Programme Area: Carbon Capture and Storage

Project: Storage Appraisal

Title: UK SAP Final Report

Abstract:

This deliverable is the final report of the United Kingdom Storage Appraisal (UKSAP) project. UKSAP was initiated by the Energy Technologies Institute to provide a comprehensive, auditable and defensible estimate of UK CO2 storage capacity. This report summarises the background to the project, methodologies applied in order to estimate storage capacity, security of containment and economics. The report discusses results in terms of how understanding of the UK's storage resource has been advanced, and what is still required in order to move the deployment of CCS forward.

Context:

This £4m project produced 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.

UKSAP

UK Storage Appraisal Project

Conducted for

The Energy Technologies Institute

By

The British Geological Survey

Durham University

Element Energy Limited

GeoPressure Technology Limited

Geospatial Research Limited

Heriot-Watt University

Imperial College London

RPS Energy Limited

Senergy Limited

University of Edinburgh

Final Report

28th October 2011

Authors	The British Geological Survey Durham University Element Energy Limited GeoPressure Technology Limited Geospatial Research Limited Heriot-Watt University Imperial College London RPS Energy Limited Senergy Limited University of Edinburgh
Technical Audit	Grahame Smith
Quality Audit	Fran Sullivan
Release to Client	Duncan Anderson
Date Released	28th October 2011 (final release)

Executive Summary

In the 2008 Climate Change Act, the United Kingdom government committed to reduce the country's Greenhouse Gas (GHG) emissions to 20% of 1990 levels, by 2050. To help meet this target, the single largest abatement technology identified in the electricity and industrial sectors is Carbon Capture and Storage (CCS). The requirements are that over the same timeframe between 2 and 5 billion tonnes, or giga tonnes (Gt), of CO_2 would have to be safely and permanently stored, increasing to perhaps 15 Gt by the end of the century. The question asked is whether or not the UK has sufficient storage capacity to meet this demand, and if such capacity may be exploited in an economic manner.

Previous estimates of UK storage capacity have produced conflicting results. At the low end of the range, storage is insufficient to meet UK national requirements; at the other extreme, there is abundant storage not only for UK emissions but also for those from other parts of Europe.

The United Kingdom Storage Appraisal Project (UKSAP) was therefore commissioned and funded by the Energy Technologies Institute to provide the first comprehensive, auditable and defensible estimate of CO_2 storage capacity, using a standardised methodology around the entire UK. To limit conflicts of use with potable and agricultural water sources and centres of population, only storage in geological formations beneath the offshore UK Continental Shelf (UKCS) was to be considered. The project was executed by a consortium of ten public and private sector organisations, took two years to complete and cost £3.9 million.

The study assessed CO_2 storage potential in the Southern, Central and Northern North Sea, East Irish Sea Basin and Western English Channel. West of Shetland was not included because of its remoteness from CO_2 emissions sources. Publicly available information from boreholes and seismic surveys and data provided by DECC, PGS and IHS were used. A bespoke web-enabled data-loading application ("CarbonStore") was constructed, with embedded computational algorithms and Geographical Information System (GIS), in order to provide storage capacity estimates and allow interaction with results.

Close to six hundred potential storage units were identified and characterised during the course of study. These typically comprise porous layers of sandstone, carbonate or chalk some 10 – 200m thick. Such porous rocks are today filled with oil or gas (hydrocarbons), or more commonly, with brine (saline aquifers). To further distinguish between different storage unit types and accommodate the diversity of sub-surface situations encountered on the UKCS, a simple 3-fold division was adopted: 1) units forming sealed compartments where fluid cannot escape (pressure compartments); 2) units overlain by impermeable seals, but where there is no tangible barrier to prevent lateral migration of aqueous fluids or CO_2 (open aquifers); 3) units where aqueous fluid can potentially escape laterally, but where injected CO_2 is physically confined within a 'trap' by virtue of its relative buoyancy (structural/ stratigraphic traps).

In order to assess the storage capacity of each type, account must be taken of where injected CO_2 might move to, or accumulate, in the sub-surface. The pressure response accompanying storage must also be considered. Since the large number of units meant that these effects could not be investigated for each unit in turn, a few simplified, representative models were constructed. Using methods derived from hydrocarbon reservoir engineering, these simplified models were then used in many flow simulations to investigate the impact of a wide range of reservoir and fluid parameters, which either have not, or can not, be measured accurately. Two detailed reservoir simulation models were also built encompassing geological structure, and reservoir architecture and quality, as indicated by available 3-D seismic and borehole data. These detailed models were used to corroborate conclusions drawn from the earlier simplified models. Understanding of the range and key controls of dynamic performance thus obtained was then applied back to all storage units identified, in order to derive final storage capacity estimates.

In parallel with this effort, the security of storage for each unit was also assessed using a Features, Events and Processes (FEP) approach. Saline aquifer storage units were the main focus, given the limited information available on them relative to hydrocarbon fields. Sixteen mechanisms affecting storage containment, and seven affecting operational aspects, were identified. Definitions were then provided to support consistent assessment of the likelihood of occurrence and severity of impact of each mechanism. Thus a matrix was developed for each storage unit, allowing easy identification of the key issues that might impact its suitability for CO_2 storage.

The cost of CO_2 transport and storage was evaluated using a model incorporating (as applicable) the anticipated capital and operating costs of storage site appraisal, shoreline compression of CO_2, construction of transmission and distribution pipelines, injection facilities and injection wells. The marginal costs of individual units span two orders of magnitude implying site selection could play a key role in optimising costs. Average undiscounted costs for aquifers are in the region of £15/t for storage, and £18/t when offshore transmission is additionally included. For hydrocarbon fields the average costs are £8/t (storage) and £12/t (transmission and storage).

A cost sensitivity analysis was carried out. A major component of storage costs for both aquifers and hydrocarbon fields is associated with the required number of injection wells and related facilities. Other key factors affecting cost are the level of remediation of old wells to ensure no leakage, and injection rate and duration. Cost of financing will be particularly important. For example, a Weighted Average Cost of Capital (discount rate) of 15% results typically in a threefold increase in costs.

As a result of the study, it is concluded that with 90% confidence on the assessment of overall accessible pore volume, the UK has at least 70 Gt of CO_2 storage capacity; 61 Gt exist in saline aquifer stores and 9 Gt in depleted oil and gas fields. However, based on currently available information, particular concern exists regarding ability to inject CO_2 in some units, because of poor reservoir quality (for example chalk formations) or proximity of reservoir pressure to fracture pressure. Excluding such units reduces overall P_{90} storage capacity to some 60 Gt. In either case though, it would appear with a high degree of confidence that physically, the UK has sufficient storage capacity to meet its CCS needs of up to 15 Gt over the next 100 years.

The fact that there is sufficient pore volume at the required depths to store CO_2 however, does not mean that the storage resource is understood well enough for storage permits to be granted. Indeed in terms of the classification system proposed by Gorecki et al (2009), the overall resource estimate may at best be considered at the lower bounds of “contingent”, in that consideration has been given to geological heterogeneity, trapping mechanisms and project economics.

that consideration has been given to geological heterogeneity, trapping mechanisms and project economics.

At present, most is known about the hydrocarbon fields, but in their entirety they offer only 12% of the overall storage resource. It is also unlikely that *all* will be converted to CO_2 storage, or be available at the time required. Consequently, in order to unlock the UK's storage potential, further appraisal of saline aquifer stores is required. These often extend over large areas. Key factors governing the secure storage of CO_2 within them that require further investigation are: leakage via natural faults, geological variability in seal quality, and unconstrained migration of CO_2 in open aquifers.

Ultimately, physical injection of CO_2 (or perhaps other fluids such as water or nitrogen) is likely to be one of the requirements to demonstrate storage site viability. Such injection tests could be prolonged and expensive. Strategic planning is thus needed to ascertain how saline aquifer appraisal programmes might be funded and conducted.

As additional appraisal information is acquired, it is expected that certain storage units will ultimately be deemed unsuitable. This is not unlike the experience of the hydrocarbon industry, where many prospects never make it to development. Equally however, others will prove to offer greater storage than initially thought, perhaps because of better quality, more extensive reservoirs or as a result of advances in technology.

In addition to a comprehensive estimate of CO_2 storage capacity around the UK, this study has developed a leading database – or atlas – that provides a model for other national CO_2 storage assessments. The database, GIS and calculation engine will be maintained beyond the life of the project, and can be developed further. Increased resolution in areas of sparse data, or geographical remoteness may be accommodated; or ability to evaluate favoured target areas for storage in much greater detail, provided. The database also contains much of the information required to compile assessment reports of selected storage units.

The UKSAP did not consider development engineering techniques that could be used to substantially increase storage capacity, for example brine extraction as a means of providing additional pore space for CO_2 storage; alternating water and CO_2 injection to influence the pathway taken by each fluid; chase brine to accelerate near wellbore trapping of injected CO_2; use of CO_2 as a 'solvent' to enhance recovery of oil and/ or gas (CO_2 EOR/ EGR). These are areas that are recommended for further phases of study.

Contents

List of Tables

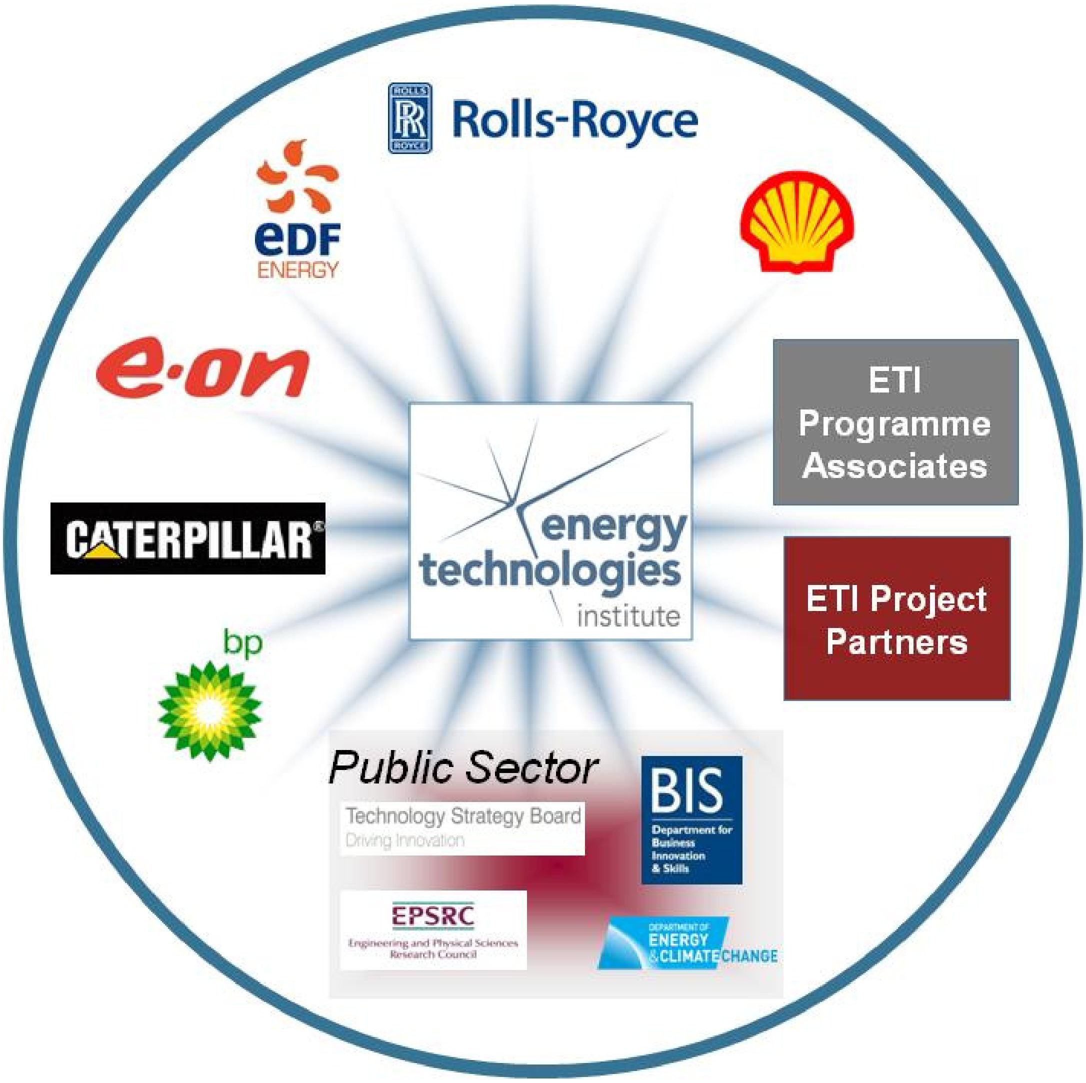
List of Figures

List of Appendices

1 Introduction

The United Kingdom Storage Appraisal Project (UKSAP) was initiated by the Energy Technologies Institute (ETI) to provide a comprehensive, auditable and defensible estimate of UK CO_2 storage capacity.

The ETI is a limited liability partnership between international energy sector companies and the UK government. Its mission is to address the challenges of climate change and low carbon energy by bridging the gulf between laboratory technologies and full-scale commercially tested systems. When the project commenced in October 2009, the ETI's members were:



Representatives from each were invited by the ETI to sit on the Project Advisory Group, and thus assist with project governance.

The project was executed by a consortium of academic, public and private sector organisations, comprising:

The British Geological Survey (BGS)

Durham University

Element Energy Limited

GeoPressure Technology Limited (GPT, an Ikon Science company)

Geospatial Research Limited (GRL)

Heriot Watt University

Imperial College London (ICL)

RPS Energy Limited

Senergy Limited

University of Edinburgh (UoE)

Primary suppliers of data to the project were

Department of Energy and Climate Change (DECC)

IHS Energy Limited

Petroleum Geo-Services (PGS)

The project ran for almost two years and cost £3.9million. The result is the UK's first comprehensive, auditable and defensible estimate of CO_2 storage capacity in offshore geological formations.

This report summarises the background to the project; methodologies applied in order to estimate storage capacity, security of containment and economics on a single source to single sink basis; and discusses results in terms of how understanding of the UK's storage resource has been advanced, and what is still required in order to move the deployment of CCS forward.

A glossary of terms is provided at the end of the report. The report is further supported by detailed technical appendices and the resultant project database and GIS, "CarbonStore" (www.carbonstore.org.uk).

2 High-level Philosophy

Under the 1997 Kyoto Protocol to the United Nations Framework Convention on Climate Change (UNFCCC), the United Kingdom committed to reduce its Greenhouse Gas (GHG) emissions by 12.5% from 1990 levels in the period 2008 – 2012, implying an 8% reduction in CO_2 emissions. Further, in June 2007, the 33rd G8 Summit agreed that G8 nations would aim to at least halve global CO_2 emissions by 2050. The UK government has gone significantly further than this, setting an ambitious long-term target of reducing GHG emissions (including those from international aviation and shipping) by 80% by 2050 compared to 1990 levels. This target is enshrined as a formal legal obligation in the 2008 Climate Change Act (Skea, Ekins & Winskel 2011).

Analysis by the Princeton Environmental Institute (Pacala and Socolow, 2004) proposed reducing global CO_2 emissions by 1 billion (10^9) tonnes per year, using any seven of fifteen different, existing technologies. Of these, Carbon Capture and Storage (CCS) has been estimated as having the potential to contribute some 20% of the overall target, larger than any other single abatement method. For the UK, such contribution would translate to CO_2 being stored at rates increasing from ~ 11 Mt/ annum in 2020 to ~ 180 Mt/ annum by 2050, and around 15 billion tonnes of CO_2 being stored over the next 100 years.

Methodologies by which regional CO_2 storage capacity may be estimated have been proposed by the Carbon Sequestration Leadership Forum (CSLF), US Department of Energy (US DOE) and others. These generally rely upon a storage coefficient, or efficiency factor (E) that is applied to the assessed pore volume of the storage site. The storage potential of UK geological formations had been the focus of various studies (Holloway et al 2006, Bentham 2006, SCCS 2009), based broadly on the CSLF/ US DOE approaches. Nonetheless, remaining uncertainty was such that at one extreme capacity might be limited such that CCS presented only a niche opportunity for a few developers; at the other, ample capacity might in fact offer a strategic UK business to additionally store CO_2 from elsewhere in Europe.

The Energy Technologies Institute (ETI) therefore commissioned the UK Storage Appraisal Project to provide the first comprehensive assessment of UK storage capacity, with a defensible and auditable methodology consistently applied. Following previous recommendations, onshore storage was deemed impractical because of potential conflict with aquifers used for potable water extraction. Deep water basins West of Shetland were also considered too remote from large industrial CO_2 emitters and likely to be very expensive to develop. The study was therefore to consider the UK Sectors of the Southern, Central and Northern North Sea, the Irish Sea/ Bristol Channel and English Channel. The primary goal was to identify whether or not the UK had sufficient offshore geological storage capacity to meet its needs, indicate the level of confidence that could be placed in the results and provide an indication of the economic viability.

2.1 Project Scope

Results of previous studies suggested that the potential storage capacity of offshore UK saline water bearing formations ("saline aquifers") was at least an order of magnitude greater than that in depleted hydrocarbon accumulations. The UK's oil and gas fields are also relatively well characterised, with generally an abundance of static data – well logs, core analyses, seismic surveys etc – as well as dynamic information from production, injection and pressure monitoring activities. The focus of the project was therefore biased towards assessing the storage capacity of saline aquifers. Incremental storage associated with CO_2 Enhanced Oil or Gas Recovery (EOR/ EGR) was specifically excluded.

The project was structured to first identify, map and characterise potential storage formations, and provide an initial overall estimate of capacity after approximately six months; this would be based merely on the static description of storage units. In parallel, a process for assessing security of containment and features that might impact storage operations was developed and applied. A Stage Gate meeting would then be held to decide whether or not preliminary assessment of overall capacity warranted further work. If so, reservoir simulation studies would follow to investigate dynamic effects, and thus provide enhanced capacity estimates. Economic analyses would also indicate the potential commercial viability of each storage unit identified.

In order to support the requirement for auditable estimates and enable interested parties to subsequently interrogate and use the results, a web-based database with embedded calculation routines (including Monte Carlo simulation) and Geographical Information System (GIS) was to be built as part of the project. It was originally intended that, with appropriate permissions, users would be able to modify input parameters and recompute results immediately. This turned out to be impractical however, due to a combination of computational time restrictions for a web-served rather than desk-top application, and utilisation of certain proprietary algorithms that were to remain external to the database. The final product thus provides a ‘snap-shot’ of overall UK storage capacity that may be periodically updated as new or additional information becomes available.

The extent of information collected and stored in the database allows UK storage resource estimates to be provided that are directly comparable to those of other nations, such as the USGS’s technically-accessible storage resource; the German estimate of CO_2 storage capacity in closed structures; and the Netherlands pressure limited resource estimate. It represents a significant advance in industry understanding of the UK’s CO_2 storage potential.

2.2 Outline Methodology

A simplified schematic of the workflow is shown below.

Each identified storage unit was categorised in terms of the nature of its boundaries (‘closed’ pressure cells, or ‘open’), and the fluids it contained (saline water or hydrocarbons). Factors likely to control the amount of CO_2 that could be stored in each – pressure increase, structural confinement, CO_2 migration – were identified, in order that the most appropriate estimate of capacity be applied.

An assessment of well injectivity was made, allowing estimation of the number of wells required to satisfy various injection scenarios.

Security of containment was also assessed using a Features, Events and Processes approach, to understand mechanisms that might adversely impact CO_2 storage.

Finally, an infrastructure design and economics model was used to evaluate the costs of offshore CO_2 transport and storage, and investigate economic viability of the capacity identified.

The detail of the individual elements of this workflow is described in subsequent chapters.

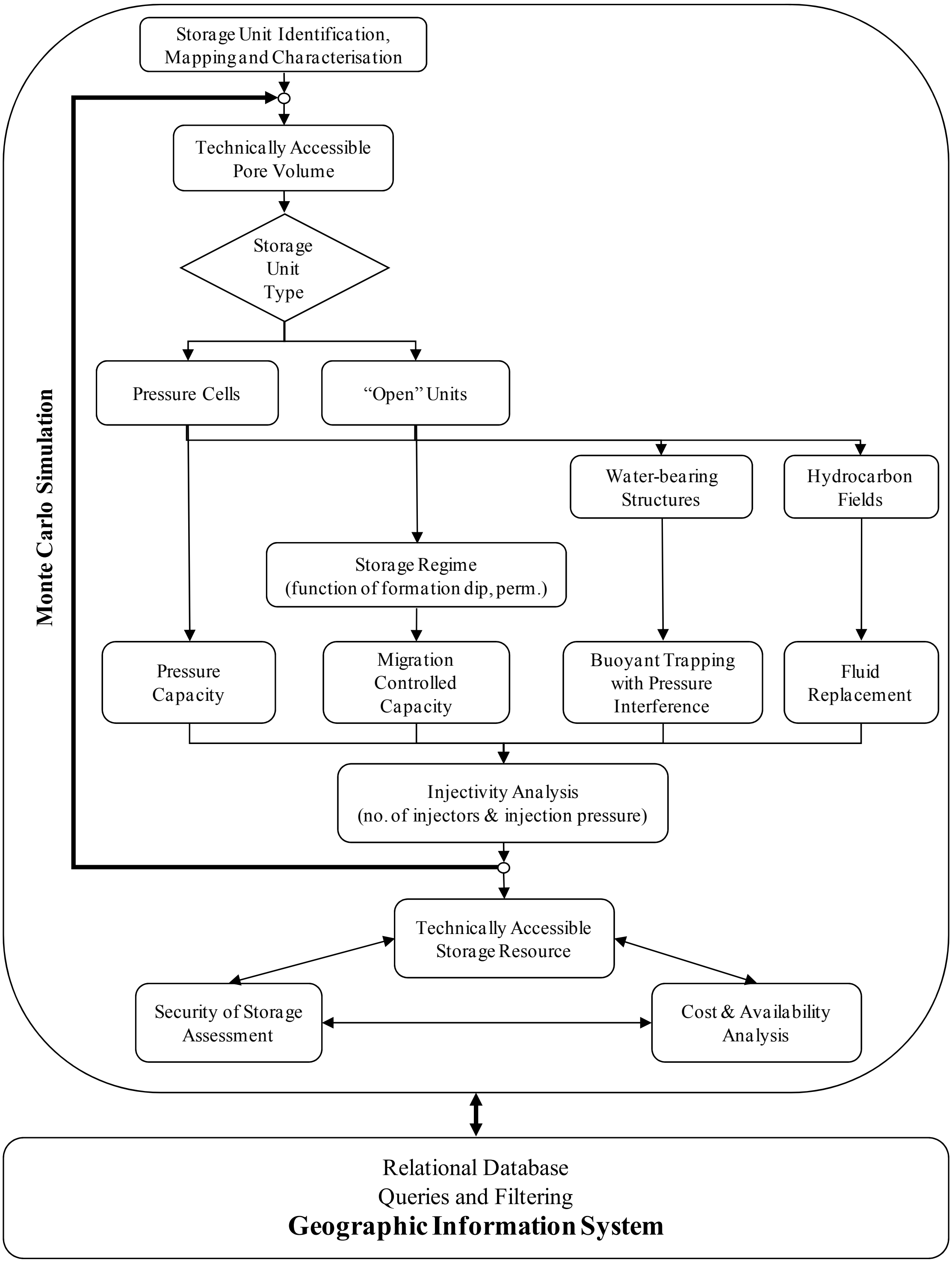


Figure 2.1: UKSAP Simplified Workflow

2.3 Project Structure

To assist project management and governance a Work Package (WP) based structure was adopted, with a project Steering Group formed from the work package leaders and additional advisors. This then provided the interface between project consortium, the ETI and its Project Advisory Group. The individual work packages and primary participants were as follows:

WP	Title	Purpose	Primary Participants
1	Geosciences	Storage unit characterisation	BGS, GPT, UoE
2	Security of Storage	Storage unit risk assessment	Durham, GRL, Senergy
3	Economics	Economic modelling	Element Energy
4	Dynamic Modelling	Reservoir simulation	ICL, Heriot-Watt, RPS
5	Database/ GIS	Software development	Senergy
6	Final Capacity Estimates	Integration of all WP results	All
7	Project Management	Project Management	Senergy

The project structure is depicted below:

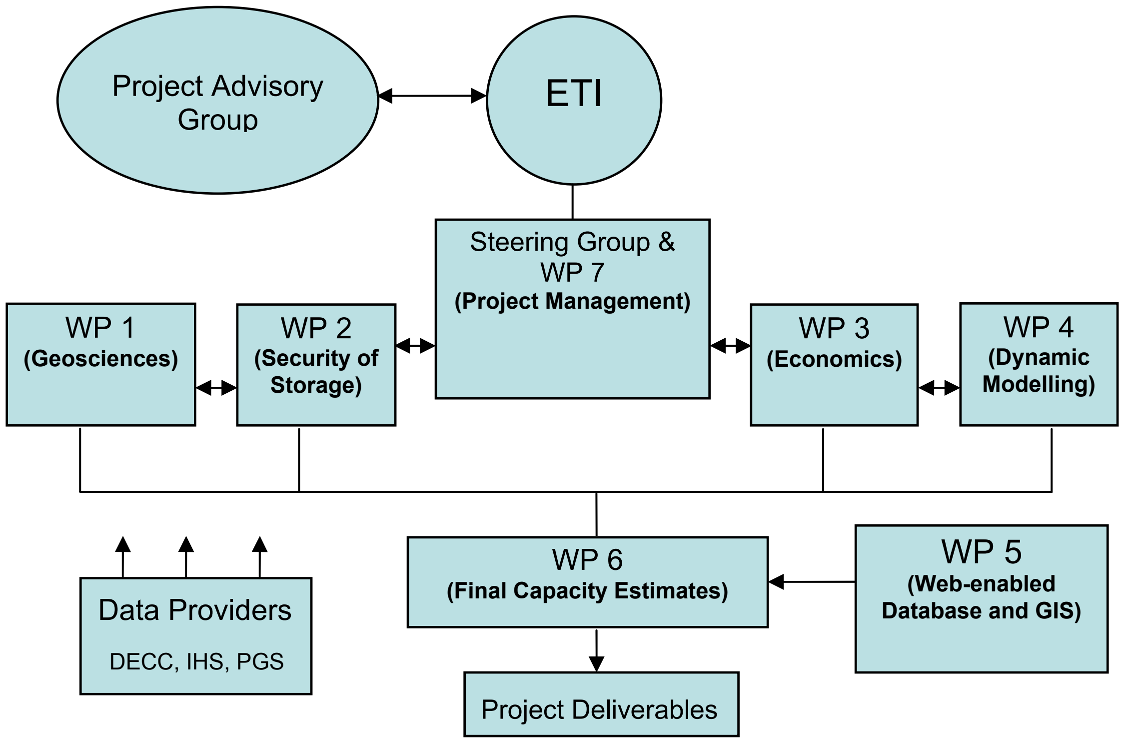


Figure 2.2: UKSAP Structure

2.4 References

1. Skea, J, Ekins, P. And Winskel, M. (eds.) 2011. *Energy 2050: making the transition to a secure low carbon energy system*. Earthscan Ltd., London.
2. Pacala S., Socolow R.H., 2004. Stabilization Wedges: Solving the Climate Problem for the Next 50 Years with Current Technologies. Science 13 August 2004 vol 305, no. 5686, pp 968 – 972.
3. CSLF, 2005: Phase I Final Report from the Task Force for Review and Identification of Standards for CO2 Storage Capacity Estimation.
4. CSLF, 2007: Phase II Final Report from the Task Force for Review and Identification of Standards for CO2 Storage Capacity Estimation.
5. CSLF, 2008: Phase III Final Report from the Task Force for Review and Identification of Standards for CO2 Storage Capacity Estimation.
6. Holloway S., Vincent C.J., Kirk K.L. (British Geological Survey), October 2006. Industrial Carbon Dioxide Emissions and Carbon Dioxide Storage Potential in the UK. Coal R308 DTI/ Pub URN 06/2027.
7. Bentham, M., 2006. An Assessment of Carbon Sequestration Potential in the UK – Southern North Sea Case Study. Tyndall Centre for Climate Change Research, Working Paper 85.
8. Scottish Centre for Carbon Storage, April 2009. Opportunities for CO_2 Storage around Scotland – an integrated strategic research study.

3 Storage Unit Mapping

3.1 Background

The goal of the UK Storage Appraisal Project is to provide a fully defensible, auditable assessment of overall UK CO_2 storage capacity in offshore geological formations.

In order for CO_2 to be injected into and retained in a geological formation, the formation must have reservoir properties, i.e. it must be both porous (having space within its solid matrix that can be filled with fluids) and permeable (being able to transmit fluids through a connected network of pore spaces and/ or fractures within its solid matrix). CO_2 can be retained in a formation through a variety of trapping mechanisms (Section 3.6.2). Porous and permeable rocks are commonly sedimentary in origin and are generally described as reservoir rocks. Geological formations that are potentially of significance for CO_2 storage are generally large mappable bodies of reservoir rock, described here as reservoir formations.

3.2 Defining and Mapping Reservoir Formations

The reservoir formations of the UK Continental Shelf (UKCS) were identified from the UKOOA lithostratigraphic nomenclature volumes (Knox & Cordey 1992 - 1994). All formations consisting dominantly of sandstone or porous and permeable carbonates were considered to be potential reservoir formations. Other formations were included or excluded according to professional judgement of the assessors. The great majority of excluded formations consist overwhelmingly of shales, mudstones and other fine-grained rocks, or carbonate or evaporite formations with little permeability.

Limit polygons, provided by BGS, showing the distribution of each reservoir formation were made available to the project in ArcGIS format. Parts of reservoir formations outside the UK Exclusive Economic Zone (EEZ) were excluded from the analysis, i.e. limit polygons were trimmed to the UK median lines.

A database of geological formation tops (IHS's EDIN GIS database) was used to determine the depth, thickness and strata overlying each reservoir formation. This database was also used to check and edit the limit polygons that define the distribution of each reservoir formation.

Detailed top surfaces of various formations interpreted from the PGS 3D seismic megamerge were also available to assist with mapping of reservoir formations.

3.3 Subdividing the Reservoir Formations into Storage Units

In many cases the location, structure and reservoir properties of individual reservoir formations indicated a need to subdivide them into volumes with common characteristics that could be treated as a single unit of assessment known as a storage unit. Storage units form the basis of the resource and capacity assessment within UKSAP. A storage unit is a mappable subsurface body of reservoir rock that is at depths greater than 800 m below sea level, has similar geological characteristics and which has the potential to retain CO_2. The basis for the subdivision of reservoir formations into storage units is described below:

9. The conditions of temperature and pressure that pertain in the UKCS subsurface mean that CO_2 stored at depths shallower than about 800 m below sea level is likely to be in the gaseous, rather than dense, phase. Thus CO_2 would occupy far greater volumes per unit of mass, storage would be significantly less efficient and the unit would not contribute significantly to the total storage capacity. Furthermore, as a result of the much lower density (and lower viscosity) of the gaseous phase, there is also considerably greater risk that CO_2 stored at less than 800 m below sea level could exploit a potential leakage pathway. Consequently, those parts of reservoir formations which are consistently at depths shallower than 800 m were excluded from the analysis (**Figure 3.1**). This involved a degree of judgement by the assessor, since certain storage units that are dominantly at depths greater than 800 m contain small areas that are above this depth, e.g. above salt domes in underlying strata. These storage units were included in the analysis.

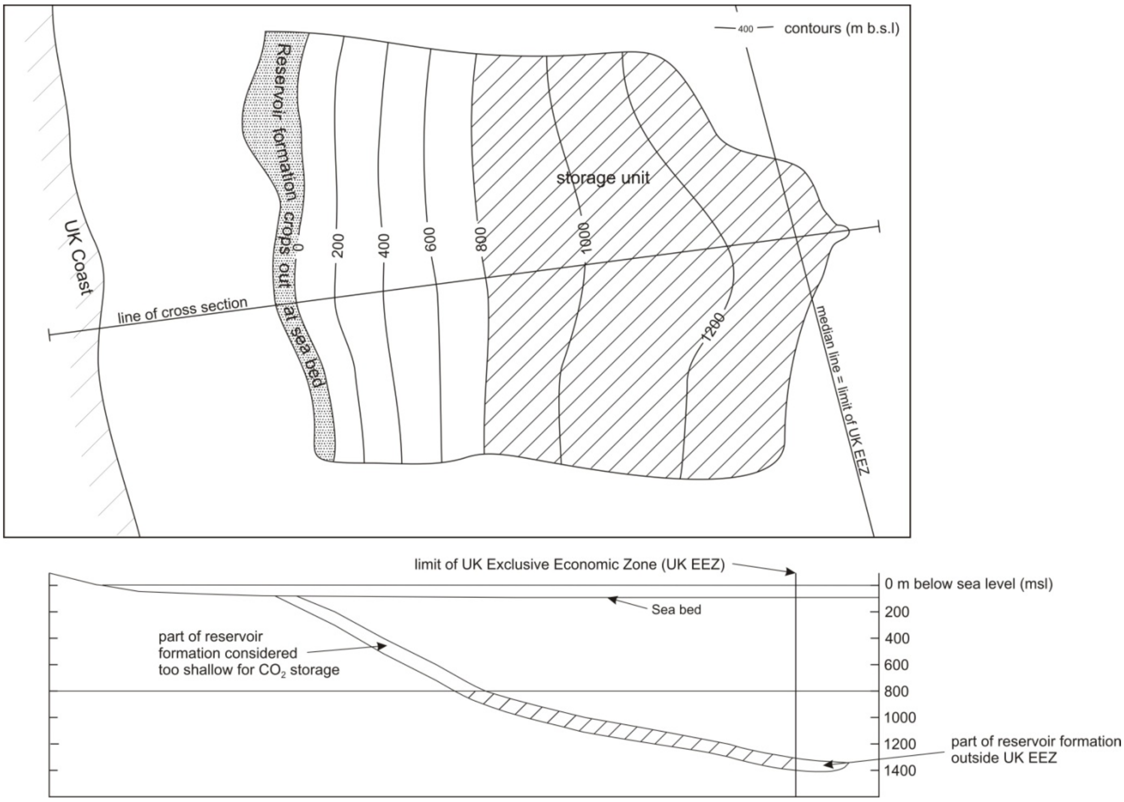


Figure 3.1: top surface and cross section of a simple reservoir formation on the UK Continental Shelf (UKCS) showing the part that comprises a 'storage unit'

(Boundaries of the reservoir formation are surrounding strata without reservoir properties on its north, south and east sides, and the seabed on its west side. Boundaries of the 'storage unit' are the same, except that its western side is limited by the 800 m below sea level depth contour and its eastern side by the limit of the UK EEZ)

2. All onshore parts of reservoir formations were excluded from analysis irrespective of depth. The project was limited geographically to offshore geological formations because of: (a) potential conflicts of use of the subsurface, e.g. with potable groundwater supply, natural gas storage and (b) the firm focus on offshore storage in the UK, (e.g. http://www.decc.gov.uk/assets/decc/What%20we%20do/UK%20energy%20supply/Energy%20mix/Carbon%20capture%20and%20storage/1075-uk-ccs-commercialscale-demonstration-programme-fu.pdf).

3. Parts of reservoir formations may be:

a Sealed by an immediately overlying caprock

b Overlain by another reservoir formation or formations that are sealed by an overlying caprock

c Not sealed

4. Those parts of reservoir formations that are not sealed by an immediately overlying caprock or not overlain by other sealed reservoir formations were excluded from the analysis.

5. Many reservoir formations contain internal permeability barriers that may prevent or severely limit fluid flow and divide them into compartments. In some cases, predominantly in the deeper, overpressured parts of the Northern and Central North Sea Basin, such compartments can be recognised because they are overpressured to a greater or lesser degree than surrounding parts of the reservoir formation (**Figure 3.2**). Reservoir pore fluid pressure data were provided and used by GeoPressure Technology to define pressure compartments within these reservoir formations.

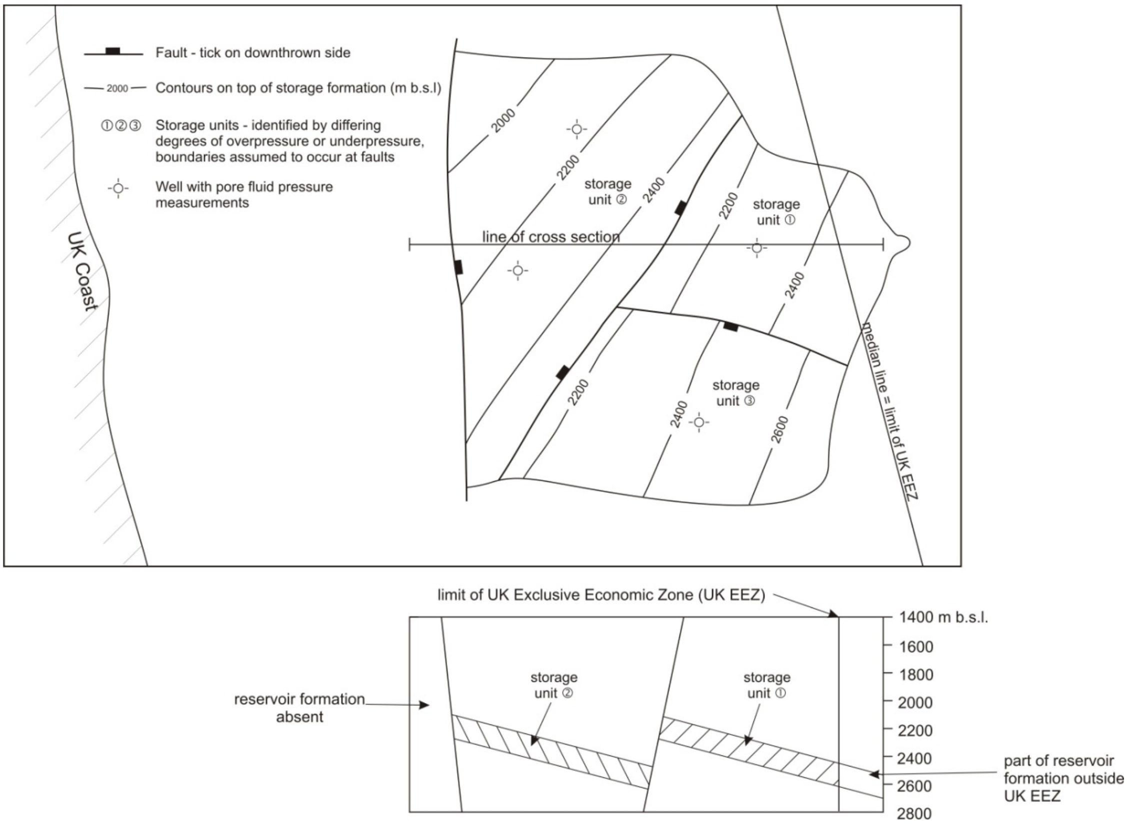


Figure 3.2: a reservoir formation that is divided into three storage units considered to be pressure cells on the basis that at a given depth their pore fluid pressures would vary. In this example, the pressure cells are assumed to be bounded by faults

Certain other reservoir formations (e.g. the Leman Sandstone Formation in the Southern North Sea) are compartmentalised, but compartmentalisation only becomes apparent when hydrocarbon fields that occur within the reservoir formation are produced. In these cases an assumption was made that the entire formation is likely to be divided into compartments of a range of sizes comparable to that of the compartments that can be identified within the producing hydrocarbon fields themselves. Where these compartments have a capacity of less than 50Mt CO_2, they were excluded from the analysis.

Many reservoir formations on the UKCS could not be subdivided into pressure compartments because either:

- they are not in fact compartmentalised, or
- they are compartmentalised, but there is insufficient diagnostic pressure data to form a basis for their subdivision.

The reservoir formations that could not be subdivided on the basis of pressure data were either treated as single storage units or subdivided in order to obtain localised storage resource data if this was considered appropriate. The criteria used to decide whether a reservoir formation should be subdivided purely to obtain localised storage resource data were:

a. whether the formation is sufficiently widespread for there to be benefit in subdividing it into multiple storage units

b. whether sufficient geological information is available to make the subdivision meaningful

Reservoir formations in which structural boundaries such as faults are thought likely but cannot be clearly demonstrated to be boundaries to fluid flow, were subdivided into storage units along their major structural features such as large faults, fault zones, salt walls or dykes – on the grounds that these form likely permeability barriers.

In reservoir formations which are not thought to contain structural barriers to fluid flow, but where a progressive change in the degree of overpressure between the deepest part of the formation and the shallower parts is observed, subdivision into storage units was made into regions of similar overpressure. Examples are the Ekofisk Formation, Forties Sandstone Member, the Mey Sandstone Member and the Maureen Formation.

The Cretaceous Chalk – perhaps the largest lithostratigraphic Group [of reservoir formations] on the UKCS – was subdivided on the basis of synclinal features that form "inverse watersheds" that would define the migration path of an injected stream of CO_2 (**Figure 3.3**).

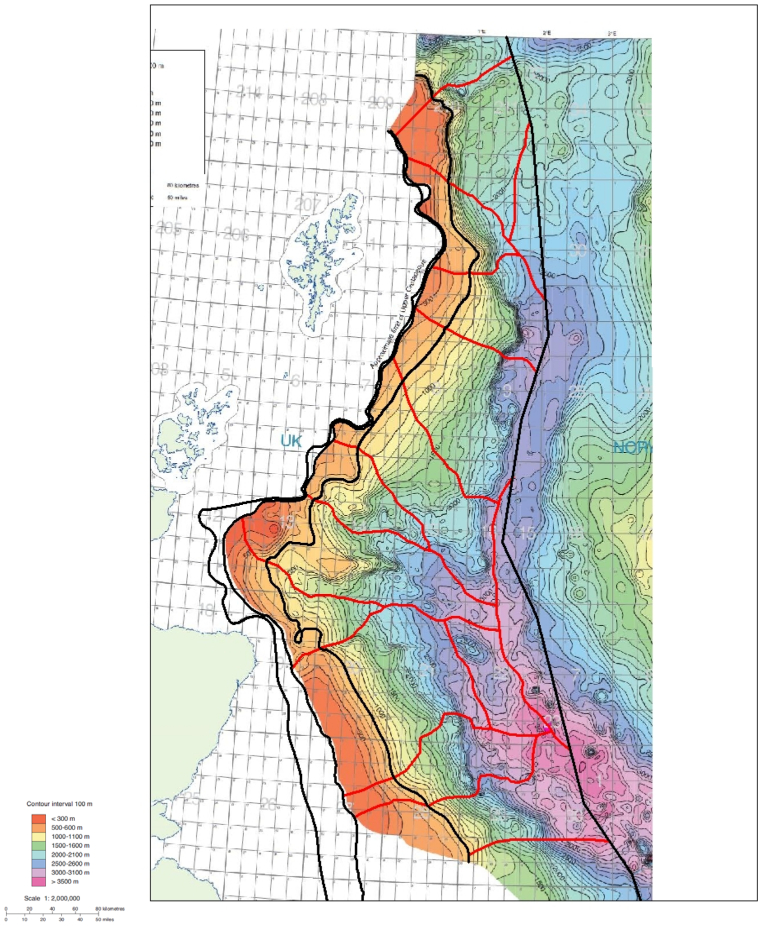


Figure 3.3: Subdivision of the Cretaceous Chalk into storage units, based on the Top Chalk Surface in the Millennium Atlas

(shown courtesy of the Millennium Atlas Co. Ltd)

6. All storage units were classified as either "pressure cells" or "non pressure cells". "Pressure cells" comprise reservoir volumes known or inferred to be hydraulically isolated from their surroundings (i.e. as having 'closed' boundaries). "Non pressure cells" include all other storage units. Typically these are large highly porous and permeable formations in which 'open' hydraulic communication within the storage unit and to the seabed is apparent or inferred. However, this category also includes some large, poorly known storage units for which there is insufficient information to conclude that they are pressure cells.

7. Because of the extremely large number of reservoir compartments that were identified, those that were considered to have a technically accessible storage resource (see below) of less than 50 Mt (assuming pressure management wells are not used) were excluded from the analysis. Although this involved the application of an economic criterion, which would not normally be expected at this stage in the analysis, it was considered necessary in order to reduce the total number of storage units to something manageable.

A total of 572 storage units (359 saline aquifers and 213 hydrocarbon fields) were defined and mapped.

It should be noted that lack of existing geological knowledge means that the basis for subdivision of many reservoir formations on the UKCS could change. Hence the number of storage units could also change as understanding advances with further geological appraisal.

Additionally, no storage units were identified in certain parts of the UK Continental Shelf, e.g. Bristol Channel, where the presence of suitable reservoirs at the required depth could not be clearly demonstrated. Undiscovered storage units could be present in some of these areas.

3.4 Identifying “daughter units” within Storage Units

Hydrocarbon fields, and mappable potential structural or stratigraphic traps in the saline water-bearing parts of storage units, have the potential to become more saturated with injected (buoyant) carbon dioxide than other parts of a storage unit. Consequently their storage capacity is calculated independently of the remainder of the storage unit in which they occur. These structures are described as daughter units in the UKSAP terminology. **Figure 3.4** shows a daughter unit within a storage unit.

