CONTENTS PAGE

ORAL ABSTRACTS
(In Programme Order)

Session One: Regional Screening

Keynote - Subsurface CCS Opportunity Screening and Risking

Catherine Witt, Head of Technical, Storegga

Catherine leads the Storegga technical team with responsibility for technical integrity of carbon storage across the Acorn Project and new ventures including the Talos (US), Sval (Norway) projects. Catherine's background is as a Reservoir/Petroleum Engineer working in the UK, Norway and Africa with BP; prior to joining Storegga in March 2021, she was BP's Upstream Segment Reserves Authority and global subsurface assurance lead for carbon storage projects. Catherine is a member of the UNFC (UN Framework Classification) working group for Injection Storage classification.

Catherine has a M.Eng in Engineering Science from Oxford University

Storegga: CCS workflows – Catherine Witt Keynote

Authors: C. Witt, A. James, R. Gilbert

"Injecting Carbon Dioxide for permanent underground storage sounds so much like oil and gas, how hard can it be?"

Well, there are two things I have learned over the last few years about the carbon storage business,

1. There are perhaps more differences than similarities between carbon storage and hydrocarbon extraction in how we approach and use subsurface workflows for the selection, design and engineering operations for safe and reliable activities.
2. Not appreciating this can get you into deep water very quickly and lead you into the selection of sub optimal storage locations and poor development choices.

On the surface, there are a lot of analogies between carbon dioxide storage and oil & gas extraction. Both rely upon subsurface understanding, both need deep wells to be drilled and geophysical remote sensing, both require careful risk assessment to manage the operational risks.

Because of these superficial similarities, it has often been considered by policy makers and analysts that oil and gas companies would clearly be "best placed" to deliver carbon storage operations.

Oil company engagement in carbon storage was initially motivated by the process of "Enhanced oil recovery" where injected CO_2 is used very effectively to extract more oil from a specific oilfield site than could be achieved without it. From the 1970's a large industry and technology grew up in the US around this practice as a response to the oil crisis, more often than not using naturally occurring CO_2 from subsurface reservoirs to drive it which was cheaper than capturing it from industrial sources.

Building on this, several large E&P companies have broadened and become active in the CO_2 storage space through the management of the Scope 3 emissions from their own operations where there was a financial justification to do so. Norway led the world here with a carbon tax which encouraged Equinor's Sleipner Gas development to have continuously injected CO_2 since 1996.

Through these early efforts the technologies and subsurface work flows for CO_2 storage have evolved and there is no doubt that critical technology and workflow developments have arisen from this early stage activity.

Today further elements of motivation are now arriving fast as climate change starts to bite. Whether this be ESG needs to eliminate Scope 3 emissions and even more to deal with Scope 1 emissions, or simply to create some activity in carbon storage to support continued social, regulatory and investor licence to continue operating in oil and gas production.

Storegga approaches CO_2 storage has a primary motivation to deliver safe and permanent geological CO_2 sequestration as a service to industry and society, as a critical piece of Net Zero Infrastructure without the production or enhancement of any oil and gas recovery.

Ultimately, subsurface workflows are developed to support design and decision making of an industry in the context of its business and financing model. This has to be a pragmatic balance between the technical requirements and the affordability (time and/or cost)

The evolving CO_2 storage sector stands proudly on the shoulders of the oil and gas industry from where it has drawn people, technology, information, experience, innovation and workflows. There are however some important differences between CO_2 storage and the oil and gas industry. Perhaps the most significant is that CO_2 storage is a waste disposal business where the cost of pollution up to now has been so low that it has proved difficult to commercialise CO_2 storage.

Workflows are driven by technical/regulatory requirement and affordability. Hydrocarbon workflows have evolved to be very effective in supporting the extraction of high value product and whilst providing a strong technical foundation, must be evolved significantly to serve in the low margin waste disposal business of permanent underground Carbon Dioxide storage.

The technical contrasts between CO_2 storage and oil and gas extraction also drive fundamental differences in subsurface workflows. These arise from the very different thermodynamic properties of CO2, the essential requirement for long term integrity of storage sites, including caprock efficacy and legacy well integrity, and the different demands created by the contrasting regulatory environments.

Summary:

In summary, there is a lot to be transferred and learnt from the oil and gas industry but it is not the direct analogue it is often thought to be. And arguably perhaps having that distinction is no bad thing for how this fledgling industry is perceived by the wider world.

Basin modeling advanced workflow applied to the screening of potential CO2 storage areas

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The scale of interest of CO_2 storage studies lies in between reservoir and basin scales. Whereas reservoir modeling software are best fitted to address some of the multiphysics issues related to the behavior of CO_2 once injected in subsurface (adsorption, dissolution, near injection wellbore mechanics and temperature), basin modeling tools handles better the basin scale heterogeneities that impact the storage potential and risk associated to the CO_2. Indeed, basin modeling allows to assess the influence of the basin geological evolution on the CO_2 storage capacity, both at the reservoir level, by helping estimating the amount of CO_2 that can be stored in its connected porosity, and at the seal level, by assessing the trap integrity. Also, by modeling the different layers, it can be used in an unusual timescale for such a model to model the evolution of pressure plume engendered by the CO_2 injection, taking into account the layers connectivity and permeability. In this work we show an application of basin modeling for the Broad Fourteenth basin, focusing on the above questions, related to large scale CO_2 storage in saline aquifer.

The 66x33km 3D basin model was constructed using the data publicly available at Nlog website. The structural model was built by integrating all available horizons, faults polygons and well markers data (Fig. 1). The retained model that focuses on the post-Permian evolution includes 3 (three) aquifers and associated seals within the Triassic units (Röt, Solling and Volpriehausen formations) and allows to take into account the connection of these units with the shallower lower Cretaceous aquifer (KNNS). The Subhercynian and late Kimmerian erosion phases were considered to assess the impact of higher past burial on the aquifers' porosity. After the basin modeling calibration (temperature, pressure, porosity), the present-day results were used to identity the areas with higher storage capacity withing the Triassic reservoirs and to simulate the pressure plume dissipation in different injection scenarios.

The basin modeling results show a high variability of permeability and porosity of the Triassic aquifer layers and an important influence of the past burial on present-day values (Fig.2). Indeed, without modeling the eroded thickness, their permeabilities may be up to 10 times overestimated. In order to analyze the effect of these permeability variations on the pressure dissipation, different CO_2 injection scenarios were defined. In all injection scenarios we observe that the pressure wave reaches the lower cretaceous by crossing the Jurassic unconformity. By following the pressure evolution through 30 years after the injection we show the impact of different injection scenarios on the location of the plume and of the areas with higher fracturing risk.

Finally we show that with a low density of well data or uncomplete 3D seismic coverage, a physically balanced large-scale model such as the result of a basin model simulation can provide proper first order insights on connected porous network, seal quality distribution, aquifers connectivity through unconformities, faults or uncomplete seal layers. This is an interesting tool that makes it possible to test different scenarios and identify key points that needs to be better constraint to limit the risk associated with the CO_2 storage in basin scale aquifers.

Basin to prospect-scale CO_2 storage characterisation, Utsira-Skade Aquifer, northern North Sea

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CO_2 storage is a key approach towards decarbonising global society over the coming decades. The current technology and industry capabilities require rapid upscaling to be sufficiently effective and contribute to meeting net-zero targets. Several studies have highlighted aquifers with large storage capacities in mature hydrocarbon basins (e.g. Halland et al., 2011; Meckel et al., 2017; Sun et al., 2018). However, there has been little work on characterisation of the aquifers to identify the best and worst areas to inject, or simulations in the better regions to understand the impact of reservoir heterogeneity on plume behaviour. The multitude of legacy hydrocarbon data and workflows established over the last century can be applied for this purpose, to form a systematic approach towards building a catalogue of CO_2 storage sites.

Here, we present a workflow to regionally characterise the seal, overburden (containment) and reservoir (capacity) of the Utsira-Skade aquifer, northern North Sea. Through adaptation of exploration workflows and introduction of a CO_2 containment confidence (CC) risk matrix (Lloyd et al., 2021a, 2021b), this work provides a robust methodology for investigating storage efficacy. 141 exploration wells, 3D broadband™ seismic and full waveform inverted (FWI) velocity data are integrated to assess aquifer 3D variability and highlight a suite of potential storage sites. Static and dynamic CO_2 injection modelling are performed to constrain storage capacities and understand plume migration and trapping using different injection strategies. This is the first academic study to present a full workflow and case study from regional aquifer characterisation to prospect maturation (Figure 1).

For the regional containment assessment, sandstone presence, connectivity and internal geometry of the 'seal interval' (overlying 50 m of reservoir) and overburden were assessed. Features were scored according to the CC matrix and risk segment mapping highlighted the most secure areas and areas that could allow migration out of the reservoir through seal bypass. In the west, sandstones were observed in the seal interval that are connected through the overburden via sandy submarine fans; this area surrounding the East Shetland Platform was assigned a negative CC score. The eastern region was also assigned a negative CC score, due to glacially-derived channel-lobe systems on clinoform foresets downlapping onto the reservoir, increasing the risk of contact with a porous migration path. The northeastern area of the aquifer has a thick, mudstone-dominated and parallel-bedded seal interval and as such, was assigned a positive CC score and identified as the best area for secure storage across the aquifer.

A full reservoir characterisation was performed. Reservoir porosity was calculated from FWI data using a well-derived function. Within the area with positive CC, porosity is demonstrated to be high (30-37%), but spatially variable. Several laterally-continuous intra-reservoir mudstones were mapped and structural traps were identified through fill-and-spill aquifer flooding simulation. Static storage capacities were calculated for the traps using two approaches: for the full reservoir thickness (FRT) beneath the trap and for only the thickness from the trap apex to spill point (TSP). Reservoir depth, well penetrations and faults were further considered to delimit the area suitable for storage, within which four prospects were located with a FRT storage capacity >5 Mt CO_2.

Two of the prospects were matured through dynamic modelling, which revealed that the threshold pressure and geometry of the intra-reservoir mudstones are key controls on migration timing, pathways and volume potential. Increasing the threshold pressure from 50 kPa to 800 kPa doubled storage capacity, due to more lateral spreading of the plume and its optimisation of the reservoir volume. Injecting CO_2 near the top of the reservoir eliminated risk associated with the observed intra-reservoir mudstones, but lesser volumes could be stored.

The containment (including the CC risk matrix) and capacity workflows presented can be adapted and applied to any aquifer for regional characterisation. Overall, the work demonstrates that it is fundamental to constrain geological heterogeneity in the reservoir, seal and overburden to identify and appraise suitable CO_2 storage sites. Hydrocarbon data, and exploration and production workflows are ideally suited for this purpose.

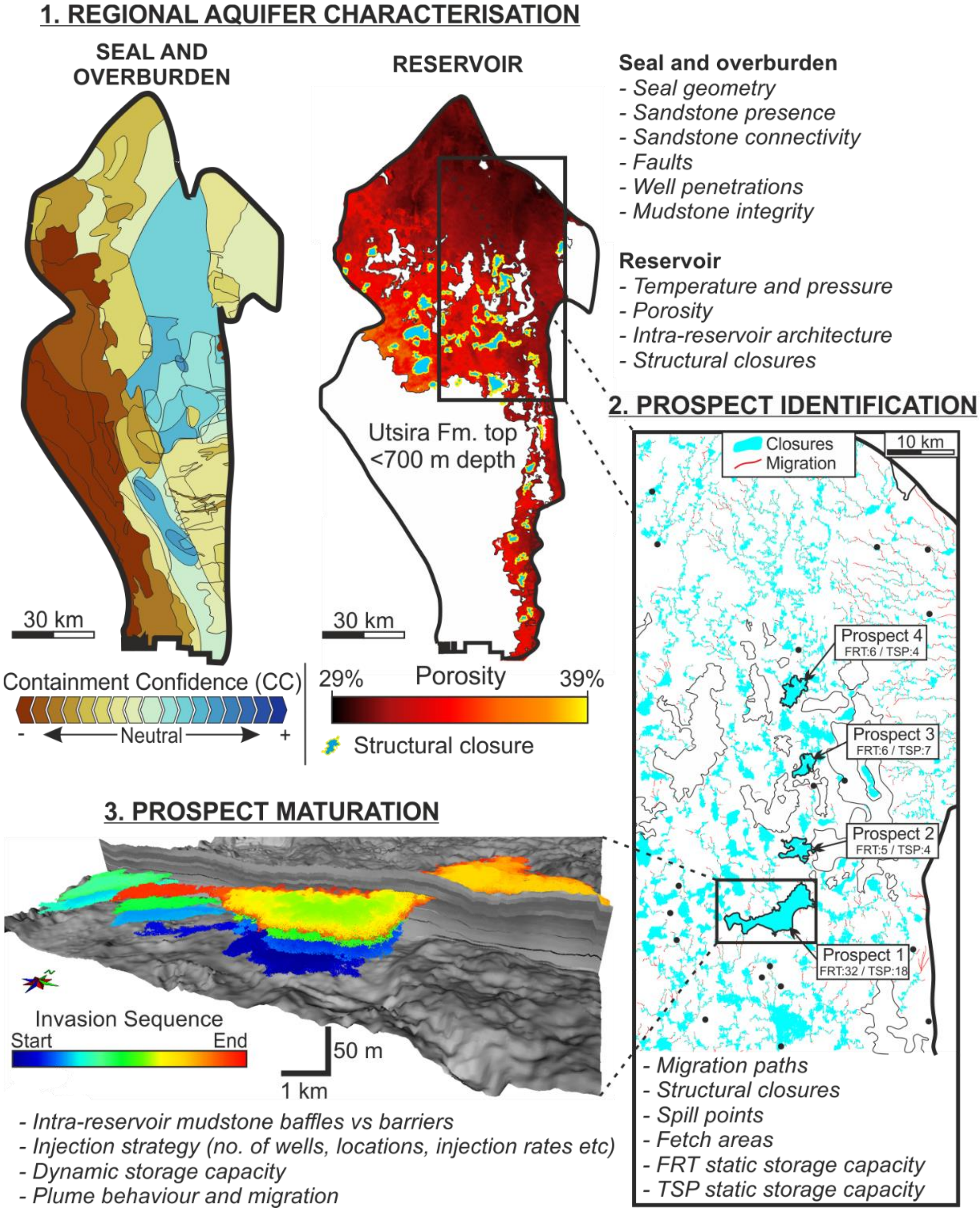

Figure 1| Scales of CO_2 storage assessment and key elements addressed in this study, with results from the Utsira-Skade Aquifer. *Storage capacities quoted in $MtCO_2$. FRT = full reservoir thickness; TSP = top to spill point.*

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Common Risk Segment (CRS) Mapping for CCS potential of Burdigalian-Langhian carbonates: A case study from onshore Cilicia Basin, NE Mediterranean region

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Workflows focusing on regional screening for hydrocarbon exploration can be used for CCS site selection as well. One of these methods is industry-wide used common risk segment mapping. It is a combination of all petroleum system elements into a single map attempting to determine the target zones. By excluding source rock probability and implementing other risk factors such as reservoir depth, area, top of overpressure zone, seal capacity, subsurface data adequacy, proximity to pipelines and infrastructures, licence availability, etc., CRS maps can be easily adapted for identification of most suitable CO_2 storage sites. Based on this concept, this study aims to make an approach for the CCS potential of Burdigalian-Langhian aged reefal carbonates deposited in onshore Cilicia Basin, NE Mediterranean region (Fig.1).

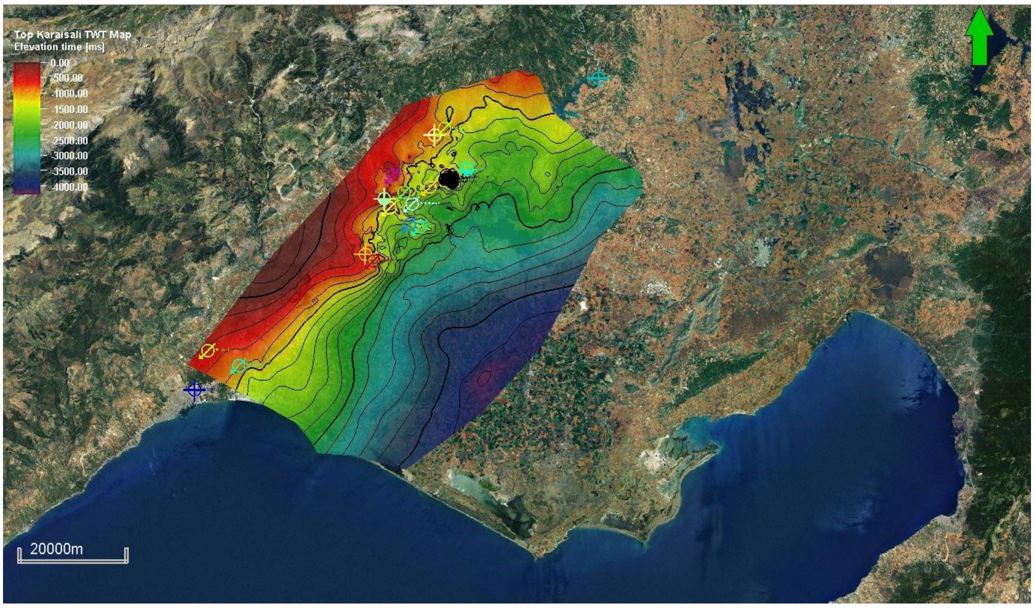

Fig 1. *TWT Map of Langhian Carbonates in Cilicia Basin*

The only commercial oil discovery in Langhian play, Bulgurdag field, has been made by the start of 1960's. The oil field is still in a production state and porosity-permability values reaching 15% and 2.54md indicate the presence of a significant reservoir quality. During the exploration campaign after the oil discovery in the play, 23 more wells penetrating Langhian carbonates have been drilled. Even though, some of them resulted with oil shows, vast majority of the wells returned either dry or water/salt water. Since the wells encountered reefal carbonates with no hydrocarbons, they can be tested for CO_2 storage by the help of re-entry operations.

