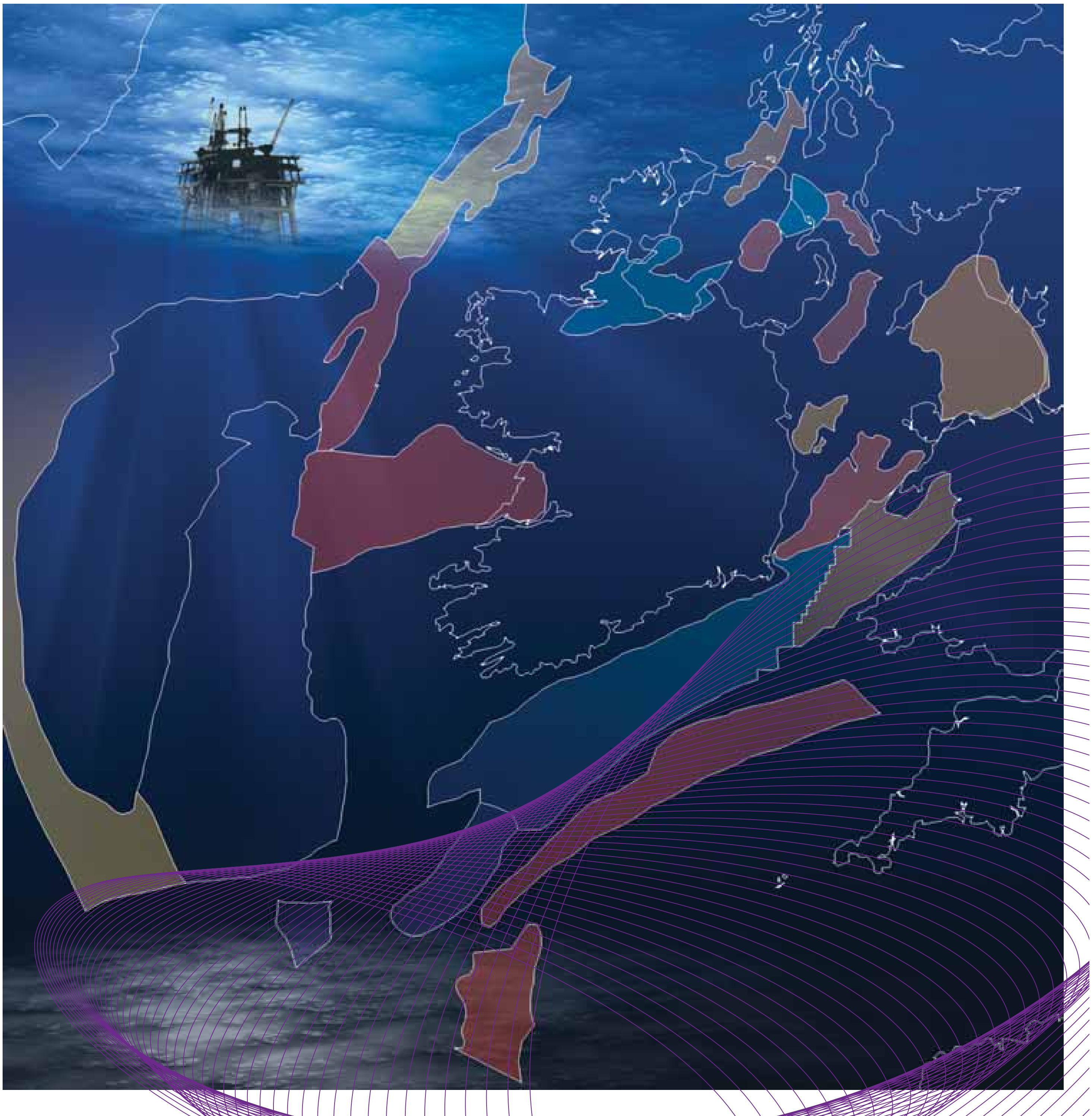
Assessment of the Potential for Geological Storage of CO_2 for the Island of Ireland



Assessment of the Potential for Geological Storage of Carbon Dioxide for the Island of Ireland

September 2008

Prepared for Sustainable Energy Ireland, Environmental Protection Agency, Geological Survey of Northern Ireland, Geological Survey of Ireland by:

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GLOSSARY OF TERMS & ACRONYMS

Ireland	Refers to the Republic of Ireland
Northern Ireland	Refers to Northern Ireland
the island of Ireland/ all-island Ireland	Refers to Ireland and Northern Ireland combined
CO_2	Carbon Dioxide
CCS	Carbon Capture and Storage
CSA	CSA Group Ltd (*lead partner*)
BÓC	Byrne Ó Cléirigh
BGS	British Geological Survey
CO2CRC	Cooperative Research Centre for Greenhouse Gas Technologies, Australia
DCENR	Department of Communications, Energy & Natural Resources (Ireland)
DETI	Department of Enterprise, Trade & Investment (Northern Ireland)
EPA	Environmental Protection Agency (Ireland)
EU	European Union
GSI	Geological Survey of Ireland
GSNI	Geological Survey of Northern Ireland
PAD	Petroleum Affairs Division (DCENR)
SEI	Sustainable Energy Ireland
CSLF	Carbon Sequestration Leadership Forum
UNFPCC	United Nations Framework Panel for Climate Change
IEA_GHG	International Energy Agency – Greenhouse Gas Programme
IPCC	International Panel on Climate Change
IRGC	International Risk Governance Council
US DOE	United States Department of Energy
ETP ZEP	European Technology Platform on Zero Emission Fossil Fuel Power Plants
EU-ETS	European Union's Emissions Trading Scheme
AR3, AR4	Third Assessment Report, Fourth Assessment Report of the IPCC
CER	Certified Emissions Reductions
CDM	Clean Development Mechanism
Depths (sub-sea)	Measured from mean sea level (*unless otherwise stated*)
ECBM	Enhanced coal bed methane recovery
EGR	Enhanced gas recovery
EIA	Environmental Impact Assessment
EOR	Enhanced oil recovery
ESHIA	Environmental, Safety and Health Impact Assessment
FEPS	Frequencies, events, processes (risk analysis)
FRAM (OSPAR Convention 2007)	Framework for Risk Assessment and Management of Storage of CO_2 Streams in Geological Formations
GIS	Geographical Information Systems
MRG	Monitoring & Reporting Guidelines (for emissions)
REFIT	Renewable Energy Feed-in Tariff Scheme
SEA	Strategic Environmental Assessment
SIA	Social Impact Assessment
WP	Work Package
ABEX	Abandonment expenditure
CAPEX	Capital expenditure
COE	Cost of Electricity
EI	Emissions intensity
IGCC	Integrated gasification combined cycle (power plant)
mD	Millidarcy – measure of permeability
MWh	Megawatt hour
Mt	Million tonnes
Mtpa	Millions tonnes per annum
NESO	Net electricity sent out
OPEX	Operating expenditure
PC	Pulverised coal
PV	Present value
TWh	Terawatt hour

EXECUTIVE SUMMARY: FINAL REPORT

ASSESSMENT OF THE POTENTIAL FOR GEOLOGICAL STORAGE OF CARBON DIOXIDE FOR THE ISLAND OF IRELAND

International response to climate change has assumed a greater urgency since the publication of the International Panel on Climate Change (IPCC)'s Fourth Assessment Report in late 2007 and governments globally are seeking ways in which to reduce anthropogenic greenhouse gas emissions. Since the commencement of this study in mid-2007, carbon capture and storage (CCS) has moved up the political agenda and is now regarded as being potentially a major component of carbon abatement strategies, as early stage research and demonstration projects suggest that it is both technically and commercially viable to implement.

The study adopted a phased approach through nine work packages (WP1 – WP9) agreed with the Client at the outset of the study, commencing with extensive data gathering and compilation to GIS to provide a preliminary geological assessment of likely storage basins and structures, both onshore and offshore the island of Ireland. This was followed by in-depth geological assessment of each identified structure/ basin, to quantify potential for storage of carbon dioxide (CO_2). While geological assessment confirmed that there are significant data gaps for many basins, the study arrived at a reasoned, quantified assessment of Ireland's geological storage potential. However, the paucity of deep geological data for many basins, particularly the offshore western basins, is the over-riding constraint to a full assessment of geological storage potential for CO_2.

The island's major point source emissions were identified and power stations emerged as the priority candidates for capture if CCS economies of scale are to be achieved.

An assessment of the all-island energy policy environment, current and future energy security and power generation mix, was used as a prism to provide an economic analysis of the most suitable technologies to capture, transport and sequester carbon, taking cognisance of Ireland's demographics, energy requirements and the likely price of carbon to 2020 and beyond.

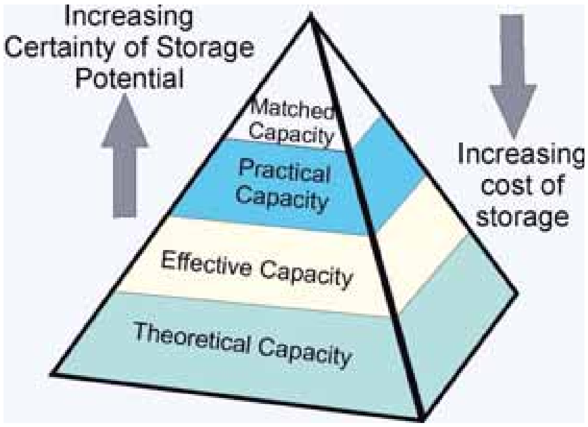
The critical factor for the advancement of CCS on the island of Ireland is the geological viability of injection and storage in a suitable location on or offshore the Island. The depleting Kinsale Head gas field presents the best short term (<10 years) option, subject to further geological analysis and full reservoir simulation. Critically, there would be no logic in investing in expensive carbon capture technologies unless a proven geological storage site within acceptable socio-environmental risk parameters were to be available to take the captured CO_2 into safe, long term storage.

Geological Assessment of Storage Capacity

An integrated assessment of the geological storage capacity of the island of Ireland was carried out for suitable onshore and offshore geological basins and structures (see Table Ex1 & Map 1 overleaf).

The study estimated, using the techno-economic resource pyramid recommended by the international Carbon Sequestration Leadership Forum (CSLF, 2007), that the island has a total storage capacity of 93,115 Mt (see Figure 1).

Figure 1: Techno Economic Resource Pyramid (CSLF 2007)



This storage volume may be subdivided as follows:

TOTAL QUANTIFIED CAPACITY 93,115 Mt

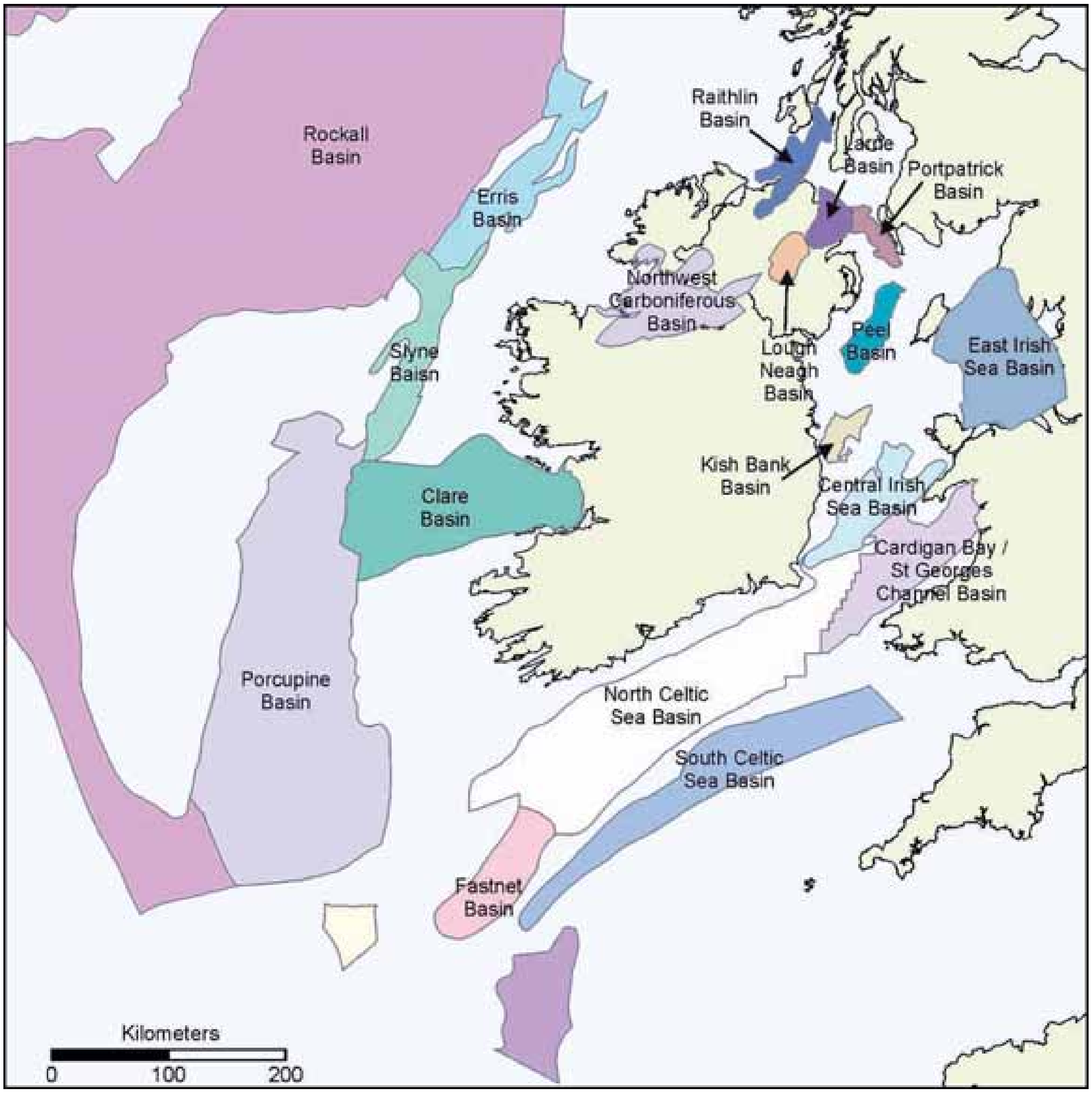
- **Theoretical Capacity: 88,770 Mt**
- **Effective Capacity 3,507 Mt**
    - ***of which 667 Mt is a subset of theoretical capacity;***
    - ***of which 2,840 Mt is additional to theoretical capacity***
- **Practical Capacity 1,505 Mt**

In the geological assessment, only theoretical, effective and limited practical capacities (see Table Ex.1 below) can be calculated due to limitations in deep geological data. To move these estimates up to the apex of the pyramid would require further geological and engineering studies for each structure.

Table Ex.1 All-Island Ireland: Quantified Geological Storage Capacity for Carbon Dioxide

ASSESSMENT OF THE ALL-ISLAND POTENTIAL FOR GEOLOGICAL STORAGE OF CO_2 IN IRELAND QUANTIFIED GEOLOGICAL STORAGE CAPACITY (July 2008)				
Basin	**Structure Type**	**Capacity Classification**	**Storage Capacity Mt**	**Quantified Storage Capacity Mt**
Kinsale	Gas Field	**Effective/ Practical**	**330**	**1505**
South West Kinsale	Gas Field		**5**	
Spanish Point	Gas Field		**120**	
East Irish Sea	Oil & Gas Field		**1050**	
Portpatrick Basin	Sherwood Sandstone selected structures	**Effective** *(subset of theoretical capacity)*	**37**	(***667***)
Central Irish Sea	Sherwood Sandstone structures		**630**	
			667	
Lough Neagh Basin	Enler Group selected structures	**Effective** *(additional to theoretical capacity)*	**1940**	**2840**
Kish Bank Basin	Sherwood sandstone structures		**270**	
East Irish Sea Basin	Ormskirk structures		**630**	
			2840	
Celtic Sea -	1 structure in the Cretaceous A sand	**Theoretical**	**40**	**88770**
Portpatrick Basin/ Larne	whole basin		**2700**	
Peel Basin	Sherwood Sandstone whole basin		**68000**	
NWICB Dowra Basin	whole basin		**730**	
Central Irish Sea	whole basin		**17300**	
Kish Bank Basin	Carboniferous sandstone and coal	**Theoretical / un-quantified**		
Rathlin Basin	Sherwood Sandstone, Permian and Carboniferous			
Celtic Sea	Cretaceous A sand			
Porcupine Basin				
Slyne/Erris Basins				
Clare Basin				
Rockall Trough				
Gas prospects				
Other onshore basins				
TOTAL (PRACTICAL/ EFFECTIVE/ THEORETICAL)			**Mt**	**93,115**

Map 1: Key Sedimentary Basins Assessed in Study – all-island Ireland



A number of sites are proposed for geological storage of CO_2 including the Kinsale Head depleted gas field in the North Celtic Sea Basin, the Portpatrick Basin in the North Channel and potentially the Clare Basin off the west coast. Significantly, the geological assessment and economic analysis indicate that:

- The **Kinsale depleting gas field** with **330 Mt** of effective storage capacity, could provide a sink for Moneypoint and Cork theoretically for 50 years. In exploration terms, the Kinsale Head Gasfield is low risk with proven reservoir potential, but in CO_2 storage terms the key risk applies to containment. Drilling of two exploration wells from the existing platforms would provide sufficient geological data to conduct reservoir simulations, to model the effect of injecting CO_2 on the stress regime and to identify potential leakage points. The highest risk of leakage may be through existing production wells; however, this could be remedied through recompletions with appropriate cement barriers to flow of CO_2.

The Portpatrick and Clare Basins are not well explored and there is a paucity of well data to assess their potential for CO_2 storage.

- The **Portpatrick saline aquifer, with 37 Mt** of effective storage capacity in closed geological structures and a further **2200 Mt** of theoretical storage capacity, could service Kilroot theoretically for 10 years in the closed structures or for 58 years if say, 10% of the theoretical storage capacity were proven up. The Portpatrick Basin has adequate 2D seismic coverage and one exploration well. There is potential for CO_2 storage because the favourable Sherwood Sandstone Group occurs in structural traps at appropriate depths. The drilling of two exploration wells would provide the additional information to prove up the potential of the Basin to store CO_2.

- The geological data available for the Clare Basin at the time of the study did not permit the quantification of the theoretical storage capacity either on- or offshore. However, there is one borehole and some 2D seismic data that cover the onshore parts of the Basin and this study found that the onshore Carboniferous sandstones are likely too shallow to provide a viable storage reservoir for CO_2. Previous oil and gas exploration suggests that storage potential is limited, but future onshore and offshore assessments using modern methods should be considered, given the basin's strategic proximity to Moneypoint. Further detailed geological work is required.

- Saline aquifer storage in e.g. the **Peel Basin** (**68,000 Mt** theoretical) and other offshore basins could offer enormous storage capacity in the longer term but will require significant and costly proving up and to do so. The **East Irish Sea Basin** may offer a very significant sink (**1060 Mt** effective/practical capacity in depleted gas reservoirs), but would require a collaborative approach with the UK Government.

If such capacities can be proven up to offer 'matched capacity' storage, then the island of Ireland could significantly reduce its contribution to atmospheric carbon emissions.

