# The East Irish Sea CCS Cluster: A Conceptual Design – Technical Report

## Hydrocarbon Resources Ltd and Peel Energy Ltd

Authors:

Andrew Coulthurst

Sam Taylor

Adam Baddeley

February 2011

*Report for:*

Hydrocarbon Resources Ltd and Peel Energy Ltd

*Prepared by:*

Andrew Coulthurst

Sam Taylor

Adam Baddeley

*Approved by:*

.........................................................

Mike Brown

*Contact Details*

Eunomia Research & Consulting Ltd
37 Queen Square
Bristol
BS1 4QS
United Kingdom

Tel: +44 (0)117 9450100
Fax: +44 (0)8717 142942

Web: www.eunomia.co.uk

*Disclaimer*

# Contents

# 1.0 Background and Introduction

## 1.1 CCS and its Significance for the UK and Ireland

The IPPC (Intergovernmental Panel on Climate Change) states that there is now a very high confidence (>90%) that the net effect of human activities have contributed to climate change.[1] As such, it is important that overall levels of greenhouse gas (GHG) emissions from human activities are reduced.

In the United Kingdom (UK), GHG emission reduction targets are encapsulated within the Climate Change Act 2008, where a legally binding target of at least an 80 percent cut in GHG emissions by 2050 (compared to levels in 1990) is required.[2] Carbon Dioxide ($CO_2$) accounts for around 85 percent of total UK GHGs (574.6 million tonnes of $CO_2$e in 2009).[3] The largest contributor to the UK's portfolio of emissions is the energy sector, which is responsible for approximately 40% of UK's $CO_2$ emissions. It is therefore vital, that this sector is able to decarbonise and reduce its overall level of emissions in order to achieve the targets.

One method of decarbonisation will undoubtedly be the use of renewable energy sources. Whilst these will continue to be an increasing feature of the energy mix in the UK and beyond, the intermittent nature and practical limitations of renewable energies such as wind, wave and solar mean that 'base-load' and flexible power generation will remain essential to any modern economy for the foreseeable future. Both the age of the existing UK fleet of power stations and European Union (EU) environmental regulations are such that significant new such generating capacity is needed.[4] Whilst the UK Coalition Government has indicated an intention that nuclear energy should continue to have a role to play, in the interests of energy security (through diversity of supply) it has also stated its belief that fossil fuels, including coal, will need to continue to play a vital role in energy generation for decades to come.[5]

Ultimately, therefore, the timing of the introduction of carbon capture and storage (CCS) will need to coincide with national targets to reduce emissions. The Committee on Climate Change (CCC) has stated that in order for the 2050 target to be met, the electricity generating sector (with the help of CCS technologies) will be required to

---

[1] IPPC (2007) *Climate change 2007: Summary for Policymakers*, Intergovernmental Panel on Climate Change Fourth Assessment Report (AR4), 2007

[2] See: http://opsi.gov.uk/acts/acts2008/ukpga_20080027_en_1

[3] See: http://www.decc.gov.uk/en/content/cms/statistics/climate_change/gg_emissions/uk_emissions/2009_prov/2009_prov.aspx

[4] Namely the EU Large Combustion Plant Directive (LCPD), the key elements of which have been incorporated into the EU Industrial Emissions Directive (IED)

[5] DECC (2010) Annual Energy Statement: DECC Departmental Memorandum, July 2010

decarbonise by 2030.[6] Section 2.0 outlines the drivers associated with meeting these targets.

All of the individual technologies within the chain of CCS have been proven at commercial scale. As the name suggests, CCS is a three stage process which involves:

1. Capturing $CO_2$ emissions from the combustion of fossil fuels – for initial CCS projects this is likely to be from large-scale emitters such as power stations or large industrial plants;[7]
2. Transporting the $CO_2$ by pipeline (or ship) for offshore storage;[8] and
3. Storing the $CO_2$ securely, usually in depleted oil and gas fields, which have previously held hydrocarbons for millions of years.[9]

The challenge to the EU, to Governments and the private sector is to now develop, integrate and prove the full technology chain at commercial scale, which could be a hugely important step towards mitigating global $CO_2$ emissions. This is a view supported by the UK Department of Energy and Climate Change (DECC):

> *Development and deployment of CCS is critical…as it has the potential to reduce the $CO_2$ emissions from power stations by around 90%, and make a significant contribution towards the UK and international climate change goals.*[10]

It should be acknowledged that CCS will not provide a long-term solution (beyond 50 years) in delivering low carbon energy due to the finite nature of fossil fuels. It is expected, however, that CCS will have a major role to play in aiding the transition to a decarbonised economy, which is not heavily reliant upon the combustion of fossil fuels.

## 1.2 The CCS Cluster Concept

The key benefits of clustering arise from the potential to share the significant infrastructure costs associated with the capture, compression, offshore transport and storage of $CO_2$, and hence the potential delivery of more affordable solutions to emitters. Figure 1-1 shows a summary schematic of the CCS chain and cluster concept.

---

[6] See: http://www.theccc.org.uk/news/press-releases/610--committee-advises-government-on-approach-to-fossil-fuel-generation

[7] For example, the power station in North Dakota operated by the North Dakota Gasification Company. See http://www.dakotagas.com/About_Us/index.html

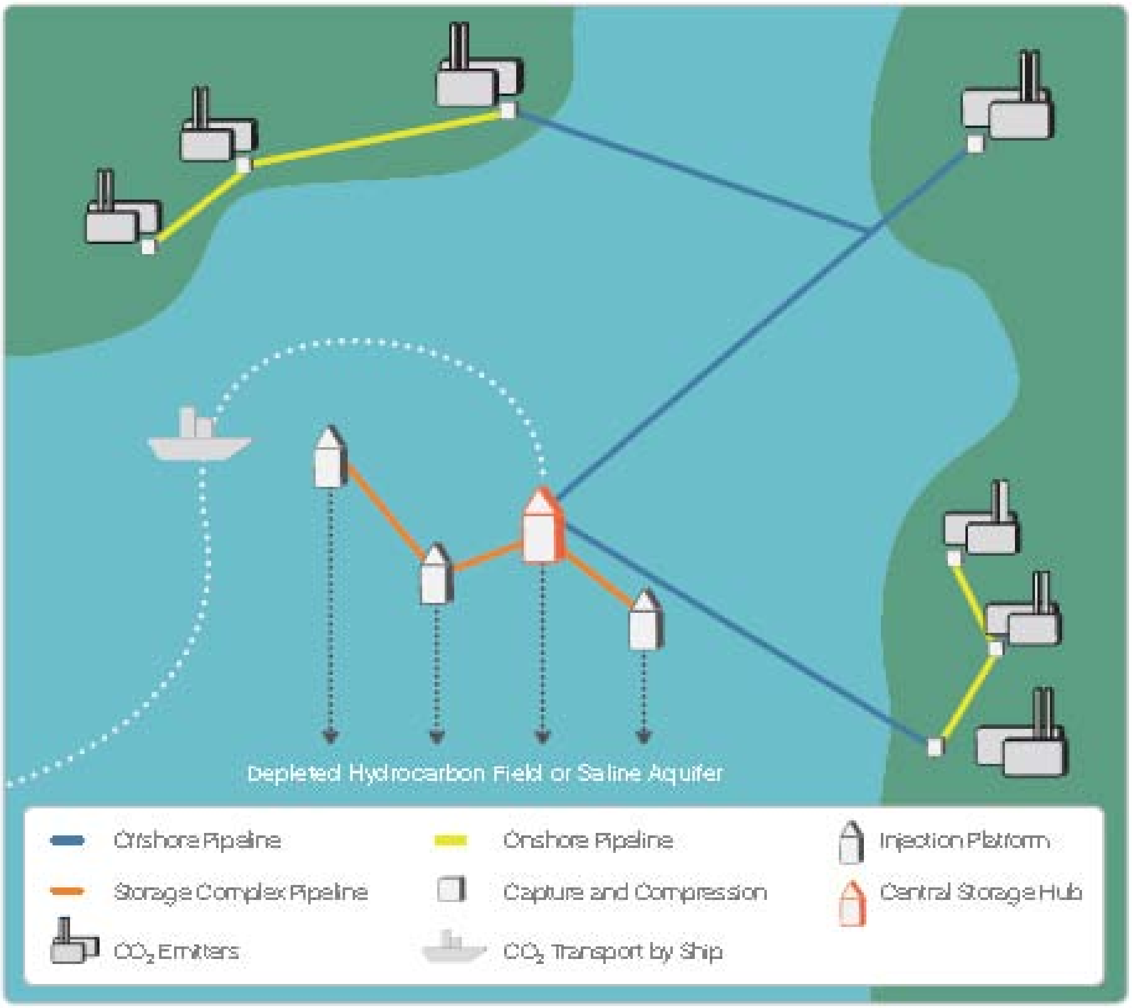
[8] For example, the $CO_2$ pipelines operated by Kinder Morgan across the US, See http://www.kindermorgan.com/business/co2/

[9] For example, storage of CO2 at Sleipner in the Norwegian sector of the North Sea. See http://www.statoil.com/en/TechnologyInnovation/ProtectingTheEnvironment/CarboncaptureAndStorage/Pages/CarbonDioxideInjectionSleipnerVest.aspx

[10] http://www.decc.gov.uk/en/content/cms/what_we_do/uk_supply/energy_mix/ccs/ccs.aspx

Research has been undertaken in a number of geographical areas in the UK to identify large scale $CO_2$ emitters and show how these might be linked to potential $CO_2$ storage sites. This body of work confirms that considerable savings in the capital and operational costs of pipeline networks can be made when they are scaled to meet the projected demand, albeit that any assumptions must be accompanied by an appreciation of the timing and extent of future deployment of CCS.[11]

Figure 1-1: Summary Schematic of CCS Chain and Cluster Concept




[11] DECC (2010) *Developing Carbon Capture and Storage (CCS) Infrastructure: Consultation on Implementing the Third Party Access Provisions of the CCS Directive and Call for Evidence on Long Term Development of CCS Infrastructure*, December 2010

# 2.0 Policy and Regulatory Drivers for CCS Clusters

The installation and deployment of CCS infrastructure is, by and large, expected to be driven by regulatory intervention and support. The UK Government is playing a lead role across EU Member States in making CCS a commercial reality through support both in terms of policy development and funding.

In the context of modelling and forecasting a phased roll-out of CCS infrastructure related to the East Irish Sea (EIS), as undertaken in Section 7.0, it is important here to highlight the key policy and regulatory mechanisms and how they will influence this trajectory. It should be noted, however, that due to the emerging nature of the regulatory framework for CCS it is subject to constant change and as such this report is based on our understanding at the time of writing.

## 2.1 Impact of the EU Emissions Trading Scheme

The primary method of regulatory intervention for the reduction of $CO_2$ emissions from the energy sector is the EU Emissions Trading Scheme (EU ETS). The EU ETS has two fundamental components, a cap on emissions, and a system for trading the 'right to emit'. The EU ETS cap sets a limit on the total emissions from the energy sector and other large emitting industries across Europe. From 2013, all individual installations within the energy sector are required to buy tradable allowances (EUAs) for each tonne of $CO_2$ they emit each year.

The ETS will therefore not function as a real driver for CCS until the avoided cost of having to purchase EUAs (i.e. the installation and operation of CCS infrastructure) is lower than that of actually purchasing EUAs. Furthermore, as the current costs of deploying CCS are today considered commercially prohibitive (without significant public subsidy), even if the price of EUAs was higher than CCS costs, power station operators may decide that closure is a preferable option to ongoing operation. It might therefore be considered that the need for an increase in the price of EUAs is somewhat less important than the need to reduce the overall costs of CCS.

## 2.2 UK and EU CCS Demonstration Programmes

The UK Government is currently progressing with a programme of four CCS demonstration projects. The commitment to funding these projects was announced by the previous administration and now backed by the current Coalition Government within their Programme for Government.[12]

The funding of the projects is expected to come from various sources. The first project (Demo 1) will be funded directly by Government. Subsequent projects (Demos 2-4) may be funded via the mechanism outlined in the Energy Act 2010. Within the Act, the Secretary of State is given power to make regulations for the introduction of a 'CCS Levy' on electricity suppliers. It is understood, however, that this proposed Levy

[12] HM Government (2010) The Coalition: Our Programme for Government, May 2010

might be subsumed into a wider support mechanism for low carbon energy sources, rather than just CCS.[13]

Although not able to provide financial support, the Government of Ireland has also recognised the need for the introduction of CCS and has commissioned a recent study to assess the potential of offshore storage reservoirs.[14] Furthermore, Enterprise Ireland has identified the need to support industry on the development of new CCS infrastructure.[15]

This support from DECC for UK projects is likely to be complemented by funding from the European Commission (EC), which has allocated 300 million EU EUAs to CCS projects from the ETS' New Entrant Reserve fund. The so-called NER300 competition is now underway, and the EC hopes it will support up to eight new CCS projects across Member States, which may include up to three in both of the UK and Ireland.[16] It should be acknowledged, however, that the number of overall projects supported will depend upon the value of EUAs when these are sold onto the market.[17]

The first UK demonstration project, commonly referred to as 'Demo 1' is scheduled for first operation in 2015, whilst the first CCS projects funded by the EU via the NER300 mechanism (which might include UK 'Demos 2-4') are expected to be operating from 2016, albeit this might now appear somewhat ambitious. It is expected that this injection of finance into pre-commercial projects will stimulate the development of CCS and reduce the overall costs of deployment. The success and timing of the demonstration projects across the EU will heavily influence the timing of wider deployment of CCS.

As discussed in detail in Section 7.0, although these potential first-mover projects will be based on point-to-point solutions, they have the potential to function as 'catalysts' for surrounding emitters, enabling wider CCS clusters, as is proposed for the EIS.

## 2.3 Statutory Installation of CCS Infrastructure

Regulatory requirements across the UK have now been aligned such that any new coal-fired power station in England, Wales and Scotland must install a minimum of

---

[13] At the time of writing, DECC has just published a consultation on Electricity Market Reform (EMR), which states that a wider feed-in tariff is more likely for CCS and other low-carbon energy sources, which might also be accompanied by a carbon 'floor' price (which builds on the existing Climate Change Levy) and some form of capacity payments for flexible, available generation

[14] Sustainable Energy Ireland & Environmental Protection Agency (2008) *Assessment of the Potential for Geological Storage of CO2 for the Island of Ireland*, September 2008

[15] Enterprise Ireland (2009) *Carbon Capture and Storage, Environment and Green Technologies Department*, January 2009

[16] See: http://ec.europa.eu/clima/funding/ner300/index_en.htm

[17] The current value of EUAs for the post-2013 period indicates that support for as many as eight CCS projects is unlikely

300MWe (net) equivalent CCS capacity.[18] This position resolutely underlines the Government's stance that no new unabated (in terms of $CO_2$) coal-fired power stations will be built in the UK.

Where consent is given under this policy it will be conditional on the developer submitting to the appropriate determining authority, prior to commencement of construction, clear evidence of the following:

1. Evidence of a valid $CO_2$ Storage Permit, issued by DECC under the Energy Act 2008 (see Section 2.4 for related discussion);[19] and
2. Evidence of valid consents and/or arrangements for transport of $CO_2$ to the proposed storage site, either by pipeline or ship.

Furthermore, all new fossil-fuel plant (with a peak output capacity of 300MWe or more), including gas-fired power stations, must be designed to be 'carbon capture ready' (CCR). Along with a series of design considerations, being CCR in the UK means that consideration must be given in the planning process to the space requirements for future retro-fit of CCS technology.[20] This policy will apply in all member states, once Article 33 of the EU CCS Directive is transposed in to relevant domestic legislation.[21]

In terms of timing for mandating retrofit of full-scale CCS, the UK Government has committed to reporting on the economic and technical viability of CCS in 2018. The current expectation is that coal-fired power stations consented under this policy framework will need to retrofit CCS to their full capacity by the end of 2025, and that any new coal-fired power stations would need to have full-scale CCS infrastructure operating from the outset of operation.

For existing thermal installations in the UK and Ireland, however, none of the above requirements currently apply and therefore further regulatory mechanisms may be required to drive CCS retrofit. Whilst most of the existing coal plant in the UK and Ireland is likely to close by 2025, a large number of combined cycle gas turbine (CCGT) plant will continue to operate unabated. In this context, the UK Committee on Climate Change (CCC) has advised UK Government that full-scale CCS should be mandated on existing and new CCGT plant such that the UK can meet its 2030 and 2050 climate change targets. We have therefore reflected this position in our modelling of roll-out of CCS on CCGT facilities in Section 7.0.

---

[18] DECC (2009) *Draft Supplementary Guidance for Section 36 Applications: New Coal Power Stations*, November 2009: Scottish Government (2010) *Thermal Power Stations in Scotland: Guidance and Information on Section 36 of the Electricity Act 1989 under which Scottish Ministers determine consents relating to thermal power stations*, March 2010

[19] Evidence would include a contract with a third party with the appropriate permit/consent

[20] DECC (2009) *Carbon Capture Readiness: A guidance note for Section 36 Electricity Act 1989 consent applications*, November 2009

[21] See: http://eur-lex.europa.eu/LexUriServ/LexUriServ.do?uri=OJ:L:2009:140:0114:0135:EN:PDF

It is understood that Ireland may not need to mandate retrofit of CCS infrastructure on CCGT plant to meet its own climate change targets, albeit that Moneypoint Power Station, should it be replaced with a similar coal plant, would be required to install full-scale CCS infrastructure.[22] As discussed in Section 2.1, however, should the cost of CCS fall sufficiently low following the roll-out of catalyst projects to enable wider clusters, it may be preferable for CCGT plant operators to install CCS infrastructure than to purchase the required number of EUAs. The proposed EIS CCS cluster could therefore be an important resource for operators of CCGT and industrial plant on the east coast of Ireland.

