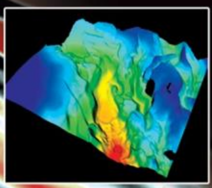
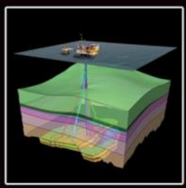




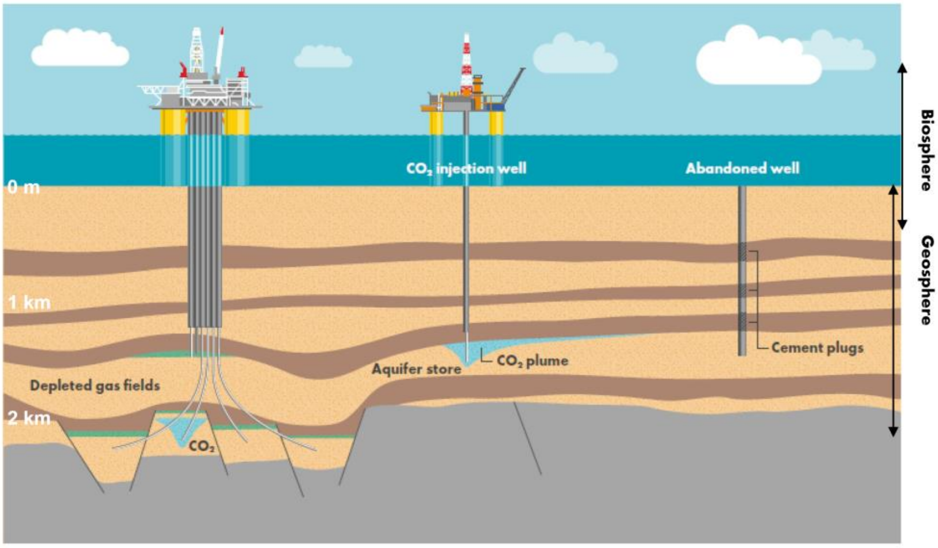
The Geological Society

Abstract Book

3rd Energy Group CCS Symposium: Characterization and Monitoring of Containment

11-13th September 2024

The Geological Society, Burlington House, Piccadilly, London



As CCS is scaled up to mitigate global warming, in line with recommendations by the IPCC, the onus is on operators and regulators to demonstrate safety and efficacy before and during operation, and to provide a robust case that carbon dioxide will be safely sequestered for centuries once operations cease. Building on the previous successful CCS conferences in 2022 (CCS workflows) and 2023 (CCS storage efficiency), this 3rd Energy Group CCS symposium will focus on the characterization and monitoring of containment to optimize CCS field development and to demonstrate safety of CO_2 storage.

This conference received contributions from industry and academia in two major categories:

1. Understanding the storage complex prior to project commencement/design phase, including: Geological seals around wellbores, Unconventional seals, Role of faults and geomechanics on containment, Geological and risk characterization of sealing sequences, Basin to pore-scale geology and characterization of seals and potential leakage features, Quantification of containment risk.
2. Monitoring during operational phase through to long term stewardship, including: Baseline, Seabed monitoring, Low-cost geophysical monitoring, Non-geophysical monitoring technologies, Remote sensing, Monitoring tools on depleted fields, Monitoring case histories and strategies.

The 3-day programme is now finalized: https://www.geolsoc.org.uk/09-EG-CCS-Symposium

It is packed with 39 talks talks and 14 poster presentations by operators, regulators, service companies and academics, a central workshop on bowtie analysis and time for networking and socializing built in.

For further information: energygroup@geolsoc.org.uk

Registration open: https://www.geolsoc.org.uk/09-EG-CCS-Symposium

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David Fallon & Robert Root

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3rd Energy Group CCS Symposium: Characterization and Monitoring of Containment

11-13 September 2024

Hybrid Conference, *Burlington House,* and Zoom, BST

Final Programme

Day One	
08.30	**Registration**
08.50	**Welcome**
09.00	**Opening keynote: Scaling Up Carbon Capture and Storage: Navigating a Critical Crossroad in Fighting Climate Change** Sofia Northridge
	Session One: CCS Containment and Risk Chair: Nick Lee Online chair: Stuart Gilfillan
09.30	**Plumbing and Bowties: An integrated approach to risk identification and mitigation in CCS projects.** Mark Wood
09.50	**Defining a bespoke and proportionate monitoring plan linked to the Early Risk Assessment (ERA) for carbon storage** Kate Thatcher
10.10 Virtual	**The insurance rationale for CCS** Rodney Garrard
10.30	**Rapid fire poster presentations (1 minute each)** All poster presenters
10.50	**BREAK – coffee/tea & posters**
11.30	**Session Two: Pore-scale characterization and modelling** Chair: Stuart Gilfillan Online chair: Mads Huuse
11.30	**Multiscale-multiproxy characterisation of targeted Mesozoic mudrock analogues in the Cleveland Basin, UK to aid assessments of seal potential and performance in the North Sea** Colm Pierce
11.50	**Compositional controls on the Lower Cretaceous Rodby Shale pore structure and surface area: a planned CCS top seal caprock for the Acorn storage site** Nourah Alnajdi
12.10 Virtual	**Pore Network Modelling of CO2-Shale Interaction in Carbon Storage and Gas Recovery: Swelling effect and Fracture Permeability** Amin Taghavinejad
12.30	**LUNCH & posters**

13.30	**Session Three: Bowtie Analysis** Chair: Elizabeth MacKie Online chair: Mark Wood
13.30	**Bowtie Analysis** Simon O'Brien & Simon Shoulders
14.15	**Bowtie workshop – *interactive*** [requires separate registration] led by Simon O'Brien & Simon Shoulders
15.45	**BREAK**
16:00	**Session Four: Bunter projects** Chair: Mads Huuse Online chair: Ivan Fabuel Perez
16.00	**East Mey: the characterisation of the storage complex** Philip Whiteley
16.20	**Understanding the impact of regional structures on pressure communication within the Bunter Sandstone Formation, UK Southern North Sea** Lucy Abel
16.40	**Sub-regional static reservoir characterisation of the Bunter Sandstone hydraulic unit for CO2 storage – A multi-discipline, multi-scale approach** Ewan Gray
17.00	**CO2 storage potential, containment, and monitoring challenges of the Humberside license (UK)** Martin Grecula
17.20	**End of day one**
17.25-18.25	**Drinks Reception**

Day Two

08.30	**Registration**
08.55	**Welcome and Summary of Day 1**
	Session Five: Projects Chair: Mark Wood Online chair: Ivan Fabuel Perez
09.00 Virtual	**Keynote: Gorgon Carbon Capture and Storage** David Fallon & Robert Root
09.30 Virtual	**Northern Lights Monitoring and CRA, the basis for safe CO2 storage operations** Catalina Acuna

09.50	**Endurance CO2 Store corrective measures planning: how can we use monitoring data effectively?** Alex Gillespie
10.10	**Monitoring CO2 storage in the Morecambe depleted gas reservoirs through seafloor deformation and time-lapse gravimetry measurements** Helen Basford
10.30	**Preliminary Monitor Strategy for CO2 storage in depleted reservoir, a case study from the Bifrost project in DK** Rasmus Lang
10.50	**BREAK – coffee/tea & posters**
11.20	**Session Six: Containment characterisation and monitoring – global examples I** Chair: Chris Lloyd Online chair: Eleanor Rollett
11.20	**Quest Carbon Capture and Storage – 4D Seismic Insights into Plume Migration and Containment** Chris Freeman
11.50	**Integrated characterisation of CO2 containment in storage complexes: A case study of the Illinois Basin – Decatur Project** Idris Bukar
12.10	**Rapid Large-scale Trapping of CO2 via Dissolution in US Natural CO2 Reservoirs** Stuart Gilfillan
12.30	**LUNCH & posters**
13.20	**Session Seven: Containment characterisation and monitoring – global examples II** Chair: Nick Lee Onine chair: Chris LLoyd
13.20	**Keynote: Risk assessment and monitoring of carbon stores in the UKCS context** Ian Barron
13.40	**CO2-injection projects in the Brazilian Pre-Salt – Storage Capacity and Geomechanical Constraints** Joao Paulo Pereiria Nunes
14.00	**Composite Confining Systems for Permanent CO2 Sequestration** Alex Bump
14.20	**BREAK**
14.50	**Session Eight: Geomechanics in risking** Chair: Eleanor Rollett Online chair: Mads Huuse
14.50	**Integrating field, laboratory, modelling and machine learning for de-risking CO_2 fault leakage** Andreas Busch
15.10	**Screening constraints imposed by fault slip potential on the deployment of carbon capture and storage** Iman Rahimzadeh Kivi

15.30	**Fast Tool for Field-Scale Simulation of Fault Leakage during CO2 Storage** HariHaran Ramachandran
15.50	**Small-strains and gentle uplift of the seabed: Modelling the regional geomechanical response to industrial-scale injection of carbon dioxide in the Bunter Sandstone** John Williams
16.10	**Aspects of Mechanical Containment in CCS Projects** Andy Kirchin
16.30	**End of day two discussion: what is the right tech and timeline for MMV?**
17.30-18.30	**Evening Social Event (tbc)**

Day Three	
08.30	**Registration**
08.55	**Welcome and Summary of Day 2**
	Session Nine: Rock Physics in CCS Chair: Mads Huuse Online chair: Nick Lee
09.00	**Efficient Storage Complex Characterisation and 4D Monitoring Feasibility using Rock Physics** Eleanor Oldham
09.20	**Examples of Gassmann fluid substitution of non-hydrocarbon fluids from the UKCS** Hector Barnett
09.40	**Evaluation of signals from monitoring CO2 injection in the North Sea using 4D seismic** Colin MacBeth
10.00	**BREAK – coffee/tea & posters**
10.30	**Session Ten: Monitoring approaches** Chair: Ivan Fabuel Perez Online chair: Elizabeth MacKie
10.30	**Leveraging Surface Distributed Acoustic Sensing for cost-effective CCS monitoring** James Butt
10.50	**Onshore passive seismic monitoring for CO2 storage projects using array methods** Joseph Asplet
11.10 Virtual	**High-resolution seismic for characterising seal geometry and leakage risk for carbon storage: A central North Sea case study** Deepak Rathee
11.30 Virtual	**Keynote: Application of muon tomography for detection and monitoring of geostored carbon dioxide** Jon Gluyas

12.00	**LUNCH & posters**
13.00	**Session Eleven: Baselines and Monitoring** Chair: Mark Wood Online chair: Chris Lloyd
13.00	**Keynote: Labarge CCS Project, Wyoming, USA: An Example of Containment Monitoring Using Non-Seismic Methods** Patricia Montoya
13.30	**Seabed monitoring of storage complexes – leveraging baselines and regulations** Robert Hines
13.50 Virtual	**Environmental baselines in geological CO2 storage monitoring- what are they really good for?** Katherine Romanak
14.10	**End of day three – final comments, proceedings, etc**
14.30	**End of Conference**

Posters
Fractured caprock failure criterion in the context of underground CO2 storage Rafael Mesquita
Geological modelling and fault seal analysis for optimising co2 storage in the koye field niger delta Claire Chukwumah
Mechanical stratigraphy and fault damage zone characterisation of the Lower Jurassic Redcar Mudstone Formation at Robin Hood's Bay, NE Yorkshire Adam Szulc
Critical Minerals from CCS Brines William Norfolk
Drilling the late Plio-Pleistocene of the North Sea for climate reconstructions, with implications for the efficacy of CCS Mads Huuse
Advantages of CO2 storage – Water Geothermal combined system to control pressure increment and enhance storage capacity Farnam Firouzbehi
Containment monitoring of a Carbon Capture Storage (CCS) project using chemical tracer technology Paul Hewitt
Bunter and Leman Sandstones Rock Physics Modelling and Geophysical Responses Analysis during CCS Jing Yang
The Röt Halite Member of the Southern North Sea – A critical top seal for carbon dioxide storage in the Bunter Sandstone Formation Harry Morris

Assessment of subsurface carbon dioxide storage potential of gas shales in Sichuan Basin, China He Yue

Assessing the sealing capacity of the Haisborough Group, Southern North Sea: insights from a continuous core succession in North Yorkshire Colm Pierce
The importance of reproducibility in CCS storage site characterisation and monitoring Mark Ireland
SAFERCCS: Sustaining fluid-flow and Assessing Feldspar solubility Enhancement Reactions in CCS reservoirs Natalie Farrell
Characterising creeping formations Matteo Loizzo

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ORAL ABSTRACTS
(In Programme Order)

Session One: CCS Containment and Risk

Plumbing and Bowties: An integrated approach to risk identification and mitigation in CCS projects.

Mark Wood, *Charlie Lee, Ben Dewever*

Plumbing diagrams were originally used in the oil and gas industry as a way to force subsurface teams to focus on what elements in a hydrocarbon reservoir would affect fluid flow. A similar approach has been taken when thinking about the containment of CO_2 in the subsurface whereby any ‘element’ in the subsurface which could allow CO_2 migration out of a CO_2 store is mapped, analyzed and understood. This understanding is then pulled together in a schematic representation of the overlying formations of a store, where faults, overburden stratigraphy and well zonal isolation can all be illustrated. In doing this tortious leak paths can be identified and better understanding of the likelihood of them becoming conduits for CO_2 is established. With this understanding, holistic, forensic, ‘bow tie’ thinking can be employed whereby a ‘top risk’ is made clear, and the factors which lead to the occurrence of the top risk and escalate it after occurrence are outlined. Similarly, the preventative and remediative actions also become clear. This talk will walk through the workflow, and demonstrate that it is an important pre-requisite to the development of an effective and rightsized MMV plan.

Defining a bespoke and proportionate monitoring plan linked to the Early Risk Assessment (ERA) for carbon storage

Kate Thatcher[1], Vicky Newling[1], Helen Basford[2], Callum Inglis[2], Chris Ward[2], Richard Metcalfe[1]

The Appraise Phase of Carbon Storage Licences involves delivery to the NSTA of an Early Risk Assessment and a Site Characterisation Review Report. Developing preliminary monitoring plans at this phase of the project can help ensure that data collection during Site Characterisation supports future monitoring. Monitoring is a requirement of the European Commission Directive and is aimed at assessing conformance with predicted behaviour and identifying irregularities and migration / leakage of CO_2.

We will discuss the development of a process, created alongside the Morecambe Net Zero (MNZ) project, to define a monitoring plan that demonstrates conformance with expected performance of the storage system. The process uses the risk scenarios identified in the ERA to test whether the monitoring plan would detect the occurrence of these risks. The process also needs to provide for the investigation of any predicted irregularities, which then links to the corrective measures plan.

Every storage complex is different and requires a bespoke approach to monitoring so that the monitoring plan is proportionate to the risk and enables investigation of any irregularities observed. Following a logical process builds confidence for both the operator and the regulator that the monitoring plan will sufficiently assess conformance with modelled behaviour, detect any migration of CO_2 within the Storage Complex and detect any significant leakage of CO_2 out with the Complex should it occur.

The insurance rationale for CCS

Rodney Garrard

Dr. Rodney Garrard, Geo Energy Adviser.

Carbon Capture and Storage (CCS) is one of the pivotal solutions to decarbonise hard-to-abate industries as well as to achieve negative emissions to achieve net zero targets. While the first CCS projects receive significant government subsidies, scaling up of the solution will require private-sector investments on the open market. Hence, how investable and ultimately insurable CCS projects are should be addressed. In this presentation we highlight some of the specific risks and highlight the ongoing development of risk protection insurance instruments in case of, for example (and not limited too), low probability high impact events (e.g., CO2 leakage).