Risk Assessment of Storage Sites

The risk of leakage of CO_2 from a deep storage structure decreases up the resource pyramid with increasing certainty of storage potential. The lowest risk basin identified was that of the gas field at Kinsale in the North Celtic Sea, lying in the 'practical capacity' field.

Risks were considered for Kinsale using FEPs (frequency, events, processes) analysis and although issues such as seal efficacy, faulting, gas chimneys, CO_2:host rock interaction and injectivity require to be modelled in detail, the structure offers an attractive storage site.

Due to the sum of its production history and known geological characteristics, the hydrodynamic and risk modelling carried out for this study, as well as a recent evaluation by Marathon (Ireland) that there are no major barriers to safe storage, the team's experience suggests that the Kinsale field has a 70% probability of providing a 'matched capacity' storage site. The costs of appraising the Kinsale reservoir for its suitability and capacity for CO_2 injection are highly uncertain. However, indicatively, to move the Kinsale field towards the apex of the pyramid, the study estimates that for a costed study of €15 million, to include injectivity and reservoir simulation, the basin could be moved to a 90% probability of safe containment, within two years of study commencement. However, further reservoir simulation, injectivity testing, fault seal analysis, new seismic acquisition and more extensive drilling may be required to fully confirm the suitability of the Kinsale Head Field and to confirm the hydraulic integrity of the reservoir seal. A maximum budget (including the initial €15 million) of €80 million, based on current hydrocarbon exploratory costs, has thus been applied in the economic analysis.

Portpatrick was also risk assessed, but at present is significantly less well understood than Kinsale and its associated risks of ineffective containment are therefore considerably higher.

Assessment of all-Island Ireland's Emissions

The island's major point source emissions of 28.8 Mt CO_2 per annum are derived from the power, alumina and cement industries. If CCS is to be viable then it must be proven to be economic at the largest point sources to take advantage of economies of scale. This suggests that the power sector is the primary target for CCS evaluation, centred on the two key generators at Moneypoint (ESB) and Kilroot (AES), with current emissions of 5.0 Mt and 2.4 Mt CO_2 respectively from their coal fired power plants. Planned CCGT power generating capacity in the Cork Harbour area, as well as proximity to Kinsale, suggested that Cork too should be considered as a potential capture point.

The technology of CO_2 capture from cement plants is in its infancy internationally, while other industrial/ power plants are either too small or too distributed to economically justify CCS at this point in time. Thus, while the study considered the concept of developing capture 'hubs' at e.g. Shannon Estuary (power, alumina, cement) and Belfast (Kilroot and Ballylumford power), in the final analysis it focussed on capture from three single power generation sources: Moneypoint, Kilroot and Cork.

Three main technologies exist for capture of CO_2: post-combustion, pre-combustion and oxy-firing. Currently, the most technically proven is post combustion capture using solvent absorption as a means of separation, which was chosen for the study. The three priority sites identified for detailed economic analysis were Moneypoint, Kilroot and Cork, because of possible economies of scale. Base cases were taken for each site with variable coal and gas fuel sources, while sensitivity analyses were applied to arrive at multiple cost comparative scenarios.

Transport for CCS

Transport options for Moneypoint to Cork-Kinsale, Cork to Kinsale and Kilroot to Portpatrick were considered. International pipeline specifications (steel grade, pipe diameters, materials, pressures) for transport of CO_2 were assessed and applied using variable economic scenarios. Shipping of CO_2 offshore to the east coast UK was considered to be sub-economic given the short distances involved.

The study suggests that the most efficacious transport option is to compress the captured gas at point source and transmit it supercritically in dense liquid phase by pipeline to the storage destination. In the case of Moneypoint, this requires c. 185km onshore and 55km offshore pipelining. Modelling suggested that it should be decompressed and injected subcritically (40-60bar) at Kinsale due to the post-production under-pressuring of the reservoir (although this would require detailed modelling to prevent thermodynamic instability in the well bore), at least in the early stages of injection. Injection pressures may be increased as the reservoir pressure increases over time. Detailed modelling of injectivity and reservoir simulation is required.

At Portpatrick, a similar model was applied, with pipelining from Belfast Harbour offshore for 40km to the Portpatrick saline aquifer storage site. This model can apply supercritical pressures throughout to optimise injectivity into the (already pressurised) aquifer at depth.

Economics of Carbon Capture & Storage

An economic analysis to evaluate the technologies and costs involved in building a complete CCS infrastructural chain, including carbon capture technology, transport and storage elements, was undertaken. A standardised International Energy Agency (IEA) economic approach, using standard coal LHV, standard discount rates, etc. was utilised. A baseline coal price of US$90 was utilised, **lying in the mid range between what IEA used as the long term coal price and the $120 per tonne that both Kilroot and Moneypoint were paying at the time of study visits. Due to rapidly rising oil and coal prices, sensitivity analysis over a wide range $60 to $175 for coal price was employed.**

The economic evaluation is presented (Table Ex.2), based on best current evidence, to evaluate whether the Governments should consider CCS as a valid part of future climate change strategy.

Table Ex.2 Modelled Costs of Electricity Sent Out (€/MWh), with CCS (all-island Ireland, 2008), including the specific cost of CO_2 avoided (€/t CO_2 avoided)

	Moneypoint PC	Moneypoint IGCC	Moneypoint with Cork Retrofit	Cork PC	Cork IGCC	Cork PC	Kilroot PC
Case Number	1A	1C	1D	2A	2C	2D	3A
Sent Out Power (MWe)	900	900	900	900	900	540	540
Total capital cost (€ million)	2,712	2,656	3,679	2,516	2,497	1,665	1,908
Annual operating cost (€ million/yr)	343	309	399	340	306	208	209
Abandonment cost (€ million)	101	87	162	54	50	50	108
Cost of Electricity Sent Out with CCS (€/MWh)	88	82	109	85	80	89	95
Specific Cost of CO_2 avoided (€/t CO_2 avoided)							
Separation	29.7	15.1	35.7	29.6	15.0	29.5	29.8
Transport	13.3	12.4	14.9	9.8	9.1	11.2	11.7
Injection	0.9	1.0	1.0	0.9	1.0	1.4	9.8
On Costs	3.5	2.9	4.5	2.9	2.4	3.3	4.5
Total	47.4	31.3	56.1	43.1	27.5	45.4	55.7

Over a 25 year project life and using standard IEA economic analysis, a new 900 MWe pulverized coal fired power plant based at Moneypoint and storing 6.7 Mt CO_2 at Kinsale (with 4.71 Mt avoided) could deliver power to the grid at €91.6 per MWh based on coal at $90 per tonne with 35euro/tonne price for carbon. A similar assessment for an equivalent sized new Integrated Gasification Combined Cycle (IGCC) coal fueled power plant could deliver power to the grid at €84.6 per MWh giving a reduction in operating costs due to the lower costs associated with the gas compression process. The costs for a pulverized coal and IGCC plant operating without CCS at Moneypoint with the full cost of carbon emissions applied at €35 per tonne would be €82.9 and €86.9 respectively. This indicates that an IGCC option for Moneypoint with CCS applied with subsequent storage of emissions in Kinsale could be competitively priced in the future energy market. In applying this solution, Ireland could eliminate 4.25 Mt of CO_2 per annum. Therefore a single project of this scale (900 MW either IGCC or PC based) could reduce national GHG emissions by 6%

which is equivalent to reducing Irelands CO_2 emissions from fossil fuel energy usage by 9% with respect to 2005 emission levels. Before any investment of this nature could be made further assessment of geological storage sites is required, capture technology development must proceed and detailed design studies undertaken for the various scenarios together with the development of new environmental regulations will be required to provide sufficient certainty for would-be investors.

At present power stations are required to participate in the European Emissions Trading Scheme (EU-ETS) for the period 2008-2012 with allocations to each power generator decided by the EPA. Under the current Phase 2of this scheme (2008 – 2012), power plants are given free allowances for ~ 83.5% of their projected CO_2 emissions over the period 2008-2012. Any emissions above this level must be purchased from another producer who has a surplus of credits via the EU-ETS trading scheme. The current price for these credits for delivery in December 2008 is €22 per tonne.

The long term goal of the EU-ETS is to ensure that eventually all emitters will pay the full price for their CO2 emissions. Some commentators expect the price of CO_2 to rise to €35 per tonne by 2020. The results of this CCS study show that the avoided cost of CO_2 could range from €28 to €56 per tonne depending on the technology option chosen. These figures indicate that as power stations are eventually faced with the full burden of cost for their carbon emissions, it may be more cost effective for them to choose CCS rather than pay the price of their emissions.

The costs of CCS for IGCC power plants are approximately €15 per tonne less than those for pulverised coal power plants. This reflects the lower energy penalty of recovering CO_2 from high pressure gasification systems, reducing the operating costs of the power plant and the amount of total CO_2 generated. The lowest cost estimate of €28 per tonne CO_2 avoided is for an IGCC power plant with CCS at Cork with storage in Kinsale Head. This cost is up to €30 per tonne CO_2 avoided less than the other source - sink combinations.

The project with the lowest capital and operating costs is the 540 MW_e pulverised coal power plant with CCS at Cork with storage in Kinsale Head. This is because the power plant is smaller and the transport distance is shorter. CCS for Kilroot to Portpatrick has slightly higher capital costs, even though the size of the power plants and the transport distances are similar. The higher capital cost reflects the more expensive platform costs for deep water. This increases the specific cost to €56 from €43 per tonne CO_2 avoided.

The project with the highest cost is retrofitting the existing natural gas fired power plants at Cork for CCS and connecting it to the CCS project from Moneypoint power plant to Kinsale Head. The capital costs are larger than the other projects because of the costs for separating CO_2 at four different power plants. The operating costs per MWh are also higher for this project because using natural gas is three times more expensive than coal. Although economies of scale are achieved for transporting a large volume of CO_2 in the offshore pipeline, the high costs of the four separate CO_2 recovery processes and the large operating costs result in a high CCS project cost.

The comparative cost of electricity (COE) including the cost of carbon credits, with and without CCS, for seven model cases is reported in the table below (Table Ex.3), where a carbon credit price of €35/t is assumed. The incremental effect of CCS-based COE with no carbon price ranges from €17 - €54/ MWh, but with a carbon price of €35/t CO_2, lies in the range of -€5 to +€20/ MWh.

These figures are significant and could mean that CCS, with the correct pricing incentives, could be an attractive option for the island of Ireland.

The economics outlined above appear robust and suggest that CCS may well be more economic in an Irish context than in some other economies. In this case there is a strong case to pursue the research into the geological and technical viability in further phases.

Table Ex.3 Cost of Electricity (COE) including the Cost for Carbon at a Price of €35/t

	Money-point 900 MW_e PC	Money-point 900 MW_e IGCC	Money-point PC with Cork Retrofit	Cork 900 MW_e PC	Cork 900 MW_e IGCC	Cork 540 MW_e PC	Kilroot 540 MW_e PC
Reference power plant without CCS (A)							
PV* (of all costs (€MM)	3,480	3,961	3,487	3,475	3,952	2,182	2,144
PV of CO_2 emitted (Mt)	51.4	45.4	70.6	51.3	45.3	31.0	30.9
PV of electricity sent out (TWh)	64	64	64	64	64	38	38
COE with no carbon price (€/MWh)	54.6	62.1	54.6	54.6	62.1	56.8	56.1
PV of carbon credits (€MM)	1,800	1,588	2,472	1,797	1,584	1,086	1,081
PV of costs incl. carbon (€MM)	5,280	5,548	5,958	5,272	5,536	3,268	3,224
COE with carbon price (€/MWh)	82.9	86.9	93.4	82.9	87.0	85.0	84.3
Power plant with CCS (B)							
PV of all costs (€MM)	5,601	5,226	6,958	5,404	5,061	3,411	3,641
PV of CO_2 emitted (Mt)	6.6	4.9	8.7	6.6	4.9	4.0	4.0
PV of electricity sent out (TWh)	64	64	64	64	64	38	38
COE with no carbon price (€/MWh)	87.9	81.9	109.0	85.0	79.5	88.8	95.2
PV of carbon credits (€MM)	232	173	305	231	172	139	140
PV of costs incl. carbon (€MM)	5,833	5,399	7,262	5,635	5,233	3,550	3,781
COE with carbon price (€/MWh)	91.6	84.6	113.8	88.6	82.2	92.4	98.9
Incremental effect of CCS (B-A)							
PV of all costs (€MM)	2,121	1,266	3,471	1,929	1,109	1,229	1,498
PV of CO_2 emitted (Mt)	-44.8	-40.4	-61.9	-44.7	-40.4	-27.1	-26.9
PV of electricity sent out (TWh)	0	0	0	0	0	0	0
COE with no carbon price (€/MWh**)**	**33.3**	**19.8**	**54.4**	**30.3**	**17.4**	**32.0**	**39.2**
PV of carbon credits (€MM)	-1,568	-1,415	-2,167	-1,566	-1,412	-947	-941
PV of costs incl. carbon (€MM)	553	-149	1,304	364	-303	281	557
COE with carbon price (€/MWh)	**8.7**	**-2.3**	**20.4**	**5.7**	**-4.8**	**7.3**	**14.6**

* The Present Value (PV) of all costs is the sum of the PV of project capital, operating and abandonment costs.

PC Pulverised Coal / IGCC Integrated gasification combined cycle

Mt Million tonnes / MWh megawatt hour / TWh terawatt hour / COE Cost of Electricity

Pricing Policy Environment
If CCS is to be viable then it must be proven to be economic at the largest single point sources on the Island to take advantage of economies of scale. Thus the power sector is the primary target for CCS evaluation and this study indicates that clean coal presents an interesting alternative to the Governments.

The option to deploy significant additional offshore wind and wave resources is being actively incentivised by the Government in Ireland and the incentive prices being offered for electricity from these new technologies are very pertinent when examining the likely economic cost of power from clean coal plants with CCS and the economics of CCS in Ireland. Energy conservation initiatives are likely to intensify as the price for carbon emissions (modelled at €35/t in this study) is set to increase progressively, and this route may contribute significantly to tempering demand and arresting growth. A policy of increasing the Island's dependency on gas fired power stations is seen as posing a major security of supply challenge in the absence of new indigenous natural gas finds.

The economic analysis undertaken in this study strongly suggests that CCS could be a valuable component of Ireland's climate change strategy on an all Island basis. The modelled cost of electricity sent out varies from €80 - €109 /MWh, while the specific cost of CO_2 avoided varies from €27.5 - €56/t CO_2.

As an interesting cross-comparison, ESB have reported that their blended cost of electricity generation in 2007 was €104 per MWh (per April 2008 press conference on €22 billion investment strategy). The SEI April 2008 price for electricity to medium size industry was €144.8 per MWh. The CER Best New Entrant 2007 price is quoted at €86 per MWh.

Electricity from offshore wind will attract a Renewable Energy Feed-In Tariff (REFIT) price of €140 per MWh while the incentive price for wave power is €220 per MWh. Incentives for other renewable energy sources range from €57 per MWh (large onshore wind) to micro-hydroelectricity of €72 per MWh. These 2006 starting prices are such that if indexation were applied, **CCS should be highly competitive, particularly in relation to offshore wind and wave energy support prices. Since the REFIT support prices are policies within the control of the Government, they are useful yardsticks when considering Government stance on CCS.**

Notwithstanding the uncertainties in relation to coal prices and capital costs this outcome is seen as very positive for CCS given the huge infrastructural investments involved - some €2.9 billion for the full power generation in the case of Moneypoint, CO_2 capture and compression, long distance pipelining and injection and storage at Kinsale.

The technology in relation to capture, compression and pipelining, whilst not installed at commercial scale power plants to date, is based on well known processes and mechanical engineering principles which, within a short number of years, could be made available with little technical risk of failure.

However, in the case of all the geological basins examined, the data available on priority storage sites is insufficient to provide definitive *matched storage capacity*. Kinsale is an attractive option, but will require detailed geological studies and reservoir simulation in order to guarantee the technical feasibility of a CCS project in the short term. The economic analysis suggests that while €15 million may increase the probability of Kinsale offering an 'matched capacity' storage site to 90%, up to €80 million may be required to provide sufficient confidence in Kinsale as a long term geological storage option, allowing for 5 new wells to be drilled to optimise injectivity of e.g. the modelled 900MWe Moneypoint's 6.7 Mtpa CO_2 emissions. A figure of €100 million has been modelled to bring Portpatrick to a sufficient level of geological confidence in its storage capacity.

It is very likely that by 2015 it would be possible to purchase power station technology fitted with CO_2 capture and compression equipment with a high certainty that the technology will function. However, there would be no logic in investing in this technology unless a proven geological storage site within acceptable risk parameters was available on or near the Island to take the CO_2 into safe, long term storage.

Environmental Considerations

The EU has recently (January 2008) adopted draft proposals for a CCS Directive to provide a legislative framework for the full source to sink CO_2 chain, addressing site selection, authorisation, monitoring plans, liability, stewardship and third party access. Existing Integrated Pollution Prevention Control (IPCC), Waste and Environmental Liability Directives respectively will be used to regulate aspects of CCS activity, although none fully address geological storage. The EU Emissions Trading Scheme (ETS) will provide market driven incentivisation for commercial CCS activity. The proposed CCS Directive and the ETS will also provide guidelines on monitoring and regulation of CCS.

The team considered current international developments in CCS, including aspects of environmental management, risk analysis, monitoring and regulation, which although in a developmental state, fundamentally underpin the technical aspects of the brief. Contacts were made with both the IEA-GHG and the International Risk Governance Council (IGRC) to ensure that best practise was adopted in this Report. The London and OSPAR Accords were amended in 2007 to allow under-sea geological storage of carbon and an emerging international consensus is developing on how best to apply rigorous standards of environmental management of storage sites, as well as long term monitoring and verification methodologies.

Risk and liability issues are being addressed at various forums such as EU, IEA, IGRC and individual state levels, and it is likely that internationally approved guidelines and standards will emerge in the near term. In the longer term, stewardship of each storage site is likely to pass to the Government of the nation in which the injection/storage site is situated, with stringent independent monitoring of the sites carried out by internationally recognised bodies. The handover from operator to the national state will only be permitted following verification that CO_2 is safely contained.

Ultimately, CCS will only be permitted where the environmental integrity can be assured, before, during and after injection to the storage facility.

Conclusions

As a result of this study, the following conclusions may be reached:

1. In the geological assessment, 93,000 Mt of potential storage capacity for carbon dioxide on the island of Ireland have been quantified. However, due to a paucity of deep geological data for many basins and structures, particularly in the western offshore, only theoretical, effective and limited practical capacities can be calculated. To move these estimates to optimal matched capacity at the apex of the CSLF techno-resource pyramid would require significant and costly geological and engineering studies for each structure.

   Should appropriate matched storage capacities be identified following such studies, questions of injectivity rates sufficient to meet the storage requirements of large point source emitters over say 40 years, as well as reservoir pressure stability as more CO_2 is injected, also remain to be tested conclusively over time. Other geological issues such as occlusion of porosity and permeability by CO_2 : host rock interaction or the long term migration of CO_2 plumes, have not been explored over sufficiently long periods of time and will require long term monitoring and modelling at injection sites.

