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RESEARCH ARTICLE

Analysis Of Co2 Storage in A Saline Aquifer Using A Fully Implicit Integrated Network Modeling Approach in the 'AZ' Field

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Abstract

The increasing carbon dioxide (CO_2) emissions from industrial and energy activities have driven the development of Carbon Capture and Storage (CCS) technology as a key solution for climate change mitigation. Among various geological storage options, saline aquifers offer significant advantages due to their large storage capacity, wide distribution, independence from hydrocarbon value, and stable geological and geochemical conditions. The "AZ" Field, located near a power plant emitting 2.2 million tons of CO_2 annually, was selected as the study site for CO_2 storage.

This study aims to analyze the trapping mechanisms and optimize the CO_2 storage capacity (storativity) using a fully implicit integrated modeling approach. The methodology involves building a static and dynamic model of the Johansen Formation saline aquifer, and integrating well and surface facility models using the well designer and network designer features in tNavigator. A 140-year simulation was conducted, comprising 40 years of injection and 100 years of post-injection period.

Simulation results show that the "AZ" Field can store up to 83.9 Mt of CO_2, predominantly through solubility/residual trapping mechanisms, in addition to structural trapping. No leakage was observed to the surface, indicating that caprock integrity remained intact throughout the simulation period. The fully implicit integrated modeling approach effectively captured the dynamic interactions between the reservoir, wells, and surface facilities, supporting the feasibility of the "AZ" Field as a safe and sustainable CO_2 storage site.

Keywords: Deep Saline Aquifer, Carbon Capture And Storage (CCS), Trapping Mechanism, Storativity, Integrated Network Modeling

1. Introduction

The rapid increase in carbon dioxide (CO_2) emissions from industrial and energy activities has intensified global concerns regarding climate change. CO_2 is the most significant anthropogenic greenhouse gas, contributing substantially to global warming and associated environmental impacts (Benson and Orr, 2008; Nayak et al., 2020; Yoro and Daramola, 2020). To address these challenges, Carbon Capture and Storage (CCS) has emerged as a promising mitigation technology, designed to capture CO_2 from large stationary sources, transport it, and store it securely in deep geological formations (Gibbins and Chalmers, 2008).

Among the various geological storage options, deep saline aquifers have attracted significant attention due to their large storage capacity, wide distribution, and independence from hydrocarbon value (Ajayi et al., 2019). Additionally, their geochemical and geological stability enhances long-term storage security (Bachu et al., 2007; Bai et al., 2016). Compared to depleted oil and gas reservoirs or unmineable coal seams, saline aquifers offer broader global applicability for large-scale CO_2 sequestration (Bakhshian et al., 2023; Mim et al., 2023).

A critical challenge in CCS deployment lies in ensuring storage safety and efficiency (Lipponen et al., 2017; Rui et al., 2025). Effective trapping mechanisms—structural, residual, solubility, and mineral trapping—play essential roles in immobilizing CO2 over geological time scales (Saadatpoor et al., 2010). Structural trapping provides immediate storage security, while residual and solubility trapping enhance long-term containment by dispersing CO_2 within pore spaces and dissolving it in brine (Bergmo et al., 2011; Eigestad et al., 2009). These mechanisms collectively minimize the risk of leakage through caprock or fault systems (Punnam et al., 2025; Song and Zhang, 2013).

Recent advances in simulation technology enable comprehensive evaluation of CCS projects by integrating reservoir, wellbore, and surface facilities into a single modeling framework (Picha, 2024). Integrated network modeling provides dynamic insights into injection performance, pressure behavior, and storage optimization under varying boundary conditions (Liang and Rubin, 2014). Fully implicit coupling approaches are particularly advantageous, as they capture the interactions between subsurface and surface systems with improved numerical stability.

This study focuses on the "AZ" Field that is located in Johansen Formation, a deep saline aquifer situated near the Mongstad power plant in Norway, which emits approximately 2.2 Mt of CO_2 annually (Bergmo et al., 2009). The main objective is to analyze trapping mechanisms and optimize storage capacity (storativity) using a fully implicit integrated network modeling approach. By coupling subsurface dynamics with surface facility constraints, this work aims to evaluate the feasibility and safety of long-term CO_2 storage in the "AZ" Field, while highlighting its potential as a sustainable CCS site (Stokes et al., 2024).

