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Integrated containment risks assessment for subsurface CO_2 storage: Overburden analysis and top seal integrity study, offshore Norway

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ABSTRACT

This study summarizes the OASIS (Overburden Analysis and Seal Integrity Study for CO_2 Sequestration in the North Sea) project that focuses on assessing the containment risks associated with the geological carbon sequestration (CCS) of the Northern Lights project. CCS is viewed as one of the most effective solutions for reducing carbon emissions, as it captures carbon dioxide from point sources and permanently stores it in suitable geological formations. However, injecting CO_2 into the subsurface may have mechanical consequences, including fault reactivation, top seal fracturing, surface heave, etc. This study proposes an interdisciplinary workflow to characterize the caprock, faults, and overburden associated with CCS projects in the Horda Platform area, to improve injection-induced containment risk assessment. Our findings show that the proposed workflows and tools effectively characterize stress-related mechanical hazards. However, due to the complex nature of rocks, it is challenging to evaluate the top seal integrity using a single method. Therefore, the proposed interdisciplinary approach is more effective for any fluid injection site's characterization, given the complex nature of the subsurface and its behavior under injection-induced stress changes. This research paper adds knowledge about the top seal integrity assessment and the reliability of injected CO_2, making CCS projects more reliable and safer. Although this study focuses on the northern North Sea, the proposed methods are equally applicable globally to characterize subsurface CO_2 storage sites. Apart from CCS projects, these research results can benefit other subsurface injection projects, such as water injection for reservoir management, wastewater injection for disposal, hydrogen storage, and hydraulic fracturing for unconventional hydrocarbon resources.

1. Introduction

Climate change over geological time is a natural phenomenon; however, the current change is more rapid than any known events in Earth's history (Allen et al., 2018). The main reason for the rapid temperature rise is the emission of human-induced greenhouse gases consisting mainly of carbon dioxide (CO_2) and methane (CH_4). The impact of global warming may trigger the critical thresholds called tipping points (Pachauri et al., 2014) if warming increases to equal or greater than 1.5 °C. Regardless of the initiatives made by the global community, global warming will still reach about 2.8 °C by the end of the century (Climate Action Tracker Report, 2021) if we can not achieve net-zero emissions by 2050 and cut by half by 2030 (Rogelj et al., 2018). According to the United Nations (UN), IPCC (International Panel on Climate Change), and IEA (International Energy Agency), carbon capture and sequestration (CCS) is required as this is one of the solutions with the lowest possible cost. The CCS project concept is to capture CO_2 from the point sources, then transport and permanently store it in suitable subsurface geological formations. CICERO (Center for International Climate Research Organization) has concluded that CCS is critical in most emission pathways to achieve the temperature reduction goals (Peters and Sognnæs, 2019) because (i) it may be challenging to reduce the source of emissions to net zero quickly enough without it, (ii) currently there are no viable alternatives to CCS for certain sectors (i.e., cement, steel, long-distance sea, and air transport, etc.), and (iii) CCS might be the cheapest and best way of reducing emissions (Longship Project Report, 2020). Therefore, it is well understood that we need more CCS projects globally for sustainability. According to Ringrose and

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Meckel (2019), we have the potential storage reservoir globally to store enough CO_2 to prevent global warming; however, to achieve the climate goal promised by global leaders, many CCS sites are required to mature as soon as possible.

Although several pilot projects demonstrate the practicalities of CCS, subsurface storage of CO_2 may have several mechanical consequences, including fault reactivation, top seal fracturing and/or failure, surface heave, leakage along the legacy wells, porosity-permeability changes due to reservoir expansion, etc. A detailed analysis of such factors is required for safe and permanent subsurface CO_2 storage. For reliable and permanent CO_2 storage, the injection processes must also consider a long-term monitoring plan. The focus should concentrate on scaling efficiency, as the trapping mechanisms, including solubility and mineral trapping, cannot retain a large amount of gas in a short time frame. Caprock and faults must be sealed to prevent the vertical buoyancy-driven CO_2 migration to provide sufficient time for other trapping mechanisms to contribute (Heinemann, 2013). Failure to uphold any of these criteria may result in CO_2 migration upwards into the overburden, where it may escape to the surface or get trapped by a secondary seal. Therefore, the overburden rock characterization is also crucial for any CCS project. It may return to the atmosphere in the worst-case scenario, thereby failing the overall CCS project objectives. Failure may also result in polluting freshwater aquifers near onshore injection sites. In addition, offshore CO_2 leaking may contaminate seawater, possibly escaping into the atmosphere.

OASIS project is one such project focusing on the containment risks assessment for CO_2 sequestration in the northern North Sea. The primary objective is to evaluate seal integrity and analyses of overburden intervals by interdisciplinary research involving laboratory experiments, petrophysical, rock physical, geophysical, geomechanical investigations, and computational modeling. The study area (northern North Sea) will be the future CCS hub, where the Norwegian government has already awarded three CCS licenses (EL001-Aurora, EL002-Smeaheia & EL004-Luna). In addition, two injection wells (31/5-A-7 AH & 31/5-C-1H) have been drilled to target megaton-level injection from 2024. As the reliability of injected CO_2 is a prime concern, OASIS project containment risks assessment contributes significantly in this regard. This paper is an overview of a Ph.D. thesis (Rahman, 2022) carried out under the OASIS project, where CCS site-specific containment risks, integrated solutions, and future improvement opportunities (limitations) have been discussed. This paper also aims to identify how integrated analyses can improve containment risk and increase injection reliability. The whole thesis (Rahman, 2022) is accessible online, but the learnings from the OASIS project are summarized and presented in this paper.

2. Containment risks

As the OASIS project is focused on top seal integrity and overburden analysis, the sealing-related containment risks are mainly described in this section. The cap and overburden rock strength is one of the crucial parameters that affect the integrity of rocks, which can trap low-density CO_2 plumes. If the reservoir pressure-induced effective stress exceeds the seal's tensile or shear strength, leakage can be triggered in cap and overburden rocks and faults (Fig. 1). A rapid increase of reservoir pressure can also lead to membrane seal failure (advection and diffusion through caprock) or hydraulically dilated faults and fractures (shear or tensile failure of caprock and reactivation of existing faults). There has been natural and geological evidences of leakages caused by pressure build-up. Gas leakage (gas chimney) through the top seal is a common phenomenon in hydrocarbon fields, which is easily detectable in seismic sections as a columnar disturbance with lower reflection continuity and amplitudes than the surrounding areas (Foschi and Cartwright, 2020; Hansen et al., 2020; Heggland, 1997; Rahman et al., 2022c; Sales, 1997). Depending on the overburden lithologies migrated CO_2 might be trapped within the overburden section or have migrated up to the seabed (offshore sites) or atmosphere (onshore sites). Seafloor pockmarks are also an indication of fluid escaping and have been observed in many basins worldwide (Foschi and Cartwright, 2020).

