Technology Collaboration Programme
by iea

Evaluating technology options to mitigate greenhouse gas emissions

IEAGHG Risk Management Network Meeting Report 2023-TR03

September 2023

IEA GREENHOUSE GAS R&D PROGRAMME

Disclaimer

Acknowledgements & Citations

This review was compiled by Nicola Clarke and Samantha Neades. Further information or copies of the report can be obtained by contacting IEAGHG at:

Email: *mail@ieaghg.org*
Phone: *+44 (0)1242 802911*
Address: *IEAGHG, Pure Offices, Cheltenham Office Park Hatherley Lane, Cheltenham, Gloucestershire, GL51 6SH, UK*

About IEAGHG

Blazing the way to net zero with leading CCS research. *We advance technology to accelerate project development & deployment.*

We are at the forefront of cutting-edge carbon, capture and storage (CCS) research. We advance technology that reduces carbon emissions and accelerates the deployment of CCS projects by improving processes, reducing costs, and overcoming barriers. Our authoritative research is peer-reviewed and widely used by governments and industry worldwide. As CCS technology specialists, we regularly input to organisations such as the IPCC and UNFCCC, contributing to the global net-zero transition.

About the IEA

The International Energy Agency (IEA), an autonomous agency, was established in November 1974. Its primary mandate is twofold: to promote energy security amongst its member countries through collective response to physical disruptions in oil supply, and provide authoritative research and analysis on ways to ensure reliable, affordable and clean energy. The IEA created Technology Collaboration Programmes (TCPs) to further facilitate international collaboration on energy related topics.


Postgraduate Centre


HERIOT
WATT

Contents

Sponsors & Co-host

HERIOT WATT UNIVERSITY

OIL AND GAS CLIMATE INITIATIVE

Summary

The Risk Management Network meeting was held as an in-person event with a particular focus on the risk of wells (particularly legacy wells) in a CCS project, looking at the topic from basin scale through to detailed characterisation of well materials and monitoring. Attended by over 75 delegates from 15 countries, the two day meeting was held at Heriot-Watt University in Edinburgh, UK. It was kicked off by a welcome reception in the Lyell Centre (home to both BGS and the Institute for GeoEnergy Engineering) and was followed by a field excursion to explore the geological history of Arthur's Seat in Edinburgh and a tour of a very new distillery located in an old train station within stone's throw of Holyrood Park.

The meeting was designed to cover the following themes: industrial perspectives on risk management and legacy well containment; how to identify, evaluate and abandon well bores for the future; long term well integrity – performance and risk assessment; well materials and testing; the challenges of monitoring, impact assessment and quantification; emerging solutions and approaches to monitoring; and finally a panel discussion on communicating well-related risk to regulators and other stakeholders.

As usual at IEAGHG Expert Network meetings, key conclusions and messages were drawn and recommendations were made. The concluding high-level messages noted that prospective storage sites with the fewest concerning legacy wells will rank among the most attractive for early deployment, but that availability of sites with higher quantity and/or lower quality of legacy wells might be unlocked as costs fall and technology to remediate improves – decisions that can be supported using approaches analogous to standard oil and gas industry 'creaming curve' analysis, as discussed later. Cements were a key topic with encouraging laboratory testing on legacy wells and samples showing the effectiveness of Portland cement as a barrier over time. Monitoring and monitoring plans were discussed and can be made streamlined with time. Insurers and financiers are starting to create products and cross-cutting meeting would be beneficial as are finding a common lexicon for communication. Standardising and streamlining the permitting process was a recurrent theme. The participants also recognised the challenges remaining including quantifying leakage rates, quantifying expected containment; how currently well-behaved wells might be impacted in practice as we start to inject; impacts of doing remediation might be higher that impact of leak (in the case of legacy wells), data management of monitoring data – e.g. how to get real-time data to shore from landers, or how to deal with extremely large datasets (e.g. DTS).

Steering Committee

Nicola Clarke, IEAGHG (Chair)
Samantha Neades, IEAGHG (Co-chair)
Aaron Cahill, Heriot Watt University (Host)
Diana Bacon, Pacific Northwest Lab
Jerry Blackford, PML
Myles Culhane, Occidental Petroleum Corporation
Bob Dilmore, NETL
Charles Jenkins, CSIRO
Thomas Le Guenan, BGRM
Franz May, BGR
Rachael Moore, Independent
Filip Neele, TNO
Kareem Shafi, OEUK
Owain Tucker, Shell & Honorary Professor HWU
Tim Wolterbeek, Shell
Ziqiu Xue, RITE
Ya-Mei (Cheryl) Yang, ITRI, Taiwan
Liwei Zhang, State Key Laboratory of Geomechanics and Geotechnical Engineering, Institute of Rock and Soil Mechanics, Chinese Academy of Sciences

With thanks for initial conversations with Bill Carey (Los Alamos), Keith Wise (OEUK) and Tim Ebben (Shell).

Session Overview

Welcome and Introduction – Aaron Cahill, Heriot Watt University and Nikki Clarke, IEAGHG

Aaron Cahill, Heriot Watt University and Nikki Clarke, IEAGHG, welcomed delegates to the meeting, recognising the steering committee which included representatives from 9 nations, the speakers and chairs, and recognising the generous support from sponsors and the hosts. Heriot Watt sponsored and hosted the meeting with additional sponsorship provided by OGCI and Shell. OGCI sponsored the welcome reception. Aaron in his welcome address outlined the work done by the Institute of GeoEnergy Engineering and how their focus was turning towards CCS in the last few years. The Lyell Centre is driving forward research in Net Zero and decarbonisation. Aaron gave a personal anecdote about attending an IEAGHG Network meeting in Montana in 2012 which led to a research stay working on the ZERT (Zero Emission Research and Technology Collaborative) site. He also noted that there are more than 8 million legacy wells globally, typically located where we might want to execute CCS, which then leads to a thought-provoking question: 'how worried should we be about them?'

Session 1

An Industry Perspective on Risk Management and Legacy Well Containment

Chair: Rachael Moore

Overview of CCS in Europe
Al Tucker, Shell

Al Tucker is general manager of Europe CCS in Shell with over 29 years of oil and gas experience, with responsibility to develop and mature Shell's CCUS portfolio in Europe through leading engagements with external customers and partners. Amongst many roles in Shell, and multiple drilling campaigns, he managed the decommissioning of the Brent field.

Al introduced Shell's CCUS strategy to set the landscape of their Net Zero journey, which includes: low carbon gas, low carbon hydrogen, bio-energy, direct air capture. Their ambitions are to have access to over 25 million tonnes of CCUS capacity by 2035. These include Quest, Gorgon, Portos, Aramis, Northern Lights, and Acorn. Al's personal view was "CCUS is like the oil and gas business I know but in reverse. We have done the chain of this before in separate elements, but when you start to live it becomes trickier to implement. Its all running in reverse. We have lots of questions from customers who don't understand the subsurface, they want to know 'where does my CO_2 end up' and telling our story in a risk-free manner is vital". Al touched on liabilities and costs in the complex chain. Investments of what can be billions of dollars means questions will be asked of a storage site such as 'will it be contained?' and 'who fits the bill if it doesn't work?'. For example, in the case of Europe only a small subset of the 27 member states have access to storage, how do you manage cross border contracts? If German CO_2 leaks in Norway, who pays? Cost is one of the biggest issues and the faster you can scale up you can bring the costs down. Unlocking and understanding legacy wells is the key to accessing storage resources. Shell's five performance requirements of CO_2 storage are: Capacity. Containment; Transport and Injectivity; Monitoring and Remediation; and Stakeholders – these are how Shell ensures safe, long term and cost-effective CO_2 storage. They have experience and capabilities in both saline aquifers and depleted fields and are a fan of both and recognise the pros and cons of both. In order to meet global emissions targets they recognise the need to step up. Society is with us in that mandate.. Al's final remarks were that "unlocking the potential of CCS requires partnership, persistence and supporting policy frameworks".

Characterising Legacy Well Risk in CCS Prospect Screening
Simon Shoulders, BP

Simon Shoulders is a Technical Advisor in bp's Centre of Expertise in CCS working with business development to identify and access new CCS opportunities globally, helps shape bp's storage technology and R&D portfolio and supports bp's advocacy activity to aid development of CCS regulation and policy.

Simon presentation aimed to precipitate discussion and took a step back to consider early prospect screening and subsurface risk scenarios, well failure and remediation, controls on vertical brine leakage and proposed a scenario-led assessment of different risks and where to focus uncertainty reduction activity. The presence and condition of barriers in a well and whether the well will experience conditions that might cause leakage of CO_2 or brine are important considerations in risk assessment of legacy well containment. Where uncertainty exists a scenario-led approach can provide insight. Four main storage concepts exist, grouped into two 'plays' depending on trapping mechanism: migration assisted storage in a saline aquifer (dipping aquifer); closure storage in either saline aquifers, depleted field or depleting field. There are likely to be fewer wells in a saline aquifer, and in closure plays most legacy wells are likely on the structure and likely to be effectively abandoned unless they also target deeper structures.

Simon presented a hypothetical scenario, a 'premortem', where you dream up everything that could go wrong, starting with a description of the sub-surface[1]. Ask 'what can go wrong?'. There are things that can happen but there are also barriers for these potential issues. The main thing is to imagine all the different issues, think broadly and capture far-field risk receptors. Understand the uncertainty associated with each risk receptor and assess the potential scale of the impact/hazard. This sets your work program.

Regarding well interventions and remediations, use the OEUK plugging and abandoning guidelines. What do you do if something goes wrong? Re-entering a legacy well is challenging, but within industry abilities. That being said, each well will have its own engineering and containment issues to address Operational and safety issues associated with legacy well remediation are likely to be less severe if the operation is undertaken before injection begins. However, the decision to make an intervention before injection comes with upfront cost and resource commitment. The decision making challenge is in the trade-off between the likelihood and impact of potential leakage and the effort and additional operational and safety risk incurred in remediating the well. With relief wells the challenge is to get wells in the right place.

[1]Klein, G., 2007. Performing a project premortem. Harvard business review, 85(9), pp.18-19

Simon explored scenarios around the impact of critical pressure on brine leakage potential, there are levels of uncertainty about wells within area of interest. For example, faults may act as baffles, or there may be pressure interactions if someone licences the adjacent area. CCS risk management needs to think about containment of both CO_2 and brine within the injection interval. Interventions on legacy wells is possible and within industry capability, however intervention on a legacy well is more straightforward prior to CO_2 injection. Working out which wells are likely to have high leakage risk combines an understanding of the barrier architecture and condition within the well and fluid flow pathways and pressure management in the subsurface. Using a framing process like a pre-mortem can help reduce surprise outcomes.

A comment during questions raised an issue with the term 'premortem', although an accepted general risk management term, it implied that death was inevitable and had negative connotations and perhaps 'health-check' might be a better descriptor especially when communicating with stakeholders.

Approach for identifying and managing high-risk wells in potential CCS project

Jeremy Sturgeon, Oxy

Jeremy Sturgeon is the Risk Engineering Lead for Oxy's Enhanced Oil Recovery (EOR) and Low Carbon Ventures (LCV) business units based in Houston, Texas, where his team provides process safety and risk engineering support to EOR. LCV and CCS related projects.

Oxy have been doing CO_2 EOR for 40 years, they currently have 20k wells, 6k injection wells and 2500 miles of CO_2 pipeline. They have developed specialised risk management (SFRM) programme to identify and manage risk associated with assets located near public receptors. A screening process is conducted followed by the assigning of tier levels (base, multiple or sensitive receptors) then the following process: gap analysis, risk assessment, economic evaluation and then an implementation plan.

Similar elements are applied when evaluating CCS projects, although CCS projects can bring additional risk evaluation considerations not specified in the SFRM program. For example: potential CO_2 migration in the subsurface; financial/business/tax impacts to stakeholders if a well or network is down; impacts to underground drinking water, active/dormant faults, wellbore corrosion; new technologies or regulation that may impact the project; and potential partnerships limiting internal guidelines.

The CCS space is moving very fast with all sorts of pieces that add value, e.g. DAC, CO_2 pipelines, CO_2 injection and storage. There are some challenges especially with guidelines, we have requirements, but they are not super specific, there is a lack of clarity on risk assessment methodologies and thresholds, limited experience with subsurface scenario identification, limited experience with identification of consequences and long-term validation. We could have migration in 20 years but we don't know if its going to happen or not. There are new technologies and designs to consider, identifying new projects with potential private landlords.

