Department for
Business, Energy
& Industrial Strategy

Endurance Storage Development Plan

Key Knowledge Document

NS051-SS-REP-000-00010

This Key Knowledge Document (KKD) was generated as part of the pre-FEED project stage for NEP/NZT and completed in June 2021. This document release was put on hold to allow for the application process for the carbon dioxide licenses CS006 and CS007 by the North Sea Transition Authority to be completed and the licenses awarded in May 2022. The contents of the KKD does not fully reflect the subsequent work after drafting in June 2021.

May 2022

Acknowledgements

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1.0 Foreword

The Net Zero Teesside (NZT) project in association with the Northern Endurance Partnership project (NEP) intend to facilitate decarbonisation of the Humber and Teesside industrial clusters during the mid-2020s. Both projects will look to take a Final Investment Decision (FID) in early 2023, with first CO2 capture and injection anticipated in 2026.

The projects address widely accepted strategic national priorities – most notably to secure green recovery and drive new jobs and economic growth. The Committee on Climate Change (CCC) identified both gas power with Carbon Capture, Utilisation and Storage (CCUS) and hydrogen production using natural gas with CCUS as critical to the UK's decarbonisation strategy. Gas power with CCUS has been independently estimated to reduce the overall UK power system cost to consumers by £19bn by 2050 (compared to alternative options such as energy storage).

1.1 Net Zero Teesside Onshore Generation & Capture

NZT Onshore Generation & Capture (G&C) is led by bp and leverages world class expertise from ENI, Equinor, and TotalEnergies. The project is anchored by a world first flexible gas power plant with CCUS which will compliment rather than compete with renewables. It aims to capture ~2 million tonnes of CO2 annually from 2026, decarbonising 750MW of flexible power and delivering on the Chancellor's pledge in the 2020 Budget to "support the construction of the UK's first CCUS power plant." The project consists of a newbuild Combined Cycle Gas Turbine (CCGT) and Capture Plant, with associated dehydration and compression for entry to the Transportation & Storage (T&S) system.

1.2 Northern Endurance Partnership Onshore/Offshore Transportation & Storage

The NEP brings together world-class organisations with the shared goal of decarbonising two of the UK's largest industrial clusters: the Humber (through the Zero Carbon Humber (ZCH) project), and Teesside (through the NZT project). NEP T&S includes the G&C partners plus Shell, along with National Grid, who provide valuable expertise on the gathering network as the current UK onshore pipeline transmission system operator.

The Onshore element of NEP will enable a reduction of Teesside's emissions by one third through partnership with industrial stakeholders, showcasing a broad range of decarbonisation technologies which underpin the UK's Clean Growth strategy and kickstarting a new market for CCUS. This includes a new gathering pipeline network across Teesside to collect CO2 from industrial stakeholders towards an industrial Booster Compression system, to condition and compress the CO2 to Offshore pipeline entry specification.

Offshore, the NEP project objective is to deliver technical and commercial solutions required to implement innovative First-of-a-Kind (FOAK) offshore low-carbon CCUS infrastructure in the UK, connecting the Humber and Teesside Industrial Clusters to the Endurance CO2 Store in the Southern North Sea (SNS). This includes CO2 pipelines connecting from Humber and Teesside compression/pumping systems to a common subsea manifold and well injection site at Endurance, allowing CO2 emissions from both clusters to be transported and stored. The NEP project meets the CCC's recommendation and HM Government's Ten Point Plan for at least two clusters storing up to 10 million tonnes per annum (Mtpa) of CO2 by 2030.

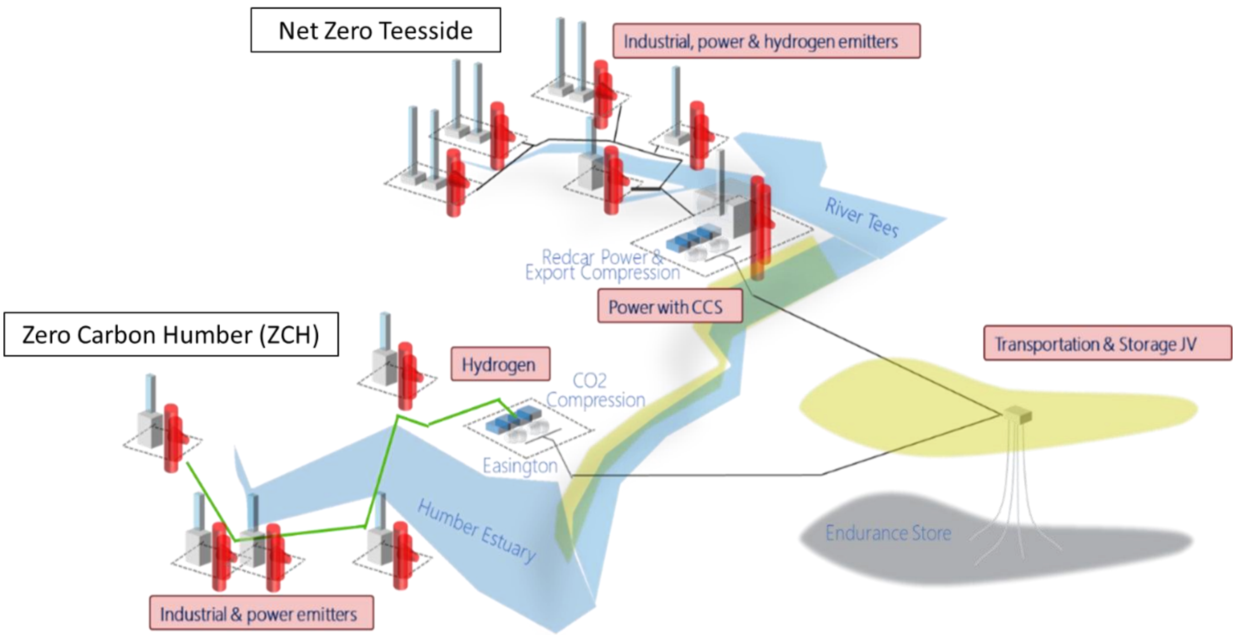


Figure 1: Overview of Net Zero Teesside and Zero Carbon Humber projects.

The project initially evaluated two offshore CO2 stores in the SNS: 'Endurance', a saline aquifer formation structural trap, and 'Hewett', a depleted gas field. The storage capacity requirement was for either store to accept 6+ Mtpa CO2 continuously for 25 years. The result of this assessment after maturation of both options, led to Endurance being selected as the primary store for the project. This recommendation is based on the following key conclusions:

- The storage capacity of Endurance is 3 to 4 times greater than that of Hewett
- The development base cost for Endurance is estimated to be 30 to 50% less than Hewett
- CO2 injection into a saline aquifer is a worldwide proven concept, whilst no benchmarking is currently available for injection in a depleted gas field in which Joule-Thompson cooling effect has to be managed via an expensive surface CO2 heating solution.

Following selection of Endurance as the primary store, screening of additional stores has been initiated to replace Hewett by other candidates. Development scenarios incorporating these additional stores will be assessed as an alternative to the sole Endurance development.

2.0 Symbols and Abbreviations

BEIS	Department of Business, Energy and Industrial Strategy
BHT	Botton Hole Temperature
CAPEX	Capital Expenditure
Capture	Collection of CO_2 from power station combustion process or other facilities and its process ready for transportation.
Carbon	An element, but used as shorthand for its gaseous oxide, CO_2.
CCGT	Combined Cycle Gas Turbine
CCS	Carbon Capture and Storage
CCUS	Carbon Capture, Utilisation and Storage
CfD	Contract for Difference
CGP	Clean Gas Project
CI	Climate Investments LLP
CO_2	Carbon Dioxide
DHPTG	Downhole Pressure-Temperature Gauge
DST	Drill-Stem Test
EOS	Equation of State
FEED	Front-End Engineering Design
FFM	Full Field Model
FID	Final Investment Decision
GW	Gas-Water
HC	Hydrocarbon
HMG	Her Majesty's Government (UK government)
ILT	Injection Logging Tool

Key Knowledge	Information that may be useful, if not vital, to understanding how some enterprise may be successfully undertaken
KZ	Vertical (Z) Permeability (K)
MDT	Modular Formation Dynamic Tester
MEG	Methanol Ethylene Glycol
MM	Million
MMV	Monitoring, Measurement, and Verification
MT	Metric Tonnes
MTPAi	Million Tonnes per Annum (instantaneous i.e. peak)
MTPAa	Million Tonnes per Annum (average i.e. annualised)
NIST	National Institute of Standards and Technology
NPV	Net Pore Volume
NUI	Normally Unmanned Installation
NZT	Net Zero Teesside
OECD	Organisation for Economic Co-operation and Development
OGCI	Oil and Gas Climate Initiative
OPEX	Operating Expenditure
P&O	Production and Operations
PBU	Pressure Build-Up
PI	Productivity Index
PTA	Average Reservoir Pressure
PVT	Pressure Volume Temperature
RAB	Regulated Asset Base
RDOL	Reservoir Defined Operating Limits
SCAL	Special Core Analysis

SPR	Seismic Phase Reversal
Storage	Containment in suitable pervious rock formations located under impervious rock formations usually under the seabed.
TDRM	Top-Down Reservoir Modelling
TDS	Total Dissolved Solids
Transport	Removing processed CO2 by pipeline from the capture and process unit to storage.
TVDSS	True Vertical Depth Subsea
VIT	Vertical Interference Test
WDOL	Wells Defined Operating Limits
WHP	Wellhead Pressure

3.0 Characterisation of the Geological Storage Site and Complex

3.1 Site Overview

The Endurance structure is a four-way dip closure straddling blocks 42/25 and 43/21 in the UK sector of the North Sea, 60 miles east of Flamborough Head, as shown in Figure 2. The structure is covered by the CCS license CCS001 first awarded to National Grid Carbon Ltd in 2011 (highlighted by the magenta polygon in Figure 4). The license ownership has been reassigned to bp as operator (and standing on the behalf of the Net Zero Teesside partners i.e. Shell, TotalEnergies, Equinor, and ENI) in 2020 alongside National Grid and Equinor as co-licensees.

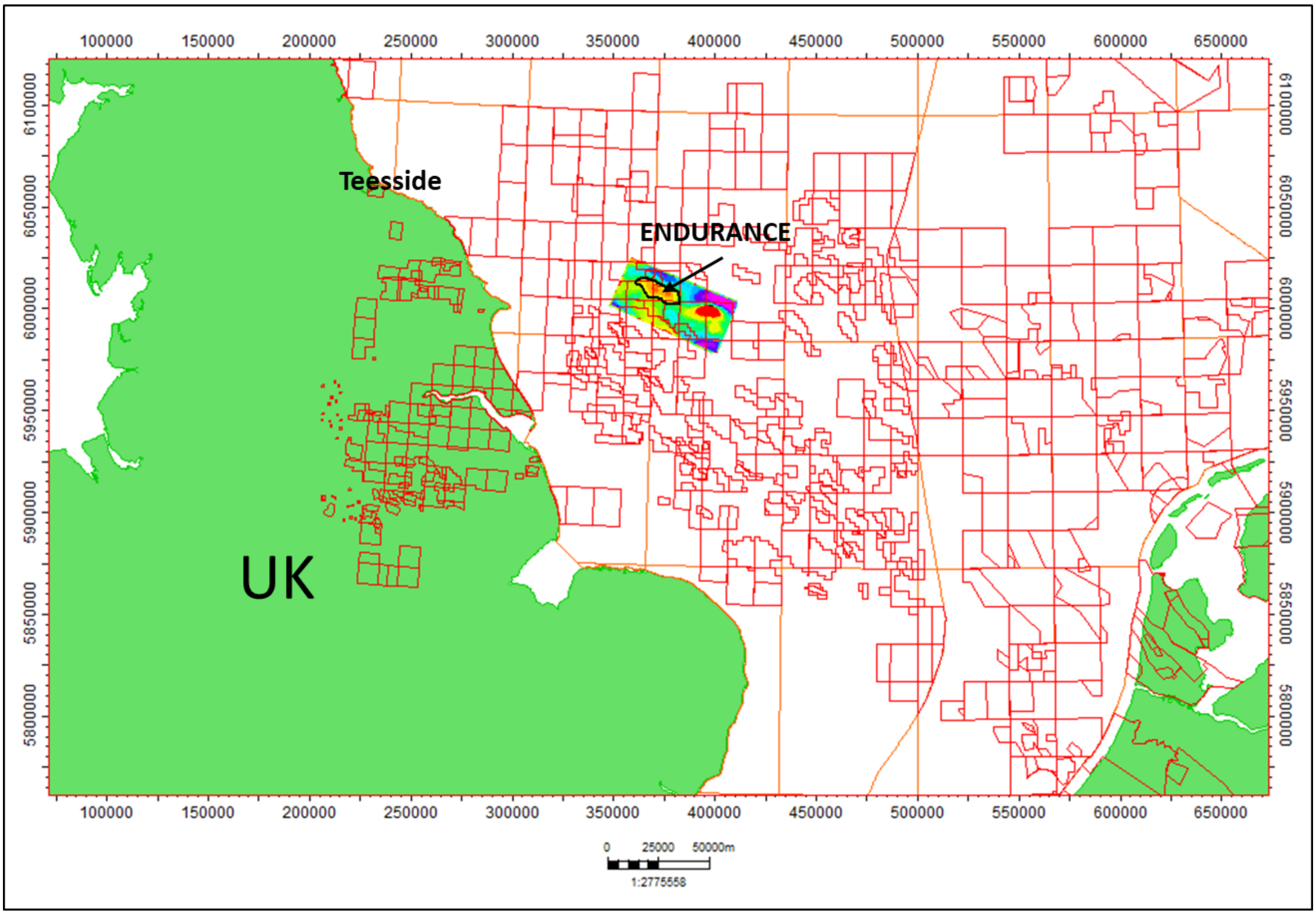


Figure 2: Endurance CO2 storage site located in the UK South North Sea.

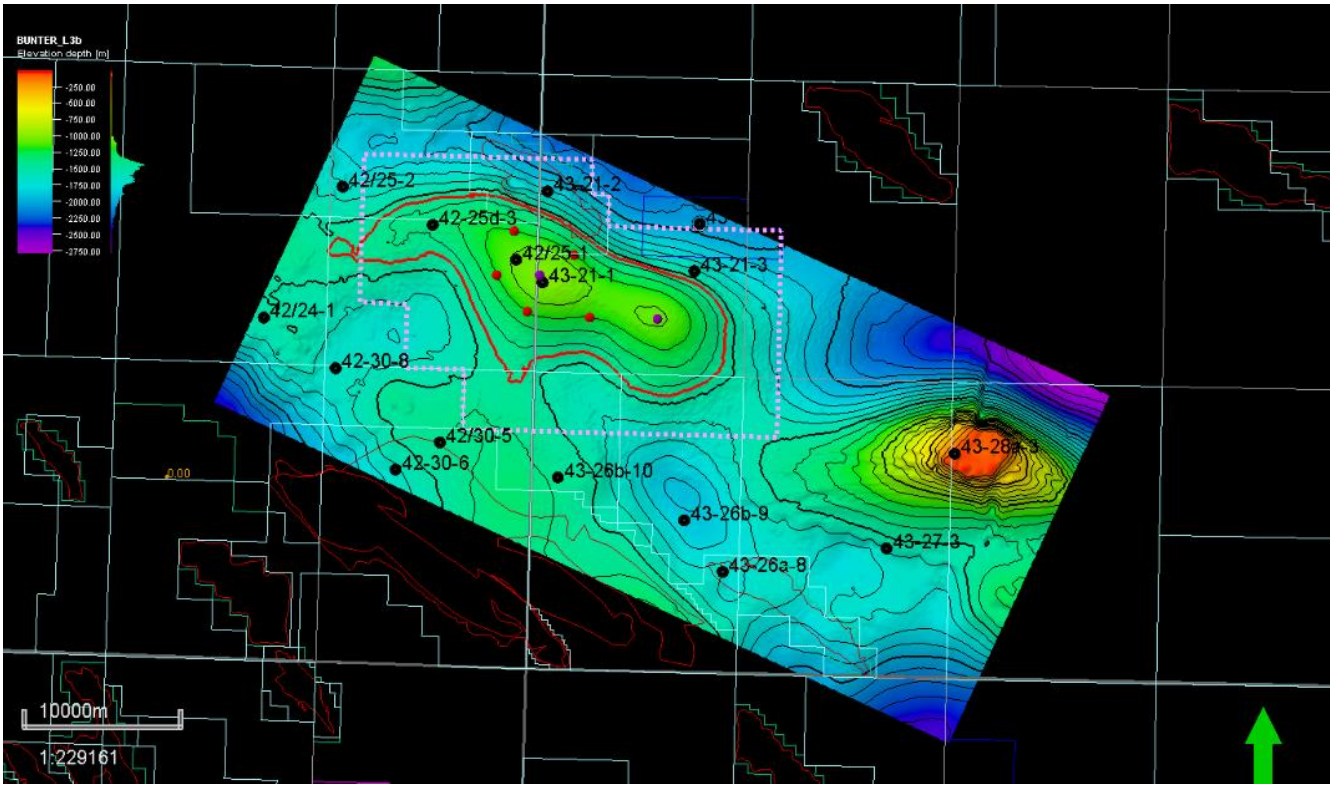


Figure 3: CCS001 license covering Endurance and its surroundings (Ravenspurn in the south and Garrow in the north)

3.2 Geological characterization of the storage site

Reservoir and Overburden Overview

This structure is approximately 22 km long, 8 km wide and over 200 m thick. The crest of the reservoir is located at a depth of approximately 1020 m below the seabed and the 4-way closure is penetrated by 3 wells above the spill point highlighted in dark blue in Figure 5.

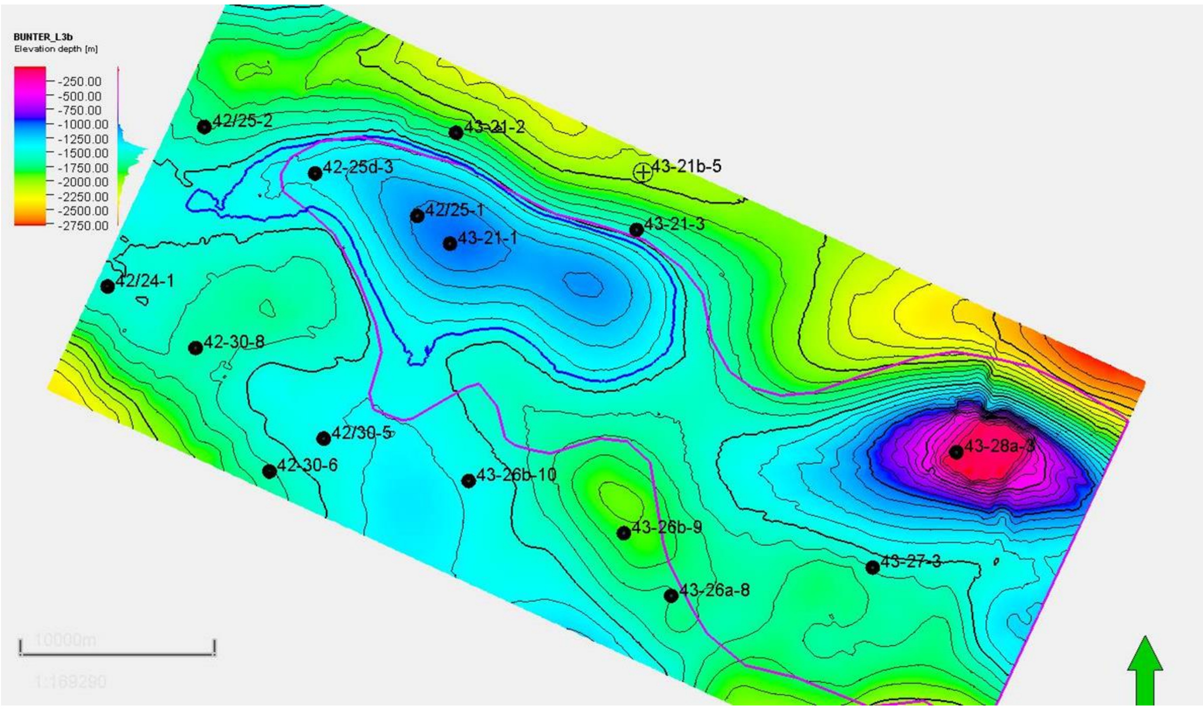


Figure 4: Endurance structure and legacy wells drilled in the area.

The reservoir where the CO2 will be injected is a saline aquifer of the Triassic age Bunter Sandstone Formation. The sands in the Bunter Sandstone Formation are penetrated by core in 42/25d-3 well and are of good reservoir quality with average porosity on the well level between16-24% and permeabilities ranging from few mD to several hundreds of mD.

It is continuous and mappable on existing seismic data and is sealed by the Rot Clay and Rot Halite formations. The overburden primarily consists of sealing lithologies such as clay, shales, anhydrites and halite at the storage site making ideal sealing potential for the targeted container (Figure 5 and 6).

Bunter Sandstone Formation comprises several large-scale fining upwards units in which predominantly fluvial and aeolian sandstones fine upwards into siltstone and claystone alternations of the playa margin facies. Lower permeability facies such as clay-rich playa mudstones and playa margin flood plain siltstones, deposited during periods of low energy or lake expansion, are abundant in the Lower Bunter (L1). Coarser grained deposits are more common in the middle and upper parts of the Bunter Sandstone (L3 and L2).

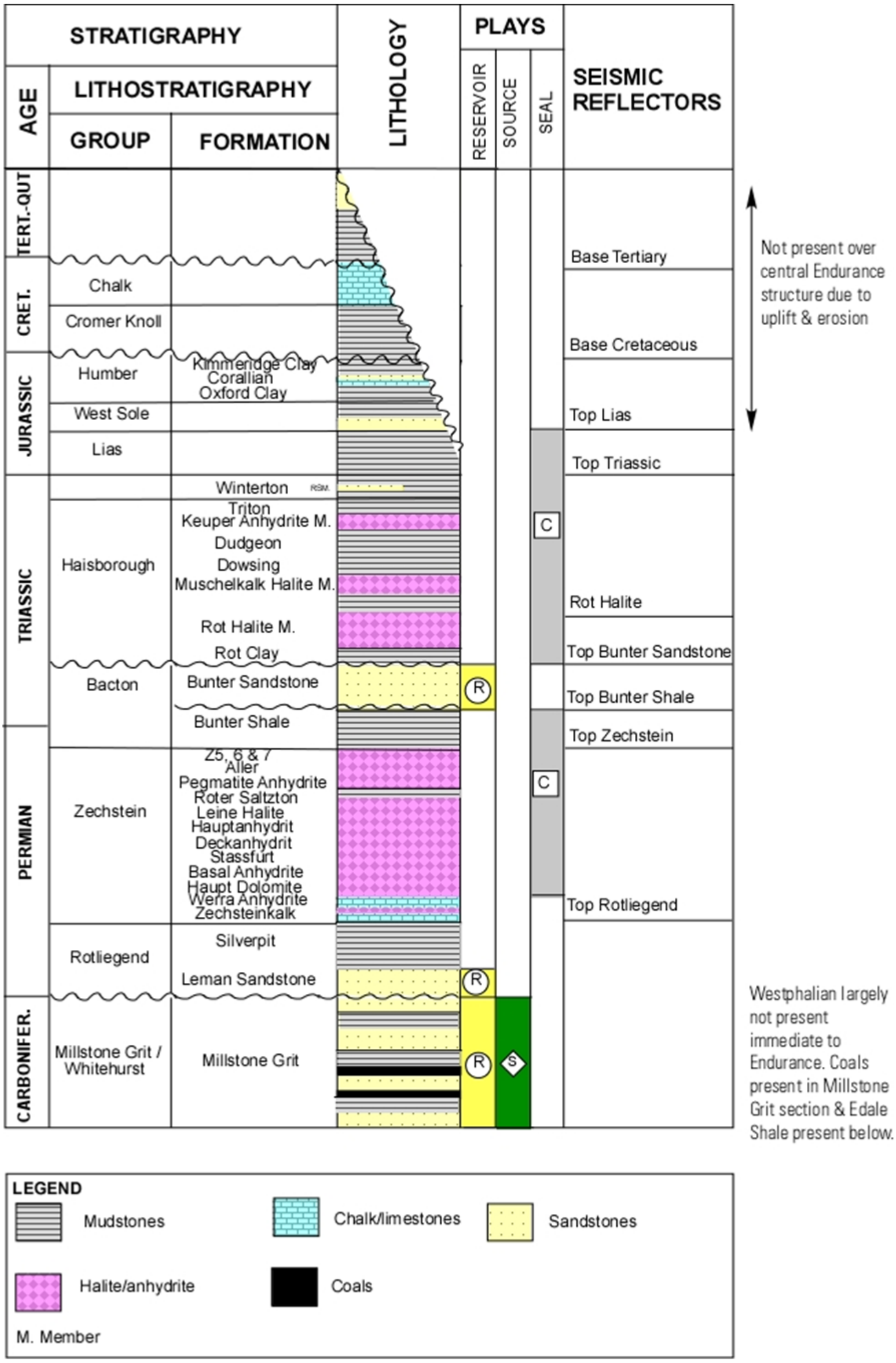


Figure 5: Lithostratigraphic chart for the Endurance structure (Please note shallow stratigraphy down to Corallian Formation is absent at the Endurance structure due to uplift and erosion.)