Induced seismicity can be triggered by any artificial fluid injection into the Earth's crust. Injected fluids not only perturb stress and create new fractures/faults, but they also potentially cause slip in pre-existing fault zones (Davies et al., 2013; Hawkes et al., 2005; Herwanger and Koutsabeloulis, 2011; Jimenez and Chalaturnyk, 2002; Nordbotten et al., 2004; Rutqvist et al., 2008, 2007; Rutqvist and Tsang, 2002; Soltanzadeh and Hawkes, 2008; Streit and Hillis, 2004). Additionally, there might be the possibility of ground deformation near the injection/production area (Mathieson et al., 2010). Globally, the injection-

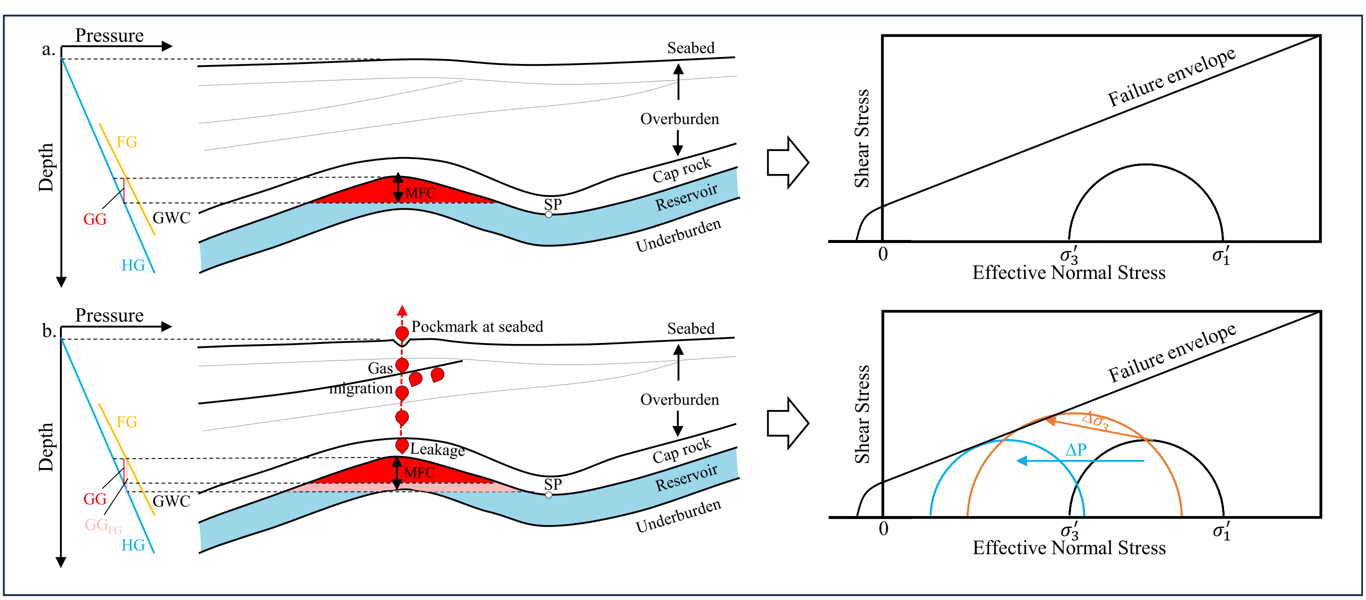

Fig. 1. Graphical illustrations of pressure-depth plots based on a structural trap with a thick fluid column (modified after Foschi and Cartwright, 2020). A representative Mohr-Coulomb failure diagram is presented for no gas leakage scenario (a) and gas leakage through caprock and overburden by diffusion and/or rock failure due to overpressure or horizontal stress perturbation (b). HG – hydrostatic gradient; FG – fracture gradient; GG – gas gradient; GG_{FG} – gas gradient during caprock fracture; GWC – gas water contact; SP – spill point; MFC – maximum fluid column; σ_1' - effective vertical stress; σ_3' - effective horizontal stress.

induced seismic activity near the injection wells has increased (Ellsworth, 2013; Fan et al., 2016; Horton, 2012; Keranen et al., 2013; Kim, 2013; Levandowski et al., 2018; Schultz et al., 2020, 2014). However, natural seismicity (earthquake) is also common and requires monitoring near injection sites to differentiate it from artificial seismicity (Rubinstein and Mahani, 2015).

An injection-induced pressure increase might introduce membrane seal failure. Due to the importance of proper seal integrity assessment for hydrocarbon exploration, the study of top seal risk assessment was started in the 1970s and 1980s, where the theoretical foundation was established in a series of published papers (Berg, 1975; Downey, 1984; England et al., 1987; du Rouchet, 1981; Sales, 1997; Schowalter, 1979; Watts, 1987). These initial studies emphasized buoyancy pressure-dependent seal capacity, where the membrane seal failure occurs if the capillary entry pressure of the top seal cannot prevent the buoyancy force (Foschi and Cartwright, 2020; Schowalter, 1979). The thickness of the caprock shale also plays a vital role during diffusion-related fluid escape (Johnson et al., 2022; Karlsen et al., 2004). The stress paths within the reservoirs and surroundings significantly affect the geomechanical risks (Addis, 1997; Grasso, 1992; Hillis, 2001; Segall, 1989). Natural fractures in caprock shales are also heterogeneous, which may significantly affect the caprock strength and, by extension, leakage pathways.

CO_2 containment study in the North Sea is also not new. There has been much research done by scientists focusing on fault and primary caprock in Sleipner, Smeaheia, and Aurora sites (Bickle et al., 2007; Chadwick et al., 2010; Lie et al., 2016; Lloyd et al., 2021; Meneguolo et al., 2022; Mulrooney et al., 2020, 2018; Osmond et al., 2022; Skurtveit et al., 2022, 2018; Wu et al., 2021). However, the OASIS project introduced different methods for containment risk assessment and highlighted the importance of overburden rocks in CO_2 containment study. The synopsis of the OASIS project outcomes is presented in this paper.

3. Key findings and limitations from OASIS

3.1. Caprock shale brittleness

The quantitative assessment of the integrity of caprock shales depends on the geomechanical properties, including brittleness and ductility. The brittleness properties of the rock and the failure criteria often control the injection-induced fracturing within the shale. However, while not universal, the brittleness scale (i.e., brittle to ductile) significantly varies between caprock shales. In addition, the transition value from brittle to ductile also varies considerably.

The OASIS project evaluated the caprock brittleness extensively. The influence of paleo-deposition and compaction processes on site-specific caprock properties has been interpreted and assessed (Rahman et al., 2022b; Rahman et al., 2020). Fig. 2 illustrates the wireline log-based regional brittleness maps for Upper Jurassic organic-rich Draupne (Fig. 2a) and Middle-Lower Jurassic Drake (Fig. 2b) caprock shales from the northern North Sea. The studied caprocks were deposited in different geological times and had a mineralogical variation where the Draupne Formation is shalier than the Drake Formation. On the contrary, considering the similar exhumation, Drake shale experienced higher compaction than Draupne. The differences in brittleness indices (BI) are apparent between these two shales using the same elastic property-based empirical equation (Fawad and Mondol, 2021a). Shalier, less