To identify most suitable wells for re-entry and potential areas in a wider scope, various properties have been converted into risk maps by Python codes. According to the outcomes, facies map derived from seismic interpretations shows that reefal limestones extend in a NESW direction while carbonate ramp deepens towards ESE (Fig.2). Cores and cuttings from wells validate this trend as the facies changes from boundstone into muddier wackestone– packstone. On the other hand, reservoir and seal thickness are at their maximum values at the same locations at where promising traps might form. Combination of all risk maps, including reservoir quality and seal capacity, have revealed two main areas for potential storage sites.

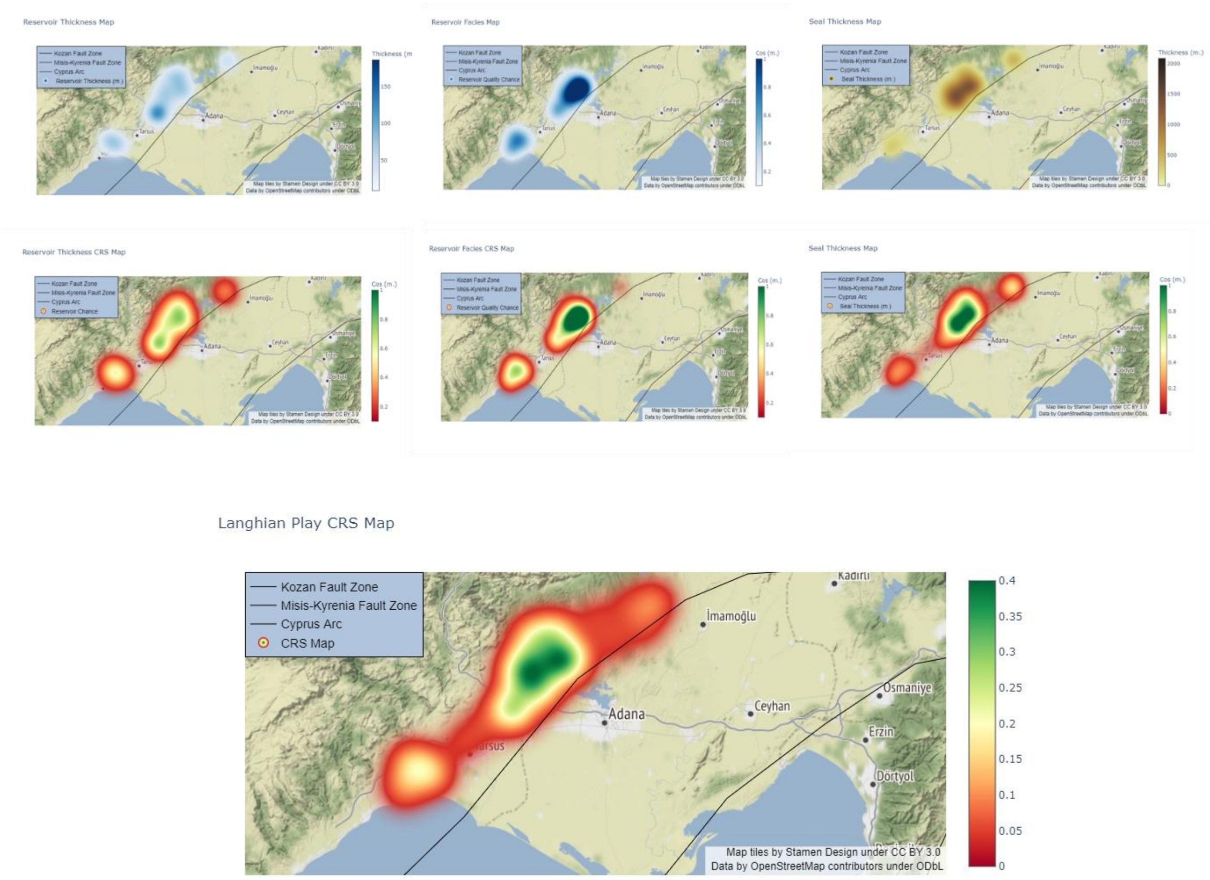

Fig 2. *Common Risk Segment (CRS) Maps*

A low-risk area is in the vicinity of Bulgurdag field while a medium risk area is located at the SW sector (Fig.2). By contrast, the highest risk zone is at the NE region. It can be suggested that the results of this study can be used for reducing the risks and restrict target zones for the early phases of potential CCS projects in the region.

Session Two: Risk and Uncertainty

Keynote – Net Zero Teeside

Catherine Gibson-Poole, Senior Geologist, BP

Introduction

Catherine Gibson-Poole is a Senior Geologist at bp, working with the Northern Endurance Partnership subsurface team to develop the Endurance CO2 store in the UK North Sea. Catherine has been a subsurface professional for 25 years, working across both academia and industry. Her research with CO2CRC (Australia) focussed on site selection and characterisation for geological CO2 storage, whilst her industry experience is mainly with bp, focussed on production geology and subsurface management for oil and gas assets. Key industry projects include In Salah CO-2 injection (Algeria), Shah Deniz gas field development (Azerbaijan) and ADNOC Onshore oil fields assurance (Abu Dhabi). Catherine has BSc and MSc degrees in geology and micropalaeontology and a PhD specialising in geological storage of CO2.

The UK needs to decarbonise industry to achieve its target of net zero emissions by 2050. The East Coast Cluster (ECC), a collaboration between Northern Endurance Partnership (NEP), Net Zero Teesside (NZT) and Zero Carbon Humber (ZCH), offers the single biggest opportunity to decarbonise industry by transporting and storing up to 50% of carbon emissions from all UK industrial clusters. NEP enables the ECC by providing the common infrastructure needed to transport CO_2 from industrial emitters in the Humber and Teesside regions to secure offshore storage in the UK North Sea.
The selected site for CO_2 storage is Endurance, a large structural closure within a saline aquifer, 75 km east offshore from Flamborough Head in the UK Southern North Sea. The four-way dip closed anticline is 25 km long by 8 km wide, with the crest of the structure at 1020 m depth below sea level. The CO_2 injection interval is fluvial-aeolian sandstones of the Triassic-age Bunter Sandstone Formation, sealed by overlying playa lake mudstones and evaporites of the Röt Clay and Röt Halite.
The project is at the front-end engineering design (FEED) stage, with first CO_2 injection planned for 2026. Phase 1 of the project aims to store 4 Mt of CO_2 per annum for 25 years.

CCUS Risk Assessment – Learning from Projects that Failed

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The evaluation of candidate sites for geological carbon storage projects must consider the three pillars on which the success of such projects rest: storage capacity, injectivity, and containment. Each of these pillars has both a degree of uncertainty and a probability of success. The uncertainty can, and should, be assessed using probabilistic methods.

Assigning a probability of success is less straightforward. In this paper, and a companion paper (Constable & Carragher 2022), we contend that, in order to understand the probability of success of a CCS or CCUS project, the question “how could the project fail?” is more relevant than the opposite question, “how can the project be successful?”, which is more common in the business of hydrocarbon exploration. A corollary of this approach is the recognition of the importance of evaluating failed injection projects, *i.e*. projects that were unable to store the expected amounts, and/or to keep these safely in the intended subsurface reservoir. An understanding of what caused these projects to fail provides important lessons that should be applied when planning for future geological carbon storage projects.

While subsurface carbon storage is relatively new, the process of storing injected fluids underground is not. Natural gas storage began more than a century ago to provide the capacity to meet winter heating needs. The widespread use of water injection wells began in the 1930s to dispose of oilfield brine and enhance oil recoveries.

The history of these operations provides insights into the types and frequency of failure incidents. Most are either facility-related failures that occur at the surface, or wellbore failures that allow fluids to migrate upwards to shallower reservoirs or the surface. In many cases, these projects are using wells that are decades-old, providing a sense of what could happen 40 or 50 years from now when carbon storage projects are reaching the end of their injection lives.

Geological factors are responsible for a small but significant fraction of injection project failures. These include 1) a lower-than-expected seal capacity of the overlying caprock, 2) the migration of injected fluids along fractures or across faults previously considered sealing, 3) an overestimate of the volume available for storage, 4) the migration of fluids away from the injector in an unanticipated direction, and 5) induced seismicity (Figure 1)

We will present several examples of injection project incidents, illustrating what happened, the factors responsible, and how these could have been foreseen.

Incidents in the case of methane injection include:

- Hutchinson, Kansas: Gas migration up a storage well and laterally through fractured dolomite to brine wells resulted in surface explosions.
- Castor, Spain: Gas injection into a depleted gas field caused progressive failure along a secondary fault below the reservoir and induced seismicity.
- Huntsman, Nebraska: Lateral migration resulted in the loss of storage gas from one structure (Huntsman Field) to another (West Engelland Field).

Some failed water injection projects are:

- Oklahoma: Oilfield-produced water was injected into deep wells causing seismicity along basement faults.

- Long Beach, California: Water injected into an oil field aquifer for pressure support moved downdip, pressuring-up wells in an adjacent oil field.
- Tordis, Norway: The injection of oil-contaminated water from the Tordis oil field into a small-volume, poor-quality sand wrongly identified as the target sand (Utsira), resulted in an unexpected pressure increase that fractured the overlying clays and caused an oil slick at the sea surface.

Despite a shorter history, examples exist of CO_2 injection projects that encountered unexpected problems, which in some cases led to project shutdown:

- In Salah, Algeria: CO_2 injected into the water leg of a gas field was expected to migrate towards the structural closure to the west, but instead migrated through fault zones to the north, causing the entry of CO_2 into a legacy borehole and fracturing of the seal.
- Weyburn, Saskatchewan: Injected CO_2, suspected by landowners of causing CO_2 surface emissions, touched off a media frenzy. Geochemical work subsequently showed that the surface CO_2 was of biological origin.
- Snøhvit, Norway: Storage capacity fell short of expectations due to subseismic faults and reservoir heterogeneities which caused the reservoir pressure to quickly increase to the calculated fracture pressure.

A recurrent theme in these examples is the fact that subsurface models were not able to capture reservoir heterogeneity, hence giving the impression of a viable project. Regulatory requirements for subsurface models may, for this reason, not allay the risk of project failure.

Subsurface models are always simplified and their representation of the subsurface can be faulty. This can lead, in turn, to underestimates of uncertainty and risk, which need to be calibrated to failure rate data from analogous wells and existing subsurface projects to help ensure objective and accurate predictions regarding the chance of project failure.

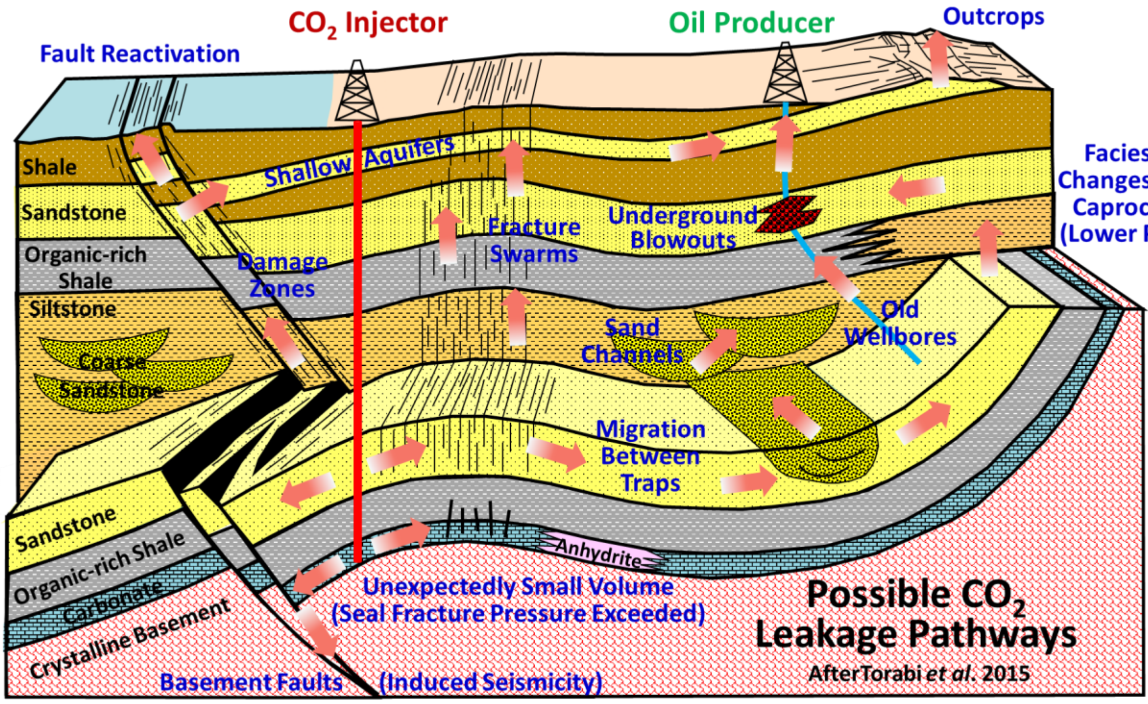

Figure 1: Possible CO2 leakage pathways and the geological conditions favoring these.

CCS Risk Assessment – a New Paradigm

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The scope for crossover of oil and gas expertise to Carbon Capture and Storage (CCS) is an important Energy Transition topic. A key aspect of this transferrable knowledge is subsurface volume and risk assessment. Oil and gas explorers strive to improve their skills at assessing the volumes and geological chance of success for prospects. However, exploration companies accept there will be failures and use the portfolio effect to ensure the value of discovered volumes exceed the program costs. Failures in exploration programs are generally an economic burden on the company.

We contend that the "portfolio effect," accepting a certain number of failures, will not be acceptable to companies, regulators, or the broader societal interests in CCS. Failure to contain CO_2 would be akin to an underground or surface hydrocarbon blowout. This has potentially catastrophic consequences for life and environment, causing significant regulatory, financial, and reputational damage. Assessing the risk in a CCS project does require an assessment of geological success and, although this is a necessary component, it is not sufficient for the complete assessment of a project over its full lifecycle.

Therefore, we propose that a paradigm shift is required from the focus on geological and subsurface success to a broader assessment of chance of failure throughout the life of a project. Operators will be required to develop plans that will monitor for and mitigate possible failures at all stages of a CCS project.

CCS projects can fail during any one of the Screening, Appraisal, Injection, or Closed-In stages. For example, in the Appraisal stage the seal and/or reservoir could be found to have poor properties or lateral continuity. During the Injection stage, induced seismicity could occur, the injection rates could fall below requirements, pressures could build to unacceptable levels, the model could fail to predict the plume migration direction, or seal failure could occur. During the Closed-in stage, failures of seal, fault or well integrity could occur leading to migration of CO_2 into a shallower aquifer, or in the worst-case, release back to the environment.

An important similarity in assessments for CCS and oil and gas projects is the likelihood that cognitive biases impact both the subsurface model and the risk assessment. Common biases that narrow the range of possibilities include motivational biases, over-confidence based on limited data, and anchoring on a single model.

Subsurface modelling of CCS projects is an essential part of the workflow in the Screening, Appraisal, and Injection stages. However, many published pre-injection model-based predictions show either minimal leakage or no failure over very long time scales. Subsurface models are necessarily a simplification of the complex geological system; therefore, stress-testing of models is a key due diligence step. Including real-world failure frequencies in the model, in addition to the subsurface data, will help to identify and better assess the risk of failure mechanisms. It is possible that models that show no failure over many thousands of years contain cognitive errors. We recommend detailed scrutiny of the underlying assumptions.

The first key difference to typical exploration risk analysis is the requirement that the subsurface store will not fail for time scales varying from the near term to over 1,000 years. Although the IPCC proposed standard is that 99% of the injected mass will be retained for at least 1,000 years, we believe that operators, regulators, and society will require near term data that provides confidence in long term security of the project. Risk assessments which must incorporate long timeframes are new to many in our industry.

The second key difference is that frequency of failures in, for example, wells and seals are likely to be very low, in the range of 1 percent per year and below. These low probability events are far lower than our usual exploration chance assessments. We maintain that we cannot use expert judgement methods to differentiate subsurface risks between, say, 0.1% and 0.01% failure rates. Therefore, a different approach is required for risking of CCS projects.

Many studies addressing risk assessment techniques for CCS projects only use non-quantified risk language such as “acceptable” or “negligible”. Some studies have attempted to link verbal risk scales to a low probability quantitative risk scale. Figure 1 presents, in two ways, a verbal scale defined by Watson (in Cook, 2014). Firstly, at the top of the table, the verbal descriptions refer to the annual frequencies; and secondly, at the base of the table, are the verbal descriptions of the 1,000-year outcomes.

Figure 1 demonstrates that at an annual failure rate of 0.1% per year, over 1,000 years there is a 63% chance of one or more failures occurring; at 0.01% per year there is a 10% chance of one or more failures. Using this particular language scale, an event that is unlikely on an annual basis, becomes almost certain to occur in a 1,000-year timescale. We therefore recommend using documented failure rate data from analogous wells and subsurface projects (e.g., gas storage or injection projects) as a guide to the base rate probabilities of failure in CCS projects.

Increasing Annual Failure Rate

KEY
>10%
1% - 5%
<1%

Increasing Time

Labels	Case 4	Case 3	Case 2	Case 1
Verbal Risk Description -Annual Chances	*Highly Improbable*	*Very Unlikely*	*Unlikely*	*Possible*
Chance of Failure Per Year	0.001%	0.010%	0.100%	1.000%
Chance of Success Per Year	*99.999%*	*99.990%*	*99.900%*	*99.000%*
Chance of One or More Failures				
in 5 Years	0.01%	0.05%	0.56%	4.86%
in 10 Years	0.02%	0.11%	1.04%	9.63%
in 25 Years	0.03%	0.26%	2.45%	22.19%
in 50 Years	0.06%	0.50%	4.77%	39.64%
in 100 Years	0.11%	1.02%	9.54%	63.61%
in 250 Years	0.25%	2.53%	22.18%	91.82%
in 500 Years	0.49%	4.94%	39.35%	99.32%
in 1000 Years	0.96%	9.56%	63.20%	100.00%
Verbal Risk Description , 1000 Year Outcome	*Possible*	*Highly Probable*	*Almost Certain*	*Certain*

Figure 1 - Monte Carlo simulation outcomes for one risk element, showing the chance that one or more failures will occur given four different annual failure rates (0.001% – 1.0% per year) over time frames from 5 to 1,000 years (models run for 100,000 iterations). Verbal Scales from Watson in Cook (2014).

