Potential leakage mechanisms and their relevance to CO$_2$ storage site risk assessment and safe operations

FME SUCCESS Synthesis report Volume 2

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Carbon Capture and Storage (CCS) is considered an essential mitigation strategy in order to reduce anthropogenic CO₂ emissions. To meet the 2°C target set in the Paris Agreement, decarbonization of the global power sector by the 2030s and the heavy industry sector beyond that is critical. CCS is currently the only option for decarbonizing the steel, chemical and cement industries.

CCS is a proven method (e.g. at Sleipner, Snøhvit, In Salah, Weyburn, Boundary Dam, Quest). There are remaining technical challenges related to upscaling, however, and cost is a critical factor in large-scale deployment of CCS.

In order to stimulate relevant research, the Norwegian Research Council has established a scheme of Centers for Environment-friendly Energy Research (FME) to develop expertise and promote innovation by focusing on long-term research in selected areas of environment-friendly energy, including CCS.

The FME SUCCESS center
The SUCCESS center for Subsurface CO₂ storage was awarded FME status in 2009 and was formally inaugurated on 1 January 2010.

Key to public acceptance and successful deployment of CCS, the FME SUCCESS center focuses on effective and safe storage of CO₂. To meet the regulatory requirements for Measurement, Monitoring and Verification (MMV), the SUCCESS center seeks to provide a sound scientific base for CO₂ injection, storage and monitoring in order to fill gaps in strategic knowledge, and to provide a system for learning and development of new expertise. Such knowledge is vital in order to ensure conformance (concordance between observed and predicted behavior), containment (proving storage performance in terms of security of CO₂ retention) and contingency (leakage quantification and environmental impacts).

The following objectives were defined in the FME SUCCESS application:
- To improve our understanding and ability to quantify reactions and flow in carbon storage.
- To develop advanced modeling tools for multiphase flow and reaction.
- To investigate the integrity of sealing materials, and test their retention capacity.
- To improve our understanding and develop new models for the relationship between saturation, flow and geomechanical response.
- To improve our understanding and develop new models for geochemical and geomechanical interactions.
- To improve our understanding and modeling tools for flow and reaction in faults and fractures.
- To test, calibrate and develop new monitoring techniques and instrumentation.
- To improve the understanding of shallow marine processes and the ecological impact of CO₂ exposure, and develop marine monitoring methods.
- To reduce risk and uncertainties in sub-surface CO₂ storage.
- To facilitate extensive and high-quality education on CO₂ storage.
One of the strengths of the FME SUCCESS center is its expertise within fundamental, theoretical research, which is internationally recognized; the center hence focuses on basic research, interpreting the results of field and laboratory experiments in order to predict the long-term effects of CO$_2$ storage. In particular, the center has used the theoretical platform to address critical and relevant scientific issues related to CO$_2$ storage.

Upon inauguration, the SUCCESS center was organized into six scientific work packages and one educational work package.

**Mid-term evaluation**

In 2013, the Norwegian Research Council conducted a mid-term evaluation of the FME centers. The mid-term evaluation of the SUCCESS center concluded that the center needed to undertake major changes in the organization and operational structure to secure integration and industry relevance.

Following the recommendations of the mid-term evaluation, the SUCCESS center reorganized the scientific activities into three work packages:

- Work Package 1: Reservoir
- Work Package 2: Containment
- Work Package 3: Monitoring

An integration Work Package, WP0, was also established for the final two year-period of the center. WP0 aimed to test and verify new knowledge and methodology developed at the SUCCESS center in connection with two case studies. The Skade and Johansen formations were originally chosen as case studies. The Johansen Formation was later replaced by the Smeaheia project case, which is the selected reservoir candidate for Norwegian full-scale demo project.

**Final reports**

As part of the center’s scientific reporting, the center’s partners and board agreed that a set of reports would be written and
summarize the major scientific findings and achievements. These reports have been referred to as Long-term Deliverables (LTD).

Knowledge and lessons from the two field pilots, Snøhvit and Sleipner, have been synthesized in separate summary reports (Volume 6 and 7). Lessons from the Longyearbyen CO\textsubscript{2} Lab, which has been an important test site for the SUCCESS center, have been and will be published in dedicated summary volumes of scientific journals.

The case studies on the Smeaheia fault block (deep, confined reservoir) and the Skade Formation (shallow, saline aquifer) in the North Sea are presented in separate reports in order to demonstrate the value of the results achieved at the SUCCESS center and associated projects, and determine how they can be applied to better quantify the storage feasibility of untested aquifers. They allow testing of the lessons and knowledge from the Snøhvit and Sleipner field pilots, and may constrain the range and use of the methods and models developed.

**Long-term deliverables**

The LTD reports (5) include the SUCCESS center’s final report on the above-mentioned deliverables. They aim to synthesize the results and findings of the SUCCESS center, and directly address the objectives of the SUCCESS center (see the figure below).

The LTD reports cover the following topics:

- **Storage capability (Volume 1)**
  - This report summarizes the SUCCESS center’s work on storage capability, which is the ability of a formation to safely store CO\textsubscript{2}. An important objective of this center has been to identify geological factors and the hydro-geomechanical processes that are most important for determining storage capability. The most important factor is whether the storage reservoir is open or closed.

- **Leakage risks (Volume 2)**
  - Summarizing the results from field, experimental and theoretical studies of potential leakage mechanisms and their relevance to CO\textsubscript{2} storage site risk assessment, this report demonstrates that viscous deformation of the shales can play an important role in their ability to keep CO\textsubscript{2} contained and that material properties and their dynamic behavior in response to the stress introduced by CO\textsubscript{2} injection need to be evaluated in order to safeguard operations.

- **Injectivity (Volume 3)**
  - This report presents experimental and computational results that have enhanced our understanding of reservoir injectivity, including a basic understanding of mechanisms, quantification of the expected impact, model calibration and case specific implications. A main outcome is a workflow that includes new computational tools, new geochemical and geomechanical experimental design/data and research-based advice.

- **Geophysical monitoring (Volume 4)**
  - The geophysical monitoring report summarizes the SUCCESS center’s work on rock physics related to pore pressure and saturation and estimating these two parameters via geophysical monitoring. By estimating their spatiotemporal distribution, we can monitor the migration of injected CO\textsubscript{2} and determine whether the containment of storage complex is secure.

- **Marine monitoring (Volume 5)**
  - This report synthesizes relevant knowledge and data regarding marine monitoring methods and strategies for inorganic carbon in the water column, based on modeling and observational work. A cost-effective strategy for a marine monitoring program should optimize the probability of detecting a leak.

*Christian Hermanrud (SUCCESS funded Prof II position, UiB) with some of his master students*
Relevance of work
The collective work of the SUCCESS center addresses various groups of stakeholders and the reporting structure is relevant to different communities. The report on storage capability is particularly relevant to storage site selection and Norwegian CO₂ storage capacity estimates, based on better constrained trapping efficiency and immobilization potential. The leakage risks report addresses important issues regarding safe operation of CO₂ storage and risk management. The report on injectivity provides valuable knowledge on the planning of CO₂ operations and reservoir utilization. Finally, there are two reports on monitoring: the report on geophysical monitoring addresses methods for measurement, monitoring and verification (MMV) of the subsurface; while the report on marine monitoring is particularly relevant to risk management and mitigation in the event of leakage to the water column.

Future work and recommendations
CO₂ storage has been successfully demonstrated at Million-tonne scale, but needs to be ramped up to Giga-tonne scale in order to achieve global emissions reductions targets. A shown in the report on Large-scale Storage of CO₂ on the Norwegian Shelf, there are no technical showstoppers for ramping up CO₂ storage (Tangen at al., 2014). However, ramping up to Giga-tonne scale requires 1) better estimate of storage capacity, 2) better pressure management strategies, and 3) smart methods for controlling and optimizing CO₂ injection (Nettvedt, A., pers. comm. * Mission innovation workshop*, 2017).

Better estimate of storage capacity requires more reliable forecasting of CO₂ migration and trapping processes, with range of uncertainties. This, in turn, requires improved physics and chemistry-based understanding of CO₂ flow and transport processes at multiple scales within heterogenous rock media.

