Call ID: LC-SC3-NZE-5-2019-2020

Demonstrating a Refinery-adapted cluster-integrated strategy
to enable full-chain CCUS implementation - REALISE

# Deliverable D3.5 - Assessment of injection profile and infrastructure requirements to control & monitor of transportation pipelines and intermediate storage vessels


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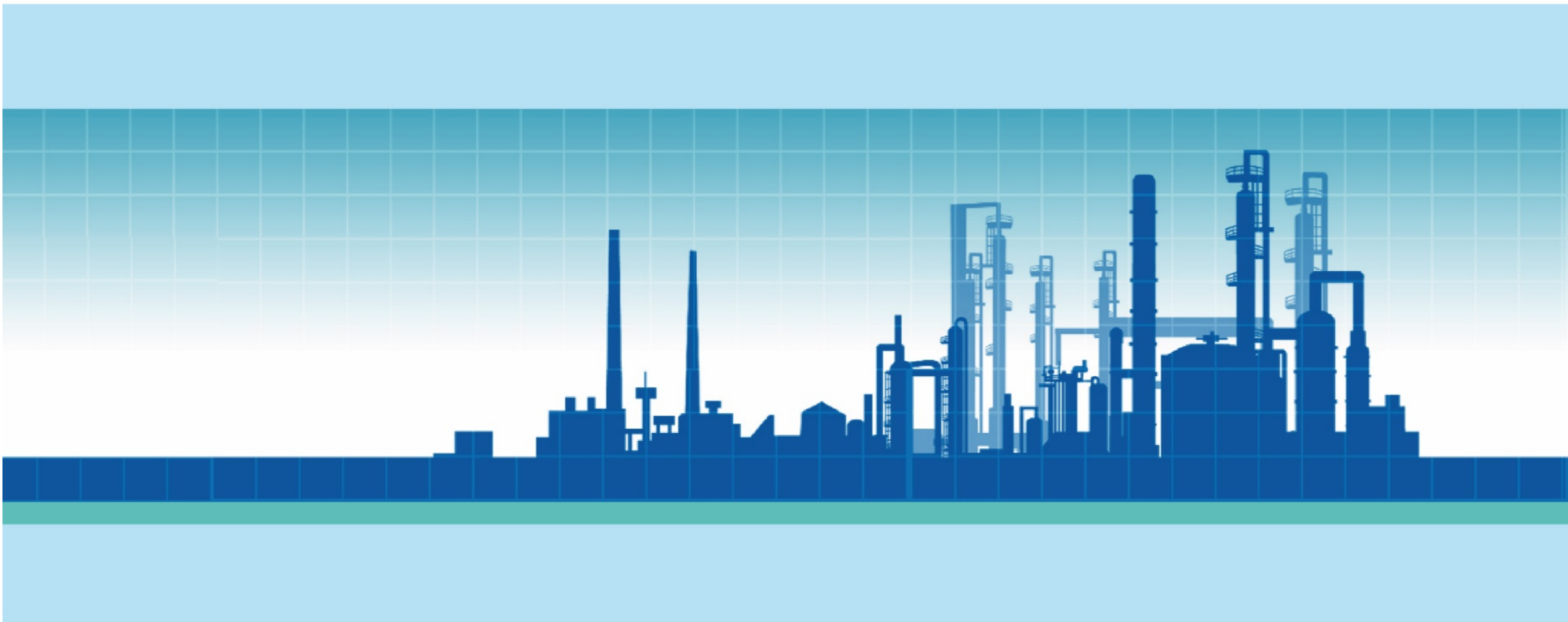


Date 06/05/2022

Dissemination Level: Public

# Document History

## Revision History

This document has been through the following revisions:

| Version No. | Revision Date | Brief Summary of Changes | Name |
|---|---|---|---|
| 0.5 | 02/02/2022 | First (Rough Cut) working draft completed | Paul Murphy (on behalf of Ervia) |
| 0.8 | 16/03/2022 | Minor revision of rough cut draft | Paul Murphy (on behalf of Ervia) |
| 1.0 | 19/04/2022 | Fine cut working draft agreed following whole team meeting reviewing comments | Paul Murphy (on behalf of Ervia) |
| 1.1 | 29/04/2022 | Final version signed off | Paul Murphy (on behalf of Ervia) |
| 2.0 | 06/05/2022 | Final version for submission | Paul Murphy (on behalf of Ervia) |
| | | | |

## Authorisation

This document requires the following approvals:

| AUTHORISATION | Name | Signature | Date |
|---|---|---|---|
| WP Leader | Paul Murphy | Paul Murphy | 06/05/2022 |
| Project Coordinator | Inna Kim | Inna Kim | 06/05/2022 |

This project has received funding from the European Union's Horizon 2020 research and innovation programme under grant agreement No 884266



## Disclaimer

# Glossary of Terms

| Acronym, Term or Abbreviation | Explanation |
|---|---|
| °C | Degrees Celsius. SI Unit of temperature |
| avg | Average |
| bar | Bar is a metric unit of pressure. It is equal to 100 kPa. |
| bara | When pressure is measured relative to a perfect vacuum, it is called absolute pressure |
| barg | When pressure is measured relative to atmospheric pressure (1 bar), it is called gauge pressure |
| BoD | Basis of Design provides all the principles, business expectations, criteria, considerations, rationale, special requirements, and assumptions used for decisions and calculations required during the design stage |
| BGE | Bord Gáis Energy. Utility company that supplies gas and electricity and boiler services to customers in Ireland and operates the Whitegate CCGT. Realise partner. |
| BHP | Bottom Hole Pressure. The pressure measured at the bottom of the hole. |
| BHT | Bottom Hole Temperature. The temperature measured at the bottom of the hole. |
| CCGT | Combined Cycle Gas Turbine. A combined-cycle power plant uses both a gas and a steam turbine together to produce up to 50% more electricity from the same fuel than a traditional open-cycle gas turbine |
| CCUS | Carbon capture, utilization and storage, also referred to as carbon capture, utilization and sequestration, is a process that captures carbon dioxide emissions from sources like industry or power plants and either reuses or stores it so it will not enter the atmosphere. |
| $CO_2$ | Carbon dioxide - a colourless gas having a faint sharp odour and a sour taste. It is a greenhouse gas, but it is a minor component of Earth's atmosphere, formed in combustion of carbon-containing materials, in fermentation, in respiration of animals, and employed by plants in the photosynthesis of carbohydrates. |
| Dense | Liquid or supercritical phase carbon dioxide |
| Depleted | Reservoir formations of natural gas fields that have produced all or part of their economically recoverable gas. |
| DNV | DNV (formerly DNV GL) is an international accredited registrar and classification society headquartered in Høvik, Norway. |
| Energy Institute | Global professional body for the energy sector; delivering good practice information and guidance, training courses and qualifications |
| EPA | Environmental Protection Agency |
| Equinor | Norwegian energy company formerly known as Statoil. Realise Partner |
| Ervia | State owned multi-utility company distributing natural gas, water and dark fibre services in Ireland. Realise partner |
| ESB | Electricity Supply Board. State owned vertically integrated utility in electricity generation, transmission and distribution to supply. Owner and operator of Aghada CCGT. Realise partner |
| GNI | Gas Networks Ireland. State owned utility who owns and operate the natural gas network in Ireland. |
| $H_2O$ | Chemical symbol for water |
| HP | High Pressure |
| Hydrates | Inorganic salts containing water molecules |
| $H_2$ | Hydrogen. This is a colourless, odourless gas. It is easily ignited. Once ignited it burns with a pale blue, almost invisible flame. |
| ID | Internal Diameter |
| Inch | Imperial unit of length. Equal to 25.4 mm. Widely used in oil and gas industry |
| Inch Gas Terminal | The entry and exit point for gas between the KEL owned and operated KHGF and GNI owned natural gas network |
| Injectivity | Rate of injection over the pressure differential between the injector and the producer |

| Acronym, Term or Abbreviation | Explanation |
|---|---|
| Intermediate Storage | Temporary storage for gas prior to onward transport to shipping |
| Irving Oil | Irving Oil Ltd. is a Canadian gasoline, oil, and natural gas producing and exporting company. They own and operate the Whitegate oil refinery. Realise partner. |
| ISO | International Organisation for Standardisation |
| Joule-Thompson effect | A thermodynamic process that occurs when a fluid expands from high pressure to low pressure at constant enthalpy (an isenthalpic process). Such a process can be approximated in the real world by expanding a fluid from high pressure to low pressure across a valve. Under the right conditions, this can cause cooling of the fluid |
| KEL | Kinsale Energy Limited |
| Kg | SI unit of mass. Equal to 1000 grams |
| Kg/h | Measure of mass flow rate |
| KHGF | Kinsale Head Gas Field |
| kJ/(kg·K) | Kilojoules per kilogramme Kelvin. SI unit of specific heat capacity. |
| km | SI unit of length. Equal to 1000 metres |
| $km^2$ | Unit of area |
| Lean | Carbon dioxide in gaseous phase |
| LNG | Liquefied Natural Gas |
| Load factor | Measure of power plant capacity utilisation for a period of time |
| LP | Low Pressure |
| LPG | Liquefied Petroleum Gas is a flammable mixture of hydrocarbon gases such as propane and butane |
| m | SI unit of length |
| m2 | Unit of area |
| m3 | Unit of volume |
| Mass flow rate | Mass of a liquid substance or gas passing per unit time |
| MEA | Monoethanolamine. Aqueous solution of MEA is a solvent commonly used in post combustion carbon capture. |
| Mn | Million |
| mol | Mole, the base unit of amount of substance in the International System of Units (SI). It is defined as exactly $6.02214076\times10^{23}$ elementary entities ("particles"), which may be atoms, molecules, ions, or electrons. |
| Mtpa | Million or Mega tonnes per annum - unit of measurement |
| MW | Megawatt - unit of energy. Equivalent to 1000 kilowatts |
| $N_2$ | Nitrogen |
| Natural gas | Naturally occurring hydrocarbon gas consisting of mostly methane. Colourless, odourless and flammable |
| Northern Lights | A commercial $CO_2$ cross-border transport connection project between several European capture initiatives with transport of the captured $CO_2$ by ship to a storage site on the Norwegian continental shelf. Equinor, Shell and Total are the joint venture partners |
| $O_2$ | Oxygen. Tasteless and colourless gas |
| Pa | Pascal. SI unit representing pressure |
| PE | Polyethylene. An inexpensive plastic material that is corrosion and chemical resistant and can be very durable. |
| Pentair | Pentair is an American water treatment and process engineering company. Its Danish subsidiary Pentair Union Engineering's main activities are worldwide sales, engineering, installation and commissioning of modular and individually designed CO2 plants. Pentair are a Realise partner |
| PI | Production Index |
| PPM | Parts Per Million |
| PSA | Pressure Swing Adsorption |

| Acronym, Term or Abbreviation | Explanation |
|---|---|
| psia | Pounds per square inch absolute. Imperial unit of pressure |
| REALISE | Demonstrating a Refinery-Adapted Cluster-Integrated Strategy to Enable Full-Chain CCUS Implementation. Project funded by the European Union's Horizon 2020 research and innovation programme under grant agreement No 884266 |
| Reservoir | Naturally occurring storage area of oil or natural gas which is contained in fracture or porous rock formations |
| SEI | Sustainable Energy Ireland. The wholesale electricity market on the island of Ireland |
| SI | International System of Units |
| Sintef | SINTEF is a broad, multidisciplinary research organisation with international top-level expertise in the fields of technology, the natural sciences, medicine and the social sciences, based in Norway. Sintef are a Realise partner |
| SPA | Special Protection Area |
| SSSV | Subsurface Safety Valve |
| Supercritical | Fluid state of $CO_2$ where it is heated and held at or above its critical temperature and pressure. In this supercritical phase, $CO_2$ exhibits properties and behaviors between that of a liquid and a gas. |
| TNO | TNO is an independent Dutch research organisation. They focus on transitions or changes in nine social themes including energy and a sustainable future. TNO is a Realise partner |
| Tonnes | SI unit of mass equivalent to 1000kg |
| tpa | Tonnes per annum |
| Transmission | Gas pipeline system and associated facilities designed for gas supply to consumers |
| TEG | TriEthylene Glycol |
| TVD | True Vertical Depth. Measurement of a straight line perpendicularly downwards from a horizontal plane |
| W | Watt. SI unit of power |
| Well | Hydrocarbon well that produces raw natural gas or oil as its primary commercial product |

# Executive summary

The REALISE project team has examined a scenario of carbon capture from the largest industrial emitters in the Cork, Ireland area, consisting of two natural gas fired power plants and an oil refinery, where they are treated as a carbon capture cluster. It was found that the cluster which currently comprises approximately 80% of the emissions within a 60 km radius of Cork Harbour could capture $CO_2$ and permanently store it either in indigenous locations or export it to permanent storage overseas. The full study includes both technical and economic assessment for the cluster.

The estimated volume of $CO_2$ that could be captured from the cluster of three emitters in the case study ranges from 1.61 million tonnes to 2.77 Million tonnes per annum (Mtpa) under the low and high scenario respectively. The base case anticipates 2.23 Mtpa of $CO_2$ can be captured annually over a period of 25 years. The base case assumes the two power plants are operated at 55% load factor while Irving Oil Whitegate refinery is operated at 96% load factor and all plant are fitted with post combustion carbon capture rate of 90%. Further studies by REALISE are examining higher capture rate, possibly up to 99%.

This study develops on a previous confidential report that presents an outline of the systems required to transport and store the captured $CO_2$, either to indigenous storage – the depleted Kinsale Head gas field – or by ship transport to the Northern Lights storage system in Norway. Systems are designed to meet the captured rates mentioned above.

In particular this report includes an assessment of injection profile and infrastructure requirements to control & monitor transportation pipelines and intermediate storage vessels.

# Table of Contents

# List of Figures



# List of Tables

# 1 Project Outline

## 1.1 Carbon Capture Utilisation and Storage

CCUS is being assessed for utilisation in Ireland as part of the overall goal to move Ireland towards a cleaner energy future by reducing $CO_2$ emissions from the electricity, heating, industry, agriculture and transport sectors.

The confidential report is focused on the feasibility of developing a CCUS project located in the lower Cork harbour area; serving two large Combined Cycle Gas Turbine (CCGT) gas power generation plants and an oil refinery.

Cork is the second largest city of Ireland with a population in excess of 300,000. It is planned that this Cork cluster could be expanded over time to bring in other industries located in the greater Cork area. The city is contained within the county of Cork which has a population of just over 540,000, an area of 7,500 $km^2$ and contains Cork Harbour, the second largest natural harbour in the world after Sydney, Australia.

Other industrial clusters in Dublin (the capital city), Limerick (the third city) and Drogheda (port town with a large Liquefied Petroleum Gas (LPG) shipping facility and cement plant) are also either under consideration or could be considered in the future.

The focus of the Cork CCUS project is to utilise the depleted Kinsale Head Gas Field (KHGF) as a long-term storage facility, coupled with marine infrastructure that would facilitate the transportation of $CO_2$ to other long-term below ground storage facilities in Europe.

## 1.2 REALISE

**REALISE – Demonstrating a Refinery-Adapted Cluster-Integrated Strategy to Enable Full-Chain CCUS Implementation**

As part of the CCUS development process, REALISE will develop carbon capture, utilisation and storage strategies for oil refineries centred industrial clusters and demonstrate in a pilot scale an absorption technology based on novel solvent for cost-efficient and environmentally sustainable $CO_2$ capture from multiple flue gas sources.

REALISE further addresses the full CCUS chain including $CO_2$ transport, storage and utilisation options for the specific business cases to be developed in the project for Ireland, South Korea and China, as well as assessment of the financial, political and regulatory barriers and opportunities in these countries.

## 1.3 Basis Of Design (BoD)

The basis of design is determined the following design parameters:

1. The main **emitters** for the study table are listed below; along with respective $CO_2$ emissions to be included as the design basis.

The following are the selected cluster locations:-

- Whitegate Oil Refinery – Owned and operated by Irving Oil,
- Aghada CCGT Power Station - Owned and operated by Electricity Supply Board (ESB) and
- Whitegate CCGT Power Station Owned and operated by Bord Gáis Energy (BGE)

2. Current options for storage are export or indigenous storage i.e.;-

I. Export: by ship to another country for injection into their geological formations or

II. Indigenous storage: injection into Ireland's geological formations

While other options will become available in the future, for REALISE the Northern Lights Project will be considered in this study as the potential receiving faculty for the produced $CO_2$ for the export option (Option i).

The Kinsale Head depleted gas field will be considered for the indigenous storage option (Option ii).

3. The **Carbon Dioxide ($CO_2$) specification** for export to the Northern Lights Project is outlined in Table **1**.Please note the specification for indigenous storage has not being developed but the Acorn Project is cited as a good example in Table 2.

Based on REALISE Task 2.0 the specification for export is given in Table 1; Table 2 gives the $CO_2$ quality requirements for transport to indigenous storage. The captured $CO_2$ will contain impurities and non-condensable gases. The non-condensable gases are components that, when pure, will be in gaseous form at 15 barg and -26°C. The content of non-condensable gases will be limited by the actual solubility in the liquid $CO_2$ in the interim storage tanks at the capture plants.

The captured $CO_2$ will require further treatment since the $CO_2$ must be free of significant impurities such as hydrogen sulphide and water, otherwise, the gas can corrode the pipeline.

The major impurities influence the characteristics of the $CO_2$ stream; in general, the impurities lower the density of the $CO_2$ stream and increase the overall 'critical pressure' leading to uncertainties over what conditions are required within the transport system.

**Table 1: Export Option - Northern Lights $CO_2$ Composition Requirements**

| Component | Concentration, ppm (mol) |
|---|---|
| Water, ($H_2O$) | ≤ 30 |
| Oxygen, ($O_2$) | ≤ 10 |
| Sulphur oxides, ($SO_x$) | ≤ 10 |
| Nitric oxide/Nitrogen dioxide, ($NO_x$) | ≤ 10 |
| Hydrogen Sulfide, ($H_2S$) | ≤ 9 |
| Carbon monoxide, (CO) | ≤ 100 |
| Amine | ≤ 10 |
| Ammonia, ($NH_3$) | ≤ 10 |
| Hydrogen, ($H_2$) | ≤ 50 |
| Formaldehyde | ≤ 20 |
| Acetaldehyde | ≤ 20 |
| Mercury, (Hg) | ≤ 0.03 |
| Cadmium, (Cd) and Thallium, (Tl) | ≤ 0.03 (sum) |

The captured $CO_2$ will contain impurities and non-condensable gases. The non-condensable gases are components that, when pure, will be in gaseous form at 15barg and -26°C. The content of non-condensable gases will be limited by the actual solubility in the liquid $CO_2$ in the interim storage tanks at the capture plants.

**Table 2: Indigenous Storage Option - Amec Foster Wheeler report[1]: Requirements**

| Component | Recommended Specification, | Advisory Notes |
|---|---|---|
| $CO_2$ | 95 mol% | |
| Hydrogen Sulphide | <200 ppmv | Health & Safety |
| Carbon Monoxide | <2000 ppmv | Health & Safety |
| NOx | <100 ppmv | Health & Safety |
| SOx | <100 ppmv | Health & Safety |
| Oxygen | <10 ppmv | Technical: Pipeline and storage |
| Nitrogen | 1 mol % | Technical: EOR led |
| Hydrogen | 1 mol % | Technical: EOR led |
| Argon | 1 mol % | Technical: EOR led |
| Methane | 1 mol % | Technical: EOR led |
| Non-condensable | 4 mol % | Technical: Pipeline led |
| Water | 50 ppmv | Technical: Hydrate & corrosion |
| Hydrocarbons | 2 mol % | |
| Particulates | 1 mg/Nm³ | Technical: Pipeline led |
| Particle size (micron) | ≤10 µm | Technical: Pipeline led |
| Mercury | Regulation | |
| Ammonia | <50 ppmv | Technical |
| Other | Caution: must not negatively impact hazards of a release, pipeline/storage/well integrity | |

The captured $CO_2$ will require further treatment since the $CO_2$ must be free of significant impurities such as hydrogen sulphide and water, otherwise, the gas can corrode the pipeline.

[1] AMEC, 2015. TVU CCUS, Work pack 5-Onshore Infrastructure. Pipeline Network $CO_2$ Quality Specification.

The major impurities influence the characteristics of the $CO_2$ stream; in general, the impurities lower the density of the $CO_2$ stream and increase the overall 'critical pressure' leading to uncertainties over what conditions are required within the transport system.

### 1.3.1 Scope Premise

The main premise for the basis of design, is that $CO_2$ is received from the capture plant output battery limit (boundary fence), where the $CO_2$ can be conditioned and compressed for transport by pipeline to either:

1. Intermediate storage for ship transport for export or
2. Onwards transportation to indigenous storage at a depleted gas field.

- Note: The carbon capture plant and related technologies are not part of the scope for Task 3.3, the capture plant is dealt with in another Project Realise Task 2 This study (Task 3.3) is focused on the $CO_2$ cluster transportation of $CO_2$ and storage only.
- The basis of this section of the study is:
- Conditioning of $CO_2$ to meet compression and transport requirements,
- Compression of $CO_2$ to meet transport requirements for export and indigenous storage ,
- Transportation of $CO_2$ via onshore pipelines,
- Export Storage of $CO_2$ to meet shipping requirements (ship size, liquefaction, temporary storage, jetty, and loading arms, and
- Indigenous Storage of $CO_2$ to meet depleted field requirements (pipelines, conditioning, compression, onshore and offshore infrastructure)

### 1.3.2 Emitters

- The scope for the Task 3.3 report is a cluster transport study that centres on the transportation of captured $CO_2$ at the selected cluster locations to potential storage locations.
- The main emitters for the study table are listed below along with respective $CO_2$ emissions; to be included as the design basis.
- The following are the selected cluster locations:
- Whitegate Oil Refinery (Irving Oil) [Grid Ref 51°49'15.0"N 8°14'27.9"W]
- Aghada CCGT Power Station (ESB) [Grid Ref 51°50'02.5"N 8°14'14.7"W]
- Whitegate CCGT Power Station (BGE) [Grid Ref 51°48'58.8"N 8°14'49.1"W]
- The locations were selected on the basis of being the optimal cluster of the largest $CO_2$ emitters in the Cork Harbour area and the cluster can be considered for potential expansions in the future, if deemed appropriate, based on the market evolution.
- The cluster location also leverages selection based on:
- Existing assets/infrastructure for repurposing potential,
- Proximity to indigenous storage (Kinsale Head depleted gas field), and
- Proximity to a deep water harbour

**Table 3: Emitter details and $CO_2$ emissions per year**

| Site / Location | Sector | Owner/Operator | Capacity (MWe) | $CO_2$ Emissions (Mt/y) As per C02 Cork cluster proposed annual production base case scenario |
|---|---|---|---|---|
| Whitegate Refinery | Oil Refining | Irving Oil | N/A | .32 |
| Aghada CCGT | Power Generation | ESB | 430 | 1.08 |
| Whitegate CCGT | Power Generation | BGE | 450 | 1.08 |

**Table 4: Emitter details and $CO_2$ flow rate in KG/hr**

| Site / Location | Min $CO_2$ KG/Hr | Max $CO_2$ KG/Hr | Average $CO_2$ KG/Hr |
|---|---|---|---|
| Whitegate Refinery | 26,849 | 38,356 | 36,822 |
| Aghada CCGT | 65,687 | 199,053 | 109,479 |
| Whitegate CCGT | 65,687 | 199,053 | 109,479 |

Table 5: Composition table between amine unit and compression unit

| Compound | Concentration | Units |
|---|---|---|
| **$CO_2$** | **Balance** | |
| N2 | 500 | ppm-V/V |
| O2 | 50 | ppm-V/V |
| Aldehydes | 5 | ppm-V/V |
| NOx | <10 | ppm-V/V |
| NH3 | <5 | ppm-V/V |
| SO2 | 0 | ppm-V/V |
| Water | Saturated at 30 C and 2 bara | |

### 1.3.3 Design cases

The three design cases to be considered are shown in Table 6.

Table 6: Design Cases

| Design Case | Description |
|---|---|
| 1 | **Export of $CO_2$** via a new jetty at Aghada site |
| 2 | **Export of $CO_2$** from the existing jetty at the Whitegate refinery |
| 3 | **Indigenous Storage of $CO_2$** via the Inch Terminal to the depleted Kinsale Head Reservoir |

The REALISE project will incorporate the following components for the various export design cases:

1. Output from the respective Capture Plant battery limit
2. Conditioning / Compression Plant adjacent to the Capture Plant (gaseous phase output)
3. Pipeline transportation (gaseous phase)
4. Liquefaction Plant (liquid phase output)
5. Pipeline transportation (liquid phase)
6. Intermediate Storage (liquid phase)
7. Pipeline transportation to vessel (liquid phase)

The REALISE project will incorporate the following components for the indigenous storage design case:

1. Conditioning / Compression Plant adjacent to the Capture Plant (gaseous phase output)
2. Pipeline transportation (gaseous phase)

## 1.4 Description of the deliverable and purpose

The purpose of this Task group within REALISE is to undertake an assessment of the potential for CCUS at an oil refinery which is part of a large CCUS cluster. The cluster transport study centres on the transportation of the captured $CO_2$ at the identified cluster locations to selected storage locations.

This report outlines the findings for deliverable D3.5 of the deliverables assigned to this Task Group, which is as follows:

- Assessment of injection profile and infrastructure requirements to control & monitor of transportation pipelines and intermediate storage vessels

This report is closely linked with deliverables D3.6 and D3.7:

- Deliverable D3.6: Assessment of options to provide flexibility in the design and operation of the transport and storage network;
- Deliverable D3.7: High-level schematics (process flow diagrams) from Emitter to Storage

# 2 Assessment of injection profile and infrastructure requirements to control & monitor transportation pipelines and intermediate storage vessels

## 2.1 Introduction

The transport of $CO_2$ from the capture site to the storage location is not always trivial. The particular properties of the fluid, e.g., $CO_2$, can result in issues regarding reliability and structural integrity as the temperature of the transported fluid can change rapidly or a phase boundary is being crossed. This will have its influence on the design choices to be made. Also, the supply of $CO_2$ will not be constant in time, a feature the system must be able to accommodate.

In this document a high-level assessment of the challenges to transport the $CO_2$ in a safe and reliable manner is outlined.

### 2.1.1 Target capture rate, intermittency

$CO_2$ is supplied by two similar CCGTs and one refinery. The average minimum and maximum supply values can be found in the Basis of Design and are listed in Table 7. The amount of $CO_2$ which needs to be transported will vary in time. These fluctuations can occur rapidly because both power stations will be used to match the supply and demand on the grid and will probably not have a constant load. The refinery however will generate a more constant supply of $CO_2$.

