Programme Area: Carbon Capture and Storage

Project: Storage Appraisal

Title: Security of Storage

Abstract:

This document is a supporting document to deliverable MS6.1 UK Storage Appraisal Final Report.

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

Appendix A6.1

Security of Storage

Conducted for

The Energy Technologies Institute

By

Senergy Alternative Energy

British Geological Survey

Geospatial Research Limited

GeoPressure Technology Limited

University of Edinburgh

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Executive Summary

All the aquifer storage Units identified in Work Package 1 have been assessed under two technical categories of risk: containment and operational. The method adopted to evaluate risk is based on a 'Features, Events and Processes' approach similar to the methods used or recommended in other geological storage site evaluation projects. Containment risk refers to leakage from the storage Unit, while operational risk is concerned with the likelihood that injection operations will be disrupted due to subsurface conditions. Likelihood and confidence data were collected and interpreted for each storage Unit.

The storage Unit likelihood and confidence assessment was completed by four participant organizations: the British Geological Survey, GeoPressure Technology Limited, Geospatial Research Limited and University of Edinburgh. Senergy Alternative Energy coordinated the Work Package.

The severity of impact of each risk was assessed on a UKCS-wide basis by an expert group that included participant and sponsor members. This expert group assessed the magnitude of impacts on both project cost and Unit storage capacity, producing generic cost-impact and capacity-impact scales. The output of the risk assessment is therefore an integration of Unit likelihood and generic severity of impact data and includes Boston square type risk matrices for each storage Unit; examples of these are included in this report.

The decision to limit the Unit risk assessment to likelihood and confidence data, and to assess impact on a generic basis was based on the large areal coverage required (entire UK continental shelf), constraints inherent in the source data, and limited knowledge of the magnitude of impacts resulting from lack of experience of operational CCS.

Quality control of the confidence and likelihood data was achieved via the provision of detailed written descriptions of low-, medium-, and high-likelihood and confidence ranges for all risk items, complemented by illustrated examples as additional guidance. Quality control also included a review of a subset of Units as they were completed, followed by feedback to the participants. A final quality control exercise including normalisation and peer review was carried out alongside the severity of impact ranking.

The normalisation exercise undertook likelihood and severity assessment for a subset of hydrocarbon reservoirs. Hydrocarbon reservoirs are expected to provide low risk storage sites for CO_2 *as they are demonstrated traps for, and allow the production of, substantial volumes of low molecular weight fluids and gases. The majority of risks assessed for these hydrocarbon reservoirs are ranked as low, with faulting a notable exception. In the absence of direct evidence from hydrocarbon containment, the risking methodology uses a conservative approach and assumes that faults do not seal. Lateral migration is also high risk for the hydrocarbon Units, reflecting a methodology developed to assess migration across geographically extensive Units without defined traps.*

Identification of the most common high risk items across the UKCS helps provide direction for future study to characterise the impact of the most important risk items. The highest frequency containment risk items in terms of impact on storage capacity include all three fault leakage items and the risk of seal degradation. The latter reflects geological variability in seal quality across laterally extensive storage Units, while the former, partly the result of the conservative approach to fault risk assessment noted above, also shows that faults are a key

feature at the majority of storage sites and illustrates the limits in our understanding of what fault characteristics are key in containment integrity. Unlike hydrocarbon exploration where trapped hydrocarbons prove containment integrity, in aquifer storage site evaluation there is no proxy evidence of fault seal. Cost impact assessment using the same Unit-specific likelihood data leads to an elevation of lateral migration risks over capacity impact assessment, with structural, depositional and dip magnitude controls on lateral migration the most frequent high risk items.

For operational risk assessment, the most frequent high risk mechanisms in the capacity impact category are structural and diagenetic controls on compartmentalisation. Cost impacts are more evenly spread across the operational risk mechanisms 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. In the Southern North Sea the laterally extensive Haisborough Group provides a basin-wide, chemically and physically robust seal with limited lateral variation over a large geographical extent (>100 x 100 km).

An evaluation of the lateral migration risk associated with Units that are assessed as having no structural containment i.e. open Units, highlights the importance of depositional, structural and dip controls on lateral migration and storage security in these volumetrically important Units.

To provide a means of comparing the overall risk of each Unit, a cumulative scoring system integrating Unit risk and confidence data was developed. Many of the lowest risk Units are found in the Southern and Central North Seas, including parts of the Bunter Sandstone in the Southern North Sea and the Cretaceous Britannia and Jurassic Piper Sandstones in the Central North Sea. The three hydrocarbon Units used for normalization also score in the lowest risk category. Notable very high risk Units include compartmentalised Northern and Central North Sea Triassic reservoirs and Paleocene fan Units with high well density, widespread pressure interference from hydrocarbon operations and lateral migration risk..

As a result of the large geographical area and geological heterogeneity within Units, caution is advised in interpreting the risk results. Although a single Unit may be found overall to have a low, medium or high level of risk, a detailed site- or structure -specific risk assessment for a storage site within a Unit may reveal a very different risk profile.

With the exception of the summary cumulative scoring exercise, all risk assessment is qualitative, considered appropriate for such a scoping study. A probabilistic approach is recommend for a site specific or sub basin-level study to provide a more comprehensive, quantitative risk assessment.

Based on output from a sub-group of the risk review panel, outline estimates of risk mitigation have been generated, with feasibility as a fraction of project cost.

Risk-weighted appraisal costs based on Unit area, normalized to hydrocarbon development strategy and costs, range from \$0.62-10.13 per tonne CO_2 *and vary as a result of the volume of viable storage reservoir and Unit area. Based on the agreed methodology typical appraisal costs integrated into WP3 are likely to be between \$0.6-1.0.*

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1 Introduction

This report describes work completed within the risk assessment Work Package ('WP2') between Q4 2009 and end Q1 2011. The data summarised in this report is from a version of the database captured in March/April 2011 and includes 378 aquifer Units.

For carbon capture and storage projects, a 'Features, Events and Processes' (FEP) type approach has been recommended for 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 many potential areas of risk to be ranked and compared; giving an initial overview of the level of risk associated with a potential geological storage site and the risk mechanisms which are unacceptably high. From these preliminary results further, more detailed investigations such as scenario-based risk analysis and potential mitigation activities can be prioritised. In this way the likelihood of occurrence and scale of impact of a risk mechanism can be assessed and compared to the potential costs associated with mitigating those risks, allowing decisions to be made on the suitability of a potential storage site.

Risk is typically defined as the product of the likelihood and severity of some mechanism which may affect a project. By combining likelihood and severity in this way, risk mechanisms are divided into those that are very low risk, low to medium risk, medium risk and high risk as presented in the risk matrix shown in **Table 1**.

		Likelihood		
Severity		***Low***	***Medium***	***High***
	Low	*Low-Low*	*Med-Low*	*High-Low*
	Medium	*Low-Med*	*Med-Med*	*High-Med*
	High	*Low-High*	*Med-High*	*High-High*

Table 1: Likelihood Severity Risk Matrix

In this project, whole Units covering a large area rather than specific storage sites are assessed and therefore a detailed, site specific type risk assessment is not possible. Instead definitions of likelihood and severity are broader than those typically used in site- and project-specific risk assessments and are qualitative rather than quantitative.

All aquifer storage Units have been assessed for likelihood of occurrence under two technical categories:

- 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 and 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 risk assessment has also been captured, based on data availability and reliability of interpretation.

Both of the above risks have cost implications for the appraisal and operation of sites within any given Unit and an attempt has been made to estimate the likely costs for input into the economic evaluation which forms WP3. This report therefore does not address the impact of the risks on the economic viability of the storage capacity of any of the Units, or the degradation in capacity that might result from minimum capacity or rate criteria for individual wells or storage sites.

The likelihood data only provide an indication of 'the likelihood that, chance of technical project success will be reduced by a feature or process'. By collating likelihood and generic severity data on a range of containment and operational downsides, the risk assessment provides a risk profile for each Unit.

With the exception of the three hydrocarbon Units used for bench-marking the risking methodology and assessment of the containment risk of wells, risk assessment has not been completed for the ~200 UKCS oil and gas fields.

Throughout this report, examples are used to illustrate the approach taken and these are separated off in discrete boxes.

2 Methodology and Approach

The subsurface risks assessed in WP2 are shown in **Table 2**. Each risk item describes a feature or process that would be expected to compromise containment security or operational performance. The list of relevant risk items was collectively agreed by the Project participants and sponsors, and is similar in breadth to published subsurface and wells CCS risk 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*
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	*5 items: vertical stratigraphic compartmentalisation, horizontal stratigraphic compartmentalisation, structural/fault compartmentalisation, diagenetic compartmentalisation, pressure isolation**

Table 2: Risk categories, subcategories and risk items.*Note pressure isolation was removed from the final results as the review team considered that it was 'double counting' i.e. its influence is already included in other risk items

Data entry and assessment was shared amongst participants based on their areas of expertise. This is summarised in **Table 3**.

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 3: Assignment of Participant Organisations to Risk Categories and Subcategories

2.1 Likelihood and Confidence Data

The 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 are not available for a storage Unit, 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.

Data entry was via a bespoke web-based data loader, with input pages constructed for each of the subcategories shown in the first column of **Table 2**. An example data entry page is provided in **Figure 1** and additional explanation is provided in the boxed description below. A critical challenge was to achieve consistency between areas and multiple participants; both illustrated guidance and written descriptions address this challenge (e.g. **Appendix A6.2 (1)**).

Example of data entry format and guidance

As an example of the data entry format and guidance, ***Figure 1*** *shows a screenshot of containment risk, seal integrity subcategory for the Lower Cretaceous Captain Sandstone Unit Captain_013_17 (Unit ID 218.000) in the Central North Sea. Data required to complete the seal risk assessment includes a formal (lithostratigraphic) name for the primary and secondary seals and an assessment of likelihood of occurrence and confidence under the following categories: fracture pressure capacity, seal chemical reactivity and seal degradation. The written guidance for assessing seal chemical reactivity likelihood of occurrence is listed at the bottom of the figure; similar guidance is provided for all risk items in all categories.*

The Captain_013_17 Unit (i.d. 218.000) is sealed by the Hidra Formation of the Chalk Group. The Hidra seal is assessed as having high likelihood of containment failure for both seal fracture pressure capacity and seal chemical reactivity. With respect to fracture pressure capacity, the high likelihood rating results from an estimate of the maximum CO_2 *column that could build-up in the formation following injection (based on an assessment of structural relief within the formation). The buoyancy pressure from this* CO_2 *column is assessed as greater than the mechanical strength of the caprock. As the Hidra includes both carbonates and immature fine-grained siliciclastic sediments it is assessed as having high likelihood of geochemical seal reactivity via* CO_2*-water-mineral reactions (seal chemical reactivity). Failure of seal integrity as a result of seal degradation is assessed as medium with Hidra Formation thickness varying from 0-500 m and lithological changes from the margins to the centre of the basin.*

All assessments of seal integrity for the Captain_013_17 Unit (i.d. 218.000) are associated with medium or low confidence, being derived from the Captain oilfield description and offset well data (Millennium Atlas and GPT respectively). Oilfields often provide the best data for the aquifers in which they are located, however due to the differences in rock properties resulting from pore fluid type: hydrocarbon versus water, and the restricted volume sampled (compared with the much larger aquifer volume) additional work to gather data and reduce uncertainty would be of value, and this might lead to a change in the assessment.

2.2 Quality Control

2.2.1 Likelihood and Confidence Definitions

Consistency in data entry was ensured via provision of written definitions of low, medium and high likelihood and confidence for all risk items (e.g. **Figure 1**). To provide an audit trail, a data source field was completed for all risk items along with a record of who entered the data and an optional comments box. To assist in assessment of likelihood and associated confidence, the definitions in the data entry pages were complemented by further written guidance and illustrations. Since the written definitions set the context in which data were entered, and provide a means to calibrate the assessment, they are included in full as **Appendix A6.2 (1)**. An example of a supplementary illustrated guidance document is shown on **Figure 2** and discussed in the box below.

Figure 2 *provides an example of a guidance document. This example was provided to assist in fault leakage risk and confidence assessment. A component of containment risk, the fault risk assessment includes an evaluation of likelihood of leakage via fault flow as a result of fault density, magnitude of fault throw and vertical extent of mapped fault planes. Two Units are represented in the interpreted seismic cross section, with the differences between them used as a supplementary guide to risk assessment. The lower Unit, shaded in red, has higher fault density, greater throws and shallower penetrating faults than the upper Unit; all items in the fault risk category are therefore ranked as high or medium for the lower example and low for the upper example. Confidence in assessment is high for both Units with fault planes and marker beds easily identified on this cross section.*

There remains a risk that contrast will result in exaggeration: i.e. a lower risk Unit in an otherwise high risk basin might be rated low risk whilst still having a much higher overall risk than a higher risk Unit in an otherwise low risk basin. A peer review exercise with CCS risk experts that took place in early 2011 provided a critical assessment of the risking methodology and the results of that exercise are now incorporated into this report and the final WP2 methodology.

The definitions for each likelihood and confidence banding for the different mechanisms (e.g. **Figure 1, Appendix 6.2 (1)**) give a relatively detailed description from which the experts can base their judgements. This helps ensure that the assessments given by different experts are relatively consistent. However some variation is to be expected between experts and for the same expert completing the assessments at different times. This is an inevitable consequence of the inherent uncertainty associated with the subsurface and the different knowledge, experience and expertise of the experts involved and the different ways in which they assimilate information.

This uncertainty needs to be borne in mind when reviewing and analysing the results.

2.3 Severity of Impact Ranking

Though likelihood data were captured for each Unit the severity of impact was not. Since impact severity of a particular mechanism is critical to the full risk analysis, it was decided to develop generic impact magnitudes for each risk mechanism.

To generate generic severity data a potential severity scale (**Table 4**) was sent to project partners before an ‘impact elicitation workshop’. In order get an idea of the range of opinions, and hence uncertainty in any consensus, and to provide a starting point for the workshop discussions, a group of experts were asked to complete the severity assessments before the meeting using the form shown in **Appendix A6.2 (3)**.

Severity of Impact	Project Values
Low (L)	No or negligible negative impact to project
Medium (M)	Negative impact, but within acceptable costs to mitigate/repair
High (H)	Negative impact sufficient to end project

Table 4: Initial Proposed Severity Scale

During the workshop, the experts were asked to assess the lower, best-guess and upper-bound severity values as defined below, for each risk mechanism:

- **Lower-bound** is the minimum impact that might be expected for a UK offshore saline aquifer
- **Best-guess** is the impact you expect for a 'typical' UK offshore saline aquifer
- **Upper-bound** is the maximum impact possible for a saline aquifer in the offshore UK

When assessing the severity, experts are asked only to consider the scale of the impact assuming the risk mechanism has occurred and ignore the likelihood that a risk mechanism might occur. The severity impact scale is shown on **Figure 3** and the results for each risk mechanism are shown on **Figure 4**. The severity of impact scales used exclude impacts on health and safety, environment and industrial viability (the latter includes media and public opposition) and therefore the final risk ranking for each Unit is only for cost and capacity impacts, not overall risk.