2. The cost of a clean coal power plant exporting 900 MWe to the grid and including carbon capture, compression, pipelining, injection and storage may cost up to €3 billion. The capital cost of power plant, capture and compression comprise the most costly part of the system (~ 70%), while transportation/storage and monitoring chain can comprise up to 30% when owners costs and contingencies are applied.

3. Under 2008 Irish conditions and prices, the case study work has indicated that the cost of power from a power station capturing 90% of the CO_2 emissions would be €91 per MWh. This is very

competitive in the current Irish situation and is lower than the ESB average generation cost (€104 per MWh) for 2007.

4. The economics in Ireland are very different to those in the USA where power stations are not exposed to the EU-ETS and where shorter pipelines have been factored into economic assessments. The price of power in Ireland is thus projected to be much higher than that demonstrated in studies in the US or by IEA, but are nonetheless competitive.

5. There is very little difference in the cost per MWh between the capture technologies (PC, IGCC) evaluated at this stage. This suggests that Ireland does not need to elect for a specific technology at this stage. Given the overall timescales involved (minimum 8 year project from start of the EIS process), Ireland could await the outcome of 12 EU supported demonstration projects before deciding on which capture technology suits the island's needs. Alternatively, Ireland could elect to undertake one of the 12 demo projects, following careful consideration of the upfront risks and cost commitments. However, a window of opportunity linked to the cessation of natural gas production at Kinsale within the next decade could be optimised to demonstrate that basin's CO_2 storage capacity in the shorter (<10 years) term.

6. The comparative analysis indicates that a power plant with CCS, which includes the cost of carbon pricing at €35/t CO_2, with correct pricing incentives, could be highly competitive in the all-island energy market place.

7. The success of CCS projects will hinge on (currently) unknown factors including the role of self-propagating, feedback mechanisms during CO_2 flow which may amplify leakage risks and potential explosive discharges. The issue of long term environmental integrity will be a key determinant as to whether CCS will be adopted by the Irish and Northern Irish governments as a mitigative option in the effort to reduce the island's carbon emissions. Adherence to international monitoring and reporting EU and IEA Guidelines is proposed.

8. **The economics outlined above appear robust and suggest that CCS may well be more economic in an Irish context than in some other economies. In this case there is a strong case to pursue research into the geological and technical viability of carbon capture and storage in further phases.**

Estimating the costs of electricity generation with CCS and alternative energy supply is subject to significant uncertainties. The comments below are indicative only and could be altered fundamentally by circumstances not foreseen in this report.

The fact that CCS-based power from Moneypoint is projected to cost less than half the price per MWh than that being offered to incentivise wave power and considerably below the incentive price of €140 per MWh for offshore wind power incentive price is highly significant. It is lower than the ESB's average 2007 generation price of €104 per MWh, which in itself does not reflect the full cost of CO_2 emissions, as a high percentage of emissions in 2007 were allocated free under the EU-ETS for that period.

The best estimate cost of €35/t CO_2 used in this study is well within the modelled range of CO_2 avoided (€28 - €56/t CO_2). The incremental effect on cost of electricity of CCS based power generation with a carbon price of €35/t is modelled at -€5 to +€20/ MWh.

The study found these results to be promising for CCS as an option for Governments and can conclude that the economics of CCS look sufficiently positive compared to alternatives, taking security of supply issues into account, that the Governments would be fully justified in expending the significant public funds needed to prove up geological storage sites.

Recommendations

The following recommendations may be made:

1. Recommendations – Storage Potential:

Priority 1.1 Kinsale **That to overcome the considerable geological uncertainties and** to match modelled CO_2 emissions from new-build power stations at Moneypoint (up to 6.27Mt injected per annum) or Cork (up to 6.24Mt injected per annum), selected work be undertaken (to include reprocessing of seismics, deviated drilling, petrophysical and geochemical test work, followed by reservoir simulation and injectivity modelling) for a cost of approximately €15 million to move the Kinsale depleted gas field from a probability of 70% (P70) to 90% (P90) that it could provide a safe, long term carbon storage site. These studies may determine that further drilling of wells would be required to achieve optimal injectivities, whereby up to €80 million (inclusive of the initial €15 million) may be required. These studies could be achieved within 2-4 years.

Priority 1.2 Portpatrick That further geological studies be undertaken to prove up a suitable and safe carbon storage site for the modelled emissions (up to 3.77 Mt CO_2 injected per annum) from a new build Kilroot power station, to include acquisition of seismics, drilling and geological studies. It is anticipated that the defined closed structures of 37Mt effective storage capacity will require detailed reservoir simulation and modelling of injectivity parameters to reduce defined risks. To move a portion of the 2200 Mt theoretical capacity to 'matched capacity' will require significant inputs. Such studies will be costly in terms of time and resources, up to €100 million over 10 years.

Priority 1.3 Clare Basin That further geological studies be undertaken to include reprocessing and acquisition of seismics, drilling and geological studies to prove up a safe carbon storage site for the Moneypoint power station. The study notes that early investigations are planned by the EPA with GSI, which work is to be welcomed. The Carboniferous Sandstones in the onshore portion of the Clare Basin may be too shallow to provide supercritical conditions for storage of CO_2 but may be viable in the deeper offshore portion of the Clare Basin. The latter should be examined, together with a re-evaluation of the deeper portion of the onshore basin.

Priority 1.4 Irish Sea Task Force That an Irish Sea Task Force be established between the Irish and UK Governments (akin to the UK-Norway-Netherlands *North Sea Task Force*) to examine the suitability in the shorter term of the East Irish Sea Basin as a joint CO_2 storage site due to its very considerable effective/practical modelled capacity (1060 Mt). In the longer term, the Kish, Peel, Central Irish Sea Basins could be examined in a similar light, under the same Task Force.

2. Recommendation – EU Demonstration Project for Ireland

Given that this study concludes that clean coal potentially offers the island of Ireland an economic option to address the considerable security of supply issues subject to the definition of matched geological storage capacity, and that the Kinsale Gas Field storage opportunity is projected to be depleted of gas within the next ten years, that Ireland take an early lead and elect to become one of the EU CCS demonstration projects.

3. Recommendation – Pricing Support

That a price support, such as REFIT, be offered to CCS in the range offered to other low carbon power generation options. The price would need to be significantly above that offered to large onshore wind (€57 per MWh), but below that offered to offshore wind (€140 per MWh) and wave (€220 per MWh). These 2006 starting prices are such that if indexation were applied, **CCS should be highly competitive, particularly in relation to offshore wind and wave energy support prices.**

4. Recommendation – Environmental Monitoring

It is recommended that emerging international guidelines (from e.g. EU-ETS and CCS Directives/ IEA/ IGRC/ OSPAR) on monitoring, verification, reporting and risk analysis of the environmental, safety, health and social impacts of CCS be adapted to site specific conditions for all-island Irish carbon storage projects.

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1 INTRODUCTION

CSA Group, with its partners British Geological Survey (BGS), Byrne Ó Cléirigh (BÓC) and Australia's Cooperative Research Centre for Greenhouse Gas Technologies (CO2CRC), hereinafter collectively called "CSA", have completed an *Assessment of the All-Island Potential for Geological Storage of Carbon Dioxide in Ireland*, on behalf of Sustainable Energy Ireland (SEI) and its partners, the Environmental Protection Agency (EPA), the Geological Survey of Ireland GSI), the Geological Survey of Northern Ireland (GSNI) and the Petroleum Affairs Division (PAD) of the Department of Communications, Energy and Natural Resources (DCENR), referred to collectively as 'the Client'.

1.1 STUDY METHODOLOGY

In line with the terms of reference, this study adopted a phased approach through nine work packages (WP1 – WP9) agreed with the Client at the outset of the study. CSA commenced (**WP1**) with extensive data gathering, from a variety of public and private sources, and compilation to GIS to provide a preliminary geological assessment of likely storage basins and structures, both onshore and offshore the island of Ireland. This was followed by an in-depth assessment (**WP2, WP3**) of each identified structure/ basin, to quantify (where possible) its potential for storage of carbon dioxide. The geological assessment confirmed that in comparison with other countries, there were significant gaps in the data, largely due to the relatively shallow profile of sub-surface exploration data (<700m) onshore and the fact that there has been only one producing gas field (Kinsale and its satellites) in the Irish offshore to date. However, with the exploratory data available, the study arrived at a reasoned, qualified assessment of Ireland's geological storage potential (**WP6**). The techno-economic methodology of the international Carbon Sequestration Leadership Forum (CSLF, 2007) was applied in the quantitative capacity assessments to provide varying levels of confidence for each basin/ structure. Risk assessments, using the qualitative FEPs (frequencies, events, processes) methodology, were carried out on those basins where data allowed (**WP4**). Two priority basins with practical / effective geological storage capacity were identified at Kinsale (depleted gas reservoir), offshore Co. Cork, and at Portpatrick (saline aquifer), offshore Cos. Antrim/ Down in the North Channel (**WP8**). Other basins, including the Clare Basin and the deeper offshore western basins such as the Porcupine and Slyne Basins, lack sufficient data at this point in time to provide a quantitative storage capacity assessment.

Given the paucity of detailed geological data outside of the Kinsale gas field to carry out site characterisation through hydrodynamic modelling and reservoir simulation, as well as risk analyses of many of Ireland's potential storage structures, considerable re-focusing of the project (with the approval of the Steering Group) to the upstream economics of capture and transport elements was undertaken, considering that international economic studies indicate that the costs of capture will comprise up to 90% of total project costs and are thus central to the case for CCS.

An assessment of the all-island energy policy environment, energy mix, security and power generation issues to 2020 and beyond, was used as a prism to provide an economic analysis of the most suitable technologies to capture, transport and sequester carbon, taking cognisance of Ireland's demographics, energy requirements and the likely price of carbon to 2020 and beyond. In tandem with the geological assessment, the study assessed the current national allocations of major point source emissions from power generation, cement production and heavy industry across the island (**WP5**), to define central operational hubs from which carbon dioxide may be economically captured and transported to viable storage sites.

Detailed consideration has been given to the costs of transporting captured CO_2 from defined sources to the geological sinks. Most international pipeline costs hinge on base costs sourced from enhanced oil/ gas recovery programmes in USA, Canada and Australia, many of which do not apply in the Irish context, given gas compositional variations from power generation emissions, terrain, population densities and associated planning challenges. This study has investigated recent Irish and UK pipeline projects and attempts to draw realistic analogies and likely costs for an Irish CCS project. Additionally, the study has considered the transport costs of shipping CO_2 from Ireland to the east coast of England for hypothetical storage in a depleted gas field in the North Sea. That scenario suggests a price range of US$15-20/t CO_2, depending on the size of vessel and volumes to be shipped, which compares unfavourably to the costs of pipelining per tonne of CO_2 to a more proximal Irish storage site.

The most suitable carbon capture technologies, plant sizes and economics were modelled **(WP7)** with inbuilt sensitivity analyses. It is apparent that retrofitting of existing plant is unlikely to be economic and that small diverse sources of carbon emissions are not feasible to capture. Scenarios were thus focussed on new-build large scale power generation plant at critical hubs. Central to that analysis is the (internationally) high Irish average cost per MWh of electricity generation (€104/ MWe in 2007 based on ESB figures reported in March 2008), which is three to four times that of a coal producing country such as Australia. Additionally, capital construction and labour costs, as well as the price paid for coal and the future traded price of carbon, will impact most heavily on the economics of carbon capture and storage in Ireland.

Among all the options considered, three key source-to-sink options were selected as case studies to conduct techno-economic analyses (**WP9**) as case studies for Irish capture and storage model projects, which are presented in the concluding chapters and Annexe 2.

Current research in UK, Europe, Australia and North America is pertinent in the formulation of Irish policy in this arena. The team has visited and/or been in contact with a variety of agencies and research bodies throughout the course of the study, most notably EU, CSLF, Australia's frontline researchers in CO2CRC, the International Energy Agency's Greenhouse Gas Programme (IEA_GHG), the US Department of Energy (US DOE) and the International Risk Governance Council (IRGC). In tandem, considerable discussions have been held with major Irish energy generators, regulators, researchers and policy makers to position the study within the evolving energy framework.

The team considered current international developments in environmental management, risk analysis, monitoring and regulation of CCS, which although in a developmental state, fundamentally underpin the technical aspects of the brief. Contacts were made with the IEA-GHG and the International Risk Governance Council to ensure that current best practice is considered in this report.

1.2 WHY CARBON CAPTURE & STORAGE?

The United Nations Environment Programme (UNEP) and the World Meteorological Organisation (WMO) jointly established the **Intergovernmental Panel on Climate Change (IPCC)** in 1988 to assess available scientific and socio-economic data on climate change and to provide options for its mitigation. It reports periodically to the United Nations Framework Convention on Climate Change (UNFCCC). Since 1990, the IPCC has produced a series of key Assessment Reports, Special Reports and Technical Reports through specialist working groups, to inform governments and the multilateral partners on options for adaptation to climate change and actions to reduce the levels of carbon emissions internationally.

In November 2007, the final synthesis of the IPCC's *Fourth Assessment Report* (AR4)[1] was published, reaching an unprecedented consensus among scientists that warming of the global climate system is unequivocal and is happening at or above modelled rates (since the *Third Assessment Report,* AR3). The IPCC and the EU consider that dangerous and irreversible climate change can be avoided if global average temperatures do not increase by more than 2ºC above pre-industrial levels. To achieve this, emissions of CO_2 and other GHGs must peak in the coming decades and then be significantly reduced. Reductions can be achieved through increased utilisation of a variety of alternative energy sources such as biomass, wind, wave etc, but the EU recognises that fossil fuels with CCS will remain in the fuel mix to guarantee energy security.

The AR4 suggested that there is a broad range of instruments available to governments to create incentives for mitigative action. CO_2 capture and storage (CCS) technologies could be used in combination with other mitigation measures (e.g. fuel switching, energy efficiency and renewable energy), which with an effective carbon-price mechanism and deployment of soon-to-be-commercialised technologies, could induce significant reductive measures across all sectors. Mitigation costs will rise with the stringency of the CO_2 reduction targets, but it is anticipated that globally, macro-economic costs will be in the order of +1% gain to -5% loss to global GDP (IPCC AR4, 2007). The costs of 'do-nothing' are predicted to be orders of magnitude more than this in environmental, infrastructural and social costs.

[1] See www.ipcc.ch for IPCC Assessment Reports 1-4 and Special Reports. The Assessment Reports are referred to by number as AR3, AR4 etc on the IPCC website, or alternatively in the literature as Third Assessment Report, TAR etc.

The IPCC Special Report on *Carbon Dioxide Capture & Storage* (2005)[2] specifically addressed aspects of concern pertaining to CCS and gaps in knowledge with regard to current technologies. It assessed new and emerging technologies for capturing CO_2, specifically the key environmental risks, legal and regulatory issues and costs associated with its use and storage. The key conclusions from the report include the following:

- The actual use of CCS, as for other mitigation options, is likely to be lower than the economic potential due to perceived environmental impacts, risks of leakage, lack of a clear legal framework or public knowledge and acceptance (*to date*)
- The widespread application of CCS will depend on technical maturity, costs, overall potential, diffusion and transfer of technologies to developing countries.
- If continuous leakage occurs it could, at least in part, offset the benefits of CCS for mitigating climate change.
- Few countries have specifically developed legal or regulatory frameworks for long-term CO_2 storage. Long-term liability issues associated with leakage of CO_2 to the atmosphere and local environmental impacts are generally unresolved.

Since the publication of the IPCC Special CCS report, as well as the Stern Report[3] in the UK, very significant urgency to reduce emissions now pertains among multilateral agencies and governments. CCS is now regarded as a major component of carbon abatement strategies, as early stage research and demonstration projects (Chapter 2 below) suggest that it is both technically and commercially viable to capture CO_2, transport and store it safely in deep structures for geologically long periods of time. CCS is not a "cure-all", but it offers a bridging strategy to governments over the next 20-100 years, as the performance and uptake of renewable and clean energy technologies improves, particularly as coal will continue to be a major power generation fuel (see Chapter 4 below).

There is a considerable challenge in defining sufficient geological storage options across Europe and worldwide. The multilateral *Climate Action Partnership* (CAP) and *Carbon Sequestration Leadership Forum* (CSLF)[4], as well as a number of EU initiatives (Chapter 2), are pursuing international collaborative options for geological capture and storage of CO_2.

Environmental and technical uncertainties remain pertaining to long term containment of CO_2 geologically, but these too are the subject of ongoing research. Most significantly for Ireland is the fact that CCS is now among the top priorities in the EU's recently published Strategic Energy Review (2007).

The combined 2007 emissions for USA and Canada were expected to reach 6Gt, while the future CO_2 emissions of the emerging Chinese economy are likely to be higher than those of the USA by 2030 (up to 8Gt), if planned coal fired energy generation continues at the current pace[5] (China built 105GW of new coal-fired power capacity in 2006[6]). In global terms, Ireland's current CO_2 emissions of 47Mt pa (EPA data) are relatively small, but are nonetheless high in per capita terms. Emissions for Ireland in 2004 are at 23% above 1990 emissions levels due to the unprecedented economic growth of the past decade. Following the EU Strategic Energy Review (2007), new regulations mean that Ireland must cut its emissions by 20%, a strong challenge given our current electricity generation portfolio. CCS may offer a means to directly reduce our emissions from major point sources.

This study aims to assess the potential for geological storage in an economically and technically viable manner through all stages from capture to compression, transport and injection to suitable storage sites for the island of Ireland. Costed economic scenarios present the case to become an active participant in carbon capture and storage projects, underpinned by the need for increased geological base data.

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[2] IPCC 2005. *Special Report on Carbon Dioxide Capture and Storage prepared by Working Group 3 of the Intergovernmental Panel on Climate Change*. Metz, Davidson, de Connick, Loos & Meyer (eds.). Cambridge University Press, UK

[3] *The Stern Review – The Economics of Climate Change*. Nicholas Stern, 2006.

[4] Formed in 2003, the CSLF is a voluntary climate initiative of developed and developing nations to enable early reduction and steady elimination of large-source greenhouse gas emissions. Its 22 members, which produce c. 75% of world emissions, collaborate in technology RD&D projects. In April 2008, the CSLF declared its support for G8 recommendations for near term deployment of CCS.

[5] Mining Journal, February 2007 and United States Department of Energy www.netl.doe.gov

[6] International Energy Agency, 2007

1.3 POLICY IN RELATION TO ELECTRICITY GENERATION PORTFOLIO

This study has been grounded within the current Irish energy policy framework, which has enormous implications for the future commercial viability of CCS.

1.3.1 The Irish Perspective on Carbon Capture and Storage

Ireland's current energy policy is framed by the White Paper '*Delivering a Sustainable Energy Future for Ireland*' published by the then Department of Communications, Marine and Natural Resources (now DCENR) in March 2007.

The primary objective of Ireland's energy policy is to deliver security of supply, environmental sustainability and economic competitiveness and each of these three high level and interrelated goals have a number of action points to support their delivery.