Oxy are involved with lots of different projects and are building internal guidelines to bring some consistency to the process. Brought in the Gulf Coast Carbon Centre and an external consultant to help develop these as a multidisciplinary team, and will continue collaboration efforts with external parties and stakeholders to enhance knowledge and understanding.

A question was posed to Jeremy about whether they has seen any induced seismicity. They had with water disposal in the Permian Basin and were developing the site with this in mind.

"Make sure that CCS can be done safely" – Porthos lessons learned and subsurface perspectives

Gloria Thürschmid, EBN

Gloria Thürschmid is a CCS-geoscientist with EBN and was assigned Discipline Lead Geoscience for Business Unit CCS at EBN in May 2023. She is involved in standardization and permitting topics on an international and European level, e.g. the review of the current guidance documents of the

EU CCS-Directive (via Zero Emissions Platform TWG) and the ISO27914/TC_{265} update. On a national level, Gloria coordinates the CO_2NSEIS project to develop a Subsurface Hazard and Risk Analysis guideline for CO_2-storage in The Netherlands.

The Porthos project is led by Dutch state-owned parties (EBN, Gasunie and the Port of Rotterdam Authority); the CO_2 will be captured by private companies (Air Liquide, Air Products, Exxon Mobile, Shell) and stored in a depleted gas field in the Dutch North Sea; the total storage capacity is ~37Mton and operation is planned to start in 2026.

Guidelines and best practices are still scare in CCS. During the storage licence application for the Porthos CCS project (which ran to over 1000 pages) it was found that these could have helped increase the efficiency of the process of preparation as well as discussions with the regulator. The risk management plan is the key document of the storage licence and includes: risk identification; risk assessments (bow-tie analysis); risk controls (monitoring plan); and risk recovery (corrective measures plan). Feedback from the regulator on subsurface related topics cited induced seismicity and loss of geo-containment as key points of concern, however, the process involved unclear requirements, long discussions and partly also extra work.

Because guidelines and best practices would be useful to numerous subjects, project CO_2NSEIS was conceived to develop a guideline for subsurface hazard and risk analysis for CO_2 storage in the Dutch offshore area. This joint initiative, co-ordinated by EBN, will support future CO_2-storage operators in identifying, assessing, and managing the associated subsurface risks, such as loss of geo-containment and induced seismicity. This can also support the regulator by providing a consistent approach to assess storage permits and to oversee ongoing injection activities. A similar guideline is required to manage well-containment risks.

Questions to Gloria included a comment from Shell that they really appreciated the work EBN has done on sharing lessons learned from Porthos and how this already helped with the Aramis storage application. A representative from Equinor asked about well configurations and plans for a back-up wells in Porthos (reference to Snøhvit that had to move their injection target); in principle, there would be one potential back-up well in Porthos, however, final plans are still to be made.

Session 1 - Discussion

Q1: How are the organisations thinking about risk in terms of their injector wells?

• Jeremy Sturgeon: Oxy are drilling new wells and assessing risks and impacts of these and looking at evaluating existing wells either remediating or plugging and starting again.

• Gloria Thürschmid: in the Netherlands the NOGPA 45 standard for abandonment of hydrocarbon wells is currently also taken as a template for CCS projects, however, we have to ask ourselves if this is the right way to do this for CCS?

• Simon Shoulders: most of bp's current projects are focussed on new wells rather than reuse of existing wells. The suitability of existing wells and pipelines for reuse in CCS should be assessed on a case by case basis.

• Al Tucker: historically Shell has spent a lot of money on cheap wells which feels like a good idea at the time, but not worth it in the long run, especially with first of a kind.

Q2: A bigger challenge is faults. Seismic data shows if they are connected to the basement but there is very little information on the fault itself especially in saline formations. How do you handle faults where data is scarce?

• Simon Shoulders: that's a tough one, when you have a lot of uncertainty it is hard to do. Where are there most likely to be issues, characterise the uncertainty and use the gaps identified to shape the forward work programme and data collection.

Q3: Why are we still using the same risk analysis techniques, should we instead look at defining what is an acceptable risk for us (the operators, the public, the regulators) and fit the projects to that?

• Jeremy Sturgeon: yes we would welcome that, it's a challenge for us at Oxy we don't have an acceptable risk criteria, we have programs that management inventory and we need to get sign off by CEO. This may be changing.

- Gloria Thürschmid: important question. Operators and industry can guide the process of defining acceptable risks, based on ALARP-principles, but in the end it's up to the regulators to decide what's acceptable. Since the number of CCS-projects has increased strongly over the last couple of years, regulators are still busy gaining experience in CCS. If risks can be reduced to ALARP-levels, this does not automatically mean that these risks are found acceptable by all stakeholders (e.g. regulators, public).

- Al Tucker: good thinking, although we may not need new tools, but we do need these conversations.

- Simon Shoulders: How we communicate and explain what is acceptable to us is important, especially to those with different backgrounds.

Q4: Does the temperature of CO_2 (especially cooler temperatures) impact the well and injection?

- Simon Shoulders: The temperature differential between the injected CO_2 and the storage reservoir is important and can be impacted by CO_2 phase changes within the system – this will impact the thermal stress that the rocks and the wells experience. We model these effects and design the project appropriately to manage the impacts. Currently it's a bespoke approach at different locations due to different conditions.

- Gloria Thürschmid: In Porthos, CO_2 will be injected in gas phase for the first couple of years to overcome risks related to cooling effects. As soon as this critical period has passed by, injection of CO_2 will be done in dense phase mode.

- Jeremy Sturgeon: There are public perception issues, people have oil and gas in their backyards with high HCS, but won't entertain CO_2 and treat it like a nuclear hazard. We need to show the benefits.

Session 2

How to identify, evaluate and abandon well bores for the future?

Chair: Ya-Mei (Cheryl) Yang

Considering well leakage risk across a geologic basin: Perspective from the U.S. DOE's National Risk Assessment Partnership

Robert Dilmore NETL, Diana Bacon and Greg Lackey

Robert Dilmore is a research engineer in the Geological and Environmental Systems Directorate in the Research & Innovation Center of the U.S. DOE's National Energy Technology Laboratory (NETL) and the Technical Director of the U.S. DOE's National Risk Assessment Partnership (NRAP) – a multi-year, multi-national laboratory effort developing approaches and computational tools to quantitatively assess and manage risks associated with large-scale geologic carbon storage.

The U.S. DOE has set ambition goals with 65 MT CO_2 /yr in 2030 and an expansion of 250 MT CO_2 per year by 2035 which will require rapid CCS industry growth to realise (Strategic Vision: The Role of FECM in Achieving Net-Zero Greenhouse Gas Emissions | Department of Energy[2]). This requires an iterative process to deployment across field projects and studies, transport and advanced storage. Well integrity and mitigation sits as an R&D focus within advanced storage. NRAP is one of three complementary projects that are working to apply computational approaches to accelerate CCUS deployment; the others are the the Science-informed Machine Learning (ML) for Accelerating Real-Time Decisions in Subsurface Applications (SMART) Initiative leverages AI/ML for real-time visualization, forecasting, and decision support, while the Energy Data eXchange for Carbon Capture and Sequestration (EDX4CCS) project provides a CCS-specific data infrastructure system.

NRAP is developing computational to support risk-related decision-making related to evaluating long-term containment effectiveness, assessing risk and liability for potential leakage and induced seismicity risks, and designing effective and efficient monitoring networks to detect potential leakage. The NRAP approach for rapid prediction of whole-system leakage risk performance links computationally efficient reduced-order models of important system components (reservoir, caprock, leakage pathways, receptors of concern) into an integrated assessment framework (the NRAP Open-Source Integrated Assessment Model – NRAP-Open-IAM can then be exercised to inform risk-related decisions (Vasylkivska et al. 2020[3]). NRAP-Open-IAM incorporates different options for quantifying well leakage risk, including a cemented well leakage ROM, a multi-segmented well leakage model, and an open borehole flux calculation ROM. Historically the NRAP risk assessment tools have been applied to estimate leakage risk at individual storage sites; previously published studies have used open borehole ROM to estimate a risk-based area of review for a greenfield site with an initially over pressured storage formation (Bacon et al. 2020[4]) and calculated leakage risk at a brownfield site with many wells (Lackey et al. 2019[5]) and considered reasonable requirements for site inspection and monitoring to effectively manage leakage risk. A similar approach is now being extended to assess leakage risks associated with rapid deployment of many commercial-scale projects across a geologic basin. NRAP tools are being applied to better understand the impact that potential competing pressure effects between multiple projects could have on leakage risk, in situ stress state, and induced seismicity potential throughout a basin. Considering leakage risk for a model geologic basin presents the challenge of characterizing, in some cases, hundreds of thousands of existing penetrations. Of these only a fraction will be expected to penetrate through the sealing caprock and warrant more detailed consideration. Simulation of basin-scale leakage risk draws on fast reservoir response estimation (analytical or reduced-order models) and well leakage ROMS, but confidence in these forecasts will be limited by parameter uncertainty. The challenges of characterizing well leakage at this scale suggests that well integrity data and machine learning approaches could be applied to predicting future leakage risk. Basin-scale integrated assessment model can be useful for comparing the leakage risk for different basin-scale deployment scenarios and considering how incremental risk might be attributed to to different operators or shared between operators.

NETL ran a well integrity workshop in 2021 to identify and discuss well integrity research needs (Lacey and Dilmore, 2021[6]) identified topics such as developing approaches to better understanding the incidence of well integrity issues, developing risk-based, data-driven approaches to forecast leakage and prioritize inspection and remedial activity, and promote field laboratory activities to better understand mechanisms that lead to

[2]https://www.energy.gov/fecm/strategic-vision-role-fecm-achieving-net-zero-greenhouse-gas-emissions
[3]https://www.sciencedirect.com/science/article/abs/pii/S1364815221001572
[4]https://www.sciencedirect.com/science/article/abs/pii/S1750583620305788
[5]https://www.sciencedirect.com/science/article/abs/pii/S1750583619302476
[6]https://www.osti.gov/servlets/purl/1828877

well integrity issues and practices that prevent well integrity issues. A ranking exercise, however, showed disparity amongst different stakeholders about their preferences – suggesting a need for continued dialog between stakeholders to focus investigations and to better prioritize resources.

Q: Have there been any discussions with EPA on how receptive they are to risk based approaches?

The EPA regulation is not risk based but they have said that a risk based analysis is useful, if not sufficient alone.

The U.S. EPA's approach to regulating CO_2 injection for geologic storage is based on avoiding impact to underground sources of drinking water; it does not specify a probabilistic, risk-based approach such as is the focus of NRAP tools and methods. It is our understanding that the regulator does recognize the value of such approaches and considers them as providing value and complementary justification to that which is required for permitting.

'Screening Legacy Wells, fit for purpose approaches'
Owain Tucker, Shell

Dr Owain Tucker is the Manager for CCS capability, assurance and project support, and the Principal Technical Expert in Carbon Storage in Shell. In these roles he leads a team of experts who support the delivery of CCS projects around the world, and are responsible for storage exploration and appraisal; technical assurance; integration; technology maturation; helping to shape the CCS research agenda; and the development of competences and capacity within Shell. He is also an Honorary Associate Professor at Heriot-Watt University where he lectures in CO_2 storage.

Owain framed the challenge that is posed by legacy wells or 'anthropogenic bioturbation', there are a lot of them and there are many ways to abandon them. Important considerations include: where they are plugged, the material, where they are perforated, what formations do they penetrate, and where they are located. It's also vital to know how to read a well report and what your terms mean, and especially useful to have a well report. Owain used a case study of the D10: WP5A Bunter Storage Development Plan, where despite a lot of good work overlooked a well on the structure (closure 36) with open casing. Looking at the Southern North Sea, the whole area is a play (SRMS) and you need to know everything about the wells, red flags are if the wells drill through your store, if it TDs in your store it might be plugged, if it doesn't penetrate your reservoir it might be fine. Be aware of abandonment standards and legislation standards that change through time. At lead level, where are the plugs? It's important to read the end of well reports which is time consuming, this is being attempted with AI but with varying degrees of success. At Prospect level, you get serious. Shell classes wells using colour coding : green, yellow, orange, red and purple. A green well – probably demands no extra work on it. Yellow – need to start asking questions, ask a well engineer. Orange ones – require monitoring and fix later or fix now? Will need to go to management to ask for money to fix. Red – can't fix unless you have salt squeeze or shale creep. Purple – there is no information so avoid injection. Regarding depleted fields, these are essentially a prospect until you can demonstrate containment. It's important to leave no stone unturned, bow-tie everything, dig into the detail. Wells pose a dilemma and the lack of digitised data makes assessment time consuming, wells are not easy to repair and this can affect storage. AI is probably about 40% successful in data mining, useful to assist but wouldn't fully trust it.