In all cases the cost impact ranking is equal to or higher than the capacity impact ranking (**Figure 4**), therefore the cost implications of risks exceed or are at least the same as the capacity implications. Overall "Faults" and "Lateral Migration" are considered the highest impact categories for costs, with all mechanisms scoring high impact for the best-guess value. For capacity impact only the "Faults" category and the "Seal degradation" mechanism score best-guess values of high impact, the rest are all medium or low (**Figure 4**).

The severity of impact values have been incorporated into the Carbonstore database to provide a combined likelihood and severity risk matrix for each Unit. The overall risk for each Unit can then assessed from the number of very-high, high, moderate and low risk mechanisms. In this way different Units can be ranked and compared based on their level of risk. The mid case/best-case impact results were used and therefore the final risk matrix has only three impact values: low, medium and high severity, combined with the three likelihood values of low, medium and high likelihood and thus nine panels (**Figure 5**).

2.4 Normalisation Exercise

The UKSAP database only assesses risk for saline aquifer Units, with all hydrocarbon accumulations assumed to be 'low/acceptable risk', and no risk assessments were completed for hydrocarbon Units except for the containment risk of wells, which was assessed for hydrocarbon accumulations.

Following the risk review, the entire risking methodology was applied to three oil and gas fields anticipated to be low risk storage sites, given they have retained low molecular weight substances for millions of years. This was designed to validate the risk approach and in particular the scales and definitions used and benchmark the level of risk. The fields chosen were:

- the Rough Field, a Permian Leman Sandstone dry gas production and storage reservoir in the Southern North Sea
- the Forties Field, a giant (multi billion barrel) Palaeocene sandstone light oil reservoir in the Central North Sea
- the Britannia Field a very large ~4 TCF 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.

If the definitions chosen suitably represent low, medium and high likelihood and confidence, then the 'low/acceptable risk' hydrocarbon Units should have few or no risk mechanisms scored as high risk. Any exceptions should be restricted to those risks that are peculiar to CO_2 as opposed to hydrocarbon saturation, or reflect the fact that the methodology was designed to assess large 3D volumes as opposed to the defined trap structures that host the hydrocarbon pools.

2.5 Cumulative Risk Xcoring

To allow comparison of the overall risk between one Unit and another, and to illustrate the differences in risk across the UKCS sub-basins, a simple scoring system was applied to the results, giving the highest score to Units with the highest number of high risks and lowest confidence in assessment. The scoring scheme and results are described in **Section 4.5**.

2.6 Risk Mitigation

An important feature of a risk assessment is to identify potential mitigation activities. In order to distinguish which risk mechanisms can be mitigated and which cannot, all experts were asked to complete the mitigation form (**Appendix A6.2 (3)**; though only three completed forms were returned). For each risk mechanism, the experts state whether the risk could potentially be mitigated, the method of mitigation and an estimate of the cost as a percentage of total project costs. This provides an understanding as to whether mitigation is technically and financially possible for each risk mechanism.

3 Summary of Participant Contributions

The following summaries provide an overview of work completed by the four participant organisations. Full participant reports including data use, discussion of risking methodology and recommendations are included in **Appendix A6.2 (2)**. The participants assessed each Unit for likelihood and uncertainty with the severity of impact completed on a generic basis by the expert reviewing team.

3.1 British Geological Survey (BGS)

The British Geological Survey (BGS) assessed the risk associated with geological storage of CO_2 for potential storage Units in the following regions: the Southern North Sea, the Palaeocene of the Northern and Central North Sea, the East Irish Sea and part of the English Channel Basin. The primary datasets used for the risking of the storage Units were the PGS Megasurvey and derived products, and the IHS EDIN well database (GIS). Published maps and papers were also used. BGS were primarily involved in risking fault leakage, lateral migration and dynamic capacity/ compartmentalisation.

Storage region	Data available
Southern North Sea	PGS Megasurvey, IHS wells, PGS surfaces, published maps and papers
Palaeocene of the Northern and Central North Sea	PGS Megasurvey, IHS wells, PGS surfaces, interpreted PGS seismic lines, published maps and papers
East Irish Sea	Published maps and papers
Channel Basin	BGS-held wells, published maps and papers

Table 5: Regions Assessed by BGS and Data Used

For storage Units covered by the PGS Megasurvey, ‘faulting’ and ‘operational risk – dynamic capacity/ compartmentalisation’ was assessed utilising the Megasurvey data at the PGS offices. The Units were assessed qualitatively by examining several representative seismic lines. Risk was then assessed using the guidance on the Carbonstore website (**Appendix A6.2 (1)**). For individual storage Units, screenshots were taken from representative seismic lines which best illustrated the structural style of the Unit (illustrations in **Appendix A6.2 (2)**). In areas covered by the PGS Megasurvey, data confidence was generally classed as high. The exception to this was regions where the seismic resolution made visualising the faults difficult. In such cases this was described in the comment box within the data loader, and is recorded in the database with an appropriate reduction in assessed confidence. Published maps and references were used to give a qualitative description of the faulting in storage Units not covered by the PGS Megasurvey. In such cases data confidence was classified as medium to low.

In the Southern North Sea and East Irish Sea, depth maps were generated in Petrel for each storage Unit using interpreted depth surfaces derived from seismic data (from PGS) and/ or IHS well data. In the East Irish Sea Basin published maps were used. Depth maps of storage Units in the Northern and Central North Sea were produced from well data using a combination of Petrel and ArcGIS. All the depth maps were imported into ArcGIS. Tools in Petrel and ArcGIS were used to calculate several of the parameters required for risk fields in the data loader. These include structural trend, dip direction and dip magnitude.

Key challenges encountered included:

- Problems of scale when assessing fault density
- Poor resolution of seismic data making it difficult to identify faults in some areas
- Lack of data to assess risk in the English Channel and East Irish Sea Basin
- Average dip for large storage Units may not reflect the true architecture and local dip variation across the Unit

Solutions and recommendations for further work:

- Fault density could be assessed using the number of faults per meter/ kilometer
- Seismic data in the East Irish Sea could be acquired in order to better assess leakage risk in this area
- As average dip does not necessarily reflect the architecture of the Unit, using the up-dip angle relative to the injection point is recommended
- It was difficult to find data related to diagenesis and diagenetic fabrics. This could be an area for further study
- The risk assessment was a broad regional assessment. Any storage Unit considered for a CO_2 storage project would need to be fully characterised and undergo a more detailed site-specific risk assessment

3.2 University of Edinburgh (UoE)

The University of Edinburgh undertook risk assessment in all sub-Palaeocene strata in the Central and Northern North Sea.

Data were entered for the following risk categories: containment risk - faults; containment risk - lateral migration; operational risk - dynamic capacity/ compartmentalisation.

Fault data were derived from the PGS Megasurvey using screenshots of interpreted seismic sections (with horizons and faults), perpendicular to the main structural trend. Confidence level was allocated based on data quality, and it is possible that small faults may have been missed. Re-interpretation of the seismic using auto tracking would probably improve confidence, along with better integration of well control data. Not all storage Units are covered by the seismic data, and for these published data was used to estimate the nature of faulting.

Structural trend was taken from maps in the Millennium Atlas, with confidence related to the proximity of the storage Unit to the available horizon map. Confidence in this method is mostly low, and in some cases a representative value for the structural trend was estimated. Edge or curvature maps of the different formations might give a more accurate structural trend estimate (a recommendation for future study). Depositional/ diagenetic fabric assessment relies on hydrocarbon field data, and if this was absent the assessment was low confidence. Dip and dip direction was estimated from measurements on depth maps from the Millennium Atlas, using a single transect chosen to be representative of the Unit. Difficulty was experienced in selecting the orientation of the dip-line when complex structures were present. Rugosity was assessed by comparing maximum relief of a Unit (taken as the depth between the shallowest and deepest top surface, from the IHS EDIN GIS database) with average Unit thickness. Confidence levels were based primarily on the density of top depth data points. Depths are derived from well logs that are likely to have been drilled through structural highs and therefore the 'relief' of a Unit may be underestimated. The 'hydrodynamics' of a Unit was often difficult to assess. The location of pressure sinks (hydrocarbon fields) within the study area were derived from published DECC offshore hydrocarbon shapefiles.

Stratigraphic compartmentalisation (both vertical and horizontal), structural/ fault compartmentalisation and diagenesis were assessed from reservoir architecture of fields in the literature. A large uncertainty was associated with the storage assessment Units with no contained hydrocarbon field. Pressure isolation was based predominantly on GeoPressure Technology 'Upper Jurassic Overpressure Compartment' maps, and the scientific literature, with varying resolution.

3.3 Geospatial Research Limited (GRL)

Geospatial Research Limited completed 2 sections within the risking section of UKSAP:

- the operational risk caused by formation damage including both mineralogy and mechanical integrity
- the containment risk associated with existing wells

All of the saline aquifers have been assessed according to these criteria, in addition the UK continental shelf oil and gas fields were assessed according to the containment risk associated with existing wells.

Risking of formation damage was completed using public domain data to assess mineralogy (of both rock matrix and cements) that might react with injected CO_2 and hence potentially compromise or halt injection. Most data were available for hydrocarbon fields, so storage units with hydrocarbon fields within them have the most reliable assessment (compared with units which do not contain hydrocarbon fields), however even in this case there is a possibility that diagenesis has been limited in the hydrocarbon leg, compared with the saline aquifer, so the data might not be truly representative. The mechanical integrity was also assessed, although there was very limited public domain data available for this. In the absence of data the risk was assigned an 'unknown' value. Risk of the mineralogy and mechanical integrity were evaluated for likelihood of an outcome, with qualitative assessment of the severity of that outcome. Finally a confidence level was assigned to the assessment.

The containment risk of wells (ie. potential for wells to provide a leakage pathway) was assessed using status, age and location data from the IHS EDIN GIS database, downloaded on 23/11/2010. For the well containment risk assessment of hydrocarbon fields only, this was merged with additional bottom-hole location data down loaded from DEAL on 21/06/2011. The storage units and hydrocarbon fields were taken from shapefiles generated by University of Edinburgh and BGS. The minimum depths of these storage units and fields were taken from the Carbonstore database (23/11/2010) and refer to the shallowest depth of the formation within the unit. These three sources were used to identify the wells lying within and potentiall penetrating each storage unit (or hydrocarbon field). If a well lies within the areal extent of a shapefile and penetrates more deeply than the minimum depth of the unit, the well is counted as a potential well penetration. Risk was then assessed for each unit based on the vintage of each potential penetrating well, and the calculated well density.

This assessment is conservative with respect to risk. If the total measured depth (TD) of a well is deeper than the minimum depth of a unit (over its whole areal extent), but not actually deep enough to reach the actual depth of the unit at the well location, then the well will be erroneousl assumed to have penetrated the unit. Equally, as measured depth of the well is used to compare with unit depth, if the well has a long horizontal section, an erroneous penetration of deeper units might be assumed

The range of well density and vintage for all units were divided into three equally sized groups, and assigned low, medium or high risk respectively.

3.4 GeoPressure Technology Limited (GPT)

GeoPressure Technology Limited's (GPT) contribution to Work Package 2 included the following:

GPT supplied algorithms for aquifer seal capacity, pore fluid pressure and CO_2 column height, all of which are used within the web-enabled database and GIS application. The results of these algorithms were used to complete the fracture pressure capacity part of the seal risking. GPT also completed likelihood of occurrence and confidence assessment for seal chemical reactivity and seal degradation.

- Direct pressure data from wells in the IHS pressure database were analysed to calculate lithostatic and fracture pressures at shallowest depth
- The likelihood of seal fracture failure at shallowest depth was assessed by comparing estimated relief and CO_2 column height (capillary entry was not assessed)
- A literature review to establish stratigraphic relationships between aquifer Units and primary and secondary sealing horizons, with potential risk of failure of both seals, was carried out. Confidence was assigned to each Unit
- Seal chemical reactivity and seal degradation was also considered though published data for the identified sealing formations

4 Results and Analysis

4.1 Intermediate WP2 Report

A previous version of this report provides an overview and analysis of the likelihood and confidence data, generated prior to the risk and severity ranking exercise (which took place in January 2011). The previous version (**Appendix A6.2 (4**)) was reviewed by the ETI and project sponsors prior to the development and application of the severity methodology and a modification on the well containment risking (incorporation of bottom hole location data into the well containment risking of hydrocarbon fields).

4.2 Examples of the Full Risk Analysis

Example 1: Risk Matrices for Bunter Unit 226.000

Figure 6 *illustrates the combined likelihood and severity of impact (capacity impact) data for Unit 226.000, which is within the Bunter Sandstone of the Southern North Sea. The high likelihood, high impact item 'fault vertical extent' (magenta) and the medium-high likelihood and severity items (red): fault throw and fault density all deserve immediate attention to reduce uncertainty associated with these most important risks. Faults within the Unit extend to shallow depths leading to a high likelihood of upward fault fluid transmission (fault vertical extent), although the potential for the fault plane itself to allow fluid flow was not assessed. The risk items in orange which include aspects of lateral migration, compartmentalisation, seal and well integrity also deserve further assessment. In a site development plan though this listing would provide a preliminary prioritisation of issues, it should not be considered comprehensive.* ***Figure 7*** *shows the same likelihood data for Unit 226.000 but uses cost impact data in place of the capacity impact data. As a result of the higher rating for many of the cost impacts e.g.* ***Figure 4****, overall risks for well integrity, seal fracture pressure, faulting, a number of lateral migration risks, and some injectivity and compartmentalisation risks are assessed as high or very high.*

<u>Example 2: Risk Matrices for Cormorant Unit 4.00</u>

*The second example risk matrices (**Figures 8 and 9**) are for Northern North Sea storage Unit 4.00 (Cormorant 003_25). These provide an illustration of a risk assessment based on sparser data than the Bunter Unit. Four risk items were not assessed because of data sabsence, compared with only a single item not assessed in the Bunter example above. The data limitations and resulting uncertainty in interpretation result from the paucity of well penetrations and poor seismic resolution for the deep Mesozoic Units in this area; Unit 4.00 centroid is at ca. 5 km depth subsea. Using the likelihood data for Unit 4.00 and the generic capacity impact data (**Figure 4**), seven risk items are high risk: seal degradation, seal fracture, all aspects of faulting, depositional controls on lateral migration and diagenetic compartmentalisation. Due to a single well penetration and no developed hydrocarbons, both risk of well leakage and migration pressure sinks are assessed as low-medium risk. No suitable direct, offset or analogue data were available to assess the likelihood of occurrence for hydrodynamic, formation mechanical integrity or salinity risks. **Figure 8** uses the same likelihood data, exchanging the capacity severity of impact data for cost severity of impact data. The generic impact data are higher for cost than capacity impacts and as a result there are now twice as many risks in the high and very high category (14 in the red and magenta boxes). Unknown items are most appropriately dealt with as if they are high risk i.e. work on these should be prioritised and Unit viability is severely limited till the unknowns are adequately understood. From a risk and uncertainty perspective this Unit is a less attractive development prospect than the Bunter Unit (226.000), development costs and storage capacity notwithstanding.*

4.3 Trends

4.3.1 Most Common High Risks across the UKCS

Identification of the most common high risk items across the UKCS helps provide direction to mature these storage opportunities by informing research and development activities and regulatory approach. As in previous sections, results are reported with risk as a product of Unit specific likelihood and generic cost and capacity impacts. The summary slides include the 378 aquifer Units in the database as of March/April 2011.

