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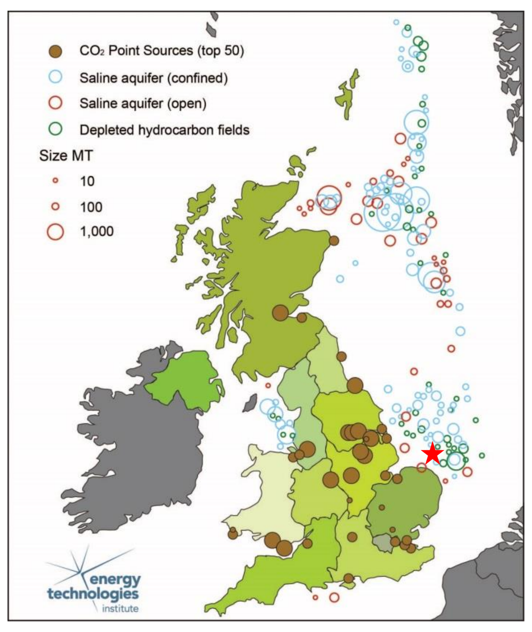
ETI April 2016 v2.1

Site 1 – 226.011 – Bunter Closure 9 – SNS



Major offshore areas covered by CO2Stored (© Energy Technologies Institute)

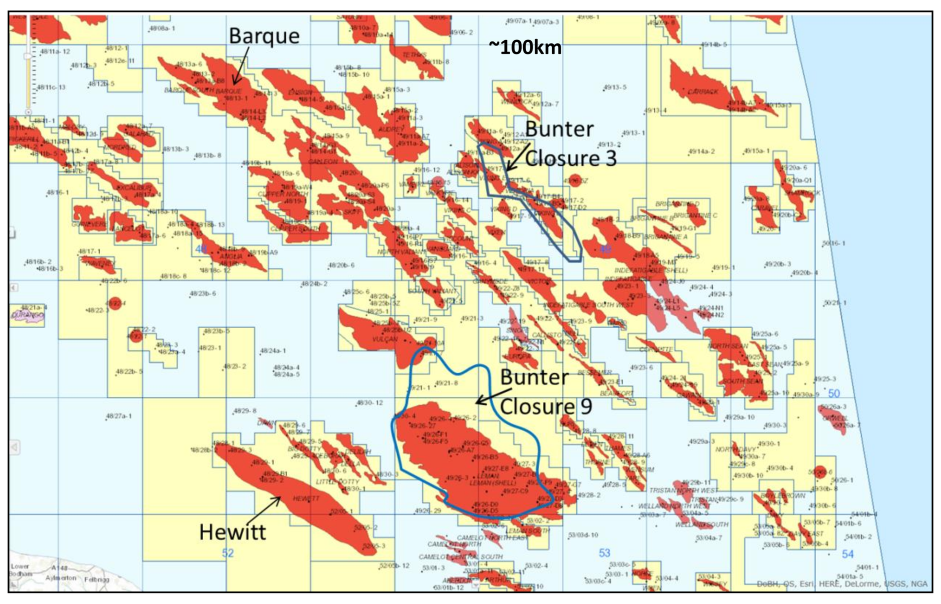


Image source: courtesy of CDA through an open licence agreement

Axis generated Top Bunter Sandstone depth map (ft)

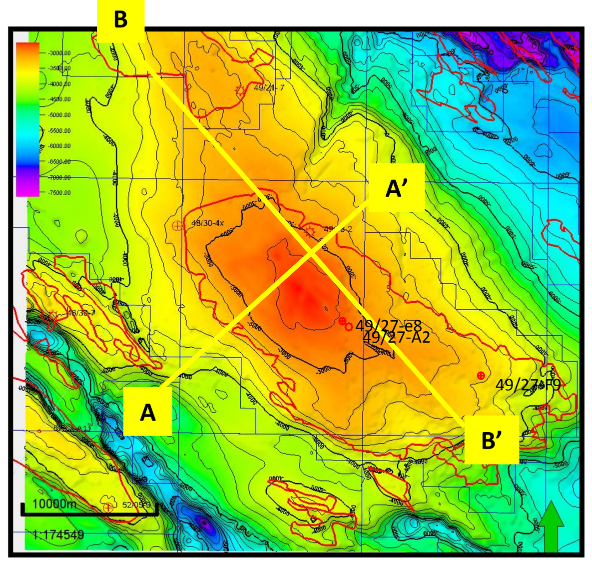


Image source: Original interpretation from Axis Well Technology, 2015

Ci: 200ft

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 DD is lower, nearby analogue Bunter Sst data show higher average porosity than those on CO2Stored resulting in a 20% higher calculated capacity.

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, and the volume should be well connected.

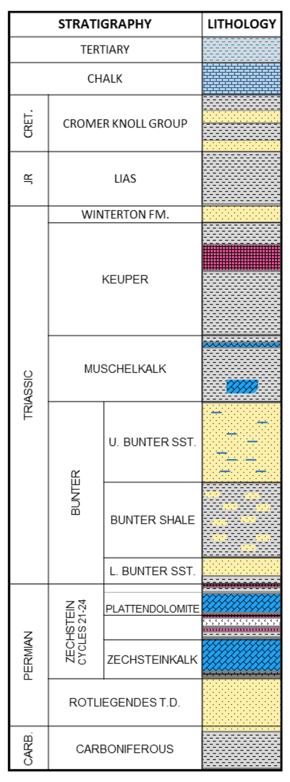


Image source: modified from Cooke-Yarborough (1991) "The Hewett Field, Blocks 48/28-29-30, 52/4a-5a, UK North Sea", *In* Abbotts, I. L. (ed.), 1991, United Kingdom Oil and Gas Fields, 25 Years Commemorative Volume, Geological Society Memoir No. **14**, pp. 433-442.

Axis generated Bunter Sst Isochore (ft), generated from well data

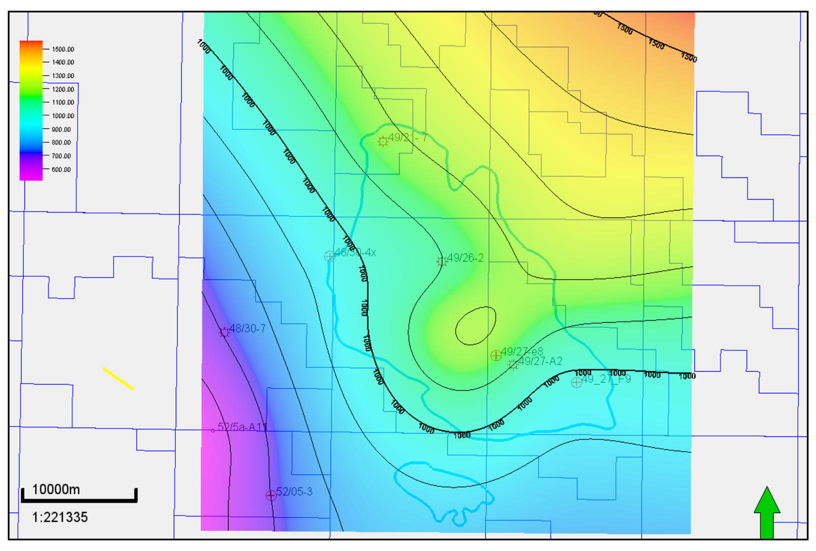


Image source: Original interpretation from Axis Well Technology, 2015

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.

Bunter 9 Dip and Strike seismic lines from PGS MegaSurvey

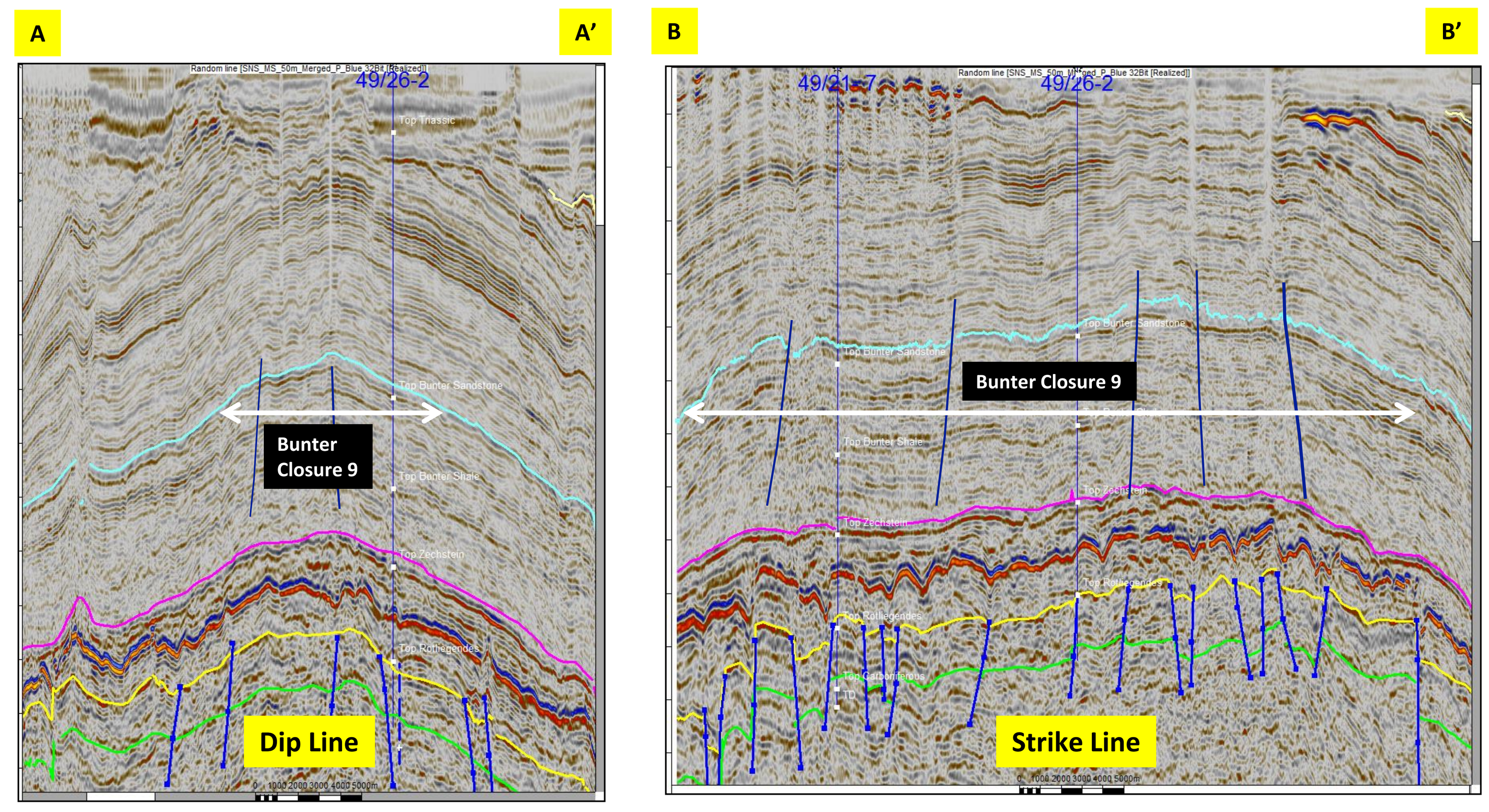


Image source: Seismic data provided by PGS under Licence Agreement. Original interpretation from Axis Well Technology, 2015.

Top Triassic
Top Rotliegendes Sandstone
Top Bunter Sandstone
Near Top Carboniferous
Top Zechstein

Key Risk Summary

Bunter Closure 9	Capacity (MT)	Injectivity (mDm)	Engineered Containment			Geo Containment
			Wells /sq.km	Leakage risk	Containment risk	
Selection Criteria	1691	33,380	0.57	n/a	n/a	9
Due Diligence	1977	94,500	0.07	0.12	0.008	9

Capacity Calculation

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

NB. 1: Analogue field data Little Dotty (Ref 6) 2: Estimated from CDA composite logs 3: CO2Stored

Injectivity Validation

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

NB. 1: Analogue field data Little Dotty (Ref 6) 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 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. 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.

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 CO2 injectivity within the SNS is considered to be good. Neither reservoir quality or injectivity are considered to be a high risk.

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). CO2 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.

Containment Validation

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 9	226.011	2	2	2	1	1	1	9
		2	2	2	1	1	1	9

Low=1 Medium=2 High=3 2 values in CO2Stored
1 no additional data to qc, values taken from CO2Stored

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 CO2.
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.

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.

Costs

Site Reference:	1	Site Description	Bunter Closure 9
Capacity:	1977	Water Depth (m)	30
Concept Cost (£m)	Comparative Development	Ultimate Development	Description
Tonnes Injected (MT)	100	1000	Total Stored CO2 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, Templates, ties-Ins,
PM & Eng:	£33m	£101m	10% of Facilities Costs
Decommissioning:	£112.5m	£552.4m	£10m per NUI, £4m per dry well, £8m per subsea 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 CO2	11.27	4.23	

*These costs are not the full cost of storage as they omit MMV, security instruments, handover to DECC and profit.

Development Concept

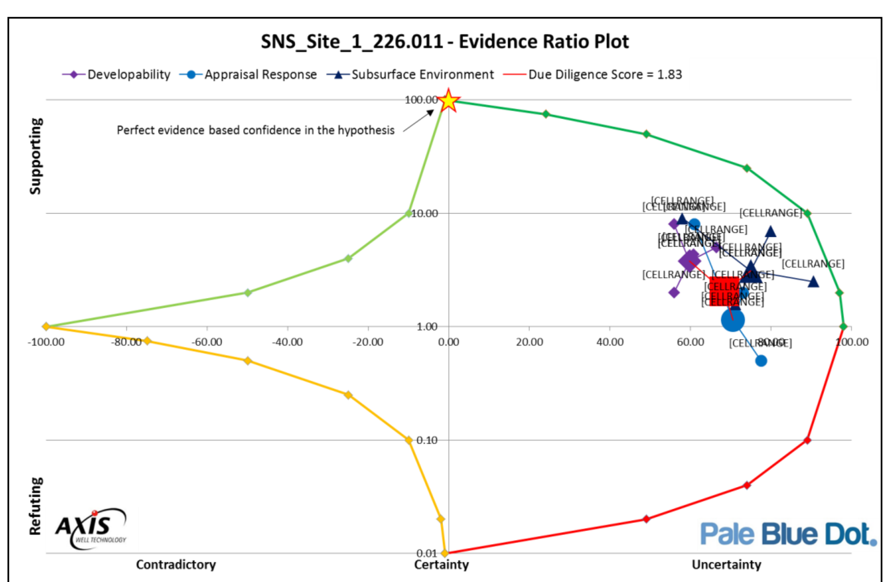
CO2 volumes cf ETI Scenarios
The ETI Concentrated Scenario shows 29MT/yr by 2030 into the SNS via Barmston. It is possible that the first 17Mt/yr could be stored at 5/42. On the basis of this Scenario, additional SNS storage would be needed by 2027 and need to be capable of storing 12Mt/yr by 2030.

Build out potential
Bunter Closure 9 is reasonably close to the two Hewett Reservoirs (600MT combined), Viking (310MT) and Bunter Closure 3 (232MT). The Barque depleted gas field (91MT) is on the likely pipeline route from Barmston. These all represent potential regional growth opportunities.

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. CO2 would be delivered via a new 20" 194km 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 ~1977MT; 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. CO2 would be delivered via a new 36" 194km 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 umbilical's.



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 CO2 storage activity which would compromise CO2 storage at this site prior to COP on Leman.

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 C9.

Due to the shallow water depth (30m), wells can 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 £80.3M.

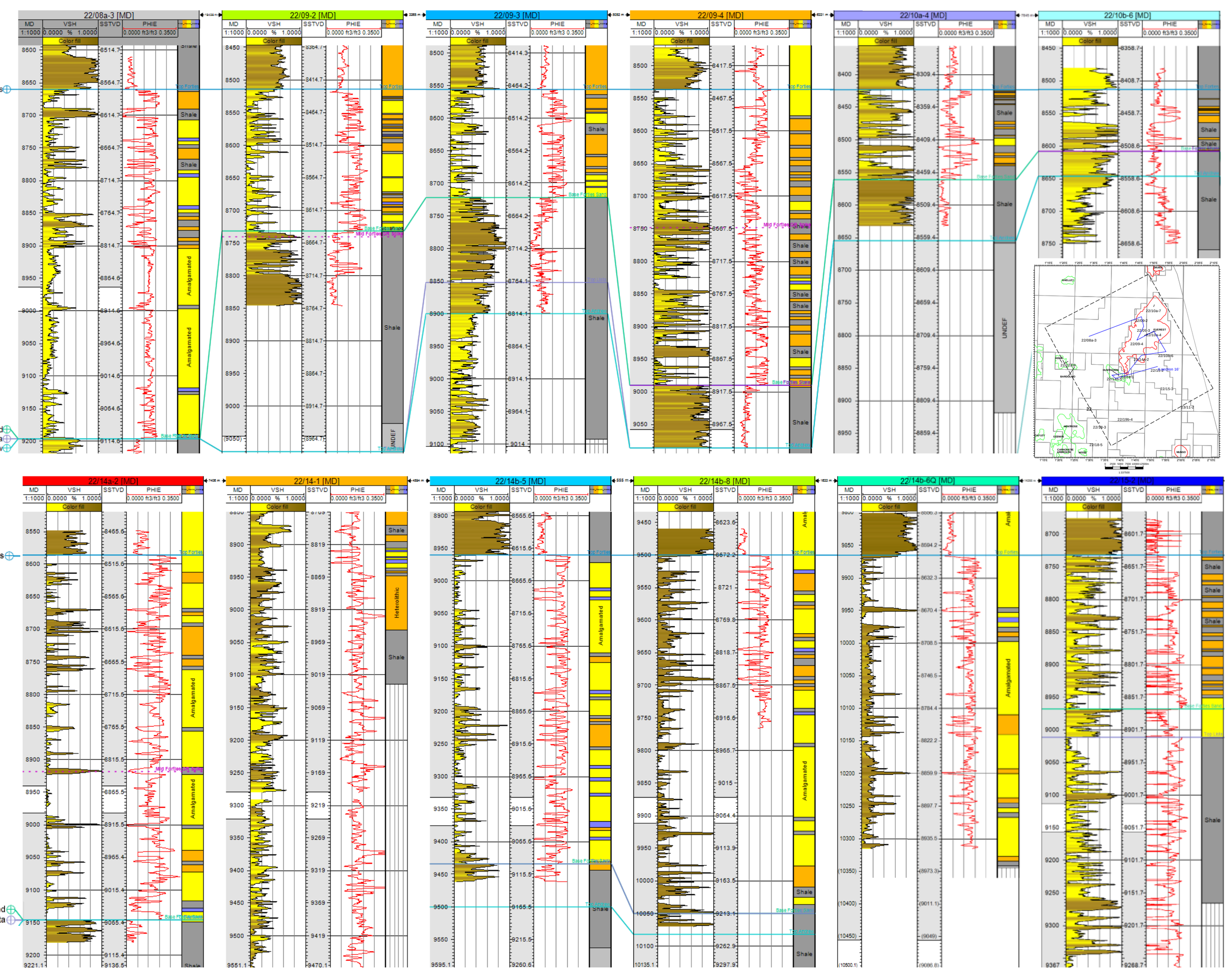
References
1. Vincent, C.J. 2005 "Porosity of the Bunter SST in the SNS Basin based on selected Borehole Neutron Logs" BGS Internal Report IR/05/074.
2. Bentham, M.S.; Green, A.; Gammer, D. 2013 The occurrence of faults in the Bunter Sandstone Formation of the UK Sector of the Southern North Sea and the potential impact on storage capacity. *Energy Procedia*, 37. 5101-5109
3. J.D.O. Williams, M. Bentham, M. Jin, G. Pickup, E. Mackay, D. Gammer, A. Green (2013) "The effect of geological structure and heterogeneity on CO2 storage in simple 4-way dip structures; a modeling study from the UK Southern North Sea", Energy Procedia, **37**, Pages 3980–3988.

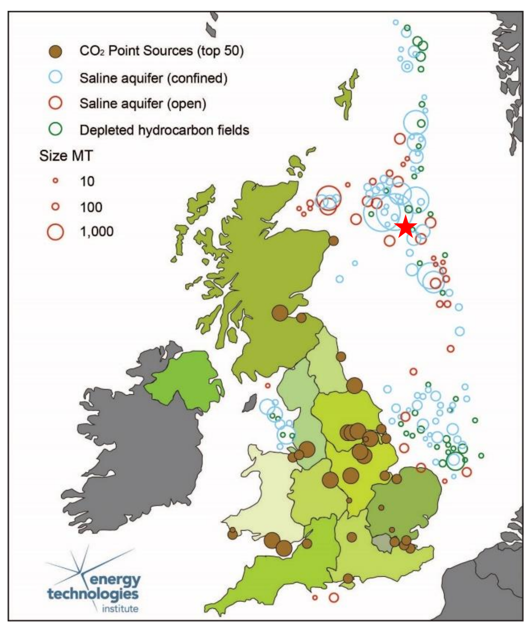
Site 1 – 226.011 – Bunter Closure 9 – SNS

Site Summary			
Capacity (Due Diligence):	1977 MT	UKCS Block:	49/26, 49/27
Unit Designation:	Saline Aquifer	Beachhead:	Barmston
Formation:	Triassic Bunter Sst	Water Depth:	30 m
Containment Unit:	Rot Halite	Reservoir Depth:	840m TVDSS (2750 ft)
Availability/COP:	n/a	Region:	SNS

Client	The Energy Technologies Institute	Title	D06: Prospect Summary Sheets	Date of Issue	7th August 2015
Project Title	DECC Strategic UK CCS Storage Appraisal Project	Classification	Client Confidential	Version	V00

Site 2 – 372.000 – Forties 5 – CNS





Major offshore areas covered by CO2Stored (© Energy Technologies Institute)

372.000 Forties 5 – Forties SST Mbr., Sele Fm., Moray Group

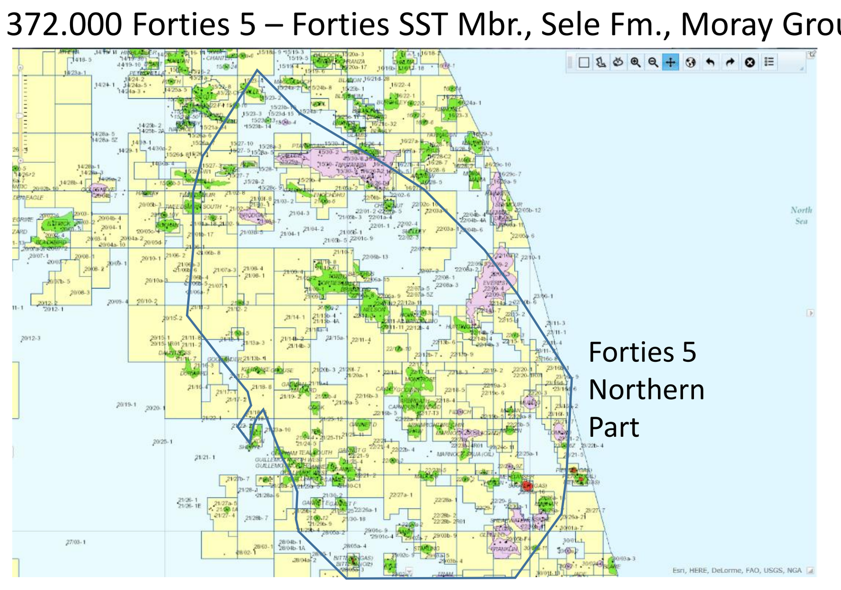


Image source: courtesy of CDA through an open licence agreement

372.000 Forties 5 – Forties SST Mbr., Sele Fm., Moray Group

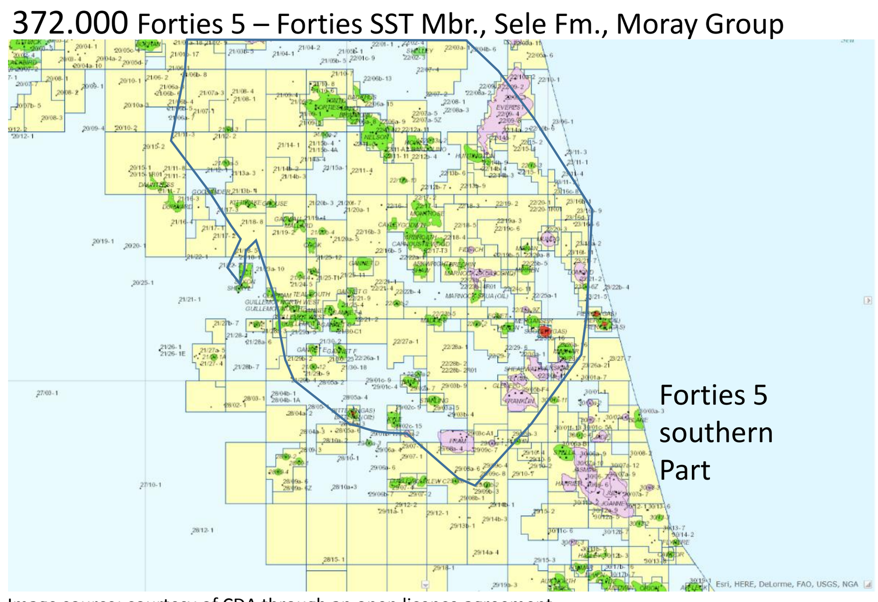
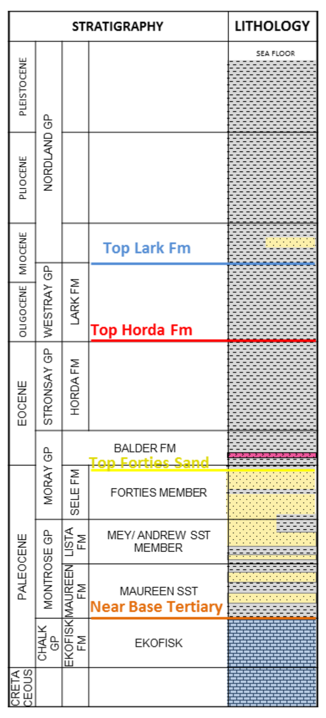


Image source: courtesy of CDA through an open licence agreement



Utsira Sands outside site area to North (22/4b-6)

Secondary Seal

Primary Seal

Primary Store

Secondary Store

Image source: modified from Wills, J. M., The Forties Field, Block 21/10, 22/6a, UK North Sea. BP Exploration, Fig 2

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.

Development Concept

CO2 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.

Build out potential
Forties 5 aquifer is en-route to the Maureen 1 and May 1 aquifers, which represent additional build out potential should it be required.

Comparative Development Concept
A new subsea development with 5 deviated wells each injecting 1MT/yr; totalling 100MT over 20 years. CO2 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. CO2 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 umbilical's.

Axis generated Palaeocene Isochore (ft)

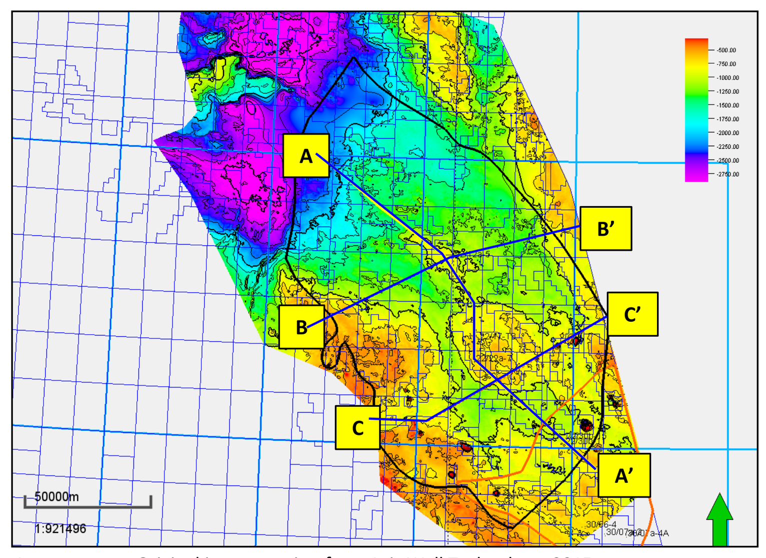


Image source: Original interpretation from Axis Well Technology, 2015

Forties 5 CO2Stored outline
Maureen 1 CO2Stored outline

Ci: 250ft

Axis generated Near Top Palaeocene depth map (ft)

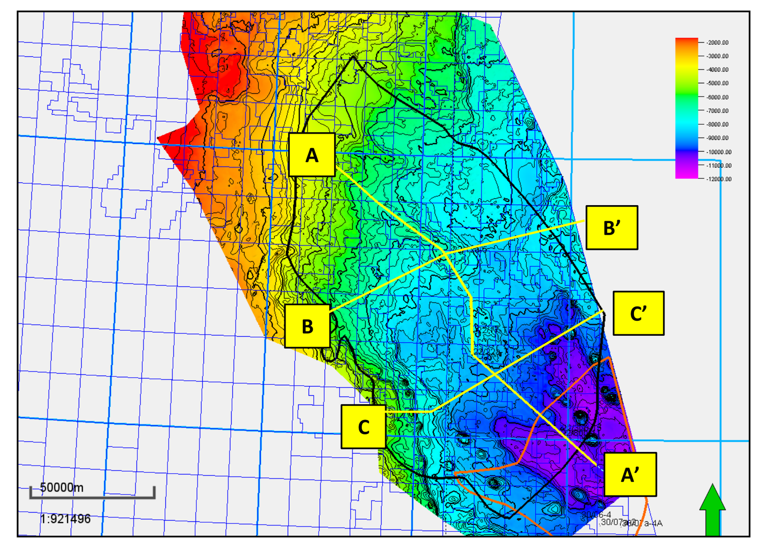


Image source: Original interpretation from Axis Well Technology, 2015

Forties 5 CO2Stored outline
Maureen 1 CO2Stored outline

Ci: 250ft

Random Dip seismic line across the Forties 5 Saline Aquifer

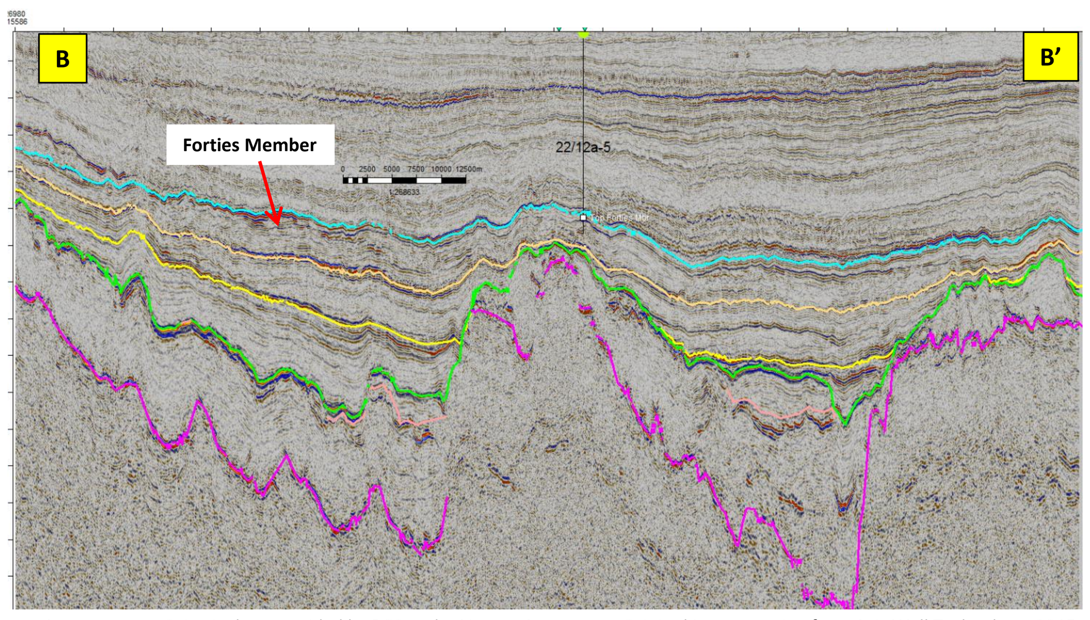


Image source: Seismic data provided by PGS under Licence Agreement. Original interpretation from Axis Well Technology, 2015.

Near Top Palaeocene
Near Base Tertiary
Near Top Lower Cretaceous
Base Cretaceous Unconformity
Near Top Middle Jurassic
Near Top Permian

Random Dip seismic line across the Forties 5 Saline Aquifer

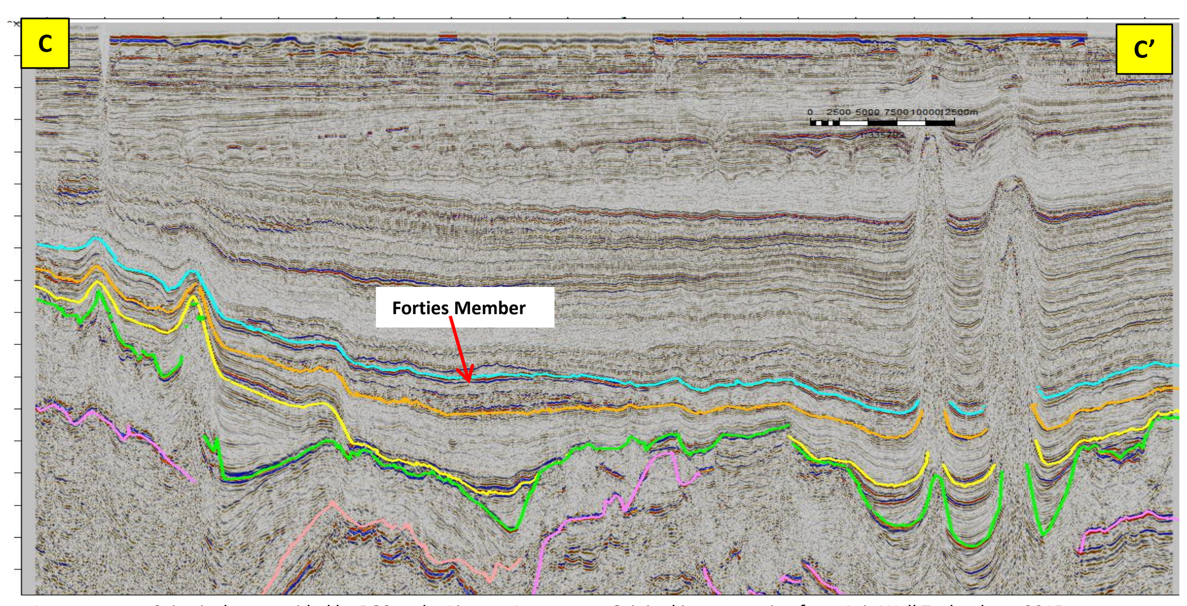


Image source: Seismic data provided by PGS under Licence Agreement. Original interpretation from Axis Well Technology, 2015.

Near Top Palaeocene
Near Base Tertiary
Near Top Lower Cretaceous
Base Cretaceous Unconformity
Near Top Middle Jurassic
Near Top Permian

Random Strike seismic line across the Forties 5 Saline Aquifer

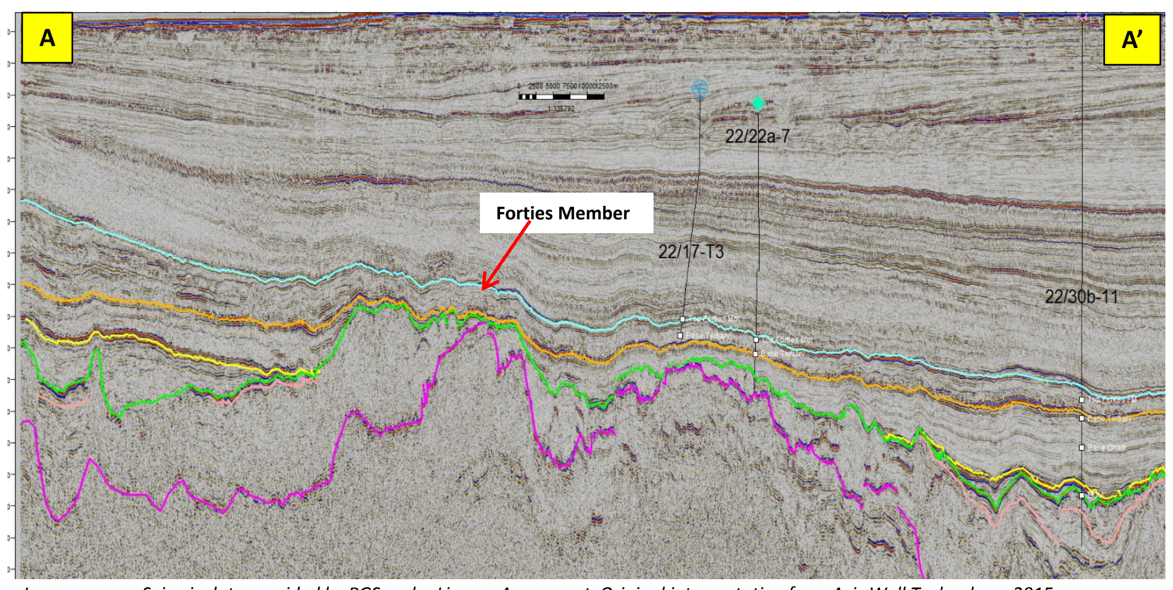


Image source: Seismic data provided by PGS under Licence Agreement. Original interpretation from Axis Well Technology, 2015.

Near Top Palaeocene
Near Base Tertiary
Near Top Lower Cretaceous
Base Cretaceous Unconformity
Near Top Middle Jurassic
Near Top Permian

Key Risk Summary

Forties 5	Capacity (MT)	Injectivity (mDm)	Engineered Containment			Geo Containment
			Wells /sq.km	Leakage risk	Containment risk	
Selection Criteria	1,388	19,012	0.13	n/a	n/a	16
Due Diligence	1,021	22,871	0.14	0.98	0.14	16

Capacity Calculation

Thickness² [m]	GRV [MMm3]	NTG²	Porosity¹	CO2 Density³ [Tonnes/ m3]	Pore Space Utilisation³	Pore Volume [MMm3]	Theoretical Capacity [MT]
134	1,849,682	0.68	0.23	0.63	0.006	289290	1021

NB. 1: Analogue field data and literature 2: Estimated from CDA composite logs 3: CO2Stored

Injectivity Validation

Zone	Depositional Environment	Gross Thickness [m]	NTG	Porosity	Perm [mD]	Kh [mDm]
Forties	Submarine Fan	134	0.68	0.23	251	22,871

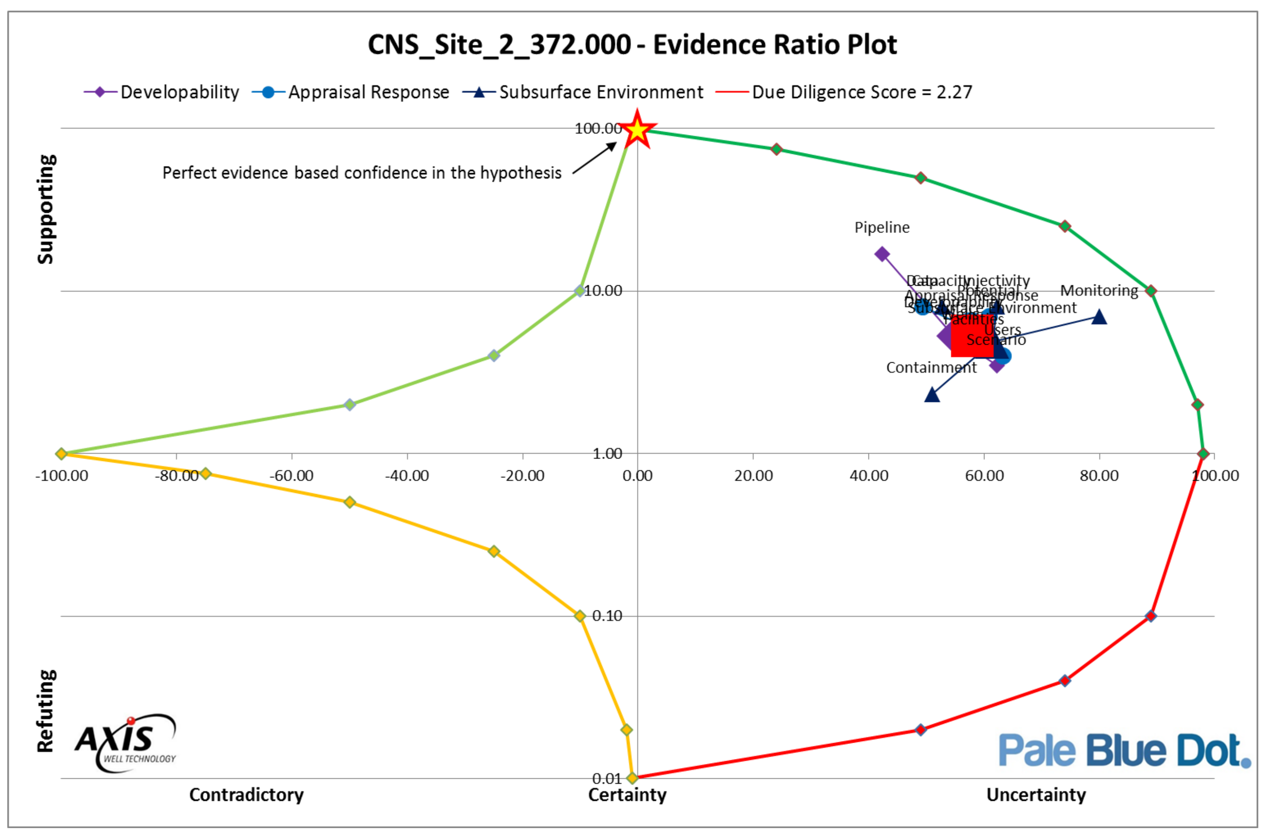
Containment Validation

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	
Forties 5	372.000	3	3	2	3	3	2	16
		3	3	2	3	3	2	16

Low=1 Medium=2 High=3

2 values in CO2Stored
1 no additional data to qc, values taken from CO2Stored

CNS_Site_2_372.000 - Evidence Ratio Plot



Capacity

The calculated storage capacity is 1021MT compared to the reported capacity in CO2Stored of 1388MT. The capacity has decreased due to an decrease 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 times thickness has been made.

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 literature 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 [1]. The aquifer extends over 7 quads, multiple blocks and fields – including the Forties Field (CDA Map). These Paleocene Forties reservoirs are found in Montrose, Arbroath, Everest, Nelson and Arkwright fields [2].

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.

Containment

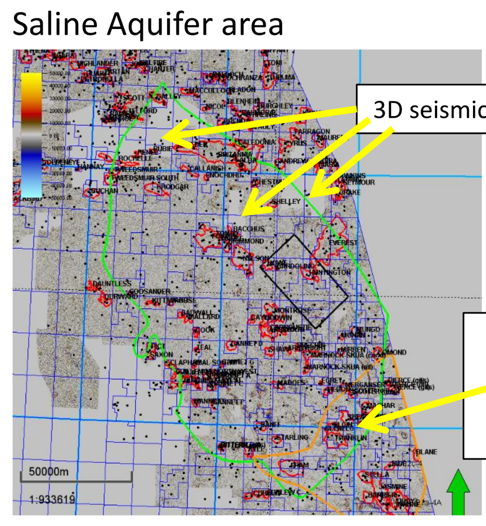
An overburden assessment has been conducted above and adjacent to the Forties 5 saline aquifer storage site to identify secondary containment horizons and potential migration pathways out of the storage complex, in the unlikely event of a seal or fault leakage of the sequestered CO2.

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.

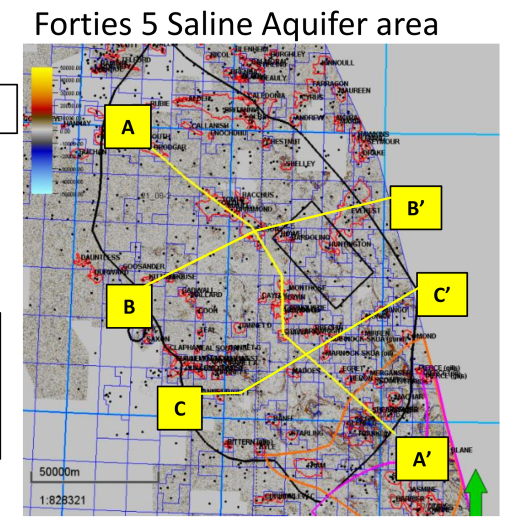
The Georisk factor has been calculated as 16, this is the same as the previously calculated factor in WP3 based on CO2Stored data.

Time slice at 4300msec through Forties Saline Aquifer area



Forties 5 CO2Stored outline
Maureen 1 CO2Stored outline
• Well
CO2Stored Forties Exemplar Model

Time slice at 4000msec through Forties 5 Saline Aquifer area



Forties 5 CO2Stored outline
Maureen 1 CO2Stored outline
CO2Stored Forties Exemplar Model

Image source: Seismic data provided by PGS under Licence Agreement. Original interpretation from Axis Well Technology, 2015.

Costs

Site Reference:	2	Site Description	Forties 5
Capacity:	1021	Water Depth (m)	80
Concept Cost (£m)	Comparative Development	Ultimate Development	Description
Tonnes Injected (MT)	100	1000	Total Stored CO2 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	£119.8m	Landfall, Pipeline, NUI, Templates, ties-Ins,
PM & Eng:	£24.8m	£12m	10% of Facilities Costs
Decommissioning:	£102m	£430m	£10m per NUI, £4m per dry well, £8m per subsea well
Subtotal	£676m	£2801.2m	-
Contingency	£135.2m	£560.3m	20% of Development & Facilities Costs
OPEX (20years)	£297.4m	£143.8m	OPEX Cost for 20 years (6% of facilities costs)
Total:	£1108.5m	£3505.2m	
£/T CO2	11.08	3.51	

*These costs are not the full cost of storage as they omit MMV, security instruments, handover to DECC and profit.

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 as 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 £215.3M.

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.

Site 2 – 372.000 – Forties 5 - CNS

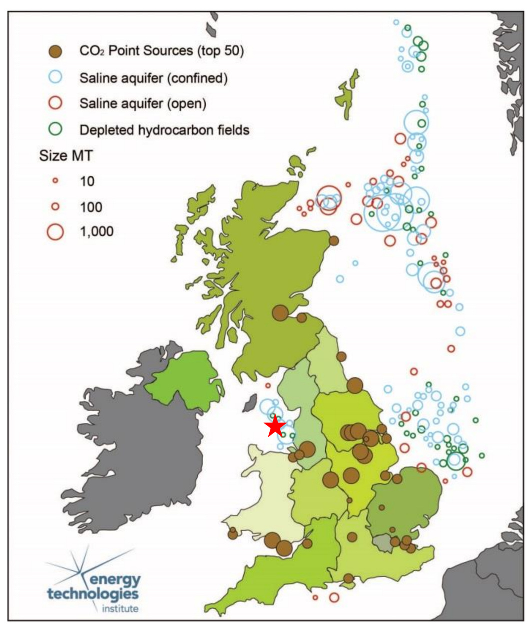
Site Summary			
Capacity (Due Diligence):	1,021 MT	UKCS Block:	Quads 15-16; 21-22; 28-30
Unit Designation:	Saline Aquifer	Beachhead:	St Fergus
Formation:	Sele Fm. (Forties Sst)	Water Depth:	80 m
Containment Unit:	Sele Fm Shale	Reservoir Depth:	1,500 m TVDSS (5,000 ft)
Availability/COP:	n/a	Region:	CNS

Client	The Energy Technologies Institute	Title	D06: Prospect Summary Sheets	Date of Issue	7th August 2015
Project Title	DECC Strategic UK CCS Storage Appraisal Project	Classification	Client Confidential	Version	V00

Strategic UK CCS Storage Appraisal Project

References
1. Carter, A. and Heale, J. (2003) "The Forties and Brimmond Fields, Blocks 21/10, 22/6a, UK North Sea", in Gluyas, J. G. & Hichens, H. M. (eds) 2003. United Kingdom Oil and Gas Fields, Commemorative Millennium Volume. Geological Society, London, Memoir, **20**, 557-561.
2. S. J. O'CONNOR and D. WALKER (1993) "Paleocene reservoirs of the Everest trend" From Petroleum Geology of Northwest Europe: Proceedings of the 4th Conference (edited by J. R. Parker). 1993 Petroleum Geology '86 Ltd. Published by The Geological Society, London, pp. 145-160.

Site 3 – 248.005 – South Morecambe Gas Field – EIS



Major offshore areas covered by CO2Stored (© Energy Technologies Institute)

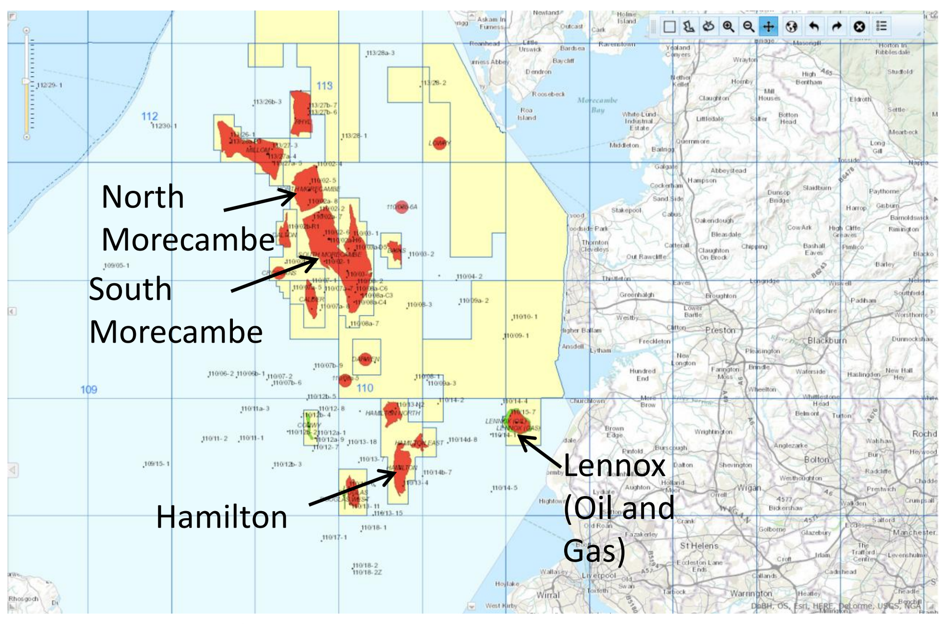


Image source: courtesy of CDA through an open licence agreement

Development Scenarios

<u>CO2 volumes cf ETI Scenarios</u>
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 CO2 being stored in the EIS before 2030).

<u>Build out potential</u>
Build out of CO2 storage would be facilitated by the nearby N Morecambe field and Hamilton.

<u>Comparative Development Concept</u>
A new Normally Unmanned Installation (NUI) comprising a jacket and topsides with 5 deviated wells each injecting 1MT/yr; totalling 100MT over 20 years. CO2 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.

<u>Site growth potential; theoretical Ultimate Development Concept</u>
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. CO2 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 umbilical's.