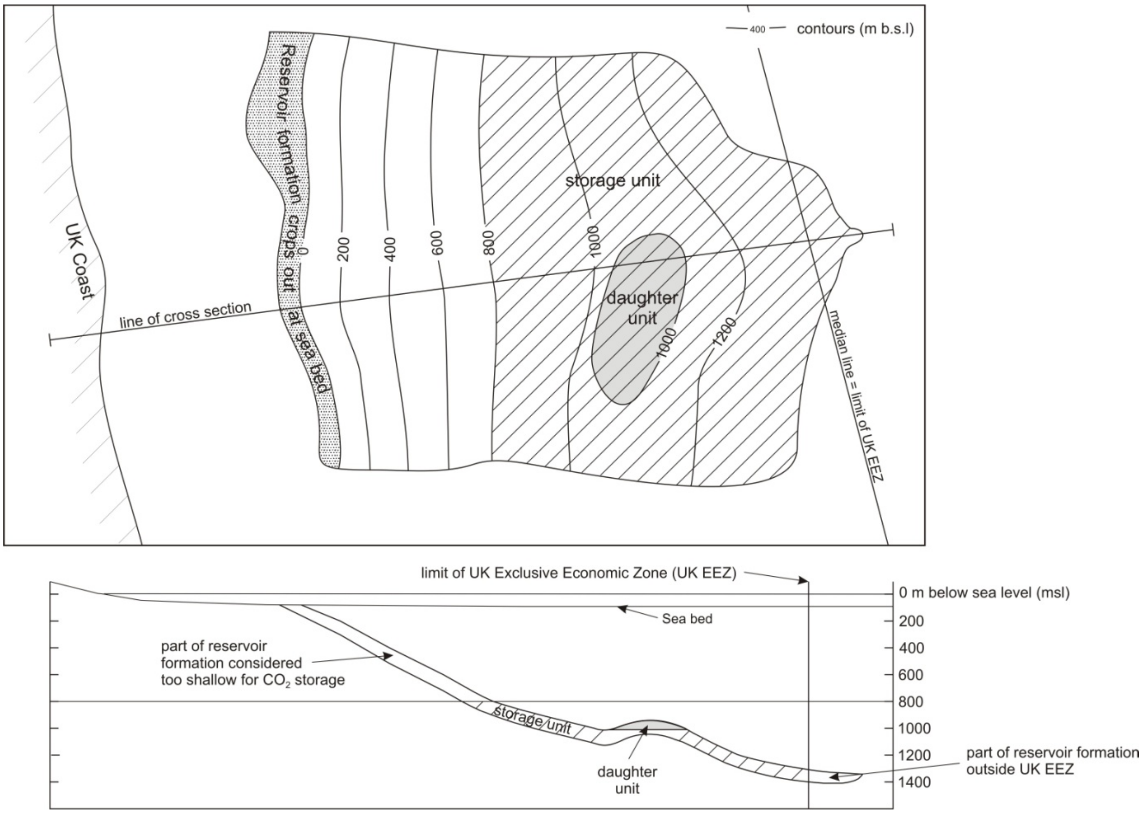


Figure 3.4: Simple Storage Unit Containing a Daughter Unit

(A higher CO_2 saturation may be achieved in the daughter unit. Therefore its storage capacity is calculated independently)

3.4.1 Hydrocarbon Fields

Hydrocarbon fields are mappable traps for buoyant fluids. In general, each may be considered as being associated with the ‘parent’ aquifer through which hydrocarbons initially migrated before becoming trapped. The majority of hydrocarbon fields within the UKSAP database are thus entered as “daughter units”. However, a few hydrocarbon fields, for which the parent aquifer could not be identified, are entered as storage units.

3.4.2 Mapped Structural and Stratigraphic Traps in Saline Water-bearing Parts of Storage Units

Potential structural and stratigraphic traps in saline water-bearing parts of storage units that could be identified and mapped using data available to the project were also treated as "daughter units", in similar fashion to the majority of hydrocarbon fields. The project did not seek to collect data on all potential saline water-bearing traps, since in general seismic data of sufficient resolution were not available with which to identify and map them. CarbonStore therefore does not contain a complete set of such storage units for the UK regions covered. Examples of such traps which were included are the large periclines mapped in the Bunter Sandstone of the Southern North Sea (the "Bunter Domes").

3.5 Summary of the Hierarchy of Reservoir Units

The hierarchy of units described above is a 3-level hierarchy consisting, in descending order, of:

- Reservoir formations (geological formations on the UKCS with reservoir properties)
- Storage units (mappable subsurface bodies of reservoir rock on the UKCS at depths greater than 800 m with the potential to retain CO_2, comprising all or part of a reservoir formation)
- Daughter units (in general, hydrocarbon fields and mappable potential traps in saline water-bearing parts of storage units)

3.6 Resource Estimation Methodology and Terminology

A resource can be defined as anything potentially available and useful to man. Pore space in a storage unit is a resource that could be used for CO_2 storage.

A reserve can be defined as that part of a resource that is available to be exploited economically using currently available technology. Given the low carbon price and absence of carbon taxes at the time of writing, economic exploitation of any part of the UK CO_2 storage resource is extremely challenging, and thus it is not considered possible to define CO_2 storage reserves at this time; the time and budget necessary to achieve the level of technical assessment required to define CO_2 storage reserves are only likely to be available within a demonstration or commercial storage project.

Even though it is not possible to define CO_2 storage reserves within the project, the goal is nonetheless to move as far as possible in this direction, in order to give policymakers and other stakeholders a more useful idea of the realistic potential for CCS in the UK. Consequently, "storage capacity", security of storage and cost are all assessed. The term "storage capacity" has been used in differing and undefined senses in previous CO_2 storage assessments, so a precise definition of its meaning in the UKSAP project is necessary. "Storage capacity[1]" is defined within UKSAP as: The probabilistic estimate of the mass of CO_2 that can be stored in daughter units or storage units without the use of dedicated

[1] Frequently abbreviated to "capacity"

pressure management wells or water injection wells[2] (For further discussion, see Section 3.6.2).

The following steps were taken to estimate storage capacity:

1. Estimate the total pore volume of individual storage units and daughter units

2. Estimate the accessible pore volume of individual storage units and daughter units. The accessible pore volume of a storage unit is the fraction of the total pore volume that can actually be filled with, and retain, CO_2 without the use of pressure management wells or water injection wells.

3. Estimate the density of CO_2 under storage conditions in individual storage units and daughter units.

4. Derive the static storage capacity[3] by multiplying the accessible storage volume by the density of CO_2 under storage conditions.

5. Modify the static storage capacity by dynamic calculations of the rate at which CO_2 could be injected and the manner in which CO_2 might subsequently move and be trapped in the subsurface, to determine the final storage capacity. The methodology for this final step is discussed in Chapters 4 and 5.

3.6.1 Estimating the Pore Volume of Storage Units

The minimum, maximum and most likely values for the area and average thickness of each storage unit were determined and entered into the project database by the assessor. These were used in combination with a 'shape factor' (between zero and one) to produce a probabilistic estimate of gross rock volume.

The minimum, maximum and most likely values for the average porosity, areal net:gross and vertical net:gross[4] in each storage unit were determined and entered into the project database by the assessor and applied to the probabilistic range of gross rock volumes to determine the probable range of pore volume in each storage unit.

The input parameters for the pore volume calculation and the results of the calculations themselves are shown on the Pore Volume pages of the project database (CarbonStore).

3.6.2 Estimating the Accessible Pore Volume of Storage Units by Static Methods

Carbon dioxide can be retained in a storage unit as follows:

- As a free phase in structural and stratigraphic traps
- Dissolved in the pore fluids present within the reservoir rock

---

[2] The term "water injection wells" is used here to refer to "chase water" wells or wells injecting water alternating with [CO_2] gas designed to reduce the mobility of CO_2 in the reservoir.
[3] The mass of CO_2 that could be stored in the accessible pore volume, calculated by multiplying the accessible pore volume by the density of CO_2 at the estimated storage temperatures and pressures in each storage unit.
[4] Net:gross, or N/G is the fraction of the gross rock volume that consists of reservoir rock

- As a residual saturation of gas or supercritical phase CO_2 trapped by capillary forces
- As precipitated salts ultimately originating from dissolution of reactive grains in the rock framework by pore waters acidified by dissolved CO_2
- Adsorption onto the surfaces of carbon-rich grains within, for example, shales or coals

However, for a wide variety of geological and engineering reasons only a fraction of the total pore space in a storage unit can actually be filled with, and retain, CO_2. For example:

- Heterogeneity in the reservoir rock and gravity effects mean that injected CO_2 will not contact all the pore space within the reservoir rock
- Build-up of the reservoir pore fluid pressure may limit the amount of CO_2 that can be injected into certain storage units before limiting pressures, e.g. pressures that might fracture the caprock, are reached
- There is an amount of formation brine that will always remain within the pore space of the reservoir rock, even in areas contacted by water-saturated CO_2. This water is immobilised, or trapped, by capillary forces and is normally referred to as a "residual" or "irreducible" saturation. This residual pore water may become saturated with dissolved CO_2 but it cannot be displaced by free gas or supercritical phase CO_2

As the mass of CO_2 that can be stored in a storage unit is not only a function of the geology, the properties of the initial pore fluid and the injected fluid, but also of the engineering deployed at the storage location, it can be increased by various engineering techniques (although these techniques would likely lead to a greater cost). For example:

- If more injection wells are drilled at appropriate spacing, an improved sweep of the reservoir rock by injected CO_2 may occur, and more CO_2 will be stored per unit volume
- If pore fluid is extracted from the storage unit, any pore fluid pressure rise accompanying CO_2 injection may be reduced, potentially allowing more CO_2 to be stored

Therefore the accessible pore volume of storage units should be assessed with reference to a given set of engineering conditions. Brennan et al. (2010) use the term "Technically Accessible CO_2 Storage Resource" (TASR) to refer to the entire resource that is accessible using all currently available technologies[5]. In the UK Storage Appraisal Project the term "Storage Capacity" is used to refer to the estimated total storage resource in areas considered accessible using all currently available technologies, excluding dedicated pressure management and/ or water injection wells. Use of the latter were considered by the project to be a development optimisation decision, and therefore not part of the 'base' capacity estimates of use to policymakers and other stakeholders. Thus storage capacity as used in this report is a subset of the Technically Accessible CO_2 Storage Resource (TASR) of Brennan et al. (2010).

In a similar vein, the term "Accessible Pore Volume", as used in this report, refers to the total pore volume that can be accessed for CO_2 storage using all currently available technologies excluding dedicated pressure management wells and water injection wells.

[5] Regardless of cost but excluding the resource present in storage units in which the salinity of pore water is less than 10,000 ppm.

3.6.2.1 Calculation of the Accessible Pore Volume within Storage Units Considered to be Pressure Cells

First a limiting pore fluid pressure for the storage unit was calculated. The data utilised came from the IHS pressure database which contains over 7,500 wells with direct and/ or indirect pressure data, such as Repeat Formation Tester (RFT), Drill Stem Test (DST), Mud Weight, Leak-Off Test (LOT), Limit test and lost circulation data. Pressure data contained in the IHS pressure database were used by GPT to interpret aquifer overpressures, which were used in defining the pressure regime for each pressure cell. Stratigraphic information allowed the pressure data to be filtered such that only direct pressure data pertaining to the stratigraphic horizon of interest were displayed. Stratigraphic data were also available from ArcGIS and the EDIN GIS database to confirm data positions, and to better delineate the stratigraphic distribution of pressure data.

A single overpressure value was picked to represent the aquifer overpressure for each unit at the given horizon. This value was recorded in Excel spreadsheets designed to calculate the aquifer pore fluid pressure, fracture pressure and lithostatic pressure at shallowest depth of closure for each unit. In areas where regional pressure study maps are available from GPT's regional pressure studies, overpressure values were taken from the appropriate stratigraphic map (GPT/ IHS, 2004, 2008).

The limiting pore fluid pressure for storage was defined as 90% of the minimum of either the assessed fracture pressure or lithostatic pressure. Fracture pressure values at the depth of interest for each unit were calculated through algorithms derived from both regional and local LOT data for each of the five principal regions. Aquifer Seal Capacity (ASC) was thus calculated as:

$$ASC = 0.9 \times \text{Min(Lithostatic Pressure, Fracture Pressure)} - \text{Initial Pore Pressure}$$

'Static' capacity was then calculated from the isothermal compressibility equation, thus:

$$S = PV \times C_t \times ASC$$

where PV = pore volume of the storage unit

$$C_t = C_w + C_f$$

and

C_t = total compressibility (of fluids plus rock matrix)

C_w = compressibility of fluids (pore water)

C_f = compressibility of the rock matrix (formation)

If available from the project data-sources, rock compressibility (C_f) was entered by the assessor as a parameter (with minimum, most likely and maximum values) in similar fashion to other characterisation variables. If not, equivalent values were calculated by 'minimum', 'most likely' and 'maximum' curve-fits to Hall's data (Hall, 1953), where rock compressibility is estimated as a function of porosity.

3.6.2.2 Calculation of the Accessible Pore Volume within Storage Units not Considered to be Pressure Cells

In order to arrive at an early estimate of overall UK storage capacity, the accessible pore volume in storage units not considered to be pressure cells was initially estimated by application of a “storage factor”, i.e. a simple fraction of the storage unit pore volume that might retain CO_2, for example in unmapped structural and stratigraphic traps or as a residual saturation.

Ideally, this factor should be based on reservoir characteristics. On the basis of previous studies (IEAGHG, 2009; Goodman et al., *in press*), a range between 1% and 6% pore-volume is suggested. It was recognised however, that significantly lower values are also possible and so an initial (minimum – most likely – maximum) range of 0.1% – 2% – 6% pore volume was applied in order to estimate ‘static’ capacity of non pressure cells. These estimates were later revised on the basis of dynamic flow simulation results (Chapter 5), although these initial ‘static’ estimates are still included within Carbonstore.

Although CO_2 may also be retained as precipitated carbonates or dissolved in formation brine, these processes are not generally regarded as representing significant supplementary storage because these processes take place relatively slowly compared to the likely duration of injection. They were therefore not explicitly included.

3.6.2.3 Calculation of the Accessible Pore Volume within Daughter Units

The expected pore volume available for CO_2 storage in mappable structural and stratigraphic traps was estimated differently, dependent on the nature of in-situ fluids.

For saline water-bearing traps there is generally little, if any, dynamic information available with which to determine the degree of hydraulic connectivity between the trap (daughter) and its associated aquifer (parent). Two estimates of the accessible pore volume were thus made, one utilising the isothermal compressibility equation, the other assuming that injected CO_2 might displace in-situ brine from the trap into an adjoining, hydraulically connected pore volume. The former is consistent with the daughter unit being isolated from its parent (or ‘closed’), the latter with it being ‘open’. In either case, the pore volume was calculated based on the minimum of the stratigraphic thickness and structural relief. Thus:

$$PV = Area \times Min(stratigraphicthickness, structuralrelief) \times \varphi \times NTGv \times NTGh \times \theta$$

1. $S = PV \times Ct \times ASC$ (‘closed’) “Pressure Capacity”

2. $S = PV \times (1 - Swirr) \times \eta$ (‘open’) “Buoyant Trapping Capacity” (fill-to-spill)

where *Swirr* = the irreducible water saturation

The accessible pore volume for the ‘closed’ scenario (limited by pressure increase) is generally at least an order of magnitude lower than that for the ‘open’ scenario (controlled by displacement and sweep efficiency). The two estimates represent realistic downside and upside accessible pore volumes, in the absence of direct evidence of the degree of communication between daughter and parent units.

For hydrocarbon fields, the pore volume available for CO_2 storage was estimated by equating the net volume of fluids withdrawn during hydrocarbon exploitation with the equivalent amount of CO_2 that could be subsequently stored. This method is by its very nature dynamic, and relationships for different hydrocarbon types were derived as follows:

Oil & Gas Fields:

Accessible Pore Volume = Np*Bo + Max[(Gp - Np*Rs, 0.0] * Bg

+ Wp * Bw

- Wi * Bw - Gi * Bg

Gas Fields:

Accessible Pore Volume = Gp * Bg

+ Wp * Bw

- Gi * Bg

Gas Condensate Fields:

Accessible Pore Volume = Gp/SF * Bg

+ Max[Ncond - (Gp/SF)*CGR*, 0.0] * Bcond

+ Wp * Bw

- Gi * Bg

where:

SF = 1 / [1 + {(CGR/5.6184) * (API - 5.9)/(API + 131.5) * 0.00309}]

Bg = 0.000352 z (T + 273) / P

and:

Np = Cumulative oil production [scm]

Ncond = Cumulative condensate production [scm]

Wp = Cumulative water produced (during production) [scm]

Wi = Cumulative water injected (during production) [scm]

Bo = Oil formation volume factor[6] [res m^3 / scm]

Bg = Gas formation volume factor [res m^3 / scm]

[6] The formation volume factor is the ratio of the volume occupied by a substance under reservoir conditions to the volume it occupies at surface conditions (15 ^oC, 0.1 MPa).

Bcond = Condensate formation volume factor [res m^3 / scm]

Bw = Water formation volume factor [res m^3 / scm]

Rs = Solution gas/oil ratio at virgin reservoir conditions [scm / scm]

CGR =Condensate to Gas ratio [scm / scm]

API = API gravity of condensate [degrees]

SF = Gas shrinkage factor [fraction]

Gi = Cumulative gas injected [scm]

Gp = Cumulative gas production [scm]

T = storage temperature [deg C]

z = Gas compressibility factor

It is recognised that natural water influx may accompany hydrocarbon extraction, particularly where the reservoir volume of injected fluids (typically water and/ or gas) is less than that of the hydrocarbons produced (Voidage Replacement Ratio < 1.0). Such influx can only be quantified through detailed analysis of production, injection and reservoir pressure data, and is rarely quoted in publicly available information. For the purposes of this study it was therefore assumed that during CO_2 storage an equal amount of water would be expelled from the field into attached aquifers, as flowed in during hydrocarbon production. This simplification ignores the effects of relative permeability hysteresis: in reality, it is possible that slightly less water leaves as entered, since as injected CO_2 drives water saturation back down (drainage cycle), the relative permeability to water generally remains less than it was during the preceding imbibition phase. Nonetheless, for most North Sea fields produced under water injection and pressure maintenance, the net influx of water is relatively small. Thus the errors introduced by this assumption are likely to be small also, and natural water influx was ignored in the estimation of storage capacity.

3.6.2.4 Calculation of Static Storage Capacity from the Accessible Pore Volume

The term static storage capacity[7] is used here to describe the mass of CO_2 that could be stored in the accessible pore volume, defined above, calculated by multiplying the accessible pore volume by the density of CO_2 at the estimated storage temperatures and pressures in each storage unit. This requires the storage temperature and pressure to be estimated.

[7] Once the static storage capacity has been calculated, it is modified by dynamic calculations of the rate at which CO_2 could be injected and the manner in which CO_2 might subsequently move and be trapped in the subsurface, to determine the theoretical storage capacity (see Chapters 4 and 5).

3.6.2.5 Estimating Storage Temperature and Pressure and CO_2 Density in Storage Units Considered to be Pressure Cells

The storage temperature in these units is taken to be the initial reservoir temperature, pre-storage. The maximum, minimum and most likely temperature was taken from corrected well temperature data where available or estimated using a surface temperature and geothermal gradient derived from the Millennium Atlas (Millennium Atlas Co Ltd, 2003). The storage pressure is considered to be the limiting pore fluid pressure determined as described above. The CO_2 density is then calculated as a function of temperature and pressure using look-up tables provided within CarbonStore.

3.6.2.6 Estimating Storage Temperature and Pressure and CO_2 Density in Storage Units not Considered to be Pressure Cells

The storage temperature and pressure in storage units not considered to be pressure cells is assumed to be the initial temperature and pressure pre-storage. The maximum, minimum and most likely temperature was taken from corrected well data where available, or estimated using a surface temperature and geothermal gradient. The reservoir pressure was taken from data supplied by GPT where possible, or, in the absence of any other data, considered to be hydrostatic. The CO_2 density was again calculated as a function of temperature and pressure using look-up tables provided within CarbonStore.

3.7 References

1. Knox, R W O'B & Cordey, W G (Eds) 1992-4. Lithostratigraphic Nomenclature of the UK North Sea (7 volumes), British Geological Survey, Nottingham.
2. Millennium Atlas Co Ltd. 2003. The Millennium Atlas: petroleum geology of the central and northern North Sea. Evans, D., Graham, C., Armour, A & Bathurst, P. (editors and co-ordinators). London: the Geological Society of London.
3. IEAGHG 2009. Development of Storage Coefficients for CO2 Storage in Deep Saline formations. Report No. 2009/13.
4. Goodman, A., Hakala, A., Bromhal, G., Deel, D., Rodosta, T., Frailey, S,, Small, M., Allen, D., Romanov, V., Fazio, J., Huerta, N., McIntyre, D., Kutchko, B. & Guthrie, G. US DOE Methodology for Development of Geologic Storage Potential for Carbon Dioxide at the National and Regional Scale. In press. International Journal of Greenhouse Gas Control.
5. J. G. Gluyas & H. M. Hitchens (eds.), United Kingdom Oil and Gas Fields, Commemorative Millennium Volume, Geological Society (London) Memoir 20.
6. Brennan, S.T., Burruss, R.C., Merrill, M.D., Freeman, P.A., Ruppert, L. F. 2010. A Probabilistic Assessment Methodology for the Evaluation of Geologic Carbon Dioxide Storage. U.S. Geological Survey, pp. 1-31.
7. Hall, H. N. Compressibility of Reservoir Rocks. Trans AIME (1953)
8. GPT/IHS North Sea Central Graben Pressure Study, 2004. Non-Proprietary study by GeoPressure Technology and IHS Global, unpublished.
9. GPT/IHS North Sea Viking Graben Pressure Study, 2008. Non-Proprietary study by Geo Pressure Technology and IHS Global, unpublished.

4 Injectivity

In order to assess the amount of CO_2 that can be *practically* stored in a unit, an estimate of the rate at which CO_2 can be injected is required. The injectivity index is dependent on characteristics of the formation, the fluid being injected (and displaced), and well completion geometry and efficiency. The achievable rate is then the product of injectivity, number of injection wells, and pressure differential that may be applied between the well and formation.

Different CO_2 supply scenarios (annual rate multiplied by duration of project) require different numbers of wells (and potentially injection facilities). Hence in order to complete the picture of capital investment required for each, a number of injection wells (NIW) matrix such as depicted in **Figure 4.1** must be completed for each storage unit.

CO2 Injection Rate [Mt/yr]	Injection Duration (yr)									
	10	20	30	40	50	60	70	80	90	100
2	2	2	2	2	2	2	3	3		
5	4	5	6							
10	9									
15	17									
20										
40										
60										

Figure 4.1: Typical Number of Injection Wells (NIW) Matrix for a Storage Unit

(In this example, the maximum amount of CO_2 that can be stored is 160 Mt (2 Mt/ yr for 80 yrs, requiring 3 injection wells). Injecting 150 Mt in only 10 yrs requires 17 wells to ensure injection pressure remains below the maximum permitted (90% of fracture pressure)

This chapter explains how injection well requirements for saline aquifers and hydrocarbon fields were estimated.

4.1 Saline Aquifer Injectivity

4.1.1 General Workflow

The general workflow for estimating the NIW for a given utilisation scenario and for a given saline aquifer storage unit is as follows:

1. Calculate the maximum pressure build-up in the injection well due to a constant injection rate of CO_2 for a given period of time

2. If the pressure build-up is greater than the maximum allowable pressure (90% of the hydraulic fracture pressure), split the domain to accommodate an additional injection well

3. Redistribute the injection rate equally between the injection wells and reassess the maximum pressure build-up

4. Sequentially increase the number of injection wells until the estimated maximum pressure build up is less than the maximum allowable pressure

For reservoirs requiring multiple wells, individual wells are assumed to be optimally placed such that each well has an equal zone of influence. Each well is then assumed to be located at the centre of a circular closed formation, the area of which is the total formation area divided by the number of wells (**Figure 4.2**). Interference between wells is accounted for by the assumption of an outer impermeable boundary.

To avoid units being specified with impractical NIW, a minimum injection rate per well of 0.1 Mt/year is imposed. Therefore, for a particular injection scenario, when the NIW increases to such an extent that the injection rate per well is < 0.1 Mt/year, the calculation method specifies that scenario is not feasible for the storage unit of concern, and the relevant cell in the NIW matrix is left blank (e.g. see **Figure 4.1**).

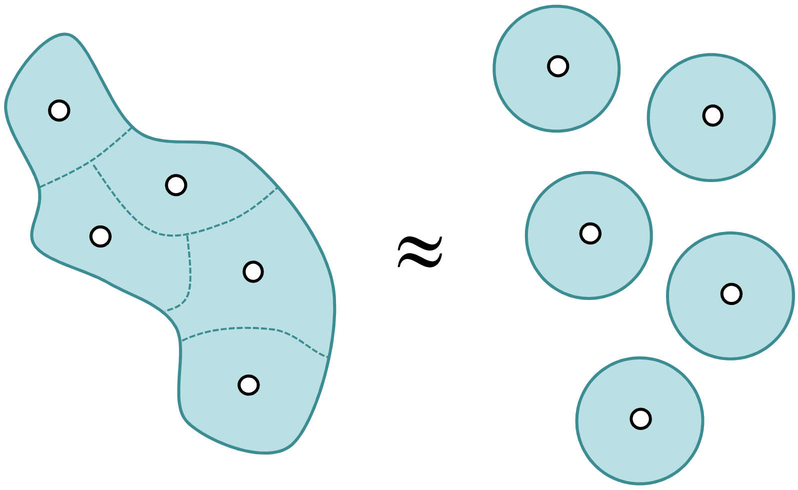


Figure 4.2: Schematic of a Reservoir Split into Identical Circular Units of Total Equivalent Area

4.1.2 Estimation of Maximum Allowable Pressure

The maximum allowable pressure is calculated from the minimum of 90% of the lithostatic pressure, 90% of the fracture pressure and 100% of the "surface pressure constrained downhole pressure" (SPCDP) (Pa). The lithostatic pressure and fracture pressure are the same as those considered for estimating aquifer seal capacity (ASC). The SPCDP is calculated using (Massey BS, 1989, p.199, 204)

$$\text{SPCDP} = \text{SP} + \rho_{CO_2} L(g - fU^2 / r_w)$$

where

SP:	maximum sustainable surface pressure, Pa
ρ_{CO_2}:	density of CO_2, kg/m^3
L:	depth to centroid of storage unit, m
g:	gravitational acceleration (9.81), m/s^2

f: friction factor, (-)

U: flow per unit area of pipe within the injection well, m/s

r_w: injection well radius, m

and the friction factor, f is calculated from (Massey BS, 1989, p.204)

$$f = \left[-3.6 \log_{10} \left(\frac{3.45 \mu_{CO_2}}{\rho_{CO_2} U r_w} + \left(\frac{k}{7.42 r_w} \right)^{1.11} \right) \right]^{-2}$$

where

μ_{CO_2}: dynamic viscosity of CO_2, Pa s

k: pipe roughness, assumed to be 0.000045 (Massey BS, 1989)

The dynamic viscosity and density of CO_2 used for the calculation of SPCDP are assumed to be properties associated with the pressure and temperature at the shallowest depth, or the centroid of the reservoir of concern, for 'closed' and 'open' reservoirs respectively.

The maximum sustainable surface pressure is assumed to be 25 MPa, consistent with the maximum pipeline pressure specifications used in the economic analyses.

4.1.3 Estimation of Pressure Build-up

To calculate pressure build-up during CO_2 injection, it is necessary to simulate the injection of supercritical CO_2 into a saline aquifer. This is conventionally achieved using a numerical multi-phase reservoir simulator. However, such models are computationally intensive to run, and are thus not amenable to the large number of realisations required for Monte Carlo analysis. Therefore, the semi-analytical solution of Mathias et al. (2011) is used, which estimates the pressure build-up due to the constant rate injection of CO_2 into a homogenous, isotropic, confined saline aquifer of finite radial extent.

The semi-analytical solution assumes mobile CO_2 and brine are separated by a sharp interface, located at an elevation, h [L], above the base of the formation (see Figure 4.3). Capillary pressure is assumed negligibly small and fluid pressure is assumed not to vary in the vertical direction over the entire thickness of the confined porous formation of vertical extent, H [L] (the Dupuit assumption). Saturation, relative permeability and viscosity are assumed constant and uniform within both the CO_2 and brine zones. Although the problem appears 2D axially symmetric, it is mathematically analogous to 1D axially symmetric Buckley Leverett flow with linear relative permeability (**Figure 4.3**).

The relevant equation to calculate pressure build-up is Eq. (20) of Mathias et al. (2011), from which it can be seen that injectivity is dependent on many reservoir specific parameters, including permeability, porosity, formation thickness, areal extent, pressure, temperature, brine salinity and relative permeability. Formation thickness and areal extents are re-scaled using the fractions: NTG (net to gross) and "Areal Net Sand", respectively.

Derivation of the semi-analytical solution requires invoking several important simplifying assumptions including:

1. Homogenous and isotropic aquifer
2. A closed confined aquifer of circular radial extent
3. Injection wells are vertical and fully completed
4. Vertical pressure equilibrium
5. Constant fluid properties
6. Negligible capillary pressure
7. Immiscible displacement (no brine evaporation and no CO_2 dissolution)

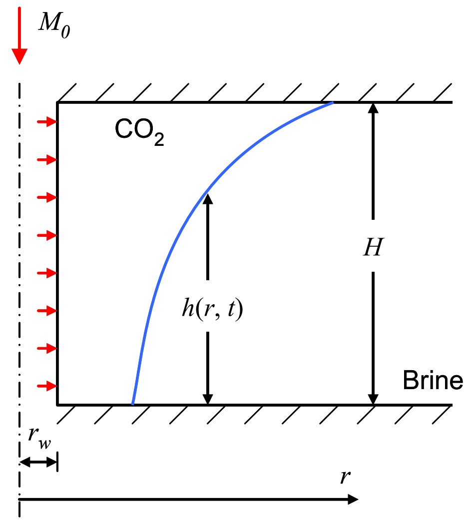


Figure 4.3: Schematic Diagram of Assumed CO_2 Brine Interface during Injection

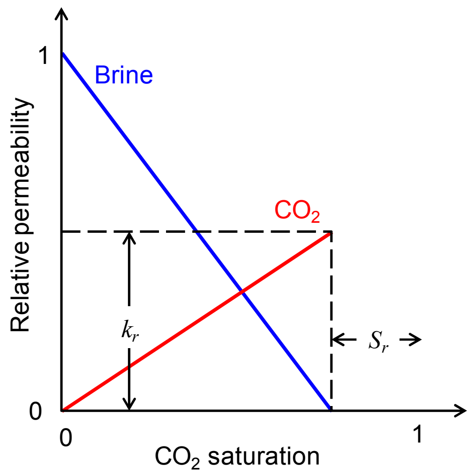


Figure 4.4: Schematic Diagram of the Relative Permeability Functions Assumed

(Note that as CO_2 displaces brine, some of the brine is residually trapped, S_r [-], giving rise to a reduced permeability for the CO_2 phase, k_r [-])

Assumption 1 is consistent with the lack of data concerning spatial variation for each unit. Assumption 2 is due to the methodology of treating multiple wells (recall **Figure 4.2**). The assumption of fully completed vertical wells represents an assumption about operation. By comparison to fully dynamic simulations using TOUGH2 with ECO2N, Mathias et al. (2011) have shown assumptions 4 to 6 to make little difference on pressure build-up estimation. The assumption of immiscible displacement results in an overestimation in pressure due to the ignoring of residual brine evaporation and volumetric decreases associated with CO_2 dissolution. However, from the study detailed in Appendix A5.8 it is found that a reasonable correction is achieved by fixing the end-point relative permeability for CO_2 at 1 ($k_r = 1$).

4.1.4 Modification for Non-pressure Cell Units

4.1.4.1 Modification of Pressures for Open Aquifers

For non-open aquifer storage units, the initial, lithostatic and fracture pressures used for the injectivity analysis are those for the shallowest depth associated with the unit as these should be the most conservative estimates. However, for the open aquifer units, pressures specified for the shallowest depth correspond to those pressures at 800 m below seabed, which is considered overly conservative in this context. Therefore, for open aquifers, it has been decided to use pressures associated with the centroid depth instead.

4.1.4.2 Modification of Plan Area for Non-pressure Cell Units

The maximum possible utilisation capacity (i.e., with NIW tending to infinity), UC_{max}, using the above injectivity method can be found from:

$$\mathrm{UC}_{\mathrm{max}} = \rho_{CO_2} \times \mathrm{PV} \times \mathrm{C_t} \times \mathrm{ASC}$$

where

PV: pore volume of storage unit, m^3

C_t: total compressibility (of fluids plus rock matrix), Pa^{-1}

ASC: aquifer seal capacity, Pa

and

$$\mathrm{PV} = \mathrm{NTG} \times H \times \text{Areal Net Sand} \times \text{Area of Formation}$$

For pressure cell units, UC_{max} = theoretical capacity, because the injectivity model assumes each injection well to be contained within a closed circular pressure cell. However, such an approach is also reasonable for non-pressure cell units (i.e., open aquifers and/or daughter units with identified structural/ stratigraphic confinement) where injectivity gives rise to the need for large quantities of wells. The reason is that, regardless of the nature of the outer boundaries of a storage unit, injection wells situated on the inside of an array of injection wells also behave as closed systems due to the pressure interference caused by proximate wells. However, for non-pressure cell units requiring 9 or less wells, well interference is not considered to be important. Therefore, for non-pressure cell units requiring ≤ 9 injection wells, the area of formation is re-scaled such that UC_{max} = theoretical capacity, i.e.:

$$\text{Scaled Formation Area} = \text{Formation Area} \times \text{Theoretical Capacity} \div UC_{max}$$

4.1.4.3 Cumulative Injection per Well Constraint for Open Aquifers

For open aquifers without identified structural/ stratigraphic confinement, which have good injectivity but are migration limited (i.e., Storage Regime 3, see Section 5.3.1), following the study detailed in Appendix A5.3, cumulative injection to individual wells is limited to 10 Mt of CO_2.

4.1.5 Insights from the Deterministic Analysis

To gain some insight from the injectivity analysis across the UKSAP saline aquifer database, a deterministic run, using the maximum likelihood values of all input parameters, was undertaken. For each storage unit, a utilisation capacity was calculated by taking the largest cumulative injection rate that can be achieved (with a number of wells identified) from the NIW matrix. The minimum NIW needed to achieve that utilisation capacity was also recorded. In this way, for the example shown in **Figure 4.1**, utilisation capacity = 80 x 2 = 160 Mt and the corresponding number of wells = 3.

Figure 4.5 shows a plot of utilisation capacity / theoretical capacity against theoretical capacity. Here it can be seen that the utilisation capacity is always ≤ theoretical capacity. Smaller capacity units tend to have lower utilisation capacity to theoretical capacity ratios because of the correspondingly smaller choice of injection rate and injection duration combinations available within the NIW matrix. There is no obvious systematic difference between utilisation capacity to theoretical capacity ratios of pressure cell and non-pressure cell units.

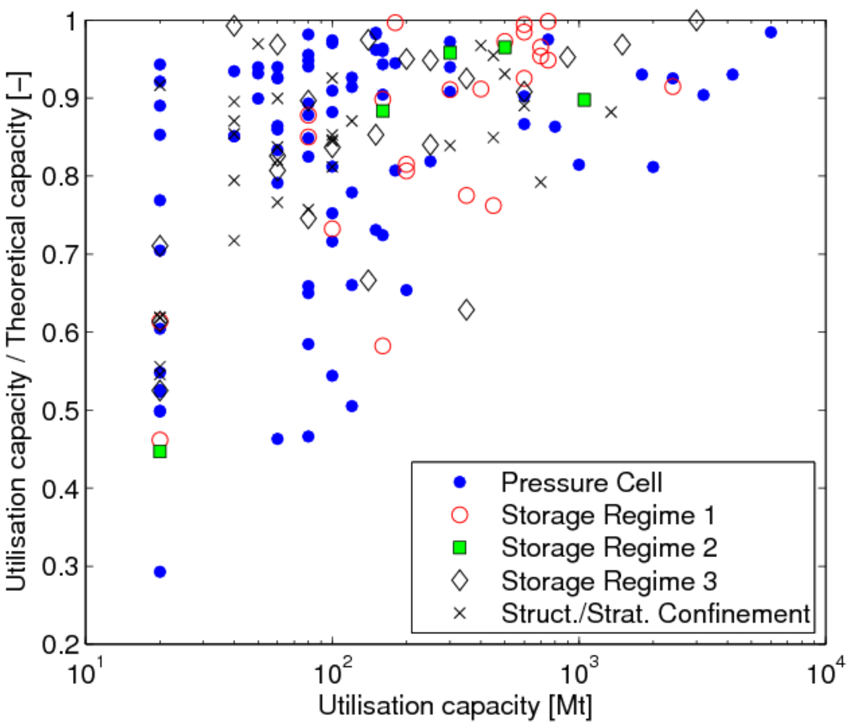


Figure 4.5: Plot of Utilisation Capacity / Theoretical Capacity against Theoretical Capacity

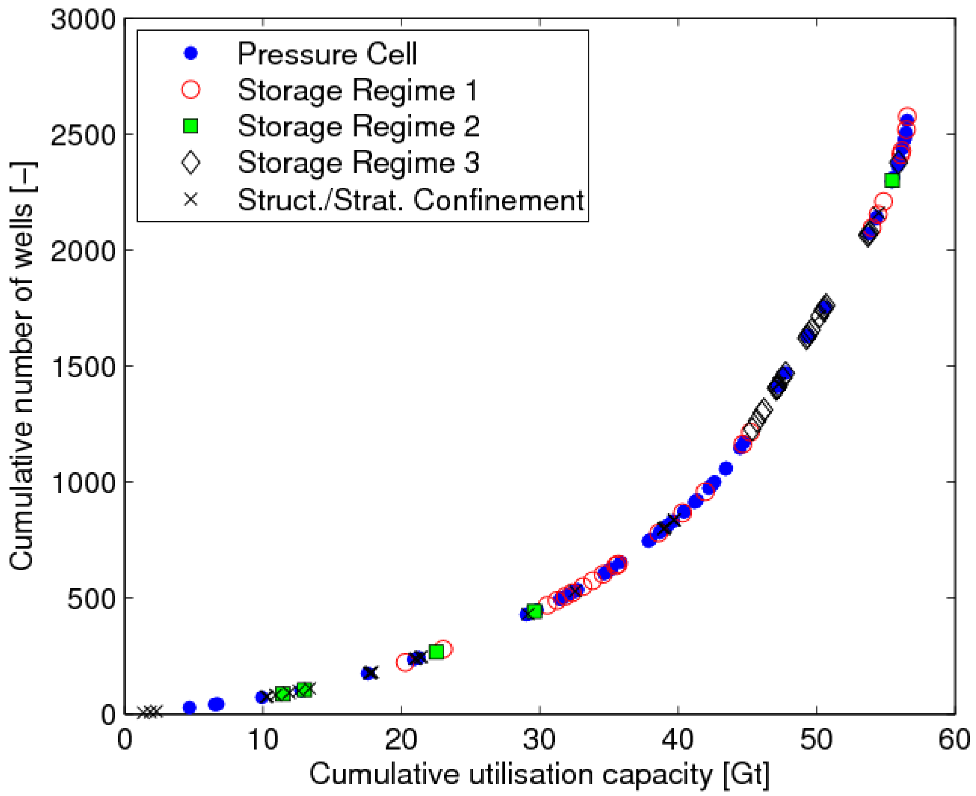


Figure 4.6: Plot of Cumulative Number of Wells against Cumulative Utilisation Capacity

Figure 4.6 shows a plot of cumulative number of wells against cumulative utilisation capacity for the entire UKSAP saline aquifer collection. Cumulative utilisation was obtained by ranking all storage units in order of increasing number of wells per Gt of utilisation capacity and then accumulated. In this way, the number of wells needed to obtain x Gt of storage, whilst utilising the most efficient storage units first, can be determined. It can be seen that the first 1000 wells yield approximately 40 Gt of storage, whereas the next 1000 wells lead to an additional yield of only around 13 Gt of storage.

The pressure cell units span across the efficiency spectrum (the blue dots). In contrast, the non-pressure cells are distributed in a relatively systematic fashion. The most efficient non-pressure cell units are those with defined structural or stratigraphic confinement or those open aquifers predefined as "Storage Regime 2" (good injectivity and good security, the green squares). All of the open aquifers characterised as "Storage Regime 3" (good injectivity but migration limited, the black diamonds) feature on the RHS (less efficient half) of the graph. This is due to the maximum cumulative injection of 10 Mt per well constraint.

4.2 Hydrocarbon Field Injectivity

With regard to hydrocarbon fields, a number of simplifying assumptions underlying the analytical solution for saline aquifer injectivity are more tenuous:

- properties of the displaced fluid (hydrocarbon) may vary considerably with depth;
- more than two phases (CO_2 and either oil, gas or brine) may be present;

- displacement may be neither incompressible nor immiscible.

In addition, as a result of reservoir characteristics and development strategies employed, different 'panels' or regions may exhibit very different pressures and/ or fluid saturations at the time that CO_2 storage operations commence. An analytical model must then be applied with consideration to the extant properties of each individual panel, and such detailed information was not generally available to the project.

Observed production rate data were however available, and from these it is possible to infer likely CO_2 injection rates 'directly', rather than predict them by mathematical model.

In a similar vein to estimating hydrocarbon field storage capacity based on cumulative production and injection *volumes*, it was therefore decided to predict the required number of CO_2 injection wells from the *rates* observed during hydrocarbon exploitation.

4.2.1 CO_2 Injection Rate

As noted earlier, injectivity (or productivity) index is a function of reservoir and fluid properties, and well completion geometry and efficiency. Thus for a given hydrocarbon field, neglecting relative permeability effects (of which more later) and assuming similar well types, the likely CO_2 injection rate per well may be related to the observed production rate by the following expression:

$$\mathrm{M}_{\mathrm{CO}_2} = \left(\mathrm{Q}_{\mathrm{HC}} \times B_{HC} + \mathrm{Q}_{\mathrm{w}} \times B_w\right) \times 365 \times Min\left[\mu_{\mathrm{HC}}, \mu_{\mathrm{CO}_2}\right] \times \Delta P_{inj} \times \rho_{\mathrm{CO}_2} \Big/ \mu_{\mathrm{CO}_2} \times \Delta P_{prod} \times 10^6$$

Where:

M_{CO2}	=	CO_2 injection rate per well [Mt/ yr]
Q_{HC}	=	hydrocarbon production rate per well [scm/ day]
B_{HC}	=	hydrocarbon Formation Volume Factor [res. m^3 / scm]
Q_w	=	water production rate [scm/ day]
B_w	=	water Formation Volume Factor [res. m^3 / scm]
μ_{HC}	=	hydrocarbon viscosity at reservoir conditions [cP]
μ_{CO2}	=	CO2 viscosity at reservoir conditions [cP]
ρ_{CO2}	=	CO2 density at reservoir conditions [g/ cc]
ΔP_{prod}	=	Production drawdown (P_{res} – P_{wf}) [MPa]
ΔP_{inj}	=	Pressure differential applied during injection (P_{wf} – P_{res}) [MPa]

With limited production drawdown data available in the public domain, a further simplifying assumption was made that $\Delta P_{inj} \sim \Delta P_{prod}$. This approximation will generally be reasonable for reservoirs that are normally pressured. However, it might be optimistic (i.e. leading to too high estimates of CO_2 injection rate) for over-pressured reservoirs at or near their fracture pressure, or where large draw-downs have been achieved through use of Electrical Submersible Pumps (ESPs); it may be pessimistic where fracture pressure is much greater than reservoir pressure.

Production performance of a ‘typical’ well was estimated for each field by identifying the peak field production rate from the DECC production database, and dividing by the number of active producers coincident with that rate. Since peak rates are often achieved early in field life and at low water-cuts, it may be argued that in general the corresponding relative permeability to hydrocarbon would have been high (close to 1.0). Similarly, and consistent with the approximation used in injectivity modelling of saline aquifer storage units, relative permeability to injected CO_2 is likely to approach 1.0, at least in the critical near-wellbore region where pressure gradients are at their highest. Neglecting relative permeability effects is thus argued as a reasonable simplifying assumption.

4.2.2 Maximum CO_2 Injection per Well

In addition to the estimate of CO_2 injection rate, another parameter of interest in terms of predicting the number of injection wells required is the likely connected volume – akin to the ‘drainage radius’ of a production well.

The maximum amount of CO_2 that might be injected in a typical well was therefore estimated for each field from:

$$\mathrm{N}_{\mathrm{CO}_2} = \mathrm{N}_{\mathrm{HC}} \times B_{HC} \times \rho_{\mathrm{CO}_2} \big/ 10^6$$

Where:

N_{CO2} = maximum amount of CO2 that can be injected by a typical well [Mt]

N_{HC} = typical hydrocarbon reserves produced per well [scm]

The typical hydrocarbon reserves produced per well were again derived from the DECC production database, dividing ultimate field recovery by the total number of active producers over the life of the field.

4.2.3 Injection Scenarios for Hydrocarbon Fields

For each hydrocarbon field, having estimated the CO2 injection rate and maximum amount of CO2 that can be stored on a per well basis, the number of wells required to meet each injection scenario in the injections wells matrix is given by:

$$\mathrm{NIW} = \frac{\mathrm{Re}\,quiredInjectionRate[\mathrm{Mt/\ yr}] \times InjectionDuration[yrs]}{Min[M_{CO_2} \times InjectionDuration[yrs], N_{CO_2}]}$$

for all scenarios where Injection Rate x Duration ≤ theoretical capacity of unit.

