Technology Collaboration Programme by IEA

IEAGHG

CO_2 Storage Site Catalogue

Technical Review 2024-TR03
July 2024

IEA Greenhouse Gas R&D Programme

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

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

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Citation

The report should be cited in literature as follows: **IEAGHG, 'CO2 Storage Site Catalogue', 2024-TR03, July 2024, doi.org/10.62849/2024-TR03**.

Acknowledgements

This technical review describes work undertaken by Nicola Clarke and James Craig IEAGHG. The contents of the report has been reviewed by a panel of independent technical experts before its release.

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Abstract

This Technical Review provides an overview of 22 CO_2 storage sites from around the world. These include CO_2-EOR, commercial scale storage sites and a number of pilot and demonstration storage sites in both depleted hydrocarbon reservoirs and saline reservoirs (Figure i and Table i). Its primary aim is to provide a convenient source of collated information with a specific focus on technical information that are in the public domain. It compiles experiences of planning and operating these sites and aims to provide the reader with an accessible and valuable reference document that could provide a gateway to further reading. Useful for potential newcomers to carbon capture and storage, and those who have more experience, such as project developers and relevant authorities. Ultimately, it is our hope that this comprehensive overview will contribute to the advancement of CO_2 storage technology and the acceleration of global efforts to combat climate change.

Introduction

The geological storage of CO_2 by injection and storage into sedimentary basins has been working safely and effectively for over 50 years, initially with CO_2 used in enhanced oil and gas recovery and latterly as an environmental measure to capture and permanently store anthropogenic CO_2. Ambitious targets to capture and store ~ 1200 Mt CO_2/yr by 2030 is called for by the IEA's Net Zero Emissions Scenario[1]. To achieve these targets will require strong cross collaboration and utilisation of past learnings to scale up projects in number and scale.

This Technical Review provides an overview of 22 CO_2 storage sites around the world which are arranged geographically. These include CO_2-EOR, commercial-scale storage sites and several pilot/demonstration storage sites in both depleted oil and gas reservoirs and saline reservoirs (Figure i and Table i). Its primary aim is to provide a convenient source of collated information with a specific focus on technical information that are in the public domain. It compiles experiences of planning and operating these sites and aims to provide the reader with an accessible and valuable reference document that could provide a gateway to further reading. Each chapter provides information about location; type of project and development history; key information about the geology i.e. reservoir, seal and overburden; the number and arrangement of injection, monitoring and other wells with key completion information including injection rates and CO_2 quantities; experiences with induced seismicity; monitoring technologies employed and experiences with monitoring are also discussed. Where possible, major learnings are summarised and key references and illustrative figures are provided to support each storage site.

Useful for potential newcomers to carbon capture and storage, and those who have more experience, such as project developers and relevant authorities. Ultimately, it is our hope that this comprehensive overview will contribute to the advancement of CO_2 storage technology and the acceleration of global efforts to combat climate change.

Carbon capture and storage is a rapidly evolving field and the contents of this review comprise information in the public domain at the time of writing. In the interest of staying current, additional storage sites will be included in subsequent updates of this review.

For further information on CCS monitoring technologies the IEAGHG monitoring selection tool has information on 40 monitoring techniques [2]. Good general references to global CCS projects across the full value chain that are regularly updated and interactive include: the Scottish Carbon Capture and Storage Global CCS Map[3], The Global CCS Institute's Facilities Database[4], Zero Emissions Platform CCS projects (Europe)[5], Clean Air Task Force Carbon Capture Activity and Project Map[6], The NETL Carbon Capture and Storage Database[7] and CCUS Map (US)[8]. The IEA has also compiled a database of global CCUS projects since the 1970s[9]. Useful technical overviews were compiled by MIT but not updated since 2016[10]. Lastly, the OGCI has published compilations of CO_2 storage resources from published records[11].

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[1] https://www.iea.org/reports/global-energy-and-climate-model/net-zero-emissions-by-2050-scenario-nze
[2] https://ieaghg.org/monitoring-selection-tool/
[3] https://www.sccs.org.uk/resources/global-ccs-map
[4] https://co2re.co/FacilityData
[5] https://zeroemissionsplatform.eu/about-ccs-ccu/css-ccu-projects/
[6] https://www.catf.us/ccsmapeurope/
[7] https://netl.doe.gov/carbon-management/carbon-storage/worldwide-ccs-database
[8] https://ccusmap.com/markers/map/
[9] https://www.iea.org/data-and-statistics/data-product/ccus-projects-database
[10] https://sequestration.mit.edu/tools/projects/index.html
[11] CO_2 Storage Resource Catalogue (SCRC) https://www.ogci.com/ccus/co2-storage-catalogue

Figure i: Location map with CO_2 storage sites covered in this review

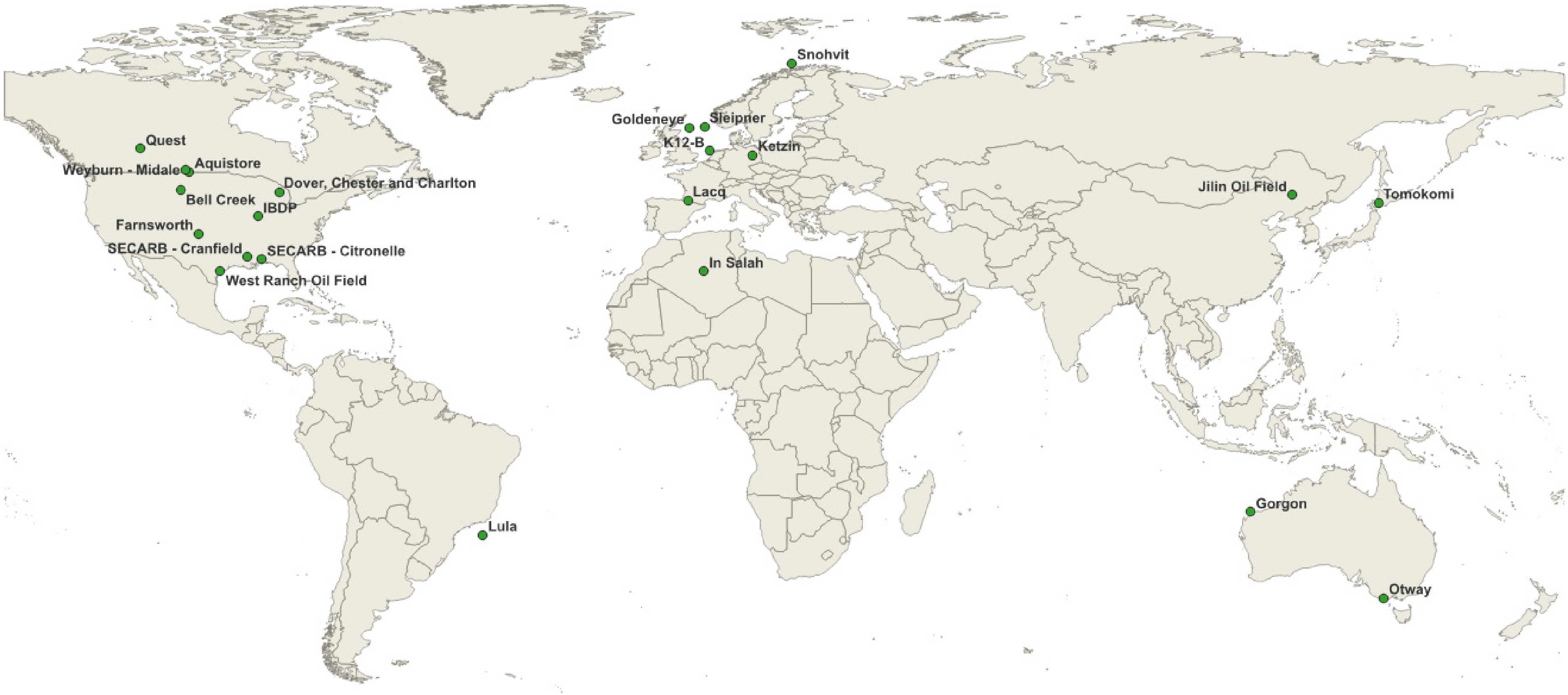


Table i: Table of CO_2 storage sites in this review

Number	Name	Region	Country	Onshore/ Offshore	Storage Type[1]	Started Operation[2]	End Operation[3]	Status	Scale	Latitude	Longitude
1	Quest	Alberta	Canada	Onshore	DSF	2015	-	Operational	Commercial	53.79725	-113.09277
2	Weyburn - Midale	Saskatchewan	Canada	Onshore	EOR	2000	-	Operational	Commercial	49.46924	-103.75906
3	Aquistore	Saskatchewan	Canada	Onshore	DSF	2015	-	Operational	Demonstration	49.09621	-103.03400
4	Bell Creek	Montana	USA	Onshore	EOR	2013	-	Operational	Commercial	45.26688	-104.80320
5	MRCSP - Dover, Chester and Charlton	Michigan	USA	Onshore	EOR	1996 (2013)[4]	-	Operational	Demonstration	44.91466	-84.54083
6	Illinois Basin - Decatur (IBDP)	Illinois	USA	Onshore	DSF	2007	2014	Completed	Demonstration	39.86930	-88.88724
7	Farnsworth	Texas	USA	Onshore	EOR	2010	-	Operational	Commercial	36.27967	-101.06662
8	SECARB - Cranfield	Mississippi	USA	Onshore	EOR & DSF	2008	2015	Completed	Demonstration	31.56353	-91.14149
9	SECARB - Citronelle	Mississippi	USA	Onshore	DSF	2012	2014	Completed	Demonstration	31.05330	-88.14390
10	West Ranch Oil Field	Texas	USA	Onshore	EOR	2016	2020	Completed	Commercial	28.78630	-96.61360
11	Lula	Santos Basin	Brazil	Offshore	EOR	2011	-	Operational	Commercial	-25.60719	-42.64893
12	Snohvit	Barents Sea	Norway	Offshore	DSF	2008	-	Operational	Commercial	70.68483	23.59064
13	Sleipner	North Sea	Norway	Offshore	DSF	1996	-	Operational	Commercial	58.41421	3.00439
14	Goldeneye	North Sea	UK	Offshore	DGF	-		Suspended/Planned	Commercial	57.47800	-1.78833
15	K12-B	Southern North Sea	The Netherlands	Offshore	DGF	2003	2017	Completed	Commercial	53.33000	4.00000
16	Ketzin	Brandenburg	Germany	Onshore	DSF	2008	2013	Completed	Demonstration	52.49114	12.86790
17	Lacq - Rousse	Nouvelle-Aquitaine	France	Onshore	DGF	2010	2013	Completed	Demonstration	43.26012	-0.40440
18	In Salah	Central Sahara	Algeria	Onshore	DGF	2004	2011	Suspended	Commercial	28.64222	2.82505
19	Jilin	Jilin Province	China	Onshore	EOR	2011	-	Operational	Commercial	44.27671	123.94359
20	Tomokomi	Hokkaido Prefecture	Japan	Offshore	DSF	2012	2019	Completed	Demonstration	42.63128	141.64907
21	Gorgon	Western Australia	Australia	Onshore	DSF	2019	-	Operational	Commercial	-20.79142	115.45115
22	Otway	Western Victoria	Australia	Onshore	DSF/ DGF	2008	-	Operational	Demonstration	-38.51670	142.80836

[1] Deep Saline Formation (DSF); Enhanced Oil Recovery (EOR); Depleted Gas Field (DGF)

[2] Generally start of injection but in some cases start of project

[3] Generally end of injection

[4] start of EOR and start of demonstration project

Glossary

ACR Artificial corner reflectors
AER Annual Efficiency Ratio
AOI Area of interest
AOR Area of review
API American Petroleum Institute (oil)
AVO Amplitude verses offset (seismic technique)
AVOA Amplitude-versus-offset-and-azimuth
AZMI Above zone monitoring interval
BGH Borehole gravity monitoring
BHP Bottom hole pressure
CBL Cement bond logs
CCGT Combined cycle gas turbine
CCS Carbon capture and storage
CO_2 Carbon Dioxide
CSEM Controlled-source electromagnetic method
D A Darcy (unit of permeability)
DAS Distributed acoustic sensing
DGF Depleted gas field
DIC Dissolved inorganic carbon
DOC Dissolved organic carbon
DOE US Department of Energy
DSF Deep saline formation
DTS Distributed temperature sensing
DV Differential valve
ECS Elemental capture spectroscopy
EGR Enhanced gas recovery
EMIT Electromagnetic monitoring tool
EOR Enhanced oil recovery
ERT Electrical resistivity tomography
ESP Electric spontaneous potential measurement
Fm (Sedimentary) formation
FMI Formation micro imager
FPSO Floating production storage and offloading units
FRS Fluid recovery systems
ft Feet
GMS Gas monitoring – Gas membrane sensor
GPS Global positioning system
GWC Gas water contact
Hrs Hours
Hz Hertz
InSAR Interferometric synthetic aperture radar
JIP Joint industry partnership
k Thousand
kH Horizontal permeability
kV Vertical permeability
l Litre
LIDAR Light detection and ranging (remote sensing)
m Metres
m/s Meters per second
MBES Multi beam echo sounder
mD Millidarcy (a unit of permeability)
MDT Modular formation dynamic tester
MEA Monoethanolamine
Mg milligram
M_I Intensity Magnitude (earthquake)
MID Magneto-induction defectoscopy
MIT Magnetic imaging tool
M_L Richter local magnitude (earthquake)
Mmscf million standard cubic feet
MMV Monitoring measurement and verification
MPa Megapascal (unit of pressure)
MRCSP Midwest Regional Carbon Sequestration Partnership
ms Millisecond
M_S Surface wave magnitude (earthquake)
MSP Moving source profiling
Mt Megatonne equivalent to 1 million tonnes
MVA Monitoring, verification and accounting
M_W Moment magnitude (earthquake)
nD Nano Darcy
NE, SW etc Northeast, southwest etc
NETL National Energy Technology Laboratory (US)
NMR Nuclear Magnetic Resonance
NRAP US DOE National Risk Assessment Partnership
NRM Non-Rigid Matching
NRMS Normalised Root Mean Square
OBC Ocean Bottom Cable
OBN Ocean Bottom Node
P&A Plugged and abandoned (wells)
P/T Pressure Temperature
PFRA Prairie Farm Rehabilitation Administration, Canada
PFT Perfluorocarbon tracer

PHIC RST measurement of neutron porosity

PLT Production logging tool

PNC Pulsed neutron capture

PNG Pulsed neutron-gamma logging

PNL Pulse neutron log

ppm Parts per million

Psi Pounds per square inch (unit of pressure)

PVC Polyvinyl chloride

P-wave, S-wave Longitudinal and transverse seismic waves

PZ Perforation zone

RMS Root mean square amplitude

ROV Remotely operated vehicle

RST Reservoir saturation tool

RT Rotary table

SECARB Southeast Regional Carbon Sequestration Partnership (US)

SEM Scanning Electron Microscope

Sh Shale

SIGM RST measurement of formation sigma

SP Spontaneous potential (well logs)

Ss Sandstone

SSS Side Scan Sonar

STA/LTA Short Time Average over Long Time Average (algorithm for seismic signal)

SVCF Statistically verified composition fingerprinting

SWP Southwest Regional Partnership on Carbon Sequestration (US)

t/d Tonnes per day

TD Total depth (wells)

TDS Total dissolved solids

TVDss True vertical depth -subsea

UIC Underground Injection control database

VSP Vertical seismic profile

WAG Water alternating gas (injection pattern)

WEC Water Electrical Conductivity

XRD X-ray diffraction

yr Year

1. Quest

Site Details					
Name	Location	Province/State	Country	Onshore	Offshore
Quest		Alberta	Canada	✓	

General storage type

Deep Saline Formation

Development History (In operation since 2015)

The Quest project was conceived in 2008 and began initial operation in August 2015 by Shell Canada. CO_2 is captured from the Scotford Upgrader Facility and permanently stored ~2 km underground at a Subsurface Storage Facility located 65 km north-east of the capture facility[1, 2] (Figure 1.1).

Three injection well sites were built and operated for the Quest Storage Facility with a single injection well located at each well site. Sustained injection from only two of the three injection wells was maintained until November 2018. During this time, the third injection well acted as a deep monitoring well. Storage has been successfully achieved since 2015 into an extensive sandstone formation immediately above the Precambrian crystalline basement. At this location it is referred to as the Basal Cambrian Sandstone (BCS). Because this was one of the world's first large-scale demonstration of a CCS facility, extensive monitoring activities tied to an MMV (monitoring, measurement and verification) Plan were implemented which is based upon a rigorous risk assessment process. MMV activities have been designed to provide assurance of the location, size and extent of the subsurface CO_2 plume and any potential migration outside the storage reservoir.

The facility plans include operations from August 2015 to 2040, when the process of decommissioning the capture facility, pipeline and storage site will begin.

Geological Characteristics

Reservoir Formation

The Basal Cambrian Sandstone (BCS) in Alberta is a widespread coarse-gained sandstone, which is like other target storage formations encountered further south; notably at Aquistore and at Decatur. It lies unconformably above the crystalline Precambrian basement (Figure 1.2).

Lateral extent / thickness variation	The BCS is between 35 – 50 m in the vicinity of the Quest site. The formation thins in each direction from the site but to varying degrees. The formation thins to less than a few meters 15 km to the west but is more laterally extensive and thicker in all other directions, especially to the north-west,

1 The Shell Quest Carbon Capture and Storage Project, 2019-04
2 Luc Rock, Simon O'Brien, Stephen Tessarolo, Jeff Duer, Vicente Oropeza Bacci, Bill Hirst, David Randell, Mohamed Helmy, Jessica Blackmore, Celina Duong, Anne Halladay, Nial Smith, Tanu Dixit, Sarah Kassam, Matthew Yaychuk, The Quest CCS Project: 1st Year Review Post Start of Injection. Energy Procedia 114 (2017) 5320 – 5328

	and east where a thickness of ~30 m is evident for at least 20 km (Figure 1.3).
Rock type	Sandstone
Sedimentary features: Depositional Environment / facies type & variation / mineral composition	The BCS consists of fine to coarse-grained sandstones with minor clay to silt-sized intercalations. The formation has an average porosity of 17% and a permeability range of 33 mD - 1,000 mD. It is a widespread formation deposited on an uneven Precambrian crystalline basement with topographic highs where the sandstone is thin or even absent. The BCS sediments were deposited in a shallow marine tide-dominated bay margin (TDBM) environment with coarser sand grains with better reservoir quality at the bottom and finer material at the top. At the injection well sites the BCS is ~40m thick[3]. There is a gradational transition to more frequent and thicker fine-grained beds which marks the top of the BCS formation. The fining upwards sequence is the consequence of a continued sea level transgression towards the present-day northeast. As deeper water and finer-grained deposition progressed a diachronous contact between the BCS and the overlying Lower Marine Sands (LMS) developed. The transition to deeper water is further reflected in the overlying Middle Cambrian Shale which forms the primary seal.
Porosity / Permeability	The BCS formation has an average porosity of 17% and a permeability range of 33 mD - 1,000 mD.
Formation fluid properties: (residual hydrocarbons / salinity concentration).	The BCS is a saline aquifer with Total Dissolved Solids (TDS) ranging between 238 k to 310 k mg/L.

Caprock / primary seal formation
There are three significant confining layers within the BCS Storage Complex including one Cambrian shale layer and two Lower Devonian salt layers overlying the BCS (Figure 1.2). These formations pinch-out towards the northeast. Above the Cambrian sediments there are Devonian basal red beds overlain by laterally extensive evaporate deposits which form highly effective regional seals. The Lower Devonian Lotsberg Salts (Lower Lotsberg and Upper Lotsberg Salt in the Quest area) thicken in the same direction towards the north-east (Figure 1.4). At the injection site the primary seal, the Middle Cambrian Shale (MCS), is 44m thick; the secondary seal, the Lower Lotsberg Salt is 34m; the tertiary (Ultimate Seal) seal, the Upper Lotsberg Salt, is 84m thick. [3]. Across the Area of Interest (AOI) which surrounds the three injection wells, the LMS, immediately above the BCS, varies in thickness from between 50 to 75 m. The average LMS porosity calculated

3 Quest pressure monitoring. 10th Monitoring Network Meeting, June, 2015

for the Shell Wells 11-32, 3-4 and 8-19 is 10 to 12%, and the effective porosity is 6%. The average permeability is 4 mD. As per the AER D65 approval, the Maximum Bottom Hole Injection pressures for the 3 Injection wells is 30 MPa. This represents 70% of the lowest fracture extension gradient measured in the BCS [4].	
Lateral extent / thickness variation	n/a
Rock type	See above
Overburden Features	
Above the Devonian evaporate and shale formations are a series of aquifers and aquitards ranging in age from Mississippian to Tertiary overlain by Quaternary glacial deposits. A schematic cross-section of the Phanerozoic (Cambrian – Quaternary) succession across Alberta from south-west to north-east shows that the BCS occurs at a depth of approximately ~1,500 m (below sea level) at the injection site and remains below 1,000 m at its maximum extent as it thins to the north-east (Figure 1.5) Evaporite deposits cover the BCS from the AOI to north-east where they extend beyond the lateral extend of the BCS[5].	
Structure	
Fold type / fault bounded	n/a
Faults /Fractures (Type – normal, reverse, strike-slip)	2D seismic (with ~3 km spacing) and 3D (covering 415 km^2) was used to build a geological profile and to detect the presence of faults in the AOI. No faults offsetting the MCS or Lotsberg seals were mapped[4].
Displacement	n/a
Stability (pre-stressed, active, stable)	n/a
Injection / storage history	
Number of injector, monitoring or other wells, well geometry, design and key completion information for injection wells, relevant well issues. Reused / new purpose drilled well.	
As part of planning, two exploration wells were drilled (Redwater 11-32 and Redwater 3-4) to characterise the BCS and siting of the injection locations and storage complex [1]. Characterisation included well logging, core sampling, and water injectivity testing. A third appraisal well (Radway 8-19) was drilled in 2010 to inform the pore space regulatory application, risk assessment and Storage Development Plan, and later converted to an injector well [1].	

4 Quest Storage Development Plan. 07-0-AA-5726-0001. AA5726-Field Development Plan. Syrie Crouch. 6th Oct, 2011

5 Quest Carbon Capture and Storage Project. Annual Summary Report – Alberta Department of Energy: 2014, Figure 3.1

<table>
<tr><td colspan="2">Water injection tests were performed on Redwater 11-32 and Radway 8-19 appraisal wells, these yielded injectivities of 41 and 379 m^3/d/MPa respectively[1].

Three injector wells were determined to be required, resulting in Radway 7-11 and Thorhild 5-35 being drilled and Radway 8-19 converted (Figure 1.1) [1]. Further injection wells may be required should the injectivity of the three wells not be sustained over time, appropriate conformance of the CO_2 plume not achieved or if the captured CO_2 volumes were increased during future development of the Scotford Complex.

Redwater 3-4, was recompleted and converted into a BCS pressure observation well in the Cooking Lake formation, measuring CO_2 conformance as it is distant from the injection wells and provides far-field pressure measurement[1].

Three observation wells include a large well bore to include microseismic and pressure monitoring at Radway 8-19, and slim well bore for pressure monitoring (Cooking Lake Fm) at the Radway 7-11 and Thorhild 5-35.

Nine shallow groundwater monitoring wells have been drilled, two on 5-35, two on 7-11 and five on 8-19. Other groundwater wells include third-party wells that lie within 3.2 km of each injection well.

The status and condition of existing wells penetrating the BCS has now been reviewed from multiple data sources. There are no known issues with legacy well integrity other than the uncertainty that arises from the age of the cement plugs and the inability to pressure test these old cement plugs[4].

Abandonment reports are available for the four third-party legacy wells in the AOI that penetrate the three seals in the BCS storage complex, as well as for the third-party legacy well penetrations in the vicinity of the AOI boundary that penetrate through one or more seals in the BCS storage complex:

Detailed abandonment descriptions are included in reference[4].</td></tr>
<tr><td>Extent and status of casing (corrosion history/ cementation records)</td><td>Cement bond logs (CBL), ultrasonic casing logs, casing caliper and electromagnetic casing logs verified the initial integrity of the cement bond and well completion along the entire length of each injector well[6]. Time-lapse logs show no deterioration of in casing and cement integrity.</td></tr>
<tr><td>Injection rates & pattern (i.e. continuous / intermittent) changes in injection behaviour</td><td>Each of the injection wells was designed to permit injection of the entire volume of captured CO_2, namely 1.2 Mt/yr[1].</td></tr>
<tr><td>Total quantities stored</td><td>By the end of December 2022, about 3.18 Mt of CO_2 had been injected into the 7-11 well, 3.18 Mt of CO_2 into the 8-19 well, and 1.42 Mt of CO_2 into the 5-35 well (~7.78 Mt in total) (Figure 1.6) [7].</td></tr>
<tr><td>Reservoir capacity (estimate)</td><td>The development plan for Quest estimated the capacity of injected CO_2 assuming no flow boundaries. Under these circumstances 27 Mt of CO_2 could be stored whilst not exceeding an increase in bottom hole pressure (BHP) of 5 MPa;</td></tr>
</table>

6 Shell Quest Carbon, Capture and Storage Project, Measurement, Monitoring and Verification Plan. – February 2017 Version. Revised: May 5th 2017 Section 4.9.3
7 https://open.alberta.ca/publications/quest-carbon-capture-and-storage-project-annual-report-2022

	and 50 Mt whilst not exceeding a BHP of 28 MPa. An area of approximately 1,500 km² is required to contain 27 Mt of CO_2 while not exceeding the designed maximum BHP of 28 MPa[4].
Fluid extraction rate (brine extraction, oil for EOR)	n/a
Seismicity	
Monitoring regime (technologies deployed)	
As part of the Quest Storage Development Plan the presence of natural seismicity was reviewed. There is a regional seismic monitoring network which has been in place for more than 80 years with a capability of detecting a magnitude 3 event. No events were detected in the Quest AOI prior to injection[8].	
Seismic events (Detection / magnitude / attribution (natural induced).	
The largest historical earthquake in the northern Great Plains occurred on 16 May 1909. Analysis of intensity assignments places the earthquake location (48.81° N, 105.38° W) close to the Montana–Saskatchewan border with an intensity magnitude M_I of 5.3–5.4. Observations from two seismic observatories in Europe give an average M_S value of 5.3. The 1909 earthquake is near an alignment of epicentres of small earthquakes in Montana and Saskatchewan and on strike with the mapped Hinsdale fault in Montana[9]. The epicentre of the 1909 event is approximately 500 km south-west from the Quest site. An induced seismic event occurred near Fox Creek, Alberta, in January 2016. It was attributed to wastewater disposal. The M_S 4.8 event led to the regulator closing down the Fox Creek operation, but not Quest[10].	
The first locatable event at Quest was recorded in July 2016, 9 months after the start of CO_2 injection. A total of three small magnitude, locatable events were detected by the end of 2016. All locatable events occurred within the Precambrian basement. Microseismic activity has been observed within the Quest area of review (AOR) which extends 10 km radially outwards from each active injection well. More than 100 locatable events were recorded in 2017, with an average magnitude of -0.7, a maximum magnitude of 0.1 and with a typical occurrence rate of 1-2 events per week. All these events have been located in the basement, with the majority clustered in a small area roughly three kilometres from the 8-19 injection site and one kilometre below the bottom of the injection reservoir [10]. As of 31 December 2020, 486 locatable events have been detected and located in the Precambrian basement within the microseismic AOR – the events show no apparent direct relationship to injection parameters but there might be an indirect relationship[7]. Figure 1.7	

8 AGS Tectonic activity map for Alberta
9 The 16 May 1909 Northern Great Plains Earthquake. by W. H. Bakun, M. C. Stickney, and G. C. Rogers. Bulletin of the Seismological Society of America, Vol. 101, No. 6, pp. 3065–3071, December 2011
10 Quest Microseismic: Observations after 2.5 million Tonnes of CO_2 Injection IEAGHG Modelling and Risk Management Network Meeting18th-22nd June 2018

Monitoring technologies applied and experiences with monitoring; (see Figure 1.8[11])	
Surface monitoring technologies deployed	
High Resolution Aeromagnetic Survey [1]	8,600 km^2
2D Seismic Surveys [1]	55 lines over 3,700 km^2
3D Seismic Surveys [1]	415 km^2
Ground water monitoring from wells < 200m[12].	Purpose
Alkalinity / Dissolved Inorganic Carbon (DIC)	Water type and water quality
As	Aquifer acidification
Ca^{2+}	Water type and water quality
Cl^-	Potential brine indicator
$\delta^{13}C$	CO_2 isotopic fingerprint
Water Electrical Conductivity (WEC)	Potential brine indicator
K^+	Water type and water quality
Mg^{2+}	Water type and water quality
Na^+	Potential brine indicator
pH	Water quality, CO_2 impact
$SO4^{2-}$	Water type and water quality
TDS	Potential brine indicator
Tier 3 (T3)	LightSource – surveillance frequency as required
T3	Shallow ground water wells geochemical analysis - quarterly
T3	InSAR – surface heave – as required
Subsurface monitoring technologies deployed (well logs)[13].	
Tier 1 (T1)	Continuous down-hole pressure (Injection Well)
T1	Continuous down-hole pressure (Monitoring Well)
Tier 2 (T2)	Microseismicity - daily
T2	Continuous DTS (distributed temperature sensing) outside casing - quarterly
T2	Pulse Neutron Log (PNL)- CO_2 presence within reservoir formation – as per AER direction
T3	SVCF (Statistically verified composition fingerprinting) (Chemical composition of formation fluid – as required)

11 Harvey, S., O'Brien, S., Minisini, S., Oates, S. and Braim, M., 2021, March. Quest CCS facility: Microseismic system monitoring and observations. In Proceedings of the 15th greenhouse gas control technologies conference (pp. 15-18).
12 Measurement, Monitoring and Verification Plan *February 2017 version.* Prepared by: Shell Canada Limited, Calgary, Alberta. Revised: May 5th, 2017 Section 4.6
13 11th IEAGHG Monitoring Network Meeting, June 13th – 15th,2017. Traverse City, Michigan. Quest – update since 2016

T3	VSP-2D (seismic amplitude – as required)
T3	2D & 3D seismic – indication of amplitude anomaly above storage complex – as required
T3	Water pH – daily
T3	Water conductivity - daily

Experience summary - effectiveness of techniques (limitations / strengths)

It was important to have collected baseline data to compare to. Effectiveness of techniques is being evaluated on a 3-year cycle and changes are captured and explained in MMV Plan updates.

Major technical/scientific studies on the site, major learnings, Conformance assessment (history-matching with models, correlation between different monitoring techniques)

The average radius of the CO_2 plume measured from DAS VSP time-lapse seismic conforms to model estimates. Asymmetries in the CO_2 plume are observed from the DAS VSP time-lapse seismic data which are not fully captured by the model. Very low amplitude seismicity has been detected in the basement, but no impact has been observed at the surface. PNL runs have revealed good horizontal permeability (kH) consequently CO_2 stays in a high permeability zone. kH is much greater than vertical permeability (kV) by a factor of 100. Reservoir modelling predicts that pressure build up within the reservoir formation is likely to be less the 2 MPa. The maximum size of plume is unlikely to exceed 2-4 km over the 25 years. Overall costs are 30% lower than expected. These observations were reported at an IEAGHG Network Meeting in 2017[13].

List of key publications covering the site

1. The Shell Quest Carbon Capture and Storage Project, 2019-04
2. Luc Rock, Simon O'Brien, Stephen Tessarolo, Jeff Duer, Vicente Oropeza Bacci, Bill Hirst, David Randell, Mohamed Helmy, Jessica Blackmore, Celina Duong, Anne Halladay, Nial Smith, Tanu Dixit, Sarah Kassam, Matthew Yaychuk. The Quest CCS Project: 1st Year Review Post Start of Injection Energy Procedia 114 (2017) 5320 – 5328
3. Quest pressure monitoring. 10th Monitoring Network Meeting, June, 2015
4. Quest Storage Development Plan. 07-0-AA-5726-0001. AA5726-Field Development Plan. Syrie Crouch. 6th Oct, 2011
5. Quest Carbon Capture and Storage Project. Annual Summary Report – Alberta Department of Energy: 2014
6. Shell Quest Carbon, Capture and Storage Project, Measurement, Monitoring and Verification Plan. – February 2017 Version. Revised: May 5th 2017 Section 4.9.3
7. https://open.alberta.ca/publications/quest-carbon-capture-and-storage-project-annual-report-2021
8. AGS Tectonic activity map for Alberta.
9. The 16 May 1909 Northern Great Plains Earthquake. by W. H. Bakun, M. C. Stickney, and G. C. Rogers. Bulletin of the Seismological Society of America, Vol. 101, No. 6, pp. 3065–3071, December 2011

10. Quest Microseismic: Observations after 2.5 million Tonnes of CO2 Injection IEAGHG Modelling and Risk Management Network Meeting18th-22nd June 2018
11. Harvey, S., O'Brien, S., Minisini, S., Oates, S. and Braim, M., 2021, March. Quest CCS facility: Microseismic system monitoring and observations. In Proceedings of the 15th greenhouse gas control technologies conference (pp. 15-18).
12. Measurement, Monitoring and Verification Plan February 2017 version. Prepared by: Shell Canada Limited, Calgary, Alberta. Revised: May 5th, 2017 Section 4.6
13. 11th IEAGHG Monitoring Network Meeting, June 13th – 15th,2017. Traverse City, Michigan. Quest – update since 2016

Other relevant information considered pertinent to the report

Bourne, S., Crouch, S. and Smith, M., 2014. A risk-based framework for measurement, monitoring and verification of the Quest CCS Project, Alberta, Canada. International Journal of Greenhouse Gas Control, 26, pp.109-126.

Alberta Government - Environmental Assessment - Shell Canada Limited Quest Carbon Capture & Storage Project

https://open.alberta.ca/dataset/environmental-assessment-shell-canada-limited-quest-carbon-capture-storage-project

Alberta Government website with links to location map

https://open.alberta.ca/dataset/8c413a33-d90f-4b41-a68d-c9f73f0240aa/resource/3b9db363-33cd-4ba8-ab83-6af05457db35/download/shell-quest-carbon-capt-and-storage-proj-map.pdf

O'Brien, S., Halladay, A. and Oropeza Bacci, V., 2018, October. Quest CCS facility: Microseismic Observations. In 14th Greenhouse Gas Control Technologies Conference Melbourne (pp. 21-26).

Figures

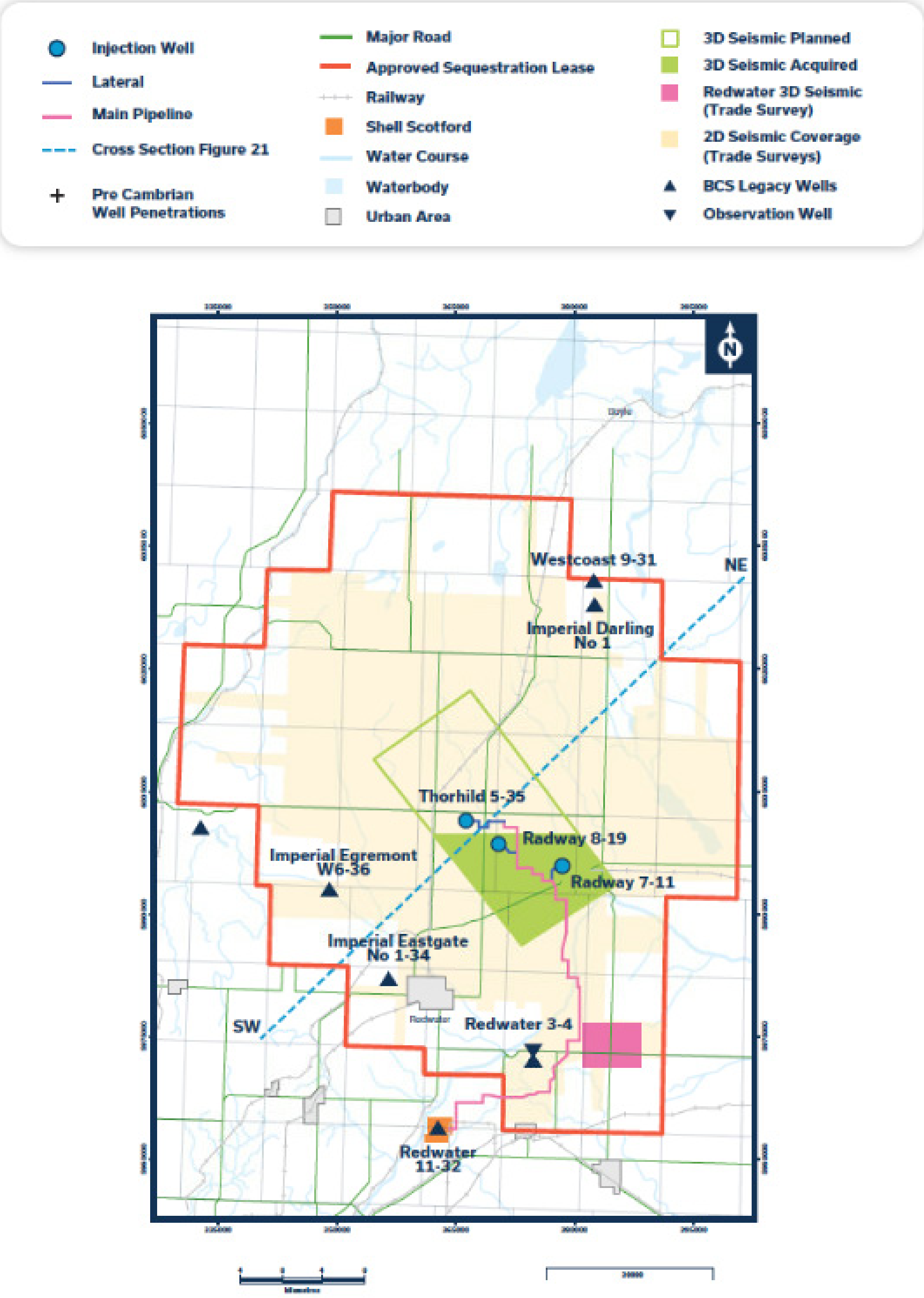


Figure 1.1: Map of the Quest project area showing location of injector wells, legacy wells, screening MMV Surveys, Scotford Upgrader, and CO_2 Pipeline[1].

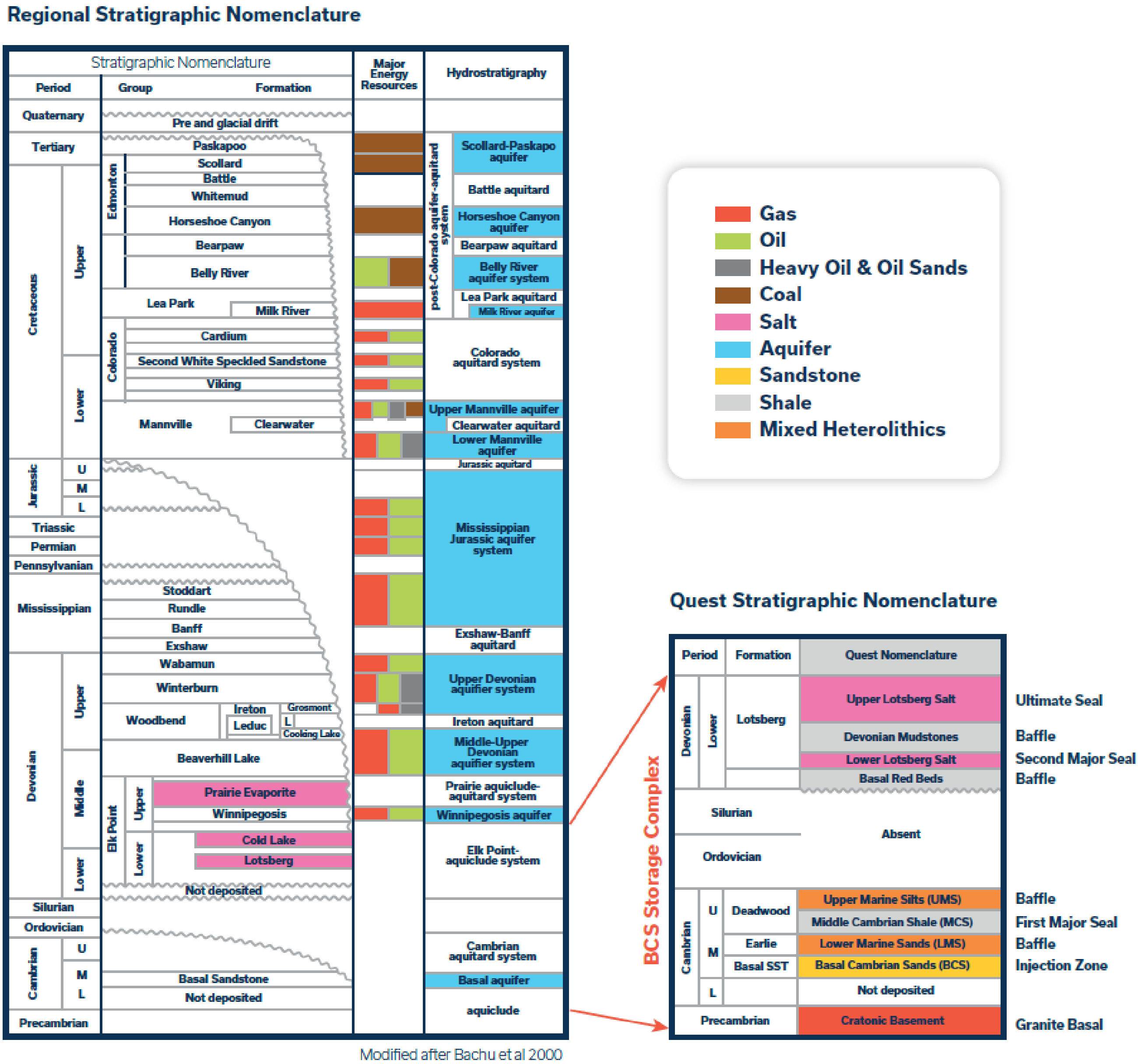


Figure 1.2: Regional stratigraphy for Shell Quest area of interest, including the Basal Cambrian Sands storage complex [1].

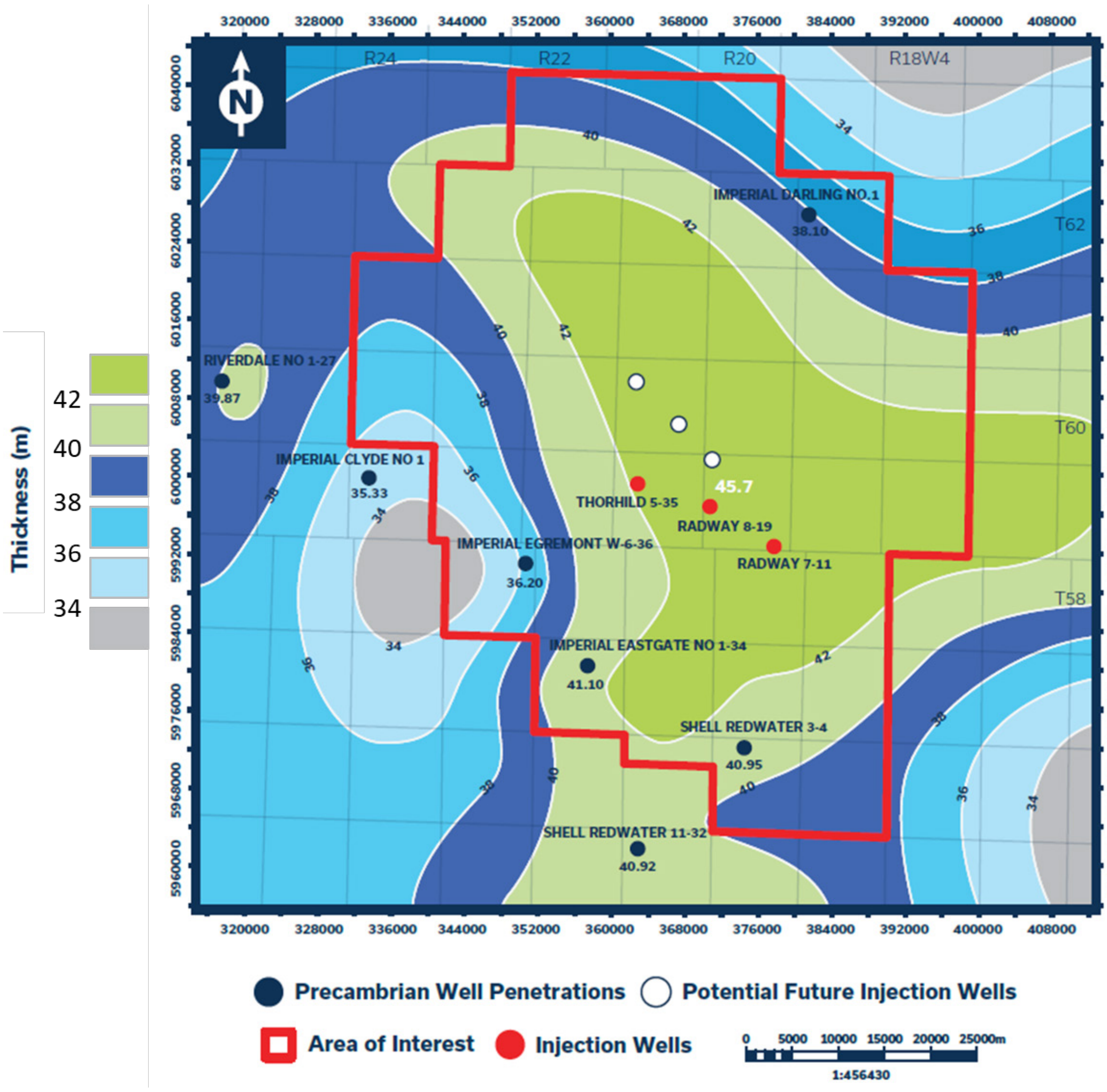
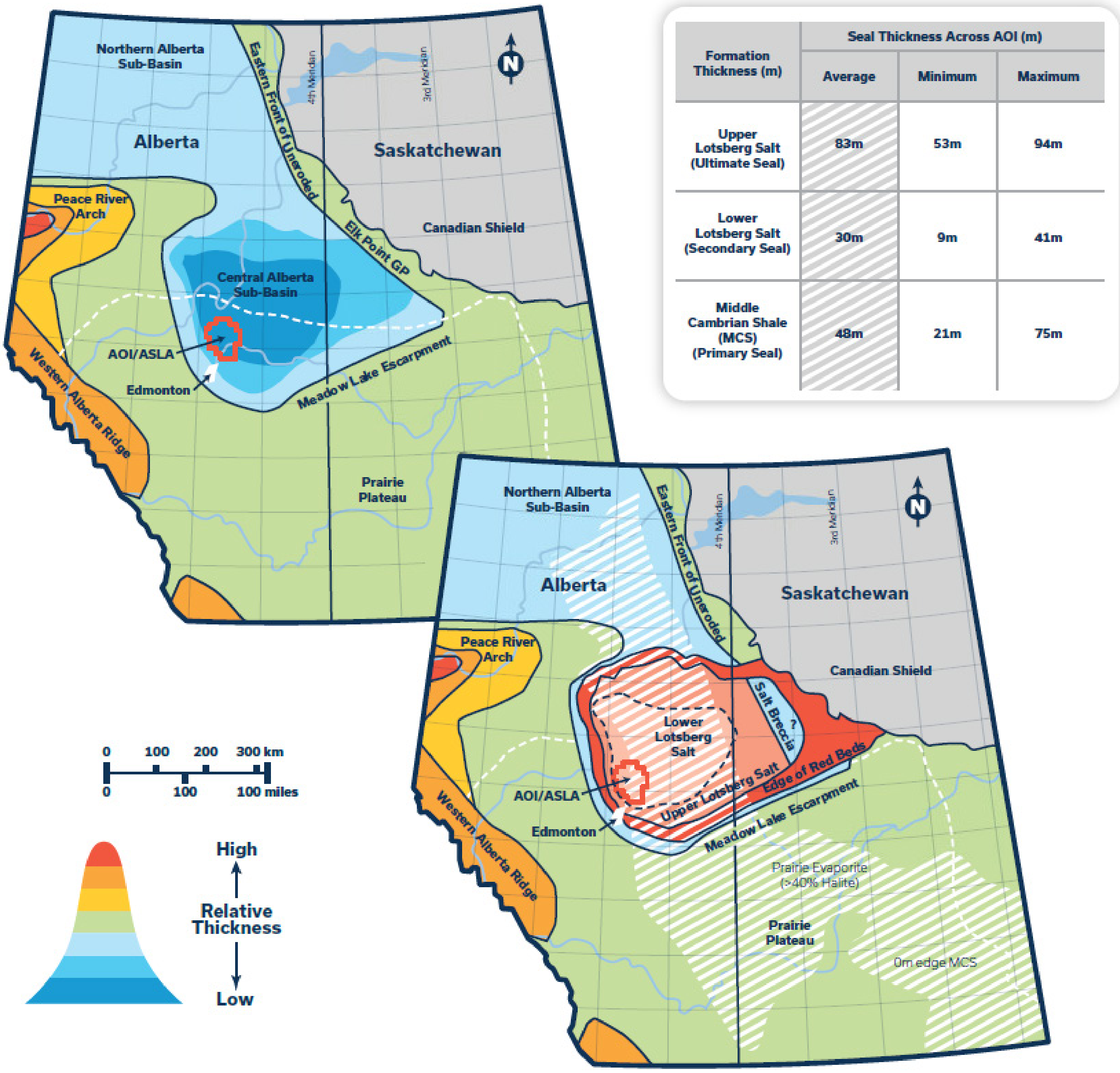


Figure 1.3: Thickness map of the storage reservoir Basal Cambrian Sands, showing legacy and injection wells in AOI [1].



Formation Thickness (m)	Seal Thickness Across AOI (m)		
	Average	Minimum	Maximum
Upper Lotsberg Salt (Ultimate Seal)	83m	53m	94m
Lower Lotsberg Salt (Secondary Seal)	30m	9m	41m
Middle Cambrian Shale (MCS) (Primary Seal)	48m	21m	75m

Figure 1.4: Regional extent of the Middle Cambrian Shale, the Lower and Upper Lotsberg Salts, and the Prairie Evaporites[1].

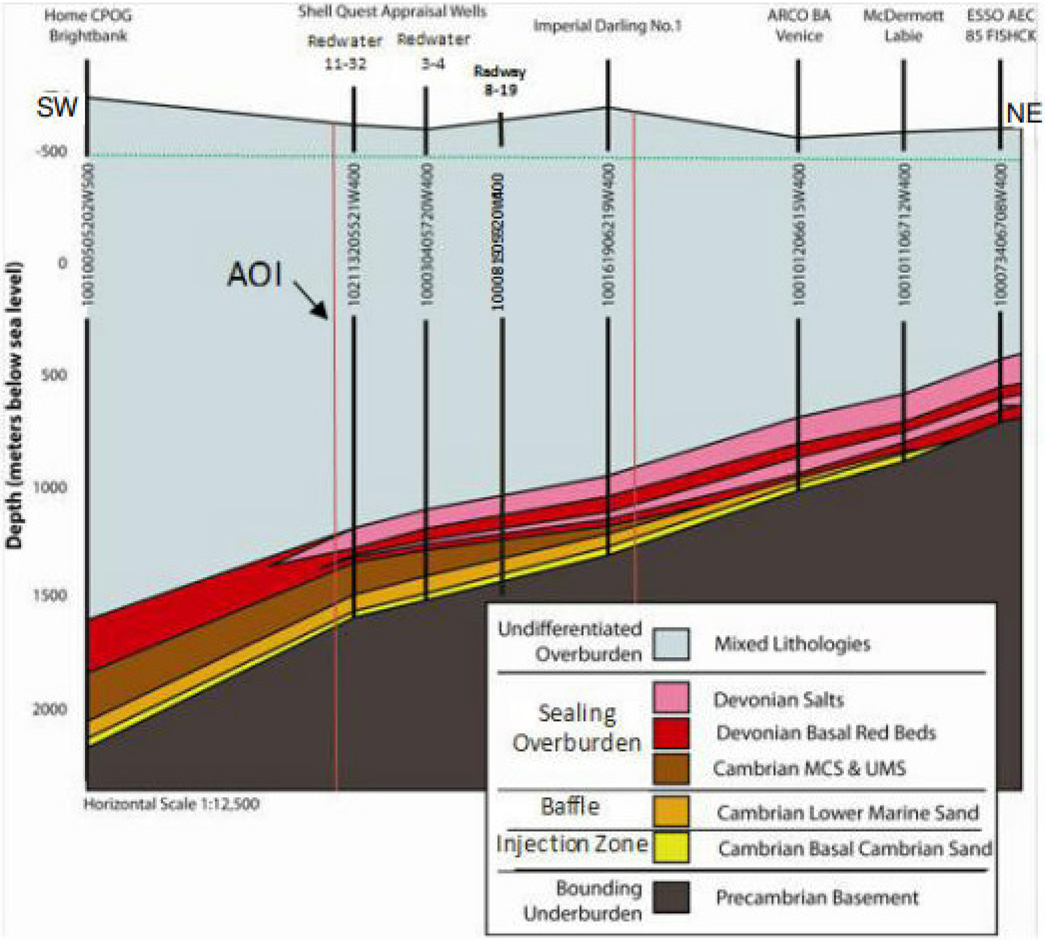


Figure 1.5: Cross-section of the Western Canada Sedimentary Basin showing the BCS Storage Complex [5].

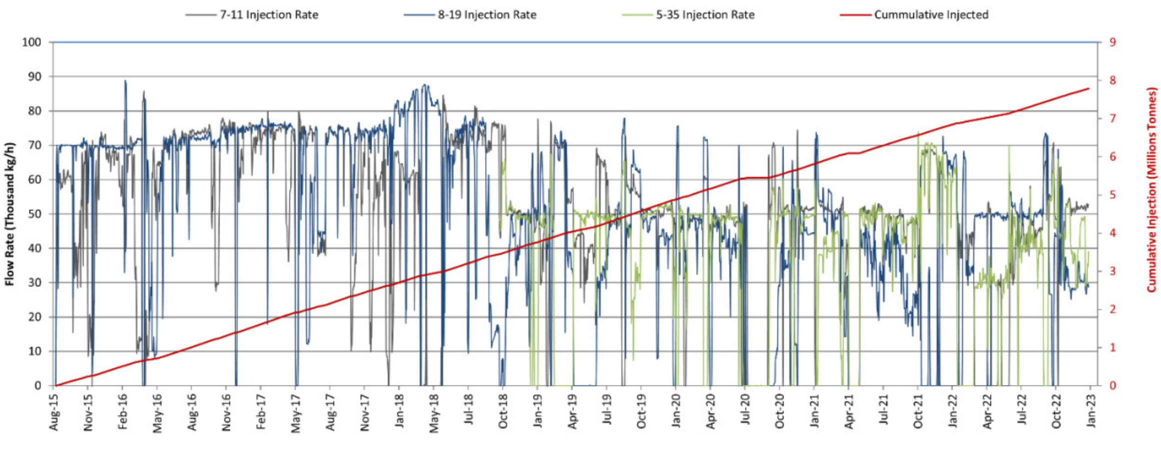


Figure 1.6: Cumulative Quest injection volumes in million tonnes of CO_2 permanently stored. Cumulative CO_2 injected into the wells from the start-up through to the end of the 2022 (red). The blue, grey and green lines show the average hourly flow rates into each of the injection wells[7] .

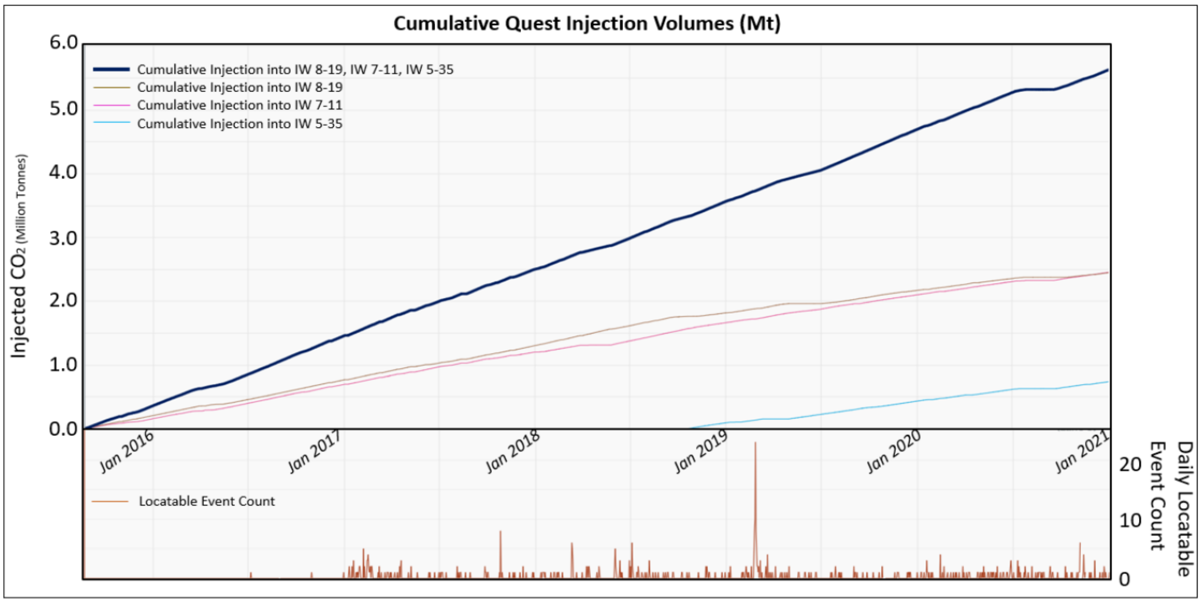


Figure 1.7: The dark blue line shows the total volume of injected CO_2 for all three wells. IW 8-19 and IW 7-11 have injected the same volume of CO_2, IW 5-35 came online in November 2018 and is represented by the blue line. Locatable events in the Precambrian basement are plotted in brown along the same time scale. ~120 events are located each year in the basement starting in 2017 [7].

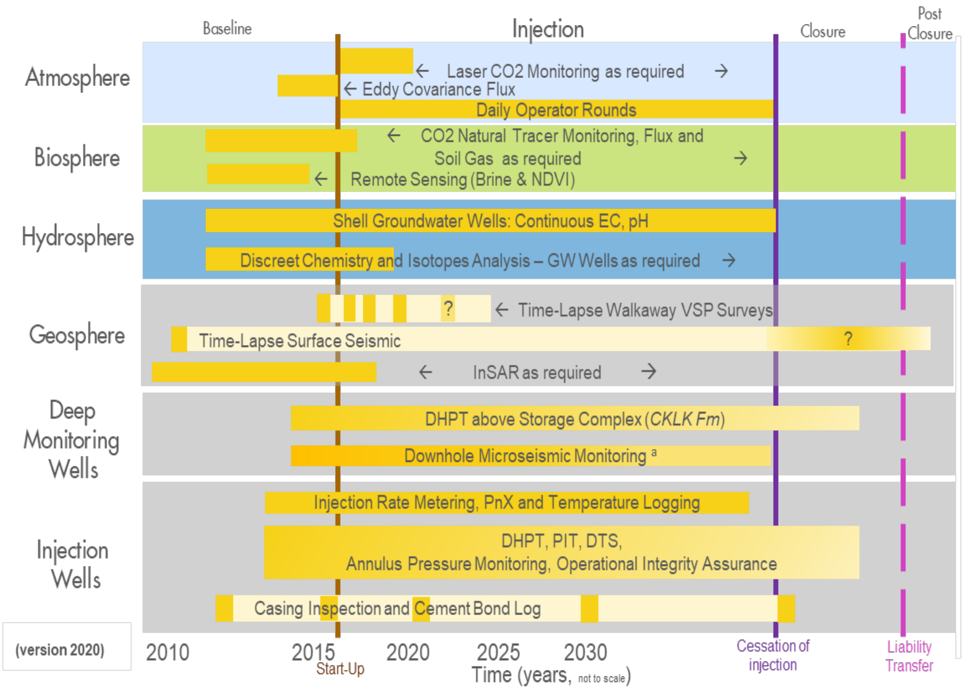


Figure 1.8: 2020 MMV planning pre-injection to post-closure[11] .

2. Weyburn

Site Details					
Name	Location	Province/State	Country	Onshore	Offshore
Weyburn		Southeastern Saskatchewan	Canada	✓	

General storage type
Depleted Oil & Gas Reservoir

Development History (Active operation)

The IEAGHG Weyburn CO_2 Monitoring and Storage Project (Weyburn Project) was initiated to study the potential for geological storage of CO_2 in a depleting oil field (Figure 2.1)[1]. Part funded by industry and government sponsors with ~$40 million, and matched by in-kind contributions by research organisations.

After 10 years of planning, CO_2 injection into the Weyburn Oil Field, southeastern Saskatchewan began in the autumn of 2000 as part of an EOR effort (Figure 2.2). Oil production has been increased by 60% as the life of the 50 year old field has been extended.

CO_2 injection in the adjacent Midale Oil Field commenced in September 2005. Pilot tests of CO_2 flooding had taken place in 1984-1989 and a demonstration project in 1992-1999.

The source of CO_2 is from the Great Plains Synfuel Plant near Beulah, North Dakota which produces 13,000 tonnes of CO_2 daily as a by-product of lignite gasification with 60% suitable for EOR operations. The CO_2 is piped 323 km north across the border to Weyburn and Midale[2].

Prior to CO_2 injection, phase one comprised a research program to investigate methods of monitoring the movement of CO_2 in the subsurface. Over 50 projects were initiated, organised into four themes, and completed in 2004[2]:

- Geological characterisation
- Prediction, monitoring and verification of CO_2 movements
- CO_2 storage capacity and distribution predications and application of economic limits
- Long-term risk assessment of the storage site.

A subsequent final phase, ran from 2004 to 2011, the IEAGHG Weyburn-Midale CO_2 monitoring and storage project, and aimed to build on phase one. The themes are both technical and non-technical and are (Figure 2.3)[2]:

- Geological integrity
- Wellbore integrity
- Monitoring methods
- Risk assessment
- Regulatory studies
- Public outreach and communication

1 Whittaker, S.G., 2005. Geological characterization of the Weyburn Field for geological storage of CO_2: Summary of Phase I Results of the IEA GHG Weyburn CO_2 Monitoring and Storage Project. Summary of Investigations, 1(6).
2 Whittaker, S., Rostron, B., Hawkes, C., Gardner, C., White, D., Johnson, J., Chalaturnyk, R. and Seeburger, D., 2011. A decade of CO_2 injection into depleting oil fields: monitoring and research activities of the IEA GHG Weyburn-Midale CO_2 Monitoring and Storage Project. Energy Procedia, 4, pp.6069-6076.

The outcome is a best practice manual on the transition of CO_2-EOR facility into dedicated carbon storage sites. In an effort to influence regulations, there was the development of an effective public consultation process and the development of effective public policy. In January 2011, a local farmer reported high levels of CO_2 in their groundwater and soil and feared that it was the result of a leak. Cenovus (the Weyburn operator) and the International Performance Assessment Centre for Geologic Storage of CO_2 (IPAC-CO_2) both initiated studies to investigate. Conclusions were that CO_2 is not leaking from Weyburn [3, 4].	
Geological Characteristics.	
Reservoir Formation	
Midale beds of the Mississippian Charles Formation, located at a depth of 1,450m[5]. Consists of two members a lower 'vuggy' limestone – with high porosity and out of which most oil have been produced prior to CO_2 flooding, and an upper 'marly' dolostone – into which CO_2 is being injected to access residual oil (Figure 2.4) [1].	
Lateral extent / thickness variation	Average depth of 1.5 km. Thin layer <30m of fractured carbonates[5], Lower Unit average 15 m thick and Upper Unit is on average 6 m thick[1]. The Midale beds pinch out to the north of the study area below a regionally extensive sub-Mesozoic unconformity (Figure 2.5).
Rock type	Comprised of a lower 'vuggy' limestone and overlying upper 'marly' dolostone[5].
Sedimentary features: Depositional Environment / facies type & variation / mineral composition	Carbonate-evaporite cycle of deposition in a shallow peritidal environment[2]. Vuggy member contains porous grainstones developed along a carbonate shoal which form good-reservoir, and low porosity mudstones, interpreted as inter-shoal deposits that are of poor reservoir quality[1].
Porosity /	Vuggy zone (10%) Marly zone (29%)
Permeability	Vuggy zone (50 mD) Marly zone (average 10 mD)
Formation fluid properties: (residual hydrocarbons / salinity concentration).	Low flow velocities (<1m/yr) and mainly horizontally orientated flow. See Figure 2.6 for formation fluid pH and alkalinity.

3 https://www.nrdc.org/experts/briana-mordick/investigations-find-no-evidence-leaks-weyburn
4 Gilfillan, S.M., Sherk, G.W., Poreda, R.J. and Haszeldine, R.S., 2017. Using noble gas fingerprints at the Kerr Farm to assess CO_2 leakage allegations linked to the Weyburn-Midale CO_2 monitoring and storage project. International Journal of Greenhouse Gas Control, 63, pp.215-225.
5 White, D., 2009. Monitoring CO_2 storage during EOR at the Weyburn-Midale Field. The Leading Edge, 28(7), pp.838-842.

<table>
<tr><td colspan="2">Caprock / primary seal formation</td></tr>
<tr><td colspan="2">Several seal mechanisms are present (and important) for the upper and lower Midale reservoir units and comprise:

Underlying Frobisher Evaporite, overlying Midale Evaporite, and the unconformably overlying Lower Watrous Member (see Figure 2.5 for regional cross section). Diagenetically altered units also inhibit porosity and form part of the trapping story[1]. Additionally, an anhydrite layer, the Oubre Evaporite, occurs in the Radcliffe Beds above the Midale is also important within the storage complex (Figure 2.5)[2].

The Lower Watrous separate a deep hydrological system including the Midale Beds from intermediate and shallow hydrological systems. These intermediate and shallow systems are much less saline and have higher permeabilities and faster flowing formation waters that the deep system. There is no evidence of flow across the Lower Watrous Member – thus the Midale Beds are hydrologically isolated from shallower strata [1, 6].</td></tr>
<tr><td>Lateral extent / thickness variation</td><td>Midale Evaporites are 2-11 m thick[5].
The Sub-Mesozoic unconformity and overlying Lower Watrous are a significant regional event.</td></tr>
<tr><td>Rock type</td><td>Dense anhydrite layer (Midale Evaporite) and diagenetically altered carbonates of Midale Carbonates[1].

Anhydritic siltstones (red beds) of the Lower Watrous Member are an important seal in trapping hydrocarbons in other parts of the norther Williston Basin[1].</td></tr>
<tr><td>Fracture pressure</td><td>n/a</td></tr>
<tr><td>Porosity</td><td>n/a</td></tr>
<tr><td>Permeability</td><td>n/a</td></tr>
<tr><td colspan="2">Overburden Features (Thickness, formations presence of secondary reservoirs / seals)</td></tr>
<tr><td colspan="2">Presence of a potable aquifer: see Figure 2.7 for aquifers and overburden.</td></tr>
<tr><td colspan="2">Structure
Large-scale regional fractures and faults are present in the larger region, most faults observed are mainly localized disturbances without recognizable offset. Regionally extensive faults in the vicinity of the Weyburn Pool also exhibit limited offset and have not compromised hydrocarbon retention. Faults are considered to be closed[1].

Figure 2.5 shows a regional N-S cross section showing dipping strata of the Midale Units and regional unconformities, with overlying units above the angular unconformity [1].</td></tr>
<tr><td>Fold type / fault bounded</td><td>n/a</td></tr>
</table>

6 White, D.J., 2011. Geophysical monitoring of the Weyburn CO_2 flood: Results during 10 years of injection. Energy Procedia, 4, pp.3628-3635.

Faults /Fractures (Type – normal, reverse, strike-slip)	The dominant fracture set within the reservoir strikes NE-SW subparallel to the regional trajectories of maximum horizontal stress[5]. Souris Valley Fault transects the study area (Figure 2.7).
Displacement	n/a
Stability (pre-stressed, active, stable)	The vertical stress at reservoir level due to lithostatic load is ~34 MPa and the minimum horizontal stress is ~18-22 MPa[7].
Injection / storage history	
Number of injection, monitoring or other wells, well geometry, design and key completion information for injection wells, relevant well issues. Reused / new purpose drilled well.	
Over 100 injection wells at Weyburn, with 17 wells injecting CO_2 only with the remaining alternating CO_2 and water[2]. There are over 4,000 wells over the Weyburn-Midale region that penetrate the reservoir level[2]. Implementation of CO_2 storage requires an understanding of the hydraulic properties of the wellbores, their response to CO_2 exposure, appropriate tools for monitoring their performance, and knowledge of appropriate remediation options[8]. Phase II planned a downhole testing program (Oct 2010). 1/3 of wells are pre-1975 vertical wells, another 1/3 are horizontal wells, both of which have higher leakage risks mainly because of cementing issues. A database of wells has been produced including parameters most likely to affect long-term wellbore integrity [2,8]. In an effort to better understand the effect of wellbores on the long-term security of CO_2 storage reservoirs, a literature review was conducted to determine what factors significantly impact wellbore integrity and if these factors may be used to predict wellbore failure. The overwhelming message from this literature review is that cement integrity is the most important indicator of wellbore integrity. Recent laboratory results show that CO_2 attack on the porosity of the cement is unlikely to cause significant wellbore failure in well cemented wellbores using cements with relatively low porosities or water-to-cement ratios[8].	
Extent and status of casing (corrosion history/ cementation records)	Main issues of wellbore integrity include cement placement, de-bonding between casing and wall rock, and channelling[2].
Injection rates & pattern (i.e. continuous / intermittent) changes in injection behaviour	(2011) 2.4 Mt and 0.4 Mt CO_2/yr are being stored in Weyburn and Midale fields[1]. Daily rates of injection at Weyburn are (2011) 6,500 t/d of new CO_2 and 6,500 t/d recycled (Figure 2.9)[2].

7 White, D.J. and Johnson, J.W., 2009. Integrated geophysical and geochemical research programs of the IEA GHG Weyburn-Midale CO_2 monitoring and storage project. Energy Procedia, 1(1), pp.2349-2356.
8 Hawkes, C., Gardner, C., Watson, T. and Chalaturnyk, R., 2011. Overview of wellbore integrity research for the IEA GHG Weyburn-Midale CO_2 Monitoring and Storage Project. Energy Procedia, 4, pp.5430-5437.

Total quantities stored	Estimated that 23 Mt of CO_2 will remain in the reservoir at the expected end of EOR operations in 2033[1].
Reservoir capacity (estimate)	Estimated that 55 Mt could be stored if CO_2 injection continued beyond EOR [1].
Fluid extraction rate (brine extraction, oil for EOR)	
Seismicity	
Monitoring regime (technologies deployed)	
Passive seismic monitoring: an array of eight triaxial geophones cemented in a vertical well within 50 m of a vertical CO_2 injection well. Background seismicity was recorded between August 2003 and January 2004, prior to the start of CO_2 injection in the adjacent well[5]. Approximately 100 locatable micro-seismic events have been recorded at ranges of up to 500 m with moment magnitudes of -3 to -1. Majority are low-frequency, dominant wavelength 165-275 m for assumed P-wave velocities between 3,300 -5,500 m/s. Highest frequency events are close to the injector and the observation well, consistent with rock-dispersion effects[5].	
Seismic events (Detection / magnitude / attribution (natural induced).	
Figure 2.8 – shows micro-seismicity over a 12 month period, CO_2 injection started in January 2004 resulting in associated micro-seismicity. Periods of not recording are noted, unfortunately during the high injection rate phase[5].	
Overall the rate of seismicity is very low within the reservoir indicating the reservoir is not undergoing significant geomechanical deformation or that it is doing so in a ductile manner[2].	
Monitoring technologies applied and experiences with monitoring;	
Surface monitoring technologies deployed	
3D Seismic	3D three-component, time-lapse seismic data have been acquired over part of the EnCana Weyburn Field in 1999 (baseline), 2001, 2002, 2004 and 2007 (monitor surveys I-IV) to monitor the CO_2 flood[5]. Reservoir when viewed in plan view show clear amplitude differences and the effects of CO_2 injection and oil production are clearly visible (Figure 2.10)[5]. Generally good agreement between injection volumes and areal extent and/or intensity of the anomaly. Except in the northern area where vertical CO_2 injection wells are used[5]. Even though large volumes of CO_2 have been injected – absence of anomalies may be due to low

	porosities (particularly the Marly unit) and most CO_2 residing in Vuggy unit[5]. Seismic also used to examine caprock integrity by using amplitude-versus-offset-and-azimuth techniques to map anisotropy within the caprock[2] (Figure 2.11).
Surface seismic array	Surface seismic array in 1B area that will further facilitate time-lapse seismic monitoring[7]. Comprises 200 3-component geophones deployed at intervals of 150-200 m on a regular grid [7].
Groundwater sampling surveys	Ten shallow groundwater sampling surveys spanning pre-injection summer 2000 to 2009 and one at Midale in 2006. On approximately 60 different wells, mostly domestic water wells[6]. Most recent (2009) sampled 24 wells used for drinking/domestic purposes within Weyburn operational area and analysed for a range of constituents commonly used to assess water quality. Including major ions, trace elements, DOC (dissolved organic carbon) and TDS[7]. No discernible changes in the quality of groundwater over the duration of the monitoring program[2], although the background water chemistry in the area is shown to be highly variable[6]. Any chemistry changes are attributed to near surface operations[6]. Groundwater samples from the Kerr Farm suspected leakage site (four ground water wells) showed the CO_2 to be derived from biogenic sources, using CO_2 concentration, stable and radioactive carbon isotopes, noble gases and fixed gas relationships[3,4]. All samples met drinking water standards with only a trace amount of hydrocarbon.
Soil gas surveys	Soil gas surveys were conducted during early phase of the project, baseline (2000) and annual monitoring (2001-2005) – with no identifiable changes in composition outside of natural variability [2, 9].

9 Johnson, J.W. and Weyburn Geochemical Research Team, 2011. Geochemical assessment of isolation performance during 10 years of CO_2 EOR at Weyburn. Energy Procedia, 4, pp.3658-3665.

	Soil gas surveys around the Kerr farm showed the CO_2 to be biogenic in origin [3,4].
Subsurface monitoring technologies deployed (well logs)	
Reservoir fluid testing	Sixteen monitoring surveys of produced reservoir fluids will document the compositional evolution of formation brines during first 10 years of flood. A consistent set of 40 to 60 wells are sampled, fluids are analysed for 42 chemical and isotopic parameters. Results used for reaction path modelling and partition phase modelling[2,9,10]. Hydrocarbons also sampled. Efforts at history matching the results with models are being made, with work on characterising fractures and alterations related to CO_2 injection using profilometry of fractures in cores and developing aperture maps to identify preferential flow paths and aperture evolution[2].
Well integrity	Field based downhole testing to evaluate well integrity initiated to re-enter an older well, drilled in 1957, that has been exposed to CO_2 within the Weyburn Field. This well, a former oil producer, is now suspended. Cased-hole logs will be obtained to assess the condition of the casing and cement sheath and to identify intervals at which to perform in situ tests. Pressure transient testing by drilling small slots into the cement sheath and isolating the slots using inflatable packers [2,8].
Electrical resistivity imaging	Electrical sounding methods using metal-cased boreholes as long electrodes for electrical resistivity imaging[2]. Modelling suggests that none of the deployment scenarios considered are likely to produce enough data with adequate signal to noise ratio and sensitivity to

10 Mayer, B., Shevalier, M., Nightingale, M., Kwon, J.S., Johnson, G., Raistrick, M., Hutcheon, I. and Perkins, E., 2013. Tracing the movement and the fate of injected CO_2 at the IEA GHG Weyburn-Midale CO_2 Monitoring and Storage project (Saskatchewan, Canada) using carbon isotope ratios. International Journal of Greenhouse Gas Control, 16, pp.S177-S184.

	allow successful inversion of electrical resistance tomography (ERT) data[11].
3D VSP	3D vertical seismic profile. First acquired in 1999 (pre-CO_2 injection), and the second in 2001 during CO_2 injection). AVO analysis performed on the time-lapse data and P- and S-wave reflectivity attributes[12].
	Tracer injection monitoring
	Cross-well seismic
Geophysical logs	Time-lapse geophysical logs to be acquired (2009) for direct comparison with time-lapse seismic results[7]. Downhole spinner surveys to test preferential flow paths (e.g. fracture systems) that have been postulated from Phase 1 seismic monitoring [7].
Reactive transport experiments	Impact of CO_2-brine-rock interactions on reservoir mineralogy, fluid composition, porosity/permeability and fracture flow is being assessed through laboratory reactive transport experiments, detailed analysis of core samples, and highly resolved characterisation of fracture dynamics[9].
Pressure	Pressure measured at wellheads, and downhole pressure measurements, will be utilized to model pressure effects to the observed seismic anomalies. It will also benefit geomechanical modelling and correlations with microseismicity[7].
Experience summary - effectiveness of techniques (limitations / strengths)	
Initial results of the Risk Assessments indicate that over 98% of the initial CO_2 in place will remain stored for several hundred years.	
Major technical/scientific studies on the site, major learnings, Conformance assessment (history-matching with models, correlation between different monitoring techniques)	
Main learnings from 10+ years of hydrogeological investigations of the site include (i) low flow rates and favourable flow directions indicate Weyburn reservoir is an excellent place to store CO_2; (ii) shallow groundwater monitoring reveals no significant changes in water chemistry; and (iii) co-	

11 Rostron, B. and Whittaker, S., 2011. 10+ years of the IEA-GHG Weyburn-Midale CO_2 monitoring and storage project: Successes and lessons learned from multiple hydrogeological investigations. Energy Procedia, 4, pp.3636-3643.
12 Ahmadi, A.B. and Morozov, I., 2011. Time-Lapse VSP Data Analysis from Weyburn CO_2 Project.

ordination and integration of multiple investigations improved understanding but were challenging to manage [6].

Results from amplitude-versus-offset (AVO) analysis and inversion to prestack P-wave data and applying stochastic inversion methods are[11]:

- Time-lapse P- and S-impedance changes combined with rock physics analysis are inverted to obtain semi-quantitative estimates of pore pressure changes and CO_2 saturation change within the reservoir zone. Maximum pore pressure increases of ~7 MPa are observed, as expected based on fluid flow simulations. Inversion results for CO_2 saturation changes are noisier due to ill-posed nature of the CO_2 inversion[11].
- Integrated reactive transport modelling, facies-based geostatistical methods with a novel Monte Carlo Markov Chain stochastic inversion technique to optimise agreement between observed and predicted storage performance[7]. Integrating seismic and geochemical data-sets to improve site characterisation and dependent predictions of long-term storage performance[11].

Cap rock integrity is examined by examining 3D seismic for potential zones of fracturing and looking at anisotropy which may be fracture related and mapped using amplitude-versus-offset-and-azimuth (AVOA) (Figure 2.11). Map shows area where anisotropy are high and uncertainty low and the associated orientations, only the southern area is deemed reliable and the areas potentially represent zones of vertical fracturing – and potentially target areas for surveillance[11].

History matching of multiple dynamic flow models to seismic data at Weyburn showed that time-lapse seismic can be used to improve CO_2 migration simulation models. This in turn can be used to optimize CO_2-EOR strategies and reduce uncertainty. A new parameterization-based approach to model-data evaluation was used.

Baseline and repeat seismic surveys were conducted in 1999, 2001, 2002, 2004 and 2007 at the Weyburn field. A reference model was provided and permeability and porosity realisations were generated. Combined production and seismic data mismatch could be effectively reduced by up to 80%. Seismic data quality and interpretation is not 'perfect', and models will contain biases related to neglected model uncertainty.

Overall, a new efficient workflow based on CO_2 flood front positions was developed for conditioning multiple models to time-lapse seismic data. This workflow was used to incorporate plume front information into a sector model. Updates of grid-cell permeability and porosity lead to an 80% reduction of the total seismic and production data mismatch at a cost of only 500 simulations[13].

13 'IEAGHG, "Combined Meeting of the IEAGHG Monitoring & Modelling Networks", 2017/05, February, 2017'

List of key publications covering the site

1. Whittaker, S.G., 2005. Geological characterization of the Weyburn Field for geological storage of CO_2: Summary of Phase I Results of the IEA GHG Weyburn CO_2 Monitoring and Storage Project. Summary of Investigations, 1(6).
2. Whittaker, S., Rostron, B., Hawkes, C., Gardner, C., White, D., Johnson, J., Chalaturnyk, R. and Seeburger, D., 2011. A decade of CO_2 injection into depleting oil fields: monitoring and research activities of the IEA GHG Weyburn-Midale CO_2 Monitoring and Storage Project. Energy Procedia, 4, pp.6069-6076.
3. https://www.nrdc.org/experts/briana-mordick/investigations-find-no-evidence-leaks-weyburn
4. Gilfillan, S.M., Sherk, G.W., Poreda, R.J. and Haszeldine, R.S., 2017. Using noble gas fingerprints at the Kerr Farm to assess CO_2 leakage allegations linked to the Weyburn-Midale CO_2 monitoring and storage project. International Journal of Greenhouse Gas Control, 63, pp.215-225.
5. White, D., 2009. Monitoring CO_2 storage during EOR at the Weyburn-Midale Field. The Leading Edge, 28(7), pp.838-842.
6. White, D.J., 2011. Geophysical monitoring of the Weyburn CO_2 flood: Results during 10 years of injection. Energy Procedia, 4, pp.3628-3635.
7. White, D.J. and Johnson, J.W., 2009. Integrated geophysical and geochemical research programs of the IEA GHG Weyburn-Midale CO_2 monitoring and storage project. Energy Procedia, 1(1), pp.2349-2356.
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10. Mayer, B., Shevalier, M., Nightingale, M., Kwon, J.S., Johnson, G., Raistrick, M., Hutcheon, I. and Perkins, E., 2013. Tracing the movement and the fate of injected CO2 at the IEA GHG Weyburn-Midale CO_2 Monitoring and Storage project (Saskatchewan, Canada) using carbon isotope ratios. International Journal of Greenhouse Gas Control, 16, pp.S177-S184.
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12. Ahmadi, A.B. and Morozov, I., 2011. Time-Lapse VSP Data Analysis from Weyburn CO_2 Project.
13. 'IEAGHG, "Combined Meeting of the IEAGHG Monitoring & Modelling Networks", 2017/05, February, 2017'

Figures

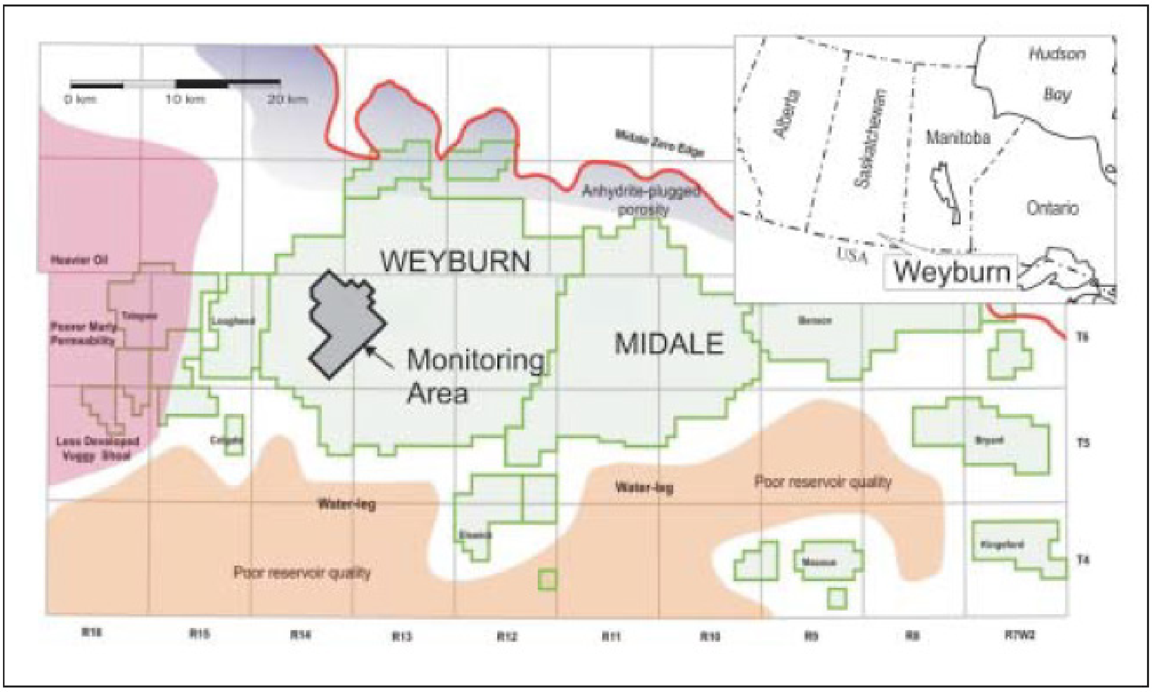

Figure 2.1: Map of Weyburn and Midale and their location in southeastern Saskatchewan. Monitoring area as shown in figures 9-11[5].

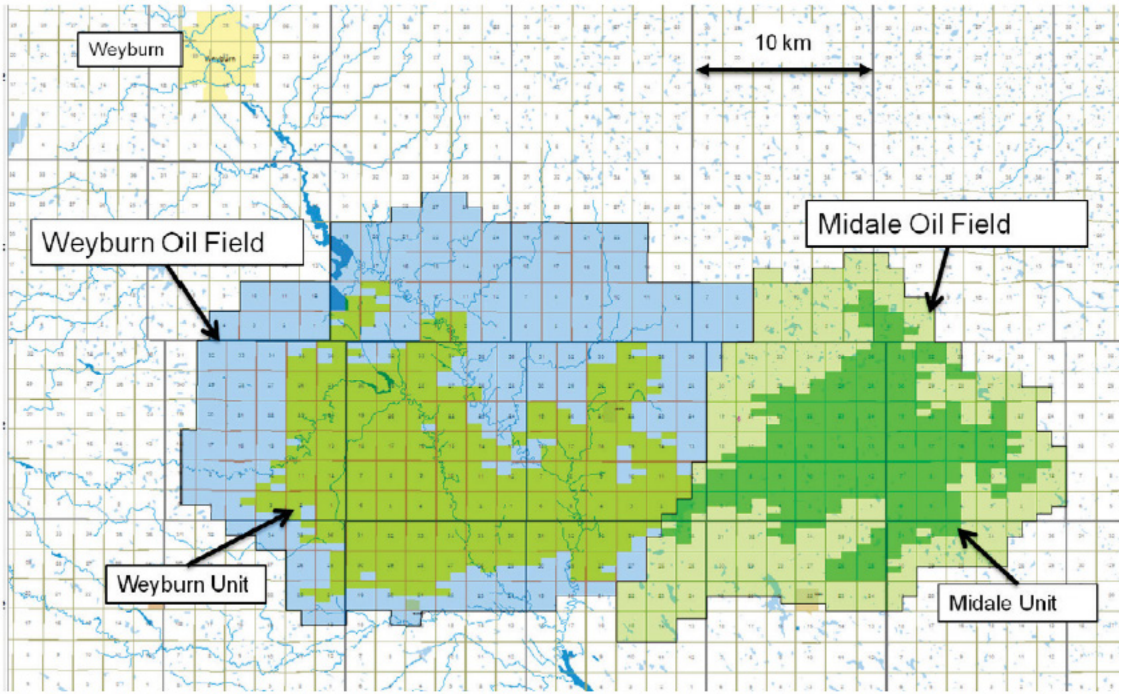

Figure 2.2: Map showing Weyburn and Midale oil fields, the units are operated as a single entity and CO_2 injection and flooding takes place within the unitised areas[2].

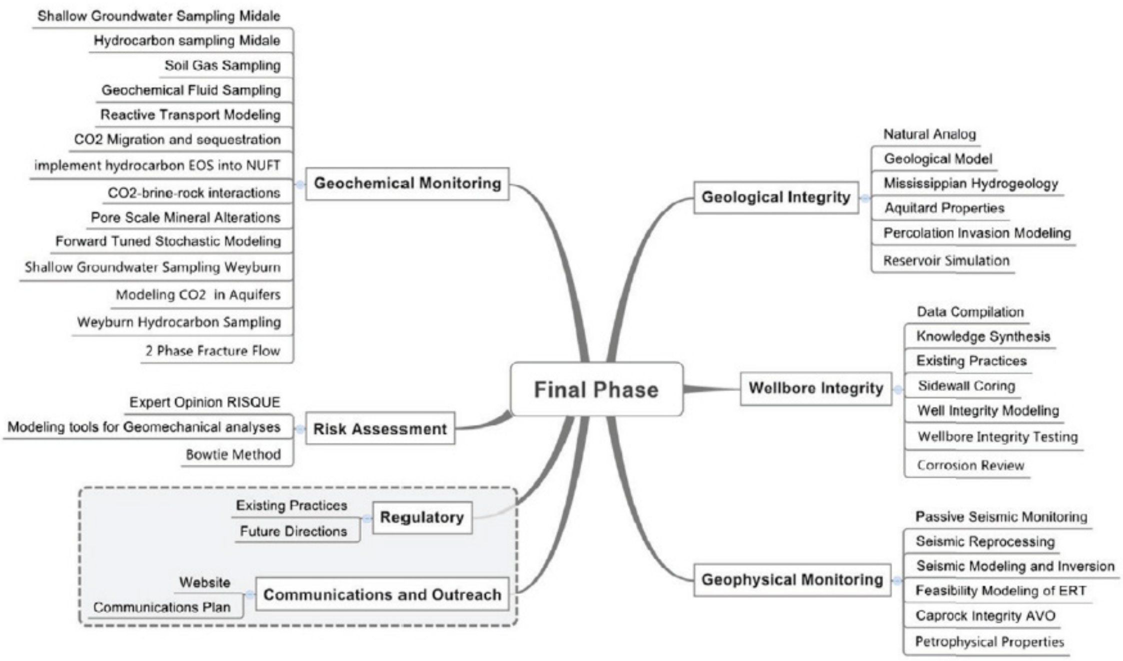

Figure 2.3: Diagram showing relationship between themes and tasks within the IEAGHG Weyburn-Midale CO_2 and Monitoring and Storage Project. The grey box indicates the non-technical components within the project[2].

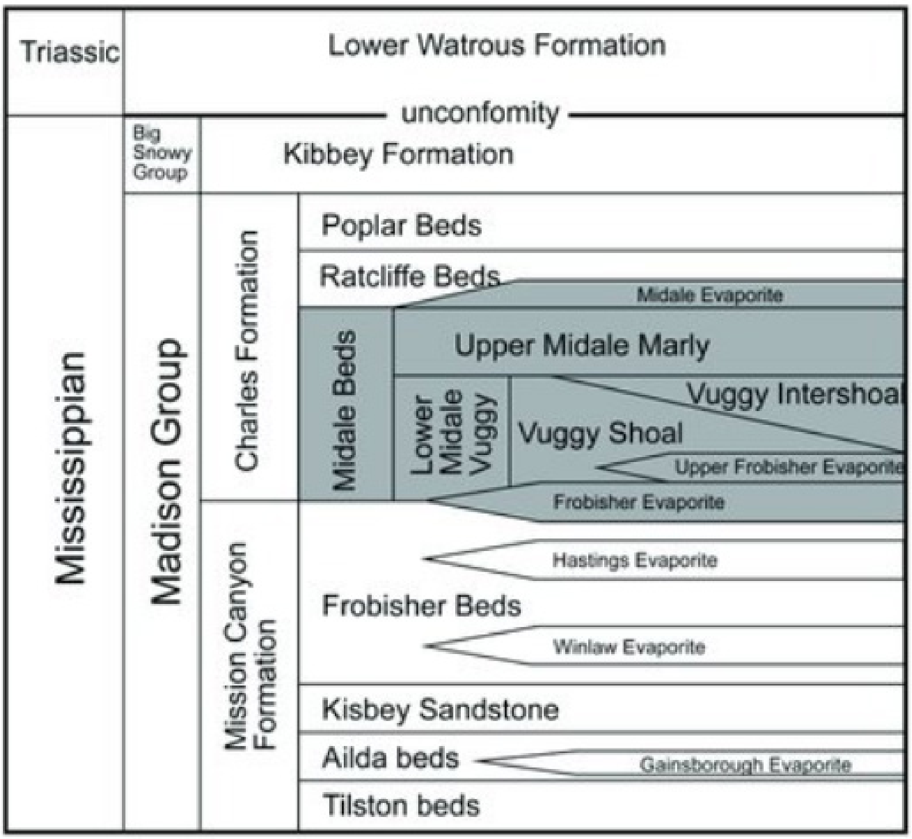

Figure 2.4: Stratigraphic column of the Weyburn Field

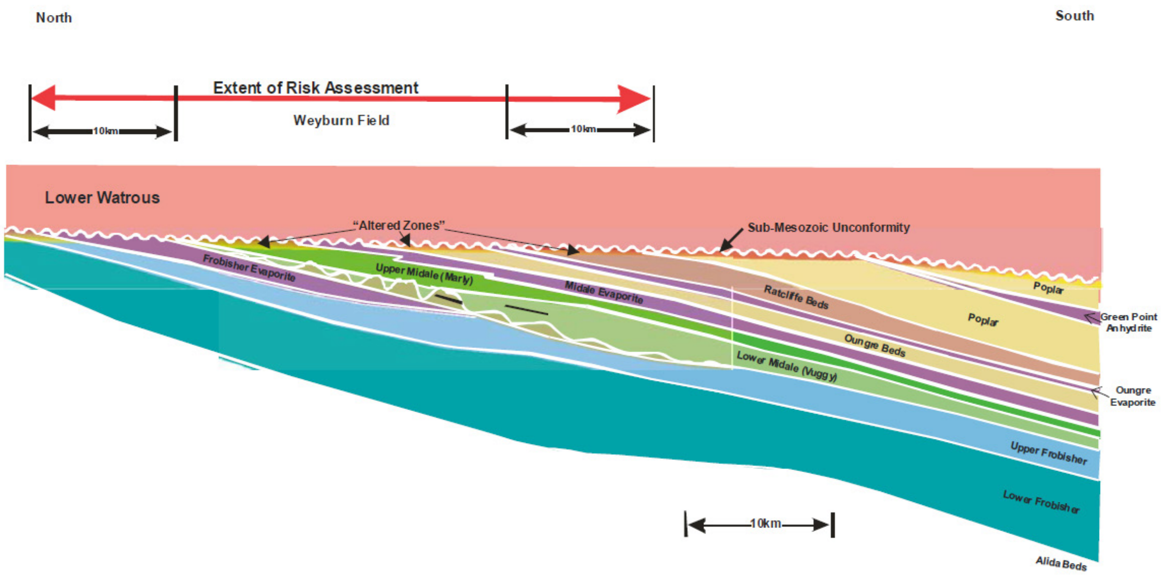

Figure 2.5: North-south cross section through the Weyburn. The section shows the truncation of inclined Mississippian strata at the Sub-Mesozoic Unconformity. The Midale and Frobisher Evaporites (anhydrite units) both act as seals for the porous carbonate Midale reservoir. The Midale Evaporite extends across most of the area. Altered zones, below the unconformity, have diagenetically reduced the porosity through anhydritization and micritization in carbonates. These act as important seals. The Lower Watrous is also an important seal[1].

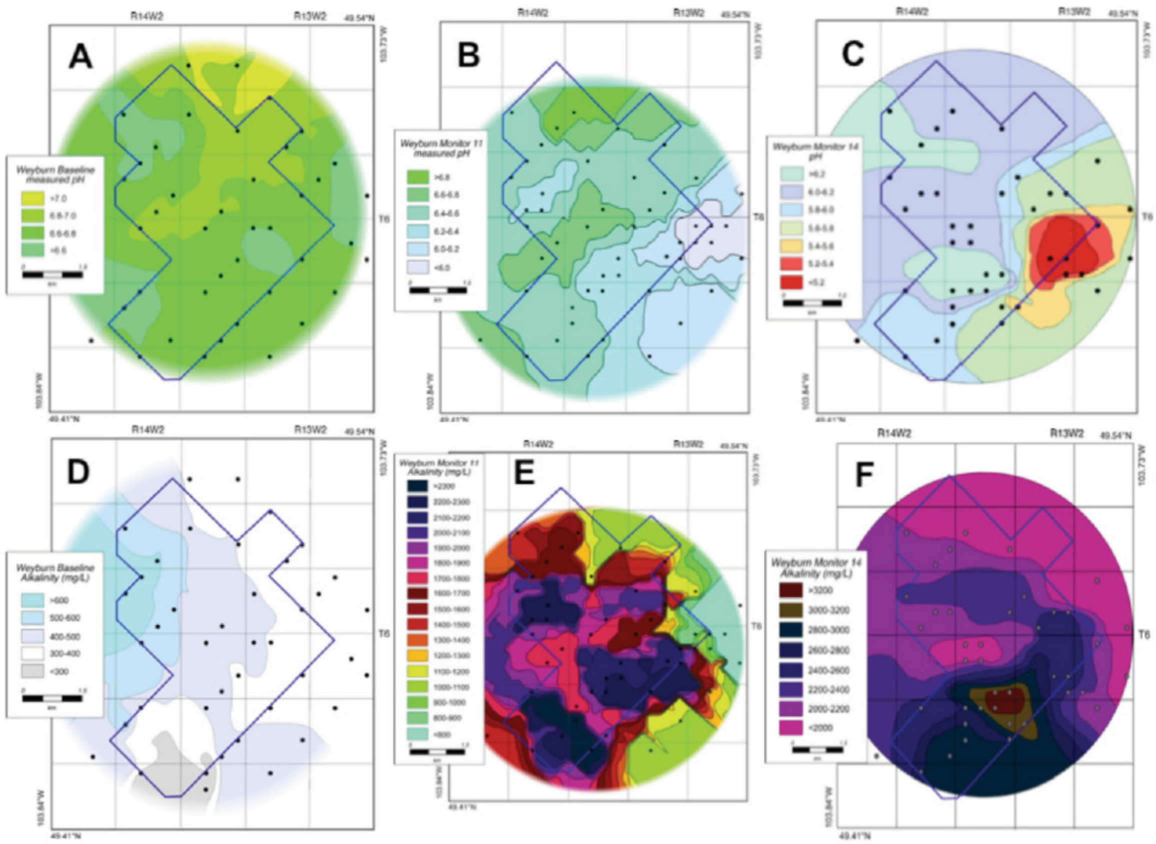

Figure 2.6: Evolution of reservoir pH (A-C) and alkalinity (D-F) within and near the Phase 1A area, primarily due to aqueous solubility and carbonate mineral dissolution during CO_2 EOR. Baseline (August 2000); Monitor 11 (September 2004) and Monitor 14 (October 2009)[9].

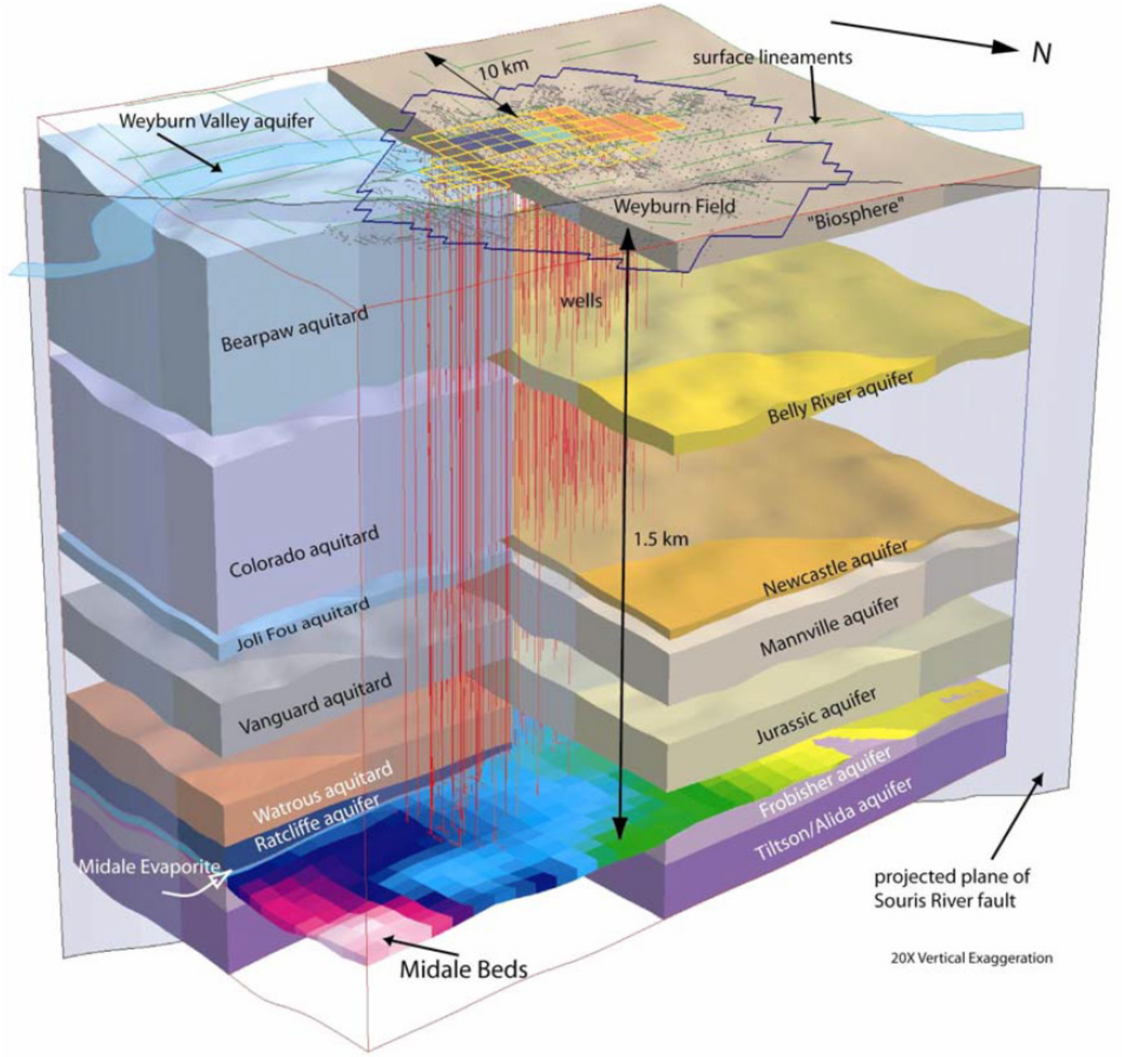

Figure 2.7: Block diagram of the Weyburn Project geological model. The model shows the main hydrostratigraphic units; aquitards (left) and aquifers (right). Yellow grid is the area planned for CO_2 injection. Lineaments as identified from satellite images are shown as green lines. The colour variations in the Midale Beds represent variations in salinity. The plane of the Souris Valley Fault is shown[1].

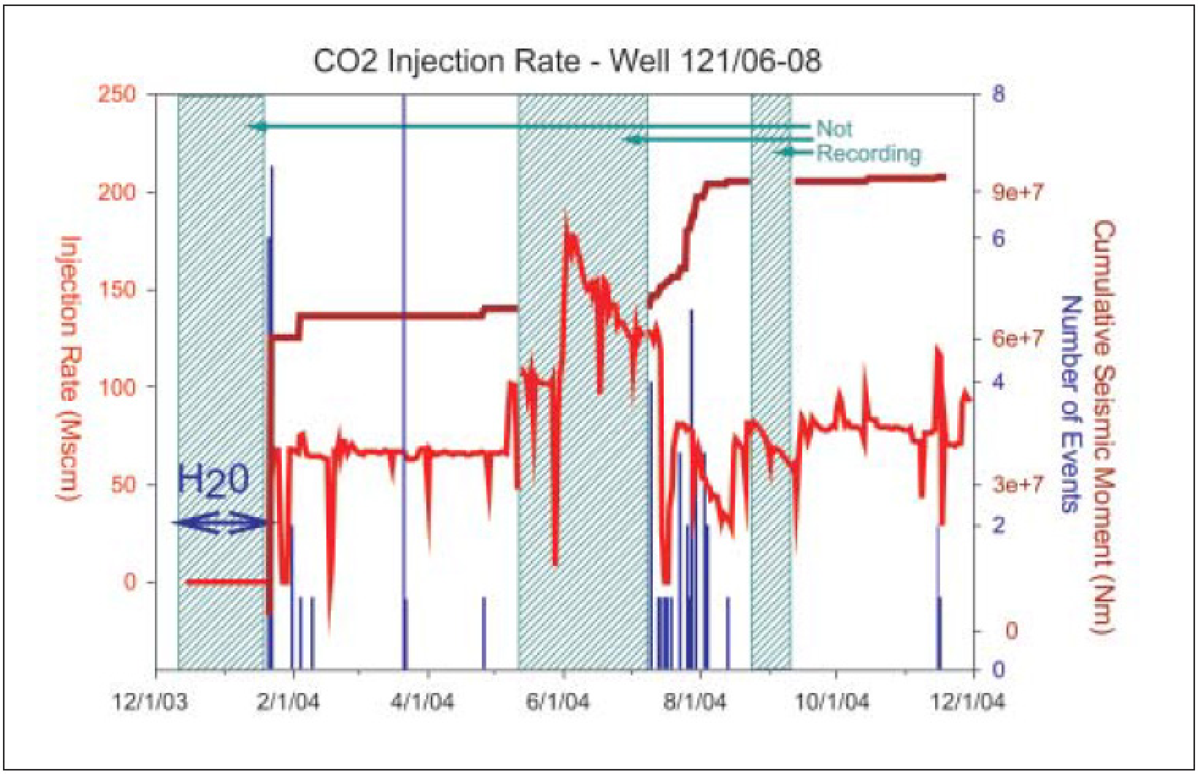

Figure 2.8: CO_2 injection rate, number of seismic events, and cumulative seismic moment versus time for a 12 month period starting 1 December 2003[5].

	Weyburn (Cenovus)	Midale (Apache)
Start of CO_2 injection / duration	2000 / 30 years	2005 / 30 years
Wellhead Injection pressure	10 - 11 MPa	
Daily injection rate of new CO_2 Recycle rate of CO_2 & produced gas Total daily CO_2 injection rate	6,500 tonnes/day 6,500 tonnes/day 13,000 tonnes/day	1,250 tonnes/day 400 tonnes/day 1,650 tonnes/day
Annual amount of new CO_2 injected	2.4 million tonnes	0.46 million tonnes
Total amount of new CO_2 injected to June 2010	16.1 million tonnes	2.11 million tonnes
Incremental / total oil production	18,000 / 28,000 barrels/day	2,600 / 5,700 barrels/day
Projected total incremental oil recovery due to CO_2	155 million barrels	60 million barrels
CO_2 utilization factor	3 - 4 Mcf/b	2.3 Mcf/b
Projected amount of CO_2 geologically stored at project completion	30+ million tonnes (gross)	10+ million tonnes (gross)
Total capital cost of EOR project	CAD $1.3 billion	CAD $475 million

Figure 2.9: Operational parameters related to CO_2 injection at the Weyburn and Midale fields as of 2011[2].

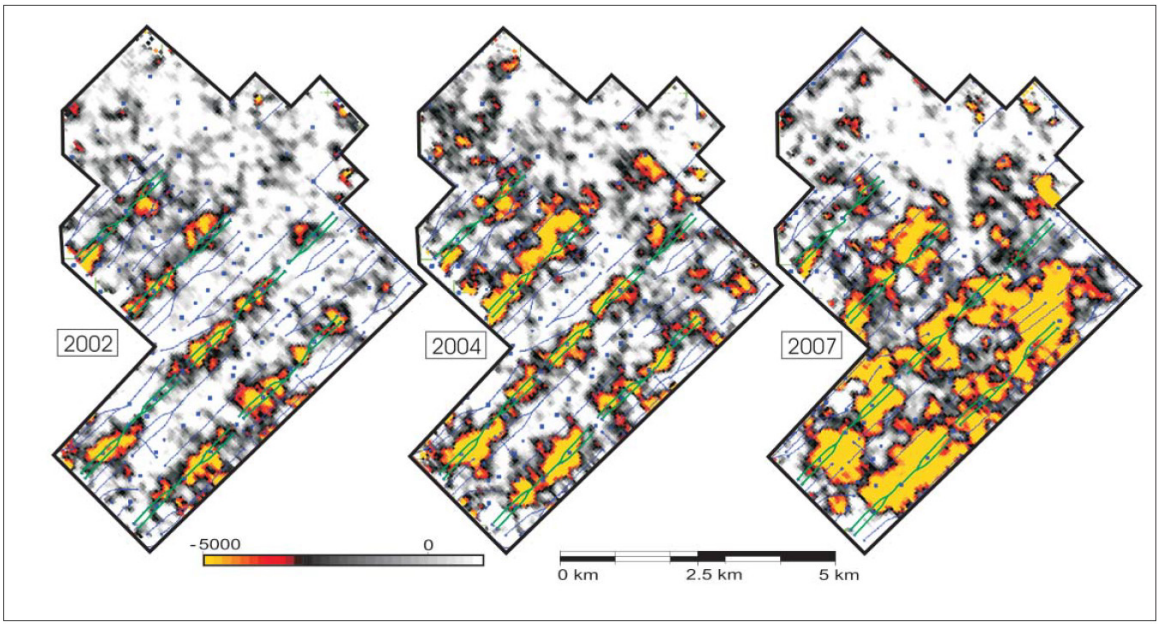

Figure 2.10: Time-lapse amplitude difference maps for the Middle Marly horizon, showing only negative amplitude differences to accentuate CO_2 saturation effects. Dual-leg wells are production (blue) or CO_2 injection (green)[5].

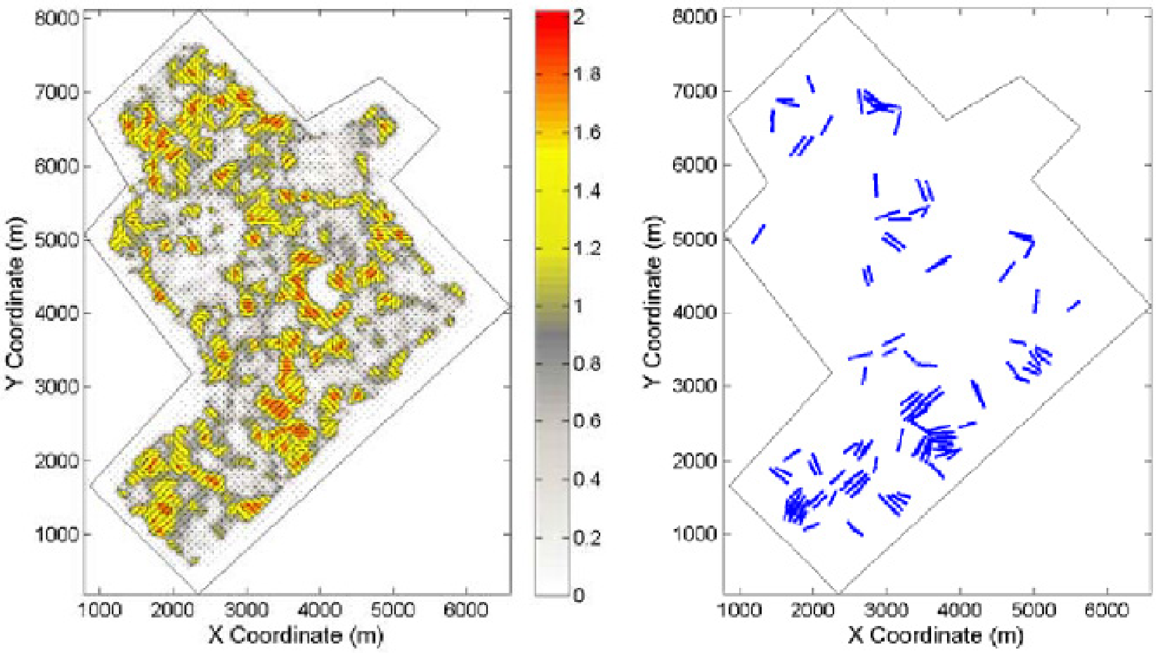

Figure 2.11: Right: normalised near-offset AVOA anisotropy magnitude from amplitude inversion of the cap rock horizon. Left: residual anisotropy vectors for anisotropy with acceptable correlation, uncertainty and above average anisotropy. Only vectors in the southern part of the area are considered as significant zones of anisotropy within the composite caprock[11].

3. Aquistore

Site Details					
Name	Location	Province/State	Country	Onshore	Offshore
Aquistore	near Estevan	Saskatchewan	Canada	✓	

General storage type (Deep Saline Aquifer)

Aquistore is a CCS combined capture & storage demonstration project in south-east Saskatchewan (Figure 3.1 & Figure 3.2). The main reservoir is the Deadwood Formation which lies unconformably on Precambrian basement which is impermeable except for the upper few meters which are heavily weathered (Figure 3.3). Geophysical surveys indicate that the unconformity contact is highly uneven with topographic highs. The geological section above the reservoir formation (which is at a depth of ~3.4 km at this location) is very well characterised partly because of oil & gas development in the area. In addition to the primary seal there is a regionally extensive evaporate seal in the overburden succession (the Prairie Evaporite Formation).

For a general background on the regional geology, hydrology, climate and natural resources more information can be found in a report of a certification framework for a site just north-east of Regina[1].