Better pressure management strategies imply control on pressure limits at both near-well and reservoir scales and quantification of allowable pressurization. Consequently, better understanding of the effects of stress field, pressure history, reservoir/caprock heterogeneities, including faults and fractures, is needed.

Smart methods for controlling and optimizing CO₂ injection include effective control and handling of transmissivity, near-well geochemical processes, formation damage, etc. Well stimulation and next-generation well technologies need to be demonstrated to enable large-scale CO₂ injection. Future advances in CO₂ storage will likely occur at the interface between industry and academia and be coupled to the execution of ramp-up CO₂ storage projects.

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**Table of contents**

The FME SUCCESS center on CO₂ storage .................................................. 2
Executive Summary .............................................................................. 8
Introduction .......................................................................................... 9
Leakage mechanisms ........................................................................... 12
  Seal capacity of caprock .................................................................. 12
  Erosion of well completing cement and corrosion of pipelines as possible leakage mechanisms .......................................................................................... 16
  Flow through existing faults and fracture networks .................. 17
  Induced tensile or shear failure of caprock .............................. 19
  Sand injections and risk of leakage .............................................. 21
  Other vertical focused fluid flow structures ................................ 21
Conclusion and recommendations ...................................................... 26
References ............................................................................................ 28

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Geological carbon capture and storage (CCS) is an emerging technology that has been designed to mitigate the impact of human activities on global warming. In order to achieve public acceptance of this technology, one needs to guarantee its safety for the environment and the population. Potential leakage of CO$_2$ from underground storage sites is one of the risks associated with CCS.

This report summarizes the results from field, experimental and theoretical studies of potential leakage mechanisms and their relevance to CO$_2$ storage site risk assessment and safe operations. We evaluated both the impact of pre-existing leakage pathways (e.g., faults and fracture networks, abandoned and former wells) and the possibility of triggering the formation of new leakage structures via hydraulic fracturing or porosity wave propagation during injection. Critical engineering parameters that might lead to reactivation or generation of a new leakage pathway and pressure limits were identified. A new mechanism of CO$_2$ plume movement, which produces localized fluid conduits is suggested. The rates of movement and likely breakthrough times are discussed. The flow properties of sealing rocks that are common to the Norwegian offshore reservoirs are summarized based on the results of laboratory measurements of capillary entry pressure and permeability. Our laboratory measurements show that shales exhibit a strong coupling between fluid flow and geomechanics. We show that viscous deformation of shales can play an important role in their ability to contain CO$_2$. Our results indicate that fluid flow mechanisms through shales are not fully understood and require further experimental and theoretical studies.

The report addresses potential leakage pathways as a knowledge support for site risk assessment. Based on our results, we have made suggestions for further development of the International Standards on Carbon Dioxide Capture, Transportation and Geological Storage such as ISO/DIS 27914.

"This report summarizes the results from field, experimental and theoretical studies of potential leakage mechanisms and their relevance to CO$_2$ storage site risk assessment and safe operations."
The role of CCS as an effective climate mitigation technology depends on our ability to securely store large volumes of carbon dioxide (CO₂) in geological formations for thousands of years. We know that oil and gas have been contained in underground reservoirs for much longer periods of time. Current experience from large-scale injection cases such as Sleipner, Snøhvit, and the CO₂-EOR projects in the USA, has confirmed that CO₂ can also be stored securely. Various trapping mechanisms like structural and stratigraphic barriers or dissolution and capillary forces work together in the subsurface to keep it from escaping back into the atmosphere. Nevertheless, as the CO₂ injected into geological reservoirs is lighter than the brine present in the rocks at pressure and temperature conditions that are typical of most reservoirs, it may leak through natural or man-made pathways, causing effects on e.g. drinking water and marine ecosystems. The total potential leakage and its extent depends on a number of parameters, including the injection rate, the proximity of the injection point to the leakage pathway, permeability of the pathway, the depth and thickness of the CO₂ storage reservoir, etc. Adequate geological, geophysical and geomechanical assessment of a potential CO₂ injection site is thus the key to safe operations. EU Directive 2009/31/EC requires that the potential for leakage from a storage complex must be characterized during assessment of a future site.

**Figure 1: Outline of possible leakage pathways for CO₂**
A number of research projects funded by the EU and other national schemes, including SACS, CO2CARE, and ECO2 have worked on identifying and characterizing various leakage mechanisms (see Fig. 1).

It is commonly observed that leakages can occur in abandoned or existing wells if they are poorly cemented or have faults in the casing or cement due to e.g. material corrosion and cement alteration (Birkholzer et al., 2011; Humez et al., 2011; Kutchko et al., 2007; Newell and Carey, 2013; Nordbotten et al., 2009). CO₂ may also leak due to a lack of a geological seal as a result of reactivation of faults and associated fracture networks (Alikarami et al., 2013; Jeanne et al., 2013; Pruess, 2005; Rutqvist et al., 2007), induced tensile or shear failure of the caprock (Gor et al., 2013; Huang et al., 2015; Rutqvist et al., 2011), diffusion through pore networks (Hou et al., 2012; Huq et al., 2017) or through seal bypass systems (Cartwright et al., 2007; Cevatoglu et al., 2015; Hermanrud et al., 2009; Räss et al., 2014; Tasiandas et al., 2016). Leakage in the pore network in shales is the least problematic of these, as the low permeability and relative permeability of the seal would imply a low velocity for the leaking fluids – so low that in most cases the CO₂ would be dissolved or react by forming mineral phases before it reaches the surface. Leakages through faults, fracture networks and wells can be rapid. Leakages in sand injections or other vertical focused fluid flow structures is also a concern where such structures are present.

The most common caprocks on reservoirs targeted for CO₂ storage are shales. The properties of shale have been studied in great detail during the past decade, given that shale is also an important source and reservoir rock in unconventional oil and gas production (e.g. Cassini et al., 2017; Chang and Zoback, 2009; Kwon et al., 2004; Makhnenko et al., 2017; Mondol et al., 2007; Rybacki et al., 2015). Shale permeability is a key parameter in both of these geo-engineering systems. There has hence been a strong focus on the properties and geochemical/geomechanical interactions that influence shale permeability. Burial and cementation can have a significant impact on shale permeability (e.g. Milliken et al., 2012). For example, a high calcite cement content may lead to lower permeabilities, while gas generation due to hydrocarbon maturation (if a shale reaches a temperature that is high enough) can re-open pore pathways, or even create new fractures, hence increasing permeability (e.g. Prince et al., 2011). The composition of shales does not always impact on its fluid flow properties. Specifically, Al Ismail and Zoback (2016) report a higher permeability for shales with a higher total organic content (TOC), but only for shales in which the porosity is mainly located in solid organics and is well connected. In their study of shales consisting mainly of calcite and clay in different ratios, the mineral content did not show a strong correlation with permeability, but a higher clay content resulted in a stronger dependence of permeability on effective confining stress.

In contrast, Metwally and Chesnokov (2011) report an increase in permeability with increasing quartz (and pyrite) content, a decline in permeability with increasing calcite and clay (especially illite) content, and no clear correlation with TOC. Ghanizadeh et al. (2013) studied different shales with varying TOC, quartz, calcite and clay content and reported that the shale composition had no clear effect on the permeability, or on the stress-dependence of the permeability. These apparent discrepancies likely reflect the fact that the very low permeability of shales is a result of a complex interplay of many different factors, where small differences can induce large effects.

Shales are strongly anisotropic, with clear...
layering due to alignment of clay minerals during deposition, which can be further enhanced by burial and diagenesis. With regards to fluid flow, this anisotropy results in a higher permeability for flow parallel to the layering. Metwally and Sondergeld (2011) report an anisotropy coefficient (the ratio of layer-parallel over layer-perpendicular permeability) of roughly 3–5 for tight gas shales. Bhandari et al. (2015) report a coefficient of ~40 for Barnett shales. The effective confining stress was not found to influence this value. Al Ismail et al. (2014) report anisotropy coefficients of two and three orders of magnitude, using He and CO₂ respectively, measured on Eagle Ford shales. The stronger anisotropy observed with CO₂ was related to the swelling of clay minerals. Ghanizadeh et al. (2014) report anisotropy coefficients in excess of one order of magnitude, with greater anisotropy for samples with higher clay contents.

