
# Engineering Requirements for Offshore $CO_2$ Transportation and Storage:

## A Summary Based on International Experiences

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# 中英（广东）CCUS 中心
## UK–China (Guangdong) CCUS Centre

In 2009, China's State Council proposed its 2020 goal for greenhouse gas emissions, and then in 2010 made Guangdong a low carbon pilot province. Guangdong has made remarkable achievements in greenhouse gas emission control to which the UK-China low carbon cooperation has contributed significantly. In September 2013 the UK Department of Energy and Climate Change (DECC) signed a joint statement in London with the Guangdong Development and Reform Commission, witnessed by governor Zhu Xiaodan of Guangdong Province, to strengthen low carbon cooperation. The joint statement highlights the importance of collaborating in Carbon Capture and Storage (CCS). Supported by the Guangdong and UK governments, the UK-China (Guangdong) Carbon Capture, Utilisation and Storage Industry Promotion and Academic Collaboration Centre (the "Centre") was officially founded on December 18th, 2013. The Centre is committed to promoting the demonstration of large-scale CCUS projects to tackle greenhouse gas emissions. At the same time, the Centre will also provide an international collaboration platform for solutions to other local pollution problems (such as haze, water pollution) caused by coal utilization, and to accelerate the industrialization for clean fossil energy technologies and to train qualified professionals.

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# Disclaimer



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# Contents

# Introduction

For CCUS deployment in Guangdong Province the feasible model is to capture $CO_2$ from a large point source along the coast, pre-process the captured $CO_2$ at a nearshore station, utilize a small portion of the $CO_2$, transport most $CO_2$ through pipeline or ship and store the $CO_2$ in offshore geological sites (GDCCSR, 2013). The reuse of legacy pipelines and infrastructure in depleted oil fields for $CO_2$ transport and storage is an option having the potential of reducing costs. In order to use the existing infrastructure for $CO_2$ storage, it is essential to carry out feasibility studies several years ahead of the fields' depletion, so that the fields have enough time to make them storage-ready (GDCCSR-SCSIO, 2013).

To date there is no full-chain CCUS project involving offshore storage in China. This report gives a general review on major engineering requirements and their relevance and justification for offshore $CO_2$ transportation and storage based on international experiences. The capital costs are mentioned briefly. The geological and system integration issues are expected to be covered in other reports.

The text presented here is mainly based on the FEED studies on the Longannet project by ScottishPower CCS Consortium and on the Kingsnorth project by E.ON CCS Consortium in UK (see **Box 1** for a brief of the two projects), while referencing other sources occasionally. For the limitations in work time and authors' knowledge, we do not assure the completeness of the report.

**Box 1.** FEED studies on the Longannet and Kingsnorth CCS projects in UK

The Front End Engineering and Design (FEED) studies of the Kingsnorth and Longannet projects were funded by the Department of Energy and Climate Change of UK in March 2010 and were carried out by E.ON CCS Consortium and ScottishPower CCS Consortium respectively. These two projects were dropped for cost and other reasons. But all the documents resulting from these studies are published online to ensure the lessons learned from the studies are disseminated as widely as possible to advance the roll-out of Carbon Capture and Storage.

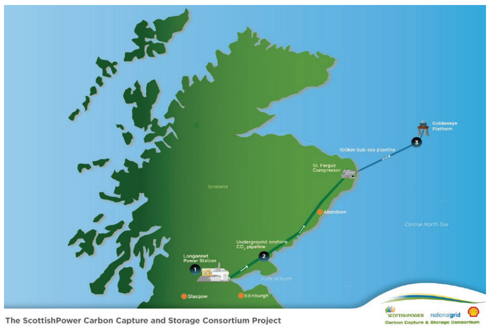
**The Kingsnorth project was designed to consist of:**

1. two 800MW power generating units at Kingsnorth power station,
2. a 300MW (net) post combustion carbon capture plant integrated into the power plant with associated dehydration and compression facilities,
3. a new 270 km (mostly offshore) 36”(900 mm) diameter high pressure pipeline for transport $CO_2$ to the Hewett gas field in the southern North Sea.
4. new platform, injection facilities, and wells built at this field for $CO_2$ injection.

**The Longannet project was designed to consist of:**

1. the Longannet power station,
2. a carbon capture plant,
3. >387 km mostly existing on- and off-shore pipelines for transportat $CO_2$ through the onshore compressor stations to the offshore depleted Goldeneye condensate and gas field in the North Sea,
4. reusing the existing platform and wells at this field for $CO_2$ injection.

Both projects were intended to capture, transport, and inject 20 million tonnes of $CO_2$ into offshore depleted gas fields over a period of 10-15 years for permanent storage.


**Left:** The Kingsnorth Carbon Capture and Storage Project

**Right:** The Longannet Carbon Capture and Storage Project

*The FEED documents of these projects are available on the following web pages:*

*http://webarchive.nationalarchives.gov.uk/20121217150421/http://decc.gov.uk/en/content/cms/emissions/ccs/ukccscomm_prog/feed/e_on_feed_/e_on_feed_.aspx*

*http://webarchive.nationalarchives.gov.uk/20121217150421/http://decc.gov.uk/en/content/cms/emissions/ccs/ukccscomm_prog/feed/scottish_power/scottish_power.aspx*

# Chapter 1

# Properties of $CO_2$ to be considered in Transport and Storage

To understand the engineering issues related to the transport and storage of $CO_2$, it is necessary to be aware of its physical properties. In this chapter the pertaining properties of $CO_2$ are discussed. Because the techniques used for $CO_2$ transportation and storage are to various degree similar to those used for natural gas transportation and production, and because it is possible to reuse some of the existing infrastructure for hydrocarbon transportation and production for CCS purpose, the properties of $CO_2$ that differ from those of natural gas are emphasized in these discussions.

## 1.1 $CO_2$ phase diagram

Pure $CO_2$ is a colorless, odorless, and non-flammable substance which can exist in solid, liquid, gas, or supercritical phases. On the $CO_2$ phase diagram **(Fig. 1.1)**, three points are of importance:

- The sublimation point at -78°C and 1 bar, at which solid $CO_2$ sublimates to a gas.
- The triple point at -56.5°C and 5.1 bar, which is the junction point of solid, liquid, and gas phases.
- The critical point at 31°C and 73.9 bar, above which $CO_2$ occurs as a single supercritical fluid, which has a liquid density but moves as a gas. This is the preferred state for an efficient $CO_2$ storage.

In the literature the term “dense-phase liquid” or “dense state” is used to describe a high-density liquid $CO_2$ above critical pressure but below critical temperature. This is generally considered as a desired state for an efficient $CO_2$ transportation, but in some cases low pressure $CO_2$ transportation is also considered (see Chapter 2 for more discussions).

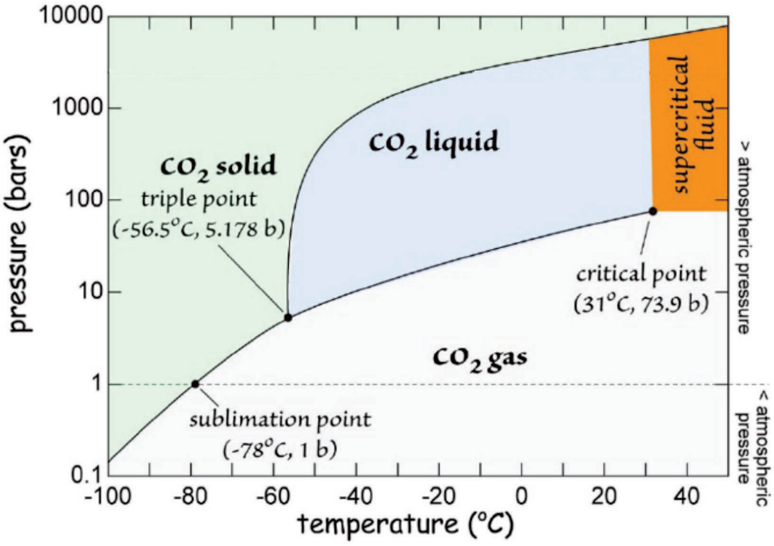



**Figure 1.1.1** $CO_2$ phase diagram showing the locations of its four important phase fields and its triple and critical points. (Copyright J.D. Myers. WSGS, 2013.)

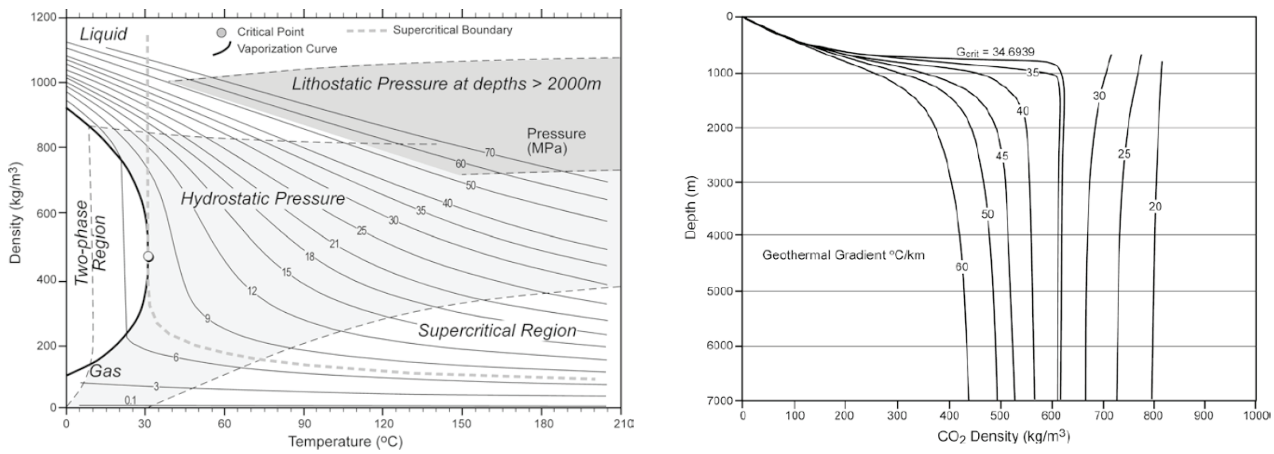
## 1.2 $CO_2$ density

At ground level $CO_2$ is about 1.5 times denser than air and is likely to accumulate in basements, trenches and low points in the landscape.

The density of $CO_2$ varies as a function of temperature and pressure **(Fig. 1.2.1a)**. At underground levels, the $CO_2$ density increases non-linearly with depth as a function of surface temperature and geothermal gradient, assuming hydrostatic pressure at depths **(Fig.1.2.1b)**. For $CO_2$ geological storage it would be more efficient to have high density $CO_2$, Therefore, the reservoir depth>800m is usually required because at these depths $CO_2$ is in supercritical state with high density, and the “cold” sedimentary basins with low geothermal gradient are more favorable than “warm” basins (Bachu, 2003).

**Figure 1.2.1**
**a)** $CO_2$ density as a function of temperature and pressure.
**b)** $CO_2$ density as a function of depth and geothermal gradient, assuming hydrostatic pressure and surface temperature of 5°C. From Bachu (2003).

**a)** **b)**



## 1.3 Joule-Thomson effect

When $CO_2$ expands inside a vessel or a pipeline during depressurization, significant chilling occurs. This is called the Joule-Thomson effect, which varies with conditions. The chilling of $CO_2$ due to pressure decrease or expansion can cause cooling and embrittlement of pipelines and wells which may become less resilient to stress and fracture. Materials of construction must be chosen with care. All equipment and pipework will be constructed of materials that have sufficient elasticity over the range of operating conditions so that they are resistant to brittle fracture. Chilling of $CO_2$ can also result in volume changes of borehole casing, which can weaken a cement bond to surrounding rock. Inadvertent chilling can also result in $CO_2$ phase change, or dissociation of mutually dissolved impurities so that multiphase fluids are created in pipelines or porespace. These effects must be understood and controlled.

## 1.4 Corrosion

The presence of water in $CO_2$ flow may cause the formation of corrosive acids. The water in solution in the $CO_2$ does not cause problem. But free water combined with $CO_2$ forms carbonic acid ($H_2CO_3$) which is detrimental to equipment manufactured from unprotected mild steel components, such as carbon steel pipelines and components. Carbon acid may dissolve also borehole cement (Portlandite), which may cause sheath defects and accelerate cement degradation. In the presence of free water corrosion rates are accelerated when the $CO_2$ is concentrated and under elevated pressures.

## 1.5 Hydrate formation

The presence of water and at elevated pressures and ambient seabed temperature, $CO_2$ hydrates can form which could cause blockages in equipment, valves, pipelines and wells.

## 1.6 Effect of Impurities

The $CO_2$ composition varies depending on the $CO_2$ source. The amount and type of impurities in captured $CO_2$ are dependent on the combustion and capture technology, and on any regulatory limits on impurities. Main impurities in the $CO_2$ stream from post-combustion capture are $H_2O$, $N_2$, $O_2$, $H_2S$, $H_2$, and CO.

The existence of impurities in $CO_2$ may affect significantly the water solubility. When impurities such as $H_2S$, $NO_x$, $SO_x$, $O_2$ and water are present, leading to the formation of stronger acids ($HNO_3$, $H_2SO_4$). These will enhance the rate of corrosion.

Some impurities may change physical properties of the $CO_2$ stream, such as the pressure and temperature of critical points **(Fig. 1.6.1)**, as well as the density and viscosity of the $CO_2$ stream.

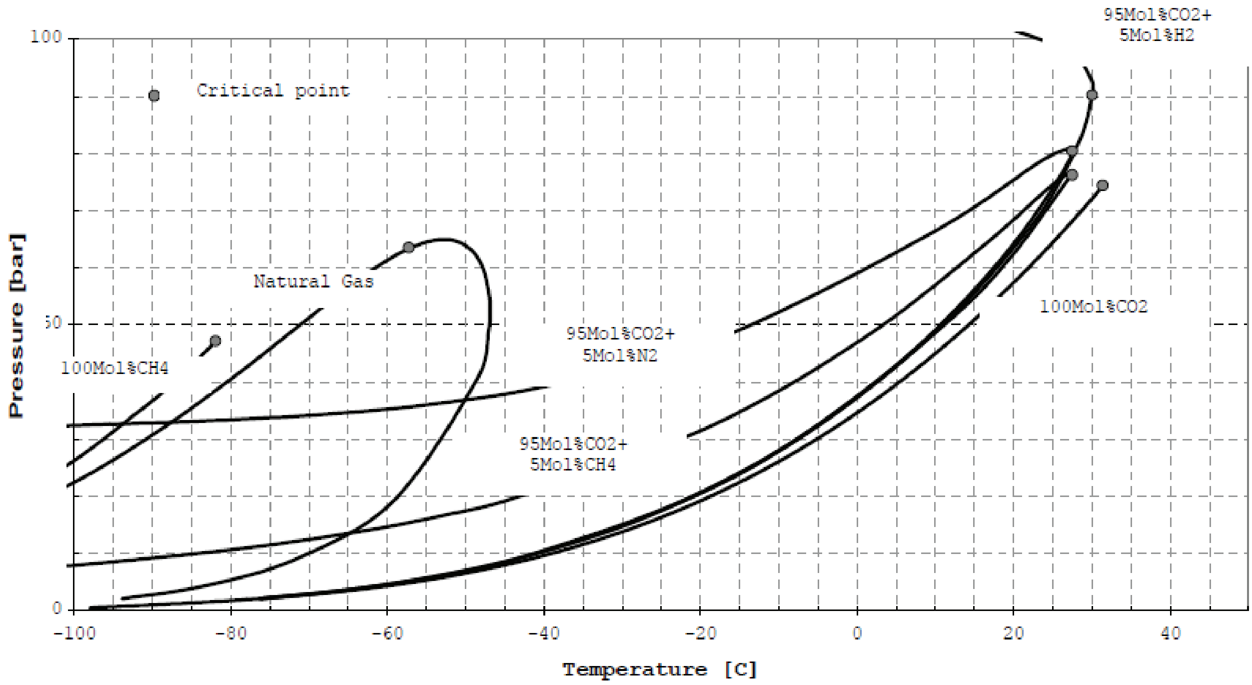



**Figure 1.6.1** Effect of selected impurities $CO_2$ on phase envelope comparison with Natural Gas (DNV, 2010b).

Some combinations, particularly if $H_2$ or $N_2$ are present, cause higher pressure and temperature drops for a given pipeline length, thus the pipeline may have to be operated at a higher pressure in order to maintain it as single-phase supercritical or dense-phase. This could require more compressor stations along the pipeline, which is not economically viable for subsea pipelines. Sudden temperature drops can have potential implications for materials choices, such as embrittlement, and can also cause hydrate formation, both of which could damage the pipeline.