'What are the good industry practices and regulations on well decommissioning for CO2 storage?'
Kareem Shafi, OEUK

Kareem Shafi is the Senior Carbon Capture and Storage Advisor at OEUK, where he is responsible for developing technical, policy, and commercial deliverables to support the deployment and future operations of CCUS.

Kareem gave an insight into UK CCUS and well decommissioning program. OEUK exists to provide good industry practice. The UK is committed to invest £20 billion into CCUS and has 78Gt potential CO_2 storage with 50% lying in the Southern North Sea (19% in Central NS and 14% in Northern NS). 20 CO_2 licences have now been granted by NSTA. 200 wells will be decommissioned per year and the next 10 years will be very busy. It's important to share good industry practice and develop guidelines (75 OEUK has Good Industry Practice Guidelines). There is a hierarchy of guidelines (e.g. EU directive at top of pyramid and company policy at the bottom), and for example the UK follows a goal-setting regime not a prescriptive one. The current regulations for well decommissioning are the 1996 Offshore Installations and Wells Regulations and state that 'so far is reasonably practicable, there can be no unplanned escape of fluids from the well' and suitable materials should be used to that end. The CO_2 storage License Act 2010 states that 'Under the proposed conditions of use of the storage site, there is no significant risk of leakage or harm to the environment or human health….' Currently looking at new regulations that would bridge the gap and best practice for industry. This presents a commercial challenge, if CO_2 were to leak there will be an obligation to pay the carbon tax. Oil and gas companies are decommissioning wells and have no goal to store CO_2. OEUK have drawn up well decommissioning for CO_2 storage guidelines, there are two user groups oil and gas operators and CO_2 storage developers. Three scopes: future CO_2 storage conditions, permanent barriers for CO_2 storage, and verification of permanent barriers and legacy well screening. The take home message is that the ways we have been decommissioning have been good, but create a list of considerations e.g. materials, where to place barrier and how long. Regarding verifications, there are already good standards in place. With legacy wells there is a lot of learning on the go. No-one has submitted a storage application yet so we don't know what good looks like yet. Kareem ended with encouraging people to read the guidelines and provide feedback.

'Screening and monitoring of legacy wells along the Norwegian Continental Shelf – enabling large scale CO2 storage'

Benjamin Emmel, Bastien Dupuy, Simone Zonetti, Anouar Romdhane, Peder Eliasson, SINTEF

Dr. Benjamin Emmel is a researcher in the Applied Geoscience Group at SINTEF – Industry. His research is mainly focused on different aspects of CO_2 and energy storage (e.g., capacity estimates, dynamic reservoir behaviour, and well integrity assessment in context of storage).

The plugging and abandonment status of legacy wells in relationship to future CO_2 storage usage of historical hydrocarbon exploration and production areas were discussed in this presentation. There are pros and cons to utilising shut down fields for CO_2 storage, cons include legacy wells, chemical interaction with residuals and a limited theoretical capacity compared to large aquifers. The Frigg field in the Norwegian Northern North Sea has >10 legacy well locations drilled between 1971 and 1990. Bottner et al, 2020 evaluated the leakage probability of legacy wells in the North Sea, results are alarming. There are 8000 wells on Norwegian Continental Shelf (NCS) (>6500 in Norwegian North Sea). Storage capacity estimations assume that the volume taken by hydrocarbons can be occupied by CO_2, this equates to 355-422Mt, approximately 10 years of Norwegian emissions. The standard for Norwegian wells is NORSOK D-10 standard from 2004, and wells are compared to this. There are strict P&A requirements on the NCS since the start of oil and gas production, wells are always plugged with cement. Norwegian well reports are open source documents. Using a desktop tailored workflow on how to screen and monitor legacy wells, the results show that further investigations and monitoring is required for the Frigg Field. Reservoir simulations of injected CO_2 at different locations all show that the plume will intersect legacy wells. Conventional monitoring is expensive. Examples of possible non-invasive (cost effective) monitoring of wells might be promising, this includes controlled source electromagnetics CSEM for casing corrosion and shallow cement plug detection and the use of seismic data.

Session 2 - Discussion

Q1: how do we reconcile discussion around quantifying leakage and the carbon tax, verses the challenges of detection and quantification of leakage offshore?

• People assume you have a system that's going to leak. The MMV plan is designed to follow the plume so you can put reactive barriers in place. Once it starts to leak we can quantify (offshore you look for bubbles, onshore is harder).

• You have a baseline survey for natural levels. Regulator agrees the MMV program. The second aspect is to ensure that our stores are secure, insurers also have specifications.

Q2: What are the critical threshold levels?

• Defining thresholds ourselves is not a good idea, it has to come from regulators. Leakage modelling is not simple.

Q3: What about jurisdictional boundaries? How do we deal with these at MT scale CO_2 storage, wells and pressure areas?

• No-one has solved this yet. Regulators are beginning to think about interference. Let's get some CO_2 in the ground first.

Q4: What is important, what we measure at the seabed or what's happening under the surface?

• It's about balance, current laws say zero emissions, but it may be an evolution. Key is environmental assessment. CCS is the most regulated industry at the moment.

• Because we are storing CO_2 for cost there is a commercial aspect to it. However, CO_2 is not considered toxic so it's just an emission, but may be an issue if it mixes with brine.

Session 3

Long term well integrity – performance and risk assessment.

Chair: Robert Dilmore

'Risks posed to CCS by legacy wells and their integrity: lessons from recent field investigations, data analytics and modelling'
Aaron Cahill, Heriot Watt University

Aaron Cahill is an Assistant Professor and Lyell Fellow in Applied Geoscience at Heriot Watt University as part of both the Lyell Centre and the Institute of Geoenergy Engineering.

Aaron began by discussing our 'Net positive past' and noting that there are more than 8 million wells globally, not all of which are legacy wells but they will all be decommissioned. We will keep using the subsurface for new geoenergy applications and these wells provide a legacy infrastructure we have to navigate. Key questions on legacy wells: how many suffer integrity failure, why does well integrity fail, and how bad is failure? What are the implications of ongoing use of the subsurface and CCS?

An onshore study (2016) of the UK counted 2,149 wells (1,700 plugged and abandoned ('P&A'd) of which 30% of those investigated showed failure. However, a follow-up project by HWU of the 6 most leaky wells found no evidence of leakage. Failure incidence rate varies by 2-9% per year

(~5% on average). Variability can be affected by weather conditions e.g. more leakage detected in warmer weather and higher wind speeds.

This work also examined P&A'd unconventional wells in BC, Canada, which are younger and have a substantially shorter life cycle (and conventional wells. Out of 10 wells visited, only one or two wells are confirmed to be leaking and 5 wells have anomalously high CO_2 flux measurements. 50% could have leakage.

Why does well integrity fail? HWU tried to use statistical methods to identify geologic and well characteristics associated with integrity failure. Since 1990s many records are digitized. There are no clear attributes, no smoking gun; the determining the root cause of well integrity failure is a more nuanced, complex and multi-faceted issue. Given the complexity of the problem and persistent data availability and data quality limitations, big data methods may not be reliable.

How bad is failure? Inspired by early CCS experiments, Professor Cahil and colleagues have conducted methane controlled release experiments to better understand what impacts might arise from well integrity failure. However, studying leakage from real wells might be a better way, how much are they leaking? Results show that the magnitude of leakage is typically not large, suggesting that it may not be worth re-abandoning these wells. It will, however, remain critical to manage risk and advance understanding of legacy well integrity in parallel with CCS deployment.

Q: what about the wells we don't know about, from 70-100 years ago? Perceived as more of a problem in the US and could present a big problem.

'CCS Containment Certainty and Well Integrity'

David Hartgill and Laura Hardiman, Black Goldfish Ltd

David Hartgill is an Independent Chartered Engineer with over 30 years' experience working as an engineering consultant and directly for international oil and gas companies. Since 2020 David has been working as a technical advisor as part of UK Government's CCUS delivery programme. David's particular focus is on the well and completion design, operation, monitoring and surveillance for CO_2 wells

David has been supporting the UK government on the track 1 clusters and was asked by the government to write a report on how confident we would be about geological storage of CO_2. This report was written for a non-technical audience with supplementary notes that are more technical[7].

Results show that well-regulated storage would result in 99.93% of CO_2 being contained, which is the same view as the BGS. From a public perception standpoint it is important to talk about storage in terms of containment, and not overly emphasize leakage. EU Emissions Trading System (ETS) costs only apply if CO_2 reaches the seabed and has important financial implications. David outlined some key definitions used in the UKs Storage of CO_2 Regulations (2010) such as: the storage site, storage complex and monitored volume. He also reviewed potential leakage pathways. Well integrity data was reviewed from hundreds of papers and databases to extract the probability of leak to the environment, associated leak rate, and duration of the leak. These fall into categories: seep (<1t/d), unlikely to be remediated; minor (1-50 t/d) - a rate that it is assumed well intervention could address; moderate (50-1,000 t/d) – treated similarly to minor leakage except with escalation; and major (>1,000 t/d) – considered as unconstrained flow.

Seepage is driven primarily by quality of cement bonds between casing migrating gas seen at the surface is not gas from the reservoir. Well failure rates have declined since 1994 when new regulations were brought in. The quantity of data for inactive wells is lower than for active wells, in particular for larger leaks. This well leak probability

[7]https://www.gov.uk/government/publications/deep-geological-storage-of-carbon-dioxide-co2-offshore-uk-containment-certainty.

data is being used to support risk assessments to judge individual well leakage probability, estimates of UK ETS exposure and input to estimates of insurance liability and premiums.

Comment: The report makes out that it is simple to remediate a well, but the reality is that it's not. Also would question 99.9% as accurate, more likely to be case by case. There has been a lot of work on this, hundreds of CO_2 wells have been worked on in US. Caution should be taken when evaluating the seriousness of the risks.

'Characterisation of well cement after 33 years of downhole exposure on the Valhal field'
Katherine Beltrán Jiménez, Equinor

Katherine Beltrán Jiménez is a petroleum engineer, she holds two PhD's: one in petroleum technology from the University of Stavanger and one in ocean engineering from the Federal University of Rio de Janeiro. Katherine works as principal engineer in drilling and wells at Equinor, but the research she is presenting today was developed while she was working as senior researcher at the Norwegian Research Center, NORCE.

Katherine began by stressing the importance of differentiating between aging, alteration and degradation (Stokes 2017 and Beltrán-Jiménez et al. 2022[8]).

The Valhall well was drilled in 1985 on the Norwegian continental shelf (NCS), and was in production for a total of 33 years. Records of the well's sustained casing pressure (SCP) were collected over the well's production life. Two sections of well were retrieved: a transition joint (119-131 m TVD) and Fish #11 (251-260 m TVD). Each section was cut in two places at the top and bottom. The sections were initially logged as received and show areas of poor bonding with a gas flag. Cross sections show the annulus is filled with cement in both sections but the bottom and top of the transition joint has notable traces of mud intrusions. At the bottom of Fish#11 there is a 2 m long zone with good cement bonding which shows seals well with a permeability similar to that of bulk cement. Analysis of bulk properties confirm the presence of cement defects such as mud contamination that may affect mechanical performance.

A comprehensive dataset (acoustic logs, leakage tests, cement core plug analysis) has been recorded on casing in casing cemented sandwich sections recovered during the abandonment of a well on the Valhall Field. There is a clear correlation between the acoustic log response and leakage measurements. The performed analysis showed that overall decrease in cement matrix integrity was low. The record of SCP in the well prior to abandonment is an indication that factors such as the existence of preferential fluid migration paths, can affect the well barrier integrity even when the bulk cement properties appear to have low degradation.

'15 years post injection monitoring at Nagaoka pilot site: Portland cement integrity from time lapse well logging'
Takahiro Nakajima and Ziqiu Xue, RITE

Dr. Nakajima has worked as a Senior Researcher at Research Institute of Innovative Technology for the Earth (RITE) since September 2010 and became an Associate Chief Researcher of the CO_2 Storage Research Group in 2017. He has been engaged in the interpretation of reservoir complex using logging data at geological CO_2 storage sites. He is also working on simulations of CO_2 behaviour in the ground using $TOUGH_2$ simulator.

A time-lapse well integrity test was performed at the Nagaoka site, Japan. The Nagoaka pilot site injected 10,400 metric tons of CO_2 between 2003 and 2005, using one injection well and three observation wells. All wells at the Nagaoka pilot-scale injection test site use Portland cement for wells. The CO_2 plume intersected two observation wells., CO_2 behaviour has been monitored for more than 15 years using geophysical logging; including CBL and ultrasonic logging. Monitoring at the site's observation well #2 (OB2) well shows

[8] https://www.sciencedirect.com/science/article/pii/S0920410521009840

no vertical migration along the well and solubility trapping can be seen in resistivity logging.