Another important factor that influences shale flow properties is the effective stress, as shale compacts significantly as a result of both elastoplastic and time-dependent creep mechanisms. Such compaction leads to a decrease in pore or crack aperture, reducing the porosity and pore connectivity, and constricting flow. Conversely, when the effective stress decreases, elastic relaxation can lead to a widening of flow pathways, thus enhancing the permeability. As changes in the pore fluid pressure lead to changes in the effective stress, these changes can have significant effects on the shale permeability, and hence seal integrity. Accurate measurements of the mechanical properties of shales are an important component for determining how shale caprocks will react to changing fluid pressures. Experimental studies have demonstrated that time-dependent creep can be an important long-term mechanism, in addition to time-independent elastic and plastic deformation (Chang and Zoback, 2009; Räss et al., 2017; Sone and Zoback, 2014).

Accordingly, permeability measurements performed on shales under increasing effective confining stress have indeed shown permeability to be dependent on effective confining stress as a result of compaction (Bhandari et al., 2015; Chalmers et al., 2012; Dong et al., 2010; Ghanizadeh et al., 2014; Heller et al., 2014; Zhang et al., 2015; Zhang et al., 2016). Dong et al. (2010) and Zhang et al. (2015) report exponential correlations between shale permeability and effective confining stress, with exponential coefficients in the range of 0.005–0.123. As noted by Chalmers et al. (2012) and Ghanizadeh et al. (2014), mineralogy is an important factor that controls both permeability and the confining pressure dependence of permeability. Gutierrez et al. (2015) report continuous measurements of the stress-dependent permeability of a compacting Mancos shale sample. They show a two order of magnitude decrease in permeability when the effective mean stress increases from ~2 to ~60 MPa. This is highly consistent with the tenfold decrease in permeability, which Metwally and Sondergeld (2011) report for a 30 MPa increase in effective stress. In addition to this direct correlation between stress and permeability, creep effects on permeability are reported in the work of Chhatre et al. (2015). However, more measurements are required here in order to determine the effects of shale and fluid properties on creep.

In this report, we summarize the work that has been conducted at the FME SUCCESS center on understanding potential leakage processes. The next few chapters explain the main results and findings from field, laboratory and theoretical studies that describe major leakage mechanisms, critical factors for their assessment, and challenges associated with predictive modelling. The report concludes by summarizing our main conclusions and recommendations for future research and practice.

"In this report, we summarize the work that has been conducted at the FME SUCCESS center on understanding potential leakage processes."
When choosing a suitable reservoir, larger structural and partly stratigraphic traps are commonly targeted in hydrocarbon exploration and CO₂ storage alike. They represent either a lateral change in the depositional system, for instance a delta sandstone shaling out laterally into tight mudstone, or unconformities. The latter can be linked to events of non-deposition or erosion of a possible reservoir/storage formation unit, with overlying units offering a seal. All of these considerations are described in detail in textbooks (e.g. Bjørlykke, 2015) and a wealth of articles. Stratigraphic traps are common in sedimentary systems, and represent a challenge in forecasting reservoir behavior and storage efficiency, as sedimentary deposits will always offer a degree of heterogeneity. Heterogeneity arises from depositional processes of sedimentation, which obey physical parameters that control body shapes and intrinsic architecture, and thereby related flow properties, on a scale not resolvable with seismic imaging. Reservoir descriptions for a given storage formation will therefore be based on large-scale observations from seismic and drill hole cores/logs, used to identify generic models developed for a given sedimentary environment. Such intrinsic heterogeneities are basically impossible to identify, even in mature fields with a comprehensive history match.

Seal capacity of caprock

Physical trapping of CO₂ in the reservoir will occur along the top surface of a given storage formation, underneath the top seal and structural traps. There, the bypassing, mobile CO₂ plume will fill small traps, with efficient CO₂ capture. In most cases, the numerous intervening stratigraphic traps limit the rate to orders of magnitude less than the rate of seepage/leakage from the storage reservoir. In order to enter the non-fractured rock, CO₂ will have to overcome the capillary entry pressure (pₑ) in intact water–wet shales, which strongly depends on a pore throat radius (r), surface tension between CO₂ and H₂O (σ) and the contact angle between H₂O and the shale surface in a CO₂ atmosphere (θ):

\[ pₑ = \frac{2σ \cos θ}{r} \]

Given that typical surface tension is about 30-40 mN/m (Bachu and Bennion, 2009), the typical contact angle is about 17–45° for supercritical CO₂ (Chen et al., 2016) and a dominant pore throat radius in the Draupne shale, which is representative of the shale barriers in the North Sea, is between 2 and 10 nm (Allen, 2014), the theoretically-expected entry pressures based on equation (1) would be between 6 and 30 MPa. Unconsolidated and silty mudstones may have lower entry pressures.

Experimentally-measured CO₂ capillary entry pressure is in the range of 0.1–5 MPa for a selection of what was assumed be intact mudrock samples (Hildenbrand et al., 2004) and 3.5-4.3 MPa for shale from the Draupne Formation in the Troll East area (Skurtveit et al., 2012). These values are generally lower than expected for the intact samples based on equation (1), and it may be that connected microfractures are responsible for the low values in some of the samples. For instance, indicates a connected pore throat radius of ~600 nm, which is not realistic for any compacted mudrocks or shales. Harrington et al. (2009) measured the capillary entry pressure for the Nordland shales (the cap for the Utsira CO₂ storage site at Sleipner) and came up with a gas breakthrough pressure of 3.1 MPa using nitrogen.

In this experiment, the flow transport mechanism is suggested as being dominated by flow in pressure-induced pathways with a limited degree of pore water displacement. Angeli et al. (2009) and Skurtveit et al. (2012) recognized the CO₂ breakthrough by a marked dilation of the test sample combined with the localized flow, supporting the idea that microfractures/pores link up to form distinct pathways for CO₂ after overcoming the capillary entry pressure in low permeable seal units. The results indicate that advective flow in low permeable seal units is linked to geomechanical...
Potential leakage mechanisms and their relevance to CO$_2$ storage processes such as microfracturing and/or pore dilation. Results from field scale gas injection testing on bentonite in Åspö Hard Rock Laboratory (Cuss et al., 2014) confirm dilatancy pathways as an important mechanism for gas migration also at field scale.

Flow of CO$_2$ through intact caprock greatly depends on the permeability of the rocks, which in turn is very sensitive to stress and pressure changes (David et al., 1994; Dong et al., 2010). Numerical simulations of the hydromechanical response of the reservoir associated with injection of CO$_2$ indicate that injection can reduce the mean effective stress in the reservoir (Rutqvist and Tsang, 2002; Wangen et al., 2016). This will also lead to an increase in pore pressure in the parts of the caprock adjacent to reservoir, causing pore dilation and changes in the permeability of the caprock.

Furthermore, pore dilation will also increase the pore radii and thus reduce the capillary entry pressures, facilitating leakage. Shales, poorly lithified sandstones and sand have compressibilities that are very sensitive to stress changes (Skurtveit et al., 2013; Yarushina et al., 2013). This sensitivity is even stronger at low effective confining pressures that are expected to develop during prolonged injection. In such stress-sensitive formations, CO$_2$ flux might increase by orders of magnitude with increasing fluid pressure. We performed permeability measurements in order to evaluate the potential CO$_2$ flux through the primary caprock for different stress and pressure conditions, assuming no faulting or fracturing of the caprock and reservoir. First, the effective Darcy permeability for CO$_2$ has been studied in the same experiments as for CO$_2$ entry pressure. High confining pressure was applied in order to avoid hydrofracturing of the sample and Darcy flow was imposed upon shale samples in the experiments by Hildenbrand et al. (2004), where a slight decline in effective CO$_2$ permeability (range of $10^{-18}$–$10^{-24}$ m$^2$) was measured compared to the water permeability (range of $10^{-19}$–$10^{-21}$ m$^2$).

Brine permeability in the range of $3\times10^{-19}$ m$^2$ was measured for the Nordland shales (Harrington et al., 2009). Skurtveit et al. (2012) measured effective CO$_2$ permeability in the order of $10^{-21}$ m$^2$, within the same order of magnitude as for brine permeability, and the effective CO$_2$ permeability was found to depend on volumetric dilation in the sample.

