Re-Use of Oil & Gas Facilities for CO_2 Transport and Storage

IEAGHG Technical Report

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IEA GREENHOUSE GAS R&D PROGRAMME

Evaluating technology options to mitigate greenhouse gas emissions

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RE-USE OF O&G FACILITIES FOR CO_2 TRANSPORT AND STORAGE (IEA CON/17/249)

Key Messages

- This report aims to improve the general understanding of issues influencing the re-use of existing Oil and Gas (O&G) infrastructure to address the fundamental question: "under what circumstances might it make sense to re-use redundant O&G infrastructure for CO_2 operations"?
- An infrastructure reusability index has been developed for the purpose of this study and applied to 5 case studies in the North and Irish Seas (Camelot, Atlantic & Cromarty, Hamilton, Goldeneye and Beatrice).
- It is not feasible to define a generic functional specification for re-use of a depleted oil or gas field because its suitability depends on the specific requirements of the project such as longevity, CO_2 injection rate, CO_2 phase and capacity.
- The reservoir pressure at the commencement of CO_2 operations, which is determined by the production strategy used on oil or gas reservoirs, influences their suitability for storing CO_2.
- Elements of O&G infrastructure have potential to be re-used for CO_2 but must be evaluated on a case by case basis.
- Suitability for re-use depends primarily on the characteristics of the intended CO_2 supply to the store.
- Integrity and life extension options are key attributes of suitability for re-use.
- O&G derived practices, processes and tests exist to assess suitability of existing infrastructure for re-use.
- From an infrastructure perspective, the primary functional specification is one of sufficiency. The equipment must have a pressure rating and material specification sufficient for the proposed project, the remaining longevity must be sufficient, and, if a platform is required, the installation must have sufficient space, power and weight bearing capability.
- Recommendations for further work include examining options for extending the life of infrastructure assets and considering regulatory processes in other regions.

Background to the Study

Our recent study 'Case Studies of CO_2 Storage in Depleted Oil and Gas Fields' (2017-01) concluded that CO_2 storage in depleted fields would not only be viable with potentially lower risk but could also be relatively cost effective, providing important intermediate-scale storage resources. The report highlighted that re-using an O&G fields would be beneficial as "there would likely be cost savings over saline aquifer sites, particularly in the characterisation stages (where there is the advantage of production history and proved hydrocarbon retention to reduce uncertainty in containment and capacity)".

Another perceived advantage for the use O&G fields for first generation CO_2 storage is the potential reduction in costs for CO_2 transport and storage by re-using existing O&G facilities, especially offshore. This report therefore aims to review the potential re-use of the related infrastructure and assess the suitability of certain infrastructure for re-use.

However studies (Noothout P, 2010) have shown that the re-use of existing infrastructure has limitations, characterised using key technical, economic and legal parameters. A recent Pale Blue Dot led study (Pale Blue Dot Energy & Axis Well Technologies, 2016) concluded that "in general, most of the O&G offshore infrastructure is likely to be unsuitable for use as CO_2 storage infrastructure" based on a UK portfolio of sites.

The decommissioning of large-scale O&G infrastructure associated with depleted fields in some regions of the world is approaching and is already occurring in the North Sea. This means it is important to understand the potential for re-using existing infrastructure for CO_2 storage, prior to scheduled decommissioning in the near future. Not only might this option be cost-effective for early deployment of intermediate scale CO_2 storage (enabling long term infrastructure of CCS in the future), the re-use of existing O&G infrastructure could also potentially defer decommissioning costs.

Scope of Work

The Technical Specification highlighted three main, and inter-linked, objectives for the study:

1. To understand the **potential scope for re-using existing infrastructure** for CO_2 storage, prior to scheduled decommissioning.
2. To assess the **opportunity of re-using existing infrastructure** (including pipelines, platforms, subsea infrastructure, wells, power, and communication) associated with depleted O&G fields for CO_2 storage.
3. To consider the technical, operational, economic, health and safety, legal/liabilities and regulatory/permitting **requirements of the potential re-use** of existing O&G infrastructure.

This report focuses on the re-use of offshore infrastructure as the case studies are located in the North and Irish seas as the contractors had access to relevant data. Onshore facilities are discussed but are not the focus of this report.

Findings of the Study

The study begins by reviewing issues relating to CO_2 storage in depleted O&G fields (e.g. relating to the re-use of pore space) then discussing re-using infrastructure.

The review of geological reservoir properties highlights the impact production strategy will have on re-use. For example, primary production (pressure depletion) will leave the reservoir pressure much lower than the caprock fracture pressure (which must not be exceeded). In comparison, secondary production (pressure support by injection) will maintain a higher pressure in the reservoir hence lowering the potential volume of CO_2 that could be injected before reaching caprock fracture pressure.

The initial review on infrastructure states there are six main elements commonly used in O&G developments: pipelines, umbilicals; platforms (including the jacket), subsea manifolds, wells and onshore facilities. Each of these elements are described in the text along with commentary on relevant decommissioning aspects and potential for re-use in CO_2 operations.

One of the significant costs associated with the re-use of an existing offshore facility is the need to complete the modification work offshore rather than onshore. The restriction on bed space and the high cost of crew and services per day are problematic for offshore infrastructure re-use. The high cost of working man-hours offshore makes it more effective to minimize the modification work. This may result in being more effective to simply mothball the existing equipment in situ and then lift on new modules for the CO_2 injection. The key to this option will be the platform's ability to take on the additional deck loading, and the costs associated with managing the long-term integrity of any mothballed equipment.

Functional Specification

The functional specification highlights the major requirements of an offshore CO_2 storage development outlining key commercial and project design issues. The areas covered in the report are:

- Storage Reservoir
- Infrastructure
- Commercial Arrangements
- Development Planning Issues
- Suitability Assessment

The storage reservoir specification is based on four primary components: containment, injectivity, connectivity and capacity. Suitable storage resource is a key requirement, the effect of rock properties, fracture pressure, initial reservoir pressure and CO_2 phase on the potential storage capacity are discussed.

Under the infrastructure functional requirements pipelines and offshore injection facilities are discussed as well as life cycle requirements and design life and history. In order to re-use an oil or gas pipeline for CCS a full pipeline integrity and life extension study will be required to confirm suitability. The results of which will help determine whether it is technically and commercially feasible to purchase an existing pipeline system. Re-qualification shall comply with the same requirements as for a pipeline designed specifically for transportation of CO_2.

It should be noted that the re-use of an existing pipeline following decommissioning may still be possible; however, the pipeline integrity may be compromised (due to cutting of ends and absence on inhibition treatment etc.). Future use of these lines would require extensive inspection, reconnection and testing and therefore is unlikely to be commercially feasible.

The fundamental decision for a project owner regarding offshore CO_2 injection facilities is the choice of how best to develop the store, deciding between platform or subsea based facilities. A stand-alone subsea development is feasible if only a small number of wells are required, minimum facilities (no filtering, heating etc.) are acceptable and a source of power and control fluid/signals is available. A platform enables the provision of enhanced process capabilities, e.g. pre-injection filtering and physical sampling to ensure CO_2 injection quality.

Regarding the transportation of CO_2, the report highlights that the injection of CO_2 requires specific pressure management (i.e. injection in the gaseous phase at the beginning of the project), meaning there are two options:

1. Gaseous transportation of the CO_2 to the injection site, which would require a large diameter (heated) pipeline (and maintaining the CO_2 pressure within a given range in order to avoid the risk of liquids forming), or

2. Transporting the CO_2 offshore in the liquid phase, and incorporating a vaporization unit (consisting of a heating train and a choke valve) to facilitate injection into the wells in the gaseous phase. The latter philosophy was assumed as the most technically and economically feasible for the ETI SSAP Project (Pale Blue Dot Energy & Axis Well Technologies, 2016).

A key aspect in the development of the project will be the design life of the CO_2 source and in hubs and cluster systems, the various CO_2 compositions coming online at different times. In general, only young O&G facilities can be realistically considered as candidates for re-use and therefore, by implication, new facilities, will be required in the majority of long duration CO_2 projects. There is no prescribed or generic process for this extending asset life and each situation would need to be evaluated on a case by case basis.

Re-Usability Index Tool

This report outlines a general approach to assessing the CO_2 re-use potential of offshore infrastructure that has previously been used for accessing, producing and transporting hydrocarbons. In practice, the suitability of such infrastructure for conversion to transport, inject and store CO_2 must be considered on a project by project basis. This is because the suitability, or otherwise, of infrastructure depends significantly on the following three factors:

- Rate of CO_2 supply (throughput capacity)
- Condition of CO_2 supply (phase, temperature, pressure)
- Duration of CO_2 supply (project life)

A Stage 1 suitability assessment (initial scoping evaluation) of the five infrastructure case studies was completed.

In the diagram below (Fig. 1) a high score (further from the centre) indicates that there is a high suitability for reuse whereas a low score (closer to the centre) indicates that the existing reservoir/equipment is not suitable for reuse and a new purpose-built design would be the preferred option. The diagram illustrates that the reservoir is very well suited for re-use in most case studies, the wells are somewhat suitable (implying that modifications may be necessary) in the Goldeneye and Hamilton case studies and that the existing subsea equipment is totally impractical to be re-used in each case study.

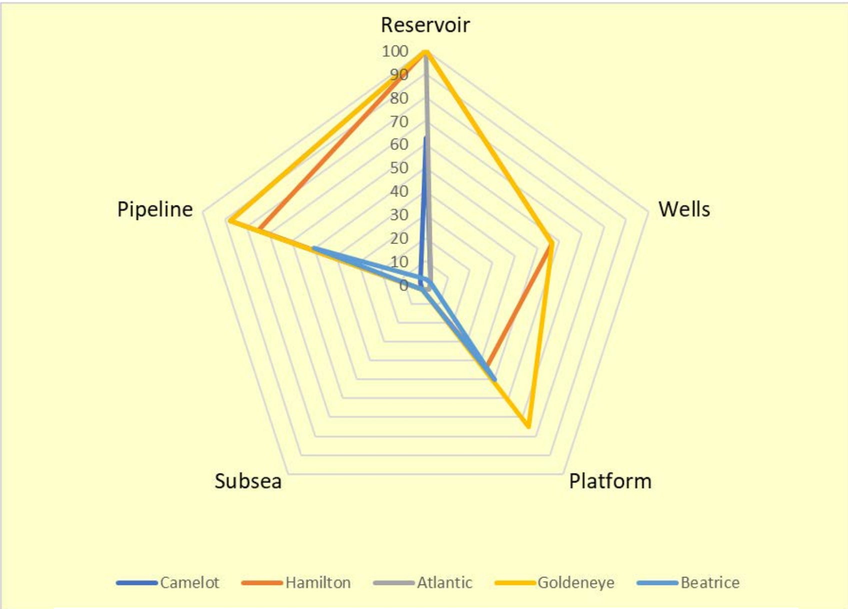

Figure 1: Summary of Re-Use Assessments for Case Studies

It should be noted that each element of infrastructure is not mutually exclusive, if the platform is suited for reuse and the pipeline is not then it is still feasible to reuse the platform but use a new pipeline. If the reservoir is not suitable for CO_2 injection is may still be possible to reuse the existing infrastructure as long as another store is available in close proximity such as the surrounding aquifer.

The suitability assessment approach in the report was applied to each case study asset assuming that the development scenario calls for a CO_2 supply of gas phase 1MT/year for 20 years.

Case Studies

Camelot

- Small NUI (Normally Unmanned Installation). Shallow (11m) water depth, close to mainland England.
- Ceased production 2009 and now decommissioned.

- 3 re-use options considered (methane storage, CO_2 storage or use on a different gas field)
- The conceptual development was to modify the platform and wells for CO_2 duty. Install a new pipeline, an external CO_2 import riser, install a heater, new generation and metering equipment. Storage would be in the depleted Rotliegendes gas reservoirs and the Bunter saline aquifer.
- The suitability assessment of the Camelot field indicated that the reservoir is the only element that would be suitable for re-use in a CO_2 storage context.

Atlantic & Cromarty

- Gas fields off Aberdeenshire coast in 115m water depth.
- Production from 2006-2009.
- Re-use of the Atlantic pipeline is a key component of the Acorn ICCUS project (https://pale-blu.com/acorn/) being developed by Pale Blue Dot Energy. The suitability of the pipeline for CO_2 transport has been highlighted on several occasions.
- Acorn will use the unique combination of legacy circumstances in North East Scotland to engineer a minimum viable full chain carbon capture, transport and offshore storage project to initiate CCS in the UK. All the components are in place to create an industrial CCS development in North East Scotland, leading to offshore CO_2 storage by the early 2020s.
- The suitability assessment of the Atlantic and Cromarty fields indicated that both the pipeline and the reservoir would be suitable for re-use in a CO_2 storage context.

Hamilton

- 25km from North Wales coast, 27m water depth.
- Still currently producing gas (started in 1997) but cessation is expected in the near term.
- No decommissioning plan published but expected to comply with requirement for small platforms to be completely remove from location (OSPAR decision 98/3).
- The Strategic UK CO_2 Storage Appraisal Project looked at developing the Hamilton gas field for CO_2 storage. Although the project used new build facilities to inject CO_2 the capacity of the field was determined based on available O&G seismic and well data. The Hamilton gas field was found to be able to store 124 MT CO_2 over 25 years with an injection rate of 5 MT/y using two injection wells and one spare/monitoring well
- The suitability assessment of the Hamilton field indicated that the reservoir and pipeline are well suited to re-use in a CO_2 storage context and that the platform and wells may be suitable with some modifications or in specific development cases.

Goldeneye

- Located in Outer Moray Firth, 102km pipeline to St Fergus gas terminal.

- Decommission strategy speculative but expected to include wells, platform and export pipeline.
- Modifications were estimated to cost approximately £208 million following the 2011 FEED programme (Scottish Power, 2011). The more recent Peterhead CCS Project FEED study estimated the costs to be £220 million; £73 million for pipeline works, £61 million for platform modifications and £88 million to recomplete the wells (Shell, 2015)
- The suitability assessment of the Goldeneye field indicated that the reservoir, pipeline, wells and platform are all likely to be suitable for re-use in a CO_2 storage context.

Beatrice

- 22km east of Caithness coast, in Outer Moray Firth.
- Ceased production 2014, considered for re-use: offshore transmission for wind turbines, hydrogen storage and CO_2 storage.
- The total absence of a large industrial emissions point in the landfall area means that there is effectively no current reuse option which involves CO_2 storage at scale.
- The suitability assessment for the Beatrice field indicated that the pipeline and platform are likely to be suitable for re-use in a CO_2 storage context, providing that a nearby storage unit is available.

Expert Review Comments

Three external reviewers returned comments. The general consensus was that the report gives a good overview of challenges that may arise when using abandoned fields and their installations for CO_2 injection. The reviewers also commented that chapters seem to be written in a way that can give insight for people without detailed knowledge of the storage. Overall a majority of the changes following the review were minor with most work being required on better communicating the suitability assessment section and the reusability index. All comments were addressed in the final copy of the report.

Conclusions

Concepts

- The production strategy used during the hydrocarbon extraction phase determines the reservoir pressure at the commencement of CO_2 operations and this in turn influences the amount of CO_2 that can be stored without breaching the fracture pressure constraint.
- Key aspects to consider when evaluating a field for re-use include: regional geology, reservoir architecture, hydraulic communication and containment.
- Containment should be considered from both geological and an engineering (or legacy wells) perspectives.

- The six key elements of infrastructure that might be re-used for CO_2 operations are: pipeline, umbilicals, platforms (including jackets), subsea manifolds, wells and onshore facilities.
    - The key attributes determining whether any item of infrastructure could be re-used are integrity and life extension options.
    - In general, all elements of infrastructure have the potential to be re-used for CO_2 operations. The re-usability index in this report showed that some elements are more likely to be re-used (e.g. pipelines) than others (e.g. platforms). However, all specific cases need to be evaluated on a project by project basis.
    - Additional generic studies about the potential for re-use are unlikely to add significant new knowledge to the sector.

Practicalities

- The functional specification for re-use of a depleted O&G reservoir has four elements: containment, injectivity, connectivity and capacity.
- It is not feasible to define a generic functional specification for re-use of a depleted oil or gas field because its suitability depends on the specific requirements of the project such as longevity, CO_2 injection rate, CO_2 phase and capacity, all of which are characteristics of the CO_2 supply.
- From an infrastructure perspective, the primary functional specification is one of sufficiency. The equipment must have a pressure rating and material specification sufficient for the proposed project, the remaining longevity must be sufficient, and the installation must have sufficient space, power and weight bearing capability.
- A CO_2 injection operation requires less complex processing systems than a hydrocarbon operation.
- The safety systems for CO_2 operations are fundamentally different than for hydrocarbon production.
- Often, hydrocarbon production installations generate their own electricity by burning some of the produced methane in a turbine. This option is not available for CO_2 operations; a different means of power generation would be required.
- Decommissioning of subsea infrastructure, pipelines and umbilicals is treated on a case by case basis, however decommissioning of smaller and/or newer platforms is complete removal and the design should take this into account.

Experience

- The five case studies summarised in the report cover a platform that has been decommissioned, three examples of infrastructure considered for re-use for CO_2 operations and one example of the re-use options for an offshore wind farm.
- Key insights from the case studies are that each situation is unique to a degree.

- Costs are important in deciding whether or not to re-use infrastructure, but they are not the sole criterion. Many other factors are considered in the decision-making process such as; corporate motivation, strategic preferences, perceptions of risk and concerns about the complexity of brownfield modification and likelihood of cost overruns.
- Most situations that have contemplated re-use for CO_2 have planned to operate in dense phase.

Recommendations

- Examine options for extending the life of infrastructure assets.

- Consider the regulatory processes and procedures in other regions and identify any important differences with those described in this report (given these case studies are focused in the North Sea).

Review of O&G Infrastructure

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1.0 Executive Summary

The production strategy used on oil or gas reservoirs influences their suitability for storing CO_2

The elements of oil and gas infrastructure have potential to be re-used for CO_2 but must be evaluated on a case by case basis

Suitability for re-use depends primarily on the characteristics of the intended CO_2 supply to the store

Integrity and life extension options are key attributes of suitability for re-use

O&G derived practices, processes and tests exist to assess suitability of existing infrastructure for re-use

An infrastructure reusability index has been developed and applied to 5 case studies

This IEAGHG commissioned report brings together existing CO_2 transport, injection and storage initiatives and experience of the authors to help improve the general understanding of issues influencing the re-use of infrastructure.

The primary objective of the overall project is to address the fundamental question of "under what circumstances might it make sense to re-use redundant oil and gas infrastructure for CO_2 operations"?

To set the scene and help establish a common understanding, the report first outlines the attributes of hydrocarbon reservoirs and infrastructure and describes how these may influence the development design of a CO_2 storage project. From a reservoir perspective, the key attributes that influence its redevelopment as a CO_2 store are identified as the: production strategy; reservoir conditions; reservoir characterisation; legacy wells, magnitude of the potential CO_2 storage resource and the range, quality and scope of available data. The influence of the regulatory regime is also discussed.

Six main elements of infrastructure commonly used in hydrocarbon production projects are described: pipelines, umbilicals; platforms including the jacket, subsea manifolds; wells and onshore facilities. The current approaches to decommissioning these pieces of infrastructure are summarised, largely based on experience from the UK sector of the North Sea. Issues relating to re-use are highlighted and a common recurring theme is the remaining longevity, and pressure rating and material specification of the infrastructure. These elements of infrastructure are illustrated in Figure 1-1, which also summarises the key aspects of a CCS project development.

To help the general understanding of offshore CO_2 developments, a functional specification outlining the requirements from subsurface and infrastructure perspectives has been created. These are presented in general terms because it is impractical to be definitive about requirements without knowing what the CO_2 supply is intended to be. A two-stage suitability assessment process, the infrastructure reusability index, has been developed and applied to the five case studies.

Case studies for five UKCS infrastructure re-use projects are presented and describe the infrastructure, the re-use options considered and the option that was selected. Where possible, the rationale for the decision is explained. These case studies include the Camelot, Hamilton, Goldeneye, Beatrice and Atlantic fields. Of these, the Atlantic field infrastructure is part of the Acorn ICCUS project and re-use of the Hamilton field infrastructure is being considered in the Rowan ICCUS project.

The two most significant conclusions of the study are:

- It is not feasible to define a generic functional specification for re-use of a depleted oil or gas field because its suitability depends on the specific requirements of the project such as longevity, CO_2 injection rate, CO_2 phase and capacity; and.
- From an infrastructure perspective, the primary functional specification is one of sufficiency. The equipment must have a pressure rating and material specification sufficient for the proposed project, the remaining longevity must be sufficient, and, if a platform is required, the installation must have sufficient space, power and weight bearing capability.

Recommendations for further work include creating a worked example of the financial security requirements implied under the CCS Directive and examining options for extending the life of infrastructure assets.

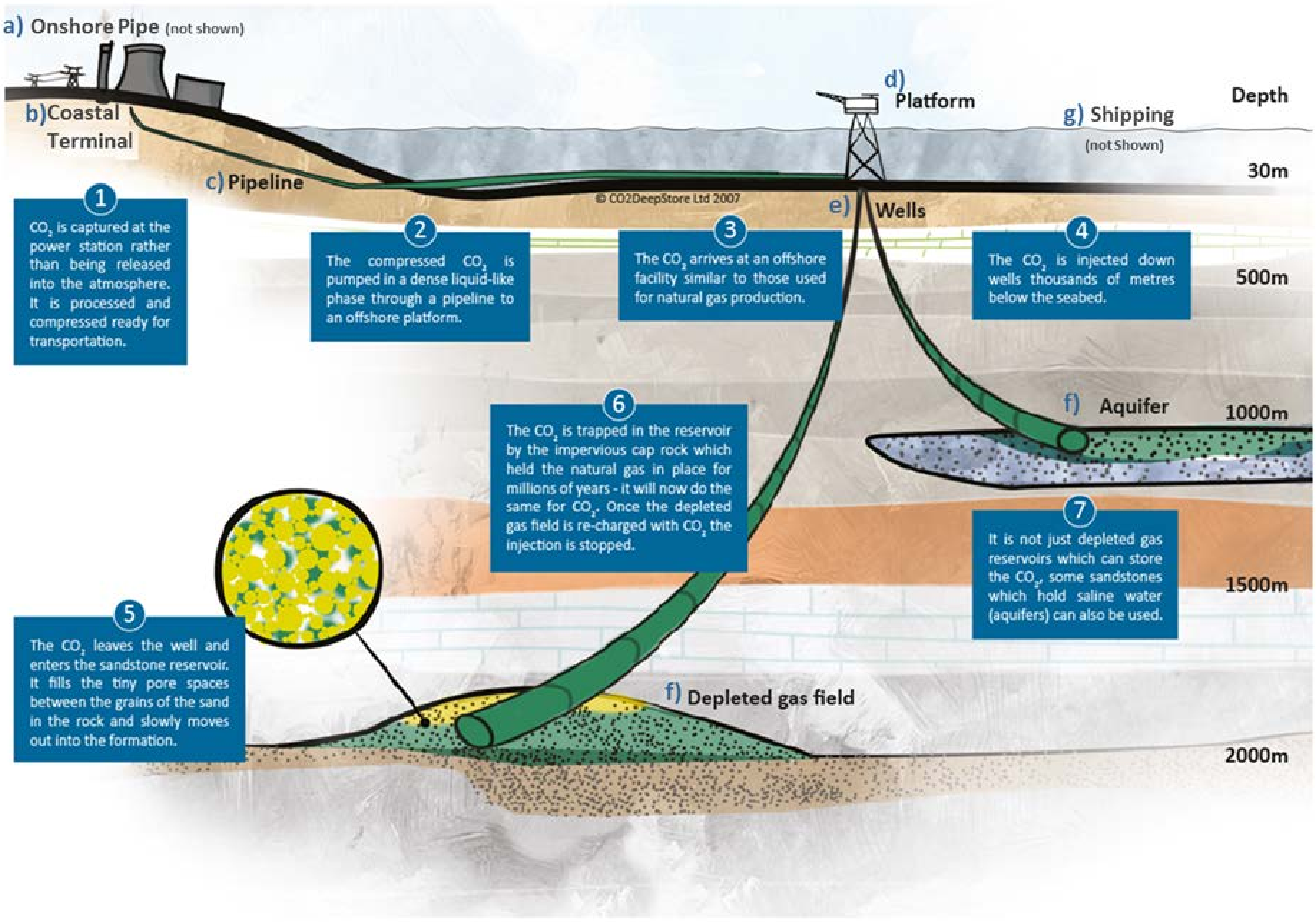


Figure 1-1: CO_2 Storage Project Infrastucture

2.0 Introduction

2.1 Background

Oil and gas (O&G) fields offer proven secure storage with well understood capacity (SPE, 2016). Depleted O&G reservoirs are often selected for first generation CO_2 storage sites because they commonly have an abundance of static and dynamic data with limited appraisal drilling to be undertaken. Another perceived advantage is the potential reduction in costs for CO_2 transport and storage by re-using existing O&G facilities, especially offshore. A recent study by the IEAGHG (IEAGHG, 2017) also concluded that CO_2 storage in depleted fields would not only be viable with potentially lower risk but could also be relatively cost effective, providing important intermediate-scale storage (Bacchu et al, 2014). However other studies (Noothout P, 2010) have shown that the re-use of existing infrastructure has limitations, characterised using key technical, economic and legal parameters. A recent Pale Blue Dot led study (Pale Blue Dot Energy & Axis Well Technologies, 2016) concluded that "in general, most of the O&G offshore infrastructure is likely to be unsuitable for use as CO_2 storage infrastructure".

At cessation of production, there will be residual hydrocarbons in the reservoir. Understanding how these fluids interact with injected CO_2 will be an important part of the injection planning and capacity estimation.

The decommissioning of large-scale O&G infrastructure associated with depleted fields in some regions of the world (BERR, 2007) is looming. This means that there is an imperative to understand the potential for re-using existing infrastructure for CO_2 storage, prior to scheduled decommissioning in the near future. Not only might this option be cost-effective for early deployment of intermediate scale CO_2 storage (enabling long term infrastructure of CCS in the future), the re-use of existing O&G infrastructure could also potentially defer decommissioning costs.

The purpose of this study is to assess the potential for re-using elements of O&G infrastructure (including pipelines, platforms, subsea infrastructure, wells, power, and communication) for CO_2 storage. In addition, the study aims to illuminate the process for assessing the suitability of infrastructure for reuse in a CO_2 project. This study considers the technical, operational, economic, health and safety, liability and regulatory implications of the re-using O&G infrastructure.

2.2 Objectives

The Technical Specification provided by IEAGHG highlighted three main, and inter-linked, objectives for the study:

1. To understand the potential scope for re-using existing infrastructure for CO_2 storage, prior to scheduled decommissioning.
2. To assess the opportunity of re-using existing infrastructure (including pipelines, platforms, subsea infrastructure, wells, power, and communication) associated with depleted O&G fields for CO_2 storage.
3. To consider the technical, operational, economic, health and safety, legal/liabilities and regulatory/permitting requirements of the potential re-use of existing O&G infrastructure.

To address these objectives the work was split into three components as illustrated in Figure 2-1.

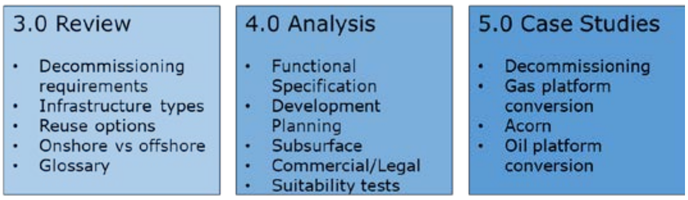


Figure 2-1: Key Activity Areas Completed

The report is structured broadly along these lines

Section 3 covers the outcome of the Review stage activities and addresses the following two tasks:

- Storage – A review of issues relating to storage in depleted oil and gas fields; and

- Infrastructure – A review of the types of infrastructure, highlighting potential reuse options (partial, total, for renewables etc.) of offshore infrastructure and describing the trade-offs between reusing and building new infrastructure. This includes a description of the main obligations and work processes relating to decommissioning activity, focussed mostly on the UK sector of the North Sea.

A short glossary of storage and infrastructure terms is also included as an appendix.

Section 4 summarises the outputs from the Analysis stage activities and addresses the following three tasks:

- Functional Specification – Consideration of the impact of the phase behaviour of CO_2 on the design requirements for CO_2 infrastructure. In particular, the way in which pressure and temperature are managed as they change over the life of a subsurface store and its associated infrastructure.
- Development Planning – Analysis of “special considerations” in the IEAGHG Technical Specification, development work by Pale Blue Dot and Costain during the UK Storage Appraisal Project (Pale Blue Dot Energy & Axis Well Technologies, 2016) and consideration of issues such as the financial security required to cover long term liabilities, transition of ownership and operations. The timing and availability implications for hub and cluster developments is also considered.
- Suitability Assessment – Consideration of two perspectives; the store and the infrastructure, to develop a holistic assessment methodology that considers the meaningfulness and reliability of information that is likely to be available.

Sections 5 - 9 summarise five case studies that collectively illustrate the range of opportunities for re-use and the associated challenges that re-use presents. This includes an assessment of the suitability for reuse.

Section 10 highlights the main conclusions and some suggestions for further work are provided in Section 11.

3.0 Storing CO_2 in Depleted Fields

This chapter provides a review of the issues relating to storage of CO_2 in depleted oil and gas fields. Initially, issues relating to the reuse of the reservoir pore space for storage are considered and then those issues relating to reusing the infrastructure and facilities.

3.1 Geological Reservoir

3.1.1 Production Strategy

The production (or depletion) strategy describes the way in which hydrocarbons have been produced from the field. In oil-field parlance there are 3 key phases, (primary, secondary and tertiary) and these influence the reusability of a field for CO_2 storage. Fields are not necessarily taken through all phases of production, as illustrated in Table 3-1.

In the North Sea the production strategies most commonly used depend upon the type of hydrocarbons and are summarised as follows:

- Oil Fields – secondary, using water injection for pressure support and sweep.
- Gas Fields – primary depletion.

3.1.2 Reservoir Conditions

3.1.2.1 Pressure and Temperature

A key limitation on the CO_2 storage resource for any site is the fracture pressure of the cap rock (Pale Blue Dot Energy & Axis Well Technologies, 2016). Thus, the difference between the fracture pressure and the reservoir pressure at the end of the production is a key determinant of the quantity of storage resource.