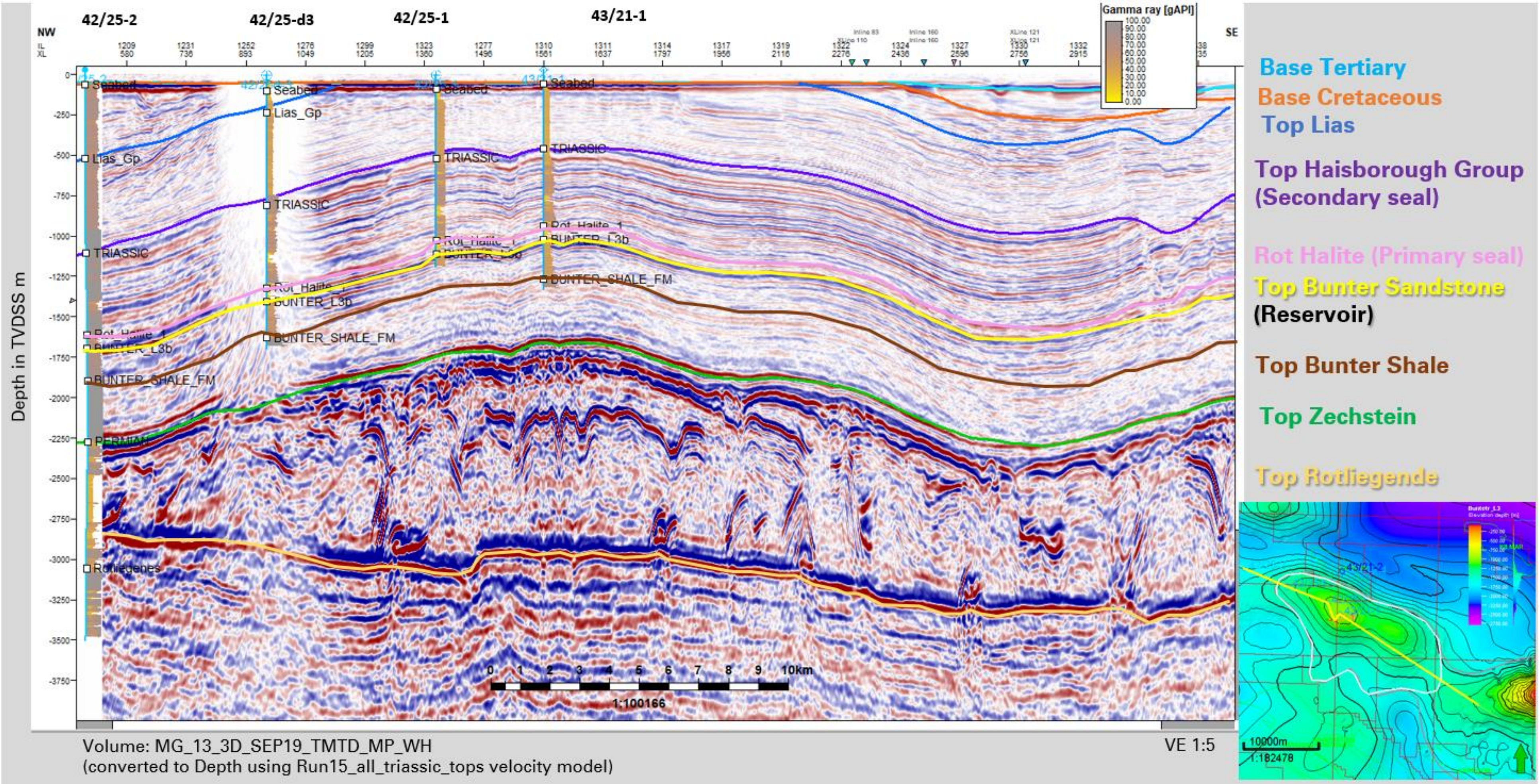


Figure 6: Section (depth converted) showing key surfaces in the overburden. NB This section ties well locations and the apparent second-order structural features are an artefact of the zig-zag across the structure. The seismic data was acquired during the drilling of 42/25d-3 and this has resulted in a data gap at the well location.

Faulting in the Overburden

A NW-SE trend is observed over the Endurance structure which is consistent with the deeper Paleozoic trend observed at Carboniferous/Permian level. Faults with displacement of the order of ~10 m can be seen in the Triassic, however, offset reduces to zero as we approach the Rot Halite and is absent at the Top Bunter Sandstone. (Figure 6). There is no evidence of faults extending into the Bunter aquifer within the closure of the Endurance anticline.

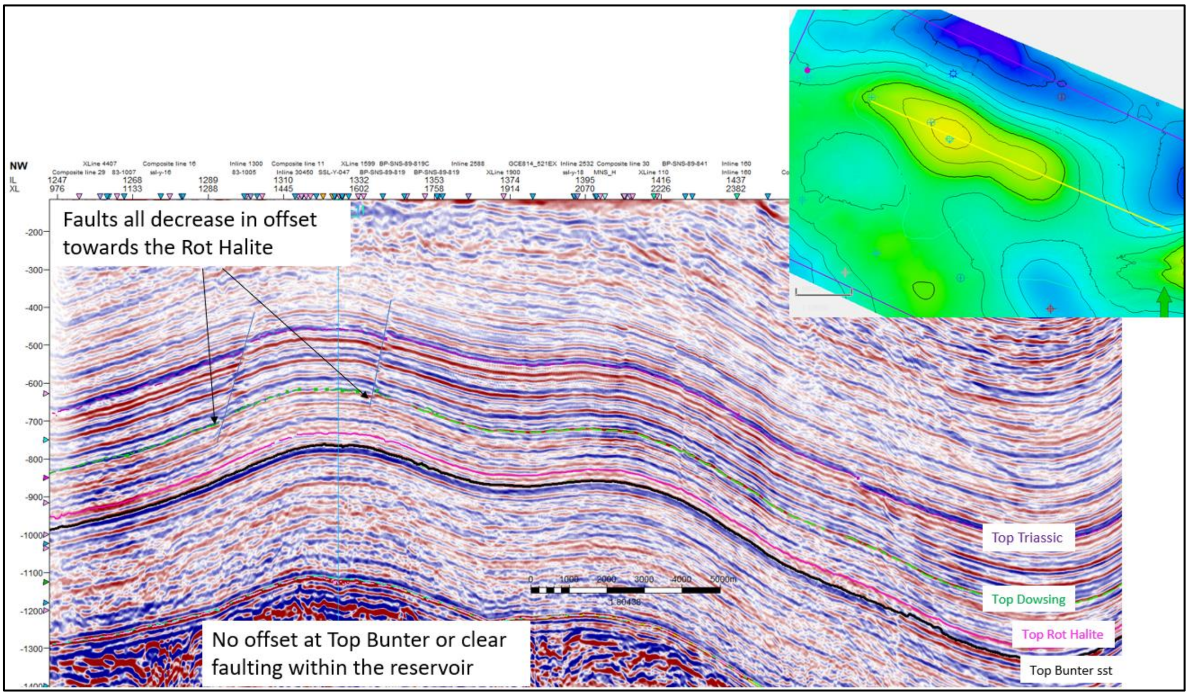


Figure 6: NW-SE Line through the Endurance structure showing faults in the overburden.

The figure below (Figure 7) shows all the overburden faults mapped, which have an overall orientation of NW-SE over the Endurance structure changing to more EW on the eastern side with complex geometries. Near the Bunter Sandstone outcrop, the faults take a radial pattern with certain faults trending NS while most trending EW. The faulting is more intense at the outcrop as compared to the main structure (See Figure 8). In some areas, there was some cross-cutting of these NS and EW trending faults, however their influence on the steep structure is a matter of debate. The halite packages within the Haisborough Group have been thought to act as a potential detachment, leading to no offset seen at Top Bunter Sandstone coincident with the overburden faulting. Since the faulting is found to be present across dominantly shale/salt lithologies, transmissibility of fault depends on lithification at the time of the faulting, but its likelihood is low.

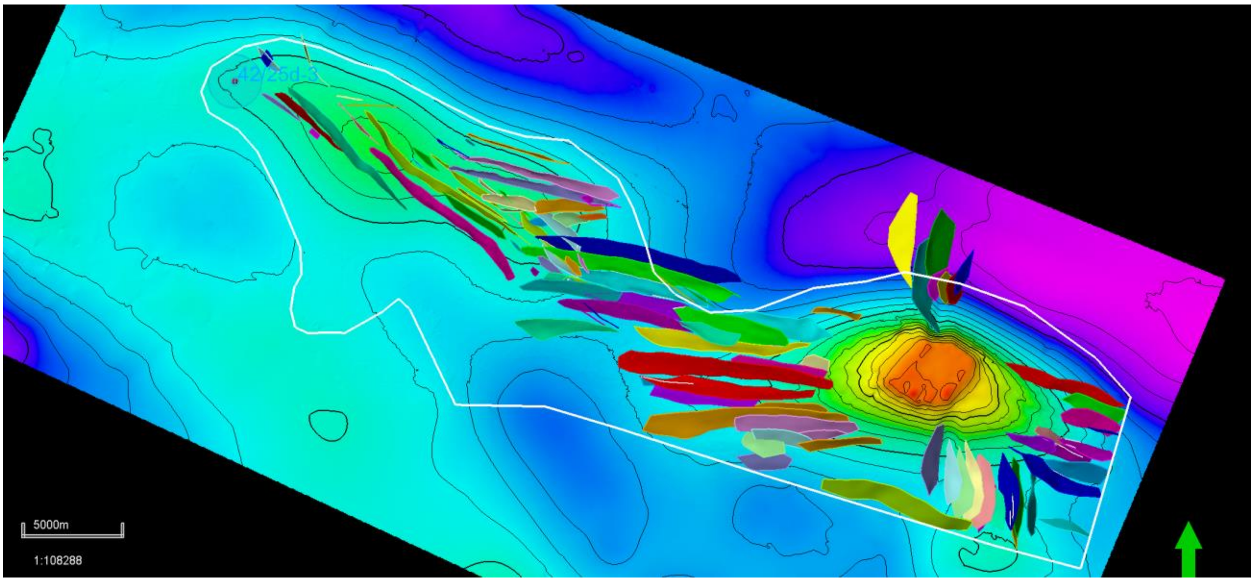


Figure 7: Overburden faults mapped over the Endurance structure.

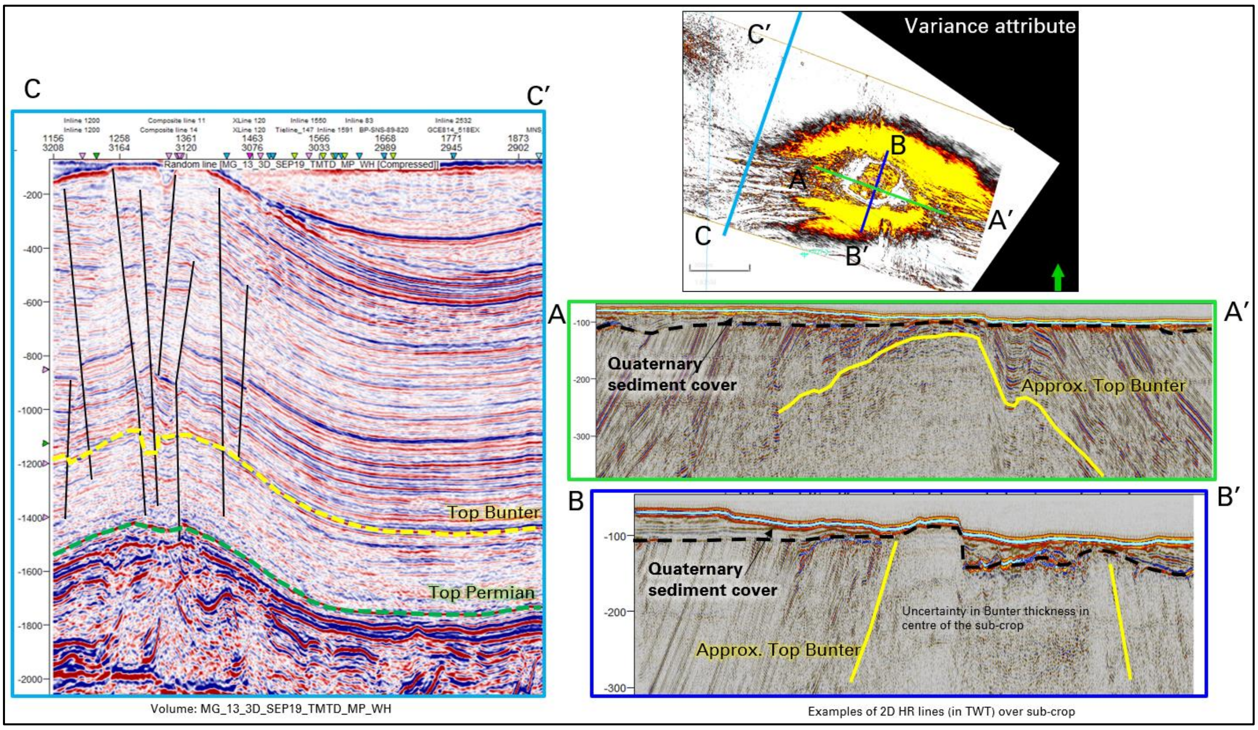
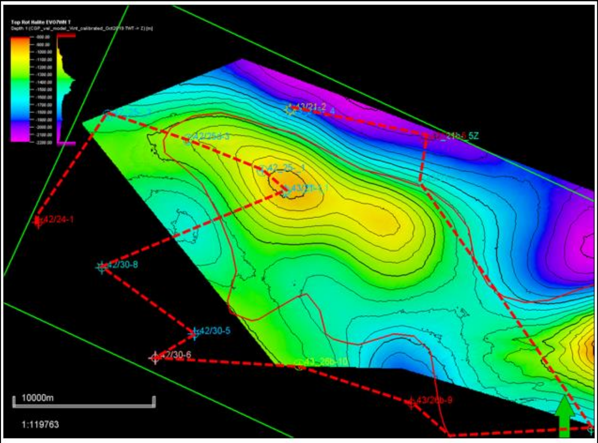


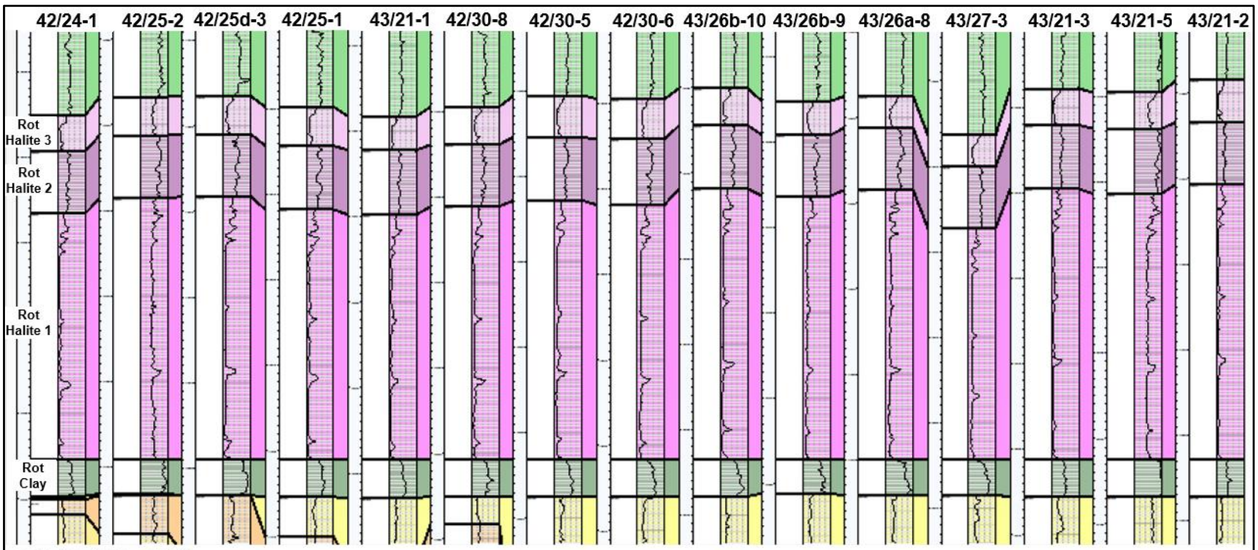
Figure 8: Intensity of faulting increases over the Endurance outcrop to the SE.

Seal Description

Rot Halite and Rot Clay formations are present extensively over the Southern North Sea and act as a seal at the Endurance Structure for the Bunter Sandstone Formation. Existing seismic data and well logs show that the Rot Halite is a consistent interval with thickness of around 100 m over the AOI.



Top Rot Halite Structure Map with well correlation both on and encircling the structure (red dashed line)



Rot Clay & Rot Halite well correlation both on and encircling the structure (red dashed line on map). Depth MD (m). Flattened Top Rot Clay.

Figure 9: Correlation of Rot Halite and Rot Clay over the offset wells in the AOI.

The fracture closure pressure of the Rot Clay, which is also a measure of sealing potential, was recorded during an MDT (Modular Formation Dynamic Tester) mini-frac test that was conducted on the appraisal well 42/25d-3. It measured 264 bars (3830 psi) at 1363 m TVDSS. This is the best direct evidence that the Rot Clay is geomechanically strong and theoretically capable of trapping a sizeable CO_2 column and withstanding a significant increase in differential pressure due to CO_2 injection.

3D Geomechanics modelling cases run so far show the Endurance structure can withstand the likely pressures encountered during injection without plastic failure of the Rot Clay or fault reactivation. Rot Clay shale seems to be a competent seal based on all available data: 42/25d-3 mini-frac data, Esmond Field analogue, petrography and geomechanics.

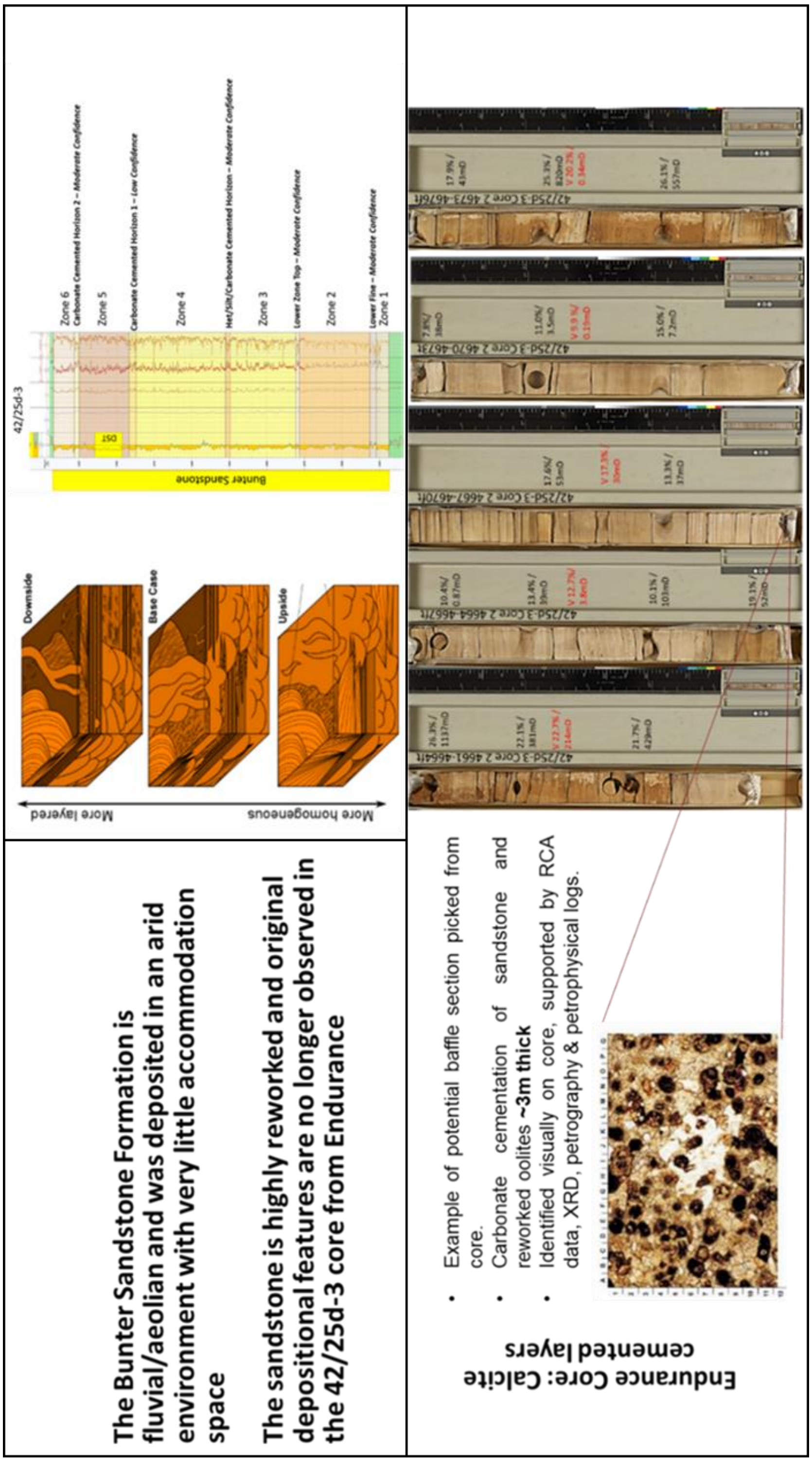


Figure 10: Overview of reservoir depositional environment and potential baffling.

Reservoir Depositional Environment

Bunter Sandstone was deposited in a broad, land-locked and gradually subsiding basin situated between 20-30 degrees N of the Equator. The rivers and streams drained into the basin from surrounding highs in a semi-arid climate and terminated in a playa lake situated within the basin centre. During drier periods, aeolian processes dominated, redistributing the sands and desiccating the mudstones.

Bunter Sandstone Formation comprises several large-scale fining upwards units in which predominantly fluvial and aeolian sandstones fine upwards into siltstone and claystone alternations of the playa margin facies. Lower permeability facies such as clay-rich playa mudstones and playa margin flood plain siltstones, deposited during periods of low energy or lake expansion, are abundant in the Lower Bunter. Coarser grained deposits are more common in the middle and upper parts of the Bunter Sandstone.

Cements (dolomite/halite cement and patchy bleached cement) and silty mud-crack surfaces, and cemented surfaces are recognised as potential barriers to flow in the reservoir. However, the sands in the Bunter Sandstone Formation are expected to be connected on a large scale as any identified baffles are not laterally continuous. Figure 10 shows the depositional environment of the Bunter Sandstone Formation at the storage site with net-to-gross values across the on-structure well stock exceeding 80-90%.

3.3 Geophysical characterization overview

Seismic Data

The project team got access to the 1997 Ravenspurn OBC survey which covers the Endurance structure but not the outcrop and have purchased the 2013 Polarcus/TGS Ravenspurn data in July 2019 which has higher fold, better overburden coverage and extends east across the outcrop (see Figure 11). There are also regional 2D lines and a small amount of 2DHR over the outcrop and a small area on the northern flank of the structure (acquired by NG).

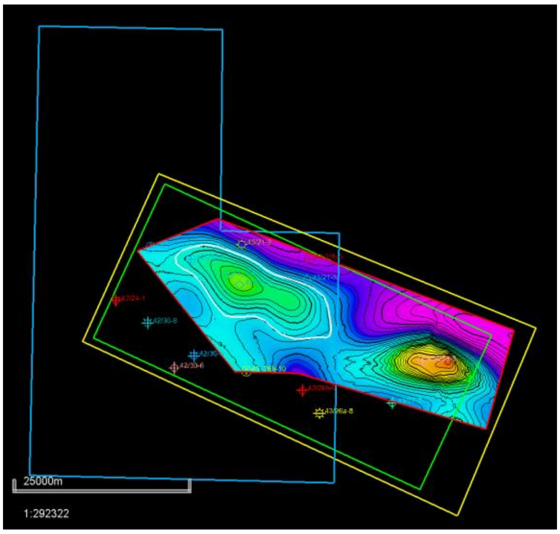


Figure 11: Outline of 1997 OBC coverage (blue line) and purchased 2013 Polarcus coverage (structure map).

Structure

Top reservoir is very clear on existing seismic data, in part due to the seismic phase reversal which shows up in all attributes (signing the abrupt change of reservoir quality, when moving from “inside” the structure to the periphery where cementation is showing, especially in the upper part of the reservoir, leading to a sharp change in acoustic impedance) and makes the Top Bunter obvious (Figure 13)

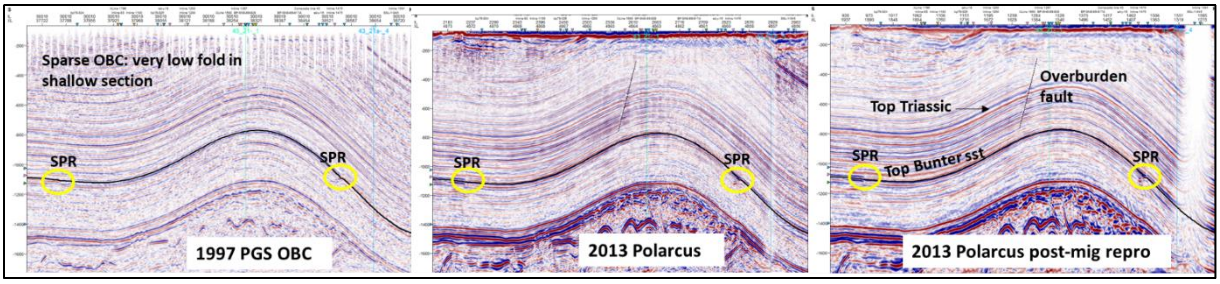


Figure 12: Comparison of Seismic volumes from L to R: 97 OBC; original Polarcus; Polarcus after post-migration reprocessing.

The seismic response of the base reservoir is dimmer than expected from synthetics and can be mapped in some areas but not reliably and consistently across the whole structure, especially away from well control. However, the average reservoir thickness from seismic mapping and the one derived from the wells within the AOI agree, combined with the regional isopachous nature of the stratigraphy, lead to relatively low uncertainty.

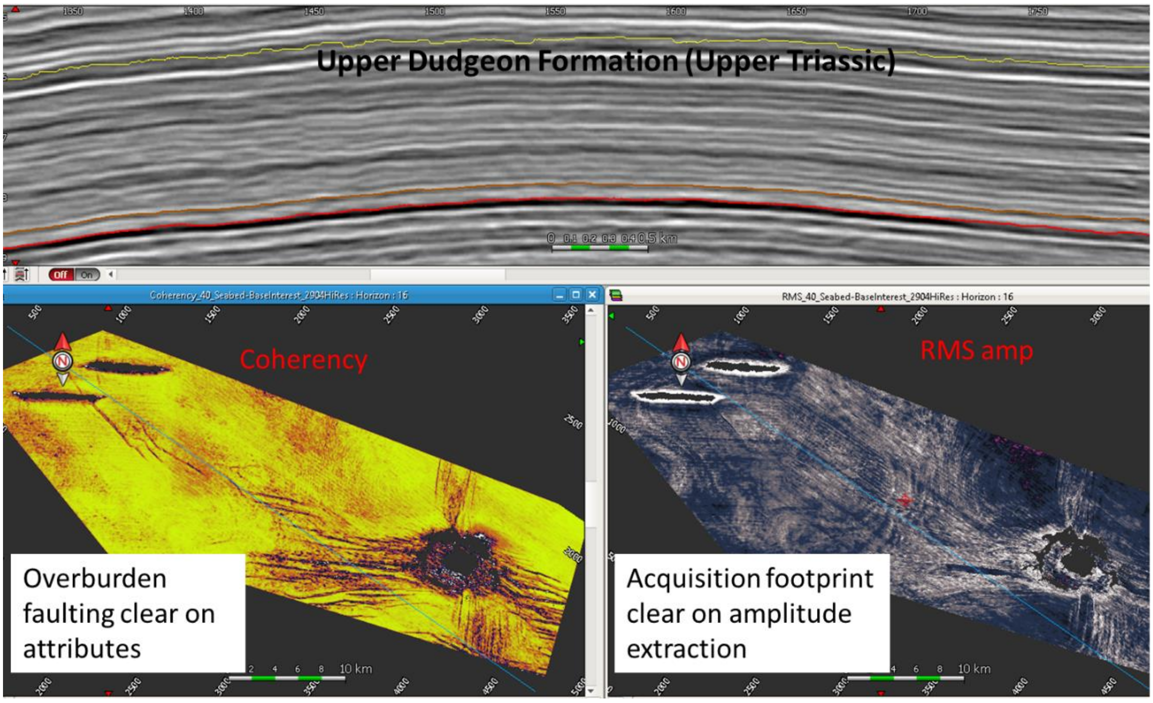


Figure 13: Overburden attribute example to highlight faulting.

