Technology Collaboration Programme
by iea

IEAGHG Technical Review
2022-TR05
October 2022

5th International Workshop on Offshore Geologic CO_2 Storage

GCCC Gulf Coast Carbon Center

IEA GREENHOUSE GAS R&D PROGRAMME

International Energy Agency

The International Energy Agency (IEA), an autonomous agency, was established in November 1974. Its primary mandate was – and is – two-fold: 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 for its 30 member countries and beyond. Within its mandate, the IEA created Technology Collaboration Programmes (TCPs) to further facilitate international collaboration on energy related topics. To date, there are 38 TCPs who carry out a wide range of activities on energy technology and related issues.

ACKNOWLEDGEMENTS AND CITATIONS

This work reports on the 5th in a series of international workshops on the offshore geological storage of CO_2, which was hosted in New Orleans, USA, by the Gulf Coast Carbon Center (GCCC), Bureau of Economic Geology (BEG) at the University of Texas at Austin, with logistical support from Southern States Energy Board.

This report was prepared by Carlos Uroza, GCCC, with input from the speakers, and edited by Samantha Neades, Tim Dixon and Katherine Romanak.

IEAGHG would like to thank the Steering Committee for their efforts in facilitating this workshop:

- Tim Dixon (Chair), IEAGHG
- Katherine Romanak (Co-Chair), GCCC
- Sue Hovorka, GCCC
- Tip Meckel, GCCC
- Alex Bump, GCCC
- John Litynski, US DOE
- Filip Neele, TNO
- Paulo Negrais Seabra, Independent Consultant, Brazil
- Ryozo Tanaka, RITE
- Owain Tucker, Shell
- Sveinung Hagen, Equinor
- Doug Connelly, National Oceanography Centre
- Charles Jenkins, CSIRO
- Samantha Neades, IEAGHG

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The report should be cited in literature as follows: 'IEAGHG, "5th International Workshop on Offshore Geologic CO_2 Storage", 2022-TR05, October 2022.'

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International Workshop on Offshore Geologic CO_2 Storage

5th International Workshop on Offshore Geologic CO_2 Storage

Organised by GCCC, BEG at the University of Texas, with IEAGHG

New Orleans, Louisiana

Thursday 19th – Friday 20th May 2022

GCCC Gulf Coast Carbon Center

ieaghg

carbon sequestration leadership forum

Contents

Executive Summary

The 5th International Workshop on Offshore Geologic CO_2 Storage was held in New Orleans, Louisiana, USA on 19-20th May, 2022, a very appropriate location given the growing interest in, and vast potential for, offshore storage in the Gulf of Mexico.

With 50 attendees in-person and 120 virtually, there was a good mix of industry, researchers and regulators. In particular there was very good attendance by US regulators, State and Federal, as rule-making is underway at the Federal level to allow and regulate offshore CCS.

Despite a very packed agenda of some 45 presentations, time for valuable discussion was also included. In the two years since the last workshop in Bergen, Norway, many new projects with offshore storage are progressing. With so many projects to fit into the schedule, we had to limit the project updates (sixteen in total) to just 5 minutes each. As well as the number, the diversity of the projects is impressive, covering many industry sectors, different routes to storage, and two including not just shipping for transport but also ship-based handling/injection, as already demonstrated by the Lula project in Brazil. Once the project updates had been covered, the workshop got into more technical details, such as issues with depleted fields, the use of deep saline formations, containment and well integrity, infrastructure re-use and shipping transport.

In the USA, regulators are currently developing offshore storage rules and are very open to receiving inputs from researchers and industry. Many new industry players are entering into the area of CCS and need information. Some of the high-level messages from the workshop were that the re-use of infrastructure is complex, both technically and legally. There were good real-life examples of the details to be considered from some projects. The new ship transport plans shared by Shell were also very impressive. Another outcome of the presentations, and especially from the discussions, was the need for standardisation in storage assessment methodologies, making the case for the use of the Storage Resource Management System (SRMS) from SPE.

The workshop presentations also indicated that outputs from EU research projects such as STEMM-CCS and ECO_2, are being used by real projects. The workshop included an example of these experimental outputs being used to 'down-select' techniques for one real project's monitoring plans, so these plans were described as being 'fit-for-purpose'. Similar moves towards 'down-selecting' monitoring methods were seen previously with the onshore US Regional Carbon Sequestration Partnerships (RCSP) and their outputs being used by larger integrated projects in 'down-selecting' monitoring strategies and techniques from the vast range tested in RSCPs.

Overall, there is impressive progress with developing CCS projects offshore, and much knowledge was shared in this workshop. The feedback from all attendees, in-person and virtual, was very appreciative with many requests for it to be repeated.

The GCCC at UT-BEG are partners with IEAGHG in co-chairing the workshop series. The GCCC sponsored and hosted the 5th International Workshop and Southern States Energy Board (SSEB) organized the venue in New Orleans. Many thanks to Carlos Uroza of the Bureau of Economic Geology for drafting this report of the workshop. Many of the presentations are available on the GCCC's Global Offshore Initiative webpage.

In-person attendants to the 5th International Workshop

Some of the virtual attendees to the 5th International Workshop

Session 1: **Welcome & Scene Setting** (Tim Dixon & Katherine Romanak)

1.1 Welcome

A welcome was given by Tim Dixon, manager of IEA Greenhouse Gas R&D Program (IEAGHG) and Katherine Romanak, research scientist from Gulf Coast Carbon Center (GCCC) at The University of Texas at Austin, Bureau of Economic Geology (UT-BEG). Tim opened the session by mentioning that gigaton-scale CO_2 can be stored in offshore basins around the world, which is convenient since many of the industrial sources of CO_2 are located on the coasts, close to potential storage sites. Also, there is growing interest in more countries to work on CCS.

Katherine Romanak mentioned that the GCCC-BEG first introduced the idea of an offshore CO_2 storage initiative at the 5th Ministerial meeting of the Carbon Sequestration Leadership Forum (CSLF) in 2013 in Washington D.C. The goal was to advance offshore CO_2 storage in the USA by learning from other countries more advanced in offshore CO_2 storage. The US Department of Energy (US DOE) subsequently led a taskforce to evaluate the potential for offshore CO_2 storage and produced a CSLF report. Recommendations were made for workshops and knowledge sharing, therefore, the workshop series initiated with the GCCC at the UT-BEG hosting the first workshop (April 2016) with the idea of facilitating sharing of knowledge and experiences among those who were doing offshore storage and those who may be interested. Other workshops followed in the USA and Norway.

This 5th Workshop on Offshore Geologic CO_2 Storage covered multiple subjects, including: summary of multiple CCS projects worldwide, subsurface considerations for depleted hydrocarbon fields, containment/ pressure management, and saline formations to store CO_2, as well as considerations on regulating offshore CCS, monitoring offshore CCS projects, CO_2 shipping and infrastructure for CO_2. Importantly, this is the first hybrid in-person and virtual workshop, which represents a milestone to bring this knowledge sharing to multiple people interested on CCS worldwide.

1.2 Scene Setting: COP26 and Outcomes for CCS

Tim Dixon (IEAGHG) covered several updates within the United Nations Framework Convention on Climate Change (UNFCCC). IEAGHG, working with BEG in awareness raising by organizing side events within the UNFCCC COP meetings. UNFCCC reached the Paris Agreement in 2015 with the intention to keep climate change below 2°Celsius and achieve net-zero emissions by the second half of century with every country to decide on their contribution and to update national pledges (Nationally Determined Contributions – NDCs) every 5 years to show progression. The first update of NDCs took place at the COP26 in Glasgow in 2021.

The IEA Energy Technology Perspectives 2020 considered the role of CCUS in reducing 25% of CO_2 emissions from the global energy sector in order to achieve net zero by 2050. The IEA published a special report on CCUS to tackle emissions for existing energy assets, propose solutions for the most challenging emissions in sectors like cement and aviation, develop a platform for low-carbon hydrogen production, and remove carbon dioxide from atmosphere direct capture. Tim showed the net zero roadmap from IEA with the role of CCS expected to abate 4 Gt CO_2 captured and stored by 2035.

At the COP26 in 2021 several goals were proposed including keeping 1.5°Celsius within reach, and finalizing the Paris Rulebook (Article 6) to become operational. The new NDCs would get us from 2.7 to

2.4°C (if all were implemented). IEA concluded that net zero pledges would get us from 2.1°C to 1.8°C. By November 2021, only 19 of the 123 NDCs submitted have CCS included. Other highlights from COP26 included a request by the UNFCCC to update NDCs again by the end of 2022. In terms of clean energy technologies, it was recommended to accelerate the efforts to phasedown ***unabated*** coal power (without CCS involved) and phase-out the inefficient fossil fuel subsides. Implementation of Article 6 is very important since it enables trading CO_2 credits between countries and creates a new project-oriented crediting mechanism. These basically set the frameworks for carbon markets internationally.

The role of IEAGHG and BEG-UT at the COP26 was to share information through side events. Tim concluded by mentioning that the new IPCC AR6-synthesis report is due out in September 2022.

Session 2: International Project Roundup (Chairs: Sue Hovorka & Katherine Romanak)

2.1 CO_2 sequestration in offshore basalt: Cascadia CarbonSAFE and Solid Carbon projects. By David Goldberg (Columbia University) -*Virtual*-

The Cascadia project is part of CarbonSAFE—US DOE; located in the Cascadia basin, 150 Km offshore Washington state, USA (Fig 2.1). Geologically, the storage formation is an ocean crust basalt aquifer with active hydrologic flow driven by heat (called a hydrothermal siphon). The hydrothermal siphon withdraws water from the ocean (hydrothermal recharge) and disposes it 10s of km away (hydrothermal discharge). The aquifer can act as permanent storage for CO_2.

The project tested aquifer potential for CO_2 storage with models. Target injection 50 Mt over 20yr, aimed to stay within basalt, capped by sediments and far from outcrop for over 70 years. Concern to have the aquifer exposed to CO_2 was not an issue; however, the question is about how fast the carbon dioxide converts into carbonate, which it is a solid form and therefore a major benefit of injecting into basalt.

The project also identified a variety of industrial sources of CO_2 near the Cascadian basin, in the order of 1-3 Mt/yr. A publication was released addressing the quality of the CO_2 and the transportation issues. The solid carbon project for the Cascadian basin site focused on the injection site, and the ability to collect data and monitor that site. There is already a cable network operated by University of Victoria, so it is an opportunity to test CO_2 injection in basalts in a great location. Some challenges of the project include the public perceptions and concerns on the biochemical/ecosystem and moral hazard/sustainability.

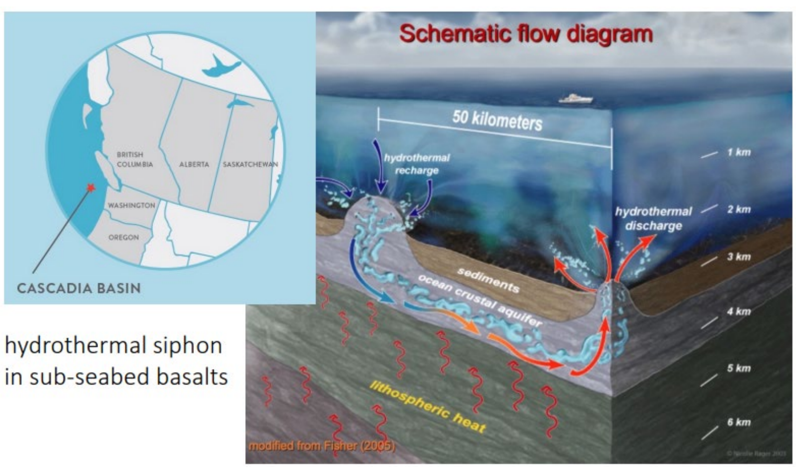


Figure 2.1. Location of Cascadia basin and explanation of flow through the basalt.

2.2. The Greensand Project: The CO_2 Transport and Storage Part of CCUS (INEOS Energy and Wintershall Dea). By Søren Reinhold Poulsen (INEOS Energy) -*Virtual*-

Located in Denmark, within the Danish part of the North Sea (Fig. 2.2), the project is turning the Siri Oil & Gas hub into a CO_2 storage hub. Siri is a cluster of reservoirs, it has for 20 years been producing oil, gas and water, so lots of operational as well as reservoir behaviour experience. Embarking on a pilot project for CO_2 injection, trying to mimic a full-scale CCS value chain. Phase 2 of the project (injection period) estimates injection of 12,000 tons CO_2 from INEOS CO_2 capturing facilities in Antwerp, Belgium in the pilot, using 14 transport round trips from end 2022 to first quarter of 2023. A consortium of 23 companies have joined Phase 2 of the project.

Phase 2 injection would test the reservoirs and understand the response. Monitoring tools would be deployed to monitor the CO_2 plume and to monitor any leak into the water column or air column above the injection site. Four-fold objective considered are: 1-understand near well bore reservoir response 2-testing of monitoring tools, 3-understand the handling of CO_2 through the value chain, 4-use of ship transport for the liquified CO_2. Project expected to mature into full scale project by end 2025, injecting up to 1.5 Mt/yr. At this point it would take CO_2 from any emitter around world. If full-scale project is successful, this would expand by adding other reservoirs and underlying aquifers, up to 8 Mt/yr. The full-scale project would consider dedicated CO_2 tankers with up to 12-20,000 tons of CO_2 per load.

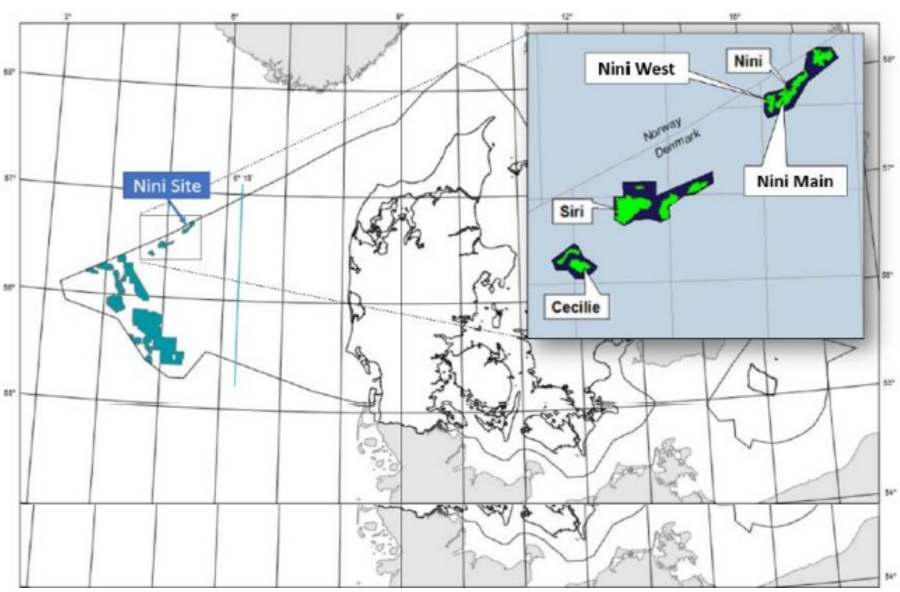


Figure 2.2. Location of Greensand project and considered gas fields.

2.3. Porthos: CO_2 transport and offshore storage from Rotterdam, The Netherlands. By Bram Herfkens (EBN) -*Virtual*-

Porthos is a critical hub in the Port of Rotterdam expected to collect CO_2 from multiple industrial sources and store it in depleted gas fields offshore (Fig. 2.3). There is an onshore low-pressure pipeline, a compression station near the shore and a high-pressure 20km offshore line to the depleted gas field. Project has been active for 4.5 yrs, and it is now ready for Final Investment Decision (2nd half 2022). Four clients are involved with contracts signed and subsides granted to support their business case.

Plans are to inject 2.5 Mt/yr with possibility to expand with time. The commercial part has been set and the FEED engineering model has been completed (facilities work and subsurface modeling). It applied for storage license 1.5yr ago and expected to be granted by June 2022. The concept license was already received from Ministry. Completed work for successful decommission of a complex well and the platform. Project still awaiting 1- Supreme court ruling on environmental permit, 2- Definitive storage license, 3- Regulatory comfort from Ministry of Economic Affairs and Climate Policy, and 4- Shareholder approval FID. Project plan is to start construction in 2023 lasting 2 years, and begin injection end 2024-2025.

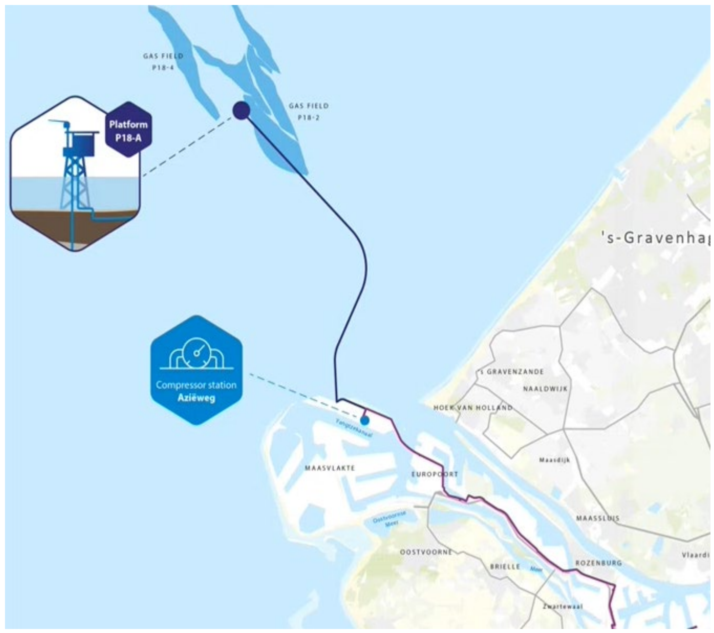


Figure 2.3. Location of Porthos project in the Netherlands, and main elements.

2.4. Pre-salt project update. By Leonardo da Silva Ribeiro (Petrobras) -*Virtual*-

Highlights of CCUS activities in Petrobras. View related to climate change based on three pillars: 1- transparency (confine carbon properly), 2- resilience to the energy transition of Petrobras position in oil & gas, 3- strengthening of the skills in line with the low-carbon economy (with technology, innovation, and developing new kind of energies). Deadline to achieve Net zero in line with Paris agreement.

