Critical Factors for Considering CO$_2$ Injectivity in Saline Aquifers

FME SUCCESS Synthesis report Volume 3

Editors
Rohaldin Miri and Helge Hellevang (UiO)

Contributing authors
Per Aagaard (UiO)
Bjørn Kvarme (UiB)
Elin Skurtveit(NGI)
Magnus Wangen (IFE)
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.

Field excursion Unis CO₂ lab workshop, Svalbard 2012
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 CO₂ storage. In particular, the center has used the theoretical platform to address critical and relevant scientific issues related to CO₂ 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 re-organized 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$_2$ 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:

<table>
<thead>
<tr>
<th>Capacity</th>
<th>Injectivity</th>
<th>Containment</th>
<th>Conformance</th>
<th>Contingency</th>
</tr>
</thead>
<tbody>
<tr>
<td>Storage capability report</td>
<td>Leaks risk report</td>
<td>Geophysical monitoring report</td>
<td>Geophysical impact of CO$_2$ exposure</td>
<td>Marine monitoring methods</td>
</tr>
</tbody>
</table>

- **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$_2$. 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$_2$ storage site risk assessment, this report demonstrates that viscous deformation of the shales can play an important role in their ability to keep CO$_2$ contained and that material properties and their dynamic behavior in response to the stress introduced by CO$_2$ 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$_2$ 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.
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 et 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 (Nøttvedt, 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.
Critical Factors for Considering CO$_2$ Injectivity in Saline Aquifers

Editors
Rohaldin Miri$^1$ and Helge Hellevang$^1$

Contributing authors
Rohaldin Miri$^1$, Helge Hellevang$^1$, Per Aagaard$^1$, Bjørn Kvamme$^2$, Elin Skurtveit$^3$ and Magnus Wangen$^4$

$^1$ University of Oslo (UiO)
$^2$ University of Bergen (UiB)
$^3$ Norwegian Geotechnical Institute (NGI)
$^4$ Institute for Energy Technology (IFE)
# Table of contents

<table>
<thead>
<tr>
<th>Section</th>
<th>Page</th>
</tr>
</thead>
<tbody>
<tr>
<td>The FME SUCCESS center on CO₂ storage</td>
<td>2</td>
</tr>
<tr>
<td>Preface</td>
<td>8</td>
</tr>
<tr>
<td>Executive Summary</td>
<td>9</td>
</tr>
<tr>
<td>Injectivity in saline aquifers</td>
<td>10</td>
</tr>
<tr>
<td> Background</td>
<td>12</td>
</tr>
<tr>
<td> Geological constraints</td>
<td>13</td>
</tr>
<tr>
<td> Transport constraints</td>
<td>14</td>
</tr>
<tr>
<td> Chemical effects</td>
<td>16</td>
</tr>
<tr>
<td> Geomechanical effects</td>
<td>17</td>
</tr>
<tr>
<td> Thermal effects</td>
<td>19</td>
</tr>
<tr>
<td>Recommendations</td>
<td>21</td>
</tr>
<tr>
<td> Recommendations for operations</td>
<td>21</td>
</tr>
<tr>
<td> Recommendations for Research</td>
<td>21</td>
</tr>
<tr>
<td>References</td>
<td>22</td>
</tr>
</tbody>
</table>

Photos and illustrations
Marit Hommedal, Ole Jørgen Bratland (Statoil), Helge Hansen, Statoil, Harald Pettersen, (Statoil), Daniel Byers (ISGS), Tor de Lange (UiB), Olav Olsen (Aftenposten) and photos/illustration from all of the FME SUCCESS Partners.
Idea, layout/design: Per Gunnar Lunde and Charlotte Gannefors Krafft, CMR
Preface

This document presents a synthesis report on the injectivity-related studies at the FME SUCCESS center. The report is mainly based on contributions from the KMB INJECT project, a fully-integrated part of the SUCCESS consortium, but also uses relevant information from other work packages at the center. The background material for the report has been published in peer-reviewed papers, proceedings and internal reports. The report is a technical/scientific document as such, but as the end users of the report are operators and service companies, we have added an executive summary containing research-based recommendations on how to retain/maximize CO₂ injectivity. Readers who seek more detailed information regarding models/experiments should review the original material.

This report begins with a brief overview of the concept of injectivity, the state of the art, implications and governing factors. The main body of the report is divided into five major categories: geological constraints, transport constraints, chemical effects, geomechanical effects, and thermal effects. In each category, the results are compiled, scientific advice is provided for end users, and research gaps which demand further experimental and/or numerical investigation are identified. This is followed by a description of the activities and plans related to injectivity modelling.

This work has been partly funded by the FME SUCCESS center for CO₂ storage under grant no. 193825/S60 from the Research Council of Norway. The FME SUCCESS center is a consortium of partners from industry and science, hosted by Christian Michelsen Research AS.
Executive Summary

A combination of technical, economic and political considerations defines the ideal CO$_2$ injection scenario. This is the storage of a predetermined amount of CO$_2$ (based on storage capacity estimations) with a sufficiently high injection rate in the shortest possible operational time (20–30 years), and with the minimum number of drilling wells.

The FME SUCCESS center has concentrated part of its research on improving the prediction of reservoir injectivity, with a particular focus on complex phenomena involved in the near-well region. To achieve this, the FME SUCCESS center has embraced interdisciplinary methods, and its work involves both state-of-the-art and innovative experimental and computational studies that have enhanced its understanding of reservoir injectivity.

The FME SUCCESS center provides a competent workflow/methodology in order to study reservoir injectivity that is useful for site screening and characterization and for the planning and management of CO$_2$ injection operations. In particular, the proposed workflow includes new computational tools, new geochemical and geomechanical experimental design/data and research-based advice.

In the following, we present the most important results of the activities conducted, organized by their relevancy for each storage case:

**Sleipner**: Unconsolidated sand with high porosity and little effect on injectivity from salt formation. Sleipner’s T and P are close to the critical point of CO$_2$, and impure CO$_2$ streams whose critical point has shifted may have a major impact on the CO$_2$ near-well flow, but this is not likely to affect the injectivity.