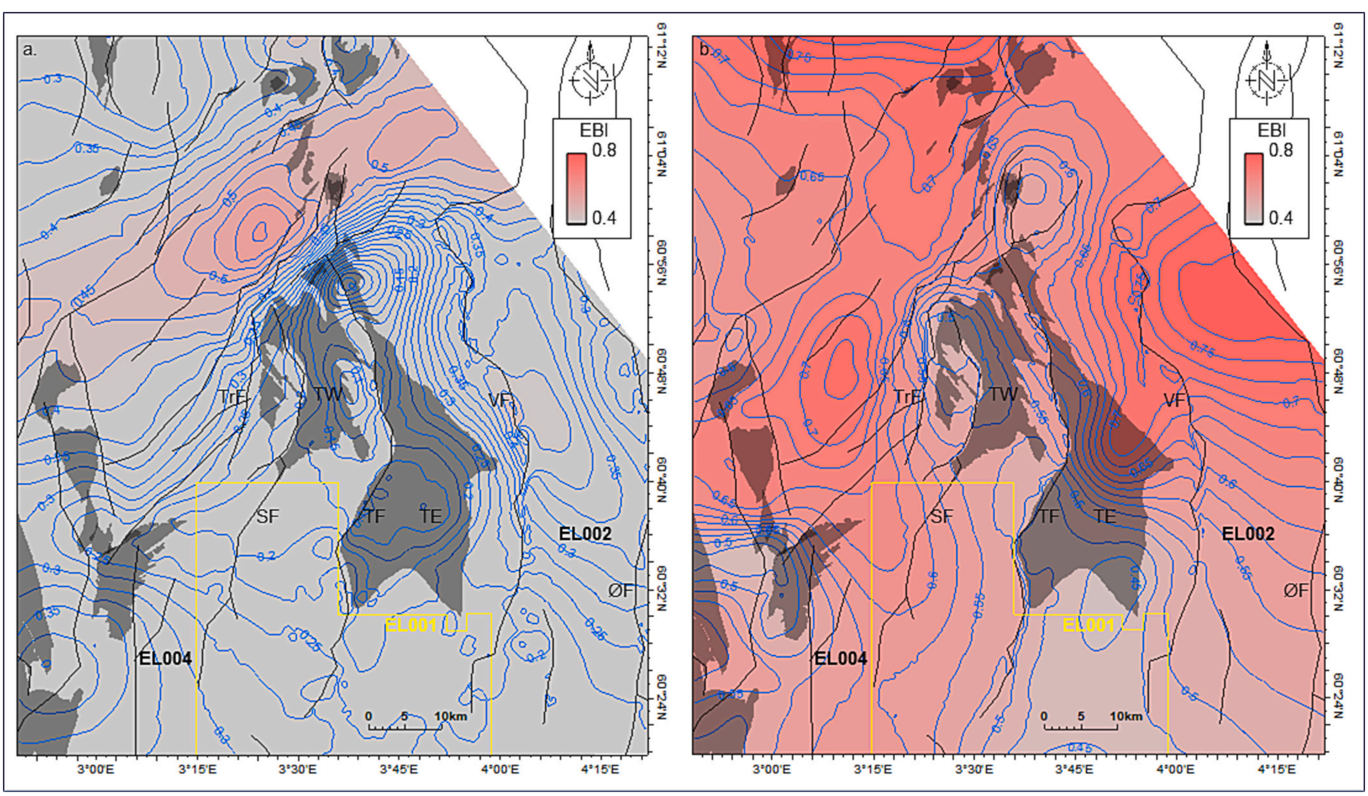

Fig. 2. Figures depict the distribution of brittleness indices based on elastic properties in the Draupne (a) and lower Drake (b) Formations, showcasing the lateral variability in the northern North Sea area. The color scale remains consistent for both figures, enabling direct comparison. The major and minor faults are represented by black lines, denoted as TrF (Troll fault), SF (Svartalv fault), TF (Tusse fault), VF (Vette fault), and ØF (Øygarden fault). Additionally, the first carbon capture and storage (CCS) license in the Horda Platform area is indicated by the yellow polygon (EL001). Two additional licenses (EL002 and EL004) for CO_2 storage have been granted in the vicinity, located east and west of the first exploitation license EL001, respectively. The grey-shaded polygons highlight the hydrocarbon fields (TE – Troll east; TW – Troll west) and discoveries within the study area. (For interpretation of the references to color in this figure legend, the reader is referred to the web version of this article.)

compacted Draupne caprock has lower BI than the Drake. Additionally, spatial variation of individual caprock shales has been identified, possibly because of structural orientation during paleo-depositional setup for that same shale unit. However, within the CCS licensed areas, the brittleness values were low to medium, indicating relatively better top seals.

Although the Draupne shale poses lower BI (ductile) compared to Drake shale, a Mohr-Coulomb failure plot in a specific well location of both caprock shales in in-situ stress state conditions indicated Drake caprock shale failure chances are lower than the Draupne caprock shale (Rahman et al., 2022c). The brittle Drake shale has higher cohesive strength and hence has lower failure risks. This indicates a negative relationship between brittleness and failure risks, where the higher the BI, the lower the chances of failure. However, the BI and failure relation is opposite, where lower BI indicated lower chances of failure in any injection-induced stress changes. This also signified the limitation of BI as the only caprock failure indicator. Therefore, the OASIS project suggests an interdisciplinary approach where initial BI estimation is a quick tool to interpret caprock strength properties qualitatively. Further analysis is needed to quantify the integrity, as illustrated in the next section.

3.2. Seismic attributes analysis and inversion of seismic data

Seismic analysis plays a crucial role in understanding the geometry of reservoirs, identifying potential traps, and predicting the lateral migration of CO_2. It helps detect faults and gas chimneys and delineate impermeable shale layers. Spectral decomposition attributes provide valuable insights into features such as paleo-channels and lateral facies changes (Fawad and Mondol, 2019). In the OASIS project, the seismic cube GN1101 underwent spectral decomposition analysis using the Continuous Wavelet Transform (CWT) method using the "Mexican Hat" wavelet. The analysis produced cubes with frequencies of 20, 40, 60, and 80 Hz. Additionally, a "Dip Steered Similarity" attribute cube was generated, using parameters of maximum dip set at 250 μs/m and delta dip at 10 μs/m, with an average statistic output. To further assess lithology, faults, and fractures in the Horda Platform area of the northern North Sea, several post-stack seismic attributes were generated, including envelope, sweetness, and variance (Rahman et al., 2022b; Rahman et al., 2022c). These attributes aid in understanding the spatial variations within the area.

The prestack inversion technique is highly valuable as it provides crucial information such as acoustic impedance, density, and velocities (Vp and Vs). These properties are essential in predicting reservoir parameters like porosity and shale volume. In the context of the OASIS project, a prestack simultaneous inversion was conducted to understand better the subsurface geology (Fawad et al., 2021a). The process involved five partial stacks, covering angles of 0–10°, 10–20°, 20–30°, 30–40°, and 40–50°. Prior to inversion, a preconditioning alignment of traces was performed using the non-rigid method (NRM). Statistical wavelets were extracted from all five partial stacks, and the seismic data was tied to the wells (32/2–1 and 32/4–1) within the seismic volume (GN1101). The default linear regressions between acoustic impedance and shear wave impedance and acoustic impedance and density were applied. The inversion analysis along the wellbore yielded reasonable results, with only minor errors observed in the shallow Nordland Group. Ultimately, simultaneous inversion was executed on the partial stacks, producing cubes of acoustic impedance (Zp), P- to S-wave velocity ratio (Vp/Vs), and Density (RHOB).

The seismic inversion process generates valuable properties such as acoustic impedance (AI), P- to S-wave ratio (Vp/Vs), and density (ρ) cubes. These properties play a crucial role in estimating geomechanical properties like Young's modulus (E) and Poisson's ratio (ν), which are essential for rock characterization (Fawad et al., 2021b) (Fig. 3c&d). The dynamic E is later converted into static by using a function wherein the shallow section $E_{static} \approx 1/5E_{dynamic}$, and deeper interval $E_{static} \approx 1/3E_{dynamic}$ have been implemented (Herwanger and Koutsabeloulis, 2011). Static ν is assumed to be equal to the dynamic ν ($\nu_{static} \approx \nu_{dynamic}$).

