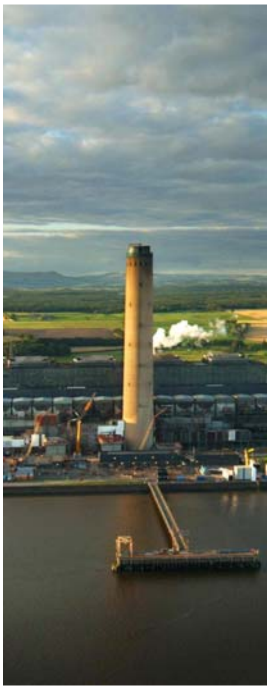

UK Carbon Capture and Storage Demonstration Competition

UKCCS - KT - S7.23 - Shell - 004

Storage Development Plan

April 2011

ScottishPower CCS Consortium

SCOTTISHPOWER nationalgrid

Carbon Capture & Storage Consortium

UK Carbon Capture and Storage Demonstration Competition

UKCCS - KT - S7.23 - Shell - 004

Storage Development Plan

April 2011

ScottishPower CCS Consortium

ScottishPower Generation Limited
Longannet Power Station
Kincardine on Forth
Clackmannanshire
Scotland

ScottishPower Consortium UKCCS Demonstration Competition: Knowledge Transfer

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Produced by Shell U.K. Limited

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IMPORTANT NOTICE

Information provided further to UK Government's Carbon Capture and Storage ("CCS") competition to develop a full-scale CCS facility (the "Competition")

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Executive summary: the plan

This plan has been prepared at the end of the FEED study of the UKCCS Demonstration Competition. As such, it presents the current state of understanding of the storage of CO_2 in the Goldeneye system. Some key areas of uncertainty are outstanding at this time. These include:

(i) Regulatory uncertainty relating to the preparation for – and receipt of – a storage permit. This might require additional work to be performed

(ii) Commercial uncertainty relating to the detail of terms for the execution of UK Demonstration project.

It is proposed to store 20 million tonnes of CO_2 in a volume centred on the depleted Goldeneye hydrocarbon field. The plan is to inject CO_2 over a period of 10-15 years, starting at the end of 2014[1].

- Dense phase CO_2 will be transferred from National Grid to Shell at the National Grid Blackhill site at St Fergus.
- It will be transported around the St Fergus site in a new build pipeline and will join up with the existing undersea Goldeneye pipeline. The current Goldeneye hydrocarbon processing facilities will not be required. The MEG system will be converted to Methanol and reused.
- The 20 inch offshore pipeline will be cleaned and reused after testing for integrity. Some valves and spool pieces will need to be replaced. The CO_2 will be transported in dense phase at a pressure of around 100 bar. The 4 inch MEG pipeline will be reused for methanol transport to the platform.
- The Goldeneye platform will be reused. The installation is normally unmanned which is also suitable for CO_2 operations. Hydrocarbon producing facilities will be decommissioned. Vent and safety systems will be modified for CO_2 service and much of the pipework will be replaced with low temperature rated pipework.
- The Goldeneye production wells will be reused for CO_2 injection. The completions will be replaced to handle cold dense phase CO_2 injection.
- In order to match the desired flow rate to well capacity, a combination of two or three injection wells will be required. Different well combinations are required for different injection rates. At any time two or three out of four wells are expected to be injecting CO_2. The fifth well will be recompleted as a reserve injection well, but will be used for monitoring.
- All five wells will be recompleted giving a degree of backup for increased reliability in order to minimise – and ideally eliminate – the need for a mid-life work over.
- CO_2 injection rates will be metered at the platform and at the wells and integrity monitoring will take place. Conformance monitoring of the CO_2 will be executed as will containment and environmental monitoring.
- The CO_2 injection facilities will be decommissioned three years after the end of injection and post-closure monitoring executed until hand over of the store.

Risk assessments have been performed on containment, transportation, facilities conversion and operability. At this point in time risks have been reduced to ALARP.

The key project challenges at this point are:

- Negotiate the project contract with the UK Government
- Obtain a site lease from the Crown Estate and storage permit from the UK regulator

Chapters

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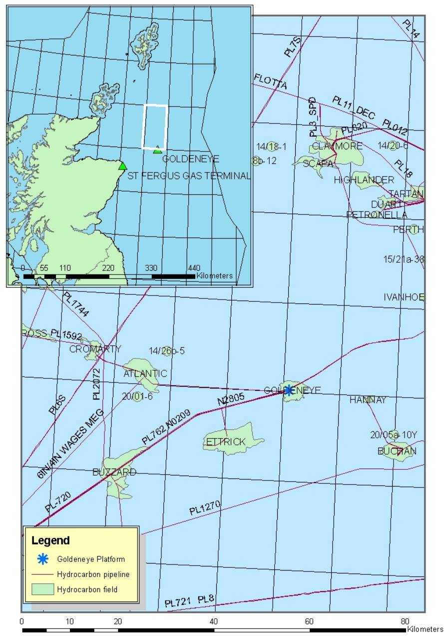
1. Synthesis of the report

This section condenses the Storage Development Plan report into six pages – highlighting the key points from each section. It aims to give the reader an overview and to reference more detailed reading.



The ScottishPower Consortium proposes, under the auspices of the UKCCS Demonstration Competition, to store 20 million tonnes of 99% purity CO_2 over a period of 10-15 years. The CO_2 will be sourced from the Longannet Power Station in Fife, and stored in an area of the UK Continental Shelf centred on the depleted Goldeneye hydrocarbon field. National Grid will transport gaseous phase CO_2 from the power station to the Blackhill compressor station, next to the Shell St Fergus plant, where it will be compressed to 120bara into dense phase and transferred to Shell.

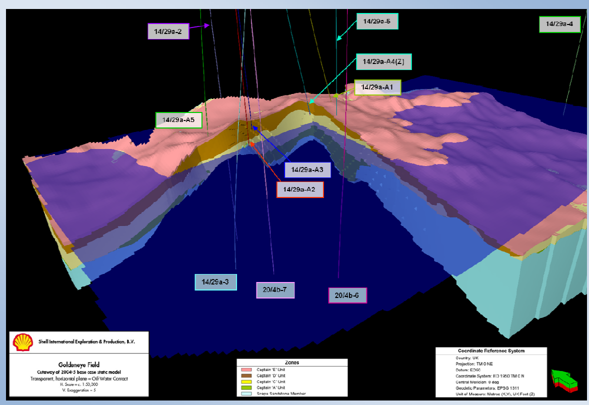
The CO_2 will be transported offshore, re-using the 102km Goldeneye gas export pipeline, to the normally unmanned Goldeneye platform above the field. The Goldeneye field is located ~100km northeast of the St Fergus gas terminal (which is near Peterhead, Aberdeenshire) in water of ~120m depth.

The CO_2 will be injected into the depleted Goldeneye field, reusing the existing hydrocarbon production wells, at a maximum rate of just over 2 million tonnes per year starting at the end of 2014.

Goldeneye platform

The aim is to re-use as much existing infrastructure as possible. The existing undersea pipelines will have front end filtration equipment installed and will be cleaned for injection operations. The platform will be modified with the addition of filtration and the replacement of much of the pipework. The vent system and all safety systems will be upgraded for CO_2 operation. The current Goldeneye hydrocarbon processing facilities at St Fergus are no longer needed and will be bypassed with the installation of a new section of pipeline. The platform will still be operated remotely from the Shell St Fergus control room.

A key challenge will be managing CO_2 as it flows into the depleted field. If it is allowed to flow freely into the reservoir the *Joule-Thompson effect* will refrigerate the CO_2 to a low of -30°C which is outside of the well design specification. The cooling will be managed by working over the wells and installing slim tubing – constricting the flow and maintaining the CO_2 in the dense phase for the whole length of the well – and by placing operational constrains on the rate of bean up/bean down and cycle frequency of the facility.

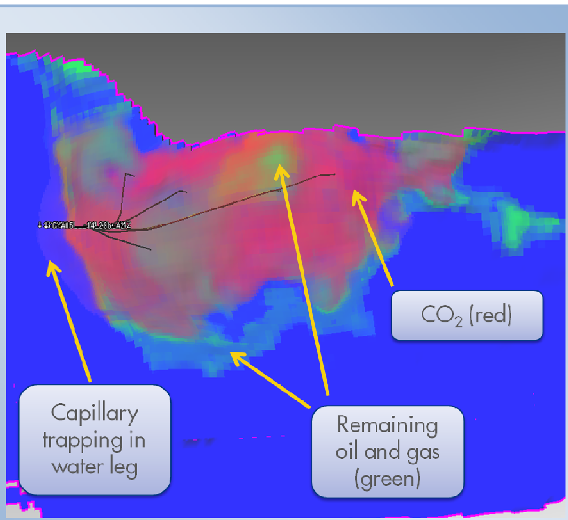


The topside facilities will also be exposed to low temperatures in the event of an emergency depressurisation. The temperature requirement necessitates the replacement of existing pipework and wellheads. As the CO_2 will be de-hydrated at Longannet, internal corrosion of the pipeline and facilities is not a concern – as long as the system remains within specification. This is being assured by the implementation of quality monitoring systems at the compression stations.

The system has to handle varying CO_2 rates from the capture plant – ranging from 75 to 250 tonnes per hour. At any specific flow rate, two or three out of a selection of four wells will be called upon to provide the desired surface and subsurface pressures. The fifth well will be recompleted as a spare injector and will also be used as the main monitoring well.

The wells each have a non-cemented completion with gravel pack and sand screens. These are to be re-used. The risk of plugging posed to these completions from fines in the offshore pipeline (residual after cleaning or from potential de-lamination of an internal coating) is being mitigated by the installation of a filtration package on the platform.

The CO_2 will be injected into the *storage site* at a depth >2516m [8255ft] below sea level into the previously gas bearing portion of the high quality Captain Sandstone Member – in total a 130km long and <10km wide ribbon of Lower Cretaceous turbiditic sandstone fringing the southern margin of the South Halibut Shelf, from UKCS block 13/23 to block 21/2. At the Goldeneye field, this sandstone has permeability of between 700 and 1500 mD.



CO_2 plume after injection. Green: hydrocarbon, Red: CO_2, Blue: water

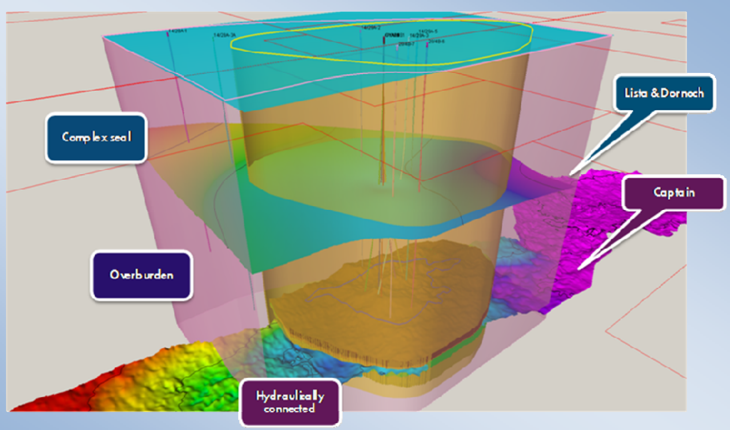
Since 2004, the field has produced 565Bscf of gas and 23MMbbl of condensate. During production, the field experienced moderate to strong aquifer support – which also served to end the gas production from the wells as each well sequentially cut water.

The primary CO_2 storage mechanism will be accommodation in the pore space previously occupied by the produced gas and condensate from the Goldeneye field. A secondary mechanism will be immobile capillary trapping in the water-leg below the original hydrocarbon accumulation.

When CO_2 is injected into the field it will displace invaded aquifer water back into the aquifer. The CO_2 will form a layer due to gravity and unstable displacement effects, and some of the injected CO_2 will be displaced below the original oil-water contact. Once CO_2 injection has ceased the CO_2 is predicted to flow back into the originally gas bearing structure, leaving between 20 and 30% of the total CO_2 injected behind, trapped due to capillary forces in the water-leg.

Analysis and modelling have shown that the field and water-leg likely have sufficient theoretical capacity to store over 30 million tonnes of CO_2 – more than sufficient for the 20 million tonnes proposed in the UK competition.

The Goldeneye field is hydraulically connected through the Captain aquifer water-leg to the neighbouring fields in the east (Hannay, 14/29a-4 discovery – named Hoylake by Shell – and, potentially to Rochelle) and in the west (the soon to cease production Atlantic & Cromarty and, potentially the still producing Blake). The pressure support from the Captain aquifer has limited the decline in Goldeneye pressure, from an original of 262bara [3800psia] to a little under ~152bara [2200psia] (at datum level of 2560m [8400ft] TVDSS). Injection of 20 million tonnes of CO_2 will raise the pressure to between ~241bara [3495psia] and ~259bara [3756psia] at the end of injection. The pressure will then drop to between ~224bara [3250psia] and ~245bara [3553psia] as it dissipates into the aquifer. Over time the fall-off rate will decline and change to slow (or no) recharge as pressure becomes controlled by the Captain aquifer and the fields connected to the same aquifer.



Storage complex

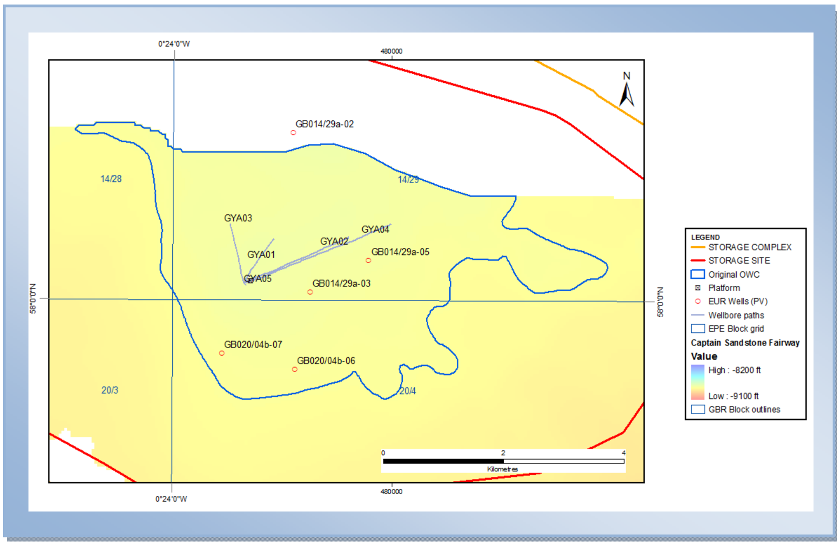
Other nearby fields (Ettrick – 20km from Goldeneye; Tweedsmuir at 30km; Buzzard at 40km; Ross at 60km) have Upper Jurassic or older reservoirs Buchan at 25km distance has a Devonian reservoir. Pressure and compositional data from these fields show that they are not in communication with the Captain Fairway fields.

Vertical containment is provided by the 300m thick *storage seal*, a package including part of the Upper Valhall Formation, Rødby Formation, Hidra Formation and the Plenus Marl Bed. No gas chimneys are observed above the Goldeneye complex. The sealing capacity of the Rødby formation is thought to be excellent as it acts as the primary seal for all hydrocarbon fields in the Captain fairway.

The *complex seal* is made up of two mudstone units that can be reliably correlated across the area of the Goldeneye Field. These are the mudstone at the top of the Lista Formation (Lista mudstone) and the Dornoch mudstone. They are found at depths greater than 800m TVDSS across the entire area under investigation meaning that any CO_2 that is stored beneath them will remain in the dense phase. They dip upwards to the northwest at 1-1.5° and crop out at seabed at least 150km away from the storage site. The Lista mudstone is also a proven seal to hydrocarbons elsewhere in the Outer Moray Firth Basin.

Secondary storage is provided by the formations between the storage and complex seals (Chalk Group, Mey Sandstone Member and lower Dornoch sandstone). The originally trapped hydrocarbons have a possible spill point to the north west which injected CO_2 could migrate to if injected in quantities significantly larger than 20 Million tonnes. However, if the CO_2 injection plume were to pass the structural spill point of the Goldeneye field, this CO_2 would then be contained under the same cap rocks within the much larger Captain fairway. In this sense the Captain fairway has the potential to be a predominantly aquifer, giant CO_2 store.

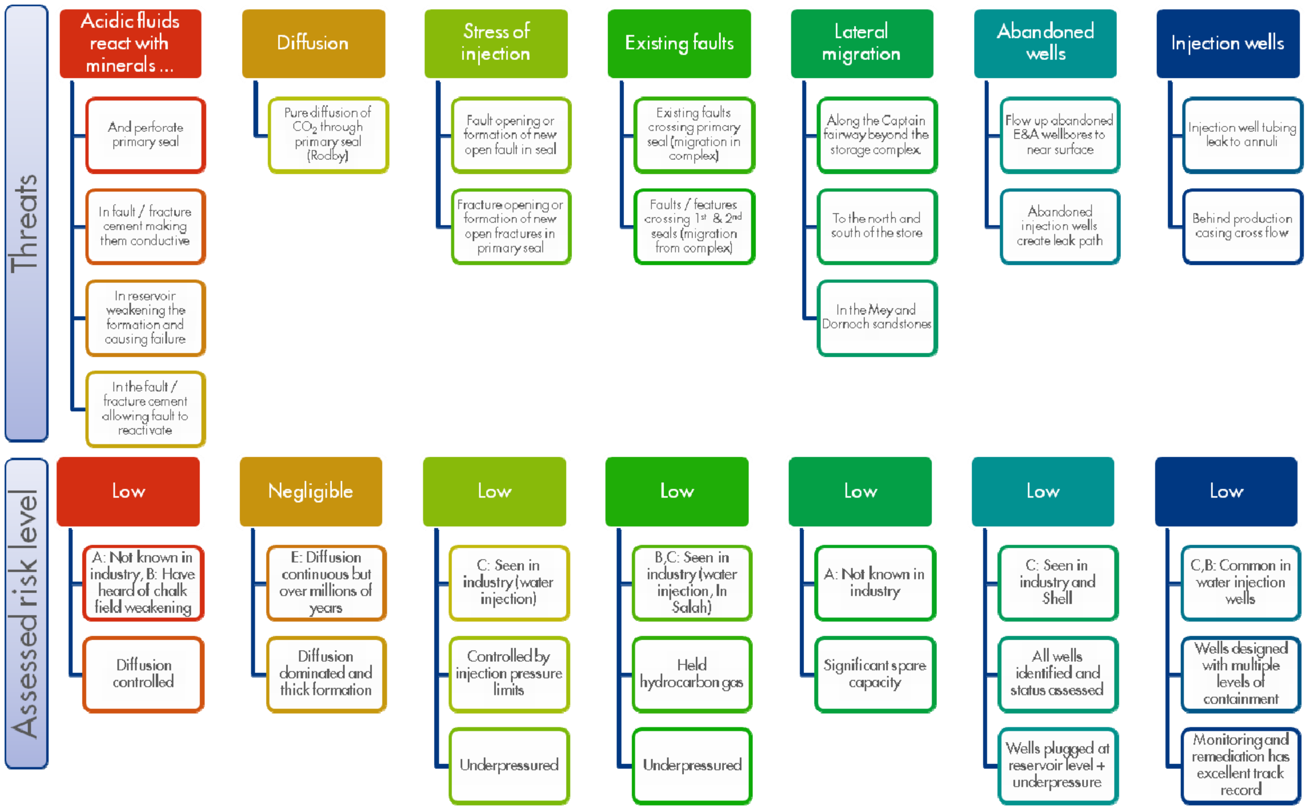
The site contains four exploration and appraisal (E&A) wells within the Captain reservoir and one immediately to the north. All of the E&A wells have good quality abandonment plugs at reservoir seal level.



Existing faults have been mapped and fractures have been analysed and none have been identified to be completely pervasive throughout the seal systems. The key advantage of using a depleted hydrocarbon field is that the caprock integrity has been tested and proven by the very presence of a gas field containing highly mobile gas that is under pressure compared to the surrounding formations. Even though no faults or fractures are observed that currently allow the migration of CO_2, two mechanisms exist that potentially allow for the formation of flow paths: the first is through geochemical interaction between the carbonic acid formed when CO_2 dissolves in water and the host rocks. These interactions have been studied and found to be of a low magnitude and speed and so will not perforate the caprock or dissolve any cementation in the faults. The second is rock failure as a result of the pressure cycling coupled with thermal weakening. Pressure cycling has been studied and the reservoir and seals are indicated to be competent. Fault remobilisation during earlier hydrocarbon depletion and proposed CO_2 injection repressuring has also been examined and results indicate that the conditions are such as to inhibit this. The injection of cold CO_2 can cause limited local thermal weakening of caprock. This can potentially lead to tensile fracture propagation into the caprock. Screening studies indicate that this does not penetrate the whole thickness of the seal complex and does not create a leak path.

The *complex seal* is penetrated by seven exploration and appraisal wells. Only two of these wells have plugs at the secondary seal, meaning that the other wells have the potential to provide migration paths should CO_2 migrate out of the primary containment and travel through the secondary storage and overburden buffers and create a migration plume that intersects one of the wells. This risk is mitigated through monitoring for which corrective measures have been identified should migration ever be observed.

All the containment risks have been assessed using the bow-tie analysis technique. This identifies the barriers to, escalations factors for, controls of and consequences of, CO_2 breaching the complex seal and (possibly) reaching the biosphere. This is summarised below:

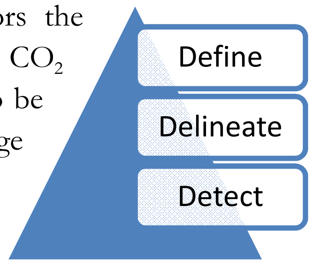


A	B	C	D	E
Never heard of in the industry	Heard of in the industry	Has happened in the organisation or more than once per year in the industry	Has happened at the location or more than once per year in the organisation	Has happened more than once per year at the location

There are seven categories of risk/threat illustrated above. Each category has, after the consideration of natural and engineered barriers (already in place or planned), been assessed as low or negligible.

The key barriers in the Goldeneye system are the primary and complex seals, the well abandonment plugs and injection well design, and the fact that the system operates at a lower average pressure than that in the surrounding formations. This means that – were a leak path to form (which is very unlikely) – formation brine would prefer to flow into the store rather than CO_2 flow out: at least until the system re-pressurises over a period of tens to hundreds of years.

A comprehensive monitoring programme has been designed tailored around the risk assessment. It consists of two plans



- *Base case plan*: is driven by the risk assessment and monitors the conformance of the injection and identifies unexpected CO_2 migration (*detect*) within the storage complex, allowing action to be taken (if required) to ensure the integrity of storage before leakage occurs.
- *Contingency plan*: in the event of CO_2 leakage outside the storage complex, the *contingency plan* is mobilised to locate the source of migration (*delineate*) and enable mitigation plans to be implemented (including quantification or *define*).

The minotoring *base case plan* includes environmental baselines before and after injection, injection well monitoring and monitoring of the seawater under the platform for traces of CO_2. The key detection mechanism for non-injection well related leaks is 4D (timelapse) seismic. A baseline survey is planned before injection. A second, monitor survey will be acquired during injection to check conformance and identify the CO_2 plume movement. Another monitor survey will be acquired one year post injection, to be used as the new baseline. The final surveys will be acquired at least six years after injection ceases, dependent on the pressure performance of the field. The seismic surveys are complemented by seabed surveying around exploration and appraisal wells to check for elevated levels of CO_2.

The *contingency plan* ties closely to the corrective measures and includes focused application of the techniques/technologies used in the *base case plan* plus additional options.

Once the required volume of CO_2 has been injected it is currently planned to monitor the reservoir pressure buildup for three years while leaving the platform in place. After this the platform and wells will be decomissioned. Handover to the *UK Competent Authority* is proposed to take place between six and twenty years post-closure. Exact timing will depend on the rate of pressure recharge, the dynamic performance of the reservoir and the acquisition of two timelapse surveys.

A *corrective measures plan* has been prepared outlining the actions that will be performed should a significant irregularity occur. The underlying principle is to identify the source/cause of the irregularity, assess its likely evolution and then plan remediation in consultation with the regulatory authorities.

2. Structure and background

This document outlines the storage development plan for offshore transport and storage of CO_2 in the depleted Goldeneye hydrocarbon field. Fine detail is not described in the report – this can be found in the relevant key documents which are listed in §15.1.

2.1. Typographic and unit conventions, key definitions

A full list of abbreviations and units can be found in §15.2 starting on p.149. Where relevant abbreviations are also listed at the end of a chapter.

The report uses a UK based field SI unit system. This means that distances are in km. Depths are in feet (ft). The depth reference is mean sea level – is generally found in the form TVDSS (in this case true vertical depth subsea). Subsurface pressures are in psi while surface pressures are in bar. Where possible dual units have been shown, *e.g.*, 14.5psi [1bar]. Hydrocarbon volumes are given in bbl (barrels) and scf (standard cubic feet) with the field unit prefix MM (as in MMbbl) indicating million, and B (as in Bscf) billion. CO_2 has been quoted in tonnes (metric tonnes), and here SI prefixes are used for this SI derived quantity, therefore Mt indicates Mega tonnes or million tonnes. CO_2 rates are given as Mt p.a. – million tonnes per annum – or are some cases tpd – tonnes per day.

References are included as foot notes, except in the case of the relevant key reports listed in §15.1.

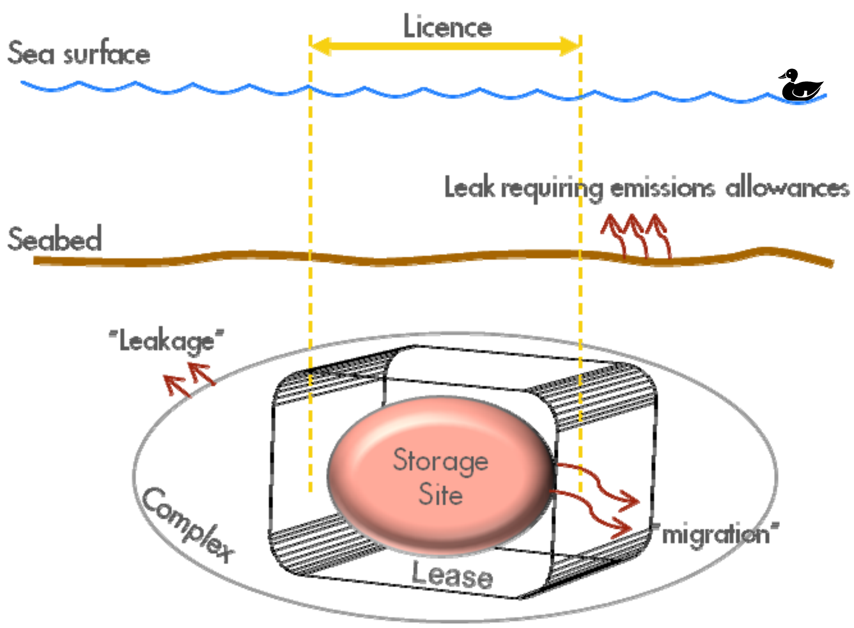


Figure 2.1 Key definitions of site, complex, leak, migration.

When used in this report, the terms *storage site* and *storage complex* have the following definitions, taken from the EU Directive on the geological storage of CO_2:

- *storage site* means a defined volume area within a geological formation used for the geological storage of CO_2 and associated surface and injection facilities;

- *storage complex* means the storage site and surrounding geological domain which can have an effect on overall storage integrity and security; that is, secondary containment formations.

Other relevant definitions are:

- *leakage* means any release of CO_2 from the storage complex
- *migration* means the movement of CO_2 within the storage complex;
- *CO_2 plume* means the dispersing volume of CO_2 in the geological formation;
- *significant irregularity* means any irregularity in the injection or storage operations or in the condition of the storage complex itself, which implies the risk of a leakage or risk to the environment or human health;
- *corrective measures* means any measures taken to correct *significant irregularities* or to close *leakages* in order to prevent or stop the release of CO_2 from the *storage complex*.

2.2. Structure of the SDP

The storage development plan is structured round demonstrating that the following can be achieved:

The store (and complex) as defined must have sufficient capacity to demonstrably contain for a period exceeding 1000 years a cumulative volume of 20Mt [2] supercritical CO_2 plus specified contaminants, injected at a rate of 2Mt p.a.[3] for an injection period of 10-15 years.

Four main pillars support the demonstration of the main question – the subordinate questions must each be satisfied – these are: *capacity, injectivity, containment, monitoring & corrective measures*:

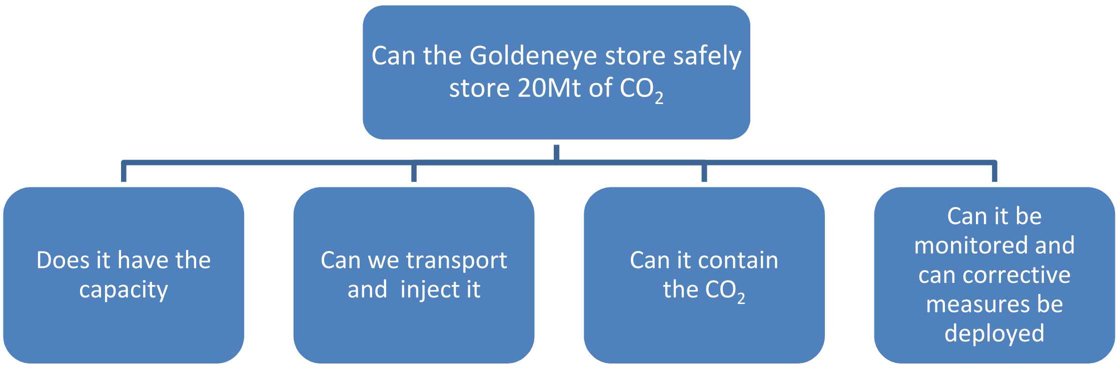


Figure 2.2 The four pillars of CO_2 storage.

In a hydrocarbon development the subsurface evaluation work focuses on understanding the *most likely* ranges for the reserves (capacity) and production rates (injectivity) and then designing a transport and processing system – with some monitoring and metering – that optimises the profitability of the development.

CO_2 storage aims to establish parameters *with high certainty (deterministic approach)*, rather than looking for the most likely case. A large portion of the work is performed on assessing the containment of the system – something that is proven *a priori* for hydrocarbon development because the presence of hydrocarbon implies that is has been contained over geological time.

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[2] Million tonnes

[3] Million tonnes per annum

Monitoring is key in order to show that the site will contain the CO_2. The monitoring plan is built around the containment risk assessment, is site specific and depends on the injection profile and parameters. However, monitoring is of little value if there is not an effective plan in place to correct a significant irregularity should one be observed, hence the corrective measures plan.

The structure of the monitoring report is as follows:

- The report is structured to first describe where it is planned to store the CO_2. The surface location of the storage site is described, along with information on other users of the area.
- The subsurface store is then outlined along with the history of the hydrocarbon field that is being reused.
- The major risks assessed as relating to the project are summarised.

The four pillars of CCS are then addressed

- Capacity
- Injection and injectivity plus transport and injection facilities
- Containment and the related subsurface risk assessment
- The proposed monitoring plan and the proposed corrective measures plans are outlined.

It is also necessary to describe the conditions required for and manner in which the site will be closed and handed over to the *UK Competent Authority* after the end of injection. This is outlined in §10 starting on p131.

The plan finishes by describing components in common with a field development plan

- HSE plan
- Facilities, pipeline and wells decommissioning plan

2.3. Background to the project

In the 2007 Budget, the UK Government announced a competition challenging industry to develop proposals to build and operate a full-scale CCS system before 2015 (the Competition). *The Energy White Paper 2007: 'Meeting the energy challenge'*, provided further detail and the Competition was launched in November 2007.

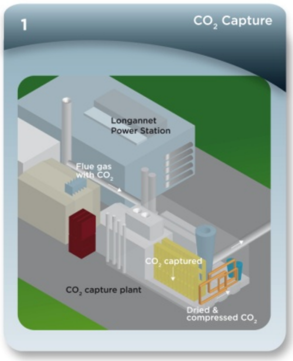
There were originally nine entrants, drawn from across the energy sector. In March 2010, two entrants, one of which was the ScottishPower CCS Consortium (consisting of ScottishPower, National Grid and Shell), were invited to develop their proposals through a FEED exercise that concluded in Q1 2011. The FEED exercise, and ultimately the Competition itself, requires each element of the CCS Chain - capture, transport and storage - to be developed and demonstrated. The ScottishPower CCS Consortium became the sole remaining entrant in the competition on the 20th October 2010 when the sole competing developer withdrew during its FEED study.

The objective of the FEED study is to develop the project design to obtain greater certainty over scope, design and costs and demonstrate risk reduction when compared with the earlier conceptual design. The scope of the FEED covers the process connection to the existing power station, carbon dioxide (CO_2) capturing and conditioning equipment, onshore CO_2 transportation, offshore transportation and permanent storage.

Figure 2.3 Elements in the ScottishPower consortium CCS project.

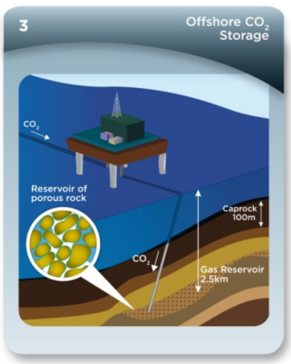
The CCS project involves the post combustion removal of CO_2 from a portion of the flue gases from one of the existing Longannet Power Station (LPS) units by retrofitting a Carbon Capture Plant (CCP) which will be located adjacent to the power station. CO_2 captured from the plant will be dried, compressed and transported in a gaseous phase via an onshore pipeline to the Blackhill (St Fergus) compressor station north of Aberdeen. At Blackhill (St Fergus) the CO_2 will be further compressed to dense phase and transported via an existing sub-sea pipeline to the Goldeneye platform in the North Sea, from where the CO_2 will be injected into a depleted gas field for geological storage.

2.4. The project partners



ScottishPower is responsible for the management of the overall project as well as the construction and operation of the capture plant at the power station. ScottishPower supplies electricity and gas to over 5 million private and industrial customers across the UK. It generates electricity from a range of sources including coal, gas, wind and marine. It's also part of the energy company Iberdrola, one of Europe's largest utility companies.

National Grid is responsible for the onshore transport of the CO_2 along new and existing pipelines, together with the associated compression facilities that drive the gas to the offshore storage site. National Grid owns Britain's high pressure natural gas transmission system. The company designs, builds and operates gas pipelines and is seeking to apply its knowledge and skills to CCS. National Grid also owns the high voltage electricity transmission network in England and Wales and operates the system across Britain.



Shell will transport the CO_2 offshore and store it in an existing gas reservoir under the Central North Sea that has ceased production. Shell is a global group of energy and petrochemical companies. The core business of the oil and gas industry is the handling of gas and liquids above and below the surface and that makes companies like Shell very well placed to help deliver CCS.

2.5. CO_2 profile for storage

As stated in the introduction, the project is required to store 20 Mt CO_2 over a period of 10 to 15 years. The detail of the profile depends on the mode of operation of the power plant and on the reliability and availability of all the components. It also depends on the details of the commissioning process – that is the phasing of the start up of train one and train two in the capture plant.

The exact details of the profile will be determined during detailed design and the project contract negotiations. At this point an initial RAM (reliability and availability model) has been constructed, and a three month separation between the start up of the trains has been assumed. The profile is shown in Figure 2.4.

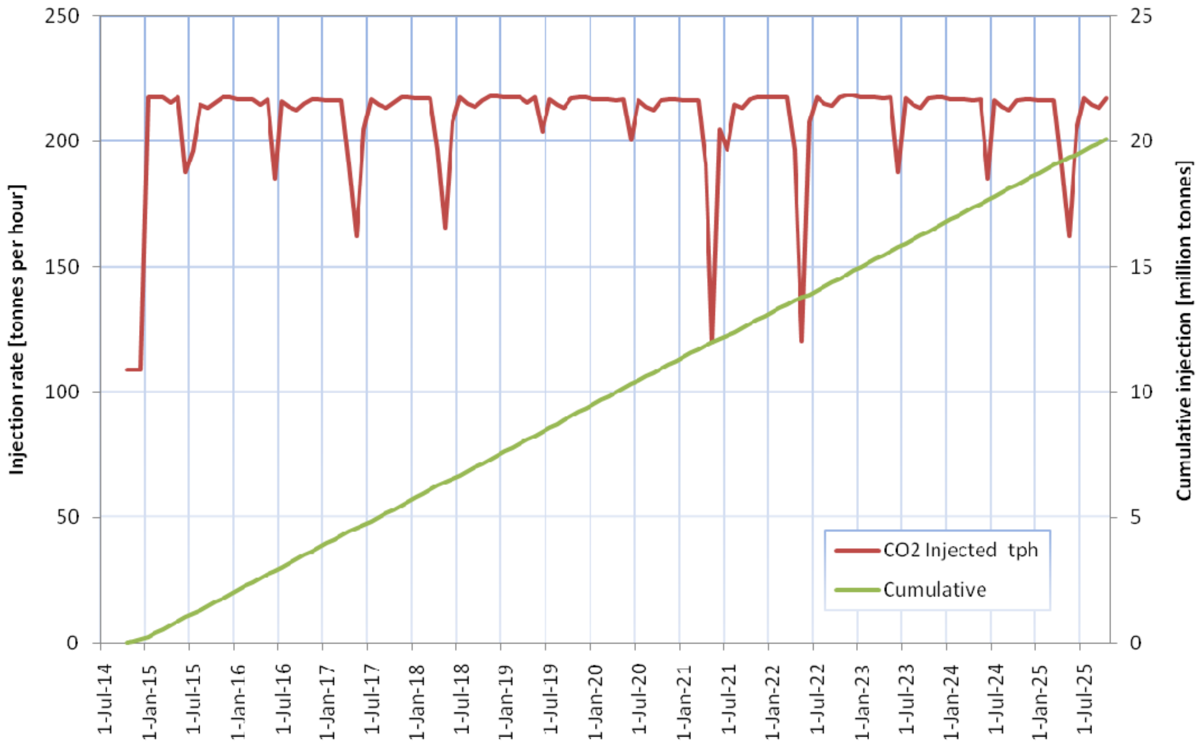


Figure 2.4 Project CO_2 injection profile.

This model results in 20Mt CO_2 being stored in 133 months (just over 11 years). The average rate (after commissioning) is 1.85Mt p.a.

3. Site description

3.1. Introduction

This chapter sets out the basic data for the storage solution for the Scottish Power CCS Consortium project, including a description of the surrounding environment, identification of other users who may be affected by the change of use of the Goldeneye gas condensate field description of the geology of the complex and the fluids contained within it. Succeeding chapters will set out the individual assessments of Capacity, Injectivity, Containment and Monitoring which use assumptions based on the understanding of the Goldeneye storage complex presented here.

3.2. Structure of the chapter

The following sections of this chapter set out to:

- Define the location and extent of the site;
- Discuss the environment, other users, geology of the storage site and complex, the facilities at Goldeneye and the expected state of the storage site at the start of injection.

3.3. Definition of the proposed site

The *storage site*[4] is based upon the use of the Goldeneye gas condensate field as the primary container for the CO_2 planned to be stored from the Longannet Power Station (Figure 3.1). The Goldeneye field is located in the Outer Moray Firth, circa 100km north-east of the St Fergus gas plant, mainly in UKCS blocks 14/29a (Offshore Hydrocarbon Production License P257) and 20/4b (License P592) but is mapped to also straddle blocks 14/28b (License P732) and 20/3b (License P739). In detail, it is defined as the pore volume between the mapped top of the Kimmeridge Clay Formation and the mapped top of the Captain Sandstone Member (Figure 3.2) that exists within an area bounded by a polygon that lies a short distance beyond the original oil-water-contact (OOWC) of the Goldeneye field (Figure 3.3). Porous and permeable lithologies exist within the Scapa Sandstone, Yawl Sandstone and Captain Sandstone Members. The last named of these acts as the hydrocarbon reservoir of the Goldeneye field.

The *storage complex* includes the *storage site*, defined above, and the following additional elements (Figure 3.4):

- Storage seal – The *storage seal* comprises all of the stratigraphic units between the top of the Captain Sandstone Member and the top of the Plenus Marl Bed (including the Upper Valhall Member & Rødby Formation – both part of the Cromer Knoll Group – and the Hidra Formation and Plenus Marl Bed – both part of the Chalk Group - Figure 3.2).
- Secondary containment (hydraulically connected) – The hydraulically connected secondary storage is intended to accommodate migration of CO_2 within the reservoir formation but beyond the licensed boundary of the *storage site*. As such, it is represented by the lateral extension of the permeable formations that make up the *storage site*.
- Secondary containment (overburden) – The purpose of *secondary storage (overburden)* is to accommodate any migration of CO_2 that escapes vertically beyond the *storage seal*. To contain this migrated volume, the secondary containment requires the presence of a

[4] Refer to §2.1 for the definitions of the *storage site* and *storage complex*.

secondary (or complex) seal. The *secondary storage (overburden)* for the Goldeneye field includes the Chalk Group above the top of the Plenus Marl Bed, the Montrose Group (particularly the Mey Sandstone Member) and the lower Dornoch sandstone, within the Moray Group (Figure 3.2).

- Complex seal – The mudstone at the top of the Lista Formation (which is referred to in this report as the Lista mudstone and is of Palaeocene age), within the Montrose Group and the Dornoch mudstone, part of the Palaeocene to Eocene-aged Dornoch Formation in the Moray Group, were chosen as the *complex seal*.

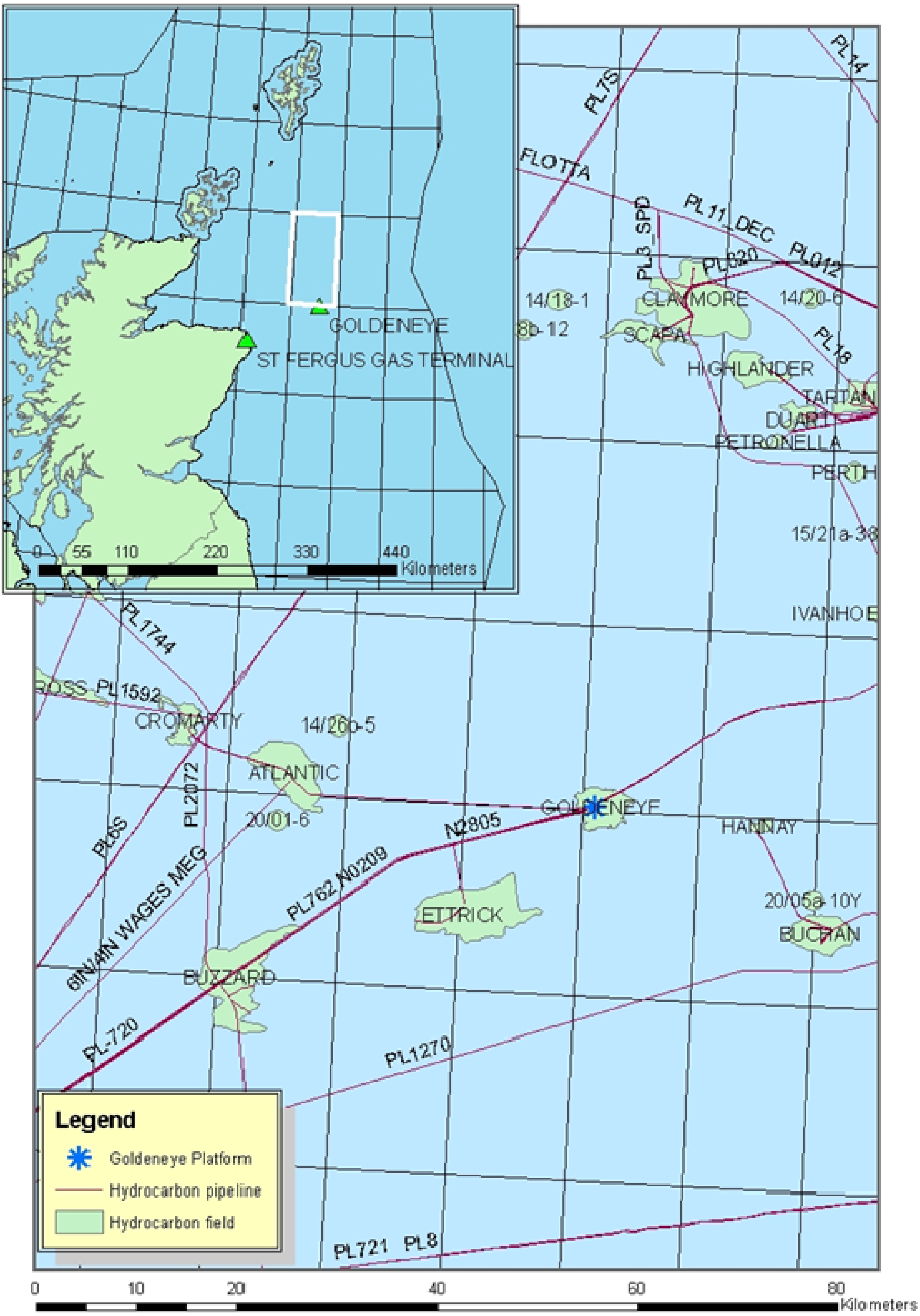


Figure 3.1 Goldeneye location map.

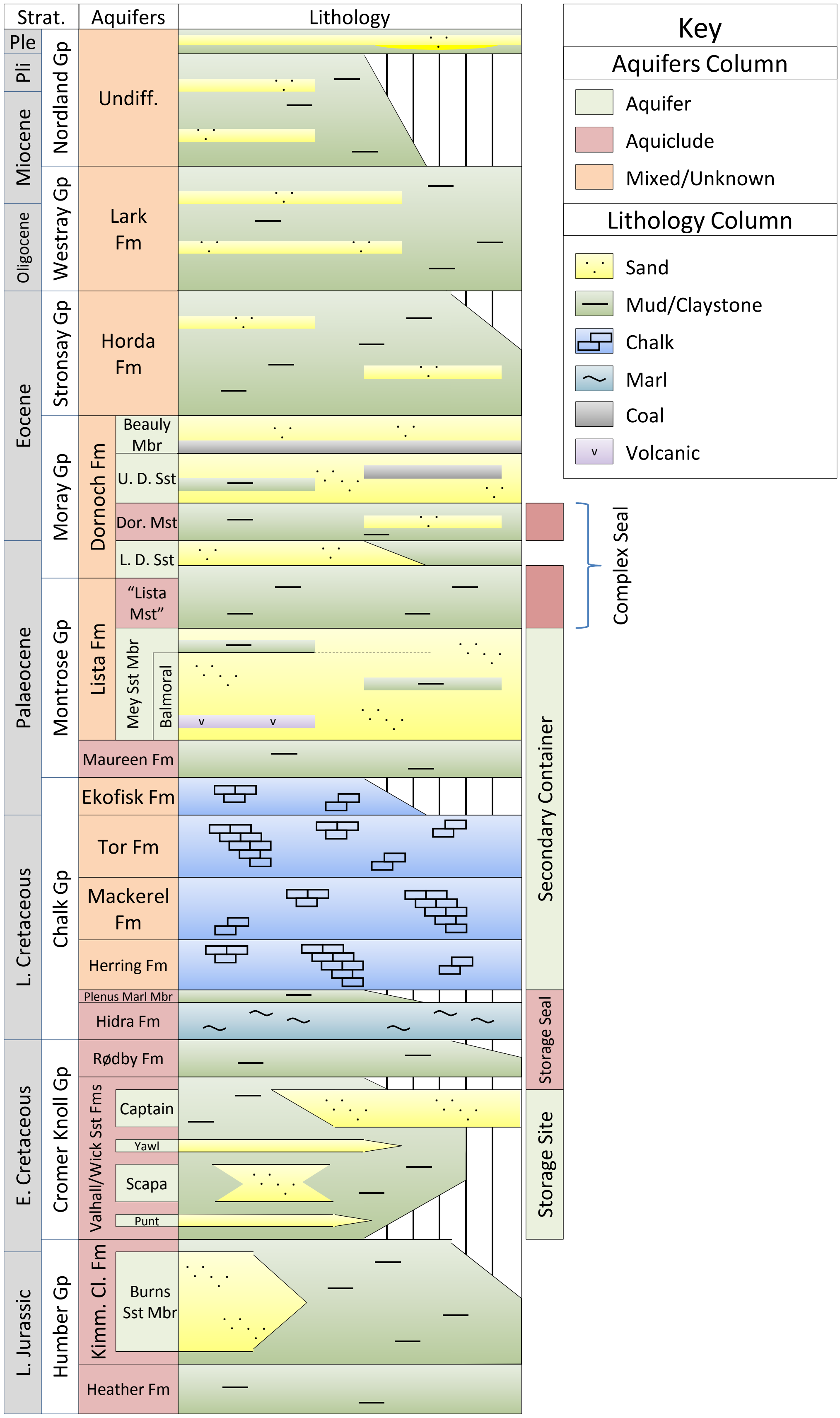


Figure 3.2 **Generalised stratigraphy of the Goldeneye storage complex.**

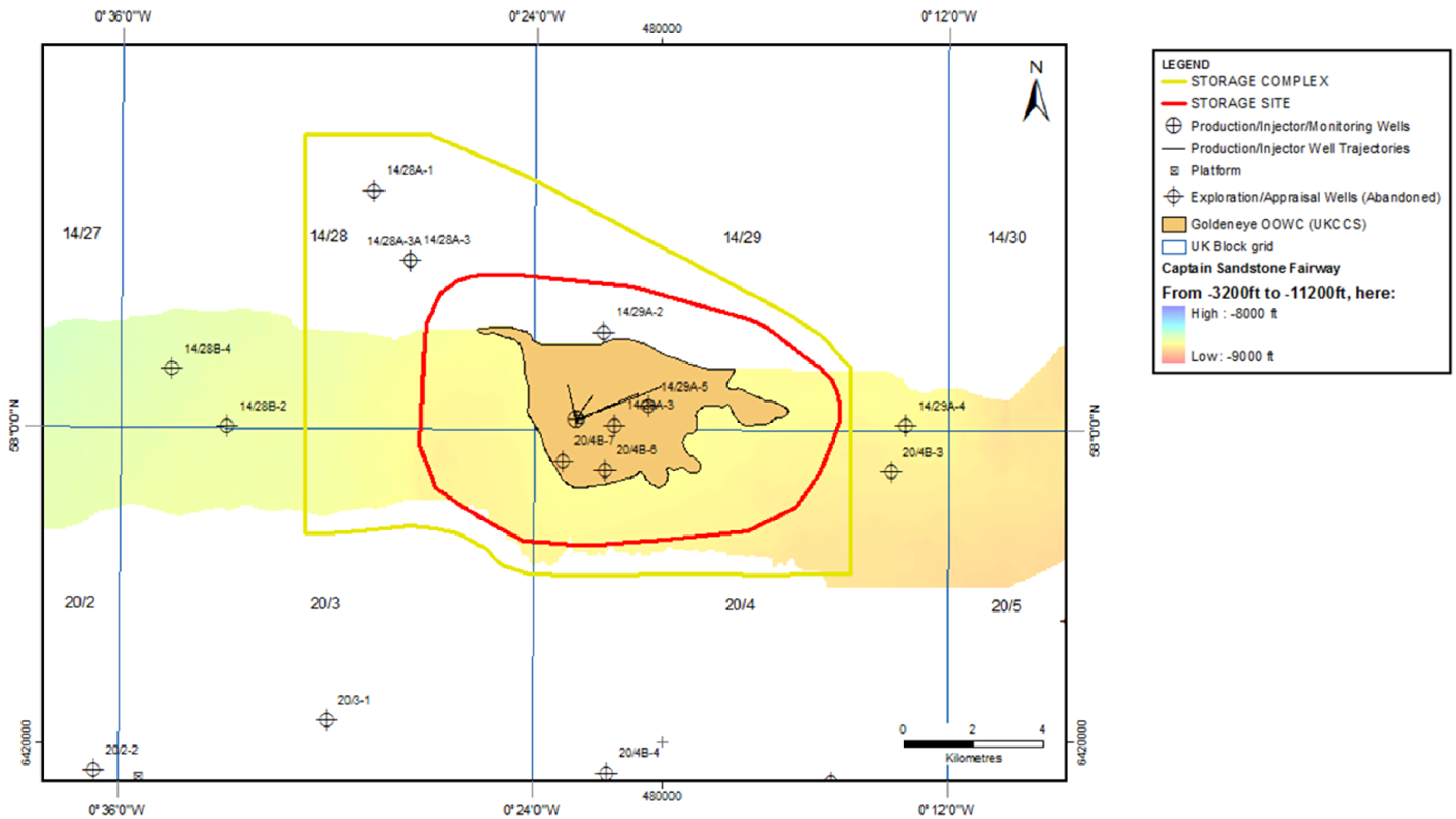


Figure 3.3 **Map to show the geographical extent of the storage site and storage complex with extent of Captain Sandstone Member aquifer indicated.**

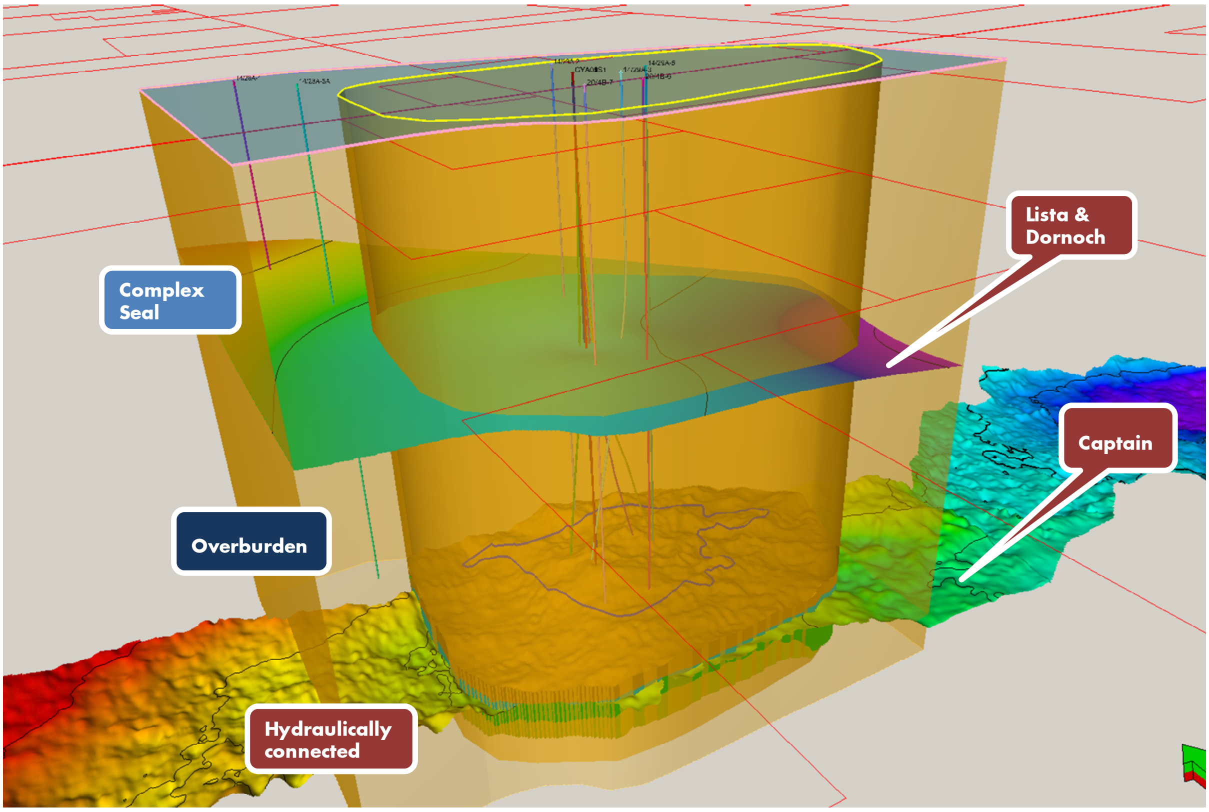


Figure 3.4 **Schematic representation of the Goldeneye *storage site* and *storage complex* – not to scale.**

3.4. Seabed and surrounding ecosystems

A draft environmental site description is reported in the Environmental Impact Assessment report and the following conclusions have been drawn:

- Sea currents are southerly and maximum surface speed (over 10 years of observation) is 0.81 m/s.
- Average sea surface temperature in the area of the development range from 6.0°C at the surface in winter to 14.5°C at the surface in summer. The water temperature at the sea bed ranges between 6.0-7.0°C.
- Wind direction and velocity is variable throughout the year, with the wind originating predominantly from the south to northwest. Annual wind velocities in the area range from 0 - 26m/s with the calmest months being June to August and the windiest months being December to March.
- The composition of benthic and planktonic communities that inhabit or use the development area is known and documented.
- Marine birds are present in the area year round but occur in highest numbers during the months of August or September.
- Cetaceans occur in low numbers throughout the year, though sightings increase slightly in the summer months.

- The nearest candidate Special Areas of Conservation (SACs) are the 'Scanner Pockmarks' and 'Braemar Pockmarks' (located ~83km and ~149km to the northeast of the Goldeneye platform respectively).
- The site surveys and pipeline route surveys undertaken in the vicinity of the development found no species or habitats of conservation significance under the UK's Offshore Petroleum Activities (Conservation of Habitats) Regulations 2001. Due to this, and the relatively large distance from the Goldeneye platform to both the 'Scanner' and 'Braemar Pockmarks', the development is not considered to pose any risk to these habitats.

More detail on the above assessment can be found in Appendix B.

3.5. Natural Seismicity

Information about the location and magnitude of all earthquakes recorded from the UK continental shelf has been plotted and reviewed (Figure 3.5). The closest recorded seismic event to the location of the Goldeneye development site is at a distance of ~55km. There are no recorded instances of seismicity related to hydrocarbon production in Goldeneye.

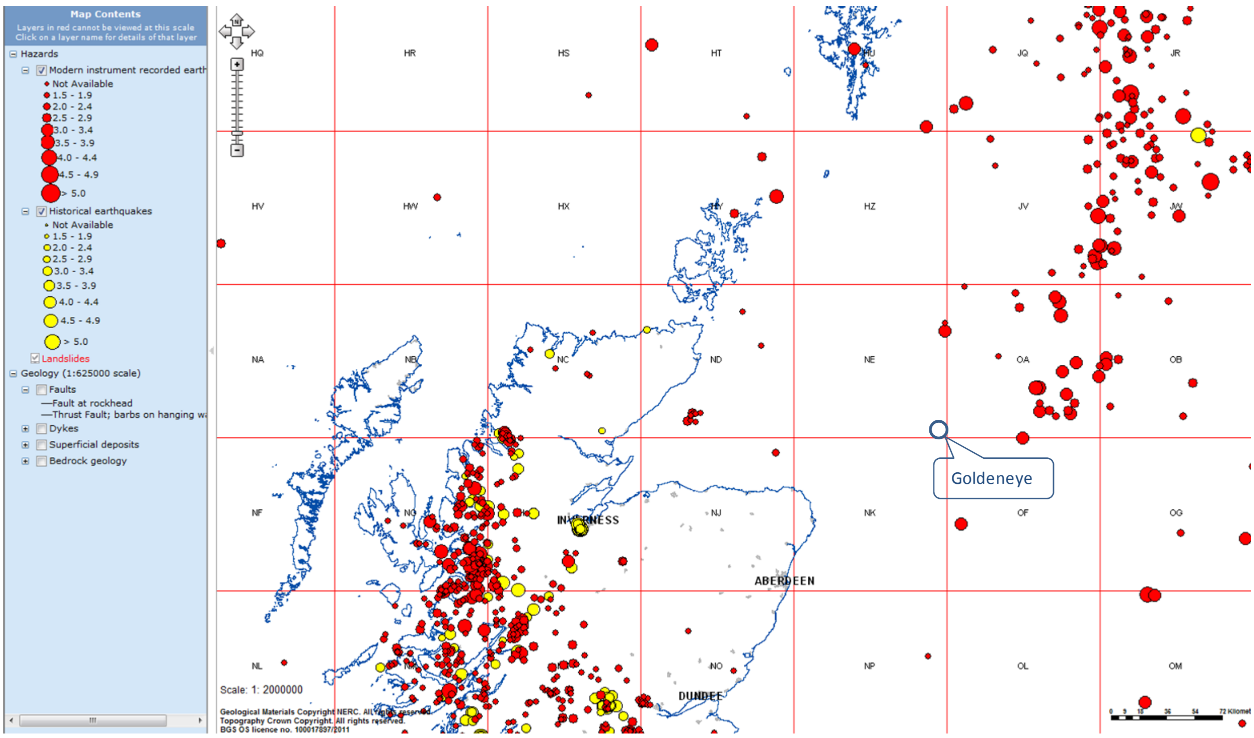


Figure 3.5 **Map of all earthquakes recorded from northern Scotland and the central and northern North Sea, from historical times until 20th January, 2011.**

3.6. Other users of the environment

A number of other users of the surface, water column and subsurface environments within and in the vicinity of the development area have been identified. These are as follows:

- **Fisheries**: Fishing intensity within the development area is low. Fishing effort expended in the development area ranged between 0.25% and 1.2% of that expended in UK waters while the catch (predominantly demersal species and crustaceans, using bottom trawl gear) from within the vicinity of the Goldeneye development represents at most 0.78% of that from UK waters.
- **Shipping**: a traffic study for the central and northern North Sea indicates moderate shipping, with between 1 and 10 vessels per day passing through the area.
- **Teleommunications and oil & gas pipelines**: There is one telecommunication cable (CNS Fibre Optic) and four hydrocarbon export pipelines (Beryl to St Fergus, Miller to St Fergus, Britannia to St Fergus and Goldeneye to St Fergus) in use in the vicinity of the development. The Goldeneye to St Fergus pipeline route crosses a number of other hydrocarbon export pipelines (Brent Alpha to St Fergus, Frigg to St Fergus, Miller to St Fergus and Britannia to St Fergus).
- **Oil & gas exploration & production**: The Goldeneye CCS storage complex covers numerous licensed oil and gas blocks as shown in Figure 3.6. The relevant equity holders and operators are shown in Table 3.1. The nearest platform is Ettrick FPSO (16km) and the next nearest is Buchan Alpha (27km).
  The Goldeneye reservoir is in pressure communication with a number of other hydrocarbon fields in the vicinity of the outer Moray Firth. Only the Blake oil field (operated by BG Group) is currently in production. At the Atlantic gas condensate (BG), Cromarty gas condensate (Hess) and Hannay (Talisman) oil fields production is currently suspended. Industry research indicates that Rochelle (operated by Endeavour) will commence production in the next 18 months. There is no evidence that Goldeneye is in pressure communication with any other producing oil or gas field. Other hydrocarbon accumulations in the area (e.g., Ettrick, Buchan and Buzzard) have reservoirs of different ages and on different pressure trends.
- **Wind farms and aggregate extraction**: There are no offshore wind farms proposed and no areas licensed for aggregate extraction in the vicinity of the development.
- **Wrecks and hazards to shipping**: No shipwrecks were identified by any of the surveys undertaken in the immediate vicinity of the development area.