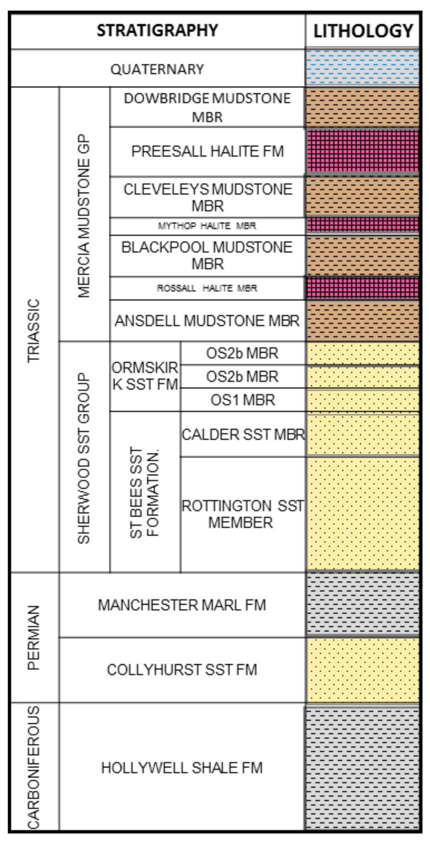


Image source: modified from Yaliz, A. and Taylor, P The Hamilton and Hamilton North Gas Fields, Block 110/13a, East Irish Sea United Kingdom Oil and Gas Fields Commemorative Millennium Volume, The Geological Society of London 2003

AXIS Depth Structure Map: South Morecambe Field: Top Sherwood Sst Fm (ft tvdss)

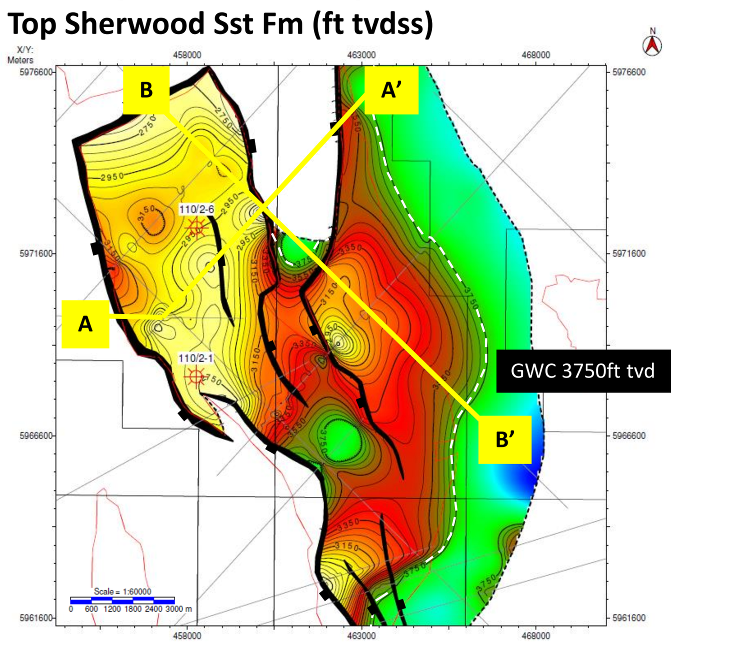


Image source: Original interpretation from Axis Well Technology, 2015

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[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 [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 (at a significant cost).

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.

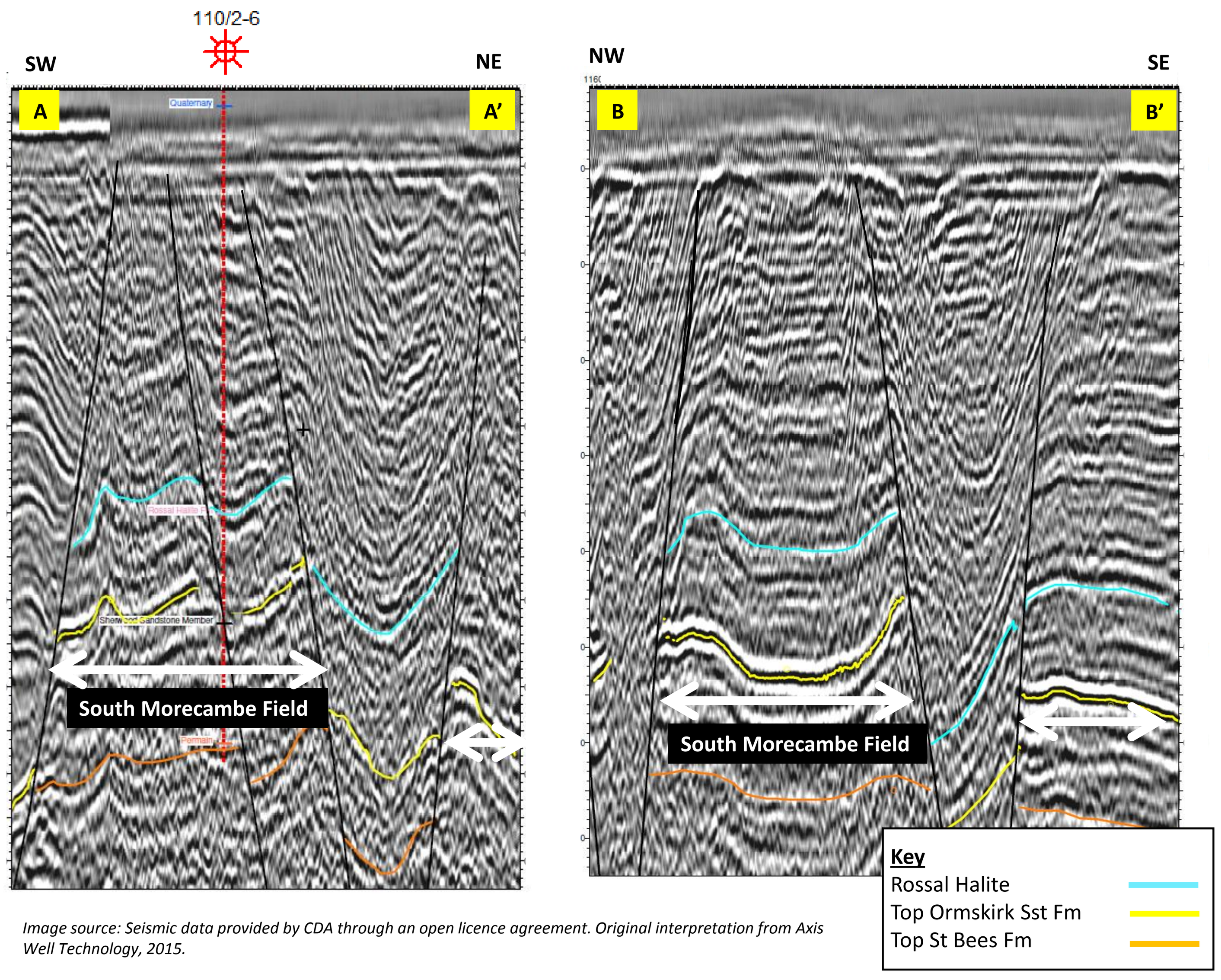


Image source: Seismic data provided by CDA through an open licence agreement. Original interpretation from Axis Well Technology, 2015.

Key Risk Summary

South Morecambe Gas Field	Capacity (MT)	Injectivity (mDm)	Engineered Containment			Geo Containment
			Wells /sq.km	Leakage risk	Containment risk	
Selection Criteria	776.2	90,753	0.44	n/a	n/a	10
Due Diligence	855	31,240	0.05	0.012	0.0006	12

Capacity Calculation

Gas Production	146555	MCM
Condensate Production	2.15	MCM
Water Production *Based on production to date	0.026	MCM
Net Reservoir Volume Produced	1000.4	MCM
Storage capacity	855	MT

NB. Volumes refer to production volumes at February 2015.

Injectivity Validation

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

Containment Validation

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	
South Morecambe gas field	248.005	3	2	1	1	1	2	10
		3	2	3	1	1	2	12

Low=1 Medium=2 High=3

2 values in CO2Stored

1 no additional data to qc, values taken from CO2Stored

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%).

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 (Ormskirk and St. Bees Fm.). Permeability decreases due to illite precipitation below the palaeo GWC (Ref 2) which limits the capacity for CO2 storage [3].

The sandstone can be subdivided into four Ormskirk zones – RL1, RL2, RL3 and RL4. The reservoir properties are summarised in the Injectivity Validation table.

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) [1].

The gross thickness is obtained from well 110/02-12 comp log and confirmed by Ref erence 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 porosity and permeability values taken from the literature.

Additional Injectivity checks

Two additional injectivity checks were carried out as part of the due diligence.

1. 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.
Early life production data from a selection of wells is available on the DECC website. CO2 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 CO2 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.
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). CO2 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.

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 CO2.

Field data and published literature were reviewed to establish the effectiveness of trap and seal. Depth to crest of the reservoir is 914 m[1] . 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 [1,2]. Extensional faults which displace the reservoir trending E-W were identified using the 1997 3D seismic data [1]. The Ormskirk sandstone reservoir is overlain by 975m (3200ft) of Mercia mudstones and halites forming an excellent continuous cap rock. CO2 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).

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.

Well Design

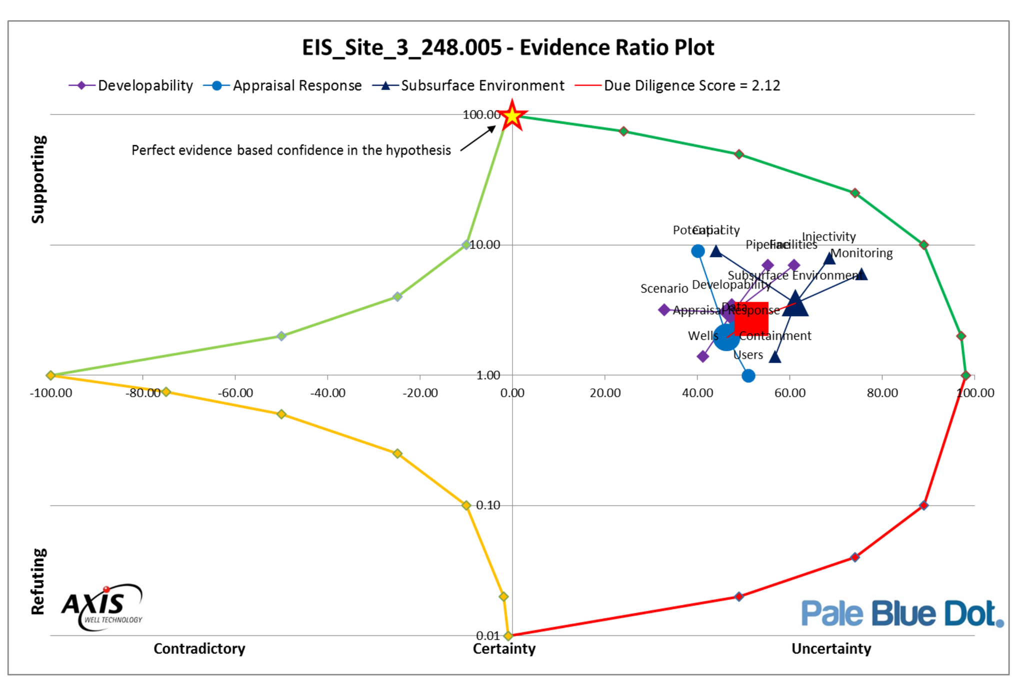
The generic well design is discussed in the supporting document 'Storage Site Due Diligence Summary'. However, the South Morecambe Bay injection wells may depart from the generic design due to the shallow reservoir depth. This suggests that, with restricted build angle and kick-off point, the well may 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 can be drilled by a low cost class 1 Jack-Up Drilling Unit. Platform well costs are assumed to be £22M per well, including a contingency cost for managing CO2 phase change, resulting in a 5 well development cost of £111.4M.

Costs

Site Reference:	3	Site Description	South Morecambe gas field
Capacity:	**855**	**Water Depth (m)**	25
Concept Cost (£m)	**Comparative Development**	**Ultimate Development**	**Description**
Tonnes Injected (MT)	100	855	Total Stored CO2 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, Templates, ties-Ins,
PM & Eng:	£14.9m	£60.7m	10% of Facilities Costs
Decommissioning:	£67.3m	£413.7m	£10m per NUI, £4m per dry well, £8m per subsea 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 CO2	5.90	3.71	

*These costs are not the full cost of storage as they omit MMV, security instruments, handover to DECC and profit.



Commercial Issues

Centrica hold the Petroleum Licence for S Morecambe (but without CO2 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 CO2 storage for Morecambe.

Site 3 – 248.005 – South Morecambe Gas Field - EIS

Site Summary			
Capacity (Due Diligence):	855 MT	**UKCS Block:**	110/2a, 3a, 8a
Unit Designation:	Gas Field	**Beachhead:**	Point of Ayr
Formation:	Ormskirk Sandstone	**Water Depth:**	25 m
Containment Unit:	Mythop Halite Member	**Reservoir Depth:**	914 m TVDSS (2998 ft)
Availability/COP:	2028	**Region:**	EIS

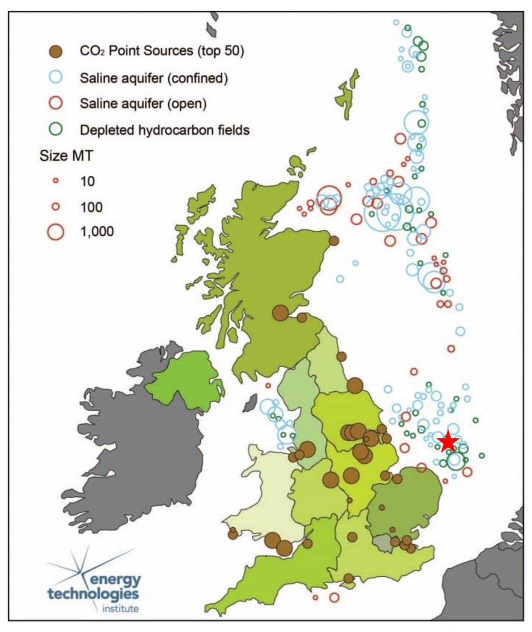
Client	The Energy Technologies Institute	**Title**	D06: Prospect Summary Sheets	**Date of Issue**	7th August 2015
Project Title	DECC Strategic UK CCS Storage Appraisal Project	**Classification**	Client Confidential	**Version**	V00

Strategic UK CCS Storage Appraisal Project

References

1. Bastin, J.C., Boycott-Brown, T., Sims, A., and Woodhouse, R. (2003) "The South Morecambe Gas Field, Blocks l10/2a, l10/3a, l10/7a and l10/8a, East Irish Sea" GLUYAS, J. G. & HICHENS, H. M. (eds) 2003. United Kingdom Oil and Gas Fields, Commemorative Millennium Volume. Geological Society, London, Memoir, 20, 107-118.
2. I.A Stuart & G.Cowan 1991 "The South Morecambe Field, Blocks 110/2a, 110/3a, 110/8a, UK East Irish Sea" From Abbotts, I. L. (ed.), 1991, United Kingdom Oil and Gas Fields, 25 Years Commemorative Volume, Geological Society Memoir No. 14, pp. 527-541
3. Kirk, K. (2006) "Potential for storage of carbon dioxide in the rocks beneath the East Irish Sea" Tyndall Centre for Climate Change Research & BGS. Working paper 100.

Site 4 – 227.007 – Bunter Closure 3 – SNS



Major offshore areas covered by CO2Stored (© Energy Technologies Institute)

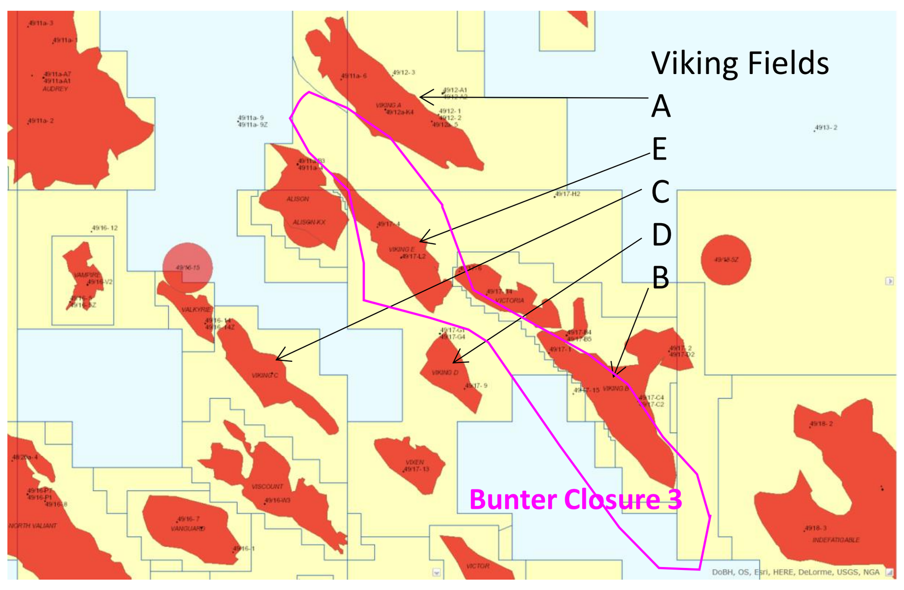


Image source: courtesy of CDA through an open licence agreement

0 10 km

Axis generated Top Bunter Sst depth (ft) map

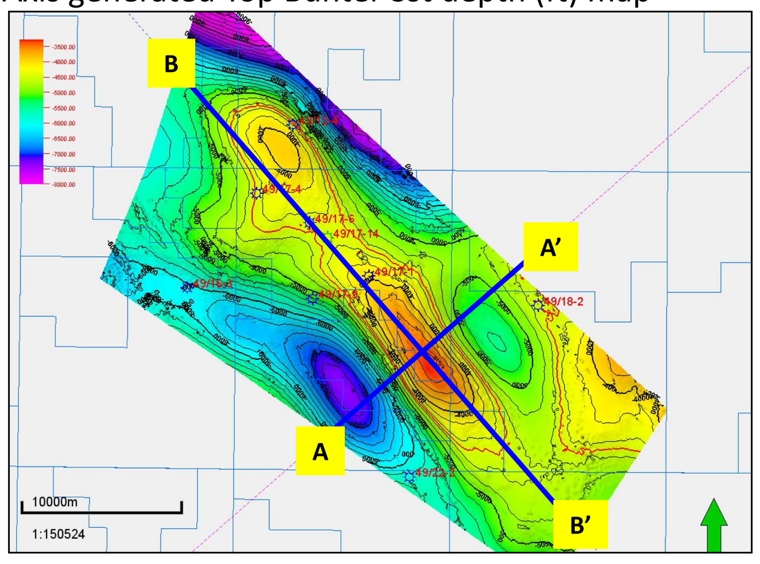


Image source: Original interpretation from Axis Well Technology, 2015

Ci: 200ft closing contour: -4500ft tvdss

Axis generated Bunter Sst Isochore (ft), generated from well data (49/17-4 ,-6 -9, 49/18-2, 49/22-2)

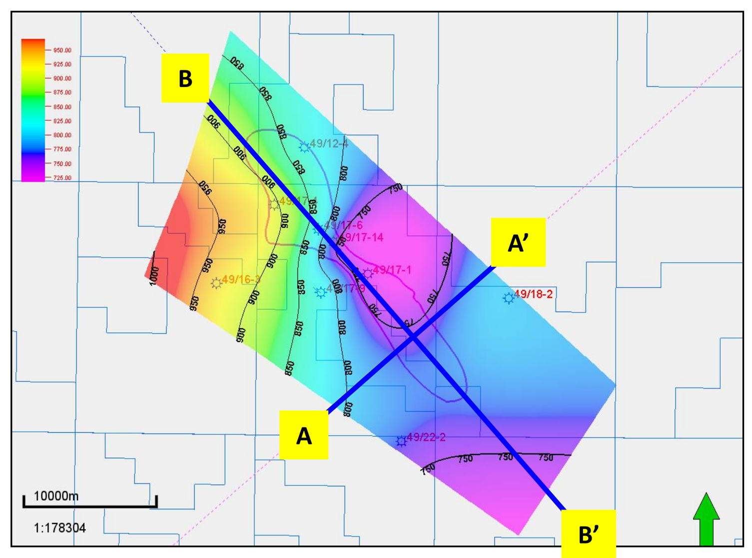


Image source: Original interpretation from Axis Well Technology, 2015

Ci: 50ft

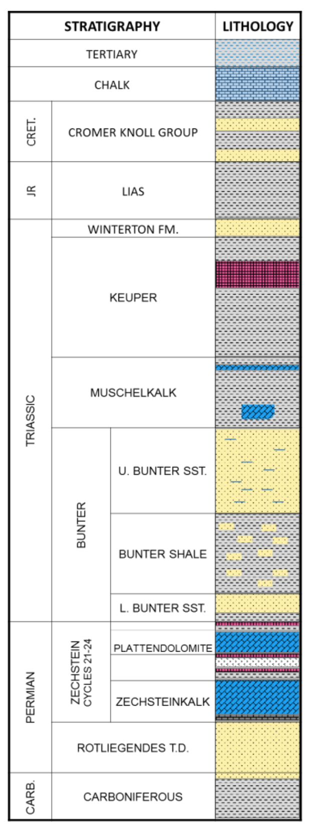


Image source: modified from Cooke-Yarborough (1991) "The Hewett Field, Blocks 48/28-29-30, 52/4a-5a, UK North Sea", *In* Abbotts, I. L. (ed.), 1991, United Kingdom Oil and Gas Fields, 25 Years Commemorative Volume, Geological Society Memoir No. **14**, pp. 433-442

Development Concept

CO2 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.

Build out potential

Bunter Closure 3 is reasonably close to the two Hewett Reservoirs (600MT), Viking (310MT) and Bunter Closure 9 (1977MT). The Barque depleted gas field (91MT) is on the likely pipeline route from Barmston. These all represent potential regional growth opportunities

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. CO2 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.

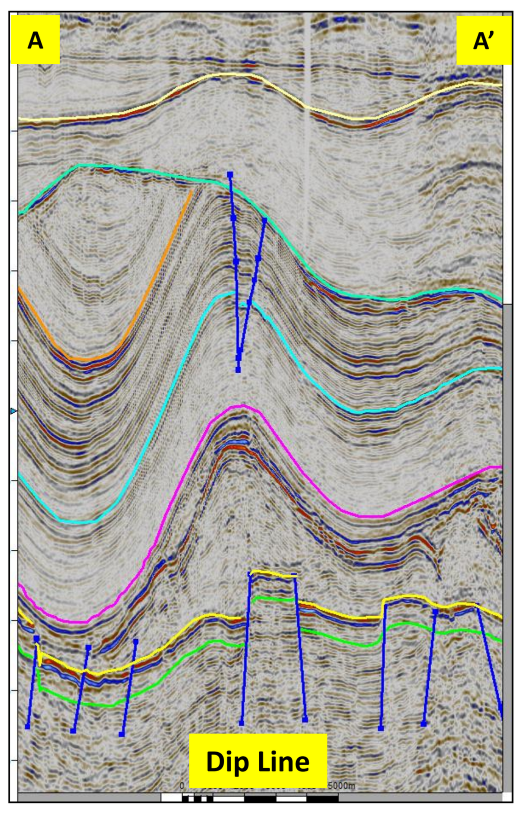
A new development comprising 3 new NUI platforms, with a total of 12 wells, injecting a total of 12Mt/yr; 232MT. CO2 would be delivered via a 26" 238 km pipeline from Barmston with a 20Mt/yr capacity. Facilities will be controlled from the beach. Power generation and controls relay will be provided from a single primary NUI. Platforms are connected by 10km infield pipelines and umbilical's.

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.

Bunter Closure 3: Strike and Dip seismic lines from PGS MegaSurvey



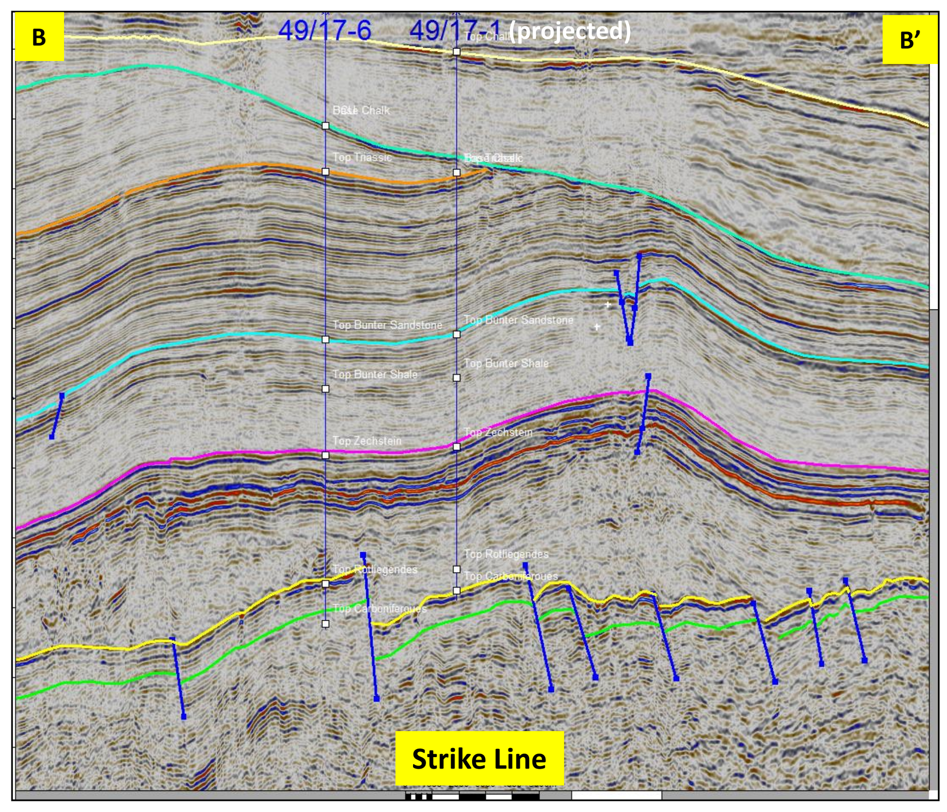


Image source: Seismic data provided by PGS under Licence Agreement. Original interpretation from Axis Well Technology, 2015.

Top Chalk | Top Bunter Sandstone | Base Chalk | Top Zechstein | Near Top Carboniferous | Top Triassic | Top Rotliegendes

Key Risk Summary

Bunter Closure 3	Capacity (MT)	Injectivity (mDm)	Engineered Containment			Geo Containment
			Wells /sq.km	Leakage risk	Containment risk	
Selection Criteria	409	23,926	0.21	n/a	n/a	9
Due Diligence	232	79,800	0.25	0.07	0.017	10

Capacity Calculation

Thickness[2] [m]	GRV [MMm3]	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

NB. 1: Analogue field data and literature 2: Estimated from CDA composite logs 3: CO2Stored

Injectivity Validation

Zone	Depositional Environment	Gross Thickness[2] [m]	NTG[2]	Porosity[1]	Perm[1] [mD]	Kh [mDm]
Bunter Sst	Fluvial/ Lacustrine	240	0.95	0.21	350	79,800

NB. 1: Analogue field data and literature 2: Estimated from CDA composite logs 3: CO2Stored

Capacity

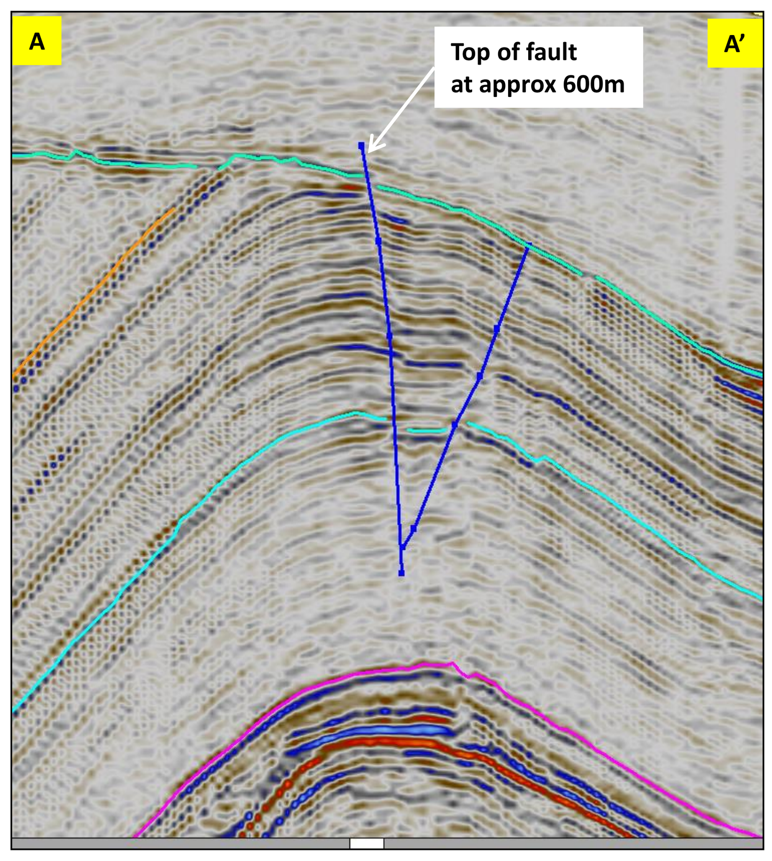
The calculated storage capacity is 232MT compared to the reported capacity in CO2Stored of 409MT. The calculated capacity is significantly smaller than that in CO2Stored, this is due to a large difference in the calculated GRV. The GRV in CO2Stored appears to be overestimated due to the simple Area x Thickness method used. This due diligence uses depths derived from the 3D seismic to calculate the GRV.

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 sites when ranked on capacity.

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.

Crestal Faults at the top of Closure 3 extend up to the base Chalk



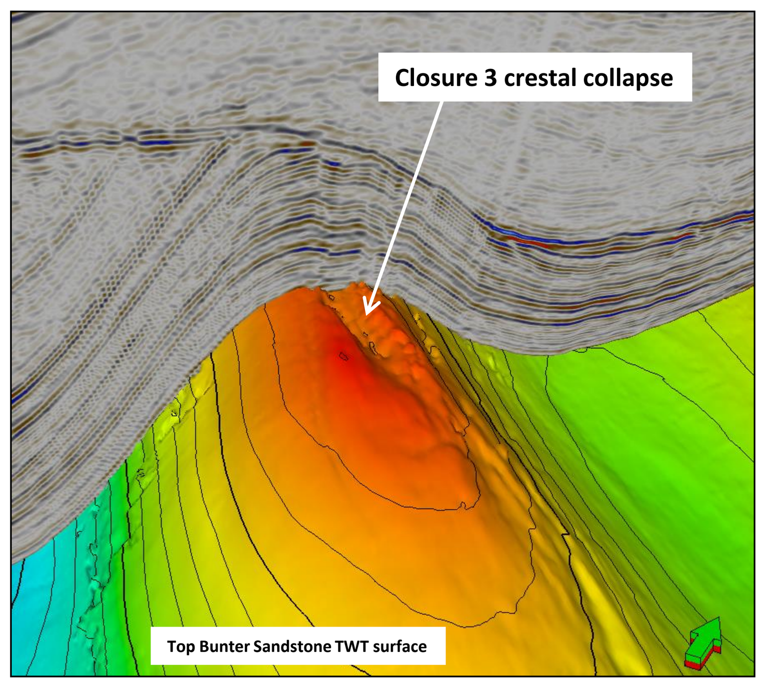


Image source: Seismic data provided by PGS under Licence Agreement. Original interpretation from Axis Well Technology, 2015.

Image source: Seismic data provided by PGS under Licence Agreement. Original interpretation from Axis Well Technology, 2015.

Base Chalk | Top Bunter Sandstone | Top Triassic | Top Zechstein

Containment Validation

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 3	227.007	2	2	2	1	1	1	9
		2	2	3	1	1	1	10

Low=1 Medium=2 High=3

2 values in CO2Stored

1 no additional data to qc, values taken from CO2Stored

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 CO2.

The site is an elongate 4-way dip closure with some faulting. The Bunter sandstone reservoir is overlain by 220m (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 (1970ft) (ref 2), however the fault throws are less than 50m (160ft).

Above the Triassic marker is a 10m (33ft) thick layer of sandstone which in turn is overlain by 150m (490ft) of Jurassic/Lower Cretaceous claystone. Above this is over 300m (980ft) 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.

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.

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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. 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.

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 CO2 injectivity within the SNS is considered to be good. Neither reservoir quality nor injectivity are considered to be a high risk.

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). CO2 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

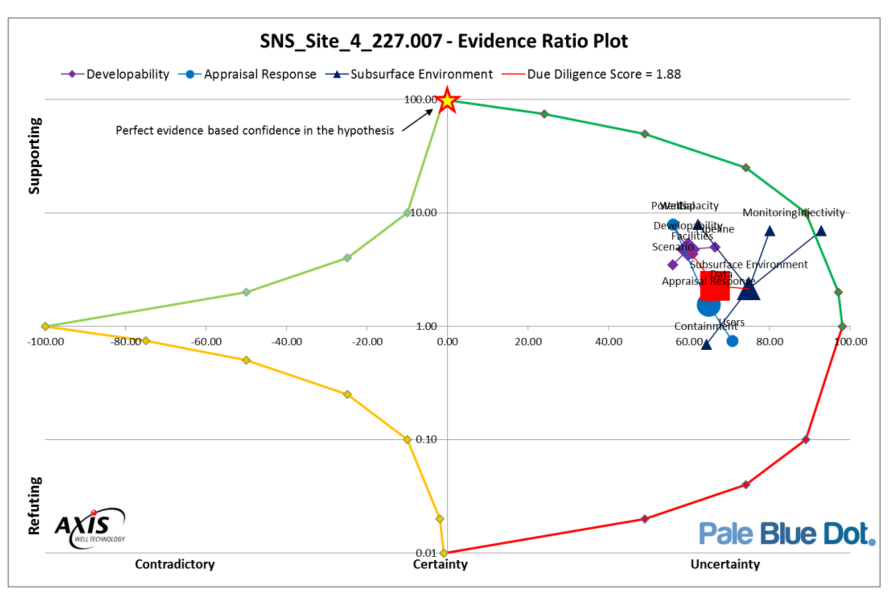
The generic well design is discussed in the supporting document 'Storage Site Due Diligence Summary'. It is likely that this well design can be achieved in the Bunter 3.

Due to the shallow water depth (40m), wells can be drilled by a low cost class 1 Jack-Up Drilling Unit. Platform well costs are assumed to be £20.0M per well, resulting in a 5 well development cost of £100.8M.

Costs

Site Reference:	4	Site Description	Bunter Closure 3
Capacity:	232	Water Depth (m)	40
Concept Cost (£m)	Comparative Development	Ultimate Development	Description
Tonnes Injected (MT)	100	232	Total Stored CO2 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	£494.9m	Landfall, Pipeline, NUI, Templates, ties-Ins,
PM & Eng:	£32.8m	£49.5m	10% of Facilities Costs
Decommissioning:	£111.9m	£201.8m	£10m per NUI, £4m per dry well, £8m per subsea well
Subtotal	£632.6m	£1047.9m	-
Contingency	£126.6m	£209.6m	20% of Development & Facilities Costs
OPEX (20years)	£392.7m	£593.8m	OPEX Cost for 20 years (6% of facilities costs)
Total:	£1151.7m	£1851.2m	
£/T CO2	11.52	7.98	

*These costs are not the full cost of storage as they omit MMV, security instruments, handover to DECC and profit.



Commercial Issues

Bunter C3 is in the vicinity of Viking. Development probably needs to take place after COP at Viking (2017)

Site 4 – 227.007 – Bunter Closure 3 - SNS

Site Summary			
Capacity (Due Diligence):	232 MT	UKCS Block:	Quad 49; blocks 11, 12, 16-18)
Unit Designation:	Saline Aquifer	Beachhead:	Barmston
Formation:	Triassic Bunter Sandstone	Water Depth:	40 m
Containment Unit:	Rot Halite	Reservoir Depth:	1020 m TVDSS (3350 ft)
Availability/COP:	n/a	Region:	SNS

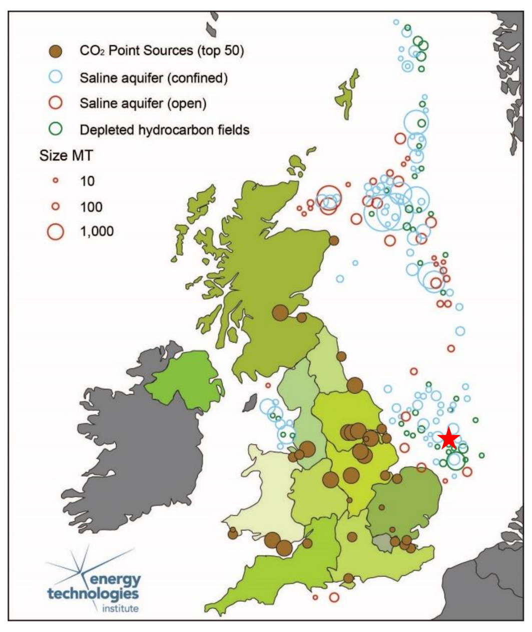
Client	The Energy Technologies Institute	Title	D06: Prospect Summary Sheets	Date of Issue	7th August 2015
Project Title	DECC Strategic UK CCS Storage Appraisal Project	Classification	Client Confidential	Version	V00

Strategic UK CCS Storage Appraisal Project

References

1. J.D.O. Williams, M. Bentham, M. Jin, G. Pickup, E. Mackay, D. Gammer, A. Green (2013) "The effect of geological structure and heterogeneity on CO2 storage in simple 4-way dip structures; a modeling study from the UK Southern North Sea", Energy Procedia, **37**, Pages 3980–3988.
2. Cooke-Yarborough (1991) "The Hewett Field, Blocks 48/28-29-30, 52/4a-5a, UK North Sea", *In* Abbotts, I. L. (ed.), 1991, United Kingdom Oil and Gas Fields, 25 Years Commemorative Volume, Geological Society Memoir No. **14**, pp. 433-442.

Site 5 – 141.035 - Viking Gas Field – SNS



Major offshore areas covered by CO2Stored (© Energy Technologies Institute)

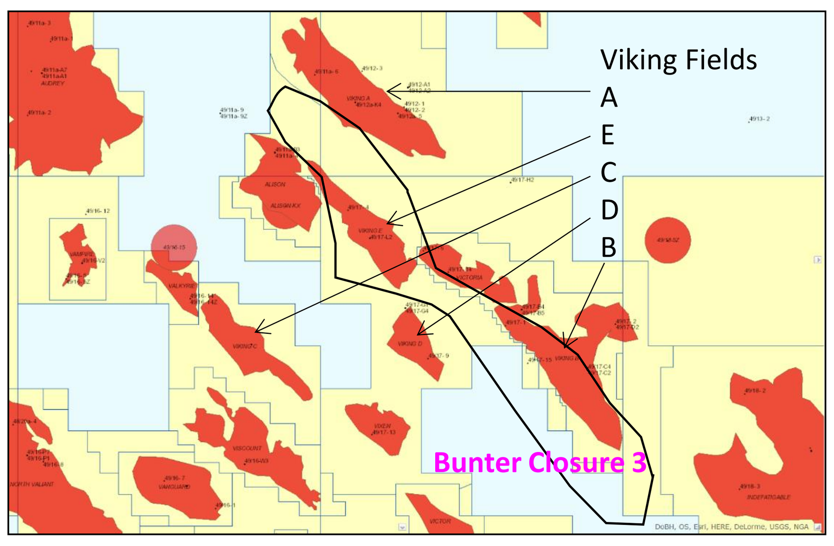


Image source: courtesy of CDA through an open licence agreement

Development Concept

<u>CO2 volumes cf ETI Scenarios</u>
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.

<u>Build out potential</u>
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.

<u>Comparative Development Concept</u>
A new Normally Unmanned Installation (NUI) comprising a jacket and topsides with 5 deviated wells each injecting 1MT/yr; totalling 100MT over 20 years. CO2 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.

<u>Site growth potential; theoretical Ultimate Development Concept</u>
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. CO2 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 umbilical's.

Axis generated Top Rotliegendes depth map (ft tvdss)

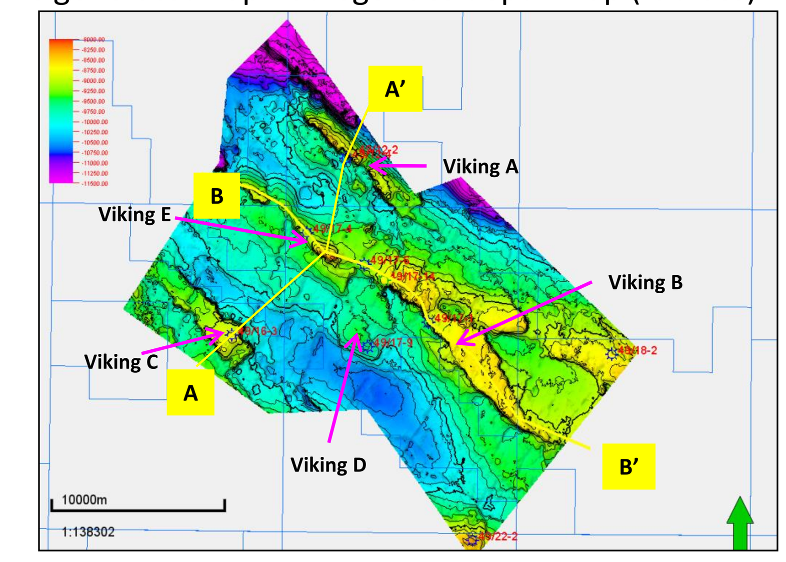


Image source: Original interpretation from Axis Well Technology, 2015

Ci: 200ft

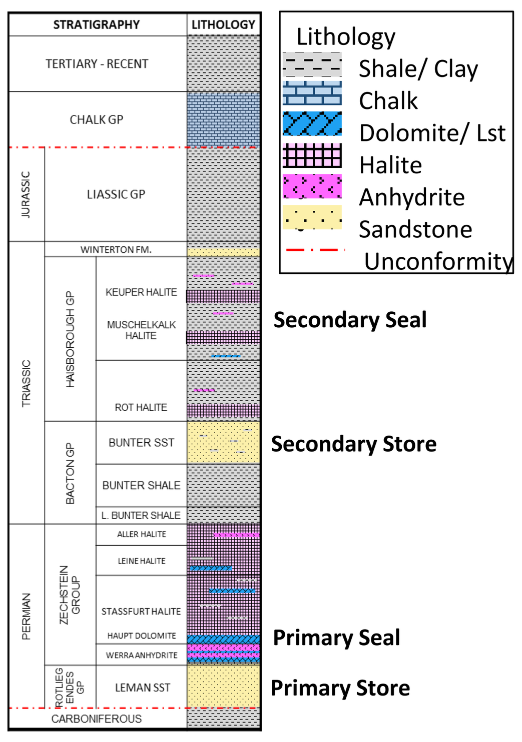
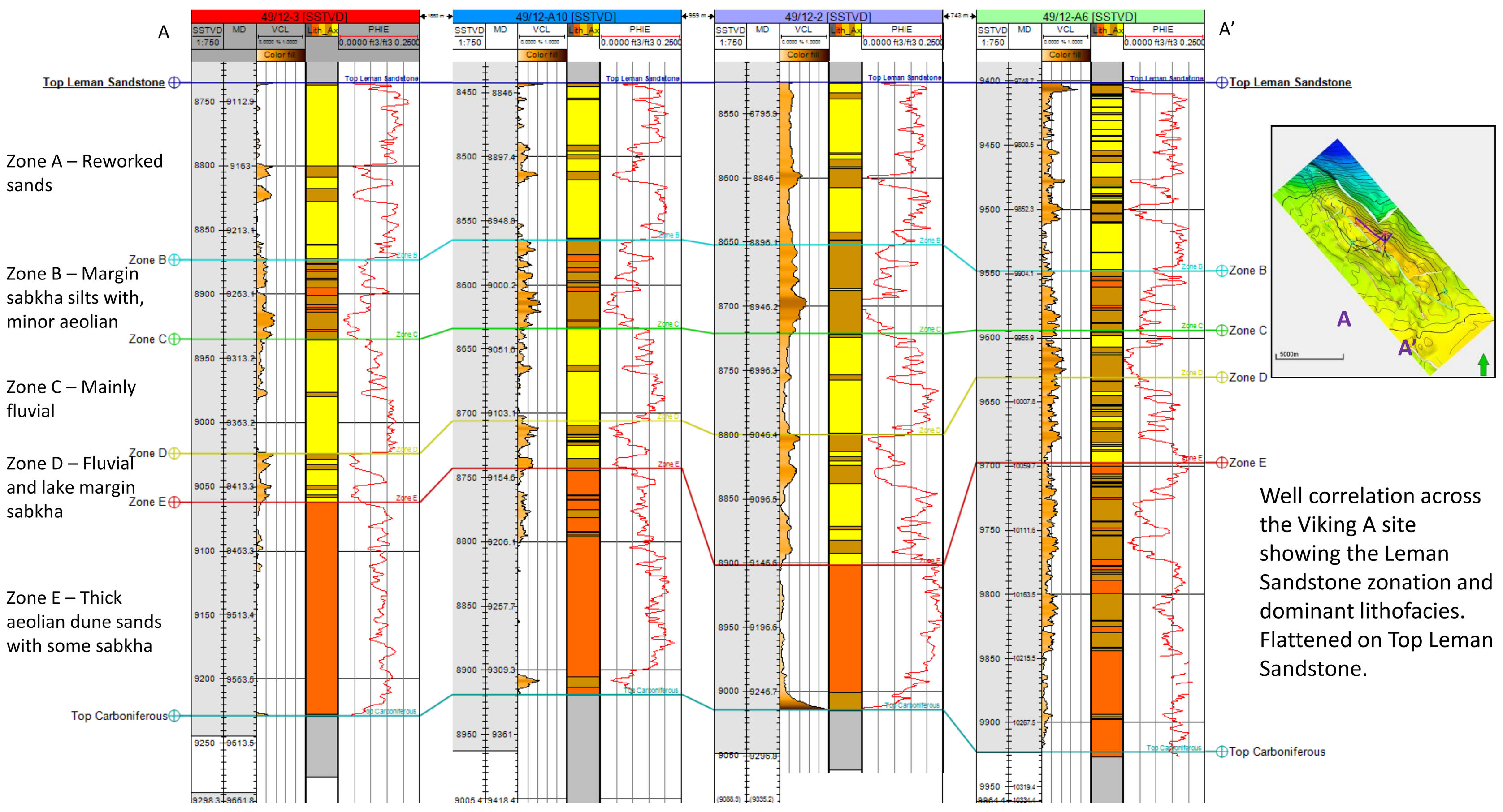


Image source: modified from Cooke-Yarborough (1991) "The Hewett Field, Blocks 48/28-29-30, 52/4a-5a, UK North Sea", *In* Abbotts, I. L. (ed.), 1991, United Kingdom Oil and Gas Fields, 25 Years Commemorative Volume, Geological Society Memoir No. **14**, pp. 433-442.



Well correlation across the Viking A site showing the Leman Sandstone zonation and dominant lithofacies. Flattened on Top Leman Sandstone.

TOP SEAL: Axis generated Zechstein Isochore (ft), (depth converted with a constant velocity of 14460 ft/sec)

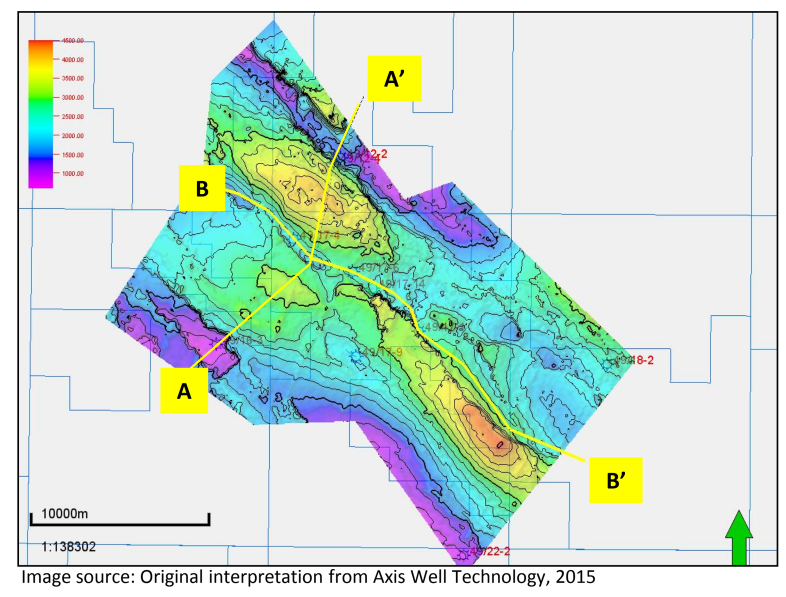


Image source: Original interpretation from Axis Well Technology, 2015

Ci: 300ft

Key Risk Summary

Viking Gas Field	Capacity (MT)	Injectivity (mDm)	Engineered Containment			Geo Containment
			Wells /sq.km	Leakage risk	Containment risk	
Selection Criteria	271	8,350	0.39	n/a	n/a	11
Due Diligence	310	5,599	1.54	0.12	0.18	11

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 210 – 240m (700 and 800ft). The well ties confirm the time interpretation.
Only limited digital logs are available in CDA.

Viking Strike and Dip seismic lines from PGS MegaSurvey

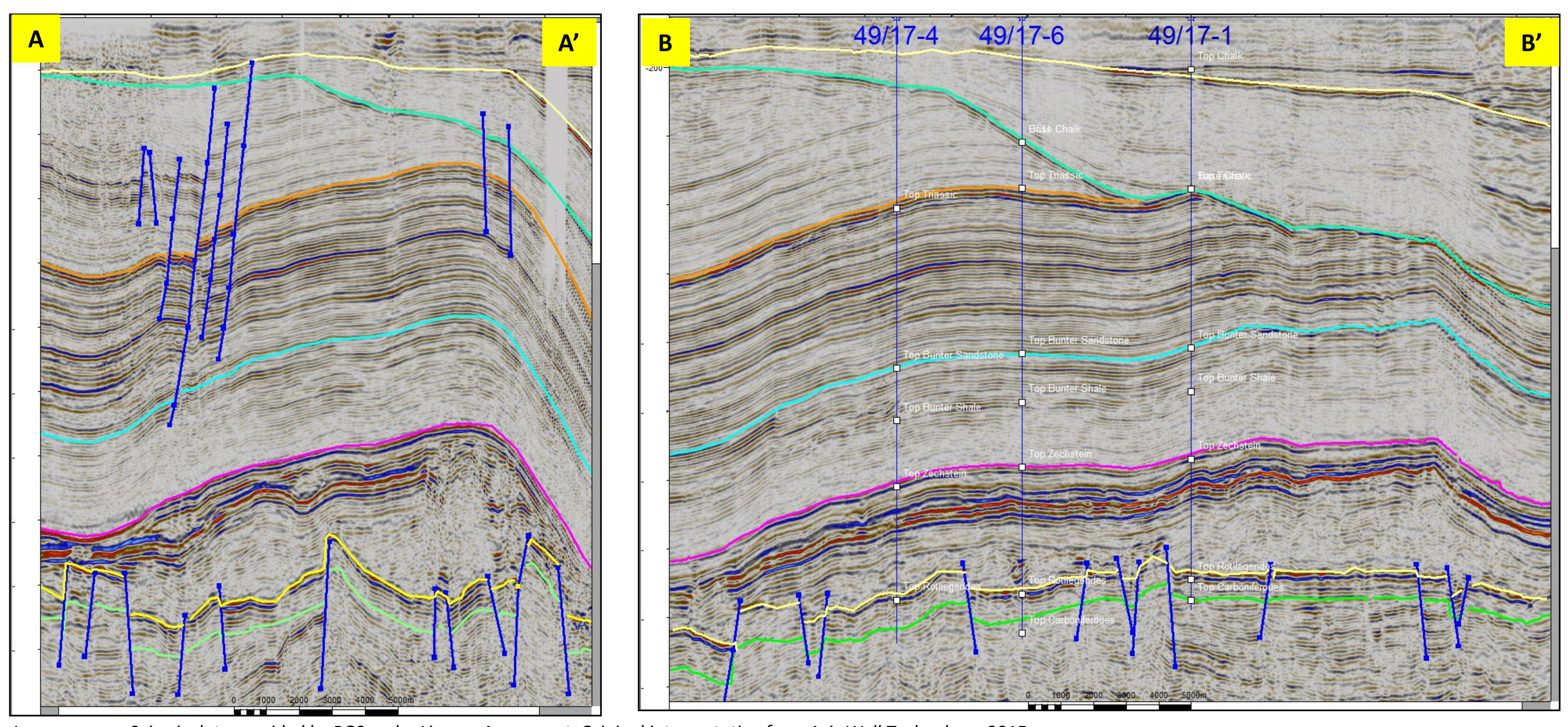


Image source: Seismic data provided by PGS under Licence Agreement. Original interpretation from Axis Well Technology, 2015.