Session Two: Pore-scale characterization and modelling

Multiscale-multiproxy characterisation of targeted Mesozoic mudrock analogues in the Cleveland Basin, UK to aid assessments of seal potential and performance in the North Sea

Colm Pierce

Colm Pierce[1]*, Michael Flowerdew[1], Adam Szulc[1], Niall Paterson[1], Simon Schneider[1], Michael Pointon[1], Michelle N. Shiers[1], João Trabucho Alexandre[2], Youp Heinhuis[2], Balzas Toro[1], David Warburton[3], Mike Curtis[1] and Stephen Vincent[1]

A research programme in the Cleveland Basin, North Yorkshire has sampled and logged more than 600 m of continuous mudrock and intercalated mudrock-evaporite/halite stratigraphy. The studies have investigated both outcrop exposures and relatively shallow continuous borehole core to document heterogeneity in mudrock units and examine the impacts on seal potential for geological carbon storage (GCS). The studied successions include the lower Lias Group in outcrop, primarily at Robin Hood's Bay, as well as the entire Mercia Mudstone and lower Lias groups in a nearby onshore core.

The stratigraphic equivalents of the study interval form primary and secondary seals to an expanding set of GCS complexes across both the adjacent and wider North Sea region. Seal units are often poorly characterised relative to corresponding reservoir lithologies within GCS complexes. However, thorough characterisation of seal rock properties is important when developing representative geomodels of their mechanical properties and leakage risks. A continuous vertical characterisation here helps constrain, to a first approximation, the likely lateral range of seal unit properties.

The primary aim of our investigations is to link a comprehensive catalogue of primary (compositional and sedimentological) and secondary (e.g. deformation/diagenesis-related) heterogeneities to variations in seal potential. To capture compositional variability, we combined sedimentary logging (1:200-1:25) and facies analysis, hand-held gamma/X-ray fluorescence (XRF) analysis, quantitative X-ray diffraction (QXRD) analysis, total organic carbon combustion analysis (TOC), optical petrography (microfacies analysis) and scanning electron microscope energy dispersive spectroscopy (SEM-EDS). These allowed targeted porosity-permeability and mercury injection capillary pressure (MICP) analyses to underpin assessments of seal capacity. A Lias Group focussed effort, combines selected TOC, SEM-EDS, MICP with field measurements to examine mechanical stratigraphy. Onshore core analyses are supported by standard industry investigative techniques, including wireline log suite, geotechnical analyses and targeted 2D seismic datasets, which accompanied coring.

Driven by the analytical results, characteristic facies-microfacies, compositional and mineralogical sub-groupings have been established and linked to seal capacity estimates. Our current focus is on optimising the delivery this comprehensive dataset, so that it can be readily integrated into existing industrial data pipelines and workflows, as well as understanding its wider significance, and calibrating risk maps with respect to reactivity and mechanical strength. When combined together, the assembled datasets suggest overall seal potential is high, provide a well-contextualised library of seal parameters, and can aid operators making containment-secondary reservoir assessments necessary for regulatory compliance and societal acceptance.

Compositional controls on the Lower Cretaceous Rodby Shale pore structure and surface area: a planned CCS top seal caprock for the Acorn storage site

Nourah Alnajdi, *Richard H. Worden, James E. P. Utley*

Compared to other lithologies in traditional petroleum systems (especially reservoirs, but also source rocks), caprocks have not been intensively studied as they are typically assumed to be effective because they have contained petroleum fluids for geological time periods. The same degree of effectiveness cannot be assumed about caprocks to either saline aquifer or depleted gas fields CCS sites given that saline aquifers have not contained any fluid except water and depleted gas fields have not contained high pressure and potentially reactive CO2. We have thus investigated the mineralogy, pore systems, and surface area characteristics of the Lower Cretaceous Rodby Shale, which is the caprock to the Captain Sandstone at the UK's planned Acorn/Goldeneye CCS site, buried to the present day maximum depth and temperature of about 6,500 ft and 60°C. Representative core samples through the Rodby Shale were selected for sedimentary core logging, and mineral quantification using XRD and light optical and SEM-EDS analysis. Grain size distribution was measured using laser particle size analysis. Porosity, permeability, pore throat diameter, surface area, and pore body size were measured via mercury intrusion porosimetry (MICP) and nitrogen adsorption analysis. The Rodby Shale is smectite-rich and contains abundant calcite as well as quartz silt with small quantities of chlorite and plagioclase. The calcite was sourced from benthic microfossils and has been locally recrystallised to create a pore-filling cement. Both the mean N2 adsorption-derived and MICP-derived mean pore throat diameter is about 17 nm, putting the Rodby in the mesopore range and suggesting the dominance of slot-like pores. Calcite cement has grown around smectite, leading to an inverse relationship between calcite content and reactive surface area. Granular silty quartz is resistant to compaction leading to an unexpected positive relationship between quartz and surface area as clays in the pressure shadows around quartz grains have undergone negligible compaction. Three end members lithotypes for the Rodby Shale CCS top-seal were identified: (i) clay-rich shale with high surface area, (ii) calcite-rich shale with low surface area, (iii) quartz-rich with intermediate surface area. Calcite can dissolve in the presence of high partial pressure CO2. This work implies that if the second lithotype encountered CO2, the resulting calcite dissolution would increase the remaining shale's surface area as reactive silicates, such as chlorite, plagioclase, or even smectite. Any newly exposed reactive silicates could ultimately lead to enhanced mineral trapping of the injected CO2.

Pore Network Modelling of CO_2-Shale Interaction in Carbon Storage and Gas Recovery: Swelling effect and Fracture Permeability

Amin Taghavinejad

Underground CO_2 storage is key to achieving net-zero carbon emissions by 2050, involving large-scale containment of gaseous CO_2 in geological formations. Shale, with its significant storage capacity and commonality as cap rock in storage sites, is crucial for trapping CO_2 and preventing its escape. This study explores the dynamic behaviour of CO_2 shale interaction at the pore scale, focusing on the physiochemical interactions between CO_2 and shale, including the impact of shale swelling, where CO_2 adsorption causes matrix deformation and alters fracture sizes. This research utilizes image-based analyses to develop triple-porosity Pore Network Model (PNM), reflecting the complex nano- to micro-scale structures of shale, to study the physiochemical interactions and dynamic responses during CO_2 injection into methane-saturated environments. The study particularly focuses on the impacts of matrix deformation caused by gas sorption, which alters fracture sizes and competes with mechanical stress effects. Findings indicate that CO_2 injection leads to a reduction in fracture permeability by up to 17% and 10% in low- and high-density fractured shales, respectively, under high confining pressures (50 MPa), and by 15.5% and 8% under lower pressures (25 MPa). Additionally, the average fracture aperture size decreases by 50nm in low-density and 25nm in high-density fractured shales, highlighting the critical balance between swelling effects and mechanical stresses in the geological sequestration of CO_2.

Session Three: Bowtie Analysis

Bowtie Analysis

Simon O'Brien & Simon Shoulders

TBC

Session Four: Bunter projects

East Mey: the characterisation of the storage complex

Philip Whiteley, Nick Hayward, Claire Imrie, Rodrigo Oropeza

Ross Abernethy, Nurlan Nurmanov

The Acorn Transport & Storage system is at the core of the Scottish Cluster. It will enable timely and efficient decarbonisation of Scotland. It will repurpose former energy pipeline infrastructure to deliver CO2 from industry to the Acorn stores, more than 100km off the north-east coast of Scotland. Emissions from Scotland's Central Belt, and Fife, will reach Acorn via further repurposed onshore pipeline infrastructure.

Acorn, a joint venture between Storegga, Shell UK, Harbour Energy and North Sea Midstream Partners, has received match funding from the UK and Scottish Governments and has benefited from two rounds of Connecting Europe Facility (CEF) funding from the European Commission.

East Mey is the build-out store to Acorn T&S. with the licence, CS012, being awarded in 3Q23. The area is proposed as a large aquifer store with CO2 being injected into Paleocene sandstones. The licence area awarded is 2082 km2 and contains 261 well penetrations and several overburden sands. Therefore, characterising the storage complex requires a systematic and multi-disciplinary approach.

Geophysical analysis has been combined with regional understanding, new biostratigraphic, petrographical and QEMSCAN analyses in order to characterise the reservoir as well as provide an overall containment assessment. Alongside this, all well penetrations have been evaluated to assess their robustness of abandonment against current guidelines and industry best practices, and identify any wells that could pose a constraint to the development of the project which could be deemed of critical importance to any injection plans.

This presentation will look at some of the work undertaken in preparation for the Early Risk Assessment on the licence, some of the issues identified and how these have been resolved.

Understanding the impact of regional structures on pressure communication within the Bunter Sandstone Formation, UK Southern North Sea

Lucy Abel, *John Williams, Jim White, Hayley Vosper, Harry Morris*

The Lower Triassic Bunter Sandstone Formation is one of the UK's principal targets for carbon capture and storage. Located in the Southern North Sea, the formation contains several periclinal closures which provide potential carbon storage opportunities for industrial clusters in eastern England. Numerical simulation studies, investigating the dynamic behaviour of industrial scale CO2 injection, have highlighted that CO2 storage can result in widespread pressurisation of the aquifer. Understanding the potential for pressure communication in the Bunter Sandstone is therefore important in the context of pore pressure management, as injection activities at one site could potentially impact negatively on operations elsewhere.

The Bunter Sandstone Formation is regionally divided by recognised fault systems and salt walls, such as the Dowsing Graben System, North Dogger Fault Zone, Audrey Salt Wall and Outer Silverpit Salt Wall. The Bunter Sandstone Formation is underlain by the Permian Zechstein Salt. Extension and transtension during the Mid-Late Triassic, Jurassic and Early Cretaceous, associated with the breakup of Pangea, and inversion during the Alpine Orogeny in the Late Cretaceous and into the Palaeogene, has resulted in mobilisation of the Zechstein Salt and the deformation of the Bunter Sandstone and its overburden.

Recently, localised studies have been completed which map zones of separation of the Lower Triassic strata within the Dowsing Graben System (Grant et al 2019; Grant et al 2020) and regionally the distribution and evolution of salt walls (Gaitan & Adam, 2023). However, there is little investigation into the characteristics of these boundaries as a whole and their likely impact on the migration pathways of fluids within the aquifer, and therefore pressure, during large-scale CO2 injection. This study uses a large seismic database to evaluate these bounding structures at Bunter level. Each boundary has been investigated and the structural variation described. A new structural map has been created for the Top Bunter Sandstone Formation and a classification scheme has been developed to map the variation in the structural character and therefore the likelihood of pressure communication across each boundary.

The structural boundaries predominantly provided distinct separation of the Bunter Sandstone Formation. Areas of uncertainty remain where: the structures are highly complex, there is little well control, and the seismic imaging is of lower resolution. Legacy well data has been sourced from the NSTA's National Data Repository to investigate formation pressures within the Bunter Sandstone Formation. These data indicate that different structural regions in the UKSNS are subject to distinct pressure gradients supporting the lack of aquifer connectivity inferred from the seismic interpretation.

Current national development plans (NSTA, 2023) envisage multiple storage sites within the wider connected aquifers. Strategic management and pressure control may become a key factor in the development and operation of these storage sites. To investigate the impact of the boundary classification on regional pressure, numerical flow modelling was used with the ELCIPSE300 simulator and the CO2STORE option. Regionally appropriate parameter values were used, primarily sourced from the CO2Stored database and other publicly available data. A realistic but ambitious CO2 injection strategy has been used with staggered injection into multiple closures, including the Endurance structure. For boundaries with uncertain connectivity, cases of closed, semi-closed and open boundaries were run and the flow of pore fluids through permeable boundaries quantified. The flow simulations provide an insight into the potential implications for pressure management for effective utilisation of storage capacity, and could be used to inform development of monitoring strategies.

Sub-regional static reservoir characterisation of the Bunter Sandstone hydraulic unit for CO2 storage – A multi-discipline, multi-scale approach

Ewan Gray, *Kirsty Hitchen, Catherine-Gibson-Poole, Michael Taplin*

A large-scale static characterisation study has been undertaken to improve description of the depositional and diagenetic controls on the reservoir properties of the Bunter Sandstone CO2 storage reservoir in the Southern North Sea, UK. The Bunter Sandstone Formation is well studied at the mega regional-scale (McKie, 2014; Geluk et al., 2018) and at the field scale in the Silver Pit Basin (Biffani, 1986; Ketter, 1991; Ritchie & Pratsides, 1993), however, characterisation at the sub-basin scale is less ubiquitous. This study integrates regional core material and an extensive well database to define the characteristics of the Bunter Sandstone across the Silver Pit Basin. The Bunter Sandstone Formation is a regionally extensive saline aquifer system, which spans 100’s km2 across the Silver Pit Basin and forms the reservoir component in multiple CCS licences.

A quantitative understanding of reservoir variability is key for confidence in CO2 injectivity, CO2 storage capacity and reliable modelling of multi-store pressure interference for containment monitoring of pressure dissipation. Assessing the rate of multistore pressure interference through the Bunter Sandstone aquifer is key for CO2 storage capacity as the caprock fracture pressure limits for individual structures may be reached sooner than planned due to the structure’s pressure headroom being reduced by pressure interference from adjacent stores.

In this study core-based depositional and heterogeneity facies schemes have been derived and logged for > 1km of core. This was then used to populate a petrophysical log lithofacies scheme in > 100 wells through the application of machine learning. Once populated, the log lithofacies is used to allocate fixed parameters which form the petrophysical model, including variable porosity-permeability functions per facies. This utilisation of data across plug-core-log scales has enabled improved accuracy of porosity and permeability estimation at the sub-basin scale. The results are also presented through a refreshed understanding of the Bunter Sandstone sub-zonation, this allows a quantitative understanding of the distribution of facies and reservoir quality over the sub-regional aquifer at the intra-reservoir scale to be defined.

The improved static description is now at the appropriate scale to assess and model multi-store interference which is key to assessing CO2 containment within the complex and mitigating containment risk in the operational phase. In addition, the reservoir characterisation allows improved injectivity predictions, better storage capacity estimation and geologically-grounded reservoir scenarios to be constructed.

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CO_2 storage potential, containment, and monitoring challenges of the Humberside license (UK)

Martin Grecula1, *Samantha Luxon1, Michiel van Dongen1, Chris Willacy1, Ben Palmer1, Serik Yergazin1 & Quentin Regnault2*

The exploration license CS028, located offshore Humberside, is the largest license awarded in the 1st UK's CCS round. The opportunity targets geological storage in the Bunter and Leman sandstone saline aquifers, in a relatively undeformed East Midlands shelf setting. The formations are part of a gently dipping monocline verging towards the shore. A migration assisted storage concept invokes the offshore trapping of CO_2 by dissolution and capillary forces. The initial plume modelling exercise suggests that the plume will stabilise at a safe distance from the shore, not impacting any onshore infrastructure. However, it will be important to refine and calibrate the model to fully understand what parameters will impact the plume behaviour most.

The Humberside license is a data-lean area, under-explored for hydrocarbons. It is covered largely by 2D seismic, and there are only eight wells in approximately 3,000 km^2. There is large uncertainty about the lateral connectivity, as well as the reservoir and seal properties. It is unclear whether there can be high permeability features focusing CO_2 towards the shore. The E&A wells present are old and typically without isolation at the Bunter level. However, they are sparse and avoidable, if injector locations are optimised. The CO_2 leakage may not be the only concern though. Even in a large, laterally well-connected aquifer, the pressure is likely to increase during injection, causing brine migration. Brine leakage may occur offshore, but also onshore, if the aquifers are laterally connected. Seismic interpretation of the transitional offshore to onshore area suggests a low density, largely disconnected network of faults, which are unlikely to create pressure barriers, or prevent aquifer flow towards the outcrop (in the case of the Bunter sandstone). Dynamic modelling of geological heterogeneity within the formation and in the overlying sealing formation will be key to assess the pattern of pressure dissipation within the formation and predict the magnitude of saline aquifer flow towards the shallow groundwater areas. Onshore hydrogelogical and geochemical data will need to be collected and analysed to assess the risk of freshwater contamination, and any significant increase of surface aquifer discharge.