4.3.1.1 Containment Risk

The most common high containment risk items in terms of impact on storage capacity include all three fault leakage items and the risk of seal degradation (**Figure 11**). The seal risk reflects geological variability in seal quality across laterally extensive storage Units, while the fault risk is partly the result of a conservative approach in that all faults are assumed to allow fluid transmission. The high proportion (~80%) of Units with an identified fault risk emphasises the value in further work to better understand the characteristics of faults (e.g. orientation with respect to stress field, gouge potential, rock mechanical constraints etc.) that constitute the major risks and therefore provide greater discrimination within this large population,

Fault and seal remain high risk items in terms of impact on storage costs (**Figure 11**) but with the other risk categories, lateral migration and well integrity, gaining in importance, reflecting the increase in cost versus capacity impact in these categories (**Figure 4**).

4.3.1.2 Operational Risk

For operational risk assessment, the most common high risk mechanisms in the capacity impact category are structural and diagenetic controls on compartmentalisation (**Figure 12**). Formation damage is assessed as having a limited impact on capacity, with a range of possible mitigation activities, hence the absence of formation damage from the high and very high risk collation. Cost impacts 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 13**).

4.3.2 Regional Variability, an Example from Seal Integrity Assessment

Seal integrity for all UKCS Units was assessed by the same organisation (GeoPressure Technology Limited), therefore the seal integrity results provide an opportunity to evaluate regional variation in risk magnitude free from potential inter-participant bias. Additionally, as the cost impact and capacity impacts are identical for seal integrity (e.g. **Figure 4**) separate reporting and interpretation of each is unnecessary.

Comparisons of seal integrity between UKCS basins show that the Southern North Sea is associated with lowest seal risk (**Figures 14 - 16**). An explanation for this is that a wide range of formations provide seals in the Central and Northern North Sea, with variable likelihood of fracture failure based on the algorithm used in this study (**Figure 14**). Failure of the seal via chemical reactivity is assessed as low throughout the UKCS, and is very low in the SNS (**Figure 15**), while lateral continuity/ degradation is most frequently assessed as high risk in the Northern North Sea (**Figure 16**). In the Southern North Sea, for the vast majority of storage Units, the laterally extensive Haisborough Group (shales and halites) and Zechstein Salt provide basin-wide high integrity seals (chemically and physically robust) with significant thickness over a large geographical extent (e.g. >100 x 100 km).

4.3.3 Variation within a Single Risk Category; Lateral Migration Risk in Open Units

In open Units lacking significant structural traps, lateral migration is a critical aspect of storage security since trapping of the mobile CO_2 as a residual saturation is the dominant storage mechanism following cessation of injection. On a macroscopic scale the amount of CO_2 that can be immobilized as a residual saturation depends on the migration rate and dispersion of the migrating CO_2 front; both of these are at least in part controlled by the mechanisms described for lateral migration risk: structural and depositional architecture (and any post depositional/diagenetic overprint).

Residual saturation trapping in open Units is expected to be an important potential storage mechanism for injected CO_2 in the UKCS with ~45% of the 378 aquifer Units reviewed in this report are classed as ‘open’ i.e. thought to be Units that would allow migration of significant volumes of fluid beyond their boundaries over operational timescales (with or without integral structural traps). The risk items within the lateral migration category parallel the factors in the sensitivity analysis in the dynamic simulation study of CO_2 injection into a structurally unconfined system (see exemplar 1 in work package 4). As the cost impact of failure via lateral migration is higher than the capacity impact (e.g. **Figure 4**), cost was chosen to illustrate the variability and extremes in risk magnitude within this category.

Figure 17 illustrates which features associated with lateral migration are most frequently assessed as high risk for the ~170 Units categorised as 'open'. Of the risk items within lateral migration, depositional control is recorded as high risk for the greatest number of Units (26%), followed by structural and dip magnitude controls on lateral migration. The proximity of transnational boundaries is relevant (i.e. high risk) for 15% of the open Units i.e. within 1km of the Unit boundary. The assessment of depositional control on lateral migration is concerned with identifying regional anisotropy in the horizontal permeability of a Unit, for example parallel and sub parallel sedimentary channels. Further work is recommended to reduce uncertainty associated with this and the other high frequency risks. Significant knowledge gaps exist for other items within the lateral migration group, in particular hydrodynamic and dip azimuth controls on migration.

4.4 Results of Normalisation

Figures 18-23 show the results of the risk assessment for the three example hydrocarbon fields on the cost and capacity impact risk matrices. The majority of risks assessed for these hydrocarbon reservoirs are low or medium. High risk items common to all three example hydrocarbon Units include faulting and lateral migration. The number of high risk items is higher for the cost impacts (**Figures 21-23**) than the capacity impact (**Figures 18-20**) reflecting the difference in the two impact scales.

The consistent high fault risk for the hydrocarbon field Units reflects a conservative approach; the assumption that faults do not seal. Only where hydrocarbons are present is there convincing evidence of adequate fault seal, in all other settings assuming faults allow fluid transmission is considered reasonable at the level of detail used in this project. A detailed assessment of fault seal based on reservoir and seal lithologies, rock mechanics and the regional stress field *inter alia* would be required to increase confidence in storage potential above the level in this study.

High risk of lateral migration due to pressure sinks is recorded for all three hydrocarbon Units, this 'high' rating reflects the presence of the producing reservoir so is of little consequence in the context of a normalisation exercise. High risking of lateral migration in Forties e.g. **Figure 22**, where structural, depositional, hydrodynamics, rugosity and dip are all high or very high risk reflects a methodology that is designed to assess migration across geographically extensive Units with no defined structural closures. This approach is valid for data-poor aquifer Units; the Forties aquifer should be associated with high risk of lateral migration despite the presence of numerous local buoyancy traps at the top of the reservoir (as evidenced by the producing oilfields), these occupy a small fraction of the aquifer volume and are likely to only locally impede CO_2 migration. The risking methodology is not designed to explicitly recognize these structures, though the rugosity assessment should partly capture them. An examination of the database shows that all Forties aquifer Units (Unit i.d.s 368-372) have at least three high risk items within the lateral migration category.

The normalisation Units are included in the following section and have cumulative risk scores in the lower third of Units confirming the validity of the risking methodology on a gross scale.

4.5 Cumulative Risk and Confidence Scoring

To provide a means of comparing the overall risk and associated confidence/uncertainty of individual Units and regional averages, a cumulative scoring system was developed. As shown on **Figure 24**, values from 1-5 are assigned to risk items based on increasing risk, with

5 assigned to very high risk items. A weighting based on confidence is included with the risk score with an addition of 2 to low confidence, 1 to medium confidence and no alteration to the risk score with high confidence. The confidence weighted risk score therefore has a range from 1-7 (**Figure 25**). Unknowns have been assigned a mid case score of 3.5.

Therefore Units with a high count high (or very high) risk items and lower confidence will have the highest score. An abundance of unknowns will not lead to a bias in either direction (high or low score).

Figure 26 shows the cumulative risk score for all UKCS aquifer Units based on capacity impact, while **Figure 27** shows the equivalent cost impact results. Storage Units are colour coded by basin, with selected high and low risk Units labeled.

On all figures the Units are listed by their unique identification number. To allow comparison of cumulative risk for aquifer Units with cumulative risk for the hydrocarbon pools assessed in the normalization exercise, the results for the three fields from the normalization exercise are plotted on the left hand side of each figure. Summarising the data on the figures, **Table 7** shows average values for cost and capacity impact risk broken down by risk category (operational, containment) and UKCS sub basin.

Sub-basin/Unit (number of Units)	All risks	Containment	Operational
Capacity impact			
UKCS (370)	79	55	24
NNS (68)	82	56	24
CNS (213)	80	56	24
SNS (60)	72	51	23
EIS (26)	80	55	26
English Channel (3)	77	52	24
Rough (1)	66	46	13
Forties (1)	62	47	15
Brent (1)	59	45	14
Cost impact			
UKCS (370)	90	62	27
NNS (68)	91	64	26
CNS (213)	92	63	27
SNS (60)	83	56	27
EIS (26)	88	59	28
English Channel (3)	83	55	27
Rough (1)	74	55	*19*
Forties (1)	78	57	*21*
Brent (1)	82	56	*25*

Table 6: Average Cumulative Risk Scores for UKCS Subdivisions and Normalisation-Hydrocarbon Units

Cost impacts are typically higher than capacity impacts; in particular for lateral migration, well integrity, formation damage, and vertical compartmentalisation (e.g. **Figure 4**). This causes an increase in the cost-impact risk scores for Units and areas over the capacity-impact; compare the upper and lower parts of **Table 6**. For all UKCS aquifer Units the capacity impact average risk score is 79 while the average cost impact score is 90, this difference is also pronounced for containment and operational components, for areal averages and for the example hydrocarbon Units.

In terms of variation in area averages across the UKCS, the Northern North Sea is higher risk than the other areas in both overall ('all risks'), containment and operational risk terms (**Table 6, Figures 26-27)**, this reflects greater data density and high quality, well characterized seals especially in the Central and Southern North Sea areas.

The three hydrocarbon Units used for normalisation: Rough, Forties and Britannia have very low values compared to the area averages, (**Figures 26-27**) reflecting good containment integrity, operational performance and adequate data availability.

In both capacity and cost impact terms many of the lowest risk Units are in the Central and Southern North Seas, including the Triassic Bunter Sandstone (e.g. Units 128, 138, 153, 229, 230) reflecting good quality seals, few well penetrations, formation integrity and limited compartmentalisation (**Figures 26-27**). Jurassic sands of the Chanter Member of the Piper Formation and Cretaceous Britannia Sandstone Formation (Units 212 and 220.001) are also highly rated, with low risk of lateral migration and good seal integrity distinguishing the Piper Unit and low risk of compartmentalisation and good seal integrity respectively for the Britannia Unit.

Notable very high risk Units in cost and capacity terms include a number of Northern and Central North Sea Triassic reservoirs e.g. Cormorant Units (Units 1-17) in the Northern North Sea and the Judy sands (Units 51 and 68) in the Central North Sea. All these Triassic Units have high risk of compartmentalisation, faulting, seal integrity and are low confidence. Similar risks and uncertainty are recorded for the Devonian Buchan Formation (Unit 216), while some of the Ormskirk Sandstone Units (a Bunter equivalent) in the East Irish Sea have high scores due to faulting and compartmentalisation. Another high risk Unit, the Southern North Sea Zechsteinkalk Formation at high risk of compartmentalisation, is limited in extent and is therefore likely to not provide a significant storage volume. Some Central North Sea Paleocene turbidite fan Units expected to be large capacity e.g. the Sele Formation Forties Sandstone Member Units 366 and 367, have high scores reflecting localised higher fault density, interference from production and lateral migration risk in the Forties aquifer. In contrast, the Forties field (233.003), though also part of the Forties aquifer, has subtle differences in reservoir properties and structure, greater data density and a lower overall risk than many Forties aquifer Units. Recent updates to some Paleocene Units (i.e. May 2011) Maureen Formation suggest that these may also have high cumulative risk score with the impact of high formation fluid pressures and shallow depth particularly bad for seal integrity.

4.6 Mitigation

Three experts were asked individually to assess each risk mechanism and the results are compiled in **Table 7**. The risk mechanisms are separated into three categories: those which all experts agreed could be mitigated; those for which there was no consensus but at least one expert thought mitigation was possible: and those for which all experts agreed could not be mitigated. For the majority of the risk mechanisms, at least one potential mitigation strategy was suggested, however for four risk mechanisms the experts all agreed that there was no mitigation option available meaning that should one of these mechanisms occur there is nothing that can be done to prevent the negative impacts occurring. These four are the 'seal degradation' mechanism and the three mechanisms in the faulting subcategory. This assessment of mitigation potential is consistent with the results of the severity ranking exercise which found these mechanisms to be high impact severity for capacity and also high impact severity for costs. However the best-guess and lower bound values for the severity assessments (**Figure 4**) suggest that for these four mechanisms, the experts (which included the three that contributed to the mitigation listing) believed some activities could be envisaged that would at least make the impacts manageable, if only for the costs.

Consensus - can be mitigated	**No consensus – at least one mitigation strategy suggested**	**Consensus – can not be mitigated**
• Fracture pressure capacity (*seal failure*) • Pressure sinks in storage Unit (*lateral migration*) • Well density (*wells*) • Well vintage (*wells*) • stratigraphic compartmentalisation vertical (*dynamic capacity*) • stratigraphic compartmentalisation horizontal (*dynamic capacity*) • diagenetic compartmentalisation (*dynamic capacity*) • structural/fault compartmentalisation (*dynamic capacity*)	• Seal chemical reactivity (*seal failure*) • Structural trend (*lateral migration*) • Depositional/diagenetic fabric (*lateral migration*) • Dip Direction (*lateral migration*) • Dip (*lateral migration*) • Rugosity (*lateral migration*) • Hydrodynamics (*lateral migration*) • Transnational migration (*lateral migration*) • mineralogy of reservoir: grains and cements (*formation damage*) • mechanical integrity of reservoir (*formation damage*) • salinity (*formation damage*) • Pressure isolation (*dynamic capacity*)	• Seal degradation (*seal failure*) • Faults density (relative to defined Unit size) (*Faults*) • Faults Throw (is estimated offset greater than effective seal thickness (*Faults*) • Faults vertical extent (do faults terminate >800m depth etc.) (*Faults*)

Table 7: Risk mechanisms categorised as consensus can be mitigated, no consensus but at least one expert has suggested a mitigation strategy and consensus, cannot be mitigated

Table 8 shows the suggested mitigation strategies/activities for each risk mechanism and the associated costs. The most expensive mitigation strategies are those associated with the lateral migration risk mechanisms where an upper limit of 100% total project costs are estimated. Should the actual costs associated with these activities reach or exceed this upper limit, it is possible that these costs would be considered unacceptable. Hence while a technical solution may be available to mitigate these risks, the financial cost of doing so would be considered too high. This assessment does not include an evaluation of the technical challenges associated with each mitigation strategy and further analysis could help distinguish the relative difficulty in implementing the different mitigation strategies.