Petrobras faces the following challenges in the pre-salt basin: 1- High CO_2 content (8-45%) in gas phase, in oil & gas reservoirs. 2- Reaching 300km offshore, up to 2500m water depth. 3- Petrobras and partners in pre-salt blocks committed not to vent CO_2 associated with produced gas. The raised questions are about the best way to capture the CO_2 in an offshore ultra-deep-water environment (up to 2,500 m WD) and 300 km from shore, and the best option for handling the captured CO_2.

CCUS technologies in pre-salt basin: 1- Separation of CO_2 associated with natural gas in ultra-deep waters with CO_2 injection into producing reservoirs, using a sophisticated membrane system that separates CO_2 molecules from the other fluids (Fig. 2.4); 2-Deepest offshore well injecting gas with CO_2 (2220 m WD); 3- Use of the alternating water and gas injection method in ultra-deep waters. Petrobras has increased CO_2 injection since 2008, achieving 8.7 Mt by 2021, cumulative 30.1 Mt 2018 to 2021.

Figure 2.4. Petrobras' FPSOs with CO_2 separation & injection facilities for EOR in the Santos basin (Pre-Salt) offshore Brazil.

2.5. deep C Store, Australian CO_2 Storage via Offshore Floating CCS Hub. By Daein Cha (deepC Store Ltd) -*Virtual*-

Significant CO_2 storage capacity in Australia - 434 Bt. Offshore capacity is 16 Bt in depleted O&G and 300 Bt in aquifer. A key challenge is that CO_2 storage sites and CO_2 emission sources are not in proximity.

Project CStore1, a first mover in the Asia-Pacific region as an offshore floating CCS hub (Fig. 2.5). Partner with oil companies, shipping companies, and utility companies. Agreement executed with Nippon Steel Corporation to provide up to 5 Mt of CO_2 annual to CStore1. Joint bid submitted with JX NOEX for greenhouse gas acreage offshore Australia. Project covers all value chain of CCS, that is, liquefaction of CO_2 onshore, transport by ships to the hub, and injection from the floater. The uniqueness of the floating CCS hub is given by: 1- Multi-user based, which can receive CO_2 from any emitter, 2- Minimal pipeline distance (only from floating hub to injection well), 3- Reduced residual value risk by reusing floating hub at new location, 4- Replicable and scalable since it can be deployed around the world. Project currently in pre-FEED phase, with operations aimed to start by 2029.

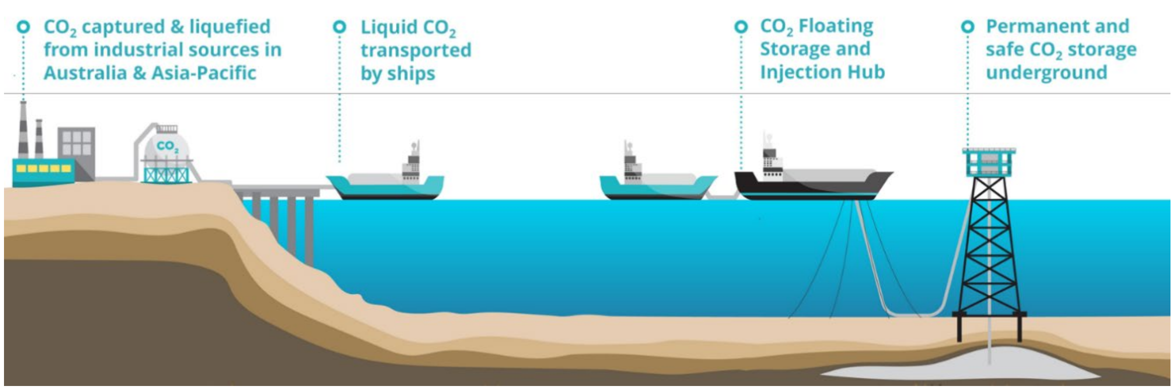


Figure 2.5. Main components of CStore 1 offshore floating CCS hub.

2.6. CarbonNet Project Update. By Nick Hoffman (CarbonNet Australia) -*Virtual*-

Project focused in the Gippsland basin, Victoria (Fig. 2.6), probably best petroleum basin in Australia. Lots of geological information. Excellent quality sandstone reservoirs with high injectivity. Proven regional topseal and additional seals at deeper levels. World-class structural storage. Pelican site >125Mt CO_2 capacity, easy to monitor stored CO_2.

Acquired new 3D seismic in 2018 over Pelican structure. Drilled appraisal well Gular-1 in 2019-20. SCAL program on appraisal well in progress (Kr for ultra-high-perm reservoirs, CO_2 capillary measurements on brown coal seals, geomechanical data). Project advancing on trial shipment of liquid hydrogen and pipeline route optimization. New static model completed, first dynamic model tests successful. Regulatory progress on GHG permit consolidation, documentation for regulatory filing, and some political progress in Australian emissions management.

Gular-1 appraisal well provided successful results. Depth and lithology as prognosed, obtained 89 m conventional core and wireline log data covering seal and reservoir, better than expected reservoir—multi-darcy clean sands. Pelican site is a 4-way large closure, showing strong seismic amplitudes corresponding to the coals that would act as topseal. New relative permeability data shows significant differences to literature models for very high permeability sandstones. Coal permeability for water 0.001mD, with significant CO_2 entry pressure of 380-430 kPa (good seal for CO_2). Planned three CO_2 injection wells, 2 monitoring wells. GipNet project to test monitoring equipment.

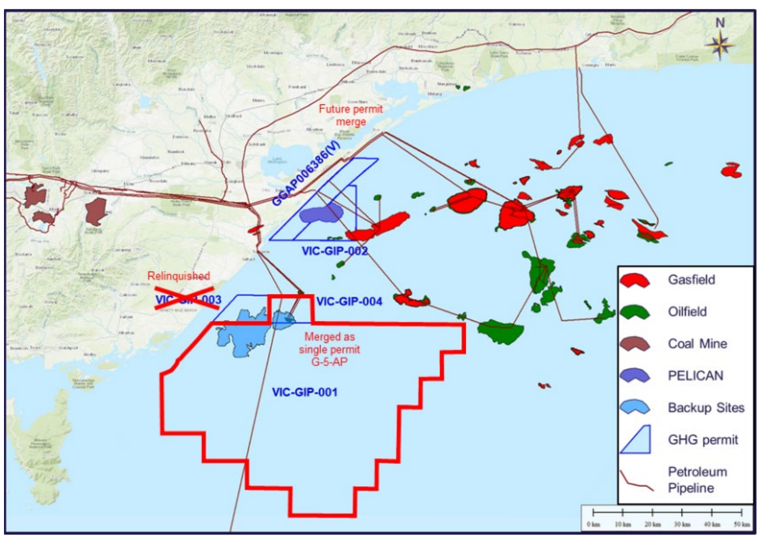


Figure 2.6. Location of Gippsland basin (Victoria, Australia) with O&G fields, including Pelican site.

2.7. Updates of CCS Status in Taiwan. By Ya-Mei (Cheryl) Yang (Ind. Tech. Research Inst., Taiwan) -*Virtual*-

Taiwan's 2050 net-zero emissions plan, by the National Development Council, estimates 40.2 Mt CO_2 reduction from CCUS. Previous studies by CPC Corporation show potential to store in west Taiwan up to 2.8 Gt onshore, and up to 45.9 Gt nearshore and offshore (Fig. 2.7). The major emission sources are also located west Taiwan. There is abundance of geological data onshore and offshore, but there is a gap in transition zone. To solve this, CPC launched a marine seismic survey to collect essential data this year, and will complete site selection and characterization by 2023.

Update on the nearshore Taipower's carbon storage project: located within the Taihsi basin; in process geological characterization of Changbin site with preliminary potential storage of 13.7 Gt in 3 reservoirs. Ongoing work: 1-evaluation of potential reservoirs, matching of sources & sinks in west Taiwan, 2-feasibility study of small-scale pilot injection test of 2 Kt/yr. Also, the ITRI conducting research on induced seismicity risk for the major fault at Changbin site, concluding small risk in fault displacement.

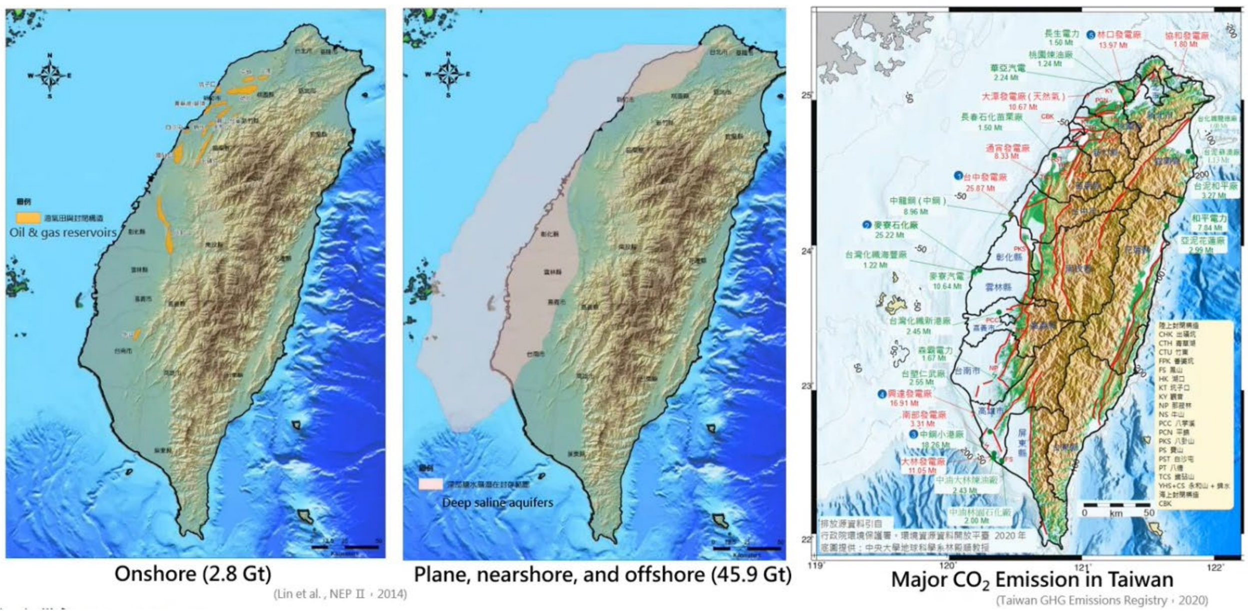


Figure 2.7. Map of Taiwan showing potential storage capacity onshore/offshore and major CO_2 emissions locations

2.8. Endurance Field, East Coast Cluster: A first-of-a-kind offshore CCUS infrastructure in the Southern North Sea. By Nicolas Bouffin (BP) -*Virtual*-

East Coast Cluster serves the Teesside and Humber power/industrial facilities (50% of current industrial emissions in the UK). Offshore CCS infrastructure for CO_2 storage into saline aquifer within Endurance field. BP operated with Equinor, TotalEnergies, Shell and National Grid as partners. Two main pipelines connecting Teesside and Humber emitters to the Endurance storage hub. (Fig. 2.8). Fully subsea project with 5 injection wells, and 1 monitoring well, tied back to 2 manifolds. Planned CO_2 injection (Phase 1) is 4 Mt/year for 25 years. Project is now on FEED after competitive bid.

Two sites were evaluated for the project (Hewitt and Endurance) with injection target being the Bunter sandstones, Triassic. Chose the Endurance structure, a 4-way closure 8km x 25km with 250 m thick well-connected reservoir section. Structural crest ~1040 m (CO_2 supercritical in the reservoir), pressure 140 bars/56°C at 1300 m TVDss. Overlying strata are all sealing facies and faulting is minimal and does not appear to connect the overburden to the reservoir.

There are 3 existing wells in the structure, including a CCS appraisal well drilled in 2013 (with injectivity and production tests). Estimated ~ 26 billion barrels of residual brine in-place above spill point. Phase 1 injection of 100 Mt CO_2 represents 3-4% of the above-spill point volume in-situ. Project would be expanded to a second phase based on results from phase 1.

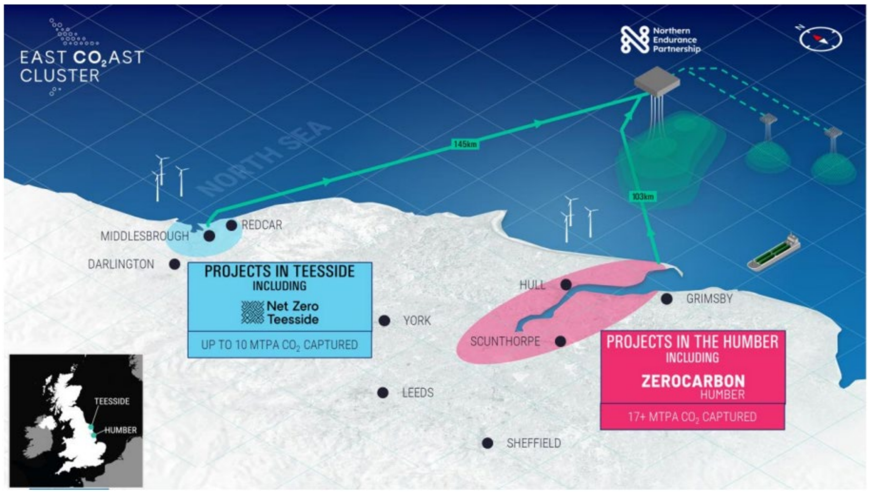


Figure 2.8. Map showing the East Coast Cluster in the Southern North Sea.

2.9. Northern Lights. By Cristel Lambton (Northern Lights JV) -*Virtual*-

The Norwegian government committed to have a full CCS value chain in Norway by 2024. Longship project comprises the full CCS value chain with onshore capture facilities that will feed the Northern Lights (transport & storage component of Longship). Project in collaboration with the Norwegian government, Equinor, Shell, and Total. Plan to collect CO_2 emissions from all around Norway and northern Europe.

Plan to start phase 1 in 2024, with 1-1.5 Mt/year, injecting into saline aquifer sandstones 2600m below seabed, in license EL001 (first storage license in North Sea, Fig. 2.9). Phase 2 initiated and planned to reach up to 7 Mt/year. Onshore facilities construction underway. Subsea facilities progressing: pipeline deliveries to Norway for installation in 2023, well #1 & 2 satellite structures installed subsea, drilling campaign for well #2 this summer, started drilling of HDD.

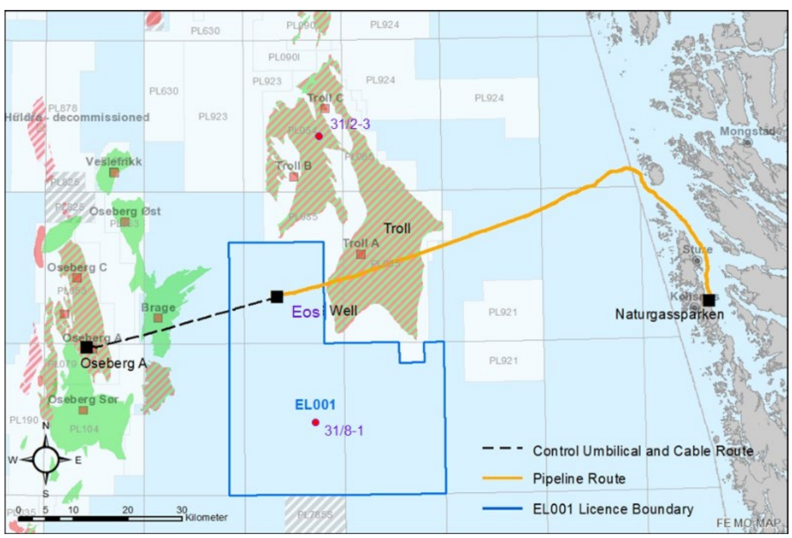


Figure 2.9. Map showing license EL001, the storage site for Northern Lights project.

2.10. Liverpool Bay and Ravenna Hub CCS projects. By Alessandro Aleandri (Eni UK Ltd.) -*Virtual*-

Liverpool Bay CCS project, western UK (Fig. 2.10a): integrated project, track 1 class, CCS license awarded October 2020 (100% Eni). Main elements include: 1- Re-deployment of 3 existing fields for CO_2 storage. 2- Sidetrack existing wells and drill new monitoring wells. 3- Re-purposing of 4 existing offshore platforms; the hub platform at Douglas, and 3 wellhead platforms. 4- new offshore pipeline and re-purposing of existing pipelines, then replace with larger in phase 2.

Project in concept definition stage. Commercial start-up 2025-26 depending on emitter availability. Phase 1 planned to inject up to 4.5 Mt/yr with full system operated in gas phase. Expansion to phase 2 up to 10 Mt/yr following conversion to dense phase. Full capacity up to 190 Mt CO_2. Projected total wells: 8 injectors, 3 monitoring (1 per field), and 2 sentinels (existing wells) for monitoring purposes.

Ravenna CCS project, Adriatic Sea, offshore Porto Marghera, Italy (Fig. 2.10b): a phased development in depleted field, with Phase 1 starting in 2023 to prove the concept. Expected CO_2 volume of 25 Kt/yr with 2 years duration and CO2 transported via existing pipeline. A Phase 2 starting in 2027, for industrial development, with up to 4 Mt/yr CO_2 injection.

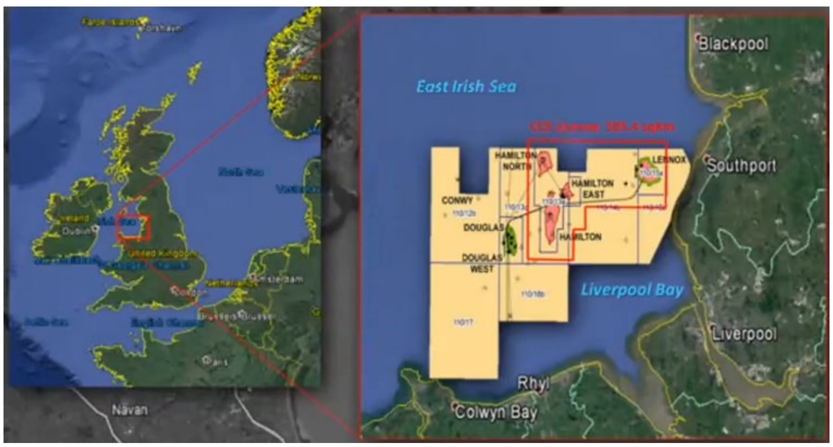


Figure 2.10a. Map showing the location of Liverpool Bay CCS license.