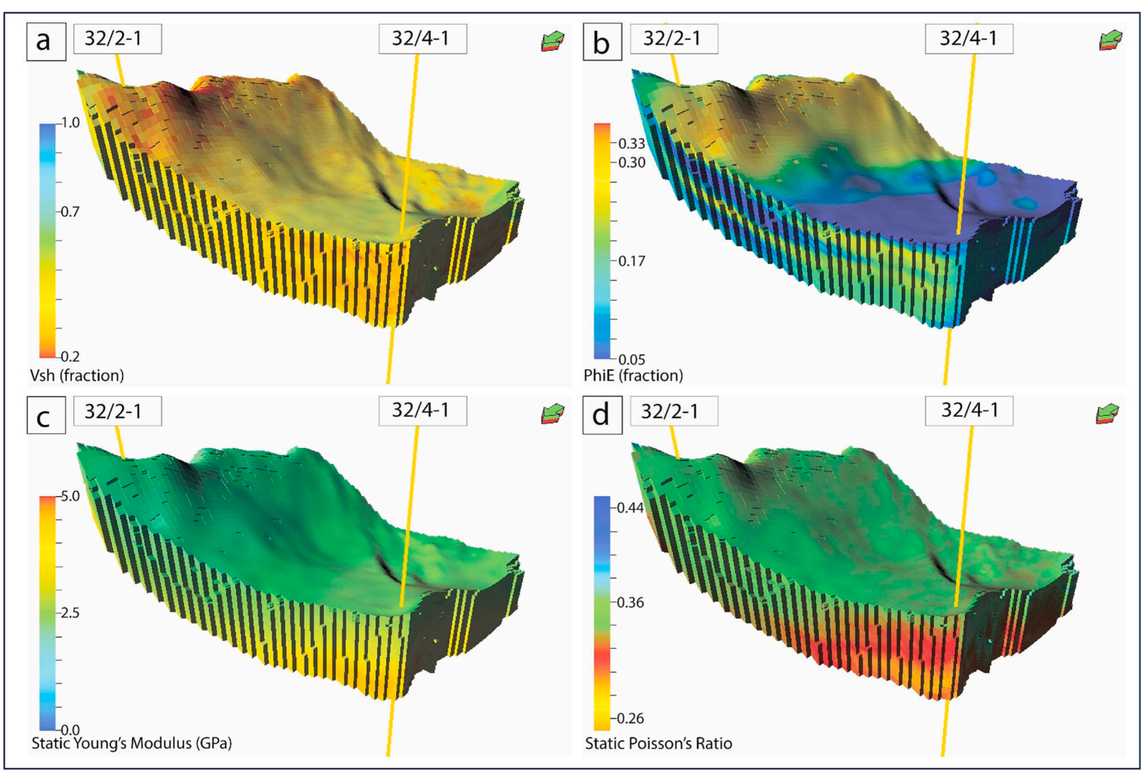

Fig. 3. Petrophysical and geomechanical properties estimated using inverted seismic cubes illustrate the lateral and vertical changes of (a) volume of shale (V_{sh}), (b) porosity (phi), (c) static Young's modulus, and (d) static Poisson's ratio (adapted from Fawad et al., 2021b).

Additional properties, such as the volume of shale (V_{sh}) and porosity (Phi) cubes, are also estimated using the relation proposed by Fawad and Mondol (2021a) (Fig. 3a&b). All these property cubes can be directly imported into reservoir/geomechanical models.

To ensure the effective monitoring of CO_2 storage sites, it is necessary to observe the movement of the injected CO_2 plume. This monitoring helps detect any potential leakage during and after the CO_2 injection process. In the OASIS project, a new rock physics model was developed for CO_2 plume monitoring (Fawad and Mondol, 2022). This model utilizes prestack seismic inverted properties to estimate the time-lapse CO_2 saturation and potential pressure changes within the CO_2 storage reservoir. Fig. 4 illustrates how this method effectively delineates the CO_2 plume, estimates its saturation levels, and identifies pressure changes using a combination of AI and Vp/Vs obtained from time-lapse or 4D seismic data.

In addition to the previously mentioned monitoring techniques, the OASIS project introduced a combined approach involving seismic and electromagnetic surveys to monitor CO_2 storage sites effectively (Fawad and Mondol, 2021b). This method aims to outline the CO_2 plume and determine gas saturation within a saline reservoir over the entire operational lifespan of the storage site (Fig. 5). These monitoring techniques can help monitor CO_2 plume's lateral and vertical migrations in the subsurface and provide reliable control over CO_2 injection and sequestration processes.

3.3. Modeling

OASIS project focuses on two modeling approaches; the first is a quick analytical solution to evaluate top seal (caprock and fault) structural reliability (Rahman et al., 2021), followed by 3D field-scale numerical simulation for geomechanical risk assessment (Rahman, 2022). In the initial stages of any fluid injection project, the analytical solution can support the project decision and play a vital role in the project's progress.

3.3.1. Analytical solution

The OASIS project evaluated fault and caprock shale structural reliability using the Mohr-Coulomb criteria-based analytical solution. This method is extensively used for geotechnical engineering purposes. However, the OASIS project first introduced it for subsurface top seal structural reliability assessment. Fault stability assessment has always been challenging because of the difficulty of accurately interpreting the subsurface fault architecture and fault-zone rock strength properties using seismic data. Seismic interpreted faults are often highly uncertain due to the low resolution (detect sub-seismic faults). Additionally, wireline logs through faults are rare because very few wells in a basin are drilling through the faults. Considering these uncertainties, a scenario-based approach would be a better solution than deterministic methods; hence, this study used four scenario-based assessments, as illustrated in Fig. 6 (Rahman et al., 2021). Based on the geological understanding of each case, a likelihood number has been assigned. Finally, an event tree approach has been applied to estimate the system failure of the structure. One great advantage of using the event tree method is that it considered all the possible cases by following an integration where the less probable but riskier cohesionless fault scenario (i.e., case 1 in Fig. 6) influenced the overall system failures. Furthermore, a single fault system failure value instead of different case outputs might help to make project decisions. According to this analysis, the Vette fault is structurally stable, indicating it has sealing potential for CO_2 injection into the Alpha structure in the Smeaheia area. This method can be utilized to evaluate any faults sealing potentials before and after fluid injection scenarios. Additionally, the input parameters sensitivity outcomes indicated the most influential property for that fault, which allowed the project team to dig deeper before running the field-scale geomechanical simulation (Rahman et al., 2021).

Like fault sealing analysis, caprock stability assessment in both Smeaheia (EL002) and Aurora (EL001) licenses from the northern North Sea have been evaluated. A comparative analysis between the shallower Draupne (Smeaheia) and deeper Drake (Aurora) caprock shales has also been carried out. Two scenarios, in-situ stress and after fluid injection-induced pressure increase, have been considered for modeling. Based on the lithological variation, Drake shale is divided into upper and lower Drake units. Overall, all the caprocks showed reliable top sealing potential where the Drake (Upper and lower units) exhibited higher reliability under initial stress state conditions compared to the Draupne shale, regardless of the variance in soft clay minerals percentage

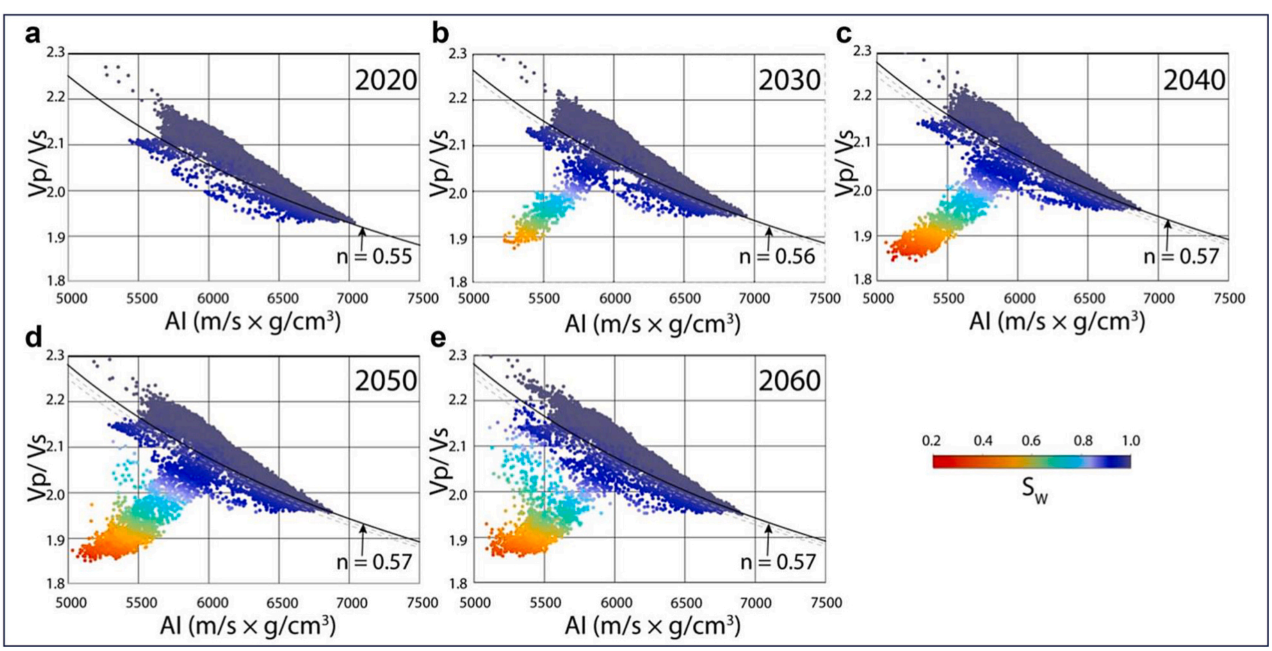

Fig. 4. The results of the updated AI versus Vp/Vs ratio rock physics model, showcasing data points representing the surface of the top Sognefjord sandstone. The data points are color-coded based on CO_2 saturation, representing the years (a) 2020, (b) 2030, (c) 2040, (d) 2050, and (e) 2060. The figure also includes the position of the brine-saturated line, along with the corresponding 'n' value. The information in the figure caption has been adapted from Fawad and Mondol (2022).

