CCS with KAPPA

Software Solutions for CO2 Injection and Containment

April 2025

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A – Executive summary

In the field of Geo-Energies, fluids are injected into and/or extracted from a geological formation. Regardless of the purpose of the operations and the fluids involved, these systems share multiple characteristics:

- Injectors and/or producing wells are required
- The fluid flow and well completions impact the injection/production performance
- The integrity of the well barriers is critical for safe and long-term well operations
- Petrophysical properties determine the technical and economical operation viability
- The fluid(s) flow through porous media, interacting with the other formation fluids
- Pressure / rate behaviors depend on well completion, reservoir properties and size
- The fluid(s) physical properties evolve with time, pressure, and temperature

Among Geo-Energies, the Oil & Gas industry has contributed to the largest technological and scientific developments in geoscience in the past century. In the Oil & Gas, KAPPA has pioneered and presently leads the field of Dynamic Data Analysis, with extensions such as Cased Hole Logging and Fluid Description.

As the demand for CCS is projected to increase, accurate reservoir modelling, injection monitoring, and well integrity assessment are critical for long-term storage security. KAPPA's software suite provides a comprehensive approach to tackling these challenges.

This document presents the areas where KAPPA software already contributes to Carbon Capture and Storage (CCS) workflows. It outlines key applications and the corresponding products:

Formation Evaluation	Azurite
Reservoir Characterization	Saphir
Reservoir Modelling	Rubis
Fluid Description	Carbone
Injection Monitoring	Emeraude
Well Integrity	Emeraude

Each section explores these applications in detail, highlighting our current strengths and limitations. The examples presented are based on publicly available data from current CCS projects.

B – Formation evaluation – Azurite

Key Capabilities of Azurite for CCS Formation Evaluation

- Formation testing analysis to determine pressure and temperature gradients
- Semi-automated workflow to evaluate the pre-test quality
- DFIT (Minifrac) interpretation to design maximum injection pressure
- Vertical interference testing for evaluating communication between formations
- Pressure transient analysis based on pre-test or Mini DST data
- Fluid analysis to evaluate contamination of samples
- Multiwell FT plots to evaluate horizontal reservoir communication

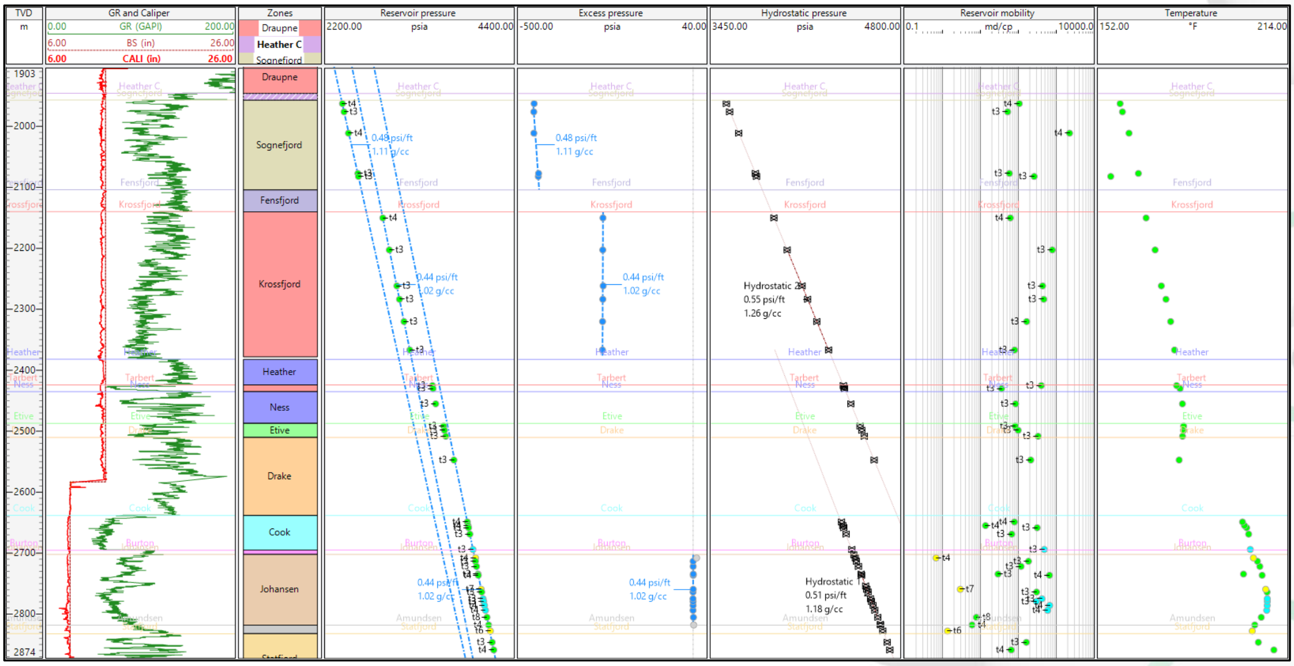
Large-scale geological sequestration of CO_2 relies on three basic building blocks:

1. Efficient geological barriers to provide long-term containment to the injected CO_2
2. Enough injectivity to admit high rates while controlling the pressure drops
3. Large pore volumes to maximize the use of the drilled wells and existing facilities

The candidate formations for CO_2 injection require a proven sealing cap rock that ensures containment while the field operates, and for many years after the wells are abandoned. Among the main tools and techniques to evaluate the cap rock sealing capability are the wireline formation testers and DFIT analysis (Section C).

The following image shows the Formation Tester analysis performed in Azurite for the Northern Lights 31/5-7 confirmation well. The target reservoirs are saline aquifers in the Cook and Johansen formations. The cap rock is the Drake formation, which should stop the CO_2 from migrating out of the storage unit. Wireline formation testers were run in the overburden (12.25 in hole) and the reservoir sections (8.5 in hole).

