Programme Area: Carbon Capture and Storage

Project: UKSAP Database Analysis

Title: UK Storage Appraisal Project Insights

Abstract:

The ‘UKSAP Insights’ deliverable resulted from a series of workshops, led by the UKSAP Chief Technologist and involving key UKSAP project and Member storage experts, aimed at drawing out further insights from the UKSAP data and producing high-level outputs to support future dissemination of UKSAP. This deliverable combines slide packs in four areas (CO2 Migration and Practical Storage, Storage Availability, Security of Storage and a summary of underlying assumptions used in the analysis).

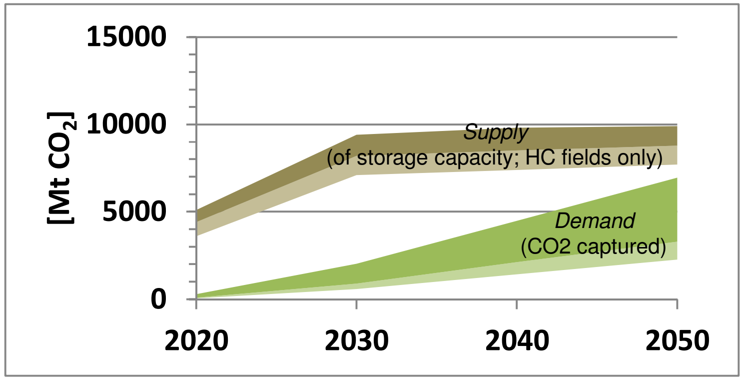
Context:

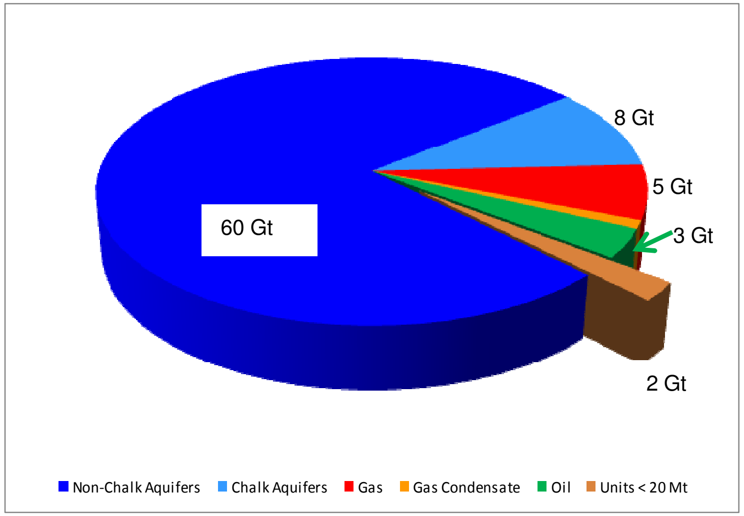
This project was part of the development of the UK’s first carbon dioxide storage appraisal database enabling more informed decisions on the economics of CO2 storage opportunities. It was delivered by a consortium of partners from across academia and industry - LR Senergy Limited, BGS, the Scottish Centre for Carbon Storage (University of Edinburgh, Heriot-Watt University), Durham University, GeoPressure Technology Ltd, Geospatial Research Ltd, Imperial College London, RPS Energy and Element Energy Ltd. The outputs were licensed to The Crown Estate and the British Geological Survey (BGS) who have hosted and further developed an online database of mapped UK offshore carbon dioxide storage capacity. This is publically available under the name CO2 Stored. It can be accessed via www.co2stored.co.uk.

UK Storage Appraisal Project

Insights

Supply versus Demand

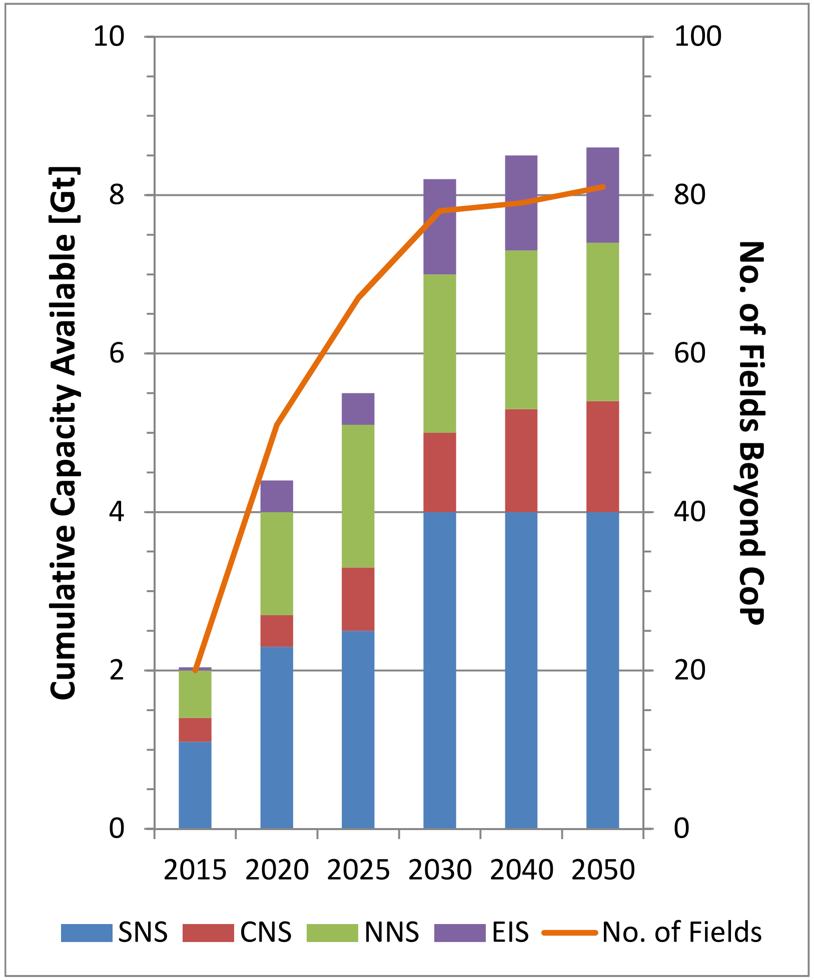




- Estimates of the amount of UK CO_2 emissions that could (or should) be captured vary widely;
- Amongst others, the UKCCC, CCSA and ETI have produced estimates based on assumptions regarding likely growth in electricity demand, the energy mix – fossil fuels, versus nuclear, versus renewables – improvements in energy generation and consumption efficiency etc, consistent with meeting an 80% reduction in CO_2 emissions by 2050;
- Such models predict that *demand* for CO_2 storage capacity based on UK emissions alone will between 2 and 7 Gt (10^9) by 2050.

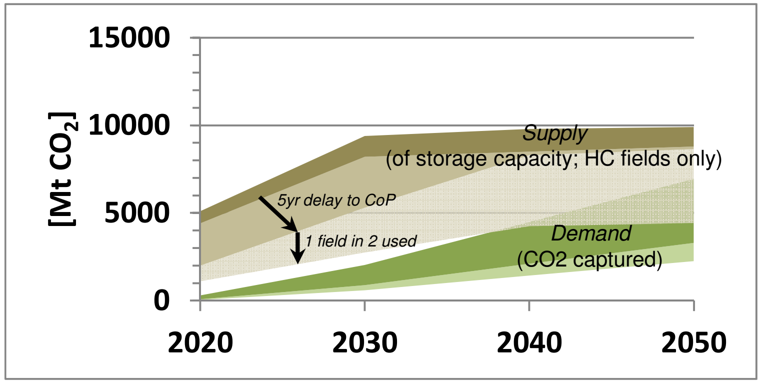
- On the *supply* side of the equation, the ETI's UK Storage Appraisal Project (UKSAP) has identified some 70 Gt of potential storage capacity in offshore geological formations
- Excluding those that are chalk (whose effective permeability and hence suitability for CO_2 storage is particularly uncertain) some 60 Gt are associated with porous and permeable formations containing saline water – or "saline aquifers"
- Potential to store around 8 Gt of CO_2 has been identified in the UK's oil and gas fields (excluding additional storage volume that might be achieved through further extraction of hydrocarbons using CO_2 enhanced oil or gas recovery schemes).
- In order to support and optimise the extraction of hydrocarbons, considerable knowledge has accrued on the nature of the subsurface in and around the UK's oil and gas fields;
- This knowledge can be brought to bear in determining the suitability (or otherwise) of a field for subsequent safe and permanent storage of CO_2.
- Combining expected Cessation of Production (CoP) dates with the estimated range of CO_2 storage capacity for each oil and gas field on the UK Continental Shelf, a curve of theoretical storage capacity *supply* may be generated.
- Comparing the Supply and Demand curves, it would appear at first glance that ample capacity will become available to store all the UK's captured CO_2 in its depleted oil and gas fields.