## 1.7 Dense phase $CO_2$ as solvent

The dense phase $CO_2$ exhibits good solubility to a wide range of organic compounds, particularly chlorine/fluoride based component. This is detrimental to elastomers commonly used in sealing parts such as valves, gaskets, coatings and O-rings. At high pressures the low viscosity, almost zero surface tension, and high fluidity allow the dense phase $CO_2$ to diffuse into the elastomers and rubber. When the pressure is reduced rapidly, degassing occurs, the $CO_2$ may not exit from the material fast enough, and then blistering and even explosions can occur as the material decompresses. Use of porous materials should therefore be avoided.

Dense phase and supercritical $CO_2$ are good solvents for oils and waxes and certain inorganic solids and will strip such material from bearings or rotating seals if they are exposed to the $CO_2$. Any compounds dissolved in the $CO_2$ during its journey are likely to be deposited in the cooler pipeline sections of the transport system.

## 1.8 $CO_2$ compared with natural gas

Existing infrastructure for hydrocarbon production and transportation may be used for CCS to reduce the cost. However, the difference in thermodynamic and chemical properties of $CO_2$ from those of natural gas along the process chain should be considered.

**1. The difference in flow state.**

Natural gas is always transported in its gaseous state in high-pressure pipelines. Design pressures of up to 100 bar are generally used for onshore gas transmission systems, while offshore transmission pipelines may have an operational pressure up to, or even beyond, 200 bar. By contrast, when $CO_2$ is transported, the fact that the $CO_2$ may be in its gaseous, liquid or dense state – depending on the operating pressure – has to be taken into consideration. Phase transitions should be avoided. In any case the operating conditions must ensure a single-phase flow, either gaseous or liquid. This is because 1) two-phase flow is almost always less efficient compared with single phase of vapour or liquid; 2) two-phase flow in the pipeline could cause cavitation and pressure peaks and would most likely damage the pipeline (Nimtz et al., 2010); 3) under certain operating conditions, gas and liquid may not be evenly distributed throughout the pipeline, but instead travel as large plugs (or 'slugs') of mostly liquid or mostly gas (GCCSI, 2013). Slugging effects will lead to vibrations and potential equipment damage (ROAD, 2012). Thus, the pressure and temperature conditions for $CO_2$ transport need to be planned toensure single phase transport from inlet to outlet of pipelines (IEA, 2014). This includes engineered input pressures, and also external ambient temperatures, and especially surface and subsurface topography. Flow assurance study through network modeling and transient multiphase simulation is needed to help defining the $CO_2$ specifications to prevent the occurrence of two-phase flow and hydrate at designed T/P conditions.

### 2. Pressure control.

Because of the single-phase requirement for $CO_2$ stream, the pressure control becomes critical. Starting and stopping $CO_2$ flow along a pipe also has important consequences for pressure pulses. Injection into sub-hydrostatic pressure deep saline aquifers, and flow rate or phase transitions along a vertical borehole can also induce transient effects which are difficult to manage.

### 3. Corrosion.

$CO_2$ in the presence of water and $H_2S$ is corrosive. This is detrimental to carbon steel pipelines and some metal parts, also may case cement dissolution and thus a loss of strength. Corrosion may occur in discrete pockets – at valves, junctions, bends or topographic sumps – so attention to detail is important. The supercritical and dense phase $CO_2$ is a detrimental solvent to the elastomers commonly used in valves, gaskets, coatings and O-rings.

### 4. The Joule-Thomson effect.

At 0°C condition the Joule-Thomson effect is in the region of 1.6°C/ bar for $CO_2$, higher than ~1.0°C/bar for natural gas. This means that $CO_2$ will chill faster than that of natural gas during expansion and resulted in stronger chilling and embrittlement effect.

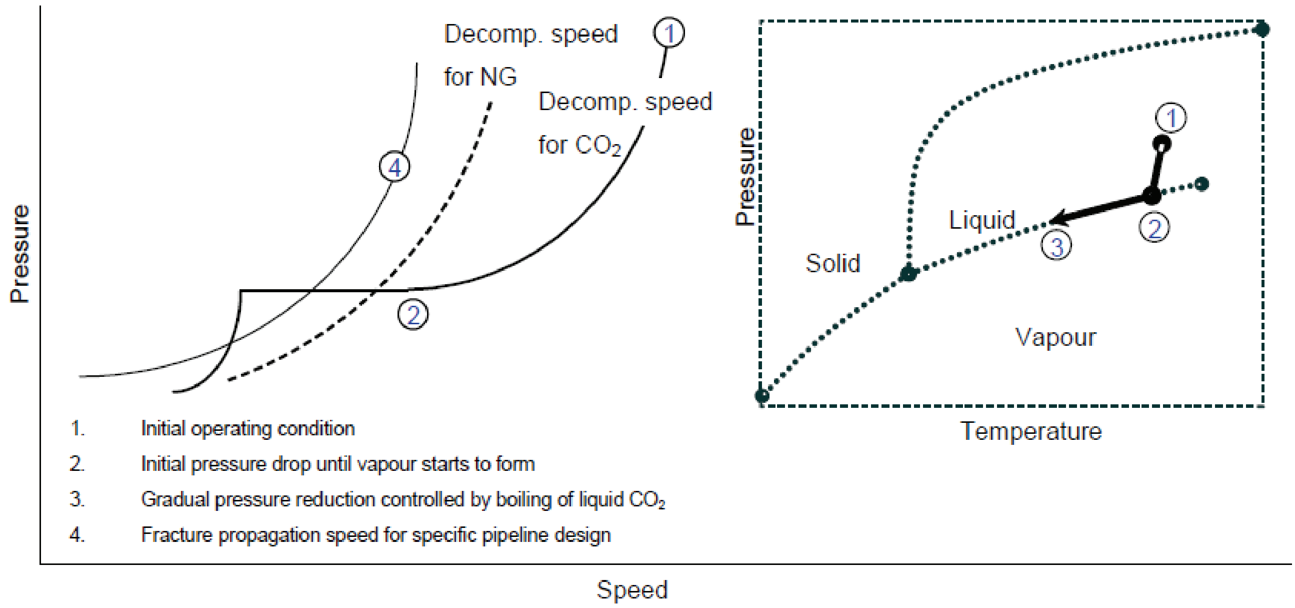
### 5. Running ductile fracture.

The pipeline shall have adequate resistance to propagating fracture. To prevent ductile running fractures, the decompression speed of the fluid needs to be higher than the fracture propagation speed of the pipe wall.

The particular issue related to $CO_2$ is the step change in decompression speed. As shown in **Fig. 1.8.1**, the decompression speed of liquid $CO_2$ may be significantly higher than that of natural gas. However, as the pressure drops down to the liquid-vapour line (saturation pressure), vapour starts to form, the decompression speed of the $CO_2$ stream drops significantly. To that extent running ductile fractures is a higher concern for $CO_2$ pipelines compared to natural gas pipelines.

Figure 1.8.1 Schematic diagram showing particular effects of decompression speed for $CO_2$ relative to fracture propagation speed of pipe wall.
Insert figure shows schematically phase envelope for pure $CO_2$.
From DNV(2010b)

This should be considered in the design pressure of the pipeline. For low design pressure (typically less than 150 bar) thin-walled pipeline, $CO_2$ pipelines may come out worse compared to natural gas pipelines. This may, however, not be the case for higher design pressure (thick-walled) pipelines (DNV, 2010b).




## 6. Hazards.

Unlike natural gas, which is combustible with explosion and dire risk, $CO_2$ is not combustible but is asphixiant. See Chapter 4 for more discussions.

Chapter 2

# $CO_2$ Transport to Offshore Storage Sites

## 2.1 Selection of transport scheme

### 2.1.1 Transport type

Transporting $CO_2$ from capture sites to the storage sites is a necessary part of the CCS chain. Currently the main offshore transportation systems are pipeline and ship, both have already mature technologies and quotable experiences. The transport solutions have different advantages depending on the transport volume, distance, geographic condition, flexibility demands, and time of investment decision.

Pipeline transport of $CO_2$, either onshore or offshore, has been demonstrated as being most effective method for large-scale, and long-term $CO_2$ transportation (IPCC, 2005). To design a regional pipeline network in the pattern of "source cluster – source hub – trunk pipeline – sink hub – sink cluster" should help increase the efficiency and reduce the unit costs of transportation per tonne $CO_2$. An integrated design of an onshore and offshore network should be made according to the distribution of sources and potential storage sites.

Shipping $CO_2$ is usually better for transport solutions requiring flexibility in terms of storage locations and/or transport durations. Compared to pipeline transport, shipping required less first time capital investment, and might be less expansive for very long distance transport (IPCC, 2005). The cost comparison of $CO_2$ shipping and pipeline transport will be discussed further in Chapter 5 of this report.

### 2.1.2 $CO_2$ phase in transport

$CO_2$ can be transported by pipelines in either dense liquid or gaseous phases. Worldwide the majority of pipelines transport $CO_2$ in dense liquid phase (IEA, 2014), which allows an efficient transport of $CO_2$. Gaseous $CO_2$ can be transported provided that the pipeline is large enough in diameter to maintain pipeline pressure well above the “bubbling line” (thus no liquid forms). This may increase the capital costs for pipelines (ZEP, 2011b).

However, there are cases in which gaseous phase transportation has some benefits, such as 1) the lower pressure requirement which fits existing compressors and pipelines; 2) the lower line-pack which means the flow to the wells can be maintained in case a loss of $CO_2$ supply occurs (ScottishPower_CCS_Consortium, 2011b); 3) a lower pressure requirement at the depleted oil or gas fields combined with a short distance from the source to the sink.

For ship transport of large volumes $CO_2$ for CCS purposes the $CO_2$ will be preferably carried in the liquid phase. See section 2.5 for detailed discussions.

## 2.2 Requirements of pre-treatment of $CO_2$ for pipeline transport

### 2.2.1 Dryness

Economic considerations lead to the use of regular high-yield carbon steel pipelines in $CO_2$ transport, identical to those used for natural gas transport. Using corrosion-resistant steels would increase the cost by an order of magnitude (ZEP, 2011b). Dehydration of $CO_2$ streams is needed to minimize the formation of carbonic acid in order to prevent the corrosion of pipeline steel. Dehydration also prevents the formation of hydrates during $CO_2$ transportation.

Currently a dryness requirement standard is not agreed nationally or internationally. In CCS projects the desired upper limit of water content in $CO_2$ is frequently specified as the ranges from 40 to 500 parts per million by volume (ppmv) $H_2O$. Little has been published on the rationale behind various selections of dryness limit. The $CO_2$EuroPipe study (Buit et al., 2010) pointed out that the lower limit of 40~50 ppmv of water is probably rather conservative, and suggests a limit of 500 ppmv water limit in $CO_2$. They argued that under normal operation conditions dense phase $CO_2$ can be transported containing 500 ppmv water without any risk of free water formation, because the water solubility is at least 1500 ppmunder these conditions. Also onshore in the USA no serious problems seem to have surfaced with ~500 ppmv water in $CO_2$.

Aspelund and Jordal (2007) also pointed out that free water and thereby corrosion hydrate and ice problems will probably not occur before the water content is more than 500 ppmv. But it is not yet clear if that analogy can be extended to offshore subsea operations and it will depend as mentioned in Chapter 1 on the other impurities present in the $CO_2$ stream. A higher dryness limit would mean a saving in money and energy, as well as a higher flexibility in the CCS chain.

Usually a more stringent limit is selected for demonstration projects and for offshore pipeline transport. Currently there is only one $CO_2$ offshore pipeline operating, which is the Snøhvit pipeline where the water content in $CO_2$ is limited to <50ppmv. For the Kingsnorth Project, the $CO_2$ is to be dried to <24 ppmv, or rise to a figure of <100 ppmv in an upset condition. For the Longannet Project, the $CO_2$ is to be dried to <50 ppmv. Clearly maintenance and repairs are much more difficult and costly offshore – perhaps at least a factor of 10x. More stringent limits to water and reduction of corrosion risk are worth detailed and specific analysis.

### 2.2.2 Impurity

Substantial studies have been undertaken on the effect of impurities on $CO_2$ transportation. However, due to a lack of experience it is not exactly known what will be acceptable for pipeline, borehole, and reservoir. Therefore, project specific $CO_2$ stream experiments on the effect of impurities might be needed. For demonstration projects more conservative specifications are usually taken. The impurity requirements for the Kingsnorth and Longannet projects are listed in **Table 2.2.1.**

**Table 2.2.1** Composition limits of $CO_2$ at the inlet of pipeline system

| Project | Longanet | Kingsnorth |
|---|---|---|
| $CO_2$ | 99 % | 99.94 % |
| $H_2O$ | ≤ 50 ppmv | ≤ 24 or 100 ppmv |
| $N_2+H_2+CH_4+Ar$ | ≤ 1 % | |
| $H_2$ | ≤ 0.3 % | Nil |
| $O_2$ | ≤ 1 ppmv | < 200 ppmv |
| $N_2$ | ≤ 0.6 % | < 350 ppmv |
| Acetaldehyde | | |
| Aldehydes | ≤ 20 ppmv | |
| Ar | ≤ 0.6 % | Nil |
| CO | ≤ 10 ppmv | Nil |

| | | |
|---|---|---|
| $CH_4$ | Nil | Nil |
| Hydrocarbons | ≤ 20 ppmv | |
| $H_2S$ | ≤ 0.5 ppmv | Nil |
| $NO_x$ | ≤ 10 ppmv | |
| $SO_x$ | ≤ 10 ppmv | |
| HCl | ≤ 1 ppmv | |
| NaCl | ≤ 1 ppmv | |
| Amines | ≤ 2 ppmv | |
| $NH_3$ | ≤ 5 ppmv | |
| Mercury | ≤ 1 ppb | |
| Particle content | | |
| Particle size | ≤ 7 microns | |

If the $CO_2$ is used for EOR, the specifications may be more stringent. $CO_2$ has been used for many decades in $CO_2$-EOR onshore. The $CO_2$ captured from power plants should be purified (>95%), compressed and cooled, to form a supercritical fluid. Should significant amounts of non condensable gases such as $O_2$, $N_2$, or $CH_2$ be present in the $CO_2$ stream, it may not be possible to practically produce a single supercritical fluid (Serpa et al., 2011) and multiple phases could co-exist. That makes effective permeability much lower in the reservoir, compared to a single fluid of $CO_2$ plus oil. Immiscible components may increase the pressure at which miscibility occurs in the reservoir and thereby decrease the efficiency of the $CO_2$. Furthermore, oxygen may cause precipitation reactions and thereby reduce the permeability of the reservoir. Oxygen reacting exothermally with oil may lead to overheating at the injection point. As a consequence specifications of 300 ppmv for nitrogen and 50 ppmv for oxygen may be required (Aspelund and Jordal, 2007). For any proposed gas composition, the pipeline designer should conduct appropriate compositional simulations to guarantee that supercritical phase behaviour can be achieved at proposed pipeline operating conditions (Serpa et al., 2011) and at the topography and geometry planned for the pipeline.

