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Characterization of European CO$_2$ Storage — European Project SiteChar
Caractérisation de sites européens de stockage de CO$_2$ — Projet européen SiteChar

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Risk Assessment-Led Characterisation of the SiteChar UK North Sea Site for the Geological Storage of CO$_2$

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Abstract — *Risk assessment-led characterisation of a site for the geological storage of CO₂ in the UK northern North Sea was performed for the EU SiteChar research project as one of a portfolio of sites. Implementation and testing of the SiteChar project site characterisation workflow has produced a 'dry-run' storage permit application that is compliant with regulatory requirements. A site suitable for commercial-scale storage was characterised, compatible with current and future industrial carbon dioxide (CO₂) sources in the northern UK. Pre-characterisation of the site, based on existing information acquired during hydrocarbon exploration and production, has been achieved from publicly available data. The project concept is to store captured CO₂ at a rate of 5 Mt per year for 20 years in the Blake Oil Field and surrounding Captain Sandstone saline aquifer. This commercial-scale storage of 100 Mt CO₂ can be achieved through a storage scenario combining injection of CO₂ into the oil field and concurrent water production down-dip of the field. There would be no encroachment of supercritical phase CO₂ for more than two kilometres beyond the field boundary and no adverse influence on operating hydrocarbon fields provided there is pressure management.*

Components of a storage permit application for the site are presented, developed as far as possible within a research project. Characterisation and technical investigations were guided by an initial assessment of perceived risks to the prospective site and a need to provide the information required for the storage permit application. The emphasis throughout was to reduce risks and uncertainty on the subsurface containment of stored CO₂, particularly with respect to site technical performance, monitoring and regulatory issues, and effects on other resources. The results of selected risk assessment-led site characterisation investigations and the subsequent risk reassessments are described together with their implications for the understanding of the site. Additional investigations are identified that could further reduce risks and uncertainties, and enable progress toward a full storage permit application. Permit performance conditions are presented as SiteChar-recommended useful tools for discussion between the competent authority and operator.

Résumé — **Caractérisation d'un site de stockage géologique de CO$_2$ situé en Mer du Nord (Royaume-Uni) sur la base d'une analyse de risques** — Dans le cadre du projet de recherche EU SiteChar, la caractérisation d'un site pour le stockage géologique du CO$_2$ situé au Royaume-Uni au nord de la mer du Nord a été réalisée sur la base d'une analyse de risques. Cette évaluation a permis de déployer et de tester la méthodologie préconisée dans SiteChar jusqu'au développement d'un dossier de permis de stockage en blanc conforme aux exigences réglementaires. Il s'agit d'un site approprié pour un stockage de CO$_2$ à une échelle commerciale, compatible avec les sources industrielles, actuelles et futures, émettrices de dioxyde de carbone dans le nord du Royaume-Uni. Une pré-caractérisation du site à partir d'informations existantes acquises au cours de l'exploration et de la production d'hydrocarbures, a été réalisée sur base de données accessibles au public. Le projet vise à stocker 5 millions de tonnes (Mt) de CO$_2$ par an pendant 20 ans dans le champ de pétrole Blake et l'aquifère salin Captain Sandstone dans lequel il se trouve. Un stockage à l'échelle commerciale de 100 Mt de CO$_2$ pourrait être réalisé grâce à un scénario combinant injection du CO$_2$ dans le champ pétrolier et production de saumure simultanée dans l'aquifère en aval. Le CO$_2$ à l'état supercritique ne s'étendrait pas sur plus de deux kilomètres au-delà de la limite du champ pétrolier et aucun effet défavorable n'affecterait la production des champs d'hydrocarbures en cours d'exploitation dans la mesure où des approches de gestion de la pression seraient mises en œuvre.

Les éléments d'une demande de permis de stockage pour ce site sont présentés ; ils ont été développés autant qu'il était possible dans le cadre d'un projet de recherche. La caractérisation du site et les investigations techniques ont été initiées par une évaluation des risques et menées de façon à fournir les informations requises pour le dossier de permis de stockage. Tout au long de l'étude, l'objectif a été de réduire les risques et les incertitudes sur le confinement souterrain du CO$_2$ stocké, en particulier ceux relatifs à la performance technique du projet de stockage, la surveillance et l'adéquation aux exigences réglementaires, ainsi que l'interaction avec les autres ressources du sous-sol. Les résultats de l'analyse de risque, de la caractérisation du site évaluation menée ainsi que la mise à jour des risques après analyse des résultats sont décrits et les implications pour la compréhension du site exposées. Les besoins d'investigations supplémentaires sont identifiés de façon à réduire encore davantage les risques et les incertitudes et permettre de compléter le permis de stockage. Des critères portant sur les conditions de performance du site sont présentés ; ce sont des éléments que SiteChar recommande comme base de discussion entre l'autorité compétente et l'opérateur.

INTRODUCTION

Depleted hydrocarbon fields and brine-saturated (saline aquifer) sandstones are the CO$_2$ storage options for proposed demonstrator sites or operational Carbon Capture and Storage (CCS) projects in the North Sea (Chadwick *et al.*, 2008; DECC, 2013; ROAD, 2013). The potential capacity for storage of CO$_2$ offshore UK is sufficient to meet the national need (DTI, 2006; SCCS, 2009; Bentham *et al.*, 2014), as one of a suite of low-carbon technologies, to achieve UK national targets for greenhouse gas emissions reduction. A prospective site for the geological storage of CO$_2$ within the UK sector of the North Sea was investigated as one of a portfolio of realistic storage sites proposed by the EU FP7-funded SiteChar research project (Delprat-Jannaud *et al.*, 2015). Characterisation of an offshore storage site that comprises a depleted hydrocarbon field and adjacent saline aquifer sandstone in the northern North Sea, anticipates commercial-scale storage site development following on

from initial demonstrator projects. Characterisation of the SiteChar UK North Sea site evaluated a storage complex to provide a credible storage injection scenario over a 25 to 50 year term compatible with likely current and future industrial CO$_2$ sources in the northern UK. Characterisation implemented and tested the workflow of the SiteChar project (Nepveu *et al.*, 2015) and was sufficient to present a 'dry-run' storage permit application to comply with the requirements of the EU storage directive (EU, 2009, 2011) as far as possible within a research project. The usage of the terms storage site and storage complex are based in Figure 3 of Guidance Document 2 for implementation of the EU CCS Directive (EU, 2011).

The objectives of this paper are to present the process of risk assessment-led site characterisation to meet the requirements of a storage permit application. Pre-characterisation of the storage site used publicly available existing data acquired during hydrocarbon exploration and production. A summary of the technical aspects of characterisation of the prospective

site and implications to risk reduction are presented. Full and detailed technical characterisation is reported and available from the project web site (www.sitechar-co2.eu). The outcomes of previous assessments of the prospective storage site are reviewed in Section 1. The prospective storage site is described in Section 2, including selection of the hydrocarbon field component, the site geology and the storage scenario. Section 3 presents risk assessment-led characterisation and the required outputs, the risk assessment process in SiteChar and a summary of risk reduction investigations for selected risks. Outputs derived from risk assessment-led characterisation for an application for a CO_2 storage permit are summarised in Section 4. Permit performance conditions are presented in Section 5.

1 PREVIOUS ASSESSMENTS OF THE PROSPECTIVE SITE

The site lies offshore in the UK sector of the North Sea approximately 75 km north-east of the St Fergus gas terminal on the north-east coast of Scotland (Fig. 1). The project concept is for commercial-scale storage of CO_2 sourced from industrial plant along the eastern coast of Scotland and transported offshore *via* existing oil and gas pipelines from St Fergus. Opportunities for carbon capture and storage offshore Scotland have been assessed and developed by previous studies (SCCS, 2009, 2011). Output of CO_2 from existing industrial sources has been quantified, the future CO_2 output forecast, storage sites assessed, and cost for pipeline and shipping for the transportation of CO_2 estimated (SCCS, 2009).

The Captain Sandstone was amongst those saline aquifers shortlisted as prospective storage assets by Scottish Centre for Carbon Storage (SCCS, 2009). It meets acceptable geological characteristics as indicated by Chadwick *et al*. (2008) and has sufficient potential storage capacity. The Captain Sandstone has an estimated static CO_2 storage capacity ranging from 36 Mt (applying a storage efficiency of 0.2%) to 363 Mt (applying a storage efficiency of 2%) (SCCS, 2009). Characterisation and calculation of storage capacity by dynamic modeling of CO_2 injection endorses a potential capacity of more than 360 Mt for the Captain Sandstone saline aquifer with a storage efficiency of more than 0.6% by Scottish Carbon Capture and Storage (SCCS, 2011).

The Captain Sandstone was selected for research assessment as an example of a commercial-scale CO_2 storage asset for Scotland following an examination of three sandstones. Each was appraised on its proximity to existing onshore CO_2 sources, estimated storage capacity, access to existing oil and gas pipelines, whether known from oil and gas exploration data and having sufficient data accessible to a research project (SCCS, 2011). Selected 2D seismic survey and well data were interpreted to map and characterise the site and a basin-scale model was constructed and attributed with petrophysical
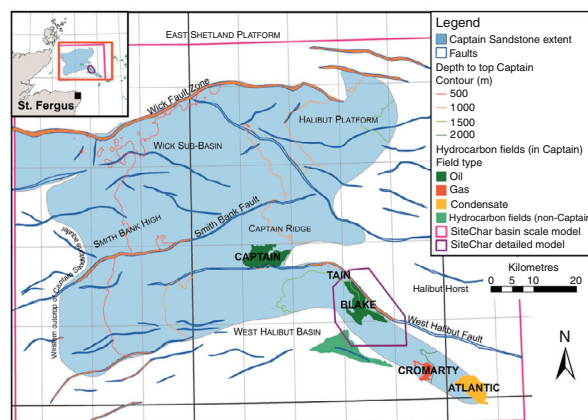
Figure 1

Map of the UK North Sea SiteChar storage site, structural contours (depth in metres True Vertical Depth Sub Sea) and faults at top Captain Sandstone surface (after SCCS, 2011) showing the SiteChar detailed model area and hydrocarbon fields hosted within the Captain Sandstone and older strata (Quinn *et al*., 2012). Contains public sector information licensed under the Open Government Licence V.1.0. Field outlines and wells from DECC 2011. Data available from: https://www.og.decc.gov.uk/pprs/full_production.htm.

characteristics (SCCS, 2011). Dynamic simulation of CO_2 calculated the potential storage capacity to be at least as much as the previously estimated upper value and possibly much greater (Jin *et al*., 2012). Further assessment of the Captain Sandstone as a potential CO_2 store was considered as justified (SCCS, 2011). The basin-scale model of Scottish Carbon Capture and Storage (SCCS, 2011) was also used for the SiteChar UK northern North Sea storage site (Fig. 1).