**Snøhvit/In Salah**: Heterogeneous, tight, providing channeling of CO$_2$ flow, may lead to severe reduction of injectivity caused by local salt precipitation. The compartmentalization and low total storage volumes ultimately result in rapid pressure build-up and thus limit the injectivity.

"... the FME SUCCESS center has embraced interdisciplinary methods, and its work involves both state-of-the-art and innovative experimental and computational studies that have enhanced its understanding of reservoir injectivity."
Deep saline aquifers with huge storage capacity of ~ 2 000 – 20 000 Gt CO₂ are considered the most promising geological option for CO₂ sequestration in order to mitigate the climate changes caused by increasing anthropogenic CO₂ (Bachu and Adams, 2003; Metz et al., 2005). Although the storage capacity of deep saline aquifers is huge, the annual worldwide greenhouse gas emissions are also enormous (~49 Gt CO₂/year in 2010, Pachauri et al., 2014). This means that significant climate change mitigation will only be achieved if CO₂ storage is implemented on a very large-scale with considerable injection rates (in the order of 10 Mt CO₂/year). Achieving such high rates in deep saline aquifers with natural heterogeneity and low to moderate permeability appears to be a great challenge, yet essential in order to reduce the costs associated with large-scale CO₂ storage.

CO₂ injection into saline aquifers has encountered some issues, for example at Snøhvit and In-Salah, partly because injectivity variations and their corresponding limiting effects have been somewhat underestimated. This experience has showed that there have been unpredicted injection problems, even for rates in the order of 1 Mt CO₂/year. In fact, two of the three commercial-scale geological storage operations, Sleipner, Snøhvit, and In-Salah, have experienced a serious decline in injectivity and have had to stop operations or switch to an adjacent reservoir (Eiken et al., 2011; Grude et al., 2014).

The In-Salah Project, which started CO₂ injection in 2004, has shown substantial geomechanical deformation due to the lack of good pressure communication with the producing parts (Verdon et al., 2013). In fact, in this project, the well injectivity problem (not the reservoir injectivity) was fully recognized as a potentially limiting factor because of the low relative permeability of the target formation (in the order of 5 mD (Michael et al., 2011). CO₂ was therefore injected through three long horizontal wells in order to improve the well injectivity. The reservoir injectivity issue and large-scale pressurization caused by injection into a compartmentalized formation were thus acknowledged, but not seen as potentially limiting factors prior to the injection.

Unlike the In Salah project, the Snøhvit CO₂ storage project experienced injectivity problems in both the well and reservoir scale during injection. Injection of CO₂ into the Tubåen Formation started in 2008 and ended in 2011 due to pressure build-up that was mainly caused by a limited reservoir volume and heterogeneities in the formation (Eiken et al., 2011; Grude et al., 2014). Well injectivity was not recognized as a possible limiting factor in the early stages because of medium to large permeability in the order of 500 mD. However, the analysis of the fall-off pressure data, together with experimental work on core plugs obtained from Snøhvit, showed that the permeability in the near-well area was severely reduced by salt precipitation induced by the evaporation of brine into the CO₂ stream (Eiken et al., 2011; Grude et al., 2014).

The question is why the CCS community was not able to properly predict these injection problems before the projects began. Part of the reason is that, in the past, research has tended to focus on CO₂ migration and trapping processes, and fairly little attention has been paid to injectivity problems.

The most relevant bodies of research with respect to injectivity during the past 15 years are:

1. development and application of analytical and numerical models for pressure build-up (Birkholzer and Zhou, 2009; Burton et al., 2009; Gasda et al., 2013b; Mathias et al., 2011; Noh et al., 2004; Nordbotten et al., 2005; Zeidouni et al., 2009) and

"..... significant climate change mitigation will only be achieved if CO₂ storage is implemented on a very large-scale with considerable injection rates ...."

"Today, 7 years later, our knowledge about near-well processes has significantly improved..."
2. development and application of methods for measuring the fracturing pressure limits (NGI, 2012). However, areas such as near-well formation damage, maximizing injectivity, large-scale pressurization, reservoir pressure management and characterization of hydrogeological boundary conditions have not been explored until recently.

Aside from all of these factors, the overall impression was that the experiences from other cases of fluid injection can be applied to CO$_2$ geological storage as well (Neades et al., 2013). It is becoming increasingly clear that this perception is far from reality, largely due to the differences in fluid properties, injection rates and overall objective of the project (Michael et al., 2011).

The FME SUCCESS center was established in 2010 in order to conduct focused research and long-term research of high international caliber in order to solve specific challenges within the field of subsurface CO$_2$ storage. Given the importance and complexity associated with CO$_2$ injection, KMB INJECT and several other groups at the FME SUCCESS center have focused their research on understanding why and under what conditions injectivity problems arise, and how to mitigate them. Today, 7 years later, our knowledge about near-well processes has significantly improved and some of the technical gaps mentioned above have been addressed. This report describes what we have learned since 2010 regarding CO$_2$ injectivity, based on field observations, mathematical modelling and laboratory studies. **"This report describes what we have learned since 2010 regarding CO$_2$ injectivity, based on field observations, mathematical modelling and laboratory studies."**

Reservoir heterogeneity has now been fully incorporated into fluid flow modelling by combining reservoir property models generated from seismology (effective porosity from acoustic impedance) with a geo-conceptual approach (Sundal, 2015; Sundal et al., 2014). The effect of site-typical geological heterogeneities, like discrete layers of low-permeability mudstone, tight calcite-cemented layers and directional permeability anisotropy on migration paths, pressure response and CO$_2$ trapping potential, has now been investigated. It has been shown that the depositional heterogeneities may limit the vertical communication of the reservoir, thus inducing further pressure build-up, but the general impact on pressure distribution around the well is seen as negligible (Sundal, 2015; Sundal et al., 2013b). These findings are nevertheless largely sensitive to the choice of boundary conditions. The issues of far-field pressure (large-scale flow boundaries) and regional connectivity of the target unit are not well known and need to be addressed in future.