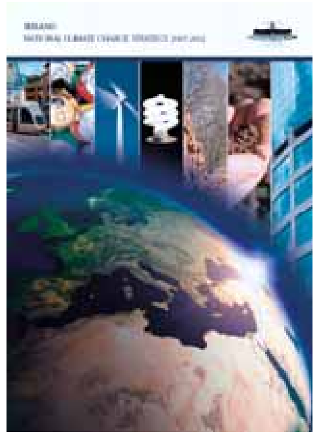
With regard to the first of these, the government proposes a number of Strategic Goals, one of which is 'Enhancing the Diversity of Fuels for Power Generation'. This notes that in the absence of significant additional hydro resources, and the statutory ban on nuclear generation, Ireland's dependence on natural gas for power generation would be 70% by 2020 without policy intervention. This is seen as unsustainable from a security of supply perspective and the government states that it is committed to reducing over-reliance on natural gas in the power generation sector by proactively pursuing alternatives.

Regarding Carbon Capture and Storage, this section of the White Paper states:

> Carbon capture and storage (CCS) offers great potential and is in developing use. However the entire CCS process in conjunction with electricity generation has not yet been demonstrated on a commercial scale. Technical, environmental and economic aspects of CCS remain uncertain and international legal frameworks such as OSPAR will need to be amended.
>
> The EU Strategic Energy Review highlights the critical importance for Europe of clean coal technology advances. The Government will keep CCS potential under close review in conjunction with CER, EirGrid, SEI and the power generation sector as well as hydrocarbon exploration and production companies. We will pay close attention to developments in the UK and in the EU generally and we will build on analysis by SEI on costs, benefits and future potential for Ireland of CCS Strategies[7]. Subject to developments, the Government would envisage the commercial operation of a new clean coal power generation plant before 2020.

[7] SEI *Carbon Capture and Storage in Ireland – Costs, Benefits and Future Potential*, August 2006

Later in 2007, the Irish Department of the Environment, Heritage and Local Government published its Climate Change Strategy[8].



Under the Kyoto Protocol, the EU committed to reduce its overall emissions by 8% from 1990 levels by the 2008-2012 period. Recognising its particular circumstances, Ireland's target within the overall reduction was set at a limit of 13% above the 1990 level. However, the most recent data at the time of the publication of the Strategy showed that Ireland stood 25% above 1990 emissions in 2005. Baseline projections with existing measures indicate that emission levels may rise to 71Mt CO_2 equivalent (CO_{2-e}) per annum during the Kyoto period (28% above 1990 levels and 8.1Mt CO_{2-e} above the Kyoto target)[9]. The Strategy proposed a number of additional quantified measures to achieve a reduction of 8.56Mt during the period and thus bring emissions below the target of 63.032 Mt CO_{2-e}. The Minister at the time stated categorically that "Ireland will meet its 2008-2012 climate change target"[10].

Ireland will use flexible mechanisms, including the Clean Development Mechanism (CDM) (established under the Kyoto Protocol) which allows countries to gain credit for emission reductions elsewhere, as part of its efforts to meet these targets. €270million has been committed under the National Development Plan 2007-2013 to comply with its commitments under the Protocol. This is in addition to €20million spent in 2006.

As would be expected, given the relatively short time to the end of this period, none of these included any reference to CCS. However, looking forward, the Climate Change Strategy recognised the importance of fuel diversity and the potential for CCS:

> The ESB's coal-fired power station at Moneypoint, Co. Clare, is the single biggest source of greenhouse gas emissions in the State. However, its continued operation is fundamental to maintaining an appropriate level of diversity in the national fuel mix for electricity generation so as to ensure security of electricity supply.
>
> Given its size in greenhouse gas emission terms and its importance to the economy, it is essential that the plant operates at maximum efficiency when measured against best available technologies. The scope for the introduction of clean coal technologies and the potential for the use of carbon capture and storage, whether in new plant or by way of refitting existing plant, will be pursued in the period to 2020, in line with the pace and scale of technological and commercial development, as well as planning frameworks, in relation to these technologies.
>
> DEH &LG *National Climate Change Strategy 2007-2012*, April 2007

The issue of fuel diversity has a particular importance for Ireland, given that ambitious targets for renewables have increased for the electricity generation portfolio in the last few years. The Energy Green Paper[11] that preceded the White Paper included a target of 30% for renewables while the White Paper stated that "We will achieve 33% of electricity consumption from renewable sources by 2020 through support for research, development, commercialisation, and technology transfer as well

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[8] DE,H &LG *National Climate Change Strategy 2007-2012*, April 2007
[9] SEI *Energy in Ireland 1990-2006*, 2007 Report
[10] Strategy Page 5
[11] DCM&NR *Towards a Sustainable Energy Future for Ireland*, October 2006

as grid connections and planning issues for offshore wind, ocean technology and biomass"[12]. Subsequently the All Island Grid Study[13] indicated that under different scenarios, the contribution of renewables, in particular wind generation, could exceed even this level, possibly to over 40%.

In order to encourage the development of renewables, the Government made a number of announcements in the early part of 2008 to increase the support available for offshore wind farms and wave energy. Electricity generated by offshore wind farms would receive €140 per megawatt hour (/MWh) of power produced and electricity produced by wave energy would receive €220 /MWh produced under the Renewable Energy Feed-in Tariff Scheme (REFIT).

These levels of support, together with the €270 million committed under the flexible mechanisms noted above, should be considered in the context of the cost of clean electricity generated by CCS-enabled, coal fired power generation discussed in this report. By way of comparison, the CER's 2007 Best New Entry (BNE) price amounted to €85.75/MWh, of which €67.60/MWh was gas.

Thus it is likely that there will be a significant increase in the penetration of renewable energy in the electricity generation portfolio in the coming years. Four plants totalling 1200 MW with the capability of generating electricity using oil (Great Island, Marina, Poolbeg Units 1, 2 & 3 and Tarbert), are due to be closed by 2010 and the only plants built in recent years and under construction at this time (at Aghada and Whitegate) are gas fired. Thus, in the absence of any other policy, additions to power generation capacity on the whole island is likely to be dominated by wind and gas. The two existing coal fired power stations on the Island – at Moneypoint, Co Clare and Kilroot, Co Antrim – are likely to reach the end of their technical life sometime between 2020 and 2030.

CO_2 emissions on the island of Ireland are dominated by these two coal fired stations and a number of other installations centred around Shannon, Dublin and Belfast, with a third smaller hub in the Cork area (see Figure 25 below).

1.3.2 The International Policy Perspective

Worldwide interest in carbon capture and storage has increased at an exponential rate in recent years and it is becoming more widely acknowledged that if the world is to achieve any of its targets to stabilise and then reduce greenhouse gas emissions, CCS will have to play a significant part. On the basis that the worldwide demand for energy will continue to increase and that a significant part of this will be for electricity generation, coal will inevitably play a key role into the future. The availability and price of other competing fossil fuels (oil, natural gas) could provide coal with a competitive cost advantage and as large coal reserves exist in some major consuming countries (China, India, USA), it is very likely that the coal will continue to be used.

There is a strong focus on international collaboration into research into CCS. Much of this is undertaken by the International Energy Agency's Greenhouse Gas Programme (IEA_GHG) which was set up in 1991 and is based in the UK. Ireland is a member of the IEA, but is not currently one of the 17 governments who are members of the GHG Programme. Research undertaken by the Programme has been used in the compilation of this report. The IEA has taken a keen interest in coal since it was founded in the aftermath of the 1974-1974 oil crisis and in 1975, it set up the Clean Coal Centre to provide information on the sustainable use of coal worldwide. Recently the principal focus of these two sister organisations has been on CCS.

As well as research commissioned and undertaken through international collaboration, considerable efforts are being made at national levels to begin the process of the commercialisation of CCS in coal fired power stations. These include, inter alia, Australia, Canada, the UK and the USA. Of particular relevance to Ireland is the decision by the UK Government to fund up to 100% of the costs of one of the first commercial scale CCS demonstration projects using post combustion capture. This will entail the capture and storage of the CO_2 from the flue gases of at least 300MW output of electricity. A competition is currently underway which should result in a company or consortium being selected by late 2009 with a view to having the plant in operation by 2014.

Legislation to permit the storage of CO_2 under offshore waters is contained in the (UK) Energy Bill 2007-2008, which is currently being enacted. It is evident that legislation permitting CCS will be needed in some other countries before it can proceed and it is interesting to note that draft

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[12] White Paper Page 29
[13] DCE&NR and DETI *All Island Grid Study*, January 2008

legislation enabling CCS was published by the Australian Government in May 2008 and the EU has proposed a Directive on the Geological Storage of Carbon Dioxide and amending Council Directives[14].

In January 2008, the EU published a Communication "Supporting the Early Demonstration of Sustainable Power Generation from Fossil Fuels"[15]. This noted that at the 2007 Spring European Council, the EU made an independent commitment to reduce emissions by at least 20% by 2020 (and possibly by 30% if a wider international agreement could be reached) and continue the emission reduction path further on after 2020. Although the allocation of this reduction between Member States has not been finally agreed, it is likely that Ireland will have to commit to reduce emissions between 1995 and 2020 by around 20%.

The EU recognises the important future role of fossil fuels for energy supply in general and coal in particular for electricity generation in Europe and in the world, while at the same time accepting that coal use needs to be compatible with environmental objectives and climate change targets. Thus the Communication states that **CCS will be a critical technology amongst the EU's portfolio of measures in delivering on the competing objectives of secure and economic electricity supplies and facing up to the climate change challenge**.

The EU believes that for there to be a widespread roll out of CCS from 2020, operational experience will be needed before then and states that there is **a need to achieve the construction by 2015 of a first series of a dozen large scale CCS demonstration power plants and to have these plants operating for an initial period until 2020 to allow conclusions on their feasibility and economics. The dozen early movers will benefit from co-ordinated exchange of operational experience, EU market brand, consulting services and EU-wide public communications. It is planned that the network of demo projects will commence in 2009 in recognition of the emissions reduction time challenges. It is anticipated that EU level financing will be available through FP7 and possibly structural funds, with EC guidelines to be published to facilitate state aid to the selected projects.**

The UK project is likely to be the first of such plants and the pressure will be on other Member States to demonstrate commitment to EU objectives and facilitate the construction of other plants during the 2015-2020 period, using a variety of different technologies.

1.3.3 Ireland – A Window of Opportunity?

As indicated above, it is likely that by 2020, in the absence of any proactive policy, the electricity generation portfolio on the island will consist of mainly wind and gas fired plant, with two coal fired stations at Moneypoint and Kilroot, both of which will be at or near the end of their technical life. Both of these will continue to emit large volumes of CO_2 throughout this period. In March 2008, the ESB, when launching its Strategic Framework to 2020 and Corporate Plan, indicated that it would consider building a clean coal plant as a replacement for Moneypoint – thus suggesting that this would come on line in the mid-2020s. This is considerably later than the policy set out in the Energy White Paper, which envisaged a clean coal plant to be operational before 2020, while the Climate Change Strategy looked for the potential for the use of carbon capture and storage, whether in new plant or by way of refitting existing plant, to be pursued in the period to 2020.

It is clear from the findings of this report, that there are a number of potentially large geological structures around the island where CO_2 could possibly be stored. However most of these will require a significant investment in time and money to bring them to a level of geological knowledge such that CO_2 could be stored with sufficient confidence that there will be no long term leakage. This overall state of affairs, compared for example with GB and Norway, is a reflection of the relatively low level of oil and gas exploration and production activity in Ireland. In these countries, the relatively high level of exploration and production activity has provided the information required to deliver the confidence that the geological structures are fully understood.

The one exception to this is might be the Kinsale Gas Field, offshore Cork, which commenced production in 1978. The Kinsale Head gas field was developed initially and three smaller gas

[14] EU COM (2008), January 2008
[15] Commission Staff Working Document SEC(2008) 47

accumulations (South West Kinsale, Ballycotton and Seven Heads) were developed subsequently utilising the same core infrastructure.

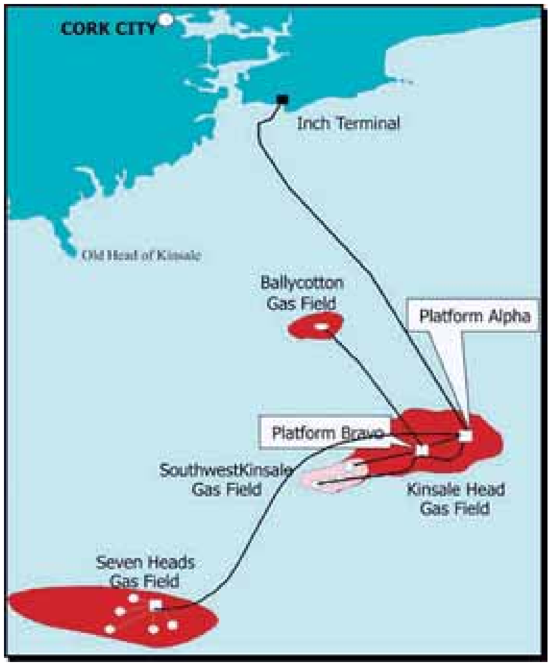
The core infrastructure consists of two platforms with wells producing from the Kinsale Head field to the shore, with subsea wells on the other three fields tied back to the two platforms (Figures, 1, 2).

It is evident that after 30 years the field is approaching the end of its economic life and it is estimated that around 95% of the ultimate recoverable reserves have now been produced. In the absence of any new discoveries in the adjacent area that could extend the economic life of the field, it will be closed down, decommissioned and the infrastructure removed. It should be noted that it may be difficult for small marginal discoveries to be developed economically as they will need to cover a large share of the operating costs of the infrastructure. This was not the case when the three previous accumulations were tied back to the platforms – at that time, a significant volume of production was available from the main Kinsale Head reservoir to cover the bulk of overhead costs.

Figure 1: Alpha Platform – Kinsale (1); Bravo Platform – Kinsale (2)

The overall field layout can be represented thus:

Figure 2: Kinsale Head field layout



It is not known when the decision will be taken to finally cease operations. However, it should be noted that the South West Kinsale reservoir is currently used as a commercial storage facility to provide additional gas supplies at periods of high demand and is the only storage facility of its kind on the island at this time. Before any cessation of operations, commercial gas storage operations will have to stop and the stored gas, together with the cushion gas in the reservoir, will need to be produced, which could take 2-3 years. The earliest that this could commence would be at the end on the 2008/2009 winter (April 2009) although this is considered unlikely, in particular if gas prices remain at their current level. In any event, it is clear that the economic life of the field is finite and in the absence of any major discovery in the area that could utilise the infrastructure, a decision to end operations is likely to have to be taken within the next few years.

Analysis has been undertaken in the UK relating to the possibility of the reuse of existing infrastructure for CO_2 storage. One study by the East of England Energy Group[16] investigated the reuse of existing offshore pipelines for a variety of purposes and concluded that there was no reason why offshore pipelines could not be used for the transportation of CO_2, provided the gas was dry. This issue is also discussed in the Transportation Section of this report. A second study by the same Group[17] analysed 15 suitable fields in the southern sector of the North Sea for conversion from natural gas production to CO_2 injection. The report estimated the costs of decommissioning the 15 fields (some of which costs would be paid indirectly by the tax payer, as would also be the case in Ireland), the cost of constructing new purpose built facilities for CO_2 transportation and injection and the costs of converting the existing facilities at the end of field life for CO_2 storage. The report concluded unsurprisingly that **the costs of converting an existing facility for CO_2 storage use was orders of magnitude less than decommissioning an existing facility and constructing a purpose built new one**.

As noted above, Kinsale field has been in production for 30 years and if the facilities were to be considered for re-use, a technical assessment would need to be undertaken to determine if the use of

[16] EEEgr *The Re-Use of Offshore Oil and Gas Pipelines*, January 2006
[17] EEEgr *Report on Infrastructure, Availability and Costs of CO2 Transportation and Storage Offshore – Southern North Sea*, February 2006

the infrastructure could be extended beyond its original design life. It is likely that this would have been done when the Seven Heads development was undertaken. At that time, reserves in Seven Heads were thought to be significantly higher than turned out to be the case and the development was based on 25 years production, commencing in 1993. This would mean that the Kinsale A platform was considered suitable for production through to 2018. It is not known if a further extension would be possible, but it is unlikely that it would be possible to use it for the full life of any Moneypoint replacement project commencing in the mid-2020s.

Significantly, the geological assessment (Chapter 3) and economic analysis of case studies (Chapters 4, 7 below) indicate that, subject to further geological and engineering studies:

- The Kinsale depleted gas field offers 330Mt of effective storage capacity, which allowing for injection of 6.27 Mt from a 900 MWe (sent out) pulverised coal, capture-ready power plant at Moneypoint, would offer >50 years of storage capacity.

- A similar figure of + 50 years for injection of 6.24Mt CO_2 into Kinsale, captured from a new build 900 MWe (sent out) pulverised coal plant at Cork, can be reached.

- The Portpatrick saline aquifer (closed structures) offers 37Mt of effective storage capacity and a further 2200Mt of theoretical storage capacity. The closed structures would offer a new build 540 MWe (sent out) pulverised coal, capture ready power plant at Kilroot storage capacity of 10 years for 3.77 Mt annual injection of CO_2. The theoretical capacity, if proven up (to say 10% practical capacity of 220Mt), could potentially offer 58 years of storage for these volumes of CO_2.

If such capacities can be proven to offer practical storage (Chapter 3.1), then the island of Ireland could significantly reduce its contribution to atmospheric carbon emissions and become a small but significant contributor to mitigation of climate change.

In light of the EU policy to have a dozen large scale CCS demonstration power plants up and running around 2015, consideration should be given to the idea that one of these should be in Ireland utilising Kinsale infrastructure, initially at least. For example, if a new CCS enabled plant were to be in operation for the 10 years before the Moneypoint replacement were to be constructed, it might be able to utilise the Kinsale infrastructure for this period to gain valuable operating experience at a cost significantly less than a new build facility.

At the end of this period, it might be necessary to build new infrastructure to store the CO_2 from both this plant and the Moneypoint replacement, thus benefiting from economies of scale and also the operating experiences of the Kinsale facilities and others in operation around the world at that time. One additional advantage of this scheme would be that it would provide a further revenue stream to the operator of the facilities, thus allowing storage operations to continue and permit further tie-ins of future gas discoveries in the area at an economic cost.

Potential for an Irish Sea Task Force?

The UK and Norway have for some time accepted that a cross border approach in the potential utilisation of their respective geological structures and infrastructure in the North Sea for carbon transportation and storage might be beneficial. To this end the two governments set up the North Sea Basin Task Force in 2005 and subsequently in 2007 the Netherlands Government was invited to join. The mandate of the Task Force is to develop common principals for managing and regulating the transport, injection and permanent storage of CO_2 in the North Sea sub-seabed; and that these principles should enable cost-effective and environmentally responsible operations.

Consideration should be given to the idea of the Irish and UK Governments setting up a similar Task Force covering the East Irish Sea Basin, and potentially Peel, Kish and Central Irish Sea Basins. This would facilitate a common approach to the possible storage of CO_2 in this area.