The short-term fluctuations of two months are plotted in Figure 1. It can be seen here that these fluctuations are ranging from 0 to 160 t/hr (0-44 kg/s). This change in $CO_2$ supply must also be accommodated in the transport phase.

**Table 7 Min/ Max and average $CO_2$ emissions of the three suppliers**

| Emitter | Avg (yearly) [Mtpa] (kg/s) | Min [kg/s] | Max [kg/s] |
|---|---|---|---|
| Whitegate Refinery (Irving Oil) | 0.32 (10.1) | 7.45 | 10.65 |
| Aghada Powerplant (ESB) | 1.08 (34.2) | 18.25 | 55.30 |
| Whitegate Powerplant (BGE) | 1.08 (34.2) | 18.25 | 55.30 |
| Total | 2.48 (78.5) | | |

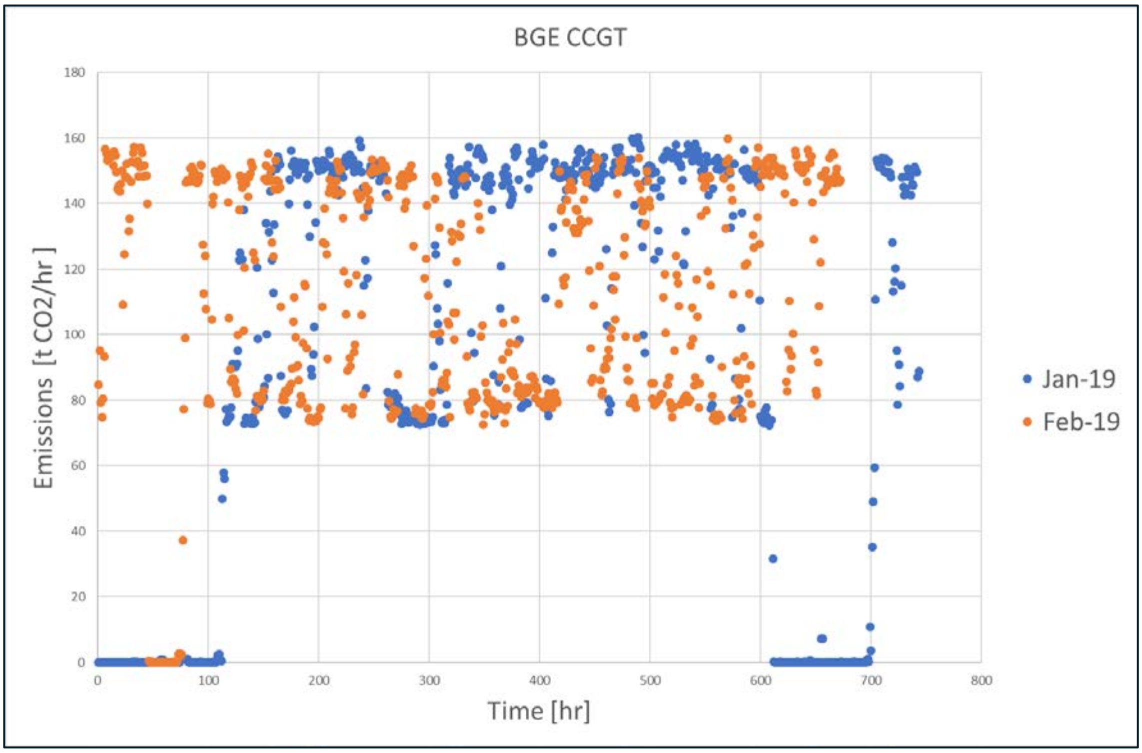


**Figure 1. Hourly data of $CO_2$ emission of the BGE Whitegate Powerplant for January and February of 2019. Emission level ranges from zero to a maximum of about 160 t/hr.**

Looking at the fluctuations in the year 2019 on hourly rate, the longest production period was 1173 hrs, the longest stop lasted 384 hrs. If a constant injection is needed, an intermediate storage capacity is required and should be able to store for ~400 hrs at the lowest injection rate. It can be reasonably assumed that the fluctuation post 2030 will be more pronounced given the anticipated increase in renewable energy production.

### 2.1.2 Layout of the system

The layout of the system can be found in Figure 2. Here the three capture locations are depicted together with the options for the CCS.

Only two options will be assessed. The storage in the indigenous field and the storage using the Northern Light location via ships. Though three cases are defined because the location of the liquefaction and intermediate stage facility, used for the $CO_2$ export option, could either be at the Aghada site or at Whitegate refinery there are only two cases for storage. However, for the analysis carried out in this report that difference has no significant influence on the results and therefore they are combined into one case.

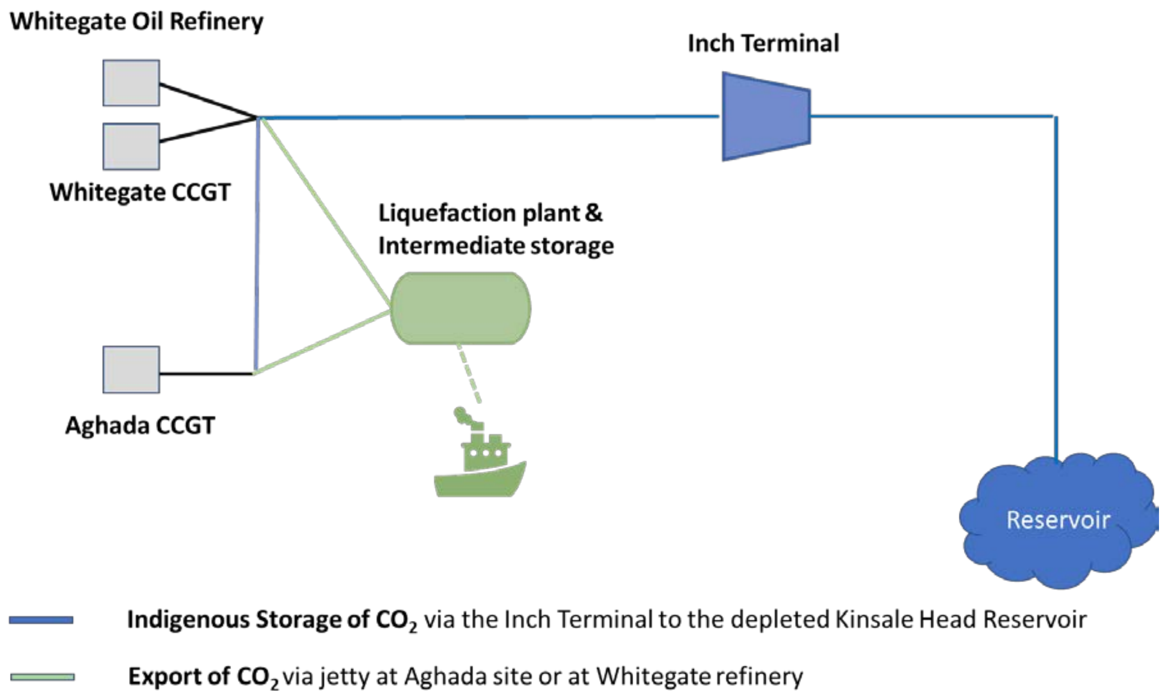


**Figure 2 Schematic layout of the system.**

In the option of transport to the indigenous field (Figure 2), at the capture site at the supplier a low-pressure compressor is installed to raise the pressure to ~35 bar. Then after the onshore pipeline the fluid arrives at the Inch Gas Terminal where the pressure is raised again to go in the offshore pipeline which takes the $CO_2$ to a platform where it enters the well to the subsurface storage location.

In Figure 2the option for the export; more processes must be completed such as drying of the $CO_2$ and the liquefaction, and an intermediate storage facility is required to store the $CO_2$ before it can be transported in the ship which brings the $CO_2$ to its final destination. The two different options are detailed in the following sections.

## 2.2 Option 1: Storage in the indigenous field

### 2.2.1 Introduction

The storage capacity and feasible injection rates of a transport and storage system are determined by the properties of the pipeline, the injection wells, and the properties of the reservoir. With reservoir properties fixed, injection rates and total storage capacity can be engineered to a certain degree through the choice of operational conditions, well design and number of wells.

Operational conditions refers to the $CO_2$ phase in the transport pipeline, whether that is gas or liquid. When pipeline pressure is below about 30 bar, the $CO_2$ is in gas phase, at temperatures relevant for subsea pipelines. When $CO_2$ is transported in dense phase, for pipeline pressures of 80 – 110 bar, the efficiency of pipeline transport increases as a result of higher density.

Figure 3 shows typical conditions of the $CO_2$ in the pipeline and the wells system, in a temperature-pressure phase diagram, for a system with $CO_2$ in the liquid phase. The size of the different boxes represents the range of conditions throughout a typical CCUS project that injects and stores $CO_2$ in a depleted gas field. It is obvious that the conditions in the pipeline and wells are all close to the phase line that separates gas phase and liquid phase, and close to the critical point. This means that two-phase conditions are likely to occur in the injection wells and in the depleted reservoir.

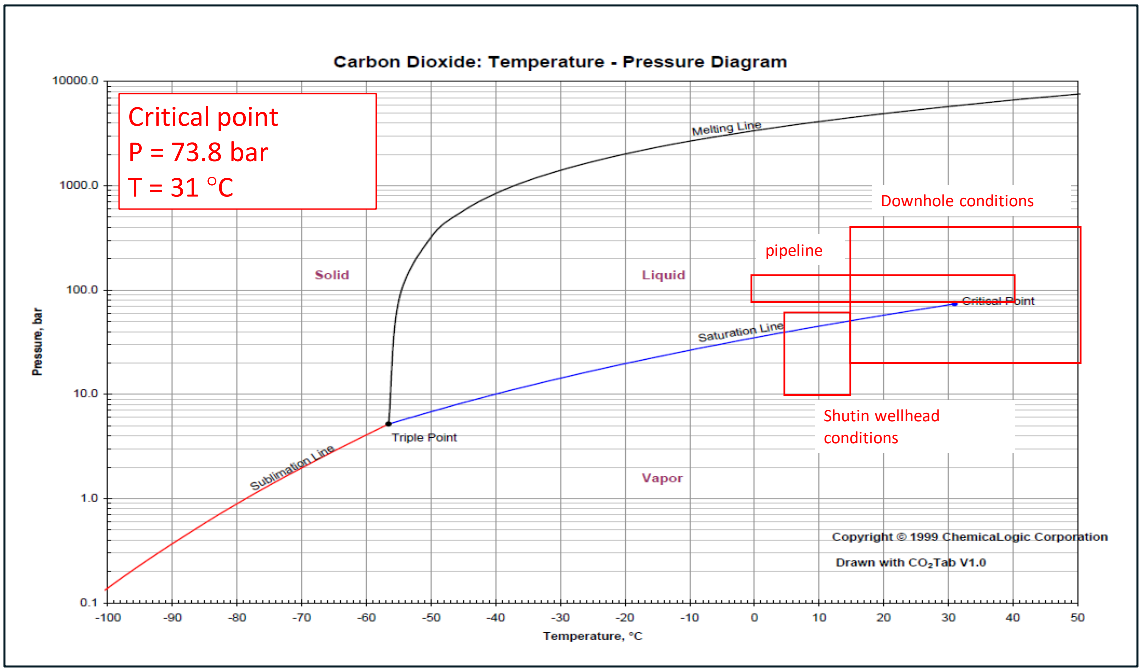


**Figure 3: Typical conditions in pipeline and injection well, for pure $CO_2$ transported in liquid phase.2**

Issues related to two-phase conditions can be avoided by operating the transport and storage system with $CO_2$ in the gas phase. However, with a pipeline operating at about 30 bar, the system will not be able to utilise the total storage capacity in a depleted field.

Two-phase flow conditions do not necessarily pose a problem. The Rotterdam Opslag en Afvang Demonstratieproject (ROAD) CCUS project planned to use an offshore depleted gas field for storage of $CO_2$ captured at a power plant, transportation and storage of gas-phase $CO_2$ during an initial phase and switching to liquid-phase $CO_2$ once the pressure in the gas field would be sufficiently high.[3] The ROAD project was cancelled in 2017, but the Porthos consortium has taken

[2] Gas Control Technologies Conference (2021), Available at SSRN: https://ssrn.com/abstract=3813026 or http://dx.doi.org/10.2139/ssrn.3813026
[3] ROAD, (2019) Close-out reports, accessed at https://www.globalccsinstitute.com/resources/publications-reports-research/road-project-close-out-report/

up its legacy and is currently developing a more extensive project that involves three depleted fields.[4]

Following the ROAD system design, the Porthos network is planned to develop an insulated 25 km subsea pipeline from the compressor to an offshore platform, which will enable higher rates during the initial period with $CO_2$ in gas phase. A switch to $CO_2$ in liquid phase will be made during the operational period. The Porthos system expects that two-phase conditions will occur, especially in the injection wells.

The transport and storage system design started by the ROAD project and further developed by the Porthos project shows that the challenge in using depleted gas fields for $CO_2$ storage lies in managing temperature in the system.[5] The $CO_2$ is to be brought from the conditions in the surface transport pipeline or in the buffer or ship, to the different conditions in the depleted field. This means bridging potentially large pressure differences, which leads to significant temperature drops. Whether the system operates with $CO_2$ in gas phase or liquid phase, the properties of the storage reservoir, the design of the injection wells and the surface transport conditions together determine the operational window of the overall system. The system operational window describes the flow rates, or injection rates, that the system can sustain or accept during its lifetime.

This section provides a first assessment of the operational window of a transport and storage system that links onshore emission points to the offshore depleted KHGF. Two design options are discussed: operating with $CO_2$ in gas phase or in liquid phase. These options have specific benefits and drawbacks, which are to be assessed in the broader context of the overall system requirements.

### 2.2.2 Target for indigenous storage

KHGF is the target reservoir for indigenous storage. The field has a total storage capacity of approximately 330 Mt as can be seen in Figure 4 taken from [6]; the estimate is based on a pressure after production of 77 psia (5.3 bara), but currently the pressure is decreased even more.

[4] Porthos, $CO_2$ reduction through storage beneath the North Sea, accessed at www.porthosco2.nl/en/.
[5] Belfroid, S. et al (2021), CCUS at Depleted Gas Fields in North Sea: Network Analysis (March 26, 2021). Proceedings of the 15th Greenhouse Gas Controls Conference, Accessed at https://papers.ssrn.com/sol3/papers.cfm?abstract_id=3813026
[6] Schlumberger (2011), Kinsale Head Field $CO_2$ Storage Evaluations

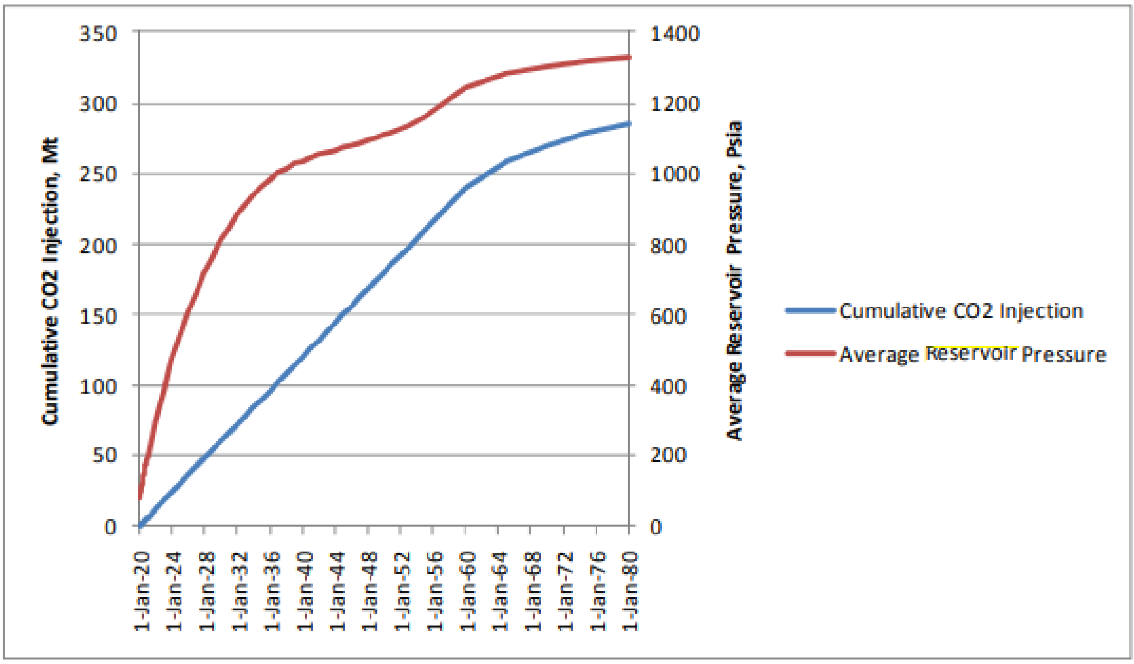


**Figure 4 $CO_2$ Cumulative Injection and Average Reservoir Pressure versus time, 60 years of injection.**

First, we will look at the shut-in conditions. Figure 5 shows the shut-in conditions at the well head for different reservoir pressures. Several observations can be made. When the reservoir pressures are below about 50 bar the well head pressure is a linear function of the reservoir pressure. At this pressure range the well will be in gas phase only. For higher reservoir pressure, the well will be in two-phase conditions and the pressure and the shut-in well head pressure is independent of the reservoir pressure.

The next observation that can be made is that for a reservoir pressure above 40 bar the injection pressure at the well head must be above 35 bar to inject $CO_2$ into the reservoir. This means that when $CO_2$ is transported in gas phase in the transport pipeline, the reservoir can be filled to a maximum average reservoir pressure of about 40 bar (580 psia). Figure 4 shows that his corresponds to a storage capacity of 130-140 Mt.

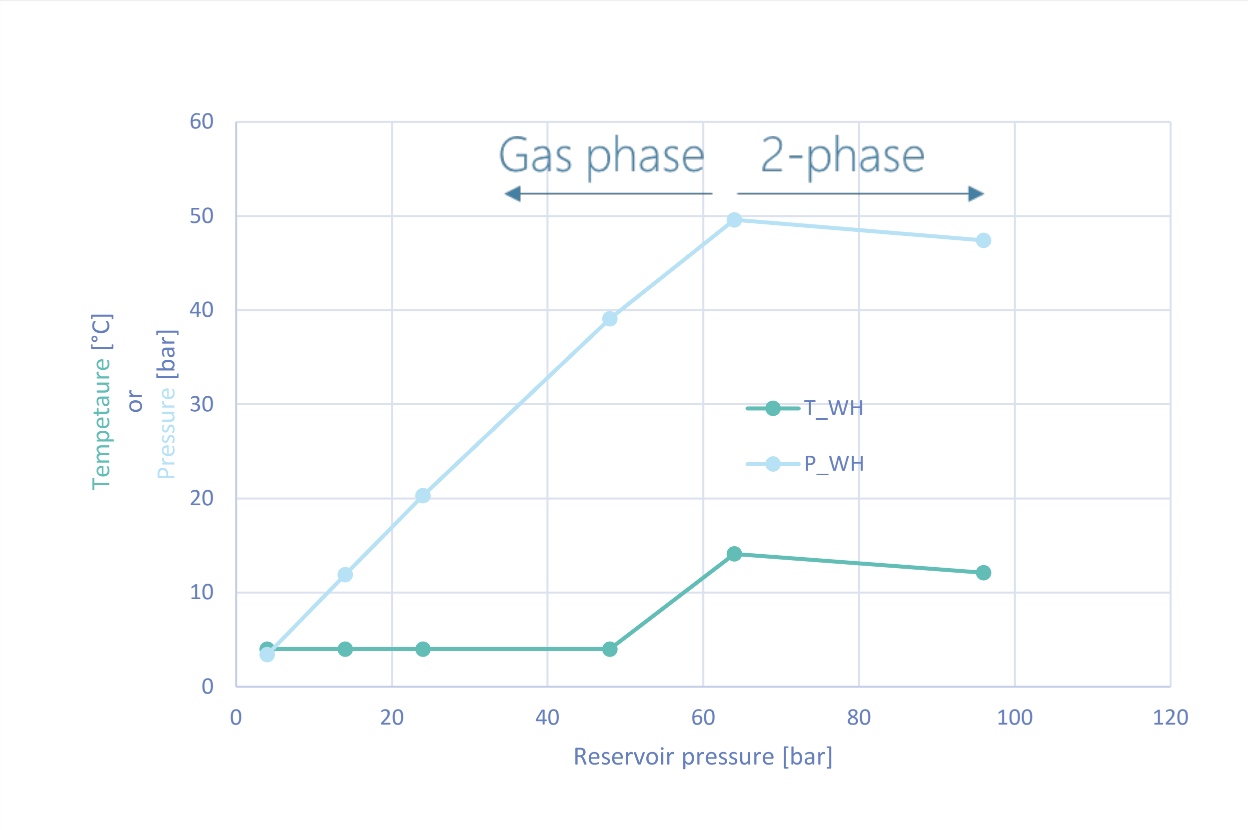


**Figure 5 Shut-in pressures and temperatures of a well in the KHGF at different reservoir pressures. T_WH: wellhead temperature; P_WH: wellhead pressure.**

### 2.2.3 Restrictions

For the safe and reliable transport of the $CO_2$, the operational conditions of the fluid must meet the following requirements (Please note the below applies for pure $CO_2$. With e.g. 1% of inert gases, the saturation pressure will be increased):

- During transport in the pipelines the fluid should be in single phase to avoid flow instabilities (see Figure 6).
    - To fulfil the first requirement that the $CO_2$ flow is in single phase, the pressure along the pipe should be maintained to keep the $CO_2$ conditions below or above the phase line, which is depicted in Figure 6. A non-insulated pipe with a seabed temperature of 4-10 °C will be assumed in this study. For a temperature of 10 °C, the phase line pressure is 44.5 bar (4 °C eq. 40bar, 20 °C eq. 57 bar). This means (with a margin of error), the pipeline pressure should be below approximately 35 bar or higher than 85 bar (above the critical temperature of 72.9 bar). In the well these pressures are not possible to maintain, and two-phase flow will eventually occur.
- Restrictions to the temperature in the well especially on the downstream side of the choke

- Low temperatures cause thermal stress in the wellhead; the temperature specification of the wellhead material determines the minimum temperature. Here, a value of -10°C is used, considered to be representative of normal wellhead material,
- Low temperature could cause temporary formation of liquid water (potentially leading to corrosion or hydrate formation). Here it is assumed that the dew point of the $CO_2$ mixture is sufficiently low to avoid the formation of free water. The definition of the $CO_2$ specification for the CCUS project should take this into account.

- Low temperatures in the well
  - Cold $CO_2$ can affect the integrity of the casing or liner. When at low temperatures, there is a risk that the casing or liner collapses. This risk can be avoided by selecting casing or liner with sufficient wall thickness to withstand the low temperatures expected to occur in the well. This aspect has not been included in the present report.
- Temperature restrictions near the bottom of the hole
  - In the presence of water from the storage reservoir, $CO_2$ hydrates can form at temperatures below about 0°C (see Figure 7). Hydrates can block the well and the pores in the reservoir near the well. However, in the case of the KHGF little water is expected to be present. Nevertheless, at the low pressure currently present in the reservoir, a minimum bottom hole temperature of 0°C is used. When there is sufficient confidence that no or very little water is present in or near the well, this restriction could be relaxed (allowing lower temperatures) or lifted,
  - Low temperature of the $CO_2$ leads to temperature contrasts in the reservoir. If the thermal stress exceeds the fracking threshold, fractures can form. Preliminary simulations of the development of pressure and temperature in the depleted field after the start of $CO_2$ injection have been performed and are presented in Appendix A,B and C. A brief discussion of the conclusions from these results is given below.
- Pressure restrictions near the bottom of the hole
  - The reservoir pressure at the start of injecting is low, around 4 bara. A high bottom hole pressure would cause high stresses in the near well bore region which could damage this area. In previous work, a maximum pressure drop of 50 bar was assumed to be safe (Schlumberger, 2011). This limit is used here.
- Flow velocities in the well
  - High flow rates in the well can lead to mechanical issues related to vibrations. An analysis of the potential occurrence and avoidance of vibrations should be done in combination with the mechanical design which is outside the scope of this study. Typical values used in the Oil and Gas industry are 20 m/s for gas flow and 10 m/s for liquid flow.

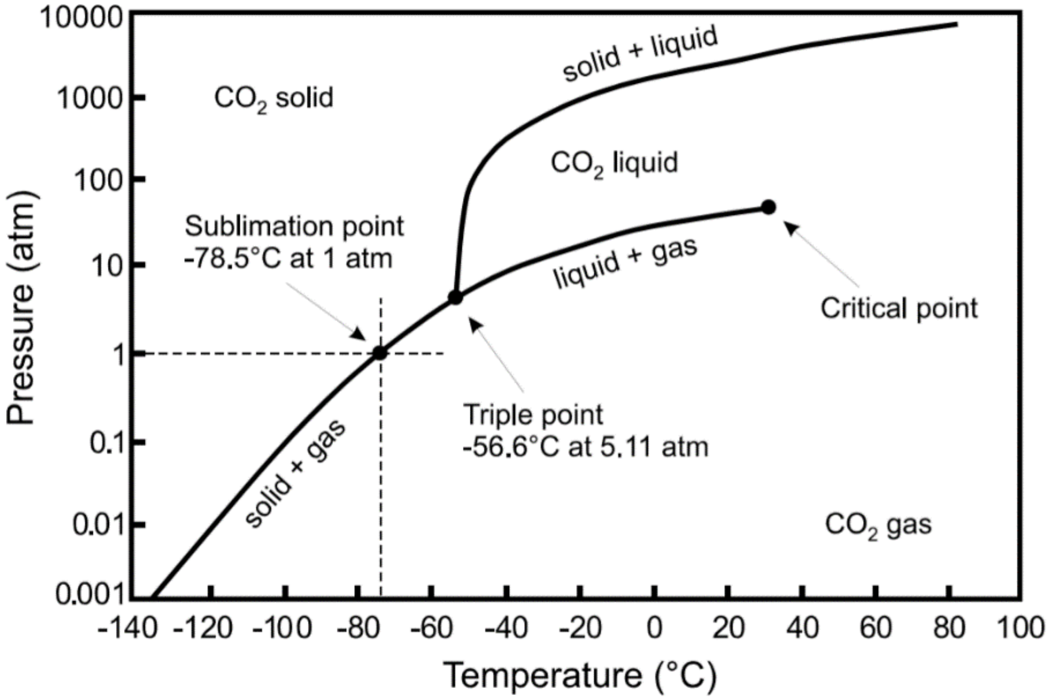


**Figure 6 Pressure-Temperature phase diagram for pure $CO_2$.**[7]

The second and third requirements are related to the minimal temperature of the fluid in the well during injection. For these two requirements it is important to determine where and how the $CO_2$ will be heated and transported. One problem associated with the offshore injection of $CO_2$ in comparison with onshore projects is the low temperature that $CO_2$ will arrive at the platform. Dependent on transport distance it is likely to arrive at a platform at ambient seawater temperature e.g. 4 to 10 °C. Injecting at these low temperatures increases the risk of hydrate formation in the reservoir which can limit injectivity and alter pore structure of the reservoir and should therefore be avoided.