Risk Mechanism	Mitigation Strategy	Cost
Fracture pressure capacity (*seal failure*)	Manage pressure, More injection wells, Produce water	~doubling of drilling costs. 5% per well, Additional 2% for water disposal. Estimate 10% of total project costs.
Pressure sinks in storage Unit (*lateral migration*)	Pressure Management Stop injection Re-assess and monitor Possibly – Produce water Inject water Inject CO_2 elsewhere Pay compensation	10% - 100% total project costs. Estimate 10%.
Well density (*wells*)	Avoid pressurising near known wells, · Monitor (more wells) – remediate as necessary – rework wells	Estimate > 10% (5% - 50%) project costs.
Well vintage (*wells*)	Avoid pressurising near known wells, · Monitor (more wells) – remediate as necessary – rework wells	Estimate > 10% (5% - 50%) project costs.
stratigraphic compartmentalisation vertical (*dynamic capacity*)	More wells or perforate more intervals. Pressure relief/water production.	Max doubling drilling costs, estimated 5% – 50% total project costs.
stratigraphic compartmentalisation horizontal (*dynamic capacity*)	More wells or perforate more intervals. Pressure relief/water production.	Max doubling drilling costs, estimated 5% – 50% total project costs.
diagenetic compartmentalisation (*dynamic capacity*)	More wells or perforate more intervals. Pressure relief/water production.	Max doubling drilling costs, estimated 5% – 50% total project costs.
structural/fault compartmentalisation (*dynamic capacity*)	More wells or perforate more intervals. Pressure relief/water production.	Max doubling drilling costs, estimated 5% – 50% total project costs.
Seal chemical reactivity (*seal failure*)	Avoid reactive thin seals, Manage reactivity, saturate formation water with suitable cations	Estimate 25% of project costs

Structural trend (*lateral migration*)	Modify injection strategy. Stop injection Re-assess and monitor Possibly – Produce water Inject water Inject CO_2 elsewhere	10% - 100% total project costs. Estimate 50%
Depositional/diagenetic fabric (*lateral migration*)	Modify injection strategy. Stop injection Re-assess and monitor Possibly – Produce water Inject water Inject CO_2 elsewhere	10% - 100% total project costs. Estimate 50%
Dip Direction (*lateral migration*)	Modify injection strategy. Stop injection Re-assess and monitor Possibly – Produce water Inject water Inject CO_2 elsewhere	10% - 100% total project costs. Estimate 50%
Dip (*lateral migration*)	Modify injection strategy. Stop injection Re-assess and monitor Possibly – Produce water Inject water Inject CO_2 elsewhere	10% - 100% total project costs. Estimate 50%
Rugosity (*lateral migration*)	Modify injection strategy. Stop injection Re-assess and monitor Possibly – Produce water Inject water Inject CO_2 elsewhere	10% - 100% total project costs. Estimate 50%
Hydrodynamics (*lateral migration*)	Modify injection strategy. Stop injection Re-assess and monitor Possibly – Produce water Inject water Inject CO_2 elsewhere	10% - 100% total project costs. Estimate 50%

Transnational migration (*lateral migration*)	Pay compensation	Unknown
Mineralogy of reservoir: grains and cements (*formation damage*)	Rework well or drill new well. Fracture stimulation.	Could double drilling costs. 1% per well for fracture stimulation.
Mechanical integrity of reservoir (*formation damage*)	Rework well or drill new well.	Could double drilling costs. 5% per well.
Salinity (*formation damage*)	Squeeze job or drill new well in worst case.	2x drilling costs (max)
Pressure isolation (*dynamic capacity*)	Drill more wells or perforate more intervals. Pressure relief/water production	Drilling – more than double drilling costs (max), more intervals (rel. inexpensive). Estimate 5% - 50% total project costs.

Table 8: Suggested Mitigation Strategies for Risk Mechanisms and Estimated Cost Green are those risk mechanisms which all experts agree can be mitigated, yellow are risk mechanisms on which the experts disagree about whether they can be mitigated where at least one expert has suggested a potential mitigation strategy.

4.7 Confidence Data

Confidence data are now reported separately from the likelihood data. Unknown, low, medium, and high confidence for each Unit will be illustrated as in **Figure 28**. Confidence data have been integrated into the cumulative scoring system (**Section 4.5)**. A summary of the relationship between likelihood and confidence data for individual Units as trends across the UKCS can be found in the original work package 2 report.

5 Recommendations

The following recommendations are condensed from the participant reports and the risk peer review (**Appendix 6.2 (2)**).

5.1 Containment Risk

5.1.1 Seal

Better definition of the stratigraphic and areal extent of the Units would allow for more detailed assessment of the requested parameters, i.e. interaction with adjacent Units and lithologies and basement and ceiling barriers.

5.1.2 Faulting

Structural interpretation of high resolution seismic data using more complete well control for each of the most promising storage Units is recommended. Using seismic interpretation software the horizons could be auto-tracked. This would allow faults with smaller displacements to be automatically picked, at a higher resolution than can be done with the human eye. If portrayed on geo-referenced maps, this would give a better representation of the density of faulting for a given area.

It is also recommended that seismic data in the East Irish Sea should be obtained in order to better assess risk in this area.

5.1.3 Lateral Migration

5.1.3.1 Structural Trend

Edge or curvature maps of the different formation tops would give a more accurate structural trend estimate.

5.1.3.2 Dip Direction and Dip Magnitude

Average dip does not reflect the architecture of the Unit, and up-dip angle relative to the injection point is important. Average dip angles could be computed using suitable software where digital surfaces are available.

5.1.3.3 Diagenesis

Further work (e.g. core analysis) for high rated units could be carried out as there are very little publically available data for this field.

5.1.4 Wells

The well risking reported here and associated GIS was completed in advance of Carbonstore completion. Integration of GRL's wells GIS with the Carbonstore GIS would reduce uncertainty and allow updates to shapefiles and wells. Use of true vertical depth for the total depth of the well, deviation surveys and top unit structure maps would help reduce uncertainty in assessment of potential well penetrations.

5.2 Operational Risk

No specific recommendations from participants.

5.3 Risk Review Team Recommendations

A number of recommendations were put forward by the risk review team; much of the emphasis was on the provisional and screening nature of the risk assessment employed. To move to the next level in terms of confidence in storage site viability and risk, a probabilistic approach using a range of risking methodologies is recommend, this will provide a more comprehensive, quantitative risk assessment. Some additional recommendations and comments are outlined below:

- A future functionality could be the ability of the database to update well risk based on the addition of new wells and their characteristics: hydrocarbon exploration, appraisal and development and CO_2 storage wells, including completion type, deviation etc.

- The assumption of better completions for wells over time and when the oil price is low is based on published work (Watson and Bachu 2007) on onshore well integrity, and was questioned by project sponsors (from operating companies). However it is likely that well completion and abandonment procedures have improved following the 1996 legislation (**Appendix A6.2 (2)**), and after discussion with project sponsors it was considered reasonable to use 1985 -1996 as the mid case in terms of well vintage related integrity, with wells drilled before 1985 considered high risk on age criteria.

- The assessment of well integrity is far from comprehensive, a more complete assessment as would be suitable for a site or structure specific study would include an assessment of well leakage risk based on well depth, well temperature, overpressure, formation type and age, formation fluids, plugging regime, production logging evidence, drilling and completion performance etc.

- The potential for migration from one Unit to another is not considered in the severity of impact assessment, though the project GIS and associated data could allow such an assessment

- Assessment of seal failure via fracturing relates Unit thickness to seal strength and uses the same calculations of seal fracture failure as the capacity assessment for hydraulically closed Units, i.e. identification of the pressure limitations. However the seal risking methodology does not take into account the fact that the background pressure would increase in a hydraulically sealed closed Unit and therefore the pressure on the seal would include both the CO_2 column buoyancy pressure in addition to the overall Unit-wide ‘background’ pressure increase. Contrastingly the closed Unit capacity assessments assume homogenous pressure distribution and do not assess the location of the injected CO_2 and influence of any local CO_2 column development. Thus the two applications of pressure data to capacity and seal integrity are complementary.

- The capillary entry pressure at which CO_2 will be able to enter the caprock provides another important constraint on seal integrity and in a more complete study would be a key risk deserving detailed quantitative assessment. In some examples capillary entry pressure for non wetting fluids is less than the pressure at which the seal would fracture (e.g. Watts 1987), and seals will leak prior to fracturing. In such cases the capacity estimates for CO_2 would be too high and risk estimates too low. Considering the data and time constraints and > 350 Units in this screening-level, basin-scale study it was decided not to undertake an estimate of capillary entry pressure.

- The impacts on cost and capacity considered here are only a fraction of the potential impacts, in a more detailed or site specific study health and safety, environment and industrial viability (which includes media and public opposition) would also deserve assessment in the context of a risk assessment. Additionally the list of risk items and applied methodologies would likely be far more extensive (e.g. Condor et al. 2010).

- Fault risking is high for aquifer and exemplar hydrocarbon Units. Does this mean faulting risking criteria are too stringent? Faults are present in many commercially viable hydrocarbon reservoirs, throws can be large enough to juxtapose sand on sand, faults can be vertically extensive and can define compartments due to fault seal for wetting and non wetting fluids. An ideal methodology would recognise the presence of faults, quantify density, orientation, offset, clay gouge, and extent, and evaluate the likelihood of leakage via an assessment of fault seal in the context of the regional stress regime, lithologies and pressure evolution during injection. Thus the high fault density would be conditioned by the evidence for adequate fault seal. However, assessing fault seal in this way is time and data intensive and typically requires extensive and site-specific data on stress, rock properties, fault orientation, shale thickness etc. In the absence of these data, and in the context of a study that attempts to evaluate more than 350 UKCS storage Units, two approaches are possible:

    1. A conservative approach as used in this study, would be to assume that high fault density, significant throws (with ref to caprock thickness) and vertical extent are indicative of the potentially high risk of leakage associated with fault flow (or cross formational flow via fault sand-sand juxtaposition). The weakness of this conservative approach is illustrated by the hydrocarbon field assessment, where, although all the features that might lead to leakage via faults are present, the faults clearly do not leak (at least at a significant enough rate to make the prospect sub economic)

    2. The alternative would be to relax the assessment definitions to a level that would rate the risk of fault leakage from the exemplar hydrocarbon fields as low, this approach could lead to aquifer Units with fluid transmitting faults, for example a failed hydrocarbon trap in a play with significant hydrocarbon charge being ranked as low risk

The first approach, although more conservative should encourage the detailed assessment of fault seal in future studies and is therefore preferable.

6 Costing Appraisal

Hydrocarbon field development data were evaluated to calibrate work package 2 input to work package 3; the economic assessment of CO_2 storage in the UKCS. Data from a subset of UKCS hydrocarbon fields were used to calculate appraisal well density and appraisal well ratio to total recovered oil along with seismic area coverage (**Table 9**). Using the results of this hydrocarbon field assessment as a means of normalizing appraisal data requirements, two methods, one based on area and one based on capacity, are available to estimate appraisal costs for UKSAP storage Units.

Typical well density at the appraisal stage 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 of field area. Based on total (estimated) recoverable volumes, between 5 and 50 MT (~35-350 mm bbls) of oil are recovered for every appraisal well drilled. The fields analysed were developed using close spaced 2D or 3D seismic data. Development for CO_2 storage would probably require 3D data. Time from discovery to first oil varies from less than 2 to more than 20 years, considering the already discovered nature of potential storage sites, a reasonable appraisal time frame for a mature CCS industry could be 5 years from beginning of appraisal to first CO_2 injection. In concert with UKSAP data for storage Units (capacity, area etc.) and cost estimates, this analysis of hydrocarbon field appraisal costs and strategy provides a means to estimate total appraisal costs for aquifer sites.

Well costs are estimated at USD10M per well (2009 costs) for a jackup or semisubmersible drilling rig on the UK continental shelf (UKCS). Total well costs are assumed to include drilling, completion, logging, sampling, fluid and pressure testing, core recovery (reservoir + caprock) and short term well testing (i.e. for permeability measurement). UKCS 3D Seismic cost estimates used here are USD 50,000/km^2. The well and seismic costs are highly uncertain and variable, and are perhaps associated with an error of -50% to +250%, with a cost increase more likely in a high oil price environment. For example typical 2011 costs with oil at more than USD100 per barrel are expected to be at least USD15-20 million/well. Included within these costs are the desk and lab components associated with well and seismic data processing and interpretation.

It is likely that new appraisal wells will be required at all sites. Storage sites with early availability are unlikely to be hydrocarbon bearing so will require extensive characterisation, while those with abundant data from in situ hydrocarbon pools will carry similar costs for target injection locations away from the accumulations, and significant costs for well management in areas exposed to migrating CO_2. Hydrocarbon wells that traverse to deeper prospects typically contain insufficient data for reservoir characterisation in any overburden formations that might be prospective for CO_2 disposal (typically only gamma ray and sonic logs), while, away from oil bearing structures, existing regional seismic data are likely to be insufficient for comprehensive site characterisation.

The cost of appraisal wells dominates appraisal costs. Any difference in appraisal cost as a result of the variation in risk between different UKSAP Units and associated variation in data requirements is likely to introduce a minor additional cost. For example special core analysis (SCAL) and follow up desk study could be USD100,000 – 1 million (i.e. for relative permeability, geomechanical analysis and core flooding). A very high risk and/or low confidence site may have a number of such technical needs and these could add up to a maximum of approximately 10% of total appraisal costs. To include the spectrum of risks and uncertainty in site appraisal costs and thus reflect the need for additional work to characterise these risks, a cost weighting is applied based on the cumulative risk-confidence scoring (**Section 4.5**). This cost weighting leads to an increase of between 5-15% in the appraisal costs (low-high risk).

The application of mitigation activities is speculative and technology dependant; cost estimates included in **Section 4.6** have uncertainty ranges of 10-100% of project costs, so these are not included in the risk weighted appraisal cost estimates.