Development History (Active operation)

Aquistore is supplied CO_2 from the coal-fired Boundary Dam power-plant which is ~3-4 km from the injection site (Figure 3.2). Two wells were drilled in 2011: an injection well & an observation well approximately 150 m away. Injection began in April 2015 but is intermittent as some of the CO_2 is sent for EOR. Aquistore is managed by the Petroleum Technology Research Centre (PTRC) and built upon the learnings of IEAGHG Weyburn-Midale CO_2 monitoring and storage project. SaskPower owns the Aquistore assets (an injection and observation well) as well as the long term liability.

Geological Characteristics.

Reservoir Formation

The CO_2 storage reservoir resides immediately above the Precambrian crystalline basement (3,400 m) and is part of a regionally extensive >200 m-thick clastic interval (Winnipeg and Deadwood formations) (Figure 3.3). There is no evidence of vertical faulting extending through the Devonian or deeper section[2]. The Deadwood Formation is a regionally extensive sandstone of variable grain-size that contains intervals of silty to shaley interbeds[3]. The overlying Winnipeg Formation

1 James E. Houseworth, Curtis M. Oldenburg, Alberto Mazzoldi, Abhishek K. Gupta, Jean-Philippe Nicot, and Steven L. Bryant (2011) Certification Framework - Leakage Risk Assessment for a Potential CO_2 Storage Project in Saskatchewan, Canada LBNL-4915E. https://www.osti.gov/servlets/purl/1048266.
2 D.J. White, C.D. Hawkes, B.J. Rostron (2016) Geological characterization of the Aquistore CO_2 storage site from 3Dseismic data. International Journal of Greenhouse Gas Control 54, 330–344
3 Geological Characterization of the Basal Cambrian System in the Williston Basin. Plains CO_2 Reduction (PCOR) Partnership Phase III. Task 16 – Deliverable D91 2012-EERC-04-19, February 2012

comprises a lower sandstone called the Black Island Member and an upper shale, the Icebox Member, which forms the primary seal to vertical migration of CO_2 [4]. Information on the stratigraphic and depositional history of the Deadwood Formation includes isopach maps of different members of this formation.	
Lateral extent / thickness variation	The approximate thickness of the formation in the Aquistore area is 146 m. It thins to approximately 73 m 50 miles (80 km) to the east and progressively thickens to 270 m 75 miles (120 km) to the west [5]. The Deadwood and overlying Winnipeg Formation >200 m at the Aquistore site. The variable thickness of this unit is attributed to infilling of topographic lows or the surface of the Precambrian basement.
Rock type	The Deadwood Formation is an extensive unit composed of coarse- to fine-grained quartzose and glauconitic sandstone. It is locally conglomeratic at its base.
Sedimentary features: Depositional Environment / facies type & variation / mineral composition	The depositional environments have been interpreted as marine foreshore to shoreline, tidal flat. Conglomeratic intervals are fluvial to alluvial [4].
Porosity / Permeability	Based on core analyses and drill-stem tests from the University of Regina Geothermal well (3-8-17-29W2), the nearest Winnipeg-Deadwood penetration to the proposed injection area, permeability (ca. 100 to 1000 mD) and porosity (ca. 11 to 17 %) indicate good injectivity potential[5]. Initial estimates of horizontal permeability (kH) 2,171 mD/m have been deducted from log analysis[6].
Formation fluid properties: (residual hydrocarbons / salinity concentration).	A previous engineering report that included brine injection into the Winnipeg – Deadwood Formations recorded 2,300 – 7,200 l/min (3,300 – 10,400 m^3/day)[7].

4 Steve Whittaker, Kyle Worth (2011) Aquistore: a fully integrated demonstration of the capture, transportation and geologic storage of CO_2 Energy Procedia 4 5607–5614
5 Anthony Henry Sarnoski (Thesis) January 2015, The Stratigraphy and Depositional History Of The Deadwood Formation, With A Focus On Early Paleozoic Subsidence In The Williston Basin,
6 Si-Yong Lee, Lee Swager, Lawrence Pekot, Mark Piercey, Robert Will, Wade Zaluski (2018) Study of operational dynamic data in Aquistore project International Journal of Greenhouse Gas Control 76, 62–77
7 Ruse, D. (2004). CO_2 Disposal Potential in the Deep Subsurface of Southeast Saskatchewan, Prepared for Helix Geological Consultants, LTD by Cavern Engineering LTD. April 2004.

	Brine salinity in the Regina region is 200,000 – 300,000 mg/L. TDS also increases dramatically towards the centre of the Williston Basin to the south-west of this location[1].
Caprock / primary seal formation	
Lateral extent / thickness variation	The reservoir is capped by a 15 m thick laterally-continuous shale unit (Icebox Member of the Winnipeg Formation). A regional evaporite at ~2,500 m depth (Prairie Formation) provides a secondary barrier to vertical flow. It is >150 m thick and shows no salt dissolution features[2].
Rock type	The primary seal at the Aquistore site is the Icebox Member of the Winnipeg Formation. Previous analysis of this lithology, elsewhere, based on resistivity and neutron porosity measurements revealed very little clay-bound water (0.14 – 0.15)[8]. The Member is therefore dry and brittle and potentially has poor sealing properties, although these conditions may not necessarily occur at Aquistore.
Fracture pressure	n/a
Porosity	n/a
Permeability	n/a
Overburden Features (Thickness, formations presence of secondary seals)	
Above the Prairie Formation are 1,500 m of laterally continuous Middle Devonian to Lower Cretaceous strata and 1,000 m of Upper Cretaceous and younger sedimentary rocks, including additional regionally-extensive aquitards that provide tertiary seals: Watrous Formation (~120 m), Colorado Group (>185 m), and Bearpaw Formation[2].	
Structure	
Fold type / fault bounded	See below
Faults /Fractures (Type – normal, reverse, strike-slip)	A local sub-vertical Precambrian basement fault is interpreted to exist. It lies beneath a flexure within the overlying Cambrian to Silurian strata. The fault is oriented at an azimuth of 75°–85° relative to the regional maximum horizontal stress making it less susceptible to reactivation during CO_2 injection. There is no clear evidence that the strata in an overlying flexure are ruptured or faulted. Natural seismicity in the area is very low and the nearest known significant

8 Schlumberger. 2009. Unpublished report number 09-DC-0047-C, prepared for the Petroleum Technology Research Centre, May 2009

	seismogenic fault zone is located ~200 km away[2].
Displacement	n/a
Stability (pre-stressed, active, stable)	n/a
Injection / storage history	
Number of injection, monitoring or other wells, well geometry, design and key completion information for injection wells, relevant well issues. Reused / new purpose drilled well.	
Injection Well Design (Figure 3.4) [5]. • Well depth 3,39 6m to Deadwood Formation in Estevan area • Surface 13-3/8" casing to ~500 m • Production 7-5/8" casing to ~3300 m • 7-5/8" production casing for operability with 4.5" tubing • 4 sets of perforations at depths 3170-3370 m • Achieves evaluation and injection objectives	
Observation Well (Figure 3.5) [5]. • 9-5/8" casing to ~620 m • 4-1/2" casing to ~3400 m Fluid recovery System P/T Gauges	
Extent and status of casing (corrosion history/ cementation records)	n/a
Injection rates & pattern (i.e. continuous / intermittent) changes in injection behaviour	
Reservoir behaviour observed during injection monitoring Supercritical CO_2 was injected through 4 perforation zones and the rate of flow was monitored to determine the flow pattern into the reservoir [6, 9]. Initial flow rates recorded from a spinner log showed that Perforation Zone (PZ-1) received ~10% of the flow rate, whereas PZ-2 & PZ-3 received 40 – 45% each. A flow rate in 2019 showed virtually all the flow (~91%) going into PZ-2, with a minor amount going into PZ-1. There was no flow into the lower two zones (PZ-3 & PZ-4). These surveys clearly show that injection flow patterns into the reservoir change with time revealing flow dynamics within the reservoir. A pulsed neutron capture (PNC) log shows a reduction in the Σ response which is caused by the displacement of brine by CO_2[10]. There is recent evidence of salt precipitation in the borehole from a camera run in May 2015 after the reservoir saturation tool (RST) log. Salt has a very large SIGM (formation Σ) and PHIC (neutron porosity) response which counters the CO_2 response. If salt is precipitated in the	

9 Aquistore Webinar presented on 12th May 2020 Petroleum Technology Research Centre (PTRC)

10 Martin Kennedy, Tess Dance, Chris Hawkes, Afton Leniuk, Erik Nickel 2018 Interpreting CO_2 Saturation Changes from Pulsed Neutron Logs at the Aquistore Site.. 14th International Conference on Greenhouse Gas Control Technologies, GHGT-14.

formation near the wellbore this increases SIGM and suppresses the measured CO_2 saturation, but should also decrease neutron porosity. The logs show no upward migration of CO_2 and therefore strong evidence for an effective seal [6].

A downhole camera survey post shut-in after 4 months showed salt precipitation in PZ-3. This reflects changes in reservoir dynamics after long shut-in periods (4 months). Data observed at Aquistore has revealed a complex interaction between reservoir temperature & injectivity expressed as the Injectivity Index.

The fracture breakdown pressure for the perforation intervals, inferred from the injection test data and closure pressure analysis, suggests a fracture gradient for the reservoir formation of 0.14 bar/m (0.62 psi/ft); and a formation breakdown pressure of 452 – 464 bar (45.2 – 46.4) MPa[6].

Casing conveyed monitoring systems at Aquistore have been used to assess casing and well integrity. Sensors that are external to the casing have been used to monitor P/T conditions which can track cementation operations during each stage of cementation revealing operational dynamics.

DTS sensors outside the casing can be used to monitor injection pressure to history match with reservoir models. The fluid recovery system (FRS) bubble tube test has also proved to be an effective technique for checking against models.

Reservoir conditions have also been monitored during periodic shut-ins as CO_2 is directed to EOR. This shows successive cooling (during injection) – and warming (during shut-ins). The thermal influence on injectivity through time shows dynamic data. Different logging sequences using different techniques have also been used for comparison revealing similar response.

Reservoir geomechanical modelling under non-isothermal conditions is ongoing.

A reservoir saturation tool was also used to evaluate well integrity and the presence of CO_2 in the wellbore's annular. No CO_2 was detected in the annular or in the formations above the injection zones [6].

The research team are contemplating the level of future monitoring that may be required for the site to determine what might be the minimum requirement to operate the site whilst maintaining compliant operation.

Other research interest includes the use of CO_2 as a thermal carrier in for geothermal energy.

Monitoring CO_2 injection and plume development

A CO_2 and related pressure plume was modelled as part of a previous risk assessment for a potential storage injection well into the Winnipeg – Deadwood Formations near Regina a CO_2. The model predicted a symmetrical plume expansion to over 2 km in ~50 years and a maximum pressure perturbation at a distance of 20 km (12 miles) from the injection well ~1 bar. The maximum pressure difference at 6 km (4 miles) is about 2 bars and drops to about 0.5 bars at 40 km (25 miles) [1]. These observations can only be treated as broadly indicative for Aquistore. Initial models of plume at the site show following trends – 2000 t/day, 1.5 Mt injected produced a plume 4 km in size after 10 years of injection (Figure 3.6) [9].

4D seismic surveys have been conducted at periodic intervals since injection began to monitor the spread of the plume and its expression revealed in processed images (Figure 3.7 & Figure 3.8). The succession of CO_2 migration can also be tied in with CO_2 saturation interpreted from well logs. Most CO_2 is diverted for EOR so injection is intermittent. The following surveys were conducted:

M1 36 kT (Feb 2016)

M2 102 kT (Nov 2016)

M3 141 kT (Mar 2018)

M4 272 kT (Jan 2020)

The 4D RMS amplified difference in the January 2020 survey clearly shows a very clear bright spot (evident in plan-view which also ties in with well logs). It also shows evidence of the plume spreading in a S – SE direction as well as a NW direction influenced by the underlying topography of the Precambrian basement (Figure 3.9) [9].

CO_2 injection began in April 2015. RST formation analysis showed CO_2 breakthrough at the observation well in the Upper Deadwood Formation by February 2016. CO_2 saturation of 39% over a 5.6 m interval (3,233 – 3,233 m) (PZ-2) was recorded. A 30% CO_2 saturation level was also recorded over a much shorter, 0.7m interval, between 3198.6 -3,199.3 m[10].

Total quantities stored	See Figure 3.10 for CO_2 injection scheme over time (up to 2020). 500k tonnes are stored as of February 2023[11]
Reservoir capacity	n/a
Fluid extraction rate (brine extraction, oil for EOR)	n/a

Seismicity

Monitoring regime (technologies deployed)

Site Characterisation: 3D Seismic [12]

Size: 30 km^2
Acquisition: UniQ
Acquired March 2012

Vibroseis source:

- 2 – 100 Hz sweep
- 5 sec record length
- 2 ms sample rate
- 2 ms
- 288 m line interval, 36 m in-line

Receivers

- 288 m line interval, 6 m in-line
- 2411 shots, 18,100 geophones
- Natural bin size: 3m x 18m
- Full fold: 88

11 https://ptrc.ca/media/whats-new/aquistore-co2-storage-project-reached-+500000-tonnes-stored
12 Advanced workshop for CO_2 storage – PPT Gonzalo Zambrano, University of Alberta August 26th, 2014 https://www.slideshare.net/globalccs/monitoring-measuring-and-verification-gonzalo-zambrano-university-of-alberta

• Offset range: 220m to 5388m
Permanent Seismic Array [12] • Active source and passive monitoring • 630 geophones over 6.25 km^2 • 20 m depth • Receiver lines 144 m, in-line 72 m • Baseline dynamite survey: • 260 shots, 1 kg at 15 m depth • Source lines 288 m, in-line 144 m
Seismic events (Detection / magnitude / attribution (natural induced).
A series of seismic events in the magnitude range of 2.2 and 4.0, recorded between 1976 and 2013 have been attributed to industrial activity in southern Saskatchewan, primarily potash mining near Esterhazy (180 km (~112 miles) to the north east) and Saskatoon (~420 km (~261 miles) to the north west)[2]. The largest known earthquake (mb= 5.5) from the area was recorded in 1909. The epicentre has been placed 200 km west of Estevan[13]. This location lies on a trajectory defined by earthquake epicentres that correlate with known fault systems, placing the nearest fault system with associated seismicity 200 km to the west of the storage site. The seismicity in the area has been attributed to reactivation of Precambrian basement faults[14].
Monitoring technologies applied and experiences with monitoring.
Surface monitoring technologies deployed
Baseline Gravity Survey [12] • Accuracy of ≤ 3,5 µGal • A10 surveys are planned at locations adjacent to GPS sites (two times per year).
Site Design for Surface Studies [12] • 49-site regular grid centred on the injection/observation wells (7 x 7=5 x 5 km) • 10-site irregular grid (targets of opportunity – e.g. ash piles) • 9-site background grid on PFRA (Prairie Farm Rehabilitation Administration) land • 12-sites slated for multi-depth probes
Soil Gas Measurement Approach [12] • Soil gas probes at 1.0 m depth at each location (2.0 m depth at multi-depth locations) • Probes leak-checked using helium prior to sampling • Soil gas probes sampled for: He, H_2, CO_2, O_2, N_2, H_2S, C_2, C_2+

13 Bakun, W.H., Stickney, M.C., Rogers, G.C., 2011. The 16 May 1909 Northern Great Plains earthquake. Bull. Seismol. Soc. Am. 101 (6), 3065–3071

14 Horner, R.B., Hasegawa, H.S., 1978. The seismotectonics of southern Saskatchewan. Can. J. Earth Sci. 15, 1341–1355.

• Also sample for stable isotopes: $\delta^{13}C$ of CO_2 and CH_4 and δ^2H of CH_4 • Also sample for ^{14}C of CO_2
Surface CO_2 Flux Measurement Approach [12] • Discrete measurement of surface CO_2 flux, soil temperature and soil moisture for ~15 minutes (N = 5) at each location • Extended measurements (~4 hrs) of surface CO_2 flux at select locations (diurnal measurements in future) • Measurements linked back to long term grassland measurements (Fort Peck, Montana – long term ecological research station).
Continuous Measurements Approach [12] • Continuous measurements (12-minute intervals) of in-situ soil gas CO_2, and soil moisture (1.0 and 2.0 depths) • Soil temperature at 4 depths (0.1, 0.5 1.0, 2.0 m) • Installed November 2012 at site 1-07, site closest to the injection well
Subsurface monitoring technologies deployed (well logs)
Wellbore Evaluation [5] Coring – multiple intervals of reservoir, caprock & seals Logging – Total depth (TD) section • Gamma Ray/ Spontaneous Potential (SP) / Resistivity / Density / Neutron • Sonic Compressional and Dipole Shear • Nuclear Magnetic Resonance • Formation Elemental Analysis • MDT (modular formation dynamics tester) – formation pressure & samples • MDT – minifrac Logging – Cased hole • Ultra sonic cement imager • Pulse Neutron Log (RST) • Spinner Log (Flow Profile)
MMV (Measurement, Monitoring, Verification) Practices & related verification of injected CO_2
MMV Programme [12] • Plume/containment monitoring • Public assurance • Research objectives
Surface-based [12] • Regional 3D seismic survey • Baseline & time-lapse • Permanent seismic array • Electrical/electromagnetic • Gravity • Passive seismic • InSAR • GPS

- Tiltmeters
- Groundwater & soil gas monitoring

Well base [12]

- Real time P&T
- Fluid sampling / tracers
- Time-lapse logging
- DAS/DTS
- Heater cable
- Cross-well seismic & VSP
- Cross-well & surface-to-downhole electrical monitoring
- Gravity
- Passive seismic

Seismic monitoring

There has been consistent seismic monitoring at the site since its inception with no evidence of induced seismicity. In addition to surface monitoring there is a down-hole DAS (fibre optic) sensor system to monitor induced seismicity.

- Minimum detectable magnitude for 3.2 km depth

BB: M_L = -0.8

Array: M_L = 1.6 to -0.6

- Magnitude of completeness (STA/LTA):

BB: M_W – 1.3

Array: M_W = 0.6

Conclusions from seismic monitoring:

- CO_2 plume contained within reservoir
- Vertical distribution of CO_2 in the reservoir illuminated
- Lateral spread of CO_2 is generally consistent with direct detection of CO_2 in the observation well
- Influence of reservoir structure is observed.
- 3D modelling confirms capability of 4D seismic to monitor deep CO_2 distribution
- Ambient noise levels affect 4D sensitivity
- No induced seismicity over first 5 years

There is a structural flexure evident from seismic which transects the reservoir, caprock and extends into the basement but it is not clear if it is a fault. Some fault slip analysis has been conducted to determine whether it could become stressed, cause slip and associated induced seismicity. This feature strikes N – NW and passes close to the injection well.

A geomechanical stress test (mini frac test) has been conducted to determine the horizontal stress. As a result the stress levels in the reservoir are below the threshold levels that could trigger slip on the fault. On this basis slip on the fault is unlikely but seismic monitoring is still monitored for signs of slip. [2,6,15]

Major technical/scientific studies on the site, major learnings, Conformance assessment (history-matching with models, correlation between different monitoring techniques)

Conclusions on Progress May 2020 [9]

Current status of Aquistore

- Premiere publicly funded and owned CCS project in Canada, and among top in the world
- Ongoing real and impactful reductions in industrial emissions
- Direct economic impact with jobs and creation of HQPs
- Real operational results
- The next CCS breakthroughs will only happen if we support existing projects
- 300,000 t CO_2 stored is equivalent to 75,000 cars off the road for one year.

List of key publications covering the site

1. Houseworth J.E., Oldenburg C.M., Mazzoldi A, Gupta A.K., Nicot J-P., and Bryant S.L. (2011) Certification Framework - Leakage Risk Assessment for a Potential CO_2 Storage Project in Saskatchewan, Canada LBNL-4915E. https://www.osti.gov/servlets/purl/1048266.
2. White D.J., Hawkes C.D., Rostron B.J. (2016) Geological characterization of the Aquistore CO_2 storage site from 3D seismic data. International Journal of Greenhouse Gas Control 54, 330–344
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Other relevant information considered pertinent to the report

Aquistore – CO_2 Storage at the World's First Integrated CCS Project Presentation to PTAC's 2013 Managing CO2 Forum. Calgary, October 29 2013 Rock Chalaturnyk (UAlberta) on behalf of Science & Engineering Research Committee (SERC)

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DM Kent & JE Christopher Chapter 27 – Geological History of the Williston Basin and Sweetgrass Arch

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Figures

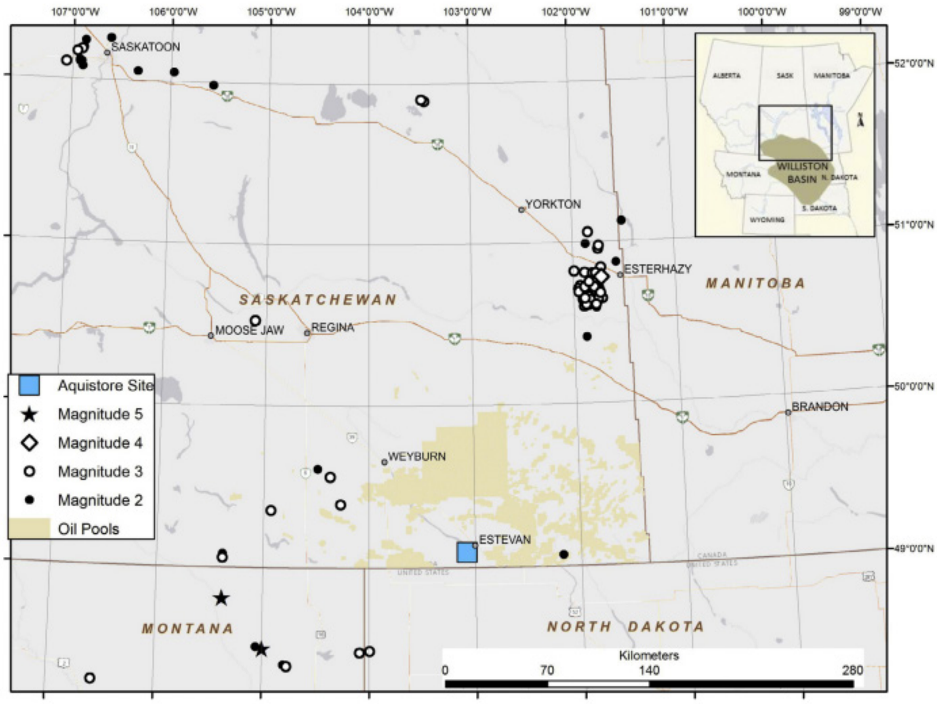


Figure 3.1: Map showing the location of the Aquistore site and the complete set of detected earthquake locations for the period 1900-2014. Inset shows the position of the smaller scale map within central North America [2].

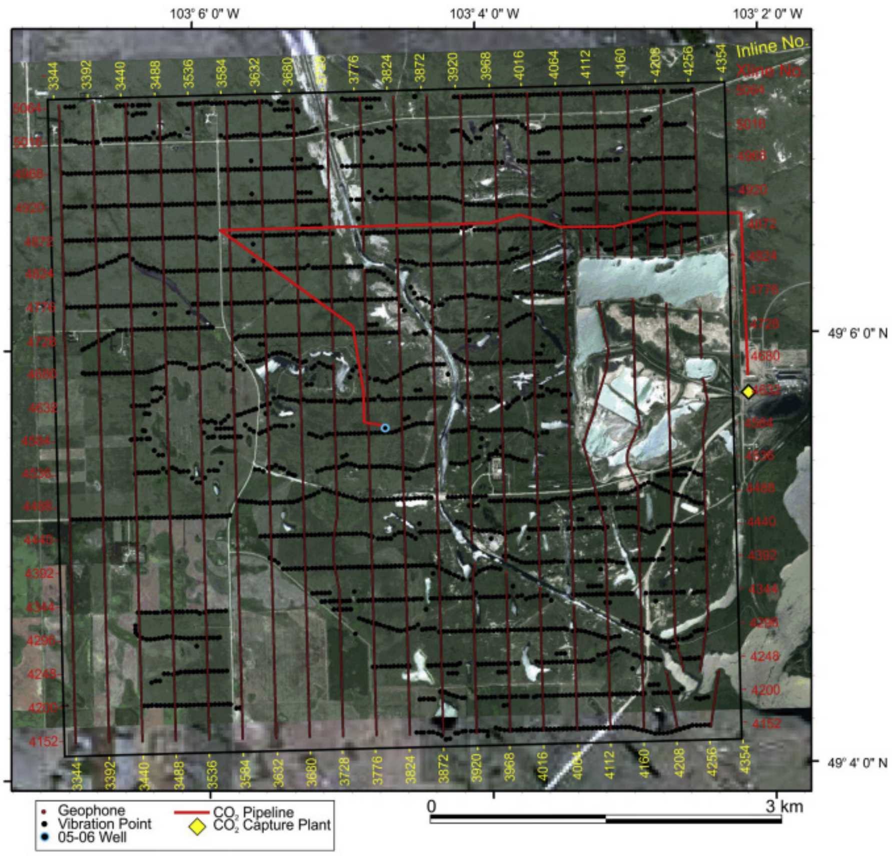


Figure 3.2: Aquistore Project site map showing the location of the Boundary Dam Power Plant, the CO_2 capture facility, and the CO_2 injection well (0/5-6-2-8-W2M well). Also shown is the area of the baseline 3D seismic survey with in-lines (N-S) and cross-lines (E-W) labelled. The survey grid is orientated at 358.5° [2].

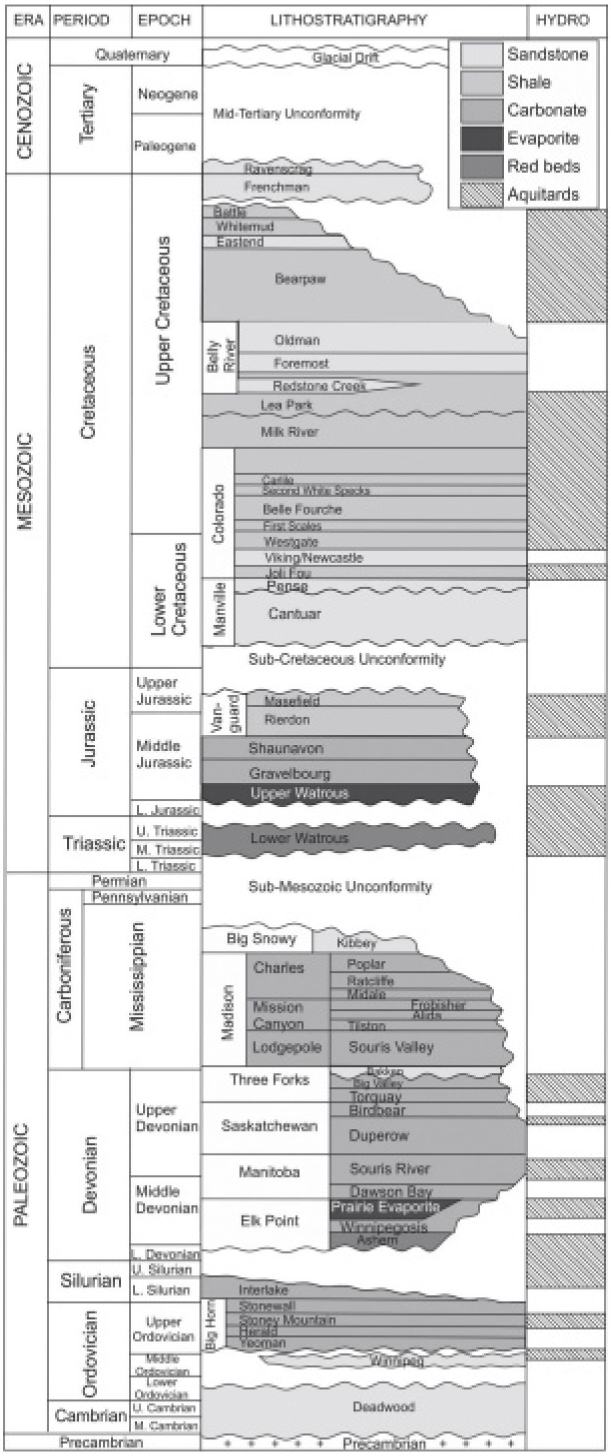


Figure 3.3: Lithostratigraphic section – simplified lithologies and hydrogeological classifications (aquifer or aquitard) are defined in the legend [2].

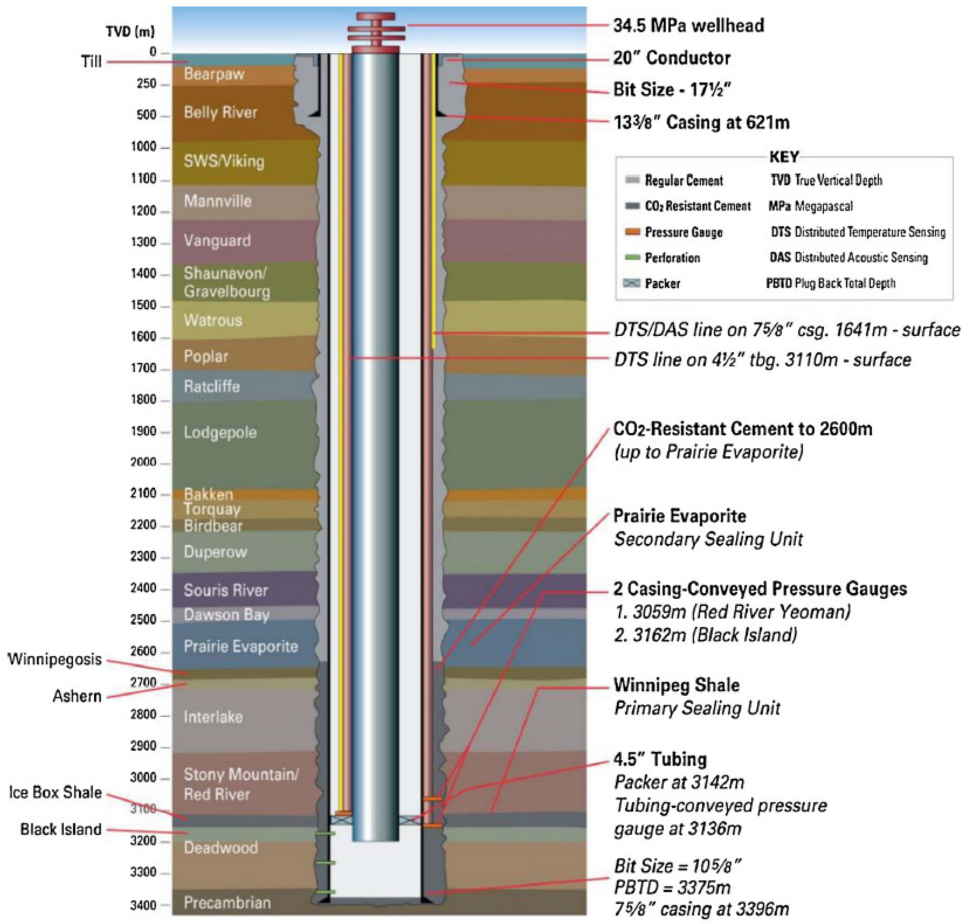


Figure 3.4: Injection well schematic [6].

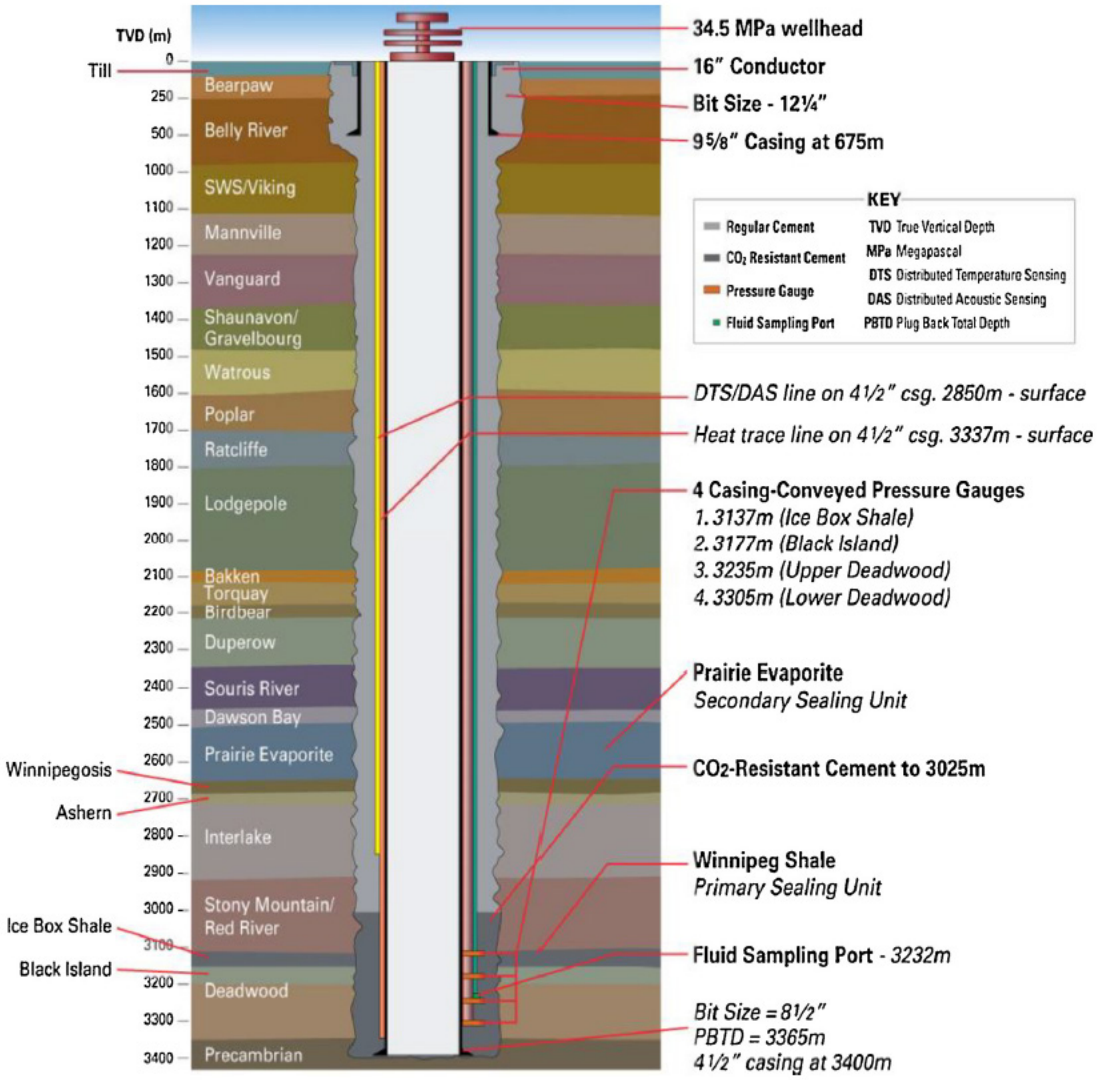


Figure 3.5: Observation well [6].

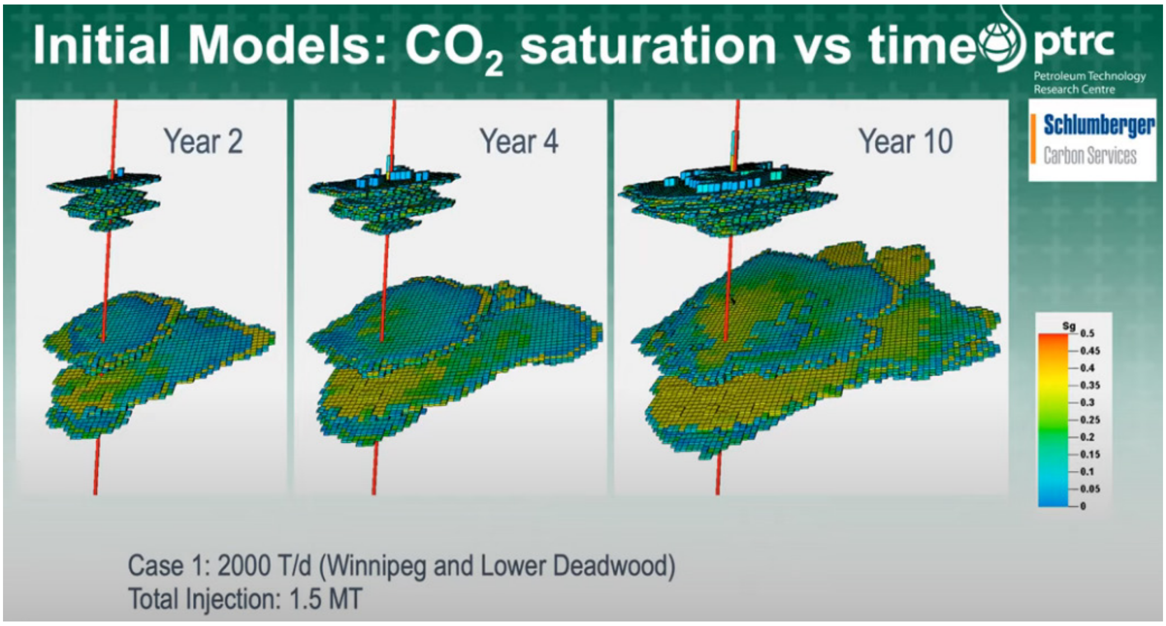


Figure 3.6: Plume modelling CO_2 saturation vs time [9].

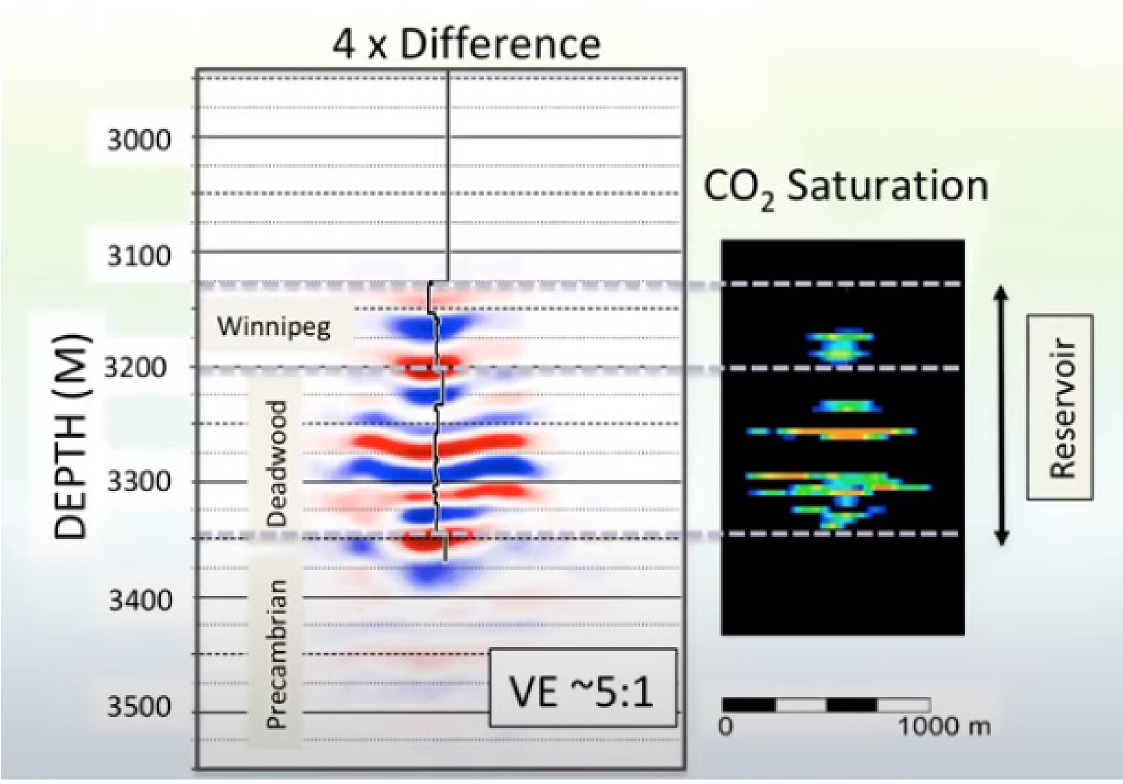


Figure 3.7: Time lapse seismic: difference vs CO_2 saturation (4D seismic)[9].

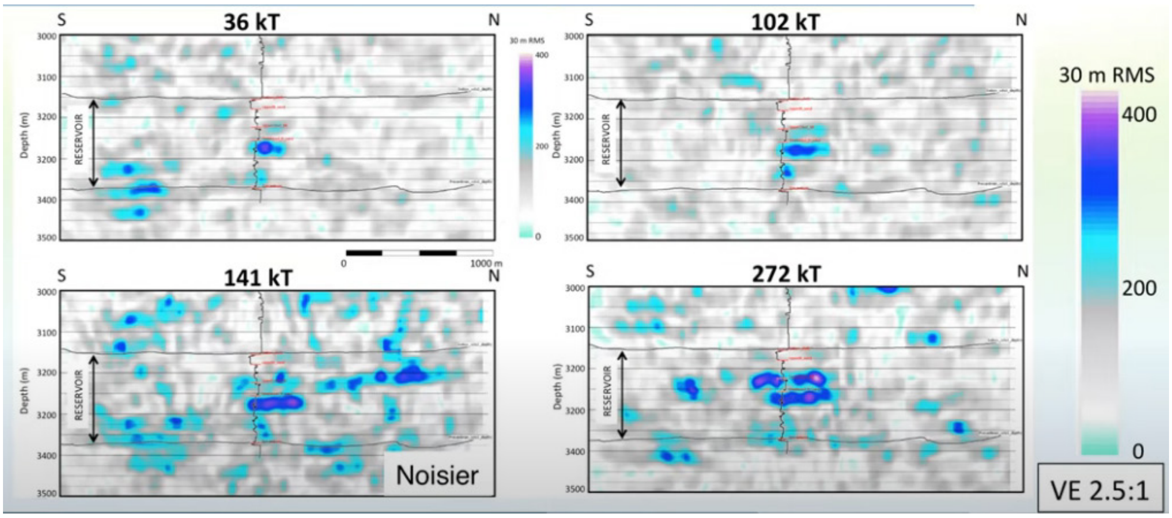


Figure 3.8: 4D RMS amplitude difference with reservoir level marked – 4 surveys are shown [9].

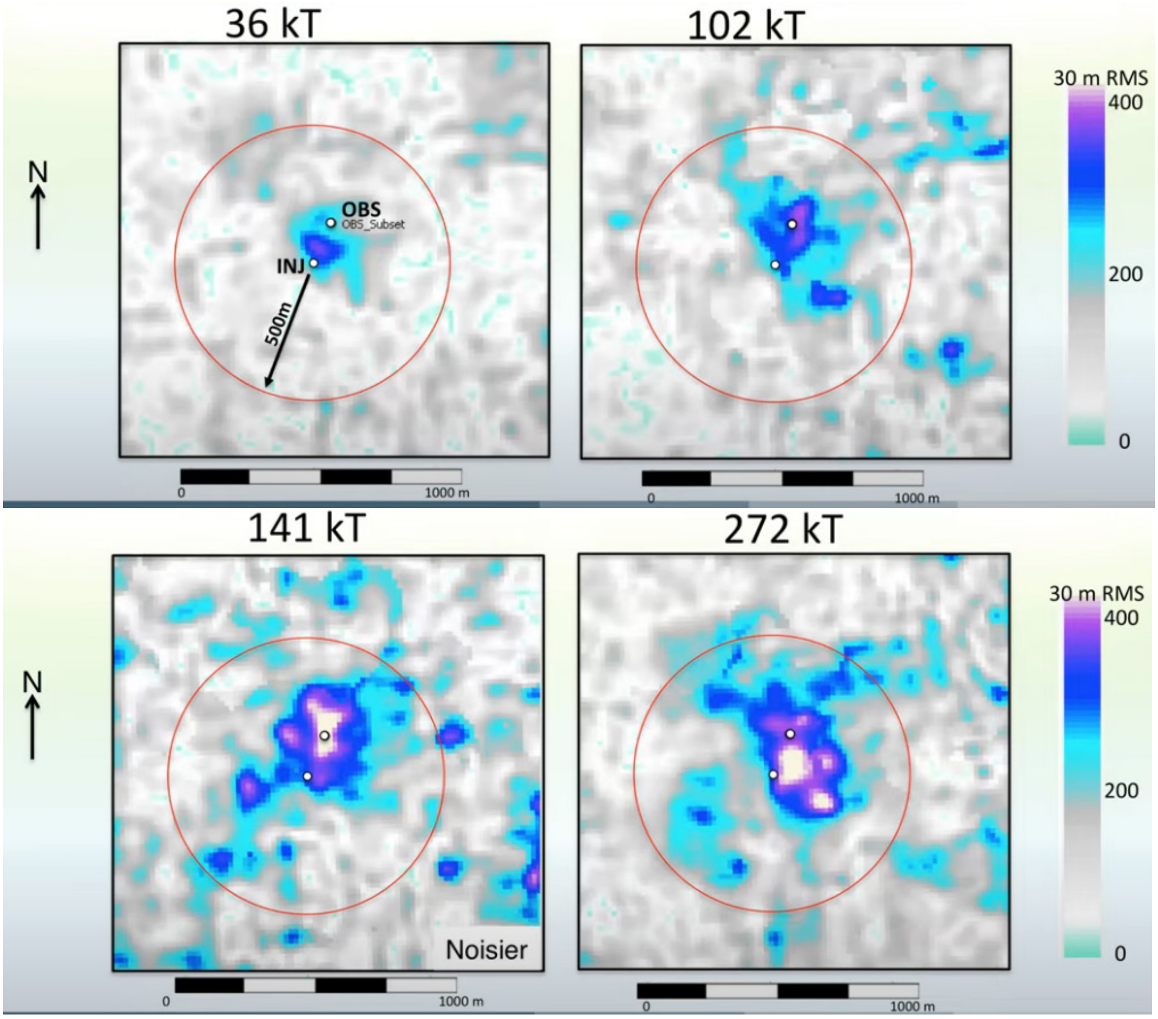


Figure 3.9: Plan view of time-lapse seismic at the Upper Deadwood formation (surveys 1-4)[9].

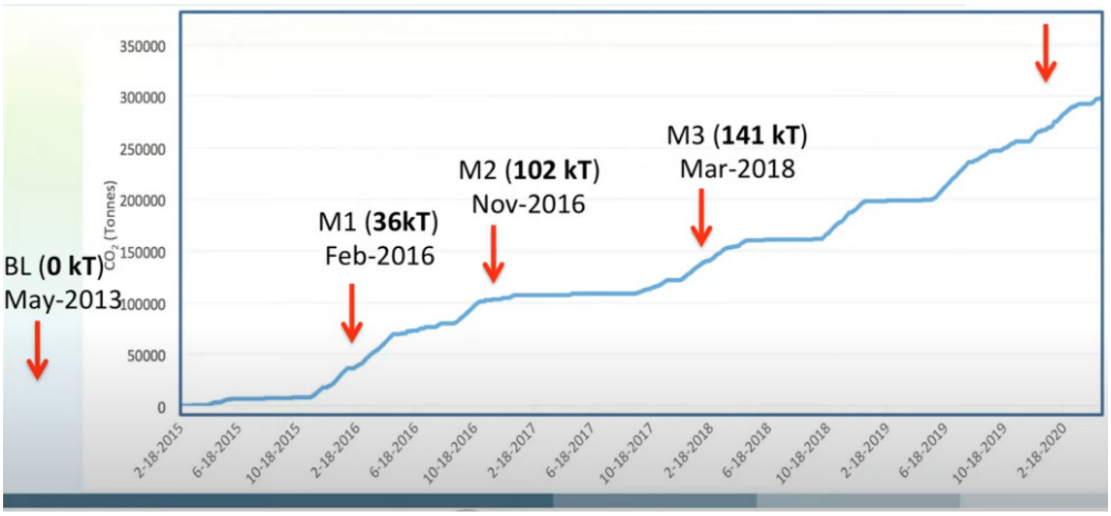


Figure 3.10: Monitoring CO_2 injection over time, also showing seismic surveys (2013-2020) [12].

4. Bell Creek

Site Details					
Name	Location	Province/State	Country	Onshore	Offshore
Bell Creek	Southeastern Montana, on the northeastern corner of the Powder River Basin	Montana	USA	✓	

General storage type
EOR – Depleted oil and gas reservoir

Development History (Active operation)
Bell Creek oil field (operated by Denbury Onshore LLC) lies on the north-eastern edge of the Powder River Basin in south-eastern Montana (Figure 4.1). Covering ~89 km^2, the oil field is a sub-normally pressured reservoir with significant hydrocarbon accumulation (353 million barrels STOOIP (stock tank original oil in place) of which 133.4 million barrels has been produced – as of 2013). Discovered in the late 1960's initially producing ~56,000 barrels/day, this has declined to ~975 barrels a day by 2012. The field contains over 450 wells. Tertiary oil recovery is planned through CO_2 injection and storage[1].   1,416,000 m^3 of CO_2 a day will be delivered via a 232 miles pipeline from the Lost Cabin gas plant in Wyoming (Figure 4.1). Injected into an oil bearing sandstone reservoir (Newcastle Formation) resulting in ~1 million tonnes of CO_2 injected annually[1] . Injection began in May 2013 and CO_2 EOR is progressing through nine development phases (Figure 4.2)[2].   A research-monitoring programme is conducted by the Plains CO_2 Reduction Partnership, led by the Energy & Environmental Research Centre (EERC)[3].

Geological Characteristics	
Reservoir Formation	
Lower Cretaceous Muddy (Newcastle) Formation (Figure 4.3 & Figure 4.4)	
Lateral extent / thickness variation	Located at a depth of ~1,310-1,372 m[1]. Thickness of clean reservoir sands vary ~6-11 m thick[4].
Rock type	Sandstone

1 Hamling, J.A., Gorecki, C.D., Klapperich, R.J., Saini, D. and Steadman, E.N. (2013) Overview of the Bell Creek combined CO_2 storage and CO_2 enhanced oil recovery project. Energy Procedia, 37, pp.6402-6411.
2 Burnison, S.A., Bosshart, N.W., Salako, O., Reed, S., Hamling, J.A. and Gorecki, C.D. (2017) 4-D seismic monitoring of injected CO_2 enhances geological interpretation, reservoir simulation, and production operations. Energy Procedia, 114, pp.2748-2759.
3 Hamling, J.A., Glazewski, K.A., Leroux, K.M., Kalenze, N.S., Bosshart, N.W., Burnison, S.A., Klapperich, R.J., Stepan, D.J., Gorecki, C.D. and Richards, T.L. (2017) Monitoring 3.2 million tonnes of CO_2 at the Bell Creek oil field. Energy Procedia, 114, pp.5553-5561.
4 Burnison, S.A., Livers, A.J., Hamling, J.A., Salako, O. and Gorecki, C.D. (2017) Design and implementation of a scalable, automated, semi-permanent seismic array for detecting CO_2 extent during geologic CO_2 injection. Energy Procedia, 114, pp.3879-3888

Sedimentary features: Depositional Environment / facies type & variation / mineral composition	Deposited in a near-shore marine environment (barrier bars)[1]. The shoreline trend is parallel to the long axis of the field (northeast-southwest)[2]. Updip it transitions to lagoonal facies. This facies change from sand to shale provides first level of trap. The sand interval pinches out in the updip direction against the overlying Springen Ranch member and the underlying Rozet member, providing stratigraphic trap (Figure 4.4)[2]. The reservoir sands are not laterally continuous, as evidenced by well penetrations with little or no reservoir quality sandstone; significant pressure, volume, temperature properties of produced hydrocarbons and considerable reservoir pressure differences. These observations resulted in sub-diving the field into nine development phases (Figure 4.2)[2]. Overlain by deltaic siltstones (strike perpendicular to the Muddy Fm) and is finally partially dissected and compartmentalised by intersecting shale-filled incisive erosional channels[1] see Figure 4.4. A final marine transgression filled area with shallow marine deposits.
Porosity	High porosity 25-35% [1].
Permeability	High permeability 100-1,175 mD[1].
Formation fluid properties: (residual hydrocarbons / salinity concentration).	
Caprock / primary seal formation	
Upper Cretaceous Mowry Formation is the primary seal.	
Lateral extent / thickness variation	n/a
Rock type	n/a
Fracture pressure	n/a
Porosity	n/a
Permeability	n/a

Overburden Features (Thickness, formations presence of secondary reservoirs / seals)	
800-1,200 m of low permeable shale formations, including the Belle Fourche, Greenhorn, Niobrara, and Pierre shales provide secondary seals in the event of a breach of the Mowry Formation[1]. Overlying these are several aquifers (Figure 4.3)	
Structure	
Fold type / fault bounded	Shallow monocline with a 1-2° dip to the northwest and axis trending southwest to northeast for ~32 km[1].
Faults /Fractures (Type – normal, reverse, strike-slip)	n/a
Displacement	n/a
Stability (pre-stressed, active, stable)	n/a
Injection / storage history	
Number of injection, monitoring or other wells, well geometry, design and key completion information for injection wells, relevant well issues. Reused / new purpose drilled well.	
The Bell Creek Field contains over 450 wells[3]. CO_2 injection is implemented in a five-spot pattern, with central injector surrounded by four production wells at approximately 0.4 km distance. The pattern repeats symmetrically[4]. Monitoring and characterisation well was drilled (December 2011) (Figure 4.2)[1].	
Extent and status of casing (corrosion history/ cementation records)	n/a
Injection rates & pattern (i.e. continuous / intermittent) changes in injection behaviour	n/a
Total quantities stored	Injection started in May 2013 and by July 2016 3.2 million tonnes of CO_2 had been stored[3].
Reservoir capacity (estimate)	n/a
Fluid extraction rate (brine extraction, oil for EOR)	n/a
Seismicity	
Monitoring regime (technologies deployed)	
n/a	
Seismic events (Detection / magnitude / attribution (natural induced).	

n/a	
Monitoring technologies applied and experiences with monitoring; See Figure 4.5 for an overview of the various surface and subsurface monitoring techniques employed at the Bell Creek field.	
Surface monitoring technologies deployed	
LIDAR survey	194 km^2 LIDAR survey (Figure 4.2) was collected over the field in July 2011. Used to correct well location and elevation data throughout the field. Improving structural interpretation of the reservoir. Also identified location of plugged and abandoned (P&A'd) wells that could be targeted by the monitoring program[1].
Fluid sampling	Chemical analysis of produced and injected fluids to better understand the chemical reactions and composition of reservoir fluids[1].
3D seismic	103.6 km^2 3D seismic survey collected late 2012 as a baseline for future time-lapse CO_2 monitoring (Figure 4.2)[1]. Improved the structural mapping. The results were combined with seismic inversion to interpret geobodies and statistically populate property distributions within the Muddy Formation to more accurately represent the physical geologic system[3]. A 28 km^2 repeat/monitor seismic survey focussed on Phase 1 and 2 was acquired in October 2014, a 2D test line proved that injected CO_2 would image well in the reservoir[2]. Time-lapse 3D highlights the injected CO_2, illuminating the location and extent of permeability and pressure barriers and imaging well-to-well communication (Figure 4.6). A shale-filled north to south permeability barrier separate Phase 1 and Phase 2 areas is well illuminated in time-lapse difference maps. Little amplitude change within the feature confirms the ability to prevent fluid and pressure communication between the areas. The data confirm that there is no vertical migration of CO_2 outside the Muddy Formation and the lateral migration is well contained within the field[2,3].

Soil Gas sampling	Baseline soil gas concentrations and water chemistries of surface water features and shallow groundwater aquifers are analysed. Time-lapse data will be utilised to determine if a chemical change in these mediums post-injection is a result of natural processes or is a result of the injection process or out-of-zone fluid migration[1].
SASSA	Scalable, automated, semipermanent, seismic array (SASSA) a novel seismic method for detecting and tracking injected CO_2 plume miscible fronts as they traverse discreet points within a reservoir. As described in[4]. Fixed location source is periodically fired into a sparse array of autonomous surface receivers (96 stations covering 2.6 km^2). As the CO_2 plume migrates, detectable character changes should occur on the recorded reflections of the reservoir[4]. Installed October 2015 until October 2016.
Subsurface monitoring technologies deployed (well logs)	
Well-logs and core analysis	Vintage well-log, core analysis, and well file data for over 700 wells within and surrounding Bell Creek were incorporated into a geological model[1]. Full suite of modern well logs (33.5 m of 10.16 cm diameter core and 47 sidewall cores) acquired through the Mowry, Muddy and Skull Creek Formations. Modern high-resolution data sets for reservoir and seal formations allow for calibration of vintage well log and core analysis data throughout the field[1]. Three casings with pressure/temperature gauges and a fibre optic distributed temperature system were deployed to provide reservoir characterisation data prior to and during injection[1].
Pulsed neutron well logs	82 pulsed neutron well logs baseline and time-lapse have been employed to characterise the field and to measure fluid saturation changes for select injection and production wells (Figure 4.2)[3]. Provide modern gamma ray, porosity and spectral lithology data for most wells in the

	Phase 1 development area (Figure 4.2)[1]. Logs will provide baseline for monitoring CO_2, water, and oil saturation changes during injection[1]. Used to evaluate near wellbore fluid saturation changes to evaluate sweep and storage efficiency within the reservoir and monitor fluid changes for CO_2 accumulations in overlying formations during and post-injection[1]. The new data provided a means to calibrate and correlate structure- and geologic property interpretations with c.1970 well log data from ~400 wells. The reservoir and 11 overlying formations were reinterpreted. Porosity data identified two intervals overlying the Muddy Formation, which may result in accumulations of gas and/pressure in the event of vertical migration of CO_2, these intervals were subsequently monitored with pressure gauges and time-lapse PNL logs to confirm containment of injected CO_2 within the injection horizon[3]. Time-lapse PNLs provided near-wellbore water, oil and CO_2 saturation profiles (Figure 4.7). Saturation profiles identified and defined geologic features in the Muddy Formation that serve as gas permeability barriers. The location and extent of these features and how they impact fluid and gas mobility provide insight into utilisation and storage efficiency[3]. Saturation also confirms the containment of injected CO_2 within the reservoir. Quantitative gas saturation data were used with time-lapse seismic surveys to evaluate sensitivity of the seismic amplitude response to gas saturations, improving interpretation of time-lapse seismic data[3]..
VSP	Two 3D VSP seismic surveys and the installation of a permanently installed geophone array (which will monitor induced seismicity). Baseline surveys will allow for time-lapse data acquisitions for CO_2 monitoring as well as passive seismic monitoring during injection[1]. Monitoring of CO_2 migration pathways between select production and injection wells. And calibration and enhanced processing of time-lapse 3D surface seismic data[1].

Tracer flood study	Tracer flood study – to better understand fluid communication pathways during injection and aid in history matching simulations[1].
	Surface casing, production casing, flow line and tubing pressure will be monitored on all active injection and production wells[1].
CESM	Controlled-source electromagnetic (CSEM) method, time-lapsed charged well casing survey. Three field campaigns from October 2017 to October 2018[5]. The CSEM survey is sensitive to electrical conductivity changes in the subsurface, as CO_2 displaces electrically conductive fluids in the pore space, the bulk conductivity of the rock decreases. Results indicate that surveys can detect the change in conductivity within the reservoir due to fluid movement[5].

MMV (Measurement, Monitoring, Verification) Practices & related verification of injected CO_2

The research-monitoring program at Bell Creek includes 16 techniques and represents 1.5 years of pre-injection monitoring and over 3 years of operational monitoring activities (as of 2017) (Figure 4.5[3]). Primary criteria were focussed on demonstrating secure storage; improving storage capacity; storage efficiency, and utilisation estimates; tracking vertical and lateral migration of CO_2; improving long-term fate of injected CO_2[3].

Initial monitoring coincided with the pre-injection and operational monitoring of the first 1 million tons of CO_2 storage[3]. Techniques were evaluated and validated to meet specific monitoring criteria and integrated with components of the adaptive management approach. This approach accounts for the potential for each component to be progressively integrated to improve other components, resulting in enhanced project performance[3]. Health, safety, and environment and operational impacts were evaluated in conjunction with data integration, data quality, cost applicability, and value for each of the demonstrated techniques

The second stage of monitoring coincided with operational monitoring of between 1 and 3 million tons of associated CO_2 storage. This stage focussed on developing, validating, and demonstrating the effectiveness of MMV strategies applicable to commercial-scale projects, and had to meet certain criteria. These strategies included InSAR, time-lapse 3D geophysical surveys, real-time downhole pressure and temperature, and near-surface monitoring techniques[3].

Major technical/scientific studies on the site, major learnings, Conformance assessment (history-matching with models, correlation between different monitoring techniques)

5 McAliley, W.A., Bloss, B.R., Irons, T., Moodie, N., Krahenbuhl, R. and Li, Y. (2019) September. Analysis of land-based CSEM data for CO_2 monitoring at Bell Creek, MT. In SEG International Exposition and Annual Meeting. OnePetro.

Modelling and numerical simulation are utilised to: 1) characterise and model the study area using advanced geological modelling; 2) develop a robust pressure, volume, and temperature (PVT) model to predict miscibility behaviour of the CO_2-Bell Creek crude system and aid in compositional simulation; and 3) history matching the constructed dynamic reservoir model. Predictive simulations will be used to aid the development of an integrated CO_2 EOR and long-term CO_2 storage project in the sub-normally pressured Muddy Formation[1]. History matching and numerical simulation of injection and production performance (from PNL data) identified diagnostic wells that were difficult to history match using legacy data and identified areas where the geological model and performance forecasts did not adequately represent the physical geologic environment. The improved structural and property models improved history match performance and subsequent performance forecasts[3, 6].
List of key publications covering the site
1. Hamling, J.A., Gorecki, C.D., Klapperich, R.J., Saini, D. and Steadman, E.N. (2013) Overview of the Bell Creek combined CO_2 storage and CO_2 enhanced oil recovery project. Energy Procedia, 37, pp.6402-6411. 2. Burnison, S.A., Bosshart, N.W., Salako, O., Reed, S., Hamling, J.A. and Gorecki, C.D. (2017) 4-D seismic monitoring of injected CO_2 enhances geological interpretation, reservoir simulation, and production operations. Energy Procedia, 114, pp.2748-2759. 3. Hamling, J.A., Glazewski, K.A., Leroux, K.M., Kalenze, N.S., Bosshart, N.W., Burnison, S.A., Klapperich, R.J., Stepan, D.J., Gorecki, C.D. and Richards, T.L. (2017) Monitoring 3.2 million tonnes of CO_2 at the Bell Creek oil field. Energy Procedia, 114, pp.5553-5561. 4. Burnison, S.A., Livers, A.J., Hamling, J.A., Salako, O. and Gorecki, C.D. (2017) Design and implementation of a scalable, automated, semi-permanent seismic array for detecting CO_2 extent during geologic CO_2 injection. Energy Procedia, 114, pp.3879-3888. 5. McAliley, W.A., Bloss, B.R., Irons, T., Moodie, N., Krahenbuhl, R. and Li, Y. (2019) September. Analysis of land-based CSEM data for CO_2 monitoring at Bell Creek, MT. In SEG International Exposition and Annual Meeting. OnePetro. 6. IEAGHG, "Monitoring Network and Modelling Network – Combined Meeting", 2015/01, February, 2015.
Other relevant information considered pertinent to the report
Mur, A., Barajas-Olalde, C., Adams, D.C., Jin, L., He, J., Hamling, J.A. and Gorecki, C.D., 2020. Integrated simulation to seismic and seismic reservoir characterization in a CO_2 EOR monitoring application. The Leading Edge, 39(9), pp.668-678. Carbon Capture and Storage: Research at Bell Creek https://www.netl.doe.gov/sites/default/files/2018-11/Bell-Creek-Project.pdf https://www.youtube.com/watch?app=desktop&v=baH4q6jGrwE Denbury and CO_2: Bringing Bell Creek Back to Life https://www.youtube.com/watch?v=TC0xO_GnLU0

6 IEAGHG, "Monitoring Network and Modelling Network – Combined Meeting", 2015/01, February, 2015.

Figures

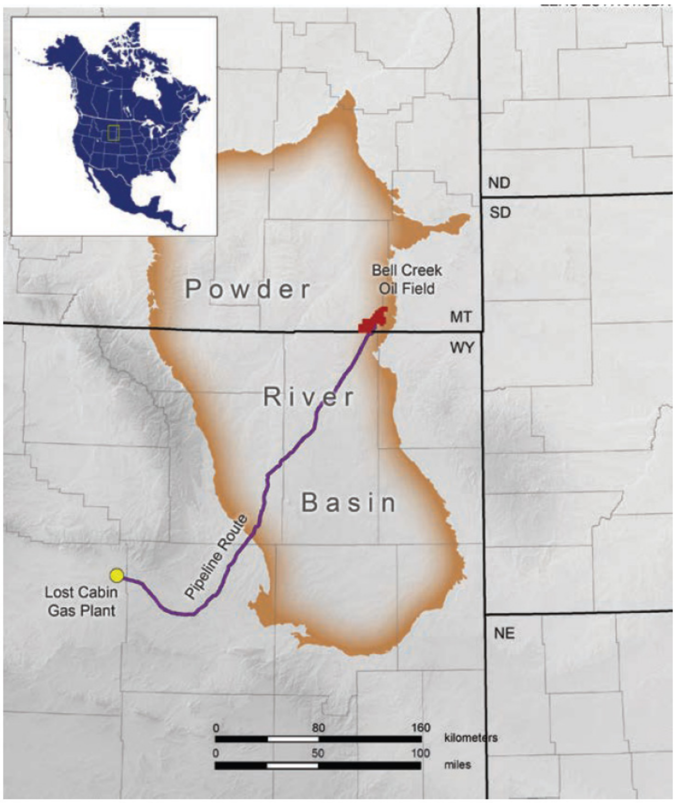


Figure 4.1: Map illustrating the location of Bell Creek oil field and ConocoPhillips owned Lost Cabin gas processing plant and the Greencore pipeline route[1].

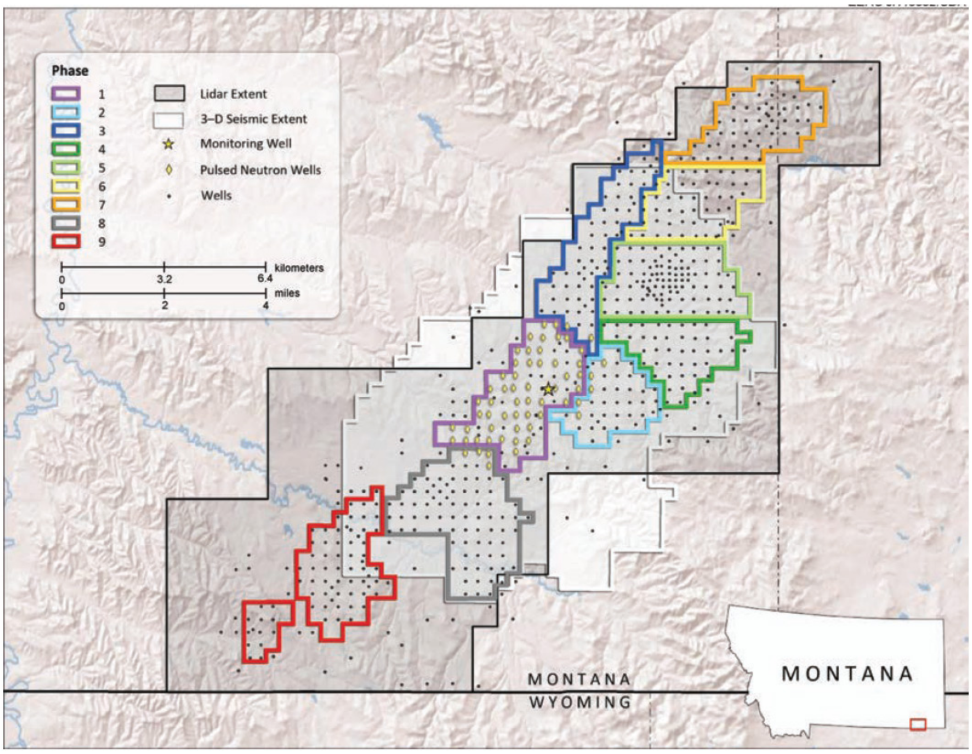


Figure 4.2: Map illustrating the phased CO_2 development program of the Bell Creek oil field. The extent of the LiDAR (Light Detection and Ranging) survey and baseline 3D seismic survey are also shown along with candidate wells for the pulsed neutron well log campaign (in yellow). The yellow star locates the 0506 OW monitoring and characterisation well[1].

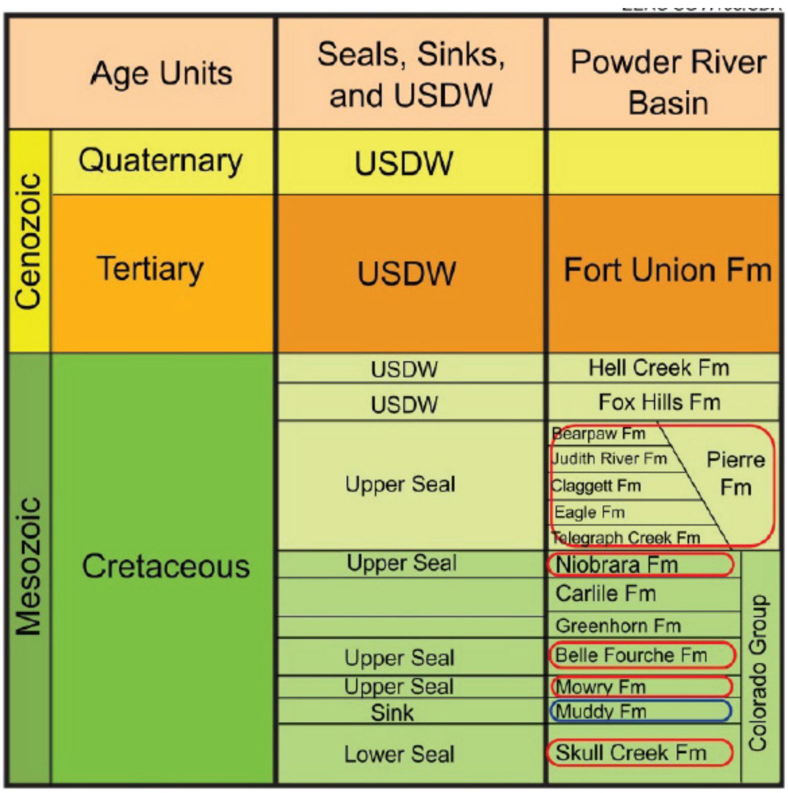


Figure 4.3: stratigraphic column of the Powder River Basin, Montana. Seals are marked red, primary reservoir is marked by and formations bearing underground sources of drinking water (USDW) are identified[1].

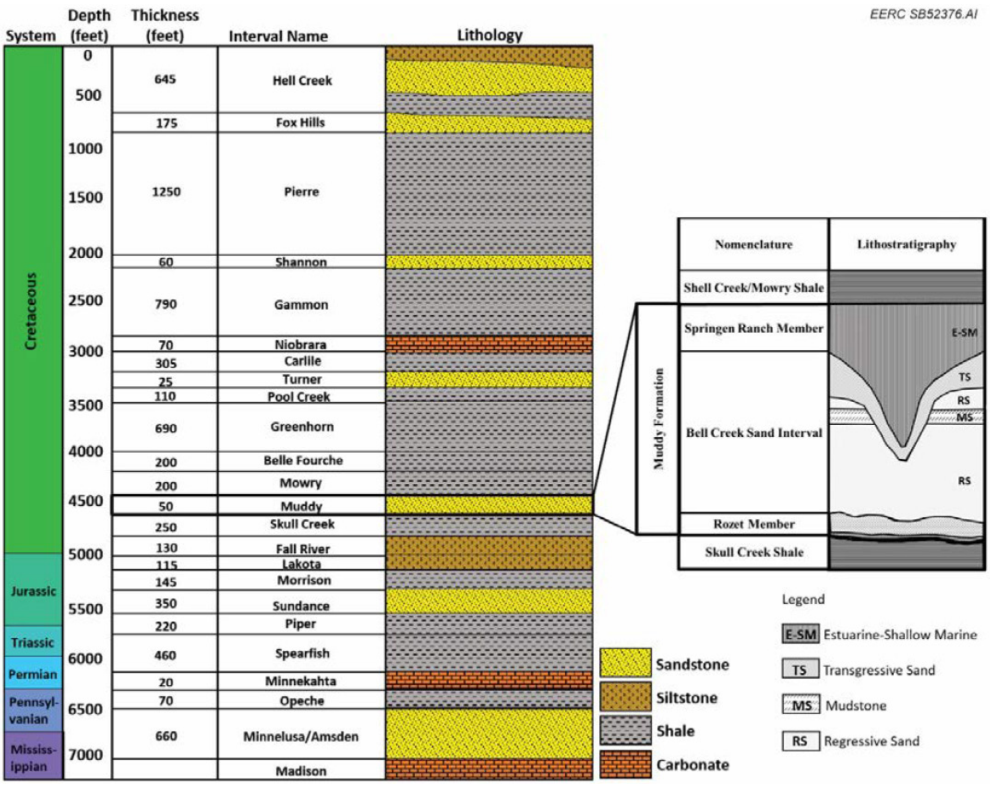


Figure 4.4: Bell Creek stratigraphic column and generalized reservoir stratigraphy[2].

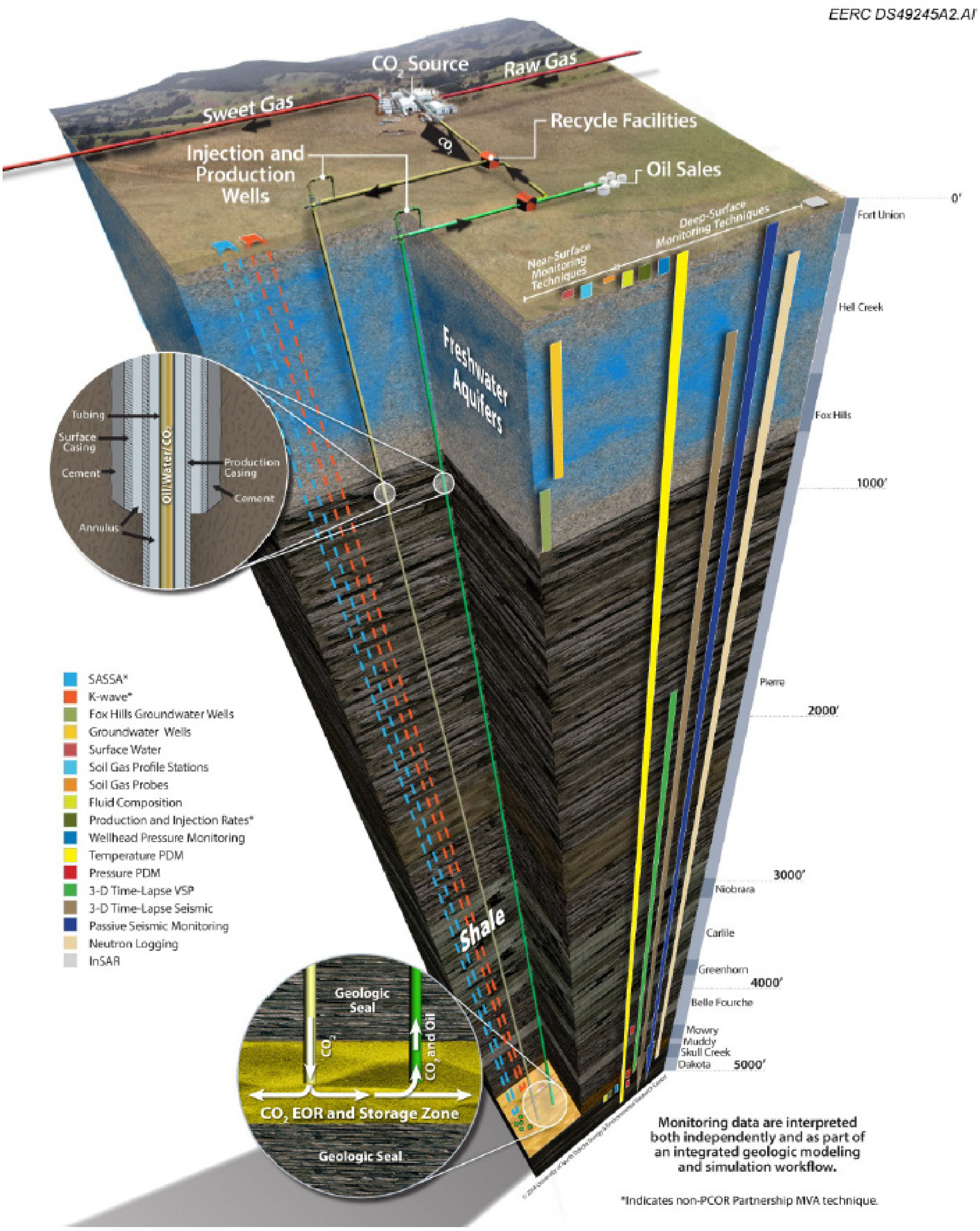


Figure 4.5: Stratigraphic column of the Bell Creek Field illustrating individual MVA techniques applied as part of the PCOR Partnership project. The bars illustrate the area of the subsurface for which each technique provides information[3].

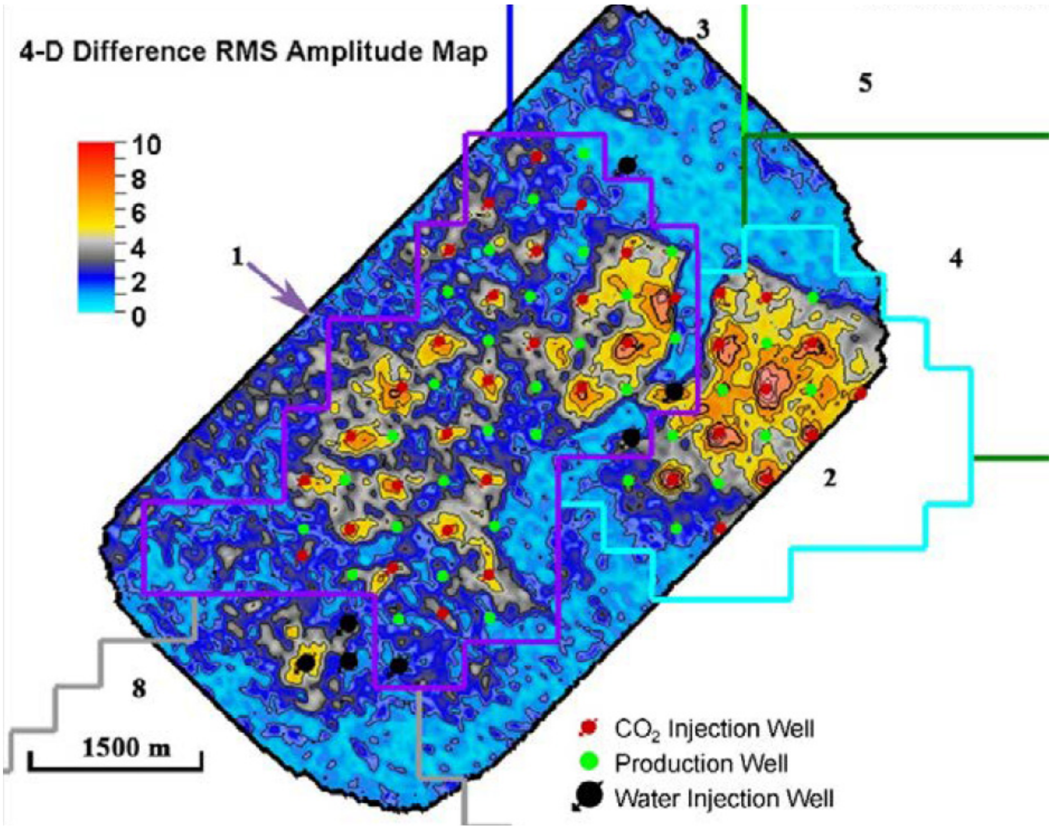


Figure 4.6: time-lapse 4D seismic amplitude difference map. Wells and development phases are marked. The warmer colours indicate regions that have experienced greater change in CO_2 saturation from the baseline seismic survey, cooler colours indicate areas with little change in CO_2 saturation or pressure. The CO_2 response outlines a permeability barrier and fluid communication between the eastern and western portions of the seismic image[2].

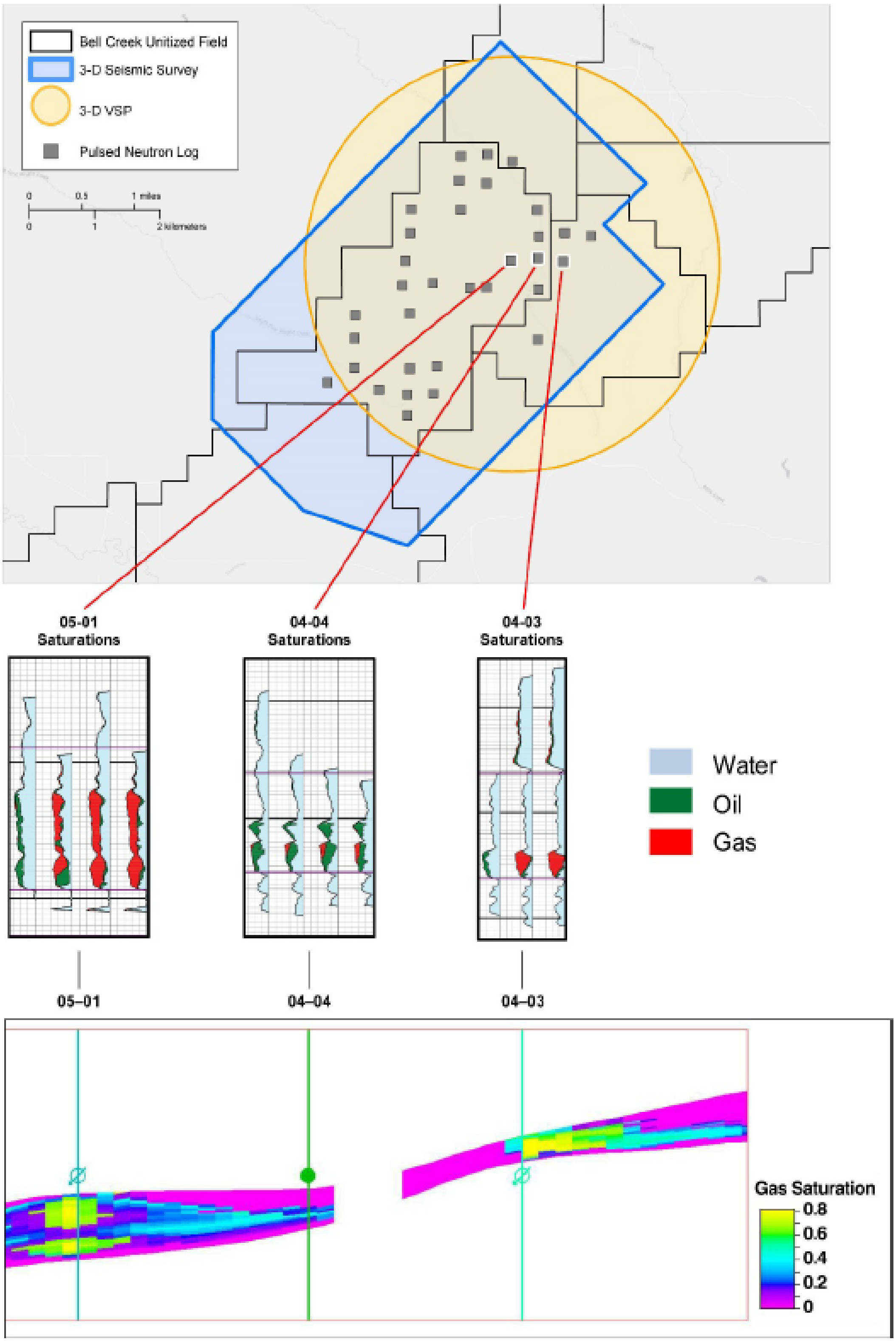


Figure 4.7: several repeat PNL logging surveys were conducted to evaluate changes in fluid composition within those wells and correlate the results with seismic data from the same location. Repeat PNL surveys from two injectors (05-01 and 04-03) and one producer (04-04) are shown. Coloured regions in the logs show changes in distribution with respect to fluids within these wells. The results of the surveys are then correlated with simulation outputs to improve modelled results[3].

5. Midwest Regional Carbon Sequestration Project

Site Details

Name	Location	Province/State	Country	Onshore	Offshore
Midwest Regional Carbon Sequestration Project	Otsego County	Michigan	USA	✓	

General storage type

Depleted oil and gas reservoirs in discrete pinnacle reef formations – Enhanced oil recovery

Development History (Active operation)

The Midwest Regional Carbon Sequestration Partnership (MRCSP) was established in 2003 as a private-public collaboration by Battelle for the U.S. Department of Energy/National Energy Technology Laboratory (DOE/NETL) to assess the technical potential, economic viability, and public acceptability of carbon capture, utilisation and storage (CCUS)[1].

The MRCSP Michigan Basin Large-Scale Injection Project has the goal of injecting and monitoring 1 million metric tons of CO_2 in conjunction with EOR. Ten depleted oil fields within a regional trend of more than 850 Silurian pinnacle reefs in northern Michigan (Figure 5.1, Figure 5.2 & Figure 5.3), are at various stages of the CO_2-EOR lifecycle: late-stage fields that have already undergone extensive EOR (n=1), active EOR fields (n=7), and new fields (not yet exposed to CO_2) (n=2)(Figure 5.2 & Table 5-1)[1]. This offered a unique opportunity to monitor CO_2 throughout the lifespan of an EOR reef.

The CO_2-EOR started in 1996, and between 2013 and 2019 the MRCSP project stored 1,537,000 metric tons of CO_2 and monitored the production of over 1,000,000 barrels of oil[2]. CO_2 for the project was sourced from gas processing plants used in production of natural gas from the nearby Antrim Shale fields (Figure 5.4). The CO_2 is separated at the Chester 10 gas processing plant and transported via Core Energy through pipelines to the reefs.

The Michigan Basin large scale injection test focussed on: 1) geologic characterisation, 2) modelling, and 3) monitoring and accounting (Table 5-1, Table 5-2, Table 5-3). Phase III of this study (2008-2020) was designed to answer questions regarding: the technical and economic feasibility of CCUS and EOR, the CO_2 storage capacity of pinnacle reef formations, and the safety and efficacy of injecting CO_2 for long term storage and utilisation in oil and gas recovery[2]. Questions also include: injectivity, capacity, containment and safety.

The complex internal architecture, lithology, and diagenetic changes in these carbonate reef fields strongly influence the storage capacity, pressure response, and ultimately the reservoir performance of each individual field. The configuration of the reefs (simple dome to two- or three-lobed shapes with varying hydraulic connection) and the wells' layout permit assessment of realistic configurations for commercial-scale CO_2 storage field development. This diverse portfolio of fields

1 Gupta, N., Kelley, M., Place, M., Cumming, L., Mawalkar, S., Srikanta, M., Haagsma, A., Mannes, R. and Pardini, R. (2017) Lessons learned from CO_2 injection, monitoring, and modeling across a diverse portfolio of depleted closed carbonate reef oil fields–the Midwest Regional Carbon Sequestration Partnership experience. Energy Procedia, 114, pp.5540-5552.

2 Gupta, N., Mishra, S., Kelley, M., Sminchak, J., Mawalkar, S. and Haagsma, A. (2020) Midwestern Regional Carbon Sequestration Partnership (MRCSP) Phase III (Development Phase) Final Technical Report(No. DOE-BATTELLE-42589). Battelle Memorial Inst., Columbus, OH (United States).

and wells provides an excellent opportunity to evaluate the geologic variability in complex carbonate reservoirs and its impact on CO_2 storage capacity[1].	
Geological Characteristics.	
Reservoir Formation	
Ten distinct Silurian aged pinnacle reefs, which comprise mound like masses of dolostone and limestone (Figure 5.2). Located at between 1200-1800 m depth, and overlain by thick deposits of evaporites, shales and tight carbonates (Figure 5.3, Figure 5.4 & Figure 5.5)[1]. The Brown Niagaran is overlain and encased by cyclic carbonate and evaporite beds of the Salina Group (Figure 5.5)[3]. The Brown Niagaran and A-1 Carbonate are the reservoirs in the Silurian reefs[3].	
Lateral extent / thickness variation	Individual reefs are closely spaced and compartmentalised from the enclosing rock, they average 0.2-1.6 km^2 in area and up to 200 m in height, with steep flanks of 30° to 45° (Figure 5.3)[2].
Rock type	Dolomite and limestone (Figure 5.6). Reservoir rocks may be completely dolomitised, all limestone or a heterogenous mix. Reservoir quality is enhanced by dolomitization, with upper parts of the reef more dolomitised than the lower parts[2]. The Dover 33, Bagley, and Charlton 19 reef fields were predominantly dolomitic, the Chester 16, Chester 2, and Charlton 6 were limestone[2]. Some reefs have an overlying A-1 carbonate that is a significant contributor to the reservoir. See Figure 5.6 for an overview of rock types and porosity for the reefs[2].
Sedimentary features: Depositional Environment / facies type & variation / mineral composition	Upper Silurian carbonate platforms developed along arches that separate the Michigan, Ohio, and Illinois Basins; the Northern Niagaran Pinnacle Reef Trend (NNPRT) developed along the northern slope of the Michigan Basin (Figure 5.3)[3]. Comprising individual reef complexes, being closely spaced and average 200m in height and 0.2-1.6 km^2 in area, with steep flanks of 30° to 45°[3].

3 Gupta, N., Haagsma, A., Conner, A., Cotter, Z., Grove, B., Main, J., Scharenberg, M., Larsen, G., Raziperchikolaee, S., Goodman, W. and Sullivan, C. (2020) Geologic Characterization for CO_2 Storage with Enhanced Oil Recovery in Northern Michigan (No. DOE-BATTELLE-42589-Geologic). Battelle Memorial Inst., Columbus, OH (United States).

	The Niagaran reefs have been subdivided by lithofacies (e.e. crinoid wackestone, coral boundstone) and depositional facies from whole core observations and correlated with wireline logs[3]. The depositional environments identified from core and gamma ray signatures include: windward reef flank, windward reef talus, reef core, leeward proximal reef apron, leeward distal reef apron, and leeward flank facies (Figure 5.7 & Figure 5.8)[3].
Porosity	Average reef porosity ranged from 1.4% to 11.7% (Figure 5.9)[2]. Depositional facies and diagenesis have an impact on porosity and both vary widely in the reefs. Diagenesis and degree of salt plugging were assigned ranks and plotted with porosity and oil recovery to illustrate reservoir quality. When plotted using porosity, Charlton 19 was ranked as the best reservoir, followed by Dover 33 and Bagley. When plotted with % recovery, Dover 33 and Chester 16 were the highest[2].
Permeability	Average permeabilities up to 94 mD. Can range from 3 mD to 10 mD[4].
Formation fluid properties: (residual hydrocarbons / salinity concentration).	n/a
Caprock / primary seal formation	
Reef facies are sealed above and along the sides by overlying evaporites (salt and/or anhydrite), tight carbonates, and shales (Figure 5.5 & Figure 5.8)[2]. This includes the A-1 evaporite, which transitions from anhydrite near the reefs to halite in the basin centre, and the A-2 evaporite, which overlies the reef and is dominantly halite in the NNPRT[3]. The thick B-Salt unit also provides a seal. In flanking and off-reef areas, the Rabbit Ears anhydrites form thin (2- to 20-foot) vertical baffles and barriers to flow within the A-1 carbonate (Figure 5.5)[3].	
Lateral extent / thickness variation	Hundreds of feet thick, varies in thickness over the pinnacle reefs.
Rock type	Evaporites, salt, anhydrite, carbonates and shales[3].
Fracture pressure	n/a

4 Mishra, S., Haagsma, A., Valluri, M. and Gupta, N. (2020) Assessment of CO_2-enhanced oil recovery and associated geologic storage potential in the Michigan Northern Pinnacle Reef Trend. Greenhouse Gases: Science and Technology, 10(1), pp.32-49.

Porosity	Average A-2 evaporite porosity in a Dover 33 well is 0.48%
Permeability	n/a
Overburden Features (Thickness, formations presence of secondary reservoirs / seals) At least 300 m of glacial deposits[3].	
Structure The pinnacle reefs reservoirs are a stratigraphic trap.	
Fold type / fault bounded	n/a
Faults /Fractures (Type – normal, reverse, strike-slip)	North Michigan has few identified faults, all of which are deep basement faults, 100s of feet beneath the injection zone and do not influence the integrity of the seal system[2].
Displacement	n/a
Stability (pre-stressed, active, stable)	n/a
Injection / storage history	
Number of injection, monitoring or other wells, well geometry, design and key completion information for injection wells, relevant well issues. Reused / new purpose drilled well.	
Dover 33 reef – 20 wells penetrate the reef [3]. Chester 16 – all wells drilled and completed in the early 1970s (5 primary production wells, 9 in total)[3] Bagley – 18 wells penetrate the reef [3]. Charlton 19 – 6 wells [3]. Dover 25 – 9 wells penetrate the reef[3]. Dover 36 – 5 wells penetrate the reef[3]. Charlton 30-31 – 9 wells penetrate the reef[3]. Charlton 6 – 3 wells penetrate the reef[3]. Chester 2 – 8 wells penetrate the reef[3]. Chester 5/6 – 10 wells were drilled on reef[3].	
Extent and status of casing (corrosion history/ cementation records)	n/a
Injection rates & pattern (i.e. continuous / intermittent) changes in injection behaviour	n/a
Total quantities stored	As of 2017 – 1.6 million metric tons CO_2 since 1996. 600,000 metric tons of CO_2 since MRCSP started monitoring and measurement in 2013[1]. 2013-2019 1.5 million metric tonnes (Figure 5.10)[2]. Life Cycle Analysis 1996-2017 2,089,350 metric tonnes of CO_2 stored via CCS. Total emissions

	(including gate-to-gate and downstream activities) were 1,929,443 metric tonnes, resulting in net emissions of -159,907 tonnes[2].
Reservoir capacity (estimate)	Analysis of >800 reefs suggest that they may store more than 250 Mt of CO_2[2]. Analysis of 383 reefs, indicate 118 million STB of incremental oil from EOR corresponding to 49 million metric tonnes of CO_2 storage and 266 million metric tonnes of total CO_2 injection[4]. Material balance technique was applied to generate high-level screening estimates of the CO_2 storage capacity created as a result of EOR. The process is described in[1].
Fluid extraction rate (brine extraction, oil for EOR)	n/a

Seismicity
Monitoring regime (technologies deployed)
Two microseismic monitoring events were conducted 39 months apart during re-pressurization of the Dover 33 reef to evaluate CO_2-injection seismicity. The first (March 2013) at the start of CO_2 injection when reservoir pressure was low (~800 psi). The second monitoring event (June/July 2016) after more than 285,000 tonnes of CO_2 had been injected and the reservoir pressure had increased to ~3,700 psi[2]. This is the first documented microseismic study related to CO_2 injection/storage in a depleted carbonate pinnacle reef reservoir[2]. The monitoring generates a very large amount of data that has to be processed and interpreted. Interpretation of the data is very complicated and requires highly specialised skills in signal processing, machine learning etc[2]. It is recommended that continuous monitoring be undertaken rather than discrete events, however this increases the data management burden[2].
Seismic events (Detection / magnitude / attribution (natural induced).
Baseline survey: 12 out of 34 events are microseismic events, located very close to the 5-33 monitoring well. No events detected within reef where CO_2 injection was occurring or near the 1-16 injector well. The cause of the events was due to tube waves not injection induced seismicity[2]. Repeat survey: thousands of events were detected. Microseismic data revealed evidence both for (e.g. increase in pressure related to CO_2 injection) and against (primarily 'noise') injection-induced microseismicity. Unable to quantify the magnitude of the events or the locations[2].

Monitoring technologies applied and experiences with monitoring: The Phase III project included a comprehensive monitoring program that included deploying 11 different monitoring technologies at one or more of the reefs (Table 5-2). See Table 5-2 for the monitoring technologies, their primary objective, and the reefs where the technology was deployed[2] . See also [5] for a comprehensive report on all eleven monitoring technologies.	
Surface monitoring technologies deployed	
InSAR[2]	InSAR is used to monitor potential land movement (uplift/subsidence) resulting from the injection of CO_2 into the Dover 33 reef. Artificial corner reflectors (ACR) were placed/installed throughout the study area to help monitor land movement because of the dense vegetation coverage which reduces radar coherence, and frequent snow coverage Natural radar reflectors full data set: 51 satellite images (1992-2000); 22 satellite images for 6 months April-October 2012 (baseline); and 76 satellite images (April 2012-March 2015) (operational period) showed little movement, with an average rate of -0.3 mm/yr. A cumulative displacement of 0.7 mm over the full data set and 1.2mm during the injection phase. Slightly greater movement during injection phase[2]. 44 satellite images (May 2013-March 2015) using ACRS to measure surface movements near Dover 33 reef. Between -0.1 and 3.9 mm/yr with an average of 1.1 mm/yr. Slightly greater movement in the area above the reef compared to the area outside the reef during the period[2]. Determined that CO_2 injection in the reefs can be done safely without risk to surface and subsurface infrastructure.
Subsurface monitoring technologies deployed (well logs)	
DTS[2]	Fiber optic DTS cable installed on the outside of casing in a CO_2 injection well and a monitoring well in the Chester 16 reef, DTS performed continuously in both wells during re-

5 Gupta, N., Kelley, M., Place, M., Conner, A., Mawalkar, S., Mishra, S. and Sminchak, J. (2020) Integrated Monitoring Volume: A Summary of Monitoring Studies Conducted in Niagaran Carbonate Pinnacle Reefs During Enhanced Oil Recovery with CO_2 (No. DOE-BATTELLE-42589-Monitoring). Battelle Memorial Inst., Columbus, OH (United States).

	pressurisation period (February 2017 through September 2019) when CO_2 was injected sans production. DTS data from the injection well shows the location of the inflow zones where CO_2 enters the reservoir. The injection well had 7 perforated intervals of equal length, the data showed that the injectivities varied. By analysing temperature change as a function of depth and time during shut-in following injection, able to detect inflow zones. A waterfall plot of temperature suggests that most injected CO_2 entered the reservoir within the target zone of injections, the A1 carbonate and the Brown Niagaran Formations[2]. DTS data from the monitoring well (~300 m from injection well) shows the vertical interval in the reservoir where CO_2 transport occurred – as indicated by a sustained decrease in temperature that started after CO_2 injection commenced[2]. Notably through the A-1 Carbonate[2].
Pulsed Neutron Capture Logging[2]	Repeat PNC logging in several wells in 4 different reefs to evaluate the use of PNC logging for detecting the arrival/presence of CO_2 at monitoring wells. The standard Sigma analysis method, while useful for distinguishing water and hydrocarbons, is not sufficient for distinguishing CO_2 when hydrocarbons are present due to similar Sigma response by CH_4 and CO_2. Triangulation Method – a new technique developed to compute multi-phase saturations (oil, gas and water) in cased wells. Using Sigma response and RATA13 response as input to Monte Carlo N-Particle simulations to generate theoretical pulsed neutron tool responses for the given well and reservoir conditions, that are compared to actual tool response to estimate probable CO_2 saturations. Workflow includes: 1) field logging and analysis of well logs to determine well conditions, 2) well condition data collection, 3) fluid properties analysis, and 4) analysis of finalized saturation profiles[2].

	PNC results were useful for detecting breakthrough/arrival of CO_2 at the 8-16 monitoring well at Chester 16 reef, also corroborated by other monitoring data (DTS). However, results can be difficult to interpret, especially in low porosity fields and does not differentiate between CH_4 and CO_2.
Reservoir Pressure Monitoring [2]	Injection and monitoring wells in multiple reefs were instrumented with memory-style recording pressure gauges to record the pressure response within the reservoir resulting from CO_2 injection an allow the following analysis: Injection wells - combined with injection rate data, determine: (a) formation properties e.g. permeability using injection-falloff tests, and (b) permeability-thickness via injectivity index calculations using injectivity analysis[2]. Monitoring wells – data used to determine: (a) hydraulic diffusivity from the arrival time of the pressure pulse, and (b) permeability from the interference response[2]. Injectivity-falloff data, injectivity analysis and arrival time analysis used for analysis of pressure and rate data from injection and monitoring wells[2].
Borehole Gravity Monitoring (BGH)	BGH carried out at the Dover 33 reef to detect the location of the injected CO_2 over time. The injection of CO_2 and redistribution of the fluids in the pore space result in changes in subsurface density that can be detected with surface and borehole gravity measurements. A passive measurement of the existing gravity field and it bridges the radius of investigation gap between near-borehole examination by well logging tools and the larger volumes by seismic methods. In a time-lapse mode, the method is responsive only to temporal density distribution changes, e.g., as associated with CO_2 injection and production[2]. Three BHG surveys were performed (2013, 2016 & 2018). Time-lapse density change between the surveys, clearly reflect where CO_2 injection and

	fluid production occurred. Within the reef the density increases between the 2013 and 2016 surveys from the injection of CO_2 and decreases between 2016 and 2018 surveys as CO_2, oil and water were produced from the reef[2]. Gravity and density changes were modelled to determine the flow and storage zones of the injected CO_2 in the reef. Forward modelling allows precise mapping of the areas of the reservoir that received most of the injected CO_2 and which zones the least. The central and lower portions of the reef held most CO_2 storage according to the models[2].
Geochemical Monitoring	A geochemistry monitoring program was implemented at three reefs (Dover 33, Charlton 19, and the Bagley Field) to determine geochemical processes/reactions occurring in the reefs because of CO_2 injection. Brine, gas and core samples were collected. Five wells in Dover 33 sampled for brine and four for gas; three wells at Charlton 19 and two wells at Bagley reef were sampled for brine and gas; core was collected at one well at the Dover 33 reef. 32 gas samples were collected from 11 wells and from the Dover 36 gas processing facility (GPF). Three core plugs collected from the Brown Niagaran Fm above, at and below the oil/water contact in the Dover 33 reef to investigate the presence of minerals that may have precipitated as the result of CO_2 injection[2]. The study demonstrated that: The injected CO_2 mixed and/or reacted with the existing brine and reservoir matrix (solid). Evidence for mixing was provided by isotope data ($\delta^{13}C$ of DIC) because the injected CO_2 from the Antrim Shale has a unique isotopic signature which acts as a tracer in the brine[2]. The injected CO_2 reacted with the matrix as evidenced by analysis of the solid phase via light microscope, SEM and XRD Precipitates of several minerals were observed in pores that may have come from the reaction of CO_2 with pore fluids and matrix[2].

	The general geochemistry parameters (major cations and anions) were not significantly affected by CO_2 injection, thus these parameters were not useful for plume tracking. Gas phase analysis were useful for identifying wells reached by injected CO_2 based on observed increase in CO_2 in the gas samples[2]. Presence of CO_2 in the Dover 33 reef prior to monitoring made it difficult to discern behaviour of newly injected CO_2 in this reef[2].
Vertical Seismic Profile Geophysical Monitoring	Time-lapse VSP used to detect and delineate a plume of more than 271,000 tonnes of CO_2 injected into the Dover 33 reef (Brown Niagaran and A-1 Carbonate Formations) between March 2013 and September 2016. P-wave and PS-wave seismic response was monitored in five 2D walkaway VSP source lines (Sept 2016) and compared to data acquired in March 2013[2]. Impedance-amplitude differencing provided inconclusive results regarding the location of the injected CO_2 in the Dover 33 reef. Also, no significant difference in travel-time differences (P-wave and S-waves) between baseline and repeat surveys, so not able to discern CO_2 plume. Lack of success may be due to properties of the carbonate formations and survey factors. Also CO_2 in the reservoir prior to the start of injection may make detection more difficult[2].
Distributed Acoustic Sensing VSP	Time-lapse DAS VSP was implemented at the Chester 16 reef to attempt to detect ~85,000 tonnes of CO_2 injected into the A-1 Carbonate and Brown Niagaran Formations. Baseline survey (February 2017) and repeat survey (August 2018), and in between CO_2 was injected without production of fluids from the reef[2]. A grid of 181 source positions comprising 44 vibrator positions and 137 dynamite shot locations was used to give approximately continuous spatial coverage of the injection zone in between two wells. The DAS data indicate a measurable change (decrease) in seismic Reflection coefficient in the A-1 Carbonate and Brown Niagaran

	Formation and near the injection well. Difference features were also observed in strata above and below the injection zone. Reflection difference feature also present near the monitoring well, within and outside of the injection zone[2].
Cross-well seismic monitoring	A cross-well seismic survey was acquired in the Chester 16 reef from September 9 to 14 2018 to detect 85,000 tonnes of CO_2 that had been injected between February 2013 and September 2018. No baseline cross-well survey was obtained. The survey conducted between the 6-16 injection well and the 8-16 monitoring well. Over 19,000 (35 receiver geophones x 4 fans [positions] x 140 source locations per fan) traces were generated, providing a dense seismic grid between the two wells. The change in acoustic velocity was mapped to detect changes in pore fluid. Because of the lack of baseline survey reflection images were not helpful in detecting the CO_2 plume. Waveform tomography demonstrate velocity changes due to injected CO_2. At least one area with velocity decrease of 400 to 600 ms that occurs in the A-1 Carbonate just above the contact with the Brown Niagaran, coinciding with the interval where CO_2 was injected at the 6-16 well. This result is corroborated by DTS, PNC and pressure monitoring[2].

Experience summary - effectiveness of techniques (limitations / strengths)

The major lessons learned[2]:
The carbonate reef reservoirs act as closed reservoirs as they are surrounded/overlain by low permeability carbonates and evaporites which prevent CO_2 leakage out of the reservoir, making them ideal for permanent CO_2 storage.

It is possible to recover almost all of the CO_2 injected into a reef during CO_2-EOR. The reefs do not irreversibly sequester significant amounts of CO_2 during the EOR process.

CO_2 injection does not cause significant land displacement (uplift/subsidence) in the area overlying the reefs.

CO_2 injection does not appear to cause significant seismic activity that could activate fractures and/or faults that could lead to CO_2 leakage out of the reservoir, even when reservoir pressure is near discovery pressure.

The carbonate reef reservoirs may contain intervals/zones of salt plugging which reduces porosity and limits CO_2 storage capacity.

Lateral migration of CO_2 within the carbonate pinnacle reef reservoirs away from the injection well may occur preferentially in thin intervals.

The carbonate pinnacle reef reservoirs may occur as single isolated ‘pods’ (e.g. Dover 33) or in groups of two or more closely spaced/overlapping pods (e.g. Charlton 19, Chester 16, Bagley)

The overall low porosity of the reefs present a significant challenge for using borehole seismic monitoring methods to detect and delineate the injected CO_2.

Fracture pressures in depleted formations/intervals can be extremely low owing to the lowering of pore pressure below hydrostatic.

Injection of CO_2 into the carbonate reef reservoirs increases the likelihood of precipitation of carbonate minerals (dolomite, calcite, huntite, and magnesite), owing to the extremely high concentrations of calcium, magnesium, sodium, potassium and chloride in the reef brines which causes them to be supersaturated with respect to these minerals.

MMV (Measurement, Monitoring, Verification) Practices & related verification of injected CO_2

Mass Balance Accounting[2]

- From February 2013 through September 2019 Battelle documented injection of approximately 1.5 million metric tonnes of new CO_2 in the 10 reef complex (Figure 5.10).
- Flow meters were installed to measure injection rate, production rate, cumulative production, CO_2 removed via produced oil, and vented CO_2.

Storage efficiency shows that every unit (e.g. tonne of CO_2) stored requires 2 to 3.5 times greater amount of injected CO_2 [2].

Major technical/scientific studies on the site, major learnings, Conformance assessment (history-matching with models, correlation between different monitoring techniques)

Three phases of modelling for simulating oil production, CO_2 injection, and associated storage in the reefs (Table 5-3)[2]:

Geological framework modelling: integrating all relevant geological and geophysical data (logs, cores and seismic surveys) about reservoir structure, geometry, rock types and property distributions (porosity, permeability, water saturation) into a 3D distributed grid-based static earth model. Using standard oil and gas workflows. See [2] for process and results. Significant advances were made in understanding the complex internal geometry of the reefs and the influence of this geometry on the reservoir[1]. Simplified lithostratigraphic models were found to represent the heterogeneity and asymmetrical geometry of the reefs but with fewer zones than more complex models[1].

Dynamic reservoir modelling: using the static earth model as a platform to simulate the movement of oil, gas, water and CO_2 within the reservoir during primary hydrocarbon production, and subsequent phases e.g. CO_2 injection assisted EOR, plume migration, and associated storage. Used compositional and pseudo-miscible modelling approaches. The objectives included evaluating CO_2 injectivity and assessing fluid migration in the reefs and aimed to validate the representativeness of the reef conceptual model by history matching production (oil, water, gas) and pressure history during primary and secondary recovery. History matching provided a representative model that captured the field observed response from primary production until end of Phase III injection period, although manual history matching can be tedious. Availability of data (pressure data during primary production, quality of water, experimental PVT and relative permeability) increased the uncertainties.

Simplified assessment of coupled process effects was also carried out (Coupled Process Monitoring), where the impacts of geochemical and geo-mechanical processes induced by CO_2 injection were studied. To understand chemical reactions after injection, developed statistical proxy models, based on coupled fluid flow and geomechanical modelling to predict surface uplift, reservoir expansion2, and in situ stress changes from CO_2 injection, were completed. Aqueous and mineral reactions are slow but can impact pressure response in ~100 year time frame and plume progression in the ~1,000 year time frame, fracture pressure increases during injection due to poroelastic effects, proxy models can capture the behaviour of full-physics geomechanical models with good accuracy.

List of key publications covering the site

1. Gupta, N., Kelley, M., Place, M., Cumming, L., Mawalkar, S., Srikanta, M., Haagsma, A., Mannes, R. and Pardini, R., 2017. Lessons learned from CO_2 injection, monitoring, and modeling across a diverse portfolio of depleted closed carbonate reef oil fields–the Midwest Regional Carbon Sequestration Partnership experience. Energy Procedia, 114, pp.5540-5552.
2. Gupta, N., Mishra, S., Kelley, M., Sminchak, J., Mawalkar, S. and Haagsma, A., 2020. Midwestern Regional Carbon Sequestration Partnership (MRCSP) Phase III (Development Phase) Final Technical Report (No. DOE-BATTELLE-42589). Battelle Memorial Inst., Columbus, OH (United States).
3. Gupta, N., Haagsma, A., Conner, A., Cotter, Z., Grove, B., Main, J., Scharenberg, M., Larsen, G., Raziperchikolaee, S., Goodman, W. and Sullivan, C., 2020. Geologic Characterization for CO_2 Storage with Enhanced Oil Recovery in Northern Michigan (No. DOE-BATTELLE-42589-Geologic). Battelle Memorial Inst., Columbus, OH (United States).
4. Mishra, S., Haagsma, A., Valluri, M. and Gupta, N., 2020. Assessment of CO_2-enhanced oil recovery and associated geologic storage potential in the Michigan Northern Pinnacle Reef Trend. Greenhouse Gases: Science and Technology, 10(1), pp.32-49.
5. Gupta, N., Kelley, M., Place, M., Conner, A., Mawalkar, S., Mishra, S. and Sminchak, J., 2020. Integrated Monitoring Volume: A Summary of Monitoring Studies Conducted in Niagaran Carbonate Pinnacle Reefs During Enhanced Oil Recovery with CO_2 (No. DOE-BATTELLE-42589-Monitoring). Battelle Memorial Inst., Columbus, OH (United States).

Other relevant information considered pertinent to the report

Gupta, N., Mawalkar, S., Burchwell, A., Keister, L. and Pasumarti, A., 2020. Mass Balance Accounting for CO_2 Storage with Enhanced Oil Recovery in Northern Michigan (No. DOE-BATTELLE-42589-MassBalance). Battelle Memorial Inst., Columbus, OH (United States).

Mawalkar, S., Burchwell, A., Gupta, N., Place, M., Kelley, M., Winecki, S., Mannes, R. and Pardini, R., 2018, October. Achieving~ 1 Million Metric Ton CO_2 Stored; Measurement and Accounting for Net CO_2 Injection in a CO_2-EOR Complex. In 14th Greenhouse Gas Control Technologies Conference Melbourne (pp. 21-26).