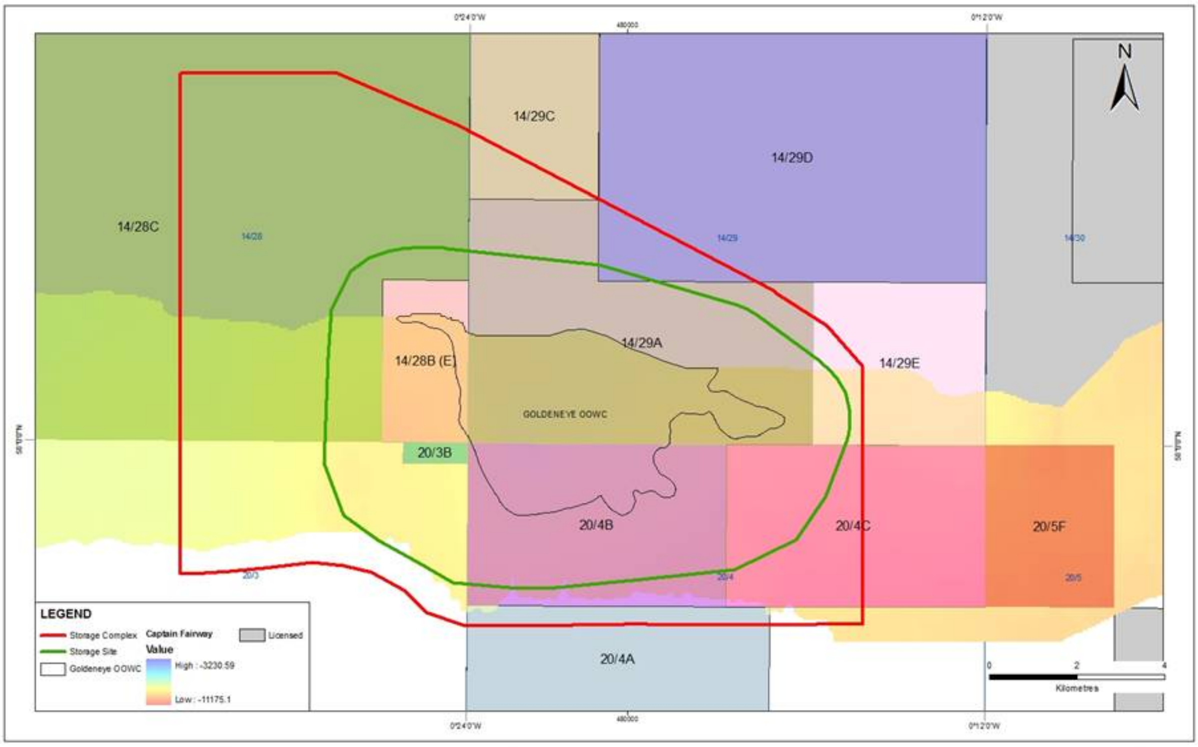


Figure 3.6 **Oil and gas licence blocks in the vicinity of the Goldeneye CCS storage complex.**

Table 3.1 **Licence block owners and operators.**

Block	Equity holders
14/28b (E)	Centrica (25%), ExxonMobil (25%), Shell* (50%)
14/28c	Black Sapphire Resources Ltd. (100%)
14/29a	ExxonMobil (50%), Shell* (50%)
14/29e**	Encore Petroleum Ltd. (100%)
14/29c	Black Sapphire Resources Ltd. (100%)
14/29d	Encore Petroleum Ltd. (100%)
20/3b	ExxonMobil (50%), Shell* (50%)
20/4a	Apache North Sea Ltd. (50%) Nexen Petroleum U.K. Ltd.* (50%)
20/4b	Centrica (17.5%), Endeavour Energy Ltd.* (37.5%), Shell* (45%)
20/4c**	Encore Petroleum Ltd. (100%)
20/5f**	Encore Petroleum Ltd. (100%)

* denotes Operator, ** potential Seaward Production Licence awards in the 26th Seaward Round.

3.7. Structural configuration and geological history

The Goldeneye field is situated in the Outer Moray Firth on the northern margin of the South Halibut Basin (Figure 3.7) and has a combined structural and stratigraphic trap of Lower Cretaceous Captain Sandstone Member. Structural dip closure is provided to the east and south and is interpreted also to the west; whilst pinchout of the Captain reservoir sands to the north provides an additional stratigraphic trapping element (Figure 3.8).

The structural configuration in Goldeneye is the result of two major extensional phases during the Late Jurassic and the Cretaceous with periods of north-south directed compression. Further minor compression, combined with a period of regional eastward tilting took place in the early Tertiary.

3.7.1. Storage site

As well as the Goldeneye field, which has a reservoir within the Captain Sandstone Member, the *storage site* also includes all of the rocks down to the base of the Cromer Knoll Group (equivalent to the top of the Kimmeridge Clay Formation). This interval is predominantly mud-prone but contains two other porous and permeable formations – the Yawl Sandstone Member and the Scapa Sandstone Member. All of the sandstone units were deposited in a deep marine, sand-rich turbidite slope/base of slope system. Additionally, the Captain Sandstone Member includes contribution from mass-wasting of locally exposed fault scarps. The Captain sandstones occur in a continuous ribbon of sand that fringes the southern boundary of the South Halibut Horst (Figure 3.7), though the others have a more localised distribution. The subdivision of the Captain Sandstone Member and the reservoir properties for each unit are shown in Table 3.2. The existing development wells have been completed within the Captain 'E' and Captain 'D' Units.

Table 3.2 Sub-division, description and average reservoir properties of the Captain Sandstone Member in the vicinity of the Goldeneye field. (Tot. Φ & Tot. K are averages for gross interval; Net Φ is an average for the net sand interval.)

Unit	Description	N/G (v/v)	Tot. Φ (v/v)	Net Φ (v/v)	Tot. K (mD)
Captain 'E' Unit	Laterally variable thin heterogeneous unit	0.61	0.13	0.21	7
Captain 'D' Unit	Laterally extensive massive sand unit	0.94	0.23	0.25	790
Captain 'C' Unit	Laterally extensive, mudstone-rich heterogeneous unit	0.33	0.07	0.22	10
Captain 'A' Unit	Laterally restricted sand-rich unit	0.84	0.19	0.23	134

Apart from the gas condensate and oil rim of the Goldeneye field, all porous formations within the storage site have been found to contain brine only. Gas condensate shows were recorded from a thin Upper Jurassic interval (Burns Sandstone Formation) to the north of the field but a pressure measurement taken from this unit indicates that it is not on the same pressure trend as Goldeneye.

3.7.2. Storage seal

As defined in §3.3, the *storage seal* includes the Upper Valhall Member & Rødby Formation – both part of the Cromer Knoll Group – and the Hidra Formation and Plenus Marl Bed – both part of the Chalk Group. Over the storage site, this interval is at least 62m in thickness and has an average thickness of 150m. The lower parts of the storage seal consist of mudstones with sporadic thin beds of argillaceous limestone, the Hidra Formation consists of bioturbated limestones with interbedded mudstones and the Plenus Marl Bed is a relatively thin unit of black mudstone.

3.7.3. Secondary containment (hydraulically connected)

The Captain Sandstone Member is interpreted to maintain its presence all the way along the Captain fairway. The Yawl and Scapa Sandstone Members (Figure 3.2) are more locally distributed. Data from wells to the west of the Goldeneye field shows that both sands are absent in this direction, though an older sandstone unit – the Punt Sandstone Member, is penetrated. To the east of the *storage site*, well data shows that the Scapa Sandstone Member shales out in this direction. The Yawl sandstone continues to be seen in wells over several tens of kilometres east of Goldeneye.

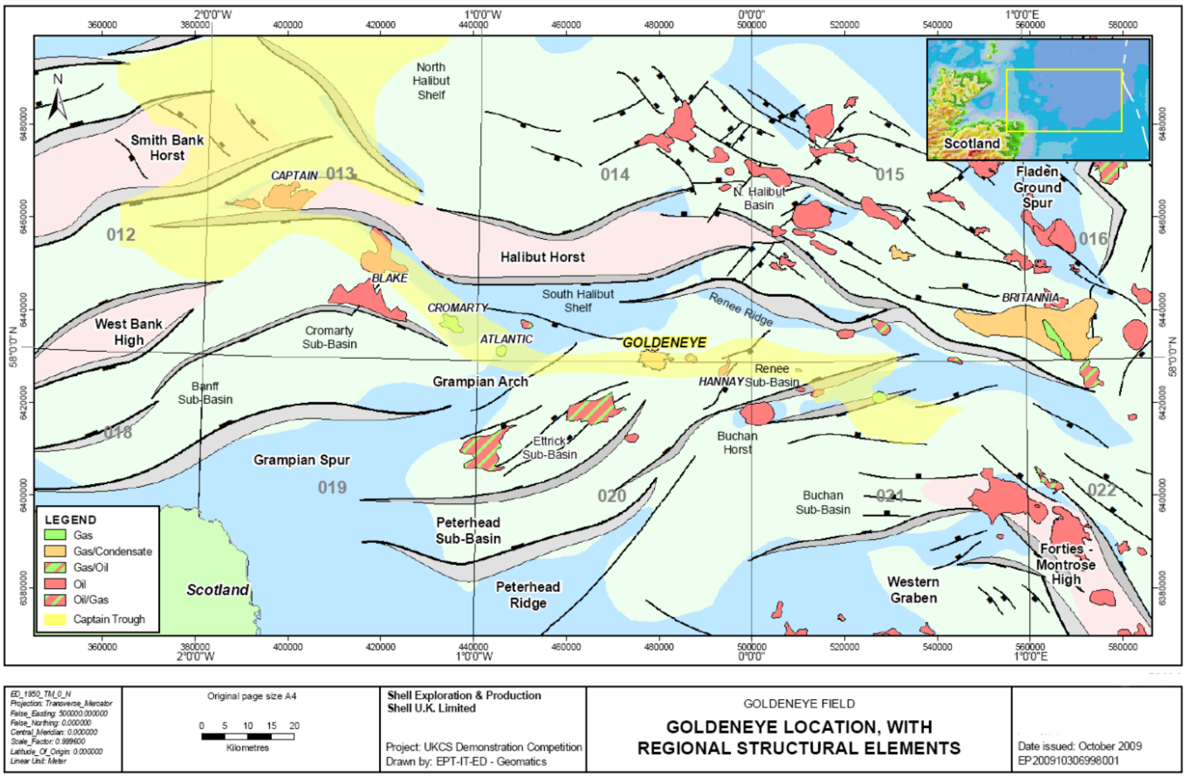


Figure 3.7 Distribution of Captain sandstone across the outer Moray Firth: Captain fairway highlighted in yellow; basinal areas in pale green.

3.7.4. Secondary containment (overburden)

The *secondary storage (overburden)* for the Goldeneye field includes the Chalk Group above the top of the Plenus Marl Bed, the Montrose Group (particularly the Mey Sandstone Member) and the lower Dornoch sandstone, within the Moray Group (Figure 3.2).

The Chalk Group formations are of Late Cretaceous to Early Palaeocene age and are composed of almost pure chalk. Fractures are seen on borehole image but these are not vertically extensive and do not interconnect. The Montrose Group (Palaeocene) contains the Lista Formation which is characterised by the presence of interbedded sandstones and mudstones. Within the Lista Formation the Mey Sandstone Member (equivalent to the Andrew Formation of the Witch Ground and Central Grabens, where it is a major hydrocarbon reservoir) includes the Balmoral Sandstone Units and the Balmoral Tuffite Unit. These rocks represent a range of environments from outer shelf to slope to basin, with shelf sands being redistributed to form slope aprons of superimposed and laterally coalescing fans. The tuffite is derived from air fall deposits associated with Hebridean province volcanism. At the top of the Lista Formation, is an un-named mudstone facies dominated unit which is one of two regionally continuous mudstones that are identified as acting as the *complex seal* (see description below). Only the lowest part of the Moray Group (Palaeocene to Early Eocene age) is included in the *storage complex* – the lower Dornoch sandstone, part of the Dornoch Formation. The lower Dornoch sandstone was deposited in a shelfal setting and consists of single or multiple sandstones interbedded with silty mudstones. Its immediate successor unit – the Dornoch mudstone, which forms part of the *complex seal* (see description below) – represents a prograding delta front.

All of the formations in the *secondary containment (overburden)* are brine bearing.

3.7.5. Complex seal

The 'Lista mudstone' and Dornoch mudstone were selected as the *complex seal* because:

- they can be reliably correlated in all wells within the *storage complex*;
- They are found at depths greater than 800m TVDSS across the entire area under investigation;
- any outcrop of these units is interpreted to be >150km away from the *storage site*, and;
- two of the abandoned exploration wells have plugs set at either Lista or Dornoch mudstone level.

The Lista mudstone and Dornoch mudstone were selected as the *complex seal* because: they can be reliably correlated in all wells within the *storage complex*; They are found at depths greater than 800m TVDSS across the entire area under investigation; any outcrop of these units is interpreted to be >150km away from the *storage site*, and; two of the abandoned exploration wells have plugs set at either Lista or Dornoch mudstone level. The lateral equivalent of the Lista mudstone is a seal to hydrocarbon reservoirs in the Central Graben area – specifically Rubie (which is 40km from the *storage site*), the MacCulloch cluster fields (at approximately 50km: MacCulloch, Donan, Nicol, Lochranza, Blenheim, Blair, Beauly, Burghley and Andrew fields) and Cyrus.

3.7.6. Fluids

The hydrocarbons of the Goldeneye field are gas condensate with a thin (7m) oil rim. Geochemical analyses have established that the condensates in all Goldeneye wells are geochemically identical indicating full pressure communication in the gas. Oils (particularly the heavy fraction) in different wells are significantly different and, therefore, the part of the reservoir below the gas-oil contact (GOC) is not fully connected.

Brine samples available from the reservoir show little variation between the samples. Salinity is measured at 54,000mg/l. From informal discussion with other operators in the Captain fairway, salinity is of a similar value from all fields in the area.

Although no samples have been collected, all of the overburden formations are interpreted to be water (brine)-bearing, based on the evidence from wireline logs and are interpreted to be of higher salinity, in the main, than the Captain Sandstone Member.

3.7.7. Faults

Fault patterns at the *storage site* and *storage seal* levels are highly interpretive due to the poor resolution of the available seismic data. The mapped faults at top Captain are of limited vertical and lateral extent with small throws (20m) parallels the observed regional structural trends orientated WNW-ESE to E-W. There has been little evidence seen during the production phase of the Goldeneye field for intra-reservoir fault compartmentalisation and so faults have been omitted from structural models of the reservoir.

In the *secondary containment (overburden)* faults trend NW to SE and are mainly developed over the eastern and south-eastern flank of the field. These faults are decoupled from the WNW-ESE to E-W trending reservoir level faults and intersect the Chalk Group and the lower part of the overlying Montrose Group. Again, difficulties with the image quality at these levels of the available seismic data (this time caused by the topography on the top of the Chalk Group, which has been karstified due to sub-aerial exposure after deposition) makes definitive fault interpretation difficult.

Above the Chalk Group, there is little evidence of significant faulting. The seismic imaging is again hindered in the Montrose Group by the presence above of thick, laterally variable coal package and large sub-glacial channels buried close to the sea-bed. Some vertical discontinuities in the seismic data were initially interpreted as faults. However, subsequent reprocessing of the seismic data using a proprietary high-resolution algorithm has shown these to be an effect of the seismic wave front being distorted due to its transit through the sub-glacial channel lithologies.

3.7.8. Stress regime

The formation pore pressure is hydrostatic in the reservoir and overburden (with a hydrostatic pore pressure gradient of 10kPa/m – 0.442psi/ft – used outside the reservoir). The recent stress regime in the Goldeneye area is Normal. The direction of maximum horizontal stress is NNW-SSE as inferred from image log, calliper and world stress map data. In the wider Goldeneye area a normal-stress regime (S_v>SH>S_h) is seen.

3.8. Brief history of the hydrocarbon field

It is planned to re-use the facilities put in place for hydrocarbon extraction. These are listed and described in the following sections.

3.8.1. Exploration

The Captain Sandstone discovery well, 14/29a-3, drilled in 1996, found a significant (303 ft) gas condensate column with a thin (24 ft) oil leg in well-developed Lower Cretaceous Captain Sands. These lie within the Upper Valhall Formation of the Lower Cretaceous Cromer Knoll Group directly above the Kimmeridge Clay Formation (Figure 3.2). Three appraisal wells were subsequently drilled - 20/4b-6 (1998), 14/29a-5 (1999) and 20/4b-7 (2000). All of these encountered varying thicknesses of hydrocarbon column but confirmed common gas / oil and oil / water contacts of 8568ft [2,611m] TVDSS and 8592ft [2,618m] TVDSS respectively.

An earlier well – 14/29a-2 drilled in 1981, did not encounter Captain sandstone reservoir, but did see gas condensate shows in the Upper Jurassic Burns Sandstone Member of the Kimmeridge Clay Formation. This is not part of the Goldeneye field and is not in communication with it.

3.8.2. Surface facilities and pipelines

The Goldeneye field was developed as a full wellstream tieback (FWT) to shore for onshore gas and condensate processing in new facilities at Shell/Esso's St Fergus terminal (Figure 3.9). This approach was possible due to Goldeneye's proximity to shore (105 km) and relatively lean gas condensate composition. Offshore, a normally unattended wellhead platform was installed for field/well control, metering and water detection. Fluids were transported through a new build multiphase, wet gas pipeline to shore under field pressure. A glycol (MEG) system (with corrosion inhibitor) was installed to prevent the formation of (methane) hydrates and corrosion.

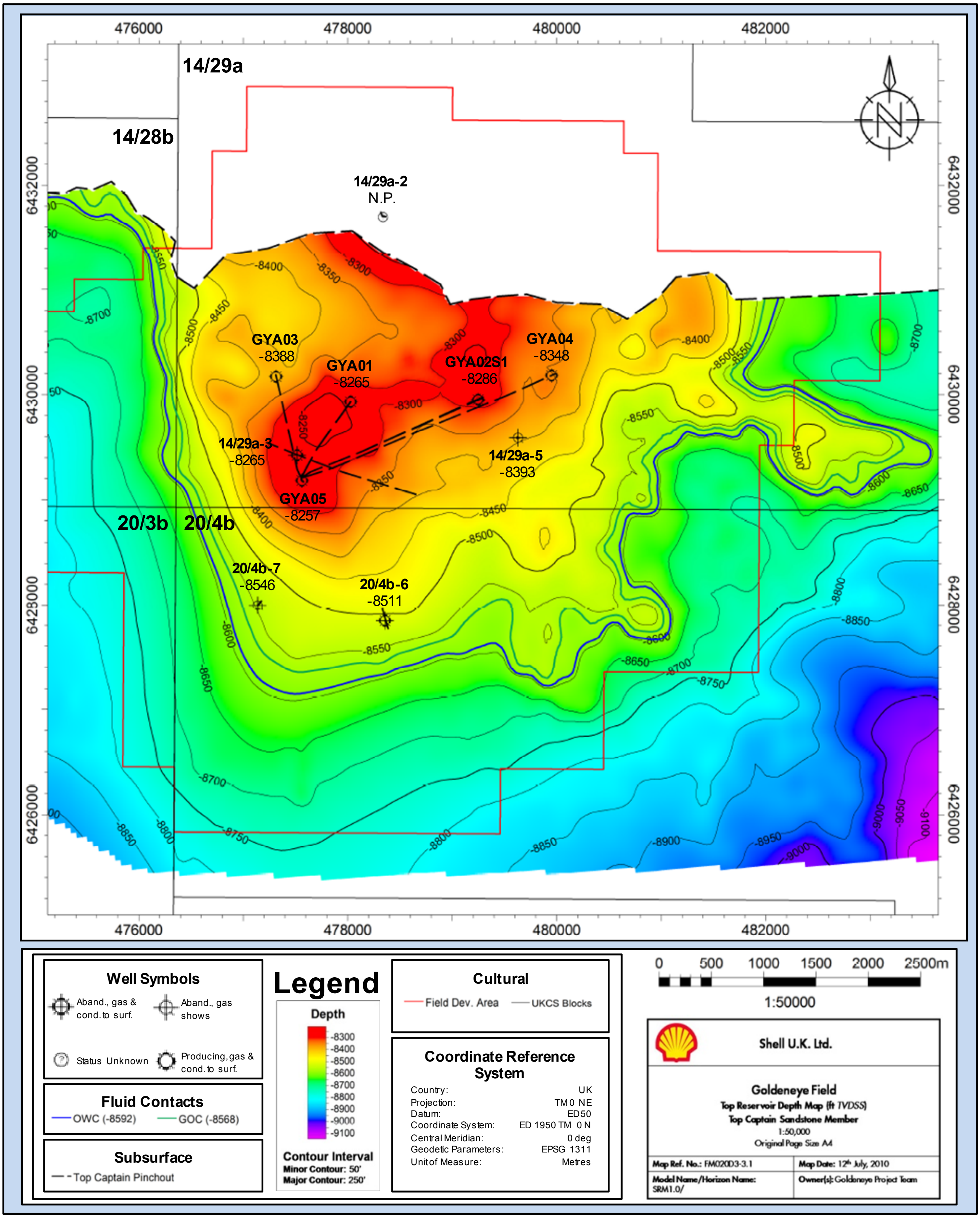


Figure 3.8 Goldeneye field top structure map – reference case. Note absence of Captain Sandstone Member in well 14/29a-2.

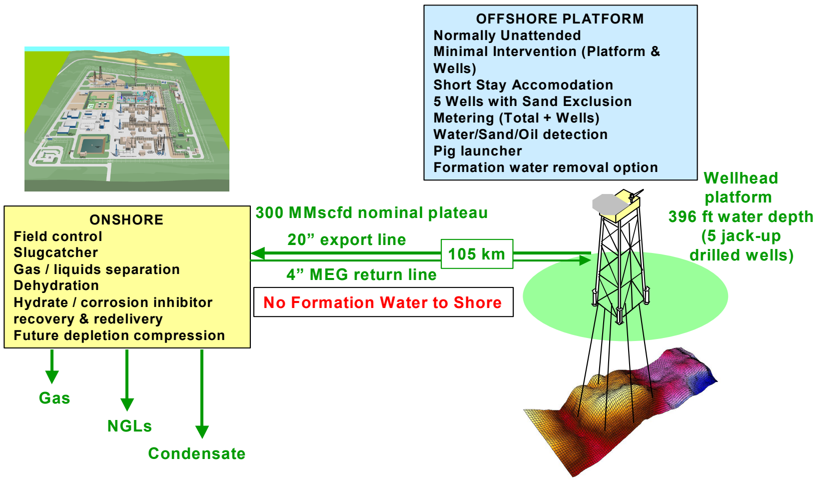


Figure 3.9 Goldeneye field development plan.

3.8.2.1. Offshore Platform

The offshore facility comprises a normally unattended installation (NUI) located in 121m of water. The installation is a simple 4-leg piled steel jacket platform with 8 slots for the wells and a small topside providing metering, water/oil detection and well/field management facilities. The platform is controlled from shore (St Fergus control room) and accessed by helicopter when required. The platform is fitted with short-stay accommodation (SSA), enabling up to twelve technicians to visit as necessary.

Each well was equipped with Venturi meters for reservoir/well management purposes, with the capability for fluids sampling. A production separator enabled field allocation metering using ultrasonic and coriolis meters.

The platform separator and the piping are designed for the maximum well CITHP (Closed in Tubing Head Pressure) up to the entry to the export system. This is protected by a High Integrity Pipeline Protection System (HIPPS), rated for 213barg [3090psi]. The header, riser, and export pipeline and system are designed for 132barg [1914 psi].

3.8.2.2. Pipelines

The export of multiphase fluids is via a 20in [508mm] export pipeline, 105km in length, operated with the continuous injection of hydrate and corrosion inhibitors. MEG, along with a corrosion inhibitor, is transported to the platform using 4in [10mm] service line from St Fergus, laid parallel to the main line and injected directly into the export system on the Goldeneye platform to suppress the hydrate formation temperature within the export pipeline. External corrosion of the pipelines was controlled by cathodic protection and anti-corrosion coatings.

Due to the diameter of the main line, a concrete weight coating was required. The service line was trenched and buried.

The evacuation and service lines were brought together 1.5km offshore and the service line piggybacked onto the main line with both lines then trenched and buried. Onshore the lines were laid together across the dunes. The multiphase flow from the pipeline was received into a slug catcher. Compression was installed after the primary separation later in field life in order to maintain production and maximise recovery.

3.8.3. Development wells

The five development wells drilled on the Goldeneye structure are listed in Table 3.3. The abbreviated well names are used in this document.

Table 3.3 Well name abbreviations.

Full well name	Abbreviated well name	Spudded (batch operations)
DTI 14/29a-A3	GYA01	8/12/2003
DTI 14/29a-A4Z	GYA02S1	13/12/2003
DTI 14/29a-A4	GYA02	As above
DTI 14/29a-A5	GYA03	19/12/2003
DTI 14/29a-A1	GYA04	5/12/2003
DTI 14/29a-A2	GYA05	2/12/2003

The production wells were designed with the following design and life cycle philosophy:

- Simple with minimal intervention requirements
- Maximum well deliverability with sand exclusion
  - Optimal well deliverability requires a producing interval of about 60ft [18m] TVT (True Vertical Thickness).
  - 7" [178mm] production tubing maximises well deliverability whilst maintaining liquid lift to depleted reservoir pressures.
  - Sand exclusion is required since sand failure is anticipated at the start of Goldeneye production
  - External gravel packs provide proven mechanical reliability and excellent productivity.
- Complete high in the column to maximise recovery.

3.9. Expected state of the field at cessation of production

3.9.1. Remaining hydrocarbons

At formal cessation of production, the ultimate volume of hydrocarbons recovered (UR) from the field is expected to be 565Bscf and 23MMbbl condensate. The full field simulation model (FFSM) predicts that a small hydrocarbon gas cap will remain in the middle of the field in units 'D' and 'C'. By-passed gas is more widely spread in the tighter 'E' unit, which is only partially flooded by the aquifer. The aquifer connected to Goldeneye has been modelled and is continuing to encroach. It is expected to repressurise the field over time.

3.9.2. Pressure

During production the field has been depleted from the initial pressure of ~3800psia [262bara] at a datum level of 8400ft [2560m] TVDSS to a little under 2200psi [152bara] today. This pressure is now forecast to recover slightly between the end of depletion and the start of injection. The magnitude of the pressure recovery depends on the balance between:

- the effect of fluid extraction operations in neighbouring fields,
- the *fast* influx of the neighbouring aquifers and depressurisation of tighter formations in the field area,
- the *slow* influx of the regional trough wide aquifer (described in §3.9.3).

Various forecasts of pressure recovery have been made (detailed in the Dynamic Modelling Output report). These are illustrated in Figure 3.10 and show an expected rise to between 2800 and 3000psia [193 and 207bara].

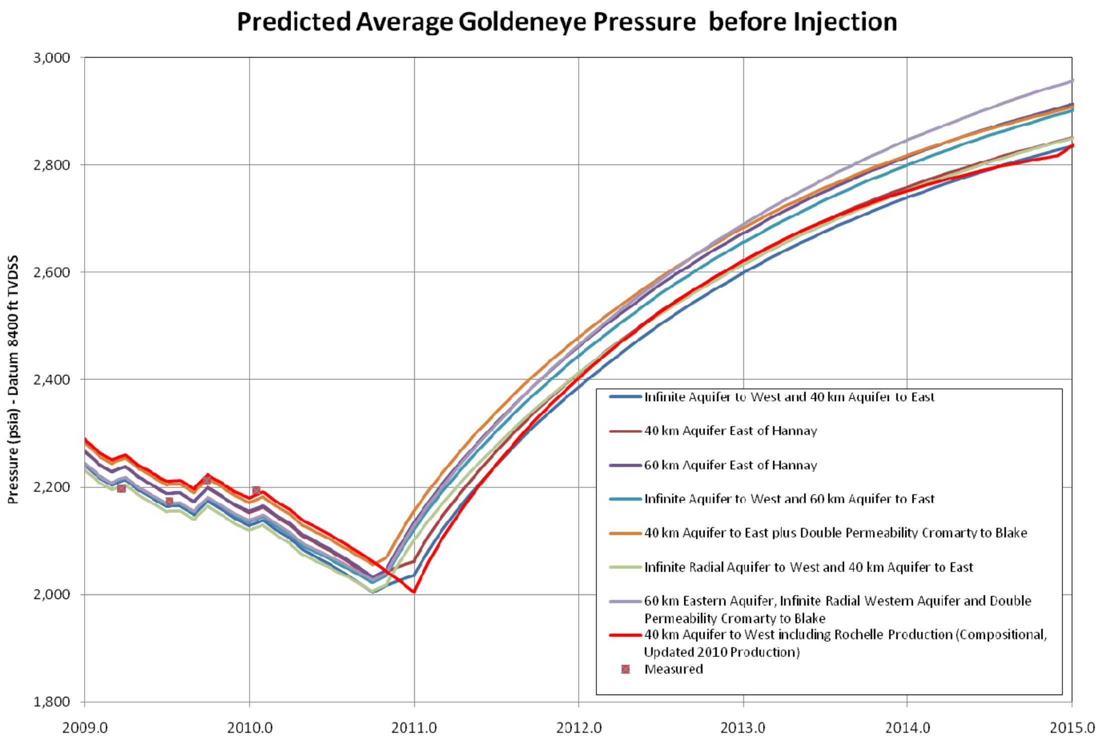


Figure 3.10 Predictions of Goldeneye pressure from field shut-in at end 2010 to 2015.

3.9.3. Hydraulically connected units

The performance of the Goldeneye reservoir has been significantly influenced by the surrounding aquifer and offtake at the other fields in the Captain fairway. This can be seen in the early pressure drop before production started (due to production at Hannay) and also in the longer term pressure history of the field which indicates significant aquifer support. As well as the Hannay field, three other fields (Atlantic, Cromarty and Blake) have produced from the Captain sandstone. A new field, Rochelle – approximately 35km east of Goldeneye – is due to come onstream in 2012. All five fields are interpreted to be in communication with Goldeneye and have influenced (and may continue to influence) its pressure performance. These have been taken into account in the design.

4. Major uncertainties and risks

The project as a whole is exposed to a number of significant risks and uncertainties and from an integrated project perspective, across the whole consortium, over seventy significant risks have been identified. The risks and uncertainties are described in the Consortium risk register and in the plans developed by each of the partners. This plan describes only the Shell scope of the project – the storage and offshore transportation of CO_2.

The major uncertainties and risks associated with the storage and offshore transportation of CO_2 can be divided into:

- regulatory, permitting, legal and commercial (§4.1-4.3)
- political and public perception(§4.4)
- technical (§4.5-0)
- schedule (§4.7)

4.1. Regulatory, permitting, legal and commercial risks

4.1.1. Storage license and permit

There is considerable uncertainty in relation to regulatory, legal and commercial terms that apply to this development project. This stems from the fact that various provisions of the EU CCS Directive are still being transposed in to UK law. Separately, the issue of Licenses and Permits for CO_2 storage by the Department of Energy & Climate Change (DECC) is in any event subject to prior completion of an ongoing update of a Strategic Environmental Assessment. In addition there is in progress a process of negotiation in respect of the Project Contract between Shell and the other members of the ScottishPower consortium, the Storage Joint Venture Parties and the Authority.

The most pressing risks in the regulatory sphere stem from:

(i) Delay in awarding a storage permit and hence project slippage
(ii) Uncertainty in the exact requirements, nature and details of requirements – leading again to project slippage, potential cost escalation, or in an extreme case the inability to execute the project

The main areas are summarized below:

First of a Kind Project Risks: The Longannet to Goldeneye CCS project looks set to be the first in Europe to be permitted under the EU CCS Directive. There are, therefore, no useful precedents or other means of guiding either the developers or the regulator on how to interpret the often broad terms of the regulatory framework. As a result, the project is exposed to a number of important 'first of a kind' regulatory risks reflecting a potential tendency towards a conservative interpretation of the rules.

Strategic Environmental Assessment: The Government has still to conclude a Strategic Environmental Assessment (SEA) to incorporate offshore CO_2 storage activities, prior to which it will be unable to issue Storage Permits. Current guidance is that this should be completed by February 2011. Any material delay in this process risks compromising the consortium's ability to secure a storage permit.

OSPAR: In 2006 the contracting parties to the 1992 OSPAR Convention agreed an amendment removing the prohibition against the sub-seabed storage of CO_2. However, this amendment can only take legal effect once ratified by a minimum of seven contacting parties. To date the EU, UK and Norway have ratified, but we understand from a recent meeting with DECC that it will be Summer 2011 at the earliest before the amendment will be ratified. Failure to ratify the OSPAR amendment would mean that the sub-seabed injection of non-indigenous CO_2 for storage purposes would be illegal under the Convention, and so far DECC have not provided a fallback plan for this eventuality.

CCS Directive: Article 38 of the CCS Directive provides for a review of the Directive by March 2015. Such a review could impose retrospective changes or introduce new obligations in connection with the operation, monitoring, closure and handover of a storage site. This provision therefore represents a source of significant regulatory uncertainty for prospective developers.

EU CCS Guidance Documents: DG Climate Action has prepared a set of draft Guidance Documents to assist stakeholders in the implementation of the CCS Directive. Whilst the Guidance Documents will not be legally binding they will nevertheless likely serve as the template for Member State legislation, and will also be an important point of reference for the EU Scientific Panel that will scrutinise Member State permit award decisions (see below). To date the documents have only been issued in draft form for consultation but the onerous and prescriptive nature of these is a source of concern.

EU Scientific Panel: The CCS Directive provides for up to four months for the EU Commission to offer a non-binding opinion on Member State decisions to award a Storage Permit (Art.10). We understand that the opinion will be based on scrutiny by an independent Scientific Panel. As one of the first projects to be taken through this process we expect a lengthy process and a significant degree of scrutiny. The lack of directly comparable precedent, and lack of a deep pool of expertise, is likely to create considerable uncertainty over the outcome of the Panel's deliberations. Whilst the opinion will not be legally binding, consideration of aspects such as public acceptance and future Storage Permit award decisions suggest that it would be unlikely for DECC to ignore the Commission's advice. Further, whilst DG Climate Action expect that the first permits could be considered as early as Q2 2011 it is unlikely that the Panel will be able to review outline project proposals or conditional award decisions. Rather they will only be able to review draft permits awarded from a national competent authority. This is potentially problematic from the standpoint of reducing regulatory uncertainty if a draft storage permit for the Goldeneye reservoir cannot be secured from DECC before execution of the project contract.

DECC Guidance Notes: Whilst the publication of informal (non-binding) Guidance Notes is not an obligatory part of developing new legislation or regulations they are increasingly recognised as a helpful tool in guiding industry's compliance with the law, especially where the law may be open to wide interpretation. Shell reviewed & commented on an early draft of DECC's Guidance Notes in March 2010 but DECC have still to publish a final version. The CCS Directive leaves considerable discretion to national competent authorities in how to implement its provisions. Guidance Notes will therefore be essential to the consortium in understanding how to comply with UK requirements, especially so in the absence of any national regulations. DECC conclusion and publishing of these is necessary for understanding what is required to secure a Storage Permit. Shell is presently in discussions with DECC to agree the detailed requirements of the Storage Permit, that will enable Shell to demonstrate progress on meeting all aspects of the permit requirements and to share plans for future work; and to identify gaps against regulatory requirements and agree if / how these can be closed, with the aim to eliminate as much regulatory uncertainty as possible prior to execution of the project contract. None of this, however, is a substitute for having DECC clearly set out its expectations for what the regulations require.

4.1.2. Goldeneye Regulatory Timeline

The anticipated timing for the Carbon Storage License and the Carbon Storage Permit is as shown below in Figure 4.1.

Award of a Carbon Storage Permit by DECC is subject both to review by a yet-to-be-established EU Scientific Panel and also prior approval by DECC of an Environmental Statement (ES) from Shell. Recognising the unique nature of this project, the timing of both of these is very uncertain though the CCS Directive at least places a 4 month cap on the review period by the Scientific Panel. Assuming a 5 to 6 month post-consultation review period by DECC of the ES, in keeping with the norm for conventional upstream oil / gas field developments, then it seems likely to be end-Q4 2011 before the Permit could be formally approved and therefore the Lease executed.

The prior award of the Carbon Storage Licence is subject to conclusion of an ongoing Strategic Environmental Assessment (SEA). Completion of the SEA has already slipped significantly but is now expected in Q2/Q3 2011.

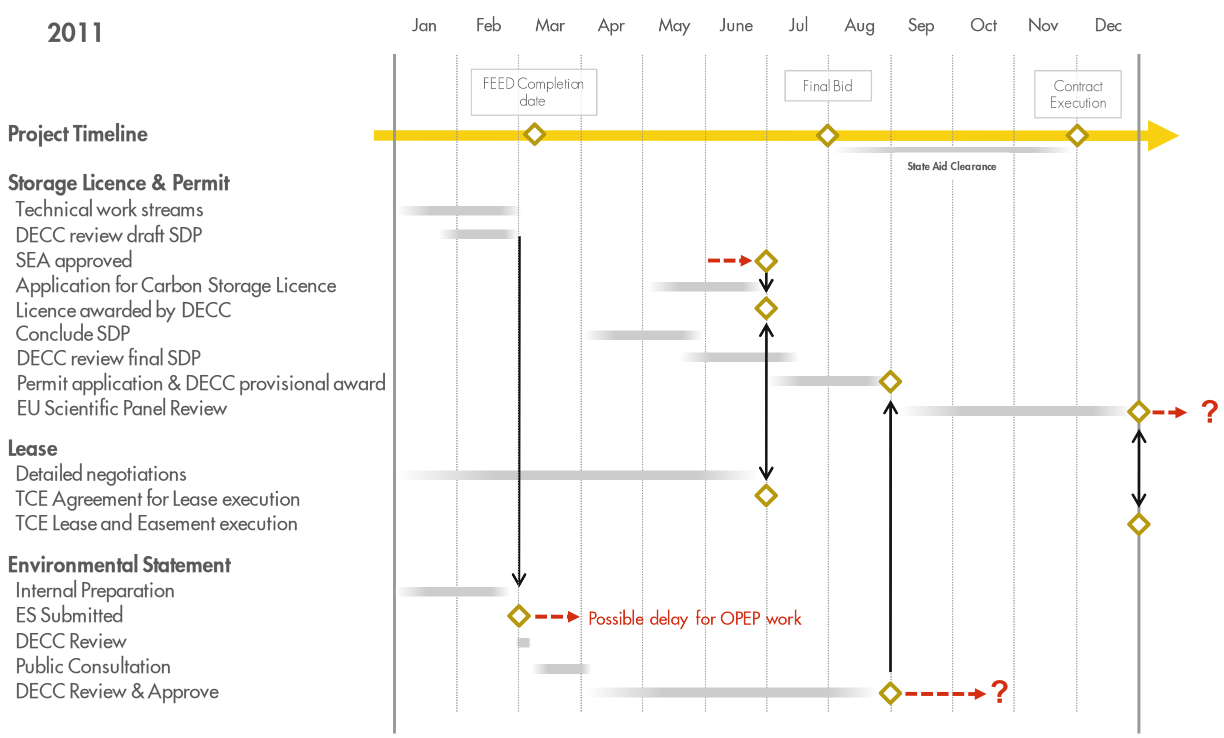


Figure 4.1 Notional Goldeneye CO_2 Storage regulatory Timeline.

4.1.2.1. Subordinate approvals for permit award

Three key plans are submitted along with the storage permit, all three must be agreed with the regulator prior to award of the permits. These plans are:

- MMV plan (see §9)
- Corrective measures plan (see §10)
- Provisional post closure plan (see §□)

They are described in detail in the relevant section of the SDP. As with everything there is no precedent in the UK or the EU and there are very few precedents worldwide.

These plans are subject to the same issues as the main permit.

4.1.3. Crown Estate Lease

In the 2008 Energy Act[5] the UK Government created one of the first bespoke legal regimes anywhere in the world specifically designed to permit the safe storage of carbon dioxide (CO_2) underground. It provides for the UK (consistent with the terms of the United Nations Convention on the Law of the Sea) to assert certain rights to make use of the offshore area beyond the territorial sea, through the designation of a Gas Importation and Storage Zone (GISZ). The GISZ was designated on 6th April 2009 by SI 2009/223.

The exclusive right to store CO_2 offshore has been vested in the Crown within an area extending from the seaward limits of the territorial sea to the boundaries of the GISZ. The Crown Estate already has the right to grant leases for any purpose within the area of the territorial sea. The vesting provisions of the Act allow The Crown Estate to grant similar authorisations in respect of carbon storage activities beyond the territorial sea but within the area of the GISZ. The new licensing scheme (described in § 4.1.1) will operate in parallel to the leases and authorisations granted by The Crown Estate.

The detailed terms of the Lease documents are still being negotiated by Shell and The Crown Estate and are therefore subject to change. For the project to proceed it requires both a lease and a storage permit. Therefore the following risks and uncertainties will need to be managed by Shell in the course of the ongoing negotiations:

- The Crown Estate may insist on additional onerous terms & conditions, or insist on requirements that conflict with or compound the terms of the storage licence or permit from DECC or the terms of the Project Contract. Shell anticipates that in progressing these arrangements with the counterparties an allowance will require to be made for any consequential changes following any material changes in another dependant arrangement.
- The Crown Estate insist on an excessive lease fee or associated indexation terms.

Satisfactory conclusion of the Lease negotiations takes longer than anticipated and / or approval of The Crown Estate Board is delayed, making this a 'critical path' activity for the project.

4.2. Other permits

As is the case with the storage permit the "first of a kind" nature of the project increases the uncertainty in the obtaining of all permits and licenses. These include

- Offshore environmental statement (referred to in §4.1.1)
- Onshore (St Fergus) environmental statement
- Revised Goldeneye and St Fergus Safety Cases
- Updated COMAH safety report
- Planning consent at St Fergus for the construction of the new onshore pipeline
- Combined operations notification (for use of mobile drilling rig alongside Goldeneye during workovers ops, drilling and platform modifications)
- Updated Major Accident Prevention Document (for Northern Operations Pipeline Systems)

[5] Specifically the CCS Directive, Part I, Chapter 3 of the Energy Act 2008

4.3. Commercial risks

The commercial project risks can be divided into

- Expense recovery: Capital, abandonment costs, operating expenses
- Return on investment
- Liability protection/transfer
- Purchase/transfer of assets to the Storage Joint Venture

Detailed commercial negotiations are taking place in order to establish all of the above. There are a number of parties involved in various sets of negotiations:

- UK Government
- Consortium partners
- Production Joint Venture
- Provisional Storage Joint Venture
- Storage Joint Venture

Failure to reach agreement in all negotiations has the potential to delay or derail the project. Some of the key points will be outlined below.

4.3.1. Expense recovery

Areas of significant complexity relate not to the core principle – which is that the UK Government will fund the project, but in the areas of liability in case of underperformance. Naturally the UK Government does not want to fund a project if it does not meet an agreed storage target at an agreed price. However this CCS project is deemed a demonstration project because offshore CCS is currently unproven at a commercial scale. No partner wants to be liable for the capital repayment to indemnify the project in the case that the project underperforms because of unforeseen circumstances.

4.3.2. Return on investment

The consortium partners are public companies with share holders. They have an obligation to invest share holder capital wisely. As a result they need to make a return on their investment. As a rule the higher the potential return the higher the level of risk that an investor is willing to take. Therefore the magnitude of this return, and the magnitude of any potential liabilities, needs to be balanced and negotiated.

4.3.3. Liability transfer

This is possibly the most complex of the areas under negotiation – the complexity resulting from the fact that the project cuts across many boundaries ranging from hydrocarbon decommissioning to cross consortium default challenges. Some of these challenges (by no means a complete list) are sketched below.

Hydrocarbon decomissioning

Sections 29&34 of the Petroleum act currently hold the petroleum licensees liable for decommissioning obligations in perpetuity. This applies to exploration and appraisal wells were they to have integrity problems. Naturally the current petroleum license holders do not want to be liable for an integrity issue caused by CO_2 storage operations, yet at this point in time they are.

Asset purchase

Current assets – the onshore and offshore pipelines and the platform and wells – need to be purchased from the current owners. For onshore work Ofgem has to give approval as National Grid is a regulated monopoly, while in the offshore situation the cost of hydrocarbon decommissioning and the complex subject of tax leakage is included in the calculations.

Electricity pricing

The current emissions legislation has led electricity generators to run coal fired power stations as peak shavers rather than base load. The capture plant is inefficient when run in an on/off mode and the injection wells are detrimentally affected by cycling. The question of who should be liable for operating a generation plant sub-optimally is therefore posed.

Cross consortium liability

A mechanism needs to be put in place to apportion liability should one component in the chain not be ready in time, suffer a failure, or cause another to fail. This is of key importance should a delay or failure impact upon cost recovery or capital repayment as discussed in §4.3.1.

Affect on neighbouring hydrocarbon fields

The extraction of subsurface volumes of hydrocarbon and associated water often affects neighbouring fields – generally reducing the drive energy and hastening the implementation of secondary recovery techniques. At present there is no liability for the impact of a development on neighbouring fields. The injection of CO_2 will increase pressures which will benefit oil developments, but for gas this is less clear cut. In addition the question arises as to whom should be liable in the event that an Operator alleges that CO_2 entered their field and affected their hydrocarbon extraction operations.

4.4. Political and public perception risks

The project is exposed to political and public perception risk. The importance of both political and public perception is highlighted in the fact that in the last year political and public perception issues have resulted in cancelling some CCS projects throughout the world. What we have learnt from our early CCS activities is that both political and public support for CCS projects is essential for them to succeed.

4.5. Technology maturation

In a relatively new field of work it is to be expected that some of the technologies that are required to deliver the project have yet to be developed. The offshore transport and storage of CO_2 is no exception. The project has a technology maturation plan and a number of key technologies are required to be mature before injection (for example seabed CO_2 flux measurement) while others have the potential to reduce costs later in the project (for example the installation of permanent gauges in abandoned wells).

These technologies are discussed in the project Technology Maturation plan. A summary is shown in Table 4.1.

Table 4.1 Technologies to be matured for project execution – including required timeline, probability of success and impact on project success.

	Description	Technical readiness level [Discovery 1-5, Develop 6-8, Deploy 9-10]	Timeline	Cost Impact	Schedule Impact	Purpose
1	**Pipeline/well operating envelope.**	10 – study[6]	<FID	Very High	Medium	Operation
2	**CO_2 vapour/liquid equilibrium behaviour**	10 – study, data collection	<FID	Very High	Medium	Operation
3	**Well injection procedure to anticipate potential variable flow from CO_2 source.**	10 – study	<FID	Very High	Medium	Operation
4	**Pipeline running ductile fracture prevention.**	6-8	<FID	Low	Very High	Operation
5	**Testing of Goldeneye pipeline internal epoxy coating.**	9	< FID	Very High	High	Operation
6	**Assessment of effect of dense phase CO_2 on non-metallic (elastomer) materials used for seals in valves, etc.**	9	< FID	Very High	Very High	Operation
7	**Assessment of cement stability in downhole CO_2 environments.**	8	< FID	Very High	Very High	Operation
8	**Manage extreme cooling of wellhead material during transient conditions.**	10 – study	< FID	Very High	Very High	Operation
9	**CO_2 friendly subsurface safety valve (SSSV) testing procedure.**	10 – study	<FID	Very High	Very High	Operation

[6] Where the word *study* is included it is defined to mean: "Further study work required during detailed design"

	Description	Technical readiness level [Discovery 1-5, Develop 6-8, Deploy 9-10]	Timeline	Cost Impact	Schedule Impact	Purpose
10	**CO_2 injection particulate management for wells.**	10 – study	<FID	Very High	High	Operation
11	**Hydrate inhibitor selection.**	10 – study	<FID	High	High	Operation
12	**Detection of CO_2 gas using Infrared (IR) technology based gas detectors.**	10 – study	<FID	Very High	Very High	Safety, impact to environment
13	**Dense phase CO_2 release modelling validation.**	8-9 & 3-4	<FID	High	Medium	Safety , impact to environment
14	**Seabed Leakage identification and quantification – (method & technologies to measure volume & concentration at seabed & shallow depth).**	Proposed	Plan <FID, detail > FID (Goldeneye as Field test)	Very High	Very High	Regulation, impact on license or environment
15	**Tracer selection and addition/CO2 fingerprinting.**	Proposed	Plan <FID, detail > FID (Goldeneye as Field test)	Very High	Very High	Reputation
16	**4D streamer in combination with ocean bottom nodes (OBN) application.**	9-10	<FID	Very High	Very High	Monitoring
17	**Pitting of 13% Cr tubing material.**	8	>FID (prior completion)	Very High	Very High	Operation
18	**Design for blowdown of supercritical CO_2.**	10 – study	>FID (detail design)	Very High	Very High	Operation

	Description	Technical readiness level [Discovery 1-5, Develop 6-8, Deploy 9-10]	Timeline	Cost Impact	Schedule Impact	Purpose
19	**Geochemical probe (conductivity, depth and temperature – CDT – & CO_2 saturation).**	8	>FID (detail design)	Very High	Very High	Monitoring
20	**Sediment sampling method.**	8	>FID (detail design)	Very High	Very High	Monitoring
21	**CO_2 blowout measures analysis.**	10 – study	>FID (prior injection)	Very High	Very High	Contingency
22	**Onsite and offsite Emergency Response (ER).**	6-7 & 4	>FID (prior injection)	Very Low	Low	Contingency
23	**Extended downhole pressure measurements (>10-15 years) for use in post-injection/closure phase.**	6	>FID (Optional)	High	High	Optional
24	**Distributed acoustic sensing (DAS).**	3-5	>FID (Optional)	Very High	Very High	Optional

4.6. Technical risks and uncertainties

Technical risks are described in detail in each technical section of the SDP – in fact a storage development plan is based round the assessment of the risks and uncertainties inherent in Capacity, Transport & Injection, Containment, and Monitoring. It is also important to show that (whilst it is very unlikely) migration leading to leakage can be managed via a corrective measures plan (a summary of the Corrective measures plan is included in §10).

All risks have been assessed as low (or negligible) after taking into account natural barriers and introduced engineered barriers, plus monitoring plans complemented by the corrective measures plan.

The technical uncertainties depend strongly on the rate and injection pressure of storage and the volume to be stored. Fundamentally the faster you inject and the more you inject the more likely you are to find the limits of the container injectivity and volume.

Any change in the scope of the current plan would require a re-assessment of the technical risks and uncertainties – and potentially significant modelling and/or appraisal work.

At this stage in the project the uncertainty has been assessed and the Goldeneye store has been shown to have a) the capacity to store more than 20Mt CO_2, and b) the injectivity to accept 2Million tonnes per annum. Containment risks have been assessed and are discussed below, while monitoring and corrective measures plans have been developed.

It is important to note that the risk assessment is a *live* document. The risk assessment draws upon all available information from sources such as:

- additional study work
- new research results
- collection additional data

The risk assessment will be updated when key sources of additional data become available. These are:

- pressures recorded during the period of aquifer recharge between cessation of hydrocarbon production and commencement of CO_2 injection
- the collection of the environmental and seismic baselines – including the isotopic analysis of any CO_2 at seabed
- the recompletion of the wells for injection
- the pigging of the offshore pipeline
- the potential receipt of additional data from other operators in the Captain trough
- the start up of injection
- the operational phase and concomitant monitoring activities
- The pressures measured as the system is re-pressurised

The risks have been broken down into the four main categories. Each category has an execution/operational risk element and all but one also have HSE risks.

CCS dimension	Description	Execution/ operational risk	HSE risk	Domain
Capacity	Can the reservoir store the required volume?	☑		Subsurface
Containment	Can we show that sequestration will be effective?	☑	☑	Subsurface
Injectivity & transport	Can we inject the required rates? Can we transport the CO_2 in a safe manner?	☑	☑	Subsurface & facilities
Monitorability & Corrective measures	Can we show that containment is being achieved, the volume is being injected, and that it is being done in a safe manner?	☑	☑	Subsurface & facilities
	Can an effective corrective measures plan be developed that satisfies regulators?	☑	☑	Subsurface

The main residual technical risks within the project stem from the fact that the project is a demonstration. It is to be noted that the injection of CO_2 into a depleted gas field has not been tested or performed on an industrial scale in an offshore setting before. This lack of prior experience leads to some risks relating to:

- thermal effects and pressure cycling on the caprock;
- the injection of cold dense phase CO_2 into a low pressure reservoir;
- and the quantification of any leak to surface were it to take place.

The main results of the technical risk assessment and the techniques used to assess the risks in each CCS theme are summarised in the table below:

CCS theme	Technique employed	Description
Capacity	Subsurface modelling study using scenarios to span the uncertainty range	Very low risk that the 20 Million tonne capacity is not available.
Containment	Bowtie risk assessment supported by: geomechanical, geochemical, fluid dynamic and geological modelling; plus detailed assessments of current state and historical well engineering experience; and monitoring & corrective measures plan. Screening studies performed (indicates that thermal fractures are not a high risk), but further modelling required.	Some aspects have higher risks and therefore require additional active/reactive plans to be put in place to reduce to ALARP – this is done in through a combination of monitoring and corrective measures. The higher risk areas are: • Well injection tubing leaks • Well penetrations in the secondary and tertiary seals Risks that require further detailed study are: • Fractures in the caprock caused by the stress of re-pressurisation and cold CO_2 injection
Injectivity & transport	Numerical modelling of: the injection of CO_2 into the well tubing (temperature and pressure); the stresses and strains imposed on the wells; assessment of risk of plugging (including geochemical and thermal fluid dynamic modelling)	A moderate risk of completion sand screen plugging was identified and mitigated by installation of surface filtration equipment. There is an increased risk of failure in the injection wells (leading to down time to ensure containment is preserved) if the whole chain delivery (rates, quality, variability in rates) is not to specification. The technique for impedance matching of the surface and subsurface conditions has not been tested on an industrial scale before.
	Numerical modelling of the whole surface pipeline system. Numerical modelling of CO_2 releases. Analysis of the condition of the surface materials and pipelines (complemented by planned intelligent pigging of the pipeline). Design: replacing materials and systems in offshore facilities. HAZID, HAZOP.	Risks do not differ significantly from conventional pipeline and plant activities, with the exception of the behaviour of CO_2 when released (sinks rather than rising). The release modelling is being improved by physical release testing experimental work[7].

[7] CO_2 release testing has been performed. The results are being analysed and the modelling updated during detailed design.

CCS theme	Technique employed	Description
Monitorability	Feasibility study to identify and assess available techniques (including detailed geophysical property modelling), combined with the bowtie risk assessment to identify the critical areas for monitoring. Surface facilities and pipeline monitoring follows standard practice as detection equipment exists.	Flows can be metered (volume and quality). Significant irregularities can be detected once they leave the reservoir, however, monitoring of the movement of CO_2 within the store is limited to point measurements. Monitoring does not indentify leak paths, only leaks. The store is under pressured and highly unlikely to leak Quantification of a leak to seabed is currently undetermined within the industry.
Corrective measures	Feasibility study identifying and assessing available techniques to address migration along the leak paths identified in the containment risk assessment.	Some geological leak paths are effectively impossible to fix, however, these are low flux and have low to negligible impact on the environment. Although the EU guidance document acknowledges this fact, it has yet to be subject to regulatory test.

4.7. Execution delay risk

Execution delay can impact the project in two main areas. (i) the current hydrocarbon infrastructure (platform and pipeline) will need to be preserved and maintained, incurring significant additional cost. In addition the condition of the pipeline could deteriorate. (ii) The reservoir pressure will continue to increase due to the aquifer re-pressurisation altering the behaviour of the injection wells. The pressure increase is described below.

Some alternative injection scenarios were run to look at the impact on pre-injection and post-injection reservoir pressure if the start of CO_2 is delayed for some reason. Geological realisation FFM 3.1 (reference case) was used, with the base case injection pattern. Figure 4-2 and Figure 4-3 illustrate the differences between reservoir pressure in Unit D, immediately before the delayed start of injection and immediately after end of injection (having injected 20Mt CO_2 in 10 years) compared to the equivalent pressures in the reference case (starting injection in December 2014). In all cases, the Unit D pressure drops rapidly after cessation of injection.

Delay to the planned date of injection start-up does not significantly alter the project. As recompletion of the existing wells, and conversion to injectors, will take place within a year of start-up, it will be possible to tune the completions to the observed pressure.

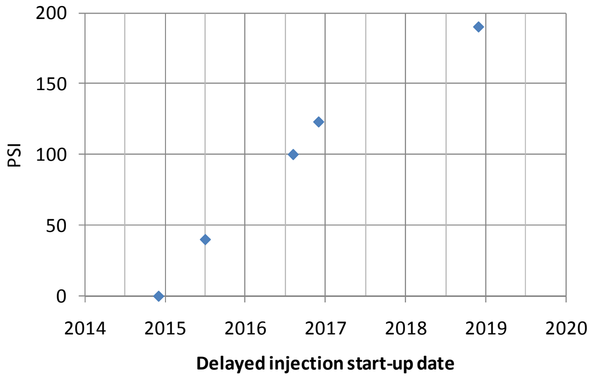


Figure 4-2. Difference in pre-injection pressure for delayed start dates.

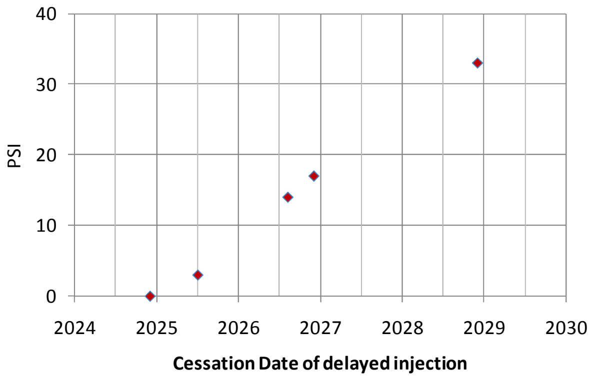


Figure 4-3. Difference in post-injection pressure for delayed injection.

5. Site capacity

5.1. Introduction

The objective of this chapter is to show that the Goldeneye store has sufficient capacity to receive 20Mt CO_2 while accounting for the affects of geological heterogeneity and refill efficiency. The stored CO_2 is split between two primary trapping mechanisms: (i) structural trapping in the original Goldeneye hydrocarbon field; and (ii) capillary trapping in the aquifer immediately below and adjacent to the field. Other trapping mechanisms exist but are minor on the injection time scale.

5.2. Structure of the Chapter

This chapter is divided into seven parts:

- Summary outlining the most important outcomes related to the storage capacity of the Goldeneye field.
- Analysis of methodology followed to assess that capacity.
- Description of the total pore volume available, voidage from production and its equivalent total theoretical CO_2 maximum storage capacity.
- Summary of the factors that could increase the sequestration capacity.
- Description of the elements that will reduce the pore volume available for CO_2.
- The storage capacity results.
- Outline of the existing key risks to capacity.

5.3. Summary of capacity

The space voided from hydrocarbon production is equivalent to **47 million tonnes of CO_2**. This represents a theoretical maximum volume of CO_2 that can be structurally trapped within the storage site. To arrive at a final estimate for the volume of CO_2 that it is possible to store, a number of other factors that either act to reduce or to increase storage capacity must be taken into account. These are discussed in detail in sections §5.7 and 5.8. A major increasing factor is the realisation that a significant volume of CO_2 will be capillary trapped in the aquifer rocks immediately below the original oil-water-contact, after the expansion and contraction of a 'Dietz Tongue' (described in sections §5.7.3.2 and 5.6.2). Together, estimates for the discounted structurally trapped and the capillary trapped volumes of CO_2, show that **34 million tonnes of CO_2** can be geologically stored in the Goldeneye storage site.

An uncertainty analysis was carried out, oriented towards the impact of CO_2 injection, aiming to deliver a set of parameter ranges and subsurface realisations that need to be modelled (static and dynamic). The study showed that three major static elements could impact the storage capacity of Goldeneye:

(a) extension of the stratigraphic pinch-out;

(b) structural dip on the western flank of the field; and

(c) internal Captain Sand stratigraphy (thickness).

In addition, dynamic elements were also considered within the uncertainties that will potentially have an impact on the CO_2 storage capacity of the field, mainly related to the displacement mechanism and the unfavourable mobility ratio of the process. These elements are:

(a) relative permeability end points (both water and gas/CO_2), and

(b) residual gas saturation (S_{gr}).

The entire suite of static reservoir model realisations have been simulated and a range of injection scenarios have been tested. With regard to the uncertainties evaluated, all the scenarios have sufficient capacity to **hold 20 million tonnes of CO_2**.

In order to determine the maximum geologic carbon storage capacity for the Goldeneye reservoir, a theoretical continuous CO_2 injection until 2035 scenario (20 years of injection) revealed that over **30Mt CO_2** had to be injected to reach the structural spill point and create an egression, i.e. there is a storage buffer of at least 10Mt.

5.4. Capacity assessment

For storage in a depleted hydrocarbon field the major factor influencing storage capacity is the voidage created – i.e. the volume of hydrocarbon and water extracted from the subsurface less anything injected. Aquifers can flow into fields, however, in so doing they lose pressure – i.e. voidage is created in the aquifer too.

This initial voidage cannot be completely refilled – there are factors that reduce the volume available and other factors that increase it. The following diagram summarizes the factors impacting the CO_2 storage capacity in a depleted hydrocarbon fields – with some specific *localisations* for the details of the Goldeneye field.

