Programme Area: Carbon Capture and Storage

Project: DECC Storage Appraisal

Title: Due Diligence and Portfolio Selection

Abstract:

Five sites have been selected from 20 for detailed evaluation. Key features of the Recommended Portfolio Inventory are:- Significant overall theoretical mid-case capacity of 1.6GT, - Good geological diversity: 1 Permian, 2 Triassic, 1 Paleogene and 1 Lower Cretaceous age sites, - Good diversity of site type: 2 depleted gas fields and 3 aquifers – 1 with structural closure and 2 more open, - Understanding of all sites can be materially progressed through the project, - Portfolio provides strategic build-out options from Phase 1 CCS projects.

Context:

This project, funded with up to £2.5m from the UK Department of Energy and Climate Change (DECC - now the Department of Business, Energy and Industrial Strategy), was led by Aberdeen-based consultancy Pale Blue Dot Energy supported by Axis Well Technology and Costain. The project appraised five selected CO2 storage sites towards readiness for Final Investment Decisions. The sites were selected from a short-list of 20 (drawn from a long-list of 579 potential sites), representing the tip of a very large strategic national CO2 storage resource potential (estimated as 78,000 million tonnes). The sites were selected based on their potential to mobilise commercial-scale carbon, capture and storage projects for the UK. Outline development plans and budgets were prepared, confirming no major technical hurdles to storing industrial scale CO2 offshore in the UK with sites able to service both mainland Europe and the UK. The project built on data from CO2 Stored - the UK's CO2 storage atlas - a database which was created from the ETI's UK Storage Appraisal Project. This is now publically available and being further developed by The Crown Estate and the British Geological Survey. Information on CO2Stored is available at www.co2stored.com.

2015

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AXIS WELL TECHNOLOGY

D05: Due Diligence and Portfolio Selection

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Disclaimer:

While the authors consider that the data and opinions contained in this report are sound, all parties must rely upon their own skill and judgement when using it. The authors do not make any representation or warranty, expressed or implied, as to the accuracy or completeness of the report. There is considerable uncertainty around the development of CO_2 stores and the available data are extremely limited. The authors assume no liability for any loss or damage arising from decisions made on the basis of this report. The views and judgements expressed here are the opinions of the authors and do not reflect those of the ETI or any of the stakeholders consulted during the course of this project.

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1.0 Executive Summary

Five sites have been selected from 20 for detailed evaluation. Key features of the Recommended Portfolio Inventory are:

- *Significant overall theoretical mid-case capacity of 1.6GT.*
- *Good geological diversity: 1 Permian, 2 Triassic, 1 Paleogene and 1 Lower Cretaceous age sites.*
- *Good diversity of site type: 2 depleted gas fields and 3 aquifers – 1 with structural closure and 2 more open.*
- *Understanding of all sites can be materially progressed through the project.*
- *Portfolio provides strategic build-out options from Phase 1 CCS projects.*

This Energy Technologies Institute (ETI) Strategic UK CCS Storage Appraisal project has been commissioned on behalf of the Department of Energy and Climate Change. The project brings together existing storage appraisal initiatives, accelerates the development of strategically important storage capacity and leverages further investment in the building this capacity to meet UK needs.

The primary objective of the overall project is to down-select and materially progress the appraisal of five potential CO_2 storage sites on their path towards final investment decision (FID) readiness from an initial site inventory of over 500. The desired outcome is the delivery of a mature set of high quality CO_2 storage options for the developers of major power and industrial CCS project developers to access in the future. The work will add significantly to the de-risking of these stores and be transferable to storage developers to complete the more capital intensive parts of storage development.

The initial stage of the project has focussed on selecting a technically and strategically robust portfolio of 5 candidate CO_2 storage sites from an initial inventory of 579 potential sites. During the next and final stage of the project a detailed subsurface evaluation of each of the sites will be completed and form part of an outline storage development plan and budget for that location.

Due Diligence evaluation of all 20 sites in the Select Inventory was undertaken and each site reviewed with respect to its ability to meet the project requirements, progress through further evaluation/appraisal and contribution to the site portfolio.

The recommended portfolio of 5 sites has been tested with industry stakeholders on 29th July 2015. It was further endorsed by third party review from academic and industry CCS expert peer review panel and finally by ETI's advisory panel. The portfolio represents a diverse set of sites from a range of perspectives:-

It services the emission requirements from the whole of the UK, including one site in the East Irish Sea (EIS), two in the Southern North Sea (SNS) and two in the Central North Sea (CNS).

It has good diversity in store types with two depleted gas fields and three aquifers, one with a structural closure and two more open systems.

It is well placed to support the future development needs of a CO_2 enhanced oil recovery industry.

It has good geological diversity with one Permian reservoir which will help to more forward significant storage potential in the Southern North Sea, two Triassic structures, one a depleted gas field and one a saline aquifer, one Lower Cretaceous Captain aquifer and one Early Tertiary Forties aquifer, the latter two systems looking to access the huge potential that open aquifer systems have to offer. This is a key strategic step if CO_2 storage is to be developed at scale in the UKCS. This diversity is important in order to manage and minimise the single point of failure risk.

Finally the portfolio represents sites that would be strong build out options from both Phase 1 projects should they go ahead.

Collectively the storage units identified in this portfolio have a target theoretical mid case capacity of 1.6GT and contains sites where appraisal can be materially progressed within the constraints of this project.

The Portfolio Inventory comprises:-

- SNS_Site_7_139.016 Bunter Closure 36 Structurally Closed Aquifer
- SNS_Site_5_141.035 Viking depleted gas fields
- CNS_Site_14_218.000 Captain_013_17 Open Aquifer System
- EIS_Site_19_248.002 Hamilton depleted gas field
- CNS_Site_2_372.000 Forties 5 Open Aquifer System

A generic work programme has been developed for WP5 in WP1 (Pale Blue Dot Energy - Axis Well Technology, 2015). This has been further refined and developed with customised elements for each storage site. These are described in this report and have been independently peer reviewed.

Finally the BGS have been commissioned to deliver a review of CO_2 Storage appraisal lessons learned from previous studies and an assessment of how these may be applied to the for appraisal of the Portfolio Inventory.

The project is well placed to achieve the Value Objective and Project Objectives.

2.0 Objectives

The primary objective for this project is to identify and materially progress the appraisal of five high potential CO_2 Storage sites on a path towards FID readiness. The desired outcome is the delivery of a mature set of high quality CO_2 Storage options for the developers of major power and industrial CCS projects to access in the future. The work will add significantly to the de-risking of these five stores and will be available to storage developers as a basis for them to commission the more capital intensive parts of storage site appraisal.

The focus of this work package 4 (WP4) is to select a Portfolio Inventory of five final storage sites on the UKCS from a Select Inventory of twenty. This "Twenty to Five" down-selection follows a process of due diligence on key data obtained from the CO2Stored database using independent sources of information wherever possible. This due diligence step was followed by a portfolio creation, scoring and ranking step. The portfolio aspects of this project are not covered by the range of best practice guidelines currently available to the industry, since these are generally focused upon the development of a single site. The ranking of the different portfolios was based upon a portfolio score which encompassed:-

1. The collective due diligence performance of each site in the portfolio.
2. The ability of the portfolio to service the requirements of the ETI build out scenarios in terms of geography, timing of availability and build out rates.
3. The ability of the portfolio to manage risk through portfolio diversity to minimize the impact of critical failure risk factors at this early stage in the industry.

Further details of the overall methodology and approach to this challenge are described in the D01 - Screening Methodology report (Pale Blue Dot Energy - Axis Well Technology, 2015). Minor aspects of this approach have been refined and are detailed here but the general method remains the same.

The scope of work for this WP4 has been divided into the following five tasks:-

1. Complete due diligence checks on each of twenty potential storage sites from the Select Inventory. These are accompanied by Storage Site Summary Sheets.
2. Execute the portfolio creation and assessment methodology.
3. Complete a report of the portfolio selection process and the results.
4. Review lessons learned from other projects and highlight those specifically relevant to the five selected sites.
5. Present the results and test the outcomes with external stakeholders and present.

This report documents the process and results of this WP4 down select.

3.0 Methodology

Approach

The Purpose of Work Package 4 (WP4) is to deliver a final down selected portfolio of five viable CO_2 Storage sites that are capable of being materially progressed within WP5 from the short list of twenty sites delivered by WP3. The workflow followed is illustrated in Figure 1.

It is anticipated that at least one of the five down-selected sites will be capable of progressing through towards the end of the appraisal stage by the end of the project or shortly thereafter. As such, it is expected that one or more of the five sites will be suitable to serve an early Phase 2 CCS project (FID ~ 2020). It is also anticipated that at least one other site will be a substantial new storage play aimed at much later FID in the late 2020s.

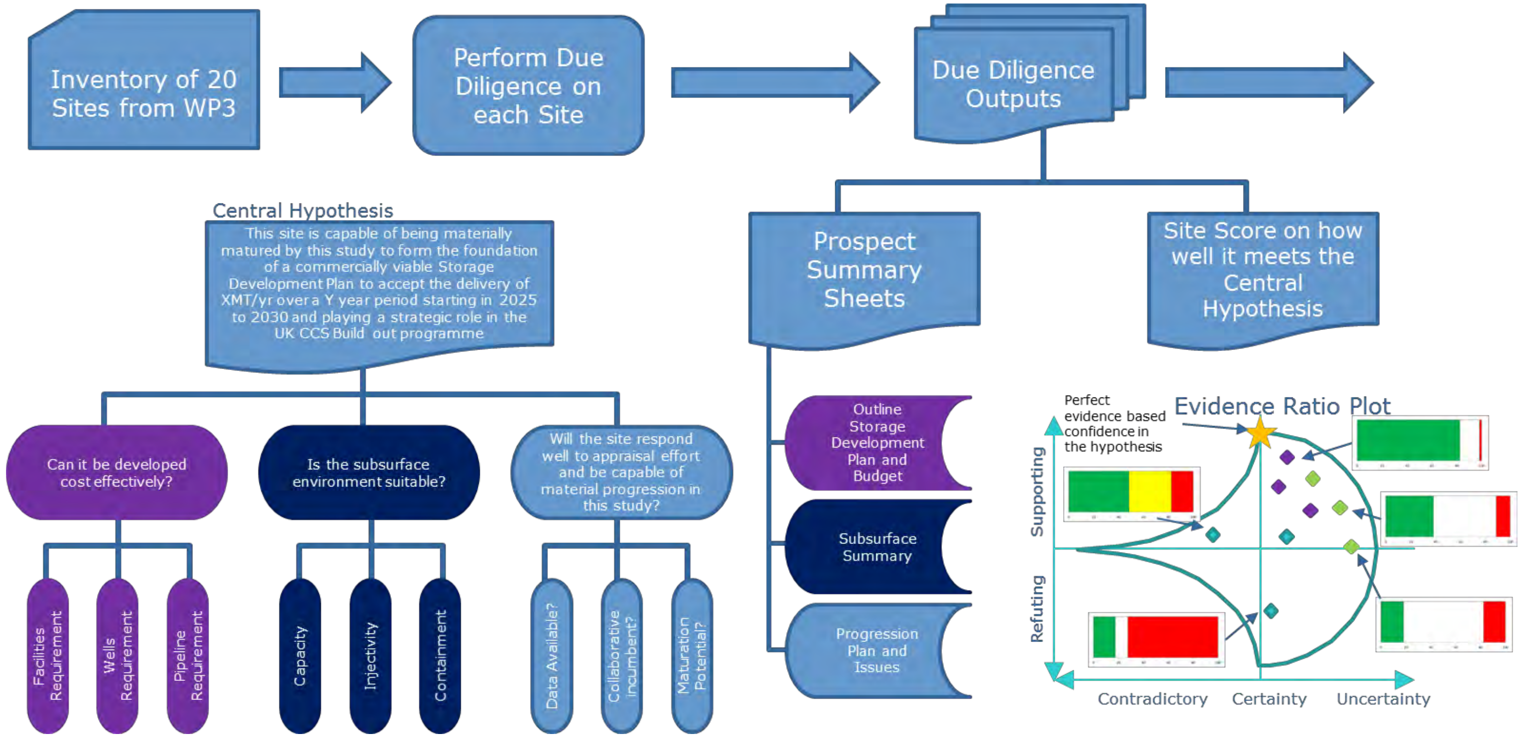

Figure 1 - WP4 "Twenty to Five" Methodology

At the end of WP3, the project had generated a well-qualified portfolio of twenty potential CO_2 storage sites, all aligned with the project objectives (Pale Blue Dot Energy - Axis Well Technology, 2015). Even with this reduced number of sites, it is impractical to seek significant new insight through original work at this stage. Instead, an evidenced based approach to site due diligence has been applied. This rigorously qualifies each site with respect to the hard evidence available. Such evidence will either support or refute the ability of the site to meet the CO_2 Storage role asked of it.

The WP4 down select process has two key steps.

1. Due Diligence - The twenty sites (Select Inventory) are subject to individual due diligence review and the storage site attributes updated as appropriate.
2. Portfolio Creation, Assessment and Ranking - Portfolio selections comprising five sites from the twenty candidates are generated and scored before selecting and recommending a final portfolio of five sites to progress to WP5 which together should meet the project objectives.

WP4 has been divided into 5 tasks culminating in this WP4 Report (D05), a key Stakeholder Workshop (R04) and Stage Gate Review 1 (R05). It has delivered the final recommendation on the five sites (plus reserve sites) to progress to detailed appraisal in WP5. In detail the methodology included:-

WP4.T1 - Complete due diligence checks on each of twenty potential storage sites. Due diligence process on the key attributes developed in WP3 was achieved through the access to representative well and seismic data. The results were compiled into storage site summary sheets (D06) and results in a due diligence score for each site.

WP4.T2 - Execute the portfolio creation and assessment methodology. The resulting recommended portfolio was tested with independent peer review, stakeholder review and expert judgement to ensure that the sites selected are robust and fully qualified members. "Near miss" sites will be captured and held in reserve. There was a specific Stakeholder Workshop (R04) held on 29th July 2015 at which the down select process and results were presented and scrutinised by a team of CO2 Storage professionals. Stakeholder comments to the recommended selection were captured to ensure that the final portfolio meets general industry expectations. The workshop report is included as Appendix 1.

WP4.T3 - Complete a report of the portfolio selection process and the results in this WP4 Report (D05).

WP4.T4 – Review lessons learned from other projects and highlight those specifically relevant to the five selected storage sites. BGS were commissioned to deliver a short review and draw lessons learned from a wide range of relevant industry projects. The focus was on drawing out lessons learned relevant to the maturation of the sites in the recommended Portfolio Inventory. The BGS report is included in Appendix 4. Finally, work programmes for each selected site together with a stated objective of what uncertainty reduction such work programme will try to achieve have been developed and tested with external experts from the Scottish Carbon Capture and Storage group (SCCS) and industry. The work programmes are presented in Section 6.1 of this report. This has served to refine the WP5 plan and deliver a bespoke work programme for each selected site.

WP4.T5 – The down-select programme and results were presented to stakeholders to test and gain approval of the five site Portfolio Inventory for

WP5. Finally the results from WP1 through to WP4 were presented to the ETI CCS Advisory board at Stage Gate Review (R05) for formal approval.

Evidence Based Approach

An evidence based approach to the due diligence of each potential storage site has tested the following central hypothesis for each storage site in the Select Inventory.

Primary Hypothesis

This site is capable of being materially matured by this study to form the foundation of a cost effective and viable Storage Development Plan to accept the delivery of between 3 and 10 MT/yr over a minimum 15 year period starting between 2025 and 2030 and thus playing a strategic role in the UK CCS build-out programme.

The hypothesis will be broken down into three key areas of consideration:

Subsurface Environment

Does the site have appropriate blend of capacity, injectivity and containment properties that give confidence that the site can meet the primary hypothesis?

Development Potential

Does the site have a potentially important role in the build-out programme of UK CCS infrastructure and can it be developed in a cost effective manner such that the pipeline, facilities, and wells capex requirements together with anticipated opex provide confidence that the site can meet the primary hypothesis?

Appraisal Response

Does the site have the right combination of data availability (type, quality and quantity), uncertainty reduction potential and Operator collaboration or support (from whichever domain oil & gas, offshore wind, sand & gravel etc.) to materially progress the appraisal status of the site in this project, given the time and budgetary constraints.

An evidence based approach was used to test each site against each hypothesis. This due diligence step will capture a consistent and clear understanding of the existing key attributes of each store candidate including:

Subsurface Environment

An outline subsurface description will be captured from existing sources. Subsurface structural configuration, reservoir quality review and potential injection well performance including risk of geochemical sensitivity will be considered.

Initial dynamic capacity review potentially including a material balance overview of the storage site.

Review of intra reservoir connectivity and medium to long term injection well performance, reservoir pressure, aquifer connectivity and injectivity. Review of caprock resilience and evidence for containment and integrity from both a geological (seal) and engineering (wells) perspective. Each site was tested against the following hypotheses:-

Capacity: The site has appropriate capacity to give confidence that it can meet the primary hypothesis and make a material contribution to a portfolio of site capacity towards 1500MT.

Injectivity: The site has appropriate injectivity of >= 1MT/yr per well giving confidence that it can meet the primary hypothesis and be fully capable to injecting CO_2 volumes at a rate of between 3 and 10MT/yr on a long term basis.

Containment: The site has appropriate containment properties to ensure that the inventory of injected CO_2 remains within the storage complex indefinitely giving confidence that the site can meet the primary hypothesis.

Monitoring: It is fully anticipated that the site will respond well to appropriate monitoring programme to meet all the requirements of the EU CCS Directive and enable full operational and post closure monitoring of the injected CO_2 inventory giving confidence that the site can meet the primary hypothesis.

Development Potential - can it be developed cost effectively?

This is a review of commercial factors likely to influence time and cost to FID including interaction with competing subsurface users, decommissioning timetables and practicality of transport connections to CO_2 sources.

As assessment of the cost of storage at the site will be made together with the potential role that each site might play within the ETI CCS Scenarios to ensure it has a strategic fit with the Project Objectives.

Scenario: Does the site have a potentially important role in the build out programme of UK CCS infrastructure providing confidence that the site can meet the primary hypothesis?

Pipeline: The site has a cost effective pipeline option which provides confidence that the site can meet the primary hypothesis.

Facilities: The site has a cost effective option for offshore facilities which provides confidence that the site can meet the primary hypothesis.

Wells: The site has a cost effective option for injection wells which provides confidence that the site can meet the primary hypothesis.

Appraisal Response - will the site respond to appraisal effort and be capable of material progression in this study?

The initial status of the maturity of the site characterisation for each site was made. This included any pre-existing CO_2 storage studies which were available together with a consideration of how the maturity of the site could be developed through WP5. This delivered a view of the maturity improvement potential. A key input here is the availability of detailed well history and status of well integrity and the willingness of any incumbent petroleum operator to collaborate and share information into the Project.

Data: The site has the right combination of data availability (type, quality and quantity) to materially progress the appraisal status of the site in this project given the time, and budgetary constraints.

Users: This site has sufficient Operator collaboration or support (from whichever domain oil & gas, offshore wind, sand & gravel etc.) to materially progress the appraisal status of the site in this project given the time, and budgetary constraints.

Potential: The site has significant uncertainty reduction potential which if addressed could materially progress the appraisal status of the site in this project given the time, and budgetary constraints available.

Evidence Ratio Plots

The evidence ratio plots are used to capture the results of the due diligence considerations against the primary hypothesis. The evidence ratio plots are kite shaped diagrams with two axes. The vertical axis describes whether the evidence for the site is mostly supporting (green) or mostly refuting (red). Those due diligence elements with mostly supporting evidence will plot in the top half of the diagram.

The horizontal axis describes the evidence base. Here, uncertainty is characterised by white space on the flags and elements with uncertainty will plot on the right hand side of the diagram. Where evidence is conflicting then this is represented by the yellow flags and the element will plot on the left hand side of the diagram.

The star located at the apex of the plot represents perfect combination of supporting evidence and confidence. Points closest to this apex have performed best in the due diligence.

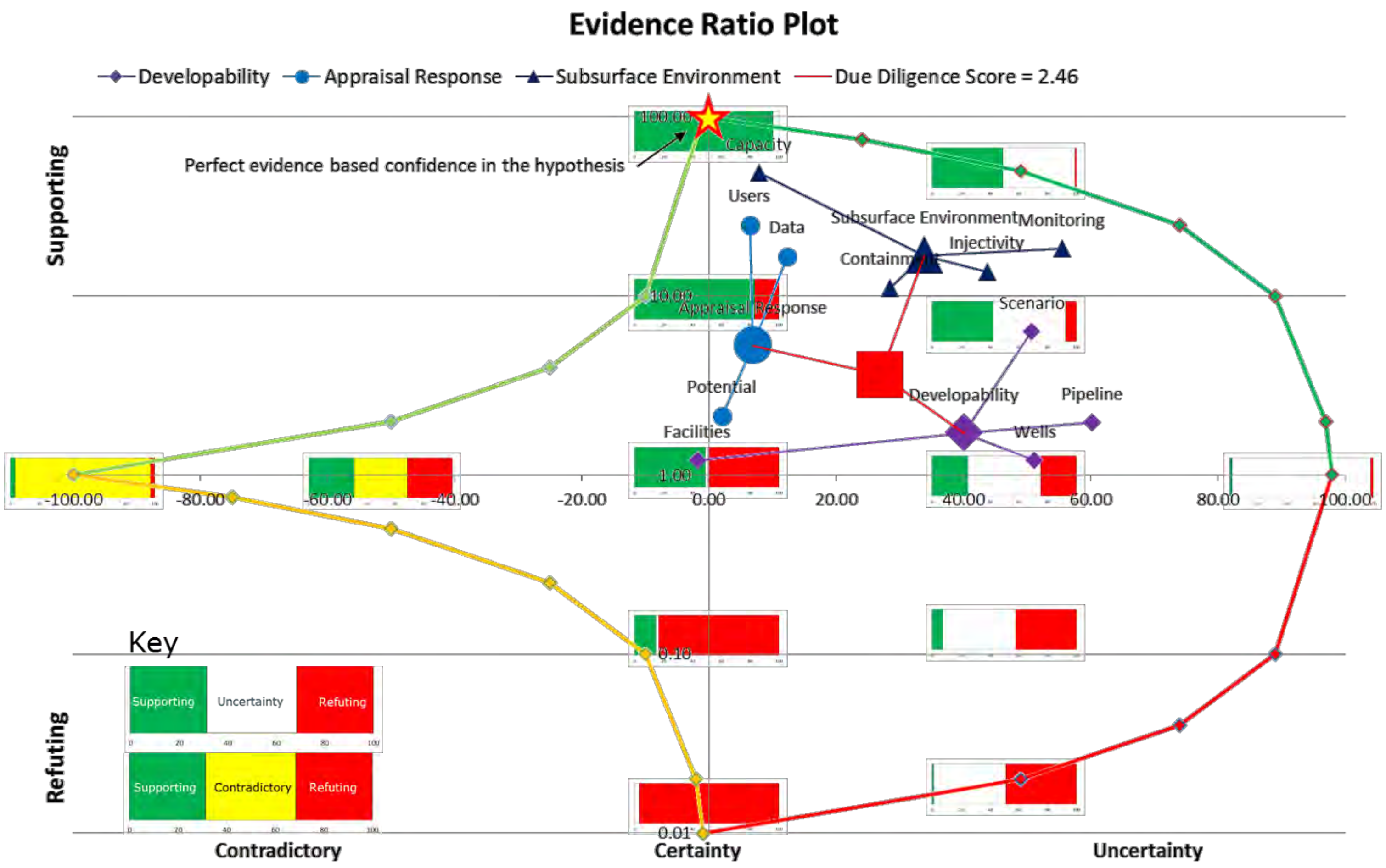

Figure 2 - Example of Evidence Ratio Plot

Each site was considered carefully with respect to how this project could materially progress the maturity of the site on its path to its development of final investment decision. The "Ability to Progress" was carefully considered against a simple " CO_2 Storage Site maturity scale" Table 1.

Level	Description
0	No consideration of CCS at all
1	Initial screening – theoretical capacity available (UKSAP)
2	Concept Model [Zero dimensional model of the container]
3	Scoping Model: basic concept [Full project model static & dynamic model] - without dynamic calibration
4	Feasibility Model: basic concept [Full project model static & dynamic model] - with dynamic calibration
5	FEED Grade Studies
6	Storage Development Plan

Table 1 - Simple CO_2 Storage Site Maturity Scale

An assessment of the current maturity was made for each site and a view developed of how far that maturity might be progressed within this project given the data, time, budget and commercial constraints in place. This resulted in an "Ability to Progress" factor which was subsequently also used in the portfolio ranking.

A narrative summarise the key aspects of each site is provided in Appendix 2. Appendix 5 contains D05 - Store Summary Sheets in poster form. These document the key aspects of each site and its evidence base in a consistent manner.

This due diligence process was used to deliver an overall score for each site regarding how well the site meets the primary hypothesis, as illustrated in Figure 2. This is the plot distance of the site due diligence findings (Red Square) from the ideal solution where there is perfect evidence based confidence in the central hypothesis (Yellow Star). This score was also used in the subsequent portfolio selection.

There were no sites that performed so poorly that they required substitution by a reserve site from the list delivered by WP3 (Pale Blue Dot Energy - Axis Well Technology, 2015).

Due Diligence Methodology

The key criteria used in the WP3 site screening and ranking were subject to careful due diligence using source data wherever possible to validate the position of the site in the Select Inventory. The due diligence process specifically examined Capacity, Injectivity and Containment.

Capacity validation - Saline Aquifers

For saline aquifers this was calculated as the accessible pore volume of the store multiplied by the storage efficiency and then converted to a mass unit using the density of CO_2 at an appropriate pressure.

$$M_{CO2} = Seff*GRV*NG*Ø*\rho_{CO2}$$

Where

MCO2: Theoretical Capacity

Seff: Storage Efficiency Factor

GRV: Gross Rock Volume

NG: Net to Gross

Ø: Porosity

pCO2: Density of CO_2

The due diligence involved a re-calculation and validation of static capacity for each of the twenty stores. The data used consisted of 3D seismic from the SNS and CNS PGS Mega-survey in a Petrel project, 2D seismic over the East Irish Sea (EIS) sites down loaded from CDA and imported into Petrel workstation project, well data down loaded from CDA and published literature.

The following steps were carried out:

- For each storage site a minimum of 2 wells were loaded to the Petrel project together with checkshots, deviation data and well tops taken from composite logs and well reports.
- A quick-look interpretation of key seismic horizons was completed and checked against the well ties. Edits were made as required.
- The 3D seismic volume was reviewed to check, fault density, fault throw and fault extents.
- Two Way Time (TWT) structure maps of the horizon near to the top of the target storage reservoir were produced for each site.
- A simple depth conversion model was designed to convert TWT structure map into an initial depth structure map.
- Well data was used to generate a simple isochore (vertical thickness) map of the storage reservoir. This was added to the top reservoir depth surface to give a base reservoir surface.
- A simple 3D grid was built in Petrel using the Top and Base reservoir depth surfaces and a gross rock volume (GRV) was calculated. Where a structural trap was being considered, an appropriate closing contour of the structural spill point was used.
- Porosity and Net to Gross (NG) average reservoir parameters are determined from the following in order of preference:
    - Conventional Core analysis from wells that penetrate the storage site.
    - Conventional Core analysis from nearby/analogue wells/fields
- Published literature from nearby analogues.
- Pore Volume and Theoretical Storage Capacity was calculated and compared with that held for the site in CO2Stored.

Note that the same storage efficiency factors were used as held in CO2Stored. These range from over 15% in structural closures to around 0.6% on open aquifers. These were derived from exemplar dynamic models which have not been validated as part of WP4 (Energy Technologies Institue, 2011). These factors will be re-evaluated for the five final sites using the dynamic modelling and will be an output of WP5.

Capacity Validation - Hydrocarbon Fields

For hydrocarbon fields the storage capacity calculation method from CO2Stored was adopted. This method links capacity to the net volume of fluids withdrawn during hydrocarbon exploitation. CO2Stored used production data up to 2010 to calculate this. The validation check in WP4 used updated production data to February 2015 from DECC for each site.

The due diligence involves a recalculation of the capacity equivalent to the net reservoir volume of fluids removed at February 2015, for each site. In addition, the net reservoir volume of fluids removed up to the projected end of field life at Cessation of Production (COP) was estimated and the capacity calculated at this time to confirm the full capacity estimate. Surface production and injection volumes were converted to reservoir fluid volumes using shrinkage factors sourced from public domain material, where available. The shrinkage factors applied in CO2Stored were checked as part of the due diligence.

This methodology is specifically simplified and does not account for the effect of ingress or egress of aquifer water into or from the producing reservoir. To do this rigorously requires access to dynamic pressure data which is held by operators and not generally available from national archives. The CO2Stored methodology as prescribed is considered a useful and consistent approach at this stage. It may result in an underestimation of capacity.

Injectivity Validation

The permeability thickness product (KH) was used as an injectivity indicator for the selection criteria in WP3. For each storage site an estimate of the KH has been calculated based upon the net thickness and an average permeability of the reservoir zones.

KH (mDm) = Gross Thickness (m) * NG * K

Gross Thickness = Average gross thickness of storage site (calculated using simple isochore used for capacity validation).

NG = Net to gross (same average as capacity validation).

K = Average permeability (estimated from conventional core analysis and published literature for field or analogue field).

Further additional checks on injectivity were carried out for each site:-

- For hydrocarbon sites the initial oil or gas production performance of early wells were converted to an equivalent CO_2 injection rate using some simple assumptions in order to gain some confidence that that the target injection rate of 1MT/year/well could be met.
- For all sites a simple dynamic model was built to investigate the impact on initial CO_2 injectivity with pressure changes in the subsurface store. This was particularly important for understanding changing injectivity with pressure / time in depleted gas reservoirs, where it was assumed that CO_2 would be injected in the gas phase. Each model was set up with a notional 5 well development scenario for comparison purposes.

Containment Validation

The containment risk is one of the most important parameters used for the selection criteria in WP3. Two aspects of containment risk were considered, the geological risk and the engineering risk. The due diligence methodology for each is outlined below.

Geo Containment Risk

The geo containment risk comprises the 6 main factors within CO2Stored that relate to fault characterisation and seal characterisation. The following steps were followed:

- The 3D seismic volume was “scanned through” to check for fault density, fault throw and fault extents.
- Independent quickl-ook interpreted horizons were used to produce a view of the continuity and thickness of the primary seal and any thinning and pinch outs of the seal were investigated.

The geo containment risk factor developed in WP3 was recalculated and compared with that derived from CO2Stored values with any changes being noted.

Geo Containment Risk	code	Fault Characterisation			Seal Characterisation			Georisk Factor
		Density	Throw & Fault Seal	Fault Verical Extent	Fracture Pressure Capacity	Seal Chemical Reactivity	Seal Degradation	
Bunter Closure 40	139.002	1	1	1	1	1	1	6
		1	1	1	1	1	1	6
Barque gas field	141.002	3	2	1	1	1	1	9
		3	2	1	1	1	1	9
		low = 1		medium = 2		high = 3		
		1	from CO2Stored data					
		1	from Due Diligence					

Table 2 – Example Calculation of Geo Containment Risk

Engineering Containment Risk

In WP3, a proxy for the engineering containment risk was developed using the density of legacy wells per square km. The well count and mid case storage site areas were derived from the CO2Stored database. Engineered containment risk is the risk that man-made reservoir penetrations at wells may leak, resulting in a loss of CO_2 from the CO_2 Storage complex. This depends on several factors, most of which are well specific. Risk, in this case, is considered to be the probability of a leak occurring. The quantification of the leakage (volume of CO_2 likely to be released) is not considered at this stage, but has been fully described in a 2012 report for DECC (Jewell & Senior, 2012) .Two main conclusions from this report have been used as input assumptions to the current risk review.

1. The range of leak risk from abandoned wells is 0.0012 to 0.005 (0.12% to 0.5%) in a 100 year period depending on age / type of abandonment.
2. The leak risk is higher for abandoned wells where the storage target is above the well target (hydrocarbon reservoir) due to less attention being paid to non-hydrocarbon bearing formations.

For the purposes of this due diligence review, the following assumptions were also made:

- The risk of leakage depends on the year of abandonment and the prevailing abandonment policies at the time.
- Wells completed to a total depth (TD) above the storage reservoir target depth pose no risk of primary leakage.
- Sidetracks below storage reservoir depth do not add further leakage risk.
- Currently active wells (producing / injecting) and suspended wells will be abandoned at the end of field life.

- Where projected cessation of production (COP) is estimated to be between 2015 and 2025, then abandonment practices will follow current recommendations.
- For COP after 2025, it is likely that storage sites will be identified and acquired and that abandonment practices will be modified to suit CO_2 storage sites, resulting in a negligible risk of leakage.
- Finally, it was assumed that the leak risk from new purpose drilled CO_2 development injection wells is the same for all sites and is negligible and has been ignored in this review.

The number of wells in each vintage of abandonment was determined by a review of the CDA database. Wells were selected from this database by field names. However, where the well count differed significantly from those in the CO2Stored database, the wells were selected by use of a search polygon in CDA. The results are summarised in Table 3. Storage target depth was taken from the CO2Stored database, with well depth from the CDA database.

A risk factor (in the range of 0.0012 to 0.005) was then assigned to each category of well abandonment, using the result of a review of UK well abandonment practices and policies. An extract of this review is provided in Table 3, the full table is provided in Appendix 5. This review led to the conclusion that well abandonment practices have improved and become more rigorous over time. This results in the current practices for wells abandoned in the reservoir having the lowest risk (0.0012). All earlier abandonment practices, and those where wells have been completed below the storage reservoir target have relatively less rigorous practices. As a consequence, a well abandoned prior to 1986 (when API guidelines were first published) where the well is targeted at a reservoir below the storage reservoir has the highest risk (0.005). These risks were then summed to give a total engineering leakage risk for the storage target.

However, as there is only a risk of CO_2 leakage from a well if the CO_2 plume encounters the well, an additional factor had to be considered. As the risk of leakage decreases with the distance of the injection wells from the abandoned wells, all risk have been multiplied by a well density factor (number of wells divided by storage area). The storage area was taken from the CO2Stored database where available. These were then checked by importing the DECC field outlines (as shape files) and the CO2Stored saline aquifer site outlines (as shape files) into Petrel and using Petrel to calculate the area of each site outline. This is a relatively simple metric, as the well density will sometimes vary considerably across the larger (in terms of area) storage sites, and injection wells can be located where well count is sparse. The final engineering containment risk is therefore the product of total storage target leakage risk by the well density factor.

ID	REF (Issue 4)	Hazard/ Risk	Hazard Effect	API RP 57	OIL AND GAS UK GUIDELINES FOR THE SUSPENSION AND ABANDONMENT OF WELLS					Comments
				Abandonment Date						
				1986 - 1994	1994 - 2001	2001 - 2005	2005 - 2009	2009 - 2012	post 2012	
				n/a	Issue 1	Issue 1	Issue 2	Issue 3	Issue 4	
1	3	Cement barrier (plug) material inadequately specified.	Leak through cement due to C02 corrosion.	Not detailed.	No specifications or characteristics for cement materials.	General cement material specification and guidelines.	General cement material specification and guidelines.	General cement material specification and guidelines.	Separate guidelines on cement materials - very specific.	Main characteristics: very low permeability, long term integrity, non shrinking, ductile-non brittle, able to bond to casing/formation.
2	3	Slumping of cement plug.	Leak through cement plug channels.	No reference to slumping but option to use bridge plug to support cement.	No reference of support to prevent slumping of cement.	No reference of support to prevent slumping of cement.	No reference of support to prevent slumping of cement.	Recommend bridge plug or pill to support cement.	Recommend bridge plug or pill to support cement.	A support, (i.e. bridge plug or viscous pill) to prevent slumping of the cement slurry is recommended for all cement plugs.
3	4	Insufficient number of barriers to isolate permeable zone.	Leak up wellbore.	Two barriers	Two barriers	Two barriers	Two barriers	Two barriers	Two barriers	Two permanent barrier for hydrocarbon zones. One barrier for water bearing zone.
4	4	Multi zones not isolated from each other.	Crossflow.	One barrier with perfs cemented off and isolated with 100ft above and 100ft below zone.	One barrier	One barrier	One barrier	One barrier	One barrier	One permanent barrier required to isolate distinct permeable zones.
5	5.1	Cement plug(s) out of position.	Leak into casing or annulus.	Cement Plug to be set across perforations and to extend 100 ft min above zone.	Plug to be set across or above the highest point of potential inflow or as close as possible.	Plug to be set across or above the highest point of potential inflow or as close as possible.	Plug to be set across or above the highest point of potential inflow or as close as possible.	Plug to be set across or above the highest point of potential inflow or as close as possible.	Plug to be set across or above the highest point of potential inflow or as close as possible.	Cement plug should be lapped by annular cement if set inside casing or liner.

Table 3 - Summary of UK Well Abandonment practices and policies

Portfolio Creation and Assessment

The second step in the WP4 methodology involves portfolio creation and assessment and is illustrated in Figure 3. Here, a large set of portfolios of five sites have been drawn from the twenty sites in the Select Inventory that pass due diligence. This represents just over 15500 combinations. Each portfolio is then assessed as a package. The portfolio assessment looks at three key elements:-

1. Site Combination Score - A summation of the site due diligence performance.
2. ETI Scenario Score - a measure of how well the portfolio matches the key requirements of the ETI CCS build out scenarios including:
    a. Does the portfolio build out from the two competition projects?
    b. Does the portfolio facilitate EOR development through its transport and / or storage infrastructure?
    c. Does the portfolio service all the key industrial clusters including the Central Belt of Scotland, Teesside, Humber, Thames and Mersey areas?
3. Portfolio Risk Score - a measure to ensure that future project risks are managed by minimising the dependency of the portfolio on single risk factors.
    d. Does the portfolio set out to appraise and develop a range of different geological formations as storage sites to minimise the probability of single point of failure risk?
    e. Does the portfolio include a range of store types from hydraulically closed stores to open stores with and without structures and saline aquifers as well as depleted hydrocarbon fields?
    f. Does the portfolio include a range of sites that are data rich and have the potential to reach FID readiness before 2025 as well as stores in which further invasive appraisal is required such that they will not be ready for FID until 2030?
    g. Does the portfolio offer upside appraisal opportunities to quickly mature further potential sites perhaps through a low cost slipstream injection programme?

Finally the scores for these three elements were summed and multiplied by the "ability to progress" the sites in the portfolio to generate a final portfolio score.

Using this approach each portfolio was scored and ranked in order of their final portfolio score. The robustness of these rankings and of the best scoring portfolios in particular was tested through stakeholder review and expert judgement to ensure that the final portfolio selection was both robust and clear. This focussed upon ensuring that the most appropriate five sites are taken through for consideration in WP5.

A final recommendation on which five sites to progress to detailed review in WP5 is presented in Section 6 of this report. This is accompanied by a development build out scenario for the recommended Portfolio Inventory and a series of bespoke work programme plans for WP5.

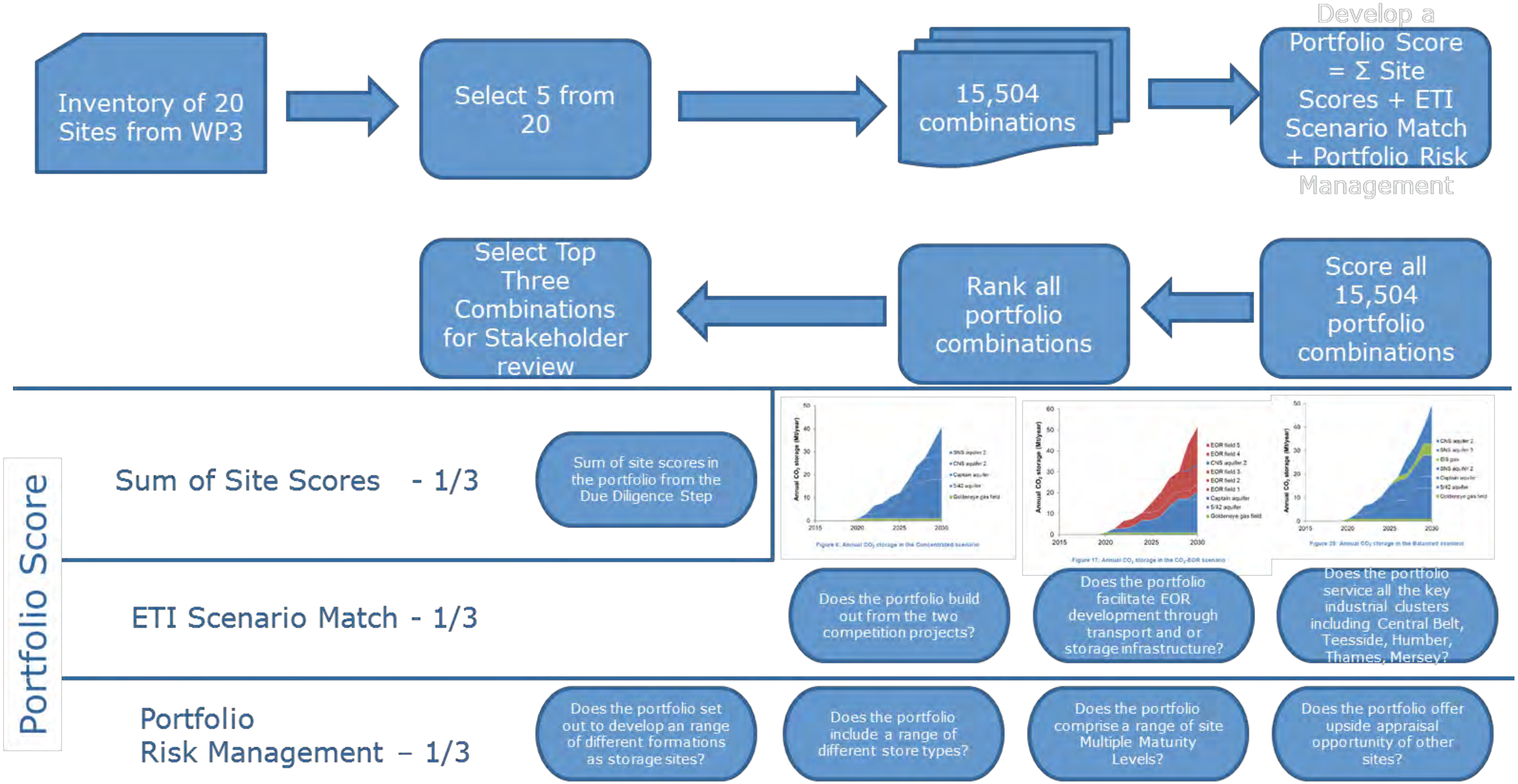

Figure 3 - WP4 - Methodology - Portfolio Creation and Assessment

Development Cost Factors

In order to start to consider and assess whether the sites from the Select Inventory can be developed cost effectively, initial cost assessments have been considered for each site as part of the due diligence process. This specifically involves a high level development concept for the transportation system, offshore facilities and injection well package. The process for these cost assessments is outlined here.

High level well design and cost estimation

In order to determine an initial well design, two primary constraints were considered:

1. Length of sand face exposure required to achieve injectivity targets
2. Reservoir depth

Given that the storage sites have been selected on a minimum permeability criteria, there was no surprise that all 20 sites were initially seen to achieve the injectivity target of 5MT/yr from 5 wells (1MT/yr per well). The key variables are the length of sand face and the injection pressure required to achieve this target. For this stage and to keep things relatively simple, it was decided to fix the length of sandface at 150m (~500ft) and consider if the injection pressure (dp) was reasonable. In Table 4 below, the injection pressure for a range of formation permeabilities and reservoir thicknesses has been calculated (assuming dense phase injection and fixed temperature/pressure) for 1MT/year.

This review suggests that a 150m sandface is suitable for most likely reservoir conditions, but also identifies the reservoirs that have a higher associated risk (coloured amber and red). Where low permeabilities are encountered, longer reservoir sections may have to be drilled, suggesting that a horizontal (or near horizontal) reservoir section would be preferred. However, due to reservoir depth and limits on the rate that well inclination can be developed (build angle), this is not feasible for all targets (see zero tangent length in Table 5). Build angle has been limited to 5 deg/100ft to allow for the installation large completion sizes (5-1/2” to 7” tubulars).

The ability to drill new wells in low pressure (depleted) reservoirs, particularly at a high angle, is also a concern due to potential wellbore stability issues. This may limit the achievable deviation in some reservoir sections. This high level review has not considered this factor further at this time, but it is likely to represent a well cost escalation factor in order to achieve a suitable engineering solution.

While 150m sand face may be considered to be longer than required for a number of sites, the extra length provides redundancy should reservoir properties deteriorate during the injection phase. It is envisaged that only the required section of this sand face will be open for injection initially (all wells currently assumed to be cemented and perforated), allowing for additional perforations as required.

It should be noted that improvements in drilling technology are happening continuously and so no challenging targets should be discounted on this basis at this stage.

	Average Gross Thickness (m)	Storage Form. Permeability (mD)	Injection Pressure (psi)
Barque gas field	229	50	60
Bruce Gas Condensate Field			
Bunter Closure 3	239	100	30
Bunter Closure 36	221	50	60
Bunter Closure 40	227	100	30
Bunter Closure 9	334	100	29
Captain Oil Field			
Captain_013_17	61	7000	1
Coracle_012_20	84	4500	1
Forties 5	98	194	17
Grid Sandstone Member	175	3500	1
Hamilton gas field	226	778	4
Harding Central oil field	72	10000	1
Hewett gas field	41	500	9
Hewett gas field (Bunter)			
Maureen 1	55	200	13
Mey 1	114	429	8
North Morecambe gas field	1219	90	31
South Morecambe gas field	605	150	19
Viking gas fields	167	50	61

Table 4 - Injection Pressures required to achieve 1MT/yr per well

Name	Water Depth (m)	Reservoir Depth (mTVD)	Extra TVD for Tangent (m) - 1175m needed to get horiz.	Tangent Length (m) - hold at 60deg	Drilled Depth (m) - inc data from Step out calc_ETI.xls	Rig Type
Barque Gas Field	30	2559	1384	2768	4218	JU 1
Bruce Gas Condi Field	116	4000	2825	5650	7100	Semi
Bunter Closure 3	20	1387	212	424	1874	JU 1
Bunter Closure 36	75	1557	382	764	2214	JU 2
Bunter Closure 40	40	1689	514	1028	2478	JU1
Bunter Closure 9	10	1006	-169	0	1250	JU 1
Captain Oil Field	105	1110	-65	0	1300	Semi
Captain_013_17	95	1110	-65	0	1300	Semi
Coracle_012_20	99	941	-234	0	1200	Semi
Forties 5	80	2286	1111	2222	3672	JU 2
Grid Sandstone	90	1249	74	148	1598	JU 2
Hamilton Gas Field	25	744	-431	0	850	JU 1
Harding Central Oil Field	110	1684	509	1018	2468	Semi
Hewett Gas Field	30	1298	123	246	1696	JU 1
Hewett Gas Field (Bunter)	30	1146	-29	0	1300	JU 1
Maureen 1	80	1797	622	1244	2694	JU 2
Mey 1	70	2145	970	1940	3390	JU 2
North Morecambe	25	1070	-105	0	1250	JU 1
South Morecambe	25	902	-273	0	1200	JU 1
Viking Gas Fields	20	2714	1539	3078	4528	JU 1

Table 5 - Well Design Summary and Required Drilling Rig Type

Where shallow depth is not a limiting factor, the preference is to step the well out to a reasonable degree (cost being a consideration here) for reservoir coverage, well separation and the desire to remove the injection point laterally from the cap rock penetration point in order to reduce the direct impact of the CO_2 plume at this location. The step out is limited by kick-off point (assumed to be a standard 500m in all cases, but subject to technical review) and hole angle (limited to the generally accepted wireline access angle of 60deg). The resultant well lengths have been used as input to the well costing exercise. Water depths have been used to constrain the type of drilling rig unit.

For simplicity in well costing, rig rates of the day were taken from www.rigzone.com. Spread rates, including logistics, shore based overheads, drilling, completion and rig services were assumed to be fixed at $264,000 per day (exchange rate of $1.5/£ used) for all operations. This could be further refined, depending on distance to shore, but at this stage an allowance of 30% has been incorporated to costs. This 30% includes engineering time and support. Tangible costs include all well construction items up to and including the christmas tree. All costs were based on platform wells (dry trees), but a 20% uplift per well was applied to Central North Sea developments where subsea wells are assumed. A further 'per well' uplift of £5m was applied to developments where a phase change in injected CO_2 from dense phase (in the delivery system) to gas phase might be expected during early field life (depleted gas fields). This uplift is based on the cost of adding an engineered means of managing the phase change. Material assumptions were 13%Cr for all CO_2 wetted surfaces. A further 25% margin should be assumed for any budgetary costings for all projects, and costs projected to the future at an appropriate rate of inflation.

Name	Region	Well Time (days excl rig move)	5 Well Campaign Time (days incl rig move)	Single Well cost (£m)	Single Well Cost +30% contingency (£m)	5 Well Campaign Cost (£m incl rig mob/demob)
Barque Gas Field	SNS	83	419	31.2	40.6	204
Bruce Gas Condi Field	CNS	133	669	75.0	97.6	490
Bunter Closure 3	SNS	44	224	15.5	20.2	102
Bunter Closure 36	SNS	49	249	18.9	24.6	124
Bunter Closure 40	SNS	54	274	18.3	23.8	120
Bunter Closure 9	SNS	32	164	12.3	16.1	82
Captain Oil Field	CNS	33	169	21.6	28.1	142
Captain_013_17	CNS	33	169	21.6	28.1	142
Coracle_012_20	CNS	31	159	20.8	27.0	137
Forties 5	CNS	74	374	33.1	43.1	216
Grid Sandstone	CNS	39	199	19.4	25.2	127
Hamilton Gas Field	EIS	25	129	15.7	20.4	103
Harding Central Oilfield	CNS	55	279	32.7	42.5	215
Hewett Gas Field	SNS	40	204	19.8	25.7	130
Hewett Gas Field (Bunter)	SNS	33	169	17.6	22.8	115
Maureen 1	CNS	58	294	26.5	34.4	173
Mey 1	CNS	70	354	30.8	40.0	201
North Morecambe	EIS	32	164	17.3	22.6	114
South Morecambe	EIS	31	159	17.1	22.3	112
Viking Gas Fields	SNS	90	454	33.2	43.2	217

Table 6 - Well Cost Summary

High level transportation and facilities design and cost estimation

The assumptions and methodology for the estimation of high level costs for the transportation and facilities are included in the report by Costain in Appendix 3.

Data Sources

The data sources for this WP4 programme have included all of the sources used for WP3 plus some additional sources. WP3 was built upon the content of the CO2Stored database and its 574 identified offshore storage units around the UKCS (Energy Technologies Institute, 2010). This was supplemented by up to date cumulative production figures to February 2015 from DECC (DECC - UK Government, 2015) and also 2015 estimates of Cessation of Production from Wood Mackenzie (Pale Blue Dot Energy - Axis Well Technology, 2015). Further published information from journals, books and atlas documents were also available, as well as the FEED deliverables from the UKCCS demonstration programmes where these have been published. A full inventory of data sources for WP3 (the Down-Select phase) is included in the D04 – Initial Screening and Down-Select report (Pale Blue Dot Energy - Axis Well Technology, 2015).

In WP4 (the Due Diligence and Portfolio Selection phase) new specific sources of information were introduced.

PGS 3D Mega Survey

This included access to the PGS Southern and Central North Sea 3D seismic Mega-survey, which provided 3D seismic coverage across the major part of the Select Inventory. This was used to develop quick look time and depth interpretations so that rock volume inputs to CO_2 capacity calculations could be verified. The seismic was also used to examine the structural and stratigraphic complexity of the reservoir and containment system to validate the assessment of containment risk and compartmentalization as part of the due diligence.

CDA Seismic and log data

This provided access to a range of released well data including headers, deviation data, formation tops, logs, core and well reports. The data from this site is of varying provenance, vintage and quality. CDA also provides access to 2D seismic lines. This was used to supplement the 3D Mega-survey and also specifically to deliver some seismic images of the East Irish Sea sites which are not covered by the Mega-survey itself. In the East Irish Sea, the three sites within the select inventory are all covered by 3D seismic data with commercial access. The terms of this commercial access have been determined and will influence the ability of these sites to be progressed.

Data Sources not currently available

At this stage in the project, there have been initial discussions with a range of operators and interested parties regarding accessing further information for deployment in the project. These are summarized below.

Petroleum Operators - dynamic flow and pressure data.

Initial conversations have been initiated with several petroleum operators regarding data access. Whilst no agreements have yet been reached, once the recommended five site portfolio has been approved these will be progressed further.

Petroleum Operators and Utilities - CCS Studies.

Several major studies have been completed by a range of parties on specific CCS and CO_2 Storage opportunities in recent years. Again, initial conversations have been held and agreements reached with Centrica and CO2DeepStore for data share to the project under non-disclosure agreements. Further agreements and arrangements may be possible with other operators. Once the recommended five site portfolio has been approved these will be progressed further.

UKCS CCS Commercialisation Storage Operators – New FEED outputs.

Detailed work on Goldeneye and Hewett has already been largely published through DECC's knowledge transfer programme in 2011.

http://webarchive.nationalarchives.gov.uk/20121217150422/http:/decc.gov.uk/en/content/cms/emissions/ccs/ukccscomm_prog/feed/feed.aspx

At this time, no FEED output from the 5/42 work conducted by National Grid has been made public by DECC. Whilst no agreements have been reached, discussions with National Grid Carbon continue to take place to explore the options available to build upon their learnings, particularly in the Southern North Sea.

CO2MultiStore Joint Industry Project - Project Output and knowledge share

This project is a joint industry and public funded research project to progress the development of Multi-user Regional CO_2 Storage Assets. The project research examines an exemplar Central North Sea sandstone, the Captain Sandstone, as a potential regional multi user storage asset for CO_2 captured from a "cluster" of Scottish sources and applies the discussion and decision-making to other offshore UK storage scenarios. It is of particular interest and value to this project. The industrial partners are Shell, The Crown Estate, Scottish Government, Scottish Enterprise and Vattenfall alongside the Scottish Carbon Capture and Storage centre. Initial discussions with the project have indicated that knowledge share will commence with a summary report which will be published in September 2015.

4.0 Due Diligence Output

Appendix 5 contains detailed due diligence records for each site in the Select Inventory. They are arranged on a geographic basis and are accompanied by Storage site summary posters in Appendix 2.

The performance of each site in the evidence based due diligence is illustrated in Figure 4. It highlights the strong due diligence performance of sites 218.000 (Captain Aquifer), 248.002 (Hamilton Field) and 372.000 (Forties 5 Aquifer). It also highlights the issues associated with sites 266.001 and 303.001 (Hewett Field). These arise solely from the challenge in progressing this site meaningfully in this project from its existing position as a high quality FEED grade project. Hewett is an important example where an excellent, high quality and mature site for CO_2 Storage will not progress to the final portfolio of sites for this project. Sites 361.000 (Mey Aquifer), 252.001 (Harding Field) and 141.002 (Barque Field) performed poorly based solely upon their technical attributes after due diligence. The due diligence was considered against a primary project hypothesis of:-

This site is capable of being materially matured by this study to form the foundation of a commercially viable Storage Development Plan to accept the delivery of 3 to 5 MT/yr over a 20 year period starting in 2025 to 2030 and playing a strategic role in the UK CCS Build out programme.

This was divided into three components for further investigation:-

1. Is the subsurface environment suitable?
2. Can it be developed cost effectively?
3. Will the site respond well to appraisal effort and be capable of material progression in this study?

Table 7, summarises the performance of each site in the Select Inventory when the suitability of the subsurface environment is considered. This is broken down further to the familiar issues of Capacity, Injectivity, Containment and Monitoring. On consideration of capacity, most sites performed well when checks were made on this, with only Harding Field, Barque field and Bunter Closure 40 having significant issues.

Injectivity was also a concern for the Leman Group fields of Barque and Viking, but also for the open aquifer systems of the Mey and Maureen in the Central North Sea.

Containment highlighted some concerns for the large Grid Sandstone aquifer in the Central North Sea largely due to potential issues with injected sands which are seen in lateral equivalent reservoirs at Alba and Chestnut fields. Bunter Closure 3 had an issue with containment risk in a faulted caprock system. The Mey and Maureen aquifers both raised containment risk concerns around limited seal capacity and the reliability of some Paleocene Shales as seals from oil and gas activity.

At this stage, no modelling work has been completed to assess the ability to monitor injected CO_2 using seismic technology, although low pressure depleted gas fields requiring injection of CO_2 in gas phase are less likely to benefit from this technology in the early stages of operations. Experience has indicated that any site can be monitored to a degree largely controlled by the cost and risk assessment. As a result sites have not been discriminated on the basis of this factor at this stage.

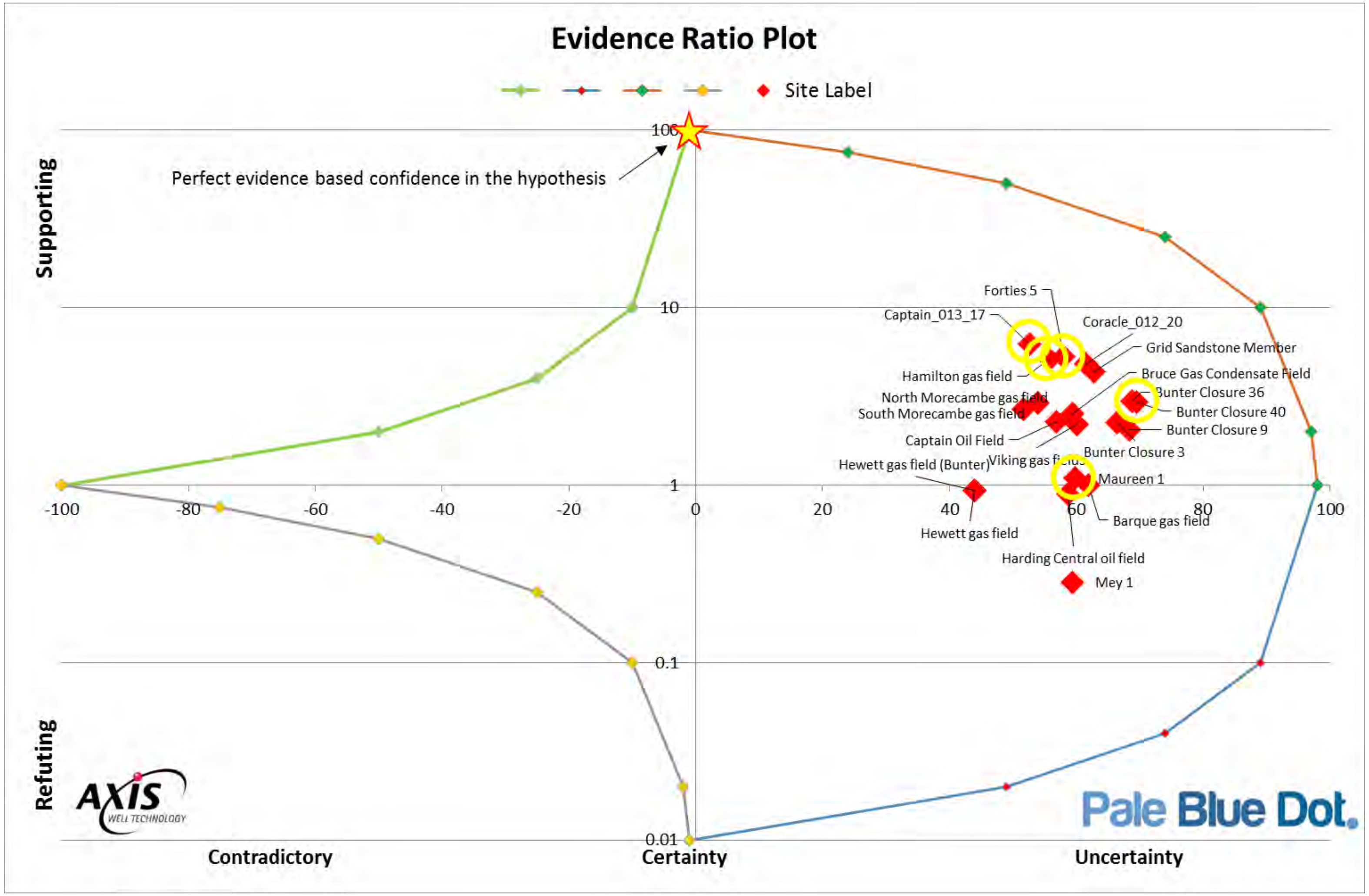

Figure 4 - Summary of Site Performance on Evidence Ratio Plot

			Capacity The site has appropriate capacity to give confidence that it can meet the primary hypothesis and make a material contribution to a portfolio of site capacity towards 1500MT				Injectivity The site has appropriate injectivity of >= 1MT/yr per well giving confidence that it can meet the primary hypothesis and be fully capable to injecting CO2 volumes at a rate of between 3 and 10MT/yr on a long term basis.				Containment The site has appropriate containment properties to ensuer that the inventory of injected CO2 remains within the storage complex indefinately, giving confidence that the site can meet the primary hypothesis.				Monitoring It is fully anticipated that the site will respond well to appropriate monitoring programme to meet all the requirements of the EU CCS Directive and enable full operational and post closure monitoring of the injected CO2 inventory giving confidence that the site can meet the primary hypothesis.			
Description	Due Diligence Score	Site Label	Evidence For	Evidence Agains	Evidence Qualit	Knowledge Base	Evidence For	Evidence Agains	Evidence Qualit	Knowledge Base	Evidence For	Evidence Agains	Evidence Qualit	Knowledge Base	Evidence For	Evidence Agains	Evidence Qualit	Knowledge Base
Captain_013_17	2.40	CNS_Site_14_218.000	80%	10%	70%	70%	80%	10%	70%	70%	80%	15%	75%	75%	70%	10%	60%	70%
Hamilton gas field	2.30	EIS_Site_19_248.002	70%	10%	70%	80%	80%	10%	70%	50%	70%	20%	60%	60%	60%	10%	50%	70%
Forties 5	2.27	CNS_Site_2_372.000	80%	10%	70%	75%	80%	10%	60%	70%	70%	30%	70%	70%	70%	10%	50%	50%
Coracle_012_20	2.20	CNS_Site_27_217.000	70%	10%	60%	50%	80%	10%	70%	70%	60%	15%	50%	50%	70%	10%	50%	70%
Grid Sandstone Member	2.15	CNS_Site_11_336.000	80%	10%	70%	70%	80%	60%	60%	10%	40%	35%	45%	45%	70%	10%	50%	50%
North Morecambe gas field	2.12	EIS_Site_10_248.004	80%	10%	70%	89%	80%	10%	70%	50%	70%	50%	60%	60%	60%	10%	50%	70%
South Morecambe gas field	2.12	EIS_Site_3_248.005	90%	10%	70%	80%	80%	10%	70%	50%	70%	50%	60%	60%	60%	10%	50%	70%
Bruce Gas Condensate Field	2.01	CNS_Site_8_133.001	75%	10%	70%	70%	80%	10%	70%	80%	70%	20%	80%	80%	70%	10%	50%	70%
Captain Oil Field	2.00	CNS_Site_24_218.001	70%	10%	70%	70%	80%	10%	70%	80%	60%	40%	80%	80%	70%	10%	50%	70%
Viking gas fields	1.95	SNS_Site_5_141.035	75%	30%	70%	70%	40%	40%	70%	60%	80%	50%	70%	70%	60%	10%	50%	60%
Bunter Closure 36	1.94	SNS_Site_7_139.016	70%	10%	60%	30%	60%	40%	30%	30%	65%	15%	65%	50%	70%	10%	50%	50%
Bunter Closure 40	1.93	SNS_Site_26_139.020	50%	10%	60%	40%	70%	30%	30%	30%	70%	20%	65%	50%	70%	10%	50%	50%
Bunter Closure 3	1.88	SNS_Site_4_227.007	80%	10%	60%	70%	70%	10%	30%	30%	45%	65%	65%	50%	70%	10%	50%	50%
Bunter Closure 9	1.83	SNS_Site_1_226.011	90%	10%	60%	70%	75%	30%	30%	30%	55%	35%	56%	50%	70%	10%	50%	50%
Hewett gas field	1.79	SNS_Site_6_266.001	85%	10%	80%	85%	80%	10%	80%	80%	90%	20%	80%	80%	70%	10%	70%	70%
Hewett gas field (Bunter)	1.79	SNS_Site_9_303.001	85%	10%	80%	85%	80%	10%	80%	80%	90%	20%	80%	80%	70%	10%	70%	70%
Maureen 1	1.70	CNS_Site_13_366.000	70%	60%	60%	60%	10%	60%	60%	60%	40%	50%	40%	50%	70%	10%	50%	50%
Barque gas field	1.65	SNS_Site_20_141.002	55%	25%	70%	70%	10%	75%	70%	60%	85%	25%	70%	70%	60%	10%	50%	60%
Harding Central oil field	1.64	CNS_Site_28.252.001	40%	70%	70%	70%	80%	10%	70%	80%	20%	60%	80%	80%	70%	10%	50%	70%
Mey 1	1.19	CNS_Site_12_361.000	5%	80%	80%	80%	10%	70%	60%	50%	40%	60%	40%	50%	70%	10%	50%	50%

Table 7 - Subsurface Characterisation Due Diligence - Summary of Site Performance

			Scenario				Pipeline				Facilities				Wells			
			Does the site have a potentially important role in the build out programme of UK CCS infrastructure providing confidence that the site can meet the primary hypothesis?				The site has a cost effective pipeline option (rendered as a levelised cost of offshore transport) which provides confidence that the site can meet the primary hypothesis?				The site has a cost effective option for offshore facilities (rendered as a levelised cost of offshore operations) which provides confidence that the site can meet the primary hypothesis?				The site has a cost effective option for injection wells (rendered as a levelised cost of offshore injection) which provides confidence that the site can meet the primary hypothesis?			
Description	Due Diligence Score	Site Label	Evidence For	Evidence Agains	Evidence Qualit	Knowledge Base	Evidence For	Evidence Agains	Evidence Qualit	Knowledge Base	Evidence For	Evidence Agains	Evidence Qualit	Knowledge Base	Evidence For	Evidence Agains	Evidence Qualit	Knowledge Base
Captain_013_17	2.40	CNS_Site_14_218.000	80%	20%	80%	70%	85%	5%	90%	90%	70%	15%	70%	70%	75%	15%	70%	70%
Hamilton gas field	2.30	EIS_Site_19_248.002	80%	10%	80%	80%	70%	10%	70%	80%	70%	10%	70%	70%	70%	50%	70%	70%
Forties 5	2.27	CNS_Site_2_372.000	70%	20%	70%	60%	85%	5%	80%	80%	70%	15%	70%	70%	75%	15%	70%	70%
Coracle_012_20	2.20	CNS_Site_27_217.000	70%	20%	80%	70%	70%	15%	70%	80%	70%	15%	70%	70%	75%	15%	70%	70%
Grid Sandstone Member	2.15	CNS_Site_11_336.000	70%	20%	70%	60%	85%	5%	80%	80%	70%	15%	70%	70%	75%	15%	70%	70%
North Morecambe gas field	2.12	EIS_Site_10_248.004	80%	25%	80%	80%	70%	10%	70%	80%	70%	10%	70%	70%	70%	50%	70%	70%
South Morecambe gas field	2.12	EIS_Site_3_248.005	80%	25%	80%	80%	70%	10%	70%	80%	70%	10%	70%	70%	70%	50%	70%	70%
Bruce Gas Condensate Field	2.01	CNS_Site_8_133.001	50%	50%	80%	70%	60%	25%	70%	80%	60%	15%	70%	70%	55%	15%	70%	70%
Captain Oil Field	2.00	CNS_Site_24_218.001	50%	70%	80%	70%	70%	15%	70%	80%	70%	15%	70%	70%	75%	15%	70%	70%
Viking gas fields	1.95	SNS_Site_5_141.035	70%	15%	70%	60%	65%	15%	75%	80%	65%	10%	70%	80%	75%	15%	70%	70%
Bunter Closure 36	1.94	SNS_Site_7_139.016	80%	20%	70%	70%	75%	10%	70%	80%	65%	15%	70%	70%	80%	10%	70%	70%
Bunter Closure 40	1.93	SNS_Site_26_139.020	80%	20%	70%	70%	80%	10%	70%	80%	65%	15%	70%	70%	80%	10%	70%	70%
Bunter Closure 3	1.88	SNS_Site_4_227.007	70%	20%	70%	70%	50%	10%	70%	80%	65%	15%	70%	70%	80%	10%	70%	70%
Bunter Closure 9	1.83	SNS_Site_1_226.011	60%	30%	70%	70%	50%	10%	70%	80%	65%	15%	70%	70%	80%	10%	70%	70%
Hewett gas field	1.79	SNS_Site_6_266.001	80%	15%	80%	80%	75%	15%	80%	90%	80%	10%	80%	90%	80%	15%	80%	80%
Hewett gas field (Bunter)	1.79	SNS_Site_9_303.001	80%	15%	80%	80%	75%	15%	80%	90%	80%	10%	80%	90%	80%	15%	80%	80%
Maureen 1	1.70	CNS_Site_13_366.000	70%	20%	70%	60%	85%	5%	80%	80%	70%	15%	70%	70%	75%	15%	70%	70%
Barque gas field	1.65	SNS_Site_20_141.002	50%	25%	70%	60%	70%	15%	75%	80%	65%	10%	70%	80%	75%	15%	70%	70%
Harding Central oil field	1.64	CNS_Site_28.252.001	10%	70%	80%	70%	70%	15%	70%	80%	70%	15%	70%	70%	75%	15%	70%	70%
Mey 1	1.19	CNS_Site_12_361.000	5%	70%	70%	70%	85%	5%	80%	80%	70%	15%	70%	70%	75%	15%	70%	70%

Table 8 - Developability Due Diligence - Summary of Site Performance

The ability to develop the site cost effectively has been divided into the three key cost components of Pipeline, Facilities and Wells, plus an additional Scenario component which asks whether the site has a potentially important role in the build out programme of UK CCS infrastructure which might contribute to longer term cost reduction. In no site is there any evidence that pipeline, facilities or wells could not be delivered cost effectively. However some sites would be more expensive to develop than others and early assessments of the capex requirement and the capital cost per tonne of CO_2 capacity are included in the following sections. Risk will be included in the cost estimating during WP5.

From the perspective of their contribution to the ETI scenarios, most sites performed well, however the Central North Sea oil and gas fields of Captain, Bruce and Harding were considered to have less of a role to play because of their distance from landfall (Harding / Bruce) and late availability (Captain). In addition, Bunter Closure 9, although carrying a large capacity potential, was considered a higher risk site as it sits directly above the actively-producing Leman Field which is not expected to become available to other subsurface users until 2029.

			Data				Users				Potential			
			The site has the right combination of data availability (type, quality and quantity) to materially progress the appraisal status of the site in this project given the time, and budgetary constraints.				This site has sufficient Operator collaboration or support (from whichever domain oil & gas, offshore wind, Sand & Gravel etc) to materially progress the appraisal status of the site in this project given the time, and budgetary constraints.				The site has significant uncertainty reduction potential which if addressed could materially progress the appraisal status of the site in this project given the time, and budgetary constraints available			
Description	Due Diligence Score	Site Label	Evidence For	Evidence Agains	Evidence Qualit	Knowledge Base	Evidence For	Evidence Agains	Evidence Qualit	Knowledge Base	Evidence For	Evidence Agains	Evidence Qualit	Knowledge Base
Captain_013_17	2.40	CNS_Site_14_218.000	80%	10%	70%	70%	70%	15%	70%	70%	80%	10%	70%	75%
Hamilton gas field	2.30	EIS_Site_19_248.002	80%	10%	80%	65%	75%	10%	70%	70%	90%	10%	80%	75%
Forties 5	2.27	CNS_Site_2_372.000	80%	10%	75%	75%	60%	15%	70%	70%	70%	10%	70%	70%
Coracle_012_20	2.20	CNS_Site_27_217.000	70%	10%	70%	70%	70%	15%	70%	70%	60%	20%	70%	75%
Grid Sandstone Member	2.15	CNS_Site_11_336.000	70%	10%	70%	70%	60%	15%	70%	70%	70%	10%	70%	70%
North Morecambe gas field	2.12	EIS_Site_10_248.004	70%	10%	70%	65%	50%	50%	70%	70%	90%	10%	80%	75%
South Morecambe gas field	2.12	EIS_Site_3_248.005	70%	30%	80%	65%	50%	50%	70%	70%	90%	10%	80%	75%
Bruce Gas Condensate Field	2.01	CNS_Site_8_133.001	90%	10%	70%	70%	30%	40%	50%	50%	70%	10%	70%	70%
Captain Oil Field	2.00	CNS_Site_24_218.001	80%	10%	70%	70%	30%	40%	50%	50%	70%	10%	70%	70%
Viking gas fields	1.95	SNS_Site_5_141.035	70%	20%	70%	75%	30%	40%	50%	60%	70%	15%	70%	60%
Bunter Closure 36	1.94	SNS_Site_7_139.016	60%	30%	60%	50%	30%	20%	50%	70%	70%	30%	70%	70%
Bunter Closure 40	1.93	SNS_Site_26_139.020	50%	30%	60%	50%	20%	20%	50%	70%	80%	10%	70%	70%
Bunter Closure 3	1.88	SNS_Site_4_227.007	60%	30%	60%	50%	30%	40%	60%	70%	80%	10%	70%	70%
Bunter Closure 9	1.83	SNS_Site_1_226.011	60%	30%	60%	50%	30%	50%	50%	70%	80%	10%	70%	70%
Hewett gas field	1.79	SNS_Site_6_266.001	80%	10%	70%	85%	60%	30%	50%	70%	10%	80%	80%	80%
Hewett gas field (Bunter)	1.79	SNS_Site_9_303.001	80%	10%	70%	85%	60%	30%	50%	70%	10%	80%	80%	80%
Maureen 1	1.70	CNS_Site_13_366.000	60%	40%	75%	70%	60%	15%	70%	70%	70%	40%	70%	70%
Barque gas field	1.65	SNS_Site_20_141.002	70%	20%	70%	75%	30%	40%	50%	60%	70%	15%	70%	60%
Harding Central oil field	1.64	CNS_Site_28.252.001	80%	10%	70%	70%	50%	20%	50%	50%	70%	10%	70%	70%
Mey 1	1.19	CNS_Site_12_361.000	50%	60%	75%	70%	60%	15%	70%	70%	70%	60%	60%	60%

Table 9 - Ability to Progress - Summary of Site Performance

The final component of the evidence based due diligence was to consider the potential of the site to respond to further analysis in this project and how it might be materially matured on its path towards being developed. This looked at whether the site has enough data of sufficient quality available to the project, whether the progression of a site is dependent upon a petroleum operator and how collaborative that operator may be in data and information sharing in a timely fashion for this project, and finally whether this project can make material progress above and beyond the current status of the site available in the public domain.

These factors are detailed in the due diligence reports for each site provided as Appendix 5 and summarised below. It was considered that all sites except Hewett could be progressed materially from their current published status. Hewett has benefited from a large FEED study as the target store for the Kingsnorth CCS project. This was extensively published by DECC in 2012; this project would not be able to add materially to this knowledge base.

Ability to Progress

The ability to progress the appraisal maturity of a site is a key requirement of this project. As a result there are some excellent quality storage sites that have for example already gone through a full scale FEED programme, and that cannot be materially matured by this project. In order to consider this important factor consistently across the Select Inventory, a simple CO_2 Storage maturity scale has been developed against which the current status of each site has been measured Table 1.

All sites considered here are at least at level 1 by merit of their inclusion in the CO2Stored database. Sites such as the benchmark Goldeneye and 5/42 plus Hewett have been through a detailed FEED programme and sit at level 5; as a result they cannot be progressed materially here. It is important that when assessing these maturity levels that they reflect the status of publically available works or studies. There are many proprietary studies in existence for a range of CO_2 storage sites that are not available outside the commercial entity for which they were developed without an NDA. These studies have been largely discounted as there is only a small likelihood of them ever being put into the public domain. No public domain releases of such studies are expected outside the DECC CCS competition programmes. It has been assumed that the FEED for all of these projects will be in the public domain before the end of 2015.

After assessing their current maturity status, an estimate of what level each site might be progressed to in this study has been made. This is dependent upon the data that is anticipated to be available to this project and also upon the willingness and ability of any incumbent operator to collaborate with the project and release data for use.

Figure 5 shows the output of this simple assessment. The largest of the blue or red bars shows the current maturity status for each site and the rightmost extent of the green bars shows the progression that might be achieved. The leftmost extent of the red bars shows how far the more mature sites could be progressed in this study, highlighting that they are unlikely to be suitable for WP5.

It has been considered generally that sites with dynamic data can be more readily progressed and dynamically validated through history matching as long as such data can be made available from the operator. As a result the depleted hydrocarbon fields generally show higher potential for maturity improvement than saline aquifers where such dynamic data often simply does not exist.

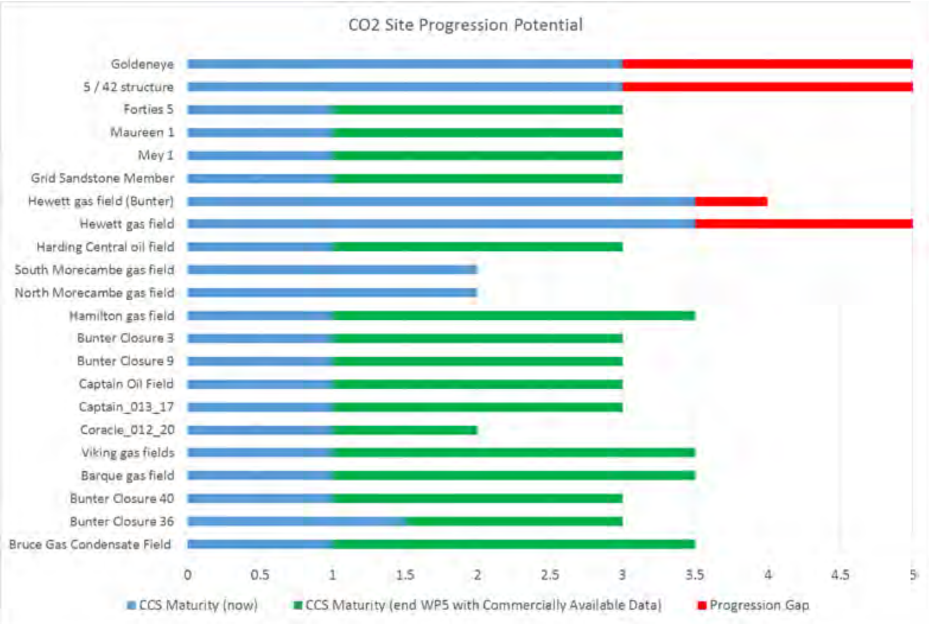

Figure 5 - CO2 Storage Site Progression Potential in this Project

Due Diligence Results

Figure 6 illustrates the outcome of the Due diligence output. It shows each of the twenty sites from the Select Inventory and maps their due diligence score against the ability of the site to make material progress within this project.

The sites that plot on the left hand side in quadrants 1 & 2 are difficult to progress meaningfully in this project either because:

1. They have already undergone FEED grade work which is in the public domain.
2. The seismic data is either wholly or significantly unavailable to this project.

The sites that plot in Quadrant 4 have the potential to be progressed in this project, but have not met up to the aspirations held for them in the CO2Stored database. Like all the sites in the Select Inventory that does not mean that they could not be developed into effective storage sites for CO_2 injection, but simply that after due diligence checks were made there were some aspects of their character that were not as promising as previously considered.

The Mey 1 aquifer capacity was significantly reduced during the due diligence because of lower assessed reservoir net to gross which also adversely impacted injectivity assessment. Concerns at Harding Central were associated with the caprock integrity because of the injected sands above the reservoir interval. The Barque Gas field and the Maureen 1 aquifer both had reduced injectivity assessments whilst Bunter Closure 9 performed well on all counts with the exception of the timing of its availability which was controlled by the production life of the underlying Leman Gas field which runs out to 2030.

Figure 6 – Measure of the Potential for a Site to be Materially Progressed in this Project

5.0 Portfolio Creation and Ranking

One key challenge faced by this project that has not directly been the subject of specific research or development of best practice guidance for CO_2 Storage is the issue of portfolio selection. The recommended sites must act together as an effective portfolio that meets the following goals:

1. Each individual site is effective and has good potential to be developed into a CO2 Storage site as part of a build out programme to support the second phase of CCS development in the UK.
2. That the portfolio as a whole fits the narrative around the ETI CCS Scenarios((Energy Technologies Institute, 2015) such that it has a high probability of being able to service the requirements from the Concentrated, Balanced or EOR scenarios and in particular their geographic, timing and capacity growth needs.
3. That the portfolio effectively manages risk across its extent and specifically looks to minimise critical "single point of failure" risks through its diversity.

With twenty sites in the Select Inventory all "qualified" as potentially strong CO_2 Storage candidates, the challenge is less about selecting the best five sites and more about meeting the portfolio objectives. As a consequence there will be some very strong candidate sites that are omitted from the final recommended portfolio simply because they do not fit a portfolio designed to meet the UK Phase 2 development plan.

Overall there are 15504 possible combinations of selecting five sites from a Select Inventory of twenty. The process used is based substantially upon that reported in WP1 for this stage of the project, but with some small refinements which are noted here. To start with every portfolio combination is identified and listed. Each is then measured against the factors that reflect the portfolio goals outlined above. Specifically these were:

1. Quality of the Sites in the portfolio - Sum of site scores in the portfolio from the Due Diligence step which collectively describe the quality of the group of sites in each portfolio
2. Match to the ETI Scenarios - This considers how the site might build out from the two competition projects, whether the portfolio facilitates EOR development through its transport and or storage infrastructure and whether the portfolio effectively services all the main emissions clusters including Central Belt, Teesside, Humber, Thames, Mersey and that the portfolio has the capacity required to satisfy the project objectives.
3. Risk Management - This looks at the diversity of the portfolio and specifically whether the portfolio covers a range of different potential storage formations and storage types.

These factors were codified from data obtained through the due diligence process for each site.

Sum of site scores	ETI Scenario Match - Strategic Fit						Portfolio Risk Management		
TOTAL Due Diligence Score	Phase 1 Build out Service	EOR Service	Industrial cluster Service	Capacity to meet project objectives	Early Availability Strength	TOTAL Scenario Match Score	Formation Diversity	Store Type Diversity	TOTAL Portfolio Risk Management Score

Figure 7 - Site Portfolio Metrics and Scoring

Where:-

Portfolio Score = (Total Due Diligence Score + Total Scenario Match Score + Total Portfolio Risk Management Score)/3

And

Total Scenario Match Score = (Phase 1 Build Out Service[0 to 10] + EOR Service[0 to 5] + Industrial Cluster Service[0 to 10] + Capacity to meet project Objectives[0 to 10] + Early Availability Strength[0 to 10])/ 5

Total Portfolio Risk Management Score = (Formation Diversity + Store Type Diversity) / 2

Finally, the ability to progress the portfolio within this project is critical to a successful project outcome. The final portfolio ranking was therefore completed on the basis of the product of the Portfolio Score (Figure 7) and the Ability to Progress the portfolio (as outlined in Section 4).

Figure 8 summarises the range of scores from this ranking process for all possible portfolios. It ranges from 0 to 78 with the lowest ranked portfolio comprising the CNS - Coracle Aquifer, EIS - North Morcambe, EIS - South Morcambe, SNS - Hewett Field (Hewett) and SNS - Hewett Field (Bunter). The highest ranked portfolio comprised SNS - Viking Gas Field, CNS - Captain Aquifer, EIS - Hamilton Field, CNS - Grid Sandstone Aquifer and CNS - Forties 5 Aquifer. This simple comparison of the top and bottom ranked portfolios highlights the strength of the overall package of 20 sites. Even the bottom ranked portfolio has some very strong individual candidates, but together they lack diversity and ability to map well to the ETI scenarios.

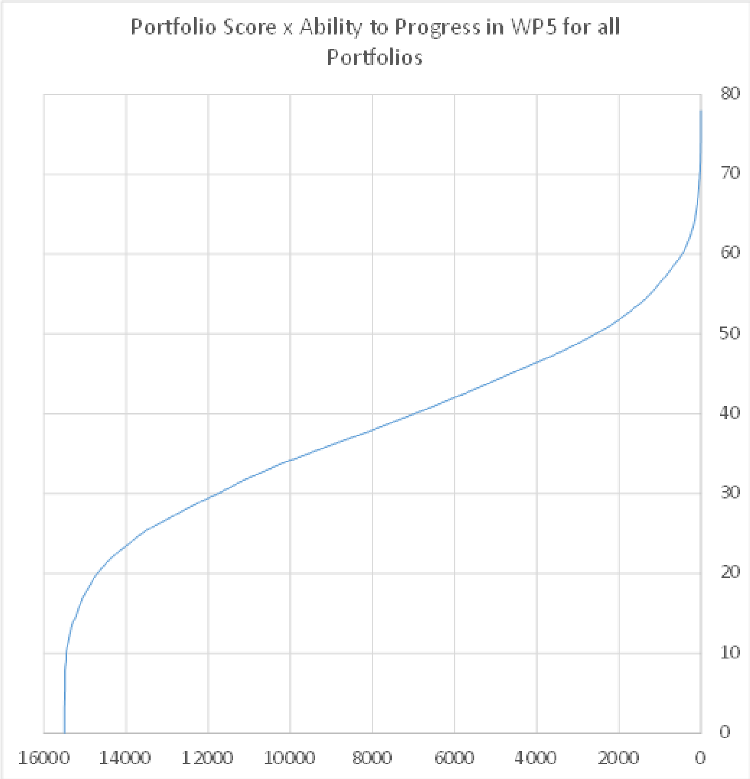

Figure 8 - Ordered Portfolio Scores from 15504 portfolio combinations of Twenty Storage Sites

The top performing portfolios are identified in Figure 9 in orange as those with the highest portfolio score and best ability to progress in this project. The final step involved expert consideration regarding the balance of the top performing portfolios. Whilst the highest scoring portfolio noted above has strong diversity and significant capacity, it is over represented by Open aquifers and sites in the Central North Sea.

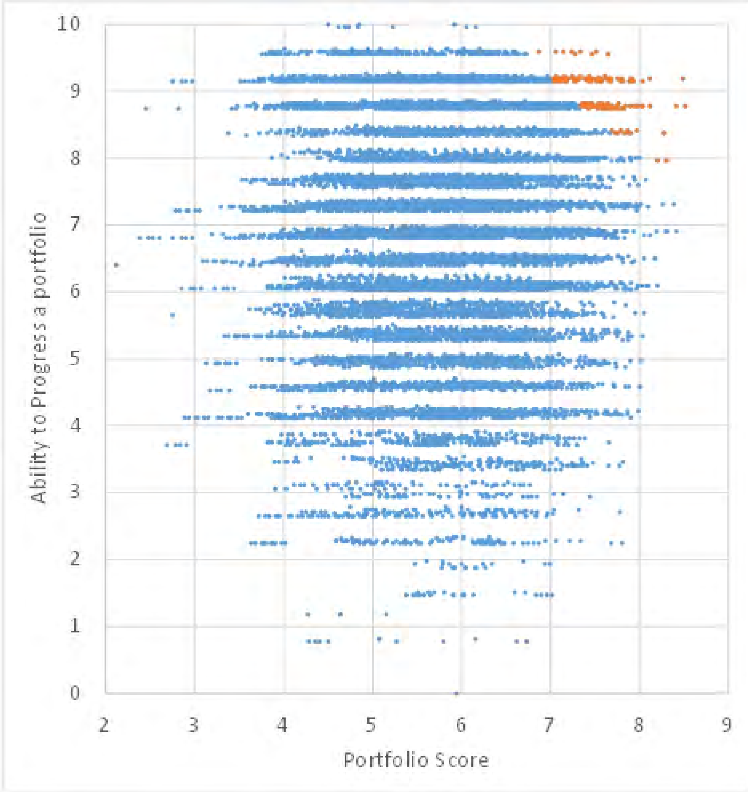

Figure 9 - Plot of Portfolio Score vs Ability to Progress

A review of the make-up of the top performing portfolios reveals a strong consistency in those sites included. Specifically, Viking Field, Captain Aquifer, Hamilton Gas Field, Grid Sandstone Aquifer and Forties 5 Aquifer are strongly represented in the Top 10, 20 and 40. Bunter Closures in the Southern North Sea are also well represented with Bunter Closure 36 being the most significant presence in Figure 10.

Locationand Site Code	Description	Occurrences in Top 10 portfolios	Occurrences in Top 20 portfolios	Occurrences in Top 40 portfolios	Occurrences in Top 80 portfolios	Occurrences in Top 160 portfolios	Occurrences in Top 320 portfolios	Occurrences in Top 640 portfolios
CNS_Site_8_133.001	Bruce Gas Condensate Field	10%	15%	23%	21%	22%	24%	27%
SNS_Site_7_139.016	Bunter Closure 36	30%	20%	23%	24%	28%	25%	27%
SNS_Site_26_139.020	Bunter Closure 40	20%	15%	13%	18%	22%	23%	23%
SNS_Site_20_141.002	Barque gas field	10%	10%	15%	26%	23%	22%	27%
SNS_Site_5_141.035	Viking gas fields	70%	80%	70%	48%	38%	51%	46%
CNS_Site_27_217.000	Coracle_012_20	0%	0%	3%	3%	4%	5%	14%
CNS_Site_14_218.000	Captain_013_17	50%	60%	63%	64%	63%	54%	50%
CNS_Site_24_218.001	Captain Oil Field	10%	5%	8%	10%	16%	18%	20%
SNS_Site_1_226.011	Bunter Closure 9	0%	10%	10%	13%	16%	15%	16%
SNS_Site_4_227.007	Bunter Closure 3	10%	15%	10%	14%	17%	19%	20%
EIS_Site_19_248.002	Hamilton gasfield	100%	90%	85%	84%	74%	64%	59%
EIS_Site_10_248.004	North Morecambe gasfield	0%	0%	0%	0%	0%	0%	0%
EIS_Site_3_248.005	South Morecambe gasfield	0%	0%	0%	0%	0%	0%	1%
CNS_Site_28.252.001	Harding Central oil field	0%	0%	3%	4%	8%	8%	11%
SNS_Site_6_266.001	Hewett gasfield	0%	0%	0%	0%	0%	0%	0%
SNS_Site_9_303.001	Hewett gasfield (Bunter)	0%	0%	0%	0%	0%	0%	0%
CNS_Site_11_336.000	Grid Sandstone Member	100%	100%	93%	90%	83%	76%	69%
CNS_Site_12_361.000	Mey 1	0%	0%	0%	0%	2%	4%	5%
CNS_Site_13_366.000	Maureen 1	0%	5%	8%	13%	13%	21%	23%
CNS_Site_2_372.000	Forties 5	90%	75%	78%	71%	75%	68%	61%

Figure 10 - Site Performance within Top Ranked Portfolios

After review, it was considered that the Top Ranking portfolio noted above was over-represented with Central North Sea sites. This may have arisen because such sites are helpful in ALL ETI scenarios including the EOR led scenario. To remedy this, one of the large open aquifer systems from the Central North Sea was removed and replaced with the most promising Bunter Closure from the Southern North Sea.

After considering the options, the Grid Sandstone aquifer was selected for removal from the portfolio for the following reasons:

1. The formation is relatively shallow and presents some concerns around the potential for injected sands which may complicate cap rock integrity.
2. The formation is very distant from St Fergus despite the fact that it might be cost effectively reached through the re-use of the Miller Gas System line
3. The Captain Aquifer and Forties Aquifer alternatives present more straightforward build out options and also would be ideally placed to support the initial built of CO_2EOR projects in the future.

So despite the very large capacity potentially available in the Grid Sandstone Aquifer, it was replaced by the Bunter Closure 36 in the Recommended Portfolio. The Grid aquifer was however retained as a reserve site (see Section 6.1).

6.0 Results – Recommended Sites

The final recommended portfolio of five sites is outlined in Table 10.

Site Code	Description
SNS_Site_7_139.016	Bunter Closure 36
SNS_Site_5_141.035	Viking gas fields
CNS_Site_14_218.000	Captain_013_17
EIS_Site_19_248.002	Hamilton gas field
CNS_Site_2_372.000	Forties 5

Table 10 - Recommended Portfolio Inventory

This portfolio carries two depleted gas fields with different challenges, one from the Southern North Sea and one from the East Irish Sea. It also includes a large Bunter Closure with a saline aquifer storage reservoir similar to the 5/42 structure. Finally it includes two open saline aquifers in the Central North Sea, the Captain which is a logical step out from Goldeneye and also a large Forties aquifer deeper into the basin which would be available later in the build out programme. The last two sites also carry the potential to support the development of CO_2 enhanced oil recovery projects in the Central North Sea.

Depleted Gas Fields

Site Code	Description
SNS_Site_5_141.035	Viking gas fields
EIS_Site_19_248.002	Hamilton gas field

Table 11 - Depleted Gas Fields in the Recommended Portfolio Inventory

Many of the challenges associated with CO_2 Storage in heavily depleted gas fields have been highlighted within the Hewett FEED study of 2011-2012. These are focused in three areas:

1. Managing the CO_2 phase control during injection into the very low pressure reservoir and the subsequent change to dense phase in the reservoir as the pressure rebuilds.
2. Managing the complexity associated with legacy well integrity issues.
3. Ensuring that the geomechanical security of the reservoir is robust to the deep depletion and re-pressurisation cycle.

Hamilton and Viking will both face these challenges to different degrees. In addition, Hamilton is very shallow, perhaps as low as 700m at the crest. Calculations during due diligence suggest that it will be possible for dense phase CO_2 to exist at the initial pressures found in the gas field before production started. In Viking the challenges are focused on reservoir quality and injectivity and managing CO_2 injection in a compartmentalized reservoir. Together Hamilton and Viking will further qualify the Southern North Sea and East Irish

Sea depleted gas field potential (CO_2 Stored Theoretical capacity - 3791 Mt & 1180Mt).