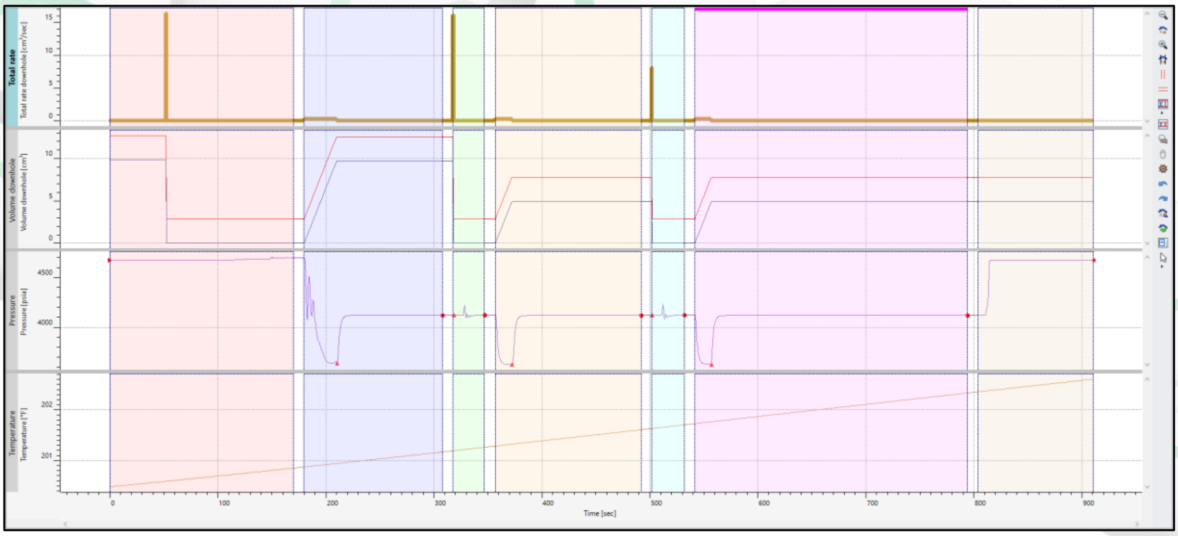
The pressure gradient analysis shows that the reservoir pressure points are aligned along three parallel gradients, with an offset between them. This indicates the presence of two sealing rocks that prevent hydraulic communication from the Johansen and Cook formations to the overburden sections. The *Excess pressure* track highlights the pressure variations between layers.



Formation Testing Interpretation - Northern Lights 31/5-7 (Azurite)

The injectivity of the target formation must be high enough to handle commercial volumes of CO_2. This implies sufficient permeability that would allow to meet the desired injection rates while not exceeding certain injection pressure. Formation tester results include an estimate of the reservoir mobility, as seen in the figure above. This is calculated under the assumption of steady-state conditions, based on the pretest rate, drawdown, and shape of the probe.

The reservoir mobility is therefore analogous to a productivity index, influenced by permeability, skin, geometrical effects, relative permeabilities, invasion, etc. The figure below shows the volume, rate, pressure, and temperature recorded during one of the FT stations. This station includes three pre-tests, which could be used to compute the reservoir pressure and mobility. The pretest with the highest quality based on different criteria is automatically selected.

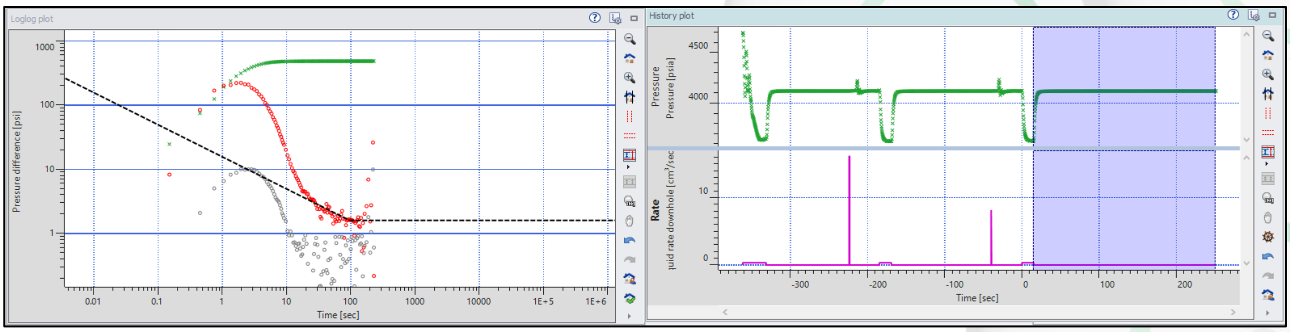


FT station with multiple pretests – Northern Lights 31/5-7 (Azurite)

The pressure buildup recorded in each pretest can be analyzed using conventional PTA methods. As seen in the image below, the Loglog plot includes the tools for the spherical flow (negative half slope) and radial flow (horizontal line). A PTA analysis of FT data may allow the calculation of radial and vertical permeability, as well as skin. This information is critical for reservoir simulation and management, as well as for understanding the effect of fluid invasion, and planning the future drilling and completion strategy.

Opportunities for Enhancement:

- Open hole petrophysics calculations
- Stresses and pore pressure calculations



PTA of an FT station – Northern Lights 31/5-7 (Azurite)