Phase	Characteristic	UKCS Example	Implications for CO_2 storage
Primary	Pressure depletion	Hamilton gas field	Low reservoir pressure at CO_2 injection start-up
Secondary	Pressure support by injection	Ninian oil field	Reservoir pressure close to or above initial pressure
Tertiary	Enhanced oil (or gas) recovery	Captain Oil Field	Reservoir pressure close to or above initial pressure

Table 3-1: Production Strategies and CO_2 Storage

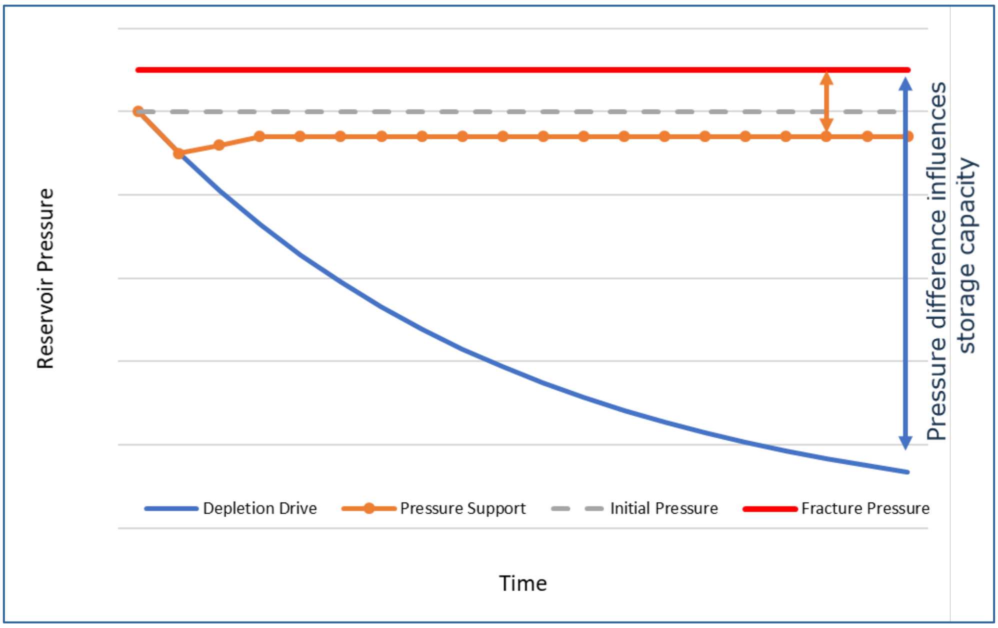


Figure 3-1: Reservoir Pressures during Production

Figure 3-1, illustrates the different profiles of reservoir pressure over the life of two hydrocarbon producing fields; one produced using pressure depletion and the other developed using pressure support such as water injection. It is evident from Figure 3-1 that the pressure in the redundant field produced under depletion can be increased by more than that in the field produced using water injection before reaching the limit imposed by the fracture pressure. This available pressure increase coupled with the ease with which the formation can dissipate pressure from the CO_2 injection wells are key determinants of designing an effective storage development plan for the site. It should be noted that in fields with a strong water drive, reservoir pressure will start to increase after production has stopped due to water influx, this will act to reduce the capacity.

Reservoir temperature is mostly influenced by the regional geothermal gradient (Figure 3-2) and generally does not vary significantly over field life.

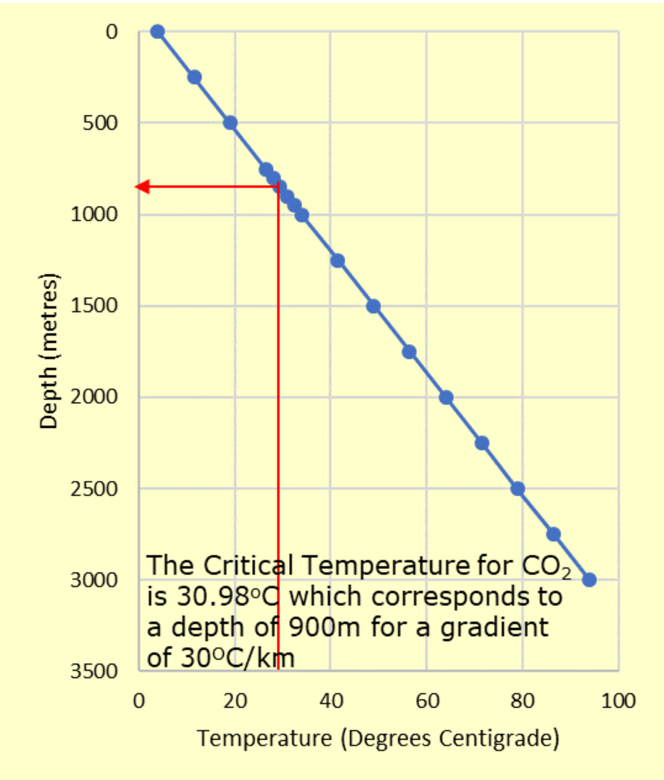


Figure 3-2: Thermal Gradient and CO_2

One of the IEAGHG screening criteria for assessing the suitability of a reservoir for effectively storing CO_2 is that it should be at a depth greater than 800m. This criterion helps assess whether a site is likely to have the right temperature to enable CO_2 to be stored in dense phase (more space-effective than gas phase). Clearly geothermal gradients vary from basin to basin and so the criterion is a guideline rather than a rule – the crest of the Hamilton field for instance is at 800m but the reservoir temperature is such that dense phase storage can be achieved.

3.1.2.2 Reservoir Fluids

Even after production has ceased, hydrocarbon fields will contain some oil, gas and water in the pore space. In the case of fields where injection has been used to provide pressure support, that fluid (typically seawater) will also be present.

The presence of these fluids is likely to affect the phase behaviour of CO_2 in the reservoir. This is not necessarily problematic for CO_2 storage.

3.1.2.3 CO_2 Phase Behaviour

The phase behaviour of CO_2 is very strongly influenced by pressure and temperature, as illustrated in Figure 3-3 (Pale Blue Dot Energy & Axis Well Technologies, 2016).

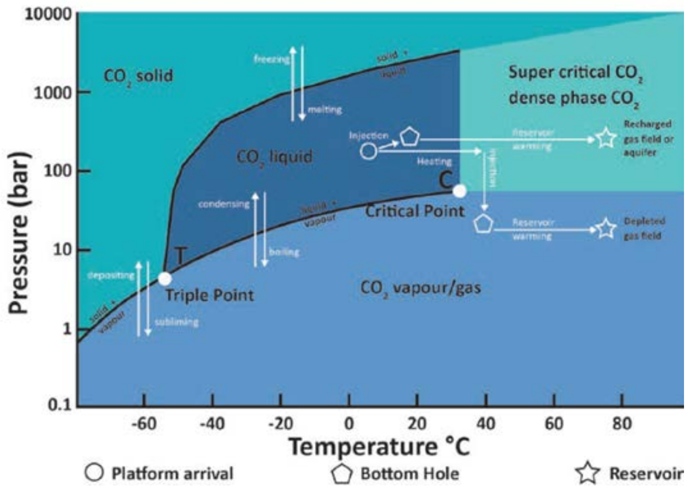


Figure 3-3: CO_2 Phase Behaviour

Understanding this behaviour and how it might change over the injection phase is very important from an operational perspective. It is also important to note that liquid CO_2 is far more dense than gaseous CO_2 and therefore it is more space-effective to store it in liquid (or dense) phase.

3.1.3 Reservoir Characterisation

3.1.3.1 Regional Setting

The storage target for a CO_2 reservoir requires a formation that contains porous and permeable rock (often sandstone). The reservoir also needs to be overlain by an effective seal to prevent buoyant CO_2 from migrating to the surface.

3.1.3.2 Reservoir Architecture

There are a variety of different trapping mechanisms for oil and gas reservoirs, as illustrated in Figure 3-4 (Pale Blue Dot Energy & Axis Well Technologies, 2016).

The key to any hydrocarbon reservoir or CO_2 store is that there must be a layer of sealing strata over the top of the target formation. A storage configuration can be defined as open or closed referring to the connected aquifer and reservoir boundaries. In an open structure the target formation extends beyond the oil and gas bearing region or the targeted store. The connected aquifer can influence the pressure in the store by allowing it to dissipate during injection or increase after production has ceased due to aquifer ingress. Stratigraphic configurations like pinch outs arise due to the changes in the subsurface over geologic timescales. Faults in the subsurface can provide sealing boundaries by offsetting the target formation against sealing strata that would normally be in the under or overburden. Faults may also represent potential leakage pathways, although it is likely that any site with such attributes would be eliminated as a candidate store during the appraisal process.

3.1.3.3 Hydraulic Communication

Hydraulic communication is a term used to describe how easily pressure and fluids can move within a reservoir unit. Essentially it is a measure of compartmentalisation. If hydraulic communication is good, then the reservoir unit is well connected and likely to have a simple architecture with no significant baffles – Hamilton is a good example. In a situation where hydraulic communication is poor the reservoir unit is often faulted or contains significant barriers to flow – Camelot is a good example.

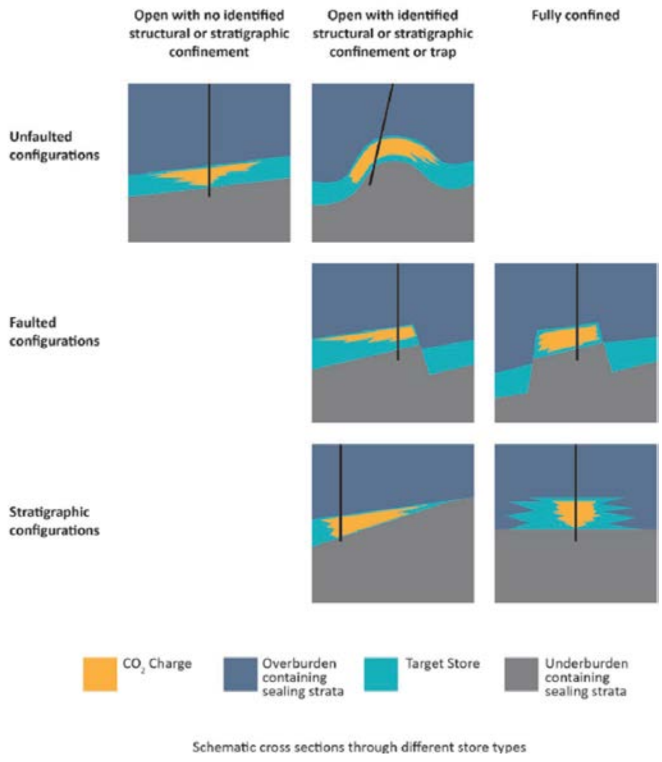


Figure 3-4: Schematic of Different Reservoir Architecture

Hydraulic communication within a reservoir unit affects hydrocarbon production, aquifer ingress, and injection. A reservoir that is very compartmentalised is likely to require more wells than fields that have good hydraulic connectivity. Each compartment could also have different rock properties leading to a greater variability across the whole field. Typically, a simpler, well connected reservoir is preferred. However, for CO_2 storage a compartmentalised structure could be developed as a series of "mini stores" that could improve confidence in containment. Such a development would necessarily involve additional wells and potentially a greater development cost.

3.1.3.4 Geological Containment

By definition, oil and gas fields have contained hydrocarbons over geological time scales and therefore, they can generally be expected to provide good geological containment for CO_2. However, CO_2 may cause changes in the geochemistry and geomechanics within the reservoir and the seal. Consequently, the containment should be evaluated for each site on a case by case basis and a monitoring plan developed to provide the necessary assurance about containment.

3.1.4 Legacy wells

Legacy wells from hydrocarbon production provide both opportunities and threats. Wells from oil and gas activity will provide data that can inform a CO_2 storage project, however, they can also present a potential CO_2 leakage risk.

3.1.4.1 Well placement

In oil and gas production the reservoir targets for drilling wells tend to be at the top of the structure. This is because of the buoyancy of hydrocarbons causes oil and gas in the reservoir to rise to the top of the structure as production continues. In a reuse case for CO_2 injection the well targets are different because the goal is to fill as much of the pore space as possible with CO_2. If the CO_2 is injected too close to the top of the structure, there is a risk that the fracture pressure limit of the seal could be reached much sooner than if the CO_2 was injected at the base of the structure.

3.1.4.2 Leakage risk

Reusing oil and gas fields for CO_2 storage introduces a containment risk known as engineered containment. This attribute arises from the presence of wells drilled during the exploration and development of the reservoir. Understanding the way these wells were abandoned and suitability of the abandonment for providing engineered containment of the proposed CO_2 store is extremely important. Figure 3-5 illustrates a range of potential leakage pathways (Pale Blue Dot Energy & Axis Well Technologies, 2016) from both geological and engineering containment perspectives.

The construction materials in legacy wells will not have taken into consideration the presence of high concentrations of CO_2 and as a result, leakage pathways can develop as cement plugs and casing strings corrode. Casing string corrosion is more likely to result in a leakage path than with concrete.

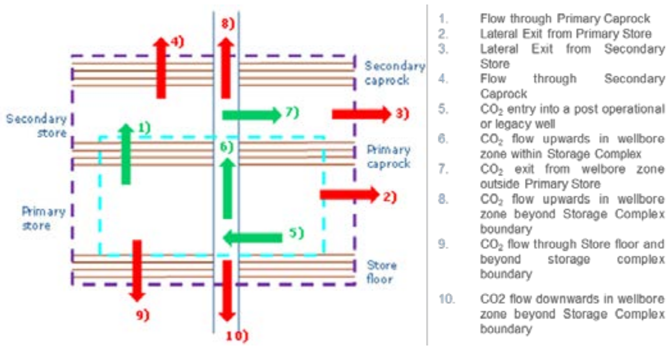


Figure 3-5: Containment Failure Modes

3.1.4.3 Construction and Completion

There is a fundamental difference between a production and an injection well due to the direction of flow. Valves are designed to operate for a single direction of flow. For either a production or water injection well to be reused as a CO_2 injector the tubing would need to be pulled and the well recompleted due to materials and valve requirements. A new wellhead and tree would be required due to the change in use. Figure 3-6 provides a simplified illustration of a well construction and completion diagram (Pale Blue Dot Energy & Axis Well Technologies, 2016).

It is possible that the casing strings could be re-used and a new completion installed inside, with an appropriate wellhead and Christmas tree. This was how the wells on the depleted Goldeneye gas field were planned to be re-used. An example completion diagram is provided as Figure 3-7 (Shell UK, 2014).

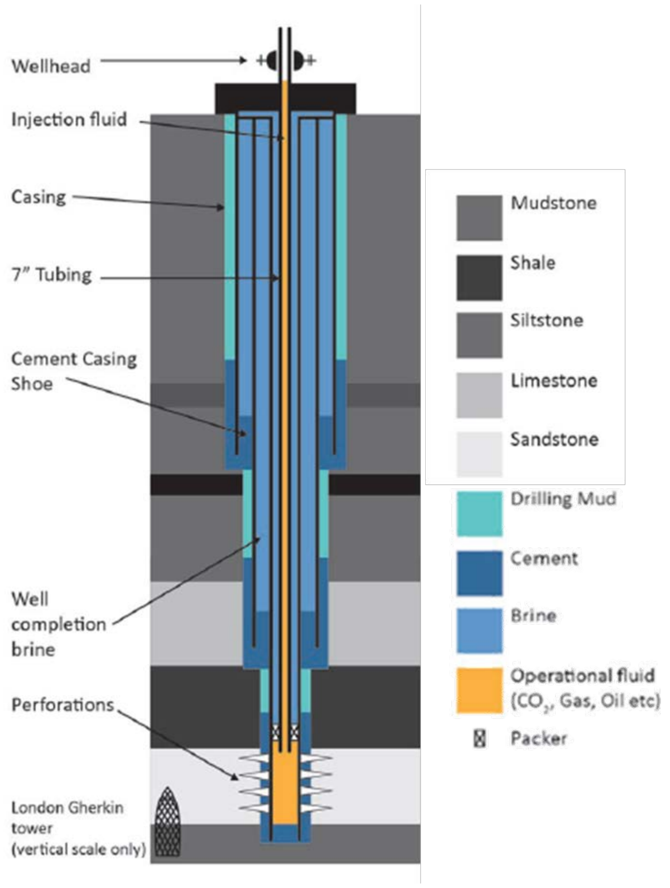


Figure 3-6: Well Construction Schematic

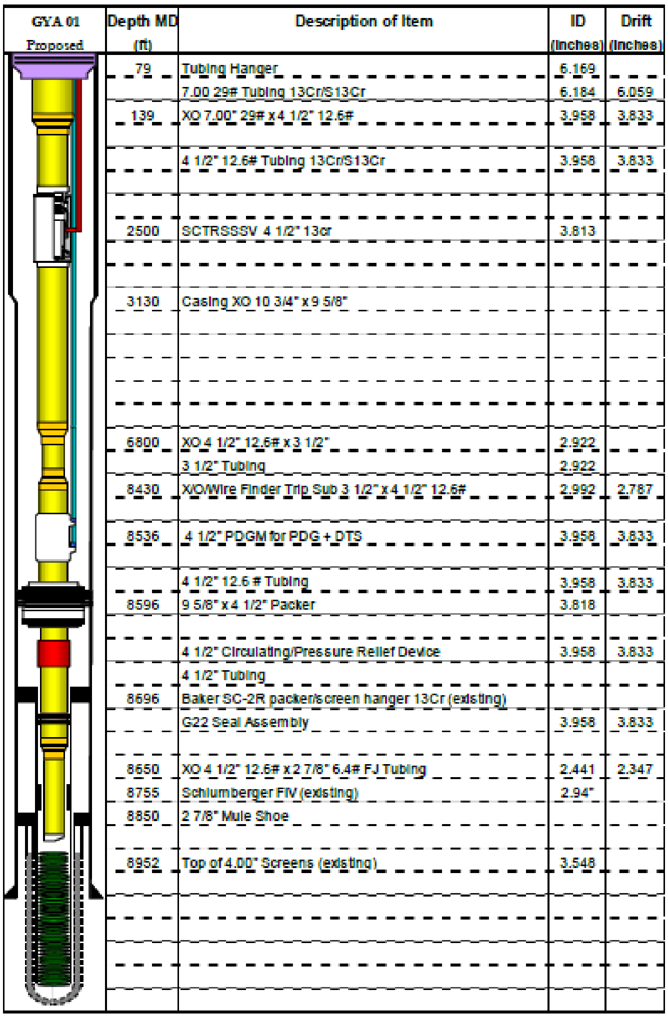
3.1.4.4 Abandoned Exploration Wells

The manner in which some unsuccessful exploration wells were abandoned may present an additional leakage risk for some potential CO_2 storage sites. Even though the abandonment is likely to have been completed in a manner that was appropriate for that purpose and at that time, it might not provide effective containment for CO_2 storage. However, there are unlikely to be significant numbers of unsuccessful exploration wells in depleted oil or gas fields.

3.1.5 Storage Resource Estimation

The storage resource (capacity) of a depleted oil or gas reservoir can be considered in a way that is analogous to calculating the oil or gas initially in place (OIIP / GIIP) for an oil and gas field. A volumetric (sometimes called a static) estimate of the resource capacity for CO_2 stores can be calculated by modifying the OIIP/GIIP equation to:

$$\text{Capacity} = \text{GRV} \times \text{NGR} \times \phi \times S_W \times \rho_{CO_2} \times \text{E}$$



GYA 01 Proposed	Depth MD (ft)	Description of Item	ID (Inches)	Drift (Inches)
	79	Tubing Hanger	6.169	
		7.00 29# Tubing 13Cr/S13Cr	6.184	6.059
	139	XO 7.00" 29# x 4 1/2" 12.6#	3.958	3.833
		4 1/2" 12.6# Tubing 13Cr/S13Cr	3.958	3.833
	2500	SCTRSSSV 4 1/2" 13cr	3.813	
	3130	Casing XO 10 3/4" x 9 5/8"		
	6800	XO 4 1/2" 12.6# x 3 1/2"	2.922	
		3 1/2" Tubing	2.922	
	8430	X/O/Wire Finder Trip Sub 3 1/2" x 4 1/2" 12.6#	2.992	2.787
	8536	4 1/2" PDGM for PDG + DTS	3.958	3.833
		4 1/2" 12.6 # Tubing	3.958	3.833
	8596	9 5/8" x 4 1/2" Packer	3.818	
		4 1/2" Circulating/Pressure Relief Device	3.958	3.833
		4 1/2" Tubing		
	8696	Baker SC-2R packer/screen hanger 13Cr (existing)		
		G22 Seal Assembly	3.958	3.833
	8650	XO 4 1/2" 12.6# x 2 7/8" 6.4# FJ Tubing	2.441	2.347
	8755	Schlumberger FIV (existing)	2.94"	
	8850	2 7/8" Mule Shoe		
	8952	Top of 4.00" Screens (existing)	3.548	

Figure 3-7: Concept Completion Diagram for Goldeneye Wells

Where:

GRV – Gross rock volume, the geometric volume of the gross reservoir interval from its top surface to the deepest level that contains hydrocarbons

NGR – Net to gross ratio, the average vertical proportion of the gross reservoir interval that can be considered to be effective (net) reservoir

ϕ – The average porosity of the net reservoir volume

S_W – The average proportion of the net reservoir volume pore space that is saturated with water

ρ_{CO2} – The average density of CO_2 in the store at the end of the injection period

E – The storage efficiency. The volume proportion of pore space within the target storage reservoir volume that can be filled with CO_2 given the development options considered

The static calculation is a simplification, and generally dynamic modelling using numerical simulation should be used to understand the magnitude of the potential storage resource. This approach will account for the very significant impact on storage resource of the chosen development scenario; variation in rock properties across the field; fracture pressure limitation and dynamic behaviour within the reservoir. Typically, the dynamic modelling will be used to assess numerous development options to achieve an optimum storage capacity such as pressure management via brine production.

Figure 3-8 illustrates a range of storage resource estimates for the Hamilton field that take into consideration both the geological and developmental parameters (Pale Blue Dot Energy & Axis Well Technologies, 2016).

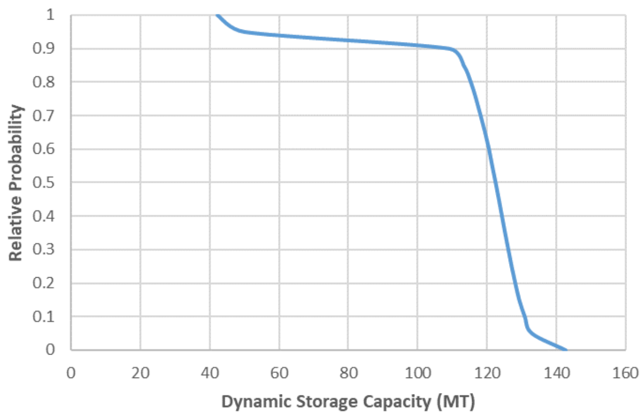


Figure 3-8: Storage Capactiy of Hamilton

3.1.5.1 Storage Efficiency

Figure 3-9 illustrates the results of a sensitivity analysis of the storage resource of the Hamilton field. Two things are apparent from this Tornado Diagram: the impact of uncertainty in any of the parameters is fairly modest and storage efficiency is a significant component. The factors controlling storage efficiency in Hamilton are principally CO_2 injection rate and how the fracture pressure of the reservoir responds to being repressurised during CO_2 injection operations.

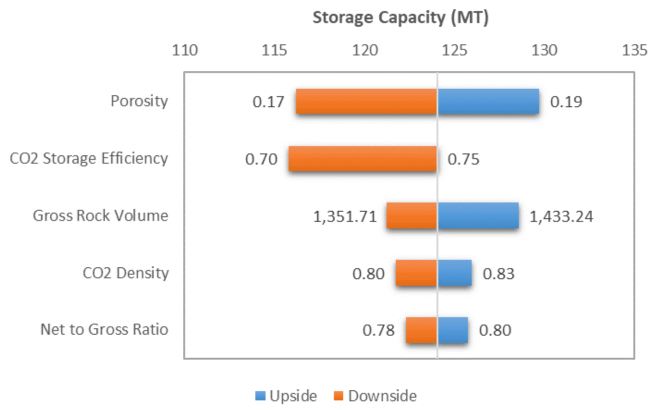


Figure 3-9: Sensitivity Analysis of the Storage Capacity of Hamilton

Storage efficiencies in depleted oil and gas fields are typically quite high, around 70%, compared to the low storage efficiencies of saline aquifers, which might have storage efficiency of around 5%. Depleted hydrocarbon fields tend to be more closed structures that initially held oil or gas and if there has not been aquifer ingress the pressure will be reduced. When CO_2 is injected the reservoir will re-pressurise allowing more CO_2 to be stored rather than the CO_2 having to push back the aquifer to make room for CO_2 storage.

3.1.6 Data

An advantage of using a depleted oil and gas field is the data that will have been acquired during the oil and gas activity. Exploration, appraisal and production wells and seismic surveys can inform models for CO_2 storage and can reduce or even eliminate the need for any further appraisal work for a CO_2 storage project. Access to data may not be a significant problem and operators may be open to a commercial proposition for them to provide data to a developer.

3.1.6.1 Seismic and Well Data Inventory

The seismic data acquired during oil and gas activity can be interpreted to determine reservoir characteristics and identify the best target for CO_2 storage. With new processing techniques older seismic datasets can be reinterpreted to provide new insights into the subsurface.

The well data available will also help to identify how reservoir properties change across the storage target allowing the injection locations to be optimised.

3.1.6.2 Reservoir Surveillance Activity

During production, all the wells in the reservoir are monitored and provide data that can be used to inform models of the reservoir. Pressure in particular, can be very useful in understanding the connectivity of a reservoir and whether or not there has been aquifer ingress to the oil/gas leg during the production phase. This information then informs data models of the field during production and will be used for storage models.

3.1.7 Regulatory Regime

The CO_2 that is injected must remain inside the storage complex after it has been injected otherwise penalties may be incurred by the Store Operator (European Commission, 2009).

Prior to development, the formation and movement of the CO_2 plume movement is evaluated using dynamic models by conducting sensitivity analyses such as varying injection rates, quantities and well locations. The predicted movement of the CO_2 plume may influence the development plan in terms of well location, injection rate and operational life to ensure that the plume remains within the storage complex.

3.2 Infrastructure

There are six main elements of infrastructure commonly used in oil and gas developments: pipelines, umbilicals; platforms (including the jacket), subsea manifolds, wells and onshore facilities. Each of these elements is described in the following text along with commentary on relevant decommissioning aspects and potential for re-use in CO_2 operations.

3.2.1 Pipeline

3.2.1.1 Overview

Pipelines are used to transport fluids. They have been used extensively in many industries and are essentially the arteries of the oil and gas industry (offshore/onshore); connecting oil/gas wells, platforms, subsea structures and onshore terminals. They are mainly used to transport hydrocarbons from oil and gas fields to production platforms/processing facilities but also used to transport chemicals (i.e. MEG), and injection water or lift gas. Rigid pipelines can be fabricated from carbon steel or corrosion resistant alloys and can be a single flowline or of pipe in pipe construction. Flexible pipelines are made up of composite construction layers of different materials (such as steel and plastic) that provide different functions depending on the environment, fluids and length.

Following installation of a pipeline it needs to be connected to the relevant facilities at each end. Offshore, this is done by installation of rigid tie-in spools or flexible spools/jumpers. The tie-in spool layout is selected to minimise transfer of loads induced by the pipeline expansion (due to pressure and temperature) and any misalignments associated with installation.

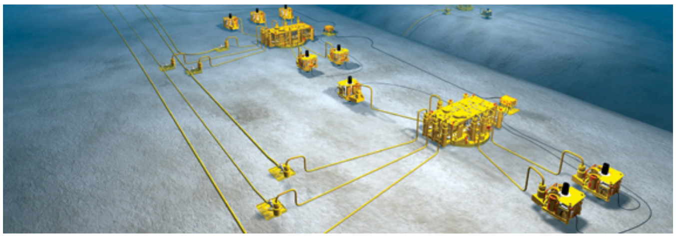


Figure 3-10: Wellhead, Manifold and PLET Tie-ins (FMC Technologies)

Rigid pipelines in the UK North Sea are designed to specifications PD8010 part 2 or DNV OS F101 (now DNVGL-ST-F101). The design of flexible pipes is performed to specification API 17J.

3.2.1.2 Trunk Pipeline

A trunk line is a pipeline that transports oil/gas from offshore oil/gas production facilities to onshore terminals for processing. Trunk lines can be hundreds of kilometres long and transport oil/gas across countries. Offshore, they are typically fabricated from carbon steel and are larger in diameter than infield pipelines. Larger diameter trunk pipelines (16" to 44" in North Sea region) are installed utilising the 'S-lay' pipelay method from a specialist lay-vessel where the pipes are welded onboard and are installed on the seabed. Due to their size, they may not require trenching against fishing protection however they may be trenched and buried in areas subject to large wave and current loads to ensure stability and avoid excessive free spans.

3.2.1.3 Infield Pipeline

An infield pipeline typically connects a subsea structure (well/manifold etc) to another structure or to a production facility. Infield pipelines can be rigid (carbon steel/corrosion resistant alloy) or flexible (composite construction) and can range in length from a few hundred metres to over 20km. In the North Sea pipelines less than 16" (40.64 cm) in diameter are typically trenched and buried for protection from fishing and other marine activity (as well as long term stability), additional rock coverage is often used to protect pipeline crossings and to mitigate upheaval buckling. Infield pipelines in the North Sea are generally installed by reel lay vessel. This is where the pipes are welded onshore and reeled onto the lay vessel for installation on the seabed.

3.2.1.4 Decommissioning

There are no internationally recognised guidelines on the decommissioning of disused pipelines. In the UKCS (UK Continental Shelf), the decommissioning of pipelines is regulated principally by the Petroleum Act 1998, as amended by the Energy Act 2016 and the Pipeline Safety Regulations 1996, as amended by The Pipeline Safety (Amendment) Regulations 2003. Due to the different circumstances surrounding each decommissioning case, each pipeline is considered individually. The Petroleum Act is now administered by the Department for Business, Energy and Industrial Strategy (BEIS).

The Petroleum Act 1998 makes the following provisions concerning pipelines:

- All decommissioning options should be considered, and a comparative assessment of options carried out.
- Any removal or partial removal of a pipeline should not result in any significant adverse effect upon the marine environment.
- Where it is intended to leave a pipeline in-situ, the rate of deterioration of the pipeline material and its present and potential future environmental impact should be considered.
- Other users of the sea should be considered.

The decision as to whether a pipeline can be left in situ is considered on a case by case basis by BEIS. However, pipelines are not included within OSPAR Decision 98/3 and there is no requirement to seek derogation to leave a pipeline in place.

The following guidelines set out conditions where non-recovery of pipelines may be considered:

- Pipelines that are adequately buried or trenched over a sufficient length and which are not subject to the development of spans and are likely to remain so;
- Pipelines which were not buried or trenched when installed, but which may self-bury within a reasonable time and remain buried;
- Pipelines where burial or trenching is undertaken to sufficient depth and is likely to be permanent; and
- Pipelines that are not trenched or buried but may still be suitable for leaving in-situ (e.g. trunk lines).

On this basis a typical pipeline decommissioning plan, that requires approval by the BEIS, will comprise the following two main activities.

Flooding and cleaning of the pipeline to remove all residual hydrocarbons so only the smallest trace remains is expected. Flushing operations may be carried out under the operational environmental permits, e.g. the Offshore Petroleum Activities (Oil Pollution Prevention and Control) Regulations 2005 as amended (OPPC) or the permit under the Offshore Chemical Regulations 2002 (as amended) (OCR) for the use and discharge of flushing and cleaning chemicals. Flushing operations have generally been carried out to the OSPAR recommendation 2001/1 performance standard (ref: OPPC guidance notes) of less than 30 parts per million (ppm).

Removal of all sections of exposed pipeline sections and pipeline infrastructure such as the tie-in spools, concrete mattresses, grout bags and any unsupported spans.

Trenched and buried pipelines are usually left in place as are the pipeline ends after being protected with burial/rock dump.

It is also worth noting that, for the purposes of decommissioning, any risers are considered as exposed pipelines and as such are to be recovered. The ancillary riser hardware, including any buoyancy modules, clamps and hold down tethers are also required to be recovered.

3.2.1.5 Options for Reuse

If an existing pipeline is appropriately located and is of sufficient size and pressure rating, it could be suitable for re-use to transport CO_2. A chemical pipeline (i.e. MEG) could be suitable for re-use if required for first injection/start-up.

Prior to deciding to re-use an oil or gas pipeline for CCS a full pipeline integrity and life extension study will be required. The results of such an analysis will help determine whether it is technically and commercially feasible to acquire (e.g. purchase or lease) and re-use an existing pipeline system.

An integrity and life extension study will typically involve detailed internal and external inspection in order to re-qualify the pipeline and verify that it is suitable for re-use to transport CO_2 for the required design life. External inspection would be carried out by Remotely Operated Vehicle (ROV) to detect any unsupported span or debris in the pipeline vicinity and assess condition of anodes where possible. Internal pipeline inspection would be carried out using intelligent pigs capable of measuring pipeline wall thickness and detecting any defects/deformations in the pipeline wall. Re-qualification shall comply with the same requirements as for a pipeline designed specifically for transportation of CO_2.