Attributes

The only clear reservoir seismic attribute which can be observed is at the seismic phase reversal (SPR) at the top of the Bunter sandstone (Figure 14). The challenge of low impedance contrasts, merging of the 2 Polarcus volumes post-migration and residual problems such as multiples mean that seismic reservoir characterisation has not been possible. In the overburden the faults show clearly on many attributes such as coherency and Variance.

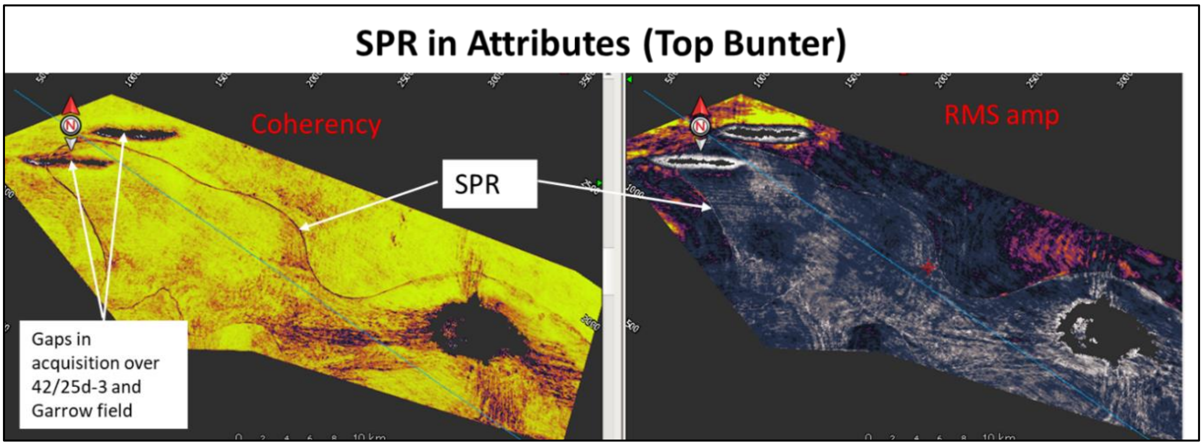


Figure 14: Seismic Phase Reversal (SPR) is clear in both coherency and amplitude maps.

3.4 Petrophysical Data Inventory

There are currently 3 wells drilled on the Endurance structure with additional near-field wells used to assess rock quality in the broader aquifer (Figure 5). Core data was acquired in two wells and the following core analysis has been conducted:

- 42/25_1 (18m of core)
  - Porosity, Permeability, Grain density (all at atmospheric pressure)
- 42/25d_3 (164m of core)
  - Porosity (ambient and stressed), Permeability (air/Klinkenberg/Brine, Ambient and stressed, Grain density, XRD, MICP, Petrography, Rel perm (please see Reservoir engineering section for further details)

Wireline log data has been collected in all 3 wells on structure (42/25_1, 42/25d_3 and 43/21_1). All wells have the following basic data:

- Gamma Ray, Resistivity, Density and Sonic.

In addition, there is some advanced log data present:

- Formation pressures – 42/25_1 and 42/25d_3
- Fluid samples + Mini-frac + Vertical interference test (VIT) – 42/25d_3
- Image logs (Dual OBMI - UBI) – 42/25_3 (although considered poor quality)
- Nuclear magnetic resonance – 42/25d_3 only

Table 1: Formation Properties for Endurance.

Formation Properties	Units		Comments
Permeability (P10-P50-P90)	mD	100 – 300 - 500	Expected range for any given well.
Permeability Directionality		Horizontal	
Kv / Kh	Fraction	Macroscale: 0.04 (derived from DST in 42/25d-3), core scale ranging from 0.01 (heterolithics or cemented sand facies) to 10% (clean sand facies)	
Porosity (P10-P50-P90)	Fraction	0.164 - 0.225 - 0.241	Expected range for any given well.
Pore Volume Compressibility	1 / psi	4*10^-6	
Thermal Expansion	1E-5/oC	4.0 (Halite – 3.85 @20-40oC, 4.24@40-60oC) / 1.4 (Shale) / 1.2 (Sand)	
Formation Dip & Azimuth	degrees	Near Crest: Dip ~4.25 degrees Azimuth ~300 degrees Down-Flank: Dip 1-2 degrees Azimuth 270 degrees	

A petrophysical model has been created for the evaluation of the saline water bearing bunter sandstone at the storage site. An initial Vcl was calculated using the Gamma ray values observed in the well while the primary method of calculating porosity was using density log data when available. Log permeability is calculated using a Porosity/Permeability relationship derived from the core data collected in the 42/25d_3 and 42/25_1 wells. The stressed core data in 42/35d_3 was used to correct all the other core data to overburden conditions and to a “brine” permeability (converting from Klinkenberg to brine perm, using the subset of data with brine perm measurements). Overburden corrected porosity is then plotted against overburden corrected permeability and a single regression is then calculated. This regression is then used to predict brine permeability from porosity.

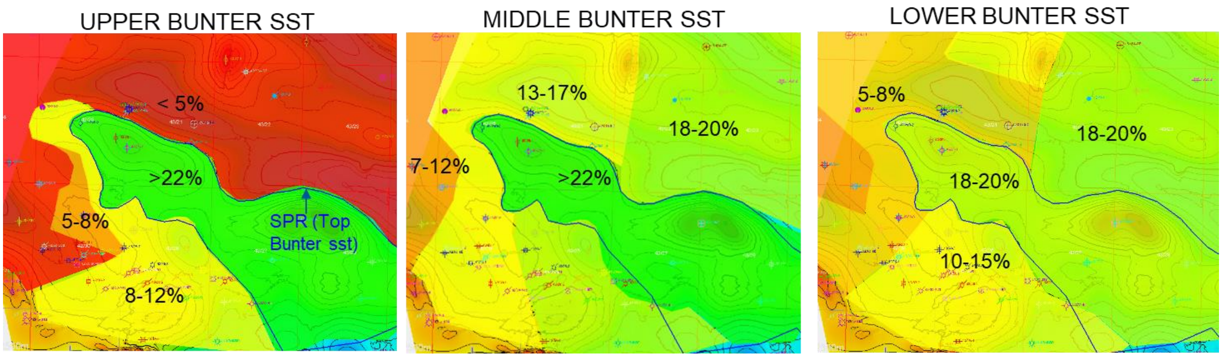


Figure 15: Porosity trend in near-store wells for Endurance.

3.5 Rock and Fluid Properties

3.5.1. Initial Reservoir Pressure and Temperature

MDT and Repeat Formation Tester pressures were taken respectively in 42/25d-3 and in the appraisal crestal well 42/25-1. Reservoir pressure of Endurance is assumed to be 140 bars and 56 degrees C (132.8 deg F) at datum of 1300 m TVDss. The decrease in reservoir pressure, of the order of 0.7 bar (10 psia) at 1300 m TVDSS, can be potentially observed by plotting two linear trendlines. The White Rose study (K40 and K41) [1] [4] suggested that this reduction in pressure is due to expansion in the Greater Bunter Sandstone Formation to fill the void created by gas production from some of the Bunter hydrocarbon gas fields (the Esmond Complex), 50 km north of Endurance. This interpretation would suggest that Endurance is in pressure communication with a large, connected volume. However, this interpretation has been questioned by latest review of the data [2]. Brine salinity data from 42/25d-3 would indicate that there is a significant salinity gradient across the brine column. The former could explain the pressure differential between the two wells in its own.

3.5.2. Brine composition

Endurance brine is hypersaline (circa 250,000 ppm %w) and presents a pH <7. In-situ fluid samples were recovered from well 42/25d-3 (MDT samples and downhole/separator samples from Drill Stem Test). There is potentially an indication of a salinity vs. depth gradient from the 3 analysed MDT samples which could explain the pressure difference observed between 42/25d-3 (drilled in 2013) and 42/25-1 (drilled in 1990). Further MDT samples at various depths will be required for future wells to confirm observation made in well 42/25d-3.

Samples indicated that the formation waters are highly saline, sodium chloride dominated brines, (TDS 300,000 ±10,000 mg/L), with significant concentrations of common rock constituents, calcium, magnesium and sulphate, and also highlighted the presence of a number of metal contaminants (White Rose Key Knowledge Document K40, 2016 [1]).

3.5.3. Rock Properties

The Bunter sandstone is well cemented reservoir with a high UCS (range ~2000 psi to ~4000 psi, generally trending stronger with depth). Measurement of static Young's modulus by FracTec on 42/25d-3 (E=1,800,000 psi) core would indicate a consolidated sandstone as well with limited risk of sanding as supported by the study on sand propensity by National Grid [3].

3.5.4. Rock-fluid Interactions

Equilibrium modelling (CO2-brine geochemical modelling) to date indicates that the only mineralogical changes likely to be observed following the saturation of reservoir brine with CO2 are slight dissolution or precipitation of carbonate minerals. These minerals are not abundant in the reservoir so their alteration is unlikely to have a substantial impact on the overall reservoir quality; however, the rate of fluid flow through a perforation might be such that an equilibrium model is no longer appropriate due to rapid removal of any dissolved material. This physical process is likely to dominate over the chemical ones in these circumstances, again aligning with the desire for the brine – CO2 front to be kept away from the near wellbore [2].

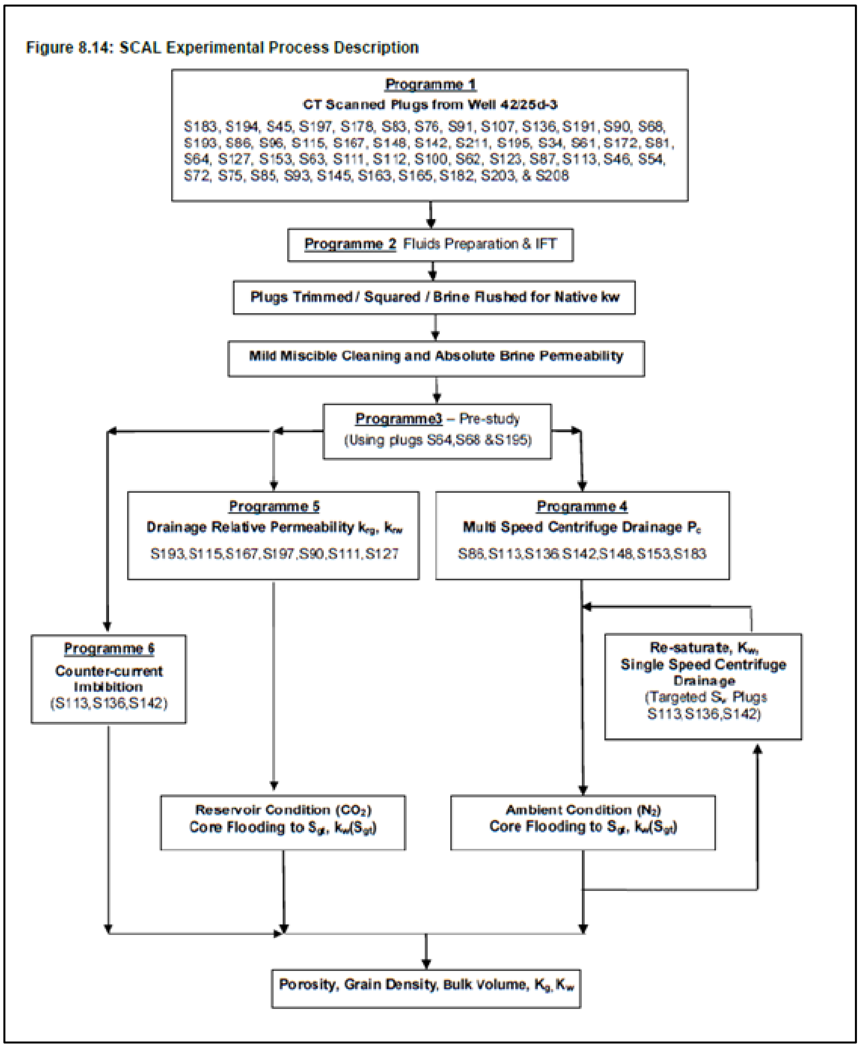


Figure 16: Summary of SCAL experiments carried out on well 42/25d-3 core.

A series of conventional and SCAL measurements were carried out on 42/25d-3 core at East Grinstead (RCA) and Winfrith (SCAL) by Weatherford Laboratories, including a series of unsteady state core flood with CO_2 displacing brine under reservoir conditions and counter-current imbibition (trapped gas saturation), as shown in Figure 13. A series of gas (CO_2) – water relative permeability models (downside/base/upside) were generated to explore a range of uncertainties demonstrated by the SCAL data from Endurance [2] and incorporated into the reservoir modelling workflow.

3.6 Dynamic Description of the Reservoir with Appraisal Well 42/25d-3

National Grid carried out an injection test on the Endurance appraisal well, as part of the White Rose project in 2013. The test aimed to produce ~ 5000 bwpd for 24 hours, followed by a 48-hour fall-off test and then a step-rate injection test at 5000, 10000, and 15000 bwpd. Likely scale precipitation led to rapid blockage of the perforations and subsequent fracking during the injectivity test (BP's scaling tendency work indicated a high risk of $CaSO_4$ scale deposition when Endurance brine is mixed with sea water)

The PBU test re-interpretation was broadly consistent with previous White Rose interpretation4 and demonstrated good reservoir properties across the perforated interval as follows:

- No lateral barrier observed once tidal effect corrected – no seabed pressure gauge makes the interpretation of the derivative difficult (not practical with Kappa-Saphir™, somewhat successful with PIE).
- Kh (horizontal permeability) ~ 260-300* mD with radial, homogeneous model with partial penetration.
- Very low ratio of vertical (Kv) over horizontal permeability (Kh) i.e. Kv/Kh = 0.004 (0.4%) to make spherical analytical model matchable (i.e. Kv ~ 0.5-1 mD).
- Low macro-scale Kv/Kh (over 50-100's meters, < 1%) & moderate to good Kv/Kh from Vertical Interference Test #1 (over smaller scale i.e. 1's meters, ~10%).

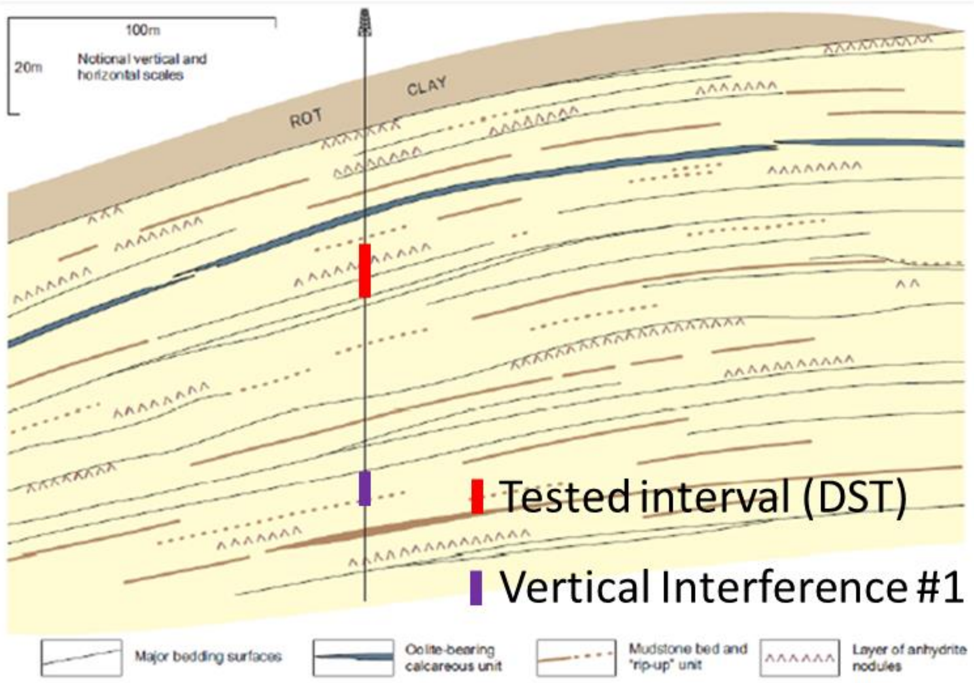


Figure 17: Illustrative cross-section through part of the 42/25d-3 area, showing potential barriers and baffles (from White Rose K42 Key Knowledge Document)

The impact of the potential baffles and barriers were evaluated through a series of uncertainty workflow (Monte Carlo simulation with the bp proprietary tool TDRM™).

4.0 Dynamic Modelling and Storage Capacity

4.1 Overview

Static properties and grid were generated in Petrel™ in 4Q 20195. A simulation reservoir model has been created in 4Q 2019 to run full-field development scenarios in Nexus®. The reservoir model has both black-oil (GAS-WATER immiscible displacement without CO2 solubility into brine) and compositional PVT formulation (solubility of CO2 into brine of the order of 1-1.5% per mass). The former primarily GAS-WATER immiscible displacement) was primarily used for scenarios and uncertainty analysis in TDRM™ (pressure prediction, brine management scoping, and storage capacity evaluation). Near wellbore effects (halite precipitation) are being modelled in GEM™ with mechanistic models [2].

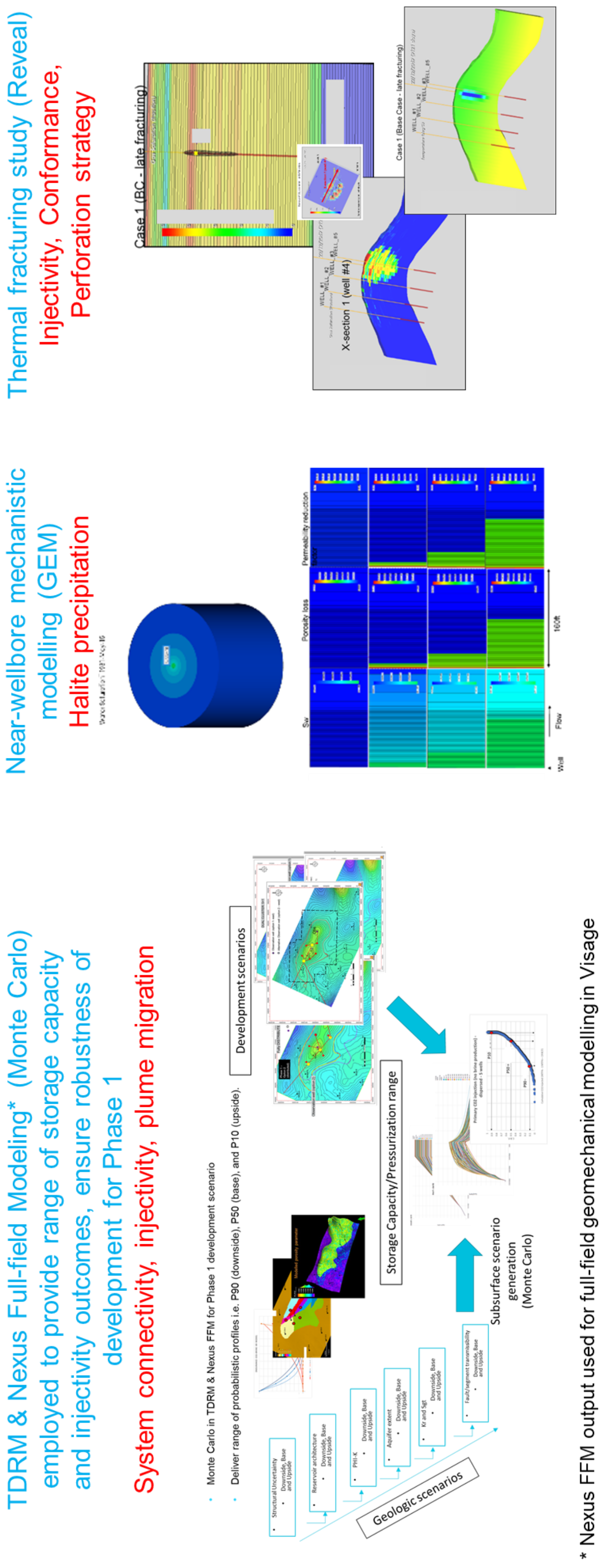


Figure 18: Reservoir modelling and simulation for Endurance.

Thermal fracturing was also investigated with Reveal to evaluate its impact on plume conformance and well injectivity over time as shown in Figure 18.

4.2 Storage Capacity for Phase 1 Development

A comprehensive subsurface study has been carried out to de-risk the Endurance store capacity throughout the combined concept development/optimise stage (3Q19 to 1Q20) with the technical assurance completed in March 2020 to ensure that sufficient storage capacity will be available for Phase 1 volumes with considered subsea development (5 wells, no brine production) [5] as shown in Figure 18.

Endurance is a very large structure, with a possible and probable net pore volume (above the spill point, in-place) of 26 Gbbls of brine giving a potential storage capacity without brine management of at least 100 MT of CO2 (P90 subsurface case) for a distributed well layout for the 25 year-long project.

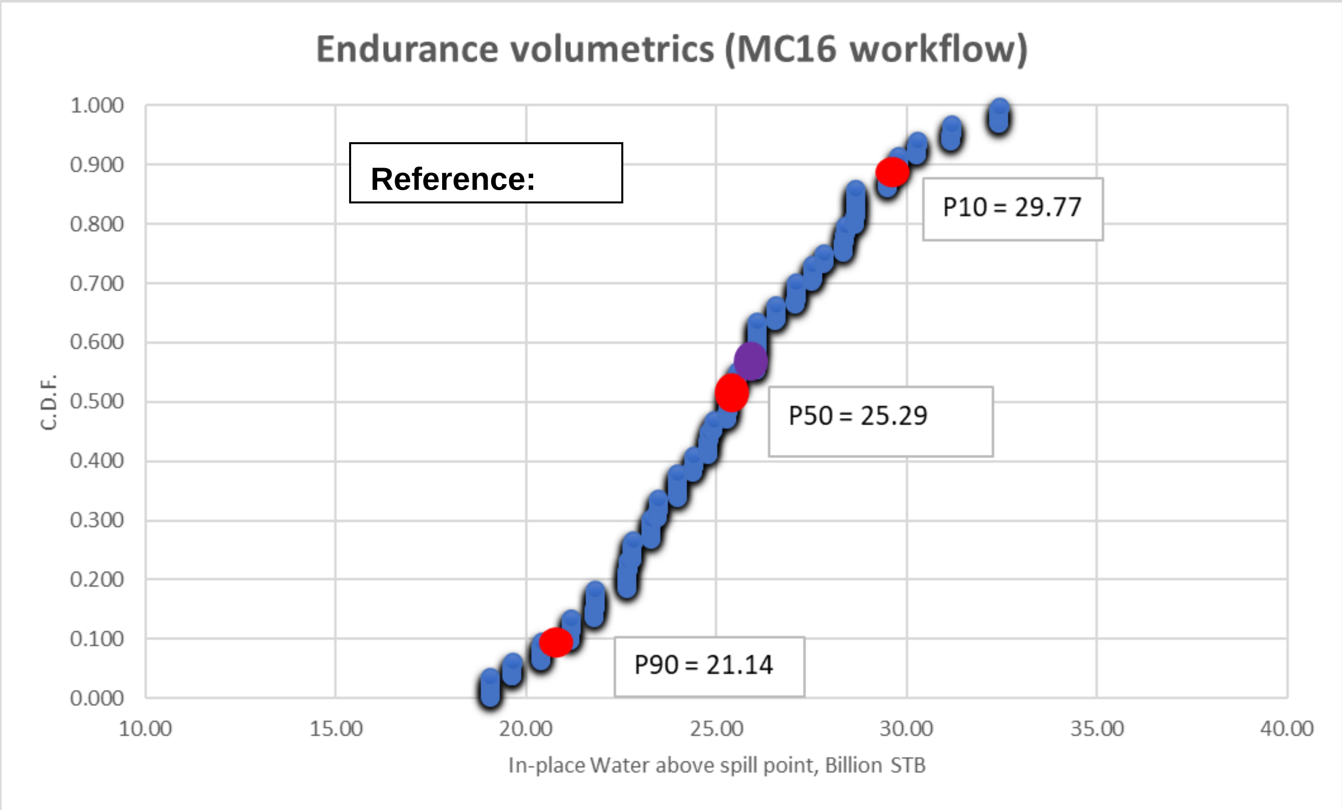
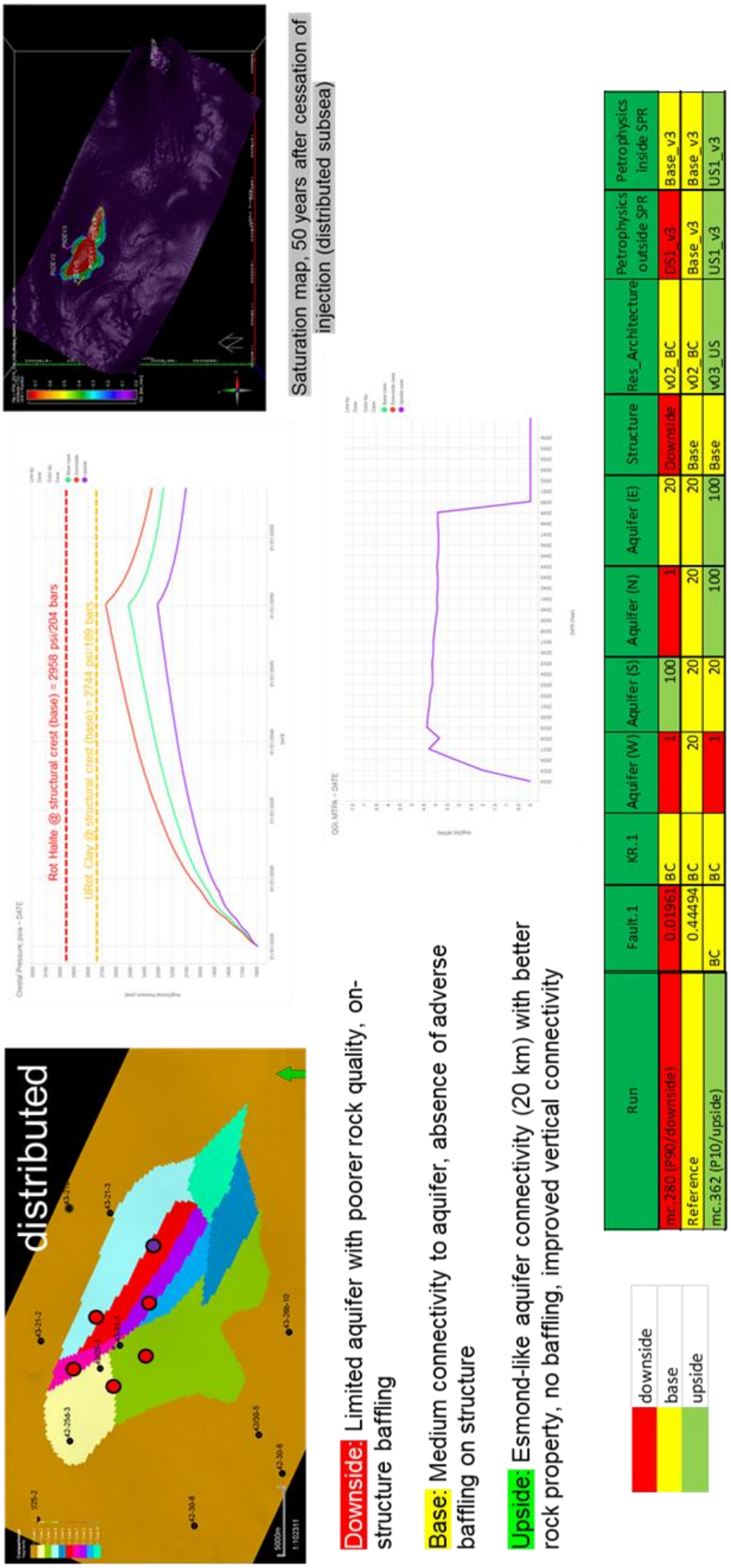


Figure 19: Volumetrics for the Endurance structure above the spill point.