In reality, CCS projects will consider multiple failure modes. Although each element may have a very small annual chance of failure, adding multiple probabilities would result in a significant chance of failure over the lifetime of the CCS project.

The presentation will review some of the techniques developed to assess long term risk of disasters in the natural world and how they can apply to the timeframes and stages of CCS projects.

Reference: Cook, P. (2014). Geologically storing carbon: Learning from the Otway Project experience, CSIRO publishing.

Extending Oil & Gas Asset Evaluation into Carbon Storage Resource Assessment: The Path Towards a First Standard Methodology

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We present a new asset evaluation workflow which enables fast and transparent screening of carbon storage assets, optionally constituting "hybrid assets", i.e., a combination of CCS assets with standard oil and gas reservoirs. This workflow builds up on an existing asset evaluation software called Ariane, which will be extended to accommodate carbon storage evaluations in a similar manner. In the presented paper, we lay out our vision of how to stretch the current methodologies and software so that transitioning geoscientists can perform the evaluation of CCS and hybrid oil & gas / CCS assets based on a solid understanding of pore space, fluid PVT properties, sealing dynamics, and other advanced geological processes.

As a starting point, we review current evaluation methodologies of oil and gas prospects. Such early assessments of exploration opportunities are generally performed with very limited data (quantity, quality, accessibility), and therefore limited knowledge of the subsurface. Numerous concepts, leads or prospects are mapped in various levels of details. Even though 3D data might exist, detailed 3D reservoir-scale models are rare at that stage. Therefore, simple methodologies often use probabilistic "Monte Carlo" simulations where practicality primes over complexity. But simple methods are also applied in data rich contexts, when time is limited, e.g., in a data room situation. The most important simplification is geometrical: The 3D aspects of a trap container are upscaled into a one-dimensional world (area-depth or GRV-depth curves). Then average values are specified for the reservoir properties, and finally, oil or gas column heights and fluid properties are assumed to obtain subsurface and surface volumes.

We then present how we extended the fluid part of the standard evaluation methodology: Fluid occurrence (oil or gas, or both), column heights and properties (densities, fluid ratios) are derived from quantitative assumptions of charge and seal processes and PVT data. Importantly, this petroleum systems workflow can already be used with only little modification for a static pore space-based assessment: How much CO_2 volume can we inject prior to fracturing, leakage through the top or fault seal, or structural spill? In the deterministic example of Figure 1, the trap is assumed to start leaking injected CO_2 through the lateral fault seal once the total injection volume approaches approximately 50 bcf. Using the same approach but probabilistically, the following parameters can be expressed as uncertainty distributions:

- Trap pore volume and spill point depth
- Trap pressure and temperature
- Gas densities
- Top seal leak-off and capillary entry pressures
- Lateral fault seal depth, leak-off and capillary entry pressures

The resulting maximum injection volumes can be used for a comparison of static volume free phase CO2 storage "resource" of that specific asset and compared with others.

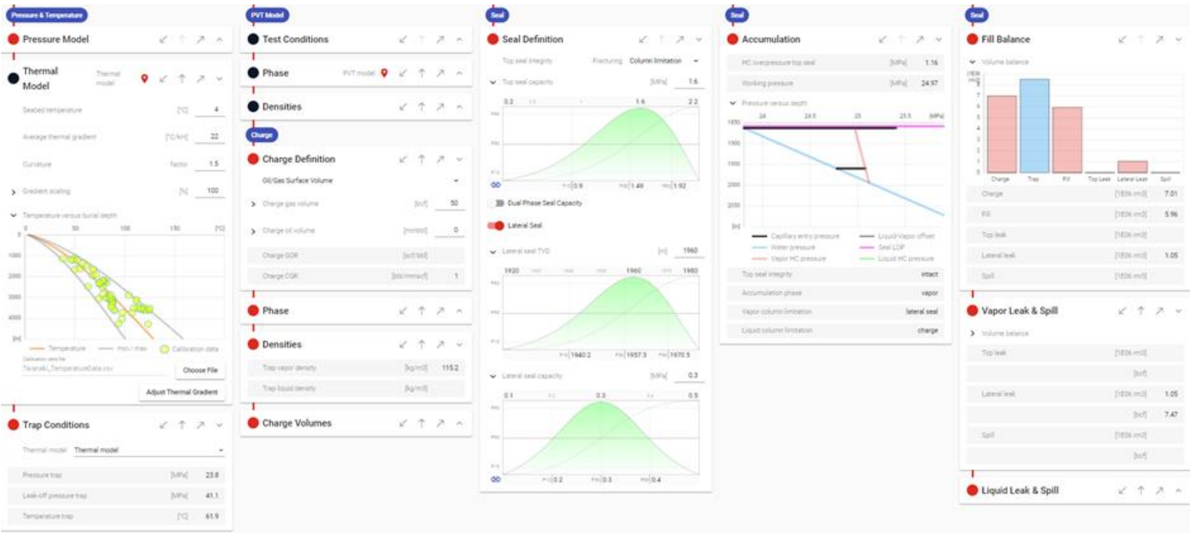

Figure 1: A static free phase CO2 fill to leak calculation using our methodology initially designed for oil and gas.

For an advanced solution, future development of the methodology is proposed. First, dynamic injection needs to be modelled at human time scales, as well as the seal response. Also, alternative ways of capturing CO2 such as water solution or mineral precipitation will need to be considered. Finally, the mixing of CO2 with other fluids occupying the trap can complicate the simple approaches currently used.

By extending oil & gas workflows to incorporate CCS evaluation methodologies, assessments of various types can be evaluated together in a single parallel workflow. Such a combined methodology allows for the evaluation of “hybrid assets”. A very good example of a long term “fluids out – fluids in” pilot projects of such combined assets is the Sleipner Field offshore Norway. For a full quantitative evaluation of hybrid assets, the two (or more) parallel workflows and their calculations need to meet in a common denominator measuring value. This value is likely a combination of NPV (net present value), in any world monetary currency (USD, EUR, etc.), and total carbon footprint balance (in mega or giga tonnes), which ideally is negative.

In conclusion, implementing screening workflows for a diversity of assets into a single resource assessment system enables the combined evaluation of hybrid assets. All components of the hybrid assets are appraised and ranked for their combined economic value but also for carbon footprint. We think that many future energy assets will be of such a hybrid nature, both from an economic but also a social acceptance perspective. Setting up those hybrid assessments workflows, combining oil and gas, CCS and potentially other energy resources or subsurface storage opportunities, shall enable experienced staff from oil and gas companies to evolve into new technologies as required by the transitioning energy industry.

A process-led approach to framing uncertainty and risk in CO_2 storage in the subsurface

Simon Shoulders, bp

Carbon Capture and Storage (CCS) has the potential to be an important tool in reducing the emissions intensity of dispatchable power generation and hard-to-abate industries such as steel and cement production. It can also be used to enable net-negative technologies such as direct air capture and storage.

CCS is facilitated by the safe long-term storage of CO_2 in the subsurface. This challenges subsurface practitioners to build on and adapt many of the techniques and processes developed for hydrocarbon exploration and production to create innovative and effective approaches to assessing CO_2 storage risk and uncertainty. This requires a good understanding of the processes controlling CO_2 behaviour in the subsurface.

In this presentation we will:

- Introduce the different storage plays and concepts that be exploited for CO_2 storage highlighting some of the different controls and risk factors to be considered in different storage concepts.
- Show how the trapping mechanisms for CO_2 evolve throughout the lifecycle of a storage project.
- Explore the interplay between CO_2 trapping mechanisms and the key controls on CO_2 plume geometry (ie: heterogeneity within the storage reservoir; the dip of the stratigraphy; and aquifer behaviour) using a series of simple conceptual models.
- Discuss a targeted approach to describing uncertainty and risk in the early screening of CO_2 storage prospects

Throughout the presentation we will highlight some of the differences and similarities between approaches applied in hydrocarbons exploration and production and CO_2 storage and show how the skills and experience of subsurface practitioners from the hydrocarbons industry are directly applicable to some of the key challenges faced in the ongoing energy transition.

Session Three: 'The Long Term'; Monitoring and Stakeholders

Keynote - Crown Estate (Stakeholder Engagement, Licencing Framework)

Adrian Topham, **BEng, MSc, Senior Development Manager CCUS, The Crown Estate**

The Crown Estate is driving forward new technologies to achieve net zero targets in accordance with our own strategy and Government targets. My role as sector lead is to help create a pipeline of geological CO_2 storage prospects that delivers CB6 targets and meets market expectations, while playing a lead spatial planning role to optimise seabed use between CCUS, wind and other sectors.

My previous experience as an engineer, team leader, general manager and now development manager stems from academic training in chemical and petroleum engineering. I have worked as a reservoir engineer, aiding hydrocarbon extraction in many countries and now I am committed to the carbon cycle and returning the by-products after use to the subsurface.

My CCUS sector interests are both technical (geophysical, geomechanical, geological) and economic (capture feasibility, transportation, removals). Currently involved in supporting research into windfarm / seismic monitoring interaction.

The rights to allocate seabed storage for CO_2 were vested in TCE by virtue of the 2008 Energy Act and TCE sees itself as having a similar role in the management and allocation of storage rights as it does for renewable energy (via the 2004 Energy Act). The primary difference in the CCUS sector is that a bespoke storage regulator is in place – the OGA which was set up in 2015 and took over the storage licensing and permit role from DECC EDU. TCE's authority for granting seabed and subsurface rights for CO_2 storage means that it has a primary role to play in delivering the CB6 and net zero targets, in a similar way as for renewable energy. However, the role of the OGA means that TCE cannot play a replica role to the one taken, for example, for offshore wind.

For CCUS, TCE intends to deliver a marine spatial plan and structure for leasing, alongside the subsurface resource plan from the OGA. The marine spatial plan will take account of the targets and ambitions of other sectors and uses of the seabed in accordance with TCE's remit.

Experienced-based saline aquifer CCS project development – a subsurface maturation perspective from the Northern Lights project, offshore Norway.

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Catalina Acuna, A/S Norske Shell

The Northern Lights CO_2 transport and storage infrastructure development offshore Norway is a first-mover establishment, enabling decarbonization of European industrial emissions at scale. Phase 1 includes transport, temporary onshore storage, permanent subsea injection and storage of up to 1.5 Mt/year liquid CO_2 via one to two dedicated injector wells, with Phase 2 ambitions of scaling up to full pipeline capacity expected to be approximately 5 Mt/year.

With Phase 1 injection start in mid-2024 in a saline aquifer setting and short timing to final investment decision, a subsurface maturation needed to be developed alongside the storage concept, as standardized procedures for saline aquifer storage sites have not yet been established. Here, we examine the subsurface maturation process undertaken by the Northern Lights project and discuss, per relevant discipline, which aspects needed a different approach and higher focus as compared to a traditional hydrocarbon subsurface workflow process.

In the framework of Norwegian CO_2 storage regulations, the feasibility and development of a CO_2 storage site requires a multidisciplinary assessment of crucial parameters such as injectivity, storage resource and integrity, often intertwined.

On discipline-specific topics, we discuss, for example, how initial hydrostatic reservoir pressure conditions have led to an increased focus on well clean-up to ensure injectivity and an increased cooperation with Drilling and Well teams. Furthermore, unlike most hydrocarbon developments, reservoir pressure will be increased above its initial level due to CO_2 injection. The associated mechanisms of reservoir pressurization and pressure dissipation around injectors and its relation to rock properties steer the storage capacity. This brings an increased focus on geomechanics and mechanical capacity limitations to define acceptable reservoir overpressure and assess cap rock integrity which are critical aspects to be defined early in the subsurface maturation phase for CO_2 storage.

A significant part of the containment risk assessment for the project was to assess the probability and consequence of CO_2 migration out of the storage complex with the support of the bow-tie method (Vebenstad *et al*., 2021). Such an assessment is specific to CO_2 storage and can identify showstoppers to the storage site or to certain capacity ambitions. Furthermore, the development of any CO_2 storage site on the Norwegian continental shelf requires that the CO_2 plume can be monitored for conformance and containment, setting an early focus on feasible subsurface monitoring strategy and methods. During injection the conformance monitoring will be integral for dynamic modelling and consequent capacity updates, in a similar way as for hydrocarbon reserves updates based on history matching. However, the added focus on containment monitoring requires a strong link to the containment risk assessment, which is not typically a part of hydrocarbon production monitoring.

Factors such as caprock integrity, reservoir property uncertainty and multi-geologic scenarios are key aspects to address, in particular during data acquisition/exploration well drilling. In addition, early detailed assessments and studies within the development workflow need to be considered and involve all subsurface and drilling and well disciplines. While the Aurora storage site in the Northern Lights project is defined by a certain subsurface framework and project constraints, sharing the learnings gained during the maturation of this project may be of valuable general benefit to saline aquifer CO_2 storage developments.

Reference

1 – Vebenstad, K., Lidstone, A., Vazquez Anzola, D., Zweigel, P., 2021, Containment risk site assessment of the Northern Lights Aurora CO2 storage site. Proceedings of the 15th Greenhouse Gas Control Technologies Conference, 15-18 March, Abu Dhabi, UAE. http://dx.doi.org/10.2139/ssrn.3820888

Well integrity strategy for CO_2 storage field development – Experience sharing from Northern Lights project, offshore Norway.

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The Northern Lights project, located in Norway, will be the first ever cross-border, open and flexible solution for European industrial emitters to store their CO_2. The objective is to transport liquid CO_2 from capture sites by ship to a terminal for intermediate storage, before being transported via pipeline for permanent storage under the seabed in the North Sea. The facilities are currently under construction. Phase 1, with an injection capacity of 1.5 Mt/year via one to two new injector wells, will be completed by 2024 and subsequently, the ambition for Phase 2 is to scale up to 5 Mt/year.

As it is a first-of-its-kind project, documenting measures undertaken to secure infrastructure integrity and storage safety is a key objective. The wells represent a critical part of the system. However, developing a CO_2 storage field presents different challenges than a standard oil & gas project and CO_2 injection introduces unique well integrity considerations. Here, we share the strategy that the Northern Lights project has established to ensure well integrity and to manage risks.

The feasibility and development of a CO_2 storage site requires assessment of the integrity of nearby legacy wells. Lack of documentation from historical wells and strengthening of plug & abandon requirements over the time generally make this evaluation difficult. Thanks to multidisciplinary work involving drilling, completion, fluids/cement, subsurface, geomechanics and by using a specific methodology, an extensive assessment of the nearby legacy wells has been carried out and this experience is a valuable learning for subsequent CO_2 storage resource developments.

A robust design of the CO_2 injector wells is essential as injection will last for at least 25 years. Formation of carbonic acid by mixing liquid CO_2 with saline formation water requires dedicated engineering work during design and planning. Material compatibility tests, bespoke cement slurry design and equipment qualifications were undertaken in-house but also with third party companies to establish competent and cost-effective well barriers. To close the loop, a tailored well integrity monitoring program has been defined to prevent any CO_2 leak after starting the injection operations.

Notwithstanding the well integrity strategy has been built based on existing oil and gas governing documentations and regulations. CO_2 storage present similarities but also significant differences compared to oil and gas developments and it raises legitimate questions: are the regulations fully adaptable for CO_2 storage developments? Is there a need for adjustments to the regulatory framework?

Fill-and-spill CO2 fairways: a new concept to enhance the efficiency and safety of underground carbon storage (CCS)

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According to the well-known fill-and-spill model for hydrocarbon migration, the structurally lowest and most proximal trap to the source kitchen is the first to receive hydrocarbon charge. Once the trap pore volume is filled down to a structural spill-point, additional excess charge will spill fromthe trap and migrate laterally up-dip along a carrier bed-mediated route, until reaching a neighbouring trap with a shallower spill plane. This fill-and-spill mechanism may continue laterally over great distances, leading to large volumes of oil and gas trapped in many closures along afairway. Although this is a well-known model for oil and gas charge, to the authors' knowledge, it has never been exploited for charging a fill spill fairway with injected CO2.

Here, we investigate harnessing the natural buoyancy and low viscosity of supercritical CO2 to efficiently fill consecutive traps along a fill-spill trajectory. This concept is tested by CO2 flow modelling in the lower Triassic Bunter Sandstone reservoir of UKCS Quadrants 43-44 (Southern North Sea – SNS), based on integrated seismic interpretation and well-based stratigraphic and petrophysical data. Just west of our Area of Interest (AOI), the "East Coast Cluster" will transport onshore-captured CO2 via pipelines to the offshore Endurance site, a saline aquifer within a large Bunter antiform trap. This site has a mid-case (85% CO2 saturation) static storage volume potential of 2700 MT of CO2 (K43 White Rose Report, 2016). Only a few percent of this volume will be utilized for storage (K43 White Rose Report, 2016), in what will be one of the UK's first Carbon Capture and Storage (CCS) project.