### 2.2.3 Pressure and Temperature

Pipeline transport demands that the $CO_2$ is compressed up to a pressure equal to the required outlet pressure, plus frictional and static pressure drops along the pipeline. The transport of $CO_2$ in dense phase requires that the pressure at the inlet of pipelines is between 80 and 150 bar depending on the ambient temperature, even up to 200 bar for offshore pipelines (ZEP, 2011b),. The transport of $CO_2$ in gaseous phase requires a lower pressure, a pressure below the gas/liquid boundary, to keep the gaseous $CO_2$ from transforming to liquid phase.

The Kingsnorth and Longannet projects designed gaseous-phase transport and injection during the demonstration stage. Until the reservoir pressure increases above the gas-liquid boundary and gaseous phase injection is no longer possible, $CO_2$ will be transported and injected in dense-phase. For the Kingsnorth project, in the demonstration stage the pipeline will operate in LP mode (low pressure, gaseous phase) up to a maximum inlet pressure of 39 bar. At this point operation will switch to HP mode (high pressure, dense phase) with a minimum operating pressure of 79 bar. The pipeline design pressure is 150 bar to accommodate dense phase operations **(Table 2.2.2)** (E.ON, 2011a).

**Table 2.2.2** Designed pressure and temperature in the UK FEED projects

| Project | Kingsnorth | Longganet | Kingsnorth | Longganet |
|---|---|---|---|---|
| Stage | Demo | Demo | Full scale | Full scale |
| $CO_2$ phase | Gaseous | Gaseous | Dense phase | Dense phase |
| Pressure | 2-39 bar | 31-34 bar | 79-150 bar | 79 bar |
| Temperature | 6-30 °C | 5-30 °C | > 4 °C | > 4 °C |

For the Longannet Project, the gaseous $CO_2$ will be compressed to between 31 and 34 bar and exported via the existing 36” onshore National Grid pipeline system in the gaseous phase. The temperature will vary between 5 °C to 30 °C. At the Blackhill compression station near the coast, the gaseous $CO_2$ will be compressed to 80~120 bar with temperature of no higher than 29 °C to be transported by the existing 20” offshore pipeline **(Table 2.2.2)** (ScottishPower_CCS_Consortium, 2011e).

## 2.3 Design concept of Pipeline transport system

### 2.3.1 Relevant standards

Currently there are more than 6500 km of $CO_2$ pipeline worldwide; most of them are linked to EOR operations in the United States.

There are several dedicated standards for $CO_2$ pipelines: CFR part 195 in United States, CSA Z662 in Canada, DNV-RP-J202 in Europe, and ISO/TC 265 under development (IEA, 2014). The DNV RP-J202 code supplements the requirements of ISO 13623, Petroleum and Natural Gas Industries - Pipeline Transportation Systems and provides guidance on the determination of the required pipeline wall thickness as appropriate for the location class and fluid category.

### 2.3.2 Pipeline transport system

The main elements of the Kingsnorth $CO_2$ transport system include pipelines (8 km onshore and 261 km offshore, outer diameter 900mm (36”)) with compressor and booster pumps, pressure control stations, flow control stations, valves, metering stations, pig launchers and receivers, supervisory control and data acquisition systems, safety systems and corrosion protection systems (Serpa et al., 2011) **(Fig. 2.3.1)**.

For Longannet CCS project the onshore $CO_2$ transportation uses new 600 mm (24”) pipeline (length not found in the documents) and existing 280 km 900mm (36”) National Grid pipelines to the proposed Blackhill Compressor Station. Then $CO_2$ is to be transported through the 106.6 km existing Goldeneye 500 mm (20”) hydrocarbon export pipeline to the existing Goldeneye offshore platform **(Fig.2.3.2)**. It is assessed that the existing Goldeneye pipeline has the capacity to transport up to 8 million tonnes of $CO_2$ per year which is in excess of the required injection rate, and the pipeline system will have a design life of 40 years.

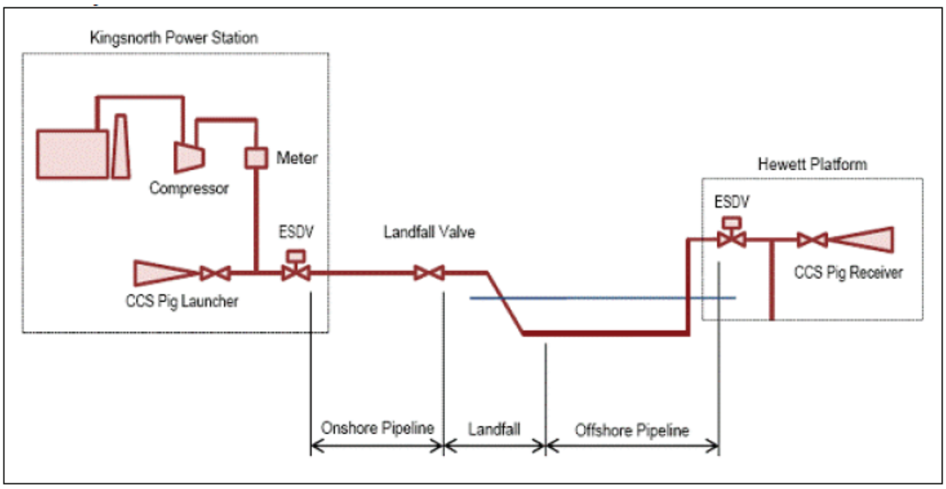



**Figure 2.3.1** Schematic diagram of the pipeline system for Kingsnorth CCS project (E.ON, 2011b)

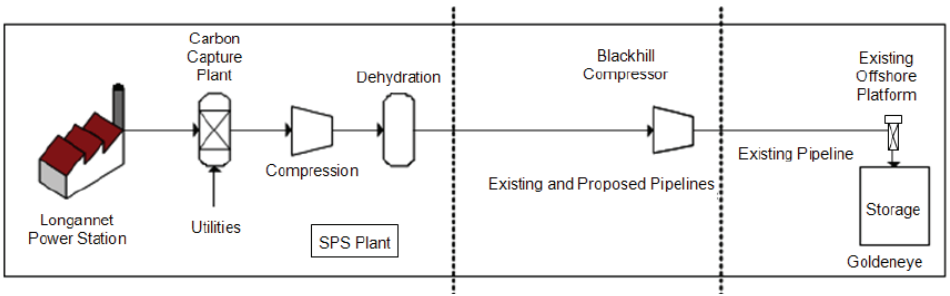



**Figure 2.3.2** Schematic diagram showing the End-to-End CCS chain for the Longannet Project. (ScottishPower_CCS_-Consortium, 2011e)

The pipeline is equipped with Emergency Shut-Down vales (ESDV) to isolate pipeline sections in case leakage occurs. Average ESDV distance is 10~20 km (IEA, 2014)

Re-use of existing oil and natural gas pipeline infrastructure may be taken as a potentially feasible option for $CO_2$ transportation. The main limitation of using existing carbon steel pipelines for $CO_2$ transportation is the design pressure. For oil and gas onshore transmission service typical pressure is between 60 and 80 bar, while new pipelines specific for dense phase $CO_2$ transport would be designed with higher pressures ranging from 85 to 150 bar. The existing pipelines should be examined and upgraded if possible, to re-qualify with the same requirements as for new pipelines designed for $CO_2$ transport. The limitation of remaining service lifetime of existing pipeline infrastructure will need to be examined, taking into account internal corrosion and the remaining fatigue lifetime (IEA, 2014).

In contrast to natural gas, high-pressure $CO_2$ pipelines are not self-arresting in terms of running ductile fracture. Thus the installation of crack arrestors is required. Crack arrestors can simply be installed by occasional joints of pipe with greater wall thickness and improved hoop-stress properties. An alternative is the periodic wrapping of pipes with non-metallic materials (IEA, 2014).

### 2.3.3 Pipeline specifications

#### Materials

Carbon steel pipeline, as used for natural gas transport, is the economic choice for $CO_2$ transport where the water content of the $CO_2$ stream is controlled to avoid formation of free water in the pipeline. Subject to any specific requirements as discussed above, a high strength grade of carbon steel is expected to be generally suitable for construction of the onshore and offshore pipeline. Direct depressurisation of dense phase $CO_2$ could lead to temperatures lower than the minimum design temperature of carbon steel; hence this issue will need to be addressed as part of the pipeline depressurization / blowdown studies.

Although the main pipeline is expected to be fabricated from carbon steel, which is specifically designed to cope with short term low temperatures, there is likely to be a requirement for corrosion resistant alloys (CRAs) at particular locations in the system, for example valve materials, or certain pipework that is subject to particularly low temperatures or positions of potential water accumulation. Selection of suitable CRAs shall take into consideration all relevant aspects of the service environment, including the pre-commissioning and commissioning phases (E.ON, 2011a).

### Pipe Diameter and Wall Thickness

Pipe Diameter should ensure the designed flow rate under designed pressure and temperature range, and prevent the formation of two-phase flow. To facilitate pigging, the pipeline is desired to have a constant inside diameter (ID) such that onshore pipelines are matched to offshore pipelines. In accordance with standard industry practice, the diameter to wall thickness ratio for onshore pipelines should not exceed 96 unless it can be demonstrated that higher values are not detrimental to the construction and in-situ integrity of the pipeline.

Formulae have been proposed to calculate the economic optimum pipe diameter and wall thickness based on parameters such as flow rate, pressure drop gradient, $CO_2$ density and viscosity, pipeline material roughness, elevation difference, and the amount and type of bends. Elevation difference and pipeline material roughness appear to be the most influential factor (Vandeginste and Piessens, 2008).

### External Corrosion Protection

The pipeline shall be protected against external corrosion using a standard anti-corrosion coating. Insulation is not required. Where the pipeline is to be subsequently concrete coated for hydrodynamic stability and/or protection, the anti-corrosion coating shall be compatible with the application of the concrete weight coating.

Field joint coating (FJC) type shall be determined. The FJC including in-fill material shall provide an equivalent level of corrosion protection as the parent coating.

The onshore pipeline will be cathodically protected using an impressed current system. Test posts will be located at a nominal spacing of 1km along the entire route of the onshore section. Isolating joints will be located at the shoreline and at power station. The onshore pipeline route may cross areas of ground which may be subject to periodic flooding and may require the installation of anti-buoyancy fittings. This may be undertaken with the installation of concrete weight coating or other measures.

The offshore pipeline shall be protected against external corrosion using a standard anticorrosion coating and sacrificial bracelet anode. Where the pipeline is to be subsequently concrete coated for hydrodynamic stability and/or protection, the anti-corrosion coating shall be compatible with the application of the concrete weight coating.

Anti-corrosion and insulation coatings and anodes shall be compatible with the design temperatures. The cathodic protection design shall be in accordance primarily with DNV-RP-F103 supplemented by ISO 15589-2.

### 2.3.4 Emergency shutdown

There are two aspects of the emergency shutdown system that are likely to challenge first expectations and/or common practice, these are (E.ON, 2011d):

1. Any $CO_2$ pipeline which supplies an offshore platform should not automatically be fitted with a Sub Sea Isolation Valve (SSIV). Although this is common practice for offshore oil and/or gas pipeline, it has sometimes been decided not to include an SSIV in the CCS design. This is because $CO_2$ is not flammable and therefore cannot feed a fire on an offshore installation, and an SSIV in a $CO_2$ pipeline could create problems as a leak or corrosion weak point (or with pipeline start up after a closure). However in the most evolved design, for Goldeneye, the security advantages of the SSIV are considered to outweigh the potential leak point problem.

2. In some instances, it may be more appropriate for an emergency pipeline shutdown response to be arranged so that only some pipeline valves move to the closed condition. There may be clear advantages, when stopping flow into the transport pipeline (for whatever reason) in keeping the pipeline outlet valve and well valves open so that the pipeline pressure equalizes with the reservoir pressure following shutdown. This approach can reduce time and energy costs in a re-start.

## 2.4 Reuse of existing pipelines

Existing natural gas transmission pipelines, either onshore or offshore, can potentially be used for $CO_2$ transport. However, the different thermodynamic properties of $CO_2$ with respect to natural gas along the process chain should be considered, as discussed in the Chapter 1 of this report.

In FEED of the Longannet CCS project existing onshore 900mm (36") diameter pipeline (280 km in length) in National Grid have been assessed and are thought to be feasible for $CO_2$ transport during the project duration. However, it is proposed to carry out internal and external inspection early in the implementation phase of the project in order to confirm its condition (ScottishPower_CCS_Consortium, 2011e)

The existing Goldeneye 500mm (20") diameter Pipeline (101.6km offshore and 0.6km onshore) was designed for natural gas/condensate multiphase transportation. Because the Goldeneye natural gas contained some $H_2S$, the pipeline is partly corrosion resistant. The pipeline has a Maximum Allowable Operating Pressure of 132 bar. A preliminary pipeline material integrity desktop review carried out during the Concept Select Phase concluded that the corrosion risk is low and the pipeline is fit for transport of $CO_2$ for the proposed 15-year design life of the CCS project.

The existing pig launcher will be replaced or converted to a receiver suitable for handling intelligent pigs, and the existing Goldeneye pig receiver shall be replaced or converted to a new (intelligent) pig launcher designed for $CO_2$ service complete with new pipework and valves connecting to all nozzles. A new $CO_2$ vent line will be routed up the existing vent tower to allow for depressurisation of the Goldeneye pipeline.

The valves of existing pipelines will need to be modified or replaced if not suitable for $CO_2$ service. The offshore pipeline has an existing non-return valve located 150 m from the riser base, which will need to be removed and replaced with an actuated sub-sea isolation valve (SSIV). The pipeline between the SSIV assembly and the riser base will also be replaced with higher pressure-rated spools to accommodate $CO_2$ thermal expansion.

The existing undersea pipelines will have front end filtration equipment installed and will be cleaned before injection operations. Commissioning of the pipeline for $CO_2$ injection service will be carefully planned to ensure that the pipeline is swept of any debris and residual hydrocarbons/water, in order to reduce the risk of well contamination.

## 2.5 Ship transportation

The practice of transporting liquefied and pressurised gases by ship dates back more than 70 years. Since then, ship transport of hydrocarbon gases has become a significant worldwide industry. Gas carriers are separated into three main categories: pressurised, semi-refrigerated, and fully refrigerated. They are also separated by the type of gas carried into three main categories: Liquid Petroleum Gas carriers (LPG) carrying mainly propane, butane and ammonia at temperatures down to –50°C; Ethylene carriers carrying ethylene and LPG cargoes at temperatures down to –104°C; and Liquefied Natural Gas Carriers (LNG) carrying natural gas consisting mainly of methane at temperatures down to –164°C (ZEP, 2011).

Ship transportation of $CO_2$ has been taking place for nearly 20 years, although only at small scale for industrial and alimentary purposes. The existing four $CO_2$ carriers in the European North Sea are around 1,500 $m^3$ each, which carry the cargo at 15-20 bar and around –30°C.

For the larger volumes required for CCS purposes it is likely that the $CO_2$ will be carried in the liquid phase at 7-9 bar and down to around –55°C. This is practically the same cargo condition as that of the significant fleet of semi-refriged LPG carriers currently in operation (ZEP, 2011). Ship transport of $CO_2$ will therefore be carried out using established technologies and procedures with a good safety record but verified in consideration of different properties, hazard, and risk of $CO_2$. Water should be removed to <50 ppm to avoid operational problems in the liquefaction process (Aspelund and Jordal, 2007).

During ship transport, heat leakage into the tanks will cause the cargo temperature to rise, increasing the cargo tank pressure from the ~7 bar at which the $CO_2$ will be loaded. For this reason, the delivery pressure from the ship is expected to be in the 8-9 bar range, depending primarily on the transportation distance. It is anticipated that $CO_2$ carriers for CCS purposes are likely to be from 10,000 $m^3$ to a maximum of ~40,000 $m^3$, most typically in the 20,000-30,000 $m^3$ range (ZEP, 2011b).