For further reading more reports can be found at https://edx.netl.doe.gov/group/rcsp-mrcsp

Figures

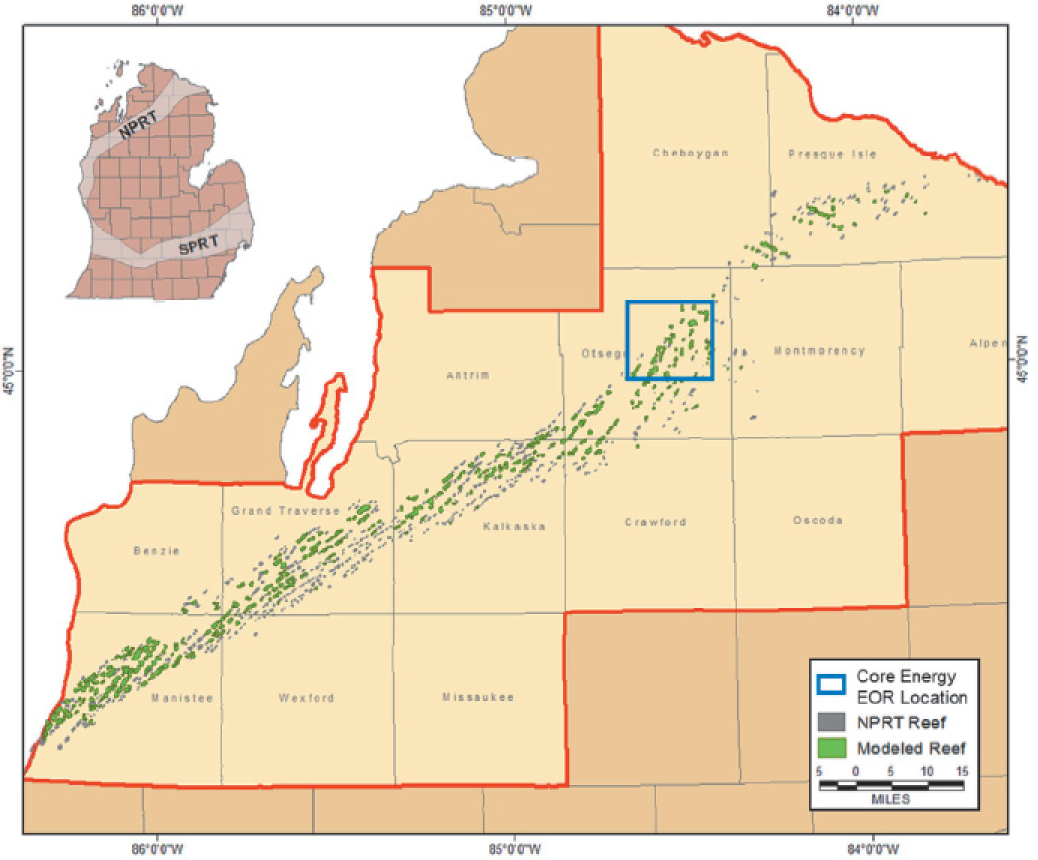


Figure 5.1: Map showing the distribution of the Northern Pinnacle Reef Trend (NPRT)[4]

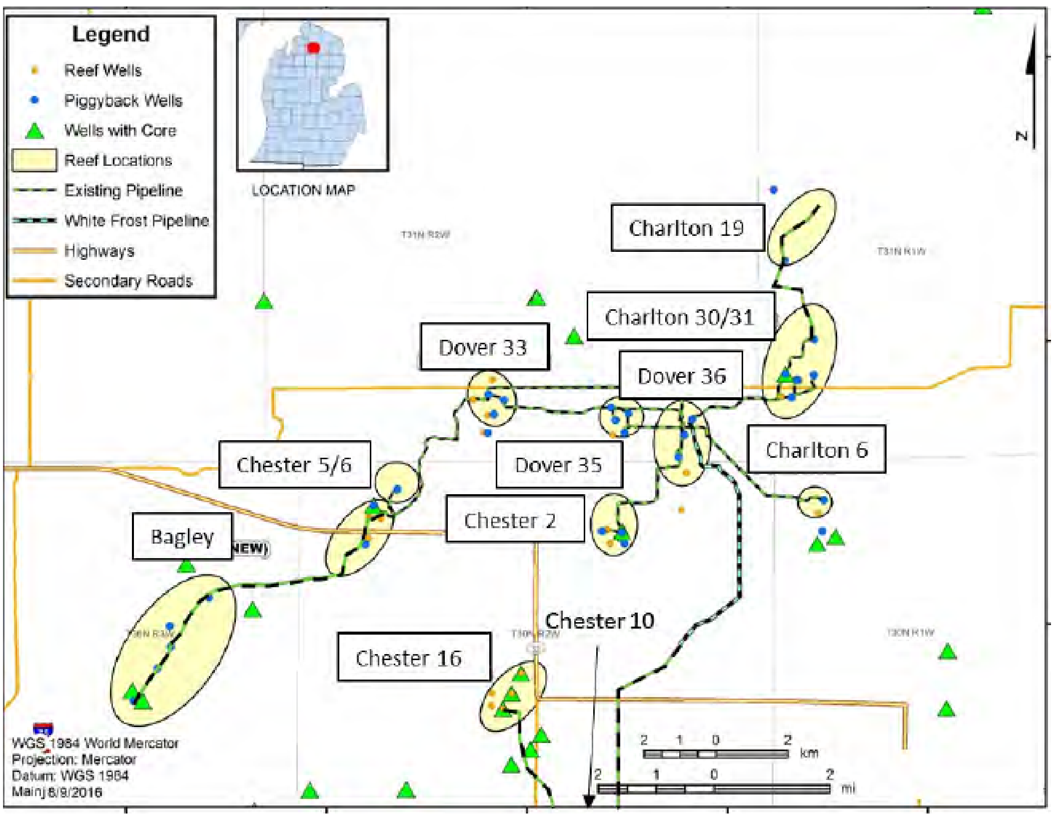


Figure 5.2: Map of reefs studied as part of Task 3, 4 and 5 of Phase III of the MRCSP Michigan Basin Large-Scale Injection Project [2]

Reef	Geologic Characterization	Modeling	Monitoring	Stage
Dover 33	X	X	X	Late
Charlton 19	X	X	X	New
Bagley	X	X	X	New
Chester 2	X		X	Active
Charlton 6	X		X	Active
Charlton 30/31	X		X	Active
Chester 5/6	X		X	Active
Dover 35	X		X	Active
Dover 36	X		X	Active
Chester 16	X	X	X	New

Table 5-1: List of reefs in study and overview of analysis performed[2].

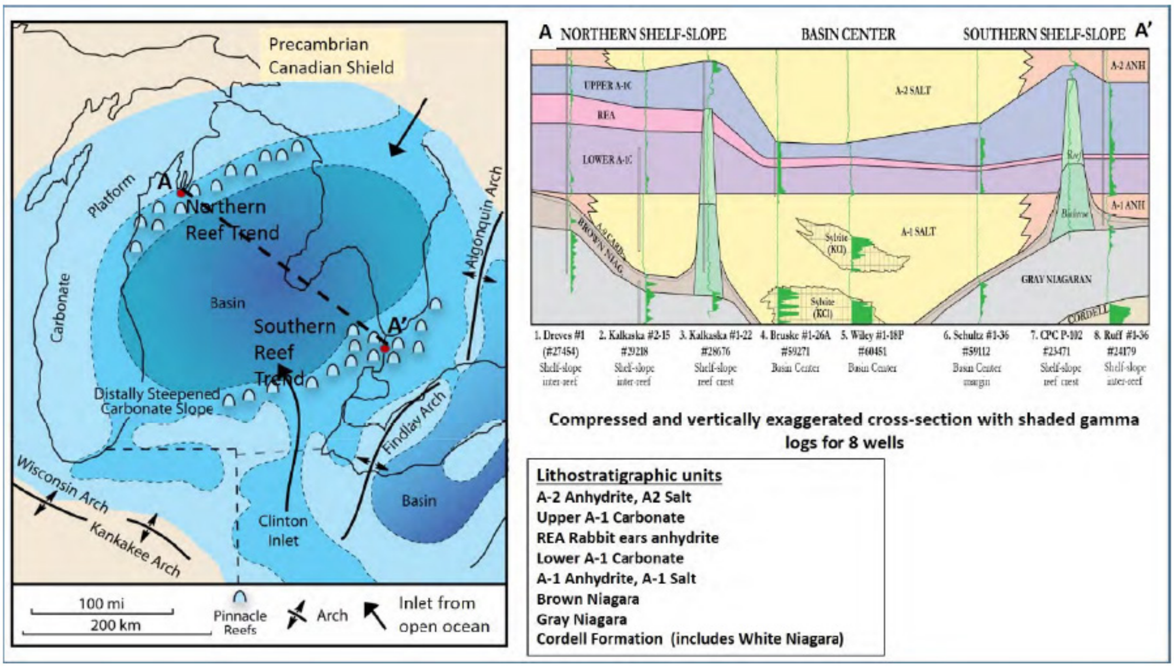


Figure 5.3: Silurian Northern Niagaran Pinnacle Reef Trend within the Michigan Basin and a cross section showing the geometry of reservoirs and seals across the Michigan Basin[3].

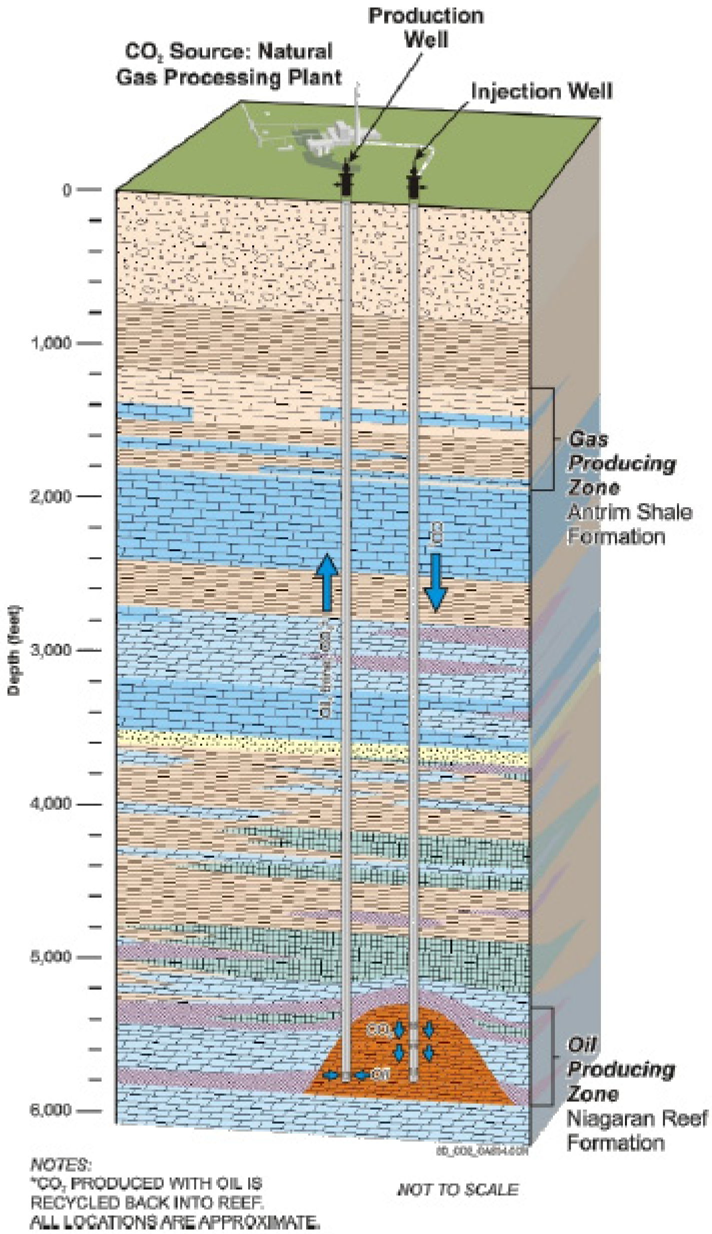


Figure 5.4: Simplified diagram of CO_2-EOR process in a pinnacle Niagaran reef[2].

	Monitoring Objective				Monitoring by Reef				
Monitoring Technology	**Mass-Balance Accounting**	**Leak Detection/ well integrity**	**CO_2 plume tracking/ interaction**	**Induced seismicity, land displacement**	**Dover 33**	**Charlton 19**	**Chester 16**	**Bagley**	**Other reefs**
CO_2 injection/ production	X				X	X	X	X	X
Reservoir Pressure		X	X		X	X	X	X	X
Temperature (DTS)		X	X				X		
PNC logging		X	X		X	X	X	X	
Borehole gravity			X		X				
Geochemistry			X		X	X	X	X	
Vertical seismic profile – geophone		X	X		X				
Vertical seismic profile – DAS		X	X				X		
Cross-well seismic			X				X		
Microseismicity				X	X				
InSAR (Satellite radar)				X	X				

Table 5-2: MRCSP Monitoring Technologies by Objective and Reefs[2] .

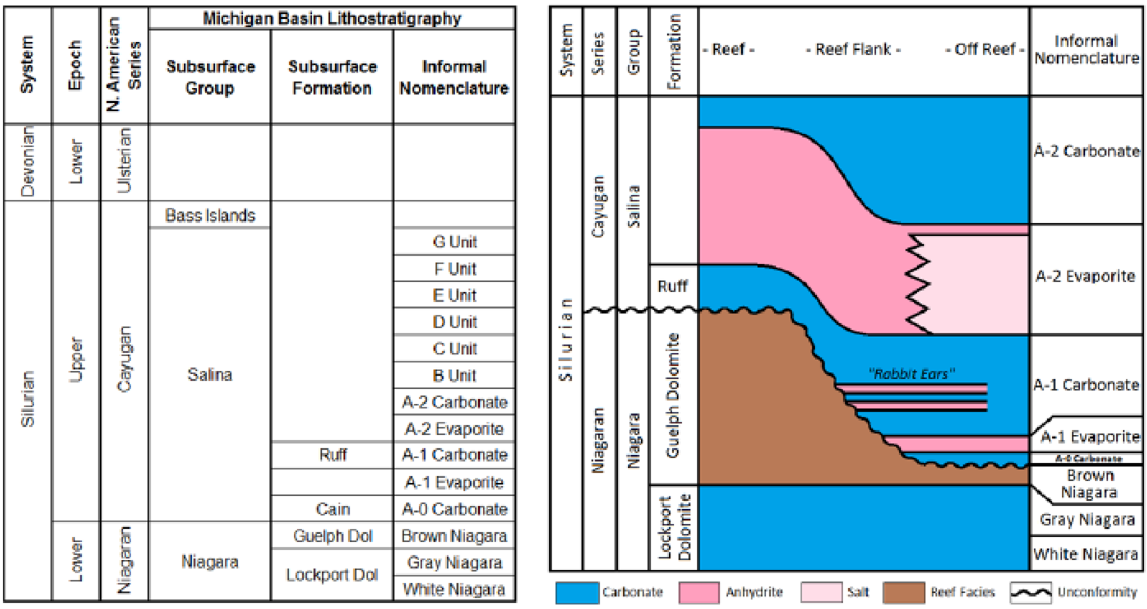


Figure 5.5: Stratigraphy of the Silurian-age Niagaran and Salina Groups in the Michigan Basin. On left is formal and informal Silurian stratigraphic nomenclature. On the right is a conceptual model and stratigraphy of the Brown Niagaran reef interval[2].

Dominantly Dolomite	Mixed Carbonate	Dominantly Limestone	A-1 Carbonate
• Dover 33, Charlton 19, and Bagley	• Dover 35, Dover 36, and Chester 5/6	• Chester 16, Chester 2, Charlton 30/31, and Charlton 6	• Chester 16, Bagley, Dover 35, Chester 5/6, and Chester 2
• 8-12% porosity, highest near the top	• 4-5% porosity, streaky where dolomitized	• 3-5% porosity, streaky to isolated	• 5-8% porosity, along cap of reef
• Minor to mild salt plugging	• mild salt plugging	• Mild to pervasive salt plugging	• all dolomitic
• Streaky to pervasive vugs & fractures	• streaky, thin intervals of vugs	• Isolated to streaky vugs	• minor salt plugging
• higher production	• moderate production	• lower production	• can contribute to production

Figure 5.6: summary of major reef categories listing common characteristics observed during geologic analysis[2].

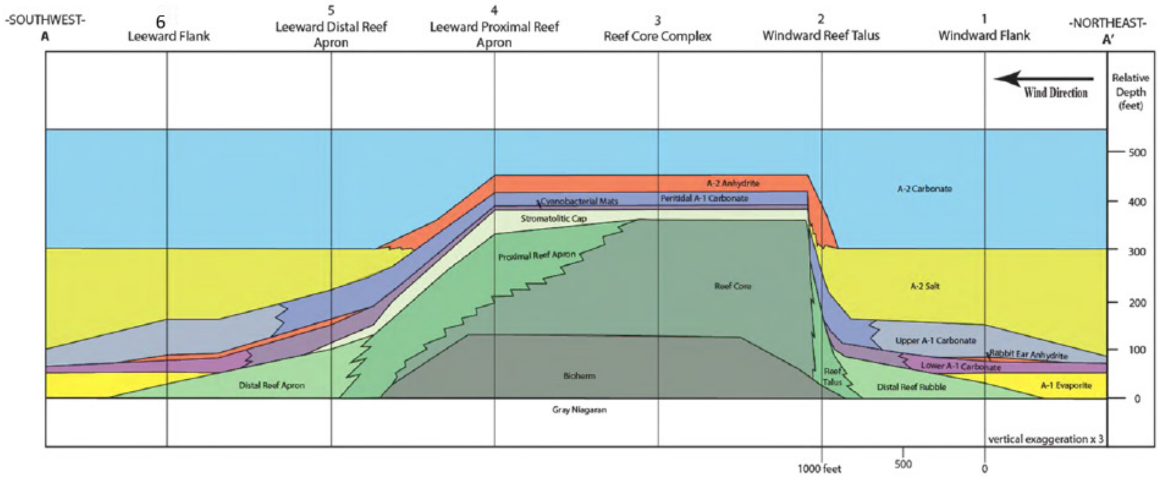


Figure 5.7: Depositional facies model developed for the pinnacle reefs[3].

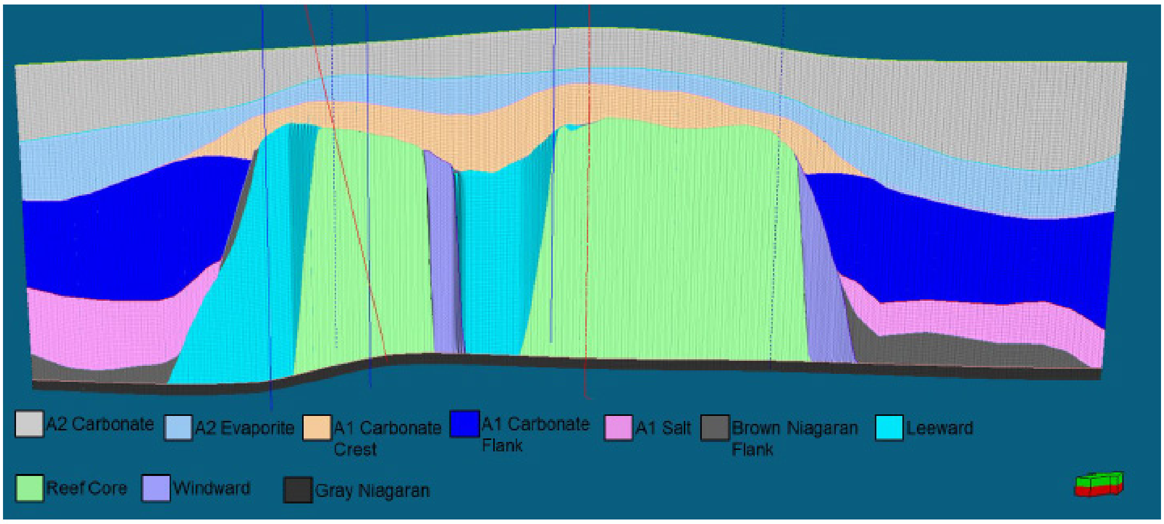


Figure 5.8: Generic cross section through Chester 16 reef field showing geologic architecture of the field including reservoirs and confining units. The green zone represents the main reef core facies with highest reservoir potential and the overlying orange zone represents high porosity A-1 carbonate[2].

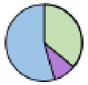
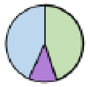
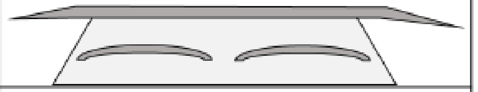
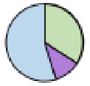
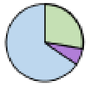
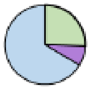
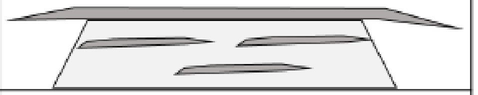
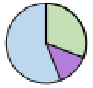
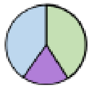
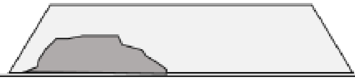
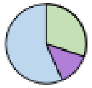
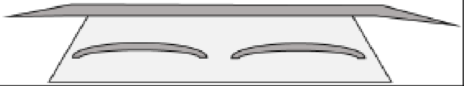
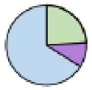
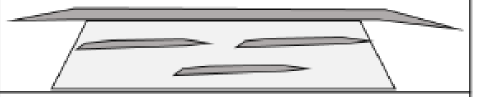
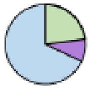
Reef	Petrophysical and Core Properties	Reservoir Attributes	Lithofacies	Production	Reservoir Pattern
Dover 33	Avg. Porosity- 8.2% Avg. Permeability-6.5 mD Lithology-Dolomite	Primary-Brown Niagaran Salt Plugging-Mild Diagenesis-Pervasive # of Reefs- 1		OOIP-3.5 MBBL Oil-1.8 MBBL Gas-1.8 MMCF	
Chester 16	Avg. Porosity- 3.6% (BN), 7.8% (A1C) Avg. Permeability- 23 mD(BN), 7.0 mD(A1C) Lithology- Dolomite (A1C), Limestone (BN)	Primary-BN and A1C Salt Plugging- Minor Diagenesis-Streaky # of Reefs- 2		OOIP-6.9 MBBL Oil-3.0 MBBL Gas-2.6 MMCF	
Bagley	Avg. Porosity- 7.9% (BN), 5.8% (A1C) Avg. Permeability- 94 mD(BN), 7.0 mD(A1C) Lithology-Dolomite	Primary-BN and A1C Salt Plugging-A1C Diagenesis- Pervasive # of Reefs- 4		OOIP-9.0 MMBL Oil- 2.9 MMBL Gas-6.7 MMCF	
Charlton 19	Avg. Porosity-11.7% Avg. Permeability-unknown Lithology-Dolomite	Primary- BN Salt Plugging-Minor Diagenesis- Extreme (Karst) # of Reefs-2		OOIP-2.6 MMBBL Oil-1.1 MMBBL Gas-2.3 MMCF	
Dover 35	Avg. Porosity- 4.7% (BN), 3.1% (A1C) Avg. Permeability-unknown Lithology-mixed carbonate	Primary- BN and A1C Salt Plugging-mild Diagenesis-Streaky # of Reefs-1		OOIP-2.5 MMBBL Oil-1.9 MMBBL Gas-.8 MMCF	
Dover 36	Avg. Porosity-1.4% Avg. Permeability-unknown Lithology- mixed carbonate	Primary-BN Salt Plugging-mild Diagenesis-Streaky # of Reefs-3		OOIP-3.7 MMBBL Oil-1.8 MMBBL Gas-1.2 MMCF	
Chester 2	Avg. Porosity- 4.0% Avg. Permeability-.2 mD Lithology- limestone, dolomitized pod	Primary-BN Salt Plugging-Pervasive Diagenesis- Isolated # of Reefs-1		OOIP- 3.2 MMBBL Oil- 1.1 MMBBL Gas-.7 MMCF	
Chester 5/6	Avg. Porosity- 4.2%(BN), 6.0% (A1C) Avg. Permeability-.8mD (BN), 16 mD (A1C) Lithology- mixed carbonate	Primary-BN and A1C Salt Plugging- mild Diagenesis- streaky # of Reefs-3		OOIP- 2.9 MMBBL Oil- 1.3 MMBBL Gas-1.3 MMCF	
Charlton 30/31	Avg. Porosity-4.6% (A1C), 4.2%(BN) Avg. Permeability-unknown Lithology- limestone	Primary- BN and A1C Salt Plugging- mild Diagenesis- streaky # of Reefs-3		OOIP-6.8 MMBBL Oil- 3.0 MMBBL Gas-3.9 MMCF	
Charlton 6	Avg. Porosity-5.3% Avg. Permeability-unknown Lithology- Limestone	Primary- BN Salt Plugging-Mild Diagenesis- Streaky # of Reefs-1		OOIP-1.7 MMBBL Oil- .7 MMBBL Gas-1.5 MMCF	

Figure 5.9: Reef properties, attributes, lithofacies, production, and reservoir pattern by reef[2].

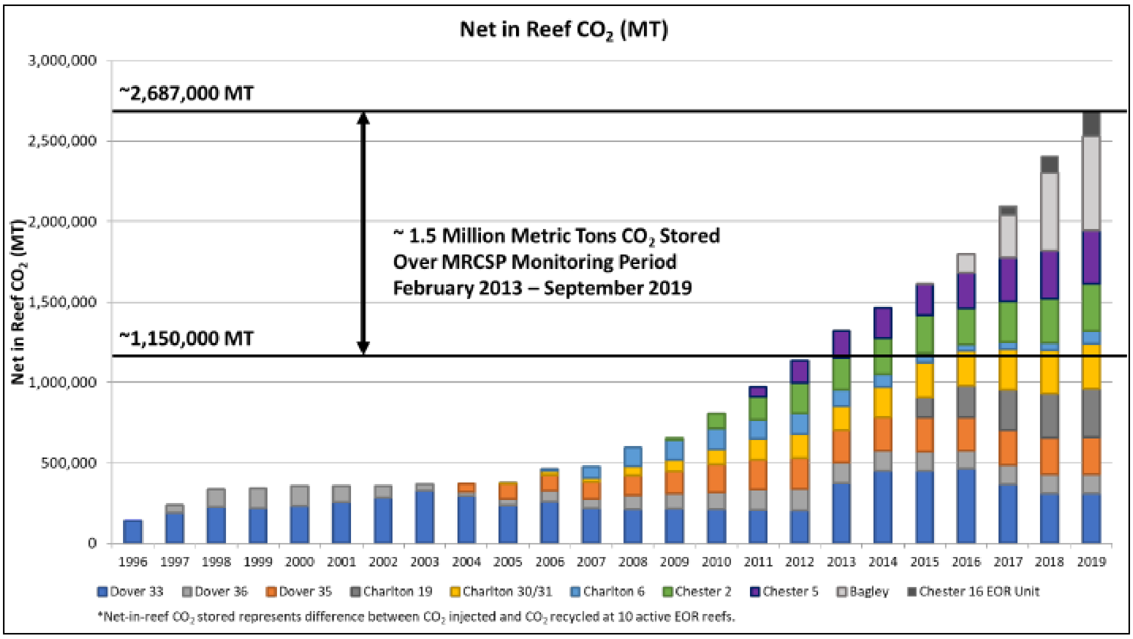


Figure 5.10: Net in-reef CO_2 over the life of secondary recovery within the MRCSP reef complex[2].

Reef	Data Integration (SEM)	History Matching	System Design	Coupled Process Understanding
Dover-33	x	x	x	x
Charlton-19	x	x		
Bagley	x	x		
Chester-16	x	x	x	

Table 5-3: Types of modelling applied to the reefs of interest[2].

6. Illinois Basin Decatur Project

Site Details					
Name	Location	Province/State	Country	Onshore	Offshore
Illinois Basin – Decatur Project (IBDP)	Decatur	Illinois	USA	✓	

General storage type
Deep Saline Formation

Development History (Closed)

The Illinois Basin – Decatur Project (IBDP) was a collaborative project of the Midwest Geological Sequestration Consortium, that consisted of University of Illinois, Archer Daniels Midland Company (ADM), Schlumberger Carbon Services, and other subcontractors. It was led by the University of Illinois – Illinois State Geological Survey with a specific objective to inject 1 Mt CO_2 from an industrial source into a large regional deep saline formation. IBDP began in 2007 with a three-year pre-injection characterisation and design period, followed by injection in November 2011 and completed injection in November 2014 after 999,215 t CO_2 had been injected. Stored CO_2 was derived from biofuel production at the ADM hosted test site. Post-injection monitoring took place from 2014 to 2021 when the project was completed. [1]

ADM began injection operating a second CCS project, the Illinois Industrial Sources Carbon Capture and Storage Project in Decatur in April 2017, permitted until 2022, and has resulted in more than 3.5 MT CO_2 stored. This entry just focusses on the IBDP.

Geological Characteristics

Reservoir Formation

The target reservoir formation at this location was the Cambrian Mt. Simon Sandstone which is a regionally extensive formation across the Illinois Basin. A regional isopach map of the Mt Simon Formation (Figure 6.1), shows its depo centre to the north-east of the Decatur site is over 2,400 feet (~732 m). This figure also shows well distributions that have penetrated the formation (assumed)[2]. At the IBDP, the Mt Simon Sandstone is underlain by Precambrian igneous basement and is approximately 1,500 ft (457 m) thick (Figure 6.2). Detailed geological characterisation of the Mt. Simon Sandstone was completed at the Decatur site. Nine different lithofacies were identified from the extensive number of side-wall and whole wellbore cores. Further characterisation of the Mt. Simon by gamma ray (GR) and neutron porosity logs, combined with petrological analysis of the

1 "Illinois State Geological Survey (ISGS), Illinois Basin - Decatur Project (IBDP) Selected Reports, April 30, 2021. Midwest Geological Sequestration Consortium (MGSC) Phase III Data Sets. DOE Cooperative Agreement No. DE-FC26-05NT42588., DOI: 10.18141/1854146"2015

2 A Depositional and Diagenetic Characterization of the Mt. Simon Sandstone at the Illinois Basin - Decatur Project Carbon Capture and Storage Site, Decatur, Illinois, USA Jared T. Freiburg, David G. Morse, Hannes E. Leetaru, Riley P. Hoss, and Qina Yan ILLINOIS STATE GEOLOGICAL SURVEY - Prairie Research Institute Circular 583 2014

<table>
<tr><td colspan="2">core samples, allowed for further characterization and identification of the formation to be subdivided into five intervals from oldest Unit A to youngest Unit E (Figure 6.3).

Three major depositional environments have been interpreted from the characterisation: fluvial-alluvial, braided river and flood plain: aeolian, sand sheet and playa: and marine-tidal to sub-tidal and channel sands. A combination of basin evolution, depositional environment and subsequent diagenesis have influence the porosity / permeability properties of the sandstone which varies significantly. Primary porosity and secondary porosity from dissolution of detrital grains in the Lower Mt. Simon have generated an excellent reservoir. Compaction and quartz cementation in the overlying Middle Mt. Simon has created a moderate seal[2].

For more detailed petrographic descriptions, interpretation and characterisation of the Decatur Mt Simon Sandstone, reference 2 is recommended.</td></tr>
<tr><td>Lateral extent / thickness variation</td><td>The Mt. Simon was found at a depth of 5,545 feet (1,690 m) to 7,051 feet (2,150 m) based on borehole logging data. CCS #1</td></tr>
<tr><td>Rock type</td><td>Sandstone</td></tr>
<tr><td>Sedimentary features: Depositional Environment / facies type & variation / mineral composition</td><td>See above</td></tr>
<tr><td>Porosity</td><td>Based on the neutron-density cross plot porosity, for Unit A an average effective porosity of 21.0% (Figure 6.3).</td></tr>
<tr><td>Permeability</td><td>An interval of high porosity and permeability was identified at the base of the Mt. Simon in CCS #1. This interval was selected as the injection interval and was perforated between 6,985 – 7,015 ft (~2,130 - ~2,139 m) and 7,025 -7,050 ft (~2,142 – 2,149 m) at the base of Mt. Simon Sandstone Formation[3].

A core porosity-permeability transform was developed based on grain size. Based on the neutron-density crossplot porosity and the core porosity-permeability transform, Unit A within the perforation depth has an average of 174.56 mD of horizontal permeability, and 19.07 mD of vertical permeability[2].</td></tr>
</table>

3 Lessons Learned from the Illinois Basin – Decatur Project: Integration of Deep Saline CO_2 Storage into the Value Change. 12th May 2015 – CO2GeoNet – Venice, Italy

Formation fluid properties: (residual hydrocarbons / salinity concentration).	*Pressure and Temperature*: Based on downhole wireline tools, formation temperatures ranged from 40°C at ~1,500 m to 50°C at ~2,250 m[4]. Zone 1 3200 psi (22 Mpa) (at start of injection) to 3340 psi (23 Mpa) at Zone 1 as injection progressed 3050 psi (21 MPa) Zone 5 at start of injection[3]. *Salinity*: >200,000 ppm[3], (Key operational results – IBDP at completion of injection).
Caprock / primary seal formation	
The Eau Claire Formation conformably overlies the Mt. Simon Sandstone and is composed of tidally deposited shale, silty mudstone, muddy siltstone, clean siltstone, and sandstone in the lower half and dolomite and siltstone in the upper half[5]. At the IBDP site, the Eau Claire Formation is 497 ft (151 m) thick. The Eau Claire shale facies comprises the primary reservoir seal for the IBDP. In addition to the Eau Claire there are two other regionally extensive shales, the Ordovician-age Maquoketa Formation and the Devonian-age New Albany Shale. All three major seals are laterally extensive and appear, from subsurface wireline correlations, to be continuous within a 100-mile (160.93 km) radius of the test site[6]. The Maquoketa Shale is estimated to be over 200 feet (60.96 m) thick at the test site and acts as a regional seal for oil reservoirs from the Ordovician Galena (Trenton) Limestone. The New Albany Shale is about 140 feet (42.67 m) thick in the project area. Extensive well control from oilfields shows that this shale is a good seal for oil accumulations. Evidence of the permeability Eau Claire Formation from the UIC (Underground Injection Control) database shows that this formation has a median permeability of 0.000026 mD and a median porosity of 4.7%[6]. Cores (414 ft (~126 m) in length) obtained from the Ancona Gas Storage Field, located 80 miles (~129 km) to the north of the Decatur site were tested for permeability. Most vertical permeability analyses were <0.001 mD. Only five of the 110 analyses were between 0.100 and 0.871 mD[6]. The closest Mt. Simon well penetration to the test site is the Harrison #1 well about 17 miles (27.36 km) to the southeast[7]. The lowermost seal, the Eau Claire, has no known penetrations within a 17-mile (27.36 km) radius surrounding the test site.	
Lateral extent / thickness variation	Regionally extensive, as above
Rock type	As above
Fracture pressure	A minifrac test in the Eau Claire Formation showed a minimum horizontal stress of 5051 psi (34.8

4 E. Mehnert, J. Damico, S. Frailey, H. Leetaru, R. Okwen, B. Storsved, and A. Valocchi. (2014) Basin-scale modeling for CO_2 sequestration in the basal sandstone reservoir of the Illinois Basin—Improving the geologic model Energy Procedia 63 2949 – 2960
5 Palkovic, M. (2015) Depositional characterisation of the Eau Claire Formation at the Illinois Basin-Decatur Project: Facies, Mineralogy and Geochemistry. Thesis MSc. University of Illinois pp88.
6 Final Environmental Assessment - Midwest Geological Sequestration Consortium (MGSC) Phase III Large-Scale Field Test Decatur, Illinois DOE/EA-1626, U.S. DOE_NETL October 2008
7 ADM, 2008a). Archer Daniels Midland. 2008. Application for Underground Injection Control. Permit. 199 pp

	MPa) at a depth of 5335 ft (1.6 km). Injection and step rate tests in the Mt. Simon showed that the fracture pressures are 4586–4965 psi (31.6–34.2 MPa) at the depth of injection of 7025 ft (2.14 km)[8]. At the IBDP site, the maximum increased pressures were 165 psi (1.14 MPa) or 5.2% above original formation pressures, as measured in VW1, 1007 ft (307 m) from the injection borehole and this pressure represent only 65% of the fracture pressure for the Mt. Simon injection zone[8].
Porosity	Median porosity is 4.7%[6].
Permeability	Median permeability is 0.000026 mD[6].
Overburden Features	
n/a	
Structure	
Fold type / fault bounded	n/a
Faults /Fractures (Type – normal, reverse, strike-slip)	There are no mapped regional faults and fractures within a 25-mile (40.23 km) radius of the Decatur site[6]. For a regional perspective of the Illinois Basin and adjacent areas the Illinois State Geological Survey have produced a series of maps covering the region[9]. Figure 6.4 shows the abundance and orientation of folds and faults. On the basis of this information the latter are highly prevalent in eastern Missouri, Kentucky and southern Illinois and but are virtually absent across most of the rest of the state. No pre-existing fault planes were seen in 3D seismic surveys conducted before injection began. Historic and instrument located earthquakes in Illinois from 1795 to 2015 have also been documented[8]. Most occur across the south of the state and a few to the north of the Decatur

8 Overview of microseismic response to CO_2 injection into the Mt.Simon saline reservoir at the Illinois Basin-Decatur Project. Robert A. Bauer, Michael Carney, Robert J. Finley. International Journal of Greenhouse Gas Control 54 (2016) 378–388

9 Geological and Geophysical Maps of the Illinois Basin–Ozark Dome Region - Illinois Map 23. Illinois State Geological Survey – Figure 11 Fault (black) and fold (magenta) traces. 2016

	site. This evidence suggests the Decatur site is seismically quiescent.
Displacement	n/a
Stability (pre-stressed, active, stable)	n/a

Seismicity

Monitoring regime (technologies deployed)

Microseismicity was recorded by three vertical arrays: one in CCS1 and another in GM1, and on temporary in a deep monitoring well with a total of 38 four- of three-component geophones[10].

Seismic events (Detection / magnitude / attribution (natural induced).

Clusters of microseismic events with magnitudes between 0.66 and 1.17 were detected. Nearly half of these were located in the Precambrian basement; the remainder mostly in the Mt Simon with a few in the pre-Mt. Simon Formation[8].

These events continued during injection and transient shut-in periods. Most developed along an elongated pattern in the SW–NE direction. Cluster orientation is consistent with the north-east principal stress direction [11].

Injection / storage history

Number of injection, monitoring or other wells, well geometry, design and key completion information for injection wells, relevant well issues. Reused / new purpose drilled well.

A series of wells were drilled at the Decatur test site (Figure 6.5) [2]:

- CCS #1 – injector depth 7,236 ft (2,205 m), completed with two zones perforated for injection. The lowermost zone at 7025-7050 ft (2141-2149 m) accepted the majority of the CO_2. Three multicomponent geophone arrays were installed[8].
- VW #1 – monitoring 7,272 ft (2,216 m), designed for deep reservoir monitoring, drilled in 2010 1007 ft (307m) north of CCS1, included sampling ports for formation water chemistry and 11 levels of formation pore pressure and temperature monitoring[8].
- GM #1 – geophysical monitoring, 196 ft (60m) west of CCS1, has 31 multicomponent geophones for VSP monitoring and also used for microseismic monitoring [8].
- 17 groundwater wells at 11 locations were installed at depths ranging from 10 to 100 meters. Four used for compliance monitoring and 13 are referred to as 'research wells'.

Summary of recovered cores[2]:

10 Greenberg, S.E., Bauer, R., Will, R., Locke II, R., Carney, M., Leetaru, H. and Medler, J., 2017. Geologic carbon storage at a one million tonne demonstration project: Lessons learned from the Illinois Basin–Decatur Project. Energy Procedia, 114, pp.5529-5539

11 Lessons Learned from the Illinois Basin – Decatur Project: Integration of Deep Saline CO_2 Storage into Value Change. Sallie E Greenberg, Advanced Energy Technology Initiative, University of Illinois – Illinois State Geological Survey. 12 May 2015 – CO2GeoNet – Venice, Italy

Table 1 Amount of Eau Claire, Mt. Simon, pre-Mt. Simon, and Precambrian core cut in the CCS #1, VW #1, and VW #2 wells[1]

Well	Total 4-in. core (ft)	RSWC	Basement (ft)	Pre-Mt. Simon (ft)	Lower Mt. Simon (ft)	Middle Mt. Simon (ft)	Upper Mt. Simon (ft)	Eau Claire (ft)
CCS #1	90	57	0	0	30	30	0	30
VW #1	588	119	15	58	316	60	38	101
VW #2	396	64	0	60	255	39	0	43

[1]RSWC, rotary sidewall core; CCS #1, Carbon capture and storage #1 well; Verification #1 well; VW #2, Verification #2 well.

Extent and status of casing (corrosion history/ cementation records)	n/a
Injection rates & pattern (i.e. continuous / intermittent) changes in injection behaviour	CO_2 injection started on 17 November 2011 and continued at a rate of approximately 1,102 tons (1,000 tonnes) per day to 26 November 2014, with various short interruptions to continuous injection. The overall average per month for the injection time period was about 30,864 tons (28,000 tonnes)[11].
Total quantities stored	CO_2 sourced from Archer Daniels Midland ethanol fermentation facility. Injection began November 2011. Injection completed 11/26/14. A total of 999,215 tonnes were stored.
Reservoir capacity (estimate)	n/a
Fluid extraction rate (brine extraction, oil for EOR)	n/a
Monitoring technologies applied and experiences with monitoring	
Surface monitoring technologies deployed (Figure 6.5).	
3D seismic surveys (time-lapse)	3D shot prior to (2011) and after completion of CO_2 injection (2015) (Figure 6.6) in order to monitor the development of the CO_2 plume. Covered an area of 4 mile^2 with 3,393 shot points. For 4D work flow see[12]. Evaluated by Normalized Root Mean Square (NRMS), Reliability, and Non-Rigid Matching (NRM) displacement field attributes and compared to the modelled plume to further constrain the model[10].
Aerial Imagery	Up to 2012. Documented project activities. Colour infrared not sufficient to quantitively describe land surface changes e.g. vegetation response[12].

12 Greenberg, S., 2021. An Assessment of Geologic Carbon Sequestration Options in the Illinois Basin: Phase III (No. DOE-UIUC-42588). The Board of Trustees of the University of Illinois.

	Lack of established and consistent vegetation over area also hindered the ability to use plant health to observe any potential CO_2 leakage.
Eddy covariance	Monitor atmospheric CO_2 fluxes, functioned intermittently and taken down in 2010[12].
Soil flux – network	Weekly measurements from April-December each year from a point network of over 100 locations. Concluded in Dec 2015[10].
Soil flux - multiplexer	Sampled every 30 minutes when operational.
InSAR	21 artificial reflectors spaced 246 ft (75 m) apart, were installed north and west of CCS1. Baseline InSAR survey acquired in July 2011 prior to injection, subsequent surveys continued through first half of injection, then discontinued. InSAR testing indicated there was no surface deflection due to injection, the method was not deemed suitable for plume delineation at the IBDP site[12].
Continuous GPS	Installed in December 2011. No surface deformation could be attributed to injection, other local activities created anomalies in the data set[12].
Near-Surface	
Soil gas sampling	Summer 2011-September 2016, and includes a total of 24 sites with up to 3 sampling depths at 0.3, 0.6, and 1.2m respectively for each location, semi-annually/annually[10].
Shallow groundwater sampling	17 shallow ground water wells, sampled monthly during injection phase and reduced to quarterly post-injection until 2020.
Subsurface monitoring technologies deployed (well logs)	
Pressure / temperature (VW1 & CCS 1)	n/a
Pulse neutron (CCS 1, VW 1, GM 1)	Annual pulse neutron logs completed on each well. PNL during the injection period showed most of the CO_2 contained in the lower Mt. Simon A interval with a small amount extending up into the bottom of the Upper Mt. Simon A. CO_2 saturations remained consistent throughout the injection period with CO_2 segmented into the permeable formation layers[12]. PNL logs of VW1 showed three high permeability sand packages and interleaved low porosity and permeability layers which strongly control vertical CO_2 plume

	geometry at significant distance (>984 ft (300 m)) from CCS1[12]. Continued post-injection to show dissipation and buoyancy effects of the plume.
Deep fluid sampling (VW 1)	Beginning May 2011, well swabbing as part of the well completion. A total of 11 fluid sampling events have occurred and continued on an annual basis until 2019.
Passive seismic monitoring (GM 1)	Continuous in the post injection phase.
Seismic/3D VSP imaging	Permanent 31-level geophone array cemented in GM1 (from 135 ft (41 m) to 3443 ft (1049 m) deep). Two shallow geophones in GM1 were set at 135 ft (41 m) and 355 ft (108 m); the remaining 29 geophones were set between 2,045 ft (623 m) and 3,443 ft (1,049 m)[12]. Four 3D-VSP surveys were acquired over 4 years (2011-2015) to monitor the CO_2 injection in the lower Mt. Simon. Figure 6.7 shows the post-injection NRMS map, the plume started from the southeast of GM1 and continues to spread to the northwest. Yellow colour is the highest change and blue the least.
Mechanical integrity (CCS 1, VW 1)	
Experience summary - effectiveness of techniques (limitations / strengths)	
Shallow groundwater quality evaluations were based on intra-well trends and statistical assessments for sentinel parameters responsive to CO_2 (pH, alkalinity, Ca, TIC for the presence of CO_2) or brine components (Br, Cl, Na, conductivity). Four different soil gas ratios/relationships including: O_2 vs. CO_2; CO_2 vs. N_2; and CO_2 vs. N_2/O_2; and the isotopic differentiation of $\delta^{13}C_{CO2}$ are used to attribute the source of the CO_2. Laboratory experimentation has been used to evaluate potential geochemical signals from local geological materials as a response to CO_2 interaction. The NRAP (US DOE National Risk Assessment Partnership) aquifer impact model was used to predict the impact of CO_2 or brine leakage were it to occur at the IBDP and those results were tested against groundwater data from the site. In general, the IBDP employs logical and statistical testing of environmental monitoring data to characterize natural variability and monitor for anomalies. If anomalies are identified, they are investigated to determine the source of the variability. No anomalies from CO_2 injection have been identified [13].	
Major technical/scientific studies on the site, major learnings, Conformance assessment (history-matching with models, correlation between different monitoring techniques)	
Mt. Simon Sandstone reservoir accepted CO_2 more easily than expected resulting in quicker detection at verification well.	

13 "12th IEAGHG Monitoring Network Meeting", 2017/10, November 2017

Movement of CO_2 was detected and monitored using time-lapse 3D seismic, pressure and temperature measurements, pulsed neutron logging, 3D VSP imaging, deep fluid sampling and passive seismic monitoring.

Upward plume growth limited by reservoir permeability stratification, as modelled, and confirmed by pressure observations (Figure 6.8 & Figure 6.9).

Resulting plume believed thinner than expected and was not detected with a 3D vertical seismic profile until April 2013.

Mt. Simon 200,000 ppm brine is more corrosive than expected.

With 999,215 tonnes injected, CO_2 remains in lowermost Mt. Simon; internal reservoir heterogeneity affecting CO_2 distribution.

No CO_2 leakage or adverse impacts detected to date[14].

Little to no risk that induces seismicity could cause fault slippage through the caprock- and compromise the reservoir seal. Microseismicity is confined to basement, the Argenta formation, and the base of the Mt Simon Sandstone.

List of key publications covering the site

1. "Illinois State Geological Survey (ISGS), Illinois Basin - Decatur Project (IBDP) Selected Reports, April 30, 2021. Midwest Geological Sequestration Consortium (MGSC) Phase III Data Sets. DOE Cooperative Agreement No. DE-FC26-05NT42588., DOI: 10.18141/1854146"
2. A Depositional and Diagenetic Characterization of the Mt. Simon Sandstone at the Illinois Basin - Decatur Project Carbon Capture and Storage Site, Decatur, Illinois, USA. Jared T. Freiburg, David G. Morse, Hannes E. Leetaru, Riley P. Hoss, and Qina Yan. ILLINOIS STATE GEOLOGICAL SURVEY - Prairie Research Institute Circular 583 2014
3. Lessons Learned from the Illinois Basin – Decatur Project: Integration of Deep Daline CO_2 Storage into the Value Change. 12th May 2015 – CO2GeoNet – Venice, Italy
4. E. Mehnert, J. Damico, S. Frailey, H. Leetaru, R. Okwen, B. Storsved, and A. Valocchi. (2014) Basin-scale modelling for CO_2 sequestration in the basal sandstone reservoir of the Illinois Basin—Improving the geologic model. Energy Procedia 63 2949 – 2960
5. Palkovic, M. (2015) Depositional characterisation of the Eau Claire Formation at the Illinois Basin-Decatur Project: Facies, Mineralogy and Geochemistry. Thesis MSc. University of Illinois pp88.
6. Final Environmental Assessment - Midwest Geological Sequestration Consortium (MGSC) Phase III Large-Scale Field Test Decatur, Illinois. DOE/EA-1626. U.S. DOE_NETL October 2008
7. Archer Daniels Midland. 2008. Application for Underground Injection Control. Permit. 199 pp

14 “Lessons Learned from Large-scale Projects: Illinois Basin – Decatur Project”. Presentation by Sallie E. Greenberg, Illinois State Geological Survey 5 October 2016 –Tokyo, Japan

8. Robert A. Bauer, Michael Carney, Robert J. Finley. (2016) Overview of microseismic response to CO_2 injection into the Mt. Simon saline reservoir at the Illinois Basin-Decatur Project. International Journal of Greenhouse Gas Control 54 378–388
9. Geological and Geophysical Maps of the Illinois Basin–Ozark Dome Region - Illinois Map 23. Illinois State Geological Survey – Figure 11 Fault (black) and fold (magenta) traces. 2016
10. Lessons Learned from the Illinois Basin – Decatur Project: Integration of Deep Saline CO_2 Storage into Value Change. Sallie E Greenberg, Advanced Energy Technology Initiative, University of Illinois – Illinois State Geological Survey. 12 May 2015 – CO2GeoNet – Venice, Italy
11. Greenberg, S.E., Bauer, R., Will, R., Locke II, R., Carney, M., Leetaru, H. and Medler, J., 2017. Geologic carbon storage at a one million tonne demonstration project: Lessons learned from the Illinois Basin–Decatur Project. Energy Procedia, 114, pp.5529-5539.
12. Greenberg, S., 2021. An Assessment of Geologic Carbon Sequestration Options in the Illinois Basin: Phase III (No. DOE-UIUC-42588). The Board of Trustees of the University of Illinois.
13. 12th IEAGHG Monitoring Network Meeting, 2017/10, November 2017, Section 8
14. Lessons Learned from Large-scale Projects: Illinois Basin – Decatur Project. Presentation by Sallie E. Greenberg, Illinois State Geological Survey 5 October 2016 –Tokyo, Japan

Other relevant information / references considered pertinent to the report

Robert J. Finley and the MGSC Project Team, Midwest Geological Sequestration Consortium - A Demonstration of Carbon Dioxide Storage at a Biofuel Facility in Decatur, Illinois USA: The Illinois Basin –Decatur Project (IBDP)

Roland Okwen, Scott Frailey, and Hannes Leetaru (2014) Assessing Reservoir Depositional Environments to Develop and Quantify Improvements in CO_2 Storage Efficiency: A Reservoir Simulation Approach (DEEP)

Illinois State Geological Survey. U.S. Department of Energy, National Energy Technology Laboratory Carbon Storage R&D Project Review Meeting Developing the Technologies and Infrastructure for CCS, August 12−14, 2014

Sallie E. Greenberg, Ph.D. and the MGSC Project Team (2015) Illinois Basin – Decatur Project, Advanced Energy Technology Initiative. University of Illinois – Illinois State Geological Survey, Carbon Storage R&D project review meeting. 18 August 2015 – Pittsburgh, PA

Ozgur Senel, Nikita Chugunov (2013) CO_2 Injection in a Saline Formation: Pre-Injection Reservoir Modelling and Uncertainty Analysis for Illinois Basin Decatur Project, Energy Procedia 37 (2013) 4598 – 4611

Marcia L. Couëslan, Robert Butsch, Robert Will, and Randall A. Locke II (2014) Integrated reservoir monitoring at the Illinois Basin – Decatur Project, Energy Procedia 63 (2014) 2836 – 2847

Randall Locke II, David Larssen, Walter Salden, Christopher Patterson, Jim Kirksey, Abbas Iranmanesh, Bracken Wimmer, Ivan Krapac (2013) Preinjection reservoir fluid characterization at a CCS demonstration site: Illinois Basin – Decatur Project, USA, Energy Procedia 37, 6424 – 6433

Randall Locke II, David Larssen, Walter Salden, Christopher Patterson, Jim Kirksey, Abbas Iranmanesh, Bracken Wimmer, Ivan Krapac (2013) Preinjection reservoir fluid characterization at a CCS demonstration site: Illinois Basin – Decatur Project, USA, Energy Procedia 37, 6424 – 6433

Comprehensive list of references held at: https://carbon.americangeosciences.org/vufind

Figures

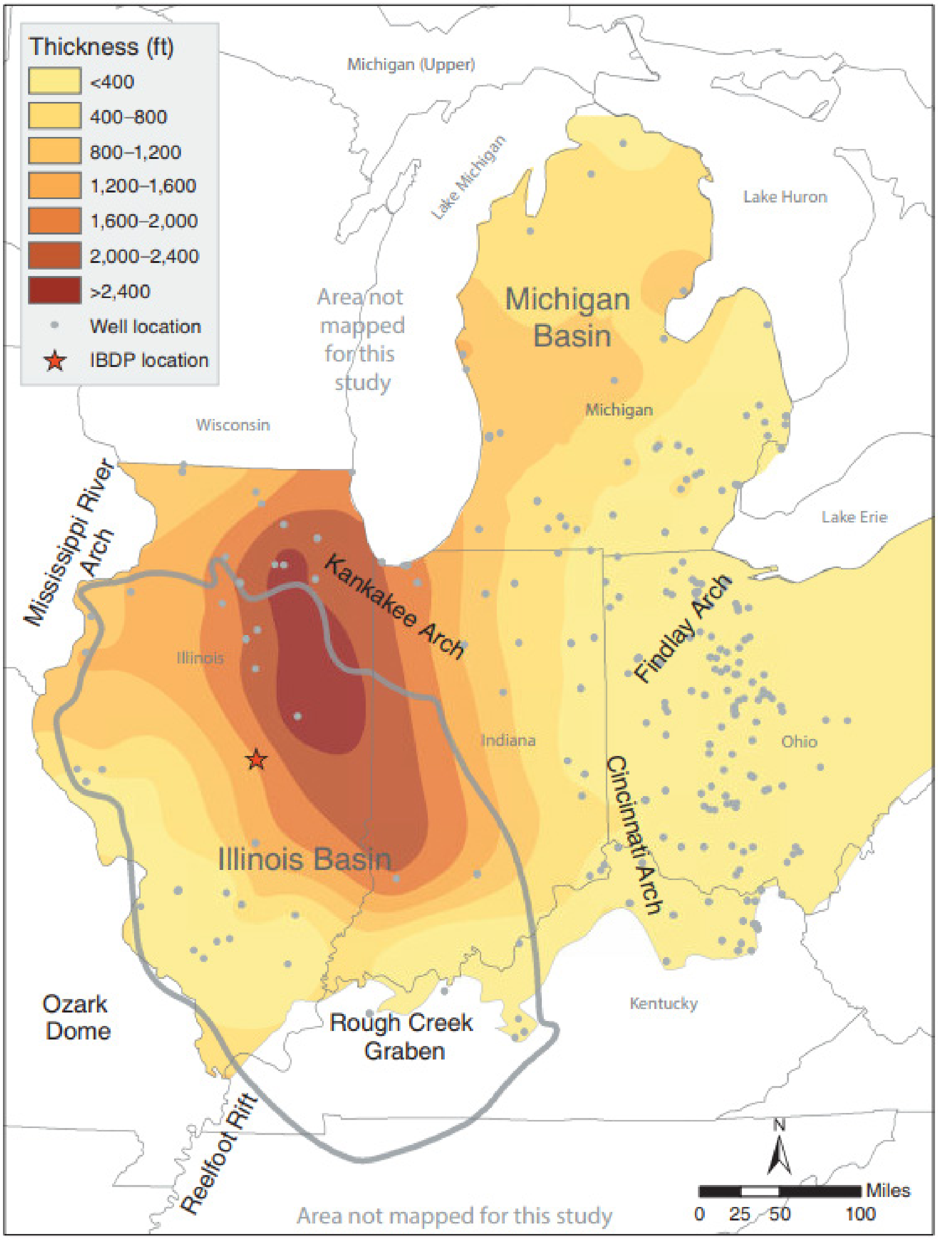


Figure 6.1:: Location of the Illinois Basin – Decatur Project (red dot) in relation to the Illinois Basin (grey outline) and regional isopach map of the Mt. Simon Sandstone[2].

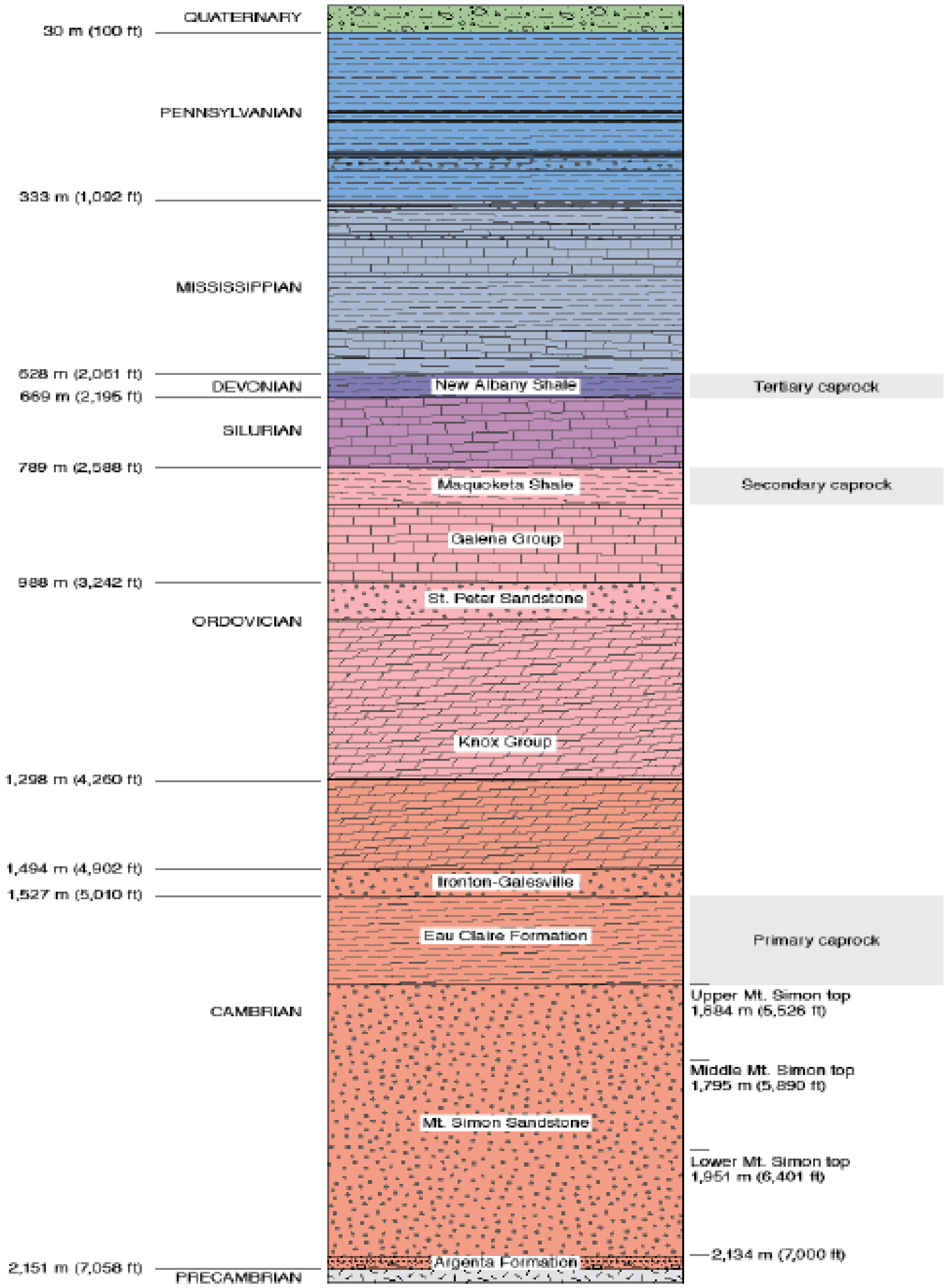


Figure 6.2: Stratigraphy of the IBDP site showing Mt. Simon reservoir and seals[8].

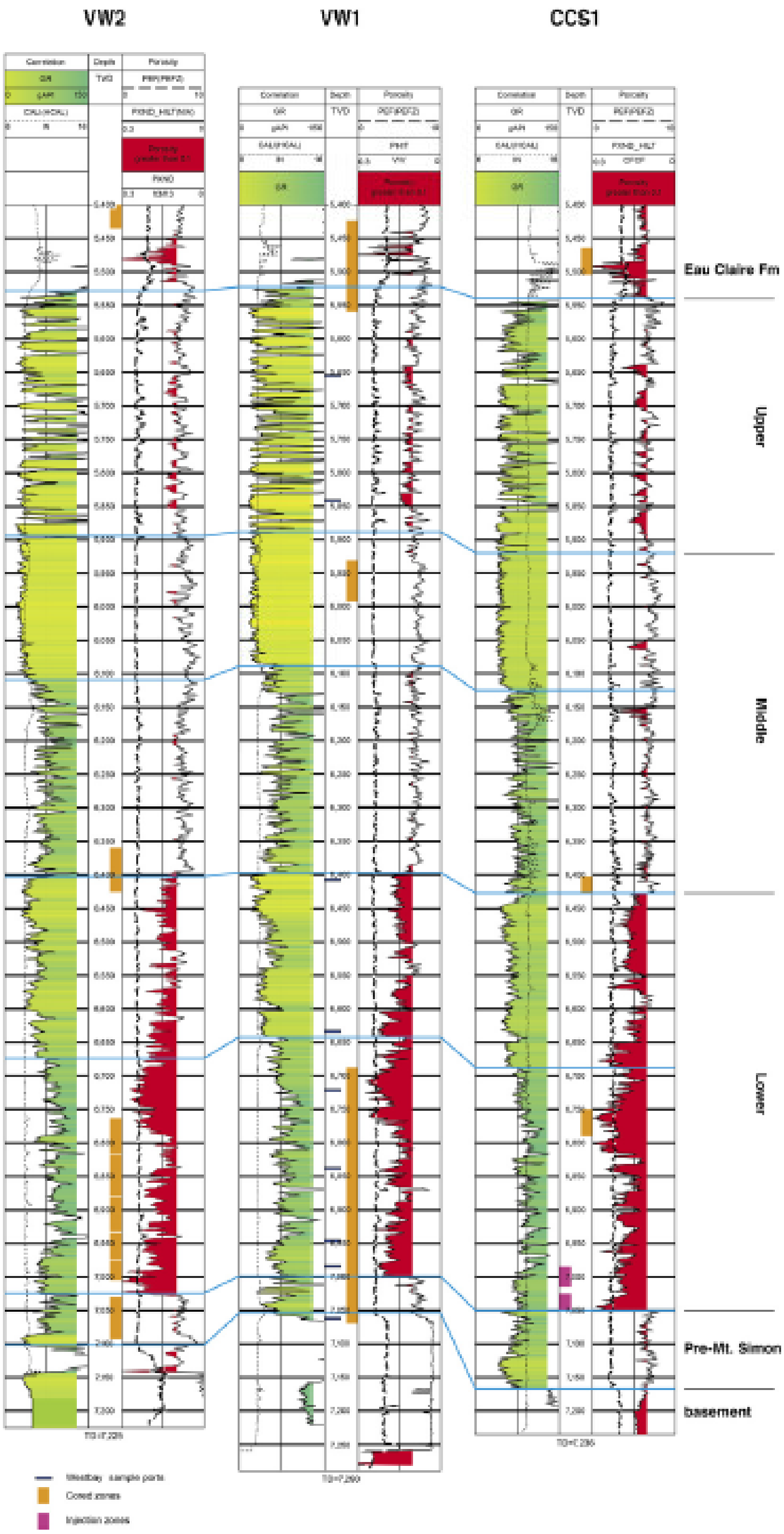


Figure 6.3:Three well-log panels across the IBDP study site showing the Mt. Simon and Pre-Mt. Simon Sandstones and part of the Eau Claire cap rock and Precambrian crystalline basement formations. Three subintervals of Mt Simon are shown with porosity logs (blue lines further divide the formation into A-E units), red shaded areas show porosity 10% and higher. Highest peaks are approaching 30% porosity[8].

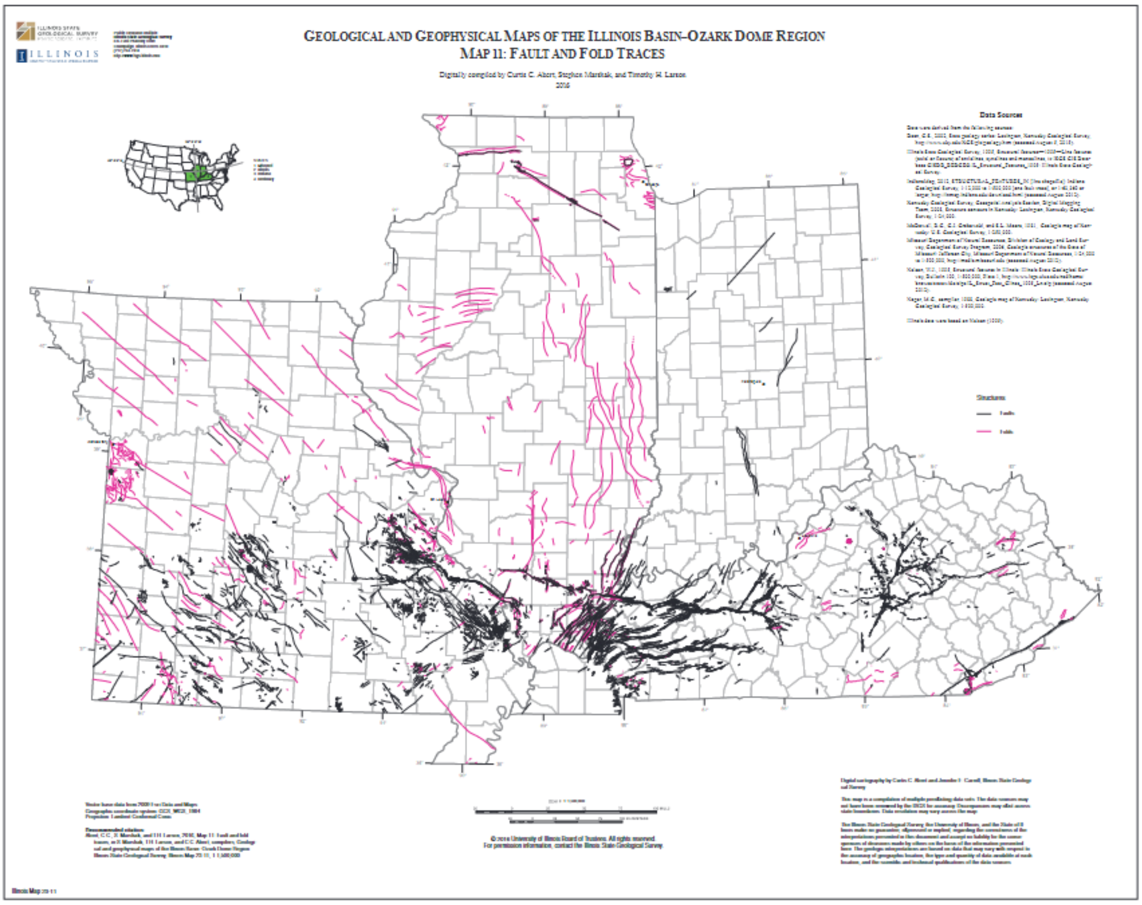


Figure 6.4: Fault (black) and fold (magenta) traces in the Illinois Basin – Ozark Dome Region[9]

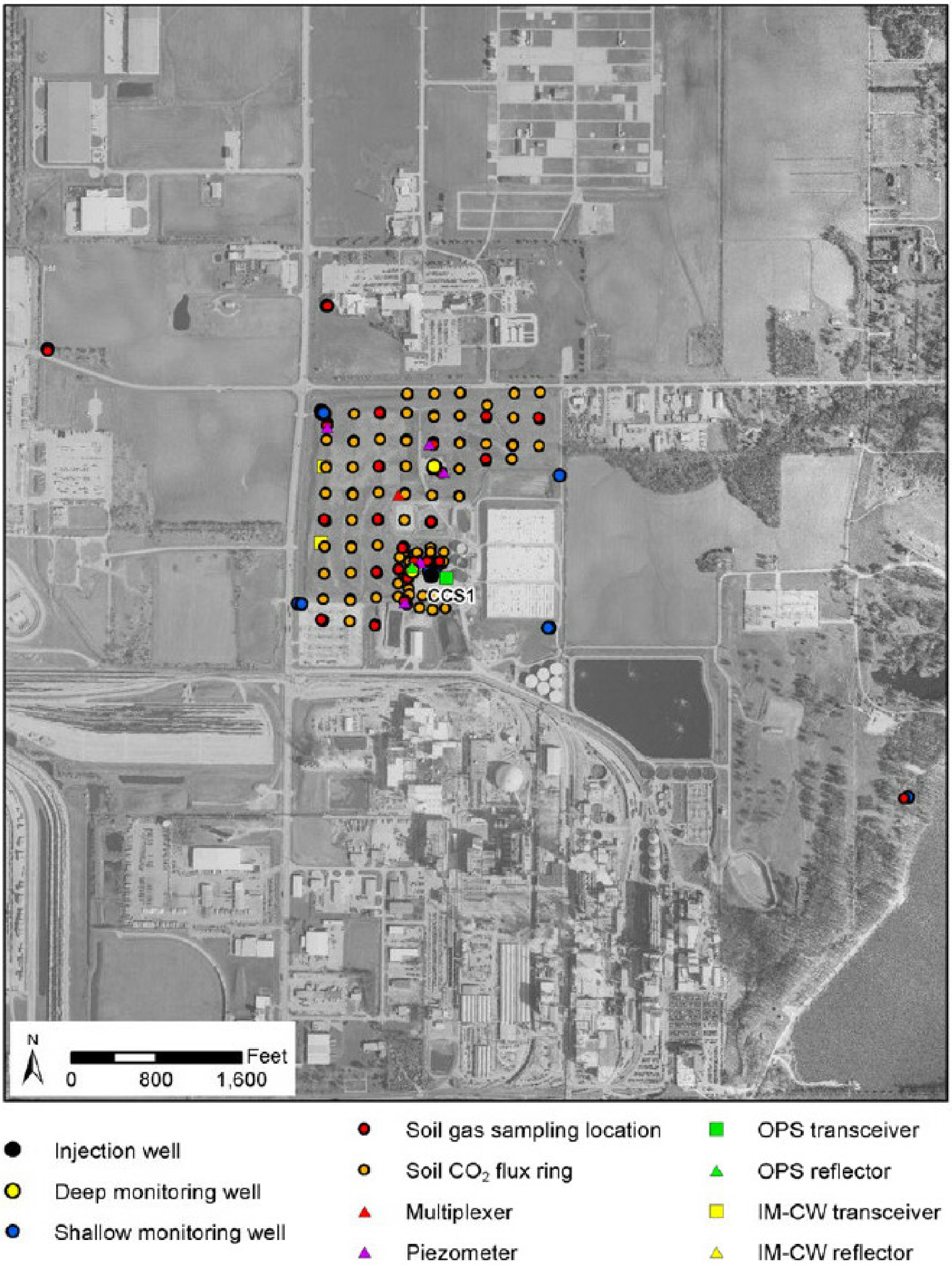


Figure 6.5: Satellite imagery with locations of surface and near-surface instrumentation[12].

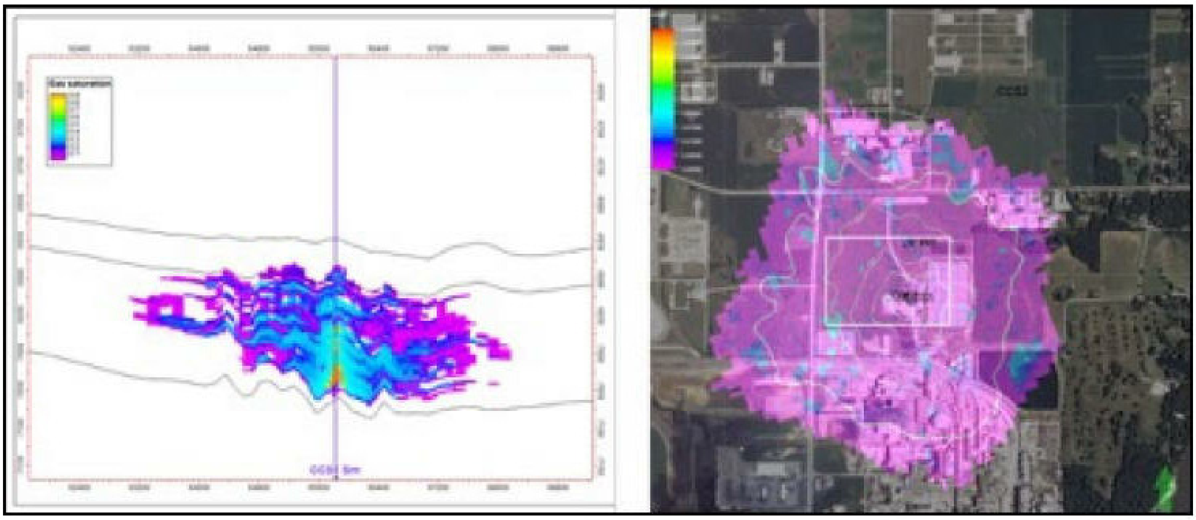


Figure 6.6: Modelled CO_2 plume at the time of the time-lapse monitor 3D seismic survey in cross section through injector CCS1 (left) and map view (right)[10].

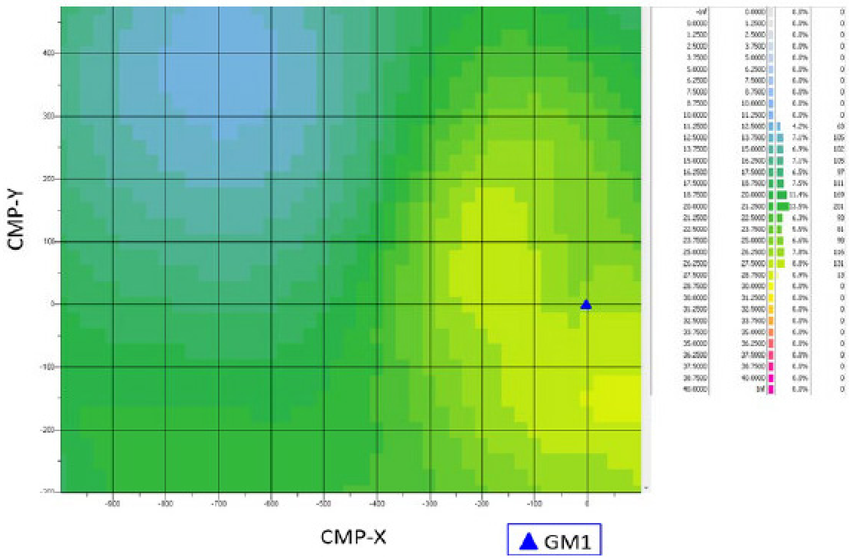


Figure 6.7: NRMS map (4D VSP) for B2-M4 migrated cubes (post-injection) computed over 6,500 to 7,200 ft (1,901 to 2,195 m) depth interval (colour scale is adjusted)[12].

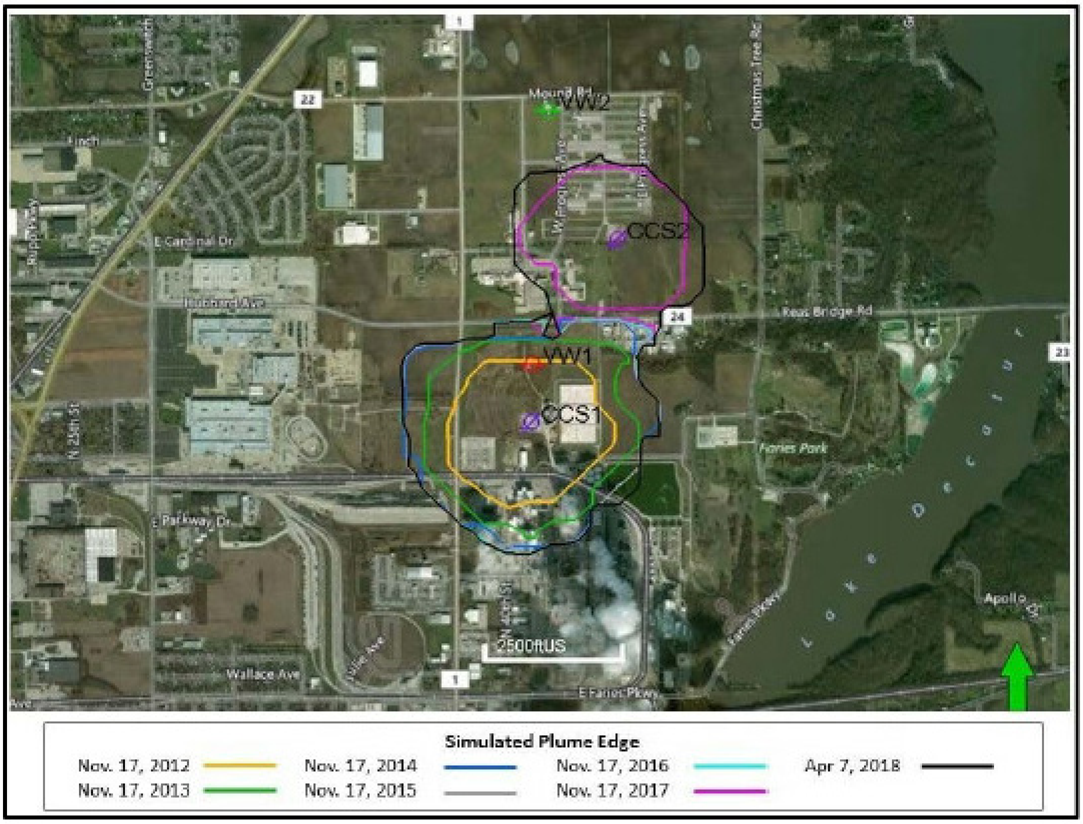


Figure 6.8: Simulated plume edge (CO2 concentration >1%) through 2018 update[12].

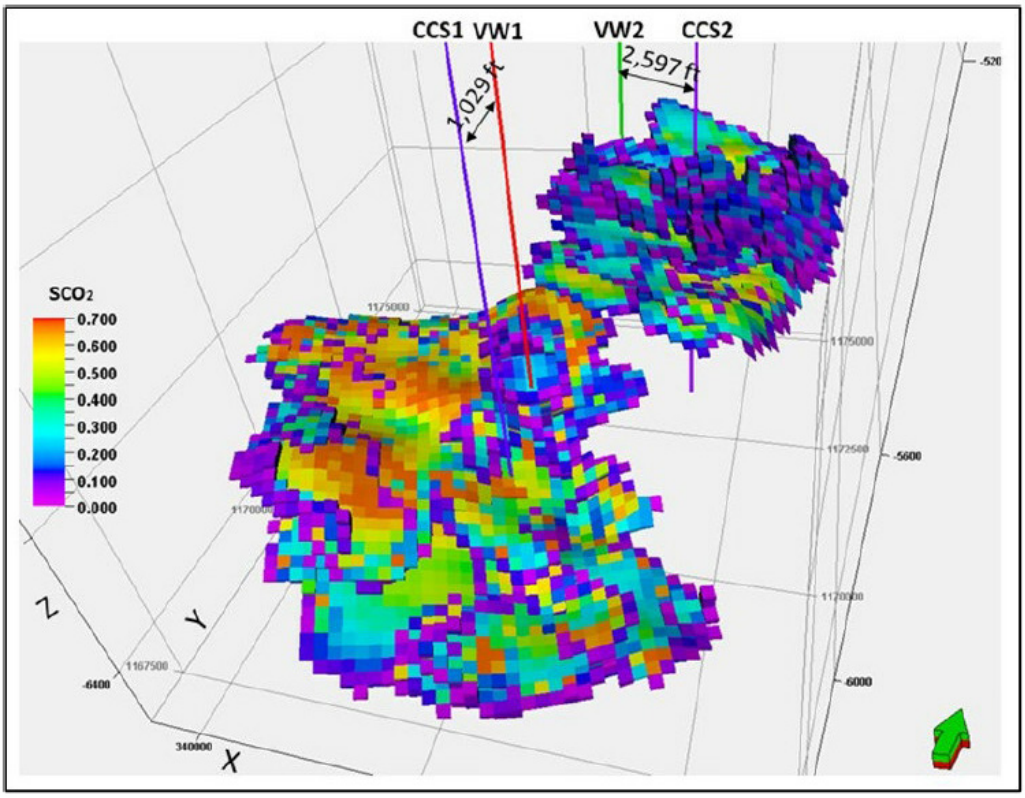


Figure 6.9: 2020 3D simulated CO_2 plume distribution. Vertical exaggeration is 5x[12].

7. Farnsworth

Site Details					
Name	Location	Province/State	Country	Onshore	Offshore
Farnsworth	Near Perrytree, Ochiltree County	Texas	USA	✓	

General storage type
Depleted oil and gas reservoir

Development History (Active operation)
Large scale CO_2 storage and EOR project, part of the Southwest Regional Partnership on Carbon Sequestration (SWP). Phase III project at Farnsworth Unit Oil Field (FWU), operated by Chaparral Energy LLC (now Canvas Energy), with CO_2 injection starting December 2010. The goal to inject at least 1 million tonnes of CO_2 into the Morrow B formation. The project is a partnership with the Petroleum Recovery Research Centre (PRRC) at New Mexico Institute of Mining and Technology (NMT) and Chaparral Energy LLC. The FWU was first produced in the mid 1950s, waterflooding began in the 1960s and now CO_2 is injected from industrial sources[1]. Arkalon Ethanol Plant and Agrium Fertilizer Plant supplies anthropogenic CO_2 for EOR.

Geological Characteristics. Farnsworth Field Unit lies on the northwestern shelf of the Anadarko basin and is one of many reservoirs that produce from a Pennsylvanian sequence of alternating mudstone and sandstone intervals (Figure 7.1).	
Reservoir Formation	
Pennsylvanian-aged Morrow B sandstone[2] which has an average dip of less than 1 degree.	
Lateral extent / thickness variation	Thickness: sandstone intervals 15-60 cm, fining upward sequence 15-46 cm caps the Morrow B sequence. Marrow Formation 5-50 m thick[3] at depths of 2330 m [3] .
Rock type	Sandstone encased in marine shales. Sequence of lithofacies in most cores are: marine mudstone, channel lag conglomerate, fluvial

1 http://www.southwestcarbonpartnership.org/phase-iii-farnsworth-unit/
2 Cather, M., Rose-Coss, D., Gallagher, S., Trujillo, N., Cather, S., Hollingworth, R.S., Mozley, P. and Leary, R.J., 2021. Deposition, diagenesis, and sequence stratigraphy of the Pennsylvanian Morrowan and Atokan Intervals at Farnsworth Unit. Energies, 14(4), p.1057.
3 Dai, Z., Viswanathan, H., Fessenden-Rahn, J., Middleton, R., Pan, F., Jia, W., Lee, S.Y., McPherson, B., Ampomah, W. and Grigg, R., 2014. Uncertainty quantification for CO_2 sequestration and enhanced oil recovery. Energy Procedia, 63, pp.7685-7693.

	coarse-grained sandstone, estuarine fine-grained sandstone and marine mudstone[2] (Figure 7.2).
Sedimentary features: Depositional Environment / facies type & variation / mineral composition	Incised valley fluvial sequences, vary from course conglomerate base to an upper fine sandstone. Sourced from adjacent Amarillo-Wichita Uplift to the south (Figure 7.2). Grades into overlying marine dominated shales and mudstone/limestone cyclical sequences of the Thirteen finger limestone[2]. Morrow B sandstone is subarkosic: 78% quartz, 7% feldspar and 15% lithic fragments[2]. A proximal granitic source, deposited high energy braided fluvial and estuarine setting (Figure 7.4). Comprising stacked mid-channel bar forms in an incised valley[2] (Figure 7.3). Isopach map shows possible southeast trending channel (Figure 7.4). Mudstones (Morrow and 13 fingered limestone) are predominantly illite/smectite clays with minor amounts of quartz[2]. Limestones are pure calcium carbonate, primarily diagenetic calcite. Deposited in an increasingly marine setting[2]. Diagenesis plays big role in rock structure and composition[2].
Porosity	5.5-22.7 %[3]
Permeability	0.2-783 mD[3]
Formation fluid properties: (residual hydrocarbons / salinity concentration).	n/a
Caprock / primary seal formation	
Upper Morrow Shale & the Thirteen Finger limestone	
Lateral extent / thickness variation	Morrow Shale: minimum thickness 12.8 m Thirteen layer limestone: 18-40 cm thick, widely distributed formation. Caprock thickness varies from 73.2m in the east to 36.6 m in the west and is continuous across the mapped extent of the FWU[4].
Rock type	Morrow Shale: generally fines upwards into a series of thin beds that alternate between upper fine sands and fine to medium black laminated

4 Trujillo, N., Rose-Coss, D., Heath, J.E., Dewers, T.A., Ampomah, W., Mozley, P.S. and Cather, M., 2021. Multiscale Assessment of Caprock Integrity for Geologic Carbon Storage in the Pennsylvanian Farnsworth Unit, Texas, USA. Energies, 14(18), p.5824.

	mudstones and includes calcareous mudstone[4]. Thirteen Finger limestone: black, carbonaceous mudstones interlayered with limestone (cementstone) and some coal[2]. Primarily diagenetic in origin.
Fracture pressure	n/a
Porosity	See Figure 7.5 for range of porosity and permeabilities of mudstones in Morrow Shale, Morrow B sandstone and Thirteen Finger limestone[4].
Permeability	
Overburden Features (Thickness, formations presence of secondary reservoirs / seals) Upper Pennsylvanian through middle Permian shales and limestones, with lesser amounts of dolomite, sandstone and evaporites[2].	
Presence of a potable aquifer. Yes, Ogallala aquifer.	
Structure FWU sits on the northwest shelf of the Anadarko Basin, from the FWU the basin plunges to the southeast reaching depths up to 40,000 ft adjacent to the Amarillo-Wichita Uplift [4]. See Figure 7.4a for a structure contour map of the Morrow B Formation[5].	
Fold type / fault bounded	Morrow is mainly a stratigraphic trap, however gentle down dipping of the top Morrow can been seen (Figure 7.4a), part of a larger regional structure that is outwidth the study area (see also Figure 7.1 for the structure of the Anadarko basement).
Faults /Fractures (Type – normal, reverse, strike-slip)	Several faults (9) interpreted on 3D seismic, none are deemed significant in terms of seal integrity or regional extent [6]. However, three of these will be the focus of studies in the future, assessing structural and hydrologic nature[6].
Displacement	Potential offset of fault identified in 3D VSP at ~70 ft (~20 m) [5].
Stability (pre-stressed, active, stable)	n/a

5 Czoski, P., 2014. Geologic characterization of the Morrow B reservoir in Farnsworth Unit, TX using 3D VSP seismic, seismic attributes, and well logs. Geophysics, p.101.

6 White, M.D., Esser, R.P., McPherson, B.P., Balch, R.S., Liu, N., Rose, P.E., Garcia, L. and Ampomah, W., 2017. Interpretation of tracer experiments on inverted five-spot well-patterns within the western half of the Farnsworth unit oil field. Energy Procedia, 114, pp.7070-7095.

Injection / storage history	
Number of injection, monitoring or other wells, well geometry, design and key completion information for injection wells, relevant well issues. Reused / new purpose drilled well.	
Up to 25 injection wells will be utilised for CO_2 flooding of the FWU field[5] (Figure 7.7). Western part of the FWU comprises 30 production wells and 21 injection wells distributed in 5 spot patterns[7]. This includes three scientific wells, five water injection wells and 15 water alternating gas (WAG) wells [7]. The gas (89-93% CO_2) mixture is produced with less than 690 ppm, and is reinjected using reciprocal compression and high-pressure horizontal pumps [8].	
Extent and status of casing (corrosion history/ cementation records)	n/a
Injection rates & pattern (i.e. continuous / intermittent) changes in injection behaviour	Up to 0.2 million tonnes/year over five years[5]. One injector well is located in the middle of four producers. Produced fluids (oil, water and CO_2) are separated and CO_2 is re-injected. WAG is implemented to deter CO_2 moving ahead of the displaced oil, improving the sweep efficiency[5].
Total quantities stored	See Figure 7.6. Between December 2010 and September 2020 – purchased CO_2 is 1.64 x 10^6 tonnes with 1.51 x 10^6 tonnes (92% of purchased) being stored [8].
Reservoir capacity (estimate)	n/a
Fluid extraction rate (brine extraction, oil for EOR)	n/a
Seismicity	
Monitoring regime (technologies deployed)	
Five broadband seismometers deployed by an injection well [9]. Analysed data collected during first three months of deployment.	
Seismic events (Detection / magnitude / attribution (natural induced).	
280 high-amplitude, regional events were identified, and a second set of 12 long period, low frequency events. No evidence of discrete seismic events with brittle deformation characteristics has been found within a 90-mile radius of the injection well. Hypocentres of the high-amplitude,	

7 Sun, Q., Ampomah, W., Kutsienyo, E.J., Appold, M., Adu-Gyamfi, B., Dai, Z. and Soltanian, M.R., 2020. Assessment of CO_2 trapping mechanisms in partially depleted oil-bearing sands. Fuel, 278, p.118356.
8 Morgan, A., Grigg, R. and Ampomah, W., 2021. A gate-to-gate life cycle assessment for the CO_2-EOR operations at Farnsworth Unit (FWU). Energies, 14(9), p.2499.
9 Kumar, A., Zorn, E., Hammack, R., Harbert, W., Ampomah, W., Balch, R. and Garcia, L., 2017. Passive seismic monitoring of an active CO_2-EOR operation in Farnsworth, Texas. In SEG Technical Program Expanded Abstracts 2017 (pp. 2851-2855). Society of Exploration Geophysicists.

regional events are distributed throughout central to western Oklahoma and are unrelated to CO_2 injection in the Farnsworth field. A local source of slow slip deformation may cause the long period events observed [9].	
Monitoring technologies applied and experiences with monitoring; See Figure 7.7 for layout of the different monitoring technologies deployed at FWU, by 2016 no signs of leakage has been detected [10].	
Surface monitoring technologies deployed	
3D Seismic	Baseline 42 mile^2 (67.7- km^2) 3D survey over the entire field in 2013[1].
Soil Flux Measurements	Surface soil CO_2 flux[1] Quarterly measurements at >93 semi-permanent sites. Soil collars 'planted' and surveyed around well 13-10A. 5-10 minutes/station with portable infrared CO_2 gas analyser with recirculating chamber records flux [10]. After two years no significant increase of CO_2 detected.
Atmospheric Flux	Atmospheric CO_2/CH_4 eddy flux[1] Provides continuous wide area coverage and point source leak detection. Continuous acquisition of CO_2 (CH_4 and H_2O) flux/concentration and wind speed and direction[10]. The greatest changes in CO_2 flux in soil and atmospheric data appear more related to the seasonal agricultural land use[1] .
Gas phase tracers[1]	
Subsurface monitoring technologies deployed (well logs)	
VSP	Three baseline 3D VSPs centred on injection wells[1] (Figure 7.7). Two in the west side and one on the east. Used for geological characterisation and for time-lapse monitoring of the evolution of the CO_2 plume[5, 11].
Cross-well tomography	Four baseline cross-well tomography segments between injector/producer pairs[1] (Figure 7.7). Refine reservoir interpretations and time-lapse monitoring [11].
Gravity	Gravity monitoring at AWT3 [12].

10 Balch, R., Esser, R. and Liu, N., 2016. Monitoring CO_2 at an enhanced oil recovery and carbon capture and storage project, Farnsworth unit, Texas.
11 El-kaseeh, G., Will, R., Balch, R. and Grigg, R., 2017. Multi-scale seismic measurements for CO2 Monitoring in an EOR/CCUS project. Energy Procedia, 114, pp.3656-3670.
12 Sugihara, M., Nawa, K., Soma, N., Ishido, T., Miyakawa, A. and Nishi, Y., 2014. Continuous gravity monitoring for CO2 geo-sequestration (2) a case study at the Farnsworth CO2-EOR field. Energy Procedia, 63, pp.4404-4410.

	Self-potential monitoring at 13-10.
Passive seismic	Dedicated monitoring well has a 16 level 3 component passive seismic monitoring array installed[1].
Reservoir Fluid chemistry	Reservoir fluid chemistry: Morrow B brine, oil and gas composition are monitored[10].
Groundwater testing	Groundwater chemistry [1] Quarterly sampling of Ogallala Aquifer to monitor for brine, oil and/or CO_2 leakage [6,10]. Including major ions, pH, conductivity, alkalinity, oxidation and reduction potentials, inorganic/organic carbon, trace metals, and isotopes (^{13}C, ^{18}O and D)[10] . 96 samples tested as part of the tracer-monitoring program and none of the injected NPT compounds have been detected[6].
Water/gas phase tracers[1,5,7&8]	Determine fluid-flow patterns and travel time between injection and production wells. Constrain and calibrate flow models; predict the fate of the injected CO_2. Detection and quantify CO_2 /brine leakage to subsurface/atmosphere. Determine CO_2 saturation levels and storage capacity. Determine sweep efficiency. Confirm other verification methods (e.g. seismic). Tracers for aqueous (naphthalene sulfonates - 8 available) and vapour phase (perflurocarbons – 7 available)[6,10]. • Three wells injected (aqueous phase) May 2014 – no observed breakthrough. • One well (aqueous phase) injected October 2015 – no observed breakthrough. • Vapour phase injected May 2015 on well 13-13 – breakthrough in production wells after 2-4 weeks. • Vapour phase injected November 2015 on well 13-10A – no data yet. Vapour phase injected May 2016 on wells 13-1 (breakthrough after 23 days) & 13-3 (breakthrough after 12 days).

	Results from tracer injections[6] Tracer travel times between injector and producer well in the order of weeks not months. Every other day sampling began a week after initial injection for both gas and aqueous phase. Maintained for at least 45 days, then reduced to once a week.
Pressure and temperature	In situ pressure and temperature[1] installed in monitoring well 13-10.

Experience summary - effectiveness of techniques (limitations / strengths)

MMV (Measurement, Monitoring, Verification) Practices & related verification of injected CO_2

Major technical/scientific studies on the site, major learnings, Conformance assessment (history-matching with models, correlation between different monitoring techniques)

For history matching studies see for example [7, 13].

List of key publications covering the site

1. http://www.southwestcarbonpartnership.org/phase-iii-farnsworth-unit/
2. Cather, M., Rose-Coss, D., Gallagher, S., Trujillo, N., Cather, S., Hollingworth, R.S., Mozley, P. and Leary, R.J., 2021. Deposition, diagenesis, and sequence stratigraphy of the Pennsylvanian Morrowan and Atokan Intervals at Farnsworth Unit. Energies, 14(4), p.1057.
3. Dai, Z., Viswanathan, H., Fessenden-Rahn, J., Middleton, R., Pan, F., Jia, W., Lee, S.Y., McPherson, B., Ampomah, W. and Grigg, R., 2014. Uncertainty quantification for CO_2 sequestration and enhanced oil recovery. Energy Procedia, 63, pp.7685-7693.
4. Trujillo, N., Rose-Coss, D., Heath, J.E., Dewers, T.A., Ampomah, W., Mozley, P.S. and Cather, M., 2021. Multiscale Assessment of Caprock Integrity for Geologic Carbon Storage in the Pennsylvanian Farnsworth Unit, Texas, USA. Energies, 14(18), p.5824.
5. Czoski, P., 2014. Geologic characterization of the Morrow B reservoir in Farnsworth Unit, TX using 3D VSP seismic, seismic attributes, and well logs. Geophysics, p.101.
6. White, M.D., Esser, R.P., McPherson, B.P., Balch, R.S., Liu, N., Rose, P.E., Garcia, L. and Ampomah, W., 2017. Interpretation of tracer experiments on inverted five-spot well-patterns within the western half of the Farnsworth unit oil field. Energy Procedia, 114, pp.7070-7095.
7. Sun, Q., Ampomah, W., Kutsienyo, E.J., Appold, M., Adu-Gyamfi, B., Dai, Z. and Soltanian, M.R., 2020. Assessment of CO_2 trapping mechanisms in partially depleted oil-bearing sands. Fuel, 278, p.118356.
8. Morgan, A., Grigg, R. and Ampomah, W., 2021. A gate-to-gate life cycle assessment for the CO_2-EOR operations at Farnsworth Unit (FWU). Energies, 14(9), p.2499.

13 Ampomah, W., Balch, R., Will, R., Cather, M., Gunda, D. and Dai, Z., 2017. Co-optimization of CO2-EOR and storage processes under geological uncertainty. Energy procedia, 114, pp.6928-6941.

9. Kumar, A., Zorn, E., Hammack, R., Harbert, W., Ampomah, W., Balch, R. and Garcia, L., 2017. Passive seismic monitoring of an active CO_2-EOR operation in Farnsworth, Texas. In SEG Technical Program Expanded Abstracts 2017 (pp. 2851-2855). Society of Exploration Geophysicists.
10. Balch, R., Esser, R. and Liu, N., 2016. Monitoring CO_2 at an enhanced oil recovery and carbon capture and storage project, Farnsworth unit, Texas.
11. El-kaseeh, G., Will, R., Balch, R. and Grigg, R., 2017. Multi-scale seismic measurements for CO_2 Monitoring in an EOR/CCUS project. Energy Procedia, 114, pp.3656-3670.
12. Sugihara, M., Nawa, K., Soma, N., Ishido, T., Miyakawa, A. and Nishi, Y., 2014. Continuous gravity monitoring for CO_2 geo-sequestration (2) a case study at the Farnsworth CO_2-EOR field. Energy Procedia, 63, pp.4404-4410.
13. Ampomah, W., Balch, R., Will, R., Cather, M., Gunda, D. and Dai, Z., 2017. Co-optimization of CO_2-EOR and storage processes under geological uncertainty. Energy Procedia, 114, pp.6928-6941.

Other relevant information considered pertinent to the report

Ampomah, W., Balch, R.S., Cather, M., Will, R., Gunda, D., Dai, Z. and Soltanian, M.R., 2017. Optimum design of CO_2 storage and oil recovery under geological uncertainty. Applied Energy, 195, pp.80-92.

Dai, Z., Middleton, R., Viswanathan, H., Fessenden-Rahn, J., Bauman, J., Pawar, R., Lee, S.Y. and McPherson, B., 2014. An integrated framework for optimizing CO_2 sequestration and enhanced oil recovery. Environmental Science & Technology Letters, 1(1), pp.49-54.

Dai, Z., Viswanathan, H., Xiao, T., Middleton, R., Pan, F., Ampomah, W., Yang, C., Zhou, Y., Jia, W., Lee, S.Y. and Cather, M., 2017. CO_2 sequestration and enhanced oil recovery at depleted oil/gas reservoirs. Energy Procedia, 114, pp.6957-6967.

Figures

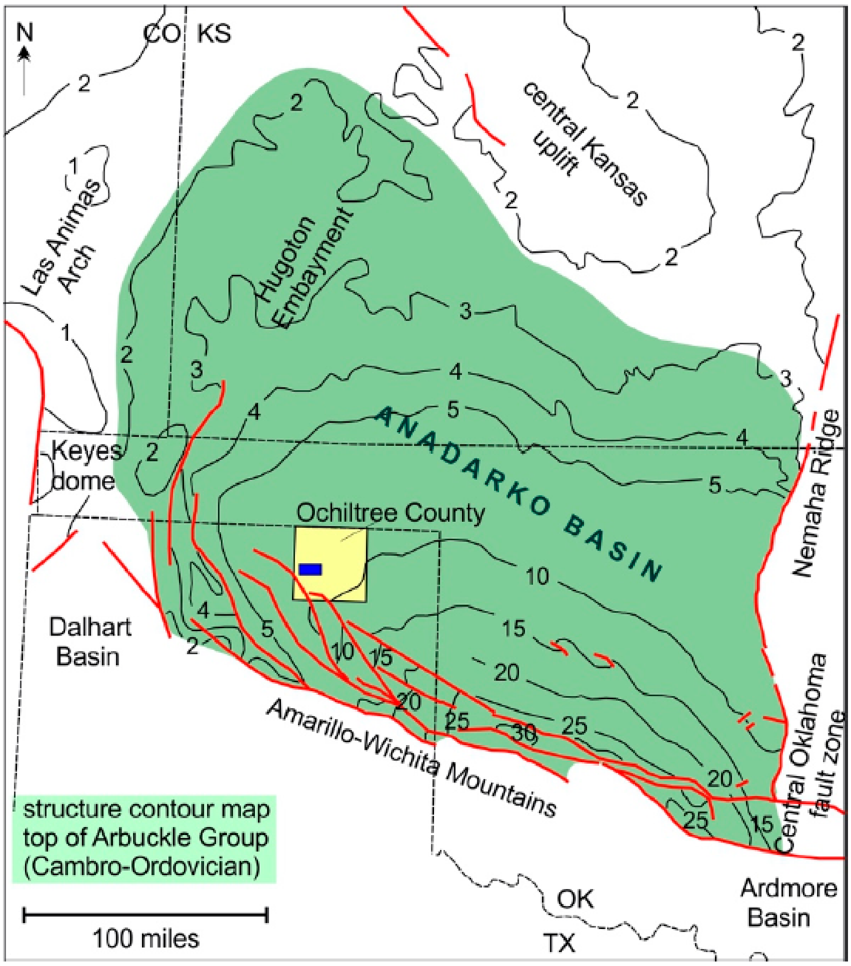


Figure 7.1: location map of Farnsworth Field Unit (in blue box) on an Anadarko basement structure map showing major basin bounding faults and tectonic elements. Contour intervals are in thousands of feet[2].

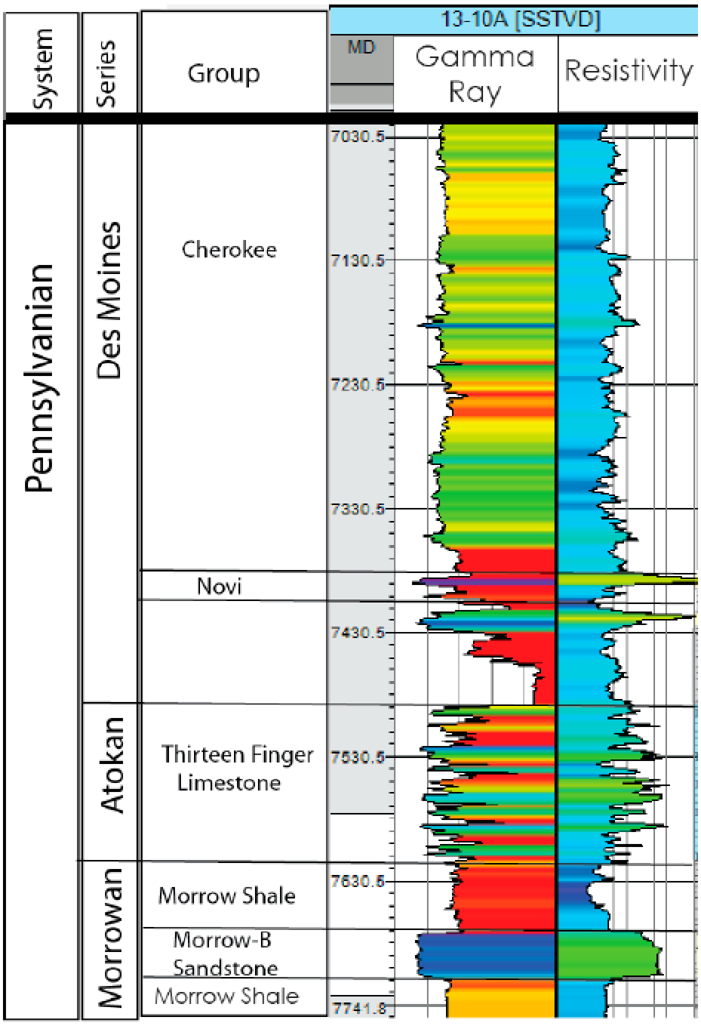


Figure 7.2: Stratigraphic column for intervals at the Farnsworth Field Unit[2] .

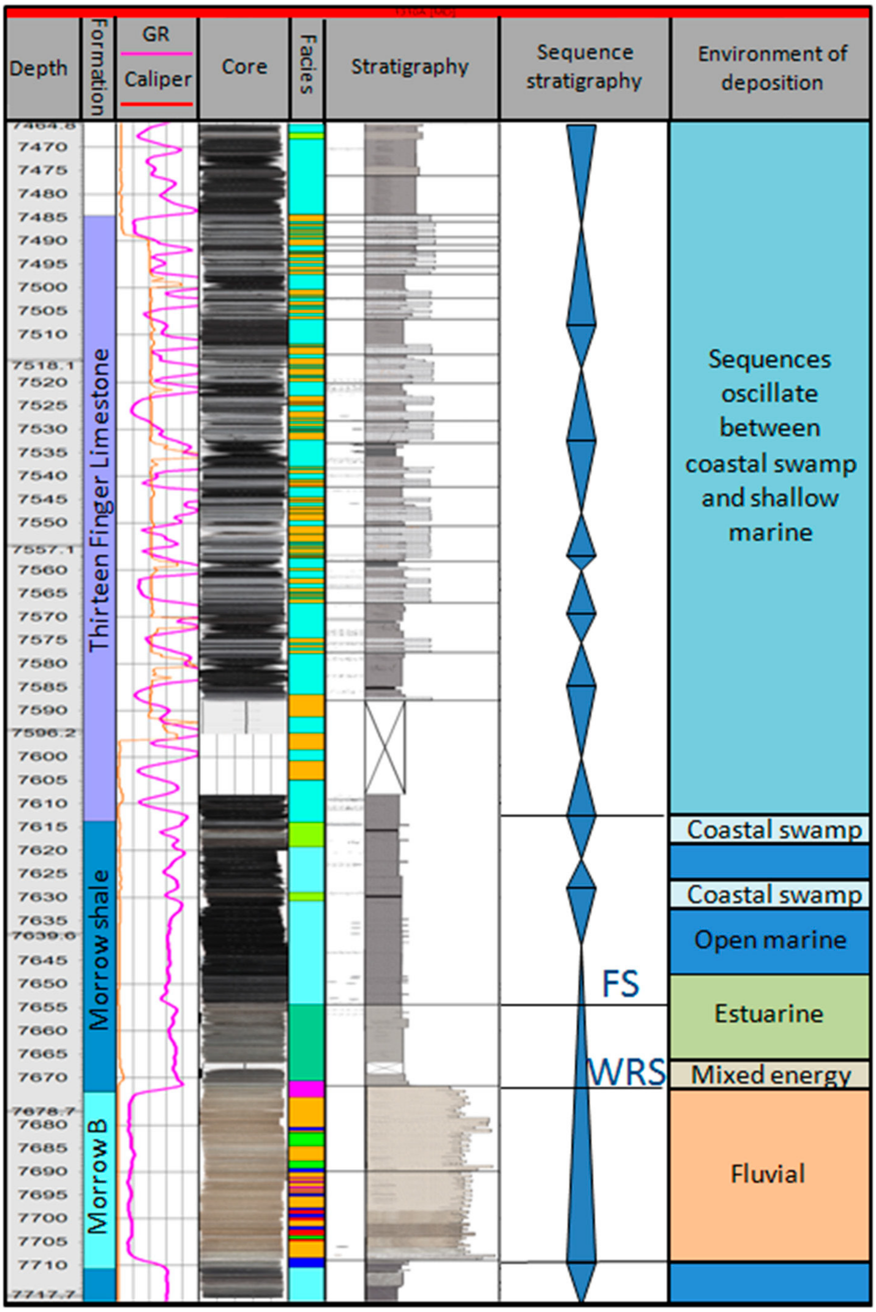
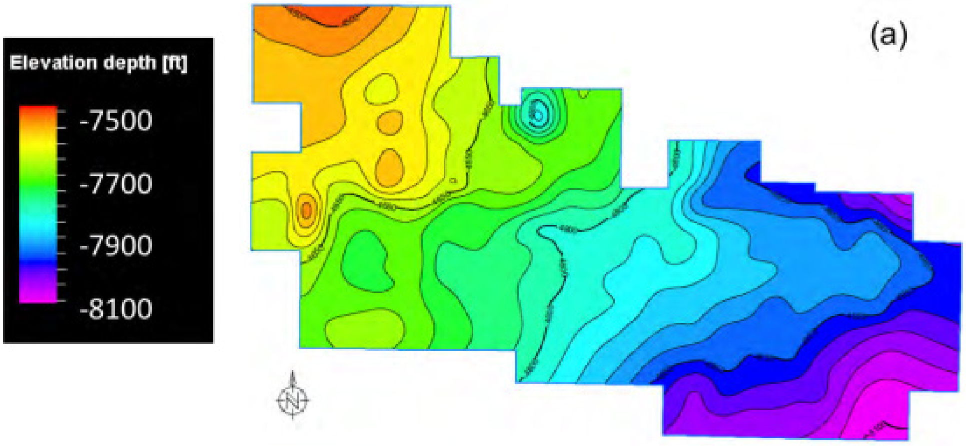


Figure 7.3: Sequence stratigraphy of the reservoir and caprock intervals in well 13-10A. WRS=possible wave ravinement surface; SR = flooding surface[2].



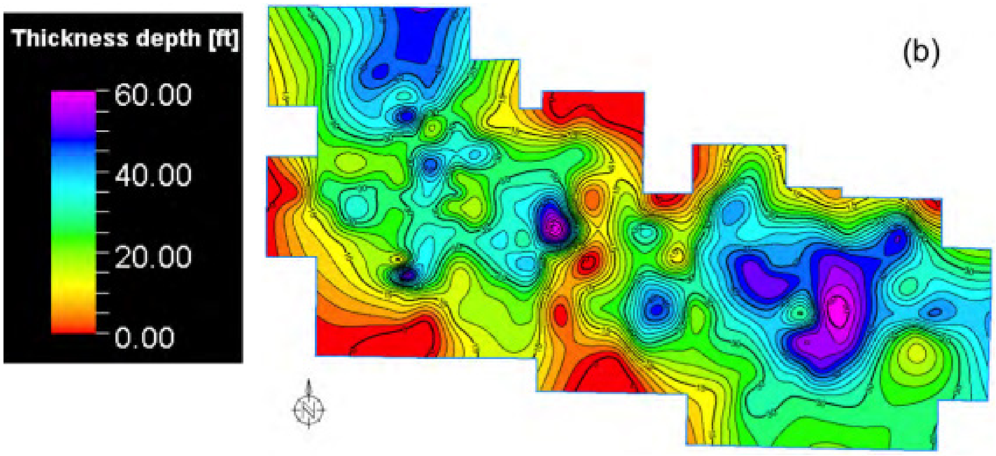


Figure 7.4: (a) Structure map from the top of the Morrow B sandstone. (b) Isopach of the Morrow B generated from gamma ray logs with the thicker sandstone running through middle of the field [5].

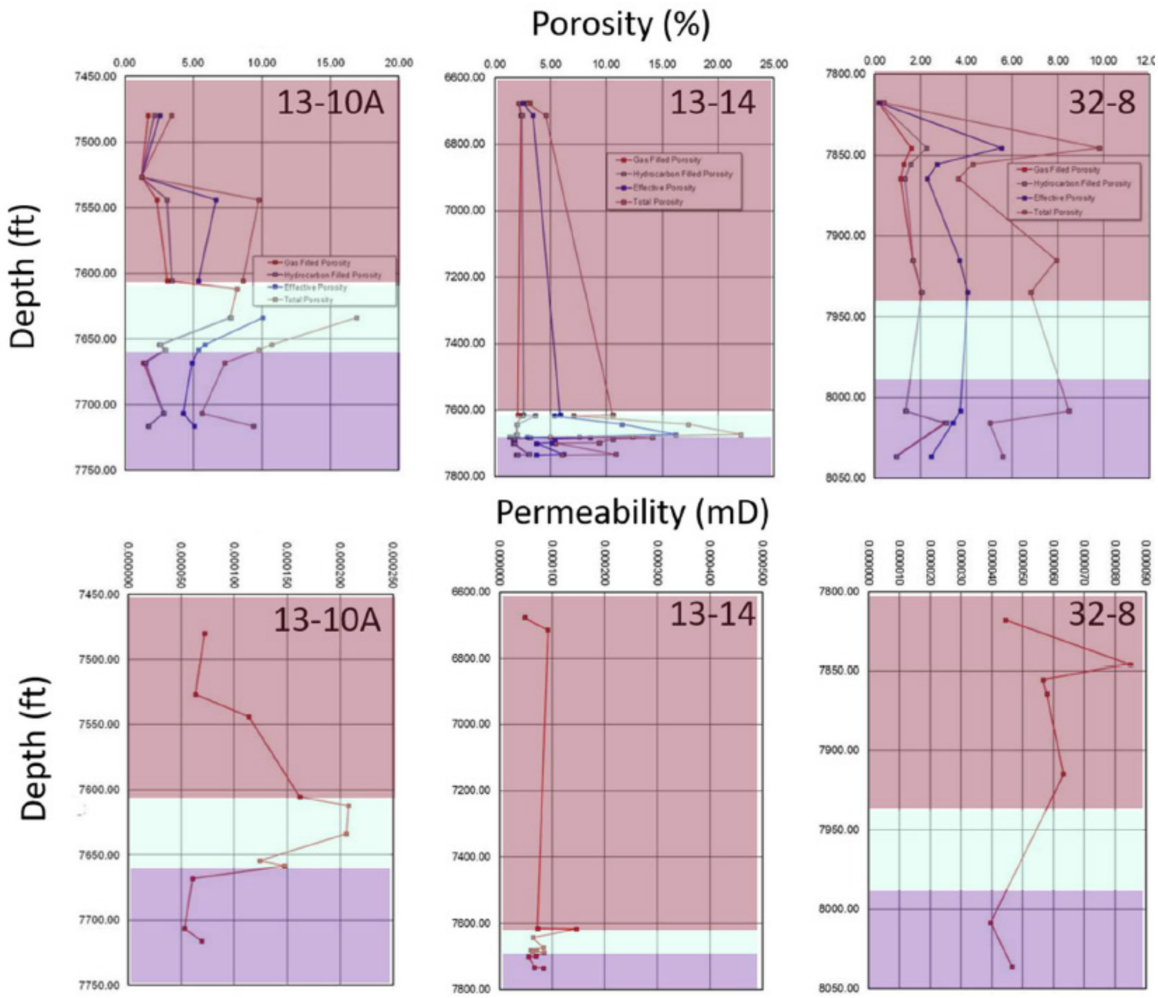


Figure 7.5: Porosity and permeability of Farnsworth mudstone lithofacies within Morrow B sandstone (purple), Morrow shale (green) and Thirteen Finger limestone (pink) for three wells[4].