Aquifers with Structural Closures

Site Code	Description
SNS_Site_7_139.016	Bunter Closure 36

Table 12 - Aquifers with Structural Closures in the Recommended Portfolio Inventory

There are 50 sites within the CO2Stored database that are saline aquifers within structural closures. Every single one of them is Triassic in age with 34 located in the Southern North Sea and 16 in the East Irish Sea. The East Irish Sea examples are challenged with very poor quality reservoirs. Overall the Bunter Closures in the Southern North Sea are seen as attractive targets, but they are generally sparsely appraised and subject to significant uncertainty. Further discussion around the performance of these Bunter Closures in this project selection is included in Appendix 6. With one of the Phase 1 storage sites at 5/42 shaping up as an early injection site, much effort has been expended in its appraisal. The results of the FEED programme are not yet available to this project and so the progression of Bunter Closure 36 will rely upon public information and released well data together with excellent 3D seismic data coverage from the PGS Mega-survey.

Open Aquifer Systems with or without identified structural or stratigraphic traps.

Site Code	Description
CNS_Site_14_218.000	Captain_013_17
CNS_Site_2_372.000	Forties 5

Table 13: Open Aquifer systems in the Recommended Portfolio Inventory

Within the CO2Stored database there is over 68600 Mt of potential theoretical storage located within saline aquifer systems; this represents over 85% of the total inventory. 12% of this potential lies in structural closures, 46% in closed boxes or deeply buried fault blocks (half of these are deeper than 3600m). This leaves over 42 % of this potential in Open aquifer systems. It is strategically important therefore that such systems are progressed within the UK if CCS is to be rolled out effectively.

Open aquifer systems are more complex than aquifers with structural closures like 5/42 and Bunter Closure 36. Their primary challenge is in the definition of the area required for the storage complex since by definition, there is not a neatly defined anticline or fault compartment to delineate it simply like an oil and gas field. However there is more CO_2 injection experience globally with Open Aquifers than with any other type of saline formation thanks to the Sleipner project which has been operating successfully for many years.

Since 2011 much research and industry work has been completed in the UK and elsewhere on the potential of these systems. This has included the CASSEM project from SCCS which looked at an open Bunter Sandstone aquifer in the east of England, the Multistore JIP which looked at the open Captain aquifer in the Central North Sea and is due to report in September 2015 and an exemplar model from the UKSAP programme on the Forties aquifer in 2010. The Captain Clean Energy Project also considered an open aquifer hybrid with a depleted gas field as a storage solution as part of it's submission in the CCS Commercialisation Programme in 2012/13.

Stakeholder review and peer review of the recommended portfolio supported the inclusion of Open Aquifer systems as part of the WP5 programme. The Captain aquifer represents an early build out opportunity from Goldeneye without which the depleted field will be capacity-constrained very quickly. The Forties aquifer represents a longer term storage prospect, most likely requiring new pipeline infrastructure. Both would significantly enhance the ability to deploy CO_2EOR in the Central North Sea.

The ultimate fate of injected and contained CO_2 will be in one of the following forms:

- A buoyant continuous (and therefore mobile) plume of CO_2 within the pore space of the aquifer.
- A discontinuous (and therefore immobile) residual saturation in the form of microscopic individual bubbles located in the pore space of the aquifer after the buoyant plume has passed through.
- As a dissolved phase within the saline water in the pore space itself.

It is accepted that over geological time periods more and more of the injected CO_2 inventory will dissolve into the aquifer water and that this may eventually end up as new carbonate minerals in some parts of the formation.

Open aquifer systems are characterised by two factors:

- They are not fully confined hydraulically in the subsurface and have some connectivity to other subsurface pore systems or to the marine or groundwater environment.
- Some portion of their pore volume can be considered to be "within closure". This is an important control on the proportion of the injected inventory which is contained as a buoyant mobile CO_2 plume.

For development projects limited to simple closures such as Bunter closure 36 and 5/42 (and in fact Goldeneye since the bulk of that closure is now occupied by water after gas production has ended), the storage complex is largely defined by the limits of the closure itself plus any areas of secondary containment reservoir which would make sense to include after a prudent risk assessment. As such the development plan is focused upon using the closure and buoyancy trapping to contain the injected CO_2 plume over the long term. Such sites are similar in many regards to conventional oil and gas fields and therefore somewhat familiar to oil and gas regulators and authorities.

In other open aquifers where the injected CO_2 inventory is much bigger than the obvious closures can contain, buoyancy trapping alone will not contain the full injected CO_2 inventory. Instead as the CO_2 plume moves under its buoyancy (generally updip) then it will leave behind it some of the inventory as a residual saturation. This is a similar process to oil moving through an oilfield under a water flood. Much of the oil is locked in place after the water passes by as a residual saturation. This may reach 25% or more of the total oil volume. To optimise this effect the store must be engineers such that the plume travels through as much of the aquifer rock volume as possible contributing to higher effective storage efficiency.

As the CO_2 plume leaves mass behind as a residual saturation as it moves, the mobile plume loses mass until it no longer has the buoyancy to continue moving. At this point the full inventory of injected CO_2 is locked in place either as a residual saturation or as buoyant plume within small closures.

This type of development is unlike conventional oil and gas offshore since the storage complex and permit area are less easy to define, depending upon many different properties of the aquifer and its development (including the target injected inventory). Ultimately it will be defined using multiple dynamic modelling scenarios which investigate each key uncertainty. The proposed storage permit boundary will then be located with the maximum plume extent of these scenarios in mind. Such sites are less familiar to oil and gas regulators and authorities and industry itself. As such the dialogue and process associated with their consenting and the consideration of investment risk is likely to be more challenging than with simple closed structures.

Figure 11 illustrates the continuum of aquifer storage sites from structural closures through to aquifer systems with no identified structural or stratigraphic traps.

Whilst Bunter Closure 36 along with 5/42 will occupy the "conventional" area of this plot which id broadly familiar to oil and gas practitioners, The Captain and Forties aquifers are likely to extend outside this region and rely less on Bouyant Trapping and more on Residual Trapping. In the early stages of Open aquifer development, it is likely that development sites will be designed and engineered to optimise the benefit of any available buoyant trapping in structural and stratigraphic closures.

Collectively the recommended portfolio has much to offer to the future UK Phase 2 CCS build out programme. This is discussed further in Section 7. This portfolio of sites was ranked 28th out of over 15,000 options. It was also the best portfolio that excluded the Grid Sandstone.

Figure 6 outlines the performance of these sites on a plot of due diligence score vs the ability of this project to progress the site. This highlights the strong performance of the Central North Sea open aquifers and the Hamilton gas field in the East Irish Sea. It also highlights the Bunter Closure 36 and the Viking Gas field as the best options for the Southern Gas Basin.

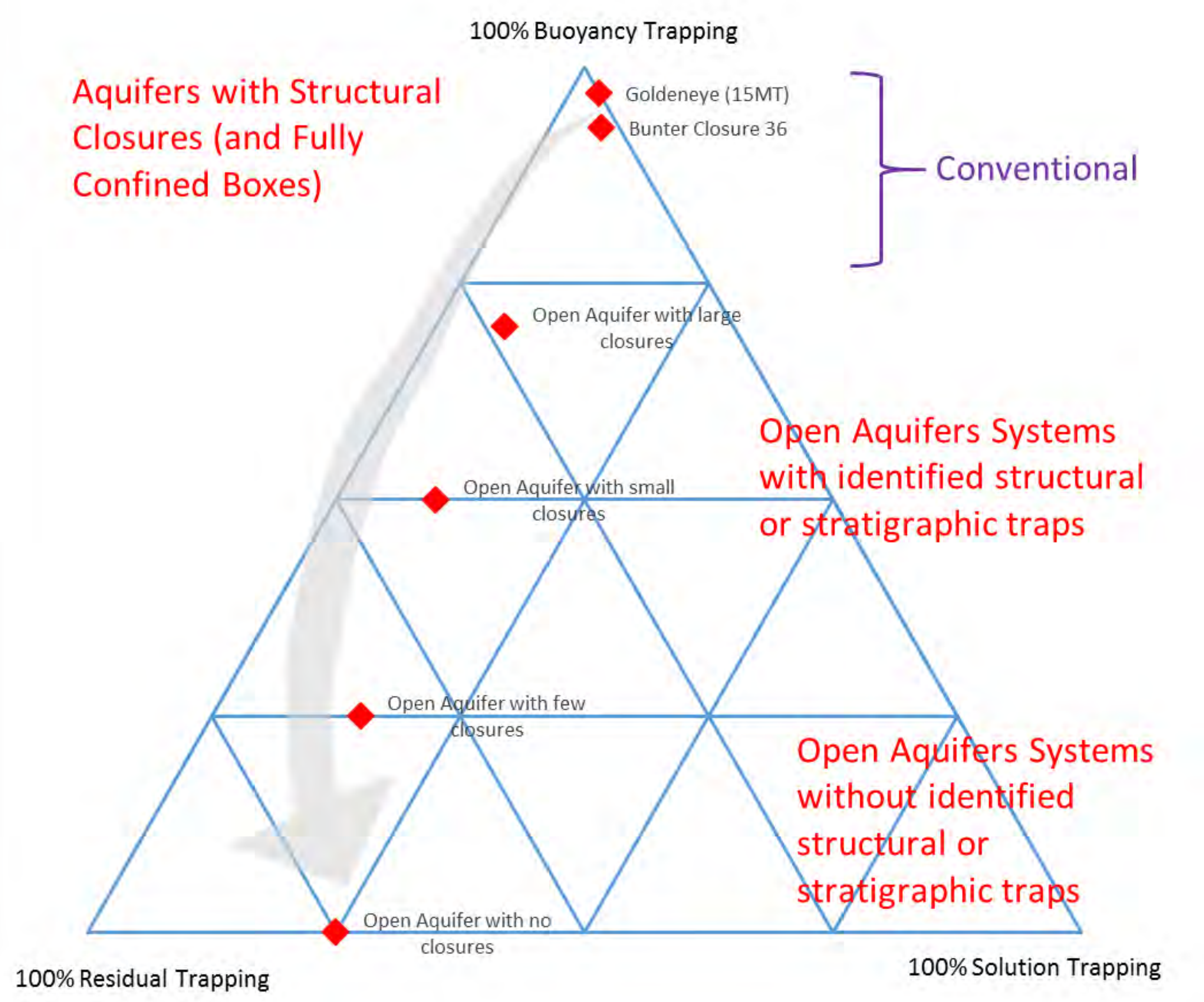

Figure 11: Schematic illustration of the continuum of aquifer storage sites from those with closures to those without closures

6.1 Reserve Sites

In the original work plan for the project outlined in WP1, it was planned to carry one reserve site to the recommended portfolio of five sites. The purpose of this reserve site was to serve as a substitute site should a fundamental "show stopping" issue be discovered early in the WP5 work on the recommended portfolio.

Given the approach taken for the selection of the portfolio coupled with the stakeholder review, it is considered that the likelihood of having to deploy a reserve site is extremely small. Nevertheless, it is still a potentially useful risk mitigation measure. At Stakeholder Review meeting Number 3 on 29th July 2015, the portfolio of five recommended sites was proposed and tested amongst a team of experienced CO_2 Storage experts from industry and academia (Appendix 1). Whilst there was strong overall support for the portfolio selection, it was suggested that a single reserve site would not be appropriate exactly because of the portfolio nature of the selection. For example should a Central North Sea site rapidly prove to be ineffective as a storage site then it might not be appropriate to replace it with a reserve site in the East Irish Sea.

As a consequence a reserve site has been identified as a back-up for each key site in the recommended portfolio outlined in Table 14.

For any of these reserve sites to be deployed effectively within this project, very early failure of one of the recommended sites will be required. The trigger for such a replacement would have to be within the first five days of project activity on that site. Should critical issues be discovered after this time, then it is very unlikely that the reserve site could be substituted and progressed to it target level of maturity within the timeframe available in the project. Of course, the Due Diligence step completed as part of this WP4 and the portfolio selection based upon this has significantly reduced the probability of such a reserve site being required in this Project.

Site Location and Code	Site Description	Designated Reserve Site	Rationale
SNS_Site_7_139.016	Bunter Closure 36	SNS_Site_26_139.020 Bunter Closure 40	Although smaller than Bunter Closure 36, this site is closer to 5/42 and would be a logical replacement. It performed well during due diligence
SNS_Site_5_141.035	Viking gas fields	SNS_Site_20_141.002 Barque gas field	Barque is the only other Leman Sandstone storage site within the Select Inventory and therefore a replacement candidate for Viking, although inferior in injectivity, capacity and the timing of availability
CNS_Site_14_218.000	Captain_013_17	CNS_Site_24_218.001 - Captain Oil Field	The Captain Oil field is a logical fall back to the Captain aquifer. This is a closed structure like Goldeneye, albeit in an oil field at shallow depth
EIS_Site_19_248.002	Hamilton gas field	SNS_Site_26_139.020 Bunter Closure 40	The only other sites available in the East Irish Sea are the North and South Morecambe fields. In this project 3D seismic is not available for these sites and so the reserve site for Hamilton has been selected from the Southern North sea and is again the Bunter Closure 40. Although smaller than Bunter Closure 36, this site is closer to 5/42 and is a strong candidate. It performed well during due diligence
CNS_Site_2_372.000	Forties 5	CNS_Site_11_336.000 Grid Sandstone Aquifer	The Grid Sandstone performed well during due diligence and was included in all of the top 20 ranked portfolios. Like all sites it has its challenges but is a strong and logical replacement candidate for Open aquifer site Forties 5

Table 14 - Recommended Portfolio Inventory Reserve Sites

7.0 WP5 Work Programme

The work programme for WP5 has been specified in generic terms in the WP1 report in two forms. The first represents a "data rich" version where the selected site benefits from a wide range of data including a good well database targeted at the specific zones of interest plus good quality 3D seismic coverage. A "data rich" site will also benefit from detailed well records including dynamic flow and pressure data which serve to characterise the dynamic performance of the site during hydrocarbon extraction. The second work programme is a subset of the "data rich" programme and is more typical of a "data poor" site. Here there is still enough well data and good quality 3D seismic data available to build an appropriate representation of the subsurface, but perhaps the log data suite is not targeted for the full evaluation of the storage reservoir and there may not be core materials or analysis available. There may be no dynamic data at all from which to calibrate any dynamic models, apart from initial pressures.

These programmes were developed to illustrate the range of work activities that were likely to be appropriate for a portfolio of five CO_2 Storage sites at a time when the identity and location of the five sites were unknown. The output and results from this WP4 include a recommendation of five sites which has been endorsed by a wide range of Stakeholders. These generic work programmes can now be tailored specifically to the needs and anticipated data availability of each recommended site, as understood after a short due diligence programme.

The key difference between the data rich sites and data poor sites is the degree to which the detailed well records and dynamic information held by the operators can be released to this project. All five selected sites benefit from excellent 3D seismic data coverage and also released well data. There is an ongoing dialogue with the operators of the various petroleum licenses which overlap with the five sites to investigate the potential for further data release. At the time of writing the indications are that such additional releases will probably be limited to average reservoir pressures at the end of production and will not include detailed well histories and pressure record from which to drive a detailed history match of dynamic models. This challenge was anticipated in WP1 and is highlighted specifically here again as a key factor which will materially impact the ability of the UK to develop its CO_2 storage resource if that is to be done by parties other than the oil and gas operators.

The smallest gap resulting from this withholding of detailed well history and dynamic data will be with Bunter Closure 36 where little such data is available anyway. Of the other sites, Viking and Hamilton are most affected, with information for Captain and Forties being moderately affected.

The base work programme. The site specific sections capture work element inclusions, or exclusions that are recommended to effect a tailored work plan for each of the five recommended sites and the specific challenges that they present.

The outline work programme is illustrated in Figure 12 and described in detail in D01 (Pale Blue Dot Energy - Axis Well Technology, 2015) and below. The evaluation for each store complex comprises four main steps:

1. Defining the storage complex.
2. Populating the model with reservoir properties.
3. Generating the development plan.
4. Assessing containment risks & remediation options.

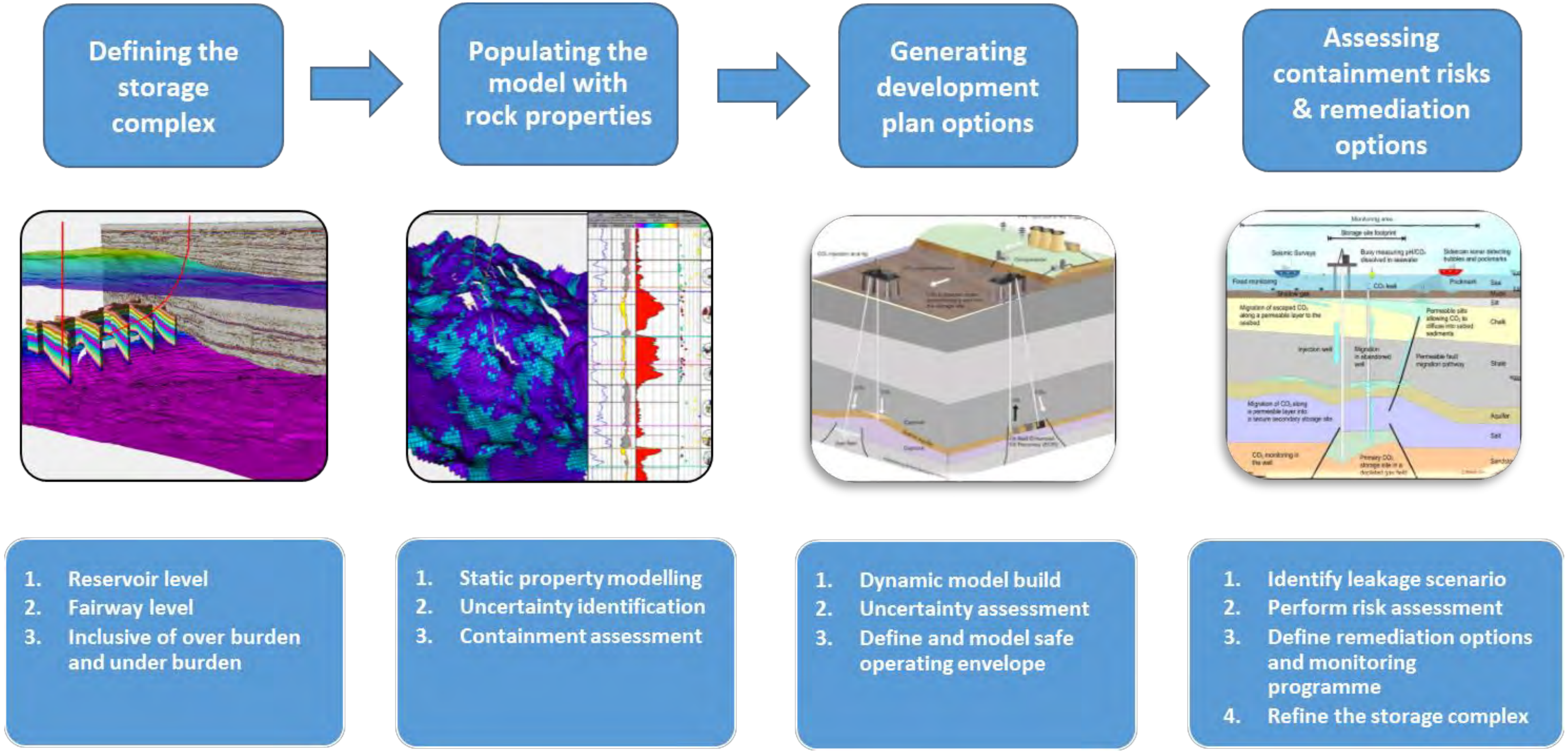

Figure 12 - Generic Technical Work Programme Outline for WP5

Base Work Programme

The outline work programme presented below is for a "data rich" site, from which other programmes can be drawn subject to data availability. This programme aligns and complies with current UK/EU directives for site licencing and certification (THE EUROPEAN PARLIAMENT AND THE COUNCIL OF THE EUROPEAN UNION,, 2009).

The workflow for this programme is drawn from direct experience from the Pre-FEED and FEED work programmes for Goldeneye and the Pre-FEED and FEED work programmes for the Captain Clean Energy Project storage solution called Aspen. The Base Work Programme is divided into 8 main sections:

1. Data Collection and Review
2. Data Interpretation and Construction of Static Models
3. Conceptual Development Plans
4. Performance Modelling and Assessment
5. Containment, Risk Assessment and Monitoring
6. Well Design
7. Development Plan Option Synthesis and Operational Planning
8. Documentation & Digital Library

1. Data Collection and Review

The section is aimed at collecting all the necessary information required for the subsequent sections, especially Sections 2 to 6. It consists of the following individual tasks.

WP5A.T1 - Data Collection and Maintenance - Interpretation of data and construction of models across a wide area surrounding the storage site will be required so that the storage complex as a whole can be characterised. This is important for reasons including understanding the areal pressure distribution during and after the injection cycle and also the potential interaction with and impact on other subsurface users. Data collection will focus on well and seismic data and to access public sources as well as data from current/previous field operators, if applicable.

WP5A.T2 - Data from the petroleum operators - The interpretation and models of the petroleum operator can be a valuable source of information and assist in the rapid review of the storage site. Where practical and timely, data release from operators under a confidentiality agreement will be collated. Whilst it is unlikely that such information and models could be uploaded to the ETI licensed database, such information can serve to improve the efficiency of the analysis, especially in the areas of well integrity and dynamic reservoir performance.

WP5A.T3 - Core Analysis Review - A rapid review of the availability and quality of core materials will be conducted together with assembly and quality control of both conventional core analysis and special core analysis where available. Ideally this will be linked with a short slabbed core viewing at a BGS facility where core from most released wells is stored in a national archive. The oil and gas focus of the operating companies will strongly influence the type of core tests that have been completed through the hydrocarbon cycle and that additional core tests will be required during CO_2 Storage. It is quite likely that these factors will contribute significantly to residual uncertainty and risk at the end of the study.

WP5A.T4 – Geological and Sedimentological Review - Log data will be used to establish an overall stratigraphic framework correlation across the available well data including a detailed hydraulic flow unit correlation within the storage reservoir. This will subdivide the subsurface into appropriate intervals for mapping and modelling work such that the permeable and impermeable formations can be accurately represented. Sedimentological review would access both regional and published papers in addition to operator reviews of wells and fields. This would build upon the brief core viewing in WP5A.T3 so that an understanding of the controls on reservoir quality can be developed as well as the distribution of permeability baffles and impermeable zones in the reservoir which can strongly influence storage efficiency and caprock intervals. The deliverable will be a short overview report and caprock intervals.

2. Data Interpretation and Construction of Static Models

This section is aimed at interpreting the data collected in Section 1 so that the results can be used in Section 3, “Performance Modelling and Assessment”. It consists of the following individual tasks:

WP5A.T5 – Seismic Interpretation - For four out of the five sites, the PGS Mega-survey merge survey will be used to seed a new independent interpretation of the reservoir, faults and overburden horizons by the study team so that the interpretation can be shared by ETI with others. Where present, the Mega-survey 3D seismic is of high quality and the outcome of the seismic interpretation is expected to deliver sufficient precision for the characterisation challenge. The well dataset will be used to establish well to seismic ties accurate enough to deliver robust horizon identification.

WP5A.T6 – Log Interpretation - Subject to the data availability, petrophysical analyses will be performed on a representative number of pre-selected wells to derive mineralogy, volume of clay, total and effective porosities, permeability estimates and water salinity, as applicable. These results will then be an input for property modelling as part of the static model construction and then used in the dynamic modelling.

WP5A.T7 – Pore Pressure Prediction - Pore pressure prediction through the overburden and target reservoir will be undertaken to ensure that safe robust well designs can be developed. Pore pressure is expected to be assessed from a wide variety of existing well and seismic information including logs, and mudlogs. This will be developed as a part of the overall geo-mechanical workflow.

WP5A.T8, T9, T10, T11 – Static Model and geological model uncertainty analysis - Due to the anticipated large size of the 3D seismic cube over the storage complex being characterised (perhaps up to 1,500 sq km) up to three different static models may be built to improve computational efficiency of dynamic models. These will be related in a parent and child sense to preserve consistency and build efficiency. Static models will be developed in Schlumberger’s Petrel Earth modelling system.

WP5A.T8 – Static Model Build - A finely gridded field static model will be constructed covering an area large enough to limit the final extent of any injected CO_2 plume. The model construction will involve data audit and loading, structural modelling, fine gridding and layering, and property modelling. Of particular focus will be the effective vertical and horizontal permeability of the storage reservoir on a large scale since the distribution of baffles and barriers to horizontal and vertical flow will control the migration of CO_2 away from the wells and also the "efficiency" of the store.

WP5A.T9 – Static Fairway Model Build - A coarser gridded “Fairway” model may be required to simulate any potential lateral movement of CO_2 out of the site and pressure interactions with other subsurface users. Such a model will be coarser in nature so that the computations involved in flow simulation can be completed in a reasonable timeframe. This is especially important as these models will be run for perhaps 1000 years into the future.

WP5A.T10 – Static Overburden Model Build - A coarse gridded model containing the over- and under burden will be constructed above and adjacent to the primary storage site in order to identify possible secondary containment horizons and potential migration pathways out of the storage complex. It will be used as a communication tool and drive tasks such as subsequent leakage workshops.

WP5A.T11 – Geological Model Uncertainty Analysis - The three static models described above will be reviewed in order to identify potential key parameters or assumptions and their associated uncertainties. This will contribute to the scenario definition for subsequent reservoir simulation sensitivities. Both the output from WP5A.T8, possibly WP5A.T9 and the uncertainty analyses will be further used as an input for the dynamic model construction.

3. Conceptual Development Plans

WP5A.T12 – Conceptual Development Plan - A series of development plan options for the site will be devised using the experience in the team. This will comprise an outline plan of the facilities required from the delivery flange of the offshore transport system through to the reservoir and will comprise wells, flowlines, and where appropriate offshore subsea and/or platform / floating structures. All development options will be maintained as possibilities for as long as possible and refined by delivery of outline cost assessments. The options will be aligned with the ETI CCS Scenarios analysis.

4. Performance Modelling and Assessment

The “Performance Modelling and Assessment” section is aimed at studying the injection performance (field and well based) of the site and to assess the performance of the caprock formations using both the static models constructed as well as collected data. It consists of the following individual work tasks.

WP5A.T13, T14, T15 – Dynamic Model Construction, Reservoir Simulations and Impact on Other Subsurface Users - The site static model developed in WP5A.T8, whose areal extent is based upon geological and geophysical interpretation work and a developed view of the storage complex will be used as a base for dynamic simulations. These will include model input and assumptions as well as appropriate history matching using production and injection data where this is available to calibrate the models dynamic performance. Storage sites capable of being dynamically history matched in this way can be significantly de-risked in terms of their medium to long term injectivity performance. Data Poor sites are likely to have limited dynamic data to support model calibration.

After an initial concept for development is defined, comprising well count, well type and facilities requirements, dynamic reservoir simulations will be performed to study the possible injection scenarios, effective dynamic storage capacity, reservoir pressure development during CO_2 injection and the extent of CO_2 plume migration from the injection points. From a developer perspective, these models may be used across many scenarios where both injection rates, well count, well placement, and numerous geological factors are sensitized so that a development plan can be designed to optimise the store. For this study and the timeframe available it is proposed that between 5 and 10 carefully selected scenarios are deployed for each site with the purpose of describing a wide range of potential performance outcomes. This is fully consistent with the Pre-FEED approach of Goldeneye, Hewett and the Captain Clean Energy Project. One of the anticipated key uncertainties in this work will be the CO_2/brine relative permeability properties of the storage reservoir. Even at the end of "DEMO1" FEED, there were no existing CO_2/brine relative permeability datasets available for any UK formations. Oil and gas experience shows that such properties vary significantly from one formation to another. Where necessary carefully selected analogue data will be used to fill data gaps whilst the uncertainty that this introduces will be monitored and minimised.

In the event that the pressure distribution during injection exceeds the boundaries of the WP5A.T10 model and/or the CO_2 plume escapes the modelled area, the WP5A.T11 “Fairway” static model could then be used to run additional simulations if required. These models will also be important to understand the possible impact on other subsurface users, such as oil and gas fields currently in production or perhaps other CO_2 Storage operations such as those assumed to active at Goldeneye or 5/42. A key output from these tasks will include the outline development plan.

WP5A.T16, T17 – Wellbore Injectivity and Near Wellbore Issues - Wellbore injection simulations will give a first look at the technical challenges related to the flow of CO_2 in the wellbore studying the potential impacts of different wellhead temperatures, different CO_2 phase injections, mass rates, different tubing sizes, impurities or possible transient regime studies such as start-up, ramp-up or down operations. The outcome of the simulations would include a CO_2 flow regime along the wellbore, wellhead pressures, flowrates, required number of injector wells and bottom-hole temperatures for each of the simulations performed. This is of particular significance for heavily depleted reservoirs such as some gas fields where the reservoir pressure is so low that early injection might have to be in gas phase rather than dense phase.

WP5A.T18, T19 – Geochemical and Geo-mechanical Review - Both geochemical and geo-mechanical review will be performed to study their potential impact on injectivity and geological containment. Geomechanical review will include consideration of leak-off and/or fracture pressures, pore pressure and local stress regime which will influence the selection of well types and well geometry. This is essential work and will contribute to the risk assessment and eventually injection operations. It will also assess the fault reactivation risk during the injection phase.

The objective, of the geochemical review work on the five sites, is to assess the range of possible geochemical consequences of injecting CO_2 into all five sites as part of UK-wide review of optimum sites for the geological storage and possible sequestration of CO_2 (Figure 13).

It is initially assumed that two key questions are:

- Whether increasing the amount (partial pressure) of CO_2 in the reservoir/aquifer/storage site will lead to mineral reactions which result in either increase or decrease of porosity and permeability of the reservoir; and
- Whether elevated partial pressure will compromise the caprock also by mineral reactions.

The preferred method is to collect water geochemical data, gas geochemical data (pre- CO_2 injection) and mineral proportion data from the reservoir and the caprock. These data all need to be quality controlled and simple initial values for water geochemistry, mineralogy and gas geochemistry for each site need to be decided. These then need to be modelled for equilibrium reactions to assess how the porosity (integrity) of the host rock may change. The sensitivity of the model output to varying the input data will be explored. An initial kinetic study of the geochemical reactions in the reservoir may then be undertaken with appropriate estimates of rock fabric and by the selection of appropriate kinetic constants for the identified reactants.

Modelling will be performed using Geochemists Workbench.

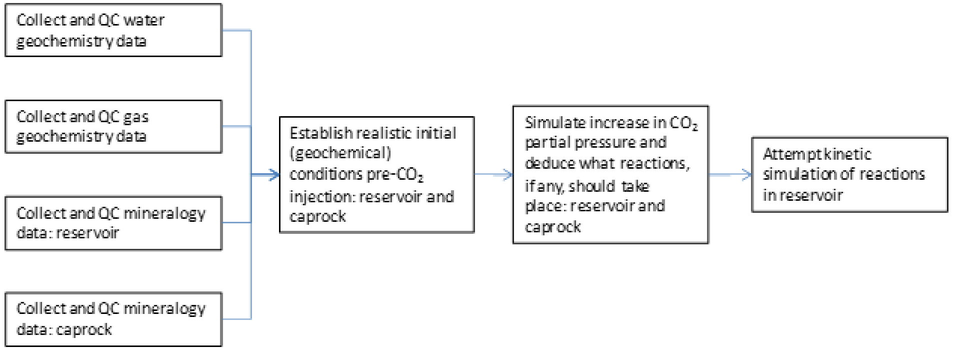

Figure 13 - Methodology for Geochemical Modelling

WP5A.T20 – Safe Operating Envelope - The results of WP5A T16 through T19 will inform and provide guidance on the safe operating envelope. This will be guidance only since it is not known at this point what the dispatch pattern of the power or industrial CO_2 sources might be. It will focus upon issues including; maximum injection rates per well at any given point in the operations so that the integrity of the site can be protected at all times; CO_2 purity requirements of injected CO_2; Wellhead temperature operating envelope, this is required to prevent thermal damage to casing or cement which might results from a series of operational well shut ins over a short period of time; maximum reservoir pressure limits - to preserve geo-mechanical integrity.

5. Containment, Risk Assessment and Modelling

This section is aimed at studying whether the CO_2 can be effectively contained within the storage complex after injection. This is perhaps the single most challenging area of CO_2 Storage appraisal since the work programme must try to "prove a negative", that the store will not leak. This task will focus upon the geological and engineering containment of the injected inventory and will deploy an evidence based approach to risk assessment. It involves six steps (Figure 144) and builds upon the work packages already in place.

Figure 14 - Six Step Storage Integrity Definition

WP5A.T21 – Storage Complex Definition - As per EU CCS directive 2009/31/EC the storage complex includes the storage site (defined volume area within a reservoir formation used for geological storage) and the surrounding geological domain which can have an impact on overall storage integrity and security (secondary containment formations). The storage complex will be defined based on the performance modelling and assessments carried out in WP5A.T10 through WP5A.T17.

WP5A.T22 – Step 1 Characterisation - Integrated Geological and Engineering Containment - Geological integrity describes the ability of the reservoir / caprock system to retain CO_2 for the long term and the nature of the secondary barriers which might prevent the CO_2 from reaching the atmosphere in the unlikely event that the CO_2 does migrate from the primary storage reservoir. Natural exit routes from the sink potentially include faults and fractures in the overburden, or permeable formations through which the CO_2 could move under its natural buoyancy or other pressure differential. For the purposes of licensing, it is also important that the CO_2 should not migrate out of the license area which has been specified and so leakage outside the license area should also be considered to be a loss of integrity. Various aspects will be considered including cap rock assessment, geomechanics, geochemical integrity, well integrity and full overburden configuration. A well integrity summary will be prepared for a representative number of legacy wells.

WP5A.T23 – Step 2 Leakage Scenario Definition Workshop - This will cover all aspects of natural and engineering integrity and is described above. The project team will come together, potentially with selected key stakeholders to brainstorm an inventory of potential leak paths (both geological and engineered). These will be drawn together into an inventory and their risk and likelihood assessed with all available evidence. These risks will form the basis of the risk assessment.

WP5A.T24 – Step 3 Degradation modelling - This will review the potential for future change in the subsurface and well environment resulting largely from chemical interaction. In wells, the rate at which completions and abandoned well materials will corrode and react in the presence of CO_2 will be considered and an assessment made of the impact of such degradation on well integrity. In the subsurface, a similar assessment on the potential for rock fluid interaction is already included in WP5A.T20 and will be used as input to this.

WP5A.T25 – Step 4 Subsurface and Wells Containment Risk Assessment - Once the inventory of identified issues for a site containment has been assembled, they will be ranked according to their impact and likelihood of occurrence as:

● Critical ● Serious ● Moderate ● Minor

The containment attributes of the site will then be considered against a hypothesis such as "Site A subsurface environment has the attributes which will enable the containment of 100Mt CO_2 on an indefinite basis."

WP5A.T26 – Step 5 Remediation Option Development - For each key risk event a remediation option will be established and a high level cost will be developed. This will distil into a clear view of storage site integrity across the complex. A key output will be a containment risk assessment table which will include a clear description of the containment risk, an assessment of the likelihood of loss of containment and its impact, potential options for remediation and high level cost. Options to improve the integrity status will be identified as required and possible.

WP5A.T27 – Step 6 Monitoring Programme – Feasibility Assessment & Plan - A proposed outline programme of monitoring will be developed to carefully monitor subsurface and well integrity across the storage complex according to the risk assessment and remediation options completed. Monitoring will be tailored to the specific nature of each site.

6. Well Design

This section is primarily focused at the design of new injectors / monitoring wells. In some rare circumstances there may be existing wells that might represent candidates for recompletion. The following tasks are envisaged:

WP5A.T28 – Specify Initial Well Design Criteria - This is effectively the basis of design for the new wells and will clearly state their intended purpose, lifetime and where possible the range of operating conditions including rates, operating temperature envelope, cement and materials selection, and clarity upon the downhole equipment required for monitoring, control, and future intervention or remediation options.

WP5A T29 – Design of up to 5 new injector/monitoring wells for each site including outline costing. - The Initial well design together with WP5A.T23, the Conceptual Development Plan WP5A.T12 and dynamic modelling results WP5A.T14 will be used to plan and cost the inventory of development wells for injection/monitoring. Well design will reflect the proposed well type and include outline casing and completion design, depths and costings.

7. Development Plan Option Synthesis and Operational Planning

WP5A.T30 – Development Plan Option Synthesis and Operational Planning - In WP5A.T12 A series of conceptual development options were identified. This section draws the results of a wide range of tasks together to deliver a synthesis of the development plan options. In particular which options are looking favourable, what the key remaining uncertainties are and what further risk reduction is envisaged in order to finalise a select decision.

8. Documentation & Digital Library

Two interim progress reports will be delivered during WP5A comprising D07 and D08. The final task for this work-package will be **WP5A.T31**. This will be to consolidate the findings into a concise technical report (Outline Storage Development Plans D09 to D13) with a summary for non-technical readers. The data without commercial IP restrictions will be consolidated into an indexed digital library ready for supply to ETI.

At the end of the work on the first storage site, a Peer Review (R07) will be held with selected stakeholders. This will help to guide progress on the subsequent 4 storage sites. This will include a preliminary data transfer cycle for the models being used to confirm transfer logistics.

The following sections carry further details of the bespoke requirements for each site which will be built into the WP5 programme.

7.1 Hamilton Gas Field

The Hamilton gas field (248.002) has been on production since 1997 and is a mature depleted gas field and will cease production at very low reservoir pressures. It is expected therefore that CO_2 will be injected in gas phase initially. As the reservoir pressure increases with CO_2 injection, the CO_2 will move gradually into a dense phase within the reservoir. A compositional model (Eclipse 300) will be used for the dynamic modelling for this site evaluation. This will allow the model to account for the mixing of CO_2 and in-situ gas, the impact of phase change and the solubility of CO_2 into water present in the reservoir.

The model will be used to confirm capacity and containment and to evaluate the development plan scenarios for the storage site, as stated in D01. The model will be calibrated to available historical production and pressure data prior to running development sensitivities.

Although faults do extend above 800m, in fact they may go to sea bed. It's not seen as a containment risk as the reservoir has already contained gas over geological time. As part of the seismic interpretation all the faults and their extent will be interpreted and incorporated into our 3D static models.

It is recognised that there could be a risk of halite issues due to reservoir dehydration. An attempt to qualify the risk will be carried out as part of the geochemistry work scope. The impact will not be incorporated into the modelling study as quantification of the impact will be too uncertain without further extensive study work. However the risk mitigation will be included in the development cost.

Hamilton is a relatively shallow reservoir in addition to being pressure depleted. This imposes challenges to the well design described in D01 (Pale Blue Dot Energy - Axis Well Technology, 2015). These challenges will be addressed and the optimum well design and cost generated for this site.

Key Challenges:

- Shallow Depth at the crest.
- Overburden faulting extends to surface.
- Very low pressure depleted gas field.
- No PGS 3D seismic coverage.
- Potential risk of halite precipitation in near wellbore area.

Workplan Adaptations:

- Detailed overburden structural mapping.
- Acquire 3D seismic from ENI.
- Qualify the halite risk through geochemical study.
- Detailed well design and phase control consideration.
- Appropriate geomechanics and PVT assessment (mixing methane and CO_2).

7.2 Viking Gas Field

The Viking gas field (141.035) is comprised of nine accumulations, some of which started production in the 1970s. It is a mature depleted area and, like Hamilton, it is expected that CO_2 will be injected in the gas phase initially as the reservoir pressure will be low but as the reservoir pressure increases with CO_2 injection, the CO_2 is expected to change to dense phase within the reservoir. A compositional model (Eclipse 300) will be used for the dynamic modelling for this site evaluation.

The model will be used to confirm capacity and containment and to evaluate the development plan scenarios for the storage site, as stated in D01 (Pale Blue Dot Energy - Axis Well Technology, 2015). The model will be calibrated to available historical production and pressure data prior to running development sensitivities.

Injectivity was highlighted as a concern during the due diligence. On average, permeability ranges from 0.1mD to 100mD and hydraulic fracturing was employed to improve the productivity from the field. However, some wells report permeabilities up to 800mD and it is expected that some better injectivity regions might exist. A key task within the detailed modelling will be to generate a better understanding of the permeability distribution to help locate injection targets.

Well density is relatively high in the Viking fields, with a large number of wells abandoned before 1986. This leads to a high engineering containment risk. Understanding the impact of the hydraulic fractures on CO_2 plume migration will be an important factor in the subsurface uncertainty modelling, in order to understand the containment risk associated with CO_2 reaching the high well density regions.

Injection target areas will be located in areas of higher permeability that also avoid the CO_2 plume migrating to the high well density areas.

Key Challenges:

- Classic Leman Gas Field compartmentalization.
- Variable reservoir quality and therefore injectivity.
- Legacy well risk from old wells.
- Access to allocated production and dynamic pressure information.

Workplan Adaptations:

- Develop a good understanding of reservoir quality variation and controls.
- Use the compartmentalization as a containment asset to manage risk.
- History match to production.
- Carefully review legacy well records where available to illuminate well integrity risk.
- Consideration of sealing CO_2 as well as CH_4 .

7.3 Bunter 36 Saline Aquifer Closure

Bunter closure 36 (139.016) sits above the Carboniferous Schooner gas field (327.000) which is scheduled to cease production in 2021. There is good coverage of the whole structure from the PGS Mega-survey 3D and there are four available well penetrations of the Bunter Sandstone from wells that targeted the deeper Carboniferous gas bearing reservoir. Some core data is also available from the Bunter.

These wells are: 44/26-2, 44/26-4, 44/26-1, 44/26-3

The development wells drilled for the Schooner field are unlikely to be available for this project. Seismic to well ties have been confirmed and the seismic data quality is good. No issues are anticipated in building a depth interpretation model for the subsurface in this area.

The structural trap style of this site means that the full area defined for this Bunter closure will be included in the storage site model and the work programme defined in D01 will be carried out (Pale Blue Dot Energy - Axis Well Technology, 2015). A further periphery around the lowest closing contour will be added to ensure there is representative grid block coverage so that any egress of CO2 from the closure can be modelled without boundary effects. As with the other saline aquifers, Eclipse 100 will be used to confirm capacity and containment and to evaluate the development plan scenarios for the storage site.

Uncertainty associated with the minimum fracture pressure was identified during the due diligence. The values quoted from CO2Stored are derived from correlations which appear to give very low minimum fracture pressures. This can be observed in the large discrepancy between the measured and estimated values for the 5/42 store; measured: 3900 psi vs estimate: 2800 psi. A review of published papers suggested a fracture gradient of 0.728psi/ft for the Bunter, giving a fracture pressure of 3,312 psi at the well depth of 4,550 ft TVDSS. The geomechanics work programme will address the uncertainty in fracture pressure.

Petrophysical analysis and review will be carried out for a selection of storage site wells and offset Bunter sandstone wells. This will include a review of offset well permeability from core analysis and the results of any well tests carried out within the Bunter sands. This work will help reduce the uncertainty associated with the Bunter rock properties, identified during the due diligence process.

Additional sensitivities will be run to explore the impact on Bunter Closure 36 performance of CO_2 injection into the Bunter Sandstone at the 5/42 site under different connectivity assumptions. A pressure boundary will be incorporated into the site model as opposed to building a dynamic model that extends to 5/42.

Key Challenges:

- Shallow Depth at the crest.
- Overburden faulting extends to surface.
- Potential risk of halite precipitation in near wellbore area.
- Uncertainty regarding Bunter Sandstone reservoir quality and the strength of aquifer support.
- Impact of high water salinity on potential for halite precipitation in the near wellbore drying zone during injection.
- Nature of the overburden structure and its impact on the integrity of the closure.

Workplan Adaptations:

- Detailed overburden structural mapping.
- Qualify the halite risk through geochemical study.
- Detailed well design and phase control consideration.
- Appropriate geomechanics and PVT assessment (mixing methane and CO_2).
- Quantify the reservoir quality through careful petrophysics and use of adjacent wells.

7.4 Captain Open Aquifer

Due to the seismic coverage and depth aspect of the Captain Sandstone formation, it has been decided to focus the detailed work programme on the "pan handle area" of the Captain fairway where there is good 3D coverage, good well data coverage and the potential for excellent dynamic calibration if dynamic pressure data can be released from the operating companies in the area. This also enables a more targeted static and dynamic model to be developed. Previous studies (Mackay, Quinn, Hitchen, Akhurst, & Jin, 2012) have suggested that the area defined in Figure 15 is a suitable storage area for the objectives of this study as the CO_2 plume is likely to be constrained to the "pan handle" area even after a significant inventory is injected. A review of these studies will be carried out and it is expected that the subsurface model will built over the area defined in **Error! Reference source not found.**.

The key risk identified as part of the due diligence is the containment risk as the top seal is relatively thin and also there is significant uncertainty in the site boundaries and fault connectivity.

Using the 3D seismic available in PGS CNS mega-survey, a detailed seismic interpretation will be undertaken to identify any faulting and these faults will be included in the 3D models to look at juxtapositions of caprocks and reservoir formations across the faults. Seismic attributes such as a coherency volume will be derived to aid rapid fault interpretation. After calibration with all the available well penetrations in the area of interest, the Top and Base Captain events will be interpreted to delineate the reservoir fairway. Previous studies (Shell Static Model Reports, Peterhead CCS Project, 19th March 2015) have highlighted the

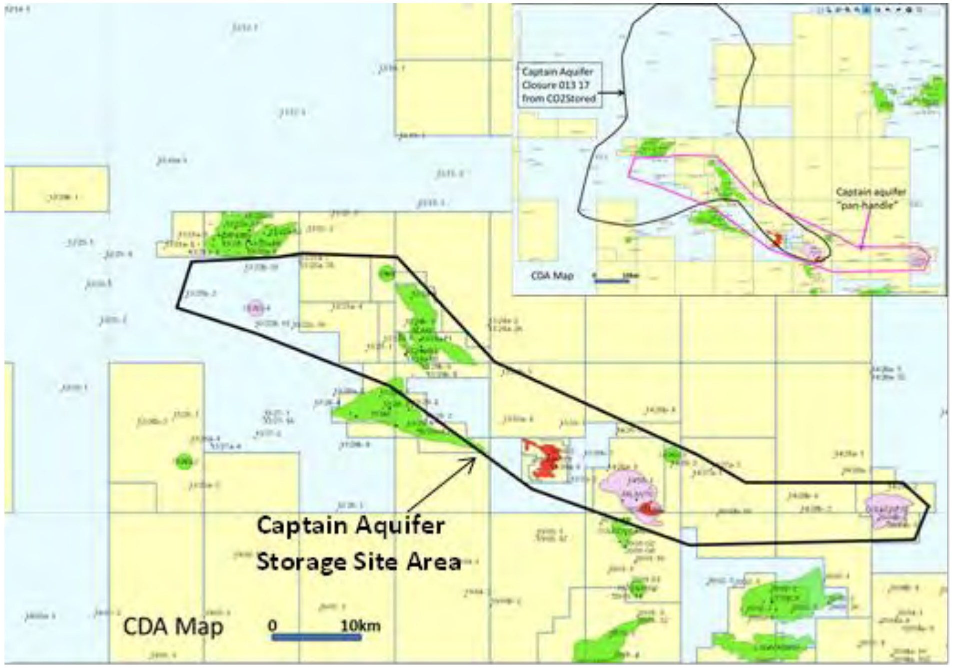

Figure 15 - Outline of proposed focus area for the Captain Sandstone Aquifer

uncertainty in defining the sand pinchout edge and a range of edges will be evaluated as a sensitivity in the models.

The geochemistry and geomechanics work programmes will be used to evaluate the uncertainty in top seal strength.

Eclipse 100 will be used to confirm capacity and containment and to evaluate the development plan scenarios for the storage site.

Simulation models will assess the degree of potential interference between Goldeneye CO_2 injection and that resulting from this project. It is anticipated that any injection into the aquifer whilst the Goldeneye CO_2 injection project is operational may slightly reduce the ultimate capacity of the Goldeneye structure itself.

Key Challenges:

- Large area.
- Nature of northern and southern limits.
- Reservoir pressure management.
- CO_2 migration pathway.
- Injection point selection.
- Access to dynamic pressure data from operators.

Workplan Adaptations:

- Detailed overburden structural mapping especially on northern and southern limits.
- Careful assessment of maximum allowable injection pressure and spacing of wells to maintain injection below this.
- Structural definition of the Top Captain Sandstone.
- Characterisation of the mid Captain Shale.
- Sensitivities on interaction with Goldeneye injection.

7.5 Forties 5 Open Aquifer

The Forties 5 aquifer (372.000) is one of five identified Forties aquifer sites within CO2Stored (Energy Technologies Institute, 2010). Unlike the other four sites, Forties 5 has a very significant potential capacity contribution and a very extensive covering an area of 13,804 sq km. It would therefore be subject to a phased development over many years. In the context of the WP5 objective, it is impractical and unnecessary to model such a large area with the fine grid definition required to predict the CO_2 plume migration over a 1000 year period with confidence. Therefore, for the Forties 5 aquifer, there will be an additional modelling step carried out at the start to locate an area within the Forties 5 aquifer that would represent a good starting point for a CO_2 storage project and from which a build out programme can be developed.

Locating the storage site within the aquifer

A 3D static model of the whole aquifer at an appropriate scale will be built using Petrel interpretation and modelling software.

Database

Up to 50 wells will be selected across the site from CDA that have composite logs, velocity data and digital logs. They will form 6 SW-NE correlation lines appropriately spaced across the site. Data availability for these wells is variable and diverse.

The site is covered by 3D seismic (PGS CNS Mega-survey) and is generally of good quality enabling a reliable depth model of the Forties reservoir to be developed.

Well Correlation

The Top and Base Forties Member picks for the selected wells will be entered from composite logs. Available digital log data will be imported and used to review and QC these to ensure consistency. A simple layering scheme appropriate for the Forties reservoir architecture will be developed and correlated throughout. This will seek to characterise sand dominant and shale dominant intervals which will be important to injected plume mobility and migration.

Seismic Interpretation

Top Forties will be interpreted on the 3D seismic. This will represent the structure of the top surface of the main storage unit and so will be an important influence on the mobility of injected CO_2.

Synthetic seismograms will be generated for approximately 10 wells to confirm the Top Forties seismic pick.

Seed interpretation will be undertaken using approximate 1000m (E-W) x 3000m (N-S) line spacing. This grid will serve as the input for auto tracking the Top Forties event to give a more complete surface.

Major faults will be interpreted.

Simple polynomial time-depth function (derived from checkshots) will be applied for the depth conversion and depth residuals applied to tie the wells.

Seismic amplitudes will be evaluated to help define the sand prone fairways and any important and persistent small scale structural features.

The Base Forties will be derived by adding a well derived isochore (vertical thickness map) to the Top Forties depth map.

The Top and Base Forties will be the inputs to the structural framework of the static model.

Static modelling

The Top and Base Forties depth surfaces will be used to build a simple 3D geological grid, incorporating major faults as required. An appropriate vertical grid resolution will be used, based on the resolution required to capture the main sand/ shale sequences. A simple Gamma Ray cut-off will be used to generate a simple sand/ shale facies log.

A simple sand/ shale facies model will be built in order to capture the main heterogeneity within the Forties Sand. The distribution and proportions will be controlled by lateral and vertical trends from the selected well data, and seismic attribute information (if possible). Published analogue data will be used for defining the facies model.

No detailed petrophysical analysis will be carried out, porosity and permeability will be based on core data, where available, and published well averages. Regional trends observed within the Forties Sand Fairway will be incorporated into the model.

The geological and simulation grid will be at the same scale, therefore requiring no upscaling.

Simulation

The dynamic simulation, for this stage, will be carried out using a black oil streamline simulator. Streamline simulation relies on transporting fluids along a dynamically changing streamline-based flow grid, as opposed to the underlying Cartesian grid. The result is that large time step sizes can be taken without numerical instabilities. Streamline simulation is many orders of magnitude faster than finite difference simulation and will allow the required sensitivities to be run to evaluate CO_2 plume migration within different targeted areas in the Forties aquifer.

Within the Forties Aquifer, regions exist where the well density is high resulting in a high engineering containment risk. These areas are mostly associated where oil field development wells are located e.g. Forties, Britannia and Guillemot. The objective of the initial screening modelling will to be to identify the injection sites within the low well density areas from which the CO_2 plume does not reach the high containment risk regions. The area with the most promising lateral containment ability will be selected for the more detailed modelling study.

Development Plan Generation

Once the target area within the Forties aquifer has been selected the study will progress as defined in the generic work plan with a refined model over a smaller area.

Defining the tank

Synthetic seismograms will be generated for additional wells in the target area to ensure the correct seismic picks are made. A detailed seismic interpretation of the top and base Forties will be undertaken together with the overburden and under burden. A site specific depth conversion study will be undertaken and the resulting velocity model used to depth convert the time horizons and faults.

Static modelling

The Top and Base Forties depth surfaces together with any interpreted faults will be used to build a 3D geological grid. Volume Base Modelling within the Petrel software will be used. Petrophysical analysis will be completed on a number of wells and the results incorporated into the property modelling.

An overburden 3D static model will also be constructed using the depth converted seismic horizons and faults to aid the containment assessment and identify secondary containment horizons.

Dynamic modelling

Eclipse 100 will be used to confirm capacity and containment and to evaluate the development plan scenarios for the storage site. Eclipse 100 has the capability to model the solubility of CO_2 into brine and the vaporisation of water into the CO_2 plume and will allow for a much faster run time compared to a compositional model.

The key risk is that the CO_2 will reach an area of high well density and high containment risk and the impact of subsurface uncertainties on CO_2 plume migration will be evaluated.

Key Challenges:

- Extreme areal extent 13,803 sqkm.
- 90 x area of 5/42 or 800 x area of Goldeneye.
- Open Aquifer Trapping Mechanism.
- Selecting where to start.
- Long term development plan.
- Huge well data set (1840).

Workplan Adaptations:

- Build a storage model for the whole area.
- Scoping simulation model to define initial development area.
- Detailed model of the initial development area.
- Focus on long run simulations to monitor low velocity trapping.

7.6 CCS Build Out Scenario

The project basis of design was developed around meeting the requirements of the ETI Scenarios for CCS build out in the UK. The portfolio sites have been considered in the context of these scenarios and tested against them.

Concentrated Scenario

The concentrated scenario focuses the CO_2 transport from St Fergus and also Humberside building directly out of the Phase 1 projects. Figure 16 shows this scenario overlain on the selected portfolio. Since this scenario has no CO_2 export into the Irish Sea before 2030, Hamilton field is not developed by this time. Also it is envisaged that neither Viking nor Bunter Closure 36 will be required in this timeframe, but that Hewett might initially take up a CO_2 supply in 2029, with 5/42 carrying most of the injection loading.

In the Central North Sea, the Captain Aquifer comes on line in 2023 with the Forties much later in 2028 as demand builds.

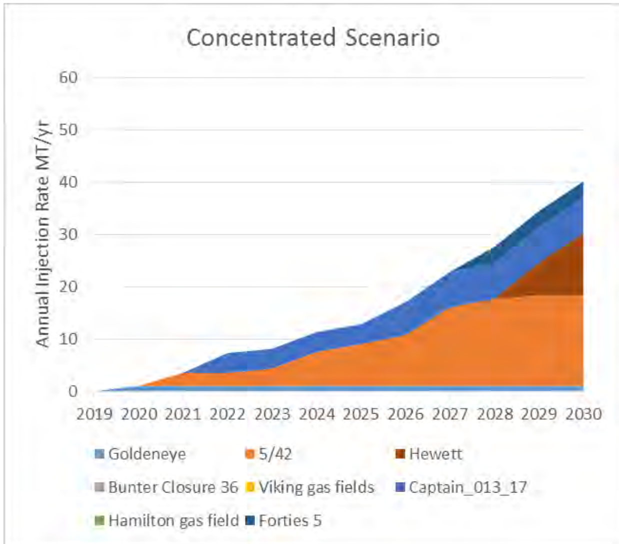

Figure 16 - Concentrated CCS Build Out Scenario with Recommended Portfolio

Concentrated Scenario (MT/yr)	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Goldeneye	0.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
5/42	0.00	0.00	2.50	2.50	3.30	6.50	8.00	9.70	15.00	16.70	17.30	17.30
Hewett	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	6.24	11.90
Bunter Closure 36	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Viking gas fields	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Captain_013_17	0.00	0.00	0.00	3.80	3.80	3.80	3.80	6.30	6.80	6.80	6.80	6.80
Hamilton gas field	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Forties 5	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	3.10	3.10	3.10
Total	0.00	1.00	3.50	7.30	8.10	11.30	12.80	17.00	22.80	27.60	34.44	40.10

Table 15 - Concentrated CCS Build Out Scenario

Balanced Scenario

The Balanced scenario sees a much faster and more geographically diverse CCS build out that includes CO_2 into the East Irish Sea and also from the Thames area (Figure 17). Again the five sites can easily accommodate this scenario alongside Phase 1 projects and Hewett. Here Viking and Hewett are deployed in the Southern North Sea ahead of Bunter Closure 36. In the Central North Sea, the Captain is brought online in 2022 to support Goldeneye and then at the end of the decade, the Forties aquifer development begins (Table 16).

By 2030, with the addition of the portfolio of five sited recommended here, there is the possibility that potential CO_2 Storage capacity under development could exceed 1500MT even without the Forties aquifer which could in time contribute a further 1000MT over time.

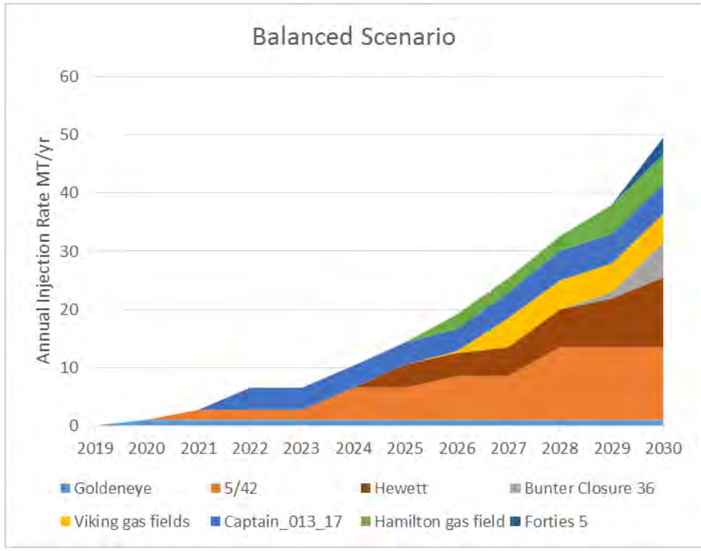

Figure 17 - Balanced CCS Build Out Scenario with Recommended Portfolio

Balanced Scenario (MT/yr)	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Goldeneye	0.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
5/42	0.00	0.00	1.70	1.70	1.70	5.50	5.50	7.50	7.50	12.50	12.50	12.50
Hewett	0.00	0.00	0.00	0.00	0.00	0.00	4.00	4.00	5.00	6.50	8.40	12.00
Bunter Closure 36	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.00	6.00
Viking gas fields	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.30	5.00	5.00	5.00	5.00
Captain_013_17	0.00	0.00	0.00	3.80	3.80	3.80	3.80	3.80	4.40	5.10	5.10	5.10
Hamilton gas field	0.00	0.00	0.00	0.00	0.00	0.00	0.00	2.50	2.50	2.50	5.00	5.00
Forties 5	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	3.00
Total	0.00	1.00	2.70	6.50	6.50	10.30	14.30	19.10	25.40	32.60	38.00	49.60

Table 16- Balanced CCS Build Out Scenario

7.0 Conclusions

Recommended Portfolio

1. The five sites have been selected as a portfolio to meet the project objectives. There are many other sites within the Select Inventory and the Qualified Inventory and beyond that can be developed into successful CO_2 Storage sites.
2. Aggregate storage of the Recommended Portfolio ~ Mid case capacity of 1.6GT.
3. Able to service all of the likely UK beachheads using 2 sites in the CNS, 2 in the SNS and 1 in the EIS.
4. Robust to systemic failure through varied geology and store type: 2 depleted gas fields, 1 closed aquifer and 2 open aquifers.
5. Knowledge and understanding of each site can be materially progressed during the remainder of the project.
6. Likely to provide valuable knowledge and strategic insight into development options for UK CO_2 storage - especially with respect to the range of different types of development that will be required, e.g. phased developments of the Forties aquifer or multi-compartment Viking area.
7. Portfolio endorsed by stakeholders during Stakeholder workshop 3.
8. Reserve sites have been identified for each of the sites in the portfolio to provide contingency options in case a "show stopper" issue is identified early in the next phase on one or more of the sites.
9. Together with 5/42, Goldeneye and Hewett, there is good potential to have at least 1500MT of CO_2 storage capacity under development by 2030 with a further 1000MT in the large Forties 5 Open aquifer system.

Due Diligence

10. The due diligence evaluation provided updated capacity estimates for each of the Select Inventory, in most cases based on a more accurate seismic-based mapping of the container (compared to the high level approach applied by the UKSAP analysis).
11. Site-specific assessments of injectivity and containment allowed a site-by-site comparison using a consistent approach for each store type and the project requirements set-out in WP1.
12. The project-specific hypotheses tested during the evidence due diligence assessment was successful at identifying the candidate sites most suitable for UK CCS Phase 2 whilst also highlighting those sites which carry good potential for later development.

Process

13. Evidence-based approach to due diligence worked very well in focusing the team on the key attributes that needed to be assessed and judging the meaningfulness and reliability of the information.
14. Working with 20 "kite" assessments was complex and more time-consuming than originally envisaged.

15. The portfolio creation process worked well & was both effective and efficient at assessing the "fit" of the 15,504 potential combinations.
16. Expert judgement was applied to the output from the portfolio computations to ensure appropriate fit with the project objectives.

Development Costs

17. Two outline development scenarios have been designed for all 20 sites in the select portfolio.
18. A comparative development scenario for each site assuming 100MT capacity & comprising 5 wells plus facilities.
19. Unit costs of the comparative developments range between £3 - 10.4/T with a mean value of £8.28/T CO_2.
20. An ultimate development scenario for each site assuming full capacity & comprising 5 wells plus facilities.
21. Unit costs of the ultimate developments range between £4 - 14.5/T with a mean value of £6.02/T CO_2.

Data

22. The PGS seismic data has also been invaluable in this phase of work.
23. Well log data in CDA is variable both in terms of completeness, quality & format. This required additional time for data handling & conversion.
24. Only 2D seismic data is available within CDA for the Hamilton field & additional seismic data will need to be procured from the field operator (Eni).

8.0 Recommendations

1. The recommended portfolio comprises Viking Gas Field and Hamilton Gas Field, Bunter Closure 36, Captain Aquifer and the Forties Aquifer. This portfolio comprising two depleted gas fields, one structurally closed aquifer and two open saline aquifers should be progressed to WP5.
2. The Forties 5 Open Aquifer will require a “Site Selection” work package. This is because the whole aquifer covers a very large area, and the initial challenge is to understand where best to start the development. This initial site must start to demonstrate the full strategic potential of open aquifer systems, but be located where a higher proportion of the injected CO2 inventory could be held within structural closures of different sizes. Some of these may be depleted oil and gas fields. Once the initial injection site is identified and peer reviewed and approved then that area will be the focus of WP5 activity for the Forties 5 Aquifer.
3. As a consequence of the Site Selection step in the Forties, this site should be started first.
4. In order to optimise project deliver and efficiency within the set timeframe and budget, it is recommended that two technical teams work in parallel. The Saline Aquifer team will focus upon the Bunter Closure 36, Captain and Forties Aquifers. The Depleted Gas Field Team will focus upon Hamilton Gas field in the East Irish Sea and also Viking Gas Field in the Southern North Sea. These two groups of site will have similar technical challenges and workflows.
5. Early engagement with operators of Hamilton and Viking is important to secure access to important dynamic data. Support from DECC and/or OGA should significantly help in this task.
6. A formal request to National Grid Carbon for key data at 5/42 should be made which will support the progression of Bunter Closure 36. Whilst Bunter closure 36 can be progressed without this data, the outcome will be improved with this information.
7. Engagement with the CO2Multistore team should continue to optimise the outcome of the Captain Aquifer site.
8. Further Petroleum operator engagement may be required once the Forties 5 Aquifer target initial injection point is identified.
9. It is recommended that the project proceed and procure the 3D data over Hamilton gas field from holders ENI.
10. There are very many other high quality stores within the UKCS beyond the five selected here. Twenty are detailed in Appendix 2 and Appendix 5. There are many others beyond this.

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App. 1 Workshop Report – 29th July

A Stakeholder workshop (03) was held on 29th July in Banchory and hosted by PBD. The objectives of this workshop were:

To keep CO_2 Storage stakeholders appraised of project progress and enrol interest from the CCS stakeholder community.

Stimulate debate around the selected portfolio of 5 sites & gather input to the process.

The materials assembled here represent a workshop report and were "work in progress" as of 29th July.

Participants

- Jeb Tyrie APEC Ltd
- Henry Allan, Independent
- Steve Furnival, Independent
- Sandy Petrie, Independent
- Arnaud Vanderbeken, Schlumberger
- Peter Brand, Taqa
- Mike Edwards, UKCCSRC
- Gordon Sim, SCCS
- Kirsty Andersen, GCCSI
- John Williams, BGS
- Brian Allison, DECC
- Den Gammer, ETI
- Andrew Green, ETI
- Alan James, Pale Blue Dot Energy
- Steve Murphy, Pale Blue Dot Energy
- Jen Hickling, Pale Blue Dot Energy
- Sam Gomersall, Pale Blue Dot Energy
- Ken Johnson, Axis Well Technology
- Doug Maxwell, Axis Well Technology
- Angus Reid, Costain

Agenda

Start	Topic	Lead
10:00	Welcome & Safety Briefing	SJM
10:05	Purpose of Workshop	SJM
10:10	Strategic UK CCS Storage Appraisal Project	SJM
10:25	Screening & Selection Subsurface Due Diligence Conceptual Development Portfolio Assessment	 KJ AR ATJ
11:10	Break	All
11:20	Recommended Portfolio	ATJ
12:20	Lunch	All
12:35	Workshop Session	All
13:40	Next Steps	SJM
13:45	Close	SJM

Output

Endorsement of the Top 5 sites proposed by the team

Bunter Closure 36 – Good site when compared to other closures. Would benefit from some key information from 5/42 - Unanimous decision to support this site in the portfolio.

Viking – Challenging, typical of Rotliegendes Storage sites, need to history match to create dynamic model (only 1 set of production data), better than the only Rotliegendes Group alternative Barque - Unanimous decision to support this site in the portfolio.

Hamilton – Shallow, close to emissions in NW England, and earliest available EIS site. Would provide encouragement that ccs in the west was under active consideration. High supply potential. Unanimous decision to support this site in the portfolio.

Forties 5 – Good site in Open aquifer system, albeit with structural closures. Key challenge is where to start? Unanimous decision to support this site in the portfolio.

Captain aquifer – Other work ongoing that won't ever be in public domain. Important to progress this site to add info to public domain. Co-operation from Multistore and Goldeneye would be beneficial. Make added value clear. Infrastructure. Unanimous decision to support this site in the portfolio.

Welcome & Objectives

- Safety moment
- Introductions
- Objectives
  - Keep CO2 storage stakeholders appraised of project progress and enrol interest from the CCS stakeholder community
  - Stimulate debate around the recommended portfolio of five candidate sites & gather input to the process

Strategic UK CCS Storage Appraisal Project

Project Overview

Objectives

Develop practical cost effective storage options that contribute to an extendable storage scheme for 1500MT of storage capacity and 50MT/y of injection capacity by 2030

Screen Many Sites	Consider a large number of possible stores & screen objectively to identify those with high potential & that form a robust portfolio of 5 sites
Appraise Top 5	Assess top 5 sites and create output material which makes a significant and tangible difference to future storage developers and complements the DECC CCS Commercialisation Programme
Plan Risk Reduction	Identify specific risk factors associated with each of the 5 sites and prepare a risk reduction plan for each site
Development Options	Estimate and schedule resources needed to fully appraise, develop and operate the 5 sites
Make Output Public	Facilitate future commercial development of UK storage capacity

Strategic UK CCS Storage Appraisal Project

Project Objectives & Value Objective

- **Project Objectives:**
  - Develop storage options which contribute to an extendable storage scheme for 1500MT of storage, injecting 50Mt/a, by 2030, incorporating storage previously de-risked by other initiatives. This will include expansion from both Phase 1 projects;
  - Screen and de-risk commercially attractive options for storage for Phase 2 projects, de-risking onshore investments by 2026;
  - Estimate and schedule the resources needed to get down-selected stores fully appraised and then operational;
  - **Facilitate the future commercial development of UK storage capacity by accelerating development of capacity and making the results of the Project available to all current and potential future stakeholders.**
- **Value Objective:**
  - Materially progress the development of strategically important UK CO2 storage capacity, bring together existing storage appraisal initiatives, leverage future investment in building storage capacity and will inform a UK national strategy for roll-out of storage capacity development
  - Do so within the Maximum ETI Funding and complete by the Target Date (1st April 2016)

Project Overview

Delivery Team

Pale Blue Dot.	Management Consultancy for the Energy Transition • Consortium Lead & Project Manager • CO_2 storage specialists • Site and portfolio evaluation
AXIS	Well Technology & Reservoir Development Specialists • Geological & Geophysical characterisation of sites • Reservoir & injectivity modelling • Well design & costing
COSTAIN	Engineering Solutions Provider • Offshore infrastructure and facilities requirements • Cost and schedule estimates

Strategic UK CCS Storage Appraisal Project

Project Overview

Schedule

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Project Overview

Status

- Screening identified 20 candidate sites for further assessment, from an initial inventory of 579
- Selection has recommended a preferred portfolio of 5 sites for detailed evaluation
- We are now seeking your thoughts on the proposed portfolio of 5 candidate sites to sense check this recommendation
- Next steps will be to complete the technical work programme on each of the sites.

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Project Overview

Stakeholder Interactions

	Title & Purpose	Target Date
R02	Broad Stakeholder Project Roll Out (WP1) Explain project scope to invited stakeholders, enrol interest & gather some input for screening & selection activity. Post D01 & D02 Broad range of stakeholders to maximise awareness and input 30-40 attendees. Mary Sumner House Westminster venue, ½ day	15/6/2015 ✓
R03	Stakeholder Methodology Acceptance (WP3) Presentation of screening results & secure agreement Post D03 & D04 ETI Advisory panel & selected stakeholders with specific interest 15-20 attendees. Pinsent Masons, City of London, ½ day	2/7/2015 ✓
R04	Stakeholder Input to WP5 (WP4) Present down-select results & secure agreement for the portfolio of 5 sites. ETI Advisory panel & selected stakeholders with specific interest 15-20 attendees. Brathens Aberdeen venue, ½ day	29/7/2015
R08	Stakeholder - Launch of Summary Report Present final results from project and project summary report Broad range of attendees. London, ½ day	21/3/2016

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Screening and Selection

Overview

Initial Basis of Design:
- Beachheads
- Site Attributes
- Facilities
- Composition
- Phase & Temp

WP3:
- Eligibility
- Screening

WP4:
- Strategic Fit
- Due Diligence
- Portfolio Creation and Assessment

WP5:
- Define the Complex
- Populate the Store Model
- Outline Development Plan
- Containment Risk Assessment

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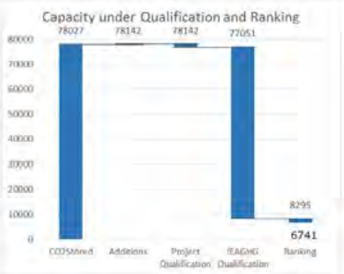
Screening and Selection

Outcome of ranking process



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Screening and Selection

3 EIS Sites

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Screening and Selection

Top 20

Top 20 sites by Storage Type	
Structural/Stratigraphic Trap	14
Fully Confined (closed box)	0
Open, no identified structural/ stratigraphic confinement	4
Open, with identified trap	2

Top 20 sites by Beachhead	
Medway	0
Barmston	8
St Fergus	9
Connah's Quay	3
Redcar	0

Top 20 sites by Geological Age	
1. Paleogene	5
3. Lower Cretaceous	3
5. Lower Jurassic	1
6. Triassic	9
7. Permian	2

Top 20 sites by Unit Designation	
Saline Aquifer	10
Gas	7
Oil & Gas	2
Gas Condensate	1

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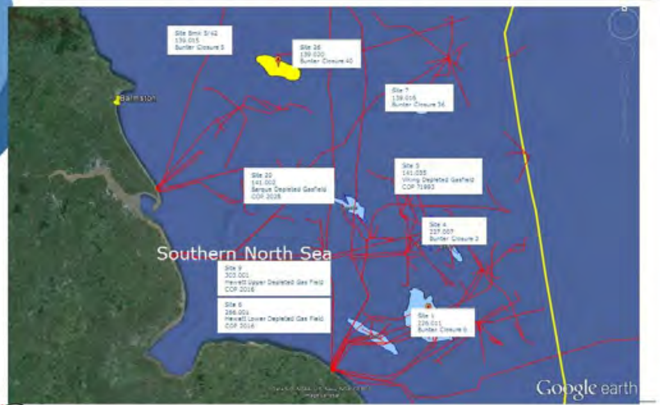
Screening and Selection

8 SNS Sites (plus 1 Benchmark site)



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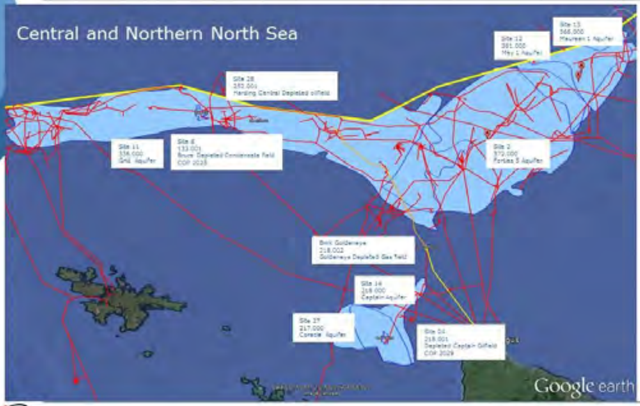
Screening and Selection

9 CNS Sites (plus 1 Benchmark site)



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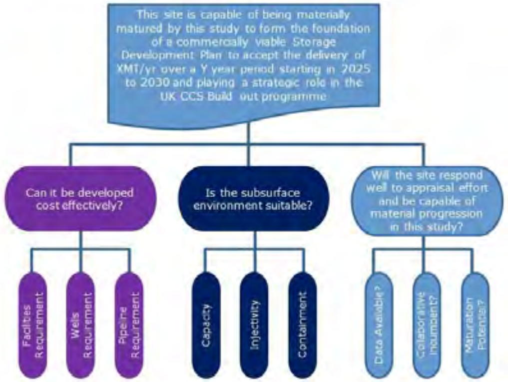
Final Selection Process

Due Diligence on Central Hypothesis



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Final Selection

Outline of current phase

- Due Diligence approach
  - Cascade the project objectives into specific hypotheses covering:
    - Subsurface assessments
    - Conceptual development planning & costing
    - Strategic fit
- Assessing of the quality, reliability and nature of the evidence
- Identifying the portfolio of 5 sites that best fits with the project objectives

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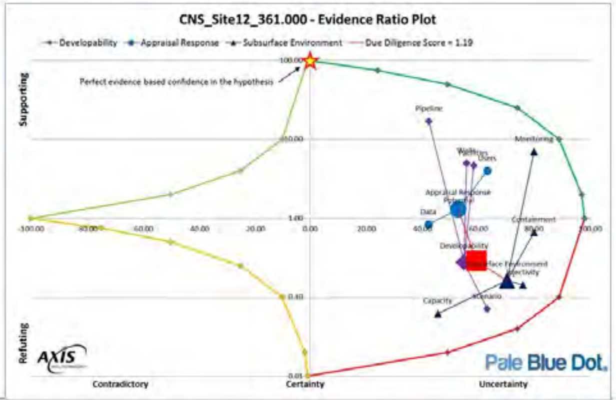
Final Selection Process

Evidence Assessment



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Due Diligence
Data Set

- PGS Southern & Central North Sea 3D seismic Mega-survey, loaded into Petrel workstation:
- East Irish Sea 2D seismic lines from CDA
- CDA well data (headers, deviation, formation tops, logs, core and well reports, time-depth data etc):
  - Selected data loaded into Petrel
  - Data availability and quality is highly variable
- Wood Mackenzie Commissioned view of COP Dates
- DECC – Production records to Feb 2015
- Published literature:
  - Millennium Atlas
  - Field Papers
  - Other

Due Diligence
Storage Capacity Validation

- Saline aquifers
  - Recalculation of capacity using quick-look Axis generated depth maps, thickness, NTG, and Porosity. Other inputs taken from CO2Stored database.
- Hydrocarbon Fields
  - Storage capacity is assumed to be equivalent to the net volume of fluids withdrawn during hydrocarbon exploitation.
  - A recalculation of the capacity equivalent to the net reservoir volume of fluids removed at February 2015, for each site. In addition, the net reservoir volume of fluids removed at COP was estimated and the capacity calculated at this time to confirm the full capacity estimate. Surface production and injection volumes were converted to reservoir fluid volumes using shrinkage factors sourced from Public Domain material, where available. The shrinkage factors applied in CO2Stored were checked as part of the DD.

Due Diligence
Injection Validation

- For all sites the permeability thickness (KH) was used as an injectivity indicator for the selection criteria. This has been validated.
- For all sites a simple dynamic box model was generated in Eclipse to check if 1MT/yr per well can be achieved.
- Hydrocarbon Fields:
  - the initial production performance per well was converted to an equivalent CO2 injection rate to gain some confidence that that the 1MT/year/well target could be met.

Due Diligence
Containment Validation

- Geological:
  - Seismic data reviewed to confirm or otherwise the inputs to the Georisk Factor (Fault density, throw, extent and seal degradation)
  - Caprock resilience inputs (Fracture pressure capacity and seal chemistry reactivity) were taken from CO2Stored.
- Engineering:
  - Review of abandonment practices was done to establish historical risk, and a probability of leakage assigned using a range of values agreed by DECC in a previous study.
  - Well count and categorization done from CDA database.
  - Probabilities assigned and risk calculated on basis of well density.

Due Diligence

Well Cost Estimates

- Generic well design constructed and costing exercise carried out.
  - Well design:
    - High angle / horizontal well to establish maximum step-out and well spacing, while removing injection point from caprock penetration point
    - Large completions assumed, so limited build angle available
  - Costing:
    - 5 well development assumed for all sites. Platform wells, except CNS where subsea wells were assumed.
    - Well depth (drilling time) was the primary differentiator
    - Allowances made for phase change control in depleted pressure sites

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Concept Development Plan

Basis

- 20 year design life
- 1 Mtpa injection rate per well (average)
- Approx cost estimate accuracy +/- 40% (given store definition)
- 2015 prices
- Transportation of cO_2 in dense phase where possible
- No offshore compression or pumping
- No offshore filters
- No water eductor (production) wells

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Concept Development Plan

2 Development Scenarios

- Comparative Development
  - To enable cost comparison
  - 100 MT Capacity (or less for smaller sites)
- Ultimate Development (Full Field)
  - To realise full site potential (if >125MT)
  - Capped at 1000MT

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Concept Development Plan

Well Head Platforms / NUI

- SNS and EIS developed using NUI (normally unmanned installation)

BP Tambar

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Concept Development Plan

Well Head Platforms / NUI

- SNS and EIS developed using NUI (normally unmanned installation)
- Well head platform with no drilling (jack-up access) and 5 wells base case
- Power generation for well control and utilities
- Control via satellite or line of site comms
- Facilities for PIG receipt
- Temp accommodation only
- Crane and helideck needed for supplies and maintenance
- Future tie-ins

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Concept Development Plan

Subsea Well Head Templates

- CNS developed using subsea well head templates

FMC Technologies

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Concept Development Plan

Subsea Well Head Templates

- CNS developed using subsea well head templates
- 6 slot template (5 XTs used as base case)
- Access via semi-sub or jack-up drill rig
- Manifolding on template to supply trees
- Facilities for future tie-in and pig receipt
- Power and controls from an external source
  - From beach (very expensive for long tie-back scenarios)
  - From existing infrastructure
  - From a control buoy

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Concept Development Plan

Pipelines - Trunkline and Infield

- Diameters estimated (20", 26" and 36")
- CO2 source assumed to be one of 5 beachheads, 5/42 or Goldeneye
- Straight line routing with some rerouting for major infrastructure (+15% allowance)
- Crossings of pipelines accounted for
- Carbon Steel Pipelines, corrosion and concrete coated
- Infield Pipelines assumed to be 20" OD, 10km length
- Where there is a tie-in, budgets include additional manifold

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Concept Development Plan

Cost Build-Up

- Appraisal & Development Well (wells team)
  - Not needed for depleted reservoirs
- Infrastructure
  - Landfall - £20M estimate
  - Pipeline – build up of materials, fabrication and installation inc crossings and tie-ins
  - NUI – function of WD, built up using Questor
  - Template – build up of materials, fabrication and installation
- OPEX (6%)
- ABEX (25% Facilities, £4M/dry, £8M/wet well)
- PME&I (10%)
- Contingency (20%)
- Not Included – carbon capture costs, onshore transportation, MMV, profit, permitting

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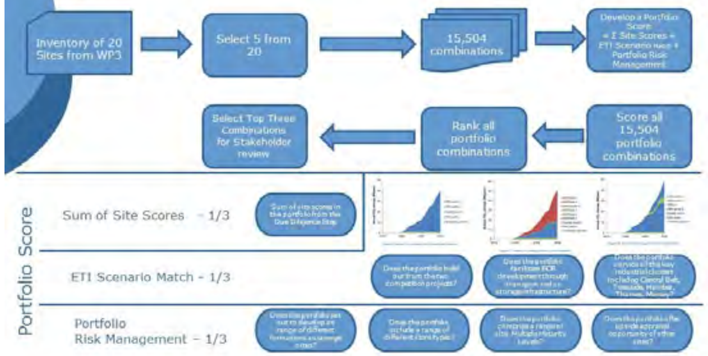
Portfolio Risk Management

WP4 Workflow – portfolio creation & assessment



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Concept Development Plan

Cost Comparison

- Comparative Site
  - Single NUI / Template
  - Trunkline to beach / source
  - Costs calculated /100MT (or less)= £/tn
- Ultimate Development
  - Multiple NUIs/Templates function of Store size
  - Trunkline to beach / source
  - Infield Flowlines between NUI/Template
  - Costs calculated /injection capacity (max 1000MT) = £/tn

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Portfolio Risk Management

Ability to Progress in WP5 – A key attribute

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Portfolio Risk Management

Portfolio Selection

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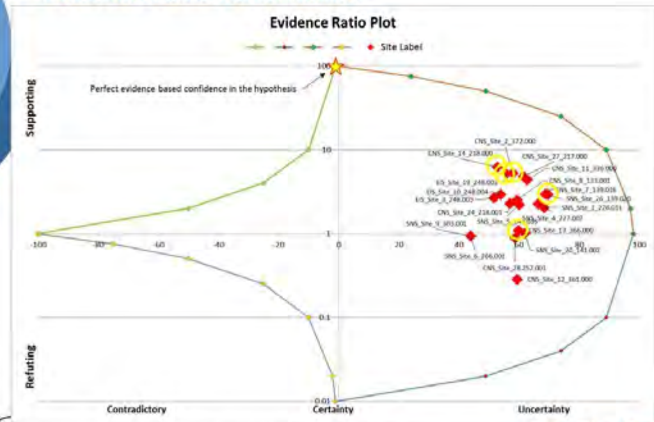
Portfolio Risk Management

Evidence Ratio Performance



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Portfolio Risk Management

Site characteristics and portfolio assessment

Top 10 Portfolios

Key to portfolio projects			Due Diligence Score	Occurrences in To 10 portfolios	DD Theoretical Capacity MT	Notional earliest injection year	Improvement Potential	Location and Site Code	Description
1	A	133.001	2.010	1	186.0	2025	2.5	CNS_Site_8_133.001	Bruce Gas Condensate field
2	B	139.016	1.970	3	252.0	2025	2.0	SNS_Site_7_139.016	Bunter Closure 36
3	C	139.020	1.930	2	100.0	2025	2.0	SNS_Site_26_139.020	Bunter Closure 40
4	D	141.002	1.650	1	86.0	2030	2.5	SNS_Site_20_141.002	Barque gasfield
5	E	141.035	1.950	7	155.0	2020	2.5	SNS_Site_5_141.035	Viking gas fields
6	F	217.000	2.200	0	35.0	2035	1.0	CNS_Site_27_217.000	Ceratia_012_20
7	G	218.000	2.400	5	49.0	2020	2.1	CNS_Site_14_218.000	Captain_012_17
8	H	218.001	2.000	1	95.8	2021	2.1	CNS_Site_24_218.001	Captain Oil Field
9	I	226.011	1.770	0	198.0	2025	2.0	SNS_Site_1_226.011	Bunter Closure 9
10	J	227.007	1.830	1	232.0	2025	2.0	SNS_Site_4_227.007	Bunter Closure 3
11	K	248.002	2.300	10	129.0	2020	2.5	EIS_Site_19_248.002	Hamilton gasfield
12	L	248.004	2.100	0	186.5	2028	0.1	EIS_Site_10_248.004	North Morecambe gasfield
13	M	248.005	2.110	0	791.0	2030	0.1	EIS_Site_3_248.005	South Morecambe gas field
14	N	252.001	1.680	0	84.7	2027	2.1	CNS_Site_28_252.001	Harding Central oil field
15	O	266.001	1.790	0	312.0	2030	-1.5	SNS_Site_6_266.001	Hewett gas field
16	P	303.001	1.790	0	288.0	2016	-0.5	SNS_Site_9_303.001	Hewett gas field (Bunter)
17	Q	336.000	2.150	9	1825.0	2028	2.0	CNS_Site_11_336.000	Grid Sandstone Member
18	R	361.000	1.190	0	22.0	2028	2.0	CNS_Site_12_361.000	Mey 1
19	S	366.000	1.700	0	101.0	2028	2.0	CNS_Site_13_366.000	Maureen 1
20	T	372.000	2.270	10	1021.0	2028	2.0	CNS_Site_2_372.000	Forties 5

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Portfolio Risk Management

Recommended Portfolio

- Total capacity 1606 Mt
- Two SNS, one EIS, two CNS
- Two depleted gas, One aquifer closure, Two open aquifers
- Selected for its strong build out from Phase 1 projects
  - GY to Captain aquifer and then to Forties Aquifer later on
  - 5/42 to Bunter Closure 36 and Viking
- All sites can be materially progressed
  - Hamilton will require access to 3D from Eni
  - Hamilton and Viking progression partly dependent upon Operator collaboration
- Good fit with ETI Scenarios
- Key Alternatives – Exchange of Bunter Closure 36
  - Grid Sandstone is a strong candidate

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Workshop
Results Sheet Handout

Site	Bunter 36 Site 7, 139.036	Viking Site 5, 141.035	Captain Site 14, 218.000	Forties 5 Site 2, 372.000	Hamilton Site 19, 242.002
Region	SNS	SNS	CNS	CNS	EIS
Type	Structured aquifer	Depl. gas	Open aquifer	Open aquifer	Depl. gas
Geology	Triassic Bunter Sandstone	Permian Leman Sandstone	Cretaceous Wick Sandstone	Paleocene Forties Sandstone	Triassic Ormskirk Sandstone
Capacity (MT)	252	155	49	1021	129
Injectivity kh (D-M)	57	5	103	22	134
Development	NUI, 75m water, 86km pipeline	NUI, 20m water, 220km pipeline	SS,95m water, 67km pipeline	SS, 80m water, 186km pipeline	NUI, 25m water, 48km pipeline
Comments	Overlies Schooner	Underlies Bunter 3	"panhandle" only	Specific storage site to be located	

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Workshop
Background

- The Screening & Selection phases have identified a portfolio of 5 sites from an initial inventory of 579 possibilities
- We are now seeking your thoughts on the portfolio to sense check this recommendation
- Next steps
  - Technical work will be performed on these sites in order to create a conceptual level development plan and budget for each store
  - This will be work package 5

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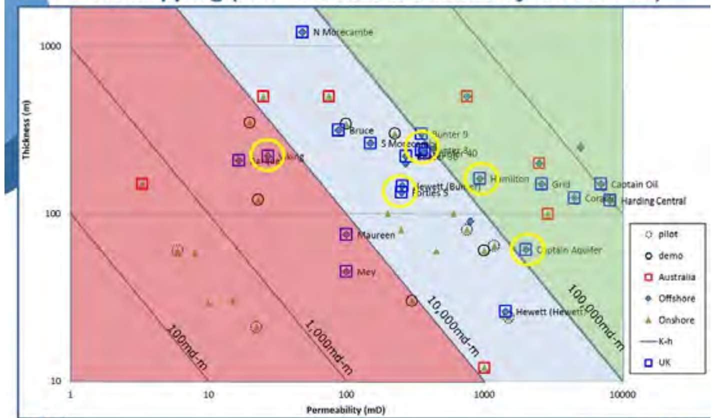
Selection Recommendation
KH Mapping (non UK sites are courtesy CarbonNet)



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Workshop
Activity

- On Your Own -10 mins
  - Review the results table provided and consider whether you believe the selection to represent a sound basis from which to achieve the project objectives
- As a Team – 20 mins
  - After your individual deliberations on the results – discuss and resolve amongst the team your preferred selection. Be prepared to summarize your rationale
- Feedback session

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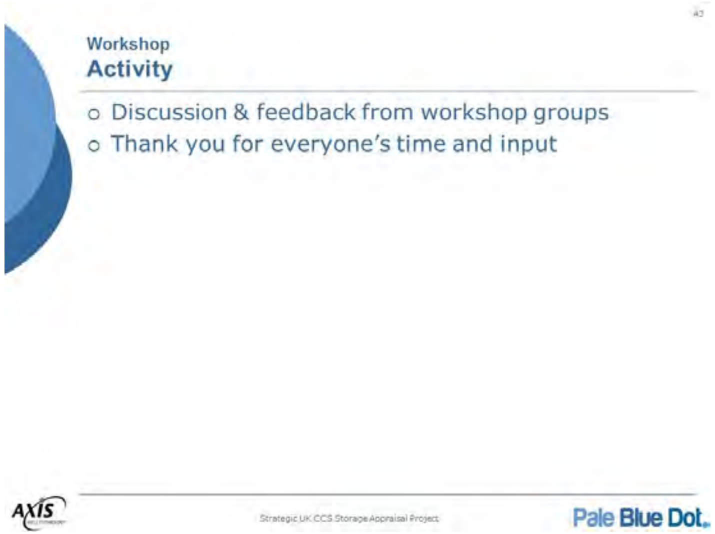
Workshop
Activity
Discussion & feedback from workshop groups
Thank you for everyone's time and input
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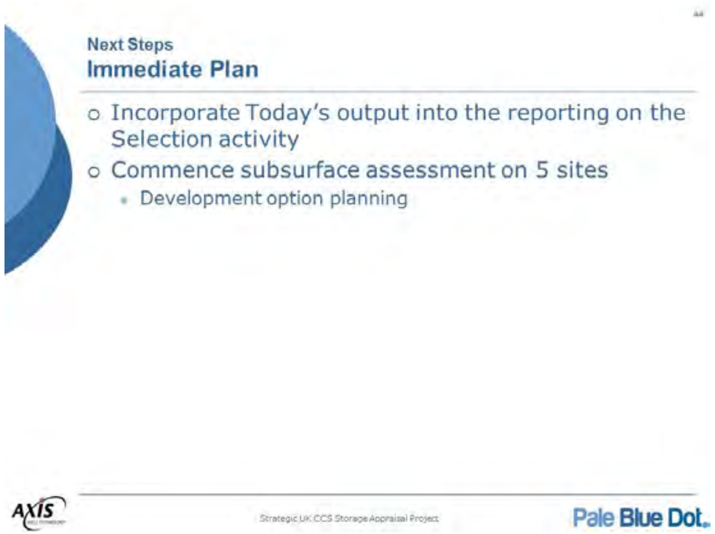
Next Steps
Immediate Plan
Incorporate Today's output into the reporting on the Selection activity
Commence subsurface assessment on 5 sites
Development option planning
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App. 2 Storage Site Summary Posters

This appendix is provided as a separate document authored by Pale Blue Dot Energy.
D05 10113ETIS WP4 Report Appendix 2 –Storage Site Summary Posters

CNS_Site_2_372.000 Forties 5

CNS_Site_8_133.001 Bruce Gas Condensate Field

CNS_Site_11_336.000 Grid Sandstone Member

CNS_Site_12_361.000 Mey 1

CNS_Site_13_366.000 Maureen 1

CNS_Site_14_218.000 Captain_013_17

CNS_Site_24_218.001 Captain Oil Field

CNS_Site_27_217.000 Coracle_012_20

CNS_Site_28.252.001 Harding Central oil field

EIS_Site_3_248.005 South Morecambe gas field

EIS_Site_10_248.004 North Morecambe gas field

EIS_Site_19_248.002 Hamilton gas field

SNS_Site_1_226.011 Bunter Closure 9

SNS_Site_4_227.007 Bunter Closure 3

SNS_Site_5_141.035 Viking gas fields

SNS_Site_6_266.001 Hewett gas field

SNS_Site_7_139.016 Bunter Closure 36

SNS_Site_9_303.001 Hewett gas field (Bunter)

SNS_Site_20_141.002 Barque gas field

SNS_Site_26_139.020 Bunter Closure 40

App. 3 Cost Estimate

This appendix is provided as a separate document authoered by Costain; The following summary tables are extracts from that document.