Now that the world is moving slowly towards large-scale industrial implementation of CCS with injection rates in the order of 3–4 Mt CO$_2$/year (for example the Gorgon Carbon Dioxide Injection Project in Australia), it appears that keeping a low-cost single well injection scenario will not provide enough injectivity in most cases. A preliminary review of injectivity issues shows that in order for CCS to be a technology that is fully deployed in the future, research will need to focus on studies that increase our understanding of maximizing injectivity at both the well and reservoir scale.

"... in the future, research will need to focus on studies that increase our understanding of maximizing injectivity at both the well and reservoir scale."
Background

The CCS community operates with several definitions of the term injectivity. It is occasionally referred to as “flow rate”, sometimes as the product of “permeability×height”, and at times as flow rate divided by pressure difference. The latter is the original definition that is also used by the petroleum industry. However, the first definition is more popular, because the objective of most CCS operations is to achieve the optimum injection rate. Generally speaking, a low injection rate increases the lifetime of a CO₂ storage operation, improving the economy of the project. As it is, it is desirable to maximize CO₂ storage within a relatively short time frame. The parameters that affect the optimum injection rate are: (1) rock and fluid properties; (2) mobility of fluids; (3) solubility of H₂O in the CO₂ phase; (4) sweep efficiency, swept and unswept areas; (5) injection design, well completion, pattern and spacing.

High injectivity might not always be favorable, as it may lead to poor sweep efficiency and thus reduce the total amount of stored CO₂ achievable. Another important point to note is that although there is a demand for maximum injectivity, shallow and low permeability reservoirs have limitations in terms of the maximum achievable injection pressure. In fact, the injection well must operate below the fracturing gradient in order to avoid creating preferential flow pathways that facilitate flow bypassing and a risk of leakage. In order to estimate the optimum injection rate, the corresponding pressure build-up for the time frame of operation must therefore be considered.

We accordingly define reservoir injectivity or reservoir injection capacity as the ability of a reservoir to accept CO₂ at an optimum flow rate (which ensures maximum sweep efficiency) for a known time frame without losing its mechanical integrity (maintaining average reservoir pressure at less than critical pressure). The well injectivity or well injection capacity, on the other hand, measures the ability of a single injection well to accept CO₂ in a formation without reactivating existing faults or creating new fractures (Birkholzer et al., 2015; Schembre-McCabe et al., 2007). Information about caprock integrity and the lateral connectivity of the target unit is required in order to obtain an estimate of reservoir injectivity. The most relevant application of reservoir injectivity is estimates of information about the overall injection rate into a reservoir and the resulting large-scale pressurization. This overall injection rate can be distributed among several injection wells, with each one operating within limits defined by well injectivity.

Well injectivity is mathematically quantified by an index represented as the injection flow rate divided by the pressure build-up (Dake, 1983).

\[ II = \frac{Q}{(P_{bh} - P)} \]  

(1)

Where \( Q \) is the injection flow rate in [m³/s], \( P_{bh} \) is the injecting wellbore pressure in [Pa], \( P \) is the volumetric average drainage area pressure in [Pa].

In fact, the well injectivity index yields near-well pressure build-up as a known volume of CO₂ is pumped into the formation. Alternatively, having averaged the injectivity index for a known time frame, one can estimate an optimum injection volume and flow rate for a CO₂ injection well that will not break the reservoir rocks. There is therefore a close relationship between the optimum flow rate, pressure build-up and the injection time frame, and they can be translated to each other through the injectivity index (see Fig. 1a). In other words, the injectivity index is a time-dependent parameter, and the total amount of CO₂ that can be stored for a given period of time is limited by pressure. Well injectivity and reservoir injectivity therefore determine the time frame for achieving a desirable or a planned storage capacity.

A common practice for direct measurement of the well injectivity index is an injectivity test. In this test, the well is allowed to inject at a constant flow rate of \( Q \) and a stabilized bottomhole pressure of \( P_{bh} \). The bottom-hole pressure is recorded continuously and the injectivity index is then calculated from Eq. (1). As the volume of CO₂ builds, the pressure required to place CO₂ into the formation gradually increases, and the injectivity decreases. When the well is allowed to inject at a constant rate for a sufficient period of time, the pressure response will touch on well boundaries and a pseudo-steady state flow regime will form. A well injecting under this regime will have a linear increase in pressure with a constant injection rate resulting in a constant injectivity index (see Fig. 1b).

As most of the well life is spent in a pseudo-steady-state flow regime, in practice the well injectivity index can be used by operators to monitor the performance of an injection well over time in order to check whether the well has become damaged due to workover, injection operations, chemical reactions or mechanical problems. If a measured \( II \) shows an unexpected decline, possible problems should be investigated.

It is generally accepted that the results of single well injectivity tests may differ from the overall reservoir injectivity (Bachu, 2015; Wang et al., 2013). In addition to technical issues (e.g. type of test fluid; water, brine or CO₂), operations related to single well injectivity are expensive and usually challenging from an environmental perspective. Numerical simulations may be considered a powerful alternative under such conditions. A more accurate assessment of reservoir injectivity requires detailed reservoir simulations and, if possible, an injectivity test (Miri and Hellevang, 2016; Miri et al., 2015b). A simpler analytical model used by reservoir engineers to estimate the injectivity index of single-phase CO₂ in a homogeneous and isotropic reservoir with a fully-penetrating vertical well flowing under...
a pseudo-steady state is expressed as:

\[
I = \frac{Q}{(\rho_{\text{sat}} - \rho_r) \Delta P} = \frac{\rho_r}{\rho_s \left( (n \frac{k}{h} + S) \mu \rho_C \right)}
\]

where \( \rho_r \) is the density of CO\(_2\) under reservoir conditions in [kg/m\(^3\)], \( \rho_s \) is the density of CO\(_2\) under standard conditions in [kg/m\(^3\)], \( k \) is the permeability of the reservoir in [m\(^2\)], \( h \) is the thickness of the reservoir in [m], \( r_w \) is the radius of the well in [m], \( r_e \) is the radius of influence in [m], \( \mu \) is the viscosity of CO\(_2\) at the well bottom in [Pa s], and \( S \) is the skin factor (wellbore formation damage). Considering Eq. (2), the naive reservoir engineering approach for injectivity is to choose reservoirs with high aquifer transmissivity (permeability-thickness product \( k \cdot h \)) (Halland et al., 2011; Hosa et al., 2011).