The effect of stresses on changing permeability was studied using transient pulse and constant flow techniques on an intact Rutikfjellet shale sample under in situ confining pressure conditions, using argon, supercritical CO$_2$ and water as the metering fluids (van Noort and Yarushina, 2016). The permeabilities measured were plotted against confining pressure in Fig. 2 (see next page). Our initial results, using argon, show a decline in permeability with increasing confining pressure that is largely recovered when the confining pressure is reduced again. We also observe a limited time-dependent decline in permeability at constant pressure.

However, breakthrough effects were observed during two subsequent flow-through measurements using CO$_2$, where the permeability suddenly increased strongly (by at least 1.5 orders of magnitude). Once this flow was stopped, the permeability quickly recovered to near-original values again, but...
Figure 2: a) All individual permeability measurements performed on the shale core plug. b) First series of measurements, performed at room temperature using argon. The permeability shows a relatively strong dependence on the effective confining pressure. Furthermore, some time-dependent healing of the core is observed at a lower confining pressure (@1). c) Argon and CO₂ permeabilities at room temperature and at 40°C. During a flow-through test using CO₂, there was breakthrough, then the permeability was temporarily greatly reduced (@2). d) Permeabilities measured using water and CO₂. The water permeability is considerably lower than the CO₂ and argon permeabilities. Furthermore, the water permeability shows some time-dependence. The decline in permeability measured using water is not recovered when the effective confining pressure is declined (@3). Flow-through tests were performed again during the CO₂ measurements, and similar breakthroughs were observed (@4 and @5). After each breakthrough, the permeability was greatly enhanced. While the permeability shows a recovery to lower values with time, it does not return to the pre-breakthrough values. Finally, during the water permeability measurements, at a constant effective confining pressure of 15 MPa, the permeability declined by a factor two over 13 days (@6). This time-dependent effect is also shown in e).
"A series of measurements with H\textsubscript{2}O as the metering fluid showed a more than 1.5 orders of magnitude lower permeability than measurements carried out using argon or CO\textsubscript{2}."

remained elevated by about 0.5 orders of magnitude for at least several days afterwards. Note that the breakthrough effects observed here do not appear to be related to capillary entry pressure, as flow occurred at lower upstream pressures during pulse measurements. Subsequent series of measurements showed a reduced dependence of permeability on confining pressure compared to the first series, most likely related to drying effects.

A series of measurements with H\textsubscript{2}O as the metering fluid showed a more than 1.5 orders of magnitude lower permeability than measurements carried out using argon or CO\textsubscript{2}. Furthermore, the declines in permeability that were observed when the confining pressure was increased in the presence of water were maintained when the confining pressure was subsequently released, suggesting a permanent effect. At a constant confining pressure of 15 MPa, time-dependent creep resulted in a decline in permeability by a factor two over 13 days (see Fig. 2e). After exposure to water, the permeability of the sample to CO\textsubscript{2} was reduced. Furthermore, breakthroughs were once again observed during constant flow tests, leading to permeability increases of up to 3 orders of magnitude. The observed effect of confining pressure on shale permeability is the result of a combination of elastic, plastic and viscous deformation of these rocks under confinement (Dong et al., 2010; Sone and Zoback, 2014; van Noort and Yarushina, 2016; Zhang et al., 2016).

More interesting, however, are the additional permeability effects of the presence of water, and of CO\textsubscript{2} flow during flow-through tests. As argued by Ghanizadeh et al. (2014), the water permeability of shales is probably lower than the permeability to other fluids, due to the flow-inhibiting effects of water adsorption on mineral surfaces. Likewise, water left behind in the pore network may inhibit the flow of CO\textsubscript{2} by blocking pore throats. During flow-through tests, evaporation and/or displacement of this water open the pore throats, thus enhancing permeability temporarily. Alternatively, these effects could be the result of the swelling and shrinkage of clay minerals in the shale.

According to Schaefer et al. (2012) and Iltén et al. (2012), the potential effects of clay mineral swelling and shrinkage due to exposure to (dry) supercritical CO\textsubscript{2} on caprock permeability could have significant consequences for shale caprocks exposed to CO\textsubscript{2} during storage in reservoirs, although this is disputed by e.g. Busch et al. (2016). It is therefore important to better understand these effects and their interplay with confining pressure and shale mineral composition. For this purpose, additional permeability measurements have been performed on confined tablets of pressed smectite clay. Our results show that under static confinement (a tablet pressed into a thick steel ring that does not allow this tablet to change its dimensions), exposure to water immediately results in a strong decline in permeability, as clay hydration and swelling block any further flow of CO\textsubscript{2}.

Under such conditions, if exposure to dry CO\textsubscript{2} leads to shrinkage, it would quickly result in the formation of (micro) cracks and fluid pathways, and hence a strong increase in permeability. However, in our experiments, long-term exposure to CO\textsubscript{2} did not result in any such enhancement of permeability. Under dynamic confinement (i.e. a constant effective confining pressure (7.5 MPa) applied through a flexible jacket, allowing the clay tablet to change its outer dimensions), sufficient wetting of the clay tablets likewise resulted in a sample permeability that declined over a period of several days. However, a higher overall sample permeability was maintained (~1.2×10\textsuperscript{-15} m\textsuperscript{2}). Further tests are needed to determine the effects of microstructures and mineralogy (clay content) and whether subsequent long-term exposure to CO\textsubscript{2} flow can result in an increase in permeability.

The results of experiments depend to a large degree on the sample size and whether or not a sample can be considered as representative. In order to constrain the long-term behavior of a potential CO\textsubscript{2} storage site and the rates of fluid seepage through real geological formations on a geological timescale, we studied the history of past fluid communication in the reservoir and caprock shales from the Longyearbyen site (Huq et al., 2017). The Longyearbyen CO\textsubscript{2} Lab of Svalbard was established in order to evaluate the potential for geological carbon sequestration on Spitsbergen. Several monitoring wells were drilled in and around the planned CO\textsubscript{2} injection site. The targeted reservoir is a sandstone layer of the De Geerdalen Formation located at 700–1000 m depth. A thick shale layer, just above the reservoir, was identified as a potential caprock. Near the surface, a thick permafrost layer provided another potential seal (Braathen et al., 2012). We used two tools to investigate fluid communication within and between these entities: 87Sr/86Sr of formation waters extracted from cores using the residual salt analysis (RSA) method, and the δ\textsuperscript{13}C of gases, principally methane and CO\textsubscript{2}, degassed from core samples (Huq et al., 2017). The Sr RSA data suggest good lateral communication on a geological timescale. However, there is a distinct barrier to ver-

"... we studied the history of past fluid communication in the reservoir and caprock shales from the Longyearbyen site..."
Erosion of well completing cement and corrosion of pipelines as possible leakage mechanisms

Injection wells for carbon dioxide are made of iron casings supported by cement. Cement primarily contains calcium oxide, which transforms into calcium carbonate in reactions involving carbon dioxide. Cement also contains other clay materials similar to calcium carbonate in terms of water structuring effects and adsorption thermodynamics. Moreover, iron transforms into iron oxide, due to sodium chloride and the acidic environment.

Pipelines are rusty even before they are installed. While rust generally consists of a mixture of iron oxide, FeO, hematite, Fe₂O₃, and magnetite Fe₃O₄, the most important of these is hematite, and it may therefore be used in studies as a model for rust. Abandoned oil and gas wells in the vicinity of an underground aquifer, plugged with cement, as well as the injection well itself, are subject to further corrosion of the rusty metal surfaces. Erosion of the cement happens due to an acidic water environment containing dissolved (and dissociated) CO₂ as well as gas bubbles that are incorporated due to the local hydrodynamics.

There are two reasons for the existence of space in between the rusty pipeline and the cement. First, it is geometrically impossible to achieve total beneficial direct contact between the surfaces of rust and cement due to the distribution of charges on the two surfaces. Second, and even more importantly, are the exothermic reactions during drying of the cement which evaporate water and lead to channel creation. At the SUCCESS center, we have studied erosion and corrosion in an acidic water environment and CO₂. We applied the principles of quantum mechanics in order to characterize charge distributions in cement and rust, and molecular dynamics simulations to evaluate adsorption structures, composition and thermodynamic properties.