# Chapter 3

# Offshore Platform and Wells for $CO_2$ Storage

Publications on engineering aspect of offshore $CO_2$ storage are rather rare. The UK Kingsnorth and Longannet FEED studies provide examples respectively for using new and existing platform and wells for $CO_2$ injection. Below we brief how the platform and wells are designed or modified to meet the engineering requirements for $CO_2$ injection under specific conditions of these two projects.

## 3.1. Design new offshore platform and wells

The Kingsnorth Project is designed to inject 20 million tonnes of $CO_2$ over a period of 10-15 years into the depleted Hewett gas field at ~1200m below seafloor in the southern North Sea. The $CO_2$ is due to be injected in gaseous phase at the rate of 6,600 tonnes/d in the demonstration stage, and in supercritical phase at the rate of 26,400 tonnes/d in the Full System Stage.

### 3.1.1 Assessing existing facilities

The Hewett gas field 28 km offshore northeast of Bacton in Norfolk, England contains an estimated 3.5 trillion cubic feet recoverable gas in Traissic Lower and Upper Bunter sandstone reservoirs about 900~1300 m deep. Both reservoirs have excellent porosity and permeability. The field started producing in 1969. By that time 22 wells had been drilled (Cumming and Wyndham, 1971). Its offshore infrastructure comprises six platforms, three of which a central processing complex which exports gas to the Bacton Gas Plant on the cost **(Fig. 3.1.1)**. The reservoir pressure is only 29 bar after depletion.

In the FEED reports of the Kingsnorth Project there is no explanation on why the exiting platforms in the Hewett field cannot be reused for $CO_2$ injection. Perhaps the reason is that these platforms are already older than 40 years and hence are difficult and expansive to convert from $CH_4$ service to $CO_2$ service.

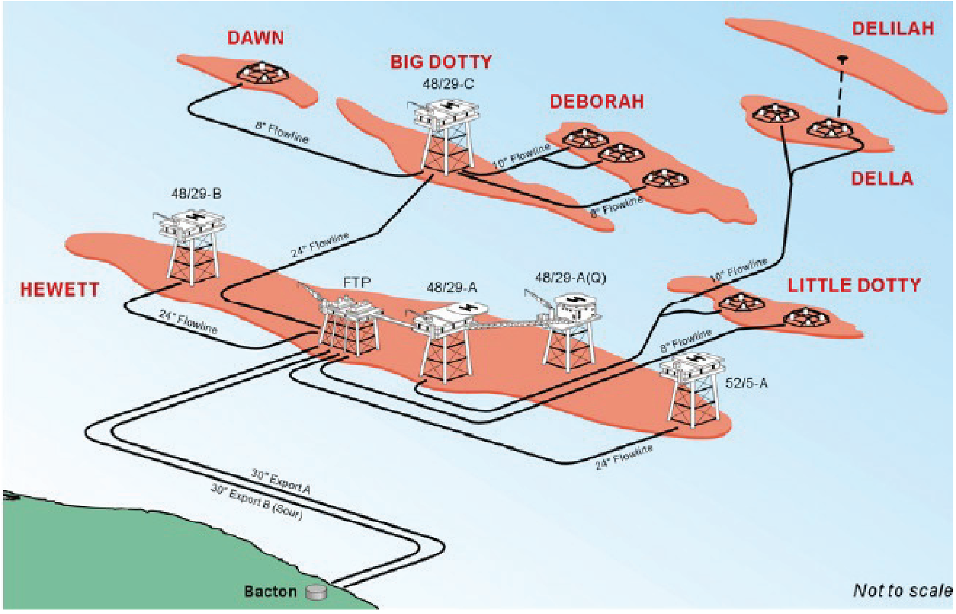



**Figure 3.1.1** Hewett gas field infrastructure [1]

[1] http://www.eni.com/en_IT/attachments/azienda/attivita-strategie/exploration-production/produz-idrocarburi/Hewett-Bacton-Field-Infrastructure/H-B_Infrastructure.pdf

In the reports there are informative discussions on assessing existing wells:

The conceptual assessment on reusing the existing wells has been performed based on the following data: field stratigraphy and general casing scheme, pressure regime, well reports including end of well reports, completion diagrams, status reports, and well-head diagrams.

The conclusion is that the existing wells are not suitable for reuse as $CO_2$ injection wells. This was made mainly due to integrity issues as follows:

1. Casing and cement corrosion and cracks. The cement and casing are very old, which may mean that the cement sheath is not complete or continuous, and may have micro-annuli or poor bonding to the formation or the casing or both. Perforations may have caused cracks in the cement. In addition, most casings are cemented to surface, which potentially minimises the migration/leakage paths to some degree, but makes the casings difficult to pull for annulus access.

2. Data incompleteness. Three wells are partially abandoned with no access or uncertain access to block potential migration/leakage paths in the abandoned legs. Remediation of these wells is difficult or impractical. There is no access to the 5 subsea exploration/appraisal wells which penetrate the Lower Bunter. Potential migration/leakage paths in these wells cannot be blocked, even to

surface.

Thus it is recommended that the $CO_2$ injection in the Hewett field will only be feasible using new wells. For the site integrity the existing wells need to be abandoned using $CO_2$ resistant materials, including non-Portland cement. The plugs should be set both above and between the permeable zones.

### 3.1.2 Conceptual design of the new platform

The new platform will be built in the vicinity of the Hewett platform complex at water depth about 37m with a service life of 40 years. The platform is designed as a liftable jacket substructure with a lift-installed integrated deck topsides structure and piled foundations. This is feasible because of the shallow seawater at the site. All drilling, injection and well maintenance activities on the platform will be carried out using a jack-up drilling unit operating in cantilever mode, such that all drilling loads will be supported by the jack-up unit (E.ON, 2011a). 12 slots are required to allow up to 12 wells to be drilled. In the initial demonstration stage 3 wells and 1 contingency well will be drilled, and further 5 wells will be drilled for the full-scale injection. The tubing size is 7″ for the two stages.

### 3.1.3 Equipment on platform and in wells

#### Arrival facilities

The 36” outside diameter $CO_2$ pipeline from Kingsnorth will tie into the base of the 36” riser at the Hewett $CO_2$ injection platform. The pipeline and riser is isolated from the platform facilities by two 36” riser valves in series (main riser and inboard riser valves). These valves will close on an ESD (Emergency Shut Down) signal. The main riser valve will not normally be closed, however if there is a differential pressure >2 bar across the valve, the pressure will have to be equalized by either increasing or decreasing the pressure in the section of piping between the main riser and inboard riser valve. Once the pressure has equalized, the riser valve can be opened. A bypass line around the inboard riser valve consisting of an ESD valve and Flow Orifice will allow the pressure to be equalized across the inboard riser valve if the valve is closed and a differential pressure has developed.

Permanent pig receiving facilities will be present on the platform that will allow intelligent pigs to be received. Pigging activities will require the presence of operators offshore to align the valves on the receiver so that it can accept a pig.

### $CO_2$ Filters

The $CO_2$ arriving at the Hewett $CO_2$ injection platform may contain particulates picked up from the pipeline (e.g. rust particles). If these particulates enter the reservoir, they may clog up the formation, reducing the injectivity to a point where a well work-over may be required. To prevent fouling of the formation, two 100% $CO_2$ Process System Filters (H-0001A/B) will be provided downstream of the arrival facilities to remove the particulates from the $CO_2$. The filters will operate on a duty/standby basis that will allow the duty filter to be changed over when it is clogged without stopping $CO_2$ injection.

Each $CO_2$ Process Filter has a remotely operated inlet valve that will allow the onshore operator at Kingsnorth to switch over the duty standby filters. If the inlet valves to both filters are closed, a differential pressure may develop across the inlet valves. A bypass line with remotely operated valve and flow orifice is provided around the filter inlet valve. This bypass line will allow the pressure across the inlet valve to equalize in a controlled manner.

### Leak Detection Meters

The filtered $CO_2$ will then pass through the Offshore Leak Detection Meter. Three metering streams, two duty and one standby, will measure the quantity of $CO_2$ arriving at the platform.

The leak detection meters will input into a real-time transient modelling leak detection and location system. This system compares pressure, temperature and in/out flow values of the pipeline with calculated values. It works continuously and provides fast information about small, medium and big leakages along the pipeline and gives rough information about the leak location.

The facility to add additional meter will be provided to allow for future expansion of the injection.

### Manifolds

The injection manifold receives the $CO_2$ from the leak detection metering facilities and routes it to the individual wells. The well kill manifold is supplied with seawater from the seawater system. The seawater lift pump is required for well kill operations. No permanent piped in well kill facilities are provided on the platform therefore it is assumed that a temporary line from the well kill manifold to the well will be installed if required. Additional temporary facilities such as a seawater injection pump may also be required during well kill operations to increase the pressure of the water supplied from the seawater system.

### $CO_2$ Heating and Injection Facilities

Flow into the reservoir needs to be controlled by a device that will throttle pressure (a choke valve). Throttling of gases from a higher pressure to a lower controlled pressure/flow rate is always accompanied by significant temperature loss (Joule-Thomson effect). Temperatures below zero in the well are to be avoided to avoid freezing of water. In the absence of specific injection testing information, maintaining a temperature above 0°C was adopted as the “safe” option.

Calculations for the Kingsnorth project indicate that heating at the wellhead choke can be avoided for the gaseous phase flow under steady state, except for some startup conditions which requires a maximum heating power rating of 2 MW. A very large and continuous heating load equivalent to around 20 MW (around 6 to 7 MW per well) of electrical heating demand will be required to support injection into the well from the lowest dense phase flowing pressures at the beginning of the field life.

The $CO_2$ from the injection manifold is routed to the $CO_2$ injection wells. There are four wells and each well has its own flowline, $CO_2$ Well Heater, $CO_2$ Well Injection Meter and choke valve. Each flowline and $CO_2$ Well Heater has a design pressure of 150 bar with a design temperature range of minus 85°C to 100°C, which is consistent with the $CO_2$ facilities downstream of the riser valve. Each $CO_2$ injection flowline can be remotely isolated from the platform and its corresponding well.

### Well Injection Meter

Each flowline will have a $CO_2$ Well Injection Meter to measure the quantity of $CO_2$ injected into each well. A non-return valve located downstream of the injection meter on each flowline will prevent backflow from the well.

### Wellheads

For the demonstration stage only four wells are required. The initial pressure in the Hewett depleted gas field is 2.69 bar, compared with the hydrostatic formation pressure of 117 bar at 1198.8m subsea vertical depth. It is assumed that conventional Christmas trees will be used. The pressure rating of the Christmas trees is API 5000 psi rated. The Christmas trees are provided with actuated valves including Downhole Safety Valve, Upper Master Valve, and Injection Wing Valve, as well as manually operated valves including Lower Master Valve, Kill Wing Valve, and Swab Valve. A hydraulic power unit will be used to provide the motive power to operate the tree wing, upper master valves and downhole safety valves.

### Well Annulus Management

Each wellhead comprises three annuli: ‘A’ annulus (9 ⅝” casing), ‘B’ Annulus (13 ⅜” casing) and ‘C’ Annulus (30” casing). The venting requirements and whether there is a requirement to monitor the pressure of each casing locally and / or remotely will be defined. At this stage it is assumed that the pressures in each well annulus are monitored and an alarm is annunciated should the pressure increase above a set value. If the well annuli require venting, then a vent knock out vessel will be brought offshore that will allow any liquids that are produced during the venting of the annuli to be collected. These liquids will be sent onshore to be processed.

### Seawater System

A seawater system will be employed on the platform to supply treated, filtered seawater to the seawater users i.e. emergency accommodation, deck washdown and wellbay well kill fluid manifold. Seawater will be pumped from the seawater caisson and then pass through the Seawater Filters to remove particulate matter. The filters will operate on a duty / standby basis when personnel are onboard that will allow change over of the filters when the duty filter becomes clogged. The seawater will then be distributed to the various seawater users as required. A copper-ion electrolytic anti-fouling system will generate a continuous supply of copper ions at the inlet of the seawater lift pump that will inhibit the growth of marine life, even when the pump is offline.

### $CO_2$ Vent System

The $CO_2$ vent system will tie together various $CO_2$ vent lines into a single vent line. The outlet of this vent line will be located below the deck level of the platform and the vent nozzle will be directed downwards towards the sea. This orientation should minimise the risk of a $CO_2$ cloud covering the platform during venting operations. Consideration will be given to the location / operation of the vent with regard to boat operations and over-side workers. There will be no automatic venting of the topsides facilities, only manual venting to mitigate these risks.

### Hydrate Inhibitor Injection Package

Occasionally water may presents in the pores of the sandstone reservoir, especially at the beginning of injection or after a long period of no injection. It is certain that there will be water present in the annulus spaces of wells and likely that water will sometimes infiltrate into the sump of the well during periods of no flow (the sump is the length of the drilled hole below the perforations).

The Hydrate Inhibitor Package (HIP) may be required on the platform to break down hydrate blockages around the $CO_2$ well heaters, choke valves and into the wellbore. It may also be used to break down hydrates that form in the vent system downstream of the $CO_2$ Well Heaters. It is anticipated that hydrate formation is unlikely post offshore commissioning and start-up. However, the HIP may be required as a contingency. When required, a hydrate inhibitor tote tank will be shipped from onshore to the Hewett $CO_2$ injection platform to replenish the stock of hydrate inhibitor.

### System Depressurisation

Depressurisation of the offshore platform topsides will take place once the platform topsides is isolated from the pipeline and wells at the inboard riser valve and well wing valves respectively thus isolating the platform from external sources of pressure. The $CO_2$ injection flowlines may also be isolated from the manifold and upstream facilities i.e. filters and metering.

The preferred method of depressurisation for the topsides is to utilise the vent line downstream of the $CO_2$ Vent Heaters. An individual flowline can be depressurised through its respective vent line and if the flowline inlet valve is open, the piping/equipment upstream of the $CO_2$ injection manifold can be also be depressurised. To mitigate against solid $CO_2$ forming in the vent line, the temperature controller upstream of the well choke valve should be set to control the $CO_2$ Well Heater and the heater should be switched on. The heater should be used to ensure that temperatures lower than minus 50°C will not be generated in the vent lines. The maximum flow to vent will be dictated by the system hydraulics and not the duty of the heater, therefore the maximum flow to vent will be determined at a later stage of design.

### Offshore Electrical Power/Electrical Heating Infrastructure

The base case option is to assume that any electrical cable that is supplying power to the offshore facility is only to be rated to handle the electrical power requirements for the facility when the pipeline is operating in the gaseous phase of the $CO_2$ phase envelope. Two alternative electrical heating cases that need to be evaluated are: 1) The demonstration case option will be supplemented at a later date by an additional A/C electrical cable, which allows the facility to produce enough heat electrically in order to handle the dense phase $CO_2$. 2) A single A/C cable being run initially, which allows the facility to produce enough heat electrically, in order to handle the dense phase $CO_2$.

## 3.2 Reuse of offshore platform and wells

In the Longannet project a total of 20 million tonnes $CO_2$ is to be injected into the depleted offshore Goldeneye gas field during 10~15 years reusing existing infrastructure.

The Goldeneye gas field, located ~100 km offshore northeast St Fergus, UK, is a structure-stratigraphic trap of ~7km × 4.5km area at ~2600m below seafloor. The reservoir is 25 m thick Cretaceous turbidite sandstone with high permeability, sealed by 60-85m laminated calcareous mudstone. Hydrocarbon production from the field started in October 2004 and ceased in December 2010. The depleted initial reservoir pressure is approximately 172 bar and this increases over the life of the $CO_2$ sequestration to a final value close to the initial reservoir pressure (264 bar).