D05 10113ETIS WP4 Report Appendix 3 – Cost Estimate

Site Description	Development Concept		Water			Wells (£m)		Pipelines (£m)		Facilities (£m)			(£m)	
			Depth (m)	Centres	Wells	Appraisal	Development	Trunk	Infield	Injection	Eng	Abex	Total	Opex
Barque gas field	Comparative	NUI-25	10	1	5	0	203	163		67	23	87	543	276
Barque gas field	Ultimate	NUI-25	10	1	5	0	203	163		67	23	87	543	276
Bruce Gas Condensate Field	Comparative	Subsea	116	1	5	0	411	152		38	19	88	708	229
Bruce Gas Condensate Field	Ultimate	Subsea	116	2	9	0	739	152	13	72	24	131	1,131	284
Bunter Closure 03	Comparative	NUI-45	40	1	5	60	101	248		79	33	112	633	393
Bunter Closure 03	Ultimate	NUI-45	40	2	12	60	242	284	13	133	43	176	951	516
Bunter Closure 09	Comparative	NUI-45	30	1	5	54	80	250		79	33	112	609	396
Bunter Closure 09	Ultimate	NUI-45	30	10	50	54	803	342	100	567	101	552	2,520	1,211
Bunter Closure 36	Comparative	NUI-75	75	1	5	66	123	90		75	16	71	442	198
Bunter Closure 36	Ultimate	NUI-75	75	2	12	66	295	90	13	146	25	130	765	298
Bunter Closure 40	Comparative	NUI-45	30	1	5	64	119	41		58	10	55	347	119
Bunter Closure 40	Ultimate	NUI-45	30	1	5	64	119	41		58	10	55	347	119
Captain Oil Field	Comparative	Subsea	105	1	5	0	140	99		59	16	80	394	190
Captain Oil Field	Ultimate	Subsea	106	1	5	0	140	99		59	16	80	394	190
Captain_013_17	Comparative	Subsea	95	1	3	0	84	0		38	4	34	160	46
Captain_013_17	Ultimate	Subsea	95	1	3	0	84	0	0	38	4	34	160	46
Coracle_012_20	Comparative	Subsea	99	1	2	74	54	0		34	3	24	190	40
Coracle_012_21	Ultimate	Subsea	99	1	2	74	54	0		34	3	24	190	40

Table 17: Development and Cost Estimate Summary - Part 1

Site Description	Development Concept		Water			Wells (£M)		Pipelines (£m)		Facilities (£m)			£(m)	
			Depth (m)	Centres	Wells	Appraisal	Development	Trunk	Infield	Injection	Eng	Abex	Total	Opex
Forties 5	Comparative	Subsea	80	1	5	86	215	189		59	25	102	676	297
Forties 5	Ultimate	Subsea	80	10	50	86	2,153	265	100	362	73	582	3,621	873
Grid Sandstone Member	Comparative	Subsea	90	1	5	68	126	0		38	4	50	285	46
Grid Sandstone Member	Ultimate	Subsea	90	10	50	68	1,258	0	100	342	44	510	2,322	530
Hamilton gas field	Comparative	NUI-25	25	1	5	0	102	47		67	11	59	286	137
Hamilton gas field	Ultimate	NUI-25	25	1	6	0	123	47		67	11	63	311	137
Harding Central oil field	Comparative	Subsea	110	1	4	0	170	77		38	12	61	358	138
Harding Central oil field	Ultimate	Subsea	110	1	4	0	170	77		38	12	61	358	138
Hewett gas field	Comparative	NUI-25	20	1	5	0	129	234		67	30	105	565	362
Hewett gas field	Ultimate	NUI-25	20	6	30	0	772	287	56	278	62	335	1,789	744
Hewett gas field (Bunter)	Comparative	NUI-45	30	1	5	0	114	239		58	30	104	546	357
Hewett gas field (Bunter)	Ultimate	NUI-45	30	6	30	0	684	294	56	330	68	350	1,782	815
Maureen 1	Comparative	Subsea	80	1	5	76	172	259		59	32	119	717	381
Maureen 1	Ultimate	Subsea	80	1	5	76	172	259	0	59	32	119	717	381
Mey 1	Comparative	Subsea	70	1	1	82	40	320		59	38	103	641	454
Mey 1	Ultimate	Subsea	70	1	1	82	40	320	0	59	38	103	641	454
North Morecambe gas field	Comparative	NUI-25	25	1	5	0	113	89		67	16	69	354	187
North Morecambe gas field	Ultimate	NUI-25	25	2	9	0	203	89	13	109	21	109	544	253
South Morecambe gas field	Comparative	NUI-25	25	1	5	0	111	82		67	15	67	342	179
South Morecambe gas field	Ultimate	NUI-25	25	9	43	0	958	114	89	404	61	414	2,039	728
Viking gas fields	Comparative	NUI-25	20	1	5	0	216	223		67	29	102	637	348
Viking gas fields	Ultimate	NUI-25	20	3	15	0	648	256	33	151	44	200	1,333	529

Table 18: Development and Cost Estimate Summary - Part 2

App. 4 Lessons from other Appraisal Projects

This appendix is provided as a separate document authored by the British Geological Survey.

D05 10113ETIS WP4 Report Appendix 4 -Lessons from other Appraisal Projects.

App. 5 Storage Unit Assessments

This appendix is provided as a separate document authored by Pale Blue Dot Energy.

D05 10113ETIS WP4 Report Appendix 5 –Storage Unit Assessments

App. 6 Review of Bunter Closures

The selection of the White Rose project 5/42 storage site, and its progression through FEED in the DECC commercialisation programme, has highlighted the potential role and contribution of structural closures in the Triassic-age Bunter Sandstone Formation of the Southern North Sea (Bunter Closures) to future CO2 Storage potential on the UKCS (Furnival, et al., 2013). Several geological closures in this formation have been mapped and screened a number of times over the past decade illustrating the interest in these structures for carbon storage. The sites are attractive due to several factors:

- The closures are generally large anticlinal features whose form is simple to understand and communicate.
- They are located relatively close to the biggest concentration of carbon emissions in the UK.
- The SNS has been an active hydrocarbon province for several decades with corresponding significant surface and subsurface access, infrastructure and knowledge.
- While the Bunter Sandstone Formation is considered a saline aquifer for the purposes of carbon storage, it also contains some producing gas fields which provide useful analogue information.
- The Bunter Closures often sit directly above the Permian Rotliegendes gas fields and, as such, already have some well penetrations which provide useful data.
- There are Bunter closures located away from current hydrocarbon license areas which simplifies access.

The sites also share many of the same challenges:-

- In the Southern North Sea, there are 87 widely distributed gas fields in the Permian Leman sandstone but only 9 tightly clustered gas fields in the Triassic Bunter Sandstone. The likelihood is that this is due to the Zechstein and impact on gas charging, however the possibility that it is linked to issues with the effectiveness of the Bunter Shale cap rock cannot be eliminated at this stage?
- Since gas production from the Bunter sandstone is limited to a small number of fields, there is little if any dynamic pressure data confirming good lateral connectivity and therefore long term injectivity.
- All oil and gas fields with limited data look simple, but then are invariably revealed as complex as more data is acquired. Bunter Closures generally have limited data with a small number of exploration wells targeting deeper horizons and as a result appear as simple.
- Appraisal costs need to include a long term flow test of between one week and three months in order to confirm reservoir connectivity and long term injection performance to a level of confidence that is appropriate to match an investment in carbon capture plant and CO_2 transportation systems.

Bunter Closures are also characterised by being dynamically unappraised. That is, previous oil and gas activities have generally not subjected these reservoirs to pressure cycles or transients which are large enough to have proven reservoir limits of connectivity. In simple terms this means that long term injectivity and capacity remain subject to significant uncertainty even if initial injectivity can be confirmed through a short term test.

In this project, the Bunter Closures contained in the CO2Stored database were taken through the qualification, ranking and selection process as described in the Work Package 1 and 3 programmes. This appendix to WP4 provides a short account of the process by which the Bunter Closure site inventory was refined down from 34 sites in the Initial Inventory to 6 sites in the Qualified Inventory and sown to a single closure in the recommended portfolio.

1. Qualification Process

In the CO2Stored database, Bunter Closures range from Closure 1 to Closure 50, although only 34 of these closures are itemised within the database itself. These 34 were all included in the Qualification and Ranking process. In total, the P50 Theoretical Capacity (pre-WP4 due diligence) for this Bunter Closure Inventory was 7923 MT with individual site capacity ranging from 5 MT to 1691 MT (average 233 MT).

The Qualification process in WP3 resulted in the elimination of 28 of these sites from further consideration. Each qualification step was based on either project-specific or best practice threshold metrics aimed at ensuring only those sites with the potential to progress during this project were taken forward for further evaluation. Failure at this stage does not necessarily imply that a site is unsuitable for CO_2 Storage simply that it did not meet the specific requirements of this project. Elimination occurred for the following key reasons (some sites failed to reach several threshold metrics):

- High Confidence of High Risk containment issues (eliminating 25 Sites; P50 capacity = 3940 MT).
- Theoretical Capacity <50MT (eliminating 12 sites; P50 capacity = 211 MT).
- No well data available (eliminating 7 sites; P50 capacity = 727 MT).
- Permeability <50mD (eliminating 6 sites; P50 capacity = 247 MT).
- Poor 3D availability (eliminating 3 sites; P50 capacity = 749 MT).
- Unavailable for licensing (eliminating 1 site; P50 capacity = 554 MT).
- Porosity below 10% (eliminating 1 site; P50 capacity = 100 MT).
- High Transnational Migration Risk (eliminating 1 site; P50 capacity = 16 MT).

Six sites remained in the Qualified Inventory following this process (Table 19):

Bunter Closure	CO2Stored P50 Theoretical Capacity (MT)
Closure 3	409
Closure 9	1691
Closure 18	56
Closure 24	63
Closure 36	232
Closure 40	84

Table 19 - Qualified Inventory - Bunter Closures

In addition, Closure 35, also identified as the White Rose 5/42 site (Capacity: 554 MT), was carried forward to help benchmark these sites. Closure 35 did not initially qualify for the ranking process due to the assumption that this site will be licensed by National Grid Carbon and will be unavailable to other storage operators. Furthermore there was incomplete 3D seismic data coverage in the PGS megasurvey dataset available to this project (it is acknowledged that an

OBC dataset does cover the remaining acreage, but this is not available to this project).

2. Ranking Process ('Many to Twenty')

Each of the qualified sites went through the ranking process which assessed the Qualified Inventory against a set of 6 weighted criteria as described in WP3

- Capacity (MT)
- Injectivity (mDm)
- Engineering Risk
- Geo-Containment Risk
- Development Cost Factor
- Proximal Upside Potential (MT)

A summary of the results for the 6 Bunter Closures is shown in Table 20.

The ranking process considered all qualified sites against a set of 4 scenarios to test the sensitivity of the site list to a range of preferred options:

- Rounded View: Uses all six criteria and initial weighting from a pairwise consideration matrix.
- Equal Weighting: Uses all six criteria with equal weighting.
- Container View: Uses the four subsurface characteristics (Capacity, Injectivity and both Containment criteria) equally weighted.
- Simple View: Uses only capacity (theoretical and upside capacity values) and development cost to focus on a “keep it simple” or 'large and low-cost' approach advocated by some stakeholders.

The results for the Bunter Closures were remarkably consistent across both the ranking methods applied and the 4 scenarios. Bunter Closures 3, 9, 36 and 40 ranked in the Top Twenty sites for 3 out of the 4 scenarios, with Closure 40 only dropping out of the top twenty in the capacity and cost-driven 'Simple View' due to its relatively small size. As a result, these 4 closures were taken forward to WP4, along with the depleted Bunter Hewett field (Figure 18), for further evaluation under the Due Diligence and Portfolio Selection programme of work.

AXIS WELL TECHNOLOGY — Strategic United Kingdom CCS Storage Appraisal Project - WP3 Downselect Recommendation 8th July 2015 — Pale Blue Dot.

													Top 20 Theoretical Capacity	6749	6510	6645	6741	6765
		Normal	Normal	Reversed	Reversed	Reversed	Normal							"Rounded View"	"Equal Weighting"	"Container View"	"Simple View"	"Final Recommendation"
		Criteria 1	Criteria 2	Criteria 3	Criteria 4	Criteria 5	Criteria 6											
Code	Site Number	Capacity MT	Injectivity mDm	Engineering Containment Risk per sq km	Geo Containment Risk	Development Cost Factor $M	Proximal Upside Potential MT	Unit Designation	Geological Age	Geological Formation	Storage Type	Site Description	Nearest Beachhead	Manual Drop Selection	Manual Drop Selection	Manual Drop Selection	Manual Drop Selection	Recommended Action
														1	2	3	4	
226.011	Site 1	1691.0	33380.0	0.6	9.0	292.1	3898.0	Saline Aquifer	6. Triassic	Bunter Sandstone Fm	Structural/Stratigraphic Trap	Bunter Closure 9	Barmston	0	0	0	0	Progress to WP4
227.007	Site 4	409.0	23926.0	0.2	9.0	313.7	4287.0	Saline Aquifer	6. Triassic	Bunter Sandstone Fm	Structural/Stratigraphic Trap	Bunter Closure 3	Barmston	0	0	0	0	Progress to WP4
139.016	Site 7	232.0	11051.5	0.2	6.0	301.5	1179.0	Saline Aquifer	6. Triassic	Bunter Sandstone Fm	Structural/Stratigraphic Trap	Bunter Closure 36	Barmston	0	0	0	0	Progress to WP4
139.020	Site 26	84.0	22673.0	0.0	6.0	278.0	2127.0	Saline Aquifer	6. Triassic	Bunter Sandstone Fm	Structural/Stratigraphic Trap	Bunter Closure 40	Barmston	0	0	0	1	Progress to WP4
139.015	Bmk 5/42	554.0	98052.0	0.0	6.0	210.4	1057.0	Saline Aquifer	6. Triassic	Bunter Sandstone Fm	Structural/Stratigraphic Trap	Bunter Closure 35 (5/42)	Barmston	1	1	1	1	BENCHMARK ONLY
226.007	Site 31	63.0	19068.0	0.3	11.0	271.3	2978.0	Saline Aquifer	6. Triassic	Bunter Sandstone Fm	Structural/Stratigraphic Trap	Bunter Closure 24	Barmston	1	1	1	1	Hold
226.002	Site 34	56.0	35476.0	0.5	9.0	317.5	4179.0	Saline Aquifer	6. Triassic	Bunter Sandstone Fm	Structural/Stratigraphic Trap	Bunter Closure 18	Medway	1	1	1	1	Hold

Table 20 - Results of the Ranking Process for Bunter Closures

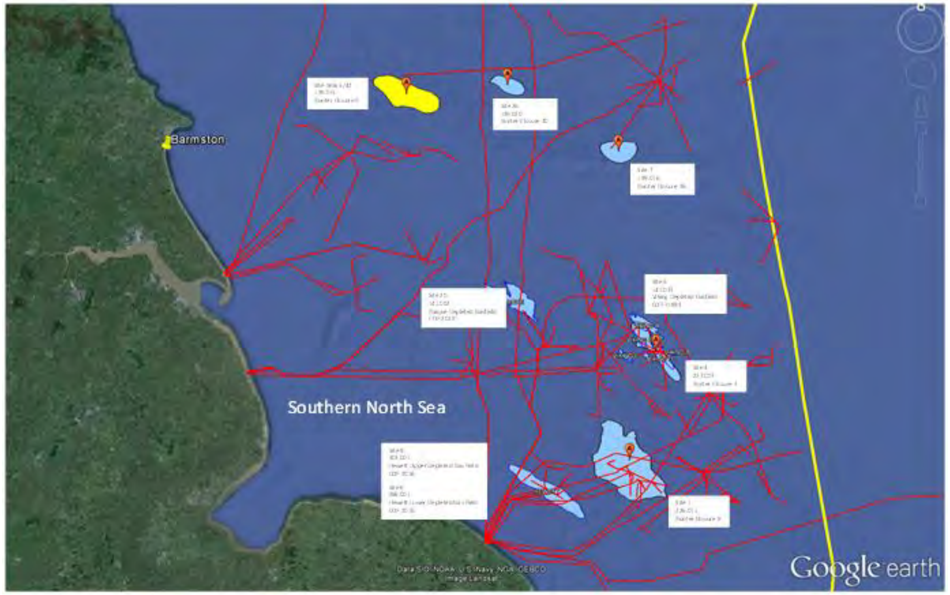

Figure 18 - SNS Saline Aquifer and depleted field sites taken forward to WP4

3. Due Diligence and Final Selection: Bunter Structures

The due diligence work programme covered the key technical elements of a storage site, evaluating each site in terms of its capacity (independently re-calculated), injectivity, and containment (geological and engineering risk). The results for each site were then taken through an evidence based risk assessment of each site's key characteristics. This approach provides an analysis of the evidence which either supports, or refutes, each of a set of hypotheses created to test the storage potential of a site. Further details of this process are included within the WP4 report.

3.1 Results of Due Diligence for Bunter Closures

The key characteristics (positive and negative) for each site per the test hypotheses are summarised below.

Data

All sites have relatively similar datasets associated with them. Each sits within the PGS megasurvey 3D dataset (although Closure 40 only has 80% coverage) and each has some well log data from wells that reach total depth in the Leman or Carboniferous reservoirs below the Bunter Sandstone Formation. Some differences in data quality are observed with seismic quality in Closures 3 and 9 deteriorating above the reservoir, increasing uncertainty in mapping any potential leakage pathways (e.g. faults) in the overburden. Closures 36 and 40 have less well data as they do not sit directly above large producing hydrocarbon reservoirs, although Closure 36 is penetrated by 4 wells testing the deeper, Carboniferous, Schooner Field. None of the sites have any engineering data associated with them; all models would rely on analogue dynamic data from one of the few producing Bunter gas fields. Limited core coverage in the Bunter sandstone is available in Closure 36 which would be highly advantageous if it can be sampled/tested.

Users

None of the sites are producing fields and so the project is not reliant on an Operator providing access to data. The sites have been previously screened by National Grid Carbon and others including the Crown Estate but the results of this work are not be made available to this project. It should also be noted that such screening is very likely to have been against different screening criteria than those used in this project and that this will strongly influence the outcome.

Potential

No detailed CCS review work is available for any of the sites. The UKSAP developed an Exemplar (dynamic model) for a sub-regional area which included Closure 36 which is available to this project but this is a very high level model covering a broad area and further work would be required to fully evaluate Closure 36. All sites therefore are considered to have good potential for further appraisal progression.

Scenario

In terms of build-out potential, the sites can be considered as clustering between 2 separate scenarios. Closures 36 and 40 lie just to the east of site 5/42 and so are well-placed to add capacity to that development should it progress. Closure 40 is closest but it has lower capacity than Closure 36.

Closures 3 and 9 are further from site 5/42 but could be considered as build-out options from Hewett which remains a high-potential storage site in the SNS. As theses lie above producing fields, availability is dependent on the CoP (end of field life) dates for the hydrocarbon operations. Closure 3 sits above the Viking fields (Viking B and E) (Figure 19) which has an anticipated CoP of 2017. Closure 9, however, sits above the Leman Field (Figure 19) which is not due to complete production until 2029/30 which is considered too late for the UK CCS Phase 2 development. These closures carry the possibility of a combined development with the lower depleted fields, however this is a technically-complex scenario given the difference in reservoir pressure between the normally-pressured Bunter aquifers and the highly depleted gas fields.

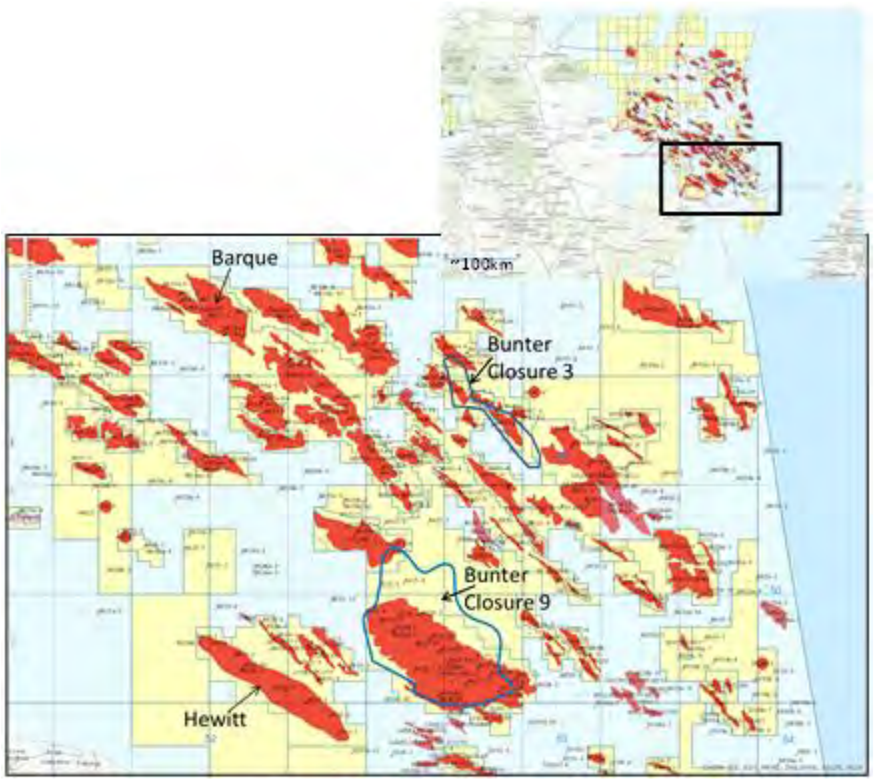

Figure 19 - Location of Bunter Closures 3 and 9 above the Viking and Leman gas fields

Pipeline

All sites would require new pipeline. Closures 36 and 40 would naturally be tied back to the main NG pipeline at the 5/42 site.

Facilities

All sites would require new facilities (normally unattended installation with control via shore has been assumed). The shallow water across this area of the SNS would allow for relatively low cost developments for all sites.

Wells

All sites are relatively shallow (800 - 1550 mTVDSS) resulting is low drilling and supports costs.

Capacity

The updated capacity estimates derived from the Due Diligence work are tabulated below. Similar levels of uncertainty are associated with each value as the key reservoir property inputs are derived from analogues (Site 5/42 for Closures 36 and 40; Little Dotty for Closures 3 and 9). Each site capacity estimate still falls well within the qualification cut-off value of 50 MT, however Closure 3 is significantly smaller than the P50 value held in the CO2Stored database due to a more considered view of gross rock volume derived from quicklook depth mapping in this project. Significant uncertainty in all capacity values remains.

Closure	Capacity (MT) Pre Due diligence	Capacity (MT) post Due Diligence
3	409	232
9	1691	1977
36	232	252
40	84	100

Table 21 - Select Inventory Bunter Closure Capacity Due Diligence

Injectivity

All sites are considered to have good reservoir quality based upon analogue information, although direct evidence from core materials is scarce. There is little evidence from the PGS seismic data for any large-scale structural compartmentalisation. Initial injectivity is not considered to be an issue in Closures 3 and 40. Simple dynamic models built during the due diligence work for Closures 9 and 36 however, indicate that the minimum injection pressure required to inject 1MT/well/year exceeds the minimum fracture pressure (i.e. pressure at which the reservoir rock would undergo geomechanical failure) value stored in the CO2Stored database. This may be a significant risk, however these fracture pressure values carry significant uncertainty as they are not direct measurements. Published data from Site 5/42 (Furnival, et al., 2013) indicate that the measured minimum fracture pressure is 1100 psi lower than the CO2Stored value for that site. In general, initial injectivity was not seen as a major risk element for any of the sites at this stage of the evaluation (this may change as further assessment is carried out in later work phases). This should be considered separately from long term injectivity which can only be assessed after long term testing. Uncertainty regarding long term injectivity remains high for all Bunter closures.

Containment

The risk of leakage out of the sites was one of the major screening factors which differentiated the Bunter closures. All the Bunter sites are simple 4-way, dip-closed structures sealed with thick sections of halite, anhydrite and mudstone. Migration and leakage through the sealing lithologies themselves is not considered to be a major risk. However Closure 40 shows a distinct sand-rich unit at the base of the seal unit which would require mapping to provide assurance that lateral migration out of structure is not a risk.

All sites sit below 800m TVDSS, although top reservoir in Closures 9 and 36 is mapped at 840m which is close to the IEA GHG depth threshold for saline aquifer stores. Further assessment of the seismic depth-model and measurement of the site-specific reservoir conditions (temperature and pressure) would be required to ensure that injected CO_2 would remain in the dense phase.

Leakage through structural pathways is more of a risk in Closures 3 and possibly Closure 9. In Closure 3 faults are observed to cut the top reservoir and caprock sections, extending vertically to the base of the overlying Chalk unit at 600m TVDSS (Figure 20). Not only are these faults possible leakage pathways, but the Chalk is considered to have some reservoir potential and so cannot be assumed to act as a secondary seal. The shallow depth (600m) of the observed fault tip point (although seismic image quality at these shallow levels is too poor to accurately map the fault extent above the Chalk) is well below the cut-off of 800m for CO2 storage. Seismic mapping of the reservoir in Closure 3 also shows well-developed crestal-collapse features (Figure 21) indicating structural complexity. In Closure 9, faults are mapped in the top reservoir and caprock (Figure 22) but these typically have throws of <50m (i.e. they do not off-set the caprock section against other, non-sealing lithologies at the seismic scale) and fault density is not high, although again, seismic image quality is poor in the shallower sections of the data.

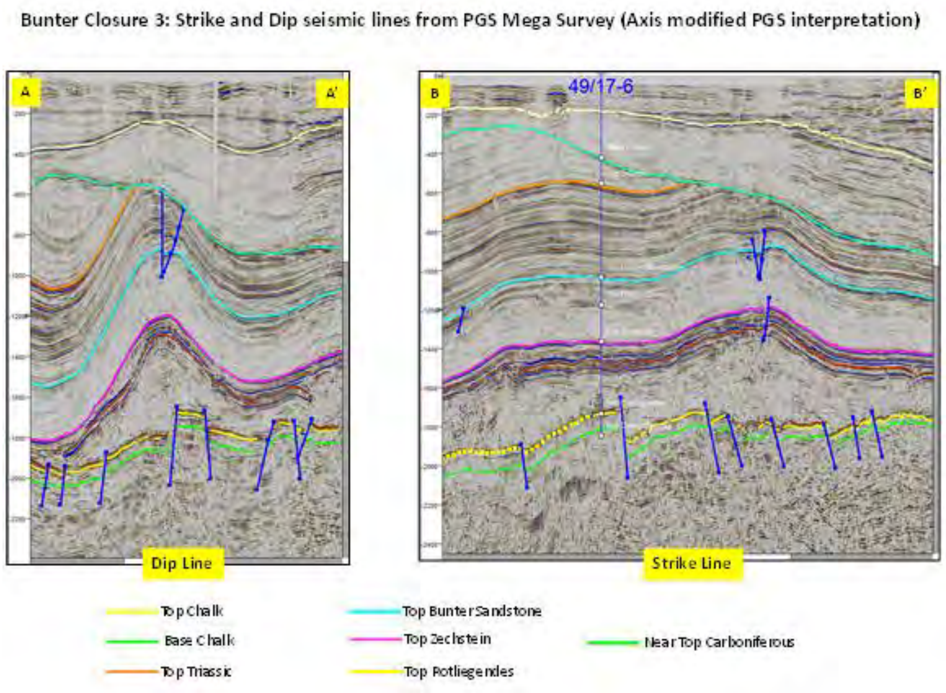

Figure 20 - Bunter Closure 3 Seismic Lines

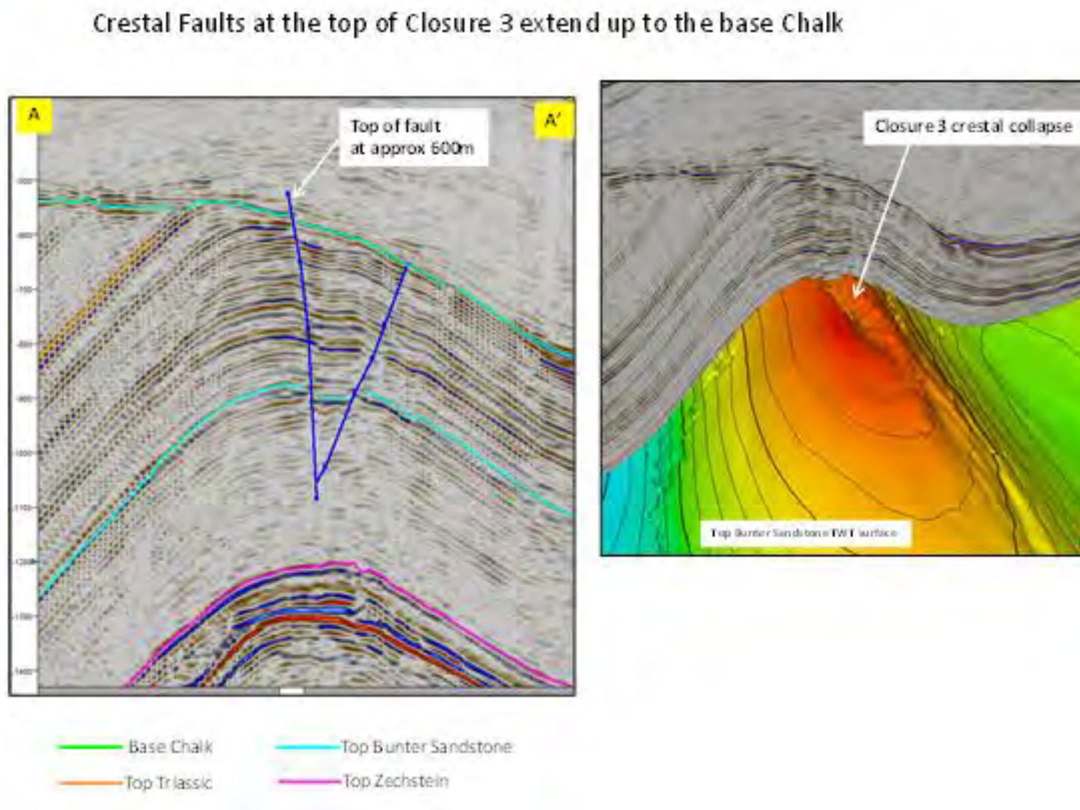

Figure 21 - Bunter Closure 3 Crestal Collapse

Structural features above Closure 3. Faults are observed to cut the top of the Bunter Sandstone Formation (blue seismic interpretation) and can be seen extending to cut the Base Chalk (green interpretation) (Figure 20). Seismic quality deteriorates in this shallow section and prevents confident mapping of the faults. A fault-related crestal-collapse feature is present over the top of the mapped closure.

Bunter 9 and Dip seismic lines from PGS Mega Survey (Axis modified PGS interpretation)

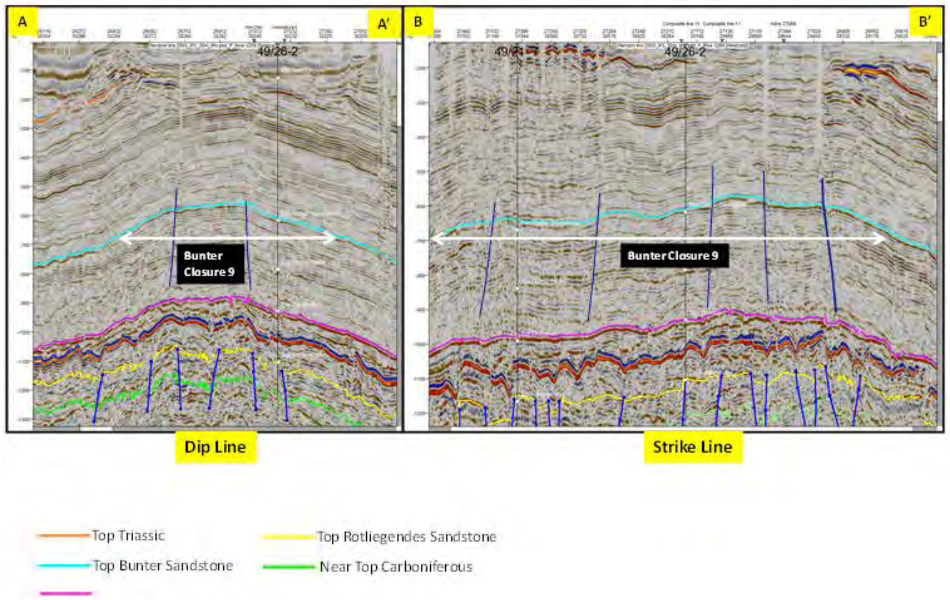

Figure 22 - Bunter Closure 9 Seismic Lines

Faulting at top Bunter level across Closure 9. Fault density is not high and does not appear to extend across the caprock (Figure 22).

Monitoring

No work on potential monitoring strategies has been carried out to date by this project. It was assumed that an appropriate and acceptable monitoring method would be found for all sites.

3.2 Due Diligence Scores

The scores for each Bunter Closure in the Top Twenty sites are shown below. The Evidence Ratio Plot illustrates that all the sites perform in a similar fashion to one another. In detail, Closures 36 and 40 perform slightly better than Closures 3 and 9 by virtue of the fact they do not 'fail' on any major risk element.

	Closure 3	Closure 9	Closure 36	Closure 40
Due Diligence Score	1.88	1.83	1.94	1.93
Evidence Ratio	66.47	68.39	68.84	69.60
Uncertainty Factor	2.26	2.65	2.96	2.94

Table 22 - Scores from Evidence based Due Diligence

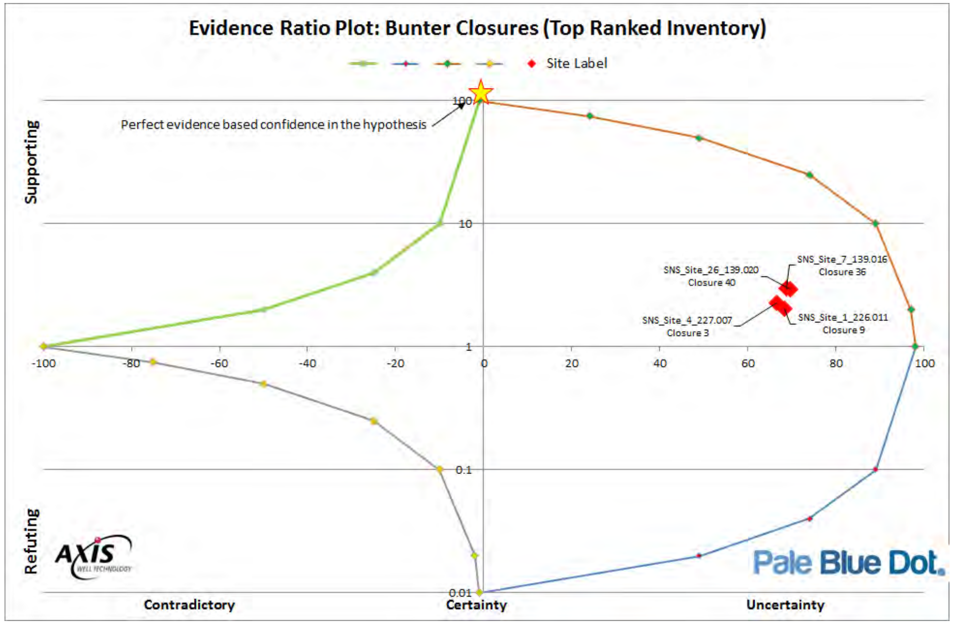

Figure 23 - Evidence Ratio Plots for Bunter Closures in Select Inventory

3.3 Summary

On the basis of the Due Diligence work carried out and the due diligence performance, Closures 36 and 40 appear to show the greatest potential for progression by this project. Closure 3 carries the greatest level of geo-containment risk compared to the other Bunter sites while Closure 9 is unlikely to be available within the required timeframe (while also carrying some uncertainty on geological risk and a higher level of engineered risk due to the increased well number). The Portfolio scoring process which was carried out following this Due Diligence work retained Bunter Closure 36 in high scoring portfolios ahead of Closure 40 on the basis of its greater capacity estimate.

2015

D05 10113ETIS WP4 Report
Appendix 3 – Cost Estimate

10113ETIS-Rep-7-02

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J1838 – Pale Blue Dot Energy Ltd

Strategic UK CO2 Storage Appraisal

Cost Estimate

WP4 – Top 20 Screening Cost Estimation

Document Number: CU-J1838-D-ES-001-A02

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Strategic UK CCS Storage Appraisal

COST ESTIMATE REPORT

WP4 – Top 20 Screening Cost Estimation

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HOLDS

None

ABBREVIATIONS

AHV	Anchor Handling Vessel
CCS	Carbon Capture and Storage
CNS	Central North Sea
CPT	Cone Penetration Test
CRA	Corrosion Resistant Alloy
DSV	Dive Support Vessel
EIS	East Irish Sea
ETI	Energy Technologies Institute
m	Meter
ml	Millilitre
mm	Millimetre
MMV	Mapping, Modelling and Visualisation
MT	Million Tonnes
n/a	Not applicable
NUI	Normally Unmanned Installation
ROV	Remotely Operated Vehicle
SNS	Southern North Sea
SSCV	Semi-Submersible Crane Vessel
WD	Water Depth

1 INTRODUCTION

In order to support Pale Blue Dot in delivering Work Pack 4 of the CO2 Strategic Storage Appraisal Project, Costain Upstream have compiled development scenario cost estimates for the 20 shortlisted storage sites as listed below:

Site	Region	Site Description
14	CNS	Captain_013_17
11	CNS	Grid Sandstone Member
19	EIS	Hamilton gas field
28	CNS	Harding Central oil field
3	EIS	South Morecambe gas field
10	EIS	North Morecambe gas field
26	SNS	Bunter Closure 40
8	CNS	Bruce Gas Condensate Field
24	CNS	Captain Oil Field
7	SNS	Bunter Closure 36
27	CNS	Coracle_012_20
20	SNS	Barque gas field
9	SNS	Hewett gas field (Bunter)
6	SNS	Hewett gas field
2	CNS	Forties 5
5	SNS	Viking gas fields
1	SNS	Bunter Closure 9
4	SNS	Bunter Closure 3
13	CNS	Maureen 1
12	CNS	Mey 1

Table 1-1 Top 20 Sites

For most stores, two development scenario cost estimates have been defined, a comparative cost estimated capped at 100MT of stored CO2, or less if the store's capacity is less than 100MT: And an ultimate cost estimate which is capped at the lesser of the P50 storage capacity of the store, or 1000MT.

This document details the methodology employed and assumptions made in order to prepare the screening level cost estimates. The cost estimates presented herein should be considered to be screening estimate level with an accuracy of ±40% cognisant of the store definition.

2 COST BASIS

The following sections detail the methodology and assumptions made in compiling the development scenario cost estimates for the 20 shortlisted storage sites.

2.1 General

The design life is assumed to be 20 years with each well injecting an average of 1Mt per year over the life time. The estimates are built up using 2015 costs. CO2 is transported in dense phase where possible and it is assumed that there are no offshore compressors, pumps and filters (screens) on the facilities and offshore venting is not required.

2.2 Appraisal Costs

Aquifer sites include a cost allowance for Appraisal activities, consisting of seismic survey data acquisition and interpretation, and drilling of two appraisal wells. Note Oil and Gas Fields are assumed to need no further Appraisal.

- Seismic Survey data acquisition and interpretation – where required, an allowance of £20MM has been applied.
- Wells (Appraisal and Injection) – where required, 2 appraisal wells have been assumed. Individual well costs as provided by Axis Wells Technology (ref Appendix 2) have been used to generate the well costs which take into consideration the water depth, drilling methodology reservoir depth, completions etc.

2.3 Development Well Costs

Development well drilling costs provided by Axis (Appendix 2) have been used to generate the Development Well Costs for the respective stores, with the number of wells defined by the concept. Comparative estimates assume a maximum of 5 development wells.

Ultimate Development cost estimates assume the required number of wells to meet the storage capacity of the store, with a cap of 1000MT applied.

Wells have been grouped into drill centres of 5 wells, note in some scenarios a 6th well has been included at a drill centre in order to get closer to the ultimate storage capacity, without the burden of adding the cost of an additional drill centre (i.e. pipeline & facilities costs).

Axis supplied drilling costs are presented in Appendix 2 along with the assumptions used to compile them. The values in the column entitled 'SINGLE WELL COST (PLATFORM OR SUBSEA)' (£)' have been used in deriving the Development Well costs.

Note drilling costs include supply and installation of the injection trees.

2.4 Infrastructure Costs

Infrastructure costs for the respective development scenarios have been compiled and include trunk and infield pipelines, pipeline crossings, pipeline landfall or pipeline extension tie in costs depending on if the store requires a new trunkline or if it is an extension to an existing pipeline, subsea templates for subsea developments or Normally Unmanned Installations (NUI) for shallow water development. Additional definition is presented in relation to these Infrastructure Cost elements in the following sections.

Note all SNS and EIS developments have been considered to be NUI developments with all CNS developments considered to be subsea developments. In some instances it may be possible to develop stores more economically in an alternate manner to that chosen herein (i.e. some CNS store may suit development via NUI, or utilize a combination of subsea and NUI facilities) however due to the screening nature of this estimate this has not been addressed at this stage. WP5 will fully address the alternate development methodologies for the shortlisted stores.

It should be noted that the very small capacity stores namely Mey [361.000], Coracle_012_20 [217.000] and slightly less so Captain_013_17 [218.000] will be penalised given the infrastructure of the development could be heavily rationalised. These small stores could be developed without drilling templates and smaller trunklines; however this is not reflected in the cost estimates prepared due to the screening nature of the estimates.

2.5 Pipeline Cost Estimation

Pipeline cost estimates have been prepared for all sites for both the Comparative and Ultimate Development concepts; note sites smaller than 100 mT will not have a separate Ultimate Development concept.

Pipeline Route Length:

Pipeline Route Length has been taken as a direct line (as the crow flies) except where there are direct impediments to adopting a direct line route, existing infrastructure etc, or where a deviation significantly reduces the number of pipeline crossings. A route allowance of 15% is then applied to the calculated distance in all instances.

Pipeline departure from landfall site is assumed as straight out to sea to minimise the cost and complexity of the associated landfall and to minimise trenched lengths.

Pipeline Route Survey:

Pipeline Route Surveys are included for all new pipelines and have been costed on the basis of the following assumptions:

- Survey speed 750m/hr (cumulative)
- Survey vessel Dayrate £115k/day.
- An allowance for Shallow Geotechnics (5m CPTs) has been included at a rate of £2000/km.

Trunklines:

The trunklines have been costed on the basis of the following assumptions:

- Carbon Steel pipelines c/w anti-corrosion and weight coating.
- Surface laid (beyond the 30m depth contour) with concrete weight coat protection.
- Installation by S Lay barge c/w 2 AHVs for anchor handling
  - Pipe carrying capacity of 14000 tonnes of pipe on Lay barge.
  - Dayrate of £350k/day.
  - Layrate of 2km/day.
  - 6 days per trip for mob/demob and transits.
  - S Lay vessel AHV's covered by £350k dayrate.
  - Pipe carrier reloading:
  - Pipe carrier capacity of 1600 tonnes.
  - Pipe carrier dayrate £50k/day.
  - 4 days per reload.
  - Touchdown monitoring performed by ROV from S Lay Barge.

Infield Pipelines:

Infield pipelines only exist for the Ultimate Development Concept Scenarios and have been costed as an extension to the Comparative Development Concept.

- 20" Carbon Steel pipelines c/w anti-corrosion and weight coating
- Surface laid (beyond the 30m depth contour) with concrete weight coat protection.
- Installation by S Lay vessel c/w ROV pipelay support – assumptions as per Trunklines apply.
- Where there are multiple drill centres/platforms the infield pipeline length has been increased to account for multiple pipelines.

It has been assumed that the Ultimate Development Concept scenarios occur in place of the Comparative Development Concept (as opposed to being phased) and therefore installation occurs in a single campaign. In practice it would not be economical to mobilise an S Lay Barge to install a single 10km 20" infield pipeline, as dual smaller diameter reel laid pipelines would be far cheaper. This assumption is deemed acceptable due to the screening nature of the cost estimates presented herein.

2.6 Shore Approach / Landfall Cost Estimation

A unit cost of £20MM has been applied to account for pipeline Shore Approach / Landfall. This is deemed an average cost and it should be noted that the landfall cost attributable to the respective beachheads could significantly exceed this cost, dependent upon the technical solution chosen.

Note the Shore Approach / Landfall cost element applies to all options except those that assume tie in or extension to the expected CO_2 trunklines to 5/42 and Goldeneye.

2.7 Pipeline Crossing Cost Estimation

The numbers of crossings have been based on the provisional routing and the current register of pipelines on the DECC website.

A unit cost of £1.5MM has been applied for pipeline crossings, this equates to an allowance for crossing construction and offshore installation in advance of pipelay.

Cable crossings have been ignored at this stage as the cables are trenched and buried, and the majority of the pipeline routing will be surface laid.

It is assumed that the infield pipelines have no crossings.

2.8 Pipeline Tie-In/Extension Costs

For the scenarios that assume the tie in or extension to a CO2 trunkline, a lump sum cost of £4.27MM has been applied to cover costs associated with providing a tie in pigging structure on the assumption of the established Oil & Gas Industry standard practice of 'Use and Replace' being adopted for CCS developments. A gravity based slope sided structure with 20" piping has been assumed.

The costs presented below cover the fabrication and installation, using manned diving operations, or a tie in structure, a DSV dayrate of £200k/day has been assumed resulting in the following tie in costs:

Description	Cost
Fabrication cost – Tie in Structure	£1,750,000
DSV Mobilisation, Transit & Demobilisation	£800,000
Structure installation	£200,000
Diver Well Tie in of structure to pipelines	£1,520,000
Total Tie In Structure Installed Cost	**£4,270,000**

Table 2-1 Tie-in Costs

No costs have been included for use of the third party facilities.

2.9 Subsea Template Cost Estimation

For the purposes of this study all CNS options have been costed on the assumption of subsea developments directly tied back to the beachhead or existing/proposed CCS development, without an associated platform. In all instances the 5 well subsea developments have been assumed to be drilled with close coupled wells arranged in a 6 well drilling template. The 6 well drilling template allows for 5 injection wells plus +1 spare to account for potential junked wells.

For the purposes of this cost estimate a modular drilling template structure design has been assumed consisting of a base drilling template section with a separate slab sided fishing and dropped object protection structure installed over the template. The outer structure would be located over the lower template section. The outer section would be designed to resist all dropped object and fishing loads. The structure would require to be piled to react all accidental and environmental type loads without load transfer into the well conductors. Each well bay would be provided with its own hinged/removable roof panels for dropped object protection, side panels would be fitted where required to prevent trawl gear entering the structure. The structure would have overall dimensions of approximately 16mL x 14mW x 7.0mH and the outer structure weight would be around 130 tonne. A central removable piping module would be located on the base template to negate the requirement for an additional manifold structure.

The below table presents the calculated costs for the generic template design:

Description	Cost
Fabrication cost (base Template, Piping Module, Protection Structure & Piles)	£2,400,000
Cost of piping Module Piping (CRA)	£150,000
Cost of piping Module Valves	£1,500,000
Engineering cost for Template design	£200,000
Cost of Delivering a Template to Quayside	**£4,250,000**
Template Installation Cost	**£1,000,000**
Total Installed Cost (per 6 well template)	**£5,250,000**

Table 2-2 Subsea Template Costs

Upon completion of drilling activities all 5 wells would be tied in using manned diving operations, a DSV dayrate of £200k/day has been assumed resulting in the following tie in costs:

Description	Cost
DSV Mobilisation, Transit & Demobilisation	£800,000
Diver Well Tie in to template Piping Module (2 days per Well)	£2,000,000
Diver Pipeline Spool Installation & Tie in (includes Spool cost)	£690,000
Total Drilling Template Tie-In Cost (5 wells and Trunkline tied in)	**£3,490,000**

Table 2-3 Template Tie-in Costs

2.10 Normally Unmanned Installation (NUI) Cost Estimation

For sites in the East Irish Sea (EIS) and Southern North Sea (SNS) the water depth is such that the preferential development concept allows for a Normally Unmanned Installation with dry trees drilled and completed by a Jack-Up drill rig.

NUI Topsides:

The NUI facilities would be limited in scope and include a crane, helideck, 12 man overnight accommodation facilities, a lifeboat and safety equipment, a local power generation package (either diesel or renewables driven), a controls and communication telemetry package, utilities package and dry trees (cantilever Jack-Up drilled) capable of injecting 1MT/yr per well so 5MT/yr per 5 well platform. No consideration has been given to a high point vent, compression, CO2 pumps and heating.

Parameter	NUI-25	NUI-40	NUI-75
Topsides Dry weight (t)	*879*	*879*	*879*
Topsides Operating weight (t)	1,079 (*938*)	1,079 (*938*)	1,079 (*938*)
Cost £GBP (Excl. Contingency)	28,232,903	28,232,903	28,232,903

Notes:

1. Que$tor generated weights shown in italics. Net weights exclusive of growth allowance are presented in brackets.
2. Dry Weight and Operating weight estimates have been generated by Que$tor. A growth allowance of 15% has been applied to the Topsides Operating Weight.

Table 2-4 Platform Topsides Costs

The above generated weights compare well with the Goldeneye NUI platform which has a topsides weight of 1000t supporting 5 cantilever Jack-Up drilled wells and no processing facilities.

Jacket Design:

Conventional 4-legged piled Steel Jackets have been assumed. Three standard jackets have been costed based on the range of water depths under consideration. The selected standard jackets are presented below and include NUI-25m for 25m WD and below (covers all East Irish Sea Sites and all SNS Sites in 25m or less WD), NUI-40m (covers SNS options in 30 & 40m WD) and a NUI-75m (covers final SNS option).

Jacket & Topsides Installation:

For the purposes of this cost estimate jacket and topsides installation has been assumed to be as independent single lifts by a Semi-Submersible Crane Vessel (SSCV). Pile Installation has been assumed to be carried out by the Jacket Installation vessel/barge.

Parameter	NUI-25	NUI-40	NUI-75
Jacket type	Conventional 4 legged Steel Jacket	Conventional 4 legged Steel Jacket	Conventional 4 legged Steel Jacket
Water depth	≤ 25m	≤ 40m	≤ 75m
Topsides operating weight (t)	1,079 (*938*)	1,079 (*938*)	1,079 (*938*)
Jacket Steel (t)	861 (*749*)	1,423 (1,237)	3,146 (*2,736*)
Jacket Piles (t)	679 (*590*)	836 (*727*)	1,198 (*1,042*)
Anodes (t)	56 (*49*)	92 (*80*)	205 (*178*)
Installation Aids (t)	43 (*37*)	71 (*62*)	158 (*137*)
Installation method	Lift	Lift	Lift
Number of conductors	7 (5 + 2 spare)	7 (5 + 2 spare)	7 (5 + 2 spare)
Number of risers	6	6	6
Number of J-tubes	1	1	1
Cost £GBP (Excl. Contingency)	13,855,484	25,982,571	42,783,871

Notes:

1. Que$tor generated weights shown in italics. Net weights exclusive of growth allowance are presented in brackets.
2. Jacket weight estimates have been generated by Que$tor. A growth allowance of 15% has been applied to Jacket weights.

Table 2-5 Jacket Costs

2.11 Power Generation

For EIS and SNS developments that include platforms, Power Generation has been in included in the topsides utilities. It is assumed that the low power demand of the minimum facilities platforms can be met by diesel powered generators. It is acknowledged that it may not be an economical approach considering the design life of the installations and the OPEX associated with diesel generators however for the purposes of the screening cost estimates it is considered a reasonable assumption.

For CNS developments that do not have an associated platform on which to mount Power Generation and Communication facilities it has been assumed power will be sourced from shore or a neighbouring installation via a subsea umbilical. Beyond approximately 50km a subsea umbilical solution become uneconomical, and will unduly bias economics and screening of the potential options. As such for subsea development concepts a lump sum allowance of £25MM has been included for power and controls on the basis that it would either permit a power and control umbilical to be run from a nearby facility or be developed via another means.

2.12 OPEX Costs

OPEX Costs have been calculated on the basis of 6% of the Facilities cost per annum, note the Facilities cost excludes the Development Wells and Appraisal Costs.

2.13 ABEX Costs

Decommissioning costs have been calculated on the basis of 25% of Facilities costs and £4m per dry well, and £8m per subsea well.

2.14 Project Management, Engineering & Insurances

Project Management, Engineering and Insurances costs have been calculated as 10% of the sum of Facilities Costs. Axis supplied Development Well Costs include a project Management and Engineering allowance.

2.15 Contingency

A Contingency allowance of 20% has been applied to the sum of Appraisal, Development Well, Facilities, PM & Eng, and ABEX costs.

Note the Axis Development Well costs state an additional margin of 25% should be applied, however as per the preceding statement contingency has been applied at 20%.

2.16 Summary

The cost estimates prepared by Costain Upstream to support Pale Blue Dot in delivering WP3 of the CO2 Strategic Storage Appraisal project, are screening level cost estimates with an accuracy of ±40% relative to the store definition provided by Pale Blue Dot. The cost estimates provided in Appendix A are intended as a screening tool only. No work has been undertaken to ascertain the technical acceptability of the costed development scenarios for the respective stores.

Assumptions with potentially significant impact on the development costs have been made in compiling the cost estimates for the individual stores, but efforts have been taken to ensure no store is unduly penalised or biased on account of the adopted assumptions. It is noted that the very small capacity stores namely Mey [361.000] will be unduly penalised given the infrastructure of the development could be heavily rationalised.

Significantly more work would be required to be undertaken in order to identify and define technically robust development solutions for each store to enable more accurate cost estimating. It is not intended that this be done at this stage of the project.

It should be noted that the cost estimates presented in Appendix A do not represent the full cost of storage as they omit MMV, security instruments, financing costs, handover to DECC and profit. They also do not include any onshore capture and transportation costs.

APPENDIX 1 OPTION COST SUMMARY RESULTS

Site	Region	Code	Site Description	Capacity MT	Nearest Beachhead	Water Depth	Shore Approach	Crossings	Wells	No. of Drill Centers	No. of Wells	Templates	NUI	Concept	TOTAL	Injected Volume	£/T CO2
11	CNS	336.000	Grid Sandstone Member	1825	St Fergus	90.0	No	0	Subsea	1.0	5.0	Yes	No	Comparative	£387,719,532	100	£3.88
		336.000		1825		90.0			Subsea	10.0	50.0		No	Ultimate	£3,317,038,185	1000	£3.32
12	CNS	361.000	Mey 1	22	St Fergus	70.0	Yes	6	Subsea	1.0	1.0	Yes	No	Comparative	£1,224,061,093	20	£61.20
		361.000		22		70.0			Subsea	1.0	1.0		No	Ultimate	£1,224,061,093		
13	CNS	366.000	Maureen 1	101	St Fergus	80.0	Yes	8	Subsea	1.0	5.0	Yes	No	Comparative	£1,240,723,207	100	£12.41
		366.000		101		80.0			Subsea	1.0	5.0		No	Ultimate	£1,240,723,207		
14	CNS	218.000	Captain_013_17	49	St Fergus	95.0	No	3	Subsea	1.0	3.0	Yes	No	Comparative	£237,046,972	49	£4.84
		218.000		49		95.0			Subsea	1.0	3.0		No	Ultimate	£237,046,972		
2	CNS	372.000	Forties 5	1021	St Fergus	80.0	Yes	6	Subsea	1.0	5.0	Yes	No	Comparative	£1,108,471,257	100	£11.08
		372.000		1021		80.0			Subsea	10.0	50.0		No	Ultimate	£5,217,857,382	1000	£5.22
24	CNS	218.001	Captain Oil Field	96	St Fergus	105.5	Yes	1	Subsea	1.0	5.0	Yes	No	Comparative	£662,608,741	96	£6.92
		218.001		96		105.5			Subsea	1.0	5.0		No	Ultimate	£662,608,741		
27	CNS	217.000	Coracle_012_20	35	St Fergus	99.0	No	1	Subsea	1.0	2.0	Yes	No	Comparative	£267,965,074	35	£7.66
		217.000		35		99.0			Subsea	1.0	2.0		No	Ultimate	£267,965,074		
28	CNS	252.001	Harding Central oil field	85	St Fergus	110.0	No	1	Subsea	1.0	4.0	Yes	No	Comparative	£567,731,398	80	£7.10
		252.001		85		110.0			Subsea	1.0	4.0		No	Ultimate	£567,731,398		
8	CNS	133.001	Bruce Gas Condensate Field	188	St Fergus	116.4	No	6	Subsea	1.0	5.0	Yes	No	Comparative	£1,077,893,605	100	£10.78
		133.001		188		116.4			Subsea	2.0	9.0		No	Ultimate	£1,641,037,167	180	£9.12
10	EIS	248.004	North Morecambe gas field	187	Connah's Quay	25.0	Yes	0	Dry	1.0	5.0	No	NUI-25	Comparative	£611,828,073	100	£6.12
		248.004		187		25.0			Dry	2.0	9.0		NUI-25	Ultimate	£905,350,702	180	£5.03
19	EIS	248.002	Hamilton gas field	130	Connah's Quay	25.0	Yes	0	Dry	1.0	5.0	No	NUI-25	Comparative	£480,356,004	100	£4.80
		248.002		130		25.0			Dry	1.0	6.0		NUI-25	Ultimate	£509,695,352	120	£4.25
3	EIS	248.005	South Morecambe gas field	855	Connah's Quay	25.0	Yes	1	Dry	1.0	5.0	No	NUI-25	Comparative	£589,503,497	100	£5.90
		248.005		855		25.0			Dry	9.0	43.0		NUI-25	Ultimate	£3,175,429,764	855	£3.71
1	SNS	226.011	Bunter Closure 9	1977	Barmston	30.0	Yes	21	Dry	1.0	5.0	No	NUI-45	Comparative	£1,126,618,363	100	£11.27
		226.011		1977		30.0			Dry	10.0	50.0		NUI-45	Ultimate	£4,234,906,210	1000	£4.23
20	SNS	141.002	Barque gas field	91	Barmston	10.0	Yes	7	Dry	1.0	5.0	No	NUI-25	Comparative	£927,863,421	91	£10.20
		141.002		91		10.0			Dry	1.0	5.0		NUI-25	Ultimate	£927,863,421		
26	SNS	139.020	Bunter Closure 40	100	Barmston	30.0	No	1	Dry	1.0	5.0	No	NUI-45	Comparative	£535,185,688	100	£5.35
		139.020		100		30.0			Dry	1.0	5.0		NUI-45	Ultimate	£535,185,688		
4	SNS	227.007	Bunter Closure 3	232	Barmston	40.0	Yes	12	Dry	1.0	5.0	No	NUI-45	Comparative	£1,151,663,658	100	£11.52
		227.007		232		40.0			Dry	2.0	12.0		NUI-45	Ultimate	£1,656,851,852	232	£7.14
5	SNS	141.035	Viking gas fields	310	Barmston	20.0	Yes	7	Dry	1.0	5.0	No	NUI-25	Comparative	£1,112,661,360	100	£11.13
		141.035		310		20.0			Dry	3.0	15.0		NUI-25	Ultimate	£2,129,015,215	300	£7.10
6	SNS	266.001	Hewett gas field	312	Barmston	20.0	Yes	22	Dry	1.0	5.0	No	NUI-25	Comparative	£1,039,903,435	100	£10.40
		266.001		600		20.0			Dry	6.0	30.0		NUI-25	Ultimate	£2,890,987,152	600	£4.82
7	SNS	139.016	Bunter Closure 36	252	Barmston	75.0	No	4	Dry	1.0	5.0	No	NUI-75	Comparative	£727,866,782	100	£7.28
		139.016		252		75.0			Dry	2.0	12.0		NUI-75	Ultimate	£1,215,881,405	240	£5.07
9	SNS	303.001	Hewett gas field (Bunter)	288	Barmston	30.0	No	23	Dry	1.0	5.0	No	NUI-45	Comparative	£1,011,844,323	100	£10.12
		303.001		600		30.0			Dry	6.0	30.0		NUI-45	Ultimate	£2,953,075,663	600	£4.92

APPENDIX 2 AXIS DEVELOPMENT WELL COSTS

2015

D05 10113ETIS WP4 Report – Appendix 4; Lessons from other Appraisal Projects - BGS

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Energy and Marine Geoscience Programme

Internal Report CR/15/072

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Foreword

This report is a review of published site appraisal activities commissioned by Pale Blue Dot to inform their appraisal of storage sites for the Strategic UK CCS Storage Appraisal Project conducted on behalf of the Energy Technologies Institute (ETI). The review is undertaken by the British Geological Survey (BGS) as a member of Scottish Carbon Capture & Storage (SCCS). The report follows the scope agreed with Pale Blue Dot to undertake a review of studies relevant to Strategic UK CCS Storage Appraisal as two tasks:

Task 1: Review of UK and international studies relevant to appraised storage sites to inform the workflow selection process;

Task 2: Refining of key lessons to apply to the five sites selected by Pale Blue Dot.

Task 1 was delivered as a draft report by 14th August 2015. This report completes Task 2 and was delivered as a revised final report on 21st August 2015.

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The information provided within this report incorporates the expertise and experience of the British Geological Survey on the selection and characterisation of geological sites for the storage of carbon dioxide (CO_2) since 1992 and from their contribution to many of the publicly available documents included in this review. The authors and Pale Blue Dot thank colleagues in the CarbonNet project for supply of pre-publication versions of papers on their site appraisal work in the Gippsland Basin.

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Summary

Previously completed, publically available UK and international studies of prospective CO_2 stores, relevant to Strategic UK CCS Storage Appraisal Project are reviewed. The selected studies address best practice in storage appraisal beyond the theoretical static capacity estimations. The review specifically assesses the workflows used in various studies to take forward storage development of sites.

Key lessons learned and knowledge gained from the review, together with the expertise and experience of the selection and characterisation of geological sites for the storage of carbon dioxide (CO_2) are presented, in 'workflow' order, in the following sections:

- Collation and review of data
- Geological models
- Risk analysis and uncertainty reduction
- Handling of uncertainty and parameter value ranges
- Storage capacity and migration path analysis
- Key metrics for site performance

Lessons learned on the location of injection points in open aquifers and trapping mechanisms are identified and included in this review.

Two generic site appraisal methodologies are reviewed, from the SiteChar Project and the CO_2 Aquifer Storage Site Evaluation and Monitoring (CASSEM) project. Two basin-scale storage appraisals are reviewed for the UK Central North Sea Hub and the Gippsland Basin, Australia.

Site appraisals by store type are reviewed for four depleted gas fields: Goldeneye Gas Condensate Field; Hewett Gas Field in the UK Central and Southern North Sea, respectively; P18-4 Gas Field in the Netherlands North Sea; and Naylor Gas Field in the Otway Basin, Australia.

Storage appraisals of saline aquifer formations are reviewed for five North Sea sandstones: National Grid appraisal of the Bunter Sandstone; UK Storage Appraisal Project (UKSAP) assessment of the Bunter Sandstone Exemplar Model: UKSAP assessment of the Forties Sandstone Exemplar Model; Captain Sandstone aquifer; Sleipner CO_2 injection site in the Norwegian sector of the North Sea.

The key lessons learned and knowledge gained are applied to the five sites selected by Pale Blue Dot: Bunter Sandstone Closure 36; Captain Sandstone aquifer; Forties Sandstone Unit 5; Hamilton Gas Field and Viking fields.

1 Introduction and scope

The UK Government has secured funding for strategic Carbon Capture and Storage (CCS) research and development in 2015-16. The UK Department of Energy and Climate Change (DECC) has tasked the Energy Technologies Institute (ETI) with commissioning and delivering a project which will bring together existing storage appraisal initiatives, accelerate the development of strategically important CO_2 storage capacity and leverage further investment in the building of this capacity to meet UK needs.

Pale Blue Dot Energy has been awarded a contract by ETI to deliver the strategic UK CCS Storage Appraisal Project. Pale Blue Dot has engaged the British Geological Survey (BGS), through a contract with SCCS, to enable the significant expertise and experience of BGS to be accessible to the appraisal project.

1.1 SCOPE

A review of previously completed studies relevant to Strategic UK CCS Storage Appraisal Project has been undertaken. The relevant studies were publically available studies of UK and international prospective CO_2 stores.

Studies have been selected that address best practice in storage appraisal beyond the theoretical static capacity. Materials reviewed included: reports from the first DECC Demonstration Competition; Joint Industry Projects; previously completed CCS storage appraisal research work. The selection ensured prospective storage sites reviewed reflect the diversity of storage capacity in the UK.

The review specifically assessed the workflows used in various studies to take forward storage development of sites. This has enabled the general lessons learned and knowledge gained to be transferred into the workflow selection for the appraisal project. The key lessons learnt from previous projects was tailored to the five sites, selected and advised by Pale Blue Dot, to inform the overall activities in the Strategic UK CCS Storage Appraisal Project.

1.2 STRUCTURE OF THE REVIEW

The review presents published methodologies, basin-scale appraisal and appraisals of individual storage sites by store type. The key lessons learned and knowledge gained from the review of the storage appraisal methods are presented in Section 2

Two generic site appraisal methodologies are reviewed in Section 3; the SiteChar Project site appraisal workflow and the CO_2 Aquifer Storage Site Evaluation and Monitoring (CASSEM) project. Basin-scale storage appraisals for the UK Central North Sea Hub and the Gippsland Basin, Australia are reviewed in Section 4.

Site appraisal by store type is reviewed for depleted gas fields in Section 4 and in saline aquifer formations in Section 5. Storage evaluation is reviewed for four depleted gas fields:

- the Goldeneye Gas Condensate Field in the UK Central North Sea,
- the Hewett Gas Field in the Southern North Sea,
- the P18-4 Gas Field, the prospective storage site for ROAD project in the Netherlands North Sea and
- the Naylor Gas Field in the Otway basin, Victoria Australia.

Storage appraisals of saline aquifer formations are reviewed in Section 6;

- five North Sea sandstones,
- the National Grid appraisal of the Bunter Sandstone,

- the UK Storage Appraisal Project (UKSAP) assessment of the Bunter Sandstone Exemplar Model and the Forties Sandstone Exemplar Model,
- the Captain Sandstone,
- the Sleipner CO_2 injection site in the Norwegian sector of the North Sea.

Key lessons learned from this review relevant to five sites selected by Pale Blue Dot are presented in Section 7.

2 Key lessons learned and knowledge gained

Site appraisal is led by an assessment of risks to focus and target detailed site characterisation investigations to meet the constraints that apply to the site assessed. The review illustrates how the assessment of risks can be constrained by national or international (European) regulatory requirements, environmental, financial or business constraints and the need to securely contain CO_2. Risk assessment-led storage appraisal is explicit or inferred in many of the storage appraisals reviewed. The detailed technical and non-technical investigations are targeted to reduce and mitigate the risks to the storage site. The recently completed and published site characterisation workflow from the SiteChar project (Figure 1; Neele et al., 2013; Nepveu et al., 2015) presents a risk assessment-led methodology relevant to appraisal of any storage site, although focused on the requirements of a storage permit application for a European site. The SiteChar methodology is presented in detail by workflow stage, including uncertainties and risk factors, by Neele et al. (2013) and is not re-iterated here.

Key lessons learned and knowledge gained are presented, in the ‘workflow’ order from the SiteChar methodology, in the following sections:

- Collation and review of data
- Geological models
- Risk analysis and uncertainty reduction
- Handling of uncertainty and parameter value ranges
- Storage capacity and migration path analysis
- Key metrics for site performance

Identification of lessons learned on the location of injection points in open aquifers and trapping mechanisms, as requested by Pale Blue Dot (personal communication, Alan James, 5th August 2015), are also included in this review.

2.1 COLLATION AND REVIEW OF DATA

Collation and review of all available data on the site selected to be appraised, or analogue data where essential information needed for characterisation from the site is not known, is the first step (a on Figure 1) and is in addition to data used for site selection.

The **data sources** should be reviewed and assessed. This should consider the vintage, character, detailed acquisition information, and the distribution and resolution of the data. All data that could be relevant to the constraints relevant to the storage site appraised should be assessed since evidence from one data source may require additional data to be acquired, i.e. data to investigate a potential migration flow pathway due to evidence of fluid flow. Data required for all disciplines of planned site investigation (Table 1) must be collated, noting that the extent and depth of data for the different disciplines may be much greater than the storage site itself.

A **quality control** check of the data collated will assure that it is of sufficient quality to characterise the site, to the required level. Data sources may be found to be incomplete, contain gaps in data distribution, of insufficient resolution, do not span the interval or area required for the appraisal, of poor quality or are not accessible. A quick scan of the data for all investigation disciplines by appraisal experts will identify what other data will be required to reduce uncertainties where the data gathered is inadequate or insufficient (b on Figure 1).

Once all data is acquired, a first **qualitative risk assessment** (c on Figure 1) and risk ranking will focus the detailed investigations (d on Figure 1) to meet the regulatory, technical or containment constraints for the storage appraisal.

2.2 GEOLOGICAL MODELS

A three-dimensional geological model (static model) underpins or informs all other geoscientific predictive models of the storage site. The more closely the geological model represents the understanding of the storage strata the better, regardless of later phases of up-scaling required for other characterisation purposes.

The **data sources** to inform the geological model should include 2D seismic data, to set the site within the regional geological framework, 3D seismic data to provide the most detailed available data on the stratigraphic and fault surfaces. Well logs, core analyses and detailed well reports, including any sedimentological or facies analysis, are needed to inform attribution of the geological model.

The assessment of **reservoir quality** to inform the CO_2 injectivity will be dependent on knowledge of the primary depositional character and subsequent diagenetic history to enable attribution of the storage formation. Reservoir quality, such as porosity, permeability and net proportion of sandstone, may be attributed by stratigraphical interval using measures based on average values. Lateral variations in reservoir quality may be attributed by measures of variance, geometry and orientation, using values inferred from sedimentological studies. Attribution by depositional facies may be undertaken where the extent, geometry and character of separate facies can be mapped.

Parameterisation of the reservoir requires judgements based on the available data and knowledge of the strata to remove artefacts, discretise the storage strata and apply numerical methods to attribute the resulting cells. Geological model surfaces may contain artefacts generated from the distribution of the input data on which the interpretation is based. Smoothing to remove irregularities must not also eliminate real surface roughness, particularly on the upper surface of the storage formation as this rugosity can enhance the physical trapping capacity within the site. Discretisation of the storage and sealing cap rock strata into a geocellular model should reflect knowledge of the internal character of the storage formation (see **reservoir quality**) at an appropriate scale. The cell layer height, horizontal and vertical dimensions should be sufficiently large to create model files with a workable number of cells. Numerical methods are applied to model the porosity from well logs, determine the relationship between porosity and measured permeability values and match the modelled output with known values. Stochastic modelling of storage formation attribution, randomly assigned values within parameters ranges defined by measured values and/or well datasets, are commonly used. The methods followed and judgements made for all reservoir parameterisation techniques used should be carefully considered and recorded.

The geological model should be used to perform a **structural analysis for assessment of risk** to capacity and containment. The geometry of an enclosing structure should be quantified from the geological model to ensure the maximum volume from structural closure to spill points is sufficient for the required storage capacity. The model should also be used for an analysis of containment and if the containing structure is fault-bounded to assess the potential for porous strata to be juxtaposed across the fault plane. Conversely, connectivity of porous strata across a fault may be assessed as beneficial to the injection scenario where the fault does not define the containing structure and facilitates dissipation of increased pressure of injection.

2.3 RISK ANALYSIS AND UNCERTAINTY REDUCTION

Risk assessment-led site characterisation is a common framework for the storage appraisals reviewed for regional and site-specific assessments, although the methods applied will vary to meet differing constraints specific to individual storage appraisals. Risk assessments can help prioritise resource intensive data acquisition and characterisation activities to ensure effective use of time and project resources. The effort required to reduce all risk is unlikely to be available, unless a full engineering and design study is undertaken. However, the risk assessment-led approach identifies what needs to be done and informs preventative measures for further investigation of a promising storage site. Uncertainty reduction and the acquisition of additional data to provide information where it is not known for the site, are essential components of risk-reduction characterisation.

The SiteChar workflow illustrates quantitative risk assessment (QRA) after completion of iterative detailed site characterisation (e on Figure 1). The cycle of site characterisation and QRA would be repeated for the number of iterations undertaken within the appraisal project. In practise, for multi-disciplinary storage site characterisation the risk re-assessment process is continuous and risk-reduction results are reviewed at every technical project progress meeting. The results from **investigations in one discipline can have implications and consequences to the investigations by other disciplines** and investigators should be engaged in the evolving understanding of the site and storage scenario.

2.4 HANDLING OF UNCERTAINTY AND PARAMETER VALUE RANGES

There is an underlying uncertainty in the interpretation of the geology, derived from subsurface datasets or analogue information. This may be investigated by **modelling alternative geological interpretations** of the available data. The effort and resources needed to model alternative interpretations deems it unlikely that multiple models would be constructed during a research project, attributed and used to predict storage site performance (unless an assessment of structural uncertainty constitutes an integral part of the project). However, site characterisations conducted to inform a Front End Engineering and Design (FEED) to ultimately submit a storage permit application to regulators would consider alternative interpretations. Investigation of alternative interpretations has been conducted for the Peterhead project, while a revision of the existing structural model has been conducted following the drilling of the storage appraisal well for the White Rose project.

Multiple realisations of the stochastic attribution of the storage formation can be conducted to reduce the underlying uncertainty of the adequate representation of the storage site by the geological model. Comparison of the results from three of more realisations will indicate the range of variation derived from the same underlying data by the numerical methods. The results should be assessed to indicate the range that might be anticipated and a realisation selected, such as with mid-point values, that is judged most representative of the storage site.

Sensitivity analysis can be conducted to assess the risk associated with uncertainty in the value of a reservoir parameter within the geological model. Repetitions of the ‘dynamic’ simulation of CO_2 injection with different values will indicate how sensitive the storage formation performance is to variations in the parameter values. The risk may be reduced if there is little difference in the response or indicate a need to obtain additional information if store performance is sensitive to variations in the parameter. A conservative approach has been adopted to ensure less probable or more extreme parameter values do not lead to increased risks to containment.

2.5 STORAGE CAPACITY AND MIGRATION PATH ANALYSIS

Simulation of CO_2 injection or ‘**dynamic’ modelling** is a key activity in risk reduction site characterisation to give greater confidence in the calculated storage capacity of the site, to predict the migration pathway of the injected CO_2 and the storage formation response to pressure changes due to CO_2 injection. **Dynamic modelling is closely integrated with other predictive geoscientific modelling of the storage site.** Dynamic modelling is intimately linked with geological modelling, uses datasets in common with geomechanical modelling and is constrained by the maximum acceptable pressure from geomechanical modelling. Iterative feedback and interaction, including agreement of property values used in modelling, between these three geoscientific modelling activities is a key learning for successful and effective characterisation.

The architecture of the ‘static’ geological model must be suitable, for example the construction of fault surfaces, and modification of the geocellular grid for ‘dynamic’ modelling should be anticipated. The geological model will be more detailed and comprise more model cells than are workable, due to the limitations on computing resources and the length of time needed to run the simulations. The size of the cells in **the geological model will be up-scaled** for dynamic modelling and the modifications should be checked by the geological modellers to ensure they are correct and reasonable. This is to ensure the model remains representative of the storage site geology and features relevant to storage appraisal are not lost during up-scaling, such as surface roughness or small volumes of highly permeable strata.

The **resolution of the model grid for dynamic modelling** is selected to be appropriate for the prediction of flow processes, injectivity. and changes in formation pressure. It is acceptable for the horizontal dimensions of the model grid to be at a lower resolution than those around the injection points. To reflect the need to predict pressure at the point of injection and in the enclosing structure and detailed migration of the injected CO_2 the grid will be refined and more finely resolved in the vicinity of the modelled CO_2 injection well. The height of cell layers within the dynamic model is also selected to predict storage site performance. The height of cell layers representing the top of the storage formation and base of the containing cap rock should be selected to ensure a realistic rate of plume migration is predicted within either formation. A **sensitivity analysis of the impact of cell grid resolution** will indicate the effect of cell size on predicted plume migration. A comparison of the extent and rate of CO_2 migration using coarse- and fine-scale grids will illustrate the sensitivity to cell size and the likely expected range of variation in predicted plume migration.

The **maximum allowable pressure within a storage formation** is a crucial constraint when appraising a site for the volume of CO_2 stored, rate of CO_2 injection and hence the storage capacity of the site. The maximum pressure within the storage site must not reactivate any existing fractures or exceed the fracture pressure of the containing cap rock to generate new fractures. Initial storage appraisals may set the maximum allowable pressure using a ‘rule of thumb’ value relative to background pressure gradients, such as between 1.3 and 1.5 times the initial pressure (SCCS, 2011; Jin et al., 2012) or some other pre-defined pressure limit. For a hydrocarbon field storage site the initial reservoir pressure value may be used as the maximum value. Site-specific maximum allowable pressure values can be calculated by geomechanical modelling, calculated using input data of mechanical properties and initial pressures for the site.

The output from **dynamic modelling of CO_2 injection is a key dataset for storage appraisal**. It provides the site storage capacity, predicts the migration pathway for the injected CO_2 plume, informs the selection of the injection scenario, and determines whether pressure management will be required. The output informs other storage appraisal activities, such as predictive wellbore migration modelling, and assessment of store operation constraints on the effects on other pore space users.

2.6 KEY METRICS FOR STORAGE

When assessing prospective sites for CO_2 storage key metrics need to be defined to inform a comparison with the requirements for the site. These are to ensure the store is suitable to contain the proposed volume of CO_2 to be stored. Geological metrics for storage are recommended here as:

- A minimum CO_2 injection rate, this might be 0.1 Mt CO_2 per well per year or greater;
- The predicted migration of the injected CO_2 plume, gaseous CO_2 and dissolved CO_2, should not extend beyond the boundary of the storage complex, i.e. storage site and the secondary containment formations (EC, 2011);
- Storage capacity sufficient to contain the proposed volume of CO_2 to be stored;
- The proposed volume of CO_2 can be securely contained within the storage site within the allowable pressure, i.e. limited to a percentage of reservoir fracture pressure such as 90%, or lower;

- For open aquifers, a migration rate limited to a specific value at a certain time after the end of injection, for example at 1000 years the CO_2 plume migration rate is less than 10 metres per year and declining.

2.7 KEY METRICS FOR SITE PERFORMANCE:

Proposed sites need to be assessed for their suitability to accommodate the injection scenario for the proposed storage project, not only the volume of CO_2 to be injected but additionally the annual rate of injection and the duration of the period of injection. Geological site performance metrics to compare and match with the anticipated supply of CO_2 are recommended here as:

- Injection rate
- Storage capacity
- Pressure prediction
- Trapping processes: percentage of residually trapped CO_2 and percentage CO_2 in solution
- Demonstrated low leakage risk at: spill points; connected formations; faults; wells

The recommended site performance metrics anticipate the components of a storage permit application, e.g. injection plan, storage performance forecast and site description. These are specific to the site and the assumed performance will need to be tested during site characterisation. The recommended metrics will be required to be met if the stores appraised are eventually to be awarded a permit for storage.

2.8 LOCATION OF INJECTION POINTS IN OPEN DIPPING AQUIFERS

The documents included in this review did not indicate best practise for the siting of injection well points in open dipping aquifers. The experience of the authors does include simulation of injection well positions within an aquifer sited away from hydrocarbon fields (SCCS, 2011) and simulation of CO_2 injection into aquifer storage sites for the SiteChar project (Delprat et al., 2013a-c). Although there is no methodology published to position injection points in an open aquifer, four European sites within or including an aquifer were appraised in the SiteChar project (Table 1). A lesson drawn from the simulation of CO_2 injection at the four SiteChar sites is that pressure increase is an important consideration. The constraint of the maximum acceptable pressure could be accommodated by a lowered rate of injection or management by pressure relief water production wells (SCCS, 2011; Delprat et al., 2013 a, b). The SiteChar UK site investigated injection into the Blake Oil Field and surrounding Captain Sandstone aquifer. The injection scenario for the site includes an injection rate of 5 Mt per year with pressure relief by water production to prevent interference with operating hydrocarbon fields (Delprat et al., 2013a, b; Akhurst et al., 2015). Optimisation of well position and injection rate is a recommendation from the investigations to maintain CO_2 injection without the need for pressure relief by water production.

In general, the siting of injection points within an open dipping aquifer would consider: well positions down-dip of the expected CO_2 plume migration pathway; optimisation of trapping by local topography and dip (Goater et al., 2011); limiting up-dip plume migration towards storage complex boundaries.

Siting of injection points for storage in aquifer sandstones with structural closures is considered by Bentham et al. (2011) and Williams et al. (2013a, b). The placement of injection wells in these investigations of the Bunter Sandstone avoids the spill points from the containing structural closures (Bentham et al., 2011; Williams et al., 2013a, b).

2.9 TRAPPING MECHANISMS

Dynamic simulation of CO_2 injection using commercially available simulation software is used to predict and distinguish between injected CO_2 in gaseous phase and CO_2 in solution. However, there is not an indication of that proportion of the gaseous phase CO_2 that is residually trapped, although the proportion is usually inferred from the simulation results. The distinction of gaseous phase CO_2 may not be distinguished from gas phase hydrocarbons by the simulation software.

Trapping mechanisms in an open dipping aquifer storage site are investigated by Goater et al. (2011) by modelling of the Forties Sandstone. They identify permeability and aquifer dip as key determinants of storage efficiency that control the velocity of the mobile CO_2 and pressure. Open aquifers of modest permeability and dip can be favourable storage sites with large storage capacities (Goater et al., 2011). The modest permeability limits the speed with which the CO_2 migrates, while the extensive open pore volume dissipates the pressure.

The effect of top-surface topography and heterogeneity within the storage formation was also investigated by Goater et al. (2011). Heterogeneity was found to reduce storage efficiency due to localised increase in pressure (Goater et al., 2011). Where pressure increase does not limit capacity, vertical heterogeneity improves storage efficiency by boosting the lateral sweep of CO_2.

Top-surface topography introduces structural closures, regions of higher and lower dip and channels (Goater et al., 2011). Goater et al. (2011) found that channels generally decrease efficiency whereas structural closures increase storage efficiency. The net result of the interacting effects of the factors examined was found to be dependent on the individual storage regime assessed and the top-surface topography (Goater et al, 2011).

3 Generic Site Appraisal Methodologies

3.1 THE SITECHAR SITE APPRAISAL WORKFLOW

The EU-funded SiteChar project, 2011 to 2013, was undertaken by industry and research participants from European countries who had already undertaken or planned to undertake site characterisation for the geological storage of CO_2. The investigations benefitted from participation by experienced CCS researchers who had contributed to the assessment and operation of the Sleipner project in Norway, assessment of the Netherlands ROAD and Danish Vedsted demonstrator projects, technical review of the UK DECC demonstration competition, industry operators of prospective gas field storage sites in Poland and appraisal of 'virgin' sites in offshore Italy and Norway. The objectives of SiteChar included facilitation of the implementation of CO_2 storage in Europe by improving and extending standard site characterisation work flows and assessing the feasibility of storage in representative sites. The workflow was developed to undertake site characterisation, assessment of risks and development of plans necessary to reach the final stage of Storage Permit licensing. Relevant industrial or government organisations contributed to each of the sites assessed (www.sitechar-co2.eu). 'Dry-run' licence applications prepared from the site characterisation were reviewed informally by an international group of regulators (Norway, Australia, Germany, France and USA). The project benefited from the advice provided by a Stakeholder Panel and offshore hydrocarbon company operators.

3.1.1 Brief overview

The SiteChar project examined the entire site characterisation chain, from the initial feasibility studies through to the final stage of application for a storage permit, on the basis of criteria defined by the relevant European legislation and taking a risk assessment-led approach. The research focussed on five feasible European storage sites, representative of various geological contexts, as test sites for the research work: a North Sea site (hydrocarbon field and aquifer) offshore Scotland, an onshore aquifer in Denmark, an onshore gas field in Poland, an offshore aquifer in Norway and an aquifer in the Southern Adriatic Sea. At the Scottish and Danish sites the site characterisations have allowed development of dry-run storage permit applications which have been evaluated by a group of independent experts and, for the UK site, made available to the competent authorities. Assessment of four sites, except the UK North Sea site, includes input and participation by an industry partner and so the technical findings for these assessments are confidential to the project. The Scottish Government was a partner to the assessment of the UK site within a hydrocarbon field and surrounding Captain Sandstone aquifer.

Three overview output documents, drawing on technical findings from all five prospective sites are available from the SiteChar project web site http://www.sitechar-co2.eu :

1. Site characterisation workflow (Neele et al, 2013; Nepveu et al., 2015);
2. Synthesis of the project and lessons learned from the application of the workflow (Delprat-Jannaud et al., 2013a);
3. Best practices and guidelines developed from the SiteChar project (Delprat-Jannaud et al., 2013a).

Peer-reviewed papers from the overview and technical reports are included in a special issue of the Oil & Gas Science and Technology http://ogst.ifpenergiesnouvelles.fr/, including: Risk reduction investigations and storage permit application components for the UK North Sea site (Akhurst et al., 2015).

A review of previous site characterisation studies and previous site-specific characterisation activities at four of the five sites was undertaken. Those parts of the process that were identified as not or only partly covered by previous studies in the site characterisation process were also identified: the sequence of component steps and timing of the process; interdependencies and feedback loops to improve the flow of results and information; explanation of how to address the requirements of the EU storage directive. An integrated risk assessment-based workflow was prepared, tested by the characterisation activities within the portfolio of five sites and refined to address the gaps and weaknesses (Figure 1). The relationship between the characterisation activities and outputs from them that are required components of an application for a storage permit application for a European storage site, were key learnings from the SiteChar project. For each step in the workflow the task, data required, relationship with other characterisation activities, uncertainties and risk factors, and key points of concern are described. Assessment of prospective sites at differing degrees of advancement has enabled the workflow to be tested from early site screening and selection stages through to advanced stages to inform economic analysis and monitoring planning.

The elements of the site characterisation workflow, following an initial screening phase, are described in detail (following the lettering in Figure 1) and summarised here.

a) Collect all available data on the site, in addition to the data collected for the screening phase.
b) A quick analysis identifies any problems related to the site before the study is continued. All available data are scrutinised, to find anything that could impede safe and secure storage, or that could affect the site's ability to meet the storage requirements
c) A qualitative Risk Assessment (RA) workshop of all specialists defines the risks associated with the site. These risks are related to the safety and security of storage, as well as the conformity with storage requirements. The aim of this step is to identify whether there are aspects that render storage at the site unviable and whether additional data is to be collected.
d) The site is studied and modelled across the different areas of expertise. Figure 1 highlights the main areas of investigation to reduce the identified risks. This is the most time-consuming and also the most complex part of the study, requiring intensive interaction within the team.
e) A Quantitative Risk Analysis (QRA) is conducted once all aspects of safe and secure storage have been studied and internal consistency in results and data is reached. Risks are compared with an a priori determined risk threshold. Mitigation actions are identified to further reduce risks. However, if risks are too high and mitigation measures cannot be taken or are too expensive, the site may be discarded.
f) Once the risks have been reduced to as low as reasonably possible and are deemed acceptable the components of a storage permit application can be prepared. These include a monitoring plan and baseline studies, drafting a site development plan, and analysing the costs of storage. The monitoring plan and a corrective measures plan are requirements for a storage site, defined in the EC Storage Directive, based on hazards that might occur. The site development plan is part of the activities of the future operator, but not formally required by the Storage Directive.

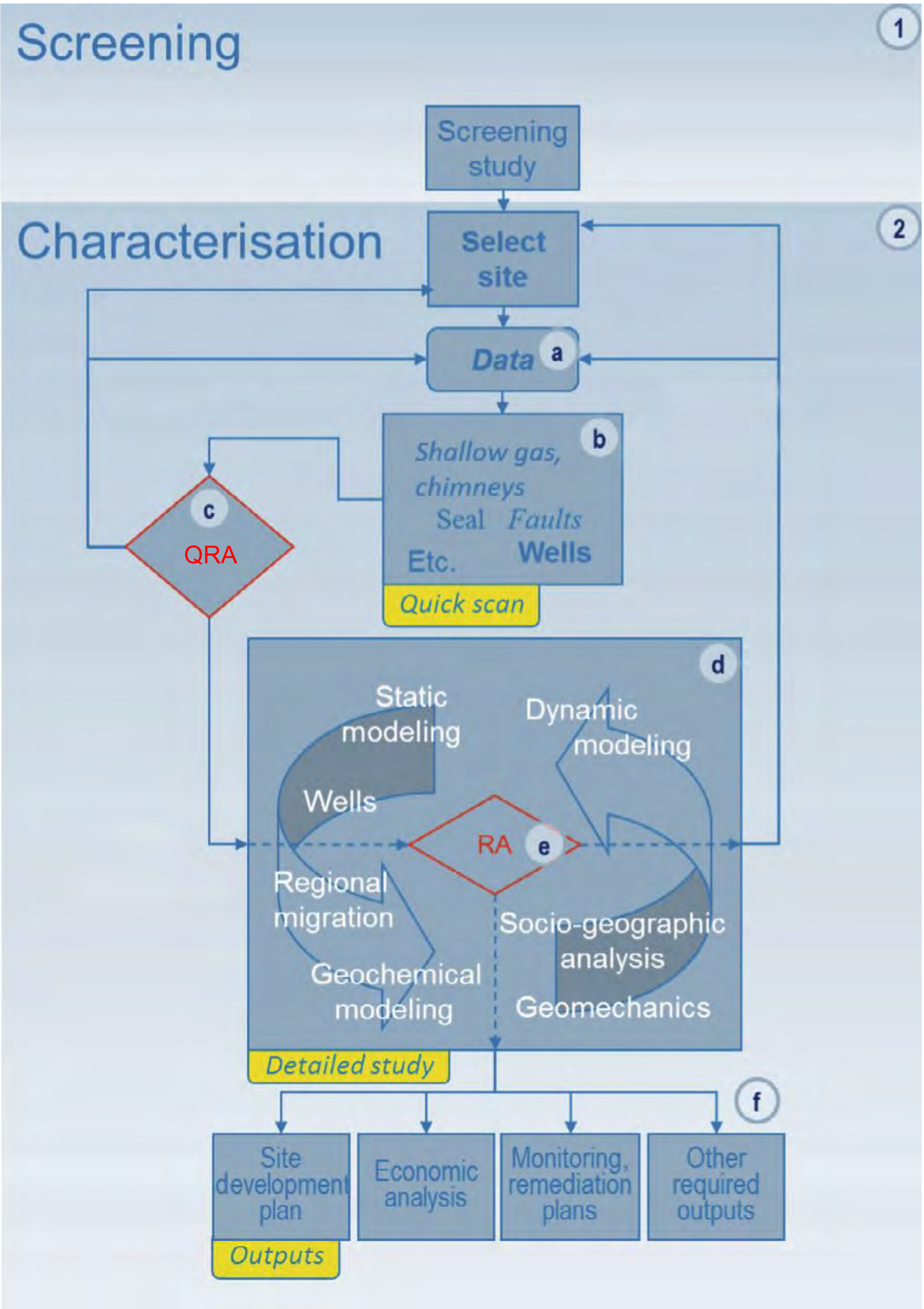

Figure 1: Workflow for site screening and characterisation from Nepveu et al. (2015).

3.1.2 Synthesis and lessons learned from the application of the SiteChar workflow,

The site characterisation activities undertaken at each of the five feasible sites included in the SiteChar project assessment were varied (Table 1).

Table 1: Application of the characterisation workflow to the SiteChar sites portfolio

	Outer Moray Firth	Vedsted	Załęcze-Zuchlów	Trøndelag Platform	Southern Adriatic Sea
Geology					
	North Sea UK	Denmark	Poland	Norway	Italy
	Offshore	Onshore	Onshore	Offshore	Offshore
	Depleted oil reservoir and host saline aquifer	Saline aquifer	Depleted oil reservoir	Saline aquifer	Saline aquifer
Reservoir	Sandstone	Sandstone	Clastic rocks	Clastic rocks	Carbonate rocks
Seal rock	Mudstone/Shale	Marine claystone	Salt	Shale	Marls
Main objectives					
	1- Dry-run permit	1- Dry-run permit	1- Whole workflow through to the development of an injection strategy	1- Basin & compartment scale evaluation	1- Methodology for characterisation in carbonate formations
	2- Relationship between hydrocarbon fields and host saline aquifer	2- Ways to supplement sparse data	2- Behaviour of the reservoir rock and cap rock	2- Possibility of leakage	2- Geomechanical and hydrodynamic behaviour
	3- Risk-led site characterisation, risk mitigation and management	3- Impact on the surrounding region		3- Injection strategy	
		4- Monitoring program/risk management		4- Monitoring/ remediation strategies	
Step of the workflow addressed					
1- Qualitative & quantitative risk assessment	X	X	X	X	
2- Static geological model construction and attribution	X	X	X	X	X
3- Hydrodynamic modeling	X	X	X	X	X
4- Geomechanical analysis	X	X	X	X	X
5- Geochemical evaluation	X		X		
6- Well integrity analysis	X	X	X		
7- Migration path analysis	X			X	
8- Social acceptability analysis	X		X		
9- Monitoring plan including shallow geohazards assessment and seismic monitoring feasibility study	X	X		X	
10- Economic assessment	X	X		X	X
11- Compliance with regulatory context	X	X			

The geology of the prospective storage site and objectives for characterisation at each site are summarised in the text. The degree of previously completed site selection and characterisation investigations is reflected in the number of workflow steps examined and lessons learned at each site. Social acceptability analysis was conducted at only the UK and Polish sites. Characterisation was sufficiently well progressed to present a ‘dry-run’ permit application for the UK and Danish sites. The method of risk assessment-led characterisation is illustrated by SiteChar project examples with the objectives, activities, investigations targeted to address specific concerns and recommendations from the findings presented for each of the workflow steps (numbered 1 to 11 in Table 1).

3.1.3 Best practices and guidelines developed from the SiteChar project

The key findings of the implementation of the SiteChar workflow and recommendations for efficient and effective site characterisation to inform and provide outputs required for a storage permit application are presented. Consolidation of the requirements of the EC Storage Directive with lessons learned at each workflow step from the SiteChar sites portfolio investigations is summarised in the best practices and guidelines report. The level of characterisation undertaken, what was achieved and lessons learned extends from selection of saline aquifer sites in 'virgin' areas, to screening of hydrocarbon field sites and detailed characterisation of onshore and offshore sites. The prospective sites with real-world problems, such as sparse data, illustrate how the associated uncertainties can be reduced by risk reduction investigations.

An integrated timeline for the process of site characterisation sufficient for a 'dry-run' storage permit application, based on the SiteChar project and numerous previous studies, is presented.