With limited information available with regard to expected abandonment pressure for most hydrocarbon fields, the bottom-hole pressure for all injection scenarios was simply assumed to be the maximum allowable (i.e. 90% fracture pressure).

4.3 Comparison of Results

Having established and applied the above methodologies for estimating the required number of injection wells in saline aquifers and hydrocarbon fields, a systematic difference was identified in results:

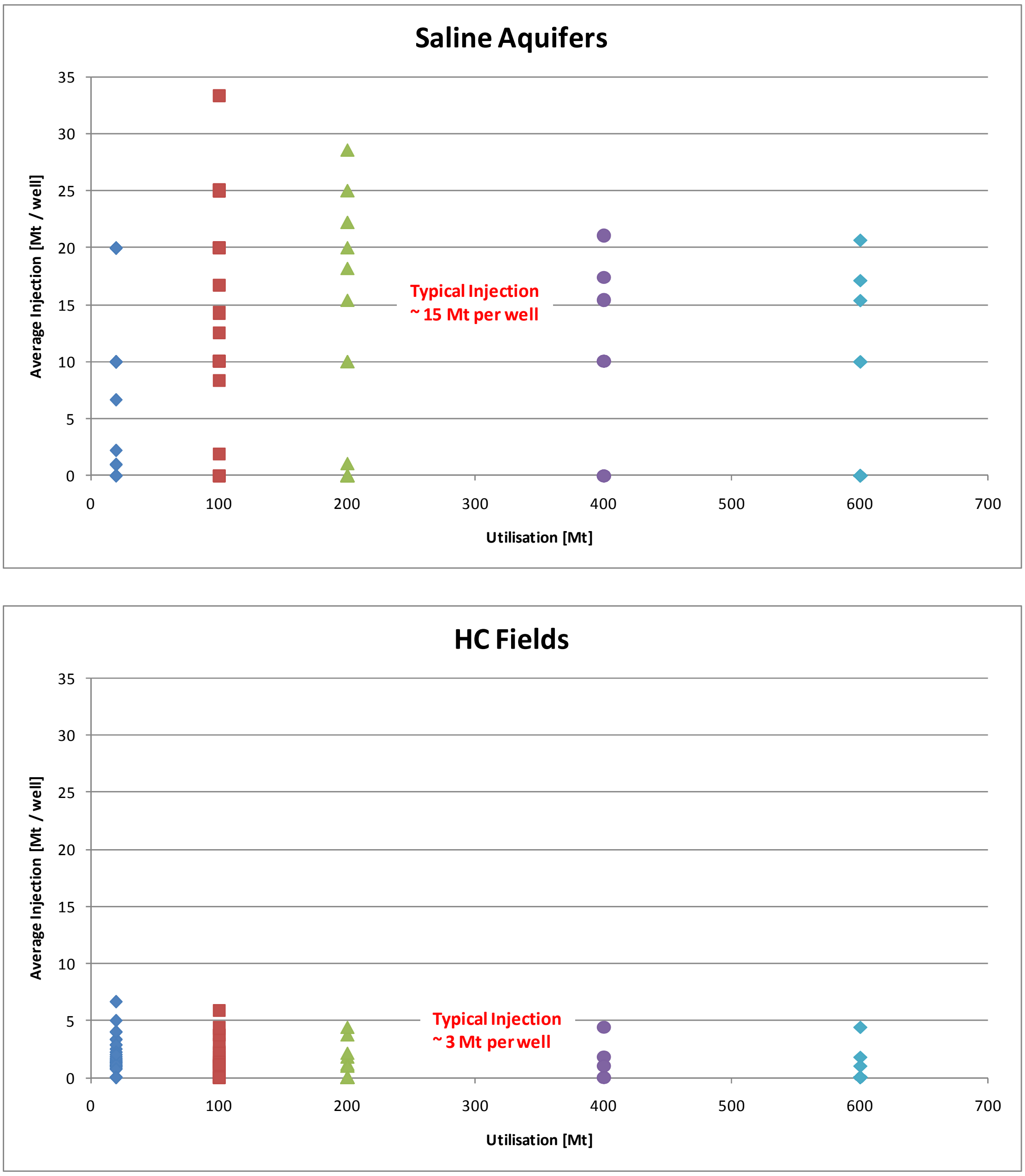
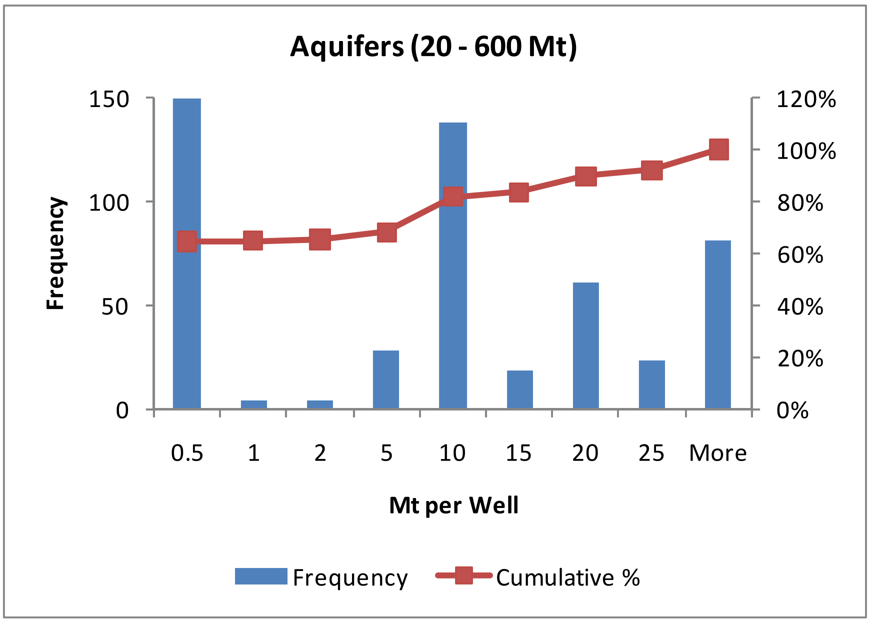


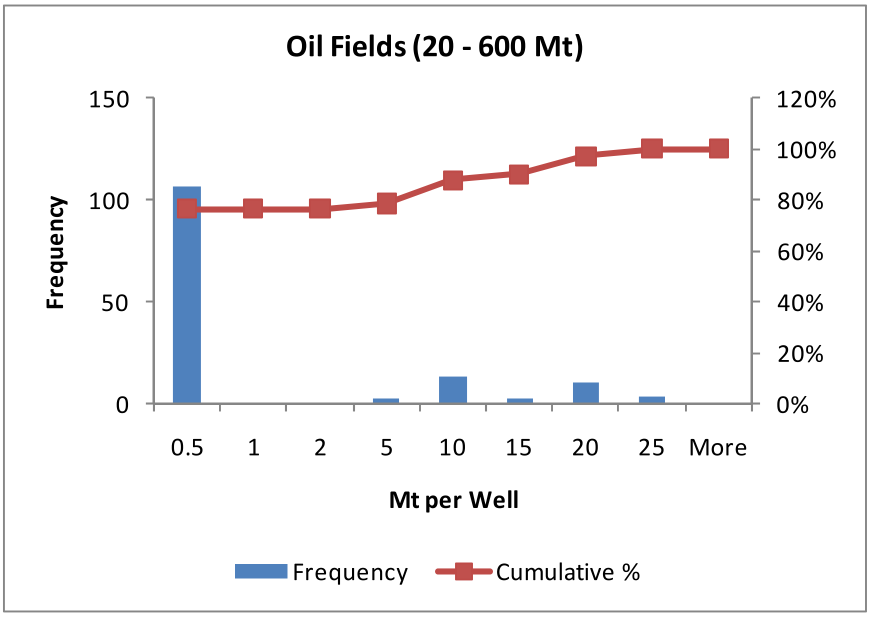
Figure 4.7: Predicted Injection Well Performance - Saline Aquifers versus Hydrocarbon Fields

Injection wells in saline aquifer storage units are predicted to inject up to about 30 Mt CO_2 per well, with typical performance of around 15 Mt; for hydrocarbon fields, typical injection per well is predicted to be only 3 Mt. This appears low compared to assumptions in other studies (eg. ~30 Mt per well, ZEP July 2011), and performance of many CO_2 or hydrocarbon gas injection wells in operational Enhanced Oil Recovery (EOR) schemes.

One reason may be that for the hydrocarbon field analyses, the 'connected volume' of each injector was estimated from the average *hydrocarbon* recovery per well, ignoring water production; many North Sea fields employ secondary waterflood to improve recovery, and hence a large proportion of produced water is a result of injected water recycle rather than being indicative of the well's true drainage volume. Another is that typical well performance was necessarily inferred from field-level rates and cumulatives; individual well profiles were not available to the project. This approach additionally requires the corresponding number of *active* wells to be identified, and again the level of detail available to the project was such that inactive wells might inadvertently have been included.

As a result, the systematic offset between the two populations was interpreted as an artefact of the different methods employed. The required number of injection wells for hydrocarbon fields was thus adjusted such that average predicted performance was consistent with the saline aquifers. The resultant distributions are depicted below:





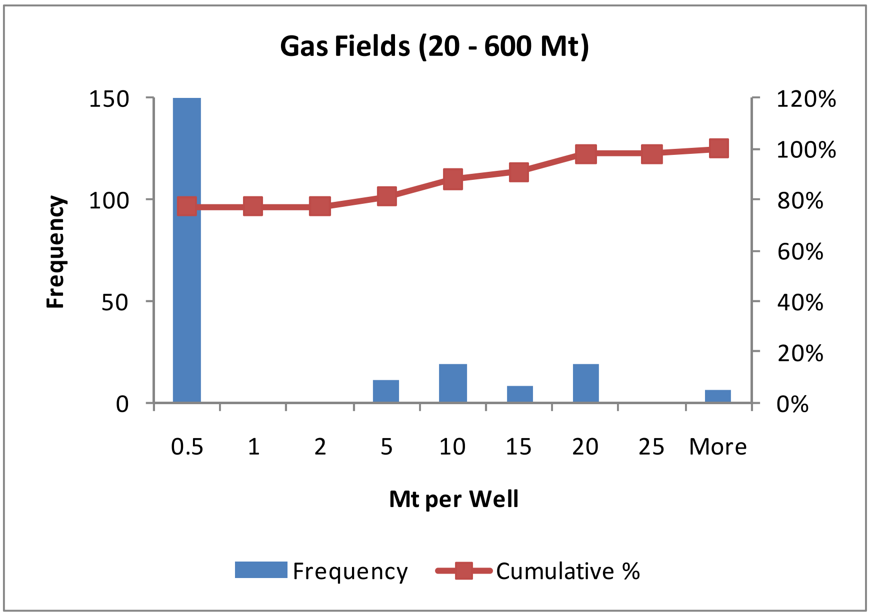


Figure 4.8: Predicted Injection Well Performance - Hydrocarbon Fields adjusted to Match Saline Aquifers

The adjusted (hydrocarbon field) injection well numbers were used in base case economic analyses, to facilitate subsequent comparison with saline aquifer storage units. Analyses based on the unadjusted injection well numbers are included in the Appendices.

4.4 References

1. Massey BS, 1989. Mechanics of Fluids, 6th ed. London, Chapman & Hall
2. Mathias SA, Gonzalez GJ, Thatcher KE & Zimmerman RW 2011. Pressure build-up during CO_2 injection into a closed brine aquifer. Transport in Porous Media, In Press doi:10.1007/s11242-011-9776-z. (Also included as Appendix A4.1)
3. The Costs of CO_2 Capture, Transport and Storage – Post-demonstration CCS in the EU, July 2011. Zero Emissions Platform (ZEP)

5 Dynamic Modelling

5.1 Introduction

Initial CO_2 storage capacity estimates were made mainly on a static (volumetric) basis as described in Section 3.6. This is a useful first step, providing a preliminary capacity estimate, but takes no account of the rate at which CO_2 could be injected nor the manner in which CO_2 might subsequently move and be trapped in the subsurface. As a result, these estimates will almost certainly be optimistic and the volumes that can actually be stored will be somewhat less. In addition, injectivity largely controls the number and type of injection wells required, and knowledge of likely CO_2 migration influences perception of long-term containment security and likely monitoring/verification requirements. Practical and economic viability of the storage unit is thus also affected. A substantial programme of dynamic modelling was therefore undertaken to take account of these factors and estimate well numbers and pressures to facilitate economic calculations.

The project identified three types of saline aquifer store relevant to UK CO_2 storage capacity: pressure cells ('closed'), non pressure cells ('open') and structural/ stratigraphic traps, see Sections 5.5, 5.3, and 5.4 respectively. All UKCS storage units were classified into these types, though in practice an element of judgement was required in certain cases. The combined initial (static) capacity associated with each type was important relative to overall UK storage capacity, and so subsequent dynamic modelling was performed for each. Typically this involved numerical simulation, using two classes of model: simplified generic models, termed 'Representative Structures', and more detailed models of selected regions of actual UKCS aquifer units, termed 'Exemplars'. The Representative Structure models were primarily used for investigating typical behaviour and its range of variation, and the Exemplars for demonstrating storage capacity in a particular type of store, verifying preliminary conclusions and investigating mechanisms unable to be included in the Representative Structure models.

Dynamic estimates of storage capacity require some constraint determining when the store is 'full', which may depend on the type of store under consideration. For example, UKSAP considers a pressure cell to be 'full' when some part of it reaches 90% of the pressure estimated to cause the rock to fracture. A structural trap may be defined as 'full' if free CO_2 starts to leave the trap if more is injected (provided the fracture pressure limit has not been exceeded either); this is equivalent to the concept of 'fill to spill', common in the oil and gas industry. The concept of 'full' is less clear for dipping open aquifers however, where such physical limitations on the quantity of CO_2 that can be injected may not be encountered. Thus an operational definition was constructed for this situation (Section 5).

The dynamic modelling work on open aquifers is described in Section 5.3 and in more detail in Appendix A5.3 and Appendix A5.4. The dynamic modelling work on structural traps is described in Section 5.4 and in more detail in Appendix A5.5 and Appendix A5.6. The dynamic modelling work on pressure cells is described in Section 5.5. This includes a semi-analytic dynamic solution, which is described more fully in Section 4.1, and numerical simulations detailed in Appendix A5.7. Appendix A5.8 describes well injection simulations incorporating geomechanical mechanisms used for validating injection in the other simulations. The dynamic modelling work was used to define input to the statistical distributions used for Monte Carlo estimates of dynamic capacity. This method is described for the open aquifers in Section 5.3.3 and for structural traps in Section 5.4.3.

5.2 Scoping Studies

The purpose of this preliminary work was to define a common approach for dynamic modelling including the physical processes to be represented, modelling tools to be used, the definition of common/standardised parameters, and a basis for these recommendations. This was achieved through an extensive literature review, investigation of modelling software and modelling assessments. The following recommendations were made, described more fully in Appendix A5.1.

Modelling gravity effects with a sufficiently fine grid where needed is important. The solubility of CO_2 in brine and the effect of capillary pressure should normally be included in dynamic models, but the effect of diffusion is not likely to be significant. The effect of hysteresis on relative permeabilities is required to model residual trapping, which may be an important trapping mechanism for poorly confined structures after injection has ceased.

Modelling studies concluded that the bulk of dynamic simulations could be performed with sufficient accuracy using the industry standard isothermal, finite difference 'black-oil' simulator ECLIPSE100™, with appropriate PVT input data. This has the advantage of speed over a combination of the ECLIPSE300™ compositional simulator and CO2STORE module. ECLIPSE 300^{TM}/ CO2STORE is specially designed for simulating CO_2 storage and allows modelling of a potential solid phase (salt); it may be appropriate where run times are less of a constraint. It was proposed that a streamline simulator, such as 3DSL™, be considered for simulation of fine scale (Exemplar) models of open aquifer units, as this would enable greater detail to be modelled due to faster run speeds. Streamline simulation is particularly effective where modelling displacement is more important than pressure changes, as for open aquifers. It was also proposed that a single simulator, GEM™, be used for well injectivity and associated thermal and geomechanical sensitivity calculations. In fact, streamline simulation was not used for open aquifers, as none of the available simulators were able to model the structural detail and mechanisms required (Appendix A5.4). VISAGE™ was used for geomechanical simulation (Appendix A5.8).

A project literature review recommended that the CO_2/brine relative permeability and capillary pressure data available from a comprehensive Canadian dataset (Bennion and Bachu, 2008) be used for modelling for consistency.

5.3 Open Aquifers

Open aquifers have potentially large storage capacity as they are less constrained by fracture pressure limits than pressure cells, and pressure can bleed off over time. However, as injected CO_2 may migrate up-dip large distances in thin plumes (**Figure 5.1**), storage security may be an issue, and such aquifers are challenging to model, requiring large computing resources. Although there is some analytic work in the literature modelling this behaviour, it is hard to apply to obtain quantitative dynamic estimates of storage capacity. The literature is also lacking in numerical reservoir simulation studies which could be readily applied to UKCS open aquifers, so this project conducted its own Representative Structure and Exemplar studies. This required processing many time consuming simulations so more resources were expended on the modelling of open aquifers than on the other two storage types.

5.3.1 Representative Structure Modelling

A technical workshop was held including geoscientists, dynamic modellers and the project technical co-ordinator to consider how to model the large dipping open aquifers identified on the UKCS. A representative model with defining parameters was agreed. The ECLIPSE100™ model consisted of a large tilted slab with some transverse curvature to enhance channelling, but with a linear dipping top surface as in **Figure 5.1**. The trapping mechanisms modelled were residual and dissolution; heterogeneity and structural trapping from surface topology were not included as these were to be investigated using the more detailed Exemplar models.

Typically CO_2 injected into this model formed a thin tongue under the overlying seal due to its density being lower than the surrounding brine, and migrated up-dip tens of kilometres over thousands of years. During this time, injected CO_2 that remained within a few kilometres of the point of injection became residually trapped (over a timeframe dependent on the formation permeability, dip and mass of CO_2 injected, but typically at least several thousand years). Depending on the modelled depth, dip and thickness, the models were up to 180 km long, 20 km wide and up to 400 m thick. Although targeted local grid refinement was used to position finer gridding in the path of the injected CO_2, run times for these models were beyond the limit of what was practical for a study requiring many cases to be run. It was therefore impractical to represent a typical full aquifer unit requiring multiple injectors with these models alone, and the number of cases simulated was also fewer than desired. A computer program using a pressure upscaling technique utilising symmetry and superposition (the method of images, see Appendix A5.3) was therefore written to post process simulation results and estimate the extent of the pressure footprint from multiple injectors, facilitating storage capacity estimates for multiple injection units.

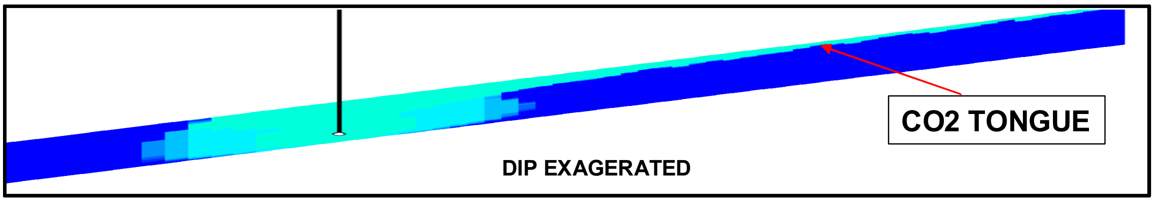


Figure 5.1: Typical behaviour of injected CO_2 in dipping open aquifer

CO_2 storage in such dipping open aquifers is termed 'Migration Assisted Storage' in the European directive on geological storage of CO_2 guidance documents (European Commission, 2011). The 'storage complex' is defined in these guidance documents as 'the storage site and surrounding geological domain which can have an effect on overall storage integrity and security; that is, secondary containment formations' (**Figure 5.2**).

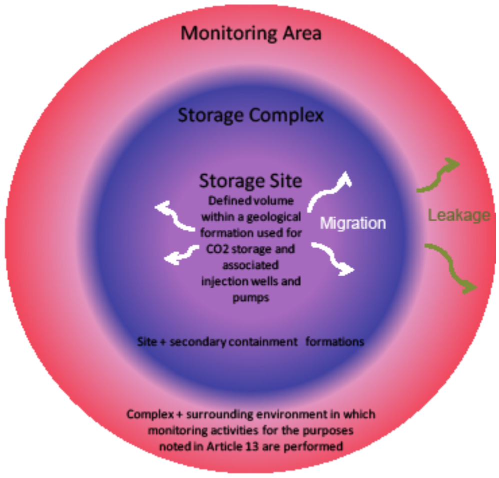


Figure 5.2: Schematic for Storage Definitions

It is essential that injected CO_2 does not leave the storage complex, which is termed 'leakage'. However, these guidelines do not preclude *all* movement of CO_2, though they do require 'long term stability' of the CO_2 plume. The guidance suggests that CO_2 migration of several metres/year could be acceptable, provided that the migration rate is declining and there is no significant risk of leakage. For the purpose of making *estimates* of CO_2 storage potential from these simple models the following definitions and constraints were adopted consistent with the EU guidance for a single injection site:

- the extent of the storage boundary in the dip direction is that boundary encompassing 99% of injected CO_2 after 1000 years;

- the CO_2 is considered stored providing:

    - the maximum CO_2 migration velocity at the storage boundary at 1000 years is less than 10 metres/year and declining;

    - and pressures remain less than 90% of the estimated fracture pressure limit.

The dip direction boundary was motivated by discussion in a special IPCC report on carbon capture and storage for policymakers which considered that it is likely that, in appropriately selected and managed stores, at least 99% of injected CO_2 will be retained after 1000 years (IPCC, 2005). *However, it is emphasised that the assumptions above are made merely to provide a defensible, practical means of estimating the storage capacities of many UK units from simplified models. These assumptions should not to be interpreted as indicating any expectation of CO_2 leakage from the storage complex, which would contravene the directive.* When implementing storage in actual units, detailed appraisal, modelling and planning will allow better estimates of both storage capacity and security, but these tasks may be substantial, see section 10.3.

Storage potential for units requiring multiple injection sites was estimated by calculating how many single injection 'patterns' (or 'footprints') could be repeated before the fracture pressure limit was violated. Thus 'storage factors' may be derived, that are the percentage of the total storage unit pore volume that would be occupied by stored CO_2 if undissolved. The theoretical mass of CO_2 that may be stored in any unit is then obtained by multiplying the total pore volume by the relevant 'storage factor' and average CO_2 density.

Almost 100 separate cases were investigated using these models, covering the range of sensitivity parameters identified at the modelling workshop and within the project database, CarbonStore. This included the role and importance of key properties such as dip, permeability, depth, porosity, thickness, vertical to horizontal permeability anisotropy, trapped gas saturation and salinity.

It was found that dip and permeability were key factors affecting the storage of CO_2 in dipping open aquifers, as they strongly influence the speed of up-dip CO_2 migration. In order to facilitate storage capacity estimation, it proved useful to classify the simplified open aquifer models into three broad storage regimes using these two key factors (Appendix A5.3).

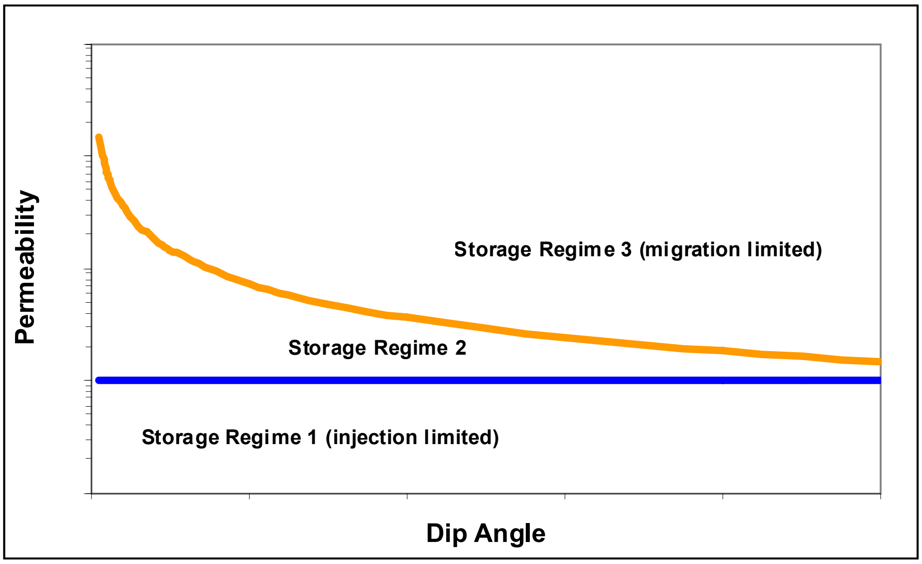


Figure 5.3: Open Aquifer Storage Regimes

Regime 1 has poor well injectivity but good storage security and is characterised by a low representative permeability. A large number of wells may be required to realise the potential storage capacity. The boundary between regimes 1 and 2 is defined by a threshold permeability taken as 10 mD.

Regime 2 is characterised by both good CO_2 injectivity and good storage security, and therefore typically has higher storage capacities.

Regime 3 has good CO_2 injectivity, but storage capacities are constrained by the tendency at higher dip and/ or formation permeability for CO_2 to continue migrating, driven by buoyancy forces. The boundary between Regions 2 and 3 is defined using an analytic estimate of the up-dip CO_2 migration velocity at 1000 years. CO_2 migration velocities for Regime 3 have the potential to exceed the 10 metres/year limit, so CO_2 injection into Regime 3 stores is restricted to ensure secure containment. The restriction aims to prevent any CO_2 remaining mobile after 1000 years, so that all is either residually trapped or dissolved in brine.

5.3.2 Exemplar Modelling

A specific Exemplar field was modelled to investigate issues not practical for investigation at the Representative Structure level. The principal aims of the Exemplar were to demonstrate the storage feasibility of an open aquifer with a realistic model case, to ascertain the impact of geological features such as top-surface structure and heterogeneity, and to substantiate the Representative Structure storage regime results.

The Forties sandstone was identified as a suitable formation to situate the Exemplar as the Representative Structure modelling indicated it was one of the better open aquifer stores and suitable modelling data were readily available. A 20 km x 40 km area of interest – shown by the black box overlaying **Figure 5.4** – was selected for the model, ensuring that the area avoided hydrocarbon fields, known faulting and communication with overlying formations. The size of the area was chosen considering the extent modelled with the Representative Structure, the project funds available for data purchase and modelling practicality.

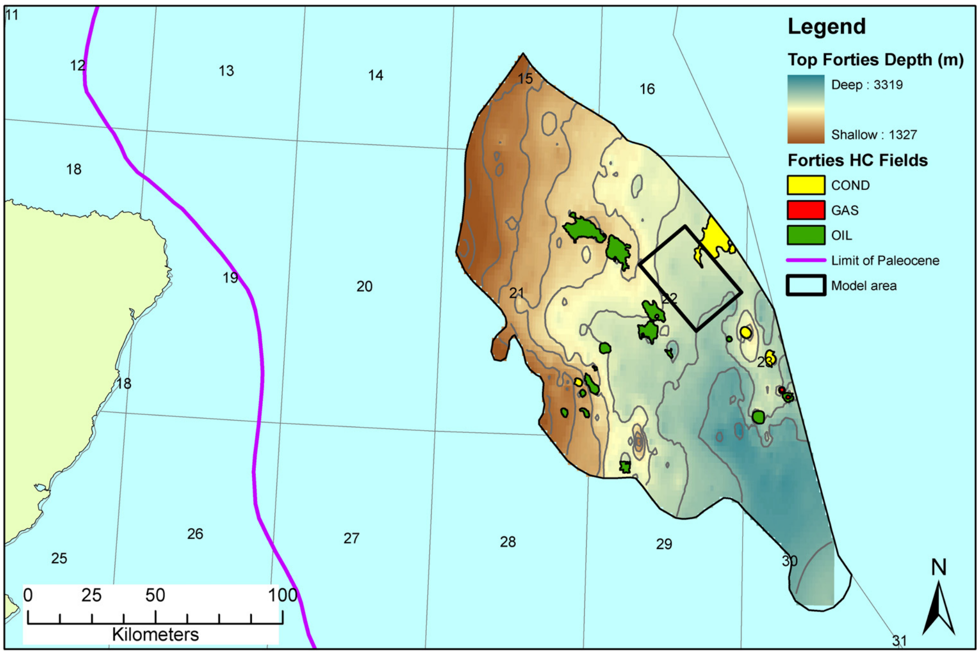


Figure 5.4: Areal Location of Exemplar in Forties Sandstone

A geological model for this region was constructed using a seismic interpretation and amplitude map of the top surface along with wireline log data, core analyses and well tops from 10 wells within the Exemplar area. Using these data a channelised sandstone and shale facies model was built using PETREL™, and reservoir properties distributed across the channels. The final geo-cellular model consisted of 1.7 million cells, however the majority of modelling work was carried out with a 450,000 cell upscaled version to yield manageable simulation times. The upscaled model had 400 m x 400 m areal resolution and layer thickness varying from 0.5m at the reservoir top to 2.5 m at the reservoir base. A grid sensitivity study showed that the change in estimated storage capacity due to the upscaling was acceptable.

The dynamic model was constructed in ECLIPSE™ into which the geological model was imported. ECLIPSE 100™ was used, rather than the compositional ECLIPSE 300™, as it was already apparent that running times were a significant constraint for these models and ECLIPSE 100™ was faster. Residual and dissolution trapping were modelled and structural trapping was calculated. Fluid and rock properties for the area of interest used for the model were collated from published data, extracted from CarbonStore or obtained from suitable correlations or other sources. To represent the pressure response from the volume of the Forties sandstone connected to the Exemplar (but outside the model), additional pore volume was added around the boundaries. More detailed description of the geological and dynamic models is found within Appendix A5.4.

A multi-well injection scenario was created, applying the constraints on security and migration speed after 1000 years and pressure during injection, as listed in Section 5.3.1. The number and location of wells were selected to promote maximum storage potential. Horizontal wells were used to increase injectivity and assist areal spread of CO_2.

Under this 'base case' scenario the storage capacity of the Exemplar model was 471 Mt, representing 3.5% of the total pore volume. The model arithmetic average permeability was 11 mD, at the lower end of the range for the whole Forties sandstone (since the area of interest is relatively distant from the sediment source). Thus 11 injection wells were required. The relatively low permeability also reduced migration velocities however, providing good storage security as shown in **Figure 5.5**. Note that, in this figure, the vertical scale is exaggerated and sections have been removed to reveal the CO_2 plume.

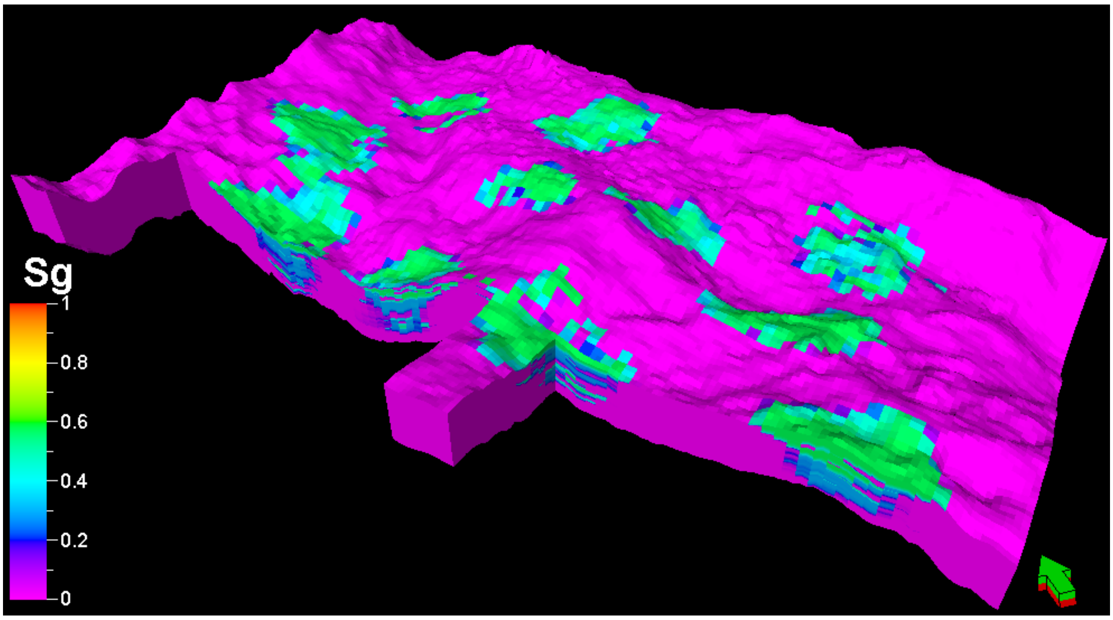


Figure 5.5: CO_2 Saturation in Exemplar Base Case Model at 1000 Years

To investigate the effect of reservoir heterogeneity and topography of the reservoir/ caprock interface (the "top surface"), models were run first with their full geological description, then with homogeneous reservoir properties, and then additionally with a smooth top surface comparable to the Representative Structure models. This analysis was then repeated, with cases having adjusted average dip and permeability. Well locations remained fixed in each case, but injection from each well was adapted to ensure that the storage constraints were honoured. These sensitivities confirmed the significance of permeability and dip upon storage capacity as revealed by the simple Representative Structure models, whether with a structured top surface and heterogeneity or not.

The effect of top surface topography is to introduce local structural traps and dip angles higher or lower than the model average. It was found that this can increase or decrease the fraction of pore volume occupied by CO_2 relative to the smooth surface Representative Structure, depending upon the strength of their competing effects. The relative importance of local structural trapping and dip can be linked to overall formation permeability and dip, or the storage regime:

In cases representative of storage regime 3, the main effect of top surface topography is to

- increase the pore volume which can be occupied by CO_2 through creation of structural traps and regions with lower dip characteristic of storage regime 2;
- maintain low occupation of the pore volume by CO_2 typical of storage regime 3 in areas with increased dip.

In cases representative of storage regime 2, top-surface topography tends to

- again increase the pore volume occupied by CO_2 through addition of structural traps;
- maintain high occupation of the pore volume by CO_2 typical of storage regime 2 where low dip is maintained;
- significantly reduce the pore volume occupied by CO_2 to levels typical of storage regime 3 where localised dip is high.

Reservoir heterogeneity influences the percentage pore volume occupied by CO_2 through its effect on injectivity and reservoir sweep. In the cases investigated, features such as shale layers were found to impede vertical segregation, and increase lateral migration of the CO_2 plume in lower 'layers'. This increases reservoir sweep, leading to a more diffuse CO_2 plume and accelerated residual saturation trapping. The result in the cases studied was to increase the pore volume occupied by CO_2, though it is possible that other forms of heterogeneity (for instance thin high permeability conduits or 'thief zones') could lead to channelling or reduced sweep. Other literature (e.g. Lengler, De Lucia et al. 2010) however, shows this to rarely be the case with permeability heterogeneity on a variety of length scales.

A second effect of heterogeneity, and in particular of impermeable shales, is to increase local pressure. Where injectivity was found to be a limiting factor, this pressure increase further decreased the pore volume occupied by CO_2.

In summary, the Exemplar results suggest that the combined effect of surface topography and heterogeneity may reasonably increase the maximum storage of open aquifers in cases where the limiting constraint is CO_2 migration (such as in storage regime 3). The largest increase found was equivalent to an additional 0.6% of the pore volume. However, further work is required to determine the average effect and frequency of such an increase due to the competing effects of upper surface topography and heterogeneity. As a result, a conservative upper bound of the percentage pore volume occupied by CO_2 was adopted for estimating theoretical capacity of regime 3 storage units. For those belonging to regime 2, a small increase was made to account for the higher percentage pore volume occupied by CO_2 achieved in homogenous, smooth top-surface Exemplar modelling.

5.3.3 Application of Dynamic Modelling to Capacity Estimation

Triangular distributions are assumed for input parameters to the Monte Carlo estimation of storage capacity, requiring minimum, most likely and maximum values to be specified for each parameter. Although triangular distributions are appropriate for minimal data, it should be noted that if skewed data are entered, mean values may differ appreciably from most likely values.

Table 5.1 gives the percentage pore volume occupied by CO_2 for each open aquifer storage regime derived from the Representative Structure and Exemplar modelling work described earlier. For the injectivity constrained regime 1, the zero minimum was chosen to reflect the possibility that no CO_2 may be able to be injected. For storage regimes 2 and 3, the zero minimums were chosen to reflect the possibility that heterogeneity might provide some CO_2 escape pathways that defeat storage security.

STORAGE REGIME	MINIMUM	MOST LIKELY	MAXIMUM
1	0	0.6	1.0
2	0	0.9	1.8
3*	0	0.6	1.0

Table 5.1: Open Aquifer 'storage factors': % Pore Volume Occupied by CO_2

*Well CO_2 injection in storage regime 3 is restricted to maintain storage security (see Section 5.3.1 and Appendix A5.3).

The most likely values were informed by mean values from the Representative Structure modelling and relevant cases from the Exemplar modelling. Maximum values are generally from the Representative Structure results, except for storage regime 2, where the Exemplar results suggested a slightly higher figure.

Note that none of these distributions are strongly skewed, so mean values are close to most likely values. Regime 2 has the highest 'storage factor' reflecting its good injectivity and storage security. Although regimes 1 and 3 have the same distributions, they are distinguished to implement the storage security restriction noted above for regime 3. Note also that particularly for storage units belonging to regimes 1 and 3, economic viability may be challenging if many injection wells are required, either due to low injectivity (regime 1) or the cumulative CO_2 injection limit per well (regime 3).

Overall, the 'dynamic' storage factors proposed for open aquifers are lower than initially assumed for the purposes of 'static' capacity estimates (0.1% - 2% - 6%, based on results from previous studies). It is believed that the principal reasons for this are accounting for the pressure footprints when utilising multiple injectors, the effect of formation dip on the predicted migration of CO_2, in combination with the adopted operational definition of when an open aquifer is "full" of stored CO_2 (namely 99% retention of injected CO_2 over 1000 years; predicted migration velocity at 1000 years less than 10m per annum and declining; maximum injection pressure less than 90% of the fracture pressure).

5.4 Structural Traps

The project did not seek to collect data on all potential saline water-bearing traps, since in general seismic data of sufficient resolution were not available with which to identify and map them, see section 3.4.2. Some data were available however, for the well-known (and large) structures found in the Bunter Formation of the Southern North Sea and Ormskirk Formation of the East Irish Sea Basin. Whereas this storage type is the least numerous in the CarbonStore database, its storage capacity is nonetheless of particular interest as such stores may combine the advantages of both open aquifers and pressure cells; containment is provided through structural trapping (which might be considered more secure than an 'open' aquifer), but since they may not be fully confined, the possibility also exists that in-situ fluids might be displaced by injected CO_2 with less attendant pore pressure increase than expected for a pressure cell.

For these reasons, and because they lie in a convenient location relative to point sources of CO_2 (**Figure 5.6)**, the Bunter domes have been studied before (e.g. Bentham, 2006). Bentham estimated the storage capacity of these domes on a volumetric basis, assuming CO_2 occupies 40% of the total pore volume. The dynamic modelling work undertaken in this project has improved these estimates, by investigating both the accessible pore volume and pressure interference between domes in a multi-injection scenario.

The Bunter Formation was sub-divided into areal Zones using structural features such as salt walls, faults and dykes as boundaries. Each of these Zones is classed as a separate, but open storage unit. Zone 4 (CarbonStore Unit 139.000) was selected for detailed study as it contains 15 of the 29 Bunter domes and so makes a significant contribution to the volumetric storage capacity in the Bunter domes.

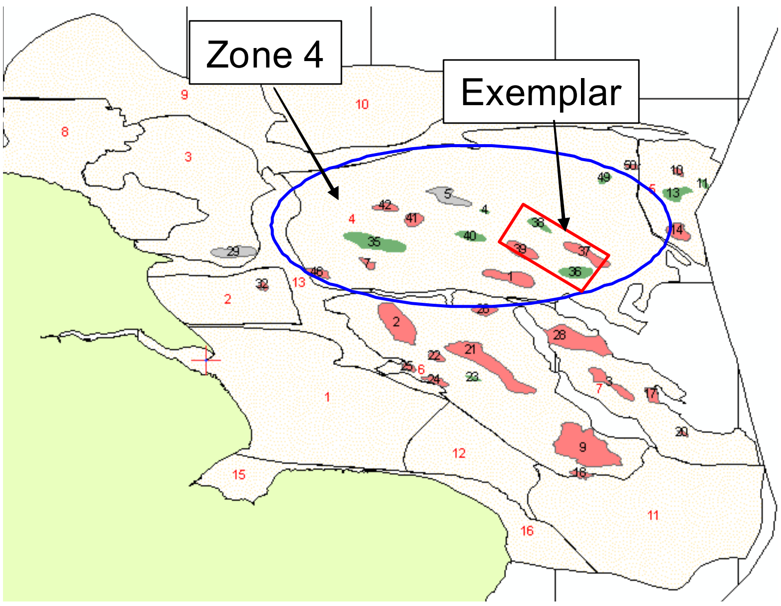


Figure 5.6: Domes in Bunter Formation

The dynamic work on structural traps involved material balance Representative Structure modelling of CO_2 injection into all fifteen of the Zone 4 domes, and fine-scale Exemplar modelling of the region around Bunter closures (domes) 36, 37, 38 and 39, primarily injecting into 36. These closures were selected based on a lower likelihood of faulting, whilst enclosing significant pore volume. The material balance Representative Structure modelling aimed to investigate pressure interference between injection sites in multiple injection scenarios. The Exemplar modelling aimed to obtain a good estimate of the range of storage capacities for an actual potential storage site and inform input data assumptions for the Representative Structure modelling.

5.4.1 Representative Structure Modelling

An ECLIPSE100™ material balance type model of the Bunter Zone 4 and all its fifteen domes was constructed with just a single cell representing each dome. Three versions of the model were produced based on the minimum, most likely and maximum properties in CarbonStore. Most simulations assumed injection into all domes simultaneously. Although the parent Unit 139.000 (Zone 4) was normally assumed open, the impact of a closed parent was also considered.

Injection was constrained by fracture pressure limits for each dome and the parent aquifer itself set by data from CarbonStore. A rough optimisation of injection well numbers was performed as usually a point of diminishing added value was reached for additional wells. The estimated assumed transmissibilities between domes and the parent aquifer were verified by comparison with the single dome Exemplar case.

Injection into a single dome gave filling times in excess of 100 years for large domes, despite using many wells. Injection into all domes simultaneously indicated significant pressure interference, substantially reducing achievable storage capacities on likely project timescales. These two results both suggest that these domes will have a practical capacity significantly less than the maximum capacity indicated by the buoyant capacity limit.

A more detailed description of this work is contained in Appendix A5.5, but key results for injection into all fifteen domes are as follows: the case based on ‘most likely’ values of reservoir properties resulted in only 6.4% of the pore volume being occupied by CO_2 because of strong pressure interference. This was reduced to 1% if the lower bounds of reservoir property values (such as permeability and pore volume) were assumed. The maximum achieved was 27.6% of the pore volume.

5.4.2 Exemplar Modelling

The region in Bunter Zone 4 (CarbonStore storage Unit 139.000) chosen for detailed modelling is shown in **Figure 5.6** and is about 44 km by 25 km. The main injection dome to model (CarbonStore Unit 139.016, Bunter closure 36) was chosen for the following reasons:

- no faulting visible on seismic over the closure
- large estimated storage capacity
- good data coverage over the region
- the region included three additional closures (CarbonStore Units 139.017, 139.018, 139.019; Bunter closures 37, 38 and 39) that could be used to study the impact of CO_2 injection on adjacent storage units

The static geocellular model was constructed in PETREL™, a software application widely used in the petroleum industry for such models (see Appendix A5.6). Geological data were obtained from a variety of sources: seismic surfaces (which inform the geological structure) were provided by PGS; well depth and core data were obtained through the IHS “EDIN GIS” database. The geological formations modelled included the Haisborough Group which is the sealing caprock overlying the storage unit in the Bunter Sandstone. The Bunter Shale and other formations were also included, partly to improve modelling of vertical flow.

The Bunter Sandstone Formation was sub-divided vertically into five assemblages based on data from geophysical well logs. Each assemblage contained a distinct distribution of three rock types with different qualities: sandstone, cemented sandstone, and shale. The latter two can act as barriers to fluid flow. For example, a continuous layer of impermeable cemented sandstone at the top of the fourth assemblage almost splits the Bunter Sandstone Formation in two (**Figure 5.8**) and has a significant effect on CO_2 storage. An example of the rock-type distribution is shown in **Figure 5.7**. The larger dome in the front middle of the figure is the main injection dome, Bunter closure 36.