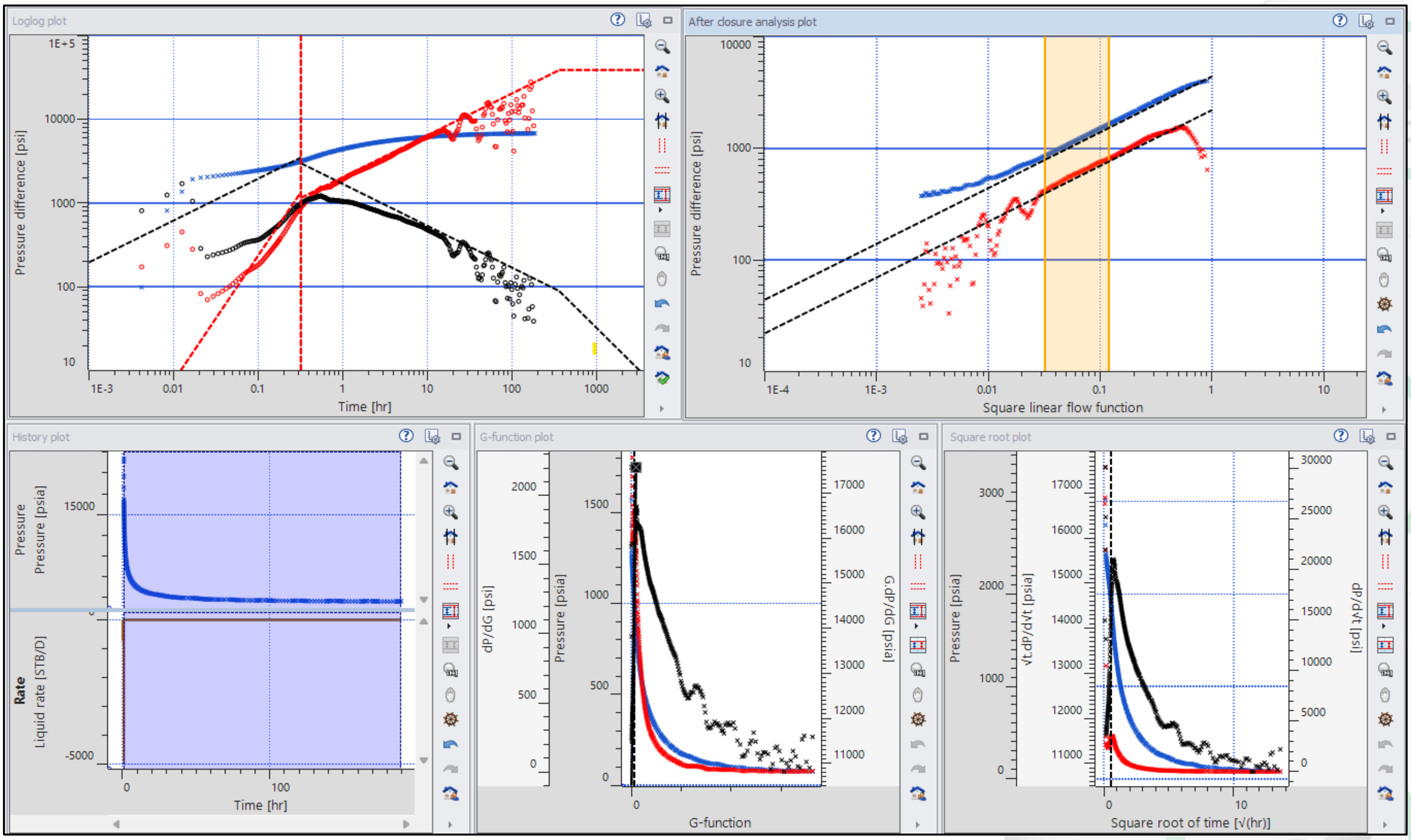
C – Reservoir characterization – Saphir

Key Capabilities of Saphir for CCS Reservoir Characterization:

- Analytical and numerical Pressure Transient Analysis
- Monophasic and multi-phase solutions
- Advanced geometries (complex faults, horizons…)
- Possibility to include gravity and non-isothermal PTA. Requires a Rubis license
- Reservoir properties and skin estimation from fall-off tests
- Plume monitoring through composite zones models (analytical and numerical), or through explicit plume modeling (numerical)
- Surface to bottomhole pressure conversion
- BO (Chung) and EOS PVT
- Reservoir pressure calculation (P*, P_{avg})
- Test design
- Interference testing: flow capacity and reservoir storativity between wells

The integrity of the cap rock is critical to the long-term success of the storage project. As CO_2 injection progresses, the reservoir pressure increases and there will also be temperature changes. These factors can lead to modifications in the stress regime of the cap rock. If a fracture propagates along the cap rock, the CO_2 could escape to the overburden layers.

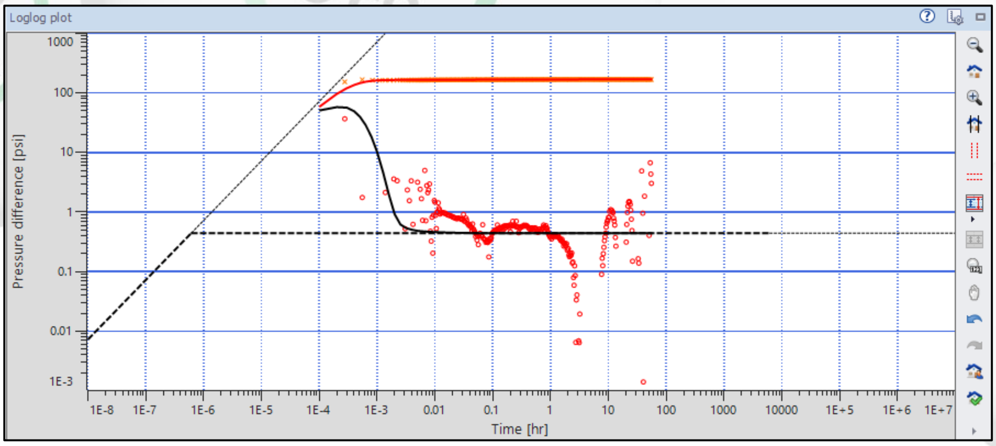
A DFIT test can be performed on the cap rock to determine the Instantaneous Shut-in Pressure (ISIP), above which the fracture would propagate. DFIT test includes a very short injection, and pressure measurement during the subsequent fall-off. This test can be performed through Formation Tester tools (and analyzed in Azurite), or surface injection and pressure monitoring. Techniques like the G-function or square root of time plots are used to estimate the fracture initiation pressure. This information is key for determining the maximum allowed CO_2 volumes to be injected into the formation.



DFIT interpretation (Saphir)

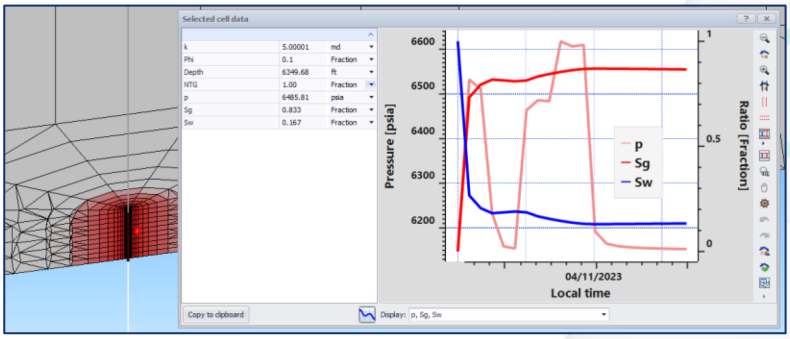
The cap rock leakage risk assessment should also consider the possibility of fault activation, and the thermomechanical effects of the CO_2 injection. These aspects are evaluated through numerical reservoir simulation.
Conventional Pressure Transient Analysis is also a valuable technique in CCS projects. In prospective CO_2 injection wells, build-up or fall-off tests are recorded before the CO_2 injection starts, with the objective of confirming reservoir quality and injection ability.

Injectivity tests, conducted using both water and CO_2 at different phases of the project, provide critical insights into the formation's permeability and injectivity. The image below shows a PTA of a build-up recorded during a drill stem test (DST) for the Northern Lights confirmation well. The testing sequence included clean-up and main flow periods (water production only), followed by an extended build-up. The good permeability allowed confirming that the formation was suitable for CO_2 injection.



PTA during DST – Northern Lights 31/5-7 (Saphir)

CO_2 injectivity tests are crucial for understanding the behavior and interaction of CO_2 with the formation. These tests ensure the safe and efficient long-term storage of CO_2 by confirming the reservoir's capacity and integrity. Understanding the heterogeneity of the reservoir and detecting barriers or fault via PTA also give significant insight in the CO2 migration patterns. Saphir offers analytical and numerical solutions covering a wide range of applications, from standard monophasic tests to advanced non-linear multiphase cases - including the temperature contrast between the injected fluid and the formation.