3.2.2 Umbilicals

An umbilical is a composite flowline used to transmit electrical power, communications, chemicals and hydraulic control fluids to subsea developments. They come in a variety of designs and sizes are typically between 2” and 6” in diameter and can originate either at a nearby platform or from a terminal onshore. Umbilicals are usually trenched and buried and are often installed with, or alongside, subsea pipelines. At the well or manifold end of the umbilical there is some form of an umbilical termination assembly (UTA), from which control services are distributed via flying leads to the subsea equipment such as trees and manifolds. One of the longest umbilicals is at the Zohr subsea gas field, offshore Egypt, which runs 180km from the onshore terminal.

Due to the different circumstances surrounding each decommissioning case, each umbilical is considered individually and similarly to a pipeline, requires a comparative assessment of the options.

In order to be suitable for re-use, the umbilical and the umbilical termination unit would need to be left in a suitable state when decommissioned (flushed and capped), have sufficient capacity to deliver required power/communications/chemicals/hydraulic fluids and have the required remaining design life. The associated UTA’s and flying leads would probably need to be replaced.

Figure 3-11: Umbilical Cross-Section

3.2.3 Platform

3.2.3.1 Overview

Platforms are offshore structures that are used to produce/process/store oil and gas. There are various types of platforms, including fixed platforms that are permanently fixed to the seabed and semi-submersibles which float and are typically held in position using mooring lines/anchors. An FPSO is a specific type of floating production platform known as a Floating Production Storage and Offloading (FPSO) unit. FPSOs generally have a ship shape hull, however some have a circular hull.

A drilling platform is a platform that has drilling facilities from which wells can be drilled. If no drilling facilities are provided on a platform then wells will require to be drilled separately, using a jack-up or semi-submersible drill rig. Oil and gas wells can have ‘dry’ or ‘wet’ trees and are discussed further in Section 3.2.5.

A fully automated offshore oil/gas platform that is operated from onshore remotely and is generally unstaffed is known as a Normally Unmanned Installation (NUI). A NUI typically comprises a small jacket structure with minimum process facilities complete with well bay and helipad, and are generally only used in shallower water, such as the Southern North Sea (SNS). The Camelot and Goldeneye developments discussed in Sections 5.0 and 8.0, both used just such a platform. Some NUIs in the SNS transport personnel by boat and use a walk-to-work gangway system to access the installation although this is not as prevalent as helicopter access.

3.2.3.2 *Platform Decommissioning*

All fixed production platforms in the North Sea will be considered to fall under OPSAR Decision 98/3 with regards to decommissioning. The regulation of which is covered under the Petroleum Act 1998 (as amended).

After cessation of production (CoP) a platform will be depressurised and made safe in preparation for removal. A fixed platform will typically have all topsides facilities removed by heavy lift vessel (HLV) or single lift vessel (SLV) and transported onshore for reuse/recycling/disposal.

All steel jackets or substructures weighing less than 10,000 tonnes, or installed after 9th February 1999, must be completely removed for re-use or recycling or final disposal on land.

The jacket structures are also completely removed to a distance below the seabed and transported onshore for dismantling/recycling/disposal.

Decommissioning of a floating platform requires a streamlined decommissioning programme. These are largely governed by Hong Kong Convention on the Safe and Environmentally Sound Recycling of Ships 2009.

A floating platform will retain any residual inventory of fuel oil, chemicals, hydraulic fluid and other solid, liquid and gaseous materials, which will be properly and securely contained and stored. After flushing and topsides release of any buoy and/or risers, the moorings can be disconnected, and the platform can be towed to shore. Note that a key commercial and schedule driver will be to minimise the duration a floating platform remains on station, and consequently on hire, following cessation of production (COP). The mooring system is considered to fall under OPSAR Decision 98/3 with regards to decommissioning.

3.2.3.3 *Re-Use Options*

Several authors, including Shell, Costain and Pale Blue Dot Energy (Pale Blue Dot Energy & Axis Well Technologies, 2016), have suggested that CO_2 injection operations are likely to need relatively simple processing systems offshore and that these can easily be housed on a normally unmanned installation (NUI) or subsea development. The exception to this general observation is in situations where offshore heating is required to maintain CO_2 in single phase – such as for the Hamilton development concept.

The more complex process and safety systems required by oil and gas production are unnecessary and not suitable for CO_2 operations and would be removed if the platform structure was to be re-used. These brownfield modification projects are, anecdotally, very complex and expensive and few operators embark on those sorts of projects lightly.

It is likely that semi-submersible installations would be most economically re-deployed on other oil and gas developments.

Other alternatives for re-use options include:

- Renewable Energy – existing platform substructures converted for use for supporting the renewable energy infrastructure e.g. wind turbines or substations; and
- Weather stations

The original design life (and remaining life expectancy) of an existing platform will be a key factor in assessing their suitability for re-use. The topsides equipment required for injection of CO_2 is generally lighter in weight than that required for processing of oil and/or gas and therefore it may be possible to extend the design life and demonstrate structural integrity of the platform by accounting for this reduction in payload, however, in addition to removing existing oil/gas production equipment there are likely to be a number of brownfield modifications/upgrades required to handle CO_2, including but not limited to piping manifold, flowlines, allocation meters, chokes, pumps and venting arrangements. If existing utilities (heating, filtration etc.), power and control systems are not suitable for re-use then these will also require removal and replacement with suitable facilities. This can result in a significant CAPEX required for modifications.

One of the significant costs associated with re-use of an existing facility is the need to complete the modification work offshore rather than onshore. The problem offshore is first the restriction on bed space and second the high cost of crew and services per day. The high cost of working man-hours offshore makes it more effective to minimize the modification work. This may result in being more effective to simply mothball the existing equipment in situ and then lift on new modules for the CO_2 injection. The key to this option will be the platform's ability to take on the additional deck loading, and the costs associated with managing the long-term integrity of any mothballed equipment.

The changes to the tax laws that allow decommissioning tax relief to be transferred to a new owner have made transfer of assets easier, however the oil and gas operators may still choose to keep the decommissioning control to mitigate again uncontrolled spend and reputational impacts.

Furthermore, transferring ownership and obligations of a platform can be significantly more onerous than that of a pipeline due their respective liabilities.

Prior to re-use for CCS an offshore safety case review will be required for any platform. Although a safety case is not a requirement for renewable energy infrastructure many operators adopt this approach too.

3.2.4 Subsea Manifolds

3.2.4.1 Overview

A subsea manifold, such as the one shown in Figure 3-12, is a subsea structure that comingles production from various sources (wells/other fields) and connects them to a pipeline that is usually tied back to a production facility, thereby reducing the number of required flowlines. A system of pipework and valves is used to control the flow, as well as to inject chemicals into the flow stream. A manifold can also house any control system components including umbilical termination assemblies (UTA), subsea control modules (SCM) and distribution units complete with electric / hydraulic / chemical jumpers out to the trees. The pipework, valves and control system are all housed within a protection structure. Subsea manifolds can be gravity based or piled, depending on the overall weight, location (i.e. whether it is located in a safety zone) and design loads (fishing gear interaction etc). The protection structure can be designed to be 'fishing friendly' or 'over-trawlable'.

Figure 3-12: Subsea Manifold

3.2.4.2 Decommissioning

Subsea manifolds are not considered to fall under OPSAR Decision 98/3 with regards to decommissioning but are regulated in a manner similar to pipelines.

A subsea manifold would generally be recovered by direct lift using a construction vessel, with piles cut below the seabed and recovered (as applicable).

3.2.4.3 Re-Use Options

Similar to the case for offshore pipelines, a subsea manifold could be suitable for re-use provided its location and pipework configuration (valving, materials, pressure rating etc.) was appropriate but would require a full integrity and life extension study to confirm technical and commercial feasibility.

3.2.5 Wells

3.2.5.1 Overview

Oil and Gas wells are used to bring hydrocarbons to the surface and also to inject water and gas to increase reservoir pressures and promote further production. A "Christmas tree" is an assembly of valves, spools and fittings at the top of a well and is used to control the flow into or out of the well, usually oil and/or gas. As mentioned in Section 3.2.3, trees can be 'dry' or 'wet'. Dry trees are used on platform wells and are located on the platform. A direct consequence is the requirement for a larger deck area and greater load-bearing capacity of the jacket to house the wells. Offshore, dry tree systems are only used on fixed platforms and tension leg platforms. Wet trees, or subsea trees are located on the seabed and are usually tied back to a subsea manifold or platform. They can be used with fixed or floating platform facilities and allow increased flexibility in field layouts because the wells can be located remotely from the platform.

Figure 3-13 and Figure 3-15 show schematics of the Christmas tree and the overall well bore respectively, from the planned Peterhead CCS project (Shell UK, 2014) where the trees were to be located on the Goldeneye platform. The diagrams illustrate the key equipment of these "dry wells" and indicate which components were planned to be replaced. An illustration of a subsea tree is provided in Figure 3-14.

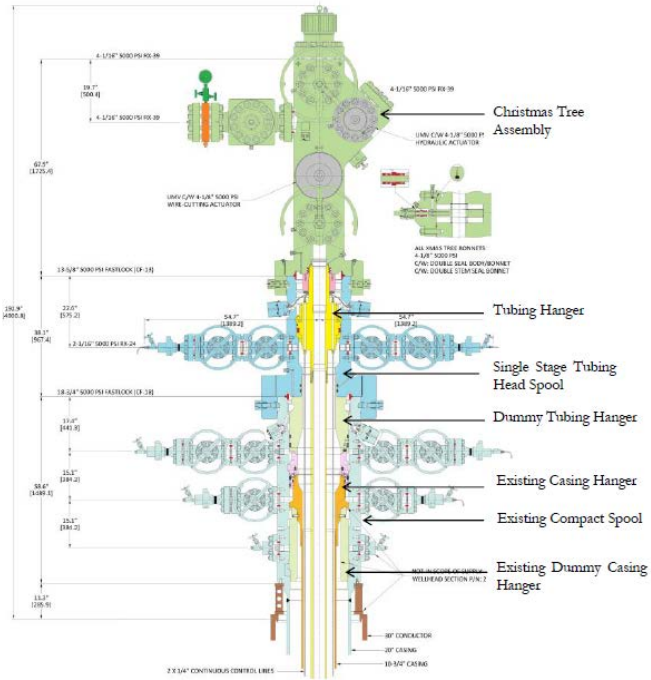


Figure 3-13: Example Wellhead and Christmas Tree

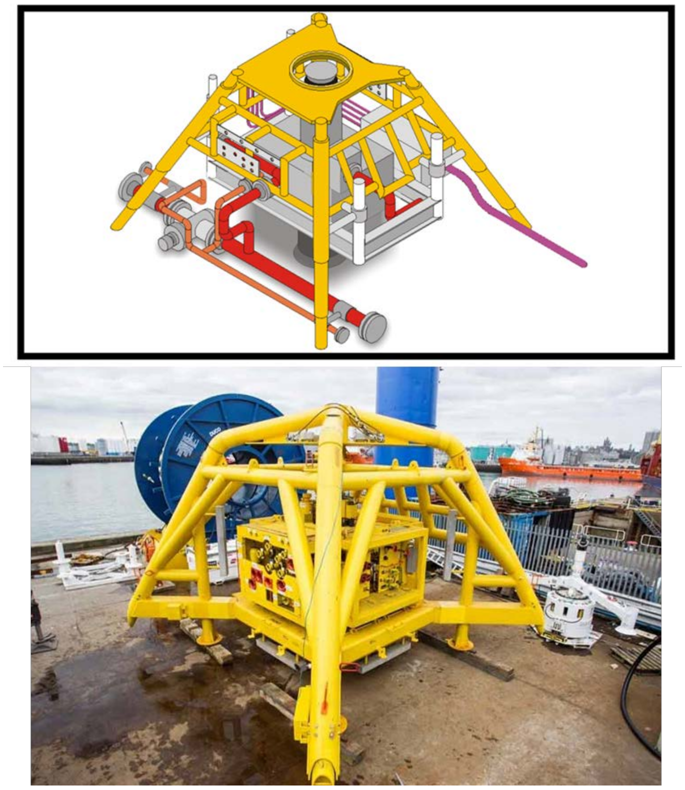


Figure 3-14: Ilustration and Picture of a Subsea Tree

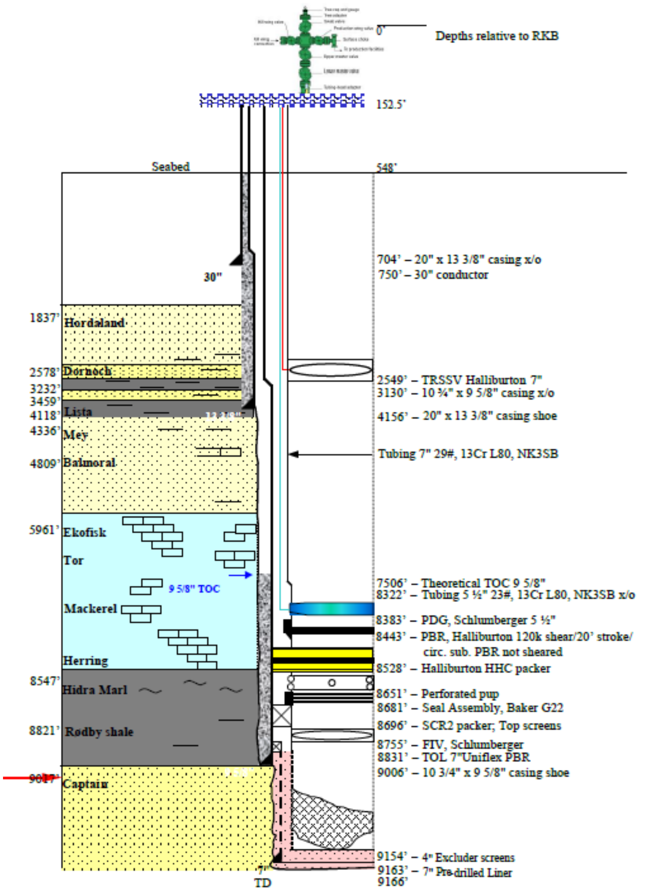


Figure 3-15: Example Gas Well Schematic

3.2.5.2 Decommissioning

The HSE requires that any proposed well abandonment programme complies fully with regulations 13 and 15 of the Offshore Installations and Wells (Design and Construction etc) Regulations 1996. The requirements of these regulations are addressed in the Oil & Gas UK Well Abandonment Guidelines.

With 'dry tree' wells the decommissioning of the wells should be one of the first activities to be undertaken, because the key objective at this stage, is to seal and secure the hydrocarbon reservoir, isolating it from the platform and thereby eliminating the risk of inadvertently releasing additional reservoir fluids. This well plugging activity can begin at any time in the UK as well activity is regulated separately from decommissioning. Until such a time as all wells are plugged and secure it will be necessary to maintain all safety and emergency shut down facilities on the platform to ensure that it remains a safe place to work. This can be a significant cost (a small platform may cost £3-5million per year just to keep it in a safe condition), so holding onto to redundant wells for potential CO_2 re-use could be expensive and decisions will have to be made quickly to avoid accumulating costs that penalise any potential re-use option. Typically, this period may last for 3 -5years.

With subsea, 'wet trees', the well abandonment can be deferred until the completion of all other decommissioning activities. This approach is consistent with decommissioning projects performed to date and mitigates the operational and schedule risks associated with simultaneous production and well operations and working within a drill rig anchor pattern.

Oil and gas wells are fully abandoned using a platform, jack-up or semi-submersible drilling rig to kill the well, pull the completion and fully isolate the reservoir according to Oil & Gas UK Well Abandonment Guidelines. The subsea trees will be recovered to surface. The casings strings are cut below seabed and this short section of casing and the wellhead are retrieved.

3.2.5.3 Re-Use Options

A wet or dry production tree would have to be replaced with a tree with valving configured for injection. Similarly, the production tubing would be unlikely to be suitable for CO_2 injection. If the bottom hole location of a production well was ideally suited for storage of CO_2, then the existing wells could be plugged and then side tracked to reuse the existing casing (provided it is suitable for CO_2) however there is unlikely to be any significant cost saving in doing so. An oil or gas well that has been plugged and abandoned will not be reusable. It is therefore rarely technically or commercially feasible to re-use existing oil and gas wells for CO_2 injection and long-term storage. It might be possible for wells to be converted and used for monitoring however this would require them to be in the right place to provide useful information on CO_2 plume development.

3.2.6 Onshore Facilities

The onshore capture facilities required for a CCS development are outside the scope of this study. However, a high-level review of required onshore transportation facilities is provided in this section.

3.2.6.1 Landfall

A landfall is where an offshore pipeline meets the shore line. The landfall can be installed by either pulling (from onshore or offshore) of the pipeline, horizontal directional drilling (HDD), tunnelling/ or open cut trenching/dredging.

Additional considerations in the design of landfall include 3rd parties, environmentally sensitive areas, vicinity of people and a limited construction period. The table below summarises the main UK landfalls that have been considered in previous CCS studies (Pale Blue Dot Energy & Axis Well Technologies, 2016).

Landfall Location	Suitability for CCS
St Fergus, Aberdeenshire	CNS hub connected by Feeder 10 to C Scotland, focus for storage and EOR in CNS. Close to Peterhead and Goldeneye project.
Redcar, Teesside	Focus for Teesside Collective, industrial emissions cluster, Storage in SNS or CNS.
Barmston, E Yorkshire	Landfall for NGC pipeline from Drax to 5/42.
Connah's Quay, Flintshire	Focus for N W England emissions at Connah's quay, Tata steel, Stanlow refinery and various industrial plants. Link to EIS storage.
Medway, Kent	Nominal focal point at Kingsnorth, representing SE England emissions with offshore transport to SNS.

Table 3-2: Suitability of Landfall Locations for CCS

3.2.6.2 Onshore Pipeline and Reception Facilities

An onshore CO_2 transmission pipeline will be required to transport the CO_2 from the source to the reception facilities, comprising gas compression and pumping facilities. A connection from the reception facilities to the offshore CO_2 pipeline will also be required. CO_2 conditioning would normally be carried out at the CO_2 capture plant.

3.2.6.3 Pig Launcher Receiver

A pig launcher/ receiver is required to launch and receive pigs used for cleaning and inspecting the pipelines to/from offshore. This would likely be incorporated into or adjacent to the reception facilities.

3.2.7 Decommissioning Summary

The decommissioning philosophy assumed for the development planning and economic analysis performed as part of this study is as summarised below. It has been assumed that any acquisition of existing facilities will include liability for decommissioning.

Note that this philosophy is subject to the outcome of the comparative assessment process and subsequent approval by BEIS.

- Wells plugged and abandoned;
- Topsides facilities are cleaned, prepared and disconnected.
- Removal of Topsides (reverse installation) using a HLV
- Steel jacket completely removed and taken ashore for dismantling and recycling.
- Pipeline is cleaned and left in place, part end recovery and ends protected by burial/rockdump.
- Pipelines >16" (40.64 cm) diameter (surface laid) are assumed to be covered by the UK fisheries offshore oil and gas legacy trust fund.
- Pipeline spools to be recovered;
- Subsea structures to be recovered (Manifold, SSIV etc);
- Subsea concrete mattresses and grout bags recovered

3.2.8 International Decommissioning Regulations

International law and policy provides a framework that influences the approach taken to offshore decommissioning by many nations. However, within this framework, different approaches have been adopted by different countries.

International legal frameworks have favoured complete removal but do not prohibit alternatives such as in-situ decommissioning, partial removal and relocation.

In the North Sea, the OSPAR (Oslo/Paris convention for the protection of the marine environment of the North Atlantic) Decision 98/3 on the disposal of Offshore Installation requires all fixed installations installed after the 9th of February 1999 to be completely decommissioned. Under certain circumstances installations, installed prior to this date may apply for a derogation to leave some or all, of the jacket in place. In the case of re-use for CO_2 storage, the circumstances deemed most relevant is steel jacket weight of over 10,000 tonnes.

The International Maritime Organisation (IMO) has developed the 'Guidelines and Standards for the Removal of Offshore Installations and Structures on the Continental Shelf and in the Exclusive Economic Zone'. This requires evaluation of each individual case prior to the decision to allow offshore infrastructure to remain on the seabed. Evaluation criteria include safety of navigation, rate of deterioration, risk of structural movement, environmental effects, costs, technical feasibility, risk of injury associated with removal. There is also reference to 'determination of a new use or other reasonable justification for in-situ disposal'.

The IMO guidelines include the following requirements:

- Complete removal of all structures in <75m of water and <4,000 tonnes in air, excluding deck and superstructure.
- Complete removal of all structures placed on the seabed after 01/01/1998, in less than 100m of water and weighing <4,000 tonnes in air excluding deck and superstructure.
- Any structure projecting above the surface of the sea should be adequately maintained to prevent structural failure.
- In cases of partial removal, an unobstructed water column sufficient to ensure safety of navigation, but not less than 55 m should be provided.

There are no international guidelines that explicitly address the decommissioning of pipelines or cables.

4.0 Functional Specification

This chapter highlights the major functional requirements of an offshore CO_2 storage development and outlines key commercial and project design issues.

4.1 Storage Reservoir

The functional specification of a geological CO_2 storage site has four primary components:

- Containment
- Injectivity
- Connectivity
- Capacity (strictly speaking, storage resource)

4.1.1 Containment

Four aspects of containment are normally considered: caprock, lateral seal, faulting and legacy wells (Pale Blue Dot Energy & Axis Well Technologies, 2016).

From a geological perspective a hydrocarbon field is likely to have suitable caprock and lateral seals since the oil and gas has been contained in the structure over geological timescales. Geochemical analysis of samples from the caprock could assess the susceptibility of those lithologies to be affected by CO_2 in a manner which significantly alters the existing permeability character and confirm their suitability, or otherwise, to contain CO_2.

Legacy exploration, production and injection wells from oil and gas activity present a series of potential containment risks, as discussed in Section 3.1.4.

One approach to assessing the containment characteristics that is gaining popularity, is the leakage scenario definition workshop used in the Strategic UK CO_2 Storage Appraisal Project. The workshop involves a multi-disciplinary team in a structured review of the subsurface characteristics of the field to understand where leakage paths might occur, a typical input is the simplified geological section provided as Figure 4-1.

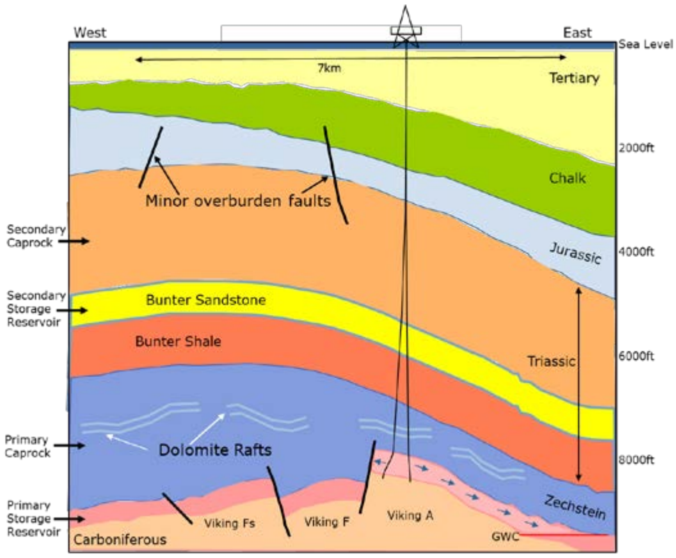


Figure 4-1: Simplified Geological Section of the Viking Gas Field

The workshop considers both the geological and engineering containment issues and identifies a variety of potential leakage paths, as illustrated in Figure 3-5.

These are then evaluated against each of the 10 potential containment failure modes (pathways for CO_2 to move out of the primary store and/or storage complex which are contrary to the storage development plan).

For each failure mode, a number of containment failure mechanisms are discussed. A containment failure mechanism is a geological or engineering feature, event or process which could cause CO_2 to move out of the primary store and/or storage complex (contrary to the storage development plan). An example is fault reactivation in primary caprock. The likelihood and impact of each failure mode is agreed using a consistent scoring mechanism such as that shown in Table 4-1 and Table 4-2.

The outputs can then be combined in a simple matrix such as the one shown in Figure 4-2 to highlight the relative significance each failure mode.

Score	1	2	3	4	5
Name	Very Low	Low	Medium	High	Very High
Description	Improbable, negligible	Remotely probably, hardly likely	Occasional, likely	Probable, very likely	Frequent, to be expected
Event (E)	Very unlikely to occur during the next 5000 years	Very unlikely to occur during injection operations	Likely to occur during injection operations	May occur several times during injection operations	Will occur several times during injection operations
Frequency	About 1 per 5000 years	About 1 per 500 years	About 1 per 50 years	About 1 per 5 years	About 1 per year or more
Feature (F)/ Process (P)	Disregarded	Not expected	50/50 chance	Expected	Sure

Table 4-1: Likelihood Scale

Score	1	2	3	4	5
Name	Very Low	Low	Medium	High	Very High
Impact on storage integrity	None	Unexpected migration of CO_2 inside the defined storage complex	Unexpected migration of CO_2 outside the defined storage complex	Leakage to seabed or water column over small area (<100m2)	Leakage seabed water column over large area (>100m2)
Impact on local environment	Minor environmental damage	Local environmental damage of short duration	Time for restitution of ecological resource <2 years	Time for restitution of ecological resource 2-5 years	Time for restitution of ecological resource such as marine Biosystems, ground water >5 years
Impact on reputation	Slight or no impact	Limited impact	Considerable impact	National impact	International impact
Consequence for Permit to operate	None	Small fine	Large fine	Temporary withdrawal of permit	Permanent loss of permit

Table 4-2: Impact Scale

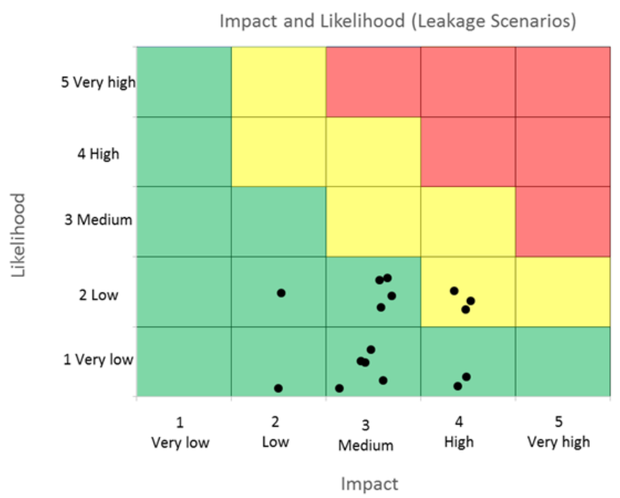


Figure 4-2: Risk Matrix of Leakage Scenarios

4.1.2 Injectivity

The injectivity needs to be sufficient for the CO_2 quantities and rates for the project under consideration. The injectivity influenced by a combination of the number of injection wells and the reservoir properties. The injectivity is characterised by the Darcy injectivity equation:

$$I \alpha \, N \times K_h \times \Delta P$$

The injectivity is proportional to the number of wells, N, multiplied by the permeability-thickness, $K_{h,}$ and the difference between the surface pressure and the bottom hole pressure, ΔP. The maximum allowable bottom hole pressure is usually defined as a percentage of the caprock fracture pressure of the caprock. Typically, a safety factor of 90%, is used to ensure that the fracture pressure is not reached. The bottom hole pressure is very dependent on the ease with which the reservoir can dissipate pressure. The rate of pressure dissipation depends on the rock properties, the degree of hydraulic connectivity and the ingress or egress of fluid (such as aquifer influx) into the reservoir. In situations where pressure is readily dissipated the pressure in the near well bore region builds up slowly, in contrast to situations where pressure is not easily dissipated and pressure in the near well bore region can reach the fracture pressure limit more quickly. Injection rate affects dissipation, the higher the rate the slower the dissipation. This is one of the primary reasons why reservoir and/or well injectivity may vary over the life of a store.

The wellhead pressure is limited by the pressure of the CO_2 as it reaches the well which in turn is constrained by the safe operating envelope of the pipeline.

4.1.3 Connectivity

The ideal storage reservoir has good hydraulic connectivity. A well-connected reservoir unit makes it more straightforward for the injected CO_2 to move away from the well bore and for the pressure increase to be dissipated through the reservoir. All other things being equal, this will lead to a higher storage capacity. The Hamilton gas field is an example of a well-connected reservoir.

Fields such as Viking (Figure 4-1), that comprise of multiple compartments can also be suitable CO_2 stores. Depending on the degree of hydraulic (pressure) communication between the fault blocks, each compartment may require its own injection well in order to fill the pore space. This will clearly influence the development cost.

4.1.4 Storage Resource

It is self-evident that the storage resource available in a depleted oil or gas field must be considered sufficient for the development project being contemplated. The quantity of CO_2 that can be injected into and contained with a store depends on many parameters.

4.1.4.1 Rock Properties

The reservoir characteristics and, in particular net pore volume, are the main determinants of CO_2 storage resource, as discussed in 3.1.5.

There are several dynamic attributes that also have a significant influence on CO_2 storage resource.

4.1.4.2 Fracture Pressure

Pressure is important in controlling the CO_2 phase as well as limiting the amount that can be injected due to the fracture pressure constraints. The pressure itself is influenced by the injection locations and the reservoir properties. CO_2 injection at the crest of the structure and with insufficient pressure dissipation can cause the fracture pressure limit to be reached sooner and restrict the amount of CO_2 that can be injected. The connected aquifer will also impact the pressure within the store, with good hydraulic connectivity the aquifer can be pushed out to make more room for the CO_2. If the aquifer cannot be pushed out by the injected CO_2 then the aquifer acts as a storage boundary.

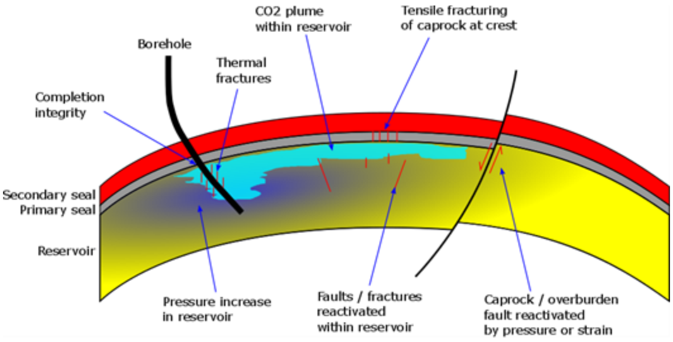


Figure 4-3: Well Placement and Fracture Pressure Implications

4.1.4.3 Initial Reservoir Pressure

The production history of the field will also play a role in the storage capacity. During the production phase, oil and gas is produced and the pressure in the reservoir declines, as illustrated in Figure 4-4 (Pale Blue Dot Energy & Axis Well Technologies, 2016). A connected aquifer can lead to water influx which will tend to increase reservoir pressure and would need to be forced back out by injected CO_2.