### 3.2.1 Assessing existing facilities

The existing Goldeneye platform at water depth of 121 m was installed in 2003. The platform is a normally unattended simple 4-leg piled steel jacket platform, with 8 slots for the wells and a small topside providing metering, water/oil detection and well/field management facilities **(Fig. 3.2.1)**. The platform is controlled from shore and accessed by helicopter when required. The platform is fitted with short-stay accommodation, enabling up to twelve technicians to visit as necessary.

The Goldeneye was originally completed with five hydrocarbon production wells, which were all drilled from the platform location using an imported heavy duty jack-up rig and then the casing string has been cemented in place.

The Goldeneye facilities is only 10 years old to date and has been in production service for only 6 years (2004 to 2010). The technical feasibility studies in the early project phases showed that

$CO_2$ storage using the Goldeneye field and facilities is possible, and the Goldeneye field has the capacity to store at least 20 million tonnes of $CO_2$. It can also act as a gateway to the larger Captain aquifer for $CO_2$ storage. Desktop studies have confirmed that the corrosion of the Goldeneye infrastructure is low, and the Portland cement in the existing wells can protect against $CO_2$ leaks. It is concluded that the Goldeneye platform, wells, and offshore pipelines can be reused without any major modifications, and the design life can be extended. Monitoring for potential egressions of $CO_2$ from the field is feasible. Re-use of the platform is made easier by 1) its recent construction (2004); 2) its modular design; 3) its previous acid gas rating; and 4) its unmanned operation – controlled by an umbilical cable from a nearby offshore platform. During conversion to $CO_2$ operations, this umbilical cable must be relocated – at large expense.


**Figure 3.2.1** The Goldeneye platform

### 3.2.2 Retrofitting Goldeneye platform

It is proposed that for $CO_2$ injection the Goldeneye platform will continue to be operated as a Normally Unattended Installation (NUI) with occasional visits by maintenance crews utilizing helicopter transportation. The platform and offshore pipeline will be controlled from the onshore St. Fergus terminal using remote satellite telemetry. Additional control interfaces with the new Blackhill Compressor Station are envisaged.

For $CO_2$ injection the platform is required to be modified in the following aspects (ScottishPower_CCS_Consortium, 2011c):

**1.** The existing pig launcher on the platform will be converted to a pig receiver by an additional spool to extend the minor barrel length. The system will be capable of supporting intelligent pigging through the offshore line.

**2.** A new pressure control valve will be ditted upstream of the injection manifold to ensure that the $CO_2$ passing through the pipeline is maintained in a sigle dense phase.

**3.** The topsides design pressure will be retained at 213 bar, higher than the import $CO_2$ pipeline pressure of 120 bar. The SIL 3 HIPPS is no longer required and can be replaced by SIL 1 alarms activated when the tubing head pressure rises above 132 bar, the maximum allowable operation pressure of the Goldeneye pipeline.

**4.** A new $CO_2$ injection manifold of 12” size will be installed on the Goldeneye platform. The new manifold is required because of the low temperature issues associated with the use of Duplex pipework with a minimum design temperature of -50°C compared with the temperature of $CO_2$ sublimation of -78.5°C.

**5.** The existing separator will be isolated and decommissioned. New filters will be installed.

**6.** Three separate vent systems are planned for the Goldeneye platform CCS facilities:

a) A platform $CO_2$ vent for topsides manual pipework depressurisation;
b) A platform $CO_2$ vent for pipeline depressuring;
c) A platform vent to handle small volumes of hydrocarbons during well operations.

**7.** Low point drains on the $CO_2$ vent pipework will be provided to remove water. No operational draining will be required from process equipment as there will be no production of stabilised non volatile liquids with $CO_2$. Drainage from the high pressure $CO_2$ pipework and equipment will be performed when the process equipment is depressurised into the Hazardous Open Drains System.

**8.** The existing SSIV(Subsea Isolation Valve) is a check valve installed to prevent hydrocarbon backflow to the platform. The SSIV will be removed from the pipeline and a new SSIV fitted within the existing SSIV protection structure. The replacement SSIV will close automatically on leak detection from the pipeline and riser in order to protect the platform from the pipeline $CO_2$ inventory.

**9.** The topsides pipework and equipment downstream of the carbon steel pipeline will be made from stainless steel. This material has good toughness and corrosion resistant properties throughout the range of temperatures expected in CCS operations.

Because the wells will be re-completed to accommodate required low temperature operation (see section 3.2.3 for details), offshore heat input is not required for injection into the Goldeneye system. The only power consumption is from instrumentation, which is negligible. Because the maximum allowable operation pressure (132 bar) of the Goldeneye pipeline is above the required injection pressure, and the pressure at which the $CO_2$ injected into the Goldeneye pipelines is 80~120 bar, there is no requirement for compression offshore on Goldeneye platform. Hence the existing surface/topsides platform facilities are adequate for reuse in injection service.

### 3.2.3 Retrofitting Goldeneye wells

It is proposed that four of the existing production wells will be reused at different times for injection. The fifth legacy well will be reused for monitoring (with augmented instrumentation), and may be completed to allow injection later on in the project life. No changes are proposed to the existing casing and gravel pack arrangements.

The materials of existing wells and their associated tubing and completions have been assessed. Major concerns are if they can cope with the specific conditions in the new $CO_2$ service, such as the Joule-Thomson effect and resulted low-temperature embrittlement, single-phase flow requirement, and problems of wet $CO_2$ corrosion of metals and supercritical $CO_2$ solution of elastomers. The assessment has concluded that (ScottishPower_CCS_Consortium, 2011d):

**1.** 13Cr steel completion materials are a proper choice for $CO_2$ resistance as long as the $O_2$ in $CO_2$ is no more than 1 ppmv. In case $O_2$ is present at higher levels, it is still only a threat under wet conditions which are not expected to occur under normal operation conditions. Low temperature properties of 13Cr steel are adequate to avoid embrittlement at the worst case lowest tubing temperature of –15 °C. It would be prudent to confirm toughness at this temperature by impact testing.

**2.** Carbon Steel (CS) for casing is a suitable material selection. It would be subject to rapid $CO_2$ corrosion if wetted in the $CO_2$ environment; but in principle the casing is protected from direct exposure to $CO_2$ by the internal 13Cr tubing and external cement. In case that exposure to wet $CO_2$ occurs, it is estimated that corrosion of ½” CS through its entire thickness would take more than one year of such exposure.

**3.** Low temperature properties of the CS production casing were assessed. Available certificates demonstrated that the installed L80 material is suitable down –40 °C, well below the worst case lowest casing temperature of -10 °C.

**4.** No mechanical problems to be expected with the Portland cement used for existing Goldeneye wells due to $CO_2$ injection.

However, the injection wells will require workover and upgrading in the following aspects:

**1.** Recompletion. Injecting $CO_2$ into the current Goldeneye completions below the saturation point would cause a Joule-Thomson effect that would cool the wellhead and upper section of tubing to around –25°C, to a depth of ~762m. To combat the problems the wells will be re-completed with a new completion arrangement designed to accommodate the injection design requirements (including corrosion resistance and low temperature operation) and maintain single phase flow in the well tubing. The recompletion will use a combination of smaller tubing sizes which will introduce sufficient frictional pressure losses into the system to maintain the supplied $CO_2$ above the saturation line over range of operating conditions required.

**2.** The Xmas Tree/Wellhead, 13Cr Tubing, Permanent Downhole Gauge, Elastomers, Petroline Expandable Wirefinder will require further qualification, calibration and/or testing before they can be used in Goldeneye CCS completions. The operation pressure and temperature, the metal corrosion and elastomer solution by $CO_2$ stream are the major factors to be considered in the qualification. In general the Goldeneye Xmas tree / wellhead design is proven a robust system adopting primary metal to metal seals. The current Goldeneye Xmas tree is designed for temperature class U (–18 to 121°C). The limitation being the bonnet and the tree block, both being made from 410 stainless steel which has a very low Charpy impact value. The Xmas tree is planned to be changed during the workover operation and the tree selected for $CO_2$ injection operations will be made of F6NM, Material class FF which conforms to API-6A impact requirements. This material is suitable to cover the predicted temperature range during transient operations. The wellhead is not in direct contact with the $CO_2$ and thus will not be changed out during the workover. But the transient operations will need to be carefully managed to stay within the temperature envelope of the equipment.

**3.** Existing valves may need to be replaced or modified for $CO_2$ service. Metallic valve components are compatible with the future $CO_2$ operating conditions provided they are not exposed to temperatures lower than their allowable minimum design temperatures. Non-metallic materials in valves, including elastomers, used for seals, gaskets, O-rings, etc., may not be suitable for dense phase $CO_2$ service. An assessment is to be carried out to determine valves which require refurbishment or replacement, and where seals will need to be replaced in $CO_2$ compatible materials with ED (Explosive Decompression) resistance.

**4.** Replacing existing flowlines. The main issues are low temperature embrittlement and external corrosion. The existing flow lines are constructed in duplex stainless steel and will not be reused. Instead, the flowlines will be constructed in Grade 316L stainless steel which has adequate toughness down to -100 °C and external corrosion will be mitigated by coating.

**5.** Cement is susceptible to uptake of $CO_2$ and may degrade to expose casing to the external environment. The degradation rate of the Portland cement applied in these Goldeneye wells has been assessed. It is concluded that the type and thickness of the cement provides adequate resistance against degradation. However, as extremely long term cement performance based on relatively short term testing is not feasible, it is advisable to select cement types with known, investigated performance.

**6.** The surface filtration facilities will be specified such that injectivity will be unaffected by contaminants.

# Chapter 4

# HSE Issues in $CO_2$ Transport and Offshore Storage

HSE (health, safety and environment) considerations are the most important factors influencing the design of the CCS chain. CCS, like all industrial processes, must meet strict health and safety regulations. In this section we discuss the HSE issues related to the $CO_2$ transportation and offshore storage only, and we do not include other HSE issues related to common substances and activities.

HSE issues in $CO_2$ transportation and storage are related mainly to the properties of $CO_2$ (as those discussed in Chapter 1 of this report) and the pressure variation during the process. Hazard occurs often associated with unintended release of $CO_2$ due to emergency or leakage.

$CO_2$ leakage is much less at risk from fire and explosion than oil or gas leakage. Historical statistics indicate that the incidence of $CO_2$ leakage is relatively small. For $CO_2$ pipelines in the USA the incident rate in 1990-2002 period was 0.00032 $km^{-1}$ $yr^{-1}$ with no injuries nor fatalities (IPCC, 2005). The probability of $CO_2$ release from storage site is low as indicated by natural analogues of natural $CO_2$ reservoirs and engineered gas storage facilities, by practice of $CO_2$-EOR, by numerical modeling of $CO_2$ dispersion and resolution, and by current $CO_2$ storage projects (IPCC, 2005).

However, risk and hazard assessment needs to be conducted to address the HSE risks for transportation and storage. Design modifications may also be involved in order to reduce risks and to facilitate risk management. Specifications in HSE risk management in projects are required under the principal of ALARP (As Low As Reasonably Practicable). This means the risks shall be both tolerable within all legislative and company requirements and also further reducible as far as reasonably practicable. $CO_2$ related HSE training of project personnel shall be developed and implemented during the execution phase of the project.

## 4.1 Human asphyxiation

$CO_2$ is not considered as a toxic or noxious substance in China and in the world. In ISO 13623 and DNV-OS-F-101 standards for pipeline transportation systems in petroleum and natural gas industries, $CO_2$ is categorized as "Non-flammable fluids which are non-toxic gases at ambient temperature and atmospheric pressure conditions".

However if unexpected $CO_2$ leak occurs in the CCS chain, elevated level of gaseous $CO_2$ in air may lead to humans asphyxiation and other health problems **(Table 4.1.1)**. As $CO_2$ is about 1.5 times denser than air, the accidentally released $CO_2$ is likely to accumulate at ground level, in basements, trenches and low points in the landscape. Exposure to lower levels gaseous $CO_2$ can cause increased acidity in the blood leading to adverse effects in the respiratory, cardiovascular and central nervous system. Dense phase liquid $CO_2$ may cause asphyxiation from vapour emitted, or cause cold burns when in contact with skin.

**Table 4.1.1** Acute health effects of high concentrations of inhaled $CO_2$. From (DNV, 2010a)1 and (ScottishPower_CCS_-Consortium, 2011c)[2]

| $CO_2$ level in air (% v/v) | Exposure time[1] | Effects on humans[1] | Designed actions[2] |
|---|---|---|---|
| 17 - 30 | Within 1 minute | Loss of controlled and purposeful activity, unconsciousness, convulsions, coma, death | |
| >10 - 15 | 1 to several minutes | Dizziness, drowsiness, severe muscle twitching, unconsciousness | |
| 7 - 10 | Few minutes | Unconsciousness, near unconsciousness | |
| | 1.5 minutes to 1 hour | Headache, increased heart rate, shortness of breath, dizziness, sweating, rapid breathing | |
| 6 | 1 - 2 minutes | Hearing and visual disturbances | |
| | ≤ 16 minutes | Headache, difficult breathing (dyspnoea) | |
| | Several hours | Tremors | |
| 4 - 5 | Within a few minutes | Headache, dizziness, increased blood pressure, uncomfortable breathing (Equivalent to concentrations expired by humans) | |
| 3 | 1 hour | Mild headache, sweating and difficult breathing at rest | executive actions, such as process emergency shutdown, be initiated |
| 2 | Several hours | Headache, difficult breathing upon mild exertion | Alarm actuated for evacuation from the immediate area, air conditioning be shut down. |
| 0.5 - 1 | 8 hours | Acceptable occupational hazard level | 8 hour time occupational exposure limit in UK. |

## 4.2 Accidental release of dense phase $CO_2$

Accidental release of dense phase $CO_2$ is the major HSE risk for transportation and storage. It may cause $CO_2$ build-up at surface in basements, trenches, and low points in the landscape, and consequently may cause human and animal asphyxy and other environmental damages. It may also lead to the following hazards (DNV, 2010b):

### Decompression and expansion

$CO_2$ differs from hydrocarbons with respect to that the release may appear as a combination of gaseous and solid state $CO_2$. When rupture occurs in a vessel containing pressurized liquid $CO_2$ above its normal boiling point, the sudden drop in pressure inside the container causes violent boiling of the liquid $CO_2$, which may lead to a powerful burst resulting in a blast wave and risk of flying fragments. This is called as BLEVE (boiling liquid expanding vapor explosion), which is a very unusual but extremely catastrophic event. The potential for a BLEVE exists at the compressor station. Its design must ensure that the facility is capable of venting or containing any significant overpressure arising from product expansion. To minimize its damage to transportation, the pipeline need to be lain as much underground as possible, and the installation of barriers around compressor interstage pipework need to be considered.

### Erosion

The erosive properties of the wet $CO_2$ and solid $CO_2$ particles released should be considered in case there is a potential for direct impingement on nearby critical equipment. Some impurities in the $CO_2$ inventory my increase the erosive properties of the release stream.

Dense phase and supercritical $CO_2$ exhibits good solubility to a wide range of organic compounds as well as contaminants (oil, wax, and inorganic solids), as discussed in section 1.5. Fittings and sealing materials need to be compatible with $CO_2$ under high pressure conditions; rubber is not appropriate for Orings and seals. Use of porous materials should therefore be avoided. All oily or organic residues to which the product comes in contact with $CO_2$ should be assessed to prevent the contaminants deposit in the cooler pipeline sections of the transport system.

### Cooling

The depressurization of gas and dense phase $CO_2$ would cause significant chilling because of the Joule-Thomson effect. Breathing vapour at extremely low temperatures can lead to cold burns to the lungs which may lead to fatalities. Measure shall be taken to minimize the risk of cryogenic burns to personnel during all commissioning, operating and maintenance activities. There is no clear industry guidance on this. Based on data used on LNG projects, personnel exposed to cold vapors below -50 °C may be considered as an immediate fatality for the purposes of risk assessment. However early indications from gas dispersion tests and subsequent physical effects modelling indicate that $CO_2$ concentration rather than temperature in a plume is likely to be the governing factor. This needs to be confirmed.