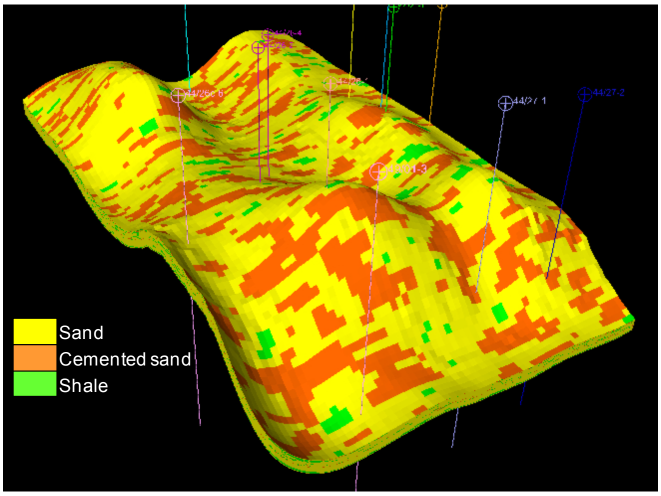


Figure 5.7: Example of the Facies in the Bunter Sandstone Formation Geocellular Model

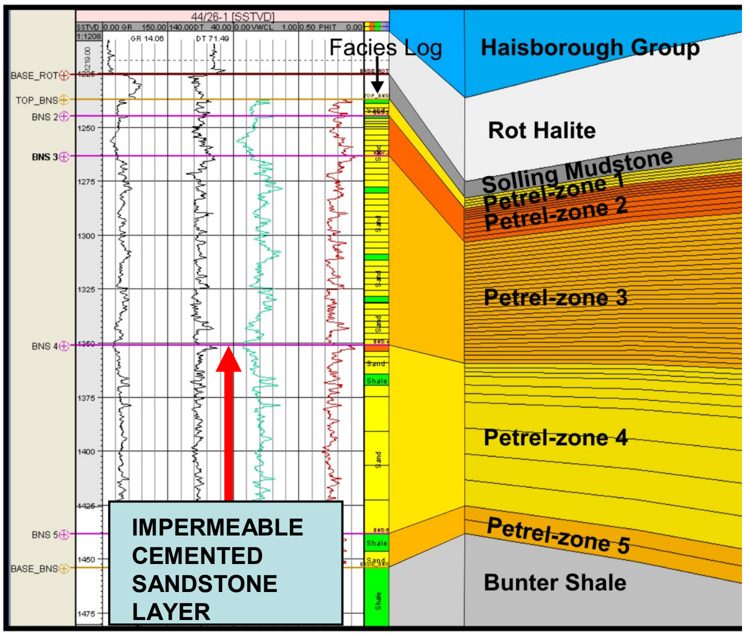


Figure 5.8: Layering and Assemblages ("Petrel-zone" 1 – 5) and their Relationship to the Facies Log

The grid has about a half million cells, of length 400 m in the horizontal with the thickness varying from 24 m to 0.5 m in the sandstone.

Lithologies were distributed through the model using stochastic techniques, and porosity values were determined for each lithology type from well logs and used to generate a stochastic distribution. Permeability values were taken from cross-plots of porosity and permeability from all core data in the Bunter Sandstone Formation, and distributed stochastically throughout the model, tied to the porosity values. The average porosity of the sandstone was 18%, the geometric average of the permeability was approximately 10 mD and arithmetic average 248 mD.

The geocellular model generated in Petrel was exported to the ECLIPSE™ simulation software package for dynamic modelling of CO_2 injection and storage. The ECLIPSE300™ fully compositional simulator was used along with the CO2STORE module, (rather than ECLIPSE100™ as for the other Exemplar study), as at this stage it was not apparent that run-times would be a significant constraint. Model properties were obtained mainly from CarbonStore, with some derived from the standard project modelling assumptions and some supplementary data from other sources.

The modelled region was substantially smaller than the expected true connected volume of the Bunter Sandstone Formation. To compensate for this, a numeric aquifer was added to the edge of the models. Since the true extent of the connected volume is uncertain however, a range of numerical aquifer sizes was tested.

CO_2 was injected into the model using 10 vertical wells completed throughout the top four assemblages of the Bunter Sandstone Formation. The wells were therefore injecting both above and below the impermeable cemented sandstone layer (**Figure 5.8**). In the base case model, CO_2 was injected only into closure 36 but various other scenarios and sensitivities were also investigated, including injection into two or three closures, either simultaneously or sequentially.

The target well injection rate was set at 2 Mt/yr, subject to the standard project assumption that pressures should not exceed 90% of the fracture pressure at the appropriate depth. A limit was also needed on migration of free CO_2 from the dome via the spill point, and this was taken to be a cumulative 0.01% of the total injected CO_2 by mass.

In the base case model many of the wells were constrained by pressure, reducing the injection rate. Injection was continued until the CO_2 migration limit was reached after 20 years. For a single dome, this gave 19% pore volume occupied by CO_2 and corresponding macroscopic sweep efficiency of 33%, much less than the theoretical buoyancy capacity (Appendix A5.6). The amount of CO_2 that can be stored is sensitive to the applied injection pressure limit however; if a lower injection pressure is set, the percentage pore volume occupied by CO_2 may increase since injection rates are reduced, CO_2 migrates to the spill point more slowly, and hence injection may be sustained for longer. A detailed analysis of this effect is presented in Appendix A5.6.

When the number of domes injected into is increased to three, the pore volume occupied by CO_2 decreases moderately due to pressure interference. However, as remarked above, this effect is dependent on the assumed well injection pressure limit.

Various other sensitivities are discussed in Appendix A5.6. A minimum of about 4% pore volume occupied by CO_2 was obtained with injection into a single dome when a closed boundary was assumed; a maximum of 33% was obtained assuming injection into a single (open) homogeneous dome. These results illustrate the wide range of storage capacity that may be achieved in structural traps, dependent on their characteristics. Controlling factors include the extent of the connected aquifer and reservoir heterogeneity: the smaller the connected volume, the greater the pressure build-up and lower the achievable percentage pore volume occupied by CO_2; presence of low permeability layers for example, may also limit the buoyant rise of CO_2, leading to faster migration towards the spill point and again tending to lower the achievable storage.

5.4.3 Application of Dynamic Modelling to Capacity Estimation

A triangular distribution was used to describe the achievable percentage pore volume occupied by CO_2, for structural traps containing saline water. These were used in Monte Carlo estimation of theoretical storage capacity (**Table 5.2**). These inputs were derived from both the Representative Structure and Exemplar modelling work.

The most likely value is obtained from a simple linear curve-fit to results obtained from injection into various numbers of traps (**Figure 5.9**). The data for 1, 2 and 3 traps are from the Exemplar results, and for 5, 10 and 15 traps from the Representative Structure modelling. The estimates for three traps from both sources were similar. The minimum was derived assuming injection into all 15 domes for the least optimistic Representative Structure case based on CarbonStore data. The maximum is taken from the Exemplar results discussed in the previous section.

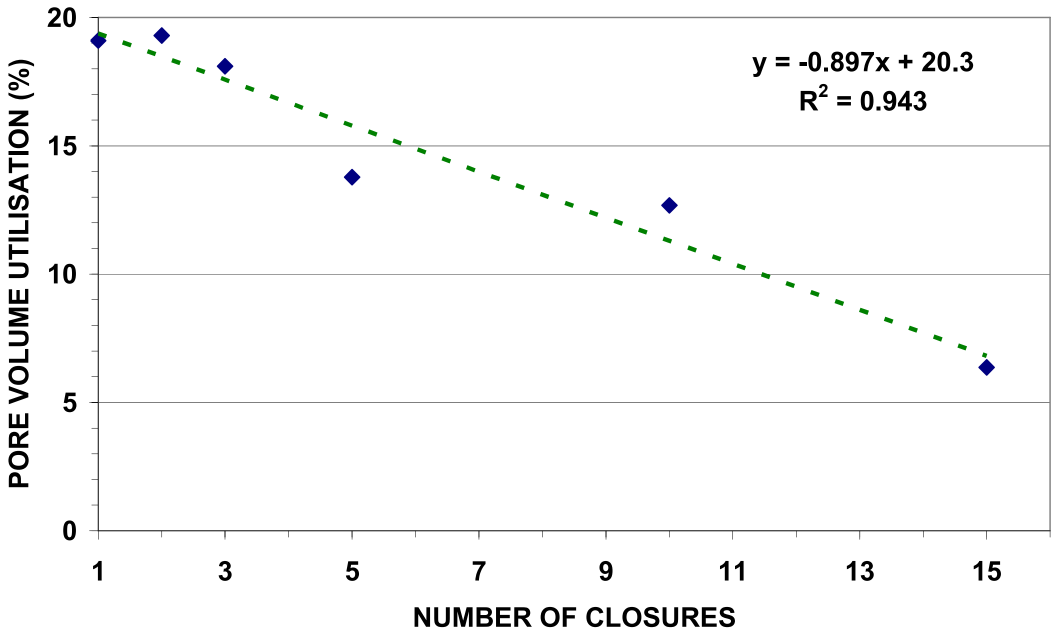


Figure 5.9: Fit for Multi-dome Injection

MINIMUM (%)	MOST LIKELY (%)	MAXIMUM (%)
1	Greater of ($20.3-0.897N_T$) and Minimum Value	33

Table 5.2: Percentage Pore Volume Occupied by CO_2 in Structural Traps

N_T= Number of water-bearing traps in parent aquifer.

MINIMUM (%)	MOST LIKELY (%)	MAXIMUM (%)
12	33	65

Table 5.3: Saline Structural Trap Macroscopic Sweep Efficiency Distribution

The Monte Carlo storage capacity estimation also requires a distribution of macroscopic sweep efficiencies for injection into a single trap. These are given in **Table 5.3** and are derived from various Exemplar cases.

5.5 Pressure Cell Modelling

Pressure cells are the most numerous storage type in the CarbonStore database. They are also the easiest to model dynamically as the CO_2 is assumed to be fully confined, so pressure behaviour rather than CO_2 transport is the key issue. For these reasons this storage type has proved amenable to an analytical solution (Mathias et al, 2009). As this analytic solution is far less computationally intensive than numerical simulation, it was used to estimate well numbers and well pressures for economic analyses. The analytic solution is described briefly in Section 4.1, and in more detail in Appendix 4.1. Such analytic solutions inevitably require simplifying assumptions, and so comparison with numerical simulation results was used to investigate consistency and applicability.

5.5.1 Representative Structure Modelling

Two ECLIPSE100™ simple box models representing a medium-sized (232 Mt storage capacity) and large (1 Gt storage capacity) pressure cell were constructed (Appendix 5.8). The analytic solution was programmed into a spreadsheet. Two sets of sensitivities were run reflecting both a simpler set of assumptions required by the analytic model, and a more realistic set including relative permeability data and different well configurations. These sensitivities included such factors as permeability, thickness, dip, porosity and aspect ratio. The simple set assumed a vertical well with linear CO_2 relative permeability, and the more realistic set a horizontal well with standard set of non-linear relative permeabilities. Although the analytic solution included both brine and rock compressibilities and endpoint relative permeabilities, it did not include CO_2 compressibility, CO_2 dissolution into brine, brine vaporisation into CO_2 or non-linear relative permeability behaviour, all of which were modelled by simulation.

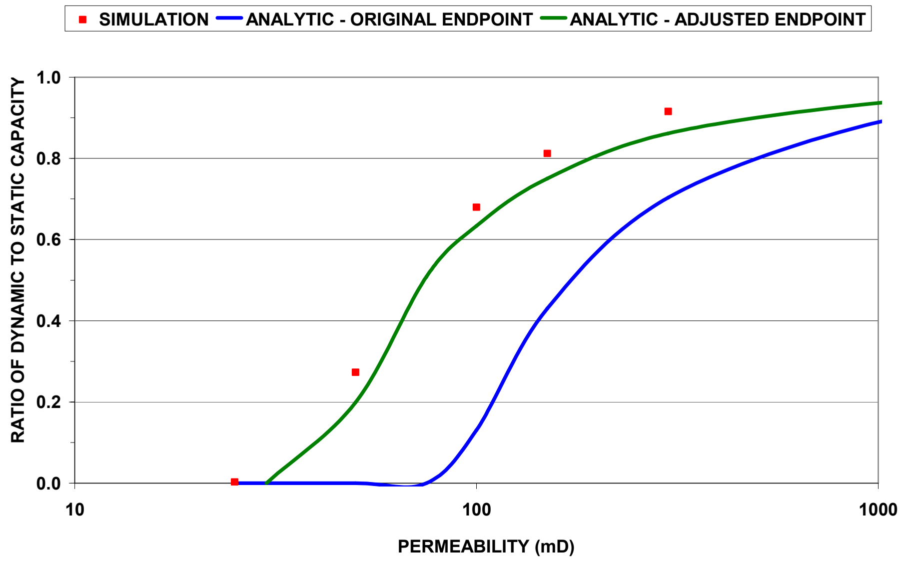


Figure 5.10: Capacity as a Function of Permeability, 'realistic' Simulation Compared with Analytic Model

The pressure profiles and storage capacities calculated from numerical simulation were compared to those from the analytic model. Very good agreement was found between the two techniques for the simple set of data. Agreement was satisfactory, though not as good, for the more realistic assumption set, diverging for lower net thicknesses and permeabilities (**Figure 5.10**). It was found however, that very good agreement could be retained through an adjustment to the assumed relative permeability endpoint in the analytic solution (**Figure 5.10**). This effectively allows for brine vaporisation into CO_2 and desiccation of the near wellbore region, such that water saturation tends to zero rather than the theoretical minimum achieved through viscous displacement; the accompanying relative permeability to CO_2 thus tends to 1.0. These conclusions were the same for each model size, and so the adjusted CO_2 relative permeability endpoint was used for direct calculation of injectivity for all storage units.

5.6 Conclusions

Defensible estimates of the ranges and most likely values of percentage pore volume occupied by CO_2 ('storage factors') were made in a systematic manner for CO_2 storage in each saline aquifer storage type.

For both open aquifers and structural saline traps, by means of detailed numerical simulation models of actual UKCS potential storage units:

- CO_2 storage security and feasibility was demonstrated;
- Detailed effects of structure and heterogeneity were investigated.

For open aquifers:

- a practical set of storage security criteria were developed;
- a useful classification of different storage regimes was defined.

For structural saline traps it was demonstrated that:

- for injection into a single trap the storage capacity will typically be significantly less than suggested by simple buoyant trapping (“fill-to-spill”);
- for injection into multiple neighbouring traps, significant pressure interference effects are likely such that the overall storage capacity that may be achieved is significantly less than the sum of individual structures.

An analytical method can be used to estimate well injectivity in saline aquifer storage units, providing an estimate of storage capacity utilisation (amount of CO_2 stored given by the product of injection rate and duration).

5.7 References

1. Bentham, M, 2006. An assessment of carbon sequestration potential in the UK – Southern North Sea case study, Tyndall Centre Working Paper No. 85.

2. Bennion, D. B., Bachu, S., 2008. Drainage and imbibition relative permeability relationships for supercritical CO2/brine and H2S/brine systems in intergranular sandstone, carbonate, shale and anhydrite rocks, SPE Reservoir Evaluation and Engineering, v.11 no.3, June, p.487-496,DOI:19.2118/99326PA.

3. European Commission, 2011. Implementation of Directive 2009/31/EC on the Geological Storage of Carbon Dioxide, Guidance Documents 1-4, http://ec.europa.eu/clima/policies/lowcarbon/ccs_implementation_en.htm.

4. Intergovernmental Panel on Climate Change, September 2005. IPCC Special Report, Carbon Dioxide Capture and Storage, Summary for Policymakers, Eighth Session of Working Group III, Montreal, Canada.

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

6. Mathias S.,A., Hardisty P.E, Trudell M.R., Zimmerman R.W., 2009. Approximate solutions for pressure build-up during CO2 injection in brine aquifers, Transp. Porous Media, Vol 79 pp 265–284.

7. Mathias S.A, Zimmerman R.W., Gonzalez, 2012. Pressure build-up during CO2 injection into a closed brine aquifer. Transp. Porous Media, In Press.

8. Swarbrick, R.E., Lahann, R.W., O'Connor, S.A. & Mallon, A.J. 2010. Role of the Chalk in development of deep overpressure in the Central North Sea. In: Vining, B.A. & Pickering, S.C. (eds) Petroleum Geology: From Mature Basins to New Frontiers, Proceedings of 7th Petroleum Geology Conference, v.1. p.493-507

6 Security of Storage

6.1 Introduction

In considering the suitability of a geological unit for CO_2 storage, its capacity (relative to the amount of CO_2 required to be stored) is clearly important. The nature of geological formations is such however, that units of substantially varying characteristics may each offer sufficient capacity. The question then, is how the particular characteristics of each influence both long term containment of CO_2, and ability to sustain required injection rates during the operational phase.

For carbon capture and storage projects, a ‘Features, Events and Processes’ (FEP) approach has been recommended for assessing storage security during initial site screening and evaluation (e.g. Maul et al., 2004; Chadwick et al., 2008; Det Norske Veritas, 2010; National Energy Technology Laboratory, 2010; Smith et al. 2011). This method allows initial ranking and comparison of many potential risk areas, from which more detailed investigations (such as scenario-based risk analysis and potential mitigation activities) can be prioritised.

Risk is typically defined as the product of likelihood of occurrence and severity of impact of events that might affect project outcome. Application in this project considers two broad categories, with definitions of likelihood and severity being broader and more qualitative than typically used in site- and project-specific risk assessments by virtue of the generally large storage units being assessed:

- Containment risk is the likelihood that CO_2 will migrate outside the designated boundaries of the unit, and includes assessment of upward leakage of CO_2 via fault flow or well or seal failure, and an assessment of the likelihood of lateral migration of CO_2 from the storage unit. Impact on adjacent units as a result of CO_2 migration or pressure increase is not considered, though the project GIS should allow this to be assessed on a case by case basis;

- Operational risk is the likelihood of occurrence of mechanisms or features in the subsurface that would lead to a reduction in injection rate or storage capacity.

The level of confidence that can be placed in the assessment has been captured, based on data availability and reliability of interpretation. An attempt has also been made to estimate the cost of further appraisal activity implied by each assessment. Such appraisal data would need to be obtained up-front by prospective operators, in order to qualify sites for CO_2 storage. These costs are subsequently included in the overall economic analyses.

With the exception of three hydrocarbon fields used to bench-mark the risking methodology, the assessments have considered only saline aquifer storage units.

6.2 Methodology

The list of relevant risk items was collectively agreed by Project participants and sponsors, and is similar in breadth to other published assessments (e.g. Savage et al. 2004):

***Category**/Subcategory*	***Risk Items***
Containment	
Seal	*3 items: seal fracture pressure , seal chemistry, seal degradation*
Faults	*3 items: fault density, fault throw, fault vertical extent*
Wells	*2 items: well density, well vintage. (It is assumed that new wells, drilled expressly for the purposes of CO2 storage, will be completed in such a manner that their leakage risk is negligible by comparison)*
Lateral Migration	*8 items: structural trend, depositional/diagenetic fabric, dip azimuth, dip angle, rugosity, hydrodynamics, pressure sinks, transnational migration*
Operational	
Formation Damage	*3 items: mineralogy of grains and cements, mechanical integrity, salinity*
Compartmentalisation	*4 items: vertical stratigraphic, horizontal stratigraphic, structural/fault, diagenetic*

Table 6.1: Risk Categories, Subcategories and Risk Items

Data entry and assessment was shared amongst participants based on their areas of expertise:

***Category**/Subcategory*	***Participant organisation***
Containment	
Seal	*GeoPressure Technology Limited (GPT)*
Faults	*University of Edinburgh (UoE), British Geological Survey (BGS)*
Wells	*Geospatial Research Limited (GRL)*
Lateral Migration	*University of Edinburgh (UoE), British Geological Survey (BGS)*
Operational	
Formation Damage	*Geospatial Research Limited (GRL)*
Compartmentalisation	*University of Edinburgh (UoE), British Geological Survey (BGS)*

Table 6.2: Assignment of Participant Organisations to Risk Categories and Subcategories

6.2.1 Likelihood and Confidence Data

Data used to assess likelihood of occurrence and confidence for all risk items included:

- A UKCS GIS database with well, cultural and field data provided by IHS
- 2D and 3D seismic data and related interpretation products from PGS
- Proprietary pressure data and algorithms from GPT/ IHS

- A wide range of public domain data including Geological Society Memoirs and Special Publications, the Millennium Atlas, technical journals etc.

The data source for each risk item was recorded within the Project database in order to provide an audit trail. Where direct data were not available, offset and/ or analogue data were used and decreased confidence in the assessment recorded. Risk items are assessed as 'unknown' when the assessor judges that there are no appropriate direct, offset or analogue data available.

Consistency in data entry was ensured via provision of written definitions of low, medium and high likelihood and confidence for all risk items, complemented by further written guidance and illustrations. A peer review exercise was also conducted to provide a critical assessment of the risking methodology, and help ensure consistency between assessors and geographical areas. Full details are included in Appendix A6.1.

6.2.2 Severity of Impact Ranking

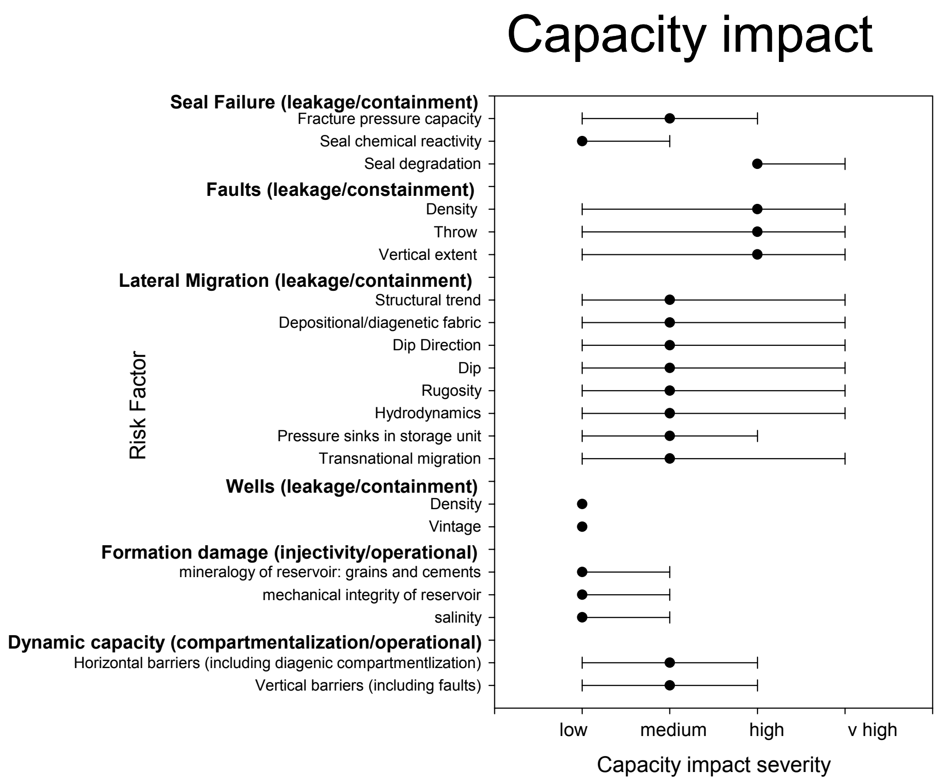
Though likelihood data were captured for each unit explicitly, generic impact magnitudes were developed for each risk mechanism, and applied to all units.

This was achieved via a workshop, and the resultant severity impact scale and results for each risk mechanism are shown below. The severity of impact scales exclude impacts on health and safety, environment and industrial viability (the latter includes media and public opposition).

Severity of Impact	CAPACITY	COSTS
Low (L)	NO IMPACT	NO IMPACT
Medium (M)	MINIMAL (e.g. <20%) IMPACT	MANAGEABLE LOW COSTS
High (H)	SIGNIGICANT (20-80%)	MANAGEABLE HIGH COSTS
Very High	NOT MANAGAEABLE	NOT MANAGAEABLE

Figure 6.1: Agreed Severity Scales

A risk profile for each saline aquifer storage unit was then generated by plotting each risk item on a matrix of likelihood of occurrence versus severity of impact; the greater the abundance of risk items assessed as lying towards the upper left-hand corner of the matrix, the more favourable the unit is for storage based on current understanding (**Figure 6.3**).



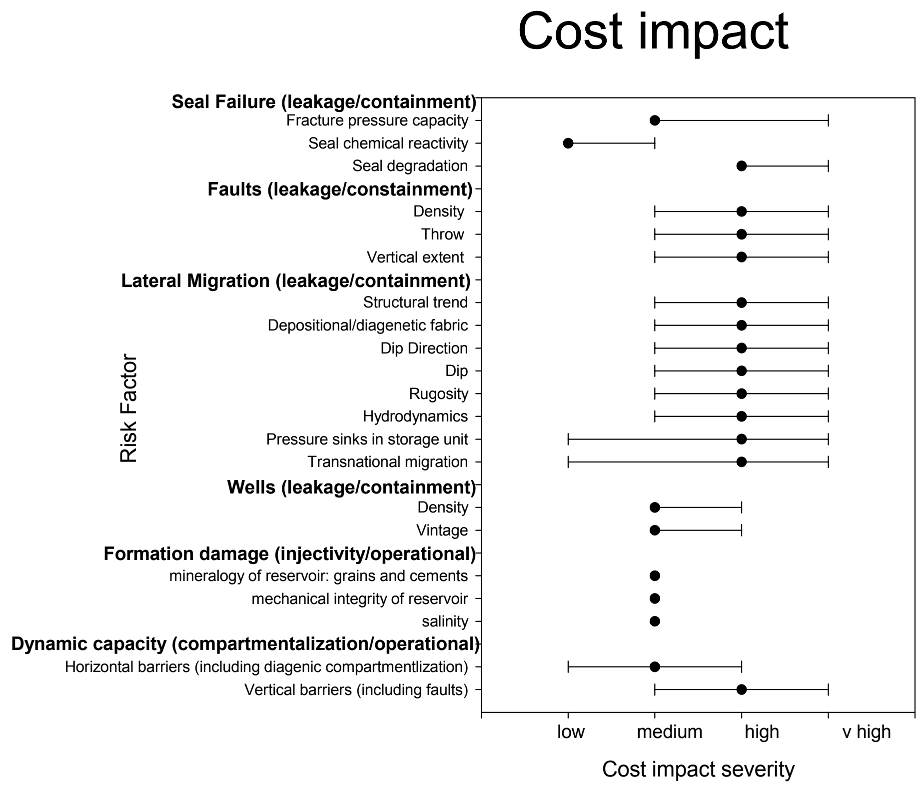


Figure 6.2: Generic Severity of Impact Rankings with Ranges

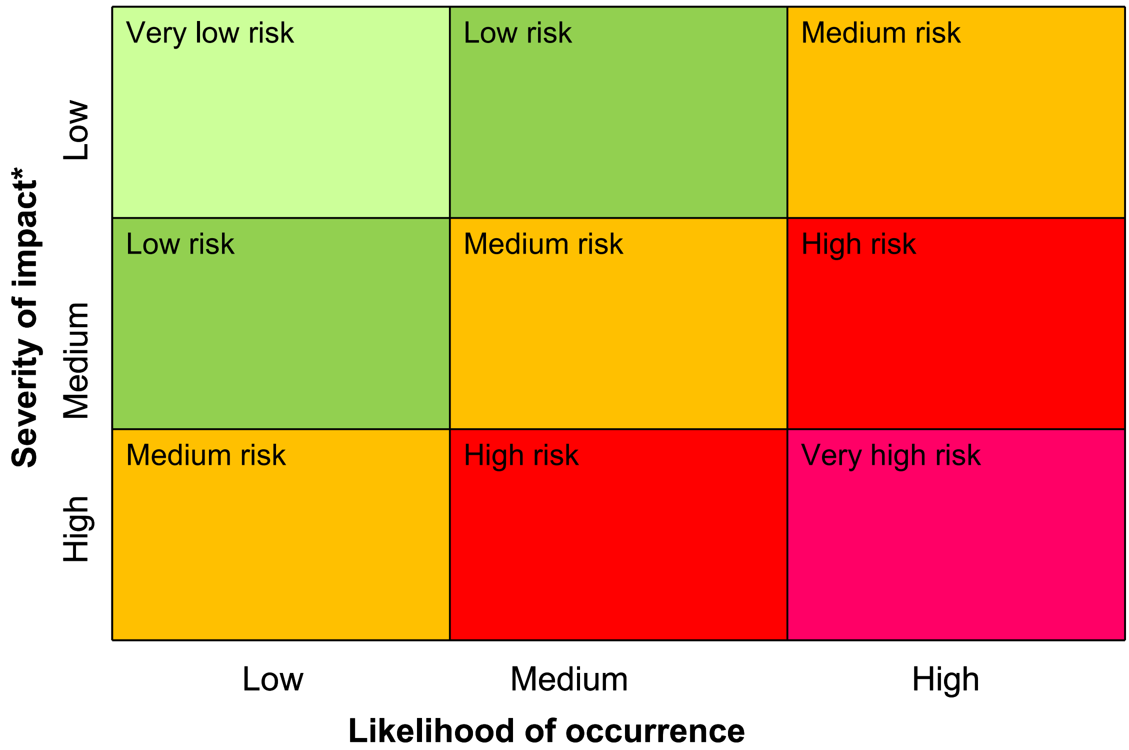


Figure 6.3: Risk Matrix for Capacity and Cost Impact

6.2.3 Normalisation Exercise

The existence of an oil or gas accumulation demonstrates that relatively low molecular weight fluids have been contained (for millennia), and for those that have been developed that ‘reasonable’ extraction or injection rates can be achieved. It would therefore be anticipated that their assessed risk items would indeed plot toward the upper left-hand corner of the above matrix. The risking methodology was thus applied to example hydrocarbon fields with a view to validating the approach, and benchmarking the particular scales and definitions used. The chosen fields were:

- the Rough Field, a Permian Leman Sandstone dry gas production and storage reservoir in the Southern North Sea;
- the Forties Field, a large (multi billion barrel) Palaeocene sandstone light oil reservoir in the Central North Sea;
- the Britannia Field, a very large ~4 TCF (4 x 10^9 standard cubic feet) Lower Cretaceous sandstone gas condensate reservoir in the Central North Sea.

In each case the assessment was confined to the main producing reservoir for each field.

6.3 Results and Analysis

6.3.1 Most Common High Risk Items

Identification of the most common high risk items provides direction to help mature storage opportunities by informing research and development activities and regulatory approach.

Containment risk

The most common high containment risk items in terms of impact on capacity include all three fault leakage mechanisms, and seal degradation. The former reflect a conservative assumption that all faults allow fluid transmission; the latter arises from geological variability in seal quality across laterally extensive units. The high proportion (~80%) of units with identified high fault risk emphasises the value of further work to understand key characteristics of faults (e.g. orientation with respect to stress field, gouge potential, rock mechanical properties etc.) and hence provide greater discrimination within this large population.

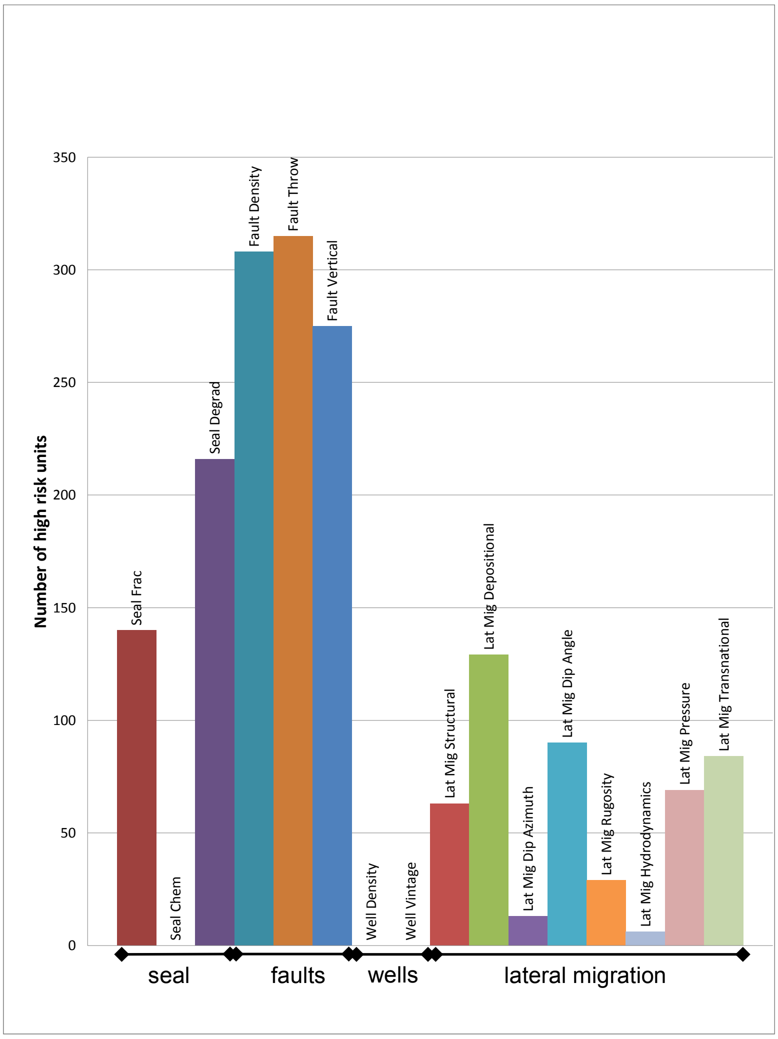


Figure 6.4: Containment High and Very High Risk Units, Capacity Impact

In terms of impact on storage costs, fault and seal integrity remain high risk items, but are joined by lateral migration and well integrity:

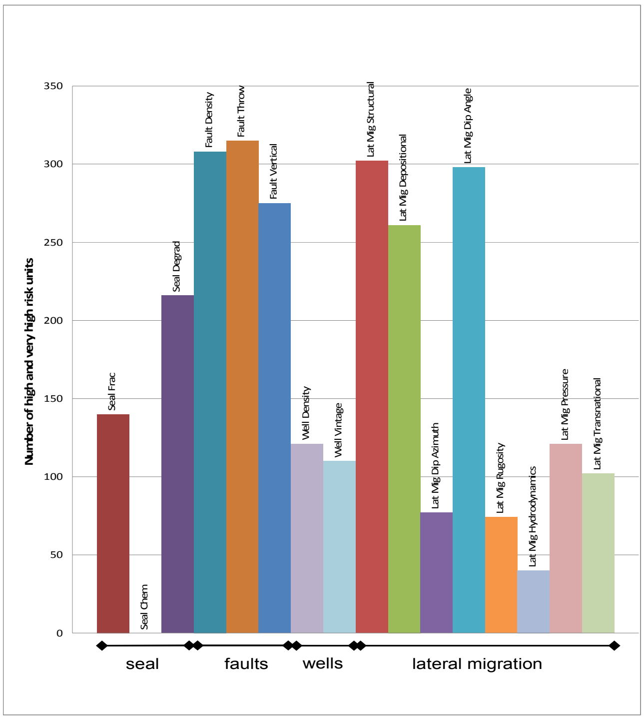


Figure 6.5: Containment High and Very High Risk Units, Cost Impact

Operational Risk

Most common high operational risk mechanisms impacting capacity are structural and diagenetic controls on compartmentalisation. Formation damage is assessed as having limited impact, with additionally a range of possible mitigation activities:

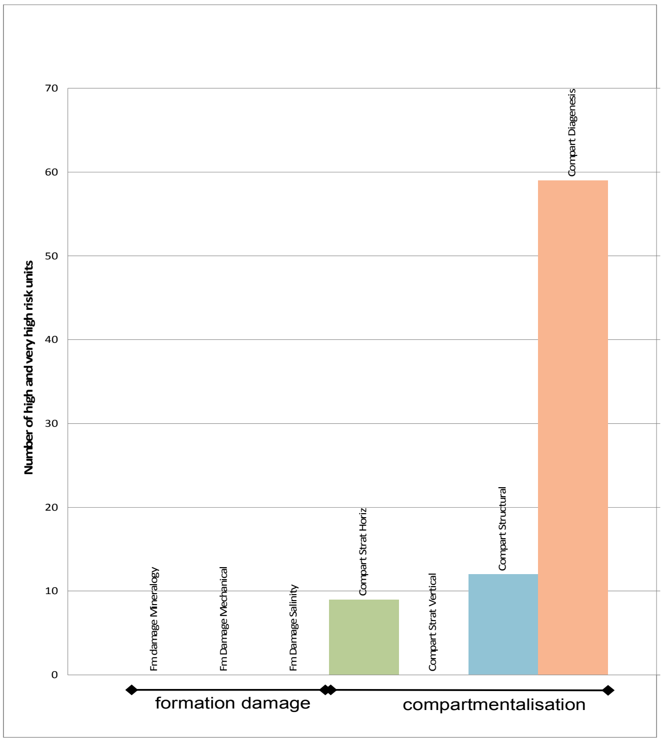


Figure 6.6: Operational High and Very High Risk Units, Capacity Impact

Cost impacts however, are more evenly spread across the operational risk mechanisms with structural compartmentalisation, horizontal stratigraphic compartmentalisation, and formation damage-prone mineralogy the most frequent high risk items:

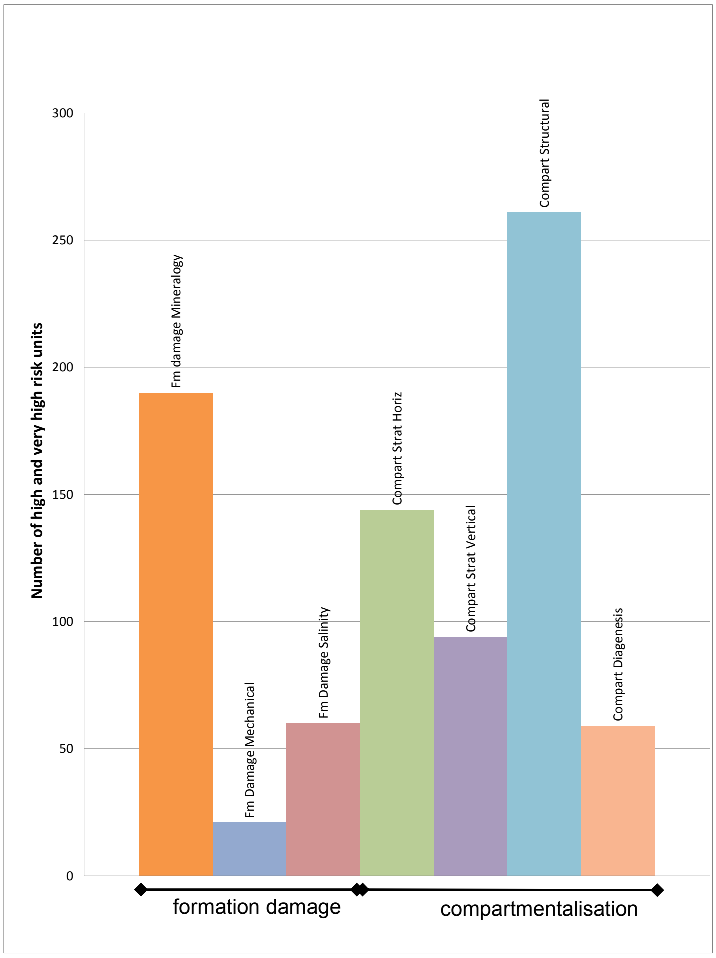


Figure 6.7: Operational High and Very High Risk Units, Cost Impact

6.3.2 Regional Variability of Seal Integrity

Comparisons of seal integrity between UKCS basins show that the Southern North Sea is associated with lowest seal risk (**Figures 6.8 – 6.10**). This is explained by existence of the laterally extensive Haisborough Group (shales and halites) and Zechstein Salt, that provide basin-wide high integrity seals (chemically and physically robust) with significant thickness over a large geographical extent (e.g. >100 x 100 km). By contrast in the Central and Northern North Sea, a wide range of potentially sealing formations have variable likelihood of fracture failure and lateral continuity/ degradation is most frequently assessed as high risk.

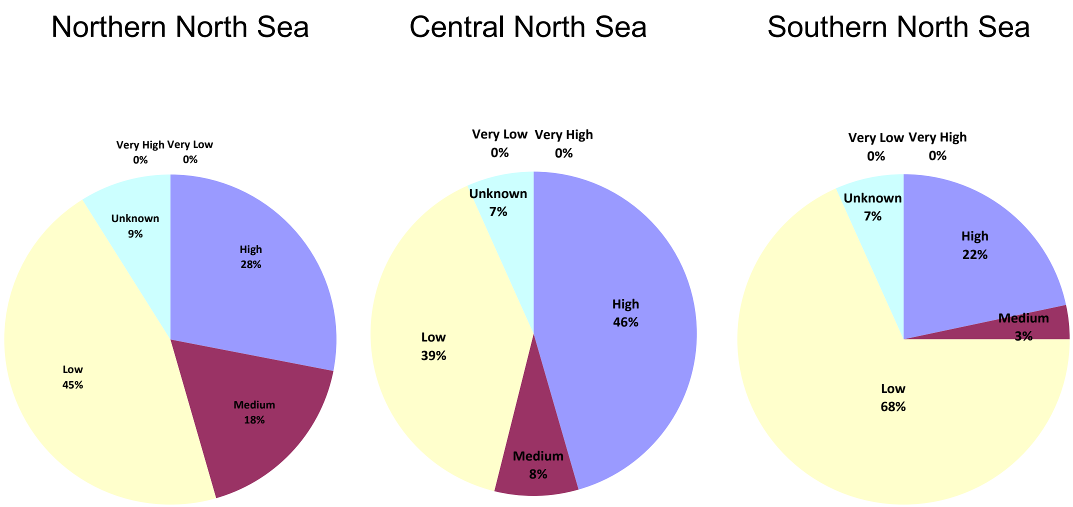


Figure 6.8: Seal Fracture Risk by Region

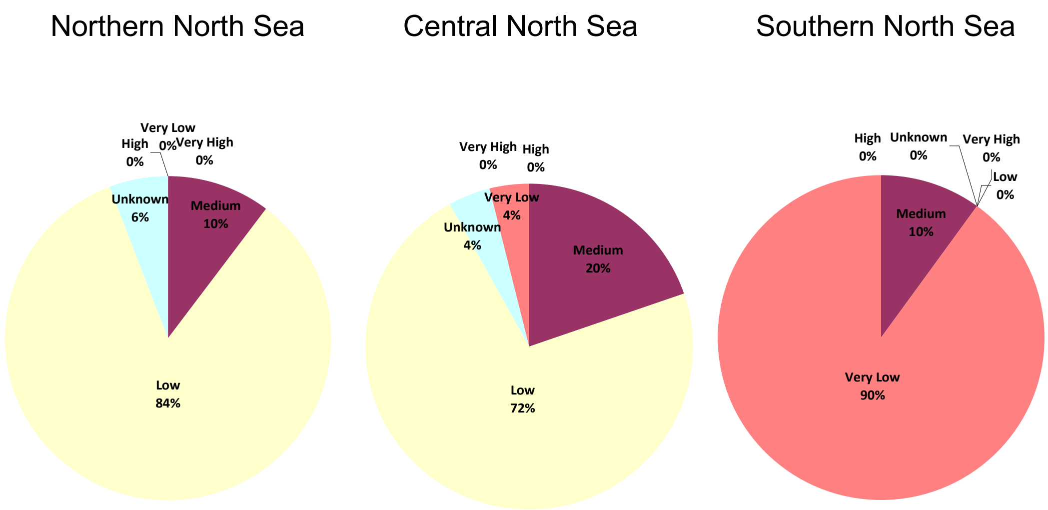


Figure 6.9: Seal Chemical Reactivity Risk by Region

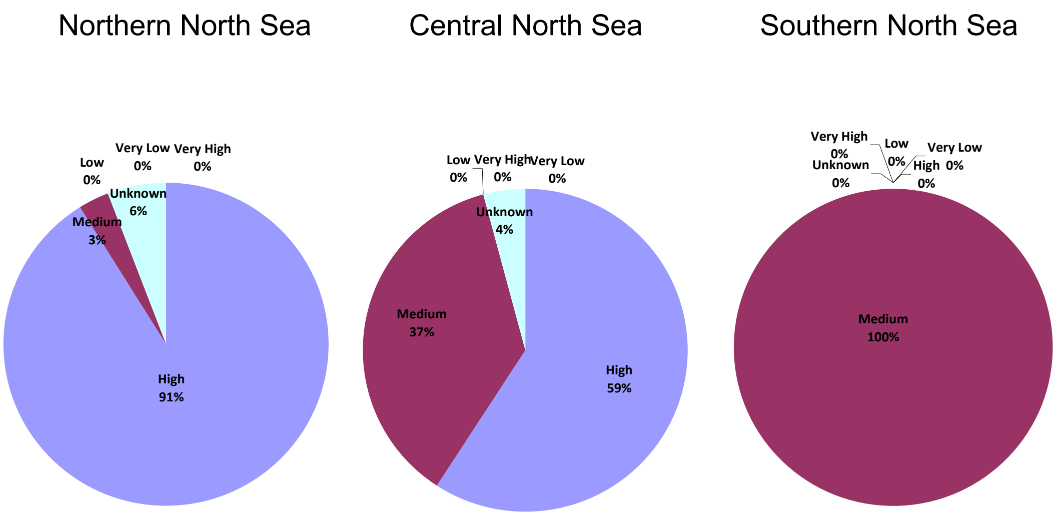


Figure 6.10: Seal Lateral Degradation Risk by Region

6.3.3 Lateral Migration in Open Units

Approximately one third of all offshore UK CO_2 storage capacity is identified as being in 'open' aquifers ie. where fluid flow could potentially occur across one or more mapped 'boundaries' of the storage unit. In such units, CO_2 must be injected in such a manner that it never reaches the open boundary, for example by becoming trapped as a residual saturation as the CO_2 cloud migrates.

Figure 6.11 illustrates assessment of the features associated with lateral migration. Depositional control is recorded as high risk for the greatest number of units (26%), and is concerned with identifying regional anisotropy in horizontal permeability (for example parallel and sub parallel sedimentary channels). Structural and dip magnitude controls are also important, as is proximity of transnational boundaries (relevant for 15% of open units).