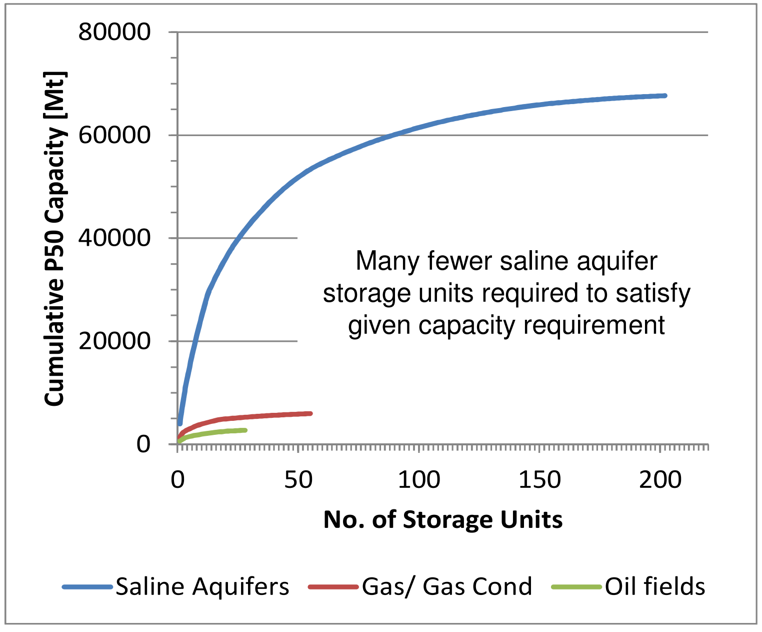
Storage Readiness



- With the exception of deliberate CO_2-enhanced hydrocarbon recovery, CO_2 injection in hydrocarbon fields will not occur prior to cessation of hydrocarbon production. There are however huge uncertainties over CoP timing, which depend on prevailing energy prices and technology development.
- In the period to 2015, current DECC forecasts estimate *ca.* twenty hydrocarbon fields may cease producing, either because declining oil and gas production makes them uneconomic or the installed facilities reach or exceed their design life and become too costly to maintain;
- By 2020 the number of fields predicted to have ceased production is more than double, potentially releasing some 4 Gt of capacity for CO_2 storage;
- Half this capacity (and number of fields) is in the generally pressure depleted Southern North Sea gas fields. These are mostly within 50 - 200 km of a cluster of large stationary CO_2 emitters in Yorkshire.
- Conventionally, once production ceases and the field is prepared for abandonment, one of the first activities undertaken is to isolate the ageing platform from further sources of hydrocarbons;
- This requires abandoning the well stock – usually in a manner that renders their re-use all but impossible;
- Opportunity to gather invaluable base-line data for subsequent monitoring of CO_2 storage operations might thus be lost;
- Expertise (and to some extent data) on facilities and reservoir performance is also typically dispersed, as key individuals transfer to other projects and incentives to manage this information decreases;
- Such eventualities burden potential CCS projects with significant additional cost;
- It is imperative therefore that the potential for CCS is considered prior to CoP, such that appropriate abandonment procedures may be identified and followed to meet the needs of all concerned;
- This requires agreement of policies that promote "storage readiness";

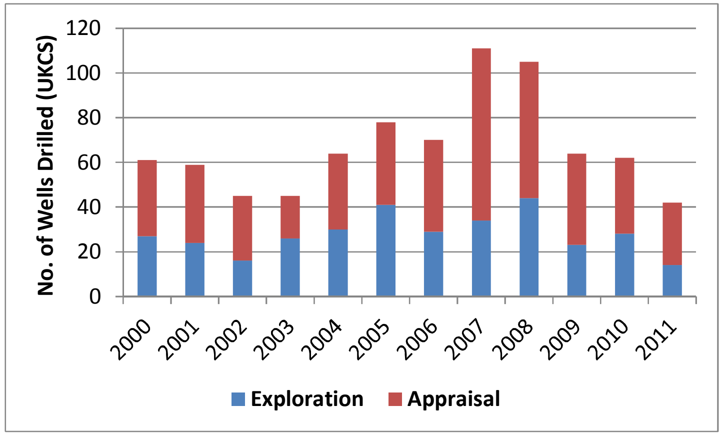
Saline Aquifer Appraisal



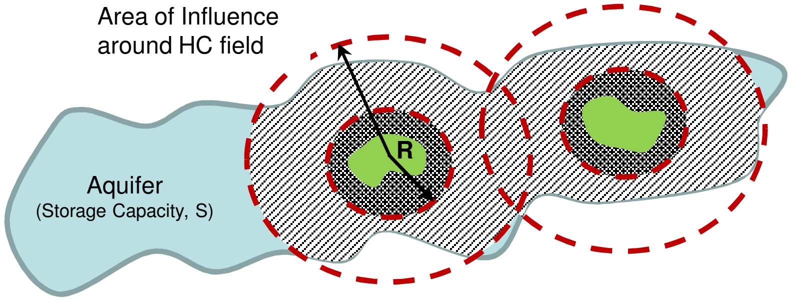


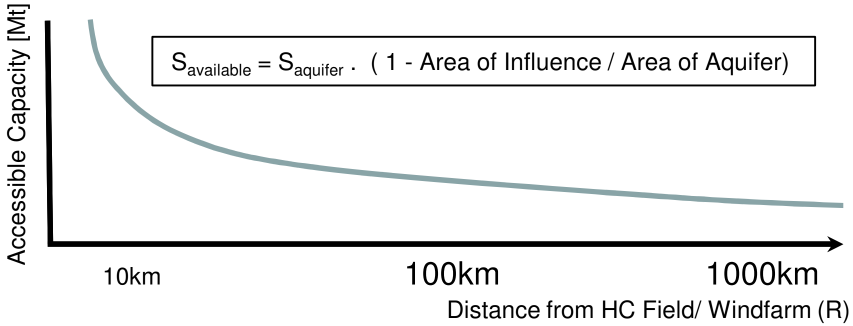
- Of course, even if hydrocarbon fields can be abandoned in a manner that is amenable to subsequent CO_2 storage, they may not all be suitable because of:
  - a field's storage capacity in relation to the requirements of nearby CO_2 capture sources;
  - how costly it might be to transport CO_2 to the site, and develop it for storage (many existing offshore facilities will require replacement as a result of age and/ or non-compatibility with CO_2 operations)
  - whether or not the nature of the reservoir rocks and overburden, and condition of wells drilled into them, are suitable for long-term safe and secure storage.
- The date at which fields will reach the end of their economic life is also uncertain: as technology advances more may be extracted from existing fields, or additional hydrocarbon accumulations tied-back – helped by generally high oil prices! Indeed CoP dates have historically shifted by a decade or so;
- The impacts of just a 5 year delay to CoP dates, and assumption that only 1 in every 2 fields will be used for storage are illustrated, and demonstrate how easily a sense of 'excess' supply over demand could be eroded.
- As previously mentioned, the UK's largest CO_2 storage resource – by an order of magnitude – is in saline aquifers;
- To provide an alternative to hydrocarbon fields, or even countenance the prospect of storing large volumes from CO_2 emitters outside of the UK, they must be considered;
- Often little is known about these formations however, and the potential seals (or barriers to CO_2 migration) that might exist above and around them. In particular, there is a general lack of *dynamic* data, to inform the likely rate of pressure increase as CO_2 is stored, or other mechanisms that might affect sustainable rates at which CO_2 might be injected – and hence the number of wells required, a key determinant of project economics;
- They must therefore be appraised – as every hydrocarbon field is appraised – before an investment decision may be taken.