For 4.0 MTPAa over 25 years (phase 1), no brine production is therefore needed with no pre-investment required. For subsequent expansion phases, where CO2 injection exceeds 4 MTPAa, brine production may be required to maintain reservoir pressure below cap rock fracture pressure limits at some point depending on the connectivity of the system or the potential on (unlikely) structure baffling.

The monitoring period for Phase 1 (dynamic appraisal) is expected to occur over a period of at least 3-5 years (accounting for circa 10 to 20% of the storage volume for Phase 1) in order to determine the degree of connectivity of the structure relative to the greater Bunter aquifer which will drive the pressure dissipation in fine.



Run	Fault.1	KR.1	Aquifer (W)	Aquifer (S)	Aquifer (N)	Aquifer (E)	Structure	Res_Architecture	Petrophysics outside SPR	Petrophysics inside SPR
mc.280 (P90/downside)	0.01961	BC	1	100	1	20	Downside	v02_BC	DS1_v3	Base_v3
Reference	0.44494	BC	20	20	20	20	Base	v02_BC	Base_v3	Base_v3
mc.362 (P10/upside)	BC	BC	1	20	100	100	Base	v03_US	US1_v3	US1_v3

Figure 20: Geologic scenarios against revised average injection profile with Humber Phase 1 volumes (3.7-4 MTPAa plateau over 25 years).

4.3 Technical Storage Capacity for Full-field Expansion

The Nexus® reservoir model for Endurance (base case geologic scenario) has been used to assess potential technical limits with plateaus at 10 MTPAa, 15 MTPAa, 18 MTPAa, and 20 MTPAa based upon the reference reservoir model. The maximum CO2 storage capacity of Endurance is estimated to be circa 450 MT (25 years at 18 MTPAa or 30 years at 15 MTPAa, corresponding to a static CO2 storage efficiency of 15%). Storage tipping point is around 18 MTPAa, above which plateau cannot be maintained to 2050 (25 years) and CO2 starts to break through into brine producers. The technical limits are based upon the reference case are dependent on the level of reservoir complexities.

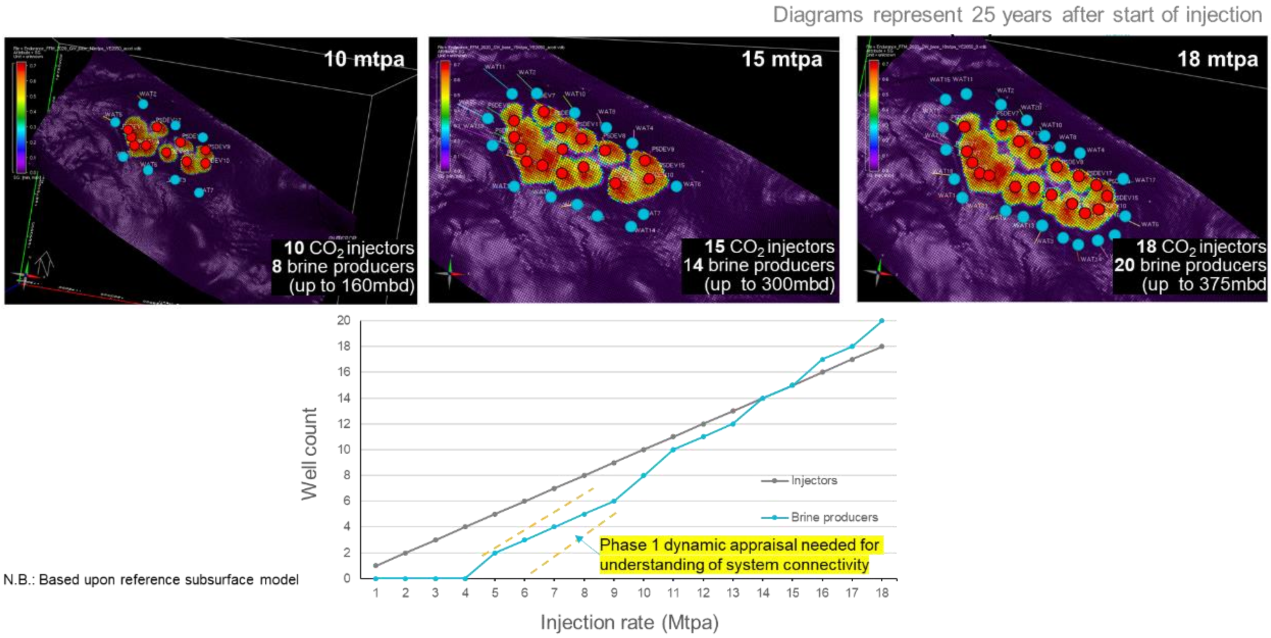


Figure 21: Technical limits for Endurance store.

Phasing is critical i.e. 3-5 years at low-rate plateau to understand reservoir connectivity to the greater Bunter aquifer (pressurization response), injection conformance (in-well monitoring such as ILT, time-lapse saturation logging), and early plume movement (4D seismic). Reservoir monitoring data will be used to further calibrate reservoir model. Any higher-rate plateau acceleration will tend to increase the risk profile by limiting the dynamic appraisal of the store before significant investment for brine production is required to ramp up to 10 MTPAa and beyond. The period of dynamic appraisal will be key to understand the pressure management requirement for high-rate plateau as well as proving additional capacity above the Phase 1 volumes without brine production required with upside scenarios capable of sustaining 6 MTPAa.

In fine, the optimal plateau will depend on the actual brine production that will be manageable to operate in terms of costs and project complexity. The best course would be to start with a low-rate plateau (i.e. 4 MTPAa for Phase 1) and refine understanding of the system connectivity after an initial period of injection at low rate (dynamic appraisal).

			Stored	Project Maturity Sub Classes	Volume, MT	Comments
Total Storage Resources	Discovered Storage Resources	Commercial	Capacity	On Injection	0	
				Approved for Development	0	
				Justified for Development	0	Phase 1 volumes (100 MT) to be moved to Capacity in Define/FEED stage (i.e. commercial framework)
		Sub-commercial	Contingent Storage Resources	Developement Pending	100	Phase 1 Endurance (4 MTPA,,no brine for P90)*
				Development on Hold	50	Phase 1 Upside (6 MTPA, 25 years, 100+50=150) MT)**
				Developement Unclarified	100	10 MTPA expansion at Endurance (100+50+100=250 MT)
				Developement Unclarified	200	Technical Limits 450 MT total e.g. 15 MTPA for 30 years
			Inaccessible Storage Resources			
	Undiscovered Storage Resources	Undiscovered Sotrage Resources	Prospective Storage Resources	Prospect	0	
				Lead	0	
				Play	0	
			Inaccessible Storage Resources			
Total Storage Resources					450	

*no brine required, **no brine required for well connected aquifer system – will be assessed with dynamic appraisal for Phase 1 well stock

Discovery criteria	Supporting data for NZT/NEP Phase 1
Direct evidence of permeable formation (Triassic-age Bunter) and containment system (Overlying strata are all sealing facies)	Log data, core in 42/25d-3 (Rot halite, Rot Clay, and Bunter) and 42/25-1, 3D seismic data (Polarcus), Bunter analogous fields in SNS (Esmond)
Flow test to support expectation of commercial CO2 injection rates	Well test in 42/25d-3, reservoir model calibrated to well test, well performance study (Reveal, Prosper, full-field)
Expectation that containment will be maintainedlong term (CO2 will not migrate laterally or vertically out of the storage complex)	Plume modelling with full-field model, regional presence of thick continous seal i.e. Rot Halite, Shallow faulting at Endurance does not extend into Bunter reservoir, Legacy well assessement for 3 on-structure wells at Endurance, Geomechanical modelling study in Visage for containment

Figure 22: Notional Storage Resource Classification for Endurance with supporting evidence for discovered resources criteria.

5.0 Endurance Storage Site Development (Northern Endurance Partnership)

5.1 Phase 1 (4 MTPAa)

Five CO2 injection subsea wells (CI1, CI2, CI3, CI4, and CI5) are considered to deliver an initial injection average volume of circa 4 MTPAa over 25 years as shown in Figure 23 (with peak injection rates of up to the equivalent of 5.6 MTPAi). One additional well CI6 (two options: western location in the main crest or eastern location) is to be utilized as an observation cum spare injection well to support dynamic appraisal of Endurance (and future expansion). Eastern location for the appraisal well appears to be more attractive as an observation well to monitor eastward plume migration and lateral pressure gradient. The well OE1 will indeed record the on-structure pressurization passively 4 kilometres east of the central manifold while providing critical appraisal data in terms of reservoir quality and structural control.

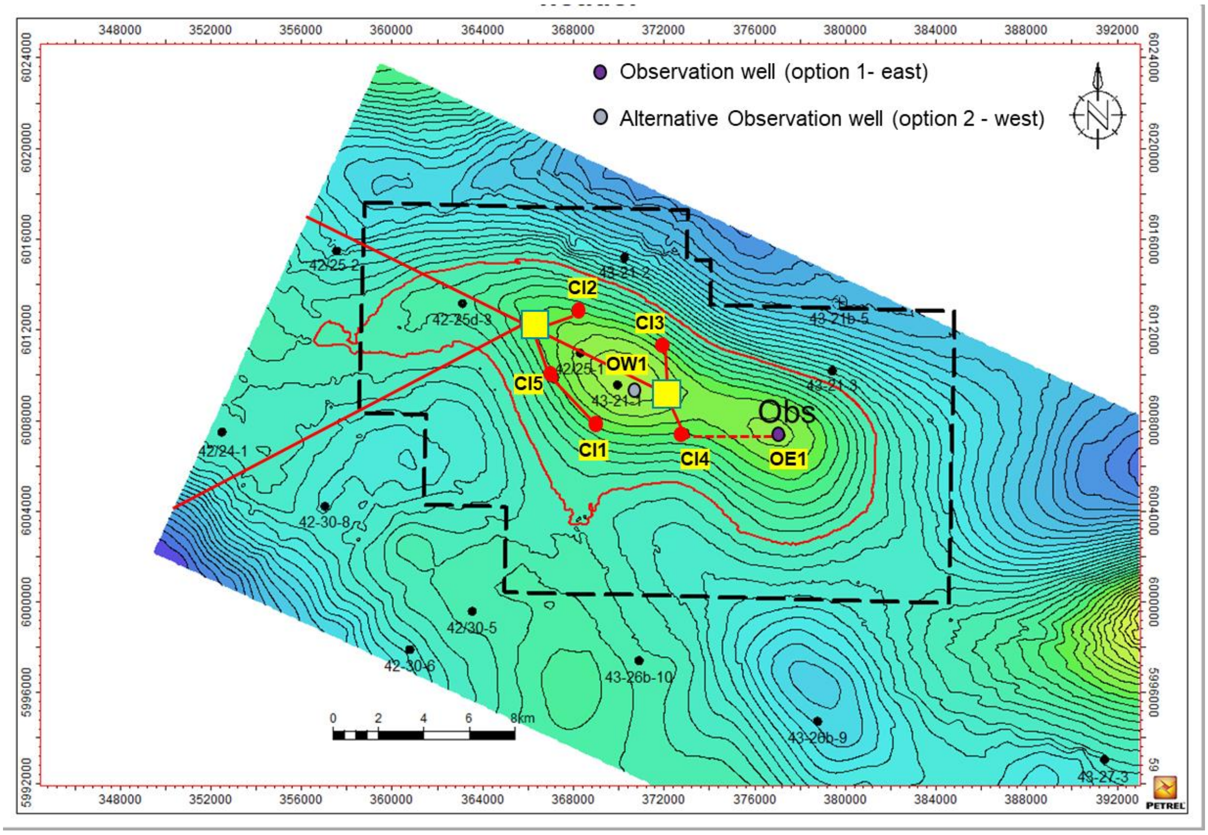


Figure 23: Phase 1 subsea development with 5 CO2 injectors and 1 observation well.

The distributed layout will enhance the dynamic appraisal of the structure as well as providing better mitigation against any unforeseen field heterogeneities or on-structure compartmentalization (with the provisional target shown in Table 2).

Geodetic Parameters: ED50, UTM Zone 31N (0E to 6E)					
Well	Easting	Northing	Latitude	Longitude	Comment
CI1	368989.01	6007788.68	54º 12’0.739” N	0º 59’29.9886” E	
CI2	368174.18	6012813.85	54º 14’42.4704” N	0º 58’37.1102” E	
CI3	371922.91	6011302.73	54º 13’57.0338” N	1º 02’6.3998” E	
CI4	372881.89	6007408.7	54º 11’51.9789” N	1º 03’5.2610” E	
CI5	367084.23	6010057.8	54º 13’6.6605” N	0º 57’45.8222” E	
OE1	377111	6007326	54º 11’53.025” N	1º 6’58.641” E	Observation Well Option on East (Reference Case)
OW1	369874	6010227	54º 13’20.399” N	1º 0’14.989” E	Observation Well Option on West

Table 2: Provisional Well Spud Locations for Phase 1 wells.

The Phase 1 well placement is provisional and will be finalized in 1H 2023 following the interpretation of the seismic survey planned for the summer of 2022 and completion of shallow hazards assessment.

5.2 Future Expansion at Endurance

5.2.1. Initial Dynamic Appraisal

A period of 3 to 5 years of dynamic appraisal (up to 20 MT of Co2 injected into the store or 20 % of Phase 1 volumes) will be required to determine the system connectivity (i.e. how connected the structure is to the Greater Bunter Aquifer) and the ability for the installed capacity of Phase 1 to meet average volumes above 4 MTPAa (injectivity per well and field-wide capacity). Even in the downside case (P90), a 4 MTPAa plateau during 25 years could be accommodated. At the contrary, an upside geologic scenario (as described in Figure 20) could potentially accommodate a 5-6 MTPAa plateau for instance without pressure management. Due to the relatively incompressibility of the system (brine-filled pore volume), any high-rate development such as 10 or 15 MTPAa and beyond will require active pressure management at some point to maintain store reservoir pressure below caprock frac-pressure with a safe margin.

5.2.2. Brine Management for Endurance

At the time of writing environmental and engineering studies are being conducted to determine the adequate engineering solution for the potential discharge of the Endurance store hypersaline brine and its potential impact. Brine management screening [6] has identified three potential development schemes for a capacity of up to 160,000 bpwd of brine being produced:

- Scenario 1: Local brine discharge from NUI's located at the Endurance field
- Scenario 2: Brine injection into suitable geologic structures in the South North Sea (depleted gas fields or other fields)
- Scenario 3: Brine treatment onshore (metal precipitation)

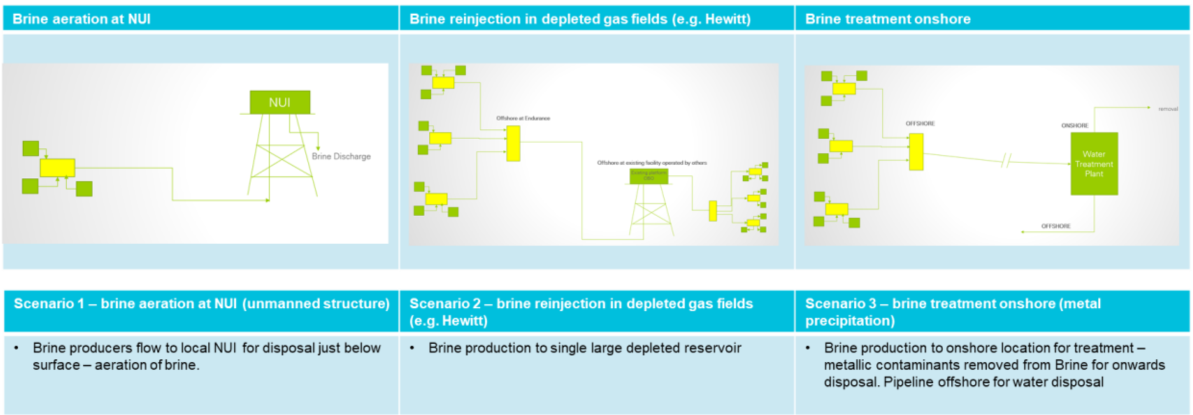


Figure 24: Brine management scenarios for Endurance (10 MTPAa plateau, up to 160 kbwpd of brine)

5.2.3. Notional 10 MTPAa Development Scheme (surface Discharge)

A notional 10 MTPAa development is described in Figure 25 as a potential expansion to 10 MTPAa from 4 MTPAa with the addition of 6 CO2 injectors and an associated manifold in the eastern side of the structure. 8 brine producers are being tied up to 3 Normally Unmanned Installations (NUI's) assuming the platform located within 5km of wells to enable free flow of brine with the capacity to produce up to 160,000 bwpd of brine:

- Umbilical from NUI to wells (power)
- NUI receiving power from shore
- Discharge from NUI at agreed depth (Assume aeration required)
- 20 kbwpd per brine producer

The viability of this option will be determined by regulator alignment & approval of local discharge of the brine (following up with the results from the environmental impact assessment). The collection of additional brine sample during the Phase 1 well drilling campaign will also help refine understanding of any spatial brine composition variability.

In fine, the concentration of metal contaminants means it is unlikely the brine can simply be released to sea and will require capital intensive treatment to enable sufficient dispersion (i.e. surface aeration and/or treatment at a minimum) and, in the worst case, onshore treatment to reduce the quantity of heavy metal components (case 3), or re-injection (case 2).

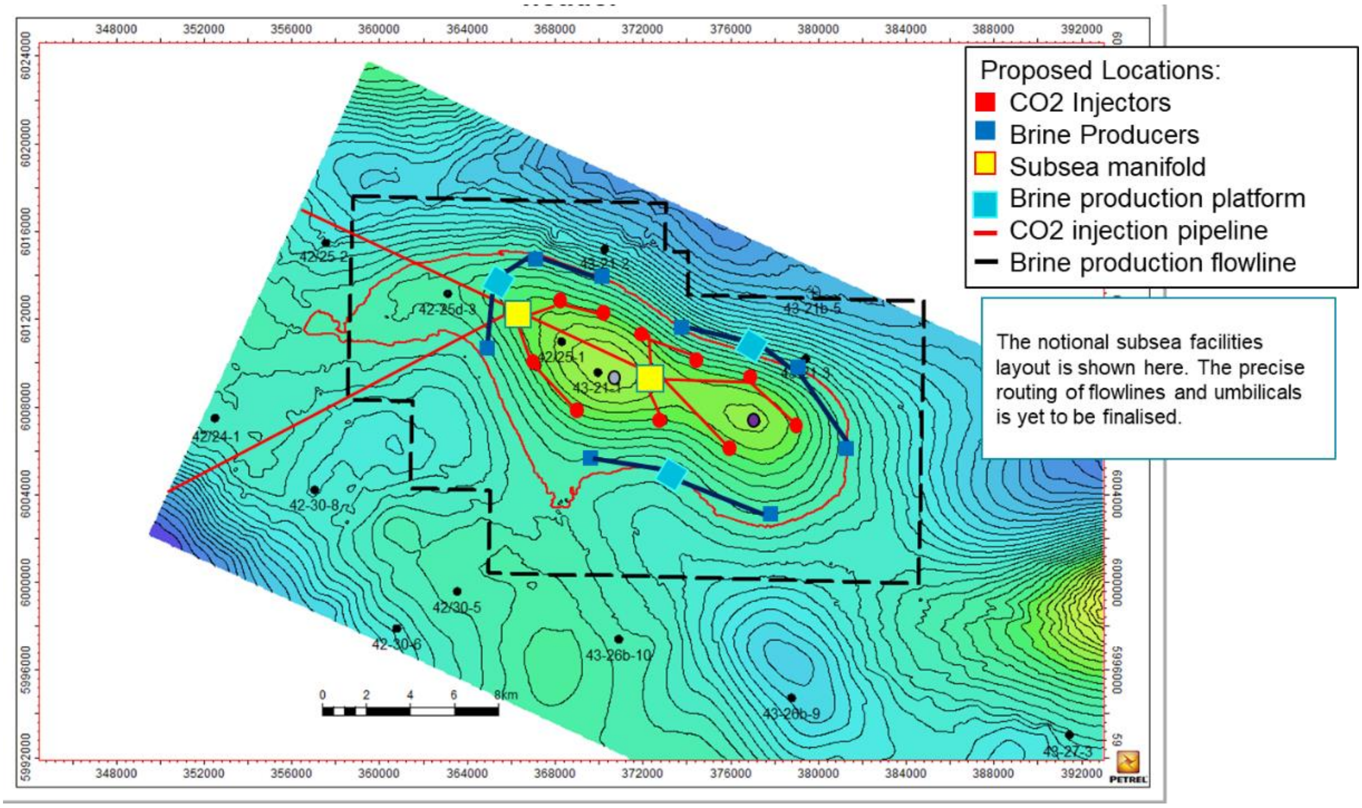


Figure 25: Notional 10 MTPAa development with 10 CO2 injectors and 8 brine producers.

Brine production is currently not in scope for Phase 1 as injection rates are expected to average 4 MTPAa over 25 years.

5.3 Northern Endurance Partnership Multi-Store Expansion Strategy

5.3.1. Notional Phasing for Future Phases

The Endurance CO2 storage site constitute the cornerstone of the storage strategy for the Northern Endurance Partnership by its size and low risks thanks to the available appraisal data. Its capacity of the order of 450 MT (achieved with Brine production) will not be sufficient to meet the potential throughput rates from the combined capacity of the Humber and Teesside pipelines (up to 27 MTPAi). Additional store sites will have to be considered to support future phases by building upon the infrastructure developed at Endurance as the hub (whose actual capacity will be refined through dynamic appraisal over the first 3 to 5 years).

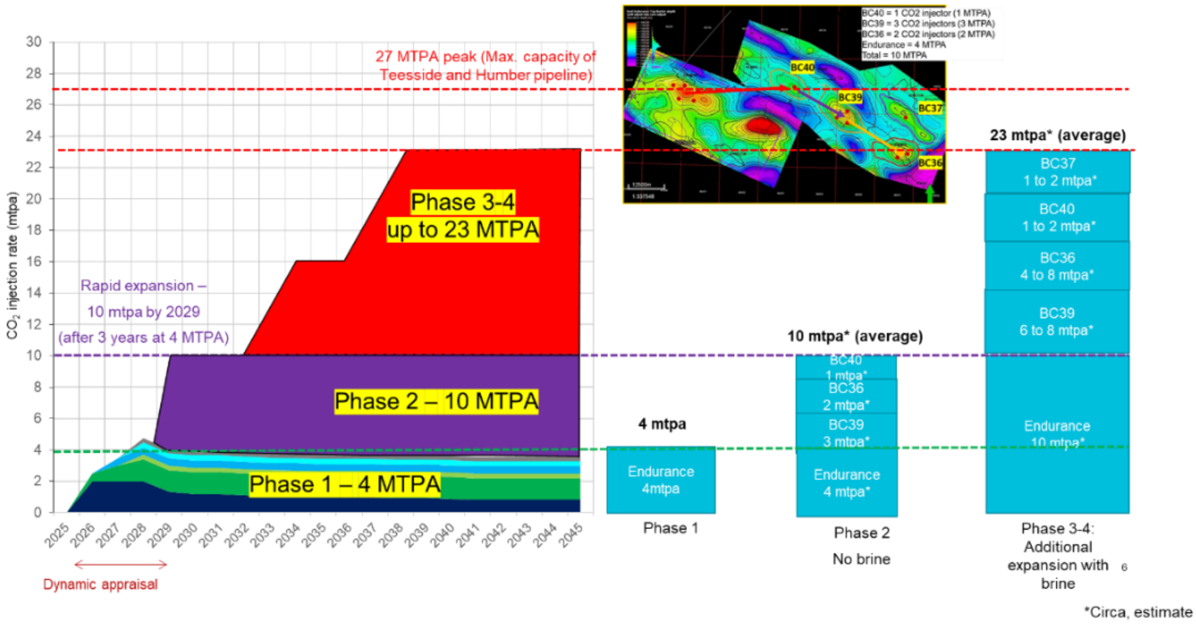


Figure 26: Notional NEP expansion strategy from 4 to 10 MTPAa to 23 MTPAa.

The phasing above shown in Figure 26 is purely hypothetical and is expected to change depending on the cluster sequencing process (T&S submission on the 9th July 2021 with the outcome expected in October 2021).

5.3.2. Bunter Closure Expansion Store License Application

In order to accommodate potential future volumes from Humber and Teesside industrial clusters (up to 23 MTPAa /27 MTPAi combined from the two pipelines), a CCS license application has been made in February 2021 to capture the acreage covering the Bunter Structures BC36, 37, 39 & 40 stores located 40 to 80 km to the east of Endurance (Figure 26). The Bunter Closure reservoirs have been selected in this early phase due to the significant potential capacity and injection rates they offer in aggregate, and their similarities with the Endurance reservoir.