Understanding of lateral migration in open units was recognised as important, and specifically studied during dynamic modelling phases of the project in order to support as realistic estimates of capacity as possible. Nonetheless significant knowledge gaps often remain, for example with regard to the precise location and nature of unit boundaries, formation dip and reservoir anisotropy. This is particularly acute where seismic and well control data are sparse (generally away from areas of hydrocarbarbon activity). Further interpretation, augmented by new data acquisition, is therefore required in order to reduce uncertainty associated with these features.

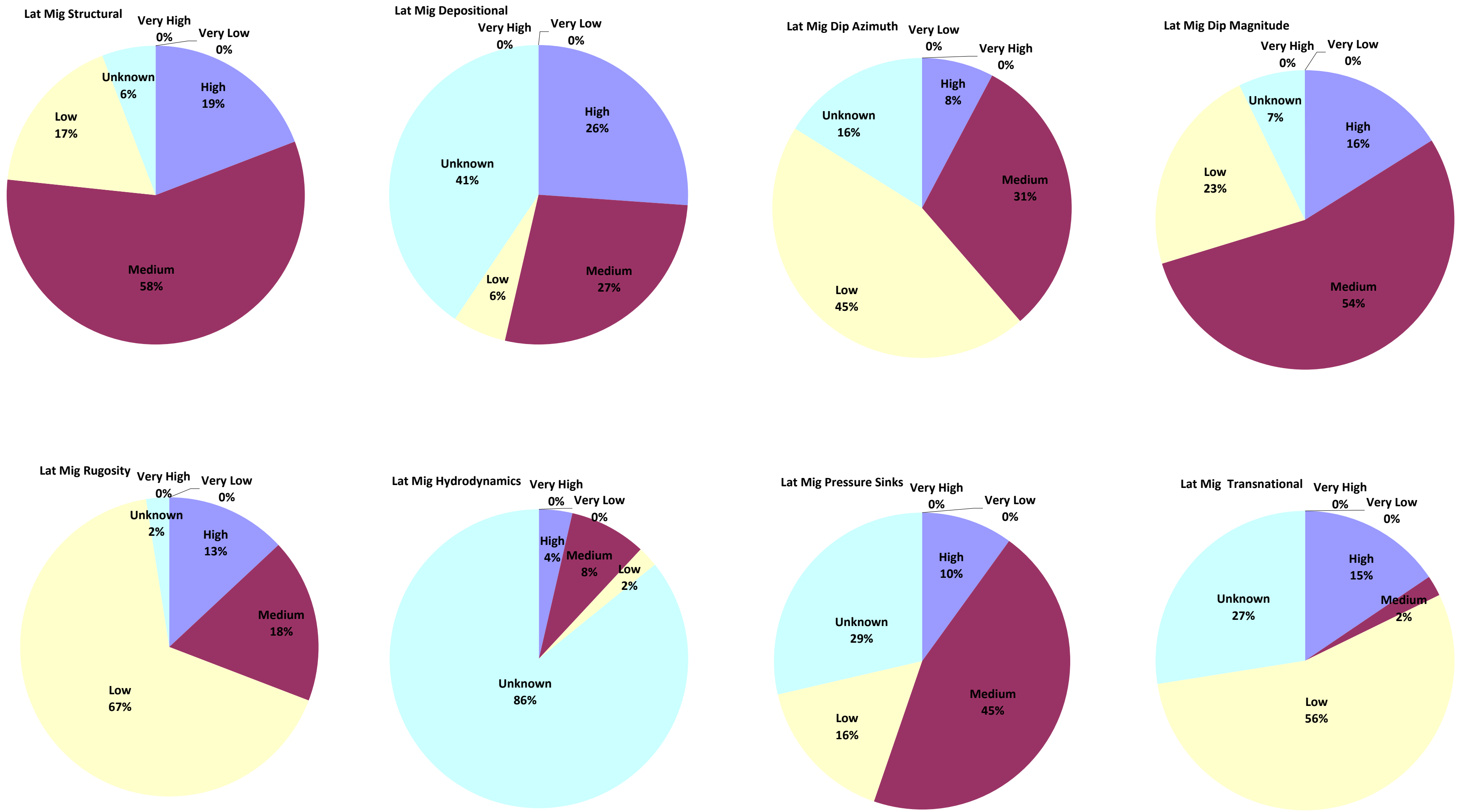


Figure 6.11: Variation across UKCS in Lateral Migration Risk Magnitude (Cost Impact) Open Units Only

6.3.4 Results of the Normalisation Exercise

Figures 6.12 - 6.13 show example results from application of the risk assessment methodology to a hydrocarbon field (Forties); other examples may be found in the technical appendices. For all fields considered the majority of risk elements are assessed as low or medium, as would be expected. Faulting and lateral migration however, are rated as high.

The consistent high fault risk results from the conservative assumption that faults do not seal. Given that the risk assessment process is focussed on saline aquifer stores this is considered reasonable; in the absence of pressure/ interference data, it is difficult to assess sealing tendency when the same fluid (brine) exists on either side of a fault; detailed study of reservoir and seal lithologies, rock mechanics and regional stresses *inter alia* would be required, and this is beyond the scope of this project.

The lateral migration risk element is intended to assess migration across geographically extensive units, with often sparse data. It is not designed to explicitly recognize relatively small scale structures, and even in the Forties aquifer where numerous local buoyancy traps are present (as evidenced by the producing oil fields), these occupy a small fraction of the aquifer volume and are likely to only locally impede CO_2 migration.

Overall then, application of the risking methodology to a selection of hydrocarbon fields did not reveal significant anomalies, and the general approach is felt to be valid.

Severity of impact \ **Likelihood of occurrence**	Low	Medium	High
Low	***Formation mineralogy***	**Seal chemical reactivity** **Well vintage** ***Formation mechanical integrity*** ***Formation salinity***	**Well density**
Medium	**Migration dip direction** **Seal fracture pressure column** **Migration national boundary** ***Fault compartment.*** ***Diagenesis compartment.***	**Migration depositional trend** **Migration structural trend** **Migration rugosity** **Migration hydrodynamics** ***Strat compartment. horizontal*** ***Strat compartment. vertical***	**Migration dip mag** **Migration pressure sinks**
High	**Seal lateral degradation** **Fault vertical extent**	**Fault density** **Fault throw**	

Figure 6.12: Risk Matrix for Capacity Impact - Forties Reservoir Unit (Paleocene) i.d. 233.003

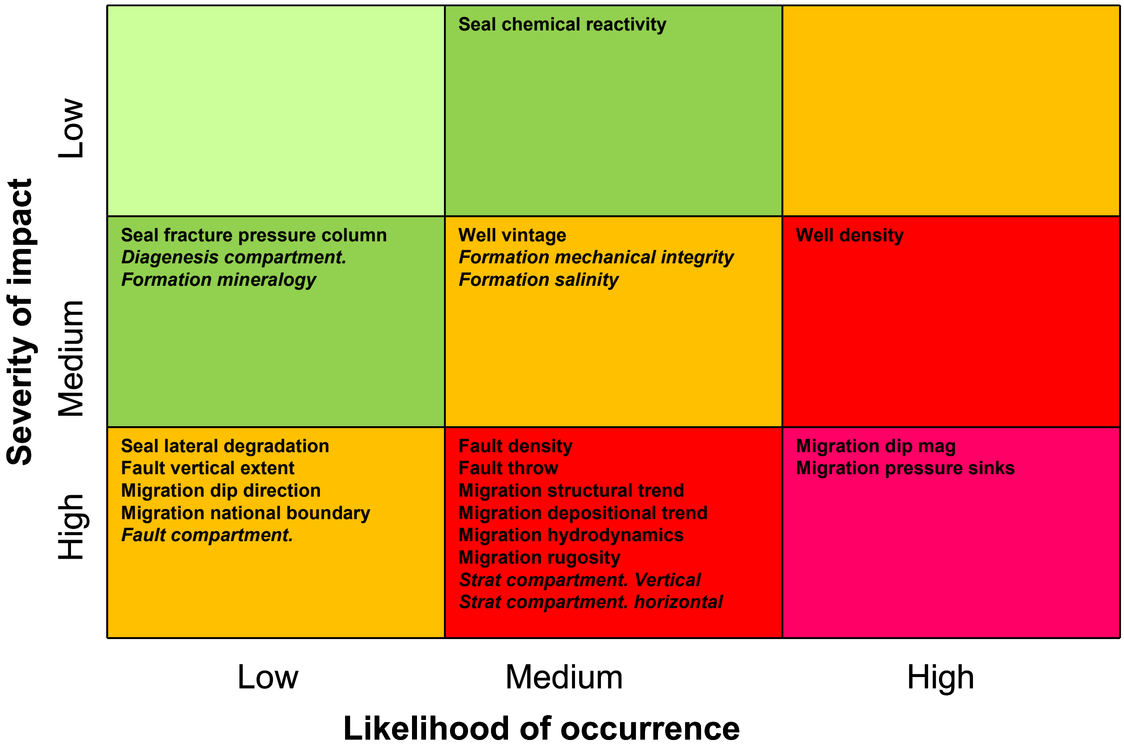


Figure 6.13: Risk Matrix for Cost Impact - Forties Reservoir Unit (Paleocene) i.d. 233.003

6.3.5 Aggregated Risk and Confidence Score

An attempt was made to summarise the many elements of risk and confidence assessment, by providing an aggregate (overall) score for each storage unit. The method used is detailed in the technical appendices to this report. It was not found to be entirely satisfactory however, suffering from the common problem that important detail is lost, leading to potentially erroneous conclusions.

The principle result of security of storage assessments therefore, are the detailed matrices presented for each unit within the project database Aggregate risk and confidence scores are used only as a weighting factor, such that higher appraisal costs are associated with units having many high risk factors identified.

6.4 Appraisal Costs

Having identified key risks and the abundance/ confidence of existing data with which each storage unit was characterised, an estimate of future appraisal costs was made in order to support economic assessments. This was achieved by analogy to the oil and gas industry.

Typical appraisal well density for hydrocarbon field development (i.e. the number of wells drilled prior to construction/ first oil), is between 1 well per 5 km^2 and 1 well per 30 km^2. Based on total recoverable oil, between 5 and 50Mt of oil are typically recovered for every appraisal well drilled. For the UK continental shelf (UKCS), jackup or semisubmersible well costs are estimated at US$10 million per well (2009 basis) to include drilling, completion, logging, sampling, fluid and pressure testing, core recovery (reservoir + caprock) and short term well testing (i.e. for permeability measurement and other near-wellbore characteristics).

Estimated 3D seismic costs are US$ 50,000/km^2 including processing and interpretation.

For estimating the appraisal cost of UKCS CO_2 storage units, two appraisal drilling scenarios were considered: 1 well per 25 km^2, and 1 well for every 20 million tonnes stored. 3D seismic across the full storage unit area was assumed.

Variation in well and seismic costs was included as a sensitivity, and results are discussed further in the Cost and Availability section of this report.

6.5 Conclusions

Likelihood and confidence data were collected and interpreted for each aquifer storage unit identified, and severity of impact assessed on a UKCS-wide basis by an expert group drawn from project participants and sponsors. Risk matrices were thus compiled for each storage unit, displaying the assessed level of probability of occurrence and severity of impact of each risk item.

Quality control was achieved via the provision of detailed written descriptions of low-, medium-, and high-likelihood and confidence for all risk items, complemented by illustrated examples as additional guidance. Review of a subset of early completed units was discussed with assessors, and a peer review and 'normalisation' exercise with example hydrocarbon fields was further used to ensure consistency of approach.

Within the security of containment category, the most important items in terms of impact on storage capacity are all three fault leakage mechanisms, and risk of seal degradation. The latter reflects geological variability in seal quality across laterally extensive units, whilst the former influence the majority of storage units and consequently deserves particular attention in site appraisal. Cost impact assessment leads to an elevation of lateral migration risks, with structural, depositional and dip magnitude the most important controls.

From an operational perspective, the most frequent high risk mechanisms affecting storage capacity are structural and diagenetic controls on compartmentalisation. Cost impacts are more evenly spread, with structural compartmentalisation and mineralogical formation damage most frequently assessed as high risk.

Comparisons of seal integrity between UKCS basins show that the Southern North Sea is associated with lowest seal risk. Here the laterally extensive Haisborough Group provides a basin-wide chemically and physically robust, high integrity seal with limited lateral variation over a large geographical extent (>100 x 100 km).

Evaluation of units having limited structural confinement highlights the importance of depositional, structural and dip controls on lateral CO_2 migration.

The qualitative risk assessment is considered appropriate for a study of this nature, though a probabilistic approach using a range of risking methodologies is recommend for site specific or sub basin-level assessments.

6.6 References

1. Chadwick A., Arts, R., Bernstone, C., May, F., Thibeau, S. and Zweigel P. Best Practice for the Storage of CO2 in Saline Aquifers. Observations and guidelines from the SACS and CO2STORE projects. British Geological Survey by Halstan & Co. Ltd, Amersham. 2008.
2. Condor, J. Unatrakarn, D, Wilson, M., and Ashgari, K. A comparative analysis of risk assessment methodologies for the geologic storage of carbon dioxide. Proceedings of the 10th International Conference on Greenhouse Gas Control Technologies Amsterdam, 2010
3. Det Norske Veritas. CO2QUALSTORE Guideline for Selection and Qualification of Sites and Projects for Geological Storage of CO2. 2010.
4. Gluyas, J.G. and Hitchens, H.M. 2003 Unnited Kingdon Oil and Gas Fields Commemorative Millenium Voleum. Geological Society Memoir 20. The Geological Society, London.
5. Maul, P., Savage, D., Benbow, S., Walke, R., Bruin, R. Development of a FEP database for the geological storage of carbon dioxide, in E.S. Rubin, D.W. Keith, C.F. Gilboy (eds.) Greenhouse Gas Control Technologies, Vol I, 701-709, Elsevier Ltd. 2005.
6. National Energy Technology Laboratory. Risk Analysis and Simulation for Geologic Storage of CO2. Report for the Department of Energy. DOE/NETL-2011/1459. 2010.
7. Savage, D., Maul, P. R., Benbow, S. and Walke, R.C. A Generic FEP Database for the Assessment of Long-term Performance and Safety of the Geological Storage of CO2. Quintessa, June 2004.
8. Sayegh, S.G., Krause, F.F., Girard, M. and DeBree, C. 1990. SPE 19392, Rock/Fluid Interactions of Carbonated Brines in a Sandstone Reservoir: Pembina Cardium, Alberta, Canada. Society of Petroleum Engineers, Formation Evaluation, December 1990, 399-405.
9. Smith M., Campbell, D., Polson, D. and Mackay E. CO2 Aquifer Storage Site Evaluation and Monitoring, Heriot-Watt University. 2011.
10. Watson T.L. and Bachu S. Evaluation of the potential for gas and CO2 leakage along wellbores. Society of Petroleum Engineers Environmental and safety conference, Galveston Texas, March 5-7 2007
11. Watts, N.L. 1987 Theoretical aspects of cap-rock and fault seals for single- and two-phase hydrocarbon columns. Marine and Petroleum Geology Volume 4, Issue 4, November 1987, Pages 274-307
12. Wildenborg T, Leijnse T, Kreft E, Nepveu M, Obdam A. Longterm safety assessment of CO2 storage: the scenario approach. In: Seventh international conference on greenhouse gas control technologies, Vancouver, Canada. 2004
13. Wildenborg T, Leijnse A, Kreft E, Nepveu M, Obdam A, Orlic B. Risk assessment methodology for CO2 storage: the scenario approach. In: Carbon dioxide capture for storage in deep geologic formations. Elsevier, Amsterdam. 2005.

7 Infrastructure Design and Economic Analysis

7.1 Background and Objectives

If CCS is to be an important component of the decarbonised UK energy system, then as well as ensuring that the volume of CO_2 storage is sufficient for future needs, it is vital to understand what infrastructure may be required and if that capacity can be accessed in an economically viable manner. It also necessary to explore the matching of future levels of demand for CO_2 storage, with the rate at which sufficient storage capacity may be made available.

The key performance indicators for carbon abatement strategies are costs (capex, opex), the scale of benefits (e.g. annual and lifetime CO_2 abatement), timescales for availability, project complexity and risks, and cost efficiency (£/tCO_2). It is also important to understand where storage capacity is located, as this will have implications for the siting and sizing of CO_2 capture facilities (e.g. at power stations and heavy industry) and associated transport infrastructure that can connect CO_2 sources with storage sites.

Previous studies have shown that in some cases, optimising the match between CO_2 supply and store, can significantly limit the useful storage that may be available, in some cases by nearly an order of magnitude below the theoretical capacity [Element Energy *et al*. 2011 CO2 pipeline infrastructure]. This study does not match supply and demand directly in a geographic sense, and it is not intended to be used as a filter, which by definition would exclude certain sinks from ongoing consideration. Instead, the objective is to understand the infrastructure implications associated with exploiting each of the CO_2 sinks within the CarbonStore dataset; the input variables have the greatest impact on costs; and to build a state of the art picture of the economic viability of CO_2 storage in the UK.

In this chapter, the costs of exploitation are most conveniently shown through marginal cost curves (cost in £/tCO_2 vs. cumulative CO_2 storage capacity) for the UK Continental Shelf. These cost curves help the ETI members and wider stakeholders understand the overall relevance of CCS as a carbon abatement strategy and identify which storage units are expected to be the most attractive to focus further analysis on with a view to eventual exploitation. The cost breakdown of individual units and sensitivity analysis helps prioritise where investment risks need to be managed and technology development should be prioritised.

The CarbonStore database provides the starting point for this analysis. CarbonStore data are used by a CCS system sizing and lifetime costing model. The model has been developed upon prior work by Element Energy with input from UKSAP project partners.

Existing cost and system sizing models developed by Element Energy for the North Sea Basin Task Force, Scottish Carbon Capture Consortium, and IEA Greenhouse Gas R&D Programme were made available for this project. These models have been adapted for cost analysis using inputs from the CarbonStore database, and the final model description is provided in Appendix A7.1.

7.2 Infrastructure and Economic Modelling Methodology

For the UK, once it is deemed technically and commercially viable, CO_2 capture technology is likely to be targeted at large stationary power or industrial plants onshore. These plants typically have emissions in the region of millions of tonnes of CO_2 each year and long lifetimes, with investment decisions often taken on the basis of 10-40 year horizons. These onshore sites are assumed to be connected to a shoreline hub through an onshore pipeline or pipeline network. The details of the onshore network are not examined; as mentioned above direct matching of supply and demand is outside the scope of this study. The model begins at a shoreline hub, where it is assumed that the CO_2 is delivered at 10 MPa (100 bar). The diagram below (**Figure 7.1**) emphasises that the study boundaries include site appraisal, CO_2 injection wells and above ground injection facilities, distribution pipelines, offshore hub located at the unit centroid, transmission pipelines, shoreline boosting but exclude supply of CO_2 from onshore sources to the shoreline hub.

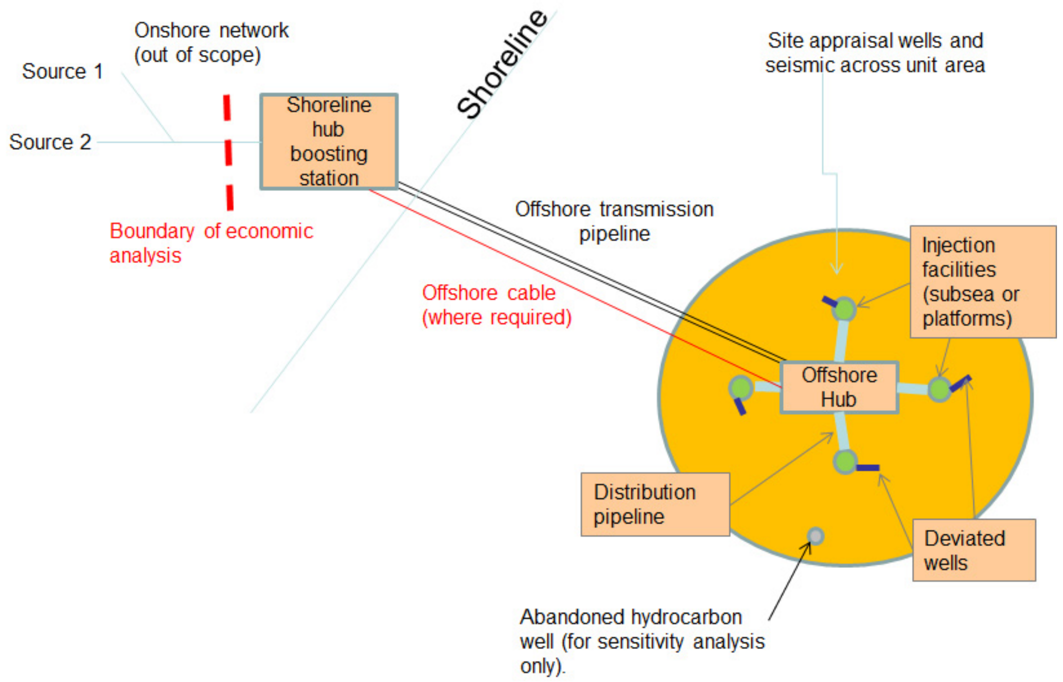


Figure 7.1: Infrastructure and economic model (plan view) from shoreline boosting to offshore wells, including site appraisal, transmission pipeline, offshore hub, distribution pipelines, and in some cases offshore cables for offshore boosting. The storage unit area is depicted in orange.

Note that for units with small areas (only a few km^2) and 6-20 wells, where no offshore pressure boosting is required, it is assumed all wells can be accessed from a single platform and neither offshore hub nor distribution pipeline network are required.

For each unit, the infrastructure requirements and costs are evaluated for a wide range of pre-defined injection scenarios that allow units to be compared against each other under similar conditions. For each unit up to 28 agreed discrete injection scenarios are examined, covering a range of injection rates (2, 5, 10, 15, 20, 40, and 60 Mt/yr) and durations (10, 20, 30 and 40 yrs). These scenarios encapsulate a large spectrum which matches the capacities expected from small demonstration scale CCS projects through large fossil power stations up to large regional hubs which aggregate the CO_2 emissions from multiple large power stations and industrial sources.

The sequence of infrastructure calculations are schematised in **Figure 7.2** and all technical assumptions and calculation descriptions are provided in Appendix A7.1.

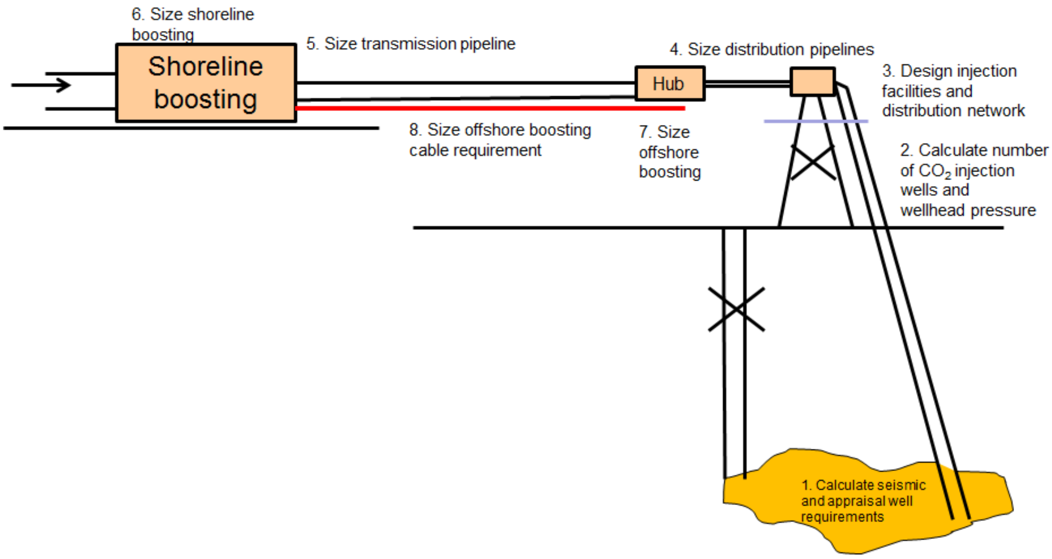


Figure 7.2: Sequence of infrastructure engineering calculations for each injection scenario.

The model proceeds in two stages. In the first stage, all components of the system have to be sized appropriately to deal with the required CO_2 flow rates, pressure limits associated with injection, and limiting pressure drops within pipelines. Subsequently, the capital, and ongoing costs for the system are developed, and lifetime system costs are generated.

Note that in this model, 'storage' costs include site appraisal, CO_2 injection wells, injection facilities, and distribution pipelines. Offshore 'transmission' costs include the costs of shoreline boosting, offshore transmission pipeline, and the offshore hub. As mentioned above, the model does not include for onshore transmission, nor for the cost of capture.

There are 15 separate components to the capex model, as illustrated in **Figure 7.3**.

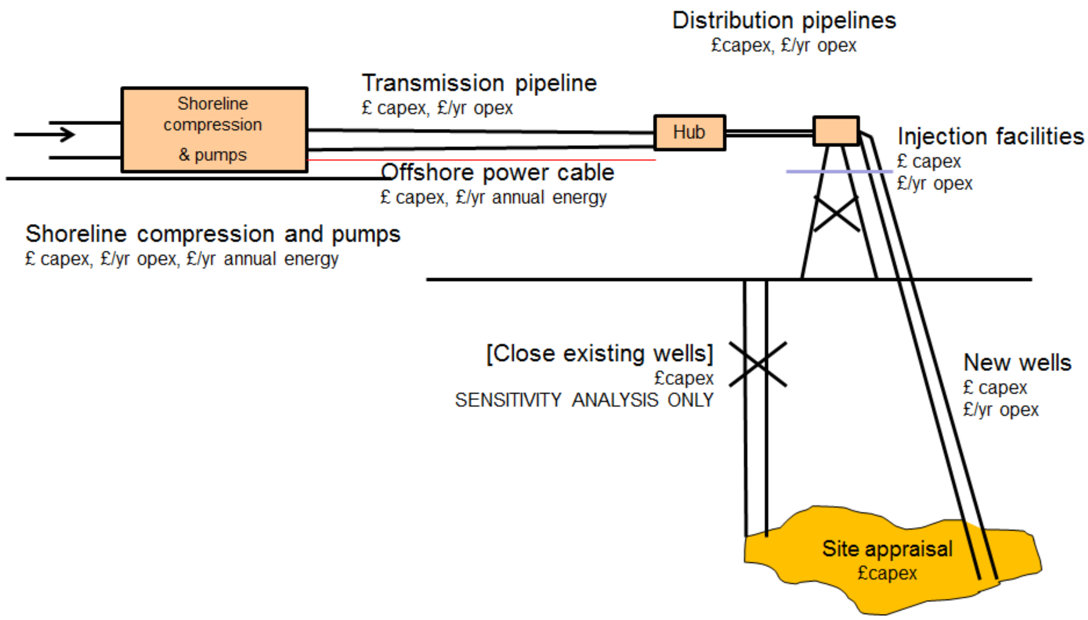


Figure 7.3: Elements of the Cost Model

Limits in the model prevent pipeline pressures from falling below set limits. In this circumstance, offshore boosting is required. Where boosting at an offshore hub is required the cost of a power cable and energy for offshore boosting are also included. Temperature management is out of scope of the analysis.

Although it was agreed to exclude these from the baseline analysis, as a sensitivity, the potential costs of revisiting existing wells drilled primarily for hydrocarbon production and resealing these, is explored ("remediation of existing wells").

No detailed site cost and performance optimisation or examination of sharing/re-use of existing infrastructure has been undertaken. The feasibility of re-use of existing infrastructure is a complex and controversial subject and is outside the scope. The costs of decommissioning CCS infrastructure and measurement, monitoring and verification requirements (MMV) are out of scope of the analysis.

The overall lifetime costs are calculated in the baseline scenario as:

i.e. *lifetime cost = sum of all capex terms + sum of all opex X project lifetime*

In this study, focussed purely on offshore transmission and storage, specific costs are expressed as £/tCO_2 stored, i.e. lifetime costs are divided by lifetime CO_2 stored[8]. For simplicity and transparency, neither costs nor CO_2 are discounted in the baseline scenario, although this is explored in a sensitivity analysis using discounted cashflow at different discount rates. As described in the sensitivity analysis, the costs of CO_2 storage are highly sensitive to assumptions on discount rate, financing structures and the requirements for early site appraisal.

[8] CO_2 'abatement' is relevant only when CO_2 capture is also included and appropriate counterfactuals can be identified to allow the CO_2 stored to be compared to the CO_2 emissions without CCS. CO_2 emissions associated with transmission are out of scope but expected to be small.

As described in the preceding chapter, UKSAP Consortium Partners developed two separate methodologies to provide inputs for the economic analysis on the number of CO_2 injection wells and maximum downhole pressures in wells for saline aquifers and hydrocarbon fields. Reflecting on the differences in these methodologies, it has been agreed that the outputs for aquifers and hydrocarbon fields are presented separately.

7.3 Saline Aquifers

7.3.1 Baseline Cost Curve (storage only) in UKCS Aquifers

Out of 67.6 Gt identified in 201 aquifer sites, each recorded as having P_{50} theoretical capacities greater than 20 Mt, the costs of exploiting up to 44.3 Gt using 159 sites have been determined.[9] The reason for a reduction from 201 sites to 159 is primarily that those omitted have require low injection rates, outside the range determined to be technically and economically relevant.

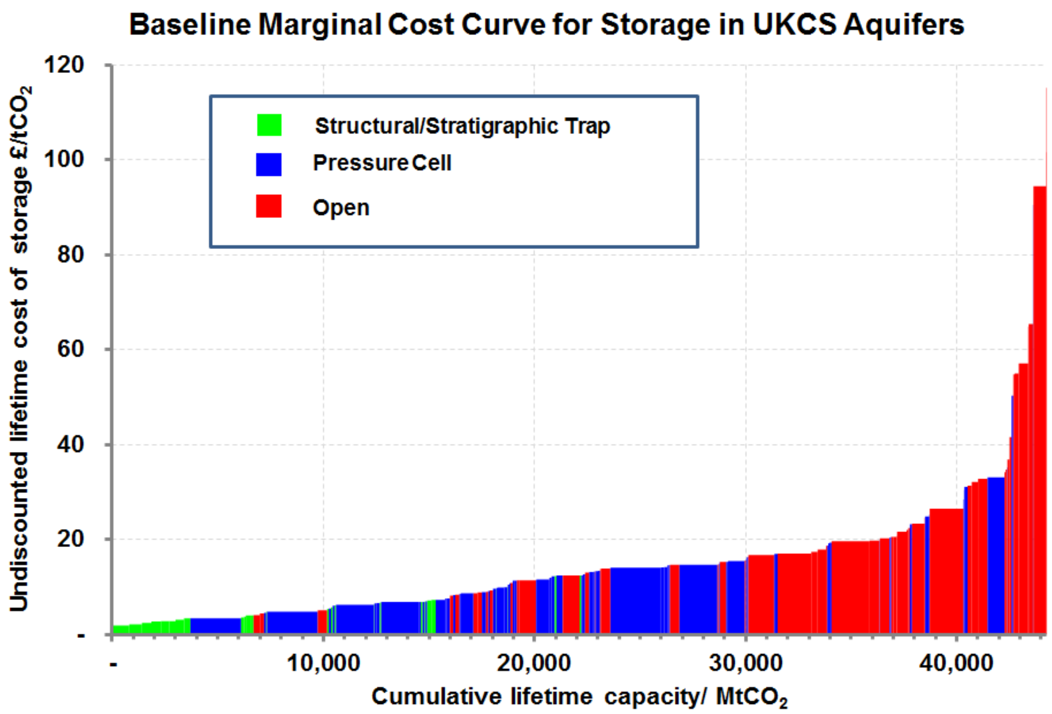


Figure 7.4: Undiscounted lifetime costs of storage in aquifers (P_{50}). Costs include site appraisal, new injection wells, new injection facilities and distribution pipelines

- The marginal storage only cost curve above depicts the £/tCO_2 stored costs of exploiting 159 aquifer units to the maximum capacity modelled in the economic analysis. Each bar represents an individual unit (or daughters) exploited. The x-axis indicates the cumulative capacity available exploiting each unit.

[9] Additional capacity above 44.3 Gt may therefore be available, but would involve injection scenarios outside those agreed and examined in this study (e.g. low injection rates below 2 Mt/yr for a unit, project durations exceeding 40 years, or alternative reservoir engineering techniques such as horizontal drilling).

- The width of each bar is proportional to its capacity. For 25 aquifer units this corresponds to the lowest injection scenario (i.e. 2 Mt/yr x 10 yr, i.e. 20 Mt overall) whereas 3 large units have costs calculated at the maximum injection scenarios of 60 Mt/yr x 40 yrs (i.e. 2,400 Mt overall). The remainder have capacities at values intermediate between 20 Mt and 2,400 Mt overall. The graph illustrates there is a mixture of large, medium and small capacity units at all cost ranges.

- The undiscounted lifetime costs of storage vary by nearly 2 orders of magnitude between units from £1.87/t for the lowest cost (Unit 226.011) up to £115/t for the highest cost (Unit 373).

- The marginal storage cost curve itself shows that the costs rise smoothly until above *ca*. 40 Gt where the undiscounted costs of storage then increase steeply from £26/t.

- The areas of each bar represent the lifetime investment associated with each unit when exploited at the appropriate capacity. These undiscounted investments range from £127 million to a maximum of £57 billion for individual projects. The total area under the curve is £646 billion. This value corresponds to the total investment in storage if all the aquifer units are exploited at the capacities indicated, assuming each unit is operated independently. This corresponds to an 'average cost' of £15/tCO_2.

- A multi-variate analysis shows that no single term dominates the trends in costs across the full storage cost range. The highest positive correlations are observed with predicted numbers of wells and predicted numbers of injection facilities. The strongest negative correlation is observed with capacity. Weak positive correlations with increasing cost are observed with increasing area, water depth and reservoir depth. Weak negative correlations with cost are observed for increasing permeability and increasing difference between fracture pressure and required well downhole pressure (see Section 7.3.3 for further analysis).

- The majority of storage capacity in structural or stratigraphic traps is relatively low cost. These traps have moderate capacities, require few injection wells, are in shallow waters and at shallow depths, which all combine to limit well and injection facility costs. The areas of these traps are also small, limiting the costs of site appraisal.

- Capacity in open units and pressure cells span a wide range of costs. Nearly all the high cost open units have most likely permeabilities less than 10 mD, i.e. likely to fall into “Regime 1”. The lower cost open units have permeability greater than 10 mD (in some cases 100s of mD). Pressure cells are found across the cost curve.

7.3.2 Costs of Offshore Transmission and Storage in UKCS Aquifers

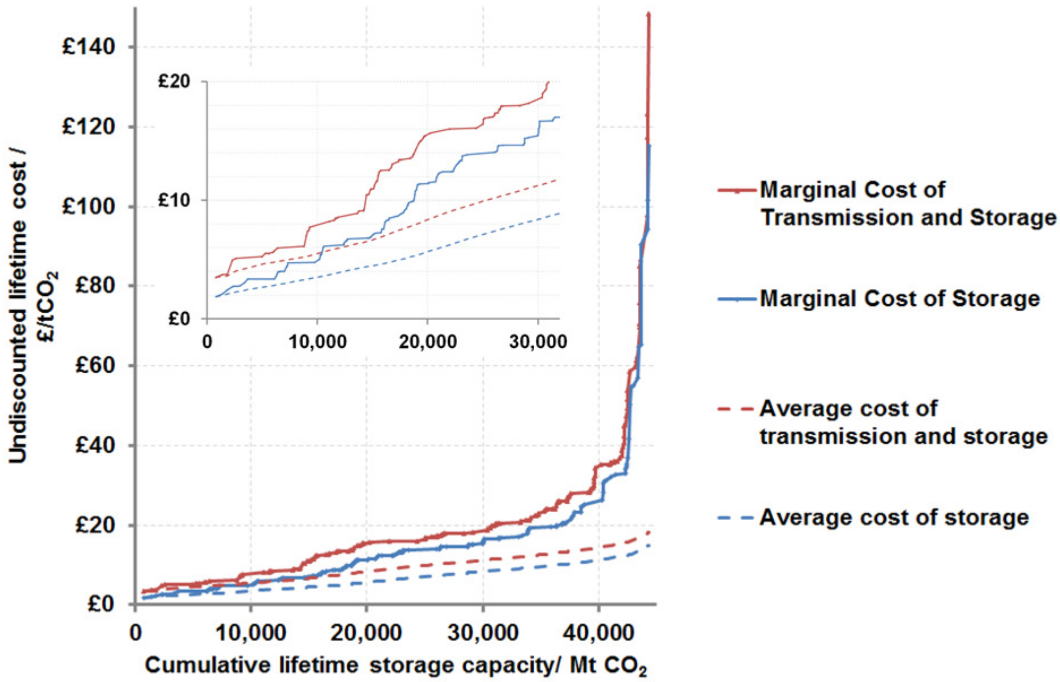


Figure 7.5: Comparison of aquifer marginal and average cost curves for storage with marginal and average cost curves for transmission and storage

As shown above, the overall shape of both the storage cost curve, and combined transmission and storage cost curve, are similar. As with storage costs, the combined transmission and storage costs increase slowly with cumulative capacity, with a steep change on costs only detectable above 40 Gt. When the costs of transmission are included, the combined undiscounted lifetime marginal costs of transmission and storage for aquifers span £3.49/t to £148/t (P_{50} scenario). The average undiscounted transmission and storage cost for exploiting all 44Gt in aquifers is £18/t.

Multi-variate analysis shows that no single variable dominates the trend in combined costs of transmission and storage. When compared under a like-for-like injection scenario, the lowest and highest cost units can be readily distinguished.

The lowest cost units benefit from a combination of favourable characteristics, namely low areas leading to low appraisal costs, water depth <100 m, good injectivity (>1 Mt/yr/well), limited requirement for onshore compression and no requirement at all for offshore compression, and proximity to shoreline terminals (e.g. less than 100 km).

In contrast, the highest cost sites (>£100/t) typically have a combination of (i) low flow rates per well (<0.5 Mt/yr/well) implying large numbers of wells and associated injection facilities (ii) large areas implying high costs of seismic appraisal and the use of widely distributed subsea injection facilities; (iii) at least one unfavourable driver from out of distance from shoreline greater than 200 km, (increasing the costs of pipelines and boosting), water depth >100 m (increasing the costs of injection facilities), or reservoir depth > 3 km (increasing the costs of wells).

The majority of sites have either (i) intermediate characteristics (e.g. flow rates of 0.5-1 Mt/yr/well, distance from shoreline of between 100 km and 200 km, water depths between 100 and 150 m, and reservoir depths between 2 and 3 km; or alternatively (ii) a combination of favourable and unfavourable characteristics.

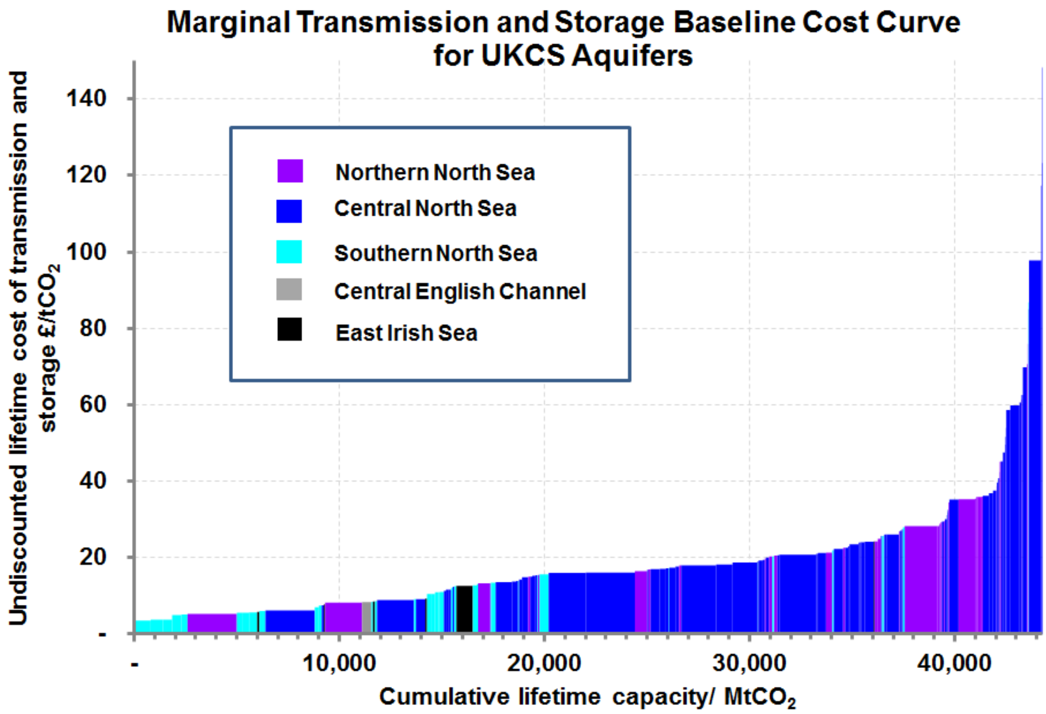


Figure 7.6: Baseline undiscounted lifetime marginal costs of transmission and storage in UKCS aquifers (based on P_{50} data)

In **Figure 7.6** the cost curve is colour coded to indicate the geographic sector of the storage unit. Highlights of the analysis by geographic sector are as follows:

- The SNS, CNS, NNS, Central English Channel and EISB all have units with marginal transmission and storage costs below a threshold of £20/t.
- The largest contribution to number of units and capacity in the cost curve comes from the pressure cells and open aquifers in the CNS.
- Storage capacity in the EISB is very limited: The lower cost (<£20/t) capacity is in structural/stratigraphic traps, and higher cost capacity in open units.
- Most of the capacity in the SNS is in structural or stratigraphic traps with marginal costs less than £20/t. There are very few expensive aquifers (e.g. >£30/t) – these are all open. There are no pressure cells in the SNS aquifer cost curve.
- Costs in the CNS span a wide range. The lower cost (<£20/t) aquifers in the CNS are mainly pressure cells, whereas the more expensive aquifers (>£30/t) are open with permeabilities below 10 mD (i.e. injectivity limited, leading to high well counts).
- The NNS cost curve comprises pressure cells with low (<£20/t) and high (>£30/t) costs, and open units with intermediate costs.
- Only one store is identified in the English Channel.

The costs for transmission are below £5/t for those units where there is a combination of low downhole pressures (i.e. limited requirement for pressure boosting) and proximity (<150 km) to the shoreline. In these cases, transmission costs form a small fraction of overall costs.

Transmission costs are high (>£20/t) for some smaller units in the CNS and NNS which are hundreds of kilometres from the shoreline (i.e. where the pipelines are long) and power is required for pressure boosting at an offshore hub. In some of these cases the transmission costs can contribute more than half of the overall costs, but not always as the storage costs are often higher for these units also.

7.3.3 Key Cost Drivers

The ratios of costs for site appraisal, injection wells, injection facilities, pipelines and compression vary between units and for any given unit, between injection scenarios. Whilst it is common for the overall costs to be fairly evenly divided among the various cost items, it is not straightforward to identify a 'typical cost breakdown'. For any given unit, the ratio of capex to opex is also sensitive to assumptions on injection scenario and discount rate. Some illustrative cost breakdowns for aquifers are provided in Appendix A7.1.

- A parametric analysis shows that the predicted number of CO_2 injection wells per Mt CO_2 injected is one of the most single important CarbonStore inputs controlling transmission and storage costs, but even this correlation is modest (R^2 = 0.6).
- In general increasing unit area, depth at centroid/reference, water depth, combined risk-confidence score (used for estimating aquifer appraisal costs), and maximum downhole pressure are all weakly (positively) correlated with increasing storage costs (R^2< 0.3).
- Storage capacity is negatively correlated with storage cost, although there are some exceptions i.e. large units which are expensive and on the right hand side of the cost curve and conversely some small units which have low costs.
- Permeability and the difference between fracture pressure and bottomhole pressure are both weakly negatively correlated with cost.
- Among the *calculated* parameters, the number of injection facilities correlates well with overall transmission storage costs.

The majority of units have intermediate costs reflecting the interplay of these factors.

7.4 Sensitivity Analysis for Aquifers

More than twenty sensitivity analyses (and further combinations of variables) were performed to understand the impacts of variations in cost model or CarbonStore inputs on the absolute and relative costs of exploiting storage units at different injection scenarios, and the composition and shape of the marginal cost curves. The most important sensitivities are listed in **Table 7.1**.