The SiteChar research benefited from publicly available assessments of the Goldeneye Gas Field for CO_2 storage (Shell, 2011a, b). The Goldeneye Field is also within the Captain Sandstone and lies 30 kilometres to the east of the SiteChar UK site study area. During 2013 the Captain Sandstone was proposed as the storage reservoir for two project entrants to the UK CCS demonstrator competition, one preferred and one reserve project (DECC, 2013). The site characterisation research presented here assesses a site that is in addition to others proposed within the Captain Sandstone as a prospective multi-user storage asset.

2 SITECHAR UK NORTH SEA STORAGE SITE

2.1 Geological Setting

The SiteChar UK North Sea storage site is within the Captain Sandstone Member of the Lower Cretaceous Wick
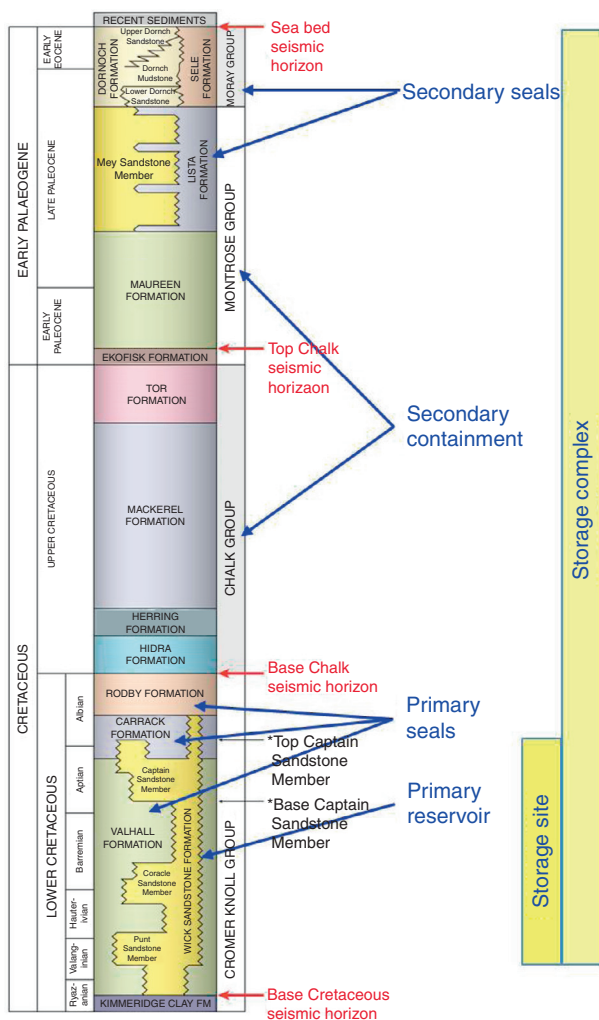
Figure 2

Stratigraphy of the SiteChar UK North Sea storage site and storage complex components (Quinn *et al*., 2012).

Sandstone Formation (Johnson and Lott, 1993) (Fig. 1, 2) (Quinn *et al*., 2012; Akhurst *et al*., 2014). The Captain Sandstone member extends over an area of at least 3 400 km² in the Outer Moray Firth, offshore Scotland in the UK northern North Sea (Fig. 1). The sandstone was delineated by Johnson and Lott (1993) and remapped by SCCS (2011). The Captain Sandstone is underlain and laterally equivalent to the argillaceous Valhall Formation, laterally equivalent to and overlain by the argillaceous Carrack Formation. Both of these formations are in turn overlain by the Rodby Formation that also has sealing potential (Johnson and Lott, 1993) (Fig. 2). Rocks of the Upper Cretaceous Chalk Group may directly overlie the Captain Sandstone where the Carrack and Rodby formations are absent (Fig. 2). The Palaeogene overburden

sequence comprises sandstone, mudstone, claystone, siltstone and limestone of the Montrose and Moray groups (Fig. 2) (Knox and Holloway, 1992; Johnson and Lott, 1993).

2.2 Hydrocarbon Field Site Selection

The Captain Sandstone contains four oil, gas and gas condensate fields within the extent of the SiteChar study area (Fig. 1). The Blake Oil Field was selected because it meets the storage criteria of Chadwick *et al*. (2008), has sufficient estimated static storage capacity (28 Mt CO_2) for a component of a commercial-scale storage site and data from the field is publicly available. The Blake Oil Field has the largest potential storage capacity of the three fields that lie at a depth greater than 800 metres, to ensure CO_2 injection in supercritical phase. It lies at a minimum depth of 1 350 metres (true vertical sub-sea depth) in approximately 100 m water depth. The Blake Field has produced oil and gas since 2002 and is now supported by water injection. There are publicly available 3D seismic surveys across the Blake Field and data from 23 well penetrations within the field to constrain the seismic interpretation and attribute the site geological model.

The Blake Oil Field is located in the north-western end of the Captain Sandstone 'pan-handle' (Fig. 1). The SiteChar UK site detailed model area lies where the 'pan-handle' begins to widen out into the main extent of the Captain Sandstone (Fig. 1). Dynamic simulation of CO_2 injection by SCCS (2011) has shown that predicted pressure increase due to CO_2 injection is greatest in the south-eastern part of the 'pan handle' where the width of the Captain Sandstone is thought to be at its narrowest. Thus the Blake Oil Field is in an appropriate position, compared to fields further south-east within the study area, to minimise the impact of the increase in pressure modeled by Jin *et al*. (2012).

2.3 Geology and Geological Models of the UK North Sea Storage Site

The Captain Sandstone was deposited in a deep-water submarine environment, sediment was derived from a source to the North and West and deposited by gravity-flow processes including high- and low-density turbidites, mud flows, debris flows, slides and slumps and settling of hemi-pelagic sediment (Law *et al*., 2000).

Within the Blake Oil Field, the Captain Sandstone has been divided into two distinct areas (Hilton, 1999) based on facies associations that reflect deep marine depositional processes: a 'Channel' facies area in the down-dip, south-western part of the field; a 'Flank' facies area up-dip to the North-East. The Channel facies area is likely to comprise sandstone with consistently high net sandstone to gross

TABLE 1

Summary of net sandstone to gross thickness (NTG) and porosity from well log data, and permeability from core measurement in the Channel and Flank facies areas of the Blake Oil Field (derived from well log and well report data) from Quinn *et al*. (2012)

Blake Oil Field	Average NTG	Average effective porosity	Average total porosity	Average permeability
Channel facies area (15 wells)	0.985	24.6%	29.2%	2 324 mD
Flank facies area (5 wells)	0.334	15.6%	20.7%	153.6 mD

thickness (NTG) values and with good permeability and porosity. However, the Flank area is expected to have much more variable petrophysical characteristics. Consequently, the juxtaposition of the Channel and Flank facies associations will result in a wide range of contact relationships, for example, between sandstone and sandstone, sandstone and shale and a high number of variations between these two end members. The Channel and Flank facies areas of the Blake Oil Field have been developed separately with the Flank area exhibiting complex reservoir architecture with possible compartmentalisation of the reservoir sandstone.

Interpretation of geophysical logs of 23 wells within the Blake Oil Field enabled porosity and NTG values to be derived for both Channel and Flank areas. These log interpretations along with permeability values taken from core analyses enabled a porosity-permeability relationship to be established and attribution of the model to be facilitated. These values are summarised in Table 1. The Channel area of the Blake Oil Field is interpreted to comprise a series of stacked and amalgamated channels that together form part of a major north-west-trending submarine channel system approximately 700 metres wide and at least 6 kilometres in length (mapping from seismic data). The sandstone contains very few shale intercalations, these being either remnant layers that were deposited in shallow depressions at times between the sand depositional episodes, and/or modified or caused by erosion as indicated by the presence of mudstone clast-rich sands. From their interpreted derivation these layers are assumed to have limited areal extent, and not expected to form significant baffles to flow within the Channel facies sandstone.

The Flank area of the Blake Oil Field is interpreted to comprise deep-marine slope strata, dominated by mud deposition, but with minor amounts of thin-bedded sandstone and moderately thick-bedded sandstone deposited by low-density and high-density turbidity currents, respectively. Evidence of sedimentary slumping, syn-sedimentary faulting and minor injection of sand have all been observed in core and Formation Micro Imagery (FMI) (Hilton and Morris, 2002). The reservoir architecture in the Flank area is complex. Hilton and Morris (2002) note that sandstone bodies recognised in flank wells are not laterally continuous. This is borne out by Du (2002) whose interpretation of

modular formation dynamics tester tool (MDT) analyses suggests that the reservoir is compartmentalised and/or layered. This interpretation is based on well pressure differences both between the underlying Coracle Sandstone (Fig. 2) and the Captain Sandstone and also the presence of oil-bearing strata and water-bearing strata over the same depth interval in two different wells, suggesting faulting or structural heterogeneity. This compartmentalisation is fully in accordance with the interpretation for a mud-rich deep marine depositional environment. The episodic sedimentation processes deposit sandstone bodies of lensoid shape, some possibly amalgamated, but generally with some lateral and vertical separation.

2.4 Storage Scenario

The concept for the storage site is for commercial-scale storage within the depleted Blake Oil Field and surrounding Captain Sandstone saline aquifer, that is, assuming storage of a total of 100 Mt CO_2. It is also assumed that the storage capacity would be maximised by active management of the reservoir pressure. Containment within the site is beneath the sealing formation that is a proven stratigraphical trap for the Blake Field and four other hydrocarbon fields in the vicinity, the latter also with reservoirs within the Captain Sandstone. The injection scenario for the site is CO_2 injection into the Blake Oil Field and up-dip migration into the adjacent Captain Sandstone saline aquifer beyond the extent of the field. The scenario assumes commercial-scale injection at a rate of 5 Mt per year, to permanently store output of CO_2 captured at industrial point sources along the eastern coast of Scotland and northern England. The duration of injection modeled is for 20 years with a total of 100 Mt CO_2 stored. It is assumed that the site must continuously receive, accept and store CO_2 at an unvarying annual rate. For the purposes of SiteChar research, injection would start in 2016 when the Blake Oil Field is estimated to have ceased production and change of use to geological storage of CO_2. Two constraints for the injection scenario are that the integrity of the site will not be compromised and also that other users of the subsurface will not be adversely affected (outside of the inter-operator agreements) by increased reservoir pressure due to the injection of CO_2 at the storage site.