At significant amount of heat loss the pipework and other metallic equipment may become brittle and less resilient to stress and consequently fracturing. The cryogenic embrittlement need to be considered in the design of equipment for re-pressurization.

## 4.3 $CO_2$ dispersion modeling

To prevent accidental release of dense phase $CO_2$ is a major concern in the design of $CO_2$ transport and storage systems. $CO_2$ dispersion modeling must be undertaken as part of a safety risk assessment.

Although dispersion modelling of gases and liquids emitted from vessels and pipelines has been undertaken routinely by Industry for several decades, $CO_2$ presents a number of new challenges to dispersion models due to its particular thermodynamic properties. Techniques for predicting the rate of release of high pressure $CO_2$ from a pipeline or other containment vessel and its physical form after release are not so well established. It is generally acknowledged that continued researches are needed to modeling the full range of $CO_2$ temperatures and pressures, and to select and standardize the modeling techniques.

## 4.4 Environmental impact analysis

$CO_2$ may affect the flora and fauna with which it comes into contact, from microbes in the deep subsurface near injection point to plants and animals in shallower soils and at the surface. Animals exposed to high $CO_2$ concentrations are assumed to experience the same effects as described for humans in section 4.1.

Environmental impact analysis is needed to determine the potential impacts of the project development on the environment. The identification of the potential impacts is undertaken using available literature and guidance documents, industry specific experience, and discussions with relevant authorities.

The initial screening assessment for the Longannet project showed that the development area is considered to be a typical Central North Sea offshore environment where no biological or other features are particularly sensitive to the type of development proposed. Therefore execution of the proposed development following the incorporation of the control measures is not expected to have a significant impact on the environment.

# Chapter 5

# Costs of $CO_2$ Transport and Storage

The cost estimates for $CO_2$ transportation and storage are rather diverse and are highly site specific, depending on local geographic and geological conditions and on the engineering design. Costs associated with demonstration projects are usually higher than commercial scale deployment. Cost estimates depend also on the method and boundary conditions used in the estimation.

In this chapter we summarize the cost estimates for $CO_2$ transportation and storage based on published reports of specific cost studies and the FEED studies of the Kingsnorth and Longannet projects, intending to provide our Guangdong stakeholders a conceptual idea on the cost ranges. Special attention has been paid to the costs in the projects involving offshore transportation and storage. Assumptions and cost boundaries are briefed because they are essential for understanding and judging the estimates. The methodology of estimation is not discussed. Key conclusions from these estimates are presented.

## 5.1 Costs of transportation

### 5.1.1 ZEP estimates

In the report on $CO_2$ transport costs released by the Zero Emission Platform of the European Commision (ZEP, 2011b), the unit transportation cost depending on transport method and distance is estimated, based on project data from member organizations up to the second quarter of 2009.

The study assumes custom design, new infrastructure, full capacity from day one, annual interest rate of 8%, 40 years lifetime, and two scenarios: 1) transport of a typical capacity of 2.5 Mtpa (million tones per year) $CO_2$ with “point-to-point” connection, and 2) transport of 20 Mtpa $CO_2$ in a network with double feeders and double distribution pipelines. Costs for compression, drying, and purification of $CO_2$ are not included. The transport costs include capital expenditure (CAPEX), annuity, and operating expenditure (OPEX). The cost boundaries are set as that the $CO_2$ is to be delivered from the capture plant at 110 bar and ambient temperature, and that the transport process is to deliver the $CO_2$ to the well-head template at storage site.

For ship transport, assuming the $CO_2$ conditioning and liquefaction are carried out onboard for "slow" discharge directly to the well(s) without the use of intermediate buffer storage.

The estimated capital and unit costs of ZEP (2011b) are listed in **Table 5.1.1**. To facilitate Chinese readers, the costs are converted from EUR(€) to RMB(¥) using the December 31, 2011 rates.

**Table 5.1.1** Estimates of capital cost (CAPEX) and unit cost (per tonne $CO_2$) for $CO_2$ transport (ZEP, 2011b) in 2011 exchange rate[2].

[2] Exchange rate on December 31, 2011:
1 EUR(€)= 8.15 RMB(¥);
1 GBP(£) = 9.77 RMB(¥);
1 USD($) = 6.29 RMB(¥).

| Distance(km) | | 180 | 500 | 750 | 1500 |
|---|---|---|---|---|---|
| Point-to-point transportation for 2.5 Mtpa $CO_2$ | | | | | |
| Onshore pipeline | CAPEX in M€(M¥) | 147.6 (1203) | n.a. | n.a. | n.a. |
| | Unit cost in €(¥)/ t $CO_2$ | 5.4 (44.0) | n.a. | n.a. | n.a. |
| Offshore pipeline | CAPEX in M€(M¥) | 250.3 (2040) | 580.6 (4732) | 827.7 (6746) | 1514 (12339) |
| | Unit cost in €(¥)/ t $CO_2$ | 9.3 (75.8) | 20.4 (166.3) | 28.7 (233.9) | 51.7 (421.4) |
| Shipping | CAPEX in M€(M¥) | 138.9 (1132) | 157.2 (1281) | 174.6 (1423) | 214.0 (1744) |
| | Unit cost in €(¥)/ t $CO_2$ | 8.2 (66.8) | 9.5 (77.4) | 10.6 (86.4) | 14.5 (118.2) |
| Liquefaction | CAPEX in M€(M¥) | 20.4 (166.3) | 20.4 (166.3) | 20.4 (166.3) | 20.4 (166.3) |
| | Unit cost in €(¥)/ t $CO_2$ | 5.3 (43.2) | 5.3 (43.2) | 5.3 (43.2) | 5.3 (43.2) |
| Large-scale transportation network for 20 Mtpa $CO_2$ with double feeders and double distribution pipelines | | | | | |
| Onshore pipeline | CAPEX in M€(M¥) | 287 (2339) | 774 (6381) | 1149 (9364) | 2283 (18606) |
| | Unit cost in €(¥)/ t $CO_2$ | 1.5 (12.2) | 3.7 (30.2) | 5.3 (43.2) | n.a. |
| Offshore pipeline | CAPEX in M€(M¥) | 423.8 (3454) | 1035 (8435) | 1552 (12649) | 3501 (28533) |
| | Unit cost in €(¥)/ t $CO_2$ | 3.4 (27.7) | 6.0 (48.9) | 8.2 (66.8) | 16.3 (132.8) |
| Shipping | CAPEX in M€(M¥) | 642 (5232) | 756 (6161) | 869 (7082) | 1121 (9136) |
| | Unit cost in €(¥)/ t $CO_2$ | 11.1 (90.5) | 12.2 (99.4) | 13.2 (107.6) | 16.1 (131.2) |
| Liquefaction | CAPEX in M€(M¥) | 132.4 (1079) | 132.4 (1079) | 132.4 (1079) | 132.4 (1079) |
| | Unit cost in €(¥)/ t $CO_2$ | 4.9 (40.0) | 4.9 (40.0) | 4.9 (40.0) | 4.9 (40.0) |

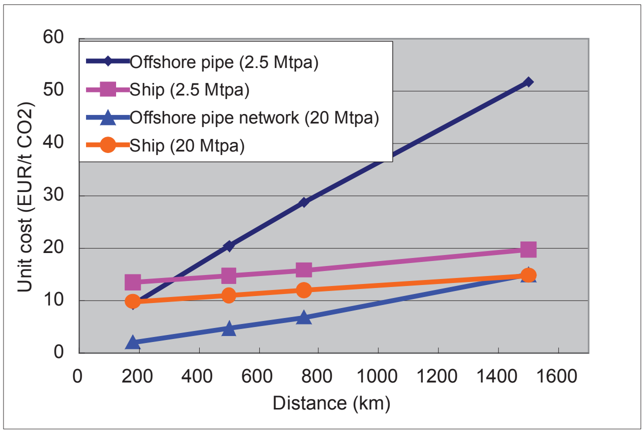



**Figure 5.1.1** Comparison of capital cost estimates for $CO_2$ offshore transport.

Data in Table 5.1.1 from ZEP (2011b).

Key conclusions from the study of ZEP (2011b) are as follows:

**1.** Pipeline costs are mainly determined (normally >90%) by CAPEX and are roughly proportional to distance. They therefore benefit significantly from economies of scale and full capacity utilisation.

**2.** Ship transport costs are less dependent (normally <50%) on distance and on scale of transport. CAPEX of ship transport is proportionally lower than for pipelines, while OPEX is much higher than for pipelines. In addition, ships have a residual value in hydrocarbon gas transportation which may reduce the financial risk.

**3.** Combining pipes and ships for offshore networks could provide cost-effective and lower risk solutions, especially for the early developments of clusters.

**4.** For large-scale transport infrastructure, long range and central planning can lead to significantly reduced long-term costs.

The estimation in ZEP(2011b) assumes a full capacity utilisation from day one, which may well prove to be unrealistic for a cluster scenario. If, for example, volumes are assumed to be linearly ramped-up over the first 10 years, this increases the unit cost of pipeline networks by ~35-50% depending on maximum flows. For ships, ramp-up is achieved by adding ships and utilities when required, resulting in only marginal unit cost increases.

### 5.1.2 UK FEED estimates

In the FEED reports for the Kingsnorth project only the development and capital costs are provided. While for the Longannet project the capital costs as well as the operating and abandonment costs are presented. Therefore in this report we can compare only capital costs.

The designs of the $CO_2$ transport systems in these two projects are described in section 2.3.2 of this report. In summary, the total length of pipelines is 269 km (264km offshore) in the Kingsnorth project and >387km (106.6km offshore) in the Longannet project. The length of offshore pipeline in the Kingsnorth project is >2.5 times of that in the Longannet project. In addition, in the Kingsnorth project the pipelines will be all new with a design lifetime of 40 years, and in the Longannet project the existing 280km onshore and 106.6km offshore pipelines are to be reused. Both systems are to transport $CO_2$ in gaseous phase during the demonstration stage.

The estimated capital costs (CAPEX) of the two transport systems for the two projects are listed in **Tables 5.1.2** and **5.1.3**. To facilitate comparison, the costs are converted to EUR and RMB using the December 31, 2011 rates (see footnote 2). The estimated costs of $CO_2$ compression and conditioning for demonstration phase are also listed, in consideration that these costs might have some dependence on the transport design.

The unit costs per tonne of $CO_2$ transported are calculated by the procedure similar to that used in ZEP(2011b)[3], assuming the interest rate 8% as used in ZEP (2011b), and the project duration 10 years. Because OPEX values are not available for the Kingsnorth Project, only the unit CAPEX costs are calculated here. Results are listed in the last two columns in **Tables 5.1.2** and **5.1.3**.

[3] In order to be comparable with the results in ZEP(2011b), we use the following procedure to calculate unit costs: 1) Calculate annuity by Annuity=CAPEX/AF, where AF (the annuity factor)=[1-1/(1+i)^n]/I, with i being the interest rate and n being the project duration in year; and 2) Unit cost = (Annuity + OPEX)/tpa, with tpa being the tonnage of $CO_2$ transported per year.

**Table 5.1.2** Estimated capital costs (CAPEX) of $CO_2$ compression and transport for Kingsnorth Project (E.ON, 2011c)

| Chain Segment | CAPEX (in 2011 rate) | | Unit CAPEX (in 2011 rate) | |
|---|---|---|---|---|
| | ($\times 10^6$ EUR) | ($\times 10^6$ RMB) | (EUR/t$CO_2$) | (RMB/t$CO_2$) |
| Land costs | | | | |
| Compressor plant & equipment | 82.4 | 671.8 | 6.2 | 50.1 |
| Civil works | 11.8 | 95.8 | 0.9 | 7.1 |
| Mobilization | 3.1 | 25.4 | 0.2 | 1.9 |
| Testing/commissioning | 1.9 | 15.4 | 0.1 | 1.1 |
| Contingency | 16.7 | 136.3 | 1.2 | 10.2 |
| Compression/conditioning total | 115.9 | 944.7 | 8.7 | 70.5 |
| Land costs | 0.1 | 0.06 | 0.005 | 0.04 |
| Transportation Plant and Equipment | 432.1 | 360.5 | 32.2 | 262.8 |
| Civil works | 102.1 | 85.2 | 7.6 | 62.1 |
| Insurances | 4.0 | 3.3 | 0.3 | 2.4 |
| Mobilisation | 36.8 | 30.7 | 2.7 | 22.4 |
| Contingency | 141.5 | 118.0 | 10.6 | 86.1 |
| Ttotal Transport CAPEX | 716.6 | 5840.3 | 53.5 | 435.8 |
| Total Compresion + Transport | 832.5 | 1542.5 | 62.2 | 506.3 |

**Table 5.1.3** Estimated capital costs (CAPEX) of $CO_2$ compression and transport for Longannet Project (ScottishPower_CCS_Consortium, 2011a)

| Chain Segment | CAPEX (in 2011 rate) | | Unit CAPEX (in 2011 rate) | |
|---|---|---|---|---|
| | ($\times 10^6$ EUR) | ($\times 10^6$ RMB) | (EUR/t$CO_2$) | (RMB/t$CO_2$) |
| Compression &conditioning | 56.6 | 461 | 4.2 | 34.4 |
| Compression & facilities at St Fergus | 145.1 | 1,182 | 10.8 | 88.1 |
| St Fergus | 17.9 | 146 | 1.3 | 10.8 |
| Risk & Contingency | 37.3 | 304 | 2.8 | 22.6 |
| Compression/conditioning total | 256.8 | 2,093 | 19.1 | 155.9 |
| Link-line | 97.5 | 794 | 7.3 | 59.2 |
| No.10 feeder (existing pipe) | 94.6 | 771 | 7.0 | 57.4 |
| FEED extension | 15.0 | 122 | 1.1 | 9.1 |

| | | | | |
|---|---|---|---|---|
| Surveys/Licenses | 26.5 | 216 | 2.0 | 16.1 |
| Pipeline preperation | 5.5 | 45 | 0.4 | 3.3 |
| Site | 98.1 | 799 | 7.3 | 59.6 |
| Risk & Contingency | 57.3 | 467 | 4.3 | 34.8 |
| Ttotal Transport CAPEX | 394.4 | 3,214 | 29.4 | 239.5 |
| Total Compresion + Transport | 651.2 | 5,307 | 48.5 | 395.5 |

### 5.1.3 Transport cost comparison

A meaningful comparison of capital cost estimate from different sources requires that the estimates being compared have as similar as possible the background conditions. In ZEP (2011b) estimates **(Table 5.1.1)**, the condition of offshore point-to-point pipeline transport of 2.5 $MtCO_2$/yr in 500km distance is the one relatively close to the conditions in the UK FEED cases **(Tables 5.1.2 and 5.1.3)**. These cost estimates and pertaining conditions are listed in **Table 5.1.4**. The ZEP (2011b) cost estimates of offshore pipeline network and ship transport are also listed in the table for comparison.