## 2.4 Emerging Regulation of $CO_2$ Storage

In simple terms, without a suitable storage capacity, there will be no value in capturing and transporting $CO_2$. Storage is therefore perhaps the most critical component of the CCS chain. Until it was amended in 2007, the 1992 OSPAR Convention[23] prohibited the geological storage of $CO_2$. The 2007 amendment was therefore a key step in removing a barrier which had previously functioned as a disincentive to proposed enhanced oil recovery projects.

In the UK, DECC is currently in the process of developing a licensing regime for offshore storage that will draw from the existing regimes for offshore petroleum exploration and production licensing.[24] In basic terms, it is proposed that relevant hydrocarbon fields will move from being licensed as petroleum extraction sites to being licensed as $CO_2$ storage sites. In reality, the proposed system is regarded by many CCS project developers as potentially presenting a real barrier to accessing potential storage assets. This and other related commercial issues, including the influence of the leasing regime proposed by The Crown Estate, are therefore discussed in detail in Section 8.0.

Finally, it is worth noting the current status of liabilities relating to proposed future $CO_2$ storage sites. In the event of a leak, not only would the responsible entity be liable for any environmental consequences, but in the current situation, there would also be a need to buy EUAs for every tonne of $CO_2$ which escaped from the site. Assuming a minimum of the current value of EUAs of €10, and storage sites holding hundreds of millions of tonnes of $CO_2$, the potential financial consequences are such that the cost of insuring $CO_2$ storage sites currently appears prohibitive. Detailed analysis of this issue sits outside the scope of this study, but it should be noted that the UK Carbon Capture and Storage Association (CCSA) is working hard with Government, the EC and industry to find solutions to the issue, to help enable financing of wider CCS infrastructure.

---

[22] Personal Communication, Bob Hanna, Chief Technical Advisor, Department of Communications, Energy & Natural Resources

[23] The 1992 OSPAR Convention is the current instrument guiding international cooperation on the protection of the marine environment of the North-East Atlantic

[24] Petroleum licensing refers to both oil and gas

# 3.0 The Case for Government Investment in CCS

Further to the climate change benefits of investment in CCS detailed in Section 1.0, there is a clear economic case for Government investment in CCS. The UK has a long established engineering and project management skills in both fossil-fuel power generation and offshore hydrocarbon exploration and production, both of which will be integral to the technical delivery of CCS. Furthermore the UK also has the supporting financial and legal expertise to deliver the complex business models and contractual agreements necessary for project delivery.

As stated in DECC's Industrial Strategy for CCS, investing in CCS projects will:[25]

- Provide direct job opportunities across the UK;
- Develop engineering and integration capabilities to stimulate domestic supply chains and skill bases; and
- Enable UK businesses to pursue global CCS opportunities and export a range of technical, legal and financial services.

These benefits are further discussed in Section 3.1 with regard to the proposed EIS CCS Cluster.

## 3.1 Economic Benefits Related to the EIS CCS Cluster

As discussed in Section 1.0, whilst many of the individual technologies involved in the CCS chain are not entirely new, they have yet to be demonstrated together at a commercial scale. As a result, there is a range of enabling technologies and related services still to be developed, which brings with it significant economic opportunities, which might be facilitated by CCS cluster development.

As a new market, estimates of the future value of demand for CCS are subject to considerable uncertainty. Recent DECC research suggests that UK spending on coal-related CCS infrastructure could reach £1 billion (Gross Value Added) per annum by 2030.[26] The majority of this spend would be associated with $CO_2$ capture technologies, with the transport and storage elements estimated to account for around 15% and 25% of total capital investment respectively. Assuming this annual spend is split equally across four funded cluster projects, this could represent £250 million a year for projects relating to the EIS Cluster.

Other recent research undertaken on behalf of DECC has focused specifically on the cost of developing transport and storage infrastructure.[27] Based on the development

---

[25] DECC (2010) *Clean coal: an industrial strategy for the development of carbon capture and storage across the UK*, March 2010

[26] AEA for DECC (2009) *Future Value of Coal Carbon Abatement Technologies to UK Industry*, June 2009

[27] Parsons Brinckenhoff for DECC (2009) *Technical Analysis of Carbon Capture & Storage Transportation Infrastructure*, May 2009

of three clusters, estimates of £2 - 3.5 billion were given, which might be considered highly optimistic. Furthermore, DECC expects UK-resident businesses to secure a large proportion of this market due to the international competitiveness of the domestic offshore oil and gas sector.

Another recent study has explored the potential deployment of CCS technologies in the UK under a range of different scenarios.[28] This study estimates that as a result of CCS infrastructure development, a total of 30,000 - 60,000 jobs will be sustained in the UK by 2030, with 50% of these directly associated with CCS.

Furthermore there is a major opportunity for the UK to capitalise on an emerging global industry. The International Energy Agency's CCS roadmap foresees a massive requirement for capital investment along full CCS chain, estimated at almost $100 Billion between 2010 and 2020, increasing to over $5,000 Billion between 2010 and 2050.[29]

At a more local level it is feasible that under a future high carbon price the existence of a proven CCS network will function as a 'magnet' to future industrial development, thus bringing substantial economic benefits to those areas connected to the EIS.

---

[28] AEA for DECC (2009) *Future Value of Coal Carbon Abatement Technologies to UK Industry*, June 2009

[29] IEA (2009) Technology Roadmap - Carbon capture and storage, 2009

# 4.0 Potential $CO_2$ Storage Assets in the EIS

The EIS Cluster, set out conceptually in this report, differs from other emerging UK CCS clusters, for example those proposed in Yorkshire and Humber or Eastern Scotland, in that it is not formed around a sole pre-defined onshore region, rather it is an offshore 'storage resource' driven cluster which will potentially accept $CO_2$ from a range of onshore areas across the UK and Ireland.

As presented in detail in Section 7.0, the EIS is surrounded by a range of large-scale $CO_2$ emitters in North West England, Northern Ireland and on the east coast of Ireland. All such 'mini-clusters' could feasibly be linked to the $CO_2$ storage sites in the EIS by either pipeline or ship. Furthermore, two further mini-clusters located on the west coast of Scotland and on the south coast of Wales have no alternative than to rely upon the EIS for $CO_2$ storage, should CCS retrofit be required.

## 4.1 The Need for Storage of $CO_2$ in the East Irish Sea

If the roll-out of CCS infrastructure becomes widespread, as is hoped by UK Government, the potential $CO_2$ storage assets of the EIS will be of strategic national importance.

The availability of $CO_2$ storage capacity is a prerequisite for CCS, and suitable resources are limited not only by geology, but also by public acceptance and regulatory constraints, with regard to onshore storage.[30] In this context, unless the EIS $CO_2$ storage capacity is enabled, current Government policy will be such that any thermal power station emitter located geographically west of the Pennines will potentially not be permitted to operate beyond 2030. As a result, in the national (and international) energy interest, every effort should be made in order to ensure transition of the hydrocarbon fields located in the EIS from oil and gas extraction to $CO_2$ storage.

The geology of the EIS is well known due the history of hydrocarbon exploration and production. All publicly available evidence suggests that once depleted, the hydrocarbon fields within the EIS could act as a natural storage resource for $CO_2$. Details of storage capacity and related issues are provided in Sections 4.2 to 4.6.

## 4.2 Assessment of Storage Capacity

The potential $CO_2$ storage capacities of both hydrocarbon fields and saline aquifers in the EIS have been assessed at high-level by the British Geological Society (BGS).[31] More detailed research has been undertaken on behalf of Ayrshire Power Ltd (APL)[32]

[30] Current legislation in the UK provides for offshore storage only

[31] DTI (2006) *Industrial carbon dioxide emissions and carbon dioxide storage potential in the UK*, October 2006

[32] Studies were undertaken by Senergy on behalf of APL, but are considered commercially confidential

which also included saline aquifers.[33] In this study, potential storage sites were evaluated using geological data derived from purchased well logs and from published work, and geophysical data from seismic surveys. The key criteria for the site search were:

- Containment – a structural closure to stop $CO_2$ migrating to the surface combined with impermeable overlying formations;
- Capacity – a sufficient volume of porous reservoir rock and a sufficient depth to allow dense phase storage of the $CO_2$; and
- Injectivity – the reservoir rock must allow high rates of $CO_2$ injection.

The best potential storage area identified in both studies was the Liverpool Bay and Morecambe Bay natural gas fields, as discussed in more detail in Sections 4.3 and 4.4.

## 4.3 Morecambe Bay Fields

The largest Morecambe Bay Fields are South Morecambe and North Morecambe, which are owned and operated by Hydrocarbon Resources Ltd (HRL), a subsidiary of Centrica plc.

Based on the aforementioned analysis on behalf of APL, the theoretical maximum $CO_2$ storage capacity for South Morecambe is approximately 820 million tonnes and for North Morecambe is approximately 180 million tonnes (measured in surface volumes).

The last hydrocarbon production from both fields is anticipated during the 2020s, albeit it is likely that North Morecambe will be first to cease production.

## 4.4 Liverpool Bay Fields

The largest Liverpool Bay Fields identified as suitable for $CO_2$ storage are Hamilton and Hamilton North. In addition, there are three producing oil fields which could provide niche opportunities for enhanced oil recovery (EOR), although this would not offer any significant long-term storage capacity.

Publicly available information suggests that the Hamilton and Hamilton North fields present the earliest opportunity for $CO_2$ storage in the EIS, with these assets potentially being available from 2014.

Based on the aforementioned analysis on behalf of APL, the theoretical maximum capacity for Hamilton is approximately 110 million tonnes and for Hamilton North is approximately 40 million tonnes (measured in surface volumes).

[33] Saline aquifers are geological formations consisting of water permeable rocks that are saturated with salt water. In theory the injected CO2 will be retained by formation waters and over time will dissolve and may be converted to carbonate minerals resulting in permanent sequestration.

## 4.5 Total Storage Capacity in Key Fields

These most significant fields highlighted in Sections 4.3 and 4.4 are summarised in Table 4-1, which shows a total estimated potential $CO_2$ storage capacity of 1,148Mt.

Table 4-1: Summary of East Irish Sea CO2 Storage Resource

| Gas Field | Likely year of Depletion | Storage Capacity ($MtCO_2$) |
|---|---|---|
| Hamilton | 2014-2017 | 113 |
| Hamilton North | 2014-2017 | 38 |
| Liverpool Bay Sub-total | | **151** |
| South Morecambe | 2023-2030 | 820 |
| North Morecambe | 2020-2023 | 177 |
| Morecambe Bay Sub-total | | **997** |
| **TOTAL** | | **1,148** |

The vast potential of these storage assets has been highlighted in a recent DECC report which outlines the significance of this resource to the UK.[34] Analysis of the significance of the potential capacity in relation to the scale of demand from geographically relevant emitters is demonstrated in Section 4.1.

It is important to highlight that a number of suitable fields have been identified as suitable for $CO_2$ storage, which provides a degree of contingency should detailed site specific appraisals rule out any one site. Due to its massive scale, identified as the second largest 'realistic' $CO_2$ storage site of UK gas fields by DECC,[35] the South Morecambe field is clearly the most valuable asset to the cluster. The close proximity of the fields, as shown in Figure 4-1, will also provide efficiencies in terms of the smaller distances (compared to other potential clusters) required to connect pipelines between $CO_2$ storage sites as part of a 'hub' solution as discussed in Section 6.4.3.

Some of the hydrocarbon fields within the EIS are now at what might be described as a 'mature' phase, meaning that some could become available for transfer into use for $CO_2$ storage during the next 2-5 years. Section 6.4 explores the issue of availability in more detail, although it should be acknowledged that such information is commercially sensitive and is therefore provided at outline level only.

---

[34] Senior CCS Solutions Ltd for DECC (2010) *CO2 Storage in the UK – Industry Potential*, 2010

[35] DECC (2009) *Carbon Capture Readiness: A guidance note for Section 36 Electricity Act 1989 consent applications*, November 2009

Figure 4-1: Geographical Location of East Irish Sea Storage Resources


## 4.6 Saline Aquifers

Given that they have successfully trapped oil and gas for millennia, hydrocarbon fields are the obvious place to start looking for long-term $CO_2$ storage capacity. The potential for significant capacity in saline aquifers, however, should not be overlooked.

The key difficulty with saline aquifers is that they are usually not well characterised, as in contrast to productive hydrocarbon fields, there has been no ongoing investigation and analysis of the related geology. At this stage, therefore, judging the suitability of any particular saline aquifers is highly speculative and the related $CO_2$ storage capacities are also unknown. Unless significant funds were to be devoted to test drilling, injection of $CO_2$ and subsequent monitoring of $CO_2$ in an aquifer, therefore, such potential storage sites are considered very unlikely to be bankable.

Publicly available information suggests that the two main aquifers within the EIS, referred to as 'Closure 5' and 'Closure 6' seem to provide for very good $CO_2$ storage properties.[36]

Further work undertaken on behalf of APL, however, indicates that both closures are too shallow (i.e. less than 700m below seabed) to be safely used for $CO_2$ storage. The same research has shown that there are also deeper aquifers beneath the hydrocarbon reservoirs, but preliminary petrophysical data indicates that the permeability is likely to be inadequate for $CO_2$ injection due to the presence of water and mineralisation. It is therefore not believed that these structures are suitable for $CO_2$ storage.

It is interesting to note that Stag Energy is looking to exploit offshore saline aquifers in the vicinity of the South Morecambe fields for the purpose of natural gas storage through its Gateway Project. Extensive geological and technical surveys have confirmed the suitability of aquifers at depths between 750 and 1,025 metres beneath the seabed. Pipelines will connect the storage area to an onshore gas processing site adjacent to the existing Morecambe terminals. The associated front-end engineering and design (FEED) phase is nearing completion with a potential final investment decision to be made in 2011.

The current phase of the Gateway Project would provide a massive 1.5 billion cubic metres of storage, and whilst it is clearly aimed at underpinning the long-term viability of the current natural gas service industry in the region, it could present substantial learning, both technical and commercial, with regard to the development of such offshore aquifer resources.

[36] K. Kirk (2006) *Potential for storage of carbon dioxide in the rocks beneath the East Irish Sea*, Tyndall Centre for Climate Change Research, February 2006: DTI (2006) *Industrial carbon dioxide emissions and carbon dioxide storage potential in the UK*, October 2006

# 5.0 Analysis of Existing Related $CO_2$ Emissions

The west coast of the UK and the east coast of Ireland host some major $CO_2$ emitters. The largest installations are typically thermal power generators and energy intensive businesses in the manufacturing and petrochemicals industries. As discussed in Section 4.1, CCS – and therefore suitable $CO_2$ storage capacity – will be essential to enable continued operation of such facilities as part of a decarbonised economy.

To facilitate assessment of the likely level of demand for CCS infrastructure in the future, it is necessary to first understand:

- Where relevant existing installations are located; and
- How much $CO_2$ is currently being generated by these installations.

These issues are explored in Sections 5.1 to 5.2.

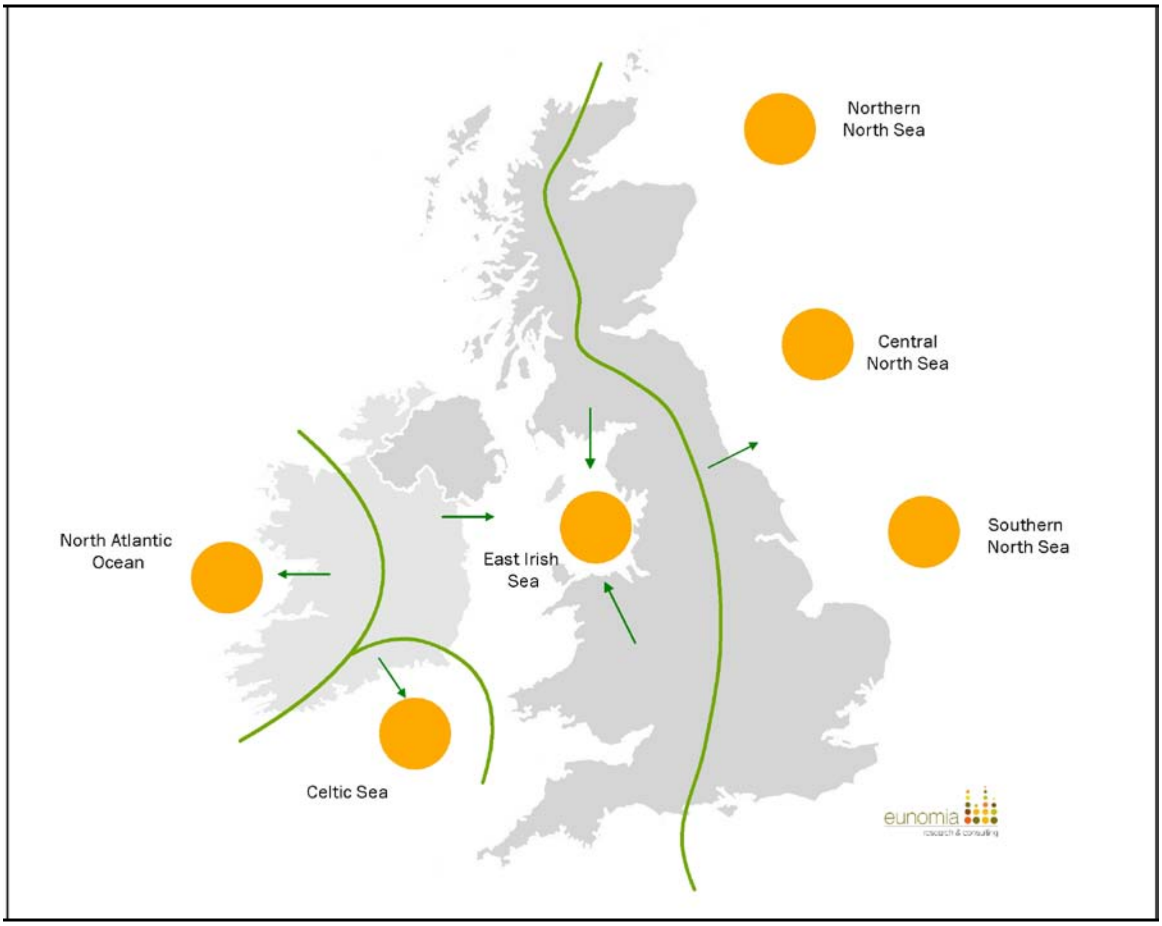
## 5.1 Location of EIS in Relation to Major Emitters

The EIS sits at the heart of the UK and Ireland, such that the existing hydrocarbon fields are immediately surrounded by emitters in North West England, North Wales and East Ireland. At high level, Figure 5-1 shows all major storage assets located within UK and Irish waters. This demonstrates that emitters on the East coast of the UK are most likely to use potential sites in the Northern, Central and Southern North Sea. Similarly, for those emitters on the West and Southern Coast of Ireland, the hydrocarbon fields in North Atlantic Ocean and the Celtic Sea[37] will be the most likely storage destinations.