Formation injectivity is controlled by several factors, including absolute and relative permeability, formation thickness, well completion, fluid properties and geochemical and petrophysical characteristics (Cinar et al., 2007; Kaldi and Gibson-Poole, 2008; Sundal et al., 2013a). In addition, several processes may change the injectivity of a reservoir as a result of CO\(_2\) injection (see Fig. 2). A massive injection of CO\(_2\) may alter the environment of the wellbore, causing thermal, hydraulic, mechanical and/or chemical effects, thereby modifying the injectivity as defined in Eq. (2). Accurate determination of these parameters and their interplay is essential for proper modelling of CO\(_2\) injectivity. These parameters are described in greater detail in the following sections. The period of use of a single site or well for CO\(_2\) injection is usually 20–30 years, occasionally longer. This report therefore focuses on the physical and chemical processes and factors that are of importance to this time frame.

**Geological constraints**

**Primary reservoir properties**

Geological factors such as permeability, size and physical boundaries are deciding factors with respect to pressure dissipation and injectivity. The regional connectivity of a reservoir unit significantly affects pressure dissipation. For extensive reservoir units like the Utsira Sand, large pore volumes can dissipate pressure. The pressure build-up is therefore minimal, and the injectivity is very high. The Tubåen Formation at Snøhvit, on the other hand, is segregated into a number of individual fluid/pressure compartments due to steep faults with sealing characteristics (Hellevang, 2015; Pham et al., 2011). Injection was performed in a channel sand with very limited lateral and vertical extent. In combination, this led to a rapid build-up of pressure.

Considering Eq. (2), the well injectivity is directly proportional to the average permeability, \( k \), and the reservoir thickness, \( h \). Accurate prediction of injectivity in subsurface saline aquifers therefore requires proper evaluation of the reservoir quality and the site-specific depositional geological heterogeneities. Primary reservoir properties like absolute permeability depend on the depositional environment and related facies distribution, burial compaction and diagenesis. Reservoir characterization has been an active area of research at the SUCCESS center. Experimental permeability analyses of reservoir rocks and detailed mineralogical information (microscopy, XRD) have been carried out for the Johanson Formation in the North Sea (Sundal et al., 2013a) and the De Geerdalen formation in Svalbard (Iden, 2012). For example, analyses of core samples from the Longyearbyen CO\(_2\) lab (Svalbard) have shown very low permeability matrices (less than 2 mD) and high capillary entry pressures (Farokhpoor et al., 2014). This may pose a serious challenge with respect to achieving practical levels of injectivity and injection pressure.

It is worth mentioning that subsurface data are often scarce and that estimating the reservoir properties of an injection well requires averaging techniques which may yield oversimplified plume geometry and formation injectivity (Sundal et al., 2013a). With respect to averaging methods for porosity and permeability, the presence of concretions rather than layers may seriously alter simulation results, as they are often present within otherwise permeable zones. Deterministic modelling of the effects of strata-bound calcite and low-permeability draping layers on CO\(_2\) and water flow would be possible with more data. Stochastic modelling would probably be more useful for of scattered concretions. Sundal et al. (2013a) suggested that scenario models that take expected site-specific geological heterogeneities on the micro and mesoscopic scale into account are useful as part of the reservoir characterization and in planning suitable injection and monitoring schemes.
The effect of geological heterogeneities

- Are flow baffles important to injectivity modelling?

Geological heterogeneity introduces alternative migration paths and may enhance immobilization and secure storage of CO₂. Reservoir heterogeneity has now been fully incorporated into fluid flow modelling by combining reservoir property models generated from seismology (effective porosity from acoustic impedance) with a geo-conceptual approach (Sundal, 2015; Sundal et al., 2014). The effect of site-typical geological heterogeneities, like discrete layers of low-permeability mudstone, tight calcite-cemented layers and directional permeability anisotropy on migration paths, pressure response and trapping potentials for CO₂ has now been investigated. We have found that depositional heterogeneities may limit the vertical communication of the reservoir, thus inducing further pressure build-up, but that the general impact on pressure distribution around the well is seen as negligible (Sundal, 2015; Sundal et al., 2013b). These findings are nonetheless largely sensitive to the choice of boundary conditions. The issue of far-field pressures (large-scale flow boundaries) and the regional connectivity of the target unit remains unresolved and needs to be addressed in the future. It has been shown that variability in terms of migration and trapping potential due to the effect of geological heterogeneity is almost in the same order of magnitude as for different physical model parameters (e.g. water and gas relative permeabilities, regional hydrodynamic gradients, CO₂-enriched brine convection) (Sundal et al., 2013a). The location of the injection well relative to the facies settings shows that the fluid distribution varies, despite comparable properties (i.e. porosity, permeability, net/gross, formation thickness), mainly due to the number and extent of cemented layers delimiting gravity-driven flow, causing separation and lateral spreading of the plume (Gasda et al., 2013a; Sundal et al., 2014, 2013a).