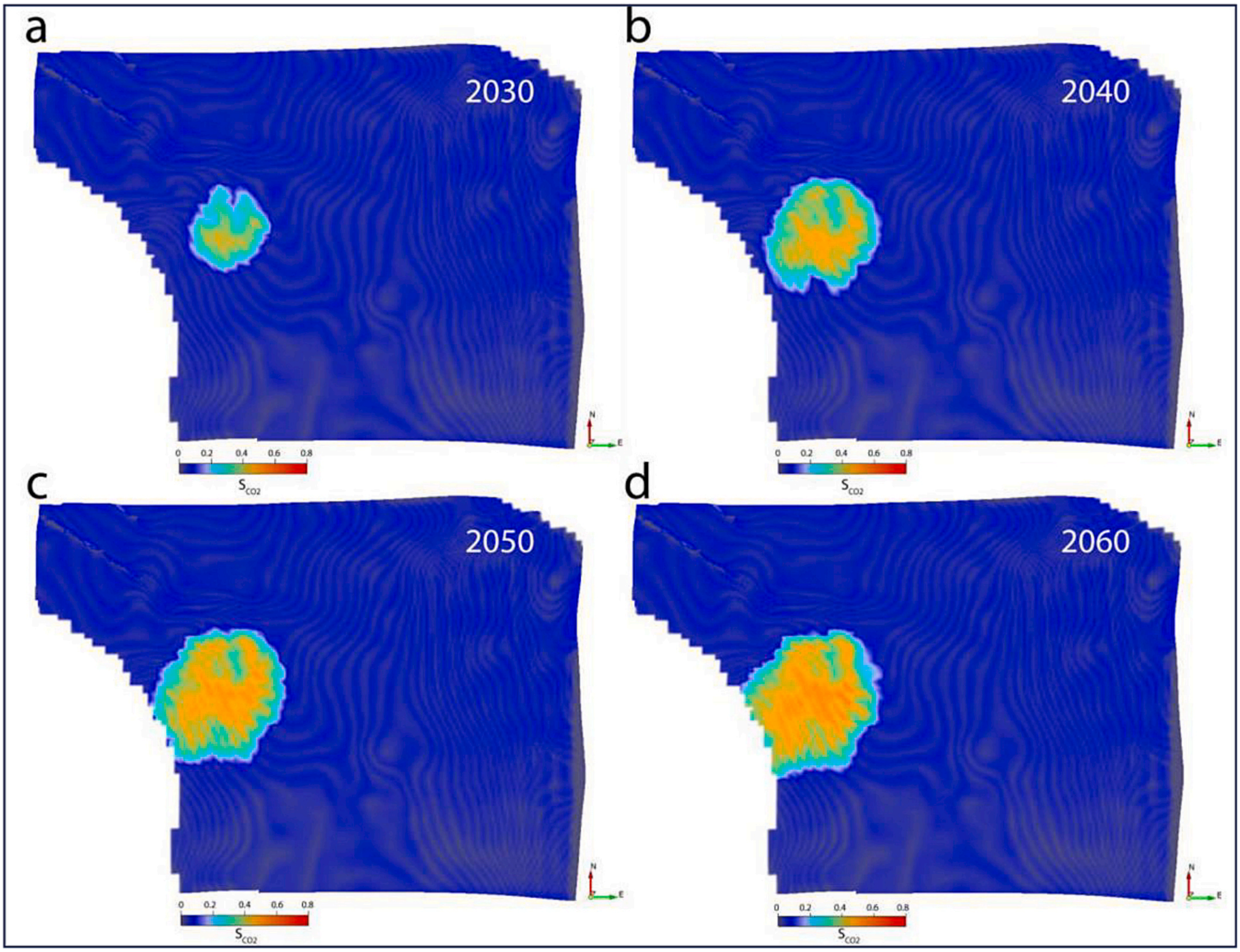

Fig. 5. CO_2 plume on top of the reservoir depth surface illustrated the saturation variation and lateral distribution with different injection periods (a) 2030, (b) 2040, (c) 2050, and (d) 2060 (adapted from Fawad and Mondol, 2021b).

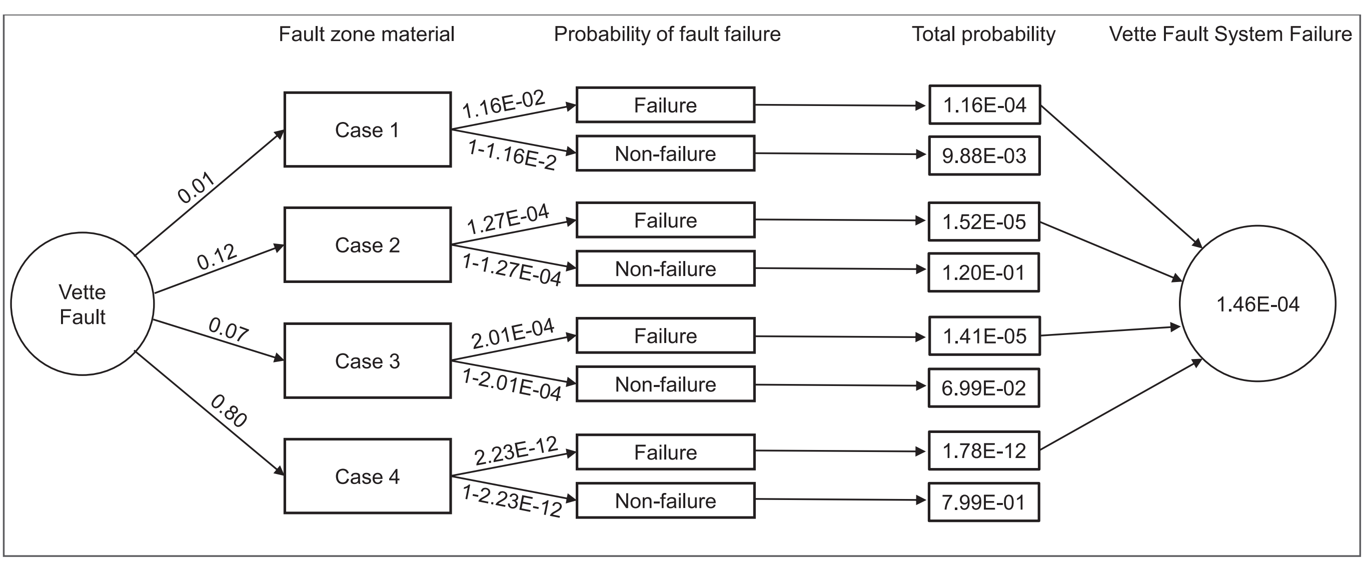

Fig. 6. Estimating Vette fault system failure using the event tree method (adapted from Rahman et al., 2021).

(Rahman et al., 2022b; Rahman et al., 2020). A positive increasing trend was observed between cohesion strength and reliability index, where reliability increases significantly with increasing shale cohesion (Fig. 7a). On the contrary, bulk clay mineralogy illustrated a negative relation with the reliability index (Fig. 7b). However, the reliability index change in theoretical failure case is insignificant compared to the initial stress-state condition (Fig. 7).