3 RISK ASSESSMENT-LED SITE CHARACTERISATION

The objective of risk assessment-led site characterisation is to provide the information required by and in agreement with the competent authority for award of a permit for geological storage of CO_2. A storage licence application is undertaken in two parts, an application for an exploration permit and an application for a storage permit. For the SiteChar UK North Sea site, comprising in part a depleted hydrocarbon field, it is assumed that an exploration permit has previously been awarded. For award of a storage permit the applicant (SiteChar research project) must demonstrate sufficient understanding of the site and proposed site operation to securely and permanently contain CO_2. The resources for a research project are necessarily less than those that would be expected for a real storage site permit application. The objectives of SiteChar research, to demonstrate geological characterisation and assess long-term storage complex behaviour, are addressed by a 'dry-run' application for a storage permit. The storage permit application template completed for the UK northern North Sea site was developed within SiteChar from stipulations and requirements in the EU Directive on the geological storage of CO_2 regulations and guidelines (EU, 2009, 2011).

Geological site characterisation activities were targeted to reduce the perceived risks, decrease uncertainty and increase understanding of the storage site (Tab. 2). Geological (static) 3D model construction and model attribution (Quinn *et al.*, 2012) was followed by coupled dynamic simulation and geomechanical modeling (Shi *et al.*, 2013) and dynamic modeling of CO_2 injection (Delprat-Jannaud *et al.*, 2012). Regional migration pathway analysis and wellbore integrity modeling was also undertaken (Delprat-Jannaud *et al.*, 2012). Shallow geohazards were assessed and the geochemical response to CO_2 injection was evaluated (Shi *et al.*, 2013). Feasibility of monitoring was assessed by rock physics studies and synthetic seismic modeling investigations (Hannis *et al.*, 2013c).

3.1 Information Required from Site Characterisation

Information and components required for a storage permit application are determined by an assessment of risks to the CO_2 storage site. Information required includes a description of the storage project and a description of the storage site. Required storage permit components include details of measures to prevent significant irregularities. Monitoring, corrective measures and post-closure plans are also required. The preventative measures component is based on a register of risks and includes a plan of risk mitigation. The risk register is a key document as the starting point for site characterisation (Hannis *et al.*, 2013b). Characterisation activities seek to reduce the perceived risks to subsurface containment

of CO_2, and uncertainties due to lack of information, to a level as low as reasonably possible.

3.2 Assessment of Risks to the CO_2 Storage Site

At a very early stage in the site characterisation process an assessment of risks to the storage site was undertaken. It is the first technical activity in the characterisation process as the results determine all other site characterisation investigations and is required by the EU CCS Directive (EU, 2009, 2010). A risk register of 79 perceived risks to the prospective CO_2 storage site were identified by SiteChar research experts. They estimated the probability of each risk occurring and the severity of impact if each risk did actually occur. This list was presented as a summary risk register (Nepveu *et al.*, 2015). The initial assessment was qualitative rather than quantitative and focused on injection- and storage-related risks. Other risks relating to capture and transport of CO_2, CO_2 stream composition, offshore health and safety operations and financial risks, were considered outside the scope of the SiteChar research project. For a real CCS project, investigation of all risks would be required for a storage permit application.

The risks were ranked according to the initial estimates of probability and severity and the ranked list used to guide site characterisation, working toward reduction of risks to an acceptable 'as low as reasonably possible' level. The resources of the research allowed investigation of selected technical risks identified within the project. Those risks that were investigated followed the methodology as far as possible. Where mitigation of a risk could not be achieved within research project resources further risk- and uncertainty-reduction activities were suggested, such as laboratory analysis, re-logging of wells, drilling new wells and baseline monitoring surveys (Hannis *et al.*, 2013a). For a storage permit application submitted by a prospective operator it is assumed that most of the risks would be reduced to an acceptable level by storage design; relatively few residual risks would remain to be monitored (Hannis *et al.*, 2013c). A list was prepared of those risks that were not mitigated by the SiteChar project investigations. This list of residual risks was used to guide the monitoring planning to ensure that any remaining risks are monitored (Hannis *et al.*, 2013c).

3.3 Risks Addressed

The technical investigations in SiteChar were targeted to inform reduction of risks to the subsurface containment of stored CO_2, where site technical performance might be less than expected, associated with monitoring and regulatory issues or have a potentially adverse effect on other resources (Tab. 2). Investigation of risks to the prospective storage site is,

TABLE 2

Risk assessment-led site characterisation investigations for selected risks identified for the SiteChar storage site in the UK North Sea discussed in this paper (for risk ratings see Tab. 3)

Risk type	Risk description	Risk reduction investigations	SiteChar technical reports
Subsurface containment of stored CO$_2$	Connection of storage site reservoir sandstone to an adjacent fault	Geological site characterisation	Quinn *et al.*, 2012
	Primary cap rock thin or absent	Geological site characterisation and 3D modeling	Quinn *et al.*, 2012
	Fluid migration pathway north-westwards out of the storage site	Dynamic modeling of CO$_2$ injection, regional migration analysis	Delprat-Jannaud *et al.*, 2012
	Secondary reservoirs not present, laterally restricted or poor quality	Geological site characterisation	Quinn *et al.*, 2012
	Fracture pressure threshold of the primary cap rock exceeded	Coupled dynamic simulation and geomechanical modeling	Shi *et al.*, 2013
	Cap rock fracture pressure threshold lower than predicted	Dynamic modeling	Delprat-Jannaud *et al.*, 2012
	Cap rock capillary entry pressure threshold exceeded		
	Injection-induced faults or fractures in cap rock	Geomechanical modeling	Shi *et al.*, 2013
	Fluid escape pathways up abandoned wells	Wellbore integrity modeling. Shallow geohazards assessment	Delprat-Jannaud *et al.*, 2012 Shi *et al.*, 2013
Technical performance less than expected	Unpredicted reservoir permeability heterogeneities	Geological modeling. Dynamic modeling of CO$_2$ injection	Quinn *et al.*, 2012 Delprat-Jannaud *et al.*, 2012
	Hydrocarbon saturation to accurately inform dynamic modeling not known	Geological site characterisation	Quinn *et al.*, 2012
	Short-term CO$_2$ injection-induced permeability reduction near wellbore	Geochemical evaluation	Shi *et al.*, 2013
	Long-term CO$_2$-induced permeability reduction in the storage reservoir due to geochemical changes	Geochemical evaluation	Shi *et al.*, 2013
Monitoring or regulatory issues	Seismic monitoring ineffective due to the presence of a strong reflector in overlying strata	Synthetic seismic modeling	Hannis *et al.*, 2013c
	Seismic monitoring ineffective at detecting CO$_2$	Rock physics studies	Hannis *et al.*, 2013c
Adverse effects on other resources	Interference with hydrocarbon fields from migration of CO$_2$ or increased pressure due to CO$_2$ injection	Dynamic modeling of CO$_2$ injection. Storage site performance forecast	Delprat-Jannaud *et al.*, 2012 Hannis *et al.*, 2013a
	Induced seismicity	Geomechanical modeling	Shi *et al.*, 2013

of necessity, confined to those risks associated with technical matters as appropriate for a research project. Risks identified by SiteChar experts associated with economic, financial and environmental issues were not addressed. Technical investigations were directed to reduce risks and provide information needed for a storage permit application.

During the course of the investigations additional data were acquired or reviewed. The increased information, either on or relevant to the storage site, imparted a greater degree of certainty and informed the subsequent re-assessment of risks. During the progress of the investigations additional risks were identified, which is to be expected.

3.4 Risk Reduction Investigations

Site characterisation investigations were targeted to address the risks identified in the risk register and also to provide the information required for a storage permit application. Selected risk reduction investigations presented here are summarised in Table 2. The list of all perceived risks to the site and reassessed values of probability of occurrence, severity of impact and revised ranking of risks after completion of the investigations are discussed by Hannis *et al.* (2013a). SiteChar investigations completed a single iteration of risk reduction activities but could not address all risks or continue with additional site characterisation to reduce risks to a level 'as low as reasonably possible'. The full register of risks, explanation and designation of both initial and revised values for probability, severity and ranking, preventative and corrective measures, also further work that could be undertaken to more accurately define the risk are presented by Hannis *et al.* (2013b).

The results of the risk reduction investigations for the risks presented in Table 2 and implications to the understanding of each perceived risk are discussed in the following text sections.

3.4.1 Risk: Connection of the Storage Site Reservoir Sandstone to an Adjacent Fault

The Captain Sandstone is inferred to extend to the adjacent West Halibut Fault from interpretation of 2D seismic survey data by SCCS (2011) (Fig. 1). The possibility of a flow pathway from the storage site reservoir sandstone to the fault bounding the Halibut Horst to the north presented a risk to the subsurface containment of CO_2.

3D seismic survey data was interpreted for the SiteChar detailed model area (Fig. 1). In the revised interpretation of more finely resolved data, the principal sandstone of the storage site, the Captain Sandstone, is interpreted to pinch out in the hanging wall succession of the West Halibut Fault within the study area (Fig. 3) (Quinn *et al.*, 2012). Dynamic modeling of CO_2 injection into the Captain Sandstone Channel facies (Tab. 1) was calculated for well locations either within the extent of the Blake Oil Field or down-dip within the brine-saturated Captain Sandstone (Delprat-Jannaud *et al.*, 2012). Twenty years of injection and thirty years after the end of injection were simulated. In all of the injection scenarios modeled, the CO_2 (in supercritical
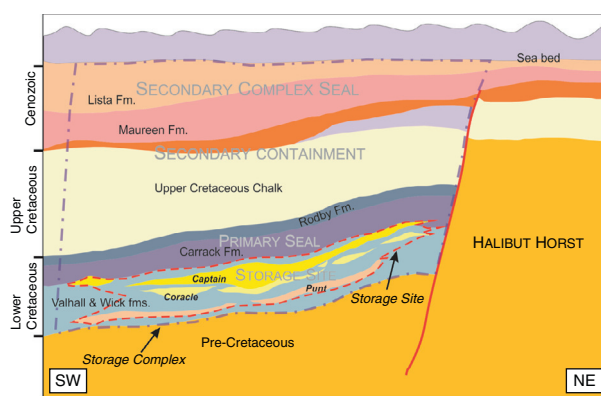
Figure 3

Diagrammatic geological cross-section across the SiteChar UK northern North Sea storage site, showing storage site boundary (red dashed line) and storage complex boundary (blue dashed line) from Quinn *et al.* (2012). Primary seal (cap rock), secondary containment reservoir and secondary seal (cap rock) to the storage complex are labelled.

phase and dissolved in water) was predominantly retained within the extent of the Channel facies. The injected CO_2 is predicted to migrate very slowly beyond the Channel into the Flank facies only after injection has ceased in the injection scenario selected for the prospective storage site.