The acceptability of the storage project by all stakeholders will depend on a convincing demonstration that a) CO_2 will stay offshore, b) groundwater resources will not be jeopardised by the planned injection capacity of the project. A project specific monitoring plan will be put in place to detect any early warnings of either pressure increase or CO_2 migration beyond the safe threshold. A phased development plan may be put in place to understand the behaviour of the system during injection, and guarantee that the storage capacity is realised within the safe operating envelope. The Humberside storage project provides an opportunity to significantly contribute to society's net zero ambitions, and at the same time, aims to minimise any risks to the environment, assets and people offshore or onshore.

Session Five: Projects

Keynote: Gorgon Carbon Capture and Storage

David Fallon & Robert Root

TBC

Northern Lights Monitoring and CRA, the basis for safe CO_2 storage operations

Catalina Acuna

TBC

Endurance CO2 Store corrective measures planning: how can we use monitoring data effectively?

Alex Gillespie

A corrective measures plan sets out the process through which monitoring data will be used and applied to containment, injectivity or capacity-related risk scenarios to ensure safe and efficient CO2 storage operation. Existing guidance on corrective measures plans predominantly takes a risk scenario-led approach, whereby a specific risk scenario is paired with corrective measures that may be applied to resolve it. However, this approach does not consider the limitations and uncertainties of interpreting monitoring data results, i.e. detected anomalies may have non-unique causes and could indicate more than one risk scenario rather than a single definitive interpretation. As part of the corrective measures planning associated with the Endurance CO2 store, an alternative monitoring-led approach was taken. This method focuses first on how the monitoring data are used to inform the appropriate way forward in light of possible ambiguity in diagnosis, rather than what actions will be taken if a particular risk scenario is already known to have occurred. This provides a more robust and flexible linkage between CO2 injection risk scenarios and monitoring data that should allow more effective management of the CO2 store.

Monitoring CO_2 storage in the Morecambe depleted gas reservoirs through seafloor deformation and time-lapse gravimetry measurements

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In 2023, Spirit Energy was awarded license CS010 to appraise the re-purposing of the Morecambe gas fields, in the UK Continental Shelf (UKCS), into high-capacity Carbon Storage (CS) sites. The current concept for the Morecambe fields is to inject CO2 in the gas phase. Over time the CO2 is expected to mix with residual natural gas and slowly dissolve into the underlying brine. The presence of depleted natural gas limits the seismic acoustic response of injected CO2, restricting the effectiveness of 4D seismic as a method for monitoring. Additionally, seismic operations with active sources in the Morecambe fields are strongly constrained by offshore infrastructure, including a planned windfarm above a part of the storage site.

The large expected changes in fluid density caused by CO2 injection in a depleted gas field and the relatively shallow reservoirs suggest that seafloor gravimetry would be an effective monitoring technology for the Morecambe fields. Furthermore, the field-wide re-pressurization due to the injection has the potential to cause seabed uplift. If accurately measured over the field, uplift can be used to calibrate geomechanical models (Ruiz et al, 2022), therefore ensuring long-term performance and conformance of subsurface CO2 storage.

In this work, we assess the effectiveness of time-lapse gravimetry and seabed deformation measurements in contributing to conformance and containment monitoring for the Morecambe carbon storage project (MNZ). The evaluation utilizes dynamic flow simulations of CO2 injection and forward-modelling of gravity and seabed displacement. The dynamic simulation model describing CO2 injection is based on a compositional representation of the fluids in the pore space. To model time-lapse gravity changes, the mass changes at the grid cells are used to forward-model the expected response on the seafloor by using Newton's law. In addition to gravity changes, the seabed displacement due to reservoir pressurization was also modelled, using Van Opstal's nucleus-of-strain model (Van Opstal, 1974).

The modelling of time-lapse gravity suggests a strong positive gravity response caused mainly by the CO2 mixing with the residual methane in the pore space. The time-lapse gravity signal in the North Morecambe area is stronger and more spatially localized when compared to South Morecambe. This is due to the greater injected CO2 mass and smaller pore volume in North Morecambe. The magnitude of the time-lapse gravity in both storage sites is well above the state-of-the-art accuracy of 1 µGal for seabed gravimetry (Ruiz et al., 2020). Highly significant gravity signals are expected after periods as short as a few months, and within realistic time intervals required for monitoring a carbon storage complex. Similarly, geomechanical modelling suggests a seabed deformation of a few millimetres per year, also well within the range of the monitoring technology considered in this work.

To evaluate the feasibility of detecting the unlikely scenario of CO2 movement out of the storage site, scenario modelling has been performed. CO2 migration to a theoretical shallow, brine-saturated interval within the Storage complex is one case that has proven useful in terms of understanding gravity and seabed displacement responses. Identifying the occurrence of such secondary containment would help improve storage management in terms of mass balance and seal capacity as well as risk management. In this scenario, the modeled gravity signal of the migration of CO_2 to a shallow layer has an intensity of 3-4 µGal and extends for 1-2 km, placing it well within the detectability threshold of the available technology.

The results of our work indicate that time-lapse gravimetry monitoring and seabed deformation monitoring can measure not only the advance of the subsurface CO_2 plume but also eventual deviations from the baseline scenario. It is anticipated that integration with pre-injection, high-resolution 3D seismic data will provide the spatial resolution to enable accurate CO_2 plume conformance monitoring. The nature of the proposed survey design will enable an adaptive approach through the lifetime of the CS project alongside the presence of windfarms that will provide key information for integrated conformance and containment monitoring.

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Preliminary Monitor Strategy for CO2 storage in depleted reservoir, a case study from the Bifrost project in DK

Rasmus Lang, *Huy Le, Piero Bassini, Nicolas Mottet, Stephane Rippe, James Young*

The depleted gas condensate field Harald West comprising Middle Jurassic sand, located in the northern part of the Danish Central Graben, is considered for CO2 storage. The field has been in production since 1997. It has been selected as a good candidate for storing CO2 due to low remaining production potential and the presence of wells, a pipeline that may be used for transportation and surface facilities. Moreover, the seal has been proven over geological time to be strong and thanks to the absence of an active aquifer, significant volumes of CO2 can be stored in the depleted gas cap, without exceeding the initial reservoir pressure.

Geological and engineering studies have been carried out as part of the TotalEnergies led Bifrost study. The Bifrost study is a collaboration between the Danish Underground Consortium (DUC: TotalEnergies, BlueNord and Nordsofonden), Ørsted and Danish Offshore Technology Centre (DTU Offshore).

The Preliminary Monitor strategy of the Harald West is an example of how a deep understanding of reservoir dynamics, overburden properties, uncertainty and risk evaluation and simulation of plume, pressure and temperature evolution over time can impact the selection of monitor tools and their timing.

The monitor strategy has been developed through multi- disciplinary containment risk assessment workshops. A Bow-tie approach was used to describe even the most remote likelihood leak paths and the natural and man-made barriers that can be counted on to prevent any leak to surface.

Reservoir simulation studies using a multi-realisation approach to represent the uncertainties, provided a range for the fields storage capacity. The chalk overburden of the Harald West includes several porous and permeable sealed layers. Simulation models were also constructed to confirm that the chalk zones can accommodate all the CO2 that unexpectedly could escape the storage complex, either through the cap-rock or from leakage along the exterior of the wells. The analysis also illustrates when in time such events would be detectable by either cased hole logs (pulsed neutron) or 4D seismic.

3D geomechanical modelling was used to ensure that the operational envelopes (injection rates, pressure, temperature) considered were safe in terms of cap rock integrity and fault reactivation. The fault stability and cap rock strength are affected by temperature and therefore, thermal compositional simulation was used. The field is heavily depleted and geomechanical simulations of the production period was consequently run to evaluate the full stress history of the storage complex and the overburden. Minor fault reactivations with mm scale displacement are possible for faults within the cold front of an injector, however, this can be tolerated as long as the faults do not propagate across the sealing units. Fortunately, the faults are truncated at the base of the caprock and are not mapped near the selected injectors and it is possible to confirm absence of fault displacement using micro seismic monitoring.

Well integrity studies were also carried out to assess the suitability for production wells to be converted to injection wells, the re-completion requirements and to evaluate the potential for cross flow along a well between the reservoir and layers in the overburden. Simulation models, representing the well architecture was used to support the cross-flow analysis. The simulation indicates that due to the large storage capacity of the chalk, the only credible path for CO2 to the surface is through the annuli of a well, leading a path to either the well head platform (along the injectors) or the seabed (along the legacy wells) with low-rate flow to a narrow area on the seabed. The analysis has this way instructed the strategy for seabed and near seabed environment to focus on point source detection near the abandoned exploration wells.

Session Six: Containment characterisation and monitoring – global examples I

Quest Carbon Capture and Storage – 4D Seismic Insights into Plume Migration and Containment

Chris Freeman, *Jonathon Hopkins, Rohit Dhawan, Hein Blanke*

The Quest Carbon Capture and Storage facility is operated by Shell Canada on behalf of the AOSP Joint Venture (Canadian Natural Upgrading Limited, Chevron Canada Oil Sands Partnership and 1745844 Alberta Ltd). Located near Fort Saskatchewan, Alberta, Canada, it has been in operation since August 2015. Since first injection, over eight million tonnes of CO2 have been safely stored in a deep saline aquifer at a depth of about two kilometres below ground, in three injection wells.

To ensure safe and permanent storage of the CO2, Quest has implemented a Measurement Monitoring and Verification plan. This plan is updated every three years and is developed based on four main principles: risk-based, site-specific, ensuring regulatory compliance, and adaptive. This paper will review observations from the seismic technologies deployed as part of the subsurface monitoring to verify containment and conformance of the injected CO2. In addition, the authors propose potential underlying geologic drivers controlling plume development.

In 2021, Quest performed its first repeat 3D surface seismic survey (4D Seismic) covering 100 square kilometres of the 400 square kilometre baseline 3D seismic survey.

CO2 plumes from all three wells have been imaged using DAS VSP technology, and two of the three plumes are covered by 4D Seismic. Both technologies show the geometry and migration behaviour of the plume, with the 4D enabling a very comprehensive imaging of the plume in 3D space. The imaging demonstrates that no seismically resolvable CO2 has migrated out of the reservoir. Furthermore, the high-quality baseline survey allows the geologic controls on plume migration to be well understood. This understanding of plume behaviour is effective in proving conformance with both reservoir and seal elements of the geological model, and increases confidence in the effective containment of the injected CO2.

In this presentation, the author will share the latest observations of CO2 plume behaviour at Quest, insights into the geologic controls, and the learnings for seal effectiveness.

Integrated characterisation of CO_2 containment in storage complexes: A case study of the Illinois Basin – Decatur Project

Idris Bukar, *Rebecca Bell, Ann Muggeridge, Sam Krevor*

CO2 migration along faults presents a major containment risk for CO2 storage. The potential for sequestered CO2 to migrate through faults is well documented from observations from geological analogues such as natural CO2 reservoirs as well as from theoretical and numerical modelling. We have identified rapid vertical CO2 migration along a fault from time-lapse seismic monitoring data at the Illinois Basin – Decatur Project site, a commercial scale CO2 storage demonstration project in Decatur, Illinois, USA. The fault provided a migration pathway for sequestered CO2 from the injection interval to bypass overlying capillary barriers and re-emerge in zones of high reservoir quality (Bukar et al., 2024). While the CO2 remains safely contained beneath multiple sealing units, this novel observation nonetheless provides an illustration of containment risk and a validation of the previously theorised behaviour of CO2 migration along faults at storage sites.

A total of 28 faults were interpreted from 3D seismic data at the Decatur site. Two other faults within the smaller monitored area were interpreted to be sealed, with the main observable peculiarity being the orientations of their planes with respect to the direction of maximum horizontal stress, SH. We therefore interpret that faults at the site with planes sub-perpendicular to the direction of SH are potentially sealed by compressive stresses, with all other faults considered potentially open. This observation could play a major role in containment risk analysis during storage site selection and characterisation, as orientations of fault planes and possibly velocities in the fault zone can potentially be used to screen for faults with higher risk of allowing fluid migration.

For predictive forward modelling, there will be a need to characterise single and multiphase flow properties of fault zones such as permeabilities and relative permeability and capillary pressure characteristics. In dynamic scenarios (i.e. during and post injection), fault permeabilities can be estimated or bounded from mass balances and related to the orientation of their planes with respect to the stress field, and possibly fault zone velocities. However, analysis of along-fault migration risk should not be performed in isolation; CO2 entry into and migration along permeable faults appears to be controlled by a balance between driving forces (viscous and buoyancy forces) and the contrast in magnitudes of flow properties, such as capillary entry pressure, between the fault and the reservoir units. Therefore, rather than simply attempting to determine which faults are open or sealed, the question to ask should be of the form “in the presence of capillary barriers or sealing formations, when will buoyancy forces drive CO2 into open faults?”

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Rapid Large-scale Trapping of CO2 via Dissolution in US Natural CO2 Reservoirs

Rory Leslie[1*], Gareth Johnson[2], Chris Holdsworth[1], R. Stuart Haszeldine[1,3], Stuart M. V. Gilfillan[1]

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Naturally occurring CO_2 reservoirs across the USA are critical natural analogues of long-term CO_2 storage in the subsurface over geological timescales and provide valuable insights into the fate of CO_2 in the subsurface. Previous measurements of CO_2 to ^3He ratios within gas samples obtained from six natural CO_2 reservoirs show that the CO_2 originated from magmatic degassing[1]. Variation in $CO_2/^3He$ across each reservoir suggests that significant amounts of CO_2, equivalent to hundreds of megatonnes, have been stored by solubility trapping[2]. However, the key question of whether CO_2 dissolution occurred during emplacement, or by diffusion and convection over geological time remains unanswered.

Here we present the results of integrating geochemical measurements with reservoir modelling to quantify both the mass of CO_2 emplaced and the proportion dissolved within each of the CO_2 reservoirs. Given the magmatic origin of the CO_2, we use the known age dates of associated igneous rocks to estimate the timing of CO_2 emplacement in each reservoir. Comparing these emplacement age dates with the results of the reservoir modelling, we show there is no relationship between the duration of CO_2 storage and the proportion of solubility trapping that has occurred. This result shows that the proportion of dissolved CO_2 does not significantly increase over geological timescales. Similarly, we find that the original mass of CO_2 does not influence the proportion of CO_2 that is solubility trapped. At our exemplar site, Sheep Mountain in Colorado (Fig. 1), we observe that the proximity of CO_2 samples to the gas-water-contact does not influence the proportion of CO_2 dissolved.

Our findings support a model where the majority of solubility trapping occurs on CO_2 injection and during the migration of the CO_2 plume. Hence, solubility trapping after the CO_2 has become structurally trapped is comparatively minor. Therefore, in engineered CO_2 stores, considerable amounts of injected CO_2 can be solubility trapped within CO_2 injection and post-injection monitoring timescales.