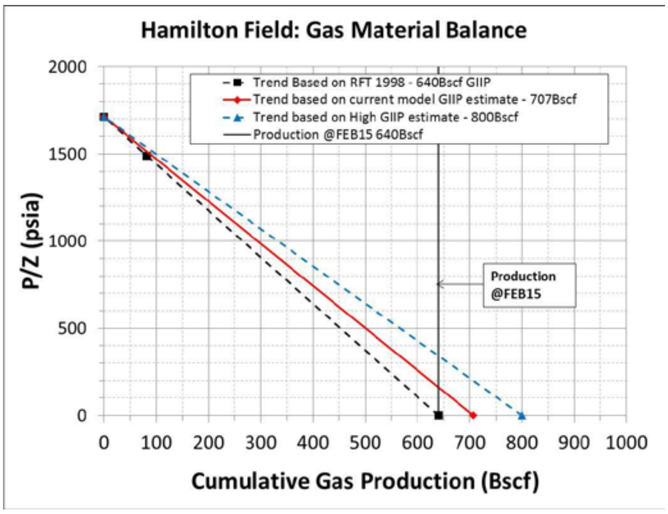


Figure 4-4: Pressure Depletion in Hamilton

4.1.4.4 CO_2 Phase

The CO_2 phase affects storage capacity. In gaseous phase the CO_2 will take up more volume with smaller mass in comparison to liquid or dense phase where more CO_2 can be stored in the same volume because the density is 800 times greater.

In a depleted gas reservoir such as Hamilton, CO_2 can be injected in gas phase conditions only until the reservoir pressure increases to a level that results in a phase change occurring in the pipeline and well tubing. Figure 4-5 shows how the reservoir bottom hole pressure (BHP) changes with the CO_2 volume injected. The chart illustrates a scenario in which two wells each inject 2.5 Mtpa (the same development as for the Reference scenario for Hamilton (Pale Blue Dot Energy & Axis Well Technologies, 2016)). The dashed green horizontal line in Figure 4-5 is the pressure above which the CO_2 in the pipeline would be in liquid phase at the ambient sea-bed temperature of 6 °C. The intersection of this line with the cumulative injection curve is the maximum amount of CO_2 that can be injected when operations are restricted to gas phase.

At seabed temperature, roughly 6°C, the bottom hole pressure will exceed the saturation pressure once circa 12-14 million tonnes of total CO_2 have been injected. Exceeding the saturation pressure, without heating, will cause the CO_2 to begin condensing and an unstable two-phase flow would occur in the pipeline, which is usually best avoided. A gas phase development can store approximately 12 -14 million tonnes of CO_2, compared to a capacity of 125 million tonnes when dense phase operations are adopted. In order to operate a dense phase injection heating would be required once the saturation pressure is reached to raise the temperature above the critical point (31.10°C) to avoid multiphase operation.

Figure 4-5 illustrates the injection potential in a depleted gas field without heating, and therefore no dense phase operation. The saturation pressure is represented by the light green dashed line and is crossed after roughly 6 million tonnes has been injected by each well. The dark green dashed line represents the critical pressure for carbon dioxide, above the dark green CO_2 would be in dense phase and operating in between the two dashed lines would result in two-phase flow.

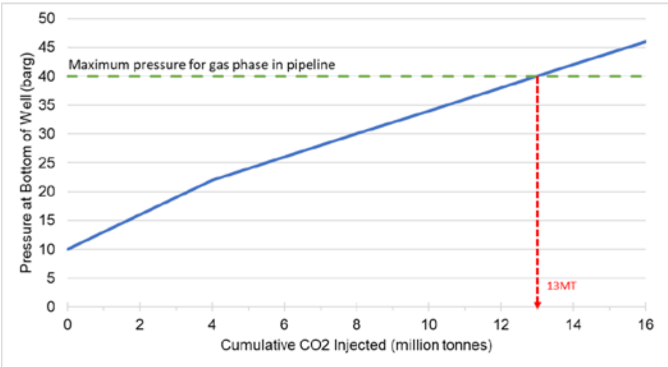


Figure 4-5: Impact of CO_2 Phase on Storage Capacity

4.1.4.5 Storage Development Plan

The chosen development scenario can have a profound impact on the ultimate capacity of the store. Well placement and the injection rate at each well are particularly important. Figure 4-6 (Pale Blue Dot Energy & Axis Well Technologies, 2016) illustrates how varying the location of injection wells can influence the ultimate quantity of CO_2 that can be injected. In this case the impact is relatively modest. However, Figure 4-7 illustrates a case in which the influence is far more significant. It is very clear in this example that the number of wells and the pattern in which they are deployed can impact storage capacity, further details can be found in the reports from the ETI's Strategic UK CO_2 Storage Appraisal project (Pale Blue Dot Energy & Axis Well Technology, 2015).

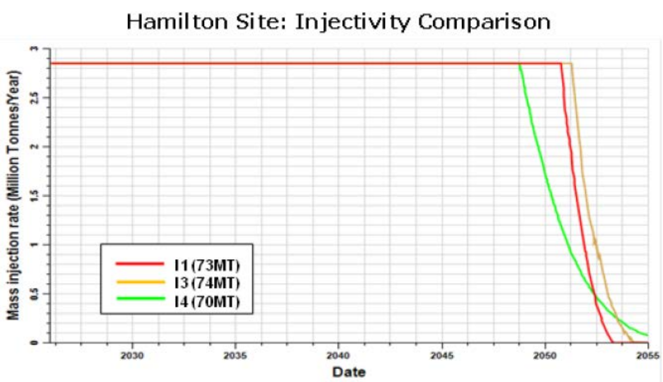


Figure 4-6: Well Placement and Storage Capacity

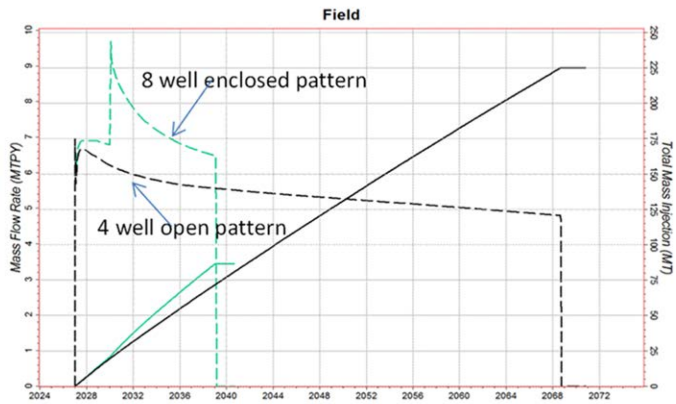


Figure 4-7: Well Pattern and Storage Capacity

4.1.4.6 Storage Complex

CO_2 storage capacity is ultimately determined by the quantity of CO_2 that can be (demonstrated to be) contained within the specified reservoir (the storage unit) in a defined storage complex.

Dynamic modelling is used to determine how far the CO_2 plume will move during the 1000 years after shut in. If the modelling shows that the plume moves outside of the storage boundary then the injection rate, quantity and locations can be adjusted until the CO_2 remains in the storage complex. This may affect the size of area required to be permitted.

4.2 Infrastructure

4.2.1 Pipeline and Subsea Infrastructure

4.2.1.1 Function Specification Overview

An overview of pipelines is presented in Section 3.2.1. CO_2 is transported in a pipeline in single phase either as a gas or in the liquid/dense phase. The required mass flow rate (typically expressed in million metric tonnes per year MT/Year) through the pipeline will be selected to ensure a sustainable plateau rate over the design life of the project, discussed further in Section 4.1.2 . The pipeline will typically be sized such that the delivery pressure at the CO_2 source/pump station is sufficient to ensure that the maximum pressure drop over the length of the pipeline results in an acceptable injection pressure during all phases of the project (gas or liquid injection) thereby avoiding further compression/pumping. Depending on the chosen injection site and its vicinity to other potential storage sites and oil/gas developments there may be merit in pre-investing in increased ullage (larger pipeline) and an increased pressure rating. Transporting the CO_2 as a liquid within the pipeline would allow a smaller pipeline (for the same ullage compared to gas phase CO_2) and can therefore be more economically attractive. Additionally, transporting the CO_2 at higher pressure can remove the requirement for injection pumps at the injection site and provide greater flexibility for future step out projects.

Pipeline design would be performed in the conventional manner using conventional codes, standards and regulations. Pipeline design would typically consider wall thickness, installation analysis, stability, expansion, buckling, free spans, and cathodic protection. A full desktop study will be required to confirm the selected pipeline route and ensure that all seabed obstructions (wells, platforms, pipelines, umbilicals and cables etc) and seabed features (rocks, sand waves, pockmarks, mud slides etc) are identified and accounted for appropriately. As discussed in Section 3.2.1, depending on the pipeline size, protection philosophy, and the water depth the pipeline may be trenched and buried during or following installation. A material selection study will also be required and should account for any contaminants that may be present in the CO_2.

Additional guidance for specific CO_2 requirements are included in DNV RP J202 'Design and Operation of CO_2 Pipelines' (Det Norske Veritas, 2010) which include flow assurance (effect on flow capacity of fluid temperature and pressure, phase behaviour, hydrates and transient operation), pipeline layout (incorporating valves to allow pipeline sectioning for risk reduction or operation and/or maintenance), vent stations (to minimise risk during depressurisation) and dewatering (commissioning, corrosion control and prevention of hydrates).

4.2.1.2 Pipeline Re-use

In order to re-use an oil or gas pipeline for CCS a full pipeline integrity and life extension study will be required to confirm suitability. The results of which will help determine whether it is technically and commercially feasible to purchase an existing pipeline system.

This will involve detailed internal and external inspection in order to re-qualify the pipeline and verify that it is suitable for re-use to transport CO_2 for the required design life. Re-qualification shall comply with the same requirements as for a pipeline designed specifically for transportation of CO_2. The figure below has been extracted from DNV RP J202 (Det Norske Veritas, 2010) and demonstrates the recommended requalification process. Further information is included in the recommended practice.

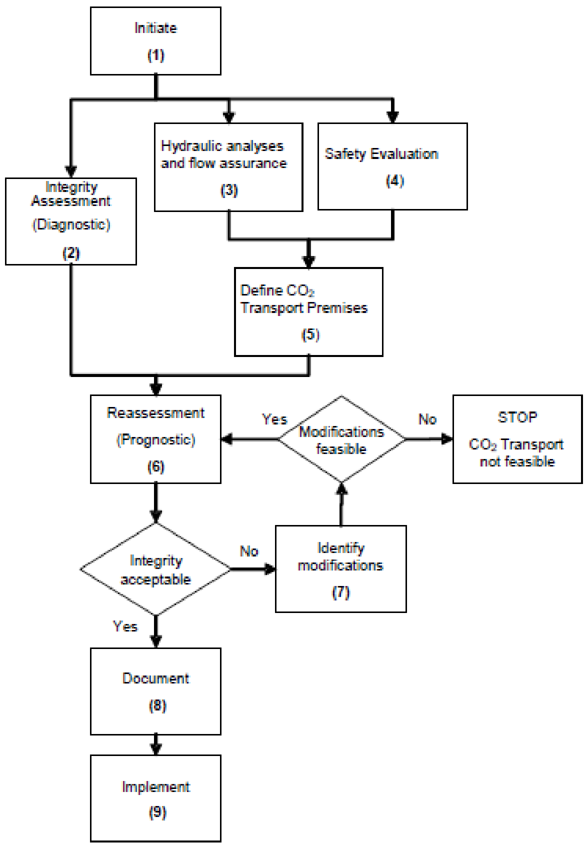


Figure 4-8: DNV RP J202 Requalification of Existing Pipeline for CO_2 Service

Due to the behaviour of CO_2, specifically the step change (i.e. reduction) in rapid decompression speed as the pressure drops down to the liquid vapour line (saturation pressure), running ductile fracture is a concern and will have to be subject to a detailed study in order to requalify an existing pipeline.

A detailed external inspection will be required by Remotely Operated Vehicle (ROV) to detect any unsupported spans and any boulders or debris in the vicinity of the pipeline, as well as to inspect, where possible, the pipeline anodes in order to determine the number of anode skids required to protect the pipeline beyond the original design life.

Internal inspection will be achieved by intelligently pigging the pipeline. Intelligent pigs will be utilised to determine the remaining thickness of the pipeline wall and any internal epoxy coating, any internal corrosion and any wall defects/deformation that may require repair/modification.

Note that if a pipeline has an internal coating then testing will be required to ensure that the coating has not dis-bonded by rapid or uncontrolled gas decompression and is suitable for exposure to dense/liquid phase CO_2. Long term testing may be required to fully determine suitability if the coating has not been proven for CO_2 service and should be considered as part of further work and may involve chemical ageing, long term permeability and erosional effects among other testing programmes. Use of filters should be considered to prevent disintegrated internal coating and corrosion particulates from entering wells (note that this may not be feasible for a subsea development).

Where a pipeline appears to be a good potential candidate for re-use for CO_2 initial steps should be taken to delay any decommissioning activity that could compromise the integrity of the line. Flooding and cleaning the pipeline should not be an issue but the preference then would be to flush with inhibited seawater and avoid, if possible, any cutting of the pipeline system. With the pipeline cleaned there will be little risk of a leak to the environment but routine inspections for spans would need to be considered while the CO_2 project is evaluated. The lack of internal monitoring could reduce the cost of keeping the pipelines available for potential CO_2 use.

In cases where a pipeline is tied in to other infrastructure that is to be removed but the pipeline could be used for CO_2 transport, then specific activities are required to suitably preserve the pipeline. The tie- in spools at the pipeline flange should be removed and blind flanges installed to allow the conditions inside the pipeline to remain intact.

Note that re-use of an existing pipeline following decommissioning may still be possible; however, the pipeline integrity may be compromised (due to cutting of ends and absence on inhibition treatment etc). Future use of these lines would require extensive inspection, reconnection and testing and therefore is unlikely to be commercially feasible.

4.2.1.3 Impact of CO_2 Phase Behaviour and Pressure Management

If a depleted gas reservoir were selected for CO_2 storage, the CO_2 would initially be required to be injected in the gaseous phase due to the low reservoir pressure conditions. This would be required until the reservoir pressure has increased sufficiently to maintain a liquid column of CO_2 in the well bore which will depend on the injection rates and size of the store. During the early period of the gas injection phase the required pipeline arrival pressures at the injection point will be such that the CO_2 is in gas phase under ambient sea temperatures throughout the year. Following a period of time governed by reservoir conditions as discussed in Section 4.1, the pressure in the well will increase and result in liquid drop out at the higher pressure end of the pipeline (at the shore/source pumping station) which could be approximately 5-10 bars higher depending on the pipeline length, selected line size and flow rates. The amount of liquids would steadily increase over the remaining design life of the project. Operating a 2 phase CO_2 pipeline is problematic and may result in damage to the offshore facilities and wells and is therefore best to be avoided.

To manage the transition phase, several options exist, including the following:

- Operating the pipeline continuously in liquid phase and then converting the liquids to gas with heaters during the initial injection phase (i.e. prior to the reservoir pressure increasing sufficiently to maintain a liquid column of CO_2).

- Operating the pipeline in gas phase providing heat to the pipeline to raise the product temperature above the vapour point. Heating the gas at the source isn't advisable as considerable insulation on the pipeline would be required and the latent risk of cooling during start-up, restarts and shutdown.
- Seed the CO_2 with Nitrogen to artificially raise the vapour temperature.

Heated pipelines (larger diameter) have a limited track record in the marine environment and are considerably more expensive than conventional pipelines. Artificially raising the vapour point may be feasible however it requires a more thorough investigation into the effects on the subsurface performance and containment and there also needs to be a reliable source of Nitrogen (or alternative) at the source of the CO_2. As discussed in Section 4.2.1.1 operating the pipeline in liquid phase reduces the size of the pipeline but, during the initial injection phase, it will require significant amounts of heating immediately prior to injection in order to ensure single gas phase conditions going downhole and to manage low temperatures (in particular due to the Joule Thompson (JT) effect).

Pressures in the liquid phase pipeline should also be kept to a strict limit both to avoid gas forming and to avoid large pressure drops across the injection chokes which would in turn require further heating. Due to the behaviour of CO_2, specifically the rapid decompression speed as the pressure drops down to the liquid vapour line (saturation pressure) running ductile fractures are also a concern (crack propagation). In addition, any leak that occurs could result in the rapid expansion of the CO_2 and rapid cooling (JT effect) that could result in a boiling liquid expanding vapour explosion, compromising the integrity of the pipeline further.

Note that this operating philosophy will be highly dependent on the composition of the supplied CO_2 and will require confirmation during FEED (steady state and transient analysis). It is likely that continuous CO_2 heating will also be required during any interim stage (gas to liquid injection).

4.2.2 Offshore CO_2 Injection Facilities

4.2.2.1 Functional Specification Overview

The project owner has several choices of how best to develop a store, but essentially the fundamental decision is between platform or subsea based facilities.

The decision will depend on many factors including the reservoir characteristics and well requirements. As discussed in Section 3.2.3, it is believed that a NUI with dry wells could be a suitable facility for CO_2 injection and storage. However, this assumes all required injection wells can be drilled from a single drill centre. Wells on a NUI are typically drilled using a jack-up drill rig cantilevered over a platform with the required number of well slots.

However, from a commercial viewpoint the design, build and installation of a NUI platform will exceed the CAPEX of an entirely subsea development. A NUI would provide flexibility on the amount of facilities that can be provided. It would generally be controlled from shore via dual redundant satellite links with system and operational procedures designed to minimise offshore visits.

A stand-alone subsea development is feasible if only a small number of wells is required, minimum facilities (no filtering, heating etc.) are acceptable and a source of power and control fluid/signals is available.

A platform enables the provision of enhanced process capabilities, including (where required) the provision of the following which are not readily achievable or is more expensive with subsea wells:

- Pre-injection filtering (filters pipeline corrosion / scaling products), which becomes more critical for a long pipeline and is especially critical when planning matrix (as opposed to fracture) injection.
- Choke heating.
- Physical sampling facilities to ensure CO_2 injection quality.
- Pressure monitoring of all well casing annuli for integrity monitoring.
- Pig receiver.

- Venting
- Future connections are easier as the connections are above water thereby avoiding water ingress into existing systems and it's easier to commission any future pipelines

Providing the following process facilities to subsea wells also is possible:

- Process monitoring, and well allocation metering for reservoir management.
- Process chemical injection of MEG, and N_2 for transient well conditions and wash water for halite control.
- Provision for receiving pigs is possible but would require the support of the vessel.

Due to the requirement of a heavy lift vessel to remove the platform and topsides at the end of field life the costs associated with decommissioning a NUI platform is likely to exceed that of a subsea development.

Platform based wells could also improve the availability of the injection wells due to more readily achievable and inexpensive maintenance and well intervention. The OPEX for intervening on subsea wells will typically exceed that of dry wells.

4.2.2.2 Impact of CO_2 Phase Behaviour and Pressure Management Issues

It is generally more economical to transport and inject CO_2 in the liquid phase. If a CCS development involves the injection of CO_2 into a depleted gas reservoir then liquid injection of CO_2 from the outset may not be feasible due to the reduced reservoir pressure, therefore the injection strategy would be based on initial gaseous injection of CO_2 until the reservoir pressure is sufficient to maintain a liquid column of CO_2 in the well bore. This requires either gaseous transport of the CO_2 to the injection site, which would require a large diameter (heated) pipeline (and maintaining the CO_2 pressure within a given range in order to avoid the risk of liquids forming), or transporting the CO_2 offshore in the liquid phase, and incorporating a vaporization unit (consisting of a heating train and a choke valve) to facilitate injection into the wells in the gaseous phase. The latter philosophy was assumed as the most technically and economically feasible for the ETI SSAP Project (Pale Blue Dot Energy & Axis Well Technologies, 2016). The offshore heating alternative would not be feasible on a subsea development and is required to ensure single phase gaseous flow and to protect the reservoir and wells from the very low temperatures generated by differential pressure across the choke valves (JT effect). While injecting the CO_2 it is important to avoid a phase change by controlling the pressure and temperature or injecting chemicals (MEG etc) to manipulate the phase boundary. Replacement wells (which could be new wells or replacement tubing depending on the development plan) may be required when the operation changes from gas-phase injection to liquid–phase injection.

If heaters are required, electrical heaters have been identified as the preferred option for adding heat to the CO_2 on a NUI (as opposed to gas or fuel heaters). A fired heater train would increase the manning levels and excessive diesel storage or a fuel gas import pipeline.

The wells development plan would require detailed analyses to determine the optimum number of wells, their configuration and the duration of gas and liquid phase injection. The duration of the initial phase of gaseous CO_2 injection will be determined, after which there will be a period of transition from gas phase to liquid phase. The gas injector wells would likely be utilised for this transition period, following which replacement liquid phase injector wells will be required through to the end of field life. Heaters will be required continuously at the gaseous CO_2 injector wells and possibly for start-up for the liquid injectors.

The use and capacity of the heaters depends on the injection rate, the down hole pressure, the required temperature rise and the sparing philosophy. This requires detailed assessment to account for the range in ambient temperature conditions (both subsea and air); flow rates; CO_2 compositions; injection pressure and temperature requirements and availability requirements.

Injection of CO_2 is a proven technology and has been in use for many years both in CO_2 storage projects such as Sleipner or EOR projects such as at Weyburn.

4.2.3 Life Cycle Requirements for CO_2 facilities

An overview of the infrastructure life cycle requirements is presented in this section.

4.2.3.1 Operation

A standard NUI would usually be capable of operating unattended for approximately 3 months (90 days). If required, a power cable will provide electrical power to the NUI from onshore or a nearby facility. The NUI will be controlled from the beach, utilizing dual redundant satellite links.

A CO_2 injection platform will require regular IMR (Inspection, Maintenance and Repair) while in operation, and it is envisaged that visits to an unmanned facility will typically be required every six weeks.

Alternatively, IMR of a subsea manifold would be limited to annual or bi-annual ROV surveys and infrequent diver campaigns.

The pipelines and any umbilicals or power cables will require regular IMR. This will include regular (typically bi-annual) surveys (ROV) to confirm integrity (e.g. spans). Although pigging facilities are usually available, the frequency will be minimal subject to an integrity management risk assessment of the control of the CO_2 quality.

4.2.3.2 Decommissioning

On completion of CO_2 injection, the wells and all infrastructure will be required to be decommissioned. The decommissioning philosophy is assumed to be the same as for oil and gas infrastructure, and final decision subject to the outcome of the comparative assessment process and subsequent approval by the relevant authority.

4.2.3.3 Post Closure Plan

The post closure period is assumed to last for a minimum of 20 years after the cessation of injection based on existing regulations (EC Directive). During this time the infrastructure will be decommissioned, and monitoring will be required. The aim of post-injection/closure monitoring is to show that all available evidence indicates that the stored CO2 will be completely and permanently contained.

4.2.3.4 Handover to Authority

Immediately following the completion of the post closure period, the responsibility for the CO_2 storage site will be handed over to the UK Competent Authority (or other appropriate authority depending on the national regulations). It is anticipated that a fee will be required at handover (European Commission, 2009).

The transfer of responsibility for the CO_2 store does not necessarily include the transfer of decommissioning liabilities. In UK waters, the Petroleum Licensee has this liability in perpetuity and it is anticipated that an equivalent provision will apply to the Storage Licensee.

4.2.4 Data Requirements

This section identifies information requirements, sources and collation of data for the screening, selection and appraisal phases of a CO_2 storage project.

- Well and seismic data
- Geological studies
- Reservoir surveillance reports
- Maintenance records
- Details of process equipment, systems etc
- Production history
- Asset management records
- Safety Case

In addition to the data noted above, there may be benefit in studying specific data releases from current oil and gas operators.

4.2.5 Design Life and History

The design life of a CCS project is another important consideration. Often the transport and storage of CO_2 is linked to the CO_2 source. The source could be a new-build power station or could be tied into an existing power plant or to a plant from an energy intensive industry such as steel production. A typical oil and gas development would have a maximum design life of 25 years, whereas new build power plants can have a design life in excess of 40 years therefore detailed integrity studies are required to align these if any existing infrastructure was to be reused.

The design life of all components/facilities that make up the project will need to align with the design life of the CO_2 source, however if a CO_2 hub is developed there will be the additional complication of multiple CO_2 sources (which may have different specifications) that are joining the system at different times and as such may have different design lives which may require an extension to the design life of facilities that are already in operation. An additional concern relates to mixing streams of differing compositions. In particular how contaminants might react together and whether that is potentially detrimental to the infrastructure.

The key point is that the design life of existing O&G facilities being considered for re-use will need to be extended to align with design life of the source(s). In general, only young O&G facilities can be realistically considered as candidates for re-use and therefore, by implication, new facilities, will be required in the majority of long duration CO_2 projects. There is no prescribed or generic process for this extending asset life and each situation would need to be evaluated on a case by case basis. The case study examples help to highlight the sorts of activities that have been contemplated previously.

4.3 Commercial Arrangements

4.3.1 CO_2 Leakage Liabilities

In general, the risk to a company arising from the possibility of liability for damages resulting from the purchase, ownership, or use of goods or services offered by that company is known as liability risk. For CO_2 storage projects, liability risk can be identified and mitigated through careful site selection, development design and operational monitoring, but may also be inherent in the nature of the geological site to some extent.

Liability is the state of being legally responsible for something (Oxford University Press, 2017). In the context of CO_2 storage activity to reduce CO_2 emissions, the liability is to contain the CO_2 within a defined geological space. The precise nature of the liability may vary according to jurisdiction.

The liability risk for CO_2 storage developments can be considered to have two major temporal components, linked to the primary activity of the project phase:

- Operational: the risks associated with the transport, injection and storage of CO_2.
- Post closure: the risks associated with the storage of CO_2 once the injection phase has finished. This phase has two sub-elements; before and after transfer of responsibility to the Competent Authority (CA).

During each of these phases five major categories of risk have been identified (M de Figueiredo, 2006) and the consequence of any risk event will be dependent upon the specific circumstances. The five areas of risk are:

- Toxicological
- Environmental
- Induced Seismicity
- Subsurface Trespass
- Climate

There are many risks in a CO_2 transportation and storage project, Table 4-3 provides some examples of the sort of event that could occur in each of the five risk categories according to project phase and is not intended to be an exclusive list of risk events.

The impacts related to the release of stored CO_2 can be classed as either local or global (IPPC, 2005), as highlighted in Table 4-3, and it is the latter class of risk that leads to the greater liabilities – particularly within Europe.

Article 1 of the CCS Directive (European Commission, 2009) states that the purpose of the directive is to provide a legal framework for the environmentally safe geological storage of CO_2 to contribute to the fight against climate change.

Article 1 also provides the following definition.

"***The purpose of environmentally safe geological storage of CO_2 is permanent containment of CO_2 in such a way as to prevent and, where this is not possible, eliminate as far as possible negative effects and any risk to the environment and human health***".

The risks and liabilities accruing to a CO_2 store operator in Europe are therefore very much focussed on the global impact of a release of stored CO_2.

Risk Category	Impact	Example Risk Events by Project Phase	
		Operational	Post Closure
Toxicological	Local	Leak from part of the equipment system that results in a large, concentrated CO_2 release in close proximity to life	Leak from the geological store that results in a large, concentrated release of CO_2 in close proximity to life
Environmental	Local	Contamination of ground water from a pipeline leak Degradation of an ecosystem due to acidification due to CO_2 mixing with groundwater	Leak from the geological store that reaches the seabed
Induced Seismicity	Local	Injection of CO_2 increases pore pressure to such an extent that it creates seismic activity that causes damage	As in the operational phase although much less likely in this phase
Subsurface Trespass	Local	Movement of the CO_2 plume into subsurface space licenced / owned / permitted by another party. This may just be an increase in pore pressure or could be an interaction of the injected CO_2 with in situ fluids	As in the operational phase
Climate	Global	Leak from equipment or the geological store that reaches the atmosphere	Leak from the geological store that reaches the atmosphere

Table 4-3: Examples of Risks in Project Lifecycle

4.3.2 Key Risks

CO_2 storage infrastructure has unique project lifetime attributes when compared with capture and transport. This includes the need for potentially lengthy and costly appraisal activity prior to final investment decision (FID) for the scheme, and the need for post-injection monitoring of the store after CO_2 injection (and therefore income) has ceased. Figure 4-9 is adapted from earlier work (Zero Emissions Platform, 2014), and shows the relative timeline and expenditure for CO_2 capture, transport and storage, highlighting the far greater duration of the storage project lifetime.

Transport and storage activities have very different technical and economic characteristics to capture activities. The likely operators of capture plant may also have markedly different risk appetite and balance sheet capabilities to likely CO_2 transport and storage operators.

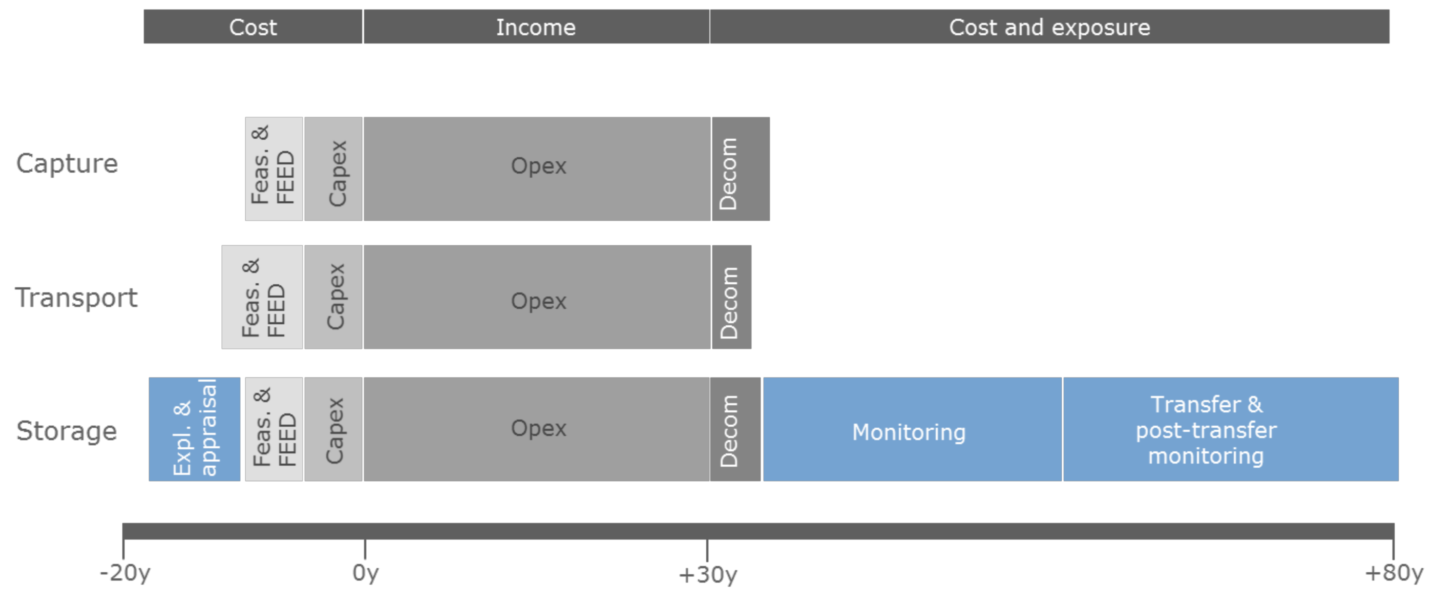


Figure 4-9: Cash Flow Timelines for CO_2 Capture, Transport and Storage

These factors give rise to specific issues which must be addressed in the development of CO_2 Transport & Storage (T&S) infrastructure, including consideration of the commercial model to support early and long-term costs and revenue flow, that achieves best value for money. Six common areas of risk which hinder development of CO_2 T&S infrastructure are listed below.

1. Uncertainty of CO_2 supply;
2. Uncapped CO_2 leakage liability;
3. Cross-chain performance;
4. Risk appetite incompatibility;
5. Change of law; and
6. Policy uncertainty

Uncertainty of CO_2 supply This can also be referred to as "volume risk" or "stranded asset risk". The current absence of a CO_2 supply for storage means there is no clear service revenue for initial T&S operators. The risk that T&S infrastructure would be built, with only some of the capacity being used and resulting in a stranded asset, deters speculative investment and development. This becomes more pronounced for larger capacity infrastructure schemes (which offer greater potential economies of scale). This area of risk can become a circular problem in that the investment decisions regarding T&S infrastructure assets and the generation and capture assets are concurrent and interdependent. It is an aspect of cross-chain risk and as such is not addressed further in this paper.