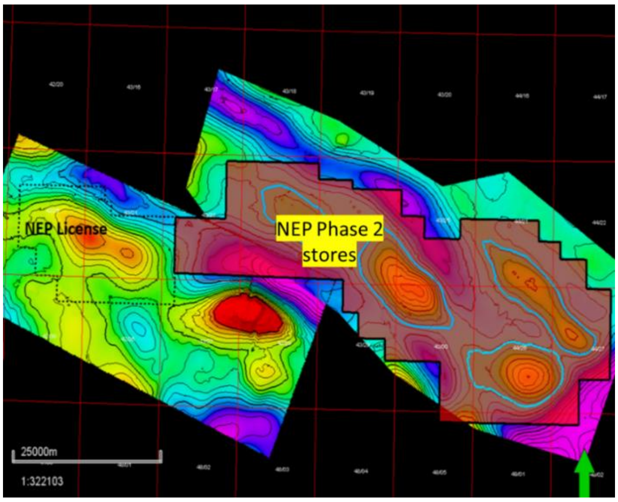


Figure 27: Potential store license boundaries covering the additional Bunter structures identified as suitable for CO2 storage near Endurance (BC40, BC39, BC36, and BC37).

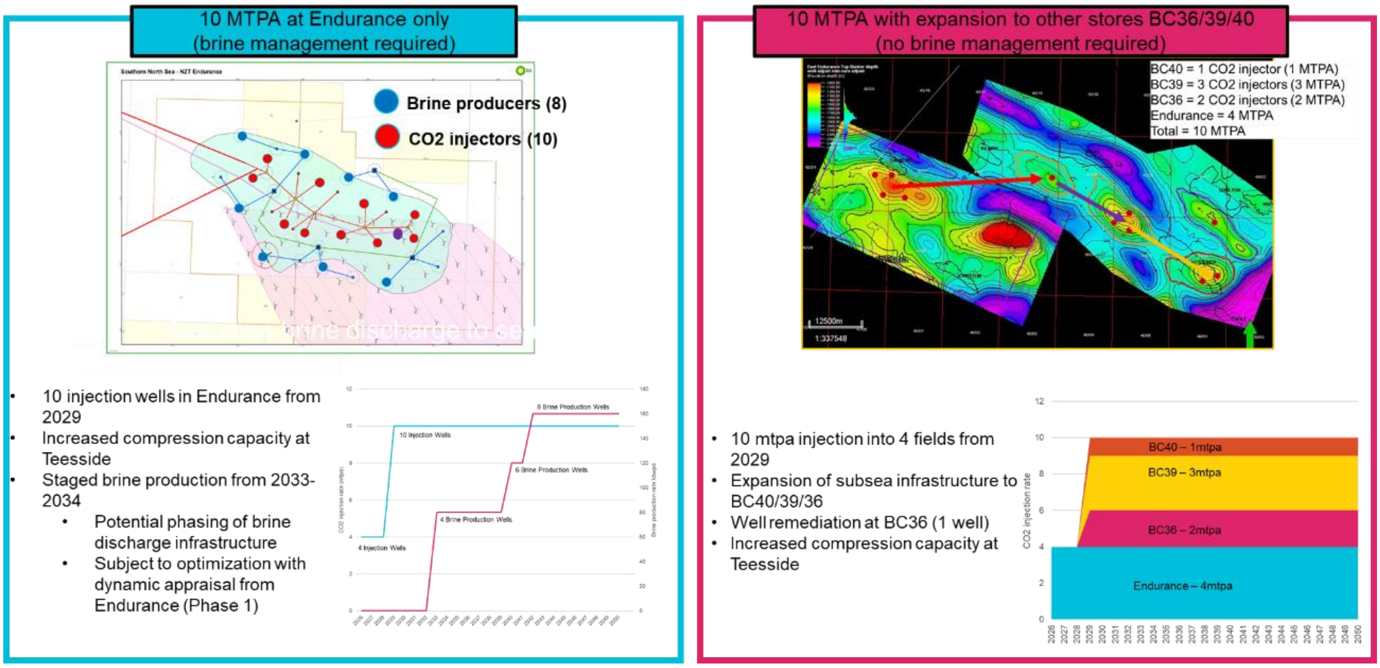


Figure 28: Path to 10 MTPAa (Phase 2) from Phase 1 (4 MTPAa at Endurance). Option 1 would involve expanding Endurance to 10 MTPAa with brine production facility while option 2 would require expansion into additional stores (BC36/39/40) to add 6 MTPAa capacity (no brine production would be expected).

For instance, utilization of the nearby Bunter Closures (‘BC’) BC36, BC37, BC39 & BC40 may enable a cost effective and lower risk expansion beyond the phase 1 development of Endurance to reach 10 MTPAa, as well as providing further opportunities for longer term expansion (23 MTPAa), as shown in Figure 28.

5.4 Reservoir Management Strategy

5.4.1. Reservoir Operating Limits

The Rot Halite is considered the primary seal (caprock) for the store hence the upper safe operating limit is 2958 psia/204 bars at structural crest (~1020m TVDss for base Rot Halite).

In terms of Reservoir Defined Operating Limits (RDOL), the primary reservoir seal will have to remain intact at crest (i.e. base Rot Halite). CO2 injectors will be drilled at various locations and will have to be managed based upon their respective average reservoir pressure (derived from Pressure Transient Analysis) relative to their structural offset to the crest as described below in Figure 29 (e.g. upper safe limit for reservoir considered at 1250m TVDss at top perforation). Assuming worst-case CO2 gradient between the crest (Dcr) and top perforation (Dw), the upper safe defined limit (USDL) at the gauge should ensure that the pressure at the crest is less than the cap rock fracture pressure at crest (2958 psia/204 bars).

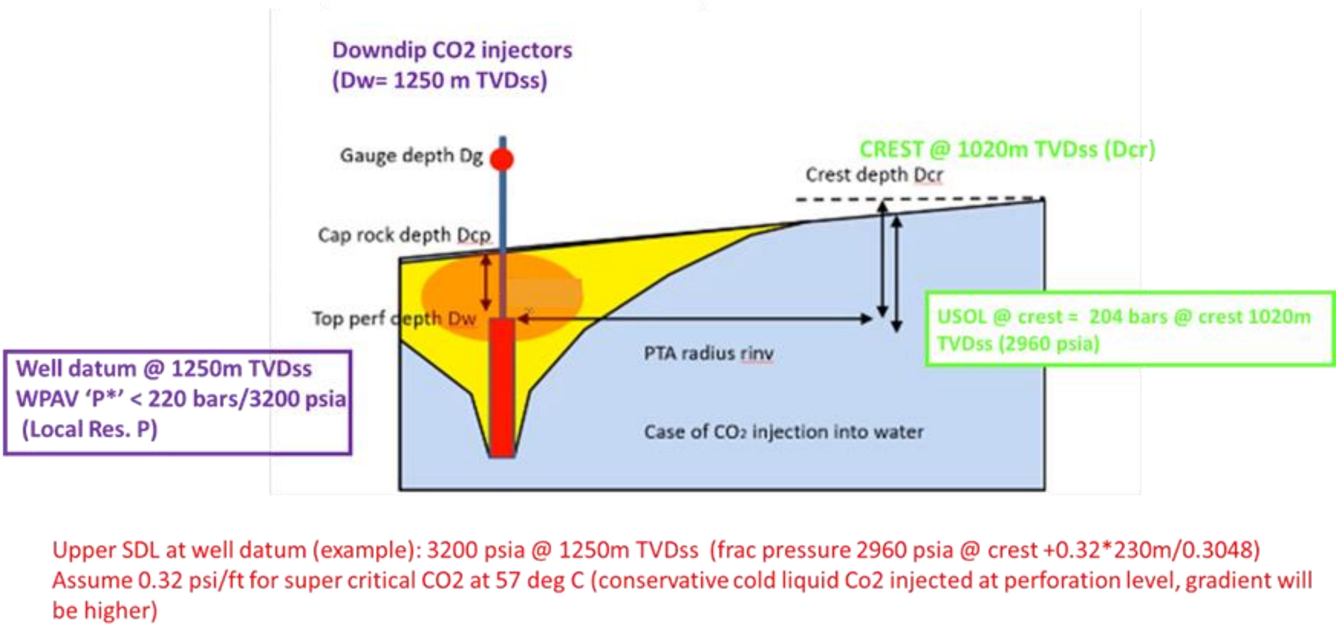


Figure 29: Reservoir Defined Operating Limit (RDOL) applied to generic Endurance CO2 injector.

In terms of Wells Defined Operating Limits, the well shall operate in order not to fracture the reservoir up to the cap rock. It is important to understand that fracturing could extend vertically to caprock (thermal fracturing) so gauge pressure limit (USDL) needs to ensure that pressure in wellbore at depth Dcp is less than caprock fracture pressure at well.

For Phase 1, reservoir pressure is anticipated to remain below the caprock limit as shown in Figure 20. Future expansion to 10 MTPAa will require active pressure management with down-flank brine extractors required to keep reservoir pressure around the CO2 injectors below the safe limit at the given normal operating limit (Figure 25).

Completion Strategy

Thanks to the potential low Kv/Kh ratio across the reservoir section as indicated by the well test in 42/25d-3, it is planned to perforate 80 meters of the reservoir in the Phase 1 injectors to maximise the completed reservoir thickness (e.g. across 1250 to 1350 m TVDss depth window). Vertical injection profiles from the ILT campaigns as well as VSP will be required to understand the reservoir architecture, identify potential high-permeability intervals, and monitor injection conformance over time.

The impact of thermal fracturing on injectors has been evaluated in REVEAL® for a sector model to inform injection conformance, injectivity over time, and wells defined operating limits (risk of vertical fracture growth). The results of the study have indicated that the risk of vertical fracture growth is manageable and low based upon screened tested cases:

- No case presents fracture reaching top Bunter by the end of injection
- Fracturing onset due to thermal effect appear to occur late limiting the negative impact on conformance
- The study has demonstrated the value of leaving a section of the Bunter unperforated (at least 20-30 meters) below the base of the Rot Clay, both for pressure limit and conformance

Selective perforation strategy looks attractive with the Cased & Perforated completion in order to avoid perforating low-quality intervals, which are likely to poorly swept and could be responsible for halite precipitation in the near wellbore (i.e. the Aquistore project where high residual water intervals are associated with halite precipitation in the wellbore).

Well Operating Philosophy

Endurance well stock is expected to inject up to a peak rate of 1.5 MTPAi per well but assumes 1 MTPAa in average per well over the project life of 25 years (up to a cumulated 20 MT per well) based upon benchmarking.

A minimum annualised rate of 0.5 MTPAa per well is required to minimise risks of skin build-up due to salt precipitation. The 5-well well stock is not expected to be fully utilized until plateau (4 MTPAa) and associated peak rates (5.6 MTPAi) are reached in order to ensure a minimum amount of Co2 is consistently injected into a given injector once CO2 has been initiated. After a baseload period of 3 years, the Teesside CCGT power plant is expected to switch to dispatchable mode leading to the wells being operated at rates ranging from 0.7 to 1.2 MTPAa in average depending on incoming capture levels at Teesside. Industrial sources at Teesside and baseload volumes of 1.7 MTPAa from Humber will help ensure that minimum CO2 volumes are distributed across the well stock rather than opening and shutting wells when CCGT dispatchable CO2 volumes are being piped to the store.

Learnings from Surveillance

Pressure monitoring from PTA in each individual well will be critical to assess the structure overall pressurization which will help determine the level of connectivity of the store to the broader Bunter aquifer and refine the ultimate storage capacity assessment without active pressure management. Each well will be tracked individually with the local average reservoir pressure compared to the other wells to identify any pressurization differential across the structure. For instance, aquifer quality is expected to be significantly higher in the south and the east relative to the west (Figure 30).

Injection logging tool (ILT) time-lapse runs will help identify high-permeability streaks and improve understanding of the heterogeneities throughout the reservoir and its impact on conformance.

The passive pressure monitoring in the observation well will allow to track pressure gradients across the structure. Saturation logging in addition to 4D seismic-based plume monitoring will be important to identify when the CO2 will be reaching the secondary crest in the east. It is expected that the well be used for coring as well and acquisition of further geo-mechanical data acquisition in the caprock i.e. FPIT (both Rot Clay and Halite formations).

Plume monitoring via 4D towed-streamer seismic and time-lapse VSP (conventional or DS VSP) will be critical to understand the overall architecture of the reservoir and map the plume migration over time. These learnings from Phase 1 monitoring will be used to refine the optimal development strategy for high-rate scheme such as the notional 10 MTPAa development in which active pressure management will be required.

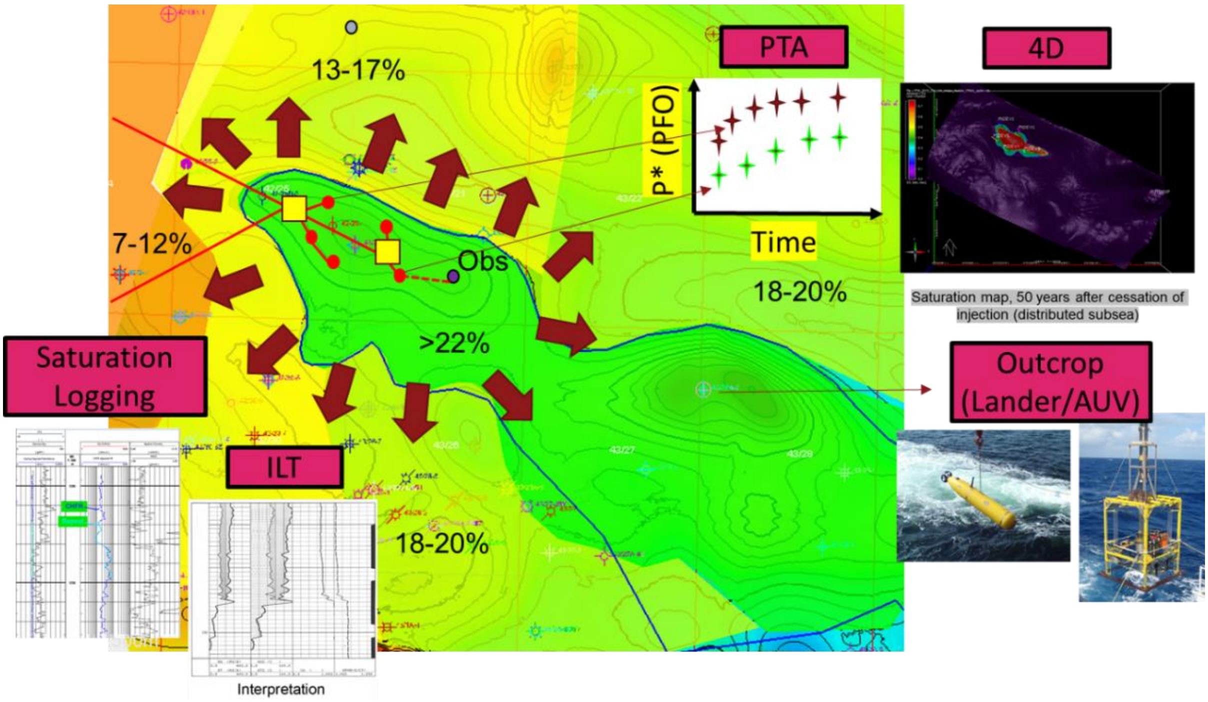


Figure 30: Reservoir surveillance for phase 1 development (mid-Bunter average porosities displayed)

6.0 Potential CO2 sources: Zero Carbon Humber and Net Zero Teesside

The phasing shown in the following section is purely hypothetical and is expected to change depending on the cluster sequencing process (T&S submission on the 9th July 2021 with the outcome expected in October 2021).

6.1 Net Zero Teesside

6.1.1. G&C Phasing

The overall decarbonisation of the Teesside region is expected to be developed in four phases as shown in Figure 31.

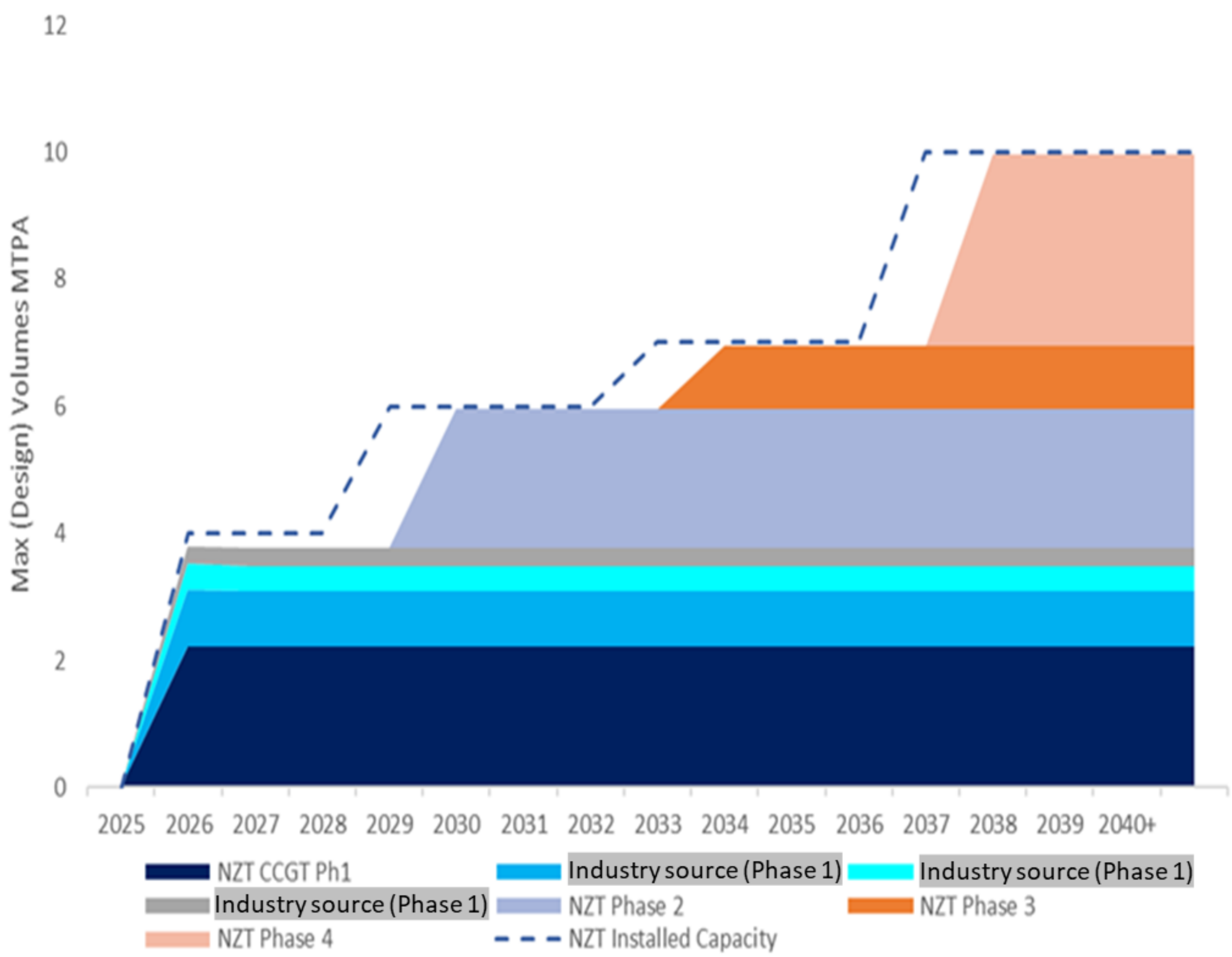


Figure 31: Phased infrastructure development for NZT

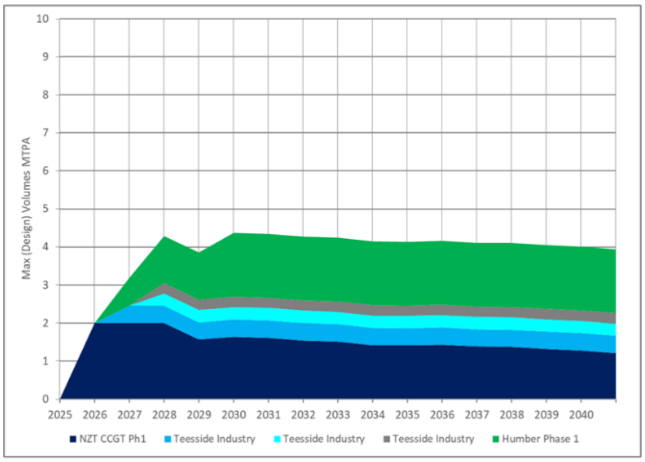
Phase 1 will include infrastructure designed for injection up to 4 MTPAi with the key industries including:

- The NZT CCGT providing 2.2 MTPAi assuming up to 95% capture.
- Teesside industries up to 1.6 MTPAi

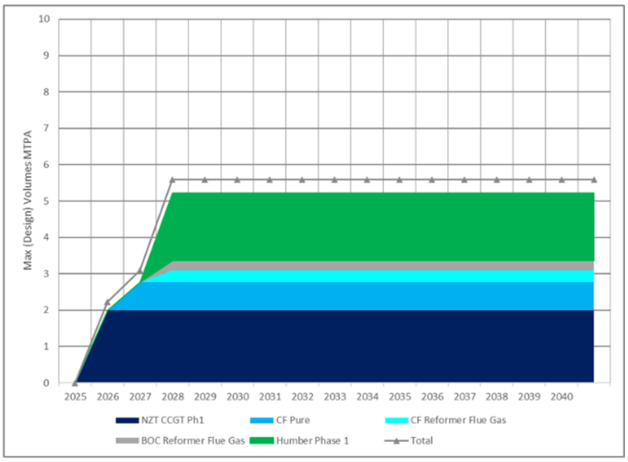
Future expansion in Phase 2 will enable injection up to 6 MTPAi mainly from bioenergy carbon capture and storage (BECCS). Further expansion up to 10 MTPAi is envisaged in Phase 3 and Phase 4 through expansion of additional 2 trains of abated CCGT power or expansion of blue hydrogen (Figure 31).

6.1.2. Annual Average Injection Rates for Phase 1

The average annual injection rates are expected to vary relative to the design capacity and over time due to dispatchable operation of the power plant and seasonal variability in industrial emissions. An example average injection profile for Phase 1 is shown in Figure 32 (including Humberside Phase 1 volumes).



Average Injection Rates



Peak injection rates (up to 5.6 MTPA)

Figure 32: Average and peak CO2 injection rates for Phase 1 (Net Zero Teesside and Zero Carbon Humber).

6.2 Zero Carbon Humber (Humberside)

In October 2020, the Zero Carbon Humber project has joined the Net Zero Teesside project on the offshore side of the CCUS chain through the Northern Endurance Partnership). A 1.7 MTPAa is expected to be captured from the Humber cluster (1.3 MTPAa including the H2H Hydrogen ATR project at Saltend and 0.4 MTPAa from industrial sources) and transported to Endurance via a separate pipeline (Figure 33).

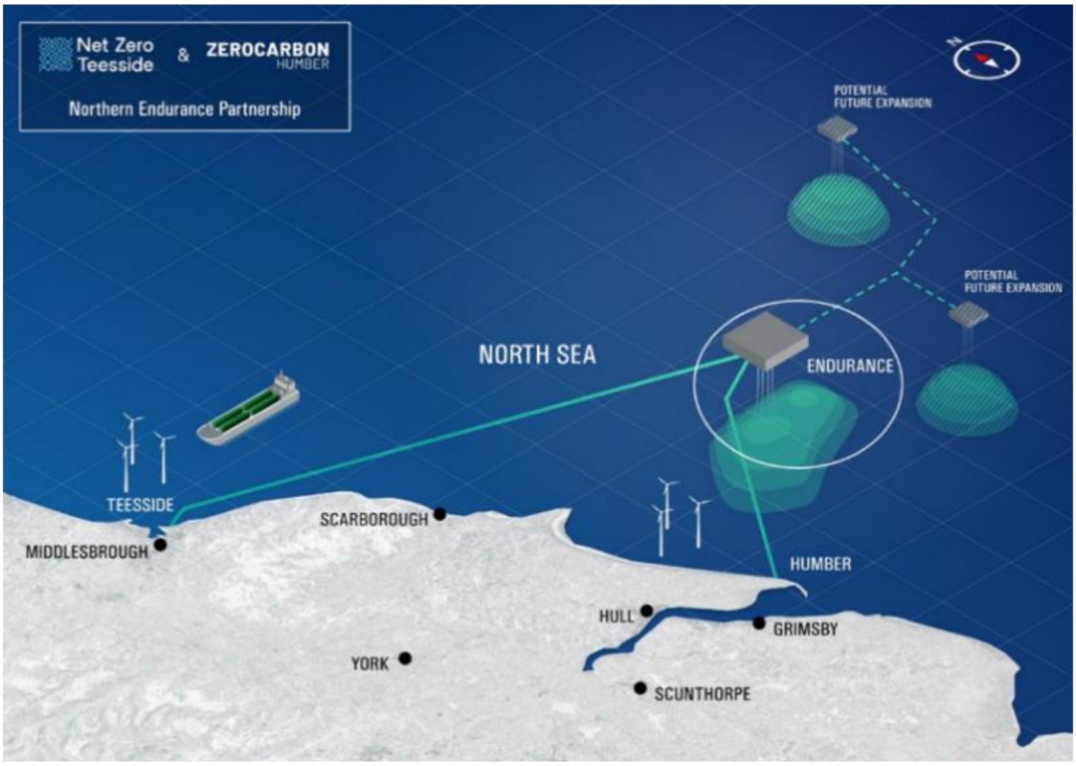


Figure 33: Northern Endurance Partnership (NEP) including the Endurance store and the two pipelines linking Teesside and Humber industrial clusters.

6.3 Northern Endurance Partnership (T&S)

The inclusion of the Humber volumes will lead to average injection rates of up to 4.0 MTPAa (with peak rates up to 5.64 MTPAi). The onshore G&C entity for Zero Carbon Humber will be considered 3rd party and will be separately operated at the time of writing. Overall, it is expected that volumes comprised from 90 to 100 MT will be captured and stored from NZT/ZCH combined Phase 1.

Future development of NEP of up to 27 MTPAi will come from a variety of industrial emitters in the Teesside and Humberside regions such as bioenergy carbon capture and storage (BECCS), industrial decarbonisation, and hydrogen (Figure 34).