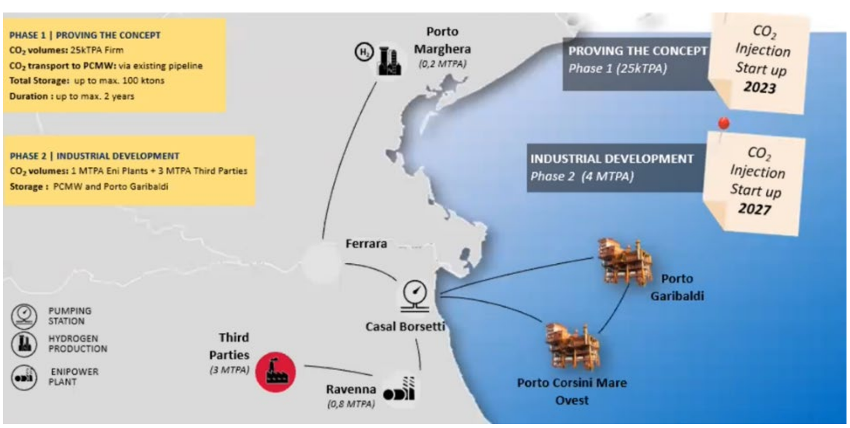


Figure 2.10b. Map showing the location of Ravenna CCS Hub, and main components of project.

2.11. Aramis project, The Netherlands. By Owain Tucker (Shell International)

Aramis project, offshore Netherlands: Follow-on from Porthos project. Aramis is bigger and part of the solution to decarbonize the Netherlands. Partners are EBN, Gasunie, Shell, & TotalEnergies. CO_2 to be transported via coasters and barges to a large terminal and linking to pipeline networks, then sending offshore thorough offshore pipeline to the depleted gas fields.

Aramis is considered a multi-source, multi-sink project (CO_2 to be delivered from multiple sources to a collection hub, Fig. 2.11). It will use massively oversized pipelines. Fields have been selected, permits are in progress, but little published material until permits granted. Phase 1 involves multiple depleted fields, later will consider aquifers. Phase 1 up to 4 Mt/yr, but expected to grow to much larger capacity. In progress, selection of the concept jointly with emitters and other stakeholders. Final investment decision (FID) and execution of the project expected by 2024. Go-live with first CO_2 transport & storage of Dutch emissions by 2026-27.

Figure 2.11. Map showing Aramis project location and concept for capture, transport, and storage.

2.12. Polaris – Barents Blue Storage Project. By Morten Sola (Horisont Energi) -*Virtual*-

Developing the most carbon and energy-efficient ammonia plant in the world. Joint venture with Horison Energi, Var Energi, and Equinor. The plant is mostly self-sufficient on power, zero emissions and environmentally-friendly plant, and compliant with the EU Taxonomy.

Start-up year: 2026. Overall CO_2 capture rate above 99%. CO_2 waste 2-6 million ton/yr (train 1-3). Planned 2 Mt/yr CO_2 per ammonia train, with 3 trains expected. Purchased natural gas to be processed and reformed to ammonia for sale into Europe. CO_2 to be sent to the Polaris storage site offshore.

The storage site is operated by Equinor. License was awarded in April 2022, located on the most northerly part of Norway (Fig. 2.12). Proven Jurassic saline aquifer (sandstones) by sub-commercial exploration well in 1988. Proven cap rock (cored in exploration well). Injection down-flank, 0.5-degree dip, planning for migration-assisted trapping updip or capillary pressure trapping or solution in the water. 50m black shale seal, plus 1km shale above. Faults may be a risk, but buried and not under critical stress. Another risk is the connected pore volume, is it large enough? Good poro-perm values. Likely CO_2 storage capacity for 3 trains ammonia plant (6 Mt/year in 25 years).

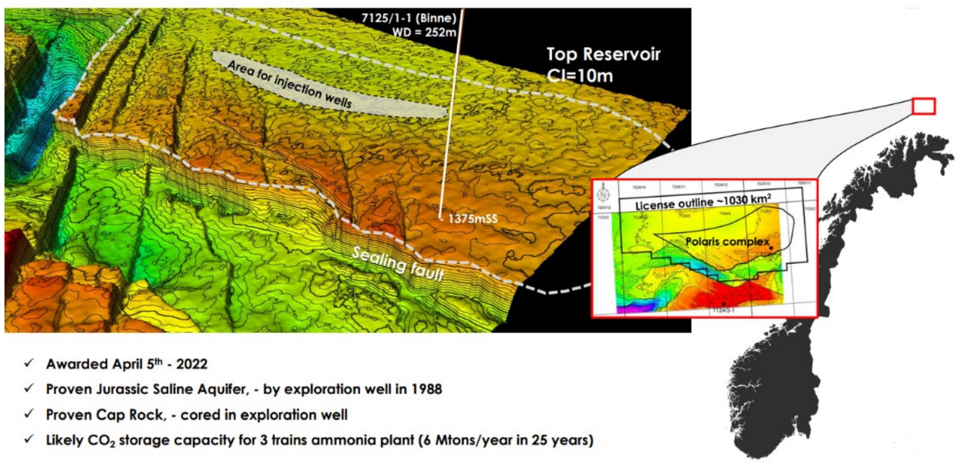


Figure 2.12. Map showing location of Polaris project and structural configuration of storage site.

2.13. Offshore Ebro, Spain CCS potential screening. By Francisco Pángaro (Repsol) -*Virtual*-

Spain generates up to 41 Mt/yr emissions from hard-to-abate industrial sector (excluding refining & power generation). 23 Mt/yr is from individual sources > 0.4 Mt/yr. Three main regions considered for CCS: Cantabrian Sea, Gulf of Cadiz, and Ebro basin (Fig. 2.13a). Largest cluster around Barcelona.

AOI in Ebro basin: shallow marine to fluvial good quality reservoirs beneath Messinian unconformity, covered by toe-of-slope Ebro shales, which are the sealing units. Reservoir section hundreds of meter-thick with 25% NTG. Porosity 13-24%, Permeability 100-1000 mD, multiple reservoir levels but challenging lateral continuity. Offset cores used to calibrate reservoir evaluation.

Key risks: Abundant extensional faulting with some faults cutting the seal (though long inactive and buried) and potential turbiditic channels within sealing unit, which might compromise the seal integrity. All these need to be addressed at prospect scale mapping.

Estimated > 40 Mt CO_2 capacity. The site is 40km offshore. Working on seal integrity using existing wells. Also, working on induced seismicity risk.

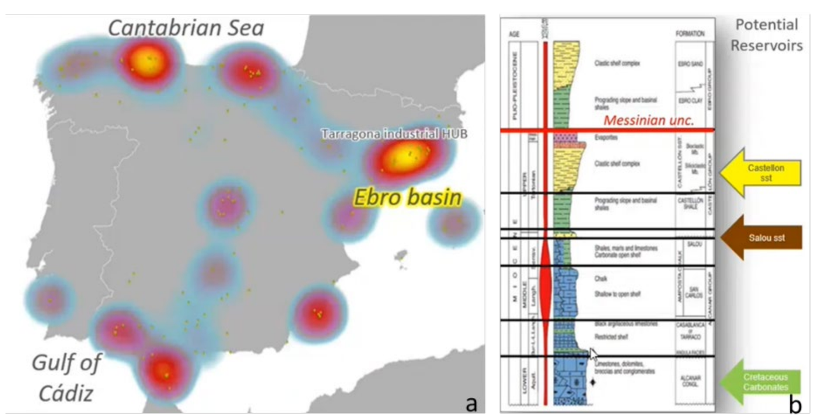


Figure 2.13. CO_2 emissions heat map, highlighting location of Ebro basin. b) Stratigraphy of the Ebro basin.

2.14. Talos Low Carbon Solutions, Gulf of Mexico, USA. By Ryan Jones. -*Virtual*-

Focused on 4 CCS projects Fig. 2.14): Coastal Bend (Corpus Christi), Freeport LNG, Jefferson County, & River Bend (chemical corridor onshore). GoM: 100+ emitters >1 MM MT CO_2/yr. Partners: Chevron, TechnipFMC, carbonvert, Storegga, Enlink, Port Corpus Christi, Howard Energy, Freeport LNG, Corelab.

Targeting 1,000'+ sandy saline aquifer columns capped by max flooding surfaces. Exceptional conventional rock properties and sealing shales. Expected to drill 3 stratigraphic wells by end of 2022.

Working on two CCS project types: 1-Regional hub using clustered industrial base as CO_2 source, injection 5–10 Mt/yr for >4 yrs. 2-Point source using single facility/plant, short pipelines, injection under existing acreage 0.3-1.5 Mt/yr for ~ 3 years. Expected up to 800 Mt storage potential in the 4 sites, capture up to 150 Mt/yr of regional emissions. Some geological work done. Using mostly published work to create static models; starting on dynamic work and own interpretation.

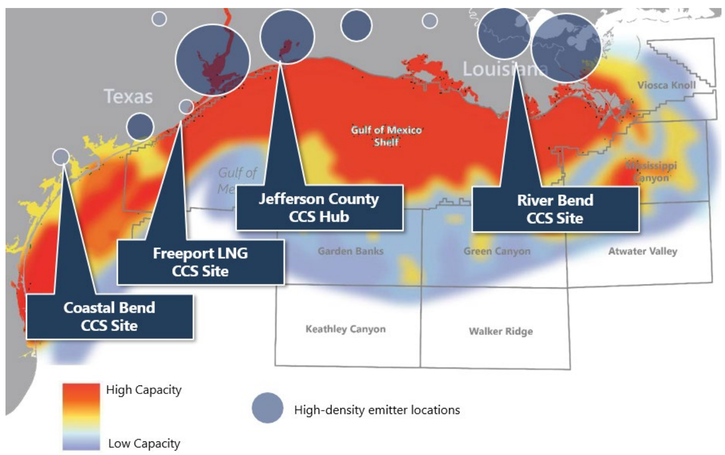


Figure 2.14. Map of Gulf of Mexico showing the 4 CCS projects of interest for Talos & partners.

2.15. GoM Depleted Field CCS Development by Cox Oil. By Mike Hopkins (Cox Oil)

Privately-owned company, operating in GoM for ~20 years, mostly on the Outer Continental Shelf (OCS). 600 production wells and 500 structures in 66 fields over ~ 1 million acres. Production ~ 1Mbbl/day. Formed Carbon-Zero US LLC in 2020, to overlay Energy Transition projects on existing assets.

Carbon-Zero goal is to repurpose existing oil and gas infrastructure for carbon sequestration projects offshore in GoM Federal waters. Availability of sub-surface data expected to shorten project life cycle. Company size allows for rapid engagement and implementation. Last year partnered with Repsol. Looking together for opportunities in depleted reservoirs and deep saline potential for CO_2 storage.

For geological assessment, using work from GoMCarb, BOEM, Secarb-Offshore. Subsurface evaluation by Cox/Repsol and D&M to evaluate CO_2 storage resources. Looking at deep saline resources at the moment. Focus on Tiger Shoal (large storage potential). Have been asked to abandon several fields, trying to figure out how to repurpose them quickly.

2.16. ExxonMobil Houston CCS Hub. By Ganesh Dasari (ExxonMobil)

Multiple CCS projects under consideration along U.S. Gulf Coast. Initial focus on high CO_2 concentration industrial sources. Close proximity to undergrown storage. Expertise on subsurface data evaluation and integration. Aim to demonstrate large-scale reduction in US emissions and pave the way for bigger projects. 40 Mt/yr in local emissions, aiming for 10% of that for capture.

Houston CCS hub targeting ~ 50 largest emitting facilities, potential to mitigate ~ 100 Mt/yr. Gulf Coast storage potential ~ 500 Gt CO_2. Baytown Blue Hydrogen Project aiming for ~ 10 Mt/yr receiving part of CO_2 from blue hydrogen plant and other Houston area facilities (Fig. 2.16). The majority of CO_2 will come from XOM Baytown refinery.

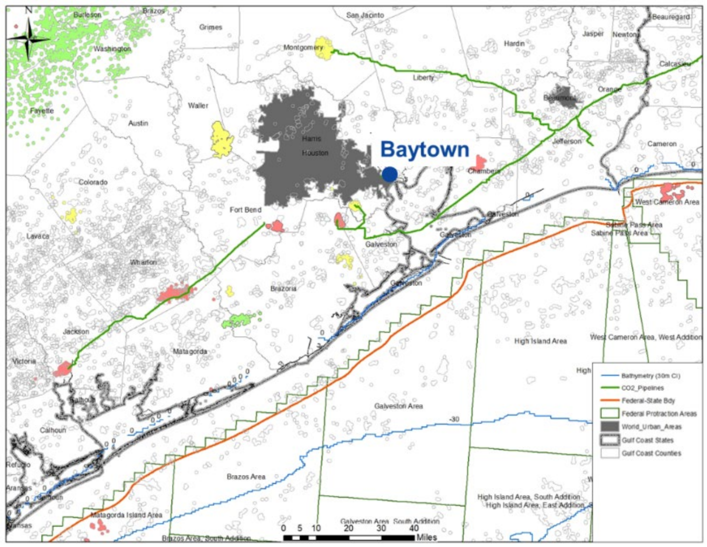


Figure 2.16. Map showing location of Baytown project within Houston area.

2.17. Discussion/Questions

- Porthos project: Motivation for low-pressure pipeline onshore. Why not high-pressure everywhere? Comment: Probably due to low-pressure pipeline passing through highly populated areas.

Session 3: **Technical Aspects of Depleted Fields** (Chair: Alex Bump)

3.1 Porthos. By Bram Herfkens (EBN) -*Virtual*-

Porthos project plan to re-use depleted gas fields and platform (Fig. 3.1). Plan to build a pipeline through the Rotterdam Port area to pressure up and then transport CO_2 in supercritical condition (85 bars pressure) to the nearest platform 20km offshore. Subsurface: 3 reservoirs for injection (2 km deep) connected to an unmanned platform. Gas field has a proven geological containment. Reservoir pressure is low (20 bar, was >350 bar).

Considerations on platform reuse: Platform in good condition, with up to 25 more years of service. Platform to be powered with solar panels and wind turbines. Concurrent operations of gas production and CO_2 injection. Change operations and logistics to daylight only and boat access. Recent increase in gas price impacts cease of gas production dates.

Considerations on wells reuse 1- well integrity: are cement bond logs reliable, status of casing, liners and conductors, do we see annulus pressures that may indicate leakage? 2- well design: do we need new completions, thermal loads and tubing of Cr25, wells to be equipped with DTS / DAS monitoring, developed subsurface safety valves (SSSV) for arctic conditions. 3- well containment: thermal loading (debonding of casing-cement-rock face), hydrostatic head/pressure as containment barrier. Working on well campaign pre-FID to de-risk the project.

Risk management: Containment risk (migration, leakage), Seismic risk (earthquake, leakage), Operational risk (flow assurance and control), Commercial risk (injectivity, storage capacity). Project status: currently on permit procedures, decommissioning of well, FID deliverables, European tender's construction compressor station and offshore pipeline. Final Investment Decision (FID) on second half of 2022. Start construction on 2023. System operational by 2024/25.

Figure 3.1. Location of Porthos project and concept for wells and platform re-use.

3.2 Aramis and Peterhead experience. By Owain Tucker (Shell)

Former Peterhead CCS project – reuse. Halted when funding withdrawn by UK Government (25th November 2015). Peterhead aimed to store CO_2 in the Goldeneye depleted field: Proven seal, all the appraisal and well data available, performance since start of production (6-year production test), facilities and wells. Depleted gas field with pressure history starting in 1996, production history from 2004. Five production wells, core, seismic, seabed surveys.

Re-use can be divided into:

1- Engineered system (platform, pipelines, umbilicals, wells;
2- Knowledge (characterization data, reports, samples),
3- Natural system (geology, the store itself).

Platforms, pipelines, and existing wells may represent a challenge for reuse. Detailed analysis needed for the purpose of managing CO_2 transport, injection, and storage. For the Aramis project (see Fig 3.2) the existing pipeline was not suited to dense phase CO_2 service, so a new one is planned to be installed.

Legacy wells can also impact the project, for instance inaccessible wellbores would not allow to re-entry and do any remediation. If the original subsurface isolation is not suited for the change of service to CO_2 storage such wells can force a project to stop, or select a different storage location.

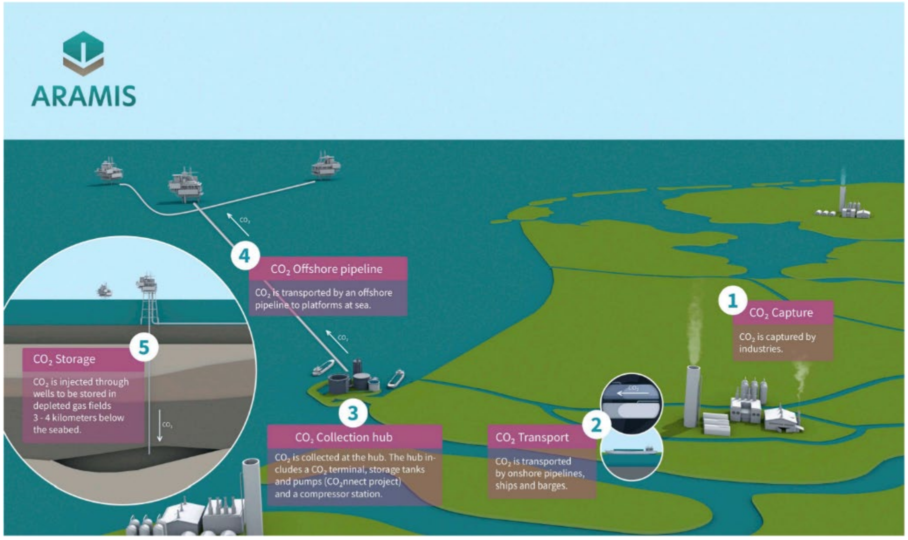


Figure 3.2. Aramis CCS project concept: reuse of platform, pipelines, umbilicals, wells.