Uncapped CO_2 leakage liabilities. This risk occurs because currently there is no cap on leakage liabilities under the CCS Directive. Any leakage from the store at any future point in time would require repayment of EUAs (European Union Allowance certificates), the future price of which is not known. Despite the licencing process and permit conditions meaning leakage can be expected to be very unlikely, the associated liability is potentially large. The risk is characterised as low likelihood but large impact and is consequently difficult to manage. The lifetime of the store and duration of the post-closure monitoring required before this liability transfers to Government are unfixed. Being uncapped and of unfixed duration, this risk is currently uninsurable and creates difficulties in making projects financeable.

Cross-chain performance. Sometimes referred to as "cross-chain funding risk" or "revenue flow risk", this is the risk that during operation, the revenue for a CO_2 T&S infrastructure provider could be reduced by interruptions to the CO_2 supply and that the T&S operator would be obliged to guarantee levels of performance to the capture project(s) since capture project revenue is also dependent upon the availability of T&S services. Given the high level of interaction between the CO_2 supplier and the CO_2 Store Operator (during planning, development, construction and operation) cross-chain risk is clearly a multi-faceted issue. Cross-chain risk is very situation specific and consequently is not addressed further in this paper.

Risk allocation. Early CCS developers may have the opportunity to agree risk sharing arrangements with Government. The ability to allocate risk will be affected by risk appetite and risk management capability of the developer, which in turn will be driven by the risk appetite, risk management capability and rates of return required by individual consortium members. This presents a risk that risk-share terms sought by the developer and government are incompatible.

Change in law. Whilst not unique to CCS, a change in law would potentially expose CCS projects to greater cost or reduced revenue. Whilst different business models may address potential change in law in different ways, this risk is not considered likely to initially drive the choice of business model, and as such change in law risk is not addressed further in this study.

Policy uncertainty. Whilst not unique to CCS, the industry considers policy uncertainty in connection with CCS is a key risk. This was exacerbated by Government's November 2015 decision to withdraw capital support to the CCS Commercialisation Competition, which was interpreted by industry as evidence that Government no longer viewed CCS as core to the UKs decarbonisation programme (Capture Power Ltd., 2016). However, whilst a clear and consistent CCS policy is required to enable CCS, this risk is not considered to be affected by the nature of the business model and is therefore not addressed further in this study.

4.3.3 Regulatory Issues

In the European region the liabilities for CO_2 storage are specified in what is known as the CCS Directive and is, more formally, Directive 2009/31/EC on the Geological Storage of Carbon Dioxide (European Commission, 2009). The four supporting guidance documents provide additional detail as summarised below.

- GD1: Lifecycle Risk Management
- GD2: Site Characterisation
- GD3: Transfer of Responsibility
- GD4: Financial Security and Financial Mechanism

There are two separate but linked regulatory regimes offshore in the UK that govern CO_2 storage activity and influence the transfer of an asset from hydrocarbon extraction to CO_2 injection. These are:

- The Petroleum Act (1998), which establishes the O&G regulatory regime and vests all rights to petroleum in the Crown. In addition, the Oil & Gas Authority grants exclusive licences to search & bore for & get petroleum; and
- The Energy Act (2008), which provides the regulatory regime and vests the rights for offshore storage of CO_2 in The Crown Estate (TCE). The Oil & Gas Authority grants exclusive licences & permits to store CO_2 and the Crown Estate awards leases for use of the seabed & subsurface.

In order to acquire an infrastructure asset from an oil and gas company there are a number of regulatory issues to be addressed, as illustrated in Figure 4-10. A high degree of interaction with the Petroleum Licensee is required to manage the transition of ownership smoothly, as illustrated in Figure 4-11.

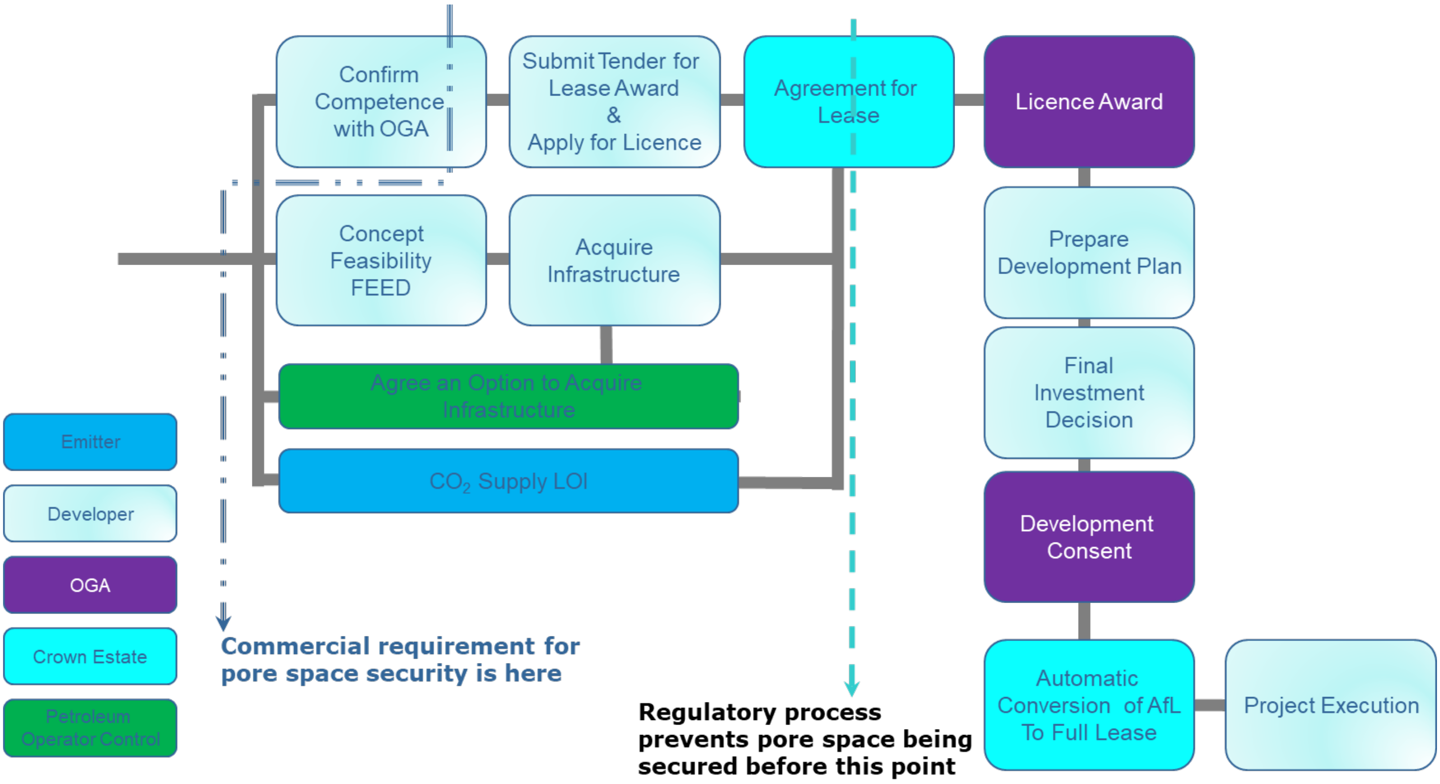
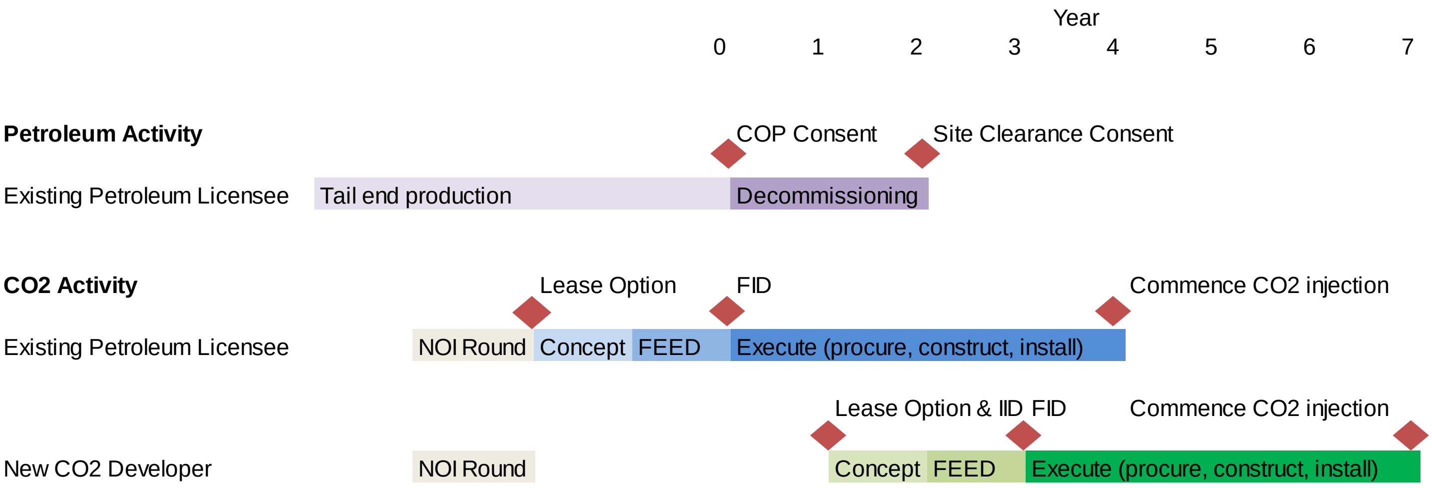


Figure 4-10: UK CO_2 Storage Regime



Notes
COP: Cessation of Production
NOI: TCE Notification of Interest / Market Test
Eclusivity: new agreement to cover tranistion of ownership & use
Lease Option: materially an Agreement for Lease
Lease: full lease agreement
FEED : Detailed Engineering
IID: Initial Investment Decision
FID: Final Investment Decision

Figure 4-11: Asset Transition Interactions

The timing and duration of the asset transition from hydrocarbon production to CO_2 injection is influenced by the access rights of the CO_2 project developer. Figure 4-11 illustrates the following two asset transition situations:

- When the CO_2 project developer is the current Petroleum Licensee. In this case comprehensive evaluation, planning and design work can commence at any time because investment in those activities is targets at assets (infrastructure and licenses) already owned by the developer; and
- When the CO_2 project developer is someone other than the current petroleum licensee. In this case, investment in studies prior to acquiring some kind of rights (exclusivity, option agreement etc) over the assets are more speculative due to the risk of another party acquiring the assets and rendering the investment worthless. In such situations it may be difficult to justify significant investment and therefore the transition process can reasonably be expected to take longer to complete. However, the evaluation work and decision assurance associated with an asset transition are likely to be very similar.

4.4 Development Planning Issues

4.4.1 Hubs and Clusters

Hubs and clusters are a long-established theme within CCS, intended to drive down costs by creating economies of scale. In the area of offshore transportation and storage the primary response to this pressure has been well characterised by National Grid Carbon's work on the Southern North Sea. This involved the careful selection and screening of a very large "oversize" storage site now called Endurance and the design of an oversized offshore (and onshore) transportation pipeline system which was capable to moving far more CO_2 than the initial target project required.

Below the headline "economies of scale" logic, lies a complex risk balancing challenge around the probability of early CCS adoption by emitters. Specifically, the balance between the return from betting on early uptake of available ullage (spare capacity in a pipeline) in a project against the actual cost of building and holding that ullage available for emitters to use. In addition, over the longer term, the rate of loss of ullage must also be accounted for as the maximum operating pressures of offshore pipelines are invariably reduced over their operating lifetimes. Overall, the additional upfront cost will increase the levelised cost of the first mover project making it more challenging to justify but will reduce the cost for follow on projects. This approach makes the first project harder to move forwards and encourages most emitters to wait for the lower cost environment of follow on projects.

For the purposes of this brief review, a cluster is considered unlikely to consist of solely depleted fields or solely of saline aquifers. Within that context, a storage site requires the following to be considered as part of a cluster:

1. There is another site which is identifiable as the anchor site or hub for the cluster;
2. That the new site shares critical infrastructure with the anchor site; and
3. That critical infrastructure will include high cost items that may be either shared at the same time or re-used later once ullage is available.

The components of infrastructure that could be usefully shared across sites are summarised below.

- **Pipelines** clearly service the locations at each end of the system, but with careful design they can also service a corridor of opportunities along the whole length of the system. Their reach can also be extended by subsidiary flowlines and extensions. This optionality places pipeline assets at the core of potential cluster developments

- **Platforms** can also provide key services for local and regional site developments in addition to their primary development role. Extended reach drilling facilities located on a platform permit the development of storage sites up to 5-10km away. Platforms can also provide servicing for subsea tie backs for up to 50-70km away from the primary site.
- **Wells** have much less utility to support cluster developments and yet some are capable of being recompleted to inject into deeper or shallower reservoirs at the location of the primary site. The addition of perforations to the Stø reservoir interval below the primary Tubåen formation was used to manage problematic pressure increases at the Snøhvit CO_2 injection project in offshore Norway. It is sensible to have such contingency pre-planned if subsurface response is poorer than expected.
- **Power and Controls** systems can be provided from a host platform or subsea development to adjacent sites even if such sites have their own dedicated pipeline system. Examples of this in oil and gas are the development of the Atlantic and Cromarty gas field some 35km from Goldeneye which has its own dedicated 80km gas export pipeline but found it economically advantageous to control the wells from the Goldeneye platform via a 35km control umbilical rather than an 80km control umbilical from the beach. This kind of arrangement builds in critical dependencies which can increase commercial complexity towards the end of field life when the anchor project is no longer injecting, but the high cost facilities are simply the "dry control point" for nearby subsea infrastructure.
- **Monitoring Measurement and Verification** (MMV) is a key requirement of any CO_2 Storage project. MMV costs associated with repeat 3D seismic monitoring can be reduced if they can be shared across several sites. As the total cost contribution of MMV to a CO_2 storage project is small on a levelised cost basis, MMV alone is very unlikely to be the motivation for a cluster development decision.

Finally, it should be highlighted that whilst clustering and the economies of scale logic can be compelling at the front end of project development, clustering builds in critical dependency upon other assets that can reduce the robustness of project commerciality. This is becoming very obvious now in North Sea oilfield developments where the decommissioning of large platforms with very high operating costs will risk cutting short the commercial life of the cluster developments around them.

Figure 4-12 illustrates the potential components of an offshore CO_2 hub and cluster development which could include store of all types including depleted O&G fields, saline aquifers and EOR developments.

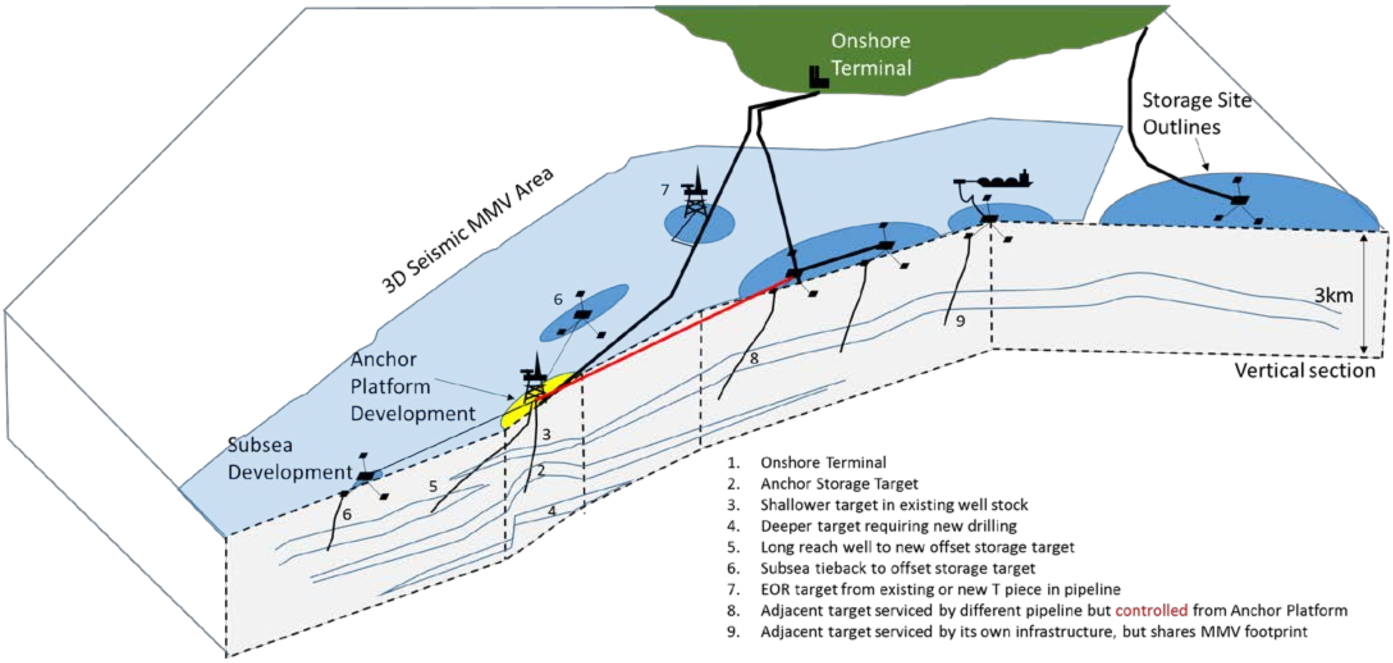


Figure 4-12: Schematic of an Offshore CO_2 Hub and Cluster Development

4.4.2 Ship Import and Export of CO_2

This section is extracted from a report on build-out options for the Acorn CCS project in Scotland (Pale Blue Dot Energy, 2018).

The transport of CO_2 in bulk by ship is established in European waters as part of the international trade in CO_2 for industrial, food and drink, and other uses. The CO_2 is, in general, obtained as a by-product of hydrogen production as part of the ammonia synthesis process. However, the scale of the current CO_2 market is small (around 3MT/yr) compared to the envisaged scale of the CCS industry at, potentially, tens to hundreds of millions of tonnes per year. There are currently only a small number of existing CO_2 transport ships and these are of low capacity, in the range of 900 to 1,800 tonnes (T), (Brownsort, 2015a).

CO_2 is carried in ships as a refrigerated liquid under pressure. Conditions used in the current fleet are typically 15-20bara pressure and -30 to -40°C. Some literature suggests CO_2 shipping is most efficient at a lower pressure and temperature, around 7bara and -50°C, as the density is greater under such conditions. However, the optimum choice of conditions for shipping in any CO_2 supply chain will depend on the upstream and downstream processes, in particular the energy required for liquefaction and for reconditioning for downstream operations, (Brownsort, 2015a).

Shipping has long been recognised as an alternative to pipeline transport of CO_2 in appropriate circumstances, (Doctor, et al., 2005). *Studies have shown that ship transport of CO_2 can be cost competitive with new offshore pipelines, generally for smaller scales and longer distances. Shipping may have lower financial risks than new offshore pipelines as it is inherently flexible with lower entry capital. This is particularly advantageous in the early and build-up phases of projects, where transport capacity can be increased in line with demand by adding ships to the fleet,* (Brownsort, 2015a).

For transport of liquid CO_2 by ship, it is generally assumed that buffer storage will be required near the ship loading and unloading points. This is because the CO_2 capture and liquefaction facilities will be continuous processes, while the shipping leg is essentially a batch process. Therefore, a buffer storage with capacity to fill one ship is generally assumed as a minimum for the loading point, (Brownsort, 2015a). *For the ship offloading point, the* *need for buffer storage depends on the downstream operation. If a continuous flow of CO_2 is required downstream, such as might be the case for some injection strategies with direct delivery of CO_2 by ship to the well location, then buffer storage at the ship offloading point may be required,* (Brownsort, 2015b)*. For delivery to a large pipeline system, the need for buffer storage near the ship offloading point is less clear as the system itself may be able to create enough capacity through line pack (i.e. increasing temporary storage of the CO_2 using pressure).*

4.4.3 Financial Security

The major risk and resulting liability to be considered is that of CO_2 leakage. Guidance Document 4 (European Commission, 2011) of the CCS Directive is key to understanding this issue.

By way of example, Table 4-4 (Pale Blue Dot Energy, Axis Well technology, Costain, 2015) shows the estimated cost of the financial securities required for the Captain X Storage Development Plan and Budget (SDP) prepared as part of the Strategic UK CO_2 Storage Appraisal Project (Pale Blue Dot Energy, Axis Well technology, Costain, 2015). Guidance Document 4 commentary is included in the table which also draws on a report published in 2013 on the permitting process for the Maasvlakte CCS project (ROAD, 2013).

Elements of CCS Directive	Security (£m)	Assumptions	GD4 Commentary
Operations			
1. Monitoring	12.8	25% contingency	Monitoring, updates of monitoring plan, and required reports of monitoring results
2. Update of corrective measures plan	2.0	£100K annually	Updates of corrective measures plan, and implementing corrective measures, including measures related to the protection of human health
3. Emissions allowances	4.5	£75/T penalty for exceeded emissions, Assumed leak 0.1%/year of cumulative quantity	Surrender of allowances for any emissions from the site, including leakages, pursuant to ETS Directive
4. Update of post closure plan	2.0	£100K annually	Update of provisional post closure plan
5. Injection operation until new storage permit is issued	83.4	25% contingency of opex	Maintaining injection operations by the CA until new storage permit is issued, if storage permit is withdrawn, including CO_2 composition analysis, risk assessment and registration, and required reports of CO_2 streams delivered and injected.
6. Update of corrective measures plan	2.0	£100K annually	Updates of corrective measures plan, and implementing corrective measures, including measures related to the protection of human health
7. Emissions allowances	22.5	£75/T penalty for exceeded emissions, Assumed single leak 1% of total	Surrender of allowances for any emissions from the site, including leakages, pursuant to ETS Directive
8. Decommissioning	46.8	25% contingency	Sealing the storage site and removing injection facilities
9. Financial Contribution	31.5	10 times the annual cost of monitoring	Making required financial contribution (FC) available to the CA
Total	207.5		

Table 4-4: Financial Security for CO_2 Storage

It is very clear from CCS Directive and associated guidance documents that the responsibility and liability for the environmentally safe geological storage of CO_2 resides with the Store Operator. The most significant items of risk and uncertainty are those numbered 3, 8 and 10 in Table 4-4 and in particular items 3 and 8.

Calculating the financial security requires an estimate of the size of a potential release of CO_2 from the geological store, the point in time at which this occurs and the price of the EUAs at that point in time. None of these are knowable in advance and give rise to the major concern in the private sector of the unknowable and uncapped nature of this particular liability.

4.4.4 Decision Making

The least cost option is not always the preferred choice. Other considerations in the decision-making process often include non-technical or economic perspectives such as: perceptions of risk; option deliverability; corporate motivations; specific context and strategic issues, amongst others. This section provides an example from the UK.

During the first UK CCS Demonstration competition, Shell and CO2Deepstore were equal partners in the Goldeneye CO_2 storage joint venture. The development plan called for the re-use of the Goldeneye platform, pipeline and wells (Scottish Power, 2011).

As part of its due diligence process, CO2Deepstore commissioned a study to assess the feasibility and cost of a subsea alternative to the base case platform development (Petrofac, 2011). The main conclusions from that study are summarised below.

- A subsea development with a direct tie-back and umbilical to St. Fergus is feasible.
- The subsea option presents fewer issues with regard to technical safety and design compared to a platform development.
- The least risky option in both the construction and operations phases was considered likely to be a tie-back.
- The subsea tie-back was estimated to cost approximately £80 million plus £25 million for a new well, a total of £105 million. Note that this is a feasibility-stage cost estimate

The modifications required to the Goldeneye platform and wells were estimated to cost £203 million excluding pipeline and contingency (Scottish Power, 2011). This FEED-stage cost estimate is considered more robust than the feasibility-stage estimate. However even allowing for estimate growth of 50%, the subsea option is still very likely to be lower cost than the platform development.

4.5 Suitability Assessment

This section outlines a general approach to assessing the CO_2 re-use potential of offshore infrastructure that has previously been used for accessing, producing and transporting hydrocarbons. In practice, the suitability of such infrastructure for conversion to transport, inject and store CO_2 must be considered on a project by project basis. This is because the suitability, or otherwise, of infrastructure depends significantly on the following three factors:

- Rate of CO_2 supply (throughput capacity)
- Condition of CO_2 supply (phase, temperature, pressure)
- Duration of CO_2 supply (project life)

It is considered likely that a two-stage approach to assessing suitability would be adopted; an initial scoping evaluation followed by a more detailed due diligence appraisal. This is discussed more fully in the following section. In both instances, details of the CO_2 supply would be required before any significant conclusions could be drawn. These assessments would also take into account the meaningfulness and reliability of the information that was available at that time.

Table 4-5 through Table 4-9 summarise the key information that would be required to assess the suitability of the five major components of infrastructure for re-use for a specific CO_2 project. These components are:

1. Reservoir
2. Wells
3. Production Facilities
4. Subsea Infrastructure
5. Pipeline

Measure	Stage 1	Information Required	Stage 2	Information Required
Seal	Identify sealing formation and extent over the target store Leakage assessment to identify potential leakage pathways	Assessment of regional geology, formation characteristics, locations of legacy wells, well abandonment records	Modelling of CO_2 plume to ensure that legacy wells with a leakage risk are avoided and that CO_2 stays within the storage boundary	Seismic, well logs, fracture pressures, CO_2 injection profile
Injectivity	Assessment of injection potential in the target store	Required injection rate, average porosity, permeability and thickness estimates	Modelling of tubing head pressures to avoid two phase injection and ensure that the fracture pressure is not reached Reservoir simulation of development, possibly including composition PVT modelling	Fracture pressure gradient, well design, CO_2 phase behaviour, reservoir temperature and pressures
Capacity	Initial static assessment of store capacity using available information	Desired injection profile, estimates of rock volume and properties, porosity, net to gross ratio, CO_2 density, storage efficiency	Dynamic storage capacity assessment using a range of input parameters informed by modelling of CO_2 injection	Results from dynamic simulation of the development plan scenarios. Upper and lower limits of the rock volume, porosity, permeability, CO_2 density and estimates of storage efficiencies that have been calculated as a result of modelling work
Connectivity	Assessment of existing data to confirm impact of surrounding aquifer &/or other subsurface activity on repressurising a depleted field	Production data, pressure measurements such as RFT, seismic data and geological maps	History match the pressure in the target store according to historical production data	Results from dynamic simulation of the development plan scenarios. Connected aquifer volumes, historical production data, reservoir pressure

Table 4-5: Information Required to Assess Reservoir CO_2 Re-use Suitabiltiy

Measure	Stage 1	Information Required	Stage 2	Information Required
Bottomhole Location	Assessment of existing bottom hole locations in the target reservoir	Well completion reports, seismic data	Modelling of injection from existing bottomhole locations to ensure that the CO_2 profile required can be injected	Well logs, seismic data, fracture pressure, CO_2 phase behaviour, CO_2 injection profile
Casing Size	Assessment of tubing head pressures and temperatures to avoid two phase flow in the well bore	CO_2 injection profile and phase behaviour Reservoir temperature, pressure and facture pressure gradient Well completion report	Operational envelope of the wells to ensure that two-phase flow in the well bore is avoided and that fracture pressures are not reached during injection	Well logs, CO_2 phase behaviour, CO_2 injection profile, fracture pressure gradient, reservoir temperature and pressure, minimum tubing head temperature
Pressure Rating	Ensure that there is sufficient pressure differential to enable CO_2 injection without the need for compression offshore	CO_2 arrival pressure, fracture pressure gradient	Structural assessment of the well bore to ensure that injectivity can be maintained for the life of the storage project at the pressures required	Original design documentation, inspection reports, CO_2 injection profile
Christmas Tree	For an injection tree, remaining design life and CO_2 throughput	Well completion report	Integrity assessment and cost estimate of any repairs or modifications that might be required	Original design documentation, inspection reports, CO_2 injection profile

Table 4-6: Information Required to Assess Well CO_2 Re-use Suitability

4.5.1 Infrastructure Suitability

Measure	Stage 1	Information Required	Stage 2	Information Required
Jacket-integrity	Remaining Design Life	Required design life of CO_2 project, established remaining design life of jacket and COP date.	Review of available integrity assessments. Cost assessment of major repairs/modifications	Historical data, inspection reports and original design documentation. CCS Topsides weight estimate
Jacket-size and capacity	Capacity for CO_2 topsides weight and facilities	Number of wells and estimated topsides weight vs original design capacity (original topsides weight)	Structural assessment/comparison for future CO_2 topsides. Cost assessment of major repairs/modifications	Historical data, inspection reports and original design documentation. CCS Topsides weight estimate
Drilling Facilities	No of available riser slots and drilling conductors and drilling facilities	Estimated number of well slots Status of existing derrick	Integrity, diameters, locations for specific targets etc. Cost assessment of major repairs and mods	Wells development plan. Conductor and drilling facilities integrity assessment
Topsides-integrity	Remaining design life	Required design life of CO_2 project, established remaining design life of facilities and COP date	Review of available integrity assessments. Cost assessment of major repairs/modifications	Historical data, inspection reports and original design documentation
Topsides-general facilities	High level comparison against minimum requirements	Number of wells and required topsides facilities	Review of existing facilities against functional requirements. Deconstruct requirements. Cost assessment	Original design data/specs and deck layouts. More detailed CO_2 facilities functional requirements
Topsides - process suitability	Verification of process facilities including rates, pressure rating, temperatures, corrosion	Process materials and pipework to confirm general requirements	Check existing facilities against material selection/spec. Process and safety studies to assess required modifications. Deconstruct requirements (if required). Cost assessment	Functional spec for topsides facilities. Material datasheets of retained process equipment, layouts, P&IDs and safety systems. Suitability for reverse flow
Topsides - control system			Control system obsolescence	CCS Control Philosophy Existing control system architecture
Topsides-power capacity	High level comparison against minimum requirements	Required topsides facilities, heating etc	Review of existing facilities, deconstruct requirements (if required). Cost assessment	Original design data/specs and layouts. Power Requirements

Table 4-7: Information Required to Assess Facilities CO_2 Re-use Suitability

Measure	Stage 1	Information Required	Stage 2	Information Required
Controls	Power and controls facilities to subsea XTs and manifolds	Required XT functions, existing subsea control layout	Assessment against specific CO_2 injection XT requirements. Cost assessment	Existing controls philosophy and CO_2 controls philosophy
MEG Supply	Facilities for MEG injection to XTs and/or manifolds	MEG supply to XT and manifold locations	Ullage calculations, high level umbilical design. Cost assessment	MEG volumes, route length from source, required injection pressures. MEG system datasheet(s).
Integrity	Ascertain design life	Required design life of CO_2 project, established remaining design life of subsea facilities and COP date	Review of available integrity assessments, intelligent pig assessment. Cost assessment of modifications and repairs.	Historical data, inspection reports and original design documentation to assess internal corrosion, external defects, anode depletion and operability
Location	Requirement for new infrastructure to reach CO_2 injection locations	Location of subsea infrastructure. Injection and host locations.	Cost assessment of re-use with extension vs new infrastructure	Location of subsea infrastructure. Injection and host locations.
Suitability	Pressure, materials/composition, ullage	Outline requirements for CO_2 development. Subsea equipment primary parameters (flowlines, manifolds, valve structures, spools)	Review of mechanical and material assessments. Cost assessment	Historical data/Inspection reports and original design documentation. Functional spec for CO_2 development. Material datasheets. Suitability for reverse flow

Table 4-8: Information Required to Assess Subsea Asset CO_2 Re-use Suitability

Measure	Stage 1	Information Required	Stage 2	Information Required
Integrity	Ascertain design life	Required design life of CO_2 project, established remaining design life of pipeline and COP date	Review of available integrity assessments, intelligent pig assessment. Cost assessment of modifications and repairs.	Historical data, inspection reports, intelligent pig reports and original design documentation to assess internal corrosion, external defects, anode depletion and freespans.
Location	Requirement for new infrastructure to reach CO_2 injection locations	Pipeline Route. CO_2 injection and supply locations	Cost assessment of re-use with extension vs new infrastructure	Cost estimates for each concept (all new infrastructure or re-use with extension if required)
Suitability	Pressure, materials and composition suitability	Outline requirements for CO_2 development, pipeline primary mechanical parameters	Mechanical and material assessment of main pipeline and its components (internal coatings, spools, valves etc). Cost assessment of any repairs and. modifications	Functional spec for CO_2 development. CO_2 source data (compositions/pumping station pressures etc). Equipment datasheets. Suitability for reverse flow
Ullage	Throughput	Forecasted injection rate. Pipeline size and length	Confirm pipeline sizing and system operability	Functional spec for CO_2 development. CO_2 source data (compositions/pumping station pressures etc) and injection profiles. Flow assurance assessment

Table 4-9: Informaiton Required to Assess Pipeline CO_2 Re-use Suitability

4.5.2 Assessment of the Case Studies

A Stage 1 suitability assessment of the five infrastructure case studies, detailed in the following chapters, has been completed and is summarised in Figure 4-13.. Details about each case study assessment are included in the relevant chapter. In the diagram a high score (further from the centre) indicates that there is a high suitability for reuse whereas a low score (closer to the centre) indicates that the existing reservoir/equipment is not suitable for reuse and a new purpose-built design would be the preferred option. The score for each element of infrastructure was determined by evaluating a number of criteria for each element based on the available data and knowledge of the sites.