According to Rahman et al. (2022d), the mechanically compacted Draupne shale caprock integrity has been influenced mainly by the principal stresses. In contrast, the chemically compacted Drake shale has been influenced by the rock strength (i.e., cohesion). These indicated that comparing two compactions domain shales is not worth it; instead, evaluating any caprock shale diagenetic history is more valuable. For example, Fig. 7 illustrated that the probabilistic failure value did not directly correlate with ductile clay mineral percentages but instead relied on the caprock's strength property, such as cohesion, with a positive correlation. Compaction processes significantly varied depending on the clay percentage and changed the cohesion accordingly.

These findings underscore the significance of considering rock properties and stress conditions in assessing the probability of caprock shale failure. By shedding light on the behavior of caprock shales under different conditions, our study contributes to the ongoing research in this field. Furthermore, it expands our understanding of the factors influencing caprock failure and emphasizes the importance of incorporating these considerations into risk assessment and mitigation strategies. This finding also indicates the need for further investigation of the relation of caprock shale mineralogy, brittleness, and structural failure potentials in injection-induced pressure increase scenarios.

3.3.2. Field-scale numerical solution

The 3D field-scale geomechanical model was simulated to evaluate the injection-induced stress-strain changes of rocks. As the OASIS project focuses on cap and overburden rocks, the influence of anisotropic overburden rocks on stress-strain simulation has been analyzed. However, the proposed workflow (Fig. 8) does not include reservoir simulation, which will be an important addition to the existing workflow where the containment risks, optimum capacity, and injectivity rate have been estimated and assessed. The detailed modeling process (building and calibration) has not been described here. For details, authors advised to read Rahman et al. (2022a). In this paper, we discuss only the key findings.

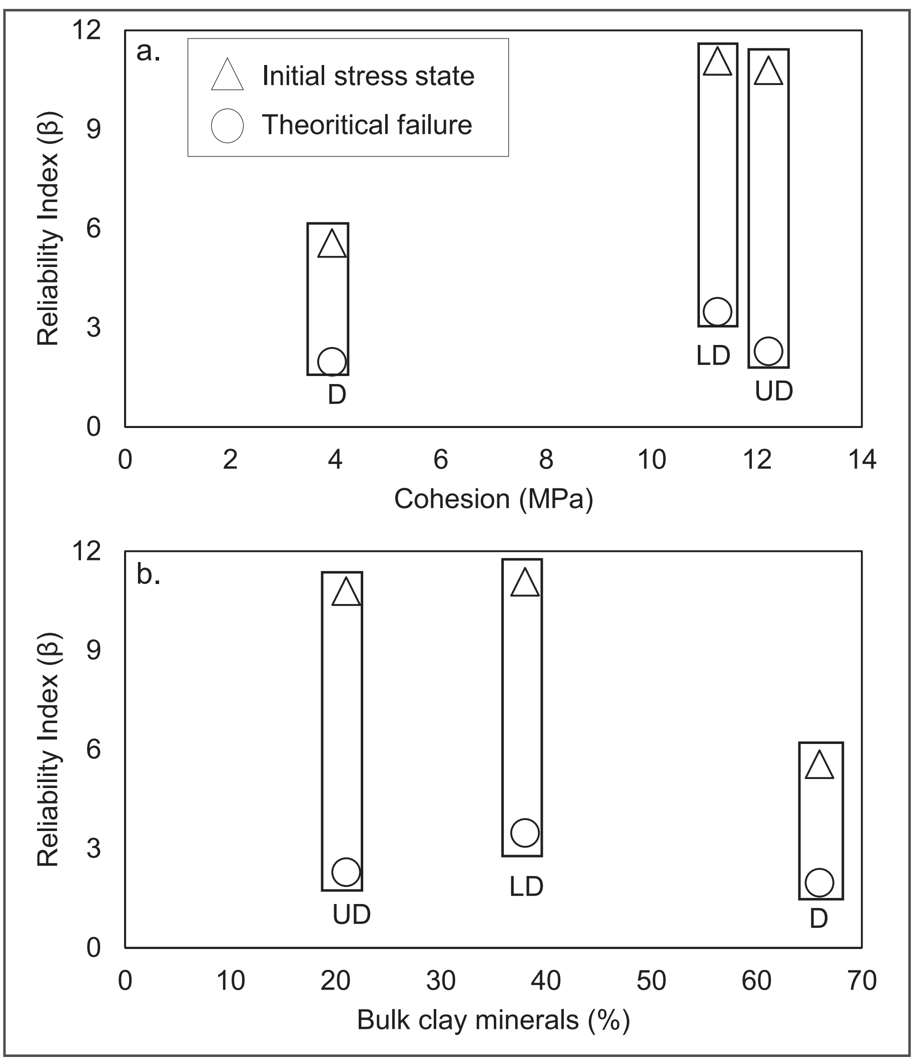

Fig. 7. This figure provides insights into the connection between two key factors, reliability index, and cohesion (a), as well as bulk clay mineralogy (b), in relation to caprock shale samples obtained from the northern North Sea. The shale samples investigated in this study are Draupne (D), upper Drake (UD), and lower Drake (LD). The figure also showcases the contrast in reliability between the in-situ state stress and a theoretical failure scenario. The reliability index and cohesion values for the Draupne shale are derived from a study conducted by Rahman et al. (2020), while the information on bulk clay mineralogy is based on Rahman et al. (2022b). The data presented here has been modified from Rahman et al. (2022d).