2 CO_2 STORAGE: INTERNATIONAL APPROACH

The international energy community is increasingly aware that CCS presents a viable opportunity to mitigate up to 15-55% of CO_2 emissions by 2100 (IPCC, CCS Special Report, 2005) and up to 28% by 2050 (IEA Technology Perspectives, 2006). The Stern Report (2006) calculated that CCS will allow carbon mitigation of 10% by 2025 and 20% by 2050.

International research in Canada, UK, Australia and Europe confirms (Bachu 2003[18], Bachu & Gunter 2004[19], Laenen et al 2004[20] and others) that CO_2 is optimally stored in a supercritical, fluid phase, at depths in excess of 700-800m with densities in excess of 600-800 kg/m^3 (at temperatures in excess of 31°C and pressures >7.4Mpa), from both a safety (reduced buoyancy; leakage/ containment) and public perception points of view. If CO_2 can be stored in supercritical phase, considerably less storage volumes will be required. As the density of a CO_2-saturated brine is 10kg/m^3 more than brine without CO_2, such densities will ensure that the CO_2 is less buoyant and less likely therefore to migrate. This will vary with the geothermal gradient, as warm basins will require increased depth (and pressure) to achieve the supercritical state.

2.1 CO_2 Geological Storage Options

There are four key geological storage options for CO_2 available:

- **Use of CO_2 in enhanced oil (EOR) and gas (EGR) recovery**: where denser CO_2 is injected into the reservoir, pushing less dense methane gas or immiscible oil upwards and increasing the effective gas volumes which can be removed economically. The injected CO_2 also prevents de-pressuring of the reservoir as increased volumes of working gas are recoverable.
- **Depleted oil and gas reservoirs**: works on the same principle as above; whereby injected CO_2 replaces the extracted working gas, and maintains reservoir pressure. Care has to be taken not to over-pressure the reservoir, which could lead to increased buoyancy and upward movement of the injected $CO_{2,}$ as well as potential seismicity in extreme cases.
- **Deep saline formations**: as for EOR, but in this case the existing water in pore spaces must be displaced to create appropriate volumes for injected CO_2 storage, while care must be taken not to overpressure the reservoir.
- **Enhanced coalbed methane recovery (ECBM**), from unmineable coal, where CO_2 adsorbs to the surface of coal as CH_4 is extracted. With increasing pressure CO absorbs into the coal, but if pressures and temperature increase significantly, the coal can become plastic, thus decreasing its permeability[21].

Future options may include:

- Formation of **marine hydrates** followed by ocean storage, but this is not currently favoured by public agencies due to perceived public 'pushback' and unknown environmental risks to the deep ocean biosphere, pH and atmosphere:ocean stabilisation[22]. Ongoing research in USA[23], suggests that captured CO_2, mixed with seawater and passed through a special desalination apparatus at c. 350m water depth, and subsequently gravity piped to >1500m depth under natural ocean pressures to below the hydrate boundary[24], will form stable crystalline CO_2 hydrates (when suitable conditions of concentration of dissolved CO_2, temperature, and pressure are achieved) without the use of any chemicals, pre-treatment or filtering. Low-salinity water is produced by the controlled dissociation of the CO_2 hydrate

[18] Bachu, S. (2003) *Screening & Ranking of Sedimentary Basins for Sequestration of CO_2 in Geological Media in response to Climate Change*. Environmental Geology (2003) 44:277-289

[19] Bachu & Gunter (2004). *Acid Gas Injection in the Alberta Basin, Canada: a CO_2 Storage Option*. In: Baines SJ, Worden RH (eds). *Geological Storage of Carbon Dioxide*. Geol. Soc. Spec. Pub. 233.

[20] Laenen, Van Tongeren, Dreesen, Dusar (2004). *CO_2 Sequestration in the Campine Basin and adjacent Roer Valley Graben (North Belgium): an Inventory*. In: Baines SJ, Worden RH (eds). *Geological Storage of Carbon Dioxide*. Geol. Soc. Spec. Pub. 233 (pp 193-210).

[21] BGS / NERC (2006). *Industrial CO_2 Emissions and Carbon Dioxide Storage Potential in UK.*

[22] IPCC 2005. *Special Report on Carbon Dioxide Capture and Storage prepared by Working Group 3 of the Intergovernmental Panel on Climate Change*. Metz, Davidson, de Connick, Loos & Meyer (eds.). Cambridge University Press, UK

[23] *Seawater Desalination as a Beneficial Factor of Oceanic CO_2 Disposal* - M.D. Max, K. Sheps, S.R. Tatro, L. Brazel & J. Osegovic. MDS Research, St. Petersburg, Florida USA. July 2007.

[24] At >30bar > 350m @ 4-9°C

while the CO_2 is sequestered in the deep ocean in a manner consistent with the Kyoto accords. Further research in this field is required.

The IPCC estimates that there is technical potential for at least 2,000 Gt CO_2 of storage capacity in geological formations worldwide[25], and each storage option is currently being explored through industrial and /or pilot scale projects. In the Irish context, depleted gas reservoirs, deep saline formations and possibly ECBM were considered as storage possibilities in the course of this study.

Key geological characteristics must be considered to determine the most suitable storage structures in any given geological setting (see Table 1).

Table 1: Geological Characteristics to be considered

Geological Characteristic	Comment
Geology – what rocks?	Sedimentary rocks: sandstones, coal, salt, limestones? Igneous, metamorphic generally inappropriate for storage?
Reservoir/ Seal Pair	***Reservoir***: Permeable rocks with primary or secondary porosity to allow gas to fill pore spaces ***Seal:*** Overlying impermeable formation which effectively 'seals off' the underlying host rock, to prevent upward migration of gas
Structure	Basin style, aquifer (hydrocarbon or non-hydrocarbon bearing), anticlinal folds, faults, thrusts.
Potential for Hydrocarbons	Producing/ depleting/ non-existent
Depth	Critical for CO_2 to reach a dense, supercritical fluid phase, generally below 650m at standard temperature and pressures, to achieve maximum volume storage capacity.
Size of Structure/ Basin	Volumes available for storage (working & effective)
Hydrogeology: **Porosity/ Permeability**	***Porosity***: permissive primary or secondary pore space between grains of the rock. May be occluded by secondary re-crystallisation of minerals such as silica, illite, dolomite, calcite etc, but may be enhanced by e.g dolomitisation. ***Permeability:*** connected permissive fluid/ gas pathways within the host rocks, may be enhanced by micro-fracturing, joints, faulting, folding and karstification.
Containment	Basin boundaries - are they faulted/ pinch-outs/ fold closures? Effectiveness of seal pair?
Compartmentalisation	Do faults cause the host reservoir to be compartmentalised? If so, multiple injection wells may have to be considered.
Pressure/ Temperature of reservoir	P/T will influence the solubility, density and buoyancy of CO_2 with both generally increasing with depth
Geothermal gradient	Relatively warm and cool basins will behave in a different fashion depending on P/T conditions
Tectonic setting	The Irish continental shelf is located on an Atlantic Passive Margin and is relatively tectonically stable for the foreseeable future. The Irish Sea is weakly seismically active.
Potential for CO_2:wall rock interaction	CO_2 reacts with wall rock in the host reservoir albeit in a generally predictable fashion. However at depth, natural secondary mineral precipitation will occur and may cause occlusion of the reservoir porosity, particularly close to the injection site.
Reservoir Recharge: Depletion Drive or Water Drive	Post production, is the natural recharge of available pore space in a reservoir by water or low pressure natural gas? If with water; the reservoir is said to have 'water drive'; if by gas, the reservoir is said to have 'depletion drive'. The latter is more favourable for CO_2 injection, as the pore space can be refilled to natural levels without over-pressuring, thus reducing the risk of leakage.

What comprises an effective geological storage site? The IEA[26] have summarised the requisite characteristics (Table 2), which are largely determined by accessibility to captured volumes of CO_2, the storage capacity of the geological structure, the amounts and rates which can be injected and finally the security of the site.

[25] See IPCC Special Report on CCS 2005, op cit.

[26] IEA (2008). Geological Storage of Carbon Dioxide – Staying Safely Undergound.

Table 2: Key Factors for Effective Geological Storage of CO_2

Accessibility	Location economically accessible to the CO_2 source
	Operator has legal rights to storage at that site
Capacity	Formation/ structure has adequate porosity and permeability to store CO_2
	Storage volumes are adequate
Injectivity	Formation/ structure can store CO_2 at the rate required to serve the intended source(s)
Security	Well defined trapping mechanism(s)
	Sufficient depth to retain supercritical Co2
	Cap rock is impermeable, continuous and thick enough to prevent upward migration
	Geological environment is sufficiently stable to ensure integrity of storage site
	No pathway faults or uncapped wells penetrate the cap rock and storage formation
	Source IEA (January 2008)

2.2 CO_2 Geological Storage Projects

This study did not set out to provide a detailed compendium of CCS projects worldwide[27]; however, it was instructive to review current projects to assess their applicability in the Irish context. Geological storage is ongoing in three industrial scale (>1Mt CO_2 per annum) projects worldwide, where a combined 3-4 Mt CO_2 is injected annually to geological formations. A number of smaller pilot or demonstration storage projects are also underway in relation to EOR, EGR and ECBM, as well as in non-hydrocarbon bearing saline formations (Table 3).

Generally results from these projects have been positive in demonstrating that carbon dioxide can be successfully injected and geologically stored, although the lead times are very short in terms of proposed storage longevity. The scope of these projects demonstrates the range of geological structures in which it is technically feasible to store CO_2 over (geologically) short periods of time.

At Statoil Hydro's flagship ***Sleipner*** project, over 10 Mt of CO_2 have been stored in the Utsira Sandstone saline aquifer since the project commenced in 1996[28]. 2,800 tonnes CO_2/ day are captured by conventional amine process, stripping CO_2 from natural gas produced on the Sleipner West field in the North Sea. The project is located 240 km offshore, where CO_2 is injected at pressures of 100b into the aquifer.

[27] The Scottish Centre for Carbon Storage has developed a free interactive resource which locates proposed CCS sites worldwide and details basic project information – see www.geos.ed.ac.uk/sccs
[28] Carbon Capture Journal, 2/5/08

Table 3: Sites of CO2 Geological Storage (current, planned, various scales - 2008)

Project	Country	Injection (Start)	Average Daily Injection Rate (tCO_2/day)	Total Planned Storage (tCO_2)	Storage Reservoir Type
INDUSTRIAL SCALE					
Sleipner	Norway	1996	3,000	20,000,000	Saline Formation (Miocene-Pliocene Utsira Formation 24,000km^2)
Weyburn	Canada	2000	3,000-5,000	20,000,000	EOR Williston sedimentary basin
In Salah	Algeria	2004	3,000-4,000	17,000,000	Gas field Krechba Sandstone Fm
PILOT SCALE					
Ketzin	Germany (EU- CO2SINK)	2008		60,000t	Saline Aquifer (onshore, from power production)
K12B	Netherlands	2004	100 to 1,000 (by 2006)	8,000,000	EGR
Frio	USA	2004	177	1600	Saline formation
Fenn Big Valley	Canada	1998	50	200	ECBM
Qinshui Basin	China	2003	30	150	ECBM
Gorgon (planned)	Australia	(2009)	10,000	3,000,000tpa/ 40 yr	Saline formation
Snøvit	Norway	May 2008	2,000	700,000t pa	Saline formation
Recopol	Poland EU with US DoE	July 2004	10,000m^3/day	For 12 months only	ECBM
Latrobe Valley	Australia	?2006		65,000,000	

(Adapted and updated from IPCC Special Report on Carbon Capture & Storage, 2005)

A number of technical challenges have been flagged during the execution of these international pilot/ demonstration projects. Many hinge on unknown geological factors rather than on specific engineering problems. Long-term occlusion of porosity and permeability by CO_2**:**host rock interaction, particularly at the injection point which has been problematical at some sites, has not been fully explored and will require significant long term monitoring at all sites.

The role of self-propagating, feedback mechanisms during CO_2 flow may amplify leakage risks and lead to e.g. secondary CO_2 accumulations and potential explosive discharges, which are poorly understood at this stage. However, recent numerical modelling indicates that there is no evidence that a sub-surface accumulation of CO_2 at ambient temperatures could give rise to a high-energy 'pneumatic eruption' discharge[29].

Questions of injectivity rates sufficient to meet the storage requirements of large point source emitters such as power stations over say 40 years, as well as reservoir pressure stability as more gas is injected, also remain to be tested conclusively over time. Finally, the key issues of long term economic feasibility and environmental integrity will in the end be the key determinants as to whether CCS will be adopted by the Irish and Northern Irish governments as a mitigative option in the effort to reduce the island's carbon emissions.

[29] Preuss, Karsten (2007). *Leakage of CO_2 from Geologic Storage: Role of Secondary Accumulations at Shallow Depth.* International Journal of Greenhouse Gas Control, Online 10 Sept. 2007.

2.3 EU Potential for CCS

The EU sees itself as a world leader in the efforts to curb carbon emissions and has adopted a number of strategies to redress the situation across member states (see Section 1.3 above). Achieving a balance between climate change concerns and security of energy supply are two major challenges[30]. The EU completed its Strategic Energy Review in 2007, with a key target to develop a unilateral commitment of at least 20% GHG emission reduction by 2020 (compared to 1990 levels), and by 30% if broad participation is gained[31]. It is recognised that coal and gas are fundamental to security of energy supply in the short to medium term and will remain in the energy mix. CCS is recognised as a central component in the strategy (see Table 4 below) and a Directive to address CCS has been proposed.

2.3.1 Proposed EU CCS Directive

On 23 January 2008, the EC adopted proposals for a Directive to enable CCS in the EU, to urgently reduce emissions while ensuring security of energy supply. Proposed enabling legislation was drafted to develop a framework for CCS (addressing site selection, authorisation, monitoring plans, liability, stewardship and third party access) and circulated to member states for comment. The environmental risks must be identified and managed in a transparent manner to win public support, while the commercial barriers to deployment must be also addressed. Whether CCS is taken up in practice will be determined by the carbon price and the cost of the technology. The CCS Directive will not be mandatory, as the technology is not yet demonstrated on a commercial scale and would be contrary to the market-based approach of the EU-ETS (see below). However, this situation may evolve: to meet target emissions reductions beyond 2020, the deployment of CCS will be essential, and by 2015 the technological options will be clearer.

Wherever possible, existing EU provisions will be used to manage the risks of CCS. The IPPC Directive 96/61/EC concerning Integrated Pollution Prevention and Control will be used to regulate the risks of CO_2 capture. Environmental Impact Assessment (EIA) Directive 85/337/EEC will be used for assessing the likely environmental impacts of capture, transport and storage. Directive 2004/35/EC on Environmental Liability will be used for regulating the liability for local environmental damage from CCS, while Directive 2003/87/EC, known as the Emissions Trading Scheme (EU-ETS), will be used for regulating the liability for climate damage, by requiring the surrender of allowances for CO_2 leakage. The proposed CCS Directive and the ETS will also provide guidelines on monitoring and regulation of CCS.

2.3.2 CCS in the context of EU Emissions Trading System

The EU-ETS, came into effect in January 2005 and is the first regulatory enforced commercial market for certified emission reductions (CERs). It is currently in Phase II (2008-2012) of operation, to the end of the first Kyoto Protocol period[32].

The ETS will provide the main incentive for CCS deployment across Europe. ETS will recognise CO_2 captured, transported and safely stored as not having been emitted. During Phase II, CCS installations can be opted in to the Scheme. For Phase III (2013 onwards), under current proposals to amend the Emissions Trading Directive, capture, transport and storage installations would be explicitly included in Annex I of the ETS, and subject to statutory monitoring and reporting (see Section 6.6.1 below).

However, uptake of CCS will depend on the carbon price and the price of source-to-sink technologies. If the price per tonne of CO_2-avoided by CCS is lower than the carbon price, then CCS may begin to be commercially attractive and subsequently deployed. In June 2008, Deutsche Bank forecast a 2008 EU Emission Allowance (EUA) price of €40 per tonne, up from €35, based on the Bank's long term gas and coal price estimates that this is the EUA price required to ensure the successful acceleration of the

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[30] Andris Piebalgs, Energy Commissioner, *Balancing European Energy & Environmental Needs*. European Energy Challenges Conference, Madrid, 1 October 2007.
[31] EU Directorate-General Energy & Transport, European CCS Summit, London, 28-29 November 2007
[32] Under the EU-ETS and Kyoto, GHG emissions are quantified according to tonnes of carbon dioxide equivalent (CO_2e). One tonne of CO_2e is known as a European Union Allowance (EUA). The ETS imposes caps on the amount of EUAs permissible in any member state. In turn, each member state must draft a National Allocation Plan (NAP) setting out how the maximum annual volume of EUAs in that EU member state is to be divided between the various sectors of GHG emitters, and setting limits on individual emitters.

EU's CCS programme[33]. Should carbon pricing be eventually correlated with rising oil, coal and gas prices, then carbon could rise to > €100 per tonne[34] in the short to medium term. According to the Commission's projections laid out in the proposal for a Directive on the geological storage of CO_2, the uptake of CCS on a commercial scale is likely to begin some time around 2020 and increase substantially after that.

The EU-ETS has the potential to be a cost-effective instrument to incentivise CCS. However, if EUA prices remain low, there may be a preference for lower-cost carbon abatement options, which are unlikely to stimulate new innovation. Thus, it is considered unlikely that ETS will lead to CCS deployment without complementary policies. The latter could include public financial support (most likely at EU member state level) such as feed-in subsidies (as are offered currently to renewables to promote commercialisation), a CO_2 price guarantee, a low-carbon portfolio standard with tradable certificates (most likely at EU level), a CCS obligation (at EU level) and/or public-private CCS development partnerships.

2.3.3 European Technology Platform on Zero Emission Fossil Fuel Power Plants

In the context of this study, the key EU initiative is the establishment of the *European Technology Platform on Zero Emission Fossil Fuel Power Plants* (ETP ZEP)[35] to develop zero emission power plants by 2020 and to coordinate research and demonstration activities in CCS. It is recognised by ETP ZEP that considerable urgency exists towards defining CO_2 storage, both in depleted hydrocarbon reservoirs and deep saline aquifers, but particularly the latter, which are perceived to offer the largest capacity and more widespread geographical distribution. Research must demonstrate that there is sufficient aquifer storage capacity available for large-scale CO_2 projects across Europe and that large CO_2 quantities (1-10 Mt/y of injected CO_2 per project) can be stored safely for indefinite periods.

[33] June 03 2008 (Carbon Capture Journal)
[34] Jeff Chapman, CEO of Carbon Capture & Storage Association, 17 July 2008.
[35] http://www.zero-emissionplatform.eu

Table 4: Proposed Actions by EU to meet Strategic Energy Review (2007) Target

EU Action	*By When?*
Regulation:	
Develop a regulatory framework to enable CCS	Immediate
Develop CCS legislation	2008
Long term perspective to Emissions Trading Scheme (ETS)	2008 - post 2012
CCS to be factored in ETS	post-2015
Research Development Deployment	
EU support to R&D (FP7 calls)	2007, 2008
Develop 12 demonstration CCS project	2015
Strategic Energy Technology Plan (SET-Plan) – adopted 2007	2008
Support for early Demonstration plants – reward 'early risers'	Ongoing
Evaluations	Ongoing
Commercial Viability	
Prove economic viability of CCS	2020
Capture–Ready Power Plants	
No new coal fired power plant without CCS – must be 'CCS ready' after that date[36]	2020
Zero Emissions Fossil Fuel Power Plants Platform (ZEFFPP) research & supports – link to a 'Flagship Programme' under the SET-Plan	Ongoing
Global Dissemination	ASAP
Aim for worldwide cooperation through technology transfers, especially to developing countries. This is a global issue.	*Bali 2007* UN conference called for technology transfers

The IPCC Special Report on CCS notes that saline aquifer storage is significantly more uncertain than depleted reservoirs due to a lack of both knowledge and an agreed methodology for evaluation. Recent EU collaborative research projects have recently developed best practice guidelines for storing CO_2 in saline aquifers[37], a useful reference manual in addressing these factors.