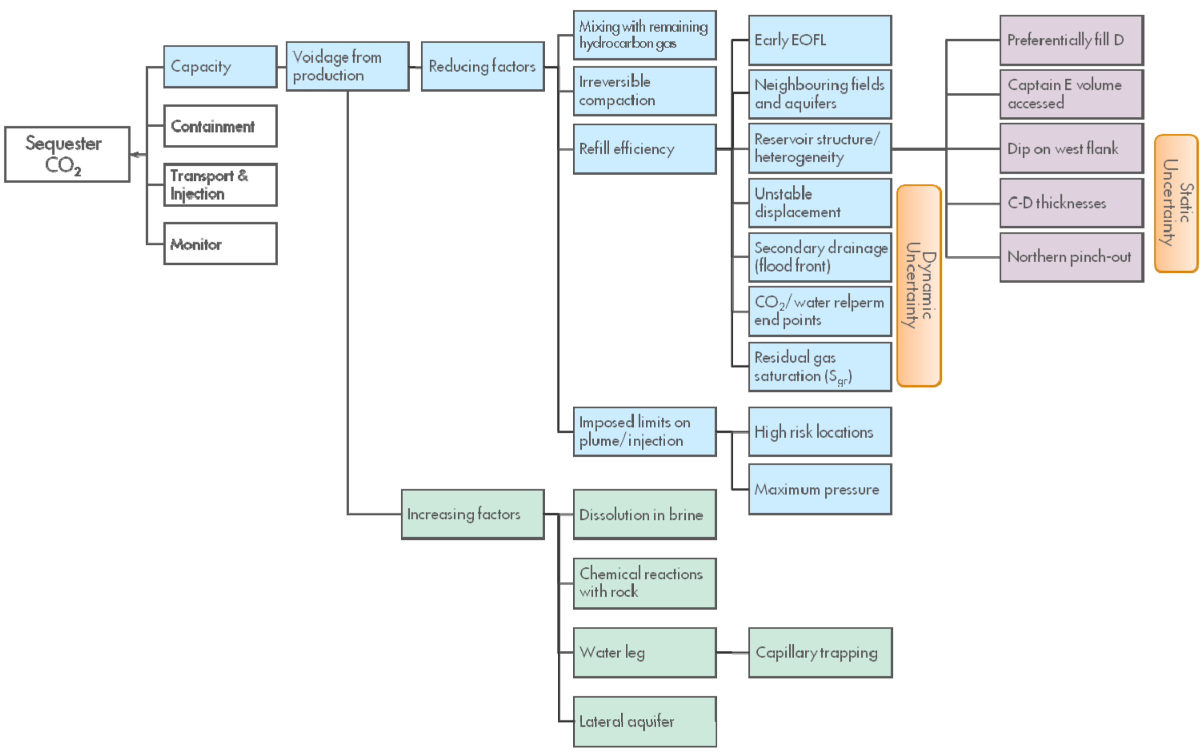


Figure 5.1 Factors impacting CO_2 Storage Capacity.

5.5. Total pore volume available: voidage from production

The total pore volume available for CO_2 was determined by making the assumption that all the pore volume vacated by produced hydrocarbons is replaced with CO_2 using the following factors:

- reservoir temperature of 83°C
- the characterised PVT properties of the Goldeneye fluids
- recharge to initial pressure at datum of 266 bara [3863 psia] at datum level of 2610m [8565 ft] true vertical depth subsea (TVDSS)

This gives a **storage capacity of 47 million tonnes of CO_2** using the current expectation production forecast till cessation of production. This is twice as much storage capacity as that needed to store 20 million tonnes of CO_2 in Goldeneye. However, this would be a maximum theoretical storage capacity assuming a perfect refill of the Goldeneye container and in reality there will be a series of additional factors, some that will increase the capacity, and some that will decrease this maximum storage capacity. The following section will analyze and describe these elements in order to estimate an effective storage capacity.

5.6. Possible increases in the sequestration capacity

Permanent sequestration ("immobilisation") of CO_2 is achieved in time through various factors such as: structural and stratigraphic trapping, dissolution of CO_2 into the formation brine, residual CO_2 trapping, and chemical reactions of CO_2 with minerals present in the formation. The latter three processes increase the sequestration capacity; their significance grows with time.

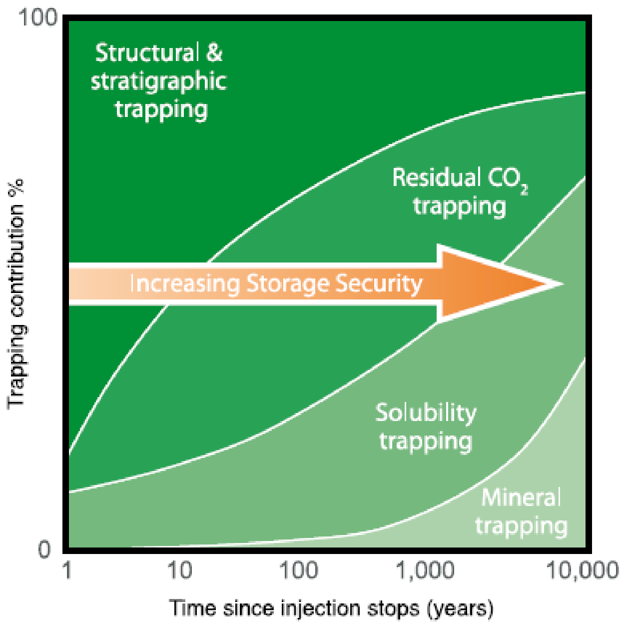


Figure 5.2 Storage security depends on a combination of different trapping mechanism[8].

[8] Special Report on Carbon Dioxide Capture and Storage, 2005. Prepared by Working Group III of the Intergovernmental Panel on Climate Change [Metz, B., O. Davidson, H. C. de Coninck, M. Loos, and L. A. Meyer (eds.)]. Cambridge University Press, Cambridge, United Kingdom and New York, NY, USA, 442 pp, 2005.

Mineralisation is strongly dependent on the geochemical composition of reservoir rock and happens over very long timescales. Over time, reactions with clay minerals will also lead to a removal of CO_2 from the continuous phase. This effect has been modelled for this system and found to work over longer time scales than the injection period and therefore will not be taken into account for the storage capacity, nevertheless, it will work in favour of the project reliability within large period of time. For detailed results regarding this topic, refer to Geochemical Reactivity Report.[9]

5.6.1. CO_2 dissolution in brine

CO_2 solubility in water is higher than that of hydrocarbon gases such as methane, and is a function of pressure, temperature and water salinity. In general, CO_2 solubility increases with pressure and decreases with temperature. An increase in salinity of the reservoir water decreases CO_2 solubility significantly. Dissolution of CO_2 is an important immobilisation mechanism.

Several correlations are available in the literature regarding CO_2 solubility. One of them was published by Chang, Coats and Nolen in 1996[10].

Applying this methodology to estimate an average CO_2 solubility for the Goldeneye reservoir conditions of ~3800 psi [262 bar], 83°C [181°F] and 53,000 ppm of salinity; results in dissolution of 145 scf/bbl [7.7 kg/bbl, 4.6 % on weight]. Goldeneye conditions are relatively favourable for CO_2 dissolution due to the low formation brine salinity.

The increment of storage capacity has been estimated at 2.2%, taking into account a CO_2 solubility of 4.6% (weight) and that CO_2 will contact approximately 25% of the brine due to the nature of the displacement process (water saturation left behind the CO_2 injection front is about 25%, estimated by fractional flow and Buckley-Leverett solution - see discussion in §5.3.3.3.)

5.6.2. Water leg and Lateral Regional Aquifer

Additional factors that could increase the storage capacity are related to the aquifer.

The lateral regional aquifer surrounding Goldeneye is not part of the current analysis, nevertheless it represents a significant opportunity for CO_2 aquifer storage. To the east of Goldeneye, the Captain sandstone extends approximately another 40-60 km and continues to deepen. To the west of the Blake field the formation starts to widen and eventually outcrops at the seabed about 50 km to the west of Blake. This could be considered for further developments in the fairway and is under study by the Scottish Centre for Carbon Storage.

The aquifer immediately below and adjacent to the Goldeneye hydrocarbon accumulation (termed the water leg) increases the capacity as when CO_2 is pushed into the water leg as a result of viscous forces and subsequently flows back up dip into the Goldeneye structure, 20-25% of the CO_2 is left behind residually trapped (often termed capillary trapping) in the water pore spaces.

5.7. Possible reductions in the pore volume available to the CO_2

Three effects were identified that reduce the vacated hydrocarbon pore volume available to CO_2:

- Mixing of the CO_2 and Goldeneye gas
- Irreversible compaction of the reservoir sands

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9 Shell 2010, Geochemical Reactivity Report

10 Chang, Coats and Nolen 1996 "A Compositional Model for CO2 Floods Including CO2 Solubility in Water" SPE35164

- Efficiency of refilling:
    - Reservoir heterogeneities (Volumetric Sweep)
    - Unstable displacement (Dietz efficiency)
    - Water from the aquifer ingress that has become effectively immovable to CO_2 injection within the pores (Secondary drainage relative permeability effects – Water displacement)
    - CO_2/water relative permeability end points

In addition, other elements can alter the capacity that can be accessed. These are:

- Operations in neighbouring fields that alter the pressure in the Captain aquifer and ultimately change the rate of pressure change in Goldeneye
- Injection in high risk locations (for example at the spill point) – this is not been done in the Goldeneye project
- Restriction on maximum injection pressures
- Plugging or loss of injection wells

If current conditions and plans are maintained, no major impact is foreseen in relation to the above.

5.7.1. Mixing of the CO_2 and Goldeneye gas

Mixing of CO_2 and the remaining hydrocarbon gas present in Goldeneye will have an impact on the CO_2 storage capacity estimation. CO_2 will be injected in a depleted predominantly methane gas reservoir. The reduction in capacity has been estimated to be as much as 6%. This is assuming 100% mixing between CO_2 and the remaining hydrocarbon gas, however, simulation has shown that instead of a perfect mix, a hydrocarbon gas bank is formed at the tip of the plume, meaning that mixing is not perfect and the reduction will be smaller than 6%, making it a small reduction factor.

5.7.2. Irreversible compaction of the reservoir sands

The reservoir is currently grain supported, therefore compaction is minimal. Additionally, the depletion during hydrocarbon production is forecast to be from ~260bara to ~140bara. Irreversible compaction is expected to be minimal. When CO_2 is injected in the Captain sandstone the small amount of calcite in/around the pores will be dissolved. However, there is not much carbonate cement in the reservoir parts that will be used for the CO_2 injection. So, the pore space will increase a small amount (so more volume to inject will be available) and the matrix will become a slightly weaker but without risk of pore collapse.

Compaction experiments carried out in 1998-1999 showed that the compaction of cores from Goldeneye sands is partly elastic (so, reversible) and partly plastic (so, irreversible). There was minimal compaction and the porosity change was about 0.3%, as a result this effect has negligible impact. For further details regarding this topic, refer to Goldeneye Geochemical Reactivity Report[11].

5.7.3. Efficiency of refilling

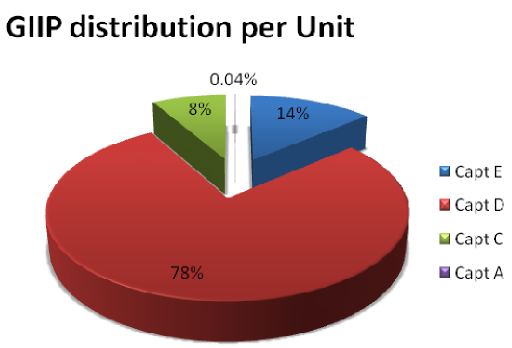
Refill efficiency has been divided into macroscopic and microscopic fill efficiency. The microscopic efficiency has been partially discussed under the last point above, but macroscopic efficiency also includes the impacts of permeability variations in the subterranean formation and dynamic stability of the flood fronts due to mobility ratio (viscosity and relative permeability).

[11] Shell 2010, Geochemical Reactivity Report

5.7.3.1. Reservoir heterogeneities

Reservoir heterogeneities are best illustrated in Goldeneye by the permeability contrasts of the various units (Figure 5.3). The best unit is the Captain D sand which accounted for ~78% of the original hydrocarbon. Injected CO_2 will tend to follow the path of least resistance. Full field simulation has confirmed that, during the injection phase, the CO_2 preferentially fills and follows the D sand. If only the D-sand were available for filling, the capacity would be reduced by **10 million tonnes CO_2**.

After injection, buoyancy forces dominate, and the CO_2 contracts back into the original gas bearing zone. It also starts to fill the overlying Captain E sand – which accounts for a further 14% of the original hydrocarbons in place – this could potentially add an additional 3.4 million tonnes CO_2 if 100% refilling efficiency is considered (based on an estimated gas ultimate recovery of 60 Bscf from the E sand). Owing to the lower permeability and vertical connectivity the refill will be relatively slow and quite a bit of interaction between the D and E sands is expected after injection ceases, driven by buoyancy. Numerical simulation results show that only **1.3 Mt of CO_2** makes its way into Captain E, twenty years after injection stops.



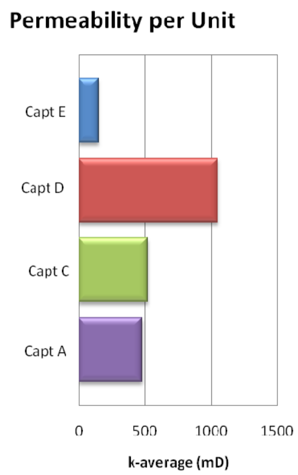


Figure 5.3 Goldeneye GIIP distribution and average permeability per geological unit.

5.7.3.2. Unstable displacement

The effects of unstable displacement during CO_2 injection process in Goldeneye could potentially reduce the short term (i.e. during injection) storage capacity.

A simulacrum simulation model was constructed to investigate these effects – this consisted of a dipping box model representing roughly one quarter of Goldeneye in volume, with similar rock properties (permeability and porosity) and dip angle to the main full field model. The model was conditioned with a 10 year depletion period, further 10 years of recharge from the aquifer and finally, a 10 year CO_2 injection period.

Sensitivities were done on a range of values of effective water relative permeability at residual gas saturation (S_{gr} = 30%) within the observed data, varying between 0.1, 0.25 and 0.6.

Results from the model confirmed that a strong override of water by CO_2 will occur in the reservoir, producing a CO_2 tongue moving downwards due to the unstable displacement (a consequence of the unfavourable mobility ratio). As expected, the tonguing effect gets enhanced by how low the water relative permeability end point can be, creating a Dietz tongue that could be almost parallel to the top of the interval. This means that, during injection, the mobile CO_2 dense phase can extend below the original hydrocarbon water contact.

Finally, the refill efficiency is highly impacted. Based on the simulation results less than 50% of Captain D will be flooded with CO_2 (in the vertical sense) before the CO_2 has moved under the original OWC. However, this is a short term effect that will happen only during injection. The Dietz tonguing behaviour means that the tip of the CO_2 plume will reach the original OWC after injecting just the first 10 to 12 million tonnes of CO_2, but the structure will continue to fill until the total 20 Mt have been injected.

5.7.3.3. Secondary Drainage Relative Permeability

The secondary drainage relative permeability curve is expected to follow the primary drainage curve, however, the time required to bring back initial water saturation will be much longer than the injection period because there is not sufficient time for gravity drainage to bring saturations into capillary equilibrium.

In order to estimate how large the effective "residual water saturation" (S_{wr}) left behind the CO_2 flood front could be, both analytical and numerical estimations were done. Buckley-Leverett displacement theory and fractional flow equations were applied for a process where gas (CO_2) is displacing water and sensitivity analysis was done within the water relative permeability Corey Exponent.

Fractional flow analysis allows calculation of the average saturation of the displacing front (CO_2) and hence, the complemented displaced phase (in this case brine).

A set of relative permeability curves as well as rock properties were used taking into account Goldeneye basic data from logs and SCAL analysis available at the time such as: S_{wi}, porosity, NTG, vertical permeability and thickness, among others. Corey exponents were used as sensitivity and CO_2 and brine properties were taken at Goldeneye reservoir conditions.

The results showed that for a range of Corey exponents of 2, 3 and 5, Sw_{avg} can vary from 0.15 to 0.25, depending on how easy it is to displace the water during CO_2 injection. Based on literature and the unfavourable mobility ratio foreseen for the reservoir, a Corey exponent of 5 could be the more appropriate which yields the higher water saturation left behind, considerably higher than the connate water saturation observed in Goldeneye (S_{wi} ~ 0.07), meaning that this factor represents an important storage capacity reduction element for Goldeneye, because it, in conjunction with S_{gr}, will reduce the pore space available.

5.7.3.4. CO_2/water relative permeability end points

The injection rate can vary significantly for different relative permeability values and injectivity could be sensitive also to variables that define the relative permeability curves. In addition, the end point of the relative permeability curves is conditioned to the mobility ratio (M) of the fluids, having a large impact on the CO_2 plume shape. As mentioned before, water will be by-passed and gas tongues will develop, leading to an unfavourable displacement. In such conditions, the CO_2 plume will travel further away from the injection point, diminishing the average CO_2 storage density and requiring a bigger area to store[12]. As a consequence, a proper assessment of the relative permeability variables is important for the refill efficiency of the system.

The main impact of the CO_2/water relative permeability end points on the storage capacity is related to the displacement mechanism, affecting the behaviour of the Dietz tongue and potentially generating scenarios where the CO_2 can move to levels below the original OWC. From there it could eventually migrate under the spill point. As a result, it is difficult to assign a specific reduction factor to it. Addressing the direct impact of end point relative permeability on the refilling efficiency (based on how unstable the displacement is, i.e. the extent of the Dietz tongue), will give an approximation of the storage capacity reduction.

Sensitivities were done, in the dipping box model, for a range of values of effective gas (CO_2) relative permeability (k_{rg}) at residual water saturation, of 0.8, 0.5 and 0.25.

The results showed that the relative permeability end points have a minor impact on the displacement, making the plume go slightly further in the case where k_{rg} = 0.80 meaning that it will move easily, and the other way round when k_{rg} is restricted (as mentioned above by different publications) to lower values such as 0.25. However, a bigger effect will be seen in injectivity, where the overpressure needed could be higher than expected. This topic will be discussed in detail in a separate report[13].

5.8. CO_2 storage capacity result

The effective storage capacity can be estimated as a function of available volume (production-based) and refill efficiencies based upon the most important reducing and increasing factors mentioned above:

- Available volume: total pore volume based on production achieved.
- Volumetric sweep: considering where the CO_2 will preferentially go in, based on reservoir quality (heterogeneities).
- Dietz efficiency: related to the unstable displacement of CO_2 displacing water under a unfavourable mobility ratio
- Water displacement: "residual water saturation" (S_{wr}) left behind the CO_2 flood front
- Mixing: of CO_2 with remaining hydrocarbon gas saturation (undeveloped + trapped)
- Dissolution: of the CO_2 in both the pore water and the underlying aquifer.

Mineralisation has been identified as a potential increasing factor, but makes significant contributions over timescales long after the injection period has finished. It is therefore not considered further here. Other factors, such as irreversible compaction, are considered negligible.

Additionally, processes such as the possible filling of Captain E sand when buoyancy forces dominate after cessation of injection, may be added at the end of the capacity estimation.

It is important to highlight that the unstable displacement factor (Dietz efficiency) will occur only during injection, and will determine the point in time when the tip of the CO_2 plume reaches the boundary of the OOWC. Thereafter, CO_2 will continue to spread inside the CO_2 storage complex. Nevertheless, it must be stressed that this discount factor could have an important role depending on the reservoir structure, as was explained in more detail in §5.7.3.2.

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12 L.P. Dake, 1978: "Fundamentals of Reservoir Engineering", Elsevier 1978

13 Shell 2010, Injectivity Analysis Preparation. .

In addition to the storage capacity defined by the structural trap of Goldeneye, the water leg beneath the reservoir that lies within the storage site, would likely add some extra capacity, based on numerical simulation results. This could potentially increase the storage capacity by 6 million tonnes, leading to a post injection combined storage capacity of **34 million tonnes of CO_2**.

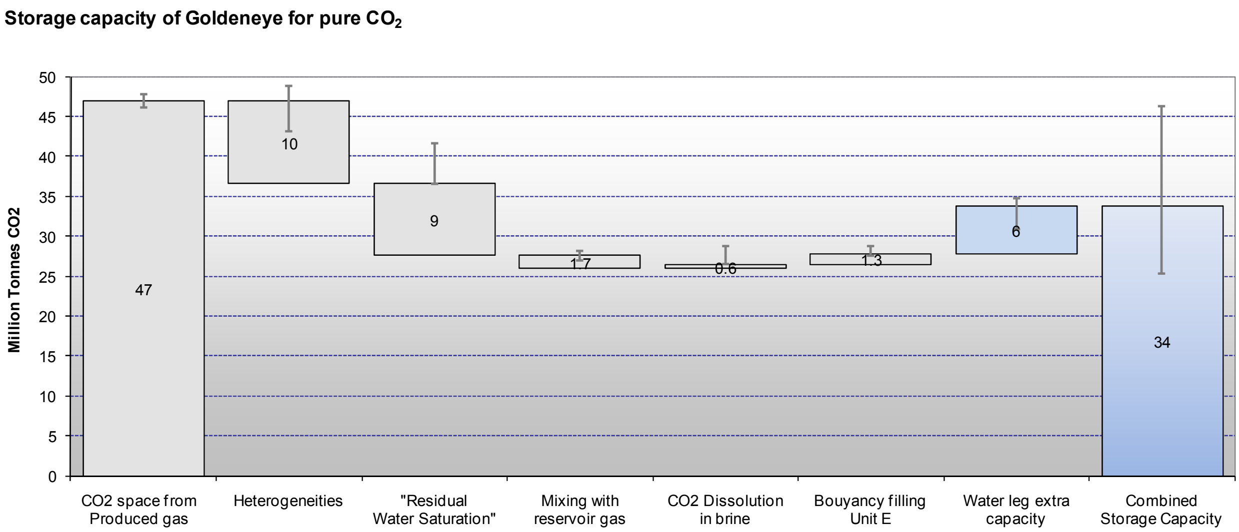

Figure 5.4 Post injection effective storage capacity of Goldeneye.

5.9. Risks to capacity

The risk to Goldeneye CO_2 storage capacity resides in the accuracy of the factors considered as elements that increase or decrease the capacity. The error bars in each of the elements of Figure 5.4 represent the risk observed.

- **Heterogeneities:** reservoir heterogeneities were highlighted in Goldeneye by the permeability contrast with Captain D sand and the assumption that most if not all of the CO_2 will be injected in Unit D. This sand contained ~78% of the original hydrocarbon, however, this has a range among all the geologic realisations available for Goldeneye, that goes from 70% to 82% and this error bar represents that span.
- **Residual water saturation:** how large the effective "residual water saturation" (S_{wr}) left behind the CO_2 flood front could be, was estimated by Buckley-Leverett displacement theory and fractional flow equations. S_{wr} ranged from 15% to 25% and this error bar represents that span.
- **Mixing with hydrocarbon gas:** the reduction in capacity was estimated to be as much as 6%. This is assuming 100% mixing between CO_2 and the remaining hydrocarbon gas, however, simulation has shown that instead of a perfect mix, a hydrocarbon gas bank is formed at the tip of the plume, meaning that mixing is not perfect and the reduction will be smaller than 6%, making it a small reduction factor. 4% was taken as a lower end for this element, which is pretty small over all.
- **CO_2 dissolution in brine:** the increment of storage capacity was estimated in 2.2%, taking into account a CO_2 solubility of 4.6% (weight) and that CO_2 will contact approximately 25% of the brine due to the water saturation left behind the CO_2 injection front. Nevertheless, dissolution is way more complicated than that obviously instantaneous dissolution describe

before. In addition there will be diffusion of the CO_2 of the carbon dioxide dissolve in the water, allowing more CO_2 from the gas phase to dissolve in the aqueous phase. There will also be a convective mixing effect because the density of water saturated with CO_2 is greater than that of undersaturated water, so density instability is created and eventually plumes of CO_2 laden water flow downwards through the formation. Assuming this, a maximum dissolution reduction was calculated to be 11.2% if not only the height of the CO_2 plume (residual water saturation) is contacted but the whole reservoir thickness in the long term.

- **Buoyancy filling of Unit E:** after injection, buoyancy forces dominate, and the CO_2 contracts back into the original gas cap and it also starts to fill the overlying Captain E sand. It was seen in simulation that Captain E will be finally flooded with CO_2 but mainly the bottom part only. It was assumed a refilling efficiency for Unit E between 33% and 66% to create the span for this error bar.
- **Water leg extra capacity:** error bar shows an uncertainty margin in this case dominated by the static uncertainties regarding the structural west flank of the field. Alternative realisation SMR3.05 (shallower west flank) allowed only 3 Mt stored in the water leg, while SMR3.15 (pinch-out sensitivity) allowed 7 Mt and reference case (SRM3.1) 6 Mt.

The summation of all the positive and negative uncertainty bars gives the total uncertainty range for the storage capacity at the end of injection. The extremes represent the unlikely scenarios where all the elements decreasing or increasing the storage capacity happen all together in the downside or upside cases.

The final capacity and the extremes are for the specific injection pattern using the current Goldeneye well penetrations and currently proposed store rock volume. If for example, more CO_2 were to be injected, an alternative pattern with new penetrations could yield a higher post injection capacity by forcing more CO_2 to be stored in the water leg.

Nevertheless, this approach still resulted in a storage capacity that sits above the 20 Mt mandated by the UK CCS Demonstration Project, depicting a lower end scenario of about 25 Mt.

6. Injection Wells and Injectivity

6.1. Introduction

After establishing that the store has sufficient capacity, the next question is *can the capacity be accessed and can the injection be sustained for the duration of the project?* The objective of this chapter is to analyse the expected injectivity in Goldeneye during the 20Mt of CO_2 injection. In addition, it will define the key elements of well requirements in order to achieve and sustain injectivity within the field.

6.2. Structure of the Chapter

The Chapter is divided into six main parts.

- A summary section lists most important outcomes related to the injection wells and injectivity.
- The following two sections analyse the transient well behaviour due to CO_2 injection into Goldeneye wells and its potential implications to the well design.
- The third section in the report summarises the well design and the workover operations required to convert current production wells into CO_2 injectors.
- The fourth section is related to the expected initial injectivity in Goldeneye. Consideration is given to the rock properties in the main reservoir, hydrocarbon productivity and the conversion from hydrocarbon production to CO_2 injectivity. The deterioration of injectivity with time or impairment is also analyzed as part of the injectivity section.
- The fifth section covers tubing sizes and number of injection wells; their operability and integrity and possible impact on Longannet power station.
- Finally, last section explains what the existing key risks to delivery of injection are.

6.3. Summary of Injection wells and Injectivity

The injection wells will consist of 13Cr corrosion resistant tubing strings (and sand screens), and carbon steel liners and casings.

Analyses have shown that injecting dense phase CO_2 into a depleted reservoir has the risk of producing low temperatures in the injection tubing. These low temperatures cause problems with the materials and fluids in the wells. In order to avoid this, small injection tubing is being installed. This will introduce enough friction and will maintain the injection column in dense phase from the well head to the sand face. However, low temperatures for a short period of time can be encountered during transient operations (start up and shut down).

The current upper completion was designed for hydrocarbon production. Changing to CO_2 injection will require a workover to install a single tapered tubing string in order to manage the CO_2 phase behaviour and to keep the integrity of the well.

There are only a limited number jack-up rigs that have the capability of working at the Goldeneye platform owing to the significant water depth.

Limitations of the different well components were investigated for the expected well conditions under CO_2 injection. The Christmas tree and the tubing hanger will be replaced in the workover with units having a lower minimum temperature rating. All completion equipment (i.e. attached to the tubing string) will have 13Cr equivalent metallurgy and will have working pressures in excess of the expected final well pressures.

The oxygen level shall be controlled below 1ppm to avoid corrosion issues in the 13Cr well components (upper and lower completion). A high level of corrosion could occur in the casings made of carbon steel and when both CO_2 and free water are present. The design takes this into account.

Based on the hydrocarbon production and the reservoir characteristics it is expected to have a good initial injectivity in the Captain D. Filters will be installed on the platform to avoid reduction of fines and hence reduction of injectivity by plugging/erosion of the lower completion. Batch hydrate inhibitor is planned before well start ups during the initial stage of injection to avoid hydrate formation in the tubing and the near-wellbore region.

In the case of injecting under fracturing conditions, there would be limitations related to the erosion of the lower completions (screens / gravel) currently installed in the well. 'Hot spot' erosion of the screens is a potential problem for fracturing conditions as the injected CO_2 is not uniformly distributed in the screens.

The installation of small bore tubing in the wells limits the operating envelope of each well. In order to accommodate the range of injection rates at the different reservoir pressures during the injection life, each well will be completed with a different tubing size/configuration tailored to a specific rate range. The wells will then have overlapping operating envelopes and any rates specified in the integrated consortium basis-for-design will then be achievable through the choice of a specific combination of wells. All five wells will be recompleted, although only two or three out of a set of four will be required for the injection at any one time. This provides a degree of redundancy within the four wells, while the fifth well acts both as a monitoring well and as a backup in the case of a significant loss of integrity in two other wells.

In the completions, there will be permanent temperature and pressure monitoring gauges. There will also be a distributed temperature gauge - a fibre optic system taking temperatures every one metre in the well, and distributed acoustic sending (DAS).

6.4. Summary of well requirements for CCS

The general requirements for the wells under Goldeneye CO_2 injection are:

- Unmanned platform
- Special jack-up rig is required in Goldenye platform due to the water depth
- 5 wells currently drilled from the platform
- Manage the CO_2 phase behaviour and the resultant temperatures
- Flexibility in injection rates
- Variable arriving CO_2 rates to the platform
- Completion design should consider the presence of CO_2 and hydrocarbon (not only CO_2)
- Pressure inflation during period of the CO_2 injection
- Manage the cold CO_2 arriving at the platform
- Maintain well integrity. All well completion materials should be compatible with the injected fluid.
- Expected remaining well life: 15-20 years
- Able to monitor wells/reservoir. Facilitate intervention. Install PDG in the wells
- Facilitate abandonment
- Minimise complexity and cost of any well work

6.5. CO_2 phase behaviour management in the wells

CO_2 will arrive at the Goldeneye Platform in liquid state at around 4°C (bottom sea temperature) and 120bar approximately. CO_2 will be injected in a single phase with wellhead pressures in the liquid phase by the introduction of friction to avoid extremely low temperatures in the well caused by the Joule Thomson effect (Figure 6.1).

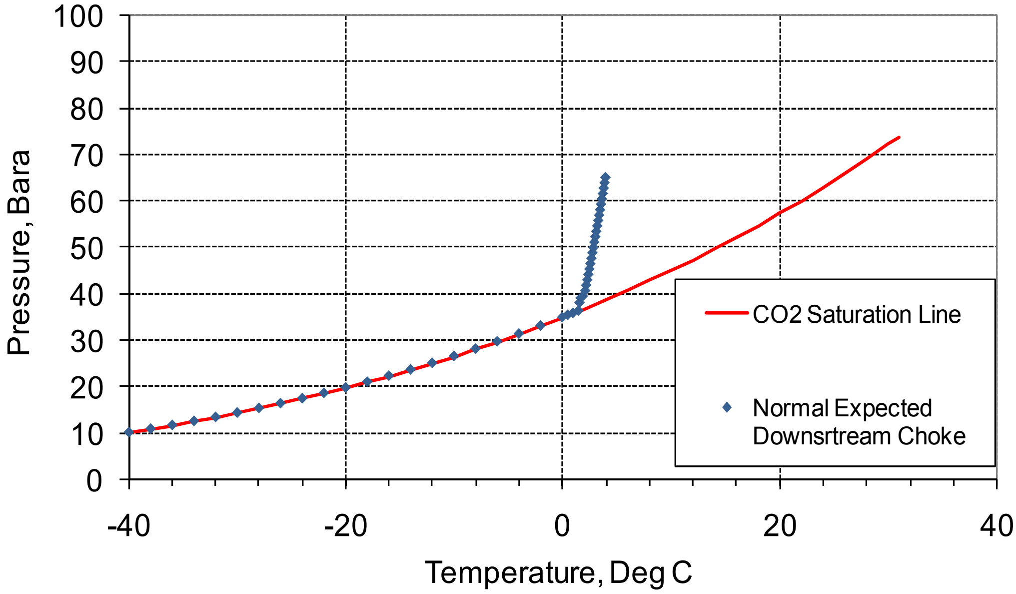

Figure 6.1 Expected CO_2 choke performance.

In the case that the wellhead is operated in two phases (liquid-vapour) the resulting temperature in the top of the well can be extremely low (with a minimum of -25°C and below 0°C above 1000m (3,048ft) TVD) during all the injection time. This is due to the flashing of the CO_2 to gas caused by relatively low reservoir pressure and practically no pressure drop in the well when using the existing 7in completion tubing. These extremely low temperatures will create serious implications in terms of well design and operability. For this case, there will be requirements to change the materials and shallow well equipment (SSSV, XMtree, hangers) which will need to be qualified or replaced for extremely low temperatures and integrity issues in the well by freezing of annuli fluid.

In order to avoid the extremely low temperatures at the top of the well under normal injection conditions, the CO_2 stream should be kept in liquid phase at the wellhead by increasing the required injection wellhead pressure above the saturation line. This will be achieved by extra pressure drop in the well by means of friction (small tubing). The minimum wellhead pressure to avoid the CO_2 in two phases has been determined at 45bar considering the arrival temperature of the CO_2 to the platform.

The required wellhead pressure will be achieved by small diameter tubing creating back pressure by friction loss.

6.6. Pressure and Temperature Profiles

6.6.1. Closed in conditions

Different CO_2 phases exist in a static well at geothermal conditions depending on reservoir pressure. For low reservoir pressure (≤3500psi [241 bar]), the top of a well will be in gas phase whilst in dense phase at the bottom of the well. With different reservoir pressures, the transition depth between gas and dense phase inside tubing will vary. Higher reservoir pressure will tend to have a smaller gas phase, moving the transition point shallower. For Goldeneye reservoir pressure, less than ~3,000psi [207 bar], CITHP remains about the same at ~37bar. At reservoir pressures above 3000psi [207 bar] the CITHP increases with pressure. See pressure profile below under close in conditions:

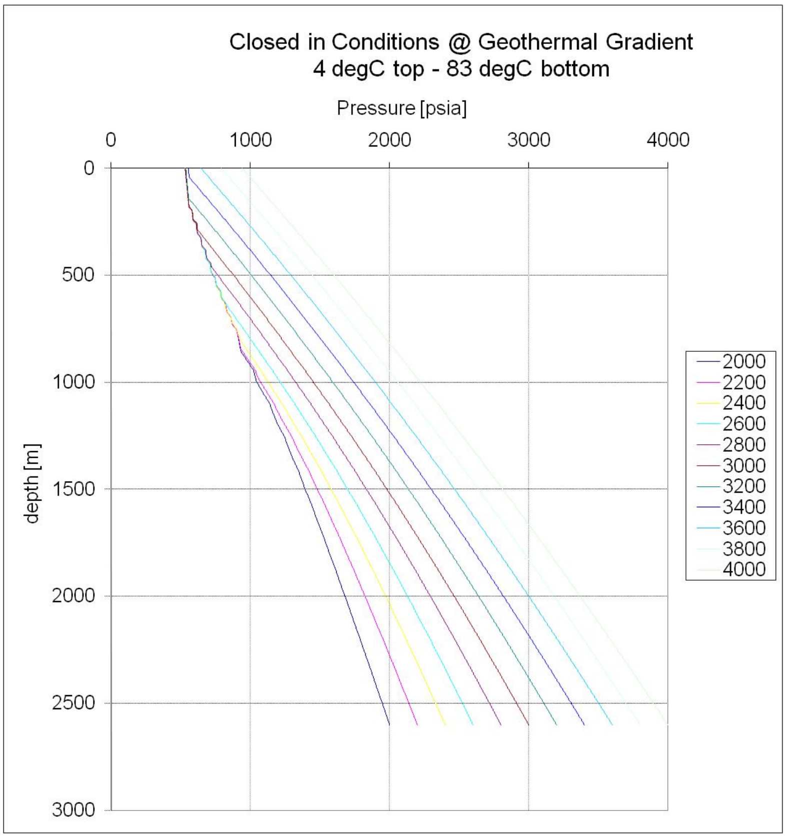

Figure 6.2 Pressure profile in a closed-in well (at geothermal conditions).

6.6.2. Steady State Conditions

The concept is presented in the following graph of outflow and inflow calculations. The outflow curves (red) are for a given tubing size and represents the bottom hole injection pressure at different wellhead pressures. The operating envelope is defined with the injectivity curve at a given reservoir pressure.

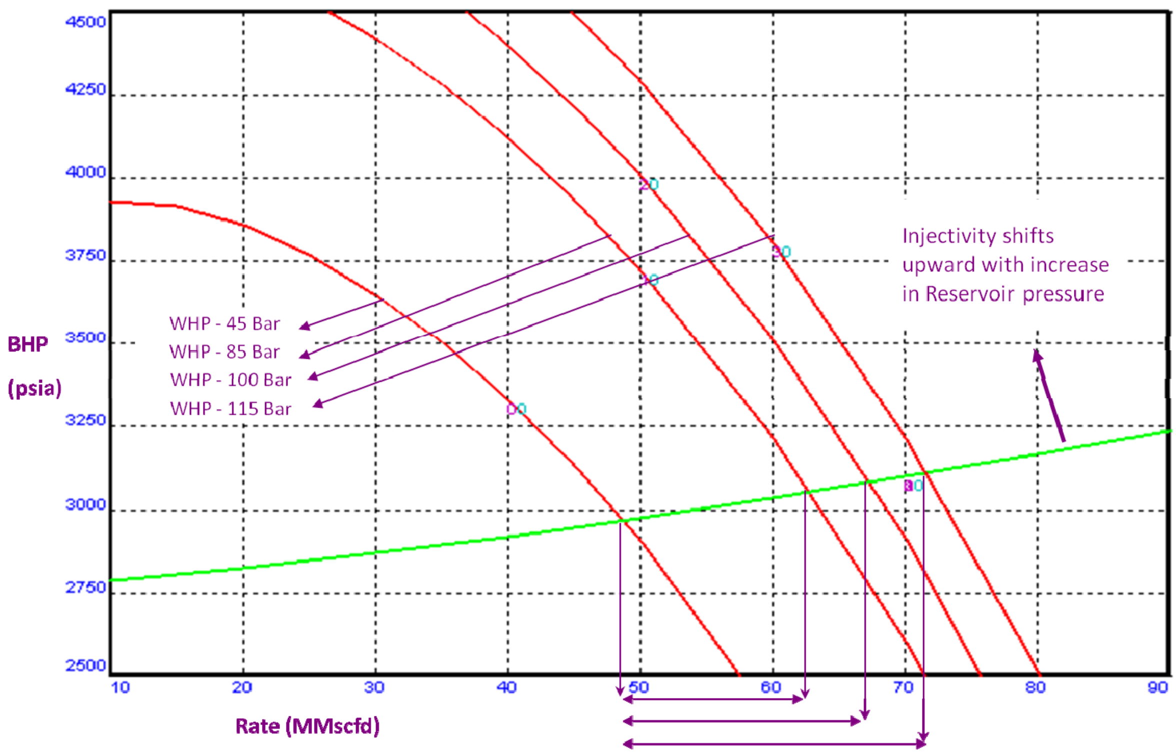

Figure 6.3 Outflow curves for the friction concept.

The CO_2 arrival temperature range to the platform is 3 to 10°C depending mainly on seabed temperature, reference case being 4°C. Reservoir temperature is 83°C at mid of Captain D.

The expected pressure and temperature profile of the CO_2 in the wells are:

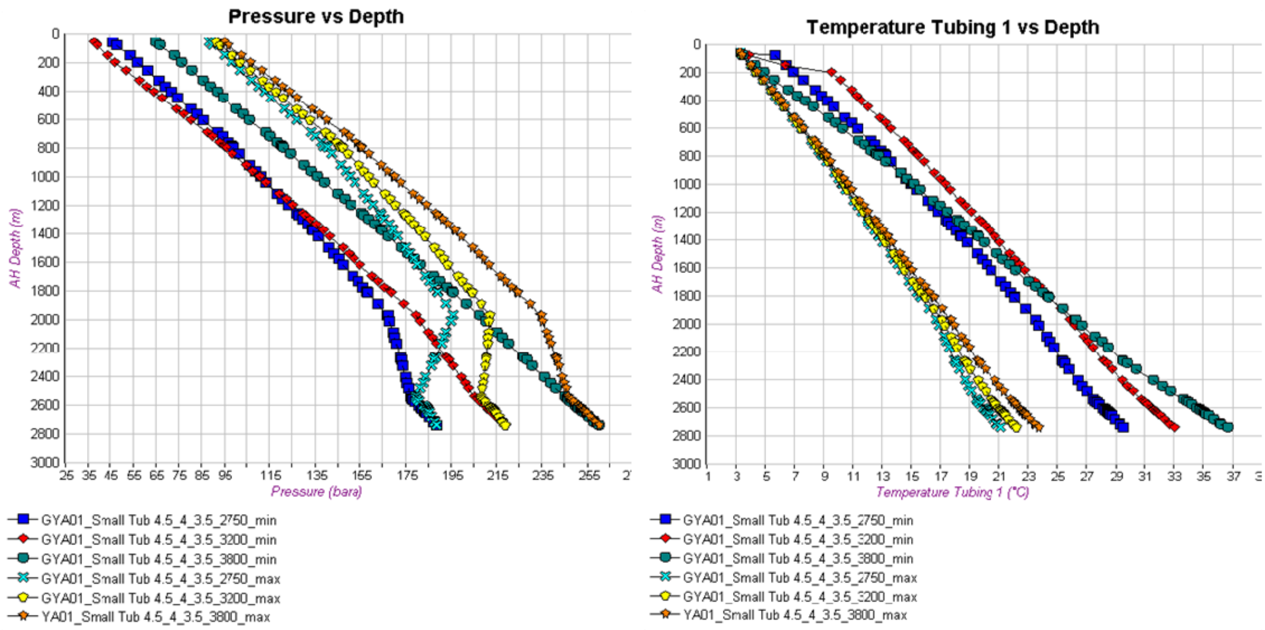

Figure 6.4 Pressure and Temperature predictions under steady state.

The bottom hole CO_2 temperature is in the range of 17 to 35°C. The lowest temperature observed from modelling is 17°C. The adiabatic bottomhole temperature is 14°C.

The CO_2 will be injected in the well at single phase (dense phase). The PVT properties of the CO_2 are well defined in this region as observed in the figure below where the CO_2 density is relatively stable travelling down in the well. This will minimise the calculation error in terms of the operating envelope in the wells and pressure traverse. See Figure 6.5 below.

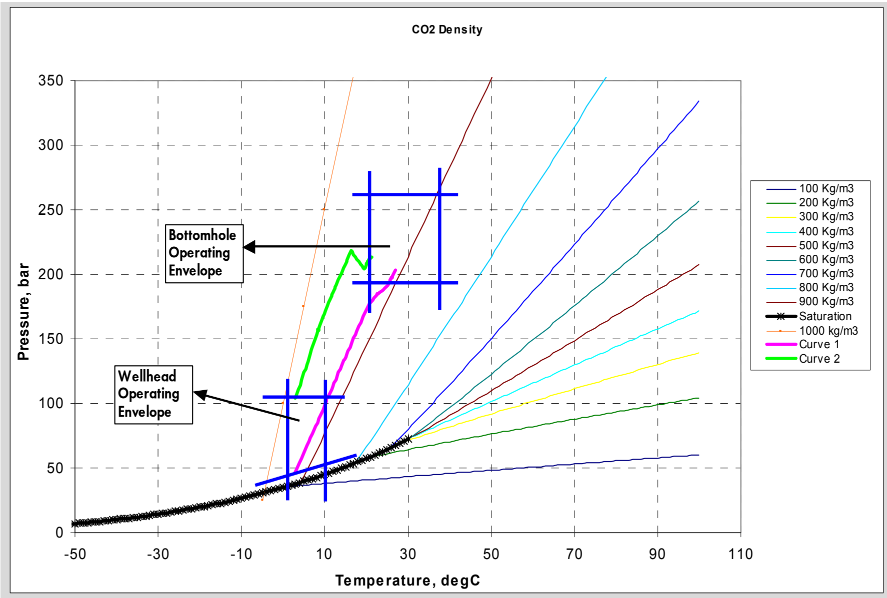

Figure 6.5 Pressure and Temperature prediction with respect to CO_2 phase envelope and density.

During steady state injection, the tubing temperature is similar to the CO_2 temperature. The A annulus and production casing temperature is also similar to the injection fluid temperature at the wellhead. At bottom hole, the A-Annulus temperature is ~1°C warmer than the injection fluid temperature. The production casing temperature is ~3°C higher than the injection fluid temperature during steady state injection.

The well components are well within the range of pressure and temperature expected during the injection period.

6.6.3. Transient conditions

During transient operations (well close-in and well start-up), temperature drop is observed at the top of the well. The faster the shut-in or faster the well opening, the less the resultant temperature drop. The cooling effect diminishes deeper into the well due to limited CO_2 flashing and heat transfer from surrounding wellbore.

The reservoir pressure affects the temperature calculation during the transient calculations. The lower the reservoir pressure, the lower is the surface temperature expected during transient operation and hence the higher the stresses/impact in terms on well design.

The recommended procedure is to bring the well to the minimum rate (rate required to keep CO_2 in liquid phase at the wellhead, i.e. injection at 45bar WH Pressure) and then close the well at the wellhead in 30 minutes. For bringing on a well on CO_2 injection, the recommended procedure is also to do it quickly. It is recommended to attain the minimum rate in 1 hour. Temperature as low as -15°C can be reached inside the tubing in the top of the well. Due to heat capacity/storage, this low temperature in the CO_2 is not observed in the other well components (tubing, annulus fluid, etc), which will see less severe temperature drops. Calculated temperatures in the well for the recommended case in the figure below.

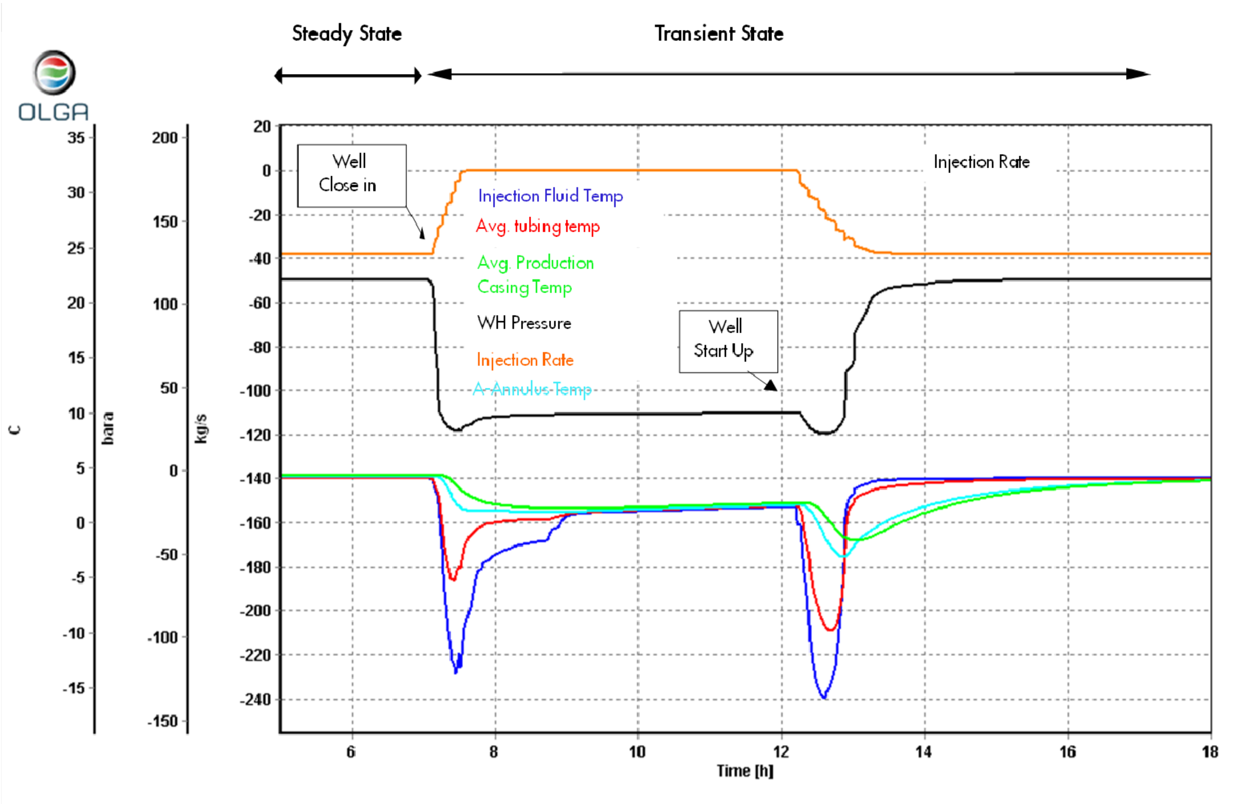

Figure 6.6 **Recommended operations case. 4°C IWHT (2500psi P reservoir).**

At ~450m CO_2 temperature in the tubing is 0°C (32 deg F). At reservoir depth, during CO_2 injection steady-state conditions, the temperature is constant around 17-20°C for injection fluid temperature of 4°C. When shut-in, this bottom hole temperature rises slowly (~2 weeks) towards initial reservoir temperature.

Design case considers a longer time to open or close the wells in case of any operational problem. For the design case, for a short period of time, surface temperature drop in the CO_2 can be in the order of -20°C during well start-up.

Figure 6.8 shows the traverse temperature profile of injection fluid, tubing and production casing at 13^{th} hr of Figure 6.1 (the coldest observed CO_2 temperature at the WH). It should be noted that the profile plot shown below is for lowest CO_2 temperature and not for lowest tubing or production casing temperature. There is a time lag observed for the lowest temperature in tubing and production casing with respect to injection fluid temperature.

Strict operational procedures need to be implemented and adopted by the Goldeneye Well Operations Group to avoid extreme cooling of the well components due to temperature limitation of the well components.

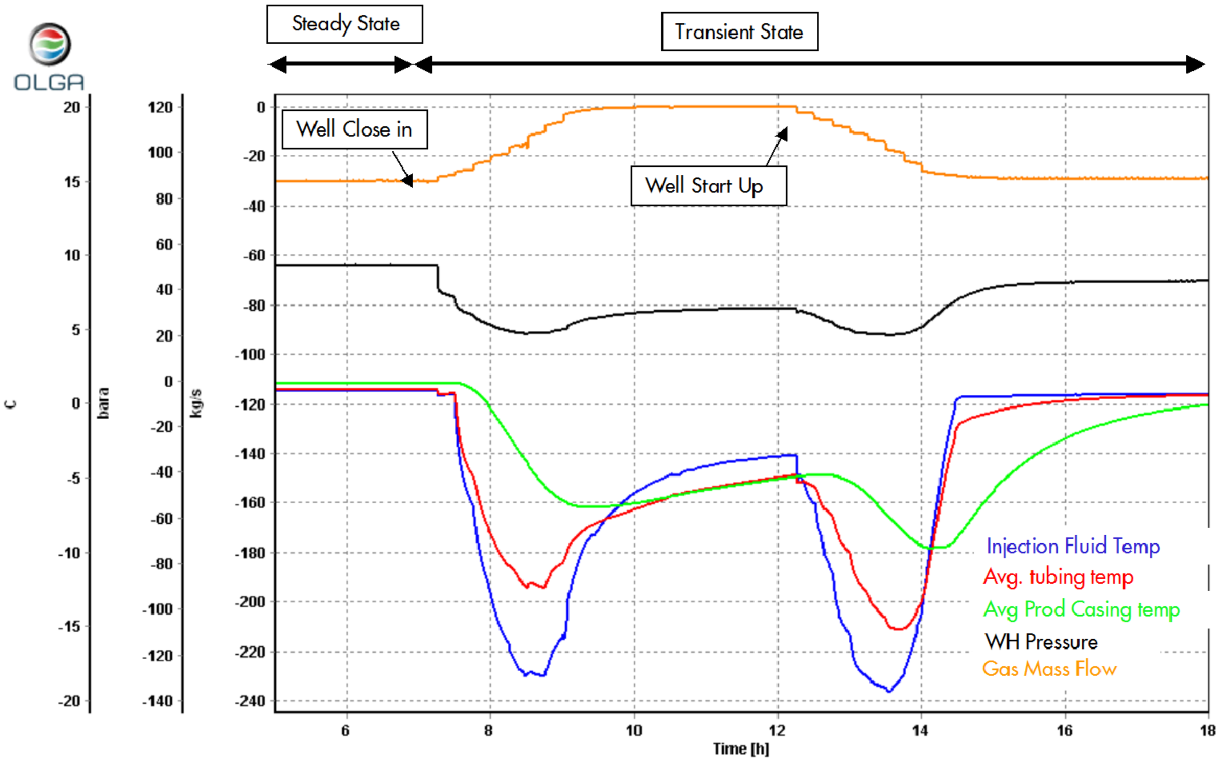

Figure 6.7 Design Case. 45bar WH pressure steady state (2500psi P reservoir)

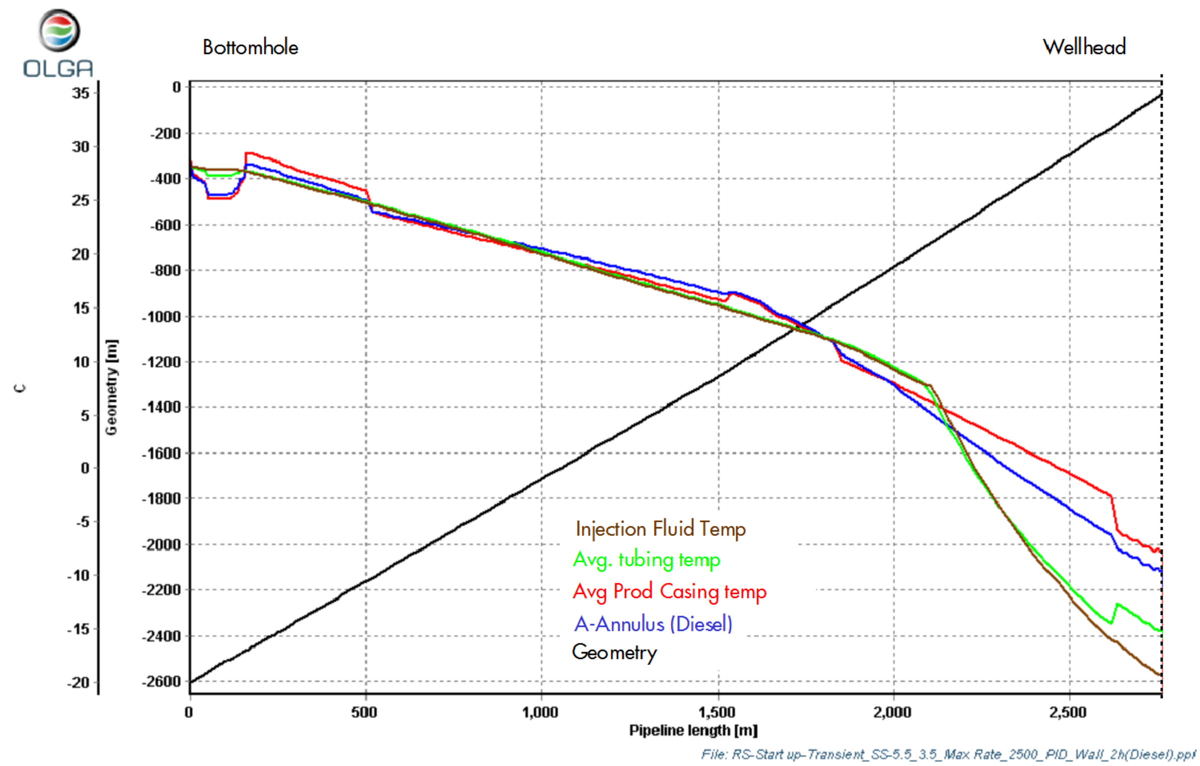

Figure 6.8 Traverse Temperature profile design case: 13.5hr. 45bar WH pressure steady state (2500psi P reservoir)

6.7. Well Design

The Goldeneye wells targeted the Captain sandstone gas reservoir and have been produced to a single NUI platform. The well design consists of 30in, 20in x 13 3/8in and 10 3/4in x 9 5/8in casing design. A pre-perforated liner has been run in all wells across the reservoir in 8 1/2in hole. This liner in turn has been covered with 4in sand screens and gravel packed. Hole angles vary up to 68 degrees - in Well GYA04.

The intent is to change their use from hydrocarbon production to CO_2 injection. There is no intention of drilling new wells or sidetrack wells, nor is there the intention of performing further workovers at a later date. However the heavy duty jackup used for the workovers could perform any well operations required.

Should CO_2 be injected into the existing Goldeneye completions, a consequence of the resulting low temperatures (even managing the Joule Thomson effect), is that the existing production tubing will contract to such an extent that the PBR shear ring, rated to 120,000 lbs has the potential to fail. This would allow the PBR seals to move and subsequently fail due to abrasion.

It is proposed to standardise the top (down to the SSV) and the bottom (up to the PDG) of the upper completion which will deal with this situation. The planned completion for CCS is shown in Figure 6.9.

6.8. Workover Operations

A heavy-duty jack up is required in Goldeneye due to the 400ft [122m] water depth. There are only a small number of jackups worldwide that can work in the water depth at Goldeneye location - less than 10, and some of those are on long-term contract.

Wells will be worked over by placing cross-linked polymers and enzymes downhole to plug the well. The design of the plug will be such that enzyme action will break down the polymers to a clean non damaging fluid, at a time after the workovers have been completed.

The existing production packer will be removed. A new packer will be installed along with the tubing, with a tail pipe seal assembly stung into the top of the sand screen hanger. An outline programme is presented below:

- Rig to location
- Kill Well / set downhole barriers
- Remove xmas tree
- Rig up & test BOPs (Blow Out Preventers)
- Recover downhole barriers
- Recover existing completion tubing
- Recover packer
- Clean scrape 9 5/8in casing
- Carry out cement logging
- Run new completion tubing
- Set packer
- Test tubing, annulus and TRSSSV (Tubing Retrievable Sub Surface safety Valve)
- Install and test Xmas tree.

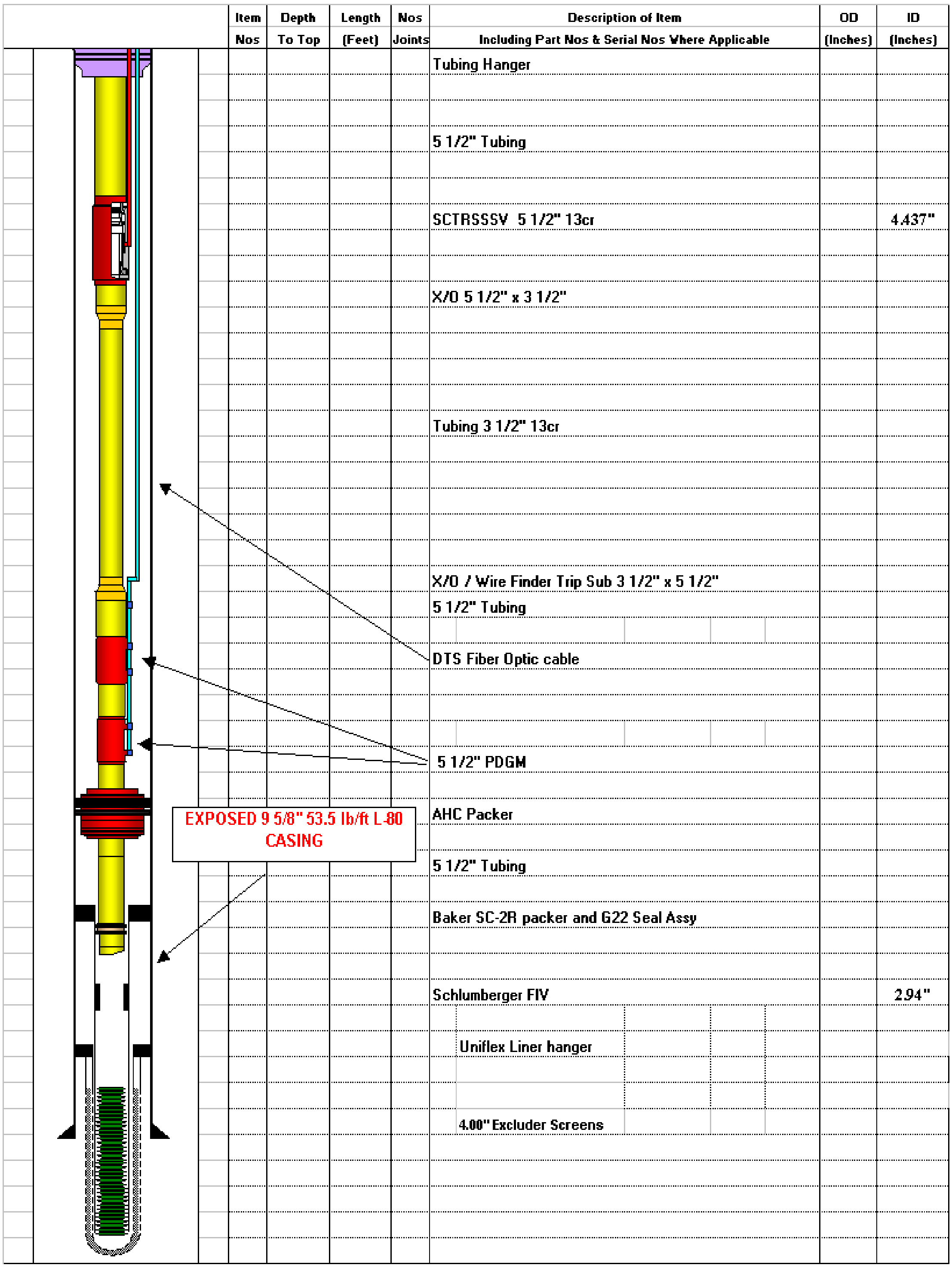

Figure 6.9 Proposed general completion.

6.9. Injectivity

6.9.1. Initial Injectivity

The initial CO_2 injectivity in Goldeneye is expected to be good, injection pressure above the reservoir pressure for the expected injection rates is in the order of 200 to 400psi [14 to 28 bar]. This conclusion is based on the rock properties and the hydrocarbon productivity. Corrections are made to the hydrocarbon productivity to obtain the expected CO_2 injectivity.

The best information available to estimate the future CO_2 injectivity is the current hydrocarbon wells productivity. The hydrocarbon productivity has been excellent and had confirmed the reservoir characteristics (see Figure 6.10 below).

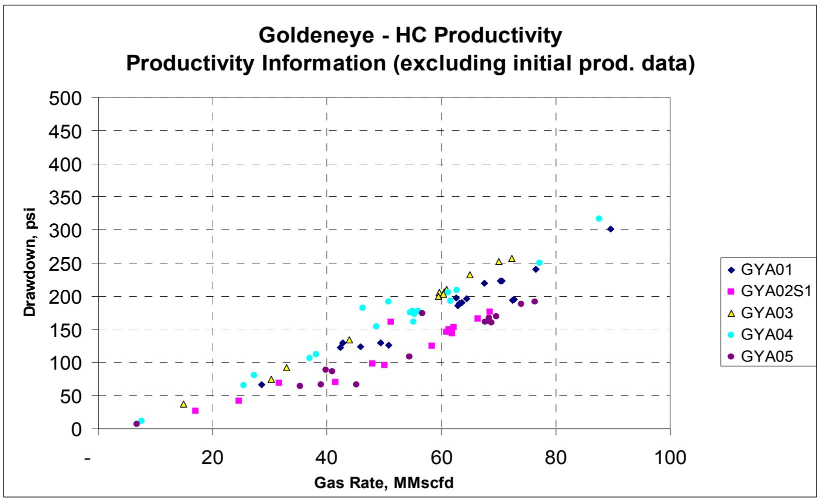

Figure 6.10 Productivity per well during long term production phase.