Damage on the tubing and casing of injection well after 15 years from the beginning of CO_2 injection has also been studied with PACE (peak analysis for cement evaluation). Good bonding is observed above the reservoir interval and results between 2001 and 2019 were consistent. The observation showed that there was no clear evidence of damage along the well and in the well cement. These results emphasize how a quality cement job is important to ensure well integrity. Inspection of tubing pipe (IW1) show no significant corrosion and changes in tubing and casing were below the measurement accuracy of the electromagnetic pipe examiner tool (EPX). Importantly there is no evidence of differences in the reservoir after large earthquakes and cementation remains good after exposure to CO_2

Session 3 - Discussion

Q1: No observed degradation in the last two research projects, this is valuable. Is there a way to provide feedback to improve cement jobs?

• Katherine Beltrán Jiménez: it is important to keep good records, we don't have access to information on how the cement is mixed from 40 years ago.

Q2: For David and Aaron, your numbers are useful for project developers and operators. How can we use those numbers to come up with acceptable risk. How do we disseminate these numbers to public and de-risk projects?

• Aaron Cahill: I'm looking at legacy wells and what that means for CCS projects. Oil and gas wells may have been leaking but no one cared, now they care about CCS and the lens on that is magnified. You need to change expectations and mindsets. An example is fracking, banned in UK and allowed in BC.

• David Hartgill: Remediation is important and needs to be part of the conversation. Are we going to be able to detect these leaks and what rates can we detect?

Q3: It's good to acknowledge that leakage is happening. In Class VI applications part of this is financial assurance and in order to get financial instruments you need to buy insurance bonds. Insurance companies are asking what the leakage rates are and its really hard to find these numbers in the literature and know whether these numbers are reliable.

• Aaron Cahill: We, the CCUS RD&D community, are not there yet with these numbers.

• David Hartgill: Prominent insurers are already insuring oil and gas operations. What information did they have at the beginning? They have made money from these policies. We should estimate the probability of leakage occurring and the cost to remediate, then consider how much of your storage credits you'll have to return.

• We are talking about risk communication, the message isn't the same to every stakeholder. The public will have difficulty understanding nuanced messages around risk or probabilities, and it will be necessary to communicate in the language of the lay person. Insurers do want to know probability, and typically care about what is the worst thing that could happen. Leakage might be a small amount, however brine leakage could cause problems or build up over time and cause an issue.

• If you have a chronic leak you can cause asphyxiation and build-up of ground gas, this could cause an issue long term. There is a grey line between leakage and a blowout. IEA have discussed how to frame risk with insurers. If there is an impression of uncapped liability (i.e., that no one knows how much its going to cost to cover liability), then it will be difficult for insurers to decide if they can insure storage operations. The emphasis in this discussion is currently on estimating incidence and magnitude of surface leaks. Do we need to consider subsurface leaks too? The oil and gas experience may not be strongly analogous due to difference in behaviour of CH_4 and CO_2 in the subsurface.

Session 4

Well materials and testing.

Chair: Liwei Zhang

'"To react or not to react?"...and is that even the right question? A critical review of CO2-cement interactions and their impact on zonal isolation integrity'

Tim Wolterbeek*, W.J.G. Keultjes, P.C. Kriesels, C. Wight, Shell

Tim Wolterbeek obtained his PhD at Utrecht University (NL), studying the impact of CO_2 reactive transport and mechanical damage on wellbore cement integrity in the context of CATO-2, the Dutch national research program on CCS. Tim continued his work as a postdoc researcher at Utrecht University, and after 12 years, Tim joined Shell's sustainable wells technology team (2022), where he now investigates wellbore sealing integrity challenges related to CCS, hydrogen storage, and novel remediation technologies.

Tim started his talk with the assurance that 'Things are not as bad as we think', Katherine already categorized alteration and degradation and in some cases alteration can also be beneficial. There are three types of wells: injection wells, operational, and legacy wells. For legacy wells there are three scenarios on injection of CO_2 nearby: 1. Exposure to pressure increase (check zonal isolation integrity via SIS); 2. contact with CO_2 and increased pressure (discussed here); and 3. Exposure to CO_2, increased pressure thermal effects (avoid injection). For scenario 2 there may be minor changes in temperature and stress state, chemical reactions when exposed to CO_2 rich fluids, although there are often P&A barriers in place e.g. conventional Portland cement (PC) seals.

Tim outlined the reaction processes between CO_2 and Portland cements, these produce a series of alteration fronts in the cement, with decreased porosity in the third zone with dense carbonation.

The main take home messages are: [A] CO_2 -Portland cement reactions progress slowly in the cement matrix under diffusive conditions (in flawless intact cement). Extrapolated models predict <1m reaction progression in 1000 years, therefore defect-free PC will maintain zonal isolation over several meters. [B] CO_2 -PC reactions on seepage via microannuli/defects is a reactive transport process and there is competition between dissolution of cement phases and the precipitation of carbonates. Experimental and modelling studies show that reaction provides capacity for self-sealing of small defects. Large defects are unlikely to self-seal and warrant remediation irrespective of reactions. [C] 'CO_2 resistant' specialty cements are less reactive and react slower but are not completely inert. For defect-free cement in caprock, reaction progression is limited by diffusion therefore no key requirement necessary. For small microannuli and fractures using CO_2 resistant materials maybe detrimental for self-sealing potential. What is needed is a quantitative assessment and holistic comparison with sealing performance of conventional Portland cements.

Q: What are the uncertainties e.g. with impurities or methane?

TW: there are exposure tests with H_2S. Do not change the diffusive nature of the reactive transport. Good to test this. Mostly concerned with reducing the uncertainty range and that would include impurities.

'Micro CT characterisation of CO2-induced cement degradation'
Liwei Zhang, Chinese Academy of Sciences.

Liwei Zhang is a professor at Institute of Rock and Soil Mechanics (IRSM), Chinese Academy of Sciences. Prof. Zhang's research has been focused on risk management of wellbore leakage, cement additives and mineral dissolution/precipitation processes. Specific research areas include development of corrosion-resisting cement additives, carbonation of cement and concrete, subsurface mineral dissolution and precipitation under geologic carbon storage conditions.

Liwei began his talk giving as way of background that China is the largest emitter in the world and 50% of energy still comes from coal and with strong cement, iron and steel industries CCUS is important and China is upscaling. Operators need to know the risks they are dealing with.

The objectives of the study are to build a cement degradation testing system under THMC coupled conditions and conduct cement degradation experiments (Gan and Zhang et al 2022). Conduct 3-D characterisation of pore structure evolution of wellbore cement after cement degradation experiments to visualise cement integrity loss.

An aqueous CO_2–cement interaction experiment along with X-ray computed micro-tomography characterization of pre- and post-exposure cement samples was carried out to investigate the cement structure evolution under geologic CO_2 storage conditions. The cement sample was a cylinder (30 mm long by 10mm diameter with a 1mm diameter hole in the centre).

An image processing framework was proposed for mapping mineral dissolution and precipitation, and for characterization of carbonate shell morphology. Zones of dissolution and precipitation were observed. By applying this framework, the 3D mineral precipitation and dissolution (or local mineral content change) map and the internal and external carbonate shells were visualised. The spatial distribution of the shell area, thickness, penetration depth and pore/calcite/portlandite content changes along the height of the sample was revealed as well. With increase of CO_2 corrosion time it's observed there is heavy carbonation in the exterior and shrinkage of cement matrix due to dissolution of cement hydrates. $CaCO_3$ is precipitated in the central hole rather than dissolution reducing the risk of leakage through a pre-existing leakage pathway. Self-sealing also occurred at the cement-granite interface inhibiting CO_2 migration. Other concepts introduced were the development of corrosion-resistant cement additives (c.f. Wang, Liu, Zhang et al 2021) which encourages precipitation of $CaCO_3$ and self-sealing. Ca-bearing montmorillonite (MT) suspension reacted with supercritical CO_2 and results compared with control sample. With the increase in corrosion time the MT sample saw less carbonation and sealing of large pores. Flow rate and effective stress on the corrosion level are studied with flow rate being the most critical factor affecting cement corrosion degree.

Q: If you add montmorillonite clay does that change the strength of the cement?

LZ: Yes –it increases the strength. Not shown by these results.

'Alternative materials for the creation of barriers in wells'
Matteo Pedrotti, University of Strathclyde

Dr Matteo Pedrotti was appointed as a Chancellor's Fellow in the Department of Civil and Environmental Engineering (CEE), at the University of Strathclyde (UoS) in April 2019. Dr Pedrotti research group focuses on the design and characterisation of advanced composite systems of geomaterials and synthesised hydrogels. The nano and micro scale characterisation of such systems aims to understand the role of atmospheric interactions, stress history and groundwater and gas chemistry on their hydro-mechanical characteristics. This allows for engineering of advanced porous materials with unprecedented macroscopic bulk performances.

Following the growing interested in the use of deplete oil fields for storage of both CO_2 and hydrogen gas, and the need to prevent leaking from existing wells, Matteo's talk showed some recent experimental results with the use of alternative grout to create barrier in wells. The use of quick clay is proposed as grouting material to form a barrier that prevents both short- and long-term leakage in plugged and abandoned wells.

Quick clay is a post-glacial Quaternary marine clay in which most of the cations have been leached out leaving it in a metastable state. It has the ability to shift from solid to liquid instantaneously and flows when disturbed. Use dry clay and make powder, mix water, results in high density, reduced permeability material. Without altering the density results in a stronger material (adding cations). When elevating shear strain it results in a dramatic decrease in viscosity and becomes pumpable, when injected into fine apertures it creates a high-density clog.

Quick clay conceptual models can create a barrier as a full column plug or used as grouting cracks. It differs from bentonite by being non swelling, high density and has a buffering capacity against high and low pH (an excellent property for a material in contact with cement). It has a particle size similar to ultrafine cement (D50 is 5micron) and is pumpable at high density.

'Lab tests – Portland Cement degradation'
Saeko Mito and Ziqiu Xue, RITE*

Dr. Saeko Mito is a Senior Researcher (geochemistry) in the CO_2 storage research group at RITE. Her research covers field and laboratory experiments on CO_2 -water-rock interactions in saline aquifers, ultra-mafic rocks and well materials. With these experiences, she has tried to contribute to public engagement based on scientific and technological knowledge. Early in her CCS research, she worked on the Nagaoka pilot-scale CO_2 injection test, the GEOREACTOR Programme (CO_2 fixation in a geothermal reservoir), and the CO_2 Ocean Sequestration Project at RITE.

Whereas new wells at a CO_2 storage site might use CO_2 resistant materials in their construction, legacy wells in the area of review will have been completed with Portland cement which could easily react with CO_2 (which has both degradation and self-sealing effects). The experiments focus on the outside of the casing, using casing-cement-sandstone (Japanese ss 100mD) samples to simulate well sample. Conducted flow through experiments, duration 40 days, CO_2 saturated brine from bottom. Temperature 50C, confining pressure 12MPa, pore pressure 10MPa. The flow of the CO_2 saturated brine became extremely slow over time.

A second experiment was conducted, an artificial void sample experiment. A core of cement with a cavity/void which was encased in Berea sandstone (50mD). Bottom half was a CO_2 saturated brine, top half wet CO_2. CT images were taken prior to and post injection. They show carbonate filling the void in some areas. Surface analysis results showed cement alteration, Ca was provided from cement to sandstone and $CaCO_3$ precipitated around the cement/rock. The cement-rock interface showed both alteration and carbonation (self-sealing) and only several mm. The precipitation of $CaCO_3$ prevents further CO_2 attack. CO_2 leakage is considered to be limited by carbonation.

Batch experiments to estimate alteration speeds (at 3, 14, 28 and 56 days) with surface analysis (microscope, alteration depth measurement and SEM, EDS) to examine results. Measurements of alteration and carbonation depths were calculated and forward estimated for 30 years exposure. Creating a look up table of results, cement grade, temp and pressure, reactive medium, equation, degradation for a 30 year CO_2 exposure (mm).

Q (Katherine Beltrán Jiménez): What is your definition of degradation?

Saeko Mito: Based on the laboratory experiments we did not observe degradation with barrier failure. My definition of degrade means just the alteration of cement.

Session 4 - Discussion

Q1. Cement CO_2 interaction, how does lab set up compare to real life scale?