Transport constraints

Among the various rock and fluid properties (e.g. capillary pressure, wettability and relative permittivity) of the storage site, relative permeability is of significance in terms of injectivity modelling. In fact, for two-phase flow, which is the case for CO₂ storage, one needs to replace the absolute permeability in Eq. (2) with the effective permeability (defined by relative saturations of the fluids as well as the nature of the reservoir). The shape and end-point of the aqueous phase relative permeability curves are critical parameters that control the balance between viscous and capillary forces, thus governing the fluid mobility and phase distribution in porous media. With increasing brine mobility, the velocity of the flooding front also increases (Sundal et al., 2015), allowing for less gaseous phase encroachment and resulting in higher injectivity. Pham et al. (2011) studied the effect of hysteresis (i.e. the irreversibility of flow processes in porous media) would result in a different saturation distribution for each of the drainage and/or imbibition processes) on injection pressure and found it to be of minor importance.

In Eq. (2), the relative permeability is considered to be that of the mixture, but in some cases, for fluids ahead of or behind the front, three phases are in equilibrium, as reported by Miri et al. (2014b) for the Longyearbyen CO₂ lab. Before CO₂ is injected into the LYBCO₂ reservoir, work on the three-phase relative permeability should therefore be undertaken in order to further improve the simulation results that predict the injection pressure.

From a modelling perspective, injectivity assessments require models that capture relative permeability properly. The van Genuchten model is one of several ways of relating relative permeabilities to CO₂ and brine saturations (Van Genuchten, 1980). The model is empirical and requires experimental data in order to identify model parameters. Unfortunately, such experiments are not available at the SUCCESS center. The variations in injectivity with respect to the uncertainty associated with relative permeabilities are therefore unclear.

As a result of the high-velocity flows near the wellbore, the viscous forces (governed by the relative permeability) are dominant and capillary forces that have little effect on the evolution of the injection pressure. It is important to proceed with great care here: the capillary forces cannot be neglected everywhere. In particular, the capillary forces are dominant at the trailing edge of the CO₂ plume where the water phase flows back along the edges into the pore space via an imbibition process (Miri et al., 2015a). This process may intensify the amount of salt...
precipitation caused by chemical interactions between the injected CO₂ with formation brine. This will be discussed later.

The effect of fluid properties

The vertical migration of CO₂ plumes primarily depends on the vertical permeability and the density difference (relative compressibility of fluids) between the CO₂ injected and a host brine, see Fig. 3a. As shown, an elevated CO₂ temperature decreases the CO₂ density, thus enhancing the gravity override, which is unfavorable in terms of injectivity (Miri et al., 2014b). The uncertainty associated with ignoring the effect of compressibility increases dramatically with late injection times when gravity forces dominate. In addition, the mutual solubility between CO₂ and water and the aqueous phase density change in relation to the impurities. For example, increasing the amount of hydrocarbons in the injection stream (even slightly) will reduce the solubility of the CO₂ in the aqueous phase, and consequently the density of the mixture (Miri et al., 2014b). CH₄ would therefore result in a favorable density difference and faster plume migration. Conversely, inclusion of SO₂ in the CO₂ stream increases the mass density of SO₂-CO₂ mixtures and the total solubility of CO₂ in water increases exponentially with respect to SO₂.

Dissolution of CO₂ in brine/formation water

CO₂ injected underground gradually dissolves in the formation water, a process that continues until all CO₂ is dissolved or all of the water is saturated with CO₂. The amount of CO₂ that can dissolve (i.e. the saturation limit) is determined by the pressure, temperature and salinity. In general, more CO₂ can dissolve at lower temperatures and higher pressures. Increasing the salt content lowers the CO₂ solubility (see Fig. 3b). There is normally plenty of water to dissolve all CO₂, but complete dissolution takes a long time, more than thousands of years (Sundal et al., 2013a). The rate of dissolution is largely diffusion controlled, i.e. controlled by the concentration gradient of carbon in the water, but may also be convection controlled if the vertical permeability is large and the formation water is not very saline (e.g. the Utsira Sand; Elenius and Gasda, 2013).

There will be full saturation at the interface between water and CO₂, and then at lower CO₂ concentrations further away from the interface. This concentration gradient provides the driving force for the diffusional transport of CO₂ into the water. The total rate of dissolution greatly depends on the interface area between the CO₂ plume and the formation water. Simulations of CO₂ injection into the Tubåen Formation from the Snøhvit field suggest that diffusion transport could be considerable, with long time frames of e.g. 5 000 years (Pham et al., 2011). This effect can therefore be safely ignored for the injection time frame.

CO₂ is a buoyant fluid and tends to migrate upwards in a reservoir until it encounters a seal. A heterogeneous layered reservoir, with tight carbonate or shaley units, will spread the CO₂ laterally over a larger area compared to a homogenous reservoir (Sundal, 2015). This will lead to an accordingly larger CO₂–water interface area and faster dissolution for the heterogeneous reservoir (Elenius and Gasda, 2013; Hellevang, 2015; Sundal, 2015). The matter of whether CO₂ dissolution is relevant or not for the relatively short time scales associated with injection (here a 30-year time frame for one well) depends on the dissolution rate being sufficiently fast in order to significantly affect the near-well pressure evolution. This will likely not be the case for most reservoirs.

Dissolution of H₂O into injected CO₂

CO₂ is a non-polar molecule, but it shows a strong solvent capability at low pressures and high temperatures (gas state), and in a supercritical state (see Fig. 4a). The amount of H₂O that can dissolve in supercritical CO₂ is determined by the pressure, temperature and salinity. In general, more H₂O can dissolve at higher temperatures and pressures. The water solubility curve (water content curve) determines the chemistry of the aqueous phase and therefore its salt content. High solubility of water in the supercritical CO₂ phase may alter the equilibrium in the aqueous phase and even lead to phase separation (e.g. solid phase salt formation), which could pose a threat to the injectivity. It is worth mentioning that increasing salt and non-polar impurities like CH₄ lowers the water solubility (see Fig. 4b) thereby reducing the probability (or rate) of forming a solid salt phase (Miri et al., 2014b).
"The precipitation of salt could thus pose a real threat to actual field scale injection of dry CO$_2$ in saline aquifers. It is clearly a mistake to limit the phenomenon to only occurring in high salinities."