Over the AOI, there are 18 discrete Triassic four-way dip closure traps, each smaller than Endurance, formed in response to the underlying Zechstein salt domes. At least 11 of these traps, including several underfilled Bunter Sandstone gas fields, are linked together in a possible filland-spill mega-fairway (Fig. 1). No significant faults are visible in the overburden, although Tertiary dykes have been mapped in the AOI. Given the range of the trap depths across the AOI, CO2 would exist as a supercritical fluid with density comparable to that of oil. In the AOI, the Bunter Sandstone shows relatively regular thicknesses (90-216 m) with petrophysics from 23 wells (some of which cored) revealing that the fairway area has good porosity (average net PHIE = 13-20%) and permeability (9-669 mD), with net-to-gross of 78-99%. The reservoir unit is overlain by a thick top-seal, including the remarkably isopachous Rot Halite (~100-150 m). All pore pressure data from the Bunter reservoir in the AOI and the nearby Endurance trap suggest connected nearhydrostatic aquifer (0.51 psi/ft). The caprock CO2 holding capacities are greater than the closure heights of most traps in the AOI, and there are no shallow gas indicators over the crests of the Bunter gas fields. Standard pressure plot modelling enables the prioritisation of monitoring acrossthose traps having higher top-seal breaching potential risk.

If filled to spill (base-case, 66% CO2 saturation), the fairway in the AOI could cumulatively store >3 times the static CO2 storage potential of the filled-to-spill Endurance trap, while being subject to a lower risk of top seal breaching. We show that a fill-and-spill injection strategy can be devised through the placement of multiple 'injection hubs' to efficiently and safely infill the fairway with CO2 within human-life timescales (Fig. 1), whilst likely requiring fewer injector wells. In addition, preliminary regional seismic interpretation work throughout the UK SNS suggests that the Bunter fill-and-spill mega-fairway may extend well beyond the boundaries of our AOI, therefore representing an important 'low hanging fruit' regional solution to the UKs near-future CCS needs.

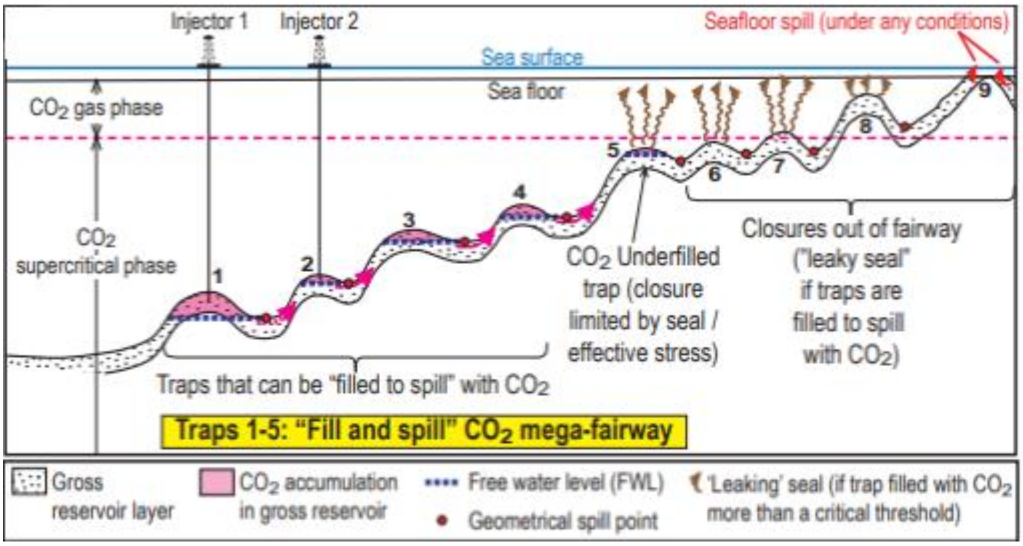

Figure 1: Fill-and-spill model applied to the underground storage of CO2.

While further work is necessary to mature the CCS fairway concept (e.g., on the effects of igneous dykes and heterogeneous partial reservoir cementation on the modelled CO2 migration route), the advantages of approaching CCS as a fill-and-spill challenge would be numerous, including:

- Maximise net pore volume for storage: structures can be filled with spill as an objective;
- Leveraging supercritical CO2 buoyancy and low viscosity to naturally drive migration through the fairway: less infrastructure will mean lower cost and less risks of CO2 leakage along infrastructures;
- Several smaller traps are used, each with a greater top-seal pressure integrity than a single very large trap at the same burial depth: the cumulative "safe CO2 effective storage capacity" is therefore much greater than in the conventional development of a stand-alone very large structure, with less risks of losing CO2 by seal breaching or lateral diffusion;
- Closures at the end of the fairway can act as a safety buffer to excess injection or CO2 solution transportation out of the structure by pore fluid flow (c.f., Trap 5 in Fig. 1), enabling

'peace of mind' when it comes to completely filling the traps in the fairway with CO_2;

- Cost-effective multi-physics seabed system for leakage and migration monitoring can be planned and focused at critical sites along the fairway by migration spill-point modelling.

Exploiting fill-and-spill fairways for CCS is a new concept with vast potential applicability globally, wherever several traps are linked together along a common migration fairway

Sleipner 25 years: Demonstrating how well-established subsurface monitoring work processes have contributed to successful offshore CO_2 injection

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In August 2021, the world's longest running offshore industrial CO_2 injection project celebrated its 25 years anniversary. During these years, the Sleipner CO_2 injection project has been invaluable in demonstrating that offshore CO_2 storage is feasible, safe, and efficient. In 2020 a new time-lapse seismic dataset was acquired over the injection site, confirming the CO_2 migration pattern in separate layers in the subsurface. In this presentation we demonstrate how this project still brings new learnings to the CCS industry.

A proxy for "the overburden" of deeper storage sites

The time-lapse seismic monitoring at Sleipner has demonstrated how a relatively shallow storage site can retain CO_2 in the subsurface. At 800-1000 m injection depth CO_2 injection in Utsira Fm at Sleipner is at the limit of what is considered practical, because CO_2 at shallower depths would transform into gaseous phase and take up a much larger volume. At these shallow depths, the high porosity reservoir combined with the acoustic properties of the CO_2 form a strong contrast to the properties of the in-situ aquifer, promoting a detailed seismic mapping of the CO_2.

Based on the time-lapse seismic observations, we estimate that the "minimum seismically detectable CO_2 volume" in Utsira Fm is in the order of 15 000 tonne, considering the small volume detected in Layer 9 already three years after injection start. This is in accordance with similar estimates from other CO_2 injection sites around the world (Figure 1). New CO_2 projects would typically be planned for deeper injection targets, which means that the Utsira Fm will serve as an excellent proxy for "the overburden" of deeper injection targets.

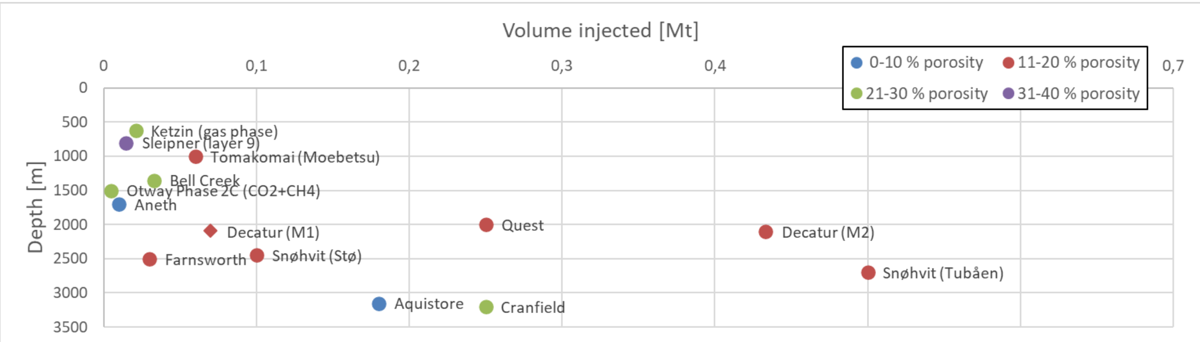

Figure 1: Estimates of minimum observed seismic detectability, as a function of injected CO_2 and depth based on reported results from existing CO_2 injection projects around the world, employing different monitoring technologies. All, except Decatur (M1) were able to detect the injected volume of CO_2.

A benchmark for CO_2 flow models

The high resolution of the seismic signal at these depths has facilitated a detailed mapping of the CO_2 migration, revealing how structural complexity helps spreading flow. Buoyancy is driving the CO_2 to migrate vertically, and to become trapped under structural highs in the subsurface. In a homogenous sandstone, this predominantly vertical migration would mean that a large structural trap would be required to retain sufficient CO_2 volumes. However, even small heterogeneities will serve to spread the CO_2 and promote secondary trapping mechanisms.

The Utsira Fm is a high-quality sandstone, with a few local thin shales intermixed, most of which are only 1-2 m thick. The time-lapse monitoring has demonstrated how even such thin shales can temporarily baffle flow, and how the shale layers have served to spread the CO_2 plume and increase storage capacity (Figure 2).

We will show a movie derived from the time-lapse monitoring demonstrating plume development during 25 years of injection. The movie visualizes the repeated layered nature in the buildup of the Utsira Fm. depositional system, the vertical chimneys transferring CO_2 between layers, and the north to south elongation of the plume.

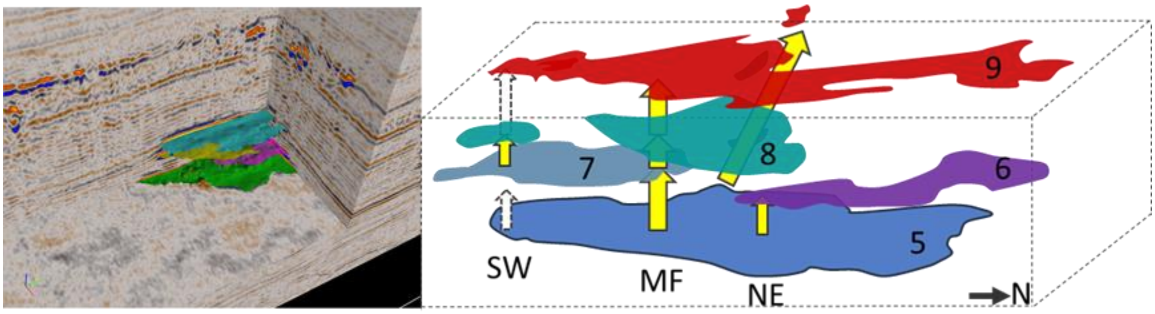

Figure 2: Left: Time-lapse seismic mapping of CO_2 reflectivity. Right: Graphical representation of CO_2 migration pattern in Utsira Fm.

A reference for optimizing seismic monitoring programmes

Proper monitoring of CO_2 injection is important for gaining stakeholder confidence and license to operate. On the other hand, monitoring is expected to constitute one of the larger operational costs of CO_2 injection projects; projects that aim to be made as cost efficient as possible. From the beginning, relatively frequent time-lapse seismic monitoring was employed at Sleipner, with 1-2 years between some of the repeated seismic surveys. Experience has shown that for conformance and containment monitoring, less frequent repeats would have been sufficient at this site. The repeat frequency is now linked to the volume of injected CO_2 in the subsurface.

Future CO_2 injection projects can build upon this, and design monitoring programmes tailored to their specific needs, based on the containment risk assessment of the specific site. One way of handling this is to plan monitoring programmes to be flexible enough to both ramp up or lax on timing and number of repeats.

Summary

The Sleipner CO_2 injection project has been crucial for extracting important technical learnings about offshore CO_2 injection operations, monitoring feasibility, and subsurface migration, thereby establishing stakeholder acceptance of the feasibility of offshore CO_2 injection.

Acknowledgments

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Session Four: Reservoir Characterisation

Keynote - Philip Ringrose
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As a specialist in Carbon Capture and Storage (CCS) and Reservoir Geoscience at Equinor and an Adjunct Professor of CO2 Storage at NTNU, Philip Ringrose is at the forefront of the push for a low carbon economy and energy transition. During his 30 years of Energy Industry and Academia experience he has built a strong reputation as an expert in reservoir geoscience and in the last ten years as a widely respected world leader in the theory and application of CCS. His strong background in reservoir geoscience has acted as a springboard for building his world-renowned position in CCS. He has worked on numerous CCS projects for Equinor such as the Sleipner and Snohvit gas fields, whilst advising around the world on committee and advisory boards to build CCS knowledge and frame future policy.

He has been a regular convenor and speaker at conferences on reservoir and CCS topics and advisor to numerous scientific committees around the world, currently sitting on the Geological Societies Energy Transition committee. He is also Chief Editor of the Geological Societies Petroleum Geoscience Journal, has been a former President of the EAGE and served on its board for 3 years (2012-2014). Dr Ringrose has been honoured with the following awards: Mobil (North Sea) Ltd Prize for outstanding performance in geophysics, Edinburgh University, 1981; Dr James MacKenzie Prize for excellence in postgraduate research, Strathclyde University, 1987; and an Honorary Professorship (2018–2021) at the University of Edinburgh, School of Geosciences.

Why CCS is not reverse gas engineering

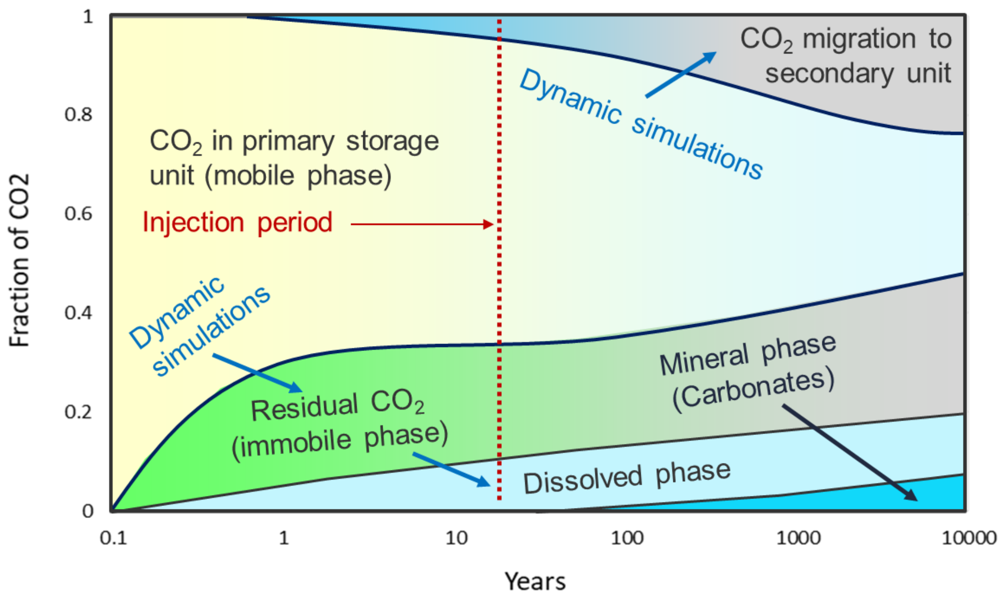
It is easy to jump to the conclusion that the geoscience and engineering methods needed for developing CO_2 storage projects are virtually the same as for oil and gas production projects, only in reverse – one is 'gas/oil out' and the other is 'gas/CO_2 in.' I argue this is a wrong inference on many levels, while accepting that some of the tools and methods used are similar.

Firstly, CO_2 injected into deep geological storage units is not (normally) a gas. The objective is that the CO_2 should be stored in the liquid or dense phase, meaning that the CO_2 behaves as a fluid substance which we are generally unfamiliar with and which has very different properties from methane or petroleum. Dense-phase CO_2 can be described as having 'gas-like viscosity' and 'fluid-like density,' but that simple summary neglects the strong thermal dependency of the *in situ* density as well as some important geochemical reactions. Secondly, in terms of flow physics, the introduction of a buoyant non-wetting phase into a water-wet porous medium (such as a sandstone) is analogous to secondary oil migration, a natural process operating on geological timescales. This means that CO_2 storage is more like 'oilfield creation' and very different from oil or gas field production. These fluid dynamical differences can be explained using dimensionless analysis of the fluid forces (e.g. the viscous-gravity ratio) and can be demonstrated empirically using laboratory and field data.

Thirdly, while the storage targets may have very similar geological architecture to analogous hydrocarbon reservoirs, CO_2 storage projects are likely to have very few wells available for model calibration. History matching of the dynamic behaviour of hydrocarbon reservoirs under production typically makes use of 10-100 well calibration points (including both static and dynamic datasets), whereas CO_2 storage projects need to forecast plume growth out from one or very few injection wells into the surrounding storage domain. Some regional oilfield legacy wells may be available for calibration, but in the local region of interest CO_2 storage projects need to rely much more heavily on forecasting and prediction methods within realistic bounds of uncertainty. They can also make effective use of non-invasive geophysical imaging as an important constraint for plume monitoring, alongside a limited set of monitoring wells in some cases. Fourthly, the forecasting timescale is significantly longer than for oilfield simulations, with CO_2 storage projects usually being required to forecast likely site behaviour 100's of years into the future (see figure below).

For the fifth category of significant differences, the well design for CO_2 storage projects involves many differences: the ideal well placement targets deeper rather than shallower intervals within a given storage unit, the well components (metals and elastomers) need to have higher corrosion resistance, and the wells require cementation and isolation procedures which are generally more stringent than for normal oil and gas production operations. There are many other differences that can be added to this list, including the lack of financial incentives and the high levels of public scrutiny applied to CCS projects. Adding all this together, the result is that CO_2 storage is an activity which is significantly different from oil or gas field production. Not at all like 'reverse gas engineering'.

The arena where there is more common ground is the knowledge base needed for CCS. Decades of hydrocarbon exploration and production in offshore and onshore sedimentary basins of the world offer datasets which are highly relevant and useful for developing CO_2 storage sites, as well as for other emerging uses of the subsurface such as seasonal/cyclic storage of hydrogen. Furthermore, the broad portfolio of advanced geological, geophysical and reservoir engineering methods which have been developed for identification and forecasting of hydrocarbon resources can be relatively easily adapted to the needs of CO_2 storage development. The toolbox is thus similar even though the objectives are quite distinct.



Sketch illustrating the likely short- and long-term fate of CO_2 in the storage complex with the main CO_2 trapping mechanisms (modified from Ringrose and Bentley 2021)

While appreciation of these technical differences is important for geoscientists and engineers working on CO_2 storage development projects, the implications of the differences for the social discourse surrounding CCS is much more critical. CCS as tool for rapid reduction in greenhouse gas emissions is still considered by many to be in the 'too-little too-late' category. Furthermore, the fossil fuel industry is viewed with scepticism and hostility when the various options for developing low or zero-emissions energy are discussed in the public arena. Even though CCS is clearly vital for achieving the required energy transition, the close association of CCS with the fossil fuel industry is often a significant impediment to deployment.