Numerical PTA showing the near wellbore pressure and saturations evolution

Opportunities for Enhancement:
- Analytical CO2 injection/fall-off model into aquifers
- Step-rate test interpretation

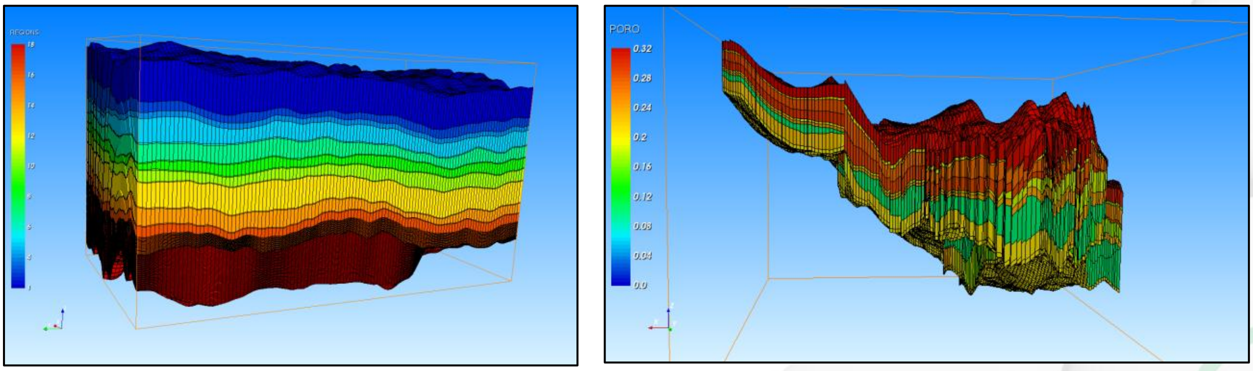
D – Reservoir Modelling – Rubis+

Key Capabilities of Rubis+ for CCS Reservoir Modelling

- 3D numerical reservoir simulation with unstructured grid
- Automatic grid refinements around wellbore to capture transient thermal effects
- Black oil (Chung) and EOS CO_2 PVT
- Temperature modelling in the reservoir and wellbore
- Production log display: rates, temperature, and pressure
- Solution trapping simulation via Rsw for the Black-Oil PVT model
- Residual (capillary) trapping simulation via hysteresis in krpc
- Simulation and design of complex PTA: dipping reservoirs, hysteresis, injection front
- Surface network with thermal modelling and phase changes along the pipeline
- Well group controls
- Trapped volumes and ratios
- Cyclic injection scenarios

As the CO_2 is injected into the reservoir, multiple complex rock-fluid interactions occur. Numerical reservoir simulation is the most comprehensive technique to account for the various trapping mechanisms. The simulations can be used for CCS development plans, injection strategy design and optimization, and cap rock integrity evaluation.

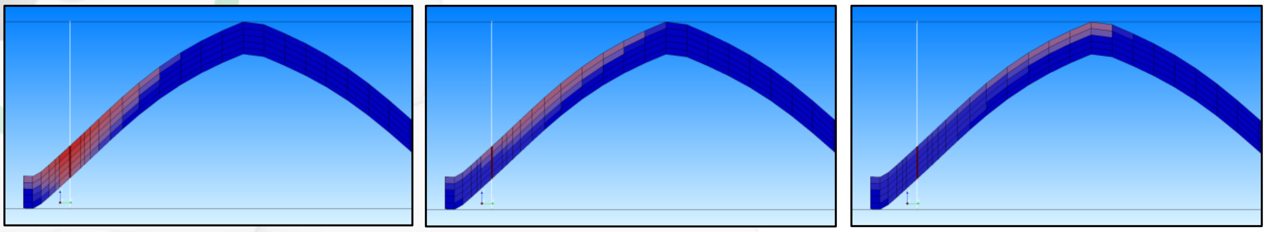
Numerical reservoir simulation starts with a geological model. The amount and quality of the available data largely vary based on the type and maturity of the CCS project. In depleted oil and gas reservoirs a good reservoir description is expected, including open hole logs, seismic data, production data, PVT, etc. However, new CCS prospects will inherently have higher uncertainty due to a limited amount of data. The images below show the geological models including property maps for the Sleipner and Johansen fields. These were created with dedicated geological software and loaded into Rubis for injection modelling.



Geological models of Sleipner (left) and Johansen (right) fields – Equinor (Rubis)

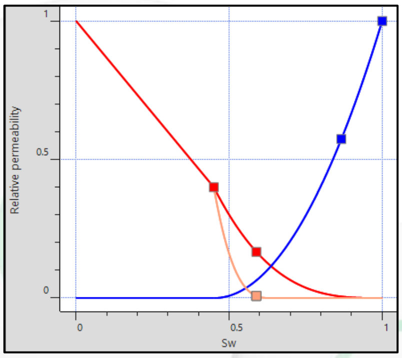
In a Deep Saline Formation, as the CO_2 enters the formation driven by a pressure gradient, it pushes away the water in the process known as drainage. Due to the large density difference with the brine, the buoyant CO_2 will migrate as a plume until it reaches the cap rock, where it will remain due to **structural trapping**. A small mass exchange occurs between phases, as the CO_2 dissolves into the water, leading to **solution trapping**. The free CO_2 decreases in volume and pressure, and the denser CO_2-rich brine forms. This tends to sink towards the bottom of the reservoir, which further accelerates the dissolution process. Both the migration of free gas and the sinking of the CO2-enriched brine can exhibit the development of viscous and gravity instabilities, enhanced by the heterogeneity. The images below demonstrate these trapping mechanisms using saturation maps. A well located on the flank of an anticline injects for 1 year, followed by 99 years of shut-in.

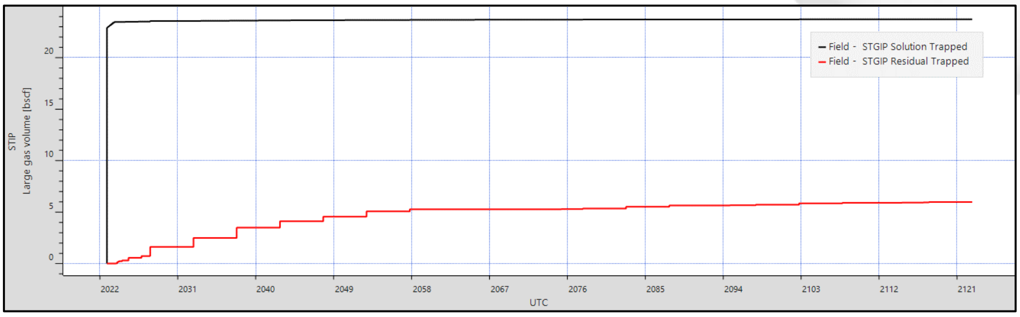
The CO_2 plume migrates towards the top of the anticline, while the overall gas saturation decreases due to dissolution.



Simulation of solution and structural trapping of CO_2. Saturations maps during injection (left), and 5 (centre) and 99 (right) years after injection has stopped (Rubis)

As the CO_2 plume moves up, the displaced water replaces the pore space previously occupied by CO_2 in the process known as *imbibition*. As the water cannot displace 100% of the CO_2, a fraction of it will remain in the pores, trapped by capillary forces. The residual saturation of the non-wetting phase during the imbibition may be up to 20% to 30%, leading to **residual trapping** or **capillary trapping** of CO_2 in the pores.