**Chemical effects**

### Drying out and salt precipitation

CO$_2$ interactions with formation water may cause injectivity issues. When injecting large volumes of under-saturated supercritical CO$_2$ into a saline aquifer, formation water eventually evaporates and the molar fraction of the water in the CO$_2$ stream increases, i.e. drying-out. In the meantime, as vaporization progresses, the concentration of dissolved salt in the brine builds up. When the salt concentration exceeds its solubility limit under the thermodynamic state of a given reservoir, the excess salt will precipitate out of the aqueous phase (salting out) and alter the porosity and permeability of the formation (Miri and Hellevang, 2016; Miri et al., 2015b).

By analyzing the fall-off pressure data, Grude et al. (2014) detected a low permeability zone in the Tubåen Formation at the Snøhvit Field (14% NaCl) surrounding the well at an early stage of injection. The explanation for this was salt accumulation and plugging of pores by halite scaling of such an extent that the salt could only be dissolved after injecting ethyl glycol (MEG). A recent study by Miri et al. (2015b) has also shown that the time scale for salt accumulation in the near-well region could be in the order of months. In addition, self-enhancing of salt growth and water film salt transport (see Fig. 5) have been introduced as underlying mechanisms of salt accumulation in the near-well area (Miri and Hellevang, 2016). Miri and Hellevang (2016) showed that this mechanism is active even at extreme CO$_2$ flow rates and that salt formation therefore could be more severe than previously concluded based only on core flooding experiments and numerical simulations. The precipitation of salt could thus pose a real threat to actual field scale injection of dry CO$_2$ in saline aquifers. It is clearly a mistake to limit the phenomenon to only occurring in high salinities.

In summary, although the FME SUCCESS center is learning more about the fundamental mechanisms and clogging behavior of salt precipitation, the degree of uncertainty associated with clogging models is very high, due to the number of inconsistencies reported in this regard. Further research on the mathematical modelling is thus the challenge at hand. Future efforts associated with implementing salt capillary pressure and development with the aid of pore scale modelling should aid progress in this area.

### Acid injection and wormhole formation

Chemical stimulation or acidizing refers to the stimulation of a reservoir by injecting a solution that contains reactive acid in order to enhance the injectivity of a well or by bypassing the formation damage. In carbonate reservoirs, the pore space becomes completely dissolved behind the front, and the permeability therefore increases clearly. The dissolution of the matrix creates channels which are referred to as wormholes and enables flow from the wellbore to the reservoir (Wangen, 2015). Deeper wormholes increase the efficiency of the stimulation job and improve injectivity, provided that the reservoir volume can accommodate the increasing injection rates. It is difficult to assess the effort, and models for predicting wormholes initiation and propagation are required in order to predict the improvement in injectivity.

![Figure 5: (a) Salt precipitation in a magnified portion of a homogeneous microchip (Miri and Hellevang, 2016). The close-up shows the porous structure of the precipitated salt. Aggregates are supported with the transport of water through the capillary continuous water films. (b) Massive salt aggregation in the porous network of the micro reactor.](image-url)
Wangen (2013b; 2014) studied the stability of reaction fronts in 2D and 3D. He found that all reaction fronts where the permeability increases behind the front become unstable. On the other hand, the fronts are stable if the permeability declines behind the front.

An important conclusion of this work is that dissolution processes may become unstable when they are coupled with fluid flow in porous media. These results imply that it is difficult to predict dissolution processes, even when the reaction kinetics are very accurate. Wormhole formation is a dissolution process where the pore space becomes completely dissolved behind the front, and the permeability therefore increases clearly. The sharp reaction front is therefore unstable for perturbations of all wavelengths. Wangen (2015) provided a numerical model for wormhole formation and propagation in 3D. The model relates the length and number of wormholes to injection parameters such as the Darcy velocity and the volume of the acids. He showed that the longest wormhole, which is the one with the shortest distance to the right-hand boundary (see Fig. 6), will grow faster at a certain point than the other wormholes, because this wormhole will have a higher Darcy flux at the front.

Geomechanical effects

The well injectivity index as defined in previous section is the relationship between the flow rate and the injection pressure. Safe injection requires a well-defined pressure limit in order to avoid undesired geomechanical effects, e.g. failure of the well or the formation integrity. The injection pressure needs to be monitored in order to ensure that the limits are not exceeded, allowing for early warning of unwanted incidents. Pressure monitoring also has the potential to provide information about a field’s development over time.

Experiences from the petroleum industry show that well integrity may eventually fail. In fact, existing fractures and faults have the potential for reactivation during CO₂ injection and may provide migration pathways for CO₂ if the injection pressure exceeds a certain limit. Fracture pressure is usually estimated based on theoretical approaches which may contain large uncertainties. Determination of the fracture pressure through in situ testing of the storage reservoir as well as the caprock unit is essential in order to assure a safe injection operation and the integrity of the CO₂ storage.

Determining injection pressure limits

Determination of a safe injection pressure requires a detailed model for the in situ stress conditions and an understanding of the failure criteria for the reservoir (including faults and fractures) and sealing units. Formation injectivity and fracture pressure are mainly addressed using different types of formation tests, e.g. Leak Off Tests (LOT), Extended Leak Off Tests (XLOT), step-rate tests (SRT) and mini-frac. The common approach for these tests is that the pressure response to injection is interpreted is providing valuable data on in situ stress conditions, formation failure and fracture response. Injection test data have been interpreted for the Longyearbyen CO₂ pilot (Bohloli et al., 2014) where both the reservoir and the caprock succession were tested. Mechanical characterization of intact reservoirs and caprock material was performed in addition to injection tests (Johnsen and Skurtveit, 2010; NGI, 2012), showing high strength and stiffness. For the Longyearbyen CO₂ pilot, the presence of pre-existing fractures (Ogata et al., 2014) combined with a very high intact tensile strength, indicates that the most important factor that controls injection is the fracture opening determined by the magnitude of in-situ stresses (Bohloli et al., 2014). The interpretation of the injection tests further indicates that fracture pressure has a higher magnitude and gradient in the overburden than in the reservoir. Fracture pressure in the reservoir interval is significantly lower than the vertical stress, which suggests that horizontal stress is the minimum principal stress. Opening pre-existing vertical to sub-vertical fractures is thus considered the most likely fracturing mode in the reservoir, whereas in the overburden it is uncertain due to the marginal difference between vertical and horizontal stresses. In summary, the combined assessment of geomechanical material characterization and injection tests was used to assess the in situ stress conditions and the behavior of the reservoir and overburden succession. This data provide essential input for addressing the pressure limit for safe CO₂ storage.