• Tim Wolterbeek: like the sandstone tests, the leached layer is much smaller. Placement is key, if you have a crappy well it won't save you. Liwei showed nice example of a hole in the middle, 1 mm, important to get flow rates, prescribe flow rates. Note residence times are short in both. There will be a change from lab scale (mm) to real life. The smaller scale shows nice detail in the reaction process. What I see is scalable.

Session 5

The challenges of monitoring, impact assessment and quantification.

Chair: Thomas Le Guenan

'Environmental impact potential of well leakage and implications for monitoring'

Jerry Blackford, PML

Jerry Blackford has ~ 15 years' experience in assessing environmental impacts and monitoring related to offshore storage. He led the world first release project (QICS) in which CO_2 was injected into the shallow subsurface, and has subsequently played leading roles in many EU funded projects including RISCS, ECO_2, STEMM-CCS, PreACT and ACTOM, in particular developing model based approaches.

Jerry asked (in the offshore environment): what could well leakage look like?; what have we learned from analogues and experiments?; what have we learned from modelling?; regarding monitoring, how do we identify anomalies, do we need baselines, or can we be smarter?; and to summarise, what are the challenges now?

Although unlikely, release rates are really challenging to predict and could vary a lot, and without in-situ surface sensors small fluxes would be difficult to impossible to spot with seismic imaging (geology) and only observes at or near seabed. Precursors such as methane and hypersaline brines are important to understand impact of too. Natural analogues[9] include volcanic plumes , offshore Italy, where a clear gradient of pH, carbonate chemistry and ecology is observed, illustrating impact potential. The QICS project, an artificial release experiment to mimic leakage, only observed impacts at the immediate release site which dissipated after 3 weeks[10]. Flow within the sediments are complex and become more focused as chimneys develop. There is a strong evidence of sediment buffering, change in pH is limited, impacts may increase with time, carbonate observations vary depending on sensor positioning and tidal cycle which has implications for monitoring.

Because experimental releases are expensive we need models (which are complex) to explore different scenarios (Dewar et al 2021[11]). Results across models are consistent showing a strong relationship between area impacted and leak rate.

[9]https://www.nature.com/articles/nature07051
[10]https://www.nature.com/articles/nclimate2381
[11]https://www.sciencedirect.com/science/article/abs/pii/S1750583621001936

Higher leak rates are more likely to be detected and mitigated and also very low probability. Scale of impacts of North Sea trawling is given as a reference marker.

Site characterisation are useful as site specific datasets to see directly the behaviour of the carbonate system and ascertain which process dominate in a particular region. However, marine systems are highly dynamic over temporal and spatial scales and fully detailed, short-term – seasonal – interannual time series will be really expensive and of limited use. As no two sites are alike, there is limited opportunity to transfer information. Options to recognize anomalies against background variability is measuring pH over very short timescales against the natural system or looking for departures from natural co-variance relationships.

Quantified CO_2 leak rates (t/day) are plotted against impact volume, impact area and detection length scale e.g. 0.01 t/day, 0.6 m3 impact volume, 0.4m2 impact area and 2.4 m detection length scale vs 1000 t/day, 0.176km3, 47.9 km2, and 7.83 km. For brine release there is negligible impact from salinity and temperature however mobilized heavy metals could be an issue and require direct sampling.

To conclude, Jerry stated that properly designed CCS storage should not leak. No two releases would be identical but we know enough from observations and models to understand scales and impact potential. One needs enough characterization/ baseline knowledge for a given site to identify anomalies with acceptably low false positives. We have sufficient technology and methodology to enable effective monitoring. The tension lies in cost and assurance, highly sensitive, expensive systems can detect kg scale releases but these would have no impact on environment or MT scale storage vs cheap, less sensitive 100T releases which cause harm and undermines storage. Middle ground balances cost and sensitivity[12].

Q: The leak rate table would be tempting to use in other areas, is this site specific?

This is for the North Sea, would be good to review e.g. the Bass Straight and Gulf of Mexico scenarios for comparison. For the GoM this could be a bigger area due to lack of tides.

‘Suitable baselines and appropriate thresholds for soil gas monitoring’
Franz May* (BGR) Stefan Schlömer, Florian Stange, Ingo Möller, Hans-Martin Schulz and Markus Furche

As a geologist, Franz May studied natural CO_2-sources in Central Europe and New Zealand, before joining the Federal Institute for Geosciences and Natural Resources (BGR) in 2000, for research on CO_2 storage. He is scientific director of the unit Deep Geothermal Energy and CO_2 Storage, and head of the DIN Committee on CCUS, contributing to international standardization, and, within one of the competent authorities, to the regulation of CO_2 storage in Germany.

Monitoring tasks include: locating anomalies (can be challenging), attributing sources, quantifying leakage to the atmosphere (geo- or hydrosphere). Baselines and thresholds are needed for all of these tasks.

Gradual response flow diagram of observations indicates a variety of actions at response levels e.g. none, inspection and checks, adaptation of baseline, additional monitoring, adapting operation, reducing injection and site abandonment.

With a focus on the terrestrial environment, challenges for baseline measurements result from technology (e.g. sensor performance, power supply, corrosion, harsh environments), spatial and temporal variability and shallow-subsurface processes (e.g. microbial processes). Formulating a monitoring plan asks: where, how many observation sites, how long, and how frequent?

For shallow processes, a natural gas field in Atzbach-Schwananstadt was studied with geochemical discrimination of natural spring and well waters attributed to sources of carbon

[12] https://www.sciencedirect.com/science/article/abs/pii/S1750583621001407

species. This work showed dilution / mixing in shallow groundwater, and a trade-off between false alarms (in background samples) and undetected leakage (in CO_2 affected waters).

Temporal variability can include seasonal and daily variations e.g. influences of tides. For Ketzin, soil gas flux monitoring show strong seasonal fluctuations. Atmospheric pressure, precipitation, soil temp, soil moisture, ground water level all impact and create interpretation challenges e.g. delayed response, dominating effects vary with time and location. Spatial variability can be pronounced e.g. soil gas CO_2 concentration around a natural CO_2 vent (10 m) wide. Spatial variability can also be demonstrated at the km scale (Altmark well survey).

It is possible to supplement baseline recordings with numerical simulations e.g. soil water dynamics, soil gas dynamics (CO_2 concentrations), impact of CO_2 influx, and with statistical methods e.g. continuous time series forecasting (when you have observed a few seasonal cycles you can make educated guess on future).

Conclusions, establishing suitable baselines and thresholds for soil gas monitoring: takes time and experienced staff; requires recording of multiple gas and environmental parameters; and should include data processing, modelling and interpretation.

'The logic and evolution of MMV'
Marcella Dean, Shell

Dr. Marcella Dean has over 20 years of experience as a geophysicist in the oil & gas industry and is currently employed by Shell Global Solutions International B.V. She is leading a subsurface specialist team responsible for developing the next generation of containment monitoring and modelling capabilities. The focus is to ensure safe and efficient CO_2, H_2, and energy storage, managing induced seismicity risks, and safeguarding hydrocarbon integrity. Prior to this role she was responsible for the development of state-of-the art geophysical and environmental monitoring technologies to verify the containment of injected fluids. Marcella was the Measurement, Monitoring and Verification (MMV) lead for the former Peterhead CCS project and delivered technology for the Quest CCS project. She is known as one of Shell's main experts in risk-based MMV for CO_2 storage and is the Principal Technical Expert (PTE) of Reservoir Integrity and Containment.

In risk based MMV the goals are: containment to demonstrate the safety of geological storage; conformance to indicate long term effectiveness of storage; and confidence to satisfy regulatory requests, generate evidence of containment and support the transfer of long term liabilities. Shell uses the bowtie risk assessment methodology to manage CO_2 storage containment risks: top event (CO_2 leaving the storage complex); threats (potential leakage/migration paths); consequences (to people, environment, economics, reputation); preventative safeguards (decrease likelihood of threat leading to top event); and corrective safeguards (decrease the likelihood of significant consequences after top event).

In developing MMV plans for the Peterhead project, Shell recognised a knowledge gap in offshore environmental monitoring. Industry experts worked with several research projects, such as ETI MMV and STEMM-CCS, over a period of 12 years to close this gap. Time-lapse surface seismic technologies represent ~75% of all MMV costs (Ocean Bottom Nodes (OBN), streamer surveys, DAS VSP (Distributed Acoustic Sensing Vertical Acoustic Profiling), processing).

Quest, operational since 2015, safely stored over 8MT CO_2 in an extremely secure deep saline aquifer. Early assessments of containment risks were very low, but a conservative approach was taken for this first-of-its-kind MMV plan. Better storage performance than expected, 5 years of MMV data and history matching of models, led to a re-evaluation of risks and a much leaner MMV plan (2020).

Microseismic events at Quest as recorded by geophones in a deep monitoring well are in the Precambrian basement and do not pose a threat to containment. No temperature anomalies have been detected (Distributed Temperature Sensing (DTS)) that could indicate loss of containment. A surface seismic baseline is always recommended but repeat surveys should be risk-based. A lower cost alternative to surface seismic is DAS VSP which at Quest shows a time-lapse change as expected in the reservoir but not overburden. Pulsed Neutron Logging shows fluids changing where you would expect and not in the overburden.

Deployment of MMV in operational settings is not business as usual there are cost reduction pressures. Storage monitoring plan will be delivered through wells and facilities management processes developed for oil and gas operations and a CO_2 storage project may be linked to a downstream asset which can result in additional IT and data management challenges. A well designed and executed MMV delivers the evidence required for a timely hand-over of responsibilities to the government. MMV is critical for a licence to operate during the injection phase, cannot inject CO_2 without approved monitoring plan and continued evidence of containment. Leveraging the potential of in-well fibre optic technologies such as DAS VSP, DAS microseismic is key to ensure efficient CO_2 storage operation (huge potential but not there yet), requiring functioning end-to-end solutions.

'Monitoring conformance – mapping the impact of uncertainty'
Filip Neele, TNO

Dr Filip Neele has a background in geophysics and is a senior consultant on CO_2 transport and storage at TNO. He has been active in the field of CCS since 2006, working in the areas of CO_2 transport and storage. He has been involved in the subsurface study for the ROAD CCS project, and has led the TNO contribution to the storage feasibility study of the depleted gas fields for the Porthos project. He currently coordinates the work in these areas within TNO. He is co-chair of the Network Technology of the Zero Emission Platform, covering the area of CO_2 transport and storage and is member of EERA-CCS.

The regulator and project developer need to agree on the approach to risk management, the questions are 'to what extent can risks be monitored?' and 'what is the impact of geological uncertainty?'. When is a monitoring system good enough? There needs to be agreement on monitoring system and approach. How do we define thresholds – when do deviations become irregular or significantly irregular? And how do we define conformance – how do we agree on site closure and handover? How do we do this, by using available geological data and existing uncertainties as the basis, use a probabilistic approach to forecast monitoring data for realistic or real injection scenarios and assess the value of new geological information or of additional monitoring techniques. What is required is a probabilistic model chain.

The monitoring workflow includes simulating monitoring responses as well as providing key performance indicators (KPIs) for a given injection scenario/strategy, including submodels and a measurement model (e.g. well output from reservoir simulator). Uncertainty is propagated using Monte Carlo approach and links risk to observations and finds injection strategy that minimises risk and optimises KPIs e.g. modelled plume outline in the area of interest A synthetic gas field test case was developed (fault bounded with 4 wells), 2Mtpa injected over 19 years with forward modelling including thermal flow in the reservoir and geomechanics. Model consists of reservoir flow and thermal simulation; stress calculation on faults, and probabilistic induced seismicity.

The outputs include a range of predicted quantities, bottom hole temperature/pressures. Final step, added history matching, model update step. Much narrower range of data after history matching, illustrating increasing certainty about storage system behaviour over time. Can be used in site characterisation and field development stage, by exploring operational window of storage.

Way forwards includes to study link between monitoring data and risk levels, define conformance levels, extend workflows to other risks and to other monitoring data, and establish value of information. Next steps include to organise discussions with regulators and operators, build a common understanding of the view of conformance assessment.

Q: how is the negotiation between operator and regulator. How is the negotiation process in the Netherlands, how involved are they? Thought was that Netherlands have a closed door. Norway there are more discussions.

FN: there is a lack of clarity about requirements, the drive for zero risk isn't helpful. This type of approach could help define that range of risk and why they stop at a certain point.