Sensitivity	Baseline	Range explored in sensitivity analysis	Impact on capacity cf. 31 Gt @ < £20/t (undiscounted T&S) in baseline	Maximum cost changes for individual units	Impact on average transmission and storage cost
WACC (discount rate)	0%	5-20%	Very high: Potential reduction to <0.1 Gt @ <£20/t. Affects all aquifers.	Up to 650% rise in cost from 0% to 20%	Average cost increases by up to 300%
Geological uncertainty (capacity, well number, downhole pressure)	P_{50}	P_{10} and P_{90}	Very high: Range is 14-51 Gt @< £20/t. Affects all aquifers.	Not meaningful as capacity also changes	Not meaningful as capacity also changes
Well remediation	Not included	Up to 100% at 60% of the cost of a well.	High: Potential reduction to 22 Gt @ < £20/t. Only affects aquifers with many existing well penetrations.	Increases of up to 1200%	Average increase in costs up to 78%.
Injection facility costs	1x baseline capex and opex.	0.5-2x baseline capex and opex	High: Range is 18-38 Gt @ < £20/t Biggest impact on units in deep water in scenarios requiring a large number of subsea injection facilities.	Maximum cost reduction = 36% Maximum cost increase = 71%	For 0.5x sensitivity, average cost reduction = 25% For 2x sensitivity, average cost increase = 51%
Well costs	1x baseline capex and opex	0.5-2x baseline capex and opex	High: Range is 21-34 Gt @ <£20/t. Biggest impact on deep units in scenarios with large predicted numbers of wells.	Maximum cost reduction for a unit is 20%. Maximum cost increase for a unit is 34%.	For 0.5x sensitivity, average cost reduction = 11% For 2x sensitivity, average cost increase = 22%
Transmission pipeline capex	1x baseline	0.5x-2.5x baseline capex	Medium: Range is 26-35 Gt @ < £25/t. Primarily raises costs of some CNS and NNS sinks in baseline.	Maximum cost reduction for a unit is 29%. Maximum cost increase for a unit is 51%	For 0.5x sensitivity, average cost reduction is 10%. For 2x sensitivity, average cost increase is 19%
Maximum offshore pressure in transmission and distribution pipelines	25 MPa	15-35 MPa	Asymmetric: Range is 21 – 31 Gt @ < £20/t. Lower pressure limit leads to increased costs as more offshore boosting required and restricts capacity from those units needing high wellhead pressures.	Not meaningful as capacities change	Not meaningful as capacities change.

Table 7.1: Sensitivity Analysis for Aquifers

Having done these sensitivities, the impacts of geological uncertainty, well remediation, cost of injection facilities and discount rate emerged as prominent in controlling cost. They are therefore described in more detail below.

Sensitivities examined which had individually had very little effect on the baseline transmission and storage cost curve included: (i) Routing correction factor; (ii) Pipeline opex; (iii) Provision for redundancy in injection wells; (iv) Well annual opex; (v) Capex and opex for shoreline boosting; (vi) Cost of energy for boosting; (vii) Capex and opex of offshore hub at unit centroid; (viii) Uncertainties recorded in Carbonstore in the water depth, reservoir depth or unit area.

7.4.1 Financing

To avoid prejudging the likely shape of government or private sector investment in CCS, which may shift over time and differ between projects, it was agreed that baseline costs would be presented undiscounted.

The overwhelming majority of financing for major infrastructure projects worldwide typically comes from a mixture of debt and equity. The financing structure, e.g. ratio of debt to equity, is generally negotiated on a project-by-project basis, and is dependent on perceived project risk, sponsor credit ratings, historical trends, and prevailing market conditions. Debt finance is generally lower in cost, but typically is hard to raise for immature technologies. To avoid the need to specify a precise debt:equity funding arrangement, it is common to use a Weighted Average Cost of Capital (WACC). This value is equivalent to a discount or hurdle rate. The higher the WACC the higher the interest that must be paid to finance early capital expenditures, and the lower the importance of future costs and revenues. The model assumes the project achieves a Net Present Value (NPV) of zero (i.e. repays all capital and any hurdle rate) at the end of its economic lifetime. Real WACC levels (i.e. excluding the effect of inflation) for infrastructure projects in the UK are :

- Public sector *ca*. 3.5%
- Regulated utilities or public-private partnerships *ca*. 10%
- Routine commercial business *ca*. 15%
- High risk private sector (including oil and gas exploration) *ca*. 20+%

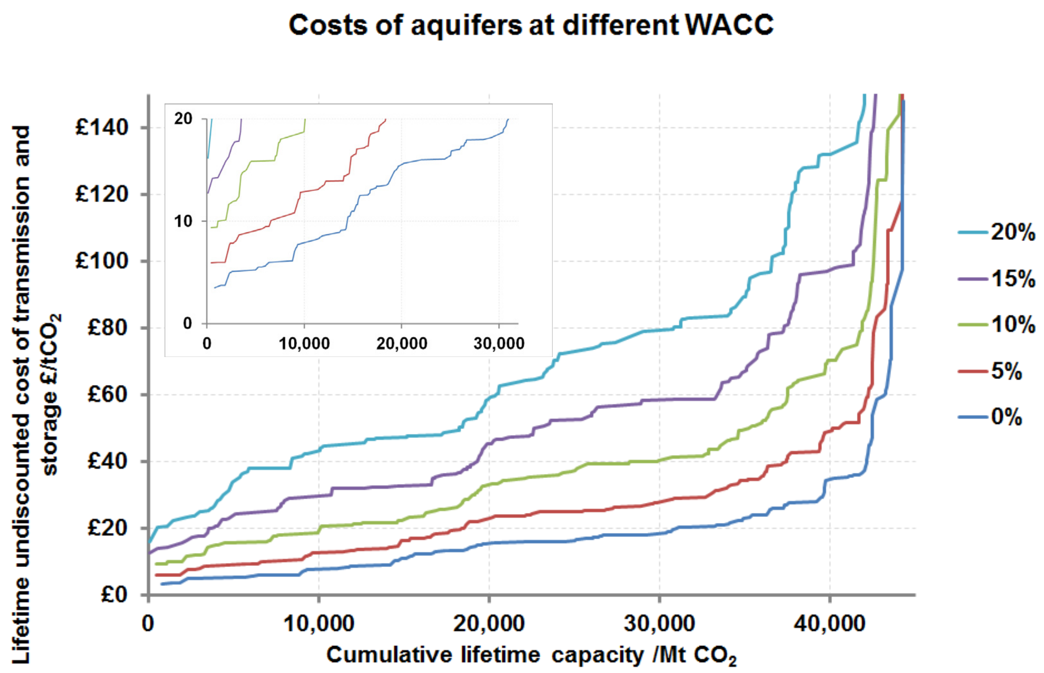


Figure 7.7: Impact of financing on the transmission and storage marginal cost curve. Inset focusses on the part of the cost curve below £20/t.

The above illustrates the sensitivity of marginal cost curves for aquifers to the weighted average cost of capital. The main reason for the high sensitivity of aquifers to discount rate arises from the requirement for substantial expenditure (£100s of millions in many cases) on aquifer appraisal, several years before storage operation actually commences.

Different injection scenarios and different units have different ratios of capital expenditure, operating expenditure, injection rates and lifetimes. In general, low discount rates favour longer duration projects, whereas at high discount rate those projects with shorter durations are favoured.

However, a combination of low discount rate and long duration does disadvantage scenarios with a high ratio of operating to capital costs, including scenarios which are modelled as using a large numbers of subsea injection facilities to cover large unit areas (as opposed to operating a large number of wells from few platforms).

The figure below presents two alternative perspectives on impact of discount rate – on the capacity available at a given range of costs at different discount rates, and on average costs.

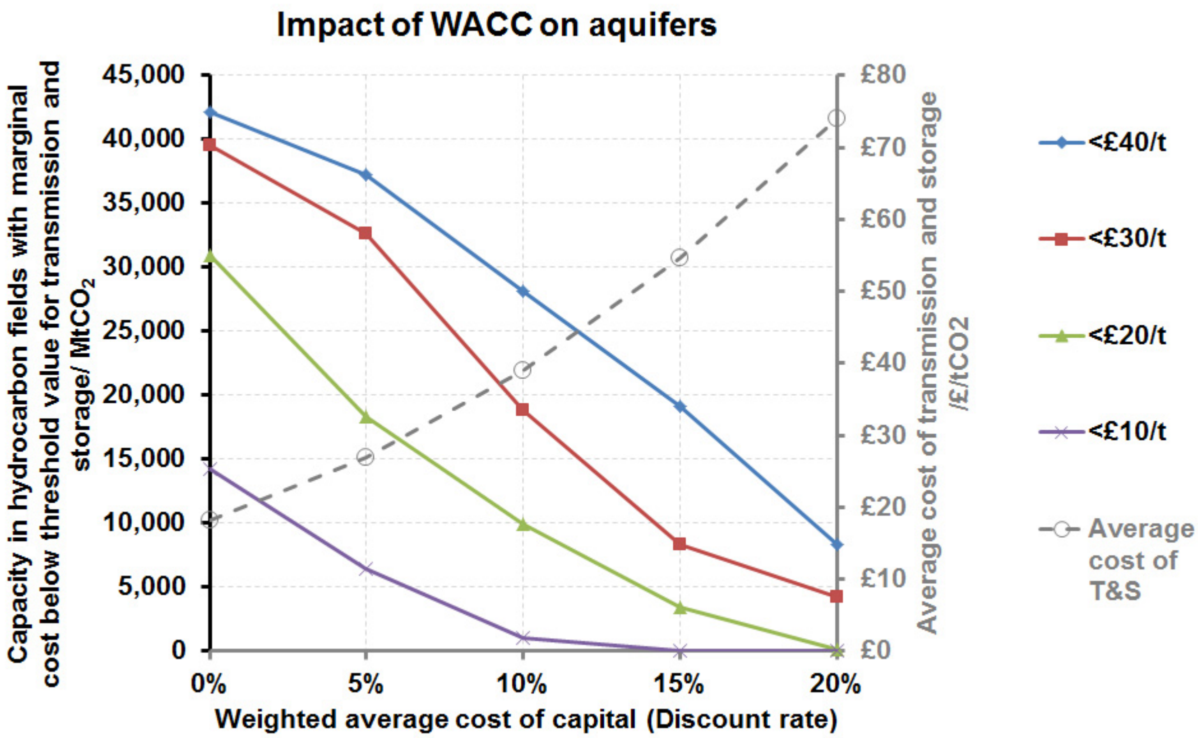


Figure 7.8 Impact of weighted average cost of capital (discount rate) on capacity below arbitrary thresholds of £10/t, £20/t, £30/t and £40/t (left-hand axis). Dashed line shows increase in average costs for transmission and storage (right-hand axis).

For a given injection rate for a given unit, increasing the project duration (e.g. from 10 years to 40 years) increases lifetime opex but generally results in a substantial decrease in average undiscounted costs as capital costs are divided by higher lifetime CO_2. If the finance repayment schedule is longer and if future benefits are discounted, this benefit diminishes.

- The impact of discount rates varies between units and is injection scenario dependent, because of differences in capex, opex and, importantly project duration.
- A sensitivity analysis shows that phasing of infrastructure, where some wells and injection facility expenditure occur late in the project lifecycle, could lead to substantial reductions in the net present costs of some storage units at high discount rates. An illustration of this is provided in Appendix A7.1.
- Whilst the economic ranking of units would change when phasing potential is considered, the technical potential to phase infrastructure is not possible to generalise at this stage. Nevertheless this could be important. The pressure build up in some units may be gradual over time - allowing some wells, injection facilities and boosting equipment to be installed late in the project deployment. For other units, pressure may build up rapidly over time, such that the majority of wells and injection facilities would need to be in place from the project outset.

7.4.2 Importance of Reducing Geological Uncertainty and Limiting Requirements for New CO_2 Injection Wells

As described in the preceding chapters, CarbonStore calculates dynamic utilisation (injection rate x duration), well numbers, and downhole pressures through Monte Carlo probabilistic simulations. The distribution of these values for individual units is captured in P_{10}, P_{50} and P_{90} values for these parameters and can be used as inputs to the economic analysis. The baseline results use P_{50} estimates.

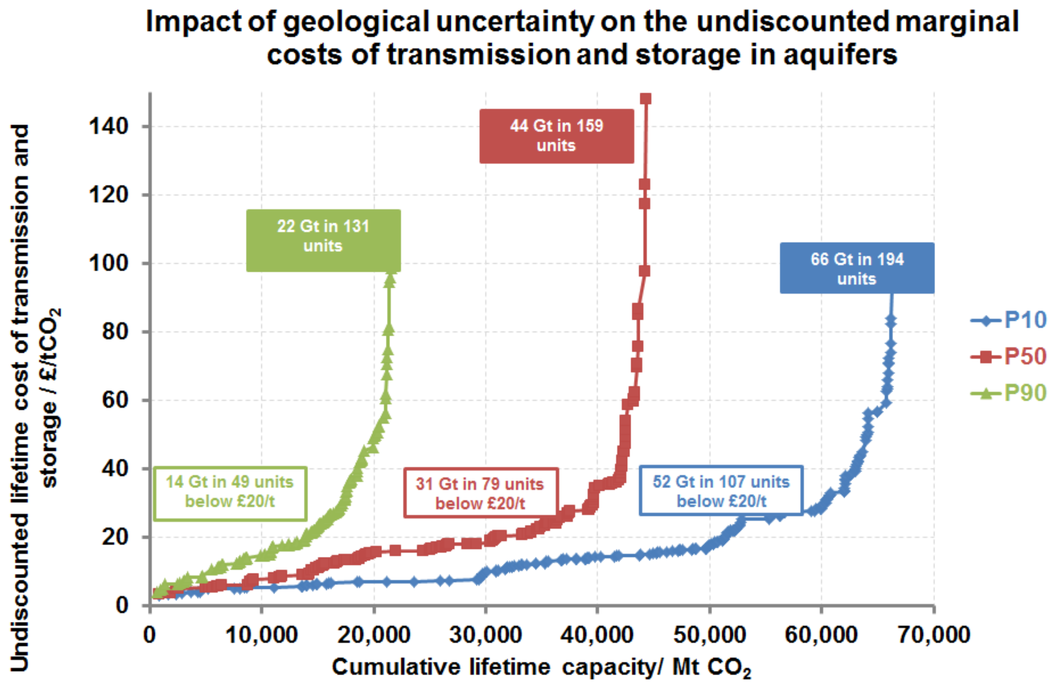


Figure 7.9: Marginal transmission and storage cost curves (undiscounted) for aquifers using P_{10}, P_{50} and P_{90} estimates of well numbers and downhole pressures

As shown in **Figure 7.9**, when P_{10} and P_{90} estimates are used the number of units for which cost analysis is carried out are significantly altered, as additional units now have well predictions (P_{10}) or some sites are removed as they no longer have CO_2 injection well / downhole pressure predictions (P_{90}) recorded in CarbonStore. In general however these additions or removals affect units with relatively limited capacity (e.g. around 20 Mt dynamic utilisation capacity). The bigger impact in going from P_{50} to either P_{10} or P_{90} is on the overall capacity modelled in the cost analysis. This is because some units now tolerate significantly larger (P_{10}) or smaller (P_{90}) injection scenarios. This leads to differences in the abilities of units to take advantage of economies of scale, and therefore affects the costs. Note that the P_{10} and P_{90} capacities identified in the marginal cost curve represent the summation of individual capacities and not the true P_{10} or P_{90} capacities of the entire UKCS.

Except for the smallest injection scenarios where rounding up of well numbers is likely to be significant, the range in well numbers is generally only a factor of two around the P_{50} estimate and the range in downhole pressures varies by only a few MPa (a few percent relative to the P_{50} estimate). Therefore the differences in the marginal cost curves between the P_{10} and P_{90} are dominated by the difference in capacity (i.e. a function of pore space) between the Monte

Carlo simulations, the differences in injectivity playing an important but secondary role. The average costs for transmission and storage are estimated at £15/t (66 Gt, based on P_{10} inputs), £18/t (44 Gt, based on P_{50} inputs) and £21/t (22 Gt, based on P_{90} inputs).

Well costs can be controlled by managing either the costs of each well and the number of wells required. Excluding general changes linked to currency fluctuations or engineering cost indices which would likely affect the costs of all terms in the cost analyses to a similar extent, costs per well could be influenced by the need to manage the impurities, temperature, and pressure and flow of the CO_2 stream. Lower costs might be available if the CO_2 existing well penetrations (e.g. those drilled for appraisal, hydrocarbon production or water injection) could be reused, although this would require that existing wells are in the correct locations for CO_2 injection and are of compatible specifications.

Fewer wells might be required if larger diameter wells can be used or if the performance of wells could be increased (e.g. through horizontal drilling which may be particularly beneficial for those units with lower than average horizontal permeabilities and higher than average vertical permeability). It was not possible to explore the trade-off of higher well design cost with improved well performance within UKSAP.

7.4.3 Project Scale

At constant project duration, the modelling predicts substantial economies of scale for most units as injection rates are increased. This is illustrated in **Figure 7.10** which shows substantial economies of scale as injection rate is increased from 2 Mt/yr to 10 Mt/yr and a modest benefit as injection rates are further increased to 60 Mt/yr. The graph also shows how the ratios of cost elements in the model change with scale. The 60 Mt/yr x 40 yrs scenario, corresponding to the largest capacity and lowest cost, is presented in the marginal cost curves presented above.

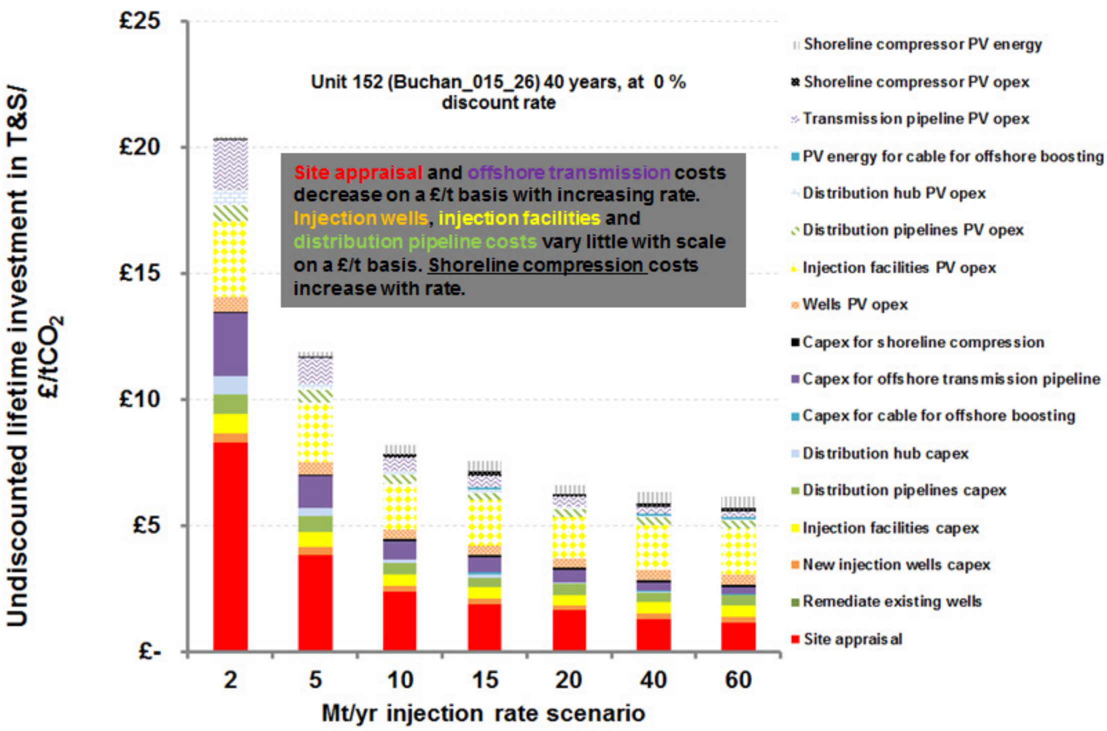


Figure 7.10: Illustration of Economies of Scale in Transmission and Storage

In a minority of cases, the pressure build up for the highest injection rates can only be accommodated with a steep increase in the numbers of wells and potentially also a requirement for offshore boosting. This raises the costs of drilling, injection facilities, distribution pipelines and compression, restricting the potential for economies of scale at the highest injection rates.[10]

7.4.4 Importance of Well Remediation

As described in the preceding Chapter, existing well penetrations (usually drilled for oil and gas exploration, appraisal, or production) could provide a pathway for CO_2 to escape from a designated storage site, potentially to the seabed or atmosphere. CarbonStore identifies the total number of *potential* penetrations of existing wells for each unit (these figures are conservative with respect to risk, that is, the algorithm used to identify a potential well penetration is known to tend towards over-estimation of the number of actual well penetrations rather than under-estimation, and this is especially notable in large saline aquifers or underneath oil and gas fields).

The requirements for managing these existing wells are only slowly becoming understood, although there is little precedent for estimating the costs of interventions. Both the number of existing wells that may require further intervention and the associated range of costs of such interventions are unclear. [Ref: DNV CO2Wells (2011)].

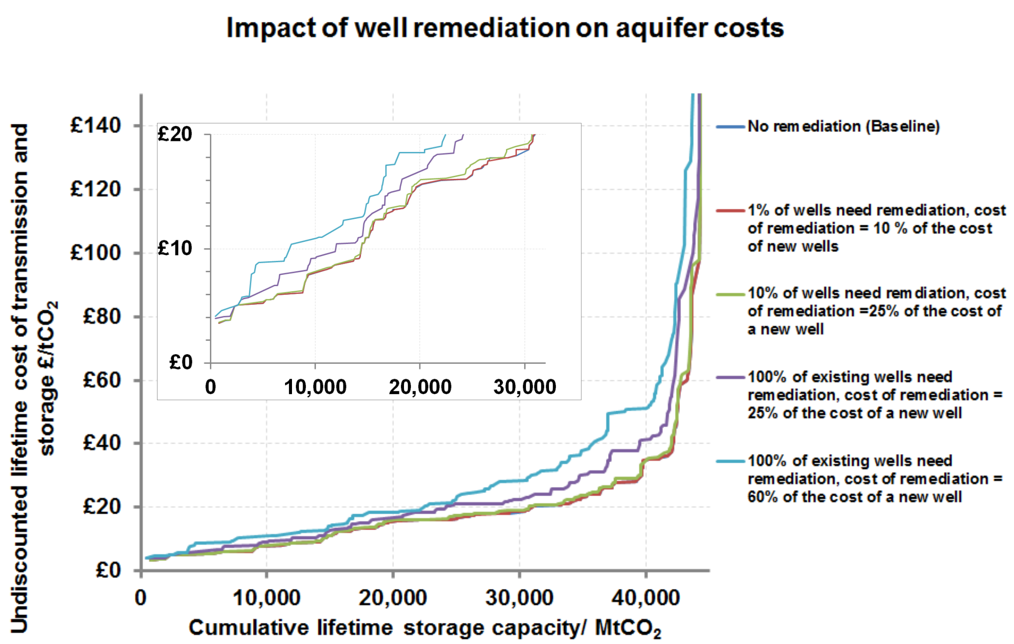


Figure 7.11: Sensitivity of Marginal Transmission and Storage Cost Curve for Aquifers to Remediation of Existing Wells. Inset highlights the capacity available below £20/t.

As shown in **Figure 7.11**, substantial interventions to remediate all existing wells can reduce the capacity below £20/t from a baseline of 31 Gt to 22 Gt. Several large aquifers have hundreds of existing wells, so that remediation costs could potentially add costs in the region of £1bn. The average undiscounted costs of transmission and storage in aquifers increase

[10] In a sensitivity analysis where the maximum offshore pipeline diameter is restricted (at between 24" and 36"), this also reduces the potential for economies of scale as two pipelines become necessary to manage the flow of 60 Mt/yr.

from £18/t to £33/t in going from the baseline scenario to one where all existing wells require intervention with an average intervention cost of 60% of the cost of a new well.

7.4.5 Importance of Injection Facilities

Since the number and cost of injection facilities required correlate with storage costs, it is unsurprising that sensitivity analyses where the number of injection facilities or the cost per facility are reduced show significant effects for some units and scenarios. Changes in the cost of injection facilities have a dramatic effect on capacity below a £20/t threshold.

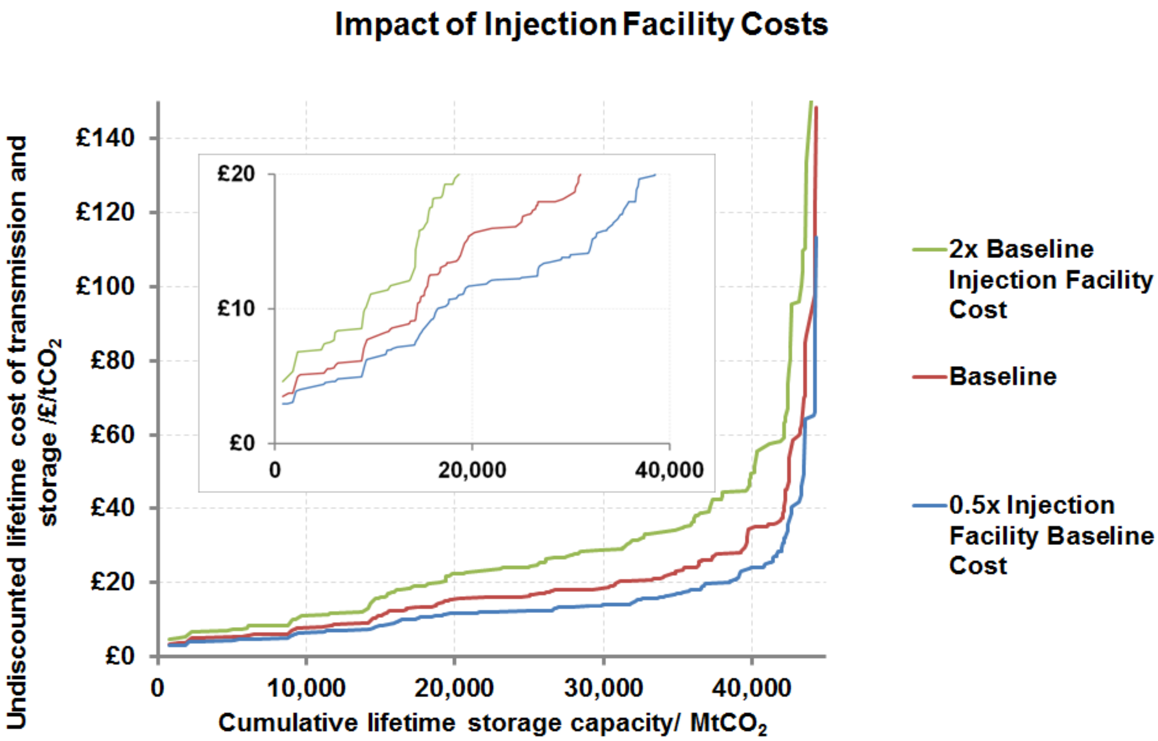


Figure 7.12: Impact of Injection Facility Costs on the Undiscounted Marginal Cost Curve for Transmission and Storage in aquifers

The units and scenarios most sensitive to injection facility costs are those units which are recorded in CarbonStore as having large areas, and moderate CO_2 injection well counts. These units are modelled as having only one well per injection facility. For these units, the wide spacing of the wells implies a large number of subsea injection facilities each serving one well. These subsea facilities have a high opex, reflecting the challenges of access and maintenance. Halving the opex for subsea injection facilities could reduce the costs of exploiting some large aquifers by up to 20%.

The units least sensitive to injection facility costs are those with very small areas and high well counts. Here the wells are closely spaced. These units are modeled with platforms, leading to economies of scale through the ability to service multiple wells from a common facility.

Excluding general changes linked to currency fluctuations or engineering cost indices, the relative capital costs of injection facilities could be reduced if these can be shared between hydrocarbon production and CCS projects, or shared among several CCS projects. Strongly deviated drilling which expands the area accessible from a single injection facility would also cut down on the number of injection facilities required.

Conversely higher injection facility costs might be encountered if there are substantial requirements for offshore gas processing (e.g. need to manage CO_2 temperature).

7.4.6 Importance of Proximity of Sinks to the Shoreline

The future locations of capture plant are uncertain, and will be influenced by diverse factors (fuel availability, future electricity demand, electricity network capacity, interest in CCS by heavy industry etc.). Among these factors is the cost of accessing CO_2 storage.

In the baseline, sinks are connected to their nearest shoreline hubs, as identified in the Appendix A7.1. One sensitivity analysis is where sinks on the east coast of the UK are connected to the second nearest shoreline hubs (e.g. sinks in the SNS that previously connected to Theddlethorpe now connect to Thames estuary or Teesside shoreline hubs) reveals that there is a significant increase in transmission cost. The median increase in the undiscounted marginal cost for transmission and storage in aquifers is 20-25% compared to when these are connected to the nearest shoreline hub.

A more extreme sensitivity analysis examines the cost of accessing all the UKCS storage from an individual regional shoreline hub. Very long offshore pipelines (>500 km) are technically feasible and common in the oil and gas sector, where they are typically associated with offshore boosting platforms. Unsurprisingly, the overall transmission costs can increase several fold the further away the store from the hub. More interestingly however, even with the longer transmission networks, the results at a full UKCS level show that the variation in storage costs between the aquifers still dominates the variation in transmission costs.

Note these conclusions are contingent on the ability to permit large diameter pipelines and large pressure drops in the offshore transmission pipelines (e.g. from 25 to 10 MPa). Where offshore pressure management is more constrained, multiple intermediate boosting stations would be required along the transmission pipeline between the shoreline hub and storage unit. Though not explored in this study, this would significantly increase costs.

7.5 Hydrocarbon Fields

7.5.1 Capacity

From an initial total CO_2 storage capacity of 9.5 Gt in 213 hydrocarbon fields recorded in CarbonStore, 8.6 Gt is available in 81 hydrocarbon fields with P_{50} theoretical capacity greater than or equal to 20 Mt.

Of these, the injectivity analysis provides predicted well number estimates to allow the costs of 63 hydrocarbon fields to be evaluated with an aggregate capacity of 6.1 Gt at the defined injection scenarios. These units were taken forward for infrastructure sizing. The baseline cost curve for hydrocarbon fields reports the cost of 4.3 Gt in 27 hydrocarbon fields.

As set out in Section 4.3, a correction was applied to the number of injection wells estimated to be required for hydrocarbon units. Caution should therefore be exercised when looking at absolute well costs for hydrocarbon fields. (A sensitivity indicating the costs before and after the correction was applied is shown in the next section).

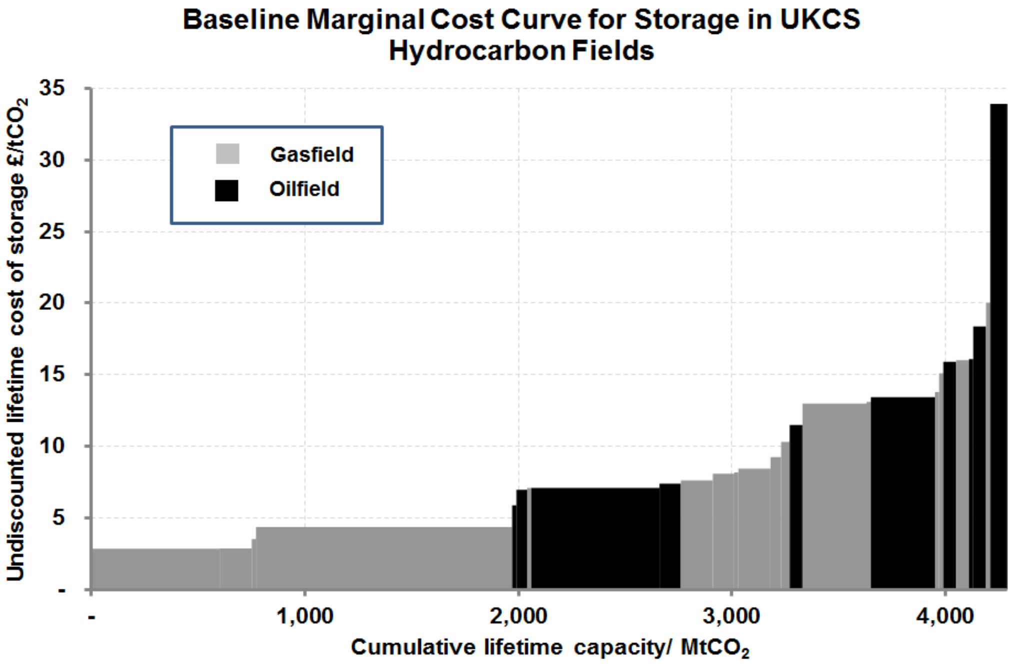


Figure 7.13: Undiscounted marginal cost curve for storage in hydrocarbon fields (N.B. uses 'normalised' well counts).

In the baseline marginal costs for storage in hydrocarbon fields ranges from £2.9/t through to £34/t. Gas fields tend to be cheaper than oil fields on a £/t metric. The total undiscounted investment associated with storing 4.3 Gt in hydrocarbon fields is £33 billion, implying an average storage cost of £7.7/t.

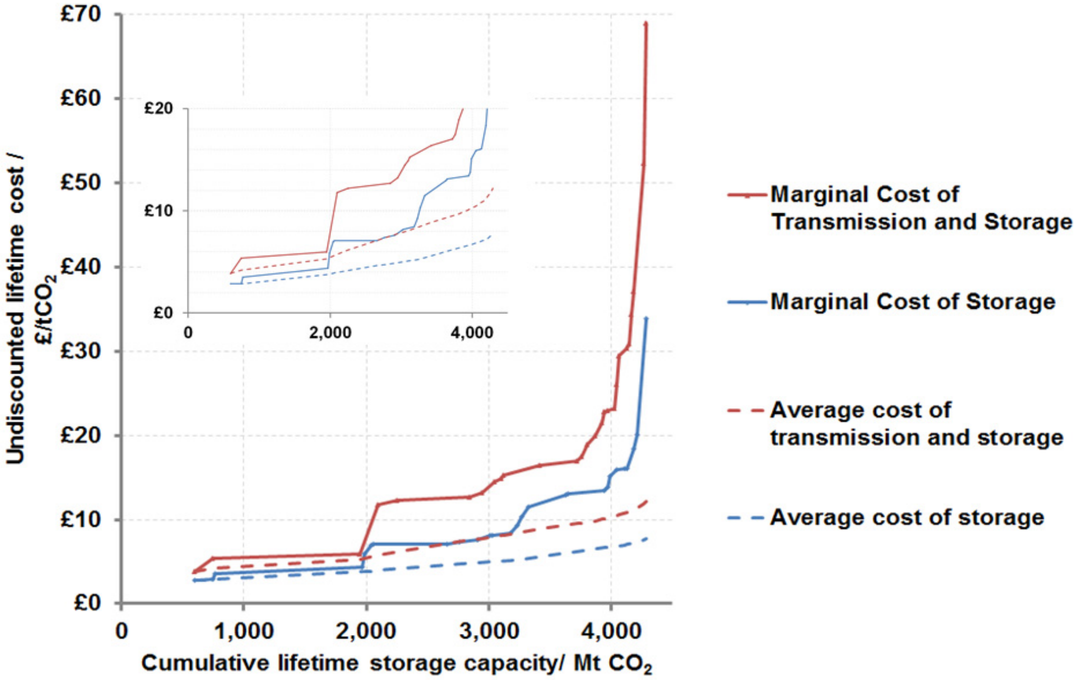


Figure 7.14: Average and marginal undiscounted lifetime costs of storage (blue) and Transmission and Storage (Red) in depleted hydrocarbon fields. Inset focusses on region under £20/t.

When transmission and storage costs are additionally included, the baseline marginal costs for transmission and storage range from £3.9/t to £69/t. The average transmission and cost for exploiting all 4.3 Gt in hydrocarbon units is £12/t.

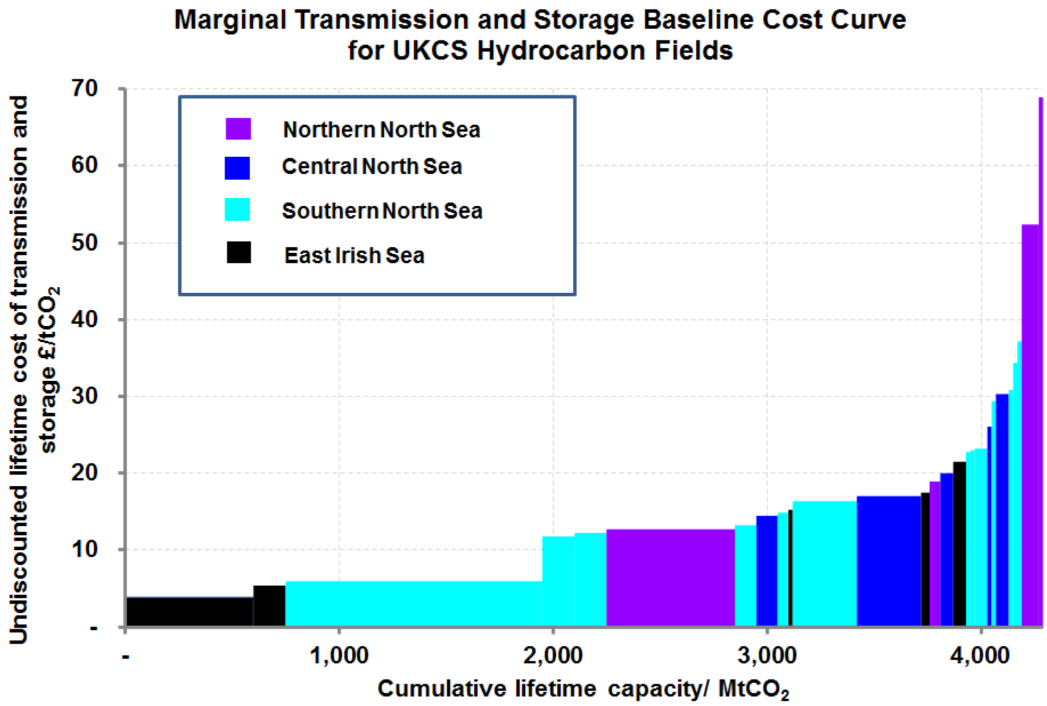


Figure 7.15: Undiscounted lifetime marginal costs of transmission and storage in depleted hydrocarbon fields

Most of the hydrocarbon field storage capacity is concentrated in the SNS gas fields which have a range of costs from £6-£37/t. Storage in the EIS is in both gas fields and oil fields, with costs between £3.9 and £21.5/t. Storage in the CNS is in oil fields with costs £14-£30/t, where transmission can account for half the overall cost. Storage in the NNS is also in oil fields; costs range from £13-£69/t. In a few cases the high costs of transmission to NNS fields is much greater than their storage costs.

7.6 Sensitivity Analysis for Hydrocarbon Units

Whilst the hydrocarbon field units display similar trends in sensitivities to the aquifer units, there are some differences in the magnitude of these.

Sensitivity	Baseline	Range explored in sensitivity analysis	Impact on capacity cf. 3.8 Gt @ < £20/t (undiscounted T&S) in baseline	Maximum cost changes for individual units	Impact on overall average transmission and storage cost
WACC (discount rate)	0%	5-20%	Reduction from 3.8 Gt to 2 Gt at discount rate of 20%	Up to 382% increase in costs from 0% to 20% discount rate	Up to 200% increase in cost from 0% to 20% discount rate
Number of wells	Well counts calibrated to aquifer performance	Unadjusted well counts	Reduction from 3.8 Gt to 0.8 Gt	Up to 290% increase	150% increase
Well remediation	Not included	Up to 100% at 60% of the cost of a well.	Reduction from 3.8 Gt to 3.3 Gt	Up to 80% increase	Up to 30% increase
Injection facility costs	1x baseline capex and opex.	0.5-2x baseline capex and opex	Range is 3-4 Gt	Up to 34% reduction for 0.5x sensitivity Up to 68% increase for 2x sensitivity	0.5x sensitivity reduces average cost by 19% 2x sensitivity raises average cost by 39%
Well costs	1x baseline capex and opex	0.5-2x baseline capex and opex	Range is 3.2-3.9 Gt	Up to 18% reduction for 0.5x sensitivity Up to 37% increase for 2x sensitivity	0.5x sensitivity reduces average costs by 13%. 2x sensitivity raises average costs by 26%
Transmission pipeline capex	1x baseline	0.5x-2.5x baseline capex per km	Range is 3.7-3.9 Gt.	For 0.5x sensitivity, maximum cost reduction is 34%. For 2x sensitivity, maximum cost increase is 67%	For 0.5x sensitivity, average cost reduction is 13%. For 2x sensitivity, average cost increase is 25%.

Table 7.2: Sensitivity Analysis for Hydrocarbon Fields

The upward shift with increasing discount rate on marginal transmission and storage cost curves for hydrocarbon fields is shown below.

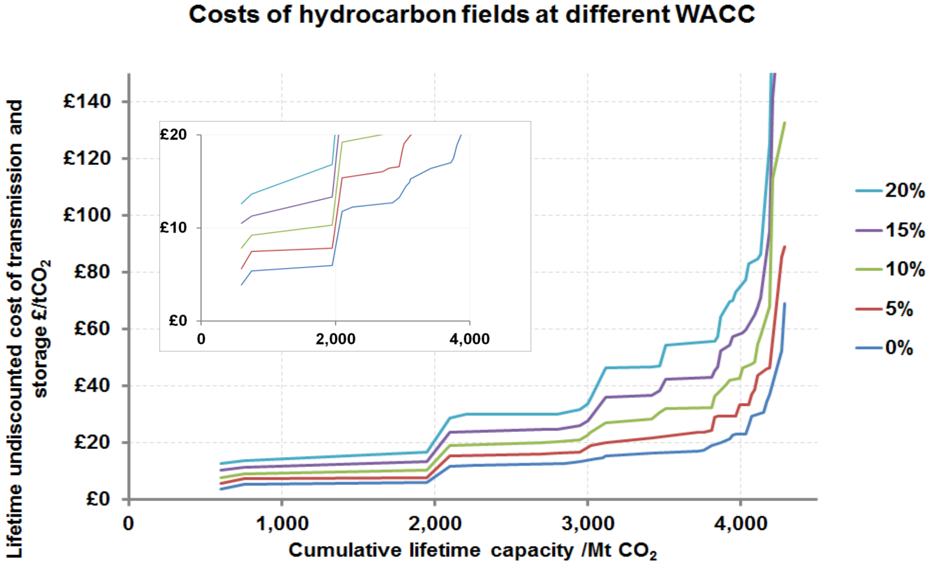


Figure 7.16: Impact of discount rate on the transmission and storage marginal cost curves for hydrocarbon fields. Inset highlights capacity below £20/t.

The impact of discount rate on capacity below arbitrary thresholds at different discount rates is shown below (solid lines, left-hand axis). Whereas discount rates of 20% cause more than an order of magnitude reduction (relative to the baseline) in capacity below £20/t for aquifers, for hydrocarbon fields the equivalent reduction is less than 50%. This can be explained by the lower up-front site appraisal costs for hydrocarbon fields, compared to aquifers. The figure also shows the increase in average cost with discount rate (dashed grey line, right hand axis).

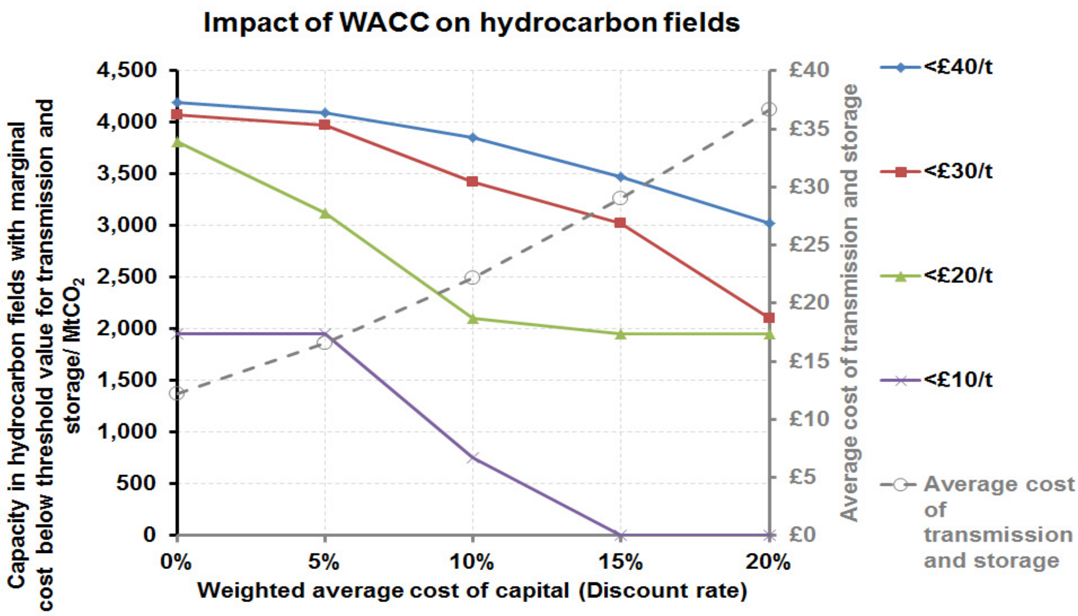


Figure 7.17: Impact of discount rate on the amount of capacity identified with the transmission and storage costs below thresholds of £10/t, £20/t, £30/t or £40/t.

Whereas the costs of injection facilities and wells are important for aquifers, these costs have less impact on capacity below £20/t for hydrocarbon fields. Many of the latter require either few wells (and are lower cost even when injection facilities and well costs double), or otherwise are far from the shoreline and so transmission costs dominate.

The graph below compares costs of storage before and after adjusting the predicted CO_2 injection well performance of hydrocarbon units, in line with that predicted for saline aquifers (Section 4.3). The graph highlights the value of further work to improve confidence in estimates of the number of injection wells required to satisfy various storage scenarios.