Key hurdles are the current lack of a regulatory framework and the time lag in developing commercially viable capture technologies. The economics will depend on the size of each investment due to increased operating costs, but it is clear that suitable CO_2 infrastructure and safe storage 'sinks' will have to be rapidly defined as part of the process.

Following the approval of the EU's strategic research agenda and deployment documents in September 2006 (under the ETP ZEP), four taskforces were set up in 2007 to implement the recommendations, which are being rolled out.

- Taskforce Technology
- Demonstration & Implementation
- Policy & Regulation
- Public Communications

The EU is moving towards a coordinated response and is promoting a PPP-like structure to provide critical mass backed by robust commercial action to ensure speed of implementation. The following were proposed:

- Facilitation of state aid for demonstration projects (due to current EU competition rules);
- Creation of a project network under FP7[38] to ensure a coordinated European approach, exchange of information and to achieve broad public understanding and acceptance;
- Commitment to supports, complementary to ETS within the SET Plan.

CCS legislation must be implemented urgently in EU, within the framework of ETS and finance must be mobilised at industry, state and EU levels. The energy technology and innovation process has

[36] A power plant with CCS may reduce CO_2 emissions by 65-90% compared to a non-CCS plant.
[37] *Best Practice for the Storage of CO2 in Saline Aquifers*. Observations and Guidelines from the SACS and CO2STORE Projects. Edited and Compiled by Chadwick, A. *et al*. (2007).
[38] EU Research & Development Framework Programmes (FP1-FP7). CCS is an activity under the FP7 to reduce the environmental impact of fossil fuels aiming at highly efficient power generation plants with near zero emissions, based on CO_2 capture and storage technologies.

structural weaknesses, such as long lead times for new technologies to mass market, locked-in infrastructure investments, diverse market incentives and network connection challenges[39]. Furthermore, the market take-up of new energy technologies is hampered because they are generally more expensive than the technologies they replace.

2.3.4 Other EU Research Projects

Under FP7 and earlier projects under FP6/ FP5, EU research is also examining the practical aspects of CO_2 storage, such as the pilot project at **Ketzin** near Brandenburg in Germany under the **CO2SINK** programme. This is the first onshore European project to examine geological carbon storage directly from power production in a saline aquifer at 800m depth, including different methods of injection and monitoring, coordinated by the German Research Center for Geosciences (GFZ) in Potsdam. The project aims to store up to 60,000t of CO_2 in a saline aquifer at a depth of more than 750m during the next 2 years. An injection well and two observation wells have been successfully drilled to depths of 800m. The project involves intensive monitoring of the injected CO_2 using a broad range of geophysical and geochemical techniques, the development and benchmarking of numerical models, as well as the definition of risk assessment strategies. These will all help to evaluate the reservoir's stability and integrity.

Other EU wide projects include the **CO_2GeoNet** (coordinated by BGS) to investigate geological sequestration; **CASTOR** to investigate source to sink options; **ENCAP** for enhanced capture of CO_2 and **ISSC** to examine in-situ capture technologies for solid fuel gasification. The results will link to ETP ZEP in devising the parameters for a planned network of 12 industrial scale demo-plants by 2015, with a view to moving to full commercial reality by 2020.

Other ZEP research is focused on public communications, capture, transport, injectivity, host rock and impurities interaction, mineral carbonation and post-storage monitoring, which have informed this project.

2.4 UK Potential for CO_2 Geological Storage

In May 2007, the UK published its Energy White Paper[40] in the wake of the publication of the Stern Report 2006[41]. The White Paper clearly commits to the concept of CCS as a means of stimulating clean coal technologies in an effort to reduce CO_2 emissions, while also providing security of supply through its continued use of coal and meeting its climate change policy goals. The UK aims to become a world leader in CCS and the government launched a competition in November 2007 to develop the UK's first full-scale demonstration project of the full chain of carbon capture and storage technologies[42], 'to commence operation in the next decade'. The government is prepared to fund up to 100% of CCS costs (not including the power plant) subject to affordability and State aid clearance by EU. The UK aims to demonstrate technologies that are fully transferable to key global markets particularly in China and other emerging economies.

CCS is rapidly becoming a mainstay of UK energy policy and the government is developing a regulatory framework to deal with the technological developments through its CCS Regulation Task Force.

By 2020, the UK will require 20GW of new power generation plant to meet national requirements. To meet emissions reduction targets, however, coal fired power coupled with CCS will be part of the mix. It also has eight CCS planned (pre- and post-combustion, oxyfuel) capture projects with a total generating capacity of nearly 7GWe, with a planned CO_2 emissions reduction of 30Mtpa.

In 2006, two studies[43] were carried out to assess the potential for CCS in Britain on behalf of the UK Government in the southern North Sea and East Irish Sea by BGS (2006). The work is highly relevant to the Irish context, given the similarities in rock types, age, geological and tectonic setting across the

[39] European Federation of Geologists 25 November 2007
[40] *Meeting the Energy Challenge – A White Paper on Energy*, May 2007. UK Department of Transport & Industry
[41] *The Stern Review – The Economics of Climate Change*. Nicholas Stern, 2006.
[42] www.hm-treasury.gov.uk/budget/budget_07
Also UK Carbon Capture & Storage Association 2007 – www.ccsassociation.org
[43] BGS/ NERC (2006) *Industrial CO_2 Emissions and CO_2 Storage Potential in the United Kingdom*
Tyndall Centre for Climate Change Research (2006) *Potential for Storage of Carbon Dioxide in the rocks beneath the East Irish Sea.*

Northwestern European continental shelf. As the productive life of many North Sea and East Irish Sea Basin hydrocarbon fields are nearing their end, options for re-use of the depleted reservoirs must be explored fairly rapidly.

The following relevant key points were made:
Timing is critical in economical and infrastructural availability terms.

- Closed structures offer traps for buoyant fluids, providing they have high porosity and permeability, with effective seals.
- Porosity and permeability vary very considerably in many favourable structures, due primarily to diagenetic recrystallisation, causing occlusion of fluid (gas) pathways
- Smaller onshore basins in UK are too small for CO_2 storage, and are also in high demand for strategic gas storage purposes.
- Coal in the UK in the shallower sub-surface is generally of low permeability above 1500m depth; therefore there is no coal bed methane recovery at present. The potential for CBM decreases with depth due to lithostatic pressure.

- The ***East Irish Sea Basin*** (EISB) is highly relevant to this study, given the geological similarities. Key potential storage reservoirs, following the depletion of known gas fields, include:
- Ormskirk Sandstone (Upper Sherwood Sandstone). The top of the Ormskirk Sandstone lies variably at 250-3000m depth and is on average 250m thick. It has very considerable porosity 8-30% and permeability of 0.05 – 10,000mD variations.
- Mercia Mudstone caprock is 3,200m thick, with halite forming 35-55% of the basal Mercia over five separate salt layers. This means that it is almost impermeable, unless it is fractured.

The estimated combined storage potential of the largest (known) fields in the EISB was 1047Mt, while a further 630Mt potential storage was calculated in recently discovered (but non-public domain) fields, non-hydrocarbon structures and aquifers.

The Morecambe Field, which is the second largest on the UK continental shelf with 12.1% of total proven UK gas reserves, originally held total recoverable reserves of 5.1tcf[44], and is operating since 1990 with a planned life of 40 years, so may be available to CCS in 2030. It is proximal to the Connah Quay power station (4.3Mt CO_2 emissions in 2002) near Liverpool, whose annual emissions are comparable to Moneypoint. All of the smaller EISB fields have come into production more recently and would not be available to CCS until at least >2020. Two fields, the Douglas Oilfield could be amenable to EOR, but is currently being water flooded to maintain reservoir pressure, while the Lennon Oilfield is currently pumping dissolved gas back into the reservoir to maintain pressure in its gas cap.

The UK also has the advantage of an existing (11,000km over past 40 years[45]) pipeline infrastructure which must be re-evaluated in the light of CO_2 transmission safety requirements.

The London Convention has been amended but some uncertainty remains regarding the OSPAR Convention, which will need resolution prior to full commercialisation of the North Sea as a geological storage site (see Chapter 6 below).

2.5 CO_2 Storage Potential in Australia

The Australian Federal Government has recently released draft Commonwealth Government legislation to establish the world's first framework for offshore CCS, as part of its national energy strategy and to guarantee continued production of brown coal and gas from the Latrobe Valley[46].

As a major coal producer, Australia has been a world leader in piloting CCS projects at all stages of the cycle (see Table 2.5, Figure 2.1 below). Australian public and private researchers participated in a collaborative research programme called GEODISC from 1999-2000 to define the preliminary

[44] For comparison, Ireland's largest gasfield at Kinsale Head, contains 1.65tcf total recoverable reserves.
[45] East of England Energy Group at Inaugural European Carbon Capture & Storage Summit, Nov 2007
[46] Victoria Ministry of Energy & Resources, Press Release 19 May 2008.

activities required to develop carbon capture, transport and storage methodologies with a view to developing a road map to the hydrogen economy[47].

Initially the options for geological storage continent-wide were investigated in more than 300 basins and eventually 48 suitable sites were identified, amenable to CCS. This was followed by a range of research into appropriate technologies for capture, transformation, injection, storage and monitoring of CO_2. The four-year programme allowed key facets of the necessary research to be advanced, while building the methodologies and indigenous skills base for defining Environmentally Sustainable Sites for CO_2 Injection (ESSCIs). The roadmap identified 4 levels of activities, to be developed within targeted timeframes.

Roadmap for Adoption of CCS – Australia

Level	***Timeframe***	***Activity***
Level 0	0-4 year	Develop roadmap
Level 1	5-10 year	R&D in capture, storage and usage of CO_2
Level 2	10-20 year	Pilot, demo & commercial projects, with R&D
Level 3	20-30 year	Roadmap to hydrogen economy, CCS key component

Following GEODISC, it was decided to prioritise a programme of CO_2 capture and storage pilot and demonstration projects, which are being rolled out through the demonstration ***Gorgon*** project on Barrow Island, WA, due for commercialisation in 2008, while the ***Latrobe Valley Hub*** demo-project is in an advanced state of planning, with CO_2 storage destined for the offshore Gippsland Basin. Other projects are focussed on enhanced coal bed methane and IGCC technologies and are being actively pursued through public-private collaborative research in the Otway Basin, Latrobe Valley and Bowen Basin in eastern Australia.

In May 2008, the Victoria State government committed A$127.4 million to a range of CCS demo projects[48], including a A$110million fund to establish new large-scale, pre-commercial CCS demonstration project and a further $5.2 million towards investigating carbon storage sites in the Gippsland basin. The CCS demonstration project is part of the State Government's second generation Energy Technology Innovation Strategy (ETIS) and will take its total clean coal investment to over $244 million since 2002. Public consultation on policy development is also underway by the Victorian State Government.

2.6 CCS: North America

The US Department of Energy (US DOE) published its *Atlas of Carbon Sequestration* for USA and Canada in 2007, as well as cost & performance baseline figures for capture from fossil energy plants[49]. The US has adopted Carbon Sequestration Regional Partnerships to advance and deploy carbon sequestration projects, carrying out site specific coordinated research and results, to prevent replication and to maximise research efforts nationally. The DOE has developed a standard methodology for development of capacity estimates to provide a high-level inventory of continental scale storage space.

DOE estimates that underground geological formations in the US and Canada have space for >3000Bt of CO_2 in oil and gas reservoirs, unmineable coal seams and porous saline rock formations, and could store CO_2 from power plants for 900 years. Most ongoing industry efforts in the US are focused on using CO_2 for enhanced extraction of gas and oil, and/or methane recovery from unmineable coalbeds. EOR is now used at c. 75 sites. However, at present, very few use CO_2 that is produced as a by-product of some other industrial activity (and could not, therefore, claim to be an emission reduction). The US are also carrying out extensive public-private research with energy companies such as BP, Chevron-Texaco, Norsk Hydro, Shell etc to determine the feasibility of CO_2 capture from a variety of fuels and storing it in unmineable coals seams and saline aquifers.

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[47] CO2CRC (2004). *Carbon Dioxide Capture and Storage: Research Development and Demonstration in Australia – A Technology Roadmap*. Cooperative Centre for Greenhouse Gas Technologies, Canberra, Publication No 2004/01, Jan. 2004. 60pp.
[48] Carbon Capture Journal 8/5/08
[49] The project team received digital copies of these documents, which are also available at USA Department of Energy website http://www.energy.gov/sciencetech/carbonsequestration.htm

In May 2008, the DOE awarded $126.6 million in two projects (over 10 years) to the West Coast Regional Carbon Sequestration Partnership (WESTCARB) and the Midwest Regional Carbon Sequestration Partnership (MRCSP) for the DOE's fifth and sixth large-scale carbon sequestration projects[50]. Industry partners will provide $56.6 million in cost-shared funds. The new projects aim to demonstrate the entire CO_2 injection process, pre-injection characterisation, injection process monitoring, and post-injection monitoring for large scale injections of > 1Mt to test the ability of different geological settings to permanently store CO_2.

The DOE announced the flagship ***FutureGen*** project in 2003 to fast track zero emissions coal power generation. Offering very substantial federal and state supports to fast-track a public-private partnership (PPP), including the DOE and American Electric Power Service Corp, Anglo American, BHP Billiton, Rio Tinto and China's largest coal-based power company, China Huaneng Group, the State of Illinois also indemnified the PPP from financial and legal liability in the event of CO_2 leakage. By 2007, the DOE reassessed the project after costs had risen by 85% in three years to $1.8 billion, seeking increased commitments from the private partners to prevent further cost escalation[51]. The programme was revisited in January 2008 and the revised FutureGen programme requires a number of monitoring and verification performance requirements for all future demonstration projects, including quantifying and assessing CO_2 capture, transport, and storage aspects, for the duration of a 3-5 year demonstration of at least 1Mtpa of CO_2 injected in a saline formation; monitoring of the injected CO_2 plume for a minimum of two years after cessation of the injection demonstration, with the results of the monitoring reported to DOE to allow accurate cost information for future financial estimations of CO_2 capture and storage schemes. In July 2008, the DOE released a Funding Opportunity Announcement (FOA) to solicit public support on the demonstration of multiple commercial-scale IGCC or other clean coal power plants with CCS. According to the FOA, the DOE's estimated investment with selected partners would range from $100 million - $600 million per project[52].

Regulation and liability issues are well advanced, using the well-established underground (hydrocarbons) injection regulatory regime. The US EPA currently regulates pilot activities based on the provisions of the Safe Water Drinking Act.

In Canada, the ground-breaking ***Weyburn*** project, which initially focused on extra production of oil through EOR, now focuses also on maximisation of CO_2 storage. Shell Canada has committed to be a co-sponsor of the final phase of the IEA GHG's Weyburn–Midale[53] CO_2 monitoring and storage project, the largest EOR project on land, in Saskatchewan, Canada. The final phase of the project, which Shell has committed to co-sponsor, will include work on site characterisation, monitoring and verification, wellbore integrity and risk assessment.

2.7 CCS: Norway

Norway has been a world leader in demonstration scale CCS projects.

Since 1996, at Statoil Hydro's flagship ***Sleipner*** project, over 10 Mt of CO_2 have been stored in the Utsira Sandstone saline aquifer which extends over 24,000km^2 in the North Sea[54]. Capture of 2,800 tonnes CO_2/day is done by conventional amine process, to strip CO_2 from natural gas produced on the Sleipner West field in the North Sea. The project is located on a compact offshore platform, 240 km offshore, where CO_2 is injected at pressures of 100b into the aquifer.

In 1999, after 2.35Mt CO_2 had been injected, and again in 2001 after 4.26Mt had been injected, the Sleipner project was monitored by time-lapse seismics. Dramatic changes in wave reflection within the aquifer were registered at nine stratigraphic levels, but the CO_2 plume has remained relatively predictable and consistent with the modelled behaviour. Moreover, Sleipner has confirmed that the amplitude of CO_2 gas migration within a given reservoir can be successfully measured and monitored[55].

[50] Carbon Capture Journal, 8 May 2008
[51] Greenpeace (May 2008) *False Hope: Why CCS won't Save the Climate*
[52] Carbon Capture Journal, July-August 2008.
[53] See Carbon Capture Journal 16 May 2008.
[54] Statoil estimate that the Utsira Formation saline aquifer could store 600 years of carbon emissions from Europe's coal and gas fired power stations.
[55] Komatina-Petrovic, S. (2006) -Member of ENeRG (European Network of Research in Geo-Energy) reporting in: *Energy, Global Changes & Sustainable Development*. European Geologist 23.

Statoil Hydro recently also began injecting CO_2 at ***Snøhvit***[56]. Natural gas is piped from the Snøhvit field to the onshore Melkøya plant outside Hammerfest, containing 5-8% percent CO_2. The CO_2 is separated from the natural gas and piped back to a saline aquifer (Tubåsen Sandstone) at the edge of the Snøhvit reservoir, to be stored 2600m beneath the seabed and sealed by an overlying shale caprock. The first carbon flow reached the storage formation during April 2008. At full capacity on Snøhvit, 700,000 tpa of CO_2 will be stored.

StatoilHydro is also involved in carbon storage on the gas and condensate field ***In Salah*** in Algeria in cooperation with BP and Sonatrach.

The Sleipner project operators are exploring the possibilities of offering other petroleum discoveries in the area the opportunity to process gas by removing CO_2 and storing it in the Utsira Formation. The possibility of receiving CO_2 from land for injection is also being considered.

The Norwegian Petroleum Directorate (NPD) has recently committed more than €3.5million to investigate the economic viability of developing integrated solutions for transport and storage of CO_2 captured at the Kårstø gas-fired power station and Mongstad combined heat and power station (under construction)**,** in cooperation with Gassco and Gassnova SF respectively. The aim is to support the Norwegian government's strategic target of establishing full-scale CCS solutions. The assessments are due to be completed by December 2008 and will take account of costs, reservoir conditions and technological risk. The ministry wishes to see whether a commercial and technical basis exists for transporting CO_2 from other emission sources via possible pipelines to Kårstø and Mongstad. Gassco is now preparing agreements with seven industrial companies, including Sargas, on studies to assess carbon transport from each company's facilities to collection points at Kårstø and Mongstad. All the CO_2 would then be piped offshore and injected into deep geological formations on the Norwegian continental shelf.