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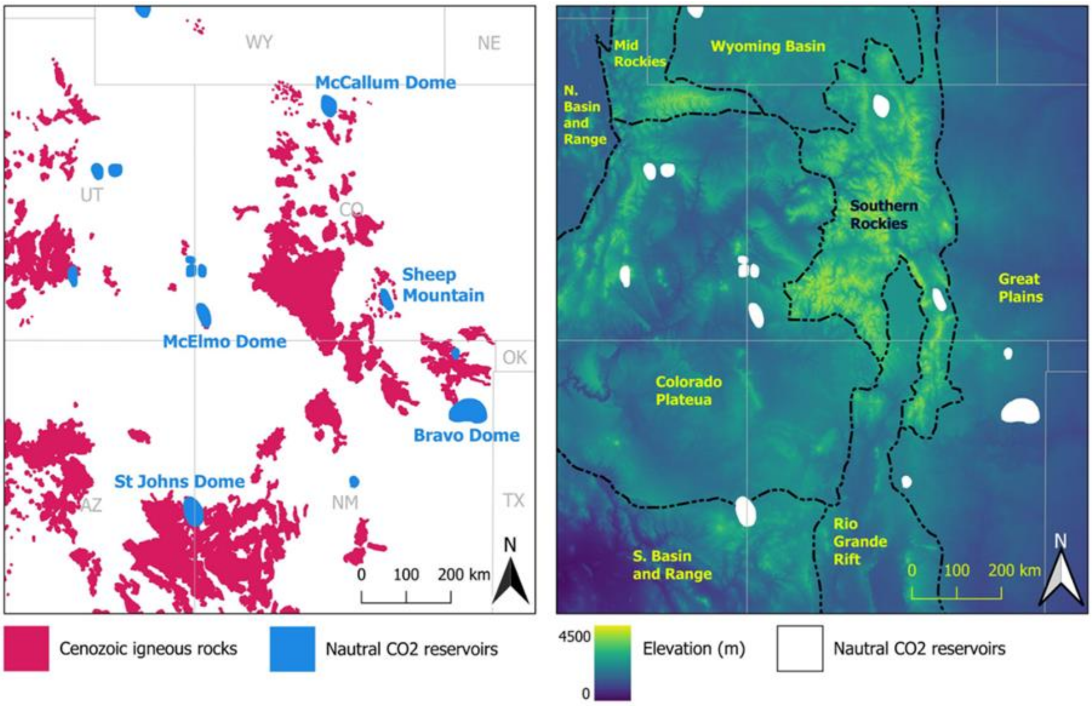

Figure 1. Map of Four Corners area USA, showing the location of significant natural CO_2 reservoirs, topographic elevation and Cenozoic-age igneous rocks. The $CO_2/^3He$ ratio of samples from Bravo Dome, St Johns Dome, McElmo Dome, Sheep Mountain and McCallum Dome show a magmatic CO_2 source.

Session Seven: Containment characterisation and monitoring – global examples II

Risk assessment and monitoring of carbon stores in the UKCS context Keynote:

Ian Barron
TBC

CO_2-injection projects in the Brazilian Pre-Salt – Storage Capacity and Geomechanical Constraints

Joao Paulo Pereiria Nunes

This presentation will describe the main geological and geomechanical aspects of the CO_2-injection projects in the Brazilian Pre-Salt reservoirs, focusing on the storage potential and geomechanical aspects of CO_2 injection. The Pre-Salt reservoirs in the Santos Basin offer favorable conditions for CCS due to their geological characteristics and existing infrastructure. The thick evaporite caprock, primarily composed of halite, acts as an efficient seal against CO_2 migration. The CO_2-injection in the Pre-Salt has been active since 2010, with significant amounts of CO_2 already stored in the reservoirs. The volumetric assessment estimates that the static storage capacity of the Pre-Salt reservoirs is over 3.3 Gt of CO_2, considering only the four fields currently undergoing injection. Geomechanical constraints, including the maximum injection pressure and caprock integrity, are crucial considerations for safe CCS operations. The high stress regime and the hydrostatic state of the caprock minimize the risk of fracturing during injection. Furthermore, dynamic storage capacity calculations indicate the feasibility of safely injecting large amounts CO_2 into Pre-Salt reservoirs. We will provide insights into the current state and future prospects of CO_2-injection projects in the Brazilian Pre-Salt, and in Brazil in general, aiming to contribute to the development of sustainable carbon mitigation strategies in the region.

Composite Confining Systems for Permanent CO_2 Sequestration

Alex Bump

To date, CO_2 storage projects have relied on high-quality geologic seals, similar to (or even the same as) those proven by petroleum accumulations. These shales and evaporites have been effective but their presence is limited--many potentially injectable reservoirs are not overlain by such seals. Moreover, the preference for such seals comes in part from the inherited experience of petroleum exploration, where the goal is finding large, concentrated volumes of mobile fluids. In that context, a high-quality seal and a sharp contact with an underlying high-quality reservoir is ideal. However, the goal of permanent sequestration is fundamentally different from that of maximizing production and it raises the question of whether there might be other ways to contain injected CO_2, perhaps even ways that might be better suited to permanent storage.

We introduce the concept of Composite Confining Systems, which we define as a thick, multi-layered sequence of barriers to upward flow, with no a priori requirements for maximum capillary entry pressure or lateral continuity of the barriers. We hypothesize that in aggregate, these systems create such a long, tortuous flow path for vertical migration that they completely attenuate the mobile fraction of injected CO_2 through residual trapping, dissolution, local capillary trapping and distributed buoyant traps that might be as small as the roughness on top of a flow unit. We investigate the concept with a combination of sandbox modelling, geologic characterization of deltaic systems from the US Gulf Coast, and numerical modelling of commercial-scale CO_2 injection. We find that barrier length and frequency are important, but that even minor reductions in capillary entry pressure are enough to divert the buoyant rise of CO_2. Study of Louisiana deltaics, shows that preserved deltaic muds are commonly several kilometers in length and sufficiently frequent in a vertical section to create an effective kv/kh ratio on the order of 0.0005. Numerical experiments show that such systems spread injected CO_2 laterally and can effectively arrest vertical migration within a few 10s of meters. The greatest risks to confining system integrity are steep dips (including conventional traps), vertically aligned holes in the barriers (e.g., Sleipner) and legacy wells.

This work opens new geography for CO_2 storage and changes the risk profile for stored CO_2—even if a pathway were to open, stored CO_2 is dispersed and effectively immobilized. Defining the retention capacity of composite confining systems and developing confidence in them will require characterizing geologic uncertainty, pushing models to failure and designing monitoring plans to guard the identified failure paths.

Session Eight: Geomechanics in risking

Integrating field, laboratory, modelling and machine learning for de-risking CO_2 fault leakage

Andreas Busch, *Florian Doster, Nathaniel Forbes Inskip, Ahmed Elsheikh, Hariharan Ramachandran, Iain de Jonge-Anderson, Uisdean Nicholson*

The success of geological carbon capture and storage projects depends on the integrity of the top seal, confining injected CO2 in the subsurface for long periods of time. Here, faults and related natural fracture networks can compromise sealing by providing an interconnected pathway for injected fluids to leak into the overburden. The prediction of fluid migration or leak rates requires a large integrated approach, spanning from reservoir/basin scale surveys to fault scale outcrop studies, laboratory tests and integrated and upscaled modelling, including machine learning. While geological models provide insights into number and geometry of seismic faults, petrophysical well log data provides initial information on properties of sealing units.

As detailed fault structures and models can usually not be obtained from CO2 storage or sealing units directly, the challenge is to study surface outcrops that are sufficiently well preserved to map fracture patters and convert to digital models for upscaled models. In addition, drill core or outcrop samples are required to obtain drill plugs for laboratory testing of stress-permeability fracture flow properties. An improved understanding of the interplay between fracture permeability, mechanical and fracture properties is required for different case studies.

All this information can then be fed into upscaled models, spanning from fracture to fracture network to reservoir scale. Such attempts have been made previously by the authors. However, significantly more case studies are required to screen the parameter space to be able to estimate the range of CO2 leakage or migration rates that can be expected for the primary caprock, or any additional sealing unit that might be part of the storage complex. This information will then inform monitoring technologies that need to be implemented for each specific CCS project. A large number of case studies (laboratory, outcrop, reservoir) integrated into upscaled models will allow the generation of significant numbers of datasets that allows application of data science to apply machine learning concepts to narrow down uncertainties.

We here introduce and discuss this concept by demonstrating specific case studies and discussing a way forward for de-risking fault leakage for CCS projects.

Screening constraints imposed by fault slip potential on the deployment of carbon capture and storage

Iman Rahimzadeh Kivi, *Silvia De Simone; Samuel Krevor*

Carbon Capture and Storage (CCS) at annual rates of several gigatonnes is central to the majority of pathways toward net-zero emissions by mid-century. However, this rapid and vast scale-up of CCS is not exempt from challenges. Wastewater disposal at comparable injection rates and volumes in the central US –not to negate fundamental differences the two technologies may have– has led to a surge in seismic activities including several felt and occasionally damaging earthquakes. If happening in the course of subsurface CO2 storage, such earthquakes may negatively affect the public perception of CCS [1] and jeopardize CO2 containment underground [2], both hindering this technology from delivering on the desired climate targets. Thus, the risk of inducing seismicity may impose constraints on CCS deployment rates in addition to reservoir injectivity issues commonly taken into account [3]. We here develop a screening tool for anticipating the risk of inducing seismicity by basin-wide CO2 injections into saline aquifers. This tool, named CO2BLOCK, employs analytical solutions of pressure changes by CO2 injection at time-varying rates into a single wellbore and the superposition principle for conservative upscaling of the calculations to multi-site injection scenarios. Assuming pore pressure diffusion as the primary mechanism of inducing seismicity, CO2BLOCK calculates the excess pressure required to cause slip along faults imported from geological maps or randomly distributed in the study area. This assumption puts fault slip estimates on the safe side under strike-slip and normal faulting stress regimes, the latter commonly encountered in offshore storage sites, as injection-induced poroelastic stresses in these settings usually contribute to increased frictional strength of the faults. Besides, we propose a probabilistic approach to deal with uncertainties in the state of stress, fault attributes and their frictional strength as the main controls on the probability of inducing seismicity. CO2BLOCK runs Monte Carlo simulations to propagate uncertainties in these parameters over numerous, equally likely realizations of the subsurface. Integration of the deterministic and probabilities modules yields the temporal evolution of fault slip probability. We benchmark the developed approach by applying it to the Oklahoma Basin where data on induced seismicity associated with wastewater disposal is available. Additionally, using CO2BLOCK in a number of offshore UK storage units, we highlight scenarios in which induced seismicity could operate as the limiting factor to CO2 storage rates. This study contributes to developing more accurate estimates of possible CCS deployment rates and available subsurface storage resources, leading to improvements in decarbonization plans.

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Fast Tool for Field-Scale Simulation of Fault Leakage during CO2 Storage

HariHaran Ramachandran, *Sebastian Geiger, Florian Doster*

Storing carbon dioxide (CO2) in geological formations is a crucial method for mitigating climate change. However, CO2 leakage during injection and storage poses a threat, with faults representing a significant concern. Accurately simulating fault properties at different scales is crucial to predict the consequences of CO2 injection and storage at the field-scale. However, this task can be challenging, particularly in the early stages of a storage project since 1) knowledge of the storage reservoir is limited, 2) Obtaining high-quality well logs, cores, and seismic data is expensive, and 3) Resolving the impact of fine-scale fault features on field-scale storage assessment is computationally expensive.

This study proposes a fast tool for CO2 leakage risk assessment that addresses these challenges at both the concept selection stage and advanced stages of project planning. The tool uses a vertically integrated reservoir model coupled with an upscaled fault leakage function based on source/sink relations. The fault is conceptualized as an increased vertical permeability through the caprock (due to the fracture network in the fault damage zone) and a reduced horizontal permeability (due to fault throw and fault core). A steady-state flow approximation is used to estimate CO2 leakage through the fault. Certain fault properties are geomechanically constrained to reflect impact of pressure changes within the reservoir-caprock system.

Example simulations are shown to illustrate 1) impact of fault leakage on storage capacity, 2) impact of geomechanically constrained fault parameters such as capillary entry pressure and permeability on fault leakage. The fast model presented in this study is a valuable tool for identifying uncertainties in key fault parameters, reservoir architecture, and other constitutive relations that affect the behavior of the storage reservoir and potential fault leakage outcomes. By incorporating this tool into the concept selection stage, stakeholders can quickly assess the risk of CO2 leakage and evaluate the feasibility of the storage site under wide range of injection conditions. Overall, the proposed tool provides a cost-effective and efficient method for screening fault leakage risk during CO2 injection and storage, helping to ensure safe and effective carbon storage.

Small-strains and gentle uplift of the seabed: Modelling the regional geomechanical response to industrial-scale injection of carbon dioxide in the Bunter Sandstone

John Williams, *Gareth Williams*

Several UK carbon storage licences target the Bunter Sandstone Formation (BNS) in large anticlinal traps located in the Silverpit Basin (SB) area of the Southern North Sea. Whilst some of these traps are gas charged, current carbon storage projects are predominantly targeting saline aquifer structures. The SB is bounded by a series of major faults and salt walls, and no extensive internal pressure barriers are currently known. It is therefore considered as a large hydraulically connected region isolated from surrounding aquifers, as supported by downhole pressure data. Bentham et al. (2017) used pressure depletion and recovery data from the Esmond gas field to infer good aquifer connectivity in the region.

Several previous studies have investigated the potential pressure response to injection in the SB area, suggesting that large-scale injection of carbon dioxide would result in elevated pressure across the region (Noy et al., 2012; Agada et al., 2017). These studies invoke the role of a seabed subcrop of the BNS in allowing pressure relief through the displacement of brine to the water column (the carbon dioxide itself is contained within the intended structural traps). The subcrop occurs above a high-relief salt dome where the BNS has been uplifted to the surface. While uncertainty exists related to the connectivity between the subcrop and the proposed injection sites, no significant barriers to flow have been identified.

Previous studies have evaluated the geomechanical response of individual BNS structures for specific CO2 storage development proposals (James et al. 2016; National Grid 2016; BP, 2021). These site specific models are generally concerned with whether the planned injection profile can be achieved without locally damaging the top seal. In an extensive hydraulically connected saline aquifer formation there are further considerations:

- Far-field stress changes;
- Induced seismicity, either locally at the injection site, or further afield;
- Reservoir dilation leading to excessive surface deformation;
- Interaction between multiple storage sites;
- Regional monitoring considerations.

A regional geological model over the full extent of the SB area is used as the basis for a coupled flow and geomechanical modelling study to evaluate the impact of industrial-scale CO2 injection. The modelled scenario is taken from the Northern Endurance Partnership path to 10 Mt per annum (Phase 2) scenario (BP, 2022), which comprises injection into four different structural closures. No pressure relief wells are considered in this scenario. The modelling indicates that increasing reservoir pressure will generate only minor uplift and some minor elastic strain with no shear or tensile failure of the reservoir, top seal or overburden. Even under a conservative case with failure envelopes representative of optimally-oriented, cohesionless materials, no failure is observed in either the BNS or its top seals. A sensitivity run was also modelled which considered a reduction in reservoir permeability. Despite higher pressure increases at the injection sites, pressure increase is mitigated through reduction of injection volumes to maintain pressure limits at the wells. Under current modelling assumptions therefore, the multi-store injection scenario is feasible without inducing significant strain or failure in the BSF or its top seal formations.

Alleviation of pressure via the seabed subcrop, along with control of injection well pressures are important factors that restrict unmitigated pressure increases in the model. Dilation of the Bunter Sandstone results in only modest uplift of the seabed (around 10 cm), concentrated at the injection sites where pressure increases are greatest. Regionally, a small amount of uplift occurs over a wide area, and is elevated above the Bunter closures. This may be because there is less overburden over the structural crests within which to accommodate the uplift via contractional strain.

Aspects of Mechanical Containment in CCS Projects

Trevor Rath

The Storage Resource Management System (SRMS) of SPE et al (2017) provides a consistent classification system that enhances comparisons between projects, groups of projects, and storage efficiency. Consistent classification is critical for CCS projects to be able to raise finance. SRMS requires estimates of a range storage volumes that includes interpretation of the subsurface which has inherent uncertainty. SRMS is clear that inherent in the evaluation of storage resources is the evaluation of containment of the stored CO2.

The 2022 Guidelines for Applications of the CO2 Storage Resources Management System discusses two forms of containment; Geological Containment and Wellbore Containment.

- Geological containment: is the ability of the geological structure to constrain the injected CO2 (in whatever phase) at the temperature and pressures planned.

- Wellbore containment is the ability of any wells in the area of the proposed store that penetrate the caprock(s) which providing geologic containment. All wellbores, regardless of status (e.g., active and producing or injecting or inactive, plugged, abandoned, and remediated) must be assessed. This includes evaluating the strength of the formation, cement placement in any annuli and cement placement within the wellbore itself.