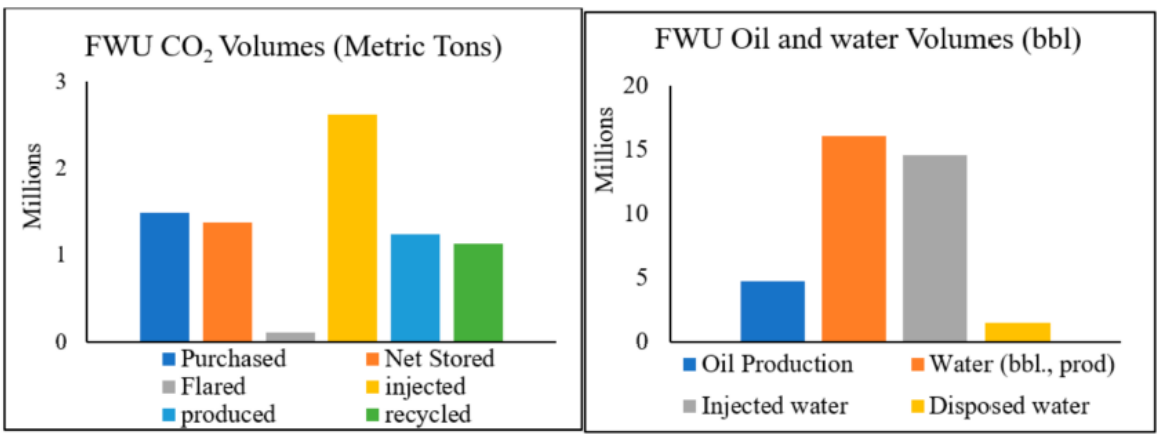


Figure 7.6: Production and injection data gathered from the FWU from December 2010 to August 2020 [8].

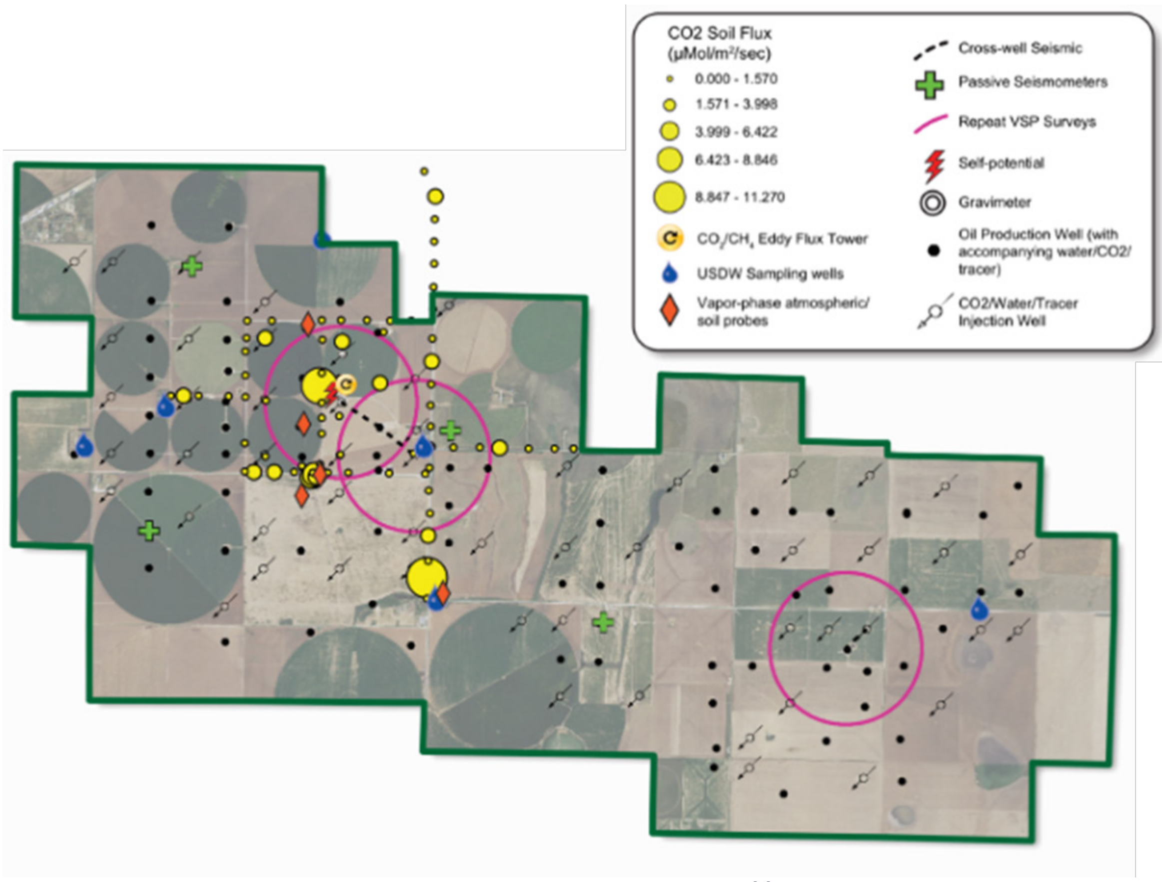


Figure 7.7: MVA Map View showing types of monitoring used at FWU[1].

8. SECARB - Cranfield

Site Details					
Name	Location	Province/State	Country	Onshore	Offshore
SECARB-Cranfield	Franklin/Adams County	Mississippi	USA	✓	

General storage type

Depleted oil and gas reservoir/saline aquifer.

Development History (Closed)

Cranfield was selected from 767 oilfields in the Southeast Regional Carbon Sequestration Partnership (SECARB) area to develop 'stacked storage' where current EOR operations would support infrastructure, characterisation, and public acceptance of longer-term saline storage[1] (Figure 8.1).

Oil and gas production at Cranfield started in 1944 and ceased by 1966 with all wells plugged and abandoned[2].

CO_2 is geologically generated and commercially produced from Jackson Dome, Mississippi, and shipped via pipeline by Denbury Onshore LLC to Cranfield[1]. CO_2 injection started in 2008.

The program objective: to demonstrate the ability to inject CO_2 safely and economically into geologic formations where it will be permanently stored in preparation for the commercialisation of geologic sequestration[2].

Cranfield specifically has three sub-goals[2] (Table 8-1):

- Effective environmental assurance monitoring
- Extent of the CO_2 plume migration in the injection interval predicted
- Magnitude and extent of pressure increase resulting from injection predicted.

A Discontinuation Plan was implemented in 2015, Denbury (operators) assumed the responsibility for all wells and oversaw P&A of all research wells. CO_2 injection continued beyond the SECARB Phase III project period as part of Denbury's commercial EOR program[3] . Monitoring returned to normal CO_2-EOR surveillance conducted commercially and aligned with international standards.

The Southern States Energy Board (SSEB) managed the overall SECARB Phase III project, and the Bureau of Economic Geology (BEG), at the University of Texas at Austin, managed all activities associated with the Early Test field site near Cranfield.

Geological Characteristics

1 Hovorka, S.D., 2013. Three-million-Metric-Ton-Monitored injection at the SECARB Cranfield project—project update. Energy Procedia, 37, pp.6412-6423.
2 Hovorka, S.D., Meckel, T.A., Trevino, R.H., Lu, J., Nicot, J.P., Choi, J.W., Freeman, D., Cook, P., Daley, T.M., Ajo-Franklin, J.B. and Freifield, B.M., 2011. Monitoring a large volume CO_2 injection: Year two results from SECARB project at Denbury's Cranfield, Mississippi, USA. Energy Procedia, 4, pp.3478-3485.
3 Nemeth, K., Berry, P., Gray, K., Wernette, B., Hill, G., & Hill, B. (2021). Final Project Report-SECARB Phase III (No. DOE-SSEB-42590-100121). Southern States Energy Board, Peachtree Corners, GA (United States).

Reservoir Formation	
Cretaceous Lower Tuscaloosa 'D-E' sandstone (Figure 8.2). Top of the reservoir is between 3,060 and 3,193 m.	
Lateral extent / thickness variation	20 to 28 m thick zone[1]. Relatively laterally continuous[2].
Rock type	Amalgamated, incised channels filled by chert- and volcanic-rock-fragment-rich sandstones and conglomerates[1]. The reservoir is heterogenous, and not resolved by seismic, wireline log or core interpretations.
Sedimentary features: Depositional Environment / facies type & variation / mineral composition	Cretaceous valley fill fluvial deposits. Chlorite, quartz and local carbonate cements and dark, channel-filling mudstones form local barriers to fluid flow, forming a complex fluid-flow environment[1].
Porosity	25.5%[1].
Permeability	Average 100 mD[2] . Range 50 mD to 1 Darcy[4].
Formation fluid properties: (residual hydrocarbons / salinity concentration).	Mixed, gas cap, oil rim and strong saline aquifer.
Caprock / primary seal formation	
Middle 'marine' Tuscaloosa (Figure 8.2).	
Lateral extent / thickness variation	Laterally extensive.
Rock type	Dark mudstones and fine-grained, fossiliferous, calcite-cemented sandstones[1].
Fracture pressure	n/a
Porosity	n/a
Permeability	n/a
Overburden Features (Thickness, formations presence of secondary reservoirs / seals) Midway shale (1,000 m above injection interval)[1]. Deeply dissected surface is mantled with loess and used for timber, farming and gravel production[2].	
Presence of a potable aquifer. Freshwater resources in Tertiary clastic units to depths of more than 600m and are sparsely used for water supply[2]. An important aquifer in the area is the Catahoula aquifer, it comprises three sub-aquifers [5].	

4 Gray, K., 2021. SECARB Regional Project Assessment (No. DOE-SSEB-42590-219). Southern States Energy Board, Peachtree Corners, GA (United States).

5 Yang, C., Mickler, P.J., Reedy, R., Scanlon, B.R., Romanak, K.D., Nicot, J.P., Hovorka, S.D., Trevino, R.H. and Larson, T., 2013. Single-well push–pull test for assessing potential impacts of CO_2 leakage on groundwater

Structure	
Fold type / fault bounded	Broad, four-way structural closure at >3,000 m depth[1]. With a northwest trending crestal graben[2] (Figure 8.3).
Faults /Fractures (Type – normal, reverse, strike-slip)	Faults on the crestal graben are normal, with displacement maximum greater than 30 m, and are now stable. A NW-SE orientated sealing fault divides the productive zone into two compartments.
Displacement	n/a
Stability (pre-stressed, active, stable)	Stable.

Injection / storage history

Number of injection, monitoring or other wells, well geometry, design and key completion information for injection wells, relevant well issues. Reused / new purpose drilled well.

Injection of CO_2 started with two wells in 2008 and increased to 24 wells by 2011 in semi-five-spot patterns with the continuous injection of CO_2. The production wells were designed on a self-lift principle to take advantage of the reservoir pressure increase due to the injection of CO_2. Initial development began at the northern end of the field and proceeded clockwise around the oil ring[6].

The Cranfield site is subdivided into five areas which each had their own timeline (Figure 8.1):

- **Phase II**: CO_2 injected into the oil bearing zone and began July 2008. An observation well was completed with a permanent digital bottom hole pressure gauge in the reservoir zone perforated in the Tuscaloosa 'D-E'. A second completion with a similar gauge was produced by perforating casing in the Tuscaloosa monitoring sandstone and isolated from the injection zone[2]. Bottom hole pressure was periodically collected from other wells in region. Pulsed-neutron RST used to measure near well saturation in a few wells.
- **High Volume Injection Test (HiVIT):** is the area used to inject up to 1 million metric tonnes/year at 200 bar (20 MPa) injection pressure. Monitoring started in April 2009 and includes:
    - Repeat 3D seismic – assess saturation change in the downdip brine areas and observe any changes in gas saturation from CO_2 injection in the areas with residual gas.
    - Geochemical monitoring of the injection interval fluids through producers, via distinctive carbon isotopes and reaction of dissolved CO_2 with rocks.
    - Groundwater quality monitoring, using new water wells accessing shallow confined sandstone aquifers over the injection area[2].

quality in a shallow Gulf Coast aquifer in Cranfield, Mississippi. *International Journal of Greenhouse Gas Control*, *18*, pp.375-387.

6 Vasco, D. W., Alfi, M., Hosseini, S. A., Zhang, R., Daley, T., Ajo-Franklin, J. B., & Hovorka, S. D. (2019). The Seismic Response to Injected Carbon Dioxide: Comparing Observations to Estimates Based Upon Fluid Flow Modeling. *Journal of Geophysical Research: Solid Earth*, *124*(7), 6880-6907. https://doi.org/10.1029/2018JB016429

• **P-site:** area where soil-gas instrumentation is placed including mud pits, P&A'd wells and well pads. Data collected from 2009. P&A well was re-entered and remediated as a producer in July 2010[2]. Tracers emplaced into lower Tuscaloosa through old perforations prior to cementing and recompletion with perforations in a deeper level. • **Detailed area of study** includes a closely spaced three well array of an injector (F-1) and two observation wells (F-2 & F-3) (Figure 8.1). Collecting dense time-lapsed data from the three wells (Figure 8.4). Injection started at the area in December 2009[2]. The goal is to measure changes as fluids evolve from single phase (brine) to two phase (CO_2-brine) flow system and document linkages between rock properties, pressure, gravity and sweep efficiency. All research wells were plugged and abandoned in 2015.	
More than 60 1945-1950 vintage wells intersect the injection interval – this risk is managed by the oilfield operator in accordance with Mississippi regulations[4].	
Extent and status of casing (corrosion history/ cementation records)	n/a
Injection rates & pattern (i.e. continuous / intermittent) changes in injection behaviour	1.2 million tons/year through 23 wells[2]. 11 million metric tonnes injected[4].
Total quantities stored	5,371,643 metric tonnes[3] at the end of January 2015. CO_2 injection will continue as part of Denbury's commercial purposes.
Reservoir capacity (estimate)	n/a
Fluid extraction rate (brine extraction, oil for EOR)	n/a

Seismicity
Monitoring regime (technologies deployed)
6-well microseismic arrays in a 3 km radius area to cover the entire Cranfield site, with commercial production data providing calibration points[7].
Monitoring started in December 2011 and concluded in December 2014 with equipment removed in February 2015[4].
Seismic events (Detection / magnitude / attribution (natural induced).
No seismic events related to CO_2 injection occurred during the recording period[4, 7] or the July 2014 period.

Monitoring technologies applied and experiences with monitoring; The design of the monitoring technologies was developed in research mode to test conceptual and numerical modelling approaches, but is not itself a commercial monitoring program[2].
Surface monitoring technologies deployed

7 Takagishi, M., Hashimoto, T., Horikawa, S., Kusunose, K., Xue, Z. and Hovorka, S.D., 2014. Microseismic monitoring at the large-scale CO_2 injection site, Cranfield, MS, USA. *Energy Procedia*, *63*, pp.4411-4417.

Soil-gas composition screening.	Vadose-zone assessment document the challenges of leakage detection in this setting[1]. There is evidence of natural seepage of methane which is common over oil fields[1]. Soil-gas composition screening at well pads, along 4 transects, 12 stations and 36 wells[8]. Seven sampling trips between 2009-2011. During pre-injection survey a small area of elevated methane (~47%) and CO_2 (up to 44%) was discovered above a plugged and abandoned well. A 6-year multi-parameter assessment of the anomaly was undertaken using stable and radioactive isotopes of CO_2 and CH_4, light hydrocarbon concentrations, noble gases and introduced tracers of SF_6 and perfluorocarbon tracer (PFT) (although a surface spill of tracers rendered these results ineffective) over time to ascertain whether the origin was from the CO_2 storage reservoir, intermediate gas-rich intervals, or a different origin[9]. Soil gas was sampled several times per year from August 2009 through February 2014 and analysed. The results showed that radiocarbon analysis to be most useful, as it can broadly distinguish modern carbon from older sources. Carbon-14 values suggest a modern carbon source rather than from the reservoir or injected CO_2. In addition, the $\delta^{13}C\text{-}CO_2$ of the soil gas differed significantly from the injected CO_2 from Jackson Dome[9]. Soil CO_2 concentration measurements may be insufficient for leakage detection, soil gas composition may be more reliable[8].
Time-lapse 3D survey[3, 10]	The first seismic survey was shot in 2007 (of the whole field) prior to CO_2 injection, and the

8 Yang, C., Romanak, K.D., Holt, R.M., Lindner, J., Smith, L., Trevino, R., Roecker, F., Xia, Y., Rickerts, J. and Hovorka, S., 2012, February. Large volume of CO_2 injection at the Cranfield, early field test of the SECARB Phase III: near-surface monitoring. In Carbon Management Technology Conference. OnePetro.
9 Anderson, J.S., Romanak, K.D., Yang, C., Lu, J., Hovorka, S.D. and Young, M.H., 2017. Gas source attribution techniques for assessing leakage at geologic CO_2 storage sites: Evaluating a CO_2 and CH_4 soil gas anomaly at the Cranfield CO_2-EOR site. *Chemical Geology*, *454*, pp.93-104.
10 Alfi, M. and Hosseini, S.A., 2016. Integration of reservoir simulation, history matching, and 4D seismic for CO_2-EOR and storage at Cranfield, Mississippi, USA. *Fuel*, *175*, pp.116-128.

	second survey in 2010 (partial area)[11]. 2 million tons of CO_2 was injected between the surveys. Alfi and Hosseini compare the 4D seismic interpretations of CO_2 plume distribution with fluid-flow numerical simulation results. There are clear discrepancies between the 4D and CO_2 saturation distribution as modelled with regard to missing CO_2 plumes and inconsistent plume locations. Attributed to uninterpretable data on the edge of seismic surveys, minimal gas saturation along the sealing fault, the probabilistic nature of the static model that directs the CO_2 plume distribution in the simulation model, and the low net-to-gross ratio in parts of the formations that would hinder seismic interpretations [10]. Vasco et al (2019) observed seismic time-lapse amplitude changes and time shifts in the 4D data, these are compatible with predictions based on multicomponent reservoir simulations. However challenges with imaging complex pore fluid distribution in enhanced oil recovery settings make constraining quantitative estimates of stored volumes difficult, especially in the absence of adequate constraints on reservoir properties[6].
Airborne magnetic and conductivity survey	Airborne magnetic and conductivity survey was conducted to better characterise the subsurface[3]. April 2013.
Ground magnetic survey	January 2014, along approximately 30 km of roadways. Combined with airborne surveys increase confidence that the infrastructure (P&A wells and pipelines) are inventoried[3].
Subsurface monitoring technologies deployed (well logs)	
Pressure monitoring in the above zone monitoring interval	AZMI – above zone monitoring interval (Figure 8.2 and Figure 8.5). A 3 m thick easily correlated sandstone with 100 mD

11 Ditkof, J., Meckel, T.A., Zeng, H. and Hovorka, S.D., 2011, December. Time lapse seismic response (4D) related to industrial-scale CO_2 injection at an EOR and CCS site, Cranfield, MS. In *AGU Fall Meeting Abstracts* (Vol. 2011, pp. GC51B-0976).

	permeability[1]. Two pressure gauges at three installations, one in the injection zone and one in the AZMI[1] (Figure 8.5). • Ella G Lees#7 (EGL7) well: AZMI exhibited a small pressure decrease tentatively interpreted as a geomechanical response to start of injection 1 km away. Pressure in the reservoir increased by 80 bar (8 MPa) during CO_2 injection then declined as reservoir pressure decreased by production below initial pressure. AZMI showed weakly correlated pressure increase followed by a decline – tentatively interpreted as a transfer of fluids between injection zone and AZMI potentially along well bores at an unknown distance from well[1]. • Detailed area of study: no response to pressure increase in injection zone – interpreted as AZMI being hydrologically isolated from injection. • AZMI across graben-marginal sealing fault: also no pressure response.
Ground water monitoring	Groundwater monitoring: is complex in Cranfield because: • Study area lies across a surface-water divide – no flow direction could be established. Would require a large number of wells. • Groundwater in numerous hydrologically isolated zones. Sampling in one might miss leakage in another. • Heterogeneity in distribution of flow units required in-depth hydrological assessment to design a robust monitoring program – outside research scope. Conventional array of water-supply wells completed at depths of 100 to 125 m over the plume area were sampled quarterly for conventional field parameters, major and minor elements, and selected stable isotopes[8] (Figure 8.6). No trends of leakage have been detected in this array[1].

	A single well push-pull test was developed to assess potential impacts of CO_2 leakage on the quality of shallow water at Cranfield[5]. The best parameters to detect leakage were pH, DIC (dissolved inorganic carbon) and $\delta^{13}C$ of DIC but only under certain conditions.
Wells in the detailed area of study collecting dense time-lapse data[2]. • ERTmeasurements. • Pulsed neutron and resistivity (wireline) • Downhole and above-zone pressure • Distributed temperature • Fluid chemistry including perfluorocarbons, noble gases, and SF_6 as tracers. • Time-lapse cross-well seismic and ERT measure saturation changes (Figure 8.4). • VSP	ERT between wells was inverted to provide high frequency (daily) images of the change in resistivity as CO_2 was substituted for brine. The inversions show that flow meandered through channels, with higher saturation reaching the well furthest from injection[4]. Time-lapse crosswell tomography between DAS well pairs. Initial survey in 2009 prior to injection and repeat in 2010. Resulting tomograms are valuable to constrain other datasets. Strongly heterogenous distribution of CO_2 between the observation wells even though in close proximity[12].
Downhole gravity	Time-lapse borehole gravity measurements were collected within two multi-use monitoring wells (F02 and F03)[13]. A baseline survey was acquired in September 2009 and follow up survey in October 2010. Between December 2009 and August 2010 124,241 metric tons of CO_2 was injected and the gravimeter is responding to this volume. The datasets picked up the boundaries of the reservoirs. The time-lapse response from the CO_2 injection is less defined but still significant with a decrease in density contrast within the reservoir.
Reservoir characterisation	Reservoir characterisation: cores, historic and new wireline logs, production history, hydrologic tests, fluid analysis, and 3D seismic survey all used in multiple numerical models to predict reservoir response[2].
Experience summary - effectiveness of techniques (limitations / strengths)	

12 Hovorka, S.D., Meckel, T.A. and Trevino, R.H., 2013. Monitoring a large-volume injection at Cranfield, Mississippi—Project design and recommendations. *International Journal of Greenhouse Gas Control*, *18*, pp.345-360.
13 Dodds, K., Krahenbuhl, R., Reitz, A., Li, Y. and Hovorka, S., 2013. Evaluating time-lapse borehole gravity for CO_2 plume detection at SECARB Cranfield. *International Journal of Greenhouse Gas Control*, *18*, pp.421-429.

Phase II: Injection profiles and RST logging show a pattern of preferential CO_2 flow into different reservoir intervals within 'D-E' reservoir interval, confirming a model of reservoir complexity. CO_2 migration to the dedicated observation well was slower than modelled[2].   **HiVIT:** fluids sampled over a year, isotopic composition of gases in produced fluids show an evolution from minor dissolved CO_2 in native brine to dominantly injected CO_2. Change in major and minor elements, pH, and alkalinity are small even in dominantly injected CO_2 [2]. 3D repeated in 2010.   **Detailed area of study:** Good hydrological connection between F1 injector and F2 and F3 observation wells – observed during pre-injection water production and reinjection test program. Fluid sampling with U-tube sampler documented first arrival for CO_2 at the F2 well by day 9 of injection, at the early end of the predicted arrival times[2] and at day 13 at the F3 well. Injection rate was increased and tracer arrival became faster at F3 – indicative of a heterogenous flow system in which complex behaviour from changes in relative permeability and capillary pressure as fluid saturations change.   A numerical simulation model of CO_2 breakthrough times in fourteen production wells matches field observations reasonably well. These demonstrate that static and dynamic reservoir models work well and the level of heterogeneity defined in the static model is adequate[10].   ERT successfully deployed at depth. Initial inversions of daily cross-well surveys showed meaningful changes in fluid resistivity as low-conductivity, free-phase CO_2 displaced high conductivity brine. Low conductivity tongue observed between F2 and F3 observation wells, then a second area not connected appeared in the upper part of the flow field, intersecting F3 well (explaining fast arrival of CO_2 at F3).   RST logging show similar pattern of saturation changes as ERT, i.e. increase in CO_2 concentration low in F2 well (perforated interval) and high in the F3 well.   **P-site:** site already selected due to higher elevated methane and CO_2 concentrations during reconnaissance of areas near plugged and abandoned wells. Observations of near surface fluids will continue after well remediation to look for tracer signal or change in methane concentration or isotopic composition. The P-site testing over 6 years showed that ^{14}C testing could differentiate the source to a modern carbon source rather than from the injected CO_2 from Jackson Dome or methane from depth. Tracers and noble gas testing were not useful at this site, but may be useful elsewhere[9].   Observed seismic time-lapse amplitude changes and time shifts are compatible with predictions based on multicomponent reservoir simulation. However, the presence of oil can depress seismic velocity changes due to the injection of CO_2. It is difficult to estimate stored volumes where there are inadequate constraints on reservoir properties and these are exacerbated during enhanced oil production where pore fluid distribution can be complex[6].   In the detailed area of syudy and also HiVIT areas the impacts of heterogeneity were measured. Good model match to trends are observed, but also many complex responses such as fast break throughs at better connected wells, which show the limits of monitoring wells in calibration of CO_2 migration through heterogeneous flow systems (Hovorka pers comms).
MMV (Measurement, Monitoring, Verification) Practices & related verification of injected CO_2
MMV storage accounting was reported to DOE quarterly.

Major technical/scientific studies on the site, major learnings, conformance assessment (history-matching with models, correlation between different monitoring techniques)
History matching of observed response to predicted response is used to interpret results and improve confidence in conceptual models and numerical approaches[2]. A deterministic model of the Phase 2 area using the GEM simulator and early characterisation data has been used to obtain a good history match with pressure observations at time steps[2]. Field-scale compositional reservoir flow modelling was conducted by Hossieni et al (2018), field evolution and history were extracted and matched to the production and pressure history[14].
List of key publications covering the site
1. Hovorka, S.D., 2013. Three-million-Metric-Ton-Monitored injection at the SECARB Cranfield project—project update. Energy Procedia, 37, pp.6412-6423. 2. Hovorka, S.D., Meckel, T.A., Trevino, R.H., Lu, J., Nicot, J.P., Choi, J.W., Freeman, D., Cook, P., Daley, T.M., Ajo-Franklin, J.B. and Freifeild, B.M., 2011. Monitoring a large volume CO_2 injection: Year two results from SECARB project at Denbury's Cranfield, Mississippi, USA. Energy Procedia, 4, pp.3478-3485. 3. Gray, K., 2021. SECARB Regional Project Assessment (No. DOE-SSEB-42590-219). Southern States Energy Board, Peachtree Corners, GA (United States). 4. Nemeth, K., Berry, P., Gray, K., Wernette, B., Hill, G., & Hill, B. (2021). Final Project Report-SECARB Phase III (No. DOE-SSEB-42590-100121). Southern States Energy Board, Peachtree Corners, GA (United States). 5. Yang, C., Mickler, P.J., Reedy, R., Scanlon, B.R., Romanak, K.D., Nicot, J.P., Hovorka, S.D., Trevino, R.H. and Larson, T., 2013. Single-well push–pull test for assessing potential impacts of CO_2 leakage on groundwater quality in a shallow Gulf Coast aquifer in Cranfield, Mississippi. *International Journal of Greenhouse Gas Control*, *18*, pp.375-387. 6. Vasco, D. W., Alfi, M., Hosseini, S. A., Zhang, R., Daley, T., Ajo-Franklin, J. B., & Hovorka, S. D. (2019). The Seismic Response to Injected Carbon Dioxide: Comparing Observations to Estimates Based Upon Fluid Flow Modeling. *Journal of Geophysical Research: Solid Earth*, *124*(7), 6880-6907. https://doi.org/10.1029/2018JB016429 7. Takagishi, M., Hashimoto, T., Horikawa, S., Kusunose, K., Xue, Z. and Hovorka, S.D., 2014. Microseismic monitoring at the large-scale CO_2 injection site, Cranfield, MS, USA. *Energy Procedia*, *63*, pp.4411-4417. 8. Yang, C., Romanak, K.D., Holt, R.M., Lindner, J., Smith, L., Trevino, R., Roecker, F., Xia, Y., Rickerts, J. and Hovorka, S., 2012, February. Large volume of CO_2 injection at the Cranfield, early field test of the SECARB Phase III: near-surface monitoring. In Carbon Management Technology Conference. OnePetro. 9. Anderson, J.S., Romanak, K.D., Yang, C., Lu, J., Hovorka, S.D. and Young, M.H., 2017. Gas source attribution techniques for assessing leakage at geologic CO_2 storage sites: Evaluating a CO_2 and CH_4 soil gas anomaly at the Cranfield CO_2-EOR site. *Chemical Geology*, *454*, pp.93-104. 10. Alfi, M. and Hosseini, S.A., 2016. Integration of reservoir simulation, history matching, and 4D seismic for CO_2-EOR and storage at Cranfield, Mississippi, USA. *Fuel*, *175*, pp.116-128.

14 Hovorka, S., 2021. SECARB Post Injection Assessment Report (No. DOE-SSEB-42590-204). Southern States Energy Board, Peachtree Corners, GA (United States).

11. Ditkof, J., Meckel, T.A., Zeng, H. and Hovorka, S.D., 2011, December. Time lapse seismic response (4D) related to industrial-scale CO_2 injection at an EOR and CCS site, Cranfield, MS. In *AGU Fall Meeting Abstracts* (Vol. 2011, pp. GC51B-0976).
12. Hovorka, S.D., Meckel, T.A. and Trevino, R.H., 2013. Monitoring a large-volume injection at Cranfield, Mississippi—Project design and recommendations. *International Journal of Greenhouse Gas Control*, *18*, pp.345-360.
13. Dodds, K., Krahenbuhl, R., Reitz, A., Li, Y. and Hovorka, S., 2013. Evaluating time-lapse borehole gravity for CO_2 plume detection at SECARB Cranfield. *International Journal of Greenhouse Gas Control*, *18*, pp.421-429.
14. Hovorka, S., 2021. SECARB Post Injection Assessment Report (No. DOE-SSEB-42590-204). Southern States Energy Board, Peachtree Corners, GA (United States).

Other relevant information considered pertinent to the report

Ditkof, J., Caspari, E., Pevzner, R., Urosevic, M., Meckel, T.A. and Hovorka, S.D., 2013. Time-lapse seismic signal analysis for enhanced oil recovery at Cranfield CO_2 sequestration site, Cranfield field, Mississippi. *Interpretation*, *1*(2), pp.T157-T166.

Hosseini, S.A., Alfi, M., Nicot, J.P. and Nuñez-Lopez, V., 2018. Analysis of CO2 storage mechanisms at a CO_2-EOR site, Cranfield, Mississippi. *Greenhouse Gases: Science and Technology*, *8*(3), pp.469-482.

Figures

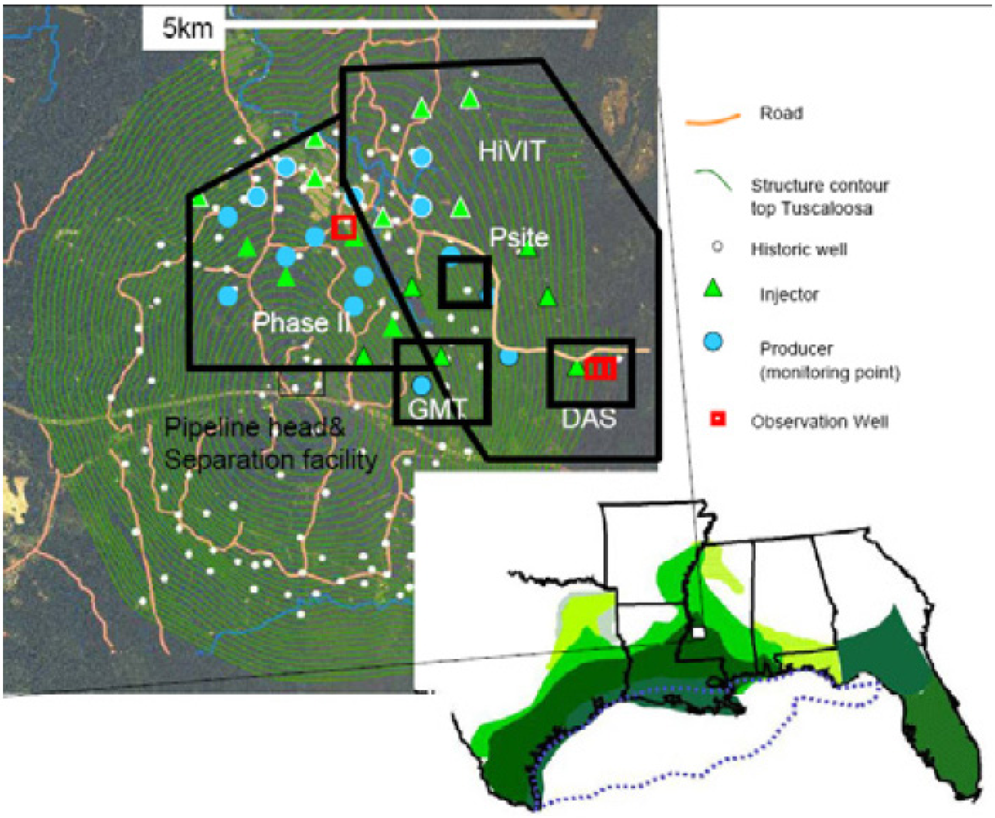


Figure 8.1: Location map. Five study areas of the SECARB experiments at Cranfield on a structure contour map of the field[2].

Commercialization goals	**Effective environmental assurance monitoring**	**Extent of CO_2 plume predicted**	**Magnitude and extent of pressure increase predicted**
Hypothesis tested ⇨	CO_2 is retained in-zone: documentation of no leakage to air & no damage to water	Observed CO_2 saturation is correctly predicted by flow modeling	Observed pressure distribution is correctly predicted by model
Field experiments ⇨	Surface monitoring: verification of groundwater and soil gas approaches.	Bounding uncertainty in reservoir characterization; CO_2 saturation and extent rigorously measured using time-lapse 4-D surface	Measure pressure changes over time and area; Microseismic test
	Above-zone monitoring: pressure, temperature, composition,	seismic, VSP, and cross-well seismic, ERT; RST; Dissolution and saturation measured via tracer chromatography	
Theory and lab ⇨	Sensitivity of tools; saturated-vadose modeling of flux and tracers.	Lab-based geophysics under various saturations. Tracer performance. Advanced flow simulation with multiphase fluid.	Advanced simulation of reservoir pressure field.

Table 8-1: Goals of Phase III SECARB research at Cranfield[2].

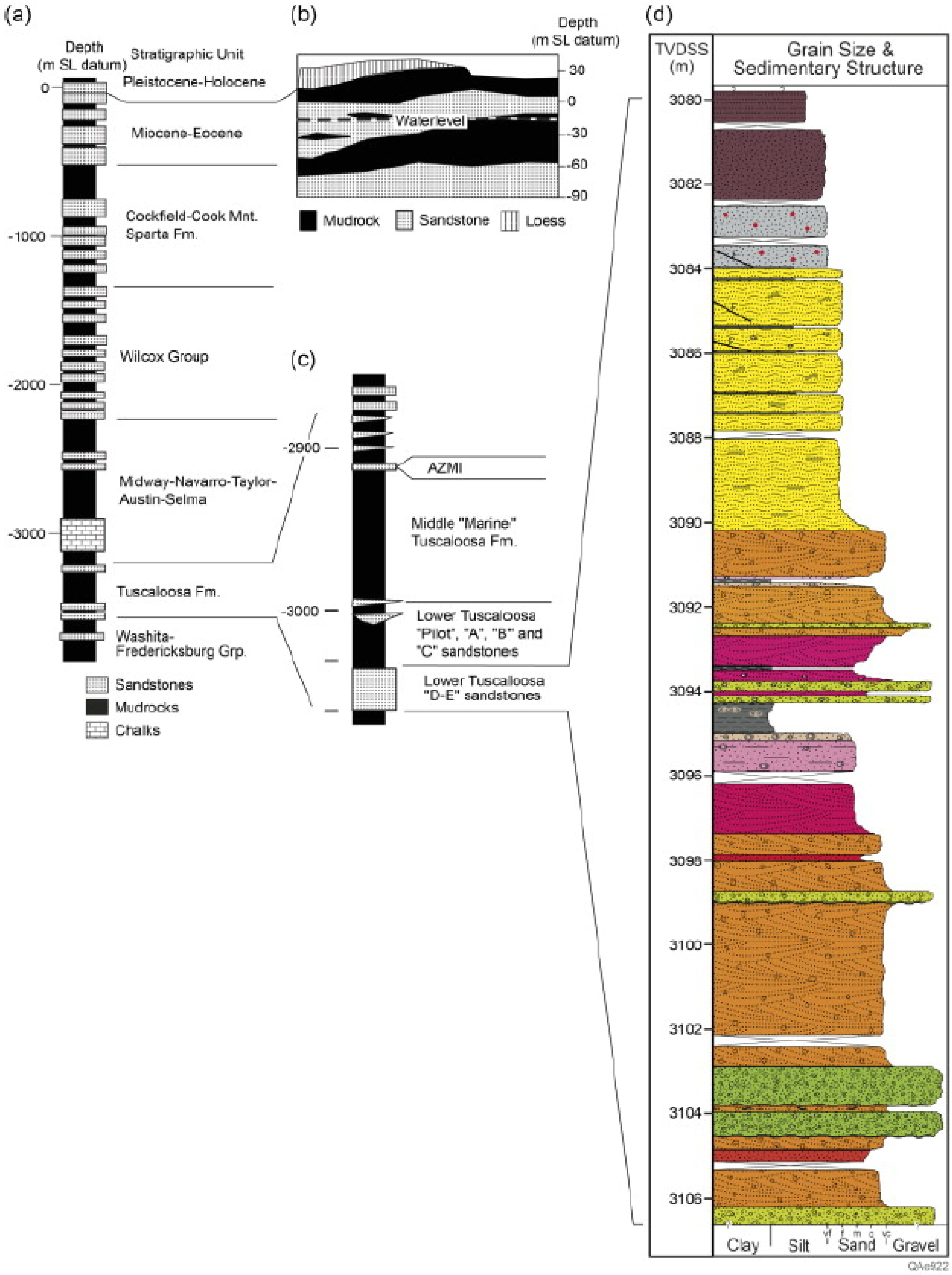


Figure 8.2: Stratigraphic chart near Cranfield, western Mississippi[3]. Detail of the Tuscaloosa Fm is generalised from wireline logs.

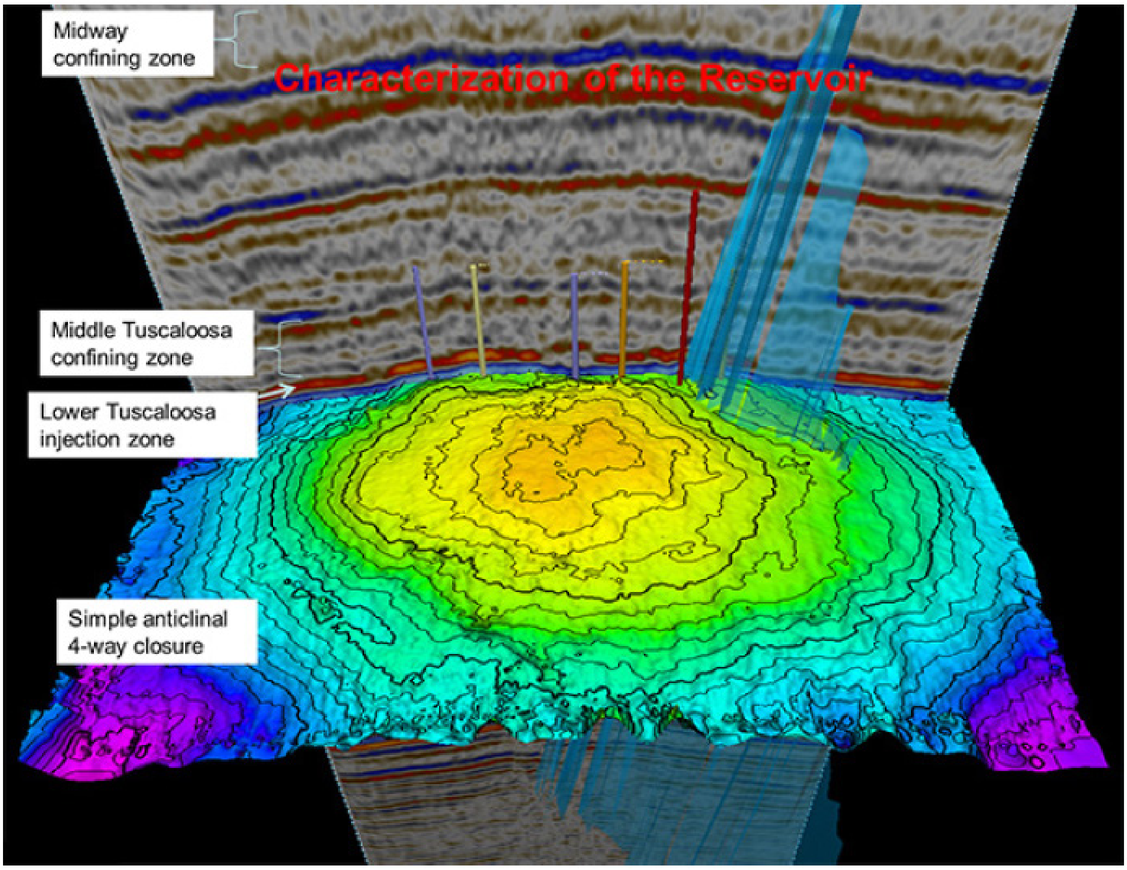


Figure 8.3: Baseline 3D survey with interpreted structure on base Tuscaloosa, showing key units. The crestal graben is shown in blue[3].

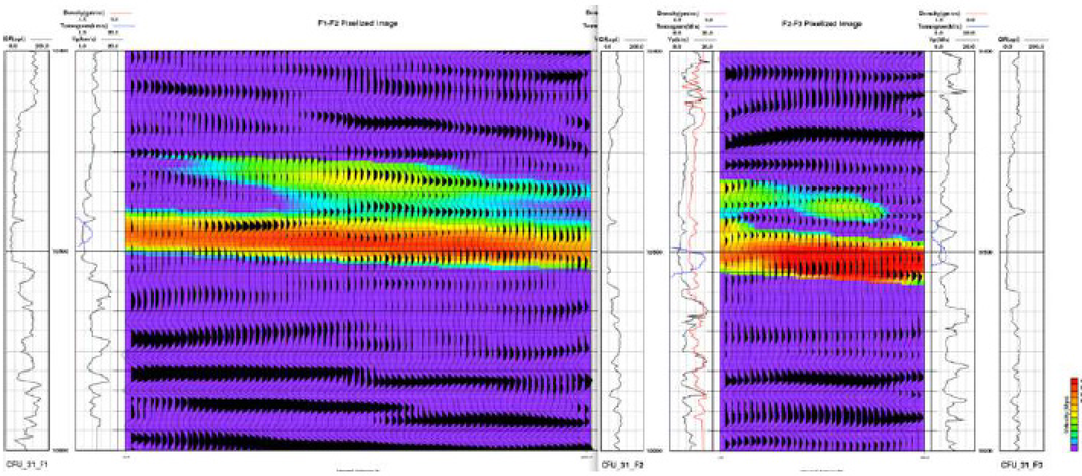


Figure 8.4: Initial analysis of time-lapse cross-well seismic data. Data shows flow in two zones with preferred flow in the eastern portion of the transect[4].

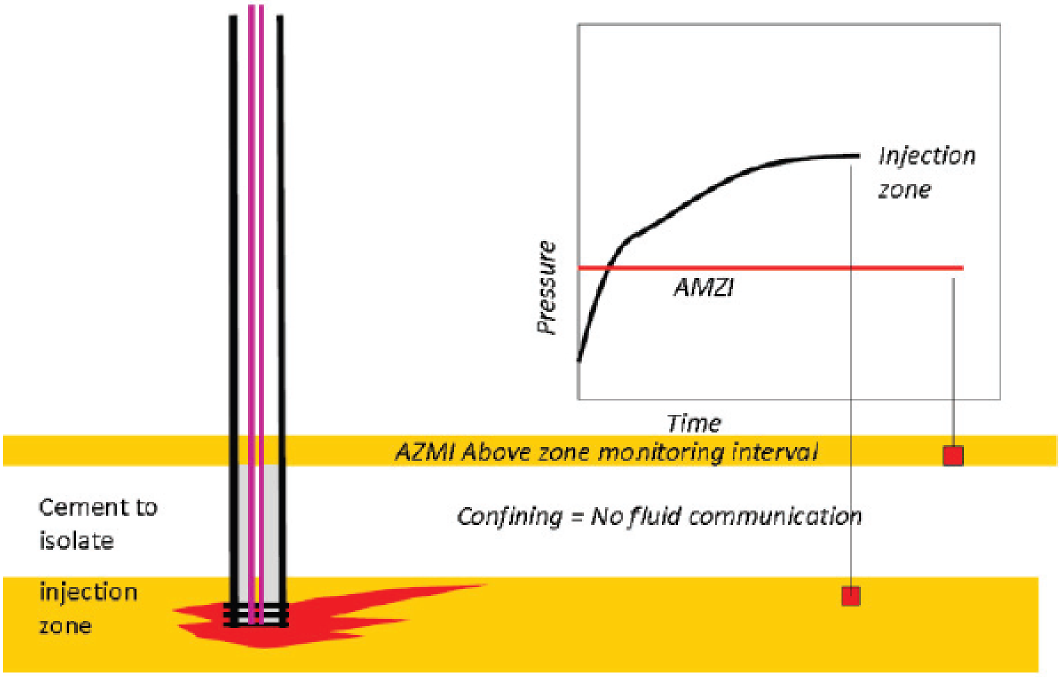


Figure 8.5: Concept of above-zone monitoring. Comparison of pressure evaluation in injection zone with AZMI during injection can uniquely demonstrate isolation[2].

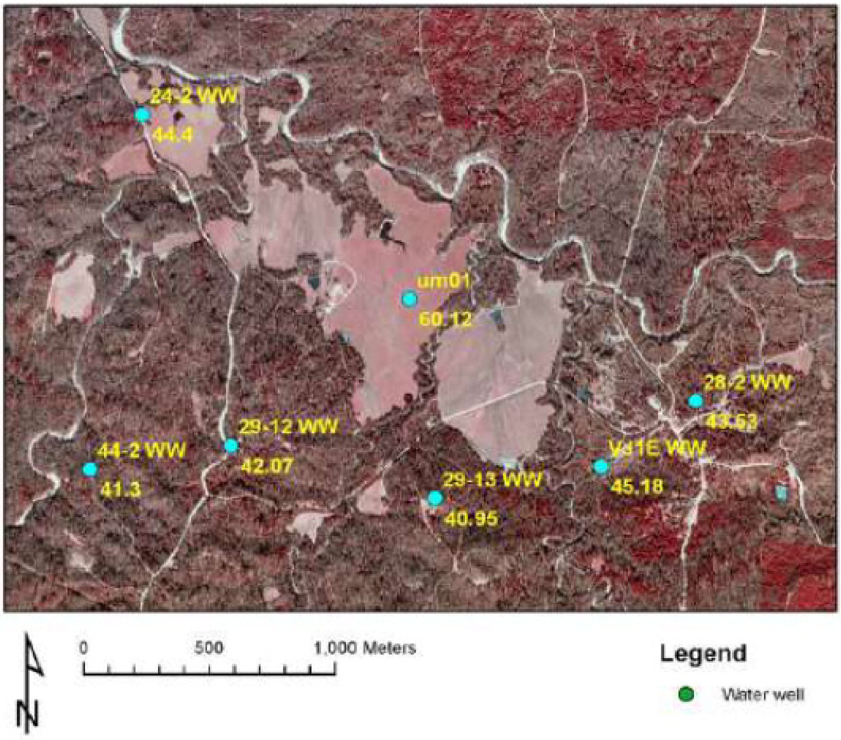


Figure 8.6: Aerial image of the Cranfield Site showing location of groundwater monitoring wells. Water-level depth (m) is marked [4]

9. SECARB - Citronelle

Site Details					
Name	Location	Province/State	Country	Onshore	Offshore
SECARB-Citronelle (Phase III)	Mobile County	Alabama	USA	✓	

General storage type
Deep Saline Aquifer

Development History (Closed)
Part of the SECARB Anthropogenic Test – to demonstrate the deployment of CO_2 capture, transport, geologic storage and monitoring technology[1]. Managed by SSEB, and funded by the DOE with cost share provided by the Electrical Power Research Institute (EPRI). CO_2 is captured from the Alabama Power Company's Plant Barry coal-fired power plant in Mobile County, Alabama, and is transported 12 miles (19.3 km) to the Citronelle oil field (operated by Denbury). CO_2 is injected into Lower Cretaceous sandstones of the upper Paluxy Formation (at 2,880 to 2,987 m)[2] (Figure 9.1). Starting in the third quarter of 2012 and continuing for 1-2 years, injection ended in September 2014, with up to 550 metric tonnes of CO_2 being injected per day[1].

Geological Characteristics.	
Reservoir Formation	
Lower Cretaceous Upper Paluxy Sandstones, a saline aquifer, is more than 330 m above the Citronelle oil reservoir[2]. Lies at 2,880 m depth (Figure 9.2). Nine out of 20 sandstone units chosen for injection, one highly permeable unit discounted to limit the extent of the CO_2 plume[3].	
Lateral extent / thickness variation	335 m thick[2]. Fluvial stacked multi-story sandstones range from 6 to 12 m thick[1]. Eight Paluxy sandstones were sampled in the injection well (Figure 9.3).
Rock type	Sandstones.
Sedimentary features: Depositional Environment / facies type & variation / mineral composition	Fluvial sandstones, siltstones and mudstones[1].
Porosity	145 m of net porous sand in the Upper Paluxy Fm, in over 20 sand units. Average porosity is 19.5% [1].

1 Koperna Jr, G.J., Kuuskraa, V., Riestenberg, D., Rhudy, R., Trautz, R., Hill, G. and Esposito, R., 2013. The SECARB anthropogenic test: status from the field. Energy Procedia, 37, pp.6273-6286.
2 Koperna, G.J., Carpenter, S.M., Petrusak, R., Trautz, R., Rhudy, D. and Esposito, R., 2014. Project assessment and evaluation of the area of review (AoR) at the Citronelle SECARB Phase III Site, Alabama USA. Energy Procedia, 63, pp.5971-5985.
3 Koperna, G., Riestenberg, D., Kuuskraa, V., Rhudy, R., Trautz, R., Hill, G.R. and Esposito, R., 2012. The SECARB anthropogenic test: a US integrated CO_2 capture, transportation and storage test.

Permeability	12-3,950 mD and averages 284 mD[2].
Formation fluid properties: (residual hydrocarbons / salinity concentration).	Brine saturated, salinity concentration is 200,000 mg/L[4].

Caprock / primary seal formation

The 46m thick basal shale of the Washita-Fredricksburg Group [2] is the primary confining unit. Internal baffles within the injection interval are mudrocks of the Paluxy Formation. Additional overlying units include the Tuscaloosa Marine Shale and the Selma Chalk and the Midway Shale Formation[1].

Lateral extent / thickness variation	Multiple area – regionally extensive.
Rock type	Prominent basal shale of the Wishita-Fredricksburg Group is the primary seal. Others include the Tuscaloosa Marine shale, the Selma chalk (~2,000 ft (~610 m) thick) and the Midway shale (Figure 9.2)[2].
Fracture pressure	n/a
Porosity	15-18%[5].
Permeability	0.1 to 0.9 mD[5].

Formation	Average Permeability (mD)	Average Porosity (%)
Selma Chalk	0.043	14.7
Lower Cretaceous Shale	9.58×10^{-7}	9.5
Marine Tuscaloosa	2.61×10^{-6}	10.2

Overburden Features (Thickness, formations presence of secondary reservoirs / seals)

Presence of a potable aquifer. Potable aquifer present in the Tertiary section (Figure 9.2).

Structure

The Citronelle field is located on the Citronelle Dome, a giant salt-cored anticline in the eastern Mississippi Salt Basin. The field covers 66.3 km^2.

Fold type / fault bounded	Forms an elliptical structural closure at all horizons[2] with four-way closure at all stratigraphic levels (Figure 9.4).
Faults /Fractures (Type – normal, reverse, strike-slip)	There is no evidence of faults or fracture zones at the Citronelle field – based on wells, field production history and 2D seismic[2].
Displacement	n/a
Stability (pre-stressed, active, stable)	Stable.

[4] Conaway, C., Thordsen, J., Manning, M., Cook, P., Trautz, R., Thomas, B., Kharaka, Y. Comparison of geochemical data obtained using four brine sampling methods at the SECARB Phase III Anthropogenic Test CO2 injection site, Citronelle Oil Field, Alabama, International Journal of Coal Geology, Volume 162, 2016, Pages 85-95,

5 Nemeth, K., Berry, P., Gray, K., Wernette, B., Hill, G. and Hill, B., 2021. Final Project Report-SECARB Phase III (No. DOE-SSEB-42590-100121). Southern States Energy Board, Peachtree Corners, GA (United States).

Injection / storage history	
Number of injection, monitoring or other wells, well geometry, design and key completion information for injection wells, relevant well issues. Reused / new purpose drilled well.	
Geological characterisation well and two injection wells were drilled in 2011[2]. **D-9-7#2** (Injector well), spudded 2nd December 2011 and completed March 2012. TD 11,775 ft (3,589 m), injection assembly was installed. Whole core recovery of 68 ft (20.7 m) of Paluxy Fm (at 9,568 ft (~2,916 m) depth)[5]. All injection took place in this well. **D-9-8#2** (characterisation and monitoring well), drilled December 2010 and completed January 2011. Cored and other characterisation. Cemented the production casing from 11,817-5,988 ft, (3,602 – 1,825 m) differential valve (DV) cementing tool used from 5,988-1,500 ft (1,825 – 457 m) [5]. **D-9-9#2** (backup injection well)[1], TD 11,780 ft (~3,590 m), 45 ft (13.72 m) of whole core of Paluxy Fm recovered. Well was never perforated or used for injection. Only used for cased hole logging and monitoring of the CO_2 plume[5]. Citronelle field contains more than 400 oil wells (Figure 9.5)[2]. Plume is estimated at 440 ft (134 m) from the injection well, only wells within this radius are the injection well D 9-7 #2, and its permanently abandoned twin. Nearest well to the injector is the D9-8 #2 but outside of the plume extent[1]. With additional injection plume is expected to grow to a radius of 720 ft (219 m).	
Extent and status of casing (corrosion history/ cementation records)	Cement bond evaluation on the injection well prior to injection demonstrates a good cement bond across the injection zone and confining unit intervals[2].
Injection rates & pattern (i.e. continuous / intermittent) changes in injection behaviour	See Figure 9.6.
Total quantities stored	More than 114,000 metric tons of CO_2 injected and stored[5] (Figure 9.6).
Reservoir capacity (estimate)	480 million to 1.9 billion metric tonnes[3].
Fluid extraction rate (brine extraction, oil for EOR)	None (saline reservoir injection).
Seismicity	
Monitoring regime (technologies deployed)	
n/a	
Seismic events (Detection / magnitude / attribution (natural induced).	
n/a	
Monitoring technologies applied and experiences with monitoring; Project objectives:	

- Test CO_2 flow, trapping and storage mechanisms of a regionally extensive Gulf Coast saline formation;
- demonstrate that favourable reservoir architecture of the saline formation can maximize CO_2 storage and minimise the extent of the plume;
- test the adaptation of commercially available oil field tools and techniques for post-injection monitoring of CO_2 storage;
- test experimental CO_2 monitoring technologies that are promising for future commercialization;
- document the permitting and compliance process for all aspects of a carbon capture and storage project;
- analyse the project management considerations and coordination required to successfully integrate all components of the project (capture, transport, injection and monitoring)[2].

Post-injection monitoring was conducted for three years[5] .
See Table 9-1 for MVA tests and their frequencies

Measurement Technique	Measurement Parameters	Application	Frequency
Reservoir and above-zone pressure	Wireline deployed downhole pressure gauges	Assess the injection pressure field and for regulatory compliance. Above-zone monitoring to detect leakage through the confining unit	Constant during injection operations, annually post-injection
Cased-hole pulsed neutron logging	Neutron capture as a function of brine displacement/CO_2 saturation buildup	Quantify CO_2 saturation near well penetrations. Demonstrates CO_2 plume migration and monitor for above zone leakage	One baseline deployment, annually during injection, semi-annually post-injection
Time-lapse seismic (crosswell and/or vertical seismic profiling)	CO_2 included change from baseline sonic velocity and amplitude	Distribution of CO_2 plue vertically and horizontally	One baseline deployment, once post-injection
Reservoir fluid sampling	Pressurized fluid samples taken from the injection zone. Analyze for pH, and selected cations and anions	Geochemical changes to injection zone that occur as a result of CO_2 injection	Semi-annually during injection phase, annually post-injection
Drinking water aquifer (USDW) monitoring	Alkalinity, DIC, DOC, selected cations and anions	Monitoring of USDWs for geochemical changes related to shallow CO_2 leakage	Quarterly during and post-injection
Injection well annular and tubing pressure	Pressure gauges located on the wellhead to monitor casing annular and tubing pressure	Annular pressure is an indication of wellbore integrity. Tubing pressure assures regulatory compliance with maximum injection pressure	Constant during injection operations and post-injection
Soil CO_2 Flux	Mass of CO_2 emitted from the soil per unit time and area	Monitor for anomalous increases in the amount of CO_2 that is emitted from the soil surface as an indication of CO_2 leakage	Quarterly during and post-injection
Perfluorocarbon tracers (PFTs) introduced in the CO_2 stream	Monitor for increased tracer levels at the ground surface around deep well penetrations	Monitor for the presence of tracer buildup near wellbores which would suggest vertical leakage of CO_2	Single baseline, annually during and post-injection
Injection Well Mechanical Integrity Test	Radioactive tracer test, annular pressure test, noise or temperature log	Assure internal and external integrity of the CO_2 injection well(s)	Once prior to injection, annually during injection or following well work over
Injection Pressure	Injection well tubing and casing pressure	Assure regulatory compliance with maximum pressure, monitor casing pressure for tubing/casing leaks	Continuous throughout the injection phase
Injection Stream Composition	Major and minor gases, organics and metals	Provide confirmation that the injectate stream meets pipeline transport and UIC permit purity requirements	Full baseline analysis; Monthly monitoring of major gases; semi-annual testing of metals, organics testing only if fuel supply or capture method is altered

Surface monitoring technologies deployed

Seismic.	Due to lower vertical resolution and higher signal to noise ratio the use of surface seismic was eliminated[1].
Soil flux.	Using flux accumulation chambers in and around injection site. Collected in time-lapse to monitor for anomalous increases in soil CO_2 output from shallow subsurface. 12 baseline sampling events by 2011[1]. Quarterly monitoring during injection.
Soil gas.	Surface soil gas monitoring of PFTs occur near injection site[1]. No tracers detected in March 2015[5].

Subsurface monitoring technologies deployed (well logs)

Wellhead pressure	Injection tubing pressure and annulus pressure monitored at the wellhead throughout injection[2].
Cross-well seismic	Integrated cross-well seismic profile: acquired focusing on the injection reservoir – using well D-9-7#2 (source well) and the monitoring well D-9-8#2 (used to house the receiver array). 2,487-2,300 m depth and 257 m between wellheads. Imaging did not reveal any visible structural barriers or faulting that could affect movement and storage of CO_2. Repeat acquisition post-injection (June 2014) to image the CO_2 plume[1]. Comparison of the 2012 and 2014 travel time tomograms indicate a decrease in seismic velocity in the upper injection zone, suggesting an increase in CO_2 saturation[5] (Figure 9.7).
Mechanical Integrity Tests.	Confirms the adequacy of the construction of an injection well and to detect internal and external problems within the well before leaks occur. Includes: (1) a radioactive tracer survey, (2) a temperature or noise log, and (3) and annular pressure test. Follow-up MITs (magnetic imaging tool) performed annually[1].
Vertical seismic profiling (VSP).	VSP (with receivers in the wellbore and source at ground surface) to provide high resolution image of the reservoir to identify baffles or barriers to CO_2 movement. Provide a baseline prior to injection for future time-lapse imaging[1]. Receiver arrays in the primary injection well D-9-7#2. Time-lapse VSP was not able to definitely resolve CO_2 plume.
Pressure in observation wells.	Pressure observations at three observation wells. Above zone pressure monitoring in the D4-13 well of lowermost sandstone in the overlying Washita-Fredricksburg Group (first sandstone above the basal shale cap rock). This is to provide indication of CO_2 migration and/or leakage across the primary confining unit[2]. Reservoir pressure response in three observation wells show no apparent pressure response or leakage of CO_2 above the seal[2].
Groundwater sampling.	Groundwater sampling in three wells drilled near injection wells. Groundwater chemistry testing focused on 20 metals identified with

	primary and secondary maximum contaminant levels (MCLs) Additional parameters include pH, alkalinity and TDS[1]. Also undertook a comparison of groundwater sampling methodologies[6]. Groundwater samples were collected throughout injection and post-injection phases[5]. Quarterly sampling during and after injection.
PFTs.	PFTs: periodically injected along with CO_2 stream.
Modular Borehole Monitoring System	Modular Borehole Monitoring System: maximises the data collected in a single well monitoring system. Include, (1) U-tube reservoir fluid sampler, (2) heat-pulse cable with fibre optic DTS, (3) geophone array, and (4) discrete down hole pressure/temperature sensors. Baseline measurements prior to injection with subsequent testing post-injection[1].
Neutron logs	Case hole pulsed neutron logs: baseline pulsed neutron capture logs were run in five project wells and repeated annually during the injection[1].
Experience summary - effectiveness of techniques (limitations / strengths)	
2015 cased hole neutron log of D-9-8#2 showed presence of CO_2 in two of the upper Paluxy injection reservoir sands. No indication of any leakage above the confining unit.	

List of key publications covering the site

1. Koperna, G.J., Carpenter, S.M., Petrusak, R., Trautz, R., Rhudy, D. and Esposito, R., 2014. Project assessment and evaluation of the area of review (AoR) at the Citronelle SECARB Phase III Site, Alabama USA. Energy Procedia, 63, pp.5971-5985.
2. Koperna Jr, G.J., Kuuskraa, V., Riestenberg, D., Rhudy, R., Trautz, R., Hill, G. and Esposito, R., 2013. The SECARB anthropogenic test: status from the field. Energy Procedia, 37, pp.6273-6286.
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6 Conaway, C.H., Thordsen, J.J., Manning, M.A., Cook, P.J., Trautz, R.C., Thomas, B. and Kharaka, Y.K., 2016. Comparison of geochemical data obtained using four brine sampling methods at the SECARB Phase III Anthropogenic Test CO_2 injection site, Citronelle Oil Field, Alabama. International Journal of Coal Geology, 162, pp.85-95.

5. Koperna, G., Riestenberg, D., Kuuskraa, V., Rhudy, R., Trautz, R., Hill, G.R. and Esposito, R., 2012. The SECARB anthropogenic test: a US integrated CO_2 capture, transportation and storage test.
6. Conaway, C.H., Thordsen, J.J., Manning, M.A., Cook, P.J., Trautz, R.C., Thomas, B. and Kharaka, Y.K., 2016. Comparison of geochemical data obtained using four brine sampling methods at the SECARB Phase III Anthropogenic Test CO_2 injection site, Citronelle Oil Field, Alabama. International Journal of Coal Geology, 162, pp.85-95.
7. Koperna, G., 2019. SECARB Phase III: Citronelle (No. DOE-SSEB-FC26-05NT42590-106). Southern States Energy Board, Peachtree Corners, GA (United States).

Figures

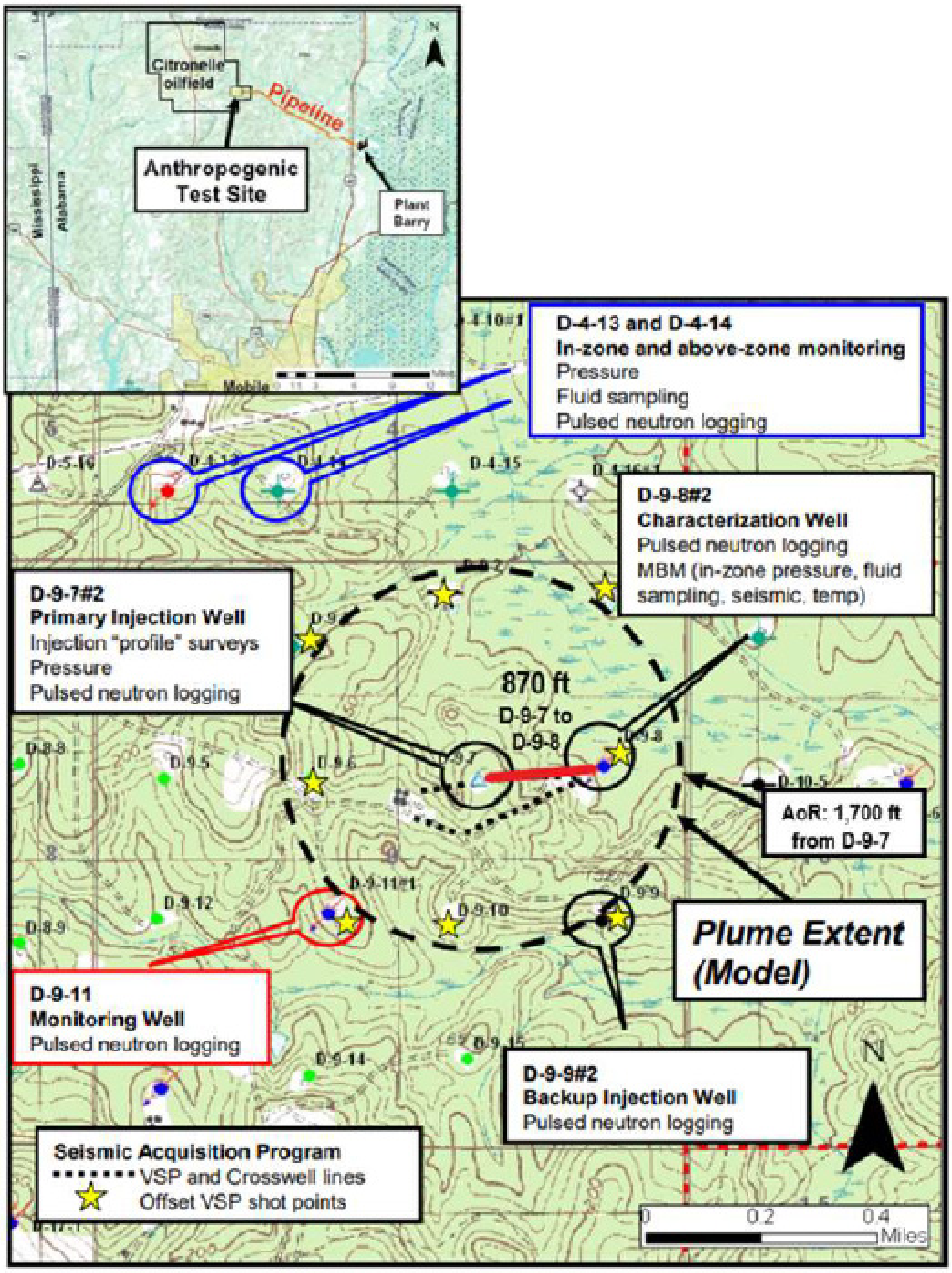

Figure 9.1: Location of SECARB – Citronelle project, and well locations and test monitoring[1].

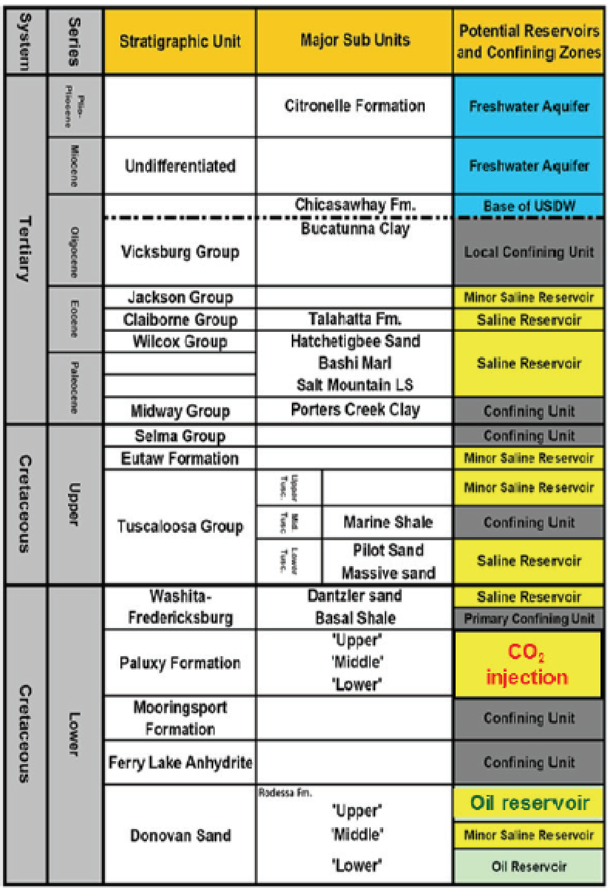

Figure 9.2: Stratigraphic Chart at Citronelle Field[1].

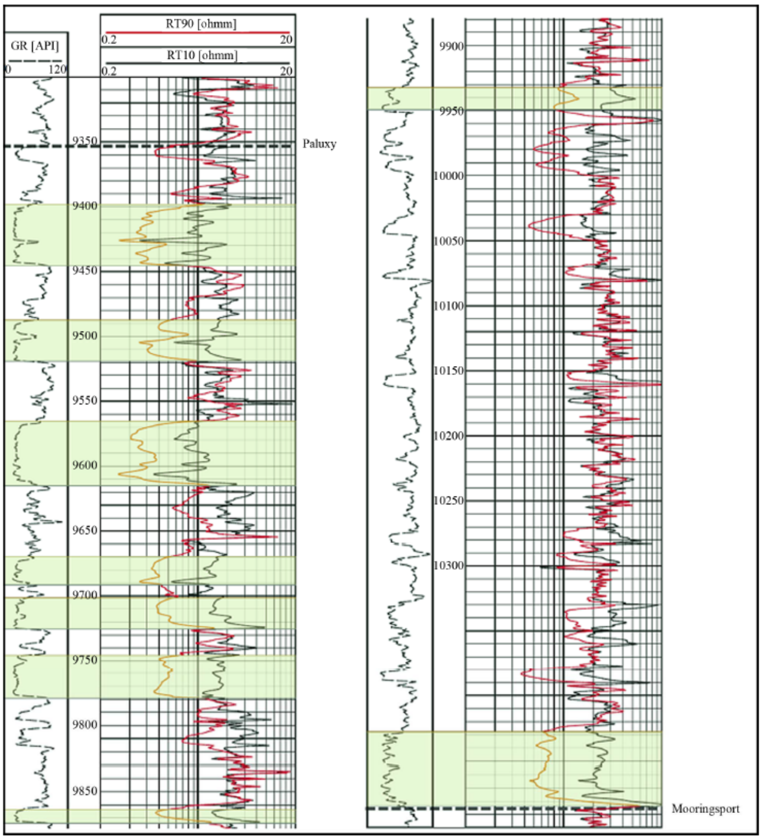

Figure 9.3: Paluxy Formation type log (D-9-8#2)[3].

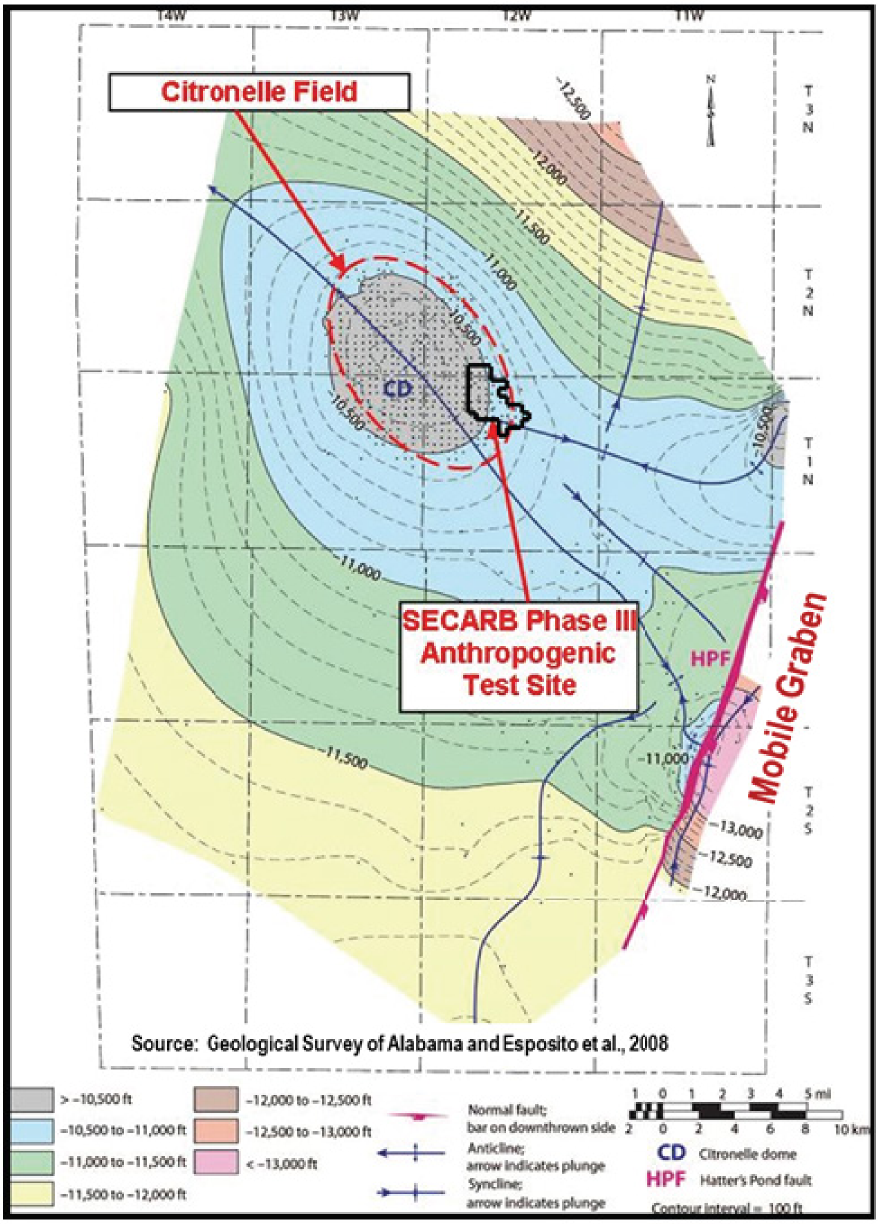

Figure 9.4: Geologic Structure of the Citronelle Dome[2].

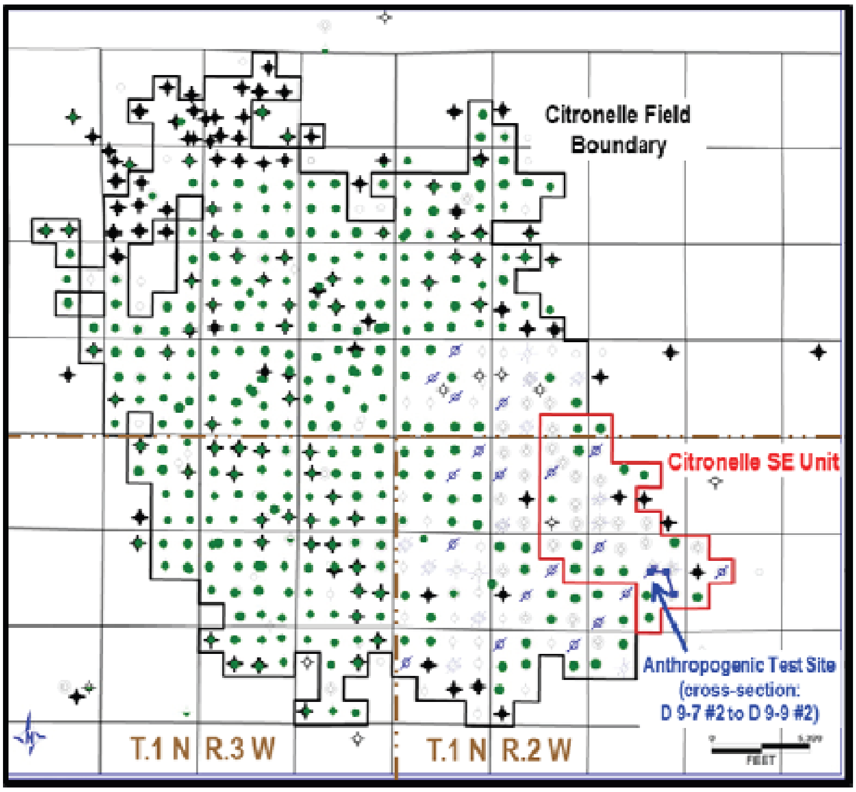

Figure 9.5: Citronelle Oil Field showing SE Unit and test site[2].

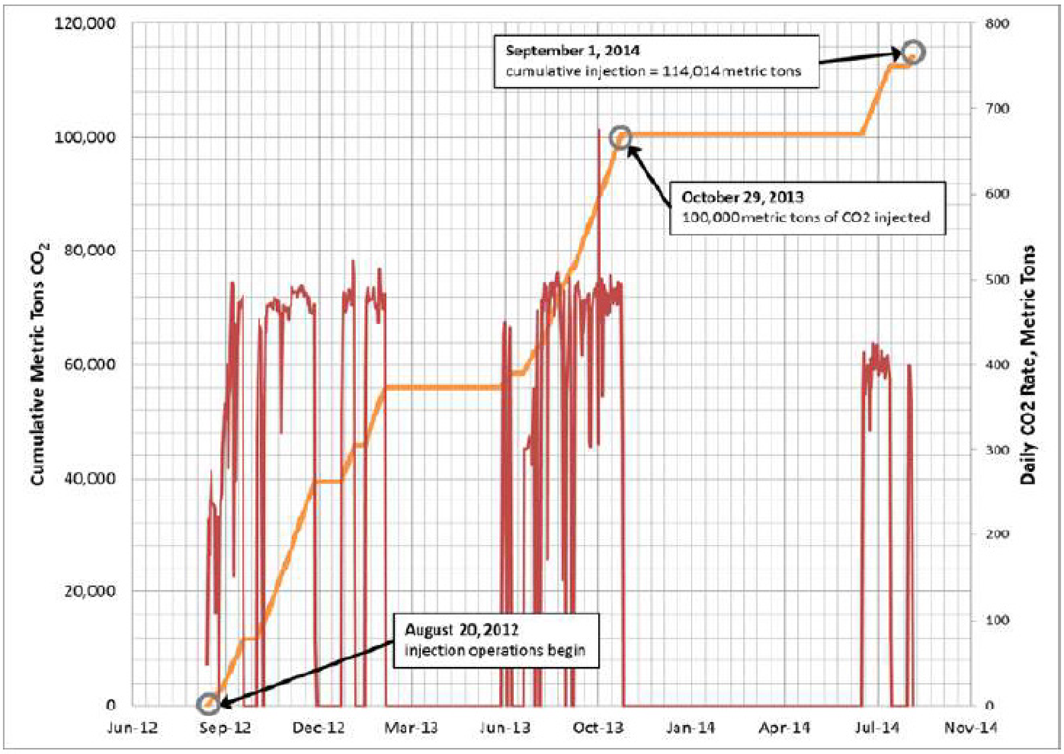

Figure 9.6: Time series of daily CO_2 injection and cumulative CO_2 injection[7] .

7 Koperna, G., 2019. SECARB Phase III: Citronelle (No. DOE-SSEB-FC26-05NT42590-106). Southern States Energy Board, Peachtree Corners, GA (United States).

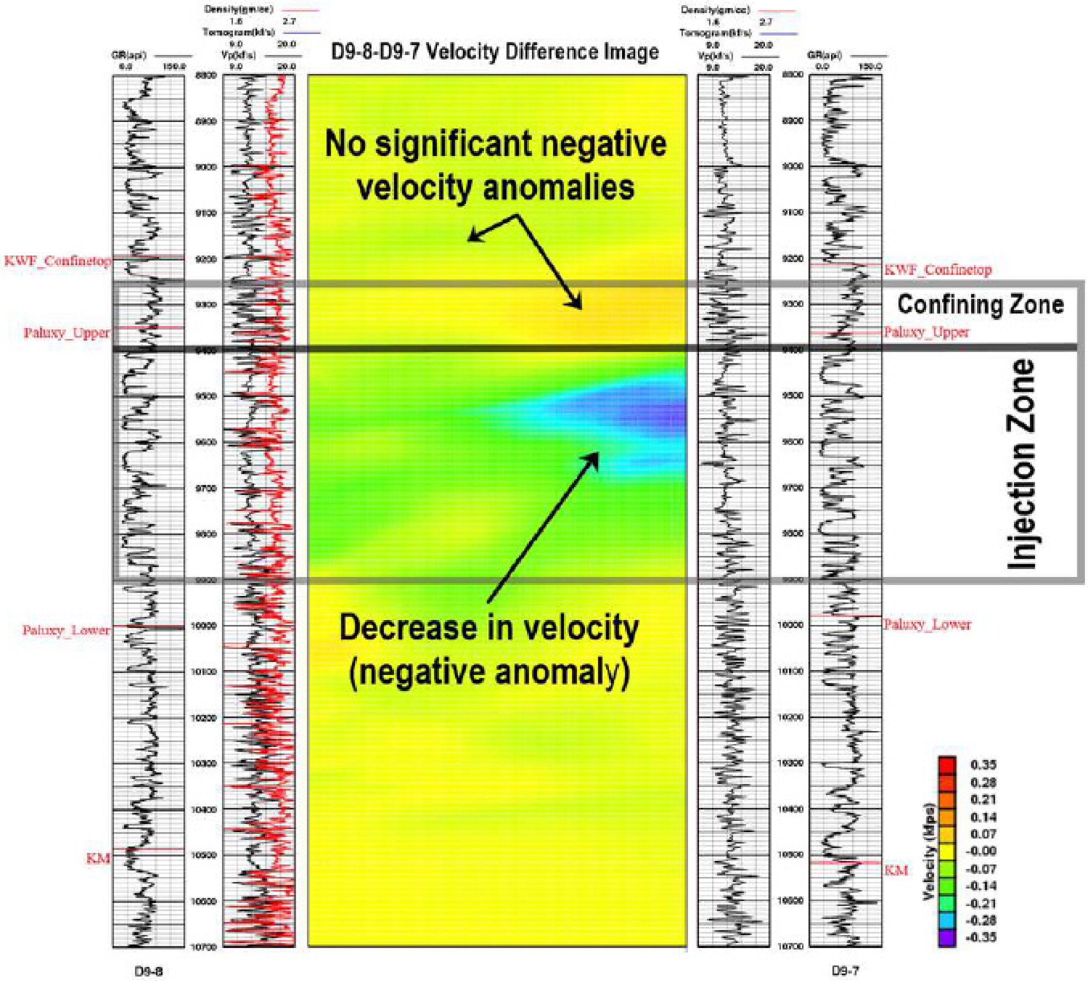

Figure 9.7: Cross-well time-lapse seismic velocity tomogram showing area of decreased velocity.

Table 9-1: MVA tests and their frequencies[1].

Measurement Technique	Measurement Parameters	Application	Frequency
Reservoir and above-zone pressure	Wireline deployed downhole pressure gauges	Assess the injection pressure field and for regulatory compliance. Above-zone monitoring to detect leakage through the confining unit	Constant during injection operations, annually post-injection
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Time-lapse seismic (crosswell and/or vertical seismic profiling)	CO_2 included change from baseline sonic velocity and amplitude	Distribution of CO_2 plue vertically and horizontally	One baseline deployment, once post-injection
Reservoir fluid sampling	Pressurized fluid samples taken from the injection zone. Analyze for pH, and selected cations and anions	Geochemical changes to injection zone that occur as a result of CO_2 injection	Semi-annually during injection phase, annually post-injection
Drinking water aquifer (USDW) monitoring	Alkalinity, DIC, DOC, selected cations and anions	Monitoring of USDWs for geochemical changes related to shallow CO_2 leakage	Quarterly during and post-injection
Injection well annular and tubing pressure	Pressure gauges located on the wellhead to monitor casing annular and tubing pressure	Annular pressure is an indication of wellbore integrity. Tubing pressure assures regulatory compliance with maximum injection pressure	Constant during injection operations and post-injection
Soil CO_2 Flux	Mass of CO_2 emitted from the soil per unit time and area	Monitor for anomalous increases in the amount of CO_2 that is emitted from the soil surface as an indication of CO_2 leakage	Quarterly during and post-injection
Perfluorocarbon tracers (PFTs) introduced in the CO_2 stream	Monitor for increased tracer levels at the ground surface around deep well penetrations	Monitor for the presence of tracer buildup near wellbores which would suggest vertical leakage of CO_2	Single baseline, annually during and post-injection
Injection Well Mechanical Integrity Test	Radioactive tracer test, annular pressure test, noise or temperature log	Assure internal and external integrity of the CO_2 injection well(s)	Once prior to injection, annually during injection or following well work over
Injection Pressure	Injection well tubing and casing pressure	Assure regulatory compliance with maximum pressure, monitor casing pressure for tubing/casing leaks	Continuous throughout the injection phase
Injection Stream Composition	Major and minor gases, organics and metals	Provide confirmation that the injectate stream meets pipeline transport and UIC permit purity requirements	Full baseline analysis; Monthly monitoring of major gases; semi-annual testing of metals, organics testing only if fuel supply or capture method is altered

Quarter	Field Activities	Notes
Jul 1-Sep 30, 2015	• Pulse test* • Pull and swap D-4-13, D-4-14, D-9-8#2, D-9-7 MRO gauges* • Fluid sample D-4-13, D-4-14, D-9-8* • RST log the D-9-9#2, D-9-8#2 and D-9-7#2* • USDW Sampling* • Monthly Soil Flux Surveys	*These activities were completed Aug 3-7th
Oct 1 – Dec 31, 2015	• Pulse test • Pull and swap D-4-13, D-4-14, D-9-8#2 MRO gauges • RST log the D-9-8#2 • USDW Sampling • Monthly Soil Flux Surveys • Vertical seismic profile survey using the fiber optic cable and geophones in D 9-8#2, and shear-wave vibrator	
Jan 1 – Mar 31, 2016	• RST log the D-4-13, D-4-14 • Fluid sample D-4-13, D-4-14 • Pull and swap D-4-13, D-4-14, D-9-8#2 MRO gauges • Kill wells and pull tubing from D-9-7#2 and D-9-8#2 • USDW Sampling • Monthly Soil Flux Surveys • Seeper Trace Survey	
Apr 1 – Jun 30, 2016	• Pulse test • Full VSP and cross-well seismic surveys (budget permitting) • USDW Sampling • Monthly Soil Flux Surveys	
Jul 1-Sep 30, 2016	• USDW Sampling • Monthly Soil Flux Surveys	
Remainder of BP 5	• Quarterly USDW Sampling • Monthly Soil Flux Survey • Annual Seeper Trace Survey	

Table 9-2: Post-injection summary of field activities by quarter[3]

10. West Ranch Oil Field

Site Details					
Name	Location	Province/State	Country	Onshore	Offshore
West Ranch Oil Field	South Texas	Jackson County, Texas	USA	✓	

General storage type
Depleted Oil and Gas Reservoir

Development History

The Petra Nova Project is a commercial scale post-combustion carbon capture project developed by a joint venture between NRG Energy, Inc (NRG) and JX Nippon Oil Exploration (EOR) Limited (JX). The project is designed to separate and capture CO_2 from an existing coal-fired unit's flue gas slipstream at NRG's WA Parish Electric Generating Station, southwest of Houston. The captured CO_2 is dried, compressed, and transported via an 81-mile pipeline to the West Ranch oilfield in Jackson County, Texas, where it is injected to boost oil production (Figure 10.1)[1].

West Ranch oil field was discovered in the early 1930s, with production peaking in the 1970s. HEC is currently the primary operator[2]. CO_2 injection started in December 2016 [1]. It is anticipated that oil production will increase from 300 barrels per day before EOR to 15,000 barrels per day after[2]. Petra Nova's operators turned off the CCS equipment in May 2020, citing low oil prices caused, in part, by the Covid pandemic[3].

Phase three of the project included a monitoring program at West Ranch to demonstrate technologies and protocols for monitoring, verification and accounting (MVA)[1]. University of Texas BEG developed the plan to synchronise with oilfield operations and manages the plan during the DOE 3-year demonstration period[1].

Geological Characteristics

Reservoir Formation

The Oligocene Frio Formation includes the Greta, Glasscock, Ward, 41-A and 98-A sand units (Figure 10.2) [4]. The Frio Formation is at 1,500 m depth and is approximately 760 m thick[4].

Proposed project incorporate EOR in fours sandstone units, Greta, Glasscock, the 41-A and 98-A units. The general order of injection includes the flooding of the lowest sand unit (98-A) first. When enough recycled CO_2 becomes available, the CO_2 flood would then proceed upward toward the highest sand unit (Greta)[2].

1 Kennedy, G., 2020. WA Parish Post-Combustion CO_2 Capture and Sequestration Demonstration Project (Final Technical Report) (No. DOE-PNPH-03311). Petra Nova Power Holdings LLC.
2 NETL (2013) US DOE W.A. Parish Post-Combustion CO_2 Capture and Sequestration Project Final Eanvironmental Impact Statement Volume I https://netl.doe.gov/sites/default/files/environmental-policy/deis-feb/EIS-0473_Vol_I-Chapters_1-12.pdf
3 Congressional Research Service (2021) Carbon Capture and Sequestration (CCS) in the United States
4 Uddameri, V. and Andruss, T., (2016) Development of Framework for a Groundwater Monitoring Program at a Geological Carbon Sequestration/Enhanced Oil Recovery Site.

The thicker more homogenous Greta unit may require more CO_2 for efficient EOR than would be available from NRG's proposed project. In contrast, the Glasscock, 41-A and 98-A units are thinner, less continuous units composed of interlayered sand and shale. It is anticipated that oil recovery would be more efficient in the 41-A and 98-A units using the volumes of CO_2 available[2]. The four primary producing oil-producing zones at the West Ranch Oil field have produced more than 322 million barrels of oil since 1938[2]. The 41-A reservoir in the West Ranch field has produced >84 million barrels of oil from the Frio Formation[5].	
Lateral extent / thickness variation	Excellent lateral continuity of the barrier core facies of 41-A. Tidal inlet facies feature discontinuous zones that occur at different stratigraphic levels[5] see Figure 10.3 for thickness variation. Greta sandstone ~15 m thick. The Glasscock is thinner than the Greta but more widespread and the most extensive producing horizon at West Ranch[2].
Rock type	Sandstone.
Sedimentary features: Depositional Environment / facies type & variation / mineral composition	Eastern part of the Greta/Carancahua Barrier/Strandplain system, located between two deltaic depocentres (Figure 10.4)[5]. The sandbody geometry of the 41-A reservoir is dominated by a northeast-trending belt of >9 m of net sandstone (shore-parallel barrier-core deposits) intersected by a complex of several northwest-trending sandstones bodies containing >21 m of net sandstone (tidal inlet deposits)[5]. The sand zone in the 98-A unit shows much lateral variation but can be ~23 m thick[2].
Porosity	n/a
Permeability	Average permeability distribution mimics facies distribution, higher in the homogenous and tabular barrier-core facies (>2,000 mD). Lower average values and greater variability in the tidal-inlet facies (<500 to 1,000 mD)[5]. The Glasscock is a relatively low permeability unit compared to the other West Ranch reservoirs[2].

5 Ambrose, W.A., Lakshminarasimhan, S., Holtz, M.H., Núñez-López, V., Hovorka, S.D. and Duncan, I., 2008. Geologic factors controlling CO_2 storage capacity and permanence: case studies based on experience with heterogeneity in oil and gas reservoirs applied to CO_2 storage. Environmental Geology, 54(8), pp.1619-1633.

Formation fluid properties: (residual hydrocarbons / salinity concentration).	n/a
Caprock / primary seal formation	
Oligocene Anahuac shale extends across the coastal area of Texas from the Sabine River to the Rio Grande River (Figure 10.5).	
Lateral extent / thickness variation	Thick (130 m), regionally extensive seal above Frio hydrocarbon production[5].
Rock type	Calcareous shale/ dark mudstone with some occasional interlaminated sand lenses, part of regionally continuous marine flooding surface[2].
Fracture pressure	n/a
Porosity	n/a
Permeability	Low permeability (~5 x 10^{-6} mD)[2].
Overburden Features (Thickness, formations presence of secondary reservoirs / seals) The Frio Formation (reservoir), Anahuac Formation (seal) and Catahoula Tuff are overlain by the Jasper Aquifer of the Gulf Coast Aquifer System (Figure 10.5). The Burkeville confining system separates the Jasper Aquifer from the Evangeline Aquifer. The shallowest aquifer in the Gulf Coast Aquifer System is the Chicot Aquifer (comprising the Wallis Sand, the Bentley and Montgomery Formations, the Beaumont Clay, and alluvial deposits at the surface)[4].	
The Gulf Coast Aquifer system is present in this area.	
Structure	
Fold type / fault bounded	Simple domal structure, with growth faults that lie out with the oilfield (to the northwest and southeast)[6].
Faults /Fractures (Type – normal, reverse, strike-slip)	Growth faults out with oilfield. No obvious faulting in the West Ranch oilfield[2].
Displacement	60 m offset of strata in fault to northwest of oilfield[6].
Stability (pre-stressed, active, stable)	n/a
Injection / storage history	
Number of injection, monitoring or other wells, well geometry, design and key completion information for injection wells, relevant well issues. Reused / new purpose drilled well.	

6 NETL (2012) US DOE W.A. Parish Post-Combustion CO_2 Capture and Sequestration Project Draft Environmental Impact Statement Summary https://www.energy.gov/sites/prod/files/EIS-0473-DEIS_Vol_II_App_A-B-2012.pdf

HEC (operator) uses produced water injection wells as part of the oil and gas production process, and separate underground injection wells to dispose of excess produced water produced during oil and gas production[2]. The excess water is injected into the Catahoula Sandstone.

Estimates that 9 injection wells and 16 production wells would be used initially[6].

Estimated that 130 injection wells and 130 production wells will be utilised over the 20-year lifespan of the project (Figure 10.6)[6]. New injection wells would be drilled if the existing wells cannot be repurposed[2].

Well construction would be performed in accordance with RRC (Railroad Commission of Texas) permitting requirements. CO_2 resistant cement would be used from the depth of the well bore to the next shallowest casing depth [2]. Existing wells used by the project would be reworked to bring them up to current construction standards[2].

In late 2018, the operating company decided to divert some of the CO_2 from the 98-A sandstone to flood the 41-A sandstone within the same reservoir complex at West Ranch. The 41-A sandstone formation is above the 98-A reservoir and below the regional Anahuac shale[1].

Extent and status of casing (corrosion history/ cementation records)	n/a
Injection rates & pattern (i.e. continuous / intermittent) changes in injection behaviour	n/a
Total quantities stored	During the three-year demonstration period, 3,904,978 short tons of CO_2 was captured[1]. See section on accounting for more details.
Reservoir capacity (estimate)	n/a
Fluid extraction rate (brine extraction, oil for EOR)	n/a

Seismicity

Southeastern Texas exhibits low seismicity and there are no major mapped faults within or near the proposed project areas[6].

Monitoring regime (technologies deployed)

BEG conducted a geophysical-log-based evaluation of regional structural features in the vicinity of West Ranch oil field, identified two growth faults in the deep subsurface to the northwest and southeast. Both faults extend through Greta, Glasscock, 41-A and 98-A sand units of the Frio[6].

Seismic events (Detection / magnitude / attribution (natural induced).

n/a

Monitoring technologies applied and experiences with monitoring:

Surface monitoring technologies deployed

Groundwater Monitoring (task 6)	One year of baseline and periodic ongoing sampling of groundwater at several ground water wells (Figure 10.7)[1]. Several groundwater collection trips were made prior to the December 2016 start of CO_2 injection. Two main aquifers targeted, four wells in the Evangeline aquifer (>300 m depth) and seven wells in the Chicot Aquifer (<70 m depth). Some variability in salinity detected, but occurred prior to CO_2 injection and no changes in groundwater chemistry observed[1]. A reactive transport model created to assess feasibility of detecting a leak of CO_2 from the top of the 80-A into overlying groundwater via changes in groundwater chemistry. A 16 km x 17 km x 0.948 km, 14 layer model was constructed, and a hypothetical leak of 340 and 315 tons/year was modelled. Results confirmed that leakage signal would be spatially small and easily missed even with a dense monitoring system[1]. The source of dissolved hydrocarbons in groundwater (e.g. deep sourced thermogenic methane vs shallow biologically produced methane) can be determined by comparing the carbon isotopic composition of methane to the ratio of methane to ethane and propane. Many monitoring wells have high biogenic methane and mixing models confirmed that there is no concern with the levels[1].
Shallow borehole geophysical logging	Using apparent electrical conductivity and natural gamma-ray activity was performed on five polyvinyl chloride (PVC) cased wells. Results show intervals with high salinity groundwater, all collected prior to CO_2 injection[1].
Soil gas monitoring (task 7)	Characterise the composition of soil gasses at West Ranch and to develop models that would predict changes to soil gas compositions by unintentional migration of CO_2 or thermogenic gases into the vadose zone from deep CO_2 injection zones.

	Preliminary field sampling and on-site analysis of soil gases at twelve sites near water wells - to determine suitability and to choose locations for semi-permanent sampling chambers. Semi-permanent soil gas sampling stations were installed at five locations at West Ranch. Two sampling ports at different depths within each borehole (total 10). Five soil gas sampling trips in July, October 2016 and January, April and August 2017[1]. Gasses analysed for CO_2, O_2, N_2 and CH_4 (BEG) and He, H_2, CO and C_2-C_6+. Selected samples analysed for carbon isotopes[1]. CO_2 ranged from 0.07% to 17.43%, O_2 ranged from 21% to 0,42%, and N_2 from 73.72% to 93.11%. No significant methane was found. One sample had relatively high N_2/O_2 ratio signalling vigorous respiration and dissolution of CO_2, which is known in some natural systems. $\delta^{13}C$ ranged from -17.9 to -22.68 per mil. Field-wide there is no indication of leakage from the storage formation. Most of the soil gas samples have a natural signal with ^{14}C greater than 100 pmc – which appears to represent a very localised and small scale potential anomaly, possibly due to an older organics carbon source utilised by microbes for respiration. $\delta^{13}C$ data for soil gas are consistent with a modelled mixed trend between soil gas source (between -10 and -21 per mil) and atmosphere[1].
Subsurface monitoring technologies deployed (well logs)	
Pressure Monitoring (task 3)	Pressure monitoring is used to calibrate the fluid flow models. Pressure monitoring: 1. Monitors pressure in the injection zone to avoid over pressuring the injection zone. 2. Monitor migration of CO_2 in the injection zone 3. Allow the comparison in pressure change between injection zone and above-zone monitoring intervals to identify vertical migration of fluids. Pressure monitoring can give confidence that injection zones are not over-pressurised, and the CO_2 is retained in the project boundaries[1].

	Since January 2016 monitoring pressure in 10 dedicated AZMI wells (5 each in two zones)[1]. Two in-zone monitoring wells collected continuous pressure data since June 2016 through mid-2018. CO_2 injection started December 2016. Two in-zone wells perforated 98-A sand to directly measure the pressure changes inside the injection zone – provided data for fluid flow model calibration. Located outside of the initial seven pattern of the CO_2 flood and provide additional. Five above zone monitoring wells perforated in the Toney sand (continuous data until end of 2019)[1]. Below the Anahuac regional shale. This proved to be very noisy because the zone was kept in production causing pressure decrease in most gauges. Headspace gas was collected, but no CO_2 was detected showing that no CO_2 had reached the perforated zone of this well[1]. Four above zone wells perforated in 80-A sand (continuous data until end 2019). The Miocene 80-A is the uppermost regionally extensive sandstone below the base of fresh water[1]. One well in Nobel sand (data until end 2019)[1] in the centre of the field where the 80-A sand was poorly developed. Pressure was stable and slightly decreasing during the project period, documenting that the zone is hydrologically isolated from underlying injection zone[1].
Pulsed Neutron Logs (task 4)	Goal to assess the extent to which CO_2 is occupying pore volume as EOR progresses. Pulsed neutron logs (RST) collected prior to injection serve as a baseline. When repeated, after CO_2 flood has progressed, changes in the log curves can be inverted to estimate how much pore space has been occupied by CO_2. Repeat RST were collected in six wells in the flood area, logs were depth corrected using gamma-ray curves. Unfortunately, environmental corrections were not successful, limiting the usefulness of the

	logs[1]. Difficulty in identifying and qualifying the reservoir zones in which CO_2 had swept.
Fluid sampling and analysis (task 5)	AZMI brine samples were collected from six wells and gas samples collected from nine wells during Phase 3. Analysis of brine and gas samples collected prior to start of CO_2 injection in December 2016 were used to establish pre-injection chemistry baseline.

MMV (Measurement, Monitoring, Verification) Practices & related verification of injected CO_2

Reservoir Modelling (task 1) – development of fluid flow simulation model using actual logging and production data.

Static models were constructed in Petrel based on rock properties interpreted from Spontaneous Potential and Gamma-Ray logs and some core samples. Rock properties (permeability, porosity, facies, fluid saturation etc) assigned from literature, field measurements and data from operating company[1].

Numerical simulation models constructed of the initial injection zone: the Frio 98-A sandstone and the second injection zone Frio 41-A. Two AZMI of Toney sandstones (below Anahuac regional seal) and 80-A sandstones (above Anahuac regional seal) were characterised for above zone pressure monitoring.

Developed a dynamic numerical model to history match the pressure and production data and simulate current and future activities in the field[1].

Well locations with injection and production volumes (monthly) integrated into numerical model to perform dynamic reservoir simulations.

Mass Balance Accounting (task 2) – accounting for injected CO_2. BEG developed a carbon mass accounting protocol that estimates CO_2 storage mass by subtracting CO_2 surface and subsurface losses to the captured CO_2 mass injected into the oil reservoir. Total mass of CO_2 injected (CO_2 captured plus recycled) was measured with a flow meter located at the capture plant and a flow meter upstream of the recycle gas compressor. Recycled gas was corrected by a composition measurement at the metered location so that only CO_2 is accounted for and produced reservoir gases are excluded. The mass of CO_2 lost from surface (vapored gas releases, blowdown releases, maintenance releases, troubleshooting releases, flare releases, venting and unusual events such as pipeline and well releases). Mass of CO_2 lost in subsurface is measured by the MVA program.

Mass accounting started March 2017 when operations from initial well patterns (7 WAG injection wells and 14 production wells) became stable. See [1] for more detail on procedure.

Under the MVA plan a total of 3,609,924 short tonnes were sequestered (mass balance accounting). During Phase Three, 3,651,244 short tons were captured and when adjusted for mol% a net capture value of 3,643,146 short tonnes captured. Thus 33,222 tonnes of surface losses (primarily maintaining surface equipment), some 99.08% of captured CO_2 being sequestered [1].

Major technical/scientific studies on the site, major learnings, conformance assessment (history-matching with models, correlation between different monitoring techniques)

Several simulations of dynamic model performed to find best combination of parameters that produced most realistic matches between simulation results and collected field data. BEG has history matched the model with the field injection-production-pressure history and has faith the model is reasonably useful for designing future development strategies for the operation in the field and forecasting the location of the CO_2 plume[1].

The 98-A and 41-A sandstone numerical simulations were able to achieve a reasonable match between the numerical models and collected field data[1].

BEG modelled a hypothetical leakage from 98-A to 80-A/Noble monitoring zone. Fluid flow models of vertical fluid leakage were used to estimate the impact of pressure observed in the 80-A zone. Pressure data from five monitoring wells perforated in the AZMI zone was gathered. Forward modelling of a leakage scenario to determine the well spacing over the plume area needed to detect the leak. Numerical models set to detect 2 psi (13.8 kPa) change in pressure- in AZMI, six months after the start of the simulated leak. Numerical simulations in the 80-A zone show that to show a pressure change in one of the five wells the leakage rate from 98-A zone should be higher than 5,000 Mscf/day[1].

List of key publications covering the site

1. Kennedy, G., 2020. WA Parish Post-Combustion CO_2 Capture and Sequestration Demonstration Project (Final Technical Report) (No. DOE-PNPH-03311). Petra Nova Power Holdings LLC.
2. NETL (2013) US DOE W.A. Parish Post-Combustion CO_2 Capture and Sequestration Project Final Eanvironmental Impact Statement Volume I https://netl.doe.gov/sites/default/files/environmental-policy/deis-feb/EIS-0473_Vol_I-Chapters_1-12.pdf
3. Congressional Research Service (2021) Carbon Capture and Sequestration (CCS) in the United States
4. Uddameri, V. and Andruss, T., (2016) Development of Framework for a Groundwater Monitoring Program at a Geological Carbon Sequestration/Enhanced Oil Recovery Site.
5. Ambrose, W.A., Lakshminarasimhan, S., Holtz, M.H., Núñez-López, V., Hovorka, S.D. and Duncan, I., 2008. Geologic factors controlling CO_2 storage capacity and permanence: case studies based on experience with heterogeneity in oil and gas reservoirs applied to CO_2 storage. Environmental Geology, 54(8), pp.1619-1633.
6. NETL (2012) US DOE W.A. Parish Post-Combustion CO_2 Capture and Sequestration Project Draft Environmental Impact Statement Summary https://www.energy.gov/sites/prod/files/EIS-0473-DEIS_Vol_II_App_A-B-2012.pdf
7. Shimokata, N., 2018. Petra Nova CCUS Project in USA. JX Nippon Oil & Gas Exploration Corporation.

Figures

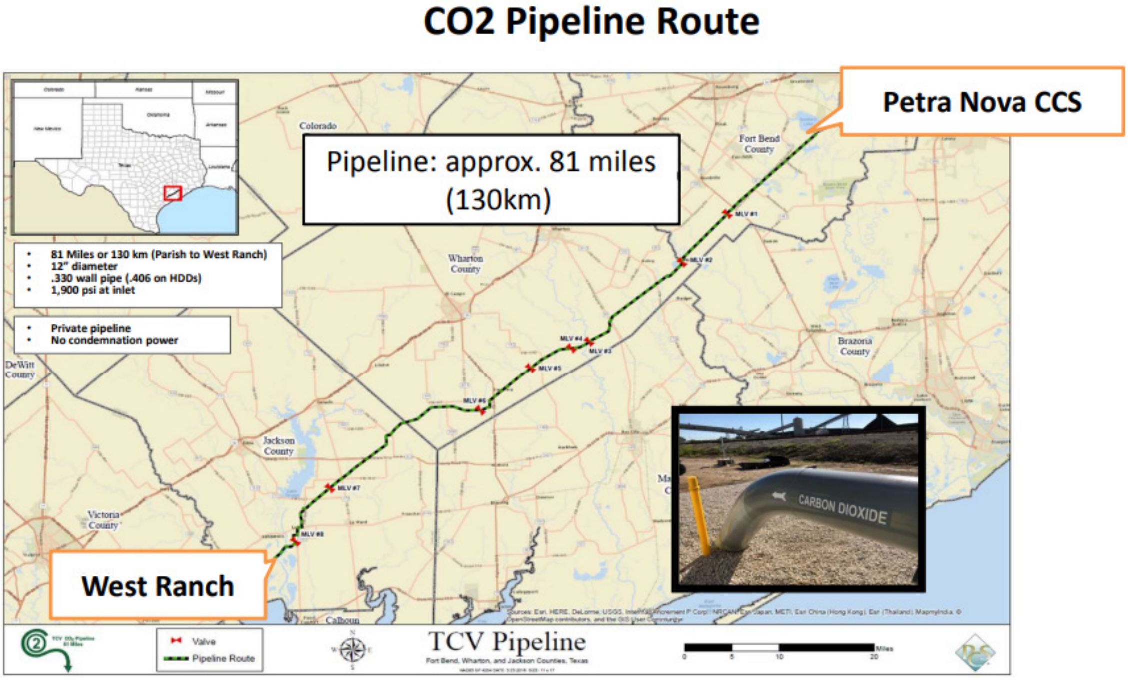


Figure 10.1: Location map of the Petra Nova CCS project and West Ranch oil field with the CO_2 pipeline[7]

7 Shimokata, N., 2018. Petra Nova CCUS Project in USA. JX Nippon Oil & Gas Exploration Corporation.

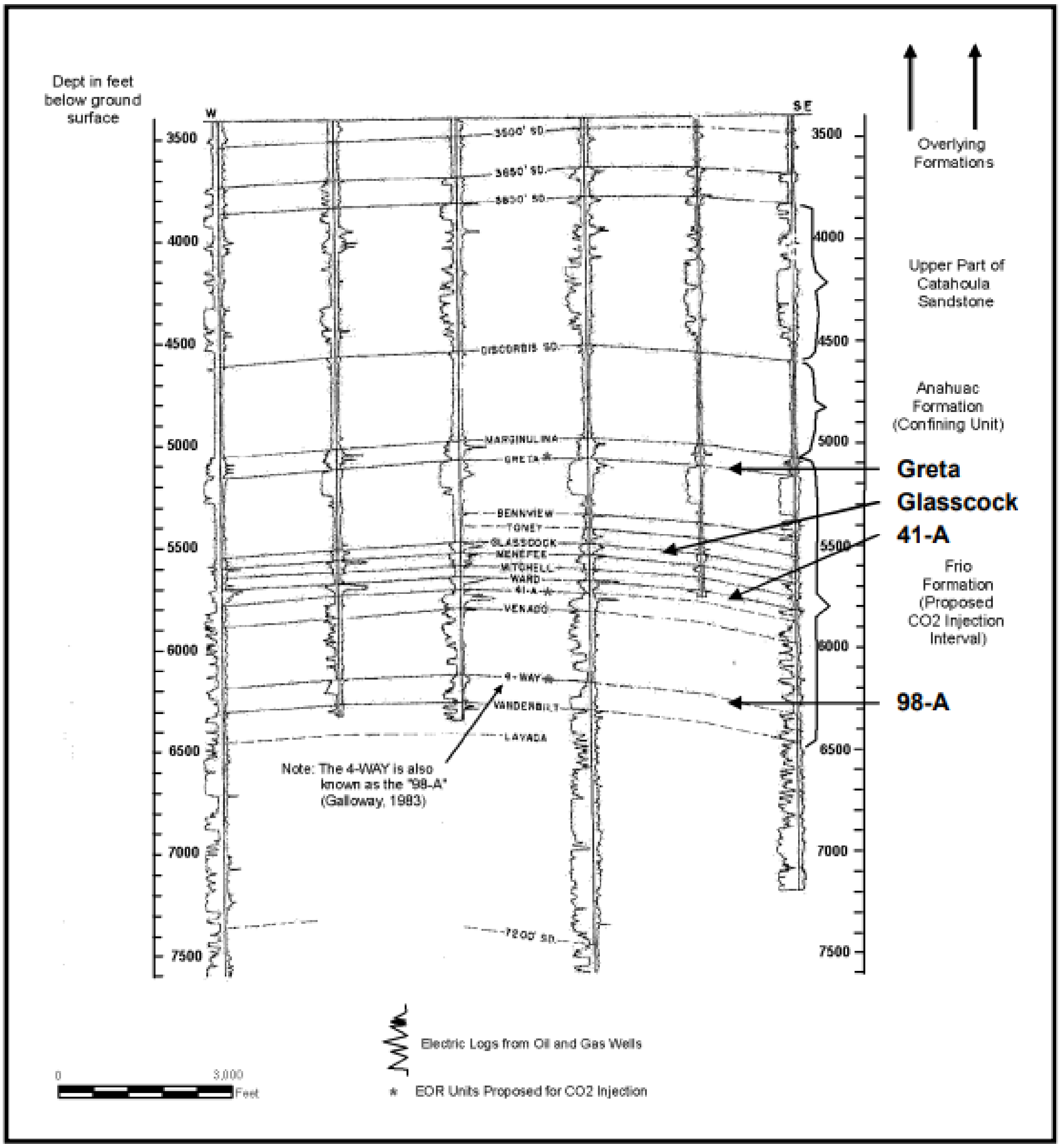


Figure 10.2: Geologic cross section showing the proposed CO_2 injection units in the West Ranch Oil field[2].