Table 9 shows actual development details from Gluyas and Hitchens 2003 and hypothetical costs for a subset of UKCS hydrocarbon fields assuming the 2009 well and seismic costs.

Typical appraisal well density for hydrocarbon developments is one well for every 5-20 km^2. Reflecting the upper end of this scale (and the anticipated lower value of the product), the well density used for CO_2 sequestration site characterisation costing is 1 well per 25 km^2. Applying the well cost, well density and seismic costs and a 5-15% premium based on the cumulative risk score (**Section 4.5**, **Table 6**, cost impact) to a sample set of UKSAP aquifer Units leads to the appraisal costs summarised in **Table 10**. Risk-weighted appraisal costs based on Unit area and the preceding cost assumptions range from \$0.62-10.14 per tonne and vary as a result of the volume of viable storage reservoir assessed per Unit area; a number calculated from the following variables *inter alia*: pore volume, pressure constraints and CO_2 density. An alternative approach, based on estimating appraisal wells required for projected tonnes stored provides more tightly constrained appraisal costs. If for example one appraisal well was required for every 20 million tonnes storage then total appraisal costs, which are primarily a function of well count and well cost would be \$0.60-2.50/tonne. For reference, on average 5-50 million tonnes of oil are recovered for each appraisal well in the hydrocarbon field examples (**Table 9**). Following a review of these alternative approaches the appraisal costing framework for WP3 was agreed as follows:

- One appraisal well per 20 MT CO_2, i.e. total storage capacity estimate (MT)/20, well cost of USD 10M
- 3D seismic for full storage Unit area, fixed cost of USD 50,000/km^2
- Risk premium as a percentage based on cumulative risk score/10

The worked example on **Figure 29** shows how appraisal costs are calculated based on the above constraints.

Field	Field area (km2)	Expected ultimate recovery TCF gas or mm bbls/MT oil	Appraisal well count (area per well, total well count)	Million tonnes oil recovered per appraisal well	Time to first oil from discovery	Appraisal well costs USD	Seismic costs (assumes 3D over area)	Total appraisal cost	Appraisal cost/T oil based on area
Leman	**300**	**9TCF/230MT**	**18 (20, 192)**	13	**12/65 through ?/68, <2 years**	**$150,000,000**	**$15,000,000**	**$165,000,000**	**$0.21**
Brent	**200**	**6TCF+2000mmbbls/460MT**	**10 (20, 130)**	46	**71-76, 5 years**	**$100,000,000**	**$10,000,000**	**$110,000,000**	**$0.24**
Nelson	**125**	**450mmbbl/70MT**	**16 (8, 40+)**	29	**67-94, 27 years**	**$160,000,000**	**$6,250,000**	**$166,250,000**	**$2.38**
Thistle	**50**	**400mmbbls/60MT**	**7 (7,35+)**	9	**72-78, 6 years**	**$70,000,000**	**$2,500,000**	**$72,500,000**	**$1.21**
South Brae	**25**	**300mmbbls/45MT**	**8 (4, 42)**	6	**77-83, 6 years**	**$70,000,000**	**$1,250,000**	**$71,250,000**	**$1.58**
Cladhan	**35**	**150mmbbls/25 MT**	**5 (7,?)**	5	**n/a**	**$50,000,000**	**$1,750,000**	**$51,750,000**	**$0.35**
Hewett	**150**	**3.5TCF/100MT**	**7 (30, 15)**	14	**66-69, 3 years**	**$50,000,000**	**$7,500,000**	**$57,500,000**	**$0.38**

Table 9: Hydrocarbon fields used to estimate appraisal wells and seismic requirements. TCF = trillion cubic feet (standard conditions), mm= million, bbls = barrels, boe =barrels of oil (energy) equivalent, MT = millions of tonnes

Field area is typically an area greater than the hydrocarbon pool boundary (hydrocarbon water contact) over which appraisal seismic survey data is collected. Exploration wells are treated as appraisal wells and total well counts are those from Gluyas and Hitchens 2003.

Unit i.d. and name	Area (km2)	Capacity estimate and method1 (MT CO2)	Exploration and appraisal well count (based on 1 well/25km2)	Well costs USD	3D seismic costs (USD)	Total appraisal cost (USD)	Appraisal cost (area)/tonne CO2	Cumulative risk score (50-120)	Risk premium	Appraisal + risk premium/tonne CO2
226.000 Bunter Sst Fm	4990	2314 PV*E	200	$2,000,000,000	$250,000,000	$2,245,522,500	$0.97	84	$0.08	$1.05
4.000 Cormorant Fm	350	17 PC?	14	$140,000,000	$17,545,500	$157,909,500	$9.29	102	$0.95	$10.14
233 Forties Sst Mbr	14462	926 PC	578	$5,780,000,000	$723,100,500	$6,507,904,500	$7.03	84	$0.59	$7.62
234 Heimdal	10389	2594 PC	416	$4,160,000,000	$519,439,500	$4,674,955,500	$1.80	92	$0.17	$1.97
385 CNS Claymore	303	238 PC	12	$120,000,000	$15,154,500	$136,390,500	$0.57	86	$0.05	$0.62
218.000 Captain Sst Mbr	6207	777 PV*E	104	$1,040,000,000	$130,342,500	$1,173,082,500	$1.51	100	$0.15	$1.66

Table 10: Appraisal costs with risk premium for example UKSAP aquifer Units, MT = millions of tonnes

Area and capacity from UKSAP database circa mid April 2011. Some Units have since been modified. Risk premium is calculated as % increase in costs based on cumulative risk score divided by 10 e.g. Unit 226.000 has 8.4% additional appraisal costs based on risk score. PV*E is the efficiency factor applied to net pore volume, PC is pressure capacity i.e. capacity constrained by fracture pressure and hydraulic compartment estimates (see Work Package 1).

7 Conclusions

Likelihood and confidence data were collected and interpreted for each aquifer storage Unit identified in Work Package 1. Severity of impact was assessed on a UKCS-wide basis by an expert group that included participant and sponsor members. The output of the risk assessment includes Boston square type risk matrices for each storage Unit, integrating likelihood and severity of impact data.

The decision to limit the Unit risk assessment to likelihood and confidence data and to assess impact on a generic basis was based on the large areal coverage required (entire UK continental shelf), constraints inherent in the source data including the uncertainty in structural definition, and limited knowledge of the magnitude of impacts resulting from lack of experience of operational CCS.

Quality control of the confidence and likelihood data 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. Quality control also included a review of a subset of Units as they were completed, followed by feedback to the participants. A final quality control exercise included normalisation and peer review, carried out alongside the severity of impact ranking.

The normalisation exercise undertook likelihood and severity assessment of a subset of hydrocarbon reservoirs. The majority of risks assessed for these hydrocarbon reservoirs are ranked as low, with faulting a notable exception, reflecting a conservative methodology. Lateral migration is also high risk for the hydrocarbon Units, reflecting a methodology developed to assess migration across geographically extensive Units without defined traps.

The highest frequency containment risk items in terms of impact on storage capacity include all three fault leakage items and the risk of seal degradation. The latter reflects geological variability in seal quality across laterally extensive storage Units, while the former, partly the result of the conservative approach to fault risk assessment also shows that faults are a key feature at the majority of storage sites and consequently deserve immediate attention in site appraisal. Cost impact assessment using the same likelihood data leads to an elevation of lateral migration risks, with structural, depositional and dip magnitude controls the most important i.e. most frequent high risk items. Identification of the most common high risk items across the UKCS helps provide direction for future study to characterise the impact of the most important risk items.

For operational risk assessment the most frequent high risk mechanisms in the capacity impact category are structural and diagenetic controls on compartmentalisation. Cost impacts are more evenly spread across the operational risk mechanisms with structural compartmentalisation and mineralogical formation damage most frequently assessed as high risk. Compartmentalisation is often a high impact risk for oilfield developments, especially in the high cost offshore environment.

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).

An evaluation of the lateral migration risks associated with Units that are assessed as having no structural containment highlights the importance of depositional, structural and dip controls on lateral migration and storage security in these volumetrically important Units.

To provide a means of comparing the overall risk of each Unit, a cumulative scoring system integrating Unit risk and confidence data was developed. Many of the lowest risk Units are found in the Southern and Central North Seas including parts of the Bunter Sandstone in the Southern North Sea and the Cretaceous Britannia and Jurassic Piper Sandstones in the Central North Sea. The three hydrocarbon Units used for normalisation score in the low risk category in all cumulative assessments. Notable very high risk Units include compartmentalised Northern and Central North Sea Triassic reservoirs and Paleocene fan Units with high well density, high initial pore pressure and pressure interference from hydrocarbon operations and lateral migration risk.

Based on output from a sub-group of the risk review panel, outline estimates of risk mitigation have been generated, with feasibility and as a fraction of project cost.

With the exception of the summary cumulative scoring exercise all risk assessment is qualitative, considered appropriate for such a scoping study. A probabilistic approach using a range of risking methodologies is recommend for a site specific or sub basin-level study to provide a more comprehensive, quantitative risk assessment. A number of other modifications to the risking methodology are also recommended and many of these would be appropriate in a future basin-scale or country-wide study like this one.

Risk-weighted appraisal costs based on Unit area, normalised to hydrocarbon development strategy and costs, range from $0.62-10.14 per tonne CO_2 and vary as a result of the volume of viable storage reservoir assessed per Unit area.

8 References

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Figure 1 Example of data entry and guidance

Unit ID: 218.000
Description: Captain_013_17

Previous Unit | Next Unit | Data I | Risk | Data II | Results | Tools

Containment Risk - Seal

	Likelihood	Severity	Source	Confidence (L,M,H)
Lithostratigraphic name of Primary Seal	Hidra Fm			
Lithostratigraphic name of Secondary Seal	Chalk Group			
Fracture pressure capacity	high	unknown	Best judgement/ Anal	
Seal chemical reactivity	high	unknown	The Millenium Atlas:	
Seal degradation	medium	unknown	The Millenium Atlas:	

Likelihood Of Failure	Low	Medium	High	Very High
Seal Chemical reactivity	evaporites (halite, sulfates etc.)	dominated by fine - very fine grained silicates (mineralogically sub mature-mature)	seal includes carbonates, felsdpar, ferromagnesian silicates and/or minerlaogically immature	undefined

Figure 2 Illustrated risking guidance, fault assessment for two units using seismic cross section

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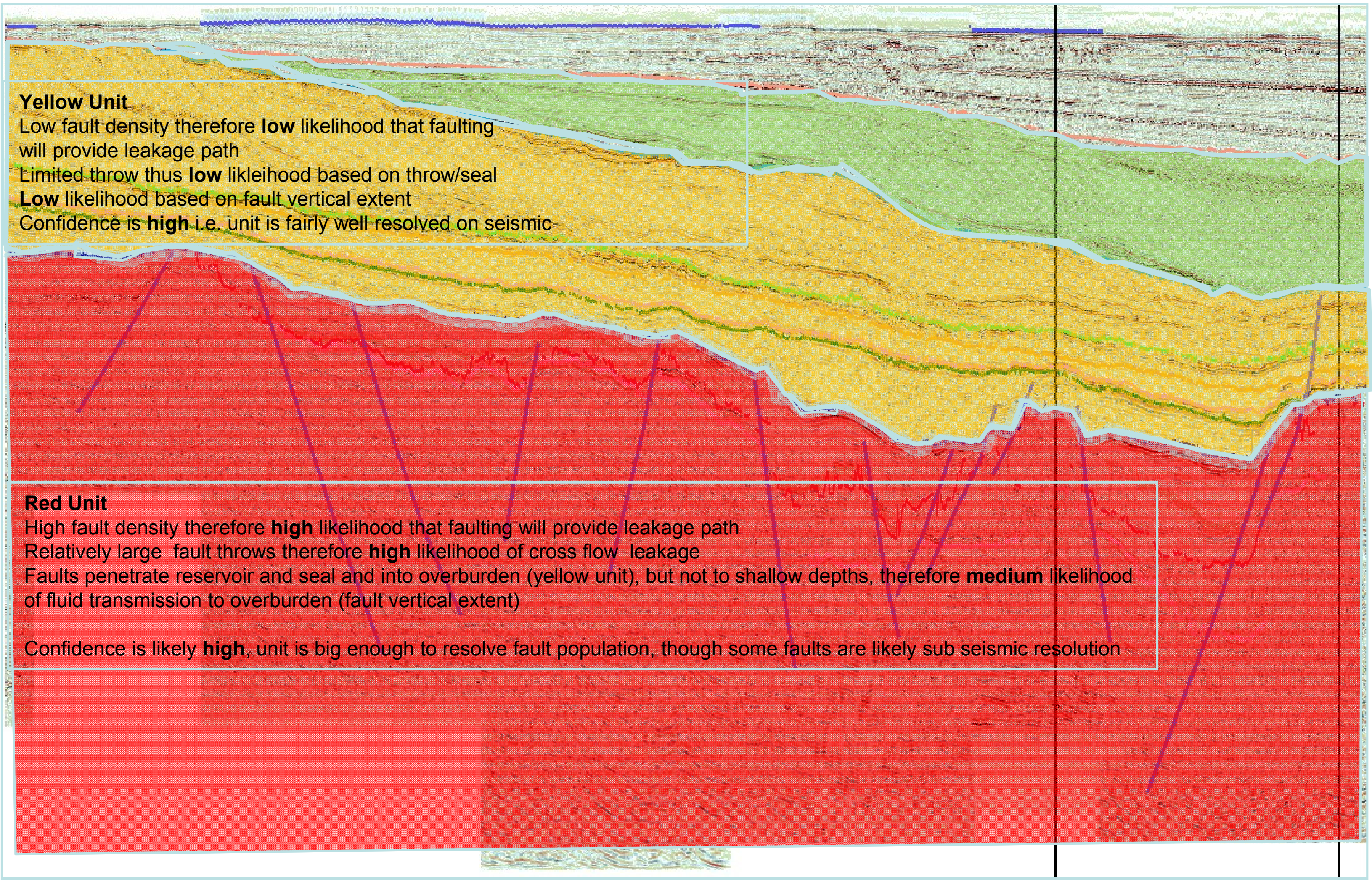