'CCS Containment Assessment for Depleted gas fields'
Willem-Jan Plug, EBN

Willem-Jan Plug has been the Subsurface Manager CCS with EBN since 2021 & Technical Manager Storage Systems at Porthos since May 2023. He is a Reservoir Engineer by background (SGS Horizon, Total E&P Netherlands, TAQA Energy BV), and has a PhD in Petroleum Engineering. As a Reservoir Engineer he produced the P18 fields, in a few years, he will be involved in filling up the P18 fields with CO_2.

There is a sense of urgency for CCS deployment despite it being a relatively new technology. Therefore, the CCS project maturation process is essential and crucial. To successfully store CO_2 without the risk of leakage from the storage complex the location (i.e. site selection), knowledge and clear regulation is key. Regulations on storage measures include ALARP statements, EU CCS Directive, National laws e.g. Dutch mining law, CCS P&A standards and criteria, ISO and Ospar guidelines. All the above is covered in the CCS 'ways-of-working' where capacity, containment & integrity, injectivity, operations/monitoring & remediation and risk management, form the five main elements.

Storage containment assessments includes evaluating well integrity through utilisation of plumbing diagrams and geological integrity which throughout the CCS lifecycle. This involves a multidisciplinary approach and a plan, act, do, check approach.

The use of plumbing diagrams is illustrated by a case study from the Porthos project (CCS in depleted gas fields). Well tops, pore pressure information and formation strength data are important to ensure the caprock can hold the pressure in the well bore below the abandonment plug. Plumbing diagrams, integrity assessment of legacy wells are important to show that no movement of fluids between formations happens during the entire CCS life cycle.

To conclude the main messages were that containment assessment is necessary during the entire CCS life cycle. The integrity and accessibility of legacy wells must be evaluated during the screening phase. It's hard to quantify leakage. Mitigations and barriers are available to reduce the risk of leakages and monitoring to confirm assumptions.

Session 5 - Discussion

Q1: looking at a deep dive into the physical processes and modelling etc, how important is it to understand the system?

• Jerry Blackford: it's really important to understand the system in order to sanity check what you do with machine learning or other approaches used. The knowledge is essential but you don't necessarily need really detailed baselines every time, you do need expert knowledge.

• Marcella Dean: it depends on the risk. Monitoring and modelling must be appropriate given the severity of the assessed risks. And you must be able to follow up and implement timely corrective measures. Higher risk requires independent sources of data to reduce uncertainty associated with each monitoring method. The more you can drive models with data the better.

• Filip Neele: if I were a regulator I would like to understand how the monitoring data proves containment. There will be differences between expected and observed, so regulator needs to be convinced by operator that observed are where there are. There is a limit to what a simulator can do. I am not sure how to answer that.

Q2: the regulators vary in what they ask for, e.g. x data or x technology, which is better?

• Marcella Dean: EU regulations are not prescriptive, you just have to manage the risk.

Q3: When I have small changes there are several ways to map them. How compelling will this be for the regulator? How do you have confidence to explain variations without project shut down.

• Jerry Blackford: when looking at emergent systems have sensitive thresholds for measurements, define optics and reduce false positives. There will always be a trade-off with how sensitive you want to be and how many false positives.

Q4: When do we have enough data? If you get more data you get more questions. Why should we do it, especially if it triggers more from the regulator.

• Marcella Dean: CCS projects rely on off the shelf monitoring. Data that is critical to answer the questions we have. In official MMV plans we don't use much R&D as we must do it reliably, cheaply and efficiently.

• Filip Neele: expect first projects will get this started and will show regulator expectations. Would hope that over time there will be a way to quantitively support certain choices, Sleipner has seismic survey every two years, this is probably too expensive for other projects. Show value at a certain point, e.g. 5 years rather than every two years.

• Simon O'Brien: reemphasise the risk based approach. On the conformance side its important to consider what are the impacts. Are they really important? Regulators need to understand clear containment and conformance monitoring, if a leak occurs will it actually impact something? If operators are not concerned then the regulators should not be.

Session 6

Emerging solutions and approaches to monitoring.

Chair: Jerry Blackford

'New technological solutions for water column-based monitoring of offshore CCS sites'

Jonathan Bull* (University of Southampton), Allison Schaap, Ben Roche, Andrew Morris and Paul White.

Professor Jonathan Bull is based within Ocean and Earth Science, National Oceanography Centre Southampton at the University of Southampton. His current research focusses on understanding and quantifying fluid flow within sediments and across the seabed; measurement, monitoring and verification related to carbon capture and storage.

To detect and quantify gas emissions from natural CH_4 and CO_2 sites and controlled CO_2 release you can use: active and passive acoustic methods. For active methods, detection of water column gaseous plumes can be achieved using 500 kHz frequencies at distances that are multiples of the seabed depth. For passive methods, hydrophones can be effective to determine flux but are only effective at short ranges (<20m).

Example of active acoustics at methane emissions site using multibeam backscatter (at different frequencies and depths) to quantify gas flux from bubble size distributions (Li, Roche, Bull et al. 2020[13]). Autonomous chemical sensors have been developed for range of nutrients, carbonate and other parameters and attached to multiple platforms, big developments and commercially available.

The STEMM CCS controlled release experiment was presented and it was noted that the work is now well published and nicely summarised in the paper by Flohr et al (2021)[14]. Detection methods that are suitable are active and passive acoustics, water column monitoring with chemical sensors. Some methods may be suitable for later and others were not suitable and discounted (e.g. ship based sampling of water or sediment, benthic chambers, ROV based bubble capture/imaging or chemical detection).

pH measurements were taken at two different heights, and the pH fluctuations correspond to gas release and current direction. Compared amount released with measured release rate. Also studied CO_2 downstream from release site and modelled – how far away from release point is the plume detectable and how far off the seafloor is it detectable and how well chemical sensors worked for difference release rates. Results show that you can detect several hundreds of metres away, but only if you are close to the seabed. Key messages include that CO_2 dissolves rapidly in seawater (bubble only 8-10 m), and that chemistry and active acoustics are highly complementary providing a low cost to CCS monitoring.

Project Greensand is located offshore Denmark and the University of Southampton and National Oceanography Centre are contributing to designing chemical and acoustic systems for long-term CCS monitoring. These systems will be located on a seabed lander attached to a surface buoy. The seabed lander with mounted sensors was tested in a dock in December 2022. The active acoustic system detected a CO_2 bubble release at greater than a 100 m distance, while both the active acoustics and chemical sensors both detected releases at c. 20 m distance. These tests have verified functionality and that small CO_2 releases are readily detected with chemical and acoustic sensors which can be designed into an MMV plan. The battery life for landers is over a year, requires reagents for chemical sensors. Issues still to resolve is getting data back. Automated Underwater Vehicles (AUVs) are another option, however its problematic getting close enough to seabed to measure the dissolved CO_2 phase.

Q: Regarding pH changes, changes appear rather small what is your perspective on background Ph changes.

The sensitivity of sensors is .01, in terms of the ocean – oceans are generally well buffered at 8.1-8.2. You will get ~7 in the middle of plume, and as you move away it decreases. Key is how big an area you are affecting with plume? Size of a table or this campus. It will change quite quickly in a release, but is buffered.

Q: how are you approaching getting data back from lander

We are looking at linking landers to existing infrastructure, working with buoy manufacturers and using 4G.

'The ACTOM toolbox: A decision support tool for environmental offshore monitoring'

Marius Dewar* (PML), Anna Oleynik (University of Bergen)

Marius Dewar is an expert in modelling two phase flow of CO_2 and other substances in the marine systems, using complex and detailed models. He did his PhD at Heriot Watt, on bubble plumes and was involved in the QICS project. He now works at Plymouth Marine Laboratory where he has develop the ACTOM decision Support Tool to support monitoring strategies.

The ACTOM project has developed a semi-automated toolbox into a streamlined and easily accessible software for designing monitoring

[13]https://agupubs.onlinelibrary.wiley.com/doi/full/10.1029/2020JC016360
[14]https://www.sciencedirect.com/science/article/pii/S1750583620306629

strategies for offshore CCS storage. The toolbox utilizes site specific information and a variety of algorithms to aid users in defining an optimal monitoring plan which will satisfy stakeholders, a communication tool to advise local communities and satisfy legal requirements. Inputs from the sites at the Gulf of Mexico (GoM) and North Sea (Smeaheia and P18) are be used for the demonstration, whereby simulated leakage scenarios are used to create risk maps simulating different release points.

The toolbox requires entry of site-specific information including: reservoir and overburden geophysical characterization; hydrodynamic data or model simulation (e.g. tides, current, thermal mixing in the water column); and biogeochemical baselines from models or observations (e.g. carbonate chemistry, oxygen, nutrients).

Data input quality is critical to output quality, data can be local but not exactly over AOI. For geological inputs, GoM looks at legacy wells as risk point, Smeaheia models a fault and P18 takes 3D seismic volume, horizons and fault maps to produce 2D relative probability maps. Potential leakage rates are output for each case. Current and tide information gathered for all three sites and data on biogeochemical data is provided. Which when input into the models shows time runs of leakage and distribution over time for each case, then the detection threshold. For the GoM, detection would be very difficult even at the maximum leakage rate and sensors would be required directly above strongest leakage in order to detect. For Smaeheia and P18 it's not possible to detect leakage over the threshold, there is no impact above natural variability. Modelling and varying the leakage rate can help with placement and number of sensors required.

Key messages: monitoring strategies can be developed through the ACTOM toolbox provided the data inputs are of sufficient quality. Inputs include hydrodynamics, biogeochemistry, geological features and leakage rates. Leakage rates are shown to be small and not easily detected above baselines, increase in the rates help in sensor placements but not always an option to place a sensor at every feature therefore moving AUVs may provide useful check.

'Methods for robust detection of anomalies – case study of Rousse pilot soil gas monitoring'

Thomas Le Guénan*, Jean-Charles Manceau, Farid Smai, Frederick Gal, BGRM

Thomas Le Guénan is a senior research engineer and project manager at BRGM for more than 15 years. He is the main expert on the topic of risks and impacts of subsurface energetic uses (i.e. CO_2 geological storage, geothermal energy, H_2 underground storage). A generalist engineer by training with a focus on environmental aspects. He is currently the lead expert in the safety and performance WP of H2020 project pilotSTRATEGY, and is currently managing internal projects on performance analysis of subsurface uses. He has been a steering committee member of the IEAGHG Risk Management Network since 2016.

Thresholds can serve as a useful tool to help stakeholders to understand that site performance is conforming with expected performance or for the operator to launch additional monitoring or mitigation actions to address. However, defining the wrong thresholds can negatively impact operations. If thresholds are tool conservative, it could lead operators to expend resources (time and money) to investigate threshold exceedances that are not problematic and cause unnecessary concern with stakeholders that creates a barrier to permission to proceed. If thresholds are too permissive, an operator may not detect irregularity in site performance. This study proposes statistical method to improve threshold setting.

Monitoring objectives are both conformance and containment, and baseline challenges include natural variability in time and space combined with risk of false negatives and false positives. In the presented case study – soil gas sampling near the Rousse injection site was considered. Soil gas samples were collected at 35 points around the injection site; data from six campaigns were used as a baseline (2008/9), several sampling campaigns were performed during injection (2010/12), and three sampling campaigns were performed in the post-injection monitoring phase (2014/15).

Classical approach comprises:

• a statistical method picking thresholds from mean and SD, for summer and winter (Gal et al 2019[15]) – when compared to dataset may have risk of false negatives.

• a process-based approach O_2/CO_2 respiration line (after Romanak et al. 2012[16]) and use this against original dataset – resulting in potentially many false positives.

• Synthetic values are also calculated to simulate a leak to aid identification of false negatives.

A common issue with application of this classical approach is that there are limited data and significant natural variation.

A probabilistic modelling method is proposed with a deterministic model, stochastic variables and conditioning with observations using Bayes theorem (inspired by Jenkins, 2013[17]). This Bayesian method requires the practitioner to explain to the model what is 'normal' and 'abnormal'. Determined from the operational data which of the normal or abnormal models is the most likely given the observations. Uses hierarchical model of CO_2 concentrations and the global O_2/CO_2 model – only need to look at value above the respiration line.

Key messages, probabilistic modelling can be used to adjust behaviour model of a variable observed before the start of operation, provide quantitative elements to design baseline acquisition, and detect data that deviates from modelled behaviour. Results can be complex to understand but not to communicate.

Q: Regarding environmental methods, the challenge we have with CO_2 leakages is that it has to get from the under burden to the overburden, so monitoring should be designed to catch it early and therefore need multiple methods and signal detection. How do we upscale?

My preferred approach would be multiple sensors and then use a mathematical framework to combine multiple streams of information.