Despite this growing body of work, several limitations remain in the current literature on CO_2 storage in saline aquifers. Many site-screening and capacity estimation studies adopt simplified reservoir representations and treat wellbore or surface network behaviour as boundary conditions, rather than explicitly coupling them within a unified model (Ajayi et al., 2019; Bachu et al., 2007). This decoupling restricts their ability to capture interactions between injection strategy, pressure build-up, and surface facility constraints, which are critical for large-scale deployment. Similarly, while recent studies have emphasised the importance of composite confining systems and caprock morphology for long-term security (Bakhshian et al., 2023; Punnam et al., 2025; Song and Zhang, 2013), they typically evaluate leakage risk at the reservoir–caprock interface only, without linking these processes to operational limits at the well and network level. Reviews of CCS deployment further highlight persistent uncertainties in storage capacity and injectivity under realistic field conditions, particularly when policy, infrastructure, and subsurface constraints must be considered simultaneously (Lipponen et al., 2017; Luo and Wang, 2026; Mim et al., 2023).

For the Johansen Formation specifically, previous studies have largely focused on reservoir-centric assessments of plume migration and storage security (Bergmo et al., 2009; Eigestad et al., 2009; Fawad and Mondol, 2019; Sundal et al., 2016). These works provide valuable insights into stratigraphic architecture, flow behaviour, and sealing capacity, yet they generally neglect explicit integration with compressor, pipeline, and well performance or adopt semi-implicit coupling strategies that may under-represent strong feedbacks between surface and subsurface domains (Liang and Rubin, 2014; Stokes et al., 2024). Moreover, most studies do not include a fully coupled geomechanical assessment of rock failure risk under different injection and network scenarios, even though well integrity and caprock stability are recognised as key barriers to large-scale CCS (Bai et al., 2016; Picha, 2024). This study addresses these gaps by implementing a fully implicit, integrated reservoir–well–surface network model for the "AZ" Field in the Johansen Formation, combined with Mohr–Coulomb-based geomechanical evaluation, to provide a more realistic estimate of storage capacity, trapping evolution, and mechanical stability under operational constraints.

2. Methodology

This study aims to develop an integrated reservoir, well, and surface network model to optimize CO_2 sequestration in a deep saline aquifer. Particular emphasis is placed on assessing the impact of subsurface uncertainties on key challenges associated with managing CO_2 storage under surface facility constraints. The Johansen Formation, a deep saline aquifer located offshore along the west coast of Norway, is selected as the case study (Sundal et al., 2016). Critical aspects to be addressed include the evaluation of storage mechanisms, the characterization of CO_2 plume migration and distribution, and the identification of processes that may compromise seal integrity by enabling CO_2 leakage from the Johansen Formation into overlying strata (Bergmo et al., 2009).

Figure 1 illustrates the proposed integrated subsurface–surface network model developed for CO_2 sequestration in the Johansen Formation. A sector model with heterogeneous rock properties was constructed, spanning a lateral extent of approximately 100 km and discretized into 11 stratigraphic grid layers. The upper five layers represent the shale caprock of the Dunlin Group, layers 6–10 comprise the high-permeability sandstone units of the Johansen Formation, and layer 11 corresponds to the low-permeability Amundsen Shale, which acts as a sealing boundary (Fawad and Mondol, 2019). Compositional simulations were performed to investigate CO_2 injection into the permeable sandstone intervals using two vertical injector wells designed to penetrate the formation through layers 6, 7, and 10. A vertical well model was incorporated, and vertical lift performance (VLP) curves were generated to define well operating constraints. To assess geomechanical stability, rock mechanical properties—including Young's modulus, Poisson's ratio, cohesion, and internal friction angle—were integrated into the model, enabling rock failure evaluation using the Mohr–Coulomb criterion. The simulation schedule comprised 40 years of continuous CO_2 injection followed by 100 years of post-injection monitoring to evaluate plume migration, trapping efficiency, and long-term storage security.

The CO_2 source was assumed to originate from the Mongstad power plant, which produces approximately 2.2 million tonnes of CO_2 annually and serves as the boundary input to the system. The CO_2 was transported in the gaseous phase through a 60 km pipeline to the storage site, where a main compressor was installed to distribute the CO_2 into the injection wells. A consistent PVT model was applied across the subsurface, wellbore, and pipeline domains to ensure uniform characterization of fluid properties. The subsurface and surface network models were coupled through the wellbore and solved iteratively. Three primary trapping mechanisms were considered during the storage process that consist of structural trapping, residual trapping, and solubility trapping. To evaluate system performance, an integrated static–dynamic workflow was developed to analyze the influence of surface facility parameters—such as pipeline internal diameter and compressor pressure—on overall storage capacity and trapping efficiency.