Injection well monitoring

Monitoring pressure and flow in injection wells is important in order to evaluate the reservoir performance. CO₂ injection data series from Snøhvit (Tubåen) and In-Salah...
Figure 7: Correlation of microseismic events and CO₂ injection history for well KB-502, In-Salah. High microseismic activity has been found to correlate with high injection rates and pressure that exceeds the estimated fracture pressure.

have been analyzed. A finding that is common to both injections is the relatively deep reservoirs with low porosity compared to Sleipner (Eiken et al., 2011). What was critical for the Snøhvit (Tubåen) injection was the increasing injection pressure required to maintain the flow rate (Eiken et al., 2011; Pham et al., 2011), whereas for In-Salah the main indications of changing geomechanical conditions were related to the surface heave measured (Onuma and Ohkawa, 2009). Both cases required an in-depth analysis and monitoring of the injection data series in order to achieve an understanding of the geomechanical response of the reservoir to injection. CO₂ injection has been shut down for both In-Salah and the Tubåen Formation.

The In-Salah injection data set was combined with microseismic monitoring (Oye et al., 2013), and the correlation between high injection pressure and microseismic activity (see Fig. 7) provides important documentation of microseismic monitoring as a useful tool for identifying fracturing events in the subsurface. Localization of microseismic events and the identification of failure modes provide data from microseismic events that can be used to identify the extent of the pressure-affected zone and to provide more detailed geomechanical models for the reservoir. After stopping CO₂ injection at In-Salah, work on microseismic monitoring has continued at the Longyearbyen CO₂ pilot (Kühn et al., 2014) in order to increase our knowledge about the link between the injection pressure and volumes, the microseismic response, and what this can tell us about the geomechanical response, including failure mechanisms and pressure distribution.

Figure 8: Injection history for the Tubåen Formation, Snøhvit. The bottomhole pressure has been estimated based on gauge pressure at 1777 m depth. The minimum fracture pressure is based on poroelasticity equations.
The injection data series from the Tubåen Formation has been analyzed with respect to the injection performance (NGI, 2010) and how the pressure and injectivity indices change over time and with stimulation (see Fig. 8). Analysis and interpretation of the injection data shows that the pressure was highest in 2008 before the well treatment (see Fig. 8). The pressure before the well treatment was close to the estimated minimum fracture pressure of 400 bar defined in NGI (2010), also calculated by Pham et al. (2011) to be about 440 bar. The reduction in the injectivity index associated with the pressure peak suggests continued matrix injection without fracturing. Extrapolation of the steady increase in injection pressure observed from 2009 to 2011, however, predicts that an estimated minimum fracture pressure of 400 bar would be reached within a few years of injection (NGI, 2010).

Detailed analysis of the injection data series and comparisons with fracture pressure require precise information about the bottomhole CO$_2$ injection pressure. One of the main challenges identified for the In-Salah and Tubåen data sets was the extrapolation of pressure gauge measurements at the well-head (for In-Salah) and at 1777 m depth (for Snøhvit) down to the injection interval (bottomhole). Uncertainties in the temperature, density and phase of CO$_2$ as well as the pipeline flow and friction give rise to high uncertainty regarding the bottomhole pressure. Measuring the CO$_2$ injection pressure as near the injection interval as possible is recommended in order to increase the accuracy of the pressure monitoring.

**Hydraulic fracturing**

Hydraulic fracturing has been used for decades as a means of increasing the injectivity of the near-well area. When the pore space in the near-well region becomes damaged as a result of drilling mud particles, hydrate formation or salt precipitation, hydraulic fracturing may become an important tool in the recovery-maximization of the injectivity of a CO$_2$ injection well.

A finite element formulation of hydraulic fracturing in 2D and 3D has been suggested by Wangen (2011; 2013a). The model is based on the Biot equations for rock. The fracture is represented in terms of elements that have their status changed from rock to fracture, and where the fracture volume is represented by means of fracture porosity. The model deals with fracturing of homogeneous and inhomogeneous rocks. The model partitions the stress into the initial stress and the additional stress caused by fluid injection. The later (additional) rock stress is obtained as a solution of the Biot equations of coupled fluid flow and deformations. It is shown how a uniform representation of the rock and the fracture is made for the pressure and the displacement equations. The model is tested on two cases, a homogeneous rock and a heterogeneous rock. The homogeneous case shows a fracture front that symmetrically propagates away from the injection point. The heterogeneous case shows a branched fracture, where there are events that fill the distance between the injection point and the farthest fracture tips (see Fig. 9a).

The well pressure increases slightly with small drops in pressure after a few initial pressure transients related to the element size. The homogeneous case shows fewer and larger events than the heterogeneous case (see Fig. 9b).