The CO_2 injectivity under matrix conditions can be estimated from the hydrocarbon productivity considering the different PVT between the hydrocarbon and the CO_2 PVTs. The impact of the PVT correction is small in the injectivity as the high viscosity of the CO_2 is compensated by the low expansion factor of the CO_2 with respect to the hydrocarbon gas. The differences in relative permeability between the hydrocarbon gas and the CO_2 have been estimated also with a small impact.

6.9.2. Injectivity declining over time

6.9.2.1. Gravel pack and formation plugging

A threat to injectivity comes from the likelihood that debris (corrosion products, sand, dis-bonded pipeline coating etc) resides in the pipeline today, after 6 years of operation. Displacement of these products into the well without any mitigation measures will plug the lower completion (screen-gravel pack) and the formation. Plugging may reduce the injectivity through the lower completion (screens / gravel) and formation with time. Mitigation options related to pipeline commissioning and filtration are required to ensure long term injectivity.

The offshore pipeline will then be cleaned during the commissioning phase of the CCS project. Removal of the solids and liquids during this phase is very important to ensure the long term integrity of the pipeline and the lower completion / formation.

Very small particles can be accepted in the injection wells to avoid plugging at the screens / gravel pack and formation. The recommended values are filtration 17 micron to avoid the plugging of the lower completion and 6 microns to avoid formation plugging.

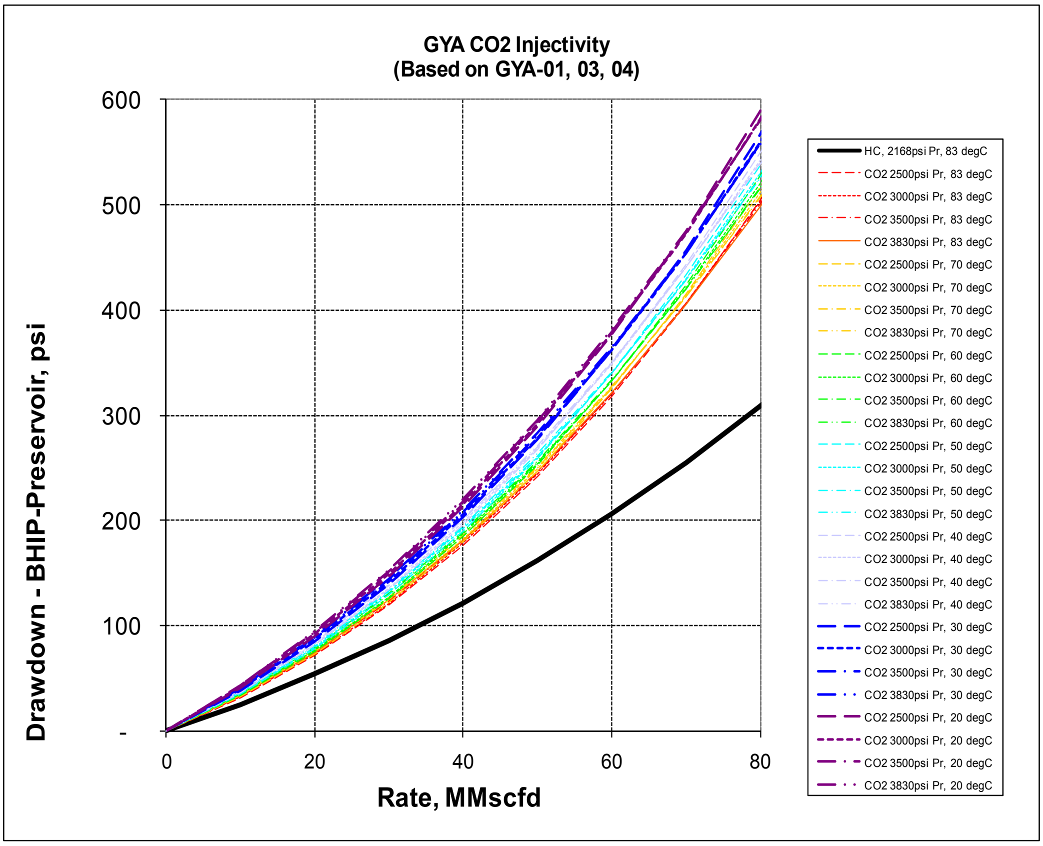

Figure 6.11 CO_2 injectivity vs hydrocarbon productivity (GYA01, GYA03 and GYA04).

6.9.2.2. Hydrates

The formation of hydrates is only possible when water is present in significant enough quantities and the temperature and pressure of the fluids are within the hydrate formation window. Hydrate curve for CO_2 and Goldeneye hydrocarbon and their mixtures in the presence of a free water phase are shown below (Hydrate region is to the left of the curve). The hydrate deposition curve depends on the composition. Hydrocarbon hydrates are formed more easily compared to CO_2 hydrates in terms of temperature. For instance, at 200bar [2,900psi] pressure and in presence of water, hydrocarbon hydrates can be formed at temperatures below 22°C whereas CO_2 hydrates only form below 11°C.

The Steady State Injection conditions are expected to be between 17 to 35°C (most likely in the 20°C scenario).

During production, water has encroached into the Goldeneye gas cap and at least part of the well gravel pack will be surrounded by water at the time injection starts. The trapped gas saturation is estimated to be 25% so some methane will remain near the well. This is miscible with CO_2 so will eventually be displaced by the injected CO_2. The initial injection of CO_2 will drive water away from a well and cool the reservoir. If the well is then shut in this water may well return into the cooled part of the reservoir where hydrates could potentially form.

The formation of hydrates in the well or near wellbore could potentially reduce or completely arrest injection of CO_2. The cooling of the injection well and the surrounding reservoir matrix induced by the injection of CO_2 have the potential to create conditions favorable for the formation of hydrates. This assessment is based on the assumption that both formation water and hydrocarbon gas will be present initially in the well and the surrounding reservoir matrix.

To reduce the risk of hydrate formation, it is considered prudent to introduce hydrate inhibition during prior to well start ups.

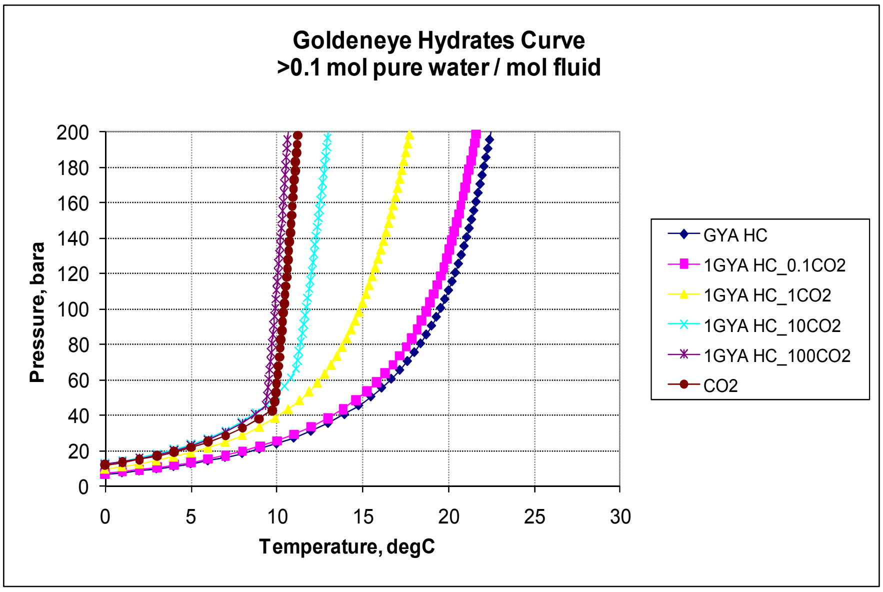

Figure 6.12 Hydrate deposition curve.

6.9.2.3. Dis-bondment of pipeline coating

The offshore pipeline was installed with an internal epoxy coating. The internal coating is a solvent based cured epoxy. The thickness of the cured epoxy is between 30-80 microns.

Although coating disbondment is not expected, there is still some degree of uncertainty of the coating response under CO_2 exposure. Should disbondment occurs during operation then particles ranging from small solids to relatively large fractions of coating may be formed, which could subsequently clog or completely block the gravel pack / formation, thereby reducing injectivity. The mitigation for this case is to have a tight control on the CO_2 quality being injected into the wells by using a filtration system on the platform.

6.9.2.4. Flow Reversal

By reversing the flow, from the production hydrocarbon production phase to the CO_2 injection phase, there might be some re-accommodation of fines currently embedded in the gravel pack under hydrocarbon production.

The effect of the flow reversing is considered because wells' productivity have been stable with time. Captain D is a well sorted sandstone and gravel pack was designed considering the general criteria in the oil industry and industry experience in underground storage with sand control

6.9.2.5. Joule Thomson cooling upon CO_2 injection into the reservoir

A Joule Thompson cooling effect can be expected when CO_2 undergoes adiabatic expansion upon entering the formation. The likelihood of encountering CO_2 expansion problems in Goldeneye is very low due to the low JT coefficient based on the injection pressure and temperature. Cooling effects of less than 3°C are anticipated.

6.9.2.6. Halite Precipitation

This problem has been observed in salt-saturated formation water reservoirs, and is caused by water evaporation around the wellbore due to CO_2 injection. The formation water in Goldeneye has a relatively low salinity that which will minimise the effect of any potential salt precipitation.

6.9.2.7. Injection under fracturing conditions

The reservoir has experienced a depletion process during the hydrocarbon production phase. The minimum stress is affected by this process. The reservoir will undergo an inflation process during the CO_2 injection and aquifer support. The minimum stress development is uncertain during an inflation process.

The CO_2 will be injected cold with an estimated difference of 63°C between the formation temperature and the injection temperature; the minimum stress will be affected by the cooling effect.

Considering the minimum stress range in the formation and the injection pressure, the most likely scenario during the initial injection period, when the reservoir pressure is relatively low, is to have injection under matrix conditions. However, as the reservoir pressure increases, it is possible that the formation is fractured during the injection process.

In the case of injecting under fracturing conditions the CO_2 quality specification can be relaxed; however, there are limitations related to the erosion of the lower completions (screens / gravel) currently installed in the well. 'Hot spot' erosion of the screens is a potential problem for fracturing conditions as the injected CO_2 is not uniformly distributed in the screens. If fracturing is suspected the recommendation is to limit the injection rate to 38 MMscfd per well; however, this limitation can be relaxed with time assuming that the frac will become wider with time.

The fractures only penetrate a small distance into the caprock, however, the exact distance depends on the interplay of thermal cooling and injection pressure.

6.10. Wells operability

6.10.1. Reservoir considerations

The reservoir pressure will increase due to the CO_2 injection and the aquifer strength. The completion is selected considering the increase of reservoir pressure from 2750psi [190 bar] (lowest predicted pressure at the start of CO_2 injection) to 3800psi [262 bar] (highest predicted reservoir pressure at the end of the CO_2 injection – 20 million tonnes).

From the reservoir perspective the order of preference to inject is as follows: GYA01, GYA04, GYA02S1 and GYA05. GYA03 is planned to be a monitor well. The well can be converted to injection once the CO_2 plume has arrived into the well. The order of preference is determining the tubing size in the wells.

6.10.2. Tubing Sizes and number of wells

A single well will not be able to inject from the minimum to the maximum injection rate due to the limited injection envelope per well.

A combination of available injector wells should be able to cover the injection rate ranges arriving to the platform. The aim is to minimise the number of wells within the overall well restrictions. The completion sizing also considers overlapping of well envelopes to give flexibility and redundancy in the system for a given arrival injection rate. At a given arrival rate different combinations will add flexibility to the system.

The current tubing sizes in the different wells are as follows:

GYA01: 4.5in-4in-3.5in (2,550-6,500-8,430 ft AHD)

GYA02S1: 4.5in-3.5in (4,000-10,803 ft AHD)

GYA04: 4.5in-4.5in-3.5in (2,566-9,400-12,665 ft AHD)

GYA05: 4.5in-3.5in-2.875in (2,591-4,700-8,070 ft AHD)

The required number of wells to be worked over to cover the injection range is four for the initial and final reservoir pressure. There is no requirement to carry out a workover in the well. The analysis was done considering the current well envelopes with different combinations (see Figure 6.13 below).

GYA03 is planned to be a monitor well. The well can be converted to injection once the CO_2 has arrived into the well. The reason for carrying out the workover in this well are: risk distribution in the case of injectivity issues in the other wells, installation of a better and new completion string for monitoring the arrival of the CO_2 plume and synergy with the initial workovers.

6.10.3. Longannet impact

Operate the injector wells by wellhead pressure.

In the case that high arriving CO_2 rates to the platform, only changing the choke parameter will allow handling changes in the arriving CO_2 rates. This situation is improved at high reservoir pressures where the operating envelope of the wells increases. However, at low arrival rates there will be requirements to carry out well closing / opening up operations in order to receive the variable arriving rates due to the limited operating envelope of the wells.

It is preferred to have base load operations at the power station. Avoid sudden changes of rate in the platform by line packing.

Under normal circumstances a redundant well will not be injecting, allowing monitoring of the reservoir in the area (reservoir pressure). It is envisaged that the redundant well will not always be the same well.

6.11. Key risks to delivery of injection

6.11.1. Well plugging

The fundamental reservoir properties of the Goldeneye field (average 790mD permeability 25% porosity), together with its hydrocarbon production history, all point to excellent properties for CO_2 injection. However the operating conditions and CO_2 composition present a risk of this injectivity declining over time as a result of two mechanisms: (i) plugging of the completion screens, gravel pack or near-well bore formation; (ii) hydrate/halite precipitation.

The screens and the gravel pack require an estimated maximum particle size of 17 microns to avoid plugging the lower completion; a size of 6-7 microns is required to avoid plugging the formation. The most probable cause of low injectivity is thought to be either fines re-accommodation in the gravel pack (resulting for flow reversal), or as a result of the failure of offshore filtration, designed to remove pipeline and other debris.

Hydrates are most likely to create a problem during initial injection conditions due to the presence of formation water and hydrocarbon gas at the wellbore. During later stages the risk of hydrates decreases due to the lower presence of water and increasing CO_2 content around the wellbore. Batch injection of methanol is currently planned to reduce this risk.

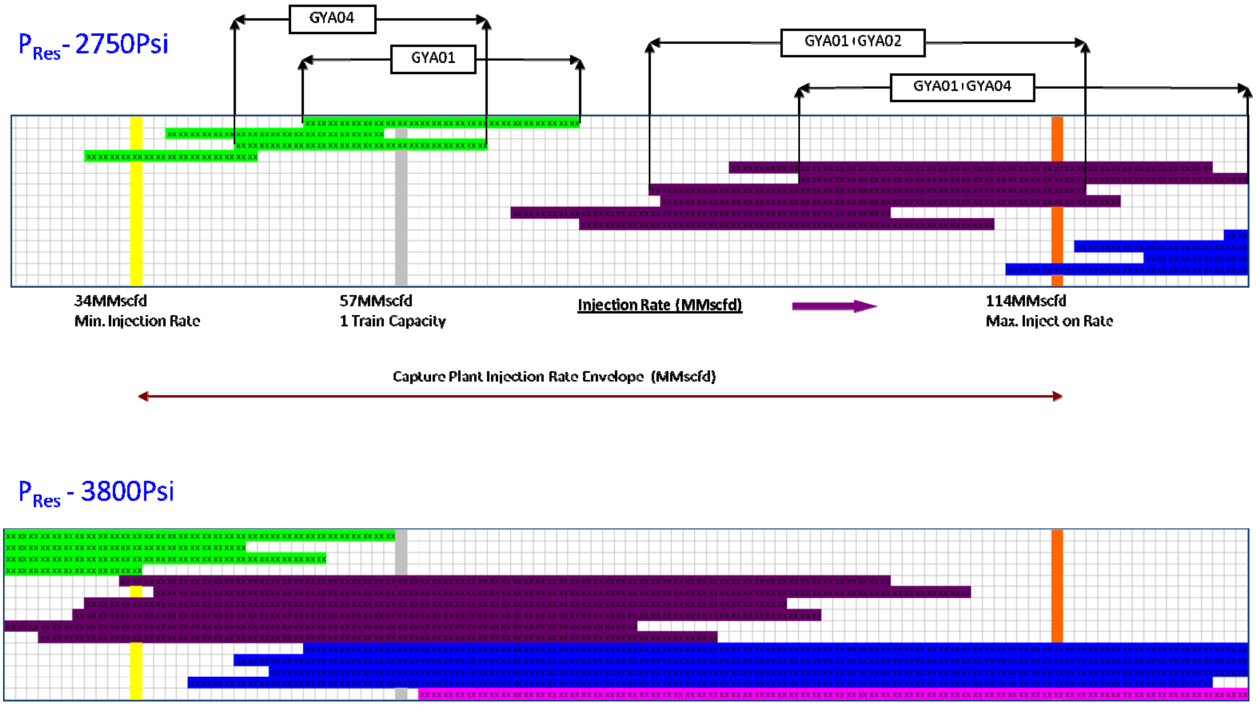

Figure 6.13 Well envelopes at different reservoir pressures.

6.11.2. 'Hot Spot' erosion at the screen level

In the case of injecting under fracturing conditions, there would be limitations related to the erosion of the lower completions (screens / gravel) currently installed in the well. 'Hot spot' erosion of the screens is a potential problem for fracturing conditions as the injected CO_2 is not uniformly distributed in the screens. If fracturing is suspected the recommendation is to limit the injection rate per well within the recommendation to manage the CO_2 by wellhead pressure.

6.11.3. Friction dominated concept

The concept in the wells is to use a friction dominated scenario by high velocities. This concept is used sometimes to restrict production from wells. The concept has been discussed in the industry to overcome the CO_2 Joule Thomson effect but none of them has been implemented.

The bottom hole pressure depends mainly on CO_2 density and tubing friction (back pressure). The CO_2 density / properties remains more or less the same along the tubing length. Once the tubing size is defined, the main factor affecting the friction is the tubing roughness. Different values for steel roughness have been used to derive the frictional losses in the well. The wells will be controlled by wellhead pressure. That is if there is not enough friction then the injection rate should be increased to the minimum pressure value of 45bar - to keep the CO_2 in the dense phase. The other mitigation factor is the overlapping of the different well envelopes.

A maximum velocity in the tubing of 12 m/s has been used in restricting the wells envelope. This value includes a safety factor of 0.75 over the equivalent experience in water injection and gas producing maximum velocities in wells as follows:

The CO_2 in the well will have a high density 900-970 kg/m3 depending on pressure and temperature and it is liquid. The maximum velocity suggested for liquid guidelines APIRP14E or ISO13703 is 4.6 or 5 m/s respectively for continuous service. These guidelines are mainly used in the design and installation of offshore production platform piping systems. Sudden change in flow directions are included in the guidelines. However, the trajectory of Goldeneye wells is smooth enough not to cause changes to flow directions. Well experience across the world has shown that the guidelines are conservative and higher values in velocity are normally used in the industry.

Operators have reported using 10 m/s in water injectors wells completed with carbon steel; the velocity is increased to 17 m/s for a duplex stainless steel or higher alloy.

Similarly 50 m/s under gas hydrocarbon conditions has been used on a continuous basis. This is equivalent to around 16 m/s under CO_2 injection using the C-factor for the ISO 13703 or APIRP14E (see Figure 6.14 below).

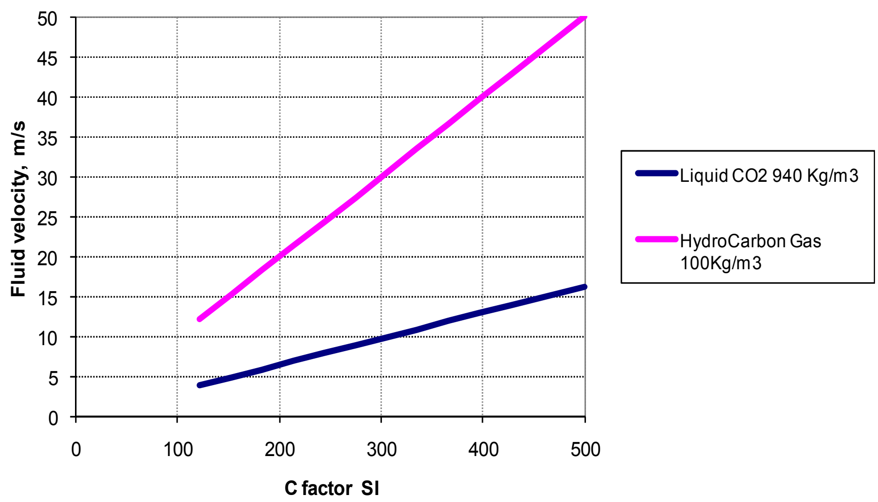

Figure 6.14 C factor comparison (from ISO13703) for CO_2 and hydrocarbon gas.

Furthermore the erosion of the metal is not considered to be an issue. Erosion is not generally a result of surface shear, but is usually a result of repeated, micro- (1) metal deformation or (2) fracture damage as a result of a mass (solid in liquid or gas, liquid in gas) changing direction at a metal surface. No "mass" changing direction equals no erosion.

Flow induced vibration/pulsation are currently investigated by a formal study with a Third Party. Vibration problems are not expected to develop based on experience in water injection wells.

6.11.4. Well integrity

The well materials are suited to the CO_2 injection characteristics if Oxygen is controlled. However, there is always the uncertainty of the long term performance.

The well components are suited to the low temperatures in the steady state and for short term very low temperatures during the transient operations. However, the number of transient cycles are not well characterised. From the wells perspective, the number of cycles needs to be minimised. Experience in cold CO_2 injection wells is not available.

Although the casing hanger is not in contact with the CO_2, it will be subject to close to the minimum transient temperatures resulting in a small chance of casing hanger failure. Casing hanger is designed to operate down to -18°C the predicted minimum transient temperature is -20°C in the CO_2 at the top of the well inside the tubing, and -15°C average tubing temperature.

Current wells were designed for producing hydrocarbons. As such they were not designed to withstand the potentially very low temperatures that would be experienced during a CO_2 blowout. These numbers are calculated to be around -50 to -80 deg C at surface / wellhead area during uncontrolled release of CO_2 at low pressure. Most of the well components are not qualified down to these low temperatures. In the case that wells need to be designed to be able to recover from a blowout scenario then the probably way forward is to re-consider re-drilling the field with new wells.

Tubing leak identification needs to consider all available information. It is proposed to have standard platform annular monitoring. Potential leak identification is augmented by the installation of DTS and PDGs.

The SCSSSV testing will be a lengthy process (20-40hr) to avoid low temperature during the bleed off operation especially at the gas-dense phase interface.

7. Transportation and Injection Facilities

7.1. Introduction

The project aims reuse as much of the existing infrastructure as possible. However the facilities and pipelines were constructed for hydrocarbon production and transport. CO_2 in contrast, has a different phase behaviour, different dispersion characteristics (and hence safety implications), and becomes corrosive when mixed with water. As a result modification have had to be made to facilitate the reuse.

The main reuse components are

- The onshore pipeline – the No. 10 feeder – will transport the CO_2 from the Central Belt to the Blackhill site at St Fergus.
- The offshore pipeline from St Fergus to Goldeneye
- The Goldeneye platform
- The production wells

7.2. Brief overview of the end-to-end chain

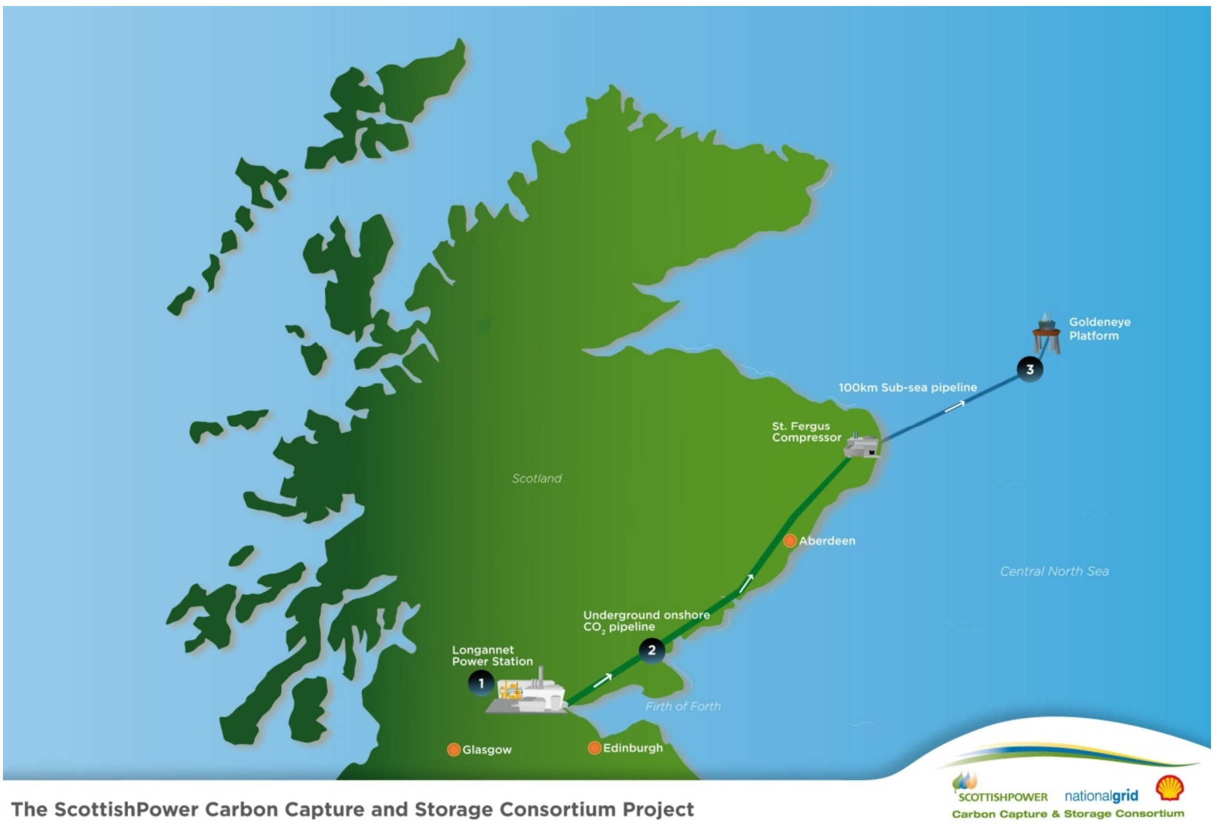

Figure 7.1 End-to-end overview of Carbon Capture and Storage system

CO_2 will be extracted from the flue gas at the Longannet Carbon Capture Plant (CCP). It will then be compressed to around 34bar, passed through a de-oxygenation unit, dehydrated and then transferred to the National Grid pipeline system.

A pig trap will be installed adjacent to the CCP and a 600mm [24in] nominal diameter inter-connecting pipeline approximately 2.2km long will be constructed between the pig trap installation and an Above Ground Installation (AGI) located on the periphery of LPS outside the power station perimeter. A 17km 36in pipeline will be constructed to the existing No. 10 Feeder pipeline. From the No. 10 Feeder pipeline tie-in, the pipeline to St Fergus passes through existing installations at Kirriemuir and Aberdeen, before reaching the National Grid Blackhill Site at St Fergus.

At Blackhill, the CO_2 is compressed to about 125barg, cooled to less than 29°C, metered and then transferred to the Shell-operated Goldeneye pipeline system. A new pig launcher and 1.4km section of 20in pipeline will transfer dense phase CO_2 at pressures up to 120bar to the existing Goldeneye offshore pipeline. The Goldeneye pipeline is 20in [508mm] diameter and runs from the beach at St Fergus to the Goldeneye platform. The 102km long pipeline runs NNE to the Goldeneye Platform that is located in 119m water-depth. The pipeline will normally run in the dense phase i.e. above the CO_2 mixture cricondenbar[14] at circa 73bara.

The Goldeneye Platform is located above the depleted Goldeneye gas condensate field and the facility will be converted to suit CO_2 injection and storage duty. This will involve installation of new pipework, CO_2 filters, flowlines and injection manifolds. All five platform production wells will be converted to CO_2 injection. This will involve changing the upper completion and Xmas trees. The fifth production well will reserved for monitoring duty, but will also serve as a backup injector should another well fail.

The existing vent and closed drains system will be retired and replaced with a number of vent systems to handle pipeline depressuring, thermal relief valve discharges, topsides pipework and vessel vents, a well fluid vent and lubricator vents. The existing MEG delivery system located onshore and offshore and connected by a 102km 4in pipeline will be converted to deliver methanol to the wells for hydrate inhibition during well start-up.

7.3. Existing Facilities

The existing Goldeneye hydrocarbon production facilities consist of a normally unattended wellhead (NUI) platform with five hydrocarbon producing wells tied back via a 101.4km long dedicated 20in diameter multiphase offshore pipeline and a 600m onshore pipeline from the landfall to the Goldeneye processing plant located within the St Fergus terminal. On the platform, the fluids are separated into the gas, condensate and water phases, metered and then recombined. An aqueous MEG and sodium hydroxide solution is added to prevent hydrate formation and act as a corrosion inhibitor. The recombined wet gas condensate stream is then forwarded to St Fergus via the 20in pipeline.

The onshore Goldeneye processing plant within the Shell St Fergus site treats the gas to sales-gas specification and delivers it to National Grid.

[14] This is still near the critical pressure of pure CO_2 (72.8 psig)

7.4. Modification Overview

This section describes the modifications proposed to the existing facilities to enable Goldeneye to be converted to CCS use. The existing Goldeneye hydrocarbon production facilities that are not required for CO_2 service will be decommissioned or retained for other projects.

7.4.1. Onshore

The onshore facilities that will be re-utilised for CCS include:

- Sealine isolation valve (with modifications to its actuation system)
- Beach ESD valve – (This may be retained and refurbished if the onshore pipeline can be protected by HIPPS and not be fully rated to the compressor discharge.)
- MEG System and offshore pipeline: This will be converted for re-use as a methanol-storage and transfer facility. The MEG regeneration system within the plant will no longer be required.

The new onshore facilities will include a new pipeline section between the National Grid Blackhill site and the beach valves. A new pig launcher suitable for launching intelligent pigs will be installed downstream of the National Grid-Shell tie-in point. If the onshore pipeline is required to be fully rated the beach ESD valve will be replaced. An NRV will be installed upstream of the beach ESD valve to minimise the inventory loss were there to be a major onshore leak and facilitate the automatic isolation of the onshore pipeline from the significant offshore pipeline inventory.

The new pipeline section will be equipped with vent systems to accommodate thermal expansion of CO_2 in the offshore pipeline. Facilities to vent and protect the onshore pipeline from overpressure will be provided by National Grid as part of their compressor facilities at Blackhill.

7.4.2. Offshore

The Goldeneye offshore pipeline will be re-used apart from the SSIV assembly adjacent to the platform. The section between the SSIV skid and the riser base will be replaced with 213 barg MAOP-rated spools. The existing NRV acting as the SSIV will be replaced with a new actuated valve. Other modifications to the skid will be made to accommodate the revised duty.

The Goldeneye jacket will be retained with some additional protection applied to critical structural members shielding them from low temperature jets of CO_2 that could result from a failure of the riser. The jacket has some structural redundancy and currently passive fire protection is not provided. Further evaluation will be performed to evaluate whether the risk from cold CO_2 jets is greater than jet fires. If it is, a product has been identified that, if proven by testing, could be used to insulate critical members and protect from material failure caused by low-temperature embrittlement due to impingement of cold jets.

Topsides modifications are summarised as follows:

- The existing pig launcher will be converted to a pig receiver capable of handling intelligent pigs. This will require extension to the pig receiver barrel.
- From the pipeline riser, existing facilities fabricated in duplex stainless steel will be isolated and decommissioned. New stainless steel pipework and equipment will be installed to link the pipeline to the injection manifold.

- A new orifice plate meter will be installed on the pipework to measure the total flow of gas injected into the reservoir.
- A back pressure control valve will control the back pressure in the pipeline so that it operates in the dense phase above the critical pressure of CO_2.
- 2x100% filters will be installed to remove particulates from the well stream
- A new injection manifold will be installed with new flowlines to injection well Christmas trees
- The flowlines will have orifice plate meters installed
- New injection chokes will be installed on the flowlines, remote from the Christmas tree
- A new methanol supply system will connect the existing 4in [102mm] MEG supply line to injection points at the wellhead and upstream of the choke valve.
- The existing vent and drains system will be largely removed to allow space for the new filters
- A new vent system for depressuring the pipeline will be installed and routed up the existing vent tower
- The existing 10in vent stack will be retained and adapted for use in the wellhead vent system
- The wellhead vent system will be installed to allow depressuring of the wells required for SSSV testing
- Several thermal relief valves will be installed on the process pipework and equipment. The discharge of these will be routed below deck.
- Several vents will be installed to allow depressuring of pipelines and equipment. The discharge of the vents will be installed below deck.

7.5. Goldeneye CCS Pipeline System

Figure 7.2 shows a schematic of the pipeline system required to implement Goldeneye CCS.

The existing offshore section of pipeline from the south-east/beach area of the Shell-operated St Fergus Terminal to the SSIV skid 150m from the Goldeneye Platform will be re-used. The SSIV skid will be refurbished with the existing NRV, installed during the hydrocarbon production phase to mitigate the risks of pipeline and riser failure close to the platform, replaced with a new 1500# actuated piggable ball valve that will function as the pipeline Sub-Sea Isolation Valve (SSIV). The MAOP of the pipeline from the SSIV to the Goldeneye Pipeline Riser base will be increased from 132barg to 213barg by replacing pipeline spools between the SSIV skid and the Goldeneye pipeline riser base. This is to prevent overpressure due to thermal expansion of dense phase CO_2 blocked in between the riser ESD valve and the SSIV.

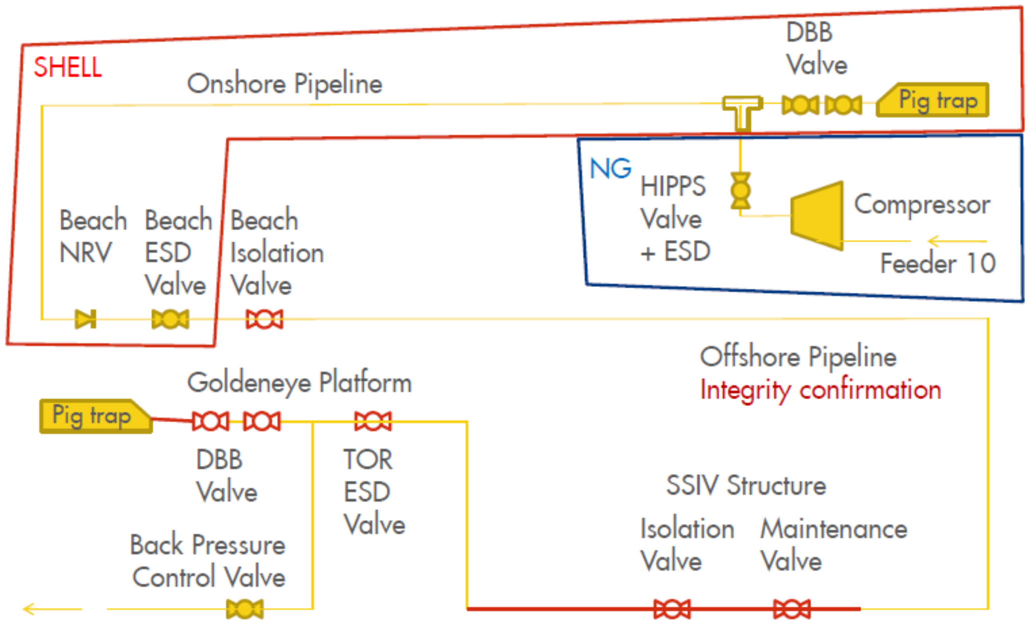

Figure 7.2 Goldeneye CCS pipeline systems.

The new pipeline route has been defined based on the route surveyed in July 2001. The route takes account of the following:

- Proximity of existing pipelines and planned Atlantic Cromarty pipeline.
- Landfall location.

Conversion to CO_2 injection service will not affect the offshore pipeline routing.

7.6. Pipeline Operating Envelope

Hydraulic analysis has been performed to confirm the capacity of the exiting for CO_2 service. This analysis confirms that the 20in pipeline can be used for transporting 250tonne/hr of CO_2 in dense phase.

The MAOP[15] of the existing pipeline system is 132barg. Considering the pipeline elevation profile and change in density (between multi-phase fluid and dense phase CO_2) it was concluded that the maximum inlet pressure of the pipeline is limited to 130barg and the outlet pressure to 129barg maximum.

Steady state simulations for summer and winter conditions have shown that the operating envelope is between 85 and 120barg.

The pipeline can be operated acceptably over the anticipated flow range from 0 to 250tonne/hr. Preliminary analyses have been carried out simulating the transient behaviour of the pipeline system. In absence of compressor curve information, the compressors' throughput has been assumed to be constant. Preliminary calculations have indicated that the sudden closure of an onshore ESD valve creates a negative surge pressure up to ~5bar in the offshore pipeline. In order to prevent phase

[15] Maximum allowable operating pressure

transition and two-phase behaviour along the pipeline and recognizing a vapour pressure of approximately 75bara, it is advised to maintain a minimum back pressure of 85 to 90barg.

Inadvertent closure of the beach valve ESD would result in a very rapid line pack due to the incompressible nature of dense phase CO_2. In order to protect the onshore pipeline fast closing valves are required for an instrumented protection function (IPF)-type overpressure protection system.

Closure of the top of riser ESD or the SSIV will result in a pipeline packing up to MAOP in approximately twelve minutes. This should be ample time for the pipeline pressure protection of the offshore pipeline. Thermal expansion of CO_2 in the pipeline has been evaluated and is discussed in §7.13.

7.7. Dense Phase Transportation of CO_2

The transportation of CO_2 down the Goldeneye pipeline will be in the dense phase, at pressures above the critical pressure of CO_2 (73bara) or cricondenbars of expected CO_2 mixtures (74.1bara). For new build pipelines, the selection of dense-phase transport is straight forward as it is the concept that gives the least pressure drop and allows the use of smaller diameter pipelines leading to lower capital costs. For Goldeneye, where it is proposed to re-use the existing 20in [508mm] pipeline that is oversized, hydraulic considerations allow consideration of other options.

There are four distinct regimes that can be used to transport CO_2. These are illustrated in Figure 7.3.

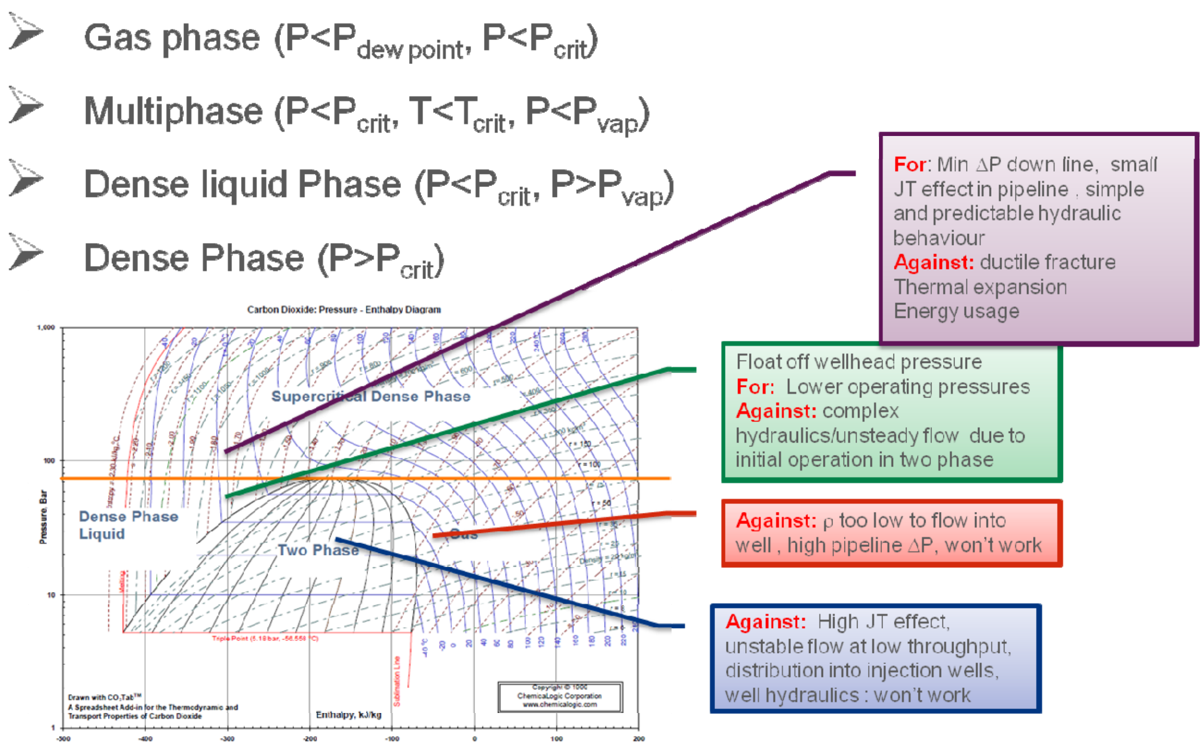

Figure 7.3 Modes of pipeline operation.

Gas phase

This has been de-selected because there would be insufficient pressure to inject into the reservoir. Compression would therefore be required offshore and this is not feasible on the existing Goldeneye Platform.

Notwithstanding the above comments, the pipeline will operate with gas phase CO_2 during initial commissioning, final decommissioning and if the pipeline is required to be depressured during its operational lifetime.

Two Phase

For two-phase flow, the pipeline operates below the critical temperature and pressure and less than the vapour pressure at the operating temperature of the pipeline. Operation of the pipe in two-phase will be required when commissioning, decommissioning and during depressuring.

Dynamic simulations have shown that the flow of CO_2 in two-phase flow conditions is stable at design throughput of 250 tonnes per hour. However, when the flow rate is reduced to 125 tonnes per hour with an inlet temperature of 30ºC the flow becomes unstable with alternating slugs with a period of ~60 hours occurring (Figure 7.4). If, however, the pipeline inlet temperature is reduced to sea temperature, a stable flow regime is attained (Figure 7.5). The reason for the unstable flow is the rapid change of density as the mixture cools from 30ºC to 4ºC. This change is sufficient to cause an imbalance between the flow entering the pipeline and the injected flow resulting cyclical behaviour. Unstable flow would cause temperature cycling of the wells with the concomitant risk of well failure. Reducing the inlet temperature would either require a significant refrigeration or auto-refrigeration to achieve the necessary low temperature.

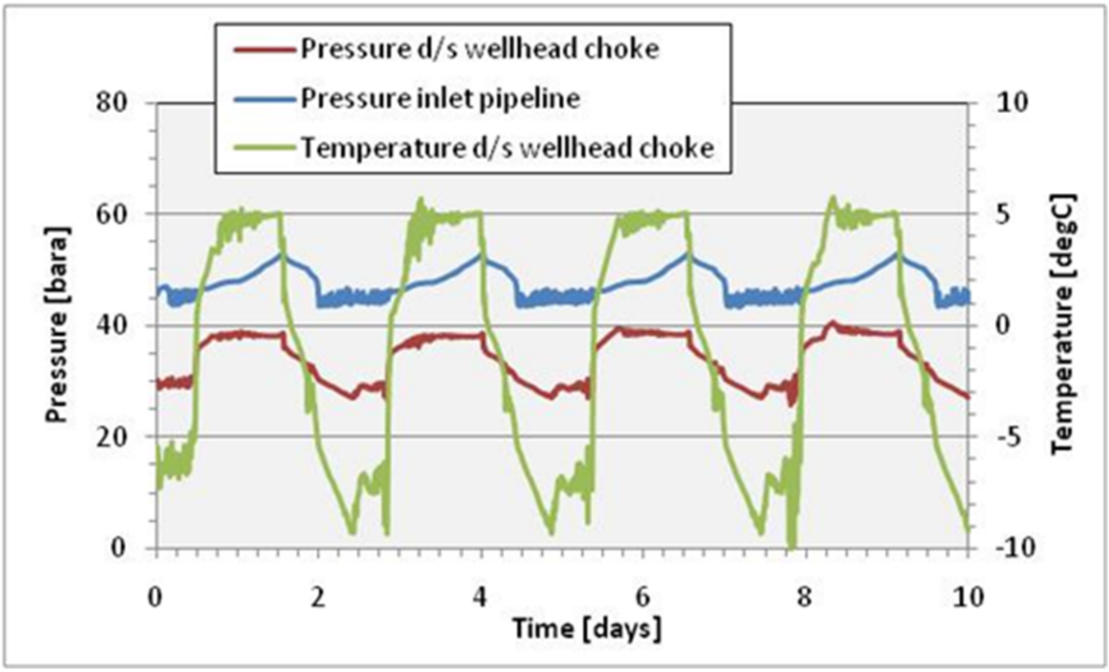

Figure 7.4 Unstable Behaviour: Two Phase at 125 tonnes/hour.

Production fluctuation cycle with a period of about 60 hrs
- Pressure build-up phase with no flow into well (from 44 to 53 bara)

- High flows during period of injection into the well (80-140 MMscf/d)
- Lowest fluid temperature d/s wellhead choke of -14 °C

In general, two-phase operation would not avoid compression or the necessity to recomplete the wells but it *would* lead to complex operating constraints.

Dense Phase Liquid

This involves operating the pipeline at a pressure below the critical pressure but at a pressure below the vapour pressure of CO_2. This could be achieved by compressing the CO_2 to ~126bara cooling to ~44ºC with air coolers and then reducing the pressure to ~50bar/14ºC. The fluid would be two phase but would condense in the pipeline to a dense phase liquid. There would be a similar well and compression requirement to dense phase (i.e. where operating pressure $>P_{critical}$) and would offer no significant advantage apart from reducing the risk of running ductile fracture without the need for refrigeration. This would be due to operation below critical hoop stress levels necessary to for crack propagation in critical regions of the pipe. However, adopting this mode of operation would reduce the operating envelope of the wells, requiring well recompletion when the reservoir pressure increases. This would be extremely costly and hence this option has not been adopted for the Goldeneye Pipeline and facilities. It should be noted though that the upper sections of the injection tubing will effectively operate in this flow regime for a significant part of project life.

Dense Phase Flow

The Goldeneye offshore system will be operated in 'dense phase'. In this context, 'dense phase' implies that the operating pressure is above the fluid critical pressure (or cricondenbar) but below the critical temperature. This will involve operating the pipeline at an inlet pressure of about 120 barg, with an arrival pressure of 115 barg upstream of the topsides pipeline back-pressure control valve.

A minimum of two wells be on line to handle the full flow of 250 m^3/hr. The wellhead chokes will be manually adjusted to attain the required flow rates in each well and the injection manifold pressure will effectively float.

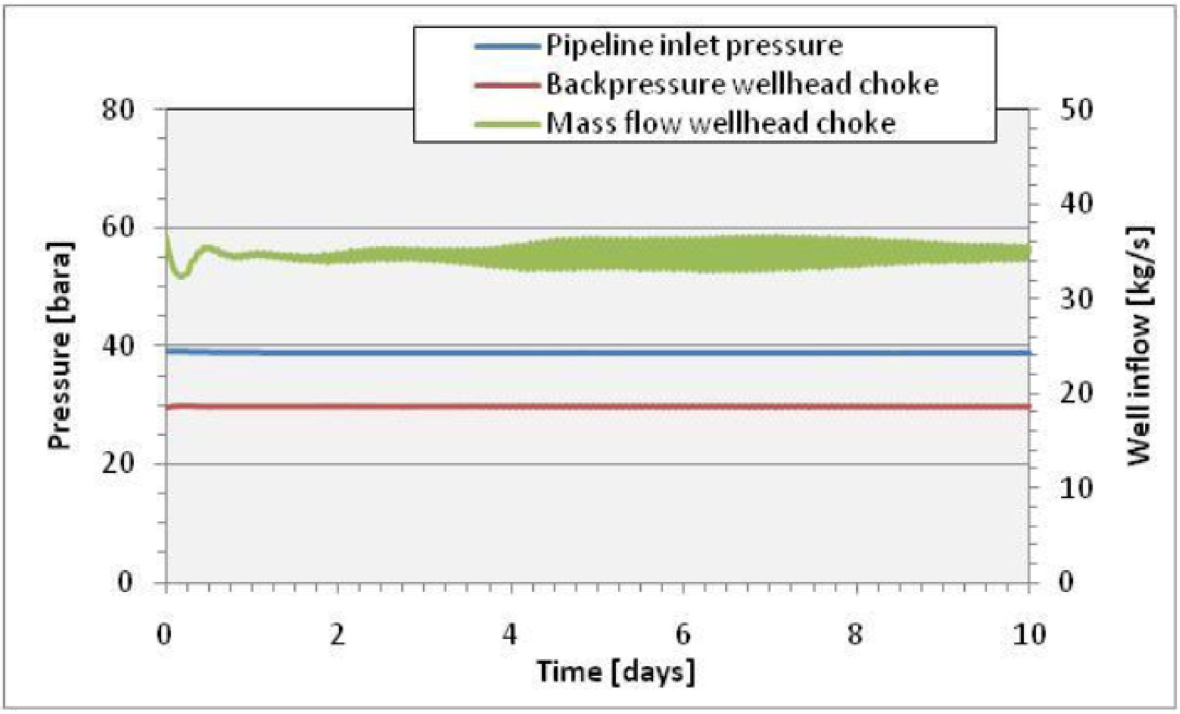

Figure 7.5 Stable behaviour: Two phase at 125 tonnes/hour.

7.8. CO_2 Filtration

There is a risk of blockage of the Lower Completions of the Goldeneye injection wells. In order to avoid costly workovers or re-drilling of wells, the injection fluids are required to exclude particles of larger than 7 microns.

Some coarse filtration will be provided by the riser. However, the velocity of 0.5 m/s will carry particles >35microns topsides and will not be sufficient. Topsides filtration is therefore required upstream of the injection wells. This will be provided by a filter separator.

In order to provide space for a new filtration skid the redundant Vent KO Drum (7815kg) will be removed. The removal of the Vent KO Drum will provide an available space envelope of 6m(L)x3m(W)x6m(H). This is insufficient for the new filtration package. An extension to the cellar deck cantilever platform will provide additional space requirement.

The additional equipment weight should be acceptable assuming that it would weigh approximately 15 to 20 tonnes, however there will need to be local steelwork checks, once the layout is confirmed. A vendor has estimated weight to be 16.2 tonnes (including internals but excluding pipework and valves). Weight constraints may limit the vessels to 2x50% or 1x100%. This needs further evaluation.

7.9. Methanol Injection

7.9.1. Conversion of existing facilities

The existing MEG system will be converted to a Methanol wellhead injection system. The existing system is primarily used for pipeline hydrate and corrosion inhibition. The onshore system currently comprises storage facilities for rich and lean MEG, a MEG regeneration system, injection pumps and a 4in pipeline to the platform. There is also a dedicated drainage system to handle drained MEG and recycle the fluid to the regeneration system. On the platform, the MEG is currently metered and commingled with the export gas before it goes into the pipeline. There are also facilities to inject MEG into the wellheads for cold start-up and equalisation across the riser ESDV.

Modifications will involve the decommissioning of the MEG regeneration system and the two injection points on the topsides associated with ESDV equalisation and pipeline inhibition. The MEG drainage system will be modified to isolate redundant feeds and remove the nitrogen blanket discharges and relief valves from the existing flare.

The MEG pumps, pipeline and lean MEG storage facilities will be retained and converted for methanol use. Methanol is more hazardous than MEG both in terms of its flammability and toxicity so its deployment must be subject to careful review. There are existing methanol facilities at St Fergus and methanol is commonly deployed both onshore and offshore so the changeover should be feasible.

Currently the MEG pipeline is not equipped with an onshore ESD valve and relies on two check valves to prevent back flow from the pipeline. The 102km x 4in pipeline would contain an inventory of some 640 tonnes of high-pressure methanol it is therefore proposed to install an ESD valve in the line onshore to isolate this inventory from the onshore facilities. Unlike the existing system, where MEG is injected continuously, methanol injection will only be required during well start-up – particularly during the initial injection period when Goldeneye Reservoir pressures are low. It is therefore expected that the system will be shut down and isolated for much of the time so adding an isolation valve will improve system safety.

7.9.2. Dosage requirements

It is expected that the requirement for methanol injection will decrease over time as light hydrocarbons and water are flushed from the well by the dry CO_2 and formation around the injection point and the reservoir pressure rises.

During the initial commissioning of a well, the tubing will contain water and light hydrocarbons. These fluids will have a hydrate formation temperature of ~20°C. CO_2 has a hydrate formation temperature of ~10°C.

During initial injection, the temperature downstream of the choke will drop due to Joule-Thompson cooling. The extent of this cooling will depend on tubing-head pressure. When the CO_2 is first injected, the column of gas in the injection tubing will cool and its density will increase leading to an initial *drop* in injection tubing head pressure. As the CO_2 rate is increased, the pressure will rise due to the frictional effect of the tubing that is sized to maintain a single phase in the tubing during steady-state injection. It is assumed that tubing head injection pressures will be maintained above 20 bar during start-up, otherwise the tubing head injection temperatures will drop below -18°C, the current minimum design temperature of the Xmas tree, and the system will trip[16]. As a worst case then, the degree of hydrate suppression required is 38°C for initial CO_2 injection. Based on a preliminary estimate to achieve this level of suppression[17], the concentration of methanol in water should exceed 61% v/v.

For well startup it is calculated that the maximum water volume for the initial injection phase (before injection) is ~18 m^3. This would require a dose of ~28 m^3 methanol to achieve the required level of suppression before CO_2 injection start-up. This would take 7 hours to achieve at a maximum pump rate of 4 m^3/hr.

Continuous injection of methanol will be required until the CO_2 has warmed up and or dried sufficiently in the well bore. Assume the injected CO_2 is saturated by residual water in the injection tubing, and that steady state injection has a minimum temperature of 0ºC at 45 bar in the well bore. The saturation water level at these conditions is ~85,000 ppmw. At an injection rate of 125 tonnes per hour, the associated saturation water rate is 3 kg/s or 10.6 m^3/hr. For a 10ºC hydrate depression (assuming pure CO_2) the required methanol injection rate is ~ 3.5 m^3/hr and is within the capacity of one of the onshore methanol (i.e. ex MEG) pumps. The residence time of the CO_2 in the well will be of the order 15 minutes at full injection rate. To start up two wells for injection at full rate, 64 m^3 methanol is thus required. This will need to be further quantified in detail design.

For initial commissioning, 800 m^3 will be required to fill the pipeline with another 1,000 m^3 required to be stored in the storage tank. CO_2 Composition and Materials

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16 It is likely that the existing Xmas trees will be replaced and the injection tubing will be designed for lower operating temperatures than 18ºC improving the operating envelope for startup and shutdown.

17 This has been estimated from the Nielsen-Bucklin equation quoted in the GPSA Gas Engineering handbook.

7.9.3. Brittle Fracture

Drop weight tear qualification tests (DWTT) were carried out during fabrication of the 20in pipeline to evaluate the risk of a running brittle fracture in the offshore pipeline. The DWTT data show that the line pipe is qualified to a minimum temperature of -20°C for a running brittle fracture.

7.9.4. Inerts and Running Ductile Fracture

Although very unlikely providing proper design and operational measures are applied, fractures can occur in pipelines when a crack occurs at hoop stress levels sufficient to propagate the crack. The fluid in the pipe will depressure through the crack generating a rarefaction wave in the pipe that propagates at sonic velocities down the pipe. For fluids that remain in the gas phase such as methane, the rarefaction wave will propagate at a speed greater than crack propagation speed. The hoop stress on the pipe is relieved by virtue of the rapid loss of pressure and the crack arrests. For fluids such as dense phase CO_2, where isentropic depressurisation leads to entry into the two phase region as the fluid drops below the bubble line, the behaviour of the system is quite different. In this case the energy of the expansion wave is dissipated in the generation of vapour and there is a rapid reduction in sonic velocity. The reduction in sonic velocity is sufficient to reduce it below the ductile crack propagation velocity. As a result, the hoop stress on the crack tip is unrelieved and the crack propagates until other factors, e.g. an increase in pipe wall thickness, reduce the stress sufficiently to reduce the crack.

Analyses have defined a range of operating conditions that will avoid the risk of a running ductile fracture. These safe operating conditions depend on the pipe wall thickness. When the pipeline exhibits a general wall thickness reduction during any period of the design life or e.g. bottom line corrosion over a long distance, there is a limit on the operating condition. On the other hand when the nominal wall thickness is intact and the pipeline has only developed local corrosion patches there is no limit on the operating conditions with respect to running ductile fracture.

For the 15.9 mm wall thickness section of the pipeline there is no risk of a running ductile fracture even if the corrosion allowance has been used. However, for the 14.3 mm wall thickness section (further offshore) there is a risk of running ductile fracture if the corrosion allowance is used us. This imposes a maximum operating temperature limit depending on the water depth and this in turn is sensitive to CO_2 composition, particularly of low levels (<1%) of volatile components such as N_2, H_2 and Ar.

Based on this analysis it has been concluded that a maximum inlet temperature of 29ºC is required to eliminate the risk of running ductile fracture for an inlet composition within the limits specified i.e. 99% mole CO_2, ≤1% H_2+N_2+Ar, ≤0.3% H_2.

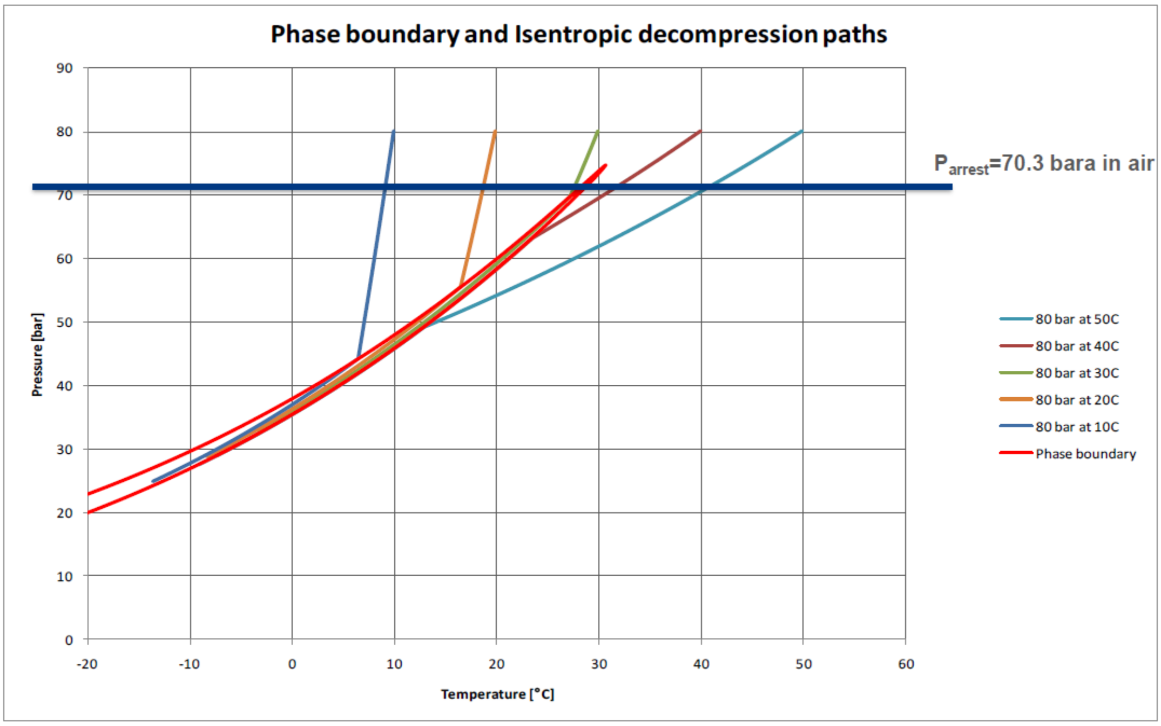


Figure 7.6 Phase boundary and isentropic decompression from 80 bara.

7.9.5. Water and Corrosion of Carbon Steel

The pipelines are constructed from carbon steel. Assuming proper control of the water content of the CO_2, specified at 20 ppmW to avoid formation of free water, a corrosion allowance of 2 mm is adequate to make the carbon steel reach the design life of 20 years. Based on an estimated CO_2 corrosion rate of 10 mm/y, this corrosion allowance is enough to cope with accidental wetting of the steel for 1% of time. In spite of this, presence of free water in the pipeline is unacceptable and it must be operated "dry". The actual corrosion allowance still in place upon cessation of hydrocarbon production needs to be confirmed.

The saturated water content of CO_2 exhibits a minimum between 30 and 40 bar (Figure 7.7). This minimum is calculated to be about 100 ppmW. The water specification for the CO_2 exported from Longannet is specified to be ≤20 ppmW [50 ppmV] to allow a margin for uncertainty as recommended by DNV[18].

There is a small but finite risk of water backflow from the wells. This will be prevented by non-return valves installed topsides and isolation valves to prevent the flow of well fluids during periods when the pipeline is at a lower pressure than tubing head pressures. In general this will not be the case, but if the well becomes filled with light hydrocarbon, the tubing head pressure could be high. Also during an injection hold situation, the contents of the CO_2 pipeline can cool leading to a significant loss of pressure (8 bar/°C).