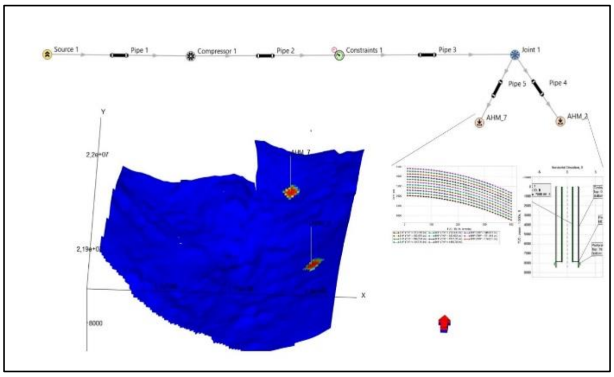
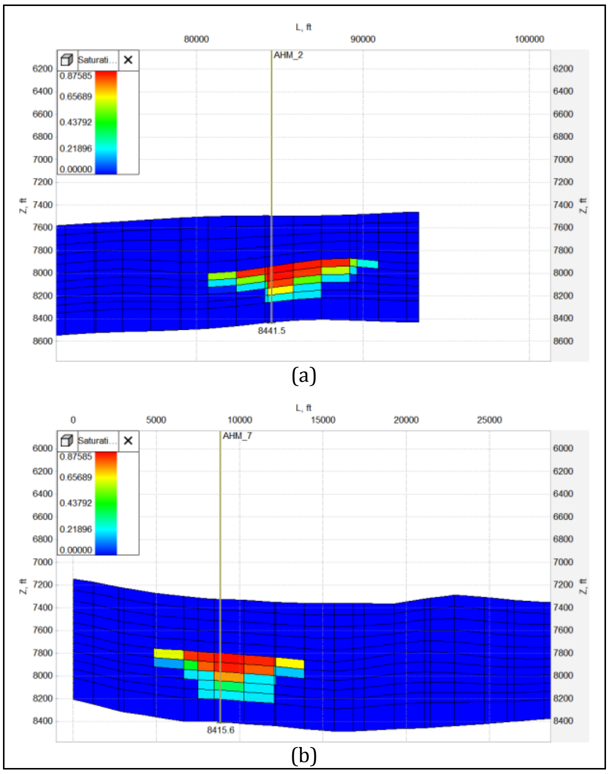


Fig. 1. The proposed integrated subsurface–surface network mode to ensure the long-term deliverability and security of CO_2 sequestration in the Johansen Formation

3. Results and Discussion

The integrated subsurface-to-surface simulation confirmed the feasibility of CO_2 injection in the "AZ" Field using wells AHM_2 and AHM_7, each operating at an injection rate of about 1.53 Msm3 per day. Over the 40-year injection period, reservoir pressure increased steadily yet remained below the critical threshold, which ensured safe injectivity without compromising caprock integrity. The simulated plume migration showed buoyancy-driven upward movement, where CO_2 preferentially migrated along high-permeability layers and accumulated in structural traps. Figures 2 illustrate plume distribution at AHM_2 and AHM_7, highlighting stable containment within the reservoir interval.



(a)

(b)

Fig. 2. Plume Migration after 40-years injection

The CO_2 plume distribution illustrated in Figure 2(a) and Figure 2(b) indicates distinct migration patterns between wells AHM_2 and AHM_7 due to heterogeneity in reservoir architecture and permeability anisotropy. In AHM_2, the plume exhibits a slightly elongated and upward-tilted morphology toward the crest of the structure, suggesting dominant buoyancy forces and lateral diffusion along a high-permeability pathway. The color gradient, ranging from blue (low saturation) to red (high saturation), reveals that CO_2 saturation is concentrated near the injection zone and gradually tapers upward, confirming capillary trapping as the major retention mechanism in this sector. Conversely, the plume at AHM_7 remains more compact and symmetrically distributed around the injector, implying that local permeability barriers or tighter lithofacies limit its lateral spread, thereby enhancing solubility and residual trapping within the matrix pores.

