changes is essential to preventing fractures in the caprock. Therefore, it is necessary to use both a 1D model, as demonstrated by the application of the thermoporoelastic effect, and a 3D simulation with a robust, heterogeneous model that accurately represents the reservoir intended for CO_2 storage. By applying the thermoporoelastic effect to the principal stresses, it is possible to apply a differential in pressure and temperature to the region near the caprock to calculate the fracture stress, which could lead to potential breakages. Using this pressure differential, it is possible to utilize this value in the simulation of the model with geomechanical coupling as a limiting pressure value for CO_2 injection. Once the fracture pressure value is reached, gas leakage through the caprock will occur. Based on the results obtained using the Mohr-Coulomb circle, it is possible to simulate fault reactivation pressure in the 3D model with geomechanical coupling, observing both the CO_2 injection pressure and the transmissibility of existing faults in the reservoir. When a fault allows the flow of CO_2 from one region to another, it can be concluded that this fault has been reactivated, potentially causing gas leakage.

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