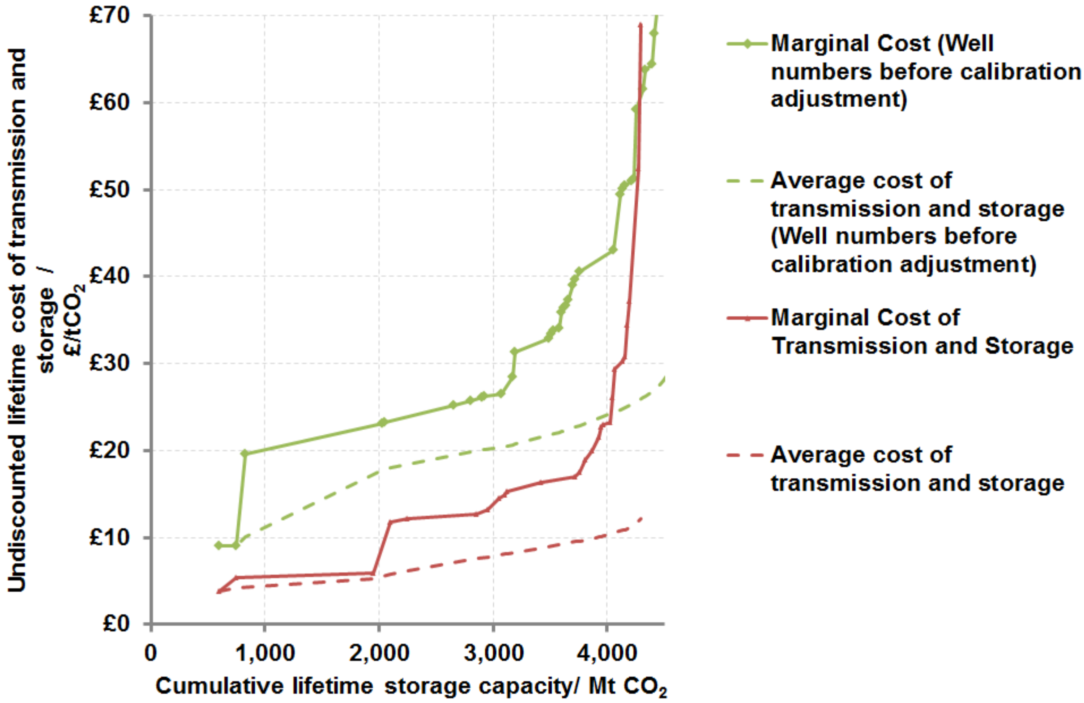


Figure 7.18: Impact of well numbers on undiscounted costs of transmission and storage in hydrocarbon fields.

The green and red lines show costs before and after numerical recalibration of the predicted injection well numbers for hydrocarbon fields respectively. Bold lines indicate marginal costs, dashed lines indicate average costs.

Interestingly, in contrast to aquifers, the cost of accessing hydrocarbon fields is less dependent on well remediation costs. Even in a scenario where all existing wells need to be remediated, with an average remediation cost per well of 60% of the cost of a new well, the capacity with marginal transmission and storage cost below £20/t is reduced from 3.8 Gt in the baseline to 3.3 Gt.

In terms of sensitivity to pipeline infrastructure needs, if the pipeline capital costs per km are reduced by 50%, the average undiscounted cost of transmission and storage is reduced by 13% to £11/t. Conversely, if the average pipeline capital costs per km are doubled, the average cost increases by 25% to £15/t. Alternatively, if the second nearest hub is used instead of the nearest hub, the median increase in undiscounted costs for transmission and storage is 25% (aquifers 20%).

As with aquifers, well redundancy requirements, routing corrections, pipeline opex, well opex, uncertainty in water depth or reservoir depth, all have limited impact.

7.7 Integrated Infrastructure

Previous studies have underscored the benefits, challenges and risks for integrated networks transport CO_2 from sources to sinks, relative to a point-to-point approach. The benefits of integrated networks with multiple sources and multiple sinks can be summarised as:

- Reduced overall system costs
- Provide a means for smaller sources to implement CCS
- Provide a means for accessing the storage capacity in smaller sinks
- Reduced planning and uncertainty (e.g. permitting risk) for sources and sinks, and limited disruption during a single construction (to the environment and to nearby stakeholders).

The challenges of integrated infrastructure can be summarised as

- Need for financing of higher capital cost for infrastructure for a technology still in demonstration phase and with high risk of stranded asset from poor utilisation.
- Need to coordinate design (e.g. capacity, entry specifications, location) among multiple users, potentially more than a decade before eventual utilisation.
- The location of the pipeline is fixed, implying high confidence in capture and storage capacities at the appropriate locations.

UKSAP has identified not only a larger number of potential storage units than previously identified, but also that these units span large areas, and overlap spatially and at different depths. Units in close proximity could be accessed through an integrated transmission and distribution network if pipelines, wells, injection facilities were carefully designed. This situation does occur for oil and gas production. Further work is required to understand how differences in CO_2 injection requirements between units could be managed, but it may be that this provides additional operational flexibility to storage operators. Whilst this could increase up-front complexity, clustering of stores allows for redundancy i.e. backup in the event that an individual store fails.

7.8 Conclusions

- An infrastructure design and economic model has been developed to enable system requirements, infrastructure, and associated costs for transmission and storage to be estimated for each storage unit
- Up to 28 injection scenarios ranging from 2 Mt/yr x 10 yrs (20 Mt stored) to 60 Mt/yr x 40 yrs (2.4 Gt stored) were considered for economic analyses
- The costs of 159 saline aquifers and 27 hydrocarbon fields were calculated in a baseline scenario that assumes maximum utilization of the theoretical capacity available in each storage unit (ie. maximum product of considered injection rate and duration that is less than or equal to the unit's theoretical capacity). The analysis provides the most detailed techno-economic assessment of UKCS storage so far published.

- In this baseline scenario, undiscounted lifetime costs for exploiting individual storage units range from the low £100s of millions to £10s of billions.
- The marginal costs of storage span two orders of magnitude, between ca. £2/t up to ca. £140/t. When the costs of offshore transmission of CO_2 from the nearest gas terminal are additionally included, the combined marginal costs are increased and range from £5-160/tCO_2.
- The low end of predicted costs is in line with previous studies. The maximum storage costs identified in UKSAP are larger than previously estimated because of additional information now available on site appraisal, unit areas, and likely well numbers and spacing that may be necessary to manage pressure build-up.
- Across all units, no individual CarbonStore input controls overall storage costs, although the predicted number of CO_2 wells per Mt CO_2 injected is one of the most important factors. This is because high well numbers increase the costs of wells and their associated injection facilities. For most units, there are significant economies of scale, implying it is usually cheaper to exploit the unit at the highest injection rate and longest duration possible.
- The least cost units have a combination of low well requirements, large capacities, shallow water depths, shallow depth at centroids, low wellhead CO_2 pressures, and proximity to shoreline.
- Among individual sensitivities analysed, the impacts of financing, geological uncertainty (i.e. use of P_{10} or P_{90} estimates of capacity and numbers of wells), scale (either Mt/yr or duration), costs of wells and injection facilities and requirements to remediate existing wells all lead to significant (more than 10%) changes in costs of storage.
- Combinations of sensitivities create significant upside and downside investment risks. An unfavourable combination of high discount rates, use of P90 estimates of capacities and well numbers, need to carry out extensive remediation activity, poor utilisation, and high engineering index prices (or unfavourable currency rates), or restrictions on use of sites with multiple risk factors could lead to a reduction in capacity and increase in costs.
- Actual projects may go ahead with alternative well designs (e.g. larger well diameters, horizontal drilling) than those assumed in this study to reduce the number and hence costs of new wells and associated injection facilities.
- Although infrastructure sharing and re-use was out of the scope of the present analysis, a priority for cost reduction would be to identify the technical feasibility, cost and window of opportunity for re-use or sharing of wells and injection facilities between a CCS project and a hydrocarbon production project or between different CCS projects.

7.9 References

1. Element Energy et al. (2010) for the IEA Greenhouse Gas R&D Programme: CO2 Pipeline Infrastructure: An analysis of global challenges and opportunities. Report available from www.ieaghg.org
2. DNV CO2Wells (2011) - Guideline for the risk management of existing wells at CO2 geological storage sites. Report available from www.dnv.com
3. UKSAP Appendix A7.1.

8 Web-Enabled Database and GIS

8.1 Introduction

The Web-enabled Database and Geographic Information System (GIS) application, or 'WDG', enables storage unit assessment data to be loaded to the project database, computed results to be viewed and interrogated, and downloaded for subsequent processing and manipulation. The following details the architecture of the application development, the technical specifications and the software development lifecycle.

The application has grown significantly from the original design and now has over 25 database tables, over 100 pages of PHP code and 37 user accessible web pages.

The database tables contain some 29 million pieces of information.

8.2 WDG Concept

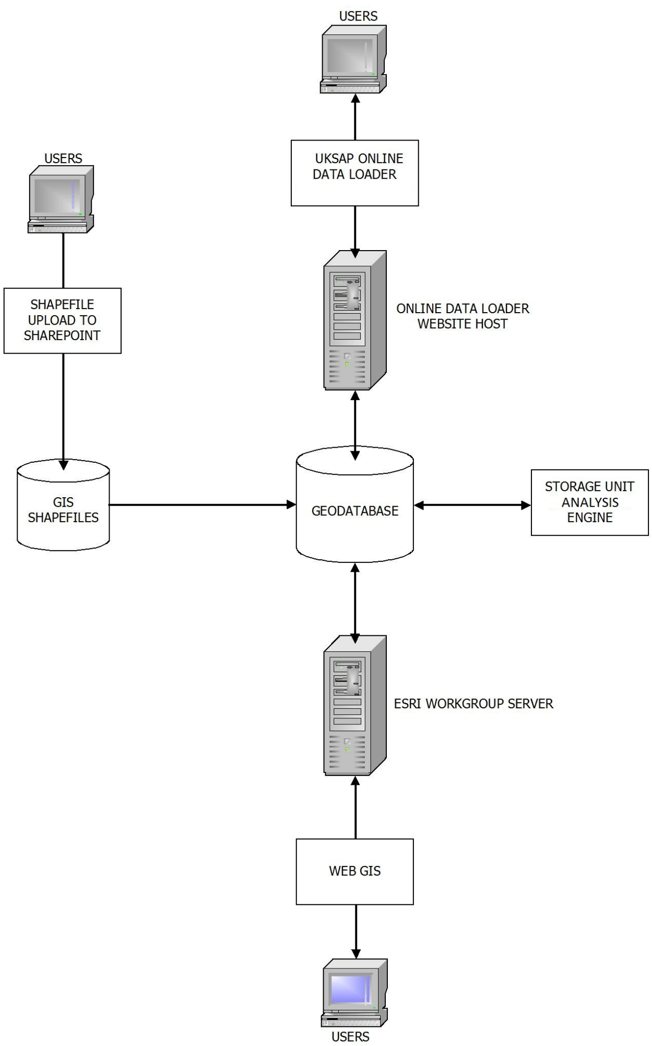


Figure 8.1: Web-enabled Database and GIS Concept

8.3 Database Design

8.3.1 General

The design of the WDG spatial database (db) and its relational links was based on requirements of the UKSAP Consortium members, and evolved from early versions of a data worksheet.

The purpose of the database is to enable entry of all relevant data for each identified storage unit. Functionality of the associated analysis engine then facilitates derivation of carbon storage capacities and associated risk matrices.

Data entry is handled via a series of user “input” pages. To provide an audit trail, information about the last user to enter information is recorded. Each data entry session is also stored separately, creating a historical trail that enables the database to be restored to an earlier date if required.

8.3.2 Database Schema

The Database Schema consisted of four groups, each containing a particular set of data. The groups are as follows:

8.3.2.1 Group 1 – Computed Data

All tables contain computed data for each storage unit, with no versioning.

The "computeddata" table acts as a trigger for the system to recompute results. There is one row per storage unit. Upon saving new data (and thus invalidating the existing computed results) the row is deleted from the "computeddata" table only. This is the signal for all computed data to be recalculated.

8.3.2.2 Group 2 – Storage Unit and Versioned Data

The table "storageunit" is the central table, with one row per storage unit. All other tables are versioned, so that every time new data are saved a new row is created. Calculating the editing data from the tables in Group 2 gives more accurate data in terms of who edited which field when, and while this information is not exposed to the user it can be used to help track down problems.

8.3.2.3 Group 3 – Miscellaneous Tables about Storage Units

The user table holds user accounts. Web pages contain one row for every data entry page the system makes available. Thus these are used in the "comments" table, to track which page they commented on, and in the "author" table, to track when a user edits a page. This editing data could have been worked out from the data tables in Group 2; but because more than one data entry page will be used to enter data for each table, using the "author" gives more accurate data with respect to which data entry page was used.

8.3.2.4 Group 4 – Other Miscellaneous Tables

A variety of tables that assist in administration of the application. It also groups the tables used to create custom downloads of information in comma separated variable (csv) format.

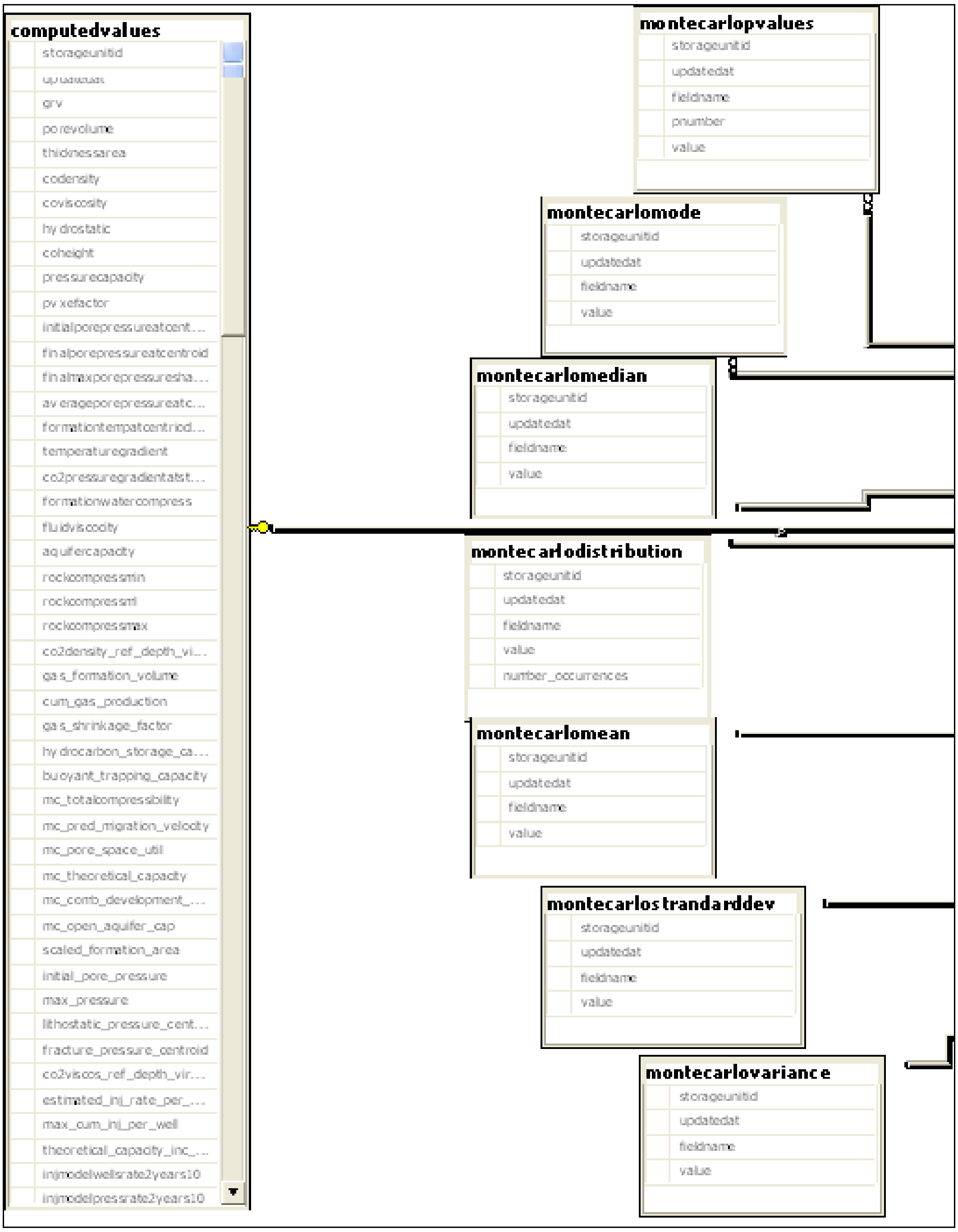


Figure 8.2: Group 1 – Computed Data

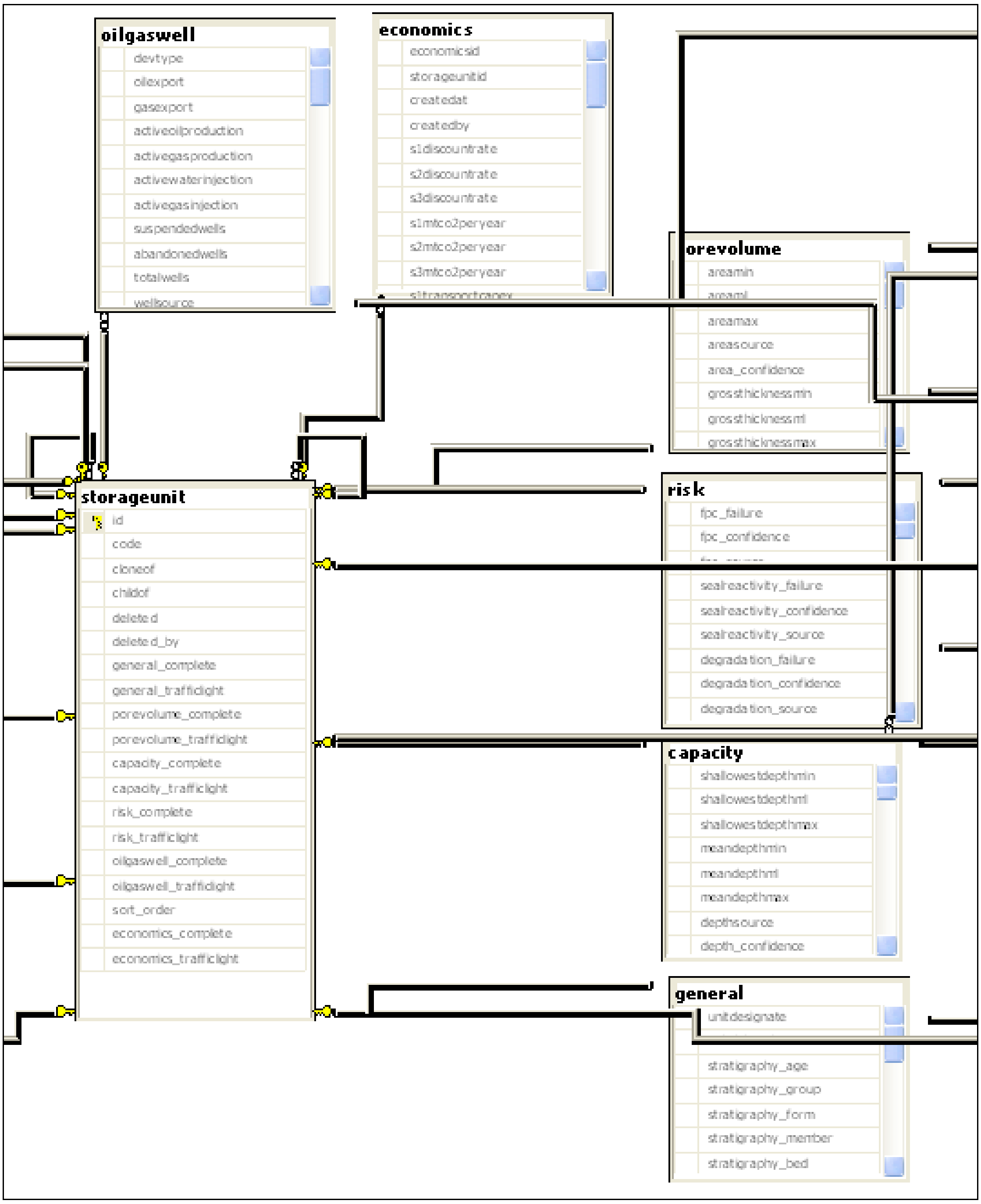


Figure 8.3: Group 2 – Storage Unit and Versioned Data

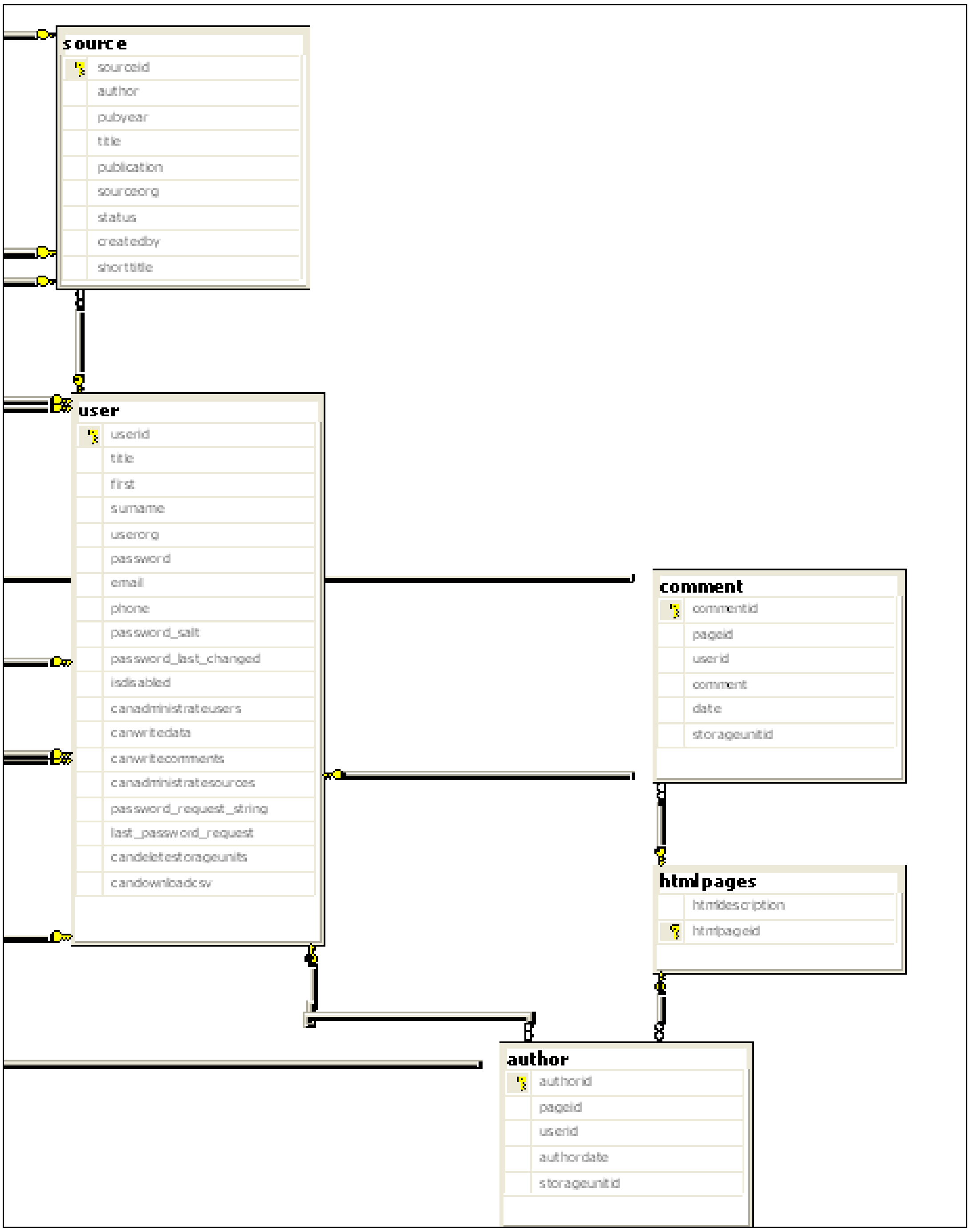


Figure 8.4: Group 3 – Miscellaneous Tables

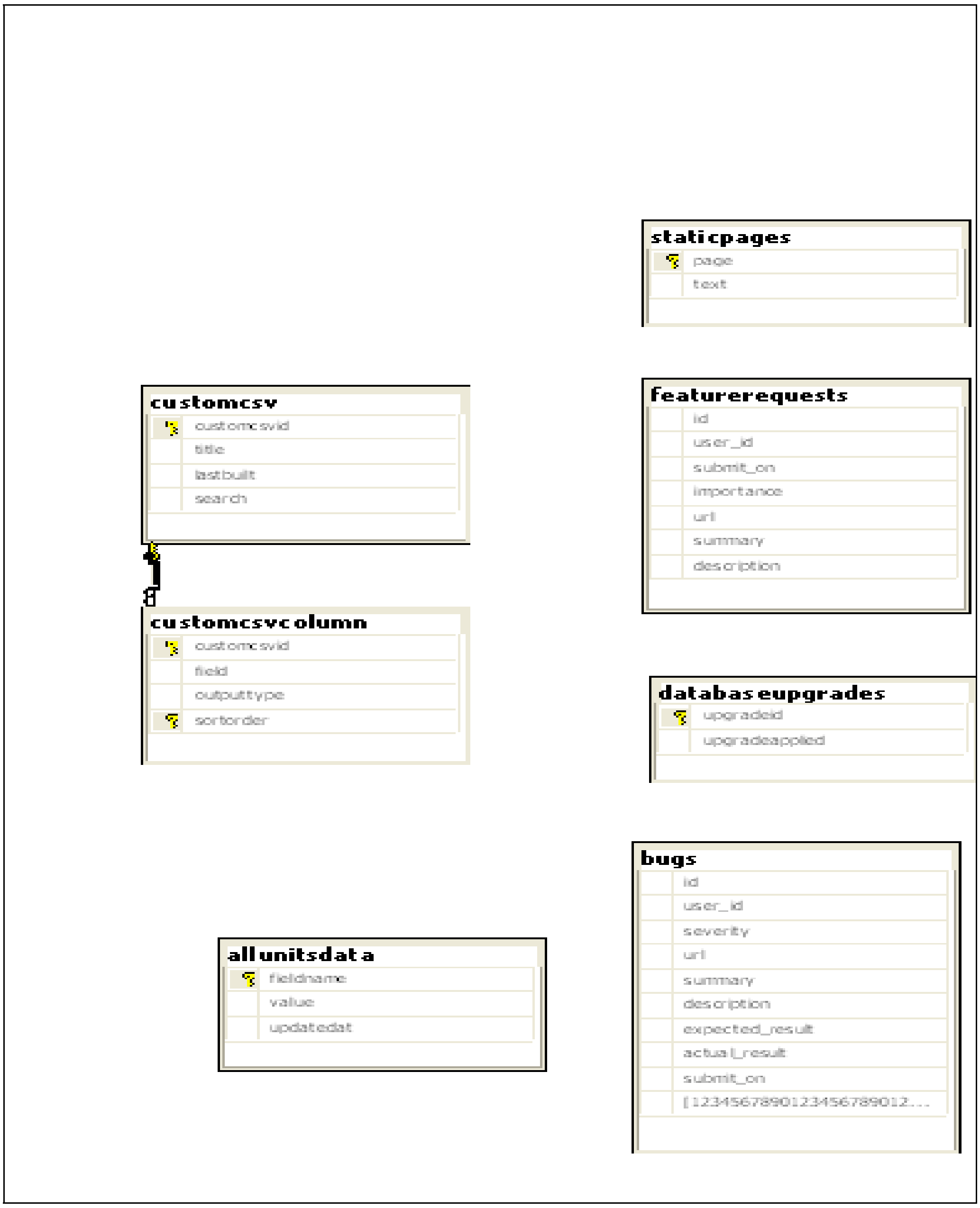


Figure 8.5: Group 4 – Miscellaneous Tables

8.4 Database Administration

A suitable database management system was put in place, and managed by the database administrator (DBA). The role of the DBA was to ensure stability and security of the application. Regular backups were created and stored offsite.

Complexity of the WDG application increased as the project progressed. In the background a series of "tasks" run to ensure all new or edited storage units are passed through the Analysis Engine and up-to-date information is available for download.

8.4.1 Security and Authorisation

The Operation System was continuously monitored and upgraded as and when new patches and security fixes were released by Microsoft. The server was locked down to ensure ports and IP address access was restricted to only authorised personnel and from specific IP addresses.

Access to the UKSAP server is via username and password. Authorisation to access the web application had a tiered approach, starting with a request for a username and password. Once this request had been approved (for example by the database host) an account is set up with appropriate permissions ("read only", "read/write" or "administrator"). Each level gives the user different permissions and functionality within the application. This allows guest users for instance, to be welcomed onto the site in the knowledge that they cannot edit, perform mass downloads or amend underlying databases.

8.4.2 Backup and Recovery

Daily backups were performed and stored on the UKSAP server; weekly backups were stored offsite. The process was automated, and backups transferred to the in-house development server before being written to CD.

The server had an approximate uptime of over 95%, with no major issues and problems encountered over the period of the project.

8.5 Data Loader Website Design

The design of the data loader website facilitates upload of carbon storage data by all authorised assessors.

An auditable QC trail ensures traceability and consistency of data entry, with ability to add comments and peer review entries. The website also performs 'online' QC checks prior to data being submitted to the database, to identify gross errors or inconsistent data entry. These checks also indicate if all pertinent data parameters have been entered to enable completion of the various embedded computations, and that all parameters have a corresponding Reference Source.

Data units follow the international system of units (SI), and each data entry field has the required units listed alongside.

The website has two levels. The first covers general administration and search facilities, and consists of the following pages:

Home

Data Entry

- New Unit
- Search Unit
- Progress Control (made invisible in final release Sept 2011)
- Reference Sources

Overall Capacity

Map

Admin

- Report a Bug
- Request a Feature
- Administer Users
- Email Users
- Download All Units
- Global Parameters

Help

- Computed Parameters
- User help file on Home page

The second level is accessed when a storage unit is selected, and this series of pages displays all data (input and computed) for the unit.

Capacity

- General
- Pore Volume (saline aquifer storage units only)
- Static Capacity (saline aquifer storage units only)
- Fluid PVT (hydrocarbon fields only)
- HC Field Volumes (hydrocarbon fields only)
- Injectivity
- Dynamic Capacity

Risk

- Seal
- Faults
- Lateral Migration
- Wells
- Formation Damage
- Connectivity
- Risk Profiles

Economics

- Economics
- Oil & Gas Wells

Results

- Probabilistic Capacity
- Deterministic Capacity

Tools

- Data Export
- Create a Clone
- Create a Child
- Delete Unit

The pages are designed to be free of clutter, making it simple to see the data and easy to edit information. Users with read/write access can [Edit] the page, enter required changes and then [Submit] or [Cancel]

The last user to edit a page is shown at the bottom along with the date on which changes were made. It is also possible to see all users that have made changes to the pages by pressing [Show All]

Users are able to add a comment regarding the storage unit, allowing queries and discussion to be contained within the site.

8.5.1 Search and Navigate

The functionality enables the user to search the WDG database by going to the Search Unit page, and selecting a series of criteria from drop-down boxes. This filters the available data and provides the user with a list of matching storage units, with summary information on each.

Selecting a storage unit then takes the user to the Level II series of menu pages, starting with the storage unit's General page.

The user is able to easily navigate through the various storage units by pressing [Previous] or [Next]. A search facility also enables the user to enter a storage unit ID, and jump directly to that unit.

8.6 Analysis Engine

A series of formulae and algorithms have been encoded within the WDG application to process raw input data. Pre-selected resultant values are then transferred and stored within the database to allow the web-based GIS to interrogate results.

The analysis engine constants, global variables and algorithms are all contained within one PHP class (Appendix A8.1). As the computation process is quite intensive, the analysis engine works as a Windows Service background process. It is triggered when new or edited input data are added; new input data clear the results databases, which in turn start the analysis engine.

The analysis engine is able to compute probabilistic results using a Monte-Carlo algorithm. Simple triangular distributions (with minimum, most likely and maximum values) are used for the relevant input data. Results are stored at decile intervals of probability (P_{10}, P_{20} & P_{90}) along with the mean and variance of the forecast distribution.

8.7 Web-Enabled Geographic Information System (GIS)

The UKSAP WDG application has an inbuilt GIS enabled map, allowing extensive interaction between users and the underlying storage unit data. The user is able to query the storage units, return a sub-set based on a geographical search, and visualise the spatial relationship between different storage units in plan view.

The GIS software used is ArcGIS Server 10 (Workgroup Edition). The software has an extensive range of functionality, and the following were used in development of the Map page. The tools were embedded in the page using Javascript.

GIS function	Description
Zoom In	Zoom In to a specific area of the map.
Zoom Out	Zoom Out to a wider overview of the map
Pan	Move the focal pointof the map to a different location
Zoom Extents	Zooms Map to the full extent
Point Select	Select an area of the map, centred on the point with a user defined radius. This returns the storage units whose centroids (as defined in the General page) are within this circle.
Polygon Select	Select an area of the map defined by the user created polygon. This again returns storage units whose centroids are contained within the search area.
Clear Selection	Clears the current selection of storage units.
Measure	Measure the distance between two points on the map

The Map is composed of a variety of layers. Each layer contains a specific set of geographical data which can be switched on or off by the user. The storage units have been separated into different Geological Age layers to make visualisation easier; many overlap each other as they are in the same geographical area but at different depths. For a 2 dimensional map, this makes for a cluttered display, unless colour and transparency are carefully selected.

The following geological age layers were created:

- Paleogene
- Upper Cretaceous
- Lower Cretaceous
- Mid/Upper Jurassic
- Lower Jurassic
- Triassic
- Permian
- Carboniferous
- Devonian
- Centroid – this is the centroid of the storage unit as defined on the “General” page.

The following layers provide backgroup contextual information:

- UKCS (UK Continental Shelf blocks)
- Coastline (European coastline)

The geographical search returned from a point or polygon query can be further refined using an "attribute" filter, which returns a sub-set of results based on, for example, a user defined range of capacity.

The bottom of the Map page shows the total capacity of all storage units summed together. Re-running the Monte Carlo analyses to predict parameters of the combined distribution would however, be too slow. The approximation is therefore made that the sum of many distributions, irrespective of their individual shapes, tends to a normal distribution. The parameters of the resultant distribution can then be estimated from:

$$\mathrm{P}_{50}\ \mathrm{overall} = \sum_{i}^{n} \mathrm{P}_{50,\mathrm{i}}$$

$$\sigma^2\ overall = \sum_{i}^{n} \sigma_i^{\ 2}$$

$$P_{90}\ overall = \mathrm{P}_{50}\ \mathrm{overall} - 1.282\sqrt{(\sigma^2\ overall)}$$

$$P_{10}\ overall = \mathrm{P}_{50}\ \mathrm{overall} + 1.282\sqrt{(\sigma^2\ overall)}$$

where n is the number of storage units whose capacities are to be summed.

This principle has been used throughout the project, whenever summed storage capacities are required (for example the summed capacity of all storage units of a particular type, Section 10).

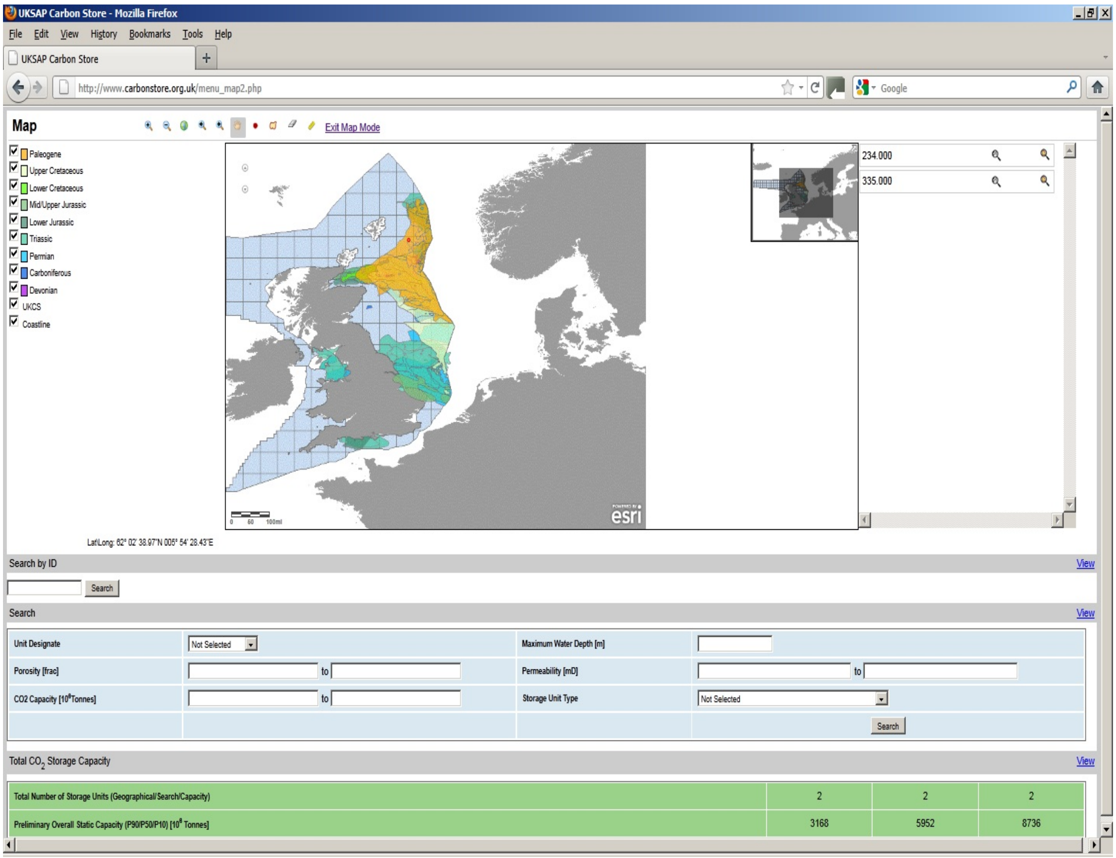


Figure 8.6: Screen-shot of Web-enabled GIS

8.7.1 GIS Developments

Three different development scenarios were presented at the contract stage:

- A 'standard' package, envisaged at the proposal and final contract document
- A 'basic' package, presenting opportunity for financial savings at the expense of GIS functionality
- An 'advanced' package, offering the most powerful set of tools at additional cost

All standard functionality was implemented, along with some advanced features. Additional features that could be implemented in future include:

- Addition of data layers to show emitter sites, bathymetry, pipelines, marine conservation areas etc
- Advanced geographical query to show storage units within a buffer zone from a pipeline, town, emitter
- Improved cartographic display of storage units, especially in relation to showing uncertainty in boundaries and different pressure regions within a storage unit. At the moment some storage units that have large variations in pore pressure have been sub-divided
- Search and result display of storage units based on economic indicators
- Query Builder and Custom Queries enabling complex custom queries to be undertaken by a user, based on multiple attributes and mathematical formula

8.8 Reporting Functions

Several reporting pages have been built into the web application, including:

Overall Theoretical Capacity

This displays the overall theoretical capacity for storage units as selected by the Search criteria. It shows the number of storage units used in the summation, and estimated P_{90}, P_{50} and P_{10} values of the aggregated distribution.

Global Parameters

This web page displays all the global parameters (or constants) used in the Analysis Engine. Where relevant it also displays the Minimum, Most Likely and Maximum values.

Computed Parameters

This web page displays all parameters that are computed. It shows which input and intermediate or pre-computed variables are required to calculate the result. The page provides an insight into why a specific parameter might not be calculated (for example, because one of the input variables is missing).

8.8.1 Storage Unit Results

For each storage unit type ('open', 'closed', saline aquifer or hydrocarbon field etc) different results are calculated. These include the following:

Probabilistic Capacity

This web page displays all the results computed using the Monte-Carlo algorithm. It displays the mean value for all the parameters followed by P_{10} to P_{90} probabilistic capacity. Statistical information is provided for the capacity.

Individual graphs for each of the computed parameters are displayed showing the distribution of Monte carlo results. A regular interval of 100 values is used to create the graph.

Deterministic Capacity

This web page shows the deterministic capacities calculated by the Analysis Engine.

The Estimated intermediate results are also shown.

Risk Profiles

This web page shows three tables: Cost, Capacity and Confidence Risk. These tables summarise the risks as entered in the "Risk" menu section.

8.8.2 Parameter Export

To enable results of the project to be used outside of the web application, an extensive range of download options are available. Ability to use these however, depends on user access privileges as set by the database administrator or host.

Downloads are in comma separated variable (csv) format, with a separate row for each storage unit. Data table parameters are written sequentially for each unit. If the csv file is imported into a spreadsheet, the number of columns may be very large and so a suitable spreadsheet package is required.

The "download all unit" web page has 14 different files available for download. Within each csv file, the unique reference ID of each unit is listed so that they may be joined if required.

The "custom data export" enables custom downloads to be created using user defined criteria. These custom export configurations can be given a name and saved, enabling them to be re-used and shared with other users.

9 Advancing Industry Understanding of CO_2 Storage Capacity in the UK

9.1 Pre-UKSAP Status of CO_2 Storage Capacity Estimates in the UK

Prior to the present study, there was no single estimate of CO_2 storage capacity that covered the saline aquifer and hydrocarbon field potential in all but the most remote areas of the UKCS – as UKSAP now does. Various, predominantly deterministic, resource estimates existed for parts of the UK CO_2 storage potential (e.g. Holloway & Baily 1996, Holloway et al. 2006, Kirk 2006, SCCS 2009). At least some of these estimates were made during the early evolution of CO_2 storage capacity estimation methodologies and the data available to some of them were less than optimal. Moreover, the methodologies used in some of the earlier studies have now been superseded.

9.2 Reasons for Undertaking the UKSAP Study

One of the main reasons for undertaking the UKSAP study was that it was apparent that these pre-existing studies could not provide answers to some of the most important questions about CO_2 storage potential in the UK posed by policymakers and other stakeholders.

Some of these questions, which have been asked on a range of scales, from the entire UKCS to an individual unit of assessment such as a saline aquifer storage unit or hydrocarbon field, are:

- What is the available storage resource?
- What type and magnitude of geological risks are associated with it?
- How much would it cost to utilise the storage potential?

Another way of thinking about this is to consider how much storage resource can be relied on at a range of costs. The UKSAP project set out to answer these questions by providing a fully scientifically defensible, auditable estimate of CO_2 storage potential in the UK.

9.3 What has the UKSAP Project Succeeded in Doing?

In providing an answer to these questions, the UKSAP project has, for the first time:

- Identified and databased the location of the potential storage formations on the UKCS.
- Identified, located and characterised the potential storage units and daughter units within these storage formations.
- Characterised the storage units and daughter units in terms of geological risk.
- Assessed the chances of successful long-term storage in each unit.
- Assessed the costs of storage in each unit.
- Made an auditable, probabilistic estimate of the CO_2 storage resource on the UKCS.

- Constructed storage cost curves at different levels of risk for a variety of sections of the storage resource.
- Developed a GIS, database and calculation engine that can maintain and refine the above.
- Web-enabled the GIS and database.
- Investigated the sensitivity of storage to a range of storage unit features, and thus provided 'storage factors' to enable capacities to be estimated.

It is argued that these achievements have significantly advanced industry understanding of the UK's CO_2 storage potential. Moreover, the flexibility of the approach used in UKSAP, and the data collected, could be used to provide resource estimates for the UK that are directly comparable with those produced by other nations, for example the USGS's technically-accessible storage resource, the German estimate of CO_2 storage capacity in closed structures, and the Netherlands pressure limited resource estimate. That said there is room for further development.

9.4 Potential for Further Development of the UKSAP Study

Although the UKSAP study is completed, the database, GIS and calculation engine will be maintained. There will always be room for further research into the various ranges of capacity and risk-related parameters entered into the UKSAP database and for other improvements.

A major advantage of the UKSAP methodology is that the storage potential is broken down into accessible and easily researched chunks (storage units and daughter units that are amenable to study either individually or as groups (e.g. all the storage units in a single reservoir formation). One of the simplest steps forward would be to prepare assessment reports for selected storage units or daughter units. These could be added to the GIS as linked text documents and could provide evidence as to how the ranges of various parameters in the database were derived. They could also provide information on whether the risk associated with any particular storage unit could realistically be reduced by further data acquisition or analysis.

Another avenue for further development could be to provide information from less promising areas for CO_2 storage. That is, areas where reservoir formations are present but are not at depths >800 m or are not sufficiently well understood to clearly identify any storage potential at present. Examples might include the Bristol Channel Basin and the St George's Channel Basin.

A third avenue could be to include the more remote areas of the UKCS that are currently considered to be too far from potential sources of CO_2 to warrant inclusion in the database, e.g. West of Shetland.

Finally, there is scope to estimate the increases in capacity that could be obtained by using advanced engineering techniques such as the use of pressure management wells, steering CO_2 plumes by withdrawing brine from the storage reservoir at selected points, alternating water injection with CO_2 injection and enhanced oil or gas recovery.