In addition to the ions related to CO₂ dissociation, there are natural ions in the groundwater which are transported into the space between rust and cement. The injection gas can contain monoethylene glycol (MEG), which is sometimes used as a hydrate inhibitor and corrosion inhibitor during transport. It might also contain some traces of components used in CO₂ separation. Our study was limited to the presence of MEG and the salinity of average seawater, as represented by positive sodium ion and negative chlorine ions. Bicarbonate and hydronium were balanced according to typical dissociation in relevant conditions.

We found that adsorbed MEG displaced adsorbed water, thus reducing the Coulomb screening of the surfaces, which yielded free energy minima of hydronium and bicarbonate that were closer to the surfaces (Olsen et al., submitted; Olsen et al., 2016). Ripples in the free energy profiles, originating from the layers of water, were altered due to adsorbed MEG, as adsorbed MEG resulted in free energy minima closer to the surfaces, hence providing more water layers for the ions to traverse. Competition between adsorbed MEG and adsorbed ions.

"At the SUCCESS center, we have studied erosion and corrosion in an acidic water environment and CO₂. We applied the principles of quantum mechanics in order to characterize charge distributions in cement and rust, and molecular dynamics simulations to evaluate adsorption structures, composition and thermodynamic properties"
"The presence of an intensive fracture network around faults, e.g. in low-porosity formations, can enhance fault permeability, while deformation bands in the fault damage zone might behave as seals for fluid flow."

for adsorption sites played a significant role in the changes that appeared in the free energy profiles, due to the adsorbed MEG. The remains of amines from CO₂ separation from hydrocarbons is expected to have similar effects on the water and ion characteristics on the two surfaces. Although hydronium and bicarbonate appeared closer to the surfaces, and as such may be more exposed to reaction sites, the transport aspects of reaction mechanisms might be affected in ways that could slow down erosion and corrosion rates.

Ab initio studies of adsorption structures similar to what was found in this study are needed for greater clarification of the consequences of the adsorbed structuring. Ab initio modelling will also provide some of the parameters needed in reaction kinetic modeling of corrosion kinetics, like activation energies for various reactions involved.

Flow through existing faults and fracture networks

Faults and associated fracture networks can significantly influence the flow of groundwater, hydrocarbons or CO₂. They can act either as barriers to fluid flow or as conduits for fluid circulation. The presence of an intensive fracture network around faults, e.g. in low-porosity formations, can enhance fault permeability, while deformation bands in the fault damage zone might behave as seals for fluid flow. Most studies emphasize the strong influence of fault-zone architecture on fault-zone hydraulic properties. Field studies of natural CO₂ reservoirs, which are widespread in sedimentary basins worldwide, show that the fracture networks developed in the damage zone of the faults influence the fluid circulation in the subsurface, making them a significant factor in CO₂ storage site assessment (Alikarami et al., 2013; Busch et al., 2014; Dockrill and Shipton, 2010). Natural CO₂ reservoirs can originate from a number of sources, such as mantle degassing, carbonate rock metamorphism or the degradation of organic matter. In many cases evidence of paleo-flow of CO₂ consists of the bleaching of sandstones or mineralization of carbonates.

The data that are most suitable for studies of CO₂ leakage in the subsurface come from the oil and gas industry, as the processes that result in leakage of CO₂ and hydrocarbons are the same, although they operate at different timescales. We have investigated the controls of hydrocarbon-water contacts in many Norwegian oil and gas fields, and considered the reasons for leakage from a set of dry structures presented in several MSc theses. We came to the conclusion that leakages have taken place along faults or at fault intersections from many structures, as documented by Hermanrud et al. (2014) for the Barents Sea. The leakages were probably comparatively rapid and short-lived, and the overpressures were not been drained from leaky and overpressured compartments. Overburden bright spots are often seen along and/or above leaky faults (Hermanrud and Georgescu, 2014; Simmenes et al., 2017; Simmenes et al., 2015). This means that faults and fault intersections especially could be leakage pathways for injected CO₂. Geophysical monitoring is especially important when the CO₂ injected meets such features, and a back-up plan needs to be in place to handle leakage through faults. The leakage that we have identified appears to be controlled by shear failure.

At the SUCCESS center, we investigated the fracture corridors of the mid to late Jurassic Entrada and the Curtis Formations of the northern Paradox Basin, Utah, which are characterized by discoloration (bleaching) due to oxide removal by circulating CO₂ and/or hydrocarbon-charged fluids (Ogata et al., 2012). The structures analyzed are located in the footwall of a km-scale, steep normal fault with displacement values in the order of hundreds of meters. The fracture corridors trend roughly perpendicularly and subordinately parallel to the main fault direction, and define a systematic network. The fracture corridors pinch and fringe out laterally and vertically into single, continuous fractures, following the axial zones of open fold systems related to the evolution of the main fault.

"We have investigated the controls of hydrocarbon–water contacts in many Norwegian oil and gas fields, and considered the reasons for leakage from a set of dry structures presented in several MSc theses."
"We have focused on cemented fractures, where the vein minerals hold an extensive record of the fluid flow history through the sediments. Stable isotope and fluid inclusion data, coupled with detailed field observations and petrographic work, have given us a fairly detailed picture of the importance of fractures in a larger migration context."

Based on the data presented, using the bleaching as a proxy for past fluid migration, we hypothesize that such fracture corridors, which connect localized reservoirs at different stratigraphic levels up towards the surface, represent preferred fluid migration pathways rather than the main faults. The corridors are found (Ogata et al., 2012) (i) in the damage zone of faults; (ii) at fault tips where displacement disappears; and (iii) along the crest of gentle folds oriented perpendicular to faults, reflecting rebound in the footwall proximal to the fault. We also investigated the distribution of deformation features (structures) such as fractures and deformation bands in the Navajo and the Entrada sandstones in the fault core and damage zones of two faults in two locations in southeastern Utah – Cache Valley and the San Rafael Swell (Alikarami et al., 2013; Skurtveit et al., 2015).

These two locations had different degrees of calcite cementation and hence are of interest in order to study the mechanical and petrophysical properties for identification of the impact of cementation. We have performed in situ measurements using a TinyPerm II and a Schmidt hammer in order to examine the distribution of permeability and strength/elasticity of rocks within the damage zone of these faults.

Microstructural characterization of deformation structures for the fault in the San Rafael Swell shows a complex interaction between deformation bands, fractures and the calcite precipitation. The development of deformation bands and their link to fracturing affected the flow field around the fault from a fault baffle to a conduit (Skurtveit et al., 2015). We have started to look at controlling parameters for fractures within and around faults, but further work is required in order to arrive at a conclusion.

Sediments, faults, fractures and other deformational features in the Basque Cantabrian Basin (BCB) were studied as an analogue for an overburden sequence at a leaking CO₂ storage site. Extensive seeps, and also some accumulation of hydrocarbons, make this basin an excellent location for studying the dynamics of large-scale fluid leakage through sediments with a variable lithology. We have focused on cemented fractures, where the vein minerals hold an extensive record of the fluid flow history through the sediments. Stable isotope and fluid inclusion data, coupled with detailed field observations and petrographic work, have given us a fairly detailed picture of the importance of fractures in a larger migration context. Textures, isotopes and fluid inclusion data prove the repeated reactivation of fractures, transmitting large volumes of highly-contrasting fluids at various times. Some samples contain evidence of more than 20 vein mineral generations, where water, gas and oil have migrated.

An interesting comparison between the BCB and the Longyearbyen Basin (LYB) is that the LYB core samples show very few mineralized fractures, while the frequency of cemented fractures is very high in the BCB. This suggests that the vertical fluid migration in the LYB has been minimal, which is consistent with the compartment observations reported by Huq et al. (2017).

These results are supported by laboratory tests of fracture permeability on a single shale plug from the Rurikfjellet formation at the Longyearbyen CO₂ storage pilot site in Svalbard, with and without a crack parallel to its axis (and parallel to its bedding) (van Noort and Yarushina, 2016). The measurements (which were performed using water as the metering fluid) show that at very low effective confining pressure (2.4 MPa), the permeability of the fractured sample is somewhat enhanced, relative to the same sample before fracturing. However, at higher effective confining pressures (17.4 MPa), the permeability of the fractured sample is lower than the permeability before fracturing. This demonstrates that the pressure and time-dependent compaction of shale caprock in the presence of water can successfully seal a fracture under in situ PT conditions. In another series of experiments, fracture flow properties have been investigated by evaluating the changes in flow and geophysical responses (sonic velocity and resistivity) of a naturally-fractured tight sandstone core plug from the De Geerdalen Formation at the Longyearbyen CO₂ storage pilot site (Nooraiepour et al., submitted).