Dip Line

Strike Line

Top Chalk
Base Chalk
Top Triassic
Top Bunter Sandstone
Top Zechstein
Top Rotliegendes Sandstone
Near Top Carboniferous

Capacity Calculation

Gas Production	9246	MCM
Condensate Production	1.3	MCM
Net Reservoir Volume Produced	423	MCM
Storage Capacity @COP	310	MT

NB. Volumes refer to production volumes at February 2015.

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 CO2 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%).

Injectivity Validation

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

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.
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 in the Injectivity Validation table.

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 porosity and permeability 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 CO2 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). CO2 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.

Containment Validation

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	
Viking gas fields	141.035	3	2	1	1	2	2	11
		3	2	1	1	2	2	11

Low=1 Medium=2 High=3

2 values in CO2Stored
1 no additional data to qc, values taken from CO2Stored

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.

<u>Geocontainment Risk</u>
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 CO2.
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[1)]. 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[1].
The Georisk factor has been calculated as 11. This is the same as that calculated in WP3 selection criteria.

<u>Engineering Risk</u>
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.

Costs

Site Reference:	5	Site Description	Viking gas fields
Capacity:	310	Water Depth (m)	20
Concept Cost (£m)	Comparative Development	Ultimate Development	Description
Tonnes Injected (MT)	100	300	Total Stored CO2 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	£649.6m	Landfall, Pipeline, NUI, Templates, ties-Ins,
PM & Eng:	£29m	£65m	10% of Facilities Costs
Decommissioning:	£102.5m	£252.4m	£10m per NUI, £4m per dry well, £8m per subsea well
Subtotal	£637.4m	£1615m	-
Contingency	£127.5m	£323m	20% of Development & Facilities Costs
OPEX (20years)	£347.9m	£779.5m	OPEX Cost for 20 years (6% of facilities costs)
Total:	£1112.7m	£2717.4m	
£/T CO2	11.13	9.06	

*These costs are not the full cost of storage as they omit MMV, security instruments, handover to DECC and profit.

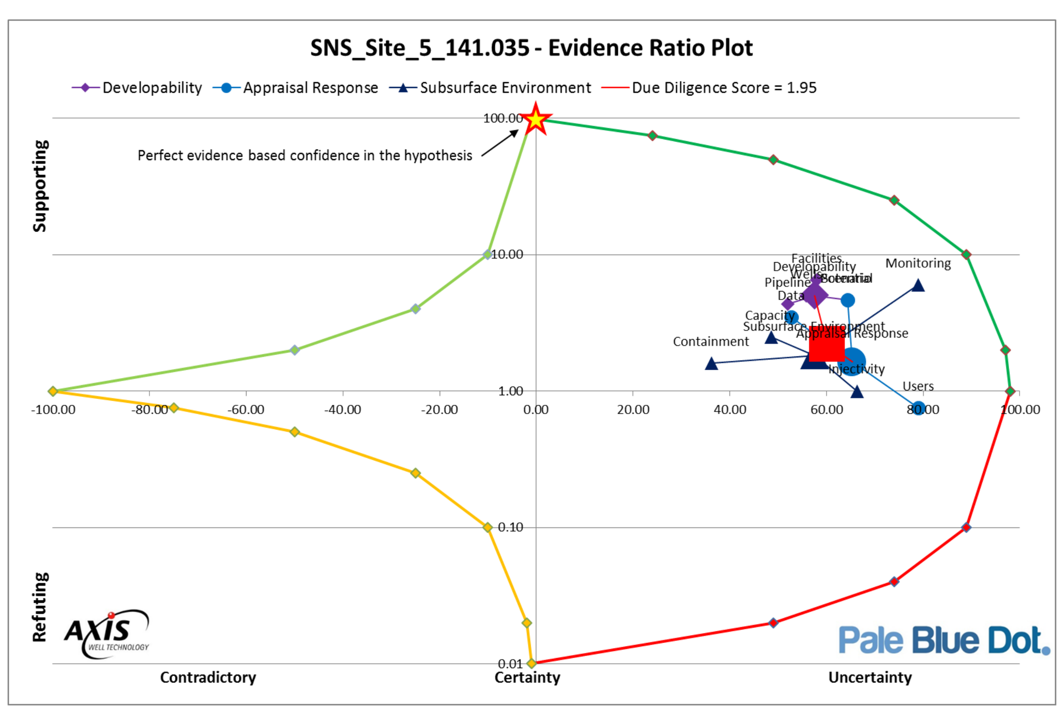
Well Design

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 subsea development solution.

Due to the shallow water depth (20 to 25m), wells can be drilled by a low cost class 1 Jack-Up Drilling Unit. Platform well costs are assumed to be £43.0M per well, including a contingency cost for managing CO2 phase change, resulting in a 5 well development cost of £216M.

SNS_Site_5_141.035 - Evidence Ratio Plot



Commercial Issues

Viking is a depleted gas field operated by ConocoPhillips. Viking A ceased production in 1993. Other Viking fields are due to cease production in 2017.

Site 5 – 141.035 - Viking Gas Field - SNS

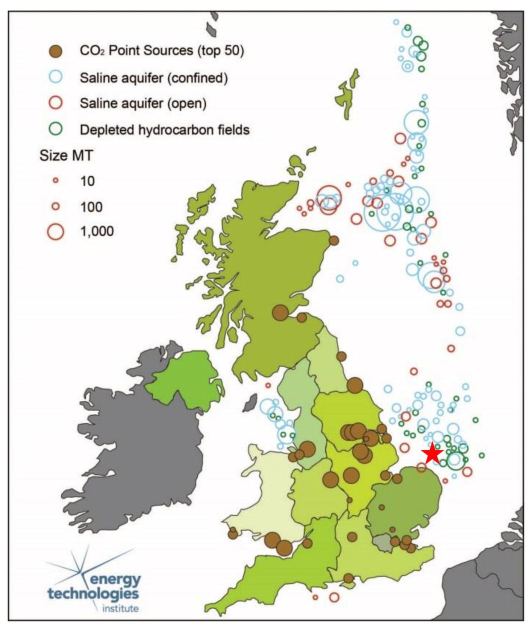
Site Summary			
Capacity (Due Diligence):	310 MT	UKCS Block:	49/12a, 49/16, 19/17
Unit Designation:	Depleted gas	Beachhead:	Barmston
Formation:	Leman sandstone	Water Depth:	25 m
Containment Unit:	Zechstein Gp	Reservoir Depth:	2,438 m TVDSS (8,000 ft)
Availability/COP:	2020	Region:	SNS

Client	The Energy Technologies Institute	Title	D06: Prospect Summary Sheets – Site 5	Date of Issue	7th August 2015
Project Title	DECC Strategic UK CCS Storage Appraisal Project	Classification	Client Confidential	Version	V00

Strategic UK CCS Storage Appraisal Project

References
1. Riches, H. (2003) "The Viking Field, Blocks 49/12a, 49/16, 49/17, UK North Sea". GLUYAS, J. G. & HICHENS, H. M. (eds) 2003. United Kingdom Oil and Gas Fields, Commemorative Millennium Volume. Geological Society, London, Memoir, 20, 871–880.
2. Michele Bentham (2006) "An assessment of carbon sequestration potential in the UK – Southern North Sea case study" Tyndall Centre for Climate Change Research and British Geological Survey
3. "Capturing carbon, tackling climate change: A vision for a CCS cluster in the South East" E.ON UK plc

Site 6 – 266.001 – Hewett Gas Field (Hewett Sst) – SNS



Major offshore areas covered by CO2Stored (© Energy Technologies Institute)

266.001 Hewett Gas Field – Bunter Shale Fm., Sherwood SST Group

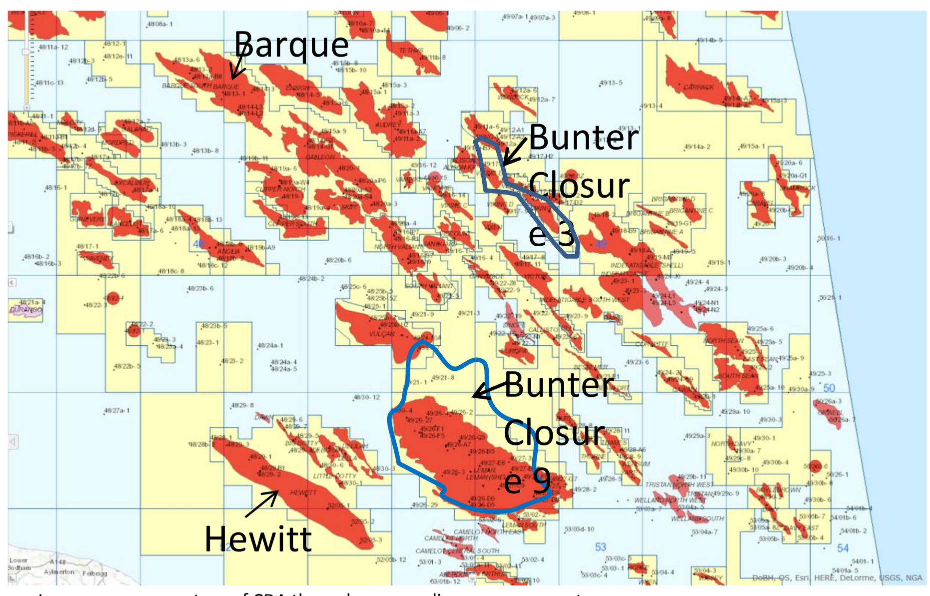


Image source: courtesy of CDA through an open licence agreement

Axis generated Top Hewett Sst depth map (ft)

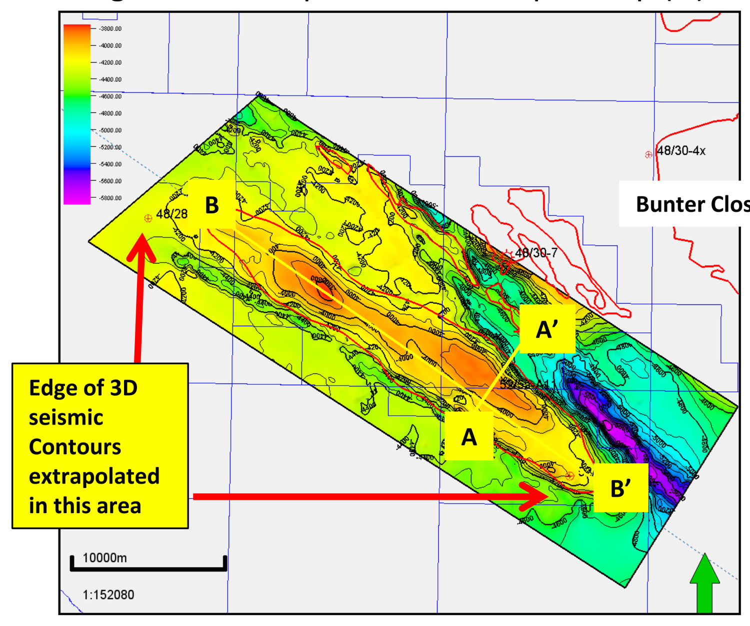


Image source: Original interpretation from Axis Well Technology, 2015

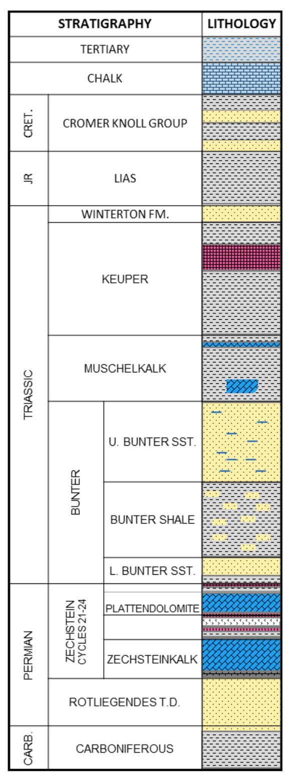


Image source: modified from Cooke-Yarborough (1991) "The Hewett Field, Blocks 48/28-29-30, 52/4a-5a, UK North Sea", *In* Abbotts, I. L. (ed.), 1991, United Kingdom Oil and Gas Fields, 25 Years Commemorative Volume, Geological Society Memoir No. **14**, pp. 433-442.

Axis generated Hewett Sst Isochore (ft), generated from well data (48/28b-2 , 48/30-7, 52/5a-A11, 52/05-2&3)

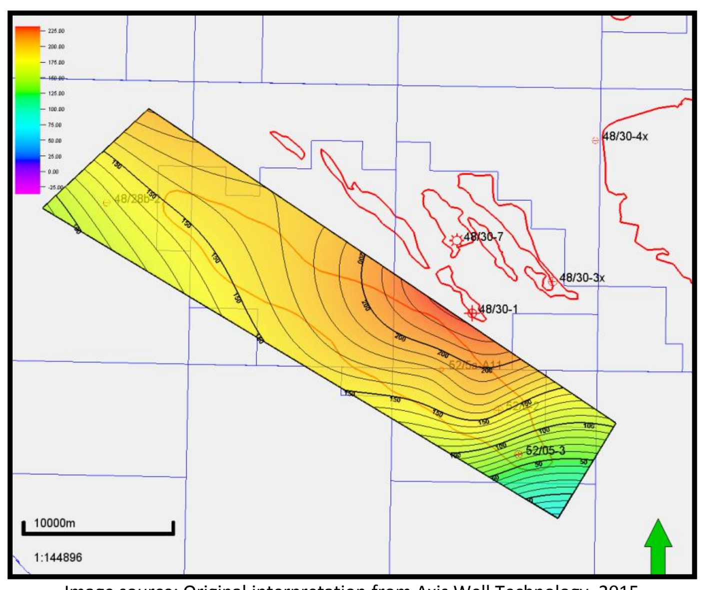


Image source: Original interpretation from Axis Well Technology, 2015

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[2].

Hewett Field: Strike and Dip seismic lines from PGS MegaSurvey

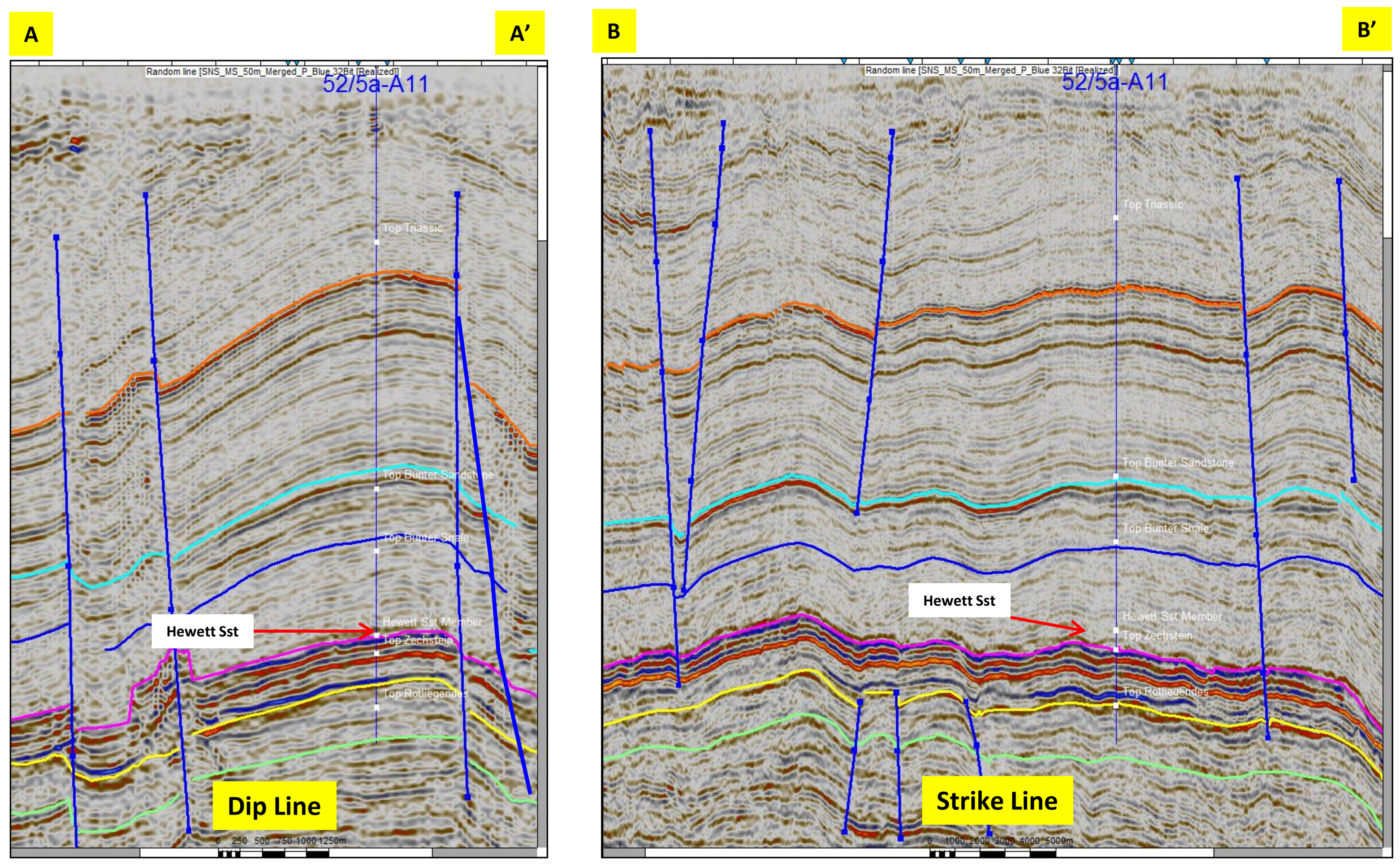


Image source: Seismic data provided by PGS under Licence Agreement. Original interpretation from Axis Well Technology, 2015.

Key Risk Summary

Hewett Gas Field Lower Bunter	Capacity (MT)	Injectivity (mDm)	Engineered Containment			Geo Containment
			Wells /sq.km	Leakage risk	Containment risk	
Selection Criteria	243.5	20,500	0.34	n/a	n/a	11
Due Diligence	312	35,641	0.43	0.11	0.048	11

Capacity Calculation

Gas Production	72220	MCM
Condensate Production	0.313	MCM
Net Reservoir Volume Produced	516	MCM
Storage Capacity @COP	312	MT

NB Volumes refer to production volumes at February 2015.

Injectivity Validation

Zone	Depositional Environment	Gross Thickness [m]	NTG	Porosity	Perm [mD]	Kh [mDm]
Hewett Sst	Alluvial sandstones	26	0.96	0.22	1428	35,641

Containment Validation

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	
Hewett gas field (Hewett Sst)	266.001	2	3	3	1	1	1	11
		2	3	3	1	1	1	11

Low=1 Medium= 2 High=3
2 values in CO2Stored
1 no additional data to qc, values taken from CO2Stored

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%).

The produced volumes and conversion to mass storage potential are shown in the Capacity Calculation table .

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[1]. 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 Injectivity Validation table.

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 (publicly available 2011[3]) and have a higher NTG and permeability than the published 2003 values[1]. The permeability thickness is moderate and based on reservoir quality the initial CO2 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). CO2 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.

Development Concept

CO2 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.

Build out potential
Hewett is within build-out reach of Viking (310MT) and Bunter Closure 9 (1977MT). The Barque depleted gas field (91MT) is on the likely pipeline route from Barmston. These all represent potential regional growth opportunities.

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. CO2 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 ~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. CO2 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 umbilical's.

Costs

Site Reference:	6	Site Description	Hewett gas field
Capacity:	312	Water Depth (m)	20
Concept Cost (£m)	Comparative Development	Ultimate Development	Description
Tonnes Injected (MT)	100	600	Total Stored CO2 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, Templates, ties-Ins,
PM & Eng:	£30.2m	£62.1m	10% of Facilities Costs
Decommissioning:	£105.4m	£335.1m	£10m per NUI, £4m per dry well, £8m per subsea well
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 CO2	10.40	4.82	

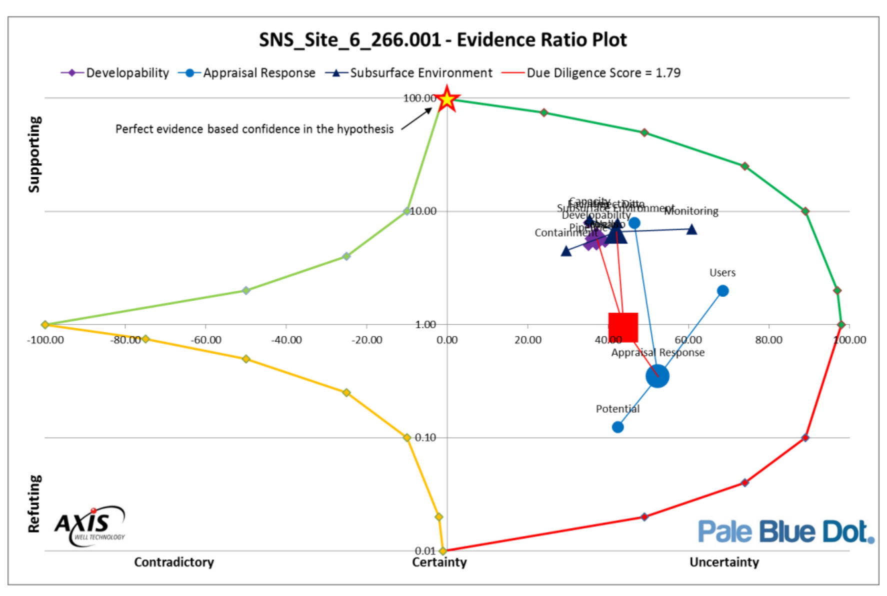
*These costs are not the full cost of storage as they omit MMV, security instruments, handover to DECC and profit.

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 CO2.
Field data and published literature were reviewed to establish the effectiveness of trap and seal. Lower Bunter Hewett sandstones are sealed by Bunter floodplane shales [1]. Below the Hewett sands is a thick evaporate and carbonate Zechstein sequence[1].
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.

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/km2, resulting in a low to moderate leakage risk assessment score of 0.048.



Commercial Issues
Hewett is a depleted gas field. COP is expected to be 2016.

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 (20m), wells can be drilled by a low cost class 1 Jack-Up Drilling Unit. Platform well costs are assumed to be £26M per well, including a contingency cost for managing CO2 phase change, resulting in a 5 well development cost of £128.6M.

References
1. Cooke-Yarborough (1991) "The Hewett Field, Blocks 48/28-29-30, 52/4a-5a, UK North Sea", *In* Gluyas, J. G & Hichens, H. M.(eds), 2003, United Kingdom Oil and Gas Fields, 25 Years Commemorative Volume, Geological Society Memoir No. **20**, pp. 731-739.
2. IEAGHG Report (2013) "UK FEED Studies 2011 – A summary". Report 2013/2012. http://www.sacccs.org.za/wp-content/uploads/members2013/2013-12%20UK%20FEED%20Studies%202011%20%20A%20Summary.pdf
3. RDS (2011) "Chapter 7: Technical Design - Wells and Storage" http://webarchive.nationalarchives.gov.uk/20111209170139/https:/www.decc.gov.uk/en/content/cms/emissions/ccs/demo_prog/feed/e_on_feed_/storage/storage.aspx

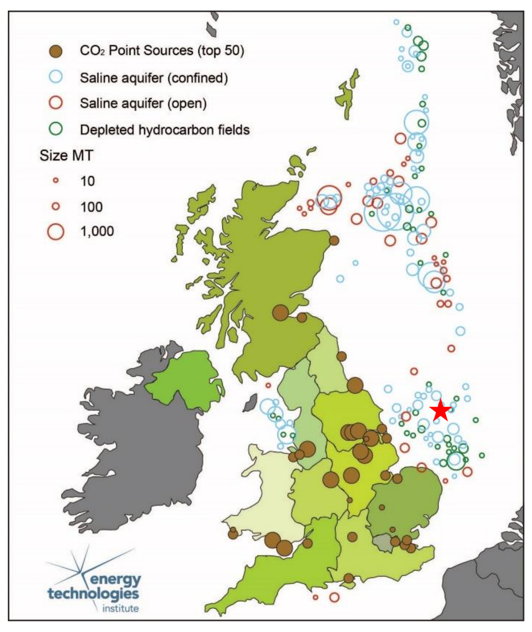
Site 6 – 266.001 – Hewett Gas Field (Hewett Sst) - SNS

Site Summary			
Capacity (Due Diligence):	312 MT	**UKCS Block:**	48/29, 48/30, 52/05
Unit Designation:	Depleted Gas	**Beachhead:**	Barmston
Formation:	Lower Bunter Hewett Sst	**Water Depth:**	20 m
Containment Unit:	Rot Halite	**Reservoir Depth:**	1152 m TVDSS (3780 ft)
Availability/COP:	n/a	**Region:**	SNS

Client	The Energy Technologies Institute	**Title**	D06: Prospect Summary Sheets	**Date of Issue**	7th August 2015
Project Title	DECC Strategic UK CCS Storage Appraisal Project	**Classification**	Client Confidential	**Version**	V00

Strategic UK CCS Storage Appraisal Project

Site 7 – 139.016 – Bunter Closure 36 – SNS



Major offshore areas covered by CO2Stored (© Energy Technologies Institute)

139.016 Bunter Closure 36 – Bunter SST Fm., Bacton Group

Over lying Schooner field (Carboniferous sst producer).

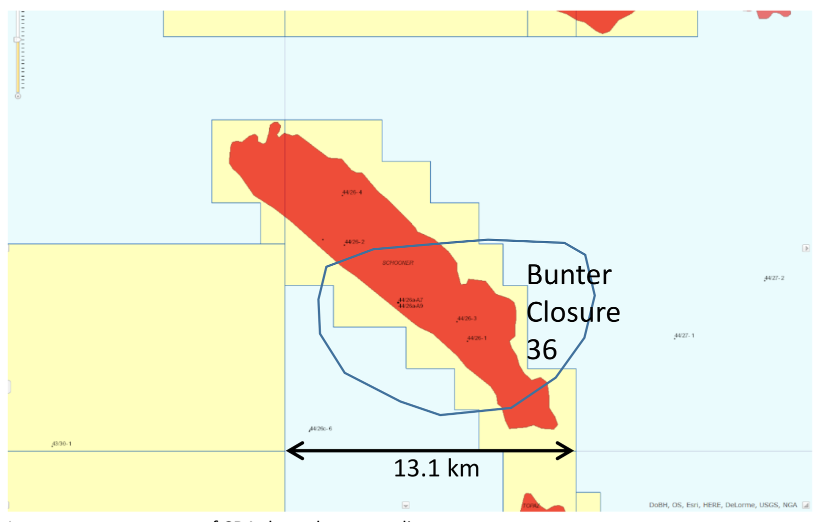


Image source: courtesy of CDA through an open licence agreement

Axis generated Top Bunter Sst depth map (ft tvdss)

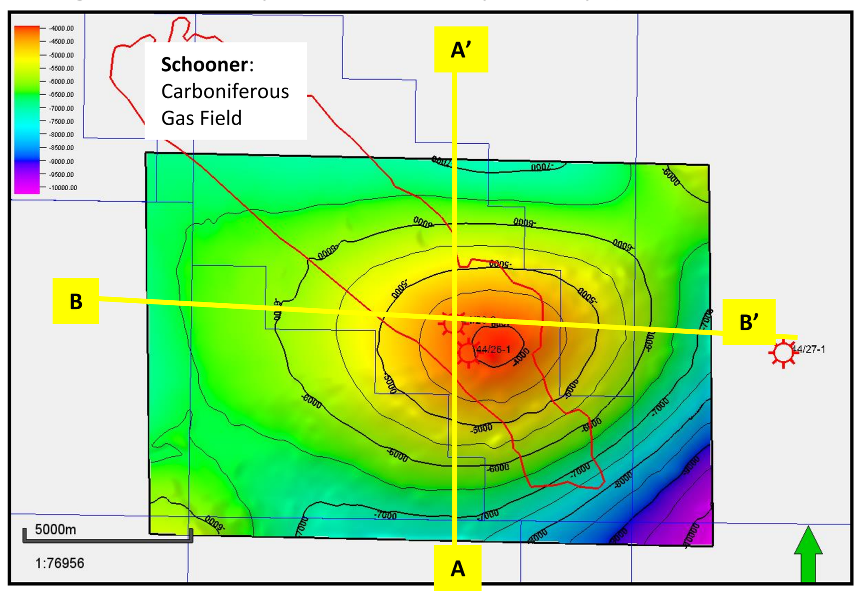


Image source: Original interpretation from Axis Well Technology, 2015

Development Concept

<u>CO2 volumes cf ETI Scenarios</u>
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.

<u>Build out potential</u>
Bunter Closure 36 is a potential build out location for other sites, such as 5/42 and Bunter Closure 40. It is possible that closure 40 could be an extension to this site.

<u>Comparative Development Concept</u>
A new Normally Unmanned Installation (NUI) comprising a jacket and topsides with 5 deviated wells each injecting 1MT/yr; totalling 100MT over 20 years. CO2 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.

<u>Site growth potential; theoretical Ultimate Development Concept</u>
The site has a theoretical storage capacity of ~252MT.

A new development comprising 2 new NUI platforms each with 6 wells injecting a total of 12Mt/yr; totalling 240MT over 20 years. CO2 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 umbilical's.

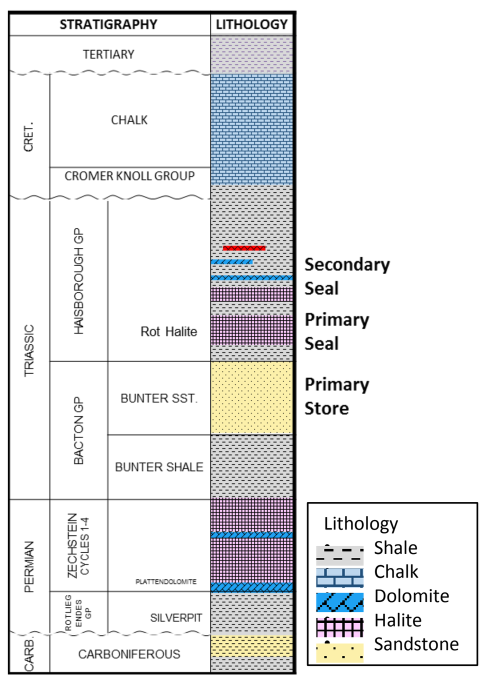
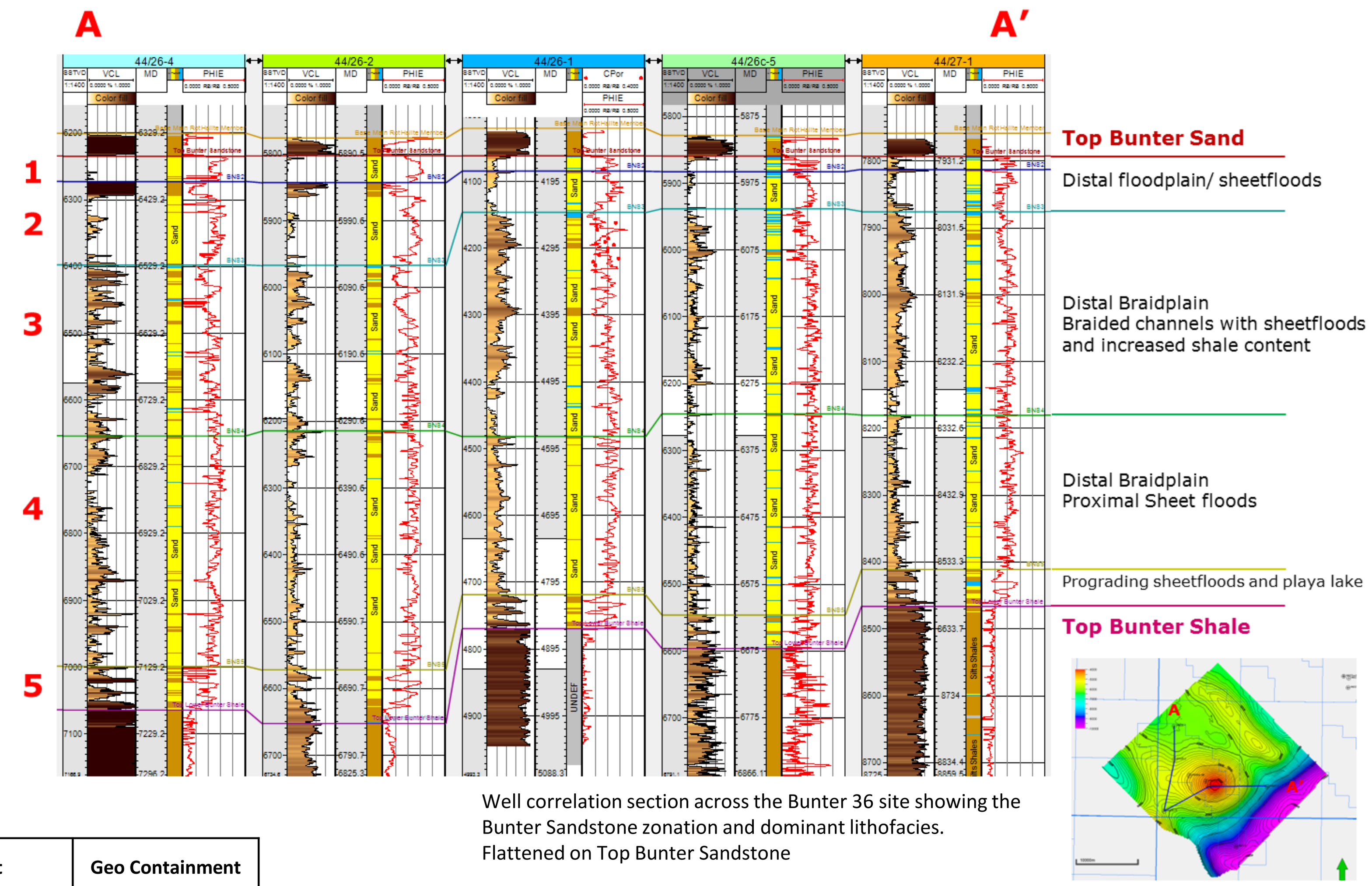


Image source: modified from Cooke-Yarborough (1991) "The Hewett Field, Blocks 48/28-29-30, 52/4a-5a, UK North Sea", *In* Abbotts, I. L. (ed.), 1991, United Kingdom Oil and Gas Fields, 25 Years Commemorative Volume, Geological Society Memoir No. **14**, pp. 433-442.



Well correlation section across the Bunter 36 site showing the Bunter Sandstone zonation and dominant lithofacies. Flattened on Top Bunter Sandstone

Axis generated Bunter Sst Isochore (ft), generated from well data (44/26-1 ,-3 and 44/27-1)

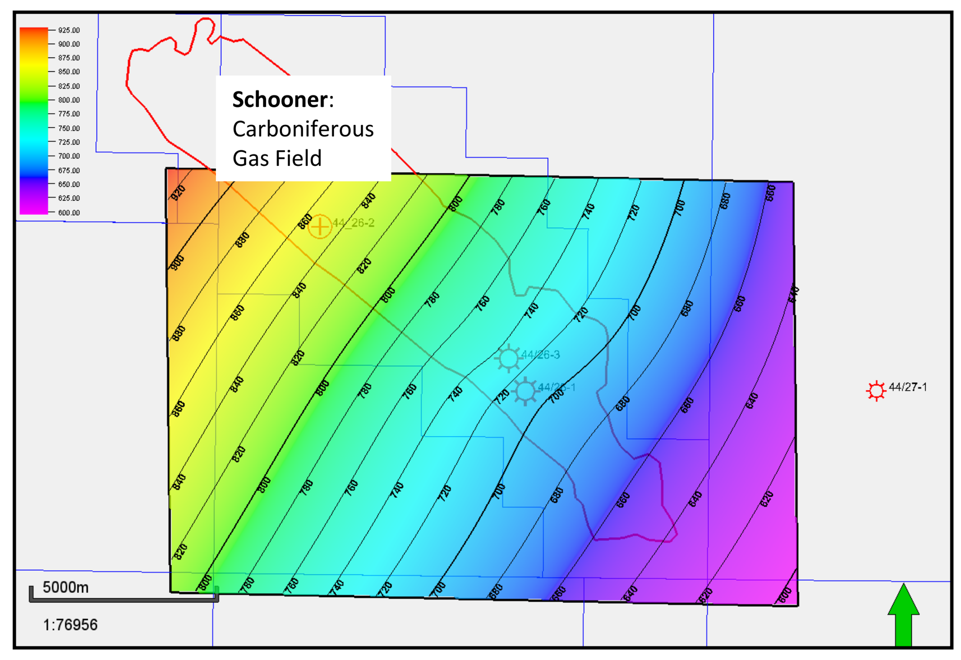


Image source: Original interpretation from Axis Well Technology, 2015

Ci: 20ft

Key Risk Summary

Bunter Closure 36	Capacity (MT)	Injectivity (mDm)	Engineered Containment			Geo Containment
			Wells /sq.km	Leakage risk	Containment risk	
Selection Criteria	232	11,051	0.24	n/a	n/a	6
Due Diligence	252	57,475	0.14	0.024	0.003	6

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.

Capacity Calculation

Thickness[2] [m]	GRV [MMm3]	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

NB. 1: Analogue site data from 5/42 (Ref 1) 2: Estimated from CDA composite logs 3: CO2Stored.

Injectivity Validation

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

NB. 1: Analogue site data from 5/42 (Ref 1) 2: Estimated from CDA composite logs 3: CO2Stored.

Containment Validation

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 36	139.016	1	1	1	1	1	1	6
		1	1	1	1	1	1	6

Low=1 Medium=2 High=3

2 values in CO2Stored

1 no additional data to qc, values taken from CO2Stored

Bunter Closure 36: Strike and Dip seismic lines from PGS MegaSurvey

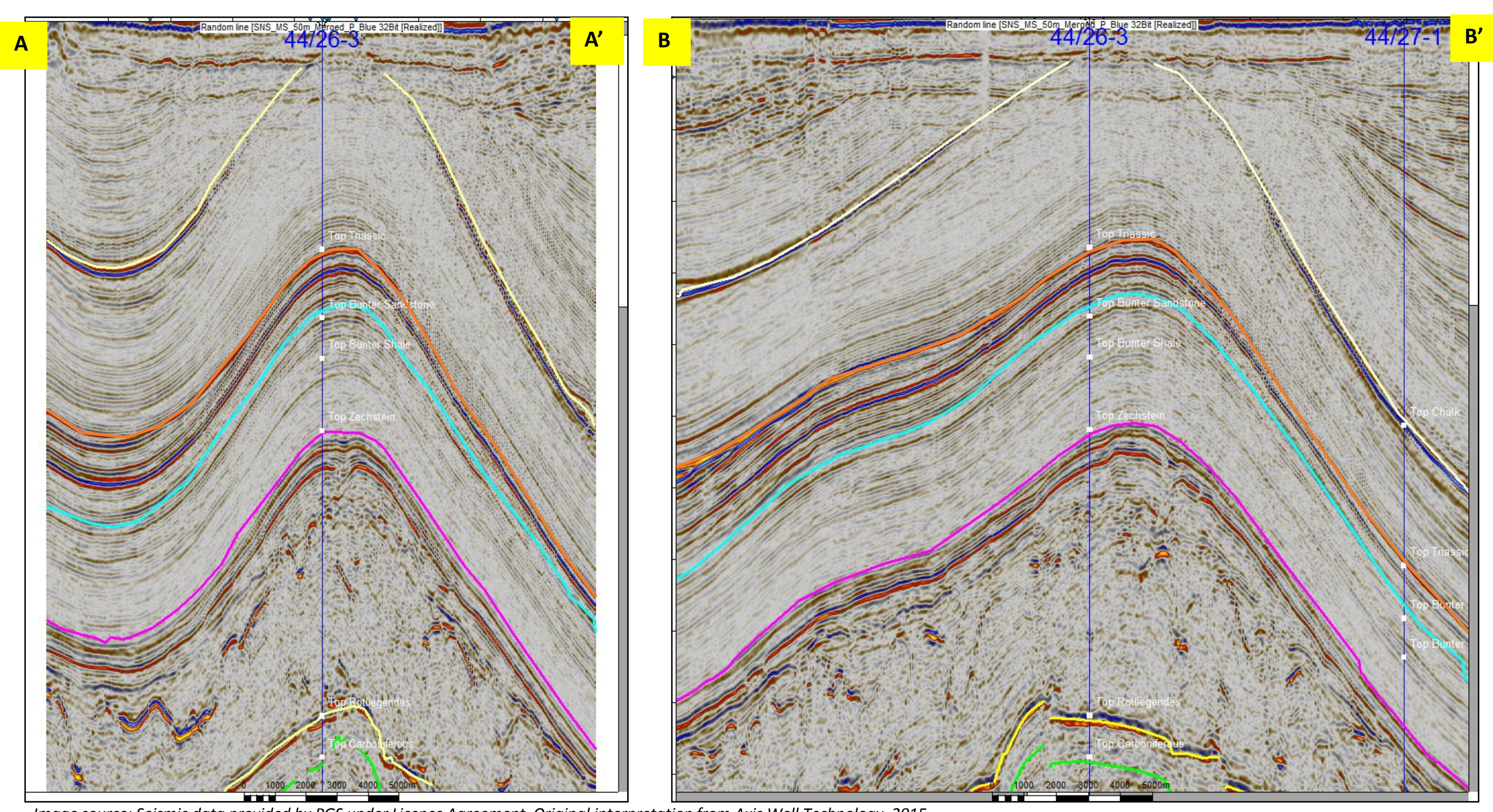


Image source: Seismic data provided by PGS under Licence Agreement. Original interpretation from Axis Well Technology, 2015.

Top Chalk
Top Triassic
Top Bunter Sandstone
Top Zechstein
Top Rotliegendes Sandstone
Near Top Carboniferous

Capacity

The calculated storage capacity is 252MT compared to the reported capacity in CO2Stored of 232MT. These are in agreement. 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 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 Sandstones 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 for this storage site.

With no permeability data available for the Bunter Sandstone at the storage site, permeability, its regional lateral variation and heterogeneity remain an uncertainty. Bunter Sandstone reservoir quality at this depth and initial CO2 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). CO2 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.

Containment

<u>Georisk</u>
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 CO2.

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.

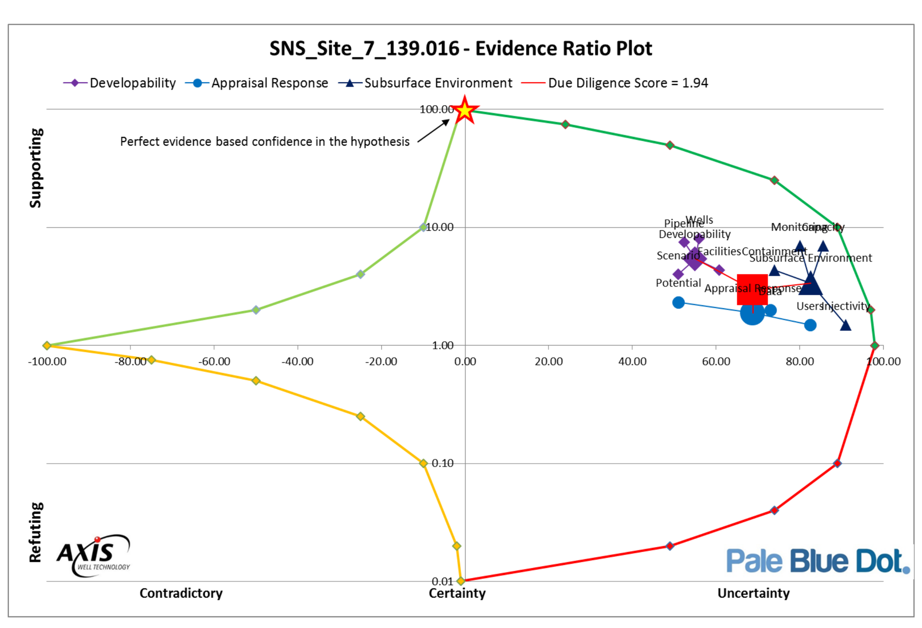
The Georisk factor has been calculated as 6, this is the same as the previously calculated factor in WP3 based on CO2Stored data.

<u>Engineering Risk</u>
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.

Costs

Site Reference:	7	Site Description	Bunter Closure 36
Capacity:	252	Water Depth (m)	75
Concept Cost (£m)	Comparative Development	Ultimate Development	Description
Tonnes Injected (MT)	100	240	Total Stored CO2 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, Templates, ties-Ins,
PM & Eng:	£16.5m	£24.9m	10% of Facilities Costs
Decommissioning:	£71.3m	£130.2m	£10m per NUI, £4m per dry well, £8m per subsea 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 CO2	7.28	5.07	

*These costs are not the full cost of storage as they omit MMV, security instruments, handover to DECC and profit.



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 (75m), wells will need to be drilled by a class 2 (heavy duty) Jack-Up Drilling Unit. Platform well costs are assumed to be £25M per well, resulting in a 5 well development cost of £123.1M.

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.

Site 7 – 139.016 – Bunter Closure 36 - SNS

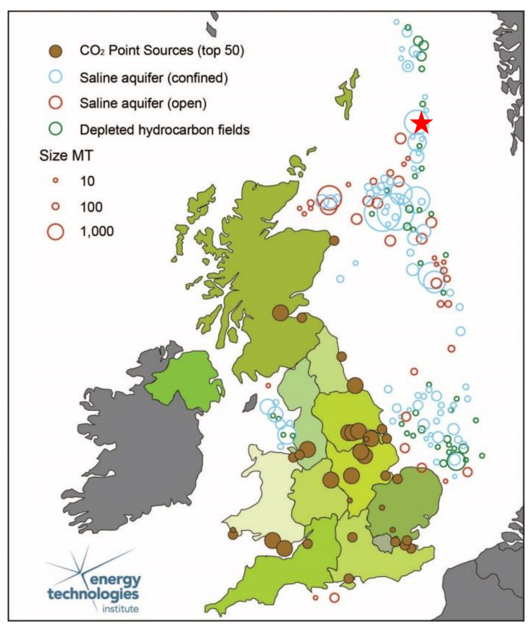
Site Summary			
Capacity (Due Diligence):	252 MT	UKCS Block:	Quad 44; Blocks 26, 27
Unit Designation:	Saline Aquifer	Beachhead:	Barmston
Formation:	Bunter Sandstone	Water Depth:	75 m
Containment Unit:	Rot Halite Member	Reservoir Depth:	840 m TVDSS (2750 ft)
Availability/COP:	n/a	Region:	SNS

Client	The Energy Technologies Institute	Title	D06: Prospect Summary Sheets	Date of Issue	7th August 2015
Project Title	DECC Strategic UK CCS Storage Appraisal Project	Classification	Client Confidential	Version	V00

Strategic UK CCS Storage Appraisal Project

References
1. Furnival, S, Humber Area CCS – 5/42 Storage Site Power Point Presentation

Site 8 – 133.001 – Bruce Gas Condensate Field – CNS



Major offshore areas covered by CO2Stored (© Energy Technologies Institute)

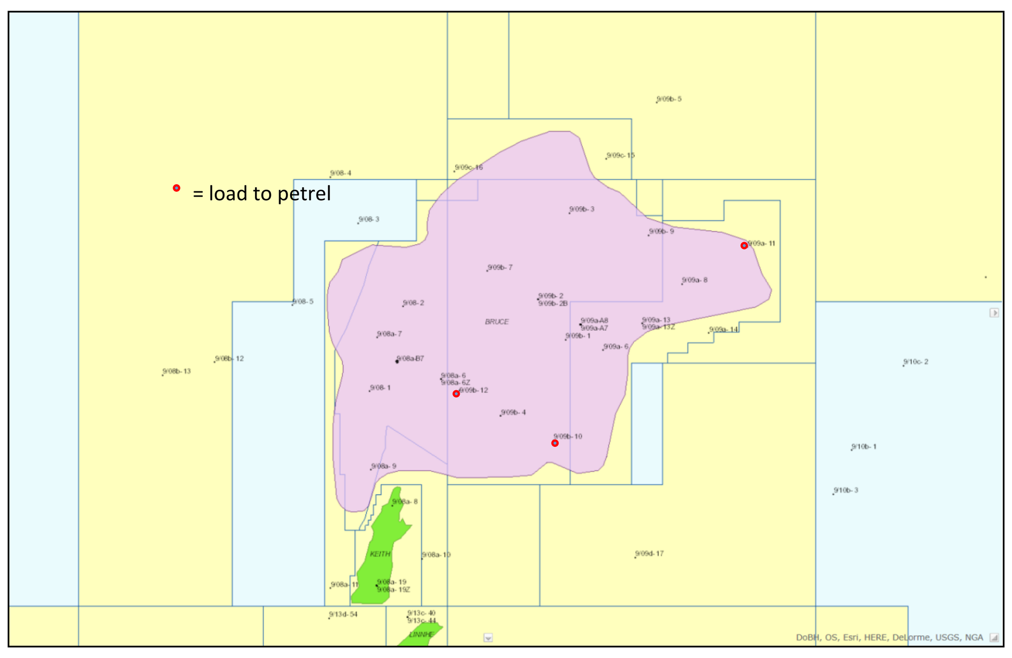


Image source: courtesy of CDA through an open licence agreement

Development Concept

CO2 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.

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.

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. CO2 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. CO2 would be delivered via CO2 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.