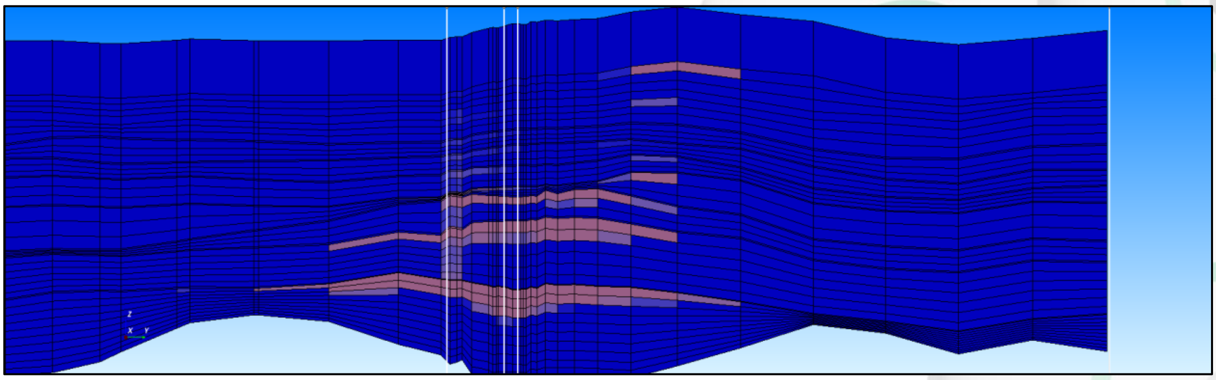




Trapped volumes of CO due to dissolution (black) and capillary (red) trapping (Rubis)

The trapped CO_2 volumes over time, due to dissolution in water and capillary effects, can be seen in the image below. This helps understand the relative importance of each trapping mechanism.

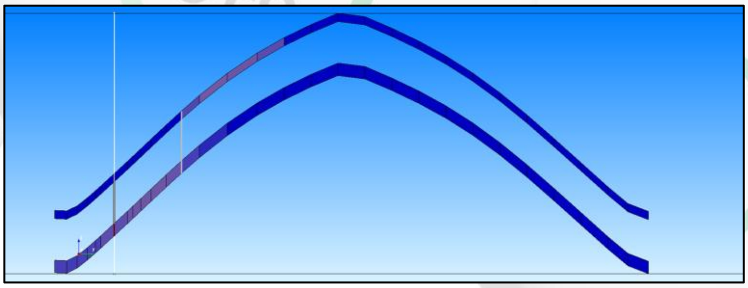
The image below shows a cross-section of the Sleipner reservoir, with the simulated saturations after 14 years of injection. This simulation was initialized from a 2-million cell CPG geological model, with 263 layers. After vertical upscaling, the model was reduced to 46 layers. A Black-oil PVT (Chung) model was used, after fine-tunning it to GERG EOS (Section D). Stratigraphic, solution and capillary trapping were considered



Saturations after 14 years of injection in the Sleipner field (Rubis)

A much slower trapping process involves precipitation of carbonate minerals from CO_2-rich water, in a process called **mineral trapping**. It is initiated by the weak acid formed by CO_2 dissolution in water, which can react with sodium, magnesium, iron, potassium, etc. This is currently not modelled by Rubis.
As mentioned in the section on formation evaluation, the sealing capability of the cap rock is critical for the long-term storage of the injected CO_2.

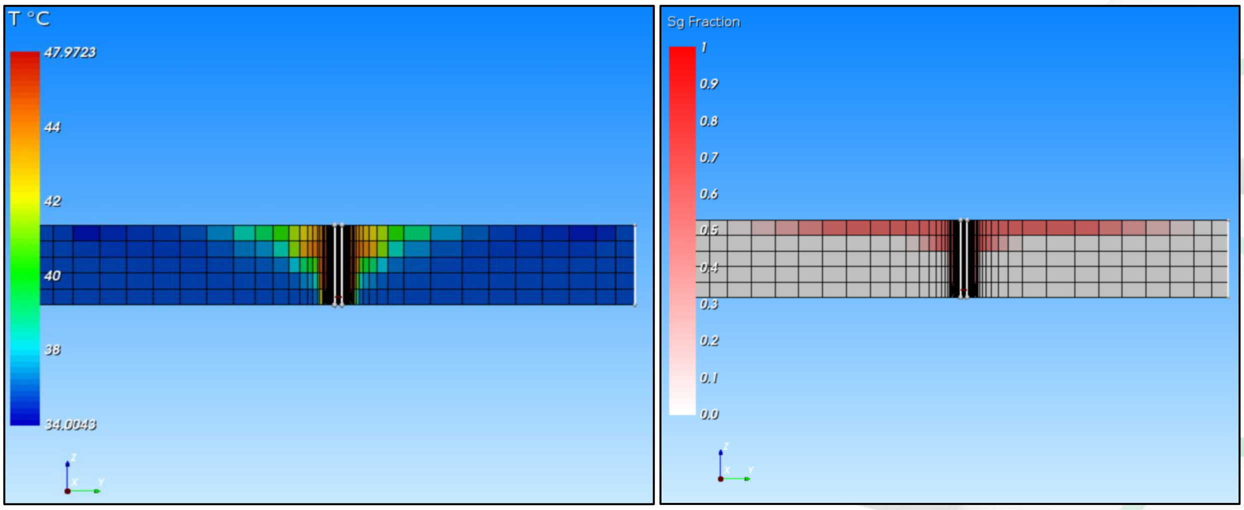
But an impermeable cap-rock might not always be sufficient to ensure containment. Reservoir simulation can also be used to evaluate possible fault reactivation, and understand if fluid migration to shallower formations is possible. The figure below shows two permeable formations separated by a 100 ft impermeable shale, with the CO_2 being injected only in the bottom layer. This simulation shows that a conductive fault allows CO_2 to reach the upper layer, which may pose a risk for the success of the project.



Conductive fault allows CO_2 vertical migration through an impermeable layer (Rubis)

The coupled wellbore-reservoir thermal simulation in Rubis is particularly advantageous for CCS modelling, as CO_2 behavior is strongly dependent on temperature, which in turn influences plume size, position, and rock-fluid interactions. The image below shows the temperature and CO_2 saturation fields for reservoir cross-section.

Thermal modelling can also be used for temperature-based injection profiling. Rubis uses a multi-segmented wellbore model, fully coupled to the reservoir. This means that the pressure and temperature evolution along the wellbore, at sandface and deeper in the formation are rigorously modelled at every time step, allowing temperature transients and the effects of temperature contrasts to be accurately captured.



Temperature and saturation field using thermal simulation (Rubis)

In CCS projects, modelling the surface network—including pipelines, compressors, and processing facilities—is crucial for ensuring safe and efficient CO_2 transport. Temperature and pressure variations along the pipeline can induce phase changes between gas, liquid, and supercritical states, directly impacting injectivity and storage efficiency. These fluctuations may also create flow assurance challenges, such as hydrate formation or excessive pressure drops, which can compromise operational stability. Rubis offers **coupled surface-subsurface modelling**, enabling a more integrated assessment of the entire CCS chain. The image below illustrates temperature variations along the planned pipeline for the Northern Lights project in Norway, transporting CO_2 from the capture station to the wellhead.