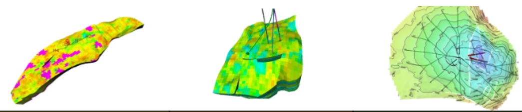
3.3 Liverpool Bay CCS. By Guglielmo Luigi D. Facchi (Eni SpA) -*Virtual*-

Overview of Liverpool Bay CCS storage sites (Fig. 3.3): **1**)- Hamilton Main, wet gas reservoir, 2270 ft TVDss, thickness 450 ft, porosity 10-23%, Av perm 600 mD, initial pressure 97 bar, initial temperature 31.6 C, start-up production 1997, RF % 95; **2**)- Hamilton North, wet gas reservoir, 2590 ft TVDss, thickness 500 ft, porosity 10-23%, Av perm 500 mD, initial pressure 106 bar, initial temperature 29.2 C, start-up production 1996, RF % 93; **3**- Lennox, Light Oil (+ gas cap) reservoir, 2450 ft TVDss, thickness 900 ft, porosity 10-23%, Av perm 2000 mD, initial pressure 112 bar, initial temperature 34.4 C, start-up production 1996, RF % 89.

Flow assurance main outcomes: Paired Flow Assurance – 3D Reservoir model, Surface equipment design to honor project injection rates, and BHT safely above the limit for all the wells involved. Cap rock integrity main outcomes: Reservoir re-pressurization path below minimum horizontal stress envelope, and injection partitioning sustainable. Thermally induced fracture main outcomes: Near-wellbore stress and temperature distributions (effective stresses positive for the whole duration in each storage complex, limited cooled front extension during injection operation), and no risk of tensile failure occurrence.

Geochemistry main outcomes: Negligible CO_2 mineral trapping, limited reactivity of caprock lithology, no threats to well injectivity recognized. Fault stability analysis main outcomes: 40+ faults analyzed across 3 storage units, no critical faults emerge from the fault stability analysis, so the risk of induced seismicity is negligible. Fault seal analysis main outcomes: Deterministic and probabilistic determination of CO_2 column height evaluation.

Conclusions/way forward: For Liverpool Bay CCS project, storage complex are de-risked by extensive and robust subsurface database and by a suite of 3D modelling and CCUS special studies (geology, reservoir engineering, geomechanics, geochemical etc.) To date studies confirm the suitability of Hamilton Main, Hamilton North and Lennox to securely store at least 109 Mt of CO_2 (base case); no criticalities are recognized. Some activities are ongoing/planned aiming to fully de-risk both CO_2 conformance and containment risks; study results will be included in the developed models.



	Hamilton Main	Hamilton North	Lennox
Fluid Type	Wet Gas	Wet Gas	Light Oil (+ gas cap)
Top Reservoir Depth (ft TVDss)	2270	2590	2450
Porosity (%)	10-23	10-23	10-23
Average Permeability (mD)	600	500	2000
Thickness (ft)*	450	500	900
Initial Condition [P,T]	97 bar, 31.6°C	106 bar, 29.2°C	112 bar, 34.4°C
Start-up	1997	1996	1996
Well type	2 Deviated 2 High Angle (+ 2 Explo)	3 Deviated (+1 Explo)	2 Deviated, 4 Horizontal 8 Multi Drain Horizontal (+ 4 Explo)
RF % (@ YE 2021)	95.2	93.4	89.4

Figure 3.3. Overview of reservoir properties for Liverpool Bay CCS storage sites.

3.4 Greensand Project. By Søren Reinhold Poulsen (INEOS Energy) -Virtual-

Located in the Danish sector of North Sea, a ship-based CCS concept pilot project (Fig. 3.4). Differently than a pipeline-based project, Greensand would inject CO_2 in cycles (no continuous injection). Phase 1 (feasibility study) concluded in 2021. Project on Phase 2 now, which implies further derisking before the Final Investment Decision. In addition to pursue the pilot injection, this phase also includes deployment of monitoring tools and lot of lab testing in addition to the classic modelling. Lot of studies being conducted in the lab as part of the consortium. Reservoir modelling being conducted in-house. At the end of Phase 2, need to obtain a “Statement of Endorsement and Data Input Storage Site Permit”

Subsurface evaluation for pilot injection: Siri Area reservoir seals proven, Storage capacity/volumes quantified through production (well-known reservoir with sufficient production data), Upscaled CO_2 injectivity unknown (small-scale studies conducted on cores with no impact on CO_2 injection, but need upscaling). By doing the pilot injectivity test, will know if there are injectivity and integrity issues due to thermal cycling of the CO_2 (reservoir would be under injection by cycles). Also, will know if there are mineral reactions in the reservoir and multiphase behavior issues with the CO_2. Pressure, temperature, and rates will be measured as well as seismic monitoring of the CO_2 plume. According to model, when reaching >5% CO_2 saturation would be able to see the plume as injection progresses.

After pilot test is completed, and confirmed commerciality, it will continue cyclic injection. Sandstone reservoir is proven for high water injectivity, though need to evaluate if injectivity deteriorates due to cyclic injection. Depleted saturations due to oil & gas production but reservoir pressure > initial pressure since reservoir has been used for dumping excess water during production, so it might need to produce some water to provide space for CO_2. Extensive aquifer interpreted below reservoir section.

A full-scale project to use a new CO_2 injection well, 50 cycles per year, 10 Kt CO_2 per cycle of 12-24 hrs duration. Shut-in time 6 days. Initial pressure 210-220 bars at 60 C. During cyclic injection expect CO_2 to remain in supercritical condition in reservoir (while injecting & shut-in). As per wellbore pressure, during injection the CO_2 would remain liquid but in gas phase during shut-in. This phase change in well might be challenging for well integrity. Also important is that injection rates would be high due to cyclicity (considering profitability of project) so need to monitor reservoir, caprock integrity and well integrity.

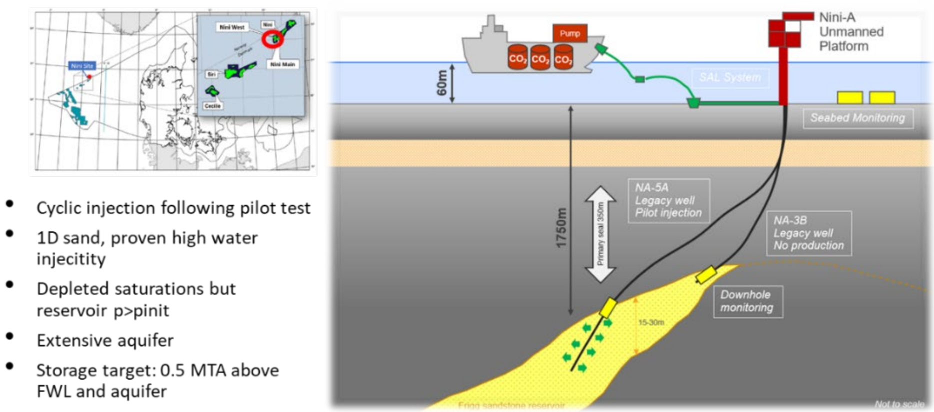


Figure 3.4. Schematic of Greensand project: a ship-based CCS concept.

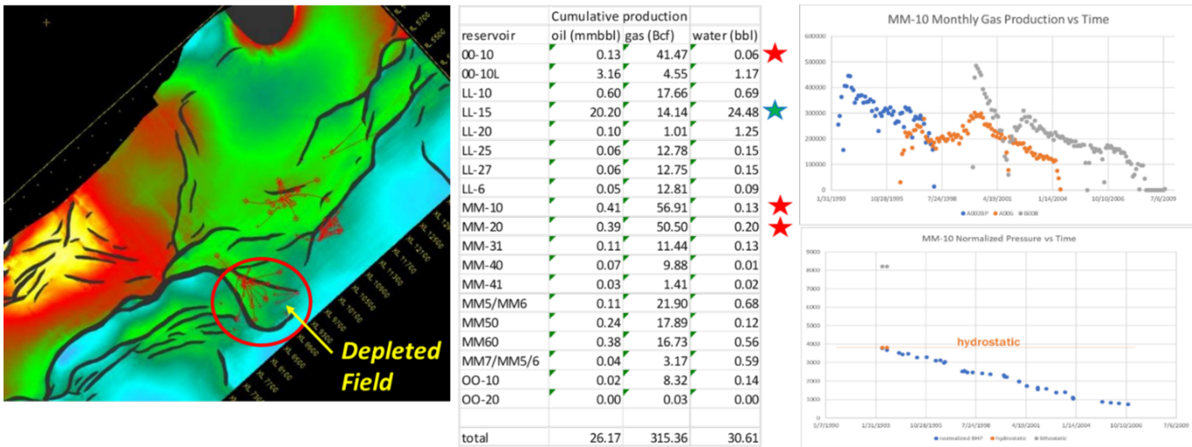
3.5 Gulf of Mexico Depleted Field Example. By Alex Bump (BEG)

This talk presented high-level work on an anonymous depleted field in Gulf of Mexico. GoM CO_2 sources and offshore reusable infrastructure represent good opportunities for CO_2 storage. In recent years there has been pressure to decommission idled infrastructure, creating a potentially limited time window in which to repurpose depleted fields. This particular depleted field was discovered in the early 1980s by a major oil company. It has produced both gas and oil (cumulative 56 mmbbl oil & water and 315Bcf gas). On a fluid replacement basis, that suggests ~ 30Mt CO_2 storage capacity. However, there are some complexities: field has had 6 operators and has produced from 19 reservoirs through 20 surface well locations and >60 bottom hole locations.

Geologically, the field is complex. The trap is a small fault-bounded compartment with a narrow connection to an aquifer (Fig. 3.5). Reservoirs are Middle Miocene, paralic depositional systems, with thin channelized sands, and moderate connectivity. Net thicknesses of individual reservoirs range from 17 to 62 feet, NTG 22 to 65%, and porosities from 22 to 28%. Permeabilities are highly variable but average 50-100mD. Producing reservoir pressure starts at hydrostatic and declines rapidly with production suggesting very limited aquifer connection.

For commercial CCS, injectivity is challenged. With ~100mD average permeability and 10m thickness for a typical reservoir sand, a single vertical well might be capable of injecting ~100 Kt/year. This could be increased using some combination of multiple wells, deviated wells and/or multi-zone completion but all of that increases project cost and complexity. For CO_2 capacity, we considered both fluid replacement calculation and EasiTool pressure-based capacity analysis, focusing on the four most prolific reservoirs.

Quick-look assessment indicates capacity of ~4Mt/reservoir. Adding water extraction allows further pressure management and could raise the capacity to ~5-6Mt/reservoir. Additional capacity enhancements include using the shallow sandy section and the wet equivalents of the producing reservoirs in adjacent fault blocks. Each of these options offers approximately another 20Mt of capacity. However, there are uncertainties and complications with both. The shallow section may not have a reliable seal, nor is it clear that all existing wells have been cemented across that interval. Remediation costs may be significant. Similarly, utilizing adjacent fault blocks would require a long step-out from the platform and new leases.



reservoir	Cumulative production oil (mmbbl)	gas (Bcf)	water (bbl)
00-10	0.13	41.47	0.06
00-10L	3.16	4.55	1.17
LL-10	0.60	17.66	0.69
LL-15	20.20	14.14	24.48
LL-20	0.10	1.01	1.25
LL-25	0.06	12.78	0.15
LL-27	0.06	12.75	0.15
LL-6	0.05	12.81	0.09
MM-10	0.41	56.91	0.13
MM-20	0.39	50.50	0.20
MM-31	0.11	11.44	0.13
MM-40	0.07	9.88	0.01
MM-41	0.03	1.41	0.02
MM5/MM6	0.11	21.90	0.68
MM50	0.24	17.89	0.12
MM60	0.38	16.73	0.56
MM7/MM5/6	0.04	3.17	0.59
OO-10	0.02	8.32	0.14
OO-20	0.00	0.03	0.00
total	26.17	315.36	30.61

Figure 3.5. Structural map and production data & analysis of a depleted field in Gulf of Mexico, USA.

3.6 Discussion

- Are there 'easy' fields?
  Alex response: There are easy fields until we take a closer look at them.
  Owain response: The Goldeneye field was easier than expected. Modeled as compartmentalized but resulted different. It was a turbiditic sandstone reservoir, with up to 35 Mt CO_2 capacity.
- Do we need to monitor the CO_2 plume in a depleted reservoir, and if gas in it, can we track it?
  Owain response: The Goldeneye reservoir has gas trapped in the pores, and water in the pores, so no in reservoir, but yes outside reservoir.
  Guglielmo Luigi D. Facchi comment: capability to detect the plume should exist even in depleted gas fields, based on physical models they have done.
- Injection case: CO_2 injected in the depleted gas zone in a reservoir with limited aquifer support, but monitoring tools were not able to see anything.
  Owain comment: in many depleted cases, if we are not over-filling the reservoir, we don't need time lapse seismic monitoring.
- Chat question to Poulsen (Greensand) on re-cyclic injections: what strategies have you envisioned for monitoring mobility changes vs residual trapping vs clogging? anything beyond BH pressure?
  Poulsen response: we need to investigate those phenomena. No clear answer yet. Every reservoir for CO_2 would be unique.

Session 4: **Containment & Pressure Management** (Chair: Tip Meckel)

4.1 Infrastructure Re-Use in the Gulf of Mexico. By Darshan Sachde (Trimeric Corp)

Evaluation of Infrastructure re-use has been a focus of Gulf of Mexico partnership (GoMCarb) for offshore carbon storage. The existing infrastructure in GoM shows two trends: lack of new infrastructure in recent years and a reduction of inventory for re-use in last years. Decommissioning has been happening at faster rate than adding new infrastructure. Questions on infrastructure reuse: What is the practical scale of the opportunity for reuse? What are risks/benefits/incentives for reuse? What are the challenges to assessing reuse? What investments & steps are required to make an assessment?

Existing pipeline analysis: ~20,000 in federal waters (+ more in state waters). New pipeline costs (offshore lines: ~2 – 3 times the cost of onshore "equivalent" for natural gas pipelines). Hidden risks/costs of new pipelines (shore crossing through environment sensitive/challenging geography, routing risks related to right of way and new regulatory requirements vs. existing lines).

Challenges on reuse existing pipelines include: Pressure Rating => new pipelines for CO_2 need to be ANSI Class 900 (working P = 2,220 psig @100 F). Existing ANSI Class 600 (working P = 1,480 psig @100 F) are designed for natural gas and may not sustain the needed flow of CO_2 per year. Also, important, when transporting CO_2 in supercritical condition (denser than gas) long distance offshore, plus the offshore gradient, it might present risk of overpressure. The age of the pipeline is very important since older lines represent higher risks (especially out of service lines). The condition of the lines is also an issue if problems with corrosion, repairs, thickness, cathodic protection. Many times, the records don't show the current condition of the pipelines. From the screening performed on 20,274 line segments in federal waters, only 5,568 active segments are considered lower-risk (1,451 line segments have working pressures >1000 psig. Only 10 lines are reported to have working pressure > 1440 psig).

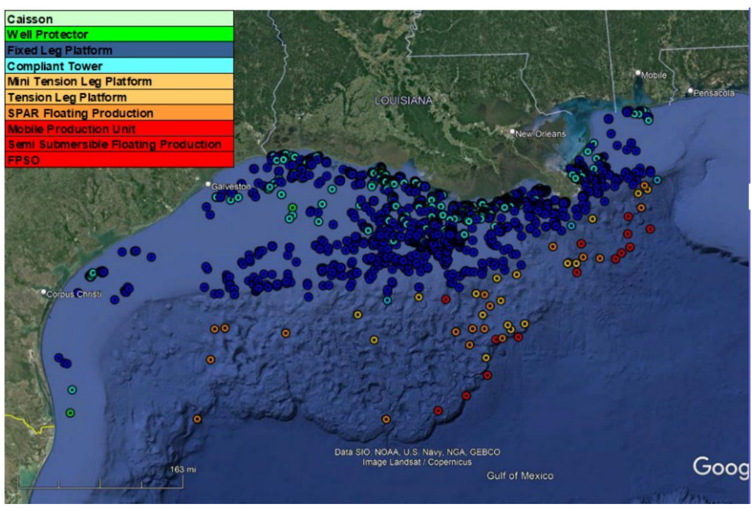


Figure 4.1. Map of Gulf of Mexico, showing the existing platforms.
Fixed leg platforms abundant on the shelf.

Existing platform analysis (Fig. 4.1, above): Repurposing platforms for CO_2 storage may offset cost of decommissioning idled platforms. High-level platform re-use criteria includes: 1- Location/proximity to preferred injection site, 2- Age/general condition of platform, 3- Space on platform, 4- Regulatory/legal considerations (How does liability/decommissioning responsibility transfer?). From the screening performed ~ 72% of the platforms are fixed-leg platforms with 41 years average age and still possible for reuse. In Texas state waters, 95% of 89 platforms are inactive. In federal waters, 1,800+ platforms offshore TX (8%) & LA (92%). High-level data available (inspection reports in some cases). In terms of age important to consider that beyond 30 yrs the structural integrity risk rises. Also important are the standards/best practices used when the platforms started operation. Critical information such as structural integrity, topsides space, etc. requires contact with operators. In conclusion, there is limited stock of “newer” platforms. Platform re-use unlikely to drive a project (vs. reservoir, pipeline, wells).

4.2 Porthos CCS: Wells, Containment, Pressure Management. By Frans Smits (EBN) -*Virtual*-

Project to use depleted gas field offshore Rotterdam. Expected 37 Mt CO_2 storage (2.5 Mt/yr). Low pressure pipeline through Rotterdam port area. Compressor station at Maasvlakte. High pressure offshore pipeline to P18 platform. P-18 platform relatively small, 25 m WD, 6 gas production wells (5 of the wells to be converted to CO_2 injectors). Reservoir (Buntsandstein) at 3400 m TVD. Caprock thickness is 600-900 mt. The reservoir depleted from 375 to 20 bars. Deviated wells reach 55 deg inclination.

Repurposing the wells for CO_2 injection would imply workovers (Fig. 4.2), for instance the safety valve would be deeper in well to keep it warm. The conductors would need to be restored since some of them have lost 22% wall thickness. Condition of 9-5/8” production casing is important to make sure it sustains the loads and be usable for many more years. Casing external cement in caprock important for injection. XMAS tree, wellhead components, elastometer seals also important. Other important considerations include: materials for injector completion design, SSSV for sub-zero temp, annulus pressure, well temperature limitations, P/T gauge & DTS/DAS system, and reservoir isolation strategy during workover.