The design and operation of a CCUS system not only has to deal with the average flow rates but also must take into account the flexibility of the system. The flexibility of the system influences the injection profile which can be used.

In this study the focus is to look at the temperatures and pressures in the well. Two locations are of interest. The first is just downstream of the top side choke, because here we can expect (very) low temperatures when the choke is partly open. Secondly, the downhole temperatures will be analysed. There are two reasons, a low temperature could lead to hydrate formation because some water could still be present in the reservoir and a large temperature difference with the existing temperature in the reservoir could lead to thermal fracking.

[7] Shakhashiri, Chemical of the Week: Carbon Dioxide; 2006; Chemistry 104-2; www.sciefun.org

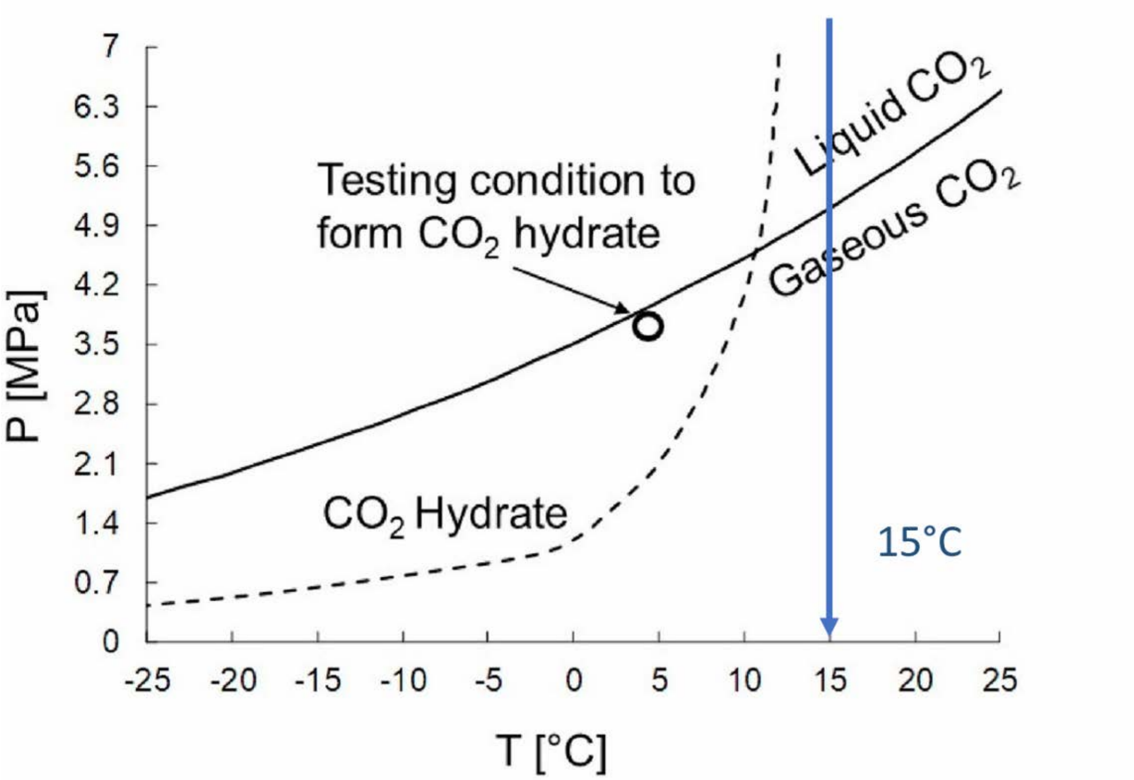


**Figure 7 Hydrate Formation map (dashed line)[8].**

For temperatures higher than 15 °C no hydrates can form. Below that it is dependent on pressure and composition. The solid curve is the phase line of $CO_2$.

Two sets of scenarios have been calculated. In the first set the $CO_2$ is in gas phase with an operating pressure of the pipeline of 30 – 35 bar, while in the second set the $CO_2$ is in liquid phase using a pipeline operating pressure of 85 bar. For both sets the following settings apply. The well is modelled as a single-diameter tubing to a depth of 880m True Vertical Depth (TVD) with a 400 m horizontal deviation. The inner diameter of the tubing in the well is 7" (0.175 m) for the scenario in gas phase and 4" (0.1 m) for the scenario in the dense phase. The overall heat transfer coefficient of the well is 9.5 $W/m^2/K$, based on the inner diameter. A geothermal gradient of 30 °C/km is used. Bottom hole pressure and temperature are set at 4 bar and 40°C, respectively. The connection with the reservoir is modelled using a so-called Production Index (PI) with a value $1.85 \cdot 10^{-5}$ kg/s/Pa, which is representative of the high-permeable sands of the reservoir formation.

For the pipeline, a 50 km pipe is modelled with an inner diameter (ID) of 584.2 mm. Here a U-value of 20 is used, which represents the thermal properties of a non-insulated pipeline. The

[8] Zadeh et al., Characteristics of formation and dissociation of $CO_2$ hydrates at different $CO_2$-Water ratios in a bulk condition, J. of **Petroleum** Science and Engineering, 196, 2021

properties of the pure $CO_2$ are modelled using the Span-Wagner Equation Of State (EOS). A valve is placed on the topside of the well which can be controlled to set a mass flow or pipe pressure. Appendix D gives more information on the properties of $CO_2$.

### 2.2.4 Gas phase

The minimum and maximum flow rates are detailed in Table 8 together with the Bottom Hole Pressure (BHP) and Bottom Hole Temperature (BHT). The minimum is due to the choking of the valve. The maximum reached is when the valve is fully open. The pressure and temperature profiles along the well are plotted in Figure 8.

**Table 8: Minimum and maximum flowrate conditions for gas phase injection**

| | Mass flow [kg/s] | BHT [°C] | BHP [barA] |
|---|---|---|---|
| Min | 30 | 0.1 | 20.3 |
| Max | 37.7 | 4.4 | 24.9 |

*BHT: bottom hole temperature; BHP: bottom hole pressure.*

For the gas phase the minimum flow rate can be reduced by lowering the pipeline pressure. This can be done by choking the flow at the beginning of the pipeline. The associated temperature drop will not affect the temperature at the injection site, some 50 km offshore. The impact of pipeline pressure on the injection rate window has not been investigated here, although lowering the pipeline pressure will decrease flow rates into the well and reservoir.

The flow rate window can also be adjusted by choosing a different tubing size, or by creating a lower number of perforations. Reducing the tubing size results in lower flow rate. As an example, changing tubing size from 7" to 4", and selecting a PI that is about half of what was used for Table 2, other parameters remaining the same, gives an operational window from 5 kg/s (minimum flow rate) to 10 kg/s (maximum flow rate). This illustrates the extent to which the operational window of a well can be engineered. However, the impact on the overall system injection capacity must be considered, as well as on the well count required to meet target rates. The number of perforations affects the effective PI and offers a way to control the injection rate window.

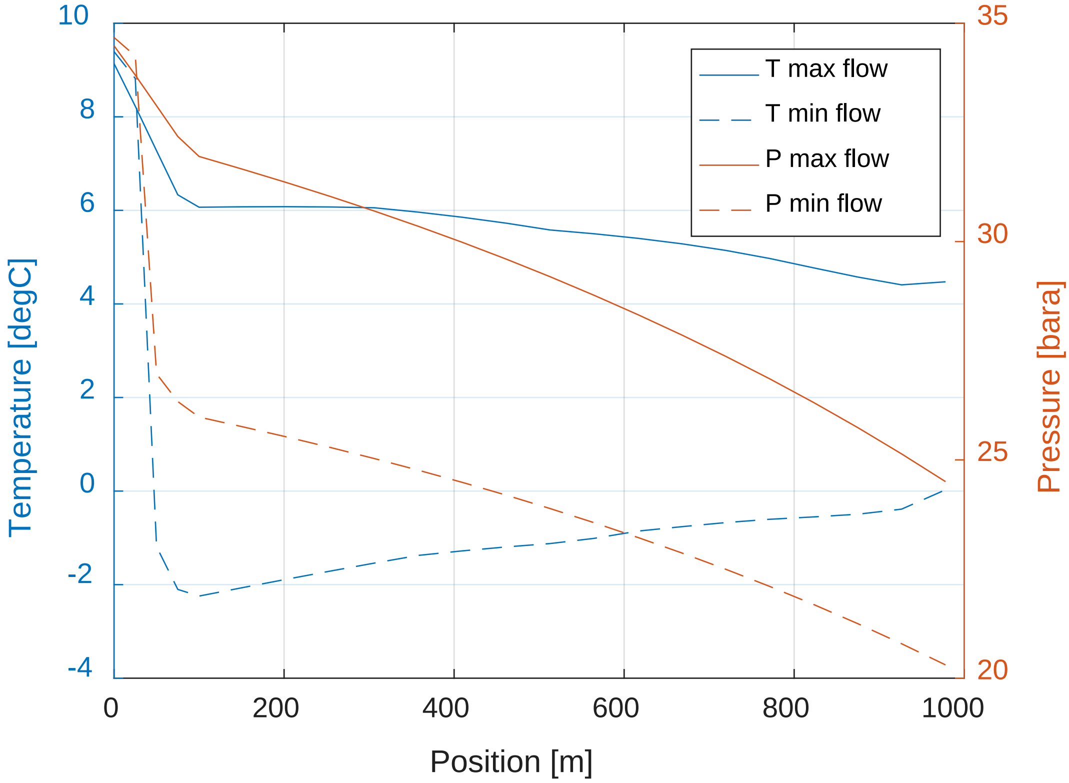


**Figure 8 Pressure and temperature for the maximum and minimum flow rate in gas phase. The wellhead is at position 0 m, the sand face at bottom hole is at position 1000 m (measured along the well).**

### 2.2.5 Liquid phase

The minimum and maximum flow rates are detailed in Table 9, together with the BHP and BHT. The maximum flow rate is now determined by the maximum allowable pressure bottom hole. In the Schlumberger report it is stated that this is 50 bar above the current reservoir pressure, i.e. 4 bar. Furthermore, the table shows that the minimum flow rate is quite high. This is due to the choking at the top side valve, as illustrated by the dashed blue curve in Figure 9. As the pipeline pressure is higher than in the gas-phase situation also the pressure drop will be higher. This results subsequently in a larger temperature drop. Another feature is that the bottom hole pressure can become high as well. To have some more details on how this affects the integrity of the reservoir should be part of a further investigation.

**Table 9: Minimum and maximum flowrate conditions for liquid $CO_2$**

| | Massflow [kg/s] | BHT [°C] | BHP [bara] |
|---|---|---|---|
| Min | 56.5 | 0.8 | 35.6 |
| Max | 87.2 | 11.3 | 52.6 |

*BHT: bottom hole temperature; BHP: bottom hole pressure.*

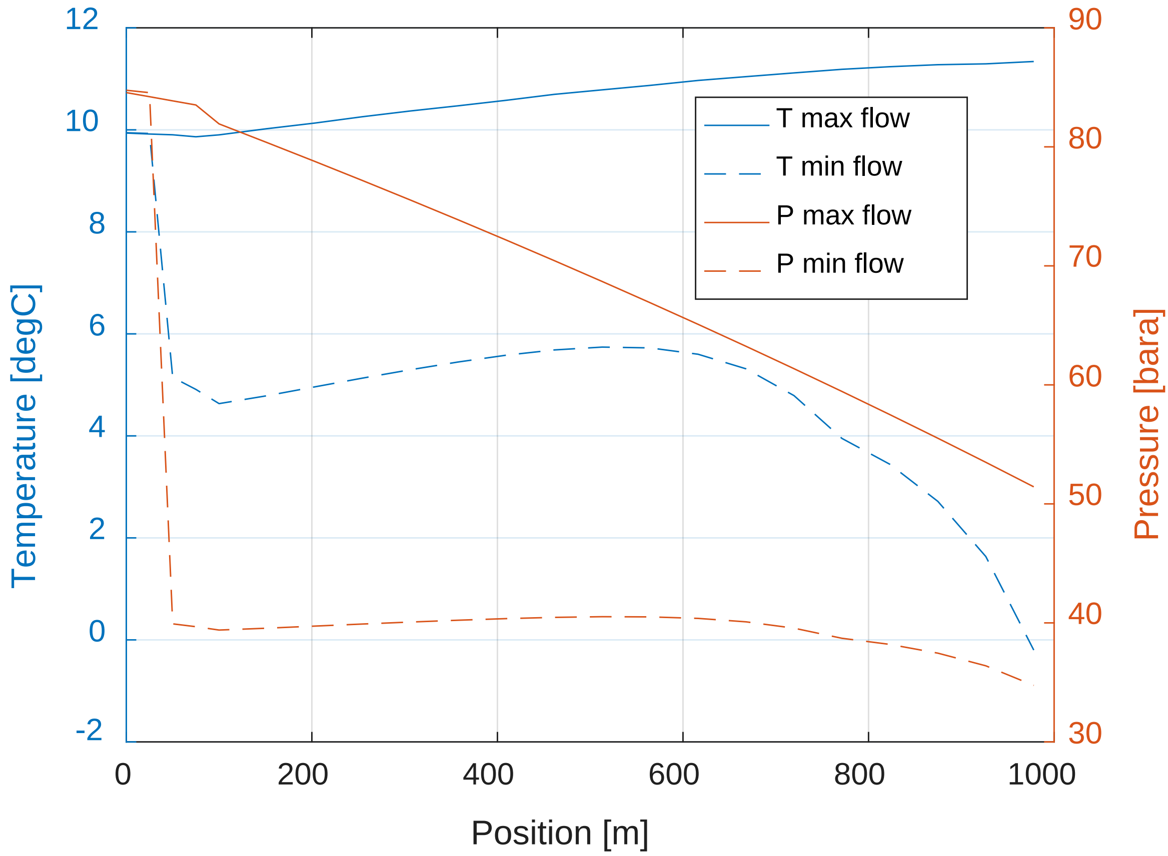


**Figure 9 Pressures and temperatures along the well for both minimum (dashed) and maximum (solid) flow rates**

## 2.3 Option 2: Export to Northern Lights location

After extraction of the $CO_2$ from the flue gases it will need compression prior to purification, pipeline transport and liquefaction.

## 2.4 Compression Introduction

Compression of the $CO_2$ gas downstream of the capture plant serves multiple purposes,

- It will allow for more efficient transportation of the $CO_2$ between the two locations defined in this work,
- More efficient purification of the $CO_2$ and
- Finally, to allow for liquefaction of the $CO_2$ before intermediate storage and export to permanent storage.

The three separate $CO_2$ emitters can be facilitated at two locations. As the BGE Whitegate Powerplant and Irving Oil Whitegate Refinery are contiguous and adjacent these can be accommodated in a single processing site for the purposes of compression.

- Aghada; where ESB Aghada CCGT Power Station is located.
- Whitegate; which includes Whitegate CCGT Power station and Whitegate Oil Refinery

Liquefaction and intermediate storage of the $CO_2$, will be considered to take place at the Whitegate site only and thus the $CO_2$ from the Aghada Power Station must be transported by pipeline in gas phase for further processing.

The conditions of the $CO_2$ before compression and inlet to the pipeline are summarised in Table 10.

Table 10: $CO_2$ conditions at battery limits between equipment

| Plant & Parameters | Capture Plant | Compression/ Conditioning | Liquefaction Plant | Intermediate $CO_2$ storage | Ship Vessel | Inch Gas Terminal |
|---|---|---|---|---|---|---|
| Inlet Temperature, Pressure | >100°C, 1.05 bara | 40°C, 1.7 bara | 40°C, ~35 bara | -52°C, 7 bara | -52°C, 7 bara | 5°C, ~35 bara |
| Outlet Temperature, Pressure | 40°C, 1.7 bara | 40°C, 35 bara | -52°C, 7 bara | -52°C, 7 bara | N/A | N/A |

At the 40 °C and 1.7 bara outlet from the capture plant the $CO_2$ gas saturated with water will have a density of 2.82 kg/m$^3$, making compression a necessity to avoid excessive pipeline diameters and unreasonable pressure drops when transporting large amounts of $CO_2$ over substantial distances.

The pipeline pressure is fixed at 35 bara, as this is aligned to the pressure needed for the indigenous storage that is facilitated through the Inch Gas Terminal. Drying is considered to be done at each location and the density of the compressed and dried $CO_2$ for pipeline transport is 72 kg/m3.

For export to Northern Lights Phase 1 a similar but separate specification would apply. The pressure would also be different.

Further the compression is needed in order to liquefy the gaseous $CO_2$, not only to reduce the electrical load associated with the refrigeration unit used for removal of the heat of evaporation for the $CO_2$, but also to steer clear of the solid phase region avoiding the formation of $CO_2$ solids upon cooling the gas.

In the phase diagram in Figure 10 the relationship between pressure and $CO_2$ sublimation/dew point can be observed. To avoid solid formation upon cooling of a $CO_2$ gas phase the pressure should be higher than that of the triple point of 5.18 bara.

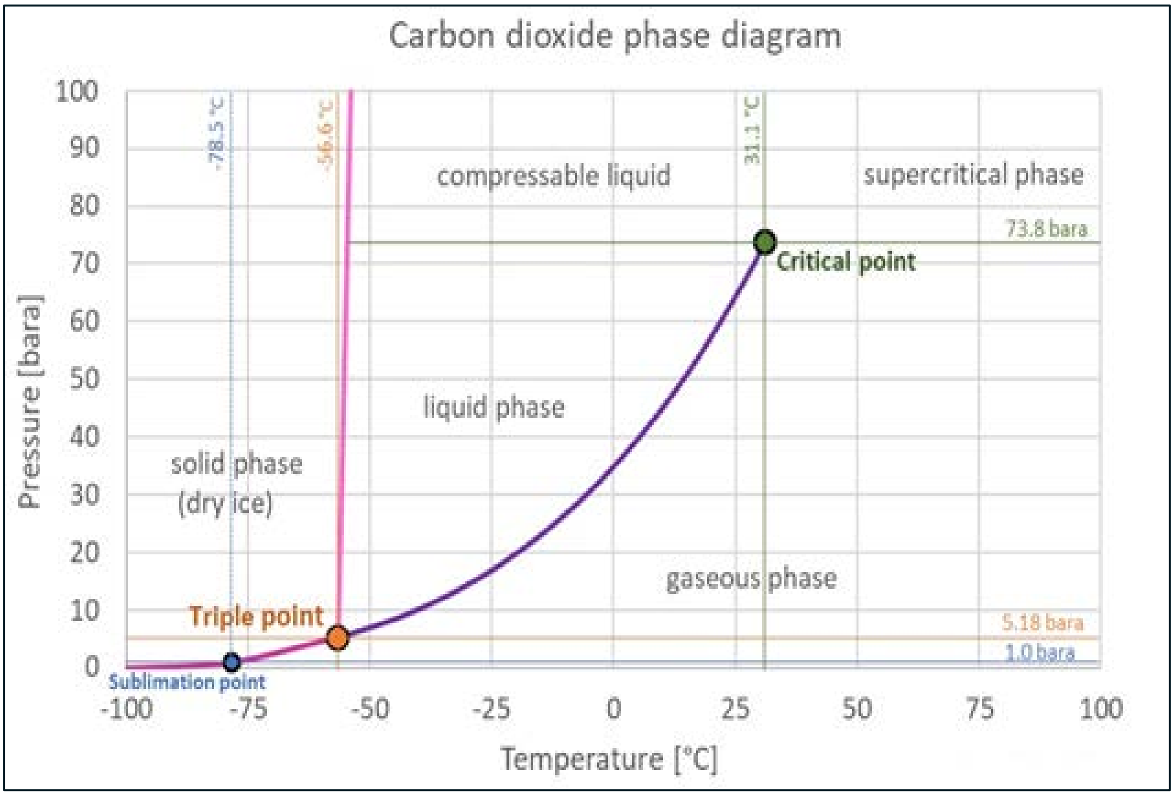


**Figure 10 Phase diagram for pure $CO_2$ [9]**

The phase change line in pink left of the triple point indicates sublimation i.e., change of phase from gas to solid directly.

Finally, the compression facilitates purification of the $CO_2$ both considering drying and removal of trace impurities. Drying is done first by condensation and further by absorption of moisture to meet pipeline and export specification. Both methods are aided by compression as water can be more readily be removed at higher partial pressures. Removal of trace impurities with a lower boiling point than $CO_2$ e.g., oxygen and nitrogen can be done by distillation, as this requires the $CO_2$ to be in a liquid form, compression to above the triple point is a prerequisite for this to take place.

Medium pressure ships carrying 7,500m$^3$ (15 bara and -28 °C) were considered for this study as this is the ship size currently used for food grade transportation. In future size ship size may increase to 70,000m$^3$ if it becomes viable to sue similar sized ships as used for transporting Liquefied Petroleum Gas (LPG) bulk loads.

This may lead to additional space requirements for intermediate storage to compensate for larger ships and also larger plant requirements. This may also have further effects on min and max flow rates.

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[9] Engineering Toolbox (2017), properties of $CO_2$, accessed at https://www.engineeringtoolbox.com/ $CO_2$-carbon-dioxide-properties-d_2017.html

## 2.5 Infrastructure Requirements to control and monitor

### 2.5.1 The storage in the indigenous field

To control and monitor the flow of $CO_2$ several measurements are required. A high-level description is provided here. A benchmarking example for a natural gas network is presented in Appendix E. Here we describe some important features which should be included. First, several pressure and temperature sensors must be installed, especially before and after the wellhead valve, as in a standard gas or oil system.

As multiphase flow is likely to occur in the well, a designated mass-flow meter (multi-phase flow meter) is required to control and monitor the actual flowrate entering the well. As can be seen in Figure 5, only the pressure is not enough to determine the flowrate. Because for a range of reservoir pressures the pressure at the well head is nearly constant, hence it is not a good indicator of the (flow) profile of the well. As discussed in the previous Chapter each well will have a minimum and maximum flow rate, depending on well design and reservoir pressure, to ensure reliable injection. These change over time as the reservoir pressure increases.

A pressure control system with a pressure relief valve must be installed to ensure that the pressure in the pipeline remains below the specifications of the pipeline. Also, a minimum pressure will be necessary to prevent implosion.

In the well a Sub-Surface Safety Valve (SSSV) will be required to shut in the well in case of an emergency.

### 2.5.2 Export option

For the export option also several measurements of pressures and temperatures are required. The pressurised intermediate storage location must have a relief system. Further a dedicated compressor for recirculation flash gas and evaporated $CO_2$ from ambient heat ingress is needed.

# 3 Conclusion

This report presents an outline of the systems required to transport and store $CO_2$ captured at two natural gas fired power plants and an oil refinery near Cork either to indigenous storage – the depleted Kinsale Head gas field – or by ship transport to the Northern Lights storage system in Norway. Systems are designed to meet the captured rates mentioned above.

The flexibility is discussed of the systems in accommodating variations in $CO_2$ supply, or in growth of the captured volumes to be stored. A high-level description of the systems needed to monitor and control the transport and storage of $CO_2$ is provided.

The main conclusions of the study are as follows.

*Injection profile (indigenous storage).*

1. If the current variability in the rate of emitted $CO_2$ from the power plants is a measure of future capture flow rate variations, the transport and storage must be able to accommodate flow rates between zero and the maximum rate. The onshore and offshore transport pipelines can be shut in when the capture rate is zero. Injection wells have to be

shut in when the rate falls below the minimum rate for the well; depending on the well completion and the condition of the $CO_2$ in the system (liquid or gaseous), minimum rates can be as high as 30 kg/s (or about 1 Mtpa; gaseous phase) or 60 kg/s (about 2 Mtpa; liquid phase). Wells must be shut in at rates below their minimum rate to avoid too low temperatures and, hence, unsafe conditions. The number of wells needed to reach the targeted capture (and injection) rate is 2 in case the $CO_2$ is injected in gaseous phase, or 1 in case of liquid $CO_2$ injection.

2. For a single well, flexibility in accepting variable flow rates will be limited to flow rates within its window of operation. The minimum and maximum flow rate can be engineered and made fit-for-purpose through the choice of tubing size or by setting the number of perforations. Furthermore, if $CO_2$ is in gaseous phase, the pressure in the transport pipeline will also influence the location of the operational window. If $CO_2$ is in liquid phase, this option offers little flexibility. However, in case the minimum flow rate of a well is reduced to avoid frequent shut-ins when supply rates are low, also reduce the maximum flow rate. This results in a higher well count and higher cost to meet target flow rates. An optimisation of the system was not performed, as too many currently unknown factors play a role in the definition of an optimum.
3. System flexibility to accommodate higher $CO_2$ supply rates, as a result of, for example, import by ship, is obtained by drilling additional wells. It is noted that these new wells will similarly have a window of operation with a minimum and maximum flow rate that determines system flexibility at the well level.
4. The indigenous storage section of the study established that the KHGF has a total storage capacity of up to 300 Mt. The Cork cluster based on this study would involve injecting circa 2.2 Mt/p.a. over 25 years equal to 55 Mt in the base case scenario.  Therefore, there is significant flexibility to accommodate $CO_2$ from other emitters in Ireland or elsewhere. The study has also determined that initially $CO_2$ will be injected in gas phase. As pressure in the reservoir gradually increases over time with continuous injection, the switch to inject liquid (dense phase) $CO_2$ will come as the reservoir pressure rises to meet the injection pressure. It was also determined that up to three new injection wells (7-inch) would be required for injection along with the associated infrastructure.
5. The intermediate storage of $CO_2$ is required as a buffer to facilitate export of $CO_2$. Intermediate storage can also facilitate more variable production of $CO_2$ and importation of $CO_2$, although these have not been considered in detail in the study.

*Infrastructure requirements for monitoring and control.*

1. Infrastructure to control and monitor the transport and storage system for indigenous storage will benefit from current practice and experience in the gas transport sector. $CO_2$ storage projects that plan to start injection earlier than the Cork CCS project will lead the way in the development or selection of $CO_2$ flow meters. No barriers are foreseen in measuring, monitoring and verifying $CO_2$ flows onshore or on an offshore platform.
2. Temporary storage for export will also benefit from early full-scale CCS projects, although the buffering of $CO_2$ for transport by coaster is existing and operational technology. No barriers have been identified for the scale-up required for large-scale $CO_2$ transport by ship.