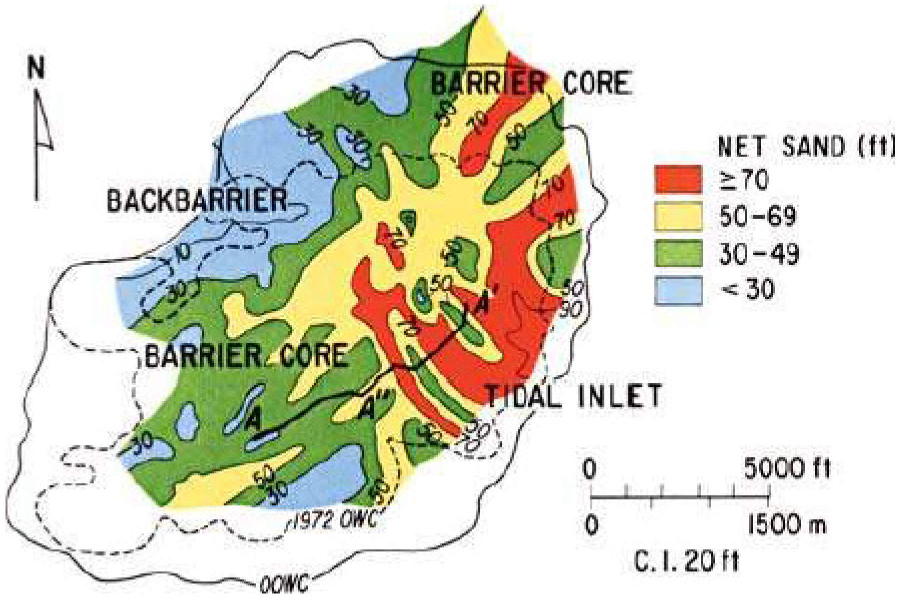


Figure 10.3: Net sandstone thickness of the 41-A reservoir in West Ranch field. OOWC original oil-water contact; 1972 OWC 1972 oil-water contact[5].

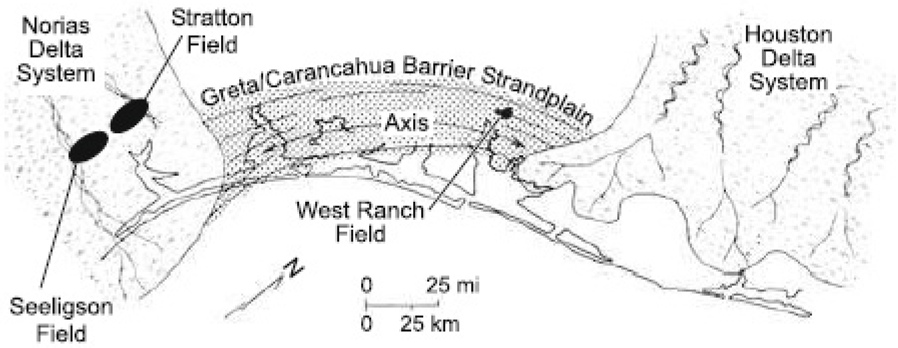


Figure 10.4: Location and Oligocene depositional setting (41-A reservoir) of West Ranch field in the Texas Gulf Coast[5].

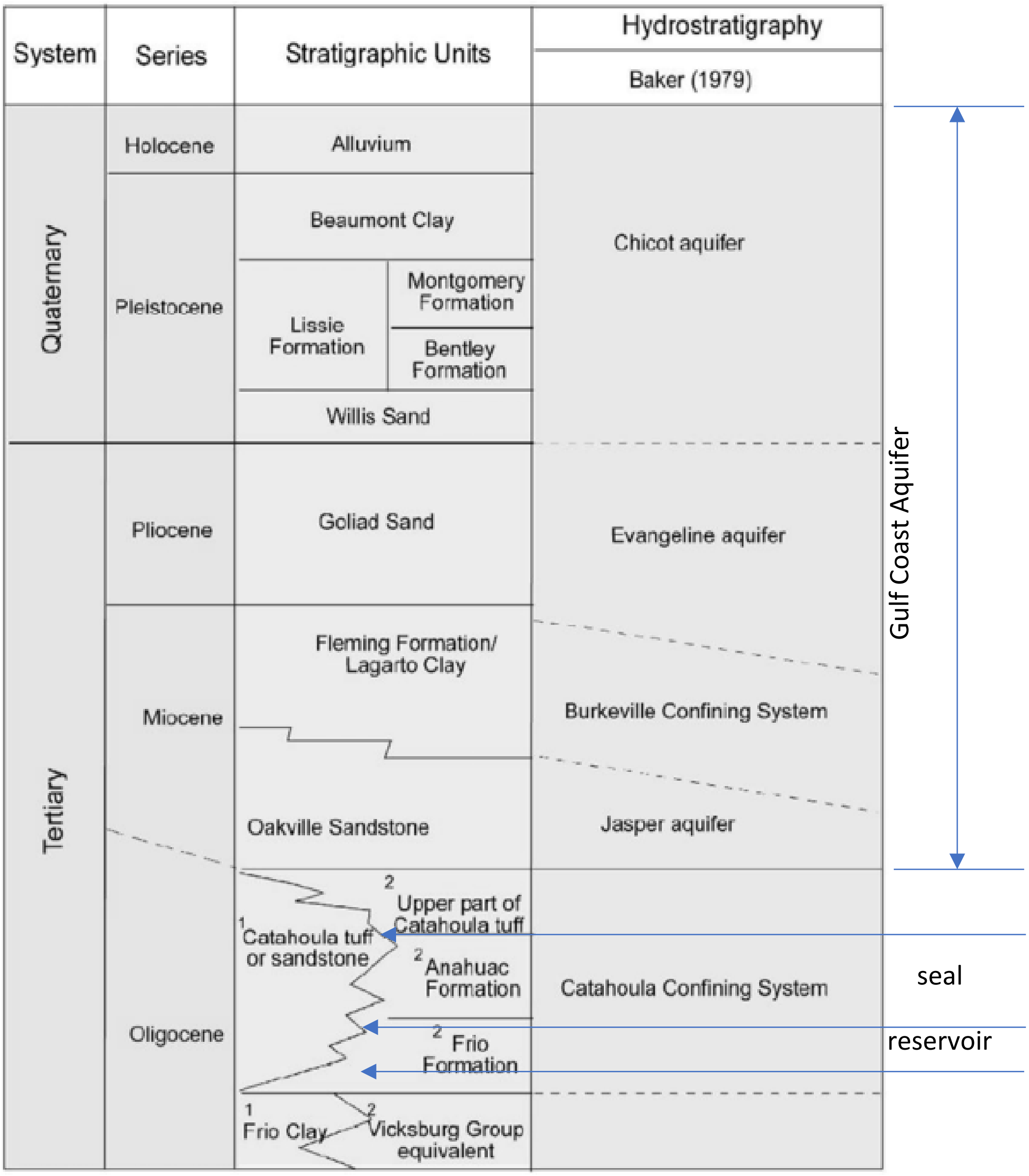


Figure 10.5: Stratigraphy of the Gulf Coast Plain showing sedimentary successions and hydrostratigraphic divisions[2].

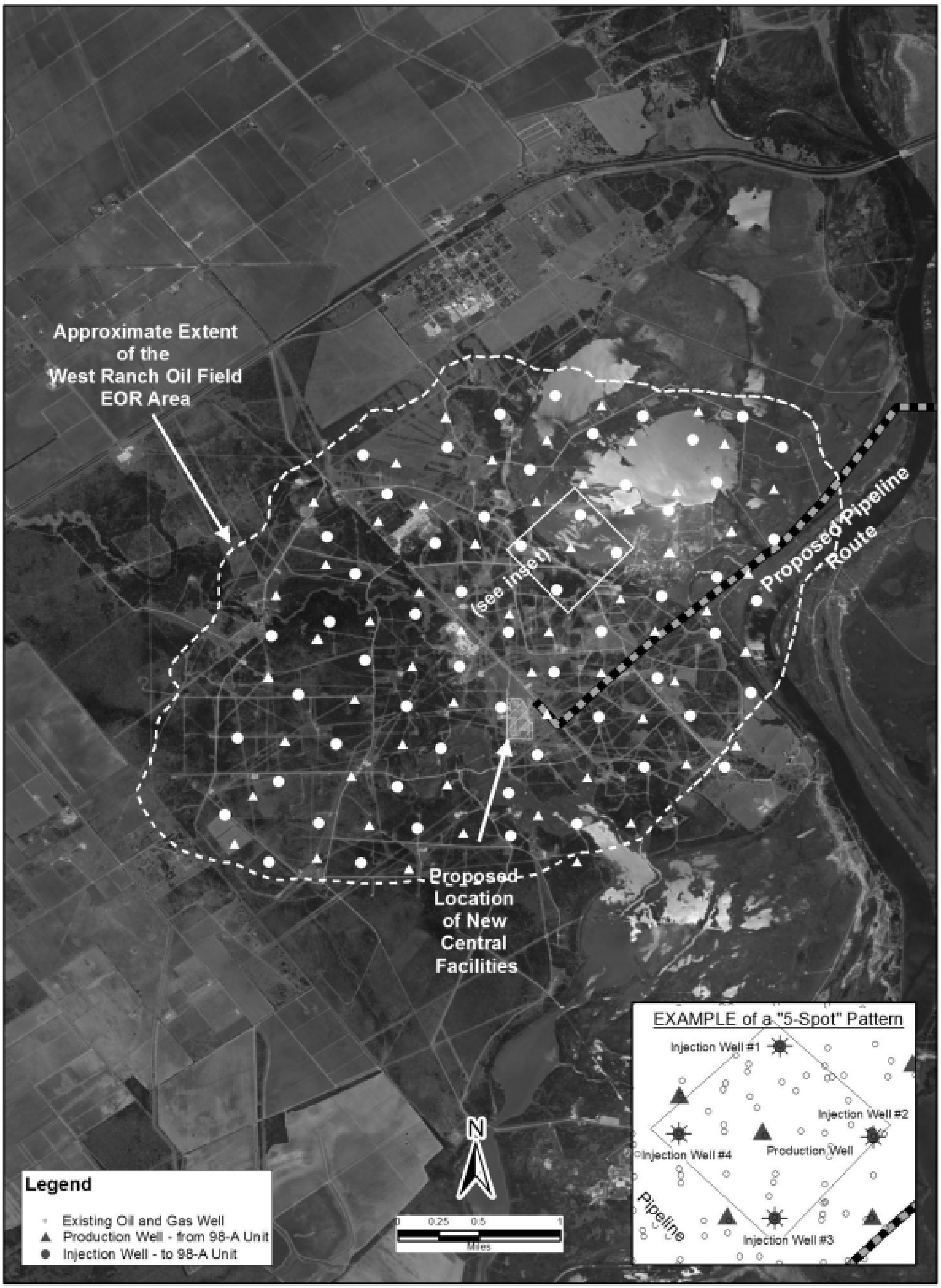


Figure 10.6: Map of West Ranch Oil Field showing conceptual arrangement of injection and production wells for proposed CO_2 flood[6].

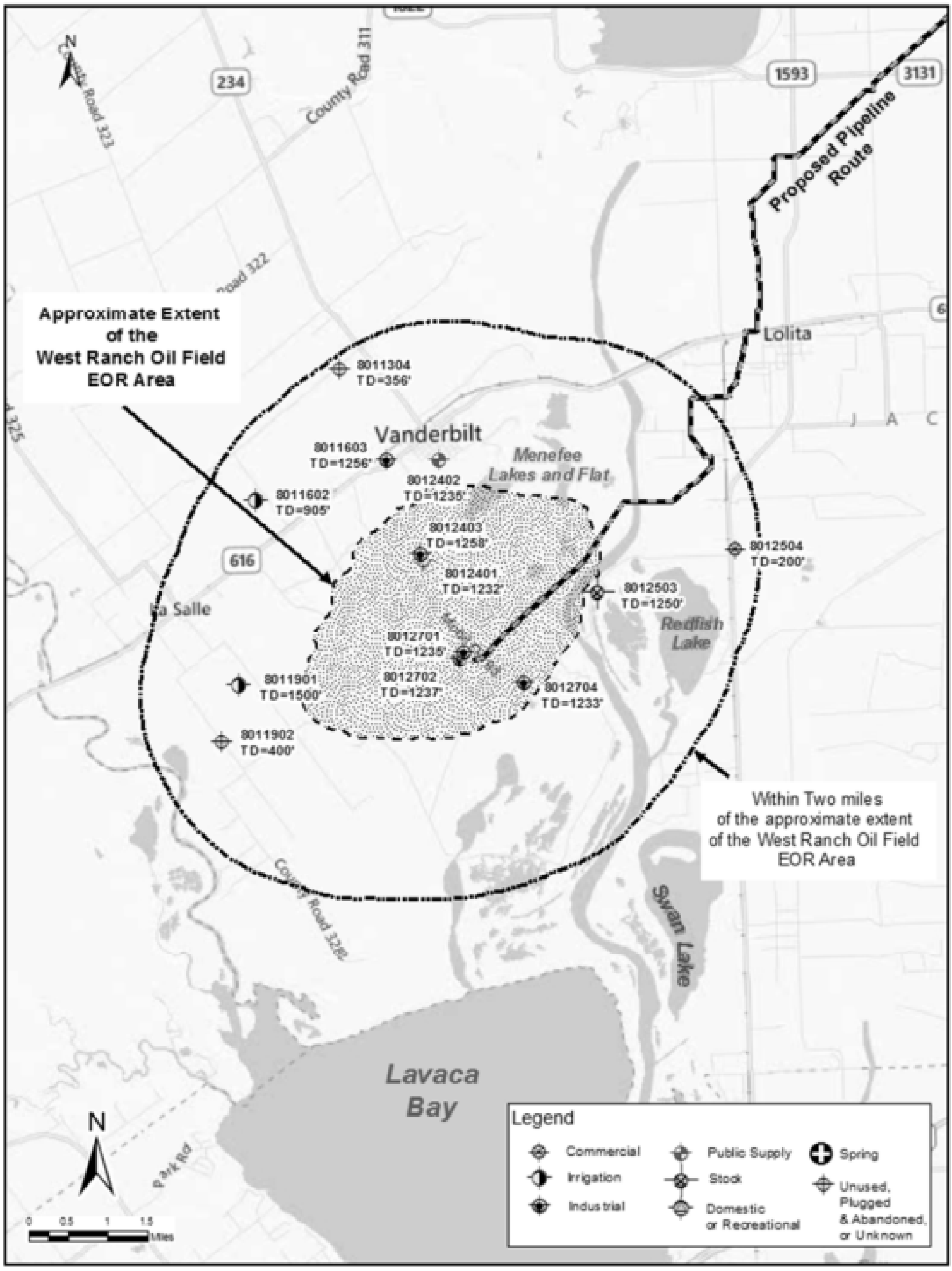


Figure 10.7: Groundwater wells within ROI for proposed West Ranch EOR Area[2]

11. Lula

Site Details					
Name	Location	Province/State	Country	Onshore	Offshore
Lula (also known as Tupi)	Santos Basin (2,200 m water depth, 230 km off the coast)		Brazil		✓ deepwater

General storage type
EOR

Development History (Active operation)
The Lula field was discovered in 2006, in the Santos Basin[1]. A super giant, deep-water, oil field in the pre-salt play (Figure 11.1, Figure 11.2, Figure 11.3). Developed by Petrobras, a pioneer in pursuing the first deep-water offshore CO_2-EOR. The CO_2 is stripped from the production stream to utilize in advanced CO_2-EOR and helped optimize development of the oil field [2]. Project planning included intensive reservoir characterisation, testing of alternative EOR options, and rigorous monitoring of pilot flood performance [2]. Available CO_2 volume was not sufficient and led to re-injection of CO_2-rich stream in either discharge wells or WAG injectors. With flexibility built in to inject either enriched CO_2 or mix of CO_2 and hydrocarbon gas [1]

Geological Characteristics. Pre-salt Santos Basin (Figure 11.1). Source rocks and reservoir in the Guaratiba Group.	
Reservoir Formation	
The reservoir is in the pre-salt, under ~2,000 m of salt.	
Lateral extent / thickness variation	Picarras Fm ~ 990 m thick. Barra Velha Fm ~300-350 m thick. Thickness variations across syn rift and thins on structural high – with lateral facies variations (Figure 11.4 and Figure 11.5).
Rock type	Lacustrine carbonates (shelly limestone coquinas) of the Picarras Formation transition to the dolomitised laminated microbialites and stromatolites of the Barra Velha Formation [3].

1 Eide, L.I. et al (2019) Enabling Large-Scale Carbon Capture, Utilisation, and Storage (CCUS) Using Offshore Carbon Dioxide (CO_2) Infrastructure Developments – A Review

2 ARI (2021) Factors determining commercially optimal development strategies for CO_2 storage with and without CO_2-EOR.

3 Clemente (2013) Petroleum geology of the Campos and Santos basins, Lower Cretaceous Brazilian sector of the South Atlantic margin

Sedimentary features: Depositional Environment / facies type & variation / mineral composition	The Hauterivian-Aptian Picarras Fm includes alternations of facies (clastic, including polymictic conglomerates, sandstones and shales and carbonate) implying a series of alluvial progradation-retractions into carbonate lakes [3]. The Upper Barremian-Aptian Barra Velha Fm represent transitional continental to shallow marine [3]. Tupi high likely caused sediment starved area and focus for carbonate platform deposition[4] transitioning from lacustrine to marine, with potentially karstification during periods of uplift leading to enhanced reservoir conditions[4] (Figure 11.3 & Figure 11.4).
Porosity	Structurally lower wells in Santos Basin total porosity 9%, corrected porosity 5% [5]. Upper Sag unit represents best reservoir interval – average porosity of 14% and up to 22% [6].
Permeability	Dependent on facies and structural location. High permeabilities (>3 Darcy) verified in well tests due to high fracture intensities and carbonate dissolution [7]. Average values ~2,000 mD [6].
Formation fluid properties: (residual hydrocarbons / salinity concentration).	Light 28-30°API (American Petroleum Institute) oil with high solution gas-oil ratio. The solution gas in the reservoir contains 8-15% CO_2 [8].
Other	Relatively low reservoir temperature (60-70°C), reduced viscosity and high pressures [9].

4 Gomes, P.O. et al (2009) The Outer High of the Santos Basin, Southern Sao Paulo Plateau, Brazil: Pre-Salt Exploration Outbreak, Paleogeographic Setting and Evolution of Syn-Rift Structures. Search and Discovery #10193

5 Izeli, M. and Vincentelli, M.G. (2017) Quantitative geophysical characterization of an Aptian carbonate reservoir in Santos Basin. 15th International Congress of the Brazilian Geophysical Society & EXPOGEF, Rio de Janeiro, Brazil, 31 July-3 August Brazilian Geophysical Society.

6 Melani, L.H., Correia, U.M., Honório, B.C. and Vidal, A.C., 3. INTEGRATED RESERVOIR AND STRATIGRAPHIC CHARACTERIZATION BASED ON SEDIMENTARY CYCLICITY ANALYSIS OF A PRE-SALT LACUSTRINE RESERVOIR FROM THE SANTOS BASIN, OFFSHORE BRAZIL. Borehole based sedimentary cyclicity and structural analysis: applications for reservoir characterization studies in the post-and pre-salt carbonates of Santos and Campos basins, SE Brazil, p.46

7 Correa, R.S.M. et al (2019) Integrated Seismic-Log-Core-Test fracture characterization, Barra Velha Formation, Pre-salt of Santos Basin. Search and Discovery Article (#42425)

8 NETL (2016) CO_2-EOR Offshore Resource Assessment

9 Godoi, J.M.A. and dos Santos Matai, P.H.L. (2021) Enhanced oil recovery with carbon dioxide geosequestration: first steps at Pre-salt in Brazil. Journal of Petroleum Exploration and Production 11:1,429-1,441

Caprock / primary seal formation	
Primary seal in the Santos Basin is the Upper Aptian salt, which is up to 4,000 m thick in places (Figure 11.4). Comprising the Ariri Formation dominated by evaporites[3].	
Lateral extent / thickness variation	~1,800 m thick at Lula field[8] can be up to 4,000 m thick [3] and laterally extensive (Figure 11.4).
Rock type	Evaporites with thick intervals of white halite, associated with white anhydrite, ochre greyish calcilutites, shares and marls[3].
Fracture pressure	n/a
Porosity	n/a
Permeability	n/a
Overburden Features (Thickness, formations presence of secondary reservoirs / seals) Laterally variable post-salt package.	
n/a	
Structure Located on the Tupi high, part of a larger Outer High, a regional basement high with four-way closure (Figure 11.3 & Figure 11.4). A series of rift fault block shoulders which were uplifted and eroded during the Late Barremian [4].	
Fold type / fault bounded	Pre-salt four-way closure covering ~1,100 km^2. Long lived structures, reactivated throughout evaporite deposition. The Tupi structure is segmented by a series of synthetic, syn-rift faults (Figure 11.3 & Figure 11.4). The eastern flank is bounded by a major SW-NE synthetic fault system – termed the 'outer hingeline' [4].
Faults /Fractures (Type – normal, reverse, strike-slip)	Normal faults associated with rifting.
Displacement	n/a
Stability (pre-stressed, active, stable)	n/a
Injection / storage history	
Number of injection, monitoring or other wells, well geometry, design and key completion information for injection wells, relevant well issues. Reused / new purpose drilled well.	
First Lula EOR pilot consisted of one injection and one production well. By April 2011 produced reservoir gas was injected into the oil field at 35 MMcfd. After 6 months the h/c gas was separated from the CO_2 and transported onshore for sale, the CO_2 was reinjected into the reservoir at 12.3 MMcfd [8]. A horizontal well was drilled in 2012 and WAG injection (water and the high CO_2 concentration gas) commenced in the second half of 2012[8].	

Testing Lula field, extended well tests (EWT) to accomplish long-term production profile of the wells, production pilots (to appraise performance of recovery methods)[9]. Two EWT on at south (May 2009) and another at NE (April 2011) [9]. Two WAG injectors and one gas injector and multiple producers [1,8]. Developed with a floating production storage and offloading units (FPSO) (Figure 11.6)[1].	
Extent and status of casing (corrosion history/ cementation records)	No flow-assurance issues, such as hydrates, asphaltene or wax precipitation or severe inorganic scaling were experienced [1].
Injection rates & pattern (i.e. continuous / intermittent) changes in injection behaviour	Flexibility to inject either water or gas in the injection wells. Possibility to alternate gas injection through different wells[9].
Total quantities stored	By 2022 40.8 million tonnes of CO_2 have been injected. The target for 2025 is the reinjection of 80 million tonnes of CO_2 in CCUS -EOR projects [10].
Reservoir capacity (estimate)	n/a
Fluid extraction rate (brine extraction, oil for EOR)	Two EWT presented oil extraction levels of 2,385 m^3/day. Production well (April 2011) presented flow rate 2,000-3,000 m^3/day, another well 11,000 m^3/day (December 2011)[9].
Seismicity	
Monitoring regime (technologies deployed)	
Not known.	
Seismic events (Detection / magnitude / attribution (natural induced).	
n/a	
Monitoring technologies applied and experiences with monitoring;	
Surface monitoring technologies deployed	
High resolution seismic techniques [9]	
Subsurface monitoring technologies deployed (well logs)	
Reservoir coring [9]	Tracer injections [8].
Complete logging [9]	
Fluid sampling [9]	

10 6th International Workshop on Offshore Geologic CO_2 Storage, Aberdeen, September 2023

Flow assurance analysis [9]	
Dynamic down hole monitoring [8]	
Experience summary - effectiveness of techniques (limitations / strengths)	
First of its kind offshore EOR facility, developed from the outset.	

List of key publications covering the site

1. Eide, L.I. et al (2019) Enabling Large-Scale Carbon Capture, Utilisation, and Storage (CCUS) Using Offshore Carbon Dioxide (CO_2) Infrastructure Developments – A Review
2. ARI (2021) Factors determining commercially optimal development strategies for CO_2 storage with and without CO_2-EOR.
3. Clemente (2013) Petroleum geology of the Campos and Santos basins, Lower Cretaceous Brazilian sector of the South Atlantic margin
4. Gomes, P.O. et al (2009) The Outer High of the Santos Basin, Southern Sao Paulo Plateau, Brazil: Pre-Salt Exploration Outbreak, Paleogeographic Setting and Evolution of Syn-Rift Structures. Search and Discovery #10193
5. Izeli, M. and Vincentelli, M.G. (2017) Quantitative geophysical characterization of an aptian carbonate reservoir in Santos Basin. 15th International Congress of the Brazilian Geophysical Society & EXPOGEF, Rio de Janeiro, Brazil, 31 July-3 August Brazilian Geophysical Society.
6. Melani, L.H., Correia, U.M., Honório, B.C. and Vidal, A.C., 3. INTEGRATED RESERVOIR AND STRATIGRAPHIC CHARACTERIZATION BASED ON SEDIMENTARY CYCLICITY ANALYSIS OF A PRE-SALT LACUSTRINE RESERVOIR FROM THE SANTOS BASIN, OFFSHORE BRAZIL. Borehole based sedimentary cyclicity and structural analysis: applications for reservoir characterization studies in the post-and pre-salt carbonates of Santos and Campos basins, SE Brazil, p.46
7. Correa, R.S.M. et al (2019) Integrated Seismic-Log-Core-Test fracture characterization, Barra Velha Formation, Pre-salt of Santos Basin. Search and Discovery Article (#42425)
8. NETL (2016) CO_2-EOR Offshore Resource Assessment
9. Godoi, J.M.A. and dos Santos Matai, P.H.L. (2021) Enhanced oil recovery with carbon dioxide geosequestration: first steps at Pre-salt in Brazil. Journal of Petroleum Exploration and Production 11:1,429-1,441
10. 6th International Workshop on Offshore Geologic CO_2 Storage, Aberdeen, September 2023
11. Lula Oil Field: Project Details https://www.geos.ed.ac.uk/sccs/project-info/53
12. Mello, M.R., Bender, A.A. and De Mio, E., (2011) October. Giant sub-salt hydrocarbon province of the greater Campos Basin, Brazil. In OTC Brasil. OnePetro.

Figures:

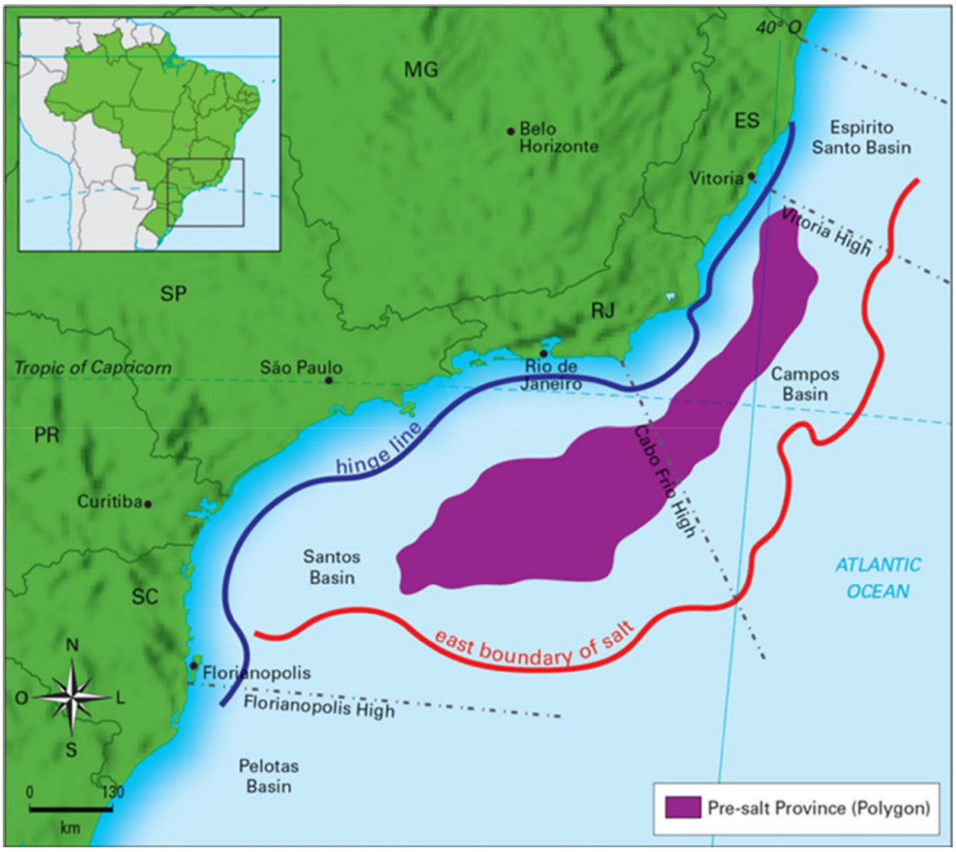


Figure 11.1:. Pre-salt offshore Brazil [9]

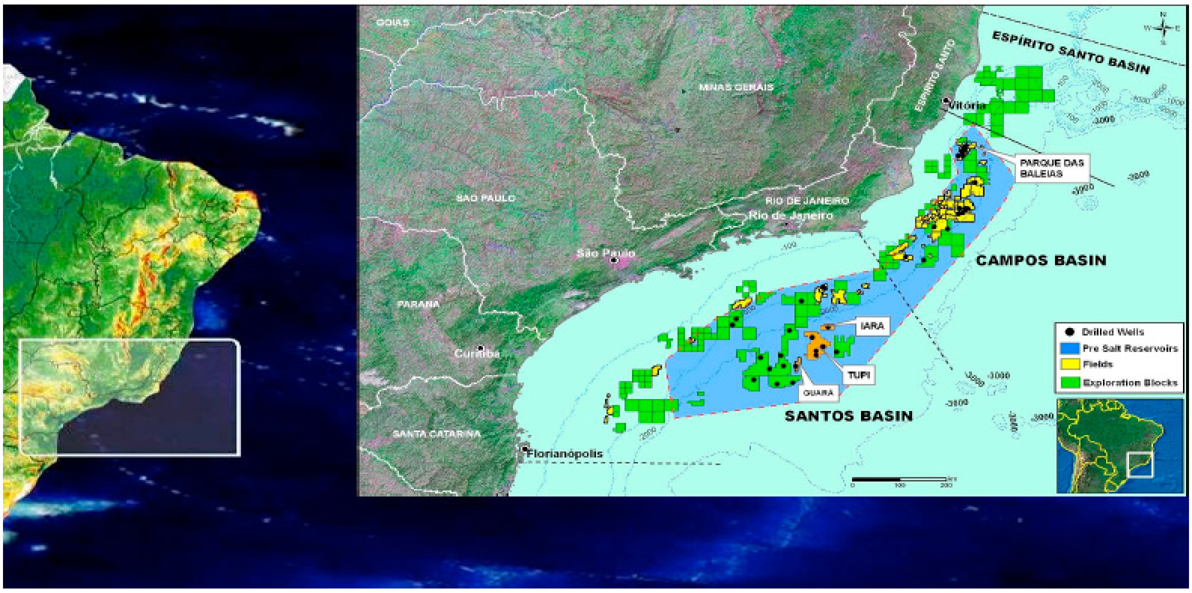


Figure 11.2: Location of the Lula (Tupi) field in the Santos Basin [1]

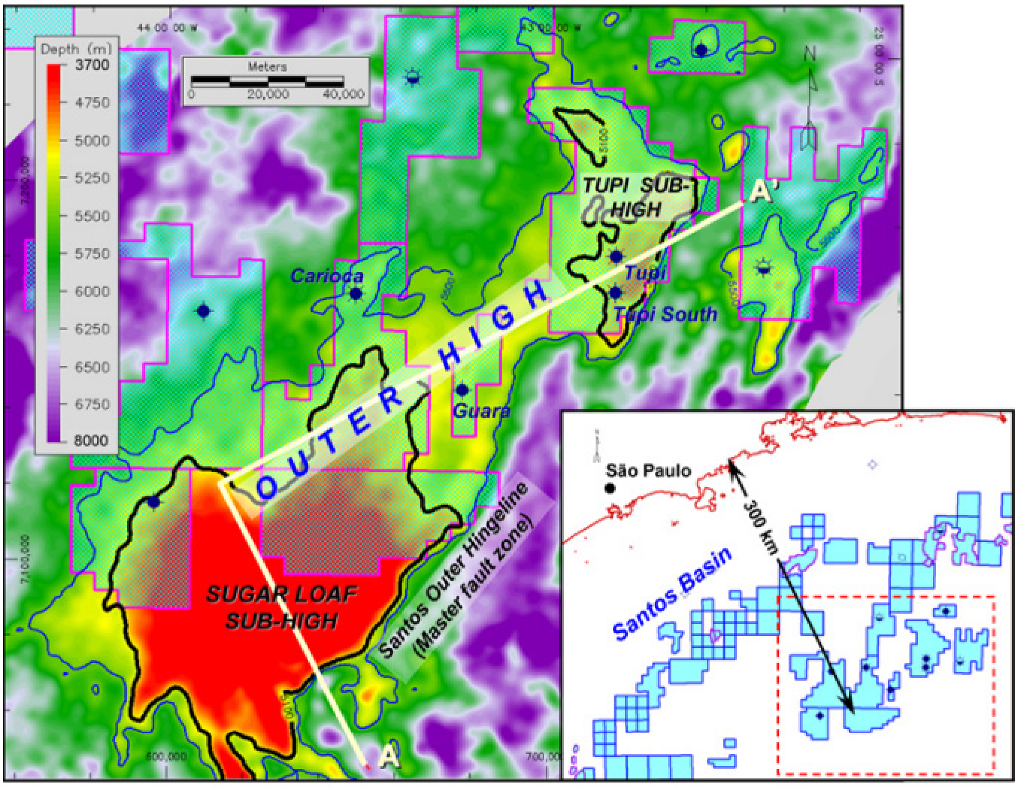


Figure 11.3: Base Salt structure map of the Outer High of the Santos Basin [4]. Note that the Lula field is located on the Tupi High. See seismic section below

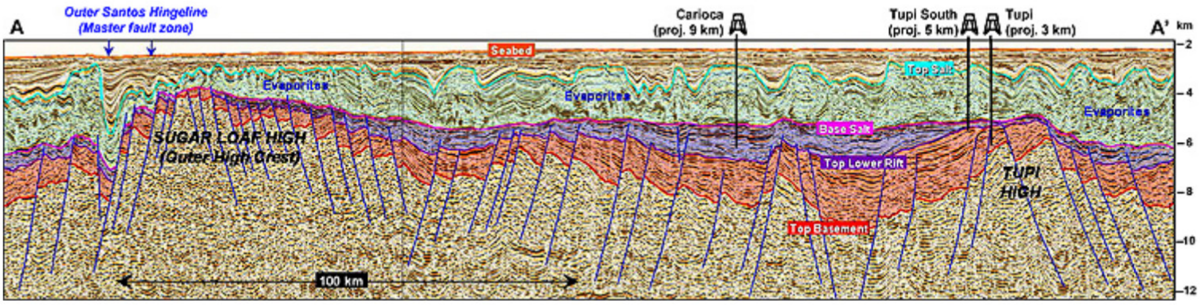


Figure 11.4:Regional interpreted seismic section across the Outer High of the Santos Basin (showing Tupi High). Red shaded area is the syn-rift, the purple represents the upper syn-rift and sag and the cyan is the salt/evaporites [4].

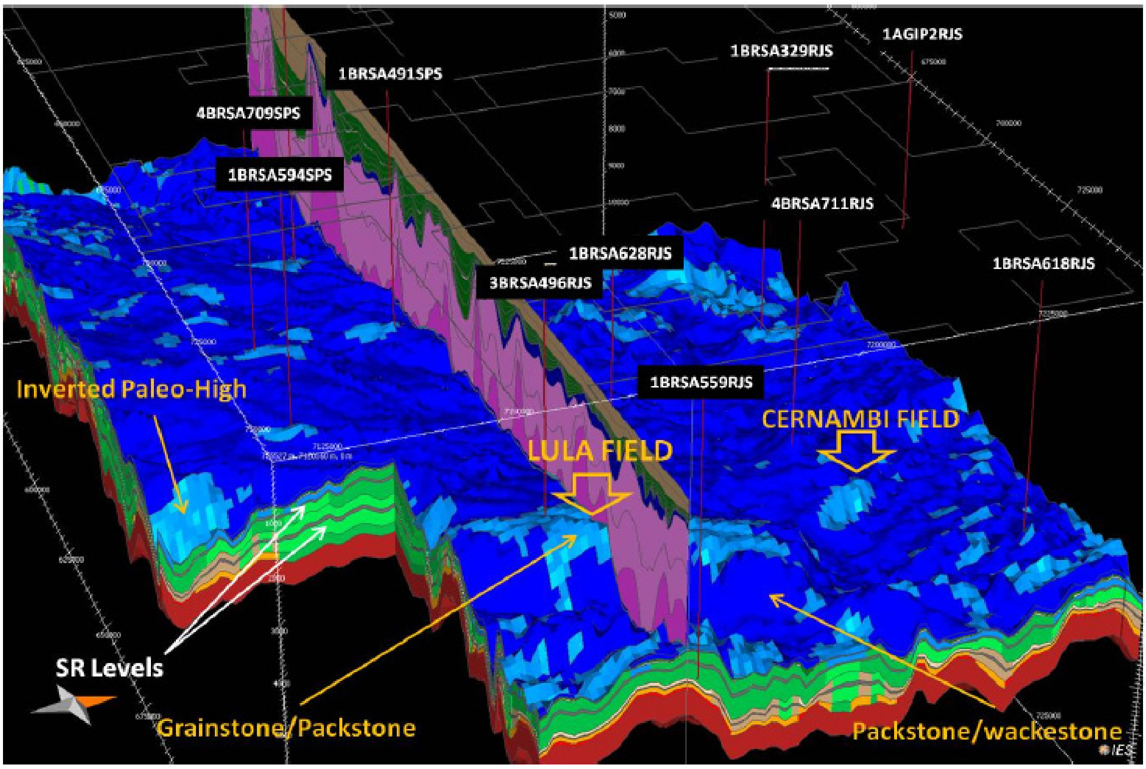


Figure 11.5: Pre-salt facies distribution model based on well data, seismic attributes and paleo geometry. Salt layers (in pink), carbonate reservoirs (pale blue), source rock levels (grey) and basement (red) [11].

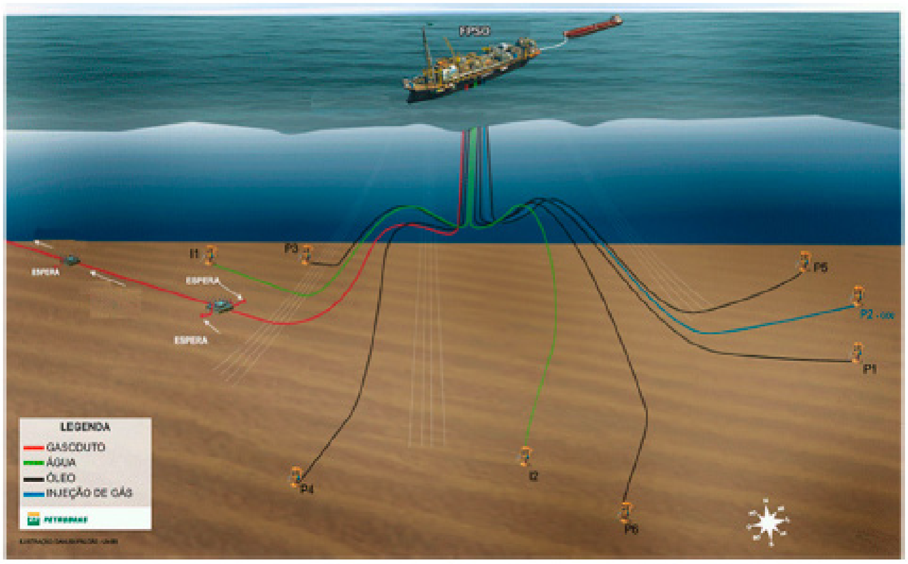


Figure 11.6: Floating production storage and offloading (FPSO) unit- and typical constellation for water-alternating-gas (WAG) and CO_2*-EOR* [1].

11 Mello, M.R., Bender, A.A. and De Mio, E., (2011) October. Giant sub-salt hydrocarbon province of the greater Campos Basin, Brazil. In OTC Brasil. OnePetro.

Gas injected (Mm^3)*	Extracted/produced (Mm^3)*		
	Oil	Gas	Water
177.3	3.1	845.8	0.0

Based on Pizarro and Branco (2012)

Specifically for Lula pilot

*Million m^3

Table 11-1 Lula pilot- cumulative injection and extraction (up to December 31, 2011): [9]

12. Snøhvit

Site Details

Name	Location	Province/State	Country	Onshore	Offshore
Snøhvit	Barents Sea 150 km north of the coast	Finnmark	Norway		✓

General storage type (Saline Aquifer)

The target storage reservoir is a deep saline formation, adjacent to a depleting gas field. Natural gas is produced from the same formations but in adjacent fault blocks. CO_2 is separated from the produced natural gas which contains 5-8% CO_2.

Development History (In operation since 2008)

The field was discovered in 1984 and, after approval in 2002 came on stream in August 2007, with CO_2 injection starting in August 2008 (Figure 12.1). The installations are all sub-sea in 290-350 m of water depth. The first CO_2 injection well (7121/4-F-2H) was drilled and completed in 2005, then a second CO_2 injection well (7121/4-G-4H) was drilled in 2016 and started injection in December 2016. Both wells have temperature and pressure gauges at the well head and down-hole, which are continuously monitored from the operation centre onshore.

The gas is produced from many wells (over 10) and transported via pipelines 150 km to the onshore Melkøya a small island near the town of Hammerfest in northern Norway LNG plant. There the CO_2 is separated from the natural gas and piped back to the Snøhvit field area and re-injected through one of two wells into the saline aquifer units near the gas field units.

In the first years, from August 2007 to April 2011 CO_2 was injected into the Tubåen Formation. As the injection progressed the reservoir pressure slowly built up (mainly due to geological barriers) and the injection operation had to be modified, with injection switched to the shallower Stø Formation. The pressure build-up was attributed to a limited reservoir volume and heterogeneities in the formation[1] . Following this, injection has continued in the Stø Formation (in the first well)[2], with a second injector drilled into the same formation in 2016 to enable long-term capacity. Since 2016 injection has continued using the second well, keeping the first available as a backup. By 2020, 7 million tonnes of CO_2 had been captured and stored. The CCS operation is ongoing, as part of this large gas field development which is likely to continue for several decades.

Geological Characteristics

Reservoir Formation

The Snøhvit Field is located in an elongated E-W trending fault block system located in the Hammerfest Basin in the western Barents Sea (Figure 12.2).

Lateral extent / thickness variation	The Tubåen Formation is located at 2560-2670 m depth, the injection unit is approximately 110

[1]Hansen O, Gilding D, Nazarian B, Osdal B, Ringrose P, Kristoffersen J-B, Eiken O, Hansen H. (2013) Snøhvit: The history of injecting and storing 1 Mt CO_2 in the fluvial Tubåen Fm. Energy Procedia 37 pp3565 – 3573
[2]Osdal, B., Zadeh, H.M., Johansen, S., Gonzalez, R.R. and Wærum, G.O., 2014, April. Snøhvit CO2 monitoring using well pressure measurement and 4D seismic. In Fourth EAGE CO2 Geological Storage Workshop (pp. cp-389). EAGE Publications BV.

	m thick and the storage zone is 2500 m wide close to the injection well, bounded by two sealing faults[1]. The overlying Stø Formation is 70-95 m thick and is 2300-2400 m deep in this site. The Stø Formation sandstones were deposited in a shallow marine setting, offering a more laterally extensive reservoir formations with fewer barriers.
Rock type	The Tubåen Formation in the Snøhvit field area comprises a deltaic to fluvial sandstone sequence, deposited in the early Jurassic. This delta plain depositional environment, with fluvial distributary channels and some marine-tidal influence, leads to highly variable sandstone facies, interbedded with siltstones and mudstones (Figure 12.3) [1]. The Stø Formation sandstones were deposited in a shallow marine setting, offering a more laterally extensive reservoir formations with fewer barriers.
Sedimentary features: Depositional Environment / facies type & variation / mineral composition	The dominance of distributary channel facies in the Tubåen Formation means that the reservoir tends to be quite compartmentalized. In addition, highly variable cementation patterns (mainly due to quartz cementation) and the many faults lead to a high prevalence of lateral and vertical permeability barriers [1].
Porosity	Sandstone porosity ranges from 7% up to 20% (Figure 12.3).
Permeability	The permeability of the Tubåen Formation at the F-2H well is mainly in the 10-800 mD range (Figure 12.3) [3].
Formation fluid properties: (residual hydrocarbons / salinity concentration)	n/a

Caprock / primary seal formation
The Tubåen formation is overlain by the Nordmela Formation that forms the cap rock of the Tubåen reservoir units. The Stø formation is overlain by the Hekkingen Formation which provides the overall seal for the gas reservoirs[4].

[3] Hansen O, Eiken O, Østmo S, Johansen RI, Smith A. (2011) Monitoring CO_2 injection into a fluvial brine-filled sandstone formation at the Snøhvit field, Barents Sea. *Expanded Abstract SEG.*

[4] Linjordet, A. and Olsen, R.G., 1992. The Jurassic Snohvit Gas Field, Hammerfest Basin, Offshore Northern Norway: Chapter 22. Of AAPG Memoir 54: Giant Oil and Gas Fields of the Decade 1978-1988

The overlying Nordmela Formation is divided into a lower unit (Nordmela 2) with very poor reservoir characteristics that forms the cap rock of the Tubåen Formation. An upper unit (Nordmela 1) has poor to moderate reservoir qualities[5].	
Lateral extent / thickness variation	n/a
Rock type	Mud rich lithology deposited in a lower coastal plain.
Fracture pressure	n/a
Porosity	13%.
Permeability	1-23 mD.
Overburden Features	
Structures in the Barents sea are overlain by thick (1,300 – 1,500 m) Upper Jurassic and Cretaceous shales that act as a regional seal. Above these formations is a ~600 m thick Palaeocene Torsk Formation covered by a thin Quaternary deposit. The Torsk Formation is described as a non-calcareous claystone with rare siltstone / limestone stringers[6].	
Structure	
Fold type / fault bounded	CO_2 was initially injected into the F-segment fault block, with large sealing faults to the north and south (see Figure 12.2). Smaller splay faults were observed on seismic and form a fault ramp system approximately 1 km west of the injection well (F-2 H). The fault ramp relay pattern implies that smaller sub-seismic faults are likely to be present in this region. The 4D seismic differences show that the main faults at Snøhvit, bounding the F-segment to the north and south, are sealing at the current pressure levels (Figure 12.4)[1]. After 2011, CO_2 has been injected into the overlying Stø Formation, within the same fault block system, but the Stø Formation has much better lateral pressure communication.
Faults /Fractures (Type – normal, reverse, strike-slip)	Faults at this site and at the depth of injection are in a normal to strike-slip tectonic regime.
Displacement	The pressure effect is interpreted to terminate against the faults for the Tubåen 1 sandstone unit. Linear flow indicates a semi-closed reservoir where faults, sandstone channels or other

[5] Estublier A and Lackner A. (2009) Long-term simulation of the Snøhvit CO_2 storage. Energy Procedia 1 pp3221-3228
[6] Norwegian Petroleum Directorate Factpage

	geological heterogeneities channelize the flow[7].
Stability (pre-stressed, active, stable)	n/a
Injection / storage history	
Number of injection, monitoring or other wells, well geometry, design and key completion information for injection wells, relevant well issues. Reused / new purpose drilled well.	
Injector well F-2H drilled at a water depth of 318 m, maximum 27° inclination and completed with a 4.5” combined 7” tubing. Well equipped with pressure and temperature gauges at the well head and down-hole. Continuously monitored. Initial well completion plan was to perforate the cemented 7” liner in the full Tubåen interval (79 m), only 30 m were initially perforated in Tubåen 1, 2 and lower parts of 3[1]. A new perforation in Tubåen was opened in April 2011 before Tubåen was plugged and injection continued in the Stø Formation[1].	
Extent and status of casing (corrosion history/ cementation records)	n/a
Injection rates & pattern (i.e. continuous / intermittent) changes in injection behaviour	The main CO_2 reinjection strategy is to maintain continuous injection of captured CO_2 volumes. Injection rate is around 2000 tonnes/day[1].
Total quantities stored	During the expected 30-year field lifetime, approximately 23 million tons of CO_2 will be separated and storage[6]. By 2020, 7 million tonnes of CO_2 had been captured and stored. Of this amount the initial 1.6 million tonnes was injected into the Tubåen Fm, and the rest in the Stø Fm. The injection rate is up to around 750,000 tonnes per year.
Reservoir capacity (estimate)	n/a
Fluid extraction rate (brine extraction, oil for EOR)	n/a
Seismicity Hydraulic fault reactivation potential at the site has been assessed and is considered unlike to occur [8].	
Monitoring regime (technologies deployed)	

[7] Grude S, Landrø M, & Dvorkin J. (2014) Pressure effects caused by CO_2 injection in the Tubåen Fm.,the Snøhvit field. International Journal of Greenhouse Gas Control 27 pp178–187

8 Chiaramonte, L., White, J.A. and Trainor-Guitton, W., 2015. Probabilistic geomechanical analysis of compartmentalization at the Snøhvit CO2 sequestration project. *Journal of Geophysical Research: Solid Earth*, *120*(2), pp.1195-1209.

n/a	
Seismic events (Detection / magnitude / attribution (natural induced).	
n/a	
Monitoring technologies applied and experiences with monitoring	
Surface monitoring technologies deployed	
4D seismic 2003 (baseline), 2009, 2011 and 2012.	Clear 4D seismic amplitude changes and 4D time shifts are observed (Figure 12.4). The CO_2 saturation and pore-pressure increase is the main contributor to the observed 4D seismic response. Figure 12.4 demonstrates that the lower perforation zone is extending further out than the lower[1].
Subsurface monitoring technologies deployed (well logs)	
Production Logging Tool (PLT)	Provided confirmation of the vertical and horizontal stratification of the injected CO_2. With 81% of the injectivity in the lowermost zone, 9% in the middle perforation and 10% in the uppermost perforation.
Gamma ray	
Resistivity	
Density / Neutron	
Experience summary - effectiveness of techniques (limitations / strengths)	
4D seismic in September 2009 and September 2011 were acquired after injection of 500 k tons and 1000 k tons CO_2, respectively. The 4D data have shown that the reservoir is much more heterogeneous than originally expected. The 4D data are therefore used to guide the geological reservoir model [1]	
Major technical/scientific studies on the site, major learnings. Conformance assessment (history-matching with models, correlation between different monitoring techniques)	
Snøhvit is an excellent case study of the impact of CO_2 into a closed reservoir bounded by faults. Pressure build-up was caused by the combination of a highly heterogeneous reservoir and sealing faults. 4D seismic data acquired at two different times enabled researchers to identify the extent of the heterogeneity and improve the geological reservoir model. Offshore, 4D seismic could provide similar detail to the PLT (production logging tool) cost-effectively. Pressure build-up led to the decision to inject CO_2 in a shallower unit (the Stø Fm), where injection has continued since.	

List of key publications covering the site

1. Hansen O, Gilding D, Nazarian B, Osdal B, Ringrose P, Kristoffersen J-B, Eiken O, Hansen H. (2013) Snøhvit: The history of injecting and storing 1 Mt CO_2 in the fluvial Tubåen Fm. Energy Procedia 37 pp3565 – 3573

2. Osdal, B., Zadeh, H.M., Johansen, S., Gonzalez, R.R. and Wærum, G.O., 2014, April. Snøhvit CO_2 monitoring using well pressure measurement and 4D seismic. In Fourth EAGE CO2 Geological Storage Workshop (pp. cp-389). EAGE Publications BV.
3. Linjordet, A. and Olsen, R.G., 1992. The Jurassic Snohvit Gas Field, Hammerfest Basin, Offshore Northern Norway: Chapter 22. Of AAPG Memoir 54: Giant Oil and Gas Fields of the Decade 1978-1988
4. Norwegian Petroleum Directorate Factpage
5. Hansen O, Eiken O, Østmo S, Johansen RI, Smith A. Monitoring CO_2 injection into a fluvial brine-filled sandstone formation at the Snøhvit field, Barents Sea. *Expanded Abstract SEG 2011*.
6. Estublier A & Lackner A. (2009) Long-term simulation of the Snøhvit CO_2 storage. Energy Procedia 1 pp3221-3228
7. Grude S, Landrø M and Dvorkin J. (2014) Pressure effects caused by CO_2 injection in the Tubåen Fm.,the Snøhvit field. International Journal of Greenhouse Gas Control 27 pp178–187

Figures

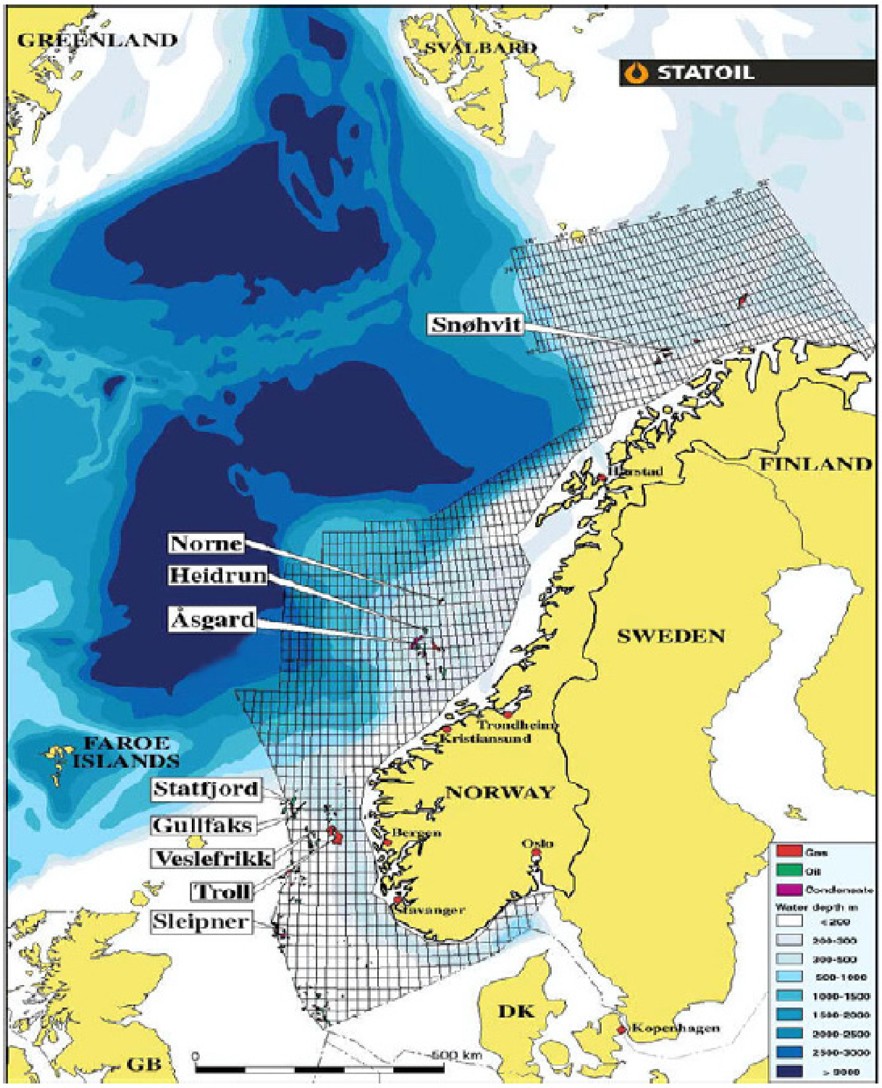


Figure 12.1: Location map showing Snøhvit field[3].

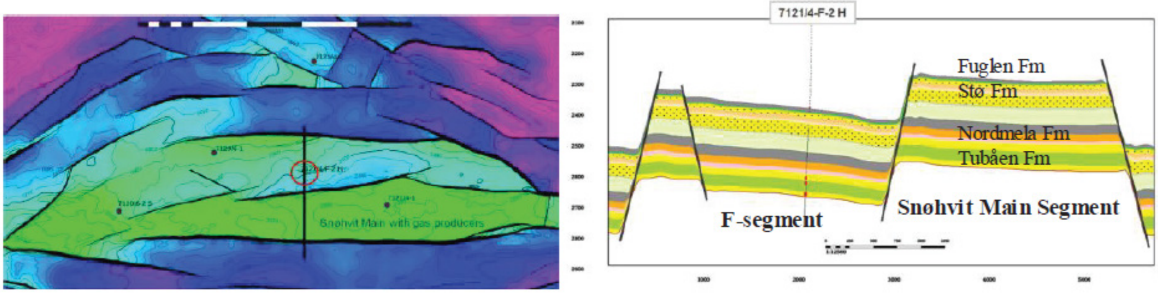


Figure 12.2: Depth map to the Top Fuglen Formation with well locations. Injection well marked by a red circle and relay ramp by arrow. Cross section is indicated by black line. Right: geological cross section N-S through reservoir sections at Snøhvit. Red dots indicate perforation locations in Tubåen[1].

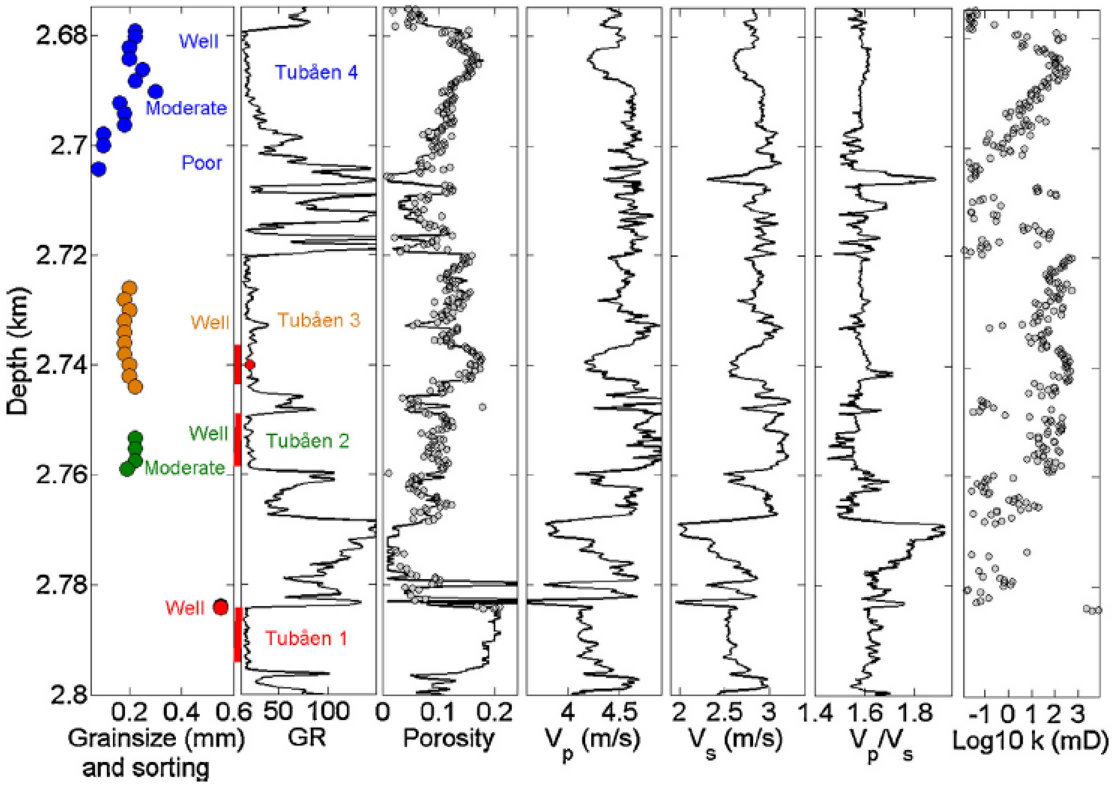


Figure 12.3: Depth plots from the injection well. Left to right: grain size and sorting (thin sections), gamma ray (GR), porosity measured in the well and in the laboratory (gray), P-wave velocity (V_p), S-wave velocity (V_s), V_p/V_s ratio, and permeability (laboratory measurements). Vertical axis shows depth in km, the well is slightly deviated. The reservoir zone is located between 2.68 and 2.8 km measured depths (MD). The four Tubåen sandstone units can be seen in the gamma log, separated by shale units [5].

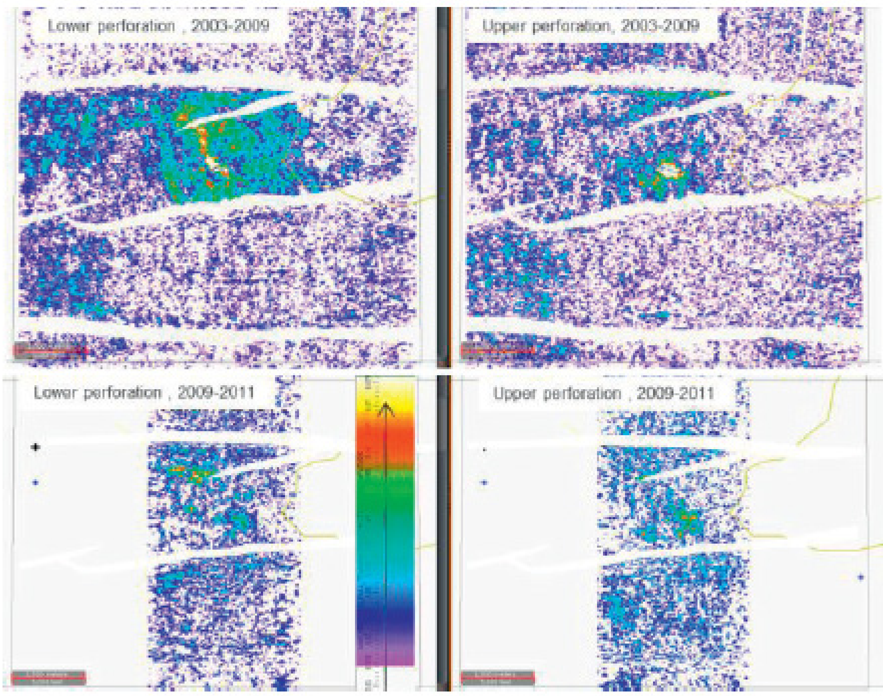


Figure 12.4: 4D difference amplitude map for the lower perforation and upper perforation for 2003-2009 and 2009-2011[1]

13. Sleipner

Site Details

Name	Location	Province/State	Country	Onshore	Offshore
Sleipner	240 km west-southwest of Stavanger (Figure 13.1)	Production licences PL046 & PL029.	Norway		✓

General storage type

Deep saline aquifer in the Utsira Formation.

Development History (in operation)

Sleipner was the world’s first industrial offshore CCS project, developed as a response to the implementation of the Norwegian offshore carbon tax. An amine plant was installed on the Sleipner T Platform to extract CO_2 from the Sleipner Vest reservoir gas (~9% CO_2) rather than venting it, which was then injected and stored 800-1,000 m below sea level at 2.5 km east of the Sleipner A platform.

Injection via a single deviated well is sub-horizontal at the injection point and 200 m below the top of the reservoir. This configuration, with the wellbore below the buoyant CO_2 plume, means the wellbore does not present a containment risk.

~20 Mt CO_2 has been injected (1996-2022), starting with on average 0.9 Mt/yr initially but reducing slightly over the years. Since 2014 CO_2 from Gudrun gas field has also been processed [1, 2].

Geological Characteristics

Reservoir Formation

Utsira Formation

Basin (laterally)-restricted low-stand fan deposit of late middle Miocene-late Pliocene age (11-3 Ma). The Utsira Formation is 200-300 m thick in the Sleipner area and consists predominately of unlithified sand with a few interbedded unlithified mud layers. Nine separate amplitude anomalies corresponding to stratigraphically trapped CO_2 have been identified from time laps seismic. This internal reservoir architecture was not possible to image on pre-injection surveys. [1].

Lateral extent / thickness variation	The whole Utsira Formation extends for more than 400 km (n-s) and 50-100 km (e-w). Eastern and western limits are defined by stratigraphic onlap, to the southwest by facies change and to

1 Furre, A.K., Eiken, O., Alnes, H., Vevatne, J.N. and Kiær, A.F., 2017. 20 years of monitoring CO_2-injection at Sleipner. *Energy procedia*, *114*, pp.3916-3926.

2 Hansen, H., Eiken, O. and Aasum, T.O., 2005, September. Tracing the path of carbon dioxide from a gas/condensate reservoir, through an amine plant and back into a subsurface aquifer–case study: the Sleipner area, Norwegian North Sea. In *SPE Offshore Europe Oil and Gas Exhibition and Conference*. OnePetro.

	the north it occupies a narrow, deepening channel [3]. Isopachs of reservoir sand define two main depocentres, one in the south (around Sleipner) where thicknesses exceed 300 m and another 200 km to the north with a thickness of ~200 m (Figure 13.2) [3, 4]. Near the injection site: sandstone intervals are 20-30 m thick and mudstones 1-1.5 m thick. The exception is the mudstone separating layer eight and nine which is 5-9 m in thickness. [1].
Rock type	Unlithified sand(stone) with interbedded unlithified mud(stone).
Sedimentary features: Depositional Environment / facies type & variation / mineral composition	The Utsira Formation comprises stacked overlapping mounds of very low relief, interpreted as individual fan-lobes and separated by thin intra-reservoir mudstone or shales. Interpreted as a low-stand fan, deposited by gravity flows in a marine environment with water-depths of 100 m or more[3] although depositional environment is disputed[4]. Mud diapirs and mud volcanoes at the base of the Formation cause significant local thickness variation[4]. An eastward thickening sand wedge in the uppermost part of the Utsira Sand is separated from the main sand package by a 6.4 m thick shale layer[4]. In the Sleipner area, seismic amplitudes of the top Utsira Sand delineate a reveal a north trending channel[5].
Porosity	Φfmn 36% (27-40) [6] Φsh 34% (31-38)

3 Chadwick, R.A., Zweigel, P., Gregersen, U., Kirby, G.A., Holloway, S. and Johannessen, P.N., 2004. Geological reservoir characterization of a CO_2 storage site: The Utsira Sand, Sleipner, northern North Sea. *Energy*, *29*(9-10), pp.1371-1381.
4 Zweigel, P., Arts, R., Lothe, A.E. and Lindeberg, E.B., 2004. Reservoir geology of the Utsira Formation at the first industrial-scale underground CO_2 storage site (Sleipner area, North Sea). *Geological Society, London, Special Publications*, *233*(1), pp.165-180.
5 Chadwick, R.A., Williams, G.A. and Falcon-Suarez, I., 2019. Forensic mapping of seismic velocity heterogeneity in a CO_2 layer at the Sleipner CO_2 storage operation, North Sea, using time-lapse seismics. *International Journal of Greenhouse Gas Control*, *90*, p.102793.
6 Sleipner 2019 Benchmark Model (CO_2 datashare.org) DOI 10.11582/2020.00004

	35-40% [7]
Permeability	The reservoir has a permeability- range of 1 to 5 Darcy and net to gross of (98%)[6]. Permeability may vary with presence of channel sands in Utsira [5]. Values from the Sleipner 2019 model on CO_2Data Share (and references therein) are given as: Kfmn 2,000 mD (1,100-5,000 mD)[6] Ksh 0.001 mD (0.00075-0.0015 mD).
Formation fluid properties: (residual hydrocarbons / salinity concentration).	Estimated brine density is 1031 kg/m^3 and estimated to be equivalent in salinity to sea water [13].
Caprock / primary seal formation	
Nordland Group: several hundred meters thick, and can be divided into three main units (lower, middle, and upper seal). Distal parts of sediment wedges prograded from the western and eastern basin margins [4].	
Lateral extent / thickness variation	50 m thick (Lower seal), extends more than 50 km west and 40 km east beyond the injection area at Sleipner [3].
Rock type	Lower seal: Primary sealing unit. Shaley basin restricted unit[3]. Grey clay silts or silty clays, predominantly massive occasionally with a weak sedimentary fabric. Localised occurrences of sandy strata. Middle seal: Prograding Pliocene sediment wedges – dominantly shaly in the basin centre but coarsening up and towards basin margins. Upper seal: Quaternary glacio-marine clays and glacial tills[3].
Fracture pressure	n/a
Porosity	Φcap 35% (34-36) [6, 12]
Permeability	Kcap 0.001 mD (0.00075-0.0015 mD) [6]
Overburden Features	
No presence of a potable aquifer .	
Structure	

7 Baklid, A., Korbøl, R., Owren, G., 1996, Sleipner Vest CO_2 disposal, CO_2 injection into a shallow underground acquifer, SPE paper 36600. SPE Annual Technical Conference and Exhibition, 6-9 October 1996, Denver, Colorado. https://doi.org/10.2118/36600-MS

Top of the Utsira Sand dips generally to the south, but in detail it is gently undulatory with small domes and valleys[3]. Base of the Utsira Sand has a north-eastward trending depression in the greater Sleipner area[4].	
Fold type / fault bounded	CO_2 presently accumulates in a small domal structural high (12 m high) and a narrow corridor, 3 km north/north-east of the injection point. The full site is larger, covering adjacent low-relief domal structures to account for long-term migration. Potential migration routes (neglecting any trapping at levels deeper than below Top Utsira or base sand wedge) are provided[4]. The base of the Utsira Formation is structurally complex, mounded and interpreted as mud diapirs, 1-2 km in diameter, or elongated up to 10 km long[4]. Utsira Formation is underlain by the Hordaland Group, which is severely deformed by soft sediment deformation and polygonal faulting[4].
Faults /Fractures (Type – normal, reverse, strike-slip)	No significant faulting of the top seal.
Displacement	n/a
Stability (pre-stressed, active, stable)	n/a
Injection / storage history	
Number of injection, monitoring or other wells, well geometry, design and key completion information for injection wells, relevant well issues. Reused / new purpose drilled well.	
The Sleipner project was the first project to inject CO_2 with the intension of storage and not motivated by oil recovery, and also the first offshore injection project[7]. The design and injection concepts are reported in refs[7,2] and needed to accommodate the shallow depth and low injection pressure, the wet CO_2 and the need for the system to dispose of available CO_2 at any time[7]. A key aspect is that injection is at the base of the formation towards the end of a highly inclined well. Reservoir entry of the well is downflank which means that the entry point is not likely to be reached by injected CO_2. A shallow long reach well was planned departing at least 3000 m from the drill centre. A special casing program included 18 5/8” x 13 3/8” surface casing down to 585 m measured depth with an inclination built to 30°. A 10 ¾” x 9 5/8” production casing into the top Utsira Formation at 2387 m measured depth (996 VD) with inclination built to the sail angle of 83°. A 7” liner was run in a 8 ½” hole drilled to a total depth of 3752 m measured depth (1163m VD) (all referred to the rotary table).	

7" monobore design to satisfy the requirement for low friction pressure low and a low rate dependency for the system as a whole[7]. No monitoring wells were drilled largely due to cost and added risks[1].	
Extent and status of casing (corrosion history/ cementation records)	Corrosion less steel was employed in the exposed parts of the well.
Injection rates & pattern (i.e. continuous / intermittent) changes in injection behaviour	CO_2 injection commenced through injection well 15/9-A-16[2] (Figure 13.3) in 1996. Challenges in the first year due to sand influx were remediated by a re-perforation and installation of a gravel pack in August 1997[1]. Injection rates were initially 1 Mt/yr and relatively uniform up to 2011 with a slight decline in recent years[3].
Total quantities stored	19 Mt CO_2 injected (1996-2022).
Reservoir capacity (estimate)	Total pore volume of Utsira Formation based on isopach map, porosity and shale volume is ~$6x10^{11}$ m^3[3] and the Norwegian Offshore Directorate values give estimates of 5.26 +11 m^3 rock volume[8]. However, this is for the whole formation, not the Sleipner site. Available pore-space within structural closures and likelihood of encountering traps is estimated at ~0.11% of total pore-volume[2]. The Sleipner site is designed and approved for 25 Mt injection.
Fluid extraction rate (brine extraction, oil for EOR)	n/a
Seismicity	
Monitoring regime (technologies deployed)	
No direct measurements of geomechanical deformation, either geodetic or microseismic have been carried out.	It is estimated that due to the small pore pressure change, it is unlikely that significant geomechanical deformation will have occurred. Due to excellent flow properties and a very large storage aquifer, pressure changes during injection are deemed to be negligible [9].

8 co2-atlas-north-sea.pdf (npd.no)

9 Verdon et al (2013) Comparison of geomechanical deformation induced by megaton-scale CO_2 storage at Sleipner, Weyburn and In Salah. Proceedings of the National Academy of Sciences 110.30 E2762-E2771.

Seismic events (Detection / magnitude / attribution (natural induced).	
n/a	
Monitoring technologies applied and experiences with monitoring; Extensive geophysical and environment monitoring programme deployed. Being a first of its kind there were no guidelines or regulations in place, Statoil and partners chose to test a large range of methods[1].	
Surface monitoring technologies deployed	
Eleven 3D seismic surveys; one baseline and ten repeats.	1994 – base survey prior to injection. 1999, 2001, 2002, 2004, 2006, 2008, 2010, 2013, 2016, and 2020 - repeats. Despite a variety of seismic surveying parameters, technologies and processing in the time range (partly due to technology improvements), the surveys have been valuable to understand plume development. This has been especially due to time-lapse processing and the strong contrast in acoustic properties between the saline aquifer host and the injected CO_2[1]. CO_2 signature of nine sand layers in the reservoir are illuminated – interpreted as CO_2 trapped beneath partially sealing intra-reservoir mudstones[5]. In recent data layers deeper layers 1-4 have become more challenging to interpret while the shallower layers are still clearly visible. There has been no indication of leakage.
Four gravity surveys.	High precision gravity monitoring offers independent measurement of density changes and therefore of saturation[10]. 2002: permanent seabed benchmarks installed over the CO_2 plume and a baseline for gravity monitoring acquired. Surveys repeated in 2005, 2009 and 2013[1] additional benchmark stations have been installed as the plume has expanded over time.

10 Alnes, H., Eiken, O. and Stenvold, T., 2008. Monitoring gas production and CO 2 injection at the Sleipner field using time-lapse gravimetry. *Geophysics*, *73*(6), pp.WA155-WA161.

	Impact of ocean tidal fluctuations, scouring sea bottom currents and gravitational response of hydrocarbon production at deeper levels have been accounted for. Within measuring uncertainty, the current amount of supercritical CO_2 is the same as the injected amount of CO_2[1]. With well constrained formation temperatures and injection temperatures changes in gravity response can be used to constrain the rate of dissolution of CO_2 in the formation water (which is undetected by seismic), Alnes et al estimate this at <1.8%/year [10].
Controlled Source Electromagnetic test line acquired over field in 2006 – with inferior resolution at the time.	Single controlled-source electromagnetic survey conducted in 2008 along one 30 km tow-line. 27 receivers were deployed on the seabed with around 500 m spacing. Challenges: • Water depth of 80 m • Injected CO_2 show up as a very weak resistivity anomaly • Pipeline network on the seabed • Shallow target detection via CSEM. However, using a 2.5D inversion algorithm able to extract resistivity profile of the injected CO_2 [11]. The CSEM shows the plume layers as discrete larger-volume anomalies, high resistive and anisotropic anomalies. Much lower resolution than seismic.
Seabed surveys – high-resolution acoustic imaging and photo mosaic. To investigate potential of escape release structures[1].	No evidence of leakage.
Sea Bed ROV video[12].	Remotely operated vehicle (ROV) used to deploy gravity meter (2002, 2005 & 2009) transmitted from seafloor continuously for 3-4 days. No seafloor bubble-streams were

11 Park, J., Sauvin, G. and Vöge, M., 2017. 2.5 D inversion and joint interpretation of CSEM data at Sleipner CO_2 storage. *Energy Procedia*, *114*, pp.3989-3996.
12 Chadwick, R.A., 2013. Offshore CO_2 storage: Sleipner natural gas field beneath the North Sea. In *Geological storage of carbon dioxide (CO_2)* (pp. 227-253e). Woodhead Publishing.

	observed, normal seabed conditions with typical flora and fauna[12].
Chemical sampling of sediments and water column to search for potential increased CO_2 levels [1].	No evidence of leakage.
Subsurface monitoring technologies deployed (well logs)	
No well penetrations in area of interest.	
Experience summary - effectiveness of techniques (limitations / strengths)	
The monitoring programme at Sleipner is generally perceived to be a great success and is commonly cited as a good example of how to monitor an industrial-scale storage site. The key tool is 4D seismic which has proved spectacularly effective in tracking the plume (Figure 13.4 - Figure 13.6). Gravimetry is also effective at estimating the density of the in-situ CO_2, and investigating the effects of temperature distribution within the plume and dissolution of the CO_2 in the formation water. Other techniques have been tested with varying degrees of success[12]. Analysis of the CSEM data has been challenging, difficult to observe clear anomalies from the plume area. Added challenges around data contamination by pipelines crossing the survey profile.	
MMV (Measurement, Monitoring, Verification) Practices & related verification of injected CO_2	
Imaging reservoir (4D Seismic)	The time-lapse seismic data reveal a complex system of strong seismic reflectors which are interpreted as CO_2 being trapped in thin layers between shale barriers. Up to nine reflectors have been interpreted, these have grown and changed in appearance over time (Figure 36). Fast upward migration of CO_2 and the development of anomalies have been interpreted as a chimney and other subtle vertical conduits[12, 13].
Out of reservoir migration (4D Seismic)	The main monitoring strategy is to use 4D seismic to track CO_2 migration in the reservoir and monitor for any changes in the overburden, no leakage from the storage complex has been detected[12].
Predictive model calibration and verification- (modelling with 3D seismic)	This has included whole plume modelling (with uncertainty arising on how the CO_2 migrates between the intra-reservoir mudstones) and also modelling of the upper layer as it has significant northwards lateral spread with the CO_2 front advancing at 1m/day (Figure 13.5)[12] .

13 Nazarian, Bamshad and Furre, Anne Kari, Simulation Study of Sleipner Plume on Entire Utsira Using A Multi-Physics Modelling Approach (October 23, 2022). Proceedings of the 16th Greenhouse Gas Control Technologies Conference (GHGT-16) 23-24 Oct 2022, *Available at SSRN 427419*

	Recent simulation studies, including all vertical sequences of the CO_2 plume and communication pathways, modelled the effects of temperature gradients and injection induced temperature variations on phase properties. The effect of salinity on dissolution and consequences for plume movement is also studied[13].
Quantification	Modelling of quantifying injected mass of CO_2 and matching it to seismic has been undertaken with varying success. Early studies focussed on plume reflectivity and velocity pushdowns gave satisfactory results up until the 1999 dataset. More recent datasets are becoming more challenging to model, however there is a strong relationship between gross seismic response of the plume and the injection history[12].

Major technical/scientific studies on the site, major learnings, Conformance assessment (history-matching with models, correlation between different monitoring techniques)
Multiple publications, research and studies have been performed on Sleipner, due to open access of data and being a pioneer in the storage of CO_2. A key element in the EU directive for CO_2 storage operation closure is that the 'actual behaviour of injected CO_2 conforms to the modelled behaviour'. One Sleipner study[14] looked at whether the modelling-monitoring loop could enhance the understanding of CO_2 migration and storage at the Sleipner CO_2 injection operation. Modelling has shown that the central part of the plume is at a higher temperature than the surrounding reservoir, arriving at a higher temperature at the gas chimney[13]. CO_2 is at 48°C at the injection point and 36°C at top of the reservoir[10] which will reduce CO_2 density and viscosity and increase mobility of the plume. Injection temperature and temperature gradient in the formation has the most significant effect on the rate of CO_2 ascending towards the top of the reservoir, simulations show that CO_2 heats up the formation up to layer 9, with diminishing effect (Figure 13.7). It was concluded that integrating monitoring data with flow simulations can enhance understanding of the reservoir and plume dynamics. Modelling can help constrain upper and lower bound parameters of geological characteristics. New high resolution seismic data acquired at Sleipner has greatly improved imaging and plume migration analysis which highlights the importance of a high quality baseline dataset to draw predictions from[13,14]. Experience from Sleipner has demonstrated that a clear image of a CO_2 plume, ~1 m thick at edge, has been evident from the first repeated survey in 1999, with layer resolution enhanced by

14 'IEAGHG, "Combined Meeting of the IEAGHG Monitoring & Modelling Networks", 2017/05, February, 2017'

advances in seismic acquisition and processing[15]. The conditions at Sleipner are ideal for seismic monitoring due to its shallow reservoir, very high porosity, unlithified reservoir and the contrast between CO_2 and brine – this may not be representative for all storage sites.

List of key publications covering the site

1. Furre, A.K., Eiken, O., Alnes, H., Vevatne, J.N. and Kiær, A.F., 2017. 20 years of monitoring CO_2-injection at Sleipner. *Energy procedia*, *114*, pp.3916-3926.
2. Hansen, H., Eiken, O. and Aasum, T.O., 2005, September. Tracing the path of carbon dioxide from a gas/condensate reservoir, through an amine plant and back into a subsurface aquifer–case study: the Sleipner area, Norwegian North Sea. In *SPE Offshore Europe Oil and Gas Exhibition and Conference*. OnePetro.
3. Chadwick, R.A., Zweigel, P., Gregersen, U., Kirby, G.A., Holloway, S. and Johannessen, P.N., 2004. Geological reservoir characterization of a CO_2 storage site: The Utsira Sand, Sleipner, northern North Sea. *Energy*, *29*(9-10), pp.1371-1381.
4. Zweigel, P., Arts, R., Lothe, A.E. and Lindeberg, E.B., 2004. Reservoir geology of the Utsira Formation at the first industrial-scale underground CO_2 storage site (Sleipner area, North Sea). *Geological Society, London, Special Publications*, *233*(1), pp.165-180.
5. Chadwick, R.A., Williams, G.A. and Falcon-Suarez, I., 2019. Forensic mapping of seismic velocity heterogeneity in a CO_2 layer at the Sleipner CO_2 storage operation, North Sea, using time-lapse seismics. *International Journal of Greenhouse Gas Control*, *90*, p.102793.
6. Sleipner 2019 Benchmark Model (CO_2 datashare.org) DOI 10.11582/2020.00004
7. Baklid, A., Korbøl, R., Owren, G., 1996, Sleipner Vest CO_2 disposal, CO_2 injection into a shallow underground acquifer, SPE paper 36600. SPE Annual Technical Conference and Exhibition, 6-9 October 1996, Denver, Colorado. https://doi.org/10.2118/36600-MS
8. Co2-atlas-north-sea.pdf (npd.no)
9. Verdon et al (2013) Comparison of geomechanical deformation induced by megaton-scale CO_2 storage at Sleipner, Weyburn and In Salah. Proceedings of the National Academy of Sciences 110.30 E2762-E2771.
10. Alnes, H., Eiken, O. and Stenvold, T., 2008. Monitoring gas production and CO_2 injection at the Sleipner field using time-lapse gravimetry. *Geophysics*, *73*(6), pp.WA155-WA161.
11. Park, J., Sauvin, G. and Vöge, M., 2017. 2.5 D inversion and joint interpretation of CSEM data at Sleipner CO2 storage. *Energy Procedia*, *114*, pp.3989-3996.
12. Chadwick, R.A., 2013. Offshore CO_2 storage: Sleipner natural gas field beneath the North Sea. In *Geological storage of carbon dioxide (CO_2)* (pp. 227-253e). Woodhead Publishing.
13. Nazarian, Bamshad and Furre, Anne Kari, Simulation Study of Sleipner Plume on Entire Utsira Using A Multi-Physics Modelling Approach (October 23, 2022). Proceedings of the 16th Greenhouse Gas Control Technologies Conference (GHGT-16) 23-24 Oct 2022, *Available at SSRN 427419*
14. 'IEAGHG, "Combined Meeting of the IEAGHG Monitoring & Modelling Networks", 2017/05, February, 2017'
15. Wierzchowska, M., Alnes, H., Oukili, J. and Otterbein, C., 2021, October. Broadband processing improves 4D repeatability and resolution at the Sleipner CO_2 storage project,

15 Wierzchowska, M., Alnes, H., Oukili, J. and Otterbein, C., 2021, October. Broadband processing improves 4D repeatability and resolution at the Sleipner CO_2 storage project, North Sea. In *82nd EAGE Annual Conference & Exhibition* (Vol. 2021, No. 1, pp. 1-5). European Association of Geoscientists & Engineers.

North Sea. In *82nd EAGE Annual Conference & Exhibition* (Vol. 2021, No. 1, pp. 1-5). European Association of Geoscientists & Engineers.
Other relevant information considered pertinent to the report
IEAGHG, “Monitoring Network and Modelling Network – Combined Meeting”, 2015/01, February, 2015.
Open access data available for Sleipner on the CO_2DataShare website[6] has been downloaded over 10,000 times (May 2022) and aims to propagate research and development of understanding.

Figures

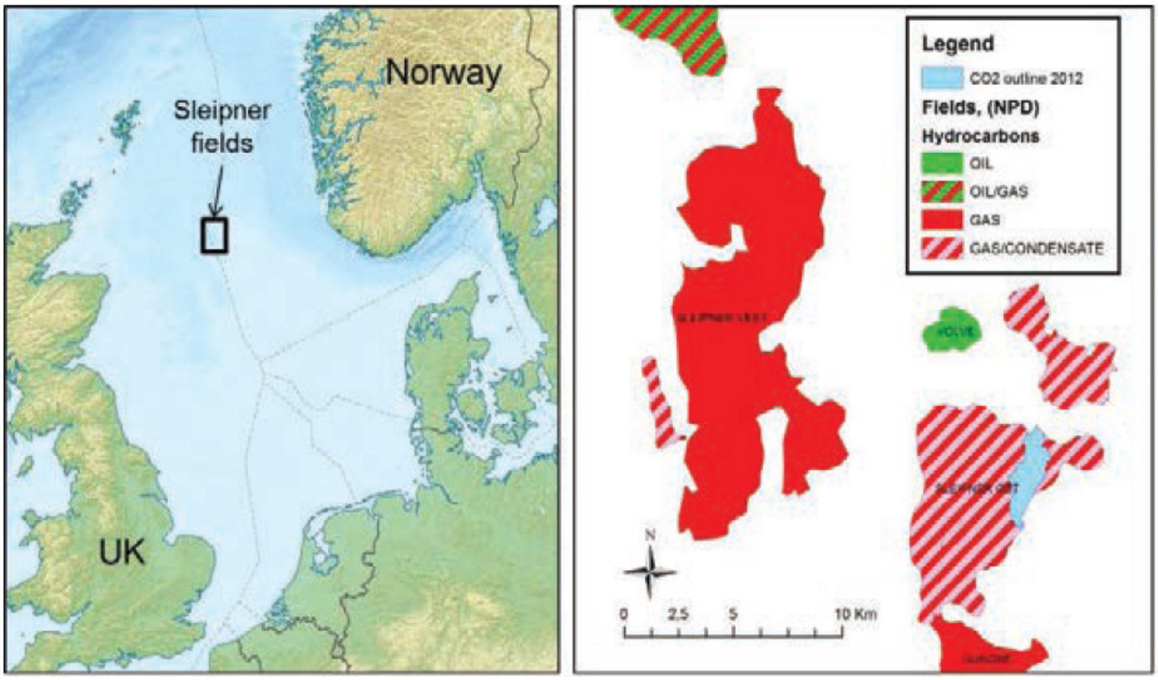


Figure 13.1: Location map (left), Sleipner fields with the outline of the CO_2 plume in 2012 (right)[1].

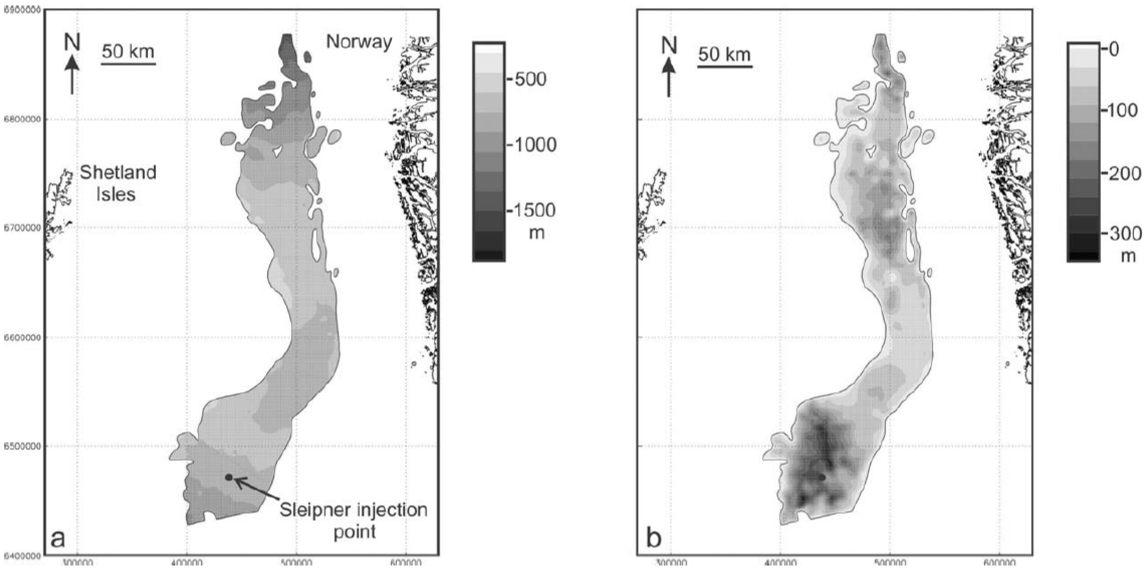


Figure 13.2: Maps of the Utsira Formation: depth to top reservoir (left) and reservoir thickness (right) [3]

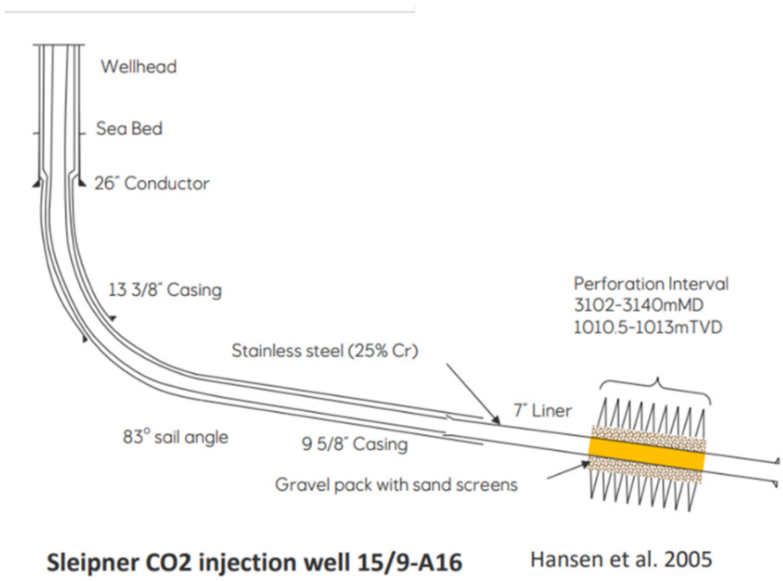


Figure 13.3: Sleipner CO_2 injection well[2]

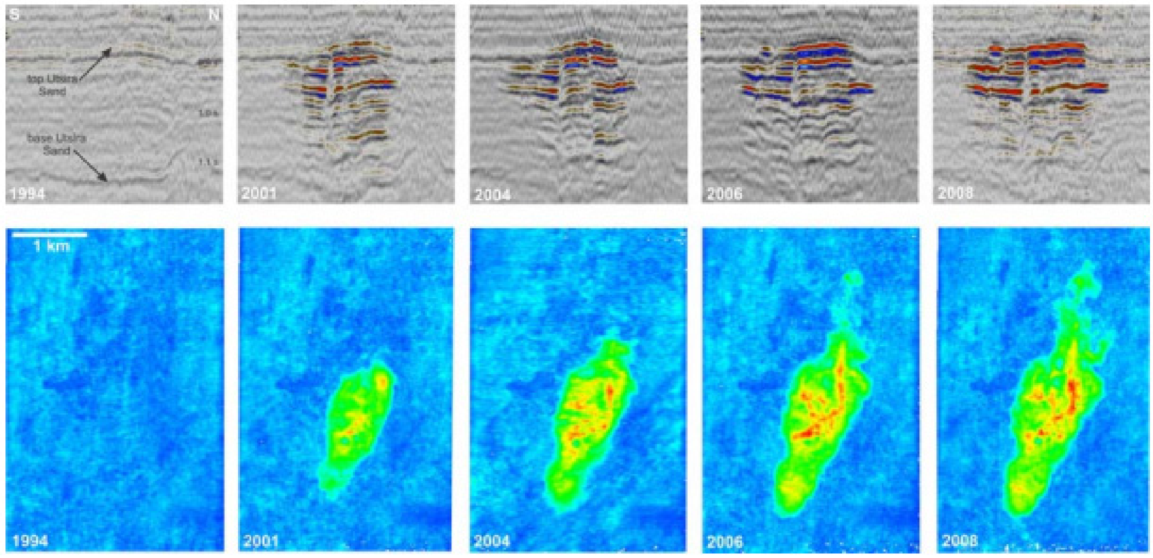


Figure 13.4: Time-lapse images of the CO_2 plume at Sleipner (1994-2008): (top) N-S inline through the plume; (bottom) map of total plume reflectivity[12].

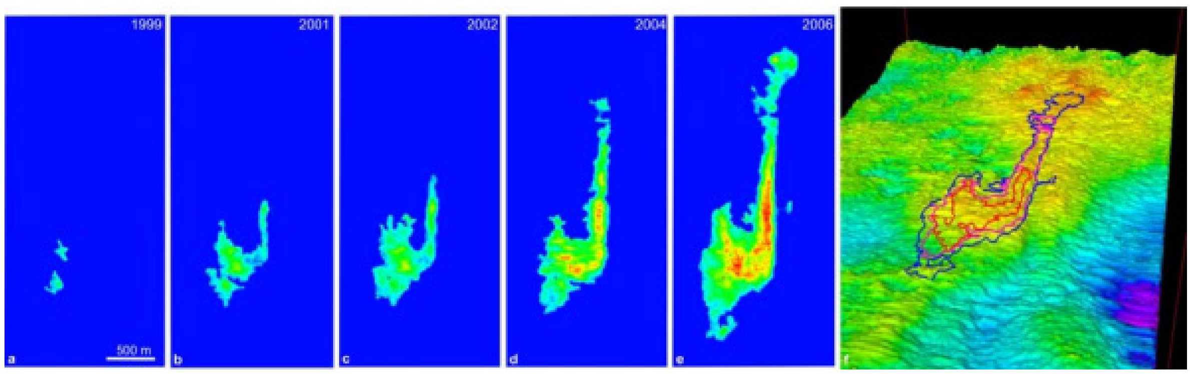


Figure 13.5: Growth of the topmost CO_2 layer at Sleipner a) – e) plan views of the layer spreading from 1999 to 2006. Perspective view of the topography of the top reservoir, showing the CO_2 – water contacts in 2001 (red), 2004 (purple) and 2006 (blue). Note the north-trending tongue of CO_2 corresponding to spilling along a linear topographic ridge [12].

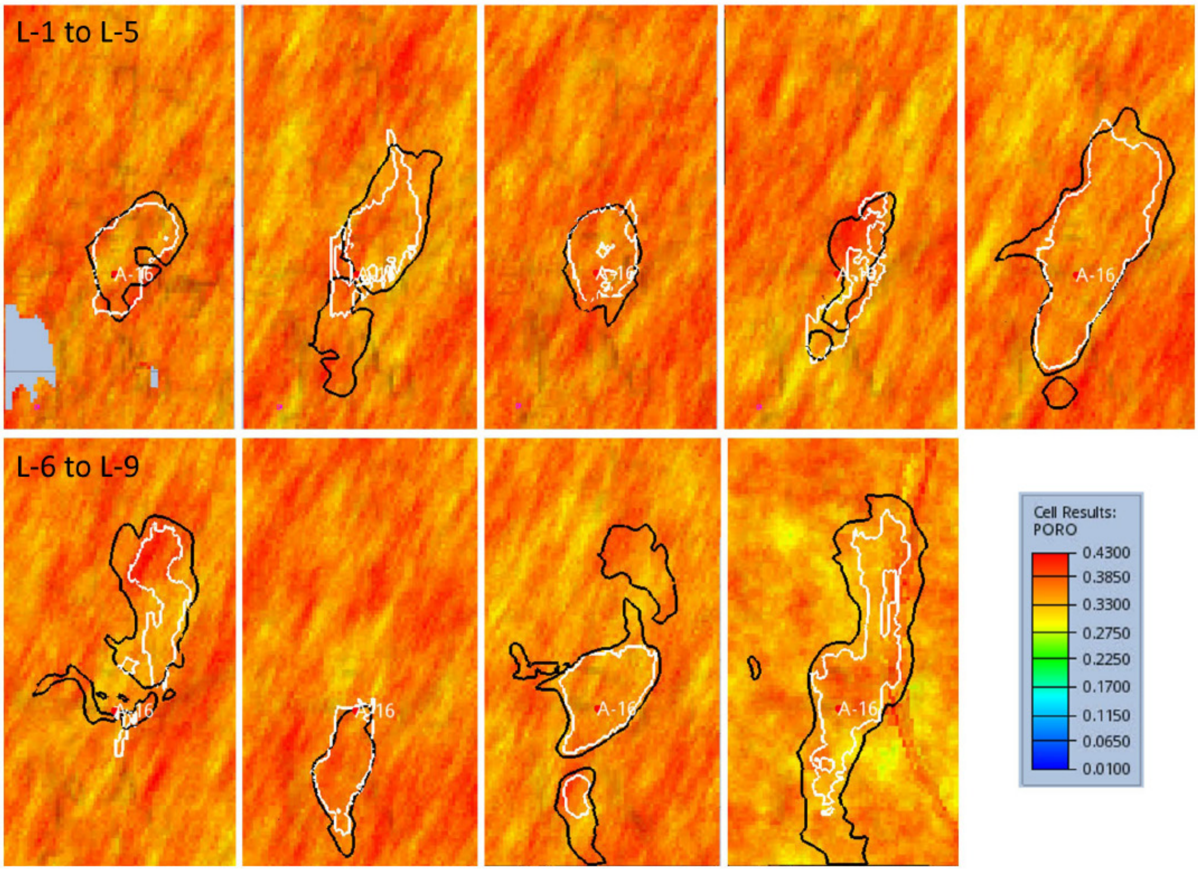


Figure 13.6: Polygons describing the maximum extent of the plume in all 9 layers from the 2010 seismic survey (white polygons) and the 2020 seismic survey (black polygons) [13]

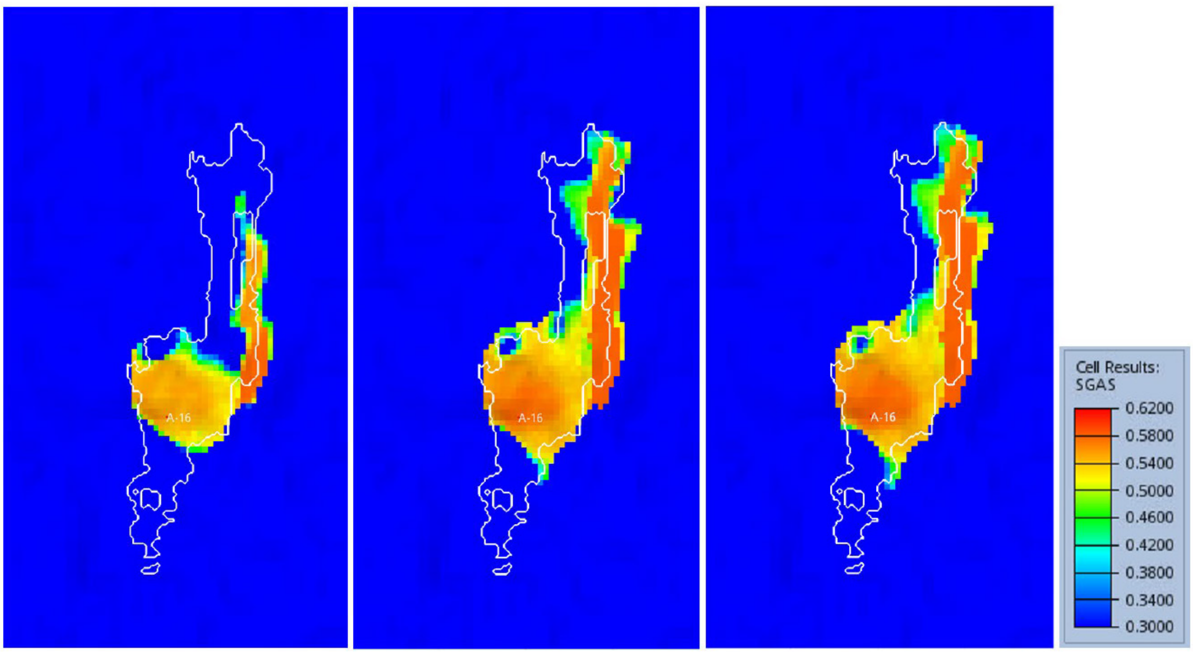


Figure 13.7: Effect of injection temperature on simulated CO_2 mass arriving at layer 9. Isothermal plume (left), CO_2 injected at 48.1°C (middle) CO_2 injected at 52°C (right) [13]

14. Goldeneye

Site Details

Name	Location / Block	Province/State	Country	Onshore	Offshore
Peterhead/ Goldeneye	14/29 (Figure 14.1)	Northern North Sea	UK		✓

General storage type

Depleted gas field - decommissioned 2011.

Goldeneye is a gas condensate field with a thin oil rim.

Development History (yet to operate)

The Peterhead CCS Project aimed to capture around 1 million tonnes of CO_2 per annum, over a period of 10-15 years, from an existing combined cycle gas turbine (CCGT) located at SSE's Peterhead Power Station in Aberdeenshire, Scotland (Figure 14.1)[1].

The storage site is centred on the depleted Goldeneye gas condensate field located in the Outer Moray Firth, circa 100 km north-east of the St Fergus gas plant, mainly in UK continental shelf blocks 14/29a (Offshore Hydrocarbon Production License P257) and 20/4b (License P592) but is mapped to also straddle blocks 14/28b (License P732) and 20/3b (License P739)[2].

From 2004 to 2011, the field produced 568 Bscf of gas and 23 MMbbl of condensate. During production, the field experienced moderate to strong aquifer support – which also served to end the gas production from the wells as each well sequentially cut water[3]. In 2018 the non-producing Normally Unattended Installation (NUI) was converted to a Permanently Unattended Installation (PUI) in preparation for decommissioning (Shell website).

It was planned to inject CO_2 into the storage site at a depth >2516 m [8255 ft] below sea level into the previously gas bearing portion of the high-quality Captain Sandstone Member – in total a 130 km long and <10 km wide ribbon of Lower Cretaceous turbiditic sandstone fringing the southern margin of the South Halibut Shelf, from UKCS block 13/23 to block 21/2. The storage complex, if projected onto the seabed (which is at about 120 m water depth), covers approximately 197 km^2.

In 2015, the UK announced it was cancelling the UK £1 billion CCS Competition six months before it was awarded having a serious consequences on the Peterhead Project[4]. In 2022, the Scotland Cluster came runner up in the latest round of funding for CCS projects by the UK Government and in September 2023 was awarded as part of the Track 2 cluster sequence, now called the Acorn

1 Peterhead CCS Project - Static Model Reports (Aquifer) PCCS-05-PT-ZG-0580-00003 19/03/2015 Ref No: 11.108
2 Spence, B., Horan, D. & Tucker, O., (2014) The Peterhead-Goldeneye gas post-combustion CCS project. Energy Procedia 63, 6258–6266
3 Dean, M. and Tucker, O., (2017). A risk-based framework for Measurement, Monitoring and Verification (MMV) of the Goldeneye storage complex for the Peterhead CCS project, UK. International Journal of Greenhouse Gas Control, 61, pp.1-15.
4 https://sequestration.mit.edu/tools/projects/peterhead.html

Project[5]. The Goldeneye field is now being considered as storage as part of the Acorn Project. The platform and wells have now been fully abandoned (2021).	
Geological Characteristics	
Reservoir Formation	
The Aptian-Albian Captain Sands form the main reservoir and are interpreted to extend over 100 km in length along the southern margin of the Halibut Horst (Figure 14.2). They were deposited in a sand-rich turbidite slope/base of slope system interpreted to trend predominantly west-east but with significant lateral sediment input from the South Halibut Shelf situated immediately to the north. Information from the four discovery/appraisal wells drilled in Goldeneye and an extensive regional database of over 200 wells in the Moray Firth area suggests that sand continuity over a large area adjacent to the regional break in slope is good (Figure 14.2). The Goldeneye reservoir can be subdivided into 4 lithostratigraphic units from top to base (Figure 14.3 and Figure 14.4)[1]. All five production wells were completed within the main reservoir unit, the Captain D. The production history from these wells has shown no evidence of compartmentalisation, with all the wells in communication[1].	
Lateral extent / thickness variation	The mapped top of the Captain Sandstone Member of the Valhall Formation which is at a depth of approximately 8300–8600 ft [2530–2620 m]. The Captain Sandstone Member varies in thickness at the wells from 192 to 830 ft [59–253 m] and is subdivided in the Goldeneye field into four units (A, C, D, and E). The existing development wells have been completed within the Captain E and Captain D units.
Rock type	Sandstone
Sedimentary features: Depositional Environment / facies type & variation / mineral composition	The **Captain D** is the primary reservoir unit, into which all the development wells have been completed. The D unit has been cored in all of the exploration and appraisal wells in the Goldeneye Field. As with the similarly massive Captain A Unit, the base of the Captain D Unit is deemed to be represented by an erosive sequence boundary (2)(Figure 14.5). Mud clasts are dispersed throughout the massive sands, as well as locally being concentrated within individual debris flow beds. The sandstones are dominantly quartzose, with subsidiary quantities of plagioclase and alkali feldspars, glauconite, lithic fragments, clay and bioclasts.

5 https://theacornproject.uk

	There is little cementation, and the bulk of authigenic minerals are composed of chloritic and kaolinite clays. It comprises medium grained massive sandstones that, with the exception of a fining-upwards sequence at the top seen in all wells in the field, show only subtle changes in grain size. Heavy mineral analyses and palaeocurrent indicators suggest that axially oriented (west-east) turbidite systems predominantly controlled deposition[1].
Porosity	Average net-to-gross from this interval is 94%, average net porosity is 25%. Average porosities of 25% to 30%.
Permeability	Average (total) permeability is 790 mD. Permeability of between 700 and 1500 mD.
Formation fluid properties: (residual hydrocarbons / salinity concentration).	n/a
Caprock / primary seal formation	
The primary top seal is the Rødby Formation and the Upper Valhall Member (Figure 14.3) which directly overlies the Captain Formation, it is a proven competent seal. The overlying Plenus Marl Bed and Hidra Formation (Chalk Group) are considered lithologically good aquicludes, offering an extension to the Rødby seal[6]. The Lista Formation is proposed as a secondary seal and the Lower Dornoch Mudstone as a tertiary seal although there is no structural closure at this level (Figure 14.3)[6].	
Lateral extent / thickness variation	The storage seal thickness as a whole varies from 470 ft [143 m] in the north to 697 ft [201 m] in the south. Rødby Formation on average 180 ft [60 m] thick over Goldeneye AOI, thinning to less than 90 ft [30 m] to the north of the Goldeneye field. It may disappear altogether to the north east, but only over the structural high to the north and is confidently mapped within depositional limits of the Captain sandstone[6]. Upper Valhall Member: 0-39 ft [0-12 m] thick, present over much of Halibut Trough area and all of Goldeneye AOI and closest offset wells. Plenus Marl & Hidra formations: 90 ft [30 m] (PM) and 260 ft [80 m] (H)[6].

6 Peterhead CCS Project - Static Model Reports (Overburden) PCCS-05-PT-ZG-0580-00005 19/03/2015 Ref No: 11.108

Rock type	Rødby Formation: calcareous and chalky mudstones with sporadic thin beds of argillaceous limestone[6]. Upper Valhall Member: pale to dark grey mudstone. Plenus Marl & Hidra formations: black anoxic mudstones (PM) and bioturbated limestones with interbedded mudstones (H).
Fracture pressure	n/a
Porosity	n/a
Permeability	n/a

Overburden Features (Thickness, formations presence of secondary reservoirs / seals)

There is approximately 2400 m of overburden stratigraphy overlying the Goldeneye field, divided into seven lithostratigraphic groups – Nordland, Westray, Stronsay, Moray, Montrose and Chalk groups (Figure 14.3). Within these are four possible aquicludes which may potentially restrict CO_2 migration from the Captain reservoir. These comprise Nordland group, Dornoch Mudstone unit (tertiary seal), Lista Formation (secondary seal) and Plenus Marl and Hidra Formations (these overly the primary seal and act as an insurance against lateral egress). The Rødby Formation is the primary seal[6].

Secondary storage for the Goldeneye field includes the Chalk Group above the top of the Plenus Marl Bed, the Montrose Group (particularly the Mey Sandstone Member) and the lower Dornoch sandstone, within the Moray Group. These are the vertically separated secondary storage units above the primary seal. Laterally, outside of the primary storage site, but hydraulically connected to the Captain Sandstone is the Captain Aquifer which has the ability and capacity to accommodate migration of CO_2 within the reservoir formations, but beyond the licensed boundary of the storage site.

The complex seal is made up of the Lista and Dornoch mudstones which can be reliably correlated in all wells within the storage complex and are found at depths greater than 2620 ft [800 m] TVDss across the entire area under investigation. Two of the abandoned exploration wells have plugs set at either Lista or Dornoch mud-stone level.

Above these formations are a series of mudstones with thinner interbedded sands of the Stronsay Group, Westray Group and the Nordland Group.

Stratigraphic units that have direct contact with the Captain Sandstone also include those juxtaposed laterally (see section 4.3[6]). These include Zechstein, Rotliegend, Firth of Forth, Old Red Sandstone and Basement groups. These are considered overburden stratigraphies in overburden models[6].

Structure

The reservoir is bounded by a three-way dip-closed anticline with a pinchout closure to the north. This explanation is in alignment with regional interpretation which supports an unconformity at the base of the Captain[3].

Fold type / fault bounded	The Goldeneye field is a combined structural and stratigraphic trap (Figure 14.6). The trap is a

	three-way dip closed anticline to south, west and east, with a northerly up-dip pinch-out[7]. The sandstones lap onto and thin onto the Halibut Horst high, creating a pinch-out [7].
Faults /Fractures (Type – normal, reverse, strike-slip)	There is no significant faulting at top Captain level. There are many small-scale faults interpreted but these have minor throws. The Captain Sandstone has little acoustic impedance contrast with the shales that encase it. Although many small faults could be interpreted, based on lateral seismic character changes and reflector discontinuities, these faults, the base Captain and the internal reservoir divisions all carry significant uncertainty. All five production wells were completed within the main reservoir unit, the Captain D. The production history from these wells has shown no evidence of compartmentalisation, with all the wells in communication[1]. To the north of the field, there is a zone of east-west southerly dipping faults that mark the northern limit of the thickest Captain Sandstone accumulation. This northern bounding fault marks the transition from the thickest reservoir accumulation to the thin drape of sediments that extends to the north of the fault. The mapped faults are of limited vertical and lateral extent with small throws (20 m). The greatest fault density is evident around the subsurface location of Well 14/29a-3 where fracture zones have been identified in core from the Captain Unit D reservoir interval. By contrast, few fracture zones have been identified in core from Well 14/29a-5 which is located in an area with fewer mapped faults. At least two different fault sets are present in the overburden, but these faults are considered to be decoupled from the Captain reservoir faults by the ductile Rødby/Hidra/Plenus Marl sediments. In summary it is concluded that any migrating CO_2 from the reservoir is not expected to reach

7 Peterhead CCS Project - Static Model Reports (Full Field) PCCS-05-PT-ZG-0580-00004 19/03/2015 DECC Ref No: 11.108

	the surface via pathways originating within the deeper parts of the overburden[6].
Displacement	Studies into fault sealing potential show that the Captain sands are clean and that cataclasites identified in core do not represent significant barriers to fluid flow, which suggests any faulting should not result in fluid barriers or baffles. Geochemical investigation into recovered gas condensate samples shows a constant geochemical fingerprint across field, again suggesting no compartmentalisation[6].
Stability (pre-stressed, active, stable)	The potential for tensile and shear failure of the Captain Sandstone was also assessed in the geomechanical study, using core data and Shell's proprietary modelling package GeoMec. The analysis demonstrated changes in minimum principal stress during gas condensate production, with similar changes during the injection phase but smaller in magnitude and in the opposite direction. In contrast, negligible changes are seen for the maximum horizontal stress. These changes were not beyond the strength of the reservoir rock: they did not give rise to predictions of either shear or tensile failure of the reservoir during the two phases of the reservoir development, and none has been observed for the production phase. It was concluded that the reservoir rock strength and the relatively limited pressure decrease owing to the strong regional aquifer act to produce only relatively small production-related effects[6].

Injection / storage history
Number of injection, monitoring or other wells, well geometry, design and key completion information for injection wells, relevant well issues. Reused / new purpose drilled well.
The Goldeneye storage complex contains a total of twelve wells, two of which are located outside the storage site boundaries (14/28a-1, 14/28a-3a), five abandoned exploration and appraisal wells (14/29a-2, 14/29a-3, 14/29a-5, 20/04b-6, 20/04b-7) are within the storage site and five production wells originate from the Goldeneye platform (Figure 14.2 and Figure 14.4)[3].
There are five production wells and four decommissioned exploration and appraisal wells in the field. Four of the five production wells will be re-fitted for CO_2 service. This will require removal of the production tubing and production packer, and replacement with dual purpose design.