The likelihood of migration of CO_2 to the West Halibut Fault for the injection scenario proposed is therefore very low. Reassessment of the initial risk from the results of remapping of the Captain Sandstone and dynamic modeling of CO_2 injection has reduced the probability of the risk occurring and so also the risk rating (Tab. 3).

3.4.2 Risk: Primary Cap Rock Thin or Absent

The top of the Captain Sandstone is generally sealed by overlying low permeability mudstone but in some places the mudstone is thin and it may be directly overlain by the unconformable Base Chalk surface. Some wells, *e.g.* Well 13/22a-28 in the Captain Oil Field, prove Chalk resting directly on the Captain Sandstone. Chalk cap rock may not be as efficient a seal as the mudstone.

The 3D seismic survey data interpreted for the SiteChar detailed study area does not resolve where the mudstone cap rock is absent but indicates where it is most likely to be thin (less than 10 metres). Although geological mapping shows the Captain Sandstone is expected to be overlain by Lower Cretaceous mudstone across the extent of the storage complex, an area where the cap rock is interpreted to be thin (<10 m) lies in the north-west part of the Blake Field within the Flank facies area (Quinn *et al.*, 2012).

TABLE 3

Risk ratings before and after the first iteration of risk reduction, based on site characterisation investigations (shown in Tab. 2) for the SiteChar UK North Sea storage site. Probability and severity ratings: 5 is high; 1 is low. NR, risk not reassessed

Risk type	Risk description	Initial risk assessment			Revised assessment		
		Probability	Severity	Risk rating	Probability	Severity	Risk rating
Subsurface containment of stored CO₂	Connection of storage site reservoir sandstone to an adjacent fault	3	3	9	1	3	3
	Primary cap rock thin or absent	4	3	12	2	3	6
	Fluid migration pathway north-westwards out of the storage site	2	3	6	1	3	3
	Secondary reservoirs not present, laterally restricted or poor quality	2	2	4	1	2	2
	Fracture pressure threshold of the primary cap rock exceeded	2	4	8	1	4	4
	Cap rock fracture pressure threshold lower than predicted	3	3	9	1	1	3
	Cap rock capillary entry pressure threshold exceeded	3	3	9	3	1	3
	Injection-induced faults or fractures in cap rock	2	4	8	1	4	4
	Fluid escape pathways up abandoned wells	4	4	16	2	2	4
Technical performance less than expected	Unpredicted reservoir permeability heterogeneities	4	4	8	2	2	4
	Hydrocarbon saturation to accurately inform dynamic modeling not known	4	3	12	2	2	4
	Short-term CO₂ injection-induced permeability reduction near wellbore	3	3	9	1	2	2
	Long-term CO₂ injection-induced permeability reduction in the storage reservoir due to geochemical changes	3	3	9	1	2	2
Monitoring or regulatory issues	Seismic monitoring ineffective due to the presence of a strong reflector in overlying strata	3	3	9	2	3	6
	Seismic monitoring ineffective at detecting CO₂	3	3	9	2	3	6
Adverse effects on other resources	Interference with hydrocarbon fields from: migration of CO₂,	2	4	8	2	2	4
	increased pressure due to CO₂ injection	4	3	12	NR	NR	NR
	Induced seismicity	2	3	6	1	3	3

However, dynamic modeling of the SiteChar storage site (Delprat-Jannaud *et al.*, 2012) predicts the distribution of the plume of dissolved and supercritical phase CO₂ to remain within the area where cap rock is mapped as being continuous and having acceptable thickness (approximately 40 metres thick).

The risk of leakage due to thin or absent primary cap rock is therefore thought to be low. Mapping of primary cap rock
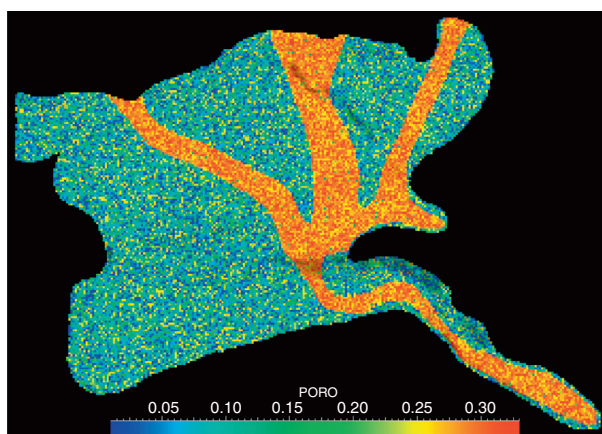
Figure 4

Modelled porosity within the SiteChar basin-scale study area illustrating the distribution of Channel facies (values mostly 0.25 and above) and Flank facies (values mostly 0.25 and below) within the Captain Sandstone, mapped from well data (Quinn *et al.*, 2012).

and dynamic modeling of the selected injection scenario (Tab. 2) has reduced the probability of the risk occurring and so also the risk rating (Tab. 3).

3.4.3 Risk: Fluid Migration Pathway North-Westwards out of the Storage Site

The Blake Oil Field forms a significant component to the storage site and is a combined structural and stratigraphical trap. The field reservoir dips to the west and south providing structural trapping to hydrocarbons filling the reservoir. The reservoir sandstone pinches out to the east providing stratigraphical trapping of hydrocarbons parallel to the Halibut Horst. However, the nature of the trap to hydrocarbons in the Blake Oil Field along its northern boundary is not clear as no structural closure to the field could be mapped within the limits of the seismic data available to the study (Quinn *et al.*, 2012). There is a significant hydrocarbon discovery, the Tain discovery, immediately to the north of the Blake Oil Field beyond the SiteChar detailed area of study (Fig. 1). It is possible that hydrocarbons have migrated beyond the northerly limits of the Blake Field, as defined by the Department of Energy and Climate Change (DECC), filling this small structure and presenting a risk to containment of CO_2 at the prospective storage site.

A regional migration analysis was conducted to identify possible secondary containment and migration paths by modeling substantial and excessive overfilling of the storage site. Prediction of CO_2 migration laterally within the Captain Sandstone (contained under the primary cap rock) if the site

is overfilled, indicates flow to the north-west in the direction of the Tain discovery (Delprat-Jannaud *et al.*, 2012). However, the results of dynamic modeling of the chosen injection scenario suggest northward migration will not occur if injection is into the Channel facies of the Blake Oil Field (Delprat-Jannaud *et al.*, 2012). Although the Tain discovery lies north-west of the storage site along a potential regional migration pathway it is not thought to be connected directly to the main Channel area of the Blake Field and may have more in common with the Flank area.

The risk to containment from fluid migration north-westwards from the storage site can therefore be considered very low. The probability of a fluid migration pathway to the north-west is reduced (Tab. 3) by conforming with the injection scenario modeled and current understanding of poor connectivity from the Channel to the Flank facies within the Captain Sandstone.

3.4.4 Risk: Secondary Reservoirs not Present, Laterally Restricted or Poor Quality

In the unlikely event of migration of injected CO_2 through the primary cap rock and out of the storage site, the CO_2 would be expected to be contained within strata with available pore space within the storage complex. Definition of secondary containment systems in the overall storage system, *i.e.* porous strata within the storage complex, is described as a component of the site (EU, 2009). A risk to the storage site is that there are no suitable secondary reservoirs.

Review of published atlases for the stratigraphical sequences in the area of the storage site (Knox and Holloway, 1992; Johnson and Lott, 1993) indicates strata potentially suitable for both secondary containment and secondary sealing for the storage of injected CO_2. Migration of injected CO_2 beyond the storage site may be contained within formations that overlie, underlie or are laterally equivalent to the Captain Sandstone (Fig. 2, 3) (Quinn *et al.*, 2012). The overlying Upper Cretaceous Chalk Group succession has an average thickness of approximately 460 metres over the detailed study area. The Chalk Group could provide additional containment for CO_2 because although the Chalk has low rock porosity and permeability it may have fracture porosity and permeability sufficient to provide storage. The overlying Palaeogene succession comprises sandstone, mudstone, claystone, siltstone and limestone and has an average thickness of approximately 1 000 metres over the SiteChar detailed study area. The sandstone could provide very good secondary containment for migrating CO_2 while the mudstone and claystone successions present in the Palaeogene Lista and Dornoch formations (Fig. 2) could provide a secondary cap rock to the storage complex (Fig. 3). Further site-specific investigation would improve the characterisation of the secondary containment

reservoir and seal rocks with an estimate of possible volumes of secondary containment (Hannis *et al.*, 2013a).

The risk associated with the possibility of inadequate secondary storage strata is much reduced based on the published information by reducing the probability of the risk happening (Tab. 3).

3.4.5 Risk: Fracture Pressure Threshold of the Primary Cap Rock Exceeded

The cap rock fracture pressure threshold defines the pressure at which local fracturing of the cap rock may occur. If the pressure threshold is exceeded the sealing properties of the cap rock could be compromised, leading to leakage from the primary storage reservoir. A value of around 75% of the lithostatic pressure is commonly assumed to approximate the fracture pressure threshold. Knowledge of the cap rock fracture pressure is vital to be able to derive realistic injection scenarios.

Coupled flow-geomechanical modeling of CO_2 injection and an evaluation of mechanical stability (Shi *et al.*, 2013) accompanied by dynamic simulations to define an appropriate CO_2 injection scenario (Delprat-Jannaud *et al.*, 2012) were investigated for the storage site. The geomechanical stability assessment used the pre-injection *in situ* stress state information (one of the main sources of uncertainties in the assessment of geomechanical stability) from the nearby Goldeneye Gas Field (Shell, 2011b). Based on these data, the overpressure value causing cap rock fracture has been estimated as between 75 and 80 bar for the depth range of the storage site (1 600-1 700 m) by Shi *et al.* (2013).