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ISO 27918:2018: Lifecycle risk management for integrated CCUS projects

# Appendix A.:$CO_2$ injection in KHGF: geomechanical effects

This is the text of report prepared by Peter A. Fokker, Daniël Loeve (TNO) to inform the Realise WP 3.3. team on geomechanical effects of injection into KHGF.

## A.1 Introduction

The Kinsale field is considered to be transformed into a CCUS site. Reservoir simulations have been carried out to explore the range of possible injection rates and temperatures, which form the basis for an assessment of the geomechanical response of the storage system. The assessment focuses on fault reactivation risk and fracturing risk. The investigation has used as input the temperature and pressure fields that result from injection of relatively cold $CO_2$ , in the target zone with large permeability, and in the overlying and underlying low-permeability layers. The geometry is relatively simple and by no means describes the reality, but the results can be used to get an indication whether the potential of fault reactivation or fracturing exists.

The results from the simulation of the injection of cold CO3 in the KHGF are shown in the following section; the next section describes the geomechanical tool used (SRIMA). Results are discussed next, and are followed by conclusions and recommendations for further study.

## A2: Pressure and temperature distribution in the KHGF

To assess the temperature and pressure distribution during injection of $CO_2$ in the Kinsale field a dynamic reservoir model is used. The TOUGH2 simulator is able to model thermal $CO_2$ injection in a depleted gas field. Since the temperature has an important influence on the stress in and outside the reservoir a radial symmetric model is used with a single well in the middle. The size of the model is 100 m thickness and 18 km or 9 km in radial direction depending on the scenario (Section A3).

The grid size in the radial direction consist of 47 nodes, which are distributed according to an exponential increasing distance between the nodes. The nodes have a dense grid distribution close to the injection well and a coarser grid in the far field area. The region of interest is the temperature effect close to the injection well. In the vertical 23 different layers. The caprock and baserock consist of 5 layers and the reservoir itself of 13 different layers. In the transition zone from caprock/reservoir and reservoir/baserock the nodes are more densely distributed. Since the properties are different in these particular zones (e.g. permeability and pressure) (Figure A2).

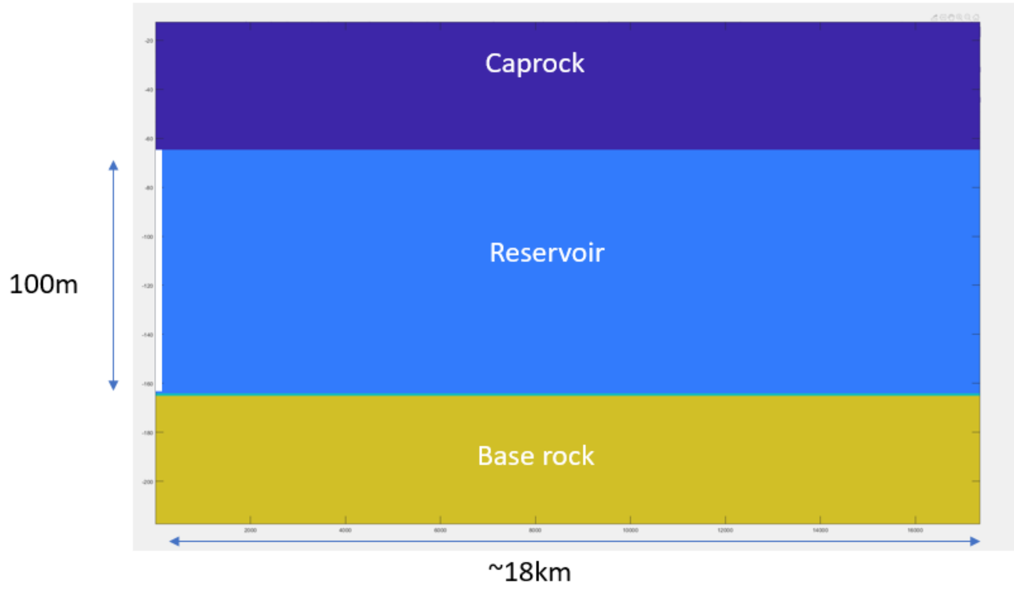


**Figure A1: Dynamic model with caprock reservoir and baserock and on the left hand side the injection well**

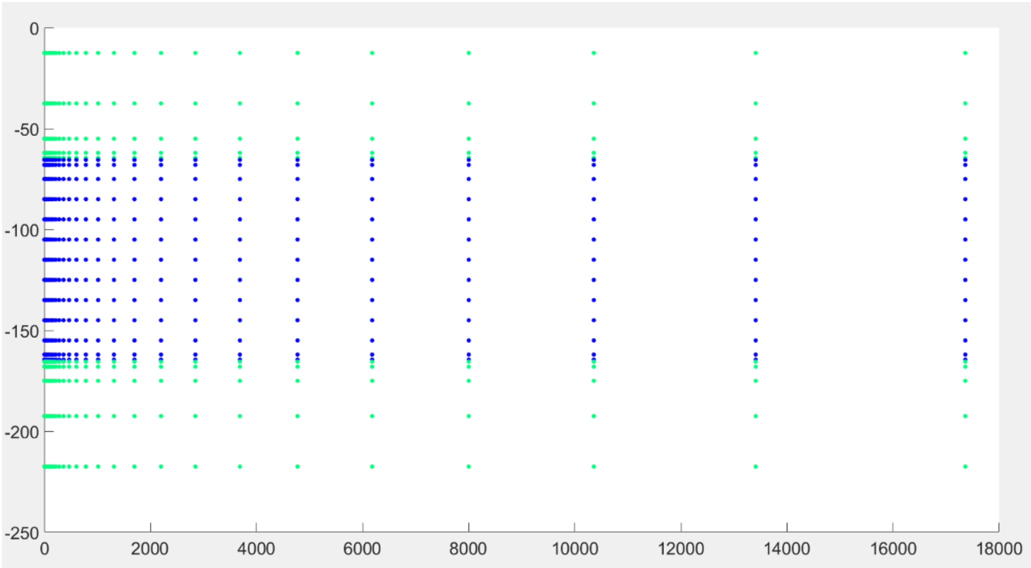


**Figure A2: The node distribution of the dynamic model with caprock baserock presented by the green dots and the reservoir in the blue dots**

A summary of the properties are given in Table A1 which are mainly based on the Kinsale Energy Limited $CO_2$ evaluation Schlumberger report (2011).

**Table A1 Properties of Kinsale TOUGH2 model**

| Property | Value | Unit | Reference |
|---|---|---|---|
| Reservoir Temperature | 40 | °C | Schlumberger report |
| Abandonment pressure/ initial injection pressure reservoir | 4 | Bar | Schlumberger report |
| Virgin pressure | 92 | Bar | Schlumberger report |
| Porosity | 0.2 | | Schlumberger report |
| Initial water saturation (Swi) in reservoir | 0.01 | | |
| Permeability | Depends on the scenario | | |
| Reservoir thickness | 100 | m | |
| Reservoir size | Depends on the scenario | | |

## A3: Scenarios

Two sets of four different injection scenarios were defined based on the injectivity. The first set of injection scenarios were based on a relatively low injectivity index and the second set of injection scenarios were based on a high injectivity index, namely of $4.5 \cdot 10^{-6}$ kg/s/Pa and $1.85 \cdot 10^{-5}$ kg/s/Pa respectively. These injection index corresponds to a homogeneous permeability of 200 mD and 822 mD in the reservoir.

Within each set two injection scenarios were developed with low pipeline operational pressure (~35 bar) injection using 5 injection wells and two injection scenarios with high pipeline operational pressure (~85 bar) injection using only 1 injection well.

All the scenarios are summarised in the following Table A2.

**Table A2: Summary of the scenario's performed on the Kinsale head reservoir model**

| nr | Scenario Label | PI (kg/s/Pa) | Operational pressure (bar) | Injection rate (Kg/s) | Injection temperature (°C) |
|---|---|---|---|---|---|
| 1a | T49 | $4.5 \cdot 10^{-6}$ | 35 | 5 | 4.9 |
| 1b | T15 | $4.5 \cdot 10^{-6}$ | 35 | 10 | 1.5 |
| 1c | T75 | $4.5 \cdot 10^{-6}$ | 85 | 27.5 | 7.5 |
| 1d | T91 | $4.5 \cdot 10^{-6}$ | 85 | 54.6 | 9.1 |
| 2a | T01H | $1.85 \cdot 10^{-5}$ | 35 | 30 | 0.1 |
| 2b | T44H | $1.85 \cdot 10^{-5}$ | 35 | 37.7 | 4.4 |
| 2c | T08H | $1.85 \cdot 10^{-5}$ | 85 | 56.5 | 0.8 |
| 2d | T115H | $1.85 \cdot 10^{-5}$ | 85 | 87.2 | 11.3 |

The injection temperature and injection rates corresponding to each scenario are based on the flow assurance study described in Section 4.2. Since the injection temperature in scenario 2a and 2c are close to 0°C, which causes convergence issues in the simulations. The actual injection temperature used in the simulations are 3.1°C and 2.8°C, respectively.

## A4: Results

In the geomechanical analyses in the next section scenario 1c or the T75 scenario is used as a base case. Therefore this scenario is also presented here. The other scenarios can be found as a reference below.

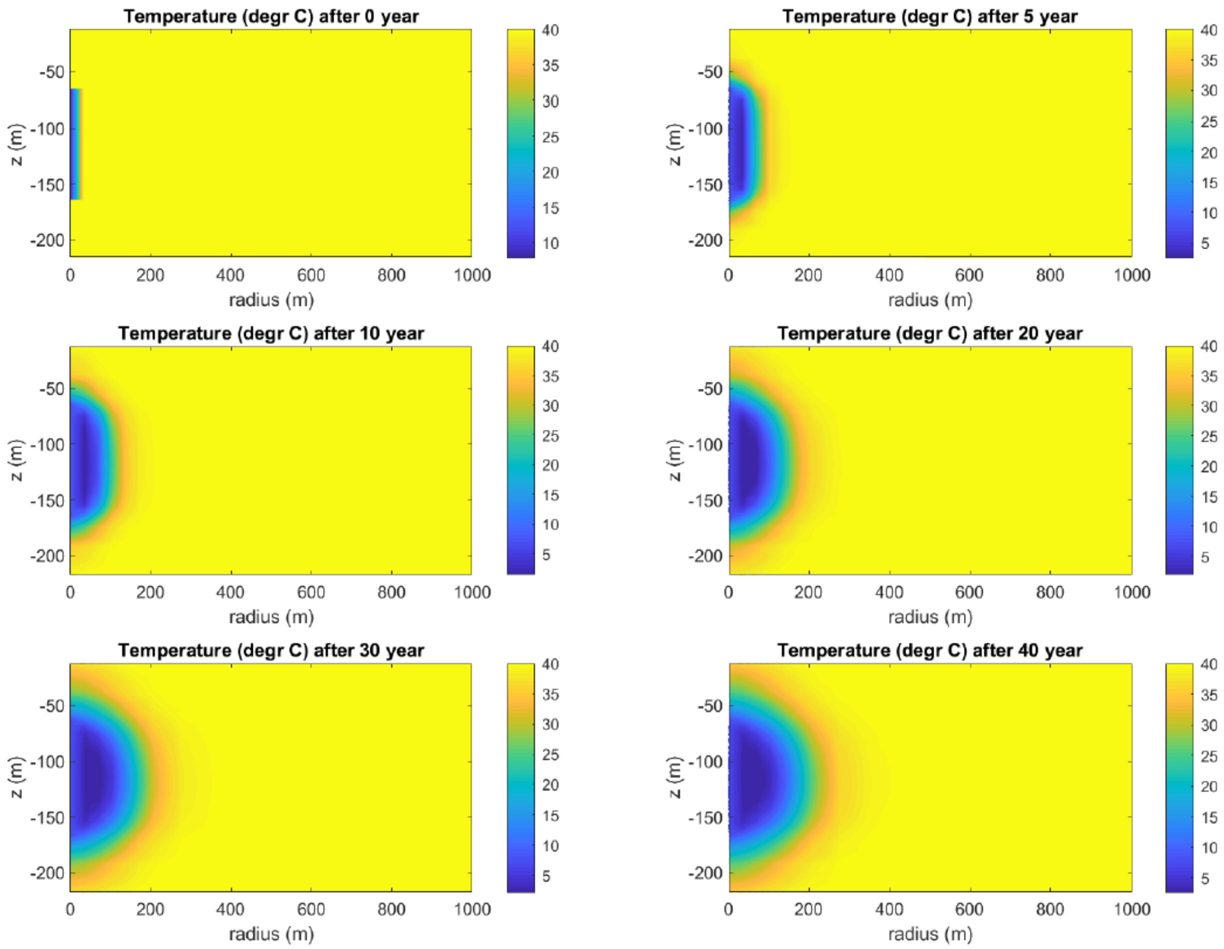


Figure A3: Temperature in the reservoir

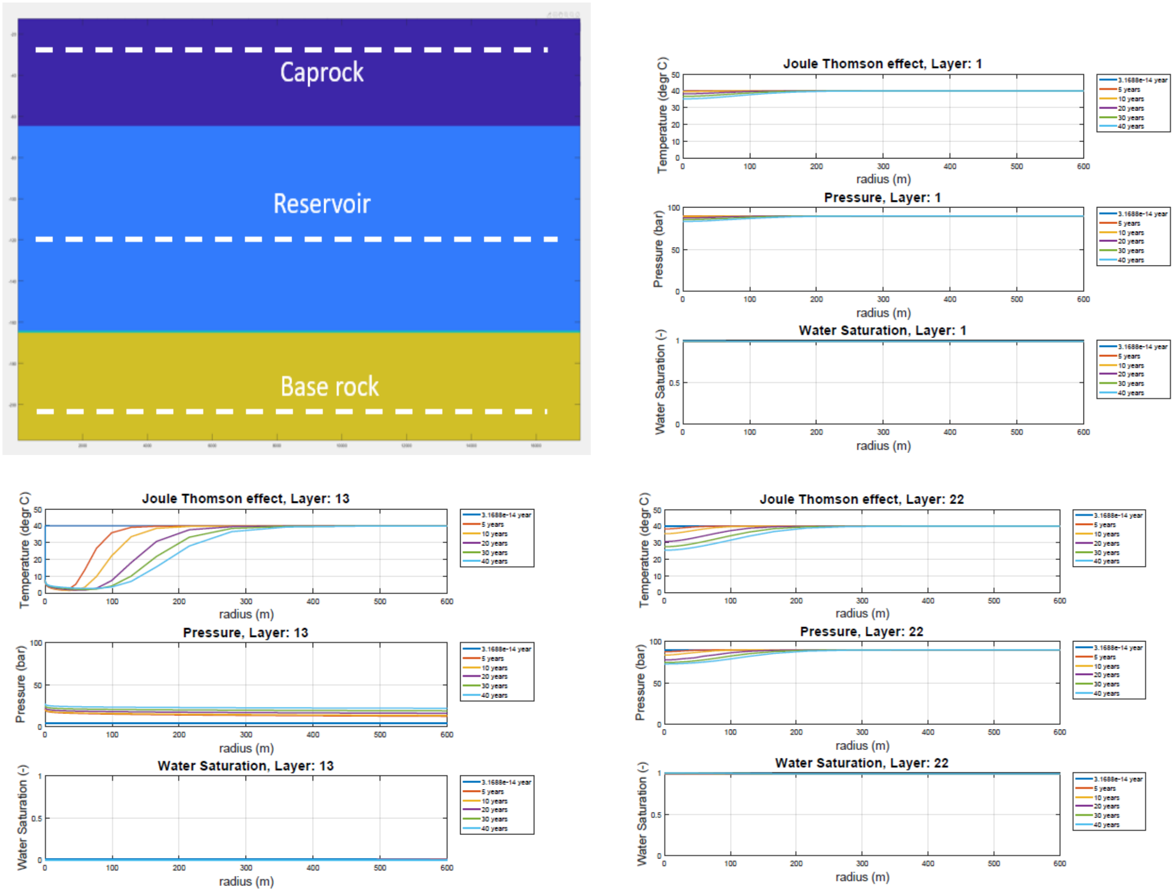


Figure A4: Temperature, pressure and water saturation profile in the caprock (top right), reservoir (bottom left) and baserock (bottom right)

## A5: Discussion

The cold front is progressing into the reservoir up to 200m into the reservoir, with a minimum temperature of 1.4°C (see table A3 for all scenarios). In this temperature and pressure regime hydrate formation is possible, however the dry out zone is progressing faster into the reservoir (Figure A4) compared to the cold zone, therefore hydrates are not expected. This is observed for all scenarios modelled in this report. Note that initial water saturation is relatively low, but also for more realistic numbers (~0.1-0.2) the dry out zone is progressing faster into the reservoir. The relative low water saturation is chosen for modelling and convergence purposes. Since evaporation of water cools down the reservoir even more, causing the temperatures to drop faster and closer to 0°C, which causes instabilities and convergence issues in the TOUGH2 simulator.

**Table A3: overview of injection temperature and minimum temperature of all scenarios**

| Scenario | Actual Injection temperature (°C) | Minimum temperature (°C) |
|---|---|---|
| 1a | 4.9 | 1.4 |
| 1b | 1.5 | -1.4 |
| 1c | 7.5 | 1.4 |
| 1d | 9.1 | -0.2 |
| 2a | 3.1 | -2.2 |
| 2b | 4.4 | 0.4 |
| 2c | 2.8 | -2.4 |
| 2d | 11.3 | 0.5 |

## A6: Conclusion

From reservoir engineering perspective no limitations are expected on the proposed injection scenarios. The injection conditions are close to or in the hydrate formation zone. As the dry out zone is progressing faster into the reservoir hydrate forming is not expected.

# Appendix B: SRIMA (Seal and Reservoir Integrity Mechanical Analysis) provided by TNO

## B1: Calculation of stresses

Pore pressure and temperature changes caused by the injection of $CO_2$ may lead to fault reactivation and induced seismicity through the induced stresses. In order to assess the potential of fault reactivation and seismicity, and enable mitigation, it is crucial to understand the interplay between the operational factors and the evolution of pressures, temperatures and associated changes in the stress fields near these faults. The evolution of these fields can be modelled analytically, semi-analytically or numerically. Analytical and semi-analytical solutions can be applied for simplified geometries, such as axisymmetric or horizontally layered (pancake-like) reservoir configurations. These 'fast' models generally require less input data (e.g. on subsurface geology), are very efficient in terms of computational costs, and can provide a first-order estimate of fault stability under changing pore pressure and temperature conditions. As the models are computationally efficient, they can be used for uncertainty and sensitivity analysis. The drawback of analytical and semi-analytical models is that they are generally based on stringent conditions for the geometry (i.e. axisymmetric, plane strain or uniaxial), and hence less well suited when the effects of spatially varying pressures and temperature fields, reservoir heterogeneity, and the effects of 'stress arching' caused by fault offset, reservoirs of limited extent and sealing faults are expected to be important.

For a first assessment of the Kinsale CCUS injection scenarios, semi-analytical mechanical models can be very efficient. Therefore we used SRIMA (Seal and Reservoir Integrity through Mechanical Analysis, by Fokker et al., in prep.). The stress response to an externally computed temperature and pressure field is used to compute induced stresses. The stress response in an elastic medium is defined by the theory of poro-elasticity and thermo-elasticity.

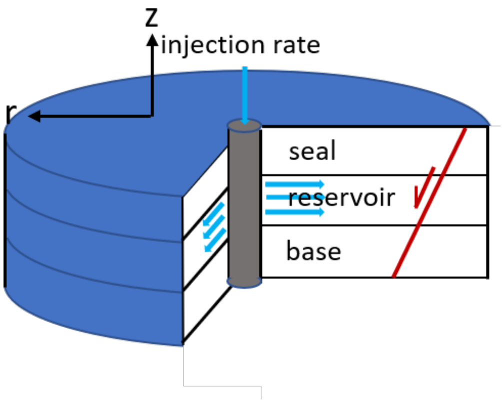


**Figure B1: Radially symmetric geometry used in SRIMA (Seal and Reservoir Integrity through Mechanical Analysis) for analysis of thermo- and poro-elastic stresses in reservoir caused by injection of cold fluids.**

Injection is assumed to take place over the entire reservoir height. Stresses are computed on a polar coordinate system and then transferred to a Cartesian coordinate system. The stress tensor is then used to compute stress changes on a single fault (presented in red).

SRIMA is based on a semi-analytical radial symmetrical solution of the pressure, temperature and stress field around a single injector well, in a reservoir of finite height, which is surrounded by low-permeable seal and base rock. The basic assumptions made in SRIMA for analysis of the effects of cooling and pressurization on stress evolution in the reservoir, seal and base rock are that the temperature and pressure fields are radially symmetric and that they do not show vertical differentiation inside the reservoir. For the computation of the thermo-elastic and poro-elastic response of the rocks due to temperature and pressure changes, all rocks are assumed to behave linearly elastically. Computation of the thermo-elastic stress changes for the radial symmetrical geometry in SRIMA are based on the approach of Myklestad (1942) and Perkins & Gonzalez (1985). They give an analytical solution for thermo-elastic stresses in a cooled cylinder with discontinuous temperature at the boundary. As the temperature distribution in our model shows a progressive and gradual cooling of the regions further away from the injection well, which cannot be included in the approach by Myklestad (1942), for computation of thermal stresses we use a multi-step function for the temperature in the reservoir instead. For 10 equally distributed temperatures between maximum and minimum, the radii are determined at which those temperatures are reached in the middle of the injection layer. The effect of conductive cooling of the seal and the base on the stress is incorporated also by a limit solution based on the Myklestad relationships. Our estimate for the thermal stress is therefore a superposition of Myklestad's solution both inside and outside the cooled cylinder in the reservoir, supplemented with a term proportional to the temperature at positions outside that region.

Myklestad developed his equations for a cooled cylinder in a space with homogeneous elastic properties. Realistic geological scenarios require the possibility of incorporating inhomogeneities, such as different elastic properties for different layers. We adapted the analytical correlations developed for homogeneous subsurface to situations with an elasticity contrast between reservoir and seal and base. The Myklestad part of the horizontal stresses is calculated with the elastic modulus of the reservoir; the modulus of seal and base is employed for the vertical stresses and for the correction required for the direct effect of the temperature with the modulus in seal and base, which is at the location of application.

The pore pressure in the reservoir is a logarithmic function of the distance from the well. SRIMA approximates the effect of the complete pressurised reservoir with the effect of a single pressurised cylinder. Then Myklestad's relationships can be used for these stresses as well. The approximation of pressure and radius of the cylinder for different positions have been derived from a numerical benchmark.

From SRIMA we obtain temporal and spatial changes in the stress tensor in the reservoir, seal and baserock. Computed stress changes can be used to assess the potential of fracturing in the seal and base rock (jeopardizing seal integrity) and potential of fault reactivation. As stresses in SRIMA are defined in a polar coordinate system, for assessing fault stress changes and fault reactivation potential stresses first need to be transferred to a cartesian coordinate system. The stress tensor is then used to compute changes in shear and normal stress on the fault. While the temperatures and pressures are assumed to be radially symmetric, the virgin stresses are not subject to such a condition.

The benchmark (Fokker et al., in draft) has shown that the SRIMA approximations reproduce numerical simulations well. They are therefore faithful input for assessments that involve stress input – but within the limits of the approximations. A first limitation is the assumption of horizontal flow. This will take place only if the reservoir has a fixed thickness and the injection takes place over the full height. For limited perforation intervals, there will be partly vertical flow close to the well. Second, if the permeability is anisotropic, the pressure and flow fields will also be anisotropic. Thirdly, inhomogeneous rocks will introduce an even larger complication: varying parameters or a reservoir with varying height break the symmetry of the system and numerical approaches will be warranted if such inhomogeneities are considerable. Still, the current implementation of SRIMA provides a good first estimate of the resulting stresses and offers the possibility to evaluate sensitivities to different parameters.

# B2: Risk measures

The SRIMA-calculated thermo-elastic and poro-elastic contributions to the stress are radially symmetric. If the virgin horizontal stresses are anisotropic, the rotational symmetry of the end product is broken and the poroelastic contributions must first be transformed to $\sigma_{\text{cart}}^{\text{PE}}$, in the Cartesian coordinate system. This involves a rotation around the vertical axis. Then the total stresses and the effective stresses are obtained by adding the induced stresses to the original stresses $\sigma_0$, and subtracting the pore pressure from the normal stress components:

$$\sigma_{\text{total}} = \sigma_0 + \sigma_{\text{cart}}^{\text{PE}}$$

$$\sigma^{\text{eff}} = \sigma_{\text{total}} - P\delta_{ij}$$

There are different possibilities to define a measure for the operational risk. A common one is exceedance of the Mohr-Coulomb failure criterion on an existing fault. For a fault characterized with a normal vector $\mathbf{n}$ we calculate the effective traction $\mathbf{T}'$ on the plane, and the effective normal and shear stresses on the plane as

$$\mathbf{T}' = \sigma^{\text{eff}} \cdot \mathbf{n}$$

$$\sigma_n = \mathbf{T}' \cdot \mathbf{n}$$

$$|\tau| = \sqrt{\mathbf{T}' \cdot \mathbf{T}' - \sigma_n^2}$$

The slip tendency of the fault at evaluation is then given by the ratio between shear and effective normal stress,

$$f = \left|\frac{\tau}{\sigma_n}\right|$$

Cohesion is not incorporated in this number, since existing faults are usually considered cohesionless. Faults with a slip tendency larger than the friction coefficient $\mu$ will be reactivated.

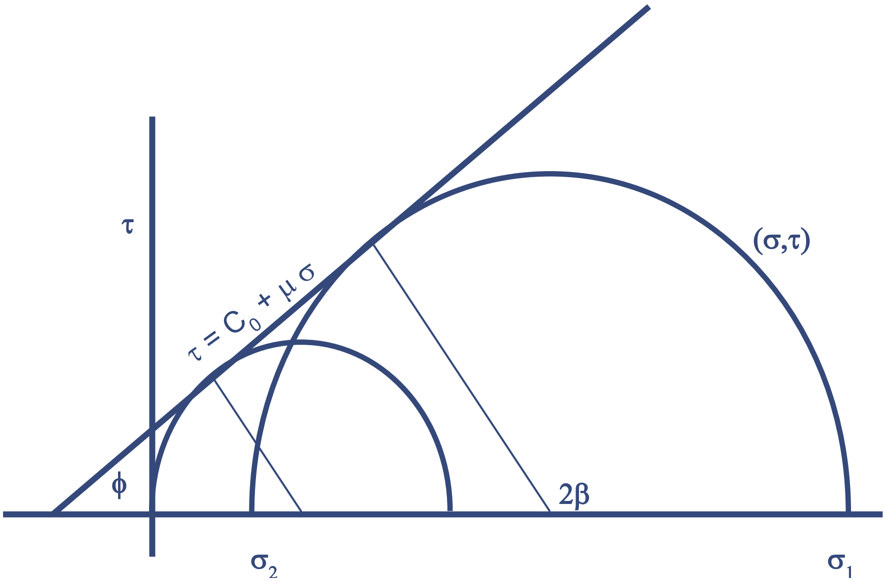


**Figure B2: Mohr diagram with Mohr-Coulomb failure line.**

The shear capacity is the Mohr circle radius divided by the distance between Mohr circle centre and failure envelope. Circles drawn in the figure have shear capacity = 1 because they touch the line.