From an integrity perspective, the completion has to be able to take cold CO_2. When transported the CO_2 cools to ambient seabed temperature, around 6°C, while the produced gas was at around 80°C. Thermal contraction is therefore important, whereas before thermal expansion was key in the design. The second purpose of the design is to provide back pressure to the CO_2 to maintain it in the dense phase. This, again, reduces cooling during injection. The decommissioned wells have all been assessed and found to have excellent abandonment plugs at the reservoir level. They are therefore suited to the new CO_2 storage duty[3].	
Extent and status of casing (corrosion history/ cementation records)	n/a
Injection rates & pattern (i.e. continuous / intermittent) changes in injection behaviour	The planned injection rate was approximately one million tons per annum for a period of up to twenty years using converted pro-duction wells specifically retrofitted to function as CO_2 injection and monitoring wells[2].
Total quantities stored	n/a
Reservoir capacity (estimate)	n/a
Fluid extraction rate (brine extraction, oil for EOR)	n/a
Seismicity	
Monitoring regime (technologies deployed)	
n/a	
Seismic events (Detection / magnitude / attribution (natural induced).	
n/a	
Monitoring technologies applied and experiences with monitoring [3]	
Surface monitoring technologies deployed	
Water column, seabed and shallow geosphere	Geochemical probes Van Veen Grab
Pock marks	Multi Beam Echo Sounder (MBES) and Side Scan Sonar (SSS)
Subsidence and uplift	Global Positioning System (GPS)
Subsurface monitoring technologies deployed (across storage complex)	
Time-lapse seismic	3D streamer
	Ocean Bottom Node (OBN) (near platform)

	DAS VSP on tubing (R&D)
Microseismic	DAS Microseismic (R&D)
Passive seismic	Seabed geophones (baseline only)
Subsurface monitoring technologies deployed (well logs)	
Well Integrity	Cement bond logging
"	Casing integrity logging
"	Tubing integrity logging
"	DTS on tubing
"	DAS on tubing (R&D)
CO_2 detection	Downhole sampling
CO_2 conformance	Sigma logging
"	Neutron porosity logging
Pressure conformance	Pressure Downhole Gauge
"	Long term gauge
"	Cased-hole pressure and temperature
Fingerprint	Inert chemical tracer (R&D)
Experience summary - effectiveness of techniques (limitations / strengths)	
The intention of the MMV program was to provide coverage over the entire storage complex including marine biosphere above it.	

MMV (Measurement, Monitoring, Verification) Practices & related verification of injected CO_2

Designed to span three different domains[3] (Figure 14.7):

Marine biosphere and shallow geosphere: includes the seawater column, seabed and shallow subsurface to the base of the formation above the secondary seal complex. Including area around abandoned exploration and appraisal wells.

Deeper geosphere: comprises geological formations within the storage complex, including storage site and up to the top of the secondary seal complex. Beyond the storage site it also includes the continuation of the Captain Sandstone reservoir.

Injection and monitoring wells: one out of five gas production wells would be plugged, three as injectors and one as a monitoring well (and a contingency injector well).

Design of the MMV plan to be: regulatory compliant; risk based; site-specific; and adaptive.

To monitor:

- CO_2 plume development inside the storage complex
- Pressure development inside the storage complex
- Legacy well integrity
- Injection well integrity
- Geological seal integrity

- Marine biosphere impacts

Initially 45 potential technologies were proposed, then ranked according to benefits, cost and likelihood of success. The summary of technologies is shown on Table 14-1.

The base case monitoring plan includes[3] (Figure 14.8):

1. Seabed and shallow layers: ROV surveys, MBES and SSS surveys, seabed and seawater sampling.
2. Geosphere: Time-lapse 3D, OBN, 3D streamer and multi-well DAS VSP.
3. Wells integrity monitoring (cement and tubing), sigma/neutron logging, fluid sampling, pressure, temperature, fibre optic monitoring DTS and DAS flow monitoring).

Major technical/scientific studies on the site, major learnings, Conformance assessment (history-matching with models, correlation between different monitoring techniques)

n/a

List of key publications covering the site

1. Peterhead CCS Project - Static Model Reports (Aquifer) PCCS-05-PT-ZG-0580-00003 19/03/2015 Ref No: 11.108
2. Spence, B., Horan, D. & Tucker, O., (2014) The Peterhead-Goldeneye gas post-combustion CCS project. Energy Procedia 63, 6258–6266
3. Dean, M. and Tucker, O., (2017). A risk-based framework for Measurement, Monitoring and Verification (MMV) of the Goldeneye storage complex for the Peterhead CCS project, UK. International Journal of Greenhouse Gas Control, 61, pp.1-15.
4. https://sequestration.mit.edu/tools/projects/peterhead.html
5. https://theacornproject.uk
6. Peterhead CCS Project - Static Model Reports (Overburden) PCCS-05-PT-ZG-0580-00005 19/03/2015 Ref No: 11.108
7. Peterhead CCS Project - Static Model Reports (Full Field) PCCS-05-PT-ZG-0580-00004 19/03/2015 DECC Ref No: 11.108

Figures

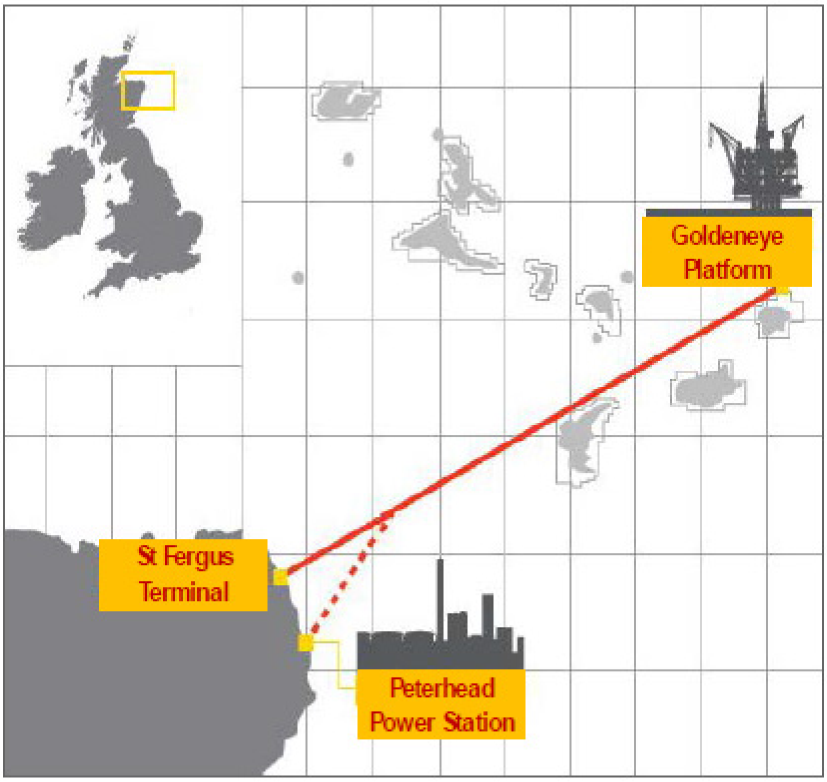


Figure 14.1: Goldeneye project location[1].

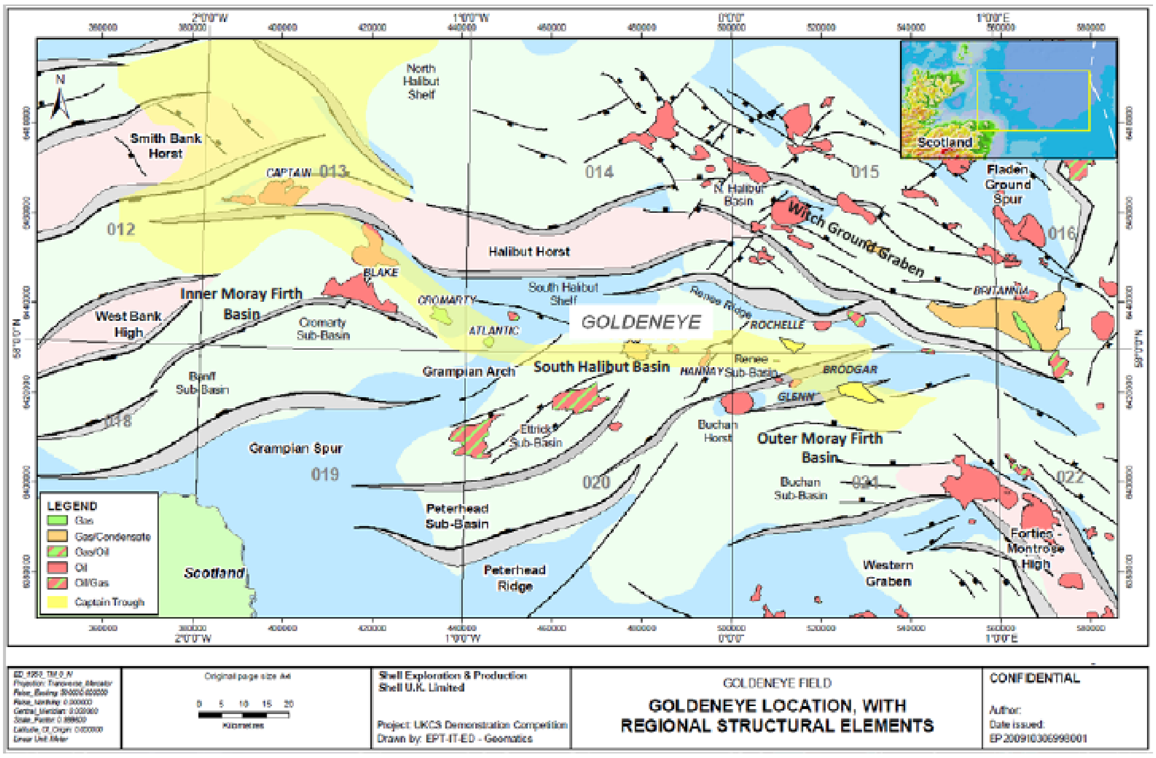


Figure 14.2: Distribution of Captain Sandstones across the Moray Firth: Captain fairway highlighted in yellow; basinal areas in pale green[1].

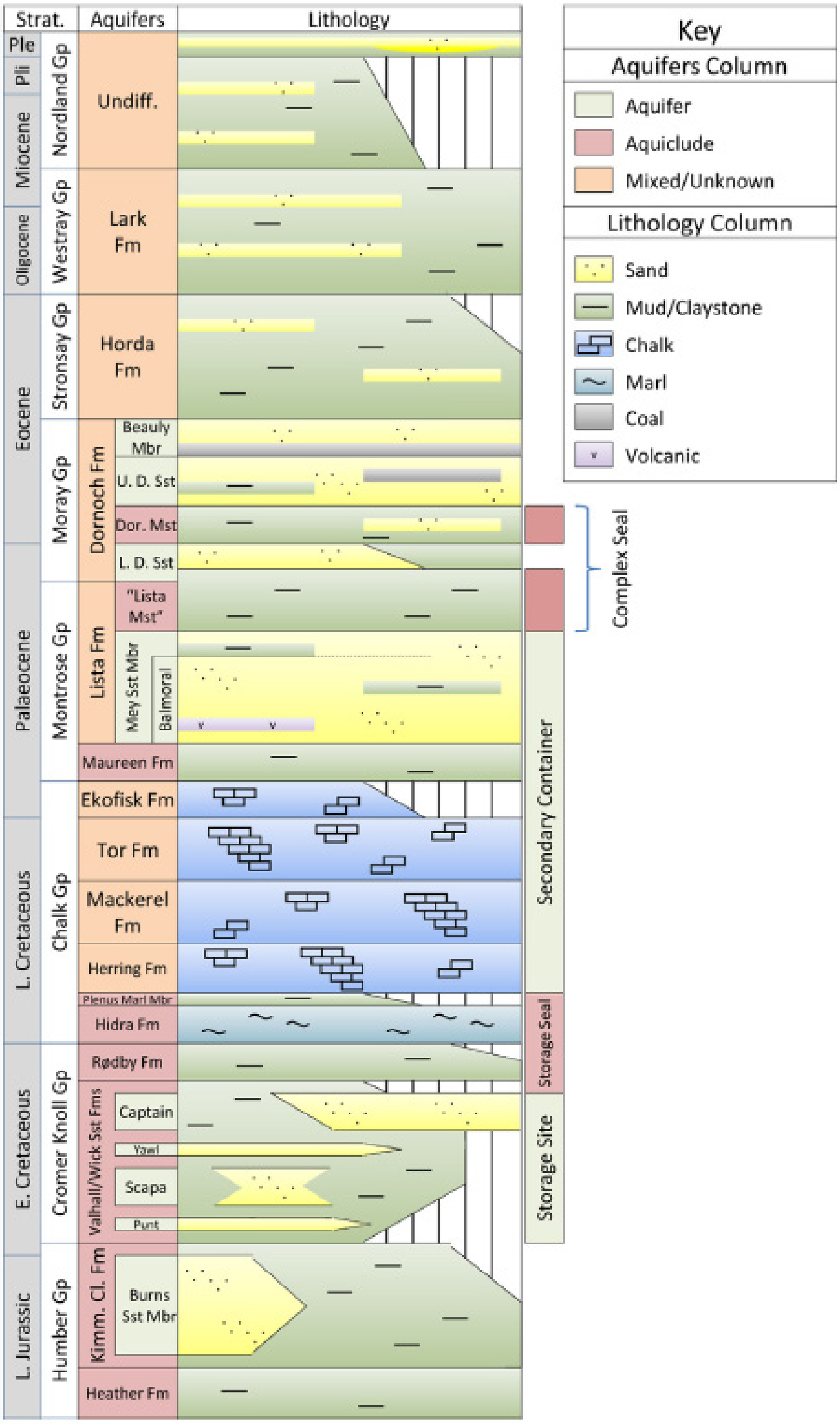


Figure 14.3: Goldeneye storage complex stratigraphy[3] .

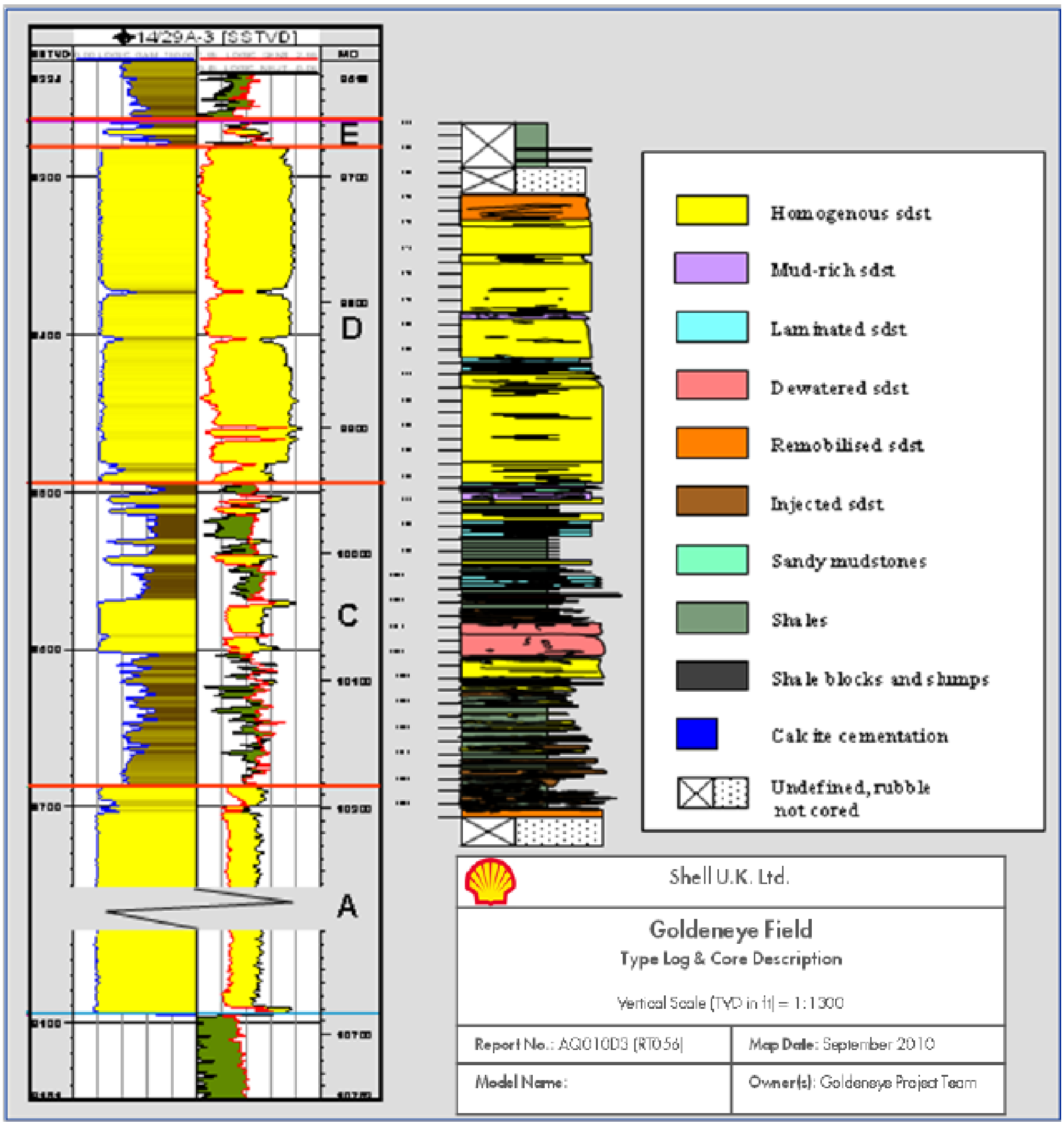


Figure 14.4: Subdivision of the Captain reservoir, Goldeneye area [1]. Log data on left (Gamma Ray (l), Density Neutron (r), net sand yellow), core facies log on right. Note A is homogenous in parts and highly variable in thickness[1].

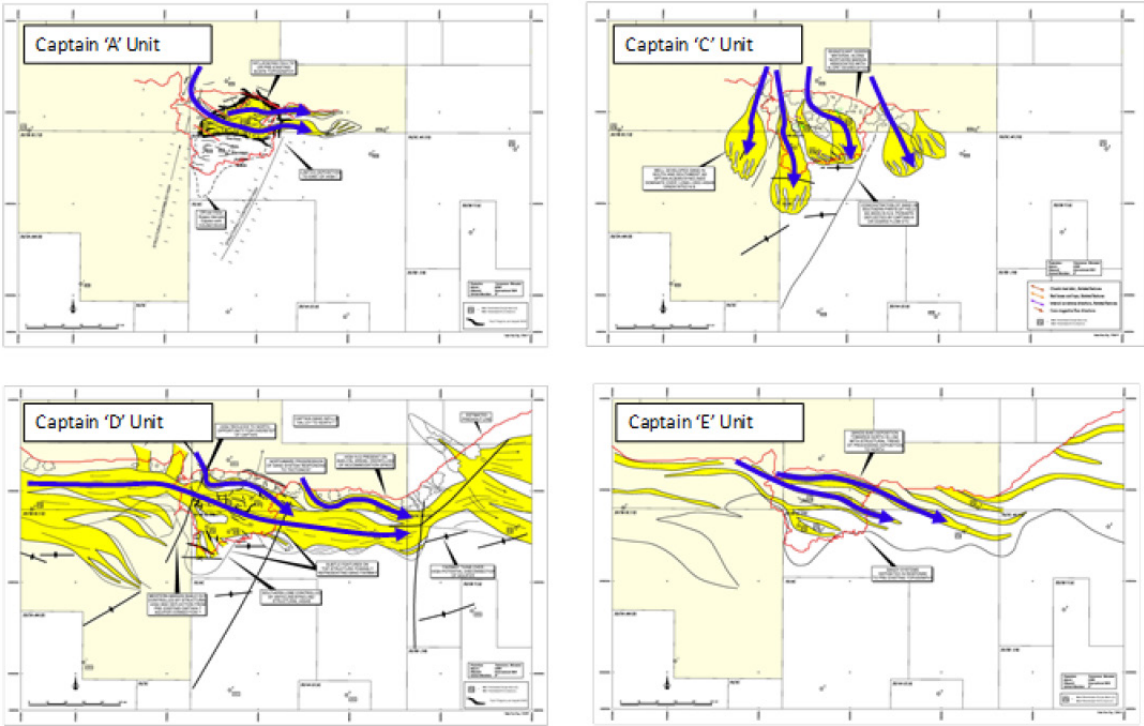


Figure 14.5: Depositional model for the Captain reservoir, A and C are more locally sourced, C sands are less extensively distributed than the overlying D & E units. D comprises amalgamated sandstones thought to have dominantly axial source. Blue arrows indicate predominant depositional directions [7].

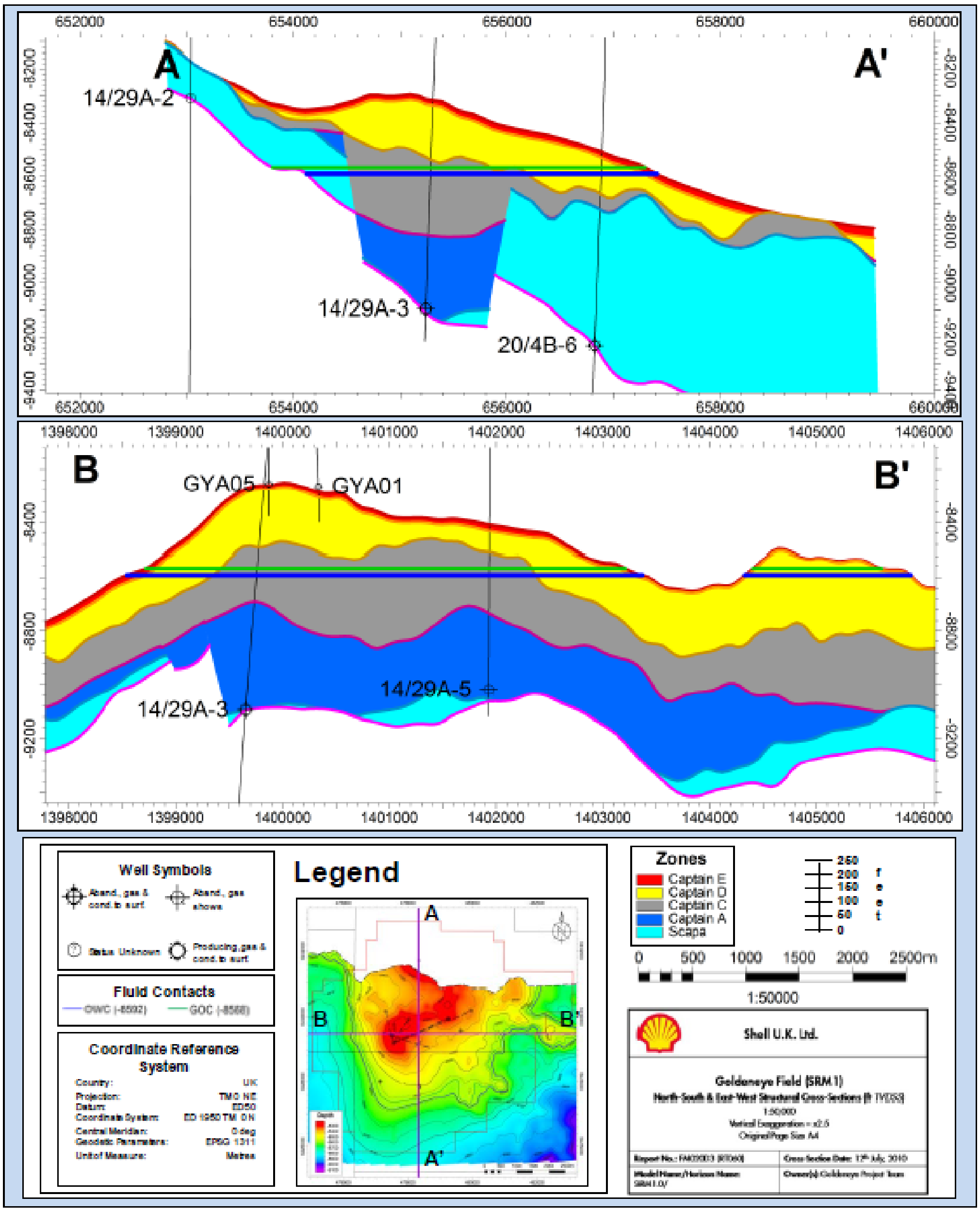


Figure 14.6: Representative structural cross-sections through Goldeneye field[7].

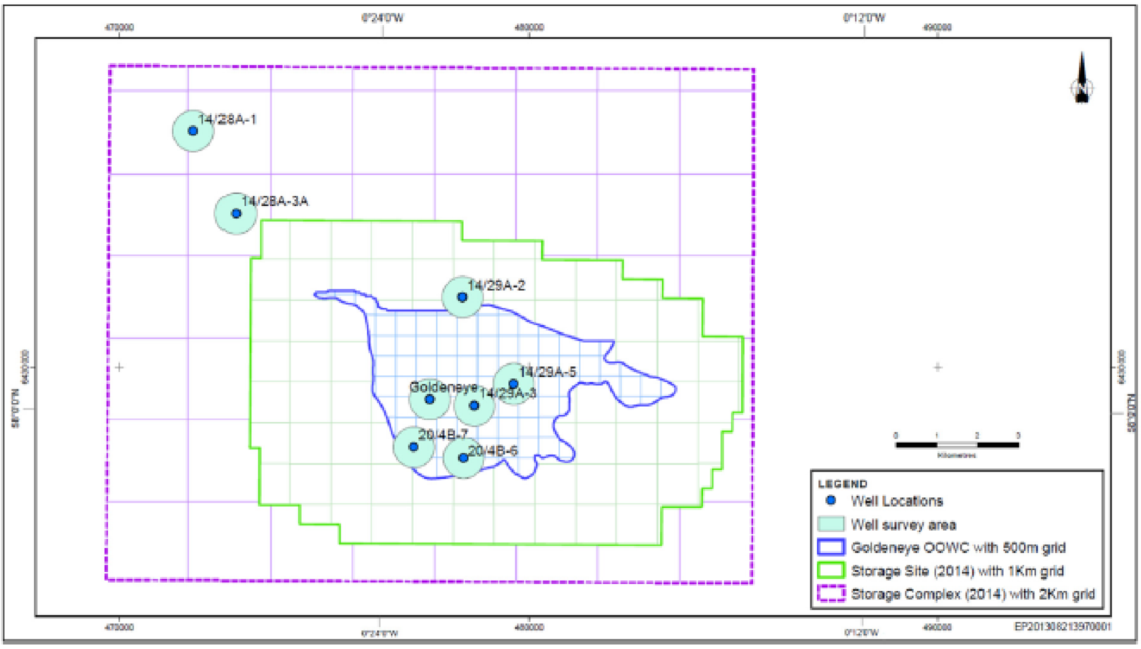


Figure 14.7: Geographic extent of the storage site, storage complex and OOWC. The planned environmental survey areas are indicated by the circles around the wells and the grids which are increasing in size away from the platform[3].

Domain	Data acquisition	Technology	Proposed in MMV Plan
Water column, seabed and shallow geosphere	Water column profiling near seabed	Geochemical probes	Yes
	Seabed sampling (seabed sediment, flora and fauna sampling)	Van Veen Grab	Yes
		Vibro Corer	No
		Core Penetrating Testing (CPT) rig fitted with a probe	No
		Hydrostatically sealed corer	No
	Pockmarks	Multi Beam Echo Sounder (MBES) and Side Scan Sonar (SSS)	Yes
	Subsidence and uplift	Global Positioning System (GPS)	Yes
	Shallow overburden seismic	Chirps/Pingers 2D lines/3D swath	No (but in contingency plan)
Deeper geosphere	Time-lapse seismic	3D streamer	Yes
		Ocean Bottom Node (OBN)	Yes
		3D swath/2D lines	No
		Geophone Vertical Seismic Profile (VSP)	No
		Distributed Acoustic Sensing (DAS) VSP on tubing	Yes (R&D)
	Microseismic	Geophone Microseismic	No
		DAS Microseismic	Yes (R&D)
	Passive seismic	Seabed geophones	Yes (baseline only)
Wells	Well integrity	Cement bond logging	Yes
		Casing integrity logging	Yes
		Tubing integrity logging	Yes
		Distributed Temperature Sensing (DTS) on tubing	Yes
		DAS on tubing	Yes (R&D)
	CO_2 Detection	U-tube	No
		Downhole sampling	Yes
	CO_2 Conformance	Sigma logging	Yes
		Neutron porosity logging	Yes
	Pressure conformance	Pressure Downhole Gauge	Yes
		Long term gauge	Yes
		Cased-hole pressure and temperature	Yes
	Fingerprint	Inert chemical tracer	Yes (R&D)

Table 14-1: Summary of monitoring technologies[3].

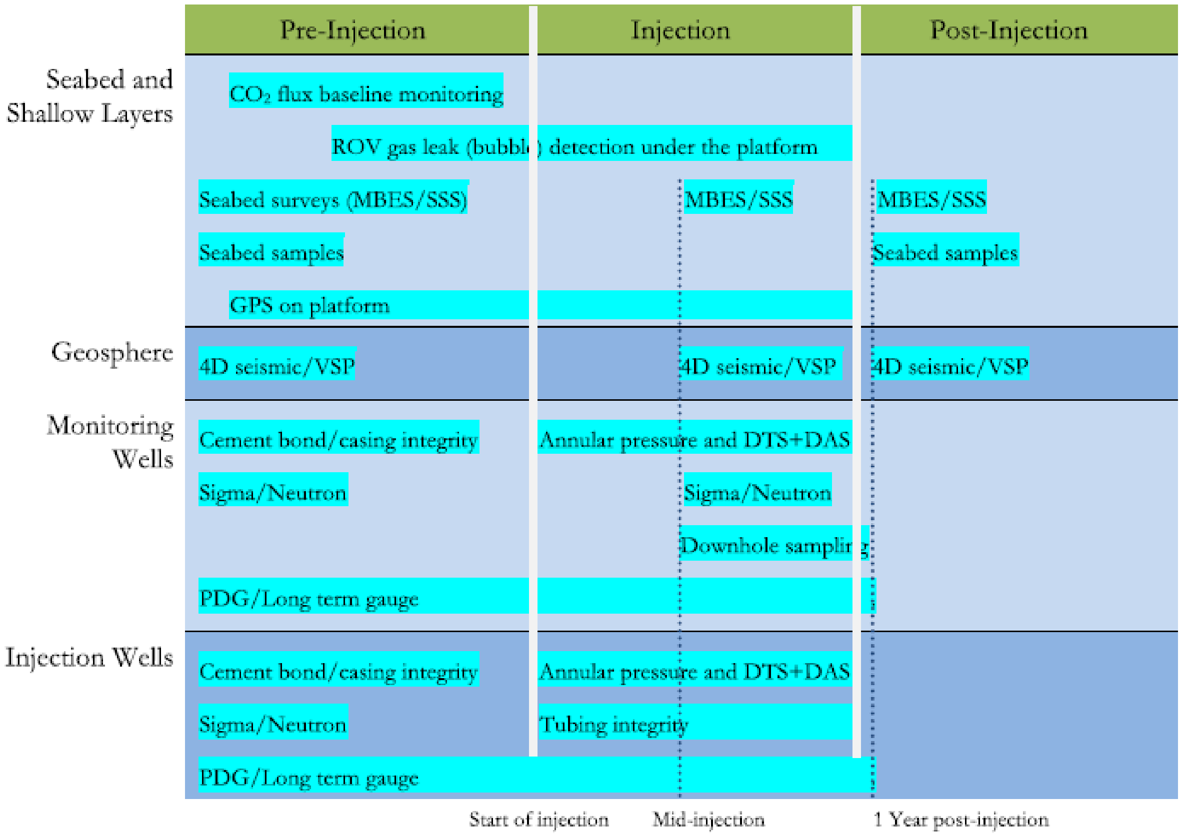


Figure 14.8: The base case monitoring plan for the Goldeneye storage complex provides comprehensive coverage within each domain and throughout the project lifecycle[3].

15. K12-B

Site Details					
Name	Location	Province/State	Country	Onshore	Offshore
K12-B	Dutch sector of the North Sea, 150 km north of Amsterdam.		The Netherlands		✓

General storage type

Depleted Gas Field

Development History (Closed)

From 2003 to 2017 the mature gas field K12-B was used as a CO_2 injection facility (Figure 15.1). K12-B produced natural gas since 1987, with relatively high CO_2 content (13%). Prior to 2004 this was vented and after this date it was re-injected into the gas reservoir, the Permian Upper Slochteren Member, of the Rotliegend Group. It's the first site in the world where CO_2 is being injected into the same reservoir as it originated. Injected above the gas water contact at 4,000 m depth[1] (Figure 15.2). Injection ceased in 2017 when the supply of CO_2 ended[1]. It was developed and operated by GDF SUEZ E&P Nederland B.V. and the current operator, since 2017, is Neptune Energy Netherlands B.V.

Geological Characteristics.

Reservoir Formation

Rotliegend sandstones of Permian age. Upper Rotliegend comprises Ten Boer Claystone, Upper Slochteren Member, Ameland Claystone and the Lower Slochteren Member (Figure 15.3). CO_2 injected into Upper Slochteren Reservoir found at 3,800 mbsl[2]. The reservoir is highly heterogenous due to a combination of sedimentary, diagenetic and tectonic processes.

Lateral extent / thickness variation	Aeolian facies (11 % rock volume) several meters thick and a few hundred meters wide. Fluvial sandstone (75 % rock volume) forms bulk of the reservoir[3]. Shale (16 % of rock volume), some are field-wide and some just a few hundred meters wide.
Rock type	Aeolian sandstone interfingered with fluvial and mud-flat facies (latter acts as a vertical permeability barriers). Aeolian facies produces 90% of the gas in the wells[1].

1 Vandeweijer, V., Hofstee, C., van Pelt, W. and Graven, H., 2021, March. CO_2 injection at K12-B, the final story. In Proceedings of the 15th Greenhouse Gas Control Technologies Conference (pp. 15-18).
2 Van der Meer, L., 2013. The K12-B CO_2 injection project in the Netherlands. Geological Storage of Carbon Dioxide (CO_2), pp.301-327.
3 Geel, C.R. (2006) Geological Site Characterisation of the Nearly Depleted K12-B gas field, offshore The Netherlands. Presentation https://web.archive.org/web/20071009090534/http://www.k12-b.nl/

Sedimentary features: Depositional Environment / facies type & variation / mineral composition	Clastics of the Rotliegend Group were deposited around the Southern Permian Basin's southern margin, under desert and desert-lake conditions as a number of alluvial fans. Grading northward into sands, shales and further north to evaporites[1] (Figure 15.3).
Porosity	Sandstones generally have porosities of 13%[2].
Permeability	Aeolian – high permeability (300-500 mD)[1] Fluvial – low permeable (5-30 mD)[1]
Formation fluid properties: (residual hydrocarbons / salinity concentration).	n/a
Caprock / primary seal formation	
Late Permian Zechstein evaporites, and fault bounded Zechstein[1]	
Lateral extent / thickness variation	500 m thick overlying salt and 600 m thick adjacent salt in bounding fault[1].
Rock type	Salt. (Four sequences of evaporites)
Fracture pressure	n/a
Porosity	Low
Permeability	Low
Overburden Features (Thickness, formations presence of secondary reservoirs / seals)	
No presence of a potable aquifer.	
Structure K12-B field comprised several tilted fault blocks (Figure 15.1), which are not or barely in pressure communication with one another[1].	
Fold type / fault bounded	Fault bounded blocks. K12-B comprises 4 compartments (Figure 15.1 and Figure 15.2), bound to the east by a large N-S trending fault and to the west by the deepest closing contour[1].
Faults /Fractures (Type – normal, reverse, strike-slip)	Normal, expected to be sealing. None of the faults reach the top of the seal. Most faults completely cemented (sealing)[1,3].
Displacement	Modest throws (10-100 m)[3].
Stability (pre-stressed, active, stable)	Stable.
Injection / storage history	
Number of injection, monitoring or other wells, well geometry, design and key completion information for injection wells, relevant well issues. Reused / new purpose drilled well.	

1st discovery well K12-6 drilled in 1981[2]. 8 production wells (Figure 15.1). 2004-2005 CO_2 injected into compartment 4 via K12-B8, to test the injection facility and examine the CO_2 phase behaviour and the reservoir response. From Feb 2005 injection into compartment 3 via K12-B6. Wells K12-B1, K12-B3st and K12-B5 kept producing gas. Lasted until 2017. Objectives to examine CO_2 phase behaviour, the reservoir response, assess potential for Enhanced Gas Recovery and the degree of corrosion along tubing of K12-B6 injection well[1]. Well monitoring work was hindered by the fact that the old gas production well, with a history of problems, was used as an injector.	
Extent and status of casing (corrosion history/ cementation records)	B12-B6: after some years of CO_2 injection changes in tubing thickness appeared larger than expected at certain depth intervals[1]. Several tubing integrity surveys have been performed in time lapse mode to image and monitor the inner tubing of CO_2 injection well K12-B6 during prolonged exposure to CO_2 [1].
Injection rates & pattern (i.e. continuous / intermittent) changes in injection behaviour	n/a
Total quantities stored	>100,000 tonnes of CO_2.
Reservoir capacity (estimate)	n/a
Fluid extraction rate (brine extraction, oil for EOR)	n/a
Seismicity	
Monitoring regime (technologies deployed)	
n/a	
Seismic events (Detection / magnitude / attribution (natural induced).	
n/a	
Monitoring technologies applied and experiences with monitoring; Seal is top class seal, so most of the risk of leakage comes through well integrity. Monitoring was focussed on well integrity and how the CO_2 behaves in the well and reservoir[4] (Table 15-2). Particularly for assessing potential for enhanced gas potential (EGR).	
Surface monitoring technologies deployed	
n/a	
Subsurface monitoring technologies deployed (well logs)	

4 Vandeweijer, V., van der Meer, B., Hofstee, C., Mulders, F., D'Hoore, D. and Graven, H., 2011. Monitoring the CO_2 injection site: K12-B. Energy Procedia, 4, pp.5471-5478.

Activity	Period
Pressure and Temperature Gradient Profiling	2004, 2005, 2007
Pressure Fall-Off Measurements	2004, 2005, 2007
Injection Gas Analysis	2004, 2005, 2007
Production Logging	2005, 2007 (Failed partially)
Production Gas Analysis	From 2005 onwards
Production Water Analyses	2005, 2007
Injection chemical Tracers	From 2005 and 2016
Detection chemical Tracers	From 2005 onwards
Multi Finger Imaging Tool	2005, 2006, 2007, 2009
Cement Bond Log	2007 (Failed)
Down Hole Video Log	2007
Electromagnetic Imaging Tool	2009
Downhole water sample from injection well	2007

Table 15-1: Overview of applied monitoring tools and techniques[1].

Main category	Type of measurement	Purpose of measurement	Results
Well integrity	Multi-finger caliper	Assessment of the tubing integrity	The tubing has been found in good condition, but scaling is likely to disturb the accuracy of the measurements.
	Cement bond log	Cement bond quality	Failed due to (at that time) unknown obstruction.
	Down-hole video	Image tubing and obstruction	Tubing and obstruction successfully visually inspected.
Reservoir characterization and EGR	Wellhead measurements	Input data for the reservoir simulation	All available data have been gathered and used in the reservoir simulations.
	Composition of production gas	Validation and tuning of the reservoir model	All available data have been gathered and used to validate the reservoir simulations.
	Composition of injected gas	Input data for the reservoir simulation, and possibly well integrity research	All available data have been gathered and used in the reservoir simulations.
	Composition of production water	Input data for future chemical modelling and well integrity research	Moderately successful. New samples need to be gathered in a different way.
	MPLT	Establish a flowing profile of the productive formation	Partial success, measurements for the K12-B8 failed, but measurements for the K12-B1 and B5 were successful.
	Down-hole pressure and temperature profiling	Validate and create PVT tables for coming reservoir studies	The data have been used to validate the lift tables and for the history match.
	Chemical tracer analysis	Validation and tuning of the reservoir model	All available data have been gathered and used to validate reservoir simulations.

MPLT, memory production log; PVT, pressure–volume–temperature.

Table 15-2: Overview of monitoring activities[2,4].

Pressure maintenance	To avoid early CO_2 breakthrough.
Continuous monitoring and reservoir simulation program	Several reservoir models (Simed, Eclipse, Though and others) applied to investigate and predict the

	fate and transport of CO_2 in the reservoir[1]. The reservoir models have been updated and fine tuned over the years using additional measurements e.g. down hole pressure and temperature, gas analysis and production water analysis, tracer analysis etc[4].
Electromagnetic imaging tool (EMIT)	Suited to imaging the pipe integrity through layers of scaling. Detects pipe integrity. Used on K12-B6, showed consistent pipe integrity over measured interval[4].
Production and gas analysis	Samples taken from the production gas stream at regular intervals. Well K12-B5 showed consistent gas composition (13% CO_2), well K12-B1 in the same compartment shows a steady increase from 15% in 2005 to over 25% in 2010. Possibly due to reservoir heterogeneity[4].
Gamma Ray tool	Run to provide data on the radiation intensity of the material inside and nearby the well – insight into mineral composition of the scaling.
Chemical tracers	Tracers were injected (well K12-B6) to investigate the migration of CO_2, the partitioning behaviour of the CO_2 and CH_4, the associated sweep efficiency and indirectly the EGR potential of the reservoir[3]. Regular sampling at K12-B1 and -B5 show tracer breakthrough at 130 days and 463 days respectively, the timing of the concentration of CO_2 differed significantly (lagged) from the tracer breakthrough. Potentially due to the higher solubility of CO_2[4].
Scale samples	Found barite precipitated between 0-3575 m[4].
Dynamic flow modelling	Verified: the permeability of the reservoir is not affected by the injection of CO_2, and reservoir response and CO_2 phase behaviour can be predicted fairly well with the aid of existing theoretical correlations and software applications. The observed CO_2 phase behaviour and reservoir behaviour fell within expected range[4].
Experience summary - effectiveness of techniques (limitations / strengths)	
Learned that conventional oil field reservoir simulation can be used to research and test certain unforeseen operational conditions, such as well problems, material balance problems and quality control on measured and observed data[2].	
List of key publications covering the site	

1. Vandeweijer, V., Hofstee, C., van Pelt, W. and Graven, H., 2021, March. CO_2 injection at K12-B, the final story. In Proceedings of the 15th Greenhouse Gas Control Technologies Conference (pp. 15-18).
2. Van der Meer, L., 2013. The K12-B CO_2 injection project in the Netherlands. Geological Storage of Carbon Dioxide (CO_2), pp.301-327.
3. Geel, C.R. (2006) Geological Site Characterisation of the Nearly Depleted K12-B gas field, offshore The Netherlands. Presentation https://web.archive.org/web/20071009090534/http://www.k12-b.nl/
4. Vandeweijer, V., van der Meer, B., Hofstee, C., Mulders, F., D'Hoore, D. and Graven, H., 2011. Monitoring the CO_2 injection site: K12-B. Energy Procedia, 4, pp.5471-5478.

Other relevant information considered pertinent to the report

Vandeweijer, V., Hofstee, C. and Graven, H., 2018, November. 13 years of safe CO2 injection at K12-B. In Fifth CO_2 Geological Storage Workshop (Vol. 2018, No. 1, pp. 1-5). European Association of Geoscientists & Engineers.

Van der Meer, L., 2013. The K12-B CO_2 injection project in the Netherlands. Geological Storage of Carbon Dioxide (CO_2), pp.301-327.

Van der Meer, L.G.H., Kreft, E., Geel, C.R., D'Hoore, D. and Hartman, J., 2006, June. CO_2 storage and testing enhanced gas recovery in the K12-B reservoir. In 23rd world gas conference, Amsterdam.

Figures

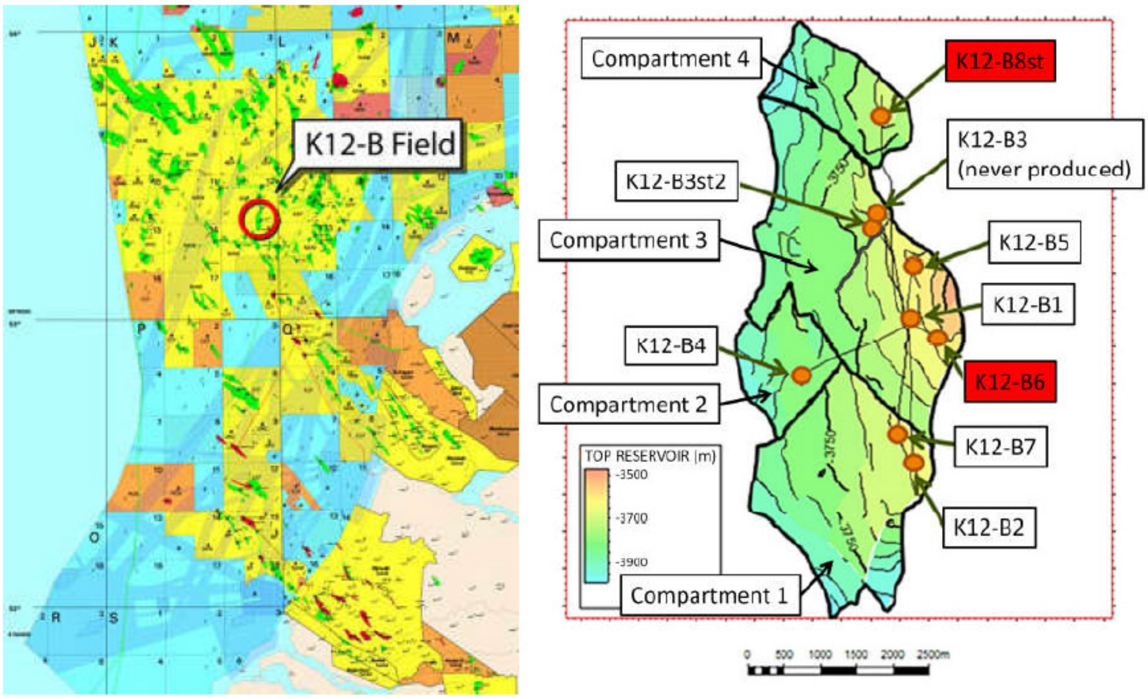


Figure 15.1: Location and overview of relevant wells and compartments of the K12-B gas field. CO_2 injection wells are highlighted red[1].

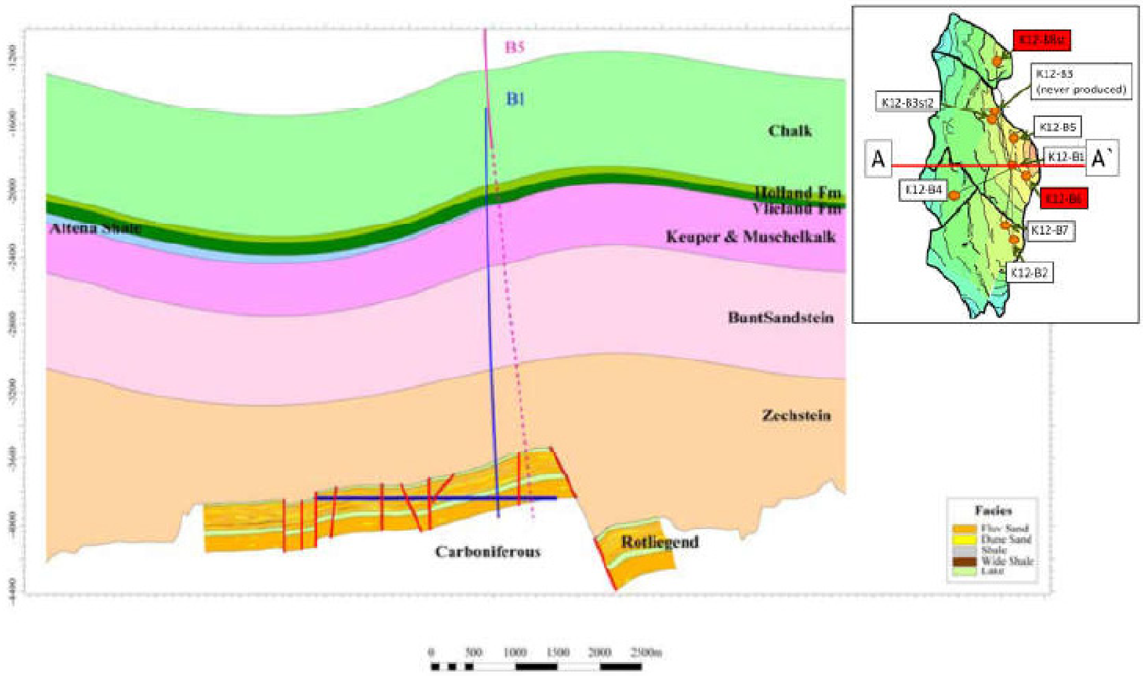


Figure 15.2: E-W cross-section through the summit of K12-B reservoir showing structural features, facies model, Rotliegend reservoir and overburden stratigraphy (Tertiary omitted) [1]. Original gas water contact is shown by a blue line.

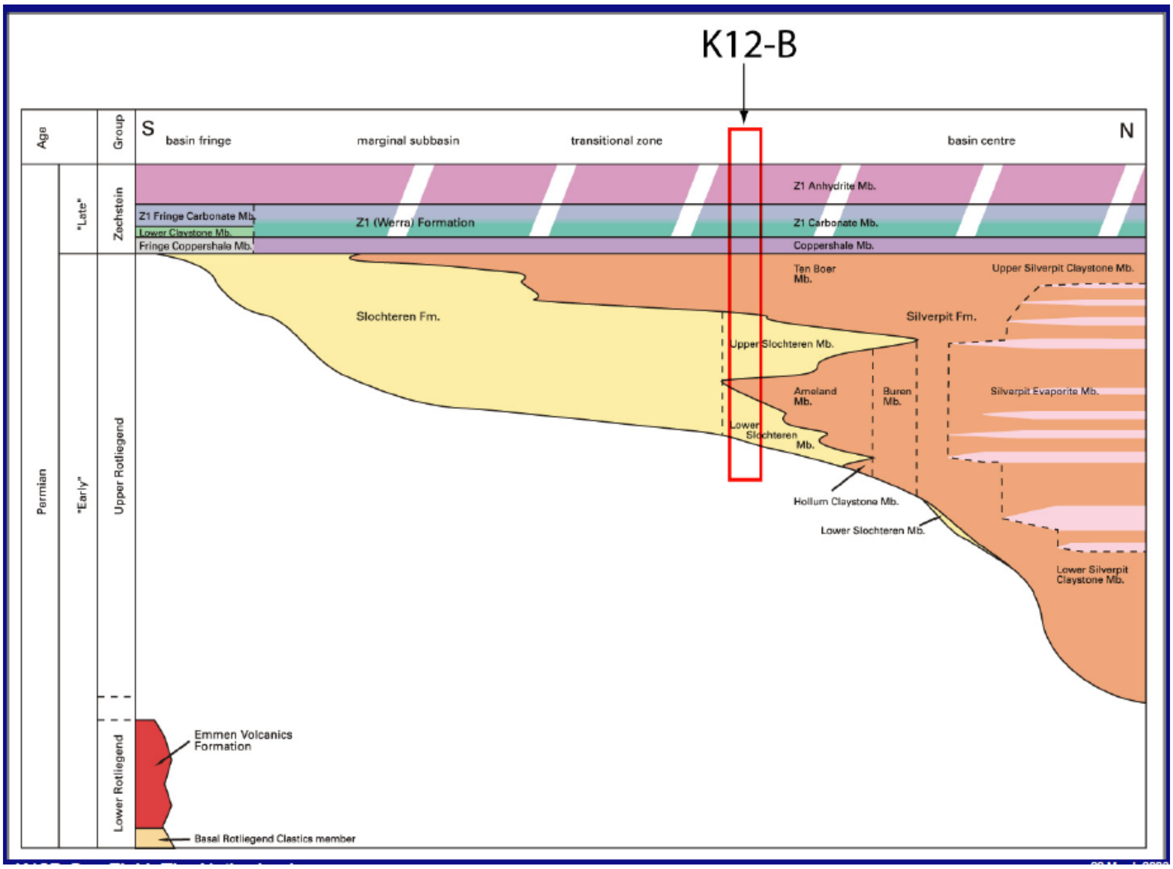


Figure 15.3: Stratigraphic chart of Rotliegend and Zechstein[3].

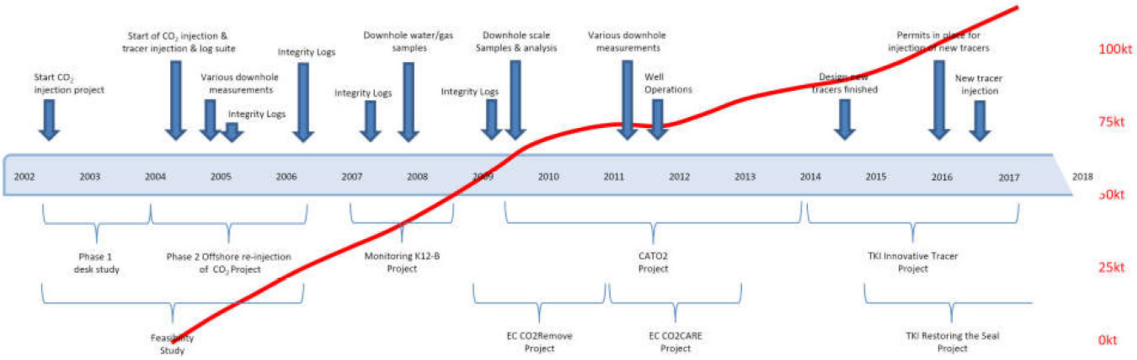


Figure 15.4: Timeline depicting the multiple CO_2 injection related projects which took place at K12-B. In red the amount of CO_2 injected over the years [1].

16. Ketzin

Site Details

Name	Location	Province/State	Country	Onshore	Offshore
Ketzin	North East German Basin	Brandenburg	Germany	✓	

General storage type

Saline aquifer at depth of 650 m in Upper Triassic Stuttgart Formation sandstones[1].

Development History (Closed)

The Ketzin site was the first European on-shore CO_2 storage project (CO_2SINK), which included two operational phases of its 5-year CO_2 injection (2008-2013) and post-injection (Figure 16.1). Located in the Ketzin-Roskow anticlinal structure of the North Eastern German Basin (NEGB), this structure has been used for gas storage in the past at shallower depth intervals (Figure 16.2)[2].

The research and development consortium the GFZ German Research Centre for Geosciences operates Ketzin and comprises 15 partners from academia and industry of 8 European countries.

Pure CO_2 from flue gas of hydrocarbon production at an oil refinery[3]. It is delivered by trucks in a cooled, liquefied state and gasified at the injection facility and heated to formation temperatures[4].

The first CO_2 storage site to be abandoned, a two-stage abandonment strategy has been negotiated and agreed[1].

Geological Characteristics.

Reservoir Formation

The reservoir is located within the Middle Keuper (Upper Triassic) section, in the Stuttgart Formation (SF) with injection at depths 625-700 m (Figure 16.3, Figure 16.4)[2].

Lateral extent / thickness variation	The lateral extent of the channel belts is highly variable, basin wide the Stuttgart Formation (SF) is on average only 20-100 m thick. At Ketzin the SF is 71-74 m thick, with maximum channel sand thicknesses of 4-10 m[2].

1 Schmidt-Hattenberger, C., Jurczyk, A., Liebscher, A., Möller, F., Norden, B., Prevedel, B., Wiese, B., Zemke, K. and Zimmer, M., 2018, October. Post-injection monitoring and well abandonment results of the Ketzin test site–an essential part for transfer of liability. In 14th Greenhouse Gas Control Technologies Conference Melbourne (pp. 21-26).
2 Norden, B. and Frykman, P., 2013. Geological modelling of the Triassic Stuttgart Formation at the Ketzin CO_2 storage site, Germany. International Journal of Greenhouse Gas Control, 19, pp.756-774.
3 Forster, A., Norden, B., Zinck-Jørgensen, K., Frykman, P., Kulenkampff, J., Spangenberg, E., Erzinger, J., Zimmer, M., Kopp, J., Borm, G. and Juhlin, C., 2006. Baseline characterization of the CO2SINK geological storage site at Ketzin, Germany. Environmental Geosciences, 13(3), pp.145-161.
4 Schilling, F., Borm, G., Würdemann, H., Möller, F., Kühn, M. and CO_2 sink group, 2009. Status report on the first European on-shore CO_2 storage site at Ketzin (Germany). Energy Procedia, 1(1), pp.2029-2035.

Rock type	Homogenous immature sandstones and muds. The sandstones are dominantly fine-grained and well to moderately sorted, feldspathic litharenites and lithic arkoses. Anhydrite is present as pore-filling cement in some sandstone intervals. Thin coaly horizons are interbedded with fine-grained overbank sediments. In the three boreholes at Ketzin the net-to-gross ratio is ~0.26-0.35[2].
Sedimentary features: Depositional Environment / facies type & variation / mineral composition	The SF consists of flood plain siltstones and mudstones with embedded channel sandstones, potentially derived from northern and eastern Europe and deposited during a lowstand in a humid climatic period[2]. The SF at Ketzin is located in a channel belt fairway, with a variety of stacking patterns owing to lateral changes in fluvial environments, likely a meandering or braided stream[2].
Porosity	Range from 5 to >35% (Figure 16.5)[2]. Average porosity is 23%[3].
Permeability	Range from 0.02 to >5,000 mD[2]. Hydraulic tests indicate permeabilities between 50 and 100 mD[2].
Formation fluid properties: (residual hydrocarbons / salinity concentration)	n/a
Caprock / primary seal formation	
The Stuttgart Formation is overlain by the ~210 m thick Weser and Arnstast Formations, which acts as the immediate caprock of the reservoir (Figure 16.3)[2].	
Lateral extent / thickness variation	A 10-20 m thick anhydrite/gypsum layer is identified at the top of the Weser Formation[2]. The playa-type succession is of basin-wide uniformity[3].
Rock type	Playa-lake couplets of mudstone and dolomite beds, stacked in groups of two to seven, forming up to several meter-thick bundles that are regionally traceable[3]. Flood-bank mudstone with anhydritic lenses[2].
Fracture pressure	n/a

Porosity	Average porosity of 17% is observed from petrophysical studies on core[3].
Permeability	Range of 0.1 -10 mD (average 0.1 mD)[3].
Overburden Features (Thickness, formations presence of secondary reservoirs / seals) At Ketzin the sedimentary succession is around 4,000 m. The middle Keuper sediments comprise the Grabfeld Formation, Stuttgart Formation, the Weser, Arnstadt and Exter Formation sandstones [3]. Transgressive sediments of Oligocene age rest above Lower Jurassic sediments and are unaffected by anticlinal uplift. The Tertiary deposits are overlain by unconsolidated Quaternary sediments (Figure 16.3)[2]. Jurassic (Sinemurian/Hettangian) reservoir sands (at depths of 250-400 m) were used as a storage facility for coal gas and natural gas for about 30 years with a cap rock of Tertiary clay (the Rupielton)[2, 3].	
Presence of a potable aquifer. The sandstones of the Exter Formation (Figure 16.3) comprise the first major aquifer above the Stuttgart Formation, and the sandstone layers of the Jurassic comprise a second major aquifer system[3]. The Tertiary clay – the Rupelton – acts as a major aquitard, separating the saline brines from the non-saline groundwater in the shallow Quaternary aquifers (~30 m thick)[3].	
Structure In the Roskow-Ketzin area, diapirism of Permian (Zechstein) salt has caused deformation of Triassic and Lower Jurassic formations generating a gently dipping (15°), ENE-WSW striking double anticline (Figure 16.2, Figure 16.6)[2]. 3D seismic data are used to constrain the structural model.	
Fold type / fault bounded	n/a
Faults /Fractures (Type – normal, reverse, strike-slip)	A WSW-ENE trending fault zone (the Central Graben Fault Zone, CGFZ) is located at the top of the anticline structure and about 1.5 km north of the CO_2 injection site (Figure 16.7). It comprises a series of discrete normal faults, well developed in the Triassic and Jurassic section, but die out quickly in the Tertiary Rupelian Clay[2]. A number of faint SE- to SSE- striking lineaments on the Top Weser indicate small-scale faults – although not present in the vicinity of the injection site[2].
Displacement	The main bounding faults have throws of up to 30 m in the Jurassic section, the small scale faults ~1.5-3.0 m[2].
Stability (pre-stressed, active, stable)	n/a
Injection / storage history	
Number of injection, monitoring or other wells, well geometry, design and key completion information for injection wells, relevant well issues. Reused / new purpose drilled well.	

One injection well and two monitoring wells drilled about 50-100 m apart (Figure 16.1)[3]. • Ktzi 201/2007 serves as a combined injection and observation well[5]. • Ktzi 200/2007 & Ktzi 202/2007 are used as observation wells[5]. • Ktzi P300/2011 was drilled to a depth of 446 m to the first aquifer above the Stuttgart Formation and serves as a sallow above-zone monitoring observation well[5]. A U-tube system is installed in well P300 for sampling of formation water and gas at 417 m to detect any leakage through the first caprock of the storage horizon at the earliest stage possible [5]. • Ktzi 203/2012 a new observation well to a depth of ~700 m, will be equipped with permanent pressure and temperature monitoring and sample rock core from the reservoir that has been exposed to CO_2 for four years[5]. In 2013 the reservoir and caprock section of well Ktzi 202 were plugged with CO_2 resistant 'EverCRETE' cement. A gas-membrane-and-pressure-sensor system monitored this cement plug for its gas tightness over two years. No gas increase or pressure changes have been detected[1]. The uppermost 3 m of the cement plug were cored in summer 2015 and their petrophysical properties analysed, after proving the integrity of this cement plug, well Ktzi 202 was abandoned by cutting the casings at their respective cement heads and backfilling the remaining part of the well with standard class G cement[1]. This two-cement approach was then applied to the remaining three deep wells Ktzi 200, Ktzi 201 and Ktzi 203 (Figure 16.8). The final abandonment of these wells took place in 2017[1]. The completion of Ktzi 203 with glass-fibre reinforced piped allowed for side-track drilling. Two side-tracks covering the lower part of the cap rock and also the entire reservoir section have been drilled and cored prior to cementation[1].	
Extent and status of casing (corrosion history/ cementation records)	n/a
Injection rates & pattern (i.e. continuous / intermittent) changes in injection behaviour	Figure 16.9 for injection rate[5].
Total quantities stored	67,000 t CO_2 injected between July 2008 and August 2013[1].
Reservoir capacity (estimate)	n/a
Fluid extraction rate (brine extraction, oil for EOR)	n/a
Seismicity	
Monitoring regime (technologies deployed)	

5 Martens, S., Liebscher, A., Möller, F., Henninges, J., Kempka, T., Lüth, S., Norden, B., Prevedel, B., Szizybalski, A., Zimmer, M. and Kühn, M., 2013. CO2 storage at the Ketzin pilot site, Germany: fourth year of injection, monitoring, modelling and verification. Energy Procedia, 37, pp.6434-6443.

2009 – fixed 2D seismic array of 120 m length installed, of receivers placed at 13 locations. At each location, a three-component geophone and a hydrophone was placed at 50 m depth. Additional geophones deployed at the surface at selected locations[6]. Active and passive seismic data acquired. Passive data for induced seismicity. For discussion of technologies see[6].	
Seismic events (Detection / magnitude / attribution (natural induced).	
n/a.	
Monitoring technologies applied and experiences with monitoring;	
Surface monitoring technologies deployed	
3D Seismic (4D time lapse)	2005 – 15 km^2 used to develop a structural model[2]. 2009 – first repeat covering 7 km^2, after 22-24,000 tonnes CO_2[5]. Estimated that 93-95% of the stored CO_2 was imaged by the survey[5]. Amplitude changes concentrated at the injection well, 5-20 m thick and extent of 300-400 m in the W-E direction[6]. 2012 – second repeat after 61,000 tonnes CO_2[5]. Similar but larger amplitude signature by ~150 m in the N-S direction and ~200 m in the W-E direction, maximum vertical thickness of 10-30 m[6]. See Figure 16.10 for comparison of the amplitude signatures between the surveys, showing a preferential propagation direction of the stored CO_2 towards the northwest[5]. The seismic data sets underwent a time-lapse cross-equalisation workflow using Hampson Russel's Pro4D software[7].
2D Seismic	2005 – baseline survey. 2009 – after 22,000 tonnes CO_2 including AVO. 2011 – after 45,000 tonnes CO_2[6].

6 Bergmann, P., Diersch, M., Goetz, J., Ivandic, M., Ivanova, A., Juhlin, C., Kummerow, J., Liebscher, A., Lueth, S., Meekes, S. and Norden, B., 2016. Review on geophysical monitoring of CO_2 injection at Ketzin, Germany. Journal of Petroleum Science and Engineering, 139, pp.112-136.

7 Lüth, S., Ivanova, A. and Kempka, T., 2015. Conformity assessment of monitoring and simulation of CO2 storage: A case study from the Ketzin pilot site. International Journal of Greenhouse Gas Control, 42, pp.329-339.

	2D lines in a star shaped acquisition geometry. Results are similar to the 4D seismic with a preferred migration pattern to the west, interpreted as a heterogeneous permeability distribution within the Stuttgart Formation[6].
Groundwater sampling	Two wells at 35 m and 55 m depth sampled as baseline[3]. pH, electrical conductivity and dissolved CO_2 measured since January 2005 [3].
Soil gas sampling	20 soil gas sampling locations at 0.6 m depth at the centre of the anticline, with surface CO_2 measurements conducted every month[3]. Measuring soil gas flux, soil moisture and temperature measurements across an area of 2 km x 2 km[5]. In 2011, this network was expanded with the installation of eight permanent stations with automated soil gas samples in the direct vicinity of the injection and observation wells.
Subsurface monitoring technologies deployed (well logs)	
Vertical Seismic Profiling (VSP)	Applied at shorter time intervals in order to image CO_2 migration during injection[4]. VSP – performed in close temporal succession to the 2D seismic surveys. Baseline in 2007 with zero-offset VSP and offset-VSP geometries. Offset-VSP comprise recordings of two source points at centres and far ends of 2D seismic[6]. Repeat survey 2011 after 45,000 tonnes CO_2 • VIBSIST-1,000/3,000. • Data acquisition in Ktzi202 at 80 depth levels (325-720 m). Correlation of VSP and 3D seismic surveys was possible with more structural detail possible with zero-offset VSP.
Moving Source Profiling (MSP)	
Cross-hole seismic tomography	Cross-hole seismic – baseline (2008), then after 700 tonnes CO_2, 1,800 tonnes CO_2, and 18,000 t CO_2[6]. Performed to track CO_2 migration between observation wells Ktzi200 and Ktzi202.

	• VIBSIST SPH 64 source at 261 depth levels in Ktzi200 (452-740 m). • 12 hydrophones in Ktzi202 with 1 m vertical spacing with hydrophone chain changed to result in max 48 receivers per source point recorded. • Lubricator needed to access Ktzi200 after arrival of CO_2. Note enough time had elapsed to fully monitor the migration of CO_2 to well Ktzi202, however time-lapse signatures were observed near Ktzi200[6].
Electrical Resistivity Tomography	Cross-hole ERT – Daily (until 2009), twice per week (2011), weekly (2012)[6]. Performed using permanently installed vertical electrical resistivity array (VERA), consisting of 45 electrodes (Figure 16.11). Stainless steel rings, mounted with 10m spacing on electrically insulated sections of borehole casings of Ktzi200, 201 and 202[6]. Covers depth range of 590-740 m. Electrical current of 2.5 A is injected between two electrodes. Time-lapse sequence of inverted resistivity shows increase in resistivity and spatial expansion into the storage horizon as injection progressed. Shows a detailed view of migration behaviour[6]. Surface-downhole ERT – two baseline surveys (2077 & 2008) and repeat surveys at 600 k CO_2, 4,500 tonnes CO_2, 13,500 tonnes CO_2, 48,000 tonnes CO_2, and 60,000 tonnes CO_2[6]. Injection of DC electric currents at the surface and measurement of potential difference using VERA electrodes. Current injections using 16 dipoles in a concentric pattern around the injection well. From the second repeat survey inverted resistivity models display an increase in resistivity around the CO_2 injector. Estimates on CO_2 saturations are consistent with PNG logging, although vertical resolution is more refined with PNG. Inverted resistivity models show a dominantly sub-horizontal CO_2 migration predominantly towards the NW, in reasonable agreement with the seismic data [6].

	Surface-to-surface ERT.
Seismic full-waveform inversion	Applied to both surface-seismic data and cross-hole seismic data[6]. Velocity anomalies are observed at the reservoir depth level and agree with conventional time-lapse 2D and 3D data sets[6].
Fluid sampling	AZMI sampling in monitoring well P300, water samples analysed for their dissolved cations, anions, gases and $^{12}C/^{13}C$ isotope ratio of CO_2 have revealed no impact of the injected CO_2 on the Exter Fm[5]. The microbial community of fluid samples was investigated using PCR-SSCP method (Single-Strand-Conformation Polymorphism and FISH (Fluorescent In Situ Hybridisation).
Pressure-temperature monitoring	Ktzi 201, downhole pressure is continuously monitored via an optical pressure-temperature gauge (Figure 16.9)[5]. Data show positive correlation between injection rate and reservoir pressure, and pressure is well within limit for the project[5].
Pulsed neutron-gamma logging (PNG)	See Figure 16.12 for PNG over the life-cycle of the project[1]. During PNG logging the macroscopic thermal capture cross section SIGMA is determined. The data of repeat 4 shows a continued development towards CO_2 saturations in the lower injection intervals – observed at Ktzi 201 since 2010 due to decreased injection rate (Figure 16.13)[5]. At Ktzi 202 observation well, a small but continuous decrease of SIGMA in the upper part of the sandstone layer at approximately 630 m depth indicates increasing CO_2 saturation within this interval[5].
Distributed Temperature Sensing	Temperature distribution along wells is continuously monitored using permanently installed fibre-optic DTS cables and 45 Electrodes (ERT array) [4,5].
Gas monitoring – Gas Membrane Sensor (GMS)	Performed with a riser tube installed in observation well Ktzi 202 since autumn 2011, fluids are produced from 600 m depth and continuously analysed with a mass spectrometer[5]. The gas composition dominated by CO_2 (>99 vol%) with traces of

	N_2, H_2, He, and CH_4, as well as the $\delta^{13}C$-values of CO_2 were constant during the monitoring period[5].
Gas composition and stable isotopes	Two side tracks drilled into Ktzi203 in 2017 to test the CO_2 gas content in pore spaces and formation fluids of the cap rock, the transition zone and the reservoir to characterise the isotopic composition and to trace the migration and spatial fate of CO_2 in the subsurface[8]. Results compared with similar study in 2012. Drill mud gas phase analysed for H_2, He, CO_2, Ar, N_2, O_2, CH_4. $^{12}C_{CO2}/^{13}C_{CO2}$ isotopic ratios sampled in mud gas phase at one minute intervals. Core gas analysis of $^{13}C/^{12}C$ of the CO_2. Samples from muddy cap rock show CO_2 concentrations of ~500 ppmV, and up to ~12,000 ppmV at the lithological transition to the reservoir sandstone and then to ~1,000 ppmV in a muddy silty layer with lower porosity. Core and mud gas samples from the cap rock show isotope values ranging from -25 to -35 and -10 to -20%, in the reservoir were -45% in the core gas and -28% in the mud gas phase[8]. The 2017 and 2012 results showed the same trends. The cap rock fluids cover range of typical Triassic formation fluids and give no indication of infiltration of injected CO_2, whereas the reservoir samples indicate the presence of injected CO_2[8].
Magneto-induction defectoscopy (MID)	[1]
Video inspection (post injection)	[1]

8 Zimmer, M., Szizybalski, A., Norden, B., Vieth-Hillebrand, A. and Liebscher, A., 2018. Monitoring of the gas composition and stable carbon isotopes during side track drilling in Ktzi 203 at the Ketzin CO 2 storage pilot site, Germany. Advances in Geosciences, 45, pp.7-11.

Experience summary - effectiveness of techniques (limitations / strengths)
CO_2 mass estimated from the 4D seismic data show 93-95% of actual mass of CO_2, with shortfall of 5-7% assumed to be due to CO_2 dissolution into the brine and limitation of the vertical resolution of the seismic data. This shortfall increased to ~15% by the second repeat survey[6]. 4D seismic proved to be the most important geophysical monitoring method employed and provided a reference for the other methods. However, due to spacing of surveys they missed the dynamic CO_2 plume development in the initial period of injection. Access issues restricted 2D layout and this also restricted imaging of early plume[6]. 2D and 3D surveys should use same source and acquisition equipment. ERT has permanent installation and thus facilitates largely unsupervised data acquisition, and measurements at high rates, whereas seismic cross-hole measurements required considerable operational efforts. Recent developments in permanent downhole source instrumentation may make it feasible to perform higher repetition rates in the future[6]. ERT demonstrated that azimuthal information on the preferential CO_2 migration direction in addition to investigation planes was possible[6]. Side-core drilling provided the opportunity to analyse gas samples from a depth interval in constant contact with injected CO_2 for more than nine years and to compare with data collected five years earlier[8]. The integrity of the results showed that the caprock and borehole cementation in the immediate vicinity of Ktzi 203 were robust[8].
Major technical/scientific studies on the site, major learnings, Conformance assessment (history-matching with models, correlation between different monitoring techniques) Soil gas baseline show all measured CO_2 fluxes are in the range of normal soil-degassing rates[3]. Since the start of injection no change in soil CO_2 gas flux could be detected in comparison to the pre-injection baseline from 2005 to 2007[5]. A northerly flow direction of CO_2 was expected due to the geometry of the anticline, however consistent imaging of a predominantly westward CO_2 flow by means of seismic and ERT imaging is a significant outcome from geophysical monitoring at Ketzin[6]. Seismic monitoring datasets and results of reservoir simulations of CO_2 storage are compared to assess conformance. For the plume footprint, conformance has reached 87% for 2009 and 39% for 2021 data sets. For plume volume, better conformance between observed and simulated behaviour is observed[7]. The comparison of the plume geometry is also discussed.
List of key publications covering the site

1. Schmidt-Hattenberger, C., Jurczyk, A., Liebscher, A., Möller, F., Norden, B., Prevedel, B., Wiese, B., Zemke, K. and Zimmer, M., 2018, October. Post-injection monitoring and well abandonment results of the Ketzin test site–an essential part for transfer of liability. In 14th Greenhouse Gas Control Technologies Conference Melbourne (pp. 21-26).
2. Norden, B. and Frykman, P., 2013. Geological modelling of the Triassic Stuttgart Formation at the Ketzin CO2 storage site, Germany. International Journal of Greenhouse Gas Control, 19, pp.756-774.
3. Forster, A., Norden, B., Zinck-Jørgensen, K., Frykman, P., Kulenkampff, J., Spangenberg, E., Erzinger, J., Zimmer, M., Kopp, J., Borm, G. and Juhlin, C., 2006. Baseline characterization of the CO2SINK geological storage site at Ketzin, Germany. Environmental Geosciences, 13(3), pp.145-161.

4. Schilling, F., Borm, G., Würdemann, H., Möller, F., Kühn, M. and CO2 sink group, 2009. Status report on the first European on-shore CO2 storage site at Ketzin (Germany). Energy Procedia, 1(1), pp.2029-2035.
5. Martens, S., Liebscher, A., Möller, F., Henninges, J., Kempka, T., Lüth, S., Norden, B., Prevedel, B., Szizybalski, A., Zimmer, M. and Kühn, M., 2013. CO2 storage at the Ketzin pilot site, Germany: fourth year of injection, monitoring, modelling and verification. Energy Procedia, 37, pp.6434-6443.
6. Bergmann, P., Diersch, M., Goetz, J., Ivandic, M., Ivanova, A., Juhlin, C., Kummerow, J., Liebscher, A., Lueth, S., Meekes, S. and Norden, B., 2016. Review on geophysical monitoring of CO2 injection at Ketzin, Germany. Journal of Petroleum Science and Engineering, 139, pp.112-136.
7. Lüth, S., Ivanova, A. and Kempka, T., 2015. Conformity assessment of monitoring and simulation of CO2 storage: A case study from the Ketzin pilot site. International Journal of Greenhouse Gas Control, 42, pp.329-339.
8. Zimmer, M., Szizybalski, A., Norden, B., Vieth-Hillebrand, A. and Liebscher, A., 2018. Monitoring of the gas composition and stable carbon isotopes during side track drilling in Ktzi 203 at the Ketzin CO 2 storage pilot site, Germany. Advances in Geosciences, 45, pp.7-11.
9. Trémosa, J., Castillo, C., Vong, C.Q., Kervévan, C., Lassin, A. and Audigane, P., 2014. Long-term assessment of geochemical reactivity of CO2 storage in highly saline aquifers: Application to Ketzin, In Salah and Snøhvit storage sites. International Journal of Greenhouse Gas Control, 20, pp.2-26.

Other relevant information considered pertinent to the report

Martens, S., Kempka, T., Liebscher, A., Lüth, S., Möller, F., Myrttinen, A., Norden, B., Schmidt-Hattenberger, C., Zimmer, M. and Kühn, M., 2012. Europe's longest-operating on-shore CO2 storage site at Ketzin, Germany: a progress report after three years of injection. Environmental Earth Sciences, 67(2), pp.323-334.

Lengler, U., De Lucia, M. and Kühn, M., 2010. The impact of heterogeneity on the distribution of CO2: Numerical simulation of CO2 storage at Ketzin. International Journal of Greenhouse Gas Control, 4(6), pp.1016-1025.

Schmidt-Hattenberger, C., Bergmann, P., Labitzke, T. and Wagner, F., 2014. CO2 migration monitoring by means of electrical resistivity tomography (ERT)–Review on five years of operation of a permanent ERT system at the Ketzin pilot site. Energy Procedia, 63, pp.4366-4373.

Figures

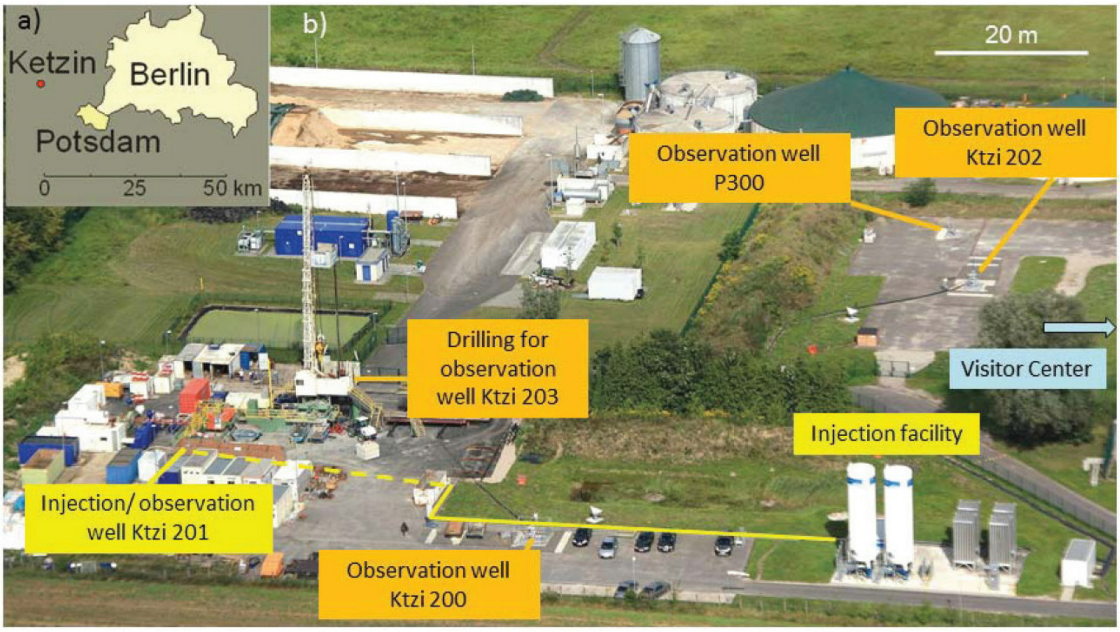


Figure 16.1: Ketzin pilot site location (a) and aerial photograph with infrastructure and drilling for well Ktzi 203 [5].

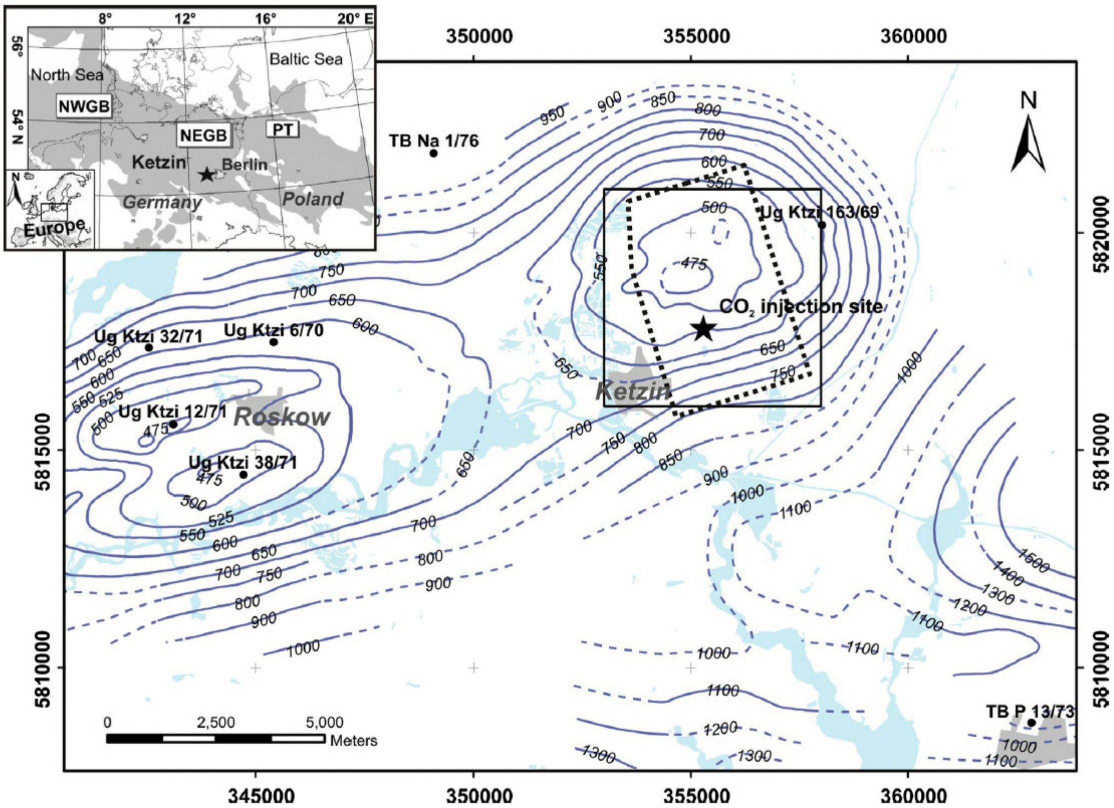


Figure 16.2: Structure of the Roskow-Ketzin double anticline, highlighted by the isolines (meters below ground level) of the strongest seismic reflector of the Triassic ("K2 horizon" uppermost Weser Formation). Shown are the locations of former exploration boreholes penetrating the Stuttgart Formation (dots) and the location of the Ketzin CO_2 boreholes (star), the extension of the 3D seismic data (stippled black lines), and the reservoir model

domain size (black square). The inset map shows the extent of the European Permian Rotliegend Basin (grey shaded) and the location of the Ketzin site in the Northeast German Basin (NEGB), located between the Northwest German Basin (NWGB) and the Polish Trough (PT) [2].

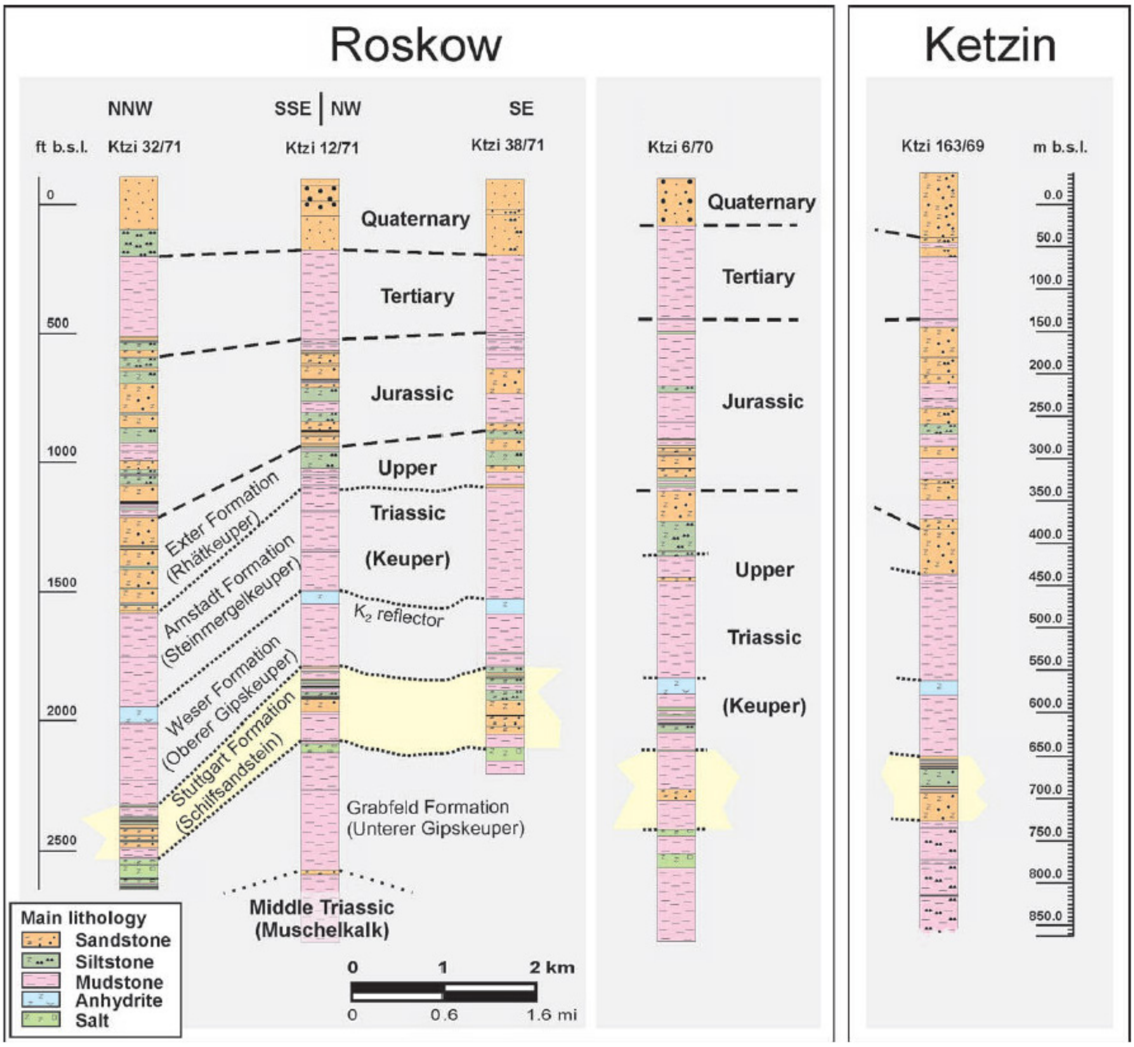


Figure 16.3: Stratigraphic and lithologic sections of boreholes penetrating the Stuttgart Formation in the Roskow-Ketzin double anticline. The K2 seismic reflector mapped in figure A is delineated [3].

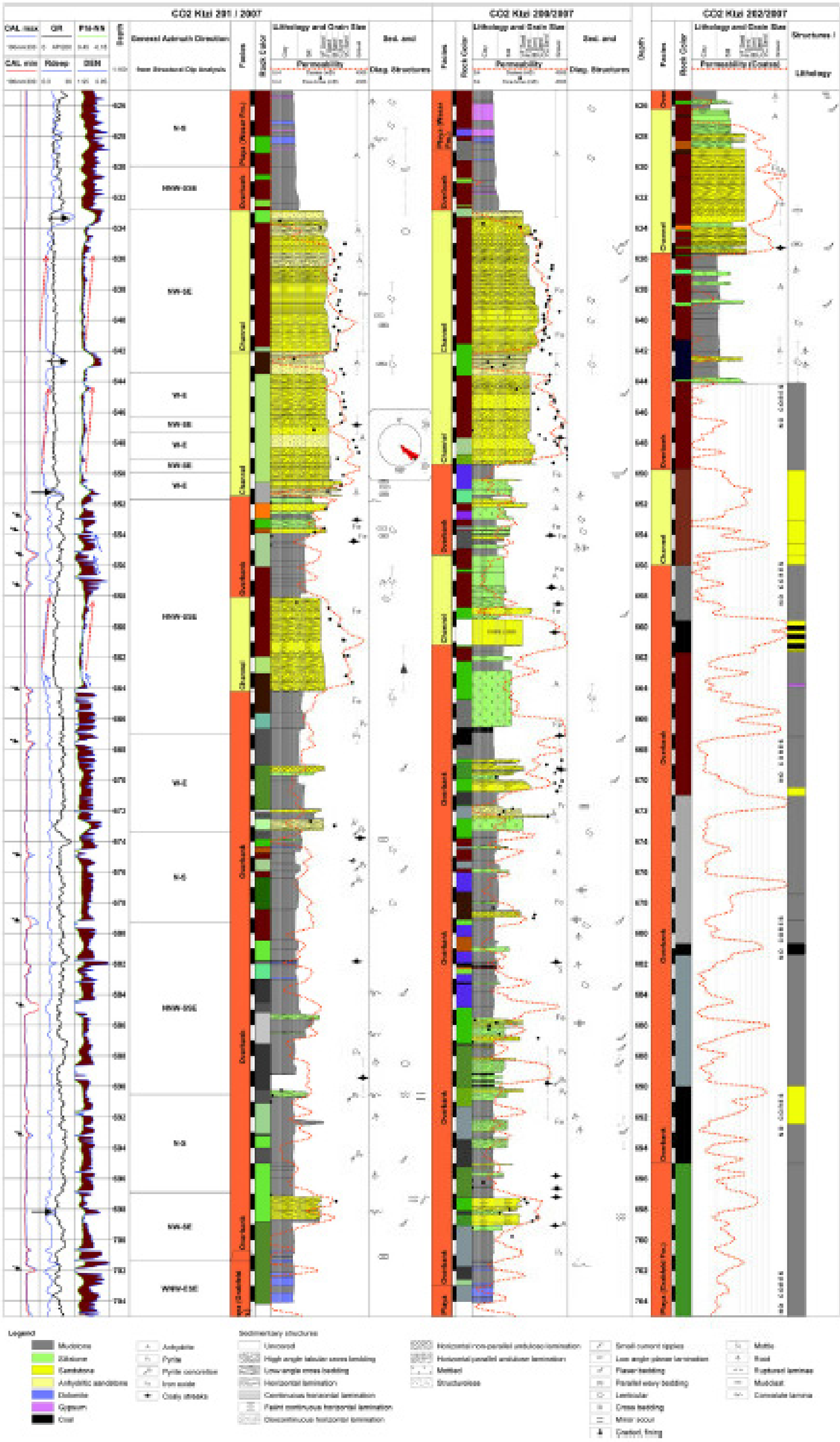


Figure 16.4: Composite plot of well-log data, lithological and sedimentological descriptive data, and derived facies data of the CO_2 Ktzi 201, 200, and 202 boreholes [2].

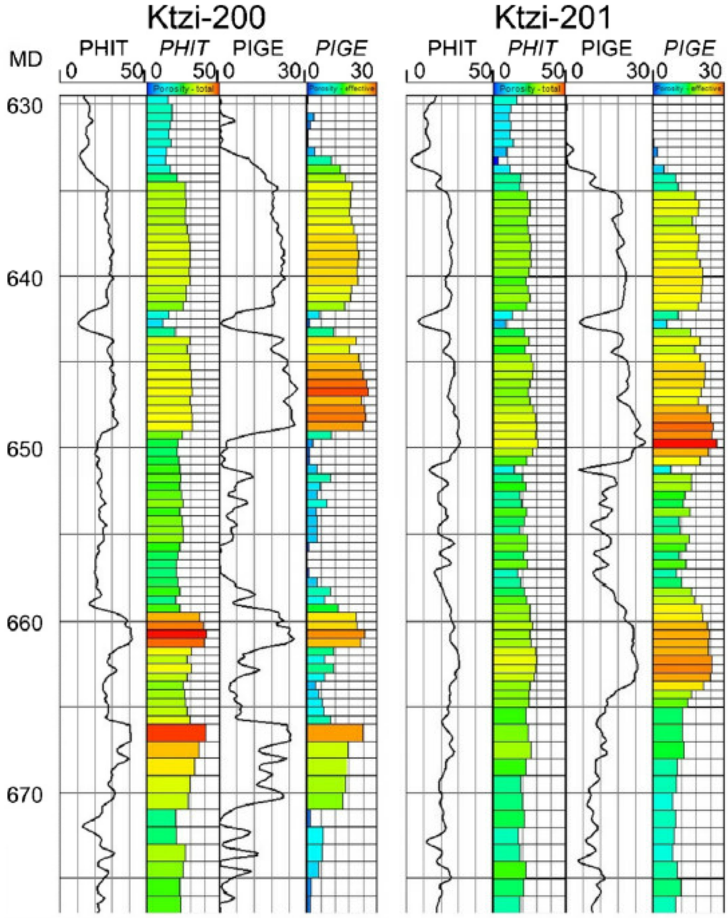


Figure 16.5: Total and effective porosity from jointed core and well-log interpretation compared to upscaled cell properties used for dynamic simulations [2].

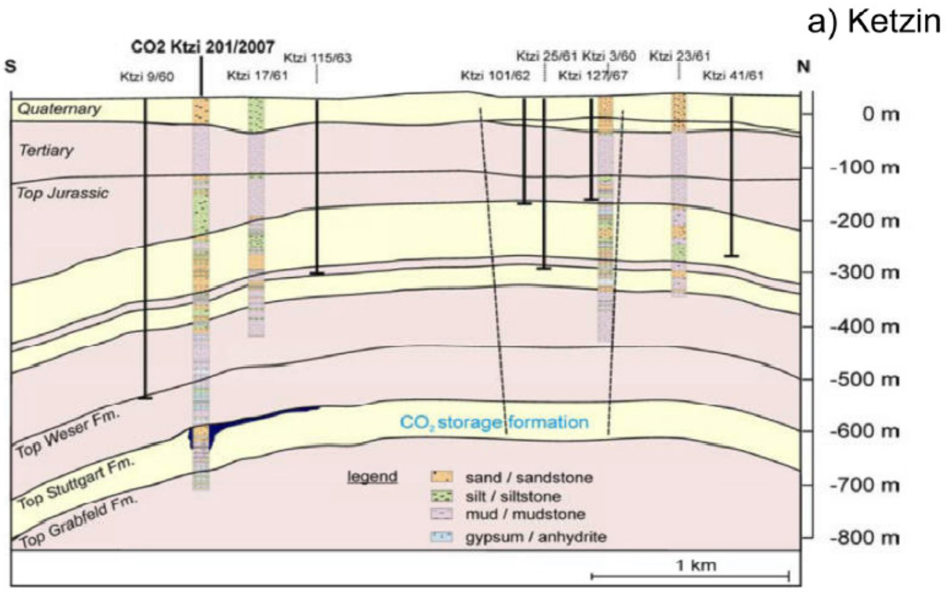


Figure 16.6: Schematic cross-section of Ketzin[9].

9 Trémosa, J., Castillo, C., Vong, C.Q., Kervévan, C., Lassin, A. and Audigane, P., 2014. Long-term assessment of geochemical reactivity of CO2 storage in highly saline aquifers: Application to Ketzin, In Salah and Snøhvit storage sites. International Journal of Greenhouse Gas Control, 20, pp.2-26.

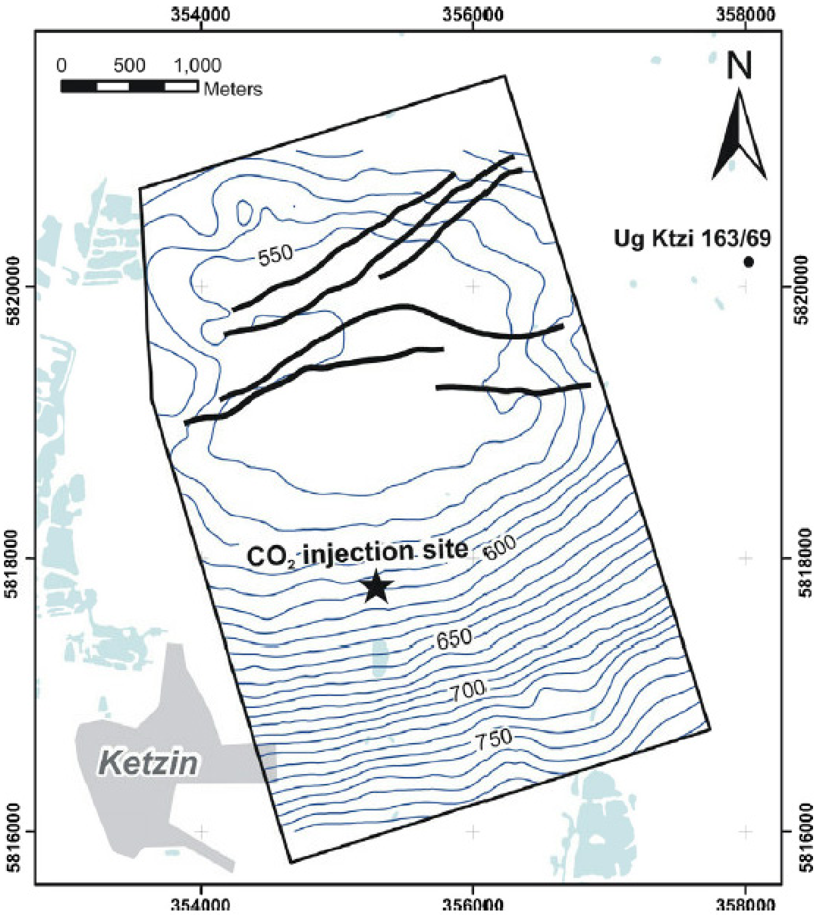


Figure 16.7: Interpreted depth of the top Stuttgart Formation (in meters below ground level) and mapped faults of the Central Graben Fault Zone (CGFZ). Star marks location of boreholes used for injection and monitoring [2].

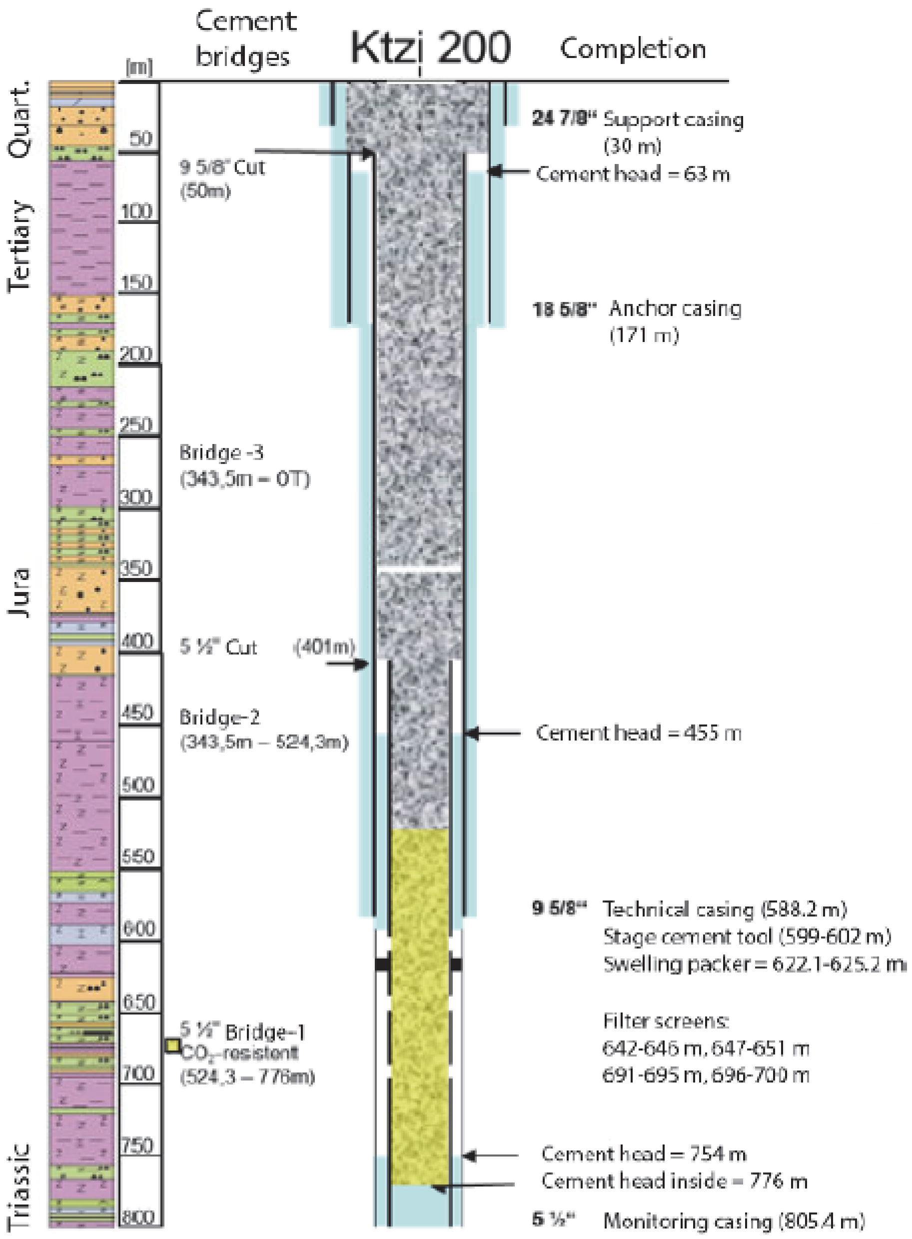


Figure 16.8: Completion scheme for Ktzi 200 according a two-cementation concept consisting of CO_2 resistant 'Evercrete' and standard class G cement [1].

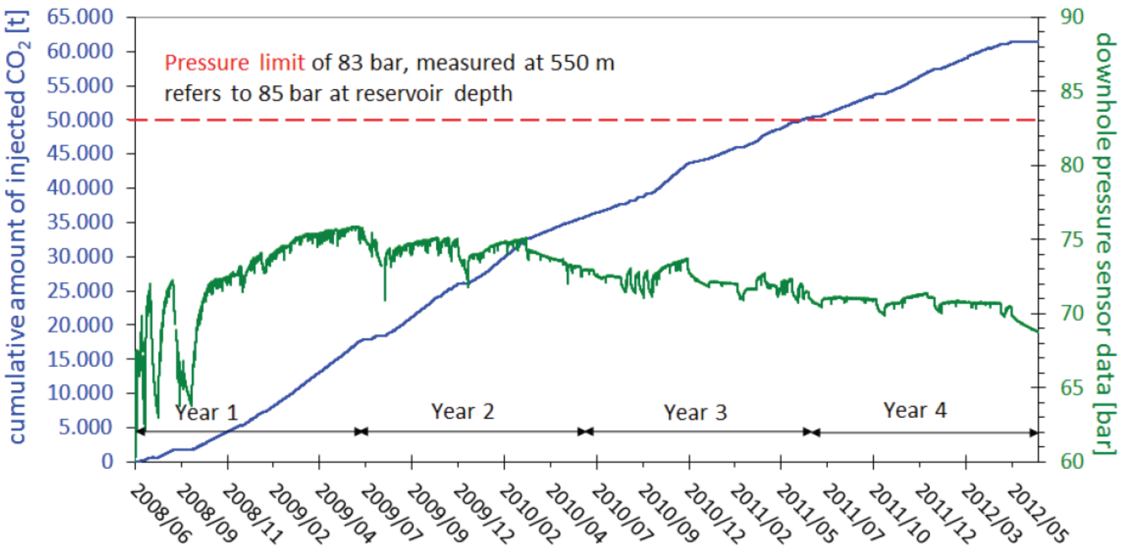


Figure 16.9: Evolution of downhole pressure and cumulative mass of injected CO_2 over four years of operation [5].

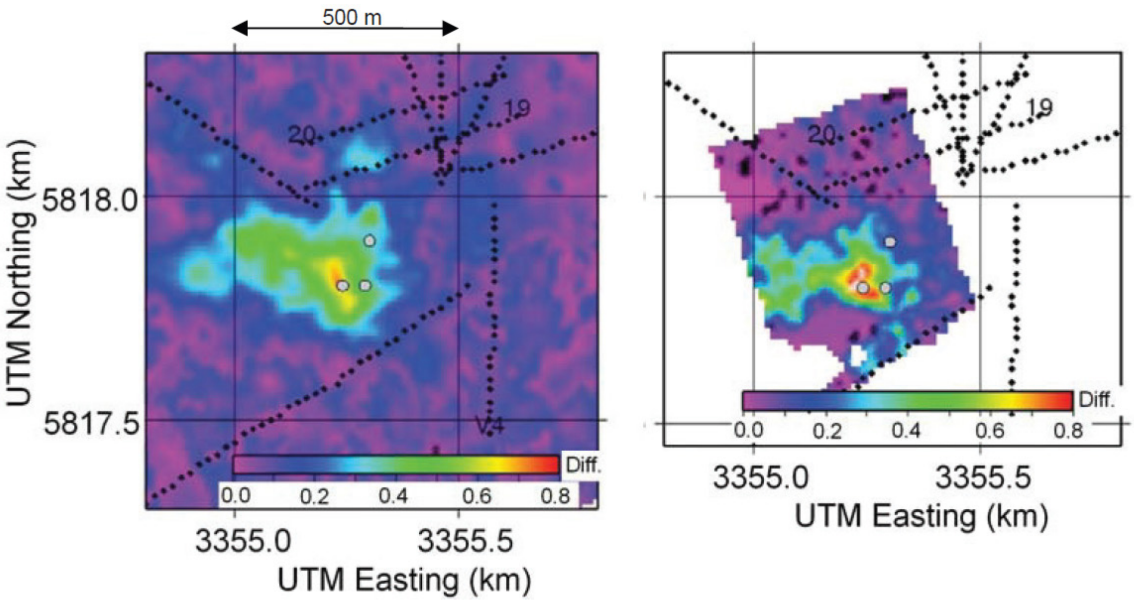


Figure 16.10: Map view with comparison of difference amplitude signatures of CO_2 in the Stuttgart Formation, derived from the 2009 full 3D seismic repeat (left panel), and from the second repeat of the sparse profile acquisition (2011). Grey dots indicate the location of the injection well Ktzi 201 and the observation wells Ktzi 200 and Ktzi 202 [5].

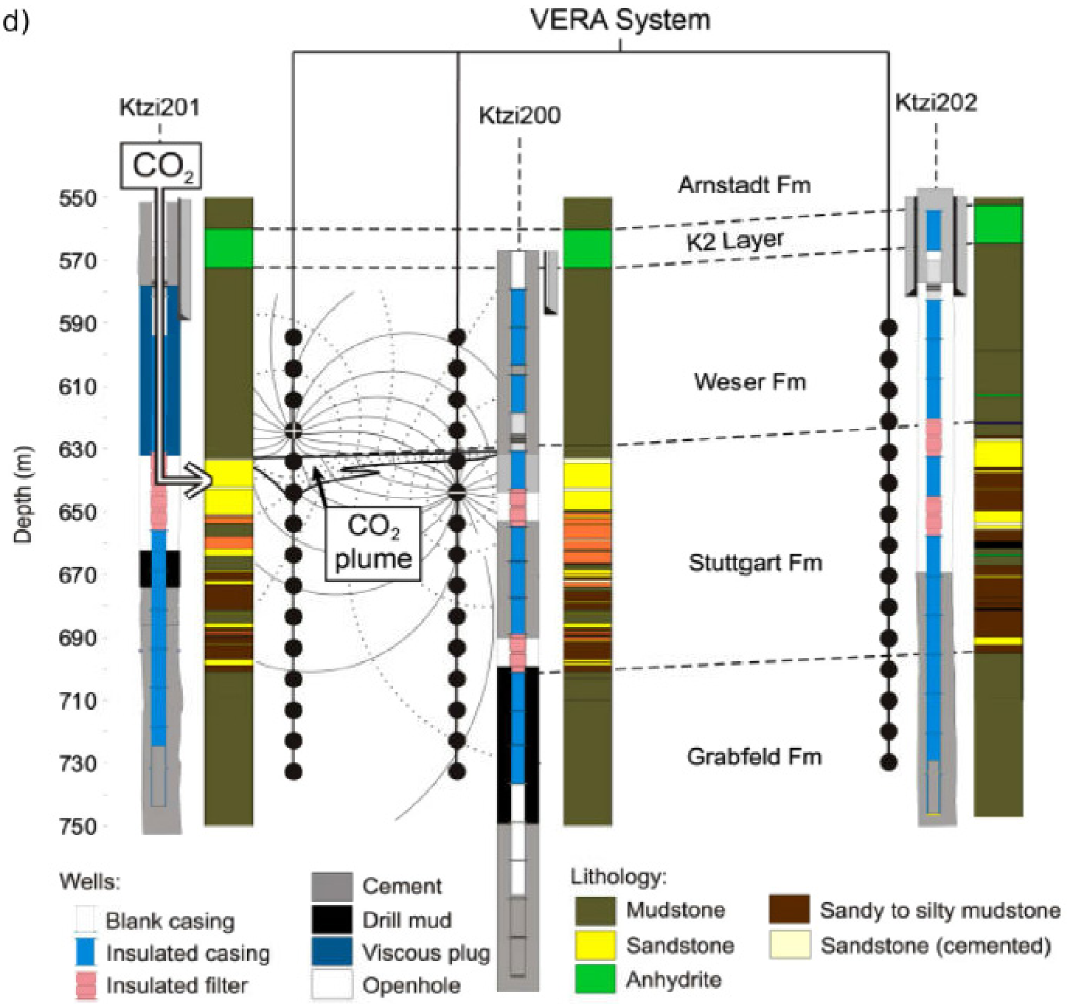


Figure 16.11: Installation and layout of the vertical electrical resistivity array (VERA) showing the well completion, lithology and electrode positions (black dots)[6].

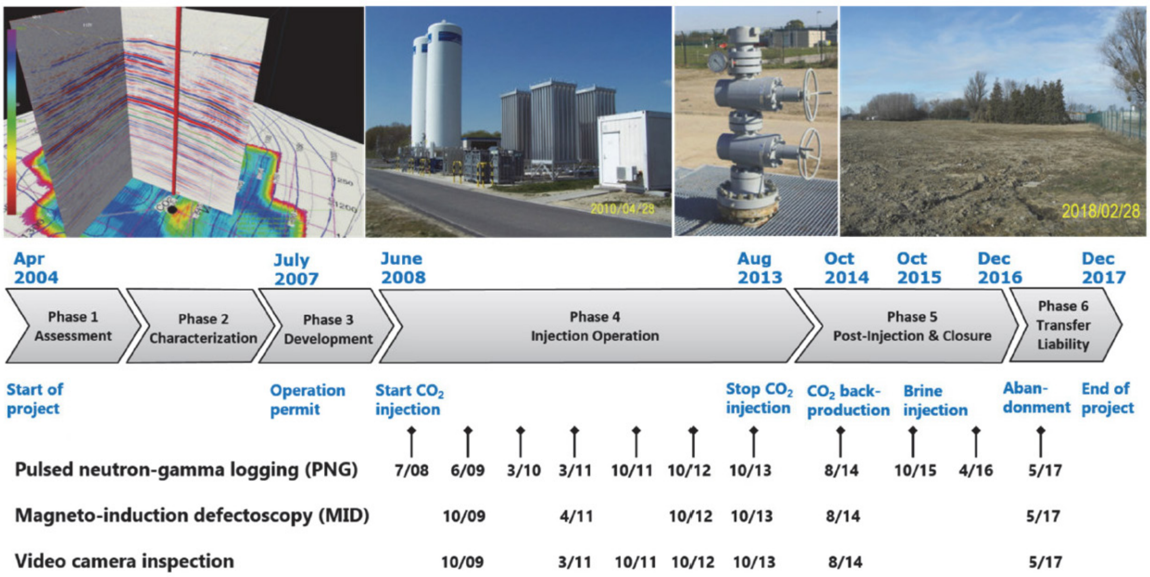


Figure 16.12: Completed life-cycle of the Ketzin CO_2 storage site with the relevant campaigns for well-integrity monitoring (month/year), continuing until the post-injection phase [1].