It is therefore argued that changing the CCS mindset towards a 'new-format' CCS industry focused on enabling significant reductions of CO_2 emissions from industry, from cities and from transport systems is a much better societal proposition. Rapid development of surface infrastructure and the subsurface resources needed to realise these emissions-reduction ambitions is urgently needed. This in turn implies that technicians, scientists, and decision makers need to develop 'CO_2 storage resource' concepts enabling the maturation of regions with suitable subsurface storage resources towards operating permits for multiple CCS projects. As argued above, CO_2 storage is technically very different from gas production engineering, but sociologically it must also become a very different kind of industry from the historical oil and gas business if it is to make sufficient progress at the scales needed for climate change mitigation.

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The value of integrated petrographical, sedimentological and structural description and interpretation in assessing CO2 storage sites: A example from the Endurance Field, North Sea

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Driven by the commitment to reach net zero by 2050, appraisal of potential CO_2 storage sites around the UK is reaching a new stage. To date, the UK's storage potential has been reported and the most promising saline aquifers identified, leading to four main carbon capture hubs around the UK to be set up. Recent funding and timescales set out by the UK Government, as well as new CO_2 sequestration licenses being awarded, such as that awarded to Harbour Energy in October 2021, means that specific fields are being investigated for development; whether it be through the interrogation of the wealth of data acquired from historical North Sea oil and gas exploration or through new drilling programs.

As such, reservoir characterisation is coming to the forefront of CO_2 storage site appraisal. The Geological Society of London's Core Values conference in May 2021, highlighted how the use of core, including the acquisition of new core, has a vital place in characterising CO_2 storage reservoirs and cap rocks in order to better understand the specific challenges posed by CO_2 injection, migration and storage.

Building on this, this paper examines how detailed integration of petrographical, sedimentological and structural datasets from a range of different investigation scales, such as thin-section analysis, core description and borehole image interpretation, can enable properties observed at the pore and plug scale to be extrapolated into the uncored intervals and laterally away from the well.

Key factors controlling CO2 injectivity such as relative permeability and pore throat size, are fundamentally controlled by primary sedimentary texture, clay and cement mineralogy and distribution. As such, variation in injectivity is largely associated with depositional make-up, with CO2 migration also affected by depositional architecture (*ie*. sandbody geometry, connectivity and orientation) and an understanding of the cross-cutting sealed vs. open fracture/fault networks. An integrated approach provides understanding of residual trapping and overpressure that may influence CO2 injection, and also allows the identification of high permeability pathways and an assessment of competency of baffles and barriers that will affect migration. As a result, application of a fully integrated dataset will allow for more confidence to be placed in CO_2 injection planning and plume migration modelling.

The presentation will take the Endurance Field, the proposed storage site for the Net Zero Teesside and Zero Carbon Humber CCUS Hubs, as a case study. Its large dataset, obtainable via the NDR and BGS, make it a suitable example to demonstrate the value of integration.

Value of legacy core material to assess subsurface carbon storage reservoir potentiality

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Carbon capture and storage (CCS) is an established technology in mitigating and managing anthropogenic climate change and support has increased globally for its widespread implementation. Consequently, a large increase in the number of planned CCS projects of varying scales has been seen recently. As a result, attention has turned to how to make well-informed decisions on storage sites. Accurate analysis of potential reservoirs is of utmost importance to assess the viability of CO_2 storage projects. Traditionally, reservoir characterisation has been performed using geological core material; the majority of available cores come from the oil and gas industry. However, a number of factors are affecting volumes of core recovered and it's availability: decreases in petroleum exploration as society moves into the energy transition; high costs associated with core recovery and storage: limited financial incentives and the time taken to establish new business models to store post-combustion carbon emissions. It is therefore unlikely that significant amounts of new core will be acquired with purely CCS in mind.

Consequently, legacy core material, originally acquired in the last fifty years for scientific research and petroleum exploration and production purposes, has a renewed value for the goals of modern geoscience. Using legacy core material made available to the CSI research group we describe a series of analytical procedures carried out on X-ray micro computed tomographic (μCT) 3D image reconstructions that aid understanding of permeability as well as porosity. We aim to demonstrate the additional value which can be retrieved from core material using digital image analysis (DIA) and digital rock physics (DRP) techniques - a relatively inexpensive, rapid and non-destructive process. We outline the workflow associated with this technique, detailing the processes of sample preparation, imaging, processing, and measuring geological characteristics and features. Additionally, we present different case studies where this established technique has been used for analysis of geological material in the frame of preliminary CCS reservoir assessment. This technique has been used to measure valuable properties including porosity, pore connectivity, permeability, pore and throat geometry and grain measurements. We showcase work on material from the Wilmslow Sandstone Formation (Sellafield BH13B, UK) and the Scottish Middle Coal Measures Formation (Glasgow GGC01, UK) (Payton et al., 2021), the Brae Formation sandstone (North Sea, UK) (Thomson et al., 2020a; 2020b), Minard Formation (Porcupine Basin, N. Atlantic) and Sherwood Sandstone Group (English Channel, UK) (Payton et al., in review).

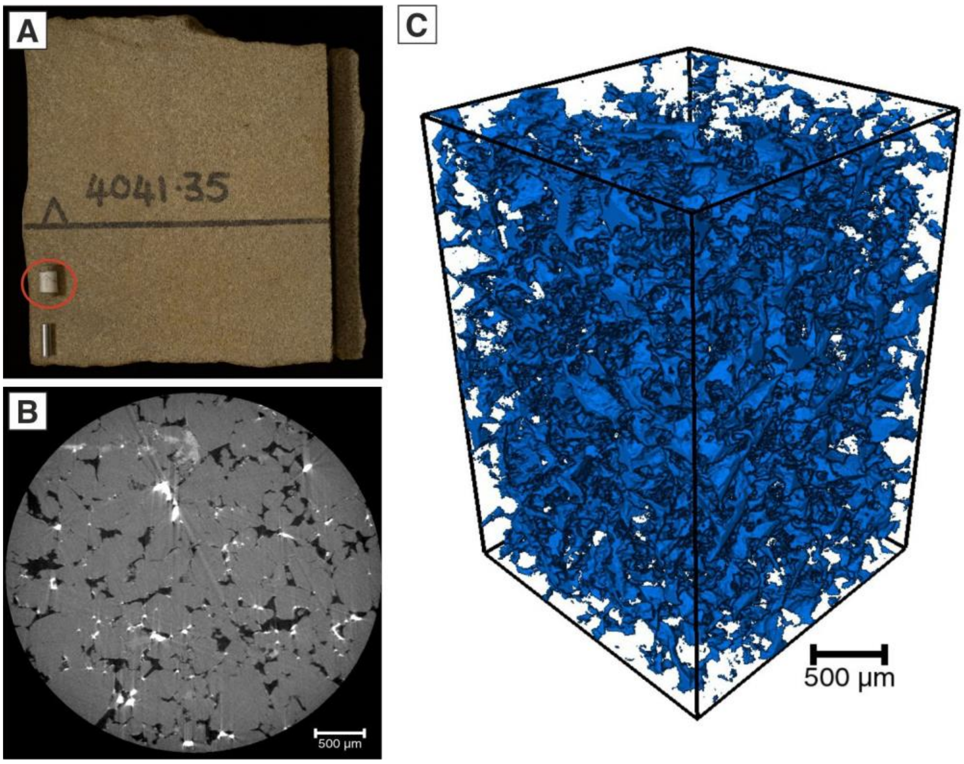

Figure caption – A) Core sample and mini core plug (red circle) of the 16/7b-20 core (Brae Fm.). B) Raw µCT image slice perpendicular to the length of the cylindrical core (core plug). C) 3D volume rendering of connected pore space (blue).

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Pore scale assessment of potential subsurface carbon storage reservoirs using digital image analysis

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Carbon capture and storage (CCS) has become a recognised technology, crucial for facilitating the reduction and management of anthropogenic climate change. At the core of geological carbon storage (GCS) is the ability of a reservoir to fulfil four main criteria to be deemed suitable. (1) The geological unit must have enough space for housing the large volumes of CO_2 which we intend to store in the coming decades. (2) The reservoir properties must be suitable to inject high pressure CO_2 and allow it to then move through the bulk of the reservoir easily and safely. (3) the geological unit should ideally possess a favourable mineralogy to facilitate reaction with the injected CO_2 to produce stable precipitates, securing carbon in the subsurface for geologically significant periods of time. (4) the reservoir must possess suitable controls to ensure that CO_2 remains trapped without leakage. Three of these four criteria can be at least initially assessed by measuring porosity, connectivity and permeability using a digital image analysis (DIA) approach. In this work we show how X-ray micro computed tomographic (μCT) imaging can be employed to analyse core plugs in the context of CCS. We present a porosity-permeability analyses of the Wilmslow Sandstone Formation (Sellafield BH13B, UK), Scottish Middle Coal Measures Formation (Glasgow GGC01, UK), Minard Formation (Porcupine Basin, N. Atlantic) and Sherwood Sandstone Group (English Channel, UK). Within these sample suites we find a range of porosities and permeabilities up to 26.4% and 6040 mD respectively within a wide variety of degrees of connectivity. Using all sample suites together we found the upper percolation threshold, the transition point from partial to full pore connectivity, to be at ca. 14% total porosity (Fig. 1). We also effectively constrained the porosity-permeability relationship above the percolation threshold according to $K = 10^{5.68}\,\phi^{3.88}$, where K is permeability and ϕ is total porosity. Through this investigation we also found that pore characteristics as opposed to those of the throats are the dominant factors in facilitating connectivity within our study samples. From these analyses we are also able to offer recommendations regarding further investigation of these reservoirs for use in GCS.

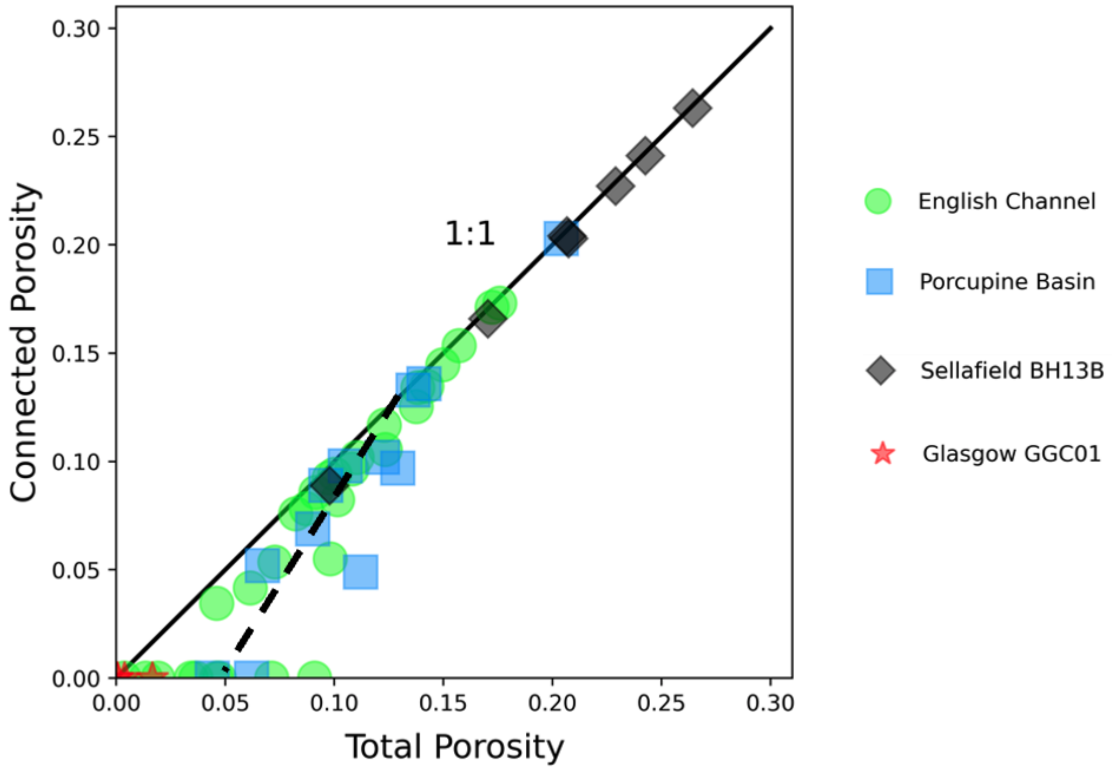

Figure 1. Porosity vs. connected porosity plot including a solid 1:1 ratio line. Samples exhibiting full connectivity plot on the line whilst those with less connectivity plot below the line. Data points begin to fall away from the line at ca. 14% total porosity, marked by the dashed line.

References

Payton, R.L., Fellgett, M., Clark, B.L., Chiarella, D., Kingdon, A., Hier-Majumder, S. 2021. Pore-scale assessment of subsurface carbon storage potential: implications for the UK Geoenergy Observatories project, *Petroleum Geoscience*, 27, https://doi.org/10.1144/petgeo2020-092

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Multi-Scale 3D & 4D Imaging-Based Characterisation Workflows and their Application to Carbon Storage

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The decarbonisation of energy supply from mainly fossil sources to low carbon energy is essential for future environmental sustainability and carbon storage is an indispensable part of this transition and to achieve negative emissions. Multi-scale 3D and 4D imaging-based characterisation workflows on scales ranging from entire basins to the scale of core samples has been proven to be very powerful tools to characterise the subsurface rocks, including reservoirs rocks and seal rocks, and can be readily re-purposed for use in carbon storage applications.

From basin-scale to pore-scale, different techniques can be applied; these are selected based on the resolution required, and what can be achieved by each and on the features that we wish to image and quantify. For example, seismic imaging at basin-scale, macro-scale X-ray computed tomography (Macro-CT) at core-scale, micro-scale X-ray computed tomography (Macro-CT) at micro-scale, nano- -scale X-ray computed tomography (nano-CT) and Focussed Ion Beam Scanning Electron Microscopy (FIB-SEM) at nanoscale, and Transmission Electron Microscopy (TEM) tomography at sub-nanoscale (Figure 1). Formations, lithofacies, aquifer and seal couplets, intra-reservoir baffles fractures, minerals grains, macropores, micropores and nanopores can be imaged in 3D and quantified at corresponding scales (e.g. Figure 2). Meanwhile, physical and chemical measurements, such as geophysical, petrophysics, geomechanics, mineralogy, porosity, permeability, and adsorption can be correlatively applied together with image-based characterisation. Varied modelling approaches such as basin modelling and flow simulations, geomechanical modelling, reactive transport and molecular modelling are performed to understand the in-depth knowledge and physics under the characterised phenomenon.

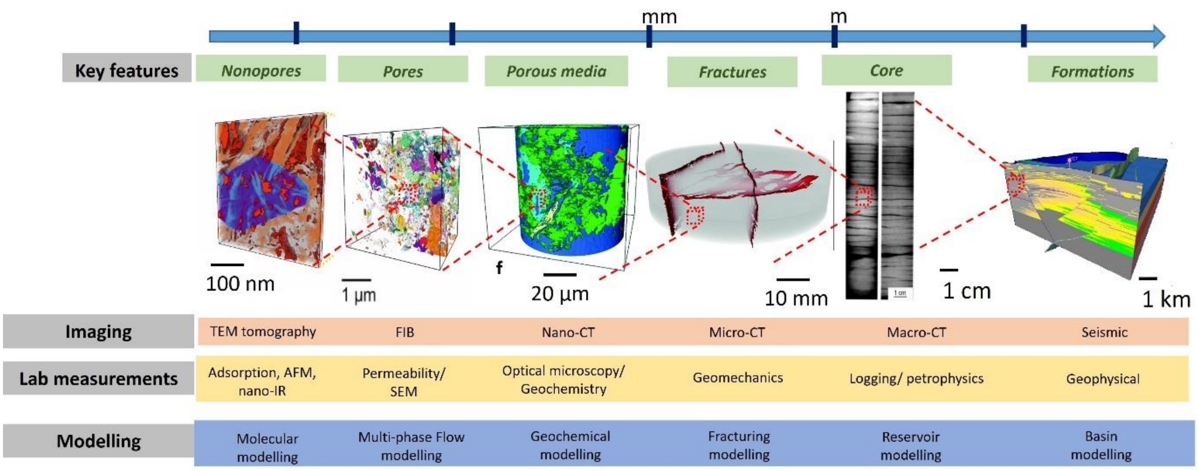

Figure 1 Multi-scale methods for 3D imaging and modelling (modified after Taylor and Ma, 2022, Geo ExPro)

Dynamic imaging can be applied to characterize the temporal and spatial evolution of rocks based on the detailed static understanding. Time-lapse seismic imaging, X-ray tomography imaging and TEM imaging are all appropriate approaches for the thermal-hydro-mechanical-chemical (THMC) processes when carbon dioxide is injected in the subsurface. For example, the sandstone intrusion can be modelled using seismic imaging (Figure 2) and therefore future CO_2 migration in the sands can be predicted based on the basin-scale sandstone distributions. As another example, the micro-nano reactions can be captured using X-ray tomography under real subsurface conditions (Figure 3): high temperature (up to 150 °C), high pressure (up to 65 MPa), mechanical forces (varied conditions, e.g. 500N indentation) and complex chemistry environment (multi-phase liquid and gas flow). The risks and uncertainties can be assessed using these 4D images.