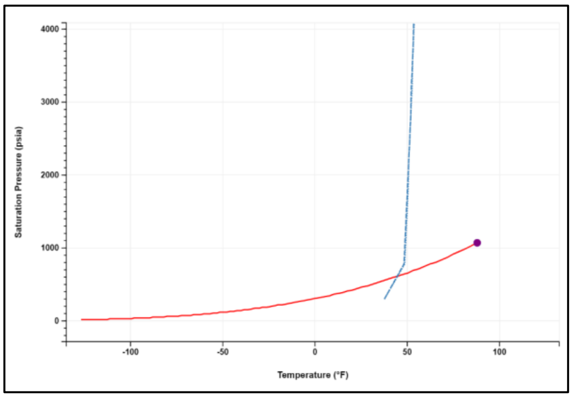
Opportunities for Enhancement:
- Miscibility: needed for CO_2 injection in depleted gas reservoirs
- Geomechanics
- Reactive transport and mineral trapping
- Prediction of hydrates and scale precipitation
- Multiple PVT

Temperature variations along the planned pipeline for the Northern Lights project (Rubis)

E – Fluid description – Carbone

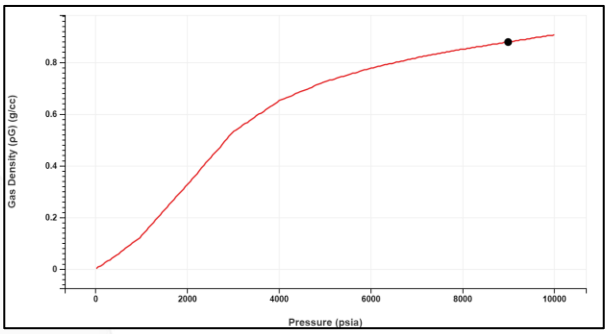
Key Capabilities of Carbone for CCS Fluid Description:
- CO_2 EOS modelling through GERG-2008, Peng-Robinson and Soave-Redlich-Kwong (SRK)
- Black oil CO_2 modelling through Chung correlation or Span-Wagner EoS
- Unit operations: compression, valves
- Hydrates modelling, including the effect of inhibitors (MEG, ethanol, etc.)

The pure CO_2 PVT is relatively simple and well established. During its transport from the capture facility to the reservoir, temperature and pressure variations cause phase changes, including transitions between the supercritical, liquid, and gas states. The image below shows the CO_2 saturation pressure (red) and the hydrates precipitation curve (blue). Hydrates may form along the pipeline, at the wellhead, in perforations, and within the reservoir, posing a flow assurance challenge.



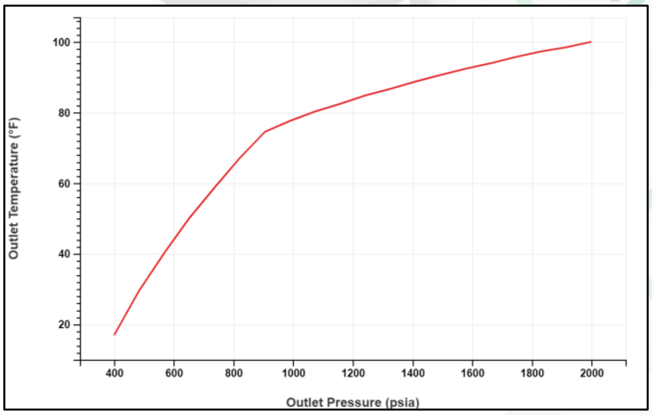
CO_2 saturation and hydrate precipitation curves (Carbone)

CO_2 may contain impurities, the most common being water, N_2, O_2, Ar, H_2, CO, SO_2, and NO. The GERG Equation of State available in Carbone allows accurate modelling of this fluid, even under supercritical conditions. The EOS fluid model can be exported as Black Oil PVT tables for use in other modules, such as Rubis and Saphir. The image below shows the phase behavior of the CO_2 with a number of typical impurities, and the output density versus pressure. The same output can be created for all the relevant fluid properties.



CO_2 + impurities phase diagram using GERG (left) and BO PVT export (right) (Carbone)

From the capture terminal, the CO_2 undergoes various processes including compression and expansion through valves. Carbone allows modelling of unit operations and estimation of relevant fluid and thermal parameters. The image below illustrates the outlet temperature of CO_2 passing through a valve as a function of outlet pressure, with a fixed inlet pressure.



Outlet temperature of the CO_2 through a valve (Carbone)

Opportunities for Enhancement:
- Brine hydrate inhibitor
- Corrosion modelling
- Dynamic Lumping/Delumping for CO_2 mixtures

F – Injection Monitoring – Emeraude

Key Capabilities of Emeraude for CCS Injection Monitoring:

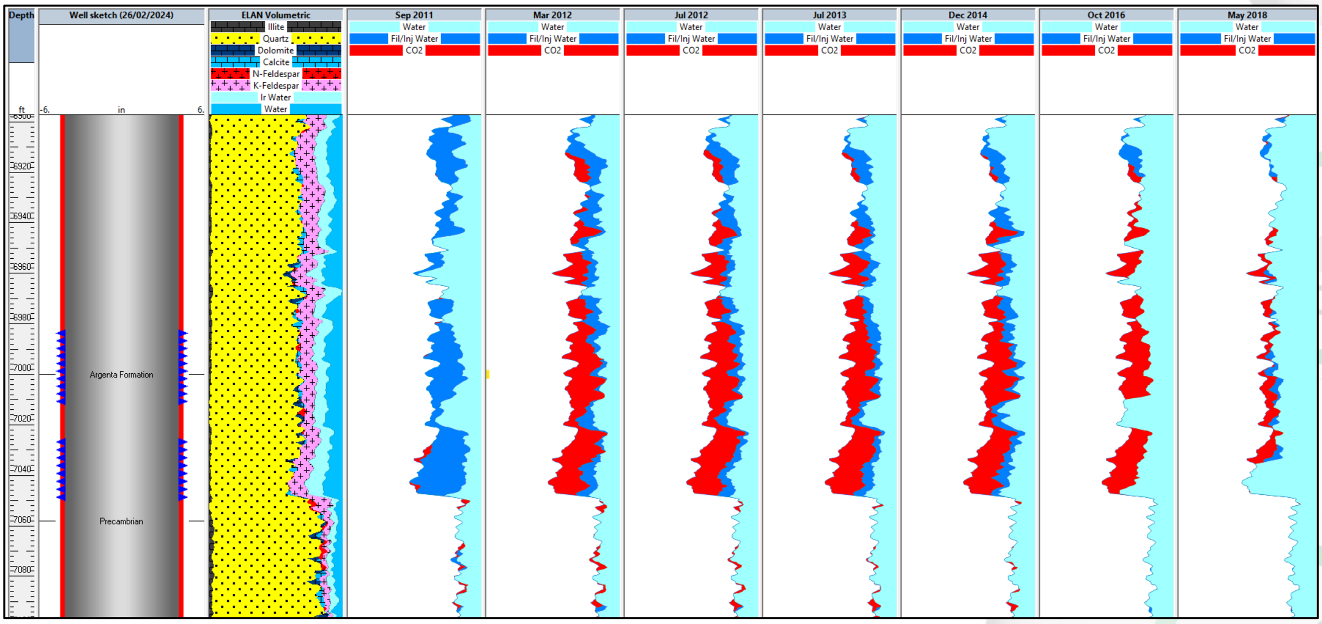
- Production Logging (PL) interpretation for CO_2 injection profiling
- CO_2 PVT: Chung correlation
- Thermal modelling for injectors and warm-back analysis
- DTS and DAS data loading and display (maps and 3D). DTS data can be used for quantitative analysis

Establishing the CO_2 injection distribution, tracking the plume position and monitoring the reservoir pressure and temperature are the pillars of the CCS reservoir surveillance programs. This requires measurements at the reservoir level that can be acquired during a wireline/slickline intervention, or through permanent monitoring techniques (i.e., DTS, DAS, permanent downhole gauges).