For most other emitters, the most technically, politically and economically viable storage location will therefore be the EIS. Whether these emitters will actually use the EIS to store $CO_2$, however, will be determined by their ability to continue operating economically under such circumstances, which is dependent upon additional parameters such as their proximity to other emitters. Assumptions relating to these parameters are explored in detail in Section 7.0.

[37] Although the storage assets identified in the Celtic Sea are in fact closer to emitters in South Wales, the effective storage capacity is relatively low (330Mt) and is likely to be fully utilised by emitters on the coast of Southern Ireland

Figure 5-1: High Level Storage Facilities (UK and Ireland)




To ensure that this report includes only emitters which are most likely to use the East Irish Sea as a storage solution, the primary focus has been limited to the following regions:

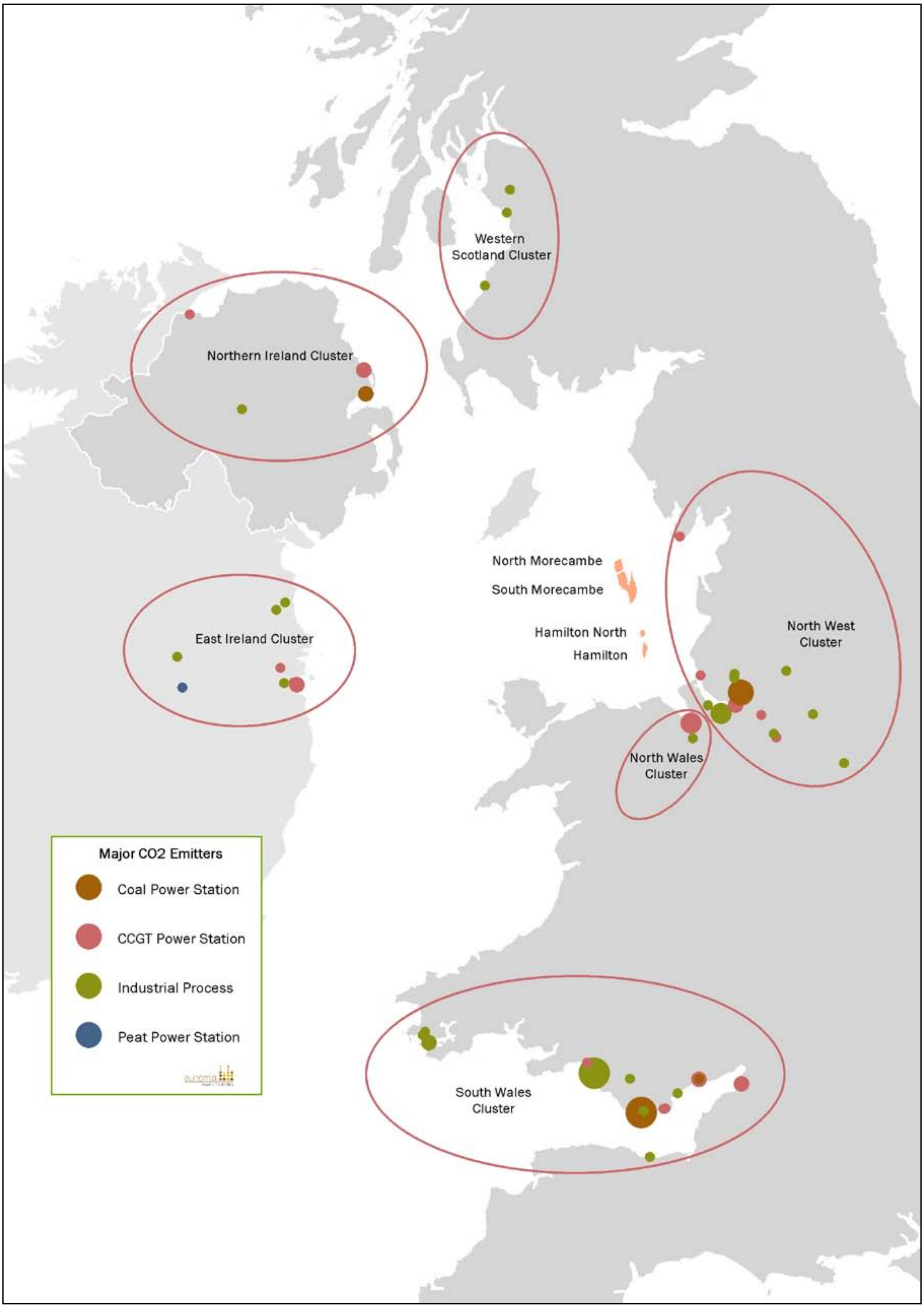
- Western Scotland;
- North West England;
- North Wales;
- South Wales
- South West England;
- Northern Ireland; and
- Eastern Ireland.

Figure 5-2 shows these regions as distinctive 'mini-cluster' groupings defined for the purpose of this study to represent existing and likely future emitters. It should be noted that emitters in South Wales have been joined with emitters in South West

England due to their proximity.[38] It should also be noted that emitters in North Wales are kept distinct from emitters in North West England despite their close proximity. This is due to the fact that the pipeline infrastructure which would most likely be utilised by the North Wales cluster will only be suitable for its own needs and could not accommodate emitters from the North West of England.

[38] Given that there are only two emitters identified in 'South West England' (Seabank gas-fired power station near Bristol and Wansbrough Paper Mill in Somerset) and their proximity to the Welsh border these have been included in the South Wales mini-cluster

Figure 5-2: Existing $CO_2$ Emitters Included in the Study



## 5.2 Current Levels of $CO_2$ Emissions

To facilitate understanding of the current and future level of $CO_2$ emissions relevant to the EIS, it is necessary to quantify emissions from each mini-cluster.

Economic and practical constraints are such that it will not be feasible for emitters of all scales to capture, compress and transport $CO_2$ to the EIS, even if this involves the use of shared transport infrastructure. In the absence of any regulatory criteria or 'cut-off' point, therefore, we have made an informed judgment as to an appropriate threshold of emissions below which we have assumed retrofit of CCS infrastructure would not take place. Based on our experience of this kind of modelling, and the relative costs of CCS related infrastructure, this threshold has been set at 50,000 tonnes of $CO_2$ per annum. Any facilities with lower levels of emissions have been excluded from this study.

For those installations which emit over 50,000 tonnes of $CO_2$ per annum ($tCO_2pa$), we have collated historic emissions data. The primary source of this data is the EU Pollutant Release and Transfer Register (E-PRTR).[39] The register amalgamates data reported by individual facilities on an annual basis to the relevant 'competent authorities' (i.e. Environment Agency and Scottish Environmental Protection Agency), which compile and check the quality of the reported data. The data is then provided to the EC and the European Environment Agency. Although comprehensive, the register only contains data for installations between 2004 and 2008. Verified emissions data for 2009 has therefore been obtained from the Community Independent Transaction Log for the EU ETS.[40]

Table 2 in Appendix 2.0 shows all relevant existing installations emitting over 50,000$tCO_2pa$ (furthermore Table 3 shows all other known planned emitters), whilst Table 5-1 below profiles total emissions by mini-cluster. The largest emitting group is South Wales, where in 2009 nearly 19 million tonnes of $CO_2$ were emitted by large-scale installations. There are also significant emissions arising from North West England. The largest individual sources of emissions throughout the mini-clusters are coal-fired power stations.

[39] See: http://prtr.ec.europa.eu/

[40] See: http://ec.europa.eu/environment/ets/

Table 5-1: Total Annual $CO_2$ Emissions by Mini-cluster Group (based on 2009 data)

| Mini-cluster | Total $CO_2$ Emissions (Mt/year) |
|---|---|
| Eastern Ireland | 6.2 |
| North Wales | 5.1 |
| North West England | 12.6 |
| Northern Ireland | 3.9 |
| South Wales | 18.9 |
| Western Scotland | 0.3 |
| **TOTAL** | **47.0** |

# 6.0 Technical Opportunities and Constraints

Compared to other substances that are routinely transported by pipeline, the issues associated with $CO_2$ are particularly complex. Even small changes in pressure and temperature may lead to rapid and substantial changes in the $CO_2$ physical properties – notably phase and density. Whilst this can be managed to make transportation as efficient as possible, it also presents technical challenges as it will often be undesirable to have multi-phase flows through a single system.

Sections 6.1 to 6.6 consider a range of technical constraints and opportunities relating to the sharing of CCS infrastructure. The goal of the analysis is to characterise the conceptual design of the EIS CCS Cluster, such that the specific areas identified as requiring further assessment might be explored in more detail at a later phase of study development.

It should be noted that the potential to share onshore pipelines largely depends upon locational and routing constraints, which are explored in terms of the mini-clusters first presented in Section 5.1. Therefore, although this Section considers issues relating to offshore 'trunk' pipelines, it is focused on onshore infrastructure, such as capture and compression plant which would facilitate the effective functioning of the wider pipeline network.

## 6.1 Sharing of $CO_2$ Capture Facilities

Under point-to-point emission and storage scenarios, $CO_2$ capture might be considered to be relatively straightforward. $CO_2$ capture is likely to be based on the following three core technology (including generation) types:

- Post combustion capture (using either amines or chilled ammonia as an adsorbent), which is linked to conventional power stations and industrial plant;
- Oxyfuel capture, which relies upon injection of additional oxygen to support the process; and
- Pre-combustion capture, which is based on gasification technology to produce a $CO_2$ stream and hydrogen-rich synthesis gas ('syngas') for energy generation.

Whilst it is not within the scope of this analysis to provide further the details of each technology here, in the context of clustering, it is important to note that the goal of each is to produce a gas stream with as high a $CO_2$ content as possible, most likely greater than 99% $CO_2$ concentration, and using as little energy as possible in the process.[41]

Given the high capital cost of a $CO_2$ capture plant and the significant associated energy requirement of the process, it is worth considering the concept of transporting flue gases from point of emission to a central shared capture facility. There are some key considerations to this approach, however, as discussed in Section 6.1.1 to 6.1.4.

---

[41] Information on each technology can be found at in the aforementioned IEA report, which details the different approaches

### 6.1.1 Costs of Steel and Energy

The $CO_2$ proportion of flue gases is typically relatively small; for example, flue gas from a coal-fired power station contains approximately 10-15% $CO_2$. The volume of gas to be transported, therefore, is significantly larger than if being solely $CO_2$. This would thus require pipeline/ducting diameters of at least an order of magnitude greater (than if transporting concentrated $CO_2$), to cope with the necessary flow. For example, whilst a pipeline of around 1 metre diameter might be required to transport liquid $CO_2$ following capture, a diameter of approximately 13 metres might be required should this be transporting the entire flue gas stream.

Furthermore, whilst transport of liquid or gaseous $CO_2$ is unlikely to be considered as energy efficient or 'low cost', transport of flue gases over any distance would require far greater energy to power both fans at the point of emission and a series of booster fans along a pipeline.

As a result, the cost of steel and energy would render such an approach very unlikely to be economically viable, unless it was only over very short distances.

### 6.1.2 Visual Impact

Flue gas pipelines of around 13 metres diameter could not easily be buried and would have a significant visual impact in any location. Gaining planning consent would therefore be very unlikely unless both over a very short distances and on land within the boundaries of two adjacent emitters.

### 6.1.3 Flue Gas Characteristics

Flue gases from diverse types of facilities, for example, a coal-fired power station and CCGT plant, have very different characteristics. This relates to both chemical composition and temperature, which both function as a constraint to shared capture facilities. Under such a scenario, thermodynamics and chemical composition of a combined gas stream would need to be regularly monitored to avoid problematic issues such as condensation and acid creation which would have a corroding effect on any shared pipeline. Combining of flue gases would therefore need to be carefully considered on a case-by-case basis according to detailed compositional data.

### 6.1.4 Specific Opportunities

The constraints detailed above indicate that the sharing of $CO_2$ capture facilities is likely to be limited to examples whereby:

- There are immediately adjacent or co-located facilities; and
- Flue gas streams are of similar composition and temperature.

There are no relevant examples within any of the proposed mini-clusters which meet both of the above criteria. Whilst Pembroke CCGT Power Station in South West Wales is located sufficiently close to a refinery, the flue gas streams from these two plants are very unlikely to be compatible.

In contrast to CCGT plant, refining processes typically produce relatively low volumes of flue gases at high pressure. As such, they require far narrower pipelines, which could present easier opportunities for shared capture plant. There do not currently exist any co-located refineries within any of the mini-clusters surrounding the EIS, but such opportunities are worthy of future consideration.

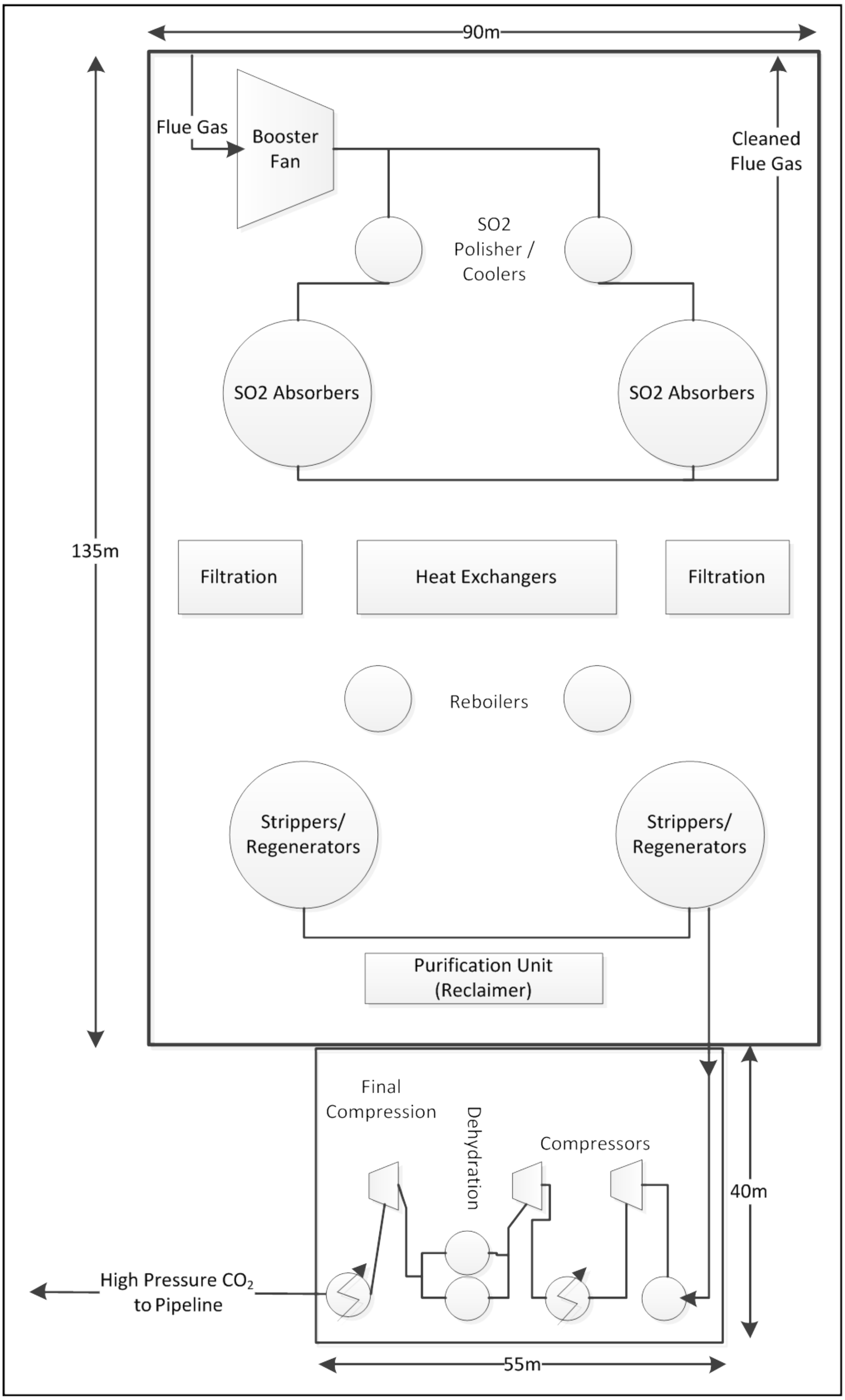
For smaller emitters, the potential future availability of modular, ‘off the shelf’ capture facilities, which might be significantly cheaper than those currently on the market, represents a more realistic means to cost reduction of CCS infrastructure than sharing capture plant. Whilst such modular plant are not yet commercially available, under a future high-price of carbon scenario it is possible that such technologies may emerge, particularly those based upon use of cheaper amines, such as DEA.[42]

## 6.2 Onshore $CO_2$ Handling and Transport

As per the discussion for $CO_2$ capture in Section 6.1, there is also merit in exploring the possibilities for sharing of $CO_2$ handling infrastructure such that the costs of CCS might be reduced across a network of emitters. Figure 6-1 provides a summary of the key elements of the $CO_2$ capture and gas handling process, which includes dehydration, compression and liquefaction infrastructure.