Appraisal of Saline Aquifers



- Saline aquifer appraisal programmes are likely to involve acquisition of seismic surveys, drilling of wells for core and log data, and testing (eg. production or injection tests, pressure transient analyses, interference tests etc).
- By analogy with hydrocarbon appraisal, several wells are likely to be required per storage site, dependent on depth of current understanding of the formations in question; their areal extent and heterogeneity; regulatory and permitting requirements; level of performance risk that potential investors are willing to tolerate etc.
- Over the past decade, ~60 exploration and appraisal wells per year have been drilled on the UKCS, predominantly related to the oil & gas industry.
- It is easy to see then, that appraisal of an aquifer site could take several years, particularly for early projects. Taken with the picture of relatively limited storage capacity in hydrocarbon fields, this demands that appraisal of offshore UK saline aquifers be given urgent attention.





- Even once ‘fully’ appraised however, an aquifer site might remain *inaccessible* for storage because of potential ‘interference’ with neighbouring activities (hydrocarbon exploitation/ exploration, windfarms etc)
- The required ‘stand-off’ (R) will depend on the surface footprint of facilities, pipelines and cables; expected migration distance of injected CO_2; degree and nature of pressure interference etc
- Clearly as R increases, so does the amount of saline aquifer storage capacity affected.
- Thus CoP dates not only govern availability of HC fields for storage, but may also impact the accessible capacity of saline aquifers
- The UKSAP database “carbonstore” contains the data necessary to compute a curve of accessible storage capacity as a function of ‘interference radius’, R, in order to gain appreciation of how important (or otherwise) this interdependency might be.

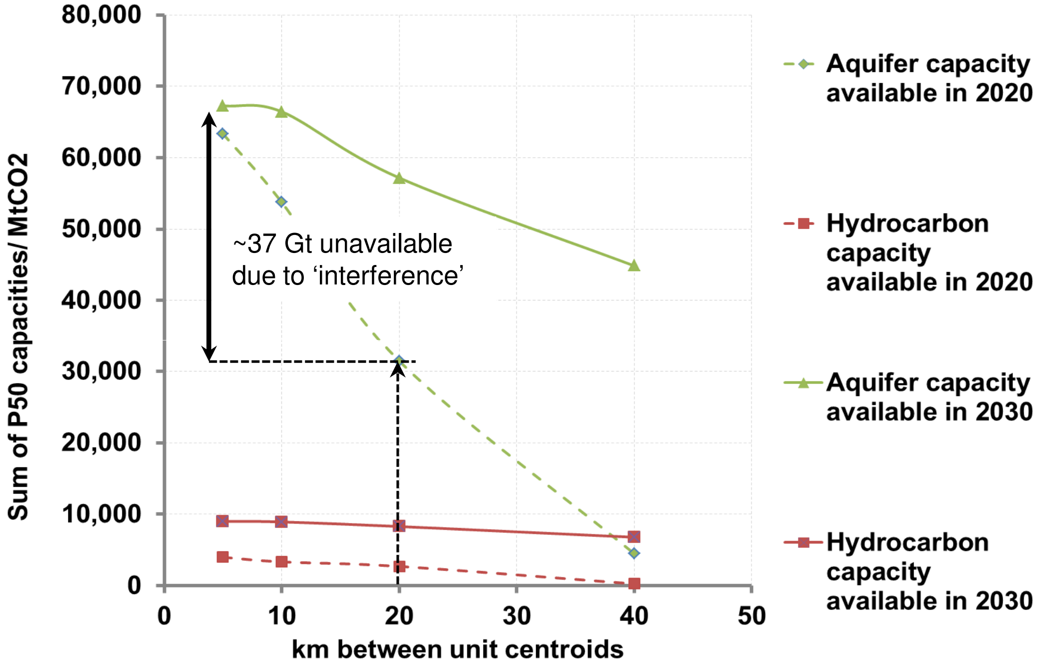
Interference between Activity

- The potential impact of hydrocarbon exploitation activity on availability of saline aquifer storage capacity may be approximated by consideration of the spatial distribution of storage unit *centroids,* rather than their full ‘shapefiles’;
- A thought experiment may be conducted: what happens to total capacity available in 2020, if units whose centroids lie within 20km of the centroid of an active hydrocarbon field are excluded?
- The example illustrates that approximately half (37.2 Gt) of the theoretical saline aquifer storage capacity, and almost 15% (1.3 Gt) of capacity in depleted oil and gas fields, might not be accessible because of interference with ongoing hydrocarbon exploitation;
- The impact could be less, particularly if in the case of extensive aquifers ‘remote’ parts of the storage volume may be developed that are still far from active hydrocarbon fields;
- Inclusion of other factors – wind farms, seabed cables and pipelines, and other marine users – would tend to increase the impact;
- The 20km radius used is arbitrary, but some form of ‘exclusion zone’ around existing infrastructure and activity is likely to be considered by regulators.

		No HC within 20 km	23,478		
Saline Aquifer	68,597				
		HC within 20 km	45,119	CoP after 2020	37,161
				CoP before 2020	7,958

		CoP after 2020	5,415		
HC	9,431				
		CoP before 2020	4,016	No HC within 20 km or same CoP	2,705
				HC within 20 km and later CoP	1,312

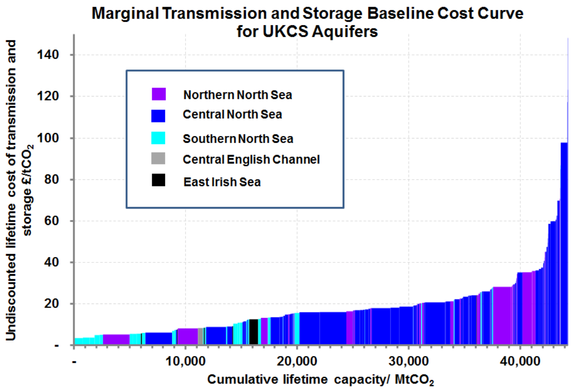
Size of 'Exclusion Zone'



- The graphic illustrates the sensitivity of 'inaccessible storage volume' to the allowable offset between neighbouring activities;
- At 40km, only 5 Gt or so of saline aquifer capacity would be accessible in 2020 based on the centroid analysis;
- By 2030 this would have increased to ~45 Gt, as additional oil and gas fields pass their anticipated CoP dates in the intervening decade.

Opportunities for cost reduction

- There are substantial differences in overall transport and storage costs between units, and across injection scenarios;
- The relative importance of different components of cost also vary widely;
- In the majority of cases, storage is most cost-effective on a £/tonne basis when units are exploited to their maximum storage capacity;
- Economy of scale may also be achieved where CO_2 pipelines from shore can be shared between different storage units.



Clustering of storage units offers multiple opportunities for CCS cost reduction:

- Site appraisal (for example seismic surveys and appraisal well data acquisition) designed to benefit all prospective developers;
- Efficient collection of integrity information on existing wells and planning of remediation campaigns;
- Re-use of existing wells and platform infrastructure, together with shared use (and re-use) of new facilities to minimise capital costs;
- Minimisation of operating costs;
- Future-proofing CO_2 transmission pipelines, by ensuring they target optimal locations for both capture and storage and are sized appropriately. It will also be important to ensure entry specifications and regulatory mechanisms are specified in a manner conducive to CCS cost reduction.