2.8 CCS: Emerging Economies

The International Energy Agency presented its annual *World Energy Outlook 2007,* which took particular cognisance of the growth of China and India as it set out scenarios through to 2030. If governments stay with current policies, the IEA base scenario predicts the world's energy needs would be well over 50% higher in 2030 than today, with China and India together accounting for 45% of the increase in demand[57]. Arguably, unless the emerging economies are also actively working to increase energy efficiencies and reduce emissions, all of the above international emissions reduction activity will be negated.

China and India are the emerging giants of the world economy and international energy markets, and are beginning to look at ways to deploy CCS to offset the increasing emissions due to their current rapid economic growth using international models.

China's coal production was ~2.3Bt in 2006, with potential to more than double by 2030 (~5Bt per year). Around 50% of coal produced goes to power generation which is 78% coal-fired and despite coal reserves of 100-200 years, China has already begun to import coal. There are serious challenges to meet this demand in terms of infrastructure, mine safety, local air quality as well as increased CO_2 emissions[58].

The EU-China Summit on Climate Change & Energy (held in September 2005) declared the wish develop and demonstrate in China and the EU advanced, near-zero emissions coal technology through carbon capture and storage by 2020. That agreement was followed by two complementary memoranda between China and the UK (2005, NZEC Phase 1)[59] and between EU and China (2006, COACH) to implement collaborative CCS projects between Chinese and UK experts, particularly building capacity in China, and also to make recommendations for the development and deployment of CCS technology in China.

The project launched on 20 November 2007 in Beijing, with an 18 month programme of collaborative work evaluating the potential options for capture at eight new-build power plants and defining likely

[56] Carbon Capture Journal, 25/4/08
[57] See Mbendi Africa, 12 November 2007 www.mbendi.co.za
[58] UK Department for Business Enterprise & Regulatory Reform at EU Summit on CCS, London, Nov. 2007.
[59] See www.nzec.info for more information.

geological storage sites, as well as regulatory and legal issues, to be undertaken by 28 partners with anticipated completion in 2009.

The UK is similarly building links with India and the BGS has already carried out a geological storage capacity study, which will provide the basis for future CCS collaboration.

It is clear from the country review above that many developed and developing nations are investigating CCS as a viable carbon abatement strategy and are examining ways in which CCS may be deployed most effectively and economically in the short to medium term, frequently adopting a public-private partnership (PPP) model.

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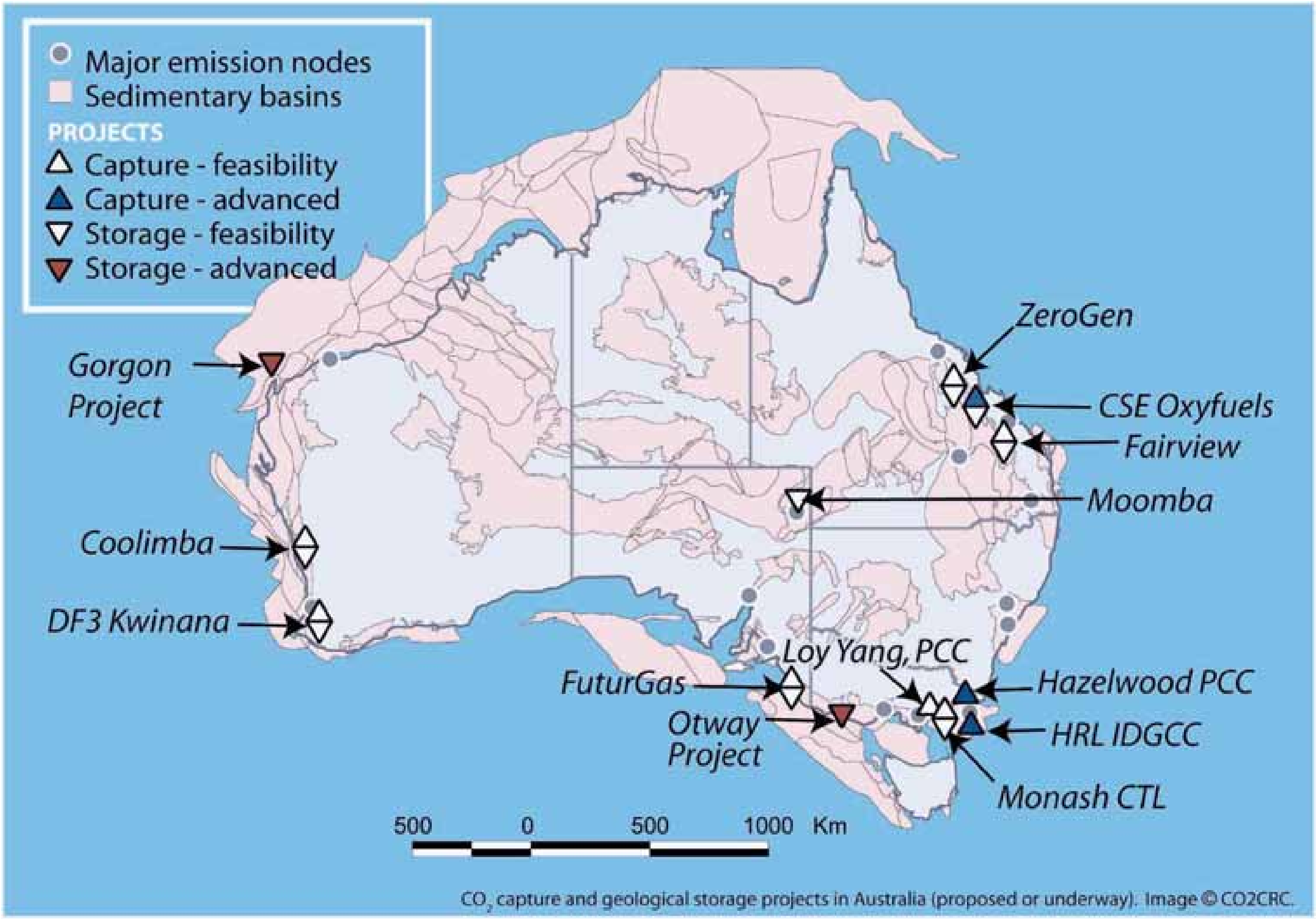
Table 5: Current carbon Capture, Transport & Storage projects, Australia (end-2007 - *see locations on Figure 3 –overleft)*

Project	*Project Type/ Stage* Description	Capture From	Injection Site	Injected / Planned Amounts	Cost (A$)	Other comment
Otway Basin, Victoria	***Storage /Advanced*** Demo site for compression, transport, injectivity of CO_2 (not demo capture)	From producing oil field	Depleted oil reservoir (2000m)		Cost A$30m	
Gorgon, Western Australia	***Storage /Advanced*** Capture	From natural gas reservoirs	Compressed & piped to proximal saline aquifer, NW Australia	Injection to commence 2009: at rate of 3Mt pa/ over 40 years	Cost: A$840m	Ongoing monitoring of large scale site.
Callide, Biloela, Queensland	***Capture Advanced/ Storage Feasibility*** Retrofit oxy-firing (of pulverised black coal) to coal power station with storage; capture combustion gases; followed by CO_2 separation, liquefaction, transport and geological storage	Flue gases, post combustion		30,000t / 3 years. Construction to commence in 2008, capture in 2009.	A$188m	Oxy-firing results in waste gas having higher concs of CO_2, easier & less costly to capture
Fairview Roma, Queensland	***Capture & Storage / Feasibility*** Gas-fired power from coal bed methane (CBM), with partial CO_2 capture.	CBM: 100MW gas turbine using CBM	Unmineable coal seams	100,000tpa/ 10 years	A$445 commencing in 2010	
Zerogen Rockhampton, Queensland	***Capture & Storage / Feasibility*** 100MW IGCC power station with CCS	IGCC Power generation	220km pipeline	420,000tpa	> A$1 billion est.	
HRL IDGCC La Trobe Victoria	***Capture/ Advanced*** Improved efficiencies of brown coal power generation, using dehydration vs gasification for combined cycle power generation	400MW power station	n/a	na/	A$750m, to commence generation in 2009	Not aimed at CCS per se, but IDGCC process is more 'capture ready' than other processes.
Hazelwood La Trobe Valley Victoria	***Capture/ Advanced*** Existing 200MW generating plant to be retrofitted with brown coal drying process to improve efficiencies, & reduce CO_2 emissions per unit of power generated	Partial capture only (50t/day)	n/a	n/a	A$369m, commence 2008	
Kwinina Perth WA	***Capture & Storage / Feasibility*** 500MW power station, coal to be transformed to H for power gen	Capture 4Mt/pa from H conversion process	Saline aquifer offshore WA (non-specified)	Construction to commence 2011, operating from 2014	>$2 billion	H burns without producing CO_2
Monash La Trobe, Victoria	***Capture & Storage / Early Feasibility*** Aim to produce liquid transport fuel from brown coals	Capture of CO_2 produced in conversion	Offshore depleted oilfields	Could be in operation by 2015	A$6-7 billion	Proposes to produce 62,000 barrels oil equiv per day

Figure 3: **Carbon Capture, Transport & Storage projects, Australia (by end -2007)**



CO_2 capture and geological storage projects in Australia (proposed or underway). Image © CO2CRC.

3 ASSESSMENT OF THE ALL-ISLAND POTENTIAL FOR GEOLOGICAL STORAGE OF CO_2 IN IRELAND

The following comprises a summary of the final geological assessment of storage potential and basin-by-basin capacity estimates carried out by the team. An early data gathering stage by CSA at the outset of the project compiled, for the first time, a single GIS database of all deep onshore and offshore geological and geophysical data for the island of Ireland, as reported in the first Progress Report of September 2007. This allowed a first pass selection and ranking of the most suitable geological basins and structures which could be reasonably be considered for storage of CO_2. The data were then analysed in more detail by partners BGS, using a well established methodology which had previously been applied in assessing storage options for the UK, India and in collaborative EU research projects such as CO2SINK. This section provides the core element of the study i.e. the geological assessment of CO_2 storage potential for the island of Ireland. The full report is presented in Annexe 1.

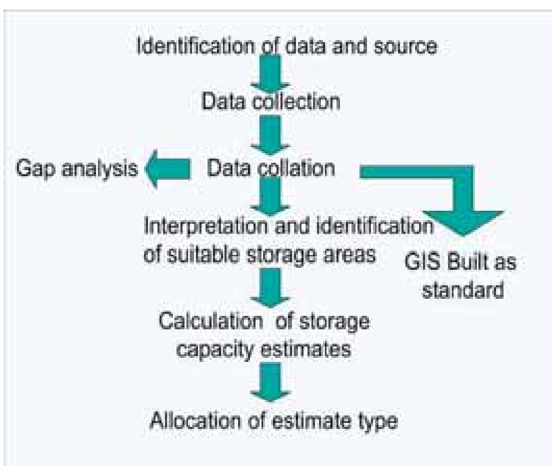
3.1 Aims and Methodology

The aim of the assessment was to identify geological storage sites for (all-island) Ireland with the potential to store the emissions of large scale CO_2 point sources. The results of this study have informed both the economic and risk assessments, to provide several CO_2 sources-to-sink (storage) case studies.

Sedimentary basins often have suitable geology in which CO_2 may be stored. Storage potential may exist in depleted oil and gas fields or saline aquifer formations. This study concentrated on the major sedimentary basins of Ireland, both onshore and offshore, where potential geological formations in which CO_2 could be stored (reservoirs) exist below 750m and where suitable sealing formations are present.

CO_2 storage capacity was assessed using a basin-by-basin approach by applying the workflow shown in Figure 4:

Figure 4: Workflow used in the Geological Appraisal



For each basin, data were collected and interpreted and assessed according to its geological characteristics and available data. Carbon dioxide storage capacity was calculated in areas where sufficient data were available and potential CO_2 storage sites could be identified (details of the methodology used to calculate storage capacity is described in Chapter 2.2 of Annexe 1).

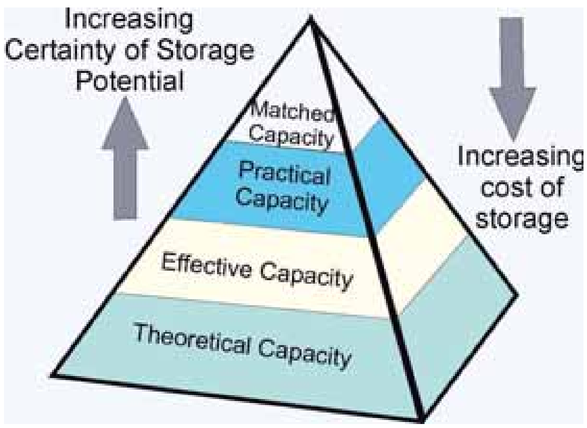
The data available for each basin are highly variable in coverage, type, quality and source. To reflect this, each basin estimate was classified according to a techno-economic resource pyramid (Figure 5) recommended by the Carbon Sequestration Leadership Forum (Bachu et al. 2007).

- ***Theoretical Capacity*** represents the maximum amount of CO_2 the geological system could store, but is likely to be unrealistic.
- ***Effective Capacity*** is a subset of theoretical capacity, but incorporates geological or engineering cut-offs.
- ***Practical Capacity*** is a subset of effective capacity, but introduces non- geological parameters such as legal, economic and regulatory factors.
- ***Matched Capacity*** includes storage site and CO_2 sources linked (source and sink matching; a more detailed description of these categories is provided in Section 2.3 in Annexe 1).

In the geological assessment undertaken, only theoretical, effective and limited practical capacities can be calculated. In some instances, effective capacity which was not a subset of theoretical capacity, was calculated on the basis of increased geological data where historical oil and gas exploration had targeted particular structures, but where the total aquifer could not be quantified.

To move these estimates up to the apex of the pyramid would require further geological and engineering inputs from a variety of sources.

Figure 5: Techno-Economic Resource Pyramid for Geological CO2 Storage Space;



Adapted from Bachu et al. 2007, with the addition of classified calculated storage capacities

The major limitation when estimating CO_2 storage capacity for this study was the availability of data. Areas in which hydrocarbon exploration has taken place have the most available data. In basins where hydrocarbon exploration has been limited, data is often very sparse and therefore, there is more uncertainty. In such locations it may not be possible to make any estimate of potential CO_2 capacity. Sedimentary basins which fall into this category may still be suitable for CO_2 storage, but have an unknown or ***unquantified*** CO_2 storage capacity. Similarly, a large amount of data does not mean that a particular basin will have good potential storage sites, but more information is available to analyse and provide conclusions.

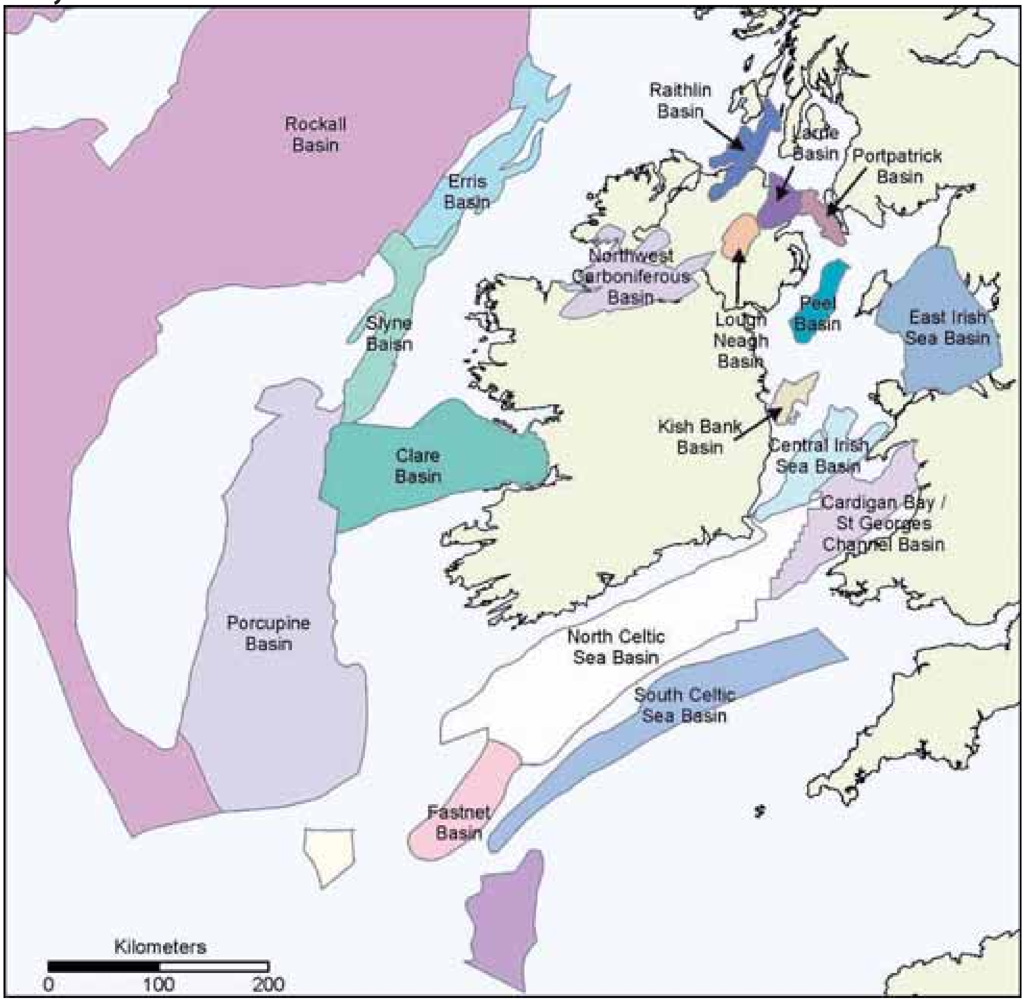
3.2 Storage Capacity of all-island Ireland

The basins assessed are shown diagrammatically on the map in

Figure 6 below. For each basin assessed the storage capacity estimate is listed in Table 7 below.

The storage capacity of all-island Ireland's sedimentary basins was assessed for both the onshore and offshore areas. Oil and gas fields and prospects were considered along with saline aquifer structures. Storage in salt caverns has not been calculated as they are too small to store the volumes of CO_2 captured from point sources. Similarly, Ireland's abandoned onshore mines are too shallow and too unconstrained to be considered for carbon storage.

Figure 6: All-Island Ireland Sedimentary Basins examined for this Study



3.2.1 Oil and Gas Fields

Ireland has limited storage capacity available in oil and gas fields. The Kinsale Gas Field in the North Celtic Sea is the largest gas field in the Republic of Ireland and is nearing the end of its producing lifetime. This could potentially offer an opportunity to convert the field into a CO_2 storage site. The calculated CO_2 storage capacity of the depleted Kinsale field is 330 Mt. If small data gaps can be filled for the remaining hydrocarbon fields and prospects, storage capacities could easily be calculated. This is dependent on the release of confidential hydrocarbon data from oil companies. There is potential to transport CO_2 from point sources to the East Irish Sea (UK sector) where 1050 Mt of CO_2 could potentially be stored in the oil and gas fields. This could also allow the opportunity to access the estimated 630 Mt of CO_2 storage capacity in the closed structures of the Ormskirk Sandstone saline aquifer formation.

3.2.2 Saline Aquifers

The majority of all-island Ireland's CO_2 storage capacity is in offshore and onshore saline aquifers.