Both the impact and probability of containment failure, whether geological or wellbore, have to be evaluated and incorporated into ongoing investment decisions at each project maturity classification, based on data available at the time of the assessment.

The purpose of this paper is to discuss aspects of wellbore containment with specific reference to UK guidance.

In November 2022, Offshore Energies UK (OEUK) published the Guidelines for Well Decommissioning for CO2 Storage. The objective is 'to provide guidelines for retaining the integrity of a future geological CO2 storage site or complex when a well penetrating such formation is decommissioned or sidetracked'.

The Well Decommissioning guidelines have been developed in response to an action set by BEIS to the UK offshore oil and gas industry, as noted in the "Re-use of oil and gas assets for carbon capture usage and storage projects" consultation response 2020 document . The guidelines provide industry recommendations and emerging good practice for well decommissioning for CO2 storage based on recent North Sea and international experience in CO2 storage.

These guidelines are intended to supplement the 'OEUK Well Decommissioning Guideline Issue 7' and have been prepared to support well operators on the considerations that are needed for decommissioning a well to retain the integrity of a future CO2 store. Furthermore, this guidelines will also support future CO2 storage operators on the considerations that are needed to assess the integrity of inherited legacy wells. The underlying principle on which the Well Decommissioning Guidelines are based is restoration of the caprock and / or intra-zonal isolation and that zones which are capable of flow must be isolated from surface.

The fundamental difference for decommissioning for future CO_2 storage, is that zones that are currently not capable of flowing to surface may be able to in future if charged with CO_2, or if subject to pressure indirectly from a CO_2 store. The latter example is particularly true for saline aquifer CO_2 stores.

This may require additional barriers to be put in place above a permeable barrier for future use of a reservoir or geological zone for CO_2 storage.

Examples of how these guidelines have been applied will be discussed.

Session Nine: Rock Physics in CCS

Efficient Storage Complex Characterisation and 4D Monitoring Feasibility using Rock Physics

Eleanor Oldham

Rock physics has its origins in the 1980s with the evolution of seismic processing flows able to retain true, geologically meaningful amplitudes. Since that time, rock physics has been used to de-risk amplitude driven hydrocarbon prospects around the world. Rock physics workflows are now being brought to the CCS domain to maximise the information that can be learned from seismic imaging. They are used to improve the characterisation of storage complexes and 4D seismic monitoring solutions. These workflows will be demonstrated through this presentation using real data from global CCS sites.

Rock physics templates can be used to characterise both reservoirs and top seal units. Fitting a rock physics model to log data can provide information regarding pore shapes, the degree of cementation and the distribution of intra-reservoir shale. Understanding these properties can, in turn, provide useful insights for planning a CO2 storage project, such as the effectiveness of the storage unit, permeability (and any preferential flow pathways), and the expected behaviour of the storage complex when subjected to pressure changes from CO2 injection. Care should always be taken to make sure that the model being fitted to the data is appropriate for the geological scenario. Different models may fit the same data but can have very different implications.

Movement of injected CO2 within the subsurface must be monitored in order to demonstrate that containment is successful and that the plume is behaving as predicted by the reservoir model (conformance). Injecting CO2 into a clean, porous, brine bearing reservoir will affect both the mix of fluids present, and the pressure in the storage unit. The consequent changes to the elastic properties (and hence seismic amplitudes) can be calibrated and predicted using rock physics modelling. The magnitude of any amplitude changes induced by CO2 injection should be evaluated at the start of a CCS project to ensure that 4D seismic is a viable option for monitoring. If the geology is favourable, saturation and pressure changes can be estimated by examining amplitude and AVO changes on time-lapse seismic. In this scenario, rock physics techniques can help define the monitoring strategy in terms of the time periods between 4D monitor surveys, seismic acquisition specifications and whether geophysical techniques (such as inversion) should be employed.

Unfortunately, rock properties in some areas are simply not conducive to highlighting changes in fluid fill through seismic imaging. It is therefore essential that rock physics feasibility modelling is carried out to avoid the acquisition of costly 4D seismic where it is unable to add value. Indeed, if seismic amplitudes are not sensitive to the changes induced by CO2 injection, then a potential storage site may have to be screened out because the commercial and operational risks cannot be mitigated with sufficient confidence.

Companies strive to carry out CCS screening and monitoring studies as effectively and efficiently as possible. To that end, rock physics analysis provides a means of extracting the maximum value out of seismic (and log) data which are already in the project database. Rock physics templates can help characterise the geological properties of the storage complex, whilst forward modelling can be used to assess whether CO2 injection is likely to generate a discernible 4D seismic amplitude response. If 4D feasibility modelling reveals that a storage complex is unlikely to produce a visible seismic anomaly upon the injection of CO2, this could be grounds for screening out a CCS opportunity.

Examples of Gassmann fluid substitution of non-hydrocarbon fluids from the UKCS

Hector Barnett, *Mark T Ireland , Cees van der Land*

The ability to safely store non-hydrocarbon fluids in the subsurface, such as carbon dioxide or hydrogen, will require reliable monitoring mechanisms. Timelapse seismic monitoring, using baseline and monitoring surveys is one method that has been shown to be effective for monitoring carbon dioxide in some geological settings. Here we investigate calculated changes in seismic response considering different reservoir properties for both carbon dioxide and hydrogen under different saturation conditions.

The bulk elastic properties of different reservoir rocks are influenced by the fluids present within the pore space and dry rock frame, hence different pore fluids modify the geophysical response of the rock. Using Gassmann fluid substitution modelling we determine the elastic properties of a reservoir substituting the saline water for non-hydrocarbon fluids under different conditions. We investigate the seismic response for three reservoirs intervals from the UK Continental Shelf (UKCS), the Triassic Bunter Sandstone, the Permian Rotliegend Sandstone and the Triassic Ormskirk Sandstone. In each scenario the water saturation is varied between 1 to 0. Subsequently we use the Gassmann fluid substitution for modelling reservoir interfaces (both seal-reservoir and reservoir-reservoir interfaces) and determine the effect of amplitude vs offset and 4D time-shift analysis.

The models demonstrate that there is an acoustic impedance change for all reservoir intervals for brine to both CO_2 and H_2 fluid substitutions, all responses show an initial large drop at in acoustic impedance (90 – 80 % water saturation) followed by a levelling out, with typically less than a 10% change at 0% water saturation (Bunter 6%, Rotliegend 10 %, and Ormskirk 8%). As porosity increases within these reservoirs as does the effect of the fluid substitution, with higher porosities having larger changes in acoustic impendence. When considering amplitude versus offset, there is little change in any reservoir – reservoir amplitudes within typical seismic offsets, with notable changes only occurring at 50+ degrees. However, for some seal – reservoir interfaces there are notable changes in amplitude when considering the calculated near stack and far/ultra far stack responses with amplitude changes of 0.15 occurring, this is especially evident for higher porosity examples. However, time shift analysis shows that even relatively small reservoir intervals substituted with CO_2 (< 50m), will cause millisecond time shifts to occur on seismic data. This suggests that time shift analysis is possibly the most useful of geophysical monitoring technique for CCS.

Evaluation of signals from monitoring CO2 injection in the North Sea using 4D seismic

Colin MacBeth, *Shi Yuan Toh, Barbara Kopydlowska, Farshad Jafarizadeh*

Carbon capture and storage technology (CCS) is considered a crucial strategy for meeting the UK's CO2 emissions reduction target. Deep saline aquifers and abandoned gas reservoirs are amongst the viable geologic storage options, with the former having the largest storage capacity (60Gt versus 5 Gt). Sound measurement, monitoring, and verification (MMV) plans for CO2 injection are fundamental to successful storage operations. An efficient surveillance and monitoring system must be capable of detecting the spatial movement and distribution of the fluids over operational time and post closure. This task is fulfilled by 4D seismic monitoring which has been a principal monitoring tool for subsurface production in the North Sea for over 30 years (for example, see the FORCE 4D workshop: 30 years of 4D seismic on the Norwegian Continental Shelf, Stavanger 2018), and will continue to remain so. With a proven track record this is most likely to remain as a primary means of areal surveillance for North Sea CCS operations. However, re-purposing of O&G 4D quantitative techniques for cost-effective monitoring requires careful evaluation of the expected characteristics of the 4D signals. In this work we describe and analyse several key signals for saline aquifers and depleted gas reservoirs. We conclude with a discussion on the 4D signals that are most likely to be detected, and how this might be achieved in a cost-effective manner.

Session Ten: Monitoring approaches

Leveraging Surface Distributed Acoustic Sensing for cost-effective CCS monitoring

James Butt, *Mike Branston, Ran Bachrach, Mathieu Chapelle, Sarah Harrington, Rob Campbell, Pilar di Martino, David Halliday*

A step change reduction in the cost of CO2 storage monitoring is a common goal across the geophysical industry. One potential method to address the cost is to adopt an adaptive monitoring strategy, tailoring the monitoring effort based on quantitative analysis, and considering alternative seismic data acquisition technologies. In recent years we have demonstrated through field trials, analysis, and processing, the viability of horizontally deployed fibre optic cable at the surface to record seismic data, which we refer to as surface distributed acoustic sensing (S-DAS) (Ramani et al., 2023).

One route to achieving efficiencies in monitoring is through the incorporation of dynamic modelling, survey design, history matching and automation to facilitate verification and update of the subsurface model. To achieve these efficiencies, it's crucial to reassess the design of the monitoring survey and the necessary data to form a valid interpretation. This includes defining new monitoring objectives, transitioning from a focus on 4D imaging to a 4D detection objective. In this way we can create a truly adaptive monitoring scheme: one that adapts the acquisition effort using sparse or dense data acquisition to monitor the subsurface, according to the subsurface models' predictions but can also be used to update the subsurface model to match the recorded data while remaining cost-effective through deploying a low-cost seismic sensor (i.e. S-DAS).

S-DAS has the advantage of superior dense spatial coverage (along the fibre optic cable) compared to conventional sensor deployments, and having no moving parts, it makes a robust sensor for long term monitoring. In collaboration with the Net Zero Technology Centre, we have investigated and tested monitoring techniques that utilize the advantages of S-DAS through a 3D synthetic dynamic earth model analogous to a Southern North Sea carbon storage site (Bachrach et al., 2023). Utilizing this model in conjunction with a rock physics modelling workflow, including third order elasticity to consider both the change in saturation and stress sensitivity of the rock elastic properties, enables us to test and understand the opportunities an S-DAS monitoring strategy can bring.

Chapelle et al., 2024, note how a series of fibre optic cables deployed on the surface (S-DAS) combined with a strategy to dramatically reduce the number of shot locations required to monitor the expansion of a CO2 plume can be implemented through a time-lapse analysis of refraction time shifts. The experiment indicates that it was possible to detect the edge of the CO2 plume with a minimum source effort (a minimum requirement of two seismic active shots located at opposite ends of an S-DAS cable traversing the injection area) and demonstrates how it can be extended in 3D with a spoke layout designed specifically for CCS monitoring (Bachrach et al. 2023).

In conclusion, S-DAS has significant potential as a seismic sensor for a CO2 storage setting. Building upon the results of recent field trials, processing projects and forward modelling studies we have demonstrated a viable means to monitor CO2 migration using 4D seismic. By re-evaluating the objectives of 4D interpretation and focusing on the need to address conformance to a predictive subsurface model, we are able to deploy an adaptive monitoring solution that provides a step change reduction in the acquisition costs typically associated with time-lapse surface seismic. Work is ongoing to extend this to address the use of this strategy to additionally meet some of the containment objectives within the CO2 MMV plan.

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Onshore passive seismic monitoring for CO2 storage projects using array methods

Joseph Asplett, *Tom Kettlety, Thomas Hudson, J Michael Kendall*

To effectively design and operate the many CO2 storage projects that are being developed in the offshore UK, seismicity rates need to be accurately characterised. Measuring seismicity can provide insights into the stress state in the region, fault density and faulting style, as well as fracturing in the overburden. Each of these can aid in the assessment of leakage risk, identifying leakage pathways and providing an input into geomechanical and reservoir models. Understanding background seismicity rates is also key to discriminating, determining the risk of, and mitigation against induced seismicity that could result from injection. This is vital to ensure the projects maintains a social licence to operate. To significantly improve the detection of smaller events in the Southern North Sea region, we have deployed a dense array of three-component broadband sensors on the North York Moors. Using this data and beamforming methods, we have more accurately characterised earthquake rates in the Southern North Sea, informing the development of CO2 storage operations in the region. Telemetry systems have also been deployed, showing that onshore dense arrays could act as a cost effective, real time, continuous monitoring method of the reservoir response to CO2 injection.

High-resolution seismic for characterising seal geometry and leakage risk for carbon storage: A central North Sea case study

Deepak Rathee

Joseph Sutcliffe & Andreas Laake

Introduction

The UK North Sea is emerging as a key player in regional efforts to tackle climate change, with significant interest and investment growing in carbon capture and storage (CCS) opportunities. This increasing focus on CCS is reflected in the launch of the first UK carbon-storage (CS) licensing round in 2022, followed by the award of 20 licenses in 2023. These licenses target both saline aquifers and depleted oil and gas fields, with the ambitious government goal of sequestering 20 to 30 million tonnes of CO2 per year (Mtpa) by 2030.

To unlock the full potential of CCS in the UK North Sea, particularly in the central North Sea (CNS) which holds an estimated 40% of the total 78 Gt storage capacity (Bentham et al., 2014), robust geological data is crucial. In support of the licensing round and ongoing carbon storage assessments within the CNS, we have undertaken a focused seismic reprocessing and imaging project. This project delivers a high-quality seismic volume specifically designed to facilitate reservoir screening in the region.

Building upon the initial reservoir screening work completed using a fast-track intermediate volume (Barlass et al. 2022), our comprehensive seismic reprocessing project provides an even more robust foundation for CCS development in the central North Sea. With the newly reimaged volume, reprocessed using full-waveform inversion (FWI), we could better delineate the seal geometries and overburden features as well as the target reservoir interval itself. This study aims to demonstrate the vital importance of high-resolution seismic data in resolving complex seal and overburden geological features that are important to characterise in detail prior to consideration of seal-integrity analysis, 3D modelling and long-term measurement, monitoring, and verification (MMV) planning.

High-resolution seismic reprocessing and imaging for carbon storage

The aim of the high-resolution, broadband seismic reprocessing and depth imaging project was to improve the resolution for reservoir targets for CS and their associated seal and overburden elements. Additionally, the workflow was designed to improve signal-to-noise ratio, reduce multiple contamination, and preserve amplitudes across a single 3D seamlessly merged seismic cube from multiple input surveys. The depth imaging work included FWI (Jiao et al. 2015), common image point tomography (Woodward et al. 2008), and Kirchhoff pre-stack depth migration to reduce the geological uncertainty and provide increased confidence in regional mapping.

By incorporating FWI in the model building workflow, we significantly improved the overall reliability of the depth image. This technique corrected distortions caused by shallow velocity anomalies of glacial origin whilst also enhancing the interpretability of the shallow section itself, providing valuable insights into variations in lithology. Following the depth imaging work, a significant improvement was observed in the continuity, clarity and definition of seismic events. Additionally, fault locations became sharper and more precise. This significantly improved image provided a much clearer picture of the Paleocene Top Mey reservoir, the primary target for CS. Furthermore, the overlying seal formations, the Sele and Balder tuff shales, were also imaged with enhanced detail. Resolving the shallow velocity anomalies also allowed us to identify potential gas leakage pathways associated with features like gas chimneys and injectites, which are common in this region of the central North Sea.

Seal and overburden characterisation with well-based lithology correlation

Paleocene basin floor deposits (buried >800 m) are ideal CNS CS targets due to their widespread, high-quality reservoirs (heterolithic turbidites, Collins et. al. 2015) and suitability for supercritical storage. The focus lies on the Mey sandstone's channel reservoirs with internal seals and the overlying Sele shale formation. While the Balder tuff (secondary seal) is easily characterised as it blankets the region, the internal and primary seals are crucial for CO2 containment. Seismic analysis using a high-resolution structurally sharpened Red-Green-Blue (RGB) volume (Laake 2015,) (2.5 m vertical resolution) revealed these seals to be heterogeneous and deposited episodically, with the primary seal infilling pre-existing submarine-channels.