In deep saline aquifers, pulsed neutron logs can be used to monitor the injection distribution, evolution of the CO_2 saturation, plume movements, etc. This is possible due to the large contrast between the capture cross-sections of the salty brine (which can exceed 130 c.u.) and that of CO_2, which is near zero, as it has a very low ability to capture epithermal neutrons.

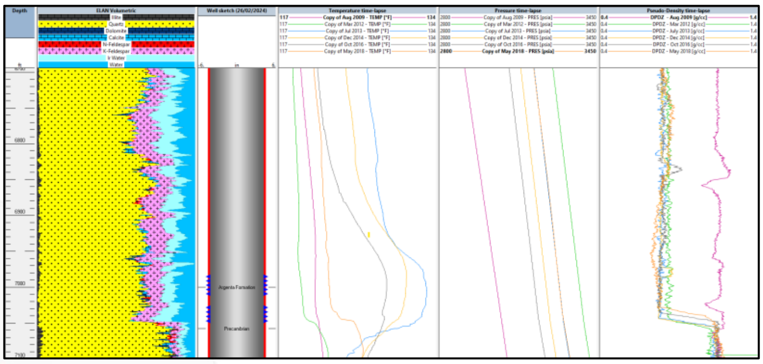
The image below shows a time-lapse PNL Sigma analysis recorded in the Decatur CCS project in the Illinois Basin (USA). From left to right, the tracks show a baseline PNL, four logs recorded while injecting, and two after injection had stopped.

Once the injection started, the CO_2 saturation increased at the perforation level, and due to buoyancy CO_2 is also detected at shallower depths. Near-wellbore CO_2 saturation does not considerably increase during the injection period. After injection ceased, the CO_2 saturation decreases, driven by plume migration, solubility in formation water, and mineralization reactions. These measurements are also helpful to understand that the CO_2 is not migrating to shallower layers above the cap rock.



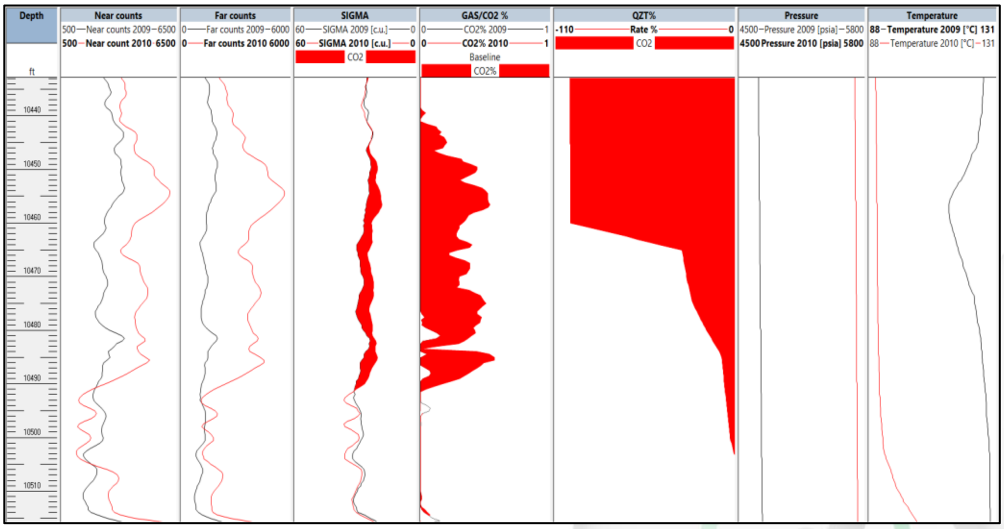
Time-lapse pulsed neutron - Decatur CCS-1 (Emeraude)

In addition to neutron logging, downhole pressure and temperature monitoring is essential for understanding reservoir dynamics, ensuring flow assurance, and assessing well and cap rock integrity. The image below shows time-lapse temperature, pressure and pseudo-density. These measurements help to understand the downhole CO_2 phase behavior, thermal response as it is injected, etc. The pseudo-density track provides insights into phase changes, helping to determine whether CO_2 remains in the supercritical phase or transitions to a different state due to pressure and temperature variations.



Time-lapse P&T monitoring - Decatur CCS-1 (Emeraude)

Apart from tracking the CO_2 saturation in the formation it is crucial to know the injection distribution, especially in multilayer reservoirs with multiple hydraulic units and different properties. Although the temperature provides indications of the depth of injection, its response is very complex due to the phase behavior of the CO_2. Conventional PLT and tracer logs can be used in CO_2 injectors for quantifying the injection profile. The example presented in the figure below is from the Cranfield CCS project in the USA. It shows the computed injection profile (QZT%) alongside with the variation of CO_2 saturation between PNL surveys from 2009 and 2010. As previously mentioned, once injected the CO_2 will tend to move towards the top of the formation, as seen with the PNL logs.



Production Logging and Pulsed Neutron – Cranfield (Emeraude)

Opportunities for Enhancement:

- CO_2 warmback analysis for injection profiling from temperature
- DAS-based injection profiling