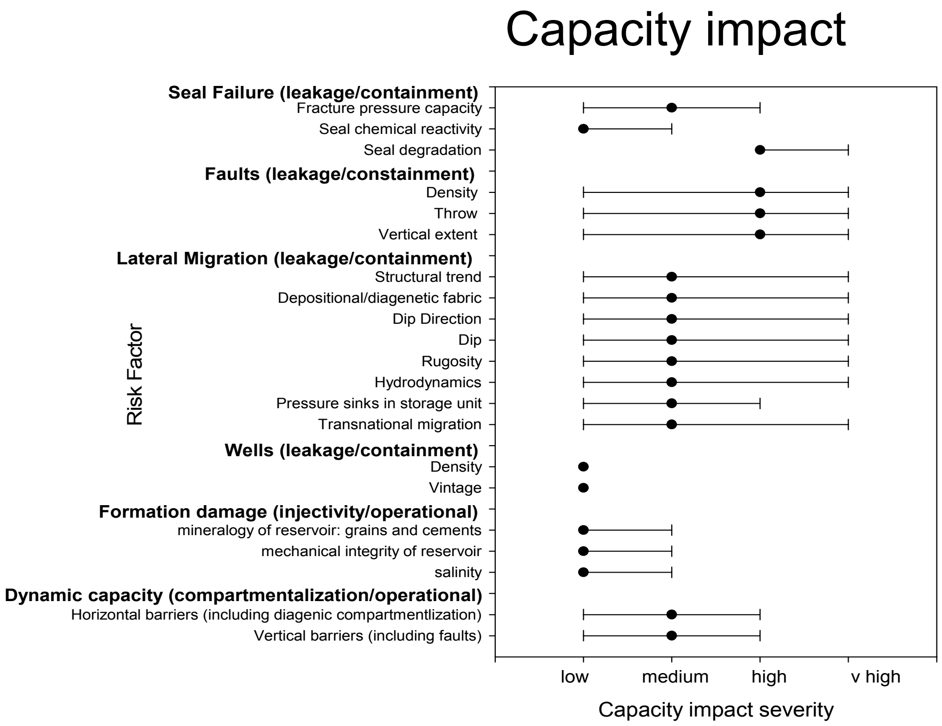
UKSAP

Figure 3 Agreed severity scales

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

UKSAP

Figure 4 Generic severity of impact rankings with ranges



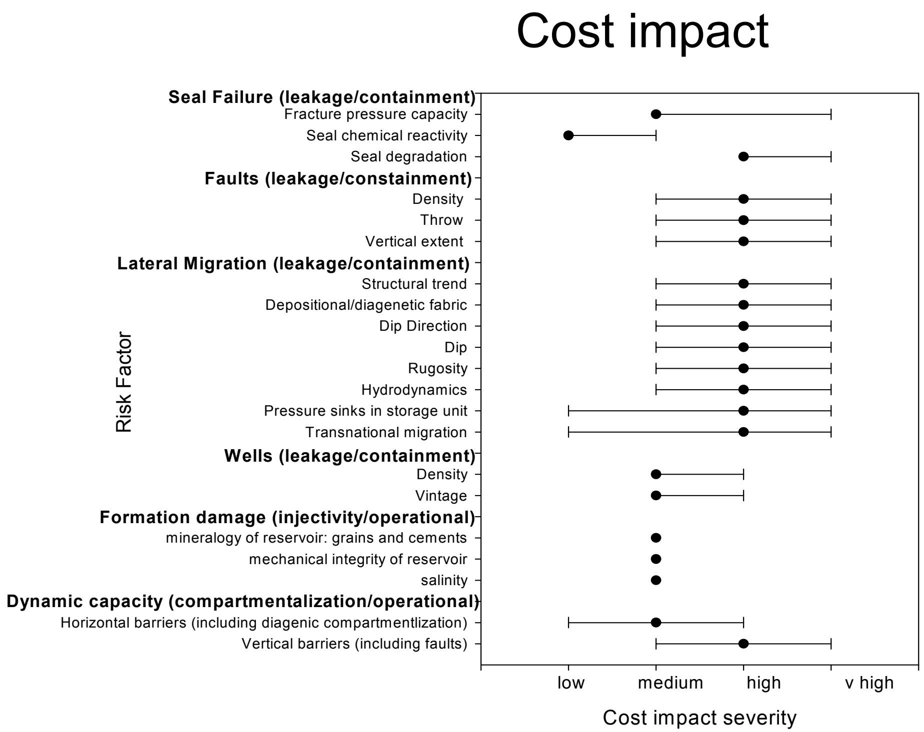


Figure 5 Risk matrix for capacity and cost impact

UKSAP

Severity of impact* \ Likelihood of occurrence	Low	Medium	High
Low	Very low risk	Low risk	Medium risk
Medium	Low risk	Medium risk	High risk
High	Medium risk	High risk	Very high risk

*though four severity bandings were used in the ranking exercise (Figure 2), the best guess values used to generate the risk matrices are all low, medium or high, hence nine boxes in matrix

Figure 6 Risk matrix for capacity impact
Bunter Sandstone Zone 6 Unit 226.000

UKSAP

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

Unknowns: *Migration dip magnitude*

UKSAP

Figure 7 Risk matrix for cost impact
Bunter Sandstone Zone 6 Unit 226.000

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

Likelihood of occurrence

Unknowns: *Migration dip magnitude*

Figure 8 Risk matrix for capacity impact
Cormorant 003_25 Unit 4.000

UKSAP

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

Likelihood of occurrence

Unknowns: *Formation mechanical integrity*, *Formation salinity*, Migration dip direction
Migration hydrodynamics

Figure 9 Risk matrix for cost impact
Cormorant 003_25 Unit 4.000

UKSAP

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

Unknowns: *Formation mechanical integrity, Formation salinity,* Migration dip direction
Migration hydrodynamics

UKSAP

Figure 10 Containment high and very high risk Units, capacity impact

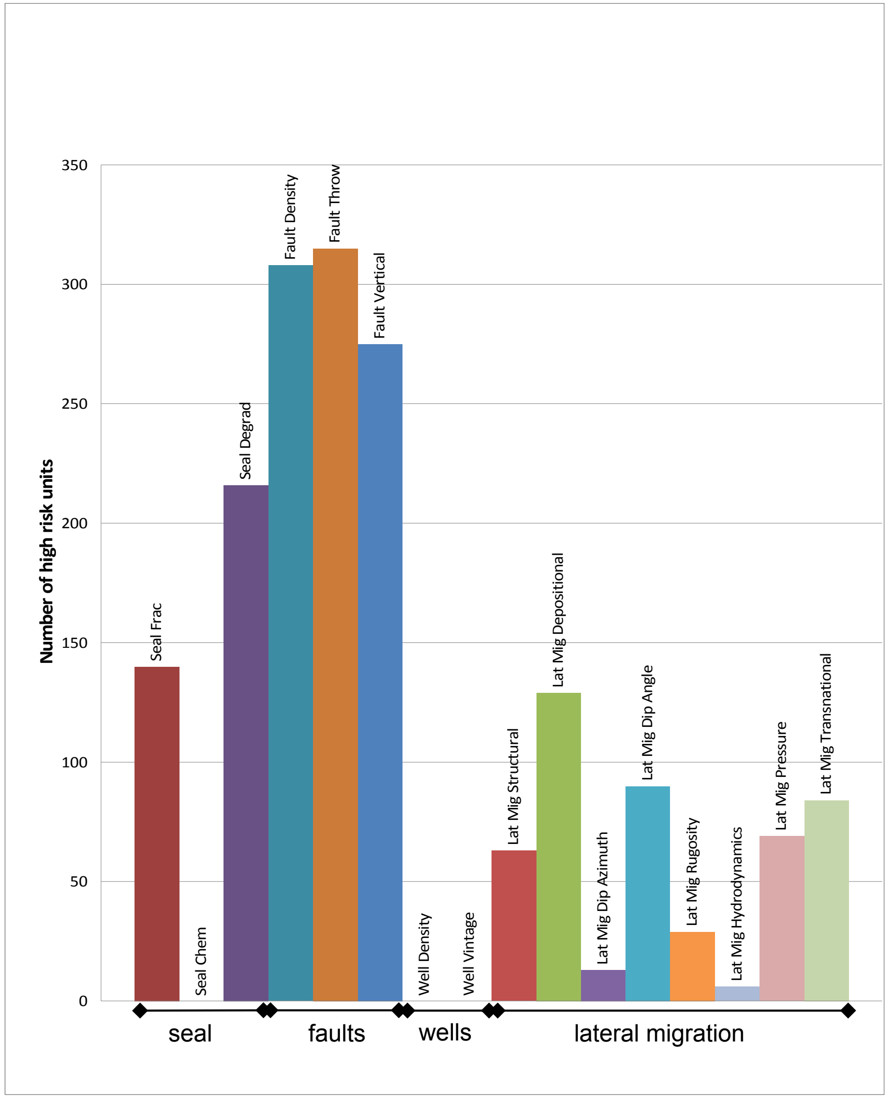


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Figure 11 Containment high and very high risk Units, cost impact

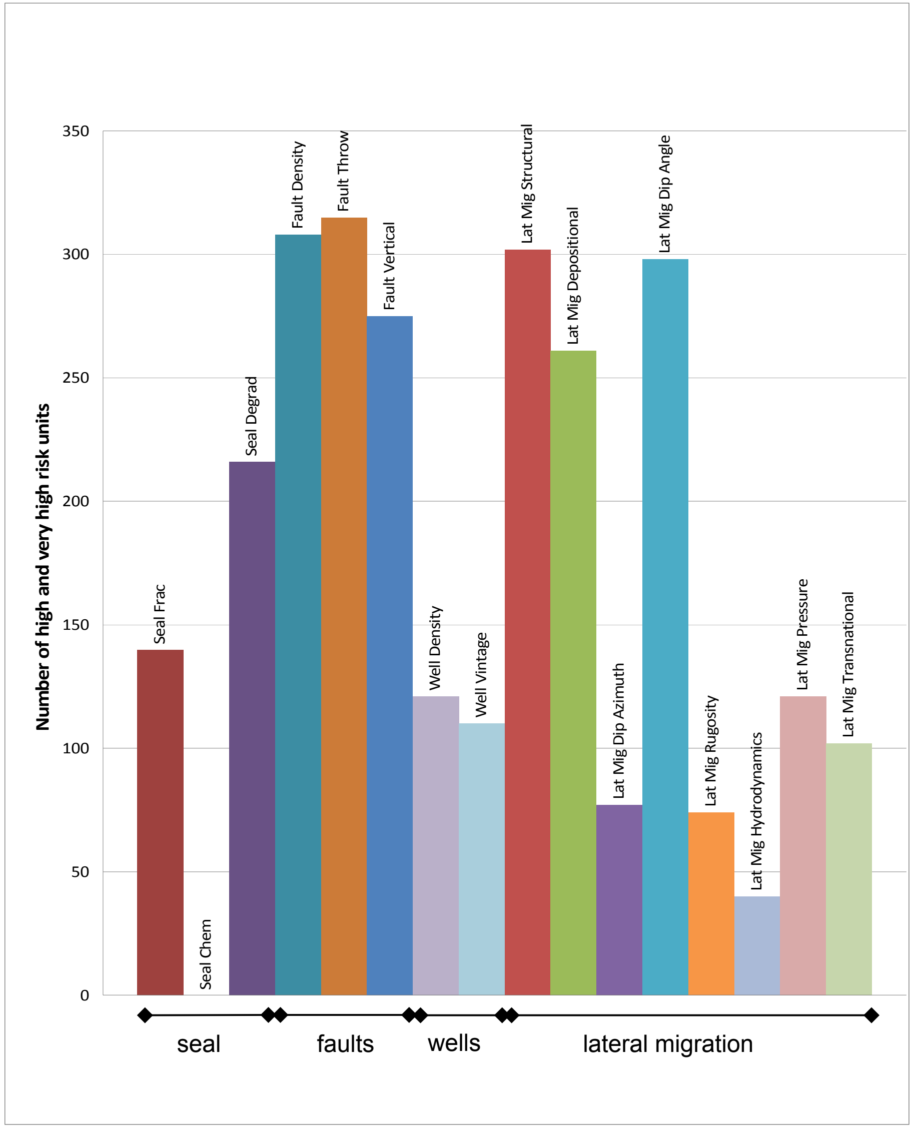

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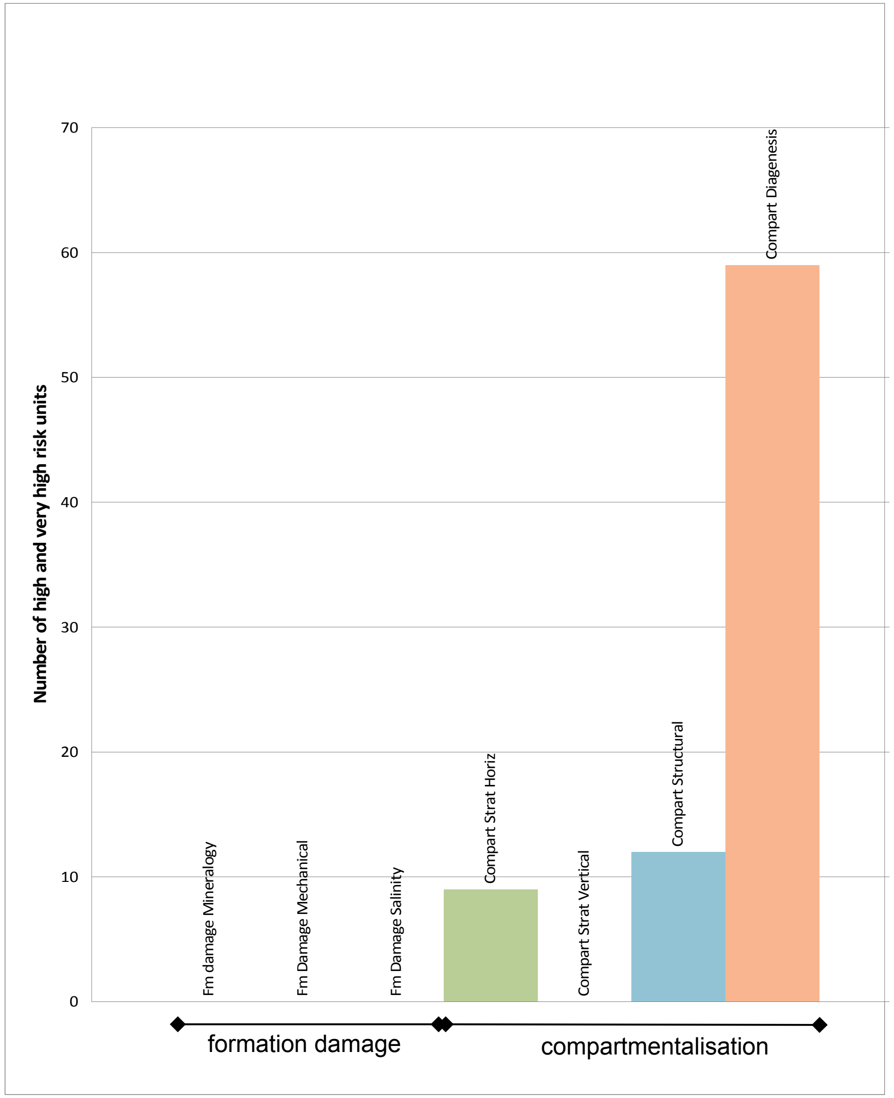
Figure 12 Operational high and very high risk Units, capacity impact