This detailed analysis identified three major NW-SE trending submarine channel systems transporting sediment of varying quantities. Additionally, the RGB volume helped pinpoint shallow drilling hazards such as glacial deposits and gas pockets and track potential gas migration pathways from the Balder seal through the overburden.

Calibrating the RGB volume with well data allowed us to map the spatial distribution of shale-rich lithologies within the internal and external seals. This detailed understanding of seal geometries, thicknesses, and reservoir compartmentalisation enabled the creation of common risk segment (CRS) maps that quantified the success potential of targeted CS sites.

Understanding the heterogeneity in both, reservoirs, and seals, is critical for storage success. Internal seals impact storage capacity, while seal thickness and extent affect pressure estimations. Therefore, detailed characterisation of reservoir and seal heterogeneity is crucial before geomechanics, 3D modelling and MMV programs.

Conclusion

Using high-resolution broadband seismic images provides vital uplift to reservoir, seal and overburden geology which aids in carbon-storage characterisation and risk assessment, allowing the development of more advanced interpretation techniques. Introducing depositional environment mapping from 3D seismic images is an effective approach to understanding the geometry, lithology and distribution of reservoir and seals. Additionally, gas migration structures can be effectively characterised from top seal through to shallow overburden providing a detailed understanding of breached reservoirs when quantifying overall carbon-storage risk. This characterisation study provides a more realistic assessment of the interaction between reservoir and seal intervals for carbon storage, and therefore a more accurate estimation of volumetric capacity and quantitative seal-integrity calculations.

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Application of muon tomography for detection and monitoring of geostored carbon dioxide

Keynote :

Jon Gluyas

TBC

Session Eleven: Baselines and Monitoring

Labarge CCS Project, Wyoming, USA: An Example of Containment Monitoring Using Non-Seismic Methods

KEYNOTE: Patricia Montoya

Patricia Montoya

This paper reviews how two decades of successful operations, monitoring and dedicated surveillance activities using non-seismic methods, have helped ExxonMobil establish a safe and profitable CO2 injection site at the LaBarge gas field.

FIELD BACKGROUND

The LaBarge gas field in Wyoming has nearly two decades of CO2 injection history in the Madison Formation saline aquifer. In 1986, ExxonMobil started producing acid gas (CO2) and sour gas (H2S) in addition to hydrocarbons (CH4) and helium (He) from the Pennsylvanian-age carbonates of the Madison Formation gas cap. Since 2005, two Madison acid gas injection (AGI) wells, located ~43 miles south of the producing field, have been successfully injecting CO2 and H2S at depths greater than 17,100 ft (5,200 m). Both disposal wells have demonstrated suitable injectivity and large storage capacity in the Madison saline aquifer.

In 2023, injectivity tests were performed in a new CO2 disposal well in the Madison reservoir and in a secondary Ordovician-age Bighorn Formation. Successful injectivity results helped justify LaBarge Phase 1 project expansion plans (Figure 1).

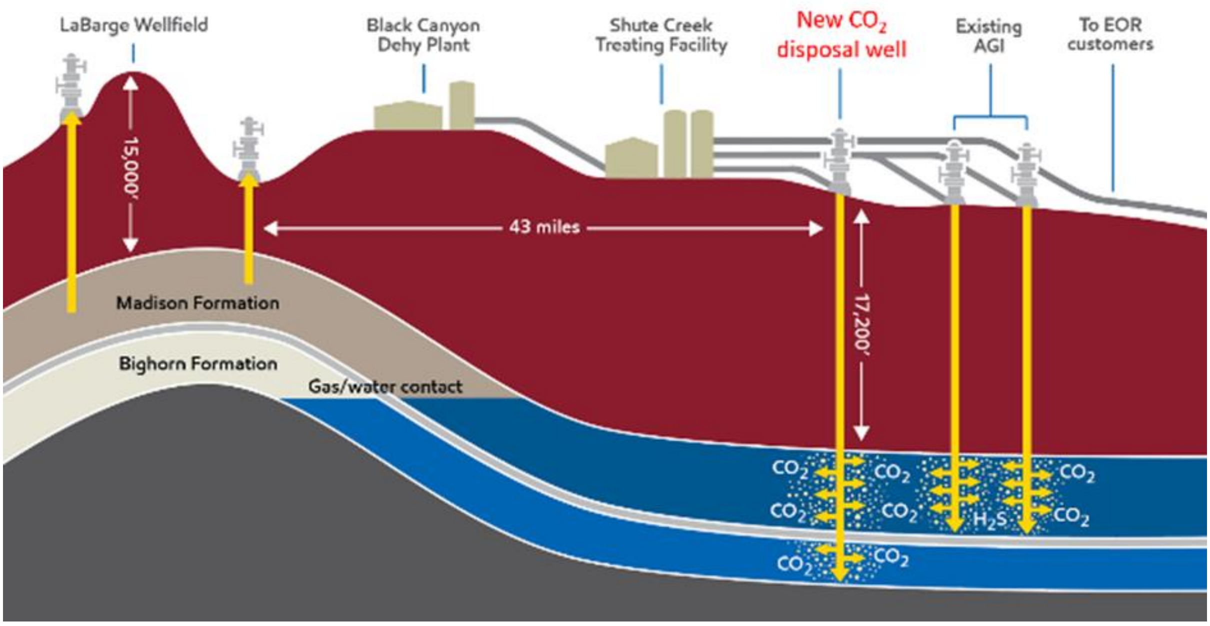

Figure 1: Schematic illustration of existing LaBarge producing well field (left), existing AGI disposal wells and carbon capture site with a new CO2 disposal well (right). Diagram not to scale.

The LaBarge field geologic formations in the saline aquifer are, from base to top: The Bighorn (disposal reservoir), the Darby (intra-seal), the Madison (disposal reservoir) and the Amsden (primary seal). Based on sub-regional well log correlations and core observations, the Madison is ~750 ft (230 m) thick and comprises alternating intervals of limestone and dolomite, divided into 6 flow units. Intermediate Madison flow unit M4 (~20 m thick) represents the highest permeable zone and takes more than 70% of all injected gas. Madison reservoir has an average 9-12% porosity, and 10-30 md average permeability.

Regionally, the Amsden Formation is ~300 ft-500 ft (90 m-150 m) thick and serves as the primary seal unit to the Madison Formation. Overlying evaporitic sequences within the ~1000-ft (300-m) thick Thaynes Formation provide an ultimate top seal.

Well log correlations indicate that the Bighorn Formation is a ~400-ft (120-m) thick interval of massive dolostone with thin beds of anhydrite. Bighorn total porosities range between 2-19% and permeabilities range between 0.1 - 230 md based on limited regional well log data.

The Devonian Darby is ~490 ft (150 m) thick in this area and is composed of carbonate, anhydrite, siltstone and shales. The shales and anhydrite layers of the Darby represent the sealing intervals between the Madison and the Bighorn Formation. Data from AGI 3-14 indicated excellent sealing properties of the Darby, with an average porosity of <1%.

Results from the 2023 new CO2 disposal well injectivity test identified two high porosity and permeability flow units with kh ~1000 to1570 average millidarcy-feet in the Madison M4 and M5/6-A intervals and two additional Bighorn flow units with kh ~230 to 410 average millidarcy-feet suitable for CO2 gas injection.

MONITORING METHODS

LaBarge deploys a robust surveillance operation including continuous collection of flow rates, pressure, temperature, and gas composition data in the Shute Creek Treating Facility (SCTF). Qualified technicians continuously monitor these data with a distributed control system (DCS). The technicians follow response and reporting protocols if/when the system delivers alerts that the data is outside acceptable limits.

Additionally, SCTF maintains in-field gas detectors to detect H2S and CO2 gas concentrations in the vicinity. An alarm by one of the gas detectors triggers an immediate response to address the situation as part of an emergency response plan.

LaBarge relies on a continuous DCS surveillance system to manage containment risks as well. The leakage detection protocol incorporates visual inspection of the surface facilities, wellhead and injection wells. Additionally, a Mechanical Integrity Testing (MIT) is performed annually in the CO2 disposal wells (Table 1).

A team of experts assessed that the risk of vertical leakage via fault pathway is highly unlikely since seismic or logs near the injector wells did not identify any faults.

Leakage Pathway	Detection Monitoring Program	Monitoring Location	Monitoring Frequency
Surface Equipment	DCS Surveillance	From injection flow meter to injection wellhead	Continuous avg/max daily rate/volume, avg/ max injection pressure, fluid composition monitoring
	Visual Inspections	At Shute Creek Treatment Facility	Daily inspections
	Inline Inspections	At surface	On an annual basis. Inline inspections are conducted through the use of a smart pig to identify potential areas of corrosion in the pipeline
	Gas Alarms H_2S gas detectors alarms at 10 ppm CO_2 gas detectors alarms at 0.5% CO_2	SCTF and well site	Continuous gas detection monitoring
	Personal H_2S Monitors		Continuous gas detection monitoring
Wells	DCS Surveillance Visual Inspections	Injection well – from wellhead to injection formation	Continuous P,T gauge equipment and periodic shut-in, transient analysis, ILT's every 2-5 years Weekly inspections at well sites
	MIT		Annually
	Gas Alarms		Continuous gas detection monitoring
	Personal H_2S Monitors		
Faults and Fractures, Formation Seal, Lateral Migration	N/A – Leakage pathway is highly improbable No faults have been identified in the saline aquifer	N/A	

Table 1: Summary monitoring and surveillance data at Shute Creek and AGI wells

ExxonMobil conducted a 4D seismic feasibility study to investigate if a Gassmann fluid substitution could detect a CO2 gas plume in the Madison formation. The study determined that the response for the M4 fluid unit is significantly below peak tuning since the dominant seismic frequency is 25 Hz at 200 m wavelength at Madison top depths (~5 km). As a result, the ability to detect gas saturation changes with 4D seismic is extremely limited.

In the absence of 4D seismic, the LaBarge subsurface team relies on a calibrated dynamic model to indirectly track movement of the gas-saturated plume over time. This dynamic model is periodically history matched as CO2 injection data and Injectivity Logging Test (ILT) results from the two AGI wells become available. Both static and dynamic models at LaBarge are currently being updated with new data from the 2023 CO2 disposal well.

In 2018, ExxonMobil conducted an analysis of the ground deformation over the CO2/H2S gas plume during 2014 to 2018 using Synthetics Aperture Radar (SAR) data. This study found insignificantly small variations in ground motion on the order of +/- 0.01 m deformation. The analysis concluded that this movement is consistent with natural variations in the vegetation and/or the absorption of water by soil top layers. This study confirmed there is no evidence for ground movement due to injection of gas in the Madison formation. In 2022, ExxonMobil built a 3D geomechanical model to evaluate heave deformation with two additional disposal wells, which resulted in a small heave deformation (~0.03 m) expected after 80 years of injection.

Lastly, ExxonMobil relies on an established seismicity monitoring network operated by the University of Utah. The southwestern Wyoming seismicity coverage includes five seismometer stations near the SCTF. This network detected no significant seismic events within the last 20 years near ExxonMobil's injection site.

Seabed monitoring of storage complexes – leveraging baselines and regulations

Robert Hines

In this presentation we will examine how to best approach seabed monitoring of carbon dioxide storage complexes. There are challenging elements in this of operators having to demonstrate containment and best practice when leak characteristics may not be indicative of an actual leak.

We will look at how operators can use the knowledge established in baseline site characterisation and the available monitoring techniques to ensure containment in a way that meets the regulatory regime and remains cost effective. Each storage complex will have its own characteristics that will mean a tailored monitoring approach to the individual risk profile. This talk will also assist operators with asking the key questions to service providers as to why their solution is fit for their store.

Building on this we will examine the progress made in the Transport and Storage business models by DESNZ and what fugitive emissions means on both a commercial and operational level.

Robert Hines has over a decade of experience in developing offshore monitoring systems. He was the lead on the Energy Technologies Institute CCS Measuring, Monitoring and Verification programme. Recently he co-authored the IOGP’s guidance on recommended practices for measurement, monitoring, and verification plans associated with geologic storage of carbon dioxide.

Environmental baselines in geological CO_2 storage monitoring- what are they really good for?

Katherine Romanak

Baseline CO_2 measurements are currently used at geologic CO_2 storage (GCS) sites as a routine part of near surface monitoring programs, both in terrestrial and marine applications. However, a minimum of 1 year of background concentration measurements is required prior to CO_2 injection to document natural seasonal ranges in CO_2 apart from leakage. If CO_2 concentrations statistically exceed the background range during the lifetime of a GCS project, a storage formation release may be indicated. The drawbacks to this approach are ; 1) complex data collection of environmental parameters is required to inform whether any changes in CO_2 are from environmental variability, 2) one year of background characterization cannot account for CO_2 variability over the lifetime (tens to hundreds of years) of a storage project, 3) has a high potential of leading to false positives for leakage, and 4) background CO_2 cannot be measured across all potential leak sites within a storage project boundaries; therefore, if concerns arise in an area lacking local background measurements, no baseline data exist with which to compare monitored CO_2 concentrations.

The latter scenario was realized In January 2011 when Saskatchewan landowners, Cam and Jane Kerr, made public allegations that CO_2 had leaked from the Weyburn-Midale CO_2-EOR operation and impacted their land. An independent study commissioned by the Kerrs wrongly concluded that soil CO_2 (~ 11 vol. %) at the Kerr farm was from the Weyburn-Midale CO_2-EOR operation; however, the scientific community's review of the report raised doubts on the study's reliability. In addition, the landowners had low trust and required engagement.

A process-based soil gas method was used to engage the landowners in a transparent and trustworthy manner and to assess the origin of soil CO_2 at the Kerr farm. This method uses a geochemical approach to leakage monitoring that does not require background data but uses simple relationships among coexisting gases (CO_2, N_2, O_2, CH_4) to distinguish background from leakage signal. The method can distinguish among; 1) biologic respiration, 2) CO_2 dissolution and reaction with soil carbonate, 3) CH_4 oxidation, and 4) atmospheric mixing. It is also simple enough for laypeople to understand and participate in, and its results are immediate, needing no complex data reduction. This approach has been tested and applied in terrestrial settings and is being developed for marine and waterlogged soil settings. It is gaining traction worldwide and has been used in Canada, USA, Australia and China.

This paper will discuss how the method was used to determine that soil CO_2 at the Kerr property is biological and not the result of a release from the Weyburn-Midale CO_2-EOR operation and how this type of approach can be targeted to other environments

The importance of reproducibility in CCS storage site characterisation and monitoring

Mark Ireland, *Hector Barnett*

Reproducibility is vital to ensure that the scientific community can verify previous findings and avoid the dissemination, or misinterpretation, of results which are unreliable or ambiguous. Geological and geophysical site characterisation frequently make use of agreed methodologies, often including industry standard software, and bespoke code to process and analyse data. Monitoring of the injection, plume migration, and storage of CO2 will form a key activity in CCS projects. As the purpose of monitoring includes the detection of migration or leakage of CO2, it is vital that the results of any modelling are reproducible and reliable. This is essential not only for demonstrating safe and compliant operations, but in building trust within the scientific community, with policy makers charged with translating research findings into public policy, and the general public.

Here, we frame the importance of considering reproducibility, reliability, and replicability in subsurface assessments through describing the qualitative and quantitative findings from recent studies into the extent to which subsurface research may be considered reproducible. We use two example workflows to illustrate some of the challenges in ensuring that results are reproducible, reliable, and replicable. Specifically we examine (i) the importance of reproducible velocity models used in depth conversion to understand structural spill points and migration pathways, and (ii) the replicability of fluid substitution modelling for CO2 and subsequent geophysical responses.