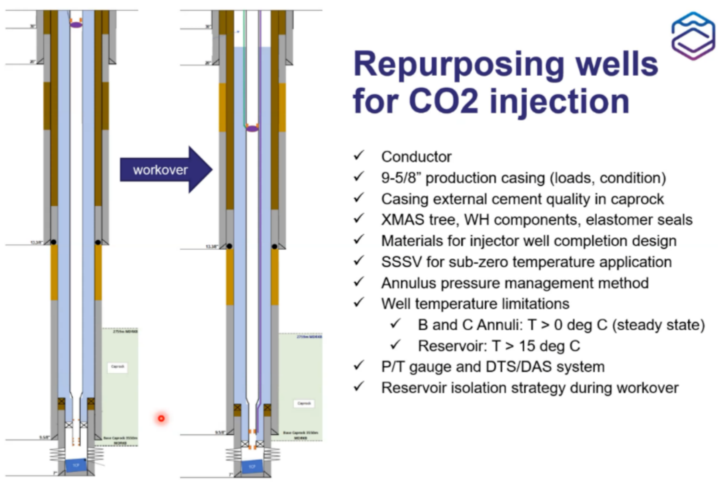


Figure 4.2. Considerations for repurposing wells for CO_2 injection. Workovers needed to upgrade wells.

Phase changes in the well are expected, with well initially full of gas. As reservoir pressure increases due to CO_2 injection the denser CO_2 (in supercritical condition) would move up and fill the well. Reservoir pressure expected to increase from 20 bars to 350 bars at the end of injection. Wellhead pressure to reach 120 bars. The 9-5/8” casing is important as a secondary barrier for tubing leak scenario. Lifetime design pressure very important due to the expected changes in pressure from 10 bars depleted reservoir to pressure increase with CO_2 injection. Eline log planned to confirm wall thickness. Porthos project would use the subsurface safety valve (SSSV) since would probably run in sub-zero temp conditions. The valve would be set at 1000 m. It has been tested in both blowout and shut-in scenarios.

4.3 REX-CO_2 Project Overview: Re-using Existing wells for CO_2 storage operations. By Bill Carey (Los Alamos National Laboratory) -*Virtual*-

REX-CO_2 is an international research project, funded through the Accelerating CCS Technologies program (ACT). 6 countries involved: Netherlands, USA, France, UK, Norway, Romania. Motivation: facilitate CCS in hydrocarbon fields. Objective: Screening methodology. Provide decision makers with mechanisms and information to evaluate re-use potential of existing oil and gas well infrastructure.

Project involves: 1-Project Management and Coordination, 2-Assessment tool for well reuse and leakage, 3-Experimental studies to support well reuse, 4-National case studies for well reuse, 5-Best practice recommendations for reusing existing wells for CO_2 storage, 6-Legal, environmental and social aspects, and 7-Dissemination and communication.

The well screening tool (Fig. 4.3) includes elements related to reservoir and caprock, well construction and history, and well integrity record. The well integrity has 5 integrity components: 1. Out of zone CO_2 loss, 2. Structural integrity, 3. Primary well barrier, 4. Secondary well barrier, 5. Material compatibility. The well evaluation results are presented in the form of traffic light recommendations (green: no or only minor remediation, yellow: moderate remediation, red: severe remediation, gray: critical info missing).

Category	Data
Reservoir and caprock	Target formation
	Caprock
	Current and expected pressure and temperature
	In-situ fluid composition
	Production history
Well construction and history	Drilling history and completion
	Well design and configuration
	Workover history
	Side-tracks
	Cement composition
	Cement evaluation logs
Well integrity record	Well barrier schematics
	Abandonment plan (if applicable)
	Completion reports or End of well report
	Mechanical integrity test
	Formation integrity/leak-off test
	Annular pressure
	History of well performance and issues
	Well maintenance history
	Load history

Figure 4.3. Elements considered in REX-CO_2 well screening tool.

As for experimental studies to support well reuse, the objective is to provide experimental data that describe how well degradation and well design influence potential re-use as CO_2 injectors, and provide experimental data on potential self-healing and remediation strategies. As for regulatory, environmental and social aspects, this includes the non-technical aspects that influence the implementation of well re-use application, from regulatory (legal) aspects to public acceptance.

The tool has been applied in several CCS cases (Porthos-NL, Vaccum-USA, Gullfaks Sør & Visund-Norway). Key findings include: Intervention required to re-purpose all wells, Primary barrier components and completions subject to cooling and may not be fit for re-use, structural integrity may be costly and technologically challenging to assess, and quality of cement sheath and casing corrosion uncertainty.

4.4 Discussion

- Assigning risk to wells, cased-uncemented or open borehole, which one to assign more risk?
  Bill Carey response: not really an answer to that. Most of our wells are cased and cemented.
  Owain comment: if a well is accessible, we can go and do remediation. If we have an exploration well with no casing, then it would be hard to do anything since it is plugged. Inaccessible wellbores are the real problem.
- Offshore, does BSEE need to use the Class VI well design in order for the operator to qualify for 45Q tax credit?

Bob Van Voorhees (online): 45Q requires the qualification process to be approved. Need to have a well approved, likely Class VI, but it can be Class II. If on the continental shelf, it has to be approved by BSEE & BOEM under the regulatory process they are working know.

Session 5: **DISCUSSION SESSION - Regulations and Offshore CCS** (Chair: Tim Dixon)

5.1 CO_2 Storage: Licensing, Regulation and Business models in Norway. By Eva Halland (Norwegian Petroleum Directorate) -*Virtual*-

Three offshore CO_2 storage licenses have been awarded (Fig. 5.1). One has been announced and several are in the pipeline, plus the Sleipner and Snohvit CCS projects. The digital CO_2 Atlas was published in 2015. A comprehensive regulatory framework for CO_2 storage was published in December 2014. Guidelines for application of license are well understood.

For safe storage of CO_2 offshore Norway, there is 1-experience: CO_2 has been injected and stored for several decades both onshore and offshore. On the Norwegian shelf we have stored CO_2 in deep saline geological formations for 25 years - which we monitor closely. 2-knowledge: Through more than 50 years of oil and gas industry in the North Sea Basin and on the Norwegian continental shelf, we have mapped, collected and interpreted geo- data which gives us a good overview of reservoirs and the sealing rocks that can be used for CO_2 storage. 3- have the instruments: We have solid regulations on site characterization and monitoring, and we set requirements. 4- have a huge storage potential: Our mapping and evaluation show that there can be capacity to store as much as 80 billion tons of CO_2 offshore Norway. 5- Its ready now: CCS is a key part for meeting our climate targets by decarbonizing the industry, can enable negative emissions with the available technology.

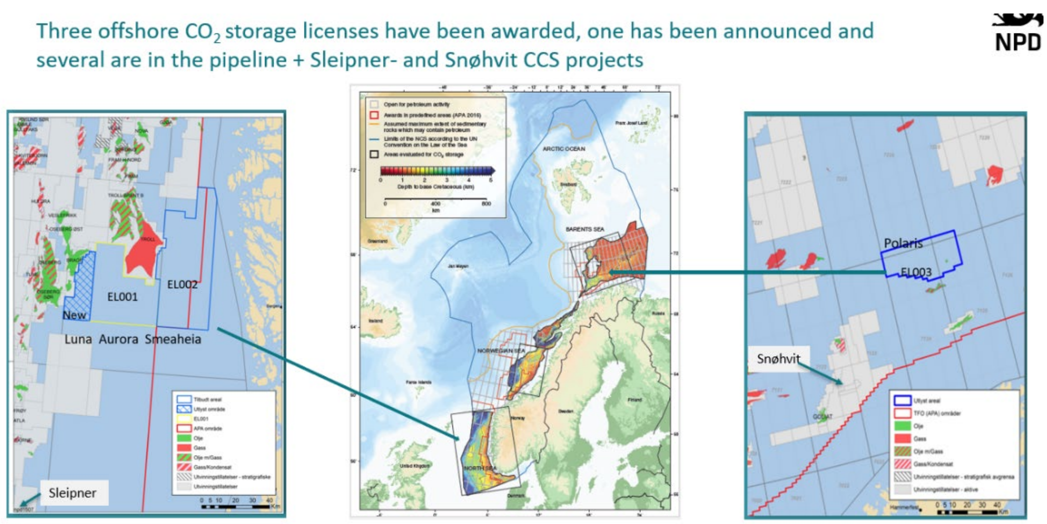


Figure 5.1. Maps showing the 3 offshore licenses awarded in Norway.

5.2 UK Regulations and Offshore CCS. By Nick Richardson (North Sea Transition Authority) – *Virtual-*

The North Sea Transition Authority (NSTA) regulate and influence the oil, gas and offshore CS industries, helping drive the North Sea energy transition. It is the licensing authority for offshore carbon dioxide storage in the UK.

The NSTA's CCS role: 1-Licensing and permitting authority for offshore carbon storage, 2-Stewardship of issued carbon storage licenses, 3-Identify, assess and understand UKCS regional carbon storage in support of CCS build out and spatial planning, 4- Encourage re-use and re-purposing as part of NSTA Cessation of Production process, 5- Consultee on operators' decommissioning plans, 6- Drive regulatory coordination, including on co-location and spatial coordination, 7- Provide advice and expertise to government and collaborate with other regulators in support of CCS policy and regulatory development, 8- Maintain carbon storage public register.

The NSTA works closely with BEIS, the Crown Estate, Crown Estate Scotland and other bodies. The licensing process for CCS includes: 1- An appraisal term for storage license application, to set the characterization and assess the storage complex and surrounding area. 2- An operational term for storage permit application (storage permit plan, monitoring plan, corrective measures plan, provisional post closure plan, financial security, operator competence, development & training program). In this term also included permitting during storage operations (five-year permit review cycle). 3- A post-closure period that includes near post-closure (proposed post closure plan) and post-closure (20-Years) for monitoring, reporting, corrective measures, maintain financial security).

As of May 2022, the NSTA has awarded 5 carbon storage licenses (Fig. 5.2), to Storegga (Acorn), ENI UK Ltd (HyNet), Harbour V Net Zero (VNetZero), BP-Equinor (Endurance Extension) and extended duration of 1 carbon storage license (Endurance). Actively stewarding 6 CS licenses towards permit applications. The NSTA has published updated carbon storage license application guidance, together with a 'Marks Scheme'. It will launch a carbon storage licensing round imminently, with high expected levels of competition. In the medium-term, NSTA intends to run regular, predictable CS license rounds.

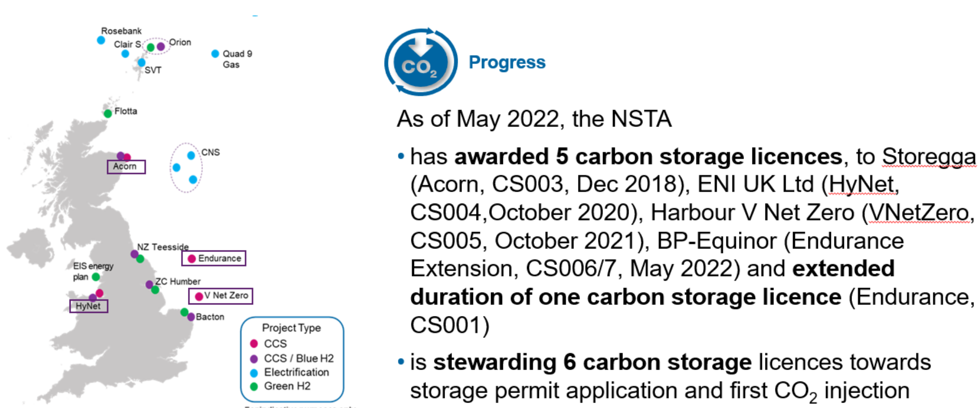


Figure 5.2. Map showing the 5 offshore licenses awarded by NSTA in UK.

5.3 BSEE experiences. By Lisa Grant (Bureau of Safety and Environmental Enforcement)

BSEE in the middle of rulemaking so limited information at the moment on the rules for CCS. In the bipartisan Infrastructure Investment and Jobs Act (2021), Section 40307 of the law amends the Outer

Continental Shelf Lands Act (OCSLA) authorizing the Dept of Interior to administer leases, easement, and rights-of-way on submerged federal lands for geologic sequestration (GS) of CO_2. The law also requires DOI to promulgate regulations by November 14, 2022.

As for the rulemaking, joint effort of BSEE with BOEM; extensive outreach on the proposed rule, learning from industry, domestic/international regulators, academia, NGOs, tribal; publication of the proposed rule in the federal register (FR); and publication of the final rule in the federal register. BSEE is currently reviewing numerous industry standards and existing regulatory frameworks, as well as engaging other federal agencies with associated expertise (i.e., Department of Energy (DOE)). BSEE is actively evaluating existing geologic sequestration programs and frameworks and mapping the applicability to the OCS environment, as well as BSEE regulations for utilization and augmentation within CO_2 operations.

Specific technical focus areas for geological sequestration include: Legacy well qualification; facility and infrastructure design and installation; injection well requirements; re-purposing of existing infrastructure; risk assessment, evaluation, mitigation, and monitoring; dynamic plume modeling; and emergency response.

5.4 Offshore Carbon Storage. By Michael Celata (Bureau of Ocean Energy Management (BOEM))

The mission of the Bureau of Ocean Energy Management is to manage development of U.S. Outer Continental Shelf energy & mineral resources in an environmentally and economically responsible way. Now involved in energy transition with expectations to generate 30 Giga watts from wind by 2030 in GoM. Challenges coming on the space distribution for multiple energy sources in GoM.

Joint BOEM – BSEE rulemaking is underway (probably not ready by the deadline). Rulemaking team established relying on existing expertise throughout the bureaus. Extensive outreach underway. Topics under consideration for the rulemaking include: Financial and economic considerations; environmental considerations; pre-lease exploration/site characterization; leasing (would need larger leases than oil & gas); plans; liability; operations, facilities, and pipelines; well qualification and offset infrastructure; emergency response and mitigation; monitoring and reporting; decommissioning.

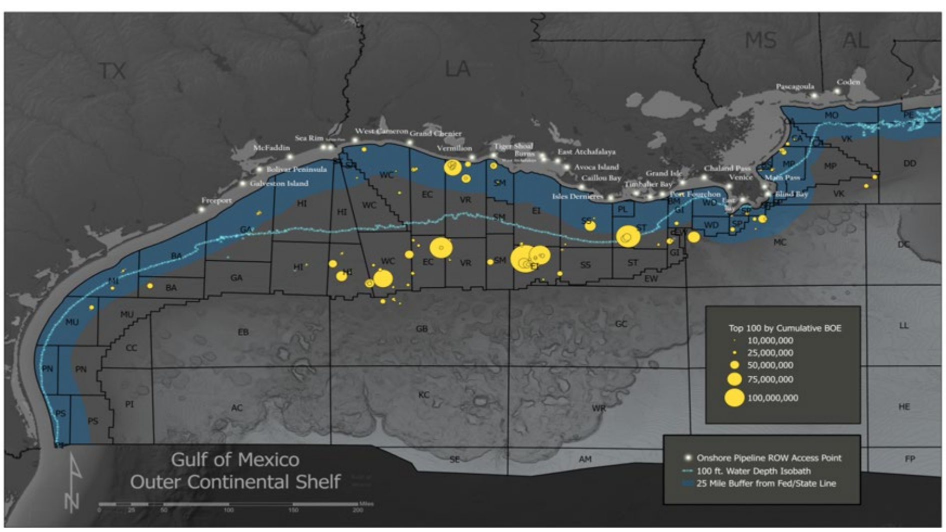


Figure 5.4. Map of GoM showing largest producing reservoirs on the shelf.

BOEM conducted an assessment on depleted reservoirs in GoM. Query analysis identified 100 largest producing reservoirs. Distance to shore and water depth refined list to 21 Reservoirs in 9 fields (Fig. 5.4, above). Assessment of storage capacity in GoM in underway in BOEM. Availability of 3000 3D surveys and 50k wells. BOEM needs to be prepare with the geologic understanding before leasing activity for CCS begins.

5.5 CCS in Louisiana. By Corey Shircliff (Louisiana Department of Natural Resources)

The department is responsible for onshore and state waters CCS activities. In past 3 years built the Class VI program with regulations promulgated on January 2021. Majority of Class VI projects are in onshore South Louisiana. Activity increase in the state regarding Class VI permitting with saline aquifers most popular (Fig. 5.5). Permanent CO_2 storage in salt caverns is not currently allowed. About 70 companies interested in Louisiana. As of May 16th 2022, seven (7) administratively complete applications under review/pending review in Louisiana. The Environment Protection Agency (EPA) also oversights the permitting process.

The steps to Class VI primacy started on March 2020 with submission and EPA review. On October 2020 the Notice of Intent (NOI) was approved and published, and the Class VI regulations were published in Louisiana Register on January 2021. On September 2021 the formal final primacy package was submitted and on May 2022 the EPA initiated the Tier 3 Rule Making Process. Likely Louisiana would be the 3rd state to have primacy on Class VI in the USA, following Wyoming & North Dakota.

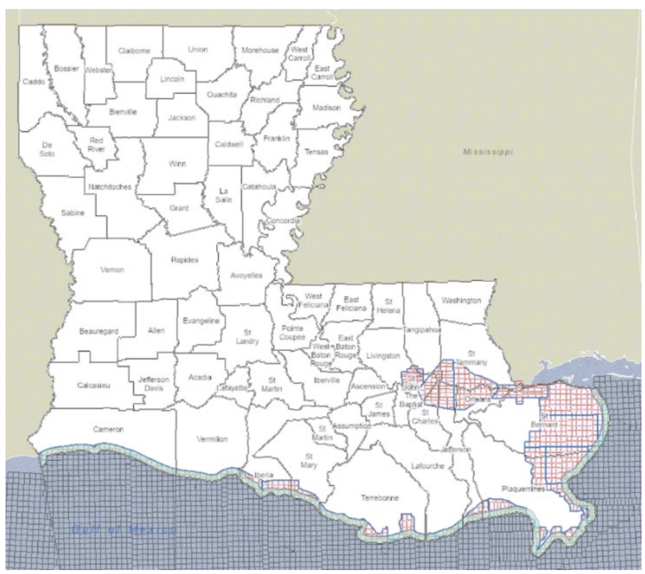


Figure 5.5. Map of Louisiana, highlighting state-owned water lands (onshore = pink, offshore=light blue). Onshore state-controlled lands have been popular candidates for CCS projects due to the single-owner status of these lands.