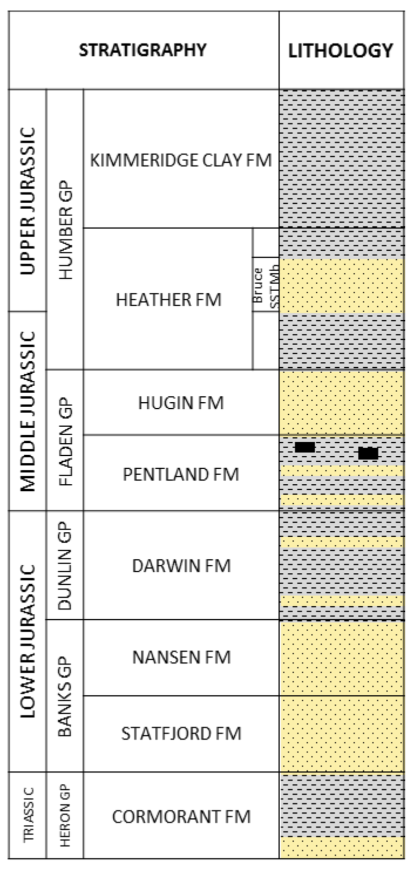


Image source: modified from Evans D, Graham C, Armour A, Bathurst P, The Millennium Atlas, The Geological Society of London 2003

Axis generated Near Top Middle Jurassic depth map (ft tvdss)

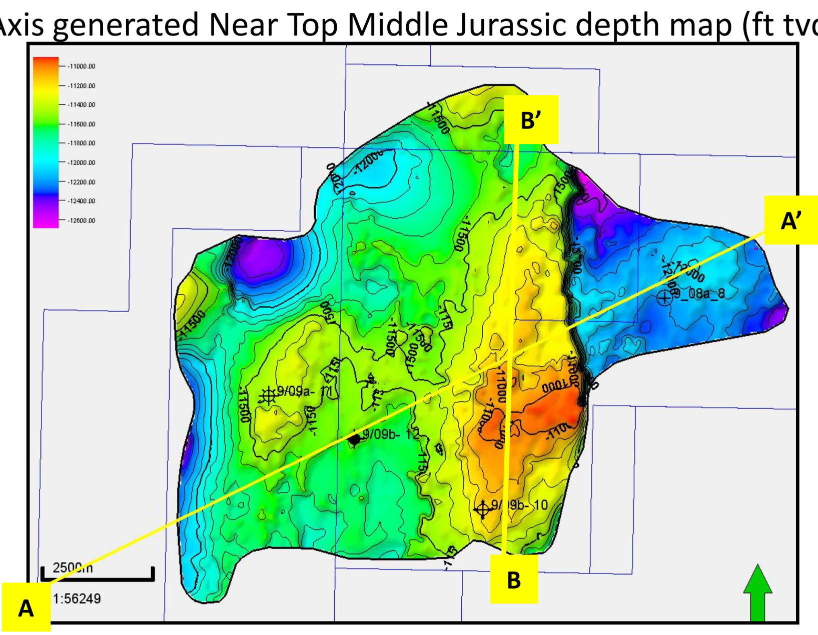


Image source: Original interpretation from Axis Well Technology, 2015

Axis generated Beryl Sands Isochore (ft), generated from well data (9/09a-8, 9/09a-11, 9/09b-10 & 9/09b-12)

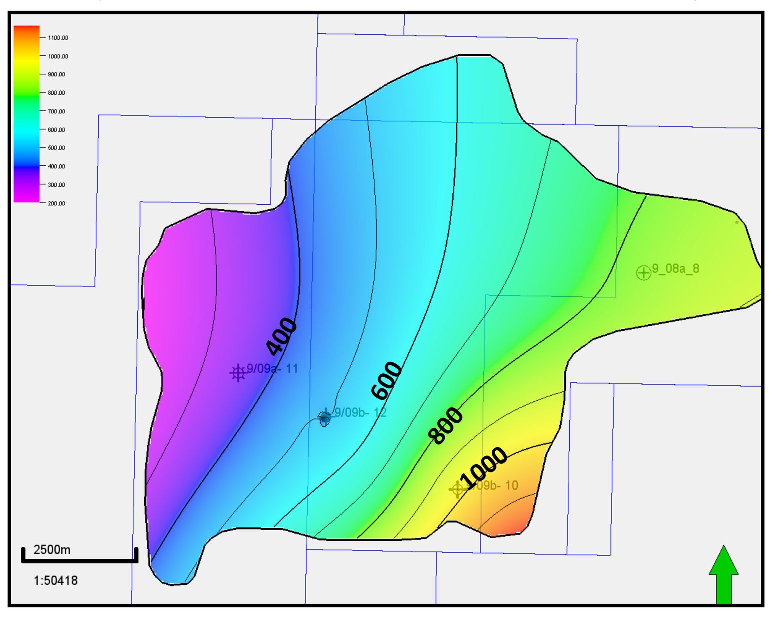


Image source: Original interpretation from Axis Well Technology, 2015

Bruce: Strike line from PGS MegaSurvey

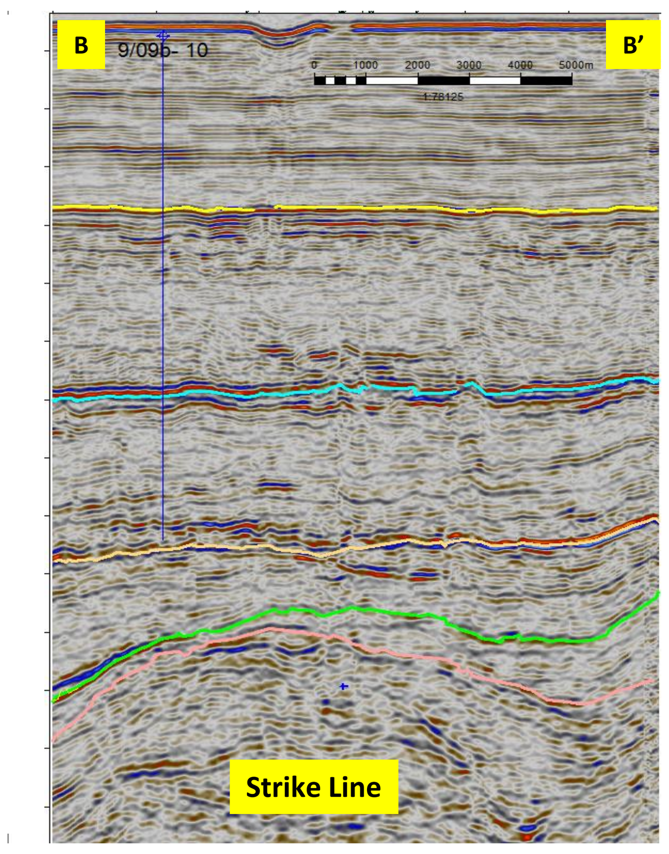


Image source: Seismic data provided by PGS under Licence Agreement. Original interpretation from Axis Well Technology, 2015.

Near Top Grid Sst
Near Top Palaeocene
Near Base Tertiary
Base Cretaceous Unconformity
Near Top Middle Jurassic

Key Risk Summary

Bruce Gas Condensate	Capacity (MT)	Injectivity (mDm)	Engineered Containment			Geo Containment
			Wells /sq.km	Leakage risk	Containment risk	
Selection Criteria	211	36,540	n/a	n/a	n/a	8.0
Due Diligence	188	20,416	0.38	0.06	0.02	8.0

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%).

The produced volumes and conversion to mass storage potential are shown in the Capacity Calculation table .

Bruce: Dip line from PGS Mega Survey

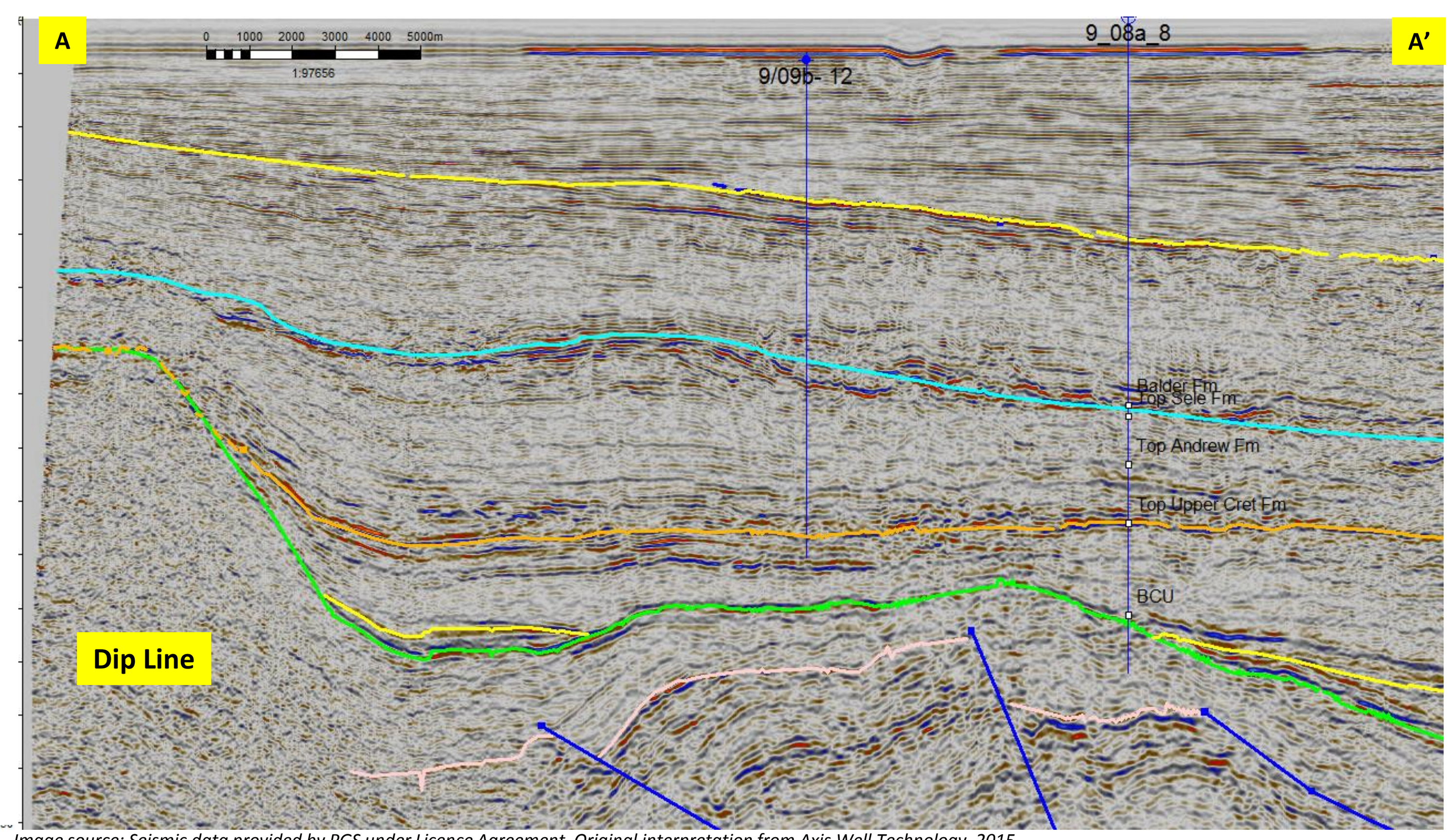


Image source: Seismic data provided by PGS under Licence Agreement. Original interpretation from Axis Well Technology, 2015.

Near Top Grid Sst
Near Top Palaeocene
Near Base Tertiary
Near Top Lower Cretaceous
Base Cretaceous Unconformity
Near Top Middle Jurassic

Capacity Calculation

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

NB. Volumes refer to production volumes at February 2015.

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[1]. A summary of the reservoir properties are summarised in the Injectivity Validation table.

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 indistinguishable[1]. A thin muddy interval exists between B and A sands, with a sharp “flooding event” boundary present between the A sands and Upper Sands[1].
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 CO2 injectivity is expected to be good.

Injectivity Validation

Zone	Depositional Environment	Gross Thickness [m]	NTG	Porosity	Perm [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

Containment Validation

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	
Bruce Gas Condensate Field	133.001	2	2	1	1	1	1	8
		2	2	1	1	1	1	8

Low=1 Medium=2 High=3

2 values in CO2Stored
1 no additional data to qc, values taken from CO2Stored

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.

Costs

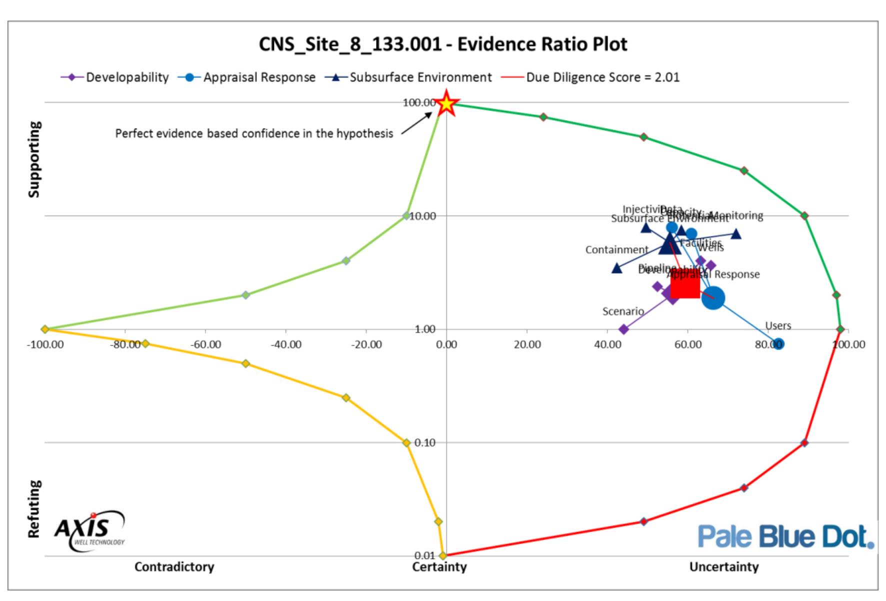
Site Reference:	8	Site Description	Bruce Gas Condensate Field
Capacity:	188	Water Depth (m)	116.4
Concept Cost (£m)	Comparative Development	Ultimate Development	Description
Tonnes Injected (MT)	100	180	Total Stored CO2 for proposed scheme
Appraisal Cost:	£0m	£0m	Appraisal Wells + Seismic Data Acquisition & Interpretation
Development Well Cost:	£410.7m	£739.2m	Drilling & Completion Costs of wells.
Facilities Cost:	£38.1m	£236.8m	Landfall, Pipeline, NUI, Templates, ties-Ins,
PM & Eng:	£3.9m	£23.7m	10% of Facilities Costs
Decommissioning:	£49.6m	£131.2m	£10m per NUI, £4m per dry well, £8m per subsea well
Subtotal	£502m	£1130.8m	
Contingency	£100.4m	£226.2m	20% of Development & Facilities Costs
OPEX (20years)	£45.7m	£284.2m	OPEX Cost for 20 years (6% of facilities costs)
Total:	£648m	£1641.1m	
£/T CO2	6.48	9.12	

*These costs are not the full cost of storage as they omit MMV, security instruments, handover to DECC and profit.

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 CO2.
Field data and published literature[1]1were reviewed to establish the effectiveness of trap and seal. Depth to crest of the reservoir is 3320 m TVDSS (10900ft) with three main reservoir blocks (Western Flank, Central Panel and Eastern High) with the western edge listric fault a significant control on the field[1]. Cross-cutting faults of various orientations are present over the field. A sufficient seal is present that CO2 is not expected to leak out of the field which is already proven.
The Georisk factor has been calculated as 8 is the same as the previous calculated factor in WP3 based on CO2Stored data.

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 was 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.



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 £82M per well, resulting in a 5 well development cost of £410.6M.

Site 8 – 133.001 – Bruce Gas Condensate Field - CNS

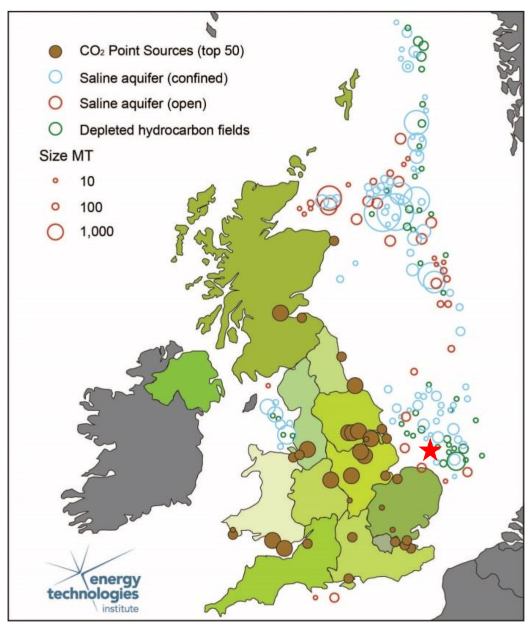
Site Summary			
Capacity (Due Diligence):	188 MT	UKCS Block:	9/9
Unit Designation:	Gas Condensate	Beachhead:	St Fergus
Formation:	Beryl Group Sands	Water Depth:	116.4 m
Containment Unit:	Heather & Kimmeridge Shales	Reservoir Depth:	3320 m TVDSS (10900ft)
Availability/COP:	2023	Region:	CNS

Client	The Energy Technologies Institute	Title	D06: Prospect Summary Sheets	Date of Issue	7th August 2015
Project Title	DECC Strategic UK CCS Storage Appraisal Project	Classification	Client Confidential	Version	V00

Strategic UK CCS Storage Appraisal Project

References
1. Beckly, A., Dodd, C., and Los, A. (1993) “The Bruce Field” Petroleum Geology of Northwest Europe: Proceedings of the 4th Conference (ed. J. R. Parker). Petroleum Geology '86 Ltd., The Geological Society, London, pp. 1453-1463.

Site 9 – 303.001 – Hewett Gas Field (Bunter) – SNS



Major offshore areas covered by CO2Stored (© Energy Technologies Institute)

266.001 Hewett Gas Field – Bunter Shale Fm., Sherwood SST Group

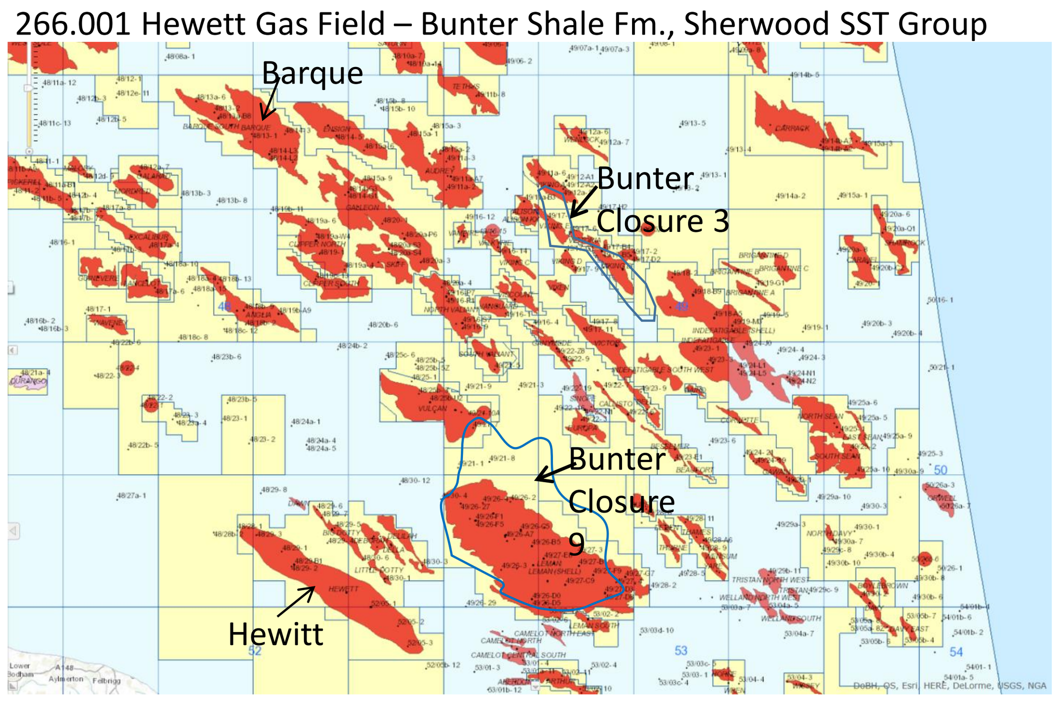


Image source: courtesy of CDA through an open licence agreement

Development Concept

CO2 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.

Build out potential
Hewett is within build-out reach of Viking (310MT) and Bunter Closure 9 (1977MT). The Barque depleted gas field (91MT) is on the likely pipeline route from Barmston. These all represent potential regional growth opportunities.

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. CO2 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. CO2 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 umbilical's.

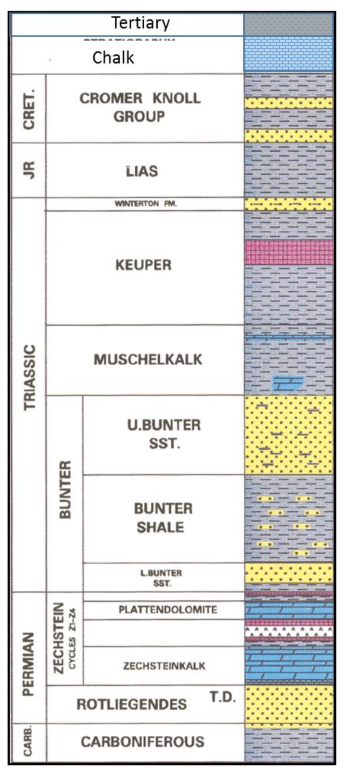


Image source: modified from Cooke-Yarborough (1991) "The Hewett Field, Blocks 48/28-29-30, 52/4a-5a, UK North Sea", *In* Abbotts, I. L. (ed.), 1991, United Kingdom Oil and Gas Fields, 25 Years Commemorative Volume, Geological Society Memoir No. **14**, pp. 433-442.

Axis generated Top Bunter Sst depth map (ft tvdss)

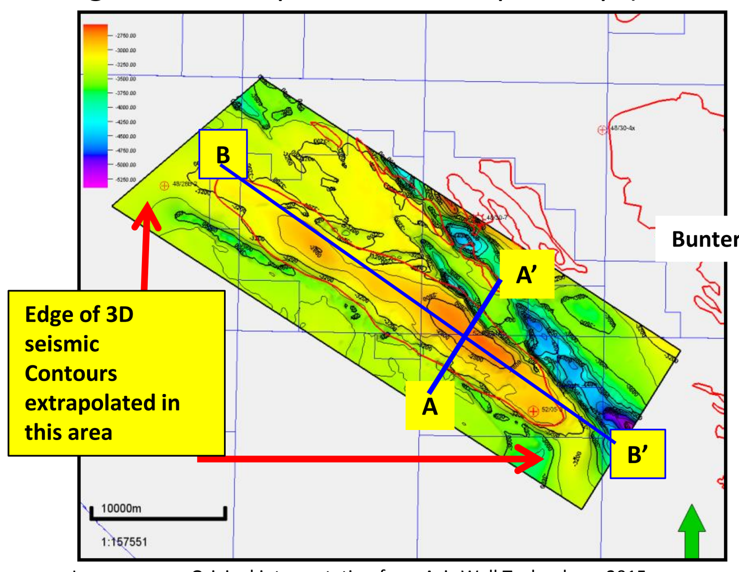


Image source: Original interpretation from Axis Well Technology, 2015

Ci: 200ft

Data

The field is covered by 3D seismic from the PGS SNS MegaSurvey 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 [2].

Axis generated Bunter Sandstone Isochore (ft), generated from well data (48/28b-2 , 48/30-7, 52/5a-A11, 52/05-2&3)

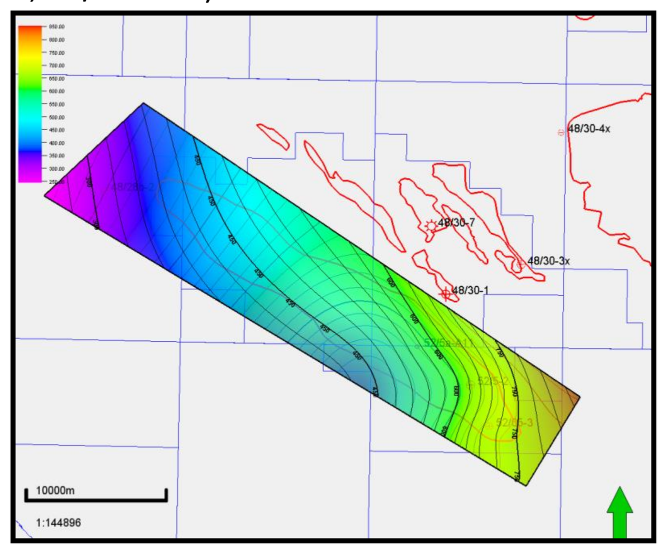


Image source: Original interpretation from Axis Well Technology, 2015

Ci: 50ft

Hewett Field: Strike and Dip seismic lines from PGS MegaSurvey

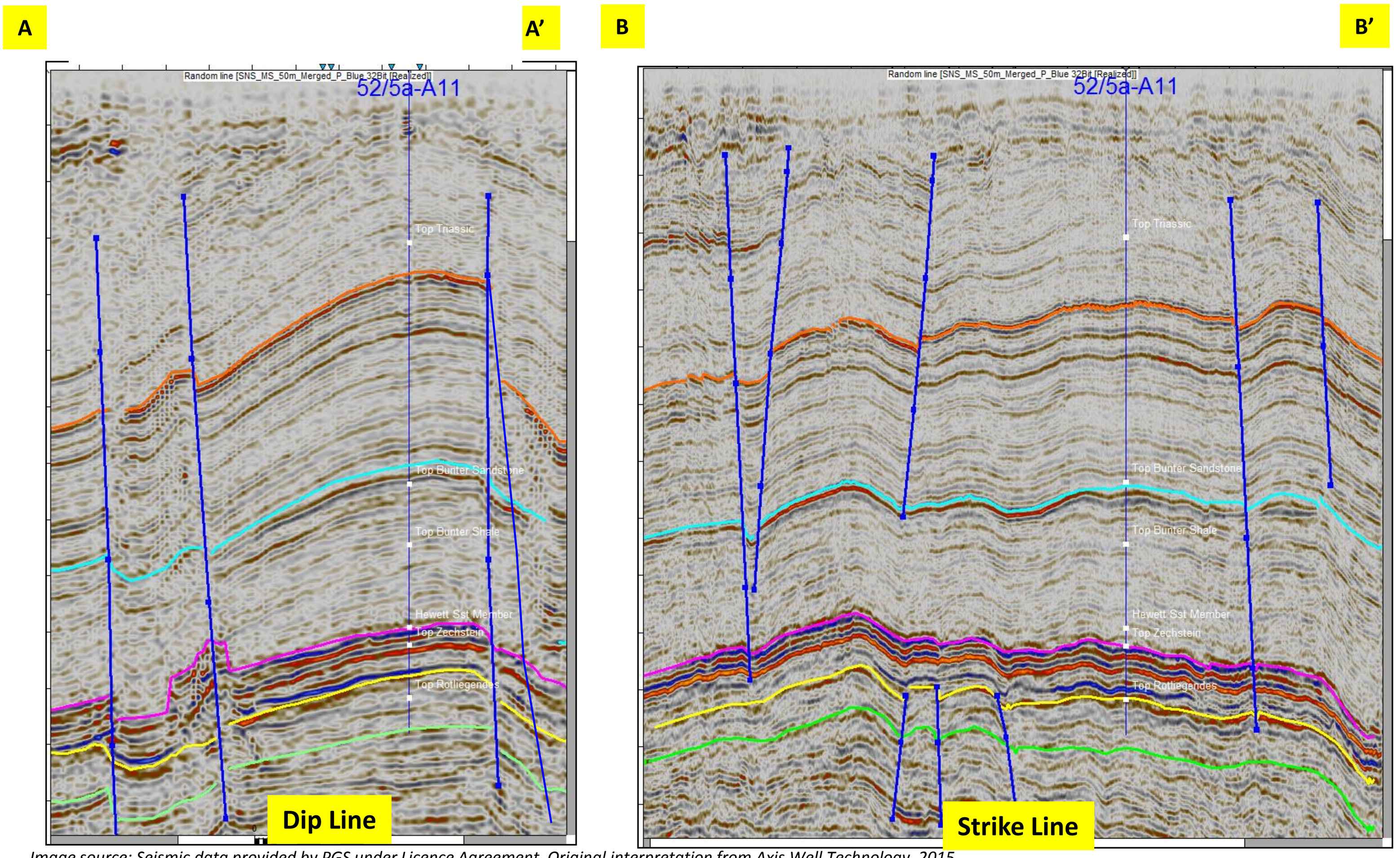


Image source: Seismic data provided by PGS under Licence Agreement. Original interpretation from Axis Well Technology, 2015.

Top Triassic
Top Zechstein
Top Bunter Sandstone
Top Rotliegendes
Near Top Carboniferous

Key Risk Summary

Hewett Gas Field	Capacity (MT)	Injectivity (mDm)	Engineered Containment			Geo Containment
			Wells /sq.km	Leakage risk	Containment risk	
Selection Criteria	205	82,749	0.34	n/a	n/a	8
Due Diligence	288	33,712	0.43	0.09	0.04	10

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).

The produced volumes and conversion to mass storage potential are shown in the table.

Capacity Calculation

Gas Production	46071	MCM
Condensate Production	0.199	MCM
Net Reservoir Volume Produced	475	MCM
Storage Capacity	288	MT

NB. Volumes refer to production volumes at February 2015.

Injectivity Validation

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

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.

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 (publicly available Ref 3). The permeability thickness is still relatively high and similar to the underlying Hewett sandstone (lower Bunter) kh, and based on reservoir quality the initial CO2 injectivity is expected to be excellent.

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 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 Injectivity Validation table.

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). CO2 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.

Containment Validation

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	
Hewett gas field (Bunter)	303.001	2	2	1	1	1	1	8
		2	2	3	1	1	1	10

Low=1 Medium=2 High=3

2 values in CO2Stored
1 no additional data to qc, values taken from CO2Stored

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 CO2.

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 [1].

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.

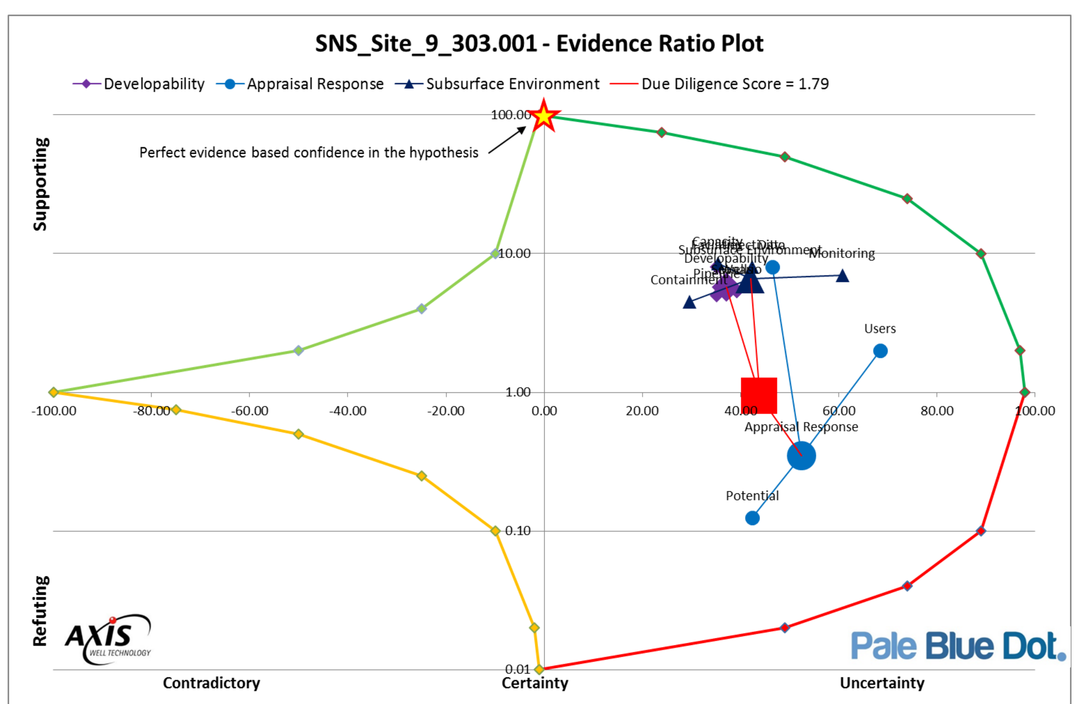
Engineering Risk

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.

Costs

Site Reference:	9	Site Description	Hewett gas field (Bunter)
Capacity:	288	Water Depth (m)	30
Concept Cost (£m)	Comparative Development	Ultimate Development	Description
Tonnes Injected (MT)	100	600	Total Stored CO2 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, Templates, ties-Ins,
PM & Eng:	£29.8m	£68m	10% of Facilities Costs
Decommissioning:	£104.4m	£349.9m	£10m per NUI, £4m per dry well, £8m per subsea 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 CO2	10.12	4.92	

*These costs are not the full cost of storage as they omit MMV, security instruments, handover to DECC and profit.



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 can be drilled by a low cost class 1 Jack-Up Drilling Unit. Platform well costs are assumed to be £23M per well, including a contingency cost for managing CO2 phase change, resulting in a 5 well development cost of £114.1M.

Commercial Issues
Hewett is a depleted gas field. COP is expected to be 2016.

Site 9 – 303.001 - Hewett Gas Field (Bunter) - SNS

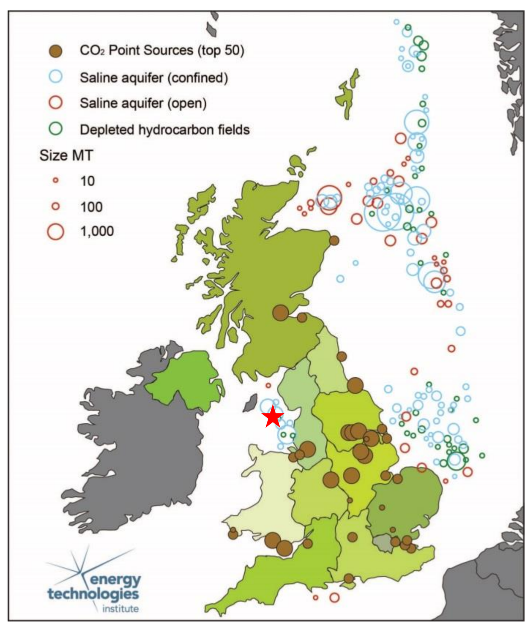
Site Summary			
Capacity (Due Diligence):	288 MT	UKCS Block:	48/29
Unit Designation:	Depleted Gas	Beachhead:	Barmston
Formation:	Bunter Sandstone	Water Depth:	30 m
Containment Unit:	Rot Halite Member	Reservoir Depth:	792 m TVDSS (2600 ft)
Availability/COP:	2016	Region:	SNS

Client	The Energy Technologies Institute	Title	D06: Prospect Summary Sheets	Date of Issue	7th August 2015
Project Title	DECC Strategic UK CCS Storage Appraisal Project	Classification	Client Confidential	Version	V00

Strategic UK CCS Storage Appraisal Project

References
1. Cooke-Yarborough (1991) “The Hewett Field, Blocks 48/28-29-30, 52/4a-5a, UK North Sea”, *In* Abbotts, I. L. (ed.), 1991, United Kingdom Oil and Gas Fields, 25 Years Commemorative Volume, Geological Society Memoir No. **14**, pp. 433-442.
2. IEAGHG Report (2013) “UK FEED Studies 2011 – A summary”. Report 2013/2012. http://www.sacccs.org.za/wp-content/uploads/members2013/2013-12%20UK%20FEED%20Studies%202011%20%20A%20Summary.pdf
3. RDS (2011) “Chapter 7: Technical Design - Wells and Storage” http://webarchive.nationalarchives.gov.uk/20111209170139/https:/www.decc.gov.uk/en/content/cms/emissions/ccs/demo_prog/feed/e_on_feed_/storage/storage.aspx

Site 10 – 248.004 – North Morecambe Gas Field – EIS



Major offshore areas covered by CO2Stored (© Energy Technologies Institute)

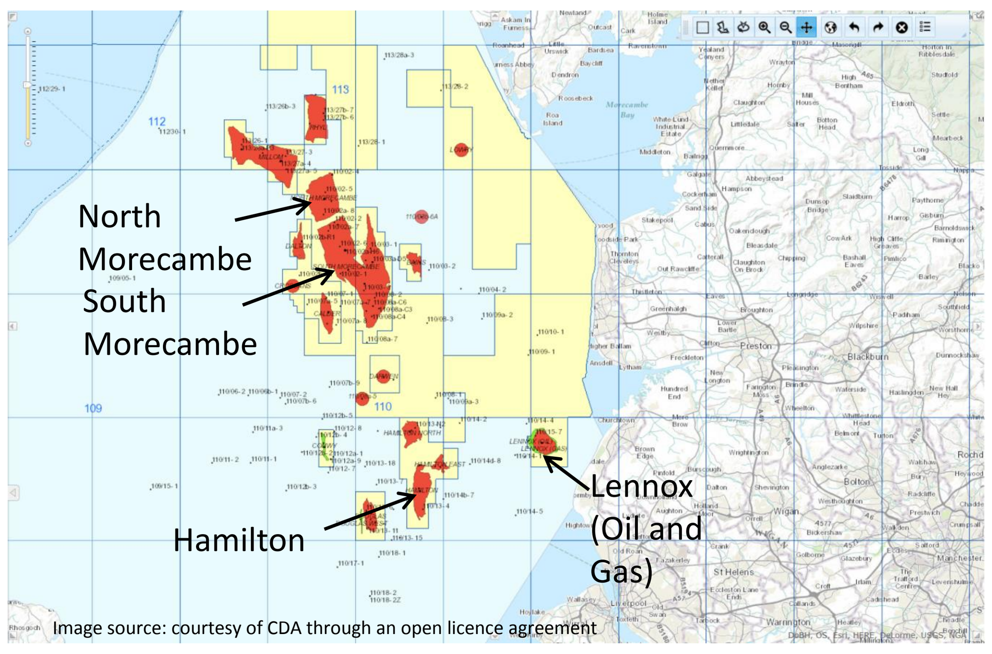


Image source: courtesy of CDA through an open licence agreement

Development Concept

CO2 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 CO2 being stored in the EIS before 2030)

Build out potential
Build out of CO2 storage would be facilitated by the nearby S Morecambe field and Hamilton Fields

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. CO2 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 ~187MT.

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. CO2 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.

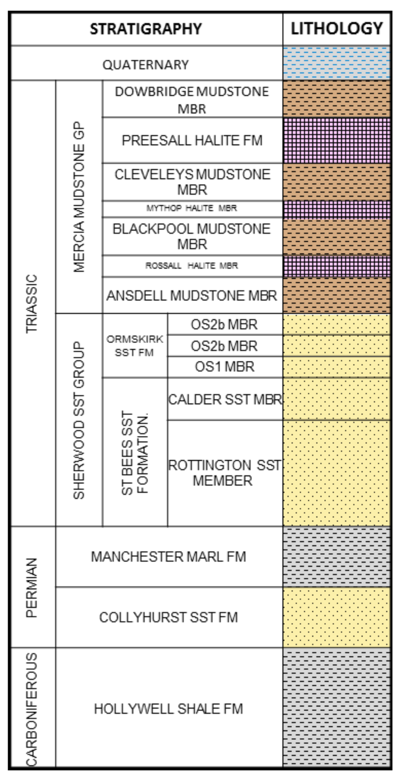


Image source: modified from Yaliz, A. and Taylor, P The Hamilton and Hamilton North Gas Fields, Block 110/13a, East Irish Sea United Kingdom Oil and Gas Fields Commemorative Millennium Volume, The Geological Society of London 2003

AXIS Depth Structure Map: North Morecambe Field: Top Sherwood Sst Fm (ft tvd)

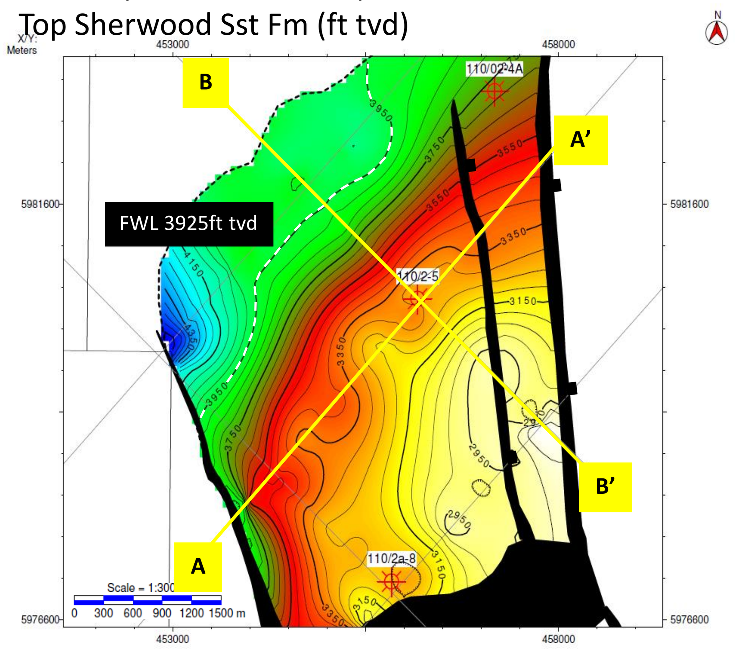


Image source: Original interpretation from Axis Well Technology, 2015

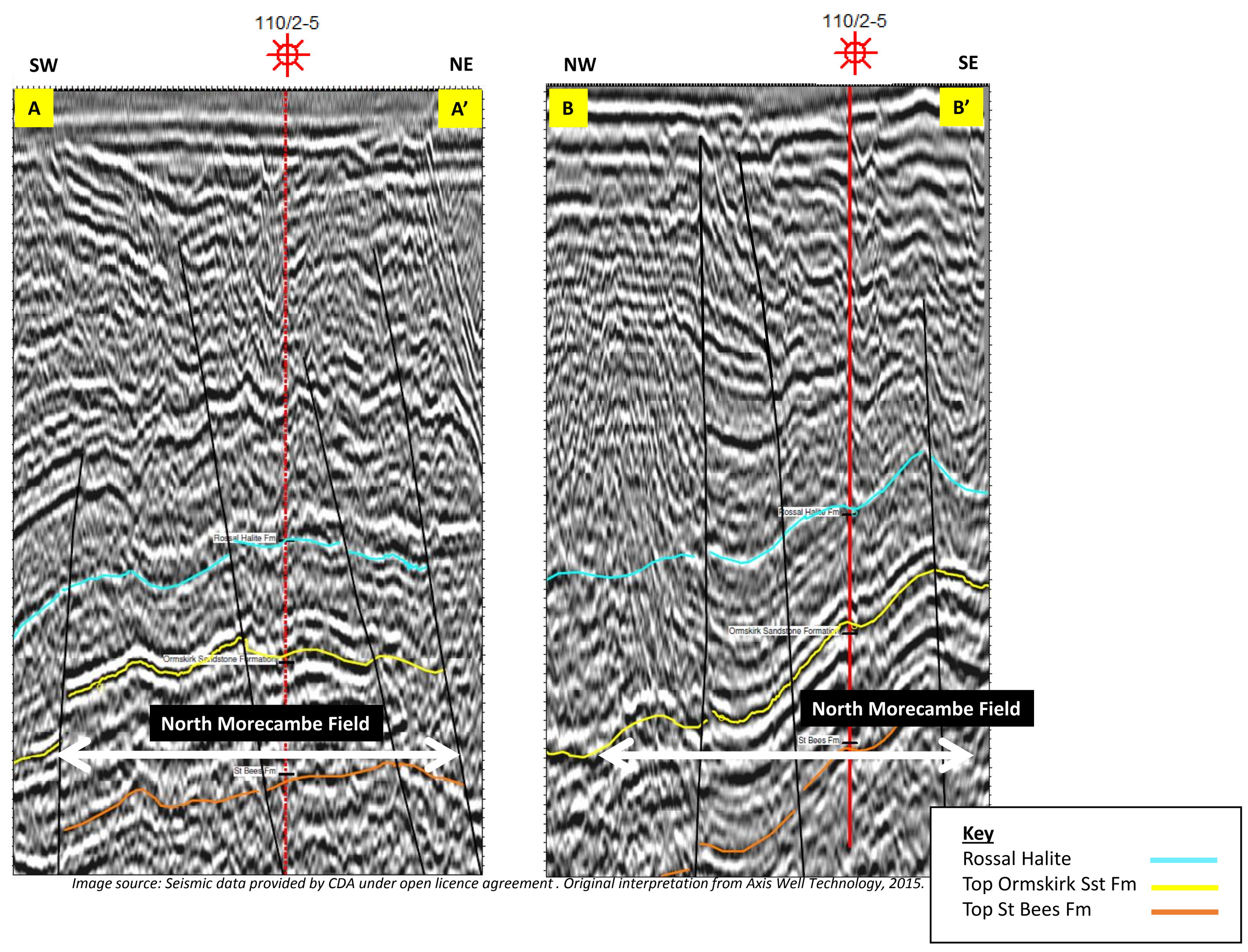


Image source: Seismic data provided by CDA under open licence agreement . Original interpretation from Axis Well Technology, 2015.

Key Risk Summary

North Morecambe Gas Field	Capacity (MT)	Injectivity (mDm)	Engineered Containment			Geo Containment
			Wells /sq.km	Leakage risk	Containment risk	
Selection Criteria	175.3 (P50)	109,728	0.58	n/a	n/a	10
Due Diligence	186.5	44,559	0.12	0.01	0.001	12

Data

There are several different vintages of 2D and 3D seismic survey covering North Morecambe field. Current WP4 evaluation is 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 (at a cost).
Data available in CDA in image format but digital log (LAS) and core data is not available.

Capacity Calculation

Gas Production	33373	MCM
Condensate Production	0.49	MCM
Water Production	0.016	MCM
Net Reservoir Volume Produced	234	MCM
Storage capacity at COP	186.5	MT

NB. Volumes refer to production volumes at February 2015.

Injectivity Validation

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

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%).

Injectivity

The selection criteria used for injectivity is the permeability thickness (Kh) value calculated using the mid case reservoir data from CO2Stored. For the North 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 in the Injectivity Validation table.

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[1].

Additional Injectivity Checks

Two additional injectivity checks were carried out as part of the due diligence.

1. 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.
Early life production data from the 10 production wells is available on the DECC website. CO2 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 CO2 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.
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). CO2 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.

Containment Validation

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	
North Morecambe gas field	248.004	3	2	1	1	1	2	10
		3	2	3	1	1	2	12

Low=1 Medium=2 High=3

2 values in CO2Stored
1 no additional data to qc, values taken from CO2Stored

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 CO2.
Field data and published literature were reviewed to establish the effectiveness of trap and seal. Depth to crest of the reservoir is 900 m[1]. Field is fault closed on three sides and dip-closed to the northwest[1]. Small scale in-field faults are mapped at Top Sherwood 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[1,2]. CO2 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).

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.

Well Design

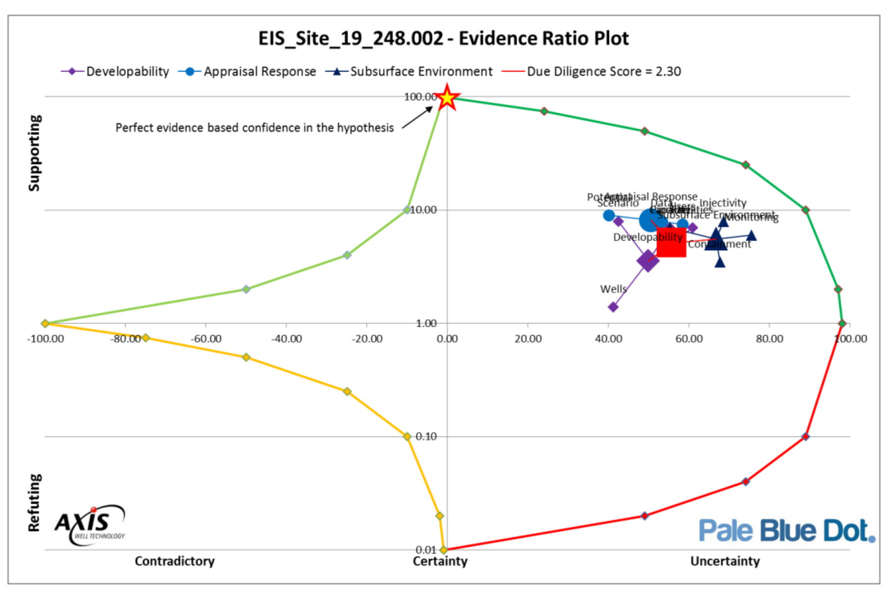
The generic well design is discussed in the supporting document 'Storage Site Due Diligence Summary'. However, the North Morecambe injection wells may depart from the generic design due to the shallow reservoir depth. This suggests that, with restricted build angle and kick-off point, the well may not 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), platform wells can be drilled by a low cost class 1 Jack-Up Drilling Unit. Platform well costs are assumed to be £23M per well, including a contingency cost for managing CO2 phase change, resulting in a 5 well development cost of £112.8M.
North Morecambe contains high levels of CO2 (approx 6%), and due to the corrosive effects a new pipeline had to be installed. The CO2 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 CO2

Costs

Site Reference:	10	Site Description	North Morecambe gas field
Capacity:	186.5	Water Depth (m)	25
Concept Cost (£m)	Comparative Development	Ultimate Development	Description
Tonnes Injected (MT)	100	180	Total Stored CO2 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, Templates, ties-Ins,
PM & Eng:	£15.7m	£21.1m	10% of Facilities Costs
Decommissioning:	£69.1m	£108.8m	£10m per NUI, £4m per dry well, £8m per subsea 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 CO2	6.12	5.03	

*These costs are not the full cost of storage as they omit MMV, security instruments, handover to DECC and profit.



Commercial Issues

Centrica hold the Petroleum Licence for North Morecambe (but without CO2 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 CO2 storage for North Morecambe. COP is 2026.