If there are no faults known or the failure of intact rock needs to be assessed, the shear capacity of the stress tensor can be determined. It is defined as the slip tendency on the plane orientation where it is the highest, divided by the value of the Mohr-Coulomb envelope (Figure B2). It can be shown to be dependent on the maximum and minimum values of the effective principal stress ($\sigma_1{}'$ and$\sigma_3{}'$) and the friction parameters (the friction coefficient $\mu$ and the cohesion$C_0$) as [Jaeger et al, 2009]

$$sc = \frac{\sqrt{1+\mu^2}(\sigma_1{}' - \sigma_3{}')}{\mu(\sigma_1{}' + \sigma_3{}') + 2C_0}$$

A value larger than 1 for this number indicates the risk of shear failure.

A final important measure is the risk of induced hydraulic fractures. Hydraulic fractures can only propagate if the minimum in-situ stress is exceeded. The appropriate number for this measure is therefore whether or not tensile effective normal stresses develop. This is the case if the minimum in-situ stress is smaller than the pore pressure.

## B3: Results

The scenarios that we have evaluated are located at a depth of about 900 m. The original pressure was 9 MPa. Depletion of the gas field had caused the original pressure to drop to about 0.4 MPa, which then is the pressure at the start of the $CO_2$ injection. The low pressure causes Joule-Thompson cooling additional to the already low temperature of the injected fluid. The original reservoir temperature is 40°C.

Eight scenarios have been evaluated. Four low-injectivity scenarios are indicated by T15, T49, T75 and T91. Four high-injectivity scenarios are labelled T01H, T08H, T44H and T115H. The description of these scenarios can be found in section D3 scenarios in the previous appendix. The temperature fields of these scenarios are presented in Figure B3 and Figure B4; the pressures in Figure B5 and Figure B6. The temperature fields mainly depend on the injection temperature and the amount of injected $CO_2$. The pressure fields show a visible pressure gradient for the low-injectivity cases; for the high-injectivity cases the pressure variation within the reservoir is negligible with regard to the differences with the seal and the base, and with the differences between elapsed time. The reservoir is pressurised almost as a tank. We have therefore used the low-injectivity cases as the base case.

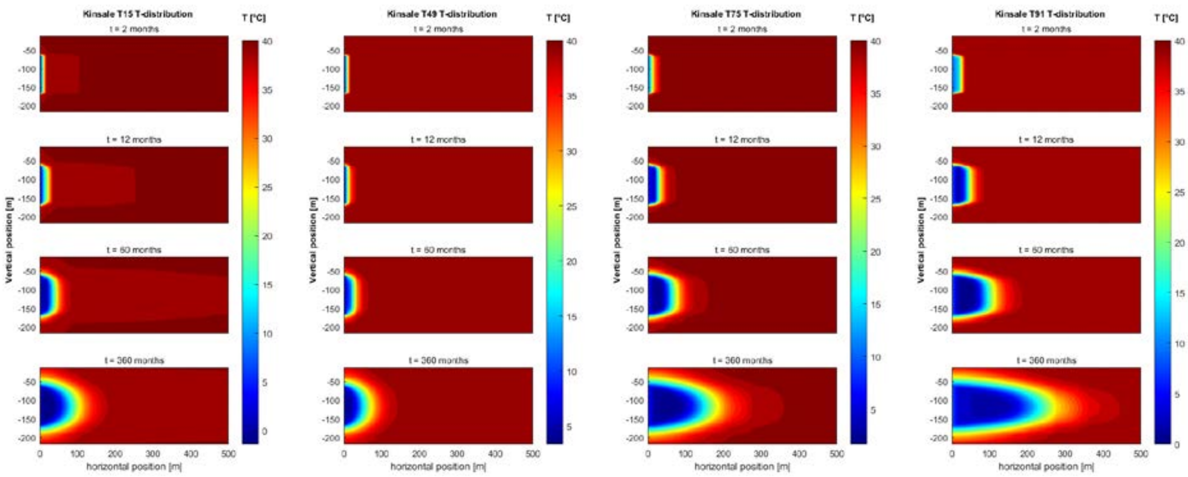


**Figure B3: Temperature fields for the 4 low-injectivity cases**

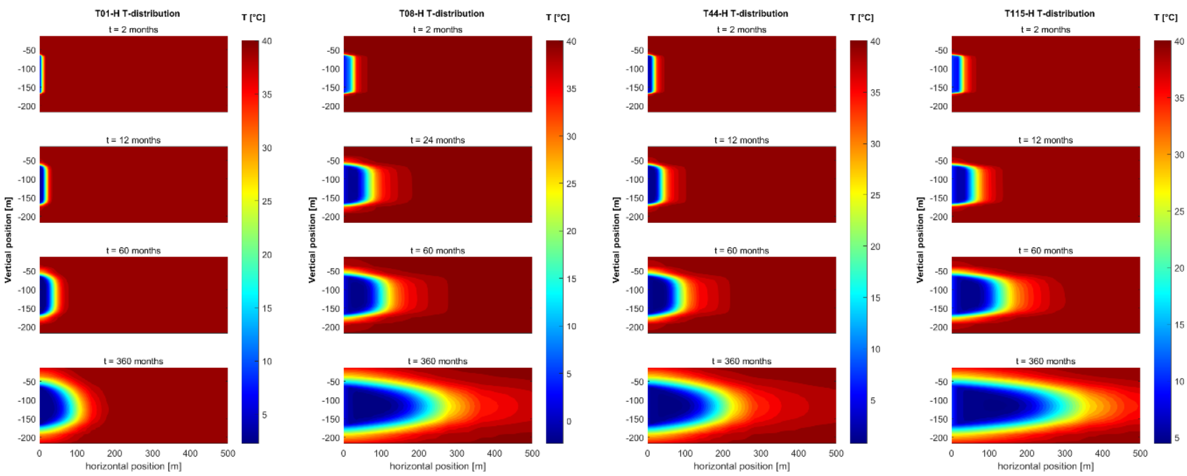


**Figure B4: Temperature field for the 4 high-injectivity cases**

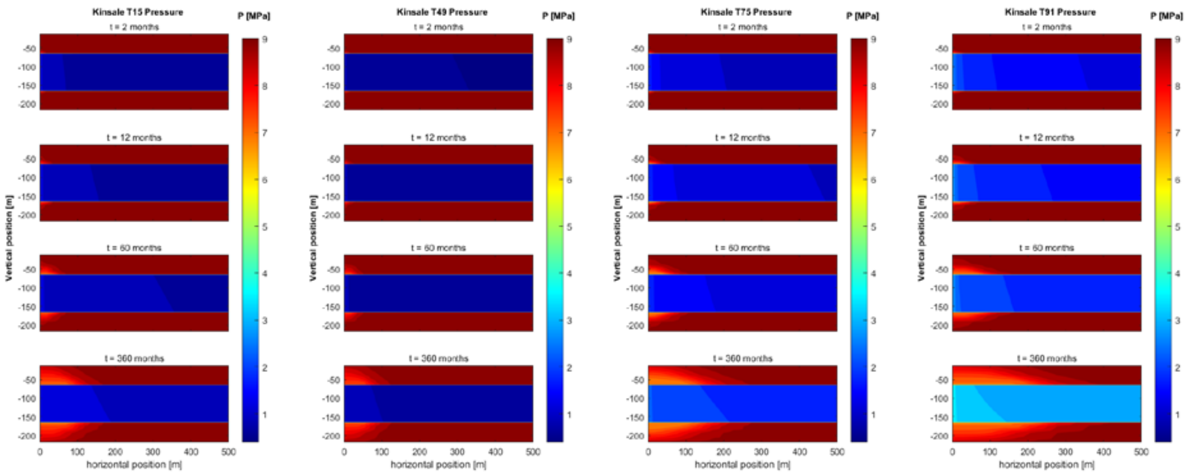


**Figure B5: Pressure fields of the 4 low-injectivity cases**

The cooling in the vicinity of the well causes the pressure to drop in the seal and the base. Further, pressurization is mainly effective on the complete reservoir, thanks to the large reservoir permeability.

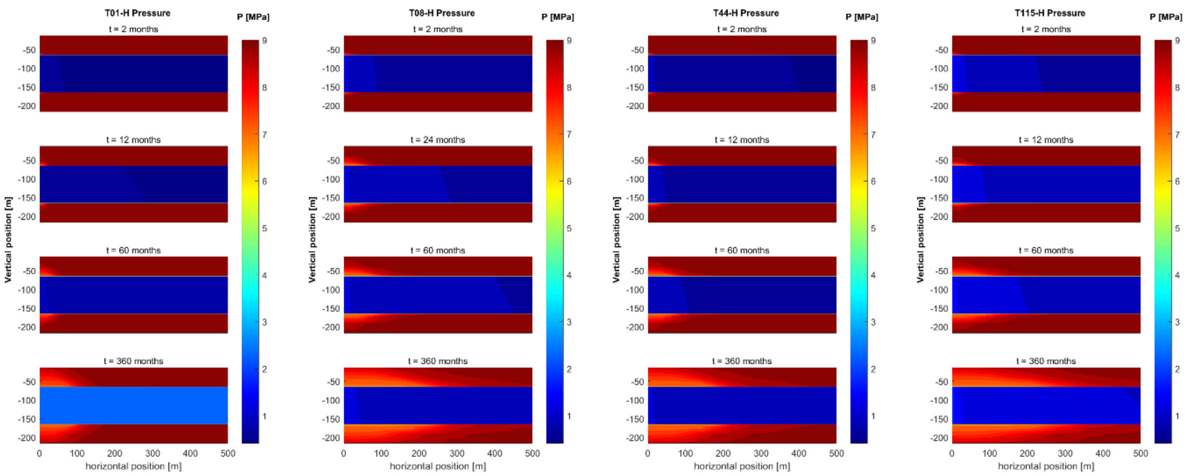


**Figure B6: Pressure fields for the 4 high-injectivity cases**

Due to the large permeability, the pressure gradients in the injection layer is minimal. At the start of the injection, there is already a distortion from the original virgin stresses, due to the pressure change associated with the gas production prior to $CO_2$ injection (Figure B7). The 8.6 MPa pressure reduction has caused the horizontal stresses to drop around 7 MPa, resulting in an increase of the effective horizontal stresses of 1.6 MPa. The vertical stresses did not change, therefore the effective vertical stresses had been increased by 8.6 MPa during gas production. This has already caused an increase in the shear capacity in the reservoir before injection of $CO_2$. After starting the injection, however, the main effect is because of the cooling of the reservoir and its surroundings. Figure B8 shows a pronounced zone of increased risk on fault activation and hydraulic fracturing. The fracturing risk is largely confined to the cooled zone. The activation risk zone extends beyond the cooling front.

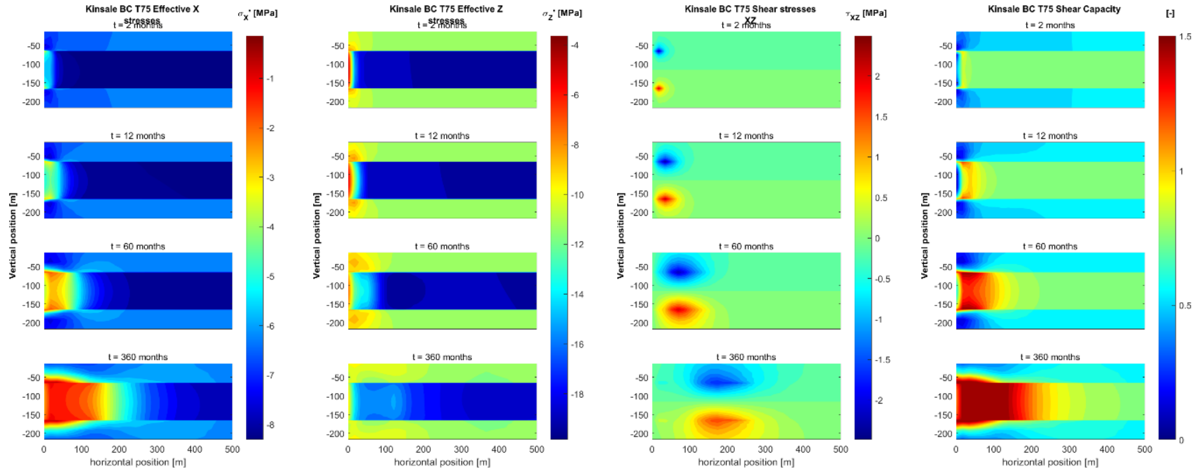


**Figure B7: Essential output of T75 case**

At the start (top figures) the stress in the Vertical effective stresses have been mainly changed due to depressurization during gas production. Horizontal stresses are mainly affected by cooling around the wellbore. As a result, shear capacity develops in the reservoir around the wellbore. Compressive stresses are negative; "smaller effective stresses" in the text refer to larger (less negative) numbers in the plots.

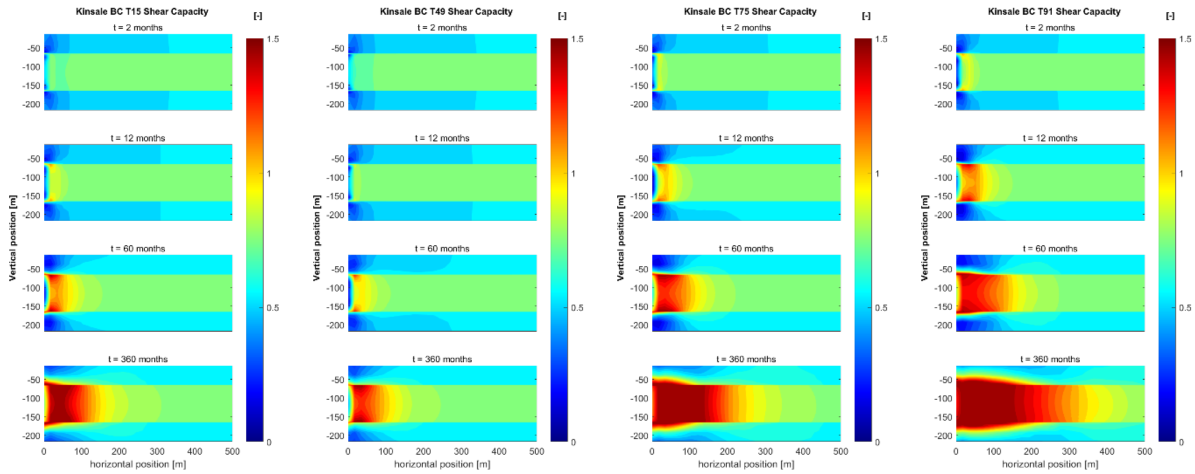


**Figure B8: Shear capacity development for the 4 injection scenarios.**

The risk zone is mainly dependent on the area that is cooled but extends further into the reservoir than the cooling front. An important question is whether the input data are reliable enough to make a faithful estimate of the induced stresses and the associated failure risks. We have started with a sensitivity study to the input parameters. The first one is the original stress anisotropy, indicated by the ratio between minimum horizontal and vertical stress. Decreasing from a value of 0.95 in steps to 0.65, i.e., from almost isotropic to almost critical at the start, we see an increasing area of activation risk (Figure B9). What is striking, however, is that even for the almost isotropic stress, fault reactivation risk in the cooled zone develops because of distorted starting value due to the reservoir depletion and the uneven change in horizontal and vertical stresses. This is also the case when we vary the friction parameters, as in Figure B10. While a very low friction coefficient indeed results in failure in the complete volume of the injection layer, the failing region for larger coefficients, and the action of a cohesion, does not have a large effect on the behaviour in the cooled zone.

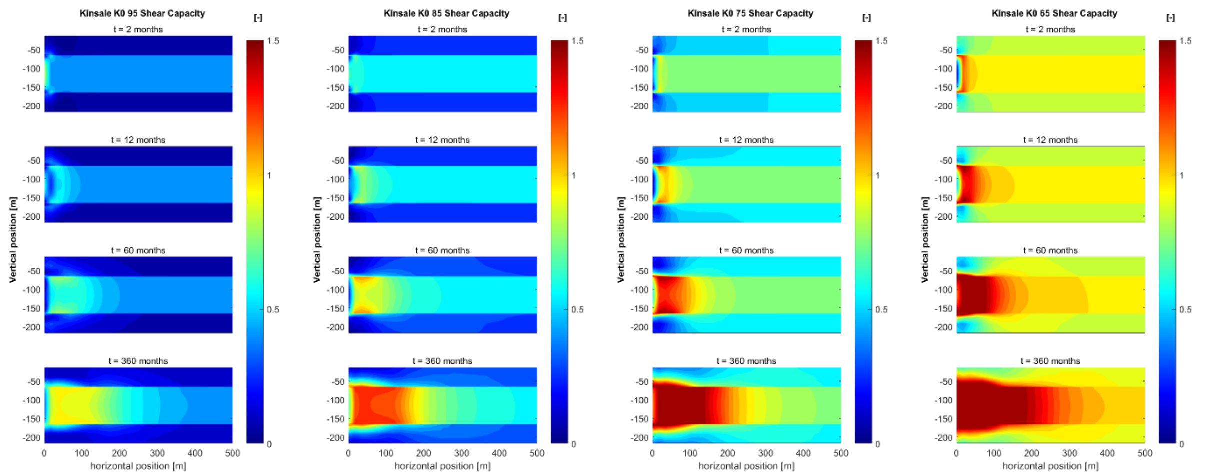


**Figure B9: Effect of initial in-situ stress ratio.**

From left to right: $\frac{\sigma_h}{\sigma_v} = \mathbf{0.95, 0.85, 0.75, 0.65}$. Even for the almost isotropic stress, fault reactivation risk in the cooled zone develops because of distorted starting value due to the reservoir depletion and the uneven change in horizontal and vertical stresses.

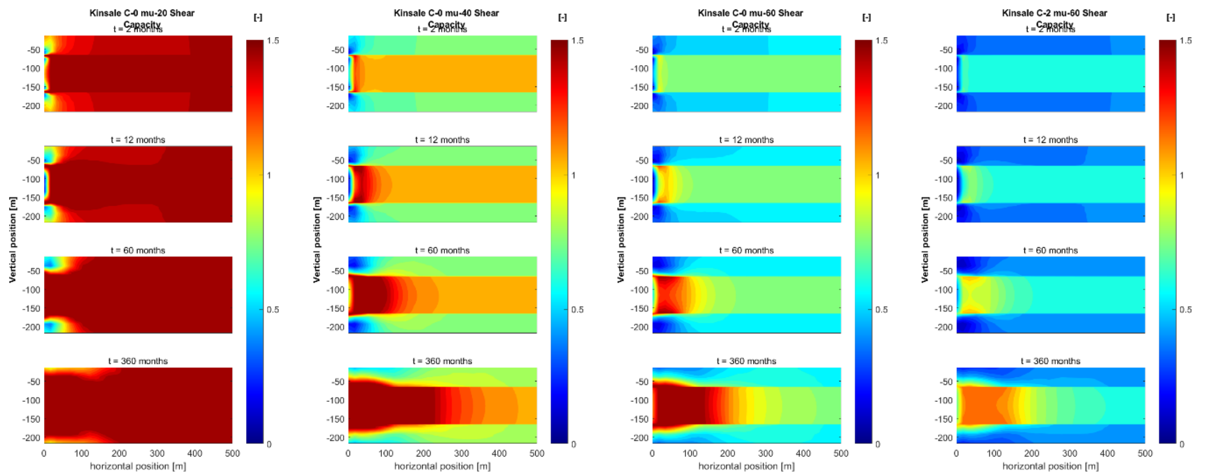


**Figure B10: Sensitivity to failure parameters**

An important input number is the elastic modulus, the Young's modulus. The Schlumberger report on Kinsale (SLB, 2011) provides a range of numbers. Typical numbers for sandstone range from

7 (low) to 25 (medium) to 55 GPa (high). The logs in the Schlumberger geomechanics report suggest that the modulus is around 10 GPa in the target reservoir and gradually increases to 35 GPa in the seal (SLB, 2011). We have therefore explored the sensitivity to this number. Figure B11 shows how the stresses depend heavily on the modulus when the values are homogeneous over the whole domain. While the patterns are comparable, the absolute values differ much. For the larger modulus, stresses become even tensile in the cooled area. Figure B12 gives the shear capacity development in the complete domain for a range of homogenous moduli.

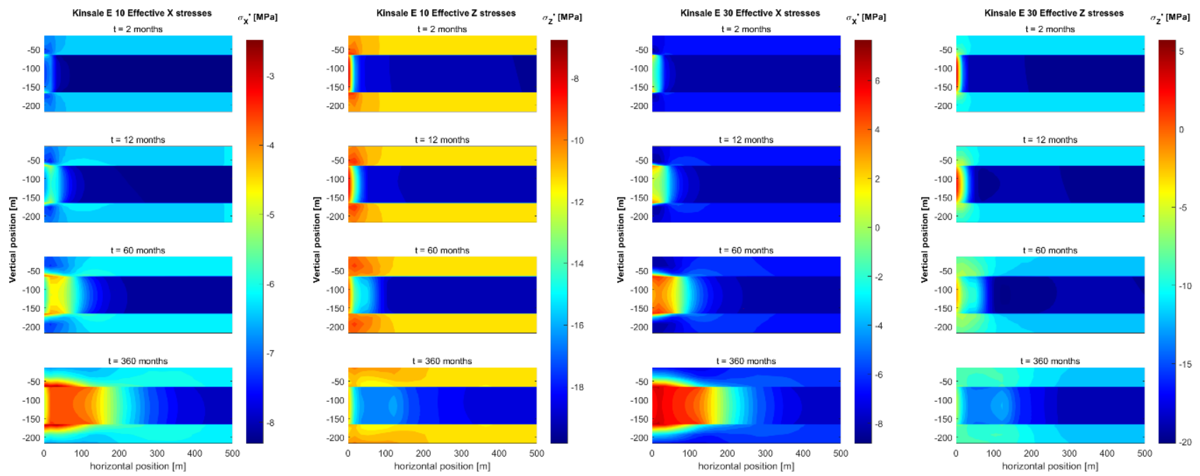


**Figure B11: Sensitivity of stress development to homogeneous elastic modulus**

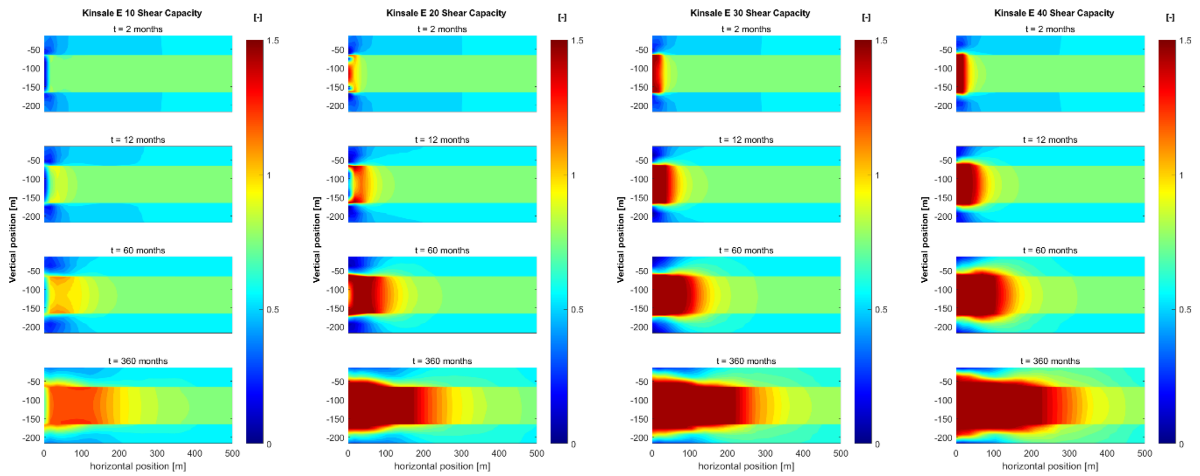


**Figure B12: Shear capacity for different values of the homogeneous elastic modulus**

Figure B13 presents the most effective radial and effective vertical stress fields for cases where the elastic modulus exhibits a contrast over the interface between injection layer and base and seal. When the bounding layers are weaker than the reservoir layer, the induced stresses are smaller. When the bounding layers are stiffer, large stress concentrations develop in them due to the cooling. The consequences of this behaviour for the stability are depicted in

Figure B14 for the shear capacity and in Figure B15 for the fracturing risk. Indeed, in the stiffer bounding layers the stresses develop into tensile stresses and hydraulic fracturing can occur in the cooled parts of these layers.