Coupled flow-geomechanical modeling of CO_2 injection into the Channel facies sandstone down-dip from the Blake Field at the commercial-scale rate without pressure management generated high overpressure values that would exceed the cap rock fracture pressure threshold after 10 years (Shi *et al.*, 2013). Even without pressure management no shear failure is predicted after 5 years of injection at a rate of 5 Mt CO_2 per year into the Captain Sandstone saline aquifer but continuation at this rate would exceed the fracture pressure threshold.

Different injection scenarios were simulated for the storage site all at a constant rate of 5 Mt CO_2 per year. The maximum reservoir pressure attained for CO_2 injection into the Blake Oil Field with pressure management does not exceed the cap rock fracture pressure (Delprat-Jannaud *et al.*, 2012). Pressure management by concurrent fluid (water) production from one well down-dip of the hydrocarbon field in the Captain Sandstone saline aquifer was modeled. The predicted maximum overpressure value for this scenario is 26 bar after 20 years of CO_2 injection. This value is substantially lower than the estimated threshold of 75-80 bar and decreases to 8 bar overpressure after cessation of injection (Delprat-Jannaud *et al.*, 2012). Further iterative dynamic

modeling using a range of injection rates and well positions would allow the maximum rate and volume of injected CO_2 without exceeding the pressure thresholds to be determined. Pressure management by implementing the chosen injection and production scenario, although it may not be the optimum, would ensure the cap rock fracture pressure would not be exceeded.

The probability of exceeding the cap rock fracture pressure has been reduced by determining the cap rock fracture pressure threshold and including pressure management in the injection scenario (Tab. 3).

3.4.6 Risk: Cap Rock Fracture Pressure Threshold Lower than Predicted

The cap rock fracture pressure threshold estimated at 75-80 bar overpressure at the storage site depth by Shi *et al.* (2013) is very similar to the assumed values derived by calculating a proportion of the lithostatic or hydrostatic pressure. The maximum overpressure value predicted for the chosen injection scenario of 26 bar overpressure is approximately one third of the estimated fracture pressure threshold. Therefore, subject to pressure management, the probability and risk that the threshold is exceeded due to a lower than predicted cap rock fracture pressure has been reduced (Tab. 3) and the likelihood is very low.

3.4.7 Risk: Cap Rock Capillary Entry Pressure Threshold Exceeded

The cap rock capillary entry pressure threshold defines the pressure at which CO_2 will start to slowly permeate through the capillaries of the sealing rock. It is lower than the fracture pressure, and leakage of CO_2 through capillaries will be slow, at low volumes, and for long periods be contained within the cap rock itself.

The estimated cap rock capillary entry pressure is 36 bar (Delprat-Jannaud *et al.*, 2012), based on the theoretical relationship (Thomas *et al.*, 1967) with and corresponding to an absolute permeability of 10^{-5} mD. The theoretical entry pressure approximates the predicted maximum overpressure of 26 bar for the selected injection scenario. However, the small pressure difference between the two is not judged to be a significant concern in terms of CO_2 migration into the cap rock over the medium- to long-term due to the low permeability of the cap rock. In the short term, the driving overpressure will drop immediately once injection ceases and further dissipate over time. As the excess pressure will drop after injection ceases, the risk is restricted to the period of injection and unlikely to be a source of leakage.

No further information was available to change the assessment of the probability that the cap rock entry pressure threshold would be exceeded. However, the rates of leakage

from this mechanism are likely to be low and occur only during the decades of CO_2 injection so the severity and overall risk rating are reduced (Tab. 3).

3.4.8 Risk: Injection-Induced Faults or Fractures in Cap Rock

Fault structures have not been identified in the Captain Sandstone reservoir and cap rock within the area of detailed study for the storage site from 3D seismic survey data (Quinn *et al.*, 2012). A risk remains that there are minor fault structures within the site that are not resolved in the seismic data and the increased pressure associated with CO_2 injection might induce fault reactivation to create flow pathways within the storage site reservoir and through the primary cap rock.

The outcomes of the geomechanical modeling and failure analysis by Shi *et al.* (2013) suggest that the likelihood of fault reactivation within the Captain Sandstone is low provided pressure is managed. An assessment of the likely presence of fractures and their connectivity within the cap rock and overburden sequence was undertaken for the UK offshore site by Shi *et al.* (2013). Fracture data for the cap rock and overburden from well log and core data sources from within and in the vicinity of the storage site were used to inform estimation of a percolating fracture network. The computed percolation probability is strongly influenced by cap rock thickness, proportion of open (conducting) fractures and the number of fractures over a specified vertical distance (line density). For the two scenarios with the lowest proportion of open fractures (0.1) and the thickest cap rock (227 m), the percolation probability is negligible.

Note here that natural gas and oil has been contained in the Blake Field and other hydrocarbon fields over the geological time scale which is evidence that should preclude the existence of a natural gas leakage pathway in the cap rock. It thus can be argued that it is unlikely that a percolating open fracture network exists in the cap rock.

The results of risk reduction investigations indicate the probability of the presence of minor fractures has been reduced and so also the risk that they might be reactivated by CO_2 injection (Tab. 3).

3.4.9 Risk: Fluid Escape Pathways Up Abandoned Wells

One of the major challenges associated with geological storage of CO_2 is the prediction of performance of the confining system and for the store to remain secure over long timescales. Abandoned exploration and production wells act as potential leakage pathways for CO_2 stored in depleted hydrocarbon fields and adjacent saline aquifer strata. Hence, it is essential to investigate well integrity during the process of storage site evaluation.

Migration path analysis for the SiteChar UK North Sea site has identified possible leaking wells as the most probable pathway to the surface, transmitting CO_2 directly to the atmosphere (Delprat-Jannaud *et al.*, 2012). Fluid-escape pathways and CO_2-induced fluid escape pathways up abandoned wells are rated as having the highest probability and severity and so ranked highest in the risk register (Hannis *et al.*, 2013a, b). The potential for leakage of injected CO_2 through the wellbore, and its sensitivity to cement bond condition and storage pressure, were investigated by numerical simulation of well integrity (Delprat-Jannaud *et al.*, 2012). The analysis is based on data from an appraisal well within the Channel facies of the Blake Oil Field (BG Exploration & Production, 1998). The scenarios simulated assume storage pressure and micro-annulus permeability values, 1 000 years of elevated pressure and predict the mass of leaked CO_2 at the top of the secondary containment strata. If reservoir pressures are maintained at 90% of the initial pressure no leakage of CO_2 *via* the wellbore is predicted, even if a pessimistic scenario for the micro-annulus permeability is assumed. At the initial reservoir pressure 1.3 tonnes of CO_2 is predicted to leak to secondary storage *via* the wellbore over a period of 1 000 years. Dynamic simulation (Delprat-Jannaud *et al.*, 2012) predicts up to 26 bar overpressure within the Captain Sandstone reservoir for the selected CO_2 injection and water production scenario. Well integrity modeling assuming CO_2 storage pressure equal to 130% of the initial reservoir pressure and pessimistic micro-annulus permeability values predicts up to 20 tonnes of CO_2 leakage to the secondary reservoir. All scenarios assume constant elevated pressure over a period of 1 000 years and the only way to reduce the pressure is *via* leakage through the wellbore. Thus the effect of relaxation after stopping injection after 20 years is not incorporated in the calculations. Such conditions may therefore be considered as very pessimistic as in reality after stopping injection the reservoir pressure will decrease with time and thus also the rate of CO_2 leakage.

The risk for the scenario investigated was reduced by the SiteChar investigations (Tab. 3). Uncertainty in the number of wells likely to fall within the predicted extent of the injected CO_2 plume (Fig. 6 in Sect. 3.4.16) and the mass of CO_2 leakage to the secondary reservoir was also reduced. Risk mitigation measures of additional well characterisation (Le Guen *et al.*, 2008) are suggested and included as part of the preventative measures plan (Hannis *et al.*, 2013c; Shi *et al.*, 2013) and 'dry-run' storage permit application for the site (Hannis *et al.*, 2013a). Baseline observation and resurvey of the sea bed during injection over existing well sites by sonar and echo sounder surveys (Shi *et al.*, 2013) are a component of the monitoring plan (Hannis *et al.*, 2013c).

3.4.10 Risk: Unpredicted Reservoir Permeability Heterogeneities

The risk of unpredicted heterogeneities in reservoir permeability, creating impediments to flow by creating low permeability 'baffles' (vertical, horizontal, or at a range of angles), could lead to a reduction in the rate of injected CO_2. The reservoir character is inferred from well geophysical logs and well core samples. The uncertainty lies in the extrapolation between wells, which may be very widely spaced, and beyond the extent of hydrocarbon fields.

Two end-members of a possible range of reservoir heterogeneity within the Captain Sandstone were examined to give an indication of the impact of heterogeneity on reservoir performance (Delprat-Jannaud et al., 2012). CO_2 injection was simulated by assuming either homogeneous or heterogeneous Channel facies sandstone. The heterogeneous petrophysical parameters (porosity and permeability) were stochastically modeled assuming a porosity distribution derived from available core measurements (Fig. 4). The permeability was attributed using the relationship between porosity and permeability values measured from core samples (Quinn et al., 2012). This method of attributing the model does not give the most realistic result in terms of the geology but gives petrophysical property distributions which are statistically representative of existing input data. Observation of the Captain Sandstone Channel facies in core recovered from within the basin-scale study area reveals it has an extremely uniform character. The Channel facies of the Captain Sandstone is interpreted to be amalgamated turbidite sandstone deposited from sand-rich turbidity currents (Law et al., 2000). The homogeneous Channel facies Captain Sandstone was populated using average values of 0.25 for porosity from well data and 2 000 mD permeability from core measurements within the Blake Oil Field (Quinn et al., 2012).

Comparison of the simulations of CO_2 injection into the Channel facies with either heterogeneous or homogeneous attribution reveals significant differences in the extent and magnitude of overpressure anomalies (Delprat-Jannaud et al., 2012). Given the extremely permeable character of the Captain Sandstone, with the majority of samples exceeding the average value of 2 000 mD (Quinn et al., 2012) the very high overpressure response predicted with heterogeneous attribution seemed unreasonable. The homogeneous attribution was selected as more representative of the Captain Sandstone Channel facies.