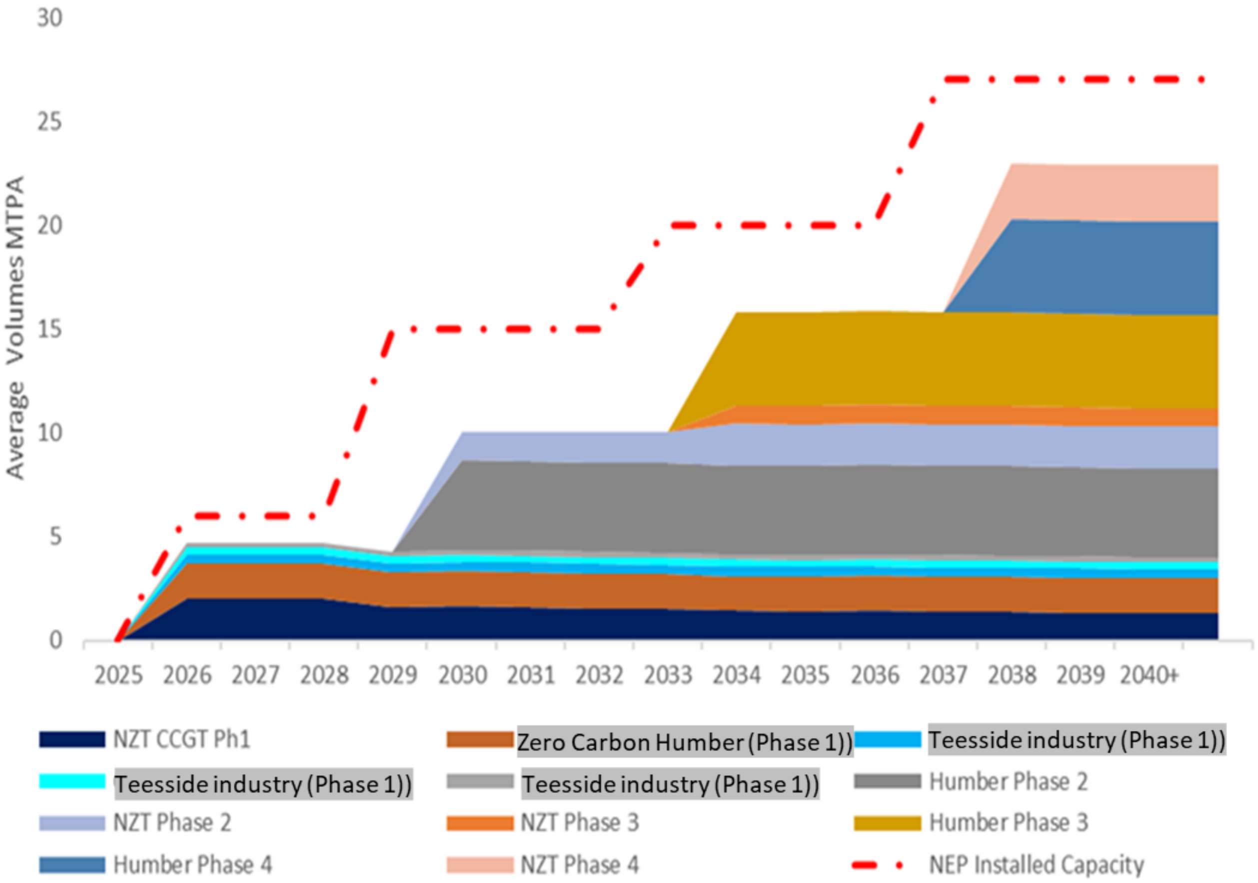


Figure 34: Phased infrastructure development for NEP (MTPA pick value)

7.0 CO2 Transportation and Injection Facilities

7.1 Overview

In summary, the scope of the project for Phase 1 is as follows:

- ~0.7 GW gas-fired dispatchable CCGT power plant in Teesside with post-combustion CO2 capture of up to 2 MTPAa as the anchor project.
- A CO2 gathering network will be developed to gather an additional 1.4 MTPAi CO2 from industries, before compression and transportation via a 142km, 10 MTPAi rated offshore pipeline (28’’ carbon steel).
- Additional 101km 28’’ carbon steel pipeline (17 MTPAi capacity) from subsea network to Easington, to transport and store up to additional 1.7MTPAi CO2 from Humber industries (Zero Carbon Humber Phase 1).
- CO2 will be injected into the Endurance saline aquifer from a subsea distributed layout comprising 5 injection and 1 monitoring wells.

The description of the full chain can be described below by the block diagram in Figure 35.

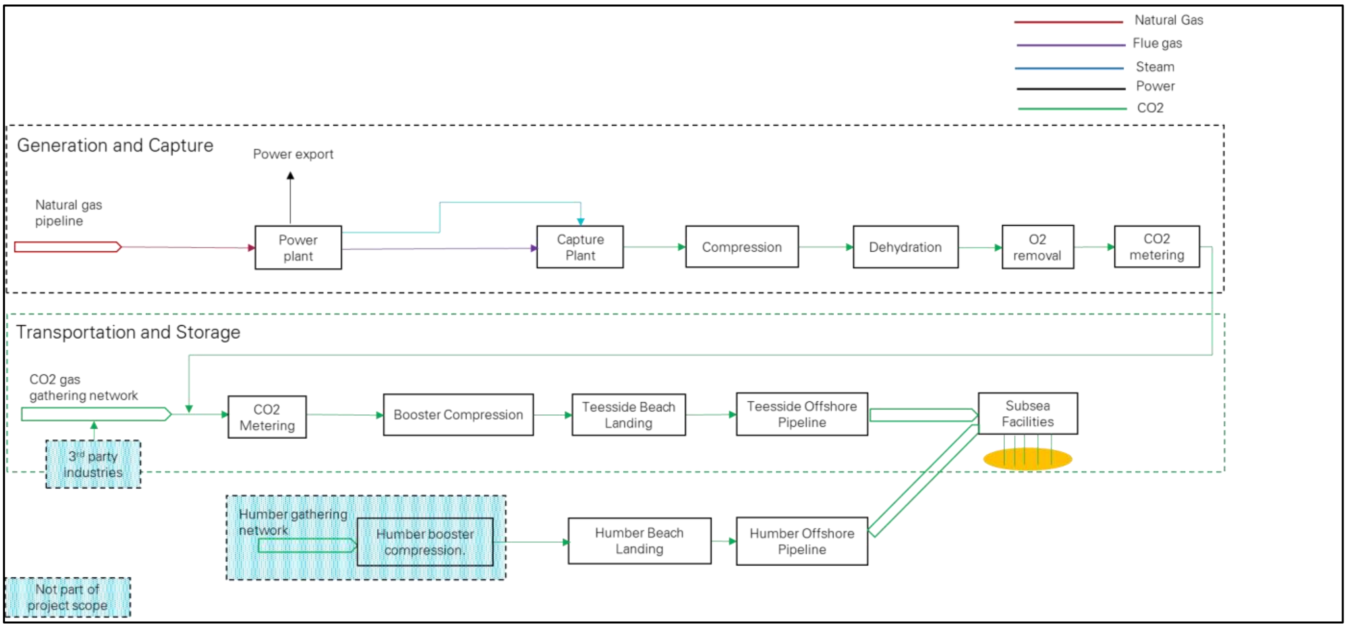


Figure 35: Block diagram showing the full chain for the NZT/NEP project.

7.2 Phase 1 Project Capacity

	Capacity
Power plant	1 train H-Class CCGT (850 MW unabated power generation)
Natural gas feed line	300 mmscfd (3 trains of H-Class CCGTs)
Post combustion carbon capture facility and conditioning	Anticipated to be circa 2 MTPAa (subject to licensor/OEM selection)
CO2 gathering network	3.8 MTPAi to enable future expansion from the North of the river
Booster CO2 compression	4 MTPAi
Teesside offshore pipeline and cable from shore	10MTPAi with future debottlenecking Cable sized for 50 kW to support up to 30 electrically actuated subsea valves
Humber offshore pipeline	17 MTPAi with future debottlenecking
Number of wells	6 (5 injectors and one monitoring well)
Injection rate per well	1 MTPAa/ well average 1.5 MTPAi/ well peak

Table 3: Project Facility Capacity

The infrastructure for NZT/NEP Phase 1 will be designed for an overall capacity of 4 MTPAi with selected components oversized for future expansion as shown in Table 3:

7.3 Offshore Pipeline

From the booster compression discharge at Teesside, the CO2 is exported through a 142 km carbon steel 28’’ pipeline to the Endurance CO2 storage site. The pipeline will be sized for 10 MTPAi to enable future decarbonisation of industries in the Teesside region. An additional 101km carbon steel 28’’ pipeline from Humber to Endurance will be used, to transport and store up to additional 17 MTPAi form Humber emitters with 1.7 MTPAa CO2 initially. Both pipelines will join at the Wye as shown in Figure 39.

7.4 Offshore facilities at Endurance

The subsea architecture includes 5 all electric operated subsea trees currently assumed to be in a distributed layout tied back to the cross over manifold and a 4-slot manifold via 8'' jumper lines.

The five wells comprise four CO2 injectors and an observation well to monitor plume migration via pressure and/or saturation measurements. The subsea distributed layout does provide the benefit of vertical wells and flexibility in reservoir pressurisation management.

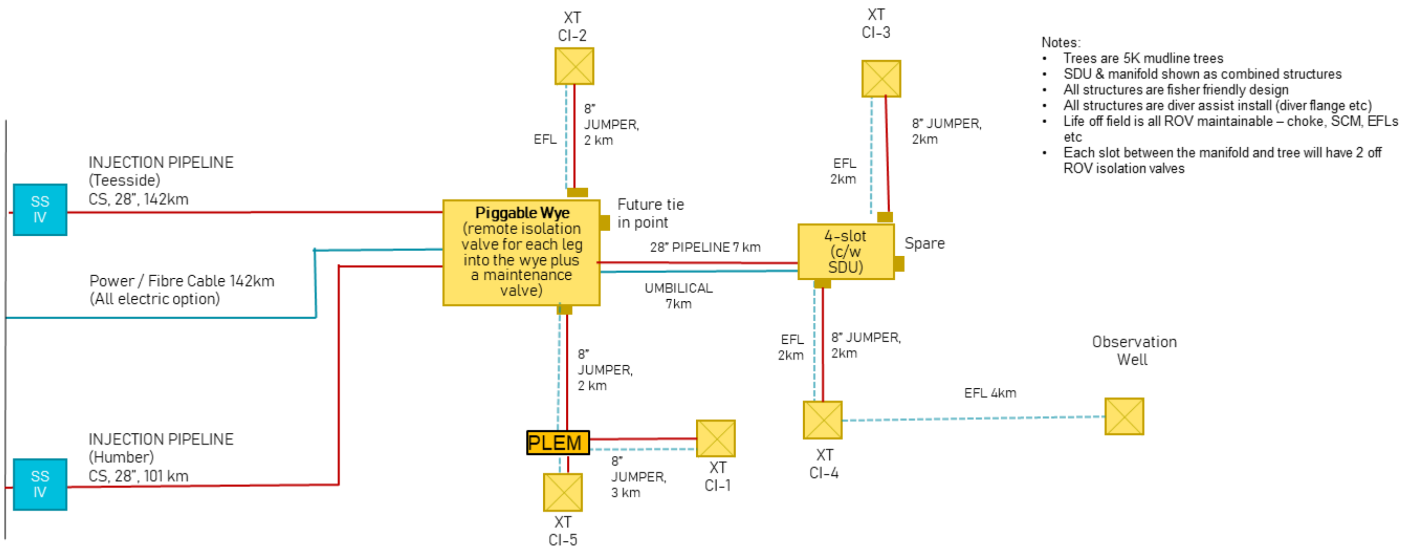


Figure 36: Distributed subsea layout.

The infrastructure is serviced via an umbilical from shore, carrying power, hydraulics and control along the pipeline route sized for the full field development up to 10 MTPAi. No permanent facilities are provided for brine management, water or chemical injection (e.g. MEG).

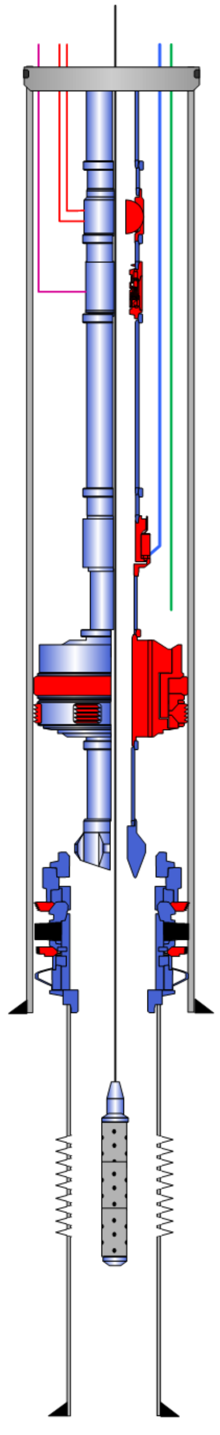
7.5 Injection Wells and Injectivity

Endurance well stock is expected to inject up to a peak rate of 1.5 MTPAi per well but assumes 1 MTPAi in average per well over the project life of 25 years (up to a cumulated 20 MT per well) based upon benchmarking. With the addition of Humber volumes, the 5th well will be likely to be utilized to cope with peak volumes around 5.6 MTPAi (e.g. with one well offline, the remaining four wells will need to be fully utilized to reach the maximum peak injection ~ 4*1.5 = 6 MTPAi).

The six wells (including the observer well) will be drilled as part of the phase 1 development in batch with a jack-up rig as the relatively shallow water depth (~60m) is unsuitable for a semi-submersible. In common with many Southern North Sea (SNS) wells targeting the Bunter Sandstone, the well design will incorporate three casing strings and a perforated liner across the reservoir section. Drilling will start in 2025 with all wells drilled before first CO2 injection in 2025. Individual well construction duration is ~70 days (performance target). The wells are designed to be able to be opened up and shut-in for dispatchability, but it is expected that a constant base-load injection rate will be maintained for the first few years of operation, which will allow brine to be swept away from the well bore and reduce the requirement for fresh water-washing for halite dissolution.

NZT CO_2 Injector - Wireline Perforating

Revision: Rev 1	**Date:** 12 Oct 2020	**Prepared by:** Russ Haley	
CO2 Injector	**Packer Fluid:** Base Oil	**Notes:** All depths approximate	



OD [in]	Nom. ID [in]	L [m]	Top [mTVD SS]	Top [mMD BRT]	Schematic	Description
			58			5 1/2" Subsea Tubing Hanger
						5 1/2" VAM Top HT Tubing (25% Chrome Super Duplex)
			475			5 1/2" Tubing Isolation / lubricator Valve (TBC for wireline perforating)
			525			5 1/2" SSSV (Alloy 925 or similar)
						5 1/2" VAM Top HT Tubing (25% Chrome Super Duplex)
			957			9 5/8" Casing TOC
			1082			5 1/2" DHPT Dual Gauge Mandrel (tubing and annulus, Alloy 925 or similar)
						DAS / DTS Fibre Bundle
			1107			9 5/8" x 5 1/2" Permanent Packer (Alloy 925 or similar)
			1137			Wireline Entry Guide
			1157			5 1/2" Liner Hanger (Alloy 925 or similar)
			1232			9 5/8" Casing Shoe (flow-wetted 25% Chrome Super Duplex)
			1238			Top Bunter Sandstone
			1318			Top Perforation (standoff from Rot Clay)
						3 3/8" HSD Gun (TBC)
			1418			Bottom Perforation
						5 1/2" VAM Top HT Liner (25% Chrome Super Duplex)
			1512			Top Bunter Shale
			1549			5 1/2" Liner Shoe

Figure 37: Notional NZT/NEP CO2 injector well completion

An overview of the wells design includes:

- Reference case with near-vertical wells as part of a daisy chained/distributed subsea architecture
- Cased and perforated liner completion.
- Flow-wetted tubulars in the lower part of the well (liner, any casing overlap and the lower part of the tubing at least) will be 25% chrome super-duplex to mitigate CO_2 corrosion in the presence of reservoir brine.
- An option to incorporate DAS fibre optic micro-seismic measurement is being evaluated. The decision to proceed with this technology will depend on the final monitoring, measurement and verification plan (MMV) and further modelling on the impact of the completion design changes on well operation and management, and xmas tree supply scope.
- Understanding additional design requirements and equipment qualification to cope with sub-zero temperatures that may occur with a loss of containment in an abnormal situation – for example a large leak caused by damage to a Christmas tree could cause CO_2 to boil off, leading to very low metal temperatures in the upper part of the well down to the subsurface safety valve (SSSV).
- The tubing-casing 'A' annulus will be filled with either base oil or MEG to mitigate the risk of a conventional brine freezing under low temperature operation, and also formation of carbonic acid should CO_2 leak past the packer into the annular space.

7.6 Flow Assurance and Operability

The flow assurance scope covers the T&S facilities which consists of (i) onshore CO_2 gathering network, (ii) onshore booster HP compression station (iii) offshore pipelines and (iv) subsea facilities.

There is flow assurance threat specific to area mentioned above but others will require a holistic approach such as the overall control strategy to ensure a robust operability of the system.

Onshore CO_2 Gathering Network

The CO_2 gathering network will receive fluid in gas phase, dehydrated and deoxygenated carbon dioxide within the entry specification. The pipeline will be run overground using existing pipeline corridors around the Teesside region. The gathering network is sized to allow expansion to 10MTPAi with operating pressure set to avoid any CO_2 condensation to a minimum ambient temperature of -15oC. The risk of two phase on the integrity of existing pipe support needs to be reviewed if the barrier is deemed insufficient. Entry specification deviations is expected to be managed by the shippers and associated deviation such as water specification on corrosion is addressed elsewhere.

Onshore Booster HP Compression Station

The ‘booster compression’ facilities compress the CO2 rich gas into dense phase through a number of identical compression trains before entering the offshore pipeline. Booster pump in series to increase discharge pressure and in parallel for additional capacity may be added for future phases. Compressors and pumps in parallel and in series makes a complex control scheme to manage changes in both flowrate and pressure.

Offshore pipelines

The offshore facilities consist of two 28inch dense phase CO2 export trunklines from the Teesside (142km) and Humberside (100km) clusters respectively. A crossover manifold at Endurance will comingle the flows from the Humber and Teesside clusters and distributed them for injection in-field at the Endurance store. The co-mingling manifold also has a tie in point to enable expansion of the pipeline to future stores.

Ability to sequester the required quantity of CO2

As the aquifer is displaced through the rock by CO2, it is possible that salts may precipitate and be left behind, impairing injectivity. Well intervention is expected to be once/ well/ year to manage water washing of the near wellbore region to dissolve these salts.

The wash water will be treated to mitigate corrosion, fouling and scaling threats. Hydrate threat mitigation will be required to bring the well back online by use of MEG. Handover to operation will be in a state to allow normal dense phase CO2 injection, i.e. near vacuum pressure at top of tubing from the MEG static head will be displaced by increasing pressure gas source to manage the Joule-Tomson cooling. This will all be part of the intervention campaign.

Control and operability

The offshore pipeline system operates in dense phase which has a viscosity similar to that of a gas, but a density closer to that of a liquid. Therefore, any imbalance in flow will change the pressure much quicker than in gas phase.

The key threat is pressure surge ‘fluid hammer’ as a result of sudden momentum change associated with stopping of outflow. The other threat is imbalance in flow causing unpacking (less flow in than out) or packing (more flow in than out) of the system. The threat of imbalance in flow comes from both the flow in from shipper or compression facilities and outflow at the wells. Unpacking threatens the offshore system into two phases, for example 1 unpacking in reverse direction; tripping of compression facilities & venting to low pressure with forward valve remained open or forward valve opened in readiness for start-up before system is pressurised. For example, 2 unpacking in forward direction; only applies when WHSIP is below critical pressure.

The power plant (>50% of flowrate from Teesside) will operate in dispatchable mode in phase I with expectation of 100 to 350 starts per year. The onshore CO2 gathering network and Humberside (seen as a shipper) is intimately connected to the offshore storage system. The operability of the system must be robust to large changes in import flowrate such as shippers operating in dispatchable mode or shutdown of either Teesside or Humberside. The pressure drop change associated with the large intended flowrate change across the pipeline system needs to be managed by the booster compression facilities at Teesside and at the shippers. The current pressure anchor is a floating WHFP set point offshore (function of well rate and reservoir pressure) and at the inlet to the booster compression facilities. A full chain simulation is required to test the functionality of the control scheme once finalised.

As we inject CO2, the reservoir will pressurise leading to continuous changing working point per store, i.e. the WHFP changes as a function of reservoir pressure and well rate. To manage store pressure, brine will be produced from wells at some distance from the injectors post phase I.

The intent is to operate the offshore pipeline system in dense phase and therefore the minimum operating pressure must be above critical point for all operating scenarios from shrinkage in shutdown or unpacking with loss of import flowrates.

It is envisaged that at initial reservoir pressure of the stores there will be small amount of gas break out in the wellbore on shutdown. The strategy is to avoid two-phase during steady state by having high minimum well flowrate, potentially not utilising all available wells until the reservoir pressure is sufficient high.

Unlike hydrocarbon systems where flowrates tends to be steady with few major changes which are often managed by use of dedicated swing wells for ease of manual adjustment, the intended big flowrate changes hence imbalance needs to be managed differently to avoid frequent high magnitude thermal, pressure and hydraulic cycles and potential steam hammering & cavitation associated with two phase flow in the wellbore. It is unclear whether frequent thermal, pressure and hydraulic cycles or steam hammering & cavitation impact the integrity of the well or performance of the injectivity, it is best to avoid/reduce the risk.

The high-level control scheme has not been finalised but the functional requirement is clear; that is an automated system that:

- Maintain gas gathering system as gas phase
- Maintain offshore pipeline system as dense phase
- Inject into all store simultaneously avoiding two phases in the wellbore
- Maintain well flowrates above minimum required to reduce halite precipitation risk

for all operating scenarios. This will be done by pre-empt adjustment in well chokes on detection of impending imbalance in flow by having real-time flowmeter readings at all shippers.

The phase envelope is highly sensitive to contaminates and the choice of EoS, therefore small intentional flowrate or pressure disturbances for the Artificial Intelligence to learn and correct algorithm response is required to avoid two phase operation.

Operating conditions	Onshore system	Offshore system
Minimum pressure	0 barg for depressurisation	Above critical point to stay in dense phase
Maximum pressure	Below dew point for avoidance of liquid drop out	Deliver flow to all reservoir stores at capacity
Minimum temperature	Minimum ambient	Pipeline; set by minimum ambient/ planned depressurization Wellhead; set by Joule-Thomson cooling from maximum pipeline to minimum wellbore pressure or LOPC
Maximum temperature	Occurs at inlet set by compressor outlet	Occurs at inlet set by compressor/pump outlet

Table 4: Operating criteria

8.0 Subsurface Uncertainty and Risks for Phase 1

8.1 Overview of Risk Assessment and Management Plan

CCUS projects consider three main risk categories in subsurface work – loss of containment (leakage), injectivity and capacity. The project team has performed numerous internal risk workshops to identify and quantify key risks to the Phase 1 project. The main methodology applied was bowtie analysis to carry out risk assessment and subsequent risk management.

The bowtie method entails building a bowtie diagram as shown below, step-by-step, to produce a qualitative risk assessment of the hazards under consideration and identify relevant prevention and mitigation controls (Figure 38).

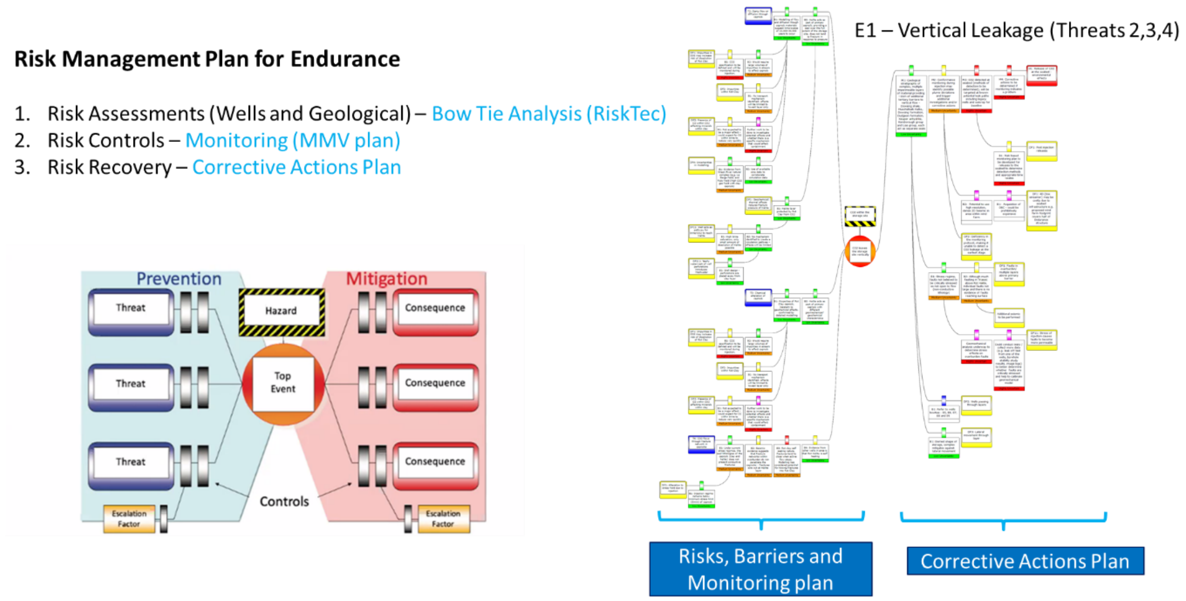


Figure 38: Risk Management Plan for Endurance based upon bowtie assessment

Hazards normally do not cause harm because they are kept under control. However, if control of the hazard is lost, an initial incident will occur – this is the top event and is shown at the centre of the bowtie diagram. For example, for the NZT/NEP project, the top event could be defined as movement of CO2 outside the confines of the storage site.

The threats (sometimes called 'causes') illustrate the various ways in which the hazard could be realised i.e. ''what could cause loss of control of the hazard?''. For subsurface storage of CO2, each individual bowtie threat describes a specific type of leak path by which CO2 could escape from the storage site. Examples of threats include CO2 leakage through existing faults which cross the primary seal, injection induced stress causing new fractures or re-opening existing faults or fractures, and flow of CO2 up through abandoned well bores.

Once control is lost and the top event occurs, there may be several ways in which the event can develop to an ultimate consequence. Each consequence will result in a specific extent of harm i.e. severity of impact. The impact might be on people, the environment, physical assets or the reputation of the company, or all the above. Examples of potential consequences relevant to the NZT/NEP Project are CO2 presence at the seabed, or CO2 presence in discharged brine.

There are barriers (also referred to as controls) in place which can prevent the realisation of the hazard (i.e. prevent the threat leading to the top event) or mitigate the consequences should the top event occur. The barriers on the left side of the bowtie diagram are prevention measures and can be items of equipment or actions taken in accordance with training and procedures. They also include natural barriers such as impermeable geological layers within the storage site. The barriers on the right side of the bowtie are mitigation measures and are called upon if the preventive measures fail to maintain control and the top event occurs. The mitigation measures are in place to interrupt development of the event and limit, or recover from, the consequences, and may include natural geological barriers outside of the storage site, items of equipment or monitoring activities and corrective actions (Figure 39).