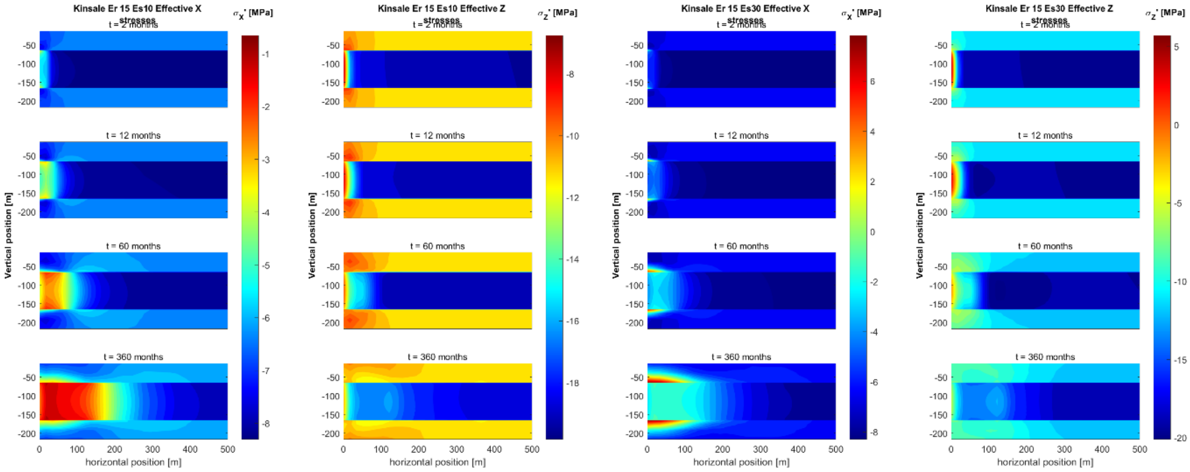


**Figure B13: Stresses for cases with an elasticity contrast**

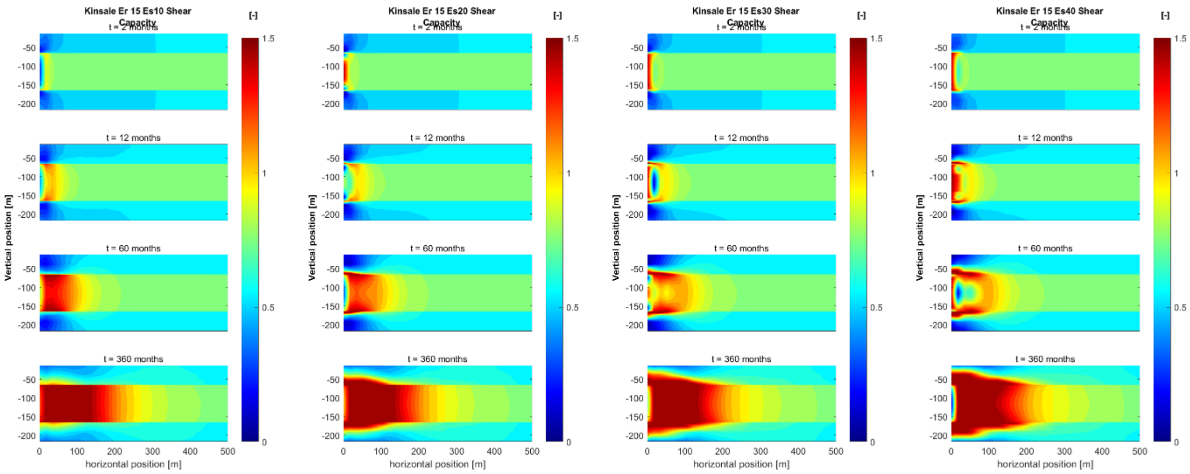


**Figure B14: Shear capacity for cases with an elasticity contrast**

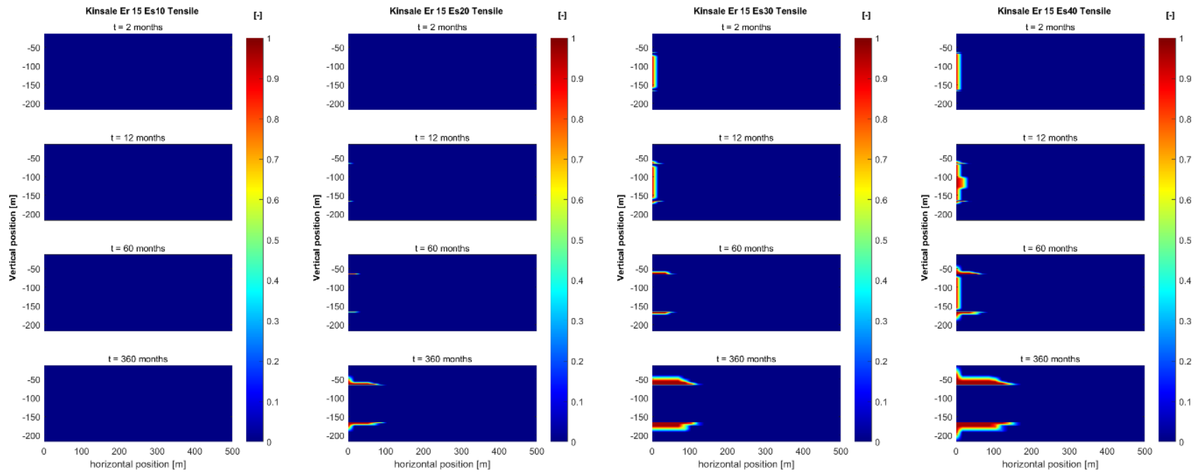


**Figure B15: Tensile stresses for cases with an elasticity contrast**

# B4: Discussion

SRIMA is a software tool that enables quick evaluation of poro-thermo-elastic stress development and associated frictional parameters for a simplified subsurface setting around an injection well. It is consequently ideally suited to perform sensitivity calculations and probabilistic studies for the potential of fault reactivation. This is what we have done for the Kinsale case in the present note.

The SRIMA setup comes with necessary limitations. Important ones are the 2D radially symmetric geometry and the 3-layer approximation. Real faults that exhibit an offset, connecting reservoir parts at different depth, cannot be modelled. For such scenarios, one has to revert to 2D plane strain models in a vertical plane that ignores the radial symmetry, or to numerical 3D simulations. A numerical approach is also warranted if inelastic behaviour needs to be modelled explicitly. Conversely, simple seismicity models that rely on stressing rates (Segall and Lu, 2015) can be fed from the output of SRIMA. Such an approach is promising and we strongly advocate a development in that direction.

We have identified the most influential parameters for geomechanical risks associated with $CO_2$ injection in the Kinsale field. They are the elastic moduli of the injection layer and the seal and the base, the starting stress situation, and the failure parameters. The injectivity has only limited effect, since economic injection operations require large permeability's that involve only small pressure changes – even for the low-injectivity cases that we considered here. The pressure of the reservoir prior to injection, however, does have a large effect, since the gas field had been depleted to very low pressures during gas production.

The temperature of the injected fluid is the most influential operational parameter. To a certain degree, this number can be controlled. An allowed operational window can be defined when the subsurface parameters are known more accurately. When $CO_2$ injection is planned in Kinsale, it is therefore important to constrain the values of these parameters. The prime parameters are the elastic moduli of target layer, seal and base: the thermoelastic effect is directly proportional to them, and modulus contrasts can induce stress concentrations at the interfaces, and tensile stresses just outside the reservoir. The potential of a tensile stress is not affected by the friction parameters, while reactivation potential is. Finally, the effect of the virgin in-situ stress is smaller than it would be in really virgin reservoirs. The gas depletion before CCUS operations has already induced a significant stress anisotropy at the start.

# B5: Conclusions

The results presented here suggest that reservoir and caprock integrity and fault stability are issues that should be studied in detail, as part of a $CO_2$ storage feasibility study of the KHGF. The geomechanical analyses suggest that fracturing of the reservoir and/or caprock as a result of injection of relatively cold $CO_2$ cannot be excluded and that fault stability may be a risk. More detailed analyses involve the use of 3D models that include reservoir, caprock and fault geometry, as well as the collection of formation specific data on mechanical properties. Such analyses can be used to assess the impact of reservoir related storage risk on the design and operation of $CO_2$ injection and will form the basis for operational risk management.

# B6: Recommendations

We recommend focused data mining when CCUS is being planned. Such data mining should definitely contain logs. Furthermore, cores need to be taken, and geomechanical tests on them like elasticity measurements and failure tests should be executed. Also, in-situ tests are necessary to have a handle on the in-situ stresses. Geological mapping, finally, is required to identify critical faults.

With such data available, one can use the knowledge obtained in this study to better design injection operations. Indeed, reactivation risks seem largely confined to cooled zones. A study like the present one can then be used to evaluate how much $CO_2$ can be injected before a certain fault is put at risk. Or, conversely, such a study could be used to estimate the minimal distance to faults of newly drilled wells.

Our knowledge of many subsurface properties is subject to large uncertainty – including the elastic properties, the stresses, and the friction parameters. The risk measures defined above therefore commonly need to be defined for a range of parameter values. Such mapping can be established in a probabilistic approach. We could define the uncertainty or variability of the key parameters and their uncertainty or variability range, and then randomly choose values of these parameters within these ranges. This creates an ensemble of realizations of parameter value combinations. For every realization, the induced stresses and reactivation measures such as the shear capacity can be calculated. The output can be divided into a number of subranges, to be plotted in a bar graph to gain insight into the effect of the parameter input value on the output measure for reactivation.

## B7: References

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Myklestad, N. O. (1942). Two problems of thermal stress in the infinite solid.

Perkins, T. K., & Gonzalez, J. A. (1984). Changes in earth stresses around a wellbore caused by radially symmetrical pressure and temperature gradients. *Society of Petroleum Engineers Journal*, *24*(02), 129-140.

Perkins, T. K., & Gonzalez, J. A. (1985). The effect of thermoelastic stresses on injection well fracturing. *Society of Petroleum Engineers Journal*, *25*(01), 78-88.

Segall, P., & Lu, S. (2015). Injection-induced seismicity: Poroelastic and earthquake nucleation effects. *Journal of Geophysical Research: Solid Earth*, *120*(7), 5082-5103.

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# Appendix C: Scenarios for geomechanical effects of $CO_2$ injection into KHGF

## C1: Scenario 1a

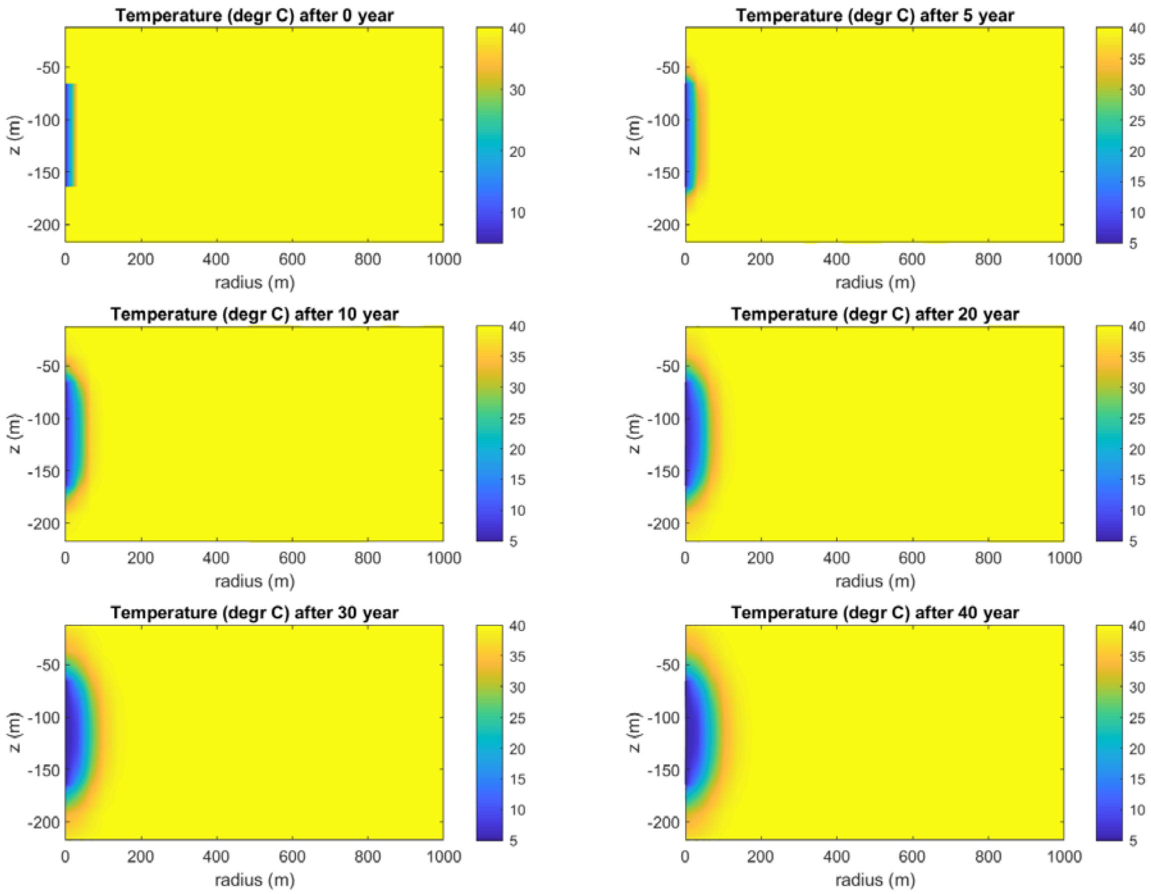


**Figure C1: Temperature in the reservoir**

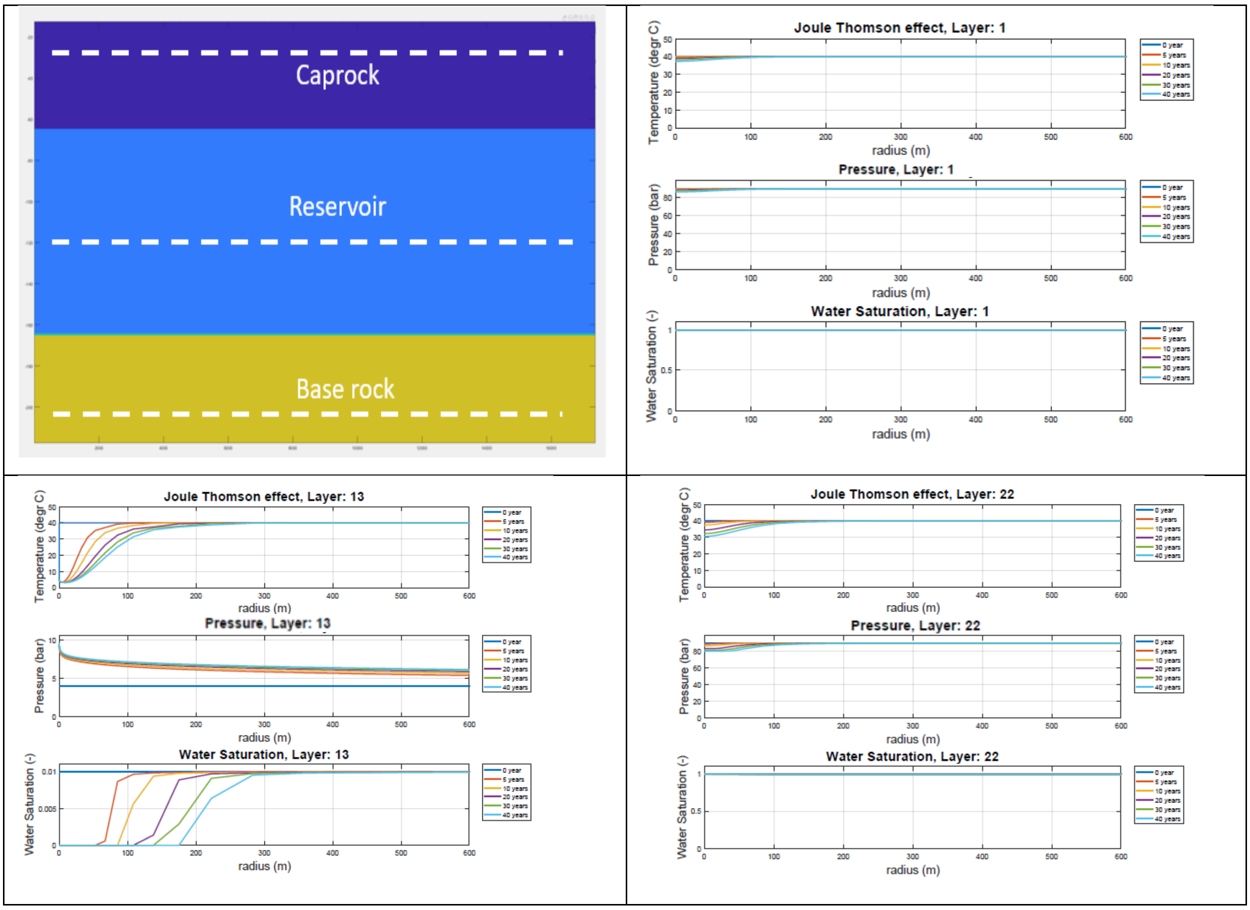


**Figure C2: Temperature, pressure and water saturation profile in the caprock (top right), reservoir (bottom left and base rock (bottom right)**

## C2: Scenario 1b

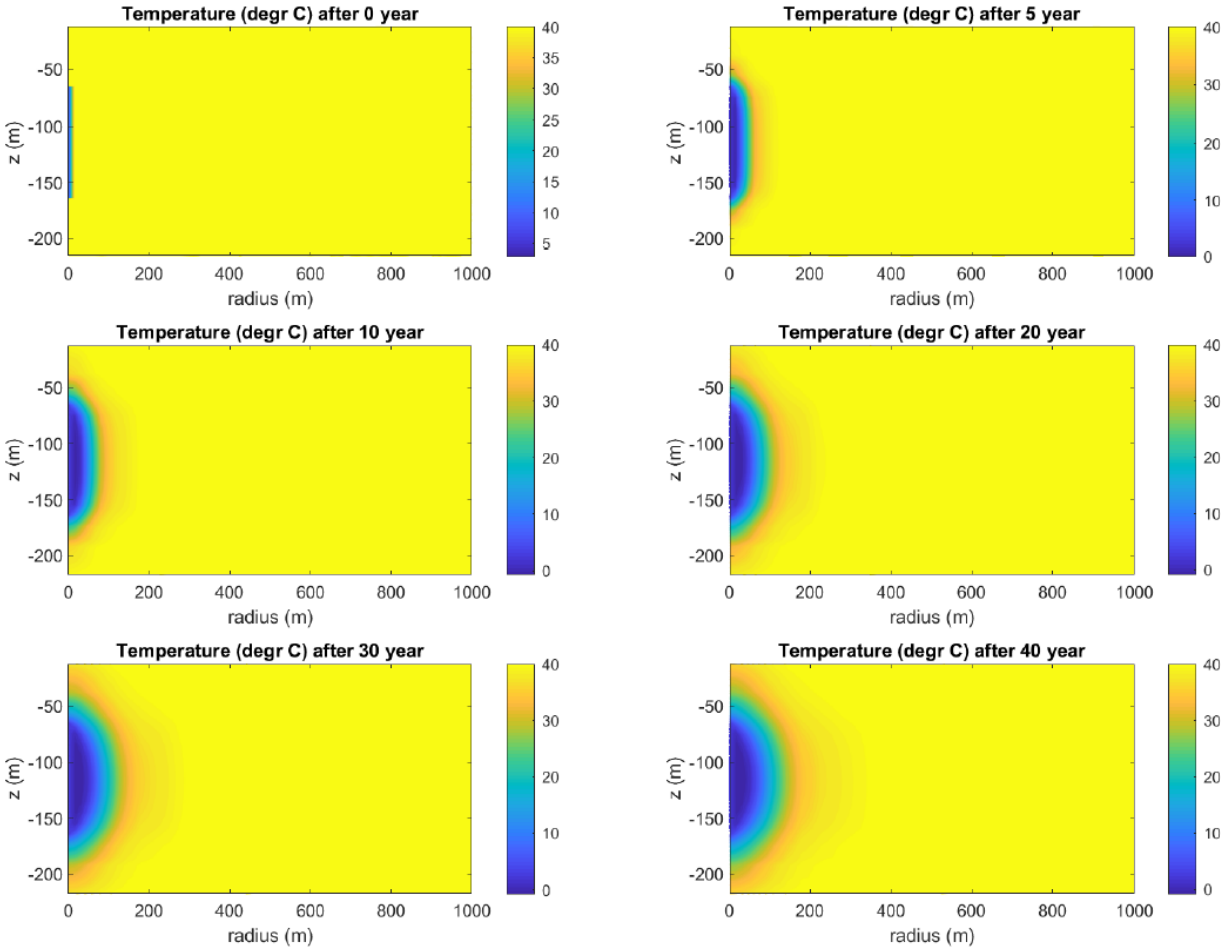


**Figure C3: Temperature in the reservoir**

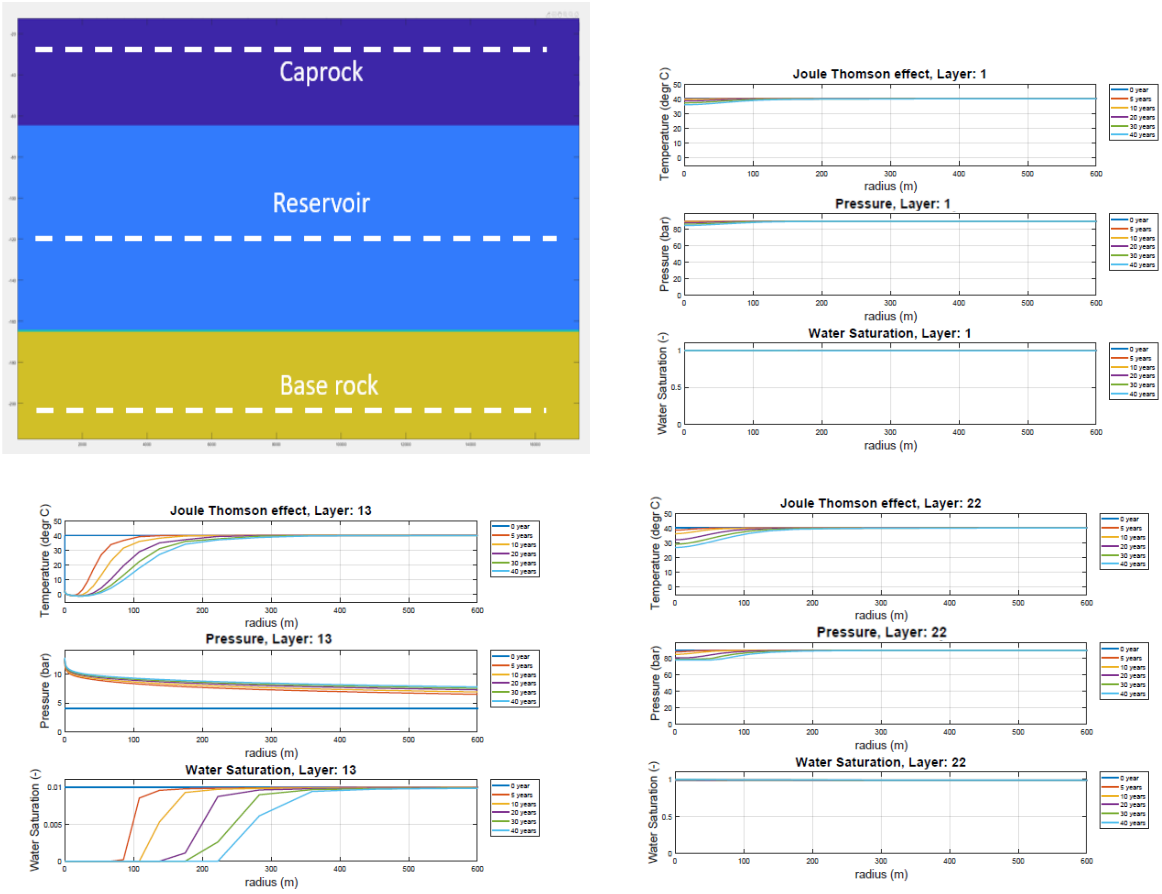


**Figure C4: Temperature, pressure and water saturation profile in the caprock (top right), reservoir (bottom left and base rock (bottom right)**

# C3: Scenario 1c

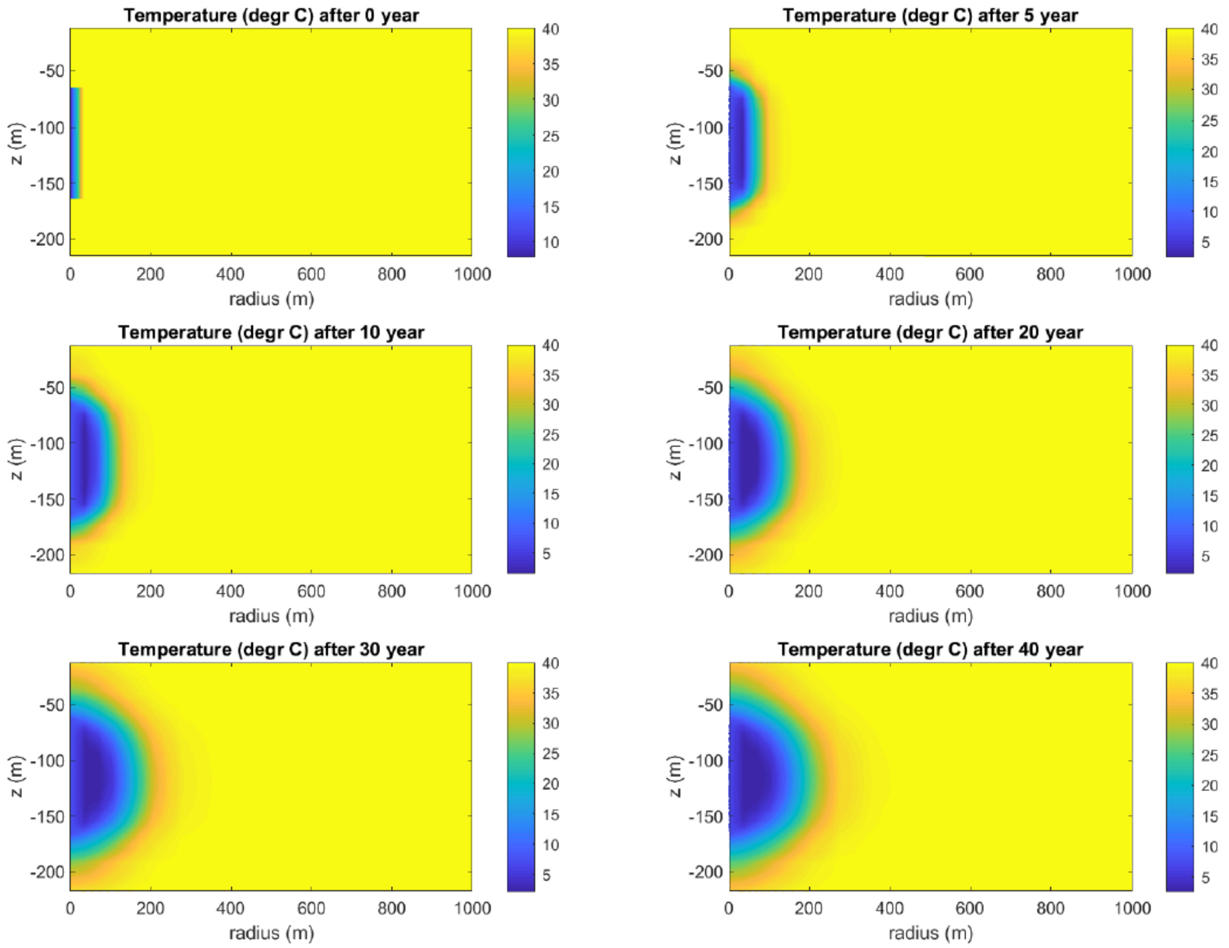


**Figure C5: Temperature in the reservoir**

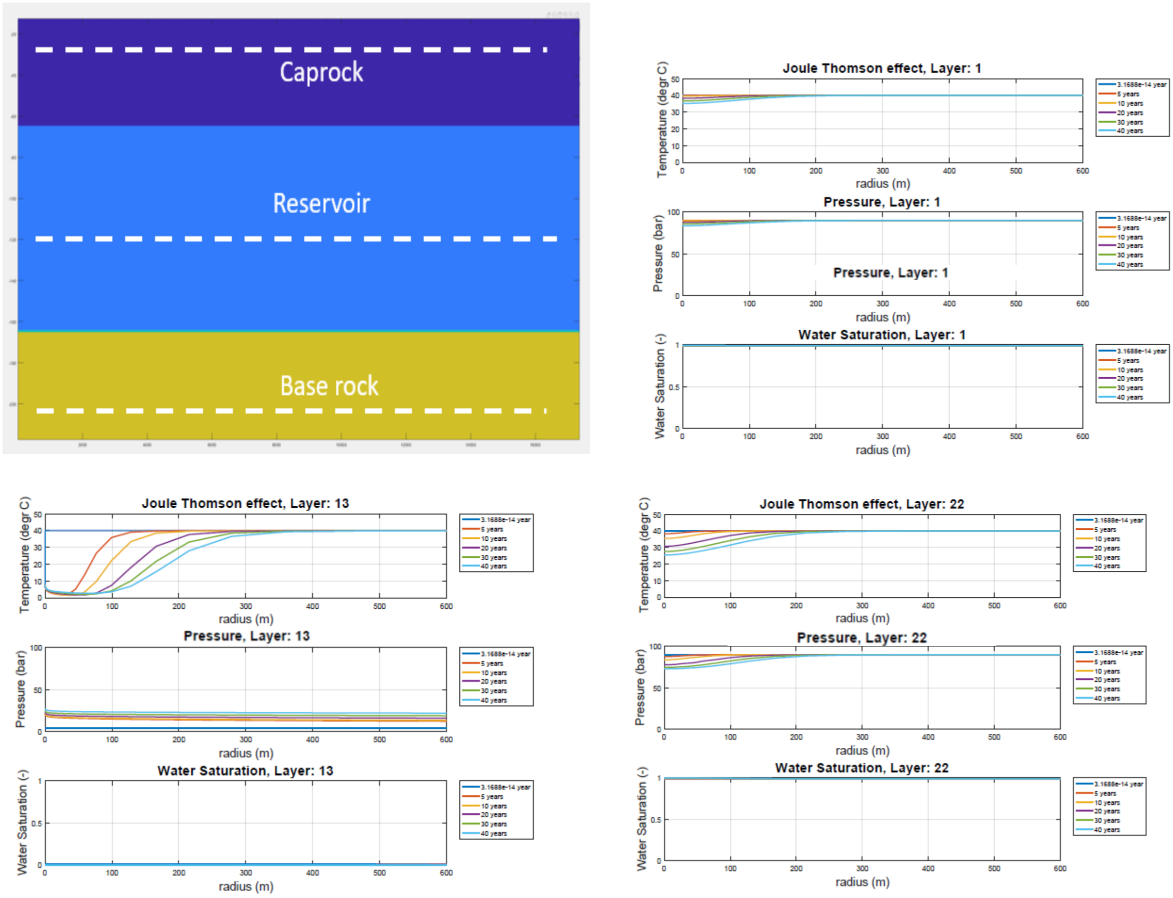


**Figure C6: Temperature, pressure and water saturation profile in the caprock (top right), reservoir (bottom left and base rock (bottom right)**