18 *DnV Recommended Practice DNV-RP-J202, Design and Operation of CO2 Pipelines, April 2010.*

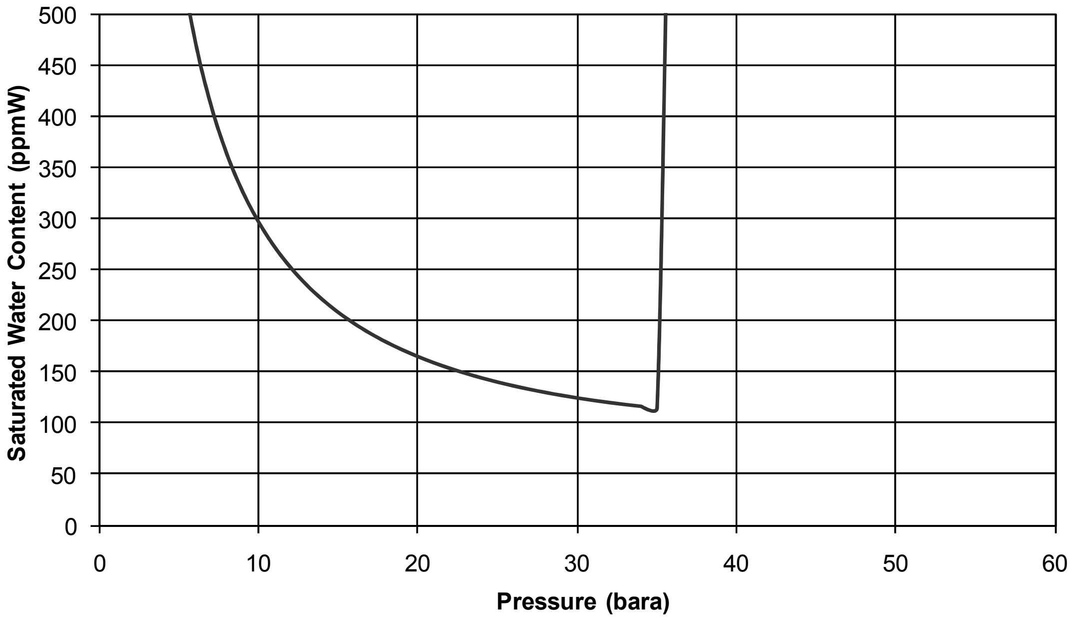


Figure 7.7 Saturated water content of CO_2 at 1ºC.

7.9.6. Oxygen and 13Cr Pitting Corrosion

Oxygen control is required to prevent pitting corrosion of components made of 13Cr in the wells. For Goldeneye CCS the decision has been made to adopt rigorous O_2 control based on Shell Group experience of tubing failures in water injection wells where oxygen levels have been poorly controlled. The difficulties and expense of organising well work-over during injection justify incremental operating and capital expenditure associated with the provision of oxygen removal equipment at Longannet power station.

The O_2 limit for Goldeneye is driven by the presence of 13Cr well completion material, not by carbon steel or other alloys. The corrosion resistance of Inconel (existing Goldeneye production separator liner if re-used) and 22Cr duplex (most of the existing pipework) in oxygen-containing environments is better than that of 13Cr.

Experience with water-injection wells, shows that there is no evidence for pitting-corrosion if O_2 concentrations in water are kept below 10 ppb (by mass).

The partition of O_2 between CO_2 and water has been calculated over a range of tubing conditions from 45 to 310 bara/0 to 85ºC .

The results predict a greater solubility of O_2 in CO_2 compared with water and that O_2 transfers to the aqueous phase as pressure increases.

The methods predict K values as an order of magnitude of ~10^2. For 10 ppb (mass) in the aqueous phase this equates to O_2 concentrations in CO_2 of the order 1 ppm (molar). It is therefore proposed that the design specification of O_2 in CO_2 is 1 ppm (molar/volume).

O_2 levels will be specified below 1 ppmV to prevention of attack of 13Cr steel well tubular. At these levels the contribution of O_2 to carbon steel corrosion is insignificant compared to that of CO_2.

Stainless steels are not immune to pitting in wet conditions in the presence of O_2 and halides (like chloride) but in the absence of halides and at the specified low O_2 level, both 316L and duplex stainless steels are not at risk of pitting. The temperature above which stress-corrosion cracking may occur in a marine environment is 50°C for 316L and 80°C for duplex stainless steel. Both these are above the operating temperatures and the limit for CO_2 transport and injection and stress-corrosion cracking is not a risk.

7.9.7. Non-Metallics

7.9.7.1. Disbonding of Internal Epoxy flow Coating during decompression

The 20in pipeline from St. Fergus to Goldeneye is provided with a "flow coating", intended to prevent corrosion during transport and commissioning. The typical thickness of the epoxy used, Copon EP 2306, is from 40 to 80 micron. No credit is to be taken for the coating against corrosion in service.

7.9.7.1.1. Background information

Experience of using these coatings in gas lines shows that they may last for 30 years if applied properly and are not subjected to mechanical forces. For the present multiphase hydrocarbon service, it is difficult to assess the status with any certainty without an internal inspection. Corrosion by the transported fluids may have affected integrity of the very thin coating. It is to be noted that the girth welds are uncoated and subject to corrosion in any case.

Once the pipeline is opened, a better impression can be obtained of the present coating status. Next to direct local visual observation, it is recommended to perform a boroscopic or remote camera inspection for at least a few pipe lengths. As a minimum, this will reveal if coating is still present.

EP 2306HF, a coating type very similar to the one used for the 20in line, has been subjected to standard qualification tests (API RP 5L2 and ISO 15741) and was fully certified. These tests, however, did not include exposure to high pressure, dense phase CO_2. Even though experience with epoxy in CO_2 service is very positive, there is no unambiguous proof that disbonding will not occur. However, the likelihood of disbonding in dense phase CO_2 service is considered low for typical decompression rates less than 5 bar/min.

It is to be noted that the intelligent pig run to be performed before commencing CO_2 service may potentially cause some damage the coating. This however is not considered a risk for operations since the coating serves no purpose in CO_2 transport and any (small) particles dislodged would be removed in the pigging process or collected later in the filters.

7.9.7.2. Consequence of coating disintegration

If disbonding of the coating occurs, it is likely that the coating will disintegrate into particles with typical sizes related to the coating thickness, up to 100 microns, rather than form larger sheets of epoxy. To avoid impairment of well injectivity, such particles would need to be removed in accordance with the reservoir plugging tendency related to the particle size. While the likelihood of disbonding is considered low, the consequence of reduced injectivity could still justify installing filters to remove particulates. Proof that the coating will not disbond would remove the need for filtering coating particulates although the risk from residual debris in the line would remain.

As an alternative to filtration in case coating would disbond, consideration could be given to up front removal of the coating. However, in view of the aggressive solutions needed to achieve removal, this is not expected to be a practically feasible route.

7.9.8. Valve material compatibility with CO_2

The analysis of valve materials for their suitability in CO_2 service includes all valves in the equipment and facilities discussed in the previous sections, i.e. the complete Shell scope.

The valves in the present Goldeneye hydrocarbon production and transport facilities have originally been selected for hydrocarbon service in specific temperature regimes. This section provides an assessment of the suitability of these valves for CO_2 service. However, only the bigger valves have been considered in detail. Valves up to 2in have been assumed to be uneconomical to refurbish for CO_2 service and are listed for replacement as the default option.

The analysis focuses on the seal replacement only in the context that the physical valves are in good condition. Repairing/overhauling valves assumes that no manufacturing on the valves is necessary and just parts need to be replaced. If the valves are not in good condition, for instance due to erosion, corrosion, pitting or any other forms of defects/deterioration on critical parts/areas, then re-manufacturing is a different scenario (for which only authorized/licensed remanufacturer shops can be used and all work must be compliant with the OEM procedures and quality standards). In this case the economics and lead times need to be re-assessed.

7.9.9. Metallic materials

Metallic valve components are compatible with the future CO_2 operating conditions provided they are not exposed to temperatures lower than their allowable minimum design temperatures. Carbon steel and stainless steels suitable for lower temperatures are generally applied in the valves. Sections with nickel-molybdenum alloys are fully compatible with dense phase CO_2.

While the onshore valves are within piping classes with a lower design temperature of -50°C, the offshore valves are in piping classes to -26°C and the pipeline is rated to -20°C. Nevertheless, most valves are designed to be suitable down to -46°C.

It may be concluded that none of the valves are suitable for temperatures down to the lowest temperature CO_2 could reach upon sublimation, -78°C, but at least their metallic parts will be suitable for CO_2 service down to the intended temperatures as defined by the piping classes.

7.9.10. Non-metallic materials evaluation

The identified failure modes of elastomers in the intended CO_2 service and are shown in Table 7.1. All non-metallic materials used have been reviewed e.g. thermoplastics, elastomers and carbon materials.

Several polymer and elastomer materials used in valve components are potentially suitable for CO_2 service. Earlier studies and field experience have contributed to today's knowledge base. However, specific materials are often qualified according to Norsok M-710. The test conditions of Norsok M-710 (fluid composition, depressurization rates) differ significantly from the envisaged Goldeneye conditions. The detailed knowledge of the effect of dense phase CO_2 on specific products is therefore limited. It is recommended, where generic properties do not provide sufficient confidence for product qualification, to perform testing of the polymeric products that will be exposed to dense phase CO_2, under representative Goldeneye conditions.

Table 7.1 Failure modes of elastomers.

Failure Mode	Comment
Swelling of elastomers	The uptake of molecules in polymeric materials and the degree of swelling strongly depend on the specific combination of polymer and fluid. Polymers that have absorbed gases are subject to the risk of explosive decompression and blistering. With the existing production systems designed for hydrocarbon service, an analysis was performed of the possible interaction between CO_2 and the polymeric materials used in valves as gaskets, packers, seals, etc., in the valves to be retained. Typically the FKM (Viton) elastomers are most at risk
Low temperature elasticity	Elastomers lose flexibility at low temperatures with reduced or failing sealing as a result. In principle, the elastomers installed in the existing valves should be adequate for the corresponding piping class. Their suitability for CO_2 service has been analysed.

Only indicative low temperature limits could be retrieved for the elastomeric seals listed in the material specification lists of the valves. To demonstrate the low temperature properties of seals, suppliers and/or manufacturers will be requested to provide values for the Tg, the TR (TR-10) and/or the brittleness point of each type/grade of the used seals and of possible alternative elastomers.

Suitability of the polymers was evaluated for both piping class service limit temperature ranges and process design temperatures. Use of process design conditions leads to a more realistic and less conservative assessment.

In a general sense, the thermoplasts used for gaskets, seats, packings, spacers, etc., and the carbon materials used for gaskets and packings provide better resistance in the envisaged CO_2 service than the elastomers used for seals and O-rings. Amongst the latter in particular FKM materials (Vitons) are known to have inadequate resistance due to their potentially high swelling rate in CO_2 and also their limited low temperature applicability. In addition, the standard grades of these materials are often not Explosive Decompression resistant.

Alternative materials with better suitability for CO_2 service are PCTFE as a thermoplastic material with a low temperature limit of -200°C and high temperature stability up to 150°C and EPDM as an alternative elastomer. EPDM seals are available as low temperature grades down to -55°C with a high temperature limitation to 150°C. Explosive-decompression resistant EPDM is a good alternative for seals as it shows only little swell in CO_2 and a good low temperature flexibility down to -55°C.

7.9.11. Valve refurbishment

Based on the evaluation of materials properties, valves to be retained have been assessed for refurbishment or replacement. Design process temperatures have been used. The assessment has examined the valve design, including location and function of the non-metallic parts, their possible exposure to dense phase CO_2 and their ease of access for replacing unsuitable components.

All valves listed can potentially be re-used, but will need more or less extensive refurbishment. For some valves this can potentially be done in place but for most valves this will have to take place in shop.

As indicated, seals will need to be replaced in CO_2 compatible materials with resistance to explosive decompression. This mostly concerns the FKM (Viton) seals. Soft seated valves using grades of Nylon will need to be thoroughly checked.

Experience has shown that simple refurbishment of large valves, including testing, could be executed in one week in fabrication facilities.

7.10. Sampling and Metering

This section provides an overview metering requirements within the Shell/Goldeneye scope. The meter details are given in Table 7.2.

Table 7.2 Onshore and offshore metering.

Measurement	Action
Pipeline flow measurement	CO_2 entering the platform will be metered using a new meter run. The new meter run will be configured using an orifice plate with an integrated type flow computer. This new meter will be referred to as the Topsides CO_2 flow meter.
Flow Line Measurement	The existing venturi tubes will be replaced with standard orifice meters with integrated type flow computers.
MEG Metering	Reuse onshore and offshore MEG flow meters for metering Methanol.

7.10.1. Metering System Architecture

The process of CO_2 export from the National Grid facility to the Shell Goldeneye subsea pipeline and on to the sequestration wells is expected to be a dynamic process. Opportunities for line packing CO_2 in the dense phase are limited so the proposed metering system model discounts line pack, line de-packing and pigging scenarios. Pipeline management and leak detection will not be discussed in this section but it will be assumed that all the metering system data can be used as inputs to the system that will be developed during detailed design.

The flow metering system architecture will be arranged such that individual flow computers will network to a Master Flow computer, this will hand off information to the Process control system see Architectural diagram in Figure 7.8.

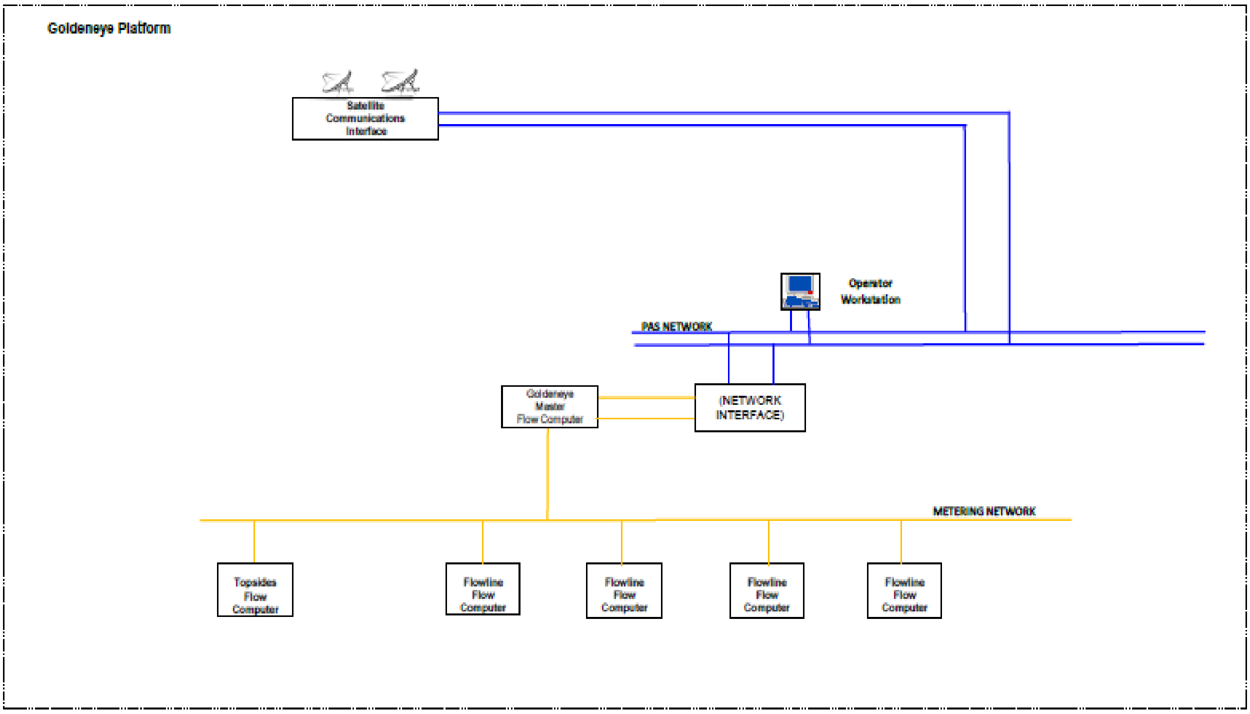


Figure 7.8 Metering architecture.

The system description is based on elements within the Shell Domain information exchanged over the end to end control network is assumed to be of a similar quality to that of the Shell generated data. Figure 7.9 shows the interconnections between the Installation meters and details the meters relevant to the Shell Scope of supply.

Figure 7.9 shows the National Grid meter at St Fergus (M1) this meter is installed in the suction side of the compressor and its adjusted input to the End to End metering system will be the reference point for all Goldeneye metering. The adjusted flow will take into consideration any compressor recycling or venting that may take place within the compressor package e.g. Mass Flow M1 = M1 Mass flow – recycle mass flow- vent mass flow.

The Offshore Goldeneye Metering System will use the adjusted M1 meter mass flow as a baseline for comparing actual flow to the Goldeneye Platform through the data collected by the Goldeneye topsides meter M2. In a continuous stable operating environment it is expected that these meters would provide data that would confirm that what entered the pipeline at St Fergus has arrived on the platform.

Goldeneye individual well mass flow data would be available on the end to end metering system but its primary use is to meter individual well flow for formation management purposes. These meters must also collectively provide information to the Offshore Goldeneye Metering system for comparison to the Topsides Meter M2 e.g. Topsides Mass Flow M2 = Individual Well Mass Flow M2.1+M2.2+M2.3+M2.4.

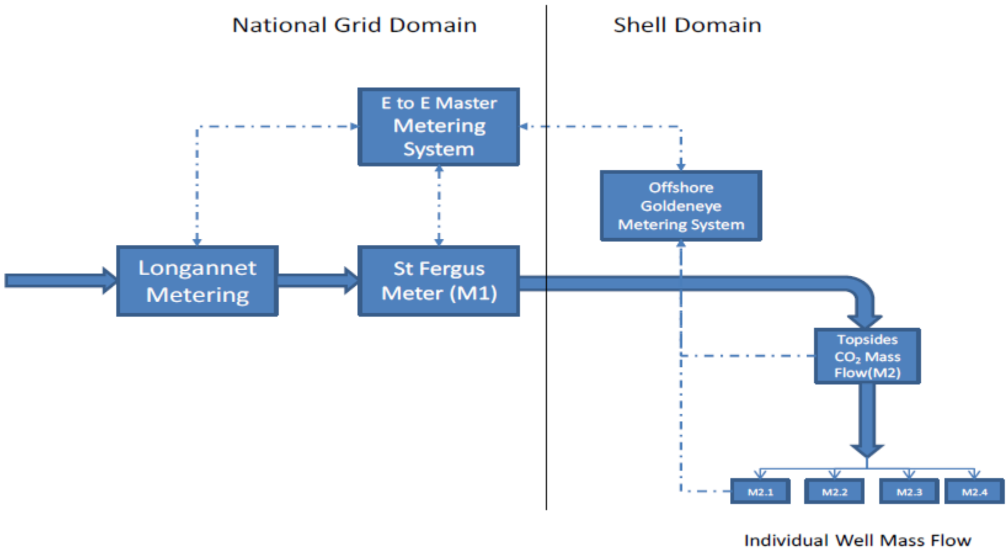


Figure 7.9 **End-to-end metering architecture.**

7.10.2. Compositional Analysis

7.10.2.1. Regulatory Framework and *installation*

The European Parliament has issued legislative requirements regarding Carbon Capture and Storage (CCS). These requirements are contained within the Commission of the European Communities "Directives". The directives contain the requirements for the monitoring and reporting of CO_2, composition at its entry into the pipeline transport system at the point of capture and at points in the transport system where waste or other matter could be added.

The Directives introduce the concept of an "Installation". The requirements for product composition analysis and reporting at the boundaries of installations are also detailed in the directives.

The proposal considers the National Grid Compression and Metering System, and the Goldeneye Platform as part of the same "Installation" for the application of the CCS Directives.

As the National Grid Metering System at Longannet is the same Installation as the Goldeneye Platform, then, the primary location for the analysis of product composition will be at the metering station at Longannet before entry into the transportation system.

7.10.2.2. Product Sampling and Analysis

Product sampling equipment will be installed at strategic points throughout the "Installation". Within the Shell assets temporary analyser(s) will be installed at the St Fergus onshore facility specifically for start-up activities and CO_2 manual sampling points will be installed at both the onshore facility and offshore on the Goldeneye platform.

Manual Sampling Points

Manual sampling points will be strategically placed throughout the Goldeneye onshore and offshore facilities. They will be used for random sampling purposes at predetermined intervals, the interval periods will be defined during detailed design by the interested parties e.g. pipeline management team, formation management team.

Automatic Sampling Points

Where necessary, or in lieu of manual sample points, automatic sampling systems will collect samples on demand or at predetermined intervals.

A sample cylinder will be installed in the sample collection system and when initiated the sample cylinder will be filled with a conditioned product sample.

Start-Up Analyser

H_2O Analyser/s will be specified to monitor the CO_2 product during start-up activities on its passage to the sequestration wells.

Analyser/s installed at St Fergus onshore facility will have accuracy equal to or better that the primary analyser system installed at National Grid at St Fergus.

It is envisaged that these analyser(s) would be used during the initial start-up phase to monitor for residual water left in the pipeline after the drying process and installed both onshore and offshore.

7.11. Goldeneye Pipeline Depressuring

Dynamic simulations of Goldeneye Pipeline depressuring indicate that, if uncontrolled, the pipeline could be chilled to temperatures below -15°C in low spots. This is shown in Figure 7.10.

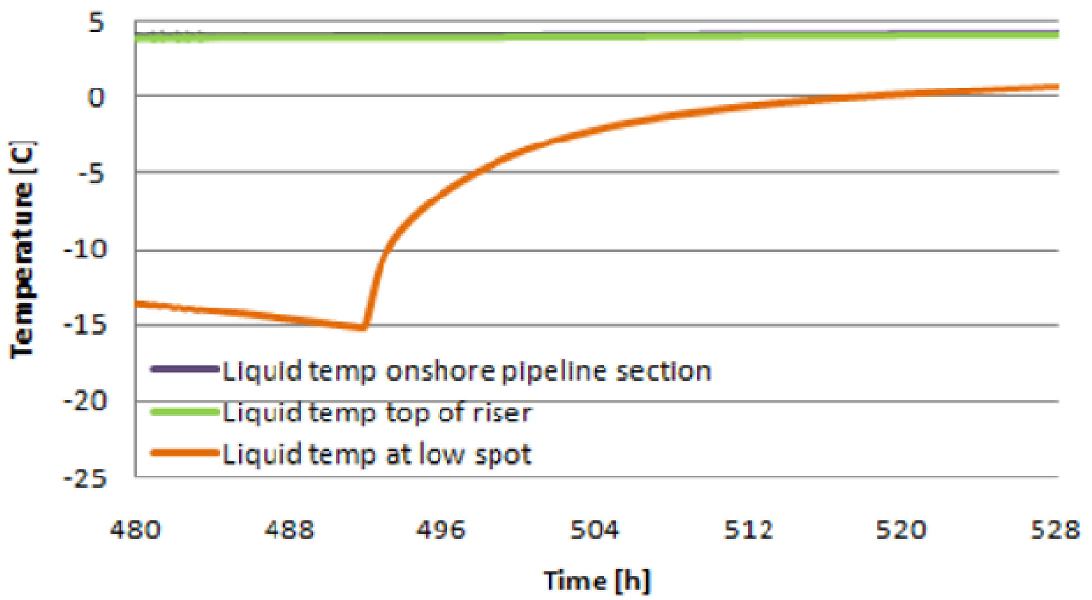


Figure 7.10 Pipeline fluid temperature 480 to 528 hours after depressuring start.

Although the pipeline material is qualified for temperatures down to -20ºC, temperatures below zero could cause local freezing that may increase pipeline buoyancy and cause damage to concrete and other pipeline coatings. Pipeline depressuring therefore needs to be controlled to avoid these risks to integrity. The low temperatures mainly affect low points.

A strategy for depressuring the Goldeneye Pipeline whilst avoiding the problems of low temperatures is illustrated in Figure 7.11.

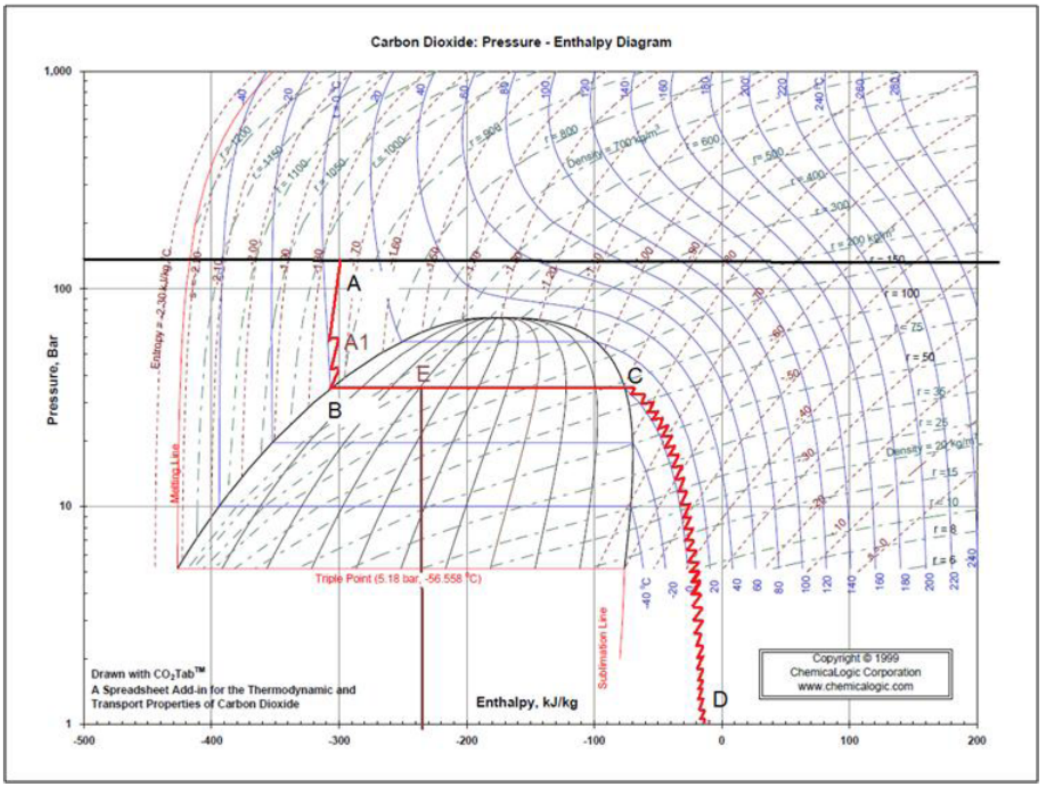


Figure 7.11 Depressuring of Goldeneye pipeline.

Goldeneye pipeline depressuring will be a rare event and performed under carefully controlled conditions on the offshore platform. This will involve disposing of some 20,000 Tonnes of CO_2 with the process expected to take several weeks.

The main constraints on the depressuring process are:

1. Avoiding a cloud of CO_2 that is sufficiently large to interfere with platform systems, pose a threat to personnel on the platform or on nearby vessels, impede helicopter movements and safe platform evacuation and escape.
2. Avoid chilling the pipeline to a level that will cause material damage by exposure to low temperatures and/or thermal stresses and stresses induced by ice formation on pipeline components and in the concrete coating. This will be controlled by carefully programmed pressure reduction of the contents in the pipeline.
3. Avoid precipitating water in the pipeline. This will be controlled by selection of a suitable water content specification for the CO_2 exported from Longannet
4. Avoid blocking the vent pipe-work and pipeline with dry ice. The vent pipe-work will be fully rated but repeated blockage will interrupt and lengthen the process. This will be minimised by controlling the pressures in the vent pipework during the depressuring process.

7.11.1. Design of Vent Systems

This section describes the design of the vent systems. The offshore vent system is required for the following duties in CCS operation:

1 Pipeline depressurisation. This will be CO_2.

2 Topsides maintenance depressurisation. This will be CO_2.

3 Topsides thermal relief valve discharge. This will be CO_2.

4 Venting wells for SSSV testing. This may contain hydrocarbons, water and methanol as well as CO_2.

5 Venting lubricators and other small inventories during well intervention. This may contain hydrocarbons as well as CO_2.

The existing offshore vent system is 150# rated and is not suitable for handling the disposal of dense phase CO_2 for the following reasons:

1 The system is 150# and designed to operate at near atmospheric pressure. Discharge of supercritical dense phase CO_2 into a system below 5.2 bara will result in solid CO_2 formation and blockage.

2 The liquid KO drum is no longer required and the space occupied by it will be used for the installation of filter packages.

The existing vent system apart from the 10in riser up the vent tower will therefore be decommissioned for CCS. The 10in vent riser will be used as a conduit to vent CO_2 from the well depressuring vent system.

7.11.2. Pipeline Depressuring System

Figure 7.12 provides a schematic of the pipeline depressuring system. The system will be fully rated. Depressuring is controlled by a PCV. The vent tip is designed to operate with an upstream pressure greater than 10 bara during the depressuring process. A low pressure alarm is provided to alert the operator to the potential for solids formation. This is to avoid solid CO_2 formation in the vent. The sizing of the orifice is determined by the calculated boil-off rate from the pipeline when the contents are in the two-phase regime. The PCV allows indirect control of the pressure in the pipeline which in turn allows indirect control of pipeline temperature. Should this fail, low pressure alarms and trips will prevent uncontrolled depressurisation. For the final phase of pipeline depressuring, when the pipeline is full of gaseous CO_2, the low temperature trip will need to be bypassed.

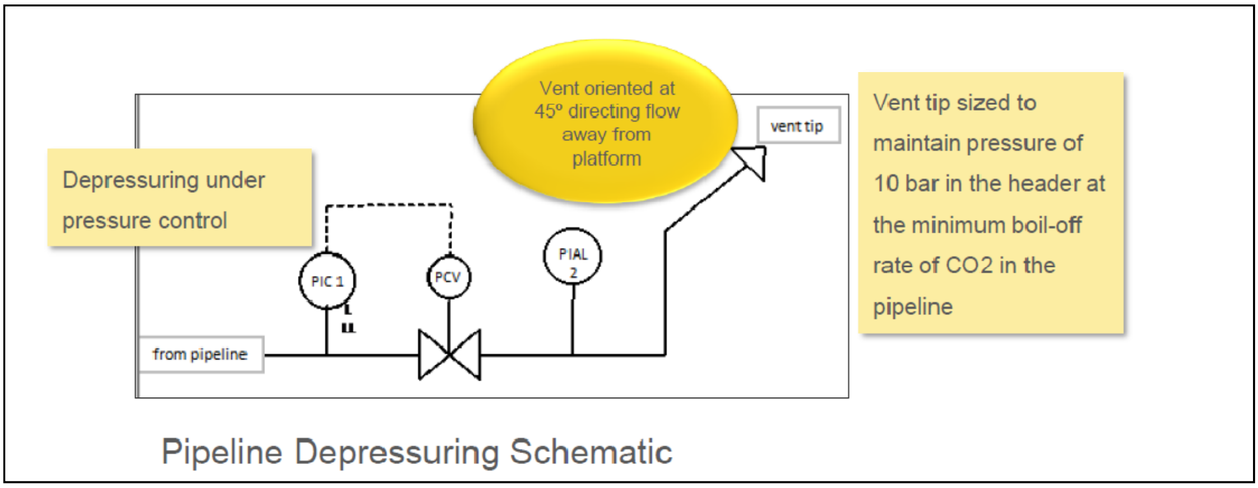


Figure 7.12 Pipeline depressuring vent schematic.

7.11.3. Well Depressuring System

There is a requirement to vent high pressure gas from the wells. This gas may contain hydrocarbons and CO_2. This is required for:

a) Depressuring the lubricator during well work-over operations
b) Depressuring the well tubing above the subsurface safety valve for 6 monthly integrity tests

When the platform is converted to CCS mode, the facility to dispose of liquids via the Goldeneye Pipeline will be removed along with the existing vent system designed for hydrocarbons. The CO_2 vents proposed for the platform are designed to vent dense phase CO_2 without the presence of liquids and hydrocarbons. The proposed wellhead system will allow the safe disposal of small quantities of well fluids using the existing Goldeneye vent stack.

A new depressurising manifold will be used to connect the wellheads to the existing vent stack, through which the vapours from the well head can be discharged to atmosphere.

For a 4.5in tubing, the rate of depressurisation of the production tubing above the Sub Surface Safety Valve (SSSV) has to remain below 0.2 kg/s corresponding to a pressure of 35 bara in order to prevent carry-over of droplets greater than 500 microns from the wellhead tubing to the platform. Similarly, for a 5.5in tubing, such rate must be kept below 0.3 kg/s corresponding to a pressure of 35 bara. Note that the diameter of the tubing is not yet fully defined.

Additionally, it is proposed to modify the base of the stack by installing a boot at its base to collect potential liquid carryover in order to decrease the risk of discharging liquids through the top of the stack. A schematic for the proposed system is shown in Figure 7.13.

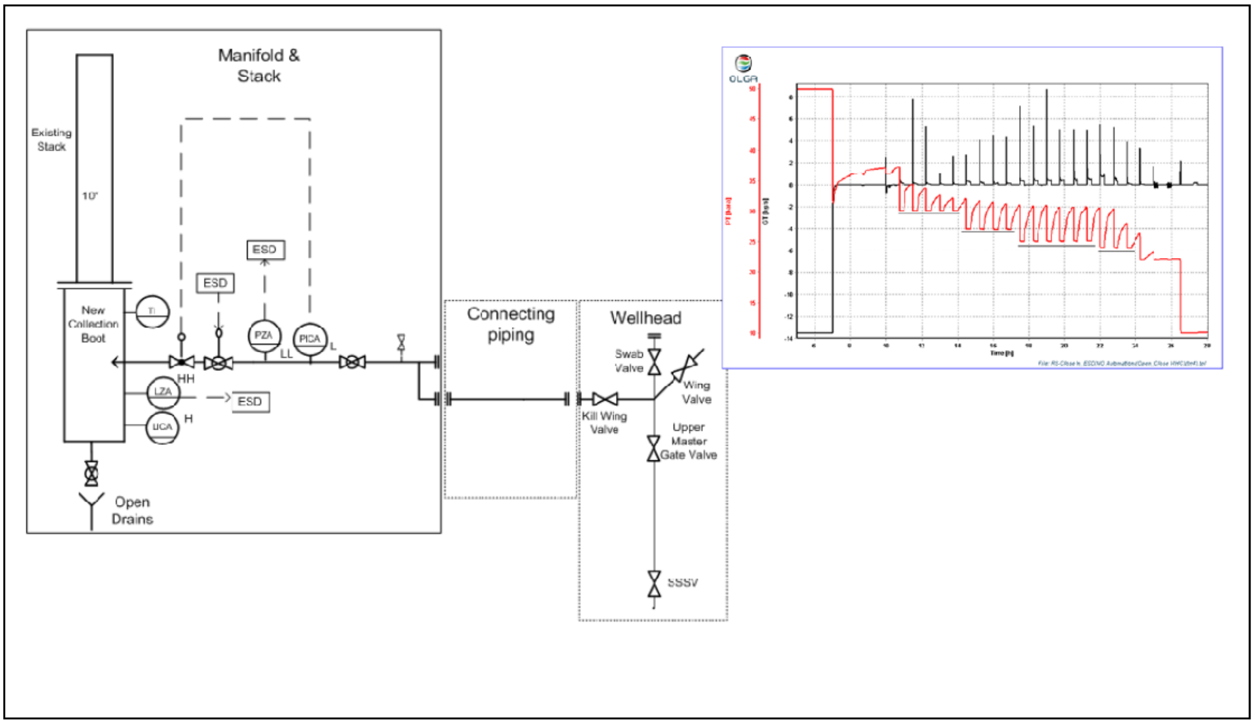


Figure 7.13 **Well vent depressuring system schematic.**

7.11.4. Topsides Process Vent Systems

A number of blocked-in inventories will be provided with relief valves and facilities to manually depressurise pipework and vessels. The issue of thermal expansion of dense phase CO_2 is discussed in §7.13.

Discharges from the relief valves and vents will be routed below deck. Initial modelling of dispersion from the under deck discharges has indicated that the plumes will disperse adequately (§7.11.5).

Each thermal relief valve will be equipped with a bursting disc upstream. This eliminates fugitive emissions and allows the detection of a thermal relief event by means of a pressure indicator installed between the bursting disc and relief valve.

Each vent valve and relief valve has its own separate vent. This ensures adequate isolation from other high pressure vent discharges when performing maintenance activities on individual vents. Discharging the vents below the platform ensures that the discharges are self draining thereby reducing the risk of ice blockage. It also avoids the construction of multiple discharge lines up the vent tower.

7.11.5. Vent Dispersion

Studies have been performed to validate the design for the vent systems. The general criterion adopted for the design of process vents has been that personnel or critical platform equipment (diesel generators, HVAC intakes etc) should not be exposed to more than 0.5% CO_2.

7.12. CO_2 Exposure Limits

Carbon dioxide content in fresh air varies between 0.03% [300 ppm] and 0.06% [600 ppm], depending upon the location. A person's exhaled breath is approximately 4.5% carbon dioxide by volume. It is dangerous when inhaled in high concentrations (greater than 7% by volume or 70,000 ppm) over a few minutes. The maximum safe level for infants, children, the elderly and individuals with cardio-pulmonary health issues is significantly less.

At very high concentrations, CO_2 acts primarily as a simple asphyxiant by displacing oxygen from air. In addition to the risk of asphyxiation, the inhalation of high concentrations of CO_2 can also lower the acidity (pH) level of the blood and trigger effects on the respiratory, cardiovascular and central nervous systems. Published information includes categorisation of Dangerous Toxic Loads (DTL) of CO_2 based upon percentage concentration and exposure duration.

The acute health effects of high concentrations of inhaled CO_2 are given in Table 7.3.

7.12.1. CO_2 Design Concentration Limits

For the end-to-end CCS chain the following CO_2 concentration design limits will apply:

(a) 5,000 ppm / 0.5% v/v:
The concentration limit during venting operations to which personnel on CCS sites, adjacent sites, members of the public and livestock are subject. However the short term limit for members of the workforce that can rapidly evacuate from the immediate area is 15,000 ppm / 1.5%v/v.

(b) 15,000 ppm / 1.5% v/v:
The short term limit for members of the workforce that can rapidly evacuate from the immediate area. The concentration at which an alarm shall be actuated at permanently and temporarily manned sites for evacuation (muster at a safe location) or mandatory use of suitable breathing apparatus. Management procedures shall be put in place to limit further exposure of personnel to CO_2 so as not to exceed the permitted total dose for the applicable duration. However consideration should be given for any gas detection in plant areas at a fraction of STEL by setting an alarm setting at (UK 8 hr OEL) 5000 ppm value.

Greater CO_2 levels e.g. NIOSH IDLH (40000 ppm) could be tolerated as an emergency limit for plant areas. This would cover secondary grades of release such as pressure relief, flange and seal leaks and inadvertent use of vent / drain valves. Higher CO_2 levels than this in plant areas should be reviewed against the UK HSE Dangerous Toxic Loads."

7.12.2. Personal Monitors

Personal monitors where used should have a low alarm limit of 5,000 ppm / 0.5% v/v and a high alarm limit of 15,000 ppm / 1.5% v/v.

7.12.3. Low Temperature Effects

Low temperatures can be experienced during expansion / pressure reduction of vapour and dense phase CO_2 and also for solid CO_2. Measures shall be taken to minimise the risk of cryogenic burns to personnel during all commissioning, operating and maintenance activities.

Table 7.3 Acute health effects of high concentrations of inhaled CO_2.

Acute Health Effects of High Concentrations of Inhaled CO_2		
CO_2 Concentration in Air (% v/v)	Exposure	Effects on Humans
17 – 30	Within 1 minute	Loss of controlled and purposeful activity, unconsciousness, convulsions, coma, death
>10 – 15	1 minute to several minutes	Dizziness, drowsiness, severe muscle twitching, unconsciousness
7 – 10	Few minutes	Unconsciousness, near unconsciousness
	1.5 minutes to 1 hour	Headache, increased heart rate, shortness of breath, dizziness, sweating, rapid breathing
6	1 - 2 minutes ≤ 16 minutes Several hours	Hearing and visual disturbances Headache, difficult breathing (dyspnoea) Tremors
4 – 5	Within a few minutes	Headache, dizziness, increased blood pressure, uncomfortable breathing (Equivalent to concentrations expired by humans)
3	1 hour	Mild headache, sweating and difficult breathing at rest
2	Several hours	Headache, difficult breathing upon mild exertion
0.5 – 1	**8 hours**	**Acceptable occupational hazard level**

Reference: Recommended Practice DNV-RP-J202 "Design and Operation of CO_2 Pipelines", April 2010, Table 3-3

7.13. Thermal Expansion

Dense phase CO_2 has an expansion coefficient significantly higher than other liquids handled in the oil and gas industry. Figure 7.15 shows the values of thermal expansion coefficient over a range of pressures and temperatures of interest. These values can be compared to the value for water, $0.88.10^{-4}/°C$, and oil, $6.4.10^{-4}/°C$.

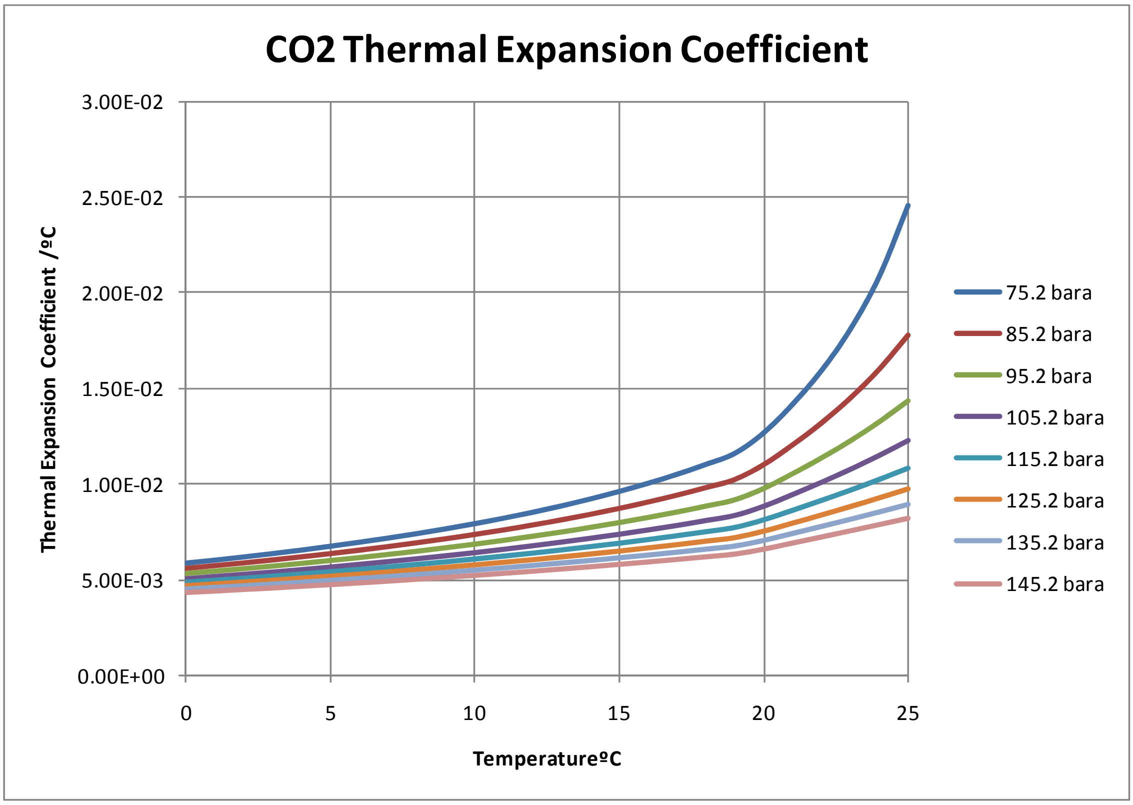


Figure 7.14 Dense phase CO_2 expansion coefficients.

This property drives many important decisions on this project, including the provision of thermal relief valves for blocked inventories and the replacement of pipe spools between the new SSIV and the riser base. Figure 7.15 shows the impact of thermal expansion on pipeline design. For a blocked-in inventory the rate of pressure rise is 7.8 bar/ºC. This gives a pressure rise of 54.6 bar for the annual range of sea temperatures (4-11ºC). A pipeline blocked in at a pressure of 78 barg and 4ºC will exceed MAOP (132 barg) when the sea temperature rises to 11ºC.

The reverse effect is seen when the pipeline is shut in as shown by simulations. Figure 7.16 shows the pipeline pressure and temperature profile immediately after shut-in and 84 hours after. The pipeline contents have cooled from the inlet temperature of 20ºC to ambient sea temperature and the pipeline pressure profile drops from ~113 bar to ~90 bar over most of its length.

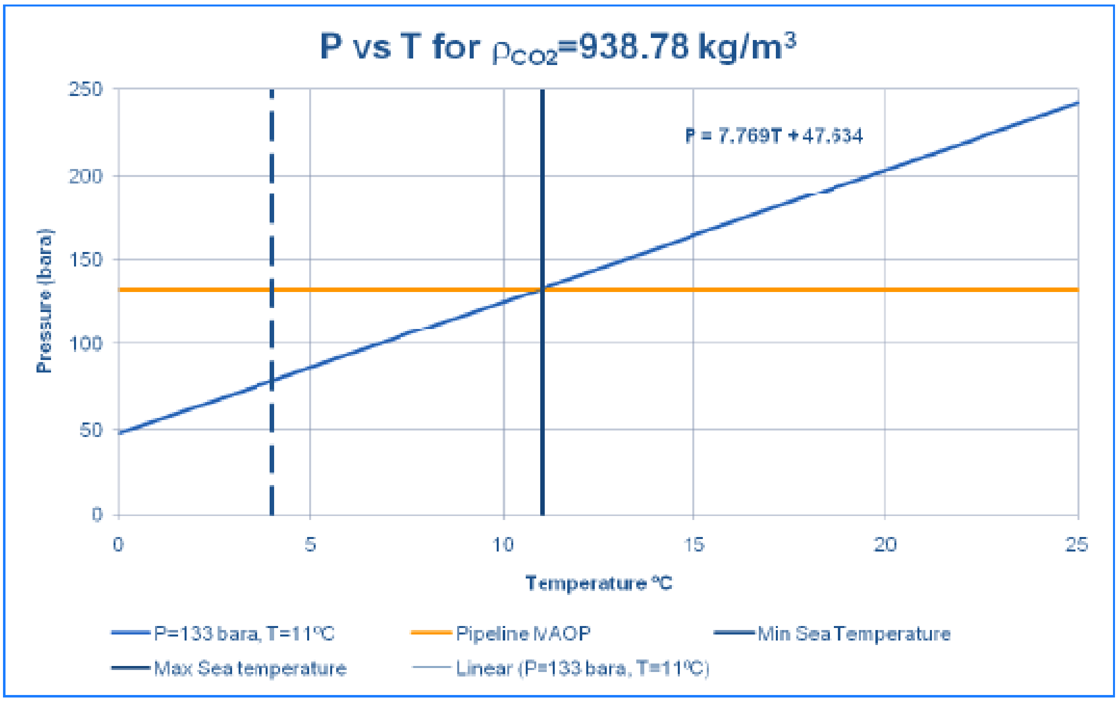


Figure 7.15 Graph showing pressure rise of dense phase CO_2 with temperature.

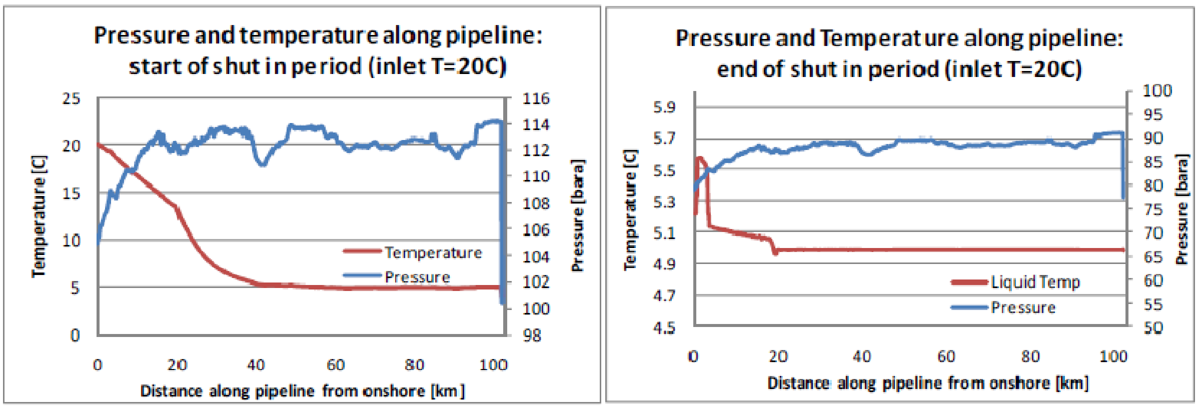


Figure 7.16 Pipeline pressure profile after shut in.

7.14. Structural

The original design of the Goldeneye platform was based on a 20 year design life. It is now intended to operate the facility until approximately 26 years after installation i.e. change of design life to 30 years. It is concluded that the original design environmental data with a return period of 100 years does not require to be changed for the increased service life.

Review of the as-built condition has revealed that only 5x30in conductors have been installed and that the 1x14in future riser is also yet to be installed. It is intended to use the existing 20in gas export riser for importing the CO_2 to the platform so the environmental loading will be less than allowed for in the design. It is therefore concluded that the current substructure in-place analysis has conservatism within the current modelling and that the actual jacket member and joint utilisations are expected to be lower than reported.

Figure 7.17 Goldeneye platform.

The jacket design allowed for a total topsides load of 2000 tonnes. Review of the current weight report shows that the actual operating weight (excluding laydown loads) is about 1662 tonnes and about 1350 tonnes if the topsides future load is also excluded. This leaves a reasonable margin for additional topsides loads by reducing the laydown capacity.

The maximum utilisation of the foundation capacity for the existing operating design loads is about 0.97, which is less than the allowable value of 1.0.

The jacket inspection reports from 2005, 2007, 2008 and 2010 have been reviewed and no significant structural anomalies have been identified that would raise major concerns about the structural capacity of the jacket.

The high level assessment of CO_2 has identified two potential failure mechanisms of the jacket structure. These are member failure from erosion and member failure caused by rapid cooling leading to non-ductile behaviour and brittle fracture.

Although unlikely, the possibility of structural failure from section loss due to erosion by solid particles of CO_2 may arise. It is considered that this failure mechanism would occur gradually as the section erodes and stresses in the nett section increase. It is not considered to be a major hazard and mitigation should be possible. The potential hazard to the conductors is less than that to the adjacent jacket leg. Further studies should be performed to better define the likelihood of this failure mechanism occurring before deciding what action is required.

The low temperature effect of a large CO_2 release is potentially a greater risk than any erosion as it could locally cause a rapid complete failure of a structural member.

It is considered that the consequence of a possible CO_2 release as defined will not initiate an overall progressive collapse of the structure although localised member failure may occur. However, it is recommended that further heat flow calculations are carried out during detailed design to identify whether it is likely that the CO_2 release would be able to reduce the steel test temperature below that which ductile behaviour can be assured. Should the heat flow calculation, previously mentioned, show non-ductile behaviour then it is recommended that further material investigations be performed using fracture mechanics to better identify the risk of occurrence of brittle fracture under the loading regime in jacket leg A2.

Two additional possible consequences of a CO_2 release from different locations have been identified and it is recommended that further study be performed in this area. One of these, a CO_2 release from topsides piping, has been assessed. The other, a subsea release, requires further study to identify if it is a realistic hazard scenario.

In conclusion it is considered that for the in-place operating and extreme loading conditions the Goldeneye substructure is capable of supporting the conversion to CO_2 injection.

8. Site containment

8.1. Introduction

The Goldeneye store has a competent and extensive caprock that has contained gas for around fifty million years. Above the caprock there are approximately 750m of low permeability chalk formations followed by a succession of approximately 700m of sandstones and mudstones beneath the secondary and tertiary seals to the complex – the Lista and Dornoch mudstones. These formations are overlain by more interbedded sands and silts that will provide a baffle to CO_2 movement.

The field has very few well penetrations (five production wells and four exploration and appraisal wells) and the status of these and of the penetrations in neighbouring areas is known. All penetrations in the storage complex that penetrate the Captain sandstone have competent cement plug abandonments at this level.

There is limited evidence of faulting in the overburden, and no faults have been identified that penetrate both the storage and complex seals. None of the faults in the storage complex are critically stressed. Data on the position and intensity of earthquakes in the North Sea shows the area in the vicinity of Goldeneye to be seismically low-active.

Geomechanical assessment of the caprock has shown that re-pressurisation does not fracture the rock, while geochemical modelling has shown that the acidic fluids created by the CO_2 injection do not perforate the caprock or cemented fractures. A coupled geochemical/geomechanical experiment on the reservoir rock has shown that the strength does not decrease upon interaction with these acidic fluids even when the calcite cement is dissolved.

Assessment of monitoring feasibility shows that migration of CO_2 outside the store can be detected using time-lapse seismic.

On the whole there are a significant number of barriers to leakage from the storage site.

8.2. Structure

This chapter provides an assessment of the containment provided by the Goldeneye storage complex. The following sections of this chapter discuss the potential factors that can affect the integrity of the storage site, and the key risks to containment.

8.3. Primary Containment

Demonstrating containment is the key element in CO_2 storage. The Goldeneye storage complex has a number of positive supporting factors to suggest that containment is at low risk. The primary containment will be provided by the structural trap of the Goldeneye field. This is a structure that has proven over a period of 50 million years to be a competent storage site for an estimated 750 Bscf of gas (containing 0.4% CO_2).

The components of the containment are described in the chapter on site description (§3.7, starting p22) and are illustrated by Figure 8.1.

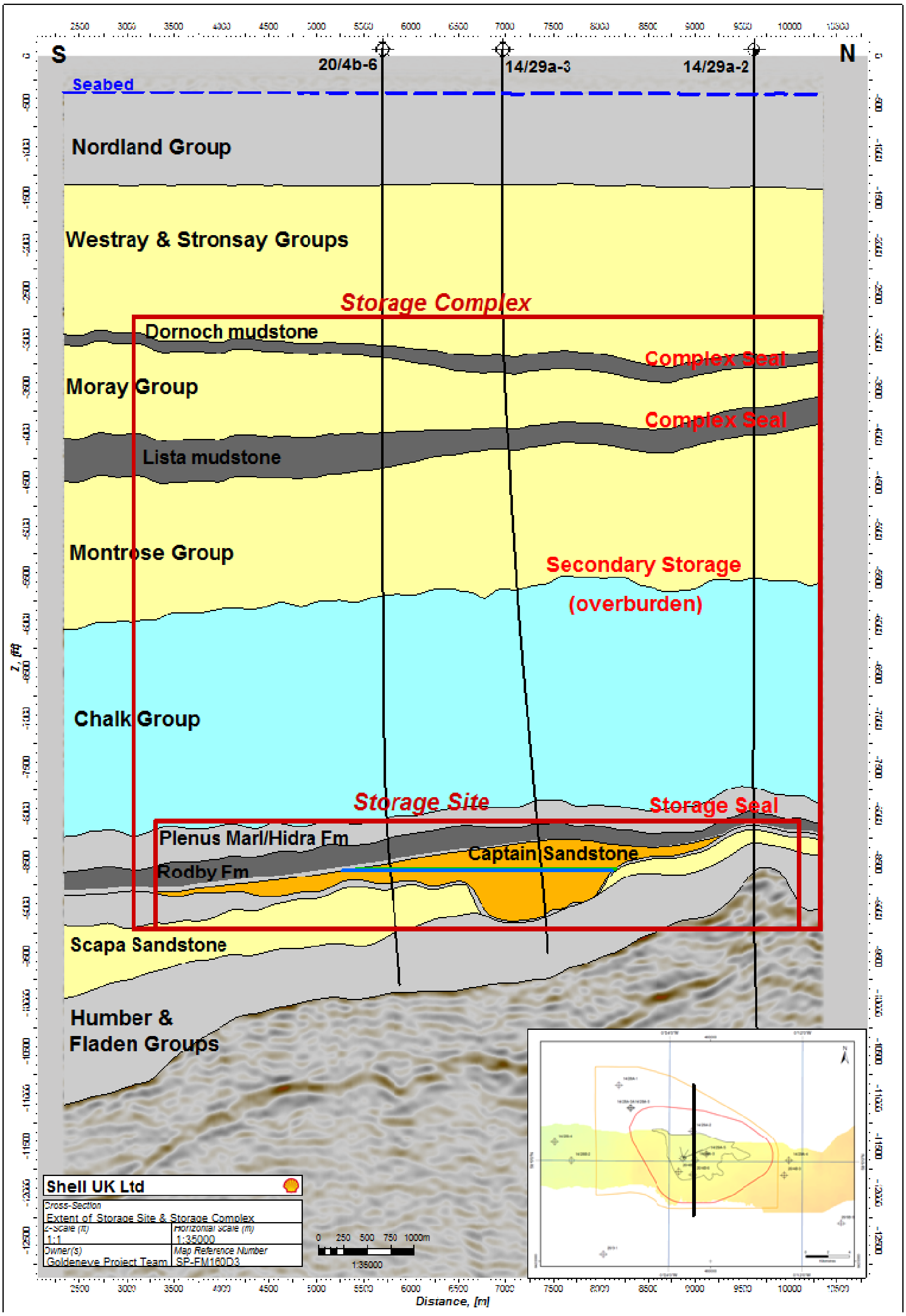


Figure 8.1 **Cross section to indicate the vertical (subsurface) extent of the *storage site* and *storage complex.***

8.4. Factors affecting the integrity of the storage site

There are several factors that can potentially reduce the integrity of the storage site. These can either weaken the caprock itself to allow CO_2 to migrate slowly through the seal or, can create leak paths that bypass the seal entirely. CO_2 can also potentially migrate laterally from the storage site along the Captain aquifer, or through juxtapositions with the underburden stratigraphy.

The following factors that can impact on the containment of CO_2 were identified as a result of a Bowtie risk assessment and are discussed below.

- Acidic fluids
- Diffusion of CO_2
- Stress of injection
- Lateral migration
- Faults and fractures
- Abandoned wells
- Injection wells

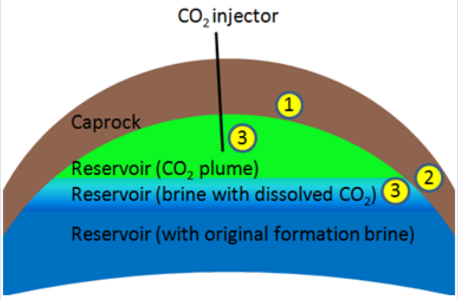
8.4.1. Acidic fluids (chemical reactive transport)

A study was performed to assess the impact of the changes in composition of the formation brine due to dissolution of CO_2, during CO_2 storage (see the Geochemical reactivity report[19]). As CO_2 dissolves, the bicarbonate (HCO_3^-) concentration increases and the pH decreases. This brings the brine out of equilibrium with respect to the various minerals that make up the reservoir and cap rock, leading to dissolution of some minerals and precipitation of others. For Goldeneye, some of these changes may have occurred already, due to the presence of 0.4% CO_2 in the hydrocarbon gas. Nevertheless, the storage leads to much higher CO_2 exposure than the reservoir has been exposed to before, and so dissolution and precipitation processes are expected to occur. The main results are summarised in Table 8.1.

Figure 8.2 shows an example of the results for the caprock showing the mineralogical changes over time (log-scale). It shows a slight porosity decrease owing to the overbalance of precipitation with respect to dissolution.

[19] Shell 2010, Geochemical Reactivity Report

Table 8.1 Overview of the main results. The numbers in the graph refer to key regions of the reservoir and caprock exposed to CO_2

	Region	Description	Conclusion
	1	Caprock exposed to CO_2 plume	CO_2 diffuses over a distance of 50-75 m in 10,000 years. Caprock alterations possible within this distance. Alterations tend to decrease porosity. Therefore low risk of induced leakage.
	2	Caprock exposed to formation brine with dissolved CO_2	Mostly same as above. Some dissolution is possible in any calcite rich features running through the caprock, but only over a small distance at their base (less than 33 cm in 10,000 years). Low risk of induced leakage.
	3	Reservoir within and close to CO_2 plume	Permeability decrease possible during injection period but unlikely to have significant impact on injectivity. Potential for a large CO_2 mineralisation in optimistic scenario. Dissolution storage relatively low (14% of injected CO_2 after 10,000 years).

8.4.2. Diffusion of CO_2

The chemical reactive transport study has shown that the CO_2 takes 10,000 years to diffuse between 50-75m. As the caprock is over 150m thick, this risk is negligible.

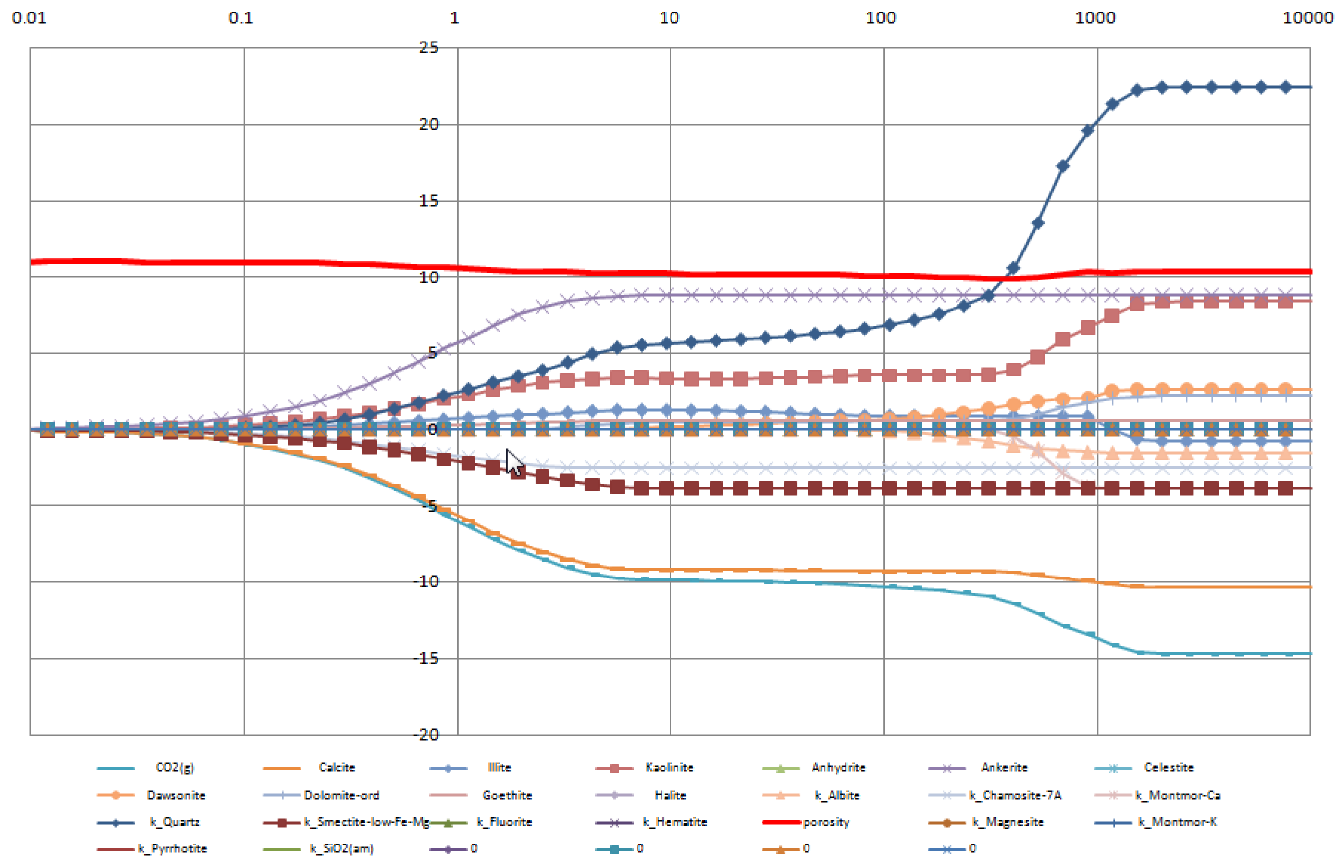


Figure 8.2 **Mineralogical changes in caprock (full set of minerals). The horizontal axis shows time (in years), the vertical axis changes in mineral abundance (mol/kgW) and porosity (%).**

8.4.3. Stress of injection

During production (of hydrocarbons), and subsequent injection of CO_2, the stress state both inside and outside the reservoir are or will be changed. A geomechanical appraisal of the Goldeneye structure was carried out to simulate injection scenarios and assess the geomechanical threats to the integrity of the storage site. There is no risk of shear or tensile failure in the reservoir or tensile failure in the caprock as during injection (assuming formation temperature), the reservoir will not be repressurised above the initial virgin pressure of 3778 psia [260.5bara] at a datum of 8507' [2593m] TVDSS. For an injection pressure of 24.4MPa [3538psia] the shear capacity utilization of the caprock is 0.92. A slightly higher injection pressure leads to slightly higher stresses in the caprock, where the pressure is not changing. As a consequence, fracturing becomes less likely.