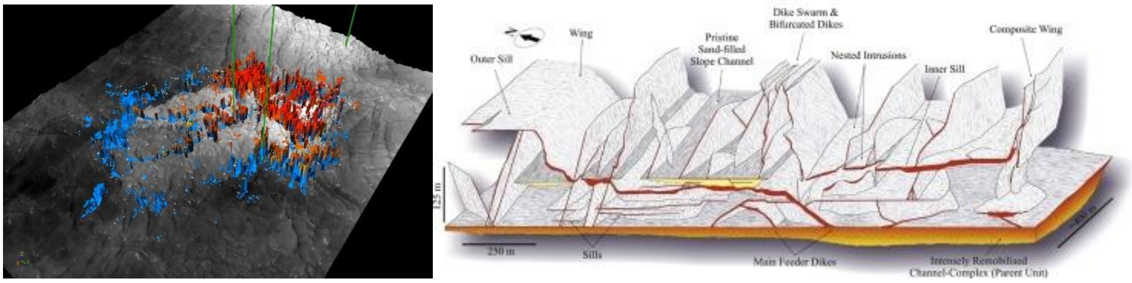

Figure 2 km-scale sand injection complex on UK/Norway border and 3D synoptic model of a large-scale sandstone intrusion complex (modified from Grippa et al., 2020)

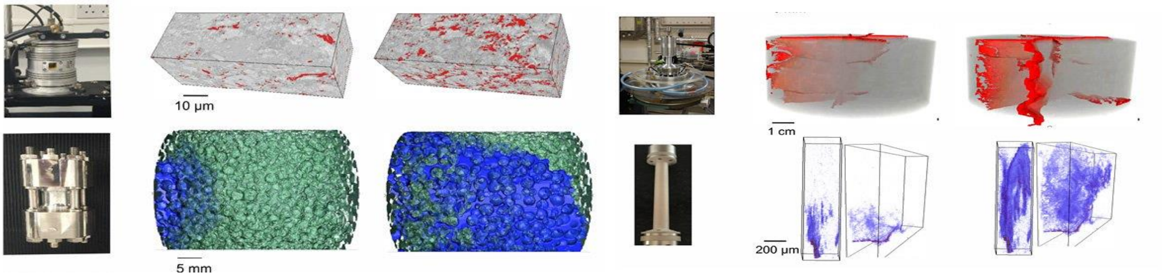

Figure 3: 4D imaging examples of thermal expansion, stimulated fracturing, multi-phase flows and mineral reactions (modified after Taylor and Ma, 2021, Geo ExPro)

It is noted the representativity of sample selection and the upscaling of the imaged behaviours need to be considered with image characterisation and quantification, especially when the scales span many orders of magnitudes (i.e. from nm-scale to km-scale). New development of multi-scale modelling approaches and machine learning assisted characterisation and modelling can even push the boundaries further. Despite promising, challenges remain on the quantification and prediction of complex subsurface reactions after long term CO_2 injection. It is undeniable that the multi-scale 3D and 4D imaging-based characterisation and modelling will contribute significantly in multidimensional quantification of the rocks under subsurface conditions for minimising risks and optimising operations in practice.

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Multiscale Stratigraphic Reservoir Characterization for Flow and Storage of CO2: Missing Models, Data and Quantitative Understanding

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Numerous studies have quantified the key geological heterogeneities that impact on flow and hydrocarbon recovery, using nested, high-resolution models that span the core- to reservoir-scale. These studies have also calculated effective (upscaled) properties relevant to hydrocarbon production that can be used to represent the impact on flow of smaller-scale heterogeneities in larger-scale models. The equivalent level of detailed, multi-scale modelling for CO2 storage has not yet been undertaken, to extend our understanding to the key metric of storage (not recovery), different fluid properties, and trapping mechanisms such as dissolution and precipitation unique to CO2 storage. In addition, both imbibition and drainage processes are relevant at the leading and trailing edges of the CO2 plume and the timescales of interest are much longer.

The main challenge in a CO2 dedicated reservoir characterization process is to determine which 3D sedimentological and stratigraphic heterogeneity type(s) at which scale(s) and in which configuration are most important for successful long-term CO2 storage. Thus, which heterogeneity type(s) matters most to CO2 sequestration at short (1 to 10 years), medium (10 to 1000 years) and long (more than 1000 years up to 10000 years) time scales?

Heterogeneities disperse the CO2, which slows the rate at which the CO2 reaches the limits of the storage site, and heterogeneity can create multiple mini-traps within the storage unit, thus increasing the storage efficiency. The heterogeneities can be considered as a set of sieves in the reservoir with varying modelling accuracy. The coarsest scale (the combined largest and most effective barriers) captures the largest volume of the CO2 when it passes through; subsequent finer sieve sizes capture increasingly smaller but still migrating volumes. In contrast, reservoir heterogeneity is detrimental in the case that one or more effective thief zone(s) are present, as these will not trap but funnel CO2.

Integrated characterisation of these heterogeneities and their effects on flow can be accomplished with a hierarchical geomodelling strategy deploying the Representative Element Volume (REV) concept. It is associated with a dedicated upscaling methodology that successively incorporates small- to large-scale heterogeneities from pore- to reservoir-scale.

The convective dissolution process in CO2 sequestration is governed by a combination of complex physical phenomena: buoyancy driven migration, dissolution of CO2 into the brine, capillary forces, chemical interactions between components of the CO2 stream and brine, diffusion, convection, and multiscale reservoir heterogeneity. The predictive capacity of modern reservoir simulators has been hampered to date by the lack of geologically realistic input models that capture key heterogeneities of interest across length-scales. At longer time scales (hundreds to thousands of years), both numerical and analytical models only approximately represent the dissolution trapping that dominates in the reservoir. Rigorous numerical investigation using an appropriate thermodynamic (phase behavior) model, and relevant physical phenomena for accurate prediction of long-term dissolution trapping in CO2 sequestration projects is required.

Assessing the Capillary Sealing Potential of Argillaceous Successions ("Shales") in an Immiscible CO_2-H_2O Fluid System : Integrating Rock, Wireline Log and Seismic Data

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The 2015 Paris Agreement set the goal of constraining long-term global temperature change to less than 2°C over pre-industrial levels. The primary mechanism for achieving this relies upon reduction of CO_2 emissions to the atmosphere. Carbon capture and storage (CCS) represent a significant component of the required reduction in atmospheric CO_2.

Geological sequestration (GCCS) is potentially capable of achieving the required contribution from CCS to atmospheric CO_2 mitigation. Storage opportunities identified for GCCS are injection in depleted oil and gas reservoirs, storage in saline aquifers, and enhanced oil recovery (EOR). Currently, multiple small to industrial-scale GCCS projects exist globally as EOR and saline aquifer storage. Combined, these projects sequester 35 to 40 megatons/year CO_2 versus the 5 to 10 gigatons/year CO_2 sequestration required by 2050 to achieve the 2°C goal of the Paris Agreement. Thus, a rapid increase in the scale of geological storage of CO_2 is required, which means a need to rapidly evaluate the feasibility of a large range of possible subsurface storage opportunities. A key component of these subsurface evaluations relies on characterizing the sealing potential of the caprocks overlying the storage reservoirs. From reservoir presence & quality, trap geometry and monitoring perspectives, shallow (~1 to 2km burial depth) saline siliciclastic aquifers represent a much more favourable and sizeable storage opportunity relative to deeper depleted oil and gas reservoirs (Fig. 1). Most of these aquifers are capped by shales, understanding the sealing capacity of these heterogenous argillaceous successions ("shales") is pivotal in assessing storage capacity in such settings.

Like the geologic time-scale entrapment of petroleum fluids, the primary control on flow and retention of supercritical CO_2 in a water-wet medium are capillary and buoyant forces. The two largest differences between CO_2 and hydrocarbons with respect to retention are fluid phase and trap geometry (or reservoir geometry). CO_2 is injected as a supercritical fluid, which is a dense (0.5 - 0.7 g/cc), low viscosity (0.02 – 0.06 cP) fluid that maximizes injectivity & storage and minimizes buoyancy forces. Additionally, supercritical CO_2 reduces aqueous solubility and concomitant mineral reactivity which allows evaluation for migration and retention as an immiscible fluid using approaches like those applied in the petroleum industry. Optimal reservoir geometries for CO2 storage are low relief broad traps, thus minimizing the buoyant forces at crestal trap locations that could compromise capillary seal capacities. Such reservoir-trap geometries are in distinct contrast to those typically exploited by the petroleum industry, which tend to be relatively high relief to maximize resource density and improve drill-well economics.

Developing appropriate descriptions of heterogeneous capillary rock properties of large caprock successions can be a daunting task. A systematic approach developed in the oil & gas industry is presented here (Fig. 2). Rock property data (Mineralogy and MICP tests) measured on cores or cuttings is correlated to wireline log data (such as porosity and clay mineral content) to develop capillary threshold pressure profiles. These profiles can be related to seismic reflection data, both through developing seismic stratigraphic packages and surfaces as well as through direct correlation to elastic attributes (acoustic impedance and Vp/Vs ratio). High resolution subsurface models of shale successions can then be built to be simulated for seal breach and containment in CO_2-H_2O systems under capillary-buoyant considerations to identify the most favourable subsurface storage locations.

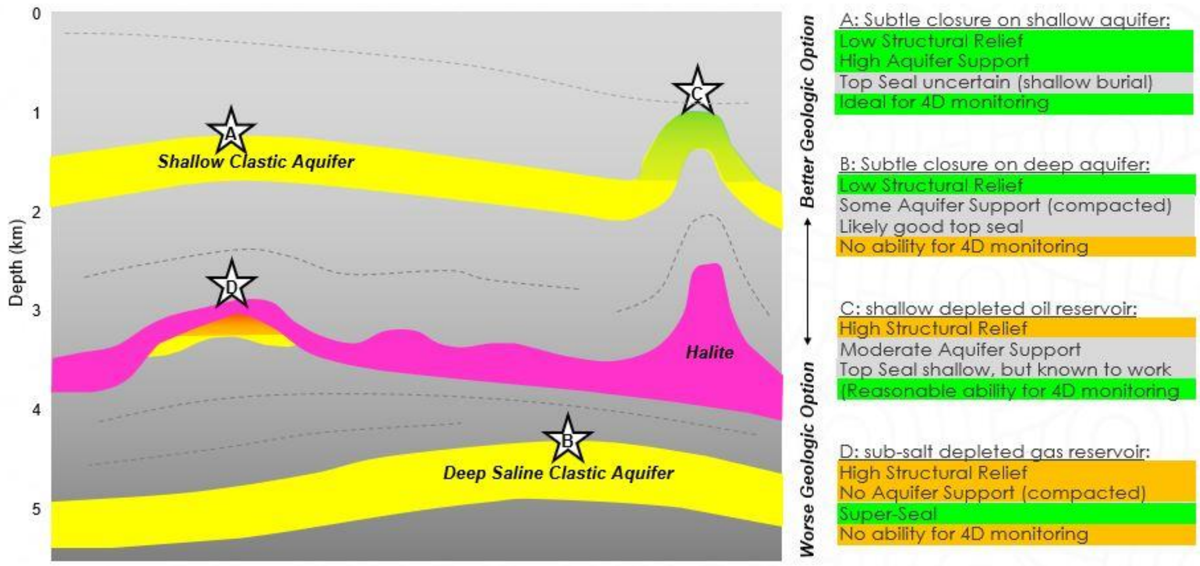

Figure 1: Cartoon cross section through a sedimentary basin, illustrating a plethora of potential GCCS sites. From basic geologic principles of reservoir architecture, trap geometry, volumetric potential and monitoring ability, shallow saline aquifers represent a favourable storage opportunity when compared to depleted oil and gas reservoirs. Key uncertainty is the capillary sealing potential of heterogeneous argillaceous caprock succesions (“shales”).

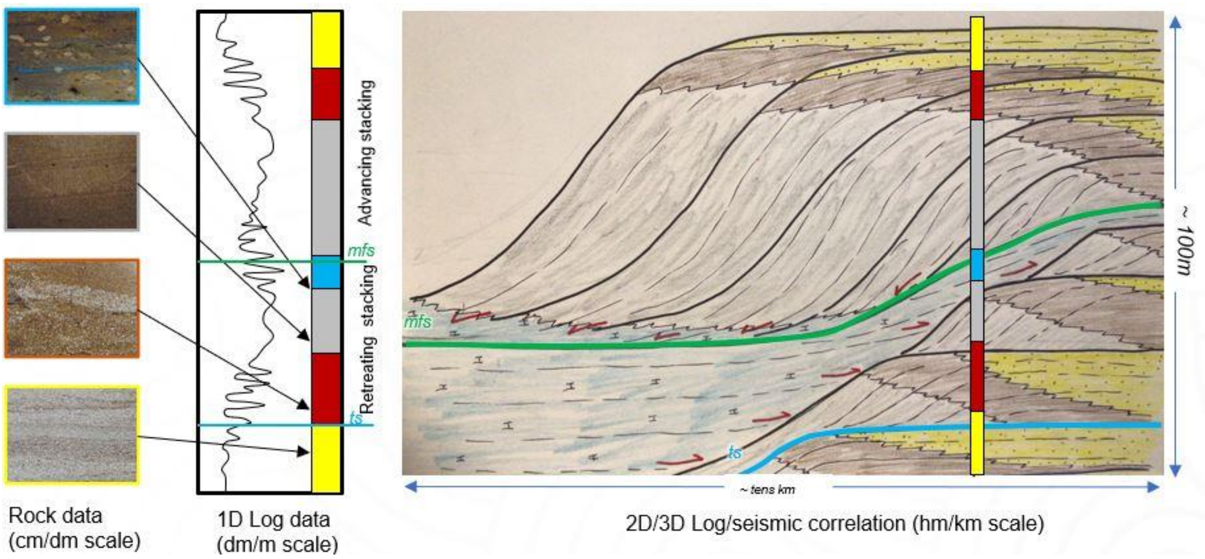

Figure 2: Workflow diagram illustrating the basic approach of integrating rock property data with wireline log properties and qualitative (reflection geometries) and quantitative (elastic rock properties) seismic data to develop high resolution capillary property models for simulation.

Closing Keynote - "ENI UK Liverpool Bay CCS: An Advanced project contributing to the UK's carbon neutrality"

Alessandro Aleandri, Eni UK Ltd

William Dickson, Eni UK Ltd

Claudio Nini, Eni UK Ltd

Eni UK Liverpool Bay CCS: an advanced project contributing to UK's carbon neutrality

Authors: B. Becker, C. Nini, A. Aleandri

As part of Eni's objective of eliminating net GHG emissions by 2050, Eni UK is participating in the ambitious HyNet Project as lead developer of the Transportation and Storage system. The HyNet project aims to de-carbonize northwest England and north Wales regions by producing blue hydrogen and storing the resulting CO2 and industry's carbon emissions in the area. The project has been selected as a Track 1 Cluster within the UK Government Cluster Sequencing process, allowing HyNet and Eni the opportunity to become one of the first UK industrial clusters to contribute to the UK energy transition and carbon neutrality measures to limit the global warming in line with the Paris Agreement.

Eni UK will develop and operate both the onshore and offshore transportation and storage system, providing a service for emitters to transport and permanently store CO2 offshore in the Company's depleted Liverpool Bay hydrocarbon fields. Eni plans to reuse and repurpose the depleted Triassic Ormskirk reservoir in the three offshore fields of Hamilton, Hamilton North and Lennox and the associated infrastructure to transport and store carbon dioxide.

The presentation aims to summarize how a pioneering project, exploits the large, consolidated geological knowledge base gained from the long term management of O&G fields to the benefit of the energy transition.

Through advanced subsurface workflows, Eni has, over the past 3 years, completed multidisciplinary studies for the evaluation of carbon dioxide containment and storage, utilizing and revising the large volume of subsurface data collected and analysed during the management of the selected fields.

Studies performed to date range from 3D models to fault seal analysis, geomechanical and geochemical evaluations, and all demonstrate that the fields are suitable candidates for the purpose of CO2 sequestration. The presentation will also address key differences with standard O&G workflows.

Moreover, an intensive data collection programme, tailored to the new objectives, in addition to crucial Measurement-Monitoring-Verification (MMV) activities is being planned to lay the foundations for the operating phase of the project.

Once operational, the project will transform one of the most energy-intensive industrial districts in the UK into one of the world's first low carbon industrial cluster and will help reduce CO2 emissions by up to 10 million tons each year beyond 2030.

POSTER ABSTRACTS

A Screening Assessment of the Impact of Sedimentological Heterogeneity on CO_2 Migration and Storage: Sherwood and Bunter Sandstones, UK

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The Triassic Sherwood Sandstone Group and stratigraphically equivalent Bunter Sandstone Formation are widely considered for large-scale CO_2 storage in saline aquifers (e.g. Endurance storage site, southern North Sea) and depleted hydrocarbon reservoirs (e.g. Liverpool Bay oil and gas fields) of the onshore and offshore UK, because of their high storage capacity and favourable injectivity. The impact of stratigraphic and sedimentological heterogeneities on CO_2 migration and storage in these units has been limited to date, although it is recognised that sedimentological heterogeneities can disperse the injected CO_2 plume as it migrates and also create small-scale stratigraphic trapping configurations that increase CO_2 storage efficiency.

We use a combination of experimental design, sketch-based reservoir modelling, and flow diagnostics to rapidly screen the impact of sedimentological heterogeneities on CO_2 migration and storage by stratigraphic trapping in the Sherwood Sandstone Group and Bunter Sandstone Formation. Integrated sketch-based reservoir modelling and flow diagnostics are implemented in open source research code (Rapid Reservoir Modelling, RRM). Our aim is to identify the key sedimentological heterogeneities that control CO_2 migration and stratigraphic-trapping potential, as a precursor for later capillary, dissolution and mineral trapping.