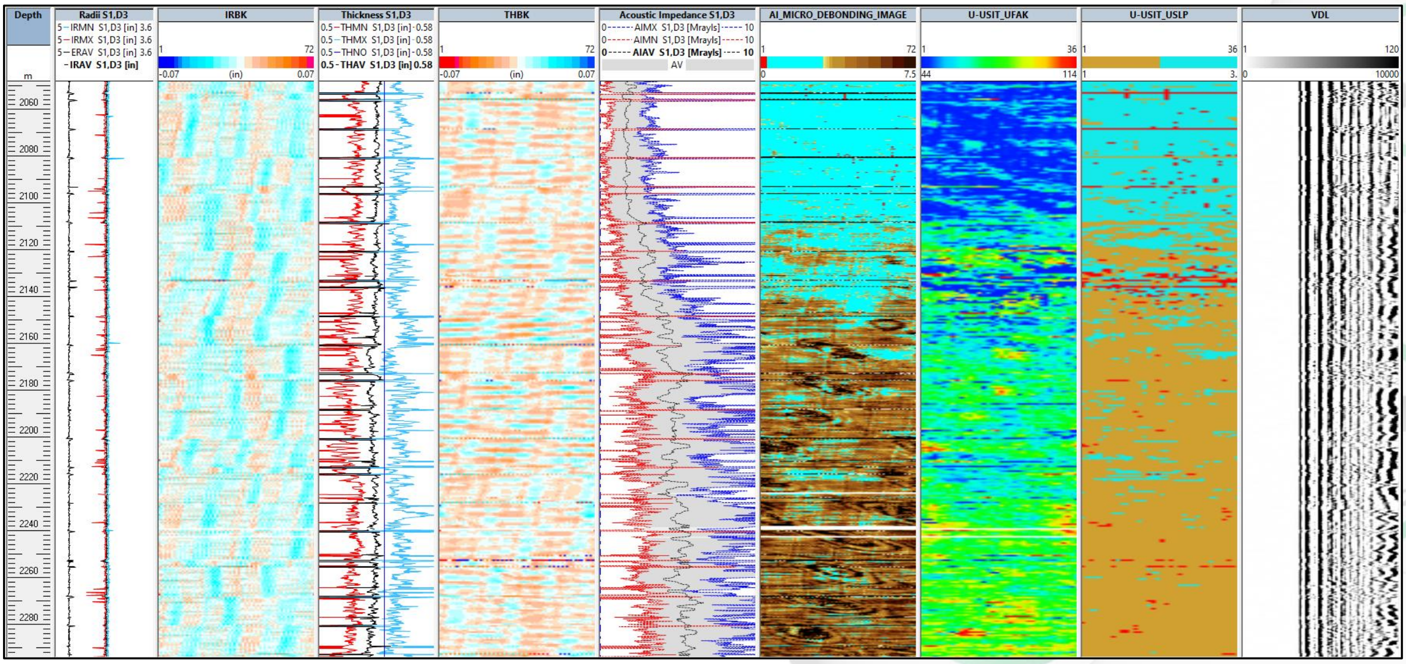
G – Well Integrity – Emeraude

Key Capabilities of Emeraude for CCS Well Integrity:

- Internal radius measurements processing and analysis: Multifinger caliper and ultrasonic.
- Pipe thickness measurements processing and analysis: electromagnetic and ultrasonic.
- Cement evaluation for sonic, segmented and ultrasonic logs.
- Spectral noise logging processing
- Well integrity results as tables with statistics per zone/pipe joint, maps, cross-sections and 3D

Even when the cap rock acts as a permanent and efficient geological barrier, the failure of one or more well barriers can lead to atmospheric releases of CO_2 or groundwater contamination. Ensuring the integrity of the annular cement and multiple tubulars does not only concern the operational life of the well, but after Plug and Abandon (P&A) the multiple barriers must prevent the movement of fluids.

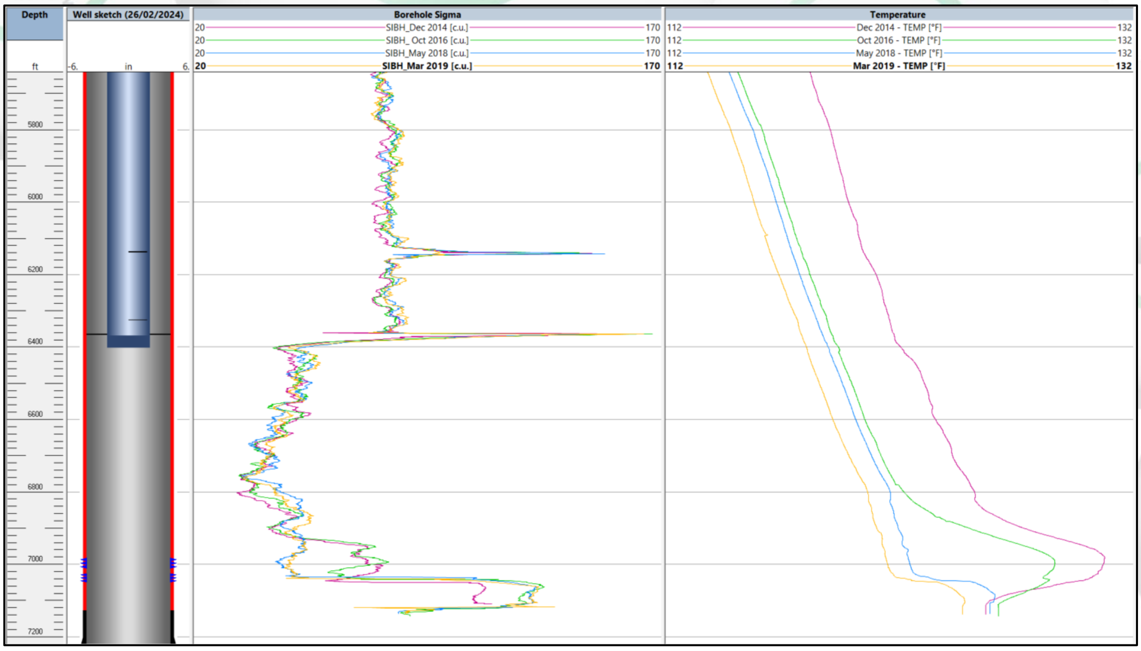
Sonic or ultrasonic measurements remain the primary evaluation technique for annular cement. Regional regulations require a minimum length of continuous good cement to ensure hydraulic isolation and prevent fluid movement. Annular hydraulic isolation is assessed based on multiple criteria, including the casing-to-cement bond, the cement-to-formation bond, and the presence of channels that may compromise sealing. The cement evaluation workflow requires incorporating data from different sensors to obtain a unique result per depth. The figure below shows acoustic impedance and flexural attenuation data, used to compute a final overall isolation criterion.



Ultrasonic cement evaluation - Equinor's Northern Lights (Emeraude)

Beyond cement integrity, maintaining the integrity of the casing and tubing is equally critical for long-term well containment. When CO_2 mixes with water it can form carbonic acid, which can accelerate corrosion and metal loss. Internal radius measurements—such as multifinger calipers, ultrasonic logs, and electromagnetic thickness tools—can be used for pipe integrity monitoring. If a leak develops, its depth can be identified using temperature and spectral noise logging surveys. All these techniques can be analyzed in Emeraude.

Pulsed neutron logs can also be used for well integrity monitoring. Early-time thermal neutron capture measurements, particularly from short-spacing GR detectors, are highly sensitive to the composition of borehole and annular fluids. This measurement is called *Sigma borehole* (SIBH). The presence of CO_2 in the wellbore or annuli reduces SIBH, providing a useful diagnostic for detecting fluid movement within these spaces. In the figure below, an increase in SIBH above the packer suggests the presence of water in the annulus, indicating that CO_2 has not migrated to shallower depths through wellbore pathways.



Borehole Sigma and Temperature - Decatur CCS-1 (Emeraude)

Opportunities for Enhancement:

- Multibarrier electromagnetic tools processing
- Pipe deformation analysis