Site 10 – 248.004 – North Morecambe Gas Field – EIS

Site Summary			
Capacity (Due Diligence):	186.5 MT	UKCS Block:	110/02
Unit Designation:	Depleted Gas	Beachhead:	Point of Ayr
Formation:	Ormskirk Sandstone FM	Water Depth:	25 m
Containment Unit:	Preesall Halite Formation	Reservoir Depth:	900 m TVDSS (2950 ft)
Availability/COP:	2026	Region:	EIS

Client	The Energy Technologies Institute	Title	D06: Prospect Summary Sheets	Date of Issue	7th August 2015
Project Title	DECC Strategic UK CCS Storage Appraisal Project	Classification	Client Confidential	Version	V00

Strategic UK CCS Storage Appraisal Project

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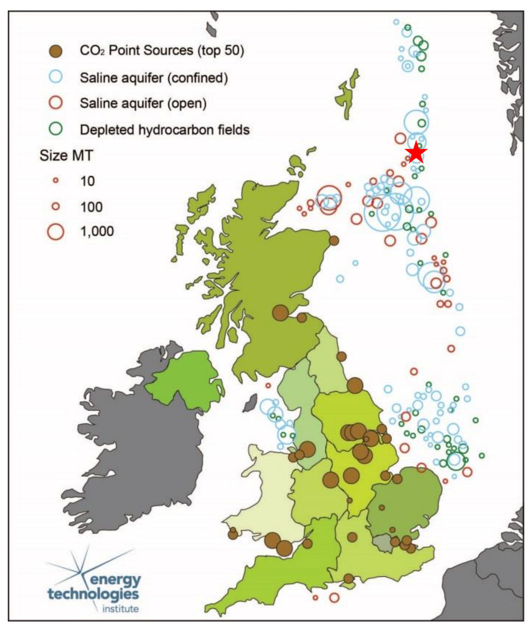
Site 11 – 336.000 – Grid Sandstone Member – CNS



Major offshore areas covered by CO2Stored (© Energy Technologies Institute)

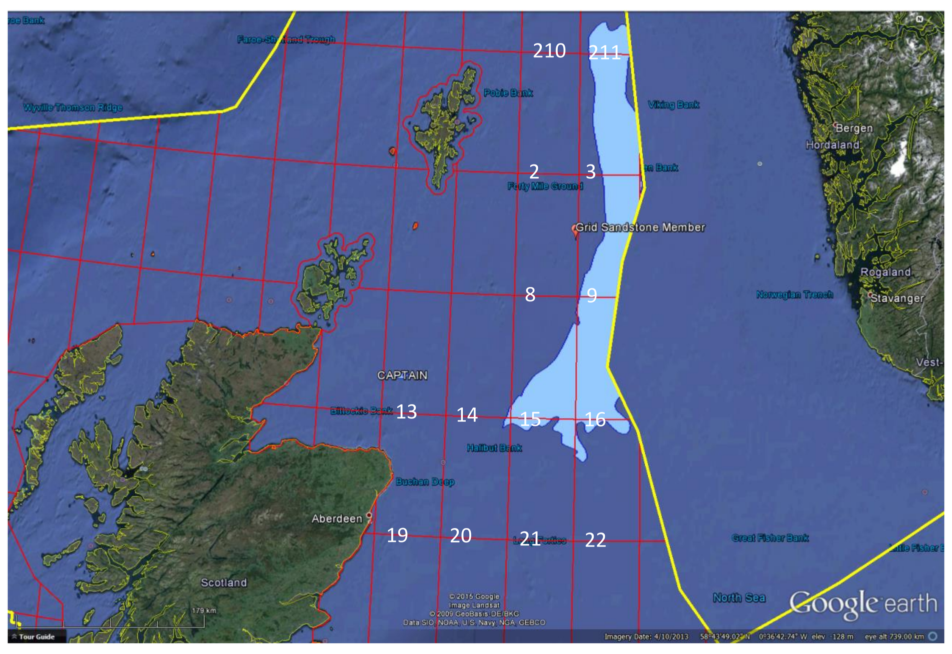


Image source: courtesy of Google Earth

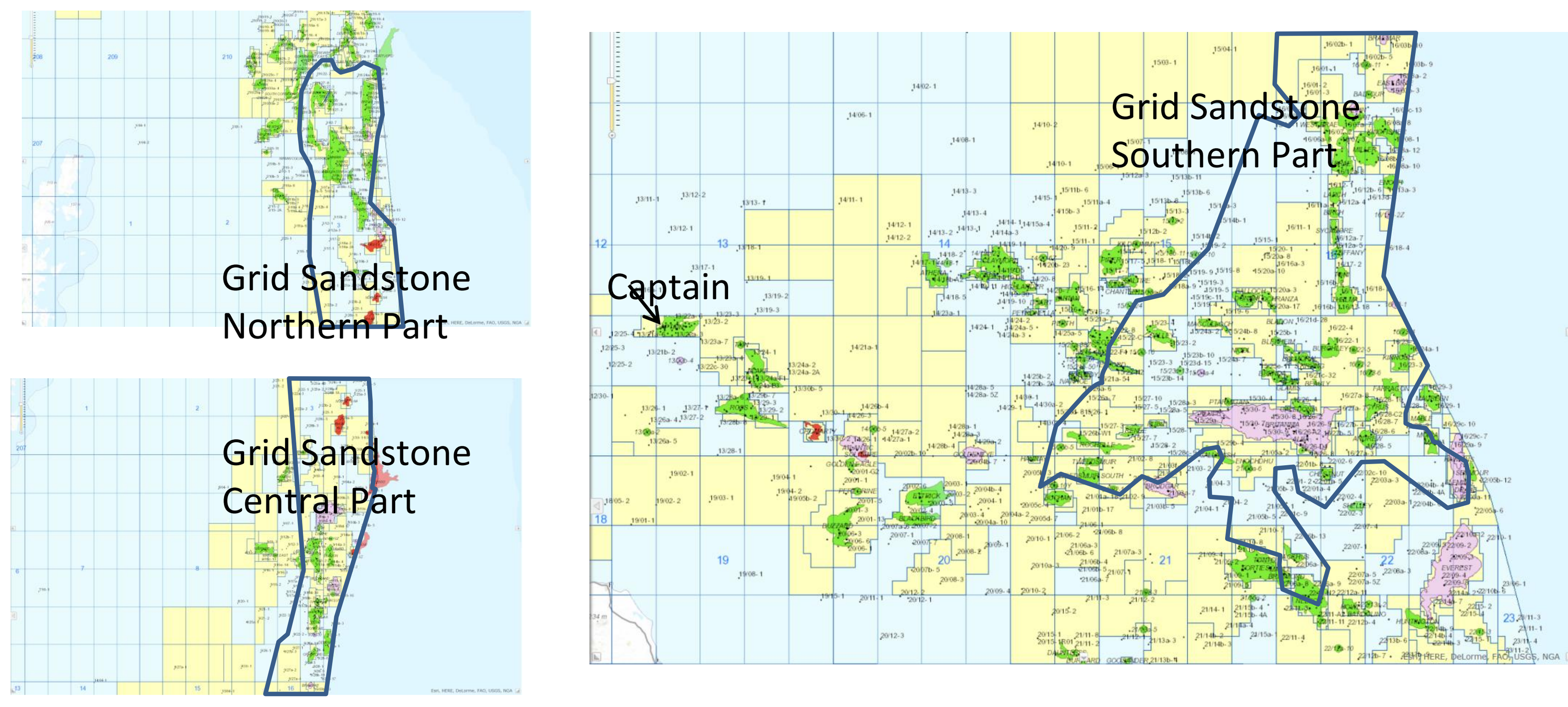


Image source: courtesy of CDA through an open licence agreement

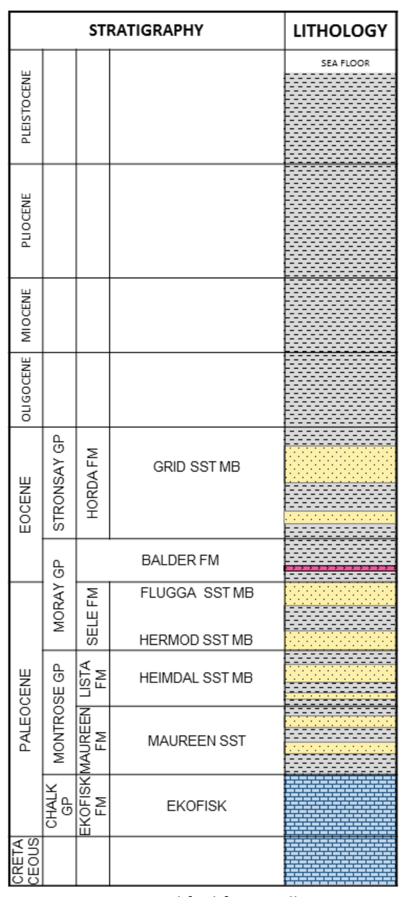


Image source: modified from Wills, J. M., The Forties Field, Block 21/10, 22/6a, UK North Sea. BP Exploration, Fig 2

Axis generated Top Grid Sst depth map (ft tvdss)

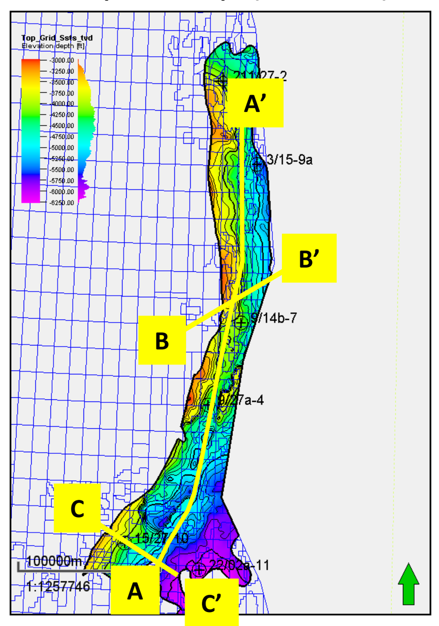


Image source: Original interpretation from Axis Well Technology, 2015

Axis generated Top Grid Sst Isochore (ft), generated from well data (3/15-9a, 9/14b-7, 9/27a-4 & 15/27-10)

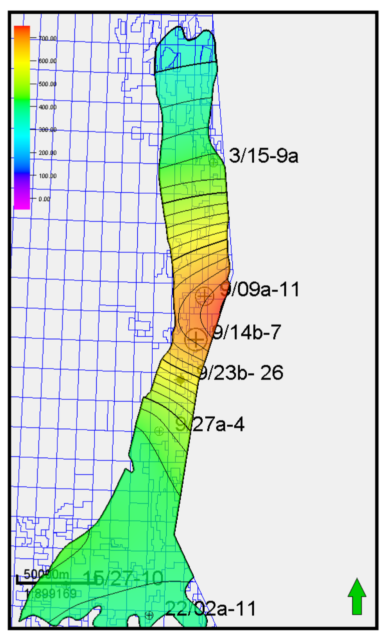


Image source: Original interpretation from Axis Well Technology, 2015

Grid Sst Site: Strike line from PGS MegaSurvey

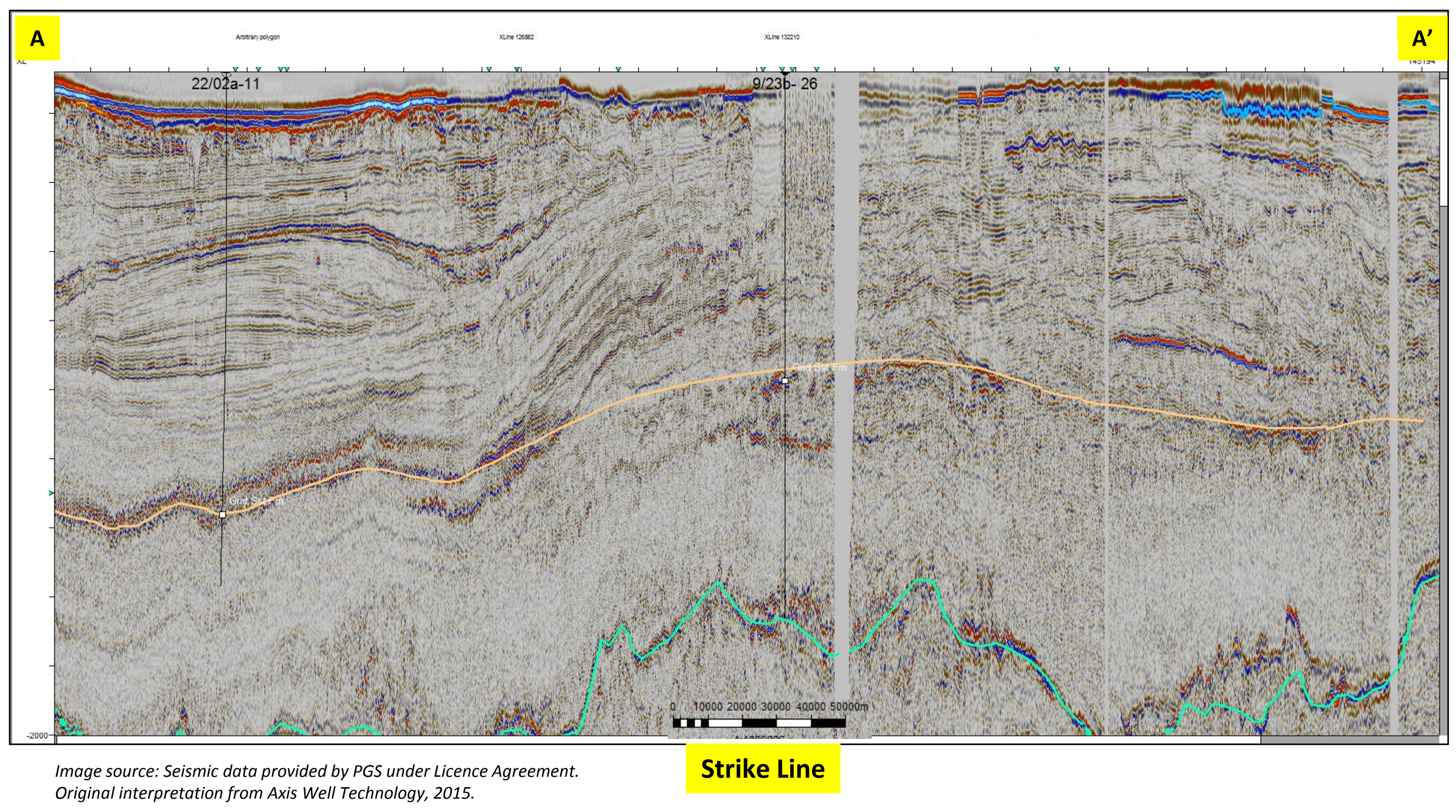


Image source: Seismic data provided by PGS under Licence Agreement. Original interpretation from Axis Well Technology, 2015.

Key Risk Summary

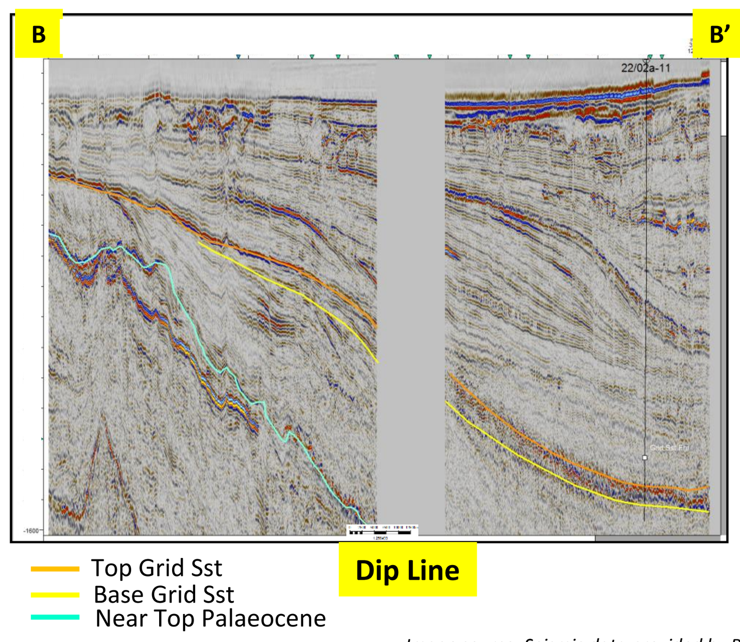
Grid Sandstone Member	Capacity (MT)	Injectivity (mDm)	Engineered Containment			Geo Containment
			Wells /sq.km	Leakage risk	Containment risk	
Selection Criteria	175	612,500	1.96	n/a	n/a	8
Due Diligence	1825	253,500	0.22	0.99	0.22	13

Capacity

The calculated storage capacity is 1825MT compared to the reported capacity in CO2Stored of 175MT. The area (and therefor the volume) reported in CO2Stored appears to be wrong by a factor of 10. The correct area is 16106 km^2.

GRV for the grid sandstone is calculated as polygon area x average thickness.

Grid Sst Site: Dip line 1 from PGS MegaSurvey



Grid Sst Site: Dip line 2 from PGS MegaSurvey

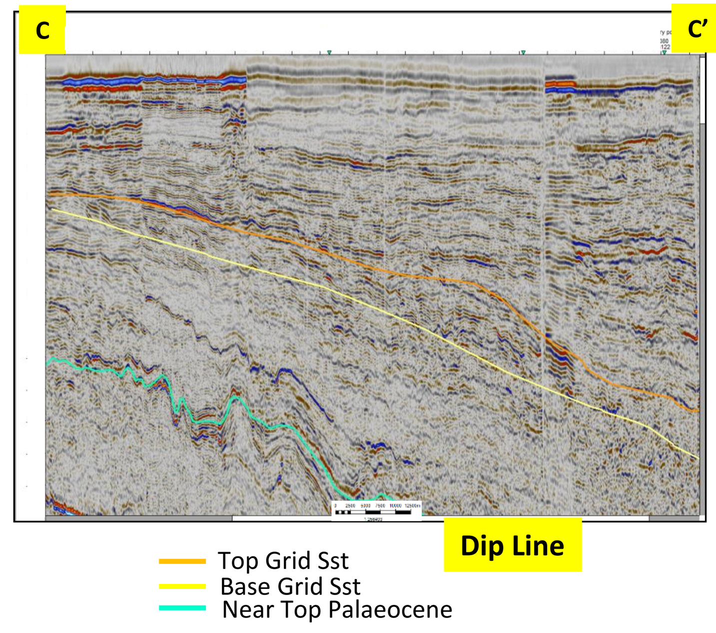


Image source: Seismic data provided by PGS under Licence Agreement. Original interpretation from Axis Well Technology, 2015.

Capacity Calculation

Thickness[2] [m]	GRV [MMm3]	NTG[2]	Porosity[1]	CO2 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

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[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 aquifer comprises high net to gross, excellent to moderate quality[3,5] remobilised[6] sandstones of the Grid Sandstone Member. The sandstone can be divided into two units – the Caran and Brodie sandstones[6]. A summary of the reservoir properties are summarised in the Injectivity Validation table.

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 CO2 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). CO2 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.

Injectivity Validation

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

Development Concept

CO2 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.

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.

Comparative Development Concept
A new subsea development in the vicinity of Miller with 5 deviated wells each injecting 1MT/yr; totalling 100MT over 20 years. CO2 will be delivered through the re-use of 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 ~1825MT; The capacity is constrained to 1000MT for this prospect evaluation stage.

A new subsea development, consisting of 10 drill centres each with 5 wells injecting a total of 50Mt/yr; totalling 1000MT over 20 years. CO2 will be delivered via re-use MGS 36" pipeline from St Fergus with 50MT/yr capacity. Power and controls will be supplied from an existing neighbouring platform or a dedicated facility. Subsea centres are connected by 10km infield pipelines.

Containment Validation

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	
Grid Sandstone Member	336	1	2	1	1	2	1	8
		3	2	1	1	2	3	13

Low=1 Medium=2 High=3

2 values in CO2Stored

1 no additional data to qc, values taken from CO2Stored

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 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.

Costs

Site Reference:	11	Site Description	Grid Sandstone Member
Capacity:	1825	Water Depth (m)	90
Concept Cost (£m)	Comparative Development	Ultimate Development	Description
Tonnes Injected (MT)	100	1000	Total Stored CO2 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	£483.9m	Landfall, Pipeline, NUI, Templates, ties-Ins,
PM & Eng:	£3.9m	£48.4m	10% of Facilities Costs
Decommissioning:	£49.6m	£521m	£10m per NUI, £4m per dry well, £8m per subsea well
Subtotal	£285.1m	£2379m	-
Contingency	£57.1m	£475.8m	20% of Development & Facilities Costs
OPEX (20years)	£45.7m	£580.6m	OPEX Cost for 20 years (6% of facilities costs)
Total:	£387.8m	£3435.3m	
£/T CO2	3.88	3.44	

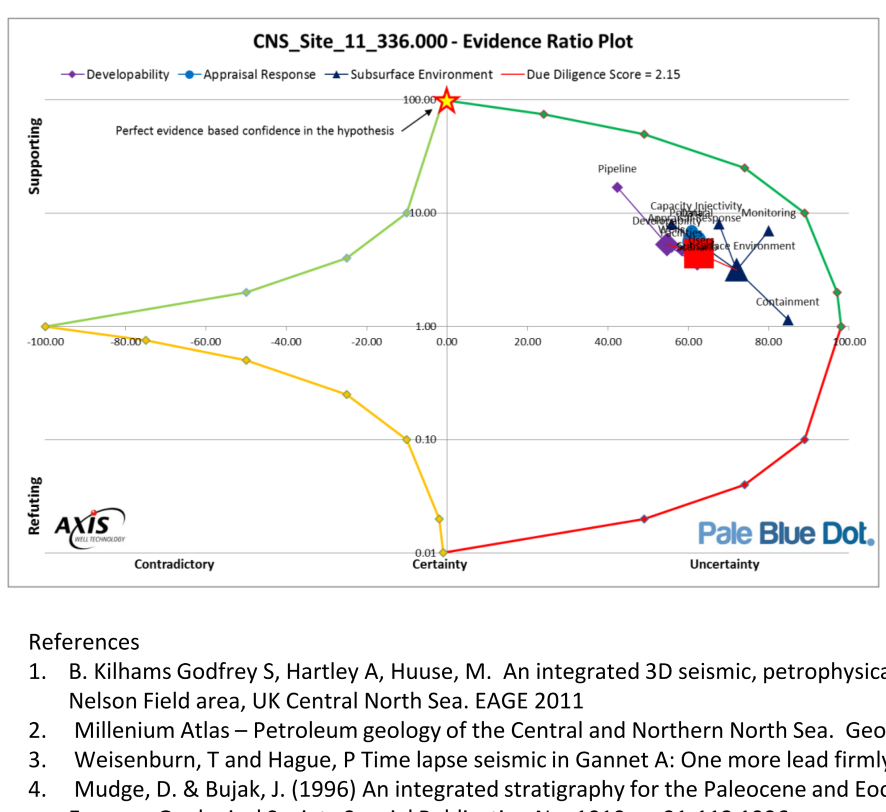
*These costs are not the full cost of storage as they omit MMV, security instruments, handover to DECC and profit.

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 CO2.
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[2].
The Georisk factor has been calculated as 13, 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 MegaSurvey identified extensive polygonal faulting within the Grid Sandstone. Also the western pinchout limit is not always covered by seismic along its entire length.

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.



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.

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 £25M per well, resulting in a 5 well development cost of £125.8M.

Site 11 – 336.000 – Grid Sandstone Member - CNS

Site Summary			
Capacity (Due Diligence):	1825 MT	UKCS Block:	16/7 vicinity
Unit Designation:	Saline Aquifer	Beachhead:	St Fergus
Formation:	Eocene Grid Sandstone Mbr	Water Depth:	90m
Containment Unit:	Horda Formation	Reservoir Depth:	908 m TVDSS (2981 ft)
Availability/COP:	n/a	Region:	CNS

Client	The Energy Technologies Institute	Title	D06: Prospect Summary Sheets	Date of Issue	7th August 2015
Project Title	DECC Strategic UK CCS Storage Appraisal Project	Classification	Client Confidential	Version	V00

Strategic UK CCS Storage Appraisal Project

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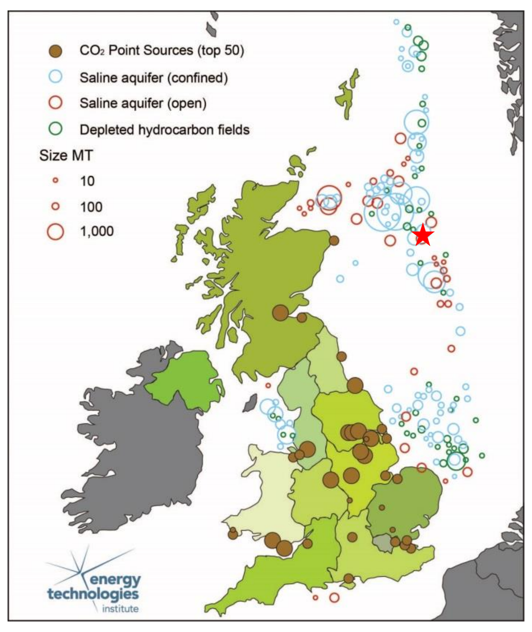
2. Millenium Atlas – Petroleum geology of the Central and Northern North Sea. Geological Society of London 2003
3. Weisenburn, T and Hague, P Time lapse seismic in Gannet A: One more lead firmly integrated. The Leading Edge January 2005
4. Mudge, D. & Bujak, J. (1996) An integrated stratigraphy for the Paleocene and Eocene of the North Sea. From Correlation of the Early Paleogene in Northwest Europe. Geological Society Special Publication No. 1010, pp91-113 1996
5. Robertson, Jenna (2013) Overpressure and Lateral Drainage in the Palaeogene Strata of the CentralNorth Sea, Durham theses, Durham University. Available at Durham E-Theses Online: http://etheses.dur.ac.uk/9452/

Site 12 – 361.000 – Mey 1 – CNS



Major offshore areas covered by CO2Stored (© Energy Technologies Institute)

361.000 Mey 1 – Mey SST Mbr., Lista Fm., Montrose Group

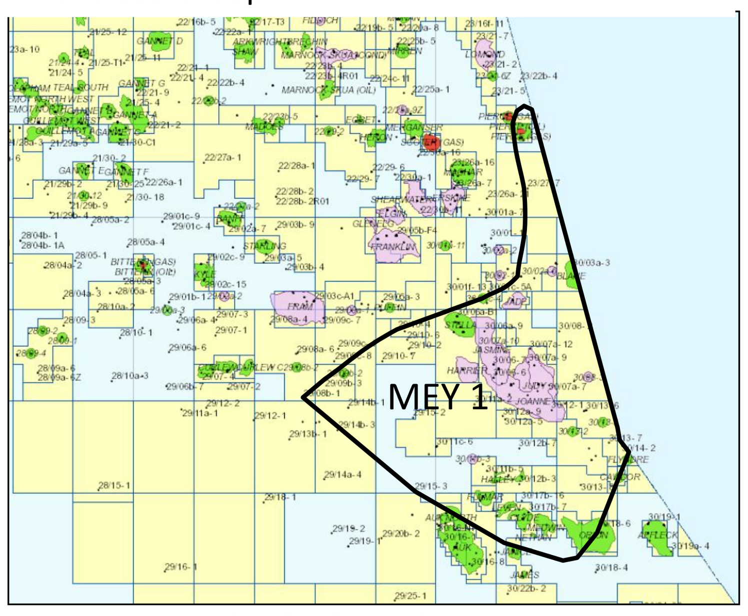


Image source: courtesy of CDA through an open licence agreement

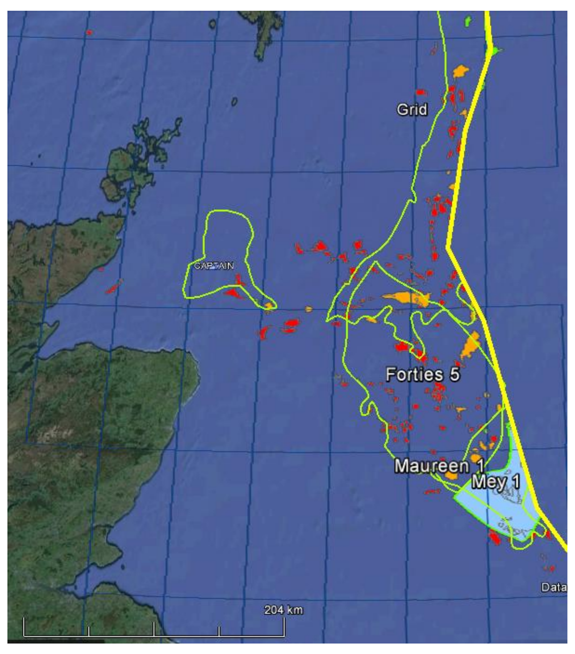
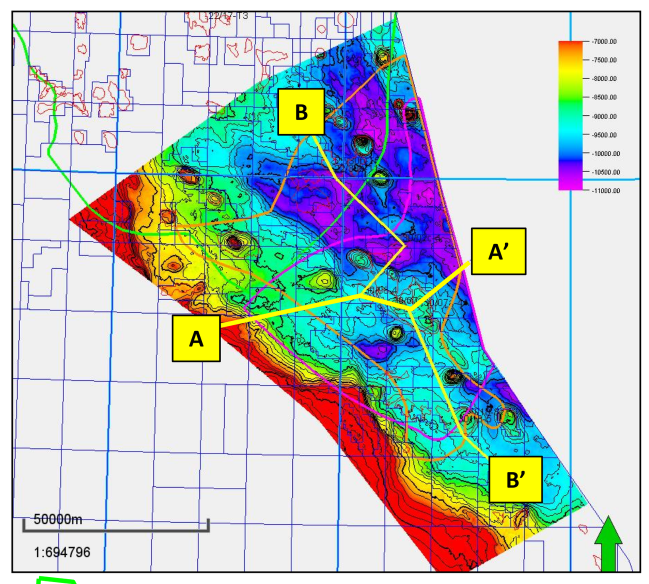


Image source: courtesy of Google Earth

Axis generated Near Top Palaeocene depth map (ft)



Forties 5 CO2Stored outline

Mey 1 CO2Stored outline

Maureen 1 CO2Stored outline

Ci: 250ft

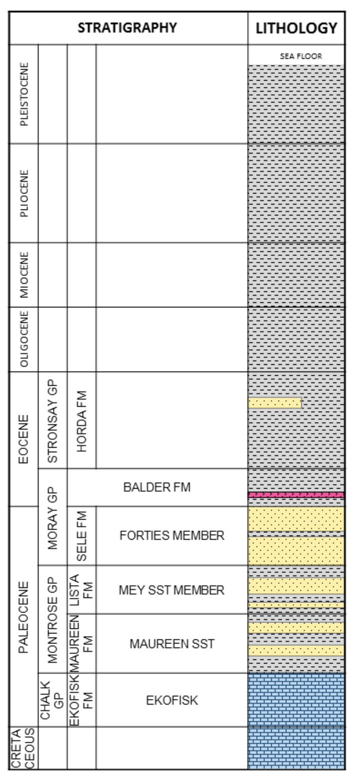
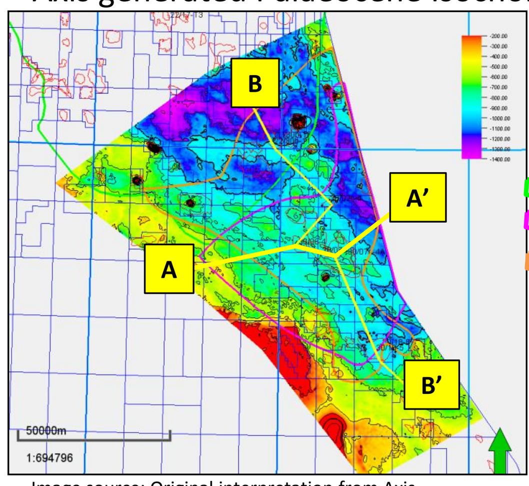


Image source: modified from Wills, J. M., The Forties Field, Block 21/10, 22/6a, UK North Sea. BP Exploration, Fig 2

Axis generated Palaeocene Isochore (ft)



Forties 5 CO2Stored outline

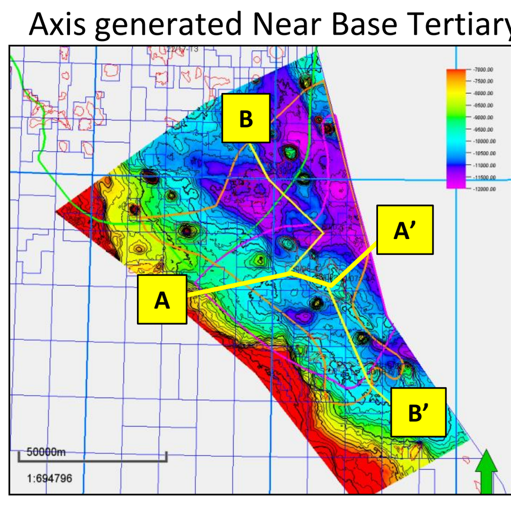
Mey 1 CO2Stored outline

Maureen 1 CO2Stored outline

Image source: Original interpretation from Axis Well Technology, 2015

Ci: 200ft

Axis generated Near Base Tertiary depth map (ft)



Forties 5 CO2Stored outline

Mey 1 CO2Stored outline

Maureen 1 CO2Stored outline

Image source: Original interpretation from Axis Well Technology, 2015

Ci: 250ft

Random Dip seismic lines across the Maureen 1 and Mey 1 saline aquifers

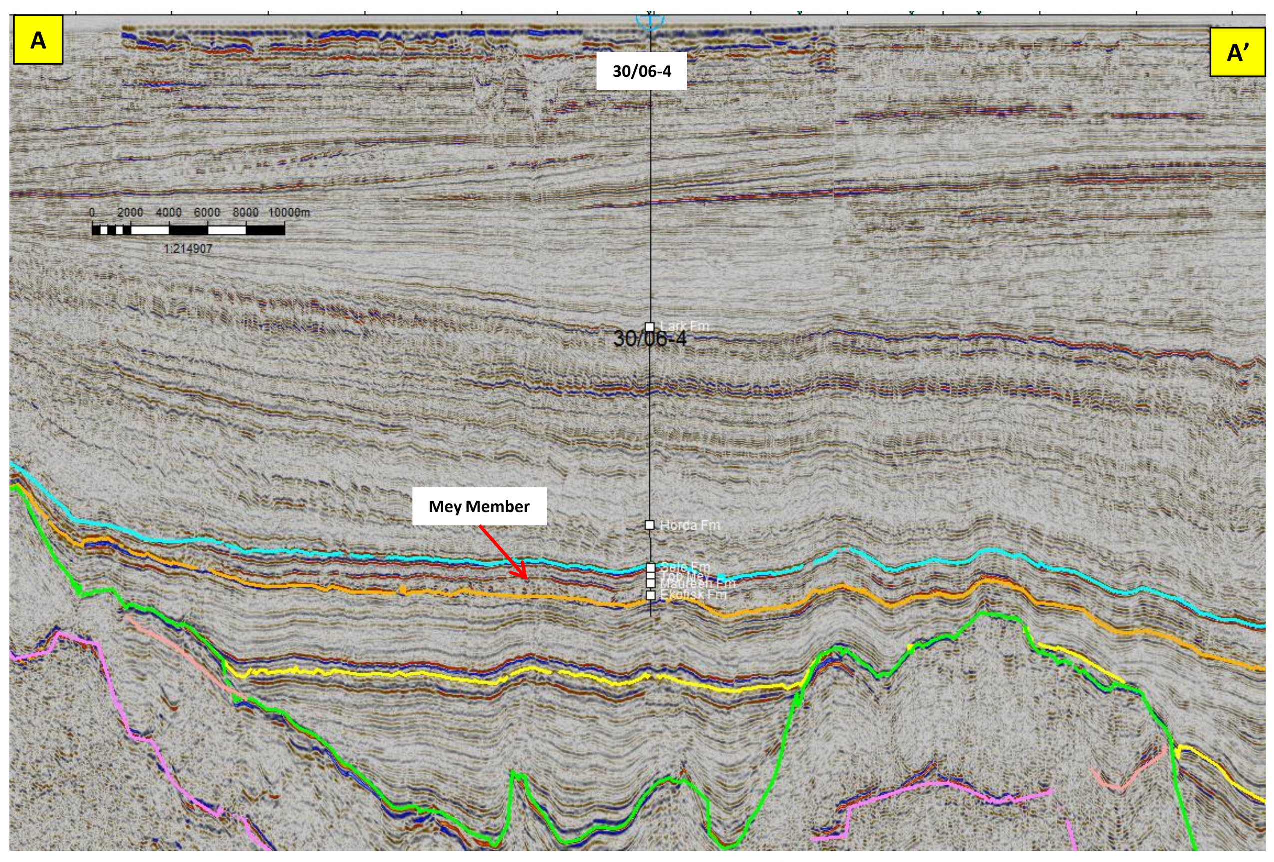


Image source: Seismic data provided by PGS under Licence Agreement. Original interpretation from Axis Well Technology, 2015.

Near Top Palaeocene
Near Base Tertiary
Near Top Lower Cretaceous
Base Cretaceous Unconformity
Near Top Middle Jurassic
Near Top Permian

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 time interpretation, 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 porosity/permeability 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

Key Risk Summary

Mey 1 Aquifer	Capacity (MT)	Injectivity (mDm)	Engineered Containment			Geo Containment
			Wells /sq.km	Leakage risk	Containment risk	
Selection Criteria	174	48,906	0.12	n/a	n/a	13
Due Diligence	22	1,125	0.07	0.45	0.033	13

Capacity Calculation

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

NB. 1: Analogue field 2: Estimated from CDA composite logs 3: CO2Stored

Injectivity Validation

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

NB. 1: Analogue field 2: Estimated from CDA composite logs 3: CO2Stored

Containment Validation

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	
Mey 1	361	3	3	2	1	2	2	13
		3	3	2	1	2	2	13

Low=1 Medium=2 High=3

2 values in CO2Stored

1 no additional data to qc, values taken from CO2Stored

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.

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

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[1].
Thin bedded turbidites, as are seen at the southern end of the Mey system, also show poorer porosity/ perm eabilitycharacteristics 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[2].

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 frac 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.

Random Strike seismic line along the Maureen 1 and Mey 1 saline aquifers

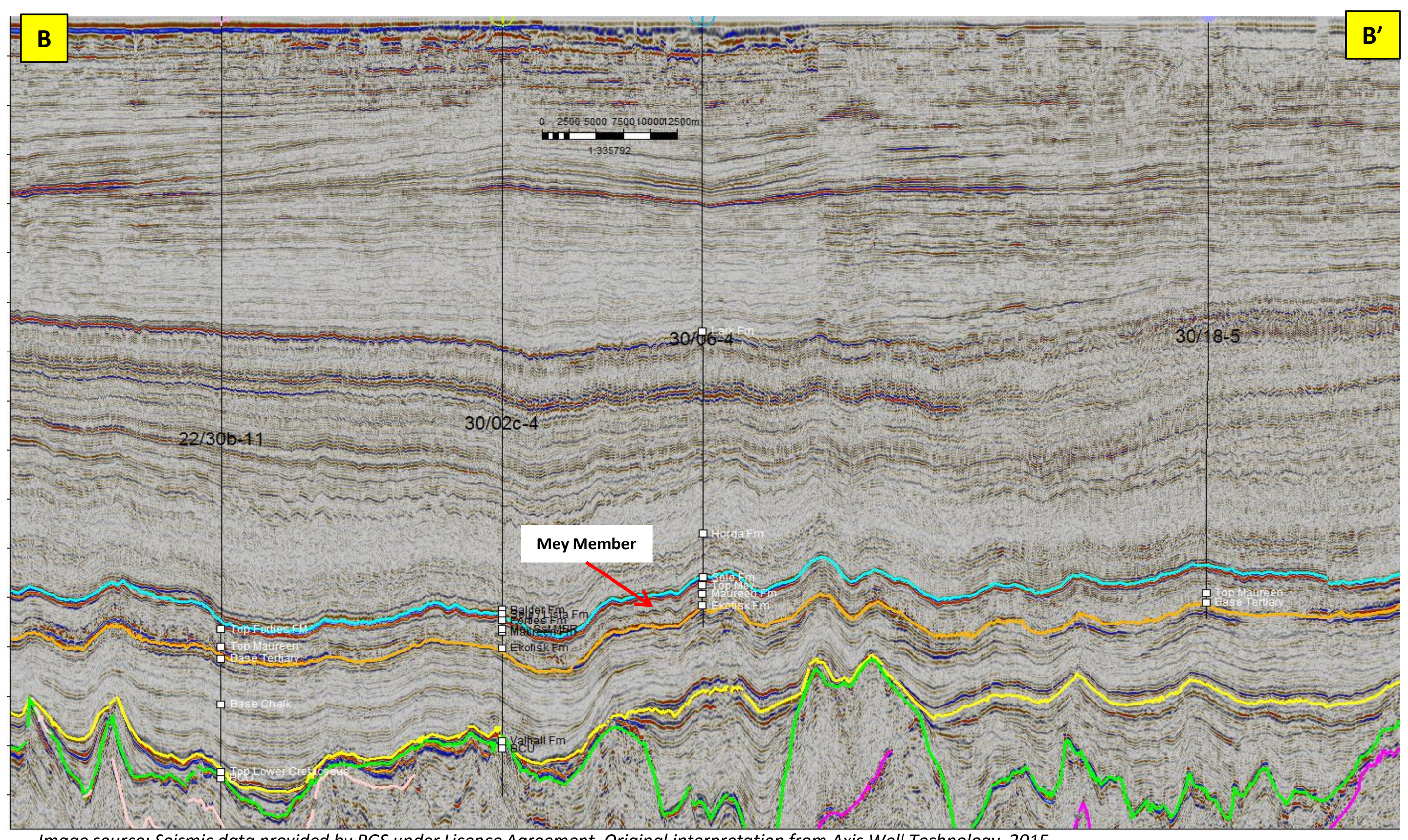


Image source: Seismic data provided by PGS under Licence Agreement. Original interpretation from Axis Well Technology, 2015.

Near Top Palaeocene
Near Base Tertiary
Near Top Lower Cretaceous
Base Cretaceous Unconformity
Near Top Middle Jurassic
Near Top Permian

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 CO2.

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.

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 CO2 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.

Development Concept

CO2 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.

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.

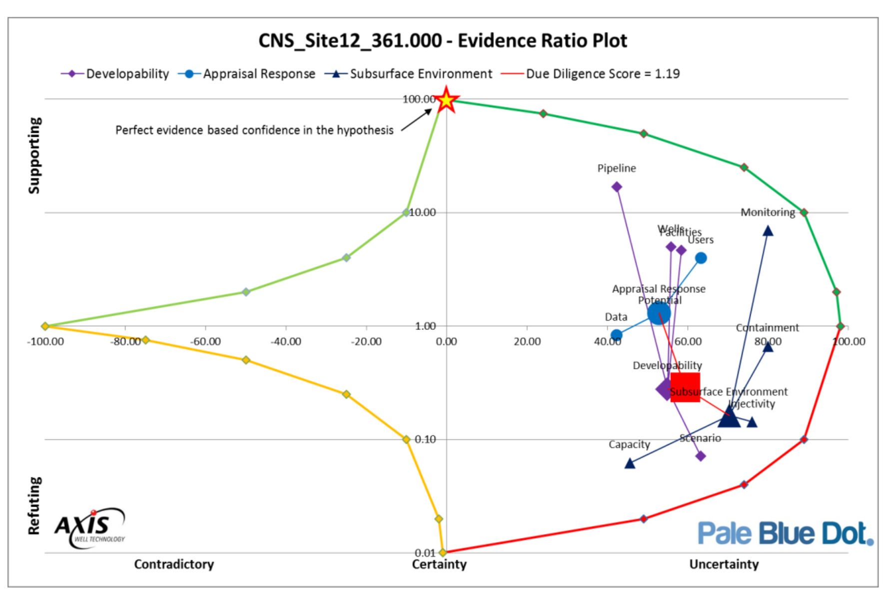
Comparative Development Concept
A new subsea development consisting of a single well injecting 1MT/yr; totalling 20MT over 20 years. CO2 will be delivered via a new 322 km pipeline from St Fergus. Power and controls will be supplied from an existing neighbouring platform. Monitoring will include downhole pressure and distributed temperature sensors.

Site growth potential; theoretical Ultimate Development Concept
The site has a theoretical storage capacity of ~22MT.
The site has no additional growth potential

Costs

Site Reference:	12	Site Description	Mey 1
Capacity:	22	Water Depth (m)	70
Concept Cost (£m)	Comparative Development	Ultimate Development	Description
Tonnes Injected (MT)	20		Total Stored CO2 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, NUI, Templates, ties-Ins,
PM & Eng:	£37.9m		10% of Facilities Costs
Decommissioning:	£102.7m		£10m per NUI, £4m per dry well, £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 CO2	61.20		

*These costs are not the full cost of storage as they omit MMV, security instruments, handover to DECC and profit.



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.

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 £200M.)

References
1. Ahmadi, Z. M., Sawyers, M., Kenyon-Roberts, S., Stanworth, C. W., Kugler, K.A., Kristensen, J. and Fugelli, E. M. G. 2003. Palaeocene. *In:* Evans, D., Graham,
2. C., Armour, A. and Bathurst, P. (eds) *The Millennium Atlas: petroleum geology of the Central and Northern North Sea*. The Geological Society London, p. 235-259

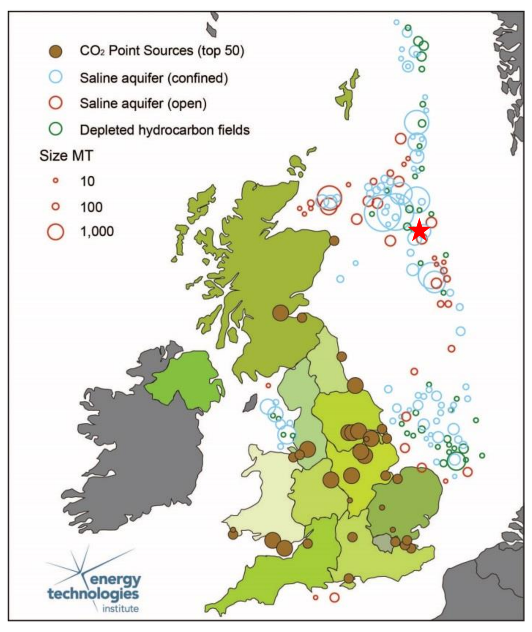
Site 12 – 361.000 – Mey 1 - CNS

Site Summary			
Capacity (Due Diligence):	22 MT	UKCS Block:	30/6 vicinity
Unit Designation:	Saline Aquifer	Beachhead:	St Fergus
Formation:	Heidmal Member	Water Depth:	70 m
Containment Unit:	Horda Formation	Reservoir Depth:	2805 TVDSS (9200 ft)
Availability/COP:	n/a	Region:	CNS

Client	The Energy Technologies Institute	Title	D06: Prospect Summary Sheets	Date of Issue	7th August 2015
Project Title	DECC Strategic UK CCS Storage Appraisal Project	Classification	Client Confidential	Version	V00

Strategic UK CCS Storage Appraisal Project

Site 13 – 366.000 – Maureen 1 – CNS



Major offshore areas covered by CO2Stored (© Energy Technologies Institute)

366.000 Maureen 1 – Maureen Fm., Montrose Group

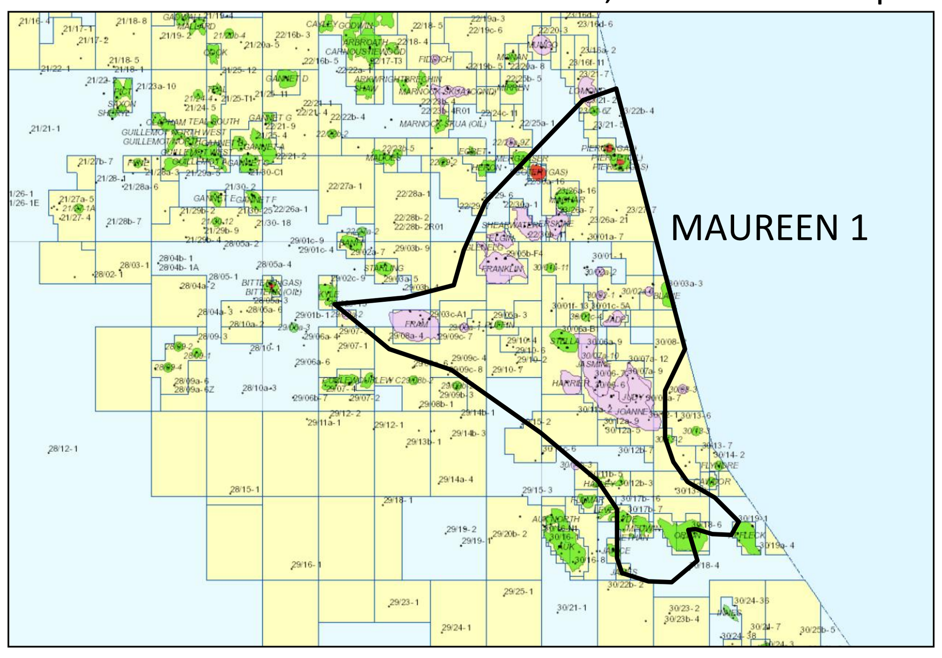


Image source: courtesy of CDA through an open licence agreement

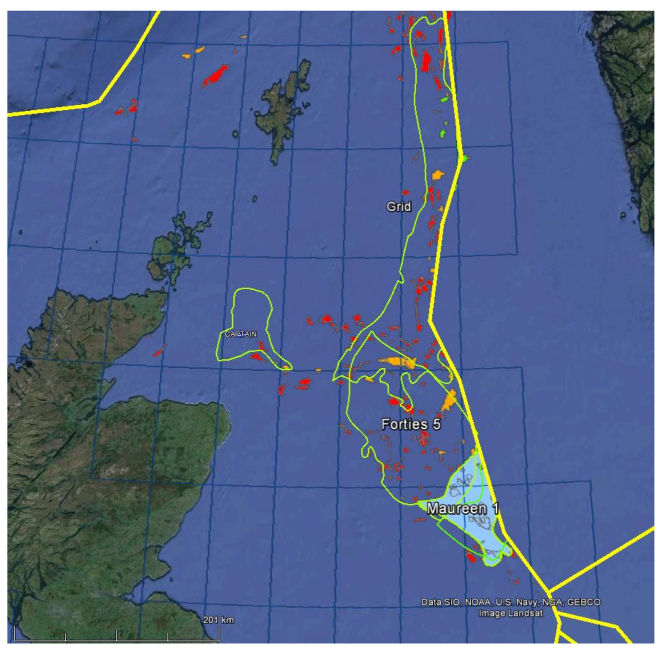
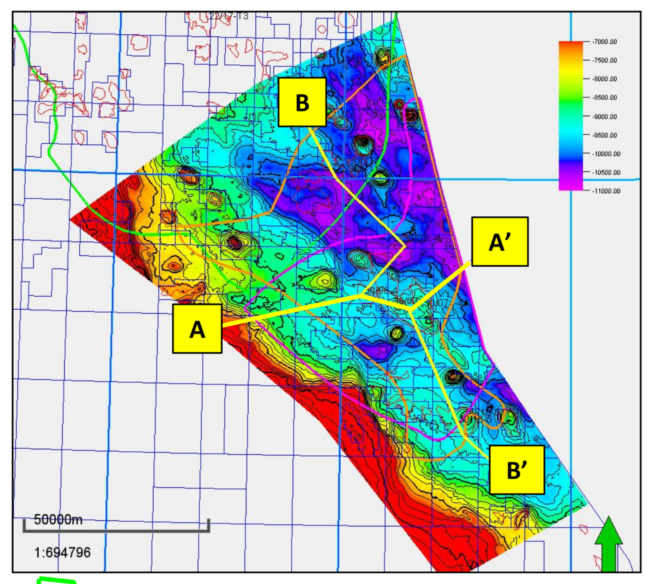


Image source: courtesy of Google Earth

Axis generated Near Top Palaeocene depth map (ft)



Forties 5 CO2Stored outline

Mey 1 CO2Stored outline

Maureen 1 CO2Stored outline

Ci: 250ft

Image source: Original interpretation from Axis Well Technology, 2015

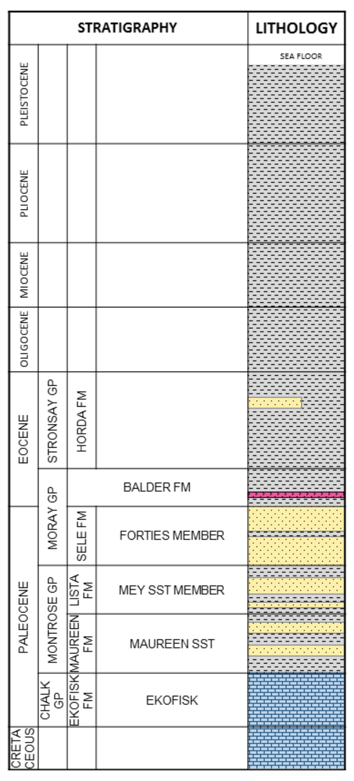
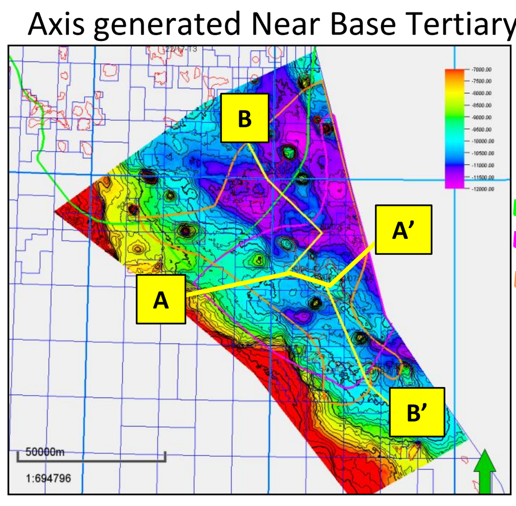


Image source: modified from Wills, J. M., The Forties Field, Block 21/10, 22/6a, UK North Sea. BP Exploration, Fig 2

Axis generated Near Base Tertiary depth map (ft)



Forties 5 CO2Stored outline

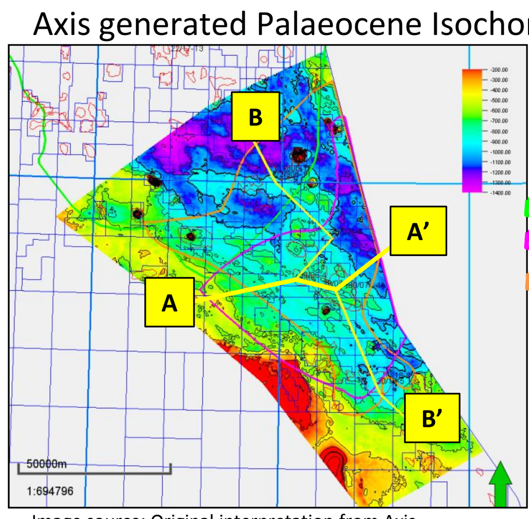
Mey 1 CO2Stored outline

Maureen 1 CO2Stored outline

Image source: Original interpretation from Axis Well Technology, 2015

Ci: 250ft

Axis generated Palaeocene Isochore (ft)



Forties 5 CO2Stored outline

Mey 1 CO2Stored outline

Maureen 1 CO2Stored outline

Image source: Original interpretation from Axis Well Technology, 2015

Ci: 200ft

Random Dip seismic lines across the Maureen 1 and Mey 1 saline aquifers

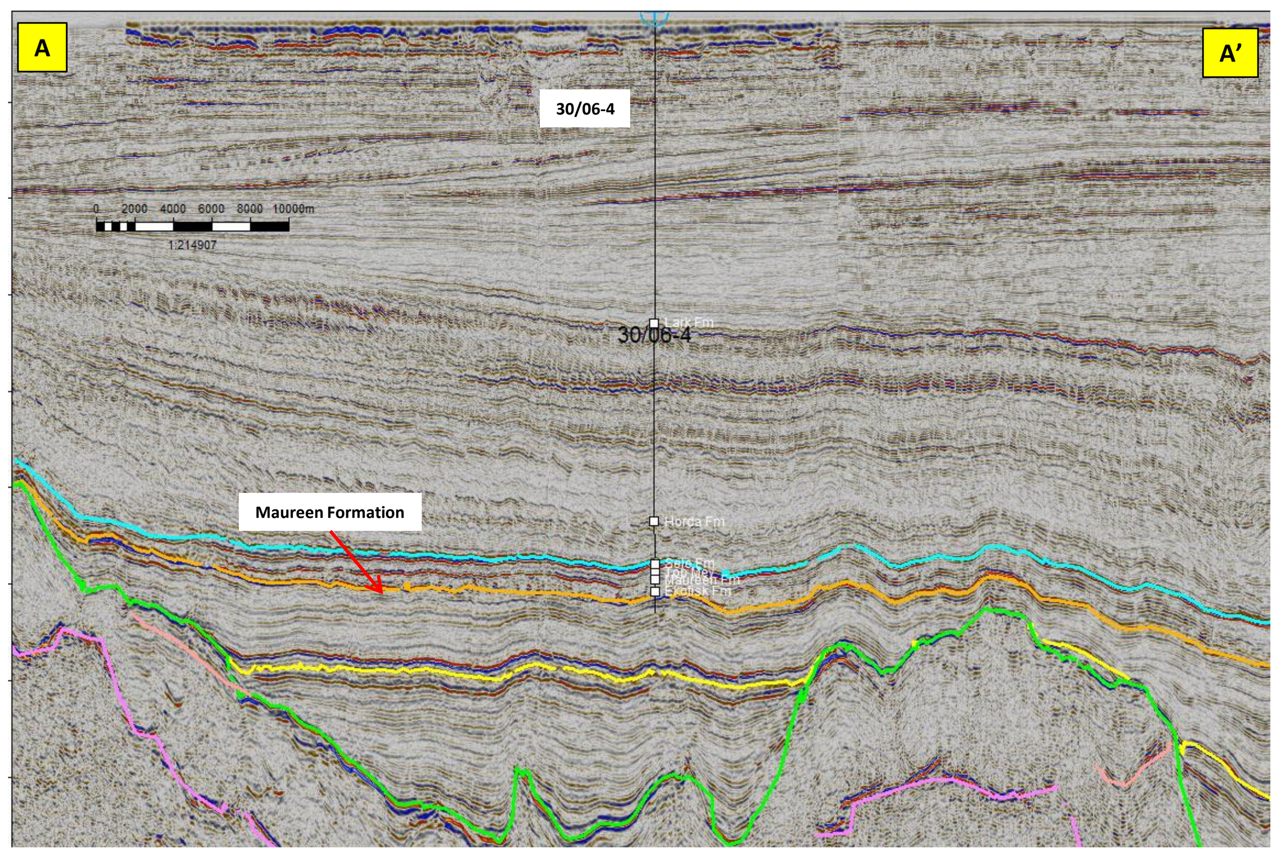


Image source: Seismic data provided by PGS under Licence Agreement. Original interpretation from Axis Well Technology, 2015.