Fracture flow experiments have also demonstrated the stress-dependent nature of fracture permeability and pointed out the role of aperture and asperities. The measured fracture permeability is in the order of (0.01–0.1mD) for effective confining pressures ranging from 5–24 MPa, and the permeability seems to be slightly higher for CO₂ than for water. Geophysical monitoring of CO₂ fracture flow has documented a change in acoustic velocity and electrical resistivity when the contribution of matrix flow is minimal. Electrical resistivity is more sensitive to the presence of CO₂ in the fracture than the sonic velocity measurements.
Induced tensile or shear failure of caprock

Apart from existing fracture networks and faults, there is a risk of fracture initiation during underground fluid injection. Different fracture modes are possible, depending on the stress state. Tensile fracturing may take place under a weak extensional stress field because of significant stress enhancement at the fracture tips. Shear fracturing may occur if shear stresses reach a failure criterion, of which the Mohr-Coulomb criterion is the most common (see Fig. 3).

Rocks do not only fracture because of critical far-field stresses, but also because of changes in an internal pore fluid pressure, which affects the stress state of the rocks. Two common failure scenarios related to the increase of fluid pressure are described in Fig. 3. The most critical shear failure is for cohesionless material, like faults and fractures, whereas tensile failure is the most critical for intact material.

There are three main approaches for determining fracture pressure: (a) theoretical methods; (b) use of formation well-test data; and (c) analysis of injection data during injection (Bohloli et al., 2017). At the SUCCESS center and in the associated PROTECT project, a direct shear box rig was developed that can determine frictional properties (see Fig. 4) and stress-dependent fracture flow of samples under high stresses representing CO$_2$ storage conditions. This apparatus can be used to measure peak and residual shear stress on pre-fractured or intact samples versus shear displacement. It provides a friction coefficient and cohesion of the material along the tested plane and thus provides us with a more accurate failure envelope (see Fig. 4) for the material and in situ conditions of interest.

At the SUCCESS center, the geomechanical models for injection-induced failure on faults have been discussed based on the Snøhvit/Tubåen pilot. Choi et al. (2015) demonstrated a significant difference in seal integrity for drained (unconfined reservoir) versus undrained (confined reservoir) conditions in a modelling study. For the case of CO$_2$ injection, the drained condition might be more critical in most cases, compared to the undrained condition. However, the assumption of a drained condition would be too conservative for sealing faults, which are often considered impermeable flow barriers. Bohloli et al. (2017) analyzed the injection pressure versus the CO$_2$ injection rate into well F-2H in the Tubåen Formation at Snøhvit and evaluated the methods for determination of fracture pressure.

The results of that work show that at Snøhvit, the fracture pressure was not exceeded based on the pressure versus rate plot showing a linear increase in the injection pressure with rate. A similar analysis for In Salah indicated injection into a fractured formation (Bohloli et al., 2017). Comparing the data sets from two CO$_2$ injection projects (In Salah and Snøhvit) demonstrates the behavioral range to be expected in future CO$_2$ injection projects, including near-wellbore effects, matrix flow and fracture flow behavior.
Modelling of the fracture initiation and propagation is a challenging task, even for simple geometries (Charlez, 1997). There are particular challenges associated with the condition for propagation of the fracture and the leak-off of fluid from the fracture into the host rocks (Yarushina and Bercovici, 2014; Yarushina et al., 2013). A large variety of numerical models have been developed, following the first pioneering analytical models.

They differ in the way they treat the porous rocks, conditions for fracturing, boundary conditions, spatial dimension, numerical methods, size of the computational domain, heterogeneities and fluid flow within the fracture (Adachi et al., 2007; Charlez, 1997; Mack and Warpinski, 2000). The approach used at the SUCCESS center is based on the Biot model for poroelasticity (Biot, 1941), but it represents the rock strength by bonds (Wangen, 2011). It therefore has similarities with earlier approaches, where the entire porous material is represented by beams (Tzschichholz and Wangen, 1998) or by springs (Flekko et al., 2002).

Our formulation models hydraulic fracturing of a reservoir rock using the finite element method (Wangen, 2011) and makes it possible to model the fracturing process without special meshing for the fracture by introducing fracture porosity. The current formulation deals with tensile (Mode I) fractures. The maximum limit of the strain in each element is used as a fracture criterion. The finite element formulation of the displacement field treats the fractured elements by setting Young’s modulus in these elements to zero or a ‘low’ value. The example below shows hydraulic fracturing of 50m x 50m horizontal part of a reservoir. The bonds in the grid are assigned random bond strength. The fluid is injected at the center of the grid and a fracture propagates away from the well into the reservoir. The presence of the weak bonds creates a branched fracture, as seen from the plots of normal effective stresses in the x and y directions (see Fig. 5).

The random bond strength results in fluctuations in the well pressure, which builds up until the first fracture event, followed by a pressure drop (see Fig. 6a). The process of pressure build-up then resumes, generating a new fracturing event. Each fracturing event can be associated with an induced microseismic event.

**Figure 5:** The normal effective stresses in the x and y directions. The effective stress is plotted around a hydraulic fracture that has developed in heterogeneous rock. The heterogeneities in the rock lead to erratic fracture geometries that might be expected in real rocks. The plot shows the tensile stress enhancement at the fracture tips (blue), which are the most likely places for further fracture propagation. The rock along the sides of the fracture becomes compressed by the opening of the fracture (red).

**Figure 6:** a) Evolution of the well pressure over time during the fracture process. b) The modelled well pressure is compared to the observed well pressure in Adventdalen, Svalbard. The well pressure is shown as the difference between the fluid pressure and the initial reservoir pressure.
"The model of hydraulic fracturing developed can be used to interpret fracture propagation and well pressure behavior, but the non-linearity of the numerical model and physical processes involved require further studies."

This model has been calibrated against pressure observations from a well drilled and tested in the Adventdalen valley in Svalbard (Wangen and Yarushina, 2015). The model reasonably replicates observed pressure variations (see Fig. 6b). The discrepancy is due to the element size and non-linearity of the model. The simulations assume an average lateral permeability in the interval of measured sandstone permeabilities. The model of hydraulic fracturing developed can be used to interpret fracture propagation and well pressure behavior, but the non-linearity of the numerical model and physical processes involved require further studies.

The same approach was used for numerical modelling of hydraulic fracturing in 3D (Wangen, 2013). The model has been tested on two cases – a homogeneous rock and a heterogeneous rock. The homogeneous case yields three orthogonal fracture planes. The fracture fronts corresponding to the tips of the fractures become circular in the heterogeneous formations, where more than three fractures can be initiated simultaneously. These will expand symmetrically away from the injection point. All fracturing events that can induce microseismicity are at the front in this case, and there are therefore no events in the interval between the front and the well. The heterogeneous case yields a branched fracture, where there are events that fill the distance between the injection point and the furthermost fracture tips. The elastic energy released in the largest events is in the order of 1 MJ, when the well pressure is in the order of 1 MPa. The homogeneous case yields fewer and larger events than the heterogeneous case.

Sand injections and risk of leakage

While the presence of sand injections within the reservoir section may result in improved reservoir connectivity and storage capacity in stacked reservoirs (Aavartsmark et al., 2017), sand injection through the caprocks of potential CO₂ storage sites may result in CO₂ leakage. Karstens and Berndt (2015) documented amplitude anomalies in the overburden above the CO₂ injection site at Sleipner. These were attributed to the presence of gas, and it was suggested that they "represent fluid conduits between deep stratigraphic levels and the shallow subsurface or even the sea floor".

Such conduits could potentially be sand injections. The presence of sand injections is important for both storage capacity, injectivity and leakage risk. The work that has been performed at the SUCCESS center to investigate the trigger mechanisms, and thereby the presence of sand injections, is covered in the report on Storage capability (Elenius et al., 2018).