[42] Diethanolamine. Monoethanolamine (MEA) is currently the most widely used adsorbent used in $CO_2$ capture technologies

Figure 6-1: $CO_2$ Capture and Gas Handling



### 6.2.1 $CO_2$ Dehydration

$CO_2$ must undergo a dehydration process to remove almost 100% of water prior to travelling any significant distance via pipeline as the presence of water within the $CO_2$ stream can produce carbonic acid which is highly corrosive. Therefore, as for capture infrastructure, it is likely that the risk of corrosion would be such that dehydration units would not be shared other than in situations whereby emitters are co-located.

To mitigate the risk of pipeline corrosion, which could lead to serious consequences both operationally and in terms of safety, more exotic materials might be considered alongside steel based on their relative resistive properties. Cathodic protection, a technique used to control corrosion by making it the cathode of an electrochemical cell, might also be option.

### 6.2.2 Onshore $CO_2$ Compression

Compressors are used not only to effect changes in $CO_2$ phases (e.g. liquefaction), but also to reduce the volume of gases and thus the required diameter of associated pipelines. Compression requires significant amounts of energy, and therefore $CO_2$ networks should aim, where possible, to minimise such use to reduce the costs of transportation, albeit this will require greater amounts of steel for increased diameter pipelines. Design of a pipeline network and compression infrastructure must also consider the 'phase' changes of $CO_2$, as pipelines move from onshore to offshore environments, which involve changes in external temperatures, which affect the state of the gas stream. Pressure drops must therefore be considered, such that $CO_2$ arrives at the destination reservoir at the desired pressure for injection.

Assuming an external temperature of 5°C (determined by the depth below sea level of the pipeline and subject to seasonal variation) $CO_2$ might be transported by pipeline in either 'dense' or 'supercritical'[43] phases at 80-100Barg. Assuming continuous transport of 2 million tonnes per annum of $CO_2$, this would require a pipeline with a diameter of around 20". Transportation in gaseous phase at 30-40Barg, in the same temperature range, would require a pipeline diameter of around 36"cm. Related energy costs would depend upon the distance of transport required and the price of power, which are not within the scope of this study.

The opportunities to reduce the level of compression depend upon:

- The volume of $CO_2$ to be transported;
- The local consenting environment; and
- The distance of transport; and
- The pressure conditions within the destination reservoir.

Within mini-clusters across short distances, there may be the opportunity to transport in gaseous phase, which also offers benefits in terms of perceived health and safety

---

[43] When $CO_2$ is close to or above its critical pressure (73.82 bar) many of its properties are similar to that of a liquid and in this state it is often referred to 'dense' phase. Above critical temperature (31.04°C) it is referred to as supercritical

constraints, as discussed in Section 6.2.4. Additional shared compressor stations might therefore be located at various points across a $CO_2$ network, potentially near an onshore-offshore boundary to optimise the energy demand and the cost of steel pipelines across the network.

For example, as shown Figure 3 in Appendix 3.0, in Northern Ireland the conceptual pipeline network might involve the cement works at Cookstown being linked in sequence to Coolkeeragh (CCGT), Ballylumford (CCGT) and finally Kilroot (coal) on the coast. Within this mini-cluster, $CO_2$ could be transported in gaseous phase, before being compressed and liquefied at a central point near Kilroot prior to entry into a higher-pressure offshore pipeline.

### 6.2.3 Road Transportation of $CO_2$ from Smaller Emitters

The concept of smaller scale emitters using modular capture systems, as described in Section 6.1.4, could also include related modular transport systems. This would negate the need for such emitters to have a potentially cost prohibitive connection to the main pipeline network. Under this approach, $CO_2$ would be captured and compressed on site before using the road network to deliver pressurised containers to a central onshore network hub.

A significant constraint to this approach, however, is the road transport containerisation limit of approximately $10m^3$. Initial calculations suggest that for a facility emitting 50,000 $tCO_2pa$ (the minimum threshold used in this study) around 16 vehicles movements would be required per day. The cost of such a requirement, not to mention the environmental impact of fuel usage, is such that this approach is unlikely to be economically viable.

### 6.2.4 Onshore Health and Safety Considerations

Consideration of onshore handling and transportation of $CO_2$, even at a conceptual stage, cannot be complete without discussion of health and safety issues. Although $CO_2$ is not considered toxic or hazardous at low concentrations and inventories, when transported by pipeline at the volumes and concentrations required for the proposed CCS cluster, it is likely to be considered a hazardous substance by the UK Health and Safety Executive (HSE). In the event of a major incident in populated areas, the main risk to human health is of asphyxiation. This risk is more acute in low-lying areas where $CO_2$, as a dense gas (50% heavier than air), can 'pond', and being odourless and colourless, it is difficult to detect. It is therefore possible that $CO_2$ streams will need to be odorised prior to onshore pipeline transport.

In the event of dense or supercritical phase $CO_2$ escaping into the atmosphere the fluid undergoes a rapid expansion. A proportion essentially 'boils' and becomes a gas while the remainder forms solid particles (dry ice), with cryogenic burns being a serious hazard to health. The HSE do not yet fully understand the behaviour of $CO_2$ when released from dense phase pipelines and further appropriate scale experimental work is therefore required to provide a more thorough comprehension.[44]

---

[44] http://www.hse.gov.uk/carboncapture/carbondioxide.htm

The most likely scenario for a large scale release would be a ruptured pipe caused by human interference. The pipeline must therefore be designed to mitigate this risk through considered routing, ensuring appropriate depth of cover, sufficient pipe wall thickness and protection against third party interference. Should the pipe be ruptured, emergency plans will need to be in place which provide details of immediate response measures. The HSE acknowledges that the likelihood of such an occurrence should be very low where the risks are well mitigated, and is currently working with relevant stakeholders to develop a shared understanding of the risks associated with CCS and the appropriate control measures.[45]

In terms of operational CCS plant it is possible chemicals and gases not previously present (or not in such quantities) will be brought onto sites and this could therefore require Hazardous Substance Consent (HSC) under the Planning (Hazardous Substances) Regulations 1992. The Control of Major Accident Hazards (COMAH) Regulations will also need to be observed to ensure all necessary measures are taken to prevent major accidents involving dangerous substances.

## 6.3 Offshore $CO_2$ Transport

### 6.3.1 Potential Trunk Pipelines to the EIS

It is likely that the proposed EIS $CO_2$ pipeline network would include a series of 'trunk' pipelines from mini-clusters to the Hamilton and Morecambe Bay storage sites. The first of these could come from the proposed power station at Hunterston, which represents the potential 'catalyst' project for the EIS cluster. Studies undertaken on behalf of APL into the economic and technical viability of transporting the $CO_2$ from Hunterston concluded at an early stage that a pipeline would be preferable to use of ships.[46]

The aforementioned studies also considered two distinct pipeline routes, an entire subsea route and a further route incorporating a landline section across Dumfries and Galloway. The analysis concluded that despite the latter route being some 40km shorter, the subsea pipeline is likely to be preferable given likely lower operating costs. The landline route is also very likely to involve greater consenting costs and therefore risk of project delays.

As shown within in Figure 6-2, a subsea pipeline from Hunterston to the Hamilton natural gas fields would be 320-340km in length given the potential indirect route, initially along from the mouth of the Clyde, through the North Channel into the EIS, passing to the West and then South of the Isle of Man, before turning East to reach the potential storage sites. This route and the principal constraints discussed in Section 6.3.1.1 are shown in Figure 6-2. It should be noted, however, that APL has since undertaken work of far greater detail on pipeline routings to support a bid to the

---

[45] See www.hse.gov.uk/carboncapture/

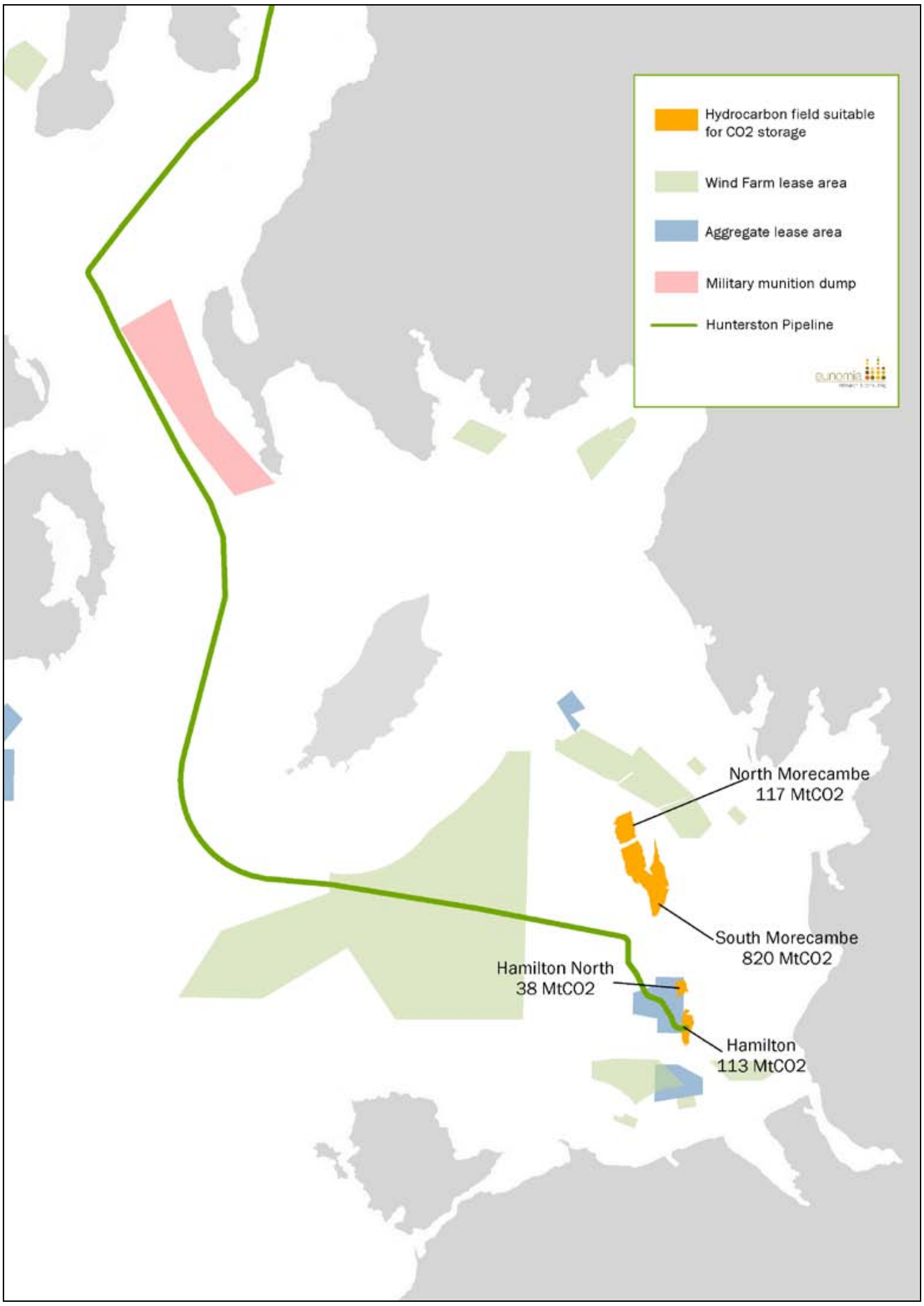
[46] Related studies were undertaken by Atkins Boreas on behalf of APL, but are considered commercially confidential

EC's New Entrant Reserve (NER) fund for CCS projects. The routes included within this conceptual report are therefore not necessarily those being developed by APL.

#### 6.3.1.1 Routing Constraints for Trunk Lines to the EIS

Each trunk line from the mini-clusters detailed in Section 5.1 will have its own routing constraints. Again, as Hunterston is regarded as the 'catalyst' project for the cluster, for the purposes of this study, it is sensible to focus on the constraints of this particular route.

Figure 6-2: Routing Constraints for 'Trunk' Pipeline from Hunterston to Hamilton Field




Note: Existing pipelines and cables are not included in this map as they are considered far easier to negotiate than other constraints

In terms of man-made constraints the potential route outlined in this study from Hunterston to the EIS is initially dominated by the need to avoid Beaufort's Dyke. This deep channel was used as a large-scale munitions dumping ground following the Second World War. Recent surveys have indicated that significant quantities of unexploded ordnance remain present outwith the designated area, and as such, any activity that would disturb the seabed in these areas should be undertaken with extreme caution. For this reason it is likely that the pipeline route from Hunterston will pass Beaufort's Dyke to the South West of the North Channel towards the coast of Northern Ireland.

A Ministry of Defence (MoD) sub-marine firing range also covers a large section of the North Channel which would require a significant detour to avoid. Due to the presence of existing cables and pipelines across this area, however, it is likely that the associated obstacles to laying of a new pipeline would not be insurmountable. It is understood that APL is having discussions with the MoD in this respect, and also with regard to a further firing range East of the Isle of Man to support the consideration of alternative routes to the Liverpool and Morecambe Bay fields.

The proposed route detailed in Figure 6-2, would also pass through the Round 3 Irish Sea development zone of the offshore windfarm leasing programme, as well as a Liverpool Bay aggregate dredging application area. These potential conflicts will need attention at a later stage as compliance with covenants and clauses within legal agreements held for their features may be required. It will of course also be necessary to consider licensed hydrocarbon blocks.

An asset check for a proposed subsea pipeline route to the Hamilton Fields has identified a number of further constraints that require consideration. There are 27 electricity or telecommunications cables (16 active, 10 inactive and 1 proposed) and 15 pipelines (14 active, 1 proposed) which would require negotiation by the potential $CO_2$ pipeline. Again, these conflicts would require consideration and negotiation by the proposed pipeline. Assuming a pipeline route is later required to the Morecambe Fields negotiation of a further 15 existing pipelines would need to be considered.

It should be noted that the constraints described above relate to the central 'trunk' pipeline from Hunterston only, and that there would be specific additional constraints relating to any additional trunk pipelines which might be linked to the network at the appropriate times in the future. All such constraints would need to be carefully managed to facilitate laying of pipelines by lay barges such as that pictured in Figure 6-3.

Figure 6-3: Dynamically Positioned Pipe-lay Vessel

Note: Image provided courtesy of Allseas

### 6.3.2 Technical Constraints relating to 'Trunk' Pipeline Design

As discussed above, even small changes in pressure and temperature may lead to rapid and substantial changes in the physical properties of $CO_2$. This presents significant technical challenges when designing offshore pipelines.

Pipeline design for $CO_2$ storage in the EIS must initially focus on knowledge of the existing reservoir conditions into which the $CO_2$ will be injected. As detailed in Table 6-1, the conditions in the EIS are expected to be broadly similar across the four potential storage assets due to their comparable depths.

Table 6-1: Anticipated Reservoir Conditions at End of Gas Production/Start of Storage

| | Hamilton | Hamilton North | South Morecambe | North Morecambe |
|---|---|---|---|---|
| Depth (feet) | 2,300 | 2,600 | 2,400 | 3,000 |
| Bottom of Reservoir Temperature (°C) | 30 | 30 | 33 | 33 |
| Reservoir Pressure (Bara) | 8-15 | 8-15 | >10 | >10 |

Pipelines and compression infrastructure must therefore be designed such that the arrival conditions of $CO_2$ in the pipeline are just sufficient to transport it down the wellbore and into the reservoir without fracturing it. Such design philosophy can be used to minimise the need for potential offshore re-heating infrastructure, which would add significant cost to the solution.

Pipeline design must also take into consideration changing reservoir conditions, as storage sites 'pressure-up' in response to ongoing $CO_2$ injection. Related modelling must therefore be undertaken to determine the likely pressure changes throughout the $CO_2$ injection phase.

Modelling of the rate and volume of $CO_2$ flow required may result in the need to consider whether the pipeline should be operated in either gaseous or liquid phase (or start in the former before being switched to the later). Delivering the $CO_2$ in liquid phase allows a volume flow many times greater than when in gaseous phase along a pipe of the same diameter. This means that a much smaller diameter pipe can be used to transport $CO_2$ as a liquid, which reduces the overall capital costs of a steel pipeline (although this is slightly offset by the additional wall thickness required to run at higher pressures). As an example a 36" diameter gaseous pipeline operating at 30-40 Barg is approximately 30% more expensive than a 20" diameter dense phase pipeline operating at 80-100 Barg. As discussed in Section 6.2.2, there is a trade-off with regard to pipeline sizing between the energy demand to compress the $CO_2$ to liquid phase and the additional costs of steel in the pipeline to operate in gaseous phase.