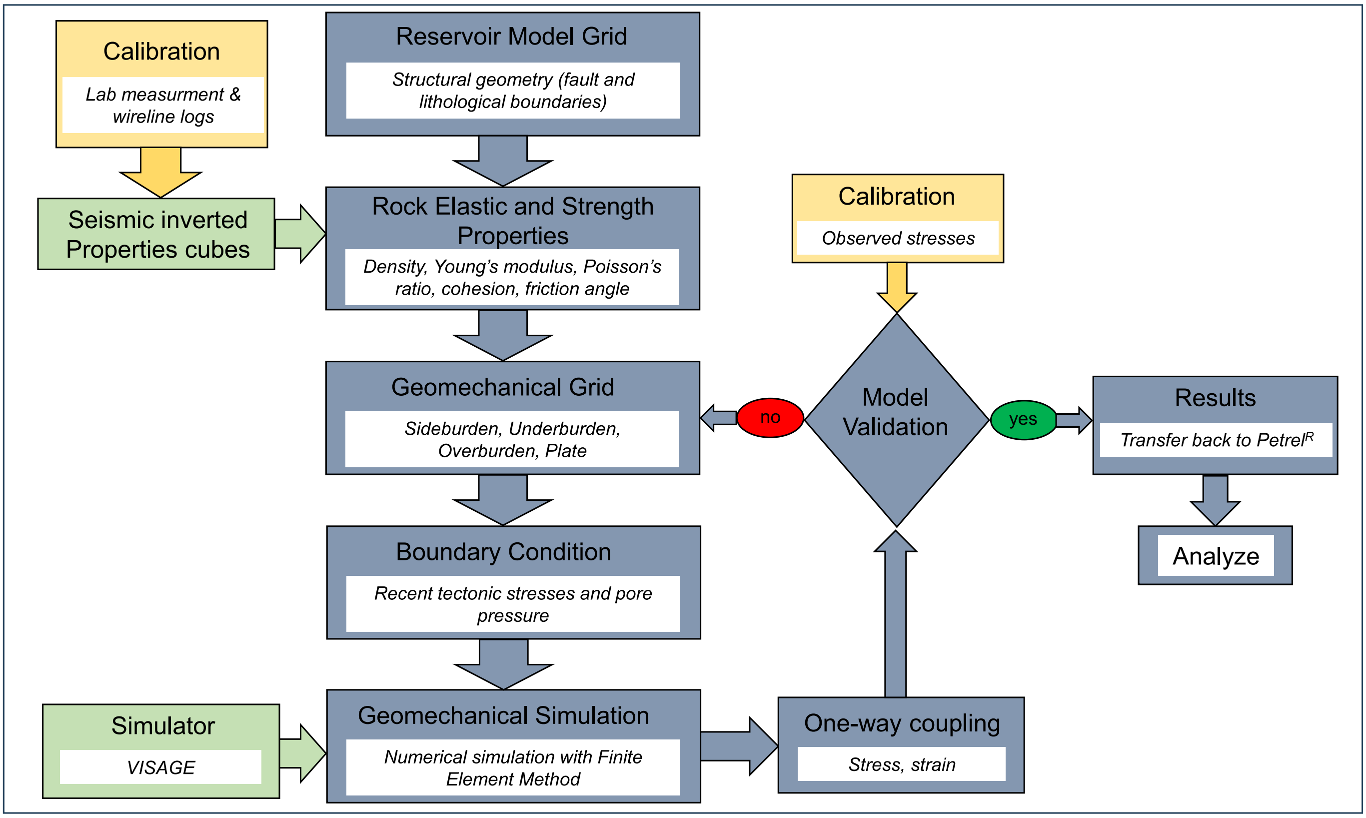

Fig. 8. Field-scale geomechanical simulation workflow (adapted from Rahman et al., 2022a).

3.4. *Influence of overburden*

In the field-scale mechanical simulation, the common practice is to have an isotropic overburden with no structural control. A wireline log-based average property has been interpolated throughout the overburden interval. However, the overburden geology is much more complex, with significant temporal and spatial variations (Rahman et al., 2022a). Additionally, in any fluid injection project site characterization, the overburden mechanical risks are critical and need to be evaluated before any injection using field-scale models with appropriate properties of the surrounding rocks to prevent any failure incidence. Generalized the overburden intervals in injection sites might over-or underestimate the rock failure risks, misleading the estimation of total capacity and injectivity. Therefore, properly characterizing the overburden properties is vital in field-scale simulation for injection site evaluation. The OASIS project evaluated the effect by introducing two field-scale models from the Smeaheia site in the northern North Sea. Fig. 9 illustrates the vertical deformation of the Smeaheia site after 50 years of injection, where the left figures demonstrated a conventional isotropic overburden model while the figures on the right revealed the new anisotropic properties with a structural control. A significant difference was observed between the models, where the vertical seafloor deformation almost doubled in the isotropic model compared to the anisotropic one (Fig. 9).

The significant influence of caprock properties on rock displacement becomes crucial because the traditional way of including simplified overburden properties in the geomechanical model might lead to an inaccurate estimation of the potential of storage and injectivity of any site. However, this study assessed only the stress-strain geomechanical deformations in a specific injection rate and time. Compared to the anisotropic case, the comparative investigation suggested a significant overestimation of potential geomechanical risks in the simple isotropic overburden structural model. If we quantify the risks, we might lose half of our safe storage capacity, influencing the project decision considerably. Additionally, seafloor installation (i.e., wellhead) might be at risk due to over-estimation of seafloor heave, resulting in a possible instability risk affecting the site-specific decision-making. However, despite the importance of overburden uncertainties, the attempt to quantify overburden uncertainties, especially for geomechanics consideration has been mostly discounted for decision-making in CCS management.

4. The proposed interdisciplinary approach

A few more challenges in the geomechanical assessment are accurately delineating in-situ physical properties such as temperature, in-situ stresses, and pressure and predicting more specific injection-induced mechanical behaviors, including subsidence/heave. However, there are many examples of incorrect engineering estimation. For instance, ~6 m seafloor subsidence in the Ekofisk field (Wikipedia, 2023) indicated a failure to predict subsidence during the development phase. Therefore, an integrated modeling approach is required for a better risk assessment.

The geomechanical model has to deal with the simultaneous assessment of temperature, pressure, stress, and chemical (THMC) changes. The modeling becomes complex when dealing with the lack of relevant subsurface information. Moreover, the sensitive phase behavior of CO_2 will complicate the modeling process further in CCS projects. For instance, supercritical CO_2 is in a liquid phase but behaves like a gas, which is very difficult to simulate in models. The buoyancy pressure and solubility rate of CO_2 are also faster and different than hydrocarbon fluids. Furthermore, depending on the local in-situ stress conditions (that may induce seismicity with changing pore pressure), a site-specific characterization and associated geomechanical analysis are suggested (Fan et al., 2016).

Generally, it is well understood that any subsurface fluid injection site containment risk estimation requires an integrated approach

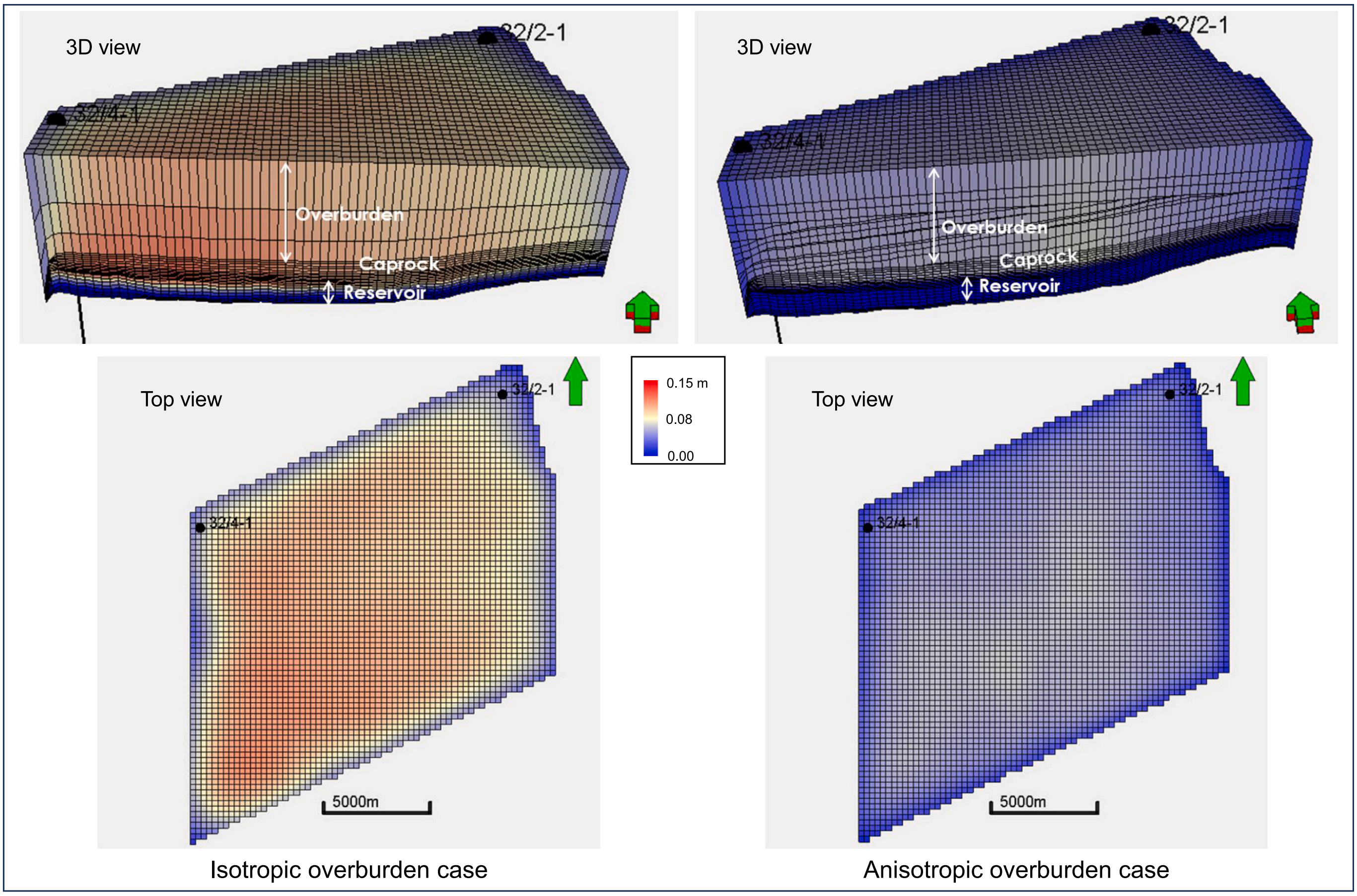

Fig. 9. Comparison between the vertical deformation of rock after 50 years of CO_2 injection within the Smeaheia reservoir in the northern North Sea. Significant spatial and vertical variations were observed between the models. The alpha (32/4-1) and Beta (32/2-1) well locations are shown as references (modified after Rahman et al., 2022a).