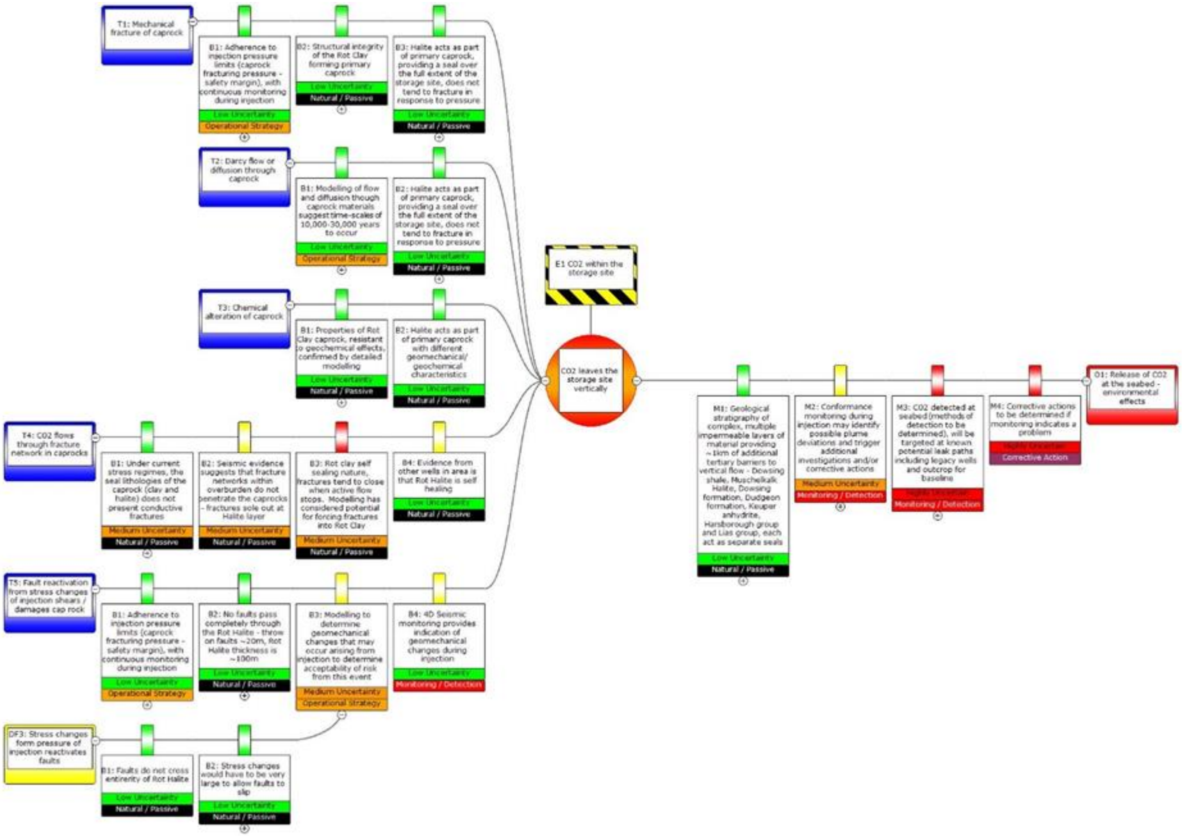
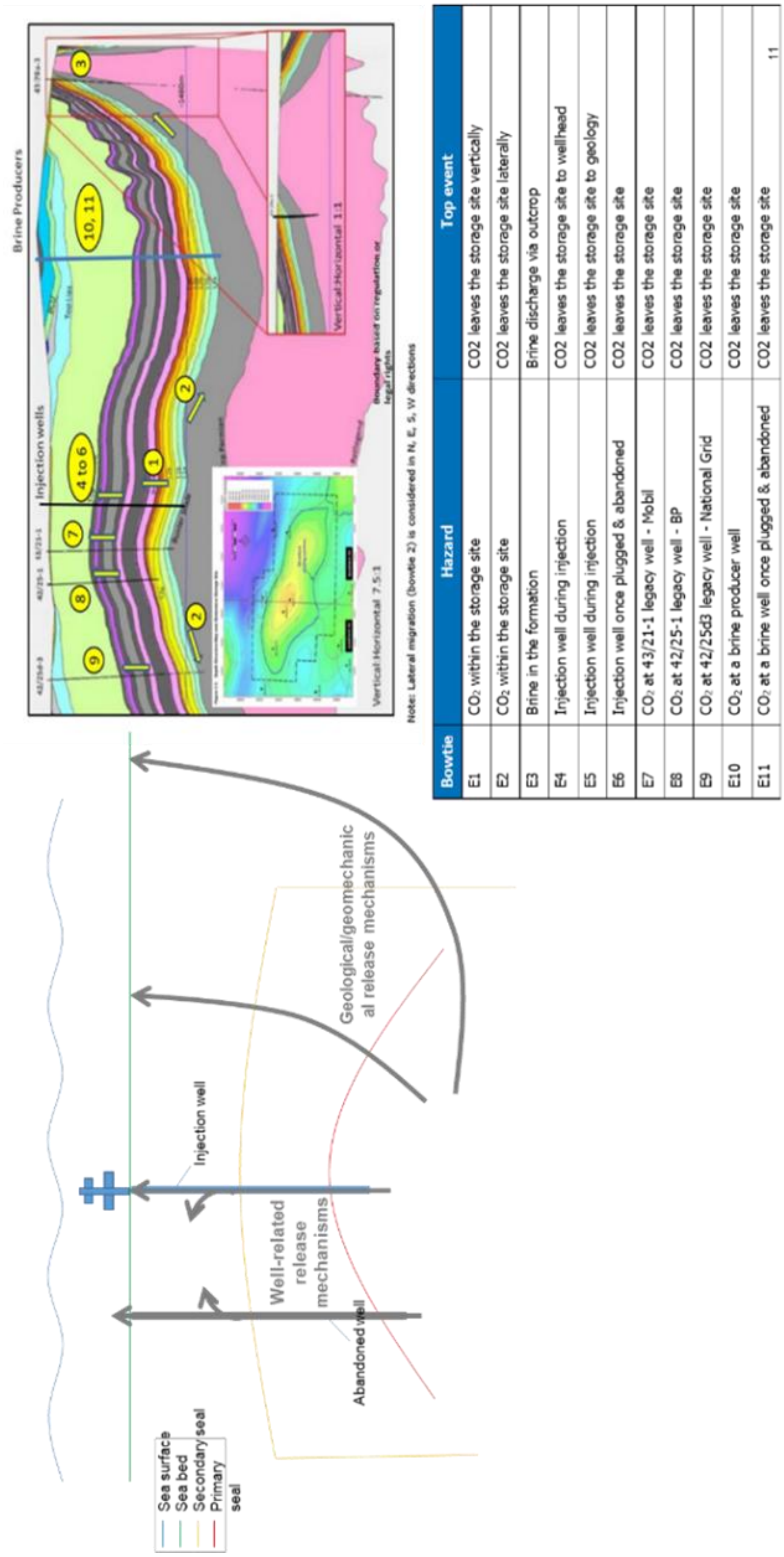


Figure 39: Example of Bow Tie (E1- CO2 leaves the storage site vertically)

A series of qualitative and quantitative assessments were carried out to assess containment risks (geological, leakage in injection wells and legacy wells), as shown in Figure 44. A total of 27 threats/leak path were identified and assessed in prospective of mitigation plan. Once on injection, well and reservoir monitoring will confirm that the storage system is understood and functions reliably (with barriers and controls in place).

Assessment confirms minimum risk of CO2 leaks for the phase I volumes if operation follows defined pressure constraints.



Bowtie	Hazard	Top event
E1	CO_2 within the storage site	CO2 leaves the storage site vertically
E2	CO_2 within the storage site	CO2 leaves the storage site laterally
E3	Brine in the formation	Brine discharge via outcrop
E4	Injection well during injection	CO2 leaves the storage site to wellhead
E5	Injection well during injection	CO2 leaves the storage site to geology
E6	Injection well once plugged & abandoned	CO2 leaves the storage site
E7	CO_2 at 43/21-1 legacy well - Mobil	CO2 leaves the storage site
E8	CO_2 at 42/25-1 legacy well - BP	CO2 leaves the storage site
E9	CO_2 at 42/25d3 legacy well - National Grid	CO2 leaves the storage site
E10	CO_2 at a brine producer well	CO2 leaves the storage site
E11	CO_2 at a brine well once plugged & abandoned	CO2 leaves the storage site

Figure 45: Leakage/containment risks for Endurance (geological, injection well, and legacy wells)

8.2 Key Risks for Phase 1

The major subsurface risks for Phase 1 can be summarized as follows:

1. Unexpected plume migration
2. Leakage risks (Risk Management Plan, MMV KKD [7], and Endurance Field Legacy Well Integrity Assessment [8])
3. Reservoir architecture uncertainty and implication on injectivity and capacity
4. Monitorability of the structure and well placement in the presence of the wind farm
5. Halite precipitation and impact on injectivity
6. Environmental/Reputational impact of outcrop brine release should the former be in hydraulic communication with Endurance store.

		Rare	Unlikely	Possible	Likely	Almost Certain
		1	2	3	4	5
Severe	5	1 - Endurance Seal Failure 2 - NZT development well leakage 9 - CO2 leakage via outcrop 10 - Natural CO2 seepage in Endurance vicinity 13 - Insufficient Monitoring Programm 14- Require Brine production (Phase 1) /19 - Endurance capacity is under estimated 15 - Water wash is not effective tool for remidiation of halite precipitaiton 17 - J-T equipment qualification 18 - Uplift and further impact on Horsea4 development	3 - License extension approval (delivery on work program)	8- Overlap with Hornsea 4 wind farm / optimized well pattern and monitoring program 5 - Reputational damage from Outcrop brine flux 16 - NGO opposition toward CCUS on Endurance		
Major	4		11 - Injectivity impairment due to phase behaviour of CO2 12 - Well damage due to dispachability 4 - Reservoir compartmentalisation	7 - Halite precipitation in the well bore		
Medium	3			6 - Legacy P&A'd well leakage		
Low	2					
Insignificant	1					

Figure 40: Subsurface Risk Register for Endurance.

8.3 Legacy Well

A legacy well assessment has been issued [8], covering the three on-structure wells (TD in the Bunter) and two off-structure wells that TD'd in the Carboniferous below.

In order to ensure well integrity is maintained during and post injection, the condition of the 5 identified wellbores in the vicinity of the Endurance field were reviewed as follows during the legacy well assessment

- An analysis of the original design parameters and the abandonment plugs set in the 5 identified abandoned Exploration and Appraisal (OFFSET) wells and compliance with UK legislation and conformance with BP and industry best practice.

- The 5 wells in scope for this analysis are:
  - 43/21-2
  - 43/21-3
  - 42/25d-3
  - 42/25-1
  - 43/21-1
- Review of cement resistance to future CO2 storage, both gas phase, dense phase and with highly saline brine.
- Assessment of likelihood of CO2 leakage from existing wells, and feasibility of remedial operations (casing is cut below seabed already).

Table 4 presents the assessment summary of the individual well barrier conditions and leak risk levels for the five screened wells. All wells have one primary barrier to CO2 leakage, though not necessarily verified to current OGA or BP standards. Secondary barriers only exist in one well. While well locations are known, no pre-emptive interventions are planned, and all wells will be subject to a specific monitoring programme as part of the MMV plan use of permanent landers or AUV around the wells to monitor CO2 or brine leakage next to their location.

	43/21-2	43/21-3	42/25d-3	42/25-1	43/21-1
Wells located on the Endurance structure	No	No	Yes	Yes	Yes
Permeable zones identified?	Bunter formation only[1]	Bunter formation only[1]	Bunter formation only[1]	Bunter formation only[1]	Bunter formation only[1]
Top Bunter formation MD	5963 ft	5295ft	4617 ft	3659 ft	3468 ft
Primary Annular Barrier MD[5]	308 -984 ft (676 ft)	Unknown	2904- 4617 ft (1713 ft)	Not applicable (OH)	Not applicable (OH)
Primary Wellbore Barrier MD[5]	364 – 984 ft (620 ft)	394 – 1,050 ft (656 ft)	3864-4617 ft (753 ft)	3429 – 3659 ft (230 ft)	3300 - 3468 ft (168 ft)
Secondary Annular Barrier MD[5]	5906 -5963 ft (57 ft)	Unknown	2904- 4617 ft (1713 ft) combination	381 – 1828 ft (1447 ft)	305 -1855 ft (1550 ft)
Secondary Wellbore Barrier MD[5]	None	None	3864-4617 ft (753 ft) combination	1667 – 1991 ft (324 ft)	1516-1962 ft (446 ft)
Verification of Primary Annular Barrier	Unknown	Unknown	Unknown	Unknown	Unknown
Verification of Primary Wellbore Barrier	Unknown	Unknown	Tag & Pressure Test No inflow test	Unknown	Unknown
Verification of Secondary Annular Barrier	CBL	Unknown	Unknown	Unknown	Unknown

	43/21-2	43/21-3	42/25d-3	42/25-1	43/21-1
Verification of Secondary Wellbore Barrier	None	None	Tag & Pressure Test No inflow test	Unknown	Tag only No pressure test No inflow test
Base of the lateral barrier at a depth at which the formation fracture pressure can withstand the pressure from the DPZs being isolated.	Primary Barrier [12.37 ppg FG]: No. No Secondary Barrier. Note: Prior injection pressure in the Bunter reservoir [2,201 psi @ 4,610 ft TVD ss] exceeds formation fracture pressure at the base of the primary barrier.	Primary Barrier [12.62 ppg FG]: No. No Secondary Barrier. Note: Prior injection pressure in the Bunter reservoir [2,201 psi @ 4,610 ft TVD ss] exceeds formation fracture pressure at the base of the primary barrier.	Primary Barrier [16.00 ppg FG]: Yes Secondary Barrier [Assumed 15.99 ppg FG]: Yes	Primary Barrier [15.82 ppg FG]: Yes Secondary Barrier [Assumed 14.60 ppg FG]: No Note: Secondary barrier base is able to withstand a maximum of 2,200 psi @ 4,610 ft TVD ss in the Bunter Reservoir, but not a 2,900 psi pressure.	Primary Barrier [15.72 ppg FG]: Yes Secondary Barrier [Assumed 14.56 ppg FG]: No Note: Secondary barrier base is able to withstand a maximum of 2,200 psi @ 4,610 ft TVD ss in the Bunter Reservoir, but not a 2,900 psi pressure.
Non-conformance to BP and Oil and Gas UK requirements	b) Only one lateral barrier f) The Bunter formation pressure can break the rock at the base of the primary barrier g) No documentation of annular barrier verification h) No documentation of wellbore barrier verification	b) Only one lateral barrier e) No information on annular barrier TOC f) The Bunter formation pressure can break the rock at the base of the primary barrier g) No documentation of annular barrier verification h) No documentation of wellbore barrier verification	g) No documentation of annular barrier verification h) Wellbore barrier verified by tagging and pressure testing but no inflow testing	f) A Bunter formation pressure of 2,900 psi can break the rock at the base of the secondary barrier g) No documentation of annular barrier verification h) No documentation of wellbore barrier verification	f) A Bunter formation pressure of 2,900 psi can break the rock at the base of the secondary barrier g) No documentation of annular barrier verification h) No documentation of wellbore barrier verification

Table 5: Well Abandonment Assessment based on BP practice and Oil & Gas UK requirements (from Net Zero Teesside Well Integrity Assessment report).

1 There are no other overlying permeable formations, perhaps only a few silt stringers.

2 BP Group Practice 100221 (GP10-60) version 2019 - Zonal Isolation. Oil and Gas UK Well Decommissioning Well Abandonment Guidelines (2018).

3 Assumes a maximum Bunter formation pressure of 2,900 psi @ 4,610 ft TVD ss, a variable CO2 density gradient calculated based on pressure and temperature.

4 As per Table 1: Requirement for well abandonment based on BP Practice for Zonal isolation and Oil and Gas UK well decommissioning guidelines.

5 These areas of cement have been inferred as primary and secondary “barriers” based on where they are situated with respect to most likely flow paths but are not necessarily fully qualified as primary or secondary barriers as per BP Group Practice 100221 (GP10-60) definition.

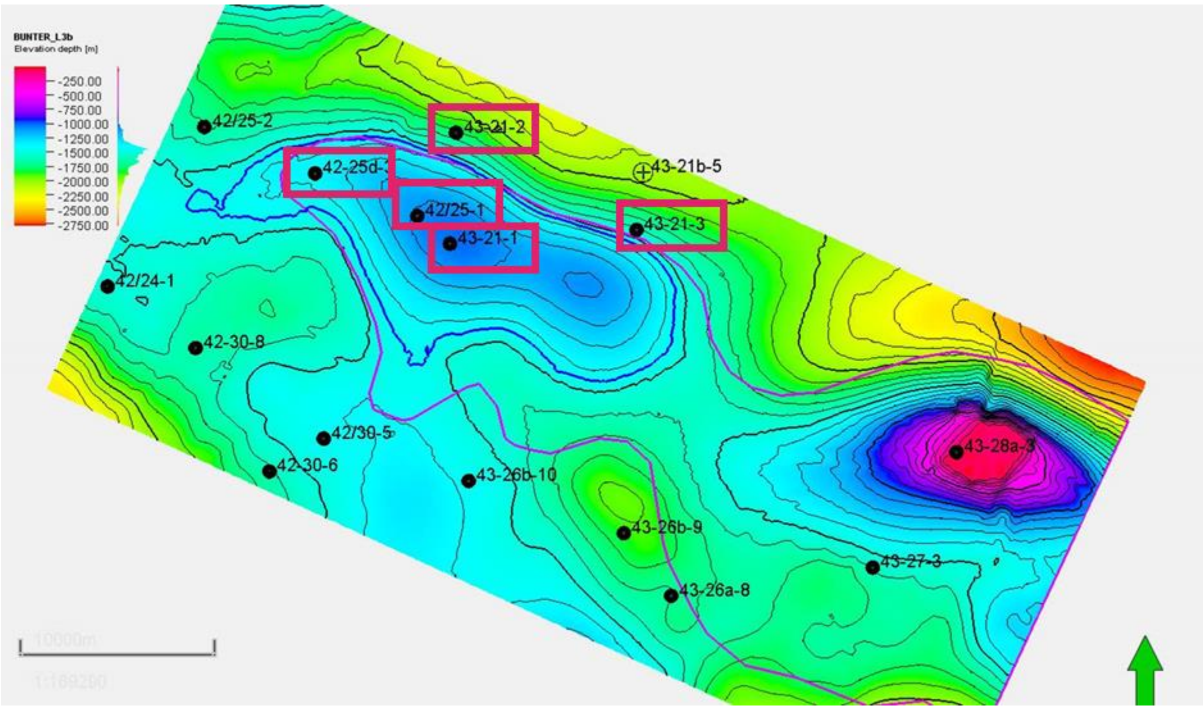


Figure 41: Well in-scope for legacy well integrity assessment

9.0 Notional Monitoring, Measurement, and Verification (MMV) for Endurance

Monitoring. Measurement and Verification program is a vital part of CO2 storage project development to ensure CO2 containment and safe, controlled injection to the selected site. MMV program has to be compliant with authorities, companies and government regulation.

Endurance MMV program is designed following OGA and EU recommendations/ regulations, address specifics of the reservoir/ location and encompasses best industry experience.

9.1 Geological Storage Site and Complex

Loss of containment during CO2 injection (leakage) refers to any release of CO2 from the storage complex.

The storage site means the defined volume area within the geological formation used for the storage of CO2 (i.e. Bunter formation and the Rot Clay). The primary seal is the Rot Halite The structure consists of the 4-way closure as shown in Figure 42.

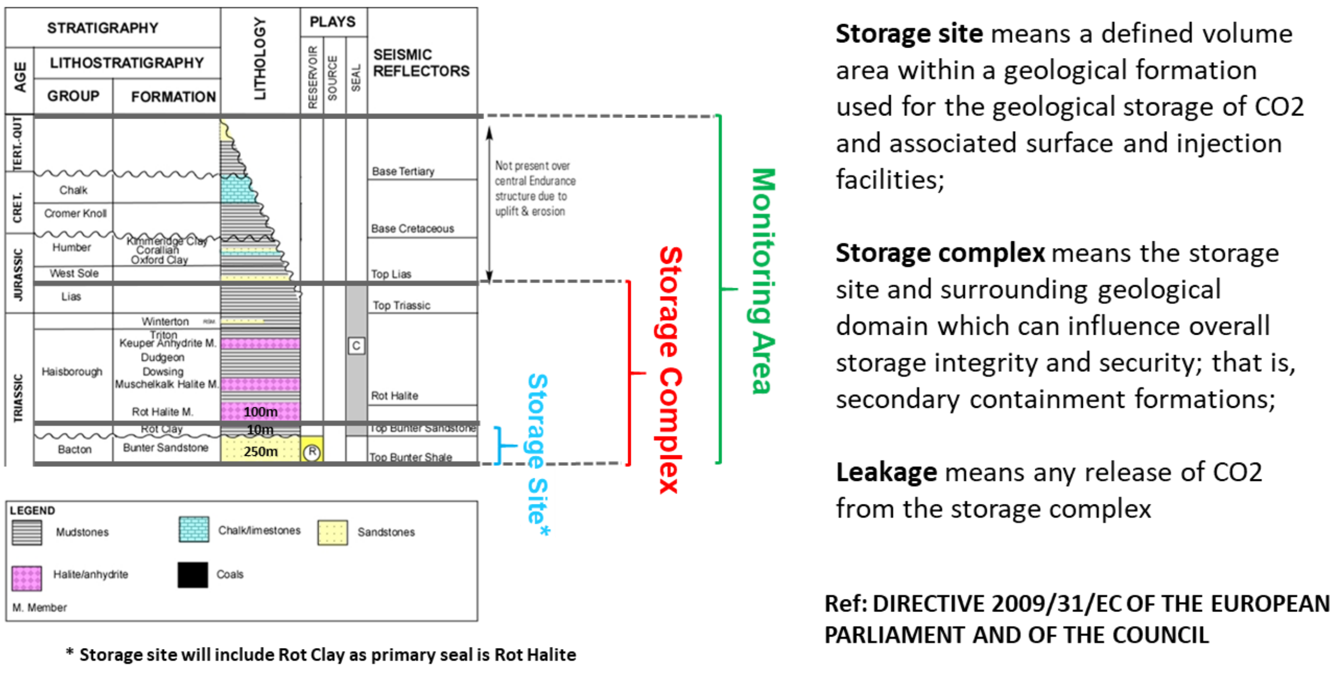


Figure 42: Vertical Storage site/Storage Complex/Monitoring Area for Endurance

The storage complex consists of the storage site and surrounding geological domain which can influence overall storage integrity and security (the outcrop area is therefore included in the lateral definition of the storage complex as it is likely to be in hydraulic communication with the Endurance structure).

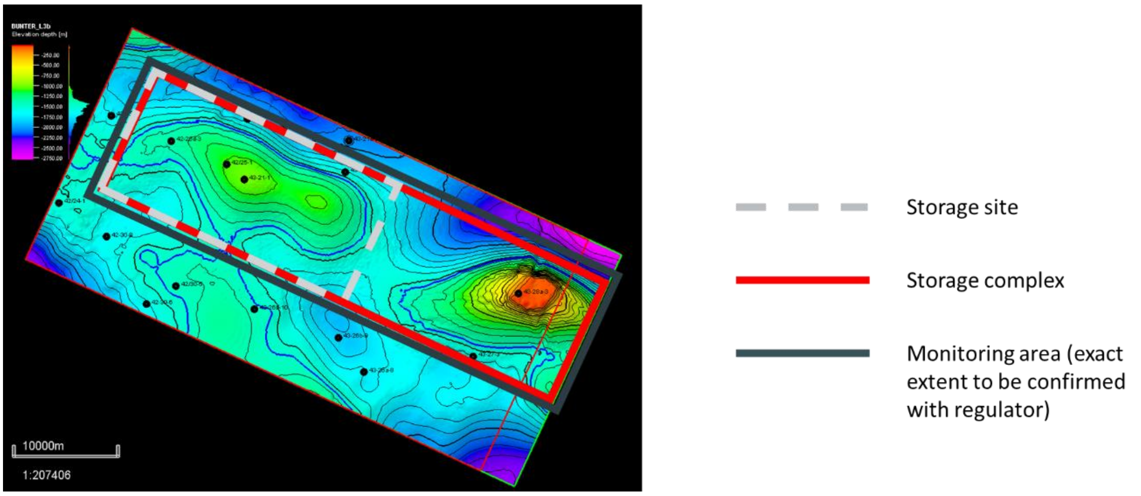


Figure 43: Lateral Storage site/Storage Complex/Monitoring Area for Endurance.

There are few peculiarities of Endurance reservoir and fluid nature which impacts MMV development to be considered:

- Large structure (over 25 km long).
- Seabed bunter outcrop with the possible hydraulic communication with the main reservoir, which can be a release brine due to pressurization.
- Hypersaline brine (250 000 ppm%w).

Philosophy of Endurance MMV design can be summarized in the points below:

- MMV is planned for 25 years of safe CO2 injection with comprehensive set of proven technologies and will provide confidence to operator, partners, authorities and community.
- MMV is designed to follow a risk-based approach to ensure robust risk mitigation identified during comprehensive Endurance risk assessment.
- 30 years of CCUS industry experience proven the use of 4D seismic, extended well monitoring and seabed surveys as the core set of data acquisition for MMV in offshore fields. This strategy and set of associated technologies are taken to enable effective CO2 monitoring for Endurance.
- Comprehensive baseline surveys (seismic and environmental) are critical for interpretation of future data.
- Cost effective interim towed-streamer seismic surveys and rely on the trigger surveys when deviation from expected behaviour is observed to monitor plume movements across the structure.

- Monitoring well on the Endurance east sub-crest will provide essential data towards lateral pressure gradients and robustness towards CO2 plume migration.
- MMV employs proven technology such 4D towed-streamer seismic for the core part and considers novel technology such DAS to increase accuracy.
- Specific solutions for outcrop monitoring.

Notional Monitoring, Measurement, and Verification (MMV) for Endurance is presented in Figure 44.