Phasing of expenditure can similarly drive down net present cost:

- The number and location of CO_2 injection wells and facilities is one of the strongest drivers of storage costs. Whereas 'upfront' drilling is standard practice in the oil and gas industry to promote early production and payback, with CCS there is potential benefit from deferring investment in wells, so long as the immediate CO_2 supply rate can be handled.
- This would allow application of learning (from earlier to later wells) in development of the storage unit, and match expected growth of CO_2 supply over time.

Integration of CSS with other offshore projects:

- The power required to operate offshore oil and gas facilities has typically been generated by burning a proportion of produced gas (fuel gas). However, as increasing numbers of North Sea fields pass their CoP dates, or saline aquifers remote from hydrocarbon operations are developed, power supply from shore might prove the only – expensive! – alternative. Integration of CCS projects with offshore 'super-grid' proposals developed for wind power transmission, should be considered.

UKSAP Insights

UK Storage Appraisal Project Insights

CO_2 Migration and Implications for Practical Storage Capacity

Eugene Balbinski
Eric Mackay
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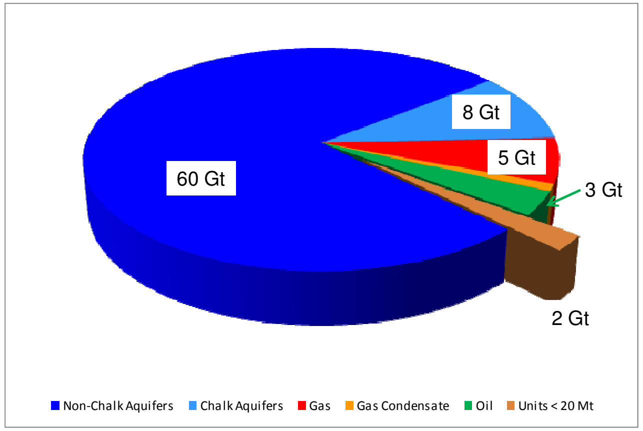
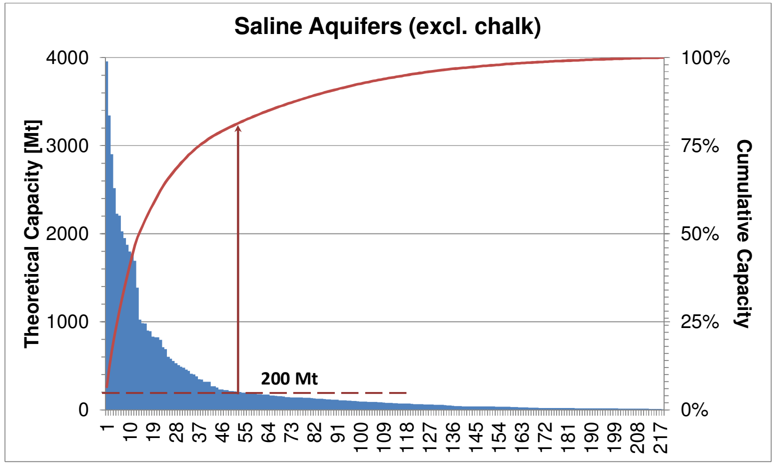
May 2012

Large deep saline aquifers dominate UKCS storage potential

- Excluding chalk reservoirs (poorly understood injectivity and storage security), deep saline aquifers contribute:
  - 78% of total UKCS storage capacity* (60.2 Gt/ 77.0 Gt)
  - Of over 300 saline aquifer storage units identified, 52 have individual P_{50} storage capacity in excess of 200 Mt – each capable of storing the CO_2 emissions from a 450 MW coal-fired (or 650 MW IGCC) power station for about 40 years
  - Together these 52 storage units contribute ~80% of total saline aquifer storage capacity on the UKCS

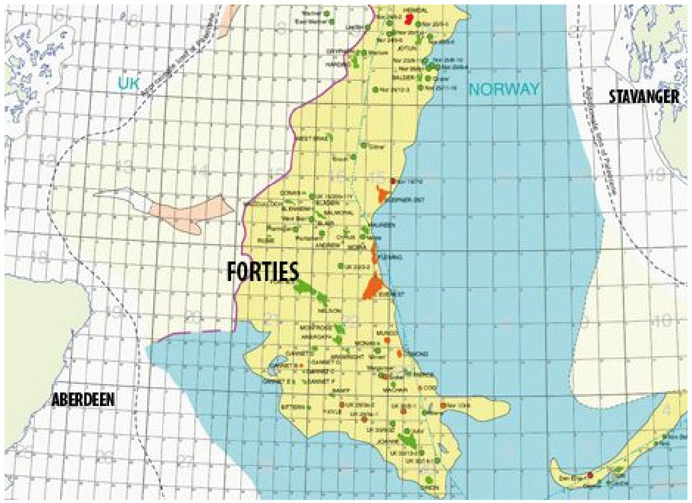




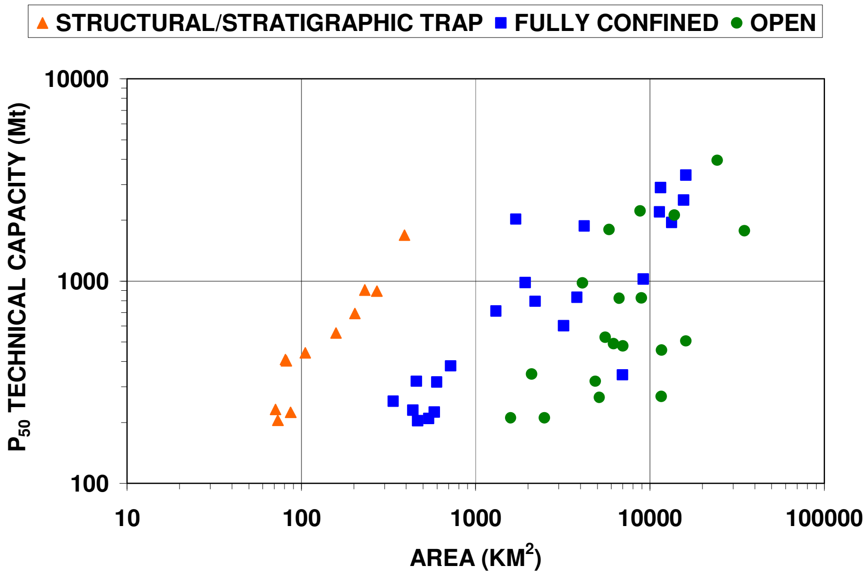
*P_{50} Theoretical Capacity

Aquifer stores cover large areas

- A large UK oil field such as Forties covers an area less than 100 km², and typical UK hydrocarbon fields are much smaller;
- Water-bearing *structures* identified by UKSAP are less than 400 km² in area, and average only 52 km².
- By contrast, 'open' saline aquifers with storage potential greater than 200 Mt typically cover thousands of km²
  - Many however, are likely to contain internal geological features (eg. faults) not captured by UKSAP;
  - Hence it is likely they could be developed as a number of discrete CO_2 injection *sites*, with perhaps limited, or at least managed, interference between them.
  - UKSAP estimates of open aquifer capacity assume all such sites are developed concurrently, with no pressure management, and so phased utilisation may present an upside in overall capacity.