The risk to injectivity was reduced by the investigations of the storage site (Tab. 3) (Hannis et al., 2013b). The relatively large range of the estimated overpressure values from the two end-members modeled reflects the sensitivity to the degree of heterogeneity represented in the model. Additional investigation of the attribution of permeability to the Channel and Flank facies is strongly advised and essential to impart greater confidence in the predicted performance of the storage site.

However, an indication of connectivity between hydrocarbon fields hosted within the Captain Sandstone is suggested by pressure effects noted from one field to another (geological well report from the adjacent Cromarty Field). This suggests that if heterogeneities in reservoir permeability exist they do not significantly affect reservoir performance.

3.4.11 Risk: Hydrocarbon Saturation to Accurately Inform Dynamic Modeling not Known

A risk to prediction of the site performance by dynamic modeling of CO_2 injection into a depleted hydrocarbon field is the lack of input data for modeling. It is important to accurately determine residual hydrocarbon distribution and saturation. This is due to the greater compressibility of hydrocarbons than water and the lower solubility of CO_2 in water than in oil and resultant lower overpressure values when injecting CO_2 (Delprat-Jannaud et al., 2012).

Uncertainty associated with this risk was reduced using water saturation information from well reports (Quinn et al., 2012). Well data indicate that residual hydrocarbon saturation after water sweep within the Blake Oil Field is likely to be 30% oil, thus reducing the uncertainty on the probability of this risk occurring. Comparison of dynamic modeling results of injection into the hydrocarbon field and into the saline aquifer suggests the effects might be less severe than initially estimated (Tab. 3).

3.4.12 Risk: Short-Term CO_2 Injection-Induced Permeability Reduction Near Wellbore

The risk of CO_2-induced permeability reduction near the wellbore could restrict the rate of injection and hence the predicted technical performance of the storage site. Permeability can be reduced by salt or mineral precipitation or by microbial activity induced by CO_2 injection. An evaluation of the geochemical effects of CO_2 storage over geological time on both the Captain Sandstone aquifer and Blake Field gas cap components of the storage site was undertaken by geochemical modeling. The potential effect of the presence of oil was also evaluated (Shi et al., 2013).

Predictions of geochemical changes, mineral precipitation and porosity changes were calculated for the storage site using an initial reservoir sandstone composition for the Captain Sandstone from Well 13/23b-05 up-dip from the Blake Field (Jappy, 2006). The mineralogical, pH and porosity change from mineral reactions calculated over a period of up to 100 000 years are summarised in Figure 5a, c and discussed in detail in Shi et al. (2013). In terms of the risk of CO_2 injection-induced permeability reduction over the geological short term, the model results show that the mineral reactions were predicted to be negligible during the injection phase. Porosity changes due to the reactions take place on
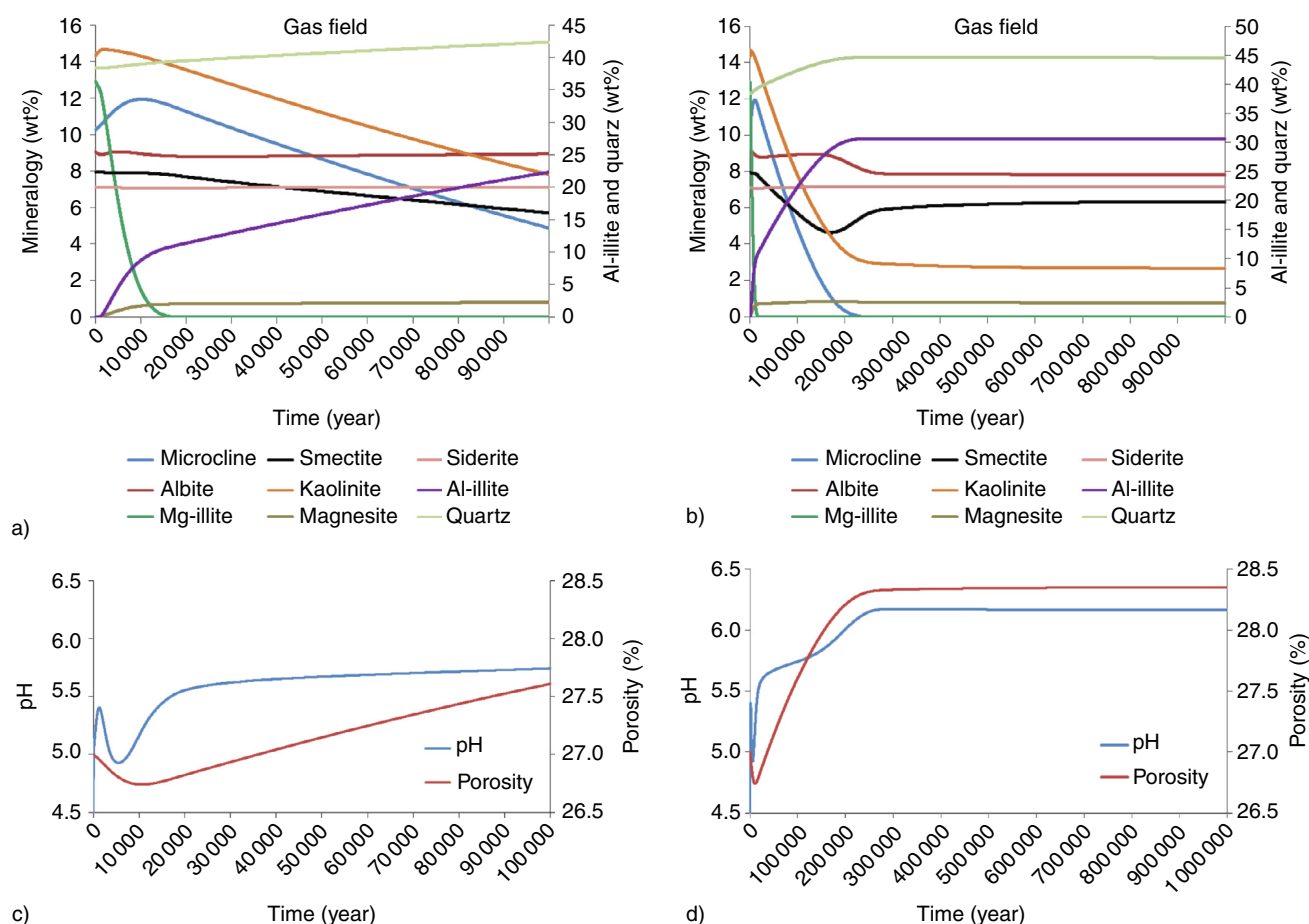
Figure 5

Geochemical modeling of changes due to CO_2 injection into the gas cap of the Blake Oil Field from Shi *et al.* (2013). a) Mineralogy changes and carbonate trapping up to 100 000 years. b) Mineralogy changes and carbonate trapping up to 1 million years. Note: % Al-illite and quartz are shown on the right *y*-axis. c) pH and porosity changes up to 100 000 years. d) pH and porosity changes up to 1 million years.

a timescale much longer than that of injection, as do the accompanying changes in permeability. The impact of CO_2 reacting with the reservoir rock on the injection process is therefore thought to be very small and the risk has been reduced (Tab. 3). The potential for halite precipitation causing salt clogging near the wellbore in a drying-out zone requires further investigation by transport modeling. The occurrence and impact of salt clogging could be prevented or reduced by regularly carrying out a water wash, which is common practice in the oil and gas industry. Future research could include a reactive transport model incorporating salt precipitation for further site characterisation. In addition, the effects of microbial activity should be assessed.

3.4.13 Risk: Long-Term CO₂-Induced Permeability Reduction in the Storage Reservoir Due to Geochemical Changes

The risk of long-term CO_2-induced permeability reduction in the Captain Sandstone reservoir resulting from

geochemical changes as a result of the injection and storage scenario were evaluated by geochemical modeling. Mineralogical, pH and porosity changes from mineral reactions were calculated over a period of up to 1 million years (Shi *et al.*, 2013). The changes are modeled for the gas cap of the Blake Oil Field and summarised in Figure 5b, d and discussed in detail in Shi *et al.* (2013).

The geochemical effects of CO_2 injection in the Blake Field gas cap (Fig. 5) or Captain Sandstone saline aquifer (Shi *et al.*, 2013) are predicted by geochemical modeling. While the short term effect of storing CO_2 in the Blake Field is a significant reduction of the pH, subsequent mineral reactions are slow. A porosity decrease from 27% to 26.7% takes more than 10 000 years in both the gas cap and the saline aquifer sandstone. Reactions in the oil reservoir of the Blake Field are expected to be even slower than in the gas cap or the aquifer (Shi *et al.*, 2013) and the risk from long-term permeability changes has been reduced (Tab. 3). After 15 000 years the amount of mineral dissolution is enhanced

compared to the amount of precipitation and porosity starts to increase slowly to a final value which is slightly above the initial value. However, the formation of large amounts of illite might significantly reduce the permeability. A permeability reduction would not necessarily pose any risks. In fact, it might enhance storage integrity by increasing capillary pressures which would hamper CO_2 migration out of the complex.

3.4.14 Risk: Seismic Monitoring Ineffective Due to the Presence of a Strong Reflector in Overlying Strata

3D seismic survey is the main method proposed at this site to monitor the CO_2 plume and surrounding environment (Hannis *et al.*, 2013c). A risk to the proposed monitoring plan is that the presence of a very strong reflector from the basal surface of the Hidra Formation, Chalk Group (Fig. 2), creates a seismic 'shadow'. Seismic reflections from the immediately underlying strata could be masked, including the primary cap rock and Captain Sandstone storage site (Fig. 2, 3), making storage site monitoring by time-lapse seismic surveys ineffective.

A detailed study of the feasibility of seismic surveys to monitor CO_2 stored in the Captain Sandstone was investigated for the SiteChar UK North Sea site (Hannis *et al.*, 2013c). The analysis was based on a 2D geological model cross-section across the site (Quinn *et al.*, 2012) attributed by seismic properties and a corresponding un-migrated seismic section (Hannis *et al.*, 2013c). A rock physics model of the reservoir was developed for a range of CO_2 saturations. A series of synthetic seismograms showing the seismic response of CO_2 in the subsurface were computed and the sensitivity to seismic noise levels was measured using standard metrics (Hannis *et al.*, 2013c).