Nine points are identified for characterisation of a prospective site to achieve what is required for a storage permit application:

- Site characterisation should be driven by activities to reduce risk and increase certainty in the prospective storage.
- Site characterisation is a complex interdisciplinary process that requires close working and integration between the disciplinary teams.
- There is a need for dialogue with the Competent Authority, because of the great variability of the storage sites, which should be started as early as possible.
- Experts have to deal with data unavailability, addressing data gaps through scenario modelling and sensitivity analysis.
- Definition of the storage complex will require consideration of plume migration, pressure response and management, as well as the locations of necessary monitoring.
- Significant additional site characterisation will be undertaken after the storage permit has been obtained and injection has begun and some flexibility in the storage permit to reflect changes in operation is recommended.
- Governments and national authorities should play an active role in CO_2 storage projects to support implementation of CCS, site characterisation, reducing risks, and providing storage strategy.
- It is crucial to agree, during permit negotiations, the exact evidence and performance conditions that will be required to enable site closure and transfer of responsibility to Competent Authorities.
- The competent authority(ies) may need to undertake its own risk assessment and supporting investigations, to provide guidance to prospective operators.

Salient points of the 'dry-run' storage permit applications for the UK North Sea and Danish onshore sites are included as Appendices A and B, respectively.

The site characterisation lessons learned (Delprat-Jannaud et al., 2013a) and best practise (Delprat-Jannaud et al., 2013a) are summarised in Delprat-Jannaud et al. (2015).

3.1.4 SiteChar Case Study: Blake Field and Captain Sandstone

A summary of the risk assessment-led characterisation of a site in the UK Outer Moray Firth intended to store CO_2 at a commercial rate of five million tonnes per year (5 Mt) for 20 years is presented by Akhurst et al. (2015). The site comprises an assumed depleted hydrocarbon field (Blake Oil Field) and surrounding saline aquifer Captain Sandstone.

3.1.4.1 CHARACTERISATION WORK UNDERTAKEN

A closely integrated multi-disciplinary approach was taken following the SiteChar workflow (Neele et al., 2013; Nepveu et al., 2015). The following characterisation work was undertaken:

- Geological site characterisation;
- 3D static geological modelling;
- Dynamic modelling of CO_2 injection;
- Regional migration path analysis;
- Coupled dynamic and geomechanical modelling;
- Wellbore integrity modelling;
- Shallow geohazards assessment;
- Geochemical evaluation;
- Synthetic seismic modelling;
- Rock physics studies.

The site selection and feasibility are based on previous SCCS studies (SCCS, 2009, 2011). The regional-scale geological model is that of SCCS (2011) and based on selected 2D seismic and well data. Additional data interpreted in the SiteChar project are described as publicly available 3D seismic surveys across the Blake Field and from 23 well penetrations within the field. Geophysical well logs from 23 wells and core plug measurements were used to attribute the geological model by facies. The underlying source SiteChar technical reports are listed, which are not currently publicly available.

The characterisation activities were targeted to address risks identified by an initial risk assessment and ranked. Those technical risks that were most highly ranked were investigated (Table 2). A summary of the risk reduction investigations undertaken for each risk, the results illustrated and the change in risk rating and ranking is described.

Table 2: Risk assessment-led site characterisation investigations for selected risks for the SiteChar storage site in the UK North sea (from Akhurst et al., 2015).

Risk type	Risk description	Risk reduction investigations
Subsurface containment of stored CO_2	Connection of storage site reservoir sandstone to an adjacent fault	Geological site characterisation
	Primary cap rock thin or absent	Geological site characterisation and 3D modelling
	Fluid migration pathway north-westwards out of the storage site	Dynamic modelling of CO_2 injection, regional migration analysis
	Secondary reservoirs not present, laterally restricted or poor quality	Geological site characterisation
	Fracture pressure threshold of the primary cap rock exceeded.	Coupled dynamic simulation and geomechanical modelling
	Cap rock fracture pressure threshold lower than predicted.	Dynamic modelling
	Cap rock capillary entry pressure threshold exceeded	
	Injection-induced faults or fractures in cap rock	Geomechanical modelling
	Fluid escape pathways up abandoned wells	Wellbore integrity modelling Shallow geohazards assessment.

Technical performance less than expected	Unpredicted reservoir permeability heterogeneities	Geological modelling. Dynamic modelling of CO_2 injection.
	Hydrocarbon saturation to accurately inform dynamic modelling not known	Geological site characterisation
	Short-term CO_2 injection-induced permeability reduction near wellbore	Geochemical evaluation
	Long-term CO_2-induced permeability reduction in the storage reservoir due to geochemical changes	Geochemical evaluation
Monitoring or regulatory issues	Seismic monitoring ineffective due to the presence of a strong reflector in overlying strata.	Synthetic seismic modelling
	Seismic monitoring ineffective at detecting CO_2	Rock physics studies
Adverse effects on other resources	Interference with hydrocarbon fields from migration of CO_2 or increased pressure due to CO_2 injection.	Dynamic modelling of CO_2 injection. Storage site performance forecast.
	Induced seismicity	Geomechanical modelling

The risk reduction activities for the injection scenario indicate:

- The storage sandstone pinches out towards the adjacent fault and there is no connection with the fault plane
- In all of the dynamic simulations the injected CO_2 was retained in the near vicinity of the injection well.
- Dynamic modelling predicts injected CO_2 would remain where the primary cap rock is mapped as continuous and have acceptable thickness to contain the dissolved and supercritical phase CO_2.
- Although regional migration path analysis indicates a possibility of flow toward the north-west, the dynamic modelling indicates the injected CO_2 will be retained within a facies which does not extend to the north-west.
- Review of published stratigraphical atlases for the sequence overlying the storage strata indicates the presence of strata potentially suitable for secondary storage, which could be confirmed by further investigation.
- Initially, the fracture pressure threshold determined by geomechanical stability analysis would not be exceeded by CO_2 injection. For continued injection, pressure management would be required and further iterative modelling to optimise injection rates and well positions is recommended.
- The maximum pressure value predicted for the injection scenario with pressure management is approximately one third of the estimated cap rock fracture pressure threshold and so unlikely to be exceeded.
- The maximum pressure during injection is less than the estimated cap rock capillary entry pressure threshold, although the difference between them is small. However, the pressure increase would drop immediately once injection has finished and rates of leakage into the cap rock are very low.
- The likelihood of fault reactivation in the cap rock due to CO_2 injection is low provided pressure is managed. Furthermore, oil and gas has been retained at the site for geological time and it is unlikely fractures that could lead to significant leakage could exist in the cap rock.

- A scenario of wellbore leakage that modelled elevated pressures from injection for a period of 1000 years, indicated 1.3 tonnes of CO_2 might migrate to secondary storage strata. However, this is very pessimistic as pressures would be raised for only 20 years and additional mitigating measures and monitoring are included in the project design.
- The storage strata were found to be very porous, highly permeable and observed as homogeneous in character. However, the increase in pressure during injection was found to be very sensitive to attribution of permeability and additional investigation is strongly advised.
- The residual hydrocarbon saturation after water sweep within the storage site is known from well data to accurately inform dynamic modelling and comparison of injection into the aquifer. The hydrocarbon field components of the site show less of a reduction in pressure change than initially anticipated.
- Geochemical modelling shows that mineral reactions and porosity were predicted to be negligible in the short-term due to CO_2 injection. Further research to assess salt precipitation and the effects of microbial activity is recommended.
- Mineral reactions due to the injection of CO_2 are slow; a 0.3% decrease in porosity takes more than 10 000 years and after 15 000 years there is an increase in porosity to a final amount above the initial value.
- Seismic numerical modelling concludes that stored CO_2 should be detected within the site even within a seismic shadow produced due to the presence of a strong reflector in overlying strata.
- Detailed rock physics studies indicate that CO_2 injection will result in a change sufficient to be detectable by standard seismic monitoring although additional seismic data acquisition is recommended.
- There is little increase in reservoir pressure for the injection and pressure management scenario modelled. Other fields have ceased operation although the modelled pressure changes may be beneficial.
- Given the low predicted magnitude of pressure increase relative to the estimated cap rock fracture over pressure threshold there is a low probability of induced seismicity However, microseismic monitoring is included in the monitoring plan to identify any adverse seismic events.

The storage site, storage complex, injection scenario and components of a storage permit application that are informed or determined by the results of the risk assessment-led site characterisation are described. Permit Performance Conditions, criteria against which to measure storage site performance, are recommended as a finding from the SiteChar research. They are useful tools for discussion between the competent authority and operator throughout site characterisation to inform the monitoring planning, and to define and agree acceptance criteria to facilitate site closure. Six Permit Performance Conditions are proposed for the SiteChar UK North Sea storage site.

3.2 CO_2 AQUIFER STORAGE SITE EVALUATION AND MONITORING (CASSEM)

The CASSEM project was one of the first UK based projects to apply full-chain integrated research from capture and transport to injection, storage and monitoring of CO_2 (Smith et al., 2011). The study focussed on developing and understanding the best-value methods by which offshore UK saline aquifers could be evaluated to provide a low risk solution to development of new low carbon power utilities and engineering services.

The project used two exemplar sites (coal-fired power plants) with contrasting geology in the nearby subsurface to evaluate storage site selection. The Ferrybridge Power station in Yorkshire offered a simple site where in close proximity there was access to a large offshore saline aquifer, the Bunter Sandstone Formation with a wealth of legacy data. A more complex site was centred around the Longannet Power Station on the Firth of Forth, near Edinburgh, where legacy data was sparse and the prospective storage site is faulted and folded.

The project scope included the following:

- Surface facilities: handling and transport
- The CO_2 storage site: provides methodologies and workflows for geological modelling, reservoir simulation, monitoring
- Risk and uncertainty
- Economics of CO_2
- Public perception

The geological interpretation and modelling workflow adopted during the CASSEM project attempted to address a natural variability which exists due to the quality of data available and range of geological histories. The workflow was flexible and resulted in validated geological models.

3.2.1 Key findings

- Use of structural restoration techniques (first response tools) provided early assessment of site suitability and highlighted inconsistencies in the geological interpretations that required further detailed modelling and risking for capacity estimates.
- Early reprocessing and reinterpretation of data (e.g. seismic) reduced uncertainty in the geological model, with improved resolution of fault structures and constraining depths of key surfaces.

3.2.2 CASSEM Workflow

A workflow was designed around the characterisation of these two sites, which differed in complexity, size, potential impacts and amount and quality of data. The workflow consists of four stages and three evaluation/decision (E/D) gates (Smith et al. 2011):

1. Site screening (selection of potential sites based on agreed criteria)

   Evaluation-Decision Gate 1

2. Level I: basic geological model (initial surfaces proposed and risk evaluation, iterative workflow loop)

   Evaluation-Decision Gate 2

3. Level II: intermediate model (completed geological surfaces and faults, structural restoration, evaluation, migration and geometric testing)

   Evaluation-Decision Gate 3

4. Level III: high-level model (final geological model, attributed and validated)

Iteration and feedback loops during the initial modelling stage were essential, to allow refinement of the data and models. The models were delivered to other workflows either at an E/D gate or straight into Level II or III, depending on its stage of refinement.

3.2.3 Site screening

Sites were screened on globally accepted CO_2 storage site selection criteria, such as porous saline aquifers at suitable depths, demonstrating reservoir-seal pairs, with sufficient data available for geometry, areal extent, properties of aquifer, overburden etc. The sites were objectively ranked using site selection criteria and parameters to be used for modelling e.g. porosity, thickness and cap rock tolerances. Also carried out at this stage are risk strategies and input to a features, events and processes (FEP) register e.g. Maul et al. 2004.

For CASSEM potential saline aquifers were identified within a 75 km radius of two clusters of major CO_2 emitters: Drax/Ferrybridge (Lincolnshire) and Longannet/Cockenzie/Grangemouth (Firth of Forth).

3.2.3.1 Evaluation-Decision Gate 1

An assessment and ranking of potential sites was carried out at this stage, including an assessment on uncertainty and potential challenges by the geology to help plan for data acquisition and decide on a modelling approach.

3.2.3.2 Level I – Building the basic geological model

Information of publicly available data for each site was collated e.g. seismic, data, underground mining, wells data, isopach and sub-crop maps and key datasets were licensed and prepared for preliminary analysis using the appropriate software (Geographix ® Seisvision, Wellbase and Landmark™). Preliminary geological surfaces were created using reference points from wells, and seismic data, which then informed where further data was required.

Rock and fluid property data such as porosity and permeability, plus in situ data e.g. temperature, fluid salinity and pressure for the aquifer, cap rock and other key horizons and rock sample listings from well cores was compiled. Where well data/core samples were sparse, regional formations may hold information that may be analogous to the area of interest.

Interpretation of seismic data provided initial geological surfaces and faults (using GOCAD or Petrel) which was confirmed by wells and outcrop data (known data points) and these were then be risk assessed. At this stage, some or all of the surfaces were tested using the CASSEM first response tool set. These tools addressed three key areas:

> ***1. Structural validity***; using 2D-Move provided key early tests where structural complexity is present e.g. major faults (with displacements of more than 15% of the fault length at slip surface mid-point), folds with large amplitudes or multiple fold sets with differing geometries.
>
> ***2. Surface regions and pathways for CO_2 migration;*** pathways for migration of CO_2 beneath the seal of a saline aquifer were assessed using a single map migration technique such as Mpath (Permedia Research Group Inc). This method investigated possible preferential migration directions for the surface being modelled.
>
> ***3. Depth critical regions for CO_2 phase behaviour;*** an estimate of the density, viscosity and solubility of CO_2 under initial depth conditions was required for reservoir modelling and monitoring. Use of CO_2 Depth Profile (Dr. M. Naylor and University of Edinburgh) where geothermal and hydrostatic gradients indicated whether multiphase behaviour was likely to be simple or complex.

These tools allowed re-evaluation as a feedback loop back the Level I workflow as required, after a which a 3D model was defined (dependant on complexity).

3.2.3.3 Evaluation-Decision Gate 2

The geological model was considered for an 'invest or hold' decision where it was compared against alternative sites identified by the client/operator. At this point, recommendations for database enhancements may be made, this is a key contribution to the cost-risk-invest decision. The Level I model may then be utilised to inform planning and decisions on methods for capacity modelling and monitorability. A crude static capacity estimate (Jin et al. 2010) was also utilised to further advise the 'invest or hold' decision.

3.2.3.4 Level II – Building the intermediate geological model

A full geological model was constructed at this stage which included key geological surfaces and faults of the target saline aquifer and cap rock and surrounding geological horizons. Models underwent structural restoration and geometric testing of the surfaces e.g. unfolding the geological succession and backstripping to assess fault movement timings and sediment thickness variations.

Significant changes may still be required to local components but this is dependent upon the degree of structural complexity. Best estimates are therefore required for thickness, dip and fault geometry at this stage. Knowledge of the surface curvature is important for strain analysis and modelling of discrete fracture networks. MPath was utilised to help with locating injection wells for reservoir simulations.

3.2.3.5 Evaluation-Decision Gate 3

All previous iterations of the model were compared and combined to produce the best model to progress to Level III and provide a framework for storage capacity modelling. Model uncertainties were evaluated to help determine the decision-making process and to make recommendations. At this stage the model was held for further analysis or progressed to the final stage.

3.2.3.6 Level III – Building the final geological model

At this stage the geological model was refined by using the best data available and was quality assured. Models were then used for reservoir simulation but were constrained by the maximum and minimum scales of use, so that the models were utilised appropriately.

3.2.4 Store Capacity Estimates

3.2.4.1 Storage efficiency calculation

The CASSEM project considered two methods (1) the compressibility method (2) the semi-closed aquifer method (Zhou et al. 2008). The first method assumes the aquifer has closed boundaries and allows pressure build-up; therefore the CO_2 only occupies space in the reservoir due to the compressibility of the brine. The second method is similar to the compressibility method but it also allows displacement of fluids from the storage site through the cap rock and/or the underburden and allows for closed or open boundaries. This method assumes that the CO_2 remains within the storage site.

CASSEM compared the results of the different methods and recommended that where possible storage efficiencies should be estimated using numerical simulation due to the information and processes that can be taken into consideration.

Storage capacities at both sites were assessed with static (compressibility) and dynamic (semi-closed and numerical simulation) modelling. Static modelling is a simple method requiring the minimum of input data where the rock and fluid properties are a constant value. There are two commonly used static modelling methods; the volumetric method and the compressibility method. Dynamic modelling includes a flow calculation for the injected CO_2, requiring much more data and is computationally intensive but is generally more accurate and can be used for monitoring the CO_2 movement within the reservoir and can be useful for locating injection wells. Common dynamic methods include decline curve analysis, material balance and reservoir simulation. The selection of the modelling technique to use depends on the scale of the assessment and the type, quality and availability of data.

Where the geology is complex then the final Level III model produced may be just one interpretation of the data available and there may be further valid models possible. However not all models can be correct and they should be assessed for the most likely model via quantification of uncertainty and risk.

3.2.4.2 Static (compressibility) method

This method assumes that the aquifer model boundaries are closed and therefore is reliant on the compressibility of rocks and native pore fluids for it to be possible to inject CO2 into the existing pore space (Obdam, 2000; van der Meer and Egberts, 2008).

$$E = V_{CO2}/V_{pore} = (c_p + c_w)\Delta P_{max} \qquad (1)$$

where E is the storage efficiency factor (ratio of the pore volume containing CO2 (V_{CO2}) to the total pore volume (V_{pore})), c is compressibility, ΔP_{max} is the maximum allowable pressure increase and the subscripts p and w refer to the pore space and water respectively.

This method provides a conservative estimate as no fluid may flow across boundaries to reduce pressure within the system (CO_2 dissolution is also not considered using this method). A maximum length of injection time may be calculated for a given injection rate and the storage capacity (Millions of tonnes: Mt) can also be calculated.

3.2.4.3 Dynamic methods

When properties within a geological storage site change in relation to temperature and pressure, a dynamic model is advisable. Although full dynamic modelling is time-consuming, simple analytical and semi-analytical methods were developed as screening tools for basin- and field-scale assessments.

Semi-Closed Aquifer

The top and bottom seals of an aquifer are generally provided by low permeability rocks which can allow pore fluid to migrate out of the aquifer as pressure increases during the injection phase. A method by Zhou et al. (2008) can model such a system where an aquifer is assumed as homogenous and top and bottom seals are modelled at the same thickness. In this method pressure build up is assumed to be uniform across the aquifer and injected CO_2 remains in the aquifer (due to capillary pressure within the seal) while native pore fluids may migrate through the seals.

$$E = (c_p + c_w)\Delta P_{max} + \tfrac{1}{2}(c_p + c_w)\, V_s/V_{pore}\, \Delta P_{max} + 2Ak_s/\mu_w H_s V_{pore} \int_0^{max} \Delta P\,(t)dt \qquad (2)$$

where A is horizontal area, H is thickness, k is permeability, μ is viscosity, ΔP is pressure build-up t is time and the subscript s is the seal.

Fluid displacement and leakage from the system can be calculated as the pressure builds up. Several iterations may be required to resolve the above equation because pressure build-up affects the leakage rate to the cap rock.

Reservoir Simulation method

This method allows modelling of the following important physical processes: build-up of pressure in both near-well regions and across the aquifer; migration of CO_2 by advection and buoyancy; dissolution in the pore fluid; residual trapping of CO_2 in the pore fluid (Jin et al., 2010).

Reservoir simulation also can take into account the effect of heterogeneity of an aquifer as well as many other factors but this means more data on the structure of the geological formation and the petrophysical properties (porosity and permeability) to build the model. Full simulations are not possible at basin scale and are more suited to local- and site-scale.

Model properties used

The distribution of petrophysical properties were generated stochastically using a Sequential Gaussian Simulation method in PETREL. Grid cell sizes of 450 m by 450 m for the Lincolnshire model and 200 m (horizontal) for the Forth model were used. Permeability distribution was obtained by correlating log permeability with porosity, and net to gross was estimated and applied as a constant across the models. Faults that were present were included in the models, though where transmissibility across them were unknown, a range of values was applied. Rock compressibility was set as a constant, based on geomechanical measurements taken from nearby well cores. Temperature gradients were taken from local hydrocarbon exploration wells and salinity gradients from pore water samples.

It was assumed that the pressure was the same across the aquifer. Pressure build-up near a well is likely to be critical and this can only be assessed by carrying out simulations. The maximum injection pressure was defined from the rock mechanical information.

To cover the whole geological structure in both models the detailed regions were extended laterally using numerical aquifers.

CO_2-brine relative permeability data is scarce and most research makes reference to Bennion and Bachu (2008) but the CASSEM project had access to data from core samples from the Lincolnshire site (Cleethorpes). This data was used for both locations.

No capillary pressure data were available, however it was possible to generate curves using the Brooks-Corey formula (Brooks and Corey, 1964):

$$P_c = P_{ce} S_n^{-1/\lambda} \qquad (3)$$

where P_{ce} is the capillary entry pressure, S_n is the normalised saturation and λ is a parameter related to the sorting of the grains.

The value for the capillary entry pressure was set for each rock type (sandstone or mudstone) and depended on the porosity and permeability.

At both sites the static models were used to estimate storage capacity assuming a closed system (Equation 1) and then a semi-closed system (Equation 2). In all cases, it was assumed that the total injection rate was 15 Mt/yr (the equivalent of that emitted by a large fossil-fuel power station). This was to be injected via 15 injection wells each carrying a target amount of 1 Mt/yr. These wells were constrained by pressure build-up and injection rates were reduced when the maximum pressure was reached. Storage efficiency was calculated by numerical simulation after 15 years which was the assumed length of the injection period. Maximum storage efficiency was calculated by running the CO_2 injection until the total field injection rate reduced to one quarter of its initial value due to well pressure constraints.

3.2.5 Assessing the fate of CO_2 in the store

3.2.5.1 Reservoir simulation workflow

A general workflow for the reservoir simulation was followed:

Phase 1 simulation – volumetric and simple rock property data – indicates whether adequate storage volume is available and assume rock type is suitable. This allowed static CO_2 storage capacity to be calculated and definition of the dynamic simulation. The model at this stage was used to calculate potential injection rates. (It would be prudent at this stage to start acquiring samples and other data and identify a suitable laboratory to perform experiments).

Phase 2 simulation —This phase can inform whether there will be sufficient injectivity and likely migration pathways that the CO_2 might follow. At this point flow modellers worked closely with the geologists that built the geological models to ensure that the flow model accurately represents the site geology. Geomechanical and geochemical processes are introduced and where site specific data is unavailable, generic values were used, so results must be treated with caution.

Phase 3 simulation – laboratory data from site-specific samples were included during this phase and were integrated with the final geological model (developed during Level III of the geological model building). During this third phase the impact from site-specific data such as permeability, mechanical rock strength and mineralogy was evaluated. From this, the storage capacity was calculated and the outputs from this phase were used for the uncertainty analysis. There may be a significant change in the results going from Phase 2 to Phase 3, depending on the specific details of the site and generic correlations from the earlier phases. This may be due to sensitive geochemical reactions of certain mineralogies to particular water compositions. Whatever the differences in results the availability of site-specific data is beneficial to validating the model and reducing uncertainty of how the storage site is likely to behave.

There is a stage gate after each of the phases at which a decision is made whether to invest and move into the next phase or to put the project on hold.

There is a wide range of commercial software tools that perform dynamic flow simulations. In this project Petrel (Schlumberger) was used to discretise the models for all three phase of the reservoir simulation. ECLIPSE 300 (Schlumberger) was used to produce the flow calculations. The injection of CO_2, it's displacement through the rock, trapping under the cap rock, residual trapping and dissolution into the pore fluid were calculated using this software. Geomechanical modelling and geochemical modelling was carried out using VISAGE (Schlumberger) and GEM-GHG (Computer Modelling Group) respectively.

3.2.6 Assessing leakage

Geomechanical modelling can evaluate likelihood of new fault creation or pre-existing fault re-activation and whether or not the cap rock is likely to be compromised due to increases in pressure during injection of CO_2. These events may occur in a location not directly linked to the migration pathway therefore it is essential to predict the geomechanical effects and fluid flow.

Samples from well cores were tested in the laboratory to determine rock properties (porosity, permeability and bulk density tested at ambient stress conditions) providing information which fed into the geomechanical simulations.

The samples were also subjected to elevated stress tests (similar to conditions found in the reservoir) to calculate the static elastic constants needed for simulation. These tests were carried out by placing the samples inside a Hoek cell where the confining pressure was servo-controlled and the compressional (P) and shear (S) seismic wave velocities at the chosen stress levels were recorded. The samples were 100% saturated with brine equivalent of that found in the reservoir before the 'dry' stress levels tests were run. The samples were therefore 'wet' when tested in the Hoek cells and the amount of fluid that exits the sample was measured. This was repeated at different stress levels to derive a range of values. This data were used to calculate the pore volume, compressibility and the sample porosity at elevated stress levels.

The samples were also used for multiple failure state (MFS) tests to determine the failure criteria, the samples were observed whilst confining pressure is increased until the rock break apart. This derives the Mohr-columb failure parameters, cohesive strength and angle of internal friction which were fed into the geomechanical model. Risk and uncertainty

A risk is defined as the likelihood of an occurrence and the magnitude of the potential impact. The CASSEM project used a quantitative approach to rank areas of potential risk to a storage project. Examples of such may be faults in the storage site that may provide leakage pathways or petrophysical properties that may be suitable for the required injection rates.

It is not possible to know the exact fate of CO_2 injected into a storage site and therefore uncertainty must be considered when assessing a site for suitability. This was achieved by making a probabilistic assessment about the long-term behaviour of the CO_2. Uncertainty strongly influences risk and risk informs decisions of future data acquisitions aimed at better understanding uncertainty.

3.2.6.1 Geological Uncertainty

Numerical simulations predict the fate of CO_2 in the subsurface modelling true properties and attempting to accurately simulate the behaviour of CO_2 in the system. No simulation can be completely accurate because of the uncertainties of the properties of the storage site over- and underburden. Simulations however can allow evaluation of likely uncertainties for a storage site. A sensitivity analysis helped to quantify uncertainty via the input parameters so that they can be applied to the models (uncertainty analysis). Table 3 provides a list of example input parameters that were used in uncertainty analysis.

Table 3 Examples of uncertainty input parameters used in the CASSEM project

Input parameter
Depth of surfaces/interfaces between layer
Potential existence of lateral no-flow boundaries
Heterogeneity within each layer
Porosity of reservoir and caprock
Permeability of reservoir and caprock
Fault locations
Fault transmissivity
Relative permeability of carbon dioxide and water

Probability density functions were applied to each of the parameters chosen which describe a range of possible values the parameters could take. These were estimated by a combination of data, expert judgement and other modelling work. Real data should be relied upon where possible though where it is lacking expert judgment may be used though this in some cases may be influenced by cognitive bias.

The sensitivity and uncertainty analysis was then applied to the reservoir simulation models to further help identifying key input parameters for the model, to validate the volume estimates and to show the impacts of the final model on the simulation predictions and to decide whether the site meets the minimum requirements (i.e. the probability of having the required security, capacity, injectivity and monitorability exceeds some minimum acceptable limit) to progress the site to development for storage. It may also be decided at this stage that more data is required to further validate the site before it can proceed.

3.2.6.2 Risk Analysis

There are many potential risks that could be associated with a CO_2 storage project that can impact on the environment or affect financial constraints. The first step in assessing risk was to compile a list of potential risks that could occur. The approach included the use of a ‘Features, Event and Processes’ (FEP) database (Maul et al. 2004). This is a list of possible scenarios and CO_2 behaviours in the storage site which may impact on the project. Each FEP was scored on the likelihood of occurrence (Table 4) and severity (Table 5) of impact on a scale of 1 to 5 which was carried out by consultation of experts.

Table 4 Likelihood scale for the CASSEM project

Likelihood		If there were 100 similar projects, impact related to this risk element (FEP) would occur:
Improbable	1	Probably not at all, never
Unlikely	2	Fewer than three times among the100 projects
Possible	3	5 to 10 times among the100 projects
Likely	4	In around half of the100 projects
Probable	5	In most or nearly all of the projects

Table 5 Severity scale for the CASSEM project

Severity of impacts		Project values Health and safety
Light	1	Minor injury or illness, first aid
Serious	2	Reversible health effect, lost time injury less than 3 days
Major	3	Irreversible health effect, lost time > 3days
Catastrophic	4	Life-threatening health effect, fatality
Multi - Catastrophic	5	Multi -fatality

To calculate the risk the likelihood score was then multiplied by the score for severity (see Figure 2).

		Likelihood				
		1	2	3	4	5
Severity	1	1	2	3	4	5
	2	2	4	6	8	10
	3	3	6	9	12	15
	4	4	8	12	16	20
	5	5	10	15	20	25

Figure 2 Combined likelihood and severity. Blue= negligible, green = low, yellow = moderate, orange = high, black = very high

Where unacceptably high risks were identified the aim was to, where possible, identify suitable ways to mitigate the risk. By doing this the risk score could be reduced. It was possible to inform data acquisition by assessing the FEPs which were then fed into the static and dynamic models to better constrain our understanding of the storage site being investigated. By doing so, some FEPs could be potentially moved into lower risk ratings.

Using sensitivity analysis, the CASSEM project demonstrated how to identify the key controlling properties of the storage site, allowing resources to be targeted on those factors that most influence uncertainty in the long-term fate of the injected CO_2.

Overall, the two largest perceived generic risks for CCS identified by the CASSEM project were financial viability and pressurisation of the cap rock. Public perception and security, although reduced in risk during the study, could be a potential show stopper.

3.2.7 Strategies for CO_2 injection

The CASSEM project investigated four different strategies for CO_2 injection in order to evaluate whether large volumes of CO_2 could be safely, reliably and securely injected into and stored within a saline aquifer. These were:

- Standard CO_2 injection – with this method there was quite a large density contrast between the injected CO_2 and the brine; therefore the CO_2 rises buoyantly upwards through the storage site and will mobile. It requires the presence of a cap rock to prevent it leaving the storage reservoir.
- CO_2-brine surface mixing and injection – with this method the CO_2 saturated brine is denser than the native brine and therefore has a downward buoyancy drive. This option removes the requirement for a cap rock and can potentially be injected safely at depths less than 800 metres. If brine was extracted from the reservoir to mix with the CO_2 it could reduce regulate the pressure and potentially enhance the migration of the CO_2 away from the injection.
- CO_2-water surface mixing and injection – essentially injection of carbonated water into the storage site, though this is less dense still that the native pore fluid it is not as great a density contrast as between the reservoir and supercritical CO_2. This strategy is limiting due to the amount of water required to inject into the store and due to its buoyancy a cap rock will be required.
- CO_2 alternating brine (CAB) injection strategy – This method relies on capillary or pore-scale trapping. Previous studies indicate that more than 90% of injected CO_2 can be trapped in a saline aquifer as an immobile phase.

The CASSEM project recommended that surface mixing of supercritical CO_2 with brine has the potential to mitigate the long-term risks during injection. This method reduces the buoyancy of the inject CO_2 and the potential upwards migration through the storage site. It is thought that this will contribute to the CO_2 becoming more easily immobilised and increase the potential for it to remain permanently trapped. It contributes to the risk reduction, addresses long-term CO_2 storage uncertainties and has the potential to reduce monitoring costs.

There are disadvantages to these injection strategies however in that it can increase surface infrastructure costs, operation from additional wells are required and brine extraction will be needed. These should therefore be carefully considered in the risk analysis stage.

4 Basin-scale storage appraisals

4.1 CENTRAL NORTH SEA HUB

The revised appendix for the Central North Sea hub study presents a high level account of an assessment of a number of anchor locations for potential storage clusters in terms of their ability to support expansion of CCS activities (Element Energy, 2014). Potential storage clusters are also characterised at a high level for robustness of their site performance and potential conflicts with other activities, both within the subsurface and at the seabed. The CO_2 Stored database is utilised to provide storage site information.

Several scenarios have been developed, which include a mixture of storage site solutions in saline aquifers and hydrocarbon fields. Three of the early scenarios developed include at least one or more fields with potential for CO_2-EOR. EOR potential is based on an earlier report by Element Energy Limited (2012). Although the report presents many analyses not deemed directly relevant to this review, a brief description of the selected scenarios are described here to illustrate the way in which the scenarios were developed, the site selection methods employed and the degree to which the clusters were characterised in terms of the subsurface geology and potential transport options.

4.1.1 Scenario 1

The first Scenario envisages the transportation of CO_2 from St Fergus to Goldeneye, assuming that the Goldeneye Gas Condensate Field progresses as a UK demonstration project. Transportation of CO_2 would be via the existing Beryl A to St Fergus SAGE gas export line, some 192 km in length. According to CO_2 Stored the capacity of the Goldeneye Field is 37 Mt. Additional storage would utilise five saline aquifer sandstones, the Mey, Captain, Burns, Auk and Buchan sandstones, together with the Buzzard oil field which is intersected by the SAGE pipeline. Buzzard has been identified as having potential for CO_2-EOR. The additional sandstone aquifer sites would all be located within 15 km of the existing pipeline.

Goldeneye is a well characterised and understood site, as is Buzzard for which the site operator has years of operational knowledge. The five potential aquifers have all been assessed as part of the UKSAP project, but further detailed mapping and modelling would be required to characterise them more fully. Of these, the Captain Sandstone is probably the best understood due to the current studies on behalf of the Goldeneye FEED programme (Section 5.1) and research by SCCS (2011).

4.1.2 Scenarios 2 and 3

Scenario 2 envisages the transport of 1–2 Mt/year of CO_2 from St Fergus to the Atlantic field, using the existing Frigg to St Fergus Line 1 South. Storage would be in the Atlantic gas condensate field, at a distance of 162 km. The storage capacity of Atlantic is not known from publically available information. This first stage has already been studied by at least one developer, but little is available in the public domain. The Mey, Captain and Burns sandstones would be considered for additional storage.

Capacity expansion (Scenario 3), would require an extended transport solution, with a pipeline expansion to the edge of the study area to allow for storage in the Mey, Scapa, Burns, Firth Coal, Buchan, Strathrory and Orcadia Sandstone saline aquifers.

4.1.3 Scenario 4

The fourth scenario involves using an offshore platform hub or facility similar to a Floating Production and Offloading Vessel (FPSO), located 304 km from St Fergus in the area adjacent to the Forties and Nelson fields. Both the Forties and Nelson oil fields may be suitable for CO_2-EOR. Further development of the cluster would involve storage in the Grid, Cromarty, Forties, Mey, Pentland, Fulmar, Auk and Buchan saline aquifers.

4.1.4 Scenario 5

Scenario 5 envisages transportation of several Mt/year from the St Fergus terminal via the existing Miller to St Fergus pipeline with storage in six fields; Rob Roy, Telford, Brae, Scott, Miller and Kingfisher. CO_2-EOR would be feasible in the Brae and Miller fields.

4.1.5 Scenario 6

Scenario 6 involves storage relatively far (300–500 km) from the eastern UK in the Fulmar area, at the southernmost tip of the CNS storage area. The Fulmar area storage cluster would be a natural gateway for direct pipeline access to CNS storage by CO_2 sources in England or Europe. Two fields, Clyde and Janice would be potential stores as the scenario develops. Clyde would require a 16 km pipeline step-out from the Fulmar field, and Janice a 13 km step-out from Clyde. The three fields are candidates for CO_2-EOR. Direct pipeline access from St Fergus would intersect at least a dozen large aquifers while alternative access from Teesside would pass over fewer potential aquifers.

4.2 GIPPSLAND BASIN

The CarbonNet Project (CarbonNet) is investigating the potential for establishing a large-scale carbon capture and storage network in the Latrobe Valley, Victoria, Australia. The network would bring together carbon dioxide (CO_2) from multiple capture projects, transporting CO_2 via a shared pipeline to offshore storage sites in the Gippsland region of Victoria which is one of Australia's most productive hydrocarbon basins. The project is exploring the potential to capture and store 1-5 million tonnes of CO_2, per year, with the possibility of scaling up.

CarbonNet is managed by the Victoria Government. It is at feasibility and commercial definition stage with extensive research, engineering and commercial studies being undertaken, including modelling of potential CO_2 storage sites. The project is funded by the Australian and Victorian governments.

This summary is compiled from the project web site http://www.energyandresources.vic.gov.au/energy/carbon-capture-and-storage/the-carbonnet-project.
In addition, three scientific papers, published or in preparation for publication, have been provided by CarbonNet to Pale Blue Dot for the purposes of this review for the UK Strategic Storage Appraisal project.

4.2.1 Site characterisation for carbon sequestration in the near shore Gippsland Basin

Investigations for screening and selection of prospective storage site follows the DNV best practise criteria of capacity, injectivity and containment also capacity requirements of the project for storage of up to 125 Mt of CO_2 (Hoffman et al., 2015a). Previous screening had selected prospective sites with top seals proven by hydrocarbon reservoirs, avoid producing oil and gas fields, areas where access is difficult and are at a depth where CO_2 would be in supercritical phase.

Three sites were selected that have at least 50 Mt CO_2 storage capacity, good injectivity (>100 kh, where k is permeability in milliDarcy and h is height in metres) and the same top seal as 80% of all petroleum resources in the basin. Initial site characterisation (Hoffman et al., 2012) investigated the known sub-units and facies variations within the top seal to assess which parameters determine the sealing character.

Detailed characterisation presented in the paper is targeted to investigate whether the sites meet the Australian greenhouse gas (GHG) storage requirements of: adequate capacity; compatibility of CO_2 with the storage strata and contained fluids; existence of suitable CO_2 injection points; definition of injection rate and duration; any requirement for engineering enhancements; effective containment. Assessment is based on data available from petroleum exploration which is required to be released within a few years of acquisition. All 'basic' data is publicly accessible for the cost of copying and includes well data and 2D and 3D recorded data.

CO_2 storage 'fairways' in the Gippsland Basin and trap types (anticlinal and upthrown fault, large stratigraphical, small stratigraphical, downthrown fault, open aquifer and basin centre traps) are reviewed. Open aquifer traps are noted as having the greatest potential on the northern, southern and western basin margin and a number of sites were screened and one taken forward as potentially acceptable.

4.2.1.1 Site characterisation activities

The CarbonNet Project has built three full generations of Static [geological] Models. In the first generation, a large-scale coarse model was constructed to provide a context for the multiple local fine-scale models required – one for each site, or cluster of sites. At all subsequent stages, only fine-scale models were constructed.

At each stage, models were designed to be fit-for-purpose and were generated using horizon and fault frameworks in depth, isopachs of key reservoir facies, and geostatistical parameters derived from well petrophysical and 3D seismic analysis of geobody extents, aspect ratios, and orientations. The models evolved in complexity over time, but were designed not to be excessively complex. As an example, faults were generally vertical in the models, rather than explicitly mapped as dipping surfaces. However, the requirements for dynamic modelling of CO_2 injection include the consideration of long-distance migration, and significant vertical penetration of the stratigraphy by the CO_2 plume. Therefore these models are more complex and extensive than an equivalent oilfield model would be.

4.2.1.2 Geological models

The CarbonNet team developed in-house high-resolution PETREL™ static models to honour data from 49 local wells and 2D and 3D seismic facies analysis. These models were used to evaluate possible available pore space for static capacity assessment and for dynamic simulation to estimate dynamic structural storage capacity of individual sites. The largest model covered an area of ~900 square kilometres and was gridded to an average cell size of 50 x 50 m. A total of 222 [cell] layers were generated based on the variation in lithological facies, which range from a few centimetres to approximately 10 metres. Total model size was 82 million cells. This model was used for CarbonNet's latest dynamic modelling (February 2014 onward).

Static [geological] modelling workflow

Up to three generations of static models have been constructed for each storage site using Schlumberger's PETREL™ software as part of the following work flow steps:

1. Well data interpretation for lithologies, stratigraphy and petrophysics and correlations.
2. Formulation of a conceptual geological model to predict facies associations and
3. geometries.
4. A constant orientation of 010° is adopted for intra-formational geobodies, matching the palaeoshoreline.
5. Seismic data interpretation using PETREL modules and some limited use of the Kingdom Suite software to generate depth surfaces of key horizons and seismic lithofacies associations. (Some iteration between steps-1-2-3).
6. Static modelling: receive step-3 surfaces and construct stratigraphic zones recognised in step-1.
7. Construction of higher resolution zonal layer also identified in step-1.
8. Fault modelling and Pillar Gridding.
9. Characterisation of the layers with step-1 petrophysical properties moulded to seismic lithofacies through use of variograms and indicator kriging/sequential Gaussian methods.

4.2.1.3 Injection scenarios

A variety of injection scenarios were modelled, based on the static models. Injection rates were simulated ranging from 1 to 5 Mt per year through nominal wells. Injection points were modelled deeper than the intended trap geometry to increase the benefit from vertical migration to enhance dissolution and residual trapping. Bottom-hole pressures were monitored to ensure geomechanical constraints were managed. Plume migration was modelled for 300 years for screening and 1000 year for project design.

4.2.1.4 Plume migration

Initially, the injected CO_2 developed symmetrically outwards and upwards driven by the pressure of injection around the injection well. As injection progresses a component of up-dip migration is driven by buoyant flow. After cessation of injection continued migration is up-dip by buoyant forces alone. If within a structural closure the buoyant CO_2 rises to the top of the structure with a flat-lying lower CO_2-water contact.

4.2.1.5 Site Characterisation

The site geology is very well known from petroleum exploration datasets. Regional and site-specific characterisation for the three sites is described by:

- Mapping

  Several generations of mapping has been conducted, based on previous regional scale work, and detailed site mapping remains in progress based on pre-processed 2D and 3D data. Refinements include the internal layering of static geological models of the 3D architecture of flow units. Formation tops picked from combined well log and seismic data have been updated from recent work.

  Depth conversion used a regional burial depth trend, average velocity down to target depth and a component of lateral velocity from compiled 3D velocity data. Seismic and well data were combined for facies modelling, and log and core data were used for facies assignment and petrophysical modelling. A detailed seismic attribute study within the 3D volume analysed the aspect ratio and dimensions of coal bodies, sand channels, and other features.

- Reservoirs

  Detailed reported investigations (links to online access to five reports provided but not reviewed) indicate the storage strata have excellent storage characteristics with strong aquifer support, and thick reservoirs with high nett:gross ratio and high porosity (25%+) and permeability (multi-Darcy).

- Seals

  The primary petroleum seal of the basin at each site is proven to be effective, either by retaining a small hydrocarbon pool, or from Mercury Injection Capillary Pressure (MICP) measurements (or both). Petroleum seal quality is well mapped with a combination of thickness, depth of burial, mineralogy, MICP quality, and facies. Whilst some seal defects can be mapped in the general area (Hoffman, et al., 2012), these occur rarely, at predictable locations, and off-structure.
- Overburden
- Basement
- Aquifers

  The offshore group of storage strata is a thick and generally well-connected sand-rich interval with a total thickness of 2-3 km. The aquifer has a number of characteristics that make it suitable for CO_2 injection: relatively low salinity that will enhance CO_2 dissolution; flow from onshore to offshore of the order of 1-5 m per year; proven lateral pressure connected extent of over 100 km to allow rapid dissipation of injection pressure (pressure thresholds for geomechanical stability are highly unlikely to be breached).

- Geochemistry

  Studies of geochemical reactions between rock minerals and CO_2 injectate will be relatively limited, due to the highly permeable, clean, quartz-rich sandstones with limited carbonate cementation in the proposed injection and storage zones.

- Reservoir Engineering

  A well engineering study has been completed. The conceptual well designs demonstrate technical feasibility for injection operations and consider the estimated injection zone injectivity, expected injection rates and wellhead delivery pressure.

- Dynamic Modelling

  Dynamic modelling simulations have been conducted by CarbonNet with a wide range of injection scenarios for each site to establish likely options for injector location, injection well geometry and completion requirements, injection rates, top hole and bottom-hole pressure constraints, and plume paths travelled. Relative permeabilities depend highly on the rock physical properties and need to be determined using experimental works for each specific reservoir rocks. These experiments are not yet carried out for CO_2-water and some analogues from literature have been used to infer relative permeability data.

  A number of cases were investigated to test the basis of design for:
  - 80 Mt at ~ 3 Mt per year for 25 years with a small ramp-up and ramp down at each end
  - 125 Mt injection at 5 Mt per year for 25 years
  -

  The scenarios tested different factors such as completion interval, surface location, injection point, well trajectory and injection rate for 1000 years of storage to observe the following parameters:
  1. CO_2 plume is retained offshore and does not affect other nearby resources.
  2. Carbonated water migration is retained offshore and not affect other nearby resources.
  3. pH alteration not to affect nearby resources.
  4. Bottom-hole pressure remains within safe geomechanical bounds.
  5. Average and peak near-field and far-field pressure within seal integrity and no adverse resource interaction.
  6. CO_2 plume permeation through an intraformational seal to demonstrate long-term safe storage.
- Geomechanics

  The CarbonNet sites have been characterised by a preliminary geomechanical analysis which shows that the modelled injection scheme results in a modest pressure increase which is well below the limit for fault reactivation

- Non-Geoscience characterisation

  CarbonNet has progressed three different sites through the screening process and has obtained DNV certification for the portfolio of three sites. The outcome of the initial site characterisation at each site is summarised. The three sites offer different opportunities and have strengths and weaknesses that must be assessed in deciding the most likely candidate for a CO_2 injection project. The authors note the optimal storage site would be with a substantial element of up-dip and/or lateral migration occurred before reaching the ultimate security of a structural closure. The structure would be ideally located on the flanks of a basin, with migration out of the basin deep and towards or into a medium to large structural trap, acting as a “backstop” to plume movement.

4.2.2 Detailed seal studies for CO_2 storage in the Gippsland Basin

The earliest publication included in this review addresses 'containment' (Hoffman et al., 2012), one of the three best practise criteria specified by DNV. The Lakes Entrance Formation, the top seal for hydrocarbon fields and also the primary seal for prospective CO_2 storage sites in the Gippsland Basin, is known to comprise sub-units and facies variations where it includes channelized submarine flows and local erosion surfaces. Characterisation of the formation to determine any vertical or lateral variation in sealing capacity was investigated by seismic mapping (unconformities, disconformities, volcanic cones and intrusions, polygonal faulting and channels), observations of seal integrity and failure within petroleum exploration data sets and MICP measurements. MICP measurements were also made of shale intervals within the storage formation.

The sealing properties of the cap rock formation, calibrated by the MICP analyses, were found to be determined by mineralogy and/or depositional setting. Further work is recommended, including more accurate mapping of the cap rock formation and further investigation of the intraformational shale intervals as sealing horizons.

4.2.3 3D Mapping and correlation of Intraformational seals within the Latrobe Group in the nearshore Gippsland Basin.

Intraformational shales and coals in prospective CO_2 storage strata within the Gippsland Basin are assessed by the CarbonNet project for their role as sealing strata for stacked storage sites or as baffles to retard and enhance residual and dissolution trapping of CO_2 (Hoffman 2015b).

The sealing capacity and role of the shale, coal and seat earths in CO_2 storage is assessed by distinct fluid pressure and salinity differences across them, observation of trapped hydrocarbons, mapping of the three-dimensional geometry and continuity of intraformational seal rocks, and measurement of seal quality (MICP). The identification of geometry of stacked seal rocks is used to define a 'seal fairway'. The depositional setting is inferred from the interpretation of the seismic and well data and a succession of fluvial systems is recognised and palaeo-river systems inferred. Intraformational seal rocks in a fluvial sequence have the capacity to provide a trapping mechanism or baffle to flow for sufficient duration to be acceptable for containment of injected CO_2.

5 Storage Evaluation in Depleted Gas Fields

In this chapter site appraisal activities that have been undertaken on depleted gas fields are reviewed. The sites that have been included are:

- Goldeneye – The depleted gas condensate field in the Captain fairway in the Northern North Sea, probably one of the most in-depth site appraisal projects undertaken for CO_2 storage in the North Sea.
- Hewett – a detailed appraisal project of a depleted gas field in the Southern North Sea.
- P18-4 – A detailed appraisal of a depleted gas field for the Dutch ROAD demonstration. Limited information is available in English in the public domain.
- Otway – appraisal for the pilot injection project in Victoria, Australia.

5.1 GOLDENEYE DEPLETED GAS CONDENSATE FIELD

Shell conducted an extensive FEED study for their Goldeneye Field as part of the Department of Energy and Climate Change Competition to select full-chain, full-scale commercial demonstrations of carbon capture from a coal-fired power station, transport and storage. A number of reports from the site characterisation at Goldeneye were published in 2011 and have been reviewed here:

Seismic Interpretation Report

Petrophysical Modelling Report

Static Model Field Report

Static Model (Overburden)

Static Model (Aquifer)

PVT Report

IIP Volume Estimate

CO_2 Storage Estimate

Pore Pressure Prediction

Geomechanics Summary Report

Storage Development Plan

Other relevant reports not reviewed:

SCAL Report

Geochemical Reactivity Report

Production Chemistry Operability Review

Fluid Flow Assurance and Technical Design

These reports are available for download here:
http://webarchive.nationalarchives.gov.uk/20130109092117/http://decc.gov.uk/en/content/cms/emissions/ccs/ukccscomm_prog/feed/scottish_power/design/design.aspx

5.1.1 Seismic Interpretation

5.1.1.1 DATA AVAILABILITY

The geophysical work was undertaken to characterise the Goldeneye storage complex. A number of seismic surveys were available having been acquired since 1994, including one 2D and four 3D surveys, plus a 3D reconnaissance survey, covering the South Halibut Trough. Although the 1997 3D survey was reprocessed, data quality at the target level remained poor and therefore a full 3D pre-Stack Depth Migration was carried out in 2001. This PreSDM dataset provided significant improvements in reflector continuity and resolution and in discontinuity definition, and was subsequently selected as the basis for the Field Development Planning at Goldeneye.

The interpretation of the Captain Sandstone, the target reservoir, was hampered by several factors inherent in the geology and these were identified during the analysis: poor impedance contract between Captain Sandstone and overlying Rodby shales; degradations caused by stacked coals and the thick high-velocity Chalk. An understanding of these impacts aided interpretation and analysis.

Three surveys were used in the seismic characterisation at Goldeneye and the seismic processing undertaken on each is documented.

5.1.1.2 SEISMIC TO WELL TIES

Seismic to well ties were generated to create a synthetic seismic trace to aid accurate identification of internal reservoir units in the Captain Sandstone. Two tie points were used to ensure accurate time matching; one close to the reservoir and a second shallower above the Chalk.

5.1.1.3 HORIZON INTERPRETATION

Twenty horizons from the seabed down to the Top Zechstein, i.e. to include the full overburden and the underburden to below the Base Cretaceous unconformity, were interpreted. The quality of each pick and its display response from the seismic datasets and any notable log responses were described for each horizon. The Captain Sandstone reservoir was subdivided into five units (Subunits A-E) and their extents within the storage complex summarised.

5.1.1.4 FAULT INTERPRETATION

5.1.1.4.1 RESERVOIR

Fault interpretation from the 2001 PreSDM dataset was focussed on the structure of the Base Cretaceous Unconformity, which controls overall field morphology, and intra-formational faulting within the Captain Sandstone. As many intraformational faults at the top-, intra- and base-reservoir reflectors, that might act as baffles or conduits to CO_2 flow were identified as possible to allow sensitivity to fault density to be assessed in the dynamic modelling of the field. Fault throws and heaves were calculated and fault planes digitised and checked against amplitude maps.

For each horizon, the potential impacts on containment, i.e. their locations and orientations, the fault throws and their interpreted periods of activity relative to reservoir deposition, were summarised. Interpretation was also based on core logging which identified fracture zones not evident from seismic interpretation. The potential for compartmentalisation was assessed.

5.1.1.4.2 OVERBURDEN

Faulting in the overburden is briefly summarised and placed into the context of the regional structural development.

5.1.1.5 DEPTH CONVERSION

The interpreted seismic time horizons were depth converted using a 10 layer depth conversion. After depth conversion, the residuals that remained at the well locations were gridded with an influence radius of 2km and then added to the top structure map, tying the surface explicitly to its observation point in each well.

5.1.1.6 Regional Aquifer model building

The regional aquifer 3D static model was constructed to complement the static reservoir model, full field static model (FFSM) and the overburden 3D static model described below. The FFSM allows subsequent dynamic simulations of fluid movements within the storage complex. Scenarios that predicted movement out of the complex could be assessed using the 'coarser', lower resolution, regional aquifer model. All three models maintained specific common features to ensure consistency between them, such as field volumes and the reservoir fairway dimensions.

The regional extent of the Captain aquifer over the Halibut Trough was mapped and depth converted (using a regional average velocity map) together with the Base Cretaceous Unconformity and the base Hidra to delineate the Lower Cretaceous section. This included calibration from all available well penetrations. To ensure consistency between the regional model and FFSM, average velocities over the Goldeneye Field were back-calculated from the FFSM to ensure the Goldeneye structure was identical in both models.

The lateral extent and variations in thickness of the Captain aquifer, including the nature of all boundaries, was summarised. The structure including large-scale faulting was also described. A brief description of the depositional models of the Captain Sandstone provided a context to a discussion of the controls on sand distribution in the Captain Fairway and the connectivity observed across the formation interpreted from pressure data in producing fields across the Fairway.

5.1.2 Petrophysical Modelling

Petrophysical data is essential to enable dynamic simulations of storage performance and to provide estimates of storage capacity. The petrophysical data used to parameterise the Goldeneye static and dynamic models (FFSM, Overburden and Aquifer models) were compiled from data acquired from exploration and development wells during the field development. Key data points are:

For the FFSM:

- Porosity
- Permeability
- Net to gross
- Fluid contact
- Saturation height model,

For Overburden and Aquifer models:

- Porosity
- Permeability
- Net to gross
- Chalk capillary entry pressure

All well data sources are tabulated for each well: 10 wells in the Goldeneye complex and 16 in the surrounding area. The quality of all data from each well was assessed to ensure discrepancies arising from different logging tools and backgrounds were correctly addressed. Neutron porosity and resistivity logs were corrected to ensure consistency between datasets. Gamma ray (GR) normalisation was undertaken for the Overburden and Aquifer models to ensure consistent shale volume estimates for net to gross calculations. It is worth noting that the GR based shale volume was chosen over neutron density due to missing density data in some older wells, to ensure greater coverage.

Data is apportioned to formations based on formation tops provided in the static models. Facies distributions within the Captain Sandstone were based on a categorisation of sand thickness and quality. These distributions were mapped.

5.1.2.1 PARAMETER DERIVATIONS

Methods for calculating *porosity*, derived from log data, were summarised. For the Captain Sandstone within the Goldeneye Field, core data was available from all four exploration wells. Porosity is derived from the matrix, bulk and fluid densities. Matrix density was obtained from core analyses fluid densities were estimated from porosity to core porosity comparisons. Porosities were stress-corrected to a pre-production state. Porosities in the overburden formations were derived using average matrix densities.

Permeabilities for each of the three facies categories were derived using linear relationships to porosity data and calibrated by SCAL data on cores where available. For the Overburden and Aquifer models, only porosity and net sand could be obtained from well log data. Permeability and capillary pressure entry data were provided by fairway analogue or regional trends. Pressure gradient and other log data were used to estimate fluid contacts for the fields within the aquifer model.

Net to gross ratios for all formations, except the Chalk, were obtained from the GR derived shale volume for above minimum shale volume and porosity values. Minimum thresholds were set to remove tight sandstone streaks.

Fluid levels were obtained from open hole pressure data and fluid contacts (gas, oil and water) were obtained from core and logs. Care was taken to interpret data with an understanding of tool calibrations and confidence in depth measurements during logging. The presence of gas or oil in the overburden was evaluated across the Goldeneye field. The free water levels were also identified in wells from five adjacent fields across the Captain Fairway. The wells used in this interpretation were listed. Water gradients across the fields from pre-production pressure data were interpreted to suggest a common aquifer flow across the Fairway trough.

The Goldeneye Captain reservoir *water saturation* height model was derived using the Leverett-J method on logging data (Leverett, 1941). The log input only includes clean sand which satisfies the following criteria:

- Porosity above 20 %
- Low clay content, CEC less than 0.1 meq/ml

The initial saturation model is calculated from clean sand logging data. It was then compared with log-derived saturation and mercury injection capillary pressure data. Water saturations produced from both inputs were in good agreement. Archie log saturations were calculated to verify the Leverett-J model performance using water resistivity from a Pickett Plot and Archie parameters

5.1.2.2 ANALOGUE DATA

Where direct measurements were unavailable, primarily permeability and capillary pressure data in the overburden, analogue data was used. This data was obtained from a number of sources including internal Shell data, extrapolation using methods applied in other regions (for capillary pressures in the Chalk), published literature on permeabilities from other fields within the Captain Fairway which is calibrated for sand quality using GR data in each well, and permeabilities in the Captain sandstone in other fields.

5.1.3 Static Model

Three static modelling tasks were undertaken to adequately and efficiently represent storage processes at Goldeneye. The Full Field Static Model created a package of detailed geological realisations that allowed issues of geological uncertainty to be assessed within the Captain Sandstone reservoir and immediate under- and overburdens. A model of the overburden allowed visulaisation of the stratigraphy and structural elements of the underburden and full overburden to sea bed. A model of the regional Captain Aquifer allowed assessment of wider potential CO_2 lateral migration processes and pressure responses in the larger regional aquifer. The three models were constructed in parallel with learning being shared between them and care taken to ensure consistency between them, to the extent this was possible with models produced at different scales.

5.1.3.1 Static ModeL for Goldeneye Field

5.1.3.1.1 Objective and scope

The primary purpose of the Static Model was to enable predictive modelling of the CO_2 injection and storage. The static model underwent some revisions to the distribution of hydrocarbon volumes to ensure as close a match as possible between prediction and observed oil production performance. Realisations varied reservoir layering and connectivity. The initial model produced by Shell's Goldeneye Asset Team for the purposes of effective management of the gas production, was modified in a number of ways since it was concluded it was not fit-for-purpose for CO_2 storage evaluation. The following modifications were necessary:

- Increase in size to include possible CO_2 migration effects.
- Revisions to accurately predict water breakthrough
- A range of realisations were created to assess specific aspects of geological uncertainty such as the distribution of the gas volumes in the reservoir and distribution of porosity and permeability in the underburden.
- Modifications to reservoir layering to better model thin, buoyant CO_2 plumes. .

Further realisations involved modifications specifically to assess different aspects of the CO_2 injection (listed below) and also to assess potential impacts of uncertainties in the Overburden model. Four geological realisations were therefore produced of the FFSM and two realisations were produced of the Overburden model. An audit trail was created to ensure all modifications were documented (and described in the produced report) and sources of data recorded.

End-member realisations were used in dynamic simulations which are themselves history-matched to the Goldeneye production data.

The static model report includes a detailed review of the geological setting including:

- Regional stratigraphy for the Outer Moray Firth and depositional settings
- The structure of the reservoir
    - o The nature of the trap: structural and stratigraphic.
    - o Height of hydrocarbon column and the location of the original oil water contact
    - o The potential for compartmentalisation as indicated by studies of intra-formational fault-sealing, core analyses which indicated the presence of minor cataclasites, and the potential for a pressure barrier to exist in nearby fields. In summary these lines of evidence indicated no compartmentalisation occurs.
    - o The nature of boundaries: pinch out to the Halibut Horst and lack of erosional top surface.
    - o Locations of spill points
- Reservoir stratigraphy and division into lithostratigraphical units, including summaries of depositional controls and average properties of these units.
- Reservoir fluids: oil, gas and water.
- Reservoir uncertainty

The reservoir uncertainty was considered an important aspect to further investigate and reduce. These uncertainties arose due to the different purposes for which the original model had been developed by the Goldeneye Asset team, namely gas production, compared with the requirements for CO_2 storage. It is instructive to list the uncertainties, taken from Shell's report, which were addressed during the static model development:

- Location of northerly stratigraphic pinch-out, which has an impact on Gross Rock Volume and therefore estimated storage capacity.
- The presence or absence of sealing faults, which impacts fluid connectivity and pressure responses.
- Top structure uncertainties, which have a small impact on Gross Rock Volume but may affect spill point and structural dip.
- Distribution of reservoir units, which has an impact on In-Place volume and also, potentially, could have an impact on the dynamic behaviour of the reservoir.

The key static modelling uncertainties for the CO_2 injection into the Goldeneye field are related to the storage capacity and containment. The static reservoir models were constructed to address these issues, in particular:

- different volume scenarios;
- unstable displacement effects (requiring finer/alternative layering);
- increased sensitivity to heterogeneities due to fluid contrast (CO_2 vs. water);
- focus on structural dip and spill location relative to injection wells for injection strategy planning;
- under-burden & over-burden focus to investigate possible CO_2 migration pathways
- alternative Captain D (main reservoir unit) interpretation;

5.1.3.1.2 Model construction

The reservoir zones were subdivided into layers to represent estimated geological heterogeneity, with the number of layers included in each unit reflecting the degree of predicted heterogeneity. The tops of units were made top conformable to better simulate the buoyant flow in these zones. Non-reservoir zones contained a single layer of cells. It is worth noting that, as with all simulation exercises, this layering was simplified during upscaling when the model was imported into the dynamic simulator, to reduce the number of cells included in calculations to speed up simulation run times. The initial eight facies developed in the Asset model were retained throughout the static model development. Facies distributions were 'automatically' produced based initially on GR responses which were subsequently modified by the geologist following interpretation of core data, core logs and well logs, before being upscaled to provide a single facies type for each layer. In heterogeneous subunits, more of the facies were included than in cleaner subunits.

5.1.3.1.3 Model parameterisation

The derived petrophysical datasets described above were upscaled into the model layers by arithmetic averaging, and then a Sequential Gaussian Simulation algorithm was used to populate the model. Input data and derived values were tabulated for each well and each interval within each well. Permeabilities for the Captain Sandstone were derived based on lithology where sufficient logging data was available using three lithology classes (reflecting different porosity ranges). Petrophysical modelling was applied consistently for all model realisations. Minimum input cut-offs were applied to zero values and to ensure net reservoir doesn't occur in shale sections. The impacts on net to gross ratios of using different cut-off values were assessed.

5.1.3.1.4 Model Quality Assurance/Quality Control

Model construction was conducted within the Integrated Reservoir management assurance framework and specific interpretations, such as the seismic interpretation were subject to separate review.

Key parameters such as the Gross Rock and In Place volumes were compared between realisations to ensure consistency. Upscaled logs were visually compared with input datasets to ensure they remained representative. At the end of the model construction, a Technical Assurer reviewed the model and modelling philosophy.

5.1.3.2 Static Model for Goldeneye overburden

5.1.3.2.1 Objectives and Scope

An overburden assessment was conducted above and adjacent to the Goldeneye field, to identify possible secondary containment horizons and possible lateral and vertical migration pathways of the storage complex. A 3D geological static model was constructed around the Goldeneye field from the seabed to the Top Triassic Heron Group, 900m below the target Captain Sandstone reservoir; i.e. the model explicitly considered the underburden to evaluate spill points and potential for lateral and downwards migration. The area of interest for the model was determined by the extent of seismic data coverage.

The model was designed to complement, and be consistent with, the FFSM. The Overburden model was designed to visualise the stratigraphy but was not used in dynamic simulations. As with the FFSM summarised above, the geological context in terms of structural setting, exploration history and stratigraphy were all reviewed and summarised.

The presence or lack of hydrocarbons in other potential reservoir rocks was evaluated.

The potential for connection of the Captain Sandstone, through faulting or stratigraphic connection with other permeable sands was assessed across the area of interest.

5.1.3.2.2 Model construction

The model was gridded at a resolution of 50x50m resulting in a total of 1.8 million cells. Twelve wells were used, from a possible total of 72 in the Halibut Trough area, using lithostratigraphic data only. Faulting was not included due to software limitations (faults must extend throughout the all zones – from top to bottom). Eighteen seismic horizons were interpreted to provide the structural framework and a further 15 correlatable stratigraphic horizons were defined to provide a total of 34 zones. The zones were assigned properties which indicated:

- The zonation between seismic mapped horizons
- The detailed log stratigraphic zones
- The stratigraphic units identified as aquifers and aquicludes
- The average Net-to-Gross for each zone.
- The average net porosity for each zone.
- The average permeability for each zone.

A small number of minor inaccuracies were identified which resulted from difficulties in mapping non-seismic zones across the model. These were listed to aid future model refinement.

5.1.3.2.3 Petrophysical modelling

A full petrophysical evaluation of the overburden lithology was carried out on 7 exploration/appraisal and 5 development wells in the Goldeneye area wherever data availability made this possible. This evaluation was carried out as described above for the FFSM, though generic values were applied for sandstones and limestones. Where data was not available, e.g. permeability data, then this was obtained from published data or other sources, as described above. Upscaling these parameters for each zone enabled each zone to be assigned as a 'storage' unit' or as an aquiclude.

5.1.3.2.4 Faulting

The evaluation of faulting undertaken in the Captain Sandstone reservoir for the FFSM, described above, was extended to consider structural trends, lineaments and faulting in the reservoir, the underburden and the overburden to ensure that faults penetrating the caprock were mapped. This mapping was placed in the regional geological and structural evolution of the Outer Moray Firth and northern North Sea.

5.1.3.3 STATIC MODEL FOR CAPTAIN AQUIFER

A static model of the wider Captain Sandstone aquifer was used to simulate potential migration pathways along the Captain Fairway. The simple geological model provides an approximation of the dimensions and regional porosity and permeability trends across the Captain Fairway including the hydrocarbon fields within it (except the Captain Field itself, being close to the footwall of the southern bounding fault of the Halibut Horst). The impacts of production and subsequent shut-in of nearby fields (Hannay, Atlantic and Cromarty) on aquifer fluxes in the Goldeneye Field enabled improved history-matching of Goldeneye production in the FFSM. Results of detailed dynamic simulations from the FFSM, such as lateral gravity-driven flow and re-pressurisation, could be further modelled in the Aquifer model.

Construction of the model allowed consideration of depositional environments and sediment sources and supply routes, using data including heavy mineral analyses, paleocurrent measurements and SCAL and core logs from wells across the Halibut Trough. The connectivity within the reservoir, and areas of potential disconnection, as indicated by aquifer mapping and a review of pressure data across the Fairway, received particular attention.

Using biostratigraphy, log correlation and seismic stratigraphy, the individual lithostratigraphic units were correlated between wells along the Halibut Trough, drawing on and comparing to a published stratigraphic framework (Jeremiah, 2000). Uncertainties in the correlation and revisions to published interpretations were clearly identified.

5.1.3.3.1 INPUT DATA

The aquifer model was constructed from interpretations of 2D and 3D seismic datasets, particularly a regional 3D survey. The seismic character of main formations was described and calibration was undertaken with all available well penetrations. As mentioned above, the Captain Sandstone itself can be difficult to identify on seismic due to its poor impedance contrast and therefore coeval shales were used to constrain its position. Captain surfaces were made consistent with those used in the FFSM. In order to represent the zonation developed in the FFSM, the aquifer was divided into four zones with isochores produced by gridding up thickness data from regional well log correlations. To enable greater resolution in dynamic simulations, the upper layers of the model are gridded with smaller grid cells.

Important uncertainties in the interpretation, that could play a significant role in controlling potential CO_2 migration, were treated as sensitivities in subsequent dynamic simulations. For example, uncertainty around the potential for disconnection of the Captain Sandstone due to faulting around the Grampian Arch, was investigated in this way.

5.1.3.3.2 PETROPHYSICAL MODELLING

As before, porosity, permeability and net to gross were evaluated in 25 wells along the Captain Fairway. Upscaling of this data was undertaken as described above. Facies modelling was not undertaken as it was considered that net to gross modelling would be appropriate given the model's scale. Note that permeabilities were derived by considering data from several fields across the Fairway to provide a single generic relationship:

$$k\_phi = 0.601 \times 10^{11.5 \times \Phi}$$

where k_phi = Permeability (mD)

$$\Phi = \text{Total porosity}$$

For very high propositions (>32%), permeabilities were clipped to a maximum of 2500 mD. The permeability was assigned a logarithmic distribution and was co-kriged with the porosity model to ensure that if a cell had a high porosity it was more likely to have a high permeability.

5.1.4 Phase behaviours

Understanding the physical characteristics of the fluids present in the Goldeneye Field was essential to accurate modelling of the phase behaviour of CO_2 during and following injection.

5.1.4.1 HYDROCARBON CHARACTERISATION

A review of Pressure, Volume, Temperature (PVT) analyses was undertaken and a consistent equation of state created for both the gas condensate and the CO_2. Compositional analyses of fluids in all five exploration and production wells were available from Repeat Formation Tester (RFT) and Modular Dynamic Tester (MDT) tests, surface samples from Drill Stem Test (DST) tests and some additional detailed analyses obtained during well clean ups. Care was taken to assure quality of analyses with some being rejected where they were considered unrepresentative or indicated contamination. Analysis of phase envelopes indicated a strong degree of consistency across the field.

The following workflow is taken directly from Shell's report:

> *In order to achieve a coherent fluid characterisation for Goldeneye, a typical workflow for a gas condensate was followed. It involved:*
>
> - *Normal regression to tune to general phase behaviour (saturation pressure, CVD and CME observations). Not attempting to get a perfect match since the subsequent lumping process would change the match.*
> - *Grouping/lumping components to reduce simulation time while retaining the predictability of the EOS.*
> - *Fine tuning regression choosing high weights on experiments or observations (Saturation*
> - *Pressure, Retrograde Condensate %, etc.) to improve the match of key data, and finally,*
> - *Matching viscosity data while decoupling the rest of the experiments, regressing on the critical volume for each component's contribution to the total viscosity.*
>
> *The Equation of State (EOS) used was Peng-Robinson 78 (PR78) (Peneloux et al., 1978). The sample was adjusted to a saturation point of 3815 psia [~263 bara] at a reservoir temperature of 181°F [82.78°C].*

The Equation of State characterisation was modified using non-linear regression, to match predictions to measured data as closely as possible. In order to reduce the number of components included in compositional models, to decrease computational time, the original components were lumped together into a smaller number of pseudo-components (Whitson et al, 1999). This is achieved in a stepwise fashion until an appropriate PVT prediction is achieved – in this case the representative C36+ composition was reduced to six pseudo-components with some fine-tuning necessary before final regression to assess each pseudo-component's contribution the total viscosity. It was highlighted that this simplification allowed modelling of displacement processes in the Goldeneye field but that further simplification might be necessary where CO_2/hydrocarbon mixing is insignificant but larger numbers of grid blocks is required.

5.1.4.2 CO_2 FLUID PROPERTIES

Accurate simulations of CO_2 behaviour require accurate predictions of CO_2 properties, using equations of state (EOS), for the specific reservoir conditions. The properties that most affect flow and transport in the reservoir include density, viscosity and solubility of CO_2. CO_2 dissolution was calculated using Henry's law, density calculated directly from the EOS (a Peng Robinson 1978 EOS was used) and viscosity was calculated from the Lohrenz-Bray-Clark correlation.

The standard EOS descriptions used in reservoir simulations were developed for hydrocarbon systems and can be less accurate for modelling CO_2 properties and some other non-hydrocarbon components such as H_2S and SO_2. As a consequence, the default pure component parameters required tuning to assure an improved match over a range of interest. This was achieved by applying a volume correction factor (after Peneloux et al, 1982). However comparisons standard and predicted densities indicate that further refinement was necessary and it was therefore decided to regress over the CO_2 volume shift parameter (C_{pen} after Peneloux) in order to minimize the error between predicted densities and those pure component CO_2 properties calculated using the Thermophysical Properties of Fluid Systems from the National Institute of Standards and Technology (NIST). Nevertheless there remained a small but significant discrepancy and the impact of this was taken into consideration, by applying conservative values during subsequent modelling and by placing these relatively small uncertainties in the context of larger uncertainties in, for example, relative permeabilities.

5.1.5 Gas Initially in Place

Gas initially in-place (GIIP) hydrocarbon volumes have been calculated for all seven FFSM realisations described above. GIIP was calculated for each of the captain Sandstone units. The calculated volumes fell within the P10-P90 range for the field, as determined by the Goldeneye Asset team. Three hundred and eighty stochastic modelling runs were undertaken across the FFSM variations. Factors that control the estimates of GIIP were investigated to their contributions to uncertainties GIIP values. The increased zonation in the FFSM had the greatest impact on the GIIP estimates, compared to the Asset team's original model.

These estimates of GIIP, combined with hydrocarbon production data, provided an estimate of available pore space volume for use in calculations of storage capacity and of the remaining hydrocarbons following close of production. The following workflow was followed:

1. Gross Rock Volume (GRV): Structural model + fluid contact(s)
2. Net Rock Volume (NRV): Gross Rock Volume combined with net-to-gross model
3. Net Pore Volume (NPV): Net Rock Volume combined with porosity model
4. Hydrocarbon Pore Volume (HCPV): Net Pore Volume combined with hydrocarbon saturation model
5. Initially In-Place Volume (IIP): Hydrocarbon Pore Volume combined with formation volume factor (commonly abbreviated to Bo for oil or Bg for gas)

Much of the GIIP study focussed on comparing revised GIIP estimates with those of the Asset team. This is considered less relevant for the present review. The PVT study indicated that the Asset team's value for Bg should be revised and although the Asset teams value was used for comparison purposes in GIIP calculations, the revised Bg was used in subsequent dynamic simulations.

5.1.6 Storage Capacity

An initial volumetric static capacity was calculated from the available pore space assuming a volumetric equivalent replacement for the produced hydrocarbons. This was based on the reservoir temperature, PVT properties of the Goldeneye fluids and assumed recharge to initial pressure. This initial estimate was subsequently revised by applying storage efficiency factors to account for the 'sweep' efficiency and the need to displace aquifer water that invaded the reservoir during production and a range of other factors.

An uncertainty analysis identified a set of parameter ranges and subsurface realisations and indicated that three major geological features could impact estimates of storage capacity: the extent of the stratigraphic pinchout, the structural dip on the western flank and the internal Captain Sandstone units and their thickness. Additional factors affecting uncertainty in the storage capacity estimates were identified as follows:

Factors increasing storage capacity:	Factors decreasing storage capacity:

- Dissolution in brine
- Chemical reactions with rock
- Capillary trapping
- Lateral aquifer (displacement?)
- Mixing with remaining hydrocarbons
- Irreversible compaction
- Refill efficiency
  - Early End of Field Life (EOFL)
  - Neighbouring fields and aquifers
  - Reservoir structure
  - Unstable displacement
  - Secondary drainage
  - CO_2/water relperms
  - Residual gas saturations
- Imposed limits on injection
  - High risk locations
  - Maximum pressure

Further revisions to the estimate were made following dynamic simulations which evaluated the potential for the water leg to provide additional capacity. The discounted analytical storage estimate was compared with the results from the three-dimensional, three-phase, full-field numerical simulations. These simulations were designed to corroborate initial storage estimates and evaluate different injection scenarios. All the static reservoir models were tested and injection scenarios ranged from:

- A reference case injecting in 4 out of 5 wells with an even injection rate for 10 years.
- Extreme cases with injection via a single well.
- Injection at twice the predicted injection rate.

All the scenarios were investigated to establish that Goldeneye had sufficient capacity to hold 20 Mt CO_2 as stipulated by the project requirements. Furthermore, fill-till-spill runs indicated a capacity of over 30 Mt CO_2 before the spill point was reached and CO_2 migrated out of the structure. Storage was achieved in both the hydrocarbon reservoir and the supporting aquifer.

The potential impacts of different relative permeabilities and residual water saturations on the migration of CO_2 during and after injection were investigated in some detail. Relative permeabilities were derived from a combination of SCAL on cores from the field, plus a literature review. Simple box-model studies of uncertainty in dynamic parameters (unstable displacement, relperms, secondary drainage and residual gas saturation) concluded that these impacts were minor compared to the potential impacts of the parameter itself. Residual water saturations were shown to have potentially significantly reduce the storage capacity at Goldeneye.

The potential for dissolution providing additional capacity was evaluated at Goldeneye, which is relatively favourable for solution due to the low salinity formation water. The incremental storage was estimated to be 2.2% assuming a calculated CO_2 solubility for Goldeneye brine of 4.6% and an assumed contact of 25%.

Mixing of CO_2 with residual hydrocarbons might reduce storage capacity. It was estimated that 25% of the pore space was filled with brine and 25% with compressible gas. Assuming perfect mixing, a reduction in capacity of up to 6% was estimated though imperfect mixing will reduce this number.

Unstable displacement was investigated since the high mobility of CO_2 relative to water was shown to create a strong override by CO_2 producing a Dietz tonguing effect that could result in CO_2 migrating below the original hydrocarbon-water contact. It should be noted that this was considered a short term effect that will only occur during injection.

Takign the above factors into account, the storage capacity was therefore calculated as:

$$St_{capacity} = \text{Available volume} \times \text{Volumetric sweep} \times \text{Dietz efficiency} \times \text{Water displacement} \times \text{Mixing} \times \text{Dissolution}$$

5.1.6.1 DYNAMIC MODELLING OF STORAGE CAPACITY

Full-field dynamic modelling was undertaken to check that the interactions of the injected CO_2 with the reservoir system did not significantly reduce the storage capacity estimates.

The models were initially history-matched with historical production data. Injection was assumed to be through existing wells in which no changes to well completions are assumed. Injection rates were matched to rates of CO_2 capture and constrained by a maximum bottom hole pressure of 4000 psi at 2560.3m depth. Initial simulations were repeated once information on well completions became available.

Several injection scenarios were investigated to test the storage margin. Scenarios varied the number of injectors available to estimate redundancy, varied the injection rate to assess the dependency of plume migration and maximum reservoir pressures on injection rate, varied the duration of injection to check the 'fill-to-spill' maximum storage capacity, preferentially inject into one half of the field to test risks of egress from the field and a 'worst case' scenario of injection into one well only. This latter worst case scenario indicated reduced injection rates, as might be expected, due to the imposed maxium BHPs. All five injection wells were tested. All scenarios were run in the three geological realisations that represented significant uncertainty in the geological models, resulting in 14 scenarios being run that included both the injection period and the period following injection (plume behaviour for 20 years after end of injection is reported). For each case, key results that were assessed included:

- Total amount of CO_2 injected
- Proportion of injected CO_2 in the original gas zone and beyond the original OWC,
- Extent of the plume
- Maximum reservoir pressure and average reservoir pressure for gas in the main storage unit.

It is worth noting that most of the sensitivity runs did not include CO_2 dissolution. One case included an assessment of potential CO_2 dissolution, which was found to not alter the extent of CO_2 migration significantly though up to 1 Mt of CO_2 was dissolved (~5% of injected volume) after 10 years of injection which increased to ~1.9 Mt after 1000 years. This was considered an overestimation due to grid effects (all CO_2 within a cell is assumed to be in contact with water).

5.1.7 Pore Pressure Prediction

The objectives of this analysis were to provide the expected pore pressure in the Captain Sandstone for future well activity and to provide an expected pore pressure regime for the storage complex as a whole.

An initial review of the minimum and maximum mud weights used for drilling the seventeen wells within the field indicated that the pore pressure regime is relatively low compared to other parts of the North Sea. Other data reviewed included pressure data from pre-production logging (typically Mudlog, sonic and resistivity) and testing (MDT, RFT) to measurements from downhole gauges installed in the production wells. These data were used in dynamic modelling in the Captain Aquifer model to predict pressure evolution from subsequent aquifer drive, following end of production.

Pressures in the reservoir, supported by geochemical fluid analysis, were evaluated to assess the potential for reservoir compartmentalisation between the five litho-stratigraphic zones identified in the SRM. It is worth noting that the Tertiary section of the North Sea is known to be overpressured below approximately 1000m (Leonard, 1993).

Pre-production data from in situ gauges in the well bores were used to identify communication with other fields (Hannay). Syn-production downhole pressure data were used to evaluate intra-reservoir communication as wells were shut-in following water cut-off. Post-production data indicated the rate of re-pressurisation from aquifer recharge. The impact of future oil production on reservoir pressures was also considered.

Evaluation of expected pore pressures in the under- and overburden used inferred measurements of formation density (compaction) to identify possible trends in pore pressure, since overpressured mudstones tend to have relatively higher porosities and lower degrees of compaction. Density variations were interpreted in the light of potential mudstone mineralogy, derived from dielectric constant measurements (DCM) which gives an indication of surface area which can be indicative of clay mineral types, since this has a direct control on density. Compaction trends for the mudstones at Goldeneye were interpreted in the context of wider responses seen across the northern North Sea to identify site-specific responses which might indicate variable compaction and suggest over pressuring.

Analysis of leak-off test (LOT) data enabled evaluation of the formation strength or fracture gradient and an estimation of the minimum horizontal stress.

5.1.8 Geomechanical Assessment

The purpose of this assessment was to identify geomechanical risk that might result from CO_2 injection and storage. A review of the geomechanical risks identified in other CCS projects provided the basis for the scenarios investigated at Goldeneye. This review included consideration of leakage risks via the caprock, faults and wells. Generic leakage via a caprock was attributed to a number of mechanisms including Joule-Thompson cooling and irreversible stress paths. Fault leakage scenarios were attributed to fault reactivation and induced seismicity during injection.

The reservoir model was used to derive geomechanical properties from predicted pore pressures, net-to-gross ratios and porosity data. The model was used to assess deformation and stress changes due to gas production and subsequent re-pressurisation due to CO_2 injection, with particular focus on the differences between them (hysteresis). Mechanical stability was predicted for both the reservoir and caprocks. The geomechanical model used Shell's proprietary software. The geomechanical model construction required inputs from:

- Structural geometry form the static reservoir model and overburden model.
- In-situ stress and pore pressure profile (described above)
- Mechanical rock properties (from SCAL, empirical relationships, porosity and NtG)
- Reservoir pressure changes
- Mechanical properties in the reservoir section

Formations were grouped to simplify the model to provide a total of five overburden, three reservoir and two underburden formations. Grid sizes were varied to increase reesoltuon around the injection points. Samples were analysed for bulk compressibility under uniaxial loading and failure strength measurements from triaxial tests. These were compared with published data for the Captain Fairway. Where parameters are subject to uncertainty or a range of expected values, then sensitivity (uncertainty) analyses were undertaken to estimate the potential impacts of combinations of end-member values.

The geomechanical modelling assessed a number of processes including:

- *Compaction and sea-floor subsidence*; where the maximum subsidence at the top of the reservoir and the seafloor, and the extent over which this might be observed, were calculated. Subsidence was evaluated both for the production phase and injection phase.
- *Stress changes in the reservoir and definition of failure criteria*; predicting changes in stress conditions during production and injection to assess the risk of shear and tensile failure for each reservoir unit.
- *Stress changes in the caprock;* predicting changes in stress conditions during production and injection to assess the risk of shear and tensile failure.

Where parameters are subject to uncertainty or a range of expected values, then sensitivity (uncertainty) analyses were undertaken to estimate the potential impacts of combinations of end-member values. Nine cases were modelled to assess the potential impacts of the uncertainties for the processes described above. The cases varied the following: Poisson's Ratio, Young Modulus cohesion and friction angle, maximum injection pressures and post-production pressure values.

5.1.8.1 Fault Reactivation

A review of seismic data was used to identify any structural discontinuities. The stress states predicted pre- and post-production and during injection were then used to calculate effective normal stress and maximum shear stress in 3D for each fault plan to identify its slip tendency. Three of the cases described above were used to assess the potential for fault reactivation.

5.1.8.2 Temperature effects close to wellbore

The stress and strain changes in the reservoir and overburden caused by the cooling from CO_2 injection were assessed for the near-wellbore region. Assessments were made for above shoe and below-shoe sections of the wellbore for the caprock.

5.1.9 Storage Development Plan

The Storage Development Plan is a detailed document that summarises the results of the activities described above. Importantly it also provides summary of the bow-tie risk assessment process that Shell undertook to ensure all risks were correctly addressed to demonstrate the risks were reduced to as low as possible.

5.2 HEWETT DEPLETED GAS FIELD

The documents for the Front End Engineering Design (FEED) of the E.ON UK Kingsnorth project have been reviewed with the aim of describing the work and methodologies used to characterise the proposed storage site. The documents for the E.ON FEED are available online at the National Archives and were reviewed. The most relevant documents were the Key Knowledge Reference Book (E.ON UK, 2011a) and Chapter 7: Technical Design Wells and Storage (E.ON UK & RDS, 2001b). Individual sub-chapters within Chapter 7 which were considered but judged to be out of scope for this review these were; 7.3, 7.4, 7.6, 7.7, 7.9, 7.10, 7.11, 7.12, 7.17 and 7.28.

5.2.1 Background

The Kingsnorth Carbon Capture and Storage Project (CCS) was designed as two 8000 MW supercritical high efficiency coal fired power generating units with post combustion capture, transporting via a 36" pipeline CO_2 for storage in the Lower Bunter Sandstone Formation of the Hewett gas field in the southern North Sea. The Hewett field is located 25 km off the north Norfolk coast in the southern North Sea and has an average water depth of around 35 m. The project was planned to store up to 20 million tonnes of CO_2 in the depleted Hewett natural gas field. The Hewett natural gas reservoir comprises the Upper Bunter, Lower Bunter and the Zechsteinkalk/Leman Sandstone reservoirs. The field is a domal anticlinal structure bounded by faults. The Brockelschiefer Member claystone is the primary caprock for the Lower Bunter and the Rot halite and Dowsing Dolomite is the primary caprock for the Upper Bunter. The nearby Little Dotty field may be in communication with the Hewett field.

The Lower Bunter was identified as the most suitable for CO_2 storage. It is typically 25 m thick and lies at a depth of about 1300 m below sea level. The storage complex comprises of the Upper Bunter and Little Dotty reservoirs.

5.2.2 Summary of Key learning's from the project

Relevant key learning's from the FEED are presented in the key knowledge project reference book, these are related to the following aspects of technical design for the wells and storage:

1. Storage and reservoir integrity and capacity
2. Construction and completion of wells
3. CO_2 properties and injectivity
4. Abandonment of existing and new wells
5. Monitoring
6. Hazard Identification (HAZID) and risk assessment
7. Key learning points

The injection for this project was proposed in two stages; an initial demonstrator stage (for 12 years in the Lower Bunter) in which the CO_2 would be transported and injected in gaseous phase, followed by transport in dense liquid phase allowing injection at higher flow rates (for 28 years in the Upper Bunter).

The work undertaken on the storage and well design is outlined below. It was recognised that during the FEED process that the storage reservoir integrity and capacity were amongst the issues that would need further development as the design processed. Highlights of the key learning's from the FEED work are described in the following sections:

Well location

Wells were planned for the south-east of the Hewett field which offered the best potential for injection into the Lower and Upper Bunter Sandstones, but the report suggests that other locations should be further investigated.

Additional storage reservoirs

It was suggested that work is required to evaluate the suitability of the Upper Bunter for CO_2 storage.

Potential Leakage Pathways

The storage complex is bounded by faults and as a result the integrity of the site depends on the sealing potential of these faults and wells. The FEED reports outline the results of work to assess the mobility of CO_2 through overburden and boundary faults at a range of injection pressures. This included an analysis of multiple caprock layers. An analysis of abandoned wells showed them to be effectively sealed where adequately plugged. In areas where possible migration pathways were identified, it was concluded that the CO_2 would remain within the storage complex; in such cases the storage site would still be in conformance.

Storage capacity

In this study the storage capacity was defined on the size (volume), porosity and the maximum pressure that can be reached without leakage. A 3D geological model of the Lower and Upper Bunter reservoirs was developed using available data (which included well records, core and logs from the initial development of the Hewett field and geophysical survey data). The model was calibrated for gas permeability using the Hewett natural gas production history, it was then used to predict the capacity and pressure for the injected CO_2 in the Lower Bunter for the demonstration phase of the project.

Pressure

The FEED specifies that to prevent migration of CO_2 through the caprock, the pressure within the reservoir must not exceed the hydrostatic (pre-production) or capillary pressure threshold of the overlying rock. In this case the hydrostatic pressure is lower than the capillary pressure of the overlying rock so the hydrostatic pressure is the limiting factor. The hydrostatic pressure is set as the limiting pressure. The authors of this review observe that no factor of safety is applied to the upper pressure threshold.

Relative Permeability

The relative permeability was estimated from reservoir modelling and measured from core. The estimated values were very high and were seen as potentially favourable for CO_2 injection, assuming the estimated values could be confirmed by observed values during injection trials.

Injection Modelling

Injection modelling was used to further refine the storage capacity estimates and to assure the required amount of CO_2 could be injected within the 12 year demonstration phase. This work also evaluated the pressure response of the reservoir during injection. It was highlighted that should this site be taken forward, injection trails would be required. It was also noted that the data acquisition to enable the analysis of injectivity was a major challenge and data quality of some data sets was poor (additional data was provided by the site operator).

Well Abandonment

A detailed analysis of wells drilled into the Hewett field was conducted. Using the data available the analysis concluded abandoned wells would be unsuitable to be reused as CO_2 injection wells and should be reworked to a CO_2 resistant specification. 28 wells were identified as operational (at the time of the study) and would need to be completed to a CO_2 resistant specification.

5.2.3 Project data

The project defined and acquired the data required to assess the capacity, injectivity and integrity of the Lower and Upper Bunter sandstone reservoirs in the Hewett Field as CO_2 storage sites. The required data is divided into ten main areas, all of which were essential for completion of the project and are listed below:

1. **Seismic Data**: essential for interpreting the structural framework (faults and horizons) of the Hewett and surrounding areas required for input to the static and dynamic models. These were required for CO_2 capacity and reservoir integrity modelling and also for determining the well locations for CO_2 injection. The acquisition of this data was crucial as it underpinned the whole project. An area of interest was defined and seismic data was obtained ffrom a number of sources, the seismic delivered was merged in to a single dataset using Kingdom software. The 3D seismic was processed to Post-Stack Time Migration (PSTM).
2. **Deviation Surveys**: the deviation surveys with the well tops and locations were required for all aspects of the project.
3. **Log Data**: included composite logs, CPI's (Computer Processed Input), production logs and the raw log LAS files of the Hewett and D-Fields. The LAS files were required for petrophysical property analysis essential for the field property modelling. The CPI's and production logs were required for the well engineering and reservoir engineering components.
4. **Core Data**: required for petrophysical and geomechanical analysis
5. **Fluid Data**: required for PVT (Pressure Fluid Temperature) analysis & full field and near well bore reservoir simulation models.
6. **Hewett Production Data**: required for PVT analysis & full field reservoir simulation modelling
7. **Pressure & Temperature Data**: required for full field reservoir simulation modelling and well completion design.
8. **Well Reports & Documents**: included well reports, well histories and well geological summaries. This data was required for all aspects of the project, particularly for the simulation and dynamic modelling processes. Well log data was obtained from ENI and downloaded from CDA (predominantly composite logs. Full log suite (where not obtained from ENI or CDA) were obtained from IHS.
9. **Field Information & Reports**: included field reports and field data which were required to understand the field history and previous work carried out where possible. This data was

required by all disciplines. Of note are the wellbore stability documents which were critical to the geomechanical studies for this project.

10. **D-Field Data**: relevant offset data from neighbouring fields, e.g. Little Dotty, Big Dotty, Deborah.

Gas production data, which would have benefited the study, but that was not available for the FEED included:

- Well-by-well monthly gas production data from the Lower and Upper Bunter
- Well-by-well pressure data
- Water production data for the Upper Bunter
- Annual production data 2004-5
- Upper Bunter 2007 pressure point data

It was noted that even after careful data acquisition, some exploration and appraisal well data was missing for several wells. It was recommended that further enquires were made as the project should include all relevant data.

The majority of data was purchased from the field operator (ENI) and all relevant or related data in the public domain was downloaded from the Common Data Access (CDA) website (www.ukdeal.co.uk). Seismic data was purchased from PGS and the exploration log data was purchased from Information Handling Systems (IHS Energy).

The FEED documents review and compare a large number of modelling and interpretation software packages, the findings are not recorded in this report as they were viewed as out of scope.

5.2.4 Static Modelling of the reservoir

The following sections outline the work undertaken to evaluate subsurface data to build 3D static models of the Hewett field area for input into the dynamic model, and to assure capacity and integrity of the storage site. A static reservoir model and full field overburden model were constructed in Schlumberger's Petrel 2009.2. The scope is detailed below:

- Undertake log analysis of key wells to develop reservoir parameters for input to 3D static model.
- Undertake Seismic interpretation of key reservoir horizons.
- Identify and evaluate the significance of faults that penetrate the reservoir and overburden.
- Construct a 3D static model.
- Assess uncertainty associated with static storage volume estimates by evaluating uncertainty in available data.

Data required were:

- Log suites for exploration wells
- Well deviation files
- Well checkshot files
- Well tops
- PGS seismic data survey
- Maximum curvature and similarity amplitudes
- Well reports

The aim of the model was to assess the potential of the Lower Bunter sand as a CO_2 storage site in the Hewett field. Log and seismic data were used as input into the 3D static model. The static model was detailed for the reservoir levels only. A full overburden model was also constructed. The area of interest extended beyond the field boundary (although the distance was not specified). The storage site was defined as the formations used for storage of CO_2 and the associated injection. The storage complex included the storage site plus the over and under burden. The stratigraphy, structure, reservoir and history of the Hewett Field are described in detail in the FEED reports as would be required for any storage evaluation.

5.2.4.1 Petrophysical Interpretation

The petrophysical interpretation to support the static modelling had two functions:

1. To edit and repair density and sonic logs for use in further geophysical workflows
2. To provide a deterministic petrophysical interpretation of the Upper and Lower Bunter Sandstone and intervals of the overburden.

A petrophysical database was created and interpreted in GEOLOG. Log repair and editing were required to ensure the correct data were loaded and that washouts were identified. Composite logs, mud logs and mud header information were used to help the interpretation and for quality checks. The data quality was evaluated and was found to be poor in the overburden sections.

Editing of the density and sonic logs was performed, erroneous spikes and wash outs were removed and logs were repaired where possible. Given the poor quality of input data and intended use of resultant edited curves, empirical relations of Faust and Gardner (1998) were successfully adopted to edit sonic and density in conjunction with cross-plot regressions and the manual removal of spikes.