A detailed study on the coupled effects of temperature and pore pressure in the caprock close to the wellbore also showed no risk of failure. This result is applicable for vertical wells only – further investigation is being performed into the effect on deviated wells. In some end member cases the cooling effect of the cold injection fluid reduces the strength of the cap rock to below the injection pressure. In these cases a fracture could propagate from the reservoir into the cap rock. This fracture would cease when it encounters warmer rock, however, the tip of the fracture has the potential to remain cold. The interaction of the back stress from the formation, the thermal diffusion rate, and the magnitude of cooling will determine the maximum extent of fracture penetration into the cap rock. *This interaction was identified as a result of the FEED study and is still under investigation.*

Fault slip reactivation was studied in the same rigorous manner as the integrity. For every fault, the slip-tendency was investigated by calculating the shear capacity for all the three stress stages (before production, after production/before injection and after injection). No fault-slip is expected to occur. Even the worst case scenario was not significantly close to slip. This conclusion is based on the assumption that the initial stress state of the faults, before depletion or injection, is the same as the initial stress sate of the surrounding rock. Assessment showed that that the faults are not critically stressed as a result of hydrocarbon extraction and subsequent CO_2 injection. This result implies that if faults are currently not leaking (which they are unlikely to be, given that a gas field was present) then they are extremely unlikely to start leaking as a result of CO_2 injection.

8.4.4. Lateral migration

CO_2 can also migrate laterally from the storage site. Movement to the west and east could occur by migration along the Captain aquifer, and to the north and south through juxtapositions with the underburden stratigraphy.

Each direction will be discussed separately below. Secondary migration – *i.e.*, lateral migration above the storage seal – will be discussed in §8.4.4.5.

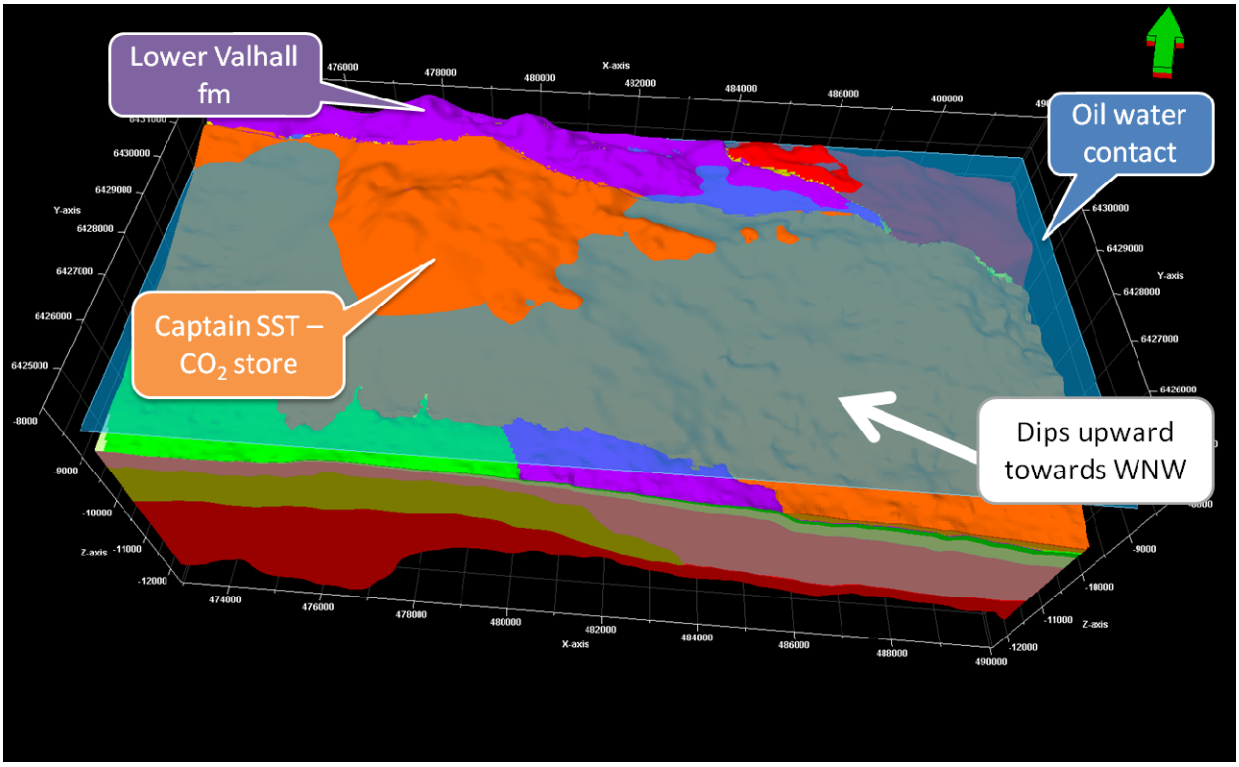


Figure 8.3 The Goldeneye structure.

8.4.4.1. Up-dip westerly migration in the Captain Sandstone Member

The potential for up dip migration along the C7aptain aquifer is discussed in detail in the CO_2 Storage Estimate report and the Dynamic Modelling output report. The Captain aquifer is interpreted to extend over 100km running west to east along the southern margins of the Halibut Horst and South Halibut Shelf. The spill point of the Goldeneye closure is in the northwest corner of the structure, at the original hydrocarbon water contact 8592' [2168m] TVDSS.

The risk of migration under the spill point is controlled by several factors relating to the distance of injection from the spill point and the rate of movement of the CO_2 front. The CO_2 Storage Estimate report shows that there is sufficient capacity in the storage site to store over 20 Million tonnes of CO_2. This leaves a significant storage buffer. Dynamic and analytical modelling has been performed (see Dynamic Modelling output report) simulating injection of 20 Million tonnes of CO_2 and in none of the scenarios did CO_2 migrate under the spill point. Because we are only partially refilling the available voidage space with CO_2, the risk of migration of CO_2 from the structural closure is limited.

As CO_2 is injected, it is possible for it to flow below the original hydrocarbon contact. The viscous forces associated with injection can create a Dietz tongue (see Dynamic Modelling output report for a description), as shown in Figure 8.4.

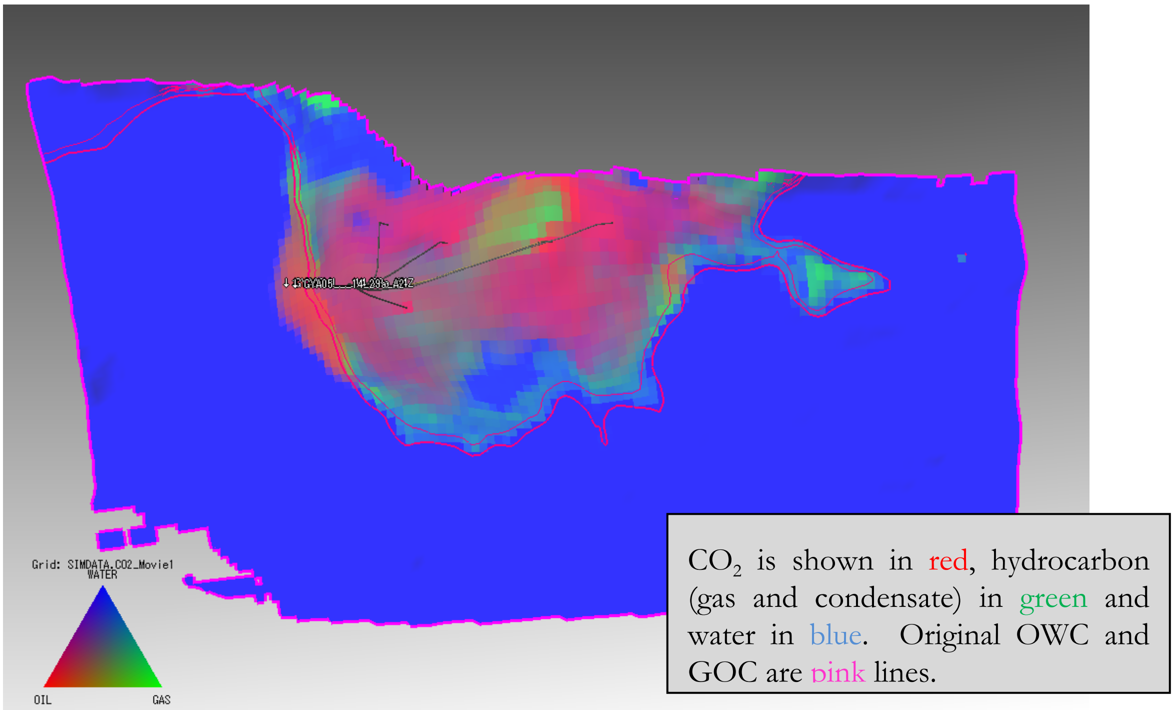


Figure 8.4 FFM3.1: Extent of CO_2 plume at top Captain D, at end of injection (2025) showing the Dietz tongue on the western flank of the field.

In the unlikely event that CO_2 were to migrate under the spill point it would be contained in the Captain sandstone aquifer under the store caprock of the Upper Valhall, Rødby, Hidra and Plenus Marl. The CO_2 would then be trapped by capillary forces, dissolution and geochemical reactivity.

8.4.4.2. Down-dip easterly migration in the Captain Sandstone Member

Down-dip migration takes place through two different mechanisms. A Dietz tongue can occur in a similar fashion to that observed in Figure 8.4 in the up-dip direction. The second mechanism is gravity flow associated with dissolved CO_2. Figure 8.5 shows the process of CO_2 dissolution over

10,000 years in a simplified structure model while Figure 8.6 and Figure 8.7 show the CO_2 dissolution and the pH with geochemical reactivity taken into account. When CO_2 dissolves in water it creates HCO_3^- and CO_3^{2-} ions and protons (H^+). The dissolved CO_2 and additional ions increase the density of the water, making it sink relative to pure water. With the addition of dissolved mineral species in the water, additional ionic species are also formed. However, the result is the same and the density is increased.

When geochemical reactions take place the acidity (and activity) of the carbonic acid is eventually neutralised and the plume loses its corrosive ability. It should be noted that there is considerable uncertainty on the timescale of the geochemical reactions. Figure 8.6 represents a fast reactivity case. The expected distance of the dissolved plume migration lies between the no reactivity case (Figure 8.5) and the high reactivity case (Figure 8.6 and Figure 8.7). As this down dip migration is will result in dissolution trapping (complemented in the long term by geochemical trapping) it is not a risk to the project.

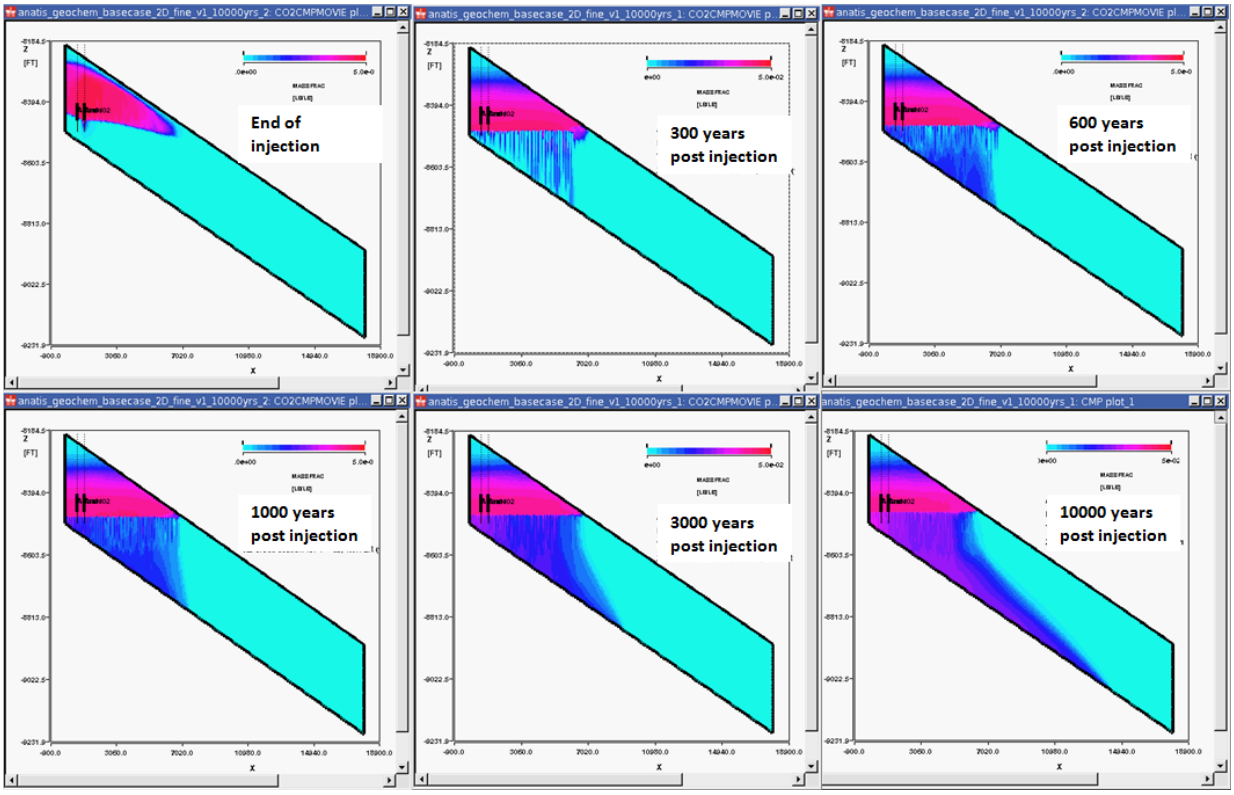


Figure 8.5 **Movement of dissolved CO_2 through time (no geochemical reaction modelling). Colour scale runs from 0 to 0.05 (mass fraction).**

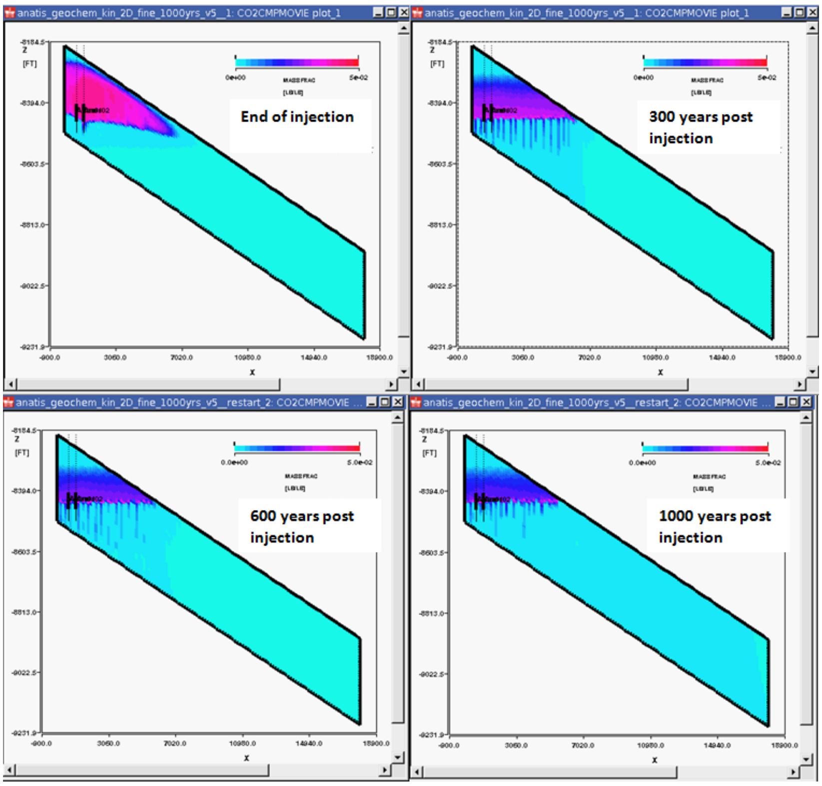


Figure 8.6 Movement of dissolved CO_2 through time (geochemical reaction modelling incorporated). Colour scale runs from 0 to 0.05 (mass fraction).

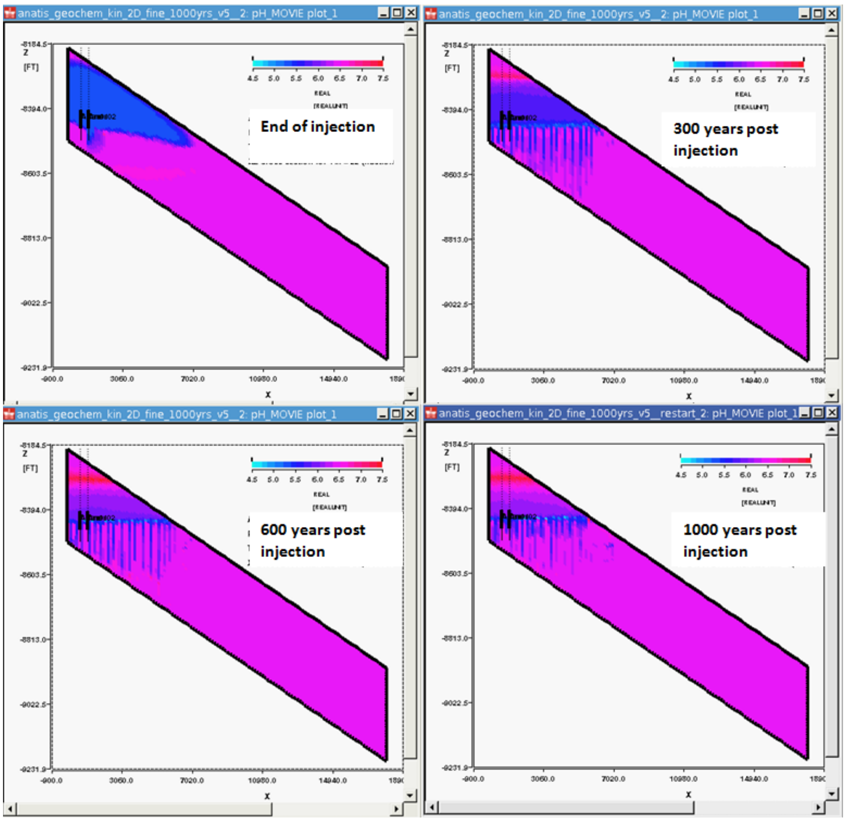


Figure 8.7 pH evolution through time. Colour scale runs from pH 4.0 to 7.5.

8.4.4.3. Northerly migration into the underburden

The Captain sandstone reservoir pinches out on to the rotated fault block to the north, forming the northerly component to the hydrocarbon trap. However, the combination of stratigraphic overstep and erosion means that there is the potential for juxtaposition of the Captain Sandstone Member with the Scapa Sandstone Member, which underlies the field. This is shown in more detail in Figure 8.8 which shows cross-sections through the reservoir section of the overburden model. The Scapa Sandstone and Yawl Sandstone Members of the Lower Valhall Formation have been included within the defined storage site to take account of this potential juxtaposition. However, it is important to note that no hydrocarbons have been encountered in the Yawl or Scapa Sandstone Members and no pressure connection has been proven. In addition, the seismic evidence for juxtaposition is equivocal (compare image C with image D in Figure 8.8, which show two equally valid seismic interpretations – the former showing Captain sands juxtaposed with Scapa sands above the hydrocarbon contact and the latter showing the connection below). The rotated fault block to the north of the Goldeneye field was drilled by well 14/29a-2 and found no hydrocarbons in the cemented Scapa sands.

The conclusion of this analysis is that there is no communication between Captain Sandstone Member and any other porous medium in the area of the field. The *storage seal* extends with significant thickness beyond the mapped extent of the Scapa and Yawl Sandstone Members. A more detailed discussion can be found in the Static model (overburden) report.

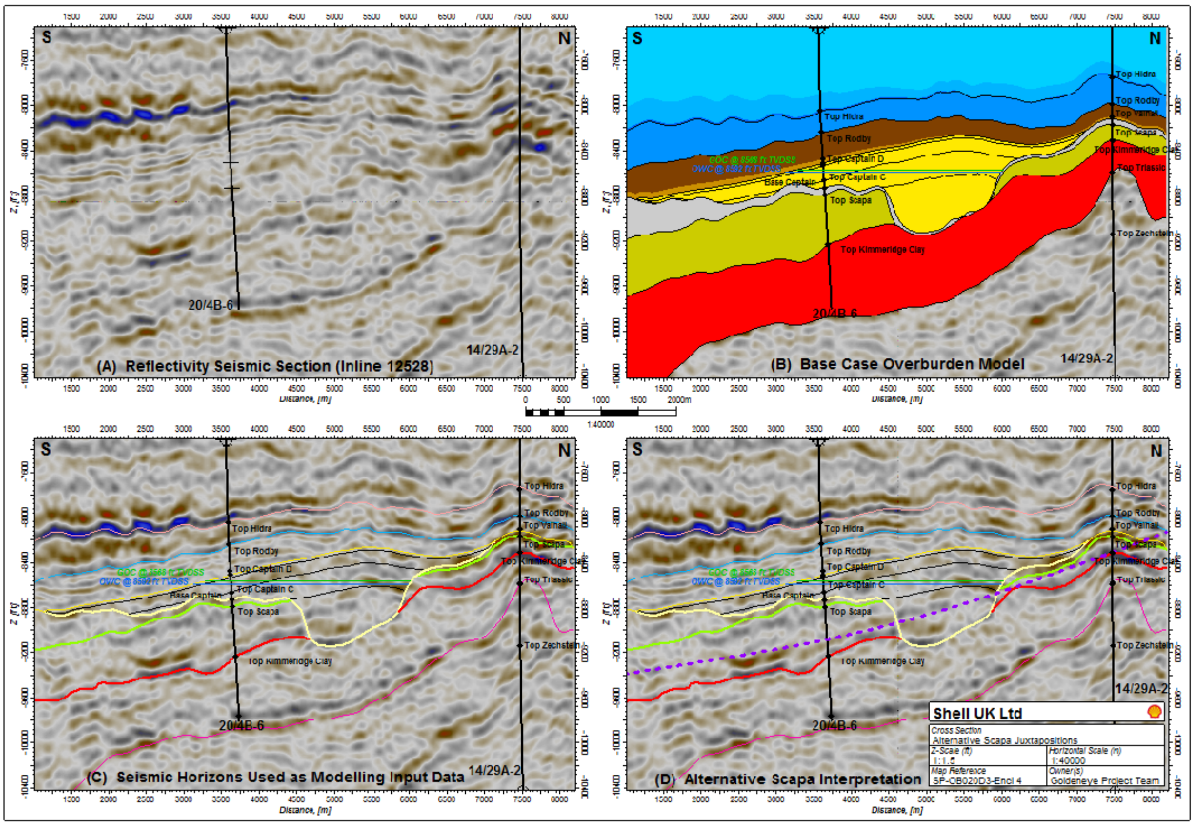


Figure 8.8 Potential juxtapositions between Captain Sandstone and Scapa Sandstone Members (north-south section between wells 14/29a-2 and 20/4b-6). Apparent continuity of (grey) Lower Valhall mudstone beneath Goldeneye field in (B) is an artefact of the modelling programme used and does not represent geological reality.

8.4.4.4. Southerly migration into the underburden

The Captain Sandstone Member also pinches out in a southerly direction, though this occurs beyond the original field boundary. For the CO_2 to migrate in this direction, similar processes have to take place as described in the down-dip migrations section (§8.4.4.2). Connectivity also has to exist to the Scapa or other permeable unit. This is assessed as unlikely, based on interpretation of available seismic and wireline log data. Additionally, no pressure support from the south was required to achieve a history match in the dynamic modelling.

8.4.4.5. Secondary migration in the Mey and Dornoch Sandstones

If CO_2 bypasses the storage seal – *e.g.*, through well bores or faults – it is expected to migrate into shallower, permeable formations beneath the complex seal of the Lista and Dornoch mudstones. These include the low permeability Chalk Group and the interbedded sandstones and mudstones of the Montrose Group (including the Balmoral and Mey sandstones) and the lower part of the Moray Group (Lower Dornoch sandstone). Any CO_2 reaching the base of the Lista mudstone is expected to migrate in the direction of the regional dip (west to northwest) until it is trapped by local structure, capillary, dissolution or chemical trapping. The Lista Formation is interpreted to crop out at the seabed over 150km to the west of Goldeneye, within the Inner Moray Firth.

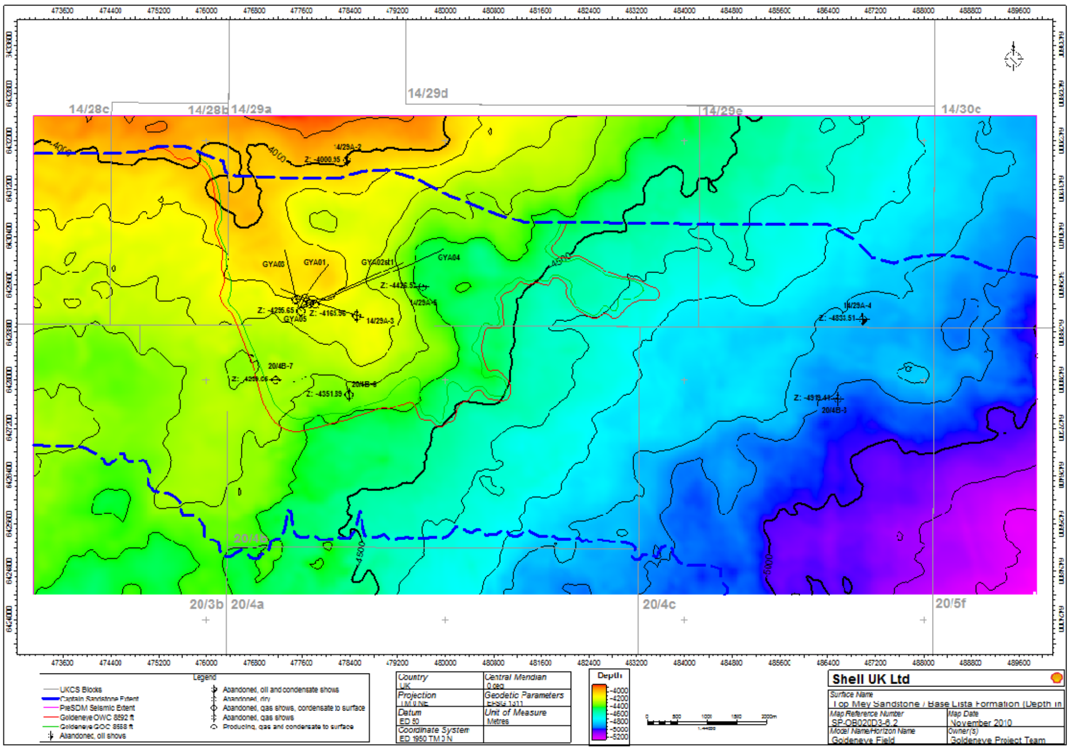


Figure 8.9 Base Lista Formation /top Mey Sandstone Member depth map [in feet].

8.4.5. Faults and fractures

Faults and fractures can potentially provide natural leak paths through the overburden lithologies that can reduce the integrity of the storage complex. As a result, a detailed study was undertaken to review the extent of faulting in the overburden interval above the Goldeneye field. The key conclusions of this work are as follows:

- No faults have been identified that cross both storage seal and complex seal.

- The fault pattern at the storage seal parallels the observed regional structural trends, orientated WNW-ESE to E-W. Faulting is relatively minor, with faults of only limited vertical and lateral extent, and small throws. Any faults propagating up through the reservoir from deeper horizons appear to have little or no throw.
- Faults within the Chalk Group trend NW to SE and are mainly developed over the eastern and south-eastern flank of the field. These faults are unconnected to the faults at storage site level or to those in the shallower overburden.
- Above the Chalk Group, there is little evidence of any significant faulting.
- None of the faults in the storage complex are critically stressed – *i.e.*, they are unlikely to be open, and will not be reactivated during injection.
- An analysis of fracture density and patterns in the storage seal and the Chalk Group shows that, fracture growth and distribution is controlled by the internal mechanical variability within the rock units. Therefore, they are "disconnected" in the vertical direction and are considered not to pose a risk for containment to the storage site.

Further detailed discussion of the faulting and fracturing in the overburden interval above the Goldeneye field can be found in the Static model (overburden) report.

8.4.5.1. Gas chimneys

No gas chimneys (which may be an indication of a leaking trap) have been indentified on seismic above the Goldeneye field. There is no seismic signature of shallow overburden gas accumulation.

8.4.6. Abandoned wells

The excellent regional seal that has trapped a large volume of hydrocarbons over geologic time has been penetrated by several wells which could potentially act as leak paths direct to the surface. As a result, the integrity of all abandoned wells in the proximity of the Goldeneye field has been investigated. Secondly, abandonment concepts for the five existing Goldeneye production wells post-injection have been studied.

The Goldeneye field itself was only penetrated by four exploration and appraisal (E&A) wells within the Captain Sandstone Member (and five production/injection wells with GYA02 also being sidetracked). Nine additional abandoned E&A wells that are located near the Goldeneye field were also evaluated. The quality of the abandonments of each E&A well at storage seal zone has been assessed in detail in the Well abandonment concept report. Figure 8.10 shows the location of the thirteen abandoned E&A wells that were evaluated. Of these, only one – 14/28b-4, might give cause for a little concern. However, this well is located 3.8km to the west of the storage complex boundary and the results of dynamic simulations show that any CO_2 plume leaking in the direction of this well will not reach it but will be capillary, dissolution or chemical trapped.

Table 8.2 shows the height of the primary cement barrier in place. The combination of good quality cementation jobs and long cement columns means that the risk of leakage through the abandonment well plugs is judged to be very low.

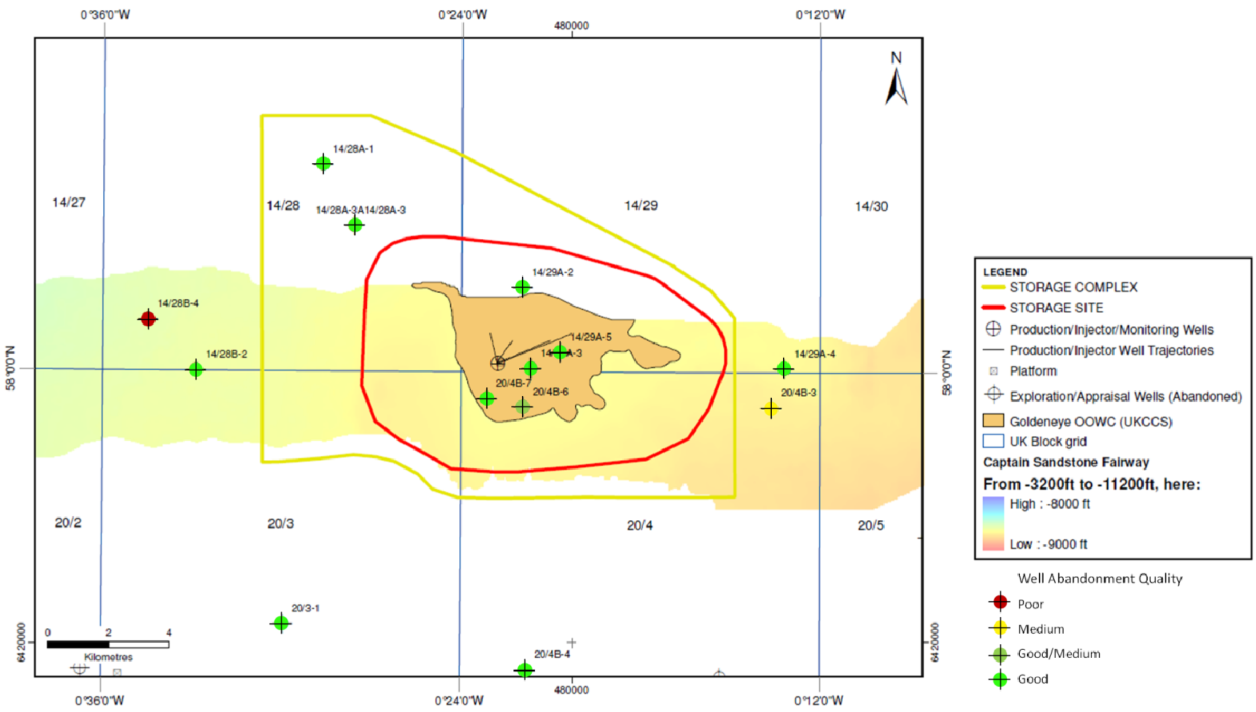


Figure 8.10 Well abandonment quality at storage seal level in the vicinity of the Goldeneye field.

Table 8.2 Assessment of well abandonment quality.

E&A Wells	Height of Primary Barrier above Captain reservoir	Well abandonment quality at storage seal	Contact with mobile CO2 [Mt]
14/28a-1	N/A	No Captain reservoir	N/A
14/28a-3	N/A	No Captain reservoir	N/A
14/28b-2	261’	Good	Outside complex
14/28b-4	0’	Poor	Outside complex
14/29a-2	743’	Good	No Captain reservoir
14/29a-3	765’	Good	13
14/29a-4	542’	Good	Down dip from Goldeneye
14/29a-5	375’	Good	8
20/3-1	N/A	No Captain reservoir	N/A
20/4b-3	309’	Medium	Down dip from Goldeneye
20/4b-4	N/A	No Captain reservoir	N/A
20/4b-6	200’	Good/Medium	1
20/4b-7	333’	Good	0

Figure 8.11 shows the volume at risk below each well within the Goldeneye field after the system has reached equilibrium in 2050, after injection of 20Mt. The chart separates CO_2 into mobile and immobile gas. CO_2 is considered immobile where its saturation is below critical gas saturation.

The chart shows that wells 20/4b-7 and 20/4b-6 have no or very little mobile CO_2 (0 Million tonnes & 1 Million tonnes) at risk, respectively. Even if an integrity issue occurred in these wells, the volume of CO_2 that is available to leak is minimal. The crestal wells have larger volumes at risk with the largest mobile volume being 13Mt in well 14/29a-3 though this has a cement column of 765' [233m] thickness immediately above the reservoir.

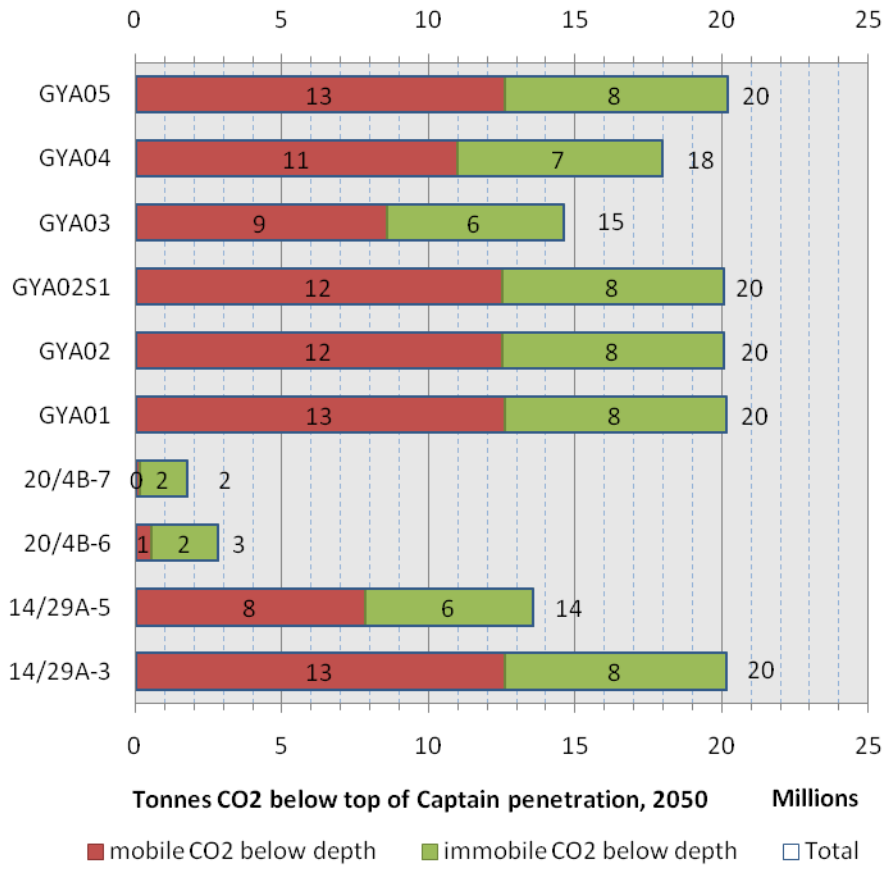


Figure 8.11 CO_2 below the top Captain Sandstone Member penetrations of wells within Goldeneye at year 2050.

The quality of the well abandonment at the complex seal level has also been assessed. These are shown in Figure 8.12 and summarized in Table 8.3. In order for CO_2 to take advantage of the potential leak paths listed in Table 8.3, it must first breach the storage seal – via a well bore; a fault or fracture-network in the caprock; or via diffusion through the caprock matrix – then migrate to the location of the well bore without being trapped by capillary, dissolution or chemical processes. Only then can it migrate up this path, and it may be concluded that such an event is extremely unlikely

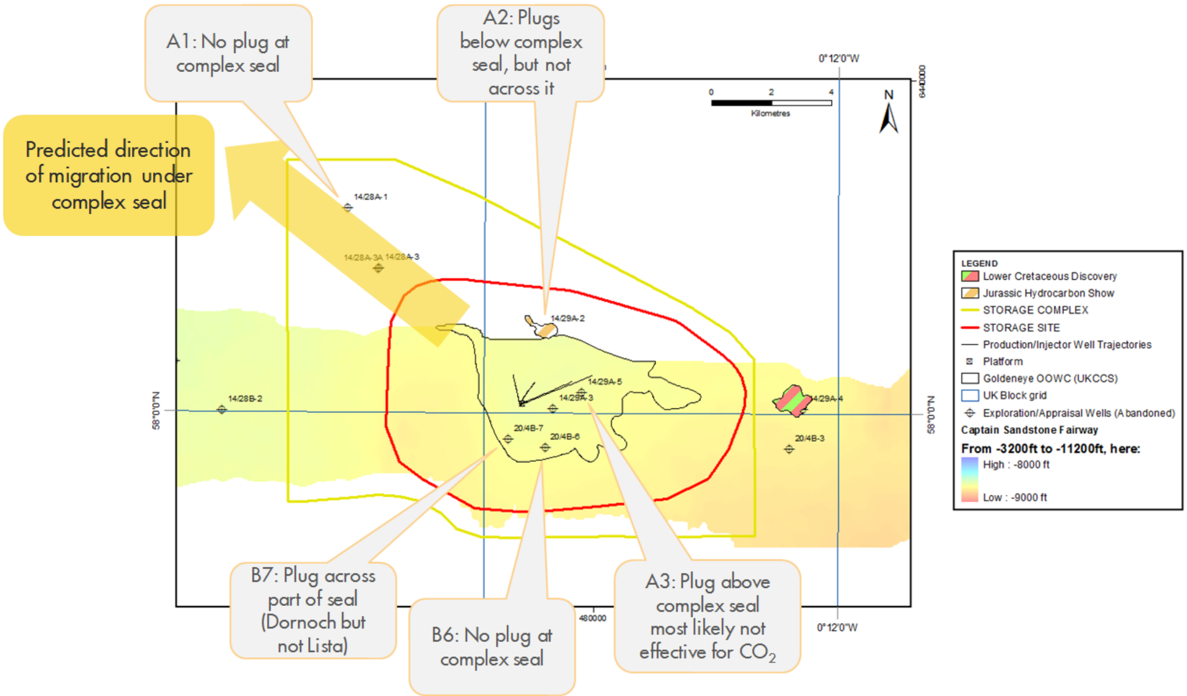


Figure 8.12 Well related risks to the complex seal.

Table 8.3 Status of abandonment plugs at complex seal.

E&A Wells	Well abandonment quality at complex seal	Contact with mobile CO_2 [Mt]
14/28a-1	No plug at seal	No Captain, up dip in complex
14/28a-3	Plugs partially across Lista and completely across Dornoch	No Captain, up dip in complex
14/28b-2	No plug at seal – plug at seabed	Up dip of Goldeneye, outside complex
14/28b-4	No plug at seal – plug at seabed	Up dip of Goldeneye, outside complex
14/29a-2	Plugs below seal but not across it	No Captain, up dip in complex
14/29a-3	Plug above seal, most likely not effective for CO_2	13
14/29a-4	No plug at seal – plug set above seal	Down dip of Goldeneye
14/29a-5	Plug across Lista only	8
20/3-1	No plug at seal – plug set above seal	No Captain, outside complex
20/4b-3	No plug at seal – plug set above seal	Down dip of Goldeneye
20/4b-4	No plug at seal – plug set above seal	No Captain, outside complex
20/4b-6	No plug at seal	1
20/4b-7	Plug across part of seal (Dornoch but not Lista)	0

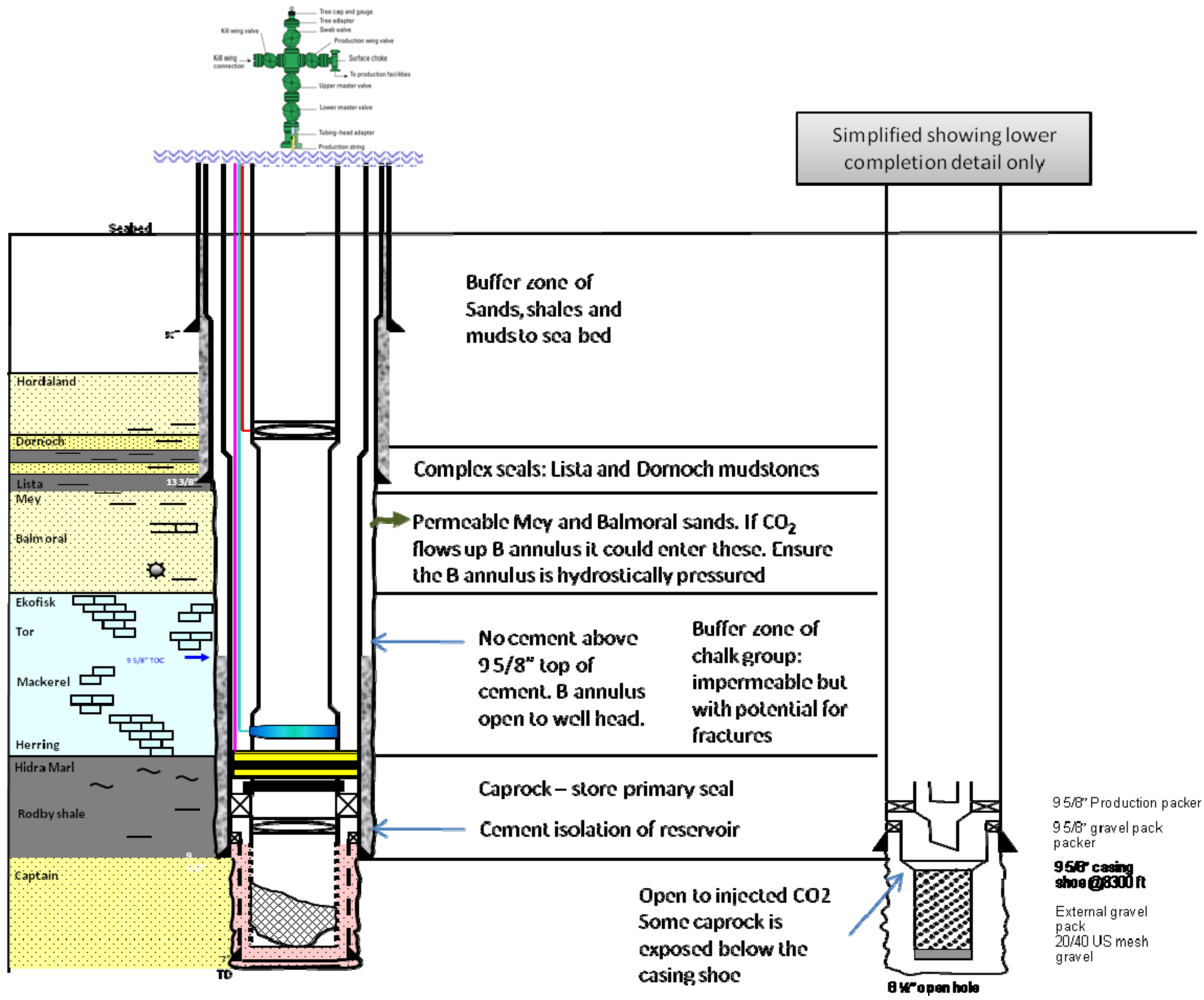


Figure 8.13 Example of injection well.

8.4.7. Injection wells

Abandonment proposals have been prepared for the Goldeneye production wells. All of these wells are planned to undergo a workover in preparation for CO_2 injection.

Figure 8.13 shows an example injection well. The key points to note are:

- a good cement isolation of the reservoir from the Chalk Group with the 9 5/8in shoe set in the caprock formations
- the completion is a predrilled liner and a gravel pack. There is no cementation in the reservoir. This means that the lower few feet of the lowest caprock formation – the Rødby – is exposed injection fluids. This can exacerbate thermal fracturing in the Rødby while within diffusive recharge range of the open section.
- the 9 5/8in cementation ceases in the Chalk Group leaving the B-annulus open – and filled with drilling mud. The annulus is in hydraulic contact with the Mey and Balmoral sands (barring any residual mud filtrate layer). It is therefore most likely to be at hydrostatic pressure. It does provide a potential path for CO_2 to reach the wellhead were it to enter the B-annulus. The B-annulus pressure is permanently monitored reducing the risk that CO_2 and

carbonic acid remain undetected in this annulus for long enough to perforate it at above the complex seals. Additional monitoring is being placed at sea bed should CO_2 manage to escape from the full set of annuli and make it to the top of the well.

Full isolation of the injector wells will be restored at abandonment. This is discussed in detail in the Well abandonment concept report.

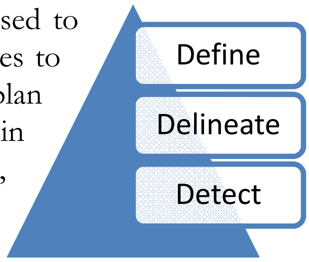
9. Proposed monitoring plan

9.1. Introduction

This chapter outlines the monitoring and verification philosophy and plan. A detailed description is contained in the MMV (Measurement, Monitoring and Verification) Plan and discussion of the effectiveness of the tools to be employed is covered by the Monitoring Technology Feasibility report. This chapter specifically describes monitoring and verification measures. Measurement has been discussed under Sampling and Metering (§7.10 starting on p.90).

As will be shown, the monitoring plan is intended to be 'trigger-based', with triggers related to leakage scenarios built from the identified leakage threats/risks. To address these, a two part monitoring programme was devised:

- *Base case plan*: monitors the conformance of the injection and identifies unexpected CO_2 migration (*detect*) within the storage complex, allowing action to be taken (if required) to ensure the integrity of storage before leakage occurs.
- *Contingency plan*: in the event of leakage, the *contingency plan* is mobilised to locate the source of the leak (*delineate*) and enable corrective measures to be implemented (including quantification or *define*). The monitoring plan encompasses all phases of the project and is illustrated schematically in Figure 9.1. The rationale and detail of the plan are summarised here, while the full details are given in the Goldeneye provisional MMV plan report (see full reference on p.149).



To ensure the MMV plan reaches its objectives, the current state of the site and complex *pre-injection* will be profiled through the acquisition of baseline data across all domains (see §9.3.2 for definition of the domains).

In the event of a leak being confirmed mitigation will be addressed by the Corrective Measures Plan, which is summarized in the following chapter (§10, starting on p.131).

9.2. Structure of the chapter

The following sections of this chapter set out to:

- Describe the strategy behind the proposed monitoring plan;
- Describe the phases of the monitoring plan and identify the 'domains' to be monitored;
- Describe the tools to be used, their detection limits and – where appropriate – their technical maturity.
- Identify remaining risks to the successful execution of the plan and outstanding issues for future investigation

9.2.1. Definitions

In this chapter the following definitions are implied (from the EU directive on the geological storage of CO_2)[20]:

- '*migration*' means the movement of CO_2 *within* the storage complex;
- '*leakage*' means any release of CO_2 from the storage complex;
- '*significant irregularity*' means any irregularity in the injection or storage operations or in the condition of the storage complex itself, which implies the risk of a leakage or risk to the environment or human health.

9.3. Base case monitoring plan

9.3.1. Risk associated strategy

The risk based *base case* plan is designed to meet two objectives:

- Demonstrate conformance;
- *Detection* of *significant irregularities* or *leakage*.

If a significant irregularity or leakage is detected, the contingency plan is then enacted.

In order to develop effective base case and contingency plans, it is important to identify the likeliest leakage event scenarios. These are based on the residual risk after natural and engineered barriers have been taken into account. The leakage scenarios are grouped by categorising threats/risks identified in the containment risk assessment. It must also be taken into account that individual risks may act in combination to turn a containable threat of migration into a leak. The scenarios are used to generate requirements for data acquisition and technology selection. The leakage scenarios are discussed in detail in the contingency plan section below (§9.4).

The base case plan was designed by examining the overlap between the risk assessment for each monitoring domain, the modelled behaviour of the injected CO_2 and the capabilities of the candidate monitoring technologies. The aim of this plan was to reduce the possibility of an undetected migration leak occurring to as low as reasonably practicable (ALARP). The plan is implemented in phases, defined by the activity level within the project (Figure 9.1):

- *pre-injection*;
- *during injection*;
- *post injection/closure* and;
- *post-handover*.

In the *pre-injection* phase, baseline surveys are required to establish pre-injection conditions of the storage complex and its environment. This is in addition to surveys required to demonstrate compliance with the standard industry environmental impact assessment requirements.

During injection pressure from the injectors increases the reservoir pressure to the highest values seen since before production start-up. Monitoring is used to identify potential migration in pathways

[20] Directive 2009/31/EC of the European Parliament and of the Council of 23 April 2009 on the geological storage of carbon dioxide and amending Council Directive 85/337/EEC,European Parliament and Council Directives 2000/60/EC, 2001/80/EC, 2004/35/EC, 2006/12/EC, 2008/1/EC and Regulation (EC) No 1013/2006

which may be activated as reservoir pressure approaches hydrostatic pressure during the injection period.

One year after cessation of injection, the various monitoring domains will be re-baselined. The year's delay is designed to allow the temperature of the injection wells to equilibrate with the formation. Other decisions with regard to additional *post-injection/closure* monitoring will be taken towards the end of the *during injection* phase in order to allow inclusion of the reservoir performance data taken during CO_2 injection. Specifically, this will enable a decision to be made as to whether to use a combination of pressure monitoring and time-lapse seismic surveying or just time-lapse seismic surveying alone for monitoring the *post-injection/closure* phase.

The monitoring programme that will be carried out in the *post-handover* phase (when responsibility for the security of the site is passed to the UK Competent Authority) will be informed by data collected in the *during injection* and *post-injection/closure* phases. It is worthwhile to note that it is expected that the platform will have been removed at this stage, making 'in-well' monitoring difficult but obviating the need for Ocean Bottom Nodes (OBN) when acquiring time-lapse seismic surveys. This phase of the project will not be considered further in this report.

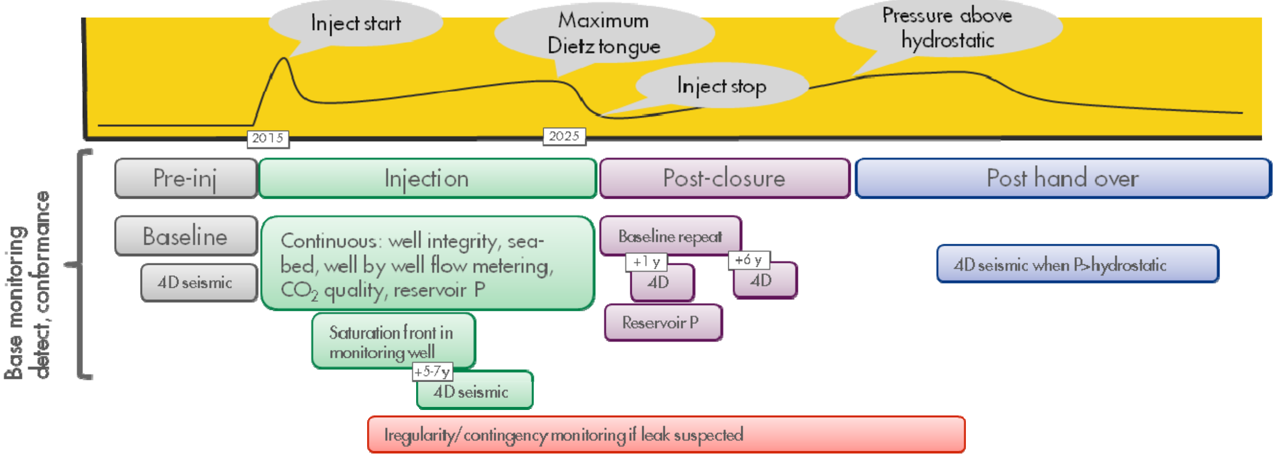


Figure 9.1 **Schematic of the monitoring plan. The vertical axis on the schematic represents risk of *significant irregularity*.**

9.3.2. MMV domains

Feasibility studies have shown that different physical domains are susceptible to different suites of monitoring techniques. A description of each domain and the key considerations for monitoring are described in the following sections.

9.3.2.1. Transport

This includes pipelines and facilities. The main tools for leakage detection in this domain are the pipeline and plant monitoring systems from Longannet to the injection wells on the Goldeneye platform. These are described in the transport and injectivity chapter and will not be considered further in this section.

9.3.2.2. Biosphere

This domain covers the seabed and the inhabited sediment immediately below. All techniques applicable in this domain rely on point measurement techniques (rather than techniques that can remote sense over a whole area) and, therefore, have to be placed at locations which have been assessed to have higher local risk – *e.g.* wellheads. These techniques also need well-defined baseline data since CO_2 and CH_4 occur naturally in this domain and this would need to be accounted for before any assessment o f leakage were made.

9.3.2.3. Geosphere

The geosphere includes all of the rock below the inhabited sediment immediately beneath the seabed contained within the geographical boundary of the storage complex, with the exception of the storage site. It also includes plugged and abandoned wells. The storage site is specifically excluded from this domain because – as will be discussed in the next chapter – it cannot, in the main, be monitored using time-lapse seismic surveying and must be assessed by 'in-well' technology. CO_2 detection techniques in this domain are based on geophysical principles (either seismic or non-seismic) and can cover large areal ranges. Detection ability is assured whilst quantification may require certain conditions: a combination of CO_2 concentration, volume and baseline conditions.

9.3.2.4. Wells and reservoir

This domain comprises the storage site and the injection wells within (from well head to total depth – TD). The focus is to monitor the location of the CO_2 plume in order to calibrate *conformance* modelling and to demonstrate that actual storage site performance matches modelled performance. Well and reservoir monitoring requires installation of gauges (preferably in all wells) and measurement of CO_2 saturation in observation wells.

9.3.3. Summary of the base case plan

A summary of the base case plan is listed in Table 9.1. The technologies to be applied are identified by the domain in which they are effective. Further details on each of the monitoring techniques can be found in the Goldeneye provisional MMV plan report

Table 9.1 Monitoring *base case* plan.

Domains	Objective	Location	Techniques	*Pre-injection*	*During injection*	*Post-injection / closure*
Biosphere	Leak detection: CO_2 profiling	Under platform	Geochemical probe		Continuous	
	Leak detection: Seabed mapping	Storage complex	Multi-Beam Echo Sounder (MBES)	Baseline		Yr +1 baseline
	Leak detection: Seabed sampling (sediment, flora & fauna, pore gas)	Grid survey + target high risk areas	Options: Van Veen Grab / Vibro-Corer / CPT + BAT probe / Hydrostatically sealed corer*	Baseline	Yr 5(±)	Yr +1 baseline
Geosphere	Overburden migration	Storage complex	Time-lapse seismic: 3D streamer + Ocean Bottom Nodes (OBN)	Baseline	Yr 5(±)	Yr +1 baseline
Wells & reservoir	Well integrity	Injection wells	Cement bond logging	Baseline		
			Casing integrity logging	Baseline		
			Annular pressure, Distributed Temperature/ Acoustic Sensing (DTS/DAS),		Continuous	
			Tubing integrity logging		Every 3 yrs	
	Saturation conformance	'Monitoring' well	Downhole sampling		Yr 5-10 annually	
			Sigma & neutron logging	Baseline	Yr 5-10 annually	
	Pressure conformance	Injection wells	Permanent Downhole Gauge (PDG) + Long-term Memory Gauge (LTMG)**	Baseline	Continuous	Yr 0-3
	Subsidence / heave	Platform	Global Navigation Satellite System (GNNS)		Continuous	
	Water leg migration	Storage complex	*Same as 'Overburden migration'*	Baseline	Yr 5(±)	Yr +1 baseline

*Technologies in need of maturation – selection made post-front-end engineering design, **LTMG replaces PDG at end of field life

9.4. Contingency plan

The contingency plan is trigger-based. This means that it will be executed when significant irregularities are detected by the monitoring activities outlined in the base case plan. The contingency plan is site-specific and, as discussed above (§9.3.1), the elements of the contingency plan have been directed at leakage scenarios compiled from threats/risks identified in the containment risk assessment. If enacted the objectives of the contingency plan are:

- *delineate* the source of any leakage to enable corrective measures to be implemented;
- *define* (measure) the volume of CO_2 leakage from the *storage complex*.

The corrective measures that will be considered to address a leakage are outlined in the next chapter. The contingency plan will also be expected to ascertain the efficacy of any corrective measures deployed.

The leakage scenarios considered for the contingency plan are listed in Table 9.2 and discussed in the following sections. Note that all action plans below are indicative. The exact detail of any plan will depend on the combination of site specific conditions and the suspected risk at the time of detection.

9.4.1. Migration/leakage through a plugged and abandoned (P&A) well

In this scenario, CO_2 migrates past plugs within an abandoned wellbore and moves into one of the secondary storage formations. When pressure is sub-hydrostatic, during the early injection phase, CO_2 migration is considered to be unlikely. The risk increases in the *post-injection/closure* phase as the pressure rises toward hydrostatic due to aquifer recharging. Also, at this time, the injection wells will have been plugged and abandoned, providing five more potential pathways. Significant irregularities may be *detected* on time-lapse seismic, by seabed sensors, or by seabed sampling near the abandoned well heads.

9.4.2. Migration/leakage through injection wells

Late in the *during-injection* phase, well injection pressures at the sand face could exceed hydrostatic pressure and, in combination with low temperatures, may induce local fractures. The risk assessment shows that there is also a possibility of fault reactivation. In addition, potential pathways for leakage to surface are available along the well casing if the cement bond fails. Baseline datasets will include cement bond/casing integrity logs acquired during recompletion, seafloor sampling, geochemical probe data and time-lapse seismic surveys. Distributed Temperature Sensing (DTS), Distributed Acoustic Sensing (DAS), annular pressure and downhole pressure data will be used to monitor for potential leaks in the wells or riser during injection. The seafloor geochemical probe is expected to *detect* changes in volume and composition of gas (hydrocarbon/CO_2) released at the seabed. Geochemical samples should be checked for the presence of tracers added in the injection stream. The planned seismic monitor surveys may *detect* induced fracture- or reactivated fault- related leak pathways. DAS also has the potential to detect Microseismic events and also flow behind casing. DTS will be installed down to the top of packers, just above the Captain reservoir. This makes it less sensitive to migration deeper in the reservoir but still more sensitive than annular pressure. Potential leakage paths between casing and formation will be detected (subject to detection limits) by the seismic surveys.

Table 9.2 Grouping of threats into leakage scenarios.

Leakage scenarios	Leakage mechanism	Threats (detailed)
Leakage through plugged and abandoned (P&A) wells	Existing P&A wells	Flow through P&A exploration wellbore.
	Post-injection P&A wells	Flow through P&A injection wellbore to near surface.
	Caprock integrity failure	Acid fluids react with wellbore plugs, cement and casing.
Leakage through injection wells	Development wells	Cross flow behind production casing.
		Injection well tubing leak.
	Caprock integrity failure	Acid fluids react with wellbore plugs, cement and casing.
Leakage through (open or reactivated) fault/fracture	Open faults/fractures	Flow along existing fault/fracture crossing primary and/or secondary seal.
	Caprock integrity failure	Acid fluids react with minerals in fault/fracture allowing fault to reactivate
		Acid fluids react with minerals in fault/fracture opening it.
	Reactivated fault/fracture	Injection pressure causes formation of new open fault in caprock.
		Injection pressure causes shear fracture.
		Injection pressure causes opening/formation of fractures in caprock.
	Caprock integrity failure	Acid fluids react with reservoir matrix, weakening it and causing failure.
Lateral migration in reservoir	Migration past spill point	Lateral migration past the spill point and into the Captain fairway.
Migration in overburden	Wells, fault/fracture, lateral migration	Combination of well or fracture leakage with lateral migration along permeable unit in overburden

9.4.3. Migration/leakage through fault/fractures

Very few faults have been interpreted on the existing 3D seismic dataset. Faults and fractures can potentially be re-activated by pressurisation both *during injection* and *post-injection/closure* (due to aquifer recharge). In sub-hydrostatic conditions, potential open faults and connected fractures are not expected to be able to conduct CO_2 upwards because of the negative pressure differential; instead, water from brine saturated formations in the overburden may flow downward. However, any indication of fluid conducting pathways appearing on seismic survey will have to be mapped and closely monitored, especially when pressure has returned to hydrostatic. Since pressure monitoring is of limited use away from the injection wells, the planned injection and post-injection seismic surveys are required to cover potential existing fault/connected fracture pathways and/or caprock integrity problems across the Goldeneye field. Seafloor geochemical probe or sampling data will initially be of limited use since these events will originate at significant depth.