The seismic numerical modeling concludes that stored CO_2 should be detected within the site, and even within the seismic shadow, by techniques to compare time-lapse offshore surface 3D seismic survey data (Hannis *et al.*, 2013c). The probability and so the risk associated with the presence of a strong reflector in the strata immediately overlying the storage site is reduced by the investigations (Tab. 3). However, the use of data acquisition techniques to guarantee a high signal-to-noise ratio and the best repeatability are recommended.

3.4.15 Risk: Seismic Monitoring Ineffective at Detecting CO2

Time-lapse 3D seismic surveys are proposed to monitor the presence and migration of CO_2 injected into the storage site. A risk to monitoring is that seismic survey methods are ineffective if there is no significant change in acoustic impedance generated by the presence of CO_2 within the site or that the detection limit (resolution) of the seismic method is too low.

Rock physics studies, calculation of synthetic seismograms and a signal-to-noise sensitivity assessment were conducted for the site (Hannis *et al.*, 2013c). These were accompanied by calculation of the seismic amplitude-*versus*-angle response to test the sensitivity to CO_2 saturation (Hannis *et al.*, 2013c). These detailed investigations indicate that CO_2 injection results in a sufficient change in acoustic impedance to be detected using 'standard' offshore surface 3D seismic survey.

The probability, and so the risk, that 'standard' seismic monitoring methods would be ineffective were reduced by the site characterisation investigations (Tab. 3). However, an optimal alternative of seismic data acquisition from a permanent ocean bottom cables system is recommended to achieve higher signal-to-noise ratios, ensure repeatability and acquisition of additional seismic property data (Hannis *et al.*, 2013c). A cost-benefit analysis would be required to indicate if the increased certainty of monitoring is justified by the additional cost.

3.4.16 Risk: Interference with Hydrocarbon Fields from Migration of CO2 or Increased Pressure Due to CO2 Injection

The EC requires that CO_2 storage operations should not present a risk to groundwater, in the offshore setting of the SiteChar UK North Sea site this is not a concern. However, the UK Government requires that CO_2 storage operations should not interfere with hydrocarbon field operations. Interference might arise either from migration of injected CO_2 or brine into a field or reservoir pressure increases as a result of CO_2 injection.

The risk that the CO_2 storage operations proposed for the site might interfere with other hydrocarbon fields was investigated by dynamic modeling (Delprat-Jannaud *et al.*, 2012). Possible interference with respect to existing hydrocarbon fields was assessed in the 'dry run' storage permit application (Hannis *et al.*, 2013a). The predicted maximum extent of injected CO_2, in both supercritical phase and dissolved in water, was mapped from the results of dynamic modeling of CO_2 injection and concurrent water production (Hannis *et al.*, 2013a). Figure 6 shows the maximum extent of the CO_2 plume during injection, at completion of injection and 1 000 years after the start of storage site operations. During the 20-year injection period the CO_2 plume (supercritical phase and dissolved in water) gradually spreads within the Channel facies sandstone (Fig. 6). Initially, the CO_2 is retained within the Blake Field, subsequently extending one to two kilometres beyond the modeled field boundary (Fig. 6). After injection ceases the CO_2 in supercritical phase does not extend further although the dissolved CO_2 continues to migrate, mostly in an up-dip direction (Fig. 6). At cessation of injection, the mapped plume has
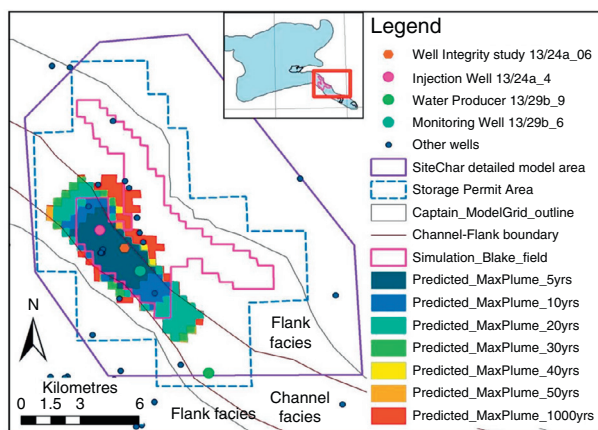
Figure 6

Maximum predicted extent of the CO_2 plume (supercritical phase and dissolved in water) mapped during and after the proposed storage site operations, showing the Channel and Flank facies Captain Sandstone, well positions and modeled extent of the Blake Oil Field from Hannis *et al.* (2013c).

a predicted area of 21 km^2, extending to 23 km^2 after a further 20 years which is the anticipated date of site closure (Hannis *et al.*, 2013a). Details of the distribution of the CO_2 in supercritical phase, dissolved CO_2 and hydrocarbon phases are discussed by Hannis *et al.* (2013a).

The predicted increase in reservoir pressure within the Blake Oil Field and adjacent sandstone, greater than the initial reservoir pressure of 161 bar, and hydrocarbon fields within the Captain Sandstone is illustrated in Figure 7 (Hannis *et al.*, 2013a). The position of the CO_2 injection and water production wells is shown in Figure 6. Little pressure change is noted at the position of the Captain Oil Field from the modeling of storage site operations. There is an initial pressure drop south-east of the site at the position of the Atlantic and Cromarty fields, due to water production. During CO_2 injection, there is a progressive increase to a maximum overpressure value of 27 bar (Fig. 7). The overpressure values drop immediately CO_2 injection ceases. The investigations did not include modeling of hydrocarbon fluids other than in the Blake Field.

The risk of migration of the injected CO_2 to other hydrocarbon fields in the vicinity of the storage site is reduced (Tab. 3) and negligible for the modeled CO_2 injection and water production (Fig. 6). There is little increase in reservoir pressure due to modeled storage operations predicted at the position of the Captain Oil Field, the only operating field hosted within the Captain Sandstone in the vicinity of the site (Fig. 7). The Atlantic and Cromarty fields have ceased production, although the modeled pressure changes might

be beneficial to any future operations. The risk from interference with hydrocarbon fields due to increased reservoir pressure from CO_2 injection was not reassessed (Tab. 3). Further modeling is required, incorporating fluid properties of nearby fields, to quantify pressure changes from storage site operations and reassess the risk to nearby hydrocarbon fields.

3.4.17 Risk: Induced Seismicity

The possibility of increased seismicity associated with the operation of a prospective storage site is identified as a required component of the characterisation and assessment of a prospective storage site (EU, 2009, 2011). Subsurface pressure changes associated with CO_2 injection may reactivate faults or generate minor fractures which may be evident as increased measured seismicity.

The outcomes of the geomechanical modeling and failure analysis for the SiteChar UK North Sea site suggest that the probability of increased seismicity induced by CO_2 injection is low when the overpressure does not exceed the fracture pressure threshold (Shi *et al.*, 2103). The scenario of CO_2 injection with pressure management by concurrent water production, which is the case for the chosen injection scenario, is proposed to ensure fracturing of reservoir or cap rock should not occur. Given the low predicted magnitude of overpressure in the Captain Sandstone (Fig. 7) relative to the estimated cap rock fracture overpressure threshold of 75-80 (Shi *et al.*, 2013) there is a low probability of the occurrence of this risk.

The site characterisation investigations have reduced the probability and so the risk of induced seismicity due to storage site operations (Tab. 3). However, microseismic monitoring is included as a regular monitoring component of the monitoring plan to assure that site integrity is maintained or to identify if the operation is inducing adverse seismic events.

4 RESULTS OF RISK ASSESSMENT-LED SITE CHARACTERISATION

Risk assessment-led site characterisation focuses investigations at a prospective site to provide information required for a storage permit application. The outputs inform the definition of the site, determine storage site design and operation or form the components of an application for a CO_2 storage permit. An application for a storage permit submitted to the competent authority of a European member state should comply with the EU directive and guidance on the geological storage of carbon dioxide (EU, 2009, 2010, 2011) and is reviewed by the European Commission.
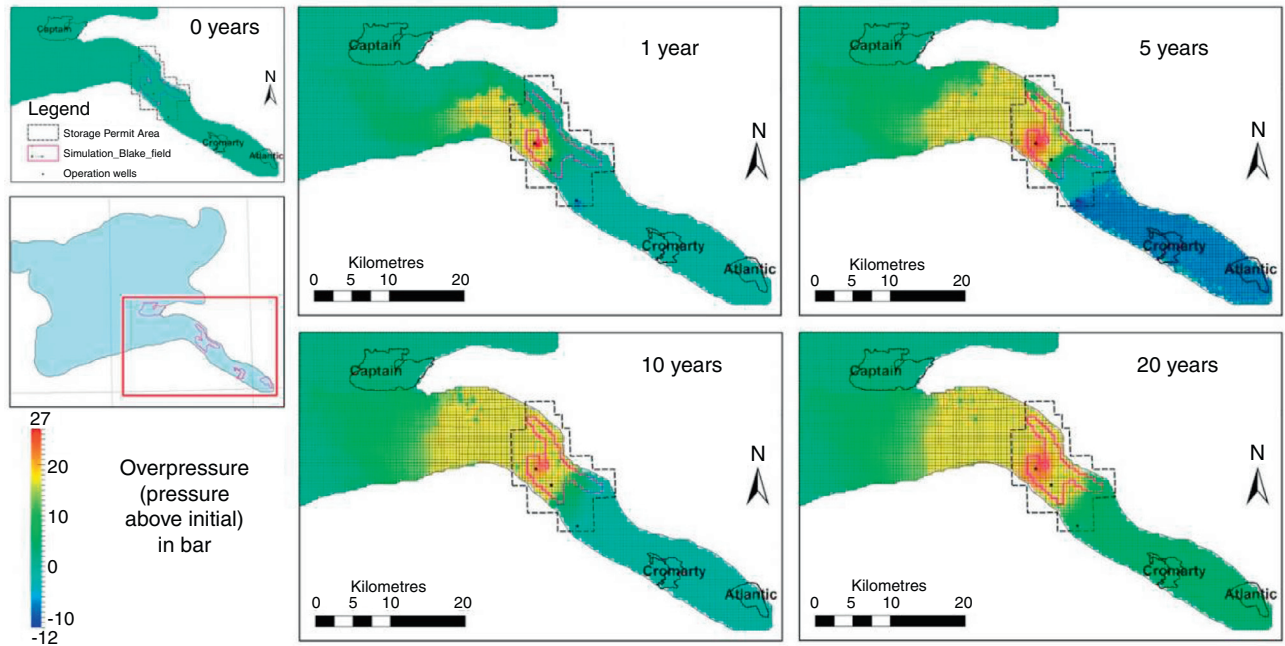
Figure 7

Reservoir pressure change in the 'pan handle' of the Captain Sandstone study area predicted from dynamic modeling of the proposed 20-year period of CO_2 injection and water production (Delprat-Jannaud et al., 2012) showing the position of hydrocarbon fields hosted within the Captain Sandstone from Hannis et al. (2013a). Inset shows the position of the Blake Field (red outline) and other hydrocarbon fields (black outlines), see also Figure 1.