5.6 Offshore CCS and regulations in The Netherlands. By Patricia Zegers-de-Beyl (Ministry of Economic Affairs and Climate Policy) -*Virtual*-

Ministry focused on awarding permits. Applications in process for Porthos: P18-2, P18-4 and Aramis: L4-A. Expected more applications in next 6 months Porthos: P18-6, Aramis: K14-FA, K6-C, K14-FB.

Permit to permanently store CO_2: Dutch legislation is based on EU Directive 2009/31/EC on the geological storage of carbon dioxide. A permit to permanently store CO_2 is a combination of permit and a field development plan (FDP): permit is for exclusive right to store CO_2 in certain storage site. FDP considers a risk management plan, monitoring plan, plan for corrective measures, and a closure plan.

Observed issues: The 4 plans are not/cannot be as well-developed as would at the same stage in oil and gas permitting (permit including the plans have to be updated occasionally). Duration of the permit: Storage company remains permit holder until 20 years after cessation of injection and has to put up financial security for the event of leakage for 30 years thereafter. Type of financial security acceptable to the government: Cash deposit, Parent Company Guarantee, Insurance.

5.7 Summary of SECARB/GoMCarb Regulators workshop. By Susan Hovorka (Gulf Coast Carbon Ctr-BEG)

Goal – Update at request of US regulators:

1- Opportunity to have a timely discussion (hybrid – virtual+ in person)
2- Topic restricted to Class VI (CO_2 storage issues)
3- Topics: updates from state regulators on Primacy and Class VI applications, updates from federal regulators, technical topical presentations selected by participants from SECARB and GoMCARB DOE Funded partnerships, industry panel

State Status:

- Louisiana - Primacy application at EPA HQ for final review: 2 ½ years effort; 7 class VI applications are “administratively complete”
- Texas – Primacy application assigned to Railroad Commission (oil and gas regulator): recently posted proposed amendments to the agency’s carbon dioxide rules for public comment; comments from general land office – major state land owner
- Alabama - Assigned authority to apply for Class VI Primacy to State Oil & Gas Board: Networking and experience, industry interest.
- Mississippi - Authority to apply for Class VI primacy: moved to MS Oil and Gas Board because of experience with EOR.

Federal updates:

- US Congress charged two agencies to make rules to prepare leases, easements, or right-of-way for CO2 storage beneath federal offshore waters by November 2022: BOEM Bureau of Ocean Energy Management -- manage development of U.S. Outer Continental Shelf energy and mineral resources; BSEE – Bureau of Safety and Environmental Enforcement.
- Rulemaking work is underway. Extensive outreach and listening.

5.8. Discussion Panel

- Tim Dixon: Reflections on UK regulations with CCS, windfarms, and other projects. How is the co-location of projects?

Owain response: they co-exist. There are negotiations between windfarms & CCS projects. However, cases like running a long-streamer seismic vessel through windfarms could be challenging.
Another opinion: colocation issues raised in terms of environmental standpoint, for instance considering windfarms as marine-protected areas.

- Ramon Gil: What's the philosophy behind the long-term liability?
  Eva Halland response: In Norway, part of the CCS process. It is 20 yrs., plus 30 yrs. after hand over to the state. Important for the directorate is that CO_2 is properly stored according to the proposed models. If the operator can demonstrate that CO_2 is properly stored and secured, the 20 yrs. can be negotiated.
- Sue Hovorka: What are the requirements from the regulator(s) for brine leakage offshore?
  Lisa Grant response: it depends. If the well has communication with a hydrocarbon zone and also has hydrocarbon release, the consequences would be different. Oil leakage has more impact than brine leakage.
  Nick Richardson response: in the UK is not a matter. There is an environment regulation group that looks at those issues. There are multiple projects that will require brine management. At the moment there is a fair amount production in the North Sea. There will be solutions for that.
  Eva Halland response: Brine is important. Effective area that can be affected by the brine needs to be included in monitoring.
- Alex Bump: There are huge variations in capacity estimations. Storage capacity likely depending on pressure and water production. What are the thoughts on effective capacity estimation? Static capacity is like oil in place (OIP) but dynamic capacity is different.
- Lisa Grant: what about the changes made in permeability and porosity as a result of compaction due to depletion? How are they considered.

Session 6: **Technical aspects of Saline Formations** (Chair: Owain Tucker)

6.1 Pressure management for improved CO_2 storage capacity and security. By Eric Mackay (Herriot-Watt University)

Storage capacity is constrained by ability to manage the following factors: 1- Migration: CO_2 must remain within storage complex boundaries (for X thousand years), 2- Pressure: Seals must not fail. There should be caprock integrity, and no risk of fault leakage, or leakage due to wells.

An example from a mature hydrocarbon basin in the North Sea is examined here: The Captain Aquifer, which has various active and abandoned oil and gas fields. For this example, the propagation of the CO_2 was simulated to determine if the CO_2 invaded a depleted gas field, and was compared with the propagation of CO_2 if no gas was initially present. The time for the CO_2 plume to reach the storage complex boundary was modeled with and without mixing with methane gas (Fig. 6.1). At 1000 years after injection, the CO_2 plume reached the complex boundary if no mixing with CH_4 occurred. At 300 years after injection, the CO_2 plume reached the complex boundary when mixed with CH_4. At 1000 years after injection, the CO_2 plume escaped the storage complex if mixed with CH_4. The CO_2-CH_4 mix migrates faster because Methane (compared to CO_2) is less dense so the mixture is more buoyant; it is less viscous so the mixture is more mobile; does not dissolve in brine so CH_4 is not soluble in brine and the migration is only retarded by residual trapping.

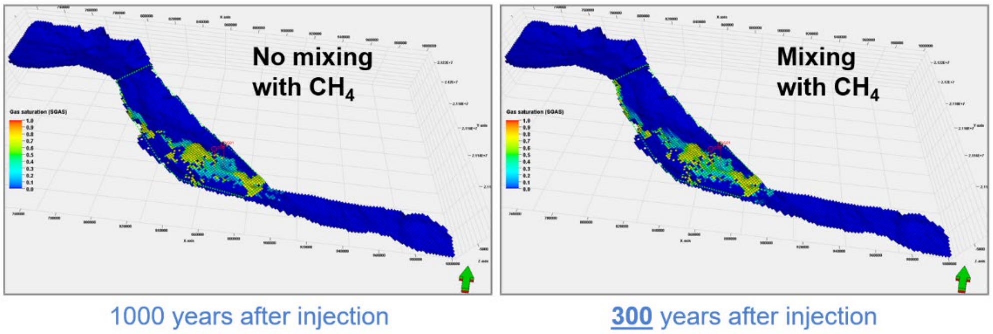


Figure 6.1. Modelling of time for CO_2 plume to reach storage complex boundary (no mix & mic with methane).

Besides the plume migration, the pressure footprint was also evaluated. The Goldeneye field was chosen for this analysis. Several pressure profiles were considered for the field, including: after cessation of gas production, after 5 years of aquifer recharge, after injection of 30 Mt, 60 Mt, 90 Mt and 180 Mt of CO_2. The results suggest that 1- natural gas production creates increased storage capacity (though it may be limited by aquifer recharge); 2- Pressure footprint propagates much faster and further than CO_2 footprint; 3- Regulators may need to consider pressure footprint as well as extent of CO_2 migration.

For pressure management in our mature hydrocarbon basin, two processes were evaluated: CO_2 replacing waterflood and brine production. For CO_2 replacing waterflood, a continuous CO_2 injection of 53 MT CO_2 for instance could increase up to 5% the oil recovery, showing better benefits than extended water-flood. Brine production can increase storage capacity up to 4 times, and it may also be used to reduce pressure after end of CO_2 injection, improving storage security. Brine production as a mechanism for pressure management is important in optimizing the well locations, by maximizing pressure support and minimize the risk of CO_2 breakthrough. It has been used in Gorgon project, Australia. The cost benefit of brine production can be analogous to brine injection in oil & gas recovery; though is not always beneficial, but a useful tool. It has some technical challenges, like the cost of wells, sand production, mineral scaling, corrosion, water treatment and disposal.

6.2 Impact potential of hypersaline brines released into the marine environment as part of reservoir pressure management. By Jerry Blackford (Plymouth Marine Laboratory)

Pressure management of reservoirs used for CO_2 storage is a key component of maintaining cap rock and reservoir integrity of the storage complex. Where storage utilizes saline aquifers, pressure management may potentially require production of reservoir brines and their dispersion in over-lying seawater or the expensive re-injection to a secondary storage facility. This research conducted by Plymouth Marine Laboratory intended to test the hypothesis that “hypersaline discharge will cause a restricted local impact, but in the context of well mixed shelf sea environments (like the North Sea), hydrodynamically driven dispersion and dilution will significantly restrict impact to regional ecosystems”. To address this, different disposal methods and environmental conditions were modelled. A variable mesh hydrodynamic model was used, which utilizes the unstructured grid, Finite-Volume Coastal Ocean Model (FVCOM) with adaptation to simulate sea-surface and seabed brine releases to assess the dispersion of hypersaline brines in the natural environment. The model allows for very high resolution in the vicinity of the release point but lower resolution towards the model boundaries. The model is also controlled by realistic tidal, current, thermal and wind driven mixing.

The detailed bathymetry within the North Sea enables assessment of any impact seafloor morphology may have on dispersal or retention of brines. The worst-case scenarios modelled included: 1- 40K bbl/ day (2.32 Mt/yr) deliberately produced brine; 2- 160K Barrels/day (9.3 Mt/yr) deliberately produced brine; 3- 20K bbl/day (1.2 Mt/yr) seeped brine from a geological outcrop. Simulations in 24hr integrated plume footprint (over 6-month) showed little evidence of sea floor morphology effect (Figure 6.2).

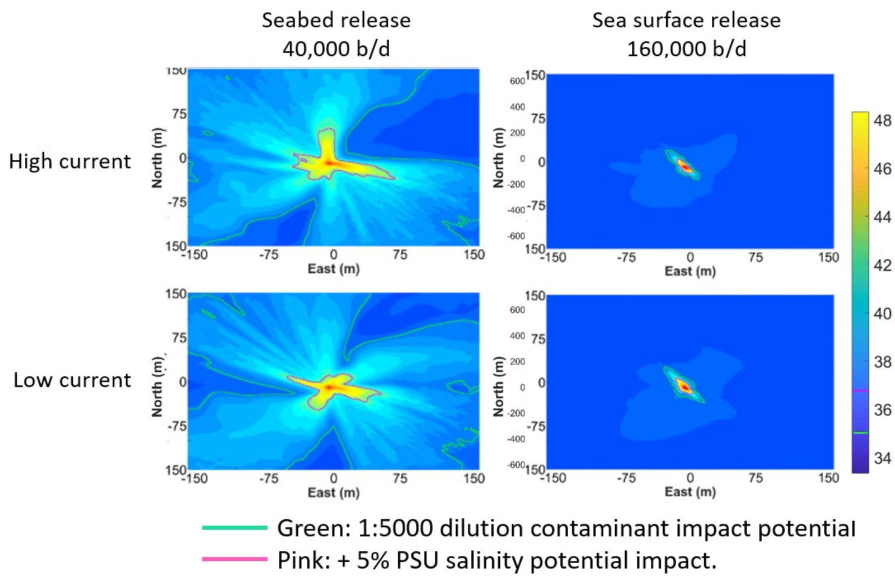


Figure 6.2. Modelling of 24hr integrated CO_2 plume footprint.

The findings of this research demonstrated that: 1- In relatively shallow well mixed environments natural mixing processes, dominated by tidal flow, disperse hypersaline plumes rapidly. 2- For all the scenarios tested the impact potential with respect to elevated temperature or hypoxia is highly localized and unlikely to be consequential for the environment. Plumes of elevated salinity are restricted to length scales of 10m-100m for the scenarios tested with no significant accumulation within the sand wave troughs. 3- There is a clear affect arising from the mode of release, with disposal at the sea surface leading to far quicker dispersion and smaller seafloor footprints due to dilution in the vertical drop. 4- The area impacted is reduced as the number of release points increases. 5- Contaminants hypothetically requiring dilutions of order 10^3 pose the largest impact concern.

6.3 CO_2 Storage Potential and Injectivity in US Gulf Coast: Implications for Baytown Blue Hydrogen Project. By Ganesh Dasari (ExxonMobil)

The US Gulf Coast has significant storage potential even after considering project life span/dynamic considerations, surface access issues, and local geologic considerations (i.e., thin beds). The Houston CCS concept for ExxonMobil would target ~ 50 large emitting facilities and potentially mitigates ~ 100 Mt CO_2 annually. The Baytown Blue Hydrogen project includes a world-scale blue hydrogen plant to process natural gas and obtain hydrogen to fuel customers and other Houston area facilities; and a world-scale CCS project to store up to 10 Mt CO_2 annually in depleted fields or saline formations onshore and offshore (both state and federal waters). The storage capacity and injectivity is likely to be influenced by faults which are mostly closely spaced (1-3 miles) and parallel to the coast (Fig. 6.3). An analysis of selected oil and gas depleted fields onshore showed a cumulative storage capacity up to 3200 Mt CO_2.

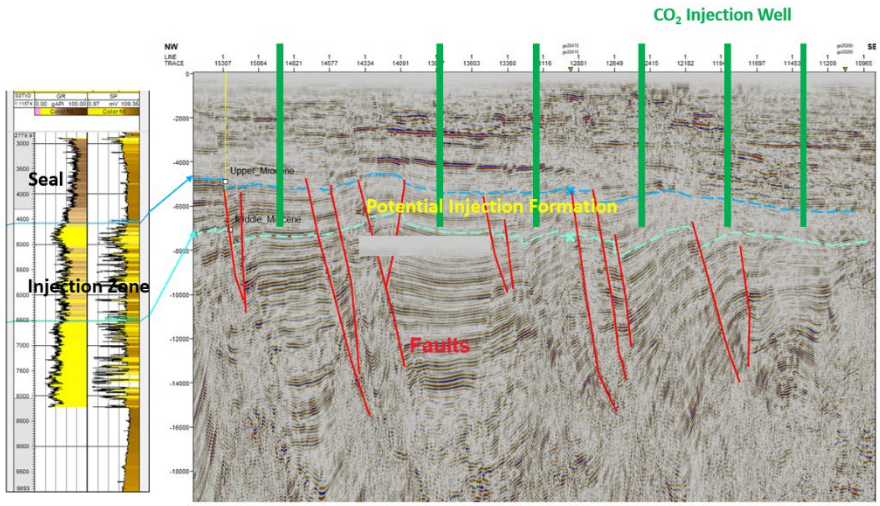


Figure 6.3. Schematic of CO_2 injections wells with respect to faults.

Legacy wells play an important role in site selection, and there is a large number of legacy wells that need to be considered. They may further impact the available CO_2 storage potential. The saline storage, with minimal number of well penetrations, are very important for CO_2 storage given the large number of legacy wells in depleted fields in the US Gulf Coast basin.

As for injectivity, we can use existing injection and production data to better understand the expected CO_2 injectivity rates. To evaluate the injectivity factor, a gas field in offshore state waters was considered. The peak production data from the gas field shows 2 Mt/yr per well. Water produced from disposal wells suggests a maximum injection rate of ~40K bbld (~ 1.6 Mt/yr) in 200 wells, and ~ 25K bbld (~1.0 Mt/yr) in 320 wells. Average injection was estimated at 2000 bbld (mostly due to intermittency).

6.4 DISCUSSION PANEL: Standardizing capacity, what should we do next?

Lead: Owain Tucker (Shell). Panelists: Alex Bump (GCCC-BEG), Ganesh Dasari (ExxonMobil)

The panel noted that different approaches yield different capacity. This is not an error, but a reflection of different screening and risk tolerance approaches. A consensus in the panel is that the use of SPE SRMS would help evaluate the expected downsizing of capacity estimates as project maturation progresses from hypothetical to project investment.

Comments pointed that a more mature capacity might be referred to as "practical" and is needed to invest in large scale storage infrastructure. Project maturation in US for example, via DOE-funded CarbonSAFE's from phase I to VI, will move up SRMS. Another comment is that confidence intervals or ranges are needed in capacity assessment.

Commenters also noted that contribution of data is needed to improve capacity assessment. Economic parameters such as value of CO_2 and certainty of this value are key inputs to capacity.

Another comment pointed that injection rate and duration define capacity because assuring that pressure increase remains below geomechanical limits is a key limit on injection rate. If the volume of CO_2 injected is greater than the compressibility of water (1% at average injection depth) the project is borrowing space from adjacent areas or having to extract water.

Next steps: use SRMS to explain to stakeholders that capacity estimates evolve, so add confidence ranges. Examples of mature capacity estimates would be useful. Add data to estimates.

Session 7: **Monitoring Offshore CCS**. (Chair: Katherine Romanak)

7.1 Marine measurement, monitoring and verification (MM&V) in a coastal setting: Gippsland Australia. By Jo Myers (CSIRO). -*Virtual*-

Monitoring program in support of CCS project in the Gippsland area, S Australia. Proximity to CO_2 sources and CarbonNet project (5 Mt/yr over a 25 years). CSIRO is commissioned to investigate and validate approaches and technologies with the potential for deployment of CCS in a dynamic coastal setting. Research aims to address a number of technical challenges defining signatures and relationship to be able to distinguish changes in CO_2 signals in the marine environment.

Challenges to consider for MM&V are: 1-the “signal-to-noise” relationship in order to distinguish CO_2 release signatures from similar naturally occurring variability to reduce false alarm rates in future baseline monitoring design; 2- characterizing impact, which involves determining the level of CO_2 release that would be associated with environmental impact at a range of scales; 3- attributing impact, to distinguish the changes resulting from other drivers and pressures in multiple-use zones (e.g. climate change) from the activities of CCS operations.