With specific regard to the potential Hunterston trunk line, it is likely that this will initially operate in gaseous phase. This will mean that 'demonstration' volumes of $CO_2$ can be accommodated and that $CO_2$ will arrive at the EIS in a state suitable for injection with minimal additional processing. The pipeline would then move into liquid phase when the reservoir has pressurised to near phase change conditions (approximately 35 Barg). This appears to occur at about the same time that full-scale CCS might need to be retrofitted at the proposed power station, which will require additional onshore and offshore processing, as discussed in Section 6.4.

One of the key issues with trunk pipeline design is anticipating the extent of additional future flows from other emitters, which might 'Tee' into the trunk line. If a future trunk pipeline from Hunterston to the EIS is developed as a point-to-point solution, the design might be relatively straightforward. If, however, the pipeline receives $CO_2$ from Northern Ireland and potentially the Republic of Ireland, this would add further complexities to the design process.

The level of potential oversizing (and thus possible future revenue streams from other emitters) must be based on a commercial decision by relevant entities, which takes into consideration both regulatory and market drivers for CCS. It should be noted that the marginal cost of increasing pipeline diameters can be relatively low if operation pressures are kept below 80 Barg, so if additional future flows are a distinct possibility then oversizing should be considered.[47] The same principal applies to all other pipelines which might be constructed as part of this potential cluster network. Such commercial models and related issues are explored in more detail in Section 8.0.

Emitter operating regimes will also impact on both offshore and onshore pipeline operation, due to fluctuating $CO_2$ input volumes. Short-term increases in volumes can be managed through a process known as 'line-packing', whereby $CO_2$ can be temporarily stored within the length of the pipeline. This is done by pushing more $CO_2$ into the pipeline and increasing the pipeline pressure. When the opposite is required, for example short power station maintenance outages, the flow can be managed through a process known as 'choke back'.

Longer term stoppages to emitter operations, for example major planned outages at power stations (for example, 12 weeks every 4 years for each generating unit) and minor planned outages (1-4 weeks every 2 years) will require careful management, which is likely to see the storage reservoir held at an equilibrium pressure for these periods of no-flow.

Stoppages may also be required from the storage end of the chain. Where these are planned it would make sense to tie these in with timetabled emitter outages. Unplanned stoppages can to some extent also be accommodated by line-packing, though longer stoppages may require contingency measures to be agreed by all parties.

### 6.3.3 Potential Spurs into Trunk Pipelines

Where there are substantial opportunities (as identified in this report) for additional emitters to join a trunk pipeline in the future, this might be taken into consideration in sizing an operating regime of the pipeline. Where some certainty is held with regard to future spurs, there is likely to be value in integrating relevant 'Tee' pieces to the trunk pipeline from the outset of operation, which should be placed at the anticipated location where spurs would connect.

These 'Tee' pieces would allow far more cost effective connection in the future, which would also potentially result in no interruption to the flow of the trunk line. Should

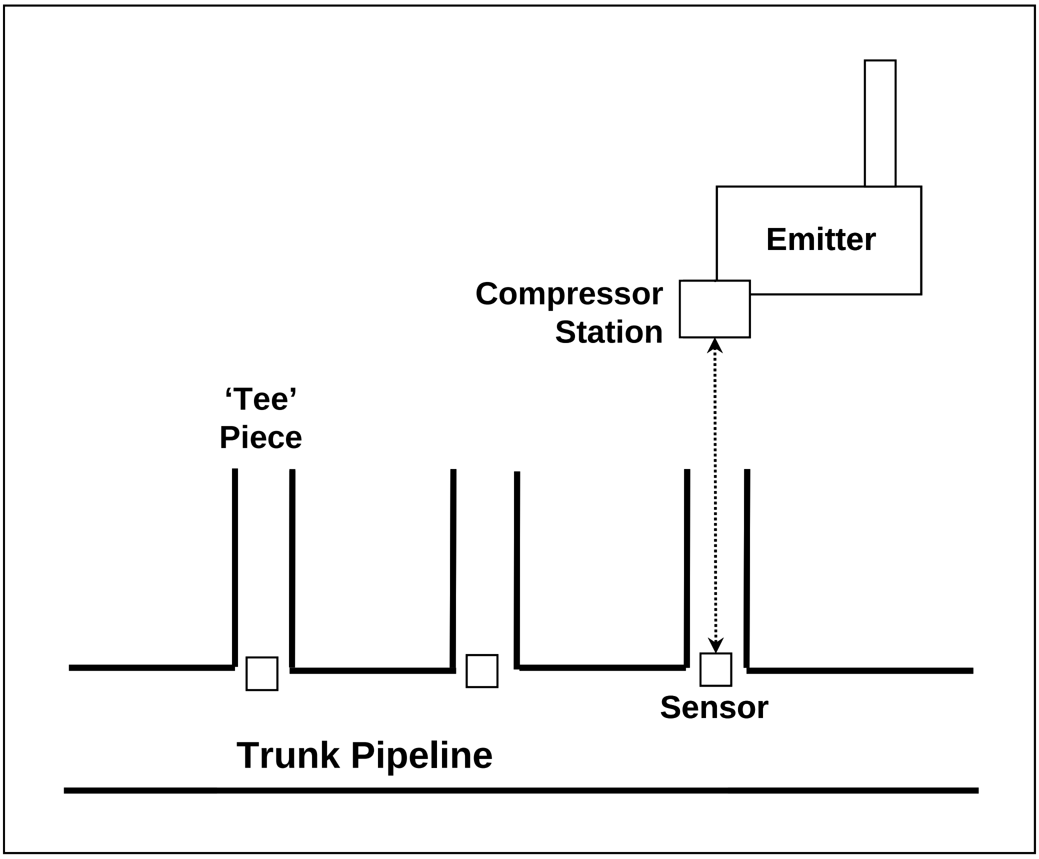
---

[47] DECC (2010) *Developing Carbon Capture and Storage Infrastructure: Consultation on Implementing the Third Party Access Provisions of the CCS Directive and Call for Evidence on Long Term Development of CCS Infrastructure*, December 2010

these ‘Tee’ pieces not be fitted in advance, connection could also be made via a process known as ‘hot-tapping’, which might also facilitate a connection without interruption to trunk flow. It should be noted, however, that although used by the oil and gas sector, ‘hot-tapping’ is far from proven for $CO_2$, and is unlikely to be acceptable to HSE for pipelines of this nature.

Whereby a large number of ‘Tee’ pieces might be required to be installed in a trunk line (for example, as for the potential South Wales mini-cluster), input pressures would need to be controlled at junction points such that these matched, as near as possible, those of the trunk line. As shown in Figure 6-4, this could be achieved by installation of a relevant sensory flow device at each ‘Tee’ piece, which continuously relays pressure data to onshore compressor stations, and which would respond in real time. Such an approach is considered to be technically viable, although it should be noted that analysis of related costs and specific technologies falls outside the scope of this study.

Figure 6-4: ‘Real-time’ Pressure Regulation at ‘Tee’ Pieces




### 6.3.4 Potential Reuse of Oil and Gas Pipelines

To reduce transport network costs, consideration of reuse of existing oil and gas pipelines should be undertaken, such that these might be reverse engineered to take $CO_2$ out to the offshore hydrocarbon fields from which the pipelines previously brought hydrocarbons ashore.

The most significant opportunity for such activity in the EIS relates to the Liverpool Bay Development, which includes not only the Hamilton and Hamilton North, but four further oil and gas fields. Gas produced by Hamilton and Hamilton North is sent via pipeline to the offshore Douglas Complex for part-processing before being piped by subsea pipeline to the Point of Ayr gas terminal for further processing. It is then sent by underground pipeline to the CCGT power station at Connah's Quay in North Wales.

This pipeline network is particularly attractive for potential future reuse for $CO_2$ transport given the close proximity of the Point of Ayr gas terminal to several large emitters. In addition to Connah's Quay Power Station there is a nearby CCGT power station at Deeside, along with a major gas-fired plant (CHP) at Shotton paper mill and a large cement kiln at Padeswood.

The preliminary technical information relating to these existing gas pipelines, as presented in Table 6-2, indicates that they would be suitable for transport $CO_2$ from North Wales. The original design pressures of 99 to 147 Barg within the main pipeline from Douglas to Point of Ayr, would be sufficient provided offshore storage pressures do not rise above 70-80 Barg, which is very unlikely based on the predicted field expiry pressures detailed in Section 4.0.

Table 6-2: Technical Information Relating to the Existing Hamilton Pipeline Network

| Pipeline | Length of Pipeline (km) | Pipeline Diameter (inches) | Pipeline Thickness (mm) | Design Temperature (°C) | Design Pressure (Barg) |
|---|---|---|---|---|---|
| Hamilton – Douglas Complex | 14.6 | 20 | 15.1 | 27 | 99 |
| Douglas Complex – Point of Ayr | 32.1 | 20 | 20.6 | 50 | 147 |
| Point of Ayr – Connah's Quay | 34 | 24 | 11.1 | 30 | 99 |

Assuming operation in liquid phase, the two lines which make up the route between Douglas and Connah's Quay could accommodate approximately 4Mt$CO_2$pa. This is expected to be sufficient capacity for the total emissions from the potential North Wales mini-cluster (3.8 Mt$CO_2$pa).

In a similar context, it is possible that the existing pipelines linking the Morecambe Bay fields to Barrow Gas Terminal could also have potential for reuse as $CO_2$ pipelines. Whilst there is presently a lack of density of existing emitters in this onshore area, National Grid (NG) has indicated its intention to build a 400kV line from

Sellafield to Heysham, which will unlock the Cumbria Ring for large scale energy investment (albeit this is likely to be dominated by future nuclear development).[48]

## 6.4 Offshore Facilities

It is anticipated that many of the platforms and offshore facilities associated with the hydrocarbon fields in the EIS can be reused and a system designed such that $CO_2$ from several different pipelines could be accommodated. These issues are discussed in Sections 6.4.1 and 6.4.2 with regard to both the Liverpool Bay and Morecambe Bay fields.

### 6.4.1 Liverpool Bay Fields

Connected to the Douglas central processing platform by the existing pipeline network, Hamilton and Hamilton North each have an unmanned satellite production platform, both which are linked by communication systems to the Douglas Complex. The Hamilton North platform became operational in 1995, with Hamilton following two years later.

The structural design basis for these satellite platforms was for 30 years, and as such a detailed structural survey of the platforms would be required to identify any serious structural issues. Should any be identified, any proposed $CO_2$ storage site operator would need to determine whether to reinforce or replace the existing platform(s).[49]

### 6.4.2 Morecambe Bay Fields

Given the considerably greater natural gas reserves capacity of Morecambe Bay compared to Liverpool Bay, unsurprisingly there is a greater network of associated platforms and offshore facilities, one of which is shown in Figure 6-5.

The Central Processing Complex at South Morecambe is a three-platform, bridge-linked complex consisting of:

- The Central Production Platform where import pipelines from the four satellite platforms terminate and the gas/condensate export pipelines begin. The platform houses all the main process and utility modules, including gas compression and main power generation equipment;
- The Accommodation Platform is located at the western end of the complex and includes the primary control centre for all related infrastructure. This platform is linked to the Central Production Platform via two bridge links;
- One bridge-linked satellite production platform, DP1, is located at the eastern end of the complex, where production separation also takes place; and

---

[48] National Grid (2009) *GB Seven Year Statement Update*, May 2009

[49] High-level initial analysis indicates, however, that there are no serious structural issues at the Hamilton Platforms

- A further four unmanned satellite production platforms are linked to the Central Production Platform.

Much of the above infrastructure has been in situ since 1985, whilst a simple unmanned satellite production platform at North Morecambe became active in 1994.

Whilst much of the South Morecambe infrastructure will be 35-40 years old by the time of depletion, it is understood that all design, materials and construction processes were of a very high standard and undertaken according to a principle of longevity. The assets have been maintained to a high standard throughout their life and have been subject to regular third party inspection and audit. The facility was inspected in 2009 under the Health and Safety Executive's KP3 audit programme and performed well in comparison to its peers. As a result, it is likely that they could support $CO_2$ storage activities for at least a similar additional timeframe without major structural modifications, although this still needs to be corroborated by structural analysis.

Figure 6-5: Platform within the Morecambe Bay Complex


Note: Image provided courtesy of Hydrocarbon Resources Ltd

### 6.4.3 Integration of Facilities to support a CCS Cluster

The timing of availability of fields for transfer from hydrocarbon production to $CO_2$ storage will determine how facilities are developed and integrated to support the proposed EIS Cluster development. As discussed in Section 4.0, it is anticipated that the Hamilton fields will become available for this transfer before those located in

Morecambe Bay. Furthermore, as explored in Section 7.0, it is envisaged that the first pipeline within the cluster will be that from the proposed power station at Hunterston, which will function as the 'catalyst' project from around 2016, followed by additional phases of development from 2025 as more emitters are required to retrofit CCS infrastructure.

In light of the above high-level assumptions, whilst Hamilton and Hamilton North might be used to store initial volumes of $CO_2$ from Hunterston, it is more likely that any major processing hub for future cluster volumes of $CO_2$ would be developed at the South Morecambe Complex. This could be facilitated relatively easily by a straightforward extension of the trunk pipeline from the Hamilton fields northwards to the South Morecambe Complex.

We understand that APL has developed such a solution to support its bids for funding from both the NER300 programme and DECC 'Demos 2-4', but such information is considered commercially confidential.

### 6.4.4 Potential of Integration of Shipping of $CO_2$

In theory, it would also be possible to accommodate any $CO_2$ arriving via ship, albeit this would require additional infrastructure, including the technology to allow ships to 'weather vane' around the associated platform. Discharge of $CO_2$ might also take place via an alternative structure some distance from the platform, prior to transfer via a riser on the side of the platform to join other streams prior to injection.

As a result of such complications at the injection site, along with other operating cost considerations, transporting the significant volumes of $CO_2$ associated with the proposed mini-clusters by ship is very unlikely to present a long-term economically viable solution. Should individual facilities, possibly from outside of the mini-clusters identified in this study, seek to transport $CO_2$ to the EIS cluster, however, the potential of shipping $CO_2$ should be considered against the merits of a new point-to-point pipeline.

## 6.5 Flow Metering

An important part of the development of CCS infrastructure is the reliable verification of the inventories of $CO_2$ which are transported through the network from point of capture to injection and storage. This is important not only towards aiding payments across different entities operating the CCS chain (see Section 8.0 for discussion of associated commercial models), but also towards identifying where in the system potential leakages might have taken place.

The detection of leakages will be of interest to the relevant regulatory body, i.e. the Environment Agency, Scottish Environmental Protection Agency (SEPA) or the Irish Environmental Protection Agency (EPA). As discussed in Section 2.1, given the requirement to purchase EUAs for every tonne of $CO_2$ emitted by power stations (and associated CCS chains) from 2013 and the potential liabilities discussed in Section 2.4, however, perhaps more important is reporting with regard to ETS obligations.

Early consultation documents published by DECC indicate that at least annual reporting will be required on the quantities and characteristics of the $CO_2$ streams delivered to storage facilities.[50] Further metering at key stages of the CCS chain will also be required such that fugitive losses can be established using a mass balance approach.

There are a number of challenges to accurate metering of $CO_2$ flow throughout the CCS chain, which are related to the physical properties of $CO_2$ and CCS process conditions. As described in Section 6.3.2, the operating 'phase envelope' of the CCS cluster is likely to span a relatively narrow range of temperatures and pressures in the context of the overall potential for phase change of $CO_2$. This phase envelope does, however, include variability between gaseous and liquid flow, which creates substantial challenges to accurate measurement as flow meters are generally designed to operate in one specific phase only (see Table 6-3).

The potential operating profile of CCS clusters is further complicated by the degree to which impurities are present within the related $CO_2$ streams, which will shift the operating envelope. To a limited extent, this issue can be managed by sampling the $CO_2$ stream throughout the transport network via Continuous Emissions Measurement Systems (CEMS) which would then enable the physical properties to be calculated using modelling software, and relevant adjustments made at compressor stations. Recent guidance suggests, however, that there can be variation in results between different software packages used to model the same $CO_2$ stream, and as such it may be necessary to develop industry standards so that a consistent approach is adopted.[51] Such standards would be particularly prudent in the context of CCS clusters as emitters begin sharing the same metering network which will add a further layer of complexity.

A number of flow metering technologies exist and the appropriate solution for the range of mini-clusters and wider EIS Cluster will be dependent on the specific conditions at each intended measurement point, rather than a 'one-size-fits-all' approach. In terms of likely metering locations, it is anticipated that the first of these would be 'post-capture' allowing direct measurement of the physical properties of the $CO_2$ stream prior to entry into the pipeline.

Due to the somewhat embryonic phase of development of CCS clusters on a global basis, accurate measurement of $CO_2$ along CCS chains is not something that is well developed. Whilst flow meters have been used to measure $CO_2$ streams in EOR projects in the US and within CCS demonstration projects there has not been wide validation of their performance.