Near Top Palaeocene | Base Cretaceous Unconformity | Near Base Tertiary | Near Top Middle Jurassic | Near Top Lower Cretaceous | Near Top Permian

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 time interpretation, 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 porosity/permeability 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.

Key Risk Summary

Maureen 1 Aquifer	Capacity (MT)	Injectivity (mDm)	Engineered Containment			Geo Containment
			Wells /sq.km	Leakage risk	Containment risk	
Selection Criteria	162	10,978	0.12	n/a	n/a	15
Due Diligence	101	2,550	0.08	0.6	0.05	14

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 (driven by low NTG) in the wells within the Maureen 1 area when compared to what has been reported in 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.

Random Strike seismic line along the Maureen 1 and Mey 1 saline aquifers

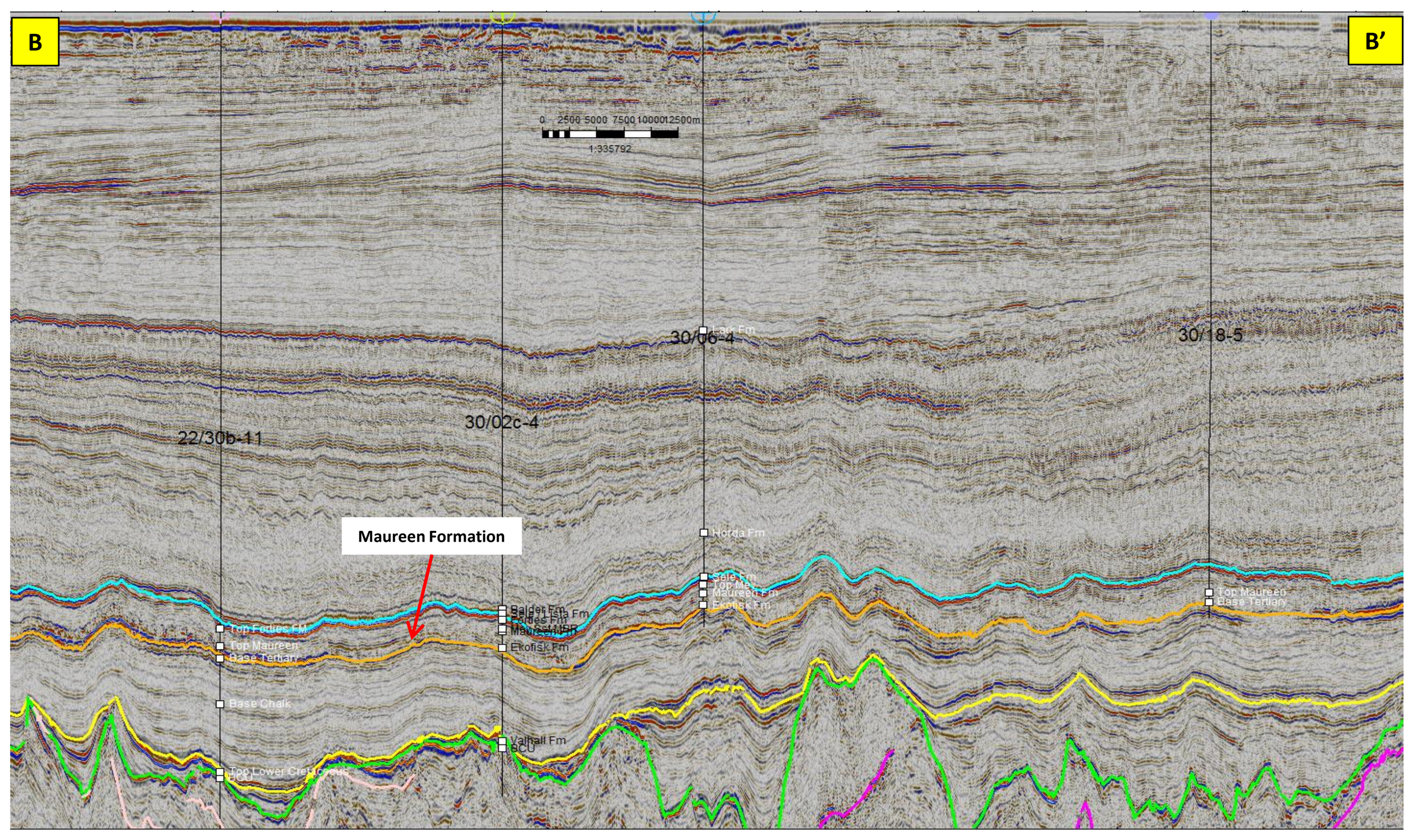


Image source: Seismic data provided by PGS under Licence Agreement. Original interpretation from Axis Well Technology, 2015.

Near Top Palaeocene | Base Cretaceous Unconformity | Near Base Tertiary | Near Top Middle Jurassic | Near Top Lower Cretaceous | Near Top Permian

Capacity Calculation

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

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 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.

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[1].

Published permeability versus depth for Paleocene reservoirs also suggests values of less than 100mD at the depths for this store[2].

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). CO2 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 but is well above the calculated min fracture pressure.

There is uncertainty associated with the assumed minimum fracture pressure, however achieving the required injectivity is identified as a risk.

Injectivity Validation

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

NB. 1: Analogue field 2: Estimated from CDA composite logs 3: CO2Stored

Containment Validation

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	
Maureen 1	366	3	3	3	1	3	2	15
		3	3	2	1	3	2	14

Low=1 Medium=2 High=3 | 2 values in CO2Stored | 1 no additional data to qc, values taken from CO2Stored

Development Concept

CO2 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

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

Comparative Development Concept

A new subsea development with 5 deviated wells each injecting 1MT/yr; totalling 100MT over 20 years. CO2 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. Monitoring will include downhole pressure and distributed temperature sensors.

Site growth potential; theoretical Ultimate Development Concept

The site has a theoretical storage capacity of ~101MT.

The site has no additional growth potential

Costs

Site Reference:	13	Site Description	Maureen 1
Capacity:	101	Water Depth (m)	80
Concept Cost (£m)	Comparative Development	Ultimate Development	Description
Tonnes Injected (MT)	100		Total Stored CO2 for proposed scheme
Appraisal Cost:	£76m		Appraisal Wells + Seismic Data Acquisition & Interpretation
Development Well Cost:	£172.1m		Drilling & Completion Costs of wells.
Facilities Cost:	£317.5m		Landfall, Pipeline, NUI, Templates, ties-Ins,
PM & Eng:	£31.8m		10% of Facilities Costs
Decommissioning:	£119.4m		£10m per NUI, £4m per dry well, £8m per subsea well
Subtotal	£716.6m		-
Contingency	£143.4m		20% of Development & Facilities Costs
OPEX (20years)	£380.9m		OPEX Cost for 20 years (6% of facilities costs)
Total:	£1240.8m		
£/T CO2	12.41		

*These costs are not the full cost of storage as they omit MMV, security instruments, handover to DECC and profit.

Containment

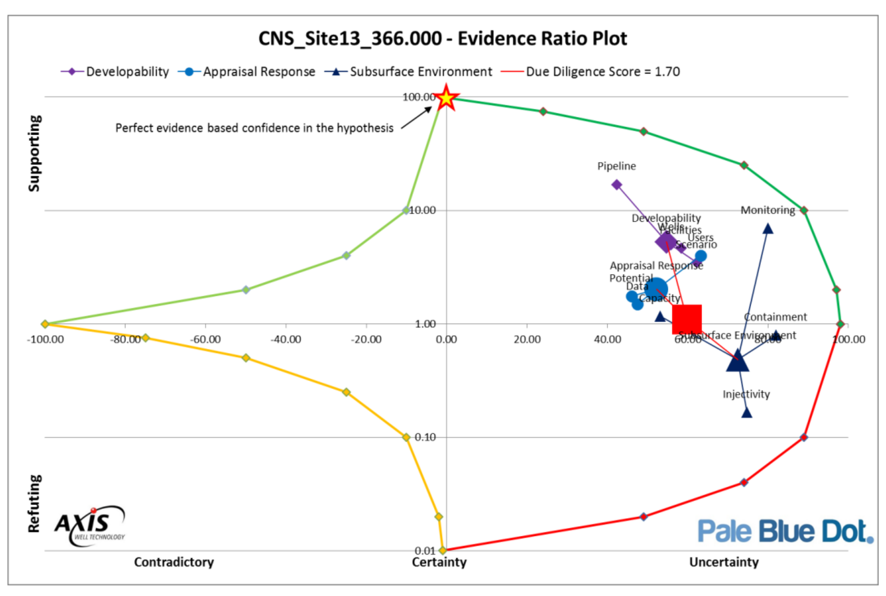
An overburden assessment has been conducted above and adjacent to the Maureen 1 saline aquifer storage site to identify secondary containment horizons and potential migration pathways out of the storage complex, in the unlikely event of a seal or fault leakage of the sequestered CO2.

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.

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 CO2 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.



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), wells have been assumed as drilled by a class 2 (Heavy Duty) Jack-Up Drilling Unit. Subsea well costs are assumed to be £34M per well, resulting in a 5 well development cost of £172M.

Site 13 – 366.000 – Maureen 1 - CNS

Site Summary			
Capacity (Due Diligence):	101 MT	UKCS Block:	30/1 vicinity
Unit Designation:	Saline Aquifer	Beachhead:	St Fergus
Formation:	Maureen	Water Depth:	80 m
Containment Unit:	Mey Sandstone Mbr	Reservoir Depth:	2835 m TVDSS (9300 ft)
Availability/COP:	n/a	Region:	CNS

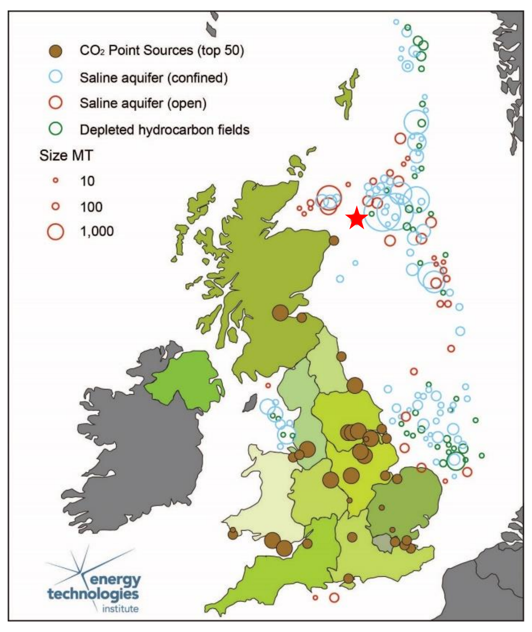
Client	The Energy Technologies Institute	Title	D06: Prospect Summary Sheets	Date of Issue	7th August 2015
Project Title	DECC Strategic UK CCS Storage Appraisal Project	Classification	Client Confidential	Version	V00

Strategic UK CCS Storage Appraisal Project

References

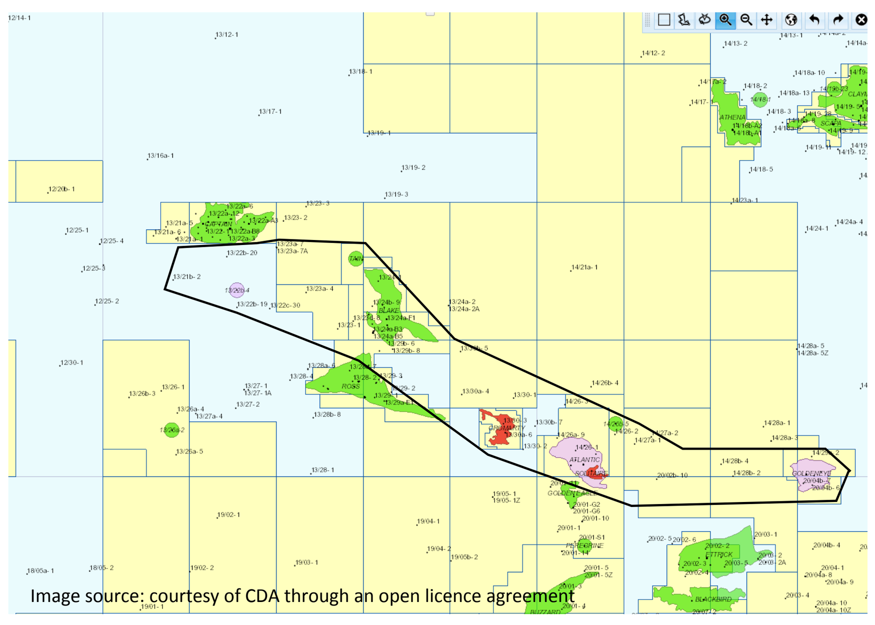
1. Cutts, P. L. (1991) The Maureen Field, Block 16/29a, UK North Sea United Kingdome Oil and Gas Fields, 25 Years Commemorative Volume, Geological Society Memoir No. 14, pp 347-352
2. Ahmadi, Z. M., Sawyers, M., Kenyon-Roberts, S., Stanworth, C. W., Kugler, K.A., Kristensen, J. and Fugelli, E. M. G. 2003. Palaeocene. In: Evans, D., Graham, C., Armour, A. and Bathurst, P. (eds) The Millennium Atlas: petroleum geology of the Central and Northern North Sea. The Geological Society London, p. 235-259

Site 14 – 218.000 - Captain Aquifer – CNS

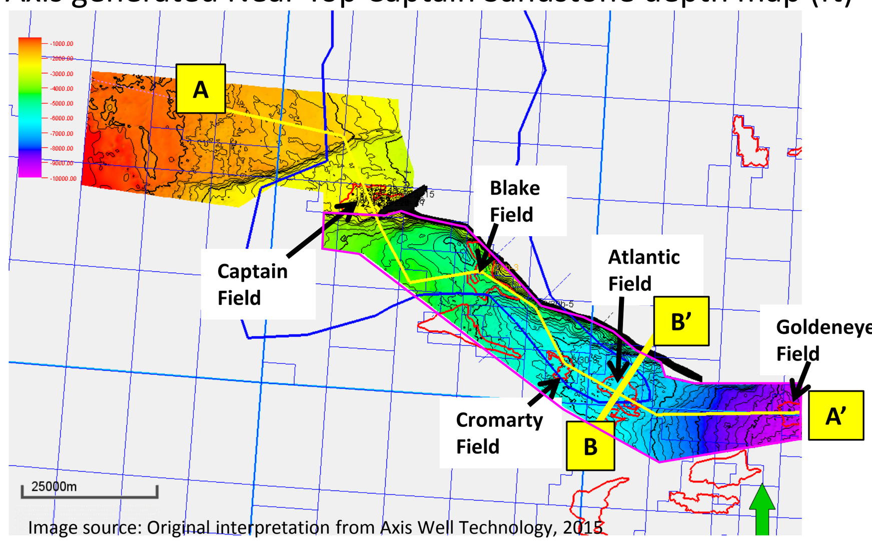


Major offshore areas covered by CO2Stored (© Energy Technologies Institute)

Captain Aquifer “pan-handle”



Axis generated Near Top Captain Sandstone depth map (ft)



CO2Stored Captain Aquifer outline polygon

Captain Aquifer “pan-handle” outline polygon

Ci: 200ft

Development Concept

<u>CO2 volumes cf ETI Scenarios</u>
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.

<u>Build out potential</u>
The site could build out to Captain oilfield and Coracle aquifer. Also, the Captain aquifer, 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.

<u>Comparative Development Concept</u>
A new subsea development, in the vicinity of Atlantic and Cromarty, with 3 deviated wells each injecting 1MT/yr; totalling 49MT over 20 years. CO2 will be delivered via the 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.

<u>Site growth potential; theoretical Ultimate Development Concept</u>
The site has a theoretical storage capacity of ~49MT.
The site has no additional growth potential

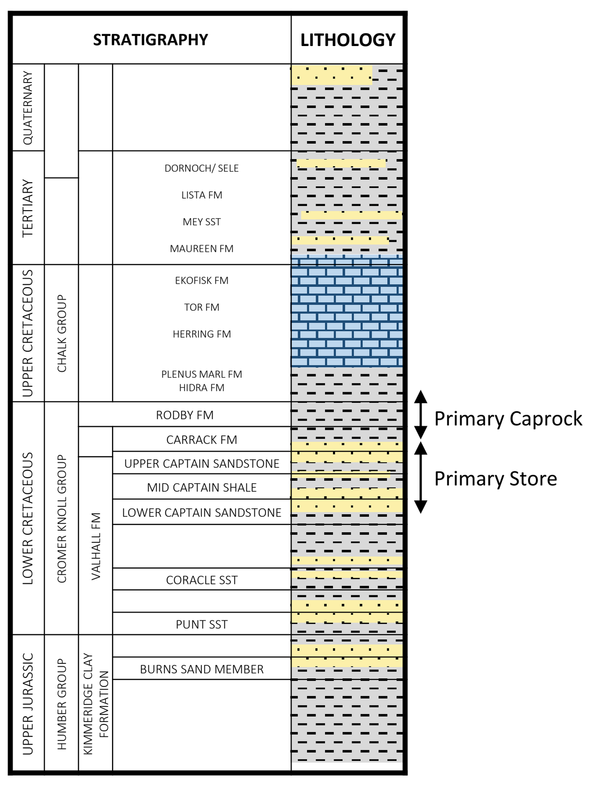
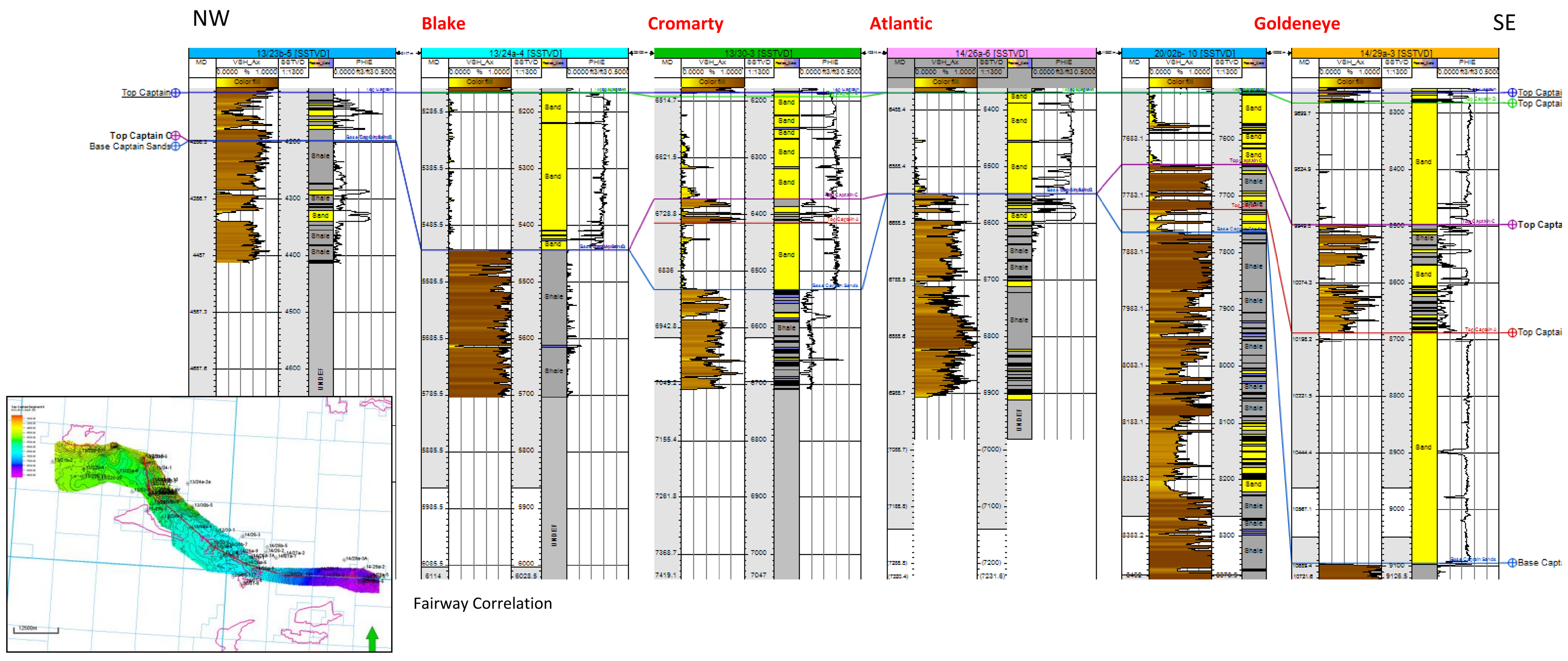


Image source: modified from Pinnock, S. J., Clitheroe, A. R. J., and Rose, P. T. S, The Captain Field, Block 13/22a, UK North Sea, Geological Society, London, Memoirs 2003, v20; p431-441



Fairway Correlation

Random seismic line across the Captain Fairway

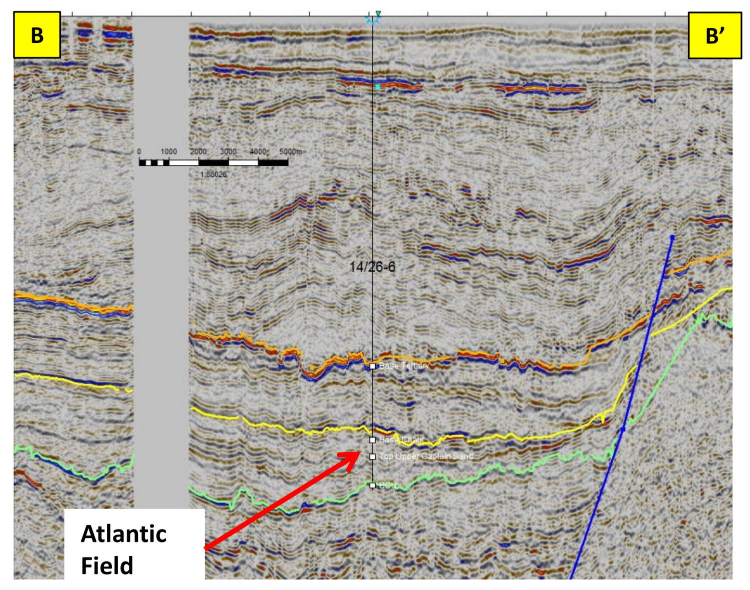


Image source: Seismic data provided by PGS under Licence Agreement. Original interpretation from Axis Well Technology, 2015.

Near Base Tertiary

Near Top Captain Sandstone

Base Cretaceous Unconformity

Key Risk Summary

Captain Saline Aquifer	Capacity (MT)	Injectivity (mDm)	Engineered Containment			Geo Containment
			Wells /sq.km	Leakage risk	Containment risk	
Selection Criteria	156	430,010	0.09	n/a	n/a	12
Due Diligence	49*	103,700	0.07	0.27	0.018	14

*Note that capacity is likely to be greater than this value, see Ref 4

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.

Capacity Calculation

Thickness[2] [m]	GRV [MMm3]	NTG[2]	Porosity[1]	CO2 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

NB. 1: Analogue field data and literature 2: Estimated from CDA composite logs 3: CO2Stored

Injectivity Validation

Zone	Depositional Environment	Gross Thickness [m]	NTG	Porosity	Perm [mD]	Kh [mDm]
Captain Sands/ Kopervik	Turbidite	61	0.85	0.31	2000	103,700

Random seismic line along the Captain Fairway

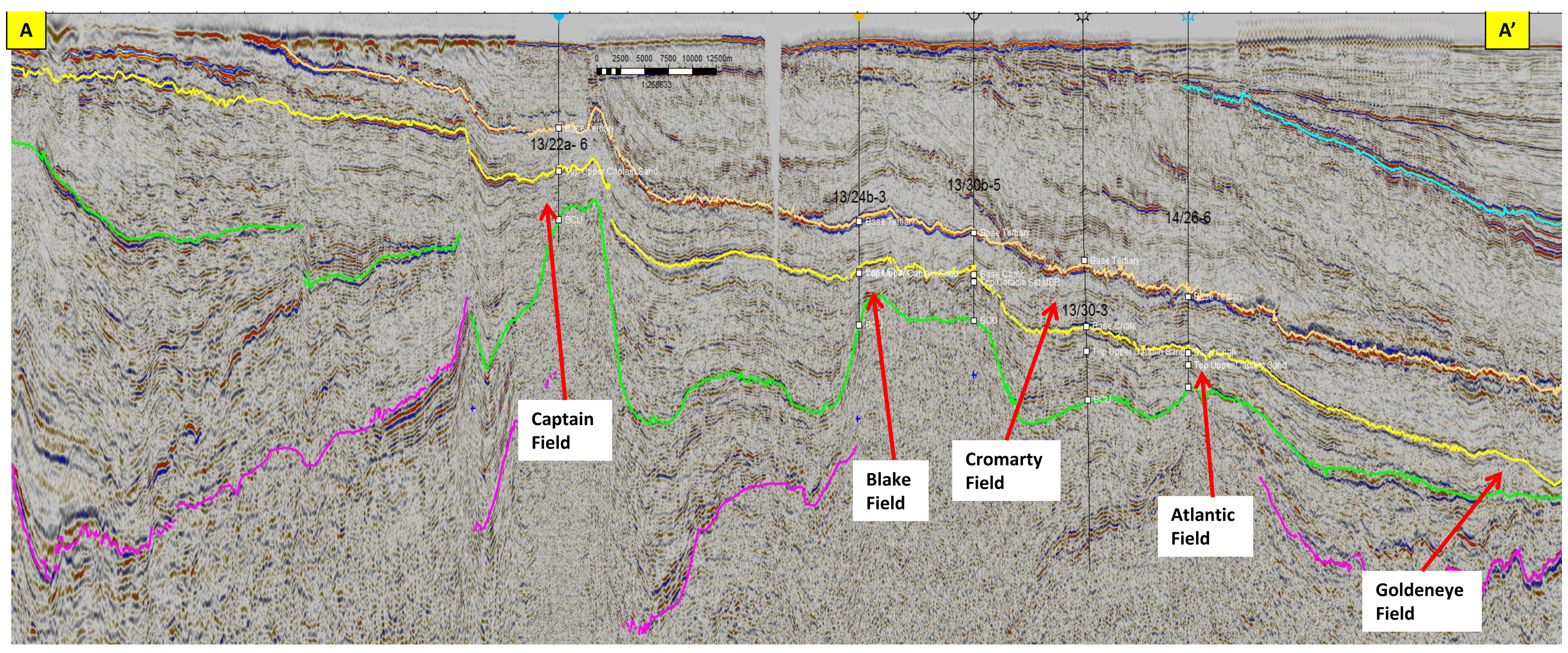


Image source: Seismic data provided by PGS under Licence Agreement. Original interpretation from Axis Well Technology, 2015.

Near Base Tertiary

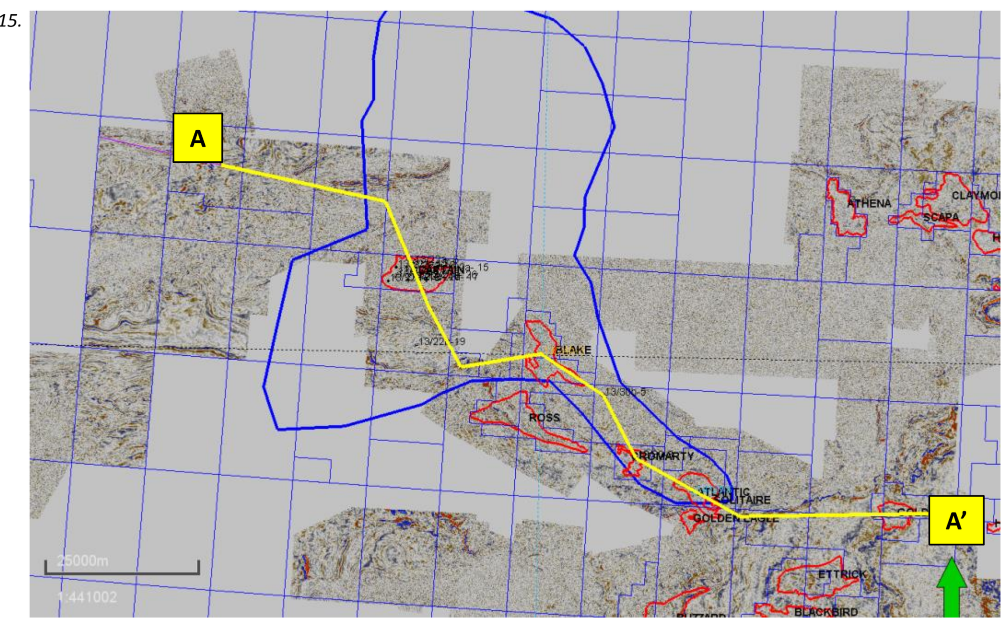
Near Top Captain Sandstone

Base Cretaceous Unconformity

Near Top Permian

Containment Validation

Geo Containment Risk	code	Fault Characterisation			Seal Characterisation			Georisk Factor
		Density	Throw & Fault Seal	Verical Extent	Fracture Pressure Capacity	Seal Chemical Reactivity	Seal Degradation	
Captain_013_17	218	1	1	2	3	3	2	12
		3	2	1	3	3	2	14
	Low=1	Medium=2	High=3	2	values in CO2Stored			
				1	no additional data to qc, values taken from CO2Stored			



Time Slice through the Captain Fairway

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.

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 in the Injectivity Validation table.

The permeability thickness calculated during the validation process is 103,700 mDm. This is significantly 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% [3]. The permeability over Captain is high with an average 7,000mD, however at Blake, this average drops to 1,500-20005. The SCCS [4] have conducted a study over this aquifer area with a lower permeability of 2000mD.
The permeability thickness however is still high and based on reservoir quality the initial CO2 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). CO2 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.

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 CO2. 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 units identified which could restrict the migration of the CO2 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 MegaSurvey identified several faults.

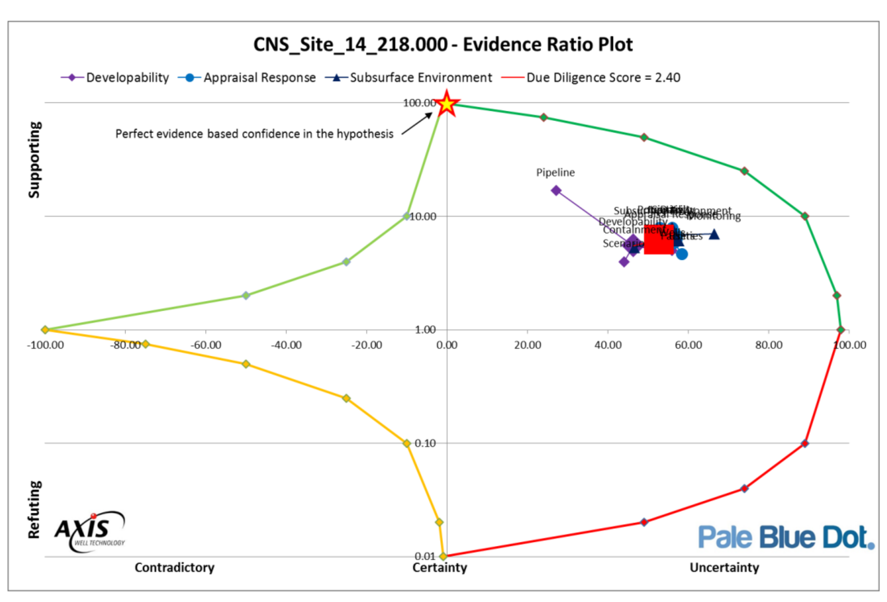
Engineering Risk

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 CO2 plume pathway is required in order to avoid the high well density locations.

Costs

Site Reference:	14	Site Description	Captain_013_17
Capacity:	49	Water Depth (m)	95
Concept Cost (£m)	Comparative Development	Ultimate Development	Description
Tonnes Injected (MT)	49		Total Stored CO2 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, NUI, Templates, ties-Ins,
PM & Eng:	£3.9m		10% of Facilities Costs
Decommissioning:	£33.6m		£10m per NUI, £4m per dry well, £8m per subsea well
<u>Subtotal</u>	£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 CO2	4.84		

*These costs are not the full cost of storage as they omit MMV, security instruments, handover to DECC and profit.



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 £28M per well, resulting in a 5 well development cost of £140.4M.

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.

Site 14 – 218.000 – Captain Aquifer - CNS

Site Summary			
Capacity (Due Diligence):	49 MT	UKCS Block:	13/23, 24, 29, 30 . 14/26, 27, 29. 20/1,2,3,4
Unit Designation:	Saline Aquifer	Beachhead:	St Fergus
Formation:	Captain Sandstone Mbr., Wick SST Fm.	Water Depth:	95 m
Containment Unit:	Hidra Formation	Reservoir Depth:	1,190 m TVDSS (3904 ft)
Availability/COP:	n/a	Region:	CNS

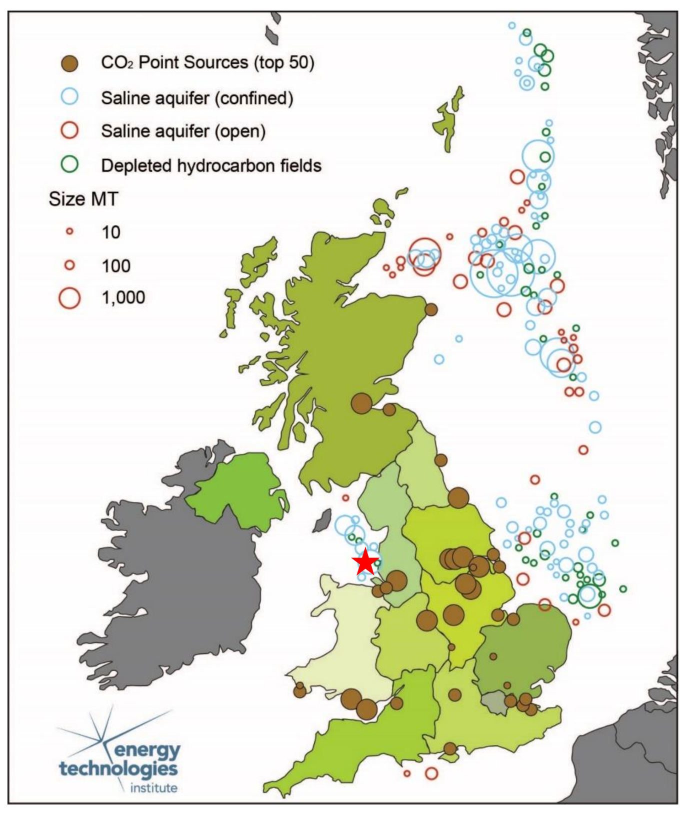
Client	The Energy Technologies Institute	Title	D06: Prospect Summary Sheets	Date of Issue	7th August 2015
Project Title	DECC Strategic UK CCS Storage Appraisal Project	Classification	Client Confidential	Version	V00

Strategic UK CCS Storage Appraisal Project

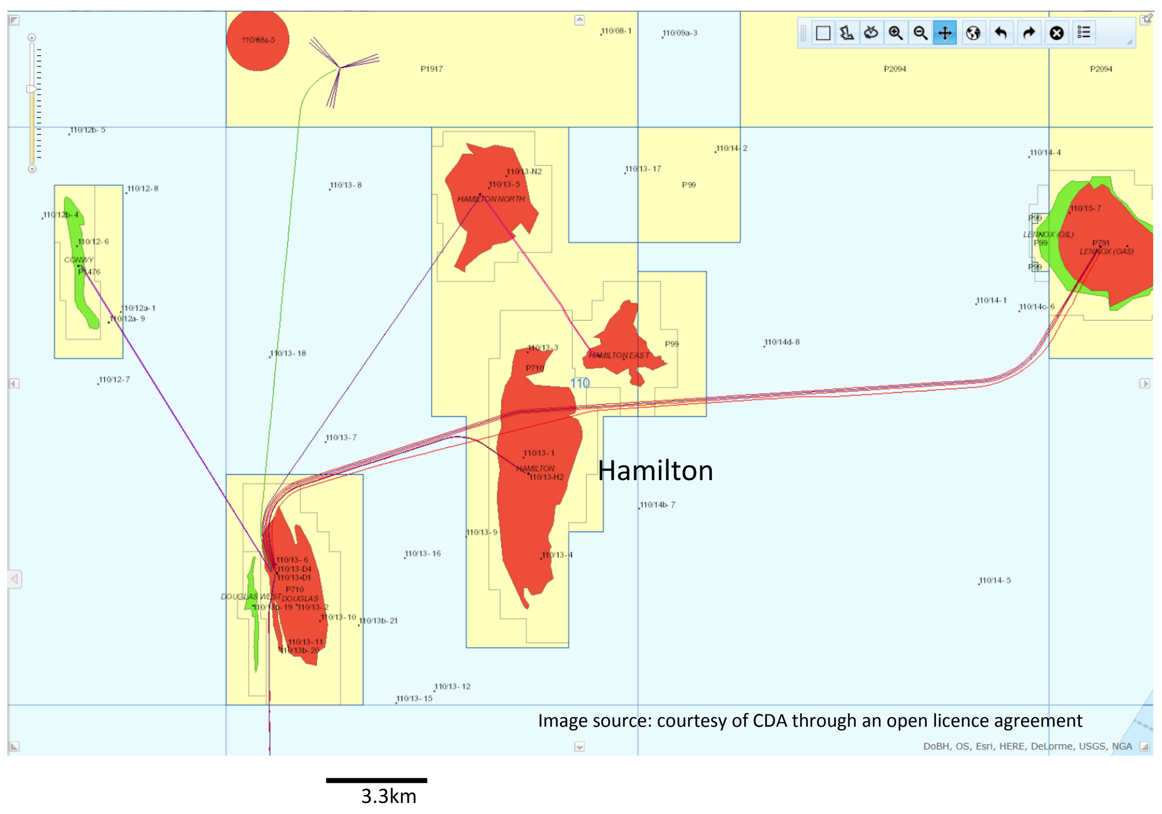
References

1. Element Energy Ltd. (2014) “Scotland and Central North Sea CCS Hub Study” Revised Final Report
2. SCCS (2011) “Progressing Scotland’s CO2 storage opportunities”
3. Law, A et al. (2000) “The Kopervik fairway, Moray Firth, UK. Petroleum Geoscience” Vol. 6 , pp. 265-274
4. Jin, M., Mackay E., Quinn M., Hitchen K. & Akhurst M., 2012. “Evaluation of the CO2 Storage Capacity of Captain Sandstone Formation” SPE154539
5. Du, K,E., et al., (2000) “Optimising the Developments of Blake Field under Tough Economic and Environmental Conditions” International Oil and Gas conference and Exhibition in China

Site 19 – 248.002 - Hamilton – EIS



Major offshore areas covered by CO2Stored (© Energy Technologies Institute)



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.

Development Concept

CO2 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 CO2 being stored in the EIS before 2030).

Build out potential
Build out of CO2 storage would be facilitated by the nearby Morecambe fields, (N & S together have a capacity of 1042MT) which are expected to reach COP by 2028.

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. CO2 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
The site has a theoretical storage capacity of ~130MT.

There is little or no additional site growth potential beyond the development concept outlined above. For completeness the Ultimate Development Concept costed is identical to the Comparative Development Concept with the additional of a further well injecting a further 1MT/yr to deliver nearer to the 130MT theoretical storage capacity over the 20years.