The work involved 22 field missions, 4 years monitoring, 68 staff, equipment at sea for ~ 9 months, 8TB of data, and 220 samples/2076 fish observations. As part of the field program, bathymetric and oceanographic data was collected to understand the variability and the drivers. Biological seasonal data was also collected, i.e., infaunal analysis in the water column and sediment coring for grain size, chemistry and infaunal abundance. The findings for the site were: 1- seafloor habitat characterized - moving ‘baseline’ dune features identified; 2- sediment grain size – effect on observed infaunal species assemblages; 3- richness/relative abundance of fish and elasmobranchs observed – low; 4- infauna - 14 species (7.8 % of all 180 taxa units) contributed 73.9% of total abundance; 5- CO_2 signal varied - sea surface temperature (SST) main driver; 6- no stratification observed; 7- wide range of sources of noise within the marine system; 8- no reliable biological indicators identified.

The deployed equipment consisted of: sensors (physical, chemical and acoustic) to measure pCO_2, pH, temperature, and salinity; fixed platforms, including moorings (surface, subsurface) and seabed landers; and unmanned surface vehicle (saildrone) (Fig 7.1). From the deployment the carbon sensors were able to detect fCO_2 levels and chemical properties of water and transmit this data in real-time, making it useful for the monitoring of the CCS site. The acoustic sensors (i.e., AZFP & EDGE systems) were useful in detecting the acoustic characteristics of the area to provide the baseline signal of the CO_2 entering the water column. Hydrophones were useful to detect ambient noise. In terms of data assimilation and modelling, it is a cyclic process that: combine observations with modelled leak-plume morphology and dynamics, select anomaly detection limit and calculate detection footprint, and adjust placement and configuration of instruments.

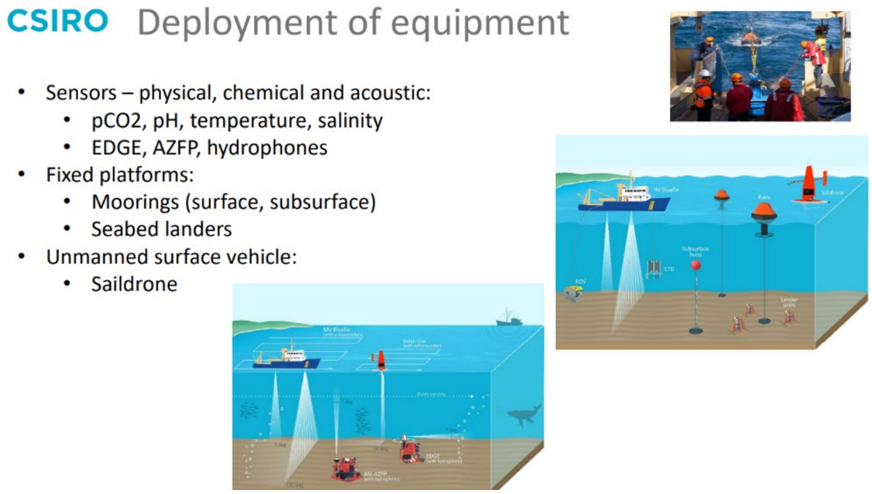


Figure 7.1. Deployment of monitoring equipment for Gippsland project.

7.2 STEMM-CCS: A summary of outcomes and legacy. By Dr Christopher Pearce (NOC, UK)

Estimated that offshore sites represent ~66% of the potential CO_2 storage capacity in Europe. Robust strategies for leakage detection and management needed to comply with international marine legislation. Precursor projects (ECO_2, QICS, ETI) advanced our ability to detect CO_2 at the seafloor, but many of those techniques were yet to be tested under realistic leakage conditions and enhanced models were needed to predict the pathways and impacts of CO_2 migration through the reservoir overburden.

The approach for the project included: 1- first controlled sub-seafloor release of CO_2 to be carried out under real life conditions; 2- establish accurate environmental baseline techniques; 3- better understanding of fluid flow pathways in the sub-seafloor and their implications for reservoir integrity; 4- develop methodologies for detecting, tracing and quantifying CO_2 leakage in the marine environment; 5- assess technologies that can enable cost-effective measurement, monitoring and verification (MMV) of marine CCS operations. The MMV technologies/techniques tested include: active acoustics (single & multibeam echosounders, and sub-bottom profilers), passive acoustics (hydrophones), optical (seafloor & water column imaging), biological (community structure mapping), geochemical (i.e., pH/TA/DIC; salinity/temperature/pressure; sediment/porewater profilers; gas tracers); computational models.

For the experiment, a custom-designed CO_2 container was built and placed 80 m from the site. A pipe connected the CO_2 container to the injection site. The injection pipe reached 4 m depth and 7 m horizontally to the CO_2 release point (3 m deep). The sensors were placed within 8 m radius of the release point (Fig. 7.2). The experiment was a success since all the sensors were able to detect the CO_2, with different detectability and measurement periods. With the results of experiment, a suitability analysis was conducted of the different MMV techniques and the ability to detect and quantify the rate of CO_2 in a real-world situation. The online monitoring tool can be seen at this website.

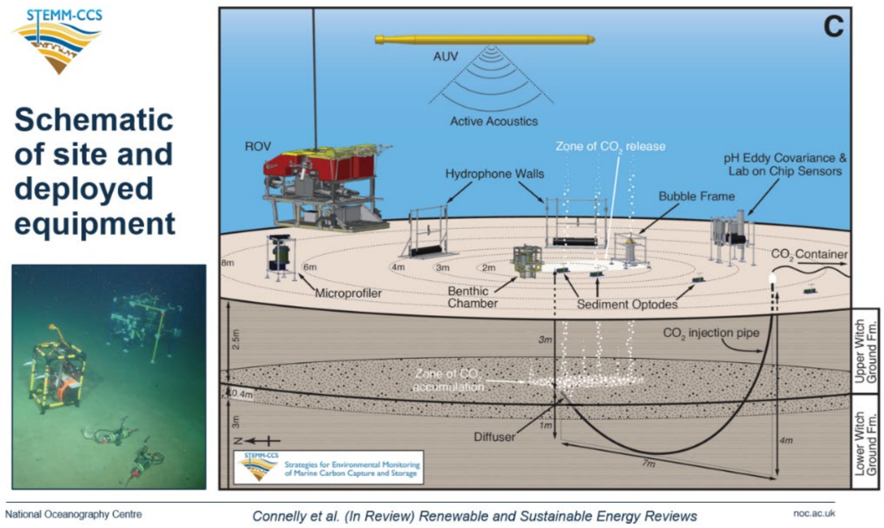


Figure 7.2. Schematic site and deployment of monitoring equipment for STEMM-CCS project.

In addition to the experiment a series of models were conducted to simulate hypothetical leaks, coupled with machine-learning techniques to identify optimal deployment of both fixed and mobile sensors. The data generated for this research can help to design baseline monitoring and landers/sensors placement. The scientific outcomes of the STEMM-CCS project are accessible through a special issue of the International Journal of Greenhouse Gas Control, available here. Two projects using the outcomes of this research are the Greensand (support for development and application of marine sensors for offshore MMV of the storage complex) and Northern Endurance Partnership (technology assessment for remote seabed environmental monitoring).

7.3 ACTOM, ACT on Offshore Monitoring. By Guttorm Alendal (University of Bergen)

An ACT funded project and spinoff from the STEMM-CCS project, with partners from 4 countries (Norway, Netherlands, UK, USA). The ACTOM project contains several work packages (WP), covering legal and regulatory aspects, technical capabilities and communication to stakeholders for marine environmental monitoring. Here the focus is on WP2 & 4, which are related to the ACTOM toolbox and demonstrating it on relevant sites. We need site specific information: 1- Reservoir and overburden geophysical characterization, where can stored CO_2 reach the seafloor, 2- Hydrodynamic data, including current velocities (tides, current, thermal and wind-driven mixing processes) to simulate transport and dilution in the overlying water column, and 3- Biochemical baseline from models or observations (carbonate chemistry, oxygen, nutrients), to be able to distinguish the signal within a naturally variable environment.

In this demonstration of the ACTOM toolkit, we focus on an example from offshore Galveston, Texas, USA (Fig. 7.3). Important to mention is that we are looking for anomalies, that is, areas with higher probability of leakage than other areas, we do not claim that such a leak will occur we are being proactive. The example uses location of known wells in the area, velocity outputs from a high resolution hindcast ROMS simulation of the Texas-Louisiana Gulf of Mexico continental shelf region, and biochemical data from 2007 and 2017 (GOMMEC 1&3). Based on this information we demonstrate output from the simulation tools, the design of a monitoring program, and the area that can potentially experience reduced pH. The toolkit will generate a report containing summary of the study, seep footprints (anomaly regions, leakage impact maps, to support licensing procedures and communication efforts.

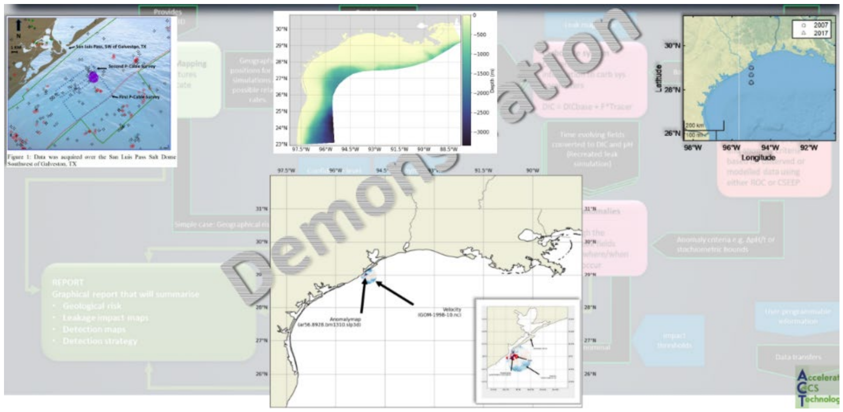


Figure 7.3. Demonstration of the ACTOM toolkit for an example offshore Galveston, Gulf of Mexico.

7.4 Regulatory framework and environmental monitoring strategy: a risk-based approach. By Laurence Pinturier (Northern Lights project, Equinor) -*Virtual*-

The regulatory framework in Norway is composed of: 1-Norwegian regulations – Based on the EU CCS Directive (CO_2 storage regulation, CO_2 safety regulation, pollution regulation); 2- Risk-based framework (plan for development, installation & operation, permits for injection and storage, permits for taking into use facilities); 3- Monitoring plan (conformance and containment, response plan). The overall monitoring plan in Northern Lights includes: ship and land facility monitoring, regular inspection and test of pipeline and subsea installation, well operations monitoring, active and passive seismic monitoring of the underground, and environmental monitoring (Fig. 7.4).

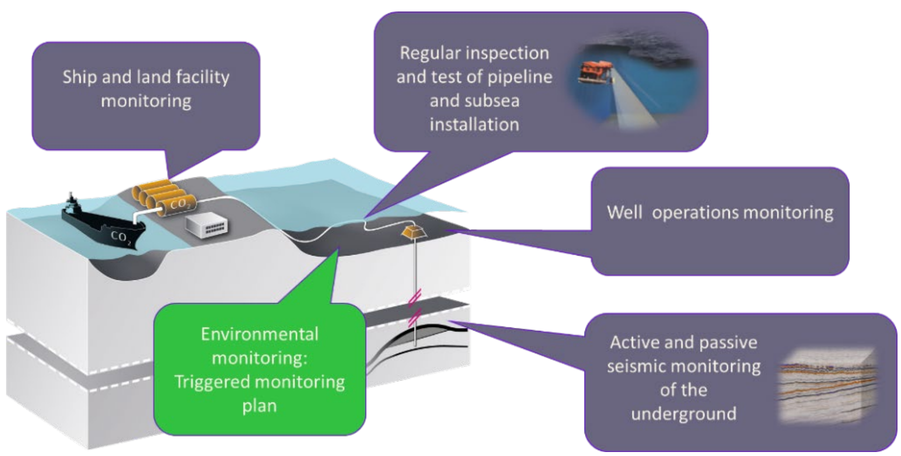


Figure 7.4. Overall monitoring plan for Northern Lights project.

The environmental risk assessment performed at the site uses the best practice guideline from DNV in the ECO_2 project. The hazard scenarios are extracted from containment risk analysis, pipeline rupture analysis, and onshore risk analysis. The pH changes are used as a proxy for effect assessment. The resource mapping is based on available data (a large dataset in Norway). The main conclusions of the environmental risk assessment in the storage site are: low risk of CO_2 leakage with no CO_2 reaching the sea surface, so low environmental risk. No vulnerable resources identified at the site. Based on the risk assessment for

Northern Lights, we defined the environmental monitoring strategy (a contingency plan). This strategy is to notify when there is a leakage and how to access the effects to the environment.

To conduct the surveys, a number of vehicles and sensors were identified (drawing from STEMM-CCS results). Decided to use ROV as most cost-effective vehicle to use. Also, looked at platforms in Norway. As for baseline surveys, in discussion with environmental authorities; though there is no plan for environmental survey before injection (i.e., taking sediment and water samples for analysis) since the area is well-known (i.e., pockmarks not active, no connection to deep CO_2 storage). There will be a triggered environmental monitoring plan in the case of irregularities. It is planned to perform field test of instrument/underwater vehicles to qualify for CO_2 detection and quantification (important for base-line monitoring).

7.5 CO_2 injection and monitoring of the Tomakomai CCS Demonstration Project. By Daiji Tanase (JCCS)

First large-scale CCS demonstration project in Japan. Location: Tomakomai City, Hokkaido Prefecture. Commissioned by: METI, NEDO. Contractor: Japan CCS Co., Ltd. (JCCS).

Project scheme and schedule: 1- The CO_2 source is a hydrogen production unit of an oil refinery; 2- A portion of PSA (Pressure Swing Adsorption) offgas containing approximately 52% CO_2 generated by a hydrogen production unit is transported by 1.4 km pipeline to the CO_2 capture facility; 3- After CO_2 capture and compression, the CO_2 is injected into two offshore subsurface reservoirs. Project started in 2012; injection from April 2016 to Nov 2019. Project is on the 4-year post injection monitoring.

Main features of Tomakomai CCS Demonstration Project: 1- World first offshore CCS project in a busy port area of large city; 2- CO_2 storage governed by Japanese law reflecting the London Protocol 1996; 3- Energy efficient CO_2 capture process; 4- Two highly deviated (up to 83 degrees) injection wells drilled from onshore targeting two separate sub-seabed reservoirs with injection intervals exceeding 1,100 m; 5- Extensive onshore and offshore monitoring system for observation of CO_2 behavior in the reservoirs, micro seismicity and natural earthquakes; 6- Marine environmental surveys conducted each season.

Reservoirs and injection & monitoring facilities (Fig. 7.5): CO_2 Injection site located onshore, 3-4 Km from storage site offshore. Two highly deviated injection wells separately reach the Moebetsu Formation (sandstone layers 1,000-1,200 m TVDSS capped by Moebetsu Fm mudstones) and the Takinoue Formation (volcanic rock layers 2,400-3,000 m TVDSS capped by Fureoi Fm, Biratori-Karumai Fm. and Nina Fm. mudstones). Injection interval length exceeding 1,100m to enhance injection efficiency. The monitoring design includes 3 observation wells onshore & offshore, 4 ocean bottom seismometers for monitoring micro-seismicity and natural earthquakes, and ocean bottom cable for 2D seismic survey and monitoring of micro-seismicity and natural earthquakes.

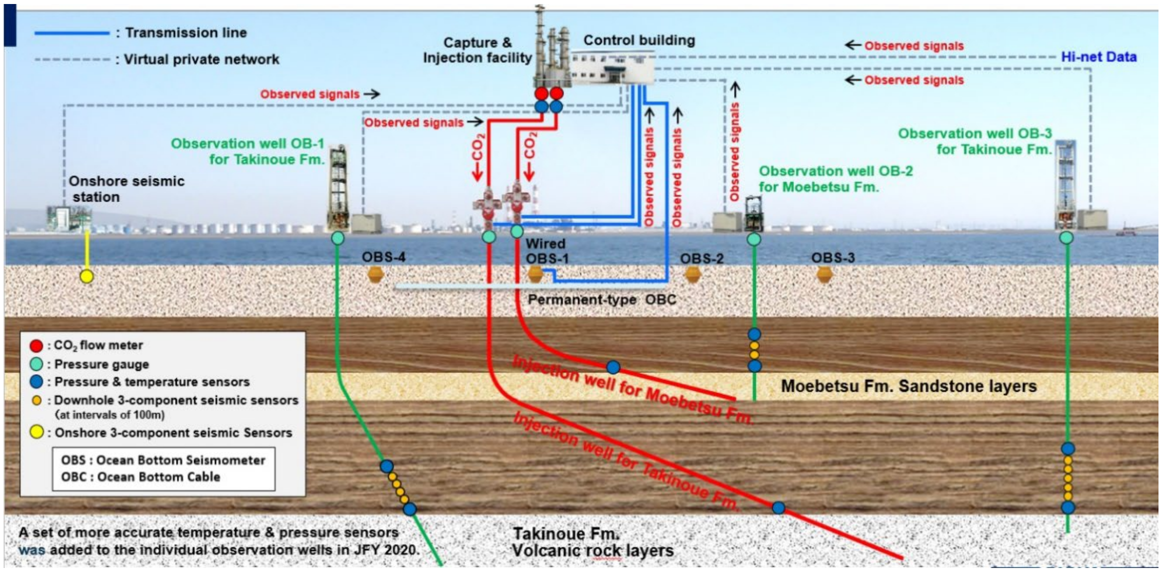


Figure 7.5. Schematic diagram of deployment of sensors for monitoring at Tomakomai project.

Key results of CO_2 injection: 1- Achieved 300,110 tones cumulative CO_2 injection into 2 reservoirs at different depths (Moebetsu Formation – 300,012 tones/good injectivity, and Takinoue Formation – 98 tones/poor injectivity with fast pressure build-up). 2- The maximum bottomhole pressures recorded by PT set close to reservoir during injection were much lower than the upper limit set to avoid destruction of the overlying cap rock.

Seismic surveys: Following the baseline 2D and 3D surveys, five monitor seismic surveys have been carried out, which are a combination of 2D, 3D and 2D plus mini-3D surveys. Comparison of 2nd to 5th time-lapse 3D seismic surveys: The 2nd, 3rd, 4th and 5th monitor seismic surveys at cumulative CO_2 injection of approx. 65,000, 207,000 and 300,000 tones into the Moebetsu Formation detected amplitude anomalies, indicating evolution of the CO_2 plume. Results of micro-seismicity monitoring: No micro-seismicity or natural earthquakes attributable to CO_2 injection were detected in vicinity of injection area between startup of injection and 16th October 2021, including before and after 2018 Hokkaido Eastern Iburi Earthquake.