(Rodriguez-Herrera et al., 2014). Considering the data uncertainties and challenges, the OASIS project was focused on improving seal integrity knowledge by building a robust geomechanical model integrating all the available data (Fig. 10). Although the OASIS project was focused on site-specific containment risk assessment by simulating one-way geomechanical modeling, this workflow implemented other two parameters such as capacity and injectivity estimation by providing two-way coupling between reservoir modeling and mechanical simulation.

According to the workflow, a quick 1D analytical assessment of rock stability can qualitatively evaluate the containment risks. Additionally, the sensitivity of the input parameters allows us to identify the most influential properties which need further assessment to reduce uncertainty for numerical simulation. Also, geological and geophysical analyses define the structural and stratigraphic framework for reservoir modeling. Lastly, combining all the assessments a 3D field-scale reservoir model has been developed for estimating optimal capacity, optimal injectivity, and surface deformation by coupling hydraulic and mechanical simulations.

5. Conclusions

This research attempts to improve the knowledge gap related to top seal integrity assessment. To our knowledge, the proposed workflow to characterize caprock, faults, and overburden stress-related risks has novelty. This research also indicates the effectiveness of these methods and approaches. The uniqueness of these processes is described below:

- The proposed interdisciplinary workflow for any fluid injection site characterization is required because of the complex nature of rock and behavior under stress changes.
- The brittleness indices of rock are a qualitative indication of rock behavior under stress. However, further analyses are required to quantify the rock integrity due to the complex relation of rock strength and brittleness indices with rock failure.
- Seismic attributes provide valuable information about lateral facies changes and faults' presence and vertical extent. Inversion of 3D seismic data can yield reservoir properties (such as porosity and shale volume) and geomechanical parameters (such as Young's modulus and Poisson's Ratio) cubes to further use in the reservoir or geomechanical modeling. Additionally, new monitoring techniques will help to monitor CO_2 plume lateral and vertical movements during and after injection.
- The subsurface structural reliability analytical model is an effective tool for quickly evaluating the failure potential and model input properties sensitivity.
- A 3D field-scale geomechanical model for stress-induced risk assessment needs to include site characterization assessment. However, a coupled fluid flow model is required to estimate the optimum capacity and injectivity rate before any real injections.

Although the OASIS project focuses on CO_2 storage site characterization in the northern North Sea, the proposed interdisciplinary workflow can be applied globally to any injection site characterization of CO_2 and hydrogen storage, wastewater disposal, and hydraulic fracking for unconventional hydrocarbon extraction.

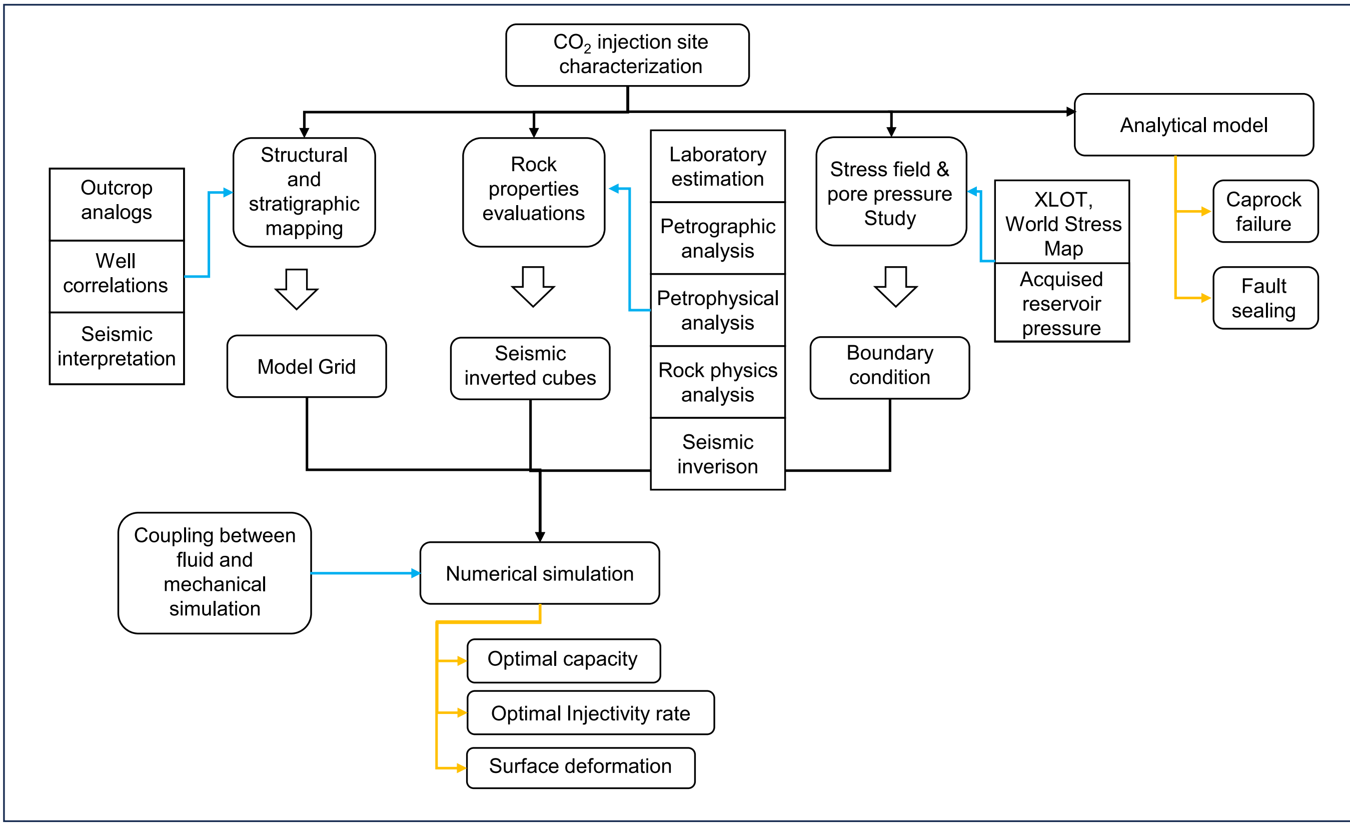

Fig. 10. The workflow illustrated the interdisciplinary steps to characterize CO_2 injection sites using the available data. Note that the sky-blue arrows represent input, the black arrows show intermediate processes, and the orange arrows represent output. (For interpretation of the references to color in this figure legend, the reader is referred to the web version of this article.)

CrediT authorship contribution statement

Md Jamilur Rahman: Conceptualization, Methodology, Formal analysis, Investigation, Writing – original draft, Writing – review & editing, Visualization, Validation

Manzar Fawad: Validation, Writing –review & editing

Nazmul Haque Mondol: Validation, Writing – review & editing, Supervision, Project administration, Funding acquisition

CRediT authorship contribution statement

Md Jamilur Rahman: Conceptualization, Formal analysis, Investigation, Methodology, Validation, Visualization, Writing – original draft, Writing – review & editing. **Manzar Fawad:** Formal analysis, Validation, Writing – review & editing. **Nazmul Haque Mondol:** Funding acquisition, Project administration, Supervision, Validation, Writing – review & editing.

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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