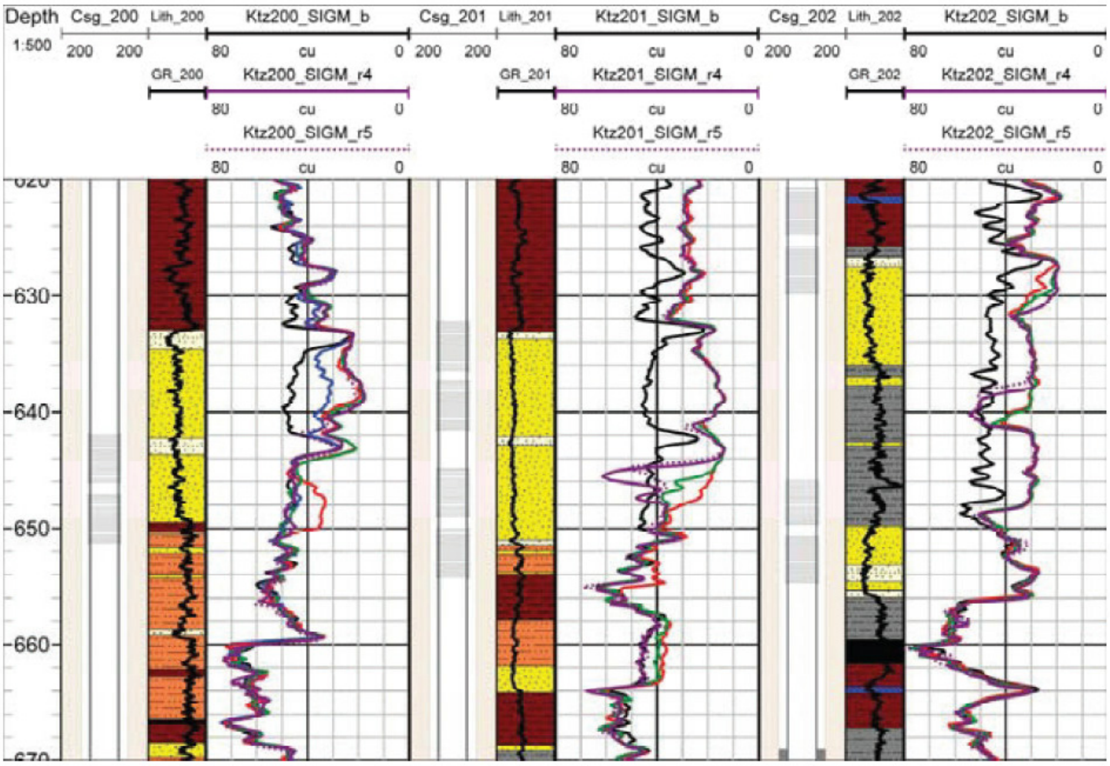


Figure 16.13: SIGMA formation curves recorded during PNG wireline logging in well Ktzi 200, Ktzi 201, and Ktzi 202 (left to right). Black: baseline, blue: repeat 1, red: repeat 2, green: repeat 3, purple: (dotted): repeat 5 [5].

17. Lacq - Rousse

Site Details

Name	Location	Province/State	Country	Onshore	Offshore
Lacq-Rousse			France	✓	

General storage type

Depleted gas field

Development History (Closed)

A three year CCS pilot project (2010-2013), designed, built and operated by Total. An existing air-gas combustion boiler was converted into an oxygen-gas combustion boiler. The 30 MW_{th} oxy-boiler was able to deliver up to 38 t/h of steam to the high pressure (HP) steam network of the Lacq sour gas production and treatment plant. After quenching of the flue gas stream, the CO_2 stream was compressed, dried and transported in gaseous phase via an existing pipeline to the Rousse depleted gas field, 29 km away, where it was injected. Over the injection period of 39 months, 51,340 metric tonnes of CO_2 were injected[1].

Some key objectives included:

- Demonstrate the technical feasibility and reliability of an integrated chain comprising CO_2 capture, transportation and injection into a depleted gas reservoir.
- Develop and apply geological storage qualification methodologies and monitoring techniques on site to serve in future onshore storage monitoring programs that will be larger in scale, longer in operation and economically and technically viable[1].
- Promote CCS knowledge sharing through an outreach and communication program to a range of stakeholders from government, public institutions, industry, academia, NGOs, local communities and the broader public.

Geological Characteristics.

The Rousse geological structure is a deep, isolated, faulted Jurassic horst, overlain by a 4,500 m thick overburden, composed of a series of turbiditic flysch deposits of Upper Cretaceous to Tertiary (Eocene), and localised within the Pyrenean foredeep basin (Figure 17.1, Figure 17.2, Figure 17.3) [1].

Reservoir Formation

The Rousse field reservoirs are located in the Mano and Meillon formations of Upper Jurassic age. Separated by argillaceous limestone of the Lons and Cagnotte formations which is also the seal for the Meillon formation and the hydrocarbon source rock. The Mano formation is used for CO_2 storage.

Lateral extent / thickness variation	n/a
Rock type	Fractured dolomites and dolomite breccias.
Sedimentary features: Depositional Environment / facies type & variation / mineral composition	Mano Formation has three main groups of facies: tidal flat, peritidal facies (mudstones-wachestones and packestones-grainstones); oolithic barrier facies (grainstones-packestones

1 Total 'Carbon Capture and Storage' The Lacq pilot, project and injection period 2006-2013

	with ooid ghosts); and breccia facies (either monogenic of hydrothermal or collapse origin or polygenic alluvial facies)[1]. Composition includes: dolomite as bulk of rock, calcite filling microfractures, silt sized quartz grains, pyrite within matrix and fractures, illite clays and chlorite along fracture walls and in matrix[1].
Porosity	Matrix has average porosity 3%[1].
Permeability	Matrix has a very low average permeabilities <1 mD[1]. Fracturation plays an important role in the Mano formation and is heterogenous, well tests show an effective permeability of 5 mD for reservoir modelling to account for fractures in the reservoir[1].
Formation fluid properties: (residual hydrocarbons / salinity concentration).	n/a
Caprock / primary seal formation	
Basal Upper Cretaceous interval which onlaps the Rousse horst. These comprise three units: the Rousse Breccias, calcareous turbidites ('Calcaire de Soumoulou' formation) and marly to silicoclastic turbiditic flysch series.	
Lateral extent / thickness variation	Breccias are limited in lateral extent and grade into Upper Cretaceous marly-calcareous turbidites. Upper Cretaceous series has a thickness of ~2,500 m.
Rock type	Two types of breccia differing in age, carbonaceous matrix with either dolomite clasts reworked from the Mano or carbonate clasts of Aptian age. Marly-calcareous turbidites becoming more shaly towards the top and include blackish marls and calcareous shale (majority of deposits) and cherty limestones (limited in extent).
Fracture pressure	n/a
Porosity	Measured porosity through a pycnometer is between 1 and 3.5%.
Permeability	Measured by gas injection technique at 100 bars four groups identified with following permeability:

	Dolomite clasts in breccia – permeability close to Mano reservoir up to 150 µD (might locally present reservoir qualities). Carbonate clasts and matrix of breccia with very low permeability <1 nD. Very low permeability carbonaceous turbidites (0.1 nD). Low permeability marls to calcareous marls (1-10 nD).
Overburden Features (Thickness, formations presence of secondary reservoirs / seals)	
Saline to brackish aquifers above the site include: Lower Eocene to Paleocene discontinuous reservoirs (between 700-2,000 m depth) and the lower Paleocene limestone aquifer of the Lasseube formation (at 2,100 m depth)[1].	
Structure Isolated, faulted Jurassic horst (Figure 17.1) resulting from pre-Pyrenean rifting. The structure is eroded by the Base Upper Cretaceous unconformity (BCS) and disconnects the structure from overlying formations. Faults at reservoir are mainly sealed by the BCS[1].	
Fold type / fault bounded	n/a
Faults /Fractures (Type – normal, reverse, strike-slip)	ESE-WNW and NNW-SSE trending normal faults.
Displacement	n/a
Stability (pre-stressed, active, stable)	n/a
Injection / storage history	
Number of injection, monitoring or other wells, well geometry, design and key completion information for injection wells, relevant well issues. Reused / new purpose drilled well.	
Rousse RSE-1 well (1967), maximum deviation of 12°. Two open hole sections drilled through caprock: a 12 $^{1}/_{4}$“ section down to 3,470 m, and a 8 $^{3}/_{8}$” section. The 12 $^{1}/_{4}$“ section was completed using 9 $^{5}/_{8}$” casing and was cemented with a top of cement (TOC) at around 2.270 m MD. The 8 $^{3}/_{8}$” section was completed with 7” casing string. Six centralizers were placed along the 9 $^{5}/_{8}$” and 7” casing strings[1]. The reservoir section was drilled with 5 $^{3}/_{4}$“ and 4 $^{1}/_{5}$” bits, reaching a total depth (TD) of 5,215 m MD, A 5” liner was set across the reservoir at a depth of 4,737 m MD (top of liner: 4,441 m MD) and cemented. The remaining open hole interval was cemented up to 4,790 m MD and the 5” liner later perforated for gas production[1].	
Extent and status of casing (corrosion history/ cementation records)	1967 cement evaluation data acquired during drilling and completion, and again in 2006 and 2009- during the work over. 1967 included Gamma Ray, one-arm calliper and compressional sonic data covering reservoir and

	caprock. Cement Bond Log acquired across 7” casing up to the 9 $^{5}/_{8}$” casing. 2006, slim cement mapping tool and multi-finger calliper tool run across the 5” liner to evaluate cement hydraulic isolation and casing condition across reservoir section – conclusion was casing-cement bond was good with no bond or cement degradation over time. 2009, an Isolation Scanner™ and a Sonic Scanner™ was run over bottom 905 m of the 2 km thick caprock across the 7” casing to evaluate the quality of cement hydraulic isolation. For results consult[1].
Injection rates & pattern (i.e. continuous / intermittent) changes in injection behaviour	n/a
Total quantities stored	Over the injection period of 39 months, 51,340 metric tonnes of CO_2 were injected[1].
Reservoir capacity (estimate)	n/a
Fluid extraction rate (brine extraction, oil for EOR)	n/a

Seismicity

The analysis of the seismicity recorded in the southwest France shows that no seismicity was induced during production of the Rousse field. The Rousse site is located in a low-to-medium risk seismic area, and no major earthquake has been recorded[1].

Monitoring regime (technologies deployed)

Baseline survey recorded October 2008 to June 2009, just after the installation of the first microseismic array in the first of seven shallow wells drilled[1]. In 2009 a permanent microseismic network of seven sun-surface tool strings of four levels each had been installed in shallow wells of ~200 m deep. Six are located on a 2 km radius circle around the injector and the seventh is on the RSE-1 well pad. An additional seismometer (Noemax 20s Velocimeter from Agecodagis based on 4.5 Hz geophones – Bandwidth: 0.05-50 Hz – sensitivity: 78.9 V/m/s) located on the surface close to one of the shallow wells is used to detect and record larger magnitude natural earthquakes. Each string is composed of four EMCI triaxis SM4-10 Hz velocimeters (Bandwidth: 10-1,000 Hz – sensitivity: 28 V/m/s), located between 130 m and 200 m depth. Each tool string is connected to an acquisition station on the wellhead.

Three triaxial micro-seismic sensors installed at the bottom of RSE-1 with spacing of 10 0m along an optical fibre cable between 4,200 and 4,400 m (150 – 350 m above the mano reservoir).

Three scales of investigation are envisaged: at fault (local) scale ~1.5 km – sensitivity M<0.0; at regional scale ~30 km - sensitivity M<1.5; and at reservoir scale ~500 m - sensitivity M<-2.0.

Results and analysis are found in chapter 6.

Seismic overloads computed at four depths in RSE-1 well[1].	
Seismic events (Detection / magnitude / attribution (natural induced).	
Rousse – 22 October 1851, strong tremor[1].	
Monitoring technologies applied and experiences with monitoring	
Surface monitoring technologies deployed	
Seismic survey: 3D	(1989-90) reprocessed in 2006
Environmental surveys – soil gas, aquifers and ecosystems	Baseline autumn 2008-autumn 2009, repeat in 2010, 2011, 2012 and 2013 and will continue until after the end of injection till March 2016[1]. Following injection a new permit is required for the permanent storage of CO_2 and a long-term post-injection monitoring program will be designed based on lessons learnt[1].
Soil Gas Monitoring	Measuring CO_2 and CH_4 concentrations one meter below the ground surface, and CO_2 and CH_4 fluxes at the soil-atmosphere interface, at 35 locations around the injection site. Gas flux are measured by the accumulation chamber method[1].
Surface water sampling	Spring and autumn sampling using two standard bio-indicators (French Standard Diatom Index – IBD, and French Standardized Benthic Invertebrate Index – IBGN) in addition to pH, water conductivity, carbonates and bicarbonate concentration at three locations on the Arribeu river that drains the Rousse area. Two external sampling sites are used as reference[1].
Flora and Fauna	Annual biodiversity survey, at 33 places around the injection site for flora and 50 places for amphibian and insect species. As of 2013 no change has been recorded[1].
Ground water sampling	Four perched aquifers above the reservoir are monitored, with pH, water conductivity, carbonates and bicarbonate concentration analysed every six months at four natural springs near the injector well – results are compared to pre-injection baseline (4x in 2009)[1].
Atmosphere	Permanent catalytic CO_2, CH_4 and H_2S sensors are placed around the injection wellhead on the

	Rousse injection pad to detect any abnormal concentration of these gases that might indicate a leakage[1].
Subsurface monitoring technologies deployed (well logs)	
Well annulus pressure (continuous)	
Downhole pressure and temperature	Fibre-optic cable with two P/T sensors at 3,300 and 4,400 m below ground level (GL). After 2010, two more pressure and temperature sensors were added during a workover, at 1,100 and 2,200 m GL (Figure 17.4). Continuous monitoring is performed at these four locations in the wellbore, the data is used for pressure transient analyses, reservoir model history matching, and for calibrating the pressure loses model[1].

MMV (Measurement, Monitoring, Verification) Practices & related verification of injected CO_2

The following parameters are monitored:

1. CO_2 stream composition, concentration and flow.
2. CO_2 atmospheric concentrations at the injection well pad.
3. Well annulus pressure.
4. Pressure and temperature along the injection well.
5. Bottom-hole reservoir pressure and temperature.
6. Reservoir and cap rock integrity.
7. Soil gas concentration and fluxes (periodically).
8. Ground water quality (periodically).
9. Surface water quality (periodically).
10. Ecosystem biodiversity (annual flora and fauna survey).

Major technical/scientific studies on the site, major learnings, Conformance assessment (history-matching with models, correlation between different monitoring techniques)

The structure of the reservoir and its location is in an area of low seismicity, has a single well and it's pressure confinement makes it low risk.

The pressure at the end of the injection period is lower than initial reservoir pressure.

The monitoring equipment designed for continuous monitoring of the reservoir behaviour and to control the injection is deemed fit for purpose. As is the monitoring devices used for controlling the well (pressure monitoring in the annuli, micro-seismic well recording, CO_2 sensors on the surface.

List of key publications covering the site

1. Total 'Carbon Capture and Storage' The Lacq pilot, project and injection period 2006-2013

Other relevant information considered pertinent to the report
Gal, F., Pokryszka, Z., Labat, N., Michel, K., Lafortune, S. and Marblé, A., 2019. Soil-gas concentrations and flux monitoring at the lacq-rousse CO2-Geological storage pilot site (French Pyrenean Foreland): from pre-injection to post-injection. Applied Sciences, 9(4), p.645 Lescanne, M., Hy-Billiot, J., Aimard, N. and Prinet, C., 2011. The site monitoring of the Lacq industrial CCS reference project. Energy Procedia, 4, pp.3518-3525. Monne, J. and Prinet, C., 2013. Lacq-Rousse industrial CCS reference project: description and operational feedback after two and half years of operation. Energy Procedia, 37, pp.6444-6457. Pourtoy, D., Onaisi, A., Lescanne, M., Thibeau, S. and Viaud, C., 2013. Seal Integrity of the Rousse depleted gas field impacted by CO2 injection (Lacq industrial CCS reference project France). Energy Procedia, 37, pp.5480-5493. Prinet, C., Thibeau, S., Lescanne, M. and Monne, J., 2013. Lacq-Rousse CO2 capture and storage demonstration pilot: Lessons learnt from two and a half years monitoring. Energy Procedia, 37, pp.3610-3620. Thibeau, S., Chiquet, P., Prinet, C. and Lescanne, M., 2013. Lacq-Rousse CO2 Capture and Storage demonstration pilot: Lessons learnt from reservoir modelling studies. Energy Procedia, 37, pp.6306-6316.

Figures

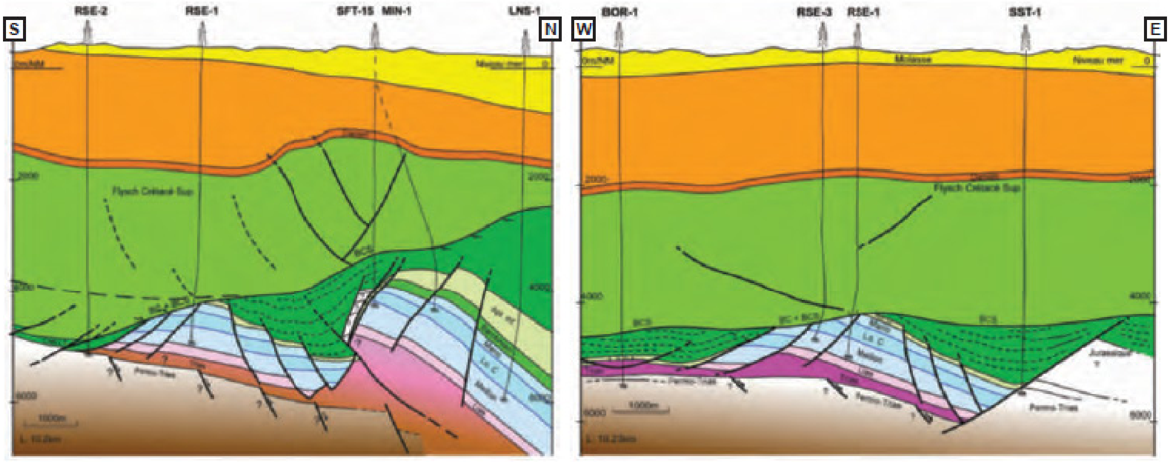


Figure 17.1: Cross sections through the Rousse field and position of the RSE-1 CO_2 injection well [1]

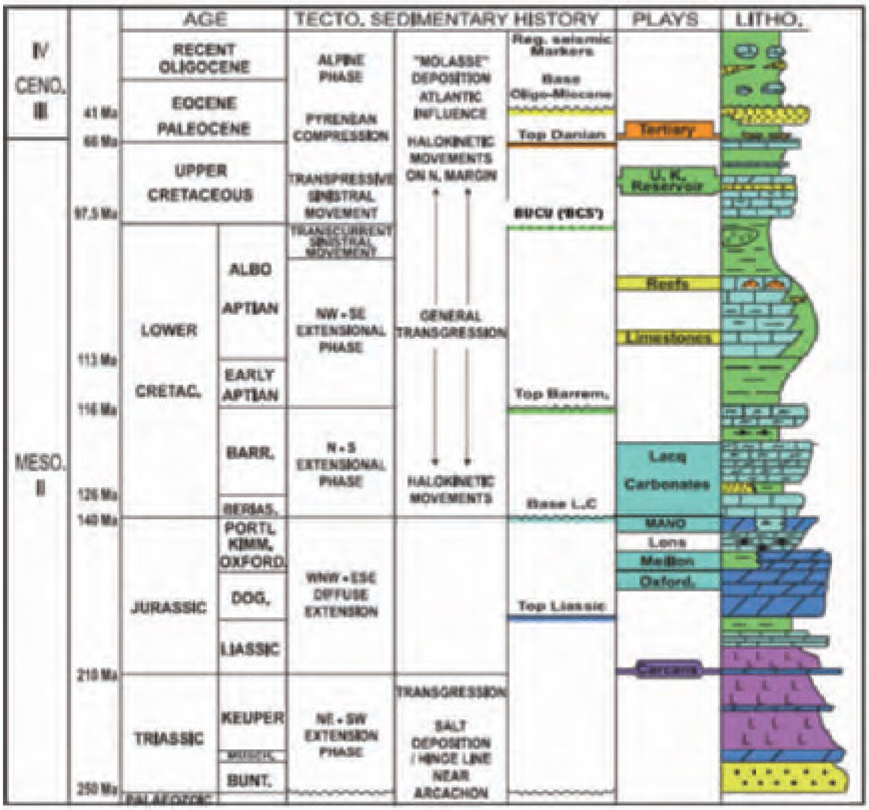


Figure 17.2: Regional lithostratigraphic column [1]

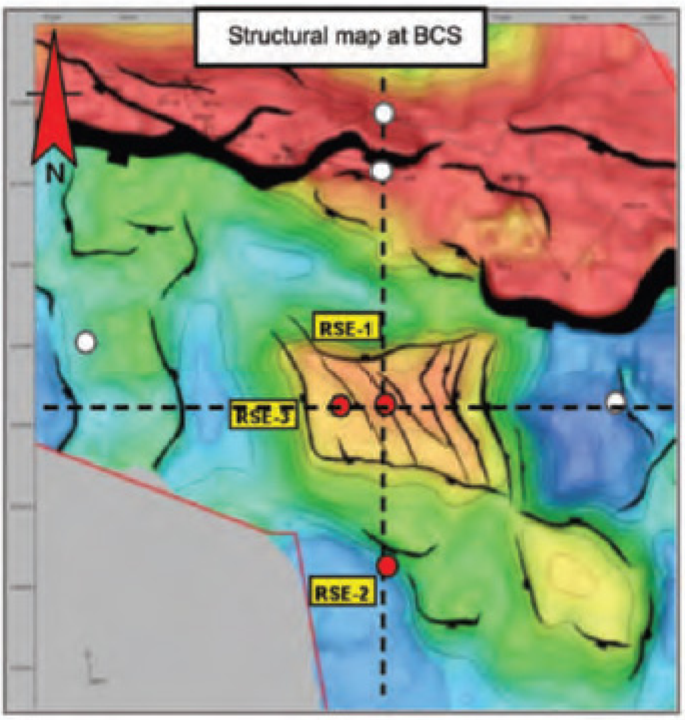


Figure 17.3: Structural map at the Base Cretaceous and showing location of wells. RSE-1 is the CO_2 injection well [1].

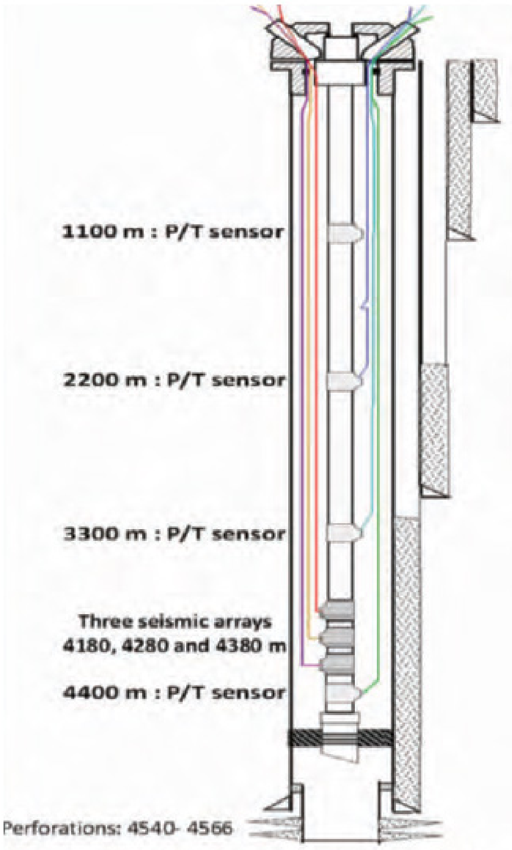


Figure 17.4: Well RSE1 notional architecture and completion [1].

18. In Salah

Site Details

Name	Location	Province/State	Country	Onshore	Offshore
In Salah	Lat 28.642220 Long 2.825050	Central Sahara region (Figure 18.1)	Algeria	✓	

General storage type

Depleted oil and gas reservoir. The CO_2 was injected in the water leg of the gas reservoir.

Development History (Active operation – CO_2 currently being vented rather than stored)

Operated as a joint venture, initially with bp, Sonatrach and Statoil (now Equinor), and ENI replaced bp in 2023, this industrial scale CCS project was used to mitigate greenhouse gas emissions associated with processing of the produced gas to meet export specifications.

CO_2 from several gas fields (CO_2 content 1-10%) was removed from gas production stream, with treatment at the Central Gas Processing Facility using MEA (monoethanolamine) process. The CO_2 was compressed, transported and stored in the 1.9 km deep Carboniferous sandstone unit at the Krechba field.

Injection commenced in 2004 until suspension in 2011 due to concerns about migration out of the s (evidence for limited migration into deeper parts of the overburden). Based on conclusions from a comprehensive monitoring programme, the injection pressures were reduced in mid-2010 and then injection was suspended in June 2011. By that time a total of 3.8 million tonnes of CO_2 had been stored. At no point was the integrity of the storage complex compromised[1, 2].

A Joint Industry project (JIP) was set up to monitor the CO_2 storage process using a variety of geochemical, geophysical, and production techniques[3].

Geological Characteristics.
Structural high of a northwest-trending anticline.

Reservoir Formation

Carboniferous sandstone unit at the Krechba field (Figure 18.2, Figure 18.3).

Lateral extent / thickness variation	20 m thick at about 1,800 to 1,900 m depth. GWC (gas water contact) is around 20 km long by 5 km wide (NNE-SSW trending).
Rock type	Carboniferous sandstone.
Sedimentary features: Depositional Environment / facies type & variation / mineral composition	Tidal deltaic sandstones, matrix dominated. Fracture influenced.

1 Ringrose, P.S. et al (2013) The In Salah CO_2 storage project: lessons learned and knowledge transfer. Energy Procedia 37 pp 6226-6236

2 White, J.A., Chiaramonte, L., Ezzedine, S., Foxall, W., Hao, Y., Ramirez, A. and McNab, W., 2014. Geomechanical behavior of the reservoir and caprock system at the In Salah CO2 storage project. Proceedings of the National Academy of Sciences, 111(24), pp.8747-8752.

3 Mathieson, A. et al (2010) CO_2 sequestration monitoring and verification technologies applied at Krechba, Algeria. The Leading Edge (February)

Porosity	13-20% (mean 15%)[3].
Permeability	Low permeability, average around 10 mD. Variable cementation and natural fractures lead to highly variable permeability (0.1 to 300 mD)[4]. Natural fractures likely enhance effective permeability.
Formation fluid properties: (residual hydrocarbons / salinity concentration).	n/a
Caprock / primary seal formation	
Lateral extent / thickness variation	Thickness of total storage complex (reservoir and overlying sealing formations) is 950 m. The immediate caprock seal is the low permeability Tournaisian shale member that lies directly over the primary storage unit[5].
Rock type	950 m of Carboniferous mudstones unconformably overlain by a thin 3 m thick impermeable anhydrite which serves as a final top seal, this is overlain by 900 m series of Cretaceous sandstones and minor mudstones (and contains regional potable aquifer)[3] .
Fracture pressure	Figure 18.4 presents the injection pressure and rate. Two periods Nov and Dec 2007 and March and April 2008 where pressure increases and injection rate doubles indicating new pathways for fluid flow, the fracture pressure is estimated from the increase in injection rate[6] Fracture pressures of 175-8 bar (wellhead pressures) are estimated.
Porosity	n/a
Permeability	Low
Structure	
Fold type / fault bounded	NNW-SSE trending broad anticlinal structure (four way dip enclosed) caused by mid to late Carboniferous basin inversion and influenced

4 Ringrose, P.S. et al (2009) Plume development around well KB-502 at the In Salah CO_2 storage site. First Break v 27

5 Ringrose P (2013) The In Salah CO2 Storage Project: Lessons Learned https://ieaghg.org/docs/General_Docs/1_Comb_Mod_Risk/1_In_Salah_CO2_Storage_Project_-_IEAGHG_Workshop_13-6-13SEC.pdf

6 Bohloli, B., Ringrose, P., Grande, L. and Nazarian, B., 2017. Determination of the fracture pressure from CO2 injection time-series datasets. International Journal of Greenhouse Gas Control, 61, pp.85-93.

	by strike-slip faults propagating from Devonian sequence below[4].
Faults /Fractures (Type – normal, reverse, strike-slip)	Faulted and fractured (NW-SE trending) sandstone. Conductive fractures align with present-day stress field (NW-SE). Significant uplift in the Tertiary resulted in stress relief joints. Minor faults at Carboniferous level and the immediately overlying cap rock, but none at the Hercynian unconformity level.
Displacement	n/a
Stability (pre-stressed, active, stable)	n/a
Injection / storage history	
Number of injection, monitoring or other wells, well geometry, design and key completion information for injection wells, relevant well issues. Reused / new purpose drilled well.	
Three horizontal injection wells (KB-501, KB-502 and KB-503) drilled between 1,500-1,800 m, using geosteering to maintain wells within the formation and perpendicular to the maximum stress field (Figure 18.2). 5 gas producing wells. In 2007 high concentrations of CO_2 were measured in KB-5 (1980 appraisal well – drilled into Carboniferous aquifer and not cemented across that interval when suspended), KB-5 lies 1.4 km northwest of the KB-502 injector and tracer analysis suggests CO_2 from KB-502. KB-502 was shut in until the well was remediated[3].	
Extent and status of casing (corrosion history/ cementation records)	n/a
Injection rates & pattern (i.e. continuous / intermittent) changes in injection behaviour	Well rates between 10 -20 mmscf (190 - 380,000 metric tonnes per year).
Total quantities stored	3.8 million tonnes of CO_2 (17 million tonnes planned).
Reservoir capacity (estimate)	Gas field is approx. 20 km by 5 km x 20 m thickness. Saline aquifer beyond this.
Fluid extraction rate (brine extraction, oil for EOR)	n/a
Seismicity	
Monitoring regime (technologies deployed)	
One microseismic pilot well (KB601) drilled to 500 m above the trajectory of the KB-502 injection well[4]. Set of vertical 3-component geophones. Six three-component (3-C) 15 Hz geophones between 80 m and 500 m deep were connected and recorded continuous data at 500 Hz until June 2011. Only one geophone reliably produced verifiable data.	
Seismic events (Detection / magnitude / attribution (natural induced).	

From 2009 to 2012 over 1,500 microseismic events related to CO_2 injection[7]. The maximum estimated moment magnitude is MW = 1.7. Event location is limited due to single site monitoring. Several margins of error in reporting due to single site. Monitoring began 5 years after injection so no baseline was produced [8,9].

One conclusion drawn from the results is that the most likely explanation for the observed surface deformation, seismic and pressure data is that the lowermost caprock was fractured by CO_2 injection and that the subsequent contact to network of pre-existing fractures could play a significant role in the migration of CO_2 into the lower most part of the overburden.

Also, when injection ceases the rate of seismic events drops quickly <10 events/day.

An analysis of pressure vs injection rate (Figure 18.4) shows that pressures in all three wells have most probably exceeded the fracture pressure of the injection horizon for limited periods of time. The observed microseismic activity from 2010 appears to correlate well with CO_2 pressure and injection rates at the KB-502 well-head[7].

Microseismic in place from 2009 and until injection ended. Microseismic events located close to injection interval (up to 100 m up above primary reservoir/storage unit) or deeper. Microseismic events recorded between 2009 and 2011 show nearly all the seismicity is deep - between 1,9 and 2,7 km depth (max error about 450 m) - and show that there is no migration of event locations to shallower depths with time[10].

Monitoring technologies applied and experiences with monitoring; (Figure 18.5**)**

Surface monitoring technologies deployed	
Surface gas monitoring	Soil gas survey around each of the new injection wells[1]. Microbiology traverses and spot sampling.
InSAR	Satellite InSAR data (images captured every 28 days) results used with rock mechanical models.
Seismic surveys	4D seismic: baseline 3D seismic 1997 – reprocessed in 2006, focussed on reservoir imaging[3]. Repeat seismic in 2009 with improved shot spacing and fold[1].
Subsurface monitoring technologies deployed (well logs)	

7 Oye, V., Aker, E., Daley, T.M., Kühn, D., Bohloli, B. and Korneev, V., 2013. Microseismic monitoring and interpretation of injection data from the In Salah CO2 storage site (Krechba), Algeria. Energy Procedia, 37, pp.4191-4198.
8 Stork, A. et al (2015) The microseismic response at the In Salah carbon capture and storage (CCS) site. Int Journal of Greenhouse Gas Control 32 pp 159-171
9 IEAGHG, "Monitoring Network and Modelling Network – Combined Meeting", 2015/01, February, 2015.
10 Stork, A. L., Verdon, J. P., & Kendall, J. M. (2014). Assessing the effect of velocity model accuracy on microseismic interpretation at the in Salah Carbon Capture and Storage site. Energy Procedia, 63, 4385-4393

Microseismic.	One pilot well drilled to 500 m above the trajectory of the KB-502 injection well. Set of vertical 3-component geophones[7].
CO_2 brine geochemistry	
Wellhead sampling (including tracers)	CO_2 tracers[4].
Down-hole logging, including image logs in new development wells and CO_2 injection wells [1].	Downhole fluid sampling.
Ground water aquifer monitoring:	5 shallow aquifer wells drilled. Hydrological head, flow rates and water geochemistry baseline recorded[1].
Core analysis (geomechanics):	Triaxial rock mechanical testing and permeability measurements, XRD, isotope analysis, SEM and X-ray elemental analysis[1].
Reservoir logs (LWD, FM) [4]	
Geologic and reservoir models	Static models (e.g. Gocad, RMS), multiphase flow (e.g. STARS, Eclipse), fracture-flow (e.g. Fraca, 4DMove) and geomechanical models (e.g. Abaqus, Stimplan)[1]. The models inform operational decisions and provide longer-term forecasts of the integrity and long term security of CO_2 storage at the site[1].
Experience summary - effectiveness of techniques (limitations / strengths)	
JIP set up at the start of the project to develop the monitoring technology and verify secure long term geological storage at the site[3]. Monitoring of the overlying Carboniferous and Cretaceous sequences was just as important as the reservoir[3]. InSAR monitoring pioneered at the site, which allows mm changes in ground surface elevation to be monitored. When combined with rock mechanical models allows detailed interpretation including influence of faults and fractures. Showed areas of uplift (3 mm/yr) around each of the injection wells and indicated increased risk of migration to the north outside of Krechba hydrocarbon lease (Figure 18.6). 4D seismic: improved imaging in later survey. Two NW-SE trending linear features observed in vicinity of KB-502 and KB-503 injector sites, correspond with dominant fracture orientation and areas of uplift (InSAR) (Figure 18.7)[1]. Microseismic data: from 2009 over 1500 microseismic events related to CO_2 injection. Event location is limited due to single site. Wellhead sampling and CO_2 tracers: Perfluorocarbon tracers added to each injection well to identify provenance in observation and production wells (differentiated from natural CO_2 sources)[1. Two cases of CO_2 breakthrough occurred; in appraisal well KB-5 in 2007 from the injection well KB-502 and to production well KB-14 in 2012 from the injection well KB-502. Surface flux monitoring: no anomalies detected apart from slightly increased CO_2 levels around the legacy KB-5 well (now	

decommissioned)[1].

MMV (Measurement, Monitoring, Verification) Practices & related verification of injected CO_2

Valuable insights gained from variety of subsurface and surface monitoring deployed.
Pre-injection risk register prepared and used to design monitoring program. Modified quantified risk registers during operations.

Concerns about vertical migration into caprock led to intensified R&D programme to understand geomechanical response to CO_2 injection at the site. Not thought that fractures propagate upwards into upper caprock and CO_2 remains safely contained in storage complex.

Major technical/scientific studies on the site, major learnings, conformance assessment (history-matching with models, correlation between different monitoring techniques)

Reservoir modelling and history matching of the CO_2 breakthrough, pressure data and satellite deformation data have allowed a detailed picture of the CO_2 plume around KB-502. Data suggests that existing vertical faults extending about 100 m into immediate caprock between KB-5 and KB-502 have provided a conduit for the injected CO_2 (Figure 18.8)[1,3].

Modelling studies show that structural geological and rock mechanical aspects of the storage system are most critical in the early injection phase, while characterisation of the pore space and fracture flow is important in the medium to long term (10-1000 years)[1].

Following 2010 QRA (quantified risk assessment) decide to reduce CO_2 injection pressures and after further analysis of reservoir, seismic and geomechanical data led to decision to suspend the CO_2 injection in June 2011[1].

Legacy wellbore integrity is a key leakage risk that has to be managed. Acquisition, modelling and integration of a full suite of baseline data, including the overburden, are vital for evaluating long term storage integrity. CO_2 plume development is far from homogeneous and requires high resolution data for reservoir characterization and modelling[1].

Injection strategies, rates and pressures need to be linked to detailed geomechanical models of the reservoir and the overburden. Early acquisition of geomechanical data in the reservoir and overburden, including extended leak-off tests, is advisable[1].

Regular risk assessments should be conducted to inform the on-going operational and monitoring strategies[1].

List of key publications covering the site

1. Ringrose, P.S. et al (2013) The In Salah CO_2 storage project: lessons learned and knowledge transfer. Energy Procedia 37 pp 6226-6236
2. White, J.A., Chiaramonte, L., Ezzedine, S., Foxall, W., Hao, Y., Ramirez, A. and McNab, W., 2014. Geomechanical behavior of the reservoir and caprock system at the In Salah CO2 storage project. Proceedings of the National Academy of Sciences, 111(24), pp.8747-8752.
3. Mathieson, A. et al (2010) CO_2 sequestration monitoring and verification technologies applied at Krechba, Algeria. The Leading Edge (February)
4. Ringrose, P.S. et al (2009) Plume development around well KB-502 at the In Salah CO_2 storage site. First Break v 27
5. Ringrose P (2013) The In Salah CO2 Storage Project: Lessons Learned https://ieaghg.org/docs/General_Docs/1_Comb_Mod_Risk/1_In_Salah_CO2_Storage_Project_-_IEAGHG_Workshop_13-6-13SEC.pdf

6. Bohloli, B., Ringrose, P., Grande, L. and Nazarian, B., 2017. Determination of the fracture pressure from CO2 injection time-series datasets. *International Journal of Greenhouse Gas Control*, *61*, pp.85-93.
7. Oye, V., Aker, E., Daley, T.M., Kühn, D., Bohloli, B. and Korneev, V., 2013. Microseismic monitoring and interpretation of injection data from the In Salah CO2 storage site (Krechba), Algeria. Energy Procedia, 37, pp.4191-4198.
8. Stork, A. et al (2015) The microseismic response at the In Salah carbon capture and storage (CCS) site. Int Journal of Greenhouse Gas Control 32 pp 159-171
9. IEAGHG, "Monitoring Network and Modelling Network – Combined Meeting", 2015/01, February, 2015.
10. Stork, A. L., Verdon, J. P., & Kendall, J. M. (2014). Assessing the effect of velocity model accuracy on microseismic interpretation at the in Salah Carbon Capture and Storage site. Energy Procedia, 63, 4385-4393

Other relevant information considered pertinent to the report

Eiken, O. et al (2011) Lessons learned from 14 years of CCS Operations: Sleipner, In Salah and Snøhvit. Energy Procedia 5 pp 5541-5548

Figures

Figure 18.1: Location of In Salah [3]

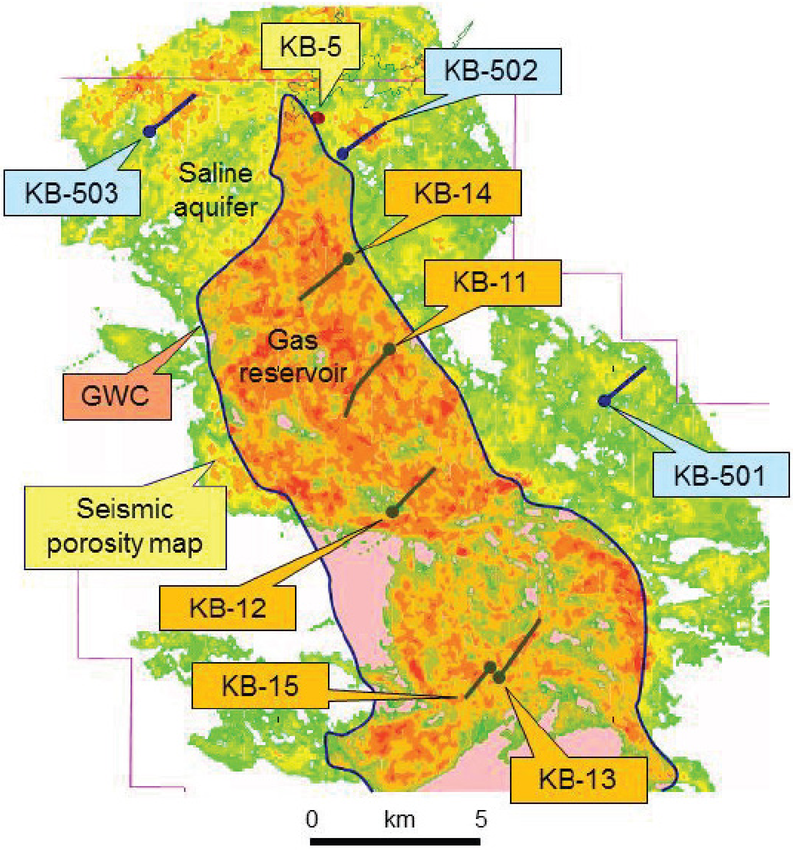


Figure 18.2: Location of Krechba reservoir showing injectors (blue) and producers on a basemap of seismic porosity (green ~10%, red ~18% [1].

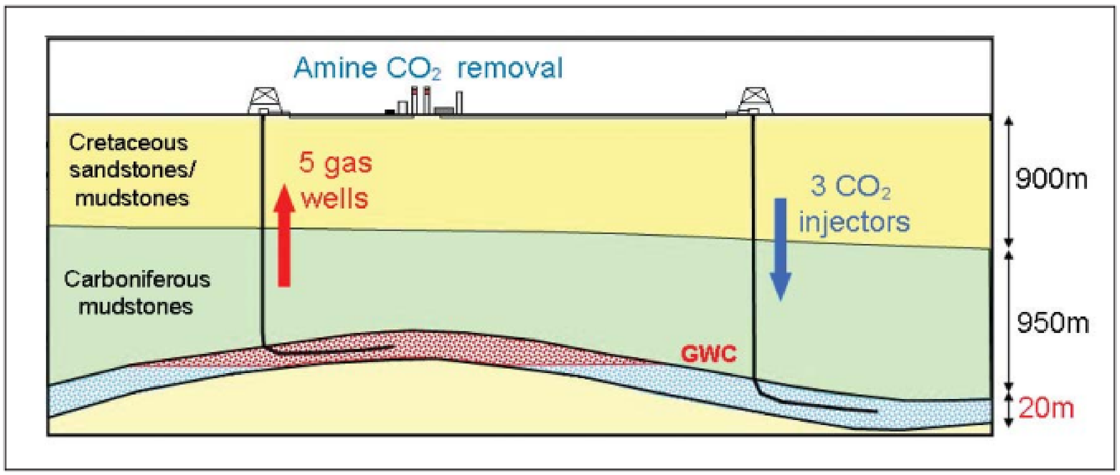


Figure 18.3: Schematic cross-section of the Krechba injection site[3].

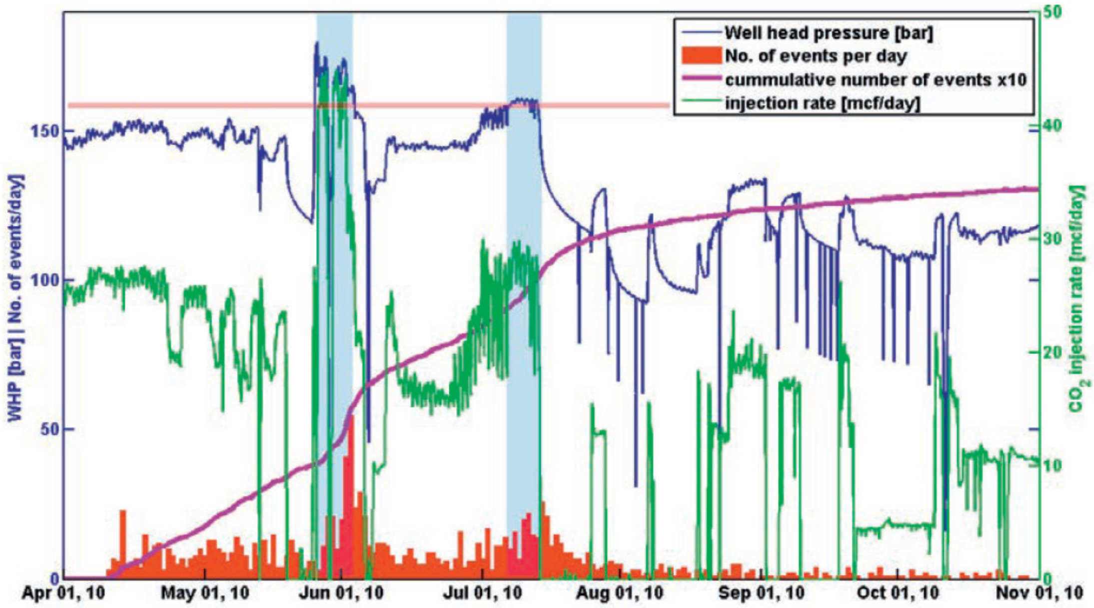


Figure 18.4: Temporal evolution of CO_2 injection rate, well-head pressure and microseismic events. A clear increase in microseismic activity of more than 20 detected events per day coincides with high injection rates and high well-head pressures. The horizontal line indicates fracture pressure [4] .

Monitoring technology	Risk to monitor	Action
Wellhead/annulus sampling	Wellbore integrity Plume migration	• Twice-monthly sampling since 2005
Tracers	Plume migration	• Implemented 2006
Wireline logging/sampling	Subsurface characterization	• Overburden samples and logs collected in new development wells
Soil gas/surface flux	Surface seepage	• Preinjection surveys in 2004 • Repeat survey in 2009
3D-4D seismic	Plume migration	• Initial survey in 1997 • High-resolution survey acquired in mid-2009. Provides feasibility evaluation for 4D
Deep-observation wells	Plume migration	• Not planned at present due to cost
Microseismic	Cap rock integrity	• Test well drilled mid-2009 above KB-502 injector • Depth 500 m, 1500 m above injection zone, 50 geophones array (10 three-component) • Recording ongoing
Electromagnetic surface and wellbore	Plume migration	• Not useful at Krechba due to subsurface architecture and logistics • Wells too widely spaced
Gravity	Plume migration	• Modeling suggests surface response negligible • May be tested in 2011 • Borehole gravity possible if suitable access available
VSP	Cap rock integrity Plume migration Fracture evaluation	• Modeling results inconclusive • Decision pending 3D VSP into microseismic array
Shallow aquifer wells	Contamination of potable aquifer Cap rock breach	• Seven shallow aquifer wells drilled • Sampling twice per year
Microbiology	Surface seepage	• First samples collected in late 2009
Eddy covariance flux towers and LIDARs	Surface seepage	• Reviewed, but weather conditions and potential equipment theft ruled this out • Reviewing potential for deployment in 2011
InSAR monitoring	Plume migration Cap rock integrity Pressure development	• Used extensively, contributions and commissioned work from several providers • Images captured every 28 days
Tiltmeters/GPS	Plume migration Cap rock integrity Pressure development	• To calibrate InSAR deformations • 70 tiltmeters deployed around KB-501 in late 2009

Figure 18.5: Monitoring technologies, risks and status [3].

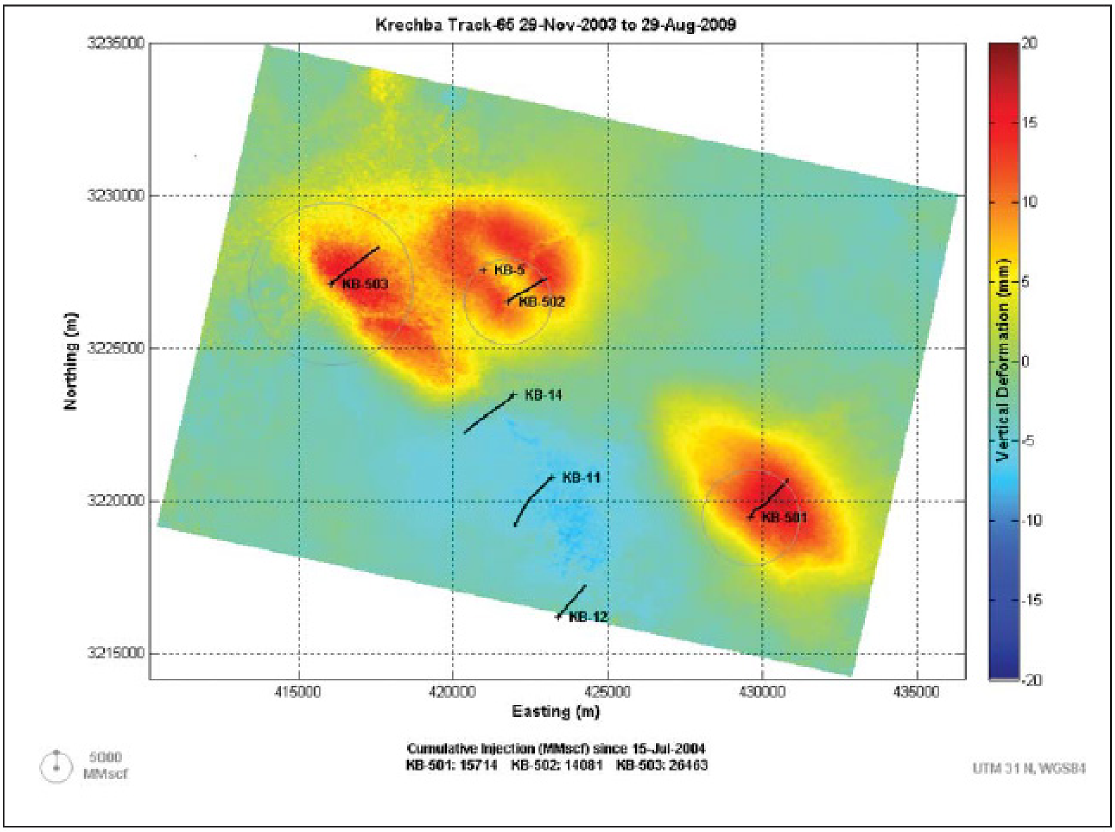


Figure 18.6: Satellite image of surface deformation at Krechba due to CO_2 injection[3].

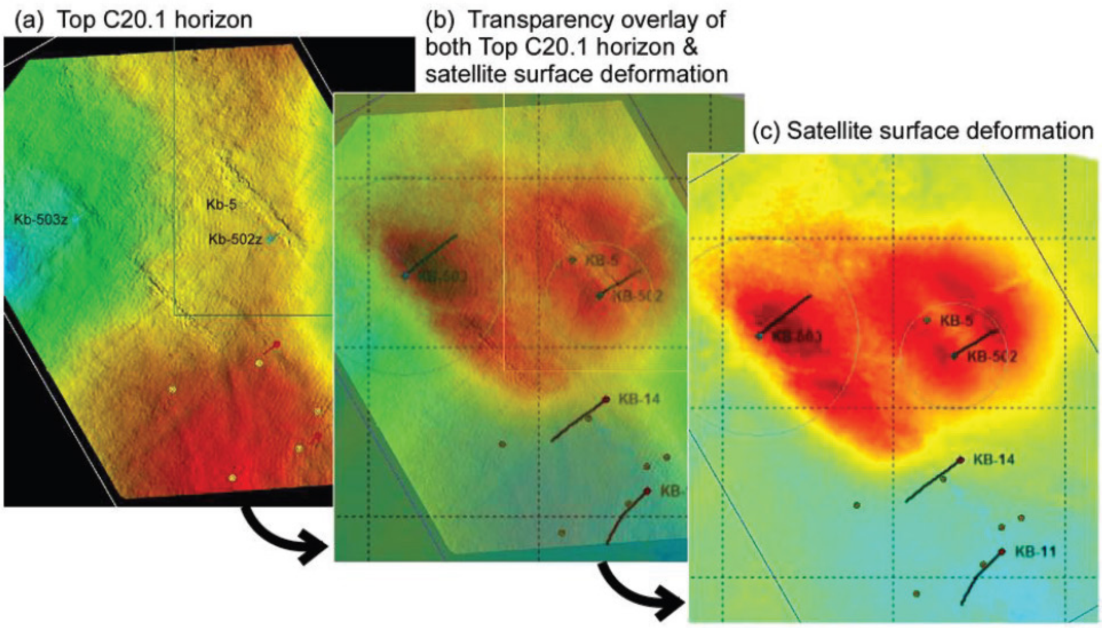


Figure 18.7: NW-SE linear features seen on 2009 3D seismic data compared with InSAR surface deformation data[1].

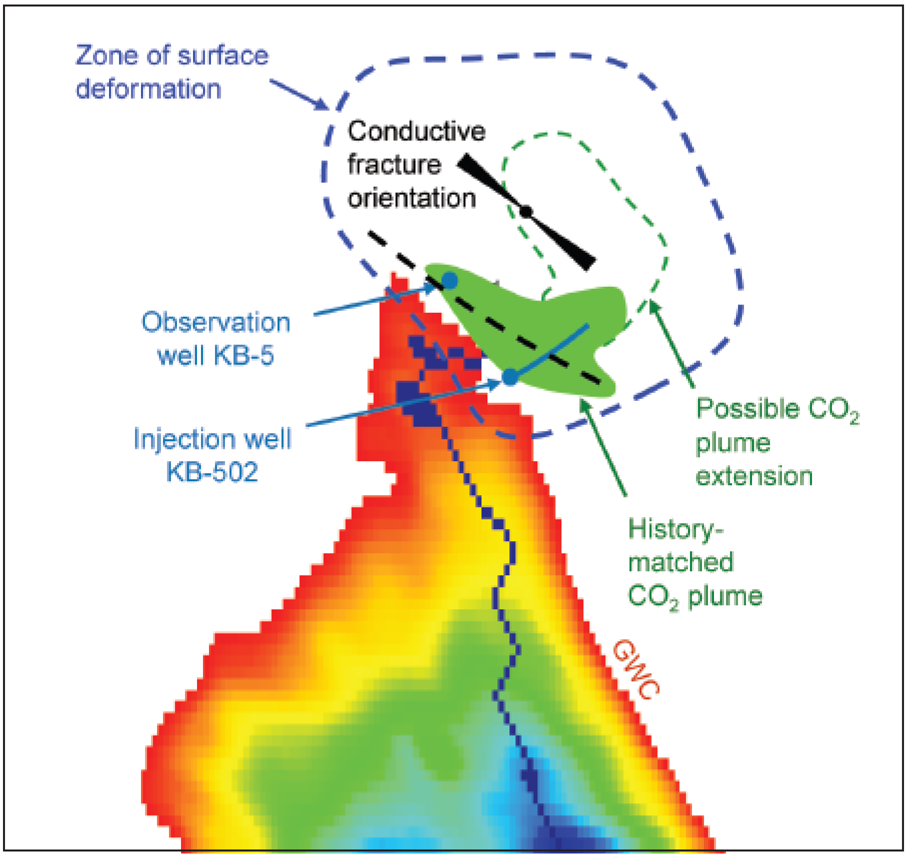


Figure 18.8: Summary of observations constraining the likely CO_2 plume development around injection well KB-502 [4] *.*

19. Jilin

Site Details

Name	Location	Province/State	Country	Onshore	Offshore
Jilin	SongLiao Basin, north-east China	Jilin province	China	✓	

General storage type

Depleted Oil & Gas Reservoir – CO_2-EOR

Development History (Active operation)

Jilin oilfield is located in the Jilin province of the Songliao Basin in northeast China (Figure 19.1). The Jilin oilfield in the Daqingzijing region is a large complex of more than 20 individual smaller oilfields separated by faults. The CO_2-EOR and storage project is the first large-scale CCS project in China, operated by China National Petroleum Corporation. The first pilot phase is in the H-59 block (Figure 19.1), where CO_2 is separated from natural gas in Chang Chun gas field (2008 – present). The second phase, in the H-79 block (Figure 19.1), CO_2 is separated from the Changling natural gas reservoir and then pumped via an 8 km pipeline (2011-present). After initial testing subsequent phases will include more than 200 well patterns in adjacent oil fields (2016 – present)[1]. These include the Daqingzjing, Daan and Qian'an fields[2].

Pilot field – primary production followed by water flooding from 2004-2008. CO_2 injection started in April 2008 initially in two wells and then to other injectors. Since June 2009 WAG injection was initiated initially in two wells then others[1]. Recovery rate by CO_2 flooding is demonstrated to be 37.1%, 14.4% higher than water flooding. Hydraulic fracturing has been widely employed and influenced the permeability and how CO_2 moved through the reservoir[3].

By 2018 facility operational at capacity of 0.6 Mt/yr[4].

Geological Characteristics

Reservoir Formation

Several producing zones from the Cretaceous, Qingshankou formation (Figure 19.2)[1]. Main pay layers #7, 12, 14, 15 in the Qing-1 formation hosts 78% of the original oil in place[1].

Lateral extent / thickness variation	11.2 to 18.2 m thick, pay zones 1-3m thick. Area of field 3.1 km^2, depth 2000-2400 m[1].
Rock type	Multiple pay zones some separated by interbedded oil shale[1]. Mainly siltstone

1 Ren, B., Ren, S., Zhang, L., Chen, G. and Zhang, H., 2016. Monitoring on CO_2 migration in a tight oil reservoir during CCS-EOR in Jilin Oilfield China. Energy, 98, pp.108-121.
2 'CCUS-EOR Practice in Jilin Oilfield' http://www.cnpc.com.cn/en/xhtml/pdf/15-CCUS-EOR%20Practice%20in%20Jilin%20Oilfield.pdf
3 Zhang, L., Ren, B., Huang, H., Li, Y., Ren, S., Chen, G. and Zhang, H., 2015. CO_2 EOR and storage in Jilin oilfield China: Monitoring program and preliminary results. Journal of Petroleum Science and Engineering, 125, pp.1-12.
4 '"Setting the pace" – China establishes world's 18th large-scale CCS facility' https://www.globalccsinstitute.com/news-media/press-room/media-releases/?page=7

	associated with a small fraction of fine sandstone and muddy siltstone[5].
Sedimentary features: Depositional Environment / facies type & variation / mineral composition	Delta front sandstone (Figure 19.2)[1, 6].
Porosity	12.7%[1].
Permeability	3.5 mD[1].
Formation fluid properties: (residual hydrocarbons / salinity concentration).	n/a
Caprock / primary seal formation	
Lateral extent / thickness variation	500-550 m thick[1].
Rock type	Thick mudstone layers and shale intercalations[1].
Fracture pressure	n/a
Porosity	n/a
Permeability	n/a
Overburden Features (Thickness, formations presence of secondary reservoirs / seals)	
Presence of a potable aquifer – not known.	
Structure The large oil complex comprises more than 20 individual small oilfields divided mainly by faults[1].	
Fold type / fault bounded	Bound by two sealing antithetic normal faults[1]. H-59 block reservoir inclines 2-4° to the east, surrounded by four normal faults from north to south with length 1-3 km[3].
Faults /Fractures (Type – normal, reverse, strike-slip)	West-east high-angle/vertical fractures, 10-30 cm length[1]. Fractures are clean with minor infill, some with small and scattered oil patches[1].
Displacement	n/a
Stability (pre-stressed, active, stable)	n/a
Injection / storage history	

5 Zhang, L., Li, X., Ren, B., Cui, G., Zhang, Y., Ren, S., Chen, G. and Zhang, H., 2016. CO_2 storage potential and trapping mechanisms in the H-59 block of Jilin oilfield China. International Journal of Greenhouse Gas Control, 49, pp.267-280.
6 Bo, L.I.U., Jiahui, S.U.N., ZHANG, Y., Junling, H.E., Xiaofei, F.U., Liang, Y.A.N.G., Jilin, X.I.N.G. and Xiaoqing, Z.H.A.O., 2021. Reservoir space and enrichment model of shale oil in the first member of Cretaceous Qingshankou Formation in the Changling sag, southern Songliao Basin, NE China. Petroleum Exploration and Development, 48(3), pp.608-624.

<table>
<tr><td colspan="2">Number of injection, monitoring or other wells, well geometry, design and key completion information for injection wells, relevant well issues. Reused / new purpose drilled well.</td></tr>
<tr><td colspan="2">Pilot area consists of 31 wells with spacing 440 x 140 m; 25 production wells and 6 CO_2 injectors (Figure 19.3)[1]. 6 well groups, with a well pattern of inverted seven or nine spots[1]. Started in 2008, due to early CO_2 breakthrough in some production wells from May 2009, aperiodic and non-simultaneous WAG operations were initiated in some injectors to improve sweeping efficiency with water-gas ratio between 1:2 and 1:5. Water injection lasted 1-4 months[3].

The second phase is an enlarged test conducted in the H-79 block where 18 injectors and 60 producers will be involved[3]. Thereafter extended to other blocks in the region with more than 200 well groups covered[3].

To guarantee wellbore integrity during injection, down-hole fault detecting and gas tightness testing were applied in the pilot wells of H-59 block before CO_2 injection[3]. Techniques used were electromagnetic inspection (EMI), pressure temperature logging, ultrasonic logging, helium gas detecting, pressure-up testing for tube faults, and amplitude/variable density logging and cement bond logging (CBL) for cementing quality[3].

No obvious leakage of CO_2 has been observed in these wells.</td></tr>
<tr><td>Extent and status of casing (corrosion history/ cementation records)</td><td>Overall corrosion rate in wellbores was controlled within the industry standard, no more than 0.076 mm/a[3].

CBL results show that the proportion of well section with good cementing is up to 90% and no cementing quality problems occurred during a three-year period of application[3].</td></tr>
<tr><td>Injection rates & pattern (i.e. continuous / intermittent) changes in injection behaviour</td><td>CO_2 injection initiated in wells 6-6 and 12-6 (April 2008) and then to other injectors. WAG initiated in well 12-6 and 6-6 (June 2009). Since 2011 H59-14-6, 10-4, 8-8 and 4-1 were converted to CO_2 injectors[1].</td></tr>
<tr><td>Total quantities stored</td><td>By June 2014 21.08 x 104 ton of CO_2 has been injected with over 95% stored[5].</td></tr>
<tr><td>Reservoir capacity (estimate)</td><td>CO_2 storage capacity in the pilot reservoir 29.6 x 10^4 ton[1].

CO_2 storage capacity in Jilin oilfield 71.2 Mt[1].</td></tr>
<tr><td>Fluid extraction rate (brine extraction, oil for EOR)</td><td>n/a</td></tr>
<tr><td colspan="2">Seismicity</td></tr>
<tr><td colspan="2">Monitoring regime (technologies deployed)</td></tr>
<tr><td colspan="2">Array of 24 three-component geophone receivers placed around the monitoring well at the near surface with a spacing of 150m and a depth of 10-30 m. With a coverage of 600 x 600 m.</td></tr>
</table>

Prior to testing CO_2 injectors were shut down for 15 hrs, then restarted when the wellhead pressure becomes low[1]. In the H59 block mapping implemented in four injector wells; H59-4-2, 6-6, 14-6 and H59-1 (Figure 19.4 and Figure 19.5). Most of the microseismic events (wells H59-1 & 6-6) are interpreted to be induced from layer #7 (Figure 19.4)[1]. The number of induced microseismic events by the CO_2 injection decreases gradually from inside near-well to the outside area. The microseismic events are induced by the pressure propagation can be used to predict and map the fluid movement trend. Results indicate that CO_2 preferential flow is in an E-W direction for both well groups, in alignment with the fractures and structural trend[1]. Results are compared with gas tracer results[1]. Comparison between CO_2 flow pattern and permeability fields was conducted for each layer in the monitoring well H59-14-6 to support the idea that natural fractures are not open during CO_2 injection[1]. The premise being that the microseismic event distribution would be similar to the permeability field (Figure 19.5). The results of the microseismic tests are in good consistency with the produced CO_2 measurements. The mapped preferential flow direction and sweeping profile of CO_2 could provide a good prediction of the production and even breakthrough of CO_2 which is useful for guiding the sweeping conformance control strategy and optimizing reservoir injection/production schemes[1].
Seismic events (Detection / magnitude / attribution (natural induced).
Not documented

Monitoring technologies applied and experiences with monitoring;	
Surface monitoring technologies deployed	
Soil gas survey	If abnormally high CO_2 concentration is detected, other gas contents, such as O_2, N_2, CH_4, C_2H_6 and C_3H_8 will be analysed to track the source of CO_2[3] . The CO_2 content in the soil gas maintained 0.34-2.95 mol% less than the background value of 3-4 mol%[3].
Shallow water monitoring	Detect levels of pH and CO_2 content in the shallow water sampled. Pre-injection monitoring was undertaken in March 2008 around all wells. Repeated measurements initiated in 2012 after CO_2 breakthrough had occurred in most of the production wells[3](Figure 19.4). CO_2 content measured 305-313 ppm CO_2 with a pH value of 6.5-7, within the background range of no more than 320 ppm and pH 6-8[3].

Subsurface monitoring technologies deployed (well logs)	
Electric spontaneous potential measurement (ESP)	Baseline ESP measurements were performed (April 2008) on injection wells H-4-2, H-6-6, H-10-8, and H-12-6. Repeated surveys undertaken in March 2009 to track and map CO_2 migration in the reservoir[3]. Time-lapse ESP data show a considerable change in ESP response between the baseline and the repeated measurement (Figure 19.6)[3]. Indicating an increase in formation water conductivity in the reservoir due to dissolution of injected CO_2. The maximum migration distance and direction in the four injection wells is shown on Figure 19.6, the patterns can be correlated to reservoir properties e.g. heterogeneity, sedimentary facies and sandbody thickness and permeability[3]. The movement speed of injected CO_2 determined by ESP measurement mainly represents the speed of CO_2-oil miscible belt. Between 0.2 and 0.3 m/d, which indicates that the miscible belt of CO_2 and oil can reach production wells 3-4 years later[3].
Cross-well seismic	In March 2008, cross-well seismic surveys were undertaken in the H-59 block (Figure 19.7). Six cross-well seismic lines were measured, with an average length of 600 m and crossing through three CO_2 injectors in the centre. The frequency band used ranges from 100 to 800 Hz, and a set of geophysical receivers with 10 m spacing were placed along the wellbore over 200 m long[3]. Repeated measurements have been delayed which means time-lapse results can’t be compared. Results from pre-injection cross well seismic between well H-14-6 and H-12-8 is shown in Figure 19.7.
Fluid sampling	Production fluids sampled from all wells (pilot study) every two weeks. Composition of gas (incl. CO_2 & N_2) and hydrocarbon components measured. pH and major ion concentrations (e.g. Ca^{2+}, Mg^{2+}, Na^+, K^+, HCO^{3-}, CO_3^{2-}, Cl^- and SO_4^{2-})[3].
Formation micro-scanner logging	Identify the lithology and natural fractures in the reservoir. Results in H-59 show the natural

	fractures are well developed in the oil reservoir but are closed and have no contribution to fluid flow[3].
Gas tracer – to detect inter-well CO_2 connectivity.	Effective response, which can track the spread of CO_2, indicate the inter-well connectivity and identify the high permeability channels in the reservoir (Figure 19.8)[3]. Second test (after first failed) implemented in the two middle well groups (H59-8-4 and 6-6). QT-1 and QT-2 (CO_2 soluble fluorocarbon) were chosen, following injection samples of casing gas and solution gas from produced oil collected once a day over 3-6 months in all the production wells. The concentration of gas tracer analysed by GC-ECD (gas chromatograph electron capture detector)[1]. Results of gas tracer for well 6-6 compared with microseismic results (Figure 19.9). Injected CO_2 generally moves towards producers in an east-west direction, consistent with CO_2 sweeping profile as indicated from microseismic distribution (Figure 19.4)[1]. The fastest rate of movement is between H59-6-6 and 4-6 at around 20 m/d, and the slowest is ~2 m/d. And the highest concentration is found in 4-6 showing good connectivity between injector and producer, potentially along fractures. Injected CO_2 in well H59-14-6 mainly spreads towards well H-12-4 and 12-6 along the direction of sealing fault line, and to other directions weakly (Figure 19.5)[1]. Injected CO_2 in well H59-4-2 shows a uniform sweeping profile. Daily average production rates verses time plots corroborate these results[1]. Gas tracer results show that the producer H59-4-4 is only impacted by the CO_2 injector H59-4-2, whereas well 59-2-2 has almost equivalent connectivity with the four CO_2 injectors[1].
Experience summary - effectiveness of techniques (limitations / strengths)	
Gas tracer test, ESP measurement and CO_2 content monitoring are effective monitoring techniques. Cross-seismic was not applied successfully due to lack of repeated data collection. Gas tracers most effective, track the spread of CO_2, indicate inter-well connectivity and identify high permeability channels in the reservoir[3].	

The gas tracer results combined with ESP and microseismic can verify the results. This makes it useful for tracking the CO_2 front and distribution in reservoir.

List of key publications covering the site

1. Ren, B., Ren, S., Zhang, L., Chen, G. and Zhang, H., 2016. Monitoring on CO_2 migration in a tight oil reservoir during CCS-EOR in Jilin Oilfield China. Energy, 98, pp.108-121.
2. 'CCUS-EOR Practice in Jilin Oilfield' http://www.cnpc.com.cn/en/xhtml/pdf/15-CCUS-EOR%20Practice%20in%20Jilin%20Oilfield.pdf
3. Zhang, L., Ren, B., Huang, H., Li, Y., Ren, S., Chen, G. and Zhang, H., 2015. CO_2 EOR and storage in Jilin oilfield China: Monitoring program and preliminary results. Journal of Petroleum Science and Engineering, 125, pp.1-12.
4. '"Setting the pace" – China establishes world's 18th large-scale CCS facility' https://www.globalccsinstitute.com/news-media/press-room/media-releases/?page=7
5. Zhang, L., Li, X., Ren, B., Cui, G., Zhang, Y., Ren, S., Chen, G. and Zhang, H., 2016. CO_2 storage potential and trapping mechanisms in the H-59 block of Jilin oilfield China. International Journal of Greenhouse Gas Control, 49, pp.267-280.
6. Bo, L.I.U., Jiahui, S.U.N., ZHANG, Y., Junling, H.E., Xiaofei, F.U., Liang, Y.A.N.G., Jilin, X.I.N.G. and Xiaoqing, Z.H.A.O., 2021. Reservoir space and enrichment model of shale oil in the first member of Cretaceous Qingshankou Formation in the Changling sag, southern Songliao Basin, NE China. Petroleum Exploration and Development, 48(3), pp.608-624.

Figures

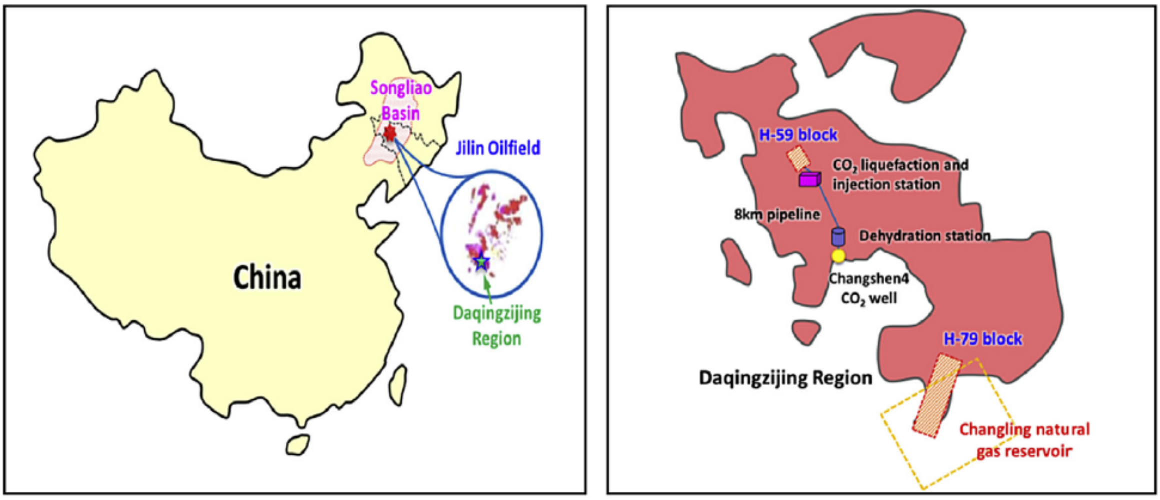


Figure 19.1: location of CO_2-EOR and storage project in Jilin oilfield northeast China[1].

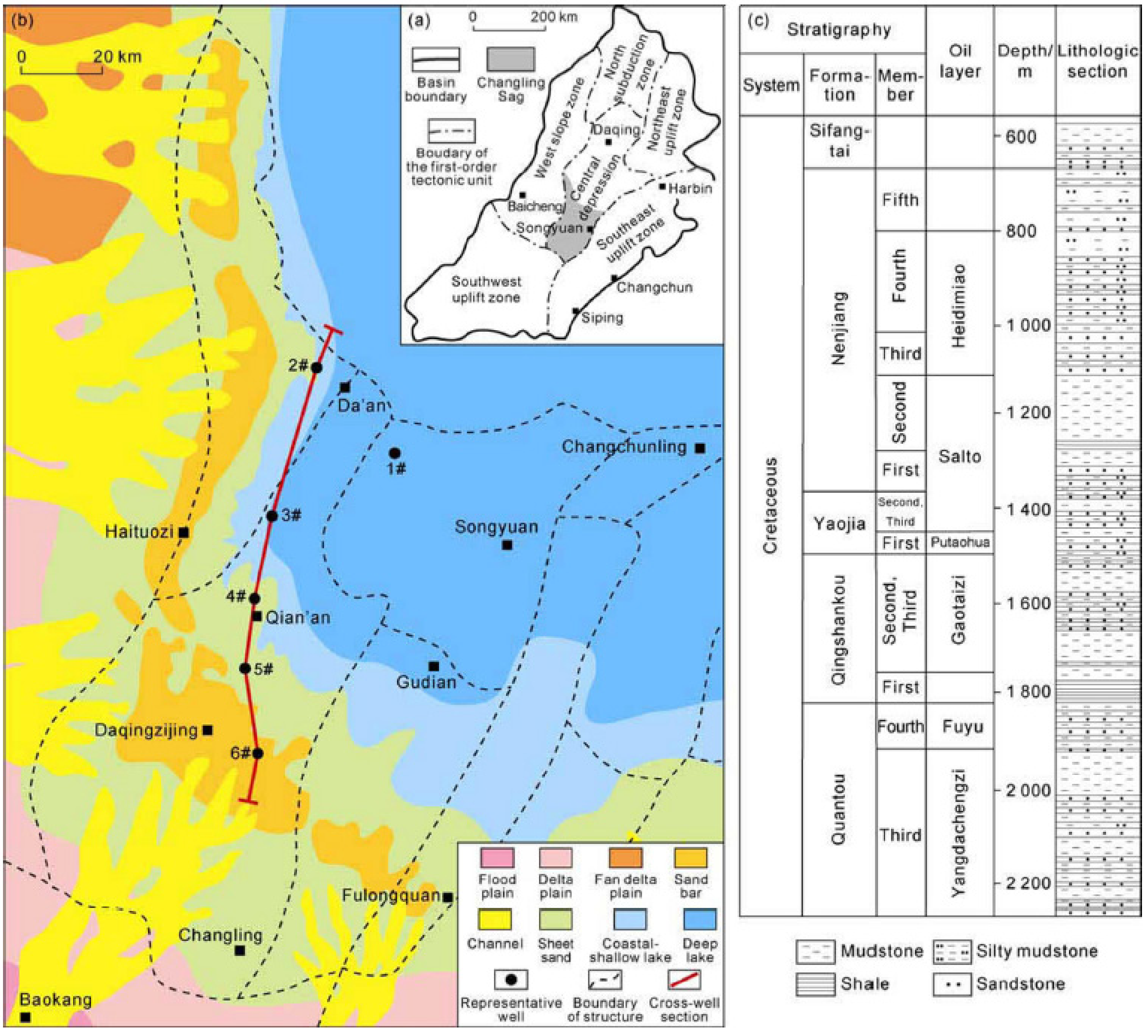


Figure 19.2: Regional geological setting and composite stratigraphic column in the Changling sag, southern Songliao Basin. The Jilin field is in the Daqingzijing area[6].

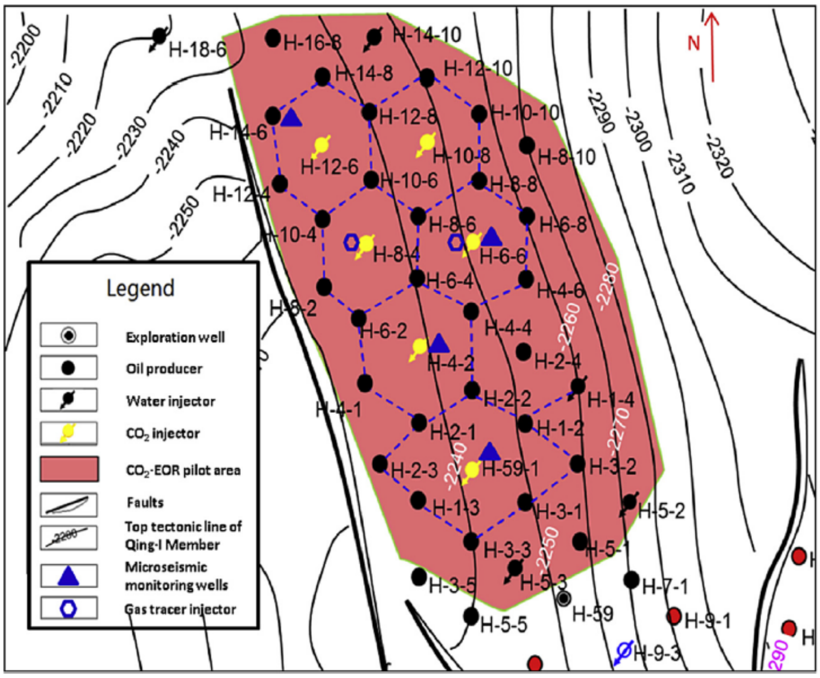
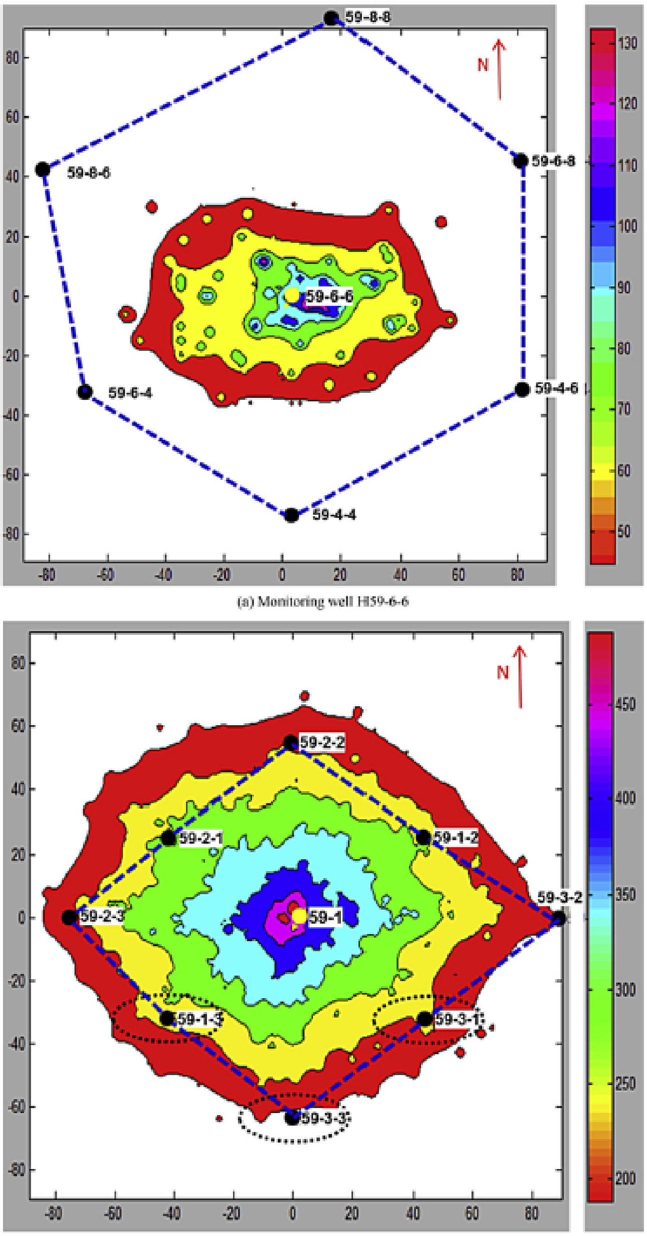


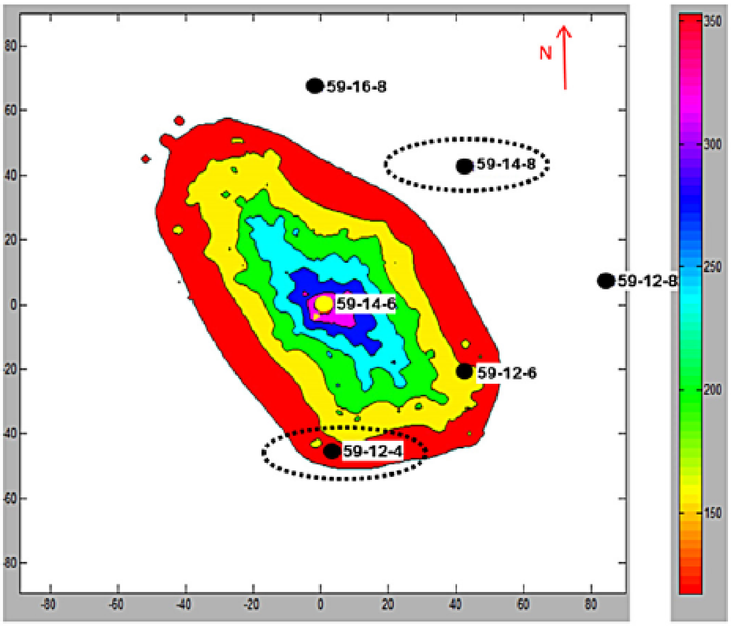
Figure 19.3: surface layout of the well pattern at the beginning of the CO_2 injection[1].



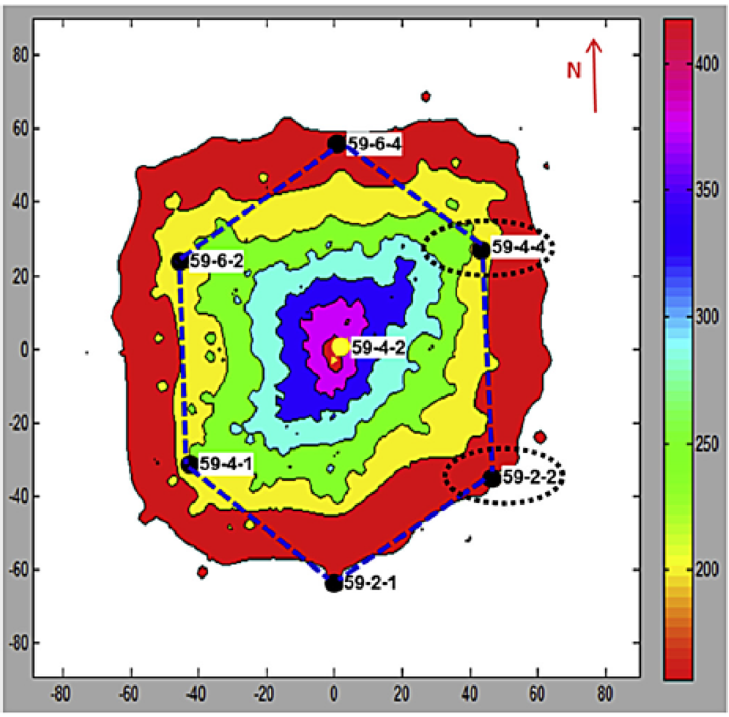
(a) Monitoring well H59-6-6

(b) Monitoring well H59-1

Figure 19.4: Microseismic events stacking at reservoir levels 7 in wells 6-6 (a) and H59-1 (b). Yellow circle is the injector, black circles are the producers. Colour bar shows the number of microseismic events detected during the monitoring period. Axis shows distance in meters[1].



(a) Monitoring well H59-14-6



(b) Monitoring well H59-4-2

Figure 19.5: Microseismic events stacking at reservoir levels 12,14 and 15 in well H59-14-6 (a) and levels 7 and 12 in well H59-4-2 (b). Microseismic observation time lasts 150 and 170 min respectively. Yellow circle is the injector, black circles are the producers. Colour bar shows the number of microseismic events detected during the monitoring period. Axis shows distance in meters[1].

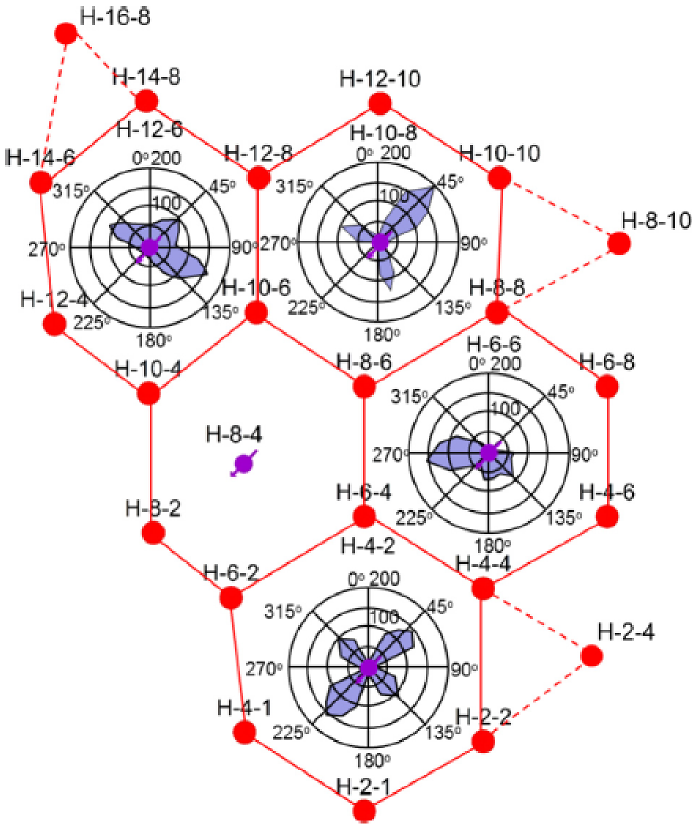


Figure 19.6: interpreted results of ESP measurements (April 2008-March 2009) showing the movement direction and distance of CO2 in the reservoir[3].

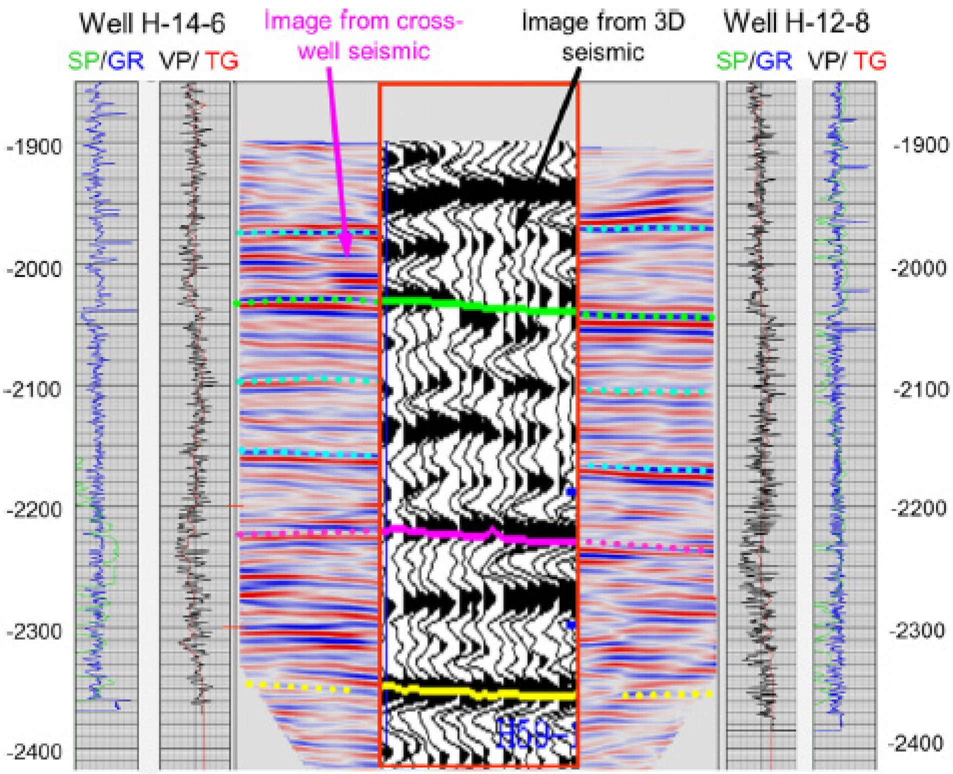


Figure 19.7: Comparison of seismic images between well H-14-6 and well H-12-8 measured by cross-well and 3D seismic techniques. The vertical resolution of cross-well seismic is nearly five times greater than that of conventional surface 3D seismic[3]. No repeat seismic was completed[3].

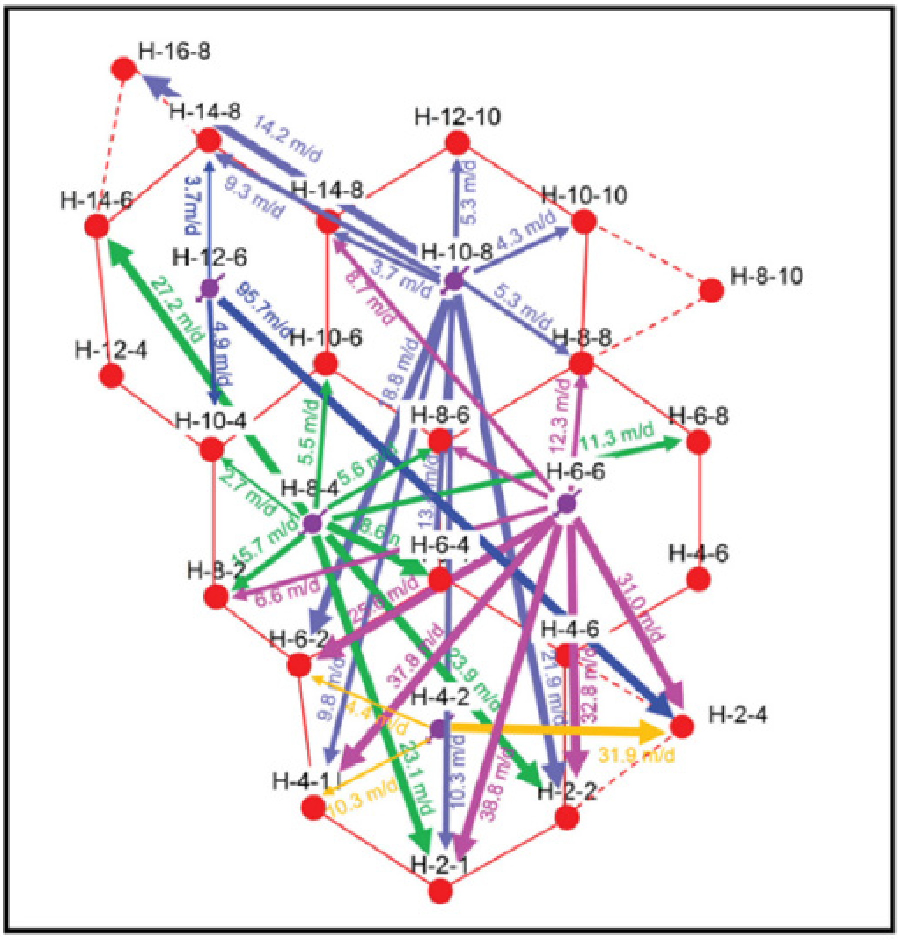


Figure 19.8: Gas tracer test conducted in January 2009, indicating fractures and high-permeability channels[5].

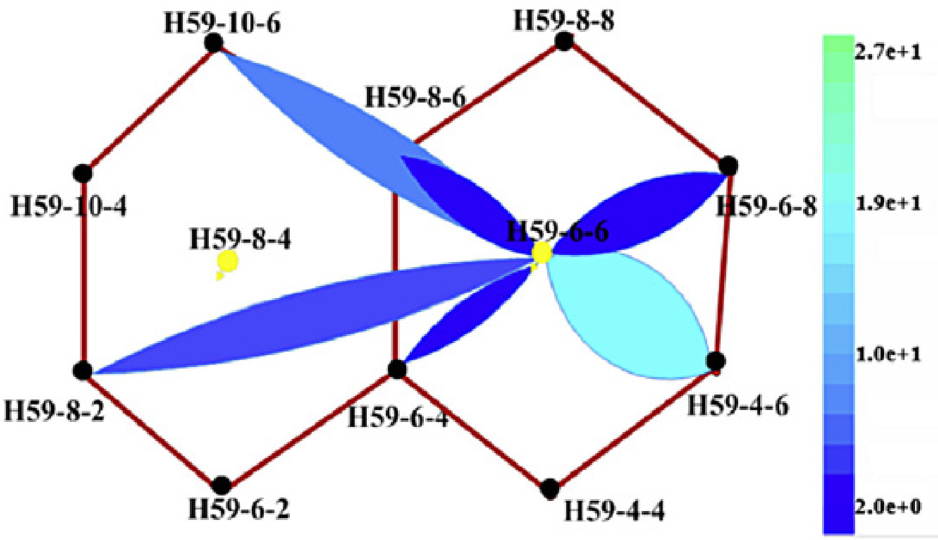


Figure 19.9: Gas tracer test with the tracer injector of H59-6-6 shown in the right yellow circle. The black solid circles are the tracer sampling production wells. The colour bar shows CO_2 average movement rate between wells in m/d. Relative width of the leaf shapes are the relative peak tracer concentration monitored during sampling period. Note most of the injected tracer moves towards producers in the E-W direction[1].

20. Tomakomai

Site Details					
Name	Location	Province/State	Country	Onshore	Offshore
Tomakomai CCS Demonstration Project	Tomakomai City	Hokkaido Prefecture	Japan		✓

General storage type

Deep saline aquifer

Development History (Post-injection monitoring phase)

The Tomakomai Project began in 2012, took four years of construction, three years and eight months of CO_2 injection and ongoing post injection monitoring (Figure 20.1)[1]. Coordinated by the Japan CCS Co., Ltd (JCCS) – founded in 2008 when a group of major companies with expertise in CCS-related fields joined forces to answer the call from the Japanese government to develop CCS technology as a countermeasure against global warming. Investigation work including 3D seismic, investigation well, geological evaluation, conceptual design, assessing CO_2 sources, capture processes and transportation work was undertaken 2009-2010 and identified the Tomakomai area to be best suited. The Ministry of Economy, Trade and Industry (METI) authorised the decision to implement the demonstration project.

The project aims to demonstrate the safety and reliability of a full cycle CCS system from capture to offshore storage, confirm the technologies adopted in the project work properly and efficiently and to establish CCS technology for practical use by around 2020.

The CO_2 is sourced from offgas from an HPU (hydrogen production unit) of an oil refinery- located at the Tomakomai Port and sent by 1.4 km pipeline to the capture facility. Captured gaseous CO_2 is recovered by an activated amine process and sent to the injection facility where it is compressed and injected by two deviated wells targeting two offshore reservoirs. CO_2 injection began in April 2016 into the Moebetsu formation until November 2019 with 300,012 tonnes injected. Low injectivity hampered injection into the Takinoue formation with only 98 tons injected[1].

Comprehensive monitoring (on- and offshore) comprised three observation well, an ocean bottom cable (OBC), four ocean bottom seismometers and an onshore seismic station, the monitoring of seismicity and pressure and temperature of the reservoirs started in February 2015, thirteen months prior to CO_2 injection. To date no indications of seepage of injected CO_2 into the ocean have been detected. The 2018 Hokkaido Eastern Iburi Earthquake (6.6 moment magnitude (M_w)) had no effect on the stored CO_2[1].

Geological Characteristics

Reservoir Formations

There are two targeted reservoirs: the sandstone layer of the Lower Quaternary Moebetsu formation (1,000 m to 1,200 m depth and 3 km off the coastline) and the volcanic and volcaniclastic

1 Tanase, D. and Tanaka, J., 2021, March. Progress of CO_2 injection and monitoring of the Tomakomai CCS Demonstration Project. In Proceedings of the 15th Greenhouse Gas Control Technologies Conference (pp. 15-18).

layers of the Miocene Takinoue formation (2,400 m to 3,000 m in depth and 4 km off the coastline) (Figure 20.2 and Figure 20.3)[1].	
Lateral extent / thickness variation	Moebetsu Formation: 1-200 m thick. Takinoue Formation: 60 0m thick.
Rock type	Moebetsu Formation – sandstones, pebbly sandstones and interbedded thin mudstone beds[2]. Takinoue Formation – volcanic and volcaniclastic rocks.
Sedimentary features: Depositional Environment / facies type & variation / mineral composition	The Moebetsu sandstone member has been recognised as a fan delta system. Progradation and retrogradational patterns are seen as identified by fining and coarsening upward patterns, as well as channel fill deposits. The fan deltas prograde from the northeast to the southwest on the shelf. Interpreted as a Highstand Systems Tract with an overlying mudstone identified as Transgressive Systems Tract (Figure 20.3)[2].
Porosity	Moebetsu: average porosity 5 to 40%. Takinoue Formation: average porosity 10 to 20%.
Permeability	n/a
Formation fluid properties: (residual hydrocarbons / salinity concentration).	n/a
Caprock / primary seal formation	
The Moebetsu Formation sandstone reservoir is overlain by a mudstone layer of the same formation. The Takinoue Formation is overlain by Miocene mudstones of the Fureoi formation, Biratori-Karumai formation and Nina formation[1].	
Lateral extent / thickness variation	Moebetsu Formation mudstone is ~200 m thick [2]. The mudstones of the Fureoi formation, Biratori-Karumai formation and Nina formation are ~1000 m thick[1].
Rock type	Mudstones.
Fracture pressure	n/a

2 Ito, D., Matsuura, T., Kawada, K., Nishimura, M., Tomita, S., Akaku, K., Inamori, T., Yamanouchi, Y. and Mikami, J., 2013. Reservoir evaluation for the Moebetsu Formation at Tomakomai candidate site for CCS demonstration project in Japan. Energy Procedia, 37, pp.4937-4945.

Porosity	n/a
Permeability	n/a
Overburden Features (Thickness, formations presence of secondary reservoirs / seals)	
n/a	
Structure	
Fold type / fault bounded	The Moebetsu Formation has a gentle monocline structure with NE dip of 1 to 3° at the planned storage area[1]. The Takinoue Formation has an anticlinal structure with a NNW-SSE trending axis, with targeted storage area located in the north-eastern wing of the anticline[1].
Faults /Fractures (Type – normal, reverse, strike-slip)	No remarkable faults cut the Moebstsu Formation[2].
Displacement	n/a
Stability (pre-stressed, active, stable)	n/a
Injection / storage history	
Number of injection, monitoring or other wells, well geometry, design and key completion information for injection wells, relevant well issues. Reused / new purpose drilled well.	
Two deviated injection wells drilled from the land to sub-seafloor thereby avoided affecting the port operation and fishing activities (Figure 20.2). Injection well for Moebetsu formation drilled to depth 3,650 m, a vertical depth of 1,188 m and a maximum inclination of 83°. It is an extended reach well (ERD) with the horizontal reach from wellhead to well bottom (horizontal distance) being 3,058 m. CO_2 is injected into reservoir through a steel pipe (3.5 inch diameter tubing). The completion interval is 1,194 m and perforated liners 7 inch in diameter were installed to enable CO_2 to penetrate the pores of the reservoir (Figure 20.4) [1, 3]. Injection well for the Takinoue formation is a highly deviated well with a drilled depth of 5,800 m, a vertical depth of 2,753 m, a maximum inclination of 72° and a horizontal reach of 4,346 m. The injection interval is also completed with slotted liners, reaching a length of 1,134 m[1].	
Three observation wells (OB-1, OB-2, OB-3), two for Takinoue Formation and one for the Moebetsu Formation. All equipped with pressure and temperature sensors and downhole 3D seismic sensors (Figure 20.5).	
Extent and status of casing (corrosion history/ cementation records)	n/a
Injection rates & pattern (i.e. continuous / intermittent) changes in injection behaviour	Maximum injection rates for both reservoirs were planned at 600 tonnes/day (220,000

3 Tanaka, Y., Sawada, Y., Tanase, D., Tanaka, J., Shiomi, S. and Kasukawa, T., 2017. Tomakomai CCS demonstration project of Japan, CO2 injection in process. Energy Procedia, 114, pp.5836-5846.

	tonnes/year at 365 operation days per year). However, brine injection tests showed extremely low permeability for the Takinoue Formation[1]. Max injection rate decreased to 3 tonnes a day. Test injection of 7,163 tonnes CO_2 into the Moebetsu Formation occurred April to May 2016[3]. Maximum bottom hole pressures demonstrated that the injectivity of the Moebetsu Formation is very high[3]. Continuous CO_2 injection started February 2017 until November 2019 – with injection rate ranging between 67,000 to 225,000 tonnes/year (Figure 20.6).
Total quantities stored	Cumulative total of 300,012 tonnes of CO_2 was injected into the Moebetsu and 98 tonnes into the Takinoue Formations (Figure 20.6)[1].
Reservoir capacity (estimate)	n/a
Fluid extraction rate (brine extraction, oil for EOR)	n/a
Seismicity	
Monitoring regime (technologies deployed)	
Using the seismometers in the observation wells, the OBC, the OBSs and the onshore seismic station (Figure 20.5), integrated monitoring of micro seismicity and natural earthquakes started on February 1, 2015, thirteen months prior to the startup of CO_2 injection[1].	
6 km by 6 km monitoring area for microseismicity covering injection area using OBC, OBSs and observation wells[1].	Possible to detect -0.5 M_w or greater at reservoir depths with accuracy[1].
50 km by 38 km monitoring area for natural seismicity using onshore seismic station and four Hi-net stations deployed by Japanese government[1].	
Seismic events (Detection / magnitude / attribution (natural induced)	
The seismicity monitoring results in the monitoring area for microseismicity are shown in Figure 20.7. Prior to injection nine events (-0.04 to 0.44 M_w) were detected at depths 5.97 km to 8.59 km, and three events (0.33 to 0.50 M_w) detected at 7.70 km to 7.80 km after the start of injection. One post-injection event of 0.59 M_w was detected at 5.86 km. All events were located in the Cretaceous basement igneous rocks and no seismicity was detected at the reservoir depth interval[1].	
In 2018, the Hokkaido Eastern Iburi Earthquake of 6.6 M_w struck the island of Hokkaido on 6 September[1]. The epicentre was ~30 km from the CO_2 injection site and at a depth of 37 km, the direct distance was 47 km. An acceleration of 158 gal was observed at the capture facility, but there	

was no damage to the capture and injection facilities[1]. Prior to the earthquake CO_2 injection had been suspended due to supply from the refinery, bottom hole pressure and temperature measurements from the Moebetsu injection well were not impacted by the earthquake suggesting there were no abnormalities in the reservoirs.
Monitoring technologies applied and experiences with monitoring See Figure 20.5 for layout.
Surface monitoring technologies deployed

An OBC equipped with 72 seismometers, buried 2 m below the seabed directly above the storage area of the reservoirs[1].	(receiver for 2D seismic survey)
Four OBSs[1].	
Onshore seismic station in the northwestern part of Tomakomai City[1].	
2D and 3D seismic surveys[1].	Baseline 3D seismic October – November 2009. Baseline 2D (crossing injection points of both formations) August 2013. Monitor surveys 2D & 3D planned every other year. Five surveys implemented (see Figure 20.8). Mini 3D survey covers only injection point of the Moebetsu formation. The 2nd, 3rd and 4th monitor surveys showed growth in the anomalies in the RMS (Root Mean Square) amplitude difference volumes corresponding to the evolution of the CO_2 plume at the upper portion of the injection interval of the Moebetsu formation (Figure 20.9).
Marine environmental survey[1]	Marine data (physical, chemical properties, biological habitat etc.). Four phases: regular survey, follow-up survey, precautionary survey, and contingency survey. Initial threshold line established based on data from seasonal baseline surveys (August 2013-May 2014). No abnormalities of chemical measurement of sea bottom sediments and plankton and benthos observation were observed[1].

	Permits last five year and are required indefinitely, the current permit was granted March 2021.
Side scan sonar (bubble detection) and pH sensor survey	Exceedance in thresholds in July 2016 resulted in modification to the monitoring plans – to be undertaken along with chemical measurement of sea water. Four follow-up surveys and no anomalies of pH, bubbles form the seabed or re-exceedance of the threshold were detected[1].
Subsurface monitoring technologies deployed (well logs)	
Downhole temperature and pressure in injection and observation wells	
Well head pressure	

Major technical/scientific studies on the site, major learnings, Conformance assessment (history-matching with models, correlation between different monitoring techniques)

A unique project including: a low energy consumption CO_2 capture process, two highly deviated injection wells drilled from the onshore targeting two separate reservoirs with long injection intervals, an extensive onshore and offshore monitoring system, and seasonal environmental survey conducted during and after CO_2 injection[1].

Despite predictions of reservoir permeability (results from an investigation well), the Takinoue Formation at the site of the injection well consisted of tuff with very low permeability – highlighting uncertainties in predicting the injectivity of volcanic rocks due to heterogeneity in lithofacies[1].

A 6.6 M_w earthquake which hit the island of Hokkaido 30 km from the CO_2 injection site had no impact of the storage site and there is no evidence to suggest a connection between the CO_2 storage and the earthquake[1].

With support of major local companies, industrial associations and fishing unions, Tomakomai city established the 'Tomakomai CCS Promotion Association' in 2010 in order to bring the demonstration project to Tomakomai, and to communicate information on CCS to its residents. Extensive social outreach events have been organised e.g. panel exhibitions, forums for residents, science classes for schoolchildren, seminars for senior citizens and site visits. On a wider level JCCS conducts seminars on CCS at Japanese universities and industrial associations and participates in large exhibitions on environmental and global warming issues in Japan and abroad[3].

List of key publications covering the site
1. Tanase, D. and Tanaka, J., 2021, March. Progress of CO_2 injection and monitoring of the Tomakomai CCS Demonstration Project. In Proceedings of the 15th Greenhouse Gas Control Technologies Conference (pp. 15-18). 2. Ito, D., Matsuura, T., Kawada, K., Nishimura, M., Tomita, S., Akaku, K., Inamori, T., Yamanouchi, Y. and Mikami, J., 2013. Reservoir evaluation for the Moebetsu Formation at Tomakomai candidate site for CCS demonstration project in Japan. Energy Procedia, 37, pp.4937-4945. 3. Tanaka, Y., Sawada, Y., Tanase, D., Tanaka, J., Shiomi, S. and Kasukawa, T., 2017. Tomakomai CCS demonstration project of Japan, CO_2 injection in process. Energy Procedia, 114, pp.5836-5846.
Other relevant information considered pertinent to the report
METI (2000) Report of Tomakomai CCS Demonstration Project at 300 thousand tonnes cumulative injection. Summary Report. https://www.meti.go.jp/english/press/2020/pdf/0515_004a.pdf Sawada, Y (2019) Progress of the Tomakomai CCS Demonstration Project https://www.globalccsinstitute.com/wp-content/uploads/2019/06/20190531APAC-CCS%EF%BC%88JCCS%EF%BC%89.pdf https://www.japanccs.com/en/

Figures

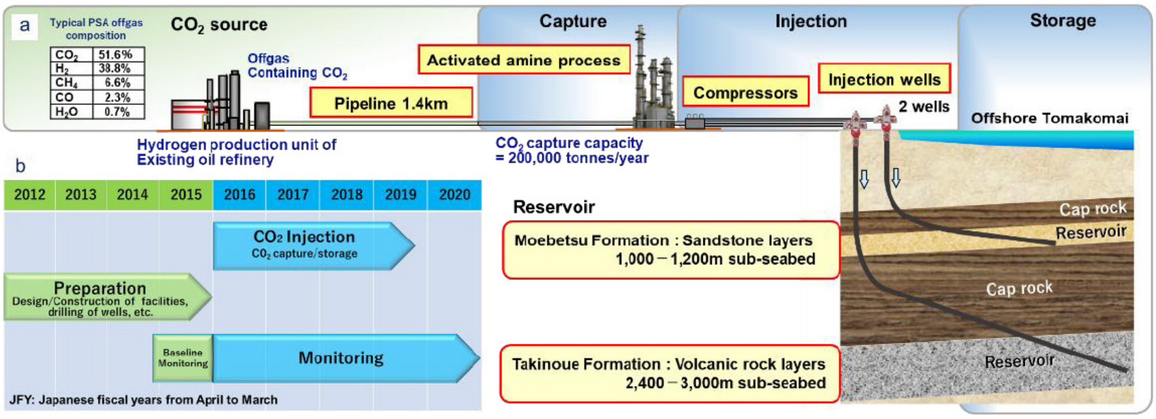


Figure 20.1: (a) Project scheme showing the flow from the CO_2 source to the two separate reservoirs (b) Project schedule [1] .