Other vertical focused fluid flow structures

Focused fluid flow through relatively narrow fluid conduits is reported for both deep and shallow Earth. It characterizes hydrothermal vent complexes, mud volcanoes, gas venting systems, reservoir leakage, etc. It is often identified using reflection seismic as near-vertical zones of disturbed data in the form of gas chimneys and fluid escape pipes.

Chimney or pipe anomalies are often observed at sub-seabed sediments on continental margins. They are found offshore Norway in actively-producing hydrocarbon fields (e.g. Nyegga, Albuskjell, Ekofisk, Eldfisk, Hod, Tommeliten, Valhall), offshore Nigeria, Namibia, Angola, in the Adriatic and Barents Seas, in the Gulf of Mexico, and even in Arctic regions (Arntsen et al., 2007; Bunz et al., 2012; Gay et al., 2007; Laseth et al., 2011; Moss and Cartwright, 2010; Ostanin et al., 2013; Roy et al., 2014). Chimneys and pipes represent almost verti-

Repeated (4D) seismic data does not reveal any amplitude changes in the overburden above Sleipner after starting CO₂ injection. This observation demonstrates that the (potential) fluid conduits between the Utsira Formation and the high amplitude regions in the overburden are not presently significant CO₂ flow conduits. One cannot preclude some CO₂ leaks through these potential conduits, but the (potential) leakage rate is so slow that the CO₂ would be dissolved in pore water and precipitate as minerals in a shorter time than it would take to leak to the surface. Thus, while leakage may be a general concern in areas with sand injection, such leakage is not a concern above the Sleipner field at present.

"The presence of sand injections is important for both storage capacity, injectivity and leakage risk. "
Figure 7: Schematic representation of fluid flow focusing due to porosity wave mechanism. High-porosity fluid-filled domains have higher buoyancy than the surrounding rocks, and thus have the ability to flow upwards as a single pocket in deformable rocks with a time-dependent response. Due to the different responses of the rocks to dilation and compaction, elongation of the initial pocket in the vertical direction leads to formation of a vertical fluid conduit.

Pockmarks that are directly observable on the seafloor are other indicators of fluid migration. They can often be related to underlying seismic chimneys. There are three main settings where pockmarks are commonly present: 1) in offshore hydrocarbon provinces where fluids that leak from reservoirs reach the seafloor; 2) in gas hydrate regions as the result of ongoing or paleo dissociation of clathrates, and 3) in estuarine and delta regions where the constantly deposited organic-rich sediments or drowned wetlands trigger the production of shallow gas (Cartwright et al., 2007; Hovland and Judd, 1988).

Focused fluid flow systems as potential leakage pathways have been the subject of several projects funded by the EU. In situ experiments on CO$_2$ injection into shallow under-consolidated marine sediments in Ardmucknish Bay in Oban, Scotland accompanied by high-resolution 2D seismic reflection surveys revealed that while CO$_2$ migration was controlled by sediment stratigraphy in the early stages of the experiment, seismic chimneys developed at an increasing flow rate and the total volume injected eventually reached the seabed (Cevatoglu et al., 2015). Production experience from Gullfaks and wastewater injection in the Hordaland Group in the Norwegian North Sea also show that injection-induced fluid pressures can result in caprock leakage (Hermanrud et al., 2013; Leseth et al., 2011).

One of the best-documented CO$_2$ storage operations today is the injection of about one million tons of CO$_2$ per year since 1996 into the Utsira Formation at Sleipner in the Norwegian North Sea. The first repeat seismic survey (1999) revealed that the migrating CO$_2$ had spread to nine distinct layers—one of these lying above the 5–6.5 m thick shale. The migrating CO$_2$ appears mainly to have been fed to the different layers from a central vertical feeder located right above the well perforations, which is expressed as a seismic chimney in the seismic data (Boait et al., 2012; Hermanrud et al., 2009).

Well data obtained inside and outside of a gas chimney reveals that chimneys are characterized by increased fluid pressure, compared to the background levels (Leseth et al., 2009). Hydraulic fracturing is one of the possible mechanisms of formation of localized fluid conduits (Arntsen et al., 2007).

Another mechanism that has been studied at the SUCCESS center is the spontaneous self-localization of porous fluid flow due to mechanical instability called “porosity waves” in the geophysical literature (Connolly and Pidlachikov, 2007; Omlin et al., 2017a; Revil, 2002; Räss et al., 2014; Yarushina et al., 2015). Hydraulic fracturing might be expected in hard brittle rocks while...
Potential leakage mechanisms and their relevance to CO$_2$ storage

Porous waves form in soft sediments. Thus, rock rheology is an important factor in determining fluid flow focusing mechanisms.

Previously, shallow reservoirs were mostly considered to behave elastically and fail as a result of frictional plasticity. Recent advances in experimental rock mechanics have made it possible to perform accurate measurements of time-dependent creep under shallow crustal temperature, pressure and stress conditions. This has led to an understanding that viscous deformation plays an important role in reservoirs at timescales that are relevant for CO$_2$ sequestration (days to 10 000 years) (Brantut et al., 2013; Chang and Zoback, 2009; Hangx et al., 2010; Räss et al., 2014; van Noort and Yarushina, 2016).

A state-of-the-art model for viscoelasto-plastic deformation coupled with fluid flow (Yarushina and Podladchikov, 2015) was specifically developed at the SUCCESS center in order to address this wide range of rheological responses. The model successfully reproduces experimental data on both instantaneous elastoplastic deformation and time-dependent creep. Based on this theoretical model, we have developed new fully-coupled numerical code (i.e. the solid feels the fluid pressure and the fluid flow is affected by solid stresses and deformation of the porous rocks), which allows the simulation of CO$_2$ injection and flow in a stressed crust that may deform in a viscoelasto-plastic manner (Räss et al., 2016; Räss et al., 2014).

Rocks are known to be heterogeneous and have a wide porosity distribution, even within the same formation or reservoir. This heterogeneity aids the formation of fluid-filled porous pockets that are lighter than the surrounding rocks (see Fig. 7). The buoyancy of porous pockets, combined with the ability of the rock matrix to creep, even under low stresses, thus is the driving force for upward fluid propagation. Slightly higher fluid pressures at the top of the porous pocket create deviatoric stresses in the rocks above.

In creeping rocks, even small stresses would cause deformation and lead to pore dilation above the fluid pocket. Fluid pressure generated by buoyancy and deviatoric stresses in the rock matrix might be sufficiently high to overcome capillary entry pressure for thin intra-reservoir shale layers and caprock. At the same time, the reduced pressures at the bottom of the pocket will lead to pore contraction, pushing the fluid pocket upwards (Connolly and Podladchikov, 2007; Yarushina et al., 2015).

Focusing of the flow from the high-porosity pocket occurs due to non-symmetrical dilation/contraction of the pore space; i.e. dilation of porosity happens much easier and faster than its contraction. Upward propagation of formed fluid conduits is further sustained by creeping rocks. Numerical modelling shows that in soft sediments, fluids or gas-filled conduits propagate upwards as a self-sustained body, losing the initial connection to the feeding reservoir or an injection point (see Fig. 8).

The momentum that a conduit has acquired during propagation is enough for its upward propagation, as long as the permeability and viscosity of the rocks do not vary significantly. If a conduit meets another layer of even more impermeable but still viscous rocks, it will be halted temporarily, spreading the fluid underneath the barrier but will resume its upward propagation on a slower timescale. Conduit formation exhibits self-organizing features, in that the number of conduits and their spatial distribution are controlled by permeability, fluid viscosity and the bulk viscosity of the rocks (McKenzie, 1987).