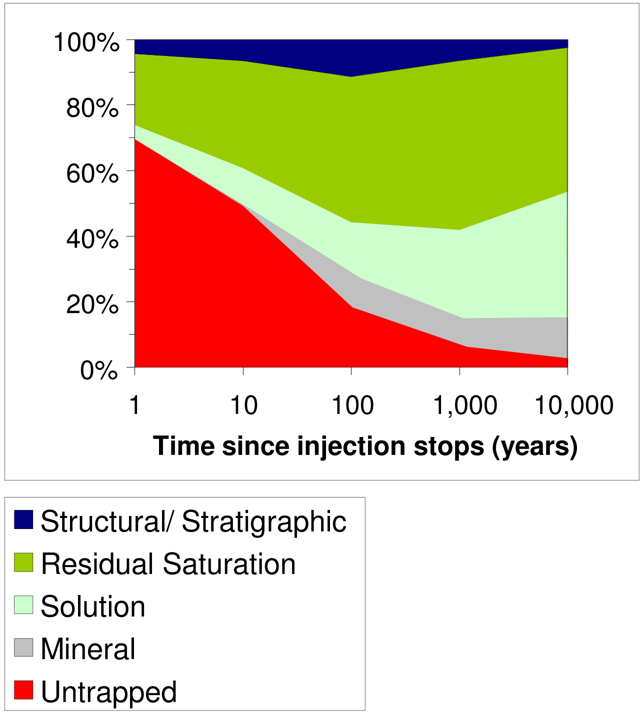
Paleocene fields and discoveries in relation to sandstone distribution. Image: Millennium Atlas, Geological Society of London

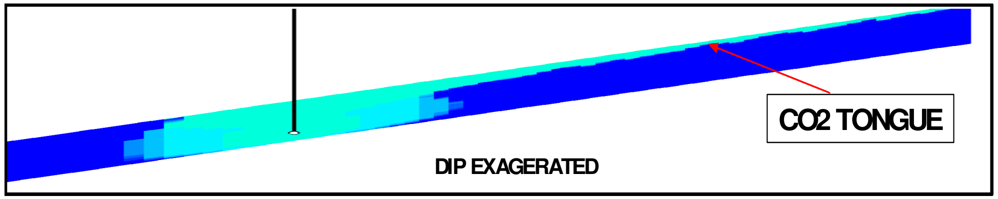


CO_2 can migrate over large distances

- Once injected into the subsurface, CO_2 becomes trapped by various mechanisms;
- However, some could remain free and mobile after 1,000 or even 10,000 years;
- Thin plumes of CO_2 can thus potentially migrate updip over large distances (tens or hundreds of kilometres), driven by buoyancy;
- Key factors affecting migration of free CO_2 are:
  - Formation dip
  - Effective permeability
  - Geological heterogeneities

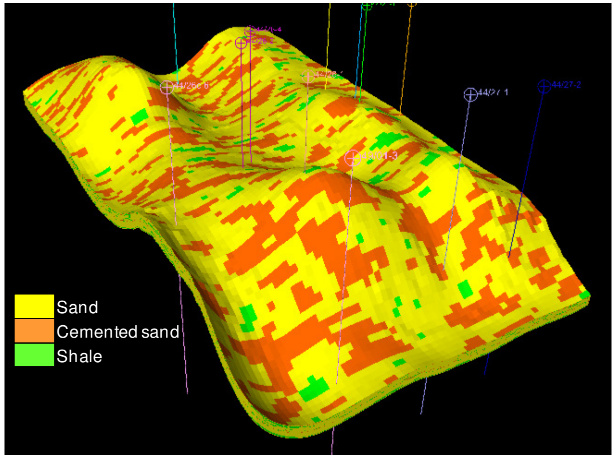
Trapping Mechanisms for an 'Open' extensive aquifer





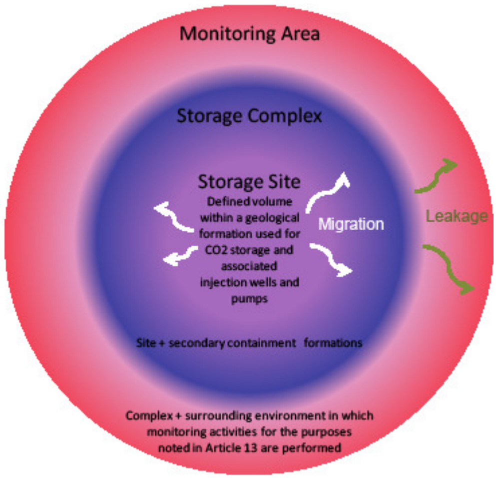
Modelling and Monitoring

- In order understand where CO_2 could migrate to, and hence effectively manage CO_2 storage operations, predictive models – or reservoir simulations – are required;
- These simulations in turn require 'hard' data – observations and measurements – to calibrate them;
- The significance of monitoring measurements is then judged by comparison with predictions from the calibrated models, and interventions taken as required;
- Thus a loop of planning activity, executing it, measuring results and adapting the plan is followed;
- This is commonly referred to as a Plan, Do, Study, Act (or PDSA) cycle.
- Although by necessity, simulation models are a mathematical simplification of real storage sites, computer technology has advanced to the point where models comprising many tens (or even hundreds) of thousands of grid-blocks can be run;
- Large open aquifers nonetheless present a challenge:
  - in order to represent relatively small-scale but important features (such as surface topography), smaller grid blocks are required;
  - with 50m x 50m blocks, 4 million cells would be needed to simulate a 50km by 20km aquifer using 10 vertical layers;
  - alternative gridding schemes, streamline simulation and parallel computing may be used to tackle some of the modelling issues;
  - but monitoring for CO_2 leakage over such an area – some 10 times greater than the UK's largest oil and gas fields – would also be technically demanding and very costly.



Regulation, Monitoring and Practicality

- EU storage directive requires monitoring activity *beyond* the extent of the storage complex;
- Such activity must be executed
  - before storage begins (to establish a baseline);
  - during CO_2 injection operations;
  - and for perhaps 20 years or so after injection ceases (the 'post closure' period).
- Extent of monitoring region will be limited by technical feasibility and cost;
- Hence storage operators and regulators likely to favour development of storage capacity with structural closure or clearly identified lateral boundaries (such as sealing faults and pinch-outs).