'Evaluation of wellbore leaks and impacts using the NRAP OPEN-IAM model'

John Hershberger and others, Battelle

John Hershberger is an early career professional in Battelle's Energy Division. He is a Reservoir Engineer with a focus on CCUS projects. He received his Bachelor of Science degree from West Virginia University in Petroleum Engineering. Mr. Hershberger is interested in Petroleum Engineering, Geology, and Dynamic Reservoir Modeling.

Midwest Regional Carbon Initiative (MRCI) uses the NRAP-Open-IAM to explore containment effectiveness and leakage risk at candidate carbon storage sites; NRAP has developed set of computational tools for purpose of assessing and mitigating risks associated with geologic CO_2 storage. The NRAP-Open-IAM Intended to simplify the simulation work needed using ROMs for representation of physical processes that may be induced by CO_2 injection. Cemented wellbore leakage workflow assessed through inputs: stratigraphy, CO_2 saturation and pressure, wellbore characteristics, shallow aquifers. And outputs include: CO_2 and brine leakage rates into aquifer and total dissolved solids (TDS) and pH change.

Three modelling scenarios were presented: central Illinois, central Ohio, and norther West Virginia. Dynamic models of storage reservoir performance produce CO_2 saturation and pressure data though 30 years of CO_2 injection and 10 years of post-injection site monitoring. These three scenarios include scenarios with stacked storage, scenarios with heterogeneous and homogenous distributions of reservoir properties, and a multi-well injection scenario.

One scenario considers a proposed storage site in the state of West Virginia with a storage reservoir

[15]https://www.mdpi.com/2076-3417/9/4/645
[16]https://agupubs.onlinelibrary.wiley.com/doi/full/10.1029/2012GL052426
[17]https://www.sciencedirect.com/science/article/abs/pii/S1750583612003325

at a depth of 1969-2001m, an intermediate porous and permeable formation ("thief zone"), an overlying shallow groundwater aquifer (8-100m depth), and three caprock layers. A scenario was considered in which 32 million metric tonnes (MMT) of CO_2 was injected over 30 years at a site with eight wells assumed to have an effective permeability of 113 mD and a radius of 4.5 inches.

Nicot et al. 2009 method was used to determine the area of review. This method was used to calculate the critical pressure build-up required to communicate fluids between storage reservoir and shallow aquifer along the permeable conduit. Simulated pressure and CO_2 saturation response to injection show that the highest pressure build up will occur in the centre of the model domain (within one mile of injector). Two of the defined, hypothetical wellbores fell within the CO_2 plume.

Risk modelling performed using dynamic reservoir simulation results and the NRAP-Open-IAM well leakage ROM show that a maximum leakage of 30 tonnes of CO_2 and 20 tonnes of brine might occur over 40 years – showing that presence of legacy well bores (both real and hypothetical) within the model domain should be minimal. Leakage risk would be further constrained with site specific wellbore permeability, with no leakage expected to occur into shallow aquifer.

Key messages: The NRAP-Open-IAM tool is effective tool to assess wellbore leakage risk and impacts based on CO_2 and brine flux to assess compliance with US EPA standards. Brine leakage rates are higher at wellbores exposed to higher pressure conditions. Leakage rates are highly dependent on wellbore permeability. In the Ritchie County, WV scenario the risk to shallow aquifers is minimal and conforms with EPA standards.

Comment: EPA guidelines (for calculation of area of review) are for open wellbore and don't take into consideration cement? So you would need to look at cement and determine where you have coverage. But if it's an open wellbore the EPA classes it as open all the way.

Q: How are leakage rates calculated? Complexity of analysing and how to assess models? Think EPA critical pressure thresholds is considered. Also is this accessible to public?

Yes, the NRAP-Open-IAM is open source. Leakage rates used in this case study were calculated using the cemented wellbore ROM – which is a response surface model developed from a a large ensemble of finite element simulations of CO_2 and brine mass transfer along a cemented well (Darcy flow with relative permeability). The NRAP-Open-IAM includes other well ROMs that were not used in this study, including a ROM based on drift flux-type modelling of fluid migration through an open conduit (Pan and Oldenburg, 2017); this open borehole ROM can be used to estimate maximum extent of potential brine migration (comparable to, but not the same as, the Nicot, 2007 approach mentioned earlier). multiphase fluid solution to it where it's simulating mass transfer of CO_2 in water and super critical phase and fluid as well.

Q: In an area of review of say 20 miles, in the US you will have wells. So do you have to check each one?

Permitting for carbon storage requires characterization of existing penetrations within the areal extent where groundwater resources could potentially be impacted. Only the subset of those wells that penetrate the caprock are considered credible potential leakage pathways and require more careful scrutiny.

'Using Distributed Temperature Sensing (DTS) technology to evaluate CO2 injection and migration'
Sanjay Mawalker and others, Battelle

Sanjay Mawalkar is a Senior Research Scientist with Battelle's Energy & Resilience group. Since joining Battelle in 1996, he has assisted in development of various oil & gas, pipelines, carbon management, ES&H, and process risk-assessment technologies for industry and government projects. He has provided data management and software development expertise for projects in the area of Energy, Transportation, and National Security. He has developed a Risk Prioritization methodology for facilities having environmental, health, and safety liabilities. Currently, Mr. Mawalkar serves as group data manager for CO_2 accounting, mass-balance calculations and operational data received on various carbon capture, utilization & sequestration (CCUS) and Enhanced Oil Recovery (EOR) projects.

An example was presented from the Chester 16 EOR Reef, one injection well and one monitoring well with three main objectives to Distributed Temperature Sensing (DTS) monitoring: to infer the inflow zone depths where CO_2 is entering the reservoir via the injection well, to assess the potential vertical migration of fluids along the well borehole, and to monitor flow stratification in the reservoir and arrival of CO_2 at the monitoring well.

DTS was installed in both the injection and monitoring wells. The injection target is two formations. Real-time temperature readings were collected at 1 m intervals along the DTS fibre-optic system with P/T memory gauges in the injection well and five behind casing P/T sensors in monitoring well, and collection of the bottom hole pressure data.

90,000 tonnes were injected in one year, with DTS data collected at various time steps for comparison with initial reference data. It was observed that, with the injection of CO_2 down well the whole well bore cools. The temperature signature was then monitored over time to understand how long the reservoir takes to re-equilibrate. Data suggest that small amounts of (un-intended) injection also occurred in Brown Niagaran – a secondary storage interval. A pblue band (representing regions of cooling) observed in the processed DTS data shows a zone of persistent cooling that is slowest to warm back to in-situ temperatures and is interpreted to indicate migration of CO_2. Critically there is no evidence of out of zone migration above caprock.

Can we detect CO_2 at monitoring well? The monitoring well is 1000 ft away. Other corroborative data is used together with temperature sensing data; pressure change shows that the pressure plume arrived at the monitoring well and observed changes in CO_2 saturation confirms that CO_2 reached the monitoring well. Comparison of baseline temperature to time series DTS wireline temperature data showed cooling in the Brown Niagran. Operator did a temperature log, showing the depth correlation in DTS was incorrect showing Brown Niagran but actually occurred in the primary storage interval A1-C. By 100k CO_2 injected there was a 8-9deg F change at monitoring well level.

Key messages: DTS is a powerful tool in CCUS allows us to monitor conditions in real time – novel in 2017 not so now and has got cheaper. DTS allows us to infer inflow zones in injection well and detect the arrival of the CO_2 front in the monitoring well. Further work is needed to re-calibrate depths at monitoring well and collate with other techniques.

Q: Pulsed Neutron Logging vs DTS. How far can DTS see into reservoir?

The signal is at the wellbore on the casing, however using multiple wells, you can do an interpolation.

DTS is on casing not on tubing, in Germany they have tested DTS on tubing. A note of caution, when downside fibre-optics on casing, and you want to change a monitoring well to production you will need to perforate, you will have to be careful of the fibre-optics and this damaged.

Q2: Why you have depth disparity of DTS and other (P/T) sensors.

We didn't have calibration and access to a good temperature at the time.

Session 6 - Discussion

Q1: could you explain, we see the value of DTS but there are still challenges, e.g. they can have installation issues, have they been addressed?

• Sanjay Mawalkar: The biggest challenge is that it's meant to be in real-time but actually it takes a lag of about a week to get data and process it. None of the analytics are built into the software itself so it takes time.

Comment from Rob Trautz – we used fibre optics on tubing for our 2012 SECARB, has a heater cable, that heat dissipates and look for thermal anomaly – heat pulse monitoring.

Q2: One thing when we know where the well is,

do we need to worry about unknown wells?

• Sanjay Mawalkar: In John's presentation this was addressed by having 6 actual wellbores and 20 hypothetical well bores, just put them in and run the model.

• Thomas Le Guénan: Risk – always have to ask 'what did I miss? What don't I know?'.

• Jonathan Bull: my impression is that people know where the well is, the positions are known but not how they are capped.

Q3: regarding the first talk, landers, how is it handled picking up the landers? How quickly get data back?

• Jonathan Bull: we are looking at different solutions, cables, surface buoys. Timeline is 6 months to a year.

Q3: Chemical sensors can these be affected by other seabed users?

• Jonathan Bull – if you are going to put out a lander you might as well put loads of sensors on it as the sensors are cheap. Windfarm – laying of cables, do it once.

Q4: what is the power consumption of DTS

• Sanjay Mawalkar: the estimate about 1000W. DTS data is collected at 1 m interval and saving every second. This is terrabytes of data. I would take a point and average over an hour and only store only that. You will still see significant result. You could do it once every day.

Session 7

Discussion Panel.

'Communicating well related risk in a CCS project to key stakeholders, including regulators, financiers and insurers (not including general communication to the public).'
Chair: Charles Jenkins

Key messages to emerge from this session

• To the degree to which we can develop standardised, streamlined, templates for permit applications it can benefit both the regulator and the operator.

• In reality, the regulator is often learning along the way. Good ongoing communication between regulator and operator is key to successful permit applications.

• Regulators do require permit applications to be definitive and in-depth. There should be no surprises.

• Caution about ensuring early applications to be best practice as other will no doubt copy, can have pros and cons.

• Language matters, and communication between technical and financiers and insurers needs to make sure we are familiar with each other's lexicon.

• Insurers are developing insurance products for CCS and would be a valuable topic for another meeting.

Alistair Macfarlane has been with the NSTA (formerly OGA) since 2016 and was Area Manager for the SNS/EIS from 2019. Alistair is the co-chair of the ASTF's CO_2 Transportation and Storage Task Force and from the 1st of February leads the NSTA's UK Carbon Transportation and Storage Team who have responsibility for evaluating and consenting to CO_2 storage permit applications. Regulator, licensing and all consenting and permitting. End of the decommissioning time as well. My team very focussed after a licence is awarded. Work program, by the time permit is received there should be no significant risk of leakage. Post injection then its about monitoring. End of storage use, 20 years of monitoring.

Jared Hawkins, sub-surface scientist from Battelle, a non-profit research institute in Columbus, Ohio with an extensive research portfolio that includes CCS among many other things. Jared and colleagues at Battelle conducted a study, sponsored by the United States Energy Association, Inc. (USEA), communicating de-risking CCS and specifically for the finance and insurance industries. Talked to technical and non-technical experts about risks, focusing on three specific risks deemed unique or important to CCS: CO_2 leakage, induced seismicity, and public acceptance. The Report is available online. Thanked colleagues for help on the study. Thanked Mike Moore and Alex Krowka of USEA for sponsoring the study and trip to the workshop.

Simon O'Brien, Global CCS lead for Shell, previously Quest. My job to get Quest up and running, and a lot of that was discussing with the regulator. Insurance and finance side, Quest largely funded by the government, continuous knowledge sharing. Funded for industry, government and regulator how it can run in a safe and reliable.

Myles Culhane, Oxy, as a lawyer and chemical engineer sit at a nexus of engineering, regulations and law. We have been working with insurance and finance industry to describe the risks. We will avoid talking about policy. Miles presented two slides, as described below.

Tale of two cities: Livingston Parish Louisiana is supportive of the O&G industry, two projects proposed, enacted a moratorium – first of two, class 2 wells and then class 5 wells (stratigraphic wells). State open to oil and gas and now clamping down on CO_2 sequestration. Challenged and successful in court. Ability to use projects to have productive conversations.

Sacramento, California – notoriously not open to fossil fuel industry, capture CO_2 from a combine cycle power plant. Further support for project. Held open and informal public workshops. Two states and very different outcomes, one very open and transparent process to communicate the risk and the other was less transparent.

Q1 – What is the biggest problem in communicating well related risk to CCUS stakeholders?