In both injection sites, plume stabilization after 40 years demonstrates that dynamic equilibrium was achieved between injection pressure and buoyant migration. No evidence of upward leakage beyond the reservoir top is observed, supporting the effectiveness of the caprock seal and validating the structural closure as a secure storage trap.

The confinement of the plume to the target interval also indicates that vertical permeability contrast and stratigraphic layering act as natural baffles, reducing vertical migration risks. Such containment behavior aligns with long-term storage safety criteria and further suggests that post-injection pressure dissipation will promote additional residual and solubility trapping, enhancing the permanence of CO_2 sequestration within the Johansen Formation.

The observed plume stabilization provides a critical precursor to evaluating the coupled geomechanical response. Because the CO_2 plume remained laterally confined and vertically restricted within the reservoir interval, the resulting pressure perturbations were spatially moderate and temporally gradual. This distribution pattern minimized stress concentration near faults and caprock interfaces, thereby reducing the risk of shear slippage or tensile fracturing. Consequently, the mechanical equilibrium of the system was preserved throughout the injection phase, confirming that the simulated flow behavior and plume geometry directly support the favorable stress state evidenced by the Mohr–Coulomb analysis. The integration of flow and geomechanical simulations thus validates that the Johansen Formation not only provides effective containment for CO_2 storage but also maintains mechanical resilience under long-term operational conditions.

Rock failure analysis presented in Figure 3 demonstrated that stress conditions across the reservoir and caprock remained below the Mohr–Coulomb failure envelope throughout the injection scenarios. This confirms that no significant fracture propagation or fault reactivation occurred, thereby ensuring the long-term mechanical stability of the storage site. The geomechanical evaluation further supports the suitability of the Johansen Formation for CO_2 sequestration, as the overlying shale maintained its sealing capacity under varying injection pressures.

The uniform blue coloration across the modeled domain in Figure 3 quantitatively indicates that the calculated rock failure index remained well below unity, confirming the absence of shear or tensile failure throughout the entire injection period. This result implies that the induced pore pressure from CO_2 injection did not exceed the critical stress threshold of the formation, thereby preserving the integrity of both reservoir and caprock layers. Furthermore, the lack of localized stress anomalies around wells AHM_2 and AHM_7 suggests that wellbore placement and pressure management strategies were appropriately optimized, minimizing the potential for mechanical weakening or fault slip. These findings collectively affirm that the Johansen Formation exhibits strong geomechanical resilience, making it a reliable candidate for long-term CO_2 containment under sustained injection and post-closure conditions.

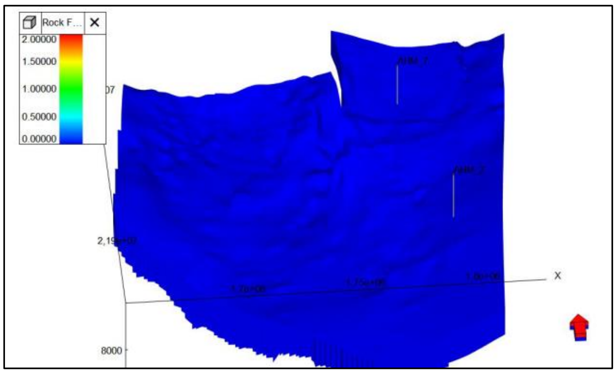


Fig. 3. Rock failure analysis based on the Mohr–Coulomb criterion indicated that the caprock remained mechanically stable, with no evidence of failure throughout the injection scenarios.

By the end of the 140-year simulation period, consisting of 40 years of continuous injection followed by 100 years of monitoring, a total of approximately 83.9 Mt of CO_2 was securely stored in the reservoir. Trapping mechanisms analysis shown in Figure 4 indicated that structural trapping dominated during the injection phase, while residual and solubility trapping became increasingly significant over time. This progression enhances long-term containment security, as immobile CO_2 and dissolved CO_2 reduce leakage risks over geological timescales. Overall, the results confirm that integrated modeling provides a reliable framework for predicting injection limits, plume dynamics, and trapping efficiency under realistic operational constraints.