9.5 References

1. Bradshaw, B.E., Spencer, L.K., Lahtinen, A.C., Khider, K., Ryan, D.J., Colwell, J.B., Chirinos, A., & Bradshaw, J., 2009. Queensland carbon dioxide geological storage atlas. Compiled by Greenhouse Gas Storage Solutions on behalf of Queensland Department of Employment, Economic Development and Innovation.
2. Brennan, S.T., Burruss, R.C., Merrill, M.D., Freeman, P.A., and Ruppert, L.F., 2010, A probabilistic assessment methodology for the evaluation of geologic carbon dioxide storage: U.S. Geological Survey Open-File Report 2010–1127, 31 p., available only at http://pubs.usgs.gov/of/2010/1127.
3. Capacity and Fairways Subgroup of the Geologic Working Group of the DOE Regional Carbon Sequestration Partnerships 2006. Methodology for Development of Carbon Sequestration Capacity Estimates. Appendix A in: Carbon Sequestration Atlas of the USA and Canada. Available at: http://www.netl.doe.gov/technologies/carbon_seq/refshelf/atlasIII/index.html
4. Carbon Storage Task Force 2009. National Carbon Mapping and Infrastructure Plan – Australia. Available at: http://www.ret.gov.au/resources/Documents/cst/DRET%20NCM%20Full%20Report-web.pdf
5. Kirk, K.L. 2006. Storing carbon dioxide in the rocks beneath the East Irish Sea. Proceedings of the GHGT-8 Conference, Trondheim, Norway, 19-22 June 2006.
6. Holloway, S & Baily, H.E. 1996. The CO2 Storage Capacity of the United Kingdom. Pp 92-104 in:
7. Holloway S. (Ed.) The Undergound Disposal of Carbon Dioxide. Final Report of Joule II Project No. CT92-0031. British Geological Survey, Nottingham.
8. Holloway, S., Vincent, C.J. & Kirk, K.L. 2006. Industrial carbon dioxide emissions and carbon dioxide storage potential in the UK. DTI Report No. COAL R308, DTI/Pub URN 06/2027.
9. Ogawa, T., Nakanashi, S., Shidahara, T., Okumura, T. & Hayashi, E. 2011. Saline-aquifer CO2 sequestration in Japan - methodology of storage capacity assessment. International Journal of Greenhouse Gas Control 5: 318–326.
10. Scottish Centre for Carbon Storage 2009. Opportunities for CO2 Storage around Scotland an integrated strategic research study. Available at: http://www.geos.ed.ac.uk/sccs/regional-study/CO2-JointStudy-Summary.pdf.
11. Van der Meer, L.G.H. & Egberts, P.J.P. 2008. A General Method for Calculating Subsurface CO2 Storage Capacity. Offshore Technology Conference Paper OTC 19309.

10 UK Storage: Effective Capacity & Exploitation

Having assessed the theoretical capacity, security of storage and economics of each unit as permitted by available data, results have been aggregated to provide a picture of where the UK's CO_2 storage potential is located, how it is distributed between different types of geological store, and what is required in order to allow its effective exploitation. This overall landscape is now discussed with reference to some of the key questions facing development of a large-scale CCS industry within the UK.

10.1 Does the United Kingdom have Sufficient Storage Capacity?

In accordance with the methodologies described in this report, the UK Storage Appraisal Project has identified that at the 90% confidence level the UK has theoretical storage capacity of some 71 Gt (10^9 tonnes), rising to 85 Gt at the 10% confidence level. These confidence levels refer only to uncertainty in the quantified pore volume, the percentage of that pore volume that may be occupied by stored CO_2, and density of the stored CO_2 itself; they do not include consideration of security of storage nor economics.

The P_{10} / P_{90} spread is 20%. Though a considerable 'portfolio effect' is to be expected (the overall capacity is an aggregate of 572 individual storage unit capacity distributions), a wider spread might be anticipated at this level of study. Reasons for the narrow range include an assumption that all distributions are independent, and that in providing auditable estimates assessors have arguably been constrained by published data rather than *perception* of how wide the uncertainty might actually be.

The minimum storage scenario considered for economic analysis was supply of 2 Mt CO_2 per year for 10 years: 20 Mt (10^6 tonnes) stored. Around 240 individual storage units fail to satisfy this requirement, based even on their upside (P_{10}) theoretical capacities. Half of these are 'closed' saline aquifer stores that are either volumetrically small or whose initial pressure is close to fracture pressure; the remainder are hydrocarbon fields that are again either small or operated at a Voidage Replacement Ratio close to 1.0. The combined impact on UK storage capacity is nevertheless small, and without them overall P_{90} and P_{10} capacity estimates are 70 and 83 Gt respectively.

Almost 90% of assessed capacity exists in saline water bearing formations ("saline aquifers"), with approximately equal proportions in 'closed' and 'open' systems. The former offer an advantage of physical limits to the migration of injected CO_2 – the 'no flow' boundaries that enclose the storage unit. Since in-situ water cannot escape however, (in the absence of other intervention) pore pressure will increase with the amount of CO_2 stored such that ultimately there is risk of seal failure via reactivation of faults or propagation of hydraulic fractures. 'Open' units on the other hand allow pressures to relieve, but at the cost of unconstrained migration of CO_2. A potentially large (and ill-defined) footprint thus needs to be monitored, both during and for extended periods after injection, to ensure that the CO_2 is permanently and safely stored.

A particular sub-set of aquifers assessed as 'open' are the chalk reservoirs (7.7 Gt combined capacity). Little is known about the likely dynamic performance of these stores; their pore volume is large but permeability of the rock matrix itself could be extremely low, severely limiting achievable injection rate unless there is connection to natural, conductive fractures. Even then, there would be limited tendency for CO_2 to leave the fracture network and enter the larger storage volume offered by pores in the rock matrix (unlike spontaneous imbibition of injected water into the matrix of many fractured carbonate oil reservoirs, for example). On the other hand, chemical reaction between dissolved CO_2 and the rock might enhance permeability. Due to the complexity of modelling such geochemical and 'dual permeability' effects, coupled with limited data with which to constrain predictions, the chalk reservoirs were not studied in detail. Their associated capacity estimates are therefore considered more speculative.

Structural and stratigraphic traps offer a further type of storage system. The scope of this project has been such that only large, previously mapped water bearing structures have been described as discrete storage units, existing primarily in the Bunter Sandstone Formation of the Southern North Sea (7.9 Gt), with lesser capacity (0.5 Gt) in the Ormskirk Sandstone Formation of the East Irish Sea Basin. Though other water bearing traps undoubtedly exist (confinement of CO_2 in minor structural features of the Utsira formation is seen at Sleipner for example), these will require additional seismic interpretation and mapping before their associated storage capacities can be assessed. Such structures (like many of the Bunter examples) may be faulted at their crests, and if these faults are conductive then secure storage would be compromised. If however seal integrity is preserved and the structure remains well connected to a larger associated pore volume, there is potential for both migration of relatively buoyant CO_2 to be limited (by virtue of the physical dimensions of the trap), and displacement of brine to alleviate pore pressure increase. Thus the benefits of both 'closed' and 'open' systems are potentially combined. A degree of interference would nonetheless be anticipated between adjacent structures, because of the in–situ brine displaced; a correction for this effect has been included in the combined capacity estimate of multiple neighbouring structures.

One of the greatest uncertainties though, is whether or not a storage unit is indeed 'open' or 'closed'; or perhaps more appropriately, the length-scale over which it *behaves* as one extreme or the other. This is particularly difficult to assess in normally pressured water bearing formations, or where there has been no observation of dynamic effects accompanying either the extraction or injection of fluids.

Depleted hydrocarbon fields thus offer many attractions in terms of potential sites for CO_2 storage. Accumulation over millennia of relatively buoyant oil or gas at least demonstrates a certain effectiveness of seal, and measured production, injection and pressure data provide insights as to the hydraulic connectivity of the potential storage formation – both on the scale of the field itself, and beyond to the associated aquifer. Numerous penetrations of the caprock by perhaps old and poorly completed/ abandoned wells however, add to concerns regarding potential leakage paths. The overall storage capacity on offer is also limited (~12% of the total, though it should be noted that this does not include additional storage that might be accessible through CO_2 Enhanced Oil or Gas Recovery (EOR/ EGR) projects). In addition, prediction of when a particular field is likely to become available for storage is complicated by aspects such as advances in technology, tie-back of satellite developments, security of energy supply, and oil or gas price, all of which may influence the economic life of the field.

Storage Unit Type		Theoretical Storage Capacity [Gt CO_2]		
		P_{90}	P_{50}	P_{10}
Saline Aquifers	'Closed'	27.4	31.3	35.2
	Structural Trap	6.8	8.4	10.0
	'Open' – non chalk	15.9	20.8	25.6
	'Open' – chalk	6.7	7.7	8.9
Oil Fields		2.6	2.8	2.9
Gas/ Gas Condensates		5.8	6.0	6.2
Overall		**70.4**	**77.0**	**83.5**

Table 10.1: Overall UK CO_2 Storage Capacity in Offshore Geological Formations

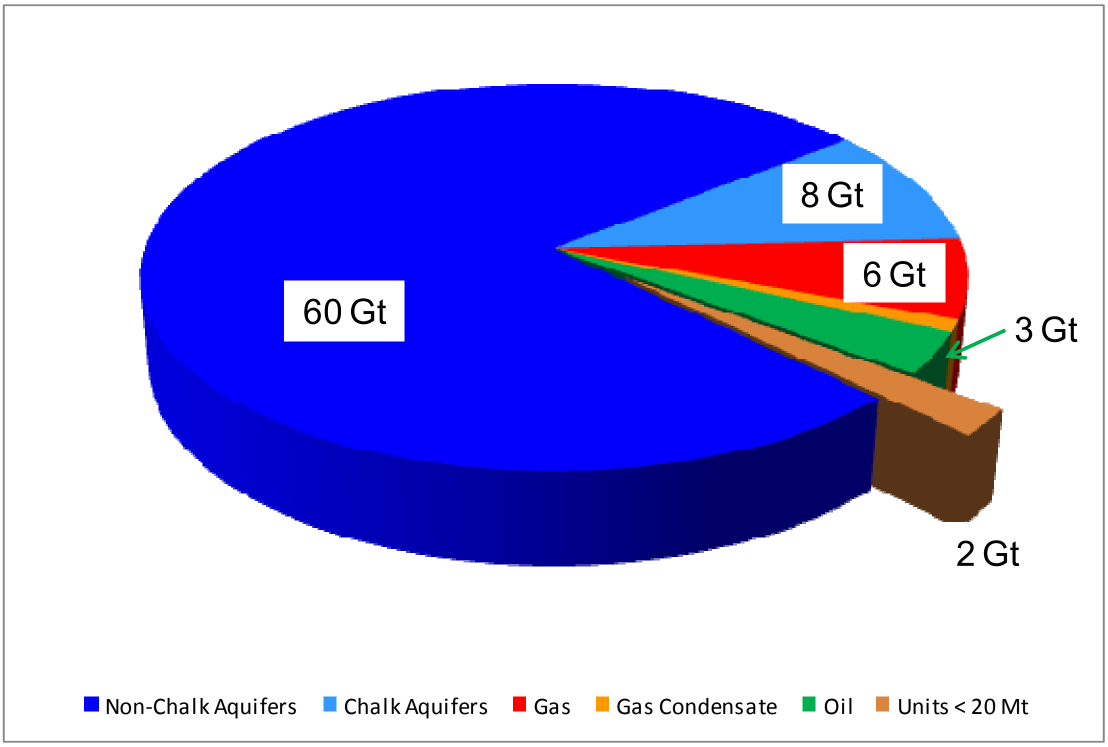


Figure 10.1: Overall UK CO_2 Storage Capacity in Offshore Geological Formations

The project has also evaluated likely injectivity at each storage unit, and considered various injection scenarios from a minimum of 2 Mt per annum for 10 years (‘demonstration’ scale, storing 20 Mt of CO_2) to 60 Mt per annum for 100 years (sequential full-scale projects, storing up to 6 Gt). As a result of this analysis, 8 Gt are at risk because either reservoir quality is so poor (4 Gt), or difference between initial and fracture pressure so small (4 Gt), that it would take an unreasonably long time to utilise all capacity theoretically available. This still leaves overall UK capacity in excess of 60 Gt.

Based on UK Committee on Climate Change (UKCCC) and Carbon Capture and Storage Association (CCSA) projections of ‘low carbon’ electricity generation, the UK storage requirement is for between 7.5 and 20 Gt over the next 100 years, dependent on the precise scenario of energy demand and low carbon technologies mix. In simple terms then, it would appear that with relatively high confidence the UK does indeed have sufficient storage capacity in offshore geological formations to meet its projected CCS requirements.

It must nonetheless be stressed that the maturity of current storage capacity estimates is such that very little (if any) of it may be considered ‘proven’. In terms of the classification system proposed by Gorecki et al (2009), the overall resource estimate may at best be considered at the lower bounds of “contingent”, in that consideration has been given to geological heterogeneity, trapping mechanisms and project economics.

The security of storage assessments set out in Section 6 and included within CarbonStore provide a rich picture of potential risks associated with storage in each saline aquifer unit. It is perhaps tempting to use these to rank or categorise units, for example into “Low/ Medium/ High” risk groups, and suggest combined capacities for each sub-set. Such methods of aggregation, and boundaries between categories, are however wholly subjective. It is also easy to lose important detail, for example assigning overall ‘low’ risk when just one risk element is in fact critical, and on its own could dramatically affect viability of a unit. Conversely a unit with many ‘high risk’ elements might ultimately prove attractive, once more appraisal information is acquired or appropriate risk mitigations put in place.

Similarly, setting an arbitrary cost threshold to provide an estimate of ‘overall economic capacity’ prejudges what ‘economic’ might mean in future; the marginal transport and storage cost curves in Section 7 show a steady rise in cost per tonne of CO_2 stored, with only a small amount of capacity at the far right associated with rapidly rising cost.

As additional appraisal information is acquired it is expected that certain storage units will, either in their entirety or at least in part, be deemed unsuitable for reasons of containment security, operational considerations or cost. This is not unlike the experience of the hydrocarbon industry, where many prospects never make it to development. Equally however, others will prove to offer greater storage capacity, perhaps because of better quality, more extensive reservoirs than currently thought, or as a result of advances in technology.

10.2 How is UK Offshore Storage Capacity Distributed?

Potential CO_2 storage locations have been identified in all areas of study, though over 50% lie beneath the waters of the Central North Sea (approximately the area east of Berwick to the Orkneys). The bulk of the remaining capacity is split equally between the Southern North Sea (East Anglia to Teeside) and Northern North Sea (east of Shetland).

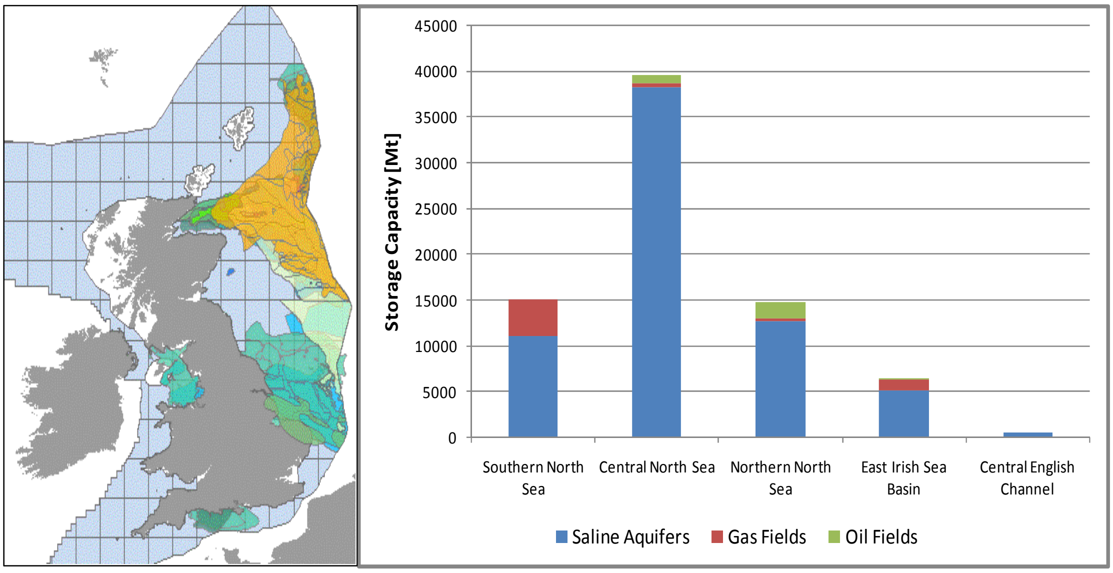


Figure 10.2: UK (P_{50}) CO_2 Storage Capacity in Offshore Geological Formations by Region

In the East Irish Sea Basin, saline aquifer storage capacity has been identified in the Ormskirk and Collyhurst Sandstone Formations. The former often shallows to less than 800 m TVDSS however, and reservoir quality of the latter is suspected of being poor; more data are required.

There is limited capacity in the western English Channel, in the Sherwood Sandstone. The Wytch Farm oil field, which lies beneath parts of east Dorset and Poole Harbour, has not been included in the capacity estimates because it is classified as an onshore field by DECC.

As well as geographical distribution, overall storage capacity may be viewed in terms of how it is split within each of the major classifications of saline aquifer, gas fields and oil fields.

Of ~240 saline aquifer stores assessed as having P_{10} capacity greater than 20 Mt, the 30 largest collectively account for 63% of the total; 14 have P_{50} theoretical capacities of greater than 1 Gt (45% of the total).

The storage capacities of individual depleted hydrocarbon fields are generally considerably smaller. Only the Leman and South Morecambe gas fields and Brent oil field have P_{50} capacities greater than 500 Mt, and in the 100 – 500 Mt range there are 14 gas fields and 5 oil fields. Together these contribute 70% of the overall P_{50} capacity associated with depleted hydrocarbon fields.

Thus the bulk of overall capacity offered by each class is found in relatively few stores. In terms of development of a large-scale UK CCS industry, this suggests a couple of distinct scenarios: either development of, and hence reliance upon, relatively few large capacity stores with many capture sources feeding the same storage complex; or clustering of many smaller and potentially independent stores to provide the total capacity required. The technical and commercial risk profiles of each could be substantially different, and warrant further investigation.

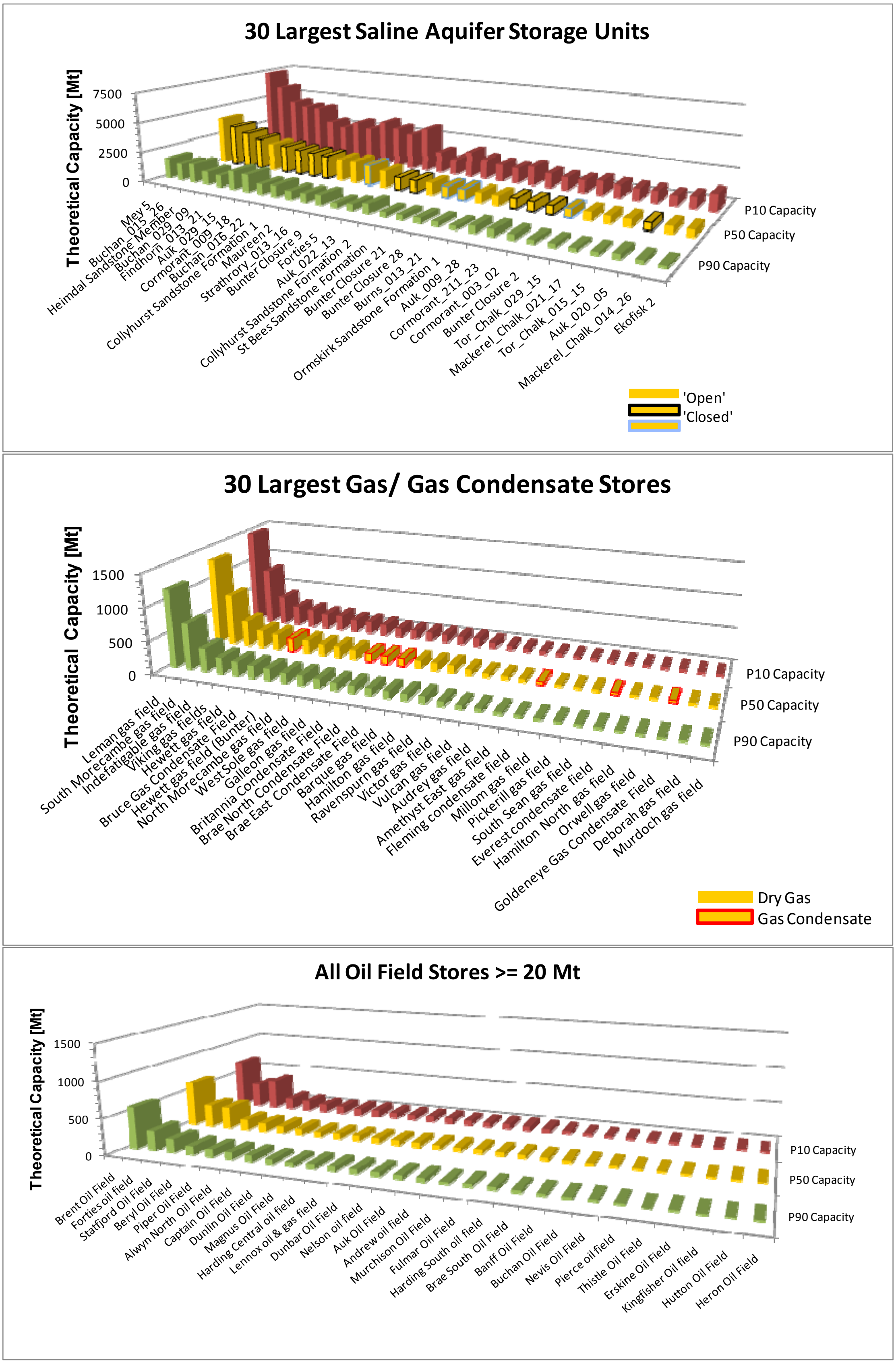


Figure 10.3: UK CO_2 Storage Capacity in Offshore Geological Formations by In Situ Fluid Type

10.3 When will the UK's Storage Capacity be Available for Use?

Although simple volumetrics suggest the UK ultimately has sufficient capacity to meet its needs, the question remains as to whether this will be available for use in time to meet increasing annual targets of UK CO_2 emissions to be captured and stored.

The majority of potential stores require further work to demonstrate to permitting authorities that they are indeed suitable for long-term safe and secure CO_2 storage. For many depleted hydrocarbon fields, providing the required level of confidence may prove simpler by virtue of subsurface knowledge gained during production operations. The UKCS hydrocarbon fields however, collectively offer only about 12% of overall capacity and many are due to continue producing oil or gas for many years to come. By contrast, the much larger storage potential offered by saline aquifer sites is less well characterised, particularly in terms of dynamic performance. The remaining appraisal task is thus substantial, though one would expect that due either to physical proximity or application of learning from early CCS projects, that the burden of appraisal for subsequent sites would reduce with time.

Taken together then, access to storage capacity about which most is known is delayed by continuing hydrocarbon production, and is ultimately limited in size; the generally larger saline aquifer storage units require more effort in terms of further appraisal (particularly for earlier projects) before they are ready for storage operations to commence.

On the other side of the equation, various curves have been suggested to describe the likely profile of CO_2 storage demand. In the UK this is likely to be dominated by ambitions to decarbonise fossil fuel power generation. The UKCCC has suggested a target of 10 GW fitted with Carbon Capture and Storage by 2030, increasing to 15 GW by 2050; the CCSA has proposed more ambitious targets of 20 – 30 GW by 2030, and 30 – 40 GW by 2050. If a 50:50 mix of coal and gas fired plant is assumed, requiring approximately 5 Mt CO_2 capture and storage per GW, the following profiles may be derived:

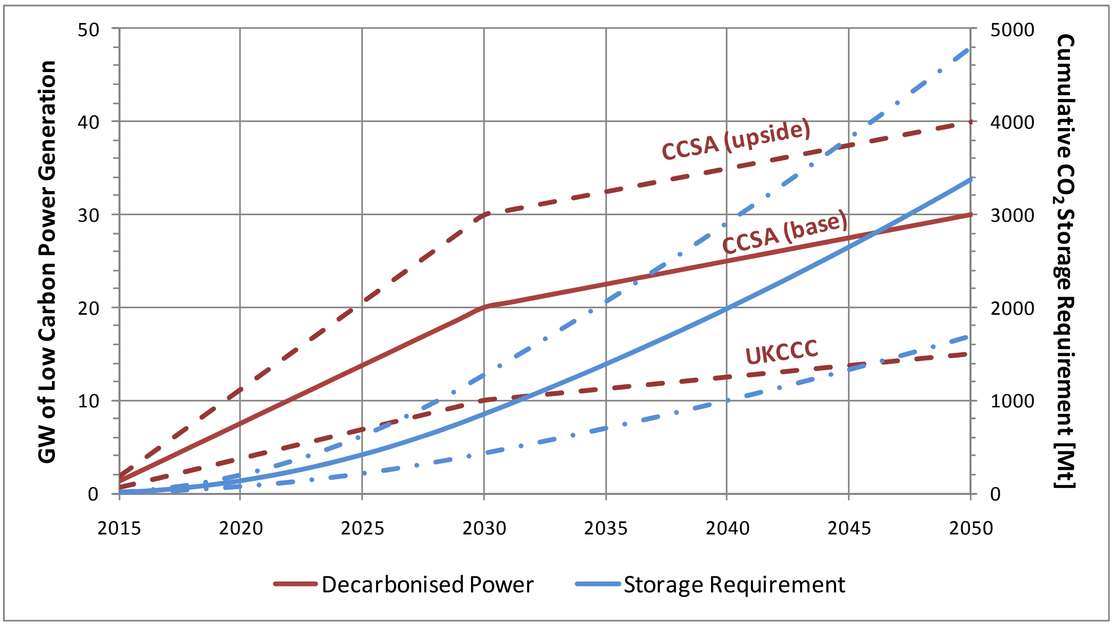


Figure 10.4: UK CO_2 Storage Demand arising from Decarbonised Fossil Fuel Power Generation

Thus, dependent on the scenario considered, of the order of 2 – 5 Gt of CO_2 storage capacity will be utilised over the next 40 years.

Taking UKSAP estimates of depleted hydrocarbon field storage capacity and current expected Close of Production dates, the theoretical storage capacity profile of the UK's oil and gas fields is depicted below:

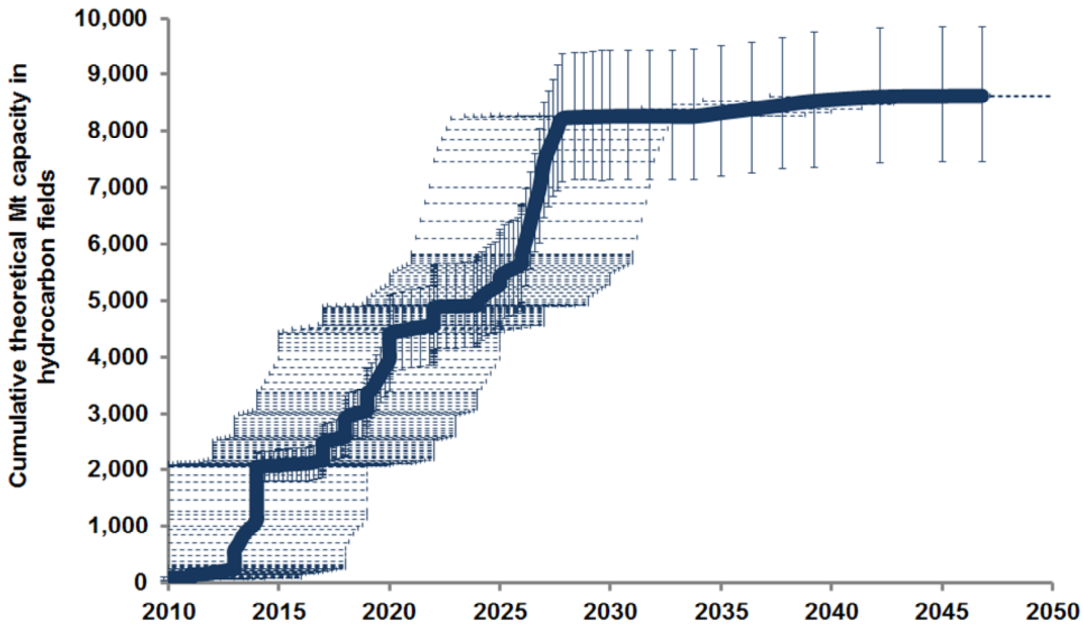


Figure 10.5: Availability of Storage in UKCS Depleted Hydrocarbon Fields.
(assumes CO_2 injection commences at expected Close of Production date and analysis excludes availability of fields through CO_2-EOR. Y-error bars show P_{10} and P_{90} capacity estimates; X-error bars show +/-5 year uncertainty in CoP)

At first glance this might suggest that, up until the middle of the century at least, the UK's CO_2 storage requirement may be comfortably met by depleted oil and gas fields. However, there are a number of factors that merit further consideration:

- Not all depleted hydrocarbon fields will prove suitable for CO_2 storage, for example due to limited capacity, and remoteness from other suitable storage sites and/ or capture sources;
- The above profile assumes all capacity becomes available on the Close of Production date – this may be true from the perspective of permitting, but of course the operational day-to-day disposal requirement must also be matched, and in some cases injection rate may be limited due to relatively poor reservoir quality. This could mean that it takes many decades to fully utilise the available capacity;
- Close of Production dates are notoriously difficult to predict, and field life is often extended through application of emerging technologies, or tie-back of newly economic prospects and other discoveries.

Of equal importance however, is the notion that in order to commit large-scale investment in either retrofit or new build power generation with CCS, it is likely that at the point of project sanction *guaranteed* storage capacity will be required for a large part, if not all, of the asset's life. Furthermore, taking account of storage site appraisal, permitting, engineering design and construction, it is easy to envisage that storage capacity might need to be identified some 10 – 15 years before first injection.

Thus, in practical terms, there are tendencies to in effect accelerate the demand curve, and suppress the availability of theoretical storage capacity in depleted hydrocarbon fields. In conjunction with potential opportunity to store CO_2 emissions from Europe, this suggests that early appraisal of saline aquifer storage units would be prudent.

10.4 What is the Cost of Storage in Offshore UK Formations?

A model for assessing infrastructure requirements, and estimating costs for offshore transmission and storage of CO_2 has been updated and developed. Storage costs included site appraisal, offshore distribution pipelines, offshore fixed facilities and CO_2 wells. Offshore transmission costs include shoreline pressure boosting, transmission pipeline, and where necessary, offshore hubs and offshore pressure boosting. As a sensitivity, the impacts of requirements for well remediation were also assessed.

The costs of storage are highly sensitive to assumptions on injection scenario (i.e. Mt/yr throughput and project duration) and financing assumptions. For nearly all units the costs of storage decrease with increasing lifetime CO_2 stored. For simplicity and transparency, in the baseline the costs are reported as undiscounted with marginal costs reported at the highest lifetime capacity.

The undiscounted costs of storage of 44 Gt in 159 aquifer units (or daughters) are shown to span two orders of magnitude from £2-£115/tCO_2 stored (P_{50} estimate). The average cost if all units are exploited independently is £15/tCO_2 stored. Considering the UKCS as a whole, the marginal storage costs in aquifers increase smoothly (i.e. with no apparent step changes) up to 40 Gt, rising steeply thereafter.

The costs of storing 4.3 Gt in 27 hydrocarbon fields have been modelled as spanning £3-£34/t, with an average storage cost of £7.7/tCO_2.

Across all units, no single input parameter drives storage costs, i.e. the shape of the marginal cost curves result from the interplay of all factors in the cost model. The highest positive correlations with storage cost are observed with the number of wells per MtCO_2 injected and the number of injection facilities required. The cheapest aquifers are the structural or stratigraphic traps (including gas fields) in the Southern North Sea and East Irish Sea. The units have limited appraisal requirements and good injectivities. The most expensive units are open units in the Central North Sea and Northern North Sea which have a combination of low permeabilities (implying large numbers of wells) and large appraisal requirements.

When the costs of transmission to the nearest shoreline hub are additionally included, the range of costs spans £3.5-£148/tCO_2. Though transmission costs obviously increase if shoreline hubs that are further away from the sink are chosen, the impact on the combined transmission and storage cost is generally less than a factor two, assuming that transmission pipelines can accommodate substantial pressure drops.

It was found that the ratio of the components of the costs differs substantially between units, and for any given unit, on the injection scenario explored. As such it is not possible to define an 'average' breakdown of costs among the 15 elements of the cost model.

In the absence of a clear cost threshold (in £/tCO_2) for CCS viability and clarity on the market and regulatory environment for CCS deployment (which could translate to a specific discount rate), there is no unique assessment of 'economic capacity'. Whilst the use of a cost threshold facilitates comparison of scenarios, it should be remembered that the higher the threshold the higher the capacity. It should also be noted that the actual site storage costs and capacities may differ as a result of site-specific issues that have not been considered in this study.

Well remediation could increase storage costs for both aquifers and hydrocarbon fields. Analysis of both aquifer and hydrocarbon field data reveals an overall sensitivity to CO_2 injection well number, design, cost, spacing, and, at high discount rates, phasing of construction. These will also influence the requirements (and hence costs) for injection facilities.

10.5 How Reliable are UKSAP Results?

The project's objective has been to assess overall UK CO_2 storage capacity in offshore geological formations, using consistently applied, defensible and auditable methodologies. The latter in itself implies use of public domain, rather than proprietary or confidential information. In combination with the fact that abundant appraisal data have simply not yet been acquired in certain areas (particularly away from known hydrocarbon provinces), it is evident that aspects of assessment will have been made on 'incomplete' data, or for certain storage units perhaps omitted altogether. Nonetheless, the documented approach allows project results to be updated, or gaps to be filled, in light of newly acquired or available information.

In addition to estimates of storage capacity and economics, the security of storage was assessed for each (saline aquifer) unit using a Features, Events and Processes approach. Uncertainty associated with source data and measures of confidence that can be placed in them were incorporated. Thus each storage unit has a predicted *range* of theoretical capacity, and a matrix describing the likelihood and severity of various mechanisms that could impact either its assessed capacity, or transport and storage costs. The assessments also provide insight as to what additional information might be sought in order to reduce uncertainty in, and increase the reliability of, current estimates.

The project's intent was not however, to rank the UK's potential storage locations in terms of 'desirability', or order in which they might be appraised or developed. Such rankings are largely subjective, and reflect different approaches to risk of those performing the ranking exercise. The project database nonetheless provides a wealth of information with which storage units may be compared and contrasted from many different perspectives.

The overall conclusion arising from project results is that the UK does indeed have sufficient offshore storage capacity to support its aspirations for CCS as an abatement technology for greenhouse gas emissions. The expectation is that as a result of further appraisal, the assessed storage capacity of some units will decrease or disappear altogether; and that of others will increase. But with a high level of confidence, the overall capacity will remain sufficient.

The degree to which CO_2 emissions from elsewhere in Europe could be accommodated is less certain, and crucially depends on the rate at which theoretical capacity in large saline aquifers can be promoted to 'proven' resource. The latter requires further appraisal of storage reservoirs and their sealing lithologies, and that appraisal will ultimately require drilling of wells in order to obtain direct formation evaluation data. One question therefore, is the rate at which the current UKCS mobile drilling fleet (and its crews) can be either augmented, or redeployed from hydrocarbon to CCS activity. Precise requirements of licensing authorities will also have an impact on the time required to interpret newly acquired appraisal information, and build a sufficiently robust case that a permit to store CO_2 may be issued.

10.6 Key Challenges Facing Exploitation of UK Storage Potential

In order to unlock the UK's CO_2 storage opportunity and convert it into a successful emissions reduction industry, a number of challenges must be addressed:

10.6.1.1 Resource Classification and Permitting

Promoting 'accessible pore volume' to 'proven' storage capacity is a non-trivial, time-consuming process. The essence of what is required is well understood, and to help build the required framework many parallels may be drawn with other resource-based industries (particularly oil and gas). There are however, specific issues regarding demonstration of long-term safe and secure storage, and eventual transfer of liability for the storage site to the State.

In order to plan, and hence estimate the time and cost of necessary appraisal activity, clear guidelines of what is expected in support of a permit application (particularly for a saline aquifer storage site) need to be developed. As well as considering the surface footprint and target storage complex of the project itself (including for example formation evaluation, well testing, facilities concept, environmental impact assessment and monitoring), guidelines should address potential interaction with other stores and users of the pore space. Many of the storage units identified within the project are vertically stacked, or cross international medians, and the manner in which they are licensed could have a significant impact on the effective capacity available (for instance if permitting and development of a shallower site effectively precludes access to and use of an underlying one).

Similarly, appraisal could be limited to support only partial use of a given units' theoretical storage capacity. This again could severely impact the UK's overall storage resource, unless such practice is either prevented or clear disclosure terms enable subsequent operators to adequately assess the risks they are inheriting.

10.6.1.2 Measurement, Monitoring & Verification (MMV)

As an extension to the above, expectations regarding MMV activities could render use of certain storage units impractical from either a technical or economic perspective, if regulatory standards are too onerous.

The Sleipner project has demonstrated the value of time-lapse 3D seismic in monitoring of its CO_2 storage operations, but this technique is unlikely to be applicable to many of the UK's deeper or structurally complex storage units. Similarly, in depleted gas fields it is not generally possible with remote sensing to resolve injected CO_2 from in-situ natural gas. Licensing requirements for safe and secure storage must therefore be flexible, catering for both direct measurement/ evidence of where the CO_2 is (within the storage complex), to where it is not (in the overburden or escaping at the sea floor).

10.6.1.3 Cost

CO_2 transmission and storage infrastructure entails substantial fixed costs. For many units, up-front expenditure lies in the range £100s of millions to £billions, whereas the benefits/ revenues emerge gradually with throughput of CO_2 after construction is complete.

While significant capacity is available at zero cost of capital, at more realistic levels, the costs of storage increase significantly. For storage investments to occur at modest cost of capital, uncertainties and risks across a range of drivers of utilisation must be managed. These include carbon and energy markets, regulations, as well as technology cost and performance and social and political support. Public private partnerships might need to be deployed to limit the cost of capital used.

The cost predictions shown are (in general) based on the most cost effective utilisation of the sink, implying long project lifetimes and highest CO_2 flow rates. In practice, many projects may not achieve these levels and so there is an upside risk to the cost estimates.

It should also be noted that the infrastructure requirements have not been optimised. For example, the well model used in this work requires wells to be evenly distributed throughout sinks, to limit pressure rises around the injection points. The need for a highly geographically-distributed infrastructure is a very strong cost driver. The practical response to this is likely to be larger diameter wells, and those which are significantly horizontally deviated. These would have the effect of increasing the CO_2 throughput in each well, reducing the overall number and associated injections facilities. Further cost reduction could include shared infrastructure from clustering of sinks.

In terms of transport requirements, the highest CO_2 capacities (which generally correspond to the most efficient infrastructure on a £/t perspective) would in practice imply connection from multiple sources. Though not examined in this study this would require a high degree of co-operation among many stakeholders and high confidence in the locations, capacities, costs and risk profiles of CO_2 storage and other elements of the CCS value chain.

10.6.1.4 Capability

The process of maturing the UK's CO_2 storage potential to proven capacity will involve the participation of skills and equipment currently deployed in the pursuit of oil and gas reserves. Competition for seismic and site survey vessels, drilling rigs, construction yards and man-power may limit the rate at which storage capacity can be made available, particularly if early CCS projects and appraisal activities are delayed.

10.7 Summary

The UK has sufficient CO_2 storage capacity in offshore geological formations to meet its needs for the next 100 years. Around 90% of this resource is in saline water bearing storage units ("saline aquifers"), approximately half of which are currently assessed as 'closed', and half as 'open'. None may be considered 'proven' at this time, and additional appraisal is required. As this information is obtained and interpreted as part of more detailed site-by-site assessments it is to be expected that some units will fail to qualify as safe and secure stores, whilst others will prove satisfactory to potential storage operators and permitting authorities.

Along the way, their assessed capacities will naturally change but could result in increases as well as decreases. Current estimates of overall capacity are some 4 – 5 times greater than upper targets of UK CO_2 emissions to be stored.

Whilst the ‘abundance’ of storage capacity looks at first reassuring, the time taken to ‘prove’ or qualify sites could be extensive, particularly for the first saline aquifer stores. If storage in depleted oil and gas fields were to be relied upon, there would be little flexibility with regard to when or where storage capacity became available, and the ‘cover’ of storage supply to demand would be dramatically reduced. Further appraisal of saline aquifer sites should therefore proceed without delay.

The size distribution of potential CO_2 storage units is (unsurprisingly) similar to that commonly found for hydrocarbon fields in sedimentary basins around the world: there are few ‘giants’, accompanied by many more smaller units. In this context however, the ‘giant’ aquifer stores are potentially large enough to meet overall UK demand for several decades. This suggests two extremes in terms of CCS development scenario – reliance on relatively few “super stores” linked to large onshore terminals supplied from many dispersed CO_2 emission sources; or rather more offshore clusters of smaller units (“storage farms”) with potentially smaller but more numerous onshore terminals. The associated appraisal and infrastructure cost profiles are quite different, not to mention implied differences in commercial and permitting arrangements, and issues related to liability transfer, public acceptance etcetera. These factors should be considered in strategic decisions related to the establishment and growth of a CCS industry for the UK.

10.8 References

1. Gorecki, C.D., Holubnyak, Y.I., Ayash S.C., Bremer, J.M., Sorensen, J.A., Steadman, E.N., Harju, J.A. 2009. A New Classification System for Evaluating CO2 Storage Resource/ Capacity Estimates. SPE 126421

11 Glossary

Variable	Meaning	Units
Arithmetic average	An average obtained from N numbers by dividing their sum by N	
BHP	Bottom-hole pressure in a well	
Buoyant trapping capacity	The CO_2 capacity of a structure when maximally filled to the spill point	
Capillary pressure	The difference in pressure between two fluids, due to a greater affinity between some fluids (e.g. water) and the rock minerals, than others (e.g. CO_2).	
Caprock	A less permeable rock providing a structural seal to a reservoir.	
'Closed' aquifer	An aquifer which behaves as if it is fully confined	
Core data	Data obtained from measurements or experiments on rock 'cores', which are small, typically cylindrical, samples of rock retrieved from the well borehole	
Compositional (in petroleum simulation)	The simulation of fluid constituents by means of a number of specific *components* rather than just oil, gas and water	
Dissolution of CO_2	The dissolving of CO_2 in another fluid (usually brine)	
Dyke		
Dynamic (modelling)	Modelling of temporal behaviour	
Facies		
Free CO_2	CO_2 which is neither trapped by capillary forces nor dissolved in another phase	
Geomechanical	Relating to rock mass characterization and mechanics	
Geometric average	An average obtained from N numbers by taking the N^{th} root of their product	
Heterogeneity (of rock)	Non-uniformities in the rock which affect how fluid flows through the pores	
Horizontal well	A well drilled at a low angle in order to penetrate more of the target formation than a vertical well.	
Hysteresis of relative permeability	The phenomenon by which the relative permeability may differ depending on whether the wetting saturation is increasing or decreasing	
Lithology		
Log data	Data obtained from a mechanical probe lowered into a well	
Material balance	A reservoir modelling technique which uses material entering and leaving the reservoir to predict changes in the reservoir (Equivalent to a single cell simulation model)	
MD	Measured Depth along a well trajectory. This will differ from the vertical depth if the well has a horizontal or deviated section	ft/m
Method of images	A mathematical technique which makes use of symmetry to compute additional solutions from an existing known solution	
Microscopic sweep efficiency	The fraction of pore space available for storage given the presence of an irreducible water saturation due to residual trapping by capillary forces	
Monte Carlo estimation	A class of computational algorithms that rely on repeated random sampling to compute their results, often used in simulating physical and mathematical systems.	
Normally pressured	A reservoir whose pore pressure is consistent with that exerted by a column of water from surface to the depth of the reservoir	
'Open' aquifer	An aquifer which behaves as if it is not fully confined	

Permeability	A rock property which measures the ability of fluid to flow through the pore spaces within the rock	
Porosity	A rock property which measures the pore space within the rock compared to the total rock volume	
Pressure cell	'Closed' aquifer	
PV	Pore Volume, i.e. the volume within a rock which is pore space	
PVU	Pore Volume Utilisation, i.e. the proportion of the pore volume which is occupied by CO_2.	
Relative permeability	The factor by which the presence of one or more additional phases in the pore space reduces the effective permeability of a phase compared to the value if it occupied the pore space alone	
Reservoir sweep	The fraction of the reservoir contacted by an injected fluid	
Residual CO_2 trapping	The trapping of CO_2 by capillary forces within pores	
Saturation	The proportion of pore space occupied by a particular fluid	
Skewed data		
Spill point	Points on the extremities of a structure beyond which fluid is unconfined so may flow out the structure	
Stochastic	Non-deterministic	
Storage capacity	The mass of CO2 which may be stored in a formation	Mt
Stratigraphic trap		
Structural trapping		
TD	Total Depth of a well	ft/m
Transmissibility	A quantity in numerical finite difference simulators which defines the degree of connectivity between simulation cells	
Trapped gas saturation	The fraction of the pore space occupied by gas residually trapped by capillary forces	
Triangular distribution	The triangular distribution is a continuous probability distribution with lower limit *a*, upper limit *b* and mode *c*, where $a < b$ and $a \le c \le b$. It is typically used as a subjective description of a population for which there is only limited sample data, and especially in cases where the relationship between variables is known, but data are scarce.	
Upscaling	The process of transferring a solution computed on a finer grid to an equivalent solution on a coarser grid	
Voidage Replacement Ratio	Volumetric ratio of fluid injected to that produced at reservoir conditions. Thus a VRR of 0.75 implies that 75% of produced fluid has been "replaced" by injected fluids	
Streamline simulator	A type of petroleum simulator in which fluid mechanical streamlines are calculated in order to advance the solution in time	
Exemplar	Detailed model of a selected region of an actual UKCS aquifer unit	
Top surface	The reservoir/caprock interface	
Geocellular model	Discrete representation of reservoir/aquifer properties such as permeability porosity and facies type	
Wireline log		