Figure 4-13 illustrates that the reservoir is very well suited for re-use in most case studies, the wells are somewhat suitable (implying that modifications may be necessary) in the Goldeneye and Hamilton case studies and that the existing subsea equipment is totally impractical to be re-used in each case study.

It should be noted that each element of infrastructure is not mutually exclusive, if the platform is suited for reuse and the pipeline is not then it is still feasible to reuse the platform but use a new pipeline. If the reservoir is not suitable for CO_2 injection is may still be possible to reuse the existing infrastructure as long as another store is available in close proximity such as the surrounding aquifer.

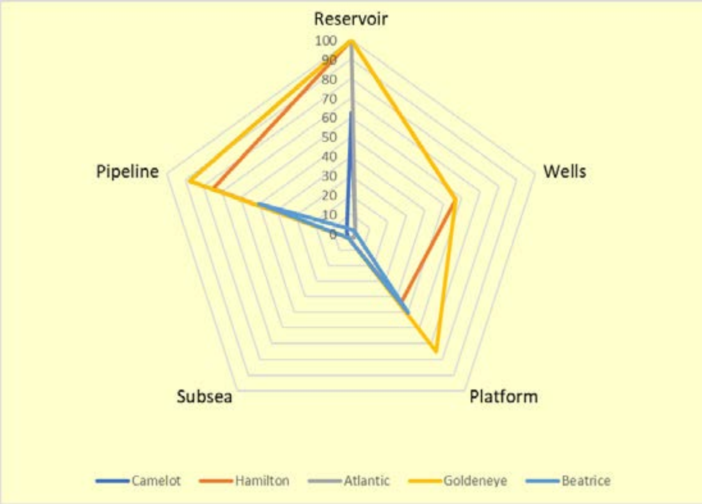


Figure 4-13: Summary of Re-use Assessments

5.0 Camelot Case Study

5.1 Description

The Camelot CA gas platform was installed during 1988 in the UK Southern North Sea (SNS) and was one of the closest platforms to shore being located just about 40km from the Norfolk coast. The original design life was 30 years. Annual surveys and integrity monitoring found little impairment of the core loadbearing members. Fatigue was not considered an issue due to the shallow water depth. Production commenced in 1989 and the field ceased production in June 2009 having produced over 247 Bcf of gas and at that time steps were taken to evaluate alternative uses for the reservoir and facilities. The field owners at the time production ceased were Energy Resource Technology (UK) Limited (operator) and ERT Camelot Limited. Each company owned 50% and were responsible for the full cost of decommissioning. In the event of a default by these owners the previous owner Mobil North Sea LLC was still jointly liable for the decommissioning under the terms of the Section 29 notice issued by the UK regulator.

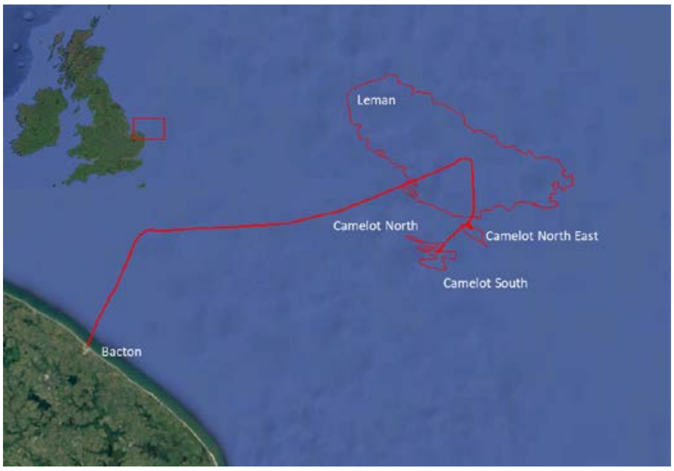


Figure 5-1: Location of Camelot

Figure 5-2: Camelot Platform

The Camelot CA platform was a small Normally Unmanned Installation (NUI) with a topside of 1,200 tons supported by a four-leg 700 ton steel jacket in just 11 m of water. The platform had 6 gas producing wells which fed through a basic process facility that simply removed any small amounts of produced water before the gas was exported via a 14 km long 12-inch (30.5 cm) concrete coated pipeline to the Leman 27A host facility operated by a third party Perenco. The process facilities cleaned the produced water to remove all hydrocarbons to a level of less than 40 ppm of oil in water. This then allowed the produced water to be discharged directly to the sea under permit from the authorities. There was also a 3-inch (7.62 cm) service line that ran the 14 km back from Leman 27A to import Mono-Ethylene Glycol (MEG) which was only used in the early years of production to avoid potential hydrate problems during well start-up.

The equipment on the NUI was designed to be very robust and therefore be capable of operating for long periods without the need for maintenance reducing the need for regular crew visits. All the wells and key process facilities were equipped with instruments and controls, so they could be monitored and managed from the onshore control room at Bacton. Communications with the platform were via a line of sight microwave system so this eliminated the need for any control umbilical. The safety systems, communications and control modules were all powered by small diesel generators with emergency battery back-up. Production started in 1989 and during over 20 years of operation the reliability of the platform equipment deteriorated naturally resulting in more frequent breakdowns and shut in of the wells.

The gradual increase in the cost of maintenance visits combined with the natural production decline and a low gas price eventually made it un-economic to continue operations resulting in the final shut in in June 2009. When the decision to cease production was made steps were taken to ensure the wells were secure and the platform remained a safe place to work. This was to reduce the need for regular visits and therefore reduce the operating cost allowing more time to explore any potential re-use option for the facility and wells. The need to refuel the platform with diesel however remained a significant cost which put severe economic and time pressure on any re-use option.

5.2 Decommissioning

5.2.1 Plan

During the life of the field the owners were in regular dialog with the UK regulator and were aware that the UK government had committed to compliance with the OSPAR decision 98/3. This commitment required that small platforms such as the Camelot CA facility be completely removed from their location and be brought ashore for re-use or recycling. The Camelot CA owners accepted this position and did not apply for a derogation to leave any topside or jacket in place. It is the National government that must to apply to OSPAR for a derogation and therefore it is only done in exceptional circumstances when safety, environmental and technical considerations make the removal impractical. To date, derogations have only been granted to large concrete gravity base structures.

To determine the most effective decommissioning plan a seabed survey was done of the jacket foundations, the drill cuttings pile and the pipelines to Leman 27A. This survey is required by the UK regulator to establish the condition of the site to ensure that the EIA is developed with recent and relevant data. The survey is summarised in the EIA and this in turn is included in the decommissioning programme that is then issued for public consultation before submission for approval by the regulator.

The CA seabed survey found no trace of any drill cuttings on the seabed around the jacket and this was attributed to the fast seabed currents generated by the tides in the shallow water where the jacket was located. The survey also found that the fast seabed currents had scoured out around the jacket legs creating a 5 m deep crater. As the jacket foundations were driven to 30+ m there were no structural issues. The survey also showed that most of the concrete coated pipeline was either buried or just level with the seabed with only occasional exposed sections.

5.2.2 Pipeline

With the surveys complete the owners completed an Environmental Impact Assessment (EIA) to determine the best options for the decommissioning. As expected the EIA determined that both the topside and jacket had to be removed and brought ashore for reuse or recycling. For the pipeline it was determined that the best option was to flush it clean and leave all the buried sections undisturbed in place. This included a TEE connection and two pipeline crossings that were completely covered by protective rock mounds. This reduced the pipeline decommissioning scope to the removal of the concrete mats and tie-in spools at each end of the pipeline. This was supported by historical survey records which showed that the sandy seabed at the exposed pipe locations was very mobile and resulted in buried sections of pipe being exposed and exposed sections of pipe becoming buried. This suggested that should the pipeline be flooded then the loss of buoyancy from the gas would increase the weight on the seabed and encourage the natural burial of the pipeline.

5.2.3 Wells

The decommissioning plan also included the decommissioning of the 6 gas producing wells. Following a review, it was agreed with both the independent well examiner and the UK authorities that the best option was to flush the wells clean and set a preliminary cement plug across the reservoir. The production tubing and gauge cables were removed so that the main cement plug could be placed level with the reservoir cap rock with no tubing or cables in place. With the permanent reservoir cement plug in place some of the remaining tubing was left in hole but below the level of the reservoir, as illustrated in Figure 5-4. An environmental cement plug was set just below the seabed to secure any residual Oil Based Mud (OBM) remaining from the original drilling. This allowed all the casings and conductors to be cut 3m below the seabed and recovered along with the platform removal.

Figure 5-3: Rig-less Abandonment of the Camelot Wells

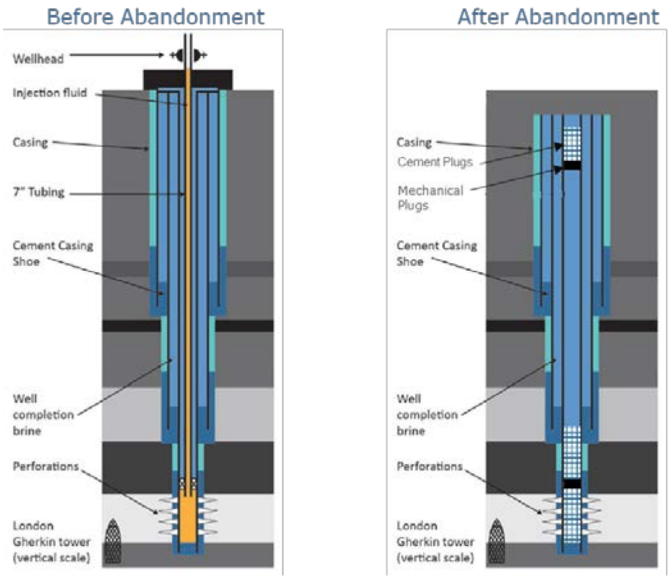


Figure 5-4: Illustrative Well Abandonment Diagrams

5.2.4 Topsides and Jacket

A shear leg lifting barge was selected for the facilities removal and having prepared the leg cuts the lift barge was rigged to the top deck and with the final cut made the top side was lifted clear and placed on a transport barge for delivery to shore. The lift barge was then rigged to the legs and a cutting device was lowered through each leg to cut them 3 m below the seabed as with the wells. With the cut complete the lift barge lifted the jacket clear of the seabed and then transported the jacket on the hook back to its home port where the selected recycling yard was located.

Figure 5-5: Removal of the Camelot A Topsides

5.3 Re-use Opportunities

When the field ceased production a number of studies were done to look at alternative uses for the reservoir and facilities. Three options were considered for re-use of the facilities, as summarised in Table 5-1 and discussed further in this section.

Option	Highlights
Methane Storage	Required new wells and injection facilities which could be more cost effectively deployed on a new platform
CO_2 **Storage**	Considered for the UK 1st CCS Competition but ultimately not progressed
Use on a different gas field	Platform designed for only 11m water depth. Topsides requires replaced. Significant risk involved in relocating. More economic and effective to use a new purpose-built facility.

Table 5-1: Re-use Options

5.3.1 Methane Storage

This included using the reservoir as a seasonal / peak (methane) gas storage facility or as a long-term storage site for CO_2 gas emissions. It also included potential reuse options for the topside and jacket. Located some 40km offshore Camelot CA is one of the closest facilities to the UK mainland and at first appeared to be an ideal candidate for seasonal fuel gas storage however the size of the reservoir and the required cushion gas were not an optimum fit for longer term seasonal loading and appeared better suited to short term daily peak loading. Studies showed the reservoir was capable of delivering the fast response required for daily gas loading and unloading but this required a large number of new wells. The need for new wells required new platforms so it was determined that there was no value in the existing platform and wells as it was more efficient to purpose build new platforms equipped with current technology rather than try and retrofit the existing but obsolete Camelot CA facilities. Although the initial gas storage economics looked attractive the growing supply and availability of reception facilities for Liquefied Natural Gas (LNG) created uncertainty in the pricing differentials required to make a storage facility work. Being located so close to Bacton was also a disadvantage as there were many sources of competing gas supply including the Interconnector to the Netherlands.

5.3.2 CO_2 Storage

Camelot was evaluated as a potential CO_2 demonstration store during the first UK CCS in 2009 (CO2DeepStore, 2009). The detailed contents of the CO2DeepStore report remain confidential however the following information can be shared.

1. There was estimated to be sufficient storage capacity in the Camelot area to accommodate the DECC competition volumes of 20 million tonnes
2. The whole of the Bunter sandstone in the UKCS Block 53/1a was estimated to have a storage capacity of approximately 290 million tonnes. It was considered possible that these have sufficient capacity to store emissions from the Thames Cluster stations for over 50 years.
3. The conceptual development was to modify the platform and wells for CO_2 duty. Install a new pipeline, an external CO_2 import riser, install a heater, new generation and metering equipment. Storage would be in the depleted Rotliegendes gas reservoirs and the Bunter saline aquifer.
4. Gas phase pipeline operation was considered to not be feasible at any stage on Camelot due to the injection rates and pressure required. Therefore, the pipeline was planned to be operated with CO_2 in dense phase.
5. The Camelot platform had sufficient space and weight bearing capacity to accommodate

20MW of direct fired heating plus ancillary equipment.

6. The Camelot platform jacket had sufficient integrity to be operational in 2030, the end of the forecast period.

The proposed project did not proceed for several reasons, the primary one being that the UK CCS demonstration competition was cancelled in 2011.

5.3.3 Using the Facilities Elsewhere

Options were also considered for removing and reusing the facilities somewhere else. However, the fact that the jacket was built for just 11m of water and was one of the shallowest platforms in the North Sea made it unsuitable for any other reasonably foreseen development in the region. The topside facilities were in good structural condition, but it was clear that the process and metering equipment would have to be replaced. Additionally, the compact deck layout limited the space available to remove the existing equipment and would have required extensive engineering to safely extract large items (such as the generator and separators) from between the various deck levels. Installing new equipment would have been complex for the same reason. The cost and the safety risk implications of moving heavy and sophisticated machinery in such tight confines meant that new owners are likely to have considered it more economic and effective to use a new purpose-built facility.

5.3.4 Final Decision

In August 2010, the sandbanks where the platform was located became a candidate Special Area of Conservation (cSAC) called Haisborough, Hammond and Winterton. This designation added to the uncertainty around re-use options due to the heightened environmental concerns in the area and the need for a more rigorous Environmental Impact Assessment (EIA) for any change of use. This introduced the potential for delay which, combined with, the absence of a tangible reuse opportunity and the cost of maintaining a safe and operational facility resulted in the decision to decommission the field.

5.3.5 Infrastructure Reusability Index

The suitability assessment approach described in Section 4.5 has been applied to the Camelot asset assuming that the development scenario calls for a CO_2 supply of gas phase 1MT/year for 20 years. The results of the assessment are shown in Table 5-2 and Figure 5-6.

Criteria	Score	Comment
Reservoir	**10**	**Reservoir could be suitable**
Seal	4	Multiple sealing formations
Injectivity	3	Variable, permeability 50 – 650mD
Capacity	2	Greater than 20MT
Compartmental-isation	1	Very compartmentalised
Wells	**0**	**Wells are not available (abandoned)**
Bottom Hole Location	0	Not applicable
Size of Production Casing	0	Not applicable
Maximum Operating Pressure	0	Not applicable
Suitability of Tree	0	Not applicable
Platform	**0**	**Platform not available (decommissioned and removed)**
Remaining Design Life	0	Not applicable
Size and Load-bearing Capacity of Jacket	0	Not applicable
Power Capacity	0	Not applicable
Adaptability of CO_2 Operations	0	Not applicable
Subsea	**0**	**No subsea infrastructure**
Power Supply	0	Not applicable
Controls	0	Not applicable
Remaining Design Life	0	Not applicable
Pressure Rating, materials	0	Not applicable
Pipeline	**0**	**Pipeline not available (decommissioned)**
Maximum Operating Pressure	0	Not applicable
Materials	0	Not applicable
Throughput Capacity	0	Not applicable
Remaining Design Life	0	Not applicable

Table 5-2: Camelot Suitability Assessment

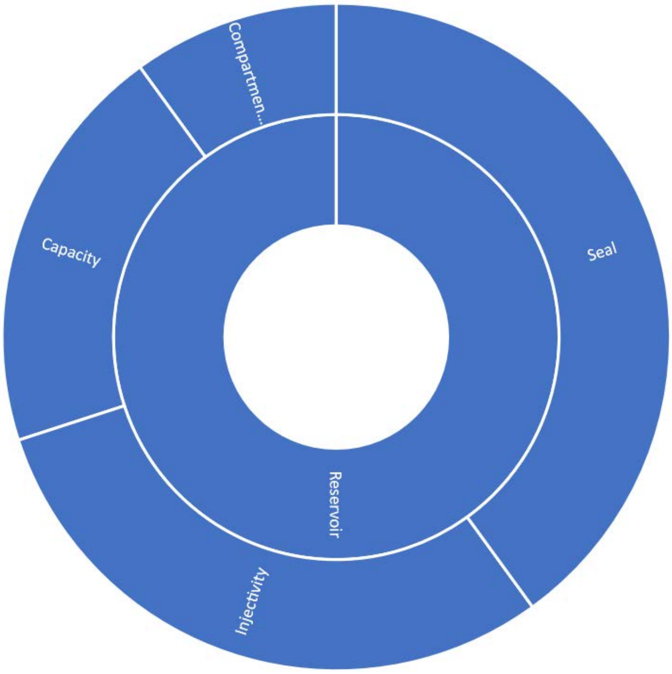


Figure 5-6: Camelot Suitability Assessment Chart

6.0 Atlantic & Cromarty Case Study

6.1 Development Overview

The Atlantic and Cromarty (A&C) gas fields are in the outer Moray Firth within blocks 14/26a and 13/30. The fields lie approximately 79km northeast of the St Fergus gas terminal on the north east Aberdeenshire coast in 115m of water, as shown in Figure 6-1.

The fields were developed using subsea wells connected to a common manifold at Atlantic and a 16” (40.64 cm) export pipeline to St Fergus. Power and control were provided from the Goldeneye platform via a 31km umbilical. Figure 6-2 shows the location of the fields, their associated subsea infrastructure and the pipeline connections back to shore.

The infrastructure was commissioned in 2005 and gas production commenced in 2006. The A&C fields produced around 130bcf (3.68 Bm^3) of gas during their three-year life and production stopped in 2009 and Cessation of Production (CoP) of the three wells was agreed in December 2011. The infrastructure was designed for an operational life of 20 years in the anticipation that there would be future opportunities to tie into the infrastructure. However, no such opportunities materialised.

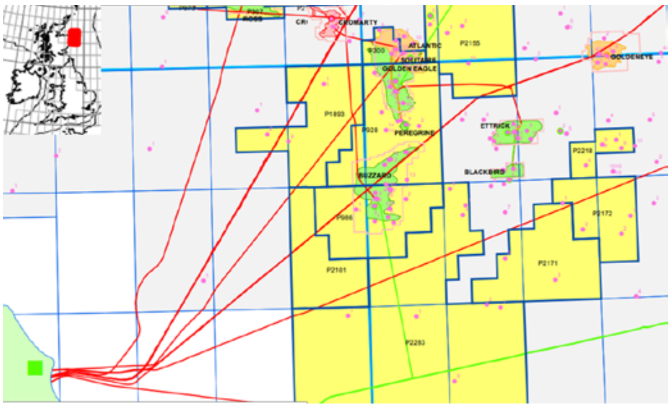


Figure 6-1: Atlantic and Cromarty Location

6.1.1 Description of Facilities

Production from the two wells at Atlantic and the single Cromarty well was routed to the Atlantic manifold and then exported by pipeline to the Scottish Area Gas Evacuation (SAGE) terminal at St. Fergus. A 4” (10.16 cm) monoethylene glycol (MEG) pipeline is piggy-backed to the gas export pipeline. MEG was injected into the gas stream to prevent hydrate formation. Control of the wells was provided by means of an umbilical from the Goldeneye platform to the Atlantic manifold and to the A&C wells. The layout of infrastructure is illustrated in Figure 6-2 (BG Group, 2016).

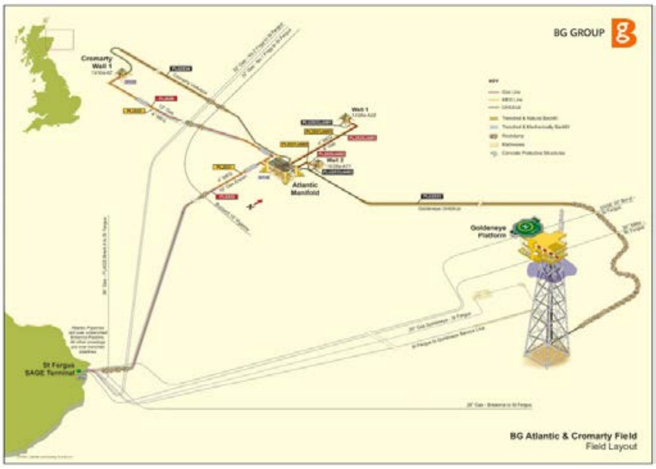


Figure 6-2: Schematic of the Atlantic and Cromarty infrastructure

6.1.2 Parties Involved

Originally, BG Global Energy Limited (BG) owned 75% of the Atlantic field with Hess Limited (Hess) owning the remaining 25%. For Cromarty the equity split is 10% and 90% respectively. BG operated the Atlantic field and Hess Limited (‘Hess’) operated the Cromarty field; BG operated the joint facilities that served both fields. Shell recently acquired BG thus the A&C assets owned by BG are now owned ultimately by Shell.

6.1.3 Historical Operation

Mechanical bridge plugs were installed in the two Atlantic wells and single Cromarty well when they were suspended in 2014. All three wells have since been permanently plugged and abandoned. The pipelines remain in place. They were flushed and cleaned until hydrocarbon free and then blind flanges installed and filled with water, MEG and corrosion inhibitor when disconnected from the wells in 2012. The export pipeline and MEG lines were then placed under an Interim Pipeline Regime (IPR) for a period of five years to allow potential third-party reuse applications to be identified and evaluated. To date no viable third-party reuse application for these pipelines has been identified. A decommissioning programme was submitted to UK Government in 2016 by BG and the development was scheduled for imminent decommissioning. The decommissioning programme does not cover the onshore pipelines and SAGE terminal at St Fergus.

6.1.4 Design Criteria and Key Engineering Data

Reservoir

Within the Central North Sea (CNS) the Captain Sandstone is a prolific hydrocarbon reservoir with many hydrocarbon fields, including Atlantic and Cromarty. The effective top seal for these is provided by mudstones of the Carrack (Sola) and Rodby Formation (Pinnock & Clitheroe, 2003). The underlying Lower Cretaceous sands of the Punt and Coracle are also prospective for hydrocarbons, with Punt being an oil bearing reservoir in Golden Eagle, Peregrine, Hobby and Solitaire fields nearby. The deeper Burns and Piper Sandstones of Upper Jurassic (below the Lower Cretaceous) are also well-documented hydrocarbon reservoirs within in the CNS. The late Jurassic Kimmeridge Clay Formation provides the source rock for the hydrocarbons, which have migrated into the Cretaceous Captain reservoir from the West Halibut Basin and Smith Bank Graben (Pinnock & Clitheroe, 2003).

Wells

The wells have been plugged and abandoned and are no longer accessible. Originally, the Atlantic Field contained two wells (14/26a-A2Z and 14/26a-A1Y) whilst the Cromarty Field contained a single well (13/30a-6Z).

Subsea

The Atlantic manifold comprises the manifold structure and a piping skid. Four piles secure the manifold to the seabed. A 12km control umbilical connected the Atlantic manifold to the Cromarty well.

A 31.4km control umbilical from the Shell-operated Goldeneye platform to the manifold provided hydraulic power, power, communications, and chemical injection to the A&C wells. A satellite link from St Fergus gas terminal controlled the field from the topsides of the Goldeneye platform.

Pipelines

The Atlantic manifold is connected to the onshore St Fergus terminal by the 79km western area gas evacuation system (WAGES) production pipeline (PL2029) and a piggy-backed MEG pipeline (PL2031). The production pipeline is 16” (40.64 cm) diameter except for a 1.2km landfall section that is 18” (45.72 cm) in diameter. The MEG pipeline is 4” (10.16 cm) diameter except for a 1.2km landfall section that is 6” (15.24 cm) diameter. The pipelines are buried in trenches or protected by rock cover along their length to a depth greater than 0.6m, except for the section between 6.4 and 10.4km from the shore, where the pipeline was laid on the seabed with only ‘spot’ rock cover.

The Atlantic manifold was connected to each of the Atlantic wells and pipelines by 8" (20.32 cm) spools laid directly onto the seabed and protected with concrete mattresses. Production from the Cromarty well was routed to the Atlantic manifold via a 12km long 12” (30.5 cm) production pipeline. MEG was supplied to both the Atlantic and Cromarty trees through 4” (10.16 cm) pipelines which piggybacked the production pipelines. Apart from the approaches to the Cromarty Christmas tree and the Atlantic manifold these pipelines are trenched and buried throughout their length. Concrete tunnels and mattresses were laid to protect the pipelines at the approach to the Cromarty well, (BG Group, 2016).

A summary of the original design parameters of the Atlantic pipelines is provided in Table 6-1 (Pale Blue Dot Energy, 2016).

Parameter	16” Pipeline (40.64 cm)	4” Pipeline (10.16 cm)
PL ID (BEIS)	PL2029	PL2031
Installation Date	2006	2006
Cessation Date	2011	2011
Design Life	20 Year	10 Year
Outer Diameter, mm	406	114
Wall Thickness, mm	15.5	6.0
Material	X65 Carbon Steel HFW (high frequency welded)	X65 Carbon Steel SMLS (seamless)
Corrosion Allowance	3mm	1mm
External Coating	Concrete weight coating 40-60mm	-
Internal Coating	0.075mm internal thin film epoxy coating	-
Cathodic Protection	Coatings and cathodic protection (CP) anodes	
Design Pressure	170barg	210barg
Operating Pressure	82barg	190barg
Design Temperatures	60 / -10°C	50 / -10°C

Table 6-1: Design data for the Altantic pipeline

6.2 Decommissioning Strategy

The Atlantic pipelines and the Atlantic to Cromarty pipelines were taken out of use in 2012 and cleaned. The pipeline contents, including hydrocarbon gas and liquids, were displaced to the onshore SAGE gas plant at St Fergus. The contents were replaced with treated fresh water for the main pipelines, or treated seawater for the umbilicals, and glycol. The treatment chemical comprised corrosion inhibitor, oxygen scavenger and biocide to prevent internal corrosion.

The pipelines were placed in the Interim Pipeline Regime (IPR) for a period of 5 years (expired December 2016) in order that potential third-party re-use applications for the pipelines could be identified and re-evaluated. The Atlantic manifold was also left in place.

The wells were suspended with mechanical bridge-plugs and cement plugs in 2014. The wells have since been fully abandoned by recovering the Christmas tree and cutting and recovering the upper 3m of all casing strings and the wellhead.

A draft decommissioning programme was issued for consultation in 2016 (BG Group, 2016) and includes the following key activities:

- Recovery of concrete mattresses
- Cutting and recovery of exposed sections of pipeline
- Recovery of the subsea manifold
- Cutting and burial by rock dumping of exposed pipeline ends
- Buried pipelines and umbilicals to be left in situ

An illustration of this plan is shown in Figure 6-3.

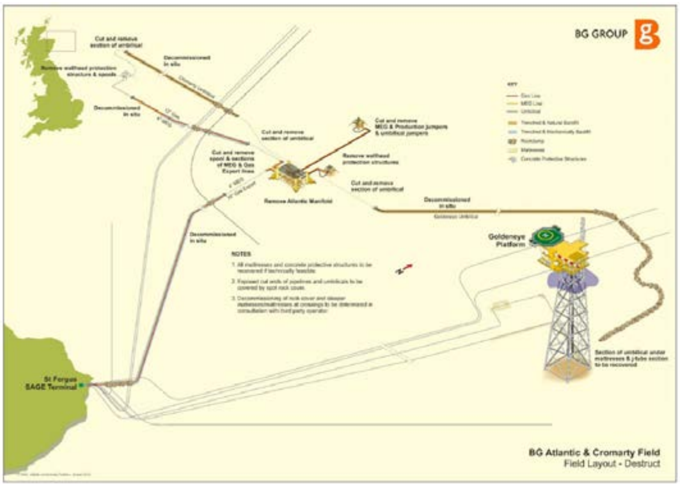


Figure 6-3: Atlantic and Cormarty Field Decommissioning Plan

Onshore the reception facilities will be mothballed and the decommissioning will be scheduled in line with the overall St Fergus plant decommissioning, to be completed at a later date.

6.3 Reuse Opportunities

The Atlantic and Cromarty infrastructure has been under consideration for re-use to transport CO_2 for injection into the Captain aquifer since 2009 (Pale Blue Dot energy, 2017).

Several other studies have also evaluated this infrastructure and geological formation, including the following:

- 2011 - Goldeneye FEED with injection at the Goldeneye platform
- 2015 - CO_2 Multistore JIP with injection at Sites "A" and "B"
- 2012 - Jin, Mackay, Quinn et all with injections sites 1 through 12.
- 2016 - The Caledonia Clean Energy Project (CCEP) study, (Pale Blue Dot Energy, 2016),
- 2016 - Strategic UK CCS Storage Appraisal Project for the Energy Technologies Institute (Pale Blue Dot Energy & Axis Well Technologies, 2016).
- Ongoing – Accelerating CCS Technologies (ACT) Acorn study (ERA-NET project 271500), Pale Blue Dot Energy, 2018

6.3.1 CO_2 Storage

Re-use of the Atlantic pipeline is a key component of the Acorn ICCUS project being developed by Pale Blue Dot Energy. The suitability of the pipeline for CO_2 transport has been highlighted on several occasions (Pale Blue Dot energy, 2017).

The 170 bar (17 MPa) design pressure rating (Pale Blue Dot Energy, Axis Well technology, Costain, 2015) of the pipeline is sufficient for the transport of dense phase CO_2 and in terms of longevity, the pipeline was designed for 25 years but operational for only 3 years. A new subsea well, subsea manifold and umbilical are the other elements of required infrastructure.