For the petrophysical evaluation a simple deterministic model was applied to predict the volume of shale, the total porosity and the effective and total water saturation. Cross plots did not supply conclusive Water Saturation vs Porosity cut offs, so widely accepted 'industry' cut offs were used to calculate volume of shale and porosity. Average porosity and average water saturation were calculated using the following equations:

$$\text{Average } \Phi = \frac{\sum \Phi h}{\sum h}$$

$$\text{Average Sw} = \frac{\sum \Phi h Sw}{\sum \Phi h}$$

Where:

Φ = porosity at a given depth increment (for net sands only)

h = the depth increment

Sw = water saturation at a given depth increment

5.2.4.2 Seismic

An area of interest was defined and seismic data was obtained for a number of sources, the seismic delivered was merged in to a single dataset using Kingdom software. The 3D seismic was processed to Post-Stack Time Migration (PSTM). A project was set up in Kingdom, contain the wells within the area of interest. Checkshot, deviation logs and well tops were imported and the appropriate coordinate reference system was used.

5.2.4.3 AAA Dip & Attribute Volume Generation

For the identification, extent and geometry of faults similarity (highlight discontinuities in seismic often associated with faulting) and curvature (curvature volumes can help identify sedimentary features and faulting) cubes were generated using Baker RDS proprietary AAA Special Attribute Workflows. The aim was to generate consistent mapped faults and surfaces for the subsequent modelling work. Additional volumes e.g. raw dip, instantaneous frequency, RMS/absolute average amplitudes were generated to support this work.

5.2.4.4 Mapping and interpretation

The objectives of the seismic interpretation were to map key horizons and faults which formed the input to the static structural modelling and fault analysis. Observations were made on the seismic data quality, coverage and the impacts of different quality data. For example, the effects of the seismic survey acquisition technique on the resultant processed and stacked seismic data were evaluated. The seismic to well ties were constructed using a series of synthetic seismograms, this ensure the correct phases were picked for each of the major stratigraphic horizons. Mappable units were picked on the seismic. In some cases where a lack of acoustic impedance contrast was observed between units, an event immediately above or below was picked and a seismic shift was applied to give a geological representation of the surface. It was concluded that this technique gave a better result than producing isopachs from an overlying horizon in the depth domain. The quality of the seismic picks were recorded and discussed.

5.2.4.5 Fault interpretation

The fault interpretation was based on the main seismic volume alongside similarity and maximum curvature volumes. Surface slices were extracted along key horizons to quality check the fault interpretation. The resultant offsets and angle of faulting were evaluated to help understand different phases of faulting. Prior to the static modelling, an exercise of "fault selection and ranking" was performed. A group of key faults which are present within the main area of interest and intersecting immediate reservoir overburden / underlying formation were selected for input to the 3D static modelling. A detailed description of the faults interpreted, along with modelling selection criterion was created.

5.2.4.6 Depth conversion

Two Way Time (TWT) grids were generated using well logs for key horizons and time depth pairs were generated. The depth conversion process was based on a comprehensive analysis of four different methods and comparison of the residuals. The methods tested were:

1. A quick, preliminary Vo-K analysis.
2. Single layer Time – Depth (Seismic TWT – Well Depth) polynomial trend analysis.
3. Multi layers Time – Depth (Seismic TWT – Well Depth) polynomial trend analysis.
4. Well Average velocity trend analysis.

The analysis found that Single layer Time – Depth (Seismic TWT – Well Depth) polynomial trend analysis gave the best results.

The faults were depth-converted using a comprehensive time depth relationship for the purpose of depth-converting the fault sticks with all the preferred final seismic TWT- well depths. From these, a consistent trend function was derived to produce good conformity of the fault sticks with the final depth converted and residual corrected surfaces. The dominant structural configuration and regional structural trend was taken into account during the modelling of the storage site.

5.2.5 3D Geological Model

A static model was constructed in Petrel of the Lower and Upper Bunter with the following objectives:

- Construct a simplistic framework to show the structural framework of the storage site over the area of interest including the horizons and faults interpreted in the seismic evaluation. The area of interest considered the Hewett and Little Dotty fields.
- To illustrate the geometry and structure of the Lower and Upper Bunter reservoirs as a potential CO_2 store site and the immediate over/underburden horizons.
- Populate the model with properties based on the petrophysical interpretation.
- Upscale the geological static model and export to GEM as the basis for the dynamic simulation model for history matching and CO_2 plume modelling.

- Generate juxtaposition diagrams for the modelled faults and identify potential locations for CO_2 migration within the storage site and leakage beyond the storage complex.
- Carry out a fault seal analysis to determine the sealing capacity of the major faults in the field.

Well tops were taken from IHS, CDA and interpreted from well correlations using Gamma Ray logs. These were all cross- and quality-checked to ensure a consistent database.

The interpreted fault and structure depth maps were used. The 97 faults represented in the structure maps were reduced to 17 for modelling purposes. For a fault to remain in the model it had to meet the following criteria:

- Faults with a significant throw (>100 ft) – for analysis of the juxtaposition of the Upper and Lower Bunter sands (Lower Bunter has an average thickness of ~85 ft).
- Faults that intersect the reservoir and overburden/underburden – for potential migration pathways.
- Faults that may be compartmentalising the reservoir.

The faults were imported as fault sticks and edited to ensure they aligned with the surfaces. Key faults were identified which play a significant role in the model e.g. where seismic resolution is poor but were small changes on the location of the fault and surfaces have a significant impact of juxtaposition of horizons. Faults were modelled as zig-zag faults with a cell size of 200 x 200 m. Problem pillars were edited and trends were added to guide the gridding process. The model was split into three sections.

Horizons were modelled from seismically derived surfaces and were smoothed and clipped to the area of interest. Wells were used to tie the horizons. An iterative process was used until a satisfactory result was achieved. This included manual editing, editing of faults to reduce spiking and the addition of pseudo-wells in areas of poor well control.

Zones of the units of interest were produced during the horizon modelling. Subzones were added using the "make zone" process. This process resulted in thickening in some areas of the model, related to uncertainly of cross-fault juxtaposition of horizons.

Multiple layers were introduced into the model within the Upper and Lower Bunter using a fine scale proportional layering approach, which would allow well logs to be upscaled to capture higher porosity streak during the property modelling process. Juxtaposition diagrams were created during the quality check phase these were used to check the model and areas of uncertainty.

Examination of core from the BGS core store gave the rock quality variation between four wells. This helped formulate the conceptual model for the two reservoir horizons.

A simplified rock quality zonation was modelled using a discrete property template where 1 is the best rock quality and 3 is the worst allowing the proximal and distal parts of the reservoir to be modelled. Core plug data and a Hydraulic Flow Unit (HFU) correlation was developed to provide an accurate method of populating porosity and permeability in the reservoir when combined with the rock quality zonation. This produced a permeability equation for each HFU, allowing permeability to be populated spatially, using the porosity grid which in turn is based on the HFU distribution in the reservoir. HFU logs were upscaled into each zone and, using the facies modelling process, properties were defined for each zone dependant on the HFU proportions. These were modelled stochastically using a sequential indicator simulation.

For porosity, a 6% cut of was applied using the Petrel calculator to generate a net porosity log for each well in the model. The log was then upscaled into the model using an arithmetic approach. A vertical variogram was used to reflect the dominant sediment transport direction and alluvial fan geometry. This was applied to each zone during the porosity modelling.

As the logs were not of sufficient quality, constant values were used for water saturation and net to gross using averages obtained from the petrophysical interpretation. Volume of Shale (VShale) was calculated during the fault seal work. Two cut-offs were applied to ensure non-reservoir sections were flagged, a porosity cut of 6% and a VShale cut of 35%. The log was then upscaled into the model using a variogram. Two static models were created; a 'juxtaposition static model' and a 'non-juxtaposition static model', the latter to address uncertainly around a major fault in the model.

5.2.6 Well bore stability

A geomechanical analysis was performed to assess the stability of new well bores associated with the planned CO_2 storage at the Hewett Field. This examined the effects of using a depleted reservoir and the potential for CO_2 injection and the effects of interruption of CO_2 supply on well bore stability.

5.2.6.1 Existing well assessment

The aim of the assessment was to examine the current status of all the wells which penetrate the Hewett Bunter reservoirs, to assess their potential for re-use, and to assess their potential to provide migration paths between formations and potential leakage paths for release of CO_2 outside the storage complex.

The workflow was:

- To review all existing wells penetrating the Hewett reservoirs
- Assess potential for reuse
- Assessment of the potential to provide leakage pathways
- Look at mitigation options

28 platform wells and 7 sidetracks were evaluated. 35 legs through the Lower Bunter 11 of which were continued into the Zechsteinkalk / Rotliegendes were analysed.

The data evaluated included:

- End of well reports
- Completion diagrams
- Status reports where available
- Wellhead diagrams

A conclusion of the study was that further studies should be carried out to evaluate the various well abandonment options.

5.2.7 Storage site integrity

This work provided an assessment of the integrity of the CO_2 storage site and complex and addressed the following:

- Capillary Pressure – a review of capillary pressure data and the availably to seal and hold the specified gas column.
- Fault Seal Analysis – results provided transmissibility values and allowed these to be applied to the modelled faults to evaluate where faults might be open or closed.
- Fault Integrity –focused on the maximum sustainable fluid pressure and the thermal effect on faulting. This was evaluated through the geomechanical model.
- Geochemistry – evaluation of CO_2 interaction with the rock and formation helped to predict the level of solubility and mineral trapping.
- Reservoir and Overburden Parameters.

5.2.7.1 Fault Seal Analysis

The sealing capacities of the faults in the Hewett field were assessed using the RDR Fault and Structural Analysis module in Petrel 2010.1. The following properties were modelled to assess the faults' sealing capacity:

- Fault throw
- Fault juxtaposition
- Fault zone thickness (perpendicular to the plane of the fault)
- Fault clay content
- Fault permeability (both across the fault and along it)
- Fault transmissibility and transmissibility multipliers

The fault seal analysis was performed by creating juxtaposition diagrams, showing horizon offset locations on the up-thrown and down-thrown sides of the fault and by determining the fault's clay content using the Shale Gouge Ratio (SGR). The bounding faults were assessed for sealing capacity and the internal faults were reviewed for any compartmentalisation. The inputs into the fault seal analysis were:

- Clay to permeability calculation.
- Clay content: A cut-off of 35% clay content was used in alignment with the petrophysical modelling.
- Clay smear: A clay smear factor of 3 was used. This means that for a faulted unit of 10m thickness with a clay content of 35%, the clay smear along the fault plane would be 30m, i.e. three times, the unit's thickness.

The fault seal analysis module calculated eight fault properties:

1. Fault permeability
2. Effective cross fault permeability
3. Fault transmissibility
4. Effective cross-fault transmissibility
5. Fault transmissibility multipliers
6. Fault thickness
7. Fault displacement
8. Fault clay content

Uncertainties in the fault seal analysis arise from the seismic uncertainty, property modelling and extent and movement of fracture zones.

5.2.7.2 Reservoir and caprock characterisation

The work included:

- Review of the interpretation of well data for the Hewett field and the derived parameters (porosity, and average net to gross) determined for the static modelling.
- A description of the depositional environment.
- Assessment of the core data (reservoir and grain scale) from the reservoir.
- Assessment of the geomechanical properties of the reservoir and field stresses.

Mechanical rock properties were determined using offset data well data and empirical correlations. Further laboratory analysis such as Special Core Analysis (SCAL), Routine Core Analysis (RCA) and geomechanical studies were undertaken to characterise the reservoir in terms of stress.

The work and methodologies used to characterise and provide validation of the reservoir rock and the overburden caprock of the Hewett field are described here and include:

- Characterisation and sedimentological description of the Hewett area stratigraphic column including a description of the depositional environment from analogue data and literature.

- Reservoir rock characterisation from core samples - assessment of rock quality variation at the reservoir scale.
- Reservoir rock characterisation at the grain scale (i.e. core plugs) – characterisation by core plug interpretation.
- Characterisation from well log data and CPI's.
- Characterisation of the Hewett area field stresses and geomechanical analysis of the reservoir rock.
- Recommendations and importance of laboratory testing for further geomechanical testing and compaction analysis.

The scope of work covered:

- Sedimentary characterisation assessment
- Porosity/permeability preliminary test on reservoir and cap rocks
- Decision on initiation of experimental work prior to licence submission
- Sedimentological characterisation
- Detailed geomechanical analysis and fault reactivation study

The stratigraphy of the storage complex and the reservoir was described. The characterisation of the core data aimed to:

- To assess the sedimentological variation in rock quality (grain size/texture etc) and note any facies changes in the Upper and Lower Bunter laterally across the field and with depth.
- To identify the scale of variability and assess the presence of high permeability zones which may influence injectivity of the CO_2. Understanding the scale of heterogeneity in the Lower and Upper Bunter was required for static and dynamic modelling in order to ensure any potential high permeability zones were represented. This evaluation was aided by using the HFU (Hydraulic Flow Unit) characterisation.
- To examine cutting samples from the overburden horizons (from the Cromer Knoll to the Bunter Shale).
- To undertake in-situ rock strength tests which were used for evaluation of compaction and input to the Full Overburden modelling exercise.

Core plug data base

Existing RCA data was available in Excel format and was reviewed to consider the amount, type and vintage of the data and identify erroneous data points. Porosity-permeability cross-plots were produced to ascertain the relationship between the two for the modelling process.

Hydraulic Flow Unit (HFU) Characterisation

The reservoir zones were characterised by Amalfue et al., by their hydraulic characteristics in order to identify facies or geological zones with similar pore geometries and common Flow Zone Values (FZI). This helped to interpret the potential petrophysical and geological characteristics.

Salinity and formation water resistivity

A review of resistivity of formation water (Rw) was conducted to help derive the most appropriate values for each reservoir, log derived Rw was used in conjunction with The North Sea Formation Waters Atlas. In addition, the project had access to compositional water samples from various wells. It was concluded that it was not appropriate to assume the same Rw in the two separate reservoirs.

5.2.8 Characterisation of field stresses and geomechanical properties of reservoir and overburden formations.

Field stresses, pore pressure, and geomechanical properties of reservoir and overburden formations are required for assessing geomechanical risks related to CO_2 injection and storage, e.g. drilling instability and solid production of the new wells, fault reactivation and cap rock fracturing.

Properties needed to help estimate the compressibility to further evaluate the compaction or expansion of the reservoir and the changes in porosity and permeability over the life of gas production or CO_2 injection are:

1. *Static elastic moduli (Youngs modulus and Poisson's ratio)* - There were no laboratory core test data available for this study to test the static elastic moduli, so density and sonic logs were used, alongside empirical correlations.
2. *Rock strength* - Mechanical core test data determining rock strength – unconfined compressive strength (UCS) and internal coefficient (IFC) were not available for this study; in their absence log correlations were used to evaluate mechanical properties of the reservoir and overlying formations. The McNally empirical calculation and Horsrud equations (Khaksar et al. 2009) were used to determine UCS. For IFC the Lal correlation was used (Khaksar et al, 2009).
3. *Pore pressure* - Pore Pressure P_p was determined from pressure measurements in the reservoir pre and post production. Aquifer recharge was taken into account.
4. *Vertical Stress S_v* - The vertical stress was calculated by integrating the density logs from an offset well.
5. *Minimum Horizontal Stress S_{hmin}* – The S_{hmin} governs the pressure required to reopen existing fractures that are perpendicular to the S_{hmin} orientation. The magnitude of S_{hmin} was estimated from Leak off Tests and losses.
6. *The orientation of Horizontal Stresses* – An examination of regional stress orientation was examined form the World Stress Map database
7. *Maximum Horizontal Stress S_{hmax}* - The magnitude of S_{hmax} was constrained by modelling the presence and absence of wellbore shear failure or breakout occurrences at reference depths in offset wells with the input of S_v, S_{hmin}, S_{hmax} orientation, break out pressure (P_b), rock strengths (both UCS and IFC) and mud weight used in drilling. The obtained S_{hmax} values at these reference depths are then transformed to the effective stress ratio to extrapolate the S_{hmax} profile from the seabed to depths of interests.

The derived data were used to produce a geomechanical model for the field. It is recommended in the report that many of these parameters should be validated and refined by geomechnical laboratory testing.

5.2.9 Dynamic Modelling of the reservoir

The study utilised reservoir model comparison studies by the Alberta Research Council to help inform the decision on which software to use. The following important required capabilities of the modelling software were:

1. Can the CO_2 phase (with impurities), viscosity and density be predicted?
2. Can the heat transfer be modelled (rock → water → CO_2 → wellbore → over/ underburden)?
3. Can the CO_2 solution in water be modelled?
4. Can the water evaporation in CO_2 be modelled?
5. Can salt precipitation/calcite dissolution be modelled?
6. Can the effects of density and viscosity as a result of the above be determined?
7. Can diffusion be modelled?

5.2.9.1 Capacity assessment and Well distribution relative to reservoir volumes

Using CMG's GEM simulator package the storage capacity of the Lower Bunter reservoir was calculated using a history matched base case full field reservoir simulation. The injection well distribution (relative to the reservoir) was also evaluated and the injection rate was determined. The model was capable of investigating a range of scenarios. The scope of the work for the full simulation model was:

- Construct the PVT description (natural gas, water and CO_2) over the anticipated reservoir pressure range.
- Build a reservoir full field simulation model to model the Upper Bunter and Lower Bunter formations in the Hewett and Little Dotty areas using the 3D geological model.
- Evaluate the key uncertainties impacting field performance.
- History match the full field simulation model with the available historical production and pressure information.
- Evaluate aquifer support and extent/flow path of reservoir water in the Upper Bunter and Lower Bunter reservoirs during historical production.
- Understand the distribution of the CO_2 injection wells from one platform relative to the reservoir volumes.
- Evaluate CO_2 storage potential in the Lower Bunter reservoir ensuring capacity constraints are maintained.

5.2.9.2 Initial full field simulation

The model imported to CMG's GEM simulator was based on the geological model described. The aim of the model in the gas production phase of the history matching was to:

- Evaluate the key uncertainties impacting field performance
- History match the full field simulation model using the available historical production and pressure information
- Gain a better understanding of any communication between the Hewett and Little Dotty fields
- Provide a suitable tool for predicting CO_2 storage capacity and evaluating the well distribution of the CO_2 injection wells relative to the reservoir volume.

The model consisted of 10 layers in the overburden, 14 layers in the Upper Bunter reservoir, 31 layers in the intra reservoir horizons, 22 layers in the Lower Bunter reservoir and 48 layers in the underburden. The following parameters were imported into the model from earlier work:

- Fault transmissibility
- Vertical permeability vs horizontal permeability was used to understand vertical heterogeneity.
- Permeability. A permeability multiplier was applied to achieve the high values of permeability observed. Sensitivity analyses were performed on the permeability multiplier to help understand the impact of this uncertainty on the well and field performance.
- Porosity
- Net to gross
- Water saturation
- Rock compressibility

Relative permeability values were derived from analogue data and sensitivities were performed to evaluate the impact of relative permeability on reservoir performance. Fluid properties were derived from well fluid samples. The well and production history for the Hewett Field was assessed from well reports and production data. Cumulative production data was entered into GEM, predicted future production was calculated through using exponential declines fitted to actual production data. Pressure data from wells was used in the model. An analytical aquifer was attached to the edge of the model, which was seen to have an impact on the pressure.

5.2.9.3 History Matching

The methodology for history matching the reservoir simulation was as follows:

- Establish the focus for history matching in the Lower Bunter and Upper Bunter reservoirs.
- Evaluate the initial simulation model history match to the available production and pressure data.
- Perform a review of input data to ascertain the range of uncertainty associated with each parameter.
- Run sensitivity cases to encapsulate the range of uncertainty.
- Determine key drivers influencing reservoir performance.
- Evaluate the impact of key uncertainties on historical field/well performance.
- Use the sensitivity analysis to guide the history matching parameters to generate the base case simulation model.

A sensitivity analysis indicated that GIIP (Free Gas Initially In Place), reservoir permeability, residual saturation and aquifer size had the biggest impact of reservoir performance.

5.2.10 CO_2 Injection Prediction

The main objectives of the GEM Hewett full field simulation model in prediction were to:

- Estimate the CO_2 storage capacity of the Lower Bunter
- Evaluate the impact of input parameter sensitivities on field performance during CO_2 injection
- Validate the pressure response from the near wellbore modelling to provide a timescale for
- Lower Bunter CO_2 injection wells

The assumptions made for the model inputs were made clear in the report. The history matched model was used for the CO_2 injection prediction. This work allowed the location of injection wells to be set based on a pre-determined CO_2 injection schedule. A sensitivity analysis was performed to evaluate the impacts on CO_2 injection performance of permeability, gas saturation and relative permeability.

5.2.11 Full overburden mobility modelling

Full overburden mobility modelling was performed to understand the conditions under which CO_2 will migrate out of the storage site. A coarse overburden model was built in Petrel (which matched the full field model) and exported into GEM to simulate potential migration pathways. Four potential migration pathways were considered:

- Caprock – where five cases were considered; minimum, maximum and average formation property values, followed by two further cases which considered the impact of higher permeabilities in the overlying shale formations.
- Faults – the fault migration modelling consisted of three cases in which sensitivities to transmissibility, permeability and the fault plane were addressed.
- Wells – two scenarios were run to address leakage through boreholes. One assuming an optimal casing cement job and the second assuming poor casing cement.
- Solubility in formation waters – one case assessed the solubility of CO_2 in the formation water of the reservoir.

Sensitivities using extreme but improbable cases were run for the caprock, wells and fault scenarios.

5.2.12 Risk Assessment

The risk assessment was performed in two parts, an identification of hazards (HAZID) which pose a risk to man and environment and a risk assessment and mitigation assessment.

5.2.12.1 HAZID Wells and Reservoir

Hazard (HAZID) identification was undertaken as one stage of the overall six stage risk management activities. The focus was to identify major risks to man and the environment. The assessment was constant with E.ON company policy. The levels are described in Table 6.

Table 6 Risk level categories

	Safety	Environment
Catastrophic	Multiple fatalities, offsite impact	Major environmental disaster causing long-term or irreversible damage and international condemnation
Major	Single fatality or serious irreversible disability with major quality of life impact	Major environmental impact resulting in significant fines
Serious	Major long term but reversible injury	Reportable incident causing serious but reversible environmental impact

Workshops were held with the aim of:

- Providing an explanation of the process/node from the design team.
- Brainstorming potential hazards that could result in significant consequences for man or the environment.
- A final guideword check to ensure that the major issues have been considered.
- Identification of initiating events that realise each hazard, along with potential consequences for man and the environment.
- Identification of expected safeguards, along with areas of uncertainty and points for subsequent clarification.

The purpose of the workshops was only to identify hazards and consequences, and not to resolve them. It was noted that the list of hazards would not be exhaustive. Separate topics (known as HAZID nodes) are listed below:

- New Wells (CO_2 Injection)
- Existing Wells Exploration
- Existing Wells, Production
- Storage Complex

5.2.12.2 Risk Assessment and Mitigation.

A brief overview of the risk assessment is given in the FEED documents. It focuses on the risk assessment and Design Risk Assessment (DRA) exercises undertaken for the reservoir storage complex and associated equipment. The subsurface risks were categorised as follows:

- XMAS tree
- wells abandoned
- new wells
- reservoir
- overall storage

The report provides the risks in tables under the following categories; cause, effect, current status and further actions.

5.3 P18-4 DEPLETED GAS FIELD FOR ROAD

The ROAD CCS demonstrator project in the Netherlands, which plans to store captured CO_2 offshore is supported by the Government of the Netherlands and the European Union. The ROAD project was awarded a storage permit in 2012. Two special reports for the Global Carbon Capture and Storage Institute (GCCSI) and a peer-reviewed publication in the International Journal of Greenhouse Gas Control were reviewed.

The GCCSI (2013) provides a high-level brief describing the permitting process for the ROAD project. The storage component is summarised as:

- Depleted gas reservoir : P18-4
- Operator : TAQA
- Depth : 3,500 meters
- Estimated capacity : 8 megatonnes
- Available : 2014

5.3.1 Storage permits

The CO_2 will be stored using the existing natural gas production platform 'P18-A', operated by TAQA Offshore B.V. (TAQA). Wells were drilled to a depth of 3,500 meters from platform P18-A to three reservoirs, designated as P18-2, P18-4 and P-18-6. At present, only P18-4 will be used for storage so a permit will only be applied for this reservoir. The existing well (borehole) will be used and needs to be adapted for the switch from gas production to CO_2 storage.

The storage of CO_2 in P18-4 requires the following permits:

- All-in-one permit for physical aspects;
- Storage permit;
- Emission permit.

The storage permitting process is described. In summary, the following plans have to be developed and accepted by the competent authority:

1. Risk management plan;
2. Monitoring plan;
3. Corrective measure plan;
4. Closure plan.

The monitoring plan is 'risk based'. This means that the level of detail of the plan depends on the results of the location-specific risk assessment, as recorded in the risk management plan. Because of this, the monitoring plan closely interacts not only with the corrective measures plan, but also with the risk management plan (Figure 3). There is actually no obligation under the CCS Directive to develop a risk management plan. Annex I of the Directive requires several risk assessments, characterisations and operational conditions. ROAD combined all of these requirements in a ′risk management plan'.

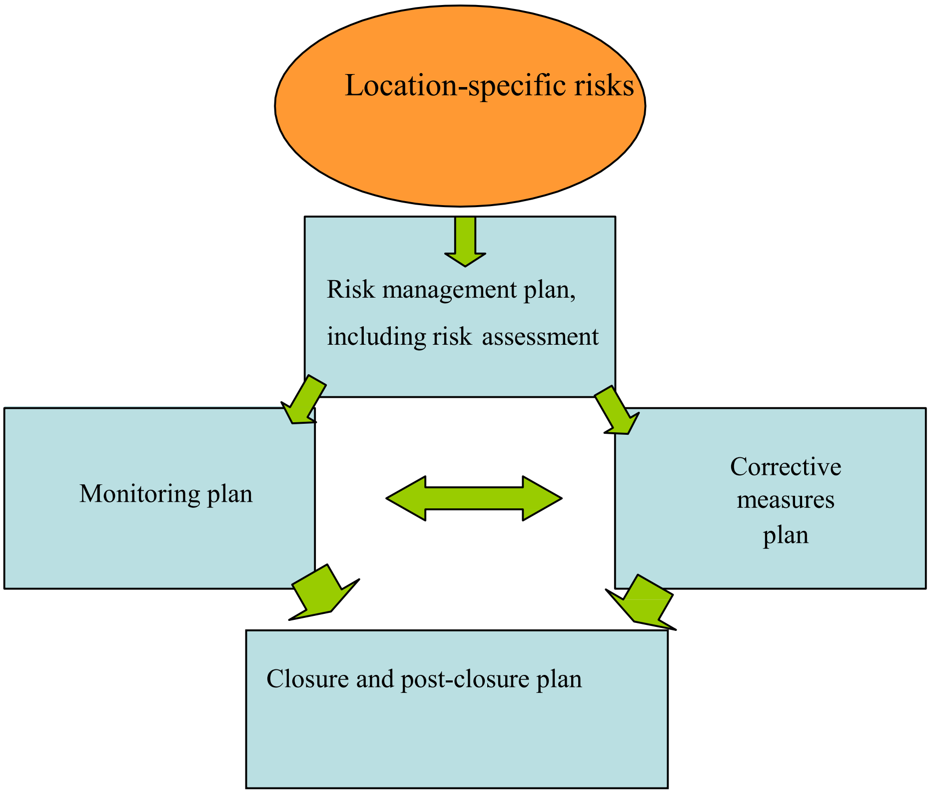

Figure 3: Consistency between [storage permit] plans for ROAD

5.3.2 Risk management plan

The suitability of a geological formation for the use as a storage site must be determined through a characterisation and assessment of the potential storage complex and surrounding area pursuant to the criteria specified in Annex I of the CCS Directive. This characterisation and assessment must be carried out in the following three steps.

5.3.2.1 Step 1: Data collection

Sufficient data must be accumulated to construct a volumetric and three-dimensional static (3D)-earth model for the storage site and storage complex, including the cap rock, and the surrounding area, including the hydraulically connected areas.

5.3.2.2 Step 2: Building the three-dimensional static geological earth model

Using the data collected in Step 1, a three-dimensional static geological earth model, or a set of such models, of the candidate storage complex, including the cap rock and the hydraulically connected areas and fluids shall be built using computer reservoir simulators.

5.3.2.3 Step 3: Characterisation of the storage dynamic behaviour, sensitivity characterisation, risk assessment.

The characterisations and assessment shall be based on dynamic modelling, comprising a variety of time-step simulations of CO_2 injection into the storage site using the three-dimensional static geological earth model(s) in the computerised storage complex simulator constructed under Step 2.

The next step is to undertake a hazard characterisation by characterising the potential for leakage from the storage complex, as established through dynamic modelling and security characterisation described above. This shall include consideration of, inter alia:

- potential leakage pathways;

- potential magnitude of leakage events for identified leakage pathways (flux rates);
- secondary effects of storage of CO_2, including displaced formation fluids and new
- substances created by the storing of CO_2;
- critical parameters affecting potential leakage (for example maximum reservoir pressure, maximum injection rate, temperature, sensitivity to various assumptions in the static geological Earth model(s));
- any other factors which could pose a hazard to human health or the environment (for example physical structures associated with the project).

The hazard characterisation shall cover the full range of potential operating conditions to test the security of the storage complex.

This characterisation and assessment should not only lead to the conclusion that the CO2 storage can take safely place, but also to operational conditions that have to be met in order to safeguard the integrity of the storage site (for example a limit on the reservoirs pressure).

The 'lessons learned' from the permitting process does not specify any technical lessons learned from site characterisation for the storage component of the ROAD project (GCCSI, 2012).

The storage component of the ROAD demonstration CCS project is summarised as within a depleted offshore gas field in the Netherlands sector of the North Sea in Arts et al. (2012). The geological background is described including the depositional setting, structural history, reservoir geology, seal and overburden and shallow gas accumulations. The geological models illustrated in the paper are briefly described in following text on history matching of production data from P18-4 gas field. The risk assessment-led characterisation process is not explicitly described but evident in the description of uncertainties identified, the related monitoring programme and the granting of a storage licence in 2012.

5.3.3 Site characterisation

A review of detailed work completed on the stratigraphy, structure and sedimentology is described. Selected well log and high-quality seismic data are illustrated from three gas fields in block P18-A (P18-2, -4 and -6). Nine wells are illustrated and detailed studies from 1996 to 2000 are referred to. It is presumed here that data sets acquired for exploration and recorded during production from the three fields are used for characterisation. The sealing strata and overburden to the shallow subsurface are described but in lesser detail. The primary seal is 10 m thickness of lacustrine claystone. The overlying Altena Group (approximately 500 m) of claystone, siltstone and marl is a secondary seal.

The characterisation of the storage site, captured within the geological model and dynamic simulation of CO_2 injection, is described within the 'history matching' text section. The site model is 'up-scaled', this may be taken as a reduction in model resolution from that used for gas production. The storage interval comprises two formations and is divided into nine layers for flow simulation. Model 1 comprises nine layers, a second model (Model 2) was also used in which each of the nine layers was subdivided into two (18 layers). Two regionally recognised shales were modelled no-flow boundaries within the reservoir. The pressure behaviour for the two models was noted as significantly different and the coarser model (Model 1) was used.

Permeability attribution of the model was achieved using a porosity-permeability relationship. The relationship was used to construct a horizontal permeability log. Core data were used to derive a vertical versus horizontal permeability ratio and create a vertical permeability log. Both logs were up-scaled independently and averaged (harmonic average for vertical and arithmetic average for horizontal permeability). Injectivity was calculated from the up-scaled logs, considering only the perforated parts of the well. A multiplier was used to reduce and match the injectivity with that measured from earlier well testing (the difference reflects the wider reservoir width used for the well test, which is not unexpected). The pore volume within the static geological model is based on an estimage of the Gas Initially In Place, with an error of 5%. Other uncertainties, such as porosity distribution and residual water saturation, have individual uncertainties much larger than 5%.

Production data indicate no influx of aquifer water or has from adjacent fields. A comparison of simulated bottom-hole pressure with measured well-head pressure using lift tables shows a satisfactory match in values. The initial reservoir pressure is taken as a maximum value (no fracture pressure values were modelled or maximum acceptable values estimated). Simulations indicate an average CO_2 injection rate of 1.1 Mt/year, with temporary higher peaks, could be sustained. Sensitivity of injection rate to three injectivity values and the either the inclusion or exclusion of shale layers with each was modelled (sensitive to extreme differences in injectivity value but no significant difference due to presence or absence of shale layers). Sealing properties of faults defining compartments, by juxtaposition of sealing and reservoir strata, justifies further investigation using 3D seismic data. Additional characterisation by assessing the geochemical, geomechanical and thermal effects on the reservoir rock and seal induced by CO_2 injection is to be conducted.

5.4 OTWAY DEPLETED GAS FIELD

The Otway Project is described as Australia's first demonstration of the deep geological storage of carbon dioxide (Otway, 2013). It is a research project, part of CO2CRC, to develop and implement rigorous monitoring and verification research, complementing the demonstration of subsurface storage. The project is defining regulatory requirements for Australian carbon capture and storage projects. Lessons learned from the project are being adopted by other CCS projects around the world.

The site in south-west Victoria is illustrated as onshore and two stages are described. Stage 1 is completed and has injected 65 000 tonnes of CO_2-rich gas into a depleted gas field, 2100 metres below surface, accompanied by baseline and monitoring observations at depth and at the surface to demonstrate safe containment. Computer models are described as refined by the monitoring observations. Stage 2 has developed an injection well, into an overlying saline aquifer formation to 1400 metres depth, and test injections have been conducted. Further research during stage 2 will include seismic monitoring.

No detail of the site characterisation is described although for the stage 1 injection it would use existing understanding of the depleted gas field.

5.4.1 Site characterisation

In an online overview[1] of the site selection and characterisation process in March 2012 site characterisation is described as three major processes:

- Reservoir modelling: building a static model of the underground storage reservoir using geological, seismic and engineering data;
- Reservoir simulation: building a dynamic model to show how the CO_2 will move through the reservoir;
- Risk assessment: determining the possible risks of CO_2 injection into the reservoir

The reservoir modelling and simulation was used to determine the position of the CRC-1 injection well although no detail is included.

[1] CO2CRC Otway Project, site selection: (http://www.co2crc.com.au/otway/site.html#modelling)

5.4.2 Risk assessment

The stages of qualitative and quantitative risk assessment reflect the siting and implementation of the CRC-1 injection well rather than risk assessment-led site characterisation:

Qualitative Risk Assessment
A detailed qualitative Risk Assessment was successfully carried out at the time the site was initially evaluated. The risks examined included:

- Project planning and pre-implementation risks
- Implementation risks following oil & gas industry standards
- Long term storage and containment risk

Quantitative Risk Assessment (QRA)
Possible risk events considered:

1. Leakage through cap rock (permeable zone)
2. Leakage through faults
3. Well integrity
4. Overpressuration at local and regional scales
5. Exceeding spill-point (overflow of the reservoir)
6. Equipment (compressor, pipeline, wellhead) failure

The risk assessment was peer reviewed by group of experts.

Risks are constantly re-evaluated throughout the main phase of the project:

1. QRA 1: Containment (start of the project-2005)
2. QRA 2: Pre-injection
3. QRA 3: During-injection
4. QRA 4: End of injection
5. QRA 5: Post-injection

QRA 1&2 had been completed at the date of the presentation showing that the project has low risk events with minimal consequences.

5.4.3 Stage 1 results from the CO2CRC Otway Project[2]

Headline results of the progress on Stage 1 of the Otway Project in March 2012 are summarised in this presentation. The content is mostly on the monitoring of the CO2 injected during Stage 1, subsurface temperature and pressure, illustrated prediction of the injection phase, down-hole and atmospheric sampling and analysis and time-lapse seismic monitoring. A link to a pre-publication version of Jenkins et al. 2012, incorporating a link to supporting information, is included.

An outline of the Otway Basin injection project, risk assessment, permitting, monitoring design, reservoir modelling and monitoring results are described in Jenkins et al. (2012). Site characterisation by creation of initial geological models is based on available well and seismic data of the Naylor Gas Field, incorporating estimates of porosity, permeability, pressure and geometry of faults, sedimentary layers and facies distribution. Preliminary dynamic models were produced and calibrated against the production history of the Naylor-1 well. Geological uncertainties were reduced by drilling of the adjacent CRC-1 well and the dynamic model refined. Methods well-established in the oil and gas industry were followed.

A wide range of baseline and monitoring observations were made, appropriate for a research project, including collection and analysis of samples from the subsurface and surface.

[2] http://www.co2crc.com.au/dls/otway/Otway_Project_stage_1_results.pdf

5.4.4 Site Characterisation

Initial reservoir modelling was revised by data from the injection well to include stacked sandstone bodies and thin shales. Four stochastic models of differing long- and short-range shale correlations were constructed. Additionally, two scenarios of relative permeability were calculated for each facies model. All eight models were considered equally probable and used for dynamic fluid-flow models to capture likely geological and property variations to evaluate predicted storage performance.

No technical details are provided of the characterisation or attribution described. One realisation of the reservoir model is shown, approximately 30 in thickness and up to 600 m in lateral extent, of the predicted gas saturation, temperature, tracer and CO_2 distribution. The predictions are described as adequate to forecast site behaviour and to proceed with CO_2 storage.

Supporting information for Jenkins et al. (2012) include further technical information on the 3D seismic surveys acquired, geological modelling of end-member facies variations in Petrel software, and differing depth conversion values for the seismic interpretation. Eclipse flow modelling and history matching using production data from Naylor-1 eliminated the extreme model cases and a good match with intermediate, plausible cases. The geological model was revised to accommodate well logs and Vertical Seismic Profiling using the CRC-1 well and attribution informed by core description. Six facies were distinguished from well log data.

Stress was estimated using extended leak-off text data and compared with the occurrence of borehole breakouts to derive minimum and maximum horizontal stress values.

The model cell horizontal dimensions are 20 m by 20 m with variable vertical cell dimensions of 0.5 m to 2.0 m. The irregular cell geometry accommodated the stratigraphic bedding, i.e. onlapping and erosional surfaces, with local grid refinements around the injection well. Differing ratios of horizontal to vertical permeability were used as appropriate for each depositional facies.

Uncertainty in the lateral extent of shale barriers between wells was investigated by small and long correlation lengths, each with five realisations that honour well data. The probability of variance is dependent of distance from the injection well using Kriging for a normal distribution. The petrophysical properties, porosity and permeability, are assigned by depositional facies. Two realisations with small and long correlation lengths are illustrated that were used for further detailed investigation.

Dynamic modelling of multiphase flow was simulated using TOUGH2 software which compared favourably with earlier Eclipse results. Simulation using a grid of small size was achievable for a model of modest extent and thickness. The character of model boundaries was assigned as flow or no-flow. The dynamic models were adjusted to match the pressure history from the production and post-production phases of Naylor-1 well. The models were mainly sensitive to aquifer parameters, particularly bulk reservoir permeability which was considered separately for each realisation. For each geological model two scenarios of reservoir relative permeability were calculated based on core measurements. The absolute permeability in each realisation was adjusted to provide a good match with the downhole pressure record at the injection well.

Predictive modelling of the seismic response by a synthetic seismic feasibility study was used to evaluate the sensitivity of time-lapse seismic surveys to detect leakage of CO_2. This was used to determine a minimum detectable leakage of 5000 tonnes of injected CO_2.

6 Storage Appraisals in Saline Aquifers

6.1 NATIONAL GRID BUNTER SANDSTONE APPRAISAL

The White Rose Carbon Capture and Storage project is currently proposing to store CO_2 captured from power plants in the Humber area in the Bunter Sandstone. The project is undertaking a Front End Engineering and Design (FEED) study as part of the UK Government's CCS Commercialisation Programme. The proposed injection site is situated in the Southern North Sea, in a structure referred to as 5/42; first identified as a prospect for CO_2 storage by Brook et al. (2003). Although a significant body of site characterisation work has been undertaken during the detailed appraisal of the 5/42 site, little information is publically available to date due to the ongoing nature of the FEED process. However, a recent conference paper (Furnival et al., 2014) provides a brief overview and describes some of the site characterisation activities undertaken. These activities are summarised in this review. Both legacy and newly acquired data have been evaluated as part of the characterisation study. The characterisation study is unique in that it involved the drilling of the UK's first CO_2 storage appraisal well by National Grid Carbon in 2013, the related activities of which are summarised by Furnival et al. (2014). The detailed results of the appraisal drilling programme are not yet available in the public domain, but it is expected that these will form a significant proportion of the FEED documentation once this has been matured and released.

6.1.1 Characterisation work undertaken – Furnival et al. 2014.

Information from previous generic studies (Brook et al. 2003; Heinemann et al. 2012; Noy et al. 2012) were used, along with specific site analysis, to identify the 5/42 structure as the preferred storage site. Two seismic reflection surveys were available over at least part of the structure and these were used to interpret the structural geometry. It is noted that a new speculative 3D seismic survey was acquired in the interim period, and that this would be obtained to assist with the structural interpretation of the site and surrounding area. From the two previous hydrocarbon exploration wells penetrating the structure, formation evaluation logs, Repeat Formation Tester (RFT) and available core were examined. Data from other wells surrounding the structure but targeting different stratigraphic horizons were also examined.

Using the legacy hydrocarbon well data, uncertainties regarding the suitability of the structure for storage were identified, namely the strength and permeability of the cap rock and the lack of suitable reservoir permeability data. The new appraisal well was drilled to reduce some of the uncertainties. Objectives of the appraisal were as follows:

- Retrieve core, especially from the caprock.
- Collect brine samples, ideally from different depths.
- Conduct production and injection tests.
- Conventional geophysical logging.
- Specialised logging such as dipole sonic and image logging for structural and geomechanical analysis, as well as Nuclear Magnetic Resonance (NMR) and electron capture spectroscopy to allow for permeability predictions and identification of mineral assemblages.
- Conduct pressure measurements.
- Mini-frac and Vertical Interference Testing (VIT).
- Flow and injection tests to assess dynamic performance.

Core acquisition was required in order to conduct the conventional and special core analyses, geomechanical testing, formation damage testing, sedimentological analysis and petrophysical analyses. The appraisal well was located down-dip of the crest, near to the structural spill-point (old exploration wells were situated near the crest), aimed at reducing structural uncertainty and to target a seismic phase reversal observed on seismic reflection data.

Formation Integrity Tests (FIT) were performed to maximum permissible pressures at two levels within the caprock to evaluate storage integrity, and two Modular Formation Dynamics Tester (MDT) runs were made and compared to regional permeability estimates. Three brine samples were collected during one of the runs, one from each of the three identified reservoir sub-divisions.

Mini-frac tests were performed to test the strength of the Röt Clay (caprock) and Lower Bunter Sandstone followed by three VITs (one in each of the three reservoir subdivisions), enabling the Kv/Kh ratio of the reservoir to be accurately determined.

Drill Stem Testing (DST) was performed over a 24 hour period to provide an average reservoir permeability and to identify that no barriers or flow baffles are present to a distance of 1.3 km radius of the well. A three-rate injection test was performed using filtered and treated sea water rather than CO_2, each of three hours duration with a 12-hour shut-in.

The main objective of the well programme was to gather additional data to refine existing models (both static geological and dynamic reservoir simulation models), and to help develop a new geomechanical model for the site. A 3D geological model and dynamic reservoir simulation model have been developed, however it is noted that the special core analysis, long duration formation damage and sanding assessments, sedimentological and petrographic work was not yet completed and is not presented by Furnival et al. (2014). It is also noted that synthetic 4D seismic responses based on dynamic model simulations have also been generated to characterise the potential for monitoring the site, though these results are not yet publically available.

6.2 BUNTER SANDSTONE EXEMPLAR MODEL FOR UKSAP

As part of the UK Storage Appraisal Project (UKSAP), a 3D Exemplar model representing a potential storage prospect in the Bunter Sandstone was constructed for the purposes of evaluating issues affecting CO_2 storage in structural traps (Bentham et al. 2011). The principal aim of the study was to use dynamic modelling to define a suitable storage efficiency factor for assessing storage capacity in structural closures. In addition to the description of the activities given by Bentham et al. (2011), a paper has been published summarising the characterisation process and main results specific to the structural closures in Bunter Sandstone (Williams et al., 2013a). A conference paper summarising some of the key generic findings that may be considered relevant for assessing CO_2 storage capacity in closed four-way dip structures is also available (Williams et al. 2013b).

It is stressed that although the characterisation work undertaken in the Exemplar modelling study is based on real site data, the overall aim of the study was to provide generic storage efficiency information for estimating the storage capacity of structural closed aquifer storage sites on the UKCS. The level of site characterisation therefore is not as comprehensive as that which might be expected for a real storage site, and the injection strategies employed for the numerical flow simulation are not necessarily realistic for any specific site.

6.2.1 Model construction

Large saline aquifer water-bearing closures of the Bunter Sandstone were identified for detailed Exemplar modelling during the UKSAP project, using available project data. The aim of the modelling study was to investigate an individual closure via detailed CO_2 injection modelling in order to determine a range of storage efficiency factors that could be used in storage capacity estimation for structurally confined storage complexes. The closure identified for the study (Closure 36) was chosen based on the following criteria and was considered to be typical of the Bunter closures in terms of its size:

- Considered to be unfaulted or with low containment risk due to faulting

- Good seismic data coverage available for the project (PGS MegaSurvey)
- Complete caprock/primary seal over the target structure
- Presence of nearby structural closures
- Crest of structure deeper than 800 m

The selected model area also encompassed closures 37, 39 and part of closure 38. A static geological model was constructed in PETREL using depth grids of various horizons provided by PGS, wireline logs from IHS, and well formation top data from the IHS EDIN database augmented with additional data from BGS databases and interpretations.

Data available included:

- 100 m increment depth grid of top Bunter Sandstone
- 100 m increment depth grid of top Triassic (Top Haisborough Group caprock)
- 100 m increment depth grid of Base Cretaceous Unconformity
- Comprehensive suite of geophysical well logs for 13 wells in model area
- Small 3D seismic survey data (TWTT) over Closure 36.

A brief literature review is presented by Bentham et al. (2011), describing the Bunter Sandstone Formation reservoir and it's immediate over and underburden. A map showing the thickness of the Haisborough Group caprock is also presented. The geocellular model includes the stratigraphy from the top of the Chalk Group, to the base of the Bunter Shale Formation which lies beneath the Bunter Sandstone. Units above the Röt Halite Member (primary caprock) are incorporated for context only and have not been considered in further detail or in the numerical simulation as the Röt Halite is expected to form an effective hydrological seal. Well data were used to model the horizons for which PGS depth data were not available.

The Bunter Sandstone was sub-divided into five reservoir zones on the basis of geophysical log correlations and the interpreted depositional environments as derived from literature. The Haisborough Group caprock is divided into three zones on the basis of log correlation in wells; the first representing the Solling Claystone directly overlying the Bunter Sandstone, the second the Röt Halite Formation (thought to be an effective barrier to flow), and the remainder of the Haisborough Group. No layers above the Solling Claystone were considered in the numerical flow simulation.

The layering schema within the reservoir zones aimed to restrict the overall number of cells to within a specified limit (~400,000 cells), and to ensure that the broad geology of the zones could be adequately reflected in the model. Care was taken to ensure that intra-reservoir shales that are more abundant at certain levels within the reservoir could be accounted for in the models. Each reservoir zone therefore has a unique layering schema designed to capture the reservoir heterogeneities, and to enable accurate simulation of CO_2 migration beneath extensive impermeable horizons. 57 layers are present within the reservoir interval with an average thickness of three metres. The final static model has a total of nine zones, 61 layers and a total of 429,660 cells with physical properties (i.e. those cells that are deemed to possess some effective permeability).

6.2.1.1 Geological model parameterisation

Net to gross and porosity logs were prepared for input for the facies and porosity modelling. Of the 21 wells in the model area, 10 possessed wireline logs over the Bunter Sandstone suitable for petrophysical analysis. Raw digital logs were obtained for these 10 wells, including gamma ray (GR), sonic transit time (DT), bulk density (RHOB) and neutron (NPHI) logs. Intervals of poor log quality were identified using calliper and density correction curves and discarded, and a temperature gradient and surface temperature were assumed for the petrophysical analysis.

Net to gross of the reservoir was calculated by generating volume of shale logs, using GR or RHOB-NPHI curves where available. Total porosity curves were generated primarily using RHOB-NPHI curves, or in their absence, sonic logs.

The equations used to generate the porosity curves included:

- Sonic (DT) – Wyllie equation
- Density (RHOB) – Standard density porosity equation
- Density-neutron (RHOB and NPHI) – Standard density-neutron cross plot method

Lithological logs were produced as discrete rock type indicators on the basis of log cut-offs from the porosity and volume of shale curves. Three litho-types were identified, including Sandstone, Tightly Cemented Sandstone (porosity very heavily occluded), and Shale. These discrete logs were upscaled to the geocellular model grid.

Each reservoir zone was populated with a discrete litho-type/facies identifier using various stochastic techniques as appropriate for the interpreted environments conditioned to the upscaled litho-type logs, to account for the interpreted depositional and post-depositional diagenetic processes. A degree of deterministic model attribution was also employed for some elements of the model deemed to be key to the distribution of flow in the reservoir. Interpretation was based upon a literature review around producing Bunter Sandstone gas fields, augmented by detailed log correlation, and some limited amount of core inspection.

Porosity was upscaled from the calculated total porosity log curves and distributed stochastically throughout the Sandstone litho-type, accounting for primary porosity trends with an elongate variogram, and a short vertical range to account for the expected high degree of vertical variation. Porosity of the shale litho-type and the shaley underburden and caprock was attributed using a constant value taken from measurements from an analogous formation in the Netherlands (Spain and Conrad, 1997).

The Röt Halite was assumed to possess no porosity, and cells attributed as cemented sandstone were assigned very low porosity values. The assumption of very low porosity was justified by examination of core from a semi-continuous cemented sandstone layer in nearby offset wells, but the physical properties of the cemented sandstone were considered likely to be highly variable in reality and this was considered an important matter of uncertainty requiring investigation during the dynamic simulation.

Permeability was estimated based on core-plug porosity-permeability data from across the Bunter Sandstone in the UK sector, and was distributed stochastically with a bivariate distribution based on the simulated porosity to ensure that permeability and porosity distributions were related. Shale permeabilities were assigned a constant value based on Spain and Conrad (1997) as per the porosity, and the Röt Halite and cemented sandstone litho-type cells were again assigned zero and very low permeabilities respectively in the base-case model.

It is noted here that the distribution of reservoir properties in the model is based on only a single stochastic realisation, and therefore is highly uncertain. However the aim of the study required only a representative reservoir property distribution based on some real data and interpretation, and so a more detailed and comprehensive characterisation of reservoir property distribution was not strictly required to meet the project objectives. Multiple sensitivity simulations were performed to account for some of the more significant parameter uncertainties.

Faults were not included in the static model (due to time constraints and the lack of faulting observed over the target structure), but the presence of faulting was evaluated in the area of the model using 3D seismic data, and was found to be insignificant in terms of the study aims. Reviews of faulting and its effect on the storage capacity of the Bunter Sandstone are given elsewhere by Bentham (2013) and Williams et al. (2014).

Brine salinity was assumed from analogue sites in the literature, while pressure, geothermal gradient and compressibility were also assumed from literature and/or values available in CarbonStore (now the CO2Stored database). A fracture pressure gradient was assumed in the absence of leak-off pressure data. Relative permeability curves were used from Viking II and Calmar for sandstone and shale respectively (Bennion and Bachu, 2006; 2008) in the absence of site-specific data.

6.2.2 Assessing storage efficiency

The assigned base-case boundary conditions were based on the pore volume expected to be connected to the structure. The aquifer volume perceived to be in communication is similar to the area considered in studies by Smith et al. (2011) and Noy et al. (2012). A review of static capacity estimation and their application to the study area is presented by Bentham et al. (2012).

Flow simulation was setup using vertical wells, with perforations in each of the sandstone layers, with ten wells in a roughly circular configuration at a given depth contour around the structure. The assumption was that 10 wells would be required to inject the volumes of CO_2 that might be captured from a 2 GW coal-fired power plant over the lifetime of the installation. Allowable Bottom-Hole Pressure (BHP) was specified for the injectors, with an additional monitoring well in the crest of the structure further limiting well injection. Initial injection rate per well was 2 Mt/year, though this was reduced during the injection period to maintain allowable pressures. Injection was also migration limited, so that injection would cease if 0.01% of the injected CO_2 left the defined structural spill point (the spill-point locations varied when injection into multiple closures was considered, as CO_2 was permitted to flow between structures). The 0.01% criterion was defined arbitrarily, based on the assumption that once a small amount of CO_2 is detected at a defined boundary the concentration could rise rapidly thereafter. Storage capacity and pore volume utilisation was calculated for each simulation based on the volume of injected CO_2 and pore volume.

In addition to the base case simulation, sensitivity to injection well position was investigated by varying the depths at which the injectors were situated (i.e. closer to crest or to spill-point). Injection into multiple structures was also investigated, with simulation runs injecting into a single structure only, and into two and then three structures both simultaneously and sequentially.

More than 100 simulations were conducted accounting for various sensitivities, including those involving varying boundary conditions and heterogeneity, in addition to those described above. Results are presented in detail by Bentham et al. (2011), though Williams et al. (2013) provide a synthesis and table of the most relevant results.

6.2.3 Key findings

The dynamic simulations showed a number of important findings relevant to the characterisation of structural closures such as those of the Bunter Sandstone:

- Pressure control results in a reduction of the injection rate leading to a reduced storage capacity.
- If the pressure limitations are not exceeded and the injection rate is maintained, the injected CO_2 is free to migrate further, and lateral migration is encouraged.
- If extensive permeability barriers are present within the reservoir, lateral CO_2 migration towards spill-points and perhaps storage complex boundaries is further encouraged.
- Storage capacity is highly sensitive to assumed fracture pressure gradients.
- In a fully open system, the pressure limitation is less significant, allowing a higher rate of injection and increased potential for CO_2 to migrate laterally from the closure.
- Pressure at the crest of the dome is important, as the fracture pressure is lower there than at the depth of injection well completions (typically lower reservoir and/or structural flanks).

- Storage capacity may be increased by controlling the ratio of viscous/gravity forces acting on the CO_2.
- Base case model results produced a pore volume utilisation of 19% for Closure 36.
- Sensitivity studies showed a significant variation with sweep efficiency ranging from 0.13 to 0.65, with a most likely value of 0.33.

6.3 FORTIES SANDSTONE EXEMPLAR MODEL FOR UKSAP

During the UK Storage Appraisal Project (UKSAP) it was found that a large proportion of UK storage capacity existed in the form of large open and dipping saline aquifer formations. To investigate issues affecting the storage capacity of such structures, a suite of generic Representative Structure (RS) simulation models were performed (Masters, 2011), using a large tilted slab with some transverse curvature to enhance channelling. In part to validate the findings of the RS models, a specific Exemplar model was developed for dynamic modelling of the Forties Sandstone to demonstrate the feasibility of storage in large open aquifers. The principal aims of the Exemplar modelling exercise were to ascertain the impacts on storage of features such as the top-surface topography and intra-reservoir heterogeneity that were not necessarily include in the RS models. In addition, a paper has been published describing the main results in detail (Goater et al., 2013), and a subsequent publication addresses the implications of post-injection regulatory guidance on storage capacity (Goater and Chadwick, 2013).

It is stressed that although the characterisation work undertaken in the Exemplar modelling study is based on real site data, the overall aim of the study was to provide generic storage efficiency information for estimating the storage capacity of large open aquifers on the UKCS. The level of site characterisation therefore is not as comprehensive as that which might be expected for a real storage site, and the injection strategies employed for the numerical flow simulation are not necessarily realistic for any specific site.

Olden (2011) presents a description of coupled geomechanical reservoir simulation models undertaken as part of UKSAP, focussed on modelling large open aquifers. As well as representative structure modelling, the study focussed on the Exemplar model based on the Forties Sandstone. The main objectives of the geomechanical study were to investigate whether or not there was scope for changing the maximum allowable injection pressures from those based purely on fracture pressure gradients, and to investigate the sensitivity of CO_2 storage capacity to the magnitude of the fracture pressure gradients assumed. This review focuses only on the geomechanical work related to the Forties Sandstone Exemplar model.

6.3.1 Geological model construction

Goater et al. (2011) describes the construction of a geological model representing the Forties Sandstone Member of the Sele Formation, and subsequent numerical simulation modelling. The characterisation of the geological setting is not described in great detail and is unavailable in the public domain. The geological model represents the reservoir only, and is divided into channelised sandstone and background shale facies. The PETREL software platform was used for the construction of the model, which consists of ~1.7 million discrete cells.

The majority of the reservoir simulation work was undertaken using an upscaled model comprising less than 450,000 cells. A grid sensitivity study showed that the results did not change significantly due to the upscaling process and that these changes were deemed to be acceptable. Simulation work was undertaken using ECLIPSE 100 to simulate residual, dissolution and structural trapping.

The key issues addressed relevant to the site characterisation activity were:

- How the top-surface structure affects storage pore volume utilisation in a dipping open aquifer, and to

- Consider the effect of reservoir heterogeneity on pore volume utilisation in a dipping open aquifer

An area of interest, 21.4 x 36 km, was chosen for modelling. The location of the area of interest avoided hydrocarbon fields, significant structural closures (as the aim was to simulate storage in open dipping aquifers), known areas of faulting and areas where communication with overlying sandstone formations was likely. The structural framework model was constructed using a top Forties Sandstone depth surface provided by PGS from interpretation of their CNS MegaSurvey seismic reflection data. The base of the model is defined by the top Andrew Sandstone Member, which constitutes the base of the Forties Sandstone, as interpreted from well tops.

As a requirement for the reservoir simulation, the model was divided vertically into three zones within the grid: a two meter roof zone at the top of the Forties Sandstone comprises four proportional layers, a five meter sub-roof zone consists of five layers and the lower zone comprising 81 layers of the remaining Forties Sandstone. Vertical resolution ranged from 0.5 m in the roof zone to 3 m at the base of the model, enabling intra-reservoir heterogeneity to be meaningfully resolved, and to allow for improved imaging of the injected CO_2 in the uppermost part of the reservoir where it would be expected to form thin plumes.

The porosity and permeability distribution were conditioned using a simple facies model describing cells as either channel sandstone or background facies. The facies model was derived from interpretation of 10 wells located within the model area, and was distributed using a stochastic object-based algorithm with a vertical proportion curve. Porosity and permeability was then modelled within the facies framework, with ranges of values taken from published data and existing local core analyses data. The background shale facies exhibited near-zero porosity and permeability in the model.

6.3.2 Reservoir simulations

A dynamic simulation model was then constructed using ECLIPSE 100, using the porosity and permeability distribution from the static model. Published drainage and imbibition relative permeability and capillary pressure data from the Viking II dataset were used (Bennion and Bachu, 2008), and relative permeability hysteresis was modelled using the Carlson method (Carlson, 1981). The initial model grid comprising of 1.7334 million cells was upscaled to the simulation grid that comprised 450,000 cells, using arithmetic averaging by a factor of 2 in the horizontal directions for porosity and permeability. Initial reservoir conditions were either taken from literature (salinity, temperature), calculated using TOUGH2 PVT Data (fluid densities), CarbonStore (now CO2Stored – rock compressibility, surrounding aquifer volume, fracture pressure gradient), or were calculated or assumed for the study (pressure).

The base-case injection simulation injected CO_2 for a period of 50 years with a further 1000 year simulation beyond the injection period when capacity was calculated. Injection and capacity were constrained by the following:

- 99% of injected CO_2 must remain within the storage boundary after 1000 years
- Migration velocity at 1000 years post-injection must be less than 10 m/year and declining
- Pressure must remain below 90% of the estimated fracture
- A minimum well injection rate of 0.1 Mt/year was applied

The amount of escaped CO_2 (that which reached the outer-most model cells), the volume of dissolved CO_2 and amount of structurally trapped CO_2 was calculated for various simulation runs. Sensitivity studies included studying the impact of varying the top surface topography and reservoir heterogeneity. Two dip sensitivity models were run, varying the mean dip of the model from 0.27° as in the base case to 1° and 3°. A model without heterogeneity, and finally without heterogeneity and with a smoothed top reservoir surface were also simulated. Average model permeability was also modified to investigate the effect on injectivity and therefore on final injected storage capacity. Multiple well placement (11 injectors) was determined by manually distributing wells in such locations as to avoid injection into significant shale horizons in the base case model, and to ensure an even geographic spread.

6.3.2.1 GEOMECHANICAL MODELLING

A sub-model (10 x 10 km) was developed over the central part of the Exemplar model for geomechanical modelling, with grid spacing reconfigured and a reduction in the number of reservoir models (Olden, 2011). Tartan gridding was employed with a central resolution of 100 x 100 m increasing to 700 m grid resolution at the model edges. 30 layers were incorporated in the model (a reduction from 90 in the original Exemplar model). Reservoir flow simulation used ECLIPSE 100 with the aquifer brine modelled as black oil.

Two different upscaling scenarios were employed to upscale porosity and permeability as properties within the grid. Firstly, facies were upscaled from two wells present in the sub-model area which successfully preserved the relative facies proportions from the Exemplar model. The other scenario upscaled the properties from the original Exemplar model, and failed to accurately preserve the correct shale/sand proportions due to differences in the model meshing. The parameters used in the ECLIPSE 100 simulation model were updated to account for the best available data at the time, as developed as the UKSAP project progressed.

The reservoir simulation model was imported to the VISAGE software package for development of the geomechanical models. The input data was conditioned for geomechanical modelling by embedding the reservoir model with an over and underburden, and rock mechanical properties were assigned to various parts of the model. The embedding process added approximately 600 m thickness of overburden and 600 m of underburden to the model, each consisting of 10 layers geometrically increasing in thickness away from the reservoir.

The model was assumed to be composed of material with uniform geomechanical properties with the reservoir only being composed of material with inelastic properties. A basic Mohr-Coulomb failure criterion with very conservative failure parameters was assumed. A coupled reservoir simulation model was run without porosity and permeability updating, such that the pressure changes from the ECLIPSE simulation modified the stress/strain in the VISAGE model by changes in effective stress only, without feedback to the ECLIPSE simulation.

Various configurations of the model were run with changes to the well orientation, horizontal permeability, injection rate, horizontal to vertical in situ stress ratio and internal friction angle modifications. The results of the simulations were reviewed to identify if failure had occurred in any of the geomechanical modelling scenarios.

A small additional study was undertaken to review the fracture pressure gradients in the Forties area using leak-off test data, and the sensitivity of the storage capacity (amount of CO_2 injected) to the fracture pressure gradient was evaluated.

6.3.3 Key findings

Key conclusions from the RS modelling exercise (Masters, 2011) include:

- Typically CO_2 formed a thin tongue beneath the overlying caprock and migrated up-dip several tens of kilometres over thousands of years.
- CO_2 that remained near the injection point gradually became residually trapped, though this took several thousand years.
- In the base case simulation (longitudinal dip of 0.4°, permeability 300 mD, maximum of 4 Mt/year injection rate, constrained by bottom-hole pressure), after 50 years of injection the injected CO_2 was contained within a 5.5 km distance from the injector.
- CO_2 dispersed with time, migrating 65 km up-dip after 10,000 years.

- After 100 years, 99% of the injected CO_2 had only migrated 13 km with a velocity of 7.5 m/year.
- After 1000 years, the fraction of residually trapped CO_2 was 34%, rising to 60% after 10,000 years.
- After 1000 years, about 10% of the CO_2 had dissolved in brine, increasing to 26% after 10,000 years.
- Representative permeability and mean dip were found to be the most important factors to influence up-dip migration.
- Cumulative injection needed to be restricted to prevent CO_2 migrating after 1000 years, as migration velocity might exceed regulatory limits.
- An analytical formula was derived and shown to provide good estimates of migration velocities.
- Typical storage capacities were equivalent to significantly less than 2% of pore volume.

Goater et al. (2013) also noted from the more detailed Exemplar modelling that permeability and aquifer dip are key parameters affecting CO_2 storage efficiency in open aquifers, since they control the rate that CO_2 flows and the amount of pressure build-up. They found that heterogeneity in a channelised sandstone system reduces the storage efficiency due to localised pressure build-up, yet also acts to improve storage security by improving lateral sweep. Top-surface topography introduces localised structural closures, regions of both higher and lower dip (compared to the regional average), and preferential flow channels.

For coupled geomechanical modelling, including over and underburden, it was found that geomechanical failure, when it occurred, was always observed at BHPs greater than that which would be predicted by the fracture pressure gradient (Olden, 2011). This discrepancy might be a result of the model not adequately representing the wellbore and its inability to simulate hydraulic fracturing due to the unsuitability of the mesh. The study concluded however, that use of the fracture pressure gradient was considered to be the most conservative criterion for injectivity avoiding geomechanical failure, and a supplementary study showed that pressure constrained injection estimates were highly sensitive to the magnitude of the fracture pressure gradient assumed (Olden, 2011).

6.4 CAPTAIN SANDSTONE

Scottish Carbon Capture & Storage (2011), hereafter referred to as SCCS (2011), provides a review of work carried-out to accelerate the delivery of actions and investments in CO_2 capture and storage, by describing amongst other assets Scotland's storage resource and opportunities. Scotland's largest storage prospects (saline aquifers) are identified, are benchmarked against relevant storage operations worldwide, and a single potential storage reservoir identified and further characterised by geological modelling and simulation of CO_2 injection. From the saline aquifers identified, the Captain Sandstone was selected for detailed study due to its relative proximity to onshore CO_2 sources, and because regional 2D seismic data of good quality was available at a cost within the study resources.

In this review the characterisation work undertaken to assess the suitability of the Captain Sandstone is summarised. Jin et al. (2012) present in detail the numerical simulation studies undertaken and outlined by SCCS (2011). Jin et al. (2012) focus on the numerical model setup and presentation of the subsequent simulation study results. It is noted that the study reviewed here is aimed at estimating the volume of CO_2 that may be stored in the Captain Sandstone, and is a regional study not intended to replicate the level of storage site characterisation that may be expected for a specific site.

6.4.1 Geological model construction

A 3D geological model was constructed over the region comprising 43 fault and six rock layer boundaries, as interpreted from regional 2D seismic surveys following depth conversion of the Two-Way Travel-Time TWTT surfaces. The depth range covered by the model includes all strata from the Base Cretaceous (lowermost surface) to mean sea level, and so encompasses the immediate underburden, the caprock and entire overburden succession. The region studied encompasses the main extent of the Captain Sandstone from its outcrop at seabed in the western part of the model, across the Captain Oil Field, and to the southeast along the Kopervik or Captain Fairway as far as the Cromarty and Atlantic Fields, terminating shortly thereafter in the area near to the Grampian Arch. The model therefore does not extend as far eastwards as the Goldeneye Field.

The top and base Captain Sandstone surfaces were not interpreted from the seismic data due to imaging constraints, but rather were interpolated from well data by reference to the overlying base Chalk surface. The Captain Sandstone reservoir was divided into the Upper and lower Captain Sandstones where separated by the Mid-Captain Shale, with the extent of the Mid-Captain Shale having been interpreted from analysis of well data. The vertical extent of faults were determined from seismic interpretation.

Well data were used to constrain the western boundaries of the various stratigraphic units, aided by seismic interpretation where imaging of the shallower subsurface allowed. All data used to populate the model was taken from oil and gas wells from across the model area. Reservoir net to gross maps were derived for the Upper and Lower Captain Sandstones (above and below the Mid-Captain Shale), as well as for the entire undivided Captain Sandstone. These were estimated from geophysical logs combined with published information from the Captain Oil Field.

The following additional properties were also derived from legacy oil and gas wells:

- Porosity
- Vertical and horizontal permeability
- Pressure
- Temperature

Salinity and compressibility data were rarely available and so were estimated.

6.4.2 Uncertainty analysis in static model

Two versions of the geological model were produced to account for uncertainty with regards to the extent of the Mid-Captain Shale, deemed to be an important potential barrier to fluid flow. In the first realisation the Mid-Captain Shale was assumed to be continuous across the total extent of the Captain Sandstone, while in the second the shale was restricted to an area as defined by its presence in oil and gas wells. The storage capacity of the Captain Sandstone was then investigated by numerical simulation of CO_2 injection. Simulations were performed to calculate the amount of injected CO_2, the best position for the injection wells, the projected migration of CO_2 in the subsurface and the resulting pressure perturbation resulting from injection. Another consideration during the study was to predict how to avoid the possibility of the injected CO_2 from reaching potential leakage points such as faults that extend upwards towards the seabed, the western fringe of the Captain Sandstone where it crops at the seabed and areas where the overlying mudstone seal rocks are thin or absent. Migration towards existing oil and gas fields was also used as a limiting factor, and extraction of water was also considered to help remain within accepted pressure limitations.

6.4.3 Storage capacity estimation

The 3D geological surfaces were imported to the PETREL software platform in order to generate the numerical model required to carry-out the numerical simulation using ECLIPSE. Numerous simulation runs were performed to investigate the effect of factors such as the injection rate, well placement, geological uncertainty and flow conditions across sandstone boundaries.

The first set of simulations evaluated the migration of CO_2 and pressure response over the entire Captain Sandstone following injection of 15 million tonnes of CO_2 per annum at 12 selected well locations. The locations of the wells were selected to ensure that the injected CO_2 would remain at depths exceeding 800 m, oil and gas fields would be avoided and significant localised pressure increase would not occur. The specific pressure response in individual wells was calculated to ensure that the pressure changes remained within accepted engineering limits. The second suite of simulations restricted the injection rate to 2.5 million tonnes of CO_2 per annum for each well.

The first simulation was used to ensure that injection of 15 Mt of CO_2 per annum for a period of 30 years at each individual injection site could be managed to avoid the migration of CO_2 to the western boundary where the Captain Sandstone is open to the seabed. In the second suite of simulations, pressure changes in the injection wells were monitored, and a low side case defined to restrict the injection rate in individual wells as shown in the table below. The assumed values were then relaxed in subsequent simulations to determine the sensitivity of the overall capacity to the different parameters. The target injection rate for each well was 2.5 Mt per annum for up to 100 years, with a total potential storage capacity of 30,000 Mt, however the injection rate progressively decreased due to the pressure constraints.

Table 7: Parameter ranges used in sensitivity analyses in assessing storage in the Captain Sandstone, SCCS (2011).

Sensitivity parameter	Low side case	High side case (relaxed)
Faults within sandstone open/closed	Sealing	Not sealing
Pore compressibility	7 x 10^{-5} 1/bar	14 x 10^{-5} 1/bar
Extent of Mid-Captain Shale	Extensive and continuous	Limited extent
Maximum allowable pressure	1.3 x initial pressure	1.5 x initial pressure
Sandstone boundary conditions	All boundaries closed to flow	Western, basal and upper sandstone boundaries open to flow
Permeability of overlying rock	Impermeable	Permeable

Fine-scale simulation of areas where CO_2 migration is predicted to occur was also carried-out, allowing for a more realistic prediction of migration extents.

6.4.4 Workflow for storage capacity estimation

The detailed workflow undertaken to calculate the storage capacity of the Captain Sandstone is given below, as given by Jin et al. (2012):

- Generate structural geological model in petrel using fault and horizon surfaces
- Identify and modify fault polygons in complex areas around intersecting faults, and quality check grid to minimise geometric errors in the numerical simulation
- Collate rock and fluid property data from published information, well logs and existing laboratory test data. Porosity and permeability correlations defined, net to gross maps generated and stress and pore compressibility determined. As few parameters have been

directly measured for the formations of interest, many of these parameters were derived from analogous sites taken from the literature

- Investigate distribution of flow properties in different formations, along with available relative permeability and capillary pressure data
- Initiate first suite of simulations to consider the whole system response, communication between fault-defined compartments, migration pathways and optimal positioning of injection wells. These simulations assumed between 1 and 4 wells (or clusters of wells) to inject up to 15 Mt/year for a period of up to 30 years
- Initiate second suite of simulations to consider pressure increases in specific wells and the impact this has on maximum storage capacity by limiting the injection rate to 2.5 Mt/year per well through 12 wells over a period of 100 years
- Investigate the impact of various assumptions regarding pressure dissipation, making a conservative calculation of storage capacity assuming worst-case scenarios, and systematically relaxing the various restrictions to ascertain their impact
- Investigate the effect of grid resolution on the simulation results using local grid refinement methods.

6.4.5 Key findings

The study concluded that further assessment and appraisal of the Captain Sandstone for potential CO_2 storage purposes is justified, and suggested the following to further examine the assumptions made during the study:

- Investigate nature of the sandstone boundaries
- Investigate nature of the faults in terms of being open or closed to cross-fault fluid flow
- Investigate intra-reservoir heterogeneities, specifically the presence or absence of low or high permeability layers and their effect on injection rate and CO_2 migration
- Investigate caprock integrity sufficiently to ensure regulators of storage site security – study to include mapping and characterisation of caprocks, geomechanical effects, fault seal studies and examination of any evidence for natural fluid migration in the subsurface

Seabed and shallow surface conditions were investigated and described on a regional basis, and features relevant to CO_2 storage operations noted. These include:

- Natural features of the seabed that may affect the citing of injection wells and/or other infrastructure
- Active movement of seabed sediments
- Baseline survey to identify seabed features indicative of natural fluid leakage
- Features relevant to subsurface imaging and monitoring
- Marine ecological features and subsequent citing of designated conservation areas, fishing and potential environmental impacts
- Existing infrastructure such as pipelines and cables

The key findings summarised from Jin et al. (2012) are detailed below:

- Storage capacity is affected by various system parameters including total pore volume
- Storage capacity of a conservative case closed-boundary Captain Sandstone aquifer is 358 Mt
- Depending on boundary conditions, capacity could be as high as 2495 Mt
- Use of 15–20 water extraction wells producing at a rate of 4000 m^3/day could increase the capacity of the closed system to 1668 Mt

- Capacity increase by ~10% if overburden and underburden are considered to be permeable (even if permeability is very low)
- Large volumes of CO_2 may be injected which avoid hydrocarbon fields and potentially leaking faults which will not reach such features within 300 years of injection (assuming no net production of hydrocarbons during simulation)
- FLUX sub-models can be used to increase precision and to reduce simulation run-times in basin-scale simulation studies
- With less pressure restraint in open systems, migration of CO_2 is faster compared to closed systems. Extended simulation time-scales are required to estimate the eventual extent of the CO_2 plume/s

6.5 SLEIPNER SITE APPRAISAL

CO_2 has been injected into sands of the Miocene–Pliocene Utsira Formation at the Sleipner storage site since 1996, where CO_2 is separated from natural gas produced from the Sleipner Vest field and captured for storage. The industrial CO_2 injection activities were accompanied by the multinational Saline Aquifer CO_2 Storage (SACS) research project which aimed to monitor and to predict the long-term fate of the CO_2 in the subsurface (Chadwick et al., 2002). A comprehensive monitoring programme involving time-lapse seismic reflection data has been undertaken since injection began, allowing for accurate characterisation of the evolving CO_2 plume and reservoir dynamics throughout the injection period (Arts et al., 2004; Bickle et al., 2007; Chadwick et al., 2009; Chadwick et al., 2012). Although the monitoring results have been used to validate and to update initial geological and numerical flow models (Cavanagh and Haszeldine 2014a; Cavanagh and Nazarian 2014b), this review focusses on the pre-injection characterisation activities, with a view to highlighting the state of understanding prior to commencement of this, the World's first industrial scale CO_2 storage operation for climate change mitigation purposes.

Although a large volume of characterisation work was undertaken by the site operator, Statoil, for which reports are not available in the public domain, the geoloigcal characterisation activities are synthesised by Zweigel et al. (2004), and the activities undertaken during the SACS project are described by Chadwick et al. (2002). It is important to reflect that the understanding of reservoir geology was largely gleaned from offset well data, with no additional appraisal wells drilled. A baseline 3D seismic survey over the site was acquired in 1994. A geological model was developed based on these data, and used to simulate the injection of CO_2.

6.5.1 Site Appraisal.

It is noted that as the Utsira Formation is not a hydrocarbon-bearing reservoir, it had not been well studied prior to its candidacy as a CO_2 storage reservoir. A detailed study of the Utsira Sand based on 3D seismic, wireline log and rock sample data was used to form the basis for reservoir simulations (Zweigel et al., 2004). A regional description of the Utsira Sand and it's over and underburden are described, before geological characteristics specific to the Sleipner area are discussed.

Wireline log and seismic reflection characteristics of the Utsira Sand are described, with the geometry of the top and base Utsira Sand reflections described in detail based on interpretation of the 3D seismic data. The presence, scale and vertical extent of faults that affect the lowermost and internal parts of the reservoir were described, and analysis of core samples and cuttings were used to describe the petrographic properties of the reservoir.

Intra-reservoir heterogeneity was evaluated by interpretation of wireline logs, with several high gamma-ray (GR) spikes interpreted as thin intra-reservoir shales. Semi-regional correlation of the logs suggested that while the individual shale horizons were correlatable over distances of approximately 1 km, unambiguous correlation was not possible over greater distances. The nature of the reservoir–caprock interface is also evaluated using the combination of wireline and seismic reflection data.

The initial interpretation was that the intra-reservoir shale horizons may constitute hydrological barriers, retarding vertical migration of CO_2 in the reservoir, a feature confirmed once repeat seismic surveys were acquired following injection.

Reservoir porosity was estimated using several methods including modal analysis of thin sections, liquid invasion measurements on core samples and from analysis of density logs. Permeability of the Utsira Sand was measured in four 1.5 inch cores of differing lengths, cut from two different brine-saturated 4 inch x 1 m core samples. Although well test data were unavailable from the immediate area, test data from wells 90 km and 250 km from Sleipner were used for comparison against the measure core-derived permeabilities. Reservoir net to gross was calculated from five wells with suitable logs from the immediate area. A single temperature measurement existed for the shallow subsurface in the Sleipner area, which was used to determine the geothermal gradient.

6.5.2 Reservoir characterisation

The geological characterisation of the Utsira Sand and its caprock was based on the interpretation of 2D and 3D seismic reflection data along with various types of well data from up to a total of 430 wells available to the project (Chadwick et al., 2002). Prior to commencing the project, the Sleipner licence group cut 9 m of core from the Utsira Sand in one of the Sleipner field development wells specifically to provide reservoir rock samples to the project. Core analyses included photography, microscopy, petrography, mineralogical modal analysis, X-ray diffraction (XRD), scanning electron microscopy (SEM) including backscattered SEM, and limited electron probe microanalyses of selected minerals. Micropalaeontological examination was also performed to obtain information on the age and sedimentary environment.

Washed cuttings from 39 wells in the UK sector of the North Sea were inspected with selected samples collected to supplement existing descriptions in well reports and company logs. Modal analyses on sand-rich thin sections from three Statoil-owned wells in the Norwegian Sector were performed. Twenty cuttings samples from UK wells and 23 from Norwegian wells were obtained from the Nordland Shale caprock, and were examined by binocular microscope and subjected to a range of analyses including XRD and SEM. Particle-size, cation exchange capacity and total organic carbon (TOC) assessments were also performed. Due to the lack of available core from the Nordland Shale, core material from the Pleistocene succession from the Ekofisk field was examined as a potential analogue.

Of the total 234 wells that had geophysical log data available (mostly GR and DT), 190 had well velocity survey data available to allow the wells to be tied to seismic data. Formation top data was available to the project, though some of the information was modified during the course of the project due to mis-interpretation at the top and base Utsira Sand levels. Seismic data available included a number of regional 2D surveys covering much of the central and northern North Sea basins, in addition to a 3D survey around the Sleipner area. Formation pressure measurements were available from the Sleipner and Brage fields.

The Utsira Sand reservoir is described in great detail, with the regional and local structures around Sleipner assessed. A variance cube was used to identify potential faults in and above the Utsira Sand. The regional stratigraphy was described with the aid of detailed well log correlations and a seismic stratigraphic framework. The regional and local stratigraphy of the cap-rock and under-burden sands was also studied in detail using well logs and seismic data.

Seismic amplitude anomalies were investigated and described in great detail, both regionally and locally around the Sleipner site, and natural fluid flow within the Utsira Sand assessed using the available pressure data and basin modelling techniques. Storage capacity, trapping potential and migration pathways were investigated with reference to depths surfaces generated during the project, to enable predictions of the fate of the injected CO_2.

Sealing capacity of the cap rock has been assessed using cuttings analysis, and petrographic characteristics compared to those from core taken from the Ekofisk field.

7 Application of the key lessons to five selected sites

The key lessons learned from the reviews are applied to five sites selected by Pale Blue Dot. The five sites confirmed by Pale Blue Dot on 16th august 2015 are:

- Bunter (36, Site 7, 139.016)
- Captain (Site 14, 218.000)
- Forties 5 (Site 2, 372.000
- Hamilton (Site 19, 242.002)
- Viking (Site 5, 141.035)

Application of the key lessons is presented by site. The Viking Field and Hamilton Field are presented together as application of the key lessons is in common to both sites.

7.1 KEY LESSONS – BUNTER SANDSTONE CLOSURE 36

The Bunter Sandstone Formation of the UK Southern North Sea is Triassic in age, comprising continental sand-dominated fluvial sediments. Throughout most of its distribution the Bunter Sandstone is overlain by the Haisborough Group, a thick sequence of predominantly red mudstones which also contain several halite members. The Haisborough Group sediments are believed to form effective traps for CO_2 (Williams et al. 2014). Halokinesis has occurred within the underlying Permian evaporites of the Zechstein Group, forming numerous four-way dip-closed structures that are prospective storage sites for CO_2. One of these closures is currently being evaluated for CO_2 storage by the White Rose project (Furnival et al. 2014), and Closure 36, situated in UK Quadrant 44 has been identified for further site characterisation as part of the current UK Appraisal Project. Previous characterisation work has been undertaken on this structure during the UKSAP project (Bentham et al. 2011; Williams et al. 2013a; 2013b) as described in Section 6.2. Although this work was undertaken using real site data, it is stressed here that the aim of the study was to calculate a range of storage efficiency factors for use by the UKSAP project in calculating the storage capacity of the Bunter closures. The resultant geological model is therefore somewhat simplified and representative, and the dynamic simulation study results necessarily generalised. A full appraisal would require a greater degree of site-specific geological and dynamic characterisation. At this point in time, detailed reports from the White Rose project FEED study are not publically available. As a comprehensive appraisal programme has been undertaken, it is believed that these documents once available would suggest a range of characterisation activities that would be relevant to the appraisal of Bunter Closure 36.

Collation and review of data

- Available data, including 2D and 3D seismic and well data over the site and surrounding aquifer volume to be acquired for appraisal
- Those elements not characterised particularly well by legacy data to be identified (i.e. effective permeability)

Geological models

- At the 5/42 site the geological model was revised following the drilling of a new appraisal well, highlighting the structural uncertainty that exists around the flanks of four-way dip closures where wells are commonly drilled over their crests

Risk analysis and uncertainty reduction

Risk reduction has been achieved by the White Rose project by drilling a new storage appraisal well (Section 6.1).

- A new appraisal well was drilled to evaluate key uncertainties at the 5/42 site
- Key uncertainties at 5/42 which could not be reduced using available legacy data are the geomechanical properties relating to caprock integrity, the reservoir permeability and anisotropy, the reservoir connectivity, and the nature of polarity phase reversal observed from seismic data.

Handling of uncertainty and parameter value ranges

- The UKSAP Exemplar modelling study (Section 6.3) considered a range of uncertainties for which the geological and dynamic models were modified and then simulated. Key uncertainties assessed included the nature of the boundary conditions, heterogeneity, Kv/Kh ratio, depth of well completions relative to spill-point, permeability of the low permeability barriers and effect of additional CO_2 storage in nearby structures

Storage capacity and migration analysis

- Storage capacity was assessed during the UKSAP Exemplar modelling (Section 6.3), and was found to be determined by a combination of pressure and CO_2 migration rather than a simple 'filling' of the storage structure. Injecting at too high a rate might encourage CO_2 to spread laterally towards the closing contour, especially if low permeability layers are present, reducing the effective relief of the structure.

7.2 KEY LESSONS – CAPTAIN SANDSTONE AQUIFER

The Captain Sandstone in the Central North Sea is the uppermost of three members of the Lower Cretaceous Wick Sandstone Formation. The Captain Sandstone of CO_2Stored (Captain unit 013_17) considered here underlies the Moray Firth of the North Sea where the sandstone contains four hydrocarbon fields (Captain Oil, Blake Oil, Cromarty Gas and Atlantic Gas Condensate fields). The geological character and hydrocarbon reservoir properties are known from publications on the fields (Law et al., 2000 and references therein). The continuity of the Captain Sandstone eastwards from the Moray Firth to form the Kopervik fairway illustrated by Law et al. (2000) is confirmed by the investigations published in 2011 from the FEED study for the UK CCS Demonstration Competition by Shell on the Goldeneye Gas Condensate Field (Section 6.4 of this report and documents at the national archive).

Research studies on the Captain Sandstone have been reviewed in this report (Sections 3.1, 4.1, 5.1 and 6.4). An overview theoretical capacity and basin-scale assessment of the Captain Sandstone within the Moray Firth has been presented by SCCS (2009, 2011) (Section 6.4). Site–specific investigations of the Blake Oil Field and surrounding Captain Sandstone, sufficient to inform a dry-run licence application and site characterisation workflow are presented by Delprat-Jannaud et al (2013a and b, 2015) and Akhurst et al. (2015) (Section 3.1). The Goldeneye Field, within the Captain Sandstone to the east of Captain (Unit 013_17), is investigated and fully characterised in preparation for a demonstration CO_2 storage project (Section 6.4). The Captain Sandstone is assessed as a component of a storage cluster stepping out from a demonstration project in the Goldeneye Field and Atlantic Field (Scenarios 1 and 2, respectively, of Element Energy, 2014) (Section 4.1).

Collation and review of data

- Datasets for the area of the Captain Sandstone (Captain_013_17) are available from hydrocarbon exploration for fields within the Captain Sandstone, also for exploration of fields within overlying and underlying strata.

- The area of the Captain Sandstone is crossed by several good quality 2D seismic datasets (SCCS, 2011, Figure 9) acquired since 1986. 3D seismic datasets for the Captain Sandstone area (Unit Captain_013_17), reviewed for the SiteChar project in 2012, revealed 3D survey data acquired up to2003 had been released but surveys acquired from 2007 to 2010 were not available.
- There are approximately 350 wells (including side-track wells) within the extent of the Captain Sandstone studied by SCCS (2011, Figure 9).
- Production data is available from the fields within the Captain Sandstone.
- Review of data by previous research investigations has shown there may be gaps in the seismic surveys datasets due to confidentiality restrictions. Reports of well data have been found to be very variable in quality. Data acquisition activities may be described but the data itself may not be included or available.

Geological Models

- Geological models are presumed to exist for the four hydrocarbon fields within the Captain Sandstone constructed by the field operators: Captain, Chevron; Blake, BG; Cromarty, Hess; Atlantic, BG (from https://itportal.decc.gov.uk/fields/fields_index.htm).
- Shell reports from the Goldeneye FEED studies indicate four models (Section 5.1):

  Petrophysical Modelling Report;

  Static Model Field Report;

  Static Model (Overburden);

  Static Model (Aquifer).

- The Static Model (Aquifer) of Shell spans the eastern part of Captain Sandstone (Unit 013_17), including the Blake, Cromarty and Atlantic fields, and extends eastwards to include the Goldeneye and Hannay fields (Static Model (Aquifer) report, Figure 5-3). The modelling is described in Section 5.1 of this report.
- A basin-scale model of Captain Sandstone (Unit 013_17) and westwards to its inferred outcrop at sea bed, was constructed by SCCS (SCCS, 2011; Jin et al., 2012) and is described in Section 6.4 of this report. CO_2 injection was simulated at 12 injection points. Water production was also modelled from 12 wells on the western side of the outcrop.
- The SiteChar model comprises the basin-scale model of the Captain Sandstone of SCCS (SCCS, 2011; Jin et al., 2012), revised in the vicinity of the Blake Field from the interpretation of 3D seismic survey acquired in 1997 incorporated into the PGS megasurvey. Attribution of the SiteChar Captain Sandstone model is by lithological faces, unlike the earlier SCCS regional models. There are two distinctive facies within the storage complex for the SiteChar modelled injection scenario which is of CO_2 injection into the Blake Field and water production from a down-dip position as is described in Section 3.1 of this report.

Risk analysis and uncertainty reduction

- A qualitative assessment of risk for the geological containment of CO_2 within the Captain Sandstone is assessed by CO_2Stored. The SiteChar investigations, as summarised in Akhurst et al. (2015), were risk-assessment led and targeted to reduce risk and uncertainty where there was insufficient data. Quantitative risk-reduction characterisation, uncertainty reduction and risk analysis was conducted within SiteChar (Table 2). Recommendations are made for preventative measures to further reduce risks that are beyond the resources of a research project. The risks to containment within the Captain Sandstone, research investigations and further mitigating activities proposed are specific to the proposed site and injection scenario (continuous injection at a rate of 5 Mt per year for five years).

- Risk management is a substantial component of the FEED investigations conducted for the UK CCS Demonstration competition entrants. The reader is referred to the 'risk management' report for the project which is not included in this review. Presentations on the site characterisation results for the Goldeneye Field given by staff from Shell refer to the 'bow-tie' method of risk assessment, analysis and risk reduction throughout their work although the method is not explicitly described in their reported results. The very detailed investigations are presumed here to have reduced all risks to 'as low as reasonably possible' to enable the progression for the site toward a storage permit.

Handling of uncertainty parameter value ranges

- Uncertainty reduction was investigated by SCCS (SCCS, 2011; Min et al., 2012) by sensitivity analysis varying eight parameters (Table 7) for 11 scenarios from very 'restricted' to 'relaxed' parameter values. The results indicate that the character of the storage formation boundaries, whether open or closed to fluid flow, is the most important of the parameters investigated (SCCS 2011, Figure 20).
- Uncertainty management is also evident in the reported results of the Goldeneye Field site characterisation. Uncertainty reduction is described for the static model of the Goldeneye Field as summarised in Section 5.1.3.1 of this review.

Storage capacity and migration pathway analysis

- The theoretical storage capacity for the Captain Sandstone was estimated by SCCS (2009) to be between 36 and 360 Mt CO_2, if storage efficiency values of 0.2% and or 2% of pore volume is used, respectively. The extent of the Captain Sandstone aquifer was revised by mapping in 2011, as seen by comparison of figures 9 and 14 in SCCS (2011). The theoretical capacity of the Captain Sandstone and included Captain and Goldeneye fields is assessed by CO_2Stored to be from 208 to 371 Mt with a P50 value of 290 Mt using a smaller sandstone extent than that of SCCS (2011).
- The dynamic utilisation capacity is assessed by CO_2Stored as between 60 to 160 with a P50 value of 120 Mt CO_2. A range of storage capacity values is calculated by dynamic modelling of injection at 12 points for 11 scenarios by SCCS (2011). The calculated storage capacity for the most 'restricted' scenario of 358 Mt confirms the previous theoretical minimum value and as much as 1600 Mt CO_2 for the more 'relaxed' scenarios (SCCS, 2011, Table 9 and Figure 20). Investigations at the Goldeneye Field are to establish that the dynamic capacity of the site was sufficient to contain 20 Mt CO_2 as required for the demonstration project storage scenario.
- Dynamic modelling to predict the flow path for migration of injected CO_2 from 12 injection points within the eastern part of the Captain Sandstone (Unit 013_17) is modelled by SCCS (2011). Simulation of the migration pathway for CO_2 injection of up to 15 Mt per year for 30 years at each of the 12 points indicates CO_2 will be contained within the sandstone and will not migrate to the western boundary of the sandstone.
- Migration path analysis, if the capacity of the storage site is substantially and excessively exceeded, was modelled for the SiteChar UK site investigations. This indicated leakage via wellbores was the most likely route of migration beyond the storage site to secondary storage strata although migration pathways beneath the primary seal, beneath the secondary seal and through the secondary seal were modelled.
- 'Fill to spill' was tested by Shell at the Goldeneye Field demonstration site (Section 5.3.1).

Key metrics for site performance and storage

The SiteChar research study of a site within the Captain Sandstone includes geological metrics for site performance as applied to the storage scenario modelled. Criteria proposed by SiteChar researchers were discussed and agreed with regulators from EC member states and representatives of potential storage site operators (offshore hydrocarbon industry) against which to define storage site performance and compliance with regulations. These are termed Permit Performance Conditions (Delprat-Jannaud, et al., 2013b; Akhurst et al., 2015, Table 4), with values that are specific to a storage project and site injection scenario to be agreed between the operator and the regulator. The SiteChar geological Permit Performance Conditions are:

- CO_2 will not pass beyond the storage permit area boundaries;
- CO_2 plume shows migration within expected modelled behaviour;
- Pressure changes will remain with pre-defined/predicted ranges;
- Geomechanical integrity of the site will be maintained.

The geological site performance metrics for the SiteChar UK site correspond to the continuous supply and storage of CO_2 via multiple wells at a rate of 5 Mt per year for 20 years. The results of the site characterisation investigations for the SiteChar injection scenario informed the definition of a storage permit area that encloses the maximum predicted plume extent (Delprat-Jannaud et al., 2013b, Appendix A). A plan for monitoring of the site (Delprat-Jannaud et al., 2013b, Figure 8.7) indicates how site performance would be verified against the modelled behaviour. The injection scenario includes pressure management by water production to ensure pressure changes remain within pre-defined ranges that would not interfere with operating hydrocarbon wells in the vicinity (Delprat-Jannaud et al., 2013b, Appendix A; Akhurst et al., 2015). Pressure management to ensure there would be no interference with hydrocarbon production operations is approximately one third of the estimated fracture pressure threshold and so maintain the geomechanical integrity of the site.

7.3 KEY LESSONS – FORTIES SANDSTONE UNIT 5

Forties Sandstone Unit 5 encompasses a large portion of the Forties Sandstone Member of the Palaeocene to Eocene Sele Formation of the Central Graben, North Sea. The Forties Sandstone consists of submarine fan deposits, and are overlain by Lower Eocene shales. Forties Sandstone Unit 5 is representative of a large dipping aquifer with regional dip towards the southeast, probably overlain by, and potentially in hydraulic communication with, younger porous and permeable formations in the shallower northwest. Except in the vicinity of isolated salt diapirs, the Forties Sandstone is largely unaffected by significant faulting, and is not folded into large structural closures. The physical property distribution within the Forties Sandstone is likely to be determined at least in part by primary depositional processes, namely the position within the submarine fan system.