• Alistair Macfarlane: There are a different set of risks to oil and gas. We require early risk assessment to identify all the risks they can see. This leads to a work programme and plans. Primary goal is to limit leakage. Granted a permit once that has been qualified. Differ to environmental agencies. A lot of work goes in. No projects (UK) are at permit stage yet, partly due to the technical work that needs to go in. Obligation on licensees themselves. We are happy to share what our process is. Taxpayers' money is going in, want value for money. Last thing we want is something to go wrong with the first projects. Do need to get this right.

• Jared Hawkins: Our work focused on insurance and financiers. We found that we were speaking different languages, different lexicon. It is important to reconcile this. For instance, a colleague cold called non-technical experts to get them interested in participating. After she described CCS, they responded 'oh you mean fracking'. Alternatively, words we use mean completely different things to financiers. Having a common understanding of what we are talking about and communicating that clearly is vital. One of the last questions we asked each of our participants was "What do you think is the most important thing we haven't covered?" This was a good way pick up interesting things they have questions about and to glean additional information about what is important to them. For instance, a lot of weight is placed on the rigor Class 6 permitting process and many stressed the importance of trust and the integrity and reputation of organisations conducted CCUS, particularly in the early projects

• Simon O'Brien: the Canada regulator is well established and in acid gas, oil and gas. CCS was a new thing for them and getting up to speed together was important. The growth of CCS – continually new staff too, which was a challenge. Interesting part of that, set of requirements, but each person had a different set of pet subjects and requirements. Developing and delivering a really robust risk management program. Regulator on hydrocarbon side, ok, but on the environmental side was a new area for us. Requires a whole new set of people, auditors on both sides.

• Myles Culhane: there are not enough geoscientists! In 2022, there were 1 million producing oil and gas wells, there is tremendous expertise in state agencies, they have been permitting oil and gas wells for over 100 years. Those individuals really understand the geology and subsurface. Overlay with EPA and state agencies. Regulators are very careful, they like the documentation and have time to understand it and you have to have people to understand it. Well trained environmental people, and people who understand the subsurface. In California, a third party engineer and geoscientist review the permit application package. Sent further review to Laurence Labs. There are 4 million legacy wells. Operators have a tremendous amount of information about those wells. Need to demonstrate to the regulators that they've done the work.

Q: Rachael Moore: At IEA we talked about permitting time and how this applies across all energy side. How can we make sure permits are streamlined, robust, and reviewed in a timely fashion? This is a critical decade for CCUS.

• Myles Culhane: Regulators are careful in reviewing applications. To the degree that applicants can follow the same format, it can help facilitate review. There are a variety of regulatory bodies that all have a role to play in permitting these applications. If we can help develop a template – so they are seeing a familiar document even if it has site specific information, if it can look the same then the regulator can find information need to find. Might have 100's of legacy wells – this takes time. EPA and regulators are aware of this challenge.

• Alistair Macfarlane: the NSTA uses a two-pronged approach. Not too prescriptive, we set out guidance on what documents should come and what should be in them. Before that, documentation – is an audit point, should be no surprizes. We run a series of workshops along the way. Will bring up all the questions. We know what we are expecting. Nothing has slipped in that we aren't aware of. Doesn't have to be thousands of pages. But we don't want anything left unsaid, it's the first time for operators. It will evolve as we go along.

• Simon O'Brien: A lot of the applications are long, and Quest was the same, a lot of documents. Would it be better to have a smaller document?

• Alistair Macfarlane: Until I see the first draft I don't know. It's really tricky. The application needs to be definitive; if something happens, it needs to be in depth. Doesn't need to be everything that has been shown to us over two years. When we grant a permit it needs to be robust.

• Jared Hawkins: I appreciate the way Myles framed it. State primacy has been held up as the solution to an overburdened EPA. However, states will not necessarily get primacy. Anything that applicants and the EPA can do to promote a standardized, a regimented, and reliable process for Class VI permitting is a useful measure to facilitate the timely processing of Class VI applications.

Q: Marcella Dean: communication. How do you see the operator developing their permit application and the regulator.

• Alistair Macfarlane: Ongoing dialogue is part of the process, two of my team act as project managers who have an ongoing dialogue with the licence. Collaborative one. We don't want to see anyone come up against a requirement that is a surprize.

• Simon O'Brien: In Canada there is lots of communication with the regulator; the process is very collaborative.

• Charles Jenkins: Filip talked about

communicating with Dutch regulators.

Q: Sanjay Mawalker – Does public perception have a number? Dollars, risk.

• Myles Culhane: For the Class VI program the project proponent is expected to cover costs of corrective action, estimated cost of emergency and remedial response, plugging abandoning, post -injection site care, endangerment to drinking water etc. Projects have to demonstrate that they have financial instrument to cover the estimated costs of these potential risks. Cost of this to the project ~ 1% of what we are going to assure.

• Alistair Macfarlane: This is similar for us. There are different ways of the operator providing that. Financial things are still being worked through. In the event that there is a leak – what needs to be done at that point? Need to do some cost benefit analysis at this point.

• Simon O'Brien: Two points. First, on money, financial assurance was addressed early on (in the Quest project) to demonstrate that we could pay for any adverse event. On quantification of risk we did deliver one even though the regulator didn't ask for one. What they do want to know, if we have an issue, how big is the issue, and what time frame you need to address it.

• Myles Culhane: In California, they (the regulator) read every line and asked about every category. They asked about every aspect.

• Charles Jenkins: Filip do you want to speak about your work about your proposed approach to a quantitative measure of risk assessment during operations. Do you think it might get easier?

• Filip Neele: it is my ambition to develop the data and risk-based approach to characterise a site and develop and operate it. It might be an approach that could be used on any site and maybe that could help create, conditions that could be similar at any site. This involves defining performance indicators, which take into account geological uncertainty. Our approach could lead to a common understanding, between regulators and operators, of the sufficiency of a risk assessment, and of a proposed monitoring system. And, as a result, lead to shorter permitting timelines Developing a method. I think this will create permit applications that are similar for each site. And help regulators to understand what will end up on their desks. Develop a method that will produce standard permitting processes and guidelines.

Q: Owain Tucker: NRAP has been trying to do this for a long time with probabilistic methods, how well are they being received? Often want no harm to drinking water, how well are regulators accepting probabilities of very small chances?

• Robert Dilmore: The US EPA are aware of what the NRAP project is doing. While the probabilistic approach to assessing risks does not align directly to what is specified in the Class VI permitting requirements, there seems to be an appreciation of the value that a quantitative, probabilistic approach provides as complementary justification to the requirements of the formal regulatory process. Opinion, based on experience from supporting technical assessments for elements of the permit applications, is that standardization of workflow (with accompanying computational tools) and standardisation of , format for presentation of analysis results can provide value to both applicant and reviewers. Following, credible, transparent, quantitative workflows can provide a useful framework for communication between stakeholders. Permits from early actors will become public record; hopefully, if they are following good practice, it will create a robust template that others can follow.

• Thomas Le Guénan: Tell the numbers. One thing to get if you want to manage the risk. Best practice in terms of risk. Regulator asks for something, get your permit – but independently that your site is safe.

• Simon O'Brien: Quantification is useful, don't not do it. If you express it as significant risk to your project that might cause delays and cost to your business.

Charles Jenkins: In chatting with regulators in Australia I have heard 'I am only interested in deterministic risk assessment'

• Myles Culhane: California requirement is to show 90% probability that 99% of CO_2 will remain in reservoir 100 years post injection. Rigorous risk assessment and developed models. Sets interesting California CCS protocol, industry most likely to have performance data will be the oil and gas company. That's what we drew upon. Put it on a computer and walked them through it. Felt strongly about our model.

• John Hamling: Owain – above a gradient, water can flow into USWD – analysis where delta pressure from injection. Define boundary, not asking certain brine. Identifying the boundaries.

• Alistair Macfarlane: I wrestle with how do you quantify amount of containment e.g. 99.9%? Commissioning some work about this and thinking about evidence required.

• Jared Hawkins: Battelle's work on the Midwest Regional Carbon Initiative (MRCI) has helped advanced CCUS in the 20-state region we operate in. Four different technical areas are studied: Subsurface Characterization (including subsurface risks), Data Sharing (including a database of reports and links to raw data), Infrastructure Assessment (including surface risk assessments and mitigation opportunities), and outreach and communications. Lots of good information. Importance of DOE in advancing CCS cannot be overstated, supported a lot of projects and really spearheaded the projects forward. Energy Data Exchange, which contains publicly available reports and data, is also an excellent resource in the US.Simon: work that you do with the regulators is vital, learning together to keep this together. Myles had really important point of keeping similar. If we are learning from existing, but if the documents are bad then that is not helping. Feedback is key – if they didn't use 1000 pages then is that necessary.

• Myles Culhane: perhaps this is a topic for another meeting, the insurance industry is starting to write and they are going to be an important part of this. Products are being written. Probabilistic assessment are being made. Judged on their behaviour. Well robust risk assessment – well constructed project can get insurance right now. Starting to see products for capture. In the event of losing CO_2 you got credit for and have to re-store? Theme for a future IEAGHG Network meeting could be the underwriting of risks.

Session 8

Conclusions & Recommendations

Conclusions and Key Messages

Well integrity is a concern for CCS projects potentially impacting loss of containment to the water column or atmosphere or through brine into drinking water and aquifers. The following are a sample of the high level conclusions.

Areas of concern

• Hydrocarbon wells show evidence of unexpected gas entering into the annulus (the space between the tubing and casing) or wellbore, however these are site specific and volumes/flow rates are low and/or unrepeatable. There is no strong link between age of well and likelihood of leakage, however improved well completion and plugging and abandoning requirements in places like the North Sea make leakage in younger wells less likely.

• Any present leakage is only a baseline, as soon as CO_2 is injected could we see leakage in previously well-behaved wells? There is much that is unknown.

• Data available on well abandonment may be fragmentary, time-consuming to assimilate or hard to interpret, it's imperative to proceed with diligence and caution.

Reasons not to be too concerned

• Theoretical, laboratory and in situ data suggest that well placed Portland Cement and casing is an effective barrier in legacy wells and should survive chemical attack.

• Oil and Gas databases e.g. North Sea, Permian, Alberta show no evidence of large gas losses.

Risk Management of Legacy Wells

• Employing a traffic light system based on available data is useful for initial triage of legacy wells: e.g. red wells kills a project; yellow wells can potentially be fixed; and green wells could be repurposed for monitoring.

• The emphasis should be on the consequences of well failure, rather than hypothesising about detailed mechanisms.

• Satisfying a (sophisticated) regulator will be via a sustained two way dialogue about the site condition, not a one-off tick-the-box process.

• The presence of wells and their condition will essentially create a creaming curve of storage sites (likened to oil and gas creaming curves) whereby the best sites are used first. Eventually breakthrough in technology may assist in the process of remediating wells and opening up previously overlooked storage.

• AI and big data have value but can't yet replace detailed analysis.

Monitoring and Verification for well integrity

• Good methods are available if the well is accessible for instrumentation.

• Inaccessible but probably OK wells – may need their own monitor wells (in the Above Zone Monitoring Interval).

• Higher leakage rates are more likely to be detected and mitigated, but are less probable.

• Baseline testing has to be well considered, can be really expensive and give widely varying results requiring expert judgement on the results and their meaning

• Confidence about false positives and negatives needs to be weighed up and requires experienced personnel to interpret results. Statistical methods can help in screening the data.

• Data lag and quantity (up to 1 week for DTS), and data retrieval are a current challenge for offshore landers.

Recommendations

• More data is needed on real, leaky wells for example through case studies.

• Convincing models of leaky wells are required that explain sustained casing pressure and related phenomena.

• Updated capacity estimates are required that account for areas currently downgraded by high/old well density (mostly in N America and Africa) but which could open up in the future with technological advancements and/or cost changes (Creaming curve)*.

• The insurance and finance sectors need to be involved in conversation around risk, as customers, for example to have a cross-cutting meeting. E.g. Industrial Economics, a US company, assessed potential risk of leakage and then performed financial assessment of FutureGen site.

• Cement, what properties do we want in cement? Slower reactions are not always better. Refocus of speciality cement to consider the properties that actually matter.

• Best practice sharing that aims to speed up permitting process*

• Present work is highly focussed in developed countries, its really important in transferring best practice to Emerging economies.

*could provide future IEAGHG work.

Evaluating technology options to mitigate greenhouse gas emissions

IEA Greenhouse Gas R&D Programme

Pure Offices, Cheltenham Office Park, Hatherley Lane,
Cheltenham, Glos. GL51 6SH, UK

Tel: +44 1242 802911
mail@ieaghg.org
www.ieaghg.org