The plan is to inject and store CO_2 in the Captain Sandstone, which is also the same formation that contained the now depleted Atlantic and Cromarty gas fields. Any residual hydrocarbons would affect the compressibility of the fluids and an appropriate injection strategy would need to be developed.

The Acorn development concept uses a Minimum Viable Development (MVD) approach. This takes the view of designing a full chain CCS development of industrial scale (which minimises or eliminates the scale up risk) but at the lowest capital cost possible, accepting that the unit cost for the initial project may be high for the first small tranche of sequestered emissions.

Acorn will use the unique combination of legacy circumstances in North East Scotland to engineer a minimum viable full chain carbon capture, transport and offshore storage project to initiate CCS in the UK. The project is illustrated in Figure 6-4 and seeks to re-purpose an existing gas sweetening plant (or build a new capture facility if required) with existing offshore pipeline infrastructure connected to a well understood offshore basin, rich in storage opportunities. All the components are in place to create an industrial CCS development in North East Scotland, leading to offshore CO_2 storage by the early 2020s.

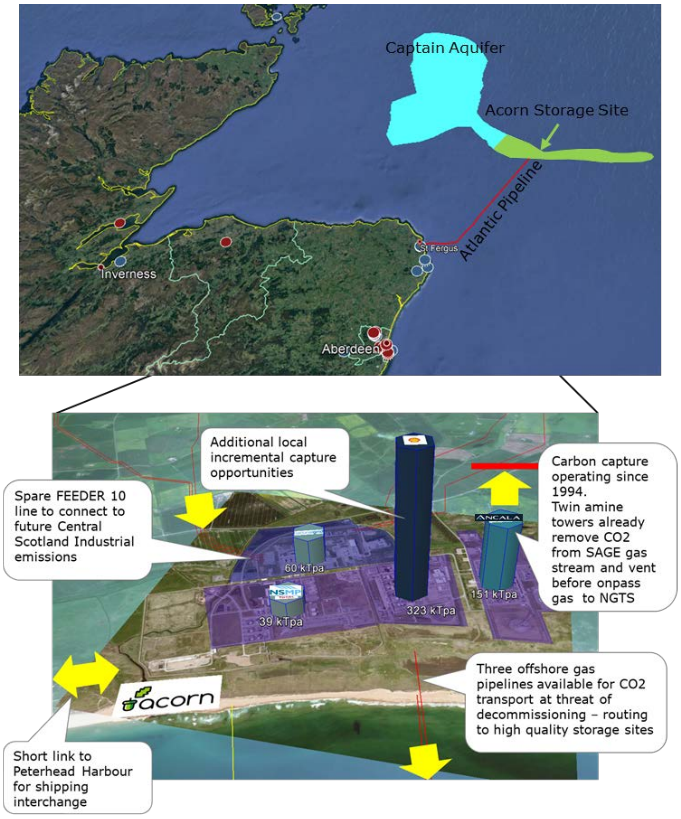


Figure 6-4: Acorn Outline Minimum Viable Development Plan

A successful project will provide the platform and improve confidence for further low-cost growth and incremental development. This will accelerate CCS deployment on a commercial basis and will provide a cost effective practical stepping stone from which to grow a regional cluster and an international CO_2 hub.

The seed infrastructure can be developed by adding additional CO_2 capture points such as from hydrogen manufacture for transport and heat, future CO_2 shipping through Peterhead Port to and from Europe and connection to UK national onshore transport infrastructure such as the Feeder 10 pipeline which can bring additional CO_2 from emissions sites in the industrial central belt of Scotland including the proposed Caledonia Clean Energy Project, CCEP. A build out scenario for Acorn used in the 2017 Projects of Common Interest (PCI) application is included as Figure 6-5.

Pale Blue Dot Energy is exploring various ways and partners to develop the Acorn project.

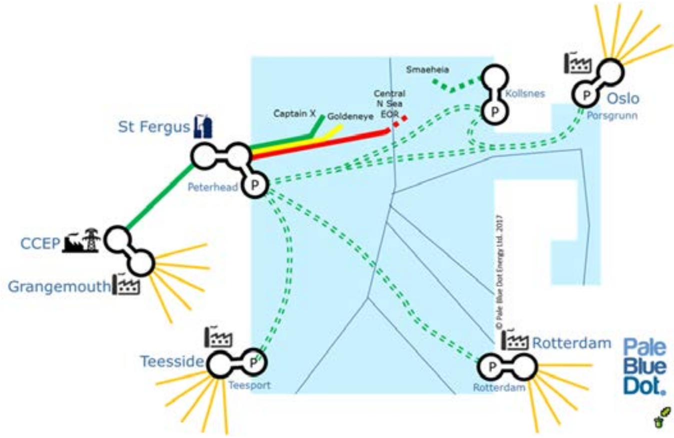


Figure 6-5: Acorn build out scenario from the 2017 PCI application

6.3.2 Infrastructure Reusability Index

The suitability assessment approach described in Section 4.5 has been applied to the Atlantic asset assuming that the development scenario calls for a CO_2 supply of gas phase 1MT/year for 20 years. The results of the assessment are shown in Table 6-2 and Figure 6-6.

Criteria	Score	Comment
Reservoir	**16**	**Reservoir very suitable**
Seal	4	Proven seal for several fields
Injectivity	4	Good quality reservoir
Capacity	4	Capable of containing more than 20MT
Compartmental-isation	4	Good connectivity
Wells	**0**	**Wells not available, abandoned**
Bottom Hole Location	0	Not applicable
Size of Production Casing	0	Not applicable
Maximum Operating Pressure	0	Not applicable
Suitability of Tree	0	Not applicable
Platform	**0**	**Platform not available, subsea development**
Remaining Design Life	0	Not applicable
Size and Load-bearing Capacity of Jacket	0	Not applicable
Power Capacity	0	Not applicable
Adaptability of CO_2 Operations	0	Not applicable
Subsea	**0**	**Equipment Not suitable**
Power Supply	0	Decommissioned
Controls	0	Decommissioned
Remaining Design Life	0	Decommissioned
Pressure Rating, materials	0	Decommissioned
Pipeline	**14**	**Pipeline likely to be suitable**
Maximum Operating Pressure	4	High operating pressure
Materials	2	Suitable for CO_2
Throughput Capacity	4	High throughput capacity
Remaining Design Life	4	Only in service for a short time

Table 6-2: Atlantic and Cromarty Suitability Assessment

Figure 6-6: Atlantic and Cromarty Suitability Assessment Chart

7.0 Hamilton Case Study

7.1 Development Overview

Hamilton is a part of the Liverpool Bay development, located within block 110/13a, that consists of Douglas, Hamilton, Hamilton North and Lennox fields. Hamilton is located 25 km from the North Wales coast and has been producing gas since 1997. The platform is a minimum-facilities, normally unmanned installation with a tieback to the Douglas platform. The Hamilton field is currently producing; however, cessation of production is expected in the near term.

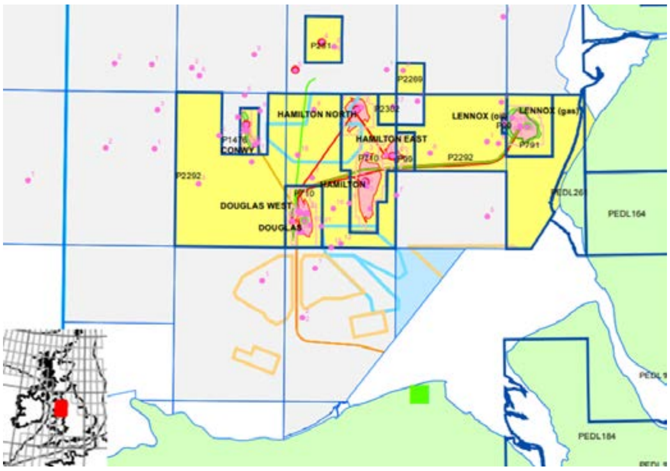


Figure 7-1: Location of Hamilton

7.1.1 Description of Facilities

The Hamilton facility consists of a 550 tonne deck supported on an 800 tonne steel jacket standing in 27m of water. The normally unmanned installation is a two-level structure with an underdeck. The facility has 6 well slots with four producing wells. Produced gas, together with condensate and formation water, is transported to the Douglas platform by a 20” (50.8 cm) infield line where it is processed before export via a 34km 20” (50.8 cm) line to the Point of Ayr terminal. As a minimum facilities NUI the Hamilton platform was designed to operate for long periods without the need for maintenance to reduce the need for crew visits. The wells and process facilities were equipped to be controlled remotely.

7.1.2 Location of Project Infrastructure & Details of Interfaces

The Hamilton field is in the Liverpool Bay area and is operated by ENI. The NUI ties back to the Douglas platform before gas is transported to the Point of Ayr terminal by pipeline. The gas export line from Douglas would need to be available to enable reuse of the existing infield line otherwise a new, purpose built, pipeline would be required.

The gas processing facilities for Hamilton are located on the Douglas platform and are shared between the Hamilton East and North as well as gas from the Lennox field.

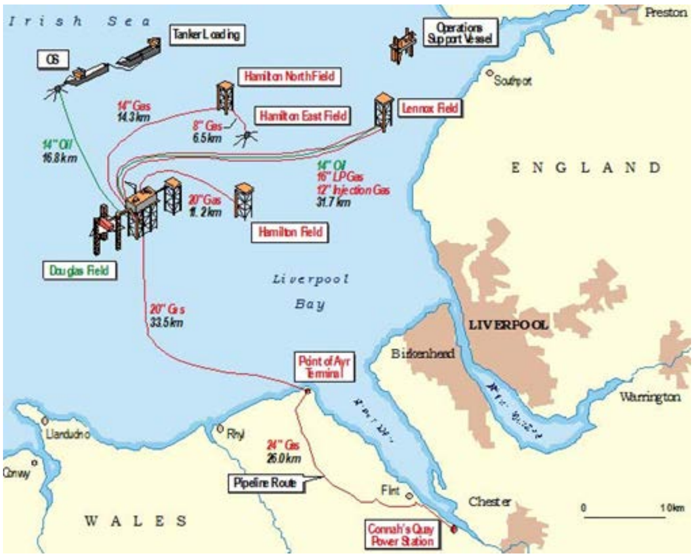


Figure 7-2: Liverpool Bay Area Infrastructure

The Hamilton North and Hamilton East developments also tieback to the Douglas platform, while they are not tied to the Hamilton NUI it is likely that they would be decommissioned at similar times so that costs could be shared.

7.1.3 Parties Involved

BHP Billiton initially held a 46.1% share in the Liverpool Bay (comprising Douglas, Lennox, Hamilton, Hamilton North, Hamilton East and Hamilton West) with the remaining 53.9% belonging to ENI.

Hamilton is currently producing and operated by ENI. The current field partners are ENI AEP ltd with an 8.9% holding, ENI ULX ltd with a 45% holding and Liverpool Bay ltd with a 46.1% holding.

7.1.4 Historical Operation

The Hamilton Gas field was discovered in July 1990 with first gas being produced in 1997. While the exact production history is not readily available, the SSAP project simulated the gas production and reservoir pressure up until an assumed COP in 2017. Pressure match was achieved with a modelled aquifer volume of 8,147MMbbls.

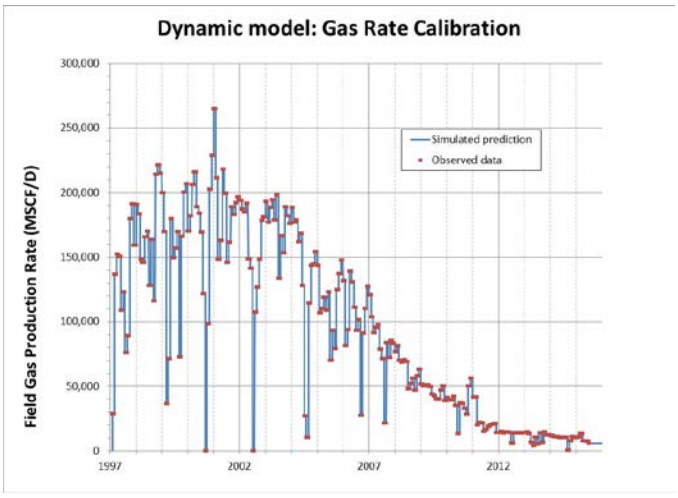


Figure 7-3: Simulated Production Rate for the Hamilton Field

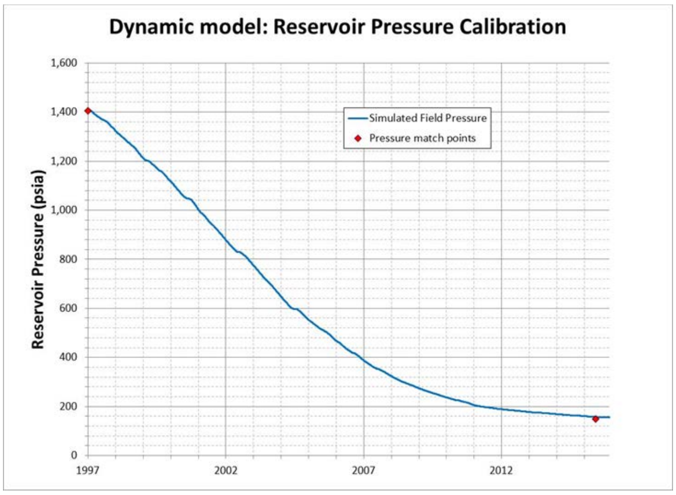


Figure 7-4: Simulated Reservoir Pressure for the Hamilton Field

The Hamilton field has produced 18,180,000 ksm^3 of gas in total up until 2015. Gas production fell below 1,000,000 ksm^3 in 2007 and was only 71,372 ksm^3 in 2015.

7.1.5 Design Criteria and Key Engineering Data

Reservoir

The Hamilton gas field is a N-S trending horst structure where gas had been trapped by a combination of fault and dipped closures. The reservoir unit is within the Ormskirk and St Bees Sandstone Formation of the Triassic Sherwood Sandstone Group. The gas field is bounded on the west side by the Hamilton fault which throws the Sherwood Sandstone down by over 150m below the gas water contact. There are also minor east-west and north-south faults that cut the structure. Within the structure the faults have sand to sand contact and are not sealing. The primary seal is the Mercia Mudstone Group which provides a proven basin seal and comprises of alternating mudstones and thick halites. Reaching thicknesses of up to 3,200m within the basin, it is roughly 700m thick at the Hamilton field and forms most of the overburden.

Wells

There are seven wells within the Hamilton field with varying amounts of data available. Three wells have core available and only two have wireline data.

Platform

The Hamilton Platform is a two-level NUI with an underdeck. Produced gas along with condensate and produced water is transported via a subsea pipeline to Douglas for further processing. The jacket was configured as a lifted four leg structure with outrigger pile sleeves. The topsides historical weight data suggests an operating weight of 525 tonnes (OSPAR, 2015). Removal of the existing basic gas processing facilities from the Hamilton platform will have a net positive weight allowance for future additions, however at least 60% of the dry weight of the topsides is likely to be structural.

Pipeline

Gas, condensate and produced water is transported to Douglas via a 20” (50.8 cm) infield pipeline. The gas export line from Douglas is a 20” (50.8 cm) 34km pipeline to the Point of Ayr. There is also a 2” (5.08 cm) chemical line that extends from the Douglas platform to the Hamilton platform.

Figure 7-5: Image of the Hamilton Platform

7.2 Decommissioning Strategy

Due to the integrated nature of the Liverpool Bay area it is possible that the Hamilton platform could be decommissioned ahead of the gas export pipeline from Douglas to the point of Ayr.

A decommissioning programme for Hamilton has not been published at the time of writing. The Hamilton platform is expected to have to comply with the OSPAR decision 98/3 requiring small platforms to be completely removed from their location and brought onshore for reuse or recycling. The owners of Hamilton would not be able to apply for a derogation to leave the topside or jacket in place. A seabed survey will be required to assess the foundations, drill cuttings pile and pipelines to determine the status and inform the decommissioning programme.

Following a seabed survey an environmental appraisal report is required to be carried out. The decommissioning programme is likely to recommend removal of the jacket and topsides for reuse or recycling. Should the seabed survey show that the pipeline is mostly buried it is likely that the recommendation will be to flush the pipeline and leave the buried sections in place. The pipeline decommissioning scope will then be reduced to removal of concrete mats, tie-in spools and make safe any exposed sections of pipeline.

7.3 Reuse Scenario

The Hamilton platform is tied back to the Douglas platform and does not have a direct pipeline to the shore. Consequently, any re-use of the Hamilton platform for CO_2 operations would either need to wait until the Douglas pipeline was available or install a new direct pipeline. Since Hamilton is close to shore the cost of a new pipeline would be relatively modest.

7.3.1 CO_2 Storage

The Hamilton platform has previously been considered for CO_2 storage as part of the DECC CCS commercialisation competition. The project, led by Peel subsidiary Ayrshire Power, intended to capture CO_2 from a coal fired power station and use the Hamilton platform to inject CO_2 into the depleted gas field.

To keep the costs of a CCS project down the platform, pipeline and wells would be considered for reuse. The main use for the Hamilton platform in a CO_2 reuse scenario would be to provide heating during injection. Heating is required to avoid a CO_2 phase change due to the low pressures in the reservoir. Avoiding a phase change is important to preserve the integrity of the well and to avoid complications in the near well bore area. The structural integrity of the platform should be sufficient for reuse although a survey and structural assessment would be required before a decision is made. Should more space be required a larger deck could be cantilevered. Reusing the pipeline system (via Douglas) is also potentially attractive to developing a low cost project.

There are two CO_2 injection cases that could reuse the reservoir and infrastructure at Hamilton. Dense phase CO_2 injection for larger quantities that would require heating and gas phase injection of CO_2 that would suit smaller quantities and would not require heating.

Additionally, the Strategic UK CO_2 Storage Appraisal Project looked at developing the Hamilton gas field for CO_2 storage. Although the project used new build facilities to inject CO_2 the capacity of the field was determined based on available oil and gas seismic and well data. The Hamilton gas field was found to be able to store 124 MT CO_2 over 25 years with an injection rate of 5 MT/y using two injection wells and one spare/monitoring well. Injection is initially in gaseous phase until the reservoir pressure increases sufficiently to enable injection in dense phase.

7.3.2 Infrastructure Reusability Index

The suitability assessment approach described in Section 4.5 has been applied to the Hamilton asset assuming that the development scenario calls for a CO_2 supply of gas phase 1MT/year for 20 years. The results of the assessment are shown in Table 7-1 and Figure 7-6.

Criteria	Score	Comment
Reservoir	**16**	**Reservoir likely to be suitable**
Seal	4	Proven hydrocarbon seal
Injectivity	4	Can inject more than 1 MT/Y
Capacity	4	Can contain more than 20MT
Compartmental-isation	4	Non-sealing faults within the structure
Wells	**9**	**Wells may be OK for gas phase**
Bottom Hole Location	3	OK
Size of Production Casing	4	OK
Maximum Operating Pressure	2	OK, subject to integrity review
Suitability of Tree	0	Would need an injection tree
Platform	**7**	
Remaining Design Life	2	Could be extended if required
Size and Load-bearing Capacity of Jacket	2	Could be increased if required
Power Capacity	1	Would need extra power
Adaptability of CO_2 Operations	2	OK
Subsea	**0**	**Not applicable**
Power Supply	0	Not applicable
Controls	0	Not applicable
Remaining Design Life	0	Not applicable
Pressure Rating, materials	0	Not applicable
Pipeline	**12**	**Pipeline could be OK for gas phase**
Maximum Operating Pressure	3	OK for gas phase
Materials	3	OK
Throughput Capacity	3	OK for gas phase
Remaining Design Life	3	OK

Table 7-1: Hamilton Suitability Assessment

Figure 7-6: Hamilton Suitability Assessment Chart

8.0 Goldeneye Case Study

8.1 Development Overview

The Goldeneye field is located, in block 14/29, in the South Halibut basin area of the outer Moray Firth. The field was discovered in 1996 by Shell/Esso. Standing in 120m of water the Goldeneye platform was installed in 2003 to produce natural gas and condensate. Hydrocarbons are exported 102km by pipeline to the St Fergus gas terminal for processing. The field ceased production in 2011 and the field has been considered for CO_2 storage in several projects.

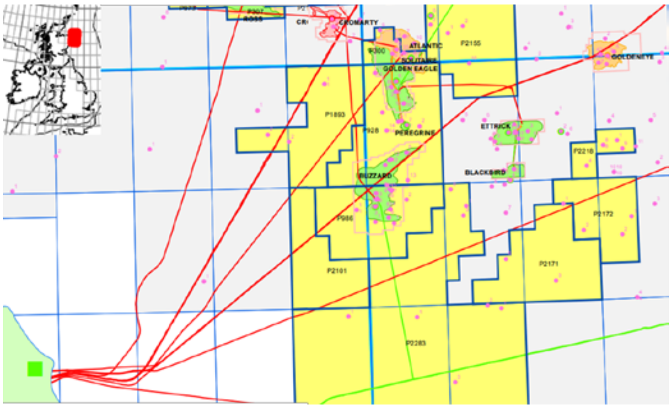


Figure 8-1: Location of Goldeneye Facilities

8.1.1 Description of Facilities

The platform is a normally unmanned installation with no hydrocarbon processing on board. Produced water management was never installed, the small amounts of produced water were exported to shore with production fluids. Gas and condensate were produced from 5 wells drilled into the field. Produced fluids were commingled in a production manifold before being separated in a three phase separator for metering after which the fluids were commingled in an export manifold. A 4” (10.16 cm) pipeline supplied MEG and corrosion inhibitor from shore to be injected into the gas stream upstream of the export manifold. Produced hydrocarbons were exported to the St Fergus gas terminal using a 102 km 20” (50.8 cm) export pipeline with a design pressure of 132 barg. At the shore end the export and service pipelines are bundled and trenched. After roughly 20km the export pipeline lays directly on the seabed and is protected by concrete coating. Close to the platform the pipeline is protected by concrete mattresses. There are five pipeline crossings that are protected by rock dumping.

8.1.2 Location of Project Infrastructure & Details of Interfaces

The main interface points for the reuse of Goldeneye are the 20” (50.8 cm) export pipeline, the 4” (10.16 cm) service line, the subsea isolation valve manifold, the wells and the control and monitoring network operating out of St Fergus.

8.1.3 Parties Involved

The offshore pipeline and wells are currently owned by the Goldeneye Production Joint Venture, which was established to produce gas from the field.

8.1.4 Historical Operation

The Goldeneye gas field has historical production data including continuous flow measurements and down hole pressure monitoring. Each well was completed with permanent downhole gauges which are connected to individual pressure, temperature and mass flow meters. Data from the production history helps to inform the modelling of the subsurface to ensure a more accurate picture of how the reservoir will behave when CO_2 is injected.

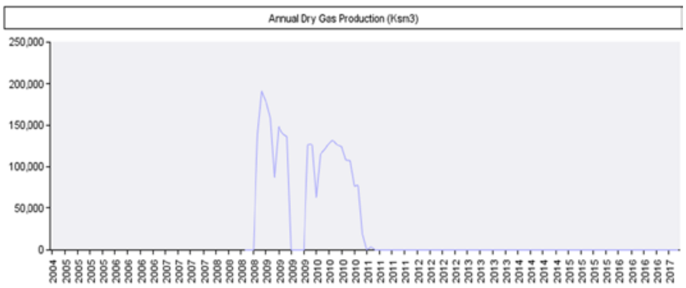


Figure 8-2: Goldeneye Production Volumes (Oil and Gas Authority, 2018)

Year	Yearly Total (Ksm³)
2008	329,111
2009	1,103,725
2010	1,200,101
2011	3,251

Figure 8-3: Annual Produced Volumes from Goldeneye (Oil and Gas Authority, 2018)

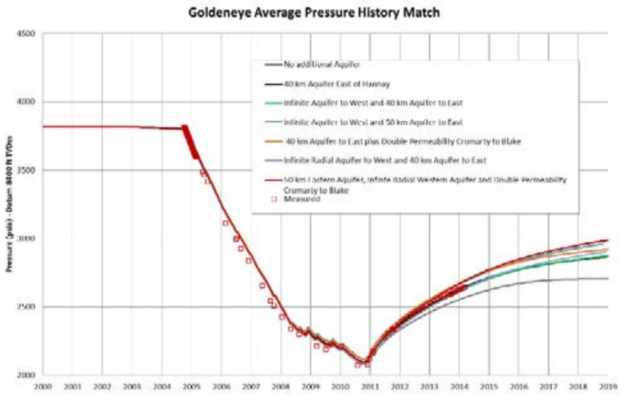


Figure 8-4: Goldeneye Reservoir Simulation Pressure Match (Shell UK ltd., 2016)

As part of the Peterhead CCS project Shell history matched the pressure for the depletion of the Goldeneye gas field. By pressure matching the reservoir model there is greater confidence in the modelling of the injected CO_2 plume.

8.1.5 Design Criteria and Key Engineering Data

Reservoir

The Goldeneye field is an anticline in the large regional Captain aquifer. The reservoir structure is a three-way dip closure (to the west, south and east) with a stratigraphic or faulted margin in the north. Impermeable mudstone rocks of the Upper Valhall mudstone, Rodby formation, Hidra formation and Plenus Marl Bed seal the reservoir. There are no faults that fully offset the caprock in the region of the field that have been mapped. The field was produced between 2004 and 2011 with official cessation of production in 2011. Current reservoir pressure is estimated at 187 bara.

Wells

There are eight slots in the well bay with five occupied by wells. Each well has 7" production tubing and a subsea safety valve. Downhole temperature and pressure was monitored as well as annuli pressures. Data was fed to the distributed control system (DCS) at St Fergus and could be accessed remotely. Each Xmas tree had a production choke valve attached to the wing valve outlet. The choke valve was used to control flow from individual wells. Hydraulic power was used to operate valves using hydraulic pumps driven by electric power. A separate hydraulic package was used for each wellhead. Each well had a MEG injection point upstream of the choke to avoid hydrate formation during start up and was controlled from St Fergus.

Platform

The Goldeneye platform is a four-legged steel structure that was installed in 2003. Two vertical piles connect the platform at each corner. The topsides deck structure includes a helideck, pedestal crane and vent stack. There are two deck levels at +22m and +31.5m with an intermediate mezzanine deck at +27.15m. The decks are 31x16m with extra length cantilevered over the west of the jacket, the opposite side to the wellheads. The cantilever supports the helideck and contains the short stay accommodation, control and equipment rooms. The installed topsides weigh roughly 1,680 tonnes and the jacket can support a topside structure up to 2,000 tonnes. The four-legged jacket structure is X-braced and was designed to be lift installed. The jacket weighs just under 2,000 tonnes.

Parameter	Value
Design Concept	Full wellstream tieback to shore, for onshore processing of the gas and condensate
Design Life	20 years (was to be extended under the PCCS project)
Wells	5 jack-up drilled wells with sand exclusion, 3 producers, 2 producer / observation wells. All wells drilled prior to commissioning and start-up (minimum is 3 wells prior to start-up)
Offshore Facility	
Facility Type	Normally Unattended Installation (NUI) Wellhead platform controlled from onshore (St Fergus) Short stay accommodation (provided for 12 Personnel On Board (POB) normally, with fold-down beds in five of the cabins to accommodate a maximum POB of 22) for overnight stays
Water Depth	119m (LAT)
Offshore Process / Equipment (Platform Topsides)	Manifold, Production Separator Gas, hydrocarbon liquids and water metering Water and oil detection, sand detection Provision for possible future water treatment and sand collection
Manning Requirements	Six campaign maintenance visits per year of 6-8 days duration with a crew of 12 (planned and unplanned maintenance c. 6000 manhours per year); additional visits for ad-hoc work

Table 8-1: Summary of Existing Goldeneye Offshore Platform Design Parameters (Shell UK ltd., 2016)

Figure 8-5: Goldeneye Platform (Scottish Power Consortium, 2011)

Subsea

All five wells are drilled from the platform and so there is no subsea infrastructure separate to the pipelines.

Pipeline

The export pipeline is a 102km 20” (50.8 cm) pipeline with a design pressure of 132 barg. The onshore arrival pressure was initially 86 bara and declined to 25 bara. In 2013 the pipeline was cleaned and made hydrocarbon free. Analysis of the solid deposits recovered during cleaning operations indicated that no detectable corrosion had taken place and the pipeline was in a satisfactory condition for reuse (Shell UK ltd., 2016).

Parameter	Value
Length and Diameter	Length: offshore 101 km, onshore 0.6 km (FLAGS route) Main pipeline: 20” (50.8 cm) (OD) MEG Service line: 2” (5.1 cm) (NB)
Onshore Arrival Pressure	Initial: 86 bara Decline to: 25 bara (minimum)
Route and Crossings	Direct from Goldeneye to terminal at St Fergus (parallel to and south of Miller / SAGE pipeline corridor) Five pipeline crossings

Table 8-2: Existing Pipeline (Shell UK ltd., 2016)

8.2 Decommissioning Strategy

Presently a draft decommissioning plan for the Goldeneye platform has not been filed and therefore the decommissioning strategy is speculative at this stage. With the cancellation of the UK government CCS commercialisation competition the decommissioning strategy is expected to include the wells, platform and export pipeline.

The wells will have the tubing and subsea safety valves pulled ahead of pugging and abandonment. With the Goldeneye reservoir featuring in several prominent CCS projects the abandonment should be comprehensive. An ideal abandonment for a CCS store would have a plug at the top of the reservoir in contact with the rock and with a good overlap with the caprock. In the overburden there would be additional plugs in formations that CO_2 could migrate through to mitigate potential leakage pathways.

Prior to removal, the topsides of the platform must be “made safe” by making them hydrocarbon free. This involves cleaning, disconnection and physical isolation of the equipment as well as waste management. Once the installation is hydrocarbon free it can be prepared for removal.

8.3 Re-use Scenario

Re-use of the Goldeneye field for CO_2 storage has been studied in a number of projects and featured in the UK Government’s CCS Commercialisation competition. The Scottish Power consortium looked to capture CO_2 from the Longannet coal fired power station, transport the CO_2 by repurposing the Feeder 10 pipeline to St Fergus and storing the CO_2 offshore in the Goldeneye reservoir. The Shell Peterhead project made the final two sites in the CCS commercialisation competition and underwent front end engineering design (FEED) before the competition was ultimately cancelled. The Peterhead project involved CO_2 capture from the exhaust gas of the Peterhead power station, a new section of pipe to connect the power station to the existing Goldeneye export line and re-use of the pipeline and the Goldeneye platform, including wells, to store the CO_2 in the Goldeneye reservoir.

8.3.1 CO_2 Storage

The Peterhead CCS Project aimed to capture approximately one million tonnes of CO_2 per annum, over a period of up to 15 years, from an existing combined cycle gas turbine (CCGT) located at SSE’s Peterhead Power Station in Aberdeenshire, Scotland. Had the project progressed, it would have been the world’s first commercial scale demonstration of CO_2 capture, transport and offshore geological storage from a (post combustion) gas-fired power station. This section of the report draws heavily on the Storage Development Plan produced as one of the key knowledge deliverables in the UK CCS Demonstration (Shell, 2011)

Post cessation of production, the Goldeneye gas-condensate production facility would have been modified to allow the injection of dense phase CO_2 captured from the post-combustion gases of Peterhead Power Station into the depleted Goldeneye reservoir.

The CO_2 was to be captured from the flue gas produced by one of the gas turbines at Peterhead Power Station using amine-based technology provided by CanSolv. After capture the CO_2 would have been routed to a compression facility, for compression, cooling and conditioning for water and oxygen removal to meet suitable transportation and storage specifications. The resulting dense phase CO_2 stream would be transported direct offshore to the wellhead platform via a new offshore pipeline which will tie-in subsea to the existing Goldeneye pipeline.