Table 6-3 summarises some of the meters that could potentially be suitable for CCS applications, including a brief summary of benefits and limitations. It is worth noting

---

[50] DECC (2009) *A Consultation on the Proposed Offshore Carbon Dioxide Storage Licensing Regime*, September 2009, http://decc.gov.uk/en/content/cms/consultations/co2_storage/co2_storage.aspx

[51] TUV NEL for National Measurement Office (2009) *Guidance Note – Measurement of CO2 throughout the carbon capture and storage (CCS) chain*, 2009

that Ultrasonic and Coriolis have undergone recent developments which make their potential application promising, whilst Venturi and V-cone flow meters have had no known exposure to $CO_2$ applications and so their inclusion should be treated with caution. It is expected that manufacturers will continue to adapt existing meters and develop new technologies, particularly as commercial demand for $CO_2$ metering evolves. TUV NEL are leading such research and are currently investigating CCS flow measurement, characterising multiphase flows and physical properties for $CO_2$ mixtures and developing testing facilities to mirror CCS conditions to enable detailed evaluation of potentially suitable flow meters.[52]

[52] Personal communication with Lynn Hunter, TUV NEL, 30th November 2010

Table 6-3: Types of Flow Meters Potentially Suitable for CCS Applications

| Type of Flow Meter | Benefits | Limitations |
|---|---|---|
| Orifice Plate<br>(Differential Pressure) | Established in measuring CO2 (EOR), under stable conditions high level of accuracy (+/-1%) under stable flow and can be used over a wide range of pipe diameters | Intrusive in pipeline which incurs pressure drops so would need to be strategically located |
| Venturi<br>(Differential Pressure) | Potential to achieve +/-1% accuracy under stable flow and can be used over a range of pipe diameters | No known exposure to $CO_2$ applications |
| V-cone<br>(Differential Pressure) | Used in multiphase flow and potential to achieve +/-1% accuracy under stable flow | No known exposure to $CO_2$ applications |
| Turbine<br>(Volumetric) | Established in measuring $CO_2$ (EOR), high level of accuracy (+/-1%) under stable flow and can be manufactured for any pipe diameters. Will work across all phases, but not multiphase | Large number of moving parts, if encounters a phase for which not designed large risk of mechanical failure |
| Ultrasonic<br>(Volumetric) | Recent developments suggest could be applicable to $CO_2$ rich applications with high level of accuracy (+/-1%) | Further validation necessary |
| Coriolis<br>(Mass Flow) | Experience in measuring $CO_2$ (EOR) and recent developments suggest that may be able to measure in two-phase conditions. Able to provide a direct mass flow measurement within 1% in stable single phase flow conditions | Limited in pipeline diameter size (can be overcome by branching a number of metres in parallel |

Notes:

1. All information has been adapted from the TUV NEL Guidance Note 2009
2. The levels of accuracy suggested are under ideal stable conditions. In reality conditions along the CCS chain will not be ideal and so these levels of accuracy could be considered as optimistic

A considerable challenge will be delivering the degree of metering accuracy required to support both commercial structures and ETS reporting. Under CCS Monitoring and Reporting guidelines developed for the ETS the measurement of $CO_2$ flow along the chain will need to be accurate to within 2%.[53] Whilst Table 6-3 shows that levels of accuracy for all are within +/-1% under ideal stable, single phase flow conditions, the cumulative errors from a number of metering points along the CCS chain, together with issues relating to sampling and physical property determination, are likely to result in levels of accuracy substantially some way outside the 2% threshold proposed by the EU.

As discussed in detail in Section 7.0, it is likely that multiphase flows will be required to be measured over the required storage lifetime, which currently might only be undertaken by V-Cone or Coriolis meters, albeit both are unproven in the context of $CO_2$. If such meters cannot be proven, multiphase flows might require mounting of $CO_2$ separators on the platform to divide the gas and liquid phases for passing through separate meters, before combining these prior to entry at the well-head. It should be noted that these separators would add a significant load to the platform facility.

## 6.6 $CO_2$ Storage Monitoring

Prior to issue of a $CO_2$ storage licence by DECC, storage site operators in the UK must have provided a robust monitoring plan. Draft DECC guidance also suggests that once injection has ceased, the licence will enter a post-closure phase, under which the requirement to monitor will continue until DECC is satisfied that permanent containment has been achieved (an indicative post-closure phase of 20 years is given in the EU CCS Directive).[54]

### 6.6.1 Monitoring Plan and Reporting

At present, the aforementioned DECC guidance proposes that the monitoring plan for the CCS chain should focus on the injection facilities and storage complex with the purpose of:

- Comparing actual and modelled behaviour of $CO_2$ and formation water in the storage site;
- Detecting significant irregularities;
- Detecting migration of $CO_2$;
- Detecting leakage of $CO_2$;
- Detecting significant adverse effects for the surrounding environment;
- Assessing the effectiveness of any corrective measures taken; and

---

53 http://ec.europa.eu/clima/documentation/lowcarbon/ccs_en.htm

54 DECC (2009) *A Consultation on the Proposed Offshore Carbon Dioxide Storage Licensing Regime*, September 2009, http://decc.gov.uk/en/content/cms/consultations/co2_storage/co2_storage.aspx

- Updating the assessment of the safety and integrity of the storage complex in the short and long-term.

These monitoring procedures represent a significant long-term commitment for potential storage site operators and will provide a range of technical challenges, particularly if $CO_2$ is injected in gaseous phase, which is likely for the initial years of use of a depleted gas field. It is likely that there will need to be reliance models, monitoring and other tools to demonstrate containment. This might include modelled pressure decline curves for the post closure period. Pressure dissipation in the reservoir following the end of injection can also be modelled and related to key parameters in assessing any potential leakage pathways (e.g. capillary and fracture pressures).

Another possible way of physically monitoring $CO_2$ containment is via pressure measurements within injection walls, although this approach would not be feasible if the platform allowing access to the wells is removed and the wells plugged and abandoned.

# 7.0 Deployment of the EIS CCS Cluster

## 7.1 Potential Development Models

The profile of implementation and wider deployment of CCS for the EIS Cluster will be dependent upon the range of policy and regulatory factors discussed in Section 2.0. It should be noted, however, that DECC has indicated that it expects investment in CCS will be provided to meet demand and the integration of infrastructure can similarly be left to market forces, as was the approach for North Sea oil and gas development which has similar spatial characteristics to the proposed roll-out of CCS.[55]

A recent study on behalf of DECC has suggested that further reforms could be introduced to improve the effectiveness of this decentralised model in terms of anticipating future demand and network creation.[56] Recommendations include:

- Creating formal 'open season' arrangements whereby there is an obligation on a developer to make its plans known to other parties prior to finalising design and applying for consent;
- Providing an obligation to provide 'Tee' pieces and interconnections to existing pipelines on request;
- Regulated tariff structures to provide control over the basis of charging for pipeline access; and
- Secondary trading for pipeline capacity to promote efficient utilisation.

There are, however, alternatives to this 'regulated decentralised' model. A centralised approach might involve a single organisation which has responsibility for aspects of the network including its design, investment and operation. Under this type of arrangement the owner of the network would also have an obligation to develop the infrastructure to meet demand on a non-discriminatory basis.

This approach could bring a strategic planning element to CCS infrastructure, although given the uncertainty surrounding CCS deployment it is unlikely that a monopoly provider would be better informed than the market. Other approaches such as collective and cooperative type arrangements might also be considered.[57]

---

[55] DECC (2010) *Developing Carbon Capture and Storage (CCS) Infrastructure: Consultation on Implementing the Third Party Access Provisions of the CCS Directive and Call for Evidence on Long Term Development of CCS Infrastructure*, December 2010

[56] NERA Economic Consulting for DECC (2009) *Developing a Regulatory Framework for CCS Transportation Infrastructure*, June 2009

[57] With regard to pipeline networks, such models are explored in detail in a recent study undertaken on behalf of One North East. See Element Energy (2010) *Developing a CCS network in the Tees Valley Region*, December 2010

## 7.2 Profile Assumptions for the EIS CCS Cluster

In order to understand the potential profile of CCS implementation in the EIS, it is necessary to provide assessment of:

- How much $CO_2$ is likely to be emitted in the future;
- When existing emitting installations are likely to close/open; and
- When existing emitters are likely to retrofit CCS infrastructure.

These issues are explored in Sections 7.2.1 to 7.2.3.

### 7.2.1 Forecasting Future Demand for $CO_2$ Storage

Any projection of the demand for $CO_2$ storage capacity must be associated with a range of assumptions. Over longer timeframes, uncertainty increases as the number of possible outcomes increases. Accordingly, this study does not aim to project $CO_2$ emissions from installations further than what is necessary to demonstrate potential significant demand. It is therefore deemed appropriate that emissions are only modelled up to 2050.

The next challenge is to make an assessment of the emissions expected to be released by each installation over this period. As outlined in Section 5.2, historic emissions data from between 2004 to 2009 has been collected for existing installations. After examining this data, it is clear that the recent economic downturn resulted in lower emissions in 2009 relative to the trend experienced between 2004 and 2008. Economic analysis suggests that that the economy may have grown during 2010, and as such it would be expected that the emissions released in 2010 are also likely to have grown.[58] To account for these year-on-year changes, we have used the average emissions between 2004 and 2009 to create a baseline emission figure for 2010.[59]

### 7.2.2 Closure of Facilities or Retrofitting of CCS?

As outlined in Section 2.0, installations will be required to decarbonise such that emissions targets can be met successfully. From 2011 to 2050, the extent to which individual installations can decarbonise is unknown. No doubt there will be industry specific circumstances which influence both the extent and degree of decarbonisation. Typically, however, there are three main methods of decarbonisation for each installation:

- Adapt the technology and processes at the installation via retrofit;
- Close the installation and replace with a lower carbon installation; and
- Close the installation without replacing it.

---

[58] See: http://www.hm-treasury.gov.uk/data_forecasts_index.htm

[59] Arithmetic mean

It is understood that energy intensive facilities typically have a large amount of carbon 'locked in' to the associated processes. The extent to which existing installations are able to adapt current technologies is therefore unclear. It is believed that the majority of the decarbonisation within the installations will occur via closure of existing facilities and reopening of newer/cleaner facilities on the same site due to the planning precedent. It is acknowledged, however, that in some instances complete closure of facilities may also be necessary.

In our modelling of future emissions from each mini-cluster, the following assumptions are made:

- All major power generation facilities are retrofitted or replaced;
- For each installation, unless closure takes place, average emissions emitted between 2004 and 2009 are expected to be released for each year from 2010 to 2050;
- Where a publicly available estimated closure date exists for an installation, the installation closes at that time, but a replacement (assumed to be constructed prior to closure of the original) begins operation the following year emitting less $CO_2$ on the basis of improved efficiency due to technological advances;[60] and
- The extent of these emissions reductions varies across installation types as shown in Table 7-1.

It is acknowledged that such high-level assumptions will not be accurate on an installation by installation basis, but that broad assumptions such as these are required for a study of this nature.

Table 7-1: Assumed Emission Reduction Following the Reopening of an Installation

| Installation Type | Emission Reduction |
|---|---|
| Coal-fired Power Stations | 25% less $CO_2$ |
| CCGT Power Stations | 10% less $CO_2$ |
| Industrial Installations | No Change |

Table 7-1 shows that gas-fired (CCGT) power stations will have a lower emission reduction factor than coal-fired power stations due to the relative modernity of the UK CCGT fleet, and hence less scope for technology advancements leading to emission reductions. It is difficult to assume a broad emission reduction factor for industrial processes as these are much more varied in nature and predicting when any

[60] This assumption was also made for installations where the predicted closure date was unknown, based on the supposition that this would be 40 years after its opening date.

emission reductions might take place would be highly speculative. As such emissions from industrial processes are assumed to be constant across the study timeline.

### 7.2.3 Planned Installations

In addition to those installations already in operation, future planned installations must also be included in the model. To avoid speculation, only developments with existing planning consent have been included. The one exception to this rule is the inclusion of the proposed Hunterston Power Station, which has submitted a Section 36 application that has not yet been determined by Scottish Ministers. Hunterston has been included as it is believed that this facility will be the enabling or 'catalyst' project driving the formation of the EIS Cluster. This is explained further in Section 7.3.1.

As no historic data for planned facilities exists, the emissions profile for each of these facilities has been predicted based on the average emissions of comparable facilities. An outline summary of the planned installations included within the modelling can be found in Appendix.2.0.

## 7.3 Phased Development of the EIS CCS Cluster

Due to the opportunities and constraints outlined in Section 6.0, it is expected that the deployment of CCS will not be consistent over time. Three potential phases of cluster development are therefore described in Sections 7.3.1 to 7.3.3. Detailed figures and related descriptions of individual mini-cluster developments can be found in Appendix 3.0. It should be noted that these show conceptual mini-cluster developments only, in particular onshore pipeline routes are not necessarily optimised, nor do they take account of inevitable constraints.

### 7.3.1 Phase 1: 2016 - 2025

To enable the EIS CCS cluster, there will be a requirement for a catalyst project to initiate the deployment of CCS infrastructure in the region. Through demonstration of the full CSS chain, and particularly proving storage suitability, it is expected that this catalyst project will help to enable subsequent facilities to install CCS through reduced technical risk and greater financial certainty.

The catalyst project is likely to bear the majority of the costs associated with the initial installation of the pipeline and storage infrastructure, albeit these are likely to be partially covered by public funding, as discussed in Section 2.2.[61] This infrastructure, if oversized, could be shared with future installations fitting carbon capture plant. Potential commercial relationships between entities operating within the proposed cluster development are considered in detail in Section 8.0.

After reviewing the existing and potential future facilities surrounding the EIS, it is apparent that only one project within the study area, the proposed Hunterston coal-fired power station in Scotland, is positioned appropriately in line with the drivers

[61] Via the UK CCS Demonstration Programme and/or the NER 300 competition

outlined in Sections 2.2 and 2.3. If successful both in securing planning consent and acquiring the appropriate levels of funding, this CCS project could potentially be operational as early as 2016. Accordingly, the EIS Cluster development described in this report has been modelled with Hunterston as the catalyst project.

For the period 2016 to 2025, the proposed Hunterston power station is required to have capture equipment fitted to at least 300MWe (net) of its output, which equates to the capture of approximately 2 million tonnes of $CO_2$ per annum. By potentially over-sizing its pipeline, the Hunterston project would be able to ensure that the related infrastructure could be used both to enable full scale CCS at the power station, and to potentially provide capacity for other emitters.[62] Such approaches might be used to reduce the operating costs for the project in the future.

To meet NER300 requirements, Hunterston is likely to need to commence storage of $CO_2$ by the end of 2016. At this time, the Hamilton and Hamilton North gas fields are the most likely candidates for $CO_2$ storage.

Table 7-2 outlines the total $CO_2$ captured from each of the mini-clusters. At the end of Phase 1 this would mean that 1,129 $MtCO_2$ of storage remains available.

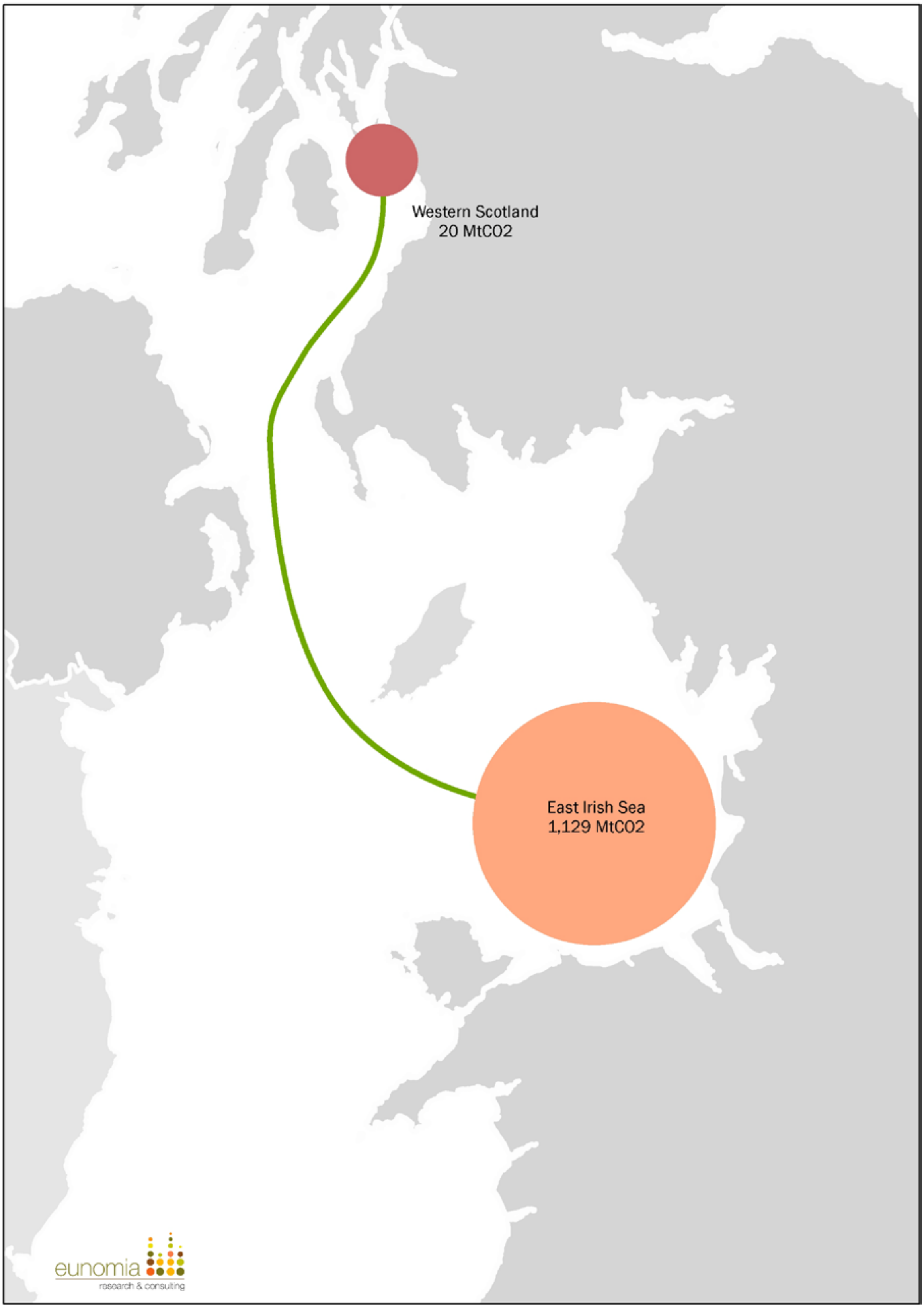
[62] It should be noted, however, that such approaches are not necessarily being proposed by Ayrshire Power Ltd (APL) for the Hunterston CCS project, and that this analysis does not reflect the views of APL or its parent company Peel Energy Ltd

Table 7-2: Profile of $CO_2$ Emission Captured and Stored at the End of Phase 1

| **Region** | **Cumulative Total Captured Emissions ($MtCO_2$) 2016-2025** |
|---|---|
| Eastern Ireland | 0 |
| North Wales | 0 |
| North West England | 0 |
| Northern Ireland | 0 |
| South Wales | 0 |
| Western Scotland | 20 |
| **TOTAL** | **20** |
| **Remaining $CO_2$ Storage Capacity in EIS** | **1,129** |

Figure 7-1 shows the Phase 1 formation of the EIS CCS cluster from 2016 to 2025.