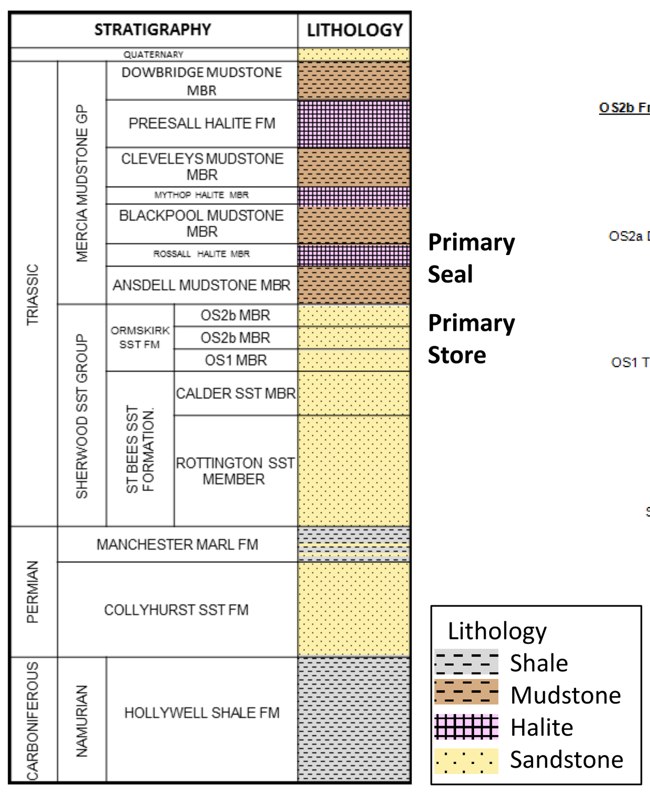


Image source: modified from Yaliz, A. and Taylor, P The Hamilton and Hamilton North Gas Fields, Block 110/13a, East Irish Sea United Kingdom Oil and Gas Fields Commemorative Millennium Volume, The Geological Society of London 2003

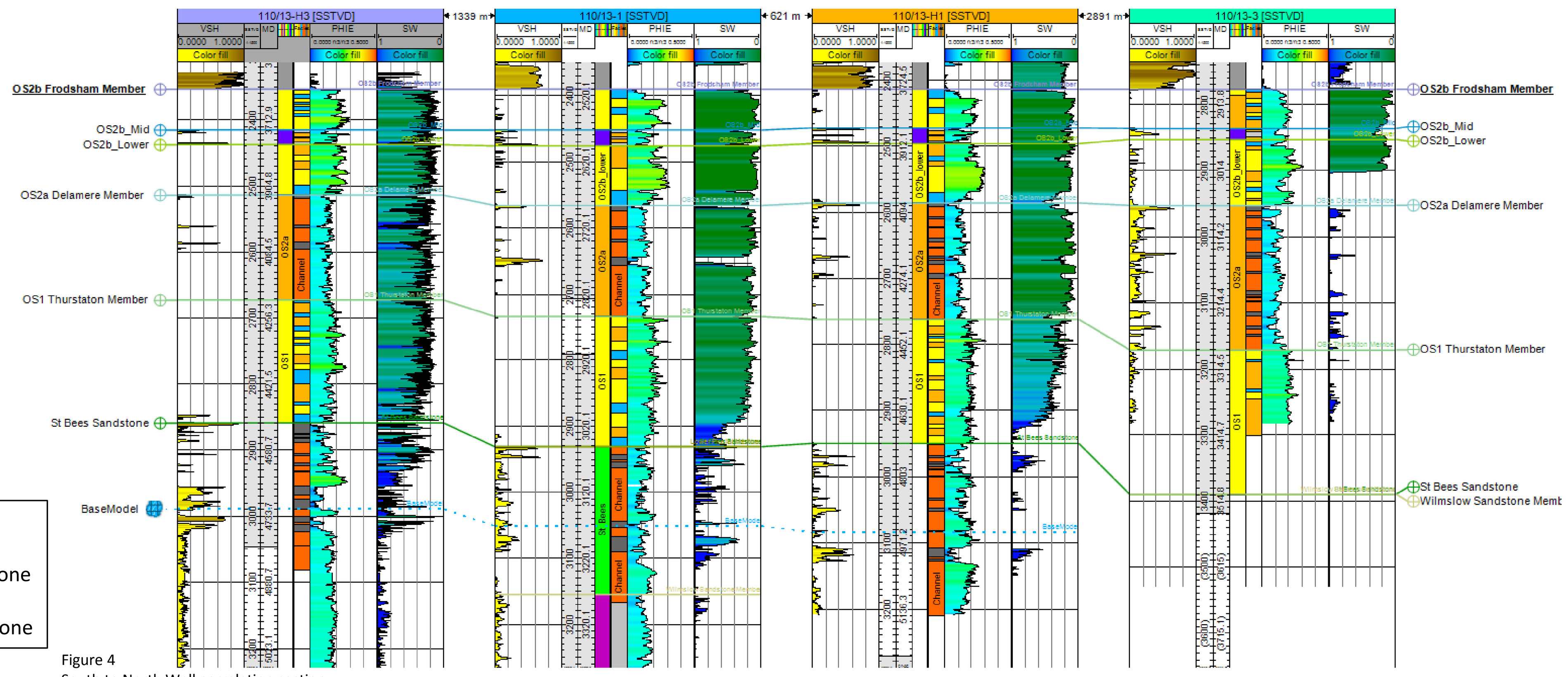
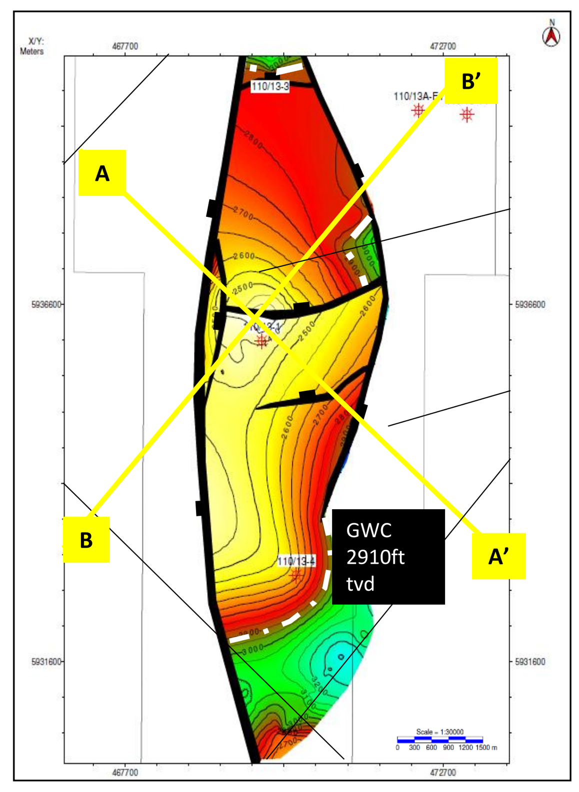


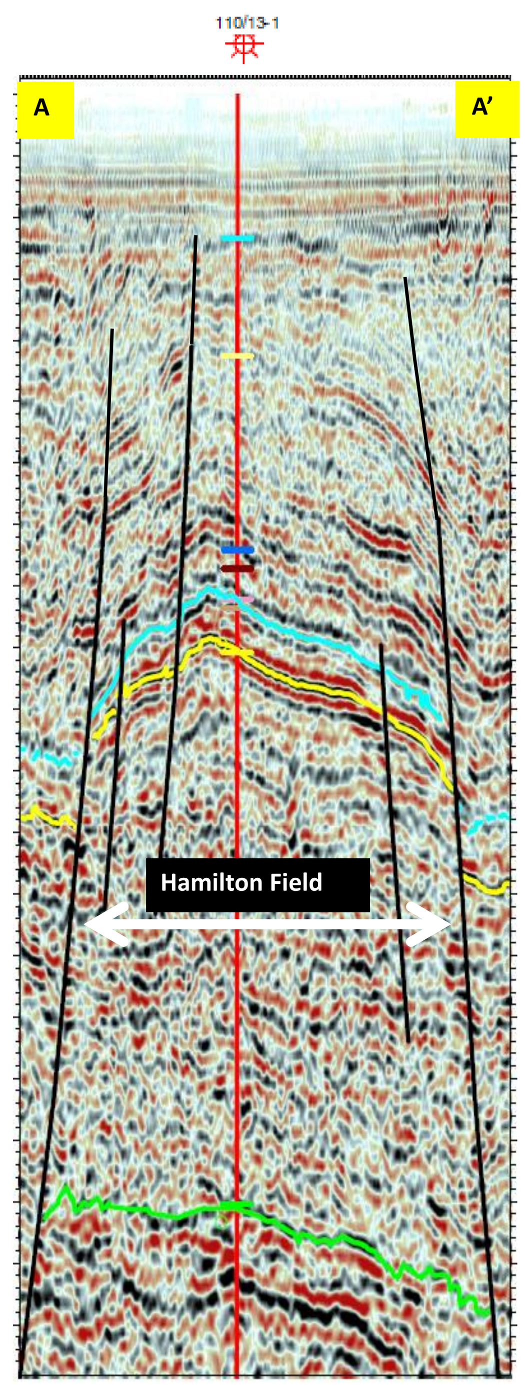
Figure 4
South to North Well correlation section
(Logs shown: Vshale, Facies, PHIE and Sw)

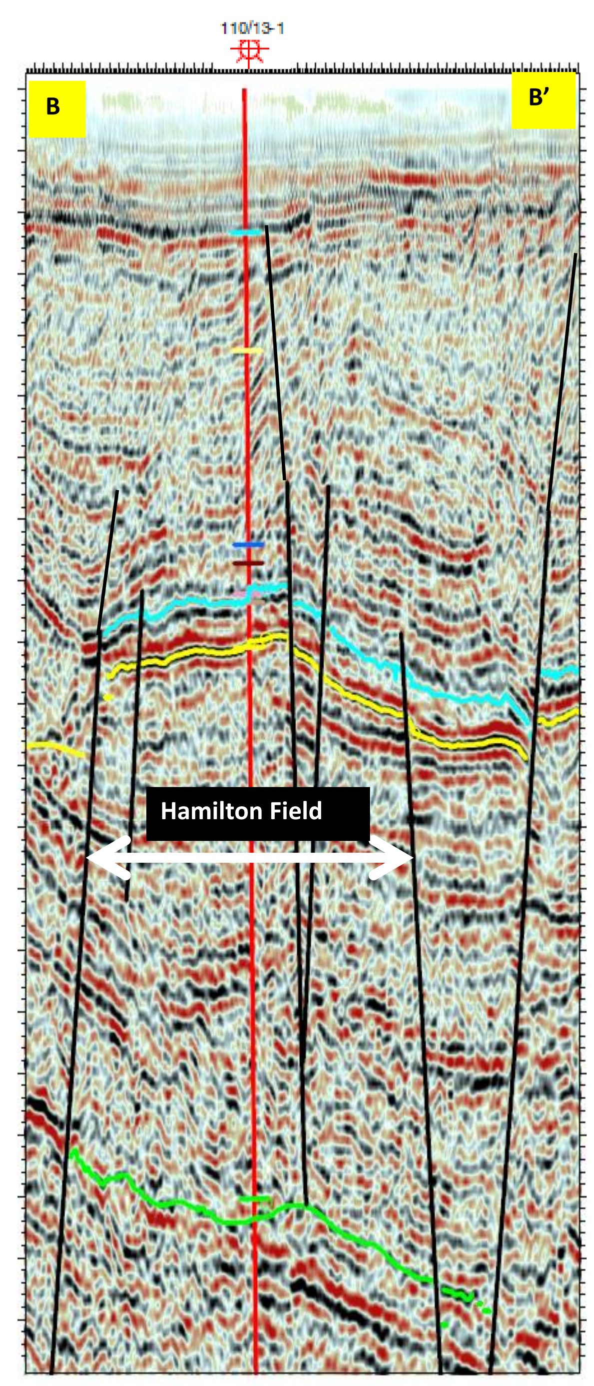
Raw log data (Gamma Ray, Density, Neutron and Sonic) were used during the well correlation. Where digital data were not available (110/13-4 and 110/13-H4) scanned composite log data were used to confirm the correlation and well tops.
Raw data and composite logs are not shown to comply with CDA licensing restrictions



Hamilton Field:
Top Ormskirk Sst Fm (ft tvdss)

Image source: Original interpretation from Axis Well Technology, 2015





Key
Rossal Halite
Top Ormskirk Sst Fm
Top Collyhurst Sst Fm

Image source: 2D seismic lines downloaded from CDA, . Original interpretation from Axis Well Technology, 2015.

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. Assuming production continues at this rate until COP, the uplift in storage capacity is small, ~0.1%.

The produced volumes and conversion to mass storage potential are shown in the Capacity Calculation table.

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 CO2 injectivity is expected to be excellent.

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 high net to gross, excellent to moderate quality aeolian and fluvial sandstones of the Ormskirk Formation[1]. 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[1]. A summary of the reservoir properties are summarised in the Injectivity Validation table.

Key Risk Summary

Hamilton Gas Field	Capacity (MT)	Injectivity (mDm)	Engineered Containment			Geo Containment
			Wells /sq.km	Leakage risk	Containment risk	
Selection Criteria	120 (P50)	175,715	0.47	n/a	n/a	11
Due Diligence	130*	133,570	0.48	0.17	0.008	13

* Based on DCA forecast

Capacity Calculation

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

Additional Injectivity Checks

Two additional injectivity checks were carried out as part of the due diligence.

1. 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.
Early life production data from the 4 production wells is available on the DECC website. CO2 injection at the initial field pressure meets the injectivity requirement per well. At low (current) field pressures, the injectivity is much smaller due to CO2 being in the gas phase. A much larger difference between well and formation pressure would be required to meet the required injection rates.

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). CO2 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.

Injectivity Validation

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

NB. Ref 1; Average taken from CDA Well logs (110/13-1; 110/13-3; 110/13-4).

Containment Validation

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	
Hamilton gas field	248.002	3	2	1	1	2	2	11
		3	2	3	1	2	2	13

Low=1 Medium=2 High=3

2 values in CO2Stored

1 no additional data to qc, values taken from CO2Stored

Containment

Georisk

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 CO2.

Field data and published literature[1] 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 trap[1]. Minor east-west and north – south faulting is present [1]. All faults within field have sand to sand contact and do not provide barrier to gas flow[1]. 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[1]. CO2 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[1]).

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).

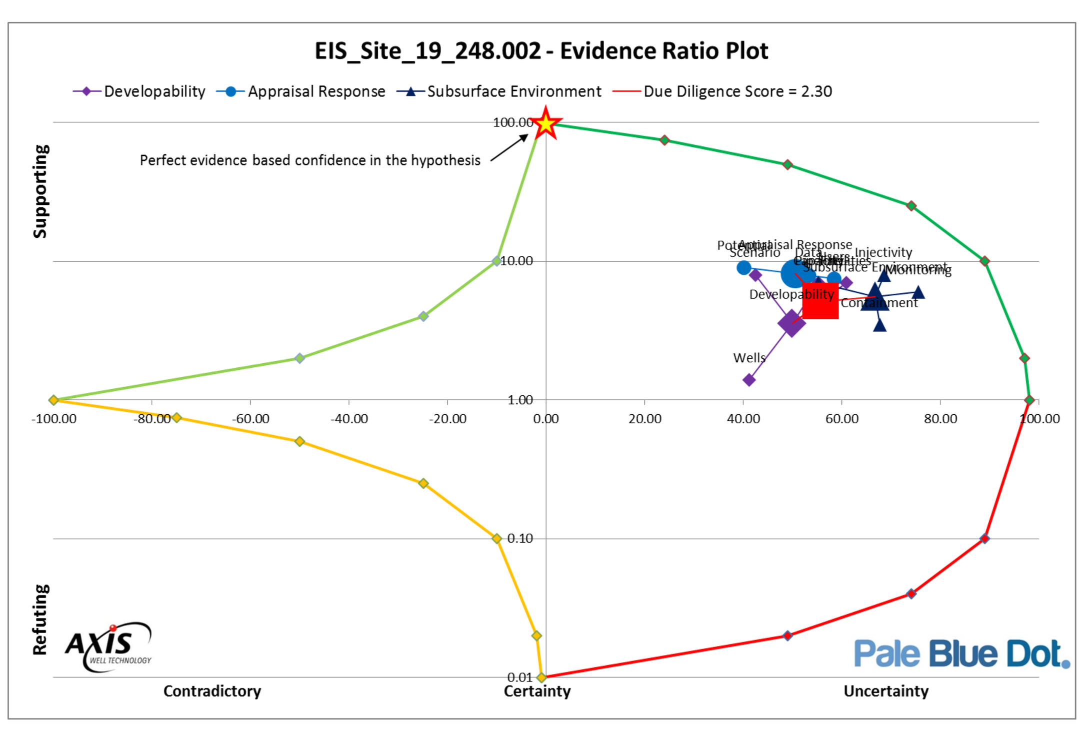
Engineering Risk

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.

Costs

Site Reference:	19	Site Description	Hamilton gas field
Capacity:	130	Water Depth (m)	25
Concept Cost (£m)	Comparative Development	Ultimate Development	Description
Tonnes Injected (MT)	100	120	Total Stored CO2 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, Templates, ties-Ins,
PM & Eng:	£11.5m	£11.5m	10% of Facilities Costs
Decommissioning:	£58.6m	£62.6m	£10m per NUI, £4m per dry well, £8m per subsea 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 CO2	4.80	4.25	

*These costs are not the full cost of storage as they omit MMV, security instruments, handover to DECC and profit.



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 can be drilled by a low cost class 1 Jack-Up Drilling Unit. Platform well costs are assumed to be £20M per well, including a contingency cost for managing CO2 phase change, resulting in a 5 well development cost of £102.2M.

References

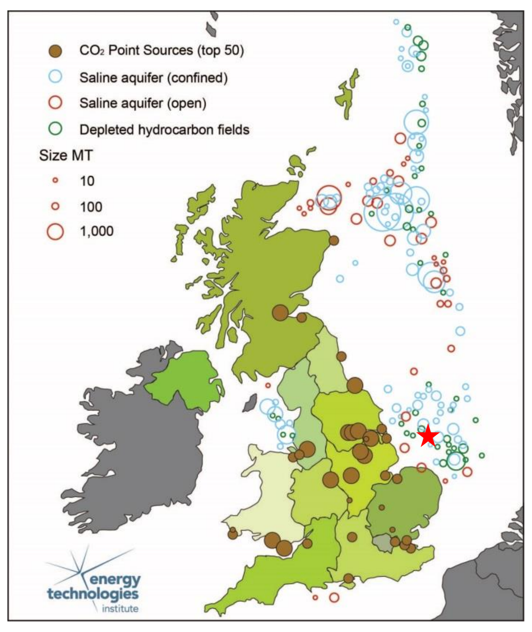
1. Yaliz, A. and Taylor, P (2003) "The Hamilton and Hamilton North Gas Fields, Block 110/13a, East Irish Sea" United Kingdom Oil and Gas Fields Commemorative Millennium Volume, The Geological Society of London 2003.
2. Karen Kirk, 2006 "Potential for storage of carbon dioxide in the rocks beneath the East Irish Sea" Tyndall Centre for Climate Change Research, Working Paper 100

Site 19 – 248.002 - Hamilton - EIS

Site Summary			
Capacity (Due Diligence):	130 MT	UKCS Block:	110/13a
Unit Designation:	Gas Field	Beachhead:	Point of Ayr
Formation:	Triassic Ormskirk Sandstone	Water Depth:	25 m
Containment Unit:	Mercia Mudstone Gp	Reservoir Depth:	701 m TVD (2300 ft)
Availability/COP:	End 2017	Region:	EIS

Client	The Energy Technologies Institute	Title	D06: Prospect Summary Sheets	Date of Issue	7th August 2015
Project Title	DECC Strategic UK CCS Storage Appraisal Project	Classification	Client Confidential	Version	V00

Site 20 – 141.002 - Barque – SNS



Major offshore areas covered by CO2Stored (© Energy Technologies Institute)

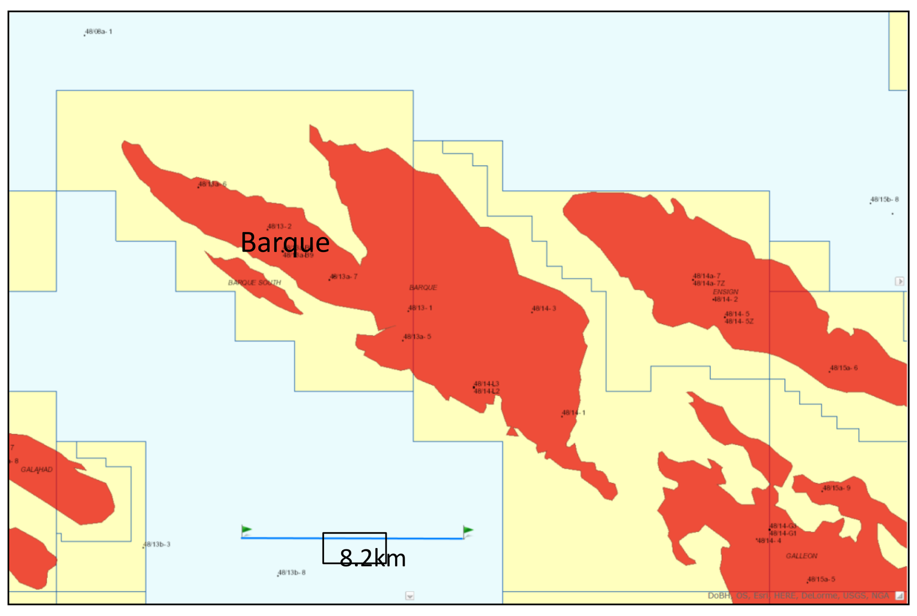


Image source: courtesy of CDA through an open licence agreement

Development Concept

CO2 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.

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 are nearby.

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. CO2 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 no additional growth potential

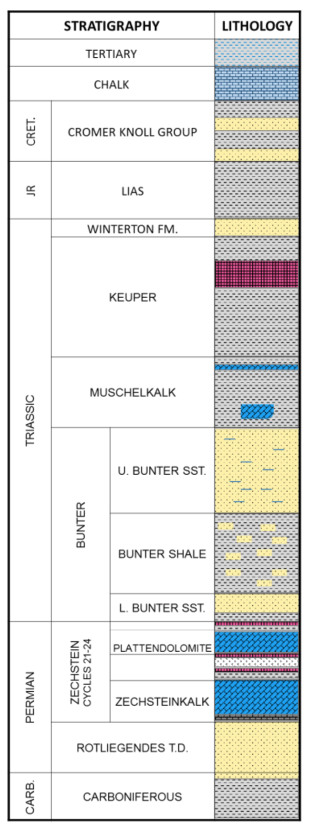


Image source: modified from Cooke-Yarborough (1991) “The Hewett Field, Blocks 48/28-29-30, 52/4a-5a, UK North Sea”, *In* Abbotts, I. L. (ed.), 1991, United Kingdom Oil and Gas Fields, 25 Years Commemorative Volume, Geological Society Memoir No. **14**, pp. 433-442.

Axis generated Top Rotliegendes depth map (ft tvdss)

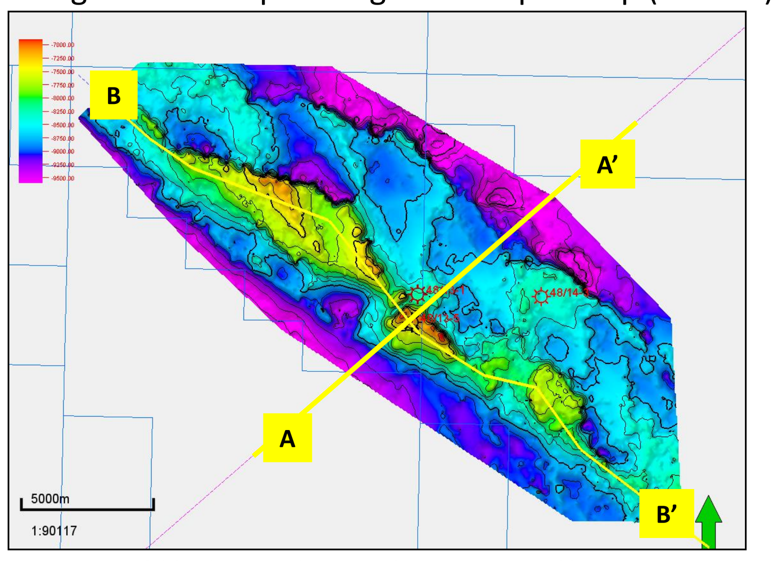


Image source: Original interpretation from Axis Well Technology, 2015

Ci: 250ft

TOP SEAL: Axis generated Zechstein Isochore (ft) (depth converted with a constant velocity of 15387 ft/sec)

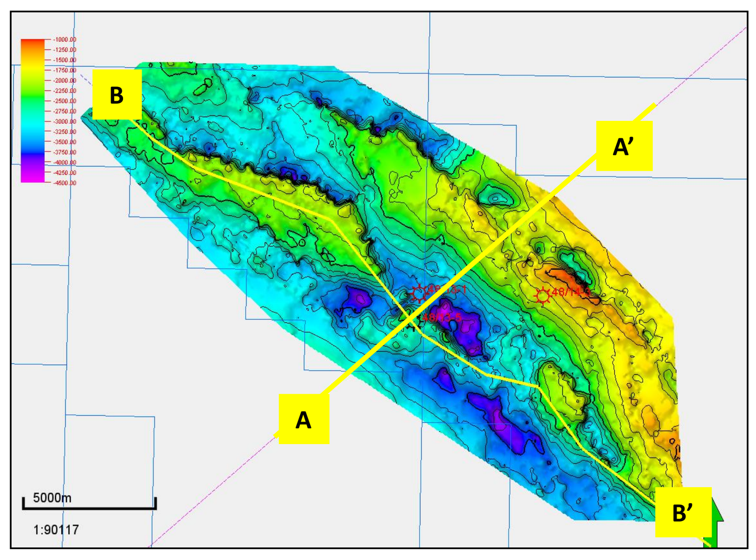


Image source: Original interpretation from Axis Well Technology, 2015

Ci: 250ft

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).

Barque Strike and Dip seismic lines from PGS MegaSurvey

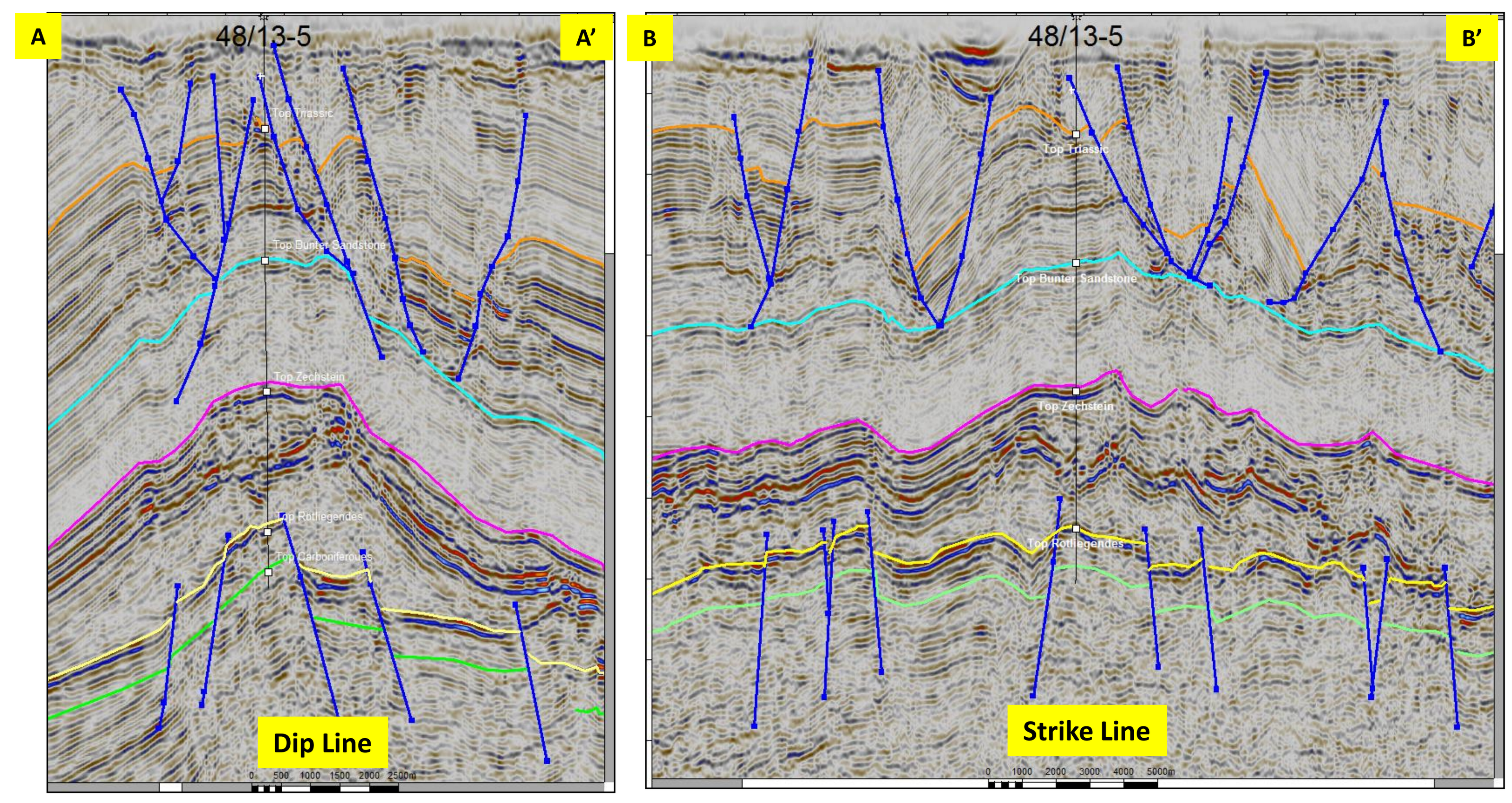


Image source: Seismic data provided by PGS under Licence Agreement. Original interpretation from Axis Well Technology, 2015.

Top Triassic
Top Rotliegendes Sandstone
Top Bunter Sandstone
Near Top Carboniferous
Top Zechstein

Key Risk Summary

Barque Gas Field	Capacity (MT)	Injectivity (mDm)	Engineered Containment			Geo Containment
			Wells /sq.km	Leakage risk	Containment risk	
Selection Criteria	120	11,430	0.63	n/a	n/a	9
Due Diligence	91	2,559	0.29	0.07	0.02	9

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.

Capacity Calculation

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

Injectivity Validation

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

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 in the Injectivity Validation table.

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 average for zone B is not mentioned explicitly in the published literature (tens of mD) [1, 2], therefore the mid value from CO2stored is used. Sarginson (2003) specifies a lower than 0.1mD average for Zones A and C – much lower than the mid case permeabilities assumed were used in the Co2stored calculation. Indications are that injectivity could be an issue.

Additional Injectivity Checks

Two additional injectivity checks were carried out as part of the due diligence.

1. 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.
Early life production data from the production wells is available on the DECC website. The initial production rate was converted to a CO2 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 report. 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.
2. 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. 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). CO2 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.

Containment Validation

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	
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

2 values in CO2Stored
1 no additional data to qc, values taken from CO2Stored

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 CO2.

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[1, 3]. The Barque field has three compartments due to faulting[1]. 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[1]. 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[1, 3]. Overlying the Zechstein is 304m (1000ft) of Bunter shale with an under-burden of Carboniferous coal measures1. CO2 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.

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.

Well Design

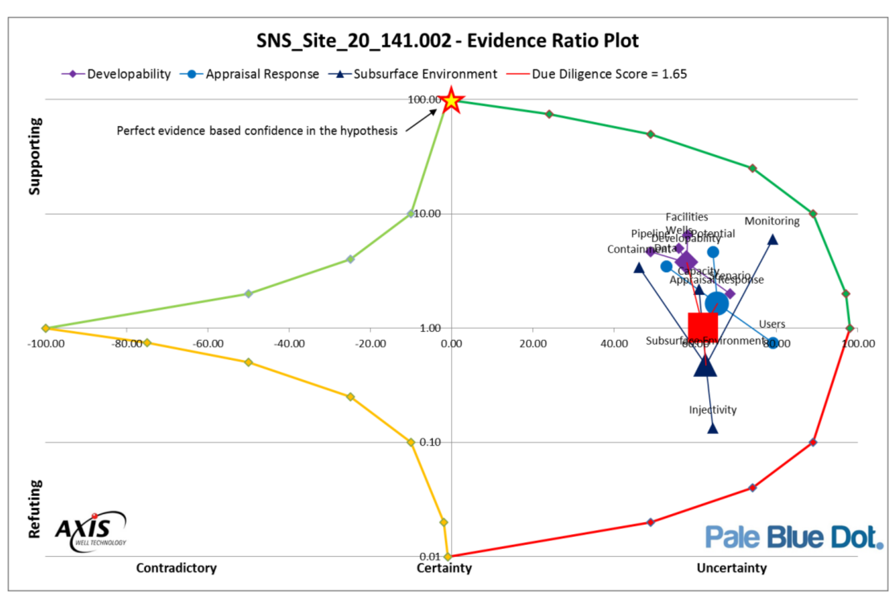
The generic well design is discussed in the supporting document ‘Storage Site Due Diligence Summary’. However, the Barque injection wells may depart from the generic design due to the poor injectivity. This suggests that long horizontal sections (>150m) may be required to reach injection targets. Alternatively, 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 can be drilled by a low cost class 1 Jack-Up Drilling Unit. Platform well costs are assumed to be £41M per well, including a contingency cost for managing CO2 phase change, resulting in a 5 well development cost of £202.8M.

Costs

Site Reference:	20	Site Description	Barque gas field
Capacity:	91	Water Depth (m)	10
Concept Cost (£m)	Comparative Development	Ultimate Development	Description
Tonnes Injected (MT)	91		Total Stored CO2 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, Templates, ties-Ins,
PM & Eng:	£23m		10% of Facilities Costs
Decommissioning:	£87.5m		£10m per NUI, £4m per dry well, £8m per subsea 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 CO2	10.20		

*These costs are not the full cost of storage as they omit MMV, security instruments, handover to DECC and profit.



Commercial Issues
Barque is a gas field in production operated by Shell, with a COP of 2028.

Site 20 – 141.002 - Barque - SNS

Site Summary			
Capacity (Due Diligence):	91 MT	UKCS Block:	48/13
Unit Designation:	Depleted Gas	Beachhead:	Barmston
Formation:	Leman SST (Rotliegend)	Water Depth:	10 m
Containment Unit:	Haupt Anhydrite	Reservoir Depth:	2133 m TVDSS (7,000 ft)
Availability/COP:	2028	Region:	SNS

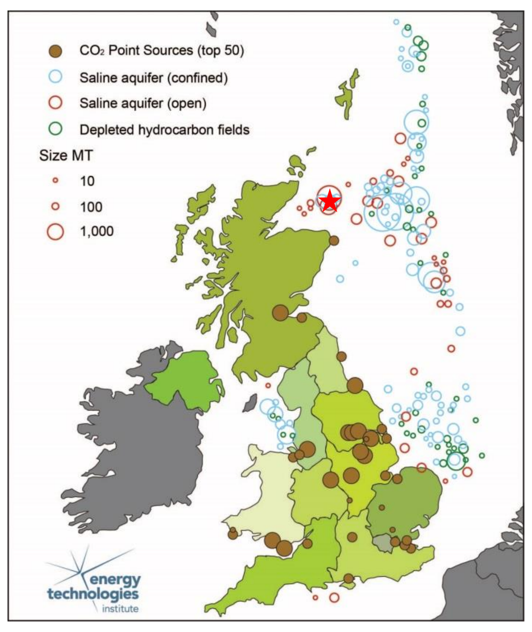
Client	The Energy Technologies Institute	Title	D06: Prospect Summary Sheets	Date of Issue	7th August 2015
Project Title	DECC Strategic UK CCS Storage Appraisal Project	Classification	Client Confidential	Version	V00

Strategic UK CCS Storage Appraisal Project

References

1. Farmer, R.T. and Hillier, A.P. (1991) **“The Barque Field, Blocks 48/13a, 48/14, UK North Sea”,** *Geological Society, London, Memoirs* 1991; v. 14; p. 395-400.
2. Holloway, S., Vincent, C.J. and Kirk, K.L. (2006) “**INDUSTRIAL CARBON DIOXIDE EMISSIONS AND CARBON DIOXIDE STORAGE POTENTIAL IN THE UK**” BGS Report No. COAL R308 DTI/Pub urn 06/2027.
3. Sarginson, M. J. (2003) **“The Barque Field, Blocks 48/13a, 48/14, UK North Sea”, United Kingdom Oil and Gas Fields, Commemorative Millennium Volume**”. Geological Society, London, Memoir, 20, p.663-670

Site 24 – 218.001 - Captain Oil Field – CNS



Major offshore areas covered by CO2Stored (© Energy Technologies Institute)

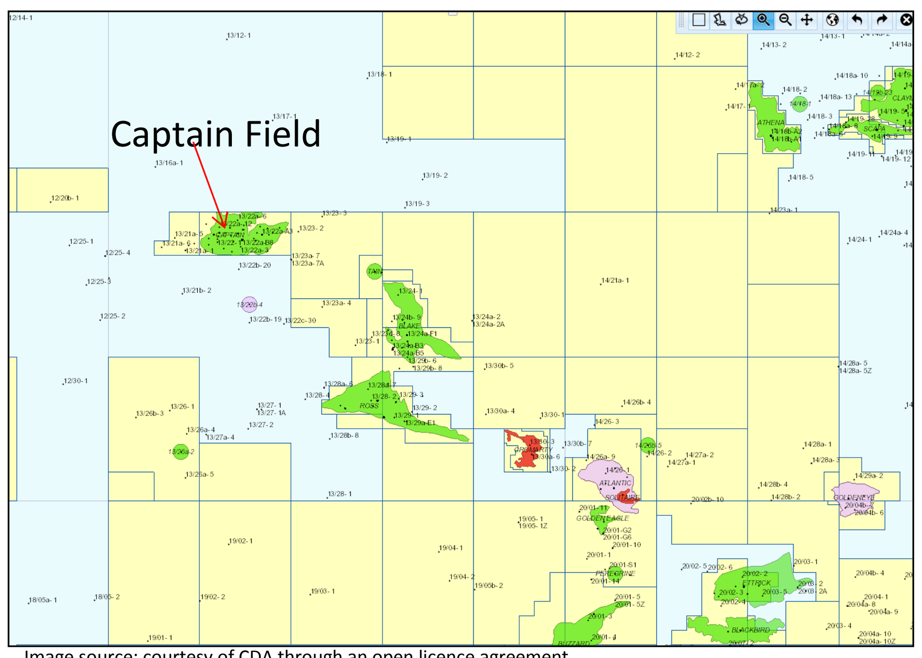


Image source: courtesy of CDA through an open licence agreement

Development Concept

CO2 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.

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.

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. CO2 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.

Site growth potential; theoretical Ultimate Development Concept
The site has a theoretical storage capacity of ~96MT.
The site has no additional growth potential.

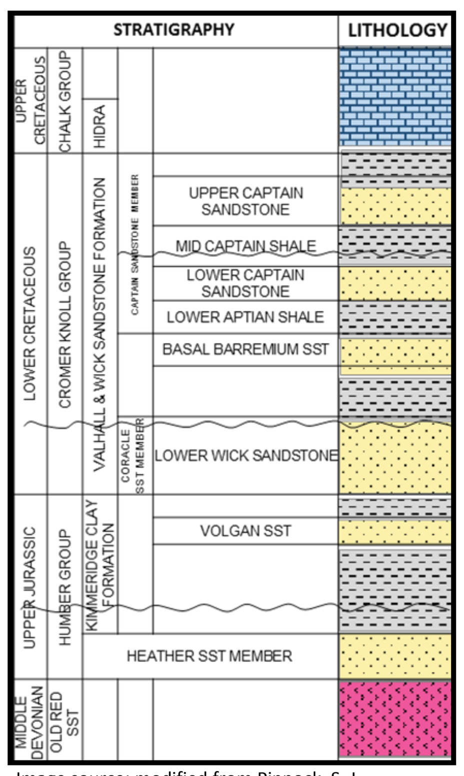


Image source: modified from Pinnock, S. J., Clitheroe, A. R. J., and Rose, P. T. S, The Captain Field, Block 13/22a, UK North Sea, Geological Society, London, Memoirs 2003, v20; p431-441

Axis generated Near Top Captain Sandstone depth map (ft)

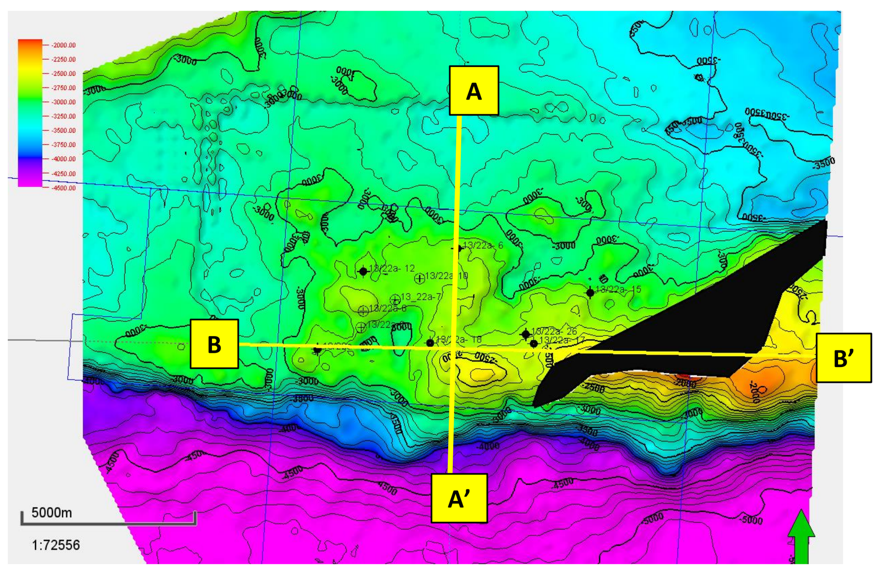


Image source: Original interpretation from Axis Well Technology, 2015

Capacity

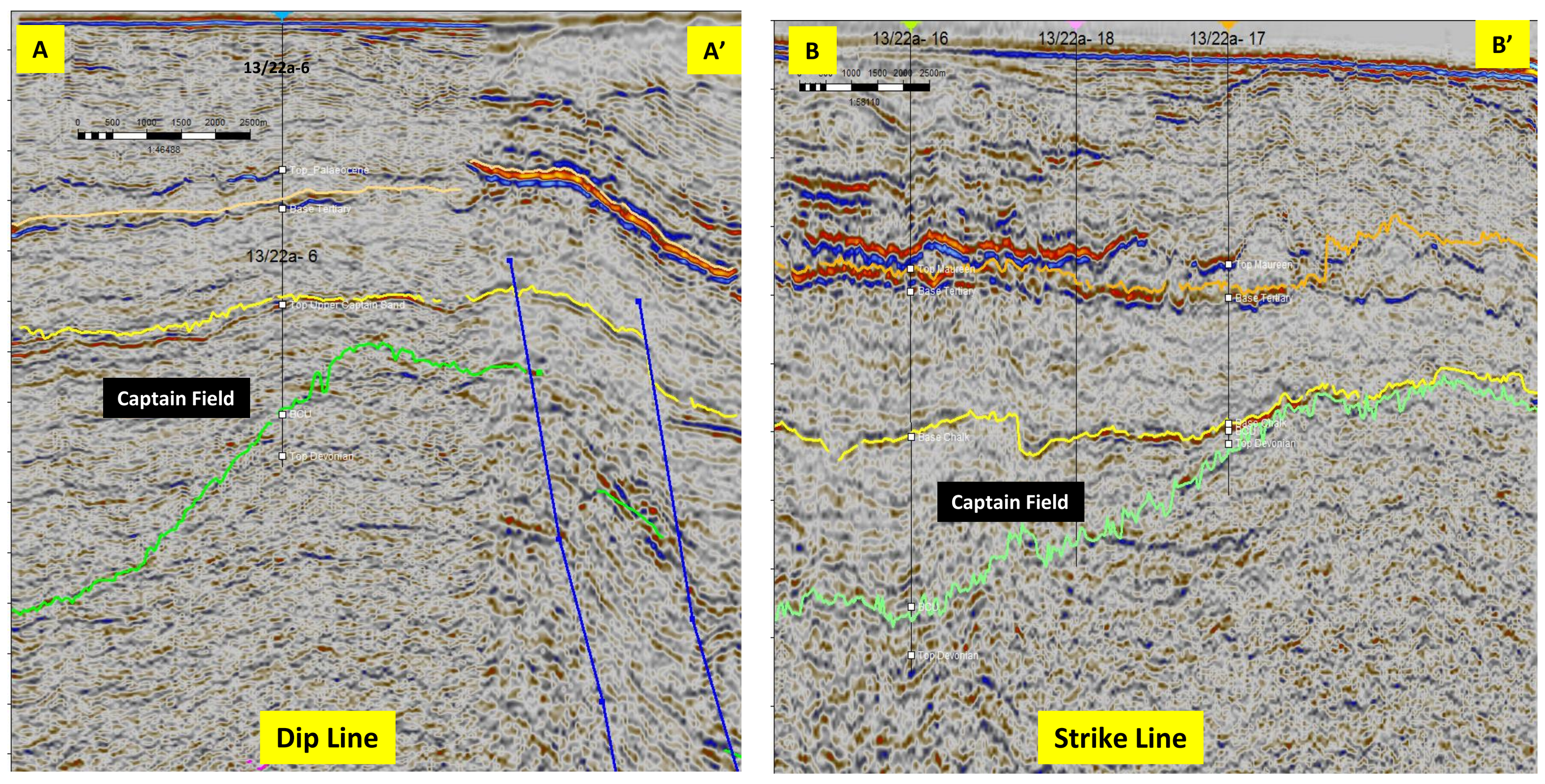
The calculated storage capacity is 95.8MT compared to the reported capacity in CO2Stored of 96.5MT.

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 is estimated to be 27.4MT (~40%).

Captain Field seismic lines from PGS MegaSurvey



Near Base Tertiary
Near Top Captain Sandstone
Base Cretaceous Unconformity

Image source: Seismic data provided by PGS under Licence Agreement. Original interpretation from Axis Well Technology, 2015.

Key Risk Summary

Captain Oil Field	Capacity (MT)	Injectivity (mDm)	Engineered Containment			Geo Containment
			Wells /sq.km	Leakage risk	Containment risk	
Selection Criteria	96.5	630,000	n/a	n/a	n/a	8
Due Diligence	95.8	997,500	2.75	0.22	0.62	9

Data

Captain Oil Field is covered by the 3D CNS PGS seismic MegaSurvey. The data quality is acceptable. The well ties confirm the time interpretation.

Well Data quality and coverage – Digital wireline and MWD/LWD logs are available for some of the Captain Field wells.

Capacity Calculation

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

NB.. Volumes refer to production volumes at February 2015.

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[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 high net to gross and excellent quality turbidite sandstones of the Valhall/Wick Sandstone Formation[1]. The reservoir has been subdivided into Upper and Lower Captain which show significant variation in reservoir quality over the entire field[1]. 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 in the Injectivity Validation table.

Injectivity Validation

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

Injectivity cont'd

The permeability thickness calculated during the validation process is 997,500 mDm. This is approx. 50% 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 CO2 injectivity is expected to be excellent.
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.
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 CO2. 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.
There is a high degree of confidence that the injectivity rates can be achieved.

Containment Validation

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	
Captain Oil Field	218.001	2	2	1	1	1	1	8
		3	2	1	1	1	1	9

Low=1 Medium=2 High=3

2 values in CO2Stored
1 no additional data to qc, values taken from CO2Stored

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 CO2.

Field data and published literature [1,2] 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 [1].
The Sola/Rodby Shale, with overlying Chalk Group, provides an effective overburden seal to the Captain field [2]. CO2 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[2] . The Lower Aptian Shales sit below the Lower Captain sands. 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.

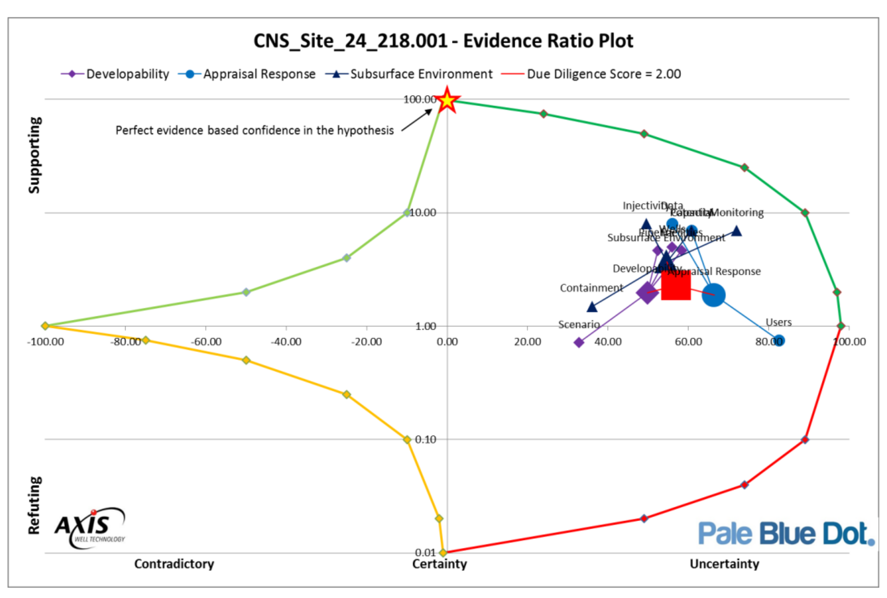
Costs

Site Reference:	24	Site Description	Captain Oil Field
Capacity:	95.8	Water Depth (m)	105.46
Concept Cost (£m)	Comparative Development	Ultimate Development	Description
Tonnes Injected (MT)	95.8		Total Stored CO2 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, NUI, Templates, ties-Ins,
PM & Eng:	£15.9m		10% of Facilities Costs
Decommissioning:	£79.6m		£10m per NUI, £4m per dry well, £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 CO2	6.92		

*These costs are not the full cost of storage as they omit MMV, security instruments, handover to DECC and profit.

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.



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 CO2 storage. With such a large density of horizontal wells, well collision could be considered a risk in this target.

Due to the deeper water depth (105m), wells have been conservatively assumed as being drilled by Semi-Submersible Drilling Unit. Subsea well costs are assumed to be £28M per well, resulting in a 5 well development cost of £140.4M.

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 CO2 storage.

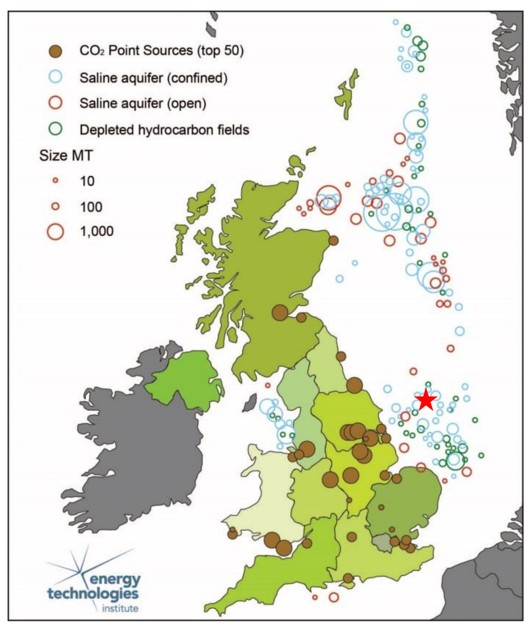
References
1. The Millennium Atlas: Petroleum Geology of the Central and Northern North Sea. Evans, D. Graham, C, Armour A, and Bathurst, P. London, The Geological Society of London.
2. S.J Pinnock & A. R .J Clitheroe. The Captain Field, Block 13/22a, UK North Sea. Geological Society, London, Memoirs 2003, v.20; p431-441.

Site 24 – 218.001 - Captain Oil Field - CNS

Site Summary			
Capacity (Due Diligence):	95.8 MT	UKCS Block:	13/22
Unit Designation:	Oil and Gas	Beachhead:	St Fergus
Formation:	Captain Sandstone Mbr., Wick SST Fm.	Water Depth:	105 m
Containment Unit:	Hidra Formation	Reservoir Depth:	823 m TVDSS (2700 ft)
Availability/COP:	2029	Region:	CNS

Client	The Energy Technologies Institute	Title	D06: Prospect Summary Sheets	Date of Issue	7th August 2015
Project Title	DECC Strategic UK CCS Storage Appraisal Project	Classification	Client Confidential	Version	V00

Site 26 – 139.020 – Bunter Closure 40 – SNS



Major offshore areas covered by CO2Stored (© Energy Technologies Institute)

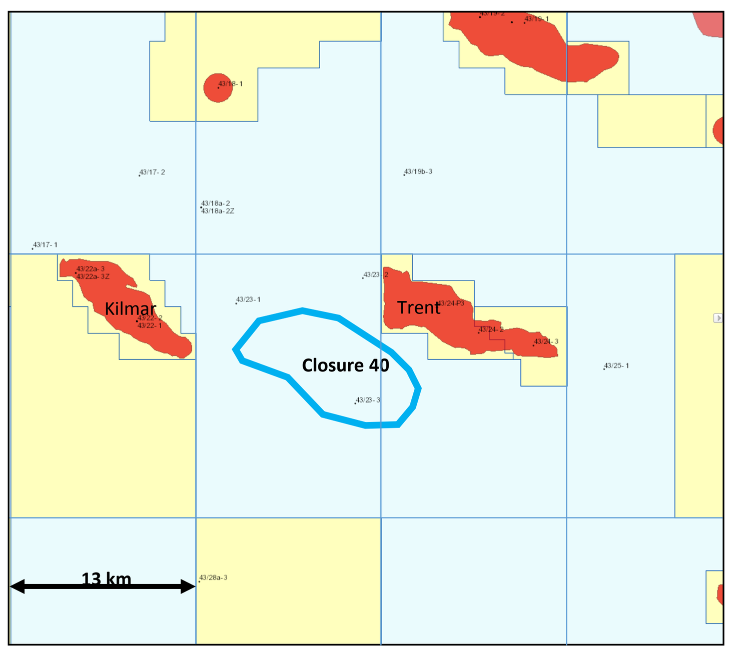


Image source: courtesy of CDA through an open licence agreement

Development Concept

CO2 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.

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.

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. CO2 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.

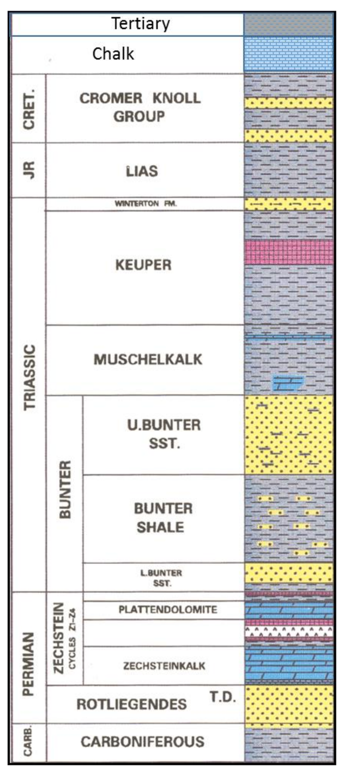


Image source: modified from Cooke-Yarborough (1991) "The Hewett Field, Blocks 48/28-29-30, 52/4a-5a, UK North Sea", *In* Abbotts, I. L. (ed.), 1991, United Kingdom Oil and Gas Fields, 25 Years Commemorative Volume, Geological Society Memoir No. **14**, pp. 433-442.