The UKSAP project conducted a series of representative model simulations to examine CO_2 migration issues in large open dipping aquifers such as Forties 5, while an Exemplar modelling exercise was also carried-out to investigate storage capacity within part of the Forties, within the extent of the Forties 5 storage unit (Section 6.3). These key learnings are also informed by joint industry projects conducted by SCCS investigating the storage capacity of the Captain Sandstone (Section 6.4), and from the geological characterisation studies conducted at the Sleipner CO_2 storage site (Section 6.5).

Collation and review of data

- Available data, including 2D and 3D seismic and well data over the site and surrounding aquifer volume to be acquired for appraisal.
- Those elements not characterised particularly well by legacy data to be identified (i.e. effective permeability).
- Data would need to be reviewed over a large area due to the potential for up-dip plume migration and to determine the extent and size of the connected aquifer volume to allow for detailed simulation studies for storage appraisal.

Geological models

- Geological models at Sleipner were produced using seismic reflection data along with fairly limited site-specific well data (data used mostly from nearby offset wells).
- Geological model from Sleipner has been modified several times following injection due to acquisition of progressive time-lapse seismic reflection data and subsequent learnings.

Risk analysis and uncertainty reduction

- As no proposed storage sites have been considered for storage at FEED level or similar, no uncertainty reduction activities have taken place for the Forties Sandstone, however a large amount of well and seismic data exist over the area, along with dynamic data from several hydrocarbon fields.
- Uncertainty reduction may involve regional pressure and communication analysis using hydrocarbon field data, or the detailed determination of the unit boundary conditions using seismic reflection data.
- As no core was available for the Sleipner storage site, a nearby hydrocarbon well was cored through the Utsira Sand specifically to test the physical properties and mineralogy of the Utsira Sand (Section 6.5).

Handling of uncertainty and parameter value ranges

- Numerous uncertainties have been described by Goater et al. (2011) as reviewed in Section 6.3, including the mean aquifer dip and the degree of heterogeneity, as well as aquifer permeability.
- The SCCS (2011) Captain Sandstone study conducted several uncertainty studies (Section 6.4), including accounting for geological uncertainty with regards to the extent of a significant intra-reservoir shale, pore compressibility, and permeability of the overlying rock.
- Dynamic simulations conducted by SCCS (2011) and Jin et al. (2012) considered uncertainty in terms of boundary conditions, cross-fault flow properties, maximum allowable injection pressures and the extent to which the injected CO_2 was permitted to migrate (away from the shallow aquifer, hydrocarbon fields and potentially leaking features such as faults).

Storage capacity and migration analysis

Appraisal studies exploring storage capacity and migration relevant to Forties 5 are discussed in Section 6.3. Some of the key learnings are described below:

- In absence of significant structural closure or variation of top surface topography, CO_2 will typically form a thin tongue beneath cap rock and will migrate up-dip several tens of kilometres over thousands of years.
- CO_2 remaining near the injection point gradually becomes residually trapped, though this may take several thousands of years for significant trapping to occur.
- Analytical formula may provide good estimation of migration velocities (Masters 2011).
- Permeability and aquifer dip are critical parameters affecting storage capacity as they limit the rate of flow.
- Heterogeneity can improve lateral sweep.
- Top surface topography is an important consideration for CO_2 migration pathways when considering open dipping aquifers.

7.4 KEY LESSONS – HAMILTON FIELD & VIKING FIELDS

The Hamilton Gas Field (CO2Stored unit 248.002) is a gas accumulation within a North –South trending horst block with dip closure. The reservoir lies within the Triassic Ormskirk Sandstone Formation and is composed of aeolian and fluvial sandstones (Yaliz and Taylor, 2003). The field is sealed by a thick sequence of mudstones and halites of the Triassic Mercia Mudstone Group. The field is located in block 110/13a in the East Irish Sea. Information for this field was collated from publicly available sources (Yaliz and Taylor, 2003) in the UKSAP project (Bentham et al. 2011) and is summarised in the CO2Stored database. The field is currently owned by a consortium including ENI AEP Limited, ENI ULX Limited and Liverpool Bay limited.

The Viking fields (CO2Stored unit 141.035) are a collection of gas tilted/inverted fault blocks. The reservoir lies within the Leman Sandstone Formation and comprises a series of aeolian and fluvial sandstones which are interbedded with silty shales in the northern part of the complex (Riches, 2003). The reservoirs are sealed by a thick sequence of halites and mudstones of Zechstein age. The field is located in blocks 49/12a, 49/16 and 49/17 in the Southern North Sea gas basin. Information for this field was collated from publicly available sources (Riches, 2003 and Morgan, 1991) in the UKSAP project (Bentham et al., 2011) and is summarised in the CO2Stored database. The field is currently owned by ConocoPhillips and BP.

Collation and review of data

Data collation suitable to construct a volumetric and 3D static model for the storage site and storage complex:

- Seismic data – 2D and preferably 3D data if available/acquirable
- Well data – raw logs (LAS files)/deviation surveys/core data/fluid data/well reports & documents
- Production data
- Pressure & Temperature data
- Field information and reports
- Analogue data from neighbouring fields

Geological Models

No known existing geological models of these fields – models will need to be built:

- Undertake seismic interpretation of key horizons
- Identify & evaluate significant faults in the reservoir
- Depth conversion
- Construct 3D static model
- Assess uncertainty associated with static storage volume using data available
- Petrophysical interpretation – predict volume of shale, total porosity and total water saturation
- Well bore stability analysis
- Storage site integrity (capillary pressure, fault seal analysis, fault integrity, geochemistry, reservoir and overburden characterisation)
- Characterisation of field stresses and geomechanical properties of reservoir and overburden (drilling instability, fault reactivation and cap rock fracturing)
- Dynamic modelling of the reservoir (CO_2 flow prediction, capacity assessment, well distribution relative to reservoir volumes, history matching)
- CO_2 injection prediction from full field simulation (estimate storage capacity, impact of input parameter sensitivities on field performance, pressure response validation, provide timescale for injection wells)

- Full overburden mobility modelling (cap rock properties, fault migration modelling, risking around wells, solubility of CO_2 in formation waters)

Risk analysis and uncertainty reduction:

- Identification of hazards
- Risk assessment and mitigation assessment
- Sensitivity analysis to highlight factors influencing uncertainty in long-term fate of injected CO_2
- Inform further data acquisition to feed into the static and dynamic models to reduce risks

Handling of uncertainty parameter value ranges

- Sensitivity and uncertainty analysis results fed into reservoir simulation model to help identify key input parameters and validate the volume estimates

Storage capacity and migration pathway analysis

- Dynamic modelling of the reservoir (CO_2 flow prediction, capacity assessment)
- Storage site integrity (capillary pressure, fault seal analysis, fault integrity, geochemistry, reservoir and overburden characterisation)

Key metrics for site performance

Key geological site performance metrics need to be compared and matched with the anticipated supply of CO_2, they are:

- Injection rate
- Storage capacity
- Pressure prediction
- Trapping processes
- Demonstration of low leakage risk

This will be required to obtain a permit for storing CO_2.

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D05: WP4 Report Appendix 5 – Site Assessments

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1 Bruce Gas Field

Overview

Capacity:	188MT	UKCS Block:	9/9
Unit Designation:	Gas condensate	Beachhead:	St Fergus
Formation:	Beryl formation	Water Depth:	116m
Earliest injection:	2025	Reservoir Depth:	4000m
Availability/COP:	2023	Region:	CNS

Table 1:Bruce Field Overview

The results of the DD review confirm that the selection criteria used for the Bruce Gas Condensate Field are reasonable except that the highest point of the structure is about 820m below the maximum depth criteria.

- Checks of injectivity indicate that the target rate of 1MT/year/well can be met.
- As this is an existing hydrocarbon structure, containment is not seen to be a significant risk.
- The Georisk factor has been calculated as 8, this is the same as the previous calculated factor in WP3 based on CO2Stored data.
- The additional risk assessment carried out for the engineering containment risk indicates that the risk is low to moderate.
- Well cost estimate (for 5 wells) is high at £411M, primarily due to reservoir depth.

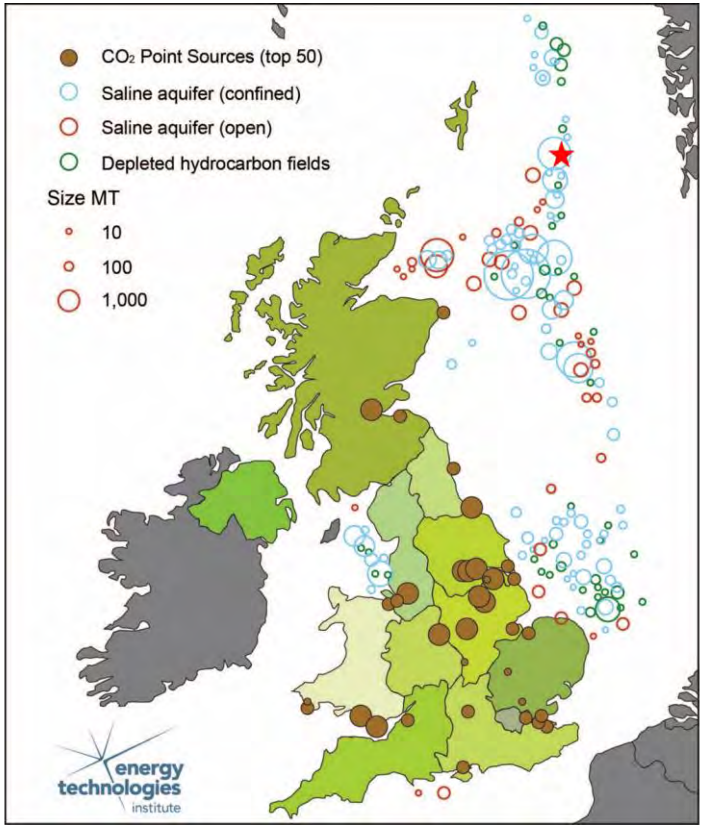


Figure 1: Bruce Field Location Map

Containment

An overburden assessment has been conducted above and adjacent to the Bruce Condensate field to identify secondary containment horizons and potential migration pathways out of the Bruce Condensate storage complex, in the unlikely event of a seal or fault leakage of the sequestered CO_2.

Field data and published literature (Beckly, A., Dodd, C., and Los, A., 1993) were reviewed to establish the effectiveness of trap and seal. Depth to crest of the reservoir is 3320 m (10,900ft tvdss), with three main reservoir blocks (Western Flank, Central Panel and Eastern High) with the western edge listric fault a significant control on the field (Beckly, A., Dodd, C., and Los, A., 1993). Cross-cutting faults of various orientations are present over the field. A sufficient seal is present that CO_2 is not expected to leak out of the site.

The Georisk factor has been calculated as 8 is the same as the previous calculated factor in WP3 based on CO2Stored data.

	Fault Characterisation			Seal Characterisation			Georisk Factor
	Density	Throw & Seal	Fault Vertical Extent	Fracture Pressure Capacity	Seal Chemical Reactivity	Sea Degradation	
CO2Stored Value	2	2	1	1	1	1	8
Due Diligence Value	2	2	1	1	1	1	8
Risk Factor Key: Low = 1, Medium = 2, High = 3							

Table 2: Bruce Field Geo-containment Risk

Engineering Risk

The engineering containment risk is low to moderate, with 74 wells in total, and only 34 considered to be at risk of leakage. 14 wells were plugged and abandoned, 8 of which were before 1986, representing the highest risk. The 100yr probability of a leakage on the field is a low 0.06, and the well density factor is 0.38 wells/km2, resulting in a moderate risk assessment score of 0.02.

Capacity

The calculated storage capacity is 188MT compared to the reported capacity in CO2Stored of 211.2MT. These are in reasonable agreement.

For the Bruce gas field, the due diligence involves a recalculation of the capacity equivalent to the net reservoir volume of fluids removed at February 2015. In addition, the net reservoir volume of fluids removed at COP was estimated and the capacity calculated at this time to confirm the full capacity estimate. The COP date for Bruce gas field in the supplied Woodmac data is 2023.

Bruce is a gas condensate field with a condensate gas ratio of 0.0003 sm3/sm3 (54.2 bbl/mmscf), and some water production. Water and gas have been injected into the field for pressure support. All produced and injected fluids were accounted for in the material balance calculation to check potential storage capacity.

Current gas rates are ~2300Ksm3/d (~81mmscf/d) and condensate rates are ~385sm3/d (~2400bbls/d). The estimated uplift in storage capacity between February 2015 and end 2023 (COP) is 7MT (~4%).

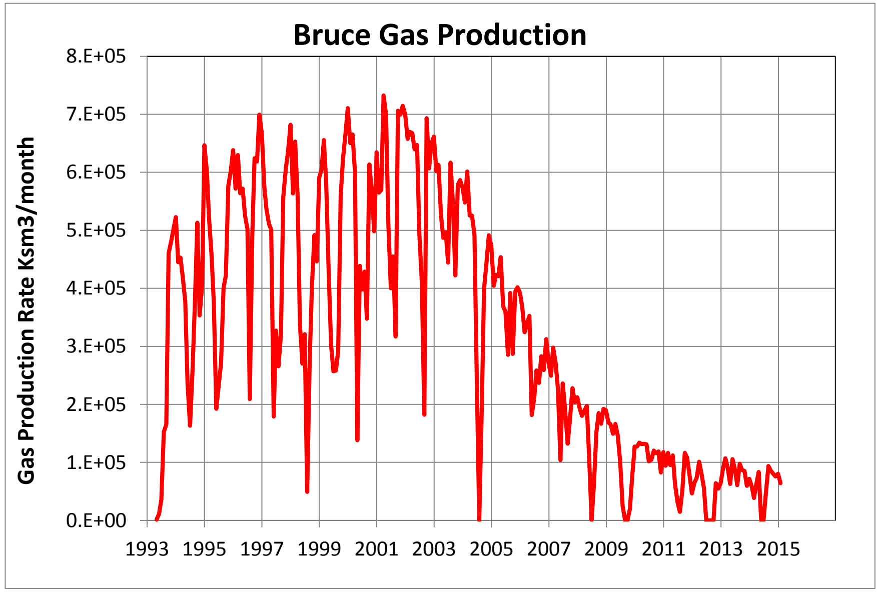


Figure 2: Bruce Field Gas Production Profile

The produced volumes and conversion to mass storage potential are shown in the table below:

Gas Production	85134	MCM
Condensate Production	25.9	MCM
Gas Injected	1.58	MCM
Water Injected	14.6	MCM
Water Production	2.5	MCM
Net Reservoir Volume Produced	242	MCM
Storage capacity	188	MT

Table 3: Bruce Field Storage Capacity

NB. Volumes refer to production volumes at February 2015.

The volumes and shrinkage factors used in the calculation are shown in the table below.

Parameter		Reference	CO2Stored
CO_2 density (kg/m3)	750	CO2STORE	750
Gas expansion factor (rm3/sm3)	0.0025	Analogue	0.023
Condensate formation volume factor (rm3/sm3)	1.75	Analogue	1.76
Water formation volume factor (rm3/sm3)	1.02	Analogue	1.02

Table 4: Bruce Field Fluid Properties

Injectivity

The selection criteria used for injectivity is the permeability thickness (Kh) value calculated using the mid case reservoir data from CO2Stored. For the Bruce Condensate Field this was calculated as 36,540 mDm.

Field data and published literature[1] have been reviewed in order to confirm the reservoir properties which have then been used to validate the permeability thickness and expected injectivity.

The field comprises moderate-high net to gross, excellent to moderate quality deep –shallow water and estuarine sandstones of the Beryl Group Formation[1]. The reservoir has been subdivided into five zones, which show variation in reservoir quality. The full stratigraphy is not always fully present in the three main field blocks (Beckly, A., Dodd, C., and Los, A., 1993). A summary of the reservoir properties are summarised below:

Zone	Depositional Environment	Gross Thickness [m]	NTG	Porosity	K [mD]	Kh [mDm]
Upper Sand	Deeper water shelf	100	0.5	13.5	85	4,250
A Sand	Storm/Sheet Sands	70	0.75	15	90	4,725
B Sand	Estuarine SST	50	0.95	17	95	4,513
C Sand	Estuarine SST	55	0.8	16	90	3,960
Nansen	Shallow Marine SST	40	0.95	16	80	3,040
All Zones		315	0.74	15.50	88	20,416

Table 5: Bruce Field Reservoir Properties

A coal barrier up to 15m thick separates the B and C sands, however, this only creates a permeability barrier vertically in the Western Flank, and where absent the B and C boundary is. A thin muddy interval exists between B and A sands, with a sharp “flooding event” boundary present between the A sands and Upper Sands indistinguishable (Beckly, A., Dodd, C., and Los, A., 1993).

The permeability thickness calculated during the validation process is 20,416 mDm. This is approx. 44% lower than the estimate based on the CO2stored data. Average properties have been used for the thickness, NTG, Porosity and permeability for each zone. The permeability thickness however is still high and based on reservoir quality the initial CO_2 injectivity is expected to be good.

The initial production performance for a selection of wells was converted to an equivalent CO_2 injection rate to gain some confidence that that the 1MT/year/well target could be met. All initial rates for the selected wells exceed this target.

Well	CO_2 Injectivity based on maximum production
	MT/yr
A01 (gas)	4811
A02 (gas)	5906
A05 (oil)	7512
A05 (gas)	5066
A06 (gas)	6114
A11 (oil)	4814
A11 (gas)	2967
B04 (gas)	4163

Table 6: Bruce Field Well Injectivity

As an additional check, a dynamic model was constructed to test the injectivity performance, at initial conditions and over time. A simple model was built in Eclipse (flat structure). Reservoir pressure of 2800 psi assumed at abandonment. CO_2 will be injected in dense phase and injection pressure of 3500 psi is required to meet the injectivity threshold of 1MT/year per well for this site. Initial reservoir pressure and fracture pressure is uncertain in this field. Considering the low recovery factor in gas condensate reservoir, pressure at abandonment condition is assumed to be 50 % of initial pressure. High productivity of different wells in the field suggests that 1MT/year can be achieved for this field.

Well Design

The generic well design is discussed in the supporting document ‘Storage Site Due Diligence Summary’. It is likely that this well design can be achieved in the

Bruce condensate field. However, as the reservoir is relatively deep, the sail angle of the well may be modified (reduced from 60deg), as the resulting step out may be significantly more than is required. Note that the well costing assumes a reduced step out, limiting hole length to 5,650m.

Due to the deep water depth (116m), the wells have been costed on the basis of drilling by a Semi-Submersible Drilling Unit. Subsea well costs are assumed to be £82.1M per well, resulting in a 5 well development cost of £411M.

Development Concept

CO_2 volumes cf ETI Scenarios

The ETI Concentrated Scenario shows 11MT/yr by 2030 into the CNS via St Fergus. 1MT goes to Goldeneye. 10MT/yr of additional storage may be required by 2030

Comparative development concept

A new subsea development in the vicinity of Bruce with 5 deviated wells each injecting 1MT/yr; totalling 100MT over 20 years. CO_2 will be delivered through the re-use of MGS 30” pipeline from St Fergus with 35MT/yr capacity, and a new 20” 148km pipeline extension to Bruce. Power and controls will be supplied from an existing neighbouring platform. Monitoring will include downhole pressure and distributed temperature sensors.

Site growth potential; theoretical ultimate development concept

The site has a theoretical storage capacity of ~188MT.

A new subsea development comprising of 2 subsea manifolds with a total of 9 wells each injecting a total of 10Mt/yr; totalling 180MT over 20 years. CO_2 would be delivered via CO_2 will be delivered through the re-use of MGS 30” pipeline from St Fergus with 35MT/yr capacity, and a new 20” 148km pipeline extension to Bruce. Power and controls will be supplied from an existing neighbouring platform.

Build out potential

Build out could be at the Grid aquifer or Harding. The site is also suitable as a centre for build out for EOR.

Development Cost

Capacity:	188	Water Depth (m)	116.4
Concept Cost (£m)	Comparative Development	Ultimate Development	Description
Tonnes Injected (MT)	100	180	Total Stored CO_2 for proposed scheme
Appraisal Cost:	£0m	£0m	Appraisal Wells + Seismic Data Acquisition & Interpretation
Development Well Cost:	£410.7m	£739.2m	Drilling & Completion Costs of wells.
Facilities Cost:	£190.5m	£236.8m	Landfall, Pipeline, Templates, ties-Ins,
PM & Eng:	£19.1m	£23.7m	10% of Facilities Costs
Decommissioning:	£87.7m	£131.2m	£8m per subsea well
Subtotal	£707.8m	£1130.8m	
Contingency	£141.6m	£226.2m	20% of Development & Facilities Costs
OPEX (20years)	£228.6m	£284.2m	OPEX Cost for 20 years (6% of facilities costs)
Total:	£1077.9m	£1641.1m	
£/T CO_2	10.78	9.12	

Table 7: Bruce Field Development Cost Estimate

Data

Seismic Data quality and coverage

Bruce condensate field is entirely covered by the 3D CNS PGS seismic megasurvey. The data quality acceptable, however seismic resolution at reservoir level is poor in areas. The well ties confirm the time interpretation.

Well Data quality and coverage

Digital log data available from CDA. Log coverage and quality variable. Limited core data coverage.

Commercial Issues

The Bruce gas condensate field is operated by BP and has a COP date of 2023.

2 Captain Oil Field

Overview

Capacity:	95.8MT	UKCS Block:	13/22
Unit Designation:	Oil and gas	**Beachhead:**	St Fergus
Formation:	Wick Sandstone	**Water Depth:**	105m
Earliest injection;	2031	**Reservoir Depth:**	1110m
Availability/COP:	2029	**Region:**	CNS

Table 8: Captain Field Overview

- Checks of injectivity indicate that the target rate of 1MT/year/well can be met.
- There are two distinct compartments i.e., Main Closure and Eastern Closure.
- As this is an existing hydrocarbon structure, containment is not seen as a significant risk.
- The Georisk factor has been calculated as 9, an increase from 8 calculated in WP3.
- STOOIP in the field is 1000 MMBBL. Expected recovery factor in the field ranges from 28-40 %.
- Upper Captain Sandstone exhibit excellent reservoir quality throughout while lower Captain Sandstone is more heterogeneous. There are some thin fine grained horizons (less than 10 % of gross volume of lower captain sandstone) which are expected to act as pressure baffles.
- The additional risk assessment carried out for the engineering containment indicates that the risk is moderate to high due to the high well density.
- Well cost estimate (for 5 wells) is £143M.

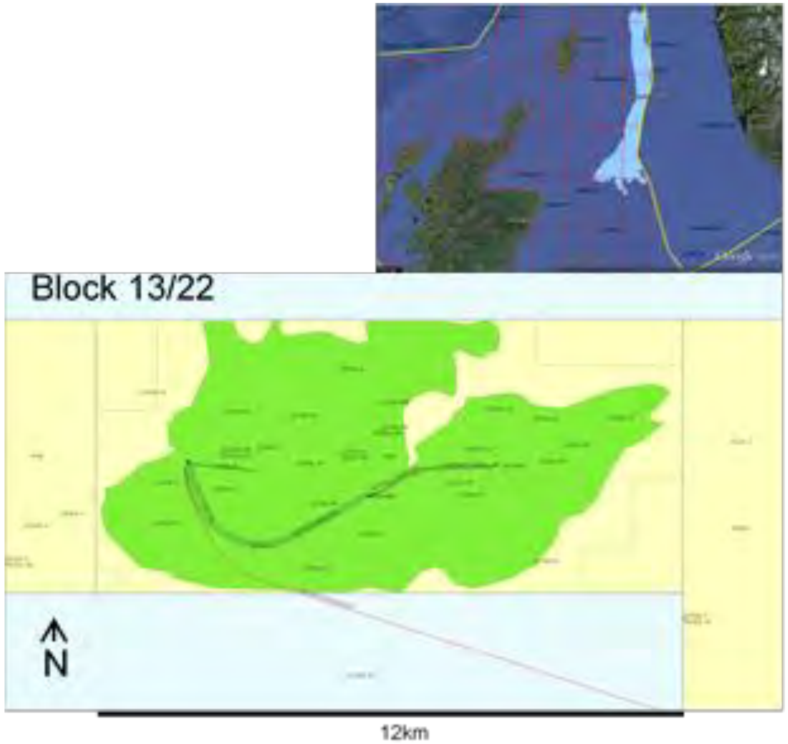


Figure 3: Captain Location Map

Containment

An overburden assessment has been conducted above and adjacent to the Captain Field to identify secondary containment horizons and potential migration pathways out of the Captain storage complex, in the unlikely event of a seal or fault leakage of the sequestered CO_2.

Field data and published literature were reviewed to establish the effectiveness of trap and seal. Depth to crest of the reservoir is 823 m (2700ft tvdss), with a structural and dip-closed stratigraphic trap in two closures – Main and Eastern (Evans, D. Graham, C, Armour A, Bathurst, P., 2003; Pinnock, S.J., Clitheroe, A. R .J., 2003) .

The Sola/Rodby Shale, with overlying Chalk Group, provides an effective overburden seal to the Captain field CO_2 is not expected to leak through the top seal, which is already proven. The Upper Captain Sandstone has very different GOCs in the Main and Eastern Closures, indicating a robust stratigraphic seal between the reservoir compartments. The Lower Aptian Shales sit below the Lower Captain sands (Pinnock, S.J., Clitheroe, A. R .J., 2003)..

The Georisk factor has been calculated as 9, which is slightly higher than previous calculated factor in WP3 based on CO2Stored data. A review of the PGS CNS mega-survey has identified a higher density of faults.

	Fault Characterisation			Seal Characterisation			Georisk Factor
	Density	Throw & Seal	Fault Vertical Extent	Fracture Pressure Capacity	Seal Chemical Reactivity	Sea Degrad-ation	
CO2Stored Value	2	2	1	1	1	1	8
Due Diligence Value	3	2	1	1	1	1	8
Risk Factor Key: Low = 1, Medium = 2, High = 3							

Table 9: Captain Field Geo-Containment Risk

Engineering Risk

The engineering containment risk is moderate to high, with 202 wells in total, and 114 abandoned wells considered being at risk of leakage. Only 1 well was plugged and abandoned before 1986, representing the highest risk. The 100yr probability of a leakage on the field is a moderate 0.22, but the well density factor is 2.75 wells/km2, resulting in a high risk assessment score of 0.62.

Capacity

The calculated storage capacity is 95.8MT compared to the reported capacity in CO2Stored of 96.5MT.

For the Captain oil field, the due diligence involves a recalculation of the capacity equivalent to the net reservoir volume of fluids removed at February 2015. In addition, the net reservoir volume of fluids removed at COP was estimated and the capacity was calculated at this time to confirm the full capacity estimate. The COP date for Captain oil field in the supplied Woodmac data is 2029.

Captain oil field produces oil with associate gas and water production. DECC reports water injection volume in field. All produced and injected fluids were accounted for in the material balance calculation to check potential storage capacity.

Current oil rates are ~3000sm3/d (~19,000bbls/d). An uplift in storage capacity between February 2015 and end 2029 (COP) is forecast to be 27.4MT (~40%).

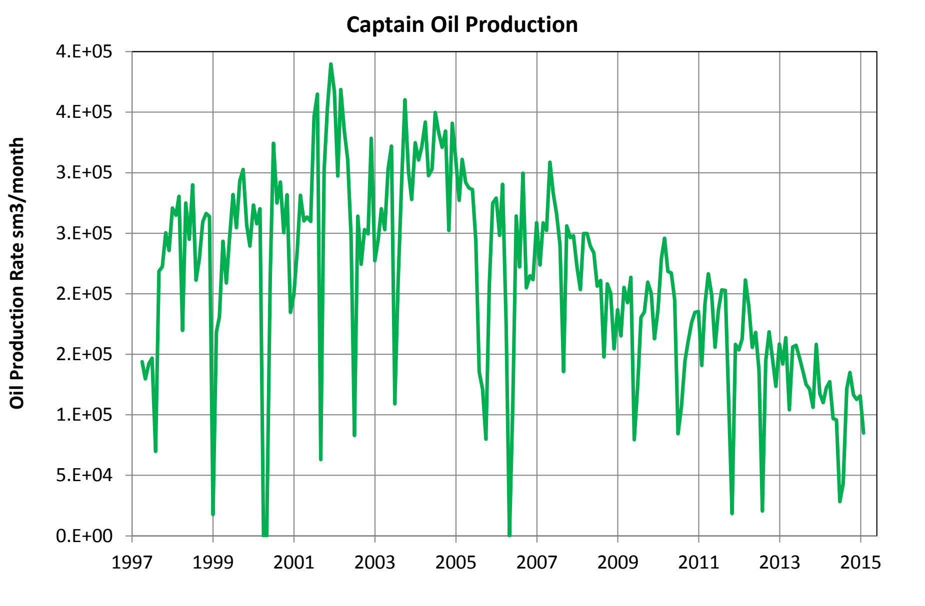


Figure 4: Captain Field Oil Production Profile

The produced volumes and conversion to mass storage potential are shown in Table 10:

Oil Production	45.4	MCM
Gas Production	1645	MCM
Water Production	147.6	MCM
Water Injection	99	MCM
Net Reservoir Volume Produced	98	MCM
Storage Capacity @COP	95.8	MT

Table 10: Captain Field Storage Capacity

NB. Volumes refer to production volumes at February 2015.

The volumes and shrinkage factors used in the calculation are shown in the table below.

Parameter		Reference	CO2Stored
CO_2 density (kg/m3)	703	CO2 Storage potential in UK-BGS Study	770
Gas expansion factor (rm3/sm3)	0.007	Ref 1. Uk Oil and Gas Fields Data	0.0079
Oil formation volume factor (rm3/sm3)	1.045	Analogue	1.05
Water formation volume factor (rm3/sm3)	1.02	Analogue	1.02

Table 11: Captain Field Fluid Properties

Injectivity

The selection criteria used for injectivity is the permeability thickness (Kh) value calculated using the mid case reservoir data from CO2Stored. For the Captain Field this was calculated as 630,000 mDm.

Field data and published literature have been reviewed in order to confirm the reservoir properties which have then been used to validate the permeability thickness and expected injectivity (Evans, D. Graham, C, Armour A, Bathurst, P., 2003; Pinnock, S.J., Clitheroe, A. R .J., 2003).

The field comprises high net to gross and excellent quality turbidite sandstones of the Valhall/Wick Sandstone Formation. The reservoir has been subdivided into upper and lower Captain which show significant variation in reservoir quality over the entire field. Permeability barriers exist in the Lower Captain sands in the form of thin fine grained horizons, which act as pressure baffles during production. The reservoir properties are summarised below:

Zone	Depositional Environment	Gross Thickness [m]	NTG	Porosity	Perm [mD]	Kh [mDm]
Upper Captain	Turbidite	66	0.95	0.31	7000	438,900
Lower Captain		84	0.95	0.31	7000	558,600
All Zones		150	0.95	0.31	7000	997,500

Table 12: Captain Field Reservoir Properties

The permeability thickness calculated during the validation process is 997,500 mDm. This is approx. 37% higher than the estimate based on the CO2stored data. The gross thickness is an average from a selection of well logs obtained from CDA. Unable to confirm separate reservoir properties at this stage for the individual zones, therefore further study would be necessary to establish NTG, porosity and permeability from the available well data. The permeability thickness is very high and based on overall reservoir quality the initial CO_2 injectivity is expected to be excellent.

Two additional injectivity checks were carried out as part of the due diligence.

The initial production performance per well was converted to an equivalent CO_2 injection rate to gain some confidence that that the 1MT/year/well target could be met.

Combination of long horizontal wells and high permeability used during production give the potential for high injectivity. The in situ oil viscosity is at least 47 cP (S.J Pinnock & A. R .J Clitheroe quote a range of 47 -150 cP). This is about 4 orders of magnitude higher than dense phase CO_2. Oil production rates of more than 2,000 m3/day recorded in several wells. This suggests relatively easy injection in terms of well performance.

Production data used was from 10 of the early wells (odd numbers C3-C21) all of them suggest that huge amounts (often over 1 million tonne/day) could be injected per well using an injection pressure equivalent to the early life production drawdown. Injectivity so good as to swamp any errors in the calculations.

Developed with 17 horizontal wells 3500-8000 ft in length. This provides spatial coverage thought the reservoirs. Individual well production rates between 5000 and 20000 BPD gross liquids. Ref - S.J Pinnock & A. R .J Clitheroe 2003.

A dynamic model was constructed to test the injectivity performance, at initial conditions and over time. A simple model was built in Eclipse (flat structure). CO_2 will be injected in critical or dense phase as the reservoir pressure is expected to be same or more than initial reservoir pressure as pressure maintenance is done in oil field. An injection pressure of 1950 psi achieves an injectivity of 1.58 MT/year per well. This is below the calculated minimum fracture pressure of 2560 psi.

There is a high degree of confidence that the injectivity rates can be achieved.

Well Design

The generic well design is discussed in the supporting document 'Storage Site Due Diligence Summary'. Due to the relatively shallow depth, achieving this well design may be a challenge in the Captain Oil Field. There are a large number of existing highly deviated and horizontal wells in the field, but build angles may be higher if the completion is smaller than that proposed for the CO_2 storage. With such a large density of horizontal wells, well collision could be considered a risk in this target.

Due to the deep water depth (105m), wells have conservatively assumed as being drilled by Semi-Submersible Drilling Unit. Subsea well costs are assumed to be £28.1M per well, resulting in a 5 well development cost of £143M.

Development Concept

CO_2 volumes cf ETI Scenarios

The ETI Concentrated Scenario shows 11MT/yr by 2030 into the CNS via St Fergus. 1MT goes to Goldeneye. 10MT/yr of additional storage may be required by 2030

Comparative development concept

A new subsea development in the vicinity of the Captain oilfield with 5 deviated wells each injecting 1MT/yr; totalling 96MT over 20 years. CO_2 will be delivered via a new 101 km 20" pipeline from St Fergus with 10MT/yr capacity. Power and controls will be supplied from an existing neighbouring platform. Monitoring will include downhole pressure and distributed temperature sensors.

Build out potential

The Captain oilfield could be built out to the Coracle aquifer or the Captain aquifer. Also, being relatively close to shore, it could be built out to Bruce, Harding, Grid aquifer. It also represents a suitable site for build out to EOR.

Site growth potential; theoretical ultimate development concept

The site has a theoretical storage capacity of ~97MT.

There is no additional site growth potential

Development Cost

Capacity:	95.8	Water Depth (m)	105
Concept Cost (£m)	**Comparative Development**	**Ultimate Development**	**Description**
Tonnes Injected (MT)	95.8		Total Stored CO_2 for proposed scheme
Appraisal Cost:	£0m		Appraisal Wells + Seismic Data Acquisition & Interpretation
Development Well Cost:	£140.4m		Drilling & Completion Costs of wells.
Facilities Cost:	£158.3m		Landfall, Pipeline, Templates, ties-Ins,
PM & Eng:	£15.9m		10% of Facilities Costs
Decommissioning:	£79.6m		£8m per subsea well
Subtotal	£394m		
Contingency	£78.8m		20% of Development & Facilities Costs
OPEX (20years)	£189.9m		OPEX Cost for 20 years (6% of facilities costs)
Total:	£662.7m		
£/T CO_2	6.92		

Table 13: Captain Field Development Cost Estimate

*These costs are not the full cost of storage as they omit MMV, security instruments, handover to DECC and profit.

Data

Captain Oil Field is covered by the 3D CNS PGS seismic megasurvey. The data quality is acceptable. The well ties confirm the time interpretations.

Well Data quality and coverage – Digital wireline and MWD/LWD logs are available for some of the Captain Field wells.

Commercial Issues

The Captain Oilfield is operated by Chevron and has a COP date of 2029. It is therefore only available very late to be considered as build out for CO_2 storage.

3 Captain Aquifer

Overview

Capacity:	49MT	UKCS Block:	14/26 vicinity
Unit Designation:	Saline Aquifer	**Beachhead:**	St Fergus
Formation:	Wick sandstone	**Water Depth:**	114m
Earliest injection:	2020	**Reservoir Depth:**	1190m
Availability/COP:	n/a	**Region:**	CNS

Table 14: Captain Aquifer Overview

- The calculated capacity is much smaller than that provided in CO2Stored, however only the pan handle area has been considered and it has been extended to include Goldeneye.
- The calculated permeability thickness is much lower than that calculated from CO2Stored however it is still extremely high and checks of injectivity indicate that the target rate of 1MT/year/well can be met.
- The Georisk factor has been calculated as 14. This is an increase from 12 (calculated in WP3). The primary top seal is relatively thin, however there are shallower formations which provide additional containment.
- Captain Sandstone is divided into the Upper Captain and Lower Captain by Mid Captain Shale. There is uncertainty in the extent of Mid Capitan Shale.
- There is uncertainty associated with site boundaries sand pinchout and fault connectivity which effect lateral migration of CO_2.
- The additional risk assessment carried out for the engineering containment risk indicates that the risk is moderate due to the large area covered by the aquifer.
- Well cost estimate (for 5 wells) is £143M.

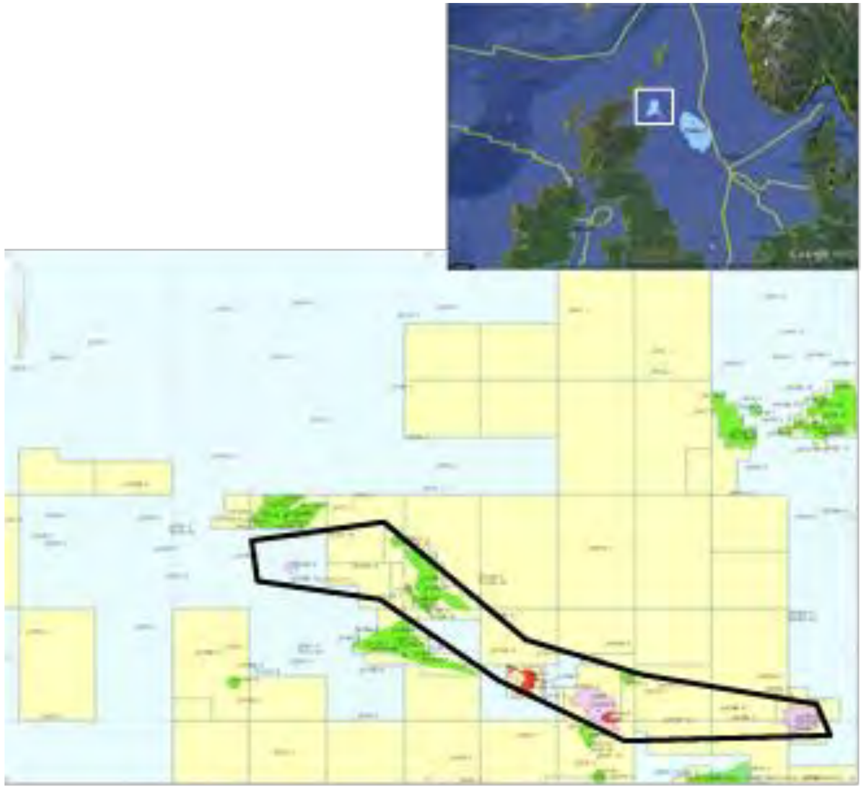


Figure 5: Captain Aquifer Location Map

Containment

An overburden assessment has been conducted above and adjacent to the Captain saline aquifer storage site to identify secondary containment horizons and potential migration pathways out of the storage complex, in the unlikely event of a seal or fault leakage of the sequestered CO_2.

The primary seal for the Captain sands is provided by the thin Sola/ Rodby mudstones directly overlying. These also provide the top seal for the Captain Field. In the overburden there are four possible aquifers identified which could restrict the migration of the CO_2 plume to the seabed should it egress from the Captain reservoir storage site. These are: Nordland Group, Dornoch Mudstone Unit, Lista Formation Mudstones, Plenus Marl & Hidra Formations.

The Georisk factor has been calculated as 14, this is higher than previous calculated factor in WP3 based on CO2Stored data. No faults in this aquifer had been previously identified in CO2Stored, however a review of the PGS CNS mega-survey identified several faults.

	Fault Characterisation			Seal Characterisation			Georisk Factor
	Density	Throw & Seal	Fault Vertical Extent	Fracture Pressure Capacity	Seal Chemical Reactivity	Sea Degradation	
CO2Stored Value	1	1	2	3	3	2	12
Due Diligence Value	3	2	1	3	3	2	14

Risk Factor Key: Low = 1, Medium = 2, High = 3

Table 15: Captain Aquifer Geo-Containment Risk

Engineering Risk

The engineering containment risk is moderate, with 74 abandoned wells, in the pan-handle area considered, at risk of leakage. 5 wells were abandoned before 1986, representing the highest risk. The 100yr probability of a leakage on the field is moderate to high at 0.22, but the well density factor is 0.08 wells/km2, resulting in a moderate risk assessment score of 0.018. Careful selection of injection site and CO_2 plume pathway is required in order to avoid the high well density locations.

Capacity

The calculated storage capacity is 49MT compared to the reported capacity in CO2Stored of 156MT. The due diligence capacity has only been calculated for the southern 'pan-handle' area, which has been extended to include the Kopervik fairway as far south east as Goldeneye (the capacity excludes the Captain Field and areas to the North and South of the field. A significant part of the C02 Stored Captain area polygon is not covered by 3D seismic.

Thickness[2] [m]	GRV [MMm3]	NTG[2]	Porosity[1]	CO_2 Density[3] [Tonnes / m3]	Pore Space Utilisation[3]	Pore Volume [MMm3]	Theoretical Capacity [MT]
62	53713	0.95	0.31	0.56	0.006	15818	49

Table 16: Captain Aquifer Storage Capacity

NB. 1: Analogue field data and literature 2: Estimated from CDA composite logs 3: CO2Stored

The full Kopervik fairway is believed to be in hydraulic communication and compartmentalisation is not thought to be a risk

Injectivity

The selection criteria used for injectivity is the permeability thickness (Kh) value calculated using the mid case reservoir data from CO2Stored. For the Captain aquifer this was calculated as 430,010 mDm.

Field data and published literature have been reviewed in order to confirm the reservoir properties which have then been used to validate the permeability thickness and expected injectivity.

The aquifer comprises Kopervik sands with a range of net to gross from 75-95% and excellent quality mass-flow sandstones of Early Cretaceous age. A summary of the reservoir properties are summarised below:

Zone	Depositional Environment	Gross Thickness [m]	NTG	Porosity	Perm [mD]	Kh [mDm]
Captain Sands/ Kopervik	Turbidite	61	0.85	0.31	2000	103,700

Table 17: Captain Aquifer Reservoir Properties

The permeability thickness calculated during the validation process is 103,700 mDm. This is approx. 76% lower than the estimate based on the CO2Stored data. CO2Stored assumes NTG and permeability similar to Captain Field. Over the larger Kopervik fairway, NTG ranges between 75 and 95% (Law, A, et al. 2000). The permeability over Captain is high with an average 7,000mD, however at Blake, this average drops to 1,500-2000 (Du, K. E., et al., 2000). The have conducted a study over this aquifer area with a lower perm of 2000mD SCCS (Jin, M., Mackay E., Quini M., Kitchen K. & Akhurst M., 2012).

The permeability thickness however is still high and based on reservoir quality the initial CO_2 injectivity is expected to be excellent.

A dynamic model was constructed to test the injectivity performance, at initial conditions and over time. A simple model was built in Eclipse (flat structure). CO_2 will be injected in critical or dense phase as the reservoir pressure is expected to be high in saline aquifer. The injectivity threshold of 1MT/year per well can be achieved with an injection pressure of 3450 psi, well below the fracture pressure of 5700 psi.

Well Design

The generic well design is discussed in the supporting document ‘Storage Site Due Diligence Summary’. Due to the varying target depth, achieving this well design may be a challenge in the shallower areas of the Captain Aquifer. Targeting the deeper zones may be necessary.

Due to the deep water depth (95m), wells have conservatively been assumed to be drilled by Semi-Submersible Drilling Unit. Subsea well costs are assumed to be £28.1M per well, resulting in a 5 well development cost of £143M.

Development Concept

CO_2 volumes cf ETI Scenarios

The ETI Concentrated Scenario shows 11MT/yr by 2030 into the CNS via St Fergus. 1MT goes to Goldeneye. 10MT/yr of additional storage may be required by 2030

Comparative development concept

A new subsea development, in the vicinity of Atlantic and Cromarty, with 3 deviated wells each injecting 1MT/yr; totalling 49MT over 20 years. CO_2 will be delivered via re-use the Atlantic and Cromarty 16” pipeline from St Fergus with 6MT/yr capacity. Power and controls will be supplied from an existing neighbouring platform. Monitoring will include downhole pressure and distributed temperature sensors.

Site growth potential; theoretical ultimate development concept

The site has a theoretical storage capacity of ~49MT based on the due diligence work although as noted above the capacity could be very much greater.

On the basis of the current estimate, the site appear to have no additional growth potential, this needs to be verified though additional subsurface evaluation.

Build out potential

The site could build out to Captain oil field and Coracle aquifer. Also, the Captain aquifer, being relatively close to shore, could be built out to Bruce, Harding, Grid aquifer. It could also represents a build out from Goldeneye or a suitable site for build out to EOR.

Development Cost

Capacity:	49	Water Depth (m)	95
Concept Cost (£m)	**Comparative Development**	**Ultimate Development**	**Description**
Tonnes Injected (MT)	49		Total Stored CO_2 for proposed scheme
Appraisal Cost:	£0m		Appraisal Wells + Seismic Data Acquisition & Interpretation
Development Well Cost:	£84.3m		Drilling & Completion Costs of wells.
Facilities Cost:	£38.1m		Landfall, Pipeline, Templates, ties-Ins,
PM & Eng:	£3.9m		10% of Facilities Costs
Decommissioning:	£33.6m		£8m per subsea well
Subtotal	£159.6m		
Contingency	£32m		20% of Development & Facilities Costs
OPEX (20years)	£45.7m		OPEX Cost for 20 years (6% of facilities costs)
Total:	£237.1m		
£/T CO_2	4.84		

Table 18: Captain Aquifer Development Cost Estimate

*These costs are not the full cost of storage as they omit MMV, security instruments, handover to DECC and profit.

Data

Captain aquifer is only partially covered by the 3D CNS PGS seismic megasurvey (approximately 60%). 3D Seismic covers main areas of interest including fairway. The data quality is variable due the large area of the aquifer encompassing several different merged 3D surveys. Degradation of seismic data quality below the chalk renders imaging of the Captain Sandstone poor in areas. The well ties confirm the time interpretation.

Digital log data is available from CDA but coverage and quality are variable. There is particularly dense coverage over the Captain Field.

Commercial Issues

The Captain aquifer could be developed from a range of sites. The development scenario outlined above suggests the vicinity of the Atlantic Field, in order to enable re-use of the Atlantic and Cromarty pipeline. The A&C fields have ceased production but are still licensed to BG and Hess. A full list of Cessation of Production dates for all fields is provided in D04 – Initial Screening and Down-select report.

4 Coracle Aquifer

Overview

Capacity:	35MT	UKCS Block:	13/22 vicinity
Unit Designation:	Saline Aquifer	**Beachhead:**	St Fergus
Formation:	Wick Sandstone	**Water Depth:**	98m
Earliest injection:	2025	**Reservoir Depth:**	1066m
Availability/COP:	n/a	**Region:**	CNS

Table 19: Coracle Aquifer Overview

The results of the due diligence review show a greatly reduced capacity due to limited seismic data coverage.

- Checks of injectivity indicate that the target rate of 1MT/year/well can.
- The Georisk factor has been calculated as 13. This is an increase from 11 (calculated in WP3).
- The additional risk assessment carried out for the engineering containment risk indicates that the risk is moderate.
- Well cost estimate (for 5 wells) is £137M

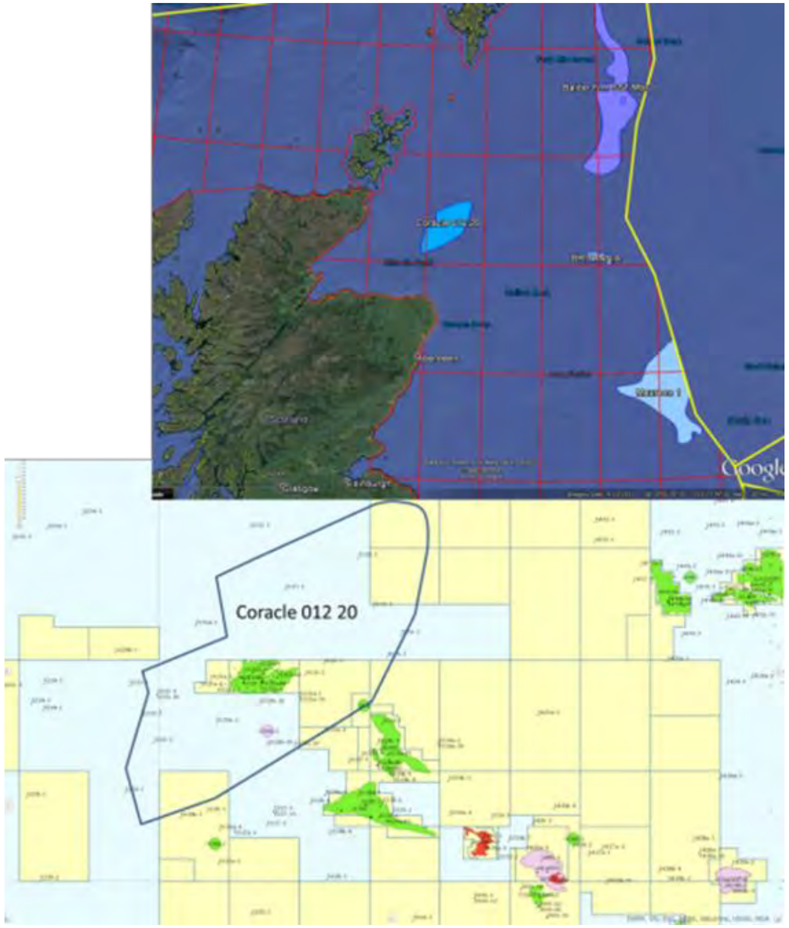


Figure 6: Coracle Aquifer Location Map

Containment

An overburden assessment has been conducted above and adjacent to the Coracle saline aquifer storage site to identify secondary containment horizons and potential migration pathways out of the storage complex, in the unlikely event of a seal or fault leakage of the sequestered CO_2.

The Upper Cretaceous Chalk Group provides the ultimate, low risk, top seal for Lower Cretaceous sands. However the individual sand intervals of the Coracle further down the section rely on high risk intra-formational mudstones to separate them from the overlying Captain Sands.

The Georisk factor has been calculated as 13 which is higher than previous calculated factor in WP3 based on CO2Stored data. No faults in this aquifer had been previously identified in CO2Stored, however a review of the PGS CNS mega-survey identified several faults.

	Fault Characterisation			Seal Characterisation			Georisk Factor
	Density	Throw & Seal	Fault Vertical Extent	Fracture Pressure Capacity	Seal Chemical Reactivity	Sea Degradation	
CO2Stored Value	1	1	2	2	3	2	11
Due Diligence Value	2	2	2	2	3	2	13
Risk Factor Key: Low = 1, Medium = 2, High = 3							

Table 20: Coracle Aquifer Geo-Containment Risk

Engineering Risk

The engineering containment risk is moderate, with 224 wells in total, and 134 abandoned wells considered to be at risk of leakage. 6 wells were abandoned before 1986, representing the highest risk. The 100yr probability of a leakage on the field is moderate at 0.25, but the well density factor is 0.09 wells/km2, resulting in a moderate risk assessment score of 0.022.

Capacity

Seismic is not available over the full Coracle Sand polygon area, and a top structure map for the full area therefore cannot be generated. Due Diligence of the GRV is based on a simple area vs thickness, where the thickness is taken from wells and the area covered by seismic is used.

The calculated storage capacity is 35MT compared to the reported capacity in CO2Stored of 83MT. This is due to the 43% reduction in area used in the calculation, due to incomplete seismic availability, pro-rated the capacity for the area difference results in an estimate of 81MT.

Capacity Calculation:

Thickness[2] [m]	GRV [MMm3]	NTG[2]	Porosity[1]	CO_2 Density[3] [Tonnes/m3]	Pore Space Utilisation[3]	Pore Volume [MMm3]	Theoretical Capacity [MT]
124	81716	0.5	0.27	0.58	0.006	11032	35

Table 21: Coracle Aquifer Storage Capacity

NB. 1: DECC relinquishment reports (KNOC, 2009) 2: Estimated from CDA composite logs 3: CO2Stored

Thickness and NTG vary greatly across the Coracle Sands, both capacity and connectivity have high range of uncertainty associated with them

Injectivity

The selection criteria used for injectivity is the permeability thickness (Kh) value calculated using the mid case reservoir data from CO2Stored. For the Coracle Aquifer this was calculated as 378,585 mDm.

Field data and published literature have been reviewed in order to confirm the reservoir properties which have then been used to validate the permeability thickness and expected injectivity (Pinnock, S.J., Clitheroe, A. R .J., 2003; Evans, D. Graham, C, Armour A, and Bathurst, P., 2003).

The Coracle reservoir comprises moderate net to gross and excellent quality channelised deepwater sandstones of the Wick Sandstone Member. The reservoir properties are summarised below:

Zone	Depositional Environment	Gross Thickness [m]	NTG	Porosity	Perm [mD]	Kh [mDm]
Coracle	Channelized deepwater	124	0.50	0.27	4500	280,038

Table 22: Coracle Aquifer Reservoir Properties

The permeability thickness calculated during the validation process is 280,038 mDm. This is approximately 25% lower than the estimate based on the CO2stored data. CO2Stored assumes a thinner gross thickness but a higher average NTG. Well 12/25-2 provides a porosity2 and NTG average – however, this well sits outside the polygon. Permeability is also a mean taken from the DECC relinquishment report for Block 13/22d2.

The permeability thickness is very high and based on reservoir quality the initial CO_2 injectivity is expected to be excellent.

As an additional check a dynamic model was constructed to test the injectivity performance, at initial conditions and over time. A simple model was built in Eclipse (flat structure). CO_2 will be injected in critical or dense phase as the reservoir pressure is expected to be high in a saline aquifer. An injection pressure of 1900 psi achieves an injectivity of 1.45 MT/year per well. This is below the calculated minimum fracture pressure of 2858 psi at the top of the reservoir.

Well Design

The generic well design is discussed in the supporting document 'Storage Site Due Diligence Summary'. Due to the varying target depth, achieving this well design may be a challenge in the shallower areas of the Coracle aquifer. Targeting the deeper zones may be necessary.

Due to the deep water depth (98m), wells have been conservatively assumed to be drilled by Semi-Submersible Drilling Unit. Subsea well costs are assumed to be £27M per well, resulting in a 5 well development cost of £137M.

Development Concept

CO_2 volumes cf ETI Scenarios

The ETI Concentrated Scenario shows 11MT/yr by 2030 into the CNS via St Fergus. 1MT goes to Goldeneye. 10MT/yr of additional storage may be required by 2030.

Comparative development concept

A new subsea development, in the vicinity of Atlantic and Cromarty, with 5 deviated wells each injecting 1MT/yr; 100MT over 20 years. Re-use Atlantic and Cromarty 16” pipeline from St Fergus with 6MT/yr capacity. Facilities will be controlled from an existing nearby platform. Monitoring will include downhole pressure and distributed temperature sensors.

Site growth potential; theoretical ultimate development concept

The site has a theoretical storage capacity of ~81MT.

There is no significant site growth potential beyond the Comparative development concept and the theoretical capacity can be incorporated within the comparative development concept

Build out potential

The Coracle aquifer, could be built out to Captain. Also, being relatively close to shore, could be built out to Bruce, Harding, Grid aquifer. It also represents a suitable site for build out to EOR.

Development Cost

Capacity:	81	Water Depth (m)	99
Concept Cost (£m)	**Comparative Development**	**Ultimate Development**	**Description**
Tonnes Injected (MT)	35		Total Stored CO_2 for proposed scheme
Appraisal Cost:	£74m		Appraisal Wells + Seismic Data Acquisition & Interpretation
Development Well Cost:	£54.1m		Drilling & Completion Costs of wells.
Facilities Cost:	£33.8m		Landfall, Pipeline, Templates, ties-Ins,
PM & Eng:	£3.4m		10% of Facilities Costs
Decommissioning:	£24.5m		£8m per subsea well
Subtotal	£189.6m		
Contingency	£38m		20% of Development & Facilities Costs
OPEX (20years)	£40.5m		OPEX Cost for 20 years (6% of facilities costs)
Total:	£268m		
£/T CO_2	7.66		

Table 23: Coracle Aquifer Development Cost Estimate

*These costs are not the full cost of storage as they omit MMV, security instruments, handover to DECC and profit.

Data

Approximately one third of the storage site is covered by 3D seismic available in the PGS Mega survey. Degradation of data quality below chalk renders the seismic mapping of the Lower Cretaceous and Jurassic less reliable2. Coracle sands are represented by weak, discontinues seismic events within the Lower Cretaceous section. Interpreting top and base sandstone is difficult and the full extent of the stratigraphic pinch-out/seal will is uncertain due to limited data coverage. The well ties confirm the time interpretations.

Digital log data is available from CDA for several of the wells across the area.

No engineering data available for aquifer sands. Analogue data and correlations used.

Commercial Issues

As with other aquifers the exact development location is flexible. Therefore site access is unlikely to be an issue.

5 Forties 5 Aquifer

Overview

Capacity:	1021MT	UKCS Block:	22/12 vicinity
Unit Designation:	Saline Aquifer	Beachhead:	St Fergus
Formation:	Sele Formation	Water Depth:	80-120m
Earliest injection:	2028	Reservoir Depth:	2286m
Availability/COP:	n/a	Region:	CNS

Table 24: Forties Aquifer Overview

The results of the due diligence review confirm that the selection criteria used for Forties 5 are generally in agreement. A slight reduction in calculated capacity is caused by assuming a thinner average thickness.

- This "site" represents a regional system and very large aquifer, with a number of major oil and gas fields within it. Further work is needed to identify and select potential site(s) which could incorporate and/or overlap with depleted oil and gas fields.
- Checks of injectivity indicate that the target rate of 1MT/year/well can be met.
- The Georisk factor has been calculated as 16, the same as calculated in WP3.
- The additional risk assessment carried out for the engineering containment indicates that the risk is very high due to the very large number of abandoned and at risk wells, despite the large area covered by the target. To mitigate this risk, carefully selected injection sites could be considered (in low well density areas), and the migration path of the CO_2 plume closely considered.
- Well cost estimate (for 5 wells) is £217M

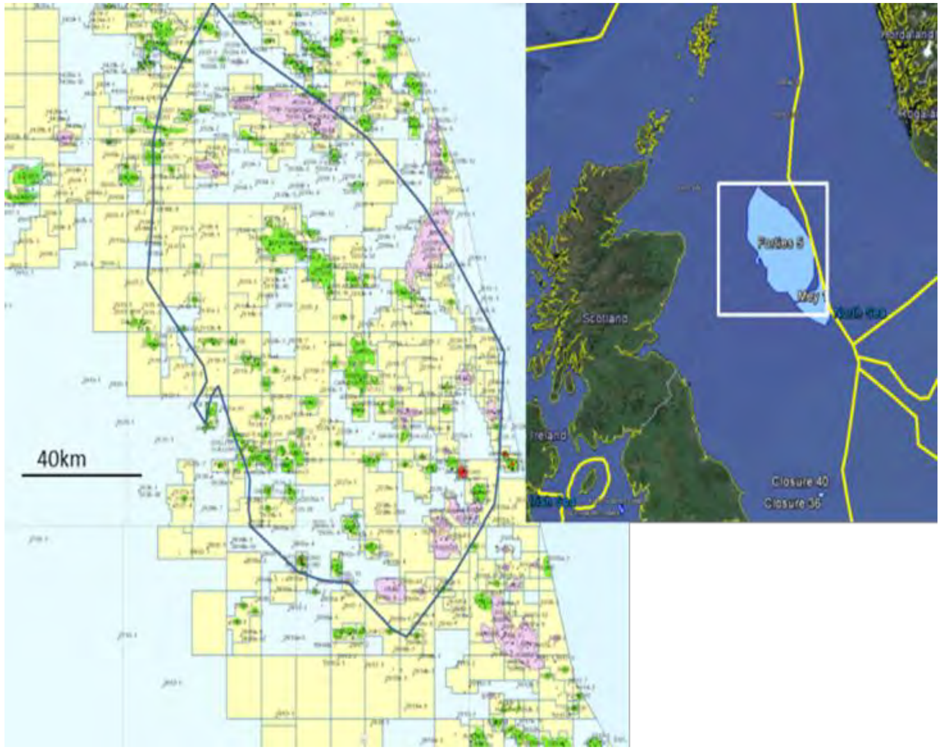


Figure 7: Forties Aquifer Location Map

Containment

An overburden assessment has been conducted above and adjacent to the Forties 5 saline aquifer storage site to identify secondary containment horizons and potential migration pathways out of the storage complex, in the unlikely event of a seal or fault leakage of the sequestered CO_2.
The primary seal for the Forties Sandstones are the overlying Sele Formation shales. These form the top seal for the Forties Sandstone hydrocarbon fields. Fault density is variable; there are large areas with no faulting. Containment risk would be dependent on the top seal and faulting within the local area of interest. The Georisk factor has been calculated as 16, this is the same as the previously calculated factor in WP3 based on CO2Stored data.

	Fault Characterisation			Seal Characterisation			Georisk Factor
	Density	Throw & Seal	Fault Vertical Extent	Fracture Pressure Capacity	Seal Chemical Reactivity	Sea Degradation	
CO2Stored Value	3	3	2	3	3	2	16
Due Diligence Value	2	2	2	2	3	2	16
Risk Factor Key: Low = 1, Medium = 2, High = 3							

Table 25: Forties Aquifer Geo-Containment Risk

Engineering Risk

The engineering containment risk is very high, with 2,106 wells in total, and 1,958 considered to be at risk of leakage. 1,190 wells were plugged and abandoned, 232 of which were before 1986, representing the highest risk. The 100yr probability of a leakage on the field is a near certain 0.98. However, the well density factor is a low 0.14 wells/km2. The resulting risk assessment score of 0.14 remains high. The area covered by the Forties 5 is a massive 13,804 km2 in a very productive area of the North Sea, hence the large number of existing wells. However, due to its size, there are also large areas where well density is relatively low. Should the Forties 5 be considered further, the location of injection wells and the plume migration path should be considered in order to significantly lower the risk of leakage. This would likely limit the overall area considered for storage.

Capacity

The calculated storage capacity is 1021MT compared to the reported capacity in CO2Stored of 1388MT. The capacity has decreased due to a reduction in the assumed average thickness

GRV for the Forties sandstone is calculated within the polygon area shown on the map (13,804 sq km). A simple calculation of area * thickness has been made.

Thickness [2] [m]	GRV [MMm3]	NTG [2]	Porosity[1]	CO_2 Density[3] [Tonnes/m3]	Pore Space Utilisation [3]	Pore Volume [MMm3]	Theoretical Capacity [MT]
134	1,849,682	0.68	0.23	0.63	0.006	289290	1021

Table 26: Forties Aquifer Storage Capacity

NB. 1: Analogue field data 2: Estimated from CDA composite logs 3: CO2Stored

Thickness and NTG are highly variable across the large Forties aquifer area. It should be possible to reduce some of this uncertainty range during any subsequent work phases both through more detailed modelling and analysis of data.

Injectivity

The WP3 selection criteria used for injectivity is the permeability thickness (Kh) value calculated using the mid case reservoir data from CO2Stored. For the Forties 5 saline aquifer this was calculated as 19,012 mDm.

Field data and published literature1 have been reviewed in order to confirm the reservoir properties which have then been used to validate the permeability thickness and expected injectivity.

Forties 5 aquifer consists of sandstones of Upper Paleocene Forties Sandstone member of the Sele Fm. and Moray Group (Carter and Heale, 2003). The aquifer extends over 7 quads, multiple blocks and fields – including the Forties Field. These Paleocene Forties reservoirs are found in Montrose, Arbroath, Everest, Nelson and Arkwright fields (Hollywood and Olson, 2010; Hogg, 2003).

Overall the variety of bed thickness ranges from the thicker central fan sequences in Forties, Montrose, Arbroath and Arkwright, to the thinner Nelson field Forties sand. Porosity generally is good for the fan sequences with the distal Forties facies in the Everest field showing diagenesis. Permeabilities reflect this with a large range over the Forties sand distribution.

Zone	Depositional Environment	Gross Thickness [m]	NTG	Porosity	Perm [mD]	Kh [mDm]
Forties	Submarine Fan	134	0.68	0.23	251	22,871

Table 27: Forties Aquifer Reservoir Properties

The permeability thickness calculated during the validation process is 22,871 mDm, which is in agreement with that calculated using CO2Stored data.

A dynamic model was also constructed to test the injectivity performance, at initial conditions and over time. A simple model was built in Eclipse (flat structure). CO_2 will be injected in critical or dense phase as the reservoir pressure is expected to be high in saline aquifer. The injectivity threshold of 1MT/year per well can be achieved with an injection pressure of 3200 psi, well below the fracture pressure of 3353 psi.

Well Design

The generic well design is discussed in the supporting document ‘Storage Site Due Diligence Summary’. It is likely that this well design can be achieved in the Forties 5.

Due to the moderate average water depth (80m), wells have been assumed to be drilled by a class 2 (Heavy Duty) Jack-Up Drilling Unit. Subsea well costs are assumed to be £43M per well, resulting in a 5 well development cost of £217M.

Development Concept

CO_2 volumes cf ETI Scenarios

The ETI Concentrated Scenario shows 11MT/yr by 2030 into the CNS via St Fergus. 1MT goes to Goldeneye. 10MT/yr of additional storage may be required by 2030

Comparative development concept

A new subsea development with 5 deviated wells each injecting 1MT/yr; totalling 100MT over 20 years. CO_2 would be delivered via a new 20” 186km pipeline from St Fergus with 10MT/yr capacity. Power and controls will be supplied from an existing neighbouring platform. Monitoring will include downhole pressure and distributed temperature sensors.

Site growth potential; theoretical ultimate development concept

The site has a theoretical storage capacity of ~1400MT; The capacity is constrained to 1000MT for this prospect evaluation stage.

A new subsea development comprising of 10 subsea manifolds each with 5 wells injecting a total of 50Mt/yr; totalling 1000MT over 20 years. CO_2 would be delivered via a 36” 186km pipeline from St Fergus with a 50Mt/yr capacity. Facilities will be controlled from the beach. Power and controls will be supplied from an existing neighbouring platform or a dedicated facility. Subsea centres are connected by 10km infield pipelines and umbilicals.

Build out potential

Forties 5 aquifer is en-route to the Maureen 1 and Mey 1 aquifers, which represent additional build out potential should it be required.

Development Cost

Capacity:	1021	Water Depth (m)	80
Concept Cost (£m)	**Comparative Development**	**Ultimate Development**	**Description**
Tonnes Injected (MT)	100	1000	Total Stored CO_2 for proposed scheme
Appraisal Cost:	£86m	£86m	Appraisal Wells + Seismic Data Acquisition & Interpretation
Development Well Cost:	£215.4m	£2153.5m	Drilling & Completion Costs of wells.
Facilities Cost:	£247.9m	£727.2m	Landfall, Pipeline, Templates, ties-Ins,
PM & Eng:	£24.8m	£72.8m	10% of Facilities Costs
Decommissioning:	£102m	£581.8m	£8m per subsea well
Subtotal	£676m	£3621.1m	
Contingency	£135.2m	£724.3m	20% of Development & Facilities Costs
OPEX (20years)	£297.4m	£872.6m	OPEX Cost for 20 years (6% of facilities costs)
Total:	£1108.5m	£5217.9m	
£/T CO_2	11.08	5.22	

Table 28: Forties Aquifer Development Cost Estimate

*These costs are not the full cost of storage as they omit MMV, security instruments, handover to DECC and profit.

Data

Approximately 95% of Forties 5 aquifer sandstone is covered by 3D seismic within the CNS PGS megasurvey. Data coverage in the northern part of the site is not as extensive as it is to the south. The data quality is generally good. The well ties confirm the seismic time interpretation, however for WP4 the top Forties sandstone member had not been mapped.

2,106 wells have been drilled in this area and a range of digital and non-digital data are available.

There are no engineering data available for aquifer sands. Analogue data and correlations will be used. Some data may be available from Forties reservoir fields.

Commercial Issues

The Forties aquifer covers a large area and therefore the centre of the development has some flexibility. Many of the blocks in the area are licensed for oil and gas, but site flexibility would suggest that access should not be an issue. It is possible that some hydrocarbon fields may still be producing when storage operations commence and the potential impact between the two operations would form part of the development plan for the store.

6 Grid Aquifer

Overview

Capacity:	1825MT	UKCS Block:	16/7 vicinity
Unit Designation:	Saline Aquifer	Beachhead:	St Fergus
Formation:	Horda formation	Water Depth:	120m
Earliest injection:	2028	Reservoir Depth:	1249m
Availability/COP:	N/A	Region	CNS

Table 29: Grid Aquifer Overview

The results of the due diligence review have identified an error with the reported capacity in CO2Stored. Permeability thickness has also reduced, but is still very high.

- This "site" represents a regional system and very large aquifer and further work is needed to identify and select potential site(s).
- Checks of injectivity indicate that the target rate of 1MT/year/well can easily be met below the min fracture pressure.
- The Georisk factor has been calculated as 10. This is an increase from 8 (calculated in WP3).
- Risk of closure in the vast size of the Grid Sandstone region has been identified. The Grid Sand extends into the Norwegian blocks to the East.
- The potential for hydraulic connectivity to underlying formations and variable degrees of sand remobilisation are additional uncertainties.
- Assuming injection closest to the shore, the NTG in the south is lower, however good average porosity and permeabilities are noted.
- Reservoir quality deteriorates from 95% NTG in north-west to 40-50% in south (Evans, D. Graham, C, Armour A, and Bathurst, P., 2003).
- The additional risk assessment carried out for the engineering containment indicates that the risk is very high due to the very large number of abandoned and at risk wells, despite the large area covered by the target. To mitigate this risk, carefully selected injection sites could be considered (in low well density areas), and the migration path of the CO_2 plume closely considered.
- Well cost estimate (for 5 wells) is £126M.

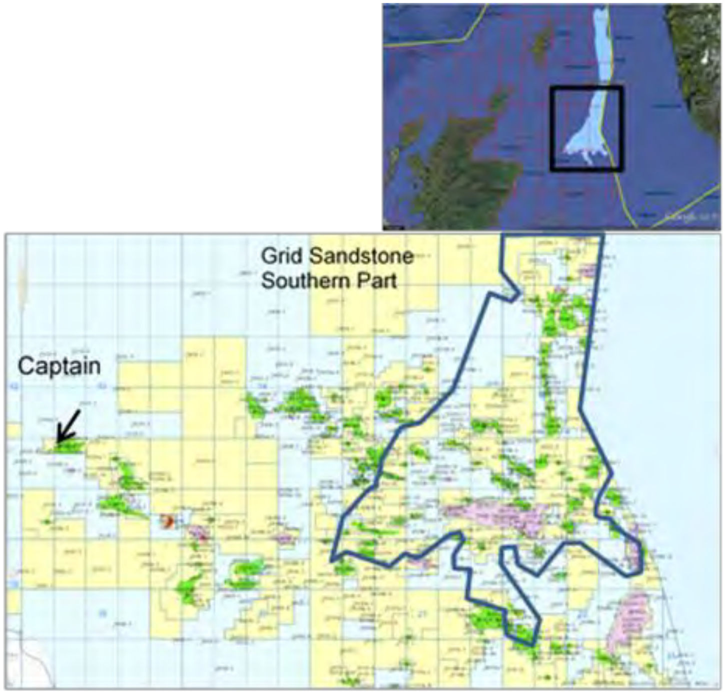


Figure 8: Grid Aquifer Location Map

Containment

An overburden assessment has been conducted above and adjacent to the Grid saline aquifer storage site to identify secondary containment horizons and potential migration pathways out of the storage complex, in the unlikely event of a seal or fault leakage of the sequestered CO_2.

The site is a large extensive turbidite system with a combined stratigraphic closure to the west and structural closure to the east. Depositional factors influence sand body thickness, geometry & orientation. Eocene silty shales and claystones of the Horda Mudstone group form a thick overlying seal (Evans, D. Graham, C, Armour A, and Bathurst, P., 2003).

The Georisk factor has been calculated as 10, this is higher than previous calculated factor in WP3 based on CO2Stored data. No faults in this aquifer had been previously identified in CO2Stored, however a review of the PGS CNS mega-survey identified extensive polygonal faulting within the Grid Sandstone.

	Fault Characterisation			**Seal Characterisation**			**Georisk Factor**
	Density	Throw & Seal	Fault Vertical Extent	Fracture Pressure Capacity	Seal Chemical Reactivity	Sea Degradation	
CO2Stored Value	1	2	1	1	2	1	8
Due Diligence Value	3	2	1	1	2	1	10
Risk Factor Key: Low = 1, Medium = 2, High = 3							

Table 30: Grid Aquifer Geo-containment Risk

Engineering Risk

The engineering containment risk is very high, with 3,580 wells in total, and 3,540 considered to be at risk of leakage. 2,052 wells were plugged and abandoned, 502 of which were before 1986, representing the highest risk. The 100yr probability of a leakage on the field is a near certain 0.99. However, the well density factor is a low 0.22 wells/km2. The resulting risk assessment score of 0.21 remains high. The area covered by the Grid Sandstone Member is a massive 16,000km2 in a very productive area of the North Sea, hence the large number of existing wells. However, due to its size, there are also large areas where well density is relatively low. Should the Grid Sandstone member be considered further, the location of injection wells and the plume migration path should be considered in order to significantly lower the risk of leakage. This would likely limit the overall area considered for storage.

Capacity

The calculated storage capacity is 1825MT (based on the CO2Stored shape-file area) compared to the reported 175MT capacity in CO2Stored. The area reported in CO2Stored is 1,712 km^2, however the shape-file area in CO2stored is 16,106 km^2 and thus CO2Stored understates the capacity.

GRV for the grid sandstone is calculated as polygon area x average thickness.

Thickness[2] [m]	GRV [MMm3]	NTG[2]	Porosity[1]	CO_2 Density[3] [Tonnes / m3]	Pore Space Utilisation[3]	Pore Volume [MMm3]	Theoretical Capacity [MT]
150	2,415,960	0.65	0.325	0.65	0.006	510372	1825

Table 31: Grid Aquifer Storage Capacity

NB. 1: Analogue field 2: Estimated from CDA composite logs 3: CO2Stored

Injectivity

The selection criteria used for injectivity is the permeability thickness (Kh) value calculated using the mid case reservoir data from CO2Stored. For the Grid Sandstone Aquifer this was calculated as 612,500 mDm.

Field data and published literature have been reviewed in order to confirm the reservoir properties which have then been used to validate the permeability thickness and expected injectivity (Kilhams B Godfrey S, Hartley A, Huuse, M., 2011).

The aquifer comprises high net to gross, excellent to moderate quality remobilised6 sandstones of the Grid Sandstone Member (Weisenburn, T., Hague, P., 2005; Robertson, J., 2013).

The sandstone can be divided into two units – the Caran and Brodie sandstones. A summary of the reservoir properties are summarised below:

Zone	Depositional Environment	Gross Thickness [m]	NTG	Porosity	Perm [mD]	Kh [mDm]
Grid	Shallow & Deep Water deposits Remobilised Sandstones	150	0.65	0.325	2600	253,500

Table 32: Grid Aquifer Reservoir Properties

The permeability thickness calculated during the validation process is 253,500 mDm, significantly lower than the estimate based on the CO2Stored data. CO2Stored assumes a thicker gross thickness than that seen at the well data in the store area. Permeability is also lower compared to published data on fields which hold Grid Sandstone time equivalent sands. The permeability thickness however is still high and based on reservoir quality the initial CO_2 injectivity is expected to be excellent.

A dynamic model was constructed to test the injectivity performance, at initial conditions and over time. A simple model was built in Eclipse (flat structure). CO_2 will be injected in critical or dense phase as the reservoir pressure is expected to be high in saline aquifer. An injection pressure of 1700 psi achieves injectivity well above the threshold of 1MT/year per well, without exceeding the min fracture pressure of 2184 psi at the well depth.

Well Design

The generic well design is discussed in the supporting document 'Storage Site Due Diligence Summary'. It is likely that this well design can be achieved in the Grid Sandstone Member at its deeper points, but may be challenging in shallower depths (the reservoir is extensive and depths vary considerably).

Due to the moderate water depth (120m), wells have been assumed to be drilled by a class 2 (Heavy Duty) Jack-Up Drilling Unit. Subsea well costs are assumed to be £25.2M per well, resulting in a 5 well development cost of £127M.

Development Concept

CO_2 volumes of ETI Scenarios

The ETI Concentrated Scenario shows 11MT/yr by 2030 into the CNS via St Fergus. 1MT goes to Goldeneye. 10MT/yr of additional storage may be required by 2030

Comparative development concept

A new subsea development, in the vicinity of Miller, with 5 deviated wells each injecting 1MT/yr; 100MT over 20 years. Re-use MGS 30" pipeline from St Fergus with 35MT/yr capacity. Power and controls will be supplied from an existing neighbouring platform. Monitoring will include downhole pressure and distributed temperature sensors.

Site growth potential; theoretical ultimate development concept

The site has a theoretical storage capacity of ~175MT.

2 subsea manifolds each with 5 wells injecting a total of 10Mt/yr; 200MT over 20 years. Re-use MGS 30" pipeline from St Fergus with 35MT/yr capacity Power and controls will be supplied from an existing neighbouring platform. Subsea centres are connected by 10km infield pipelines and umbilicals.

Build out potential

Grid is the most Northerly aquifer considered as part of the Select inventory. Build out could be at Bruce or Harding. The site is also suitable as a centre for build out for EOR.

Development Cost

Capacity:	1825	Water Depth (m)	90
Concept Cost (£m)	Comparative Development	Ultimate Development	Description
Tonnes Injected (MT)	100	1000	Total Stored CO_2 for proposed scheme
Appraisal Cost:	£68m	£68m	Appraisal Wells + Seismic Data Acquisition & Interpretation
Development Well Cost:	£125.8m	£1257.8m	Drilling & Completion Costs of wells.
Facilities Cost:	£38.1m	£441.9m	Landfall, Pipeline, Templates, ties-Ins,
PM & Eng:	£3.9m	£44.2m	10% of Facilities Costs
Decommissioning:	£49.6m	£510.5m	£8m per subsea well
Subtotal	£285.1m	£2322.4m	
Contingency	£57.1m	£464.5m	20% of Development & Facilities Costs
OPEX (20years)	£45.7m	£530.3m	OPEX Cost for 20 years (6% of facilities costs)
Total:	£387.8m	£3317.1m	
£/T CO_2	3.88	3.32	

Table 33: Grid Aquifer Development Cost Estimate

*These costs are not the full cost of storage as they omit MMV, security instruments, handover to DECC and profit.

Data

Approximately 90% of Grid Sandstone is covered by the 3D seismic from the PGS megasurvey. Data coverage in the north western part of the site is not as extensive as it is to the south west, making it difficult to completely map the stratigraphic closure to the west in areas. The data quality is generally good. The well ties confirm the time interpretation.

A significant number of wells cover this vast area. Certain wells from fields have been selected in the southern part and downloaded from CDA. Exploration wells outside of producing fields in the centre and northern coverage of the Grid Sandstone have also been downloaded. Wells 9/23b-26 and 22/02-11 provide a well time for the Grid Sandstone member.

No engineering data available for aquifer sands. Analogue data and correlations will be used.

Commercial Issues

The Grid aquifer covers a significant area of the Central and Northern N Sea. For the development concept above it is assumed that the development is centred in the Miller area, to benefit from the re-use of the Miller pipeline. Although petroleum activity has ceased in this field, we understand the petroleum licences are still held by the relevant oil companies (BP, Shell, Conoco). Acquisition of the MGS pipeline would be required for this development scenario.

It is possible that some hydrocarbon fields may still be producing when storage operations commence and the potential impact between the two operations would form part of the development plan for the store.

7 Harding Central Oil Field

Overview

Capacity:	76MT	UKCS Block:	9/23
Unit Designation:	Oil and Gas	Beachhead:	St Fergus
Formation:	Balder formation	Water Depth:	110m
Earliest injection:	2027	Reservoir Depth:	1684m
Availability/COP:	2025	Region:	CNS

Table 34: Harding Field Overview

The results of the due diligence review confirm the injectivity and containment values are in agreement. There are however large risks associated with containment, with significant risks associated with both geological and engineering containment.

- Checks of injectivity indicate that the target rate of 1MT/year/well can be met.
- Geological containment risk is identified as medium.
- The additional risk assessment carried out for the engineering containment risk indicates that the risk is high due to the large number of abandoned and at risk wells in a relatively small area.
- Well cost estimate (for 5 wells) is £170M.

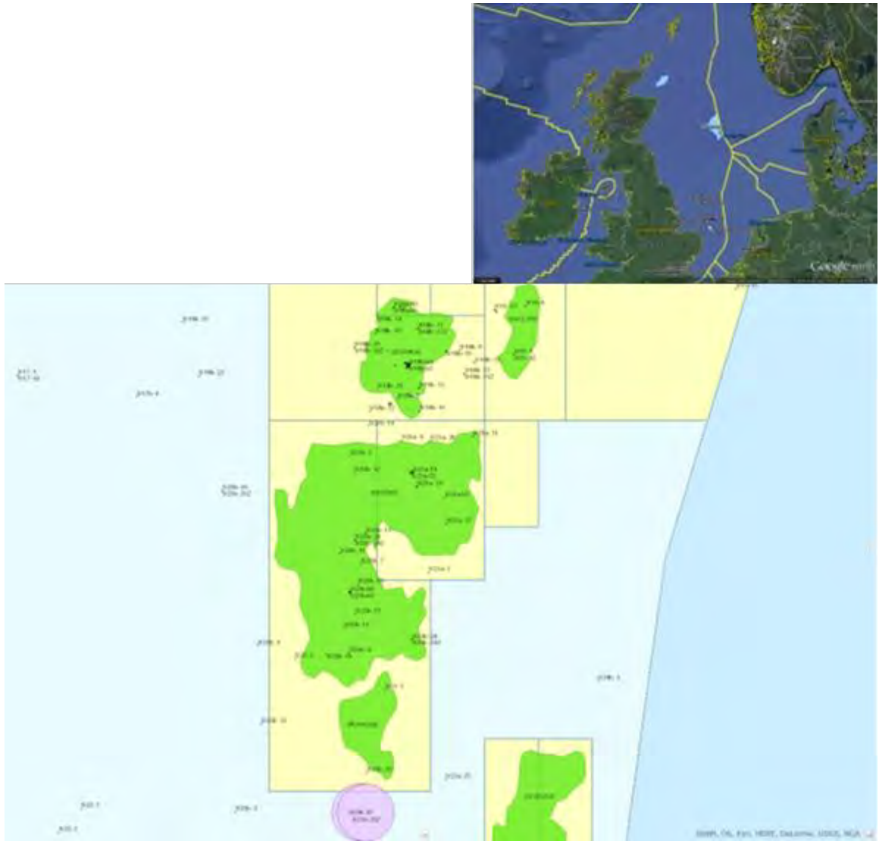


Figure 9: Harding Field Location Map

Containment

An overburden assessment has been conducted above and adjacent to the Central Harding field to identify secondary containment horizons and potential migration pathways out of the Harding storage complex, in the unlikely event of a seal or fault leakage of the sequestered CO_2.

Field data and published literature were reviewed to establish the effectiveness of trap and seal. Depth to crest of the reservoir is ~1548m (5080ft), with stratigraphic and structural trap – compactional drape to the west1. The T60 interval above the Upper Sandy Unit provides an effective overburden seal to the Harding field1. CO_2 is not expected to leak through the top Mercia seal which has already trapped Harding hydrocarbons over geological time. Each accumulation in the Harding field is isolated with the underlying Sele Fm. providing a suitable underburden seal for containment.

	Fault Characterisation			Seal Characterisation			Georisk Factor
	Density	Throw & Seal	Fault Vertical Extent	Fracture Pressure Capacity	Seal Chemical Reactivity	Sea Degradation	
CO2Stored Value	2	2	1	1	1	1	8
Due Diligence Value	2	2	1	1	1	2	9
Risk Factor Key: Low = 1, Medium = 2, High = 3							

Table 35: Harding Field Geo-containment Risk

There is however significant risk associated with containment between the different Harding area fields (Harding Central/ North, Gryphon and Maclure). Due to the injected nature of the reservoir sands, connectivity is extremely complex and often sub-seismic resolution. It is however known that several of the Harding and Gryphon accumulations show connection through the gas cap. This is not captured in the georisk factor as defined in CO2Stored.

Engineering Risk

The engineering containment risk for the Harding complex is high, with 95 wells in total, and 86 considered to be at risk of leakage. 65 wells were plugged and abandoned, but only 1 of which was before 1986, representing the highest risk. The 100yr probability of a leakage on the field is a moderate 0.17, but the well density factor is very high at 17.2 wells/km2, resulting in a very high risk assessment score of 2.86.

Capacity

The calculated storage capacity is 84.8MT compared to the reported capacity in CO2Stored of 76.2MT. They are in reasonable agreement.

For the Harding Central oil field, the due diligence involves a recalculation of the capacity equivalent to the net reservoir volume of fluids removed at February 2015. In addition, the net reservoir volume of fluids removed at COP was estimated and the capacity calculated at this time to confirm the full capacity estimate. The COP date for Harding Central field in the supplied Woodmac data is 2025.

Harding Central field produces oil with associate gas and water production. Pressure support has been achieved with water and gas injection. All produced and injected fluids were accounted for in the material balance calculation to check potential storage capacity.

Current oil rates are ~1900sm3/d (~12000bbls/d). The production estimate between February 2015 and end 2025 (COP) equates to an uplift in storage capacity of 6MT (~8%)

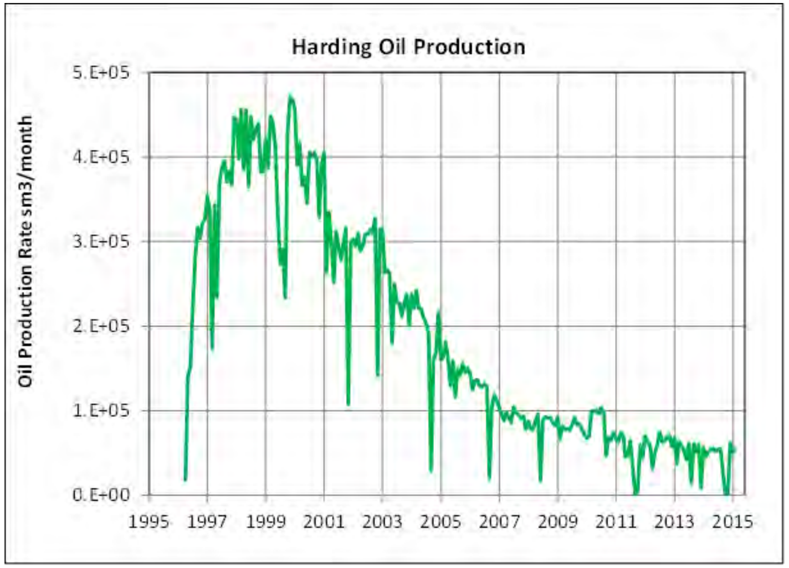


Figure 10: Harding Field Oil Production Profile

The produced volumes and conversion to mass storage potential are shown in Table 36:

Oil Production	**42.5**	**MCM**
Gas Production	3262	MCM
Water Production	100.2	MCM
Water Injection	27.5	MCM
Gas Injection	991	MCM
Net Reservoir Volume Produced	115	MCM
Storage Capacity @COP	84.7	MT

Table 36: Harding Field Storage Capacity

NB. Volumes refer to production volumes at February 2015.
The volumes and shrinkage factors used in the calculation are shown in the table below.

Parameter		**Reference**	**CO2Stored**
CO_2 density (kg/m3)	683	CO_2 Storage potential in UK-BGS Study	680
Gas expansion factor (rm3/sm3)	0.006	Ref 1. Uk Oil and Gas Fields Data	0.01
Oil formation volume factor (rm3/sm3)	1.11	Ref 1. Uk Oil and Gas Fields Data	1.11
Water formation volume factor (rm3/sm3)	1.02	Analogue	1.02

Table 37: Harding Field Fluid Properties

Harding Central is a well-connected, high NTG sand. There are not expected to be any issues related to compartmentalisation. Confidence in the storage capacity is high.

Injectivity

The selection criteria used for injectivity is the permeability thickness (Kh) value calculated using the mid case reservoir data from CO2Stored. For the Harding Field this was calculated as 723,900 mDm.

Field data and published literature have been reviewed in order to confirm the reservoir properties which have then been used to validate the permeability thickness and expected injectivity (Beckly, A. J., Nash, T., Pollard, R. Bruce, C. Freeman, P and Page, G., 2003).

The Harding field is split by multiple accumulations: North, Central and South. The CO_2 storage assessment concentrates only on the Central reservoir. Two reservoir zones are identified which vary in net to gross, but have excellent quality mass flow and remobilised sandstones of the Eocene Balder Formation. No field wide permeability barriers or baffles exist horizontally or vertically, with communication to the upper injected sandstones confirmed by pressure data.

Zone	Depositional Environment	Gross Thickness [m]	NTG	Porosity	Perm [mD]	Kh [mDm]
Upper Sandy Unit	Remobilised injected SST	7	0.32	0.35	10000	23,520
Massive Sand	Eocene Balder mass flow	113	0.99	0.33	6300	703,534
All Zones		120	0.95	0.34	8150	929,296

Table 38: Harding Field Reservoir Properties

The permeability thickness calculated during the validation process for the primary, massive sandstone reservoir interval is 703,534mDm This is approx. 3% lower than the estimate based on the CO2Stored data. Log data from CDA has a larger gross thickness, than the mid case used in the CO_2 storage calculation, and is representative of the average thickness quoted in published literature1. NTG, poro and perm for the Upper Sandy Unit is taken from the average values quoted by Beckly et al. (2003), whereas the Massive Sand derives average core data from well 9/23b-11. Well 9/23b-26 provided an approximate NTG for the Upper Sand Unit.

The permeability thickness is very high and based on reservoir quality and the initial CO_2 injectivity is expected to be excellent.

Two additional injectivity checks were carried out as part of the due diligence.

The initial production performance per well was converted to an equivalent CO_2 injection rate to gain some confidence that the 1MT/year/well target could be met. The rates are shown in the table below. All wells exceed the target rate.

Estimated CO_2 injection rate	
Well	Tonnes/day
A1	495864
A2	255139
A4	464145
A6	426187
A9	217795
A11	256875
A12	269389
A14	174092
A15	209299
A16	271591
A17	166366
A19	86900

Table 39: Harding Field Well Injectivity

Heavy oil gives very high potential injectivity due to high in situ oil viscosity. Very high injectivity supported by high permeability value (see above). Note that in reality wells will not be able to deliver this amount of CO_2 to the sandface.

As a further check a dynamic model was constructed to test the injectivity performance, at initial conditions and over time. A simple model was built in Eclipse (flat structure). CO_2 will be injected in critical or dense phase as the reservoir pressure is expected to be same or more than initial reservoir pressure as pressure maintenance is done in oil field. An injection pressure of 2750 psi achieves an injectivity of 1.23 MT/year per well. This is below the calculated minimum fracture pressure of 3790 psi assuming fracture gradient of 0.702 psi/ft

Well Design

The generic well design is discussed in the supporting document 'Storage Site Due Diligence Summary'. It is likely that this well design can be achieved in the Harding Central Oilfield.

Due to the deep water depth (107m), wells have been assumed to be drilled by Semi-Submersible Drilling Unit. Subsea well costs are assumed to be £42.5M per well, resulting in a 5 well development cost of £215M.

Development Concept

CO_2 volumes cf ETI Scenarios

The ETI Concentrated Scenario shows 11MT/yr by 2030 into the CNS via St Fergus. 1MT goes to Goldeneye. 10MT/yr of additional storage may be required by 2030

Comparative development concept

A new subsea development, in the vicinity of Harding, with 5 deviated wells each injecting 1MT/yr; 100MT over 20 years. Re-use MGS 30" pipeline from St Fergus with 35MT/yr capacity, with a new 20" 68km pipeline extension to Harding. Power and controls will be supplied from an existing neighbouring platform. Monitoring will include downhole pressure and distributed temperature sensors.

Site growth potential; theoretical ultimate development concept

The site has a theoretical storage capacity of ~76MT.

The is no site growth potential beyond the Comparative development concept

Build out potential

Build out could be at the Grid aquifer or Bruce. The site is also suitable as a centre for build out for EOR.

Development Cost

Capacity:	85	Water Depth (m)	110
Concept Cost (£m)	**Comparative Development**	**Ultimate Development**	**Description**
Tonnes Injected (MT)	80		Total Stored CO_2 for proposed scheme
Appraisal Cost:	£0m		Appraisal Wells + Seismic Data Acquisition & Interpretation
Development Well Cost:	£170.2m		Drilling & Completion Costs of wells.
Facilities Cost:	£115.3m		Landfall, Pipeline, Templates, ties-Ins,
PM & Eng:	£11.6m		10% of Facilities Costs
Decommissioning:	£60.9m		£8m per subsea well
Subtotal	£357.9m		
Contingency	£71.6m		20% of Development & Facilities Costs
OPEX (20years)	£138.4m		OPEX Cost for 20 years (6% of facilities costs)
Total:	£567.8m		
£/T CO_2	7.10		

Table 40: Harding Field Development Cost Estimate

*These costs are not the full cost of storage as they omit MMV, security instruments, handover to DECC and profit.

Data

Harding Field area is entirely covered by good quality 3D seismic data provided by the CNS PGS seismic megasurvey.

Digital log data is available for several of the wells across the area.

Commercial Issues

The COP date for Harding is currently 2025. Harding is operated under Petroleum License P478 by Taqa.