# C4: Scenario 1d

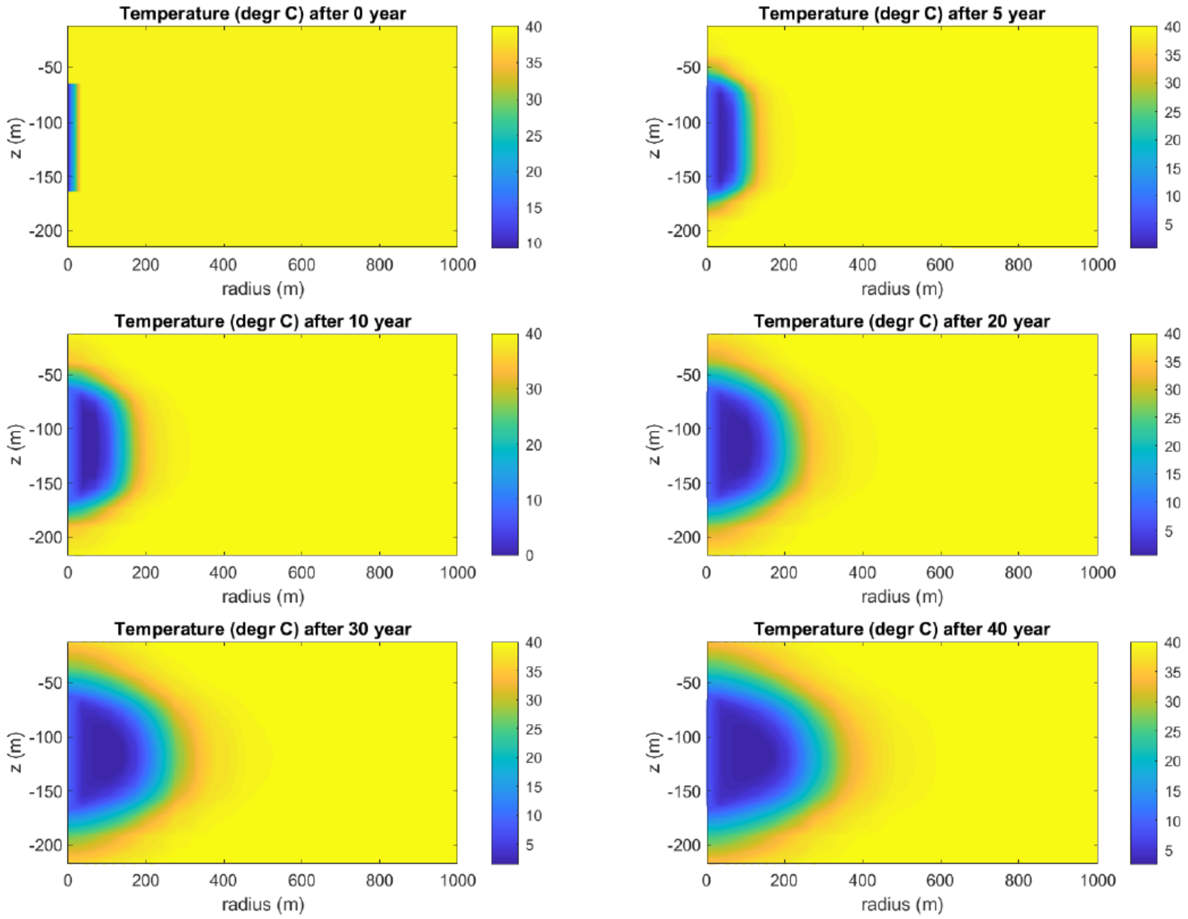


**Figure C7: Temperature in the reservoir**

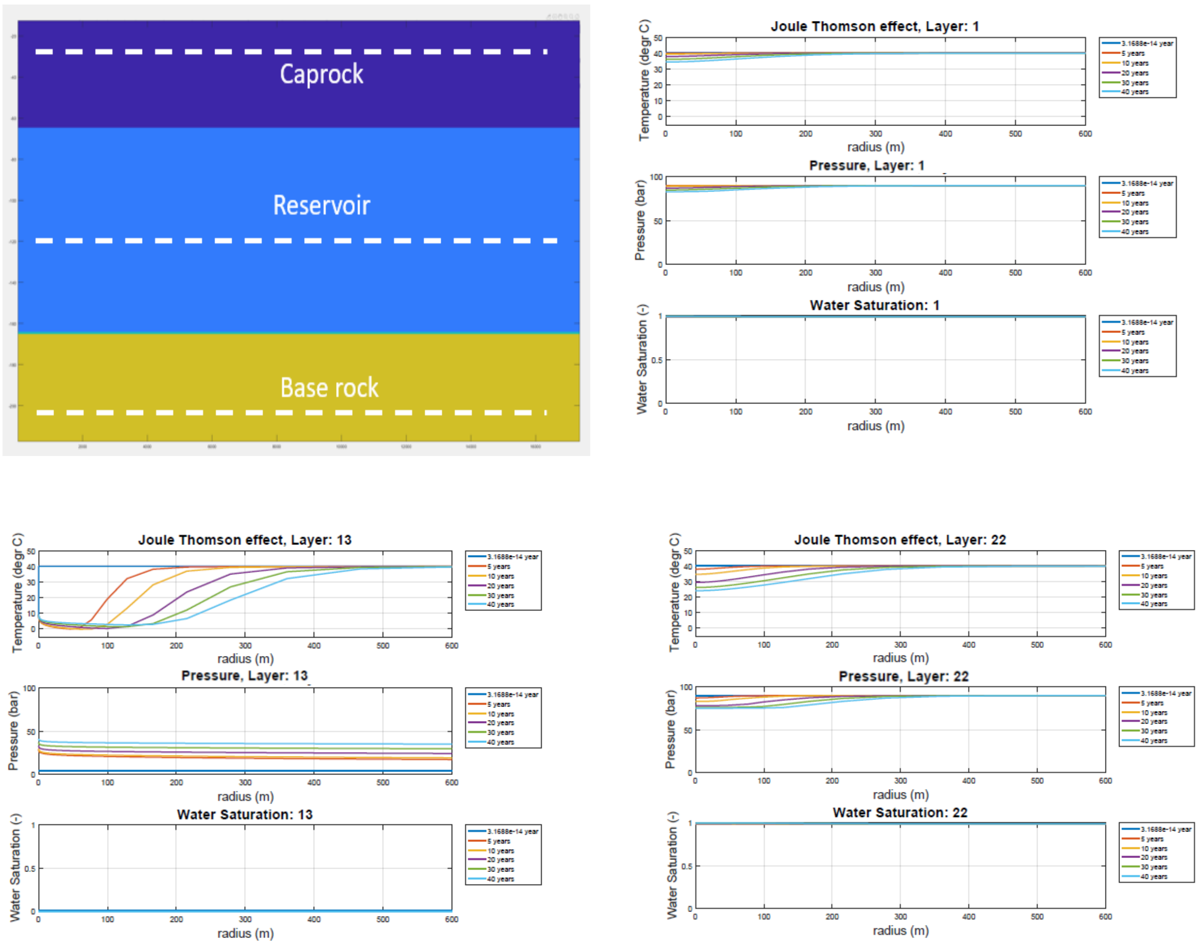


**Figure C8: Temperature, pressure and water saturation profile in the caprock (top right), reservoir (bottom left and base rock (bottom right)**

## C5: Scenario 2a

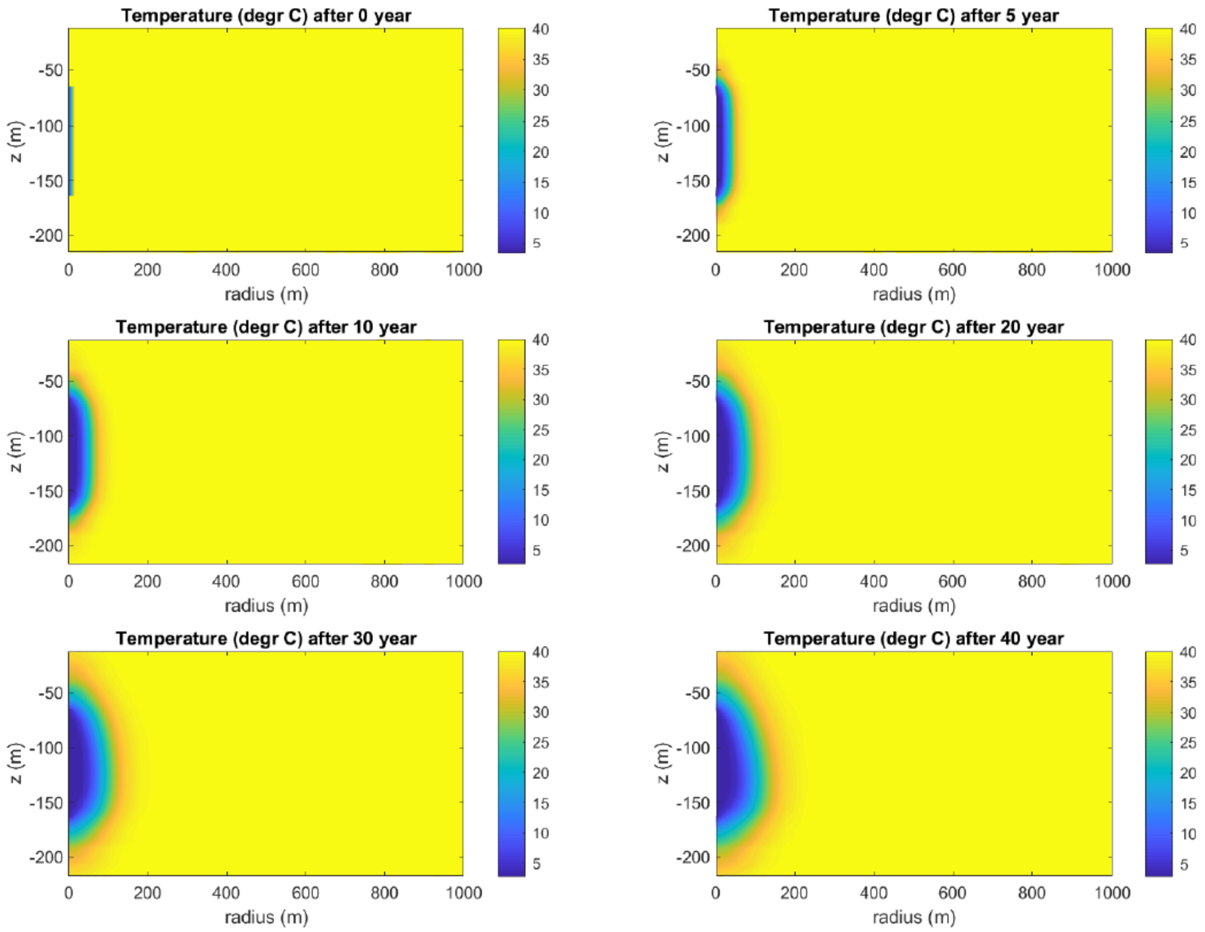


**Figure C9: Temperature in the reservoir**

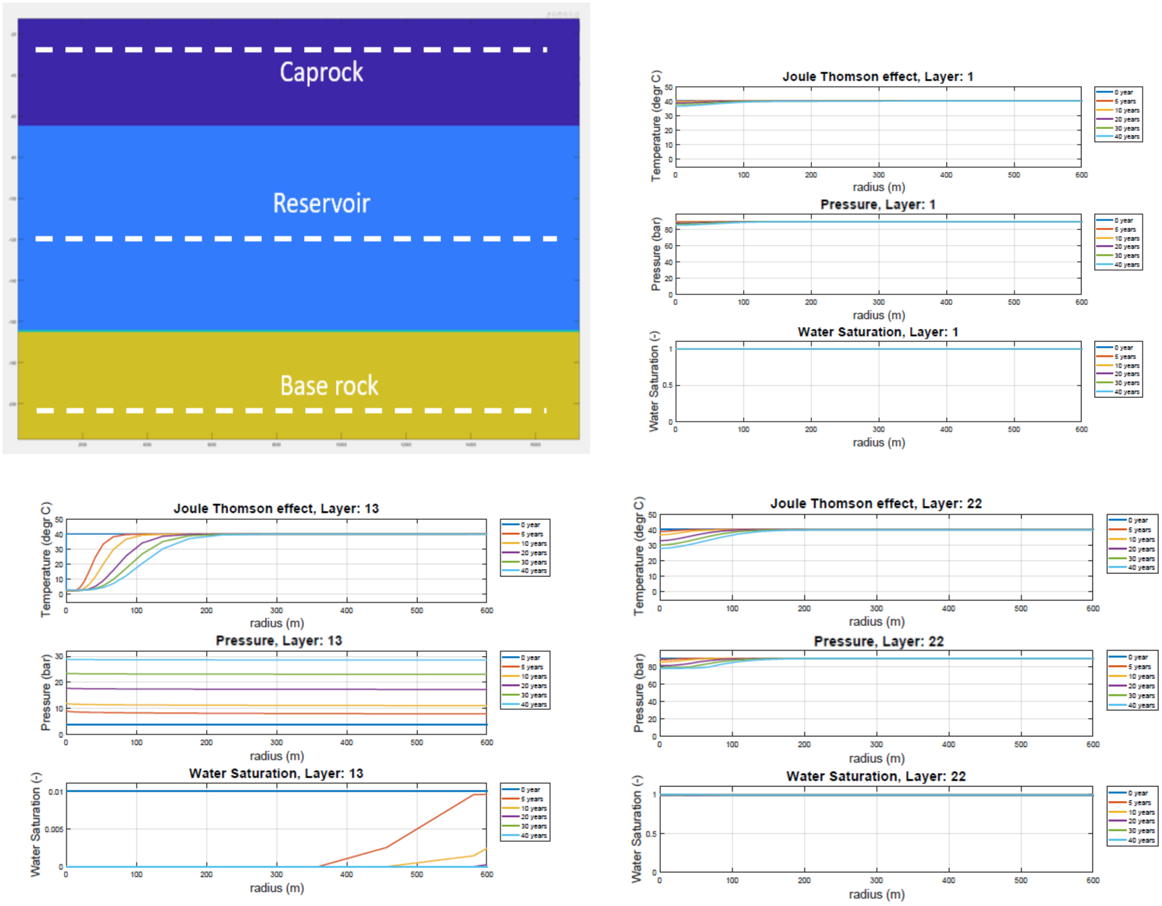


**Figure C10: Temperature, pressure and water saturation profile in the caprock (top right), reservoir (bottom left and base rock (bottom right)**

# C6: Scenario 2b

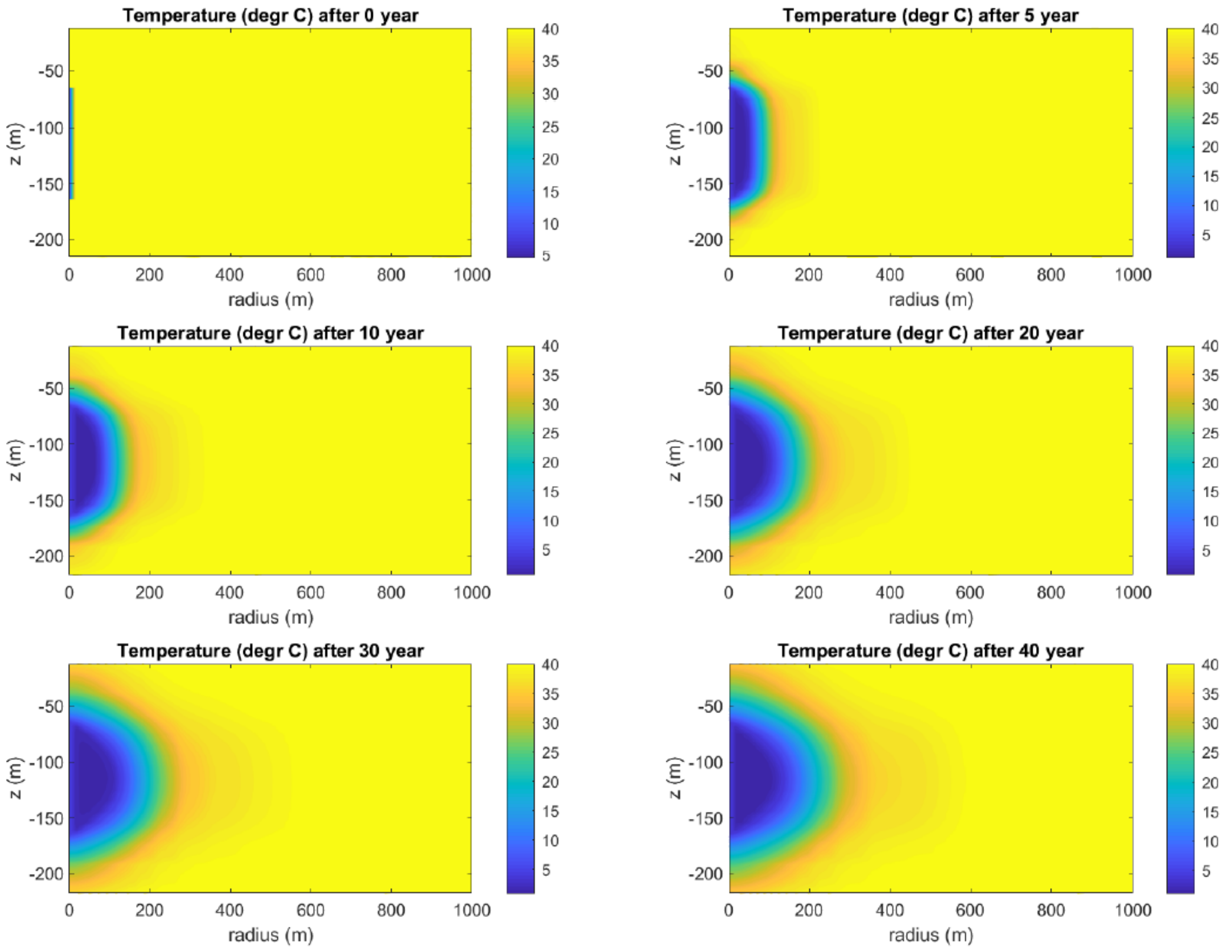


**Figure C11: Temperature in the reservoir**

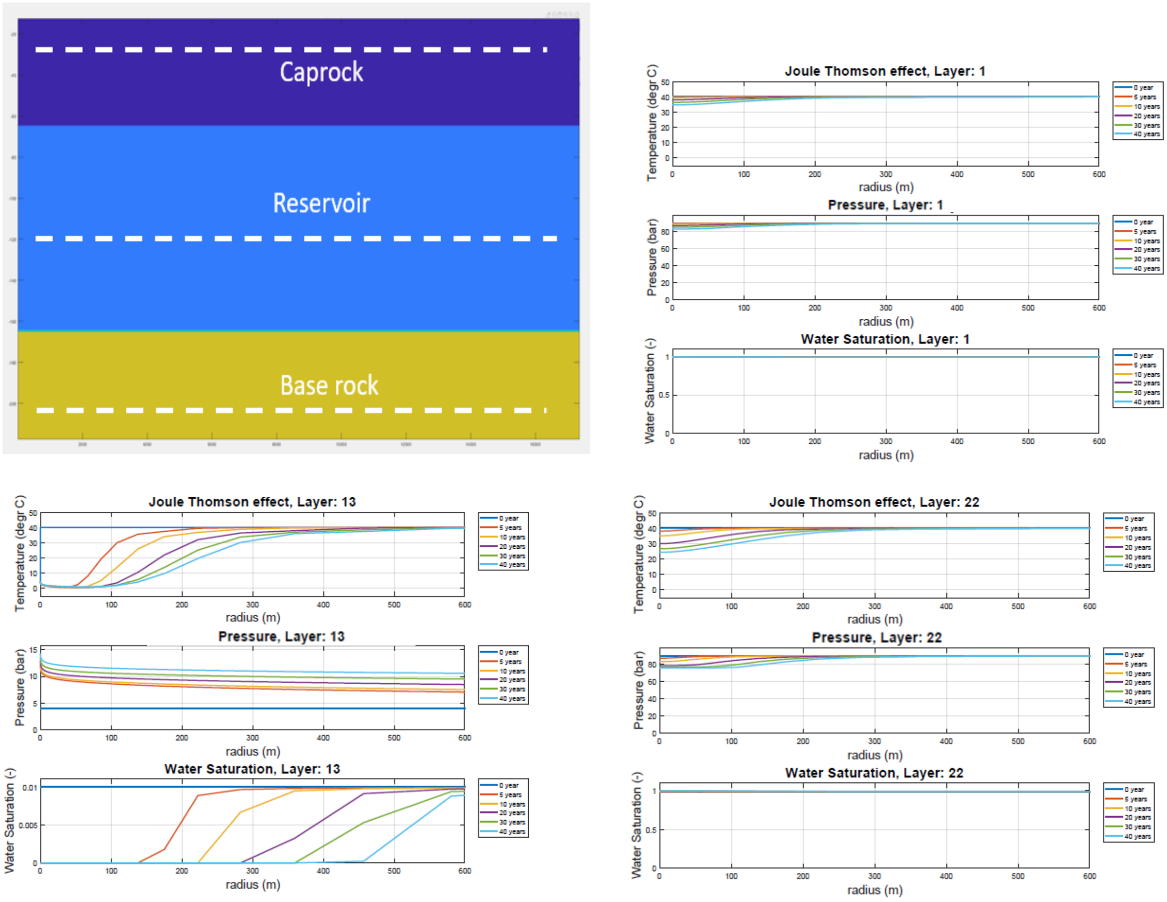


**Figure C12: Temperature, pressure and water saturation profile in the caprock (top right), reservoir (bottom left and base rock (bottom right)**