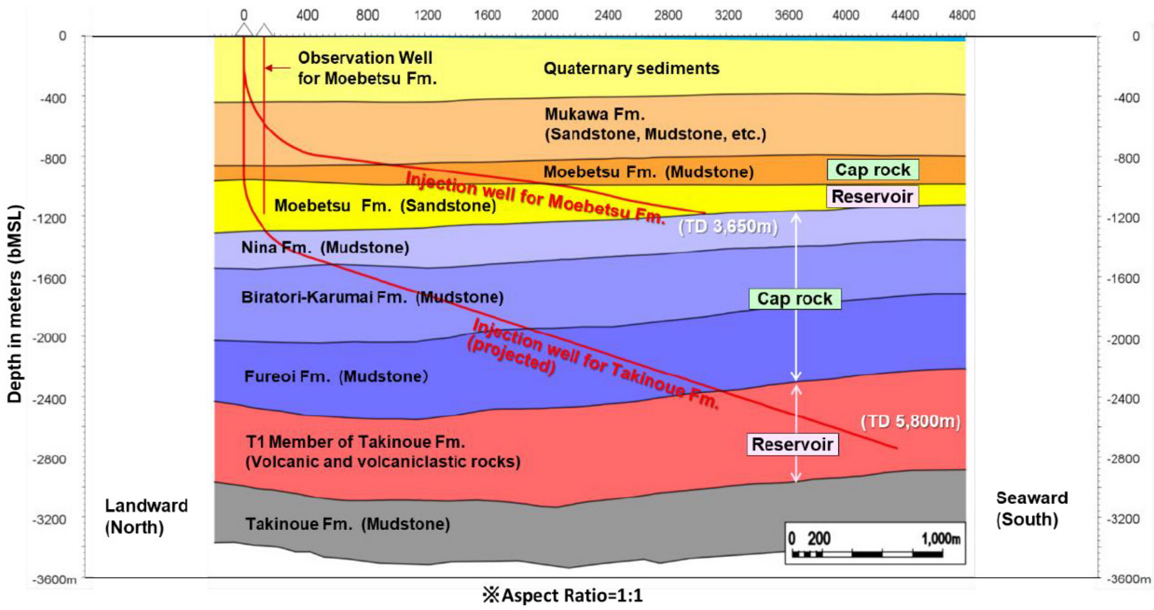


Figure 20.2: Schematic geological cross section showing the positional relationships of injection wells, reservoirs and caprocks [1]

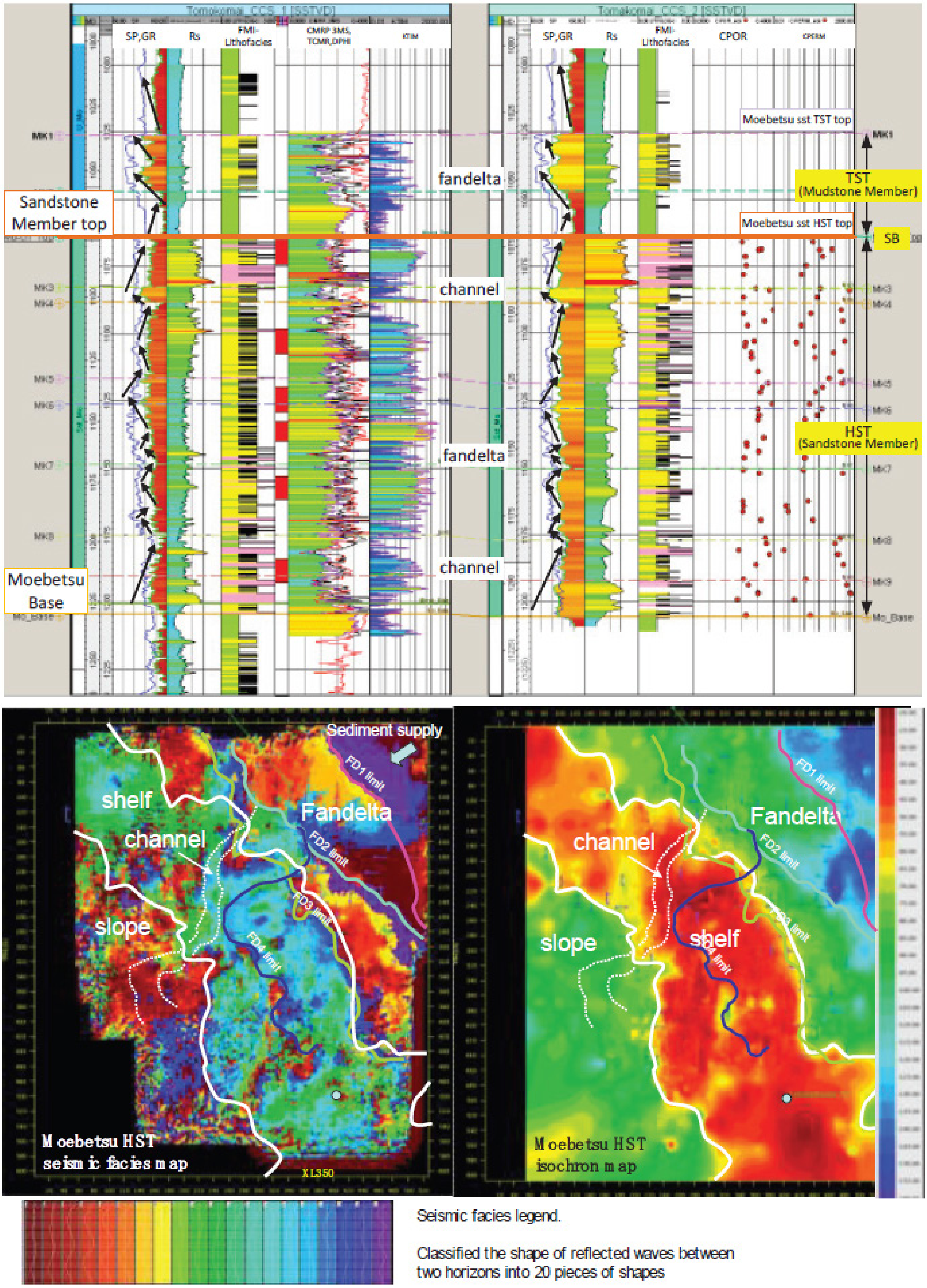


Figure 20.3: (a) Geological column of Moebetsu sandstone reservoir from FMI image with other well logs, (b) seismic facies map and (c) isochron map of the Moebetsu HST [2]

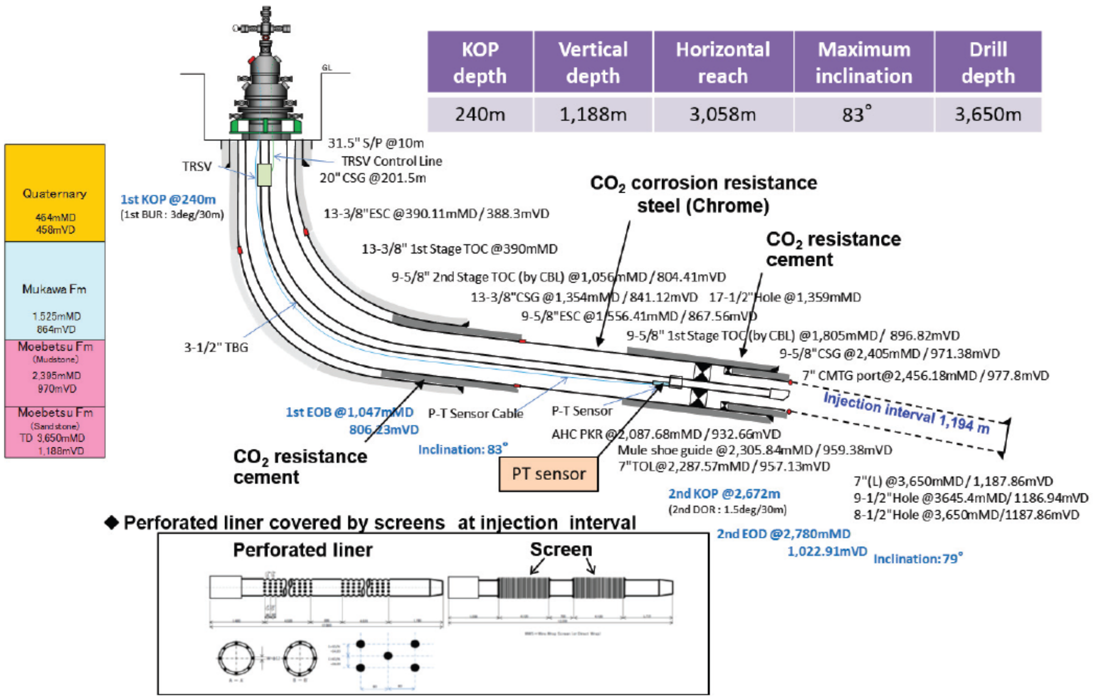
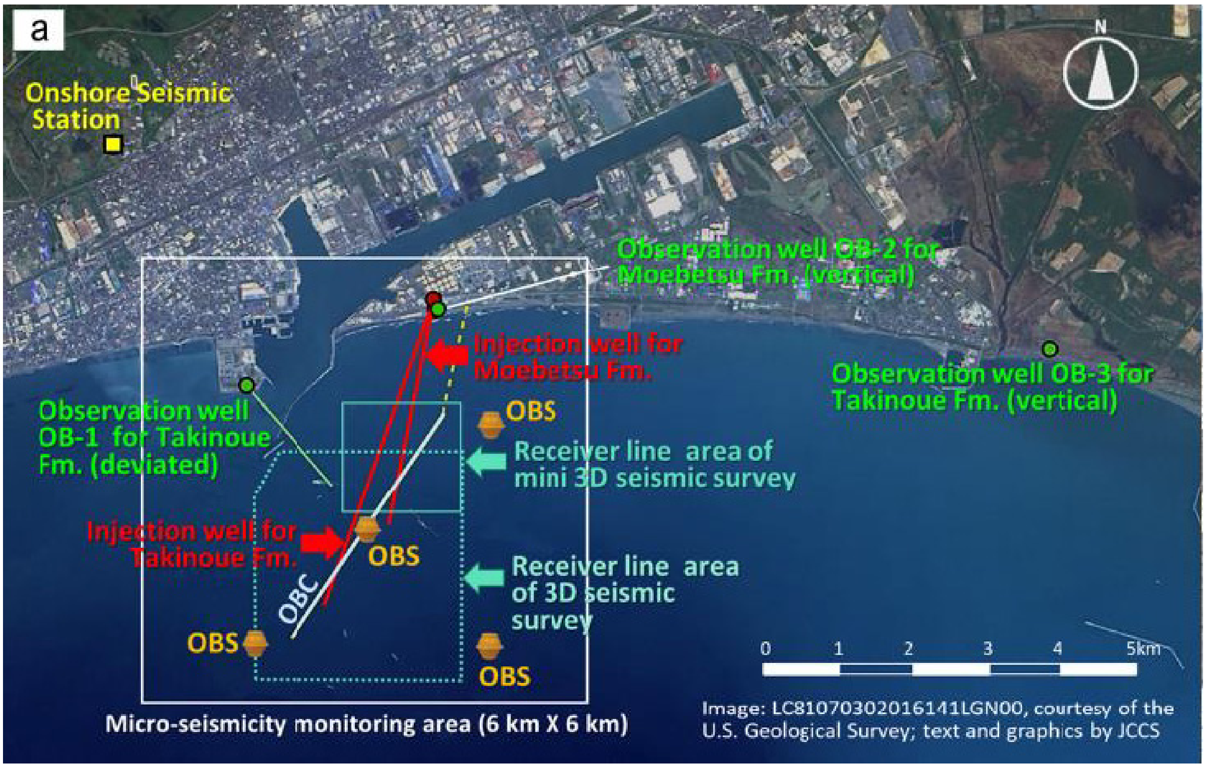


Figure 20.4: Profile of the injection well (IW-2) for the Moebetsu Formation[3].



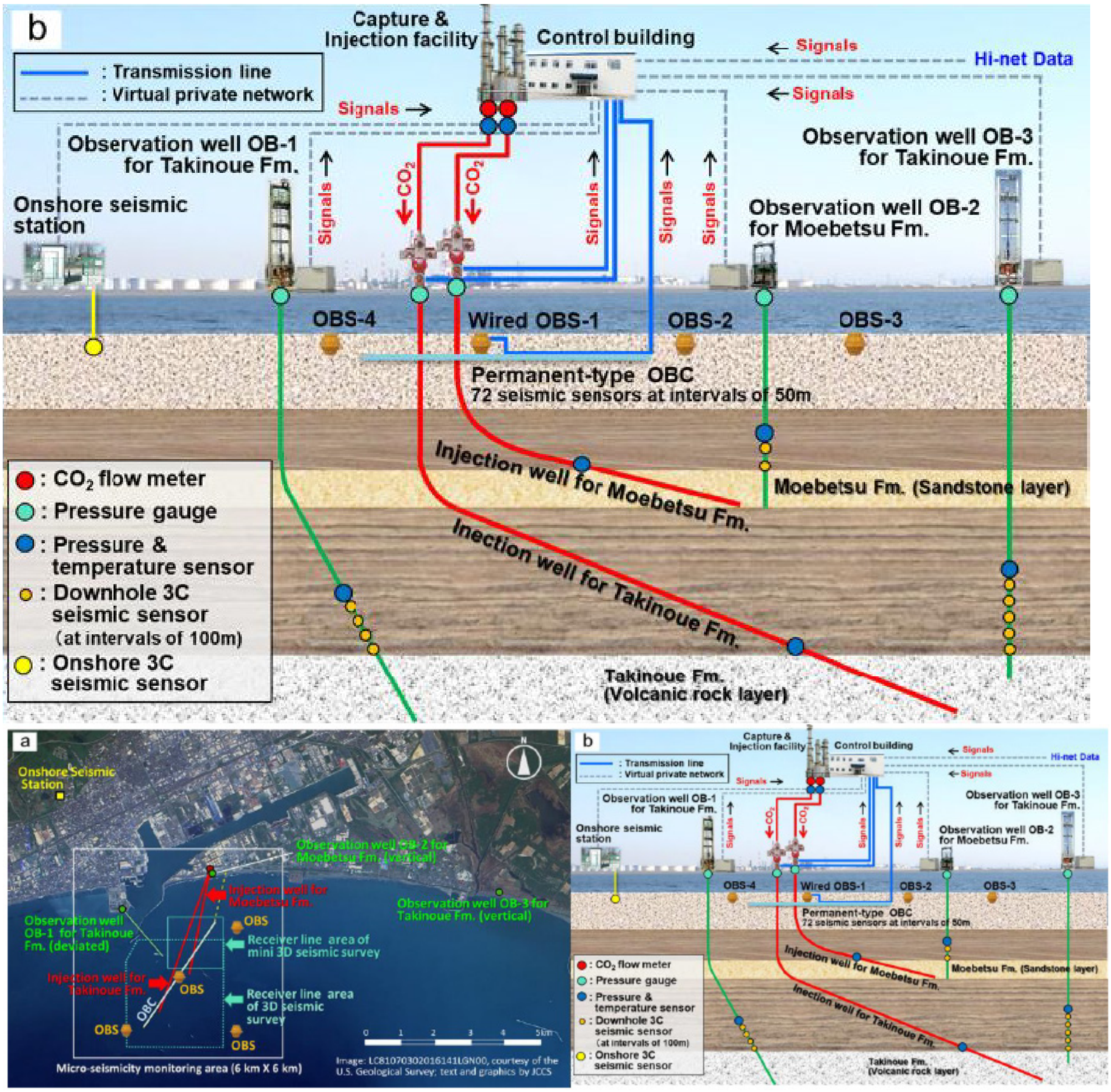


Figure 20.5: (a) Layout of monitoring facilities (plan view). (b) Schematic diagram of sensors in monitoring facilities (profile). A comprehensive seismic observation system consisting of a permanent-type ocean bottom cable (OBC) with 72 seismic sensors, four ocean bottom seismometers, three observation wells with eleven seismic sensors in total and an onshore seismic station is deployed [1] .

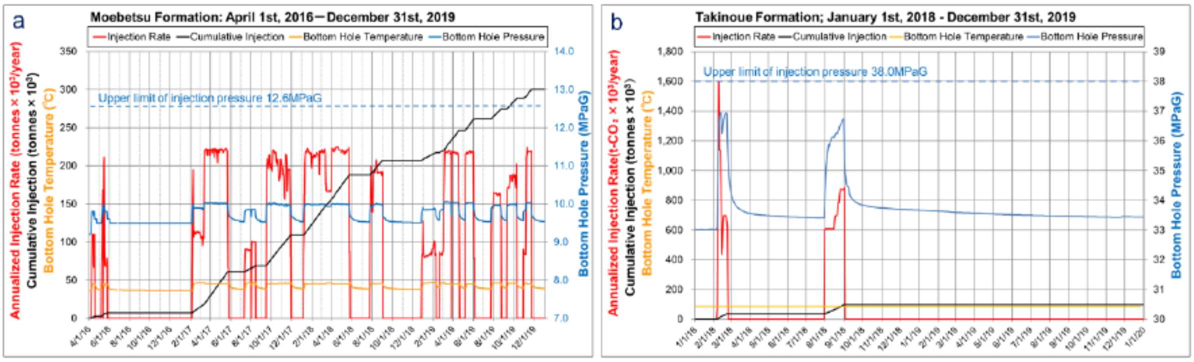
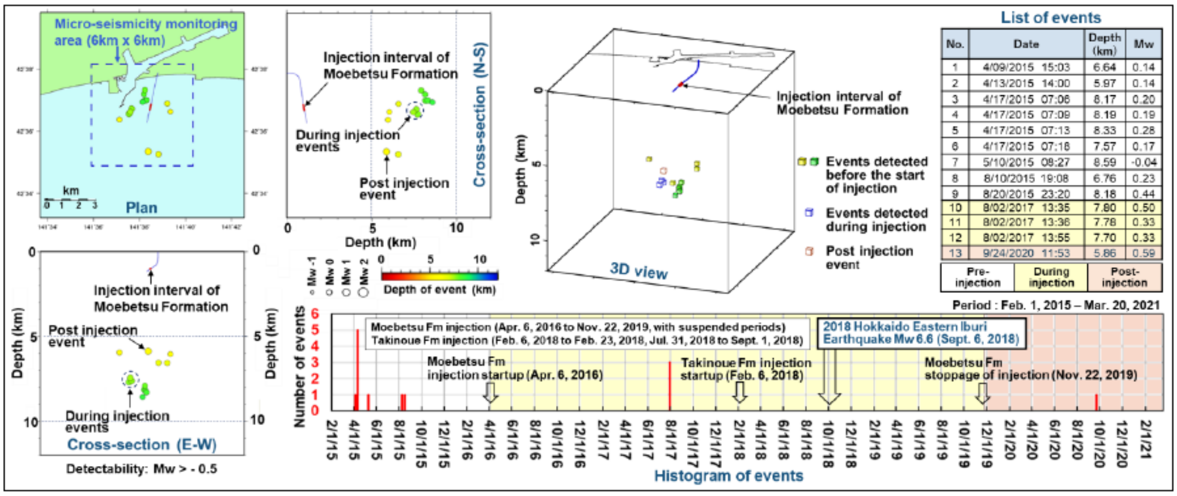
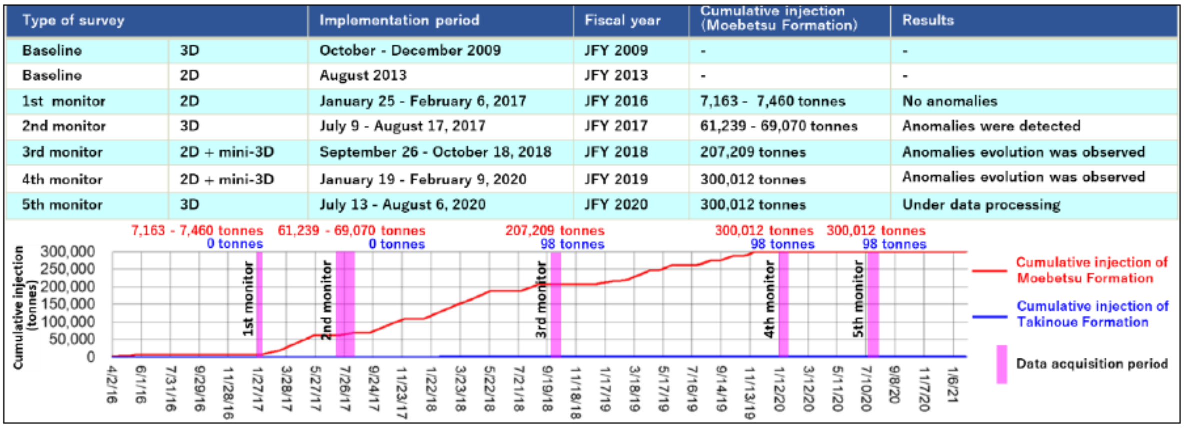


Figure 20.6: CO_2 injection record of the Moebetsu formation (a) and the Takinoue Formation (b) [1]



No.	Date	Depth (km)	Mw
1	4/09/2015 15:03	6.64	0.14
2	4/13/2015 14:00	5.97	0.14
3	4/17/2015 07:06	8.17	0.20
4	4/17/2015 07:09	8.19	0.19
5	4/17/2015 07:13	8.33	0.28
6	4/17/2015 07:18	7.57	0.17
7	5/10/2015 08:27	8.59	-0.04
8	8/10/2015 19:08	6.76	0.23
9	8/20/2015 23:20	8.18	0.44
10	8/02/2017 13:35	7.80	0.50
11	8/02/2017 13:36	7.78	0.33
12	8/02/2017 13:55	7.70	0.33
13	9/24/2020 11:53	5.86	0.59

Figure 20.7: Locations of detected events in the micro-seismicity monitoring area shown in plan, profile and three-dimensional views with list and histogram of events from February 1, 2016 to December 26, 2020. No micro-seismicity or natural earthquakes attributed to CO2 injection was detected in the vicinity of injection area including before and after the 2018 Hokkaido Eastern Iburi Earthquake [1].



Type of survey		Implementation period	Fiscal year	Cumulative injection (Moebetsu Formation)	Results
Baseline	3D	October - December 2009	JFY 2009	-	-
Baseline	2D	August 2013	JFY 2013	-	-
1st monitor	2D	January 25 - February 6, 2017	JFY 2016	7,163 - 7,460 tonnes	No anomalies
2nd monitor	3D	July 9 - August 17, 2017	JFY 2017	61,239 - 69,070 tonnes	Anomalies were detected
3rd monitor	2D + mini-3D	September 26 - October 18, 2018	JFY 2018	207,209 tonnes	Anomalies evolution was observed
4th monitor	2D + mini-3D	January 19 - February 9, 2020	JFY 2019	300,012 tonnes	Anomalies evolution was observed
5th monitor	3D	July 13 - August 6, 2020	JFY 2020	300,012 tonnes	Under data processing

Figure 20.8: Implementation results of seismic surveys showing data acquisition periods and relation to cumulative CO_2 injection [1].

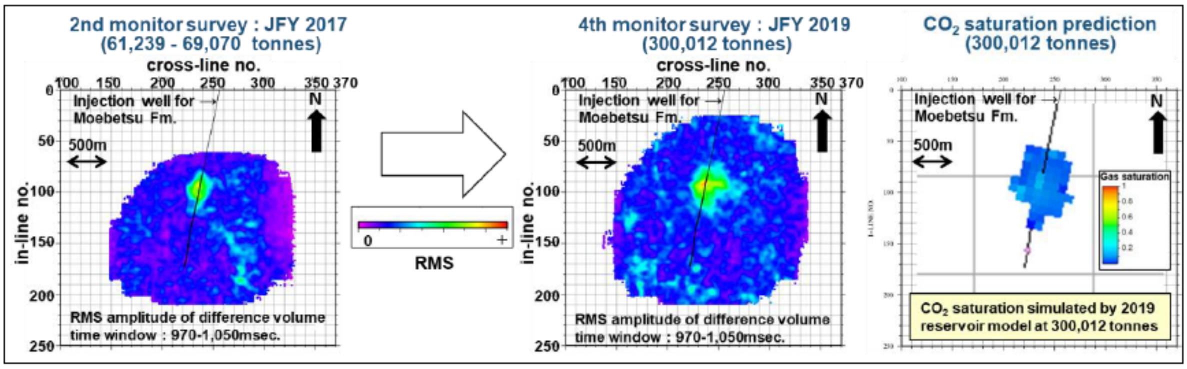


Figure 20.9: Anomalies detected at 2nd and 4th monitor surveys, comparison with CO_2 saturation prediction at cumulative 300,012 tonnes injection [1].

21. Gorgon

Site Details					
Name	Location	Province/State	Country	Onshore	Offshore
Gorgon	Barrow Island	Western Australia	Australia	✓	

General storage type
Deep saline aquifer

Development History (Active operation)
Gorgon Carbon Dioxide Injection Project, also known as Gorgon Carbon Capture and Storage, is part of the Gorgon Project, one of the world's largest natural gas projects – operated by Chevron Australia. Located on Barrow Island, it includes a liquefied natural gas (LNG) plant, a domestic gas plant and a CO_2 injection project (Figure 21.1). CO_2 injection commenced in August 2019, and 100 Mt over the project's lifetime (40% of total Gorgon Project emissions).

Geological Characteristics.	
Reservoir Formation	
Late Jurassic Dupuy Formation – 2 km beneath Barrow Island.	
Lateral extent / thickness variation	Dupuy Fm is a regionally extensive clastic formation[1]. Locally thick (~500 m). The Dupuy Formation has a thickness between 200 to 500 m of massive sandstones and highly bioturbated siltstones[2].
Rock type	Dupuy Fm is divided into four main rock units (Figure 21.4). The Lower and Upper Massive Sand units are injection targets and comprise a fine grained sandstone and siltstone (Lower Dupuy) and a fine to medium grained, blocky sandstone (Upper Massive Sand)[1]. The Upper Massive Sand contains low permeable intra-reservoir siltstone baffles, e.g., the Perforans 'Shale'.
Sedimentary features: Depositional Environment / facies type & variation / mineral composition	Deposited in a deep water slope setting, dominated by gravity processes. Sediment is sourced from a number of influx points to the east[1]. Slumping and disturbed bedding is present. The Dupuy Formation, a sand-rich formation deposited during the Late Jurassic,

1 Flett, M., Brantjes, J., Gurton, R., McKenna, J., Tankersley, T. and Trupp, M., 2009. Subsurface development of CO_2 disposal for the Gorgon Project. Energy Procedia, 1(1), pp.3031-3038.
2 Barranco, I., Mahon, E. and Sixsmith, P., 2013. Stratigraphic interpretation and reservoir modelling of the Barrow Group below Barrow Island. In The Sedimentary Basins of Western Australia 4. Proceedings of the Petroleum Exploration Society of Australia Symposium, Perth, WApp (pp. 1-23).

	not long after the Barrow rift formed. The stratigraphic interpretation of the Dupuy Formation is that it consists of a channelised slope to base-of-slope deposit which was deposited on a rugose submarine gravity slide with pressure waves and topographic lows which were infilled with better reservoir quality sands[3].
Porosity	n/a
Permeability	Moderate permeability and many baffles. A fine-grained sand sequence was deposited above the mass-transport infill section with variable reservoir quality with permeabilities below 0.1 md in the bioturbated siltstones and debris flows to permeabilities up to 200 md in the turbiditic sandstones. A more massive sand unit was deposited above that (Upper Massive Sand), however despite being cleaner, chlorite grain coatings resulted in lower permeability below 100 md[4,5]. Above the top porosity sandstone there is approximately 100 m of bioturbated silty waste zone before the first sealing unit, the Basal Barrow Group Shale (BBGS)[3].
Formation fluid properties: (residual hydrocarbons / salinity concentration).	CO_2 trapped in formation water and residual gas trapping. Salinity ~ 6,000 – 8,000 ppm.

Caprock / primary seal formation	
Cretaceous Barrow group – particularly the Basal Barrow Group shale. Multiple seals between injection zone and surface.	
Lateral extent / thickness variation	Laterally extensive. ~50 m thick K10 interval and thickens to the south[2].
Rock type	Lower part of the Cretaceous Barrow Group consists of interbedded shales and sandstones and includes thin mudstone deposit at base of

3 Trupp, M., Ryan, Scott., Barranco, Ishtar., Leon, Daniel., Scoby-Smith, Leigh., 2021. Developing the world's largest CO2 Injection System – a history of the Gorgon Carbon Dioxide Injection System. 15th International Conference on Greenhouse Gas Control Technologies, GHGT-15 15th 18th March 2021 Abu Dhabi, UAE.

4 Xia, H., Perez, E.H. and Dunn, T.L., 2020. The impact of grain-coating chlorite on the effective porosity of sandstones. *Marine and Petroleum Geology*, *115*, p.104237.

5 Golab, A., Arena, A., Barranco, I., Salazar-Tio, R., Hamilton, J., Idowu, N., Rajan, P., Sommacal, S., Young, B., Carnerup, A. and Schembre-McCabe, J.M., 2015, September. Mineralogical and Petrophysical Characterisation of a Fine Grained Sandstone With Significant Clay Coating Using 3D Micro-CT and SEM Imaging From a 5mm Plug. In *International Conference & Exhibition*.

	the Barrow Group (the Basal Barrow Group Shale). The BBGS provides top seal[6].
Fracture pressure	n/a
Porosity	n/a
Permeability	n/a
Overburden Features (Thickness, formations presence of secondary reservoirs / seals)	
Comprises Cretaceous Barrow Group and Tertiary carbonates. No presence of a potable aquifer.	
Structure: Barrow Island is in the Barrow Basin and part of the Barrow Block bound on the SE by the Gregory West fault (Figure 21.2).	
Fold type / fault bounded	Barrow Island anticline is 26 km long by 11 km wide doubly plunging NNE trending anticline (Figure 21.2 - Figure 21.4). Inversion structure that also deforms the continental shelf, and forms hanging wall anticline above Flinders and Sholl Island faults at depth[7].
Faults /Fractures (Type – normal, reverse, strike-slip)	The anticline is obliquely crossed by a number of faults including Barrow fault, the Plato fault and the Godwit fault (Figure 21.2, Figure 21.3) [7].
Displacement	n/a
Stability (pre-stressed, active, stable)	Onset of growth of the Barrow Island anticline initiated in the late Neogene and Quaternary and remains active along an overall transform sense of motion[7].
Injection / storage history	
Number of injection, monitoring or other wells, well geometry, design and key completion information for injection wells, relevant well issues. Reused / new purpose drilled well.	
A total of nine CO_2 injection wells and two reservoir surveillance wells from three drill centres. Four water production (pressure management) wells[1] and two water disposal wells from two pressure management drill centres. One above zone monitoring well (repurposed appraisal well).	

6 Trupp, M., Frontczak, J. and Torkington, J., 2013. The Gorgon CO_2 injection project–2012 update. Energy Procedia, 37, pp.6237-6247.
7 Whitney, B.B., Hengesh, J.V. and Gillam, D., STYLES OF FAULT REACTIVATION ALONG A FORMERLY RIFTED CONTINENTAL MARGIN, BARROW ISLAND REGION, WESTERN AUSTRALIA. Neotectonic Deformation in the Western Australia Shear Zone.

The pressure management wells extract water from the injection interval (away from plume area) to reduce pressure in the formation, enabling efficient injection of CO_2 and reducing pressure on key faults. Reservoir surveillance wells provide a means of in-situ monitoring of the migration of the plume away from the injection wells.	
Extent and status of casing (corrosion history/ cementation records)	Used Corrosion Resistant Alloy (CRA) material in the injection wells; wellheads and downhole tubular to reduce potential for corrosion. Wells may be backflushed from time to time to remove debris in the perforations, free water may be produced with the CO_2[6]. Detailed well engineering work to design well types with emphasis on casing design to ensure robust cementing, and detailed assessment of the completion designs[6]. The wells were designed to ensure a high-quality cement job across key reservoir and seal intervals. Cement bond logs demonstrated this outcome was achieved. All parts of the well system exposed to CO_2 were completed with 25 Cr (~25% chromium) tubulars. This is to allow for the contingency of future flow-back of the wells in case of injectivity degradation[3].
Injection rates & pattern (i.e. continuous / intermittent) changes in injection behaviour	More than 7 million tonnes of CO_2 was injected between August 2019 and October 2022 (average rate of 2.2 million tonnes per annum).
Total quantities stored	More than 7 million tonnes of CO_2 injected to date (from CCS system start up in August 2019 to October 2022).
Reservoir capacity (estimate)	More than 100 million tonnes of CO_2 expected to be mitigated over the life of the CCS system [8].
Fluid extraction rate (brine extraction, oil for EOR)	
Seismicity	
Monitoring regime (technologies deployed)	
Passive seismic monitoring is employed within the field, including a 4-station multi-component geophone array installed in the 2006 data-well and a purpose designed set of near-surface receiver locations[3].	

8 https://australia.chevron.com/-/media/australia/publications/documents/gorgon-carbon-capture-and-storage--fact-sheet.pdf

Monitoring technologies applied and experiences with monitoring; See Figure 21.5[9]	
Surface monitoring technologies deployed	
4D Seismic[1]	Lateral extent and broad vertical distribution 3D baseline survey over predicted plume area. Repeat 2D and 3D surveys over project life. 3D seismic in 2009 across northern half of Barrow Island[6]. Pre-injection baseline dataset – using three different seismic sources. Significant improvement in data quality on legacy seismic. A pre-injection survey was acquired over the vibroseis area of the original baseline survey in 2017 using autonomous node technology. The final product was of very good quality and now considered the baseline dataset for repeat surveys, the first of which was planned for 2021[3].
Soil Gas[1]	Soil gas flux sampling over the 3D seismic source grid and at potential near-surface seepage points.
Pressure sensors and CO_2 detection equipment within compression and pipeline facilities [10]	
Reservoir modelling	To evaluate subsurface uncertainty in reservoir volume, continuity and permeability. Test plume evolution under a range of geological plausible realizations. Especially the impact of permeability on injectivity and plume migration[1]. Improved with 2009 3D survey[6].
Static and dynamic models	
Subsurface monitoring technologies deployed (well logs)	
CO_2 Injection & Pressure Management Wells[1]	Well head pressure and temperature Flow rate. Continuous down-hole pressure and temperature. PLT & casing/cement integrity logs.

9 Harbert, W., Daley, T.M., Bromhal, G., Sullivan, C. and Huang, L., 2016. Progress in monitoring strategies for risk reduction in geologic CO_2 storage. International Journal of Greenhouse Gas Control, 51, pp.260-275.
10 Liu, J., 2011. CCS projects in Western Australia—Gorgon and Collie Hub. Department of Mines and Petroleum, Government of Western Australia, Perth.

Surveillance Wells[1]	Vertical Distribution and Volumetric Calculation. Continuous downhole pressure. Saturation and casing/cement integrity logs. VSP.
Core flood experiments[6]	That appraisal well collected an extensive set of geological data including 500 m of core covering the Basal Barrow Group Shale seal and most of the Dupuy Formation injection interval. A number of subsurface studies were completed, which included (1) detailed laboratory core flood experiments and reactive transport modelling to assess the potential for geochemical alteration of the Dupuy Formation in the presence of CO_2, (2) comprehensive special core analysis results from a detailed study were integrated into the reservoir model via capillary pressure curves, drainage relative permeability curves and gas trapping parameters (i.e. Lands Constant), effectively defining the imbibition relative permeability curves, and (3) a CO_2 core flood of the Basal Barrow Group Shale to understand potential geochemical and geomechanical effects of CO_2 exposure.

List of key publications covering the site

1. Flett, M., Brantjes, J., Gurton, R., McKenna, J., Tankersley, T. and Trupp, M., 2009. Subsurface development of CO_2 disposal for the Gorgon Project. Energy Procedia, 1(1), pp.3031-3038.
2. Barranco, I., Mahon, E. and Sixsmith, P., 2013. Stratigraphic interpretation and reservoir modelling of the Barrow Group below Barrow Island. In The Sedimentary Basins of Western Australia 4. Proceedings of the Petroleum Exploration Society of Australia Symposium, Perth, WApp (pp. 1-23).
3. Trupp, M., Ryan, Scott., Barranco, Ishtar., Leon, Daniel., Scoby-Smith, Leigh., 2021. Developing the world's largest CO2 Injection System – a history of the Gorgon Carbon Dioxide Injection System. 15th International Conference on Greenhouse Gas Control Technologies, GHGT-15 15th 18th March 2021 Abu Dhabi, UAE.
4. Xia, H., Perez, E.H. and Dunn, T.L., 2020. The impact of grain-coating chlorite on the effective porosity of sandstones. *Marine and Petroleum Geology*, *115*, p.104237.
5. Golab, A., Arena, A., Barranco, I., Salazar-Tio, R., Hamilton, J., Idowu, N., Rajan, P., Sommacal, S., Young, B., Carnerup, A. and Schembre-McCabe, J.M., 2015, September. Mineralogical and Petrophysical Characterisation of a Fine Grained Sandstone With Significant Clay Coating Using 3D Micro-CT and SEM Imaging From a 5mm Plug. In *International Conference & Exhibition*.
6. Trupp, M., Frontczak, J. and Torkington, J., 2013. The gorgon CO_2 injection project–2012 update. Energy Procedia, 37, pp.6237-6247.

7. Whitney, B.B., Hengesh, J.V. and Gillam, D., STYLES OF FAULT REACTIVATION ALONG A FORMERLY RIFTED CONTINENTAL MARGIN, BARROW ISLAND REGION, WESTERN AUSTRALIA. Neotectonic Deformation in the Western Australia Shear Zone.
8. https://australia.chevron.com/-/media/australia/publications/documents/gorgon-carbon-capture-and-storage--fact-sheet.pdf
9. Harbert, W., Daley, T.M., Bromhal, G., Sullivan, C. and Huang, L., 2016. Progress in monitoring strategies for risk reduction in geologic CO_2 storage. International Journal of Greenhouse Gas Control, 51, pp.260-275.
10. Liu, J., 2011. CCS projects in Western Australia—Gorgon and Collie Hub. Department of Mines and Petroleum, Government of Western Australia, Perth.

Other relevant information considered pertinent to the report

Article date 10 February 2022 8:29 GMT UPDATED 16 February 2022 https://www.upstreamonline.com/energy-transition/chevrons-flagship-gorgon-ccs-project-still-failing-to-live-up-to-expectations/2-1-1166185

Brantjes, J. Formation Evaluation for CO_2 Disposal, SPWLA-2008-TTT, SPWLA 49th Annual Logging Symposium, May 25-28, 2008.

Figures

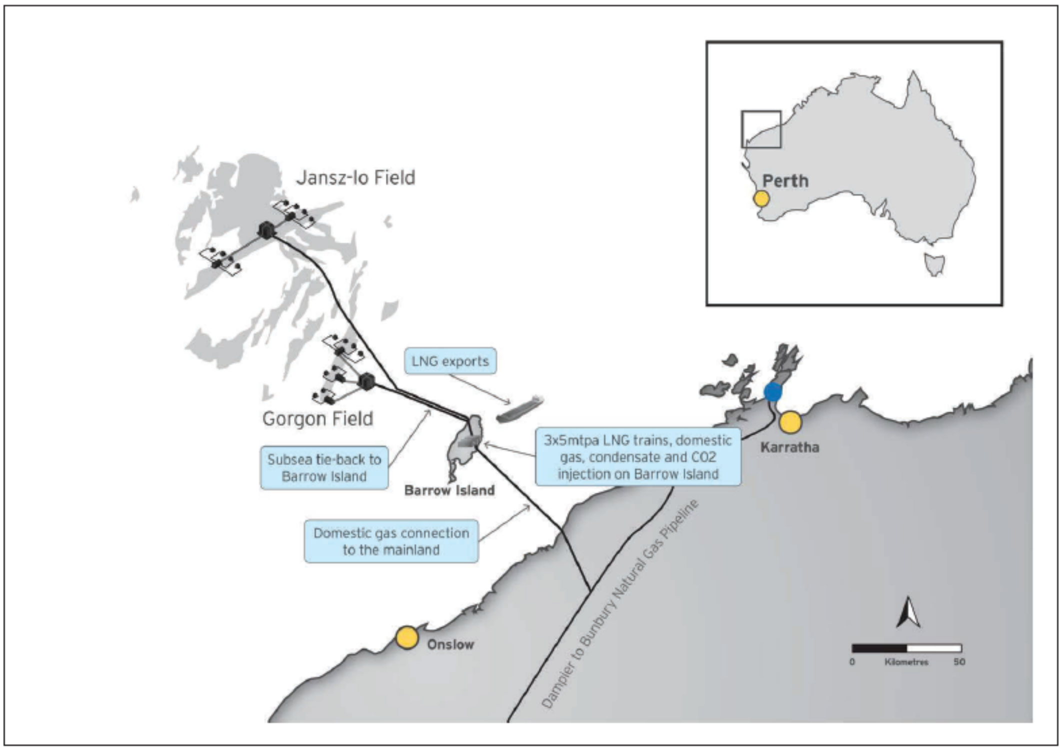


Figure 21.1:. Gorgon Project location map [6]

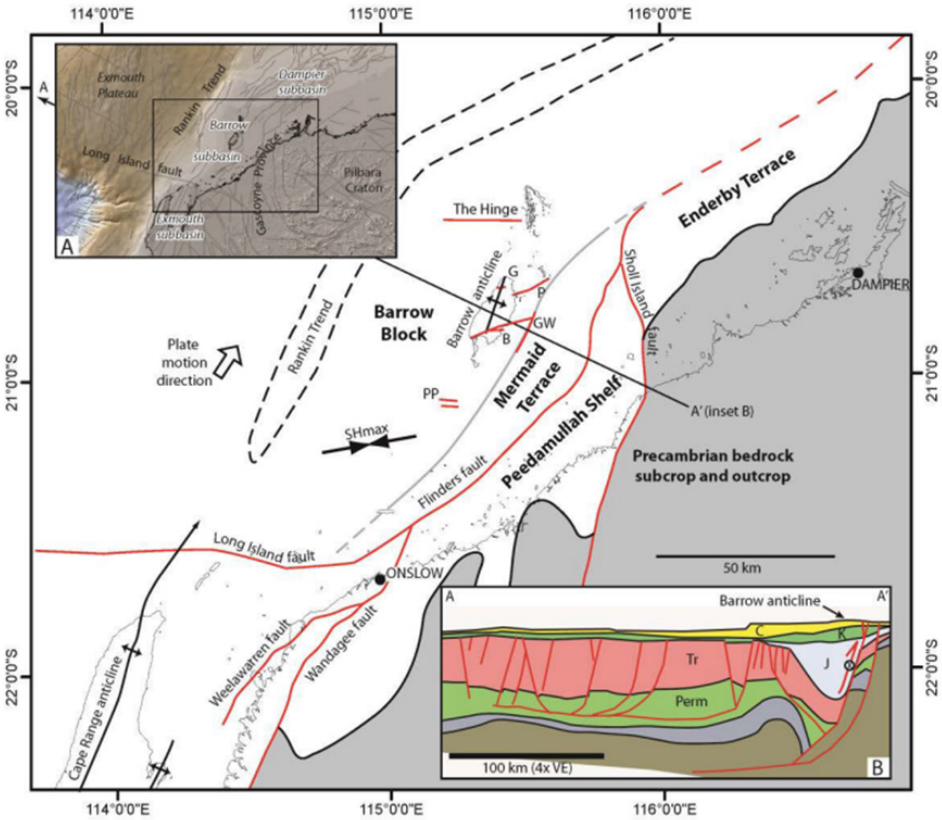


Figure 21.2: Tectonic elements map and cross section. B: Barrow Fault, G: Godwit Fault, P: Plato Fault, GW: Gregory West Fault[7]

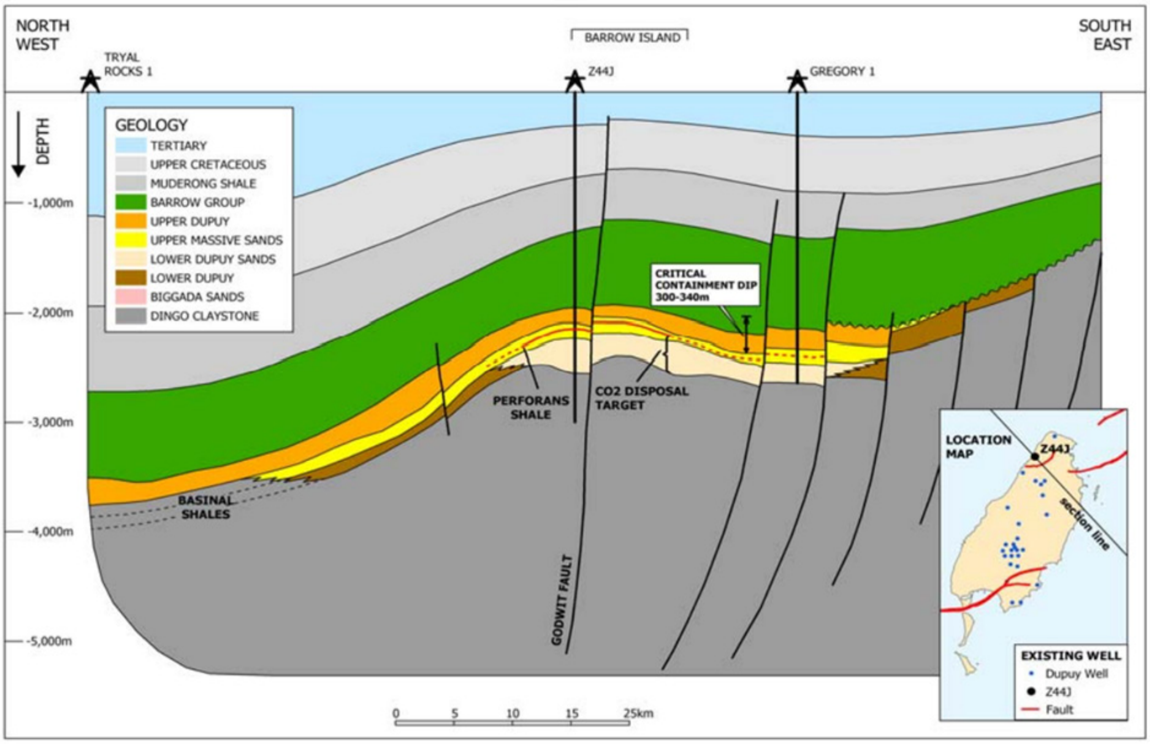


Figure 21.3: Schematic cross section over the Barrow Anticline showing injection target[10]

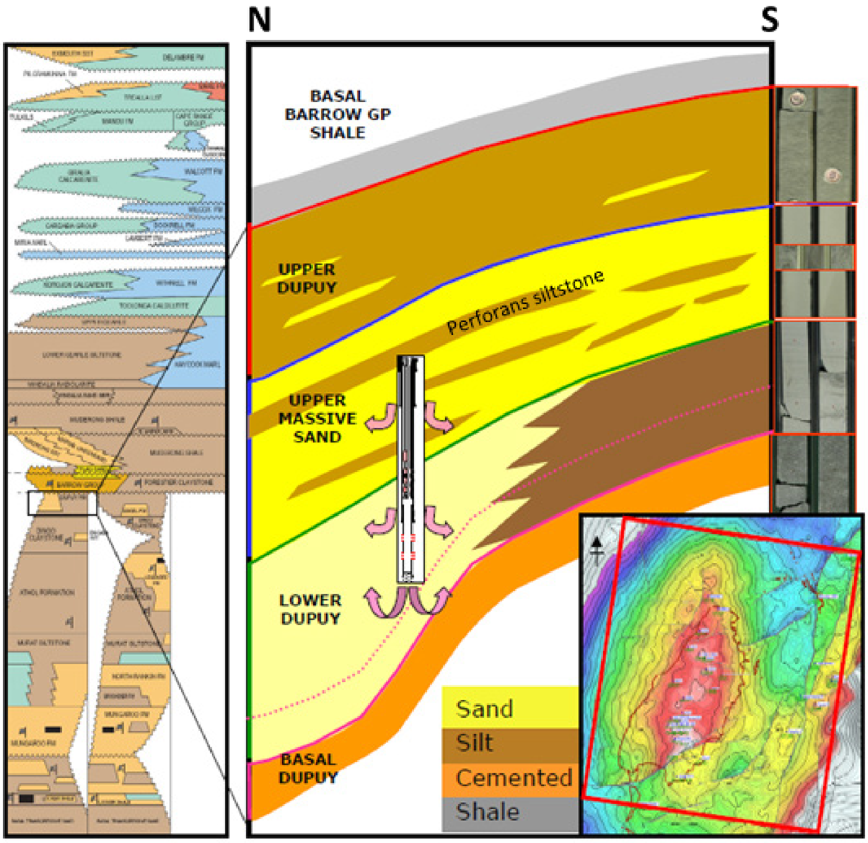


Figure 21.4: Regional geological setting, Dupuy rock unit summary with injection well completed in target interval, Dupuy core photos and Top Dupuy Structure map. Basal Dupuy: siderite cemented fine-med SS. Lower Dupuy poor quality fine ss in north and sh/silt in south, 100-200 m. Upper Massive Sand: fine-med blocky ss capped by fining upward unit. Intraformational baffles 100-200 m. Upper Dupuy: bioturbated siltstone with ss lenses 100-150 m [1]

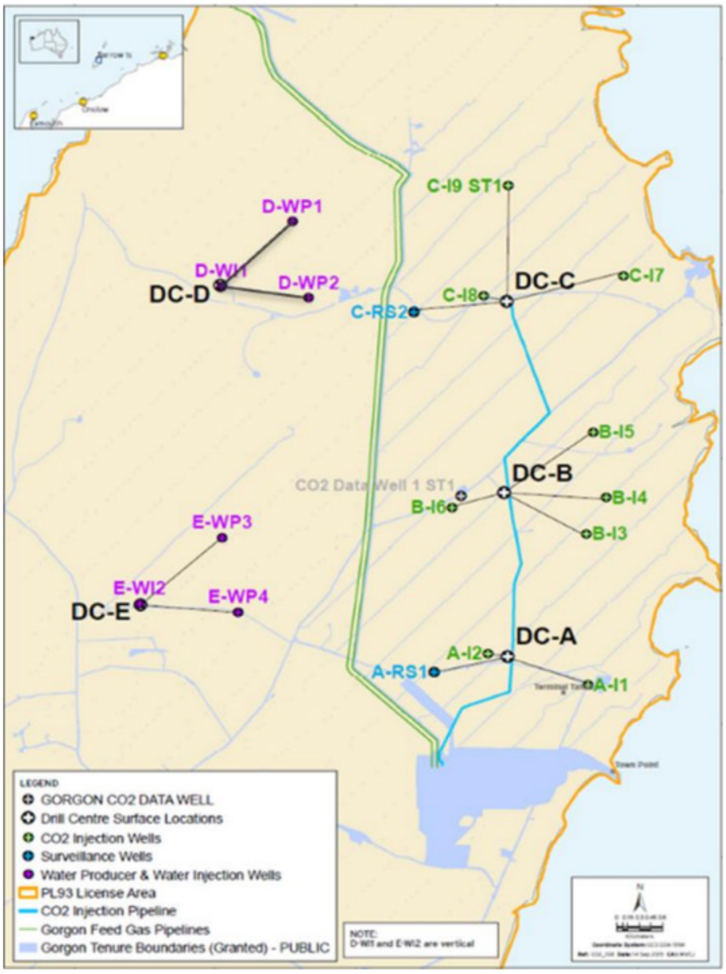


Figure 21.5: Map of Barrow island showing monitoring schedule of surveillance and pressure management wells and seismic surveys[1] .

22. Otway

Site Details					
Name	Location	Province/State	Country	Onshore	Offshore
Otway		Western Victoria	Australia	✓	

General storage type

Depleted gas field in the Naylor gas field and deep saline formation of the overlying Paaratte Formation.

Development History (Active operation)

The CO2CRC Otway Research Facility in western Victoria, Australia is a CO_2 storage demonstration project. Located in the western Port Campbell Embayment, the onshore extension of the Shipwreck Trough (Figure 22.1)[1].

Otway Stage 1 depleted gas field storage project injected 65,445 t of CO_2 into the Waarre-C sandstone, of the Naylor gas field, via the CRC-1 injection well between March 2008 and August 2009. The CO_2 is sourced from a nearby gas field (Buttress) at ~2 km depth. Gas is extracted from Buttress-1 well, processed and compressed, before being transported along a 2.25 km pipeline to the facility (Figure 22.1 & Figure 22.2)[2,3].

The Otway Stage 2B downhole residual and solubility trapping experiment in the Paaratte Formation (a saline formation) with a small injection of 150 t of pure CO_2 via CRC-2 well (tested in 2011 and repeated in 2014)[4,5]. The injected CO_2 used in 2014 was a mix of industrial CO_2 captured at the Callide Oxyfuel pilot capture plant in Queensland and food grade CO_2 from the Boggy Creek well in the vicinity of the Otway site (Figure 22.1).

The Otway Stage 2C project been developed as an end-to-end, field-scale CO_2 saline formation storage investigation. Designed to understand the effectiveness of various seismic technologies for monitoring CO_2 in the subsurface, enable effective conformance of monitoring data to the geological and dynamic reservoir model, and demonstrate the plume migration and stabilisation processes[1,6].15,000 t of CO_2 (Buttress gas) was injected via the CRC-2 injection well in 2015/16.

1 Watson, M., Pevzner, R., Dance, T., Gurevich, B., Ennis-King, J., Glubokovskikh, S., Urosevic, M., Tertyshnikov, K., La Force, T., Tenthorey, E. and Bagheri, M., 2018, October. The Otway Stage 2C Project–End to end CO2 storage in a saline formation, comprising characterisation, injection and monitoring. In 14th Greenhouse Gas Control Technologies Conference Melbourne (pp. 21-26).

2 Jenkins C, Cook P, Ennis-King J, Underschultz J, Boreham C, de Caritat P, Dance T, Etheridge D, Hortle A, Freifeld B, Kirste D, Paterson L, Pevzner R, Schacht U, Sharma S, Stalker, L, Urosevic M., 2012, Safe storage and effective monitoring of CO2 in depleted gas fields. Proceedings of the National Academy of Science of the USA. 109(2): p. 353

3 Dance, T., 2013. Assessment and geological characterisation of the CO2CRC Otway Project CO2 storage demonstration site: From prefeasibility to injection. Marine and Petroleum Geology, 46, pp.251-269.

4 Jenkins, C., Ennis King, J. and Gunning, J. (2022) Monitoring with earth tides at the CO2CRC Otway Project. Abstract. 16th International Conference on Greenhouse Gas Control Technologies, Lyon, France

5 Jackson, S., Gunning, J., Dance, T., Bagheri, M., Barraclough, P., Pevzner, R., Ennis-King, J. and Jenkins, C. (2022) Time-lapse pressure tomography of a migrating CO2 plume at the Otway Stage 3 site. Abstract. 16th International Conference on Greenhouse Gas Control Technologies, Lyon, France

6 Dance, T., LaForce, T., Glubokovskikh, S., Ennis-King, J. and Pevzner, R., 2019. Illuminating the geology: Post-injection reservoir characterisation of the CO2CRC Otway site. International Journal of Greenhouse Gas Control, 86, pp.146-157.

The research objectives were: 1. Detect injected Buttress gas in the subsurface; ascertain minimum seismic detection limit; 2. Observe the gas plume development using time lapse seismic; 3. Verify stabilisation of the plume in the saline formation using time-lapse seismic. The Otway Stage 3 project was designed to deploy and field test a toolbox of monitoring and verification (M&V) techniques for saline aquifer. 15,000 t of CO_2 (Buttress gas) was injected via the CRC-3 injection well between December 2020 and April 2021. Two primary monitoring techniques were trialled – pressure tomography and downhole seismic – but earth tides, pressure inversion and passive seismic were also tested to better understand their application in an industrial context [7]. The Otway Stage 4 project commenced in 2023. The objectives of Otway Stage 4 are to substantially improve CO_2 storage resource usage, furthering CO_2 storage as an economically viable option for decreasing CO_2 emissions to the atmosphere. This will be achieved through: • Acquisition and analysis of CO_2 saturation and chemical data during plume migration and trapping, combined with investigation of fine-scale geological heterogeneity's role in CO_2 flow dynamics, in order to refine modelling workflows and, ultimately develop strategies for optimising commercial CO_2 storage. • Demonstrating whether CO_2 microbubbles (MB), owing to their smaller size, lower buoyancy effect and enhanced dissolution properties, significantly increase storage efficiency compared to standard CO_2 injection, thereby unlocking previously untenable reservoirs for CO_2 storage. • Enhancing seismic monitoring to comprehensively assess storage performance and microbubble behaviour, including quantitative derivation of CO_2 saturation. • Demonstrating the capability of Distributed Strain Sensing (DSS) to measure geomechanical changes associated with CO_2 injection quantitatively.

Geological Characteristics.	
Reservoir Formation	
The Waarre Formation is the basal group of the Sherbrook Group (Turonian – Maastrichtian ~91 – 65.5 Ma) overlying the Otway Unconformity. It is subdivided into units A-C[3]. The reservoir target for Otway stage 1 was the Cretaceous Waarre-C formation[2]. The reservoir targets for Otway stage 2B, 2C, 3 and 4 was/is the Late Cretaceous Paaratte Formation (Figure 22.2, Figure 22.3).	
Lateral extent / thickness variation	Waarre-C is ~25-40 m thick[3]. The proximal mouth bar sands and delta front sands of the Paaratte Formation are expected to be laterally continuous over the area modelled[6]. Analogous sandstone bodies are up to 20 km long and 3 km wide[6].

7 Barraclough, P., Jenkins, C., and Pevzner, R. (2022) Delivering Innovative Solutions for CCS Monitoring – CO2CRC Stage 3 Project Operations Summary. Abstract. 16th International Conference on Greenhouse Gas Control Technologies, Lyon, France

Rock type	Waarre-C comprises stacked sandstone bodies of varying grain sizes, with thin shale baffles and streaks[2]. Unit A is a fine-grained lithic sandstone with low to moderate porosity. Unit B consists of hard, grey to back carbonaceous mudstone, and unit C is the main gas producing reservoir and consists of poorly sorted very fine to course quartz sands and occasional gravels, 2-14 m thick, separated by minor mudstones[3]. The Paaratte comprises intercalations of medium to high permeability sands thinly interbedded with carbonaceous mud-rich lithologies, and are overprinted with diagenetic carbonate cement layers which serve as seals of varying quality[8]. The injection interval is selected within a relatively homogenous sandstone unit between two cemented sandstones.
Sedimentary features: Depositional Environment / facies type & variation / mineral composition	Waarre-C is interpreted to be deposited in near-shore, tidally influenced channel setting[2]. Two depositional models, first transgressive shoreline model with dominant depositional direction in an east-west orientation. The second is a regressive, braided fluvial model, deposited in north-south direction[3]. Paaratte Formation is deposited in a shallow marine deltaic setting with dominant fluvial and tidal processes[8]. Proximal and distal mouthbars, distributary channels and delta front facies (Figure 22.3). The highest reservoir potential lie within the proximal mouthbar and distributary channel sandstones[6].
Porosity	Waarre-C has average porosity of 20%[2]. Reservoir quality ranges from 10 to 28% with an average of 17%[3]. Core cuttings have porosity of 2-25%[3].

8 Paterson L, Boreham C, Bunch M, Dance T, Ennis-King J, Freifeld B, Haese R, Jenkins C, La Force T, Raab M, Singh R, Stalker L, Zhang Y. Overview of the CO2CRC Otway residual saturation and dissolution test. In: Energy Procedia. 2012; 37: p. 6140-6148.

	Paaratte Formation has an average porosity of 28% (25-30%), dolomite cement reduces the porosity to 5-10%[8].
Permeability	Waarre-C has an average permeability of 2,700 mD[3]. Core cuttings show permeability of 1-2 D[3] but range from 8 mD up to 6 D showing great heterogeneity. Paaratte Formation has an average permeability of 2.1 D, dolomite porosity reduces the permeability to 1-10 mD[8].
Formation fluid properties: (residual hydrocarbons / salinity concentration).	

Caprock / primary seal formation

Overlying the Waarre-C formation is the low permeability Flaxmans Formation and the Belfast Mudstone (Figure 22.1)[2]. The Belfast Mudstone is the primary seal to the Waarre-C Formation.

Parasequence 3 – a drowned transgressive coal within an overall progradational highstand systems tract marks the ultimate seal of the Otway stage 2C storage complex (Figure 22.3)[1,6].

Lateral extent / thickness variation	
Rock type	Flaxmans Formation consists of interbedded siltstone and fine grained sandstone, fining upward to highly bioturbated mudstone[3]. The Belfast Mudstone is black, pyritic offshore mudstone[3].
Fracture pressure	
Porosity	Belfast Mudstone <15% porosity[3].
Permeability	Belfast Mudstone <1 mD.

Overburden Features (Thickness, formations presence of secondary reservoirs / seals)

Overlying the Skull Creek Mudstone are the Paaratte Formation and Timboon Sandstone, water collected from the Timboon sands shows total dissolved solids of ~500ppm, suggesting potential as town water supply and categorised at potable. It has not been exploited due to its depth (>1,000 m) and the abundance of freshwater in shallower aquifers. However, it may be a future resource and its integrity assured[3].

The Wangerrip Group overly the Timboon Sandstone, including the Massacre Shale and Pember Mudstone which are potential secondary seals to the site. The Massacre Shale (931-1,026 m depth) is a glauconitic mudstone and relatively thin (~20-30 m thick) but can be mapped continuously across the Otway Basin. The Pember Mudstone is a pro-deltaic, silty mudstone approximately 50 m thick in the study area[3].

Above the Pember Mudstone is the Dilwyn Formation. It comprises a thick (~250 m) shallow marine to coastal plain sandstone and mudstones and is a major fresh water aquifer. A second aquifer is in the Port Campbell Limestone in the overlying Heytesbury Group[3].

Structure	
Fold type / fault bounded	The gas reservoir in the Waarre-C formation is fault-bounded on three sides and has a dip closure to the east, against the 300 m thick Belfast Mudstone, forming a structural trap (Figure 22.2[2,3]. Structural dip is estimated at ~14°[3]. Maximum depth for the structural spill point (-2015 mTVDSS)[3]. There is no apparent structure closure within the overlying Paaratte Formation[8]. The Paaratte strata are gently dipping in the study area with average dip angles ~2-6°. Down-dip is towards the west and a slight incline to the east-southeast along a ridge associated with the up-thrown side of the splay fault[6]. The focus area is bound to the south by the Naylor South fault, and to the north by the Boggy Creek and Buttress fault complex[1]. See also structure map (Figure 22.4).
Faults /Fractures (Type – normal, reverse, strike-slip)	Unlike many of the larger faults in the region that were reactivated through to the Tertiary, the faults flanking the Naylor Field terminate in the Belfast Mudstone seal[3].
Displacement	n/a
Stability (pre-stressed, active, stable)	The risk that the faults of the Naylor Field would provide vertical leakage pathways into the overlying aquifers was considered unlikely[3]. The Boggy Creek and Buttress Fault complex beyond the northern boundary of the model are considered to be partially sealing[6].

Injection / storage history
Number of injection, monitoring or other wells, well geometry, design and key completion information for injection wells, relevant well issues. Reused / new purpose drilled well.
Naylor-1, a former production well at the crest of the depleted reservoir structure has been converted to a monitoring well (Figure 22.5). Drilled to 2,157 m below rotary table (RT at 51.09 m and elevation 46.4 m)[9] in May 2001, completed with 3.5 in monobore production casing. Initially perforated at 2,028.5 to 2,032.5 mRT, the well was reperforated at the Waarre C reservoir level in October 2007[9]. The Bottom Hole Assembly (BHA) was installed designed for monitoring the

9 Underschultz, J., Boreham, C., Dance, T., Stalker, L., Freifeld, B., Kirste, D. and Ennis-King, J., 2011. CO2 storage in a depleted gas field: An overview of the CO2CRC Otway Project and initial results. International Journal of Greenhouse Gas Control, 5(4), pp.922-932.

reservoir. A packer seals off the wellbore above the top of the leaking Waarre C casing patch, above the packer are 3 three-component and 8 single-component geophones used for microseismic monitoring and seismic reflection surveys. Below the packer are 3 geophones and 3 hydrophones for performing high resolution travel time measurements[9]. Three U-tube sampling ports are installed. **CRC-1**, drilled for injection 308 m down-dip from Naylor-1 in February 2007, with injection at depth 2,003 m – 2,014 m for Otway Phase 1[2]. 24 m of core from the Waarre-C was recovered and 25 m of core from the overlying reservoirs and seals[3]. **CRC-2** was drilled for residual saturation and dissolution test (Stage 2B) in 2011[8] with injection at 1,392-1,399 m TVDSS ~ 600 m shallower than stage 1. Completed with 0.140 m (5.5 inch) outer diameter production casing and 0.0253 m (1.0 inch) internal radius tubing. Sets of pressure/temperature gauges were installed at the top and bottom of the perforated interval, along with fibre-optic distributed temperature sensor and heat-pulse conductors[8]. A U-tube sampling system was installed at the top of the perforated interval for fluid sampling under in situ pressure conditions. The CRC-2 was positioned at the top of a structural saddle, north of the Naylor South fault, where the flatter structure would allow for limited mobility and quicker plume stabilisation[6]. **CRC-2** was recompleted for Otway Stage 2C, including the perforation of the PS1 interval, it included installation of a pressure gauge at the top and base of both the PS1 injection zone, and the PS2 AZMI. The well was also completed with DAS cable, DTS, and u-tube sampling facilities[1]. **CRC-3,** drilled for injection for Otway Stage 3. The well was also completed with DAS cable, DTS. **CRC-4, 5, 6, 7** drilled for monitor wells for Otway Stage 3, deviated wells to 1600 m depth. CRC-4 and -5 were directionally drilled from a single pad to intersect the target zone at around 500 m from the injection well. CRC-6 and -7 were also drilled directionally and intersect the target zone around 1.5 km from the injection well. The wells were constructed to oil and gas specifications, cased and cemented to well termination, and perforated at the target zone. CRC-3 to -7 all have pressure gauges in the reservoir interval, and DAS cemented in the exterior of the casing[10]. The location of the wells for stage 3 were based on: the likely path and extent of the plume, derived from static and dynamic models; a favourable geometry for SOV-DAS for VSPs to interrogate the plume or for Pressure Tomography the combination of water injectors and monitors interrogated the predicted location of the plume; checking that the reservoir intervals were of good quality; reconciling the proposed well locations with surface access for well pads and services and SOVs[10]. CRC-8, drilled as a monitor well for Otway Stage 4 activities in 2023, is a deviated well to approximately 1620 mTVDss. CRC-8 was directionally drilled from the same well pad as CRC-3, -4 and -5. CRC-8 is equipped with DAS/DTS/DSS cemented outside of the casing. The location of the CRC-8 (observation) well is based on the likely path and extent of the plume from injection into the CRC-3 well so that high temporal saturation logs can be acquired in CRC-8.	
Extent and status of casing (corrosion history/ cementation records)	

10 Jenkins, C., Barraclough, P., Bagheri, M., Correa, J., Dance, T., Ennis-King, J., Freifeld, B., Glubokovskikh, S., Green, C., Gunning, J. and Gurevich, B., 2021. Drilling an array of monitoring wells for a CCS experiment: Lessons from Otway Stage 3.

Injection rates & pattern (i.e. continuous / intermittent) changes in injection behaviour	Otway Stage 1 – injection began March 2008 until August 2009 at an average rate of 124 t/day[3]. Arrival of the plume at Naylor-1 occurred in July 2008 after injection of 21,100 tonne. Otway Stage 2B – For the test sequence of water production, water injection and CO_2 injection see Figure 22.6 and ref[8]. Otway Stage 2C – Buttress-1 CO_2 was injected at an average rate of 120 t/day between December 2015 and April 2016[1]. Injection in three phases (paused at 5,000 t and 10,000 t) to accommodate the M1 and M2 seismic surveys[1]. Otway Stage 3 – Buttress-1 CO_2 was injected at a rate of 50 kt/yr of CO_2 for five months between December 2020 and April 2021[7]. Injection in three phases (paused at 4,000 t and 12,000 t) to accommodate M7 and M8 4D DAS VSP surveys[11]. Water injection for Pressure Tomography for 6 hours at a rate of 229 t/day and an 18 hour fall-off before next injection – water injections took place over four days[10].
Total quantities stored	Otway Stage 1 - 65,445 t of CO_2. Otway Stage 2B a small injection of 150 t of pure CO_2[8]. Otway Stage 2C – 15,006 t by 4 April 2016[1]. Otway Stage 3 – 15,000 t of CO_2 (December 2020-April 2021)[7].
Reservoir capacity (estimate)	Waarre-C formation in the Naylor depleted gas reservoir has estimated capacity of 150,000 t of CO_2[2]. Structural trapping would confine the plume to a 0.5 km^2 footprint.
Fluid extraction rate (brine extraction, oil for EOR)	n/a
Seismicity	
Monitoring regime (technologies deployed)	
Downhole DAS receivers deployed behind the casing in injector and monitoring wells CRC-3,4,5,6,7 (Otway Stage 3) – although permanent seismic sources were operating during the daylight hours,	

the DAS data was acquired continuously, providing the opportunity to evaluate both natural and induced seismicity and to explore options for purely passive seismic monitoring[11].

Seismic events (Detection / magnitude / attribution (natural induced).

Stage 2C and 3 injections have coincided with some minor microseismicity (magnitudes between -2 and 0), and natural regional earthquakes which have enabled the further detection of the plume in CRC3 (Figure 22.7)[11]. Iterative data scanning detected 24 events in 600 days of continuous passive monitoring.

Monitoring technologies applied and experiences with monitoring;

Monitoring Modality	Acquisition Timing	Source	Acquisition Type	Receiver
Seismic	**Pre-injection** (M0); **During injection**: 5,000 t (M1), 10,000 t (M2) **End injection** (M3) **Post Injection**: 1 year (M4), 2 years (M5)	Vibroseis	Active 4D Surface seismic	Surface Geophones Surface DAS
			Active 3D VSP	VSP tool - CRC-2 DAS - CRC-2
			Active Offset VSP	VSP tool - CRC-1
	2 hrs per day	SOV x 2	Active 4D Surface seismic	Surface Geophones Surface DAS
	Continuous	Ambient	Passive Surface Seismic	Surface Geophones
Pressure	Continuous	Injection	Top AZMI Base AZMI	2 x P/T gauge (CRC-2) 2 x P/T gauge (CRC-2)
			Top In Zone Base In Zone	2 x P/T gauge (CRC-2) 2 x P/T gauge (CRC-2)
Downhole Fluid sampling	Ad hoc	Injection	AZMI In Zone	Single U-tube sample port Single U-tube sample port
Gas Saturation	End Injection	Pulsed Neutron Tool	Paaratte Fm. Unit A	CRC-1 well CRC-2 well

Table 22-1: Otway 2C monitoring operations (Figure 22.8 for layout)[1].

Surface monitoring technologies deployed

Soil gas composition	(Otway Stage 1) Sampled annually during summer, 150 samples collected on a 4x3 km grid over expected location of plume (the area the major faults terminate close to surface). CO_2 atmospheric analysers located near the injection site to monitor larger anomalies and deep soil fluxes[2]. Data shows a consistent correlation between $\delta^{13}C$ and CO_2 concentration. Most $\delta^{13}CO_2$ values are also lower than those of injected CO_2 so there is no indication of changes that could be attributed to injection[2].
Atmospheric CO_2, isotopes and gas tracers.	(Otway Stage 1) Concentration and flux of CO_2, isotopic composition ($\delta^{13}C$ CO_2), and tracers of injected gas (SF_6, CH_4) monitored

11 Pevzner, R., Isaenkov, R., Yavuz, S., Yurikov, A., Tertyshnikov, K., Shashkin, P., Gurevich, B., Correa, J., Glubokovskikh, S., Wood, T., Freifeld, B and Barraclough, P. (2022) Multiwell DAS VSP for monitoring of a small-scale CO2 injection: experience from the Stage 3 Otway Project. Abstract. 16th International Conference on Greenhouse Gas Control Technologies, Lyon, France

	700 m northeast of the injection well and compared to the undisturbed background measured at the long-established Cape Grim site (Tasmania)[2, 12]. CD_4, Kr and SF_6 were injected in April 2008, and in January 2009 a second batch of tracer compounds (SF_6 and R-134a) was added to the CRC-1 mixed gas injection stream[9]. Large diurnal and seasonal variations are observed, reflecting the effects of plant respiration, photosynthesis and atmospheric dispersion[12]. No evidence for changes in concentrations of CO_2 or tracers, isotopes of CO_2 fluxes that would indicate leakage from subsurface to atmosphere[12].
3D seismic surveys	Baseline survey shot in January 2008, and repeats acquired in early 2009 and 2010 after 35,000 and 65,445 t of CO_2 had been injected (Otway Stage 1)[2]. Time-lapse images to evaluate Waarre-C and overlying aquifers. Injected gas was detected in the 2008-2009 surveys but not confirmed in 2010. Modelling predicts that changes would be below the noise level on the time-lapse seismic images[2]. Seismic monitoring for Stage 2C comprised six 3D seismic surveys, including the baseline and five repeat surveys during injection in three stages 5,000 t, 10,000 t, 15,000 t and 9 months and 23 months afterwards (Table 22-1 and Figure 22.8)[1,6]. A strong time-lapse seismic anomaly was observed after 5,000 t and the consequent evolution could be clearly identified (Figure 22.9)[6]. Baseline 3D (VSP) survey (M6) was acquired for Otway Stage 3 in March 2020[11]. Additional surveys (M7, M8) were also acquired as part of Stage 3.

12 Etheridge, D., Luhar, A., Loh, Z., Leuning, R., Spencer, D., Steele, P., Zegelin, S., Allison, C., Krummel, P., Leist, M. and van der Schoot, M., 2011. Atmospheric monitoring of the CO2CRC Otway Project and lessons for large scale CO2 storage projects. Energy Procedia, 4, pp.3666-3675.

Subsurface monitoring technologies deployed (well logs)	
Wire-line log	CRC-1 wire-line log included Gamma Ray, Nuclear Magnetic Resonance (NMR), Elemental Capture Spectroscopy (ECS), and Formation Micro Imager (FMI) were recorded to complement resistivity-density-porosity logs[3]. Modular formation dynamic tester (MDT) samples allowed multiple fluid samples.
Vertical Seismic Profiling (VSP)	Acquired at CRC-1 and Naylor-1[3]. Otway Stage 3: 4D VSP acquired using conventional vibroseis trucks and downhole DAS receivers in the injector (CRC-3) and four monitoring wells (CRC 4, 5, 6, 7), a baseline survey and two monitor surveys were made at 4 kt and 12 kt CO_2 (Figure 22.10)[11]. 26,000 lb Inova Vibroseis Truck, 6-150 Hz linear 24 s sweep, 1 sweep per shot point. Illumination is up to 700 m, the target interval is imaged and in 4D the stage 3 plume is imaged and evidence of remobilisation of stage 2C plume (Figure 22.11).
Continuous automated DAS VSP with Surface Orbital Vibrators (SOV).	Otway Stage 3: a multi-offset time-lapse VSP using the same borehole receivers (CRC 3-7) and nine permanently deployed surface orbital vibrators (SOVs) acting as permanent seismic sources (Figure 22.12)[13]. ~8-105 Hz bandwidth (SOV 3-9) and ~8-80 Hz bandwidth (SOV 1-2). See Figure 22.10 for timing. Results compared with 4D VSP are shown in Figure 22.11.
Ground water wells	(Otway Stage 1) Water chemistry sampled twice a year from 24 existing wells within a 5 km radius of CRC-1[2]. Data show no significant pre-to post-injection changes in bicarbonate or electrical conductivity, with a small (statistically significant) increase in median pH[2]. Overall water quality is unaffected by injection to within natural variability.

13 Pevzner, R., Isaenkov, R., Yavuz, S., Yurikov, A., Tertyshnikov, K., Shashkin, P., Gurevich, B., Correa, J., Glubokovskikh, S., Wood, T. and Freifeld, B., 2021. Seismic monitoring of a small CO2 injection using a multi-well DAS array: Operations and initial results of Stage 3 of the CO2CRC Otway project. International Journal of Greenhouse Gas Control, 110, p.103437.

Fluid sampling	(Otway Stage 1) Direct measurements of reservoir fluids at Naylor-1 are the primary confirmation of containment. Three sampling points in the well-bore straddle the pre-injection gas water contact, marking the boundary between residual and free CH_4. Shortly after injection (at CRC-1) tracers (deuterated methane CD_4, Kr and SF_6) were added to ensure unambiguous detection of CO_2 at Naylor-1. The small amounts of CO_2 originally present in the Naylor reservoir have a distinct ^{13}C signature, so this isotope is a tracer[2, 14]. The arrival of CO_2 at the monitoring well is a key indicator of the progress of the storage, a rapid breakthrough is observed followed by a plateau in concentrations. These compare with modelled predictions although breakthrough is slightly earlier than predicted. Some dissolved CO_2 and tracer concentrations were first picked up in the U-tube below the gas cap 121 days after injection commenced[3,14]. Water sampling showed a sharp decrease in pH with increasing CO_2 content and water composition are consistent with minor dissolution of carbonate and silicate minerals[2]. Otway 2B noble gasses krypton (Kr) and xenon (Xe) were injected with water before CO_2 injection to act as non-partitioning tracers, then again after residual saturation was obtained to act as partitioning tracers[8]. Otway 2B ester tracers triacetin, propylene glycol diacetate and tripropionin are included in the test sequence.
Pressure and Temperature	Otway Stage 2B temperature is recorded using a fibre-optic heat-pulse sensor[8].

14 Boreham, C., Underschultz, J., Stalker, L., Kirste, D., Freifeld, B., Jenkins, C. and Ennis-King, J., 2011. Monitoring of CO_2 storage in a depleted natural gas reservoir: Gas geochemistry from the CO2CRC Otway Project, Australia. International Journal of Greenhouse Gas Control, 5(4), pp.1039-1054.

	Otway 2B (repeated)[15]. Pressure tomography was employed during Otway Stage 3. The spatial distribution of CO_2 properties are inferred from a tomographic survey, with a series of water injections (a baseline and after 5 kt, 10 kt and 15 kt of CO_2 injection) and measured pressure response at 6 wells completed at ~1,500 m in the Paaratte Formation. When the differential pressure is monitored, this is seen to reduce in each successive survey due to the compressibility and diffusivity impact of the CO_2 plume 'absorbing' the pressure from the cross-well water injections. This absorbing effect is increased as the mass and volume of CO_2 increased in-between the wells. The difference signal was inverted using a Bayesian inversion scheme to produce the spatial location of the CO_2 plume and depth-averaged maps of the CO_2 saturation evolution[5]. Pressure measurements in five monitoring wells during injection of CO_2 during Otway Stage 3 has been used to investigate impact of 'earth tides' on the reservoir. Supercritical CO_2 is very compressible and small changes in saturation can produce changes in compressibility of the reservoir. These can be detected by the pressure response to earth tides (the displacement of the solid earth's surface by the gravity of the moon and sun) – and is a potential way of detecting the approach of a CO_2 plume. At the Otway site, pressure measurements in 5 monitoring wells can detect the approach and, in some instances, passing of the CO_2 plume. Simple analytical estimates of the size of these effects are possible and give useful indications of size and proximity of the plume[4].
Pulsed neutron logging	Otway Stage 1 – thermal neutron logging of Naylor-1 using a RST to indicate the post-production/pre-injection gas-water contact[3]. Pulsed neutron logging and sonic logs yielded

15 Ennis-King J, LaForce T, Paterson L, Black JR, Vu HP, Haese R, Serno S, Gilfillan S, Johnson G, Freifeld B, Singh R. Stepping into the same river twice: field evidence for the repeatability of a CO2 injection test. Energy Procedia. 2017; 114: p. 2760–2771.

	saturations of 15-20% adjacent to perforations[3]. Otway Stage 2B – on three occasions a RST was used to log the well over a 255 m interval, prior to CO_2 injection, after CO_2 injection, and after water injection to determine the CO_2 saturation[8]. Residual saturation was ~0.18 in the lower half and ~0.23 in the top half. Otway 2B (repeated)[15]. Otway Stage 2C – Baker Hughes RPM was deployed in CRC-1 and CRC-2.
Dissolution testing	Otway Stage 2B – measuring residual gas testing by injecting gas-free formation brine to dissolve the residual gas from a region around the well bore, the brine is produced and the gas content of the returning water measured[8].
Experience summary - effectiveness of techniques (limitations / strengths)	
Ground water and soil gas results provide assurance by showing water and soils are practically unaffected. Geochemistry confirms realistic storage model, and containment is demonstrated by the consistency of the geochemical forward models. The injected gas mixture is denser than the in-situ methane cap, but less dense than water, thus Is first detected at the gas water contact[3]. The observed arrival time (Otway Stage 1) is within predicted forecasts for breakthrough, the highly channelised, well-connected nature of the reservoir sands may explain why arrival of CO_2 was at the early end of the simulated results[3]. Post-injection seismic data (Otway Stage 2C) informs the plume extent, the continuity of baffles above the plume, the likely location of channels and their orientation, as well as highlighted faults that were previously unseen[6]. Pressure monitoring (Otway Stage 2C) has helped better understand connectivity and thickness of zones, average horizontal permeability, splay fault properties, intra-formational- seal effectiveness, and shown that permeability is underestimated in core and log measurements[6]. Saturation at the wells shows the vertical distribution of saturation shows the upper part of the perforation receives the most CO_2 (Otway Stage 2C). The saturation profile at the monitoring well shows there is connection via a channel facies between the two wells, and there is no CO_2 above the primary storage zone[6].	

3D VSP agrees with surface time-lapse seismic[16]. For an offset of up to 1 km at the target interval the signal to noise ratio of DAS data are at least comparable to that of geophones – demonstrating the value of DAS[16]. It appears that the plume centred around well CRC-2 from Otway Stage 2 has likely merged with the new plume emanating from CRC-3 (Otway Stage 3), due to the south-east topography and fault-driven migration. This is detected using pressure tomography, 4D DAS VSP and DAS SOV[5,7,11]. Continuous seismic monitoring using permanently installed seismic equipment is proven to be economic and effective, the data acquisition and processing can be fully automated and performed remotely. They also have low environmental and societal impact[16]. Pressure monitoring of earth tide response in reservoir has been shown to be an accurate predictor of the approach and movement of the CO_2 plume and is well within sensitivity limits and could potentially be an effective monitoring tool[4].
Major technical/scientific studies on the site, major learnings, Conformance assessment (history-matching with models, correlation between different monitoring techniques)
Ref[17] details history matching for a range of criteria from Otway Stage 1. The geological models and derived simulations have been able to fit most of the key features of the field data, including downhole pressure measurements and the arrival time at the observation well. The use of multiple geostatistical realisations of heterogeneity demonstrates the importance of capturing the range of uncertainty in the geology, and the consequent scatter in forward predictions. Pressure data from downhole gauges has proved to be very valuable for adjusting the bulk reservoir properties in the simulation model, and improving the accuracy of simulation predictions[17].
List of key publications covering the site
1. Watson, M., Pevzner, R., Dance, T., Gurevich, B., Ennis-King, J., Glubokovskikh, S., Urosevic, M., Tertyshnikov, K., La Force, T., Tenthorey, E. and Bagheri, M., 2018, October. The Otway Stage 2C Project–End to end CO2 storage in a saline formation, comprising characterisation, injection and monitoring. In 14th Greenhouse Gas Control Technologies Conference Melbourne (pp. 21-26). 2. Jenkins C, Cook P, Ennis-King J, Underschultz J, Boreham C, de Caritat P, Dance T, Etheridge D, Hortle A, Freifeld B, Kirste D, Paterson L, Pevzner R, Schacht U, Sharma S, Stalker, L, Urosevic M. Safe storage and effective monitoring of CO2 in depleted gas fields. Proceedings of the National Academy of Science of the USA. 2012; 109(2): p. 353 3. Dance, T., 2013. Assessment and geological characterisation of the CO2CRC Otway Project CO2 storage demonstration site: From prefeasibility to injection. Marine and Petroleum Geology, 46, pp.251-269.

16 Isaenkov, R., Pevzner, R., Glubokovskikh, S., Yavuz, S., Yurikov, A., Tertyshnikov, K., Gurevich, B., Correa, J., Wood, T., Freifeld, B. and Mondanos, M., 2021. An automated system for continuous monitoring of CO2 geosequestration using multi-well offset VSP with permanent seismic sources and receivers: Stage 3 of the CO2CRC Otway Project. International Journal of Greenhouse Gas Control, 108, p.103317.

17 Ennis-King, J., Dance, T., Xu, J., Boreham, C., Freifeld, B., Jenkins, C., Paterson, L., Sharma, S., Stalker, L. and Underschultz, J., 2011. The role of heterogeneity in CO_2 storage in a depleted gas field: history matching of simulation models to field data for the CO2CRC Otway Project, Australia. Energy Procedia, 4, pp.3494-3501.

4. Jenkins, C., Ennis King, J. and Gunning, J. (2022) Monitoring with earth tides at the CO2CRC Otway Project. Abstract. 16th International Conference on Greenhouse Gas Control Technologies, Lyon, France
5. Jackson, S., Gunning, J., Dance, T., Bagheri, M., Barraclough, P., Pevzner, R., Ennis-King, J. and Jenkins, C. (2022) Time-lapse pressure tomography of a migrating CO2 plume at the Otway Stage 3 site. Abstract. 16th International Conference on Greenhouse Gas Control Technologies, Lyon, France
6. Dance, T., LaForce, T., Glubokovskikh, S., Ennis-King, J. and Pevzner, R., 2019. Illuminating the geology: Post-injection reservoir characterisation of the CO2CRC Otway site. International Journal of Greenhouse Gas Control, 86, pp.146-157.
7. Barraclough, P., Jenkins, C., and Pevzner, R. (2022) Delivering Innovative Solutions for CCS Monitoring – CO2CRC Stage 3 Project Operations Summary. Abstract. 16th International Conference on Greenhouse Gas Control Technologies, Lyon, France
8. Paterson L, Boreham C, Bunch M, Dance T, Ennis-King J, Freifeld B, Haese R, Jenkins C, La Force T, Raab M, Singh R, Stalker L, Zhang Y. Overview of the CO2CRC Otway residual saturation and dissolution test. In: Energy Procedia. 2012; 37: p. 6140-6148.
9. Underschultz, J., Boreham, C., Dance, T., Stalker, L., Freifeld, B., Kirste, D. and Ennis-King, J., 2011. CO2 storage in a depleted gas field: An overview of the CO2CRC Otway Project and initial results. International Journal of Greenhouse Gas Control, 5(4), pp.922-932.
10. Jenkins, C., Barraclough, P., Bagheri, M., Correa, J., Dance, T., Ennis-King, J., Freifeld, B., Glubokovskikh, S., Green, C., Gunning, J. and Gurevich, B., 2021. Drilling an array of monitoring wells for a CCS experiment: Lessons from Otway Stage 3.
11. Pevzner, R., Isaenkov, R., Yavuz, S., Yurikov, A., Tertyshnikov, K., Shashkin, P., Gurevich, B., Correa, J., Glubokovskikh, S., Wood, T., Freifeld, B and Barraclough, P. (2022) Multiwell DAS VSP for monitoring of a small-scale CO2 injection: experience from the Stage 3 Otway Project. Abstract. 16th International Conference on Greenhouse Gas Control Technologies, Lyon, France
12. Etheridge, D., Luhar, A., Loh, Z., Leuning, R., Spencer, D., Steele, P., Zegelin, S., Allison, C., Krummel, P., Leist, M. and van der Schoot, M., 2011. Atmospheric monitoring of the CO2CRC Otway Project and lessons for large scale CO2 storage projects. Energy Procedia, 4, pp.3666-3675.
13. Pevzner, R., Isaenkov, R., Yavuz, S., Yurikov, A., Tertyshnikov, K., Shashkin, P., Gurevich, B., Correa, J., Glubokovskikh, S., Wood, T. and Freifeld, B., 2021. Seismic monitoring of a small CO2 injection using a multi-well DAS array: Operations and initial results of Stage 3 of the CO2CRC Otway project. International Journal of Greenhouse Gas Control, 110, p.103437.
14. Boreham, C., Underschultz, J., Stalker, L., Kirste, D., Freifeld, B., Jenkins, C. and Ennis-King, J., 2011. Monitoring of CO_2 storage in a depleted natural gas reservoir: Gas geochemistry from the CO2CRC Otway Project, Australia. International Journal of Greenhouse Gas Control, 5(4), pp.1039-1054.
15. Ennis-King J, LaForce T, Paterson L, Black JR, Vu HP, Haese R, Serno S, Gilfillan S, Johnson G, Freifeld B, Singh R. Stepping into the same river twice: field evidence for the repeatability of a CO2 injection test. Energy Procedia. 2017; 114: p. 2760–2771.
16. Isaenkov, R., Pevzner, R., Glubokovskikh, S., Yavuz, S., Yurikov, A., Tertyshnikov, K., Gurevich, B., Correa, J., Wood, T., Freifeld, B. and Mondanos, M., 2021. An automated system for continuous monitoring of CO2 geosequestration using multi-well offset VSP with permanent seismic sources and receivers: Stage 3 of the CO2CRC Otway Project. International Journal of Greenhouse Gas Control, 108, p.103317.
17. Ennis-King, J., Dance, T., Xu, J., Boreham, C., Freifeld, B., Jenkins, C., Paterson, L., Sharma, S., Stalker, L. and Underschultz, J., 2011. The role of heterogeneity in CO2 storage in a depleted gas field: history matching of simulation models to field data for the CO2CRC Otway Project, Australia. Energy Procedia, 4, pp.3494-3501.

18. LaForce, T., Dance, T., Ennis-King, J., Paterson, L. and Cinar, Y., 2018, October. How good is good enough in CO2 storage modelling? Looking back over three generations of models for the Otway Stage 2C project. In 14th Greenhouse Gas Control Technologies Conference Melbourne (pp. 21-26).

Other relevant information considered pertinent to the report
Dance T, Paterson L. Observations of carbon dioxide saturation distribution and residual trapping using core analysis and repeat pulsed-neutron logging at the CO2CRC Otway site. International Journal of Greenhouse Gas Control. 2016; 47: p. 210–220. Jackson, S., Gunning, J., Ennis-King, J., Jenkins, C., Dance, T., Bagheri, M. and Barraclough, P., 2021, March. Baseline monitoring for time-lapse pressure tomography: Initial results from Otway Stage 3. In Proceedings of the 15th greenhouse gas control technologies conference (pp. 15-18).

Figures

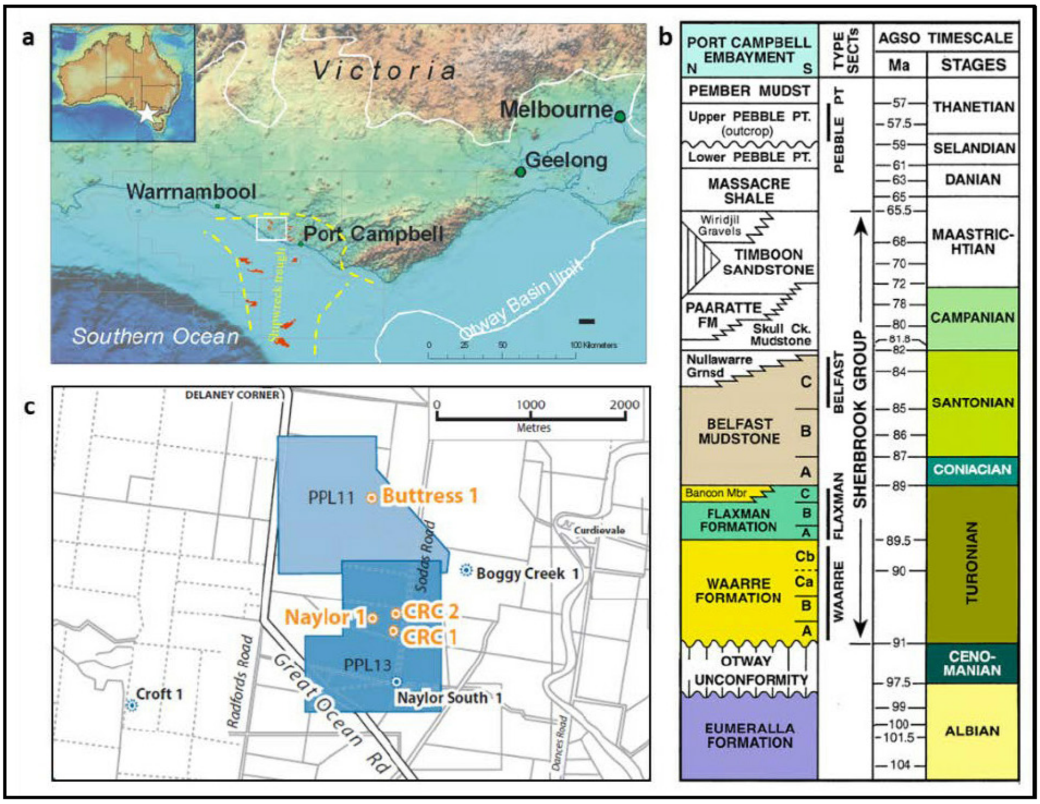


Figure 22.1: Location of the CO2CRC Otway Research Facility (a) The western Port Campbell Embayment in the onshore extension of the Shipwreck Trough (yellow) (b) Stratigraphic table of the Otway Basin's Port Campbell Embayment, (c) Petroleum blocks and well locations for the Otway Research Facility[1].

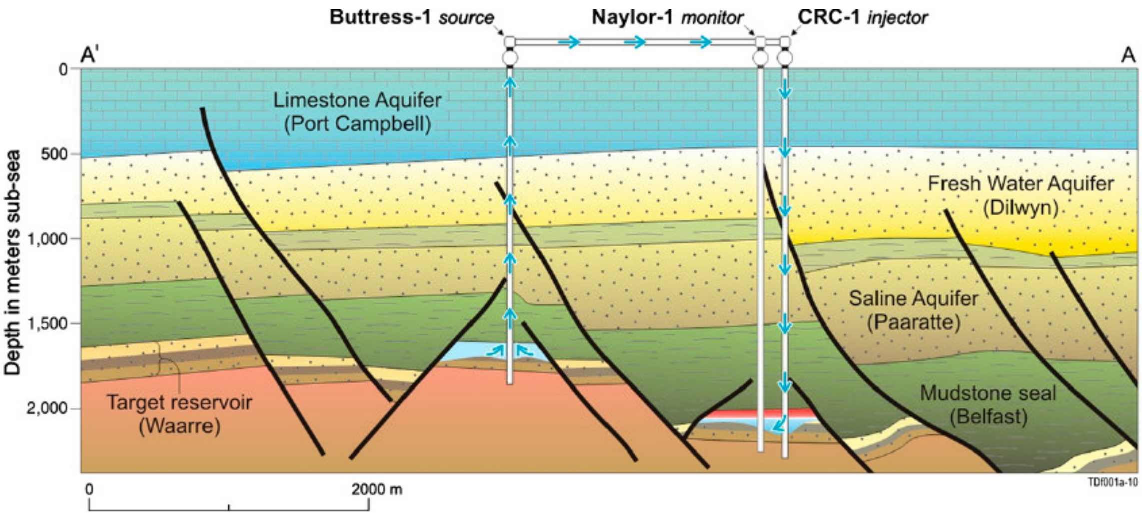


Figure 22.2: Schematic geological cross-section. The storage reservoir for Otway 1 is the Waarre-C formation and the regional seal is the Belfast Mudstone. Faults are denoted as black lines and formations are labelled[2].

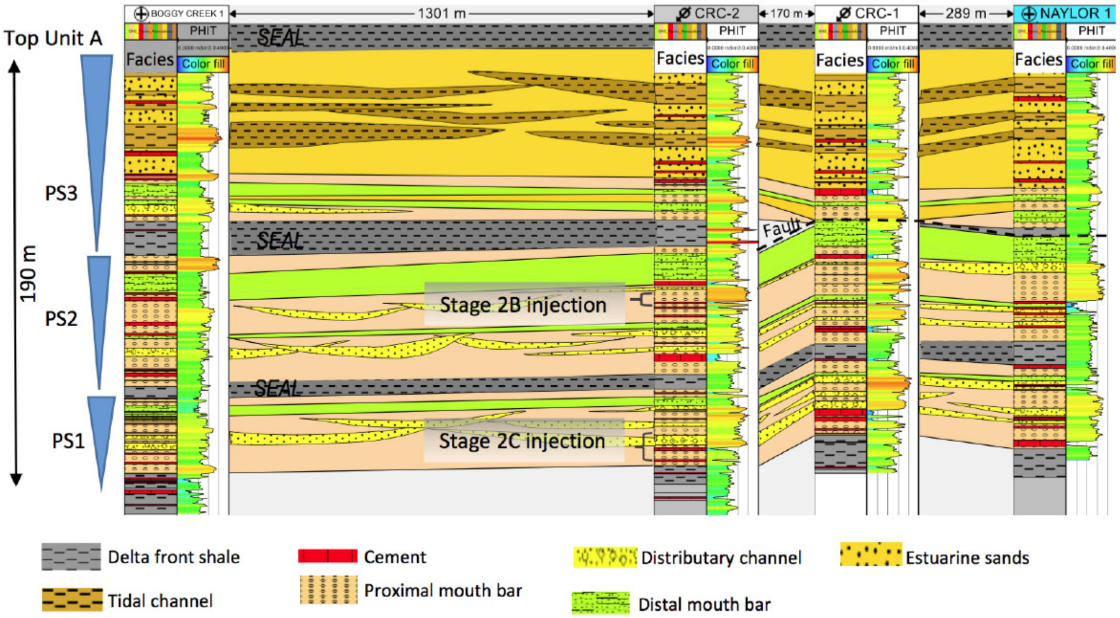


Figure 22.3: Well correlation of the three Paaratte Formation Unit A parasequences separated by transgressive mudstones and shales that provide intraformational seals for the Stage 2B tests and the final choice for the Stage 2C test. The blue triangles represent grainsize coarsening upwards profiles [18].

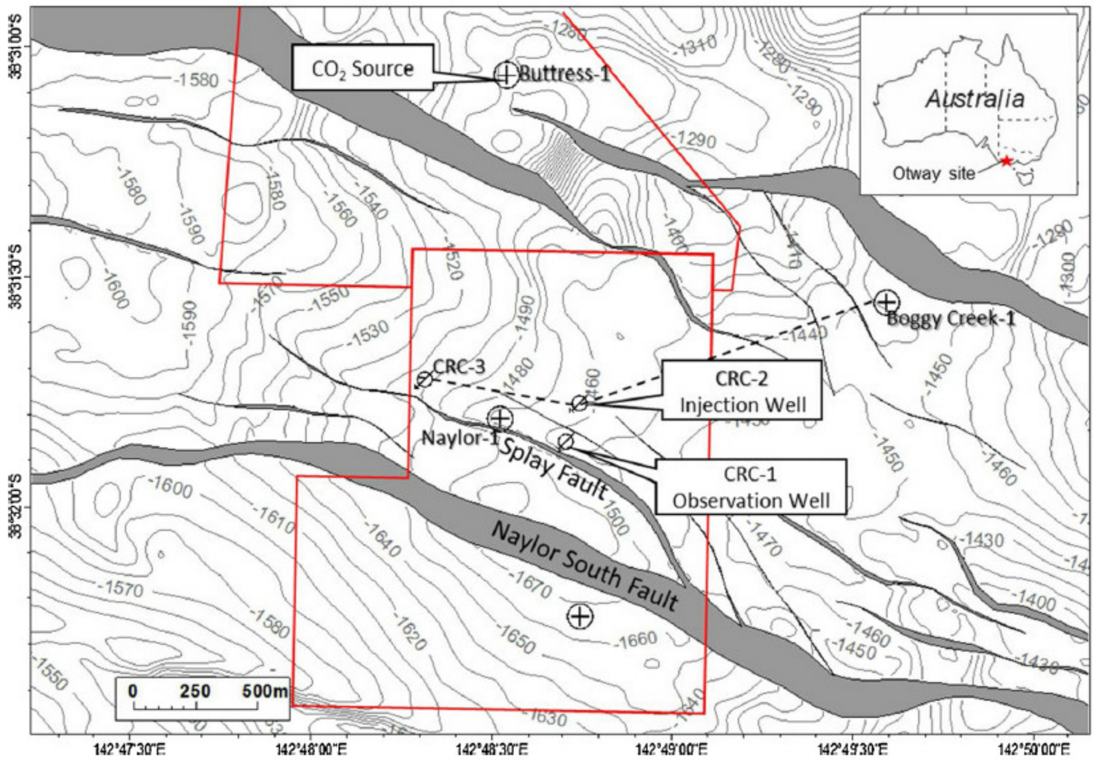


Figure 22.4:Structure and depth map of the top of the injection interval Parasequence 1, Unit A of the Paaratte Formation at the Otway site (10m depth contour intervals in TVD meters sub-sea level). The Naylor South splay fault runs just south of the CRC-1 and Naylor wells, and the Boggy Creek fault is to the north of the CRC-2[6].

18 LaForce, T., Dance, T., Ennis-King, J., Paterson, L. and Cinar, Y., 2018, October. How good is good enough in CO2 storage modelling? Looking back over three generations of models for the Otway Stage 2C project. In 14th Greenhouse Gas Control Technologies Conference Melbourne (pp. 21-26).

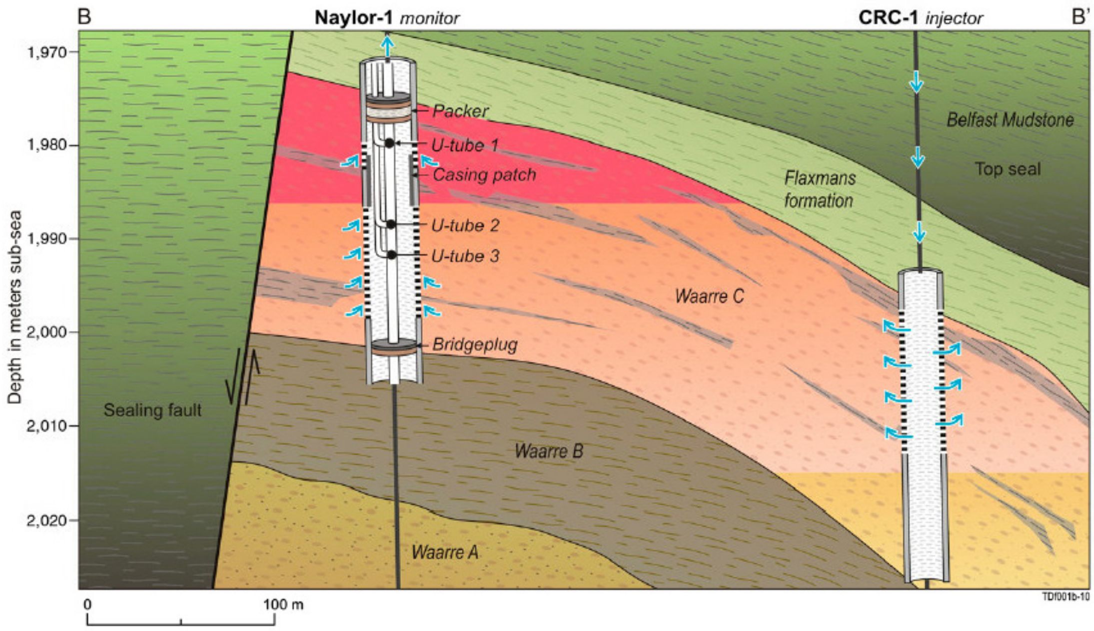


Figure 22.5: Schematic of the Otway 1 injection and monitoring wells, indicating wellbore perforations and U-tube inlets. U-tube 1 accesses the free gas cap (red) through leaks in a casing patch installed during production. Free natural gas is bounded below the gas-water contact. In the light orange zone natural gas is immobile and the pore space contains mostly water [2].

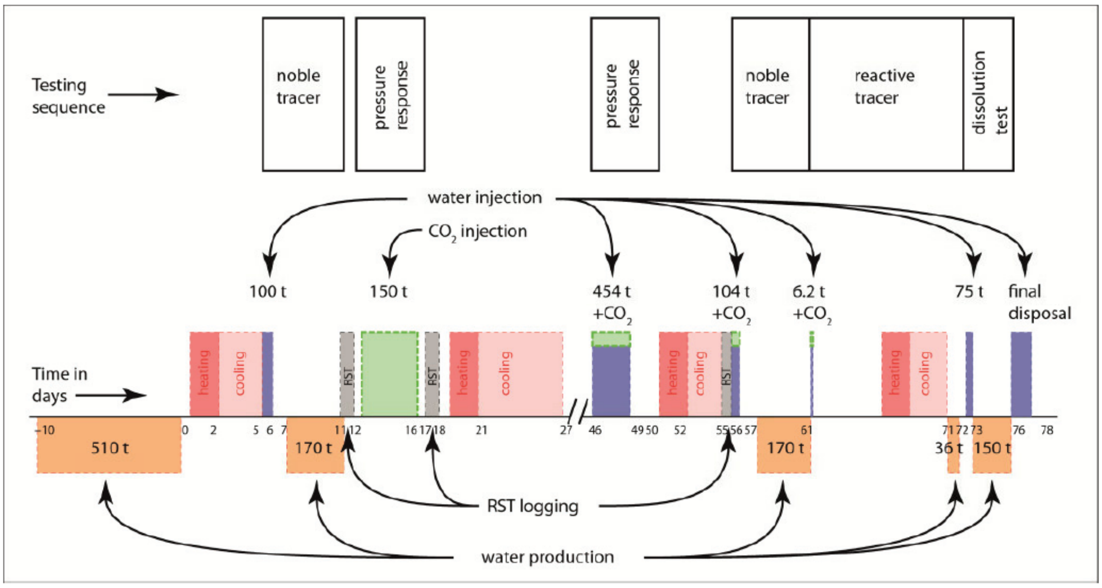


Figure 22.6: Sequence used in the Otway stage 2B residual saturation and dissolution test[8].

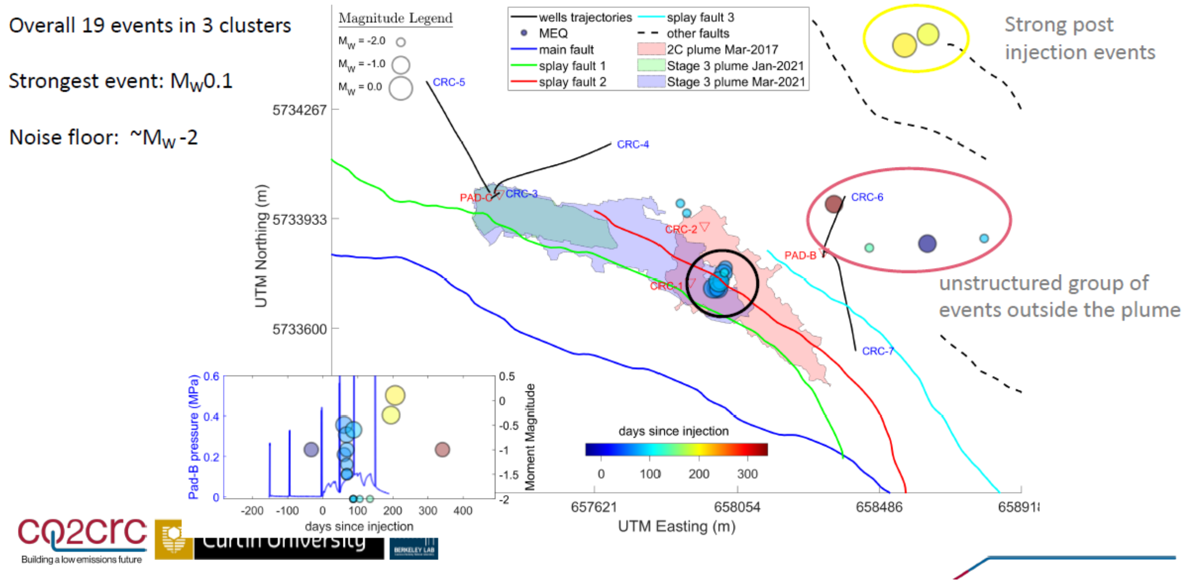


Figure 22.7: showing location of wells, plume extent, structure and the hypocentre distribution detected during passive seismic monitoring [11].

Figure 22.8: Vibroseis source (red lines) and buried geophone (numbered white lines) locations for the surface seismic monitoring (Otway 2C)[1].

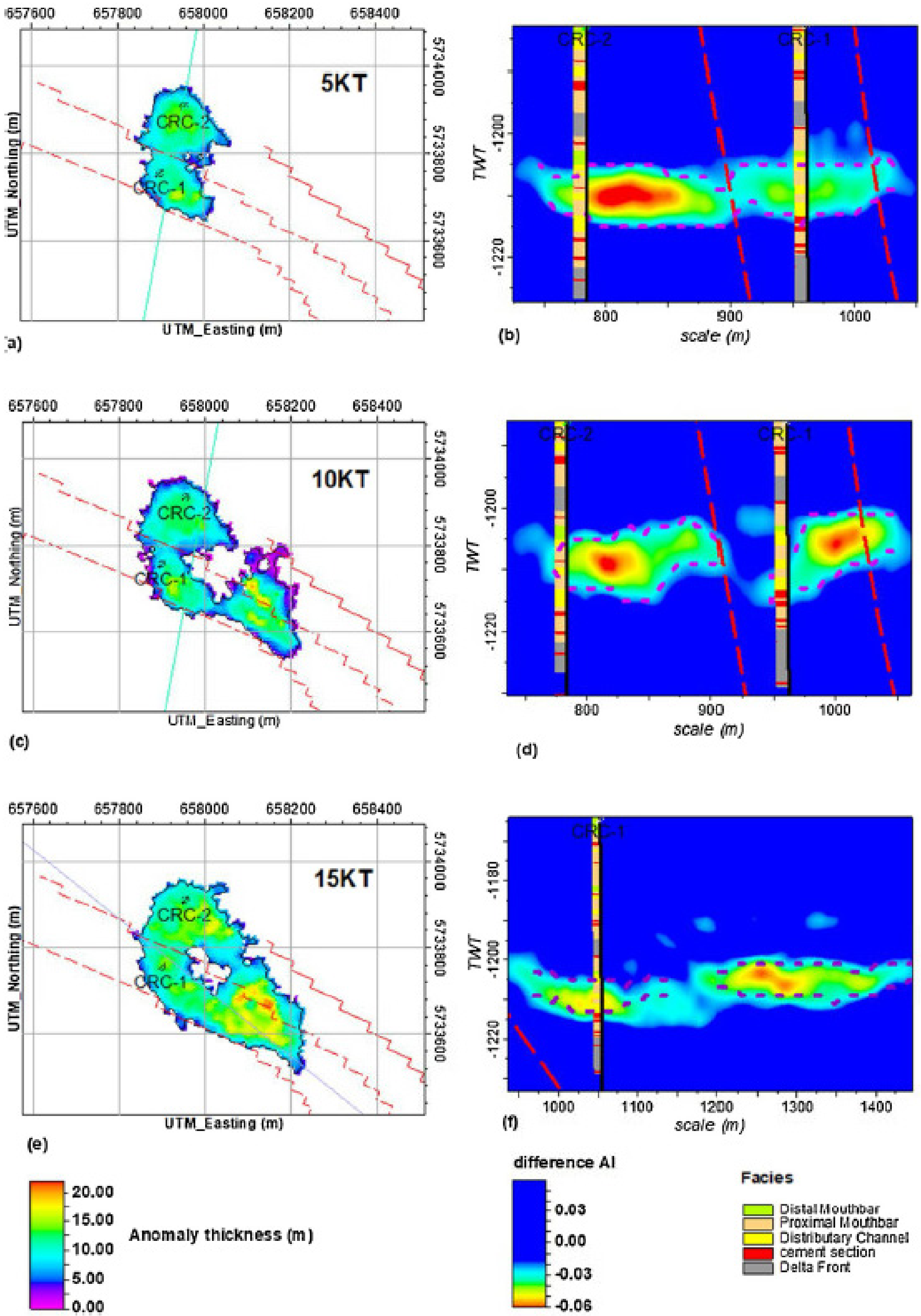


Figure 22.9: Inverted relative changes of acoustic impedance ΔAI corresponding to seismic vintages acquired during the injection (Otway stage 2C). Left column contains plume thickness maps along with the interpreted faults (red lines) and cross-section locations (blue lines). The plume bodies are extracted from the noisy inversion results based on the intensity and connectivity of the ΔAI samples as shown in the vertical sections on the right[6].

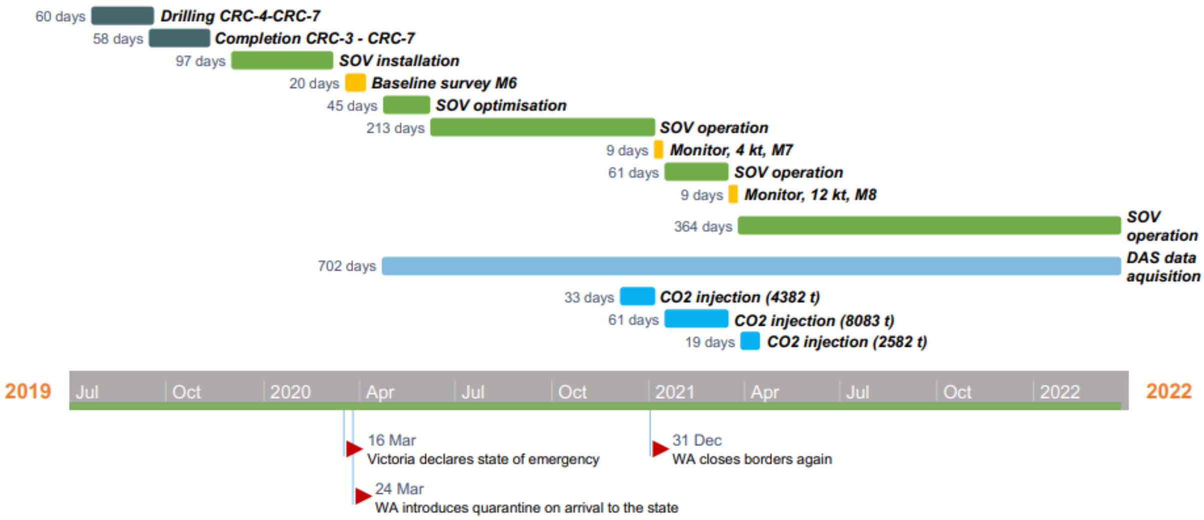


Figure 22.10: Project timeline of Otway stage 3 [9].

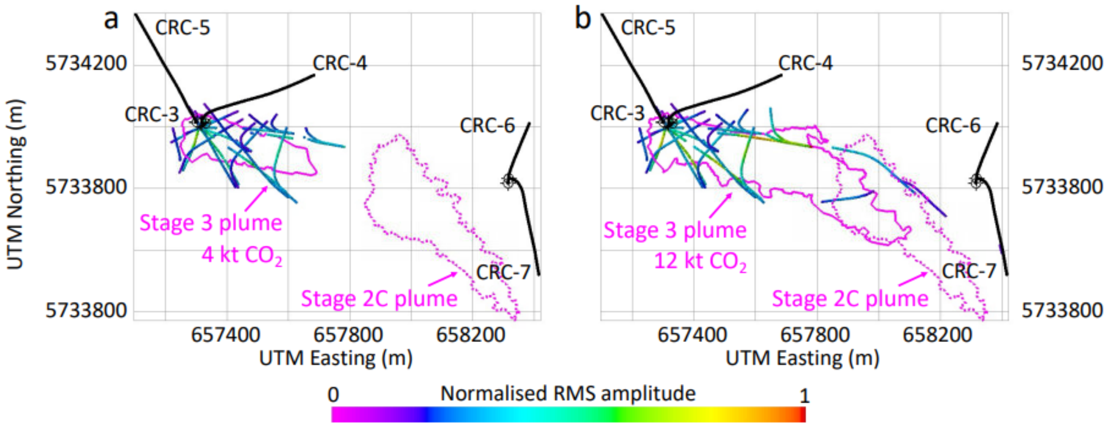


Figure 22.11: Comparison of SOV and 4D VSP data with extent of plumes after injection of 4t CO_2 (left) and 12t CO_2 (right) [9].

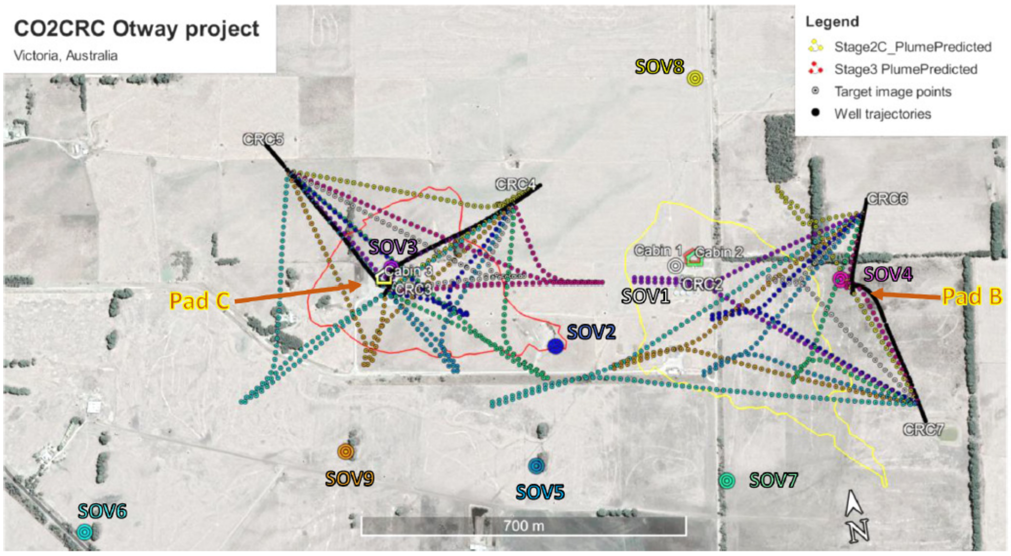


Figure 22.12: Permanent seismic monitoring at Otway Stage 3 – location of Seismic Orbital Vibrators (SOVs) and wells. Dotted lines show the projection of specular reflection points at the target interval colour-coded by the corresponding SOV. Stage 2C and Stage 3 predicted plume contours are simulated for 15,000 t CO_2 injection [13].

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