4.1 Definition of the Storage Site and Storage Complex

The SiteChar UK North Sea storage site (Fig. 2, 3) is located principally in the Captain Sandstone Member of the Lower Cretaceous Wick Sandstone Formation (Johnson and Lott, 1993). Vertically, the storage site is defined as the entire Wick Sandstone Formation because the Captain Sandstone may be hydraulically connected to the underlying Coracle and Punt sandstone members (Fig. 2, 3) (Quinn et al., 2012; Akhurst et al., 2014).

The storage complex is a defined volume that extends beyond the storage site. The SiteChar UK North Sea storage complex extends vertically to include the rocks directly above the storage site up to the sea bed (Fig. 3). The storage complex includes the primary cap rock to the storage site, comprising mudstone of the Valhall, Carrack and Rodby formations (Johnson and Lott, 1993) (Fig. 2). Rocks of the overlying Chalk Group may also act as seal if they are of sufficiently low permeability (Fig. 2). Secondary reservoirs for CO_2 are strata overlying and laterally continuous with the storage site that may be hydraulically connected. These include any rocks with available pore volume that overlie the primary cap rock, for example rocks of the Chalk Group and sandstones in the Lista Formation of the Montrose Group (Knox and Holloway, 1992; Johnson and Lott, 1993) (Fig. 2). Secondary seal rocks (cap rocks to the secondary reservoirs) are anticipated to be primarily non-calcareous mudstone of the Lista Formation of the Montrose Group and the mud-prone Moray Group (Fig. 2) (Quinn et al., 2012; Akhurst et al., 2014).

Laterally, the storage complex boundaries enclose a defined volume beyond the storage site. The lateral extent of the storage complex is the same as the storage permit area shown in Figure 6 (Hannis et al., 2013a). The storage complex area encloses the maximum predicted plume extent (Fig. 6) and extends one kilometre beyond to reflect the single investigation of sensitivities conducted during site characterisation and recommendation for additional investigations (Hannis et al., 2013a). The complex includes the lowest closing structural contour enclosing both the injection and water production well of the Captain Sandstone upper surface. It also encompasses the area up-dip (North-East) of the predicted plume extent to reflect the lack of knowledge of the property variations between the Channel and Flank facies sandstones in this direction (Delprat-Jannaud et al., 2012). The overall recti-linear shape of the storage complex is defined by the existing hydrocarbon licence blocks for which agreement with existing licence holders

would be expected to be sought for a storage site permit application (Hannis *et al.*, 2013a).

4.2 Injection Scenario

A component of the storage permit application is the project description. The project description includes an injection plan. For the SiteChar UK North Sea site, the injection plan is determined by the results of site characterisation summarised in this paper. CO_2 injection is proposed to be *via* multiple wells in the vicinity of Well 13/24a-4 (*i.e.* in the Blake Field) at a commercial-scale rate of 5 Mt of CO_2 per year for 20 years resulting in a total 100 Mt of CO_2 injected (Hannis *et al.*, 2013a). Increased reservoir pressure due to injection of CO_2 at the site will be managed by water production. Simultaneous water production through Well 13/29b-9 (*i.e.* down-dip in the saline aquifer) at a rate of 4.75 Mt per year is proposed (Delprat-Jannaud *et al.*, 2012) to manage reservoir pressure to a level one third of the estimated fracture pressure threshold (Shi *et al.*, 2013). This rate of water production will also ensure that CO_2 breakthrough does not occur at the production well. The pressure increase due to injection is expected to extend beyond the storage complex but not interfere with the Captain Oil Field, the only operating field within the Captain Sandstone in the vicinity of the site (Hannis *et al.*, 2013a). Once injection ceases after 20 years the site will be in the post-injection phase. Dynamic modeling results predict rapid pressure dissipation and little post-injection movement of the CO_2 plume (Hannis *et al.*, 2013c).

4.3 Storage Permit Application Components

The risk assessment-led characterisation process presents outputs that are required components of a storage permit application that complies with the EU directive for geological storage of CO_2 (EU, 2009, 2010, 2011). In SiteChar, all components presented for the UK North Sea site as a 'dry-run' storage permit application (Hannis *et al.*, 2013a) were completed as much as possible within the resources of a research project:

– register of risks (Hannis *et al.*, 2013b),
– preventative measures plan,
– monitoring plan,
– provisional corrective measures plan,
– provisional post-closure plan.

The provisional nature of some of the storage permit components reflects the early stage of site characterisation possible within a research project. Site characterisation was confined to those risks associated with technical matters. Some storage permit components that would be prepared for a real storage permit application are beyond the scope

of the SiteChar research and are not included in the SiteChar 'dry-run' application:

– a full Environmental Impact Assessment (EIA),
– provisions relating to the acceptance and injection of CO_2,
– details of financial security,
– a fully developed post-closure plan,
– provisions for reporting.

5 PERMIT PERFORMANCE CONDITIONS

Permit Performance Conditions, criteria against which to measure storage site performance, are recommended as a finding from the SiteChar research. They are useful tools for discussion between the competent authority and operator throughout site characterisation to inform the monitoring plan, and to define and agree acceptance criteria to facilitate site closure.

Six Permit Performance Conditions (PPC) are proposed for the UK North Sea storage site and defined in Table 4. These aim to be unambiguous and achievable by defining ranges of acceptable expected performance. Specific justification for each condition and definition of evidence acceptable to support these statements is documented by Hannis *et al.* (2013a). These criteria were discussed and agreed with regulators from EC Member States and representatives of potential site operators (offshore hydrocarbon industry). PPC define limits to site behaviour which, if exceeded, indicate that a significant irregularity has occurred. This will trigger appropriate corrective measures. They were identified through risk assessment and the resulting risk register and inform the monitoring plan (Hannis *et al.*, 2013c). Although ordinarily the PPC would lie solely in the corrective measures and post-closure plans, they are included as they are necessary for the monitoring plan. PPC are not

TABLE 4

Permit Performance Conditions (PPC) for the SiteChar UK northern North Sea storage site (Hannis *et al.*, 2013a)

Number	Condition
PPC 1	Environmental or human health will not be adversely affected by the storage operation
PPC 2	CO_2 will not pass beyond the storage complex area boundaries
PPC 3	CO_2 plume shows migration within expected modeled behaviour
PPC 4	Pressure changes will remain within predefined/predicted ranges
PPC 5	Geomechanical integrity of the site will be maintained
PPC 6	Cost per tonne of CO_2 will remain within a set limit

explicitly required by the EU storage directive (EU, 2009) but are SiteChar-recommended useful tools for discussion between the competent authority and operator and a way to define and agree acceptance criteria. This will ultimately also facilitate site hand-over and closure at the end of the term, if a storage permit is awarded.

CONCLUSIONS

Risk assessment-led site characterisation investigations targeted to meet the requirements of a storage permit application have been implemented for a prospective storage site in the UK northern North Sea. The process of risk assessment-led site characterisation has been followed, as specified in the EC directive for the geological storage of CO_2, to provide the required components as a 'dry-run' storage permit application. Pre-characterisation of a storage site comprising a hydrocarbon field and adjacent saline aquifer sandstone has been achieved based on publicly available data acquired during hydrocarbon exploration and production. Access to data available to the hydrocarbon field operator would greatly reduce uncertainties associated with site characterisation assessment.

Commercial-scale storage of 100 Mt CO_2, injected at an annual rate of 5 Mt for 20 years, can be achieved without threat to the integrity of the site by pressure management. The pressure is managed by injection of CO_2 into the Blake Oil Field and concurrent water production from the Captain Sandstone saline aquifer down-dip from the field. Optimisation of the CO_2 injection and water production well positions and the CO_2 injection rate is recommended to maximise storage capacity and minimise the cost of the storage operation.

Site characterisation and a first iteration of risk reduction have been conducted for the mostly highly rated technical risks. Site characterisation has reduced most of the risks investigated. However, further iterations of risk assessment-led site characterisation are required to reduce the risks to 'as low as reasonably possible' and to be sufficient to warrant submission of a storage permit application to the competent authorities.

Risk reduction and mitigation measures are proposed to further reduce risks, decrease uncertainties, and increase certainty in the prospective storage site. Abandoned wells remain the most likely fluid escape pathways. However, the mass of CO_2 migrating within the storage complex *via* a leaking wellbore is modeled as a maximum of 20 tonnes per 100 million tonnes injected, despite assuming very pessimistic conditions.

The impact of CO_2 reacting with the reservoir rock during the period of injection is predicted to be negligible by geochemical modeling with a modest net increase in porosity over a period of one million years. The potential for salt precipitation and the effects of microbial activity should also be assessed.

Rock physics studies and seismic modeling indicate the injected CO_2 should be detectable using time-lapse surface 3D seismic survey data acquired using standard methods. However, a cost-benefit analysis for acquisition of sea bottom seismic data is recommended. Dynamic simulation of the Blake Oil Field and adjacent Captain Sandstone indicates that after 1 000 years the injected supercritical phase CO_2 would be retained within two kilometres beyond the field boundary. Provided the pressure of injection within the sandstone is maintained at acceptable levels there would be no adverse influence on operating hydrocarbon fields from the pressure of injection. The pressure changes on adjacent non-producing hydrocarbon fields are predicted for the proposed injection scenario and geology modeled.

The risk assessment-led characterisation process presents outputs that are required components of a storage permit application that complies with the EU directive for geological storage of CO_2 (EU, 2009, 2010, 2011). A prospective storage site, storage complex and storage scenario have been defined and storage permit components were presented, as much as possible within the resources of a research project. In addition, PPC, criteria against which to measure the site performance, are recommended as useful tools for discussion between the competent authority and operator throughout the site characterisation process to inform the monitoring plan, define and agree acceptance criteria to facilitate site closure.

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