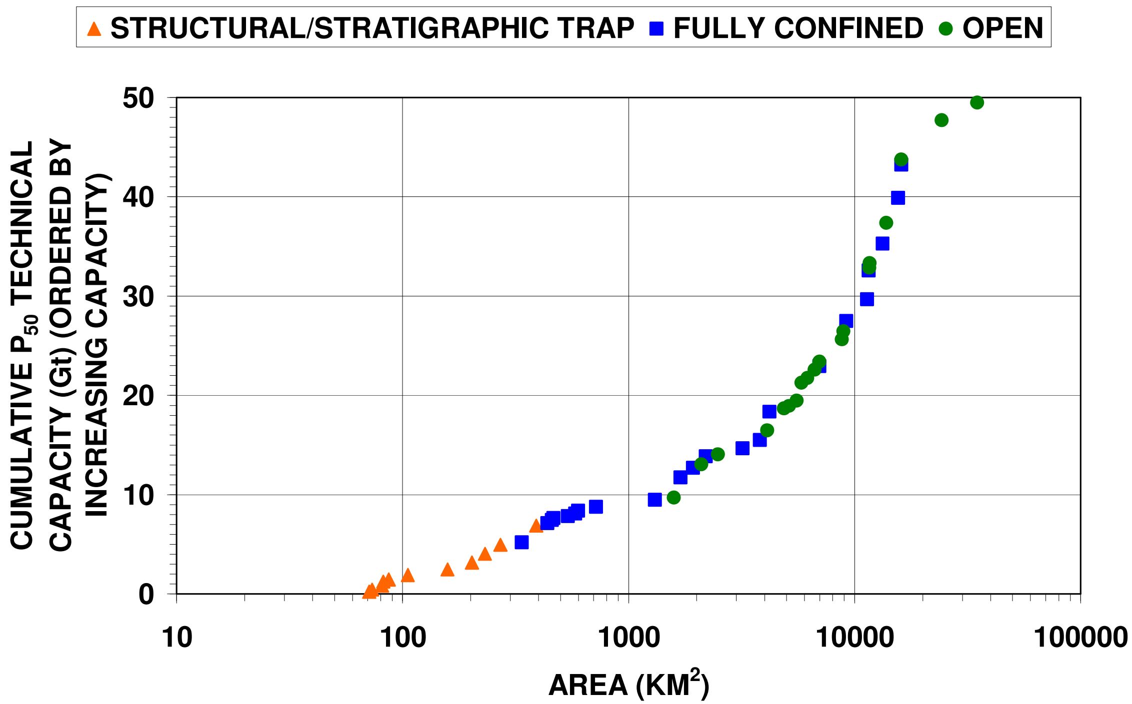


EU Guidance Document Storage Schematic

Exploiting localised storage potential

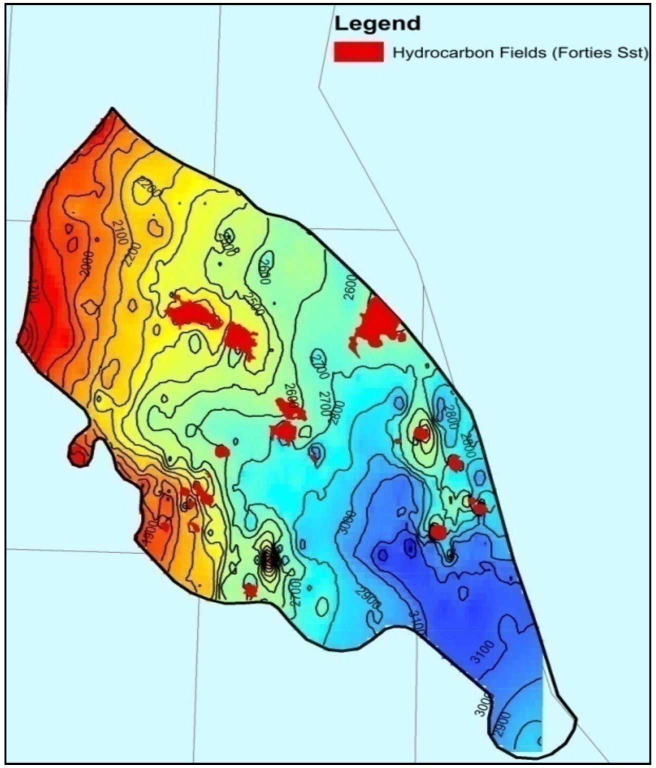
- Inject into structural traps, ceasing injection before spill point reached
  - UKSAP has identified 6.6 Gt capacity* in water-bearing structural traps, each with an estimated capacity of more than 200 Mt and area less than 400 km^2
- Inject into fully confined aquifers of moderate area
  - UKSAP has 2.5 Gt capacity* in such aquifers with capacity > 200 Mt and area <1000 km^2
  - Consider water production to offset reservoir pressure increase as CO2 is injected, thereby increasing storage capacity.

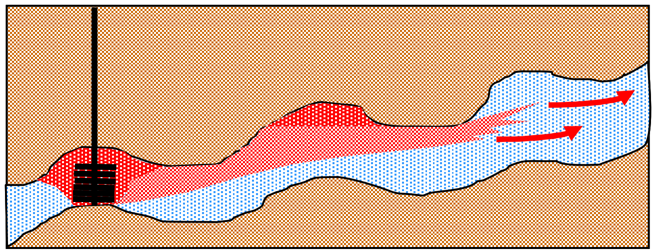
*P50 Theoretical Capacity



Exploiting potential in larger stores

- An extensive regional study like UKSAP cannot identify and characterise all ‘small-scale’ sub-surface features, that are nonetheless likely to exist and affect migration of injected CO_2;
- analogy may however be drawn with hydrocarbons, which are generated in organic-rich source rocks and then migrate, driven by the same buoyancy forces that will cause CO_2 to migrate;
- large quantities (~70 billion barrels) of it became trapped in various types and size of structure, now recognised as the UK’s oil and gas fields;
- it will be possible to explore for, identify and characterise similar features and exploit them for CO_2 storage.
- Thus injection sites may be chosen where local geology tends to retard updip migration, for example:
  - local structural traps updip of injection site;
  - low mean dip;
  - moderate permeability (but sufficient for injectivity);
  - beneficial heterogeneous barriers, such as shale lenses in Utsira (open aquifer) storage project at Sleipner.
- Engineering techniques may also be used to augment the effects of natural geological features, for example by promoting local residual trapping with co-injection of CO_2 and water, or considering chemical flow diversion to retard CO_2 migration.





UK Storage Appraisal Project

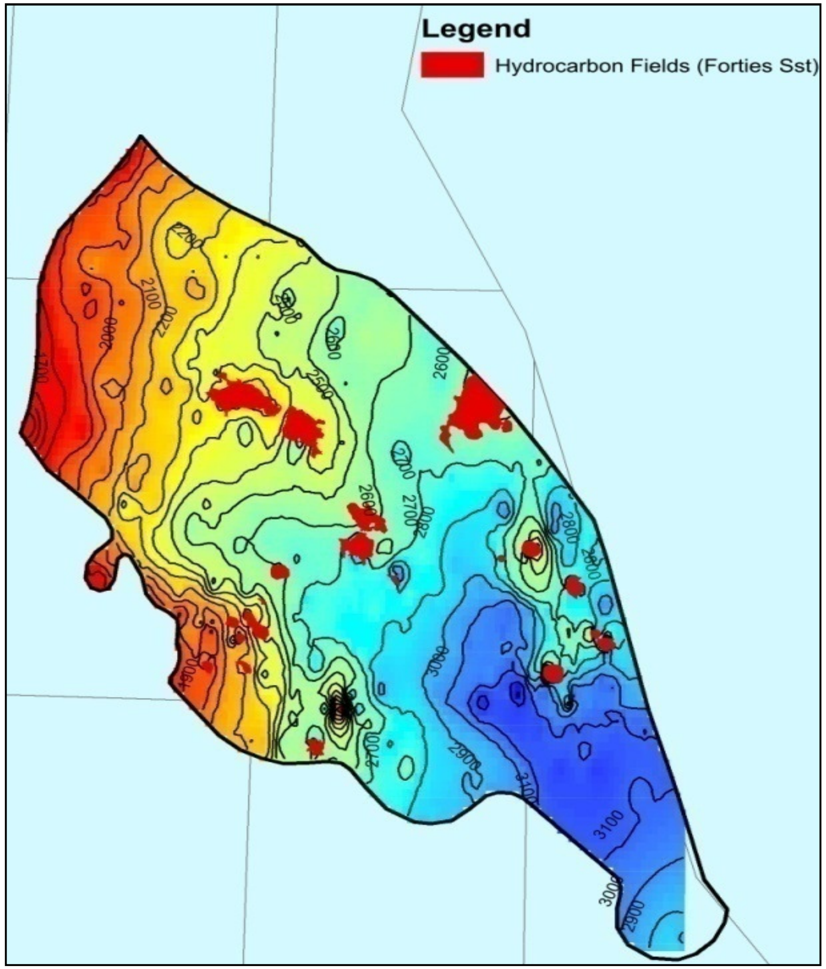
Insights

Security of Storage

- Each saline aquifer storage unit has been assessed to evaluate security of
  - Containment - the likelihood that mechanisms or features might be present that could result in CO_2 migrating beyond the designated boundaries of the storage unit (for example via flow along fault planes, through well bores, via failure of the overlying seal (caprock), or lateral migration from the storage unit);
  - Operations - potential for mechanisms or features in the subsurface to unduly impair achievable injection rate, and hence reduce practical storage capacity.

- The aims are to:
  - enable identification of key uncertainties and potential failure mechanisms that could have an adverse impact on the assessed overall UK CO_2 storage potential;
  - allow prioritisation of mitigation activities, and further investigations such as scenario-based analysis.

Parallels with hydrocarbon extraction



- Over millenia hydrocarbons have naturally been generated and migrated over many kilometres, becoming 'stored' (or trapped) in what are now known as the UK's oil and gas fields;
- These fields comprise the same porous and permeable reservoir rocks, overlain by impermeable seals (such as mudstones or halites) that constitute the potential CO_2 storage units identified by UKSAP;
- All may be impacted – to a greater or lesser extent – by similar geological features including faults, fractures and variations in rock quality (porosity and permeability), and be penetrated by wells drilled from surface.
- Thus, though natural variability means there is always an element of uncertainty, there are many decades-worth of experience managing these uncertainties to draw from, and apply to CO_2 storage.
- The UKSAP security of storage assessment process has been applied to three successful hydrocarbon production operations (Forties, Britannia and Rough), to bench-mark results and reduce subjectivity in assessment of saline aquifer storage units (for which generally less is known).