There is a need for all work that underpins the characterisation and monitoring of CCS sites to adopt a framework for reporting the methods and data that improve the reproducibility, reliability and replicability of geoscience studies. Given the vital role of subsurface geoscience as part of sustainable development pathways and in achieving Net Zero there is likely to be increased scrutiny on the reproducibility of geoscience results going forward.

Fractured caprock failure criterion in the context of underground CO_2 storage

Rafael Mesquita, *Nathaniel Forbes Inskip, Florian Doster, Andreas Busch*

Carbon capture and storage (CCS) is an essential technology supporting the energy transition. The aim is to reduce greenhouse gas emissions, notably carbon dioxide (CO_2), mostly generated from industrial processes and energy production. Identifying geological formations capable of securely storing CO_2 over extended periods of time creates a significant challenge, especially considering features like faults or natural fractures into caprock that often bring complexity to storage operations.
The prevalent use of the Mohr-Coulomb failure criterion in modelling underscores the need for differentiated adjustments, particularly when analysing fractured rock formations (reservoir and sealing rock). The Mohr-Coulomb failure criterion is commonly employed when modelling geological formations containing fractures and faults, where a reduced cohesion (Co) value is used to reflect the loss, or reduction, of cohesion. Yet, the adjustment of the coefficient of internal friction (μi) in modelling is often overlooked, potentially due to insufficient laboratory data. Therefore, conducting triaxial tests is required to support the characterization of strength properties of fractured rocks, particularly those found in potential CO_2 storage reservoirs and their sealing formations. As a result, these can be defined more accurately within the Mohr-Coulomb failure envelope. Additionally, the gathered data could facilitate an assessment of whether alternative failure criteria offer improved representations of fractured rock rupture.
The objective of this work is to detail the experimental laboratory testing procedures for obtaining the requisite properties essential for developing a failure criterion envelop for fractured rock. Through this effort, the aim is to gain insights into the behaviour of fractured rock, which is pivotal for advancing the comprehension of fractured rock mechanics and delineating alternative failure criteria that are better suited to capturing rupture patterns, particularly in caprock. Hence, outcomes from proposed laboratory tests will provide crucial additional data for enabling more robust and reliable modelling approaches, essential for optimizing CCS strategies and facilitating the global transition towards a sustainable, low-carbon energy landscape

Geological modelling and fault seal analysis for optimising co2 storage in the koye field niger delta

Claire Chukwumah,

The negative impacts of CO_2 and Greenhouse Gases (GHG) have immensely affected the environment and the earth's sustainability. The Paris Agreement stipulates that emissions must be reduced to 45% by 2030 to attain the net zero goal by 2050, resulting in the decrease of global warming to 1.5°C. CCS in depleted reservoirs is an effective method of reducing these atmospheric gas emissions. This study aims to identify and characterize subsurface formation’s structural integrity and capacity potentials for CO_2 storage in the KOYE Field Niger Delta Basin. It assesses, the risk of leakage and migration of gasses stored in the reservoir as a result of a breach in the fault and cap rock of the reservoir unit. To optimally characterize the reservoirs, well logs and 3D seismic data were utilized with an emphasis on characterizing subsurface structural configuration and explaining the petrophysical parameters of the reservoirs. Five reservoirs were mapped; K_01, K_02, K_03, K_04 and K _05 with thicknesses of 18.2m, 105m, 50.64m, 23.19m and 48.4m respectively. Normal faulting was observed in the field. A total of forty (40) faults were identified; six (6) major faults and thirty four (34) intermediate faults or minor faults. The major faults act as closures or traps for the reservoirs drilled at the Koye 004ST1well. The K_02 reservoir was picked as a target for carbon storage because it had the largest area and suited the criteria depth of 800m and thickness of 10m. The results of the static model and petrophysics estimated values for the K_02 reservoir as; a porosity range of 20-24%, permeability (>100mD), shale volume >30%, and carbon dioxide storage capacity of 25.5852 x 106kgm3. Fluid flow parameters of throw juxtapositions and the Shale Gouge Ratio was (>40%). This implies the faults in this region have good sealing capacity. Consequently, the K_02 reservoir is suitable for carbon storage, has a low leakage risk and good sealing capacity because it exceeds the cutoff values of (15% -20) %. This is necessary to mitigate risks to mitigate risks of fault reactivation and potential leakage that could occur during CO_2 injection and storage projects in the field.

Key words; Petrophysics, Geological Model, Shale Gouge Ratio, Fault Seal Capacity

Mechanical stratigraphy and fault damage zone characterisation of the Lower Jurassic Redcar Mudstone Formation at Robin Hood's Bay, NE Yorkshire

Adam Szulc, *Colm Pierce, Mike Curtis, Steve Vincent, Niall Paterson, Michael Flowerdew, Mick Pointon, Balazs Toro*

The Lower Jurassic Redcar Mudstone Formation of the Cleveland Basin is directly analogous to the mudrock seals of incipient CO2 storage complexes in the North Sea (Powell, 2010). The formation is subdivided into four members based on compositional changes and is cut by a pervasive fault-related fracture network (Howarth, 2002). The mudstones outcrop along the cliffs and foreshores of NE Yorkshire and provide an opportunity for characterisation to a level of detail that cannot be achieved offshore. This study focuses on Robin Hood's Bay, where up to ~190 m of the ~330 m thick Redcar Mudstone Formation is exposed. Field and analytical work was conducted to investigate the mechanical stratigraphy and fault damage zones of the mudrock seal. Fracturing was characterized by circular scanline analysis and associated samples were subjected to TOC, MICP and SEM analyses. Context is provided by the results of a parallel study of detailed logging and mudstone characterisation throughout the succession.

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Critical Minerals from CCS Brines

William Norfolk, *Shannon Flynn, Mark Ireland*

As the UK looks to reach net zero by 2050 there is an increased focus on the subsurface as a means of achieving this goal, whether through carbon capture & storage (CCS), geothermal energy, or hydrogen storage, as evidenced by the government's "Build Back Greener" strategy (Department for Energy Security & Net Zero, 2021). Deep saline aquifers underground are ideal sites for CO2 injection due to their vast storage capacity (Celia, Bachu, & Bandilla, 2015). After injection underground the pressure of these aquifers must be managed and this may require extraction of subsurface brines that can be difficult to treat depending on the source and composition of the brine. As well as CCS technology, there is a requirement for electrification and an increase in renewable energy production in order to reach net zero by 2050 (IEA, 2021). These technologies require what are known as critical minerals, which includes elements such as lithium, cobalt, copper, nickel, and rare earth elements.

This project aims to analyse and catalogue subsurface water chemistry data currently available in the UK to understand where the geochemical conditions are best for the enrichment of critical minerals and potentially toxic elements (PTEs) in subsurface fluids at a regional scale. Geochemical analyses of over 2000 water samples from the BGS, Environment Agency, and published papers have been catalogued from both onshore (boreholes, mine drainage, wells) and offshore (drill stem tests) sample sources. Data on depth, formation, geological period, and lithology have been recorded along with chemical parameters such as temperature and pH, major and minor ion concentrations, and a wide range of metal and non-metal concentrations.

Sampling sites recorded so far have been mapped using ArcGIS (ESRI, 2023) software and show good coverage for both onshore and offshore locations. Statistical analyses using R (R Studio 4.3.2, 2023) allow for detailed comparisons between different lithologies, formations, and regions across the UK. Clusters of sampling locations at similar depths can also reveal flow directions, while outliers can provide additional information to further understand the local geologic conditions of the aquifer. It is also possible to explore correlations between elements at differing depths and lithologies, however, issues with missing data are causing a problem for PCA analysis at this time. By building a comprehensive map of geochemical data across the UK it is then possible to better understand what the geochemical conditions would be like at existing CCS sites, or at potential future CCS sites, and whether these sites would be desirable for extraction of critical minerals. Extracting critical minerals or removing PTEs from CCS brines is desirable as a way to increase the financial merit of CCS sites.

The second phase of this project will focus on measuring critical minerals and PTEs in the fluids extracted at one or more CCS clusters in the UK to determine the water chemistry and variation with varying extraction rates and changes with CO2 injection (i.e. acidification and mineral dissolution). The final phase of the project will be to determine the efficiency of low cost sorbents, such as iron oxyhydroxide minerals, at or when used in sequence removing critical minerals and/or PTEs to enhance the circular economy of subsurface projects such as CCS or enhance the treatment of waters before release or use.

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Drilling the late Plio-Pleistocene of the North Sea for climate reconstructions, with implications for the efficacy of CCS

Mads Huuse, *Georgina Heldreich, Andrew Newton, Heather Stewart, Margaret Stewart*

A cooling climate at the Plio-Pleistocene boundary led to large-scale ice sheet development across the Northern Hemisphere. The impact of this transition can be observed in the North Sea Basin, with numerous glacial-interglacial cycles having dominated the infill of the basin through glaciogenic and fluvio-deltaic processes. The antecedent structure of the basin, combined with subsidence, has led to the deposition of up to ~1.2 km of sediments in just ~2.8 Myr. This sedimentary sequence offers a detailed stratigraphic record of environmental change, providing a valuable palaeoclimate archive spanning millions of years that is important for placing contemporary climate change into the context of past change.

Despite a long history of well-documented petroleum systems at deeper depths, the sedimentary architecture, glaciogenic history, and palaeoclimate record of the region's late Plio-Pleistocene subsurface is insufficiently researched and is primed for scientific ocean research drilling. To that end, a Virtual Site Survey Investigation was carried out to pinpoint and characterise potential sites as part of a proposal to be submitted to the International Ocean Discovery Programme (IODP) that will recover high-resolution late Plio-Pleistocene climate records of the European glaciated margin. Utilising a 130,000 km2 3D reflection seismic dataset, along with industry and research borehole records, the project facilitated identification of target zones with high accumulation rates of mud-prone sediments. Drilling hazards, such as shallow gas accumulations, lithological anomalies, and geohazards were also assessed, to identify optimal drill sites while considering areas of conservation interest and known hazardous objects. This work culminated in the submission of a pre-proposal to IODP in April 2023. This was well-received and the IODP encouraged a full proposal. Subsequently, a full proposal was developed and submitted in April 2024 as the "GLACE-NS project" that will investigate Glaciers, Landscapes, Climate, and Ecosystems of the North Sea over the late Plio-Pleistocene.

While the overarching aims of the GLACE-NS project are to unravel long-term records of climate change, the late Plio-Pleistocene is a crucial succession for two applied reasons that are relevant to this conference: 1) the shallowest subsurface is used for renewables, such as windfarm siting, and 2) the entire late Plio-Pleistocene succession, for many potential CCS sites in the North Sea, comprise a large part of the overburden stratigraphy, and therefore has an impact on the efficacy of carbon storage (e.g., Lloyd et al. 2021). A successful drilling campaign will return materials that improve our understanding of not just past climate changes and how they may relate to our future, but also the reservoir seal integrity of potential storage sites. Thus, the GLACE-NS project will directly and indirectly help to identify suitable sites for CCS in the North Sea and show why they might be necessary to limit the impacts of future climate change – using the worst of the geological past to help prevent it happening in the future.

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Advantages of CO_2 storage – Water Geothermal combined system to control pressure increment and enhance storage capacity

Farnam Firouzbehi, *Carsten M. Nielsen, Sabina Bigi*

In recent years, CO_2 emission in the atmosphere has increased significantly because of burning fossil fuels as main reasons of increasing the concentration of the CO_2 - main greenhouse gas - in the atmosphere leading to 'Global warming' disaster. Tackling global warming needs both carbon removal and emission reduction technologies. Carbon Capture and Storage (CCS) is a developing technology to reduce the concentration of CO_2 in the atmosphere. In this technology CO_2 is captured and is transported to be stored in a geological reservoir which have the potential for storing large volume CO_2 safely for long terms. Clean energies can also contribute to tackling global warming. One of these technologies is water geothermal energy production (GE). In this method the water is injected to contact with the warm subsurface rocks and is produced in higher temperatures, the heat is then extracted using geothermal power plants.

CCS is associated with multiple Risks that must be considered to have a safe and successful storage. Risk of wellbore failure, CO_2 leakage, fault reactivation and seal failure are main subsurface risks that are usually the result of pressure increase due to injecting a new fluid into the formation. During injection the pressure pulse propagates much faster and wider than the CO_2 plume. Hence, controlling pressure in the storing reservoir is one of the most important objectives to reach better storge efficiency and safety in a CCS project.

The main idea of this study is to address the main risks, by combining CCS and GE with the pore space replacement method. This technique has been previously used in hydrocarbon reservoirs as a way of providing pressure support by injecting water to replace produced hydrocarbon volume. Now, this technique is used to balance the pressure in the storge site by producing water applicable in GE.

The geological setting favourable for combination of these technologies can to some degree be similar, i.e. porous, and permeable subsurface sandstone layers constituting a reservoir or aquifer and, in a depth, range from approximate 1000 - 3000m. In more shallow reservoirs the temperature will be insufficient together with the unfavourable thermodynamic state of the CO_2 phase for storage. At greater depth the reservoir rock permeability will be limited. The hydraulic capacity and the extension of the reservoirs are critical parameters for the success of this Combination. An additional demand for a CCS site is the existence of a structural closure of the reservoir combined with an overlying caprock or another type of trap configuration.

The benefits for the GE plants are predominantly in the early site characterization phase, were shared exploration and appraisal cost can reduce the investments for the individual GE development projects. Benefit for the CCS operation is both in the exploration phase and in the operation phase, where pressure propagation can be mitigated through the GE operations, and to some degree in the post injection phase where the GE wells can be used as monitoring wells.

The simulations were done based on Vedsted structure, a structural closure in the Gassume formation with an overlaying caprock, a potential geological CO_2 storage site in Denmark.

Relevant geological and geophysical data are analysed to characterise reservoir formation. Geological models and reservoir simulation models are constructed and used to investigate several scenarios of combining GE and GCS and applying a sensitivity analysis on different parameters like number of wells, location of injection wells, injection and production rates, and wettability. Eclipse 100 was used as reservoir simulator, as the focus was on pressure distribution isotherm mode (default mode) was used, Petrel was used as post processing tool and a python code developed by Equinor is used for well placement optimization.

The main objective of this study is to investigate how pressure pulse and saturation plume behave.

Containment monitoring of a Carbon Capture Storage (CCS) project using chemical tracer technology

Paul Hewitt, *Sophie Maude*

Carbon Capture Storage (CCS) is set to play a key role in global efforts to reduce greenhouse gas emissions. While the process of capturing waste carbon dioxide (CO2) and depositing it underground is relatively straightforward after a suitable geological structure has been found, the very nature of the gas being present in the atmosphere or a mature oil reservoir makes the detection of small leakages, should it escape from its targeted containment geology, difficult.

Specialist chemical tracer technology has been developed that allows the integrity of a geological storage structure to be monitored. This method not only confirms a storage seal but also identifies leak source in the event of a containment breach. It can be used to measure the presence of any escaping carbon dioxide either into observation or monitoring wells or in an uncontrolled manner into the surrounding environment, be it onshore surface air or seawater on a seabed.

This poster will detail the practical steps taken to develop, design and execute a CCS CO2 integrity tracer monitoring project with details showing how a suitable chemical tracer is selected, amounts to be used calculated, options open for CO2 tracer addition, a sampling strategy and tracer analysis methodology.

Bunter and Leman Sandstones Rock Physics Modelling and Geophysical Responses Analysis during CCS

Jing Yang, *Mads Huuse*

Geophysical methods (seismic, controlled source electromagnetic, gravity) can be used to monitor changes in elastic properties over time during containment of stored CO2 (Gasperikova and Hoversten, 2006; Lumley, 2010). The petrophysical parameters of reservoir, such as water saturation, will change with the injection of CO2. The link between petrophysical parameters and elastic characteristics can be determined by rock physics modelling. Geophysical modelling can be used to establish a connection between elastic properties and geophysical responses. Consequently, changes in CO2 saturation and the geophysical responses are correlated.