Marine environmental surveys according to the monitoring plan submitted by METI to MOE (Ministry of the Environment): Marine environmental surveys, seismic surveys and other monitoring were conducted under the five-year injection permit (FY2016–2020) from MOE on the condition of implementation of the "monitoring plan" approved by MOE. The monitoring plan included: marine environmental survey, location and extent of CO_2, conditions of the formations, and conditions of CO_2. There were also follow-up surveys in case of exceedance of the threshold. The follow-up surveys have been conducted on four occasions and each time MOE issued an official statement that there was no seepage or threat of seepage of injected carbon dioxide into the ocean.

7.6 DISCUSSION PANEL: How much data is needed?

Lead: Katherine Romanak (GCCC). Panelists: Jerry Blackford (PML), Guttorm Alendal (Uni. of Bergen), Daiji Tanase (Japan CCS), Toni Knap (Texas A&M)

Katherine Romanak: We have the tools for monitoring. However, there is so much variability and it would be important to know how much of this variability we need to capture during monitoring the storage site.

The more data we collect the more natural variability we see, and we need to explain it. We need good attributes to be able to differentiate if there is a leakage of it is the natural environment. So, the question for the panel is how much data do we need when monitoring a storage site?

Guttorm Alendal: Part of the reason we find more variability is because we do more measurements. There is a lot of data already in ocean environmental monitoring. Instead of monitoring a particular project, why we don't go together with other environmental activities going on during ocean surveys, especially in view of the ongoing UN ocean decade 2021-2030.

Additional question: do we really need to be measuring 0.01 pH units?

Jerry Blackford: There is lot of data and models out there for ocean monitoring, but high-resolution in time observations need to be done since they are not as part of oceanography research. So, measuring pH every minute is feasible and allow to detect short-term variabilities. There are not so many variables to worry about. About measuring 0.01 pH units, there is a reason for this because we might not be near the hypothetical leak point but we need to be able to detect the signal which it would be very small, so this high resolution in pH monitoring is useful and be possible to do by sensors.

Tony Knap: comment on pH, it is logarithmic so 0.1 to 0.2 is 10 times the acidity. Another comment, 20km from Galveston there is a coral reef that would be very sensitive to CO_2, so wondering how BSEE would deal with this.

Katherine Romanak: There is already monitoring in many areas for ocean acidification, but they are not always the correct parameters we are looking for. We might need to collect data differently.

Guttorm Alendal: In the North Sea they measure acidification at the ocean surface, so they would need to collect data from the seabed for our purpose. As an example, in the winter time, the North Sea is mixed but in summer time it is stratified. Can we find a correlation between surface and the seabed? This could reduce the need for fixed installations at the seafloor. Such studies are of course very interesting for studies of the ongoing acidification of the oceans, so clear synergies here.

Katherine Romanak: In Tomakomai, once the false positive happened the monitoring included more points of monitoring; the same type of measuring but more of them. Was that helpful?

Daiji Tanase: We had 4 times false positives in Tomakomai. Natural variability in the sea water of Tomakomai is very large. If we want to avoid the false positives we need long-time baseline investigation (possibly a costly process), even then false positives would still occur. The marine environment survey in Tomakomai has another important role. In Japan, the fishermen are like land-owners of their fishing grounds. In Tomakomai they are the most important stakeholders. They are very aware of global warming. We are reporting all the research to the Fishermen Corporate Association. This helps to stablish good relationship with them.

Katherine Romanak: What to do if we find a CO_2 anomaly. In the way many regulations are written, they don't focus on attribution of that anomaly. If we measure a baseline for a year, we get a certain scattered data. If we increase measuring timing, we increase the data scattering. The key is to know if we find a CO_2 anomaly, how can we distinguish between natural and leakage. With global warming happening, CO_2 in the ocean is always increasing; so false positive would be happening. For the panel: if we find a CO_2 anomaly, how would you know if it is leakage?

Guttorm Alendal: For data sampling we need to expand the specifications; sample at a certain time and on certain places based on we already know about the system. Don't need a 10 yr continuous survey, but we can do specific surveys at specific times based on the knowledge we have. If we see an anomaly, we should not sound the alarm, but understand that the probability of something to happen has increased. This is readily done through Bayesian data analysis; however, a challenge can be to communicate our uncertainties to the public.

Jerry Blackford: we might be looking the rate of change of CO_2 that do not happen naturally. By looking the biological system, the rate of change of pH maximized over a seasonal time scale this is where we see the real differences, but is a short time scale the anomaly could be a noise in the system. For instance, if we see a change of 0.1 N or 0.2 N pH units over a site in a 50 min timeframe it is not natural. It could be a leak or some natural gas released from seabed.

Tony Knap: Long-term measurements of the ocean are very important. Started time-series off Bermuda in 1988 measuring things on the ocean and found things that never thought to happen. The biology completely changed from organisms that were fixing carbon. So, to see the effect of acidification we would need to deal with these natural changes.

Daiji Tanase: In Tomakomai we conducted a CO_2 leakage simulation with a geologically improbable scenario. In the simulation, we injected 600K tons CO_2 in 3 yrs; pressure build-up reached a maximum. At this time, simulations considered that a big fault cutting from the reservoir to the seabed (permeability of shear zone of 1 Darcy) would emerge. The CO_2 would reach the seabed in 8 yrs. Over the next 40 yrs 7,000 tons of CO_2 would seep into the ocean at a maximum seepage rate of 600 tons per year. CO_2 concentration in the ocean would have not exceeded the natural variation. With no fault above the reservoir of the Tomakomai, we would be certain that no leakage would occur.

Owain Tucker: when we see an anomaly, is it physically possible to create that anomaly with the sources we are doing? We have learned in Peterhead is that there has been instant pollution from objects from ships and platforms, but if we are putting CO_2 kilometers underground it might take very long time to come out. Things need to be placed in context rather than relying on a set of statistical measures.

Sue Hovorka: People over-focused on CO_2 as main indicator. It would be important to link the subsurface with surface observations. We can check for leakage pathways. For instance, if we have a leakage it would release brine first, then methane, and later CO_2.

Mark McCoy: it would be important to look at other parameters, like using submersibles vehicles that can measure thermal anomalies. If we have a significant CO_2 leak we should be able to see a thermal anomaly. What about doing spectral monitoring in the sediments since CO_2 would come through them.

Session 8: Shipping and Shore Infrastructure (Chair: Darshan Sachde)

8.1 The role of liquid CO_2 shipping in carbon capture and storage. By Steve Burthom (Shell) - V*irtual*-

Shell is involved in 2 CCS projects in operation (Quest in Canada, Gorgon in Australia), and 10 projects in development (Polaris in Canada, SE Asia Hub in Singapore, Louisiana Hub & Ohio River Valley in USA, Acorn in Scotland, South Wales Industrial Cluster, Northern Endurance Partnership in UK, Northern Lights in Norway, Aramis & Porthos in Netherlands). Six of these projects have potential for shipping solution (SE Asia, Ohio River, Acorn, S Wales, N Lights, & Aramis). Current fleet for liquid CO_2 transport is limited (only 4 vessels less than 1,500 m^3 capacity -medium pressure carriage). A difficulty to carry liquid CO_2 is the Triple Point which is above atmospheric pressure. To overcome this difficulty, two shipping concepts are under development for medium and low pressure. The medium pressure solution involves a carriage at -27 °Celsius and 15-16 bars. This concept has been already proven in CO_2 transport for the food & drinks sector. The low-pressure solution involves a carriage at -48 °Celsius and 7-8 bars. Transporting CO_2 at lower pressure would allow to build larger vessels. Using existing vessels, like LNG, for transport would not allow the CO_2 to be carried at the required pressure to keep it above of the Triple Point. A large number of LPG vessels were also evaluated but they were not suitable to carry CO_2 at the required conditions.

Pipeline transport economics are good for short-distance transport but transportation of liquid CO_2 by ships can be a cost-effective solution for long distances between emitter and storage locations, or an enabler where pipelines are not feasible. CO_2 shipping also provides flexibility to increase the scale of the volume to export as well as a providing diverse options of storage locations for emitters. The use of standardized CO_2 shipping would allow to stablish a regional liquid CO_2 trade within multiple emitters and storage locations.

Shell with partners on design of the first CO_2 carrier for Northern Lights project (up to 7,500 m^3 capacity). Expected completion 2024. Other designs in progress include vessels for 12,000 m^3, 36,000 m^3, 40,000 m3 & 70,000 m^3 capacities. Also active on designing low pressure liquid CO_2 (LCO_2) carriers and incorporation of energy efficient technology into CO_2 vessel designs (up to 43% emissions reduction). Shell also active in the industry developing standardization for LCO_2 shipping by joining industry project on low-pressure CO_2 transport materials and thermodynamic assessment, as well as starting LCO_2 technical study with International Organization for Standards (ISO) starting a working group with Society of International Gas Tanker and Terminal Operators (SIGTTO). It is also important for Shell to reduce CO_2 emissions in shipping, by switching to more efficient technologies like fuel cells and LNG as fuel, and introducing hydrogen as the future fuel with no emissions (Fig. 8.1, overleaf).

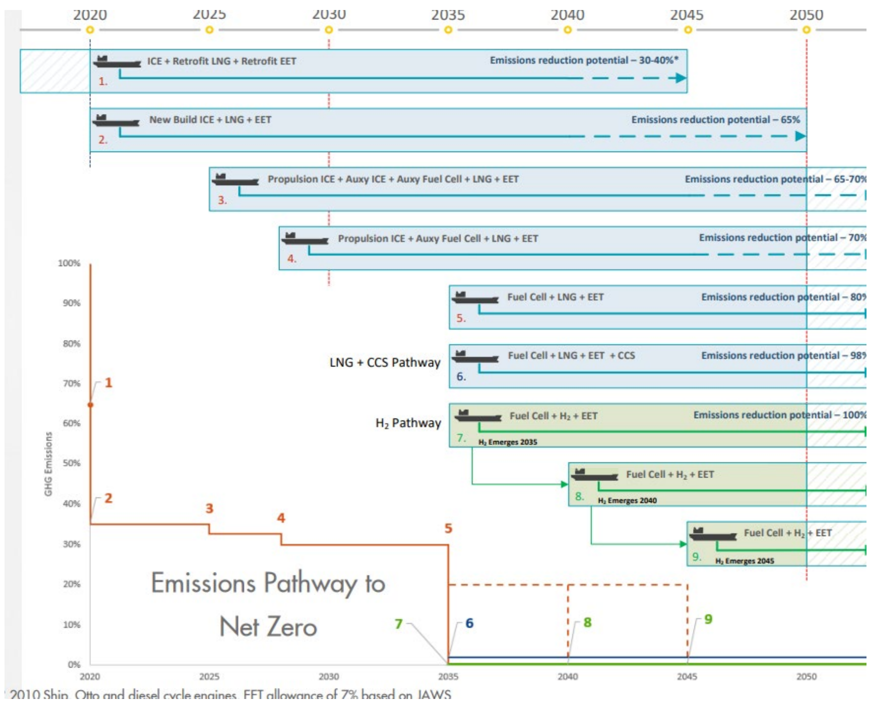


Figure 8.1. Path to net-zero emissions in shipping technology.

8.2 Centralized Carbon Management at the Port of Corpus Christy Authority. By Jeff Pollack. -*Virtual-*

Port of Corpus Christy located in Texas, USA. Largest port in the country by revenue tonnage (167.3 M tons moved in 2021). The Port climate action is to reduce GHG emissions per cargo ton handled by 7.5 % annually. The port has built an air emission inventory in the last 10 yrs, which: 1- it is updated every three years, 2- includes greenhouse gas emissions, 3- incorporated state's emissions data to yield 2-country airshed inventory, 4- expanded to include lightering operations, 5- support coastal bend air quality partnership.

The Port has engaged in important partnerships with the public sector, in support of decarbonization efforts and creation of an emerging hydrogen hub. Last year like for instance stablished an MOU with the State of Texas (Land Office) to develop centralized infrastructure to enable geologic storage of captured carbon in state waters. Another important commercial agreement was signed on February 2022 with Talos Energy & Howard Energy for CCS on 13000 acres onshore owned by the Port, with the objectives of conducting research and develop local fully integrated CCS hub for regional customers.

On the feasibility for CO_2 storage, the Port has identified about 7 areas in their acreage with mean estimated CO_2 capacity ranging from 32.8 to 113.7 Mt. The Port of Corpus Christy is sending signals to customers saying that it's committed to be part of low-carbon management solutions. The Port has demonstrated that has cultivated CCUS opportunities, and a number of e-fuel and green concrete projects. The Port has the capability to provide connectivity between emitters and target injection locations onshore and offshore. It can help any construction operator to avoid the complications to have to aggregate properties across dozens of landowners. The Port is also capable of deploying capital to fund key infrastructure elements.

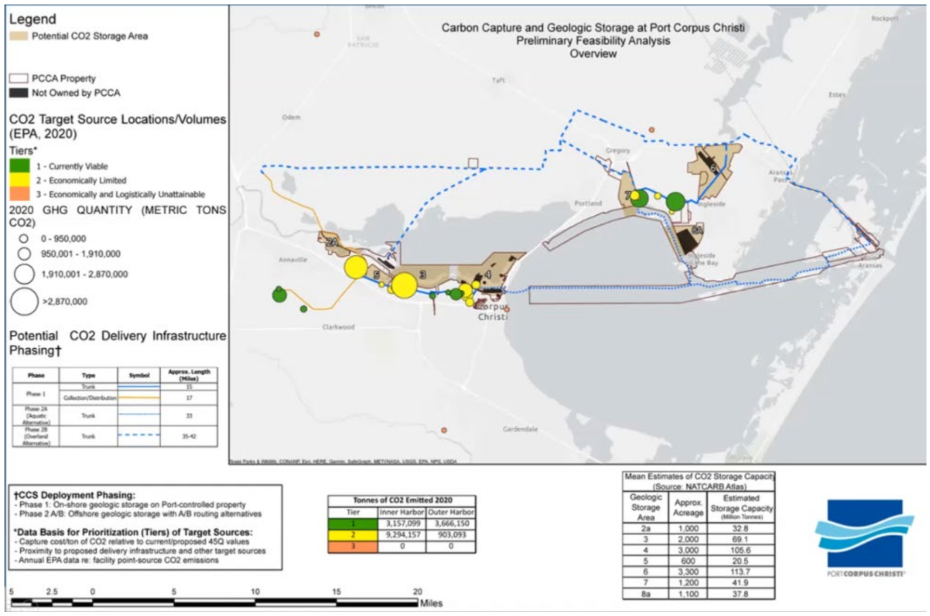


Figure 8.2. The Port of Corpus Christi as an emerging carbon management hub.

8.3 Discussion

Question online (Don Rehmer): How is this carbon neutral when burning fuel to transport CO_2 when CO_2 was created by burning fuel in the first place?

Steve Burthom (speaker): Our aim is to keep emissions produced by the vessels compared to the amount transported below 0.1%. Amount of emissions when transporting CO_2 is very low. We are working in lowering emission by deploying as many energy-efficient technologies available.

Question online (Hailun Ni): For CO_2 shipping, is there any CO_2 loss during transportation?

Steve Burthom (speaker): it is totally enclosed. We have zero venting, so for the loading and discharge operation we use a vaporator so we have a piston effect where we transport the vapor from the ship and onshore back and forth to the vaporator. Short passage allowing pressure to build-up.

Darshan Sachde: For a long-distance transport would you have to vent with temperatures?

Steve Burthom (speaker): For longer distances, i.e., shipping to Japan, we are looking at some kind of liquefaction on board. So, maintaining the same temperature and pressure.

Ramon Gill: For the Port of Corpus Christi, how are you dealing with the public engagement?

Jeff Pollack (speaker): our portfolio stakeholders is diverse, from private sector, customers that we provide services. For instance, when agreement with Talos was reached, we communicated the public for 2 weeks, met with every elected official in the region. Went out to the community in multiple forums. We made our best efforts to get everyone comfortable with the notion of moving pressurized CO_2 around the community.

Question from audience: have you though on barge transportation for the CO_2?

Steve Burthom (speaker): For Europe, we are considering self-propelled barge design for Aramis project. Also working on push-barge design for the project in Ohio River (USA). Steve Burthom (speaker): In our case we are prepared to receive vessels carrying-CO_2 in a variety of classes. The maritime instructions we have support everything from brown-water barges to very large crude carriers. Barge transportation would not be a limiting factor to transport CO_2.

Session 9: **Summary and Recommendations** (Moderated by Tim Dixon, Katherine Romanak and Sue Hovorka)

The following conclusions and recommendations were agreed by the workshop delegates.

Conclusions from this workshop:

- The growing number of projects since last workshop. We are in a momentum.
- The range of projects in design and coverage of emissions. Good for others to learn from.
- Some project planning to use shipping for transport and/or injection.
- Good participation by regulators in this workshop, i.e., BSSE, BOEM.
- New industry players coming in, with new interest and ideas.
- Re-use of infrastructure is complex, technically and legally. Good examples of the details needed from some projects.
- Can we co-locate activities, i.e., CCS projects with wind farms? It can be complex and not always possible.
- Good display on the use of environmental monitoring research outputs for real projects (STEMM-CCS and ECO2 to Northern Lights, Greensand, Northern Endurance Partnership).
- Northern Lights environmental monitoring plan, 'down-selecting' from R&D projects, so as to be 'fit for purpose'

Recommendations from this workshop:

- Continue this outreach – to new industry players and sectors, and to new countries.
- Reach towards investors?
- Capacity estimations need consistency – use SRMS
- Need work on environmental impacts in GoM, there is a data gap to fill in GoM.
- Make needs and perspectives known to regulators ASAP.
- Each site is different. Need to let regulators know. One size does not fit all.
- Need EPA (Environment Protection Agency) engagement in USA.

Tim ended the workshop by thanking BEG for hosting and sponsoring, SSEB for organizing the venue, all the presenters for sharing, and all attendees for attending and contributing to the questions and discussion.

Evaluating technology options to mitigate greenhouse gas emissions

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