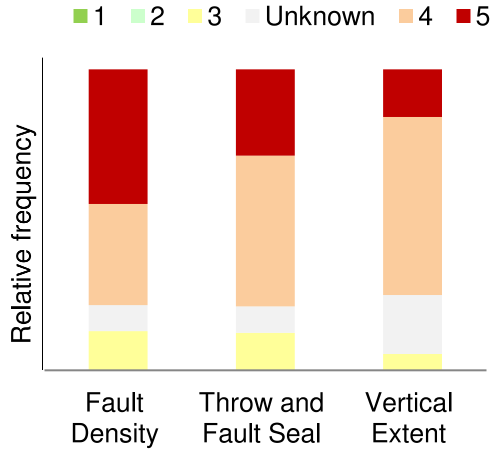
Assessment Process

- Security of containment is assessed under four broad categories:
  - Seal integrity (three sub-categories of potential failure mechanism)
  - Faulting (three sub-categories)
  - Lateral migration (eight sub-categories)
  - Pre-existing wells (two sub-categories)
- Security of operations is assessed with regard to:
  - Reservoir connectivity (five sub-categories)
  - Formation damage/ injectivity impairment (three sub-categories)
- The *likelihood* of occurrence is assessed for each failure mechanism, together with generic evaluation of the *severity* of impact were it to occur.

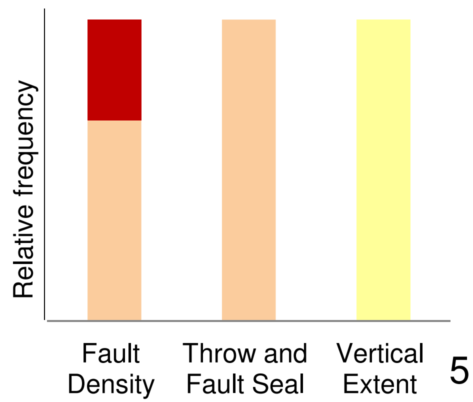
Example: Security of Containment - Faulting

- Three sub-categories of failure mechanism are assessed with respect to faulting
  - Fault density – number of faults per unit as seen on representative seismic lines;
  - Throw and fault seal – comparison of fault offset with caprock thickness;
  - Vertical extent – how shallow faults penetrate above the storage unit.
- Scores are assigned for 1) saline aquifers and 2) hydrocarbon fields, based on pre-defined definitions of low, medium and high likelihood/ severity;
- Scores range from 1 to 5:
  - 1 indicates low likelihood of occurrence and low impact;
  - 5 indicates high likelihood of occurrence and high impact;
  - If insufficient data are available to support assessment, 'unknown' is recorded.
- In the example, no units score either 1 or 2; faults are present to some extent in all potential storage units;
- Some hydrocarbon fields have a score of 5 for fault density. However hydrocarbon was successfully retained within the field, so a high score does not necessarily imply the fault *will* leak;
- Other mechanisms of fault seal (eg. clay smear or cataclasis, which require greater depth of investigation to assess), have not been included; in this respect, the assessment is conservative.

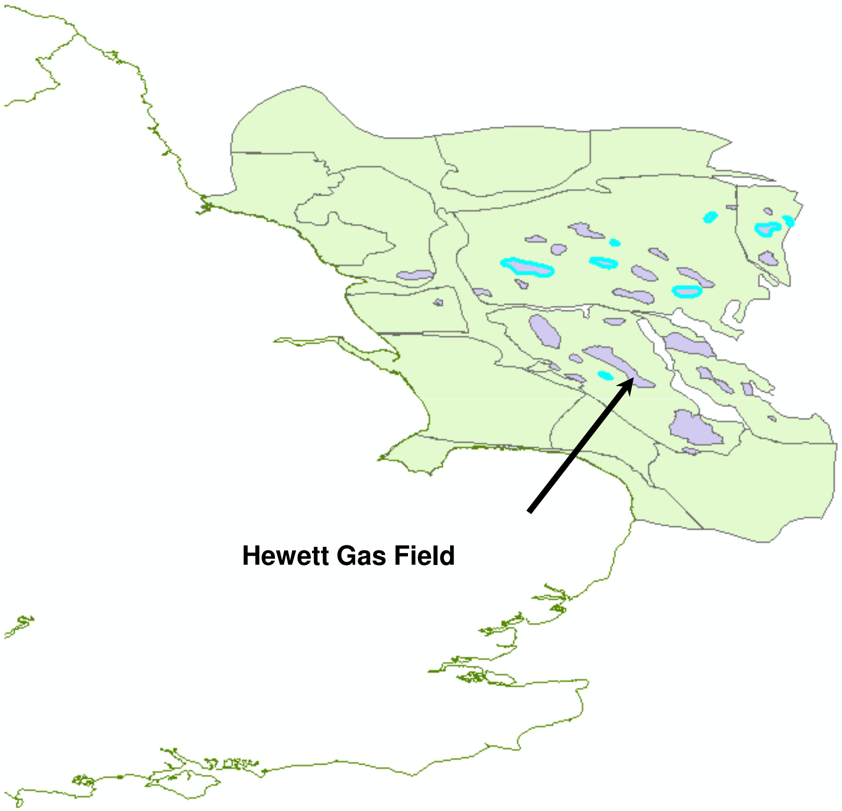
Saline Aquifer Potential Storage Units: Faulting



Benchmark: Hydrocarbon Fields



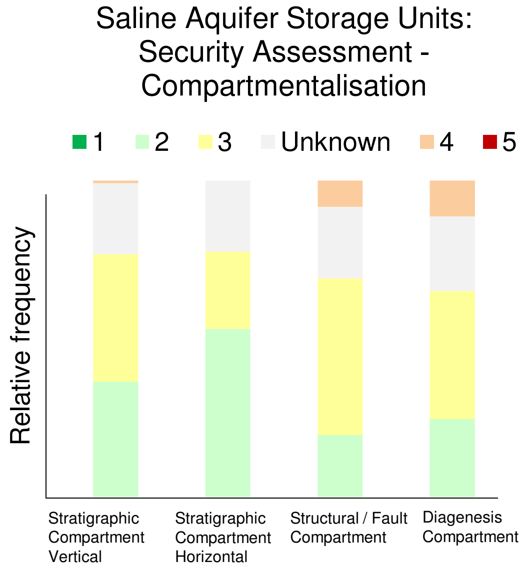
Faulting in the Bunter – a further example

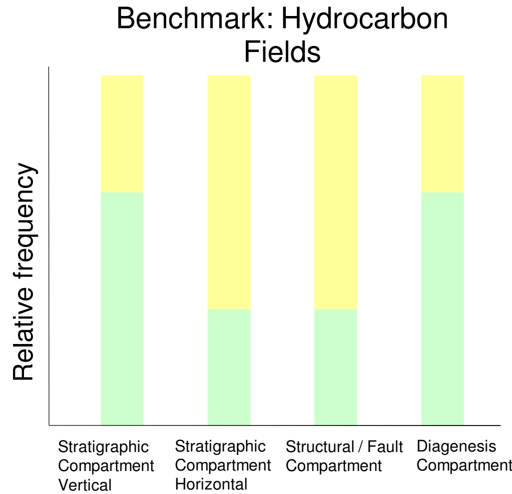


- The Bunter Formation of the Southern North Sea extends offshore from the Lincolnshire and Yorkshire coasts;
- Identified storage units that have been classified as 'structural closures' (anticlines) are shaded purple;
- Green-shaded units are 'open' (no significant structural closure currently identified);
- The blue-highlighted units have a fault density score of 3. However, the Hewett gas field produced from Bunter sandstone (as did neighbouring field Little Dotty). Both are faulted; the faults in these instances are sealing.