Figure 7-1: Phase 1 Cluster Profile ($CO_2$ tonnages are expressed cumulatively)



### 7.3.2 Phase 2: 2025 - 2035

Following the installation of demonstration scale CCS at Hunterston, it is expected that from 2025 legislation will require CCS to be installed to the entire output of the proposed Hunterston power station. The same requirement will also affect other new coal power stations within the UK. This will result in significantly more $CO_2$ being captured and stored than previously.

If the CCC target for the decarbonisation of the electricity sector is to be achieved in 2030, it could also be assumed that the wider deployment of CCS will be required around the same timeline. As such, the model reflects this by assuming that CCGT power stations within the study area will have started to install full scale CCS equipment by 2030. In order to reflect a likely staged deployment, with early adopters and some laggards, the model assumes that CCS will be retrofitted to these power stations between 2028 and 2032.

As the various emitters identified in this study are not all grouped in one geographical region, it is expected that Phase 2 will herald the arrival of mini-clusters, as discussed at various point above. Within these sub-groups, infrastructure may be shared, which will potentially enable more cost effective deployment of CCS technologies.

If it is assumed that Hamilton gas field is the only storage facility utilised in Phase 1, during Phase 2, further storage will be required, as the theoretical maximum storage capacity of Hamilton gas field is limited to 113 Mt. As shown in Table 7-3, based on the assumptions used in this study, it is anticipated that nearly three times this capacity will be required by the end of 2035. Given that the largest storage asset in the EIS, South Morecambe, is likely to become available for transfer to $CO_2$ storage between 2023 and 2030, it is reasonable to assume that this will be utilised once the Hamilton Field becomes full.

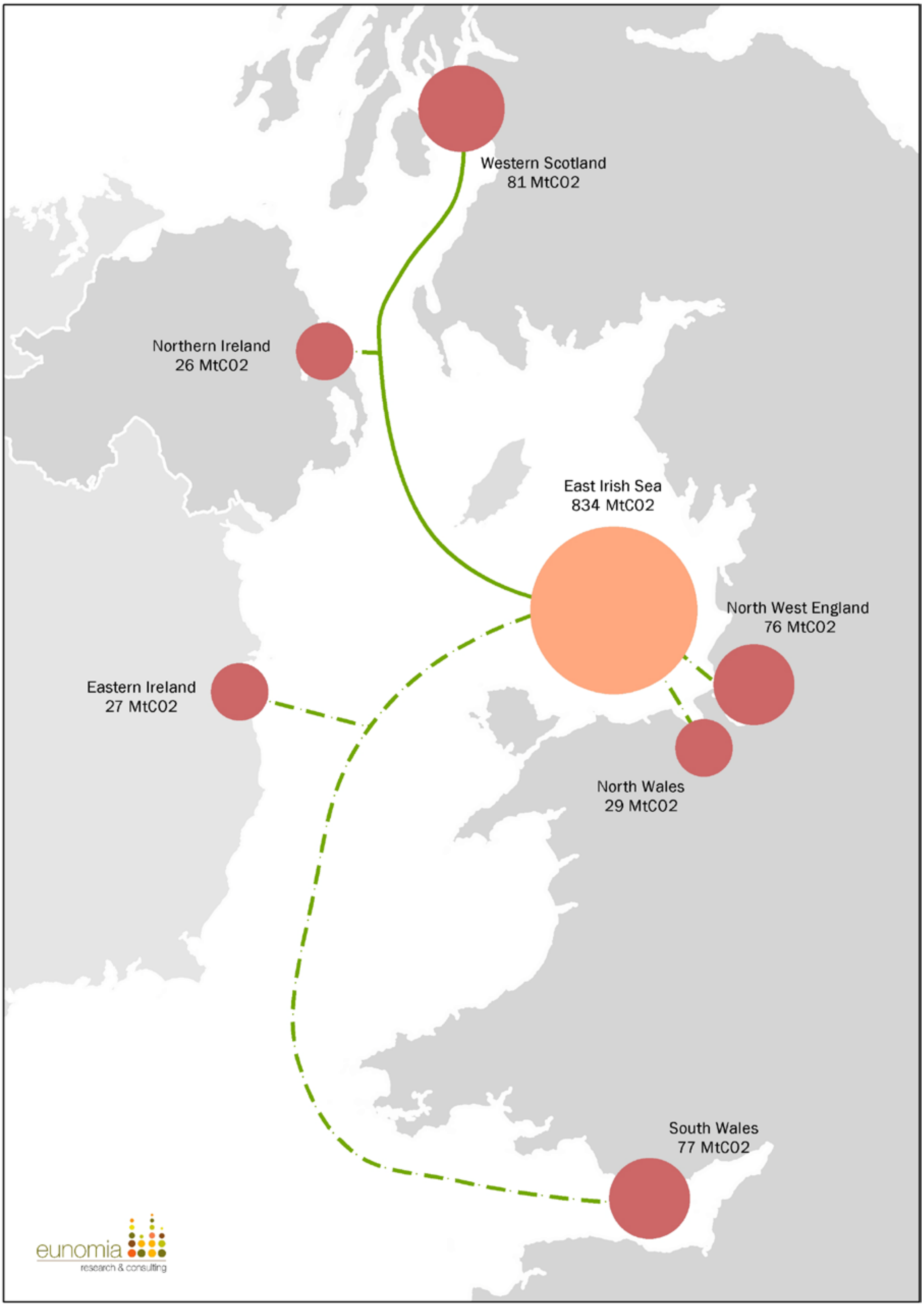
With regard to the spatial distribution of captured $CO_2$ emissions, Table 7-3 shows that by 2035 the largest amount of $CO_2$ will still come from Western Scotland (where the Hunterston project is located). It is also expected that North West England and South Wales will also capture a large quantity of $CO_2$ due to a number of CCGT power stations being located within these regions. At the end of Phase 2 this would mean that 834Mt$CO_2$ storage remains available in the East Irish Sea.

Table 7-3: Profile of $CO_2$ Emissions Captured and Stored at the End of Phase 2

| Region | Cumulative Total Captured Emissions ($MtCO_2$) 2016-2035 |
|---|---|
| Eastern Ireland | 27 |
| North Wales | 29 |
| North West England | 76 |
| Northern Ireland | 26 |
| South Wales | 77 |
| Western Scotland | 81 |
| **TOTAL** | **316** |
| **Remaining $CO_2$ Storage Capacity in EIS** | **834** |

Figure 7-2 outlines the spatial distribution and associated tonnages captured within the cluster in 2035.

Figure 7-2: Phase 2 Cluster Profile ($CO_2$ tonnages are expressed cumulatively)



### 7.3.3 Phase 3: 2035 - 2050

The third and final phase of deployment of CCS technologies is expected to be the installation of carbon capture equipment on large scale industrial emitters of $CO_2$. These facilities are assumed to be the final facilities to install CCS equipment as they generate lower overall quantities of $CO_2$ than thermal power stations and so the requirement for installing CCS equipment is likely to be less compelling from both regulatory and commercial perspectives.

Accordingly, it is expected that these emitters will link to wider CCS networks once the technology has become established and deployment is commercially attractive. Our model therefore assumes that industrial emitters retrofit CCS between 2038 and 2042.

By the end of Phase 3, the total emissions captured are expected to be 1,032 million tonnes, leaving 116 $MtCO_2$ of storage remaining. This total would exceed the theoretical capacity of the combined Hamilton and South Morecambe gas fields (933 $MtCO_2$) towards the very end of Phase 3. Therefore, assuming this development profile was accurate (and we recognise it is but one of a number of potential future scenarios) an additional gas field would be required for storage. This might either be North Morecambe or the Hamilton North gas field, though given the greater storage capacity at North Morecambe it would appear likely that this would be the first choice. In this context, it should be noted, that either field would need to be mothballed, rather than fully decommissioned following its productive life, such that it was still available for $CO_2$ storage when required during Phase 3.

Table 7-4 shows the total quantity of $CO_2$ expected to be stored by 2050, when the largest tonnage of $CO_2$ would come from the South Wales mini-cluster, which contains some of the largest industrial facilities.

Table 7-4: Profile of $CO_2$ Emission Captured and Stored at the End of Phase 1 to 3

| Region | Cumulative Total Captured Emissions ($MtCO_2$) 2016-2050 |
|---|---|
| Eastern Ireland | 107 |
| North Wales | 98 |
| North West England | 270 |
| Northern Ireland | 78 |
| South Wales | 324 |
| Western Scotland | 155 |
| **TOTAL** | **1,032** |
| **Remaining $CO_2$ Storage Capacity in EIS** | **116** |

Figure 7-3 illustrates the profile of $CO_2$ emissions captured over the study period. It shows that the catalyst project at Hunterston is such that Western Scotland represents the largest source of $CO_2$ captured until 2035. After this date, due to the installation of CCS at industrial plant (during Phase 3), both the North West and South Wales mini-clusters become the largest sources of $CO_2$ captured.

Figure 7-3: Tonnage of $CO_2$ Captured by all Mini-clusters surrounding the EIS Cluster

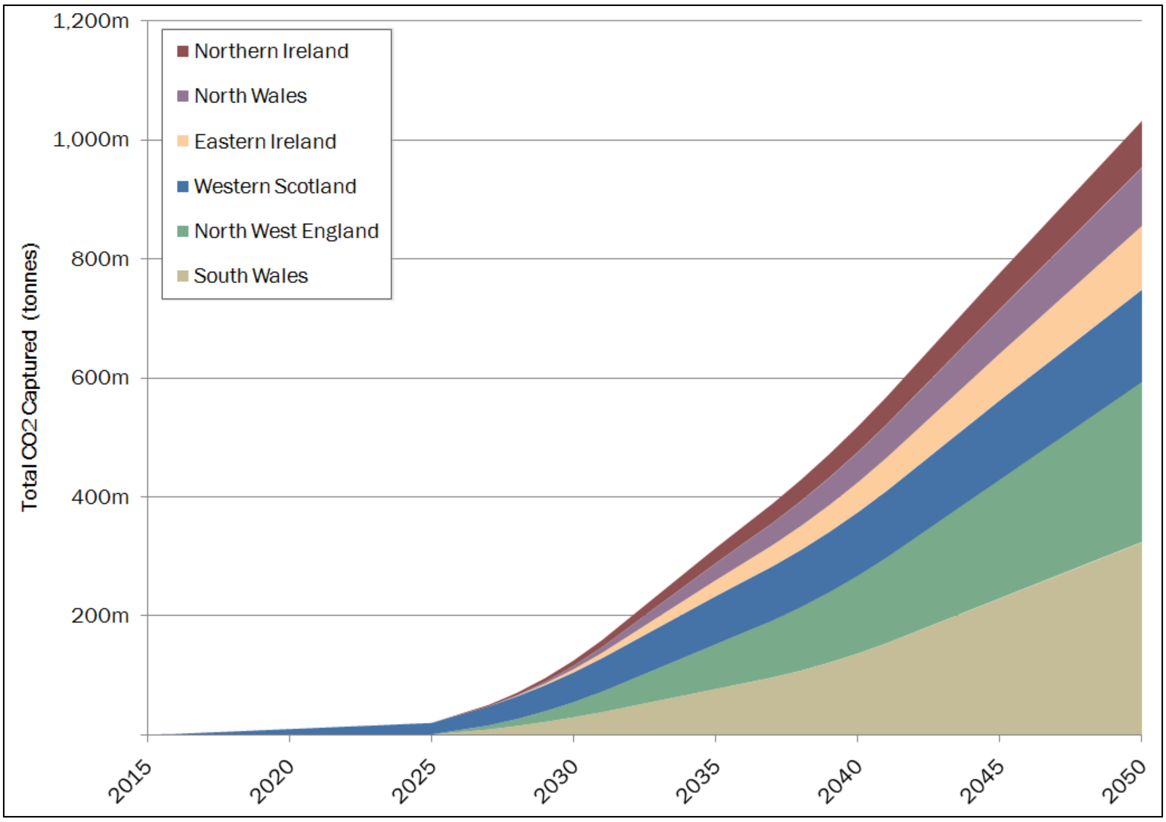
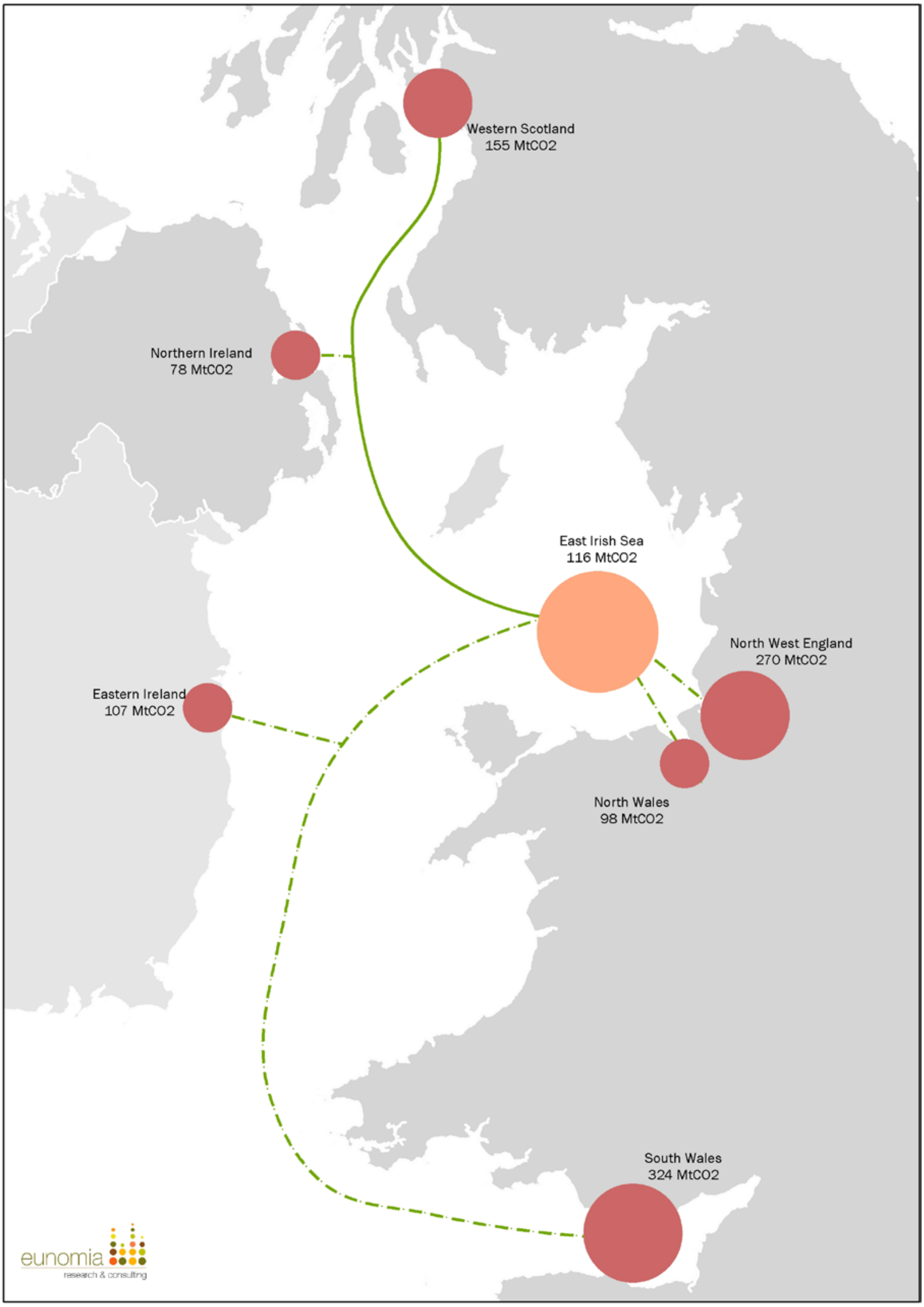


Figure 7-4 outlines the final spatial distribution and associated tonnages captured within the EIS CCS cluster in 2050.