UKSAP

Figure 13 Operational high and very high risk Units, cost impact

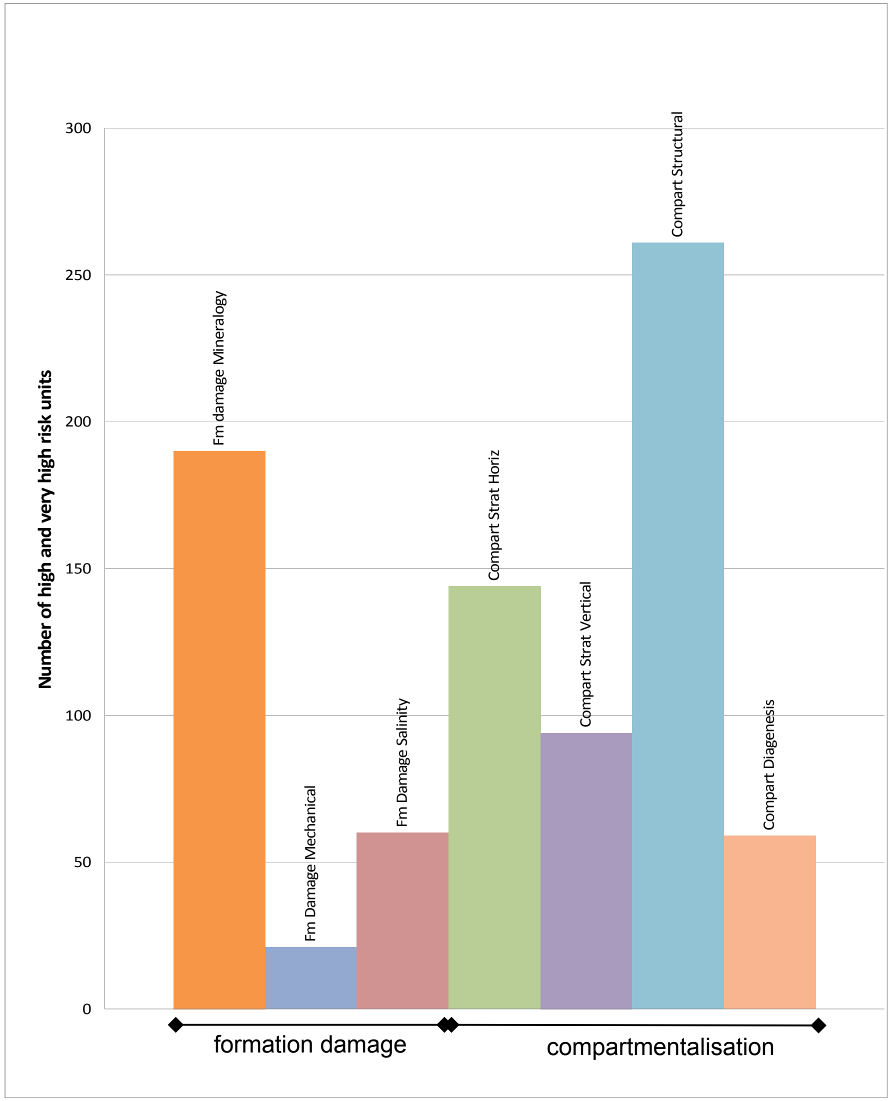


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Figure 14 Seal fracture risk by region

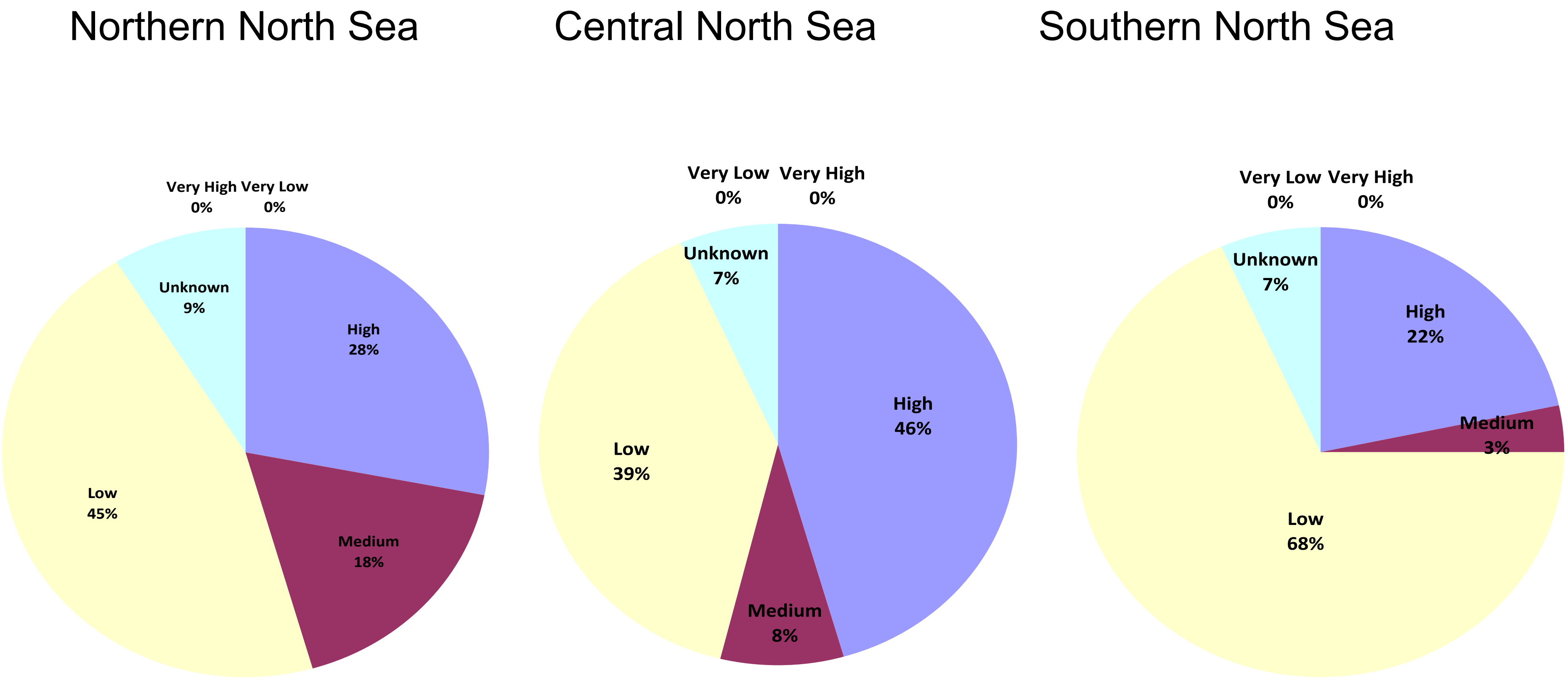

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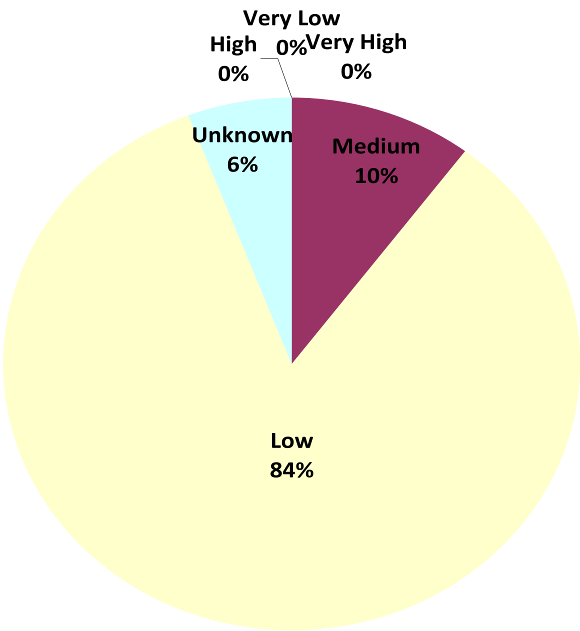
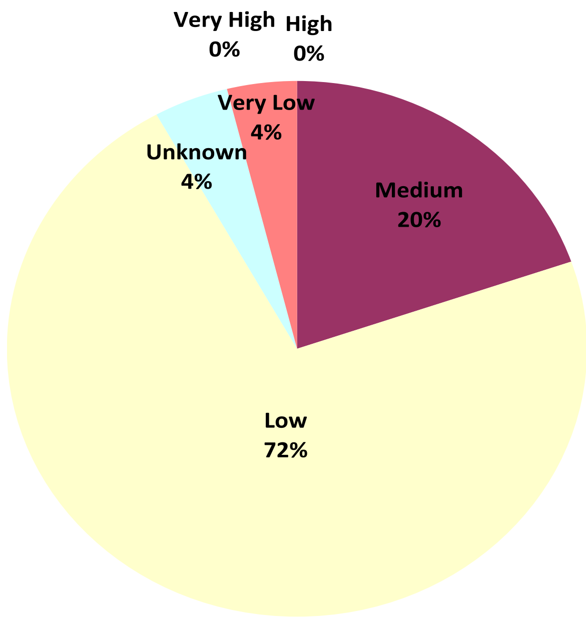
Figure 15 Seal chemical reactivity risk by region

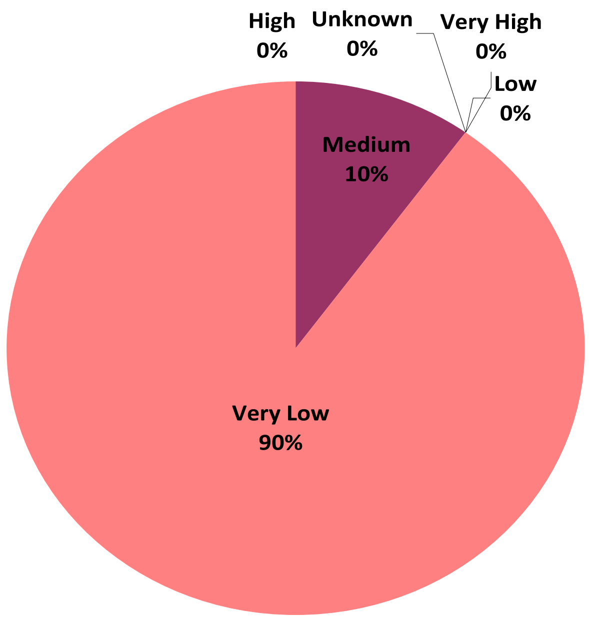
Northern North Sea



Central North Sea



Southern North Sea



UKSAP

Figure 16 Seal lateral degradation risk by region

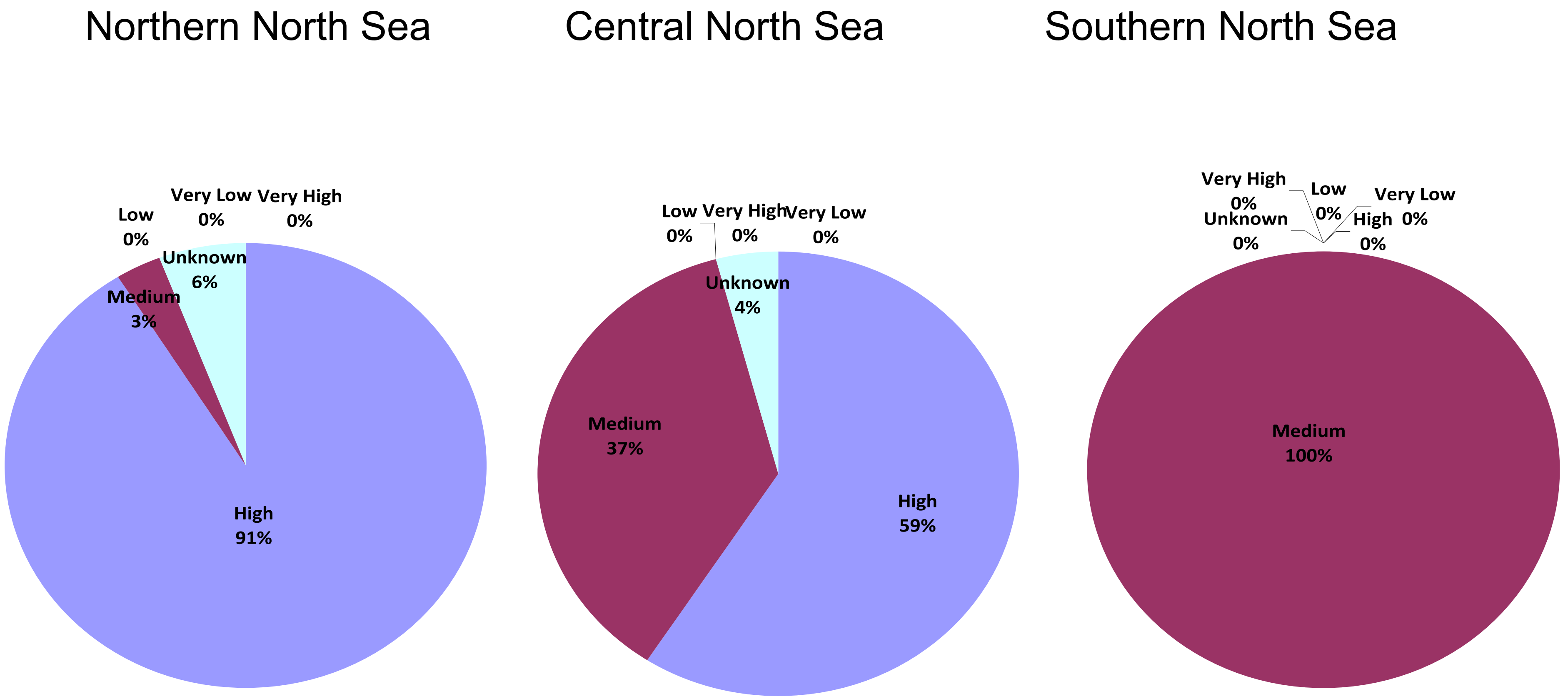


Figure 17 Variation across UKCS in lateral migration risk magnitude (cost impact) open units only