**Table 5.1.4** Comparison of cost estimates for point-to-point $CO_2$ transport

| Case | ZEP (2011b) offshore | Kingsnorth | Longannet | ZEP (2011b) ship | ZEP (2011b) network |
|---|---|---|---|---|---|
| Total amount (Mtpa $CO_2$) | 2.5 | 1.3~2.0 | 1.3~2.0 | 2.5 | 20 |
| Total pipeline length (km) | 500 | 269 | >387 | | 500 |
| Offshore length (km) | 500 | 261 | 107 | 500 | 500 |
| Pipeline/ship condition | New | New | Mostly reused | New | New |
| Pipeline outer diameter in inch (mm) | 16 (400) | 36 (900) | 36 (900) | (Liquefaction included) | 32 (800) |
| Project duration (years) | 40 | 10~15 | 10~15 | 40 | 40 |
| CAPEX in M€(M¥) | 580 (2040) | 717 (5840) | 394 (3214) | 157 (1280) | 1035 (8435) |
| Unit transport cost in EUR(RMB)/$tCO_2$ | 20.4 (166) | 53.5 (436) | 29.4 (240) | 14.8 (120) | 5.4 (44) |

Although conditions for these estimates are not the same, and the capital cost estimates are also affected by many other factors not listed in **Table 5.1.4**, there are still some features can be discussed:

**1.** The estimate of $CO_2$ transport unit cost is >2 times higher in the Kingsnorth case then in the ZEP (2011b) case, both of which uses new pipelines. The difference would be even larger in consideration that the Kingsnorth estimate are only for capital cost while the ZEP estimate contains both capital and operation costs, and the offshore transport distance is shorter in the Kingsnorth case than that in the ZEP case. The cost difference may be mainly caused by the different pipeline design. In Kinsnorth Project 36”(900mm) pipelines are selected to transport ~2 Mtpa $CO_2$ over

264km offshore distance, while in ZEP (2011b) 12”(300mm) and 16”(400mm) pipelines are used to transport 2.5 Mtpa $CO_2$ over 180km and 500km offshore distances respectively. In ZEP (2011b) the maximum outer diameter of 18” (500mm) is designed for pipeline transport over 1500km. It is beyond the scope of this report to discuss the rationality of pipeline design, we only point out that if calculate the unit pipeline cost per inch diameter per km length, the results will be similar for ZEP(2011b) and Kingsnorth.

**2.** In comparison of the estimates of unit capital $CO_2$ transport cost from the two UK FEED studies, the estimate in the Longannet case is only 55% of that in the Kingsnorth case. Two factors may be mostly responsible for the less cost in Longannet project: 1) the reuse of legacy onshore and offshore pipelines, and 2) the shorter offshore pipeline length. It would be interesting to examine how much each of the factors has contributed to the cost reduction. However, the unit cost of compression and conditioning in Longannet project is more than two times that in Kingsnorth project. This offsets some cost difference in transport, but still the sum of compression/conditioning and transport capital costs is lower (78%) in Longannet project, even with longer total transport distance.

**3.** Comparing $CO_2$ shipping with pipeline transport in terms of cost, IPCC (2005) stated that when the distance is over 1250 km, the cost of shipping may be equal to or lower than that of pipeline transportation for 6 Mtpa of $CO_2$ transported. A later study by Decarre et al. (2010) suggested that transport of 2.8 Mtpa $CO_2$ by ship becomes a more economical option compared with an off shore pipeline when the distance exceeds 350 km and with an coast to coast onshore pipeline when the distance exceeds 1100 km.

The estimates of ZEP (2011b) show that for 40 years of transport of 2.8 Mtpa $CO_2$, the unit transport cost in shipping (including liquefaction) is cheaper than that in offshore point-to-point pipeline transport when the distance exceeds 350 km, and the difference increases with distance **(Fig. 5.1.1)**. This estimation agrees with that of Decarre et al. (2010). In high volume $CO_2$ transport (such as 20 Mtpa), shipping is less cost effective compared with pipeline network, unless the transport distance exceeds 1500 km. In other words, pipeline is cheaper than ship only for networking and for short distance (<350 km) point-to-point transport.

**Table 5.1.4** shows that in terms of unit transport cost, shipping is much cheaper than the pipeline transport designed for the demonstration phase of Kingsnorth and Longannet projects. It would be interesting to examine if shipping is still cheaper for the commercial phase of these projects.

## 5.2 Costs of $CO_2$ storage

In this section the estimates of capital costs for $CO_2$ storage given by ZEP (2011a) study and by the two UK FEED studies are presented and compared. The factors considered in the ZEP (2011a) study are also listed as an example to show what should be considered in the estimation.

### 5.2.1 ZEP (2011a) study on the costs of $CO_2$ storage

ZEP has published a report on the costs of $CO_2$ storage (ZEP, 2011a). The cost estimation was conducted using a “bottom-up” approach based on potentially relevant cost components **(Table 5.2.1)** utilizing the technical and economical knowledge of ZEP members. Sensitivity analysis was performed for 8 main cost components which are listed in **Table 5.2.2**. Other 18 cost components, listed in **Table 5.2.3** are not considered in sensitivity analysis because their sensitivity range would be small or well understood (ZEP, 2011a).. From these tables we can learn what factors have been considered and what their assumed values are in the “bottom-up” estimation.

The total storage cost includes capital and operational costs in 20 years for the three actions: the site selection and characterization, $CO_2$ injection for 40 years, and MMV (monitoring, measurements, and verification). The resulted total storage costs in Low, Medium, and High scenarios are counted as the cost of per tonne of $CO_2$ stored, not abated, and are presented in Fig. 5.2.1. The parameters and estimated costs for the cases ④,⑤,and ⑥ are listed in **Table 5.2.4**.

**Table 5.2.1** Typical cost elements in typical stages of a $CO_2$ storage project (ZEP, 2011a)

* Acronyms: MMV – Monitoring, measurement, and verification; OPEX – Operation cost.

| Stage | Activity | Typical cost elements |
|---|---|---|
| Pre-FID | Activities prior to decision whether to go ahead with injection | Seismic survey, exploration wells, injection testing, modeling, permitting |
| Structure | Construction for injection wells (e.g. offshore platform) | New build or refurbishment (offshore) |
| Wells | Construction of injectors | Drilling of new wells, refurbishing legacy wells |
| Injection | $CO_2$ injection (40 years) | Operations and maintenance OPEX |
| MMV | Monitoring (both during injection and post-injection) | Drilling observation wells, monitoring OPEX, final seismic survey |
| Close down | Close down activities | Decommissioning, liability transfer |

**Table 5.2.2** Eight main cost elements and their assumed values in the study (ZEP, 2011a).

| Cost driver | Medium case assumption | Sensitivity range | Rationale |
|---|---|---|---|
| Field capacity | 66 Mt per field | 200 Mt per field<br>40 Mt per field | Based on Geocapacity data |
| Well injection rate | 0.8 Mtpa per well | 2.5 Mtpa<br>0.2 Mtpa* | Medium value based on actual projects<br>High and low based n oil and gas industry experience |
| Liability transfer costs | EUR1.00 per tonne $CO_2$ stored | EUR0.20<br>EUR2.00 | Rough estimate of liability transfer cost<br>Wide ranges reflect uncertainty |
| Weighted average capital cost | 8% | 6%<br>10% | Same range as McKinsey (2008) study |
| Well depth | 2000 m | 1000 m<br>3000 m | Well cost strongly dependent on depth** |
| Well completion costs | Offshore cost 3 times onshore cost | -50%<br>+50% | Based on actual project experience |
| Number of observation wells | 1 for onshore<br>Nil for offshore | 2 for onshore<br>1 for offshore | 1 well extra to better monitor the field |
| Number of exploration wells | 4 for SA<br>Nil for DOGF | 2 for SA, nil for DOGF<br>7 for SA, nil for DOGF | DOGF are known and no sensitivity analysis needed<br>SA reflects expected exploration success rate |

* 0.2 Mtpa not modeled for offshore cases as costs would become too high to be viable.
** Supercritical state of $CO_2$ occurs a t depths below 700-800 m.
Acronyms: SA – saline formation; DOGF – depleted oil and gas field.

**Table 5.2.3** The 18 other cost elements.

Acronyms: MMV – Monitoring, measurement, and verification; DOGF – depleted oil and gas field; CAPEX – Capital cost.

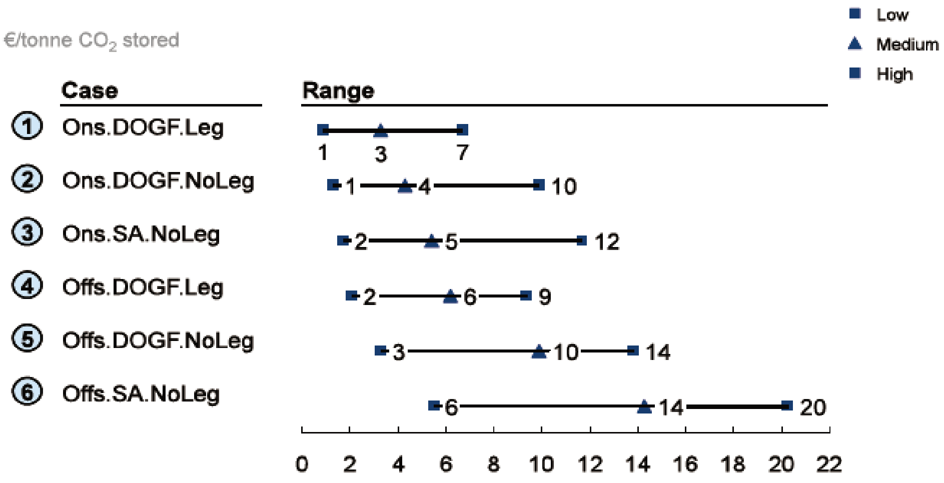
| Cost driver | Assumption |
|---|---|
| Reuse of exploration wells | 1 out of 3 exploration wells is reusable as an injection well; others are not located correctly, do not match the injection depth, etc. |
| Utilization | 86% utilization, implying a peak production of 116% average |
| Contingency wells | 10% of the required number of injection wells is added as a contingency, with a minimum of 1 per field |
| Well re-tooling | Re-tooling legacy wells as exploration wells, or exploration wells as injection wells, costs 10% of building the required well from scratch |
| Operations & maintenance | 4% of CAPEX costs for platform and new wells |
| Injection testing | Fixed cost 1 million EUR per site |
| Modeling/logging | Fixed cost per field; SA costs ~2 times as much as DOGF |
| Seismic survey + MMV baseline | Fixed cost per field; offshore costs ~2 times as much as onshore. At the end of its economic life, final seismic survey is performed prior to handover (costs discounted for time value of money) |
| MMV recurring | Fixed cost per field; offshore costs ~2 times as much as onshore. |
| Permitting | 1 million EUR per project |
| Well remediation | Provision ranging from nil to 60% of new well costs, based on risky wells and the costs of handling them |
| Platform for offshore | SA is assumed to require a new platform; DOGF is assumed to require refurbishment of an existing platform |
| Decommissioning | 15% of CAPEX of all operational wells and CAPEX of platform |
| Post-closure monitoring | 20 years at 10% of yearly MMV expenses during first 40 years |
| Economic life | Bse case 40 years; demonstration phase 25 year (in lin with assumptions for capture |
| Learning rate | 0% as $CO_2$ storage technologies are well known and build on oil and gas industry experience |
| Exchange rate | 1.387 USD/EUR as of 6 October 2010 |
| Plant $CO_2$ yearly captured | Assumed to be 5 Mt per year. Variation in the amount captured is implicitly modeled by variation in storage capacity as a sensitivity |

**Fig. 5.2.1** and **Table 5.2.4** show that the cost of $CO_2$ storage is highly variable. The "High" cost scenario can be 3~10 times more expensive than the "Low" cost scenario. This is mainly due to natural variability between storage reservoirs (e.g.. field capacity and well injectivity) and only to a lesser degree to uncertainty in cost elements ZEP (2011a).

**Figure 5.2.1** Storage cost per case, with uncertainty ranges.

Ranges driven by setting field capacity, well injection rate and liability transfer costs to Low, Medium, and High cost scenarios. Triangles correspond to base assumptions. (ZEP, 2011a).

Abbreviations:
Ons. – onshore,
Offs. – offshore,
DOGF – depleted oil/gas field,
SA – saline formation,
Leg – legacy infrastructure,
No Leg – no legacy infrastructure.




The general trends of the total capital costs are (ZEP, 2011a):

1 Onshore is cheaper than offshore.
2 DOGF (depleted oil and gas fields) are cheaper that SA (deep saline aquifers) and even more so when they have reusable legacy wells.
3 The highest cost and the widest cost range occur for offshore SA.

The sensitivity studies revealed the following:

1 Field capacity has either the largest or second largest effect in all case. Thus the selection of storage reservoirs based on their capacity is a key element in reducing the cost of $CO_2$ storage.
2 Although well costs are ~40-70% of total storage costs, the wide ranges in total costs (up to a factor of 10 for a given case) are driven more by variations in geology and storage characteristics (because these are highly site-specific) than by the uncertainty of cost estimates.

**Figure 5.2.4** Cost estimates in EUR(RMB) for offshore depleted oil/gas fields (DOGF) and saline aquifers in low (L), medium(M), and high(H) scenarios (ZEP, 2011a, Table 4)

ZEP④:Offshore depleted fields, legacy wells
ZEP⑤:Offshore depleted fields, no legacy wells
ZEP⑥:Offshore saline aquifer, no legacy wells

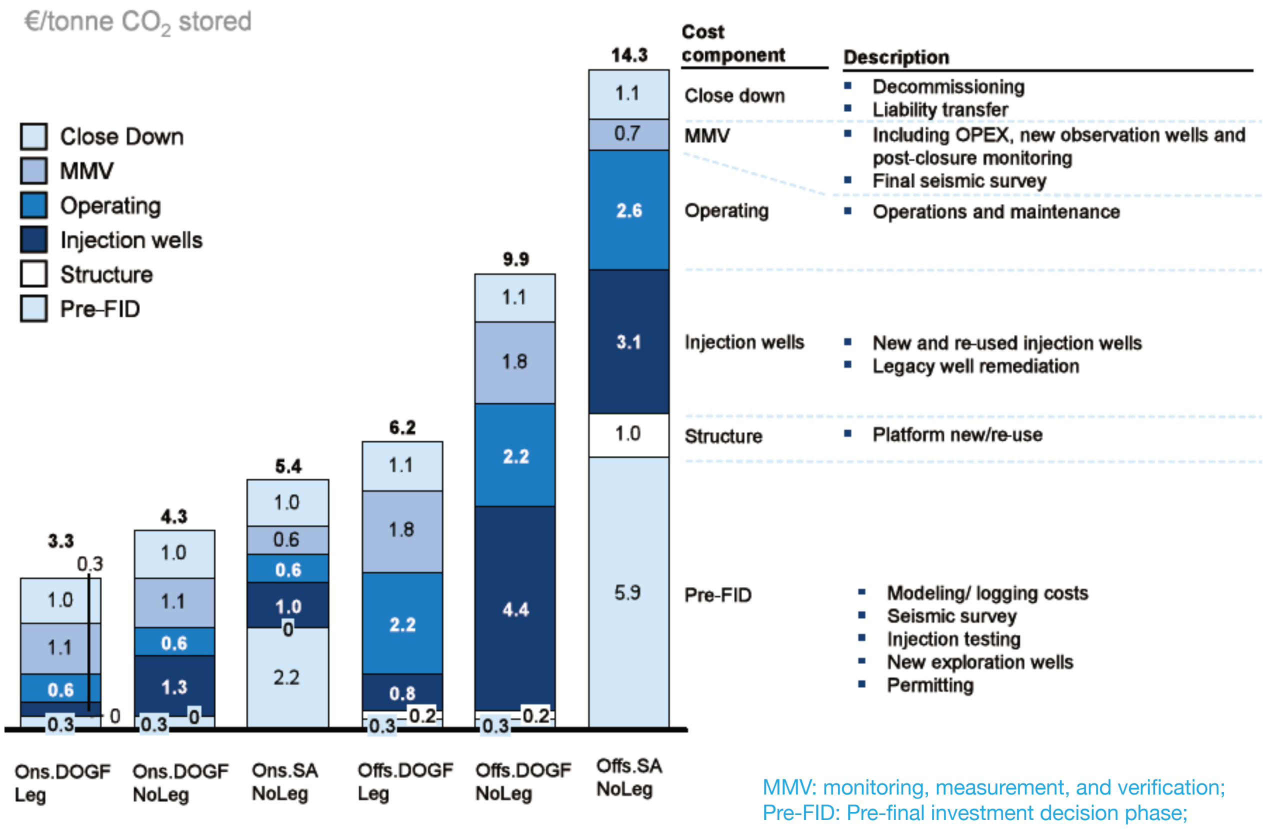
Scenario: L-Low, M-Medium, H-High

| Case | ZEP④ Offshore DOCF with legacy wells | | | ZEP⑤ Offshore DOCF no legacy wells | | | ZEP⑥ Offshore aquifer no legacy wells | | |
|---|---|---|---|---|---|---|---|---|---|
| Scenario | L | M | H | L | M | H | L | M | H |
| $CO_2$ stored ($\times 10^6$ t) | 200 | 66 | 40 | 200 | 66 | 40 | 200 | 66 | 40 |
| Lifetime (year) | 40 | 40 | 40 | 40 | 40 | 40 | 40 | 40 | 40 |
| Injection rate (Mt per yr) | 5 | 2 | 1 | | 2 | 1 | 5 | 2 | 1 |
| CAPEX ($\times 10^6$ €) | 56 | 48 | 44 | 127 | 120 | 96 | 238 | 199 | 169 |
| Unit CAPEX (€ per tonne) | 0.28 | 0.73 | 1.10 | 0.64 | 1.82 | 2.40 | 1 | 3 | 6 |
| OPEX ($\times 10^6$ € per yr) | 6 | 6 | 6 | 6 | 6 | 6 | 8 | 7 | 6 |
| Unit OPEX (€ per tonne) | 1.2 | 3.6 | 6.0 | 1.2 | 3.6 | 6.0 | 1.6 | 4.2 | 6.0 |
| Unit cost of storage(€ per tonne) | 2 | 6 | 9 | 3 | 10 | 14 | 6 | 14 | 20 |