**Thermal effects**

Some of the reservoirs in the North Sea and in the Barents Sea have very low seafloor temperatures. In addition, injecting CO$_2$ with high flow rates may cause a Joule-Thomson cooling effect – the temperature drop that occurs when CO$_2$ expands from high to low pressure at constant enthalpy. In such cases, the injectivity may be severely reduced due to the generation of CO$_2$ or mixed-gas hydrates, with an impact on porosity, permeability and geomechanics. Hydrate formation is not expected in the Snøhvit CO$_2$ storage reservoirs, however, as the isenthalpic temperature drop in the reservoir resulting from the CO$_2$ expansion is very modest at the reservoir pressures and bottomhole temperatures (see Fig. 10). Joule-Thomson cooling may nevertheless cause hydrate stability in future CO$_2$ storage prospects, and the challenges associated with existing or newly-formed hydrates are therefore discussed below.

The reservoir cooling may result in reduced formation strength and lower fracture gradients as well. To properly control this effect, accurate temperature modelling of the pipeline and the wellbore is required. The extent of the reduction in fracture strength due to the cooling effect in the near-wellbore depends on the thermal expansion coefficient, which can be obtained from specialized core analysis. Using molecular dynamics (MD) simulations, Van Cuong et al. (2017) showed that the injection of CO$_2$ into saline aquifers under cold conditions results in reduced rock strength.

![Figure 9: a) The homogeneous case shows a symmetrical fracture made by three orthogonal planes. b) The inhomogeneous case shows a branched fracture without any preferred fracture planes.](image-url)
al. (2012) showed that CO₂ transport and interface stability are strongly affected by the temperature in the presence of calcite (see Fig. 11a). They found that open cages, always present at the hydrate surface, provide adsorption sites that trap carbon dioxide. These carbon dioxide molecules will assume the role of hydrate guest molecules and will promote restructuring of the neighboring water into hydrate-like patterns. In addition, Van Cuong et al. (2012) showed a positive correlation between the number of adsorbed CO₂ molecules and the temperature, while the adsorption stability declined (see Fig. 11a). These results are important when CO₂ is injected into reservoirs with pre-existing clathrate hydrates.

Vafaei et al. (2012) proposed non-equilibrium description of hydrates in reservoirs based on the direction of the free energy minimum. This involves hydrate formation on a water/carbon dioxide interface, from water solution and from carbon dioxide adsorbed on mineral surfaces, as well as all possible hydrate dissociations. Kvamme et al. (2011) and Vafaei et al. (2012) introduced a new hydrate reservoir simulator, based on this idea. The reservoir simulator was developed from a platform that was previously created for carbon dioxide storage in aquifers, the RetrasoCodeBright (RCB) software. The main tools for generating kinetic models have been phase field theory simulations, with thermodynamic properties derived from molecular modeling. To sum up, the thermodynamic conditions for hydrate formation have been studied at the FME SUCCESS center and this knowledge has also been implemented in numerical models. Predictive information about hydrate formation and injectivity loss is yet to be reported.

Hydrate formation might become a serious issue for pipeline transport of CO₂ as well. To control this, information is required on the upper bound of water content permissible in a stream of dense carbon dioxide. Kvamme et al. (2014) applied the combination of molecular dynamics simulations and classical thermodynamic relationships in order to estimate water drop-out onto rusty pipeline walls in the presence of hydrogen sulfide impurity. They found that hydrogen sulfide at a carbon dioxide concentration higher than 0.1 mol% can lead to water drop-out and growth of multiple hydrate phases immediately adjacent to the adsorbed water layers.
Critical Factors for Considering CO₂ Injectivity in Saline Aquifers

Recommendations for operations

- Proper geological characterization, including mapping large-scale compartmentalization by lithological and structural flow barriers/heterogeneities, should be performed with the data available. Quantitative stochastic uncertainty modelling should serve as an additional method.
- Salt will be an issue in most saline aquifers, but this will not cause a major problem for the total (long-term) injectivity (which is controlled by the available reservoir volume), as mitigation is relatively straightforward (e.g. injection of low-saline water). Potential salt scale should still be taken into account, as this may reduce the costs of workover.
- The uncertainty in relative permeability data has a great impact on the estimated injectivity of open aquifers; up to a fourfold variation in injectivity prediction reported by Mathias et al. (2013). Special core analysis (SCAL) of preserved/analogous samples in the injectivity assessment program is therefore recommended in order to obtain further accurate value.

Recommendations for Research

- The FME SUCCESS center has provided different elements that are required in order to properly model the injectivity of a proposed site. It is important at this stage to integrate all of these elements systematically into a single easy-to-use numerical tool and apply them to specific storage cases. A stochastic model is likely required in order to quantify the uncertainty that is mainly associated with the geological parameters.
- Although more has been learnt at the FME SUCCESS center about the fundamental mechanisms and the clogging behavior of the salt precipitation phenomenon, the level of uncertainty associated with clogging models is very high, as a number of inconsistencies have been reported in this regard. Further research on the mathematical modelling is therefore the most demanding task at present. Implementing salt capillary pressure and development with the aid of pore scale modelling is expected to aid progress in this area.
- The effect of depositional heterogeneities on the pressure build-up was only part of the project at the FME SUCCESS center. It would be interesting to test this effect under different geological settings and quantify the consequences, so that the results can be used in the assessment of injectivity.
- Near-well rate dependent skin effects were outside the scope of the FME SUCCESS center, but should be investigated further.

"Although more has been learnt at the FME SUCCESS center about the fundamental mechanisms and the clogging behavior of the salt precipitation phenomenon.......Implementing salt capillary pressure and development with the aid of pore scale modelling is expected to aid progress in this area."
References

* FME SUCCESS publication


Critical Factors for Considering CO₂ Injectivity in Saline Aquifers
Postal Address
FME-SUCCESS
Christian Michelsen Research AS
P.O. Box 6031
NO-5892 Bergen, Norway

Visiting Address
Christian Michelsen Research AS
Fantøftvegen 38
Bergen, Norway

Contact info
post@fme-success.no
charlotte@cmr.no
www.fme-success.no

This work was funded by the FME SUCCESS center for CO₂ storage under grant no. 193825/S60 from the Research Council of Norway. The FME SUCCESS center is a consortium of partners from industry and science, hosted by Christian Michelsen Research AS.