9.4.4. Migration/leakage along the Captain aquifer (lateral migration)

A 'Dietz tongue' (see §5.7.3.2 on p.50 for explanation) of CO_2 is propelled through the field by viscous forces and is expected to migrate beyond the original oil-water contact (OOWC). The absence of injection pressure in the *post-injection/closure* phase allows dynamic stabilization, when the tongue will retract. The tongue only becomes leakage a risk of if it passes the structural spill point in the northwest of the field. As the Captain 'D' reservoir is homogeneous, the possibility of a CO_2 spill will depend on the injection pressure and rate and the location of the injectors relative to the spill point. GYA03, the closest well to the spill point, is allocated as a monitoring well (base case) until CO_2 breakthrough is observed. Observation in the monitoring well utilises saturation logging, downhole fluid sampling and down hold pressure gauges. Data from all re-completed wells (injectors and monitoring well) will be used to calibrate the dynamic simulation of CO_2 plume movement within the Captain reservoir and predict the timing and volume of CO_2 potentially escaping at the spill point.

In the event of migration of CO_2 beyond the spill point, leakage risk will increase significantly if the CO_2 plume reaches well 14/28b-4, to the west of Goldeneye. This well has a poor abandonment history and there is a risk that it may act as a conduit to shallow formations and/or the surface. Indications of the CO_2 plume moving towards this well will be obtained from Full Field Model (FFM) projections or from the planned *during injection* or *post-injection/closure* seismic surveys.

9.4.5. Migration/leakage along the permeable unit in overburden (combination of well or fault and lateral migration)

If CO_2 passes through the storage seal there are several permeable units in the overburden that can act as additional storage containers. As no significant structural closures have been mapped above the Goldeneye field, the migrated CO_2 could move up dip towards shallower structures to the west or northwest until it becomes capillary-trapped or mineralised. Seismic surveying has been shown to be the most effective method to monitor for CO_2 accumulations in formations above the store. This is because the difference in acoustic impedance, caused by CO_2 invading a high porosity brine saturated formation, caused a clear signal under time-lapse seismic investigation.

9.4.6. Delineation & Definition

Each of these scenarios has a detailed plan to assess any significant irregularities or leakage that is detected. Quantification is necessary to satisfy European Union Emissions Trading Scheme (EU ETS) regulations, which require the calculation of CO_2 volume at the seabed (biosphere) in the event of leakage. Detailed descriptions of these plans are available in the MMV Plan. In general, the workflow followed in each case is as follows:

1. Identify the significant irregularity or suspected leak source using data from the monitoring technologies employed by the *base case* plan. Cases where a leak has caused CO_2 to migrate beyond the bounds of the surveying footprints (*e.g.* leakage into the aquifer and, potentially, in the overburden) will require additional monitoring data to be acquired (in the example of lateral migration, it may require additional seismic surveying). In all cases it will be necessary to update FFMs to match the observed behaviour.
2. Use one or more of the techniques listed in Table 9.3 to measure/calculate plume extent, volume and CO_2 concentration. It should be recognised that these measurements will show variation in both detection limits and uncertainty ranges. Indirect measurements of leakage volume may also be obtained from predictive modelling or extrapolation of direct measurements (*e.g.* reservoir pressure between wells). These methods are applicable for all leakage with the exception of at surface leakage where direct measurements such as sediment sampling or MBES surveying are the only suitable methods.
3. Build a reservoir model to cover the area where the CO_2 leakage is observed. The size of the model is driven by source of plume, direction of movement and the potential pathways to the surface. This model is then used to obtain a range of estimates (low-medium-high) of migrated volumes. Time-lapse seismic, MBES and visual data acquisition are used to constrain the modelled volume range by minimising the uncertainty.

A summary of quantification techniques is shown in Table 9.3.

Table 9.3 Leakage/migration quantification techniques summary.

Techniques	Information gained	Event
Reservoir pressure, injector rates and in-flow composition	Volume & concentration	Migration/leakage from source (injectors)
Quantitative seismic interpretation and inversion using reservoir dynamic model	Volume & concentration prediction	Migration/leakage above/below complex seal
Shallow seismic	Volume interpretation Delineation of area for sampling	Leakage near seabed
MBES	Flux rate (high flux rate). Delineation of area for sampling	Leakage at seabed
Sediment sampling (including pore gas)	Concentration	

9.4.7. Link to corrective measures

The identification of significant irregularity in the behaviour of the CO_2 plume and, especially, leakage from the storage complex, may require that some corrective action be taken to prevent or repair this eventuality. These are described in the following chapter (§10). Table 9.2 lists the possible migration routes associated with each leakage scenario to allow correlation between each scenario and the appropriate corrective measure (illustrated in Figure 9.2).

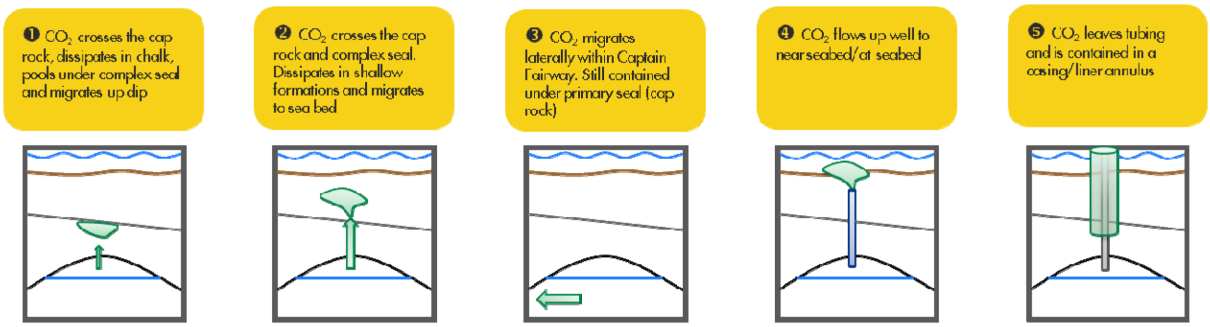


Figure 9.2 Migration routes in the Goldeneye system.

9.5. Risks

As documented in both the Monitoring Technology Feasibility Report and the MMV Plan, all of the tools that are intended to be employed in the *base case* and *contingency plans* have detection thresholds which means that it is possible for small volumes of CO_2 to leak from the storage complex undetected.

10. Provisional corrective measures plan

10.1. Introduction

This chapter outlines the corrective measures philosophy and plan. The whole plan is detailed in the separate Corrective Measures Plan and covers the specific measures in detail.

10.1.1. Key grounding principles

The key factors in the development of the corrective measures plan are the boundary conditions and definitions as described in the EU directive. The boundary conditions and definitions are summarised below:

(i) Corrective measures are actions, measures or activities taken to correct *significant irregularities* or to close leakages in order to prevent or stop the release of CO_2 from the *storage complex*.

(ii) *significant irregularity* means any irregularity in the injection or storage operations or in the condition of the *storage complex* itself, which implies the risk of a *leakage* or risk to the *environment* or *human health*;

(iii) *leakage* means any release of CO_2 from the *storage complex*;

(iv) *storage complex* means the storage site and surrounding geological domain which can have an effect on overall storage integrity and security; that is, secondary containment formations;

The corrective measures plan acts to (in order of priority):

1. Prevent risks to *human health*
2. Prevent risks to the *environment*
3. Prevent *leakage* from the *storage complex*

The plan is *site specific* and *risk based* and covers the storage complex. The release of CO_2 at the surface, be it from a well head or surface pipe work is covered by standard operating practices and the outcomes of the facilities HAZID and HAZOP studies (industry standard analytical techniques used to identify, classify and mitigate possible design and operational risks and hazards).

10.1.2. Annuli designations

Reference is made to annuli in this report, especially when referencing potentially leaking tubulars and annular monitoring. It is important to understand where the annuli are with respect to the casing strings and also to the formations (Figure 10.1):

- The 'A' annulus is between the production tubing and the production casing. It is a completely enclosed volume with metal-to-metal (casing or tubing) or high reliability seals (packer). During the workover of the production wells to injection wells, it is planned to fill this annulus with an oil based fluid, potentially with a nitrogen cushion in order to compensate for the cooling effects from injection of CO_2.
- The 'B' annulus is between the production and intermediate casing strings. It is connected to permeable intervals via an "open shoe" (production casing cement below the base of the intermediate casing). These permeable intervals are the secondary containment units below the secondary seal (Lista / Dornoch shales).
- The 'C' annulus is the volume between the 30in conductor and the surface/intermediate casing. This volume is open at the top (wellhead) and is also in communication with the sea via slots in the conductor above seabed level. The surface/intermediate casing string is cemented up to seabed.

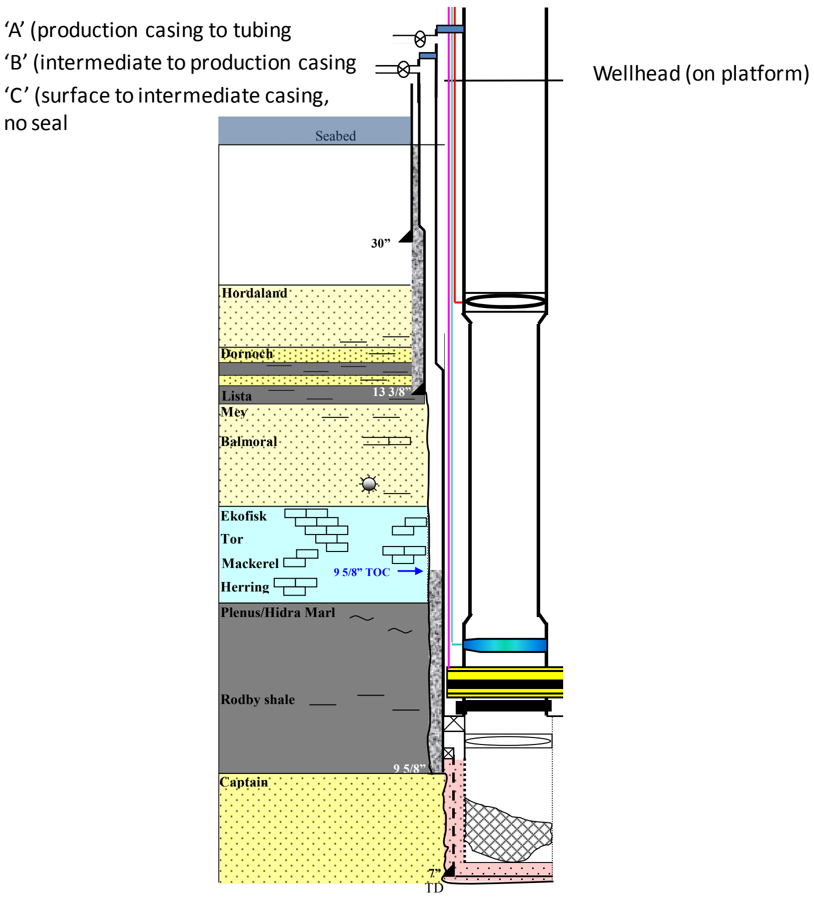


Figure 10.1 Proposed completion design and annuli designations.

10.2. Summary of site specific corrective measures

A site specific containment risk assessment has been performed using the bow-tie risk assessment methodology. The Goldeneye bow-tie selected a *leak from the storage complex* as the top level event – in line with the principles outlined above. The risk assessment details the potential subsurface migration paths that CO_2 can take. These are grouped into five classes as shown in Figure 10.2.

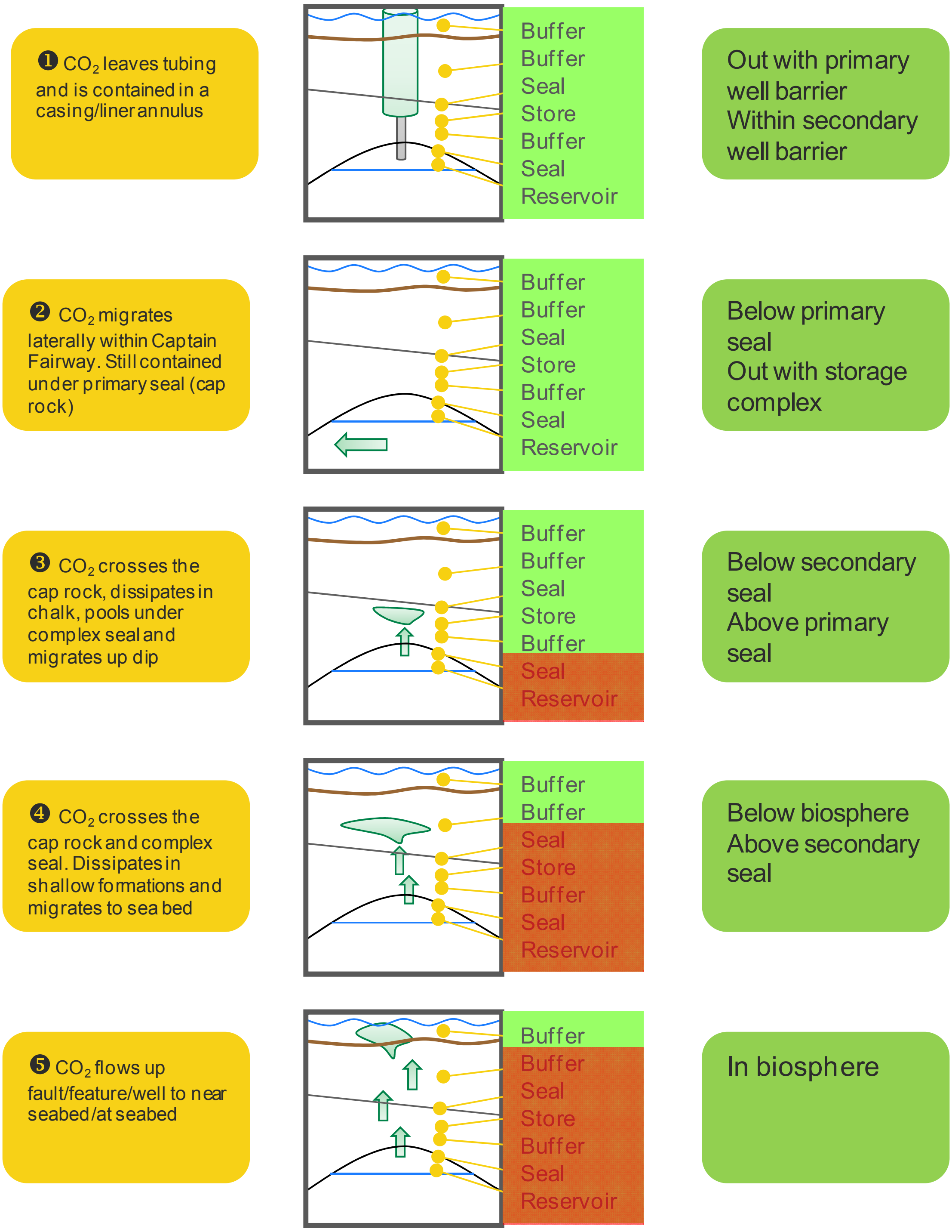


Figure 10.2 Potential migration routes in the Goldeneye system.

The first two are potential precursors to the other three. Only with escalation and the failure or bypassing of the primary AND secondary seal and the failure of the multiple buffers and secondary stores to disperse or absorb CO_2 will there be a migration of CO_2 into the biosphere.

It is important that a systematic approach be adopted for the detection and assessment of any suspected irregularity. If this is not done there are risks that incorrect corrective actions may be employed that could increase the impact of any irregularity. An example could be the drilling of an additional well into the complex adding an extra potential leak path. Mitigating a single risk (or perceived risk) should always be premised on the basis of an overall reduction in the total risk.

The process for detecting and then analysing any suspected irregularity is outlined below:

Monitoring base plan	• Detect a potential irregularity
Monitoring contingency plan	• Investigate further (delineate) • Confirm the nature of the suspected irregularity
Risk assess	• Assess the risk posed by the irregularity • Threat to people, environment? • Could it become a significant irregularity?
Act	• Discuss potential actions with the regulator •Agree course of action with the regulator

Figure 10.3 Process for detecting and analysing a suspected irregularity

It is essential to note that the actions depend strongly on the risk assessment. Referring to Figure 10.2 the potential actions depend on the assessment of the potential consequences. Reading from left to right in the figure:

❶ CO_2 leaves tubing and is contained in a casing/liner annulus.

This leak is outside the subsurface complex, but is still within the storage site as the site definition includes the surface facilities. However, it has the potential to impact on humans and the environment if the final engineered barriers were to fail. This type of leak is relatively common in some oil fields – hence the design of multiple independent engineered containment barriers. Well-practiced oil field techniques would be rapidly employed to fix the leak and thus prevent further escalation.

❷ CO_2 migrates laterally within Captain Fairway. Still contained under primary seal (cap rock).

In this scenario the CO_2 is still contained and the risk to humans and the environment is nil. CO_2 has however moved out of the licensed store and the defined complex. Additional risk exposure exists because CO_2 is migrating in an area that could have additional risk features – primarily decommissioned wells, producing fields, or geological features like faults or fractures.

The initial response would be to risk assess the size, nature and magnitude of migration, increase the monitoring and model the current and potential migration. The risk assessment establishes the risk of further escalation (primarily CO_2 encroachment towards a poorly decommissioned well). Corrective measures such as changing the injection pattern and planning a relief well for such decommissioned wells would be assessed.

❸ CO_2 crosses the cap rock, dissipates in chalk, accumulates under complex seal and migrates up dip.

The immediate risk to people and the environment is nil as the CO_2 is still contained within by the secondary seal and there is no irregularity as such. The contingency monitoring and the risk assessment would identify the potential causes of the leak. If it were injection well related then a fix might be appropriate. If the leak were found to be geological in origin then the action would most likely be to intensify monitoring and apply to licence additional storage volume.

❹ CO_2 crosses the cap rock and complex seal. Dissipates in shallow formations as it migrates towards sea bed.

This is an escalation from ❸ but there is still a low risk to people and the environment as CO_2 has not yet migrated to the biosphere. There is however now a significant irregularity as both the primary and secondary seals have been bypassed. Focussed contingency monitoring would again inform a risk assessment as to if the CO_2 would reach the sea bed. Additionally, the monitoring plan dictates quantitative monitoring of the sea bed to determine if a CO_2 flux is present.

The response will depend on the nature and severity of impacts or potential impacts as determined by the risk assessment. It will also depend on the source of the leak:

- If it is a point source (wells related), then the leak could potentially be repaired. An important factor is that a repair to an injection well is bound to be easier and more successful than a repair to an abandoned E&A well. This is because an abandoned E&A well has had its wellhead removed and any remedial activities to repair subsurface leaks can only be made by means of a "relief" well. Note that CO_2 already migrating through shallow sediments cannot be halted
- If the source is entirely geological in nature – for example a fault zone – the application of potential corrective measures is reduced. Depending on the nature and scale of migration, the most likely corrective measure is to reduce the leak rate where possible by adjusting the injection pattern if it is believed to have any impact.

❺ CO_2 flows up to near seabed/at seabed.

This is an escalation from ❹ and is the HSE critical risk. CO_2 could enter the environment (the biosphere) and potentially impact flora and fauna. If the release is large enough it could increase the concentration of CO_2 at sea level enough to be a risk to humans.

Once the monitoring efforts have identified the source of the leak, quantification would take place. An effects assessment has been performed as part of the environmental statement which would allow estimation of the potential impact when the location and severity of the migration are known.

In the most likely scenario of a well providing at least part of the flowpath through either the primary or secondary seal, it is likely that the agreed corrective measure would be to repair or plug the leak path at the primary seal or secondary complex seal.

The risks assessment concludes that it is highly unlikely that CO_2 would migrate to the surface in significant quantities independent of any wellbores:

- Faults are not critically stressed – i.e. are unlikely to be open.
- No detected faults rise to the seabed.
- Fluid flow up a fault/fracture will be dominated by capillary flow – therefore, due to, the underbalance in the reservoir, flow cannot occur until the system re-pressurises.
- In this unlikely event that migration to the seabed occurs independent of any wellbore, using current technology, the application of potential corrective measures is reduced. It is theoretically possible to remove the reservoir of CO_2 behind the leak, for example by building a platform, drilling wells, and pumping the CO_2 out again – and disposing of it into another as yet undeveloped store or the atmosphere. The challenge will be to weigh-up the impact of the corrective measure against the impact of the leak. This will be done in conjunction with the regulator. Alternatively, leak rates may be reduced by adjusting the injection pattern or reducing / curtailing injection.

11. Provisional closure and post-closure plan

11.1. Legislative framework

The provisional closure and post-closure plans have been prepared with reference to draft, unpublished guidelines from DECC in connection with UK regulations on the storage of carbon dioxide, and to EU CCS Directive, relevant excerpts from which are given below.

11.1.1. DECC guidelines

A provisional Post Closure Plan shall be submitted with the permit application, for approval by DECC, and shall describe the monitoring, reporting and implementation of corrective measures for any leakages.

The Post Closure Plan requires a discussion of the monitoring techniques that will be conducted after the operational phase of CO_2 injection has finished. The details of this long-term monitoring plan shall be discussed in a provisional Post Closure Plan, which shall be submitted `[with the application for a Storage Permit]` *as a separate document for approval by DECC. The long-term monitoring plan will be site specific and may include use of dedicated pressure observation wells, ongoing seismic surveys etc. Whatever techniques are selected, they must be able to identify any leakages or significant irregularities. The plan should be updated as necessary, taking account of risk analysis, best practice and technological improvements.*

The long term monitoring plan should also include the options for remedial action if test results are not as anticipated.

11.1.2. EU Directive on the geological storage of carbon dioxide

(31) A storage site should be closed if the relevant conditions stated in the permit have been complied with, upon request from the operator after authorisation of the competent authority, or if the competent authority so decides after the withdrawal of a storage permit.

(32) After a storage site has been closed, the operator should remain responsible for maintenance, monitoring and control, reporting, and corrective measures pursuant to the requirements of this Directive on the basis of a post-closure plan submitted to and approved by the competent authority as well as for all ensuing obligations under other relevant Community legislation until the responsibility for the storage site is transferred to the competent authority.

(33) The responsibility for the storage site, including specific legal obligations, should be transferred to the competent authority, if and when all available evidence indicates that the stored CO_2 will be completely and permanently contained.

To this end, the operator should submit a report to the competent authority for approval of the transfer. In the early phase of the implementation of this Directive, to ensure consistency in implementation of the requirements of this Directive across the Community, all reports should be made available to the Commission after receipt. The draft approval decisions should be transmitted to the Commission to enable it to issue an opinion on the draft approval decisions within four months of their receipt. The national authorities should take this opinion into consideration when taking a decision on the approval *and should justify any departure from the Commission's opinion. The review of draft approval decisions should, in the same way as the review of draft storage permits at Community level, also help to enhance public confidence in CCS.*

11.2. Conditions upon which this plan has been based

The plan is provisional. In accordance with the terms of the Directive and the UK storage regulations this plan will be updated during injection operations as more is learnt about the behaviour of the injected CO_2 and the integrity of the storage site, but in order to write a provisional plan a number of long-range assumptions about the performance of the store, the complex and the surrounding area, need to be made. These are laid out below:

1. The CO_2 injection and store performs as in the expectation case plan – i.e. there are no significant irregularities; the CO_2 is contained within the currently proposed store; the currently planned injection facilities are used. The Corrective Measures plan covers the eventuality of the leak during the post-closure period. If an irregularity were to occur this pland would be updated.
2. 20Mt – the currently proposed mass – is injected over a period of 10-15 years starting at the end of 2014/beginning of 2015. If the mass were to be increased some elements of the plan, like the timing of the monitoring, could change.
3. No other storage takes place in the formations hydraulically connected with the Goldeneye store.
4. Extraction of hydrocarbons (and potentially water injection) in adjacent hydrocarbon fields is as currently understood: Atlantic & Cromarty ceasing production, and Hoylake ceasing production or continuing with a short period of depletion drive production; Roschelle starting depletion drive production; Blake continuing with voidage replacement.

   Any changes to these assumptions during the life of the storage site will be accommodated in future updates to the plan.

11.3. Site closure performance criteria

The aim of *post- closure* monitoring is to show that *all available evidence indicates that the stored CO_2 will be completely and permanently contained.* Once this has been shown the site can be transferred to the UK *Competent Authority.*

In Goldeneye this translates into the following performance criteria:

(i) ***Behaving as predicted and is unlikely to deviate from prediction:*** 3D dynamic simulation forecasts of the movement of continuous phase[21] CO_2 indicate the following:
For structural/stratigraphic trapping the continuous phase CO_2 within the site is approaching a gravity stable equilibrium[22].
For aquifer storage CO_2 plumes undergoing migration assisted storage in a saline aquifer are migrating at a rate and in the direction predicted by 3D dynamic simulations and the simulations and observations show that the CO_2 will remain with the site boundaries for at least 1000 years from the point of closure.

(ii) ***No leaks or unexpected migration paths are observed:*** Two separate post closure surveys[23] – with a minimum separation of five years, the second survey taking place after the condition in (i) has been met – show that the continuous phase CO_2 is not migrating laterally or vertically from the licensed storage site[24].

It is noted that CO_2 which has undergone dissolution trapping will sink vertically downwards and the dissolved CO_2 (and associated ionic compounds) will migrate down dip. This CO_2 is sequestered and cannot be practicably monitored.

Once these conditions have been met the site will be considered to be in a position that is suitable for handover.

11.4. Goldeneye specific conditions and risks

Goldeneye is a structural store in a depleted hydrocarbon field. Depletion means that the field is at a lower pressure than the fluids in the surrounding rock formations. Where those surrounding rock formations are permeable (for example, the adjacent Captain Aquifer) then any fluids within them will tend to flow with the pressure gradient towards the field. By contrast, where the rock is impermeable (for example, the caprock) the pressure differential is maintained and all else being equal we would expect any fluid flow to be negligible. If in the very remote case that a leak path were to develop though the caprock, or in a water filled well that is in hydraulic communication with the overburden (or even the sea), the pressure differential should ensure that fluids will flow into the store. CO_2 will not flow out until the store has reached a pressure that is near its original pressure.

This leads, for risk assessment purposes, to the separation of the post closure period into alternate scenarios of *post closure at hydrostatic* and *post closure below hydrostatic. The difference this makes to the post closure field management is explained in §11.5.1 below.* The post closure monitoring will therefore be driven by the following considerations:

(i) Determine the rate of average reservoir pressure recovery

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[21] Continuous phase means: dense phase or gaseous phase – not dissolved CO_2 which will slowly sink downwards over thousands of years

[22] In the Goldeneye specific case this means that the *Dietz* tongue is contracting back into the structure and the CO_2 is moving to the location where it is expected to stay for 1000 years

[23] In the Goldeneye specific case a post closure survey is a combination of a time-lapse 3D seismic survey for subsurface profiling and site surveys of well locations to look for surface indications of CO_2 leakage.

[24] This is not necessarily the original site, if CO_2 has migrated then the site will have been extended and a new volume licensed – but in this discussion we are assuming that it will be the current site.

(ii) Forecast when this will near hydrostatic and therefore when the reservoir has the potential to drive CO_2 into the overlying formations.

(iii) If the pressure at the crest of the reservoir exceeds the hydrostatic gradient of the formations above the caprock the shoot a seismic survey 2-5 years after this point: when there is sufficient time to establish a concentration above the detection limit.

(iv) Survey the abandoned well locations to look for surface leaks (see MMV plan for details)

If the pressure recovery is projected to take more than 20 years then hand over will need to take place before the pressure *at hydrostatic* condition has been achieved.

How the pressure monitoring will be achieved depends on technology innovation.

- At the current time it would be necessary to leave the platform in place for the first three years post closure and the wells open in order to collect pressure data.
- Technology to allow the wells to be abandoned and the platform removed while still giving pressure monitoring is conceivable (similar applications but of shorter duration have been achieved for isolated sub-sea wells) but is the subject of ongoing research and development.

11.5. Provisional closure and post-closure plan

Taking the above considerations into account – and referring to the MMV plan, leads to the following plan.

11.5.1. Monitoring, facilities and hand-over

Prior to and during injection monitoring takes place. The results of this monitoring taken together with the reservoir history match provide a base for comparison in the post closure period. The baseline and during injection monitoring (fully described in the MMV plan) is summarised below:

- A pre-injection baseline, consisting of sea-bed profiling and environmental mapping plus 3D seismic surveying, is planned.
- During injection the reservoir pressures and conformance will be monitored. Additionally a 3D seismic survey is planned near the point when 10Mt has been injected (exact timing tailored using the conformance 3D dynamic modelling). Additional continuous monitoring (of wells and seabed) is also described in the MMV plan.

At Year 1 *post- closure*, seabed and 3D seismic surveys will be acquired for the purpose of setting a baseline for the *post closure* period. The timing is set to allow the injection wells to come to temperature equilibrium with the formation to minimise spurious effects that might lead to a false positive. These surveys will be compared to the previous surveys to look for any changes hinting at leakage.

At the current point in time, given the maturity of technology and the potential improvement plans, the following pressure and well monitoring is planned.

1. Leave the platform in place with the wells accessible and collecting pressure data for three years post cessation of injection.

  - This will allow the collection of pressure build up information and the forecasting of when the system will reach hystrostatic equilibrium with the hydraulically connected formations
  - Dynamic modelling indicates that during this period the CO_2 that will have moved both laterally and downwards under viscous forces during injection will flow back upwards under buoyancy drive and the CO_2 /water contact will move towards a stable (and horizontal) equilibrium
  - Partial decommissioning can start in this period (for example of pipelines and some injection facilities).
2. After year three, remove the all the injection facilities (platform). At this point the path taken depends on the performance of the pressure build up monitoring and the technology available. If it is practicable to monitor reservoir pressure by, for example, recompleting the wells as subsea wells, leaving an isolated well head platform, or installing gauges below the cemented abandonments, then this will be considered. The risks and costs of not abandoning the wells and platform have to be weighed against the value of continued pressure build up data.
3. Collect a second post-closure time-lapse seismic survey covering the storage complex – and including seabed surveying and sampling at the abandoned well locations. The timing of this survey depends on the forecast (or measured) rate of pressure build-up as this influences the timing of potential leaks.
  - If the build-up is happening at a rate that will take many decades to reach hydrostatic pressure (greater than 20 years) then a survey will be taken five years after the previous one, at year six *post closure* (refer to §11.3). This will check for leak paths involving long columns of CO_2 in well bores. At this point a request will be made to the Competent Authority for handover as the risk profile will not change for the foreseeable future.
  - If the build-up looks likely to reach hydrostatic before 20 years post closure then the second survey will take place two years after predicted (or ideally measured) achievement of hydrostatic pressure. Assuming no indications of migration are found (refer to §11.3) then this will be strong positive evidence of no significant irregularity and will significantly reduce the future risk profile. A request will then be made for handover.

The MMV plan also outlines a scenario with no pressure monitoring post closure – involving increased frequency of seismic surveys. This would potentially be triggered should an integrity issue with the injection facilities mandate their immediate removal. It is not, however, the preferred option at this point.

11.5.2. Corrective measures

The corrective measures pertaining to the post-closure period are outlined in detail in the *Corrective Measures Plan*. Once the injection wells have been abandoned they, naturally, exclude all corrective measures associated with standard well interventions into the wells. The corrective measures take a stepwise approach using the Detect, Delineate and Define philosophy outlined in the MMV plan.

1. Detect a potential irregularity
2. Delineate the irregularity
    a. Confirm that it is taking place

   b. Identify the source of the irregularity (is it a well related, fault related etc.)
3. Define the irregularity
   a. Assess the magnitude – how much has leaked?
   b. Assess the impact – what ecosystems are being affected and in what manner?
4. Determine the best course of action to remediate – in agreement with the regulatory authorities

The potential courses of action are outlined in the Corrective Measures plan while details of contingency monitoring are outlined in the MMV plan.

11.6. Summary

The table below summarizes the post closure plan.

Timing post cessation of injection	Detail of activity	Monitoring	Corrective measure
+0 to +3	Platform remains with wells accessible	Pressure monitoring	Detect, Delineate, Define, Determine best corrective action in agreement with regulators [see Corrective Measures Plan]
+1	Re-baseline, check for irregularities	4D seismic and environmental monitoring	
+3	Decommission platform and seal wells	Pressure check for the abandonment plugs	
>+3	Monitor build up if practicable	Remote pressure monitoring if technology mature[25]	
If sub-hydrostatic for > +20 years At year +6	Final survey and hand over	4D seismic and abandoned well seabed surveying	
If hydrostatic < +20 years	Final survey and hand over 2 years after hydrostatic achieved	4D seismic and abandoned well seabed surveying	

[25] This monitoring reduces uncertainty in pressures and potentially cost as better information can lead to a reduction in the frequency of application of other more expensive monitoring techniques.

12. Future work and data collection

12.1. Pre-Development Data Enhancement

The FEED study used data available from the production and pre-production phases of the Goldeneye gas condensate field. Whilst some new data characterisation was initiated during this phase of work (*e.g.* petrographic analysis of reservoir and caprock), most new data have yet to be collected, either due to lack of time to execute a comprehensive study within the eleven months of the FEED phase, or due to lack of financial commitment prior to the final investment decision (FID) being made.

Owing to the fact that this is a demonstration project the FEED programme included significant study work. This work has identified a number of areas where further study are required:

- Operability of wells with Joule Thompson cooling
- Potential for thermal fracturing of caprock

There are also additional work elements that might be required by the regulatory bodies before the granting of a licence – partially because this is a first on a kind project and there are few precedents.

Post-production, *pre-injection* baselines are required for all the domains that will be monitored both during and after injection into the field. These are necessary to allow the operator to demonstrate that any changes in fluid distribution within the reservoir are the result of CO_2 injection, to calibrate conformance modelling and to allow for the identification of irregularities that may lead to leakage. These baselines are listed in §12.2.

Finally, one of the purposes of the FEED study is to identify work required to prepare the site and the operator for the injection phase of the project. The work programmes currently identified are described in §12.3.

12.1.1. Geomechanical experimental testing

Experimental work for the purpose of investigating the geomechanical properties of the Goldeneye reservoir and caprock was included as an optional activity in the FEED plan. Computer simulations of the response of the reservoir and caprock to depressurisation (through production) and repressurisation (through injection and aquifer encroachment) show that, in the worst case scenarios, some mechanical degradation of the caprock can be expected. These low cases are based on generic analogue data and are considered to be conservative. To better understand the lower bounds of the operating envelope additional microscopic analysis of the caprock is being performed.

The impact of temperature changes induced by the introduction of relatively cold CO_2 (~20°C) into the reservoir (83°C) on rock strength also needs to be taken into account when assessing the likelihood of geomechanical failure and this is still being investigated, as is the effect of well deviation coupled with cold CO_2.

12.1.2. Injectivity

The end-to-end model for the injection process makes a number of assumptions regarding power station and capture plant performance and the type and nature of the (National Grid) compressor at Blackhill. Once these assumptions have been confirmed or clarified (especially the turn down limits of the compressor) , the model will require updating. This will also force an update of the tubing selection and modelling.

This new model – along with the results of additional geomechanical study, assessment of risks associated with the formation and migration of a 'Dietz' tongue and the details of the well completion design – will be used to optimise injection patterns. The optimised injection scenarios will also require further aquifer strength scenarios.

12.1.3. Leak path modelling

Dynamic simulation of CO_2 movement in the overburden to the field is required to better define monitoring needs. In particular, multistep leak paths require investigation. This will need a refinement of the existing static and dynamic models available for the overburden to the field. It also needs to be coupled to synthetic seismic further refine detection limits.

12.1.4. MMV design

The MMV plan report describes the techniques intended to be applied to monitoring the performance and conformance of the Goldeneye CO_2 store. All of the domains that will be monitored will require post-production, *pre-injection* baseline surveys, which now need detailed design. Many of the technologies that are proposed for the monitoring plan are novel and their maturation and qualification for use in the manner envisaged needs to be progressed. As well as detection of leaks, quantification of any escaped CO_2 volume is necessary and techniques to achieve this must also be progressed. As this is expected to be a general requirement for any offshore CO_2 storage venture, it is assumed that this will require the establishment of industry or academic research partnerships.

12.1.5. Special core analysis (SCAL)

A SCAL programme was identified prior to FEED as part of the original workscope definition. Operational issues have meant that this work will not be complete prior to the end of the FEED contract. An extension to this contract has been sought and granted to allow the completion of this activity. The extra time will enable the detailed analysis of the results of the SCAL simulation modelling and the assessment of the effects of the investigated rock properties on injectivity and capacity.

12.1.6. CO_2 release testing

Experimental work aimed to how CO_2 disperses within the atmosphere after a release from a surface source (such as a fractured pipeline) was initiated at the Spadeadam test site in Cumbria. The test data is still being analysed and validation of the computer models used for predicting release rates and dispersion is ongoing.

12.2. Monitoring plan baselines

The largest part of the remaining data collection envisaged for the project prior to injection start-up is in the form of baseline surveys for the *during injection* monitoring plan. This plan is set out in detail in the MMV plan. The data collection planned for the *pre-injection* phase is as follows:

- seabed mapping (MBES surveying)
- seabed sampling (van Veen grab, vibro-corer, cone penetration tester, BAT probe, hydrostatically sealed corer, geochemical probe installation)
- time lapse seismic (streamer and OBN)
- well integrity assessment (cement bond and casing integrity logging)
- saturation conformance (logging and sampling)

- well gauge installation (Probe/PDG/DTS/DAS).

It is anticipated that pre-injection seismic survey will be used in three ways. Firstly, it will be compared to the pre-production seismic survey (1997 Greater Ettrick 3D seismic survey) to attempt to identify changes in fluid distribution within the reservoir due to hydrocarbon extraction. This information will enable the conditioning and calibration of dynamic models of the field. A second function of the seismic baseline survey is to provide the basis of for an update of the static reservoir and dynamic full field simulation models of the field. Finally, the survey will function as the baseline to which the *during injection* seismic surveys are compared.

12.3. Further characterisation work

As mentioned in §12.2 above, one of the pieces of work envisaged to be completed during the pre-injection phase is a full rebuild of the static reservoir model and full field simulation model for the Goldeneye field. Only small modifications of these were considered as part of the FEED study as no new information had come available since their original construction and they were performing their tasks of predicting production performance adequately. However, as discussed in a number of documents produced during FEED (*e.g.*, static model report (field)), it is recognised that the hazards and uncertainties associated with CO_2 storage are different to those associated with producing hydrocarbons and, once a significant dataset – such as a new seismic survey – becomes available, it is appropriate to recreate them with a new focus.

12.4. Key update cycles

The collection of new data – be it from baseline surveys, experience from analogue projects, or from monitoring during injection – will lead to an update of the risk assessment. This in turn can lead to an update fo the monitoring and corrective measures plans. Additionally the introduction of new technologies, or a change in use of areas adjacent to the store, can lead to an update of monitoring and corrective measures plans. Notwithstanding the above there is also a five yearly update cycle for the plans.

13. Health, Safety and Environmental Management

All phases of the Goldeneye project will be conducted in accordance with the Shell UK Policy on Health, Safety, and the Environment (HS&E). The Policy is implemented via the Health & Safety Management System and the Environmental Management System (EMS). The latter is ISO14001-certified and is subject to regular audits from independent assessors. Shell has introduced a common Health, Safety, Security, Environment and Social Performance (HSSE & SP) control framework for all activities under its control. This includes the Projects Manual which requires HS&E requirements to be defined and integrated into project decisions.

A high priority is given to the prevention of incidents that could endanger personnel, the environment, or the asset. Design of the modifications to the Goldeneye facilities will incorporate hazard management principles and the use of best available techniques to eliminate, reduce and/or control hazards to acceptable levels. In particular In particular Shell's Hazards and Effects Management Process (HEMP) has been followed in a systematic way. The process comprises four basic steps:

- Systematically **identify** hazards, threats and potential hazardous events.
- **Assess** the risks against accepted screening criteria, taking into account the likelihood of occurrence and severity of the consequences to people, assets, the environment and reputation
  - How likely is it to occur?
  - How serious is it?
- Implement suitable risk reduction measures to eliminate or **control** or mitigate the hazard or its consequences
  - Can the hazard be eliminated or controlled?
  - Can the probability of occurrence be reduced?
  - Can the consequences be reduced?
- Plan for **recovery** in the event of a loss of control.
  - What measures are required if the hazard occurs?

The main objective of HEMP activities is to demonstrate that hazards (and associated risks) have been identified and where hazards cannot be eliminated, the risks are tolerable and have been managed to ALARP. The various HEMP activities will be documented in the Design HSE Case, the Environmental Statement and the required updates to documents such as the Offshore Safety Case.

The health and safety assessment process has included various hazard identification workshops and subsequent hazard assessments including both qualitative and quantitative risk assessment. The assessments have addressed risk from the storage complex (sub-surface risk) and the transport and injection facilities (surface risk). The surface risk assessments have been developed based on the existing Control of Major Accident Hazards (COMAH) Safety Report for the Shell Terminal at St Fergus and the Offshore Safety Case for the Goldeneye Platform. This includes full scale experiments at Spadeadam, undertaken in order to calibrate the computerised models used to assess the consequences of accidental releases.

During the FEED process Environmental Hazard Identification (ENVID) workshops were held. The results of these workshops will inform the Environmental Impact Assessment (EIA) and resultant Environmental Statement (ES) required under the Offshore Petroleum Production and Pipelines (Assessment of Environmental Effects) Regulations 2007 (as amended). The scope of the ES includes all offshore activities associated with the redevelopment of the Goldeneye facilities for the purposes of CO_2 transportation, injection and storage.

14. Decommissioning

Decommissioning of facilities and wells will be in accordance with the regulations and best practice in place at the time of decommissioning.

It is likely that well decommissioning will be more involved that for a hydrocarbon project. Options for well decommissioning are outlined in the Well Abandonment Concept report.

15. Glossary and list of key reports

15.1. Key reports referenced in the SDP

Well Abandonment Concept

Temperature & Pressure modelling

CO_2 Storage Estimate

Corrective Measures Plan

Dynamic Modelling Output Report

Geomechanics Summary Report

Geochemical Reactivity Report

Static Model (Field)

Static Model (aquifer)

Static Model (overburden)

Monitoring Technology Feasibility Report

MMV Plan Report

Operations Philosophy

15.2. Glossary of terms

ALARP	As Low As Reasonably Practicable
Bscf	Billion Standard Cubic Feet
CBIL	Circumferential Borehole Imaging Log
CCS	Carbon Capture and Storage
CDT	Conductivity, Depth and Temperature
CH_4	Methane
CNS	Central North Sea
CPT	Cone Penetration Testing
CO_2	Carbon Dioxide
DAS	Distributed Acoustic Sensing
DTS	Distributed Temperature Sensing
EGP	External Gravel Pack
EIA	Environmental Impact Assessment
ES	Environmental Statement
ESS	Expandable Sand Screens
ETS	Emissions Trading Scheme

EU	European Union
FFM	Full Field Model
FFSM	Full Field Simulation Model
Fm	Formation
FMI	Formation Micro Image
GNNS	Global Navigation Satellite System
GOC	Gas-Oil Contact
ICES	International Council for the Exploration of the Sea
K	Permeability
LOT	Leak-Off Test
LT	Limit Test
LTMG	Long Term Memory Gauge
MBES	Multi-Beam Echo Sounder
NUI	Normally Unattended Installation
MEG	Monoethylene Glycol
MMV	Measurement, Monitoring and Verification
Mst	Mudstone
N/G	Net-to-Gross
NGL	Non-Gas Liquids
OBN	Ocean Bottom Nodes
OWC	Oil-Water Contact
OOWC	Original Oil-Water Contact
Φ	Porosity
P&A	Plugged and Abandoned
PDG	Permanent Downhole Gauge
SAC	Special Area of Conservation
SDP	Storage Development Plan
SC-SSSV	Surface Controlled Subsurface Safety Valve
SEA	Strategic Environmental Assessment
SH	Maximum Horizontal Stress
Sh	Minimum Horizontal Stress
Sv	Vertical Stress
Sst	Sandstone
TVDSS	True Vertical Depth Subsea
UBI	Ultrasonic Borehole Imager
UKCS	United Kingdom Continental Shelf
UR	Ultimate Recovery (volume)

VRE	Vitrinite Reflectance Equivalent
WBT	Water Break Through

Storage Development Plan Appendices

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A. Well and reservoir management plan

The Well and Reservoir Management (WRM) plan in Goldeneye is an integral part of the MMV (Monitoring, Measurement and Verification) plan.

The main objectives of the MMV plan are the verification and validation (or conformance) of dynamic earth models in the short term, to estimate the long-term behaviour of the CO_2 plume, to inform the frequency and duration of the monitoring plan and to confirm secure containment.

Optimising the injection phase is the objective of the WRM team during operation of the storage site. Since reservoir behaviour is complex in a CO_2 injection project, WRM focuses on continuous performance monitoring, recognising issues/problems, and acting upon these variances.

The frequency of monitoring and verification will change over time because the risk profile of the storage complex changes over time. An annual surveillance plan is issued to ensure the reservoir is adequately monitored.

WRM seeks to optimise injection and to improve the understanding of the reservoir. Data is collected to enable decisions to be taken: on activities either on the existing well stock or even on the requirement on new wells.

(Post-injection monitoring is covered in the MMV plan)

A.1. Objectives of the WRM

The main objectives of the well and reservoir management plan are:

Integrity management of the CO_2 in the injector wells.

1a. Minimize well failures. The initial well design is the main barrier against well failures. During the injection phase, adequate maintenance and well servicing should reduce the risk of failure.

1b. Integrity issues identification. Well surveillance is required to identify as early as possible potential well integrity issues.

1c. Remedial integrity activities. Once the action is properly identified then remedial plans can be executed.

Maintain and understand CO_2 injectivity during the life of the project.

2a. CO_2 downhole injectivity. Downhole injectivity needs to be monitored and maintained during the life of the project. Early deviations to the plan need to be recognized for planning of remedial activities if required.

Hydrate inhibition and filtration are important elements to maintain the integrity of the injection. Rate control might be required to avoid 'hot spot' erosion of the sand screens installed in the lower completion.

2b. Understand the CO_2 behaviour in the well. Under normal injection conditions, the CO_2 should be in dense phase along the well because of the created friction. As such, the minimum wellhead pressure under injection conditions should be 45bar. This pressure needs to be continuously monitored to ensure it is maintained. The maximum pressure available at the wells is ~115bar.

2c. Manage CO_2 arrival rates. Longannet operation will not always be at base load. Fluctuations in arrival CO_2 rate to the platform are expected. The arrival rates will be monitored and optimization of the well carried out to manage the injection rates.

Monitor the reservoir performance under CO_2 injection.

3a. Reservoir pressure inflation

3b. CO_2 monitoring. The focus is to monitor the exact location of the CO_2 plume to calibrate reservoir modelling.

3c. Reservoir Modelling. The validated reservoir model would then be able to predict further CO_2 plume movement in directions where wells do not exist.

Surface Facilities.

4a. CO_2 rates. Quantification of in-flow of CO_2 both in absolute terms and well allocation through use of appropriate flow meters

4b. Gas detection. Gas detection in and around the facilities (for the protection of staff and the environment).

A.2. Well management

A.2.1. Well Activities

The wells are designed to manage the phase behaviour of the CO_2 by friction. A workover will be required to modify the current well completion for CO_2 injection.

Basic well management activities and restrictions to the injection well envelope are as follow:

Wellhead pressure

CO_2 will be injected in a single phase with wellhead (WH) pressures above the saturation line to avoid extremely low temperatures in the well caused by the Joule-Thomson effect. Minimum wellhead pressure of 45bar should be kept on the wells.

The maximum WH pressure is dictated by the pressure limitations in the pipeline. Including pressure drops in the platform it is estimated that the maximum pressure at the wellhead will be in the order of 115bar.

The ideal way of managing the wells is to operate them by pressure instead of rate. Aim to operate each well at around 80bar WH injection pressure. This will give flexibility in case of receiving different rates at the platform by only choking the well down or beaning up the well. This might avoid the transient operations of closing or opening wells thereby introducing additional cooling cycles to the wells.

CO_2 arrival rates

A single well will have a limited injection envelope per well. A combination of available injector wells should be able to cover the injection rate ranges arriving to the platform.

The completion sizing also considers overlapping of well envelopes to give flexibility and redundancy in the system for a given arrival injection rate. At a given arrival rate different combinations will add flexibility to the system.

Long term injectivity

Filtration of the CO_2 stream is required to 6-7 microns particle size. Filtration to this level is required to avoid plugging downhole screens, hence maintaining injectivity during the life of the project.

Hydrate inhibition will be done by batch methanol injection in the wells prior to starting the well up during the initial year of injection. Thereafter, the inhibitor batch treatment only will continue in the case water is introduced in the well.

Maximum bottom-hole injection Pressure

This pressure is dictated by the maximum allowable bottom hole injection pressure to reduce the risk of fracturing the seal above the formation and includes the cooling of the formation.

[HOLD: Value for exceeding the fraccing pressure including cooling being re-evaluated by the geo-mechanists]

Captain D fracturing

The injection pressure might exceed the minimum stress of the formation. This can create propagating fractures into the Captain 'D' sandstone. These fractures are not detrimental to the containment capacity of the reservoir. The problem is related to potential 'hot spot' erosion across the screens. The rate in which the potential of having the 'hot spot' erosion is calculated for each well.

Well Integrity

Ensure wellhead and tree maintenance (WHM) is carried out to the optimum levels (usually every 6 months).

Carry out SSSV testing at the prescribed frequency to know that the well is safe to operate (normally every 6 months. Frequency to be defined in the detail design phase).

Pressure test. Yearly. Monitor of the annulus pressure with a positive pressure in the tubing.

A.2.2. Well surveillance

Standard surface monitoring is recommended in the Goldeneye wells.

The wells will be equipped with elements to facilitate surveillance like PDG and DTS.

Although no well intervention work has yet been carried out on Goldeneye wells, several studies have been undertaken to investigate a number of well intervention scenarios that could potentially take place on the Goldeneye platform. The conclusion is that executing wireline and even coil tubing operations are feasible on Goldeneye. There are some limitations in terms of tool lengths and weights which need to be considered (especially) during the first activities. A full site survey will be required prior to intervention operations.

Following the proposed surveillance activities (Table A-1) in the injector wells during the injection phase at different phases of the project:

Table A-1 Well surveillance activities

Activity	Description	WRM Objective
Surveillance during initial workover	Cement bond logging & Casing integrity logging. Initial well integrity logging will be performed during the workover. This will evaluate cement bond quality and casing integrity prior to injection.	Baseline condition of cement bond between casing and formation Baseline condition of casing thickness Objective: 1a, 1b
Surface P/T monitoring	Monitor the different well elements pressures, temperatures in a continuous basis. Basic elements to be monitored: wellhead, A and B annulus and control lines.	Basic but powerful well monitoring Objective: 1b, 2a, 2b, 2c, 3a, 3c
PDG	Permanent Downhole Gauges (PDG) will be installed in the injector wells. Pressure and Temperature readings above the production packer The selected PDG's will require to be specially calibrated for the lower BHT (17°C-35°C) expected when injecting CO_2. It is possible that two PDG will be installed into each of the Goldeneye wells that are to be recompleted for CCS operations – this gives accurate gradient information allowing better estimation of the reservoir pressure.	Accurate and stable pressure measurements are essential for long-term well and reservoir monitoring. Identify pressure conformance in Captain reservoir, identify when system will re-pressurise and have energy to drive fluids out of the store Objective: 1b, 2a, 2b, 2c, 3a, 3c
DTS	Distributed Temperature System (DTS) will be installed in the external part of the tubing. Temperature reading in the external part of the tubing. The selected Neon opto-electric monitoring cable for the PDG enables simultaneous acquisition of pressure gauge data and distributed temperature data.	One of the primary functions of DTS on Goldeneye is to quickly identify if tubing integrity has been compromised and identify the source of a leak by observing differences in the temperature profile along the length of the tubing. It might identify CO_2 migrating outside the casings. Objective: 4a

Activity	Description	WRM Objective
Tubing integrity	Tubing integrity logging. Tubing integrity logging serves an operational as well as a monitoring purpose. It will serve to predict the tubing life time. Assuming current base case realisation, tubing integrity logging will start at Year 3 and will be repeated every five years until the end of injection. It will help in planning major workover activities is required.	Indicate likelihood of failure in the tubing using direct measurement Objective: 1a, 2a

Based on the interpretations on the surveillance activities and their interpretations well issues might arise. Those issues will require a remedial activity.

A.2.3. Reservoir management

The injection target is the upper part of the Captain 'D' subunit where the CO_2 will displace and mix with the remaining reservoir hydrocarbon and the aquifer water that has swept the reservoir during production. The CO_2 will refill the voided hydrocarbon structure. As the refilling takes place there will be a front of CO_2 moving though the original hydrocarbon volume, displacing the invaded water. Viscous forces will tend to dominate over gravity forces and there is potential for a tongue of CO_2 to move below the original hydrocarbon water contact.

The reservoir pressure will increase due to the CO_2 injection and the aquifer strength. The completion is selected considering the increase of reservoir pressure from 2750psi [190 bar] (lowest predicted pressure at the start of CO_2 injection) to 3800psi [262 bar] (highest predicted reservoir pressure at the end of the CO_2 injection – 20 million tonnes).

The first stage will involve creating reliable baseline for each domain to establish a pre-injection condition. Monitoring of the reservoir performance starts during the pre-injection phase by recording and analyzing the reservoir pressure.

During the injection phase will be a period of intensive monitoring to validate and update numerical models and ensure safe injection operations.

Reservoir monitoring requires installation of pressure gauges and measurement of saturation in observation wells.

The following tables specified the general surveillance activities related in general to the reservoir during the injection phase:

Table A-2 Reservoir surveillance activities

Activity	Description	WRM Objective
Reservoir Pressure – PDG	By PDG installed in the wells. GYA03 will be a monitor well during the initial phase of injection providing an undisturbed reservoir pressure monitoring.	Identify pressure conformance in Captain reservoir, identify when system will re-pressurise and have energy to drive fluids out of the store Identify pressure conformance in Captain reservoir Objective: 3a, 3c
CO_2 tracer	If geochemical tracers are proven an effective technique then it is envisaged that they could be added to the Goldeneye CO_2 stream. The tracer is expected to be added using continuous injection method. CO_2 tracer management will require further study.	The primary aim of adding a tracer is to uniquely tag the Goldeneye CO_2 stream, which will help with the identification of sources of any CO_2 detected outside the Goldeneye complex.

The focus is to monitor the exact location of the CO_2 plume to calibrate reservoir modelling. The validated reservoir model would then be able to predict further CO_2 plume movement in directions where wells do not exist. GYA03 will be initially used as a monitoring well for this purpose.

Dynamic simulation prediction drives the start and duration of the surveillance programme in GYA03. It suggests the timing when the CO_2 plume will reach the monitoring well (GYA-03 in the base case scenario) and the number of saturation data points required to characterise the model.

Table A-3 Monitoring well (GYA03) surveillance activities

Activities in GYA03	Description	WRM Objective
Saturation quantification	Wireline intervention. Sigma logging Neutron porosity logging Yr 5-10, periodically every year For saturation logging, the baseline is a test run, to see if sigma and neutron porosity logging precondition requirements are met. The logging requires a repeat run and quick log interpretation to determine fluid contact between remaining hydrocarbon gas (if any) and water column before the tool is pulled out, to allow for an additional run if log interpretation is of low confidence.	Identify breakthrough CO_2 interval profile for saturation conformance Objective: 3b
Saturation detection	Downhole sampling. Yr 5-10, periodically every year Downhole sampling will be run after fluid profiling interpretation from RST (complemented by gradiometer) is obtained. The downhole sampling is run with wireline, which has already been set up for saturation logging.	Identify CO_2 concentration profile for saturation performance. This logging is targeted at conformance rather than containment, its aim being to confirm and constrain the dynamic simulation modelling by providing information on the movement of the CO_2 front within the store Objective: 3b
Pressure conformance	PDG Long term gauge Inclusion of up to four gauges in the monitoring well (GYA03) is being evaluated in order to give better discrimination of the multiple fluids contacts that could occur in the wellbore. This will be pursued during the detailed design phase.	Objective: 3a, 3b, 3c

A.3. Surface facilities monitoring

Table A-4 Surface surveillance activities

Activity	Description	WRM Objective
Flow Metering	Each injection flowline will be installed with orifice meter run complete with temperature and pressure measurement for continuous measurement. Mass flow will be the standard flow measurement unit for CO_2 throughout the installation. Total flow will be measured using an orifice meter run and density compensation added as an input to the mass flow calculation.	Measure flow rates Objective 1b, 2a, 2b, 2c, 3c, 4a
Gas Detection	For gas detection, line-of-sight (LOS) techniques will be used due to their reliable coverage of large areas. This technology is especially useful for detecting the migration of significant gas clouds between process modules and the accumulation of gas clouds within process modules. In areas where there is a risk of leakage (e.g., concentration of flanged joints, screwed joints, valve spindles/packing and complex instrumentation piping) point detectors using the IR absorption technique shall be employed	HSE: Gas detection Objective 4a
Composition	Compositional data is available from multiple points between the source at Longannet and the St Fergus gas terminal. Analysis will be carried out on a continuous basis but the sample processing time is in the order of 15 minutes.	Monitor specially for water and oxygen concentration Objective 1a, 2a

A. Bowtie containment risk assessment

A.1. Overview of bowtie risk assessment method

The benefits of using bowtie analysis for risk management have been realised by organisations world-wide across a variety of business sectors and the method has been in widespread use since the mid-1990s. It provides a readily understandable visualisation of the relationships between the causes of unwanted events, the escalation of such events to a range of possible outcomes, the controls preventing the event from occurring and the mitigation measures in place to limit the consequences.

Illustrating the preventive and mitigation controls against their respective causes and consequences in such a structured way demonstrates that risks are understood and are being controlled, and can highlight gaps in risk control which should be a focus for remedial action. The bowtie diagram provides a simple visual demonstration of the way in which risks are managed. This allows understanding at all levels, including non-risk specialists, giving everyone the opportunity to review the existing controls in place and to identify any potential improvements.

A.1.1. *Bowtie method*

The bowtie method entails building a bowtie diagram (Figure A-1), step-by-step, to produce a qualitative risk assessment of the hazard under consideration.

For the Goldeneye CCS project, the hazard is leakage of carbon dioxide (CO_2) from the storage complex. It has the potential to cause harm (e.g. by asphyxiating people who are engulfed by a cloud of CO_2, from acidic corrosion when CO_2 is dissolved in water or by contributing to greenhouse gas environmental damage).

Hazards normally do not cause harm because they are kept under control. However, if control of the hazard is lost, an initial incident will occur – this is the **top event** and is shown at the centre of the bowtie diagram. For the Goldeneye CCS project, the top event is movement of CO_2 outside the confines of the storage complex i.e. movement of CO_2 laterally more than 2km beyond the original Goldeneye hydrocarbon water contact or vertically above the Lista secondary seal.

The **causes** (sometimes called "**threats**") illustrate the various ways in which the hazard could be released i.e. what could cause loss of control of the hazard? Examples of causes which could result in movement of CO_2 outside the Goldeneye storage complex include leakage through existing faults or fractures which cross the primary and secondary seal, injection induced stress causing new faults or fractures or re-opening existing faults or fractures, and flow of CO_2 up through abandoned wellbores (as described above in Sections 8.4.5 and 8.4.6).

Once control is lost and the top event occurs, there may be a number of ways in which the event can develop to the ultimate **consequence**. Each consequence will result in a specific extent of harm i.e. severity of impact. The impact might be on people, the environment, physical assets or the reputation of the company, or all of these. Examples of potential consequences relevant to the Goldeneye project are release of CO_2 at the seabed, release into the shallow subsurface, or a deeper release just above the Lista secondary seal.

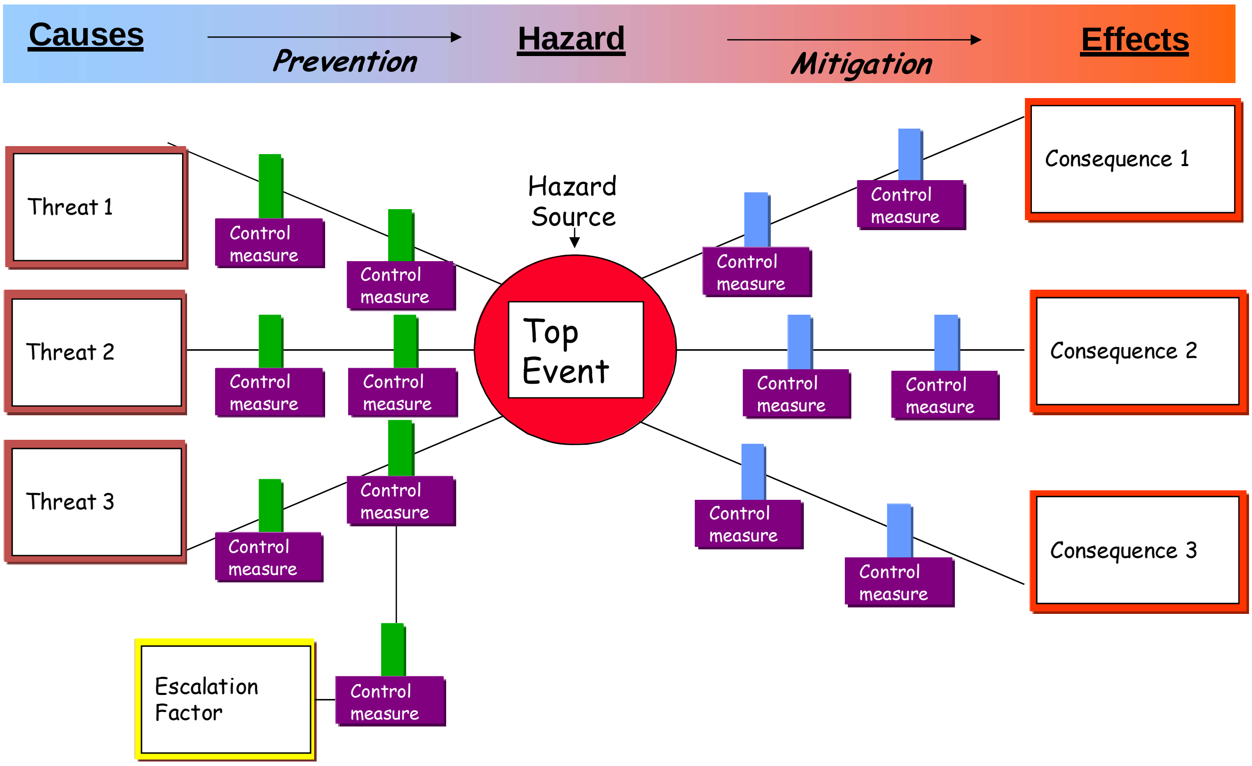


Figure A-1: Bowtie diagram schematic

There are **barriers** in place which can prevent the release of the hazard (i.e. prevent the threat leading to the top event). These barriers are shown on the left side of the bowtie diagram and can be items of equipment or actions taken in accordance with training and procedures. They also include natural barriers such as impermeable geological layers. No control can be 100% effective, so if the preventive measures fail to maintain control and the top event occurs, further **mitigation measures** are in place to interrupt development of the event and limit, or recover from, the consequences.