Axis generated Top Bunter Sst depth map (ft tvdss)

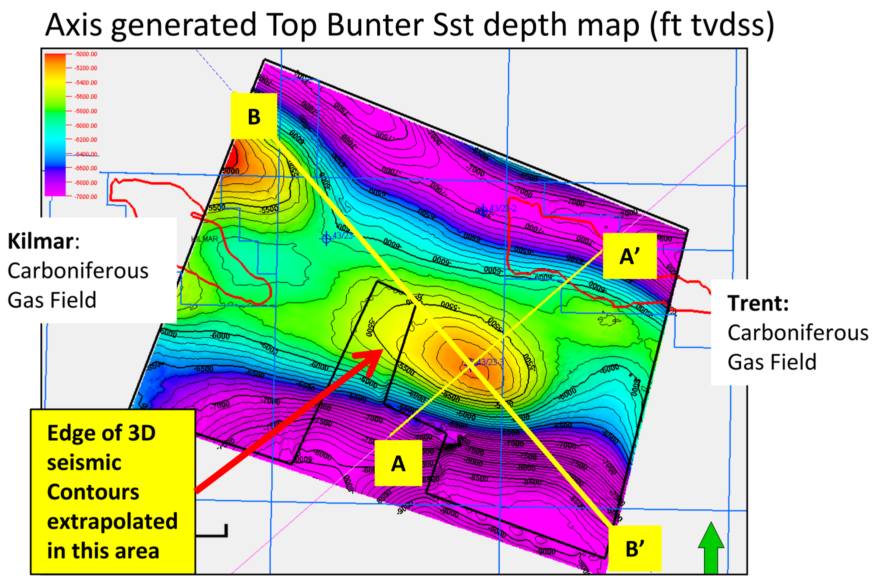


Image source: Original interpretation from Axis Well Technology, 2015

Ci: 100ft
Closing Contour: 5700 ftss

Axis generated Bunter Sst Isochore (ft), generated from well data (43/23-1 ,-2 and -3)

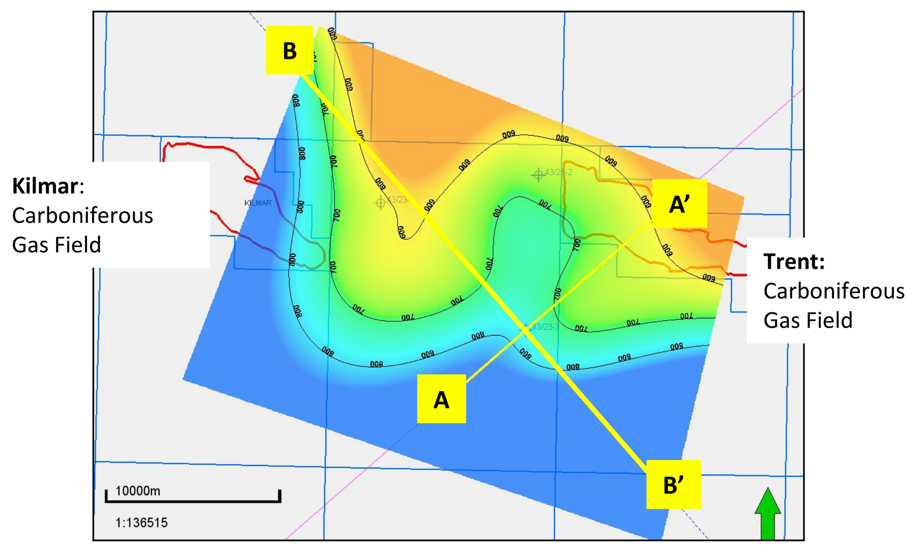


Image source: Original interpretation from Axis Well Technology, 2015

Ci: 100ft

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.

Key Risk Summary

Bunter Closure 40	Capacity (MT)	Injectivity (mDm)	Engineered Containment			Geo Containment
			Wells /sq.km	Leakage risk	Containment risk	
Selection Criteria	84	22,673	0.02	n/a	n/a	6
Due Diligence	100	49,864	0.02	0.002	0.00004	6

Capacity Calculation

Thickness² [m]	GRV [MMm3]	NTG²	Porosity¹	CO2 Density³ [Tonnes/ m3]	Pore Space Utilisation³	Pore Volume [MMm3]	Theoretical Capacity [MT]
230	6952	0.8	0.2	0.79	0.11	1112	100

NB. 1: Analogue site data from 5/42 2: Estimated from CDA composite logs 3: CO2Stored

Injectivity Validation

Zone	Depositional Environment	Gross Thickness² [m]	NTG²	Porosity¹	Perm¹ [mD]	Kh [mDm]
Bunter Sst	Fluvial/ Lacustrine	230	0.8	0.2	271	49864

NB. 1: Analogue site data from 5/42 2: Estimated from CDA composite logs 3: CO2Stored

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.

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 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 for this storage site.

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 CO2 injectivity within the SNS is considered to be good. Neither reservoir quality nor injectivity are considered to be a high risk.

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). CO2 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.

Bunter Closure 40: Strike and Dip seismic lines from PGS MegaSurvey

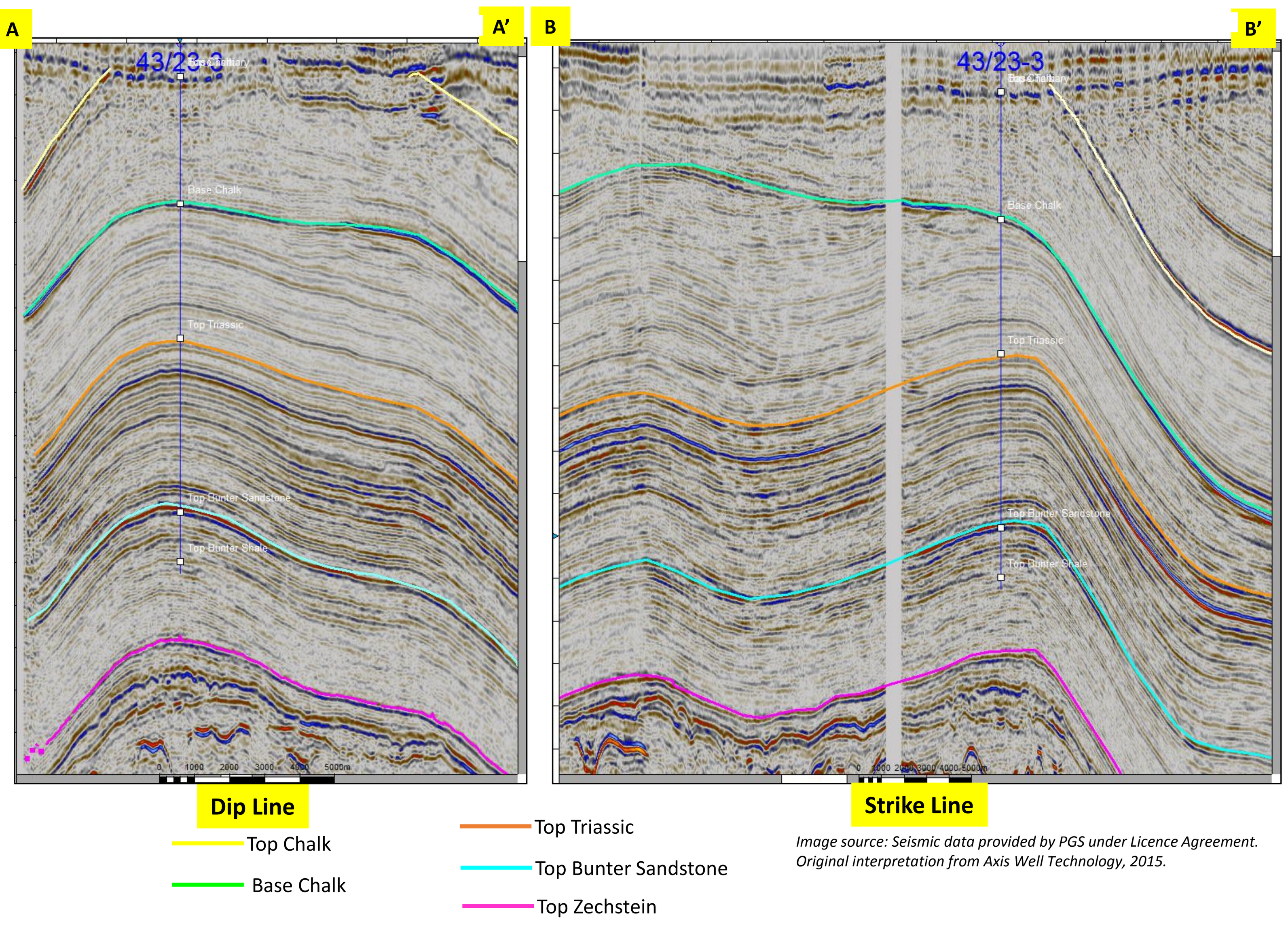


Image source: Seismic data provided by PGS under Licence Agreement. Original interpretation from Axis Well Technology, 2015.

Containment Validation

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

Low=1 Medium=2 High=3 2 values in CO2Stored
1 no additional data to qc, values taken from CO2Stored

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 can be drilled by a low cost class 1 Jack-Up Drilling Unit. Platform well costs are assumed to be £24M per well, resulting in a 5 well development cost of £118.9M.

Costs

Site Reference:	26	Site Description	Bunter Closure 40
Capacity:	100	Water Depth (m)	30
Concept Cost (£m)	Comparative Development	Ultimate Development	Description
Tonnes Injected (MT)	100		Total Stored CO2 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, Templates, ties-Ins,
PM & Eng:	£10m		10% of Facilities Costs
Decommissioning:	£54.8m		£10m per NUI, £4m per dry well, £8m per subsea 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 CO2	5.35		

*These costs are not the full cost of storage as they omit MMV, security instruments, handover to DECC and profit.

Containment

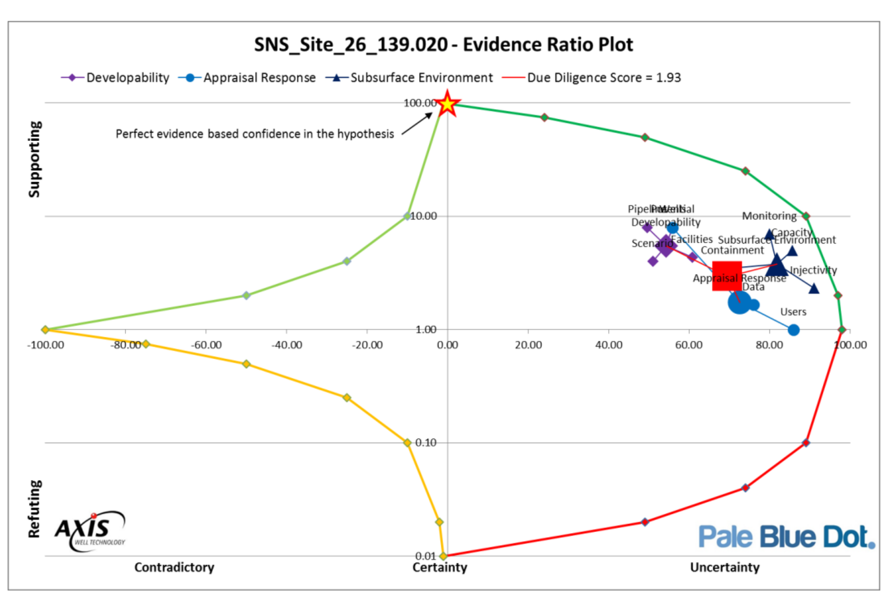
An overburden assessment has been conducted above and adjacent to the Bunter Sandstone to identify secondary containment horizons and potential migration pathways out of the storage complex, in the unlikely event of a seal or fault leakage of the sequestered CO2.

The site is a simple 4-way dip closure. The Bunter sandstone reservoir is overlain by 2000ft 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 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.

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.



Commercial Issues

Bunter closure 40 is in the vicinity of 43/23 which is currently unlicensed for oil and gas activity

Site 26 – 139.020 – Bunter Closure 40 - SNS

Site Summary			
Capacity (Due Diligence):	100 MT	UKCS Block:	Quad 43; Blocks 23, 24
Unit Designation:	Saline Aquifer	Beachhead:	Barmston
Formation:	Triassic Bunter Sandstone	Water Depth:	30 m
Containment Unit:	Rot Halite Member	Reservoir Depth:	1550 m TVDSS (5,085 ft)
Availability/COP:	n/a	Region:	SNS

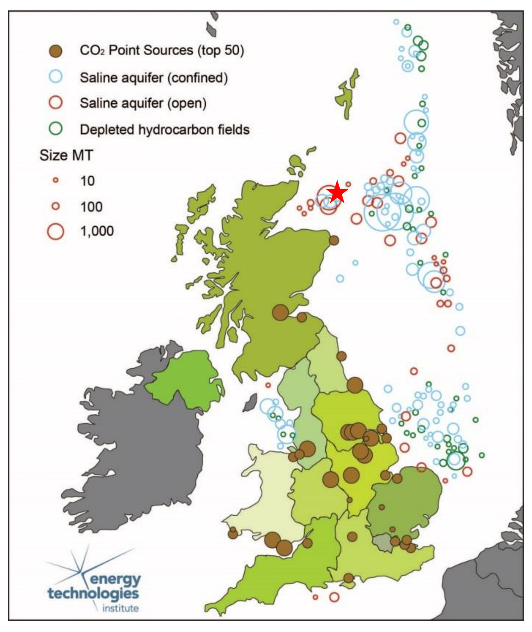
Client	The Energy Technologies Institute	Title	D06: Prospect Summary Sheets	Date of Issue	7th August 2015
Project Title	DECC Strategic UK CCS Storage Appraisal Project	Classification	Client Confidential	Version	V00

Strategic UK CCS Storage Appraisal Project

References

1. Michele Bentham (2006) "An assessment of carbon sequestration potential in the UK – Southern North Sea case study" Tyndall Centre for Climate Change Research and British Geological Survey
2. Heinemann, N., Wilkinson, M., Pickup, G.E., Haszeldine, R.S. and Cutler, N.A. (2011) "Co2 storage in the offshore UK Bunter Sandstone Formation", *International Journal of Greenhouse Gas Control* **6** (2012), 210-219.

Site 27 – 217.000 - Coracle – CNS



Major offshore areas covered by CO2Stored (© Energy Technologies Institute)

217.000 Coracle Closure 012 20 – **Coracle SST Mbr.**, Wick SST Fm., Cromer Knoll Group

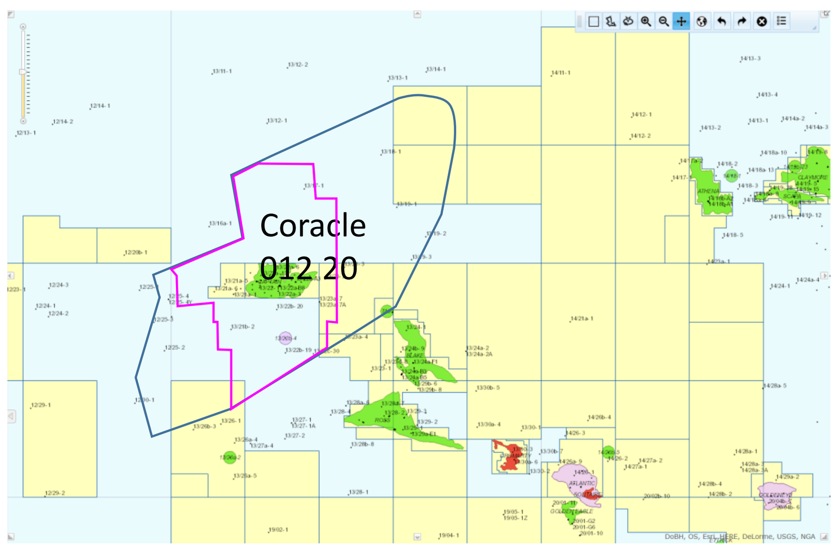


Image source: courtesy of CDA through an open licence agreement

Area covered by 3D

Development Concept

<u>CO2 volumes cf ETI Scenarios</u>
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

<u>Build out potential</u>
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.

<u>Comparative Development Concept</u>
A new subsea development in the vicinity of Atlantic and Cromarty, with 2 deviated wells each injecting 1MT/yr; totalling 35MT over 20 years. CO2 delivered via re-use of 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.

<u>Site growth potential; theoretical Ultimate Development Concept</u>
The site has a theoretical storage capacity of ~35MT.
The site has no additional growth potential.

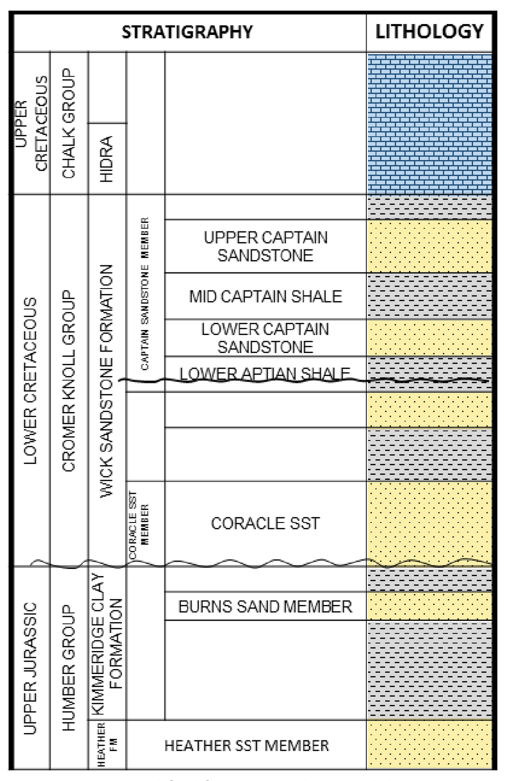
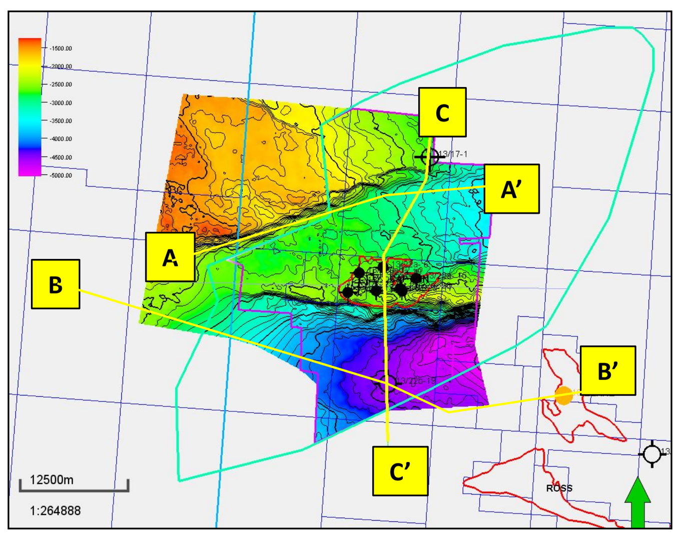


Image source: modified from Pinnock, S. J., Clitheroe, A. R. J., and Rose, P. T. S, The Captain Field, Block 13/22a, UK North Sea, Geological Society, London, Memoirs 2003, v20; p431-441

Axis generated Near Top Lower Cretaceous depth map (ft)



Coracle CO2Stored outline

Ci: 100ft

3D seismic coverage within the Coracle CO2Stored outline (649 sq km)

Data

Approximately one third of the storage site is covered by 3D seismic available in the PGS MegaSurvey. Degradation of data quality below chalk renders the seismic mapping of the Lower Cretaceous and Jurassic less reliable[2]. 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.

Random Strike seismic line along the Coracle Saline Aquifer

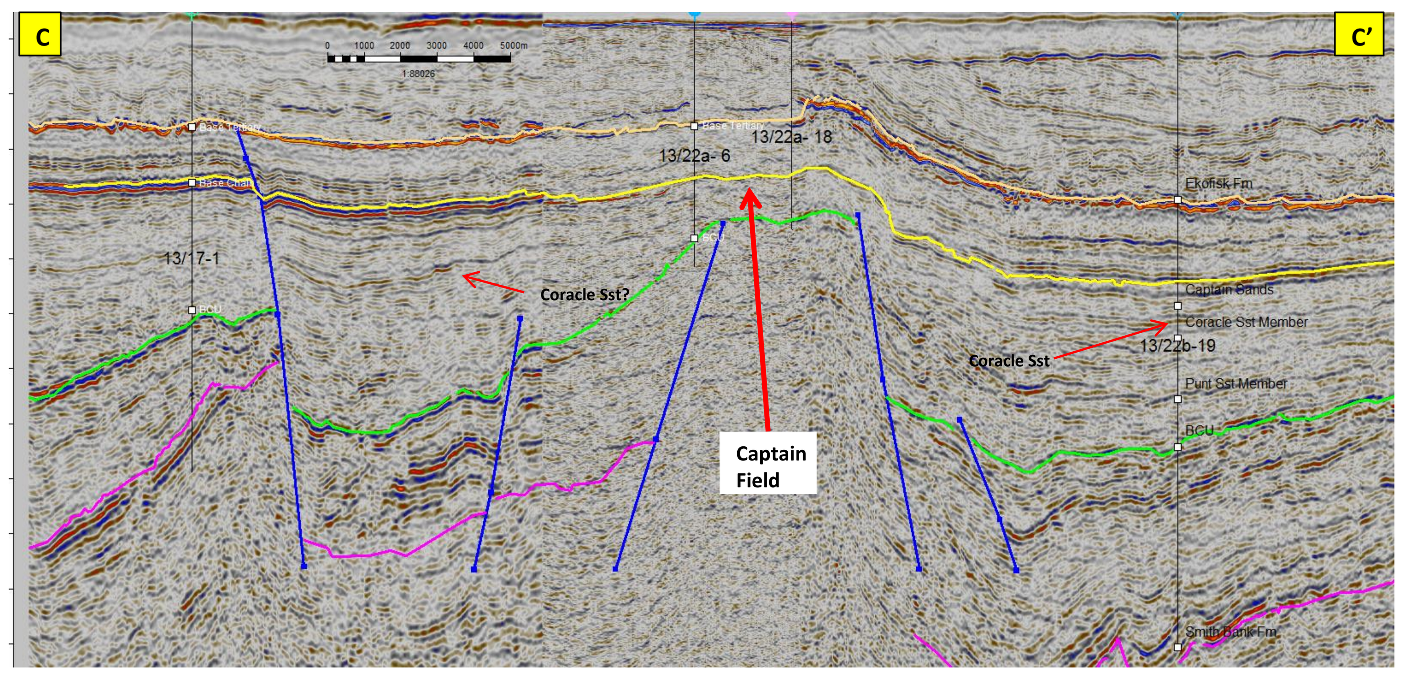
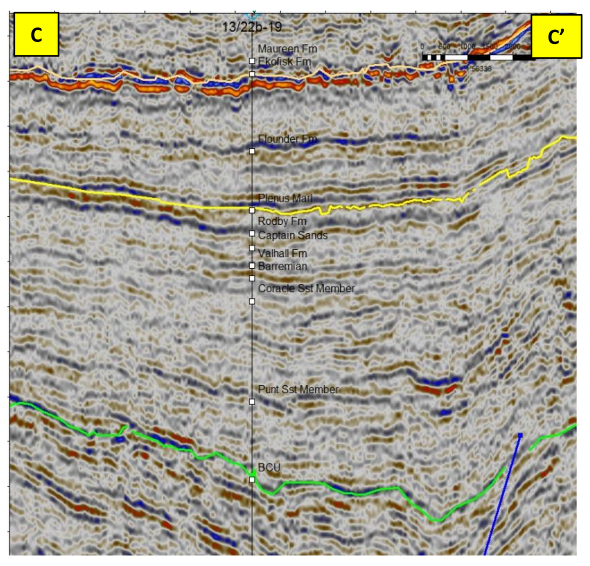


Image source: Seismic data provided by PGS under Licence Agreement. Original interpretation from Axis Well Technology, 2015.

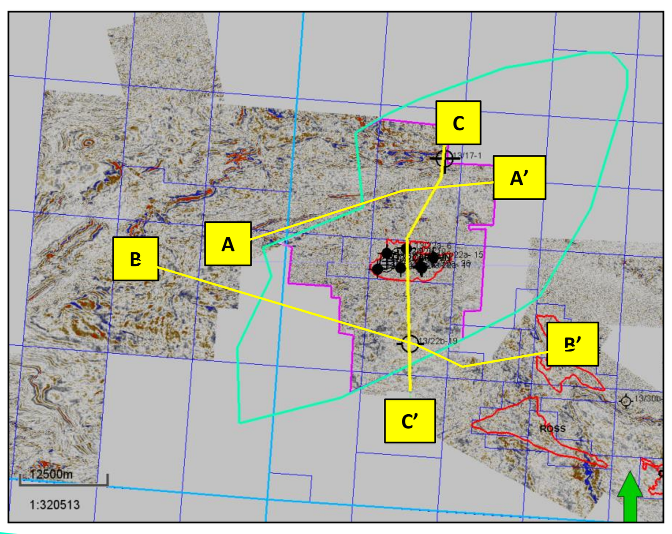
Near Base Tertiary
Base Cretaceous Unconformity
Near Top Captain Sandstone
Near Top Permian

Random Strike seismic line along the Coracle Fairway



Near Base Tertiary
Near Top Captain Sandstone
Base Cretaceous Unconformity

Time slice at 1300msec through Coracle Saline Aquifer area



Coracle CO2Stored outline

3D seismic coverage within the Coracle CO2Stored outline (649 sq km)

Random Dip seismic lines across the Coracle Saline Aquifer

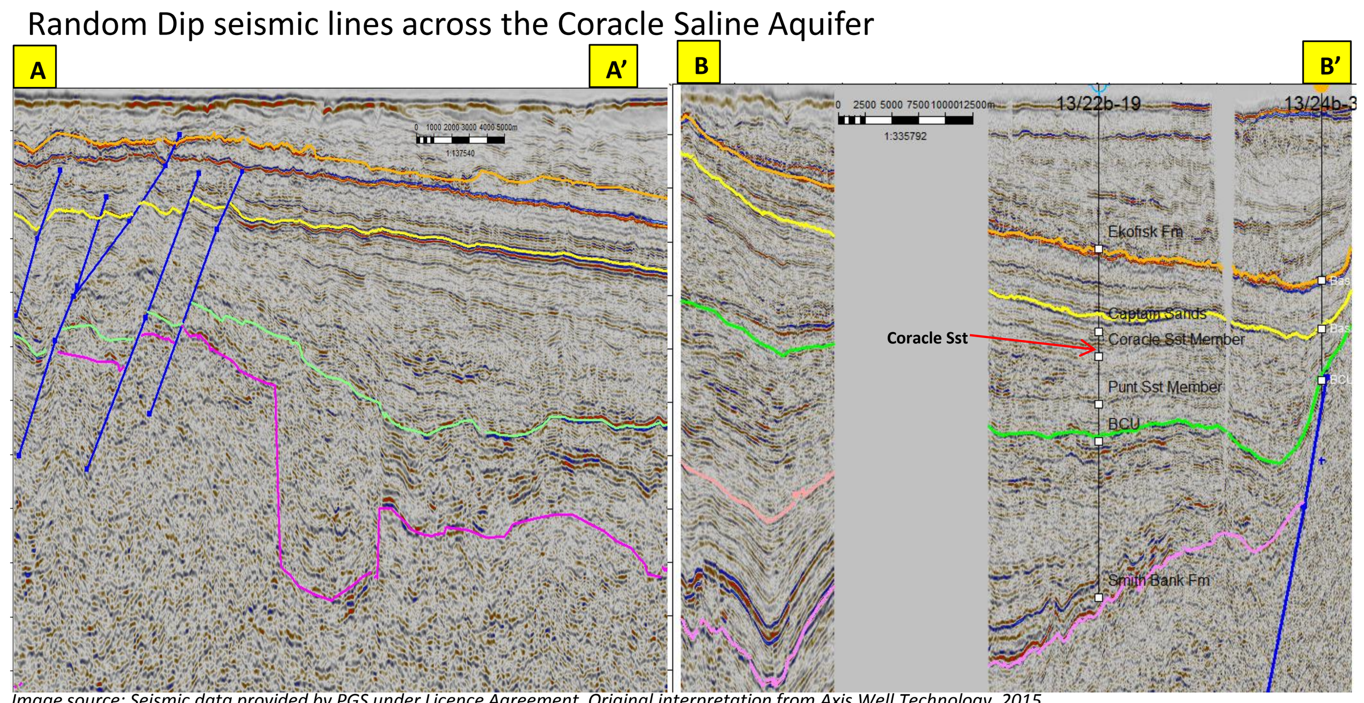


Image source: Seismic data provided by PGS under Licence Agreement. Original interpretation from Axis Well Technology, 2015.

Near Base Tertiary
Base Cretaceous Unconformity
Near Top Captain Sandstone
Near Top Middle Jurassic
Near Top Permian

Key Risk Summary

Coracle	Capacity (MT)	Injectivity (mDm)	Engineered Containment			Geo Containment
			Wells /sq.km	Leakage risk	Containment risk	
Selection Criteria	81	378,585	0.13	n/a	n/a	11
Due Diligence	35	280,038	0.1	0.21	0.021	13

Capacity Calculation

Thickness[2] [m]	GRV [MMm3]	NTG[2]	Porosity[1]	CO2 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

NB. 1: DECC relinquishment reports 2: Estimated from CDA composite logs 3: CO2Stored

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 greatly reduced area used, due to incomplete seismic availability.
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.
The Coracle reservoir comprises moderate net to gross and excellent quality channelised deepwater sandstones of the Wick Sandstone Member. The reservoir properties are summarised in the Injectivity Validation table.

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 CO2 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). CO2 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 1850 psi achieves an injectivity of 2.48 MT/year per well. This is below the calculated minimum fracture pressure of 2632 psi at the top of the reservoir.

Injectivity Validation

Zone	Depositional Environment	Gross Thickness [m]	NTG	Porosity	Perm [mD]	Kh [mDm]
Coracle	Channelised deepwater	124	0.50	0.27	4500	280,038

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 CO2.

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.

Engineering Risk

The engineering containment risk is moderate, with 224 wells in total, and 134 abandoned wells considered to be at risk of leakage. Six 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.

Costs

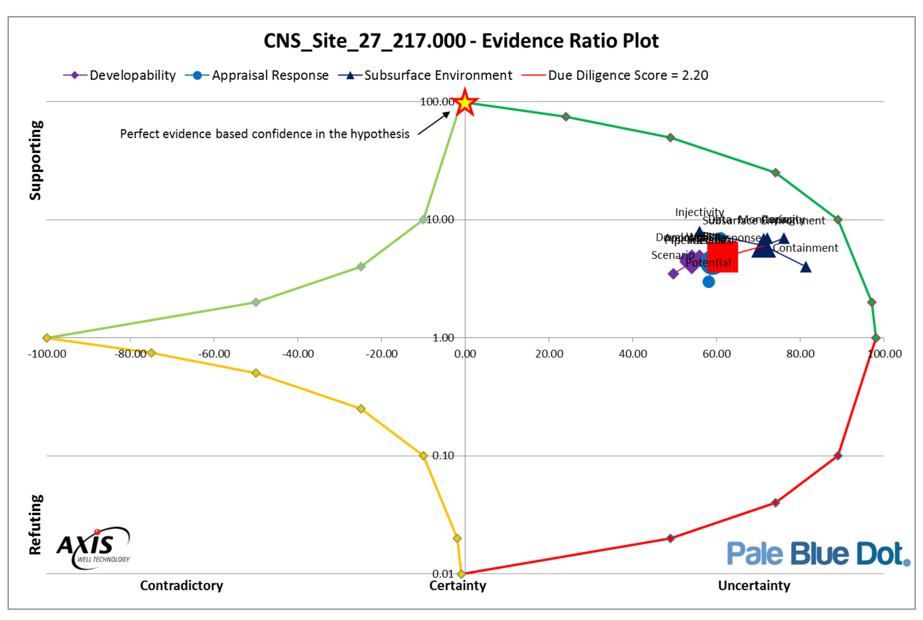
Site Reference:	27	Site Description	Coracle_012_20
Capacity:	35	Water Depth (m)	99
Concept Cost (£m)	Comparative Development	Ultimate Development	Description
Tonnes Injected (MT)	35		Total Stored CO2 for proposed scheme
Appraisal Cost:	£74m		Appraisal Wells + Seismic Data Acquisition & Interpretation
Development Well Cost:	£54.1m		Drilling & Completion Costs of wells.
Facilities Cost:	£158.3m		Landfall, Pipeline, NUI, Templates, ties-Ins,
PM & Eng:	£15.9m		10% of Facilities Costs
Decommissioning:	£55.6m		£10m per NUI, £4m per dry well, £8m per subsea well
<u>Subtotal</u>	£357.7m		-
Contingency	£71.6m		20% of Development & Facilities Costs
OPEX (20years)	£189.9m		OPEX Cost for 20 years (6% of facilities costs)
Total:	£619m		
£/T CO2	17.69		

*These costs are not the full cost of storage as they omit MMV, security instruments, handover to DECC and profit.

Containment Validation

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	
Coracle_012_20	217	1	1	2	2	3	2	11
		2	2	2	2	3	2	13

Low=1 Medium=2 High=3 2 values in CO2Stored
1 no additional data to qc, values taken from CO2Stored



Well Design

Due to the deep water depth (98m), wells have conservatively been 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 £135M

Commercial Issues

As with other aquifers the exact development location is flexible. Therefore site access is unlikely to be an issue.

Site 17 – 217.000 - Coracle - CNS

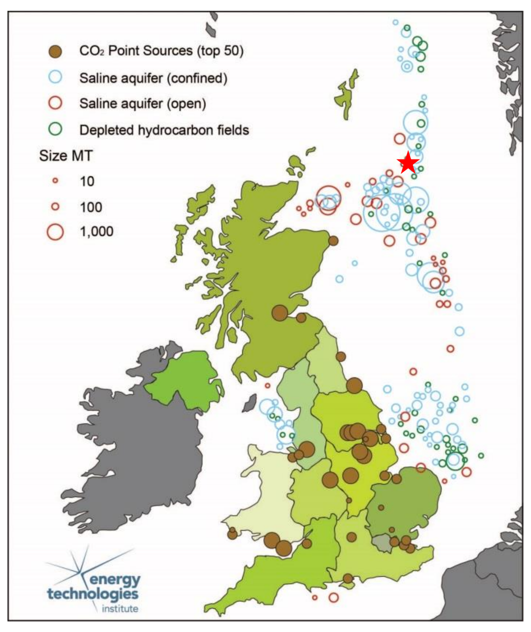
Site Summary			
Capacity (Due Diligence):	35 MT	UKCS Block:	Quadrant 13
Unit Designation:	Saline Aquifer	Beachhead:	St Fergus
Formation:	Coracle Sandstones Lower Cretaceous	Water Depth:	99 m
Containment Unit:	Hidra Formation	Reservoir Depth:	1066 m TVDSS (3500 ft)
Availability/COP:	n/a	Region:	CNS

Client	The Energy Technologies Institute	Title	D06: Prospect Summary Sheets	Date of Issue	7th August 2015
Project Title	DECC Strategic UK CCS Storage Appraisal Project	Classification	Client Confidential	Version	V00

Strategic UK CCS Storage Appraisal Project

References
1. S.J Pinnock & A. R .J Clitheroe The Captain Field, Block 13/22a, UK North Sea. Geological Society, London, Memoirs 2003, v.20; p431-441.
2. Relinquishment Report, License P1403, Block 13/22d, Chevron North Sea Limited, Korean National Oil Company

Site 28 – 252.001 - Harding Central Oil Field – CNS



Major offshore areas covered by CO2Stored (© Energy Technologies Institute)

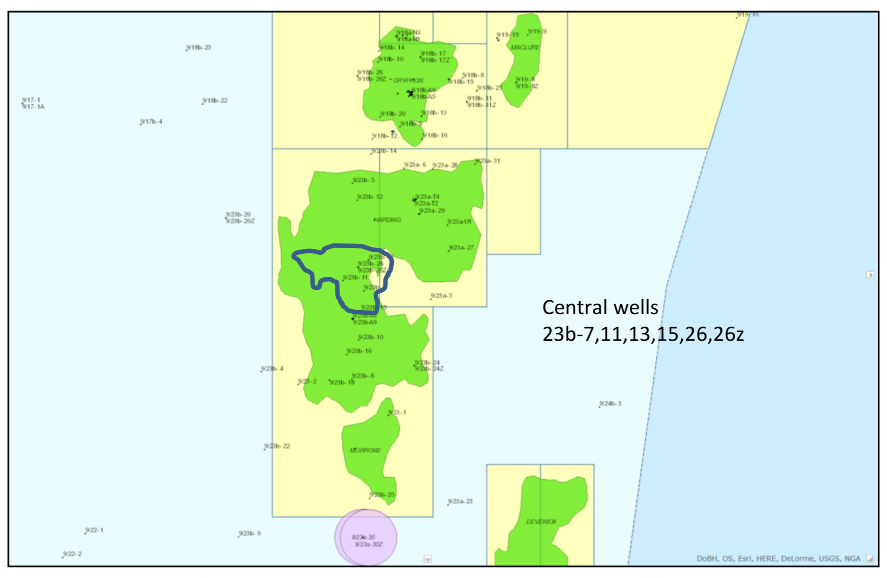


Image source: courtesy of CDA through an open licence agreement

Harding Central

Development Concept

CO2 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

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.

Comparative Development Concept
A new subsea development in the vicinity of Harding, with 4 deviated wells each injecting 1MT/yr; totalling 80MT over 20 years. CO2 delivered via the re-use MGS 30" pipeline from St Fergus with 35MT/yr capacity combined with a new 20" 78km 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 ~85MT.
The site has no additional growth potential.

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.

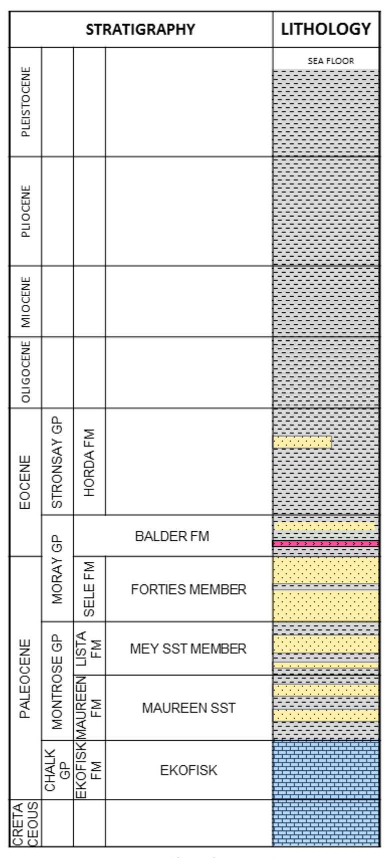


Image source: modified from Wills, J. M., The Forties Field, Block 21/10, 22/6a, UK North Sea. BP Exploration, Fig 2

Axis generated Top Balder Sst depth map (ft tvdss)

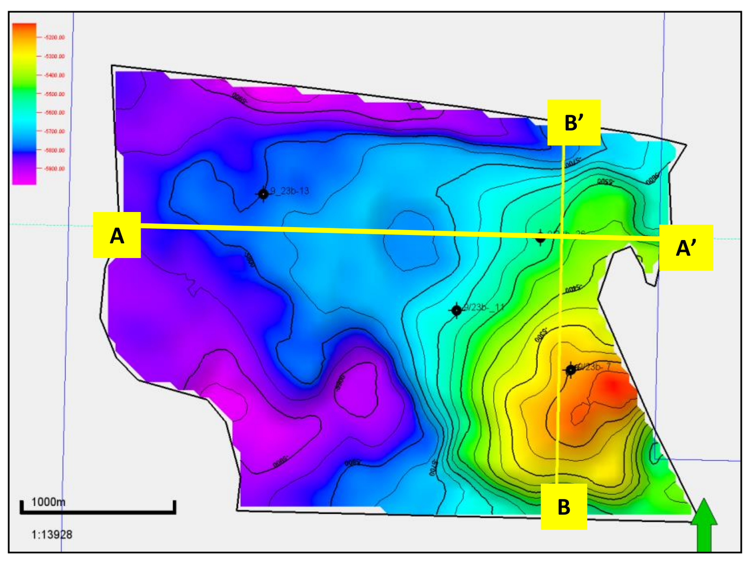


Image source: Original interpretation from Axis Well Technology, 2015

Ci:50ft

Axis generated Balder Sst Isochore, generated from well data (9/23b-7, -11 and -26)

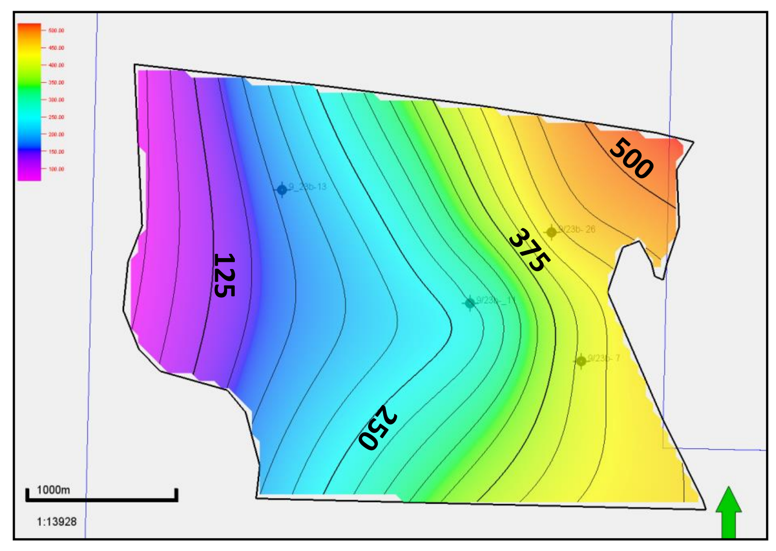


Image source: Original interpretation from Axis Well Technology, 2015

Ci:25ft

Harding Oil Field: Strike and Dip seismic lines from PGS MegaSurvey)

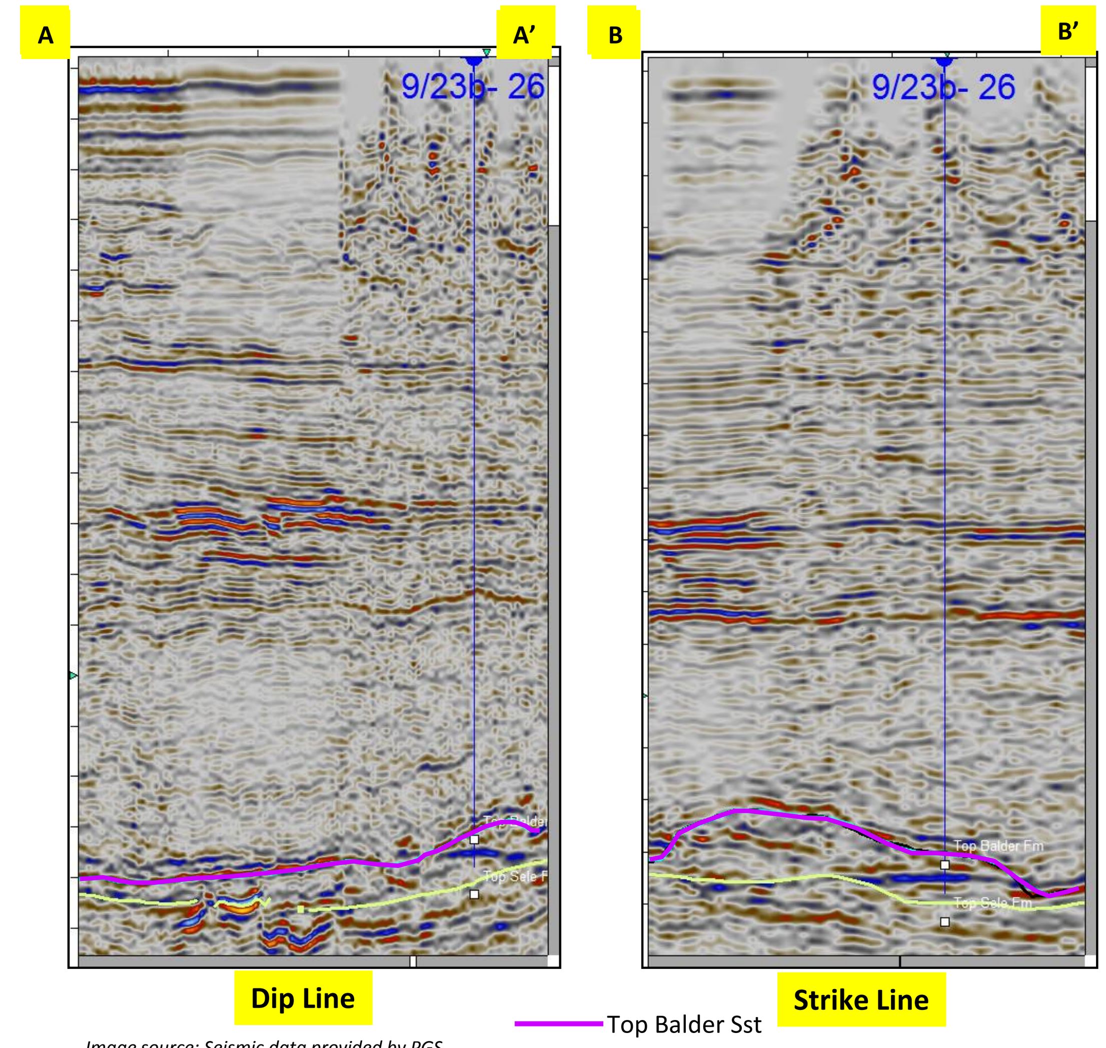


Image source: Seismic data provided by PGS under Licence Agreement. Original interpretation from Axis Well Technology, 2015.

Key Risk Summary

Harding Central Oil Field	Capacity (MT)	Injectivity (mDm)	Engineered Containment			Geo Containment
			Wells /sq.km	Leakage risk	Containment risk	
Selection Criteria	76.2	723,900	18.4	n/a	n/a	8
Due Diligence	84.8	703,534	17.2	0.17	2.86	9

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%).

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.

Capacity Calculation

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 at COP	84.7	MT

NB.. Volumes refer to production volumes at February 2015.

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 literature1 have been reviewed in order to confirm the reservoir properties which have then been used to validate the permeability thickness and expected injectivity.

The Harding field is split by multiple accumulations: North, Central and South. The CO2 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[1]. No field wide permeability barriers or baffles exist horizontally or vertically, with communication to the upper injected sandstones confirmed by pressure data (Ref1). The reservoir properties are summarised in the table.

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 CO2storage calculation, and is representative of the average thickness quoted in published literature1. NTG, porosity and permeability 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 Sandy Unit.

The permeability thickness is very high and based on reservoir quality and the initial CO2 injectivity is expected to be excellent.
The initial production performance per well was converted to an equivalent CO2 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.

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 CO2 to the sandface.

Injectivity Validation

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

Costs

Site Reference:	28	Site Description	Harding Central oil field
Capacity:	**84.8**	**Water Depth (m)**	110
Concept Cost (£m)	**Comparative Development**	**Ultimate Development**	**Description**
Tonnes Injected (MT)	80		Total Stored CO2 for proposed scheme
Appraisal Cost:	£0m		Appraisal Wells + Seismic Data Acquisition & Interpretation
Development Well Cost:	£170.2m		Drilling & Completion Costs of wells.
Facilities Cost:	£38.1m		Landfall, Pipeline, NUI, Templates, ties-Ins,
PM & Eng:	£3.9m		10% of Facilities Costs
Decommissioning:	£41.6m		£10m per NUI, £4m per dry well, £8m per subsea well
Subtotal	£253.5m		-
Contingency	£50.7m		20% of Development & Facilities Costs
OPEX (20years)	£45.7m		OPEX Cost for 20 years (6% of facilities costs)
Total:	£349.8m		
£/T CO2	4.37		

*These costs are not the full cost of storage as they omit MMV, security instruments, handover to DECC and profit.

Containment Validation

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	
Harding Central oil field	252.001	2	2	1	1	1	1	8
		2	2	1	1	1	2	9

Low=1 Medium=2 High=3
2 values in CO2Stored
1 no additional data to qc, values taken from CO2Stored

Containment

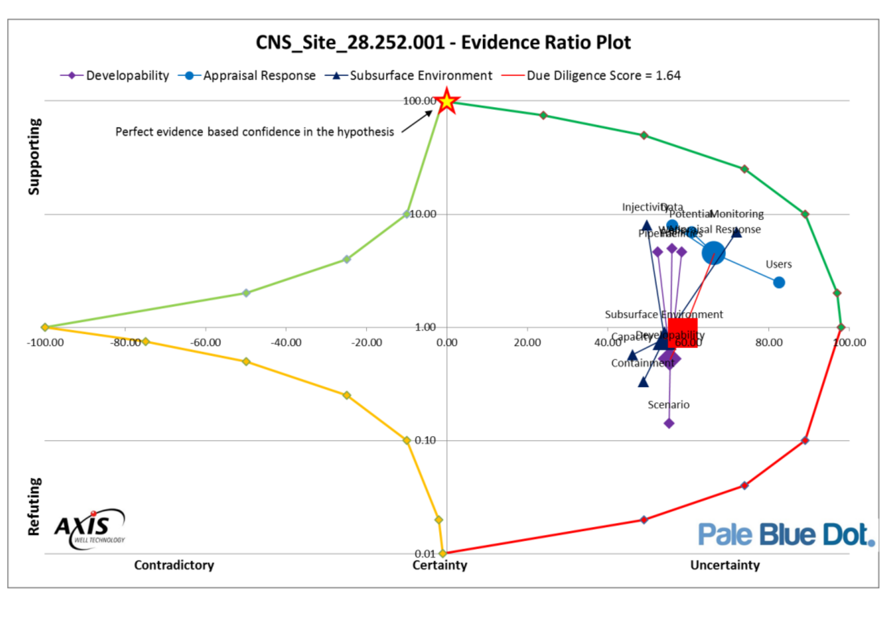
An overburden assessment has been conducted above and adjacent to the Central Harding field to identify secondary containment horizons and potential migration pathways out of the Harding storage complex, in the unlikely event of a seal or fault leakage of the sequestered CO2.

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 west[1]. The T60 interval above the Upper Sandy Unit provides an effective overburden seal to the Harding field[1]. CO2 is not expected to leak through the top Mercia seal which has already trapped Harding hydrocarbons over geological time.

There is however significant risk associated with containment between the different Harding area fields (Harding Central/ North, Gryphon and Maclure). Due to the sand injectite 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 is high for the Harding Field Complex, 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.



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 will need to be drilled by Semi-Submersible Drilling Unit. Subsea well costs are assumed to be £43M per well, resulting in a 5 well development cost of £212.7M.

Commercial Issues

The COP date for Harding is currently 2025. Harding is operated under Petroleum Licence P478 by Taqa.

Site 28 – 252.001 - Harding Central Oil Field - CNS

Site Summary			
Capacity (Due Diligence):	84.8 MT	**UKCS Block:**	9/23
Unit Designation:	Oil	**Beachhead:**	St Fergus
Formation:	Eocene Balder Formation	**Water Depth:**	110 m
Containment Unit:	Horda Formation	**Reservoir Depth:**	1548 m TVDSS (5080 ft)
Availability/COP:	2025	**Region:**	CNS

Client	The Energy Technologies Institute	**Title**	D06: Prospect Summary Sheets	**Date of Issue**	7th August 2015
Project Title	DECC Strategic UK CCS Storage Appraisal Project	**Classification**	Client Confidential	**Version**	V00

Strategic UK CCS Storage Appraisal Project

References
1. Beckly, A. J., Nash, T., Pollard, R. Bruce, C. Freeman, P and Page, G. (2003) "The Harding Field, Block 9/23b", United Kingdom Oil and Gas Fields, Commemorative Millennium Volume. Geological Society, London Memoir 20, 283-290