Once at the platform the CO_2 would be injected into the Goldeneye depleted hydrocarbon gas reservoir, more than 2 km under the seabed of the North Sea.

Three wells were planned to be recompleted as injectors, although mostly one well will be required for the injection at any one time. This provides a degree of redundancy within the wells. The fourth well acts both as a monitoring well and as a backup in the case of a significant loss of integrity in other wells. The plan was to recomplete these existing gas production wells by installing small bore tubing in the wells. This design was selected to accommodate the range of injection rates at the different reservoir pressures during the injection life, each well would be completed with a different tubing size/configuration tailored to a specific rate range. The wells would then have overlapping operating envelopes, and minimum and maximum rates from the capture plant can be injected through the choice of a specific combination of wells.

The plan was to partially re-use the Goldeneye offshore pipeline apart from the SSIV assembly adjacent to the platform. The section between the SSIV skid and the riser base will be replaced with 214 bara MAOP-rated spools.

The Goldeneye jacket would 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.

The major planned modification to the topsides are summarised as follows:

- The existing pig launcher will be converted to a pig receiver capable of handling intelligent pigs.
- 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.
- 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.
- New injection chokes will be installed on the flowlines.
- A new vent system for depressuring the pipeline will be installed and routed up the existing vent tower.
- The existing 10” (25.4 cm) vent stack will be retained and adapted for use in the wellhead vent system.
- Several vents will be installed to allow depressuring of pipelines and equipment. The discharge of the vents will be installed below deck.

These modifications were estimated to cost approximately £208 million following the 2011 FEED programme (Scottish Power, 2011). The more recent Peterhead CCS Project FEED study estimated the costs to be £220 million; £73 million for pipeline works, £61 million for platform modifications and £88 million to recomplete the wells (Shell, 2015).

Following the cancellation of the CCS commercialisation competition it is anticipated that Shell will decommission the Goldeneye platform. However, there is still interest in CO_2 storage in the Captain aquifer. Even if the Goldeneye platform is decommissioned there is still potential for the Goldeneye pipeline to be reused providing that it is not cut as a part of the decommissioning programme. Ideally, to facilitate reuse, the pipeline should be blanked and left in a state where reconnection is still possible.

8.3.2 Infrastructure Reusability Index

The suitability assessment approach described in Section 4.5 has been applied to the Goldeneye asset assuming that the development scenario calls for a CO_2 supply of gas phase 1MT/year for 20 years. The results of the assessment are shown in Table 8-3 and Figure 8-6.

Criteria	Score	Comment
Reservoir	**16**	**Reservoir likely to be OK for re-use**
Seal	4	Excellent
Injectivity	4	OK
Capacity	4	Can contain > 20MT
Compartmentalisation	4	OK
Wells	**9**	**Wells likely to be OK for re-use**
Bottom Hole Location	3	OK
Size of Production Casing	3	OK, recompletion required
Maximum Operating Pressure	3	OK
Suitability of Tree	0	Would need to be replaced
Platform	**12**	**Platform likely to be OK for re-use**
Remaining Design Life	3	OK
Size and Load-bearing Capacity of Jacket	3	OK
Power Capacity	3	OK
Adaptability of CO_2 Operations	3	OK
Subsea	**0**	**No subsea infrastructure**
Power Supply	0	Not applicable
Controls	0	Not applicable
Remaining Design Life	0	Not applicable
Pressure Rating, materials	0	Not applicable
Pipeline	**14**	**Wells likely to be OK for re-use**
Maximum Operating Pressure	4	OK
Materials	2	OK, part of pipeline to be replaced
Throughput Capacity	4	OK
Remaining Design Life	4	OK

Table 8-3: Goldeneye Suitability Assessment

Figure 8-6: Goldeneye Suitability Assessment Chart

9.0 Beatrice Case Study

9.1 Development Overview

The Beatrice oilfield is located around 22km east of the Caithness coast in the Outer Moray Firth, UKCA Block 11/30a. There are four platforms installed. Beatrice Alpha consists of two bridge linked platforms (AD and AP), one for drilling and accommodation and the second for oil production and processing. The third and fourth platforms are satellite structures hosting two separate additional drill centres. The field was discovered by Mesa Petroleum but is now owned by Repsol Sinopec. The field was in production from 1981 to March 2015. Crude oil was exported through a 16", (40.64 cm) 67km submarine pipeline to Shandwick and a 9km buried onshore pipeline to the Nigg Oil Terminal in the Cromarty Firth.

Beatrice became fuel-gas deficient in 1987. Since that time, electricity has been imported to the field from the onshore power grid via a 25km submarine cable.

In 2007, as part of an offshore wind demonstrator programme, two 5MWe wind turbines were installed to partially replace and supplement the imported power. The offshore wind demonstrator is partly owned by Scottish and Southern Energy, although classed as "oilfield infrastructure" as they provided power to the platforms. The three-blade 5MWe wind turbines are each mounted on a four-leg jacket, they have a hub height of 88m and a blade diameter of 126m. Subsea cables connect the turbines to Beatrice Alpha platform, as illustrated in Figure 9-2.

9.1.1 Parties Involved

In 2008 Talisman's 100% interest in the Beatrice field was leased to Ithaca Energy (74.75%) and Dyas (25.25%) for a minimum period of three years, with the option for the lease to be extended until the end of field production. Ithaca Energy assumed operatorship of the field while Talisman, now Repsol Sinopec retained the decommissioning liability as part of the deal.

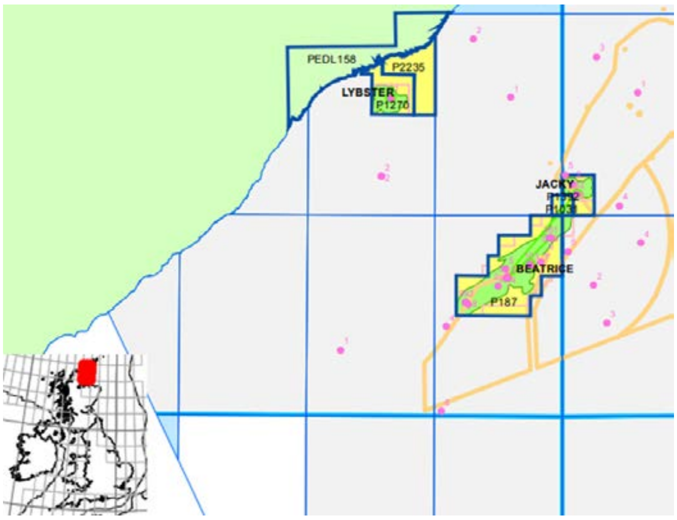


Figure 9-1: Beatrice Location

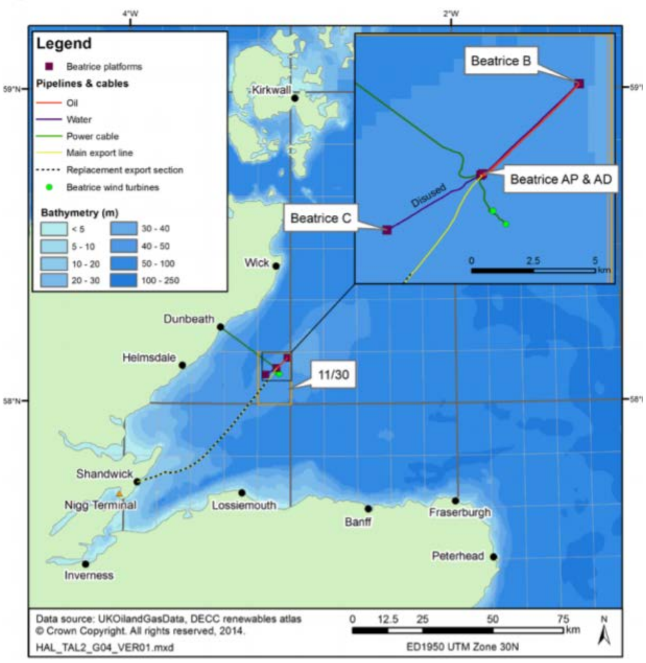


Figure 9-2: Location of Beatrice Oilfield Infrastructure

9.1.2 Historical Operation

Production at Beatrice began in 1981 with 5 wells producing at a combined rate of 20,000 b/d. Production from the B platform began in 1984 at a rate of 14,000 b/d. Commissioning of the water injection wells on the C platform in 1985 boosted output to a peak of 54,000 b/d. Production of the field continued to decline until a field redevelopment in 2000 boosted output from 3,000 b/d to

8,000 b/d in 2002. A further programme from 2006 to 2010 included eight water injection wells and led to a slight increase in production, as shown in Figure 9-3.

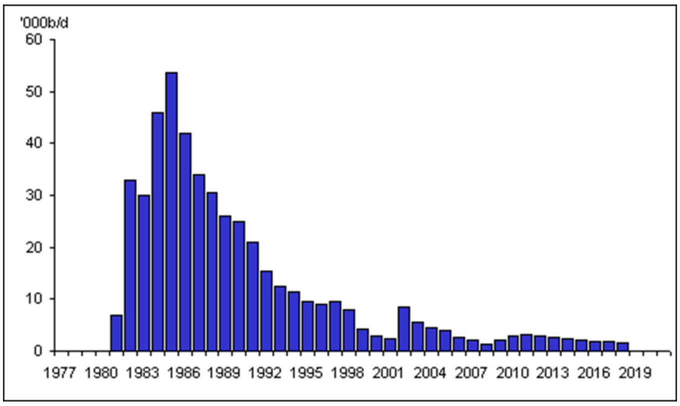


Figure 9-3: Beatrice Production Profile

The development history of the infrastructure is summarised in Figure 9-4 (Repsol Sinopec, 2017).

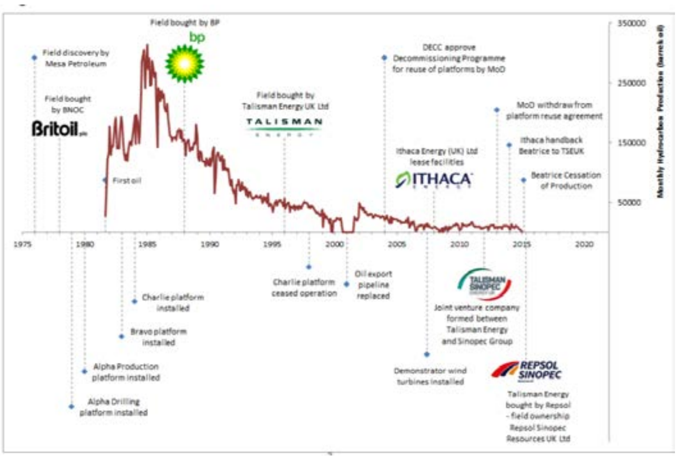


Figure 9-4: Histroy of Development at Beatrice

9.1.3 Wind Turbine Project

A general layout diagram of the Beatrice oilfield infrastructure is provided as Figure 9-5 (Repsol Sinopec, 2017). Figure 9-6 shows a photograph of one of the turbines next to two of the Beatrice oil platforms.

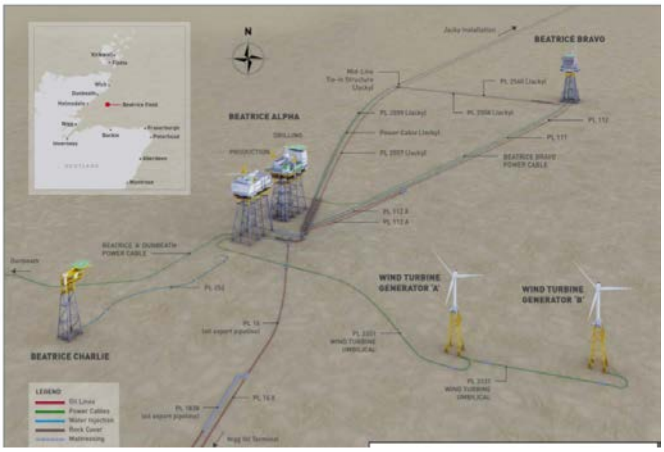


Figure 9-5: General Layout Diagram of Beatrice Infrastructure

Figure 9-6: Beatrice AD and AP Platforms with one of the 5MWe turbines

9.2 Decommissioning

The decommissioning plan is currently under development. The broad scope of decommissioning work includes:

- The plugging and abandoning of all 43 Beatrice wells;
- The flushing and cleaning of topsides and the main oil export pipeline (note that all infield pipelines relevant to the decommissioning programme have already been cleaned and disconnected);
- Removal of special wastes and topside modules and return to shore for recycling or disposal;

- The removal of platform jackets and return to shore for recycling;
- The decommissioning of pipelines and removal of other subsea infrastructure and deposits (e.g. mattresses);
- The removal of two wind turbine generators and associated jackets and recovery to shore for recycling or disposal; and
- The decommissioning of subsea power cables.

Further details regarding the current plan and options are available in the Beatrice Decommissioning Environmental Impact Assessment Scoping Report from May 2017 (Repsol Sinopec, 2017)

9.3 Re-use Opportunities

With such a diverse infrastructure base, a near coast location and moderate water depths there have been, and continue to be, many potential re-use opportunities for part or all of the Beatrice infrastructure. Repsol Sinopec Resources UK are considering other reuse options for the facilities, and this will be a key consideration leading to a final decision on the nature and timing of field decommissioning.

A decommissioning programme for Beatrice for the reuse of the platforms was originally approved in 2004 by the former UK DTI (relevant regulatory functions now within BEIS and OGA). This programme was based on an agreement with the UK's Ministry of Defence (MoD) for them to use the platforms for military training after Cessation of Production (CoP). The MoD has subsequently exercised their right to terminate the agreement, and therefore the decommissioning programme is required to be updated. Cessation of Production was granted for the Beatrice Field in 2014 when continued production was considered to no longer be economically viable. In addition, the field life extension options that were investigated were all found to be sub-economic.

Other potential options for partial or full re-use of the facilities have included:

Option	Highlights
Offshore Transmission Module for BOWL	The large SSE-led Beatrice Offshore windfarm is a stand-alone development of over 80 wind turbines located just north of the Beatrice oilfield.
CO_2 Storage	Potential to use the site for CO_2 Injection was briefly considered
Hydrogen Storage	Ongoing interest exists in the potential role for bulk underground hydrogen storage as a means to storing constrained wind farm output
Community Windfarm development	The potential to refurbish the offshore wind demonstrator and export power back to the grid and local community via the existing power import cable.

Table 9-1: Reuse Options considered by a range of interested parties

9.3.1 Offshore Transmission Module

The large SSE led Beatrice Offshore Windfarm Ltd (BOWL) is a 588MW wind farm project currently in construction. The project carries a requirement for the installation of an offshore transmission module on a jacket structure. Despite the availability of five nearby jackets used for oilfield development, the operator found it most cost effective to plan the installation of a new dedicated OTM facility during 2018. The reasons for this are not known but may be connected with assurance of 25-year service life and the high cost associated with modifying offshore platforms (brownfield modifications).

9.3.2 CO_2 Storage

Whilst the field is ideally close to landfall, affording a very low-cost CO_2 transport link to the platform, the environment at the landfall is a rural area with very low emissions intensity. As a result, the use of the field for CO_2 storage has only really been contemplated for academic motives. This has included some consideration of using CO_2 for enhanced oil recovery. The total absence of a large industrial emissions point in the area means that there is effectively no current reuse option which involves CO_2 storage at scale.

9.3.3 Hydrogen Storage

The development of the large Beatrice Offshore Windfarm has created an upsurge of interest in the potential to use the subsurface reservoir for storing hydrogen gas which is electrolysed from offshore wind power when the grid is constrained. The alternative is for the wind farm to be paid by the National Grid not to despatch power. The constraint payments available to offshore wind operators is falling year on year and operators are now looking at alternatives to enable the continued monetisation of the offshore wind generation infrastructure even when the grid is constrained. Hydrogen electrolysis and storage is a potential solution for this and the offshore field or parts of it have been considered for hydrogen storage. The platforms could therefore be considered to host the electrolysis and fuel cell regeneration equipment at the wellhead.

Such considerations are pre-commercial at this time and unlikely to factor into a commercial re-use opportunity for a range of technical, commercial and timing reasons.

9.3.4 Community Windfarm Development

A small project developer has considered acquisition of the two 5MWe offshore wind turbine demonstrators together with the Beatrice power import facilities to enable the continued production of renewable energy and export to the grid connection at Dunbeath. The output is believed to be limited by the power demands of the platform and a direct subsea connection of the turbines to the power import line would be required to achieve a direct grid connection. There is also a reported issue with main hub bearings which requires rotor removal for repair. Both turbines are currently switched off and are free rotating. They have not operated since December 2014. The current plan is to leave the turbines to free rotate and decommission them alongside the platforms.

Commercial challenges around ownership and access agreements prevented this option from being developed further.

9.3.5 Final Decision

Repsol Sinopec Resources UK continue to consider other reuse options for the facilities, and this will be a key consideration leading to a final decision on the nature and timing of field decommissioning.

9.3.6 Infrastructure Reusability Index

The suitability assessment approach described in Section 4.5 has been applied to the Beatrice asset assuming that the development scenario calls for a CO_2 supply of gas phase 1MT/year for 20 years. The results of the assessment are shown in Table 9-2 and Figure 9-7.

Criteria	Score	Comment
Reservoir	**0**	**Unlikely to be suitable**
Seal	1	Might be OK
Injectivity	0	Low due to the reservoir pressure
Capacity	0	Insufficient due to reservoir pressure
Compartmentalisation	0	May be problematic
Wells	**0**	**Wells unlikely to be suitable**
Bottom Hole Location	0	Unlikely to be suitable
Size of Production Casing	1	OK
Maximum Operating Pressure	0	Unknown
Suitability of Tree	0	Would need to be replaced
Platform	**8**	**Platform might be suitable**
Remaining Design Life	2	OK, could be extended
Size and Load-bearing Capacity of Jacket	2	OK, could be increased
Power Capacity	2	OK
Adaptability of CO_2 Operations	2	OK
Subsea	**0**	**Not applicable**
Power Supply	0	Not applicable
Controls	0	Not applicable
Remaining Design Life	0	Not applicable
Pressure Rating, materials	0	Not applicable
Pipeline	**8**	**Pipeline might be suitable**
Maximum Operating Pressure	2	OK
Materials	2	OK
Throughput Capacity	2	OK
Remaining Design Life	2	OK

Table 9-2: Beatrice Suitability Assessment

Figure 9-7: Beatrice Suitability Assessment Chart

10.0 Conclusions & Recommendations

10.1 Conclusions

Concepts

- As has been reported by many authors previously, depleted oil and gas reservoirs can often be re-used for storing CO_2.
- The production strategy used during the hydrocarbon extraction phase determines the reservoir pressure at the commencement of CO_2 operations and this in turn influences the amount of CO_2 that can be stored without breaching the fracture pressure constraint.
- Key aspects to consider when evaluating a field for re-use include: regional geology, reservoir architecture, hydraulic communication and containment.
- Containment should be considered from both geological and an engineering (or legacy wells) perspectives.
- Depleted oil and gas fields will typically have plenty of relevant data with which to assess its' suitability for CO_2 storage operations.
- The six key elements of infrastructure that might be re-used for CO_2 operations are: pipeline, umbilicals, platforms (including jackets), subsea manifolds, wells and onshore facilities.
- The key attributes determining whether any item of infrastructure could be re-used are integrity and life extension options.
- In general, all elements of infrastructure have the potential to be re-used for CO_2 operations. However, all specific cases need to be evaluated on a project by project basis.
- Additional generic studies about the potential for re-use are unlikely to add significant new knowledge to the sector.

Practicalities

- The functional specification for re-use of a depleted oil and gas reservoir has four elements: containment, injectivity, connectivity and capacity.
- It is not feasible to define a generic functional specification for re-use of a depleted oil or gas field because its suitability depends on the specific requirements of the project such as longevity, CO_2 injection rate, CO_2 phase and capacity, all of which are characteristics of the CO_2 supply.
- From an infrastructure perspective, the primary functional specification is one of sufficiency. The equipment must have a pressure rating and material specification sufficient for the proposed project, the remaining longevity must be sufficient, and the installation must have sufficient space, power and weight bearing capability.
- A CO_2 injection operation requires less complex processing systems than a hydrocarbon operation.
- The safety systems for CO_2 operations are fundamentally different than for hydrocarbon production.
- Often, hydrocarbon production installations generate their own electricity by burning some of the produced methane in a turbine. This option is not available for CO_2 operations; a different means of power generation would be required.
- Decommissioning of subsea infrastructure, pipelines and umbilicals is treated on a case by case basis, however decommissioning of smaller and/or newer platforms is complete removal and the design should take this into account.
- A suitability assessment tool has been built for this project and early indications of its

usefulness in evaluating the re-use potential of existing infrastructure are promising.

Experience

- The five case studies summarised in the report cover a platform that has been decommissioned, three examples of infrastructure considered for re-use for CO_2 operations and one example of the re-use options for an offshore wind farm.
- Key insights from the case studies are that each situation is unique to a degree.
- Costs are important in deciding whether or not to re-use infrastructure, but they are not the sole criterion. Many other factors are considered in the decision-making process such as; corporate motivation, strategic preferences, perceptions of risk and concerns about the complexity of brownfield modification and likelihood of cost overruns.
- Most situations that have contemplated re-use for CO_2 have planned to operate in dense phase.

Case Studies

- The suitability assessment of the Camelot field indicated that the reservoir is the only element that would be suitable for re-use in a CO_2 storage context.
- The suitability assessment of the Atlantic and Cromarty fields indicated that both the pipeline and the reservoir would be suitable for re-use in a CO_2 storage context.
- The suitability assessment of the Hamilton field indicated that the reservoir and pipeline are well suited to re-use in a CO_2 storage context and that the platform and wells may be suitable with some modifications or in specific development cases.
- The suitability assessment of the Goldeneye field indicated that the reservoir, pipeline, wells and platform are all likely to be suitable for re-use in a CO_2 storage context.
- The suitability assessment for the Beatrice field indicated that the pipeline and platform are likely to be suitable for re-use in a CO_2 storage context, providing that a nearby storage unit is available.

10.2 Recommendations

- Commission further work to develop a clearer understanding of how the financial security guidance document will be applied and some worked examples for specific situations would be useful for the industry.
- Examine options for extending the life of infrastructure assets.
- Consider the regulatory processes and procedures in other jurisdictions and identify any important differences with those described in this report.

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Appendix A: Glossary

Defined Term	Acronym	Definition
1C		Denotes low estimate scenario of Contingent Storage Resources.
2C		Denotes best estimate scenario of Contingent Storage Resources.
3C		Denotes high estimate scenario of Contingent Storage Resources.
Aeolian		Pertaining to material transported and deposited (aeolian deposit) by the wind. Includes clastic materials such as dune sands, sand sheets, loess deposits, and clay.
Air Gap		Term used to denote the distance between the lower deck of a platform and the sea level.
Alluvial Plain		General term for the accumulation of fluvial sediments (including floodplains, fan and braided stream deposits) that form low gradient and low relief areas, often on the flanks of mountains.
Base Year		The common year to which discounted quantities are referenced for all stores.
Basin		A low lying area, of tectonic origin, in which sediments have accumulated.
Department for Business, Energy and Industrial Strategy	BEIS	The UK government department that deals with the regulation and approval of offshore oil and gas decommissioning.
Bottom Hole Pressure	BHP	This the pressure at the mid point of the open perforations in a well connected to a reservoir system.
Central North Sea	CNS	
Clastic		Pertaining to rock or sediment composed mainly of fragments derived from pre-existing rocks or minerals and moved from their place of origin. Often used to denote sandstones and siltstones.
Closed		Describes the pressure isolation of a subsurface pore space from adjacent pore spaces which may limit the injected inventory achieved.
Closure		A configuration of a storage formation and overlying caprock formation which enables the buoyant trapping of CO_2 in the storage formation.
CO_2 Plume		The dispersing volume of CO_2 in a geological storage formation.
Common Data Access Ltd.	CDA	A wholly-owned subsidiary of Oil & Gas UK. The company was established by industry in 1995 with the aim of sharing the costs and benefits associated with managing subsurface Exploration and Production data through collaborative working.
Containment Failure Mechanism		The geological or engineering feature or event which could cause CO_2 to leave the primary store and/or storage complex.
Containment Failure Modes		Pathways for CO_2 to move out of the primary store and/or storage complex which are contrary to the storage development plan.
Containment Risk Scenario		A specific scenario comprising a Containment Failure Mechanism and Containment Failure Mode which might result in the movement of CO_2 out of the primary store and/or storage complex.
Cessation of Production	CoP	Cessation of production of an offshore oil and gas field.
Darcy	D	Industry unit of permeability equal to 10(^-12) m^2.

Defined Term	Acronym	Definition
Evaporite		Sediments chemically precipitated due to evaporation of water. Common evaporates can be dominated by halite (salt), anhydrite and gypsum. Evaporites may be marine formed by the evaporation within an oceanic basin, or non-marine typically formed in arid environments.
Facies (Sedimentary)		A volume of rock that can be defined and recognised by a particular set of characteristics (physical, compositional, chemical) often reflecting its environment of deposition.
Fault		Fracture discontinuity in a volume of rock, across which there has been significant displacement as a result of rock movement.
Final Investment Decision	FID	Decision gate prior to a large capital investment into a project.
Floating Production Storage and Offloading	FPSO	A floating vessel used for the production, processing and storage of hydrocarbons.
Fluvial		Pertaining to or produced by streams or rivers.
Formation		A formation is a geological rock unit that is distinctive enough in appearance and properties to distinguish it from surrounding rock units. It must also be thick enough and extensive enough to capture in a map or model. Formations are given names that include the geographic name of a permanent feature near the location where the rocks are well exposed. If the formation consists of a single or dominant rock type, such as shale or sandstone, then the rock type is included in the name.
Front End Engineering Design	FEED	
Gardner's Equation		A relationship between seismic velocity V in ft/s (ie. the inverse of the sonic log measured in ms/ft) and density r in g/cm3 for saturated sedimentary rocks. The equation was proposed by Gardner et al (1974) based on lab experiments and is of the form r=aVb. Typically, a=0.23 and b=0.25 but these values should be refined if measured V and r are available for calibration.
Halokinesis		The study of salt tectonics, which includes the mobilization and flow of subsurface salt, and the subsequent emplacement and resulting structure of salt bodies.
Heavy Lift Vessel	HLV	A vessel specifically designed to lift very large loads.
Heating, Ventilation, Air Conditioning	HVAC	
Horizontal Directional Drilling	HDD	A method of installing underground pipe or cable that does not require trenching/excavation. Directional drilling is controlled from a surface located drill rig.
Hydraulic Unit		A Hydraulic Unit is a hydraulically connected pore space where pressure communication can be measured by technical means and which is bordered by flow barriers, such as faults, salt domes, lithological boundaries, or by the wedging out or outcropping of the formation (EU CCS Directive).

Defined Term	Acronym	Definition
International Maritime Organisation	IMO	A specialised agency of the United Nations responsible for regulating shipping.
Leak		The movement of CO_2 from the storage complex.
Levelised Cost		The levelised cost of transportation and storage for a development is the ratio of the discounted life-cycle cost to the discounted injection profile. Both items discounted at the same discount rate and to the same base year.
Maximum Flooding Surface	MFS	This is a geological surface which represents the deepest water facies within any particular sequence. It marks the change from a period of relative sea level rise to a period of relative sea level fall. an MFS commonly displays evidence of condensed or slow deposition. Such surfaces are key aids to understanding the stratigraphic evolution of a geological sequence.
Mega Watt electric	MWe	The electric output of a power plant in megawatt.
Mono Ethylene Glycol	MEG	An anti-freeze chemical commonly injected into oil and gas production pipelines.
Normally Unmanned Installation	NUI	A type of offshore installation designed to be operated remotely without the constant presence of personnel.
Oil and Gas Authority	OGA	An executive agency of the UK government's Department for Business, Energy and Industrial Strategy. Its role is to work with industry and government to maximise the economic recovery of UK oil and gas.
Outline Storage Development Plan	OSDP	The Outline Storage Development Plan defines the scope of the application process for a storage permit, including identification of required documents. These documents, include a Characterization Report (CR), an Injection and Operating Plan (IOP) (including a tentative site closure plan), a Storage Performance Forecast (SPF), an Impact Hypothesis (IH), a Contingency Plan (CP), and a Monitoring, Measurement and Verification, (MMV) plan.
Oslo / Paris Conventions	OSPAR	The mechanism by which 15 governments and the EU cooperate to protect the marine environment of the North-East Atlantic.
Playa Lake		A shallow, intermittent lake in an arid or semiarid region, covering or occupying a playa in the wet season but drying up in summer; an ephemeral lake that upon evaporation leaves or forms a playa.
Pipeline End Termination	PLET	
Primary Migration		The movement of CO_2 within the injection system and primary reservoir according to and in line with the Storage Development Plan
Remotely Operated Vehicle	ROV	
Rowan CCS Project		A full chain ICCS project concept in NW England which may reuse elements of the Hamilton infrastructure
Sabkha		A flat area of sedimentation and erosion formed under semiarid or arid conditions commonly along coastal areas but can also be deposited in interior areas (basin floors slightly above playa lake beds).
Secondary Migration		The movement of CO_2 within subsurface or wells environment beyond the scope of the Storage Development Plan.

Defined Term	Acronym	Definition
Silver Pit Basin		Located in the northern part of the Southern North Sea. Over much of the basin up to 400 m of Silverpit Formation interbedded shales and evaporites are present. The absence of the Leman Sandstone reservoir over much of the basin has meant that gas fields predominate in the Carboniferous rather than in the Permian, as is the case in the Sole Pit Basin to the South.
Simultaneous Operations	SIMOPS	
Site Closure		The definitive cessation of CO_2 injection into a Storage Site.
Single Lift Vessel	SLV	A vessel designed to lift platform topsides off in one lift. In the Southern North Sea these can be smaller topsides and therefore vessels, but in the Central and Northern North Sea these are specifically deigned to lift very large topsides in one lift.
Southern North Sea	SNS	
Subsea Isolation Valve	SSIV	An emergency shutdown valve located subsea used to protect an offshore facility from uncontrolled release of pipeline fluids or gases.
Storage Complex		The Storage Complex is storage site and surrounding geological domain which can have an effect on overall storage integrity and security; that is, secondary containment formations (EU CCS Directive).
Storage Site		Storage Site is a defined volume within a geological formation that is or could be used for the geological storage of CO2. The Storage Site includes its associated surface and injection facilities (EU CCS Directive).
Storage Unit		A Storage Unit is a mappable subsurface body of reservoir rock that is at depths greater than 800 m below sea level, has similar geological characteristics and which has the potential to retain CO_2 (UKSAP).
Stratigraphic Column		A diagram that shows the vertical sequence of rock units present beneath a given location with the oldest at the bottom and youngest at the top.
Stratigraphy		The study of sedimentary rock units, including their geographic extent, age, classification, characteristics and formation.
Subsea Control Module	SCM	An underwater component of an oil and gas production system providing control of hydraulic power, electrical power and communications to subsea infrastructure.
Subsurface safety valve	SSSV	A fail-safe valve located within the well bore to protect the offshore facility or environment from an uncontrolled release of fluids or gases from the reservoir.
Tectonic		Relating to the structure of the earth's crust, the forces or conditions causing movements of the crust and the resulting features.
TEE		Branch connection to a pipeline or flowline
Tubing Head Pressure	THP	The pressure at the top of the injection tubing in a well downstream of any choke valve.
Umbilical Termination Assembly	UTA	A component located at the end of a subsea umbilical that breaks out the hydraulic, chemical and electrical services.
United Kingdom Continental Shelf	UKCS	

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