8 Maureen Aquifer

Overview

Capacity:	101MT	UKCS Block:	30/1 vicinity
Unit Designation:	Saline Aquifer	**Beachhead:**	St Fergus
Formation:	Maureen	**Water Depth:**	80m
Earliest injection	2028	**Reservoir Depth:**	2900m
Availability/COP:	n/a	**Region:**	CNS

Table 41: Maureen Aquifer Overview

The results of the due diligence review show the selection criteria to be lower than reported in CO2Stored. Whilst the capacity is still reasonable, a reduction in rock quality and net sand thickness has greatly reduced the permeability thickness.

- Checks of injectivity indicate that the target rate of 1MT/year/well cannot be met. There is also uncertainty related to possible over-pressuring of the sands in the storage area.
- The Georisk factor has been calculated as 14. Slightly lower than that calculated in WP3. There are risks identified with containment related to the quality of the seal.
- The additional risk assessment carried out for the engineering containment indicates that the risk is moderate to high due to the large number of abandoned and at risk wells, and is only kept out of the very high risk bracket by the large site area (3614km2).
- Well cost estimate (for 5 wells) is £172M.

Figure 11: Maureen Aquifer Location Map

Containment

An overburden assessment has been conducted above and adjacent to the Maureen 1 saline aquifer storage site to identify secondary containment horizons and potential migration pathways out of the storage complex, in the unlikely event of a seal or fault leakage of the sequestered CO_2.

The primary seal for the Maureen Sands are shales of the overlying Palaeocene Lista Formation. However hydrocarbons within the Paleocene normally occur in the highest reservoir unit in any well from which it can be deduced that Palaeocene shales do not generally form reliable seals. There is therefore a high risk of migration into the overlying Palaeocene Mey and Forties sands which are also present over this region.

The Georisk factor has been calculated as 14 which is lower than the previous calculated factor in WP3 based on CO2Stored data. A review of the PGS CNS mega-survey could find no faults extending upwards to shallower than 800m.

	Fault Characterisation			Seal Characterisation			Georisk Factor
	Density	Throw & Seal	Fault Vertical Extent	Fracture Pressure Capacity	Seal Chemical Reactivity	Sea Degradation	
CO2Stored Value	3	3	3	1	3	2	15
Due Diligence Value	3	3	2	1	3	2	14
Risk Factor Key: Low = 1, Medium = 2, High = 3							

Table 42: Maureen Aquifer Geo-containment Risk

Engineering Risk

The engineering containment risk is moderate to high, with 518 wells in total, and 300 abandoned wells considered to be at risk of leakage. 53 of these abandonments were before 1986, representing the highest risk. The 100yr probability of a leakage on the field is a high 0.6, and the well density factor is 0.08 wells/km2, resulting in a moderate risk assessment score of 0.05. However, localised well density is such that injection sites and CO_2 plume pathways need to be carefully selected to avoid producing fields. Should a smaller section of the Maureen 1 be considered, this risk review should be revisited.

Capacity

The calculated storage capacity is 101MT compared to the reported capacity in CO2Stored of 138MT. The drop in capacity is related to a thinner net thickness due to a reduced average NTG in the wells within the Maureen 1 area when compared to what has been reported in CO2Stored.

Thickness[2] [m]	GRV [MMm3]	NTG[2]	Porosity[1]	CO2 Density[3] [Tonnes/m3]	Pore Space Utilisation[3]	Pore Volume [MMm3]	Theoretical Capacity [MT]
75	267,475	0.34	0.25	0.78	0.006	22735	101

Table 43: Maureen Aquifer Storage Capacity

NB. 1: Analogue field data 2: Estimated from CDA composite logs 3: CO2Stored

The Maureen 1 store is at the southern end of the Maureen sand depositional system resulting in thinner sands and a big reduction in the NTG seen within the Maureen Formation. There is a far greater proportion of non-net siltstones and claystones than is seen in the Northern Maureen Formation intervals.

Reservoir sand presence and thickness is highly variable across the area, there is a high degree of uncertainty with the storage capacity that has been calculated.

Injectivity

The selection criteria used for injectivity is the permeability thickness (Kh) value calculated using the mid case reservoir data from CO2Stored. For the Maureen 1 this was calculated as 10,978 mDm.

The permeability thickness calculated during the validation process is 2,550 mDm. This is approx. 75% lower than the estimate based on the CO2Stored data. This is largely caused by the lower average permeability that has been assumed, although the assumed lower average NTG also contributes.

Zone	Depositional Environment	Gross Thickness[2] [m]	NTG[2]	Porosity[1]	Perm[1] [mD]	Kh [mDm]
Maureen	S. fan/ turbidite	75	0.34	0.25	100	2,550

Table 44: Maureen Aquifer Reservoir Properties

NB. 1: Analogue field data – Maureen Field aquifer 2: Estimated from CDA composite logs 3: CO2Stored

No permeability data is available for Maureen Sands at the storage site, permeability, its regional lateral variation and heterogeneity remain a big uncertainty.

Reservoir properties for the Maureen Field are excellent with permeabilities up to 1500 mD, but it is a significant distance to the North and approximately 500m shallower. Permabilities within the Maureen Field aquifer are much reduced, generally less than 100mD (Cutts, P. L., 1991).

Published permeability versus depth for Paleocene reservoirs also suggests values of less than 100mD at the depths for this store (Evans, D. Graham, C, Armour A, and Bathurst, P., 2003).

Based on these observations an average permeability of 100 mD has been assumed.

A dynamic model was constructed to test the injectivity performance, at initial conditions and over time. A simple model was built in Eclipse (flat structure). CO_2 will be injected in critical or dense phase as the reservoir pressure is expected to be high in the saline aquifer.

An injection pressure of 6300 psi does achieve the threshold of 1MT/year per well, but exceeds the assumed minimum fracture pressure of 5917 psi (based on a frac gradient of 0.726 psi/ft).

There is some evidence from published literature that the Maureen may be over pressured by up to 2000 psi at the southern end. A sensitivity was run and an injection pressure of 7917 psi achieves an injection of 1.01MT/year per well, however this is well above the calculated minimum fracture pressure of 5912 psi.

There is uncertainty associated with the assumed minimum fracture pressure, however achieving the required injectivity is identified as a risk.

Well Design

The generic well design is discussed in the supporting document 'Storage Site Due Diligence Summary'. It is likely that this well design can be achieved in the Maureen 1.

Due to the moderate water depth (80m), have been assumed to be drilled by a class 2 (Heavy Duty) Jack-Up Drilling Unit. Subsea well costs are assumed to be £34.4M per well, resulting in a 5 well development cost of £173M.

Development Concept

CO_2 volumes of ETI Scenarios

The ETI Concentrated Scenario shows 11MT/yr by 2030 into the CNS via St Fergus. 1MT goes to Goldeneye. 10MT/yr of additional storage may be required by 2030

Comparative development concept

A new subsea development with 5 deviated wells each injecting 1MT/yr; totalling 100MT over 20 years. CO_2 will be delivered via a new 20" 255 km pipeline from St Fergus with 10MT/yr capacity. Power and controls will be supplied from an existing neighbouring platform.

Site growth potential; theoretical ultimate development concept

The site has a theoretical storage capacity of ~101MT.

The site has no additional growth potential.

Build out potential

The Mey aquifer is close to the Maureen aquifer which could act as a build out option. Both of these sites could be build out for the Forties aquifer

Development Cost

Capacity:	101	Water Depth (m)	80
Concept Cost (£m)	**Comparative Development**	**Ultimate Development**	**Description**
Tonnes Injected (MT)	100	160	Total Stored CO_2 for proposed scheme
Appraisal Cost:	£76m	£76m	Appraisal Wells + Seismic Data Acquisition & Interpretation
Development Well Cost:	£172.1m	£275.3m	Drilling & Completion Costs of wells.
Facilities Cost:	£317.5m	£363.7m	Landfall, Pipeline, Templates, ties-Ins,
PM & Eng:	£31.8m	£36.4m	10% of Facilities Costs
Decommissioning:	£119.4m	£155m	£8m per subsea well
Subtotal	£716.6m	£906.3m	
Contingency	£143.4m	£181.3m	20% of Development & Facilities Costs
OPEX (20years)	£380.9m	£436.5m	OPEX Cost for 20 years (6% of facilities costs)
Total:	£1240.8m	£1524m	
£/T CO_2	12.41	9.52	

Table 45: Maureen Aquifer Development Cost Estimate

*These costs are not the full cost of storage as they omit MMV, security instruments, handover to DECC and profit.

Data

Approximately 98% of Maureen 1 aquifer sandstone is covered by the 3D seismic by the CNS PGS Megasurvey. The data quality is generally good. The well ties confirm the PGS time interpretations, however the top Maureen sandstone member had not been mapped.

A significant amount of wells cover this area and a range of digital and non-digital data are available. Offset poro/perm data may not be readily available for the aquifer section of the Maureen Sand.

No engineering data available for aquifer sands. Analogue data and correlations will be used.

Commercial Issues

The Maureen aquifer could be developed from within a wide area in upper Block 29. As such, although most of this area is licensed for petroleum, it is not expected that petroleum license interaction will limit development potential.

9 Mey Aquifer

Overview

Capacity:	22MT	UKCS Block:	30/1 (vicinity)
Unit Designation:	Saline Aquifer	Beachhead:	St Fergus
Formation:	Lista	Water Depth:	80m
Earliest injection year:	2028	Reservoir Depth:	2845m
Availability/COP:	n/a	Region:	CNS

Table 46: Mey Aquifer Overview

The results of the due diligence review show the selection criteria to be lower than reported in CO2Stored. The thicknesses and NTG recorded in CO2Stored appear to be grossly overestimated, perhaps representative of the Mey sands to the North, which have not been reviewed here. Average permeabilities in CO2Stored also appear high.

- Checks of injectivity indicate that the target rate of 1MT/year/well cannot without exceeding the calculated min fracture pressure.
- The Georisk factor has been calculated as 13. The same as calculated in WP3.
- The additional risk assessment carried out for the engineering containment risk indicates that the risk is moderate to high, as there is a high well count but a large storage area (2612km2).
- Well cost estimate (for 5 wells) £201M

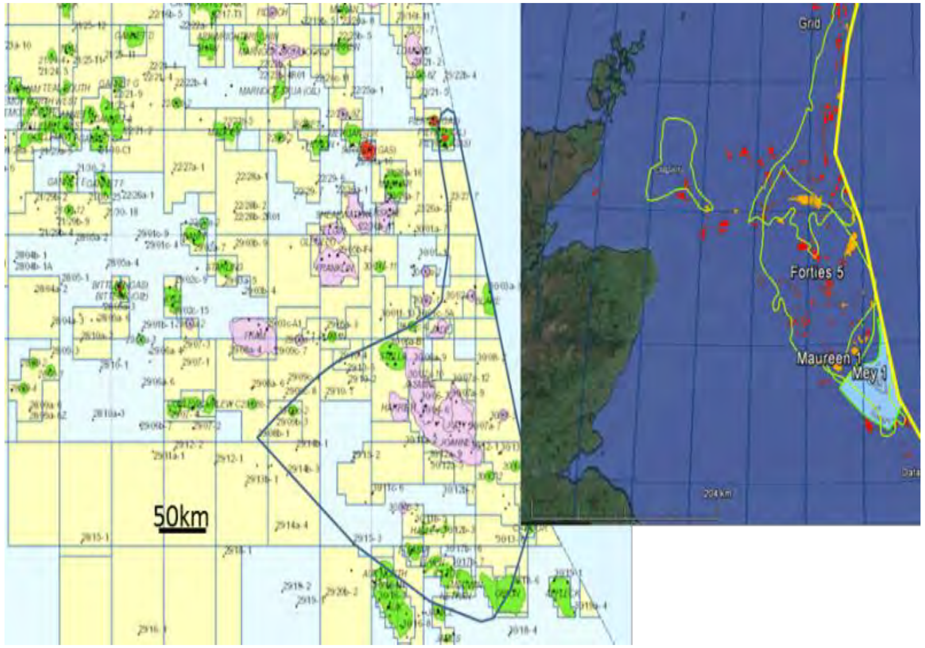


Figure 12: Mey Aquifer Location Map

Containment

An overburden assessment has been conducted above and adjacent to the Mey 1 saline aquifer storage site to identify secondary containment horizons and potential migration pathways out of the storage complex, in the unlikely event of a seal or fault leakage of the sequestered CO_2.

The primary seal for the Mey Sands are the intra-formation shales of the Palaeocene Lista Formation. However hydrocarbons within Paleocene reservoirs normally occur in the highest reservoir unit in any well, from which it can be deduced that Palaeocene shales do not generally form reliable seals. There is therefore a high risk of migration into overlying Palaeocene sands which are also present over this region.

The Georisk factor has been calculated as 13, the same as previously calculated factor in WP3 based on CO2Stored data.

	Fault Characterisation		Seal Characterisation				Georisk Factor
	Density	Throw & Seal	Fault Vertical Extent	Fracture Pressure Capacity	Seal Chemical Reactivity	Sea Degradation	
CO2Stored Value	3	3	2	1	2	2	13
Due Diligence Value	3	3	2	1	2	2	13
Risk Factor Key: Low = 1, Medium = 2, High = 3							

Table 47: Mey Aquifer Geo-containment Risk

Engineering Risk

The engineering containment risk is moderate to high, with 376 wells in total, and 194 abandoned wells considered to be at risk of leakage, 38 of which were before 1986. The 100yr probability of a leakage on the field is a moderately high 0.45 and the well density factor is 0.07 wells/km2, resulting in a moderate risk assessment score of 0.033. However, localised well density is such that injection sites and CO_2 plume pathways need to be carefully selected to avoid producing fields. Should a smaller section of the Mey 1 be considered, this risk review should be revisited.

Capacity

The calculated storage capacity is 22MT compared to the reported capacity in CO2Stored of 138MT. The drop in capacity is related to a thinner net thickness (driven by low NTG) in the wells within the Mey 1 area when compared to what has been reported in CO2Stored.

Thickness[2] [m]	GRV [MMm3]	NTG[2]	Porosity[1]	CO2 Density[3] [Tonnes/m3]	Pore Space Utilisation[3]	Pore Volume [MMm3]	Theoretical Capacity [MT]
15	102,692	0.34	0.26	0.59	0.006	6675	22

Table 48: Mey Aquifer Storage Capacity

NB. 1: Analogue field data 2: Estimated from CDA composite logs 3: CO2Stored

The Mey 1 store is at the southern end of the sand depositional system resulting in thinner sands and a big reduction in the NTG. Sands become thin and there is a far greater proportion of non-net siltstones and claystones than is seen in the equivalent intervals to the North.

Reservoir sand presence and thickness is highly variable across the area, there is a high degree of uncertainty with the storage capacity that has been calculated.

Injectivity

The selection criteria used for injectivity is the permeability thickness (Kh) value calculated using the mid case reservoir data from CO2Stored. For the Mey 1 this was calculated as 48,096 mDm.

The permeability thickness calculated during the validation process is 1,125 mDm. This is much lower than the Kh calculated using the CO2Stored data. This is largely caused by the lower average permeability and thickness that has been assumed, although the assumed lower average NTG also contributes.

Zone	Depositional Environment	Gross Thickness[2] [m]	NTG[2]	Porosity[1]	Perm[1] [mD]	Kh [mDm]
Mey	Turbidite	45	0.25	0.26	100	1,125

Table 49: Mey Aquifer Reservoir Properties

NB. 1: Analogue field data – Maureen Field aquifer 2: Estimated from CDA composite logs 3: CO2Stored

No permeability data is available for Mey Sands at the storage site, permeability, its regional lateral variation and heterogeneity remain a big uncertainty.

Reservoir properties for hydrocarbon field analogues have excellent reservoir quality with darcy sands in the Balmoral and Macculloch fields. However permeabilities within the aquifer sands of several Palaeocene analogue reservoirs (Maureen, Moira) are known to be lower (Cutts, P. L., 1991).

Thin bedded turbidites, as are seen at the southern end of the Mey system, also show poorer poro/ perm characteristics than the more massive, thickly bedded sands to the North.

Published permeability versus depth for Paleocene reservoirs also suggests values of less than 100mD at the depths for this store (Evans, D. Graham, C, Armour A, and Bathurst, P., 2003).

Based on these observations an average permeability of 100 mD has been assumed.

An injection pressure of 2150 psi achieves the threshold of 1MT/year per well, but exceeds the assumed minimum fracture pressure of 1941 psi (based on a fracture gradient of 0.726 psi/ft).

There is some evidence from published literature that the Mey may be over pressured by up to 2000 psi at the southern end. A sensitivity was run and an injection pressure of 3900 psi is required to achieve the threshold injectivity per well. However this again exceeds the calculated fracture pressure.

There is uncertainty associated with the assumed minimum fracture pressure, however achieving the required injectivity below the min fracture pressure, is identified as a risk.

Well Design

The generic well design is discussed in the supporting document ‘Storage Site Due Diligence Summary’. It is likely that this well design can be achieved in the Mey 1.

Due to the moderate water depth (80m), wells have been assumed to be drilled by a class 2 (Heavy Duty) Jack-Up Drilling Unit. Subsea well costs are assumed to be £40M per well, resulting in a 5 well development cost of £201M.

Development Concept

CO_2 volumes cf ETI Scenarios

The ETI Concentrated Scenario shows 11MT/yr by 2030 into the CNS via St Fergus. 1MT goes to Goldeneye. 10MT/yr of additional storage may be required by 2030

Comparative development concept

A new subsea development consisting of a single well injecting 1MT/yr; totalling 20MT over 20 years. CO_2 will be delivered via a new 322 km pipeline from St Fergus. Power and controls will be supplied from an existing neighbouring platform. Monitoring will include downhole pressure and distributed temperature sensors.

Site growth potential; theoretical ultimate development concept

The site has a theoretical storage capacity of ~22MT.

There is no site growth potential beyond the Comparative development concept.

Build out potential

The Mey aquifer is close to the Maureen aquifer which could act as a build out option. Both of these sites could be build out for the Forties aquifer.

Development Cost

Capacity:	22	Water Depth (m)	70
Concept Cost (£m)	**Comparative Development**	**Ultimate Development**	**Description**
Tonnes Injected (MT)	20		Total Stored CO_2 for proposed scheme
Appraisal Cost:	£82m		Appraisal Wells + Seismic Data Acquisition & Interpretation
Development Well Cost:	£40.1m		Drilling & Completion Costs of wells.
Facilities Cost:	£378.8m		Landfall, Pipeline, Templates, ties-Ins,
PM & Eng:	£37.9m		10% of Facilities Costs
Decommissioning:	£102.7m		£8m per subsea well
Subtotal	£641.4m		
Contingency	£128.3m		20% of Development & Facilities Costs
OPEX (20years)	£454.5m		OPEX Cost for 20 years (6% of facilities costs)
Total:	£1224.1m		
£/T CO_2	61.20		

Table 50: Mey Aquifer Development Cost Estimate

Data

Approximately 98% of Mey 1 aquifer sandstone is covered by the 3D seismic by the CNS PGS megasurvey. The data quality is generally good. The well ties confirm the PGS time interpretations, however the top Mey sandstone member has not been mapped.

A significant amount of wells cover this area and a range of digital and non-digital data are available. Offset poro/perm data may not be readily available for the aquifer section of the Mey Sand.

No engineering data is available for aquifer sands. Analogue data and correlations will be used

Commercial Issues

The Mey aquifer could be developed from within a wide area in upper Block 30. As such, although most of this area is licensed for petroleum, it is not expected that petroleum license interaction will limit development potential.

10 Barque Gas Field

Overview

Capacity:	91MT	UKCS Block:	48/13
Unit Designation:	Depleted gas	**Beachhead:**	Barmston
Formation:	Leman sandstone	**Water Depth:**	35m
Earliest injection:	2030	**Reservoir Depth:**	2559m
Availability/COP:	2028	**Region:**	SNS

Table 51: Barque Field Overview

- Checks of injectivity indicate that the target rate of 1MT/year/well cannot be met without well stimulation (fracturing), additional well stock or potentially very long horizontal wells. Current production is achieved through natural fractures, with generally poor matrix properties.
- The Georisk factor has been calculated as 9. This is the same as that calculated in WP3 selection criteria. Compartmentalisation may be an issue.
- Extension of natural fractures to the cap rock and beyond through high pressure injection is a current concern and would need to be validated.
- The additional risk assessment carried out for the engineering containment risk indicates that the risk is low.
- The ability to drill high angle wells in the depleted reservoir is a carried engineering risk. Phase behaviour will also be an issue.
- The risk of halite issues due to reservoir dehydration in the near wellbore is also recognised.
- Well cost estimate (for 5 wells) £204M.

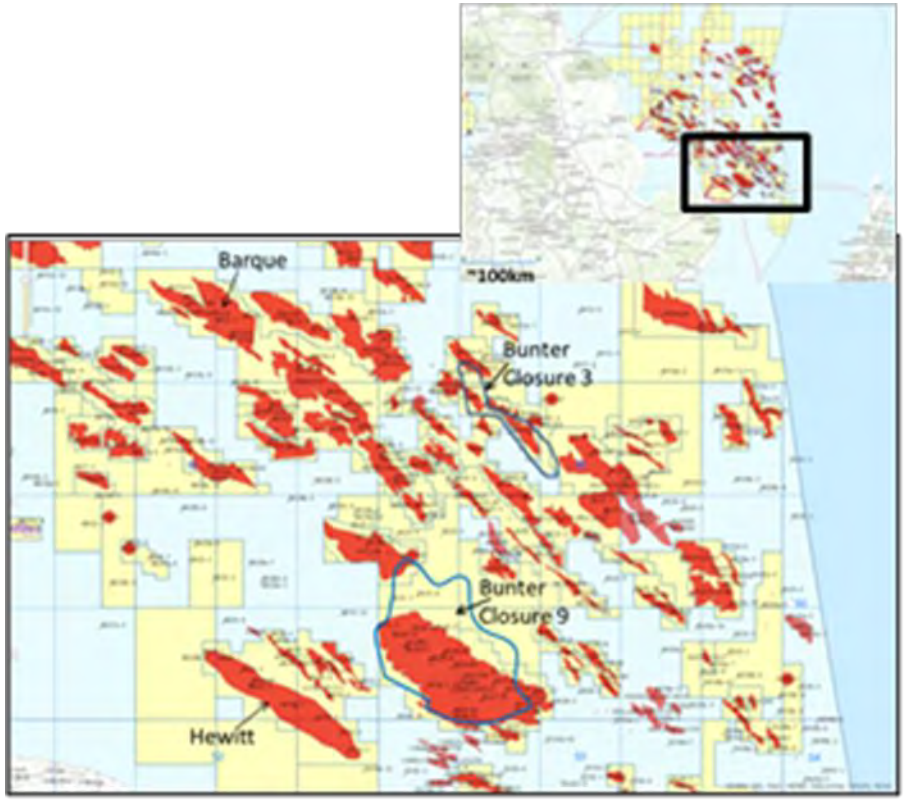


Figure 13: Barque Field Location Map

Containment

An overburden assessment has been conducted above and adjacent to the Barque field to identify secondary containment horizons and potential migration pathways out of the Barque storage complex, in the unlikely event of a seal or fault leakage of the sequestered CO_2.

Field data and published literature were reviewed to establish the effectiveness of trap and seal. Depth to crest of the reservoir is 2134 m (7000ft tvdss). Dip closure with anticlinal rollover against fault forms the trap, with the field developed in conjunction with the Clipper field to the South-East ((Sarginson, M. J., 2003)). The Barque field has three compartments due to faulting. NNW trending faults are mapped and some of these are believed to form barriers to fluid flow. Fault compartments within the field, where the throw does not offset the sandstone completely, are believed to result from cataclasis and mineralization along fault zones. The major boundary fault is clearly recognised as sealing where the Rotliegend is juxtaposed against the Zechstein. The Rotliegendes sandstone reservoir is overlain by 152 – 1219m (500 to 4000ft) of Zechstein halites and anhyrites forming an excellent cap rock that is continuous and not broken by faulting (Bentham, M.S., Green, A.; Gammer, D., 2013). Overlying the Zechstein is 304m (1000ft) of Bunter shale with an under-burden of Carboniferous coal measures (Sarginson, M. J., 2003). CO_2 is not expected to leak through the top Zechstein seal which has already trapped Barque gas over geological time, or via reservoir level faults.

The Georisk factor has been calculated as 9. This is the same as that calculated in WP3 selection criteria.

	Fault Characterisation			Seal Characterisation			Georisk Factor
	Density	Throw & Seal	Fault Vertical Extent	Fracture Pressure Capacity	Seal Chemical Reactivity	Sea Degradation	
CO2Stored Value	3	2	1	1	1	1	9
Due Diligence Value	3	2	1	1	1	1	9
Risk Factor Key: Low = 1, Medium = 2, High = 3							

Table 52: Barque Field Geo-containment Risk

Engineering Risk

The engineering containment risk is low, with 47 wells in the field and 23 considered at risk of leakage (other wells are suspended or still producing and are assumed to be abandoned at COP, which being after 2025, is expected to result in a negligible leak risk). 9 wells were plugged and abandoned before 1986, representing the highest assessed risk. The total storage target leakage probability is 0.07 and the well density factor is 0.29 wells/km2, resulting in a low leakage risk assessment score of 0.02.

Capacity

The calculated storage capacity is 91MT, 29MT less than the capacity calculated in CO2Stored.

For the Barque field, the due diligence involves a recalculation of the capacity equivalent to the net reservoir volume of fluids removed at February 2015. In addition, the net reservoir volume of fluids removed at COP was estimated and the capacity calculated at this time to confirm the full capacity estimate.

Barque produces a dry gas with traces of water and relatively low condensate production. All produced fluids were accounted for in the material balance calculation to check potential storage capacity.

The field is currently producing at ~1400Ksm3/d (~49mmscf/d) and the COP estimate from Woodmac is end 2028. The remaining production was estimated using DCA to be ~5.6BM3, equivalent to 19% of the URR. This results in a 17.5MT (~24%) uplift in storage capacity between February 2015 and end 2028 (COP).

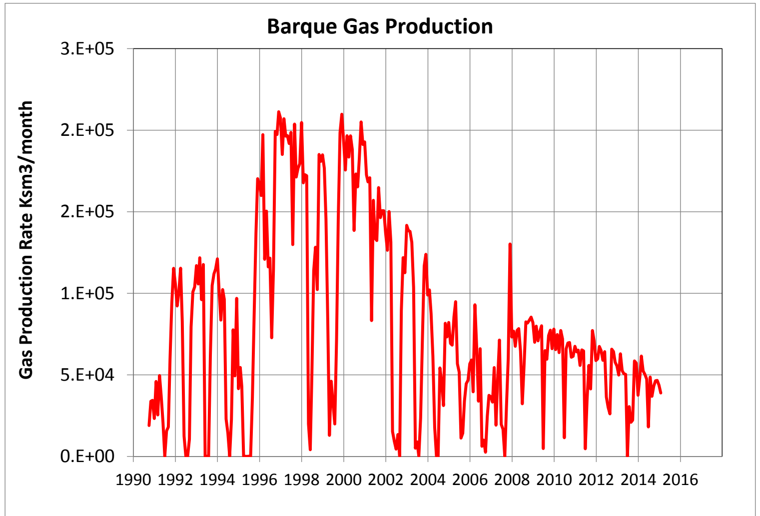


Figure 14: Barque Gas Production Profile

The produced volumes and conversion to mass storage potential are shown in the table below:

Gas Production	23746	MCM
Condensate Production	0.119	MCM
Water Production	0.042	MCM
Net Reservoir Volume Produced	104	MCM
Storage Capacity to COP	91	MT

Table 53: Barque Field Storage Capacity

The volumes and shrinkage factors used in the calculation are shown in the table below.

Parameter		Reference	CO2Stored
CO_2 density (kg/m3)	710	CO_2 Storage potential in UK-BGS Study	710
Gas expansion factor (rm3/sm3)	0.00437	Ref 1. Uk Oil and Gas Fields Data	0.0044
Condensate formation volume factor (rm3/sm3)	1.75	Analogue	n/a
Water formation volume factor (rm3/sm3)	1.02	Analogue	1.02

Table 54: Barque Field Fluid Properties

Injectivity

The selection criteria used for injectivity is the permeability thickness (Kh) value calculated using the mid case reservoir data from CO2Stored. For the Barque Field this was calculated as 11,430 mDm.

Field data and published literature have been reviewed in order to confirm the reservoir properties which have then been used to validate the permeability thickness and expected injectivity.

The field comprises high net to gross, low-moderate quality dune and interdune sandstones of the Lower Permian Leman sandstone fm, which have been affected by illite diagenesis. Sandstone can be subdivided into three Leman zones – A, B and C. cause Baffle to flow between Zones A and B. Muddy sabkha layers. A summary of the reservoir properties are summarised below:

Zone	Depositional Environment	Gross Thickness [m]	NTG	Porosity	Perm [mD]	Kh [mDm]
A	Sabkha	108	0.76	0.1	0.1	8
B	Aeolian Dunes	57	0.86	0.175	50	2,464
C	Interbedded Aeolian	43	0.505	0.111	0.1	2
All Zones		208	0.73	0.13	16.7	2,559

Table 55: Barque Field Reservoir Properties

The permeability thickness calculated during the validation process is 2,559mDm. This is approximately 78% lower than the estimate based on the CO2Stored data. Permeability averages for zone B are not mentioned explicitly in the published literature (quoted as 10s of mD) (Sarginson, M. J., 2003,), therefore the mid value from CO2Stored (50mD) is used. Sarginson (2003) specify a lower than 0.1mD average for Zones A and C – much lower than the mid case perms assumed were used in the CO2Stored calculation. Indications are that injectivity would be an issue.

Two additional injectivity checks were carried out as part of the due diligence.

The initial production performance per well was converted to an equivalent CO_2 injection rate to gain some confidence that that the 1MT/year/well target could be met.

Early life production data from the production wells is available on the DECC website. The initial production rate was converted to a CO_2 injection equivalent rate at the initial field pressure and at an estimated final reservoir pressure at COP (10% of initial pressure) for 10 of the wells. The calculated injectivities are shown in the table below. Injectivity does not meet the 1MT/year threshold for any of the wells at the initial pressure and is reduced significantly due to phase change at the lower pressure.

Well	CO_2 Injection Rate (MT/y)	
	Initial pressure (3600 psi)	Final pressure (363 psi)
B1	0.51	0.15
B3	0.19	0.06
B5	0.15	0.05
B7	0.31	0.09
B9	0.27	0.08
B11	0.07	0.02
L1	0.47	0.14
L3	0.58	0.17
L5	0.34	0.1
L7	0.34	0.1

Table 56: Barque Field Well Injectivity

NB. Final pressure is assumed to be 10% of the initial pressure.

The field produces due to presence of natural fractures and the matrix permeability average is less than 1mD. In the west of the field the fractures are cemented due to diagenesis, compartmentalising the reservoir. Production is more difficult in that area.

As a further check a dynamic model was constructed to test the injectivity performance, at initial conditions and over time. A simple model was built in Eclipse (flat structure). CO_2 will be injected in the gas phase initially as the reservoir pressure is expected to be too low for dense phase injection. A DP (well–formation pressure) range of 150psi to 650psi was tested and the corresponding injectivity per well is 0.03MT/year and 0.1MT/year. The modelling confirms that the injectivity threshold of 1MT/year per well cannot be achieved for this site.

Well Design

The generic well design is discussed in the supporting document 'Storage Site Due Diligence Summary'. However, the Barque injection wells may depart from the generic design due to the poor injectivity. This suggests that long horizontal sections (>150m) may be required to reach injection targets. Alternatively, a higher well stock than the 5 wells assumed may be required. Hydraulic stimulation may result in acceptable injection rates, but the additional cost and containment risk make this option unattractive. Of further concern is the ability to drill new wells in the depleted gas field, particularly at a high angle, due to wellbore stability issues. This may limit the achievable deviation in the reservoir section.

Due to the shallow water depth (30m), wells have been assumed to be drilled by a low cost class 1 Jack-Up Drilling Unit. Platform well costs are assumed to be £40.6M per well, including a contingency cost for managing CO_2 phase change, resulting in a 5 well development cost of £204M.

Development Concept

CO_2 volumes cf ETI Scenarios

The ETI Concentrated Scenario shows 29MT/yr by 2030 into the SNS via Barmston. It is possible that the first 17Mt/yr could be stored at 5/42. On the basis of this Scenario, additional SNS storage would be needed by 2027 and need to be capable of storing 12Mt/yr by 2030.

Comparative development concept

A new Normally Unmanned Installation (NUI) comprising a jacket and topsides with 5 deviated wells each injecting 1MT/yr; totalling 91MT over 20 years. CO_2 will be delivered via a 20" 157km pipeline from Barmston with 10MT/yr capacity. Facilities will be controlled from the beach with the NUI providing its own power and controls. Monitoring will include downhole pressure and distributed temperature sensors.

Site growth potential; theoretical ultimate development concept

The site has a theoretical storage capacity of ~91MT.

The site has little upside capacity above the Comparative development concept

Build out potential

Barque is in the centre of the SNS and build out potential is possible to Hewett, Viking and Bunter Closures 9, 3 and 5 although none is nearby.

Development Cost

Capacity:	91	Water Depth (m)	10
Concept Cost (£m)	Comparative Development	Ultimate Development	Description
Tonnes Injected (MT)	91		Total Stored CO_2 for proposed scheme
Appraisal Cost:	£0m		Appraisal Wells + Seismic Data Acquisition & Interpretation
Development Well Cost:	£202.9m		Drilling & Completion Costs of wells.
Facilities Cost:	£230m		Landfall, Pipeline, NUI, ties-Ins,
PM & Eng:	£23m		10% of Facilities Costs
Decommissioning:	£87.5m		£10m per NUI, £4m per dry well
Subtotal	£543.3m		
Contingency	£108.7m		20% of Development & Facilities Costs
OPEX (20years)	£276m		OPEX Cost for 20 years (6% of facilities costs)
Total:	£927.9m		
£/T CO_2	10.20		

Table 57: Barque Field Development Cost Estimate

Data

The Barque Gas Field is covered by the 3D seismic from the SNS PGS megasurvey. The data quality is generally good, however there are reservoir imaging problems due to ray bending particularly in the areas of heavy Triassic/Jurassic faulting. The data quality is not good enough to pick the base Rotliegendes reservoir, however well control shows that the Rotliegendes thickness to be between 700 and 800ft. The well ties confirm the time interpretation.

Well data are available for the Barque field from CDA. E&A well data has been downloaded.

Commercial Issues

Barque is a gas field in production operated by Shell, with a COP of 2028.

11 Bunter Aquifer 3

Overview

Capacity:	232MT	UKCS Block:	49/17 vicinity
Unit Designation:	Saline Aquifer	**Beachhead:**	Barmston
Formation:	Triassic Bunter sandstone	**Water Depth:**	35m
Earliest injection:	2020	**Reservoir Depth:**	1050m
Availability/COP:	2017	**Region:**	SNS

Table 58: Bunter Aquifer 3 Overview

The results of the due diligence review confirm a significant reduction in the capacity based on more robust mapping of the structure.

- Permeability thickness has increased due to an increase in the assumed average permeability.
- Additional checks of injectivity indicate that the target rate of 1MT/year/well can be met assuming a minimum injection pressure of 2550 psi. This is below the calculated minimum fracture pressure of 3349 psi at the well depth.
- There is a large uncertainty associated with the minimum fracture pressures. The values quoted in CO2Stored are derived from correlations which appear to give very low minimum fracture pressures. This can be observed in the large discrepancy between the measured and estimated values for the 5/42 store; measured: 3900 psi vs estimate: 2800 psi. A review of published papers suggested a frac gradient of 0.728 for the Bunter, giving a frac pressure of 3349 psi at the well depth of 4,600ft TVDSS.
- The Georisk factor has been calculated as 10. This is a slight increase from 9 (calculated in WP3).
- The additional risk assessment carried out for the engineering containment risk indicates that the risk is low to moderate, as there are only 20 wells on the field, but most being plugged and abandoned, 7 of them before 1986.
- The risk of halite issues due to reservoir dehydration in the near wellbore is recognised.
- Well cost estimate (for 5 wells) is £101M.

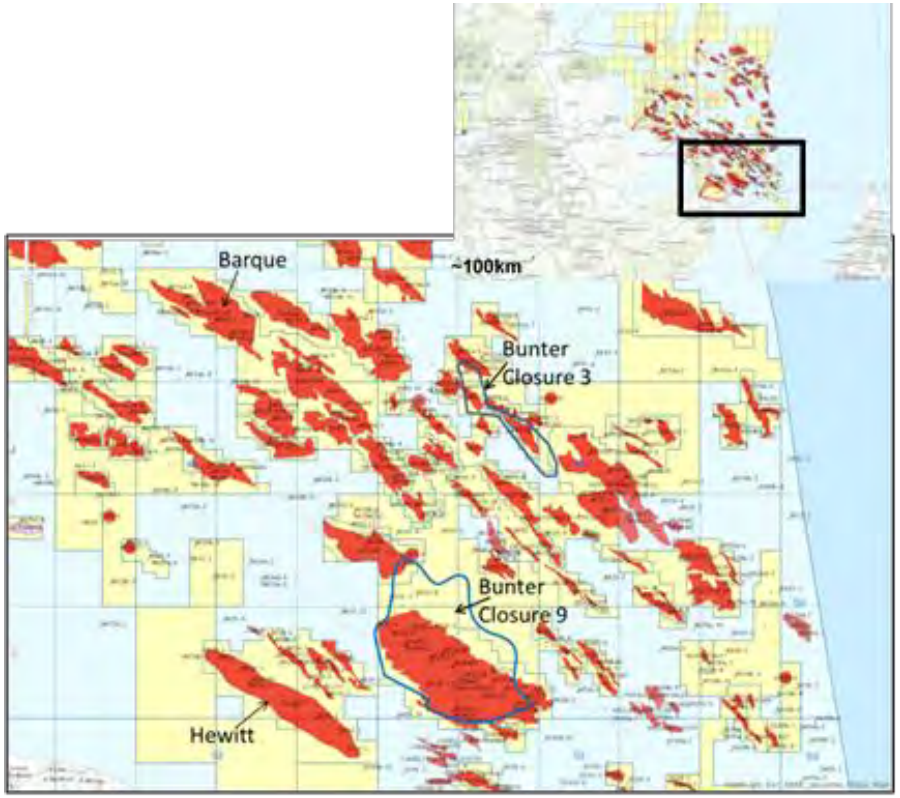


Figure 15: Bunter Aquifer 3 Location Map

Containment

An overburden assessment has been conducted above and adjacent to the Bunter Sandstone to identify secondary containment horizons and potential migration pathways out of the storage complex, in the unlikely event of a seal or fault leakage of the sequestered CO_2.

The site is an elongate 4-way dip closure with some faulting. The Bunter sandstone reservoir is overlain by 730ft of Triassic halites and claystones forming an excellent cap rock however it is broken by faulting. There are less than 10 faults but some extend up to the Base Chalk at approximately $600m^2$, however the fault throws are less than 50m. The clear seismic evidence for faults cutting Bunter is one significant difference between this site and others (including 5/42), resulting in additional containment risk (at least relative to 5/42).

Above the Triassic marker is a 10m thick layer of sandstone which in turn is overlain by 150m of Jurassic/Lower Cretaceous claystone. Above this is over 300m of Upper Cretaceous Chalk which is a potential reservoir with recent sediments on top which may only have a limited seal capacity.

The Georisk factor has been calculated as 10, this is higher than previous calculated factor in WP3 based on CO2Stored data. This is due to the Fault Vertical Extent being increase from 2 to 3 as it is clear from the seismic that faults extend above 800m.

	Fault Characterisation			Seal Characterisation			Georisk Factor
	Density	Throw & Seal	Fault Vertical Extent	Fracture Pressure Capacity	Seal Chemical Reactivity	Sea Degradation	
CO2Stored Value	2	2	2	1	1	1	9
Due Diligence Value	2	2	3	1	1	1	10
Risk Factor Key: Low = 1, Medium = 2, High = 3							

Table 59: Bunter Aquifer 3 Geo-containment Risk

Engineering Risk

The engineering containment risk is low to moderate, with 20 wells considered at risk of leakage. 11 wells were plugged and abandoned, 7 of which were before 1986, representing the highest risk. The 100yr probability of a leakage on the field is 0.07, and the well density factor is 0.25 wells/km2, resulting in a moderate containment risk assessment score of 0.017.

Capacity

The calculated storage capacity is 232MT compared to the reported capacity in CO2Stored of 409MT. The calculated capacity is significantly smaller than that in CO2Stored, this is due to a large difference in the calculated GRV. The GRV in CO2Stored appears to be overestimated due to the simple Area x Thickness method used.

The structure is elongate with a saddle in the middle. The relief in the north of the structure is significantly lower than in the South. This is not accounted for in the simple approach to GRV calculation used for CO2Stored.

The due diligence process is based on a depth top structure map and mapped sand thickness from wells, which takes into account these variations in the structural elevation. This is a more robust methodology than what has been applied in CO2Stored.

A storage capacity of 232MT still places this site in the top 10 sited when ranked on capacity.

Thickness[2] [m]	GRV [MM m3]	NTG[2]	Porosity[1]	CO2 Density[3] [Tonnes/m3]	Pore Space Utilisation[3]	Pore Volume [MMm3]	Theoretical Capacity [MT]
240	9996	0.95	0.21	0.78	0.15	1994	232

Table 60: Bunter Aquifer 3 Storage Capacity

NB. 1: Analogue field data Little Dotty (Ref 6) 2: Estimated from CDA composite logs 3: CO2Stored

Whilst there are uncertainties associated with the inputs to the capacity calculation, there is a high degree of confidence in the storage capacity which has been calculated.

Whilst faulting within the Bunter can developed due to post depositional halokenisis, compartmentalisation due to faulting is not thought to be a risk for this storage site.

Injectivity

The selection criteria used for injectivity is the permeability thickness (Kh) value calculated using the mid case reservoir data from CO2Stored. For the Bunter Closure 3 this was calculated as 33,380 mDm.

The permeability thickness calculated during the validation process is 79,800 mDm. This is considerably higher than the estimate based on the CO2Stored data, and is due to a difference in the assumed average permeability. CO2Stored assumes an average permeability of 100mD. This is very low when compared to nearby SNS analogue Bunter Sst reservoirs. The Hewett Gas Field has average permeabilites in excess of 500 mD (Cooke, Yarborough, 1991).

The nearby Little Dotty Gas Field (a part of Hewett), with average Bunter Sst permeabilities of 350 mD, is used as an analogue for this storage site.

Zone	Depositional Environment	Gross Thicknes s[2] [m]	NTG [2]	Porosi ty[1]	Perm [1] [mD]	Kh [mDm]
Bunter Sst	Fluvial/ Lacustrine	240	0.95	0.21	350	79,800

Table 61: Bunter Aquifer 3 Reservoir Properties

NB. 1: Analogue field data Little Dotty (Ref 6) 2: Estimated from CDA composite logs 3: CO2Stored

With no permeability data available for the Bunter Sst at the storage site, permeability, its regional lateral variation and heterogeneity remain an uncertainty that would need to be addressed should the site be evaluated further. Bunter Sst reservoir quality at this depth and initial CO_2 injectivity within the SNS is considered to be good. Neither reservoir quality nor injectivity are considered to be a high risk.

As an additional check a dynamic model was constructed to test the injectivity performance, at initial conditions and over time. A simple model was built in Eclipse (flat structure). CO_2 will be injected in critical or dense phase as the reservoir pressure is expected to be high in saline aquifer. Injection pressure of 2550 psi is required to achieve the injectivity threshold of 1MT/year per well. This is below the calculated minimum fracture pressure of 3349 psi at the well depth.

Well Design

The generic well design is discussed in the supporting document 'Storage Site Due Diligence Summary'. It is likely that this well design can be achieved in the Bunter 3.

Due to the shallow water depth (20m), wells have been assumed to be drilled by a low cost class 1 Jack-Up Drilling Unit. Platform well costs are assumed to be £20.2M per well, resulting in a 5 well development cost of £101M.

Development Concept

CO_2 volumes cf ETI Scenarios

The ETI Concentrated Scenario shows 29MT/yr by 2030 into the SNS via Barmston. It is possible that the first 17Mt/yr could be stored at 5/42. On the basis of this Scenario, additional SNS storage would be needed by 2027 and need to be capable of storing 12Mt/yr by 2030.

Comparative development concept

A new Normally Unmanned Installation (NUI) comprising a jacket and topsides with 5 deviated wells each injecting 1MT/yr; totalling 100MT over 20 years. CO_2 would be delivered via a 20" 238 km pipeline from Barmston with 10MT/yr capacity. Facilities will be controlled from the beach with the NUI providing its own power and controls. Monitoring will include downhole pressure and distributed temperature sensors.

Site growth potential; theoretical ultimate development concept

The site has a theoretical storage capacity of ~232MT.

A new development comprising 2 new NUI platforms, with a total of 12 wells, injecting a total of 12Mt/yr; 232MT. CO_2 would be delivered via a 26" 238 km pipeline from Barmston with a 20Mt/yr capacity. Facilities will be controlled from the beach. Power generation and controls relay will be provided from a single primary NUI. Platforms are connected by 10km infield pipelines and umbilicals.

Build out potential

Bunter Closure 3 is reasonably close to the two Hewett Reservoirs (448MT), Viking (271MT) and Bunter Closure 9 (1691MT). The Barque depleted gas field (120MT) is on the likely pipeline route from Barmston. These all represent potential regional growth opportunities

Development Cost

Capacity:	232	Water Depth (m)	40
Concept Cost (£m)	**Comparative Development**	**Ultimate Development**	**Description**
Tonnes Injected (MT)	100	232	Total Stored CO_2 for proposed scheme
Appraisal Cost:	£60m	£60m	Appraisal Wells + Seismic Data Acquisition & Interpretation
Development Well Cost:	£100.8m	£241.9m	Drilling & Completion Costs of wells.
Facilities Cost:	£327.3m	£430.2m	Landfall, Pipeline, NUI, ties-Ins,
PM & Eng:	£32.8m	£43.1m	10% of Facilities Costs
Decommissioning:	£111.9m	£175.6m	£10m per NUI, £4m per dry well
Subtotal	£632.6m	£950.6m	
Contingency	£126.6m	£190.2m	20% of Development & Facilities Costs
OPEX (20years)	£392.7m	£516.2m	OPEX Cost for 20 years (6% of facilities costs)
Total:	£1151.7m	£1656.9m	
£/T CO_2	11.52	7.14	

Table 62: Bunter Aquifer 3 Development Cost Estimate

Data

Bunter Closure 3 is covered by the 3D seismic from the SNS PGS megasurvey. The data quality is generally good. The well ties confirm the time interpretation.

CDA well data is available for wells targeting the underlying Viking Field and surrounding areas. Log coverage for the Bunter interval is variable.

Commercial Issues

Bunter C3 is in the vicinity of Viking. Development probably needs to take place after COP at Viking (2017)

12 Bunter Closure 9

Overview

Capacity:	1977MT	UKCS Block:	49/26 vicinity
Unit Designation:	Saline Aquifer	**Beachhead:**	Barmston
Formation:	Bunter sandstone	**Water Depth:**	27m
Earliest injection:	2025	**Reservoir Depth:**	920m
Availability/COP:	n/a	**Region:**	SNS

Table 63: Bunter Aquifer 9 Overview

The results of the due diligence review confirm that the selection criteria used for Bunter Closure 9 are all better than those currently in CO2Stored.

- Additional checks of injectivity indicate that the target rate of 1MT/year/well can be met assuming a minimum injection pressure of 1950 psi. This is above the calculated minimum fracture pressure of 2475 psi at the well depth.
- There is a large uncertainty associated with the minimum fracture pressures. The values quoted from CO2Stored are derived from correlations which appear to give very low minimum fracture pressures. This can be observed in the large discrepancy between the measured and estimated values for the 5/42 store measured: 3900 psi vs estimate: 2800 psi. A review of published papers suggested a frac gradient of 0.728 for the Bunter, giving a frac pressure of 2,475si psi at the well depth of 3,400 ft TVDSS.
- The Georisk factor has been calculated as 9. This is the same as that calculated in WP3 selection criteria.
- The additional risk assessment carried out for the engineering containment risk indicates that the risk is moderate to low, as there are a large number of wells, but only a limited number considered to be at risk of leakage.
- The risk of halite issues due to reservoir dehydration in the near wellbore is recognised.
- Well cost estimate (for 5 wells) is £80M

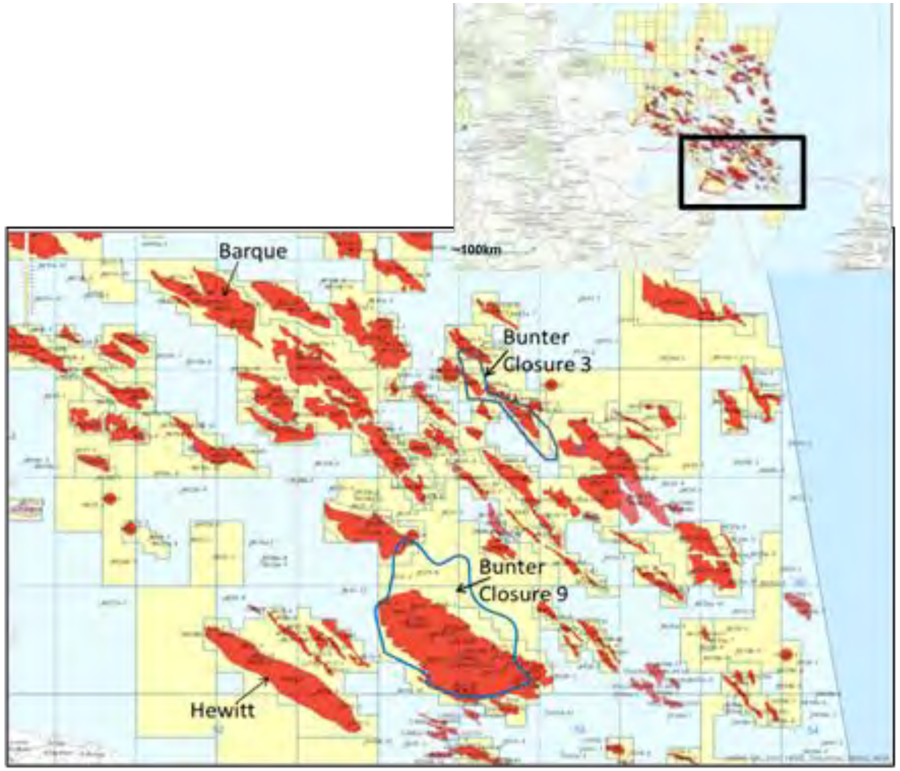


Figure 16: Bunter Aquifer 9 Location Map

Containment

An overburden assessment has been conducted above and adjacent to the Bunter Sandstone to identify secondary containment horizons and potential migration pathways out of the storage complex, in the unlikely event of a seal or fault leakage of the sequestered CO_2.

The site is an elongate 4-way dip closure with some faulting. The Bunter sandstone reservoir is overlain by over 2500ft of Triassic halites and claystones extending to the seabed and forming an excellent cap rock, however it is penetrated by faulting. There are less than 10 faults with throws of less than 50m.

The Georisk factor has been calculated as 9. This is the same as the previous calculated factor in WP3 based on CO2Stored data. Due to poor shallow seismic data quality the vertical extent of the faults above the Bunter Sandstone is difficult to resolve.

	Fault Characterisation			Seal Characterisation			Georisk Factor
	Density	Throw & Seal	Fault Vertical Extent	Fracture Pressure Capacity	Seal Chemical Reactivity	Sea Degradation	
CO2Stored Value	2	2	2	1	1	1	9
Due Diligence Value	2	2	2	1	1	1	9
Risk Factor Key: Low = 1, Medium = 2, High = 3							

Table 64: Bunter Aquifer 9 Geo-containment Risk

Engineering Risk

The engineering containment risk is moderate to low, with 226 wells in total, but only 28 considered at risk of leakage. From CDA data there appears to be a large number of current producing wells, suggesting that they might not be abandoned until near COP, estimated to be 2030 by Wood Mac. This seems unlikely given the age of the wells and requires further investigation. From data available, 28 wells were plugged and abandoned, 13 of which were before 1986, representing the highest risk. The 100yr probability of a leakage on the field is a moderate 0.12, and the well density factor is 0.07 wells/km2, resulting in a low containment risk assessment score of 0.008.

Capacity

The calculated storage capacity is 1977MT compared to the reported capacity in CO2Stored of 1691MT. Whilst the gross rock volume (GRV) calculated as a part of the due diligence is lower, nearby analogue Bunter Sst data show higher average porosity than those on CO2Stored resulting in a 20% higher calculated capacity.

Thickness[2] [m]	GRV [MMm3]	NTG[2]	Porosity[1]	CO2 Density[3] [Tonnes/m3]	Pore Space Utilisation[3]	Pore Volume [MMm3]	Theoretical Capacity [MT]
300	106,534	0.9	0.21	0.75	0.13	20,135	1977

Table 65: Bunter Aquifer 9 Storage Capacity

NB. 1: Analogue field data Little Dotty (Ref 6) 2: Estimated from CDA composite logs 3: CO2Stored

Whilst there are uncertainties associated with the inputs to the capacity calculation, there is a high degree of confidence in the storage capacity which has been calculated.

Whilst faulting within the Bunter can develop due to post depositional halokenisis, compartmentalisation due to faulting is not thought to be a risk for this storage site, and the volume should be well connected.

Injectivity

The selection criteria used for injectivity is the permeability thickness (Kh) value calculated using the mid case reservoir data from CO2Stored. For the Bunter Closure 9 this was calculated as 33,380 mDm.

The permeability thickness calculated during the validation process is 94,500 mDm. This is considerably higher than the estimate based on the CO2Stored data, and is due to a difference in the assumed average permeability. CO2Stored assumes an average permeability of 100mD. This is very low when compared to nearby SNS analogue Bunter Sst reservoirs. The Hewett Gas Field has average permeabilites in excess of 500 mD (Cooke, Yarborough, 1991). The nearby Little Dotty Gas Field (a part of Hewett), with average Bunter Sst permeabilities of 350 mD, is used as an analogue for this storage site.

Zone	Depositional Environment	Gross Thickness[2] [m]	NTG[2]	Porosity[1]	Perm[1] [mD]	Kh [mDm]
Bunter Sst	Fluvial/ Lacustrine	300	0.9	0.21	350	94,500

Table 66: Bunter Aquifer 9 Reservoir Properties

NB. 1: Analogue field data Little Dotty 2: Estimated from CDA composite logs 3: CO2Stored

With no permeability data available for the Bunter Sst at the storage site, permeability, its regional lateral variation and heterogeneity remain an uncertainty. Bunter Sst reservoir quality at this depth and initial CO_2 injectivity within the SNS is considered to be good. Neither reservoir quality onr injectivity are considered to be a high risk.

As an additional check a dynamic model was constructed to test the injectivity performance, at initial conditions and over time. A simple model was built in Eclipse (flat structure). CO_2 will be injected in critical or dense phase as the reservoir pressure is expected to be high in saline aquifer. Injection pressure of 1900 psi is required to achieve the injectivity threshold of 1MT/year per well.

Well Design

The generic well design is discussed in the supporting document 'Storage Site Due Diligence Summary'. It is likely that this well design can be achieved in the Bunter 9.

Due to the shallow water depth (27m), wells have been assumed to be drilled by a low cost class 1 Jack-Up Drilling Unit. Platform well costs are assumed to be £16M per well, resulting in a 5 well development cost of £81M.

Development Concept

CO_2 volumes cf ETI Scenarios

The ETI Concentrated Scenario shows 29MT/yr by 2030 into the SNS via Barmston. It is possible that the first 17Mt/yr could be stored at 5/42. On the basis of this Scenario, additional SNS storage would be needed by 2027 and need to be capable of storing 12Mt/yr by 2030.

Comparative development concept

A new Normally Unmanned Installation (NUI) comprising a jacket and topsides with 5 deviated wells, each injecting 1MT/yr; totalling 100MT over 20 years. CO_2 would be delivered via a new 20" 227km pipeline from Barmston with 10MT/yr capacity. Facilities will be controlled from the beach with the NUI including power generation and controls relay. Monitoring will include downhole pressure and distributed temperature sensors.

Site growth potential; theoretical ultimate development concept

The site has a theoretical storage capacity of ~1997MT; the capacity is constrained to 1000MT for this prospect evaluation stage.

10 new NUI Platforms, each with 5 wells injecting a total of 50Mt/yr; totalling 1000MT over 20 years. CO_2 would be delivered via a new 36" 227km pipeline from Barmston with a 50Mt/yr capacity. Facilities will be controlled from the beach. Power generation and controls relay will be provided from a single primary NUI. Platforms are connected by 10km infield pipelines and umbilicals.

Build out potential

Bunter Closure 9 is reasonably close to the two Hewett Reservoirs (448MT), Viking (271MT) and Bunter Closure 3 (409MT). The Barque depleted gas field (120MT) is on the likely pipeline route from Barmston. These all represent potential regional growth opportunities.

Development Cost

Capacity:	1997	Water Depth (m)	30
Concept Cost (£m)	**Comparative Development**	**Ultimate Development**	**Description**
Tonnes Injected (MT)	100	1000	Total Stored CO_2 for proposed scheme
Appraisal Cost:	£54m	£54m	Appraisal Wells + Seismic Data Acquisition & Interpretation
Development Well Cost:	£80.3m	£802.7m	Drilling & Completion Costs of wells.
Facilities Cost:	£329.7m	£1009.6m	Landfall, Pipeline, NUI, ties-Ins,
PM & Eng:	£33m	£101m	10% of Facilities Costs
Decommissioning:	£112.5m	£552.4m	£10m per NUI, £4m per dry well
Subtotal	£609.3m	£2519.6m	
Contingency	£121.9m	£504m	20% of Development & Facilities Costs
OPEX (20years)	£395.6m	£1211.5m	OPEX Cost for 20 years (6% of facilities costs)
Total:	£1126.7m	£4235m	
£/T CO_2	11.27	4.23	

Table 67: Bunter Aquifer 9 Development Cost Estimate

*These costs are not the full cost of storage as they omit MMV, security instruments, handover to DECC and profit.

Data

Bunter Closure 9 is covered by the 3D seismic from the SNS PGS megasurvey. The data quality is generally moderate due to low fold of coverage in the shallow section. The acquisition foot-print can clearly be seen in shallow time slices. The well ties confirm the time interpretation.

CDA well data is available over the Leman field and surrounding exploration wells. E&A well data has been downloaded from CDA. Log coverage over the Bunter interval is variable.

Commercial Issues

Bunter C9 is in the vicinity of the Leman gas field which is not expected to cease production until 2030. There is likely to be some risk of operational interaction between gas extraction and CO_2 storage activity which would compromise CO_2 storage at this site prior to COP on Leman.

13 Bunter Aquifer 36

Overview

Capacity:	252MT	UKCS Block:	44/26 vicinity
Unit Designation:	Saline Aquifer	**Beachhead:**	Barmston
Formation:	Bunter sandstone	**Water Depth:**	72m
Earliest injection:	2025	**Reservoir Depth:**	1557m
Availability/COP:	n/a	**Region:**	SNS

Table 68: Bunter Aquifer 36 Overview

- Additional checks of injectivity indicate that the target rate of 1MT/year/well can be met assuming a minimum injection pressure of 2800 psi. This is below the calculated minimum fracture pressure of 3312 psi at the well depth.
- There is a large uncertainty associated with the minimum fracture pressures. The values quoted from CO2Stored are derived from correlations which appear to give very low minimum fracture pressures. This can be observed in the large discrepancy between the measured and estimated values for the 5/42 store; measured: 3900 psi vs estimate: 2800 psi. However, a review of published papers suggested a frac gradient of 0.728 for the Bunter, giving a frac pressure of 3,312 psi at the well depth of 4,550 ft TVDSS.
- The Georisk factor has been calculated as 6. This is the same as that calculated in WP3 selection criteria.
- Permeability remains a key uncertainty to be assessed in detail if this store is taken forward.
- The additional risk assessment carried out for the engineering containment risk indicates that the risk is low, as there are only 15 wells on the field, with 5 being plugged and abandoned, only 1 of which before 1986.
- The risk of halite issues due to reservoir dehydration in the near wellbore is recognised as significant.
- Well cost estimate (for 5 wells) is £123M.

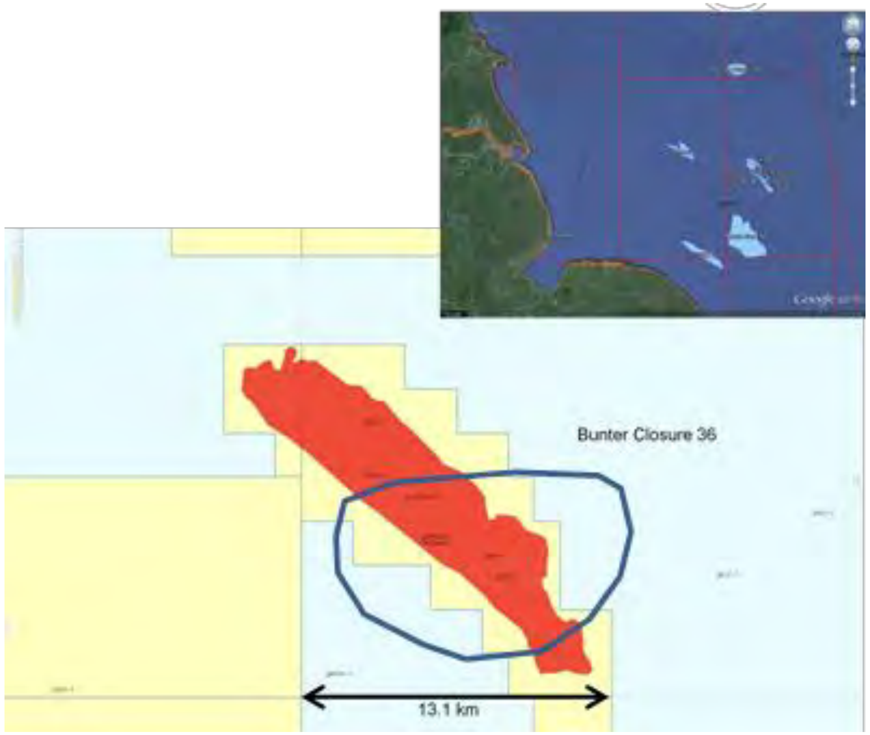


Figure 17: Bunter Aquifer 36 Location Map

Containment

An overburden assessment has been conducted above and adjacent to the Bunter Sandstone to identify secondary containment horizons and potential migration pathways out of the storage complex, in the unlikely event of a seal or fault leakage of the sequestered CO_2.

The site is a simple 4-way dip closure. The Bunter sandstone reservoir is overlain by 1000ft of Triassic halites, anhyrites and claystones forming an excellent cap rock that is continuous and not penetrated by faulting. Above the Triassic is an additional 20ft of Jurassic/Lower Cretaceous claystone. Overlying the Lower Cretaceous is approximately 1000ft of Upper Cretaceous Chalk which is a potential reservoir, with 200ft of Tertiary and recent sediments on top which may only have a limited seal capacity.

The Georisk factor has been calculated as 6, this is the same as the previously calculated factor in WP3 based on CO2Stored data.

	Fault Characterisation			Seal Characterisation			Georisk Factor
	Density	Throw & Seal	Fault Vertical Extent	Fracture Pressure Capacity	Seal Chemical Reactivity	Sea Degradation	
CO2Stored Value	1	1	1	1	1	1	6
Due Diligence Value	1	1	1	1	1	1	6
Risk Factor Key: Low = 1, Medium = 2, High = 3							

Table 69: Bunter Aquifer 36 Geo-containment Risk

Engineering Risk

The engineering containment risk is low, with 15 wells in total. Five wells were plugged and abandoned, only 1 of which was before 1986, representing the highest risk. The 100yr probability of a leakage on the field is a low 0.03, and the well density factor is 0.2 wells/km2, resulting in a low containment risk assessment score of 0.006.

Capacity

The calculated storage capacity is 252MT compared to the reported capacity in CO2Stored of 232MT. These are in agreement.

Thickness[2] [m]	GRV [MM m3]	NTG[2]	Porosity[1]	CO2 Density[3] [Tonnes/ m3]	Pore Space Utilisation[3]	Pore Volume [MMm3]	Theoretical Capacity [MT]
220	13137	0.95	0.2	0.85	0.12	2496	252

Table 70: Bunter Aquifer 36 Storage Capacity

NB. 1: Analogue site data from 5/42 (Ref x) 2: Estimated from CDA composite logs 3: CO2Stored

Whilst there are uncertainties associated with the inputs to the capacity calculation, there is a high degree of confidence in the storage capacity which has been calculated.

Faulting within the Bunter can develop due to post depositional halokenisis, however compartmentalisation due to faulting is not thought to be a risk for this storage site, and the volume should be well connected.

Injectivity

The selection criteria used for injectivity is the permeability thickness (Kh) value calculated using the mid case reservoir data from CO2Stored. For the Bunter Closure 36 this was calculated as 11,051 mDm.

The permeability thickness calculated during the validation process is 56,639 mDm. This is considerably higher than the estimate based on the CO2Stored data, and is due to a difference in the assumed average permeability.

CO2Stored assumes an average permeability of 50mD. This is very low when compared to nearby SNS analogue Bunter Sst reservoirs. The Hewett Gas Field has average permeabilites in excess of 500 mD (Cooke, Yarborough, 1991). The nearby 42/25d-3 (5/42 Storage Site), with a published permeability of 271mD, is used as an analogue for this storage site (Furnival, S., 2015).

Zone	Depositional Environment	Gross Thickness[2] [m]	NTG[2]	Porosity[1]	Perm[1] [mD]	Kh [mDm]
Bunter Sst	Fluvial/ Lacustrine	220	0.95	0.2	271	56639

Table 71: Bunter Aquifer 36 Reservoir Properties

NB. 1: Analogue field data 5-42 2: Estimated from CDA composite logs 3: CO2Stored

With no permeability data available for the Bunter Sst at the storage site, permeability, its regional lateral variation and heterogeneity remain an uncertainty. Bunter Sandstone reservoir quality at this depth and initial CO_2 injectivity within the SNS is considered to be good. Neither reservoir quality nor injectivity are considered to be a high risk.

An additional injectivity check was carried out as part of the due diligence. A dynamic model was constructed to test the injectivity performance, at initial conditions and over time. A simple model was built in Eclipse (flat structure and average reservoir properties). CO_2 will be injected in critical or dense phase as the reservoir pressure is not expected to be depleted in the saline aquifer. An injection pressure of 2800 psi is required to achieve the injectivity threshold of 1MT/year per well, which is below the estimated minimum fracture pressure of 3312 psi at the well depth of 4550 ft tvdss.

Well Design

The generic well design is discussed in the supporting document 'Storage Site Due Diligence Summary'. It is likely that this well design can be achieved in the Bunter 36.

Due to the moderate water depth (72m), wells have been assumed to be drilled by a class 2 (heavy duty) Jack-Up Drilling Unit. Platform well costs are assumed to be £24.6M per well, resulting in a 5 well development cost of £124M.

Development Concept

CO_2 volumes cf ETI Scenarios

The ETI Concentrated Scenario shows 29MT/yr by 2030 into the SNS via Barmston. It is possible that the first 17Mt/yr could be stored at 5/42. On the basis of this Scenario, additional SNS storage would be needed by 2027 and need to be capable of storing 12Mt/yr by 2030.

Comparative development concept

A new Normally Unmanned Installation (NUI) comprising a jacket and topsides with 5 deviated wells each injecting 1MT/yr; totalling 100MT over 20 years. CO_2 would be delivered via a 20" 86km pipeline extension from 5/42 with 10MT/yr capacity, assuming that sufficient ullage exists in the 5/42 pipeline. Facilities will be controlled from the beach or 5/42 with the NUI providing its own power and controls. Monitoring will include downhole pressure and distributed temperature sensors.

Site growth potential; theoretical ultimate development concept

The site has a theoretical storage capacity of ~250MT.

2 unmanned injection platforms, each with 5 wells injecting a total of 10Mt/yr; 200MT. 20" 75km pipeline from 5/42 with a 10Mt/yr capacity. Facilities controlled from the beach. Platforms are connected by 10km infield pipelines and umbilicals

Build out potential

A new development comprising 2 new NUI platforms each with 6 wells injecting a total of 12Mt/yr; totalling 240MT over 20 years. CO_2 would be delivered via a 20" 86km pipeline from 5/42 assuming that sufficient ullage exists in the 5/42 pipeline. Power generation and controls relay will be provided from a single primary NUI or from 5/42. Platforms are connected by 10km infield pipelines and umbilicals.

Development Cost

Capacity:	252	Water Depth (m)	75
Concept Cost (£m)	**Comparative Development**	**Ultimate Development**	**Description**
Tonnes Injected (MT)	100	240	Total Stored CO_2 for proposed scheme
Appraisal Cost:	£66m	£66m	Appraisal Wells + Seismic Data Acquisition & Interpretation
Development Well Cost:	£123.1m	£295.4m	Drilling & Completion Costs of wells.
Facilities Cost:	£164.9m	£248.5m	Landfall, Pipeline, NUI, ties-Ins,
PM & Eng:	£16.5m	£24.9m	10% of Facilities Costs
Decommissioning:	£71.3m	£130.2m	£10m per NUI, £4m per dry well
Subtotal	£441.7m	£764.8m	
Contingency	£88.4m	£153m	20% of Development & Facilities Costs
OPEX (20years)	£197.9m	£298.2m	OPEX Cost for 20 years (6% of facilities costs)
Total:	£727.9m	£1215.9m	
£/T CO_2	7.28	5.07	

Table 72: Bunter Aquifer 36 Development Cost Estimate

*These costs are not the full cost of storage as they omit MMV, security instruments, handover to DECC and profit.

Data

Bunter Closure 36 is covered by the 3D seismic from the SNS PGS megasurvey. The data quality is good. Well ties confirm the time interpretations.

All wells target the deeper Carboniferous sands. Digital log data and composite logs are available for some wells on the CDA website. There is limited core coverage from the Bunter interval in 1 well.

No engineering data available for aquifer sands. Analogue data and correlations will be used.

Commercial Issues

Bunter C36 is in the vicinity of the Schooner depleted gas field. COP on Schooner is 2021. Development of C36 should take place after COP on Schooner to minimise any operational interaction.

14 Bunter Aquifer 40

Overview

Capacity:	100MT	UKCS Block:	43/23 vicinity
Unit Designation:	Saline Aquifer	Beachhead:	Barmston
Formation:	Bunter sandstone	Water Depth:	50m
Earliest injection:	2025	Reservoir Depth:	1550m
Availability/COP:	n/a	Region:	SNS

Table 73: Bunter Aquifer 40 Overview

The results of the due diligence review confirm that the selection criteria used for Bunter Closure 40 are all reasonable; the only large variation is in permeability thickness which the due diligence work estimates may be higher due to better average permeabilities.

During the due diligence review minimum fracture pressure has been identified as a high risk.

- Additional checks of injectivity indicate that the target rate of 1MT/year/well can be met assuming a minimum injection pressure of 3600 psi. This is below the calculated minimum fracture pressure of 4077 psi at the well depth.
- There is a large uncertainty associated with the minimum fracture pressures. The values quoted from CO2Stored are derived from correlations which appear to give very low minimum fracture pressures. This can be observed in the large discrepancy between the measured and estimated values for the 5/42 store measured: 3900 psi vs estimate: 2800 psi. A review of published papers suggested a frac gradient of 0.728 for the Bunter, giving a frac pressure of 3,695psi at 5,075ft TVDSS.
- The Georisk factor has been calculated as 6. This is the same as that calculated in WP3 selection criteria.
- Permeability remains a key uncertainty to be assessed in detail if this store is taken forward.
- The additional risk assessment carried out for the engineering containment risk indicates that the risk is very low, as there is only 1 well on the field, which was plugged and abandoned in 1994.
- The risk of halite issues due to reservoir dehydration in the near wellbore is recognised.
- Well cost estimate (for 5 wells) is £119M.

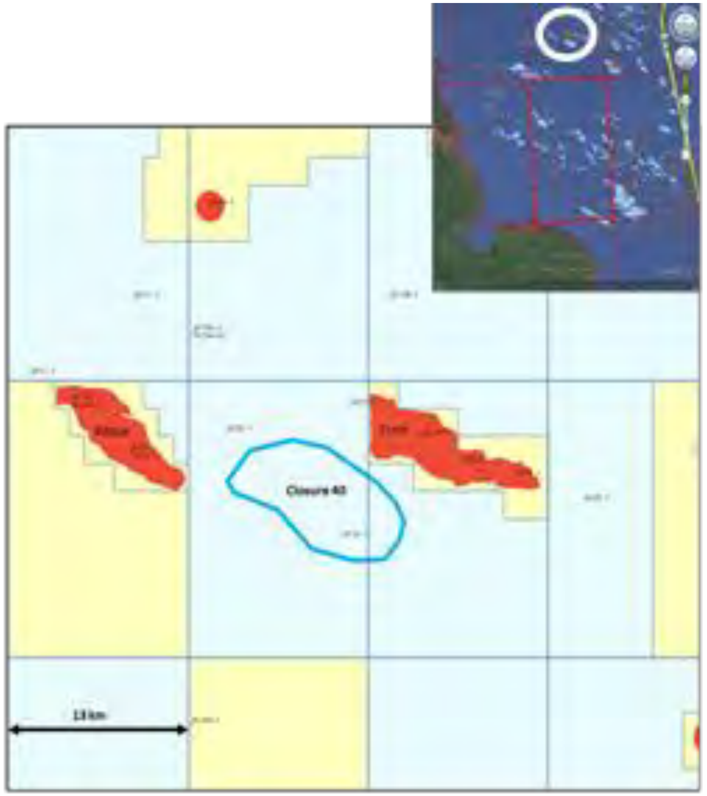


Figure 18: Bunter Aquifer 40 Location Map

Containment

An overburden assessment has been conducted above and adjacent to the Bunter Sandstone to identify secondary containment horizons and potential migration pathways out of the storage complex, in the unlikely event of a seal or fault leakage of the sequestered CO_2.

The site is a simple 4-way dip closure. The Bunter sandstone reservoir is overlain by 2000ft of Triassic halites, anhydrites and claystones forming an excellent cap rock that is continuous and not penetrated by faulting. Above the Triassic is an additional 1300ft of Jurassic/Lower Cretaceous claystone. Overlying the Lower Cretaceous is approximately 1100 ft of Upper Cretaceous Chalk which is a potential reservoir, with 300-400ft of Tertiary and recent sediments on top which may only have a limited seal capacity.

The Georisk factor has been calculated as 6, this is the same as the previously calculated factor in WP3 based on CO2Stored data.

	Fault Characterisation			Seal Characterisation			Georisk Factor
	Density	Throw & Seal	Fault Vertical Extent	Fracture Pressure Capacity	Seal Chemical Reactivity	Sea Degradation	
CO2Stored Value	1	1	1	1	1	1	6
Due Diligence Value	1	1	1	1	1	1	6
Risk Factor Key: Low = 1, Medium = 2, High = 3							

Table 74: Bunter Closure 40 Geo-containment Risk

Engineering Risk

The engineering containment risk is very low, with only one well drilled and at risk of leaking. This well was plugged and abandoned in 1994. The 100yr probability of a leakage on the field is a low 0.002, and the well density factor is 0.02 wells/km2, resulting in a very low containment risk assessment score of 0.0004.

Capacity

The calculated storage capacity is 100MT compared to the reported capacity in CO2Stored of 84MT. These are in broad agreement; the increase in the calculated capacity is due to a higher average porosity being assumed based on offset analogue field data.

Thickness[2] [m]	GRV [MM m3]	NTG[2]	Porosity[1]	CO2 Density[3] [Tonnes/ m3]	Pore Space Utilisation[3]	Pore Volume [MMm3]	Theoretical Capacity [MT]
230	6952	0.8	0.2	0.79	0.11	1112	100

Table 75: Bunter Aquifer 40 Storage Capacity

NB. 1: Analogue site data from 5/42 (Ref x) 2: Estimated from CDA composite logs 3: CO2Stored

Whilst there are uncertainties associated with the inputs to the capacity calculation, there is a high degree of confidence in the storage capacity which has been calculated.

Faulting within the Bunter can develop due to post depositional halokenisis, compartmentalisation due to faulting is not thought to be a risk for this storage site, and the volume should be well connected.

Injectivity

The selection criteria used for injectivity is the permeability thickness (Kh) value calculated using the mid case reservoir data from CO2Stored. For the Bunter Closure 40 this was calculated as 22,673 mDm.

The permeability thickness calculated during the validation process is 49,864 mDm. This is considerably higher than the estimate based on the CO2Stored data, and is due to a difference in the assumed average permeability.

CO2Stored assumes an average permeability of 100mD. This is very low when compared to nearby SNS analogue Bunter Sst reservoirs. The Hewett Gas Field has average permeabilites in excess of 500 mD. The nearby 42/25d-3 (5/42 Storage Site), with a published permeability of 271mD, is used as an analogue (Furnival, S., 2015)

Zone	Depositional Environment	Gross Thickness[2] [m]	NTG[2]	Porosity[1]	Perm[1] [mD]	Kh [mDm]
Bunter Sst	Fluvial/ Lacustrine	230	0.8	0.2	271	49864

Table 76: Bunter Aquifer 40 Reservoir Properties

NB. 1: Analogue field data 5-42 (Ref x) 2: Estimated from CDA composite logs 3: CO2Stored

With no permeability data available for the Bunter Sst at the storage site, permeability, its regional lateral variation and heterogeneity remain an uncertainty. Bunter Sst reservoir quality at this depth and initial CO_2 injectivity within the SNS is considered to be good. Neither reservoir quality nor injectivity are considered to be a high risk.

As an additional check a dynamic model was constructed to test the injectivity performance, at initial conditions and over time. A simple model was built in Eclipse (flat structure). CO_2 will be injected in critical or dense phase as the reservoir pressure is expected to be high in saline aquifer. Injection pressure of 3600 psi is required to achieve the injectivity threshold of 1MT/year per well, which is below the minimum fracture pressure of 4077psi at the well depth.

Well Design

The generic well design is discussed in the supporting document 'Storage Site Due Diligence Summary'. It is likely that this well design can be achieved in the Bunter 40.

Due to the relatively shallow water depth (50m), wells have been assumed to be drilled by a low cost class 1 Jack-Up Drilling Unit. Platform well costs are assumed to be £23.7M per well, resulting in a 5 well development cost of £119M.

Development Concept

CO_2 volumes cf ETI Scenarios

The ETI Concentrated Scenario shows 29MT/yr by 2030 into the SNS via Barmston. It is possible that the first 17Mt/yr could be stored at 5/42. On the basis of this Scenario, additional SNS storage would be needed by 2027 and need to be capable of storing 12Mt/yr by 2030.

Comparative development concept

A new Normally Unmanned Installation (NUI) comprising a jacket and topsides with 5 deviated wells each injecting 1MT/yr; totalling 100MT over 20 years. CO_2 will be delivered via a 20" 40km pipeline extension from 5/42 with10MT/yr capacity, assuming that sufficient ullage exists in the 5/42 pipeline. Facilities will be controlled from the beach or 5/42 with the NUI providing its own power and controls. Monitoring will include downhole pressure and distributed temperature sensors.

Site growth potential; theoretical ultimate development concept

The site has a theoretical storage capacity of ~100MT.

The site has no additional growth potential

Build out potential

Bunter Closure 40 is a potential build out location for 5/42. Build out from this site could be to Bunter Closure 36.

Development Cost

Capacity:	100	Water Depth (m)	30
Concept Cost (£m)	**Comparative Development**	**Ultimate Development**	**Description**
Tonnes Injected (MT)	80		Total Stored CO_2 for proposed scheme
Appraisal Cost:	£64m		Appraisal Wells + Seismic Data Acquisition & Interpretation
Development Well Cost:	£118.9m		Drilling & Completion Costs of wells.
Facilities Cost:	£99.2m		Landfall, Pipeline, NUI, ties-Ins,
PM & Eng:	£10m		10% of Facilities Costs
Decommissioning:	£54.8m		£10m per NUI, £4m per dry well
Subtotal	£346.8m		
Contingency	£69.4m		20% of Development & Facilities Costs
OPEX (20years)	£119.1m		OPEX Cost for 20 years (6% of facilities costs)
Total:	£535.2m		
£/T CO_2	5.35		

Table 77: Bunter Aquifer 40 Development Cost Estimate

Data

Approximately 80% of Bunter Closure 40 is covered by the 3D seismic from the SNS PGS megasurvey. The data quality is generally good. The well ties confirm the time interpretation.

There is a gap in coverage to the west and the horizon gridding has been allowed to extrapolate through this gap. There is a spec 3D seismic volume available and a small volume of data could be purchased to fill the gap.

The single well (43/23-3) penetrating the structure, and two nearby offset wells are available in CDA with limited digital log data. No core data available.

No engineering data available for aquifer sands. Analogue data and correlations will be used.

Commercial Issues

Bunter closure 40 is in the vicinity of 43/23 which is currently unlicensed for oil and gas activity.

15 Hewett (Bunter Sandstone) Gas Field

Overview

Capacity:	288MT	UKCS Block:	48/29
Unit Designation:	Depleted Gas	Beachhead:	Barmston
Formation:	Bunter Sandstone	Water Depth:	37m
Earliest injection:	2020	Reservoir Depth:	800m
Availability/COP:	2016	Region:	SNS

Table 78: Hewett (Bunter) Field Overview

The results of the due diligence have identified a number of risks:

- Whilst still high, the permeability thickness (mDm) calculated during the due diligence is significantly lower than that calculated using CO2Stored data.
- Dynamic modelling checks of injectivity indicate that the target rate of 1MT/year/well can only be met initially with a relatively high DP from well to formation of 800 psi or more.
- The Geo containment risk factor is unchanged and whilst high, the presence of hydrocarbons proves containment integrity.
- Connection between Lower and Upper Bunter would also be an issue for the CO_2 plume development (IEAGHG Report, 2013).
- The additional risk assessment carried out for the engineering containment risk indicates that the risk is moderate, as there are 52 wells on the field, with 12 being plugged and abandoned, most of them in the 60's.
- Due to the shallow depth of the reservoir, there is a chance that the well may not reach horizontal in the target reservoir.
- The ability to drill high angle wells in the depleted reservoir is a carried engineering risk.
- The risk of halite issues due to reservoir dehydration in the near wellbore is also recognised as being severe.
- Well cost estimate (for 5 wells) is £114M.

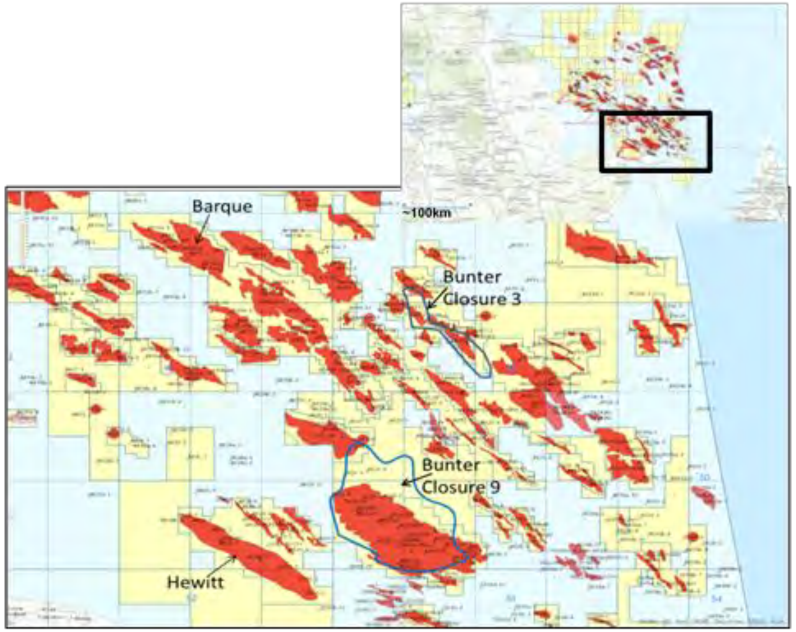


Figure 19:Hewett (Bunter) Field Location Map

Containment

An overburden assessment has been conducted above and adjacent to the Bunter Sandstone to identify secondary containment horizons and potential migration pathways out of the Hewett storage complex, in the unlikely event of a seal or fault leakage of the sequestered CO_2.

Field data and published literature were reviewed to establish the effectiveness of trap and seal. Upper Bunter sandstones are sealed by the 2000ft of Triassic shales, salt and anhydrite. Below the Bunter sandstone is the Bunter shales and Hewett sandstone (Cooke, Yarborough, 1991).

The Georisk factor has been calculated as 10, this is higher than previous calculated factor in WP3 based on CO2Stored data as faults are seen to extend above 800m. The factor is lower than for the Hewett Field Hewett Sandstone as the Hewett sandstone is thinner and completely offset by faults along the NE margin of the field.

	Fault Characterisation			Seal Characterisation			Georisk Factor
	Density	Throw & Seal	Fault Vertical Extent	Fracture Pressure Capacity	Seal Chemical Reactivity	Sea Degradation	
CO2Stored Value	2	2	1	1	1	1	8
Due Diligence Value	2	2	3	1	1	1	10
Risk Factor Key: Low = 1, Medium = 2, High = 3							

Table 79: Hewett (Bunter) Field Geo-containment Risk

Engineering Risk

The engineering containment risk is moderate, with 52 wells considered at risk of leakage. 12 wells were plugged and abandoned, 10 of which were before 1986, representing the highest risk. Total storage target leakage risk is 0.08 and the well density factor is 0.43 wells/km2, resulting in a moderate leakage risk assessment score of 0.04.

Capacity

The calculated storage capacity is 288MT compared to the reported capacity in CO2Stored of 205MT.

For the Hewett Bunter Sandstone field, the due diligence involves a recalculation of the capacity equivalent to the net reservoir volume of fluids removed at February 2015. In addition, the net reservoir volume of fluids removed at COP was estimated and the capacity calculated at this time to confirm the full capacity estimate. The COP date for Hewett Bunter Sandstone in the supplied Woodmac data is 2020.

Hewett Bunter Sandstone produces a dry gas with small amount of condensate and no water production. DECC reports no gas and water injection volume. All produced fluids were accounted for in the material balance calculation to check potential storage capacity.

Current gas rates are low, 235Ksm3/d (8.3mmscf/d) at this stage of the field's producing life (see below), resulting in 2.5MT (<0.9%) uplift in storage capacity between February 2015 and end 2020 (COP).

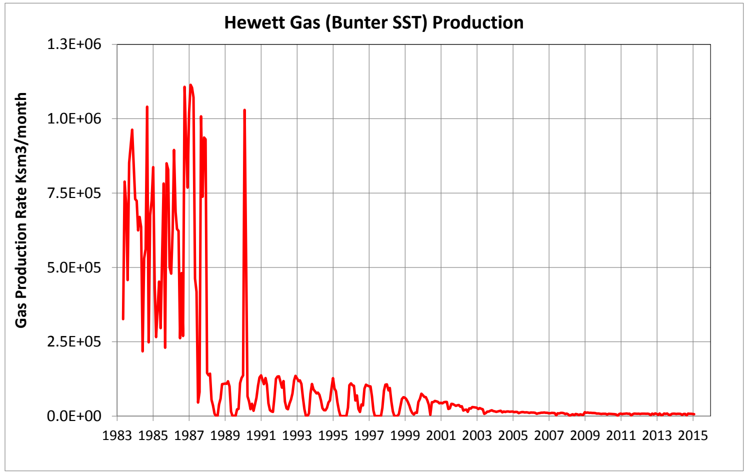


Figure 20: Hewett (Bunter) Gas Production Profile

The produced volumes and conversion to mass storage potential are shown in the table below.

Gas Production	46071	MCM
Condensate Production	0.199	MCM
Net Reservoir Volume Produced	475	MCM
Storage Capacity	288	MT

Table 80: Hewett (Bunter) Field Storage Capacity

NB. Volumes refer to production volumes at February 2015.
The volumes and shrinkage factors used in the calculation are shown in Table 81.

Parameter		Reference	CO2Stored
CO_2 density (kg/m3)	600	CO_2 Storage	600
Gas expansion factor (rm3/sm3)	0.0103	Ref. 1 UK Oil and Gas Data	0.0103
Condensate formation volume factor (rm3/sm3)	1.75	Analogue	n/a
Water formation volume factor (rm3/sm3)	1.02	Analogue	1.02

Table 81: Hewett (Bunter) Field Fluid Properties

Injectivity

The selection criteria used for injectivity is the permeability thickness (Kh) value calculated using the mid case reservoir data from CO2Stored. For the Hewett Field Upper Bunter sandstone this was calculated as 82,749mDm.

Field data and published literature have been reviewed in order to confirm the reservoir properties which have then been used to validate the permeability thickness and expected injectivity.

The permeability thickness calculated during the validation process is 33,712 mDm. This is 69% less than the estimate based on the CO2Stored data. The reservoir properties have been obtained from an RDS study for E.ON conducted in March 2010 (EON 2011). The permeability thickness is still relatively high and similar to the underlying Hewett sandstone (lower Bunter) kh, and based on reservoir quality the initial CO_2 injectivity is expected to be excellent.

The Upper Bunter sandstone field is composed of fluvial channel and sheetflood sandstones of the Lower Triassic. The Upper Bunter sandstones have a depth to crest at 792m TVDSS with excellent net to gross, porosity and permeability's. A summary of the reservoir properties are detailed in the table below.

Zone	Depositional Environment	Gross Thickness [m]	NTG	Porosity	Perm [mD]	Kh [mDm]
Upper Bunter	Alluvial plain SSTs	146	0.94	0.2	245.64	33,712

Table 82: Hewett (Bunter) Field Reservoir Properties

As an additional check a dynamic model was constructed to test the injectivity performance, at initial conditions and over time. A simple model was built in Eclipse (flat structure). CO_2 will be injected in the gas phase initially as the reservoir pressure is expected to be too low for dense phase injection. A DP (well–formation pressure) range of 150psi to 650psi was tested and the corresponding injectivity per well is 0.17MT/year and 0.8MT/year. The modelling confirms that the injectivity threshold of 1MT/year per well can only be achieved for a DP of 800 psi or more.

Well Design

The generic well design is discussed in the supporting document 'Storage Site Due Diligence Summary'. It is likely that this well design can be achieved in the Hewett, although there are concerns over the ability to drill new wells in the depleted gas field, particularly at a high angle, due to wellbore stability issues. This may limit the achievable deviation in the reservoir section. Current producing wells are primarily low angle wells, although some horizontals have been drilled.

Due to the shallow water depth (30m), wells have been assumed to be drilled by a low cost class 1 Jack-Up Drilling Unit. Platform well costs are assumed to be £25.78M per well, including a contingency cost for managing CO_2 phase change, resulting in a 5 well development cost of £129M.

Development Concept

CO_2 volumes cf ETI Scenarios

The ETI Concentrated Scenario shows 29MT/yr by 2030 into the SNS via Barmston. It is possible that the first 17Mt/yr could be stored at 5/42. On the basis of this Scenario, additional SNS storage would be needed by 2027 and need to be capable of storing 12Mt/yr by 2030.

Comparative development concept

A new Normally Unmanned Installation (NUI) comprising a jacket and topsides with 5 deviated wells each injecting 1MT/yr; totalling 100MT over 20 years. CO_2 will be delivered via a 20" 212km pipeline from Barmston with 10MT/yr capacity. Facilities will be controlled from the beach with the NUI providing its own power and controls. Monitoring will include downhole pressure and distributed temperature sensors.

Site growth potential; theoretical ultimate development concept

The site has a theoretical storage capacity of ~288MT. In addition Site 6, Bunter Shale (312MT) is at the same location. The ultimate development is therefore considered to be a combined development with both horizons and a total theoretical capacity of ~ 600MT.

A new development comprising 6 new NUI platforms each with 5 wells injecting a total of 30Mt/yr; totalling 600MT over 20 years. CO_2 would be delivered via a 30" 212km pipeline from Barmston with a 35Mt/yr capacity. Power generation and controls relay will be provided from a single primary NUI. Platforms are connected by 10km infield pipelines and umbilicals.

Build out potential

Hewett is within build-out reach of Viking (271MT) and Bunter Closure 9 (1691MT). The Barque depleted gas field (120MT) is on the likely pipeline route from Barmston. These all represent potential regional growth opportunities

Development Cost

Capacity:	288	Water Depth (m)	30
Concept Cost (£m)	**Comparative Development**	**Ultimate Development**	**Description**
Tonnes Injected (MT)	100	600	Total Stored CO_2 for proposed scheme
Appraisal Cost:	£0m	£0m	Appraisal Wells + Seismic Data Acquisition & Interpretation
Development Well Cost:	£114.1m	£684.5m	Drilling & Completion Costs of wells.
Facilities Cost:	£297.6m	£679.4m	Landfall, Pipeline, NUI, ties-Ins,
PM & Eng:	£29.8m	£68m	10% of Facilities Costs
Decommissioning:	£104.4m	£349.9m	£10m per NUI, £4m per dry well
Subtotal	£545.8m	£1781.6m	
Contingency	£109.2m	£356.4m	20% of Development & Facilities Costs
OPEX (20years)	£357.1m	£815.2m	OPEX Cost for 20 years (6% of facilities costs)
Total:	£1011.9m	£2953.1m	
£/T CO_2	10.12	4.92	

Table 83: Hewett (Bunter) Field Development Cost Estimate

Data

The field is covered by 3D seismic from the PGS SNS mega survey and is of good quality.

Well data available for the Hewett field from CDA. E&A well data has been downloaded. A review of well logs show washouts in some shale sections – existing wells are poor quality (IEAGHG, 2013).

Commercial Issues

Hewett is a depleted gas field. COP is expected to be 2016.

16 Hewett (Hewett Sandstone) Gas Field

Overview

Capacity:	312MT	UKCS Block:	48/29
Unit Designation:	Depleted Gas	**Beachhead:**	Barmston
Formation:	Bunter Shale	**Water Depth:**	37m
Earliest injection:	2020	**Reservoir Depth:**	1277m
Availability/COP:	2016	**Region:**	SNS

Table 84: Hewett (Hewett) Field Overview

The results of the due diligence review confirm that the selection criteria used for Hewett are all reasonable. There are small variations in injectivity and containment values. Note that the gas production at February 2015 is higher than the GIIP reported in the UK oil and gas field database[1].