The Sherwood Sandstone Group and Bunter Sandstone Formation consist of fluvial sandstones with subordinate aeolian sandstones, floodplain and sabkha heteroliths, and lacustrine mudstones. The types and spatial organisation of sedimentological heterogeneities are constrained using published descriptions of these units at outcrop and in the subsurface. The predominant control on effective horizontal permeability is the lateral continuity of aeolian sandstone intervals. Effective vertical permeability is controlled by the lateral extent, thickness and abundance of lacustrine mudstone layers, the lateral extent of sheetflood sandstones in floodplain-and-sabkha-heterolith layers, and also the lateral continuity of aeolian sandstone intervals. Storage efficiency due to stratigraphic trapping is approximated by the pore volume injected at breakthrough time, which is controlled largely by three heterogeneities: (1) the lateral continuity of aeolian sandstone intervals; (2) the lateral extent of lacustrine mudstone layers, and (3) the thickness and abundance of fluvial-sandstone, aeolian-sandstone, floodplain-and-sabkha-heterolith and lacustrine-mudstone layers. Other investigated heterogeneities have little influence, including the proportion and connectivity of channelised fluvial sandstones in floodplain-and-sabkha-heterolith layers, and the lateral extent and distribution of carbonate-cemented basal channel lags in multilateral, multistorey fluvial-sandstone layers. Our results suggest that future effort should be focussed on characterising the lateral extent and continuity of high-permeability streaks (e.g. aeolian sandstones) and low-permeability barriers (e.g. lacustrine mudstones), and stratigraphic layering of these and intermediate-permeability rock types.

Caprock integrity evaluation for geosequestration of CO_2 in depleted petroleum reservoirs

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Carbon dioxide (CO_2) geosequestration represents one of the most promising options for reducing atmospheric emissions of CO_2. It is an achievable option that may satisfy the demand for future large-scale seasonal energy storage, and improved oil recovery. CO_2 geosequestration has been proposed as one solution to global climate change caused by heat-trapping of anthropogenic gases in the atmosphere. However, caprock integrity ascertained based on the geomechanical and petrophysical properties of caprock is vital to ensure safe and sustainable storage of CO_2. Therefore, the aim of this research is to evaluate caprock integrity under cyclic stress loadings. In specific terms, the objective of the study is to investigate the impact of overburden and fluid pressure variation on caprock properties as CO_2 is injected and stored in the reservoir over a long period.

This research will be conducted using numerical simulation and experimental studies. The research design will be based on numerical modelling using ANSYS Workbench. The numerical study will be based on time-dependent effects during petroleum reservoir depletion and re-pressurisation, and CO_2 injection and storage. The numerical simulation results will be validated using results from relevant experimental studies conducted by previous researchers. Data will be analysed using ANSYS software and broader data visualisation will be generated using Microsoft Excel Spreadsheet package, and the results will be presented as tables, graphs or images. Findings of the study will help understand how caprock integrity is impacted as CO_2 is injected and stored in the reservoir over a long period and under variation in pressure within the system. This would be achieved by evaluating the variations in stresses and strains within the caprock during the period of CO_2 injection and storage.

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DNA Diagnostic enabled Total Fluid Monitoring Tool applied as a Non-Invasive, Cost-Effective, Low Carbon Footprint Surveillance Technology for CCUS/CCS Complexes.

GeolSoc: **Applicability of Hydrocarbon Subsurface Workflows to CCS**

Authors: **Caroline Burke**, Matthew Haggerty, Mathias Schlecht,Thomas Ishoey

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Carbon Capture and Storage is now accepted as the only technologically viable method to mitigate carbon emissions and control climate change, while keeping net-zero targets within reach. Federal and State incentives have made CCS/CCUS economically viable and the focus of much of the growing decarbonization effort. While significant progress has been made in CCS technology in the last decade, there are still many challenges to commercial deployment.

Biota presents an independent tool to help high-grade, de-risk and monitor subsurface carbon storage opportunities, inform management strategies and provide long-term monitoring to improve efficiency and meet regulatory requirements.

The application of DNA markers to inform CCUS applications is a parallel to Biota's current commercial applications of DNA monitoring in Oil & Gas which have facilitated insights into Drained Rock Volumes (DRV's), fracture barrier integrity, total fluids production allocation, enhanced recovery with pressure management across a pad and improved sweep efficiency with water flooding.

Subsurface DNA diagnostics provides a spatially and temporally scalable, non-invasive measurement for tracking fluid movement in the subsurface. DNA enabled total fluid monitoring can inform both cap-rock integrity over time and flag changes in aquifers and rock formations that should be safely above the cap-rock or beyond the modelled limits of the CO2 plume. This is a high resolution, cost-effective and low carbon foot-print monitoring technology which can be carried out over the lifetime of a project. The ease of sampling and rapid turnaround time will allow for active field development management ensuring maximum CO2 storage. The technology provides leading indicators which can be used to trigger more cost and effort-intensive field monitoring or development technologies.

The applications discussed in this paper will include high resolution, time-lapse monitoring of total fluid from the storage complex and overburden enabling detection of any perturbations in the microbial system, CO2 plume migration monitoring, the use of leading indicators for supercritical-CO2 front detection as well as potential microbial remediation upon CO2 dissolution.

DNA diagnostic enabled total fluid monitoring must be part of an integrated, multi-disciplinary approach for effective CCS/CCUS implementation and surveillance. The DNA marker stratigraphy is also a valuable new dataset to integrate with other subsurface data to enable improved, high resolution reservoir models leading to more robust predictions of CO2 migration.

This technology promises to be an integral tool to ensure safe storage of CO2 and in doing so play an important role in the journey to net zero.

A Screening Assessment of the Impact of Sedimentological Heterogeneity on CO_2 Migration and Storage: Johansen and Cook Formations, Northern Lights Project, Offshore Norway

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The saline aquifers of the Johansen and Cook formations constitute the primary CO_2 storage unit in the Northern Lights project, offshore Norway, but are sparsely sampled in the storage site. As a result, there remains uncertainty in the types, distribution and potential impact of sedimentological heterogeneities in the wave-dominated deltaic sandstones of the Johansen-Cook storage unit.

We use a method combining experimental design, sketch-based reservoir modelling, and flow diagnostics to rapidly screen the impact of sedimentological heterogeneities on CO_2 migration and storage by stratigraphic trapping. Experimental design allows efficient exploration of a wide parameter space, sketch-based modelling enables rapid construction of deterministic models of interpreted geological scenarios, and flow diagnostics provide computationally cheap approximations of full-physics, multiphase simulations that are reasonable for many subsurface-flow conditions. Integrated sketch-based reservoir modelling and flow diagnostics are implemented in open source research code (Rapid Reservoir Modelling, RRM).

The types and spatial organisation of sedimentological heterogeneities in the wave-dominated deltaic sandstones of the Johansen-Cook storage unit are constrained using publically available core data from the 31/5-7 (Eos) well, previous interpretations of seismic data and regional well-log correlations, and outcrop and subsurface analogues. Delta planform geometry, clinoform dip, and facies-interfingering extent along clinoforms control the distribution and connectivity of high-permeability medial and proximal delta-front sandstones, effective horizontal and vertical permeability characteristics of the storage unit, and pore volumes injected at breakthrough time (which approximates storage efficiency due to stratigraphic trapping). In addition, the lateral continuity of carbonate-cemented concretionary layers along transgressive surfaces impacts effective vertical permeability, and bioturbation intensity impacts effective horizontal and vertical permeability. The combined effects of these and other heterogeneities are also influential. Our results suggest that more detailed modelling studies should in future incorporate the effects of sedimentological heterogeneity on CO_2 migration and stratigraphic-trapping potential, as a precursor for later capillary, dissolution and mineral trapping.

Large Scale Regional Carbon Capture Storage: is there a place for regional high-end quality multi-client dataset-product?

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The world is in urgent need of Carbon Capture storage (CCS) sites/facilities to achieve ambitious net carbon dioxide (CO2) emissions goals. After CO2 capture and transport, storage is the third step, into the CO2 journey. One way to store CO2 in significant quantities is to identify sufficiently largescale CCS sites. At present, there are less than 30 sites worldwide storing around 40 Mt of CO2/year (GCCSI, 2020; Ringrose and Meckel, 2019), and the expectation is to have close to 300 Mt storage capacity per year by 2050 (European Commission, 2018). Thus, there is an immediate need to identify viable CCS storage sites fast. To do this, accessing large scale regional quality seismic information would be a significant step in that direction.

In the present case study, we have developed and implemented an integrated G&G workflow over a proof-of-concept (PoC) area considering two aspects of the CCS storage: capacity and the containment. Other aspects of CCS, such as injectivity and monitoring, will be assessed at a later stage. The integrated CCS site assessment workflow allows validation of the various technologies, workflows locally with the option and feasibility to be expanded regionally. The objectives being to evaluate the use of all the data (seismic and wells) for the capacity and containment assessment.

The current PoC has been established using PGS regional multi-client broadband dataset in the North Sea which comprises an extensive cross border regional dataset in the UK and Norway. The broadband nature of the seismic data allows significant and efficient site assessment value, especially for storage capacity and the containment, by providing detailed descriptions and understanding of the subsurface, more accurate/reliable pre-stack attributes for key storage parameters such as: net-to-gross, porosity and thickness. All of this determined mainly using the seismic dataset and very few calibration wells. Capacity analysis is run in parallel to containment evaluation analysis which will be highlighted during the presentation.

This PoC is showing that getting access to regional recent broadband dataset permit to evaluate site in an efficient and in reliable manner.

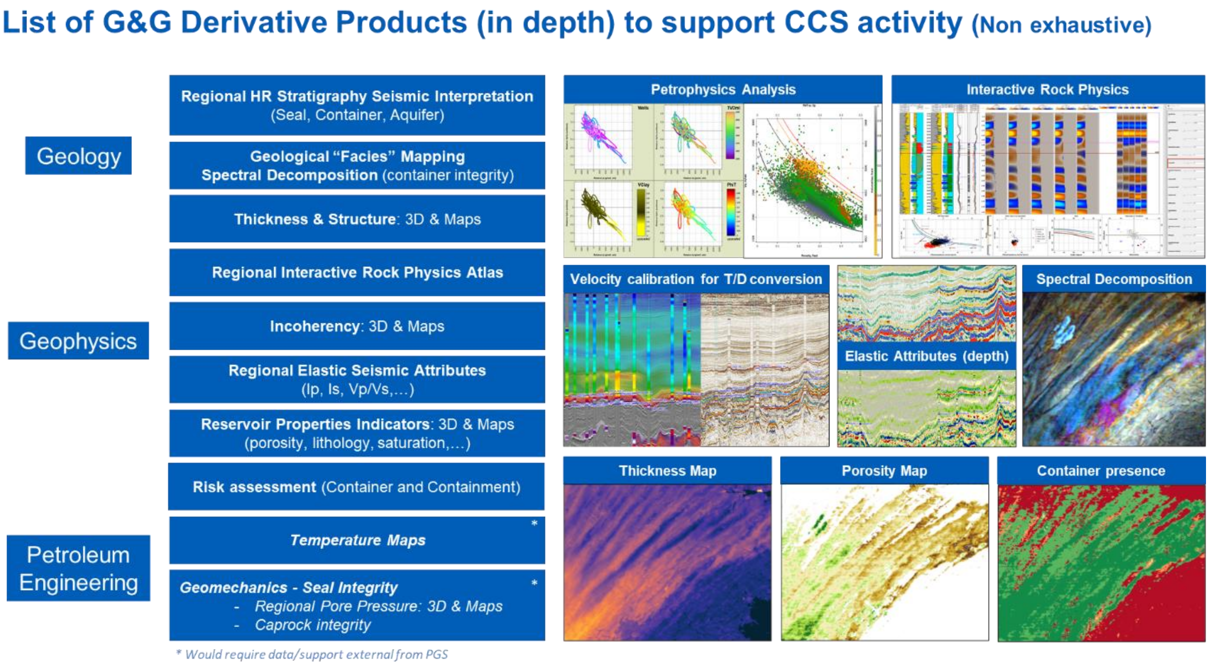

Figure illustrating the main results obtain through our integrated G&G workflow.

CO2 Geological Storage: Digital tools for Screening & Maturation of Marketable Volumes

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Many organisations and governments have committed to Net Zero GHG emissions by 2050 - or earlier- with more to follow suit after the recent IPCC report and the agreements arising from COP-26.

Effective CCS will be the key enabler of new business models to meet Net Zero. These include carbon negative (and permanent) CO2 storage – whether the source is atmospheric (direct air capture), industrial (cement, steel) or cleaner energy solutions such as Biomass Energy with CCS (BECCS). CCS will also enable otherwise stranded fossil fuel operations during energy transition.

Site selection may be different, depending on each business model. Depleted oil/gas fields may be accessible, data rich with existing infrastructure; however, they may be challenged in terms of storage capacity and scalability, as well as containment risks. Saline aquifers comprise an extensive portfolio of crucial Gigaton scale CO2 storage options, though they may pose challenges to characterisation through data gaps and uncertainties.

Volumetric estimations of CO2 storage to marketable (commercially viable) volumes will require clear technical guidelines through specialised subsurface expertise. To ensure safe and permanent containment, three (3) technically robust core activities are required. 1. Storage characterization & CO2 storage resources estimation with a consideration of scalability. 2. Containment risk assessment: Considering geological but also anthropogenic (wells) leak paths. 3. Costs and risk mitigation: Implementing the correct technologies to ensure permanent containment and storage effectiveness.

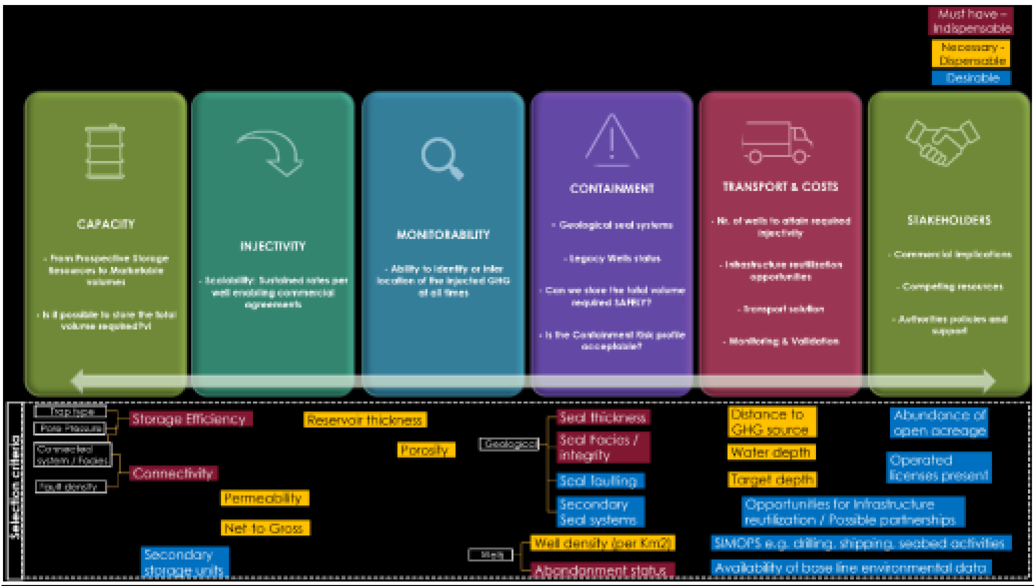

Fig. 1 - Requirements and specific criteria for a successful GHG/CO2 storage site

Aiming to aid develop viable projects within an optimal timeline, there are key selection criteria (Fig.1 - bottom) that can be used to rank prospective geological storage sites, either if they are depleted fields or saline aquifers. These criteria help establish what available data is needed to carry out an adequate risk assessment and estimation of CO2 storage resources, but also potential data acquisition/appraisal plans.

The author has developed a user-friendly App to carry out high level assessments of suitable geological storage sites. The App would not replace a detailed site-specific assessment towards a CO2 storage verification or certification, but it can be useful to establish a first pass idea of the maturity/confidence of a particular candidate storage site.

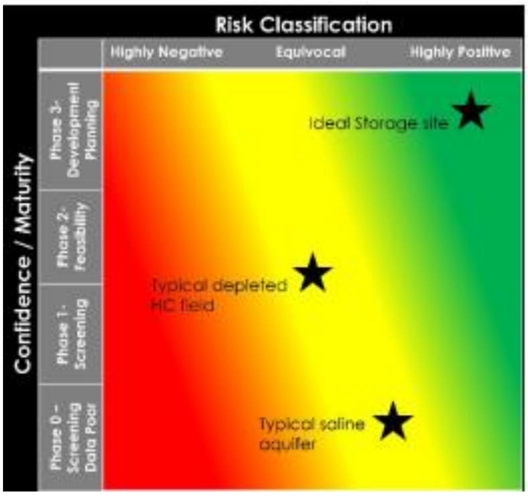

Fig. 2 – Classification system implemented in our GHG/CO2 Storage screening App

The App can help define storage suitability and maturity level following Technical requirements, but also other requirements within the “ECOP” spectrum. Based on specific criteria linked to the 6 main requirements (Fig.1), the App provides an Objective Classification in terms of Qualitative RISK and Level of MATURITY/CONFIDENCE (Fig. 2).

The ultimate intention is to support operators, and authorities alike, mature reliable CO2 storage resources, following the SPE SRMS system, but also ensure permanent containment through a multidisciplinary Containment Risk analysis, resulting in strictly risk-based Monitoring and Verification plans that meet International and Australian technical standards and requirements.

From experience on high-profile CCS projects in Europe, the author identified the missteps that can occur when petroleum professionals have attempted to quantify CO2 storage resources. Therefore, the App can be linked to a code that, with the relevant input, can adequately account for all dynamic aspects of CO2 injection into saline aquifers or depleted fields, which allows to estimate realistic CO2 storage resources for a particular notional development plan (Fig. 3).

This tool underlines the importance to consider site specific transient effects in Pressures, caprock integrity, rock and fluid Compressibility, Temperature, CO2 density, stress regime, among others, over the static pore space analysis often used by petroleum professionals when CO2 storage resources are reported.