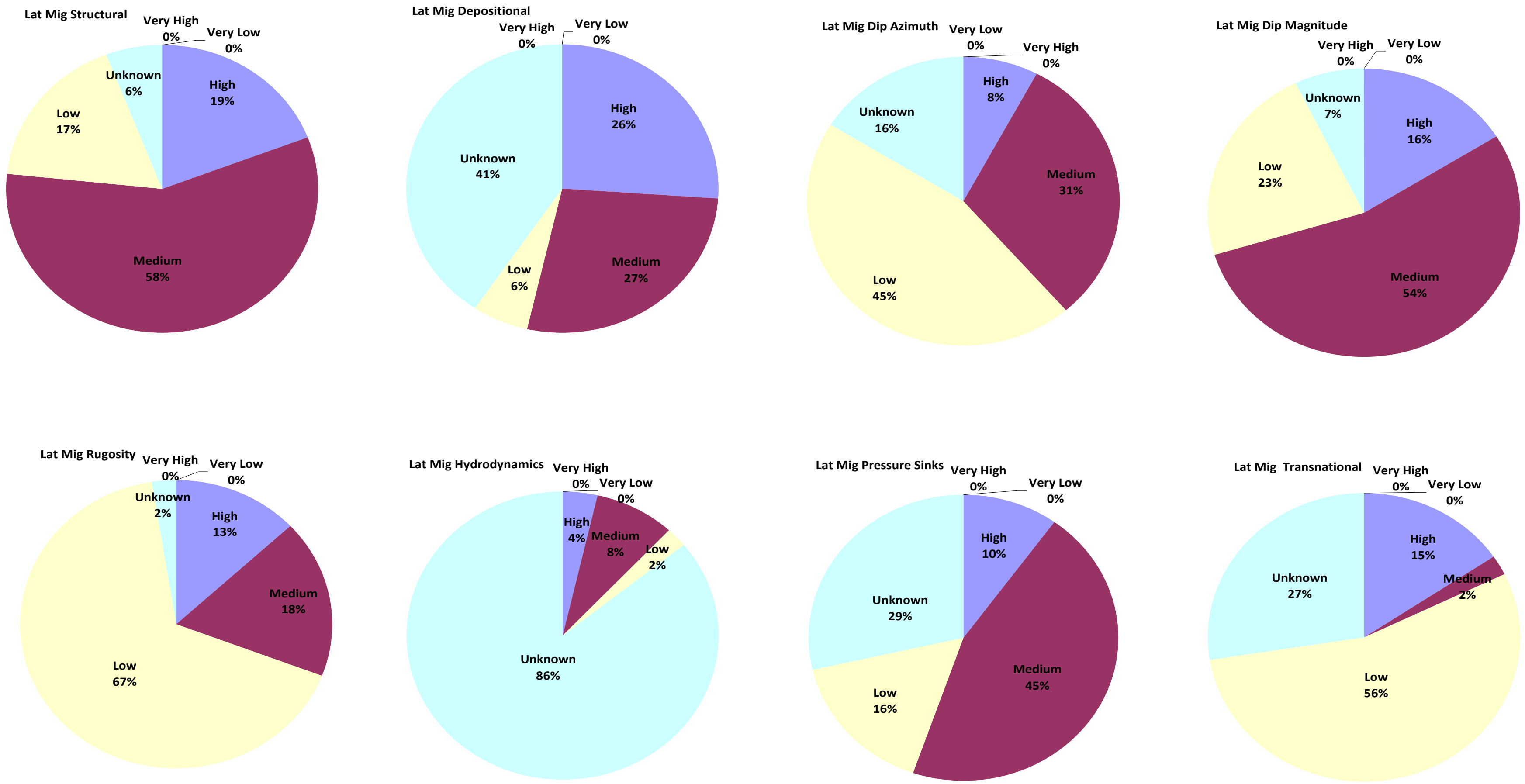


Figure 18 Risk matrix for capacity impact
Rough Gas Storage Unit (Permian Leman Sandstone) i.d. 141.072

UKSAP

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

Figure 19 Risk matrix for capacity impact
Forties Reservoir Unit (Paleocene) i.d. 233.003

UKSAP

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	

UKSAP

Figure 20 Risk matrix for capacity impact
Britannia Reservoir Unit (Cretaceous) i.d. 220.001

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

Figure 21 Risk matrix for cost impact
Rough Gas Storage Unit (Permian Leman Sandstone) i.d. 141.072

UKSAP

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

Figure 22 Risk matrix for cost impact
Forties Reservoir Unit (Paleocene) i.d. 233.003

UKSAP

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

Figure 23 Risk matrix for cost impact
Britannia Reservoir Unit (Cretaceous) i.d. 220.001

UKSAP

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

Figure 24 Risk matrix scores

UKSAP

Severity of impact	Low likelihood	Medium likelihood	High likelihood
Low	Very low risk = 1	Low risk = 2	Medium risk = 3
Medium	Low risk = 2	Medium risk = 3	High risk = 4
High	Medium risk = 3	High risk = 4	Very high risk = 5

Likelihood of occurrence

Figure 25 Uncertainty and risk - scores for cumulative risk

UKSAP

Risk	High (as **Figure 23)**	Medium (+1)	Low (+2)
Very Low	1	2	3
Low	2	3	4
Medium	3	4	5
High	4	5	6
Very High	5	6	7

Confidence

Figure 26 Cumulative risk and confidence score, capacity impact all risks, all UKCS aquifer units u/k=3

UKSAP

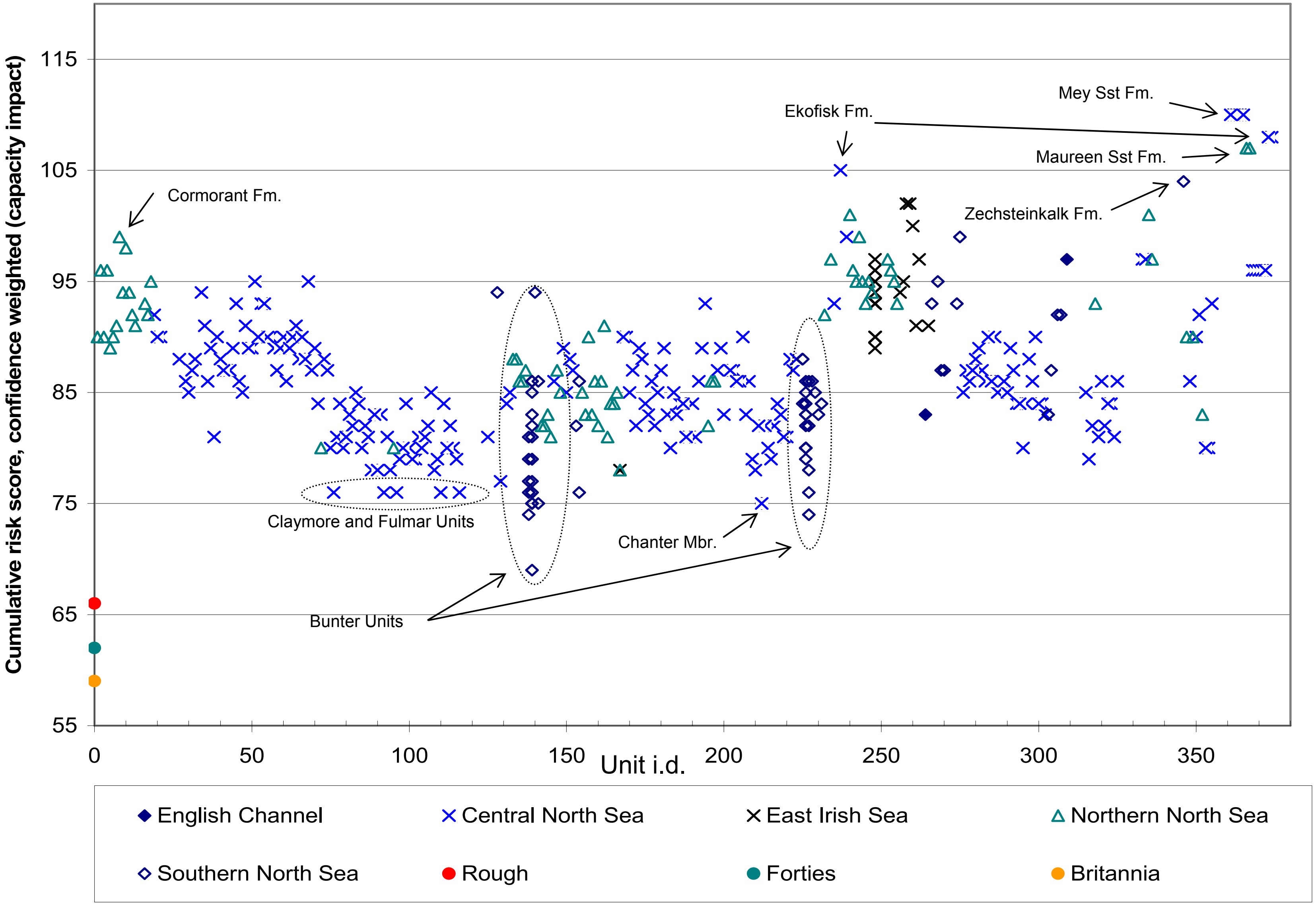


Figure 27 Cumulative risk and confidence score, cost impact all risks, all UKCS aquifer units u/k = 3

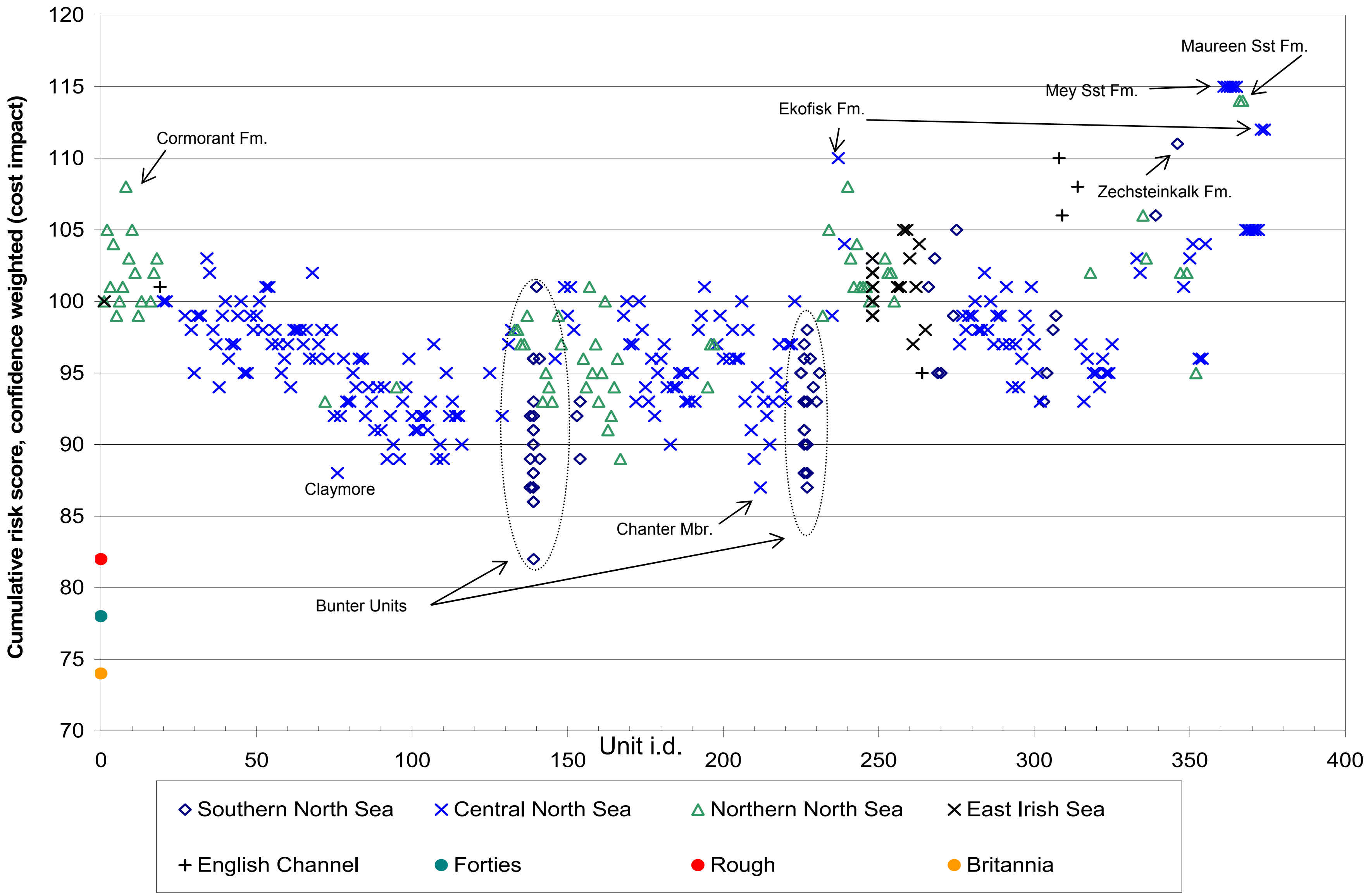


Figure 28 Example of confidence data presentation format from project database (data from unit 226.000)

UKSAP

High confidence	**Medium confidence**	**Low confidence**	**Unknown**
Seal Fracture Pressure Seal chemical reactivity Seal lateral degradation Fault throw Fault density Fault vertical extent Migration pressure sinks Migration national boundary Well density Well vintage *Fault compartmentalisation*	Migration rugosity Migration dip direction Migration structural trend *Stratigraphic compartmentalisation vertical* *Stratigraphic compartmentalisation horizontal*	Migraiton depositional trend Migraiton hydrodynamics *Formaiton mineralogy* *Formaiton salinity* *Diagenetic compartmentalisation*	Migration dip magnitude

Figure 29 Example of appraisal cost calculation

UKSAP

Seismic per square km				**£ 31,250**
Well cost				**£ 10,000,000**
Mt CO2 allowed per appraisal well				**20**
Note GBP=1.6USD (2010)				
Worked examples				
Unit ID	Storage plan	Area	Cumulative risk score	Risk premium correction factor
1A	2 Mt/yr for 10 years	100	**54**	**5%**
2A	60 Mt/yr for 40 years	1000	**43**	**4%**

	Unit 1A	**Unit 2A**
Seismic cost	£ 3,125,000	£ 31,250,000
No of wells needed	1	120
Cost of a well	£ 10,000,000	£ 10,000,000
Cost of appraisal wells	£ 10,000,000	£ 1,200,000,000
Subtotal cost	£ 13,125,000	£ 1,231,250,000
Risk premium	£ 708,750	£ 52,943,750
Total appraisal cost	£ 13,833,750	£ 1,284,193,750
Appraisal cost per T CO2	**£ 0.69**	**£ 0.54**