- Additional checks of injectivity indicate that the target rate of 1MT/year/well can be met at the low reservoir pressures with a reasonable DP from well to formation.
- The Geo containment risk factor is unchanged and whilst high, the presence of hydrocarbons proves containment integrity.
- Connection between Lower and Upper Bunter would also be an issue for the CO_2 plume development (IEAGHG Report, 2013).
- Overall, the reservoir characteristics are good for NTG, porosity and permeability with sufficient trap, overburden seal (sealed faults), and underburden for storage of CO_2.
- The additional risk assessment carried out for the engineering containment risk indicates that the risk is low to moderate.
- Due to the shallow depth of the reservoir, there is a chance that the well may not reach horizontal in the target reservoir.
- The ability to drill high angle wells in the depleted reservoir is a carried engineering risk.
- The risk of halite issues due to reservoir dehydration in the near wellbore is also recognised as being severe.
- Well cost estimate (for 5 wells) is £129M.

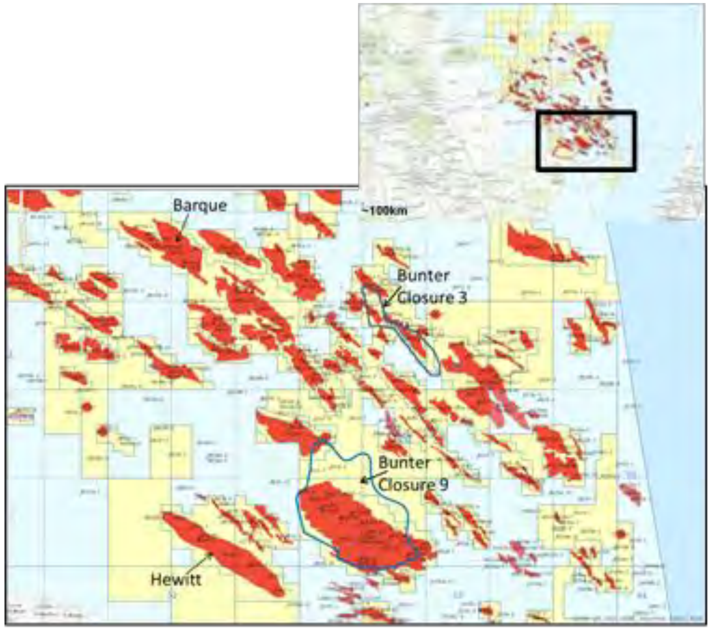


Figure 21: Hewett (Hewett) Field Location Map

Containment

An overburden assessment has been conducted above and adjacent to the Hewett sandstone to identify secondary containment horizons and potential migration pathways out of the Hewett storage complex, in the unlikely event of a seal or fault leakage of the sequestered CO_2.

Field data and published literature were reviewed to establish the effectiveness of trap and seal. Lower Bunter Hewett sandstones are sealed by Bunter floodplain shales (Cooke, Yarborough, 1991). Below the Hewett sands is a thick evaporate and carbonate Zechstein sequence.

The Georisk factor has been calculated as 11, this is the same as previous calculated factor in WP3 based on CO2Stored data. The factor is higher than for the Hewett Field Bunter Sandstone as the Hewett sandstone is thinner and completely offset by faults along the NE margin of the field.

	Fault Characterisation			Seal Characterisation			Georisk Factor
	Density	Throw & Seal	Fault Vertical Extent	Fracture Pressure Capacity	Seal Chemical Reactivity	Sea Degradation	
CO2Stored Value	2	2	2	1	2	2	11
Due Diligence Value	2	2	2	1	2	2	11
Risk Factor Key: Low = 1, Medium = 2, High = 3							

Table 85: Hewett (Hewett) Field Geo-containment Risk

Engineering Risk

The engineering containment risk is low to moderate, with 52 wells in the field. 10 wells were plugged and abandoned before 1986, representing the highest assessed risk. Total storage target leakage risk is 0.11 and the well density factor is 0.43 wells/km^2, resulting in a low to moderate leakage risk assessment score of 0.048.

Capacity

The calculated storage capacity is 312MT compared to the reported capacity in CO2Stored of 244MT.

The due diligence involves a recalculation of the capacity equivalent to the net reservoir volume of fluids removed at February 2015. In addition, the net reservoir volume of fluids removed at COP was estimated and the capacity calculated at this time to confirm the full capacity estimate. The COP date for Hewett Sandstone is 2020 in the supplied Woodmac data.

Hewett Sandstone produces a dry gas with small traces of condensate and no water production. DECC reports no gas and water injection volume. All produced fluids were accounted for in the material balance calculation to check potential storage capacity.

Current gas rates are low, ~370 ksm3/d (13 mmscf/d). Assuming this rate is maintained until COP, the additional storage capacity associated with this production is 2.5MT (~0.8%).

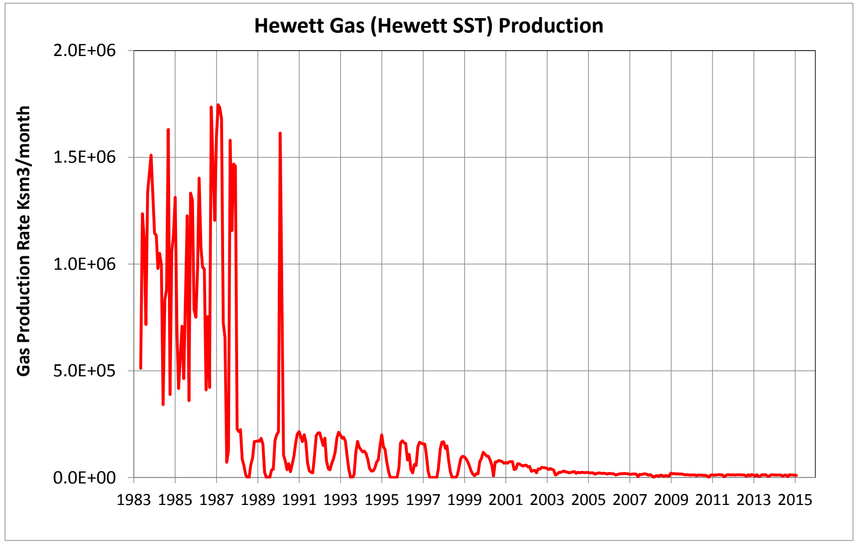


Figure 22: Hewett (Hewett) Gas Production Profile

The produced volumes and conversion to mass storage potential are shown in the table below:

Gas Production	72220	MCM
Condensate Production	0.313	MCM
Net Reservoir Volume Produced	516	MCM
Storage Capacity @COP	312	MT

Table 86: Hewett (Hewett) Field Storage Capacity

NB. Volumes refer to production volumes at February 2015.

The volumes and shrinkage factors used in the calculation are shown in Table 87.

Parameter		Reference	CO2Stored
CO_2 density (kg/m3)	600	CO_2 Storage	600
Gas expansion factor (rm3/sm3)	0.007	Ref. 1 Uk Oil and Gas Fields Data	0.0071
Condensate formation volume factor (rm3/sm3)	1.75	Analogue	n/a
Water formation volume factor (rm3/sm3)	1.02	Analogue	1.02

Table 87: Hewett (Hewett) Field Fluid Properties

Injectivity

The selection criteria used for injectivity is the permeability thickness (Kh) value calculated using the mid case reservoir data from CO2Stored. For the Hewett sandstone this was calculated as 20,500 mDm.

Field data and published literature have been reviewed in order to confirm the reservoir properties which have then been used to validate the permeability thickness and expected injectivity.

The Hewett sandstone (lower Bunter) is composed of alluvial plain sandstones of the Lower Triassic (Cooke, Yarborough, 1991). The Hewett sandstones have a depth to crest of 1,227m TVDSS with excellent net to gross, porosity and permeability. The reservoir properties are detailed in the table below.

Zone	Depositional Environment	Gross Thickness [m]	NTG	Porosity	Perm [mD]	Kh [mDm]
Hewett Sst	Alluvial sandstones	26	0.96	0.22	1428	35,641

Table 88: Hewett (Hewett) Field Reservoir Properties

The permeability thickness calculated during the validation process is 35,641 mDm. This is 42% more than the estimate based on the CO2Stored data. The reservoir properties have been obtained for an RDS study for E.ON conducted in March 2010 (EON 2011) and have a higher NTG and permeability than the published 2003 values (Cooke, Yarborough, 1991). The permeability thickness is moderate and based on reservoir quality the initial CO_2 injectivity is expected to be excellent.

As an additional check, a dynamic model was constructed to test the injectivity performance, at initial conditions and over time. A simple model was built in Eclipse (flat structure). CO_2 will be injected in the gas phase initially as the reservoir pressure is expected to be too low for dense phase injection. A DP (well–formation pressure) range of 150psi to 650psi was tested and the corresponding injectivity per well is 0.5MT/year and 2.0 MT/year. The modelling confirms that the injectivity threshold of 1MT/year per well can be achieved for this site at DP of 300 psi.

Well Design

The generic well design is discussed in the supporting document 'Storage Site Due Diligence Summary'. It is likely that this well design can be achieved in the Hewett, although there are concerns over the ability to drill new wells in the depleted gas field, particularly at a high angle, due to wellbore stability issues. This may limit the achievable deviation in the reservoir section. Current producing wells are primarily low angle wells, although some horizontals have been drilled.

Due to the shallow water depth (37m), wells have been assumed to be drilled by a low cost class 1 Jack-Up Drilling Unit. Platform well costs are assumed to be £22.8M per well, including a contingency cost for managing CO_2 phase change, resulting in a 5 well development cost of £115M.

Development Concept

CO_2 volumes cf ETI Scenarios

The ETI Concentrated Scenario shows 29MT/yr by 2030 into the SNS via Barmston. It is possible that the first 17Mt/yr could be stored at 5/42. On the basis of this Scenario, additional SNS storage would be needed by 2027 and need to be capable of storing 12Mt/yr by 2030.

Comparative development concept

A new Normally Unmanned Installation (NUI) comprising a jacket and topsides with 5 deviated wells each injecting 1MT/yr; totalling 100MT over 20 years. CO_2 would be delivered via a 20" 208 km pipeline from Barmston with 10MT/yr capacity. Facilities will be controlled from the beach with the NUI providing its own power and controls. Monitoring will include downhole pressure and distributed temperature sensors.

Site growth potential; theoretical ultimate development concept

The site has a theoretical storage capacity of ~312MT. In addition Site 9, Bunter Sandstone (288MT) is at the same location. The ultimate development is therefore considered to be a combined development with both horizons and a total theoretical capacity of ~ 600MT.

A new development comprising 6 new NUI platforms each with 5 wells injecting a total of 30Mt/yr; totalling 600MT over 20 years. CO_2 would be delivered via a 30" 208km pipeline from Barmston with a 35Mt/yr capacity. Power generation and controls relay will be provided from a single primary NUI. Platforms are connected by 10km infield pipelines and umbilicals.

Build out potential

Hewett is within build-out reach of Viking (310MT) and Bunter Closure 9 (1997MT). The Barque depleted gas field (120MT) is on the likely pipeline route from Barmston. These all represent potential regional growth opportunities.

Development Cost

Capacity:	312	Water Depth (m)	20
Concept Cost (£m)	Comparative Development	Ultimate Development	Description
Tonnes Injected (MT)	100	600	Total Stored CO_2 for proposed scheme
Appraisal Cost:	£0m	£0m	Appraisal Wells + Seismic Data Acquisition & Interpretation
Development Well Cost:	£128.7m	£771.7m	Drilling & Completion Costs of wells.
Facilities Cost:	£301.3m	£620.3m	Landfall, Pipeline, NUI, ties-Ins,
PM & Eng:	£30.2m	£62.1m	10% of Facilities Costs
Decommissio ning:	£105.4m	£335.1m	£10m per NUI, £4m per dry welll
Subtotal	£565.4m	£1789m	
Contingency	£113.1m	£357.8m	20% of Development & Facilities Costs
OPEX (20years)	£361.6m	£744.3m	OPEX Cost for 20 years (6% of facilities costs)
Total:	£1040m	£2891m	
£/T CO_2	10.40	4.82	

Table 89: Hewett (Hewett) Field Development Cost Estimate

Data

The field is covered by 3D seismic from the PGS SNS megasurvey and is of good quality.

Well data is available for the Hewett field from CDA. E&A well data has been downloaded. Data ranges from 1966 to 2008. A review of well logs show washouts in some shale sections – existing wells are poor quality (IEAGHG, 2013).

Commercial Issues

Hewett is a depleted gas field. COP is expected to be 2016.

17 Viking Gas Field

Overview

Capacity:	310MT	UKCS Block:	49/17
Unit Designation:	Depleted gas	Beachhead:	Barmston
Formation:	Leman sandstone	Water Depth:	25m
Earliest injection	2020	Reservoir Depth:	2439m
Availability/COP:	2017	Region:	SNS

Table 90: Viking Field Overview

- The capacity calculation for the Viking complex is in agreement with the capacity used for the selection criteria. However, the capacity is not fully connected as it exists in separate fault compartments and if injection wells do not target all the separate compartments the full capacity will not be accessed.
- The results of the due diligence indicate that there is a high risk that the required injectivity will not be achieved.
- The Georisk factor has been calculated as 11. This is the same as that calculated in WP3 selection criteria.
- The additional risk assessment carried out for the engineering containment risk indicates that the risk is moderate to high due to a moderately high well density, with a large number of wells abandoned prior to 1986.
- The ability to drill high angle wells in the depleted reservoir is a carried engineering risk.
- The risk of halite issues due to reservoir dehydration in the near wellbore is also recognised.
- Well cost estimate (for 5 wells) £216M.

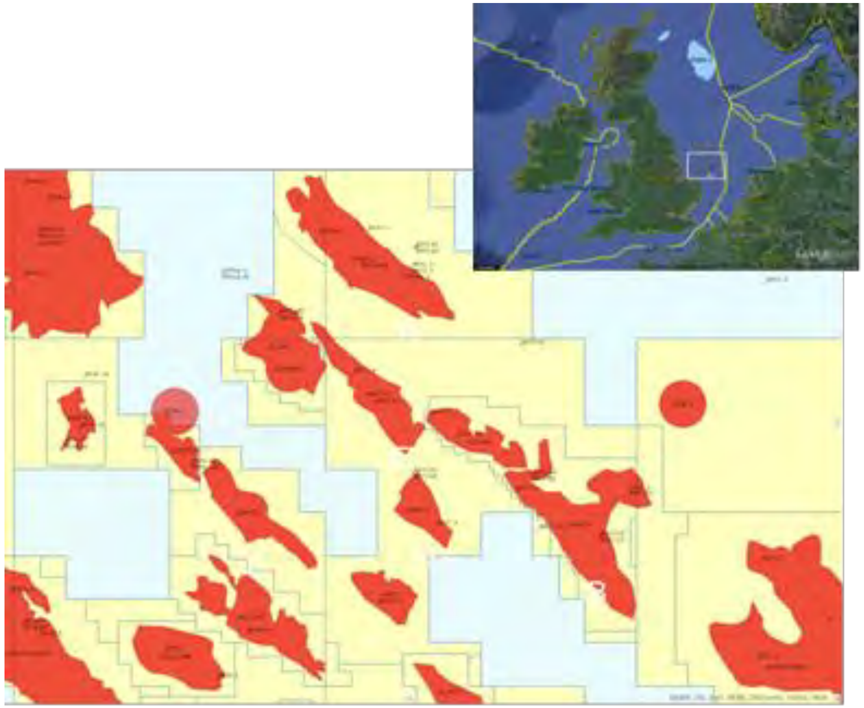


Figure 23: Viking Field Location Map

Containment

The traps consist of a series of tilted fault blocks separated by major normal faults trending E-W. Some of the faults act as permeability barriers and divide some of the pools into individual compartments. However, other faults in the north of the field are permeable and the individual fault blocks are connected forming a stair of connected pools.

An overburden assessment has been conducted above and adjacent to the Viking Sandstone to identify secondary containment horizons and potential migration pathways out of the Viking field storage complex, in the unlikely event of a seal or fault leakage of the sequestered CO_2.

The traps consist of a series of tilted fault blocks separated by major normal faults trending E-W. Some of the faults act as permeability barriers dividing the field into 11 individual compartments many with different GWCs. The Fields are overlain by Zechstein salt and anhydrites which vary in thickness from 182 – 1372m (600 to 4500ft) (Richies, H. 2003). This forms an excellent and continuous seal. Above the Zechstein is a further 305m (1000ft) of Lower Bunter shale followed by 210- 245m (700-800ft) of Bunter Sandstone (a potential secondary storage reservoir) which is overlain by over 610m (2000ft) of Triassic shales and Halites.

The Georisk factor has been calculated as 11. This is the same as that calculated in WP3 selection criteria.

	Fault Characterisation			Seal Characterisation			Georisk Factor
	Density	Throw & Seal	Fault Vertical Extent	Fracture Pressure Capacity	Seal Chemical Reactivity	Sea Degradation	
CO2Stored Value	3	2	1	1	2	2	11
Due Diligence Value	3	2	1	1	2	2	11
Risk Factor Key: Low = 1, Medium = 2, High = 3							

Table 91: Viking Field Geo-containment Risk

Engineering Risk

The engineering containment risk is moderate to high, with 73 wells considered at risk of leakage. 27 wells were plugged and abandoned, most of which were before 1986, representing the highest risk. The 100yr probability of a leakage on the field is 0.12, which is a concern, and with a high well density factor of 1.54 wells/km2, this results in a high containment risk assessment score of 0.18.

Capacity

The calculated storage capacity is 310MT compared to the reported capacity in CO2Stored of 271MT.

The Viking gas complex comprises 11 separate gas accumulations. The production is not allocated to the individual accumulations in the available data and the capacity for each accumulation can therefore not be calculated. The CO_2 storage development for this site might not access all accumulations and will therefore not access the 310MT capacity.

For the Viking gas field, the due diligence involved a recalculation of the capacity equivalent to the net reservoir volume of fluids removed at February 2015. In addition, the net reservoir volume of fluids removed at COP was estimated based on an assumption of maintaining the current production rate to COP and the capacity was calculated at this time. The expected COP date for the Viking gas field, in the supplied Woodmac data, is 2020.

Viking gas field produces a dry gas with no water and small condensate production. The complete production history is not reported in DECC as it only reports production post 1983. However, production up to December 1999 is reported in Ref 1. The complete production volume was calculated by summing Ref 1 production and production post Dec. 1999 reported from DECC. Total production is 92.5 BCM and equates to a capacity of 308MT.

Current gas rates are low, ~330 Ksm3/d (~12 mmscf/d). Assuming this rate is sustained until COP, the additional production is estimated to be 547 MCM (19.3 Bscf). This equates to an additional capacity of 1.9MT (+0.6%).

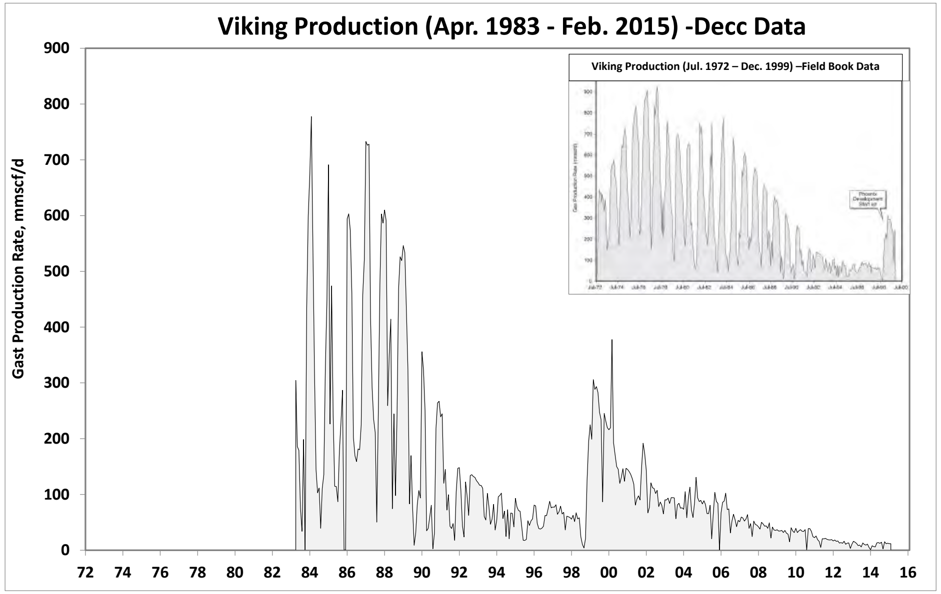


Table 92: Viking Gas Production Profile

The produced volumes and conversion to mass storage potential are shown in the table below:

Gas Production	9246	MCM
Condensate Production	1.3	MCM
Net Reservoir Volume Produced	423	MCM
Storage Capacity @COP	310	MT

Table 93: Viking Field Storage Capacity

NB. Volumes refer to production volumes at February 2015.

The volumes and shrinkage factors used in the calculation are shown in the table below.

Parameter		Reference	CO2Stored
CO_2 density (kg/m3)	729	CO_2 Storage potential in UK-BGS Study	710
Gas expansion factor (rm3/sm3)	0.00455	Analogue	0.0041
Condensate formation volume factor (rm3/sm3)	1.75	Analogue	n/a
Water formation volume factor (rm3/sm3)	1.02	Analogue	1.02

Table 94: Viking Field Fluid Properties

Injectivity

The selection criteria used for injectivity is the permeability thickness (Kh) value calculated using the mid case reservoir data from CO2Stored. For the Viking Fields this was calculated as 8,350 mDm.

Field data and published literature have been reviewed in order to confirm the reservoir properties which have then been used to validate the permeability thickness and expected injectivity (Richies, H. 2003)

The field comprises low to high net to gross, poor to moderate quality aeolian and fluvial sandstones of the Leman Sandstone Formation. Vertically there are permeability barriers, specifically in the sabkha silts in zones D and B. The reservoir is subdivided into nine zones, which vary between the North and South areas, and show significant variation in reservoir quality. A summary of the six main reservoir zones properties are summarised below:

Zone	Depositional Environment	Gross Thickness [m]	NTG	Porosity	Perm [mD]	Kh [mDm]
A	Aeolian Dune	49	0.95	0.1	5	235
B	Sabkha	29	0.44	0.1	5	64
C	Aeolian Dune	28	1	0.1	50	1,395
D	Sabkha	12	0.34	0.1	5	21
E	Aeolian Dune	68	0.91	0.2	50	3,106
F	Fluvial Sands/silts/shales	33	0.94	0.1	50	1,554
All Zones		220	0.92	0.12	27.5	5,599

Table 95: Viking Field Reservoir Properties

The permeability thickness calculated during the validation process is 5,599 mDm. This is approx. 33% lower than the estimate based on the CO2Stored data. The Viking fields consist of multiple separate accumulations. Reservoir quality is extremely variable both between these accumulations and within the 6 reservoir zones. The average poro and perm values are estimated from literature, and are highly uncertain. Well and core data would need to be more extensively reviewed to reduce this uncertainty. The Gross thickness and resulting net to gross (taken from a Phoenix type log in the North Viking area) is also variable with an increase in thickness to the SW.

There is an encroaching aquifer in one of the southern compartments. The water flowing into the field may cause injection problems and reduce storage capacity.

It is believed that some of the later wells were hydraulically fractured to improve productivity. The impact of these fractures on containment needs to be assessed.

Two additional injectivity checks were carried out as part of the due diligence.

1. The initial production performance for a selection of representative wells in Viking was converted to an equivalent CO_2 injection rate to gain some confidence that the 1MT/year/well target could be met. None of the wells meet the target rate. The rates are shown in the table below.

2. A dynamic model was constructed to test the injectivity performance, at initial conditions and over time. A simple model was built in Eclipse (flat structure and average properties). CO_2 will be injected in the gas phase initially as the reservoir pressure is expected to be too low for dense phase injection. A reasonable pressure drop from well to formation is expected to range from 150psi to 650psi. Both cases were tested and the corresponding injectivity per well is 0.03MT/year and 0.13MT/year. The modelling indicates that the injectivity threshold of 1MT/year per well might not be achieved for this site.

		CO2 Injection (MT/y CO2)
	Well	4000 psi
Phoenix	49/12a- 9	0.85
	49/12a-K2	0.31
	49/12a-K3	0.50
	49/17-L2Z	0.71
Early life	Low	0.18
	Mid	0.36
	High	0.55
peak	Low	0.16
	Mid	0.33
	High	0.49

Table 96: Viking Field Well Injectivity

Well Design

The generic well design is discussed in the supporting document 'Storage Site Due Diligence Summary'. It is likely that this well design can be achieved in the Viking fields, although there are concerns over the ability to drill new wells in the depleted gas field, particularly at a high angle, due to wellbore stability issues. This may limit the achievable deviation in the reservoir section. Current producing wells are primarily deviated wells, although 2 horizontals have been drilled in the late 90's.

As the Viking field is a conglomerate of smaller fields, achieving access to all of these from a single drill centre (assumed to be an unmanned platform) would be technically challenging. This is more likely to result in the adoption of a hybrid platform / subsea development solution.

Due to the shallow water depth (20 to 25m), wells have been assumed to be drilled by a low cost class 1 Jack-Up Drilling Unit. Platform well costs are assumed to be £43.2M per well, including a contingency cost for managing CO_2 phase change, resulting in a 5 well development cost of £217M.

Development Concept

CO_2 volumes cf ETI Scenarios

The ETI Concentrated Scenario shows 29MT/yr by 2030 into the SNS via Barmston. It is possible that the first 17Mt/yr could be stored at 5/42. On the basis of this Scenario, additional SNS storage would be needed by 2027 and need to be capable of storing 12Mt/yr by 2030.

Comparative development concept

A new Normally Unmanned Installation (NUI) comprising a jacket and topsides with 5 deviated wells each injecting 1MT/yr; totalling 100MT over 20 years. CO_2 would be delivered via a 20" 220 km pipeline from Barmston with 10MT/yr capacity. Facilities will be controlled from the beach with the NUI providing its own power and controls. Monitoring will include downhole pressure and distributed temperature sensors.

Site growth potential; theoretical ultimate development concept

The site has a theoretical storage capacity of ~310MT.

A new development comprising 3 new NUI platforms each with 5 wells injecting a total of 15Mt/yr; totalling 300MT over 20 years. CO_2 would be delivered via a 26" 220 km pipeline from Barmston with a 20Mt/yr capacity. Facilities will be controlled from the beach. Power generation and controls relay will be provided from a single primary NUI. Platforms are connected by 10km infield pipelines and umbilicals.

Build out potential

Bunter closure 3 is in the vicinity of Viking and represents a low cost build out option. The Barque depleted gas field (120MT) is on the likely pipeline route from Barmston. These represent potential regional growth opportunities.

Development Cost

Capacity:	310	Water Depth (m)	20
Concept Cost (£m)	**Comparative Development**	**Ultimate Development**	**Description**
Tonnes Injected (MT)	100	300	Total Stored CO_2 for proposed scheme
Appraisal Cost:	£0m	£0m	Appraisal Wells + Seismic Data Acquisition & Interpretation
Development Well Cost:	£216.1m	£648.1m	Drilling & Completion Costs of wells.
Facilities Cost:	£289.9m	£440.9m	Landfall, Pipeline, NUI, ties-Ins,
PM & Eng:	£29m	£44.1m	10% of Facilities Costs
Decommissioning:	£102.5m	£200.3m	£10m per NUI, £4m per dry well
Subtotal	£637.4m	£1333.3m	
Contingency	£127.5m	£266.7m	20% of Development & Facilities Costs
OPEX (20years)	£347.9m	£529.1m	OPEX Cost for 20 years (6% of facilities costs)
Total:	£1112.7m	£2129.1m	
£/T CO_2	11.13	7.10	

Table 97: Viking Field Development Cost Estimate

Data

The Viking Gas Fields are covered by the 3D seismic from the SNS PGS megasurvey. The data quality is generally good, however there are reservoir imaging problems due to ray bending particularly in the areas of heavy Triassic/Jurassic faulting. The data quality is not good enough to pick the base Rotliegendes reservoir, however well control shows that the Rotliegendes thickness is between 700 and 800ft. The well ties confirm the time interpretations.

Only limited digital logs are available in CDA.

Commercial Issues

Viking is a depleted gas field operated by ConocoPhillips. Viking 1 ceased production in 1993. Other Viking fields are due to cease production in 2017.

18 Hamilton Gas Field

Overview

Capacity:	130MT	UKCS Block:	110/13a
Unit Designation:	Depleted gas	**Beachhead:**	Point of Ayr
Formation:	Ormskirk Sandstone	**Water Depth:**	25m
Earliest injection:	2020	**Reservoir Depth:**	744m
Availability/COP:	2014	**Region:**	East Irish Sea

Table 98: Hamilton Field Overview

The results of the due diligence review confirm that the selection criteria used for Hamilton are all reasonable. There are small variations in injectivity and containment values.

- Additional checks of injectivity indicate that the target rate of 1MT/year/well can be met at the low reservoir pressures with a reasonable DP from well to formation.
- The Georisk factor has been calculated as 13. This has increased from 11 (calculated in WP3). The increase is due to the Fault vertical extent factor being increased from 1 to 3 (as the faults extend above 800m and possibly to the seabed).
- The additional risk assessment carried out for the engineering containment risk indicates that the risk is relatively low, as there is a small number of wells on the field.
- Due to the shallow depth of the Hamilton reservoir there may be CO_2 phase issues during the development. Additionally there is a chance that the well may not reach horizontal in the target reservoir. Current producing wells include horizontals, but may not have the restricted build angles assumed here for large completions. Further detailed well design work is required, and the Hamilton target should not be discounted on this basis at this stage.
- The ability to drill high angle wells in the depleted reservoir is a carried engineering risk.
- The risk of halite issues due to reservoir dehydration in the near wellbore is also recognised, but not costed at this stage.
- Well cost estimate (for 5 wells) is £102M
- Additional data needs to be procured to enable full evaluation of this site:

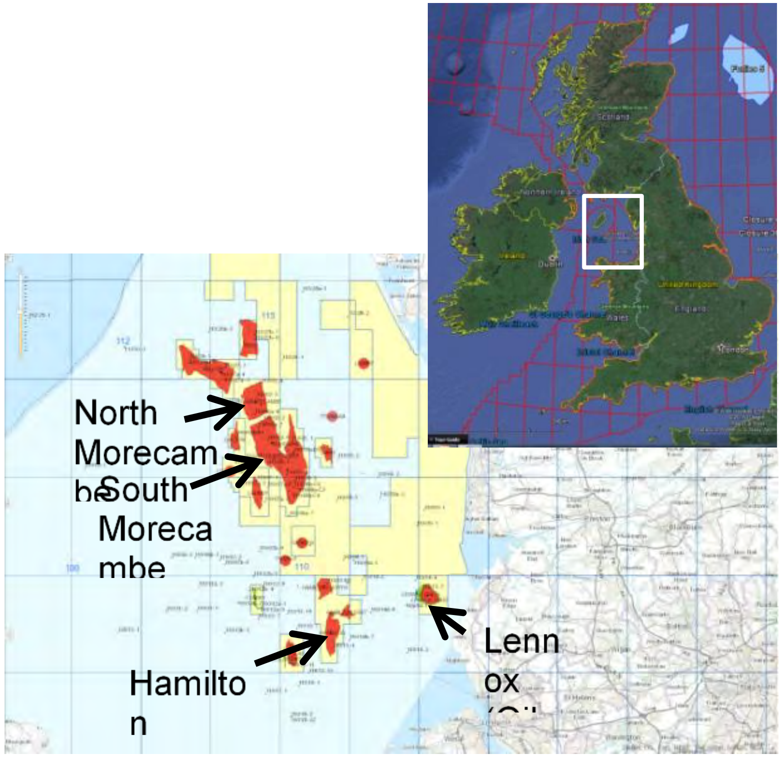


Figure 24: Hamilton Field Location Map

Containment

An overburden assessment has been conducted above and adjacent to the Hamilton field to identify secondary containment horizons and potential migration pathways out of the Hamilton storage complex, in the unlikely event of a seal or fault leakage of the sequestered CO_2.

Field data and published literature1 were reviewed to establish the effectiveness of trap and seal. Depth to crest of the reservoir is 701 m (2300ft tvdss), with a simple horst block and dip closure trap1. Minor east-west and north – south faulting is present (Yaliz, A., Taylor, P., 2003). All faults within field have sand to sand contact and do not provide barrier to gas flow1. Although difficult to see on the currently available 2D seismic lines, a published seismic image from the 3D seismic volume shows faults extending possibly up to the seabed. However, the Mercia Mudstone Group (>700m thick shale and halite) provides an effective overburden seal to the Hamilton field (Yaliz, A., Taylor, P., 2003). CO_2 is not expected to leak through the top Mercia seal which has already trapped Hamilton gas over geological time, or via reservoir level faults. The underlying St Bees Sst Fm. does provide the Hamilton field with an additional zone containing gas, with the Manchester Marl Fm. below this (>150m thick).

The Georisk factor has been calculated as 13, this is higher than the previous calculated factor which was 11. This is due to the Fault vertical extent being increased from 1 to 3 (as the faults extend above 800m).

	Fault Characterisation			Seal Characterisation			Georisk Factor
	Density	Throw & Seal	Fault Vertical Extent	Fracture Pressure Capacity	Seal Chemical Reactivity	Sea Degradation	
CO2Stored Value	3	2	1	1	2	2	11
Due Diligence Value	3	2	3	1	2	2	13
Risk Factor Key: Low = 1, Medium = 2, High = 3							

Table 99: Hamilton Field Geo-containment Risk

Engineering Risk

The engineering containment risk is relatively low, with only 7 wells considered at risk of leakage. Two wells were plugged and abandoned in 1990, representing the highest risk. Total storage target leakage risk is 0.017 and the well density factor is 0.48 wells/km2, resulting in a low leakage risk assessment score of 0.008.

Capacity

The calculated storage capacity is 130MT compared to the reported capacity in CO2Stored of 120MT. These are in reasonable agreement.
For the Hamilton field, the due diligence involves a recalculation of the capacity equivalent to the net reservoir volume of fluids removed at February 2015. In addition, the net reservoir volume of fluids removed at COP was estimated and the capacity calculated at this time to confirm the full capacity estimate. There is no reference to a COP date for Hamilton in the literature or the supplied Woodmac data (as COP is expected before 2020). An estimate of end 2017 was made to determine impact of future production in capacity potential.
Hamilton produces a dry gas with traces of water and condensate production. DECC reports a small gas injection volume. All produced and injected fluids were accounted for in the material balance calculation to check potential storage capacity.
Current gas rates are relatively low at this stage of the field's producing life (see below). Assuming production continues at this rate until COP, the uplift in storage capacity is small, ~0.1%.

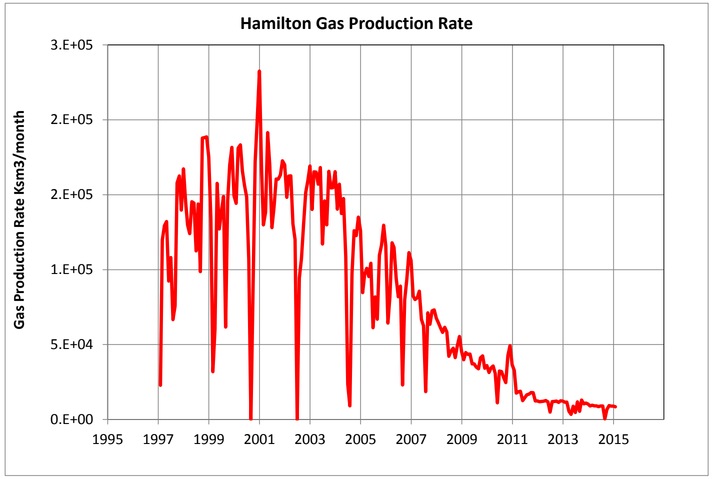


Figure 25: Hamilton Gas Production Profile

The produced volumes and conversion to mass storage potential are shown in the table below:

Gas Production	18127	MCM
Condensate Production	0.33	MCM
Water Production	0.013	MCM
Gas Injection	88.6	MCM
Net Reservoir Volume Produced	168.4	MCM
Storage capacity	130	MT

Table 100: Hamilton Field Storage Capacity

NB. Volumes refer to production volumes at February 2015.

The volumes and shrinkage factors used in the calculation are shown in the table below.

Parameter		Reference	CO2Stored
CO_2 density (kg/m3)	764	Karen Kirk, 2006	780
Gas expansion factor (rm3/sm3)	0.0093	Analogue	0.0093
Condensate formation volume factor (rm3/sm3)	1.75	Analogue	n/a
Water formation volume factor (rm3/sm3)	1.02	Analogue	1.02

Table 101: Hamilton Field Fluid Properties

Injectivity

The selection criteria used for injectivity is the permeability thickness (Kh) value calculated using the mid case reservoir data from CO2Stored. For the Hamilton Field this was calculated as 175,517 mDm.

The permeability thickness calculated during the validation process is 133,570 mDm. This is approx. 25% lower than the estimate based on the CO2Stored data. CO2Stored assumes a thicker gross thickness than that seen at the well data on the field.

The permeability thickness however is still high and based on reservoir quality the initial CO_2 injectivity is expected to be excellent.

Field data and published literature (Yaliz, A., Taylor, P., 2003) have been reviewed in order to confirm the reservoir properties which have then been used to validate the permeability thickness and expected injectivity.

The field comprises high net to gross, excellent to moderate quality aeolian and fluvial sandstones of the Ormskirk Formation. No field wide permeability barriers or baffles exist and there is little lateral variation in reservoir quality. The reservoir has been subdivided into three zones which do show some variation in reservoir quality. A summary of the reservoir properties are summarised below:

Zone	Depositional Environment	Gross Thickness[1] [m]	NTG[2]	Porosity[1]	Perm[1] [mD]	Kh [mDm]
Zone I	Aeolian	52	0.94	0.186	2100	102,286
Zone II	Fluvial	55	0.75	0.112	320	13,168
Zone III	Aeolian/ Fluvial	55	0.98	0.178	370	19,894
All Zones		162	0.89	0.16	930	133,570

Table 102: Hamilton Field Reservoir Properties

NB. Ref 1[1]; Average taken from CDA Well logs (110/13-1; 110/13-3; 110/13-4)[2].

Two additional injectivity checks were carried out as part of the due diligence.

The initial production performance per well was converted to an equivalent CO_2 injection rate to gain some confidence that that the 1MT/year/well target could be met.

Early life production data from the 4 production wells is available on the DECC website. CO_2 injection at the initial field pressure meets the injectivity requirement per well. At low (current) field pressures, the injectivity is much smaller due to CO_2 being in the gas phase. A much larger difference between well and formation pressure would be required to meet the required injection rates.

A dynamic model was constructed to test the injectivity performance, at initial conditions and over time. A simple model was built in Eclipse (flat structure). CO_2 will be injected in the gas phase initially as the reservoir pressure is expected to be too low for dense phase injection. A DP (well–formation pressure) range of 150psi to 650psi was tested and the corresponding injectivity per well is 0.7MT/year and 2.7MT/year. The required DP cannot be determined accurately with this simple model but the results indicate that the injectivity can be achieved with a reasonable DP for this site.

Well	CO2 Injection Rate (MT/y)	
	Initial pressure (1400 psi)	Final pressure (145 psi)
H1	1.6	0.14
H2	2.1	0.18
H3	1.4	0.12
H4	1.0	0.09

Table 103: Hamilton Field Well Injectivity

NB. Final pressure is assumed to be 10% of the initial pressure.

Well Design

The generic well design is discussed in the supporting document 'Storage Site Due Diligence Summary'. However, the Hamilton injection wells may depart from the generic design due to the shallow reservoir depth. This suggests that, with restricted build angle and kick-off point, the well may not reach horizontal in the target reservoir. Current producing wells include horizontals, but may not have the restricted build angles assumed here for large completions. Further detailed well design work is required, and the Hamilton target should not be discounted on this basis at this stage. Of further concern is the ability to drill new wells in the depleted gas field, particularly at a high angle, due to wellbore stability issues. This may limit the achievable deviation in the reservoir section.

Due to the shallow water depth (25m), wells have been assumed to be drilled by a low cost class 1 Jack-Up Drilling Unit. Platform well costs are assumed to be £20.4M per well, including a contingency cost for managing CO_2 phase change, resulting in a 5 well development cost of £103M.

Development Concept

CO_2 volumes cf ETI Scenarios

The ETI Balanced Scenario shows 5MT/y into the EIS by 2030, with initial injection circa 2026. Hamilton has capacity for this rate and volume for ~20 years. (Concentrated and EOR scenarios show no CO_2 being stored in the EIS before 2030)

Comparative development concept

A new Normally Unmanned Installation (NUI) comprising a jacket and topsides with 5 deviated wells each injecting 1MT/yr; totalling 100MT over 20 years. CO_2 will be delivered via a 48km, 20" pipeline from Point of Ayr with 10MT/yr capacity. Facilities will be controlled from the beach with the NUI providing its own power and controls. Monitoring will include downhole pressure and distributed temperature sensors.

Site growth potential; theoretical ultimate development concept

There is little or no additional site growth potential beyond the development concept outlined above.

Build out potential

Build out of CO_2 storage would be facilitated by the nearby Morecambe fields, (N & S together have a capacity of 950MT) which are expected to reach COP by 2028.

Development Cost

Capacity:	130	Water Depth (m)	25
Concept Cost (£m)	**Comparative Development**	**Ultimate Development**	**Description**
Tonnes Injected (MT)	100	120	Total Stored CO_2 for proposed scheme
Appraisal Cost:	£0m	£0m	Appraisal Wells + Seismic Data Acquisition & Interpretation
Development Well Cost:	£102.3m	£122.7m	Drilling & Completion Costs of wells.
Facilities Cost:	£114.1m	£114.1m	Landfall, Pipeline, NUI, ties-Ins,
PM & Eng:	£11.5m	£11.5m	10% of Facilities Costs
Decommissioning:	£58.6m	£62.6m	£10m per NUI, £4m per dry well
Subtotal	£286.3m	£310.7m	
Contingency	£57.3m	£62.2m	20% of Development & Facilities Costs
OPEX (20years)	£136.9m	£136.9m	OPEX Cost for 20 years (6% of facilities costs)
Total:	£480.4m	£509.7m	
£/T CO_2	4.80	4.25	

Table 104: Hamilton Field Development Cost Estimate

*These costs are not the full cost of storage as they omit MMV, security instruments, handover to DECC and profit.

Data

A 3D seismic survey acquired in 1992 has been released and can be requested via the owner ENI. Current WP4 evaluation based on 2D seismic interpretation with data downloaded from CDA.

Where available, log data has been downloaded from CDA. Log data is only available in Lis format. These logs have been converted to LAS files via Schlumberger Log Data Toolbox and loaded to Petrel. Missing digital log data is available to purchase from IHS. Well reports and log images are also available for most wells and have been downloaded from CDA.

Production data was made available from DECC on a field level. Well data is available up to 1999. Production data per well is required to progress this site to a more detailed modelling study. The data needs to be sourced from the Operator. In addition, current reservoir pressure data is required for any further modelling work.

Commercial Issues

ENI hold the Petroleum Licence for Hamilton (but without CO_2 storage rights). ENI hold 100% of the licence. Seismic and well log data available. Production data may be available from ENI. Current oil and gas activity has precluded any other local activity, such as offshore wind. The CO_2 pipeline routing planned is the same as the gas export pipeline avoiding offshore wind developments.

19 South Morecambe Gas Field

Overview

Capacity:	855MT	UKCS Block:	110/2a, 110/3a & 110/8a
Unit Designation:	Depleted gas	**Beachhead:**	Point of Ayr
Formation:	Ormskirk Sandstone	**Water Depth:**	30m
Earliest injection	2030	**Reservoir Depth:**	902m
Availability/COP:	2028	**Region:**	East Irish Sea

Table 105: S Morecambe Filed Overview

- The capacity was confirmed by the due diligence calculation and it should be well connected as the reservoir behaves in a “tank-like” fashion with a high degree of lateral communication across the reservoir (Ref 1).
- Additional checks of injectivity indicate that the target rate of 1MT/year/well can be met at the low reservoir pressures with a higher DP of 770 psi or more from well to formation.
- The Georisk factor has been calculated as 12. This has increased from 10 (calculated in WP3). The increase is due to the Fault vertical extent factor being increased from 1 to 3 (as the faults extend above 800m and possibly to the seabed).
- The additional risk assessment carried out for the engineering containment indicates that the risk is relatively low, as there are a relatively small number of wells on the field that will be abandoned before 2025. However, as a large number of wells in this field have been drilled as slant wells (deviated to 30deg from surface), a bespoke abandonment methodology will need to be devised and assessed for risk.
- Due to the shallow depth of the reservoir, there is a chance that the well may not reach horizontal in the target reservoir. Some current producing wells have been drilled as slant from surface to achieve the required step out. Further detailed well design work is required, and the South Morecambe Bay target should not be discounted on this basis at this stage.
- The ability to drill high angle wells in the depleted reservoir is a carried engineering risk.
- The risk of halite issues due to reservoir dehydration in the near wellbore is also recognised as being severe.
- Well cost estimate (for 5 wells) £111M.

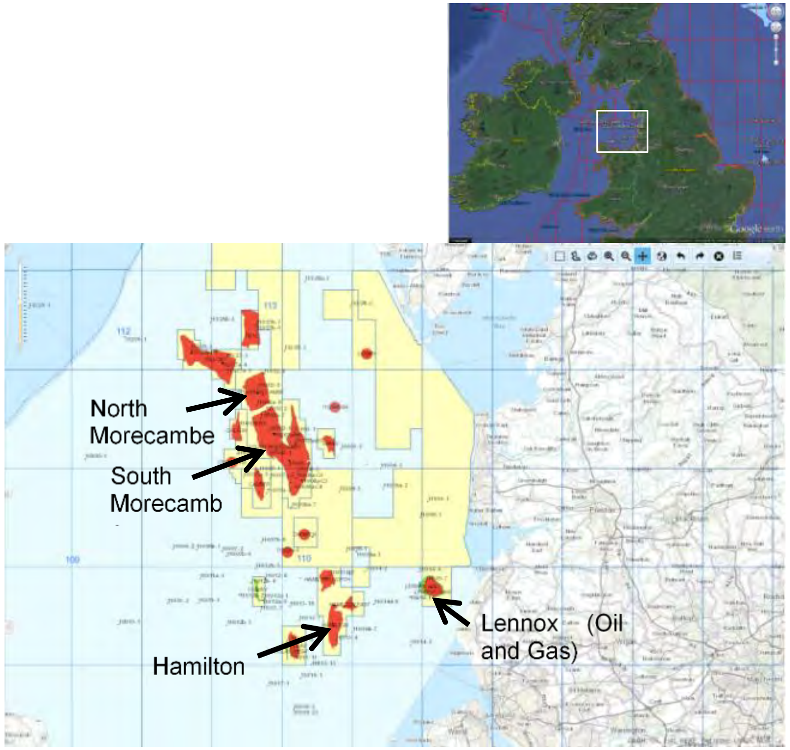


Figure 26: S Morecambe Field Location Map

Containment

An overburden assessment has been conducted above and adjacent to the Ormskirk Sandstone to identify secondary containment horizons and potential migration pathways out of the storage complex, in the unlikely event of a seal or fault leakage of the sequestered CO_2.

Field data and published literature were reviewed (Bastin, J.C., Boycott-Brown, T., Sims, A., and Woodhouse, R., 2003) to establish the effectiveness of trap and seal. Depth to crest of the reservoir is 914 m. Broad domal horst-structure passing southward to tilted fault blocks forms the trap South Morecambe, fault bounded on the western margin with closure on the eastern margin formed by an easterly dip. Extensional faults which displace the reservoir trending E-W were identified using the 1997 3D seismic data. The Ormskirk sandstone reservoir is overlain by 975m (3200ft) of Mercia mudstones and halites forming an excellent continuous cap rock. CO_2 is not expected to leak through the top seal which has already trapped South Morecambe gas over geological time, or via reservoir level faults.

The Georisk factor has been calculated as 12. This has increased from 10 (calculated in WP3). The increase is due to the Fault vertical extent factor being increased from 1 to 3 (as the faults extend above 800m and possibly to the seabed).

	Fault Characterisation			Seal Characterisation			Georisk Factor
	Density	Throw & Seal	Fault Vertical Extent	Fracture Pressure Capacity	Seal Chemical Reactivity	Sea Degradation	
CO2Stored Value	3	2	1	1	1	2	10
Due Diligence Value	3	2	3	1	1	2	12
Risk Factor Key: Low = 1, Medium = 2, High = 3							

Table 106: S Morecambe Geo-containment Risk

Engineering Risk

The calculated engineering containment risk is low, with forty four wells in the field and only 4 considered at risk of leakage (other wells are suspended or still producing and are assumed to be abandoned at COP, which being after 2025, is expected to result in a negligible leak risk). Three wells were plugged and abandoned before 1986, representing the highest assessed risk. However, there is concern over future well abandonments as a number of the producing wells have been drilled at a 30deg slant from surface (i.e. their production trees are also at a slant). There is no drilling rig that can access these slant wells currently operating in the UK. It is likely that coiled tubing abandonment will be used. Furthermore, as the wells are slant from surface, the top section of the well represents multiple point leak paths to surface (rather than parallel to the wellbore as with conventional wells). This will require a bespoke abandonment practice to be developed in the future, which will need to be risk assessed at that time. Assuming slant wells have been abandoned to the same standards as conventional wells, the total storage target leakage risk is 0.012 and the well density factor is 0.05 wells/km2, resulting in a very low leakage risk assessment score of 0.0006. This figure is subject to future review.

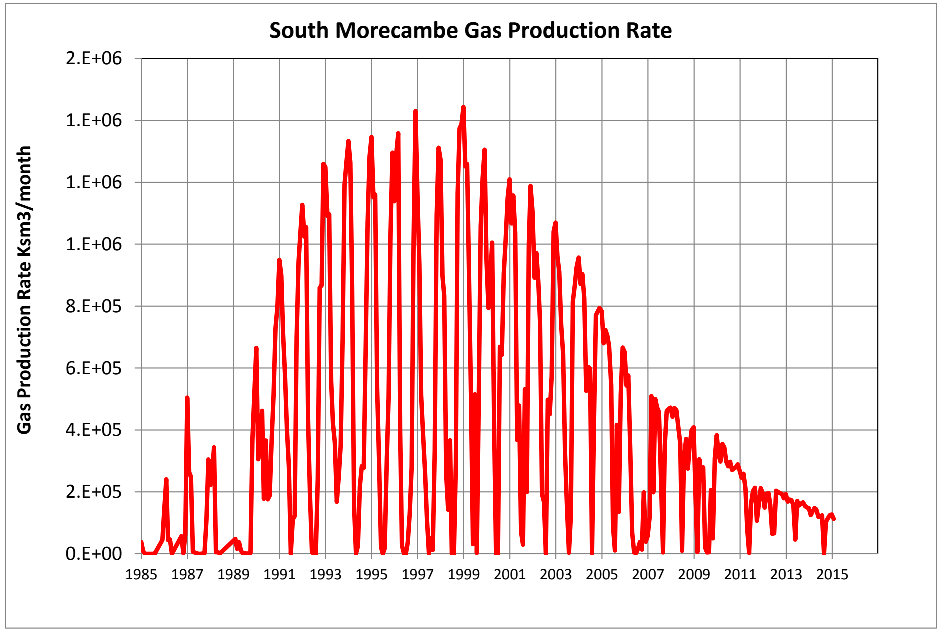
Capacity

The calculated storage capacity is 855MT compared to the reported capacity in CO2Stored of 776.2MT. These are in reasonable agreement.

For the South Morecambe field, the due diligence involves a recalculation of the capacity equivalent to the net reservoir volume of fluids removed at February 2015. In addition, the net reservoir volume of fluids removed at COP was estimated and the capacity calculated at this time to confirm the full capacity estimate. The COP date for South Morecambe in the supplied Woodmac data is 2028.

South Morecambe produces a dry gas with condensate and small volumes of water production. DECC reports no gas and no water injection volumes. All produced fluids were accounted for in the material balance calculation to check potential storage capacity.

Current gas rates are ~4000Ksm3/d (~142mmscf/d). The additional storage capacity associated with continued production to COP is estimated to be 64MT (~8%).



The produced volumes and conversion to mass storage potential are shown in the table below.

Gas Production	146,555	MCM
Condensate Production	2.15	MCM
Water Production	0.026	MCM
Net Reservoir Volume Produced	1000.4	MCM
Storage capacity	855	MT

Table 107: S Morecambe Field Storage Capacity

NB. Volumes refer to production volumes at February 2015.
The volumes and shrinkage factors used in the calculation are shown in the table below.

Parameter		Reference	CO2Stored
CO_2 density (kg/m3)	790.7	CO_2 STORE	790.7
Gas expansion factor (rm3/sm3)	0.0068	Ref.1 Uk Oil and Gas Fields Data	0.0068
Condensate formation volume factor (rm3/sm3)	1.75	Standard value	n/a
Water formation volume factor (rm3/sm3)	1.02	Standard value	1.02

Table 108: S Morecambe Field Fluid Properties

Injectivity

The selection criteria used for injectivity is the permeability thickness (Kh) value calculated using the mid case reservoir data from CO2Stored. For the South Morecambe Field this was calculated as 90,753 mDm.

Field data and published literature have been reviewed in order to confirm the reservoir properties which have then been used to validate the permeability thickness and expected injectivity.

The field comprises moderate average net to gross, low-moderate quality dune and stacked fluvial sandstones of the Sherwood Sandstone Group (Ormskirk and St. Bees Fm.). Permeability decreases due to illite precipitation below the palaeo-GWC (Bastin, J.C., Boycott-Brown, T., Sims, A., and Woodhouse, R., 2003) which limits the capacity for CO_2 storage (Kirk, K. 2006).

The sandstone can be subdivided into four Ormskirk zones – RL1, RL2, RL3 and RL4. The reservoir properties are summarised below.

Zone	Depositional Environment	Gross Thickness [m]	NTG	Porosity	Perm [mD]	Kh [mDm]
RLI	Stacked fluvial	26	0.79	0.14	150	3,034
RL2	Fluvial/aeolian/sabkha	93	0.79	0.14	150	11,016
RL3	Sandflat SST	71	0.79	0.14	150	8,416
RL4	Aeolian	54	0.79	0.14	150	6,357
St. Bees	Stacked fluvial	20	0.79	0.14	150	2,417
All Zones		264	0.79	0.14	150	31,240

Table 109: S Morecambe Field Reservoir Properties

The permeability thickness calculated during the validation process is 31,240 mDm. This is approximately 66% lower than the estimate based on the CO2Stored data. The gross thickness of the St Bees reservoir is uncertain, and could be up to 1200m thicker below the Ormskirk (200-260m thick) (Ref 1).

The gross thickness is obtained from well 110/02-12 comp log and confirmed by Ref 1. Available well log data does not cover the entire St. Bees formation; therefore the NTG of this formation is also uncertain. Only 110/8a-12 has a full section of the St. Bees Formation and a FWL of the reservoir is only calculated by RFT pressure data. Reservoir quality is extremely variable due to the presence of illite, with average poro and perm values taken from the literature.

Two additional injectivity checks were carried out as part of the due diligence.

The initial production performance per well was converted to an equivalent CO_2 injection rate to gain some confidence that that the 1MT/year/well target could be met.

Early life production data from a selection of wells is available on the DECC website. CO_2 injection at the initial field pressure mostly meets the injectivity requirement per well. At low (current) field pressures, the injectivity is much smaller due to CO_2 being in the gas phase. A much larger difference between well and formation pressure would be required to meet the required Final production pressure is based on depletion of approximately 10% of initial pressure.

A dynamic model was constructed to test the injectivity performance, at initial conditions and over time. A simple model was built in Eclipse (flat structure). CO_2 will be injected in the gas phase initially as the reservoir pressure is expected to be too low for dense phase injection. A DP (well–formation pressure) range of 150psi to 650psi was tested and the corresponding injectivity per well is 0.08 MT/year and 0.41 MT/year. However required target of 1 MT /year is achieved for higher DP of 770 psi. Injection pressure required to achieve 1 MT/ year is 950 psi which is less than the fracture pressure of 3265 psi. The required DP cannot be determined accurately with this simple model but the results indicate that the injectivity can be achieved with higher DP of 770 psi for this site.

Well	Near initial production pressure	Near final production pressure
	CO_2 injectivity at 1300 psi	CO_2 injectivity at 145 psi (1 MPa)
	MT/year	MT/year
A1	0.8	0.07
A2	1.0	0.09
A3	1.0	0.09
C1	1.2	0.10
C2	0.9	0.08
D1	1.0	0.08
D2	0.8	0.08
D3	1.0	0.08
F1	1.1	0.09
F2	1.7	0.15
F3	1.0	0.09
H1	0.8	0.07
H2	0.5	0.05
H3	0.8	0.08

Table 110: S Morecambe Field well Injectivity

Well Design

The generic well design is discussed in the supporting document 'Storage Site Due Diligence Summary'. However, the South Morecambe Bay injection wells may depart from the generic design due to the shallow reservoir depth. This suggests that, with restricted build angle and kick-off point, the well may not reach horizontal in the target reservoir. Current producing wells include high angle wells (~60deg), but these have been drilled at an angle from surface in order to achieve the step out required. Further detailed well design work is required, and the South Morecambe Bay target should not be discounted on this basis at this stage. Of further concern is the ability to drill new wells in the depleted gas field, particularly at a high angle, due to wellbore stability issues. This may limit the achievable deviation in the reservoir section.

Due to the shallow water depth (25m), wells have been assumed to be drilled by a low cost class 1 Jack-Up Drilling Unit. Platform well costs are assumed to be £22.3M per well, including a contingency cost for managing CO_2 phase change, resulting in a 5 well development cost of £111M.

Development Concept

CO_2 volumes cf ETI Scenarios

The ETI Balanced Scenario shows 5MT/y into the EIS by 2030, with initial injection circa 2026. S Morecambe does not become available until 2028. (Concentrated and EOR scenarios show no CO_2 being stored in the EIS before 2030).

Comparative development concept

A new Normally Unmanned Installation (NUI) comprising a jacket and topsides with 5 deviated wells each injecting 1MT/yr; totalling 100MT over 20 years. CO_2 would be delivered via a 20" 83km pipeline from Point of Ayr with 10MT/yr capacity. Facilities will be controlled from the beach with the NUI providing its own power and controls. Monitoring will include downhole pressure and distributed temperature sensors.

Site growth potential; theoretical ultimate development concept

The site has a theoretical storage capacity of ~855MT.

A new development comprising 9 new NUI platforms, with a total of 43 wells injecting a total of 43Mt/yr; totalling 855MT. CO_2 would be delivered via a 36" 83 km pipeline from Point of Ayr with a 50Mt/yr capacity. Facilities will be controlled from the beach. Power generation and controls relay will be provided from a single primary NUI. Platforms are connected by 10km infield pipelines and umbilicals.

Build out potential

Build out of CO_2 storage would be facilitated by the nearby N Morecambe field and Hamilton.

Development Cost

Capacity:	855	Water Depth (m)	25
Concept Cost (£m)	**Comparative Development**	**Ultimate Development**	**Description**
Tonnes Injected (MT)	100	855	Total Stored CO_2 for proposed scheme
Appraisal Cost:	£0m	£0m	Appraisal Wells + Seismic Data Acquisition & Interpretation
Development Well Cost:	£111.5m	£958.5m	Drilling & Completion Costs of wells.
Facilities Cost:	£148.9m	£606.7m	Landfall, Pipeline, NUI, ties-Ins,
PM & Eng:	£14.9m	£60.7m	10% of Facilities Costs
Decommissioning:	£67.3m	£413.7m	£10m per NUI, £4m per dry well
Subtotal	£342.4m	£2039.5m	
Contingency	£68.5m	£407.9m	20% of Development & Facilities Costs
OPEX (20years)	£178.7m	£728.1m	OPEX Cost for 20 years (6% of facilities costs)
Total:	£589.6m	£3175.5m	
£/T CO_2	5.90	3.71	

Table 111: S Morecambe Field Development Cost Estimate

*These costs are not the full cost of storage as they omit MMV, security instruments, handover to DECC and profit.

Data

South Morecambe Gas field is densely covered by 2D seismic of varying vintages and one large 3D survey acquired in 1994. Much of early data has poor reflection quality and high background noise (Ref 2). 3D Survey covers 700 km2 and undershoots 6 platforms. Although footprints of the platforms are visible on the data, the deeper reflectors can be discerned (Ref 1). Current evaluation for WP4 is based on 2D seismic interpretation. The 3D seismic volume is released data and a copy can be obtained from the operator via CDA.

Data is available in CDA but digital log and core data is limited. Well 110/2a-12 has log data available in dlis and lis format.

Commercial Issues

Centrica hold the Petroleum Licence for S Morecambe (but without CO_2 storage rights). Centrica hold 100% of the licence. Seismic and well log data available. Production data may be available from Centrica. Current oil and gas activity has precluded any other local activity, such as offshore wind. Centrica have previously done a study into CO_2 storage for Morecambe.

20 North Morecambe Gas Field

Overview

Capacity:	187MT	UKCS Block:	110/2
Unit Designation:	Depleted gas	Beachhead:	Point of Ayr
Formation:	Ormskirk Sandstone	Water Depth:	34m
Earliest injection	2030	Reservoir Depth:	902m
Availability/COP:	2028	Region:	East Irish Sea

Table 112: N Morecambe Field Overview

- The due diligence capacity calculation is in agreement with the selection criteria capacity.
- The permeability thickness calculated during the validation process is 44,599 mDm. This is 59% lower than the estimate based on the CO2Stored data due to a reduction in average permeability from90 to 48 mD
- Additional checks of injectivity indicate that the target rate of 1MT/year/well cannot be met at the low reservoir pressures with a reasonable DP from well to formation.
- The Georisk factor has been calculated as 12. This has increased from 10 (calculated in WP3). The increase is due to the Fault vertical extent factor being increased from 1 to 3 (as the faults extend above 800m and possibly to the seabed).
- The additional risk assessment carried out for the engineering containment indicates that the risk is low, as there are a relatively small number of wells on the field.
- Due to the shallow depth of the reservoir, there is a chance that the well may not reach horizontal in the target reservoir. Further detailed well design work is required, and the North Morecambe Bay target should not be discounted on this basis at this stage.
- The ability to drill high angle wells in the depleted reservoir is a carried engineering risk.
- The risk of halite issues due to reservoir dehydration in the near wellbore is also recognised as being severe.
- Well cost estimate (for 5 wells) £113M.

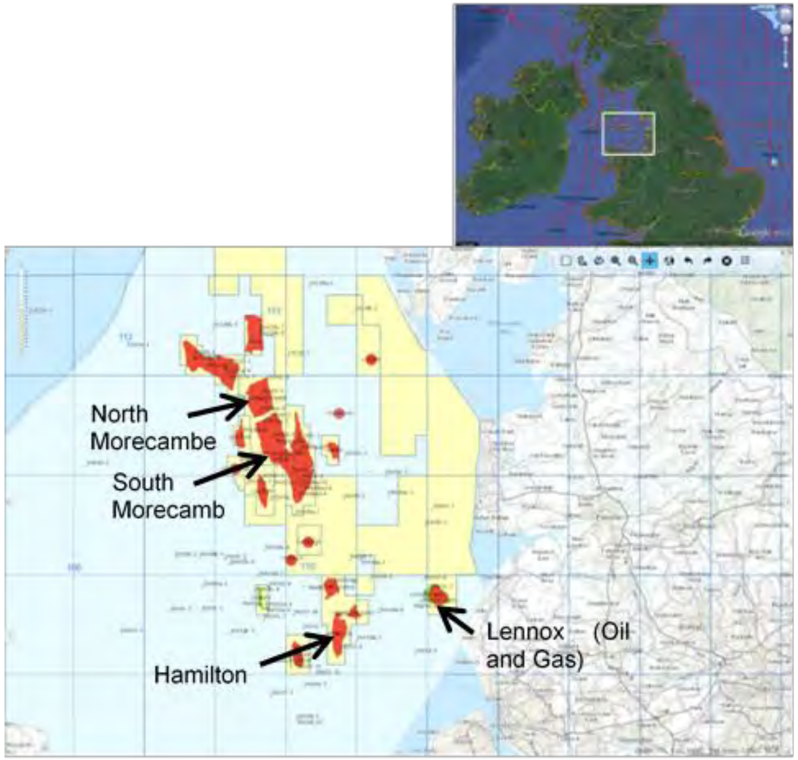


Figure 27: N Morecambe Field Location Map

Containment

An overburden assessment has been conducted above and adjacent to the Sherwood Sandstone to identify secondary containment horizons and potential migration pathways out of the storage complex, in the unlikely event of a seal or fault leakage of the sequestered CO_2.

Field data and published literature were reviewed (Cowan, G. and Boycott-Brown, T., 2003). to establish the effectiveness of trap and seal. Depth to crest of the reservoir is 900 m. Field is fault closed on three sides and dip-closed to the northwest[1]. Small scale in-field faults are mapped at Top Ormskirk Sandstone level by the operator. The Ormskirk sandstone reservoir is overlain by 900m (2950ft) of Mercia mudstones and halites forming an excellent cap rock that is continuous and not broken by faulting. CO_2 is not expected to leak through the top seal which has already trapped North Morecambe gas over geological time, or via reservoir level faults.

The Georisk factor has been calculated as 12. This has increased from 10 (calculated in WP3). The increase is due to the Fault vertical extent factor being increased from 1 to 3 (as the faults extend above 800m and possibly to the seabed).

	Fault Characterisation			Seal Characterisation			Georisk Factor
	Density	Throw & Seal	Fault Vertical Extent	Fracture Pressure Capacity	Seal Chemical Reactivity	Sea Degradation	
CO2Stored Value	3	2	1	1	1	2	10
Due Diligence Value	3	2	3	1	1	2	12
Risk Factor Key: Low = 1, Medium = 2, High = 3							

Table 113: N Morecambe Field Geo-containment Risk

Engineering Risk

The engineering containment risk is relatively low, with only 14 wells in the field and only 3 considered at risk of leakage (other wells are suspended or still producing and are assumed to be abandoned at COP, which being after 2025, is expected to result in a negligible leak risk). The three at risk wells were plugged and abandoned in the 70's, representing the highest risk. Total storage target leakage risk is 0.01 and the well density factor is 0.12 wells/km2, resulting in an acceptable leakage risk assessment score of 0.001.

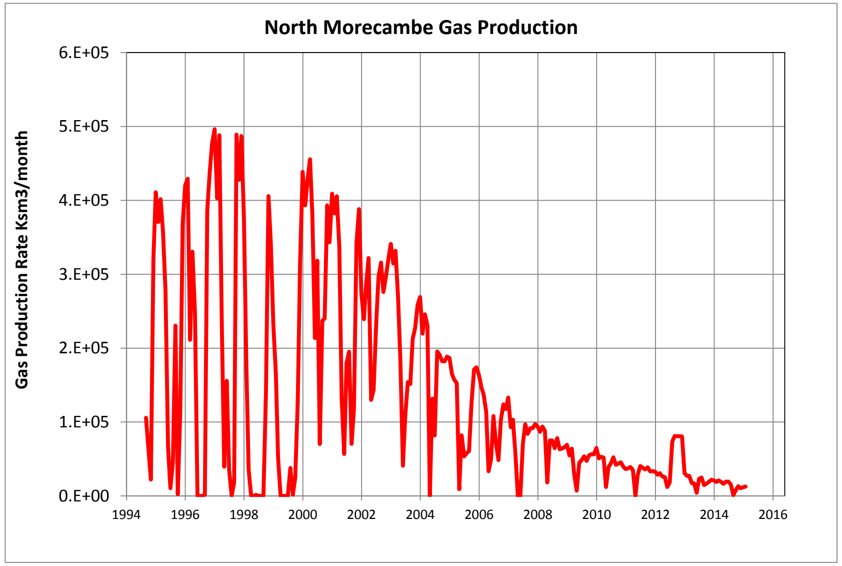
Capacity

The calculated storage capacity is 186.5MT compared to the reported capacity in CO2Stored of 175.3MT. These are in reasonable agreement.

For the North Morecambe field, the due diligence involves a recalculation of the capacity equivalent to the net reservoir volume of fluids removed at February 2015. In addition, the net reservoir volume of fluids removed at COP was estimated and the capacity calculated at this time to confirm the full capacity estimate. The COP date for North Morecambe in the supplied Woodmac data is 2026.

North Morecambe produces a dry gas with condensate and small volumes of water production. DECC reports no gas and water injection volume. All produced fluids were accounted for in the material balance calculation to check potential storage capacity.

Current gas rates are low, ~460Ksm3/d (~16.1mmscf/d) at this stage of the field's producing life (see below). If this rate is maintained until COP the uplift in storage capacity is estimated to be 4MT (2%).



The produced volumes and conversion to mass storage potential are shown in the table below:

Gas Production	33373	MCM
Condensate Production	0.49	MCM
Water Production	0.016	MCM
Net Reservoir Volume Produced	234	MCM
Storage capacity	186.5	MT

Table 114: N Morecambe Field Storage Capacity

NB. Volumes refer to production volumes at February 2015.

The volumes and shrinkage factors used in the calculation are shown in the table below.

Parameter		Reference	CO2Stored
CO_2 density (kg/m3)	781	CO_2 STORE	781
Gas expansion factor (rm3/sm3)	0.007	UK Oil and Gas Fields Data	0.007
Condensate formation volume factor (rm3/sm3)	1.75	Analogue	n/a
Water formation volume factor (rm3/sm3)	1.02	Analogue	1.02

Table 115: N Morecambe Field Fluid Properties

Injectivity

The selection criteria used for injectivity is the permeability thickness (Kh) value calculated using the mid case reservoir data from CO2Stored. For the South Morecambe Field this was calculated as 109,728 mDm.

Field data and published literature have been reviewed in order to confirm the reservoir properties which have then been used to validate the permeability thickness and expected injectivity.

The field comprises high average net to gross, low-moderate quality dune and stacked fluvial sandstones of the Sherwood Sandstone (Ormskirk and St. Bees Fm.). The reservoir is subdivided by the illite free and illite affected layers in the Ormskirk. The St. Bees Formation below contains only illite affected reservoir. A summary of the reservoir properties are summarised below:

Zone	Depositional Environment	Gross Thickness [m]	NTG	Porosity	Perm [mD]	Kh [mDm]
Illite Free	Aeolian/ fluvial	149	0.92	0.12	126.7	17338
Illite Affected	Aeolian/ Fluvial	95	0.74	0.12	9.1	636
St Bees (Illite Affected)	Stacked braided fluvial	975	0.74	0.12	9.1	6521
All Zones		1219	0.76	0.12	48.3	44,599

Table 116: N Morecambe Field Reservoir Properties

The permeability thickness calculated during the validation process is 44,599 mDm. This is 59% lower than the estimate based on the CO2Stored data. Split of the Ormskirk gross thickness (244m), between illite free (61%) and illite affected (39%), zones calculated from development wells in the North Morecambe field, where 'Top Ormskirk' and 'Top Platy Illite' well log picks are available. Available well log data does not cover the entire St. Bees formation (wells down to TD); therefore the NTG of this formation is uncertain. Reservoir quality is extremely variable due to the presence of illite. The average porosity and permeability values for the illite free and illite affected zones are taken from the core analysis data of well 110/2a-8. Earlier wells did not have this zone split and only have core analysis over the entire Ormskirk zone. Significantly lower permeability for the illite affected zones compared to the CO2Stored data (90 md Mid) pulls down the Kh.

Field reservoir can be divided into two diagenetic zones, an uppermost illite-free zone and a lower illite-affected zone. The top of the illitized zone forms a tilted surface which marks a palaeo hydrocarbon-water contact. Platy illite reduces the permeability by two or three orders of magnitude in the lower illite affected zone of the reservoir. Carbonate and evaporate cements reduce porosity but have little effect on the permeability. Highest porosities are preserved near the crest and cement abundance increases down flank (Ref 1).

Two additional injectivity checks were carried out as part of the due diligence.

The initial production performance per well was converted to an equivalent CO_2 injection rate to gain some confidence that that the 1MT/year/well target could be met.
Early life production data from the 10 production wells is available on the DECC website. CO_2 injection at the initial field pressure mostly meets the injectivity requirement per well. At low (current) field pressures, the injectivity is much smaller due to CO_2 being in the gas phase. A much larger difference between well and formation pressure would be required to meet the required Final production pressure is based on depletion of approximately 10% of initial pressure.

A dynamic model was constructed to test the injectivity performance, at initial conditions and over time. A simple model was built in Eclipse (flat structure). CO_2 will be injected in the gas phase initially as the reservoir pressure is expected to be too low for dense phase injection. A DP (well–formation pressure) range of 150psi to 650psi was tested and the corresponding injectivity per well is 0.01MT/year and 0.03MT/year. The required DP cannot be determined accurately with this simple model but the results indicate that the injectivity cannot be achieved with a reasonable DP for this site.

Well	Potential injectivity at early production pressure (1,500 psi)	Potential injectivity at final production pressure (150psi)
	Mtonne/year	Mtonne/year
N1	1.05	0.09
N2	0.72	0.06
N3	0.73	0.06
N4	0.92	0.08
N5	0.88	0.08
N6	0.95	0.08
N7	0.87	0.08
N8	0.98	0.09
N9	0.96	0.08
N10	0.95	0.08

Table 117: N Morecambe Field Well Injectivity

Well Design

The generic well design is discussed in the supporting document 'Storage Site Due Diligence Summary'. However, the North Morecambe injection wells may depart from the generic design due to the shallow reservoir depth. This suggests that, with restricted build angle and kick-off point, the well may not reach horizontal in the target reservoir. Current producing wells include some high angle wells targeting the illite affected lower reservoir. Further detailed well design work is required, and the Hamilton target should not be discounted on this basis at this stage. Of further concern is the ability to drill new wells in the depleted gas field, particularly at a high angle, due to wellbore stability issues. This may limit the achievable deviation in the reservoir section.

Due to the shallow water depth (25m), wells have been assumed to be drilled by a low cost class 1 Jack-Up Drilling Unit. Platform well costs are assumed to be £22.5M per well, including a contingency cost for managing CO_2 phase change, resulting in a 5 well development cost of £113M.

North Morecambe contains high levels of CO_2 (approx 6%), and due to the corrosive effects a new pipeline had to be installed. The CO_2 is removed during processing on the north Morecambe terminal 1. Therefore, the infrastructure is already sufficient to cope with the corrosive effects expected whilst injecting CO_2.

Development Concept

CO_2 volumes cf ETI Scenarios

The ETI Balanced Scenario shows 5MT/y into the EIS by 2030, with initial injection circa 2026. N Morecambe does not become available until 2026. (Concentrated and EOR scenarios show no CO_2 being stored in the EIS before 2030)

Comparative development concept

A new Normally Unmanned Installation (NUI) comprising a jacket and topsides with 5 deviated wells each injecting 1MT/yr; totalling 100MT over 20 years. CO_2 will be delivered via a 92km long 20” pipeline from Point of Ayr with 10MT/yr capacity. Facilities will be controlled from the beach with the NUI providing its own power and controls. Monitoring will include downhole pressure and distributed temperature sensors.

Site growth potential; theoretical ultimate development concept

The site has a theoretical storage capacity of ~186MT.

A new development comprising of 2 NUIs with a total of 9 wells, each injecting a total of 10Mt/yr; totalling 180MT over 20 years. CO_2 will be delivered via a 92km long 20” pipeline from Point of Ayr with 10MT/yr capacity. Facilities will be controlled from the beach with the NUI providing its own power and controls. Monitoring will include downhole pressure and distributed temperature sensors.

Build out potential

Build out of CO_2 storage would be facilitated by the nearby S Morecambe field and Hamilton Fields.

Development Cost

Capacity:	186	Water Depth (m)	25
Concept Cost (£m)	**Comparative Development**	**Ultimate Development**	**Description**
Tonnes Injected (MT)	100	180	Total Stored CO_2 for proposed scheme
Appraisal Cost:	£0m	£0m	Appraisal Wells + Seismic Data Acquisition & Interpretation
Development Well Cost:	£112.8m	£203m	Drilling & Completion Costs of wells.
Facilities Cost:	£156.3m	£210.9m	Landfall, Pipeline, NUI, ties-Ins,
PM & Eng:	£15.7m	£21.1m	10% of Facilities Costs
Decommissio ning:	£69.1m	£108.8m	£10m per NUI, £4m per dry well
Subtotal	£353.7m	£543.7m	
Contingency	£70.8m	£108.8m	20% of Development & Facilities Costs
OPEX (20years)	£187.5m	£253.1m	OPEX Cost for 20 years (6% of facilities costs)
Total:	£611.9m	£905.4m	
£/T CO_2	6.12	5.03	

Table 118: N Morecambe Filed Development Cost Estimate

*These costs are not the full cost of storage as they omit MMV, security instruments, handover to DECC and profit.

Data

There are several different vintages of 2D and 3D seismic survey covering Hamilton field. Current WP4 evaluation based on 2D seismic interpretation with data downloaded from CDA. The 3D seismic data was not available at the time but data is released and is available from operator.

Data available in CDA in image format but digital log (las) and core data is not available.

Commercial Issues

Centrica hold the Petroleum Licence for N Morecambe (but without CO_2 storage rights). Centrica hold 100% of the licence. Seismic and well log data available. Production data may be available from Centrica. Current oil and gas activity has precluded any other local activity, such as offshore wind. Centrica have previously done a study into CO_2 storage for Morecambe. COP is 2026.

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22 Appendix A – Well Risk Assessment

ID	REF (Issue 4)	Hazard/Risk	Hazard Effect	API RP 57	OIL AND GAS UK GUIDELINES FOR THE SUSPENSION AND ABANDONMENT OF WELLS					Comments
				Abandonment Date						
				1986 - 1994	1994 - 2001	2001 - 2005	2005 - 2009	2009 - 2012	post 2012	
				n/a	Issue 1	Issue 1	Issue 2	Issue 3	Issue 4	
1	3	Cement barrier (plug) material inadequately specified.	Leak through cement due to C02 corrosion.	Not detailed.	No specifications or characteristics for cement materials.	General cement material specification and guidelines.	General cement material specification and guidelines.	General cement material specification and guidelines.	Seperate guidelines on cement materials - very specific.	Main characteristics: very low permeability, long term integrity, non shrinking, ductile-non brittle, able to bond to casing/formation.
2	3	Slumping of cement plug.	Leak through cement plug channels.	No reference to slumping but option to use bridge plug to support cement.	No reference of support to prevent slumping of cement.	No reference of support to prevent slumping of cement.	No reference of support to prevent slumping of cement.	Recommend bridge plug or pill to support cement.	Recommend bridge plug or pill to support cement.	A support, (ie bridge plug or viscous pill) to prevent slumping of the cement slurry is recommended for all cement plugs.
3	4	Insufficient number of barriers to isolate permeable zone.	Leak up wellbore.	Two barriers	Two barriers	Two barriers	Two barriers	Two barriers	Two barriers	Two permanent barrier for hydrocarbon zones. One barrier for water bearing zone.
4	4	Multi zones not isolated from each other.	Crossflow.	One barrier with perfs cemented off and isolated with 100ft above and 100ft below zone.	One barrier	One barrier	One barrier	One barrier	One barrier	One permanent barrier required to isolate distinct permeable zones.
5	5.1	Cement plug(s) out of position.	Leak into casing or annulus.	Cement Plug to be set across perforations and to extend 100 ft min above zone.	Plug to be set across or above the highest point of potential inflow or as close as possible.	Plug to be set across or above the highest point of potential inflow or as close as possible.	Plug to be set across or above the highest point of potential inflow or as close as possible.	Plug to be set across or above the highest point of potential inflow or as close as possible.	Plug to be set across or above the highest point of potential inflow or as close as possible.	Cement plug should be lapped by annular cement if set inside casing or liner.

ID	REF (Issue 4)	Hazard/Risk	Hazard Effect	API RP 57	OIL AND GAS UK GUIDELINES FOR THE SUSPENSION AND ABANDONMENT OF WELLS — Abandonment Date					Comments
				1986 - 1994 n/a	1994 - 2001 Issue 1	2001 - 2005 Issue 1	2005 - 2009 Issue 2	2009 - 2012 Issue 3	post 2012 Issue 4	
6	5.1	Base of barrier above point of inflow (eg set on top of production packer or liner hanger).	Leak into the casing at the permeable zone.	Not detailed.	Formation fracture pressure at the base of the barrier to be in excess of the potential internal pressure.	Formation fracture pressure at the base of the barrier to be in excess of the potential internal pressure.	Formation fracture pressure at the base of the barrier to be in excess of the potential internal pressure.	Formation fracture pressure at the base of the barrier to be in excess of the potential internal pressure.	Formation fracture pressure at the base of the barrier to be in excess of the potential internal pressure.	In situation where the base of the barrier is significantly above the point of inflow, eg liner hanger packer, the formation fracture pressure at the base of the barrier should be in excess of the potential internal pressure.
7	5.1	Caprock is not capable of containing the max anticipated pressure from the permeable zone. Caprock barrier cannot be shared for two or more zones.	Leak into formation.	Not detailed.	Not detailed.	Not detailed.	Not detailed.	Not detailed.	Position of permanent barriers as determined by the actual geological settings.	Clarification on issue 4 with barrier location determined by geological settings.
8	5.2	Insufficient length of cement plug - min 100ft of good cement.	Leak through cement plug.	Primary plug; min 100 ft plus perforated interval or zone. Secondary plug 150 ft min.	100 ft good cement - no 500 ft min recommended.	Generally 500 ft to obtain 100 ft of good cement.	Generally 500 ft to obtain 100 ft of good cement.	Generally 500 ft to obtain 100 ft of good cement.	Generally 500 ft to obtain 100 ft of good cement.	Typically 500ft cement plug to obtain at least 100 ft of good cement. Annulus should contain 100ft good cement opposite internal plug.
9	5.3	Openhole well - single zone, with potential internal pressure <u>not exceeding</u> the casing shoe fracture pressure.	Leak into wellbore.	Zone cemented off and isolated with 100ft above and 100ft below zone. Additional cased hole barrier.	Openhole cement plug cannot be considered first barrier due to inability to confirm positive pressure test; Two barriers inside casing shoe.	Openhole cement plug cannot be considered first barrier due to inability to confirm positive pressure test; Two barriers inside casing shoe.	Open hole cement plug (if adequately verified - weight tested) and cased hole cement plug.	Two barriers inside casing shoe.	Two barriers inside casing shoe.	Typically 500 ft each cement plug with at least 100ft of good cement. Additional open hole cement plug required if dual zones with distinct permeable zones.

ID	REF (Issue 4)	Hazard/Risk	Hazard Effect	API RP 57	OIL AND GAS UK GUIDELINES FOR THE SUSPENSION AND ABANDONMENT OF WELLS					Comments
				Abandonment Date						
				1986 - 1994	1994 - 2001	2001 - 2005	2005 - 2009	2009 - 2012	post 2012	
				n/a	Issue 1	Issue 1	Issue 2	Issue 3	Issue 4	
10	5.3	Openhole well - single zone, with potential internal pressure exceeding the casing shoe fracture pressure.	Leak into wellbore.	Not detailed.	First barrier in the open hole or set inside the casing shoe. Second barrier inside casing.	First barrier in the open hole or set inside the casing shoe. Second barrier inside casing.	First barrier in the open hole or set inside the casing shoe. Second barrier inside casing.	One open hole barrier and one barrier set inside casing shoe.	Two open hole barriers and additional barrier inside casing shoe.	Typically 500 ft each cement plug with at least 100ft of good cement. Additional open hole cement plug required if dual zones with distinct permeable zones.
11	5.4	Cement plug should be lapped by annulus cement if set inside liner or casing.	Vertical flow - Leak through corroded casing and into annulus.	No annular space should be left - if this exists it should be plugged with cement.	100ft good annulus cement bond if logged or 1000ft if TOC estimated.	100ft good annulus cement bond if logged or 1000ft if TOC estimated.	100ft good annulus cement bond if logged or 1000ft if TOC estimated.	100ft good annulus cement bond if logged or 1000ft if TOC estimated.	100ft good annulus cement bond if logged or 1000ft if TOC estimated.	Cemented casing is not considered to constitute a permanent barrier to laterial flow into or out of the wellbore. However, it is considered a barrier to vertical flow if sufficient good cement.
12	7.3	Radioactive source downhole.	Exposure to radiation.	Not detailed.	Not detailed.	Best efforts to recover source.	Best efforts to recover source.	Best efforts to recover source.	Best efforts to recover source.	If it cannot be recovered, it should be located, fully documented and isolated with 100 ft cement above the source.
13	7.4	Isolating high angle or horizontal wells - one distinct permeable zone.	Leak into wellbore through poor or inadequate isolation.	Not detailed.	Mechancal device set just above the start of the reservoir with a cement plug on top.	Mechancal device set just above the start of the reservoir with a cement plug on top.	Mechancal device set just above the start of the reservoir with a cement plug on top.	Mechancal device set just above the start of the reservoir with a cement plug on top.	Mechancal device set just above the start of the reservoir with a cement plug on top.	Abandonment is no different from a standard well, however, in general, it is more difficult to achieve in a horizontal or high angle well. Use of mechancial device (bridge plug) to prevent slumping for primary barrier.

ID	REF (Issue 4)	Hazard/Risk	Hazard Effect	API RP 57 1986 - 1994 n/a	OIL AND GAS UK GUIDELINES FOR THE SUSPENSION AND ABANDONMENT OF WELLS Abandonment Date 1994 - 2001 Issue 1	2001 - 2005 Issue 1	2005 - 2009 Issue 2	2009 - 2012 Issue 3	post 2012 Issue 4	Comments
14	7.4	Isolating high angle or horizontal wells - two or more distinct permeable zone.	Leak into wellbore or crossflow between zones.	Not detailed.	Annular and internal isolation should be attempted.	Annular and internal isolation should be attempted.	Annular and internal isolation should be attempted.	Annular and internal isolation should be attempted.	Annular and internal isolation should be attempted.	Completion design should have considered annular isolation between zones. Recognised there can be significant difficulties in annular isolation through cementing in an uncemented liner in the horizontal.
15	7.6	Liner lap.	Leak into wellbore - vertical flow.	Not detailed.	Considered a permanent barrier if good cement is assured. No min length specified.	At least 100ft of good cement should be assured in the liner lap.	At least 100ft of good cement should be assured in the liner lap.	At least 100ft of good cement should be assured in the liner lap.	At least 100ft of good cement should be assured in the liner lap.	Liner top packers are common immediately after the cement job. The packer and liner lap are normally tested together, therefore, impossible to know which is holding. A liner packer is NOT considered a barrier.
16	7.7	Casing cuts.	Vertical flow (leak).	Not detailed.	At least 100ft of good cement should be assured behind a cut casing.	At least 100ft of good cement should be assured behind a cut casing.	At least 100ft of good cement should be assured behind a cut casing.	At least 100ft of good cement should be assured behind a cut casing.	At least 100ft of good cement should be assured behind a cut casing.	Same as full casing string: 100ft of good cement to form a permanent barrier for vertical flow. If not the annulus may be squeezed to achieve permanent barrier.
17	7.8	Removal of downhole equipment.	Leak up wellbore.	Not detailed.	Removal of downhole equipment is not required provided guidelines are followed.	Removal of downhole equipment is not required provided guidelines are followed.	Removal of downhole equipment is not required provided guidelines are followed.	Removal of downhole equipment is not required provided guidelines are followed.	Removal of downhole equipment is not required provided guidelines are followed.	Typically for through tubing abandonments, where part of the completion and casing strings will be left downhole - see 7.10.
18	7.9	Control lines, ESP cables, Gauge Cables.	Leak up control lines/cables left inhole.	Not detailed.	Not detailed.	Cables and control lines should not form part of the permanent barrier.	Cables and control lines should not form part of the permanent barrier.	Cables and control lines should not form part of the permanent barrier.	Cables and control lines should not form part of the permanent barrier.	Cables and control lines are potential leak paths.

ID	REF (Issue 4)	Hazard/Risk	Hazard Effect	API RP 57	OIL AND GAS UK GUIDELINES FOR THE SUSPENSION AND ABANDONMENT OF WELLS					Comments
				Abandonment Date						
				1986 - 1994	1994 - 2001	2001 - 2005	2005 - 2009	2009 - 2012	post 2012	
				n/a	Issue 1	Issue 1	Issue 2	Issue 3	Issue 4	
19	7.10	Through Tubing Abandonment.	Leak in wellbore due to cement fingering or slumping.	Not detailed.	Not detailed.	Increased length to account for annulus cement fingering and/or slumping. Accurate method of determining TOC for both tubing and annulus.	Increased length to account for annulus cement fingering and/or slumping. Accurate method of determining TOC for both tubing and annulus.	Increased length to account for annulus cement fingering and/or slumping. Accurate method of determining TOC for both tubing and annulus.	Increased length to account for annulus cement fingering and/or slumping. Accurate method of determining TOC for both tubing and annulus.	Allowances (additional plug length and base for slurry) should be made for annulus cement fingering or slumping. Allowances should also be made for high angles at the point of placement, eccentricity and small radial clearances. Where permanent barriers are installed through and around tubulars, reliable methods and procedures to install and verify position should be established.
20	7.12	Well containing H2S.	Leak due to corrosion.	not detailed - API spec does not include wells with H2S	Not detailed.	Barriers placed in well containing H2S should be chosen and designed to withstand the corrosive environment.	Barriers placed in well containing H2S should be chosen and designed to withstand the corrosive environment.	Barriers placed in well containing H2S should be chosen and designed to withstand the corrosive environment.	Barriers placed in well containing H2S should be chosen and designed to withstand the corrosive environment.	Risk of corrosion due to H2S.

ID	REF (Issue 4)	Hazard/Risk	Hazard Effect	API RP 57	OIL AND GAS UK GUIDELINES FOR THE SUSPENSION AND ABANDONMENT OF WELLS					Comments
					Abandonment Date					
				1986 - 1994	1994 - 2001	2001 - 2005	2005 - 2009	2009 - 2012	post 2012	
				n/a	Issue 1	Issue 1	Issue 2	Issue 3	Issue 4	
21	7.13	Well containing naturally occuring C02.	Degradation of cement, steel and subsurface formations which may cause a leak.	Not detailed.	Not detailed.	Not detailed.	Not detailed.	Barriers placed in a well with significant concentration of C02 should be chosen and designed to withstand the potential effects.	Barriers placed in a well with significant concentration of C02 should be chosen and designed to withstand the potential effects.	**C02 Sequestration is outwith the scope of these guidelines**. C02 may degrade cement in the presense of water, in particular Portland cement increasing its permeability. C02 also accelerate corrosion of steel and can increase permeability of subsurface formations ie shale. (Non portland cement recommended for C02 storage).
22	7.14	Gas and high GOR wells.	Potential gas migration through barriers.	Not detailed.	Not detailed.	Select barrier material and placement technique to counteract this condition.	Select barrier material and placement technique to counteract this condition.	Select barrier material and placement technique to counteract this condition.	Select barrier material and placement technique to counteract this condition.	Added complcation with Gas Wells or high GOR wells. A barrier using a mechanical plug may obsure a good barrier test over time.
23	7.15	Sealing formations.	Potential flow between casing and sealing formation.	Not detailed.	Not detailed.	Not detailed.	Not detailed.	Not detailed.	Demonstrate that the resulting seal of the formation against the casing is adequate to prevent flow.	Certain formation, ie certain shales and certain salts, are know to move as a result of stress differences and are able to close an annular space where cement is missing.
24	7.16	Reservoir compaction and subsidence.	Potential leak path if compaction/ subsidence occurs.	Not detailed.	Not detailed.	Not detailed.	Not detailed.	Not detailed.	Related geological movement should be considered when selecting barriers.	Some geological environments are prone to compaction and/or subsidence of the seabed.

ID	REF (Issue 4)	Hazard/Risk	Hazard Effect	API RP 57	OIL AND GAS UK GUIDELINES FOR THE SUSPENSION AND ABANDONMENT OF WELLS					Comments
					Abandonment Date					
				1986 - 1994	1994 - 2001	2001 - 2005	2005 - 2009	2009 - 2012	post 2012	
				n/a	Issue 1	Issue 1	Issue 2	Issue 3	Issue 4	
25	7.17	Annular Fluids.	Environmentally unfriendly fluids exposure to the environment.	Not detailed.	Not detailed.	Fluid positioned above the uppermost barrier and cannot be discharged should be removed with best efforts.	Fluid positioned above the uppermost barrier and cannot be discharged should be removed with best efforts.	Fluid positioned above the uppermost barrier and cannot be discharged should be removed with best efforts.	Fluid positioned above the uppermost barrier and cannot be discharged should be removed with best efforts.	This is part of the well which will be exposed to the environment after wellhead removal.
26	7.18	Shallow Permeable Zones.	Potential leak path to the surface.	Not detailed.	Not detailed.	Decision to isolate shallow permeable zones in a well will depend on local conditions, on a well by well basis.	Decision to isolate shallow permeable zones in a well will depend on local conditions, on a well by well basis.	Decision to isolate shallow permeable zones in a well will depend on local conditions, on a well by well basis.	Decision to isolate shallow permeable zones in a well will depend on local conditions, on a well by well basis.	Isolate depending on whether shallow permeable zone is vertically connected to the seabed.
27	7.2	Subsea equipment.	Potential hazard to other users of the seas if equipment is not removed.	not detailed - API spec does not include subsea wells.	Retrieve all casing strings to a min of 10 ft below seabed.	Retrieve all casing strings to a min of 10 ft below seabed.	Retrieve all casing strings to a min of 10 ft below seabed.	Retrieve all casing strings to a min of 10 ft below seabed.	Retrieve all casing strings to a min of 10 ft below seabed.	Redundant subsea equipment must not present a hazard to other users of the seas. All subsea equipment and debris should be removed.
28	7.3	Surface equipment - land wells.	Potential hazard to other land users around site.	Not detailed.	Not detailed.	Not detailed.	Required wellsite conditions to be agreed with local authorities.	Required wellsite conditions to be agreed with local authorities.	Required wellsite conditions to be agreed with local authorities.	Land wells only.