The link between elastic properties (velocity, resistivity and density) and petrophysical parameters (water saturation, porosity, and clay content) can be established by rock physics modelling (Zhang et al., 2024). The seismic wave velocities, resistivity, and density variations in various CO2 saturations can be characterised (Liu et al., 2023).

Geophysical modelling will be performed to link the geophysical responses (seismic reflections, electromagnetic response, and gravity data) with elastic properties (Mohamed et al., 2023; Um et al., 2023; Yilo et al., 2024). In order to investigate the effects of reservoir petrophysical parameters on geophysical responses, we conducted 1D geophysical modelling. With variations of CO2 saturations, the effects of changes in reservoir petrophysical parameters on seismic reflections, electromagnetic response and gravity data can be analysed.

The monitoring strategies selected for a variety of storage targets could be informed by the results of this study.

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The Röt Halite Member of the Southern North Sea – A critical top seal for carbon dioxide storage in the Bunter Sandstone Formation

Harry Morris, *John Williams, Lucy Abel*

The Bunter Sandstone Formation is under consideration as a storage reservoir for carbon dioxide in the UK Southern North Sea, where the Dowsing Formation provides the top seal. Over much of the basin, an evaporitic unit known as the Röt Halite Member is present at the base of the Dowsing Formation. The Röt Halite is separated from the Bunter Sandstone by a thin mudstone unit equivalent to the Solling Formation of the Netherlands. Previous studies have suggested that the Röt Halite will provide an effective top seal for carbon dioxide storage on the basis that it is dominated by bedded halite (Heinemann et al., 2012; Williams et al., 2014). Despite this, detailed knowledge of the lithological heterogeneities and structural variations within the unit are lacking, specifically with respect to its potential to act as an effective seal for carbon dioxide. High-resolution correlation of petrophysical logs was conducted to provide an improved understanding of the distribution of individual halite cycles across the UK Southern North Sea. Seismic reflection data were then used to elicit information on post-depositional deformation styles, in an attempt to relate Röt Halite thickness and the number of individual cycles to the presence or absence of throughgoing faults.

The Röt Halite is easily differentiated by the presence to halite, relative to the red-brown, playa-lake mudstones of the lowermost Dowsing Formation. Southworth (1987) recognised five evaporite cycles within the Röt Halite, each separated by a thin mudstone overlain by a thin bed of dolomite or anhydrite. Each halite cycle resulted from a rapid marine transgression followed by gradual marine regression, with halites generally precipitated in shallow evaporite basins. The Röt Halite is overlain by a sabkha facies comprising an interbedded sequence of anhydrites, dolomites and dolomitic mudstones, which overstep the Röt Halite towards the landward margins.

Isochore maps for each of the individual depositional cycles within the Röt Halite provide an indication of the palaeoenvironmental evolution. Top seal quality is expected to be optimal in regions where all five of the evaporite cycles are present. The margins of individual cycles are most likely to comprise of impure halites (Southworth, 1987), and may also be affected by dissolution features which could potentially have resulted in deformation and fracturing which can form seal bypass systems through salt (Cartwright et al., 2007). While the presence of halite does suggest that top seal quality will be maintained, identifying the location of such margins may be used as an indicator to help identify objectives for further appraisal and risk reduction measures.

Correlation of petrophysical logs and seismic reflection data suggest a conformable and generally uninterrupted distribution of Röt Halite across the basin. Zones of deformation and halokinesis are largely constrained to major structural discontinuities caused by post-depositional mobility of deeper evaporites of the Zechstein Group. The Röt Halite has been invaded by potassium-rick Zechstein salts in some areas, resulting in allochthonous salt overhangs adjacent to some salt walls. Pre-existing faults represent one of the key geological containment risks for carbon dioxide storage in the Bunter Sandstone (Williams et al., 2014). Small-offset extensional faulting near the resolution of seismic data occurs over the crests of many anticlinal structures of interest for carbon dioxide storage in the Bunter Sandstone. In some structures, the Röt Halite acts as a detachment layer preventing faults from extending downwards into the Bunter Sandstone. In contrast, other structures exhibit faults are throughgoing with clear offsets are observed both above and below the Röt Halite. Whilst no direct relationship is inferred, observations are presented to compare the thickness of Röt Halite and number of evaporite cycles with the degree of throughgoing faulting.

Assessment of subsurface carbon dioxide storage potential of gas shales in Sichuan Basin, China

He Yue, *Sudeshna Basugupta*

Carbon Capture and Storage (CCS) technology stands as a crucial decarbonization strategy, particularly vital for developing nations in their pursuit of achieving net-zero emissions. Central to this technology is the integral component of CO2 geological storage. In contrast to conventional research primarily concentrating on CO2 storage within saline aquifers, shale introduces an innovative prospect as a potential subterranean reservoir for CO2. This perspective is substantiated by research that illustrates the superior adsorption capability of shale for CO2 when compared to CH4 (Ansari et al., 2022). However, the effect of CO2 adsorption on shale remains unclear. In addition to pore characteristics, the influence of organic matter and constituent minerals on shale adsorption and total storage capacity needs to be further clarified. In this study, we compare the CO2 storage capacity of shales from lower Silurian Longmaxi formation located east of Sichuan Basin,to the saline aquifer of the upper Triassic Xujiahe formation and middle Triassic Leikoupo formation in Sichuan Basin. Further, we will also investigate how the pore network and morphology can be influenced by mineralogy and organic matter, to assess their impact on the total storage capacity. The Sichuan Basin, situated in southwest China, is a significant oil and gas basin characterized by multiple tectonic cycles on the Yangtze Block. Its geological evolution saw the transition from marine to continental conditions during the Indosinian movement in the Middle Triassic (Zhang et al., 2013). The Longmaxi formation was deposited during the upper Silurian period. As sea levels rose, a variety of shales including siliceous shale, carbonaceous shale, and silty shale were deposited in anoxic deep-water shelf environments (Nie et al., 2021). The Xujiahe Formation was formed in the upper Triassic shallow lake depositional environment. It is composed of interbedded mudstone, shale, and medium-grained sandstone (Lai et al., 2018). The Leikoupo formation is dominated by limited platform deposits with interbedded limestone, anhydrite, sandstone, and mudstone (Wang et al., 2023). Lei 3rd member in the central Sichuan area consists of argilliferous and gypsiferous limestone as the main lithofacies of the target reservoir.

Samples have been extracted from four cores from Pengye-1 Well and depth from 2095-2140m, belonging to the lower Silurian Longmaxi Formation, which is the primary shale gas-producing formation in southwest China. A combination of methods is being applied for this assessment of gas shales. These include geochemical analysis and adsorption experiments BET (Brunauer-Emmett-Teller) and MICP (Mercury Injection Capillary Pressure), in conjunction with detailed imaging in different scales applying CT (Computed Tomography) scanning electron microscopy,

For preliminary assessment, a comparative theoretical estimation of the storage capacity of the gas shales and saline aquifer was conducted in the central part of the Sichuan Basin, aligned to previous studies. (Singh, et al., 2021; Tao and Clarens (2013). This research optimized the shale gas and saline aquifer storage estimation by carefully defining the reservoir units and accounting for the interbeds. Based on these calculations The Xujiahe and Leikoupo formations in Sichuan can store 9.5GT and 2.5GT of CO2 respectively, with substantial contribution of the interbed shale formations not considered in previous studies. Compared with sandstone, shale reservoirs from the south (Changning area), east (Fuling area), and center (Weiyuan area) of Sichuan Basin can store 5.4GT, 3.9GT and 12.92GT respectively. This indicates that gas shales have a very high CO_2 storage potential that needs better understanding.

Assessing the sealing capacity of the Haisborough Group, Southern North Sea: insights from a continuous core succession in North Yorkshire

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Successful geological carbon storage (GCS) depends on the co-occurrence of a suitable reservoir and an effective seal. In the Southern North Sea region, the Lower Triassic Bunter Sandstone Formation and the overlying Middle to Upper Triassic Haisborough Group form such a couplet, and are a major GCS target in the UK and beyond. Nevertheless, due to a dearth of core material, the mudstones and evaporites of the Haisborough Group are grossly understudied; their lithostratigraphy is largely based on wireline logs, and their actual sealing capacity is poorly known. The SM14 core from the Anglo American Woodsmith Mine site in the Cleveland Basin north of Scarborough, North Yorkshire, UK, offers a unique opportunity to address these issues. The core preserves a complete, near 300-m-thick succession of the Haisborough Group, which serves as an immediate analogue for potential GCS storage sites offshore.

CASP has documented the entire succession via sedimentary logging and high-resolution facies analysis, and has taken a total of 455 hand-held X-ray fluorescence (XRF) measurements directly from the core. For further analysis, 64 more or less evenly spaced large core samples, which are representative of the facies heterogeneity of the Haisborough Group, were collected. Quantitative X-ray diffraction (QXRD) analysis, optical petrography and scanning electron microscope energy dispersive spectroscopy (SEM-EDS) are combined with the facies scheme and XRF data to accurately characterise the rocks. These techniques provide insights at different scales and on different components, and thus are complementary rather than interchangeable. Porosity-permeability and mercury injection capillary pressure (MICP) analyses are coupled with geomechanical analytical results from fresh core to assess the suitability of the Haisborough Group strata as a seal. To facilitate robust correlation to the offshore subsurface, all results will be integrated with palynostratigraphy from more than 130 samples and with a comprehensive suite of wireline log data. In a next step, direct comparison of the SM14 dataset to select cores and samples from offshore wells in the UK and Dutch sectors of the North Sea will be made. In parallel, sister projects of CASP investigate the underlying Bunter Sandstone Formation and its reservoir properties, but also extend the seal studies into the overlying Lower Jurassic Redcar Mudstone Formation of the Cleveland Basin.

Logging and facies analysis identified a conformal but distinct boundary between the Bunter Sandstone Formation and the overlying Haisborough Group. A preliminary lithostratigraphy for the latter unit has been developed, focusing on sediment textures and the abundances of halite, anhydrite and dolomite cement for subdivision. Throughout the succession, optical petrographic, SEM-EDS and QXRD analyses identify anhydrite, clay minerals, dolomite, quartz and feldspar as common mineral components at varying proportions. Halite is largely confined to the Röt Halite Member of the Dowsing Formation, where it forms a massive deposit, but also fills veins or occurs interspersed with siliciclastic material and anhydrite in the form of wind-blown grains. Elsewhere, compositional variation is mostly driven by the abundance of anhydrite, which occurs either finely dispersed, or concentrated in streaks, veins or nodules, often also healing fractures. QXRD analysis further records widely varying clay contents (10 to 65%), mainly illite + smectite, but also significant proportions of muscovite, chlorite and corrensite. Porosity-permeability and MICP analyses, together with a variety of rock strength tests, yield encouraging results with regard to validating the suitability of the Mercia Mudstone Group as a seal.

SAFERCCS: Sustaining fluid-flow and Assessing Feldspar solubility Enhancement Reactions in CCS reservoirs

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Feldspars are a common framework grain in CCS sandstone reservoirs. They are mechanically weak under reservoir conditions and are very likely to react with CO2 injected into saline aquifers or depleted hydrocarbon reservoirs. Reactions could dissolve feldspar and precipitate new minerals to an extent that fundamentally change reservoir properties and mineralise injected CO2. The general consensus is that these features are unlikely to impact fluid migration during the injection lifespan of any CCS project.

In this contribution, the magnitude of any “feldspar effect” is re-evaluated. Firstly, using petrography, SEM analysis and the determination of Pb isotopic compositions of detrital feldspars, sediment provenance and subsequent diagenesis are shown to be significant drivers on feldspar composition and texture prior to injection. This is important because it is understood that different feldspar types react with CO2-rich fluids at different rates, thus any feldspar effect could significantly vary within a reservoir with mixed provenance and burial history on a sub-basinal scale. Secondly, in a series of hydrostatic chemical dissolution experiments conducted at CCS reservoir pressure and reservoir temperature and higher temperatures, enhanced fracturing and dissolution of some feldspar types was observed along with some precipitation of secondary minerals, whereas other feldspar types were apparently unaffected (Figure 1).

The magnitude of the feldspar effect is illustrated using pilot studies conducted on sandy turbidite fairways comprising the Eocene Forties Sandstone and Lower Cretaceous Captain Sandstone members in the Central North Sea. The latter is the target reservoir unit for CO2 injection as part of the Acorn CCS Project.

The outcome of our re-evaluation is that the impact of feldspars in CCS reservoirs is likely overlooked, but until further experimental work is carried out to constrain how quickly feldspar interactions will impact fluid flow within the reservoir, uncertainties will remain with regard to their impact on CO2 injectivity and capacity.

Figure 1. Back-scattered electron image of experimentally altered K-feldspar.

Characterising creeping formations

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Some formations are unable to withstand shear stress and undergo viscoplastic deformation, creeping with time as they try to re-establish an isotropic state of stress. Boreholes induce shear in the surrounding rocks, stimulating their closure: this is at the root of a host of stability problems during drilling, variously referred to as pack-off, ballooning, sloughing shales.

Whereas many rocks exhibit some degree of plasticity over geological timescales, some creep fast, within hours to weeks. The most common are evaporites (with the notable exception of anhydrite) and shales, including marls, provided they have a smectite-rich matrix. The ability of other clay minerals e.g., illite, to creep is currently debated though authors such as Sone & Zoback (2014) suggest that they may be too slow to contribute to containment over the life of CCS storage projects, around 50 years.

Creep will cause the formation to deform and grip the casing or cement, exerting radial stress that keeps the interfaces shut, thereby throttling slow leaks through microannuli. This closure stress will be equal to the far field isotropic stress in halite - except for anomalous salt and boundary shear zones, as reviewed by Look (2017) - but it is meaningfully less than the minimum horizontal stress in shales. Early work (Loizzo et al., 2017; van Oort et al., 2020) posited that the minimum horizontal stress will eventually be reached at the wellbore, but observations of far-field stress anisotropy makes it unlikely. Shales' porosity means that lower effective stress plays a role in closure stress being permanently lower than in the far field, as may do the absence of pressure solution-precipitation at low deviatoric stress.

Creep and the resulting closure stress not only control debonding, the cause of persistent small leaks of up to 100 metric tons per year or so, but it can can also seal open sections of the annulus and large cement defects like mud channels (which affect wells as deviation exceeds 60 degrees). This has been demonstrated by ultrasonic cement evaluation logs and by a study of the Rot Halite, a plastic caprock overlying the Bunter Sandstone (Loizzo et al., 2024). The presence of a thin, <1 mm, drilling mud layer between crept rock and casing does not affect the quality of the barrier element since the pressurised, gelled fluid is likely to prevent bubble formation and small gas leaks (Bauer et al., 2021).

Creeping formations are thus able to prevent Major Accident Hazards by sealing large pathways, as well as to throttle small leaks through microannuli. However, they have a safe operating envelope as every other component of the well barrier system does: if we exceed the closure stress, an interface debonds and a small leak ensues; if we exceed fracture pressure, a hydraulic fracture open and containment is lost - possibly in a catastrophic manner.

Identifying creeping formations and characterising them by estimating (and validating) closure stress is thus imperative when assessing leakage risk from legacy wells and designing new, robust CO2 injectors. Indeed, pumping a cold, high-pressure fluid increases the risk of a microannulus.

Geological Engineering Models integrate stratigraphic and lithological information with a geomechanical analysis that predicts closure and fracture pressure, driving mechanical modelling at each interface.

Examples of the coupled mechanical-flow models with brine and CO2 demonstrate the role of closure stress in preventing leaks and controlling the rate, both for annular and plug cements. The latter are disadvantaged because the casing will reduce the available closure stress by around one half.

Using the integrated geological-mechanical design for new injectors can help decide on an optimum strategy for casing shoe depths and cement tops, so that leak probability is reduced, their detectability increased, and effective mitigation becomes possible.

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