Example: Security of Operations - Compartmentalisation

- Four sub-categories of compartmentalisation have been assessed for 1) saline aquifers and 2) hydrocarbon fields:
    - Stratigraphic compartmentalisation with vertical barriers – relating to vertical connectivity of sand bodies and/ or lateral extension of shales or salts;
    - Stratigraphic compartmentalisation with horizontal barriers – relating to laterally continuous or isolated reservoir bodies, or other lithological barrier;
    - Structural / Fault Compartmentalisation – relating to evidence for fluid transmission or fault sealing;
    - Diagenesis – evidence or expectation that diagenesis reduces reservoir quality to such an extent that pressure isolation occurs.
- As previously, scores range from 1 to 5 and indicate increasing likelihood of occurrence and severity of impact. If insufficient data exist with which to make an assessment, ‘unknown’ is recorded.
- In the example, no units score 1 or 5;
- Just over half the saline aquifers score 3 or 4, and of these the most common mechanisms for compartmentalisation relate to structure/ faults or diagenesis;
- The hydrocarbon fields score 2 or 3 for all factors;
- Comparison suggests that assessment of the generally lesser-known saline aquifer storage units is reasonable, albeit perhaps a little conservative.





Reduction in uncertainty / mitigation

- Prevalent risks, in terms of both frequency of occurrence and potential impact on UK storage capacity, are associated with integrity of the seal, presence of faults and reservoir compartmentalisation.
- Presence of a seal may often be mapped from seismic data. Its sealing potential however, whilst evident in hydrocarbon fields (where buoyant fluids have been trapped) is more difficult to assess for saline aquifers; appraisal drilling and coring of the caprock will often be required.
- Where faults cut across or extend above the storage complex, there is potential for CO_2 to migrate beyond its boundaries. Likelihood of faults being 'open' or 'closed' may be assessed from fault orientation relative to principle in-situ stress; shale gouge potential; cataclasis tendency; fault density and throw; comparison with analogues (for example sealing potential of faults inferred from reservoir performance during hydrocarbon exploitation) etc. In some cases, Pressure Transient Analyses or average reservoir pressure change during (extended) well tests may be used to assess sealing nature.

Reduction in uncertainty / mitigation

- Reservoir compartmentalisation may restrict migration of injected CO_2, but could also lead to rapid build-up of pressure around injection sites leading to requirement for many wells and hence increased CAPEX.
- Nonetheless if compartment boundaries can be identified, for example on high resolution seismic, multilateral or extended reach wells may be used to exploit (or negate) their existence. Alternatively pressure management may be employed, for example through water production – the environmental impact of which needs to be assessed.

- *Unknowns*: the risk assessments help highlight the fact that for many saline aquifer storage units, data are sparse. Significant appraisal activity is therefore required, particularly to characterise those that are distant from hydrocarbon fairways (see Availability of Storage).

UK Storage Appraisal Project

Insights into major assumptions underlying the methodology

Project Scope

- The UK Storage Appraisal Project (UKSAP) covers more ground than any other recent large-scale assessment:
  - Probabilistic resource assessment;
  - Geological uncertainty;
  - Injectivity;
  - Security of storage;
  - Economics;
  - Significant research into storage efficiency.

As is necessary in any such assessment, various (simplifying) assumptions are made, and these are described in the following.

Pressure Management

- In estimating storage capacities, interventions to control or manage reservoir pressure have not been considered:
  - It is assumed that during the operational phase, reservoir pressure around the injection site will increase and potentially limit the amount of CO_2 that can be stored;
  - In theory, actions could be taken to mitigate this rise in pressure, but they require assessment on a site-by-site basis, will add cost to the project, and in the case of (saline) water production (to make 'space' for more CO_2) raise other environmental concerns;
  - UKSAP argues that excluding such actions moves the methodology along the resource to reserves spectrum, towards *practical* capacity.

As a result, storage potential estimated in UKSAP is lower (more conservative) than some other resource estimates e.g. USGS, US DoE Carbon Sequestration Partnerships. These are at the left-hand end of the resource – reserves spectrum.

UKSAP static methodology similar (but not identical) to Netherlands

Injectivity

- In order to estimate the number of injection wells required to satisfy a given CO_2 storage rate and duration it is assumed that:
  - All wells start injecting at the same time;
  - All inject at a (reduced) *constant* rate, such that the final (maximum) injection pressure is maintained below 90% of the fracture pressure.

Conservative assumption for *capacity* in large open storage units, where different parts of the storage unit could be developed over time, allowing pressure to bleed-off in other areas;

Also conservative in terms of economic assessment since capital cost of wells is all ‘up front’; in many circumstances the cost of drilling could be phased, injecting at maximum pressure (and hence rate) in fewer wells and adding additional well capacity as pressure build-up causes injection rate to decline.

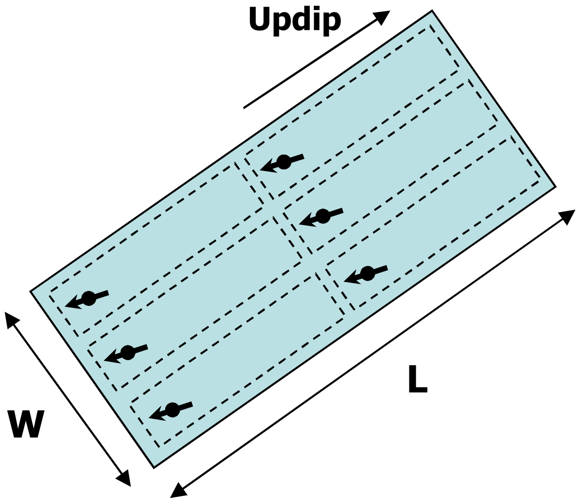
Chase-Water Injection/ WAG

- Only continuous injection of CO_2 has been considered:
  - Studies suggest that the mobility of injected CO_2 may be reduced by following with 'chase water', promoting residual saturation trapping in the vicinity of the wellbore;
  - Water Alternating Gas (WAG) injection may also be used to modify CO_2 sweep efficiency and improve storage.

These processes are not considered within UKSAP, thus capacity estimates for large open units limited by migration of CO_2 may be conservative.

Capacity Estimation of Large Open Units

- The number of injection 'patterns' that can be placed within a unit is determined by two criteria:
  - Extent of the 'accessible pore volume' in the dip direction is that which encompasses 99% of injected CO_2 after 1,000 years, and
  - Injection wells situated on the 'inside' of the pattern tend to behave as though in a closed system, irrespective of the nature of the storage unit's outer boundaries; interference between proximate wells increases pressure, and spacing must be such that fracture pressure is not exceeded.



- Using this approach, 'storage factors' for open units were derived from single-well simulation results, and divided into 3 storage regimes:

Capacity Estimation of Large Open Units

			Storage Factor [%]	
Storage Regime	Characteristic	Low	Mid	High
1. Injectivity-limited	Permeability (k) < 10mD	0.0	0.6	1.0
2. Pressure-limited	High k, low dip **OR** low k, higher dip	0.0	0.9	1.8
3. Migration-limited	Migration vel. > 10m pa	0.0	0.6	1.0

UKSAP 'storage factors' are conservative relative to some other studies (which typically centre around 2%), since pressure, permeability *and* dip of the formation have been considered.

‘Pressure Space’

- Storage capacity of fully closed units is based on an assumption that reservoir pressure continues to rise as CO_2 is stored
  - *no* fluid escape from the system
- Limiting pressure taken as fracture pressure “at the shallowest point in the assessment unit”;
  - Some units – particularly those at deeper depth or structurally complex – are poorly imaged on seismic;
  - Thus “shallowest point” taken as shallowest depth encountered by a well;
  - Shallower points in the storage unit could nonetheless exist, in which case the calculated pressure capacity would be optimistic.

Overall however, capacity estimates based on pressure limitations are likely to be conservative, since there is no allowance made for proactive pressure management.