Figure 7-4: Phase 3 Cluster Profile ($CO_2$ tonnages are expressed cumulatively)



# 8.0 Potential Commercial Structures

## 8.1 Summary of Drivers for Investment in CCS

As discussed in detail in Section 2.0, it is useful to frame the following discussion of commercial issues with a summary of the primary drivers for thermal plant operators in the UK to invest in CCS infrastructure, as follows:

- The mandating of demonstration scale (300MW 'net' equivalent) infrastructure on all new coal-fired power stations;
- The need for all new thermal plant to be CCR;
- The potential for full-scale CCS to be mandated on all CCGT plant by 2030, subject to the Government's consideration of this recommendation from the CCC;
- The funding provided for commercial demonstration projects by the EC NER300 and DECC Demonstration Competitions; and
- The EU ETS, provided the cost of CCS (per tonne of CO2 captured, transported and stored) falls below price of EUAs.

Sections 8.2 to 8.5 provide a discussion of the key issues relating to the emerging commercial structures which will be required to develop CCS projects and associated clusters.

## 8.2 Role of the Emitter

Both DECC and the EC expect that emitters will lead consortia of organisations bidding for funding from the UK Demonstration and NER300 Competitions. This is because demand for CCS infrastructure is currently emitter-driven given that, via electricity (and potentially heat) or product sales, the emitter (power generation or industrial) is the only element of the CCS chain which independently generates revenues which come from outside of the scope of the chain or cluster itself.

As a result, it is likely that a proportion of these external revenues (along with any public funding received) will be cascaded down the chain to capture, transport and storage elements, whether these are owned by the emitter entity, or are distinct Special Purpose Vehicles (SPVs), as discussed in detail in Section 8.4 with regard to risk transfer.

In response to the policy and regulatory drivers discussed in Section 2.0, it is likely to be both the desire for extension of the life of existing installations and for future new build which causes emitters to seek development or access to CCS infrastructure. Given the current associated high capex and opex, however, CCS will not be economically viable without public funding for some years. As for the EIS cluster, it is hoped that the roll-out of commercial demonstration projects (for example, the Hunterston project, should it be successful), will bring down these costs and enable entry of a range of emitters onto shared pipeline networks, injection facilities and storage sites.

## 8.3 Impact of Proposed $CO_2$ Storage Regime

As highlighted in Section 2.4, the proposed system of licensing $CO_2$ storage proposed by DECC in the UK is regarded by many CCS project developers as potentially presenting a real barrier to CCS. The proposed regime for offshore storage will draw upon the existing regimes for offshore petroleum exploration and production licensing.[63] In basic terms, it is proposed that relevant hydrocarbon fields will move from being licensed as petroleum extraction sites to being licensed as $CO_2$ storage sites.

It is proposed by DECC that where the licensee of a field still in production wishes to redevelop it for $CO_2$ storage, it will be able to seek a storage licence on a 'first refusal' basis, provided this is done at the earliest opportunity (i.e. whilst the field is still producing and not less than 12 months in advance of licence expiry).[64] Where the licensee has made no application by this time, DECC and the Crown Estate would offer respective licence and lease opportunities to other parties interested in $CO_2$ storage at that particular field.

Given that, in the short term, offshore gas fields represent the best potential for the secure long-term storage of $CO_2$, the owner and operators of these assets are generally natural gas production companies. At the end of their economic life gas fields are required to undergo decommissioning as deemed appropriate by the regulator. As a result, these potential storage assets have historically been viewed by gas production companies as a substantial liability on the balance sheet.

The investment case for conversion of fields from gas production to $CO_2$ storage is therefore potentially profound given that this could represent a significant reduction in the level of associated liability should the field be transferred to another entity, or potentially a significant asset if ownership was retained.

Given that a number of gas production companies are part of integrated utilities also involved in thermal energy production, conversion of fields to $CO_2$ storage represents an opportunity for such organisations to directly 'close the carbon loop' and enable thermal plant to continue operating following any regulatory mandating of CCS.

The case for investment by gas production or utility companies is further boosted by the possibility of using $CO_2$ for enhanced gas recovery (EGR). It should be noted, however, that in contrast to EOR whilst this practice has been the subject of simulation studies, it is our understanding that it has yet to be undertaken either on a commercial scale or in the offshore environment.

To date, however, the experience in the UK has been that hydrocarbon field operators have generally lacked appetite for investment in $CO_2$ storage. This position is somewhat understandable given that the associated rewards are likely to be some way below those associated with hydrocarbon production, whilst many of the potential

---

[63] Petroleum licensing refers to both oil and gas

[64] DECC (2009) *A Consultation on the Proposed Offshore Carbon Dioxide Storage Licensing Regime*, September 2009

suitable storage assets are still producing hydrocarbons, as is the case for the gas fields identified in this study. Furthermore, gas producers have for decades been operating under a business model in which assets require decommissioning at the end of their economic life. As such this liability is built into long-term business plans that are well understood and carry less risk than might be perceived in their transfer for as $CO_2$ storage sites.

As a result of the focus of oil and gas companies being elsewhere, a limited number of organisations have emerged, which are either solely focused on $CO_2$ storage site ownership and operation, or which are SPVs linked to specific CCS projects. Such structures are explored further in Section 8.4.

Aspiring $CO_2$ storage site operators have expressed concern at the low probability, but very large liabilities, associated with major well or geological leakage during the operational or post-closure phase. As discussed in Section 2.1, under the EU ETS a substantial leak of $CO_2$ incurs a liability to buy EUA's at an unknown future price. Original EC proposals suggested that very large financial securities be put in place to cover future leakages up front. Following consultation, however, the EC has issued a revised Guidance Document in Financial Securities which takes into consideration probabilities of leakage and allows flexibility for governments to act as the ultimate insurer.[65] At the time of writing, neither in the UK and Ireland, is there any clarity on how such a system might function. In the UK, however, the CCSA is actively working with Government and industry to reach a viable solution.

To reduce costs associated with converting hydrocarbon fields into $CO_2$ storage sites, related activities should commence as soon as possible following cessation of production. The advantages of such an approach can be summarised as follows:

1) Existing infrastructure can be reused where applicable, thus avoiding the installation of new platforms and other equipment;
2) Loss in the maintenance regime to existing infrastructure will be limited, thereby reducing future remedial costs;
3) Decommissioning costs can be largely avoided by hydrocarbon licence holders; and
4) Experienced staff with knowledge of the assets can be retained.

Without the timely conversion of production sites in to $CO_2$ storage sites, it is expected that the uncertainty caused by delay and associated costs may be prohibitive to develop these assets in the future. As such, there is an optimum window for the development of viable CCS projects, particularly with regard to some of the storage assets identified in this study.

[65] Email correspondence with Ian Philips (Director, $CO_2$Deepstore), Chair of the CCS Association Regulatory Work Group

## 8.4 Business Models and Potential Risk Transfer

Developers of initial CCS infrastructure will undoubtedly need to carry significant business risk along the uncertain integration of technologies. At its most extreme this risk could lead to significant stranded assets.

Investment will ultimately be provided to meet demand, and the design, operation and integration of CCS infrastructure can similarly be left to market forces. Investment in capacity over and above that needed to fulfil immediate demand will be a trade-off between the additional costs involved and the discounted value of foreseeable additional demand. This is an approach that was used to develop oil and gas infrastructure in the North Sea. It should be noted, however, that oil and gas infrastructure is typically sized to accommodate peak load which creates ullage which other parties are able to exploit. $CO_2$ pipelines will differ in that volumes from particular emission sources are likely to remain relatively constant (or increase in a predictable way) over the lifetime of a facility, with aggregate volumes expected to increase over time as CCS becomes more widely deployed.

One difficulty in applying this market-based approach to CCS at the present time is that there is, as yet, no established value chain for CCS. This means that there is no basis against which to establish a benchmark for a financial return on CCS infrastructure which strikes a fair balance between current and future need.

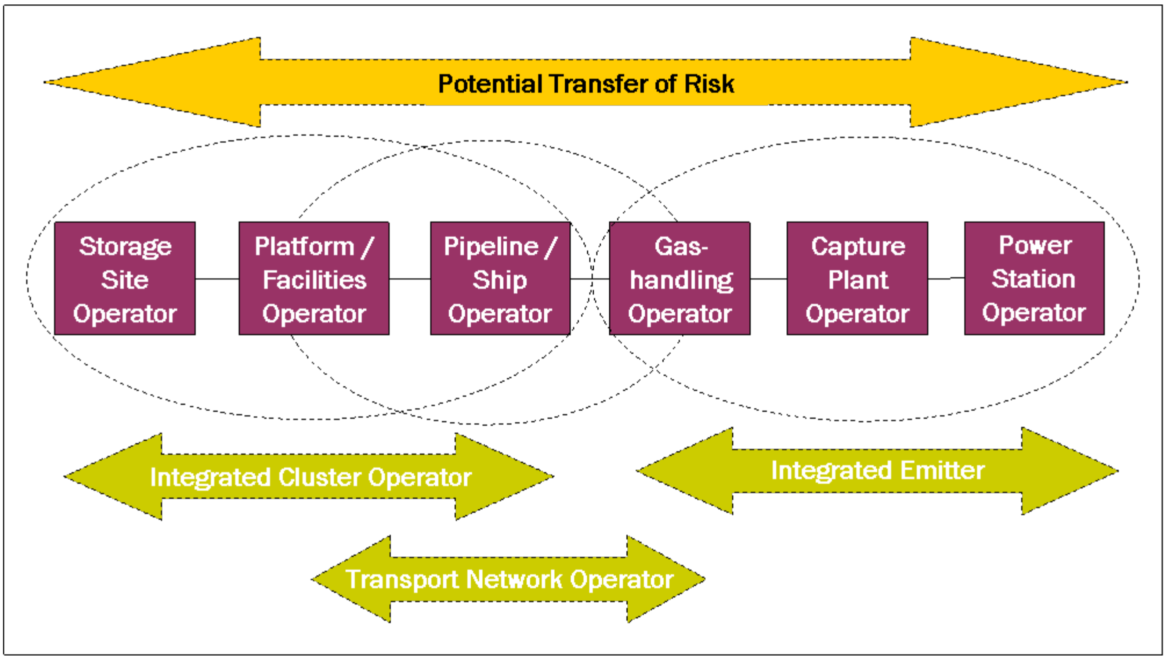
The CCS chain might conceivably be split into the key constituent parts as shown in Figure 8-1. A level of risk is associated with each, whilst the overall level of risk for the full chain might be considered as greater than the sum of these parts due to additional integration risk. Figure 8-1 also shows that multiple partnerships might be developed to spread risk across the CCS chain, which might involve a series of SPVs, with several entities holding a share in more than one element of the chain.

It should be noted that the magnitude of technical risk varies across the different elements of the CCS chain, and as a result, expectations will vary in terms of rates of return. Such variation will depend upon the commercial structures and payment mechanisms in place (as discussed in Section 8.5), but in broad terms, at the storage end of the chain, developers might expect rates of return consistent with those of the existing oil and gas industry given the risk involved. Due to the lower relative technology risk of pipeline operation, however, there will be far lower rates of return in this element of the chain.

The CCS Directive makes the storage site permit holder legally responsible for such contingent liabilities. This would not, however, stop the emitter and the storage site operator reaching agreement to share the cost in the unlikely event that such liabilities materialised. The extent that such guaranteed risk sharing is practical will depend on the financial strength of the parties involved and the availability of risk transfer instruments, such as insurance (and the willingness of Government to share this risk). Clearly the balance of risk in such circumstances would have a significant impact on the commercial terms of storage.

Project risks should be substantially mitigated for later CCS projects which can not only take advantage of technology maturation and greater market certainty, but also of the unit cost savings achievable via the use of shared infrastructure across CCS clusters.

Figure 8-1: Potential Business Models and Transfer of Risk along the CCS Chain




## 8.5 Potential CCS Payment Mechanisms

The following analysis represents a very brief summary of potential payment mechanisms. Given that as an operational industry, CCS is currently in its infancy it is quite possible that alternative, and as yet unknown, mechanisms will emerge as the first commercial demonstration scale projects are rolled-out.

### 8.5.1 'Take-or-Pay' and 'Send-or-Pay'

Given the complex nature of the CCS chain it is considered likely that contract arrangements between parties will be based on some kind of tolling agreement. In the case of point-to-point projects, given the lower relative technical risk associated with the pipeline element, both 'take-or-pay' and 'send-or-pay' mechanisms are likely to be most applicable between the emitters and the storage operator.

Under the 'send-or-pay' element, the emitter is obligated to pay for a minimum tonnage even if this amount is not actually sent for storage. This minimum might cover a certain threshold level of $CO_2$ per annum, based on expected volumes. The 'take-or-pay' element is very similar, albeit the onus is put onto the storage operator. Under such arrangements, if the storage operator does not accept $CO_2$ according to a set of predetermined contractual criteria, then penalties would apply, which might be taken from future base payments. In this way each partner bears responsibility for its own operational risk but with some limited risk transferred to the other party.

In calibrating the relevant base or minimum payments, consideration will need to be given to the debt service obligations of both entities. To ensure this can take place, some element of open-book accounting may be required, which might be facilitated by some kind of initial equity sharing and subsequent equity swap system.

It is also likely that a variable, unit structure would be built into both 'take-or-pay' and 'send-or-pay' mechanisms such that tonnages of $CO_2$ (sent or taken) over and above an agreed threshold would trigger payments between the entities. In this way, both entities are encouraged to send or take as much $CO_2$ as possible.

Such mechanisms are likely to become further complicated by the addition of future emitters as part of CCS clusters. It is possible that contracts between first-mover entities will include clauses for reductions in minimum payments by emitters to storage operators, once additional emitters send $CO_2$ via the cluster network.

### 8.5.2 Capacity Rights and Options

The existing model used for natural gas storage whereby storage volume rights or 'storage bundle units' can be purchased for a given time might be applicable in governing relationships between emitters and storage operators. Future pipelines might also be funded by firm capacity rights and/or options. Firm capacity rights would offer maximum flexibility in terms of agreed flow volumes whilst via options; this capacity could also be fully tradable.

Under the pipeline scenario, options would be paid by each customer (or emitter) on sections of downstream pipeline constructed. On a 'per tonne' basis, these options could be either exercised at a later date or sold to other emitters. This approach would enable construction of larger pipelines which would allow for future growth in the CCS pipeline network.

### 8.5.3 Variable Unit Contracts

Depending on the specifics of a project and the risk profile, for new emitters coming onto an existing network, it might be appropriate for a pipeline operator to be contracted on a more basic model of per unit of $CO_2$ transported. Oil and gas industry contracts are often arranged in this way, for example, according to a Transportation Production and Operation Services Agreement (TPOSA).

## 8.6 Management of Consequential Losses

A key constraint to splitting up the ownership and operation of the CCS chain, as shown in Figure 8-1 above, is the ability to cover consequential losses. Should one element of the chain cease to operate for any given reason, depending upon the contractual payment mechanisms in place, it may need to compensate not only all other members of the chain, but also potentially the power station, which if coal-fired, under the existing regulatory regime, would not be allowed to operate without the CCS chain.

This issue is particularly acute for the storage element of the chain, which due to geological uncertainty, might be considered to have the highest technical risk. One way of circumventing this problem might be to 'wrap-up' all parts of the CCS chain (and potentially the power station) into a single entity, but similarly, any such organisation would still risk significant losses if any part of the chain broke down. As a result, investors will find it very difficult to provide debt or equity funding for new coal plant (and associated CCS infrastructure) unless:

1. Government is willing to share the technical and consequential risks of $CO_2$ storage; or
2. The current regulations relating to operation of new coal-fired power stations are relaxed such that these are permitted to operate unabated for certain periods (during the CCS project demonstration phase only) whilst technical problems associated with injection and storage are resolved.[66]

Should neither of these measures be put in place, even if projects win public funding competitions, financing any new coal plant and associated CCS chains (with future wider cluster infrastructure) will potentially prove too great a challenge.

[66] At the time of writing, Government has proposed, in its most recent consultation on Electricity Market Reform (issued December 2010), that any new coal plant must operate in accordance with an Emissions Performance Standard (EPS) which is set at an average annual carbon intensity of 600g$CO_2$/kWh

# 9.0 Recommendations

In summary, the evidence presented in this study suggests that:

- UK Government should continue not only to support CCS through at least four demonstration projects, but should ensure that those selected are evenly spread across geographies. This will ensure that new $CO_2$ storage infrastructure is enabled to support future CCS infrastructure in all areas where existing thermal plant are located across the UK;
- UK Government should clarify as soon as possible the nature of support to be provided to thermal plant under the proposed feed-in tariff and capacity payments for low carbon energy sources being considered as part of the current Electricity Market Reform (EMR) consultation;
- UK Government should take into consideration the issue of management of consequential risks (due to losses from other parts of the CCS chain and potentially the power station, when any element breaks down) when designing the potential emissions performance standard (EPS) being considered as part of the EMR;
- Within the NER300 and DECC 'Demos 2-4' Competitions, weight should be given within scoring processes to each projects' potential to act as a 'catalyst' for wider CCS clusters;[67]
- The EC should recognise the limitations of current metering technology with regard to EU ETS requirements, such that the related accuracy target becomes achievable by first-mover CCS projects. Without this flexibility, emitters will potentially have to purchase greater amounts of EUAs, which might threaten project viability;
- The emerging Mersey and Greater Manchester Local Enterprise Partnerships (which will replace the functions of the North West Development Agency), and Sustainable Energy Authority of Ireland (SEAI) should invest in further exploring the potential economic and environmental benefits of the EIS cluster; and
- Relevant public sector entities should consider the development of funding bids to the EC to fund further cross-border working on the EIS CCS cluster between Ireland and the UK.

[67] Based on the Call for Proposals issued by the EC for the NER process, it is understood that projects will not formally be scored higher for being linked to clusters