Circumstances may arise which undermine a preventive or mitigation control and reduce its effectiveness; these are recorded on the diagram as **escalation factors** (i.e. they allow the event to escalate). Escalation factors are, in turn, managed by further control measures.

Mapping the hazard in this manner promotes a structured review of the hazard, each threat and each consequence, identifying not only what is planned to be in place, but also how control efficacy can be improved or further controls can be added to provide more effective management of the risk.

B. Environmental details

The full site selection and characterisation, addressing all details of Appendix I of the EU directive, is incorporated in the separate report: site selection, characterisation, and dynamic modelling. This section presents a concise summary and only discusses information directly relevant to the storage development decision.

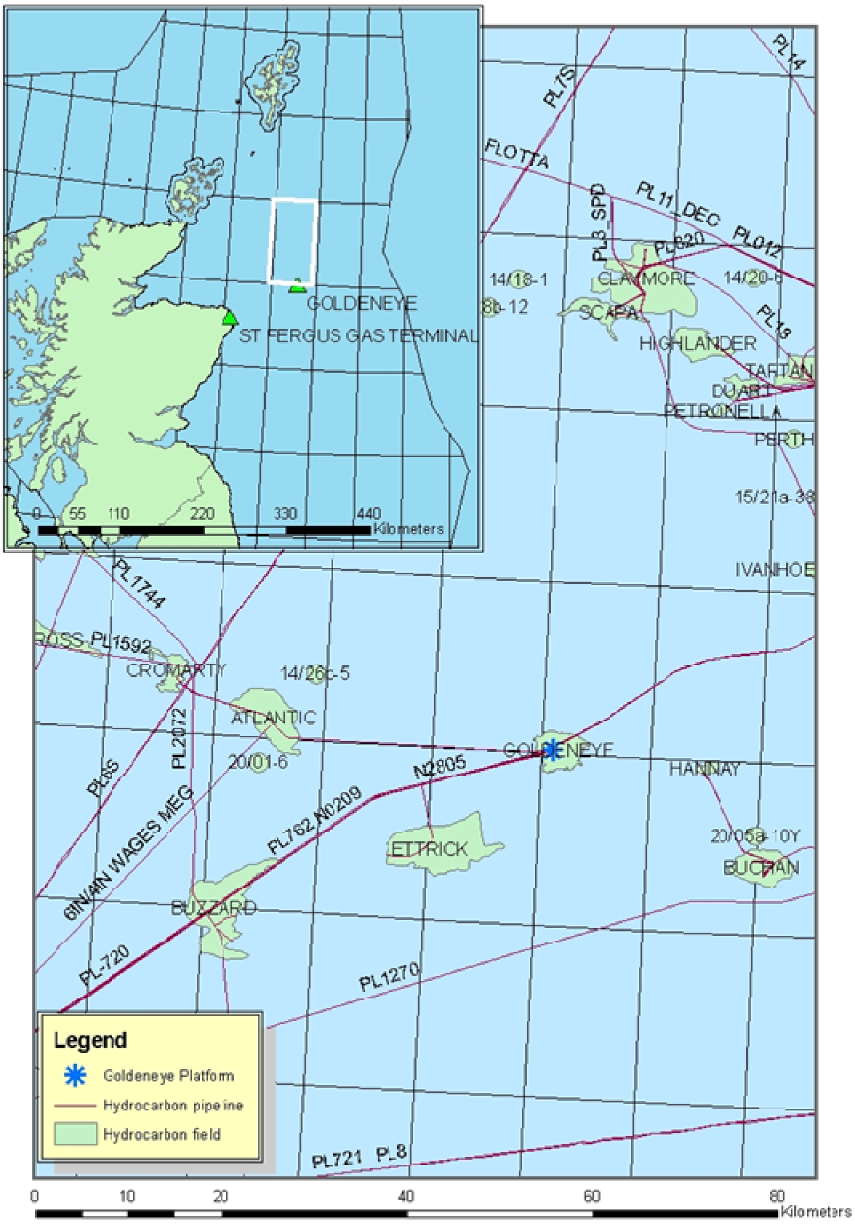


Figure B-1 Goldeneye location map

A1.1. Location of site

The Goldeneye field is located mainly in UKCS blocks 14/29a (Offshore Hydrocarbon Production License P257) and 20/4b (License P592), and is mapped to straddle blocks 14/28b (License P732) and 20/3b (License P739), in water of approximately 120m depth. The field is located approximately 100km northeast of the St Fergus gas terminal on the east coast of Scotland (Figure B-1).

B.1. Seabed and surrounding ecosystems

A brief synopsis of the baseline environment over the Goldeneye Storage Complex can be found in the following sections. This is based on an Environmental Impact Assessment (EIA)[1] written in anticipation of the submission of an Environmental Statement (ES) to the Secretary of State under the modified Offshore Petroleum Production and Pipelines (Assessment of Environmental Effects) Regulations 1999. This will form the basis of any such submission and will be updated prior to submission for the consideration of the Secretary of State.

B.1.1. Physical environment

B.1.1.1. Currents, temperature and wind

The prevailing current over the Goldeneye CCS storage complex is southerly and has a uniform speed between the surface and mid-water, reducing towards the seabed (Table B-1).

Table B-1 Maximum sea currents in the Goldeneye Development Area.

	1 Year		10 Year	
Current direction	Velocity m/s surface	Velocity m/s seabed	Velocity m/s surface	Velocity m/s seabed
Goldeneye NUI	0.75	0.43	0.81	0.46
Block 20/6 (eastern pipeline route section)	1.04	0.59	1.14	0.65
Block 19/13 (western pipeline route section)	1.4	0.80	1.55	0.90

Average sea surface temperature in the area of the development range from 6.0°C at the surface in winter and 14.5°C at the surface in summer. The water temperature at the seabed is similar during the winter; however, in summer the mean is approximately 7.0°C[2].

Wind direction and velocity is variable throughout the year with the wind originating predominantly from the south to northwest. Annual wind velocities in the area range from 0 - 26 m/s with the calmest months being June to August and the windiest months being December to March.

[1] Shell, 2010. SP-F_HS010D3 Environmental Impact Assessment

[2] NERC, 1998. *United Kingdom digital marine atlas (UKDMAP) – version 3, July 1998*. Birkenhead, Merseyside: National Environmental Research Council/British Oceanographic Data Centre, Bidston Observatory

B.1.2. Benthos

From a survey of the area approximately 15x15 km around the Goldeneye platform, the most abundant taxa recorded were polychaetes, with the ampinomid polychaete (fireworm) *Paramphinome jeffreysii* being recorded at an exceptionally high abundance of 625.4 individuals per sample. Of the remaining taxa all but five were polychaetes, the exceptions being the bivalves *Andontorhina similes, Parvicardium minimum* and *Mendicula ferruginosa*, the opisthobranch *Cylichnia umbilicata* and nemertean (ribbon) worms. All but twelve of the most abundant taxa occurred in a high proportion of the samples, seven occurring in all of the samples acquired. The high frequencies of occurrence calculated suggested that there was minimal differentiation of community across the survey area, an interpretation supported by analysis of abundance and dominance across sample sites. The benthic assemblage is consistent with silty sand that is the dominant sediment type throughout the survey area.

The epifaunal community recorded from underwater photographic data was sparse, although extensive bioturbation was observed suggesting that a substantial burrowing megafaunal community may occur within the survey area. The most prominent epifaunal species seen were the seapens *Virgularia mirabilis* and *Pennatula phosphorea*, accompanying these sedentary epifaunal species were occasional hermit crabs (order *Paguroidea*).

B.1.3. Plankton

Planktonic populations are widely distributed and numerous in the North Sea. Though individual planktonic organisms can experience toxic effects from oil and dissolved CO_2 in water, the very high turnover of plankton populations means that it is unlikely that the impact on plankton from offshore developments will be significant.

B.1.4. Fish and crustacea

The development lies within the vicinity of spawning and/or nursery grounds for Haddock, lemon sole, sand eel, blue whiting, Norway pout, whiting, saithe, plaice, sprat, herring and *Nephrops*. Spawning and nursery grounds for these species cover large areas of the North Sea, and as such, they are unlikely to be significantly affected by any single offshore development.

B.1.5. Seabirds

At the Goldeneye platform offshore bird vulnerability is very high in August and September with the remainder of the year being low, moderate, or high. Table B-2 shows the vulnerability index. Towards inshore waters offshore vulnerability increases with Blocks 19/12 and 19/13 experiencing very high or high offshore vulnerability throughout the year. Divers, guillemot, fulmar, sooty shearwater, manx shearwater, storm petrel, gannet, cormorant, shag, common scoter, arctic & great skua, common gull, lesser black backed gull, kittiwake, herring gull, great black backed gull, tern, razorbill, little auk and puffin are likely to be present in the development area and thus the species most at risk.

Table B-2 Oil vulnerability index for seabirds within the Goldeneye Development Area

Block	J	F	M	A	M	J	J	A	S	O	N	D	Overall
14/28	4	2	3	3	4	3	1	1	1	2	3	3	2
14/29	4	2	4	4	4	4	2	1	1	2	3	3	3
14/30	3	2	4	4	3	4	2	1	1	2	1	3	2
19/9	3	2	2	2	2	1	1	1	1	1	2	3	1
19/10	3	2	2	2	2	1	1	1	1	1	2	3	1
19/12	1	2	2	1	2	1	1	1	1	1	1	1	1
19/13	1	2	2	1	2	1	1	1	1	1	1	1	1
19/14	3	2	3	3	2	1	1	1	1	1	2	3	1
20/1	4	2	3	3	4	2	1	1	1	4	3	3	2
20/2	4	2	3	3	4	2	1	1	1	4	3	3	2
20/3	4	2	3	3	4	2	1	1	1	1	2	3	2
20/4	4	2	4	4	4	3	2	1	1	1	2	3	2
20/5	3	2	3	4	3	3	2	1	1	1	1	3	2
20/6	4	2	3	3	2	2	1	1	1	4	2	4	2

Very high 1 High 2 Moderate 3 Low 4

B.1.6. Marine mammals

Low numbers of cetaceans occur throughout the year. Sightings suggest that harbour porpoise, minke whale, white beaked dolphin, white sided dolphin, and bottlenose dolphin may be present in the area. The highest number of sightings is commonly in the summer months, though large numbers of harbour porpoise and white beaked dolphin are also sighted in winter months. Table B-3 shows marine mammal abundance/density.

Table B-3 Cetaceans likely to frequent the Goldeneye Development Area[3,4]

Species	J	F	M	A	M	J	J	A	S	O	N	D	Abundance	Density
Harbour porpoise													47131	0.294
Minke whale													4449	0.028
White beaked dolphin													7862	0.049
White sided dolphin													6460	0.040
Bottlenose dolphin													123	0.001

0-0.001 individuals per hour	0.001-0.01 individuals per hour	0.01-1 individuals per hour	1-10 individuals per hour	Patterned cell: > 100 hrs effort	No pattern: Less than 100hrs effort

Note: The data for white-sided dolphin refers to white-beaked dolphin and white sided dolphin combined due to difficulty in distinguishing the two species in the field.

B.1.7. Protected areas

At the moment, there are thirteen candidate/draft/possible Special Areas of Conservation (SACs) on the UKCS. Of these, two are located within the vicinity of the Goldeneye development. 'Scanner Pockmarks' and 'Braemar Pockmarks' are located ~83km and ~149km to the northeast of the Goldeneye platform, respectively. They are shown in Figure B-2. Both features contain Annex I habitat:

"Submarine structures made by leaking gases"

The site surveys and pipeline route surveys undertaken in the vicinity of the development found no species or habitats of conservation significance under the UK's Offshore Petroleum Activities (Conservation of Habitats) Regulations 2001, which implement the EC Habitats Directive 92/43/EEC. Due to this, and the relatively large distance from the Goldeneye platform to both the 'Scanner' and 'Braemar Pockmarks', the development is not considered to pose any risk to these Annex I habitats.

[3] Reid, J.B., Evans, P.G.H. and Northridge, S.P. 2003. *Atlas of cetacean distribution in north-west European waters.* Peterborough, UK: Joint Nature Conservation Committee

[4] JNCC, 2008. The deliberate disturbance of marine European species; guidance for English and Welsh territorial waters and the UK offshore marine area. Peterborough, UK: Joint Nature Conservation Committee

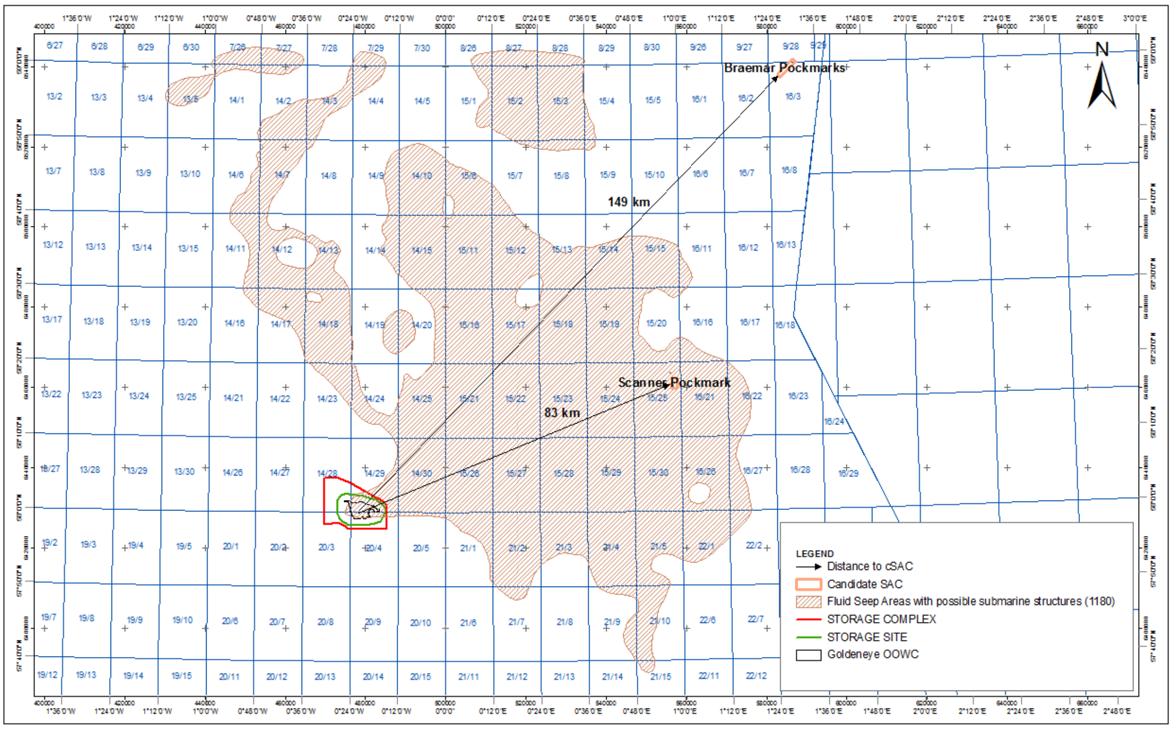


Figure B-2 Goldeneye location in relation to the 'Scanner' and 'Braemar Pockmarks'.

B.2. Other users of the environment

Fishing effort

The fishing effort by UK vessels for International Council for the Exploration of the Sea (ICES) block 45E9 (which includes the Goldeneye Development Area) and 44E9 and 44E8 (the pipeline route) remained steady during 2007 and 2008 showing a slight decrease in effort throughout 2009. ICES blocks 44E8 and 44E9 along the Goldeneye pipeline route are less intensively fished, however, fishing effort in these blocks increased from 2007 to 2009. Overall, the fishing effort within the development area is relatively low in comparison to other blocks where the fishing effort can be as high as 20,000 hours per year. Correspondingly, in 2008 fishing effort in ICES 44E8 represented 0.25% of the total fishing effort in UK waters in the same year. During 2007, UK vessel fishing effort in ICES block 45E9 represented 1.2% of the total UK fishing fleet effort during that year.

Fishing intensity within the development area is relatively low. Fishing effort expended in the development area ranged between 0.25% and 1.2% of that expended in UK waters while the catch from the ICES blocks within the vicinity of the Goldeneye development represents at most 0.78% of that from UK waters.

The data obtained from the Marine Directorate (Sea Fisheries Management Division, Marine Directorate, 2010) shows that 44E8 and 44E9 are predominantly targeted for demersal species, using bottom trawl gear while 45E9 is targeted mainly for crustaceans using bottom trawl gear. Landings from ICES 44E8, 45E8, and 45E9 represent between 0.24% and 0.72% of the total UK catch.

Shipping

Based on data presented for the Strategic Environmental Assessment 2 (SEA2) area indicates that shipping in the central and northern North Sea is relatively moderate. An average of between 1 and 10 vessels per day pass through, with the greater part of traffic consisting of merchant ships, supply vessels, and tankers. Merchant vessels account for over 61% of vessels with 45% of these vessels falling within the weight class of 0-1499 dwt. Supply vessel routes originate in Aberdeen or Peterhead. A number of tanker routes exist within the SEA2 region, the majority of which are orientated along a north-south heading. All tankers within the area weigh in excess of 40,000 dwt[5] (DTI, 2001).

Submarine cables and pipeline

Figure B-3 shows that there is one telecommunication cable in use in the vicinity of the development (CNS Fibre Optic (BP)).

The 36" Beryl to St Fergus (operated by ExxonMobil) and 30" Miller to St Fergus (operated by BP) pipelines pass to the north of the Goldeneye platform. The Britannia to St Fergus gas export pipeline passes the Goldeneye platform ~20km to the south as shown in Figure B-3. The Goldeneye pipeline route crosses a number of pipelines as shown in Table B-4.

Table B-4 Pipeline crossings

KP	Easting	Northing	Burial status	Description
8.720	399,580	6,383,665	Buried	36" Brent A to St Fergus Pipeline
13.415	404,269	6,383,409	Buried	32" Frigg No. 2 to St Fergus Pipeline
13.599	404,452	6,383,399	Buried	32" Frigg No. 1 to St Fergus Pipeline
14.631	405,483	6,383,342	Buried	30" Miller to St Fergus Gas Pipeline
17.158	407,785	6,384,066	Exposed	28" Britannia to St Fergus Gas Pipeline

[5] DTI, 2001. Strategic environmental assessment of the mature areas of the offshore North Sea. SEA 2, September 2001. Department of Trade and Industry

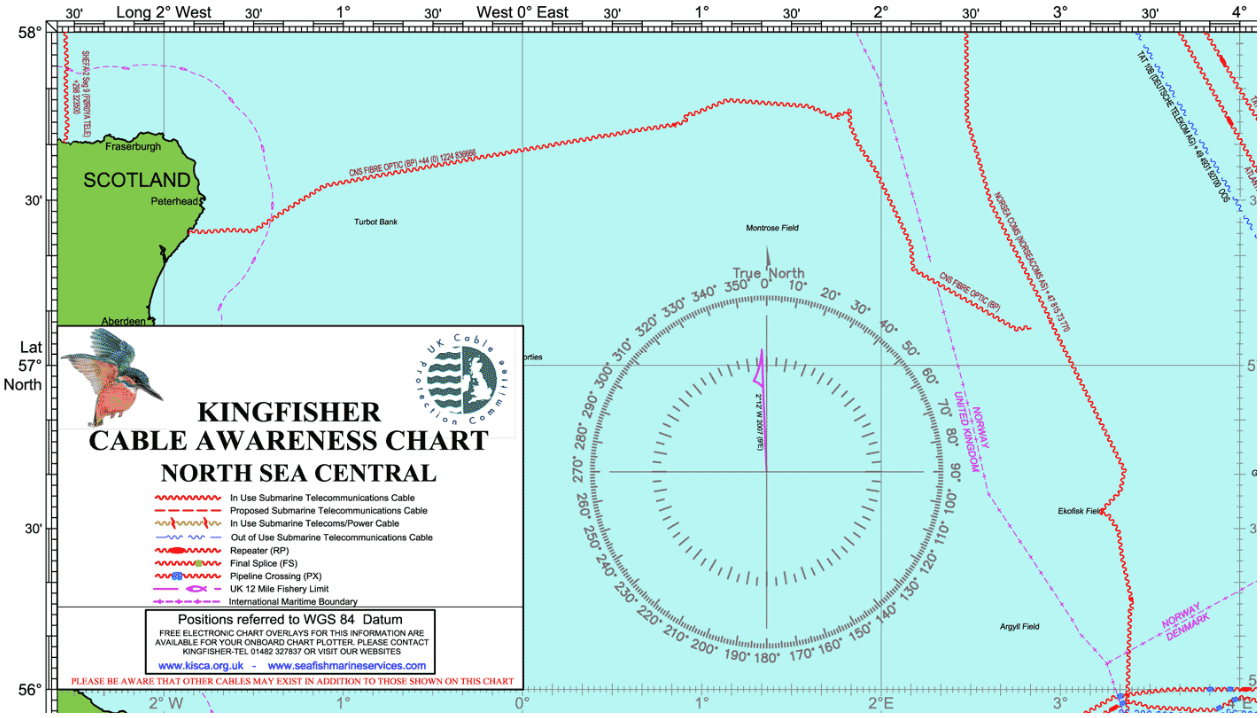


Figure B-3 Cables in the vicinity of the Goldeneye area[6]

Wind farms, Aggregates extraction, Shipwrecks

There are no offshore wind farms proposed in the vicinity of the development.

There are no areas licensed for aggregate extraction in the vicinity of the development[7].

No shipwrecks were identified in the immediate vicinity of the development by any of the surveys undertaken in the development area.

[6] Kingfisher, 2009. Central North Sea cable awareness chart.

[7] Crown, Estate, 2010.

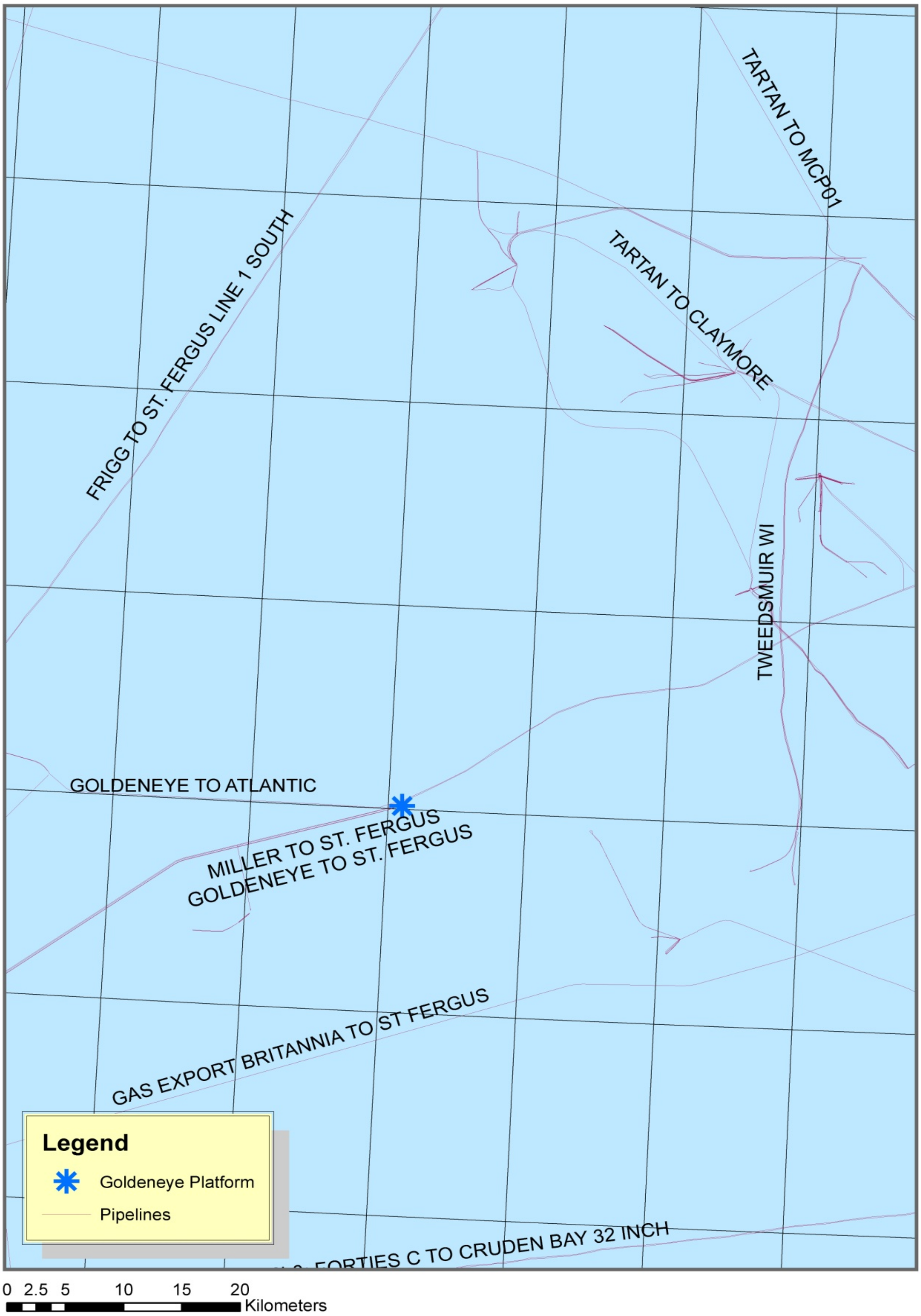


Figure B-4 Pipelines in the vicinity of the development.

C. Outline T&Cs to License Required Storage Complex

This appendix repeats deliverable SP-F_CO010-Outline T&C's to License Required Storage Complex

C.1. Purpose of this document

The intended purpose of this document is to describe as far as possible the anticipated conditions for the award of, and terms for complying with, a Carbon Storage Licence and a Carbon Storage Permit for the storage of carbon dioxide (CO_2) in the Goldeneye Field.

As set out more fully below, various provisions of the EU CCS Directive are still being transposed in to UK law. Separately, the issue of Licences and Permits for CO_2 storage by the Department of Energy & Climate Change (DECC) is in any event subject to prior completion of an ongoing update of a Strategic Environmental Assessment. This report is therefore written against the backdrop of significant regulatory change and uncertainty. In the absence of having secured either a Licence or a Permit this report therefore describes as much as is presently known about the anticipated terms and conditions but should not be regarded as definitive.

The position set out in this deliverable represents Shell current understanding of the position. It must be noted however that this position may be subject to change depending on the outcome of the negotiations in respect of the Project Contract between Shell and the other members of the ScottishPower consortium, the Storage Joint Venture Parties and the Authority. In addition, dependant on the outcome of those negotiations and any consequential amendments to any of the other arrangements being negotiated by Shell to enable Shell to implement its obligations under the Project Contract, changes to the position set out herein may require to be dealt with depending on the outcome of such negotiations. The position set out herein is without prejudice to Shells position in relation to any such negotiations.

C.2. Legislative background

C.2.1. CCS Directive

Directive 2009/31/EC on the geological storage of carbon dioxide (CCS Directive) establishes a legal framework for the environmentally safe geological storage of carbon dioxide (CO_2), including the division of responsibilities between the EU and Member States. It covers all CO_2 storage in geological formations in the EU both onshore and offshore and lays down requirements covering the entire lifetime of a storage site. Existing legal frameworks are used to regulate the capture and transport components of CCS.

The Directive lays down extensive requirements for site selection, which is crucial to ensuring the integrity of a project and thus to the long-term security of geological storage. Article 4 provides that Member States have the right to determine the areas where storage sites may be selected, but a site can only be selected for use if a prior analysis shows that, under the proposed conditions of use, there is no significant risk of leakage or damage to human health or the environment. The suitability of a geological formation for use as a storage site must be determined through a detailed characterisation and assessment process, which is described in Annex I to the Directive.

Pursuant to Article 5, exploration for possible storage sites is permissible only with an exploration permit, the award of which is subject to entities possessing the necessary capacities based on objective published criteria. The exploration stage could, however, be 'skipped' if sufficient data is already available. Exploration permits may be granted for a limited volume area and for no more than the period necessary to carry out the exploration activities, but with the possibility of a limited extension. The permit holder will have exclusive exploration rights and Member States must ensure that no conflicting uses of the permitted area are authorised during the period of the permit's validity.

Member States must subsequently ensure that operation of a storage site is permissible only with a storage permit, similarly awarded on non-discriminatory terms and subject to objective, published criteria. Although storage permits are matters of national jurisdiction, Member States must inform the European Commission (EC) of all draft storage permit award decisions. The EC then has a period of up to four months within which it may issue an opinion on a draft permit, which the relevant competent authority is required to take into account when making its final decision. If the competent authority deviates from the EC's opinion, it must provide the EC with its reasons. Further comment on this particular aspect is provided in section 3.3 below.

The storage permit conditions must ensure that the injected stream consists overwhelmingly of CO_2 in order to prevent any adverse effects on the security of the transport network or the storage site. Award of a storage permit is also subject to Member State approval of a Monitoring Plan, which meets the criteria, set out in Annex II of the Directive, to confirm that the injected CO_2 is behaving as expected and in particular is not leaking or causing other adverse effects. The plan must be updated every five years to take account of technical developments.

The Directive also contains criteria for the transfer of responsibility from the operator to the competent authority, setting out a series of closure and post-closure obligations including a requirement for decommissioning the infrastructure and stipulation that a period of time must elapse between cessation of the injection operations and closure of a site in order to ascertain and confirm that the stored CO_2 is evolving towards long-term permanent containment.

Finally, a financial security needs to be established before injection commences to ensure that obligations arising under the storage permit (as defined by the terms of the CCS Directive and the Emissions Trading Directive) can be met. A second financial instrument is the financial contribution of the storage operator to the competent authority in order to cover the anticipated cost of monitoring after the transfer of responsibility.

With regard to liability for any leakage, the Directive establishing Phase III of the EU ETS (2013 - 2020) explicitly recognises CCS such that emissions captured, transported, and stored according to this Directive will be considered as not emitted, meaning that emissions allowances would have to be surrendered for any emissions resulting from leakage from the capture, transport, or storage. Liability for local damage to the environment is dealt with by using the existing Directive on Environmental Liability. As for other activities, liability for damage to health and property is not regulated at EU level.

The Directive was adopted on 23rd April 2009, and Member States have until 25th June 2011 to adopt its provisions.

C.2.2. 2008 Energy Act

Transposing most of the provisions of the CCS Directive, Part I, Chapter 3 of the Energy Act 2008 provides one of the first bespoke legal regimes anywhere in the world specifically designed to permit the safe storage of carbon dioxide underground. It provides for the UK, consistently with the terms of the United Nations Convention on the Law of the Sea, to assert certain rights to make use of the offshore area beyond the territorial sea for CO_2 storage through the designation of a Gas Importation and Storage Zone (GISZ). The GISZ was designated on 6th April 2009 by SI 2009/223. The licensing regime for CO_2 storage will extend throughout the GISZ, as well as the area of the territorial sea, which will together cover an area extending up to 200 nautical miles from the baselines of the territorial sea.

The Energy Act also contains primary legislation providing for Government to define a regulatory regime for CO_2 storage in the UK offshore area, and for certain relevant existing offshore oil and gas legislation, for example the decommissioning regime of Part IV of the Petroleum Act 1998, to be applied to facilities used for CO_2 storage.

Under the provisions of the Act, the Scottish Ministers also have the regulation-making, licensing and enforcement powers in relation to carbon storage sites located in the territorial sea adjacent to Scotland. In the remainder of the relevant UK waters, such powers are vested in the Secretary of State.

C.2.3. Storage Regulations

On 9th September 2010 the Department of Energy and Climate Change (DECC) laid before Parliament the Storage of Carbon Dioxide (Licensing etc.) Regulations 2010 (SI 2010 No 2221). These Regulations make provisions for implementing the CCS Directive and for implementing an amendment to Directive 2004/35/EC ("the Environmental Liability Directive") to enable the sub-seabed storage of CO_2. The Regulations came in to force on 1st October 2010.

The Regulations relate solely to licences granted by the Secretary of State for activities, which take place in the offshore area (but wholly outside territorial waters adjacent to Scotland), and installations which are in the offshore area (but outside territorial waters adjacent to Scotland). They do not apply to the category of licence, which authorises the exploration of the offshore area by means of non-intrusive methods such as seismic surveys and shallow drilling (see section 3.1, below). Such licences will be issued in conjunction with the corresponding licences granted under section 4 of the Act and section 3 of the Petroleum Act 1998.

The Regulations implement the requirements of the CCS Directive concerning: (1) the licensing of carbon dioxide storage (and related exploration activities); (2) the obligations of the storage operator (for example in relation to monitoring, reporting and corrective measures) whilst storage activities are taking place; and (3) the operator's continuing obligations for a period after the closure of the store until the licence is terminated. The subsequent transfer of liabilities from the operator to the authority, on termination of the licence, is the subject of a separate instrument (see section 2.5 below).

Until the provisions of the Act are extended to cover the entire territory of the United Kingdom, both onshore (including internal waters) and offshore, the requirements of the Directive are implemented with respect to storage within the offshore area only.

C.2.4. Environmental Amendment Order

The Energy Act 2008 (Consequential Modifications) (Offshore Environmental Protection) Order 2010 modifies numerous pieces of environmental legislation so that they apply to CO_2 storage and to pipelines conveying CO_2. The principal environmental regulations that will be applied to these new developments are:

- The Offshore Petroleum Production and Pipelines (Assessment of Environmental Effects) Regulations 1999 (as amended). These regulations implement the EU Environmental Impact Assessment Directive for relevant categories of offshore activities.
- The Offshore Petroleum Activities (Conservation of Habitats) Regulations 2001 (as amended). These regulations implement the EU Habitats and Birds Directives for relevant categories of offshore activities.
- The Offshore Combustion Installations (Prevention and Control of Pollution) Regulations 2001 (as amended). These regulations implement the EU Integrated Pollution Prevention and Control regime – since November 2010 replaced by the Industrial Emissions Directive 2010/75/EU – in so far as it applies to offshore combustion installations with an aggregated thermal capacity of greater than 50 Megawatts (thermal).
- The Greenhouse Gas Emissions Trading Scheme Regulations 2005 (as amended). These regulations implement the EU Emissions Trading Scheme, which applies to all combustion installations with an aggregated thermal capacity of greater than 20 Megawatts (thermal). Phase II of the Scheme commenced in January 2008, and covers the period up to the Kyoto commitment deadline of December 2012. Phase III of the EU-ETS commences in 2013 and recognises CO_2 stored in accordance with the CCS Directive as "not emitted" for the purposes of purchasing Emissions Allowances.
- The Offshore Chemicals Regulations 2002. These regulations implement an international convention agreement (the OSPAR Convention) relating to the permitting of chemical use and discharge in the course of offshore oil and gas activities, but the provisions of the regulations are considered to be equally relevant to developments covered by the Energy Act licences. See also the REACH Regulations 2008 (below).
- The Offshore Petroleum Activities (Oil Pollution Prevention and Control) Regulations 2005. These regulations control the discharge of hydrocarbons ("oil"), and the provisions are considered to be equally relevant to developments covered by the Energy Act licences.
- The Offshore Installations (Emergency Pollution Control) Regulations 2002. These regulations implement the recommendations of the Donaldson Report requiring the appointment of a Secretary of State's representative (SoSREP) to oversee the response to "oil" pollution incidents, establishing powers to allow the DECC SoSREP to intervene in the event of an offshore incident or where there is a significant threat of pollution.
- Offshore Marine Conservation (Natural Habitats, &c) Regulations 2007 (as amended). These regulations implement the EU Habitats and Birds Directives for relevant categories of offshore activities in relation to activities consented to by the Department for the Environment, Food, and Rural Affairs (Defra).
- Environmental Protection (Controls on Ozone-Depleting Substances) Regulations 2002 (as amended). These regulations enforce the EU Ozone-Depleting Substances (ODS) Regulation which, among other things, aims to control / reduce emissions of ODS (i.e. halons) from existing equipment such as refrigeration systems, air-conditioning units and fire-protection systems.
- REACH Enforcement Regulations 2008. These regulations enforce the EU REACH (Registration, Evaluation, Authorisation, and Restriction of Chemicals) Regulation which imposes obligations on manufacturers / importers of chemical substances and downstream users, to evaluate and control the risks associated with their use.

- Fluorinated Greenhouse Gases Regulations 2009. These regulations enforce the EU F-Gases Regulation which aims to contain, prevent and reduce emissions of F-Gases (i.e. Hydrofluorocarbons (HFCs)) from equipment such as refrigeration systems, air-conditioning units and fire-protection systems. The UK Regulations apply to the offshore oil / gas industry which is required to comply with the obligations on leakage checking; the keeping of records (relating to the maintenance of equipment); and the reporting of F-Gas emissions.

Article 2 of the Energy Act 2008 (Consequential Modifications) (Offshore Environmental Protection) Order 2010 modifies The Offshore Petroleum Production and Pipelines (Assessment of Environmental Effects) Regulations 1999 (as amended). As a result, there is a requirement to include an Environmental Statement (ES) in an application for a project, which plans to carry out storage or pipeline conveyance of CO_2. Therefore, before any Carbon Storage Permit can be issued an ES must be approved. The anticipated approval timeline from submission to DECC is 6 months, which includes a minimum 28-day public consultation period under the Public Participation Directive.

C.2.5. Further Legislation

Transfer of Responsibility

At the date of this report, DECC have recently concluded a public consultation on a proposed new draft Regulation (The Storage of Carbon Dioxide (Termination of Licences) Regulations 2011) intended to define arrangements for the transfer of responsibility for a CO_2 storage site at the end of operations. Shell responded to this consultation, and provided input to separate responses by the Carbon Capture & Storage Association (CCSA) and by Oil & Gas UK (OGUK).

Very broadly, the draft Regulation does little more than transpose the provisions of Articles 18 and 20 of the CCS Directive, and in this regard Shell has no significant concerns with DECC's proposals. However, incremental to the requirements of the Directive the Regulation does make provision for open-ended powers for the Secretary of State to impose additional obligations on storage site operators at will. This has been challenged in Shell's submission to the public consultation and we await a response from DECC.

Subject to the findings of the consultation exercise, we understand it is DECC's intent to lay the new Regulation before Parliament with a view to it coming in to force before end-Q2 2011.

C.3. UK CO_2 Storage Licensing Regime

On the basis of ongoing discussions with DECC, and on the UK Storage Regulations, we understand and envisage the following requirements for an exploration licence, Carbon Storage Licence and Carbon Storage Permit for the proposed storage of carbon dioxide in the Goldeneye field. Note, however, that until any such licences are received Shell will not be in a position to confirm their actual form. As regulation 1(2)(b) of the storage regulations makes clear, it is not necessary for the provisions included in a licence or storage permit to be verbally identical to the specified provisions, as long as they have the same legal effect.

The key elements of the UK's CO_2 storage licensing regime are set out schematically in Figure 1 below.

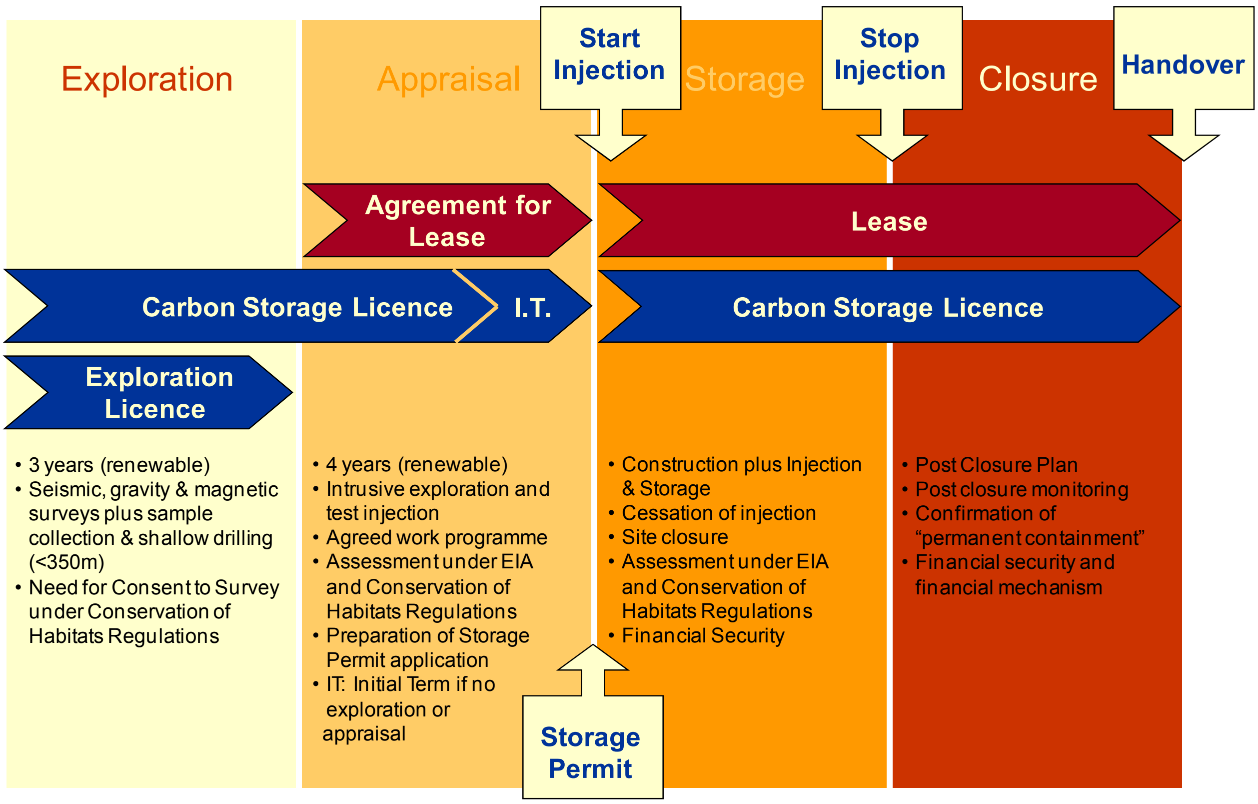
C.3.1. Exploration Licence

Non-intrusive exploration activities, in areas below the low water mark, are already regulated under the Petroleum Act 1998. Since the activities involved in such exploration do not depend on the ultimate purpose, DECC is currently adapting the existing Exploration Licence so that it becomes a combined licence issued under the Petroleum Act and the Energy Act 2008. It will then cover any combination of exploratory activities relating to petroleum, carbon dioxide storage, or storage and gas unloading of natural gas as applicable, enabling seismic, gravity and magnetic surveys; sample collection and shallow drilling (i.e. not beyond 350 meters below the seabed surface). The licence is valid for three years, renewable on request, and currently costs £500.

At this stage of exploration, a developer would not be required to have a Crown Estate lease or a carbon storage licence, though consents required by the Regulations implementing EU Council Directive 79/409/EEC on the conservation of wild birds and Council Directive 92/43/EEC on the conservation of natural habitats and wild fauna and flora may be necessary.

The requirement for an Exploration Licence in connection with the proposed storage of CO2 in the Goldeneye Field is subject to agreement on the detailed Project Execution Plan.

FIGURE 1: UK Carbon Dioxide Storage Licensing Framework



C.3.2. Carbon Storage Licence

A carbon storage licence will be required in order to undertake storage site appraisal activities, and to prepare and submit to DECC an application for consent for storage operations. Regulation 3 requires that the licence application shall be for a licence with, or without, an "appraisal term" (during which the holder will have the right to carry on exploration activities with view to selecting a site for carbon dioxide storage). If an application is made for a licence without an appraisal term, reasons must be given in the application. By regulation 4(3), a licence without an appraisal term must instead have an "initial term"; any application by the licence holder for a permit to store carbon dioxide must be made before the end of the appraisal term or (as the case may be) the initial term. Licence award will be subject to an agreed work programme, whilst Regulation 3(1)(b) requires that a £2,100 will be payable upon application.

Regulation 4 requires that a time limit is placed on licence duration, in order to limit the possible hoarding of potential storage sites. There is no specific limit placed by Regulation 4 on the licence term, though in its 2009 consultation DECC suggested it might be limited to four years, extendable on request, which we consider to be adequate for the scope of work planned on Goldeneye.

The potential award of a carbon storage licence will require prior assessment under the Habitats Regulations, as is the case for Petroleum Production Licences. Drilling and test injection would also need to be assessed and approved under the Habitats Regulations and the Offshore Petroleum Production and Pipe-lines (Assessment of Environmental Effects) Regulations 1999 – "the EIA Regulations" (as extended to include carbon storage).

Finally, Regulation 5 requires that a carbon storage licence must include the closure and post-closure obligations of Schedule 1. Specifically, that a storage site may not be closed without permission, that closure is subject to prior approval of a post-closure plan from the Operator, and that the Operator's post-closure obligations include, but are not limited to, a requirement to monitor the storage site, maintain regular reporting and to remain responsible for any corrective measures, until Transfer of Responsibility has been agreed.

For the purposes of appraisal activities, the Operator will also require an Agreement for Lease from the Crown Estate. Obtaining a Licence and Lease is conditional upon obtaining the other. Early and extensive contact has been be made with both DECC and Crown Estate during the FEED study to discuss the proposals for storing carbon dioxide in the Goldeneye Field, to establish the likely licences and consents required, and to clarify the processes for securing these.

C.3.3. Carbon Storage Permit

Key Conditions for the Award and Content of a Carbon Storage Permit

DECC consent for storage operations will initiate the operational phase of the licence. The issue of a Storage Permit will allow the construction of the storage facilities and the commencement of storage injection, though operations will be subject to certain thresholds on aspects such as the permissible injection rate and the purity of the injected carbon dioxide stream.

Regulation 6 requires that an application for a Storage Permit must include at least the following:

- evidence that the site is sufficiently well characterised and is able to safely contain the intended volumes of CO_2 significant risk of leakage or of harm to the environment or human health;
- an estimate of the total quantity that is to be injected and stored;

- the prospective sources and transport methods;
- the composition of the CO_2 streams that are to be injected;
- the proposed injection rates and pressures;
- the proposed location of the injection facilities;
- a description of measures to prevent any significant irregularities;
- a proposed monitoring plan drawn up in accordance with Annex II to the Directive and that takes into account the obligations imposed on the operator under legislation implementing Article 14 of the ETS Directive;
- a proposed corrective measures plan;
- a proposed provisional post-closure plan;
- the information required to be provided in relation to the storage site under legislation implementing Article 5 of Council Directive 85/337/EEC (a);
- details of financial security that will satisfy the requirements in paragraph 7(1) of Schedule 2, including proof that (if the storage permit is granted) such a security will be in force before the proposed date on which injection is to commence.

In accordance with Regulation 7, award of a carbon storage permit is subject to an assessment of the technical competence of the Operator and to provision by the Operator of an appropriate programme of professional and technical development and training. Securing a storage permit will also depend upon successfully demonstrating that the expected behaviour of the CO_2 once stored is such that permanent containment can be achieved following cessation of injection operations and a suitable post-closure monitoring period.

There is no definitive term to the Storage Permit, but it is expected that the Permit will stipulate criteria constraining the maximum permissible amount of CO_2 that can be stored in the licensed site. In accordance with DECC's 2009 public consultation, an indicative fee of £40,000 in consideration of the resource time for assessing a Storage Permit application has been assumed.

The potential award of a consent for storage operations will need to be assessed under the EIA and Habitats Regulations, and may require approval under other environmental regulations that will be applied to carbon storage, as is presently the case for oil and gas Field Development Plans. The Operator will also need to enter into an agreement with The Crown Estate for a lease that will run in parallel with the carbon storage site until the site is closed and handover to the State has been achieved.

Regulation 8 in conjunction with Schedule 2 requires that a carbon storage permit must contain at least the following:

- the name and address of a single person who is a holder of the licence and who is designated as the operator of the storage site;
- the precise location and delimitation of the storage site and the storage complex, and any relevant information concerning the hydraulic unit;
- the operational requirements for storage, including—

  (i) the total quantity of CO_2 authorised to be stored;

  (ii) the reservoir pressure limits; and

  (iii) the maximum injection rates and pressures;

- the composition of the carbon dioxide streams that may be injected into the store, including the obligation of the operator to maintain a register of the quantities and properties of the streams injected
- any other requirements relating to injection and storage that the authority considers necessary, in particular to prevent significant irregularities;
- requirements designed to prevent any undue interference with other uses of the area surrounding the storage site;
- details of plans to monitor the storage site and complex;
- plans for the submission of periodic reports on monitoring, injection, financial security, and any other information that the authority considers relevant;
- provisions relating to reporting, and notification of leakages and significant irregularities;
- the provisions relating to notification and implementation of changes, and to review and modification or revocation of the permit;
- the corrective measures plan, and the provisions relating to corrective measures;
- the conditions for closure of the storage site;
- the provisional post-closure plan; and
- the provisions relating to financial security to be maintained by the Operator.

Referral to EU Commission

In accordance with the terms of the CCS Directive, Regulation 7(7) requires that if the authority is minded to grant award of a Carbon Storage Permit then it must forward a draft of the proposed permit to the European Commission, together with any material taken into consideration that has not already been provided under regulation 6(4). The Directive provides that the EU's Scientific Panel has up to four months to provide an opinion on the authority's draft permit award decision, subsequent to which the authority must before granting the permit consider any opinion on the draft that is issued under Article 10(1) of the Directive.

Other Key Provisions

Regulation 9 prescribes the information to be included on the public register maintained under section 29 of the 2008 Energy Act. This will be information about storage licences and storage permits, and about storage sites both before and after the closure of the site.

Regulation 10 enables the licensing authority to direct the operator to take corrective measures, in the event of a significant irregularity or leakage, and enables (or in some cases requires) the authority to take such measures itself and to recover the costs from the operator.

Regulation 11 enables the licensing authority to modify or revoke the storage permit in certain circumstances. By regulation 11(1) such a modification may be made where a change is planned by the operator, and by regulation 11(2) a modification must be made where the change appears to the authority to be substantial; alternatively in such a case the authority may prohibit the change. Regulation 11(5) and (6) sets out circumstances in which the authority must consider whether to modify or revoke the permit. This duty arises where the authority receives certain information – for instance that permit conditions have been breached or that there have been leakages or significant irregularities – and in any event five years after the grant of the permit (and then every ten years).

Regulation 12 deals with the consequences of a storage permit being revoked. The authority may either close the storage site immediately, or first consider applications for a new licence and a new storage permit in respect of the site. If a new storage permit is granted, the existing licence terminates and with it the previous operator's obligation to meet the authority's costs. In all other cases that obligation continues in respect of the store that is now closed, but the authority takes over responsibility for performing the post-closure obligations.

Before a site is closed, the definitive version of a "post-closure plan" must be approved by the authority under regulation 13.

Regulation 14 deals with liabilities of the operator after the site has been closed. Its obligations to remedy environmental damage under the Environmental Liability Directive will continue, as will those to surrender emissions allowances. Such obligations continue until the licence is terminated, as does the obligation to maintain a financial security.

C.4. Goldeneye Regulatory Timeline

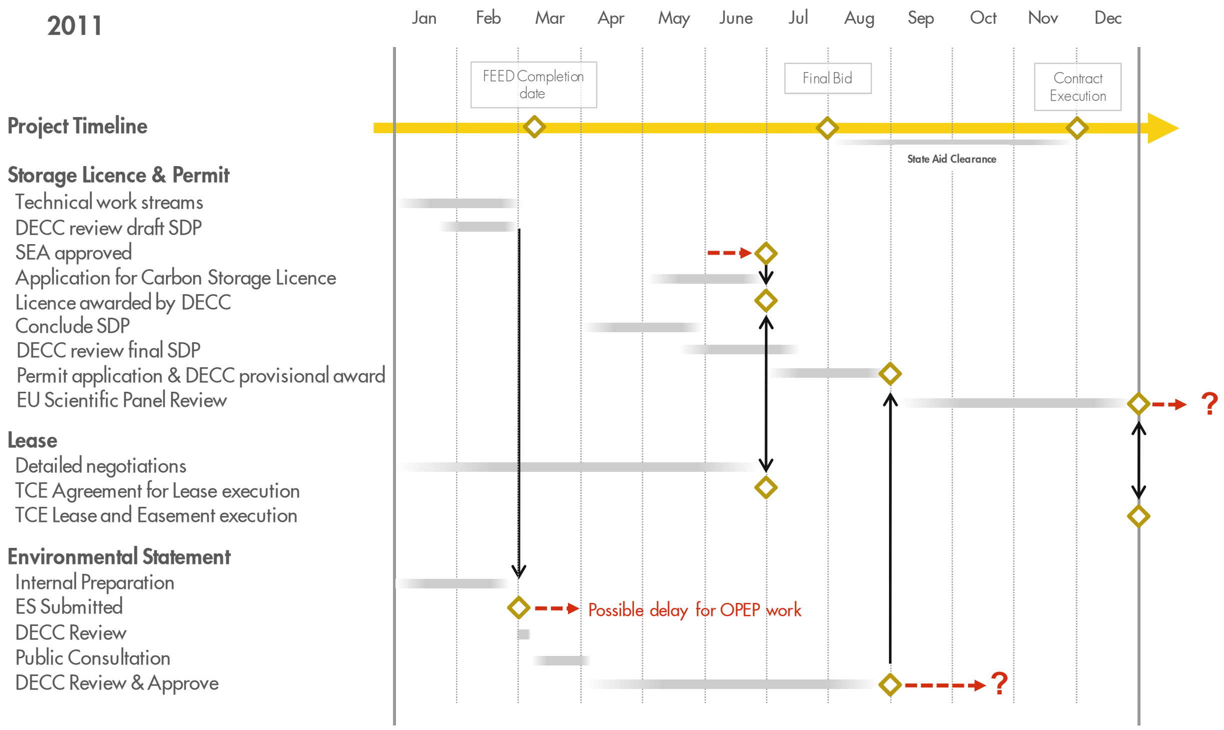
The anticipated timing for the Carbon Storage Licence and the Carbon Storage Permit is as shown below in Figure 2.

Award of a Carbon Storage Permit by DECC is subject both to review by a yet-to-be-established EU Scientific Panel and also prior approval by DECC of an Environmental Statement (ES) from Shell. Recognising the unique nature of this project, the timing of both of these is very uncertain though the CCS Directive at least places a 4 month cap on the review period by the Scientific Panel. Assuming a 5 to 6 month post-consultation review period by DECC of the ES, in keeping with the norm for conventional upstream oil / gas field developments, then it seems likely to be end-Q4 2011 before the Permit could be formally approved and therefore the Lease executed.

The prior award of the Carbon Storage Licence is subject to conclusion of an ongoing Strategic Environmental Assessment (SEA). Completion of the SEA has already slipped significantly but is now expected in Q2/Q3 2011.

FIGURE 2: Notional Goldeneye CO_2 Storage regulatory Timeline

Note that the timing of certain of the activities shown in this diagram is subject to award of an advanced works contract.



C.5. Other Important Aspects

Despite the progress that has been made in transposing the provisions of the CCS Directive a number of significant regulatory uncertainties remain to be resolved, amongst the most important of which are:

First of a Kind Project Risks: The Longannet to Goldeneye CCS project looks set to be the first in Europe to be permitted under the EU CCS Directive whilst, at the date of writing, the publication of final versions of the Guidance Notes from the European Commission is still pending. There are, therefore, no useful precedents or other means of guiding either the developers or the regulator on how to interpret the often broad terms of the regulatory framework. As a result, the project is exposed to a number of important 'first of a kind' regulatory risks reflecting a potential tendency towards a conservative interpretation of the rules. These include, but are not limited to, possible limits on the size of the licensable volume, constraints on the permissible injection rate or total stored volume, onerous site characterisation requirements, limits on the purity of the CO_2 stream intended for injection, and/or onerous operational and/or post-closure monitoring obligations. All of these aspects have the potential either to impose material constraints on the otherwise intended operating envelope of the project or to add significant additional cost. Therefore, whilst Shell continues to work closely with the DECC regulatory team to narrow down the uncertainties in pursuing approval of its Storage Development Plan and award of a Storage Permit each is identified in the project risk matrix and will remain until the exact licensing requirements for the storage of CO_2 at Goldeneye become clear.

Strategic Environmental Assessment: The Government has still to conclude a Strategic Environmental Assessment (SEA) to incorporate offshore CO_2 storage activities, prior to which it will be unable to issue Storage Permits. Current guidance is that this should be completed by February 2011, but there has already been significant slippage and any further material delay in this process risks compromising the consortium's ability to secure a storage permit for the Goldeneye reservoir prior to executing the project contract, whilst also prolonging the uncertainty of knowing exactly what rights and obligations will be conferred by the regulations.

OSPAR: In 2006 the contracting parties to the 1992 OSPAR Convention agreed an amendment removing the prohibition against the sub-seabed storage of CO_2. However, this amendment can only take legal effect once ratified by a minimum of seven contacting parties. To date the EU, UK and Norway have ratified, but we understand from a recent meeting with DECC that it will be Summer 2011 at the earliest before the minimum seven could be achieved, but with a real risk that this minimum may not be achieved in time for commencement of project operations in 2014. Failure to ratify the OSPAR amendment would mean that the sub-seabed injection of non-indigenous CO_2 for storage purposes would be illegal under the Convention, and so far DECC have not been able to provide a fallback plan for this eventuality.

CCS Directive: Article 38 of the CCS Directive provides for a review of the Directive by March 2015. Insofar as such a review could impose retrospective changes or introduce new obligations in connection with the operation, monitoring, closure and handover of a storage site then it will represent a source of significant regulatory uncertainty for prospective developers.

EU CCS Guidance Documents: DG Climate Action has prepared a set of draft Guidance Documents to assist stakeholders in the implementation of the CCS Directive, addressing (i) CO_2 storage life-cycle approach to risk management; (ii) Specific approaches to key stages of the CO_2 storage life-cycle (site selection, CO_2 stream composition, monitoring, corrective measures); (iii) Transfer of responsibility; and (iv) Financial security. Whilst the Guidance Documents will not be legally binding they will nevertheless likely serve as the template for Member State legislation, and will also be an important point of reference for the EU Scientific Panel that will scrutinise Member State permit award decisions (see below). To date the documents have only been issued in draft form for consultation but the onerous and prescriptive nature of these is a source of concern. This is particularly true of the Guidance in connection with the provision of Financial Security. These Guidance Documents, like the Directive itself, have been developed with the long term commercial deployment of CCS in mind. In so doing they ignore the fundamental need for Member States to first partner industry in the demonstration of this technology. These views have been registered in separate responses to a Commission consultation which closed at the end of July 2010.

EU Scientific Panel: The CCS Directive provides for up to four months for the EU Commission to offer a non-binding opinion on Member State decisions to award a Storage Permit (Art.10). We understand that the opinion will be based on scrutiny by an independent Scientific Panel that the Commission hopes to recruit during Q4 2010. As one of the first projects to be taken through this process, and since DG Climate Action has yet to set up the

Panel, we expect a lengthy process and a significant degree of scrutiny. The lack of directly comparable precedent is likely to create considerable uncertainty over the outcome of the Panel's deliberations. Whilst the opinion will not be legally binding, consideration of aspects such as public acceptance and future Storage Permit award decisions suggest that it would be unlikely for DECC to ignore the Commission's advice. Further, whilst DG Climate Action expect that the first permits could be considered as early as Q2 2011 it is unlikely that the Panel will be able to review outline project proposals or conditional award decisions. Rather they will only be able to review draft permits awarded from a national competent authority. This is potentially problematic from the standpoint of reducing regulatory uncertainty if a draft storage permit for the Goldeneye reservoir cannot be secured from DECC before execution of the project contract.

DECC Guidance Notes: Whilst the publication of informal (non-binding) Guidance Notes is not an obligatory part of developing new legislation or regulations they are increasingly recognised as a helpful tool in guiding industry's compliance with the law, especially where the law may be open to wide interpretation. Shell reviewed & commented on an early draft of DECC's Guidance Notes in March 2010 but DECC have still to publish a final version. The CCS Directive leaves considerable discretion to national competent authorities in how to implement its provisions. Guidance Notes will therefore be essential to the consortium in understanding how to comply with UK requirements, especially so in the absence of any national regulations. Shell is presently in discussions with DECC to agree the detailed requirements of the Storage Permit, that will enable Shell to demonstrate progress on meeting all aspects of the permit requirements and to share plans for future work; and to identify gaps against regulatory requirements and agree if / how these can be closed, with the aim to eliminate as much regulatory uncertainty as possible prior to execution of the project contract. None of this, however, is a substitute for having DECC clearly set out its expectations for what the regulations require.

Abbreviations

BHT	Bottom Hole Temperature
CCS	Carbon Capture & Storage
CCSA	Carbon Capture & Storage Association
CNS	Central North Sea
DECC	Department of Energy & Climate Change
Defra	Department for Environment, Food & Rural Affairs
DG	[EU] Directorate-General
DTS	Distributed Temperature Sensing
EC	European Commission
EIA	Environmental Impact Assessment
ES	Environmental Statement

ETS	Emissions Trading Scheme
EU	European Union
GISZ	Gas Importation & Storage Zone
HFC	Hydrofluorocarbon
HSE	Health, Safety & Environment
ICES	International Council for the Exploration of the Sea
LOS	Line of Sight
MMV	Monitoring, Measurement & Verification
ODS	Ozone Depleting Substances
OGUK	Oil & Gas UK
OSPAR	OSPAR (Oslo, Paris Conventions) Commission
PDG	Permanent Downhole Gauge
P/T	Pressure/Temperature
REACH	Registration, Evaluation, Authorisation & Restriction of Chemicals
SAC	Special Area of Conservation
SEA2	Strategic Environment Assessment 2
SoSREP	Secretary of State's Representative
SSSV	Subsea Safety Valve
OSPAR	OSPAR (Oslo, Paris Conventions) Commission
TPA	Third Party Access
WH	Wellhead
WHM	Wellhead Maintenance
WRM	Well & Reservoir Management