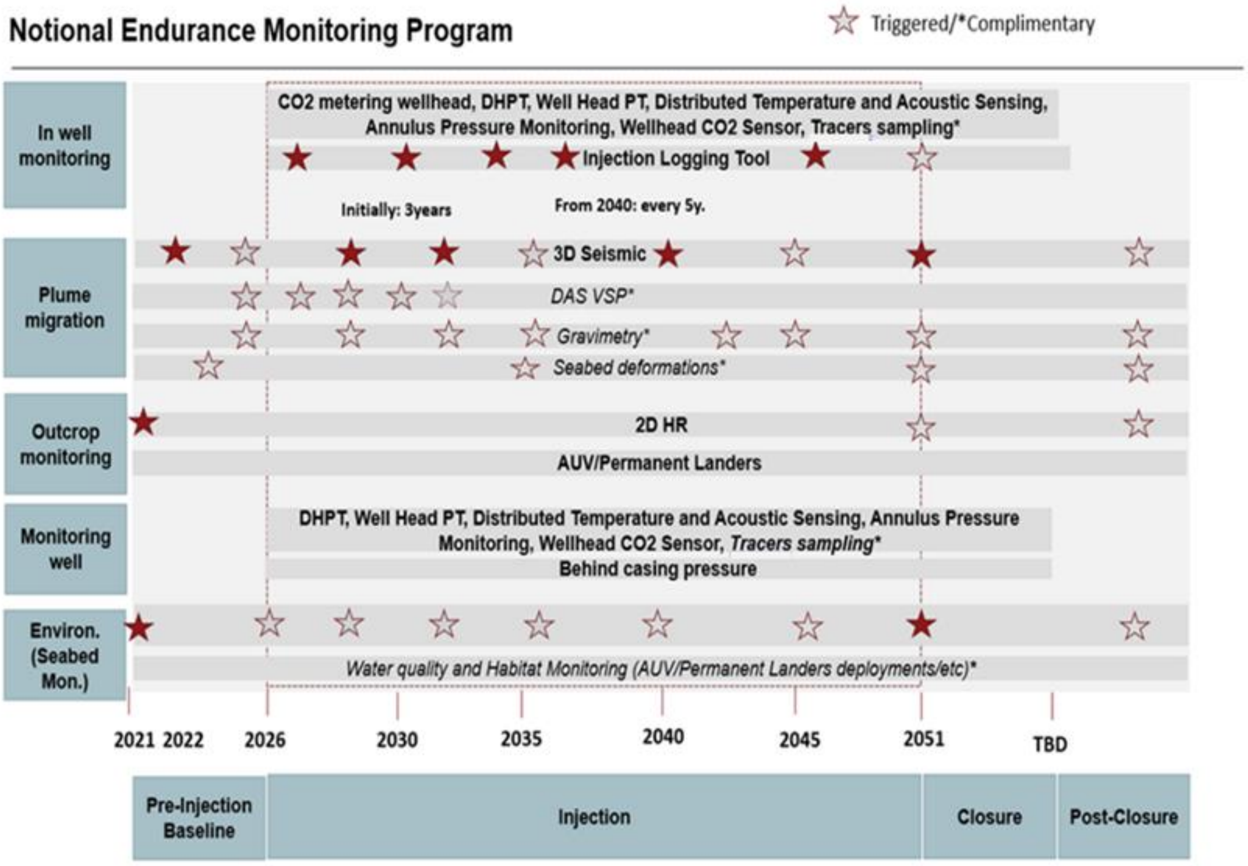


Figure 44: MMV timeline for Endurance.

Rigorous technology screening is displayed as an outcome of this assessment in the figure below (In white the main proven methods, in yellow the complementary ones, in red, the studied ones but not (yet) matured).

Area	CO2 Plume Migration Mon.	Well Integrity	Outcrop Monitoring	Brine Management (Phase 2++)	Environmental/ Seabed Mon. (not subsurface perimeter)
Mitigated risks	Geological leakage. Unexpected plume migration. Wells leakage.	Well leakage. Legacy wells leakage.	Outcrop leakage (CO2 and Brine). Unexpected plume migration.	CO2 leakage via brine producers. Brine disposal impact to seabed.	Environmental impact of CO2 leakage and brine disposal.
Methods	Seismic methods (4D combined with 2D HR) 2D HR 3D Survey Saturation logs (cased hole) Well rates/pressure ILT Gravimetry VSP DAS DTS to the top perf ILT DAS Borehole gravity Behind casing monitoring on crestal well Tracers Seabed deformation measurements EM (CSEM)	Annulus A Acoustic cement logs Visual/Chemical survey (Landers/AUV) VSP DAS Casing inspection tools	AUV Landers Tracers	Brine producers well rates CO2 content/Ph/Salinity AUV PLT Tracers Landers Saturation logs (cased hole)	Comprehensive Base line (seabed sediment, flora and fauna) Seabed mapping (MBES and side-scan sonar) Time-lapse AUV Landers Tracers

White – proven technology/base case; Orange – optional/under development; Red – not suitable for Endurance conditions

Figure 45: Technology assessment for Endurance.

9.2 Intervention requirements and in-well monitoring

A series of intervention requirements and in-well monitoring will be required to support Phase 1 offshore storage project.

Water washing:

Based on GEM™ modelling for halite deposition, two days per injector per year are expected to flush the near wellbore with fresh water after an initial pre-flush prior to CO2 injection. This will be done from a vessel set up to connect to either the tree or manifold in a similar manner to a scale squeeze.

Intentional Surveillance (light interventions):

- Baseline Injection Logging Tool (ILT) in all wells for NZT/NEP Phase 1 to establish inflow profile after one year of injection.
- Regular ILT surveys carried out from a light well intervention vessel (LWIV) to provide time-lapse monitoring of sweep (notionally every 5 years per well).
- Time-lapse Saturation log in the observation well

Heavy intervention from a rig might be required for well intervention such as recompletion or workovers.

In-well monitoring:

In-well continuous surveillance is planned as follows:

- Downhole pressure-temperature gauge (DHPTG) in both the tubing and the annulus. The annulus gauge is included to allow ‘A’ annulus pressure monitoring when the fluid level drops due to thermal contraction on injection. Under these conditions, the conventional gauge in the tree is not in contact with the fluid and so does not register.

An alternative is to install a nitrogen-cushion to expand to fill the void, but this is operationally more complex.

- Behind-casing pressure monitoring is a technology option. Systems are available from several vendors that allow pressure to be monitored behind cemented casing, which would enhance reservoir surveillance particularly in the observation well close to the crest.

9.3 Seismic Monitoring

Seismic monitoring with complimentary gravity, seabed deformation surveys are identified as core technologies to track plume migration. In addition, DAS VSP is seen as promising for initial injection period however currently due to distance from onshore, it is a technology stretch.

A new 3DHR (high resolution) towed-streamer seismic survey is planned to be acquired in mid-2022. This acquisition will be optimized for the Bunter sandstone at Endurance and will provide high resolution overburden imaging. Compared to the existing data, this new acquisition will benefit from having a full offset range, higher fold, and utilize a high resolution set up which will produce around double the resolution. 3DHR will be envisaged to conduct 4D monitoring by taking the 2022 survey as the 4D baseline. Alternatively, OBN can also be used for 3D monitoring.

It is envisaged that 4D repeat surveys would start at around a 3-year interval for the first 6 years (2 repeats) and then space out based on results the from the first 2 surveys, the phasing of the development and the conformance of the other monitoring data. A full 3D survey will be required at store closure and potentially also at a point preceding the exit from the acreage and the handover of the store.

9.4 Outcrop Monitoring

The pressurization of the structure in Endurance might also lead to the release of brine into the sea through the underwater Bunter outcrop 20 km east of Endurance (assuming the Bunter outcrop is in hydraulic communication with the Endurance store). This release is expected to be quite marginal in terms of flux (potentially in the order of thousands of barrels over 1 to 2 square kilometres in late life of the project – phase 1 only -) with mobilized brine from the shallow depths of the outcrop (100-200m below seabed) through which brine composition is expected to be close to sea water. The 2D UHR seismic survey (acquired during the summer of 2020) did confirm that the Bunter sandstone appears to be exposed to the seabed and a shallow borehole is planned during the survey in 2022 to acquire a brine sample (from a formation sampling wireline tool) from the 1st 100-200 meters of Bunter below seabed to confirm the brine composition.

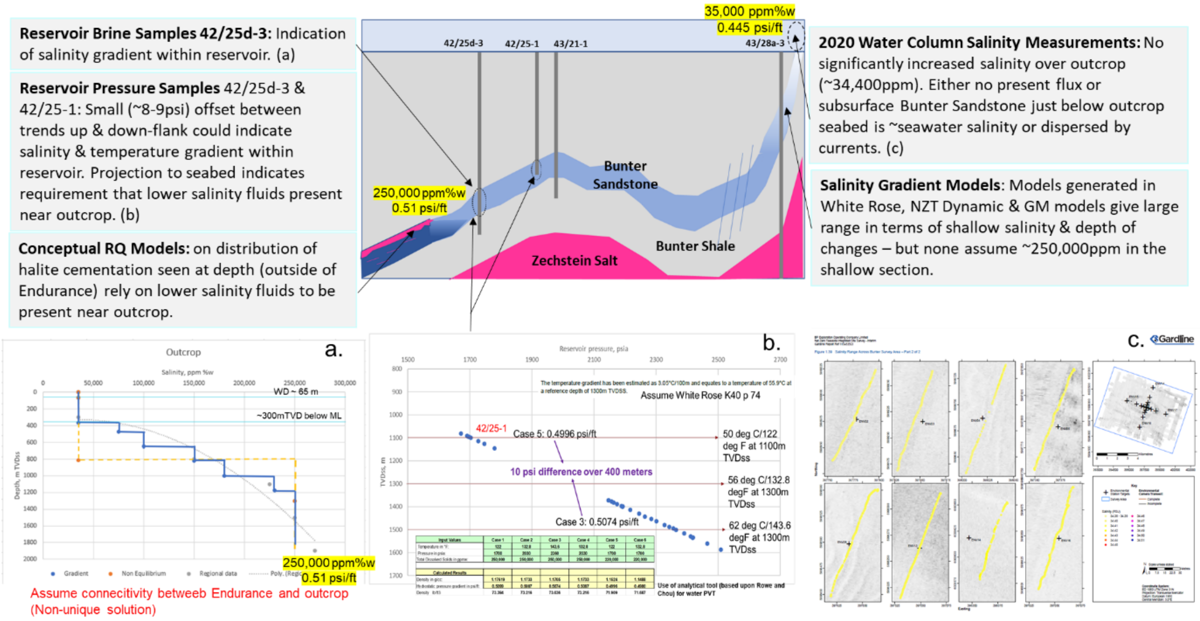


Figure 46: Salinity Gradients – Supporting Data & Models

An environmental baseline survey (salinity of ambient sea water and trace component) over the outcrop was carried out in the 2020 survey campaign to enable the future detection of hypersaline brine release from the outcrop throughout the injection period. Despite robust modelling methodologies employed that predicted salinity of brine release at the outcrop for Phase 1 volumes to be likely closer towards seawater, and hence composition by proxy, there remains a low probability residual risk of heavy metal content within that brine that cannot be definitively discounted by modelling alone. Therefore, agreement was reached with the NZT/NEP partnership in March 2021 to proceed with the study and planning of a deep geotechnical borehole with a geotechnical vessel or better with a jack-up rig in order to obtain a representative sample by 2Q 2022 and to eliminate this risk, subject to further Partner approval.

9.5 Monitoring Well

Monitoring well is planned to be drilled at the east subcrest (see figure below) of Endurance structure to meet multiple objectives including gradient pressure monitoring, plume migration control, verification/control of geomechanical parameters, etc. The passive pressure monitoring in the observation well will allow to track pressure gradients across the structure. Saturation logging in addition to 4D seismic-based plume monitoring will be important to identify when the CO2 will be reaching the secondary crest in the east. It is expected that the well be used for coring as well and acquisition of further geo-mechanical data acquisition in the caprock i.e. FPIT (both Rot Clay and Halite formations).

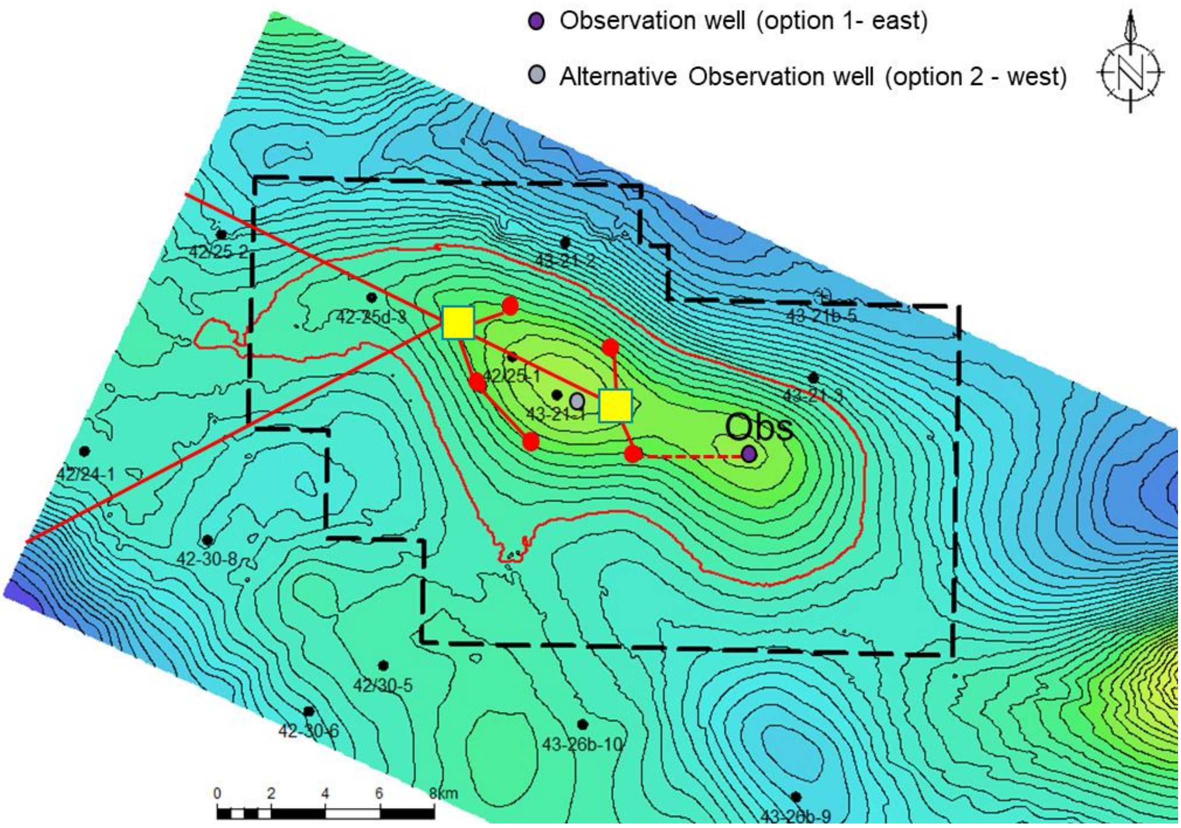


Figure 47: Monitoring (observation) well positioning

10.0 Seismicity and Near-field Activity

Information about the location and magnitude of all earthquakes recorded from the UK continental shelf for the particular area of interest has been plotted and reviewed as follows, indicating low natural seismic activity. DAS technology in the Phase 1 wells will potentially permit the passive monitoring of background seismicity in the field once on injection.

The area is currently protected due to the presence of harbour porpoise.

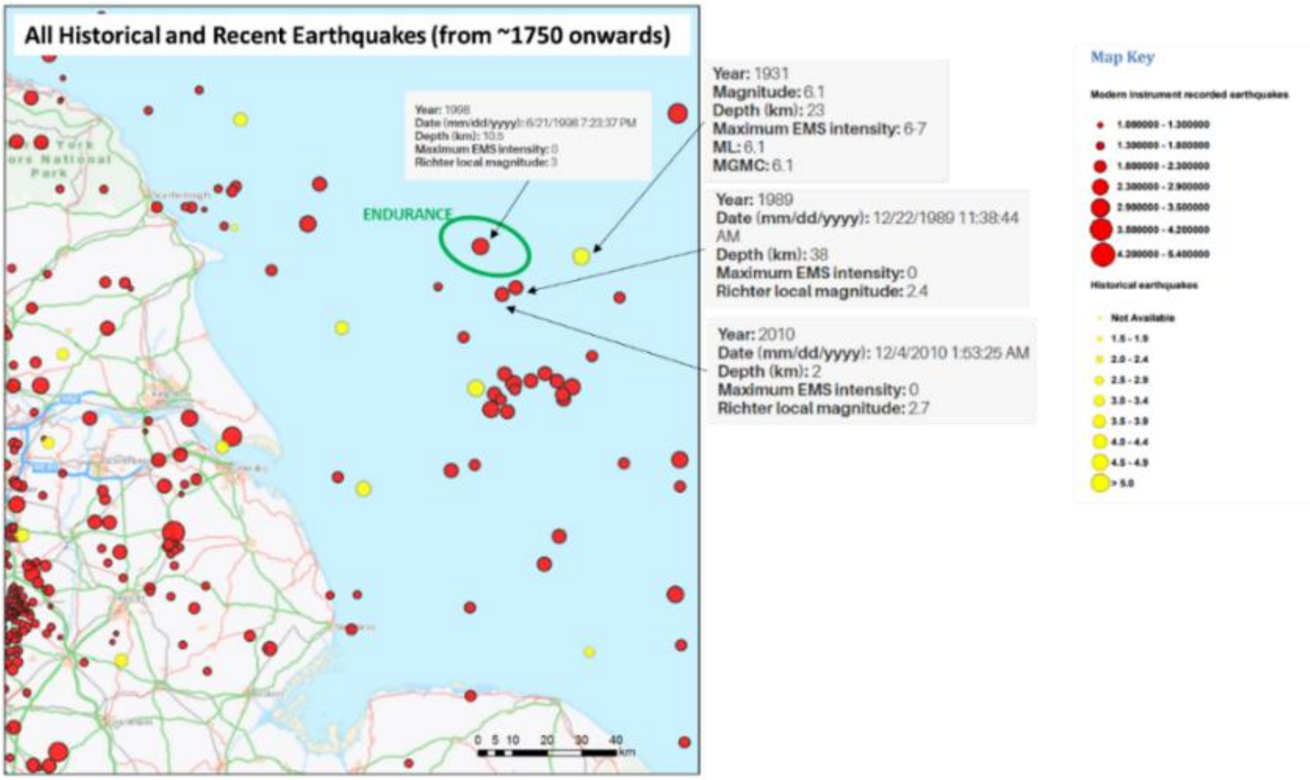


Figure 48: Map of all earthquakes recorded from northern England and the southern North Sea.

North of Endurance structure lies two Paleozoic-age gas fields Garrow and Kilmar (the latter further east) operated by Alpha Petroleum Limited. Ravenspurn gas field is located 15 km south of the CCS001 license. Current work is being undertaken to assess the impact of the pressurization of the Bunter aquifer on offset wells.

11.0 Technology Maturation Plan

The following technology maturation plan is currently being worked:

Significant value uplift is seen on fibre optic technology maturation in subsea concepts to reduce cost and increase definition of PT, saturation logs, VSP and improve wells integrity monitoring.

Ocean-bottom node acquisition will continue to be developed as an enhancing technology to complement towed-streamer technique. Tracking seabed deformation (uplift) needs to be matured as well as background seismicity monitoring

Crest pressure monitoring technology while injection – similar to Halliburton (Linx) installed in crestal observation well.

Landers and AOV qualification for seabed monitoring for both on-structure/off-structure legacy wells and outcrop (hypersaline and CO_2 seepage)

Metering of CO_2 content in brine producers for the Phase II (subsea).

Subsurface Safety Valve: When injecting CO_2 offshore from a platform, safety legislation requires the use of subsurface safety valve (SSSV) or equivalent, to prevent the backflow of CO_2 from the store to the platform in the event of a loss of control of the well. This prevents the build-up of a plume of CO_2 which could hamper the evacuation of personnel from the installation. Following a loss of containment at surface, any liquid or dense phase CO_2 above a closed SSSV will boil off with the temperature at the gas-liquid interface around -28°C. This “cold front” moves slowly down the well until it encounters the SSSV where it is possible for further cooling to take place. If the SSSV has a small leak (which is permitted under the API specification for a hydrocarbon SSSV) then continuous cooling can continue at the SSSV with the lowest temperature reaching around -78.5°C in theory for an atmospheric vent. For NZT/NEP’s subsurface scheme, the lowest temperature expected in such an event is -55 deg C due to the hydrostatic head of seawater reducing J-T cooling.

12.0 Future Data Acquisition

The data acquisition plan will be finalized in define, but the following provides the best estimate at this point in time. The information here will be superseded by the individual well SOR for data collected during the drilling and completions phase and by the “MMV plan” for data collected during well operations.

Table 6: Data Acquisition for the overburden section

Overburden data					
Section	**Logging Data**	**Main Objectives**	**Number of wells**	**Comments**	**Conveyance**
Upper section	Gamma Ray, Resistivity, Sonic (Compressional)	Seismic well tie	All		LWD preferred
	Density, Sonic (compressional and shear), oriented calipers	Seismic well tie	Single crestal well	Expectation that a pilot hole will be needed to acquire good quality data	LWD or WL
	Vertical Seismic profile	Seismic well tie	1	May not be necessary if DAS technology can provide a suitable alternative.	WL only
Intermediate section	Gamma Ray, Resistivity	Casing point selection	All		LWD only
	Density, Sonic (compressional and shear)	Seismic well tie	All		LWD or WL
	Cross dipole sonic, calipers	Geomechanics	Single crestal well		WL only
	Image log	Looking for evidence of fracturing or faulting (primarily in halite)	Single crestal well	Latest generation tool required for high quality image	LWD or WL
	Rotary sidewall cores	Analysis of rot halite (assessing the heterogeneity of the halite)	Single crestal well	Over Rot halite only. Whole core would also satisfy objectives	WL only
	Vertical Seismic profile	Seismic well tie	1-3	May not be necessary if DAS technology can provide a suitable alternative.	WL only

Reservoir (Bunter Sandstone) data				
Logging Data	**Main Objectives**	**Number of wells**	**Comments**	**Conveyance**
Gamma Ray, Resistivity, Density, Neutron	Basic reservoir characterization Seismic well tie	All		LWD or WL
Sonic (Compressional, shear), oriented calipers	Seismic well tie Reservoir characterization	All		WL preferred
Nuclear Magnetic resonance	Assessing vertical variability in rock quality to aid perforation selection	All	Assumes cased and perforated completion	WL preferred
Density spectroscopy	Advanced reservoir characterization (variations in matrix density)	All		LWD or WL
Formation pressures	Assessing original pressure in wells pre-injection Assessing variation in salinity across the structure	All		LWD or WL
Formation fluid samples	Assessing variation in salinity across the structure	2 - 4	The number of wells will depend on whether the clustered or dispersed option is selected for well location	WL only
High resolution image logs	Sedimentology characterization	4	Latest generation resistivity tool required for high quality image	WL only
Vertical Seismic profile	Seismic well tie	1 - 3	May not be necessary if DAS technology can provide a suitable alternative.	WL only

Table 7: Data Acquisition for the reservoir section (1).

Whole core data		
Formation	**Main Objectives**	**Number of wells**
Rot clay	• Additional geomechanics measurements ○ Gain measurements at the crest of the structure and inform properties relative to the flank • Determination of shale properties ○ 42/25d_3 core was incorrectly cleaned and did not achieve this objective	1 in a clustered development, 2 in a dispersed development. Please note low deviation wells are preferred for whole core acquisition. If all wells are planned with significant deviation, bypass coring may need to be considered.
Bunter Sandstone	• Geological description: ○ Lower part of the Bunter sandstone has not been cored in the field. ○ No modern core is present in the proposed development area – risk that geology is different to the down flank cored location • Static property calibration ○ Test the assumption that properties derived from the cored well on the Western flank are applicable to the entire structure. • Dynamic property calibration ○ Improve understanding of vertical and lateral connectivity – integrate with injection data	

Table 8: Data Acquisition for the reservoir section (2).

Dedicated Geomechanics data				
Formation	Data	Objective	Number of wells	Comments
Rot Halite	FPIT	Calibration of geomechanics model at structure crest	Single crestal well	Test expected to be carried out in middle of Halite, to approximately overburden stress. Will require a dedicated tool to be run.
Rot clay	FPIT	Calibration of geomechanics model at structure crest	Single crestal well	Depending on well design could be combined with standard FIT at start of hole section.

Table 9: Dedicated Geo-mechanical data.

Cased hole data (During drilling phase)			
Section	**Logging Data**	**Main Objectives**	**Number of wells**
Upper casing (assumed 13 3/8")	CBL/VDL	To determine quality of bond between casing and cement. This will provide assurance on future integrity or assist in developing remediation programs	All N.B. This data is primarily to address regulatory concerns
Intermediat e casing	Ultrasonic cement evaluation	To determine quality of bond between casing and cement. This will provide assurance on future integrity or assist in developing remediation programs	All
	CBL/VDL		
Production l iner	Ultrasonic cement evaluation	To determine quality of bond between casing and cement. This will provide assurance on future integrity or assist in developing remediation programs	All
	CBL/VDL		
	Ultrasonic cement evaluation	Baseline saturation log, with well in initial conditions. Characterizes the in situ brine system, which will make monitoring CO2 migration easier significantly more accurate for future surveillance.	1
	Pulse neutron log		

Injectivity test and interference testing		
Formation	**Main objectives**	**Number of wells**
Bunter sandstone (completion interval TBC)	• Determination of injectivity for each well with initial pre-flush with fresh water in each CO2 injector (CI1, CI2, CI3, CI4, and CI5) • Limited volumes (up to 6000 barrels per well) can be brought to the rig via a supply boat for post-completion surge (bullhead into subsea well head)	5 injectors (CI1 to CI5) for initial pre-flush

Bunter sandstone (completion interval TBC)	• Extended injectivity test could be carried out between a pair of wells to perform inter-well interference test
	  • Larger fresh-water volumes would be required (of the order of several 10,000's stb) to be injected over 5-10 days to expect sufficient pressure pulse at downdip injectors. **A fracking boat will be required to bring required volumes of fresh water to the rig for injection.**
	  • Seabed pressure gauge in at least one downdip injection well (CI1, CI2, CI3, CI4, or CI5) would be required to be able to deconvolute tidal effects
	  • Reservoir pressure from downhole gauges in CI1, CI2, CI3, CI4, or CI5 could be retrieved from wellhead with telemetry technology (e.g. Sonardyne)
	• Alternatively, an extended production test could be considered for CI6 (in replacement for the extended injection pulse test)
	  • Would require in-well ESP to lift the reservoir water which would be disposed of overboard thereafter (several 10,000 stb of brine over 5-10 days to induce sufficient depletion 2 to 3 km away.
		1 extended injection test in one well depending on final well layout (if achievable)

Table 10:Cased Hole Data acquisition and potential interference testing

13.0 References

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