Based on this theoretical model, we have developed new fully-coupled numerical code, which allows the simulation of CO$_2$ injection and flow in a stressed crust that may deform in a viscoelasto-plastic manner
Figure 8: Fluid escape pipes formed in soft sediments as a result of leakage from a fluid-filled reservoir. a) Initial conditions used for numerical modelling: the high-porosity ($\phi$) elliptical reservoir is centered at 1/5 of the domain depth. Inside the reservoir the initial porosity is three times higher than in the rest of the domain ($\phi_0$). The gravity force is acting downwards, thus initiating buoyancy-driven fluid extraction. b) Fluid escape pipes began to grow from the initially elliptical reservoir shown on the left. The colors indicate porosity normalized to the homogeneous background value. Note that porosity within the pipe might be higher than in the initial reservoir. c) Fluid-escape pipes in 3D. The colors indicate permeability normalized by fluid viscosity. d) Outline of a typical pipe drawn on the basis of available observations (from (Løseth et al., 2011)).
Systematic numerical simulations show that the speed of propagation of conduits can be up to 1000 times greater than the speed of the background diffusional fluid flow defined by simple Darcy’s law (see Fig. 9) (Omlin et al., 2017b). The Darcy velocity of the flow outside of the conduit mainly depends on the fluid viscosity and permeability (see Fig. 9b).

The flow of CO₂ through shales with permeability of $10^{-7}$ D ($10^{-19}$ m²) and fluid viscosity of $10^{-3}$ Pa s results in the Darcy velocity of $≈10^4 + 10^5$ m/yr. Fluid-filled conduits can thus propagate with a speed in the order of $≈1 \pm 10$ cm/yr. It will take 1000 to 10000 years to penetrate 100 m of a nearly impermeable shale layer, due to the effects of the time-dependent ability of shales to relax stresses. If the presence of CO₂, as measured in the laboratory, shows chemical effects of permeability enhancement (Armitage et al., 2013), the timescale of conduit propagation will be reduced even further, leading to a propagation velocity of meters per year.

Our simulations replicate features observed in CO₂ injection operations, such as localization of flow into separate conduits and flow that is locally and periodically faster than predicted by Darcy diffusional flow. The possibility of triggering focused fluid flow via vertical conduits must thus be considered in the risk analysis of the anticipated fluid injection operations during geological CO₂ storage and wastewater injection, and must be added to the list of potential leakage pathways alongside existing faults.

At the same time, accurate creep rate formulations based on experimental data need to be included into theoretical models and numerical codes for fluid flow in soft sediments.

![Figure 9: a) Results from a systematic investigation that shows the dependence of the speed of upward conduit propagation on the bulk viscosity of the porous rocks during compaction, $\eta_C$, and dilation, $\eta_D$, and the shear viscosity of the rocks, $\mu$. The contoured values are the maximum vertical fluid percolation flux normalized by the background Darcy velocity $V_D$. b) The background Darcy velocities $V_D$ expressed in meter per year as a function of effective permeability $k$ and fluid viscosity $\mu$. $\phi_b$ is the background porosity.](image-url)
A combined experimental, field and numerical modelling study of various leakage pathways was undertaken at the FME SUCCESS center. We showed that oil and gas industry techniques for assessing reservoir compartmentalization may be useful for investigating prospective CO₂ storage sites. They may help constrain material parameters and the past history of fluid communication in the reservoir and caprock, and thus define the quality of the seal. Broader application of caprock characterization techniques, such as geochemical methods, is needed, especially during establishment of new CO₂ storage sites.

The possibility of generating new leakage pathways was considered together with leakage through pre-existing structures. The development of leakage pathways during injection is different in different types of rock. In soft rocks, it occurs due to the formation of focused fluid flow systems as a result of fluid flow instability (i.e. solitary porosity waves) and strongly-coupled flow and deformation processes. In hard rocks, hydraulic fractures will be initiated if stresses reach critical levels. Both of these represent preferential leakage pathways. In a sequence of hard/soft rocks, hydrofracturing will be halted as soon as it hits the soft rocks. Porosity waves are then responsible for fluid flow through soft layers, as hydraulic fracturing of soft rocks is very difficult and unlikely due to the high strain potential of such rocks. While there is a considerable body of work on the generation of hydraulic fractures, much less research has been undertaken on the formation of focused fluid flow systems in soft rocks. Further studies on the formation of focused fluid flow systems in soft rocks are thus needed in the future in order to constrain the critical material and engineering parameters that are responsible for formation of these features and also for predictive modelling at the relevant storage sites.

Our work indicates that the flow through fractures and faults depends on the permeability of the fault gauge, fracture surface roughness and the degree of confinement, while flow through intact rocks depends on stress and time-dependent permeability, elastic bulk moduli and effective bulk viscosity of the rocks. Forecasting flow in rocks with complex material properties is difficult, and more work is needed on coupled geomechanics and fluid flow/reservoir simulations. Stress- and time-dependent rock properties such as those measured for shales and a number of other rock types need to be included in numerical models. However, very few commercial simulators and research codes are capable of this, which creates a need for development of a new generation of geomechanical simulators coupled with reservoir flow that would account for stress and time dependency of rock properties. Controlling parameters for fractures within and around faults also need better understanding and quantification. Further research is needed in order to identify actions required to reduce risk.

Based on the results of our work, we suggest that the workflow for assessment of future CO₂ injection sites must include studies on two scales. On a large scale, identification of sealing sequences is needed, which includes all important sealing objects, their interdependence on each other and their function with respect to CO₂ retention capacity. On the small scale of an individual object, an evaluation is needed of the material properties and their dynamic behavior in response to the stress introduced by CO₂ injection needs.

The following guidelines and recommendations for environmental practices are based on these experiences.

"Broader application of caprock characterization techniques, such as geochemical methods, is needed, especially during establishment of new CO₂ storage sites."
"Coupled geomechanical/flow modelling should be used to identify the injection strategy that would minimize the potential for stress changes, deformation, induced seismicity, formation of fractures and new focused fluid flow pathways."

Identifying the ideal reservoir

Geological and hydrogeological characterization of the storage unit should include identification and characterization of fault zones and focused fluid flow features that could affect containment. Conventional techniques for assessing reservoir compartmentalization in the oil and gas industry may be useful for investigating prospective CO\textsubscript{2} storage sites. Isotope geochemistry is an effective tool for understanding the fluid communication in reservoirs and caprock shale on a geological timescale, and thus to help constrain the long-term behavior of a potential CO\textsubscript{2} storage site.

Geostatic modelling

Large identified features, including faults, focused fluid flow features, compartmentalization, etc. need to be incorporated into geological models that should form the basis for flow modeling. The geological models should provide information on porosity and permeability distribution, the initial pressure, temperature and stress distribution, elastic moduli and failure parameters already identified by ISO/DIS27914 (2017), but also shear and bulk viscosities of the reservoir and caprock, as they affect flow behavior and the long-term fate of injected CO\textsubscript{2}.

Predictive flow modelling

Numerical modelling must be applied in order to predict the behavior of the storage of complex and injected CO\textsubscript{2}. Oil and gas industry modelling software packages may be used as a first order estimate for the processes that occur in the reservoir. There is a need for further development of more robust flow simulators, coupled with geomechanical modelling that accounts for realistic stress- and time-dependent properties for reservoir and caprock. Coupled geomechanical/flow modelling should be used to identify the injection strategy that would minimize the potential for stress changes, deformation, induced seismicity, formation of fractures and new focused fluid flow pathways.

In addition to the key flow and geomechanical modelling parameters outlined by ISO/DIS27914 (2017) (pressure, temperature, fluid saturations; chemical composition of formation fluids; porosity distribution; permeability distribution; formation geometry; fluid and rock compressibilities; and the thermal properties of fluids and rocks), pressure dependence and time dependence of porosity, permeability and rock compressibilities must be taken into account. Bulk viscosity of the rock should be included in the list of key material parameters affecting the flow.

Geomechanical site characterization

Baseline geomechanical characterization should include the following rock mechanical properties of both the storage unit and overlying seal: strength and deformation properties, according to the observed material behavior of the concerned rock, including stress-dependent elastic moduli (e.g. Poisson’s ratio and Young’s modulus); creep rates and stress-dependent bulk viscosity; estimation of the fracture propagation pressure and failure parameters, including the cohesion and friction angle. The flow properties of existing faults and focused fluid flow structures also need to be evaluated.

Site closure

Coupled geomechanical/flow modelling, which accounts for time-dependent evolution of rock properties (rock weakening, pressure-dependent elastic moduli, rock viscosity) should be used for long-term (post-injection) safety assessment of the injection site, especially for large-scale operations.

"The flow properties of existing faults and focused fluid flow structures also need to be evaluated."
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28

Synthesis report from FME SUCCESS
Potential leakage mechanisms and their relevance to CO₂ storage


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