# C7: Scenario 2c

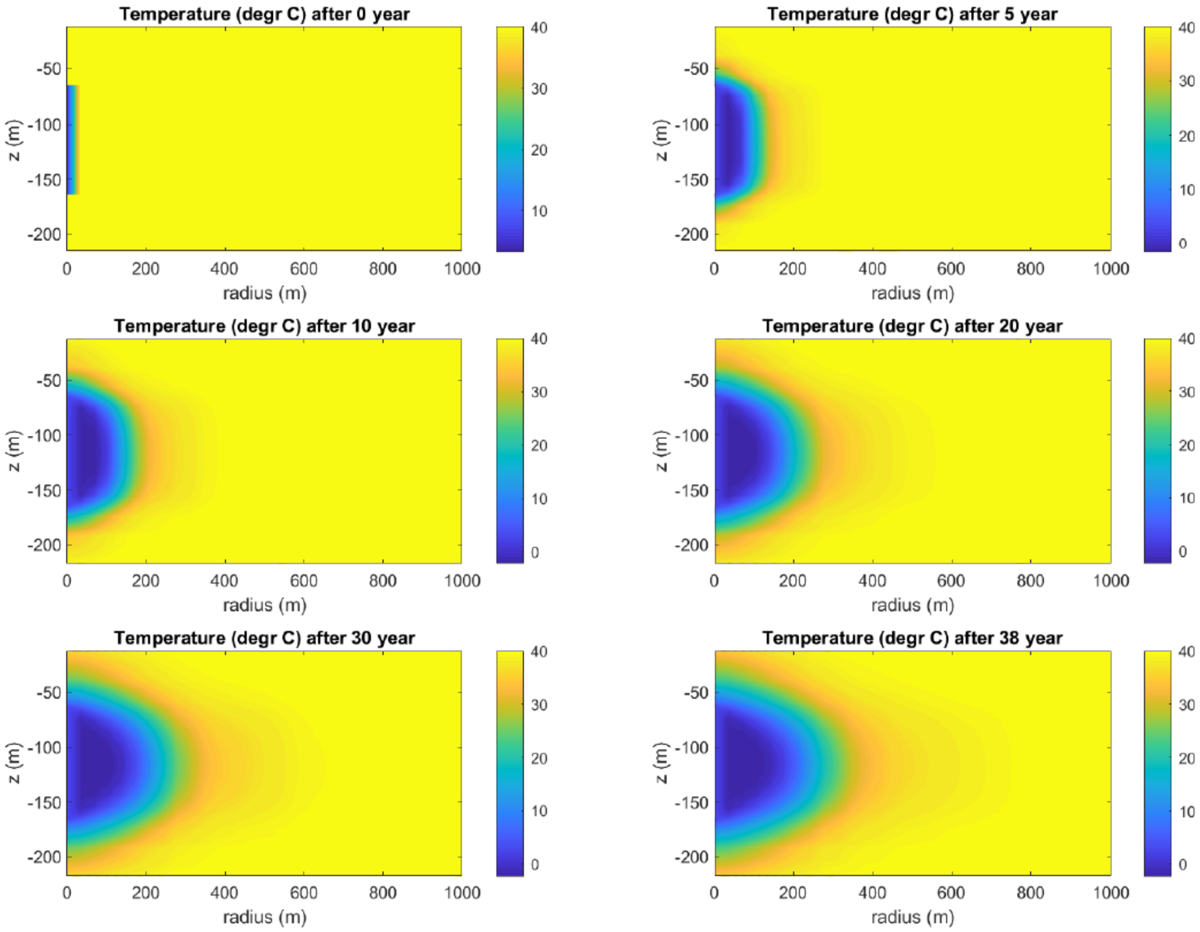


**Figure C13: Temperature in the reservoir**

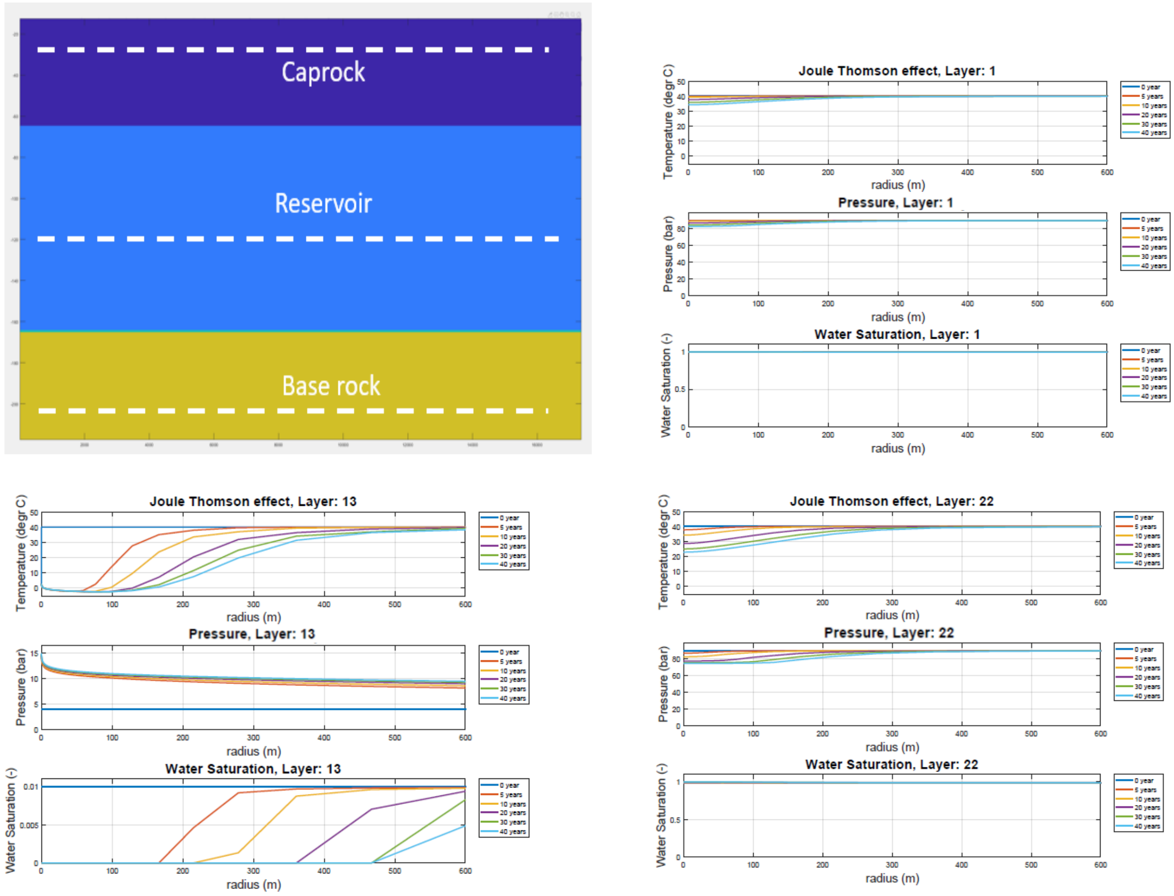


**Figure C14: Temperature, pressure and water saturation profile in the caprock (top right), reservoir (bottom left and base rock (bottom right)**

# C8: Scenario 2d

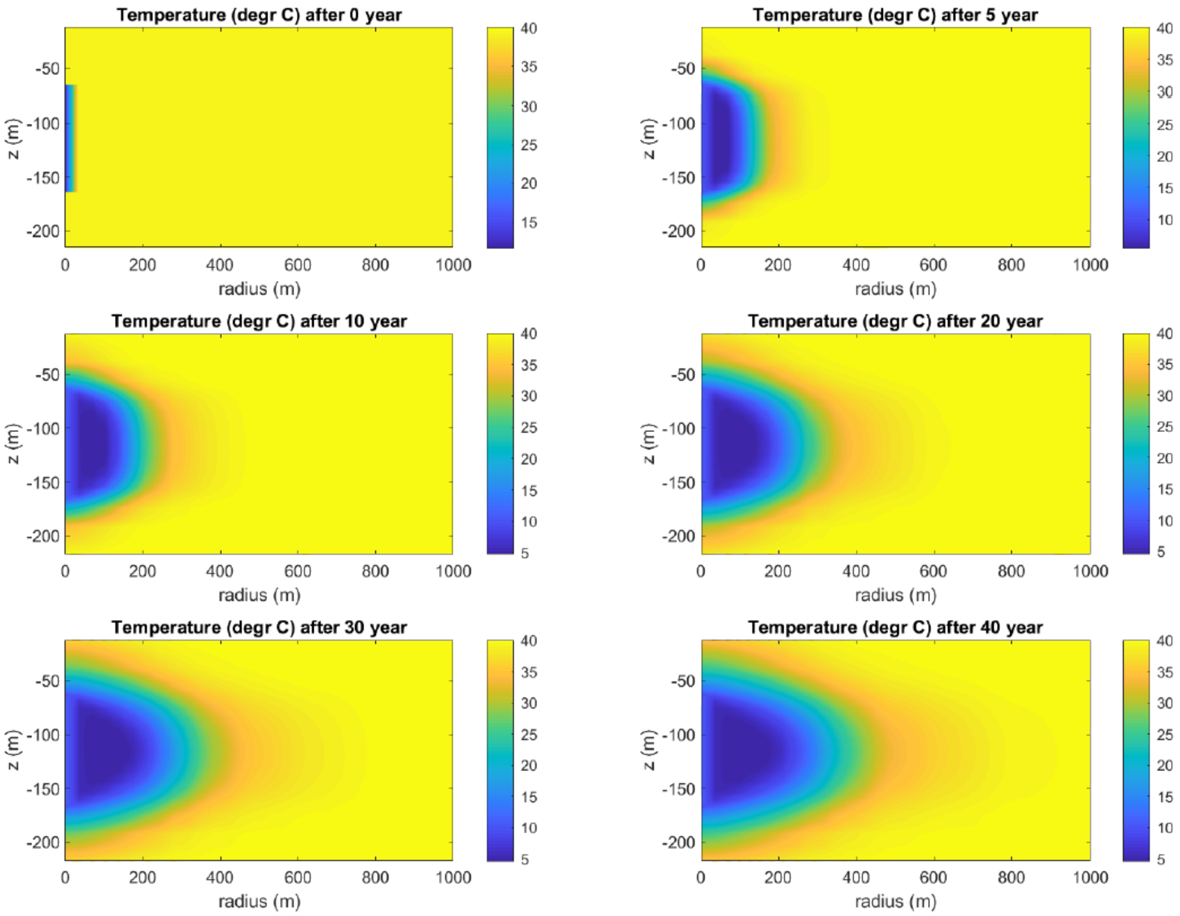


**Figure C15: Temperature in the reservoir**

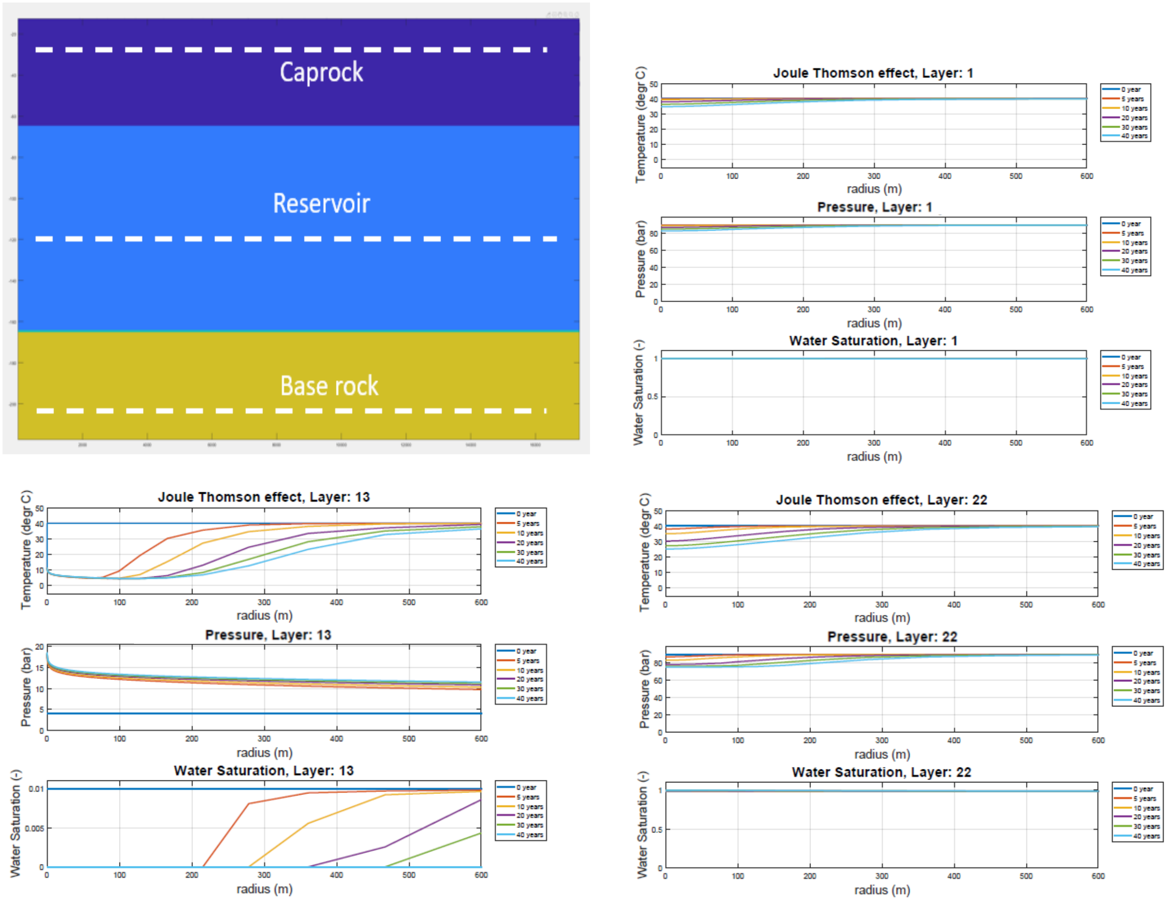


**Figure C16: Temperature, pressure and water saturation profile in the caprock (top right), reservoir (bottom left and base rock (bottom right)**

# Appendix D: Properties of $CO_2$

$CO_2$ is a non-polar chemical compound composed of two oxygen atoms covalently bonded to a single carbon atom (O=C=O); the molecule has a zero-dipole moment. $CO_2$ appears colourless and, at ambient temperature and pressure, it is defined odourless at low concentration.

$CO_2$ is present on the Earth either in geological formations or in the atmosphere where the concentration is typically 0.040% by volume.

This section presents and discusses specific properties and behaviour of $CO_2$ that is relevant for the design and operation of the transportation process of CCUS.

## D1: Physical Properties of Pure $CO_2$

Fundamental physical properties of pure $CO_2$ are listed in D1 with reference to the phase diagram given in Figure D1..

**Table D1: Physical properties of pure $CO_2$**

| Property | Value | Unit | Value | Unit |
|---|---|---|---|---|
| Critical density | 10.63 | mol/dm$^3$ | 467.6 | kg/ m$^3$ |
| Critical pressure | 7.38 | MPa=MN/m$^2$ | 73.8 | bar |
| Critical temperature | 304.25 | K | 31.1 | °C |
| Critical volume | 94.12 | cm$^3$/mol | 0.00214 | m$^3$/kg |
| Density, gas at 32°F/0°C 1 atm | 44.9 | mol/m$^3$ | 1.977 | kg/ m$^3$ |
| Density, liquid at -34.6 °F/-37°C, saturation pressure | 25017 | mol/m$^3$ | 1101 | kg/ m$^3$ |
| Heat (enthalpy) of evaporation at 15°C | 16.7 | kJ/mol | 379.5 | kJ/kg |
| Molecular Weight | 44.0095 | g/mol | | |
| Solubility in water | 0.148 | g/100 g | 1.48 | g/l=mg/ml |
| Sublimation Point | 194.686 | K | -78.464 | °C |
| Triple point pressure | 0.518 | MPa=MN/m$^2$ | 5.18 | bar |
| Triple point temperature | 216.59 | K | -56.56 | °C |

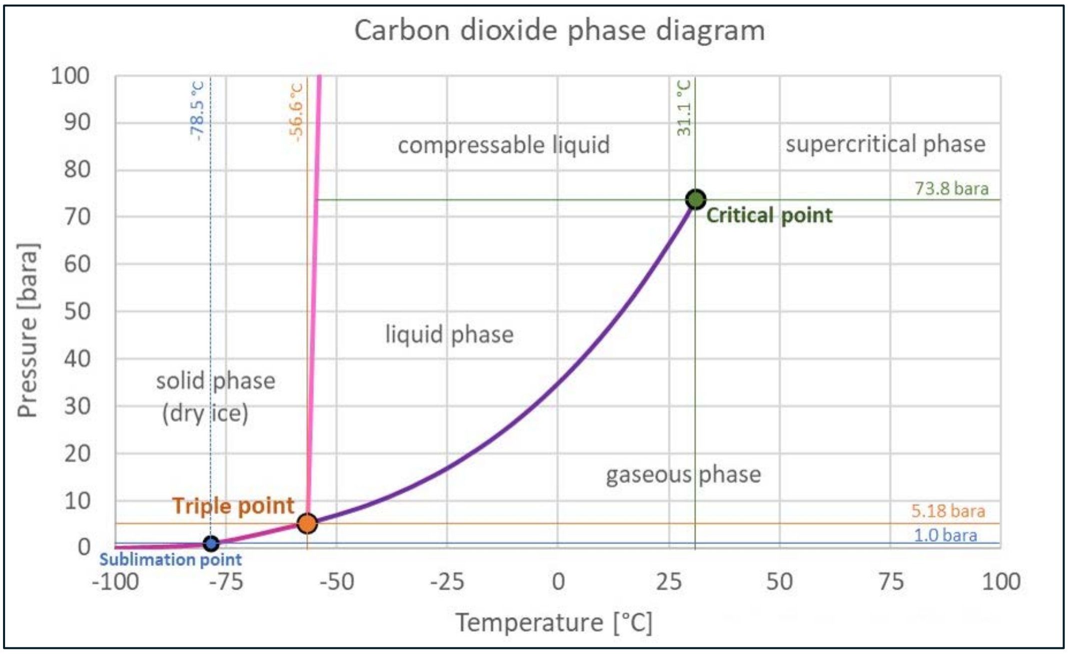


**Figure D1 Carbon dioxide phase diagram10.**

At normal atmospheric pressure and temperature, carbon dioxide exists in gas phase with a higher density than air; this characteristic is relevant to analyse the dispersion of $CO_2$ in the atmosphere.

For the $CO_2$ to transform from liquid to gas at constant pressure, it is a prerequisite that heat is added in the same way as heat is required to be added to convert water (liquid $H_2O$) into steam.

For temperatures below 31.1°C, the reduction of pressure would result in a transformation from liquid to gaseous phase when the conditions of the $CO_2$ cross the gaseous-liquid line. As it can be observed in Figure D2, below 31.1°C, a phase change from liquid to gas results in an accompanying step change in density.

The triple point identifies the coexistence of gas, liquid and solid phase. The triple point of $CO_2$ is at -56.6°C and 5.18 bar.

At the right combination of pressure and temperature $CO_2$ may turn into the solid state commonly known as dry ice.

The critical point, at the end point of the liquid-gaseous curve, designates conditions under which a liquid and its vapour can coexist. At higher temperatures, the gas exists in the supercritical phase and cannot be liquefied by pressure alone. In these conditions, there are no noticeable changes when the pressure is reduced from above to below the critical pressure, a smooth enthalpy change occurs from super critical fluid to gas. Therefore, at supercritical conditions,

[10] Engineeringtoolbox.com, (2019), Carbon Dioxide - Thermophysical Properties.

carbon dioxide is a highly volatile fluid and will rapidly evaporate when depressurised to ambient conditions.

Figure D2 shows the mass density of pure $CO_2$ as a function of temperature and pressure. The step change in mass density from vapour to liquid state should be noted. In general, the effect of temperature and pressure on mass density should be considered in any optimisation of transportation capacity. It should be noted that various types of other chemical components in the $CO_2$ stream may, to various degrees, affect the mass density.

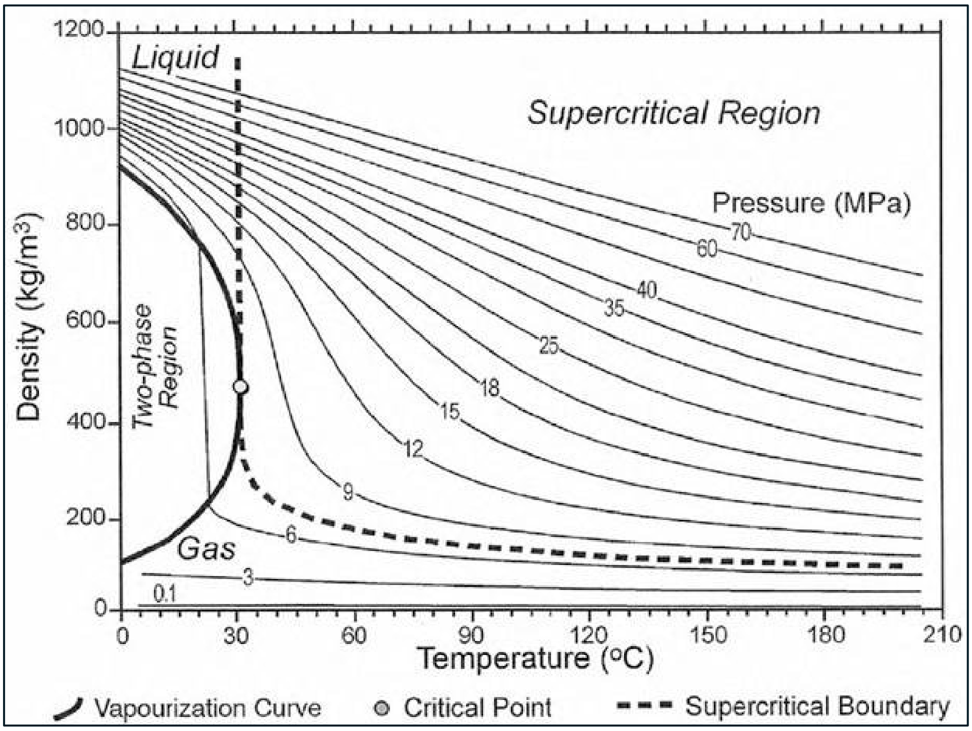


**Figure D2 Variation of $CO_2$ density with pressure and temperature11.**

[11] Global CCUS Institute (2013). The Global Status of CCUS.

# Appendix E: Benchmarking of monitoring and control assets of a natural gas network

## E1 Introduction

A review was carried out of Gas Networks Ireland's Functional Specification Requirement documents to provide and inform a high level view of the assets needed in a monitoring and control system transporting a gaseous fluid (natural gas) as a benchmarking exercise.

## E2 Overview of control system assets and instrumentation

**Asset Interface**

Each control system has its own dedicated fully integrated package for control of whatever system is intended to control, e.g. gas temperature set-point.

Each control system is linked to a central control room and telemetry feedbacks are monitored.

**Compressor Turbine Control System**

Each Compressor has its own dedicated control system package with all of the requirements for turbine control/compressor control, Fire and Gas control, and safety monitoring for the full package.

**Flow Control Systems**

Flow control systems can be used to control gas flow rate to a set point value sent via a telemetry system from central control.

**Line Valve Control Systems**

Line valve control systems can be used for pipeline isolation in the event of pipeline damage / rupture on the network on receipt of a close command, which energises a remote solenoid coupled to the line valve..

**Remote Telemetry Unit (RTU)**

The RTU is a microprocessor-controlled device that acts as the interface between physical instrumentation in a network installation and the control room.

**Fire & Gas Detection/Fire Suppression Control System**

Fire and Gas (F&G) detection systems are deployed to continuously monitor plant activity and in case of hazardous conditions initiate appropriate actions. The panel receives the signals from the instruments in the event of a fire or gas detection and initiates a response (alarm, turbine shut-down, fire suppression, air intake door closure, etc).

### Chatterbox

To ensure a safe connection between external customer's assets and company assets, intrinsically safe isolation must be maintained. A unit called a Chatterbox is used to create the isolation between the two systems.

### Differential Pressure Switch / Gauge

A Differential pressure switch is a device which utilizes a differential pressure across the switch to actuate an electric switch at a pre-set actuation point. The gauge measures the pressure at 2 points and displays the difference on a single dial. This may be the difference between two positive or two negative pressures, one of each, or a positive and atmospheric or a negative and atmospheric pressure.

### Differential Pressure (Indicating) Transmitter

Differential Pressure (DP) transmitters measure the difference between two pressures. They use a reference point called the low-side pressure and compare it to the high-side pressure. Ports in the instrument are marked high-side and low-side. The DP reading can be either negative or positive depending on whether the low-side or high-side is the larger value. An indicating transmitter will contain a local display.

### Flame Detector

Flame detectors are used to detect the presence of flame or fire within a network installation and are often an integral part of a network installation safety system.

### Flow/Pressure/Temperature and GC Controllers

Controllers are typically used to control flow, pressure or temperature to predefined setpoints. Controllers can be either electronic or pneumatic.

### Flow Control Panel (Field)

Typically used to house pneumatic devices including I to P converters, pneumatic Flow/Pressure/Temp and GC Controllers, pressure switches solenoid valves etc for controlling gas flow.

### Heat Detector

Heat detectors are used to detect the presence of convected thermal energy from fire within a network installation and are often an integral part of a network installation safety system.

### Level Switch / Gauge

Level switches and gauges are used to detect liquid levels via an electrical switching action and contact with the liquid being measured. When the level within the liquid being monitored goes above the level the switch is set/installed at, they switch contacts change from Open/Close (or vice-versa).

When connected to a control system/RTU, this feedback can allow remote monitoring and response to events within the Gas Network. Level switches and gauges are typically installed in heating systems to monitor the levels of fluids used in Heat Exchanger/Boiler systems.

### Level (Indicating) Transmitter

A Level Transmitter is an instrument that provides continuous level measurement. Level transmitters can be used to determine the level of a given liquid or bulk-solid at any given time.

Typically, level transmitters convert the input signal from the source then transmit a standardized output signal to the control device will contain a local display.

### Logger

A logger is a device used for autonomously logging (recording) gas data (pressure, temperature, flow) over a defined period of time (hourly, daily, and weekly). The data can be retrieved remotely or locally and evaluated after it has been recorded.

### Modem

A modem is utilised to forward information (in the form of data packets) between a network and the internet. A modems function is to direct internet traffic entering/exiting a network installation.

### Pressure Switch / Gauge

A pressure switch / gauge is a device which utilizes a pressure across the switch or gauge to actuate an electric switch at a pre-set actuation point. This is the difference between a process (positive/negative) and atmospheric pressure. Pressure can be displayed in BarG or PSI.

### Pressure Transducer

A pressure transducer is an instrument that interfaces a pressure value to a measurement for use by a control device (e.g. RTU, logger, display etc.).

Typically, pressure transducers convert the input signal from the source then transmit a standardized output signal to the control device.

### Pressure (Indicating) Transmitter

Pressure transmitters are used to measure the gas pressure in a pipeline/network installation. The output a current signal is transmitted to a control system/RTU.

Accurate and stable pressure measurements ensure the safe, reliable, and profitable operation of a pipeline/network installation.

**Temperature Element**

Temperature elements are the instruments that are designed to change their own characteristics depending upon the temperature of the surrounding conditions. Typically a RTD (Resistance Temperature Detector) or a thermocouple provides temperature measurement through an electrical signal – Ohms.

**Temperature Switch / Gauge**

Temperature switches and gauges are used to detect temperature levels via an electrical switching action. When the temperature of the gas being monitored goes above or below the required setpoint at which the switch is set/installed at, they switch contacts change from Open/Close (or vice-versa).

When connected to a control system/RTU, this feedback can allow remote monitoring and response to events within the network.

**Temperature (Indicating) Transmitter**

A temperature transmitter is an instrument that interfaces a temperature element to a measurement for use by a control device (e.g., RTU, DCS, logger, display etc.).

Typically, temperature transmitters convert the input signal from the element then transmit a standardized output signal to the control device. An indicating transmitter will contain a local display.

**Voltage Transmitter**

A voltage transmitter is an instrument that interfaces a voltage source (e.g., Battery Voltage) to a measurement for use by a control device (e.g., RTU, DCS, logger, display etc.).

Typically, voltage transmitters convert the input signal from the source then transmit a standardized output signal to the control device.