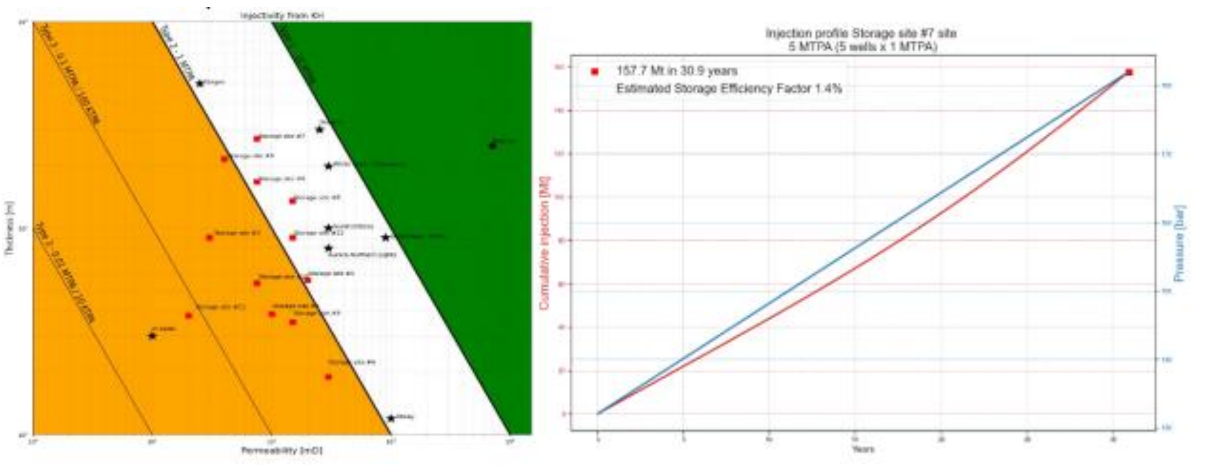

Fig. 3 – Example outputs from our tool to reliably estimate CO2 storage resources

Geologic storage of CO2: numerical modeling of the geological history for site screening and storage modeling

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Geosciences have taken a leap forward with the growing demand for Oil and Gas during the last decades. We learned how to characterize the deep sub-surface in order to better predict habitat and nature of trapped hydrocarbons and we developed dedicated workflows and tools to help us doing it.

Geoscientists and subsurface modelers have now to face a new challenge: where and how could we inject huge volumes of CO2 in the deep saline aquifers of the subsurface?

More precisely, we will first need to characterize the deep saline aquifers very precisely in order to find the best spots where to set up injection facilities. In a similar way with oil and gas exploration, we will have to explore the sedimentary basins to find optimal injection sites. Once the screening phase is completed, we will have to design the exploitations and forecast their impact on the environment.

The screening for injection sites is based on several parameters including porosity, permeability, and aquifer thickness. These parameters are controlled by geologic factors like sedimentologic processes, burial and subsequent overpressure rise and compaction. Knowing that very few data are usually available for such deeply buried geologic objects making data interpolation unreliable, we will have to understand and model the past to better characterize these aquifers and their surrounding sedimentary basins, as it is at present.

Oil and gas explorationist have developed numerical codes dedicated to the simulation of these processes: i) the stratigraphic models which simulate the sedimentologic processes through geological times and deliver a full 3D prediction of the sedimentological architecture of a basin and ii) the so-called “basin models” which simulate compaction and subsequent fluid flow through geological time and deliver a full 3D description of porosity, permeability, fluid pressure and vertical stress at present. With very few improvements, these basin models will help us to identify the best injection spots in terms of available storage volume, injectivity and risks of leakage or cap rock destabilization.

After the screening, when the injection sites are selected, we will need to design the injection process. At this stage, we will use dedicated simulators inherited from the so-called “reservoir simulators” used at present to simulate hydrocarbon reservoir exploitation. At this stage, the information delivered by the simulations of the geological processes through geological time will be used as initial and boundary conditions. Rock properties, pressure and stress calculated by these models inherited from the so-called “basin simulators” will be used as inputs.

Each simulation tool used in this general workflow is presently more or less available, and little improvements are necessary to update them for this new use. We illustrate this presentation with a demonstration on a real case study in the North Sea, where we learned to use numerical modeling of the geological history (“basin modeling” according to the Oil & Gas workflows) to screen the basin for the best injection spots. This study clearly demonstrated the added value of the modeling of geological history to better characterize the target aquifers in terms of injectivity, storage capacity and risks by using standard basin modeling workflows as well as quick-look injection simulations.

Pore scale numerical modelling of CO_2 mineral trapping using true pore geometries

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During the process of storing CO_2 in subsurface reservoirs a series of processes take place allowing carbon to be sequestered; mineral trapping is the most secure and offers the most long-term storage solution. Mineral trapping occurs where host rock silicate minerals dissolve in the induced low pH environment, following CO_2 injection, releasing reactive metal cations (Ca, Mg, Fe). These cations react with free carbonate ions forming thermodynamically stable precipitates such as calcite, magnesite, and siderite. In this work we consider the precipitation of $CaCO_3$, this process can be described chemically according to the following:

$$sCO_2 + H_2O_{(l)} \leftrightarrow H^+_{(aq)} + HCO^-_{3\,(aq)} \tag{1}$$

$$CaAl_2Si_2O_{8\,(s)} + 8H^+_{(aq)} \leftrightarrow Ca^{2+}_{(aq)} + 2Al^{3+}_{(aq)} + 2H_4SiO_{4\,(aq)} \tag{2}$$

$$2Al^{3+}_{(aq)} + 2H_4SiO_{4\,(aq)} + H_2O_{(l)} \leftrightarrow Al_2Si_2O_5(OH)_{4\,(s)} + 6H^+_{(aq)} \tag{3}$$

$$Ca^{2+}_{(aq)} + HCO^-_{3\,(aq)} \leftrightarrow CaCO_{3\,(s)} + H^+_{(aq)} \tag{4}$$

The processes facilitating carbon capture and storage (CCS) through mineral trapping are occur at the pore scale and therefore it is crucial to understand controlling factors on reaction at this scale in a CCS context. In this work we present a novel technique of investigating the influence of reactivity and availability of solid reactant on the mass of $CaCO_3$ precipitated over a 2,000 year period. In addition, we investigate how the geometry (branching, throat sizes and tortuosity) of the pore structure itself influences both the mass of $CaCO_3$ precipitated as well as its spatial variation. We present an advection-diffusion-reaction numerical model based on the finite element method which is directly applied to a 3D model domain extracted from X-ray micro computed tomography (µCT) images. The processes considered by our model can be summarised schematically in Figure 1.

Using this model, we find evidence that a greater tortuosity, greater degree of branching and narrower pore throats are detrimental to mineral trapping. Greater tortuosity and branching can result in isolating significant portions of the pore structure from fluid flow due to preferential flow pathways developing. This has the potential to reduce the efficiency with which a storage reservoir is filled. Meanwhile, narrower pore throats show significant potential to clog and isolate key pathways throughout the structure, further reducing the efficiency of storage. We suggest that a tortuosity of less than 2 is critical in promoting greater precipitation per unit volume and should be considered alongside porosity and permeability when assessing reservoirs for geological carbon storage. We are also able to use our model to show that the dominant influence of the precipitated mass of $CaCO_3$ is the Damköhler number, or reaction rate, as opposed to the availability of reactive minerals. Therefore, we are able to recommend a focus on reactivity when engineering subsurface carbon storage reservoirs for long term security.

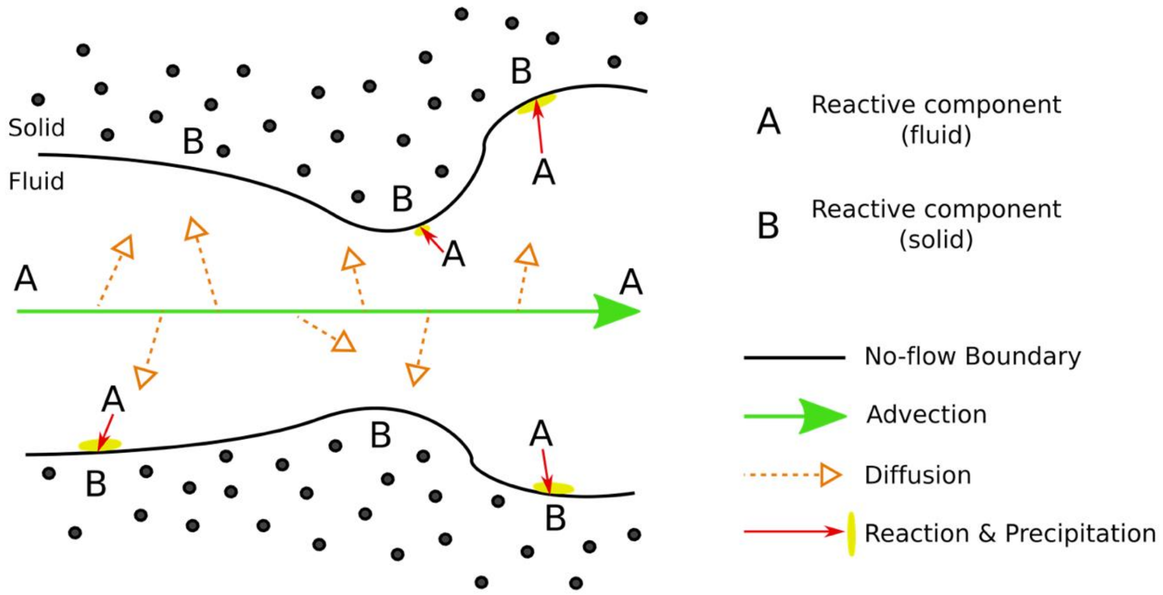

Figure 1. Schematic representation of the advection-diffusion-reaction processes described by the numerical model.

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Assessment of a Miocene CCS Prospect using Seismic Facies Analysis, Norwegian North Sea

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Carbon Capture and Storage (CCS) plays an important role in net zero scenarios aligned with the Paris Agreement (IEA, 2021). Saline aquifers that have tens of megatons storage capacities are the most suitable targets with the advantage of the data acquired and evaluated for hydrocarbon exploration purposes (Lloyd, 2021). The North Sea is in effect a laboratory for CCS studies with its long history of exploration and production of large hydrocarbon fields resulting in a vast database of exploration and production data. In this study, we assess a potential CCS field by analysing the Zulu Øst shallow gas discovery located on the Patch Bank Ridge (PBR) in the Norwegian North Sea using seismic facies analysis.

Data and Methods

The CCS prospectivity assessment utilized a 3D seismic dataset acquired by PGS in 2009. The dataset covers an area of 852.8 km2 and is located offshore within the Patch Bank Ridge (Figure 1a). Well 26/10-1 was drilled to test a Neogene submarine fan complex, the uppermost sands of which belong to the Miocene-early Pliocene Utsira Formation. The discovery well is located in 140 m water depth, ~120 km offshore near the border between the 26/10 and 17/1 blocks (NPD, 2017). The well reached a total depth (TD) of 1025 m. Three sand packages with high average porosity of 35-36% were encountered in the Utsira and Skade Formations, but only the topmost Utsira Formation 23m-thick sandstone is gas bearing while the other two sands are water filled. To determine the hydrocarbon and CCS potential of the northern lobe, seismic facies analysis has been performed. Seismic facies analysis has been used to identify petroleum system elements in the northern lobe. In the Zulu Øst field, once we identified reservoir and seal intervals on seismic section using GR logs, we described the seismic facies based on their reflection parameters.

Results

The seal interval for the Zulu Øst methane discovery is the Nordland Group mudstone, which is 61 m (~ 60 ms) thick at well location and its thickness in time varies between 58 ms and 97 ms across the structure. The top of this formation is picked on a mostly smooth, continuous, low to moderate amplitude reflection. The internal reflection geometry consists of sheet-like, parallel to subparallel, semi-transparent, high to very high continuity reflectors displaying mostly low to moderate amplitude. The same seismic facies exist above an adjacent and coeval undrilled sedimentary lobe to the north. The Nordland Group mudstones are overlain by the glaciogenic Naust Formation clinoform succession up to more than 1.1 km thick in the basin centre. Together the Nordland mudstone and Naust potentially form a good seal and overburden of the Utsira Formation and underlying Skade Formation sandstones (Lamb et al, 2018; Lloyd et al. 2021; Ottesen et al, 2018).

The gas bearing reservoir sands of Utsira formation are 23 m (29 ms) thick at the well location. The top of the reservoir is observed at 855 ms in TWT and it is encountered in the well at 803 m, which is shallow but in the limits of appropriate CCS reservoir depth. It is difficult to map the distribution of this facies because of its limited thickness which is mostly under the limit of the vertical resolution. At the well location, this sand interval is bounded by high amplitude soft and hard reflections at the top and base, respectively, with an internal low amplitude continuous facies (Figure1b). The TWT-structure map of the Utsira Formation defines a second 4-way closure, which is similar in appearance but separate from the Zulu Øst prospect. This finger-like shape shows very classic example of submarine fan geometry (Figure 1c). In this northern lobe, a similar seismic facies pattern is observed. The trap for both lobes relates to differential compaction above deeper Skade Fm sandstone.

The deeper reservoir interval encountered belongs to the Skade Fm sands, which is the thickest sand interval, being 82 m (84 ms) in the well. The top of this unit is low amplitude, discontinuous and not easy to follow in the study area, but the base is defined by a semicontinuous, moderate to high amplitude reflection. This sand interval seismic facies is characterised by irregular V-shaped and sheet-like, wavy to subparallel, semi continuous, and low to moderate amplitude reflections. The seismic facies and –geomorphology suggests possible submarine fan systems with mixed/sandy turbidite deposition. The northern lobe has similar seismic facies which could be interpreted as the same sand interval with irregular, low to moderate amplitude, discontinuous reflections. Comparable to its equivalent, the top reflection is discontinuous whereas its base reflection is mostly continuous with moderate to high amplitude.

Seismic facies analysis allowed us to compare a proven hydrocarbon field to a prospect which could be used as a future CCS field. This simple but straightforward approach is crucial to quickly assess any potential field to prevent unnecessary waste of time and budget. The Zulu Øst field represents a good analogue to the northern lobe. Because the northern lobe CCS prospect is slightly deeper than its southern counterpart, which is on the limit for safe subsurface storage of supercritical CO_2, it could be an important asset for CCS development with its thick reservoir and seal units.

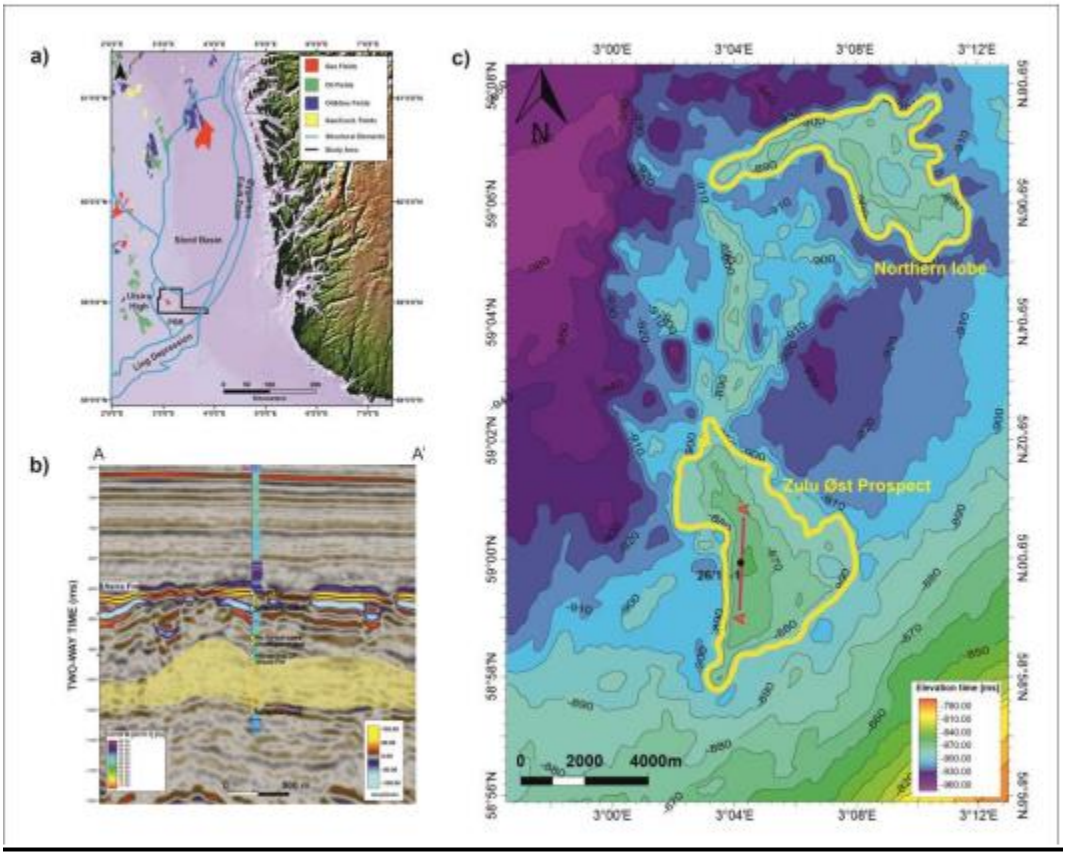

Figure 1 a) Location of the study area. Figure made with GeoMapApp (www.geomapapp.org) using Norwegian Petroleum Directorate database. b) Seismic sections at the well location of Zulu Øst field c) Two-way-time map of Top Utsira Formation showing Zulu Øst Field and northern lobe.

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Main Piccadilly Entrance
Straight out door and walk around to the Courtyard.

Close the doors when leaving a room. **DO NOT SWITCH OFF THE LIGHTS**.

Assemble in the Courtyard in front of the Royal Academy, outside the Royal Astronomical Society.

Please do not re-enter the building except when you are advised that it is safe to do so by the Fire Brigade.

First Aid
All accidents should be reported to Reception and First Aid assistance will be provided if necessary.

Facilities
The ladies toilets are situated in the basement at the bottom of the staircase outside the Lecture Theatre.

The Gents toilets are situated on the ground floor in the corridor leading to the Arthur Holmes Room.

The cloakroom is located along the corridor to the Arthur Holmes Room.

Ground Floor Plan of The Geological Society