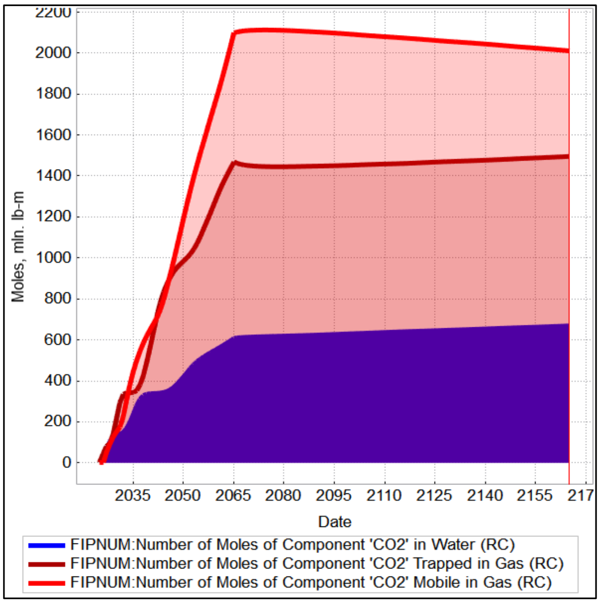


Fig. 4. Evolution of CO_2 trapping mechanisms during injection and post-injection periods, showing mobile CO_2, residually trapped CO_2, and CO_2 dissolved in formation water

The temporal evolution of CO_2 behavior reveals three distinct trapping regimes that govern the storage performance throughout the simulation. During the early injection phase (2030–2070), the steep rise in mobile CO_2 (red curve) signifies rapid accumulation in the gas phase, primarily controlled by structural and stratigraphic trapping beneath the sealing caprock. As injection progresses, the mobile fraction begins to plateau, reflecting the onset of pressure equilibrium and capillary resistance at the plume front. Meanwhile, the gradual increase of the residually trapped CO_2 (purple region) and CO_2 dissolved in water (blue region) marks a shift toward more stable trapping processes.

This transition demonstrates how reservoir heterogeneity and pore-scale capillary forces jointly facilitate a self-limiting mechanism, whereby buoyant CO_2 becomes immobilized and partially solubilized in brine, reinforcing containment security beyond the injection horizon.

In the post-injection phase (2070–2170), the system transitions into a slow stabilization period dominated by solubility trapping. The continual upward trend in the blue curve indicates progressive diffusion and convective mixing between supercritical CO_2 and formation water, enhancing the overall storage capacity through aqueous dissolution. This dissolved phase not only contributes to long-term chemical stabilization but also serves as a precursor for mineral trapping, where carbonate precipitation can occur over extended geologic timescales. Simultaneously, the minor decline in mobile CO_2 suggests a natural self-attenuation process, as residual and dissolved fractions gradually increase at the expense of the free phase. These coupled behaviors confirm that, even without additional engineering intervention, the reservoir system evolves toward a thermodynamically stable and permanently immobilized state, validating the long-term security of CO_2 sequestration within the Johansen Formation.

Although the present analysis is tailored to the Johansen Formation, the fully implicit integrated modeling framework is, in principle, transferable to other candidate CCS sites. The sector-model construction, compositional flow formulation, and network coupling strategy can be applied to different saline aquifers, depleted hydrocarbon reservoirs, or regional multi-well developments, provided that site-specific geological, petrophysical, PVT, and geomechanical data are available. In more heterogeneous or structurally complex settings, additional calibration of relative permeability, capillary pressure, and fault transmissibility would be required, and geomechanical parameters may need to reflect weaker or more compartmentalised confining systems. Likewise, surface configurations with different compressor layouts, pipeline lengths, or manifold designs can be represented by adjusting boundary conditions in the network model. Consequently, the workflow demonstrated for the “AZ” Field offers a scalable template for screening and optimising CO_2 storage projects in other basins, while still requiring careful site-specific validation against monitoring data and regulatory performance criteria.

4. Conclusion

An integrated compositional reservoir, wellbore, and surface network model was successfully applied to evaluate CO_2 sequestration in the “AZ” Field within the Johansen Formation. The fully implicit workflow demonstrated that CO_2 injection at a rate of 1.53 Msm3 per day per well can be achieved safely, resulting in a total storage of about 83.9 Mt over the injection period. The model captured plume migration, trapping mechanisms, and pressure evolution while confirming that the caprock remained mechanically stable throughout the operation. The results highlight the importance of integrating surface facility constraints with subsurface processes to obtain realistic predictions of storage capacity and injection performance. Structural trapping dominated immediately after injection, while residual and solubility trapping enhanced long-term storage security during the post-injection phase. The integrated modeling workflow developed here is transferable to other CCS projects, as long as site-specific geological, PVT, and geomechanical data are available, making it a scalable template for screening and optimising CO_2 storage in diverse formations.

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