The cost breakdown by cost components are shown in **Fig. 5.2.2.** The main cost differentiators are as follows (ZEP, 2011a):

1. High pre-FID (Final Investment Decision) costs for SA compared to DOGF. The reason is that SA need exploration to determine their suitability for storage. This pre-FID activity is assumed to require a seismic survey, as well as drilling of exploration wells and modelling (study) activities. These requirements are highly site-specific. Such costs could accrue to several tens of millions of euros.
2. Offshore storage is more expensive than onshore for nearly all cost elements since it is a more expensive environment for construction, drilling and operation, and maintenance.
3. DOGF with re-usable legacy wells has lower well costs (less than one fifth of the offshore DOGF without legacy wells). This is a key differentiator offshore because of the high drilling and completion costs in that environment.
4. For SA scenarios (both on- and offshore) the cost of site selection and characterization in the Pre-final investment decision (Pre-FID) phase is the highest. In ZEP's estimates this is 41% of SA storage costs.

**Figure 5.2.2** Breakdown of cost components in medium scenario for all six cases (ZEP 2011a).




MMV: monitoring, measurement, and verification;
Pre-FID: Pre-final investment decision phase;
Other acronyms are the same as those in **Fig. 5.2.1.**

### 5.2.2 UK FEED cost estimates of offshore $CO_2$ storage

Because the 40 years injection period assumed by ZEP (2011a) may be too long for some CCS projects, especially when the projects include offshore storage, here we cite the cost estimates of the UK FEED studies for the Kingsnorth and Longannet projects, which have shorter injection time. Each of these projects is designed as a demonstration project to inject a total of 20 $MtCO_2$ in a depleted gas field in North Sea in the period of 10 to 15 years. The Kingsnorth project is to build new platform and wells at the depleted offshore Hewett gas field, while the Longannet project will use legacy platform and wells for $CO_2$ injection at the offshore Goldeneye gas field. Resulted cost estimates for the two projects are listed in **Tables 5.2.5** and **5.2.6**, respectively.

The unit costs per tonne of $CO_2$ stored are calculated by the procedure similar to that used for the unit costs of transport (see footnote 3 for description), assuming the interest rate 8% as used in ZEP (2011a), and the project duration 10 years. Because OPEX values are not available for the Kingsnorth Project, only the unit CAPEX costs are calculated here. Results are listed in the last two columns in **Tables 5.2.5** and **5.2.6**.

**Table 5.2.5** Capital costs (CAPEX) proforma for $CO_2$ storage in the Hewett field of Kingsnorth Project (E.ON, 2011c)

| Chain Segment | CAPEX (in 2011 rate) | | Unit CAPEX (in 2011 rate) | |
|---|---|---|---|---|
| | ($\times10^6$ EUR) | ($\times10^6$ RMB) | (EUR/$tCO_2$) | (RMB/$tCO_2$) |
| Injection Infrastructure | 113.1 | 921.6 | 8.4 | 68.8 |
| Well interface | 4.9 | 40.2 | 0.4 | 3.0 |
| Insurances | 2.5 | 20.3 | 0.2 | 1.5 |
| Mobilisation | 5.7 | 46.5 | 0.4 | 3.5 |
| Testing/Commissioning | 6.8 | 55.6 | 0.5 | 4.1 |
| Contingency | 47.8 | 389.3 | 3.6 | 29.1 |
| **Injection facilities & infrastructure total** | **180.8** | **1473.5** | 13.5 | 110.0 |
| Land costs | | | | |
| Wells | 58.1 | 473.2 | 4.3 | 35.3 |
| Insurances | 16.1 | 131.2 | 1.2 | 9.8 |
| Mobilisation | 5.3 | 42.8 | 0.4 | 3.2 |
| Contingency | 12.2 | 99.5 | 0.9 | 7.4 |
| **Geological storage total** | **91.6** | **746.8** | 6.8 | 55.7 |
| **$CO_2$ storage total** | **272.4** | **2220.3** | **20.3** | **165.7** |

Table 5.2.6 Capital costs (CAPEX) proforma for $CO_2$ storage in the Goldeneye field of Longanent Project (ScottishPower_CCS_-Consortium, 2011b)

| Chain Segment | CAPEX (in 2011 rate) | | Unit CAPEX (in 2011 rate) | |
|---|---|---|---|---|
| | ($\times10^6$ EUR) | ($\times10^6$ RMB) | (EUR/t$CO_2$) | (RMB/t$CO_2$) |
| Topsides / platform | 109.4 | 892 | 8.2 | 66.5 |
| Subsea | 10.7 | 87 | 0.8 | 6.5 |
| Wells | 45.0 | 366 | 3.3 | 27.3 |
| Pre-injection | 19.2 | 156 | 1.4 | 11.6 |
| Site | 64.9 | 529 | 4.8 | 39.4 |
| Risk & Contingency | 42.3 | 345 | 3.2 | 25.7 |
| **$CO_2$ storage total** | **291.4** | **2375** | **21.7** | **177.0** |

## 5.3 Comparison of storage cost estimates

Bearing in mind that the cost estimates for $CO_2$ storage is highly site-specific, the estimates of total capital costs for offshore $CO_2$ storage as discussed in the previous section are compared in **Table 5.3.1.** Two features shown in the table are discusses below:

Table 5.3.1 Comparison of estimated unit capital cost (CAPEX) for offshore $CO_2$ storage

| Case | Hewett (Table 5.2.5) | Goldeneyet (Table 5.2.6) | ZEP ④ (Table 5.2.4) | ZEP ⑤ (Table 5.2.4) |
|---|---|---|---|---|
| Total $CO_2$ stored ($\times10^6$ tonne) | 20 | 20 | 66 | 66 |
| Lifetime (year) | 10-15 | 10-15 | 40 | 40 |
| CAPEX in EUR (RMB) | 272.4 (2220) | 291.4 (2375) | 48 (391) | 120 (978) |
| Unit CAPEX for $CO_2$ storage in EUR/t (RMB/t) | 20.3 (166) | 21.7 (177) | 0.7 (6) | 1.8 (15) |

**1.** The unit capital costs estimated from UK FEED studies are much higher than those from ZEP (2011a). The Longannet case (Goldeneye field) is similar to the ZEP④ case in the reuse of legacy wells, but the estimate of unit CAPEX storage cost for Goldeneye is >30 times of the ZEP's estimate. The Kingsnorth case (Hewett field) is similar to the ZEP⑤ case in using newbuilt wells, but the cost estimate for the formal is >11 times of the latter. Reasons for such great differences in cost estimates need to be investigated. Apparently a longer operation period and large total volume to be stored (in commercial scale projects) in the ZEP's cases may reduce the unit capital costs significantly, compared with the UK FEED cases designer for specific demonstration projects. But the cost differences are perhaps too large to be attributed solely to this. The methodology, cost components and boundaries, and parameters used in the estimation need to be checked in order to answer the question.

**2.** The unit storage cost in the Longannet case (Goldeneye field) is slightly higher than that in the Kingsnorth case (Hewett field). However, this result should not be regarded as contradict to the expectation that reuse of legacy infrastructure would be less expensive than new. It may reflect mainly the high site-specific nature of the costs. Strictly speaking, a meaningful cost comparison may be made only for the same site. However, detailed works are perhaps needed to examine if there are other reasons, such as the methodology, cost components and underlying values used in the estimations by different companies. The Goldeneye example may indicate that the reuse legacy infrastructure may be more expensive than previously expected. The right answers are important for stakeholders especially decision makers in CCUS development.

## 5.4 Comparison of estimated capital costs for the CCS chain

For reference the estimated unit capital costs for the components of the CCS chain is compared for the two UK FEED projects in this section. **See Table 5.4.1** and **Fig. 5.4.1**.

**Table 5.4.1** Estimated unit capital costs for Kingthnorth and Longannet CCS Projects.

Cost in in EUR and RMB per tonne $CO_2$ by 2011 rate.

| Chain segment | Kingsnorth | | | Longannet | | |
|---|---|---|---|---|---|---|
| | EUR/t$CO_2$ | RMB/t$CO_2$ | % | EUR/t$CO_2$ | RMB/t$CO_2$ | % |
| Development | 6.5 | 52.6 | 6 | | | |
| Capture plant | 19.2 | 156.6 | 18 | 49.5 | 403.2 | 41 |
| Compression/condition | 8.7 | 70.5 | 8 | 19.1 | 155.9 | 16 |
| Transport | 53.5 | 435.8 | 49 | 29.4 | 239.5 | 24 |
| Storage | 20.3 | 165.7 | 19 | 21.7 | 177.0 | 19 |
| **Total** | **108.1** | **881.3** | | **119.7** | **975.7** | |

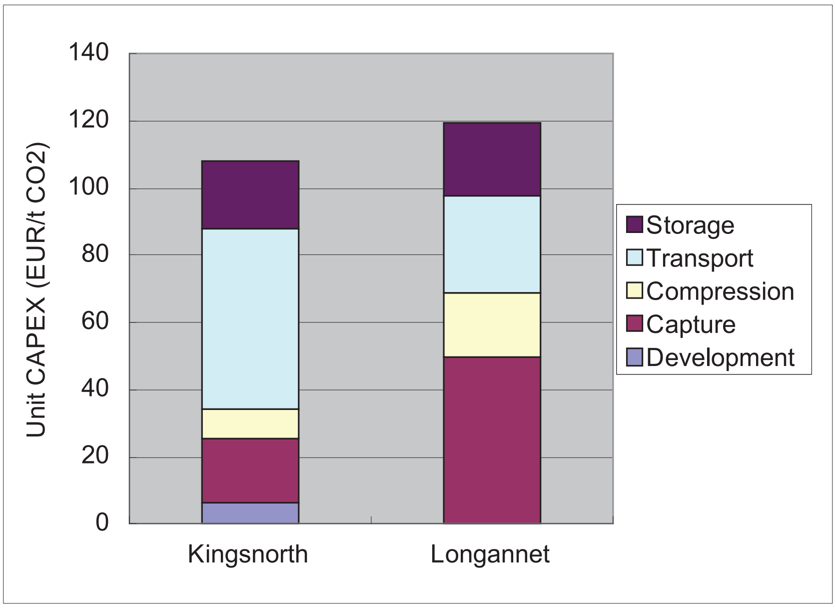



**Figure 5.4.1** Estimated unit capital costs for the Kingthnorth and Longannet CCS Projects. Data are from **Table 5.4.1**

A striking feature of these data is the high transport cost (near 50% of the total cost) for the Kingsnorth project. This shows that in offshore condition the transport can be the most costly component in the full CCS chain, especially when a longoffshore pipeline is to be built.

# Concluding Remarks

In this report the engineering requirements for $CO_2$ transport and storage offshore are summarized based on available literatures, especially the documents released from the FEED studies for the Kingsnorth and Longannet projects in UK. We reviewed the physical properties of $CO_2$, especially the differences between $CO_2$ and natural gas. Then the engineering requirements for $CO_2$ transport and storage, especially those for offshore, are summarized; the health, safety, and environmental issues are discussed; the cost estimates for $CO_2$ transport and storage are listed and compared. Due to the limitations in work time and authors knowledge, this summary can not be complete and should be considered as an introduction to beginners. For the technical details in $CO_2$ transport and storage and the methodology of cost estimates, our readers are referred to the original documents and literatures.

Several general conclusions can be made from this report:

1. The engineering requirements as well as infrastructure for $CO_2$ transport and storage are mostly transferable from those for natural gas transport and production. The modifications required are relatively minor and mostly derived from the differences in physical properties between $CO_2$ and natural gas, such as the different phases boundaries that require different pressure and temperature in operations, the single-phase transport requirement for $CO_2$ transport, the corrosive nature of wet $CO_2$ and the solvent nature of dense phase $CO_2$, the influences of impurities in $CO_2$ stream, and the different hazard and risk in emergency situations and unintended release. The specifications on engineering requirement for offshore $CO_2$ capture and storage listed in this report can serve as references for project planning and design. However, as the $CO_2$ transport storage and storage are highly dependent on geological and geographical conditions, the engineering requirements for any particular project need to be determined according to its particular conditions.

**2.** The health, safety, and environmental issues in $CO_2$ transport and storage are in general manageable with proper engineering design and strict operational regularity controls. But risk and hazard assessment and simulation need to be conducted, and design modifications may be involved. Regularities and personnel training on HSE issues are also essential.

**3.** The present cost estimates on $CO_2$ transport and storage are highly diverse. Although these estimations are highly site specific in nature, some general trends are seen from the estimates collected in this report. For example, offshore is more expansive than onshore; large quatity, longer distance and period may reduce the unit cost for transportation; pipeline transport costs are more determined by capital costs and are more depend on distance than shipping; and the unit cost of shipping may be more cost effective than point-to-point pipeline for long-distance (e.g. >350km) transport and comparable to the cost of large-scaled pipeline network. For the Kingsnorth project the cost of pipeline transport is nearly half of the total. This indicates that pipeling networking is essential for cost reduction in CCS projects involving offshore $CO_2$ transport. In the total cost of storage the cost of wells may be as high as 40-70% and is highly site-specific; among the factors for reducing the unit cost of storage, a large storage capacity at the site has the most significant contribution.

However, questions remain to be solved for the cost estimates, such as:

**1)** The estimates of offshore storage costs by ZEP (2011b) are much (11 to 30 times) smaller than those given by UK FEED studies for the Hewett and Goldeneye $CO_2$ storage. Although commercial projects with larger storage volume and longer total period in ZEP's cases can reduce the unit storage cost, the differences in estimates seem too large to be explained only by this factor.

**2)** Comparing the unit capital costs for the two UK FEED studies, the costs for the Longanett project, where legacy pipelines, platform and wells are used, are not all less than the costs for the Kingsnorth project using all new infrastructures. The major reason for these unexpected cost estimates may be the high site-specific nature of the costs. However, detailed works are perhaps needed to examine if there are other reasons, such as the methodology, cost components, boundaries, and parameters used in the estimations by different companies. The right answers are important for stakeholders especially decision makers in CCUS development.

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