The Permo-Triassic basins located down the eastern flank of Ireland offer the most quantifiable CO_2 storage capacity for saline aquifers due to the data available from hydrocarbon exploration. The

Triassic Sherwood Sandstone Group (including the Ormskirk Sandstone Formation) reservoir with a Mercia Mudstone seal is a prolific hydrocarbon reservoir in the East Irish Sea Basin. This reservoir-seal pair is present in several other Permo–Triassic Basins including the offshore Kish Bank, Central Irish Sea, Portpatrick and Peel Basins. Onshore prospective basins include the Larne, Lough Neagh and Rathlin Basins. Offshore the total effective storage capacity of the closed structures in the Kish Bank Basin, Portpatrick and Central Irish Sea Basins combined is 937 Mt.

Data and resources were not available to calculate the storage capacity of the Sherwood Sandstone Formation for the onshore basins. In some areas the Sherwood Sandstone Group is not at sufficient depth for CO_2 storage. The Permian Enler Group offers some saline aquifer storage potential in the Larne and Lough Neagh Basins. Data were only available to calculate effective storage capacity for two identified closures in the Lough Beg area of the Lough Neagh Basin. The calculated combined effective storage capacity of the two closures is 1940 Mt.

Sufficient data were only available to calculate the theoretical storage capacity of one other onshore sedimentary basin; the Northwest Carboniferous Basin. There are several potential reservoirs in the Carboniferous sediments of the basin, including the Dowra Sandstone Formation. The theoretical total basin storage capacity of the Dowra Sandstone formation has been calculated at 730 Mt. An important caveat is that this storage capacity may not be accessible due to expected difficulties injecting CO_2 into a tight gas reservoir.

Further saline aquifer potential may exist offshore in the Celtic Sea in the Cretaceous 'A' and 'B' Sands and the Jurassic Sinemurian Sandstone.

Large, but unquantified, potential may exist in the Clare, Slyne, Erris, Porcupine and Rockall Basins.

Thus, the total quantified, but unproven, CO_2 storage capacity of the island of Ireland is approximately 93,000 Mt.

- The total **theoretical CO_2 storage capacity is 88,800 Mt**, which estimate is based on whole saline aquifer storage.
- The total **effective CO_2 storage capacity is 3,500 Mt** (the effective capacity is based on targeted structures within saline aquifers where there is more detailed information), of which **660 Mt** are a subset of the theoretical capacity (subset because a whole aquifer estimate has been provided) and **2,840 Mt** are additional to the theoretical capacity (additional because there has not been a whole aquifer estimate within the theoretical category).
- The total **practical CO_2 storage capacity is 1,500 Mt** which is the estimated storage capacity available within the hydrocarbon fields; this is additional to the theoretical and effective storage capacity estimates as there has not been a whole aquifer estimate in these cases.

Figure 7: Quantified Distribution of Potential CO2 Storage Basins, all-island Ireland

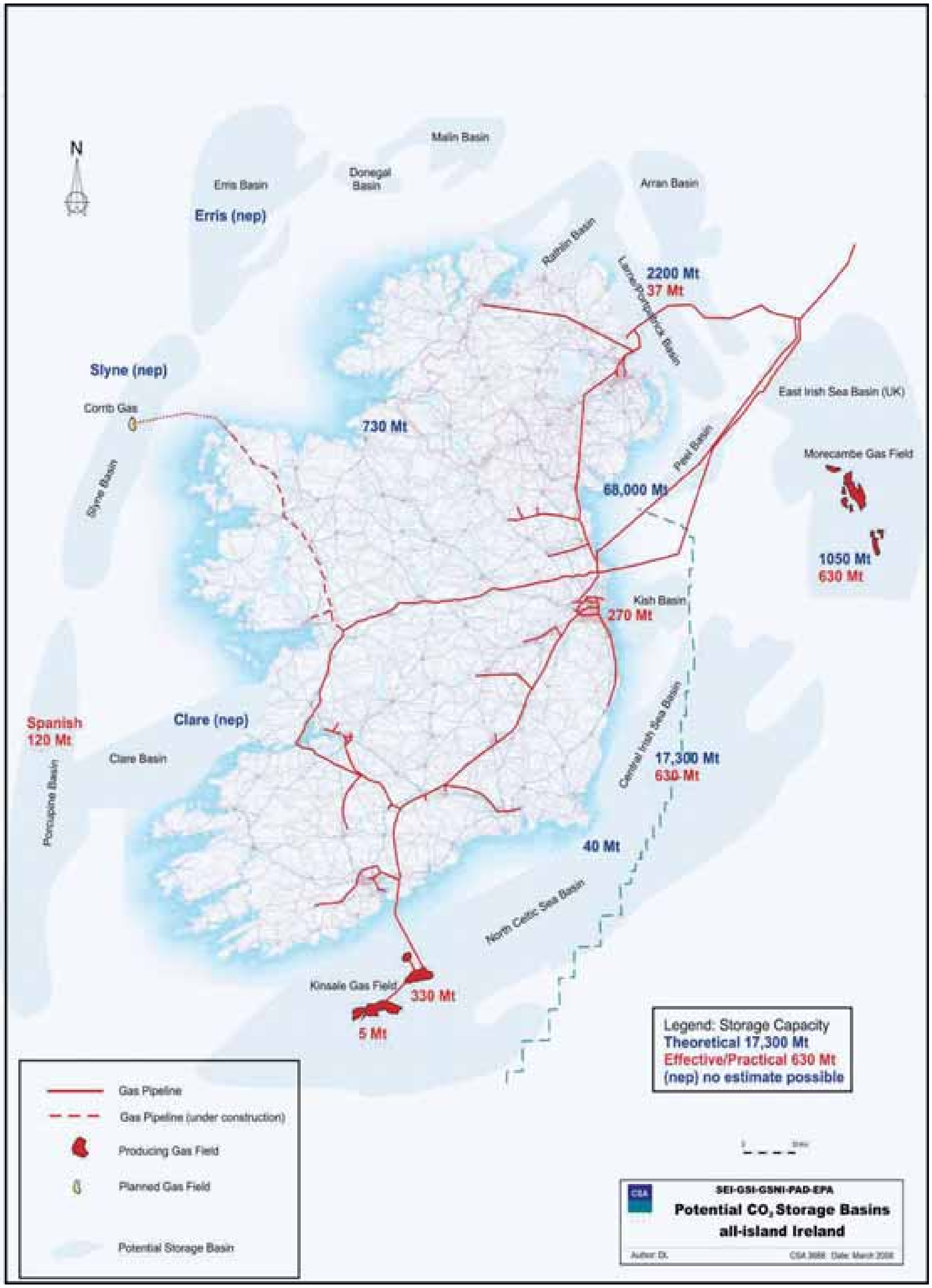


Table 6: All-Island Ireland : Summary Quantified Storage Capacity (July 2008)

Basin	Capacity Classification	Quantified capacity Mt	Storage
Kinsale Gas Field	Practical		330
South West Kinsale Gas Field	Practical		5
Spanish Point Gas field	Practical		120
East Irish Sea oil and Gas fields	Practical		1,050
Total Practical Storage (*additional to theoretical & effective*) (Mt)			1,505
Portpatrick Basin Sherwood Sandstone selected structures	Effective		37
Central Irish Sea Sherwood Sandstone structures	Effective		630
Total Effective Storage (*subset of theoretical*) (Mt)			667
Lough Neagh Basin Enler Group selected structures	Effective		1,940
East Irish Sea Basin Ormskirk structures	Effective		630
Kish Bank Basin Sherwood sandstone structures	Effective		270
Total Effective Storage (*additional to theoretical*) (Mt)			2,840
Celtic Sea - 1 structure in the Cretaceous A sand	Theoretical		40
Portpatrick Basin/ Larne whole basin	Theoretical		2700
Peel Basin Sherwood Sandstone whole basin	Theoretical		68,000
Northwest Carboniferous Dowra Basin whole basin	Theoretical		730
Central Irish Sea whole basin	Theoretical		17,300
Kish Bank Basin Carboniferous sandstone and coal	Theoretical / un-quantified		
Rathlin Basin Sherwood Sandstone, Permian and Carboniferous	Theoretical / un-quantified		
Celtic Sea Cretaceous A sand	Theoretical / un-quantified		
Porcupine Basin	Theoretical / un-quantified		
Slyne/Erris Basins	Theoretical / un-quantified		
Clare Basin	Theoretical / un-quantified		
Rockall Trough	Theoretical / un-quantified		
Gas prospects	Theoretical / un-quantified		
Other onshore basins	Theoretical / un-quantified		
Total Theoretical Storage (Mt)			88,770
TOTAL STORAGE CAPACITY (PRACTICAL/ EFFECTIVE/ THEORETICAL)			93,115 Mt

Table 7: Estimated CO_2 Storage Capacities of all-island Ireland

Target Basin and Formation	Estimate Type	Storage Type	Explanation	Major data gaps	Potential Storage Capacity Mt Total Basin	Potential Storage Capacity Mt Closed Structures	Initial risks identified
Gas/ Oil fields, discoveries and prospects (all island Ireland).	Practical	Depleted gas fields	Good data available for some of the prospects and fields, effective storage capacities were calculated. These are the best estimate without a full site investigation	Data from oil companies to fill the gaps would make it possible to calculate capacities for more prospects.		**Kinsale – 330** **SW Kinsale – 5** **Spanish Point - 120**	Variable risk for each prospect
Kish Bank Basin Sherwood Sandstone Group	Effective	Aquifer	Based on the information (Depth map and several wells) available reasonable estimates could be made.	Not every structure has a well drilled into it. A more accurate structure and depth map would improve the estimate.		**270**	Gas seepage from the Codling fault zone. Therefore major faults may act as migration
Kish Bank Basin Carboniferous Sandstone	Theoretical/ Unquantifie d	Aquifer	Reservoir is present, only one well is drilled into it. This is at the very base of the pyramid as theoretical potential but unqualified.	Depth maps, thickness maps, well data would be required to calculate storage capacity	*No estimate possible*	*No estimate possible*	Lack of data to identify risks
Kish Bank Basin Carboniferous Coal	Theoretical/ Unquantifie d	Coal	The lack of data makes this a theoretical but un quantifiable option.	Depth maps, thickness maps, well data would be required to calculate storage capacity	*No estimate possible*	*No estimate possible*	Lack of data to identify risks
Central Irish Sea Basin Sherwood Sandstone Group	Effective/ Theoretical	Aquifer	Based on the information available reasonable estimates could be made.	More detailed depth, structural and reservoir information could improve estimates.	**17,300**	**630**	Seal potential deteriorates to in south and limits of the basin. Possible leakage risk on line of Codling fault zone.
East Irish Sea Basin Ormskirk Formation	Effective	Aquifer	Good data from hydrocarbon exploration and production in the area. Best estimates with the data available.	The next step would be analysis of individual structures followed by site investigation to more the estimates towards the apex of the pyramid.		**630**	Possible fractures in seal.

East Irish Sea Basin Oil and gas fields	Practical	Depleted oil and gas field	Good data from hydrocarbon exploration and production in the area. Best estimates with the data available	The next step would be analysis of individual structures followed by site investigation to more the estimates towards the apex of the pyramid.		Total oil and gas fields - **1,050**	Wells represent potential leakage pathways
Peel Basin Sherwood Sandstone Group	Theoretical	Aquifer	Basic data and equivalent data used from nearby basin used to make this estimate. It would sit near the base of the triangle.	Better depth data. Wells drilled and analysis of seismic would improve estimates	**68,000**		Shallow gas may indicate seal failure.
Celtic Sea Basin Cretaceous A and B Sands	Theoretical/ Unquantifie d	Aquifer	Well data analysed (100 plus wells) only one structure could be identified.	To produce further estimates structure maps would be required.		Single closure in 'A' sand: **40**	Potential migration pathway through fault in seal. Seal failure in pressure tests.
Larne Portpatrick Basin Sherwood Sandstone	Theoretical and Effective	Aquifer	Basic data and equivalent averages used from equivalent formation nearby basin used to make this estimate. It would sit near the base of the triangle.	Better depth data. Wells drilled and analysis of seismic would improve estimates	**2,700**	**37** *(in 4 closures)*	Insufficient seal thickness may allow migration from Enler Group
Porcupine Basin Volgian Sandstone, Bantry and Kenmore Group Sandstones	Theoretical/ Unquantifie d	Aquifer	Potential reservoir strata are present but the lack of data makes this a theoretical but unquantifiable option.	Depth maps, thickness maps, porosity information etc would be required to calculate a storage capacity	*No estimate possible*	*No estimate possible*	Lack of data
Slyne/Erris Basin Sherwood Sandstone Group and Carboniferous Sandstones	Theoretical/ Unquantifie d	Aquifer	Potential reservoir strata are present but the lack of data makes this a theoretical but unquantifiable option.	Depth maps, thickness maps, porosity information etc would be required to calculate a storage capacity	*No estimate possible*	*No estimate possible*	Gas chimneys observed over major faults may indicate seal failure.
Rathlin Sherwood Sandstone Group, Enler Group and Carboniferous Sandstones.	Theoretical/ Unquantifie d	Aquifer	Potential reservoir strata are present but the lack of data makes this a theoretical but unquantifiable option.	Depth maps, thickness maps, porosity information etc would be required to calculate a storage capacity	*No estimate possible*	*No estimate possible*	Lack of data

Clare Basin onshore and offshore Carboniferous Sandstones	Theoretical/ Unquantified	Aquifer	Potential reservoir strata are present but the lack of data makes this a theoretical but unquantifiable option.	Data acquisition would make it possible to quality the storage capacity of the Clare Basin	*No estimate possible*	*No estimate possible*	Lack of data is the greatest risk
Rockall	Theoretical/ Unquantified	Aquifer	Potential reservoir strata are present but the lack of data makes this a theoretical but unquantifiable option.	Data acquisition would make it possible to quality the storage capacity of the Rockall trough	*No estimate possible*	*No estimate possible*	Deep water, harsh climatic conditions, distance from CO_2 sources combines with geological uncertainty make this high risk option.
Lough Neagh Enler Group	Effective	Aquifer	Good well and depth map data for a small area for the Lough Neagh Basin	Better data coverage across the basin would make quantifying the whole basin possible. Depth conversion of TWT maps for selected prospects could also be useful.		**1,940**	Onshore. Thickness of seal may not be sufficient
Northwest Carboniferous Basin Dowra Sandstone	Theoretical	Aquifer	Limited data only a whole basin estimate was possible.	Depth conversion of TWT maps and isopach from Robertson reports would improve the data valuable for estimates.	**730**		Injection into the reservoir may not be possible as the permeability is too low.

***NB// for any of the potential storage options to move up towards the top of the resource pyramid a full site investigation would have to be conducted*.**

3.3 Classified Storage Capacities

The storage capacities for each basin have been grouped according to the CSLF resource triangle as follows (as illustrated above in Figure 5):

A. Theoretical Storage Capacity –unquantified
The following basins have proven reservoir rocks with the potential to store CO_2, but a lack of data available for this study has prevented further estimation of CO_2 storage capacity:

- **Kish Bank Basin**: Carboniferous Sandstone and Coal
- **Rathlin Basin**: Sherwood Sandstone, Permian and Carboniferous sandstones
- **Porcupine Basin**: Jurassic and Cretaceous sandstones
- **Slyne/Erris Basin**: Triassic Sherwood Sandstone Group
- **Clare Basin**: Carboniferous Sandstones
- **Rockall Trough**
- **Onshore basins**: (excluding the Northwest Carboniferous Basin, Lough Neagh Basin, Larne Basin)
- **Celtic Sea Basin**: Cretaceous 'A' Sand
- **Gas prospects**: (Kinsale Head, SW Kinsale, Ballycotton, Corrib, Seven Heads, Spanish Point, Burren, Connemara). These potentially could be quantified if small data gaps were filled.

B. Theoretical Storage Capacity –whole basin estimates
- **Peel Basin**: Sherwood Sandstone Group
- **Northwest Carboniferous Basin**: Dowra Sandstone
- **Central Irish Sea Basin:** Sherwood Sandstone Group

C. Effective Storage Capacity –selected closed structures
- **Port Patrick Basin**: selected structures
- **Lough Neagh Basin**: selected structures
- **East Irish Sea Basin**: Ormskirk Sandstone Formation
- **Kish Bank Basin:** Sherwood Sandstone Group
- **Central Irish Sea:** Sherwood Sandstone Group

D. Effective/Practical Storage Capacity –Prospects and Gas Fields
- **Kinsale Gas Field**
- **Kinsale Head Gas Field**
- **Corrib Gas Field**
- **East Irish Sea** oil and gas fields

Based on estimates of storage capacity alone and not considering the geological risks, the basins with promising storage capacity are:

- Closed Structures in the Kish Bank Basin
- Closed structures in the Central Irish Sea Basin
- Closed structures in the Portpatrick Basin
- East Irish Sea, closed structures in the Ormskirk Sandstone Formation and oil and gas fields
- Offshore gas fields and prospects (particularly the Kinsale gas field)
- Northwest Carboniferous Basin Dowra Sandstone

- Celtic Sea Cretaceous ‘A’ and ‘B’ Sands.

Some risks to CO_2 stored in these locations have been identified in this study and should be fully assessed before considering CO_2 storage. Basins should not be disqualified based purely on the basis of a perceived geological risk.

In the Kish Bank Basin for example, natural gas migration has been observed along the line of the Codling Fault Zone. CO_2 stored in the vicinity of this fault zone would be likely to escape to surface along migration pathways. If the major basinal faults are avoided, a secure storage site may be located and tested by rigorous site assessment. The basin should not be discounted purely on this uncertain risk, as it lies only 20km from Dublin/ East Coast point sources. This proximity to CO_2 source may make further exploration for suitable storage sites away from the major fault zones worthwhile.

It was proposed that the following storage sites, based on their location and geological characteristics, could be used as Case Studies for the economic modelling:

Priority 1

- Kinsale Gas Field, Republic of Ireland
- Portpatrick Basin Northern Ireland
- Sherwood Sandstone of Kish Bank Basin and the Central Irish Sea Basin.

Priority 2

- East Irish Sea Basin, UK
- North Celtic Sea, Republic of Ireland

Priority 3

- Clare Basin, Republic of Ireland (due to its proximity to the largest point source, the Moneypoint power station, despite the lack of geological data and in anticipation of work to be undertaken by the EPA/ GSI)[60]

Given the geological data constraints alluded to in the assessment above, in the event, it was feasible to economically model just two Priority 1 basins in a realistic manner, namely Kinsale and Portpatrick. Summary results of that analysis are presented in Chapter 7 below, with full details in Annexe 2.

[60] In February 2008, a tender was called by the EPA, with partners GSI, to investigate the deep geology of the Clare Basin.

3.4 Conclusions: Geological Storage Capacity

It is concluded that Ireland has a large potential resource in the sedimentary basins assessed in this study to store considerable quantities of CO_2 from large point sources, effectively preventing the CO_2 emissions from entering the atmosphere. However, there are very significant data limitations for the understanding of the deep geology of many of the island's basins, particularly in the western offshore basins. Notwithstanding, the total quantified CO_2 storage capacity of the island of Ireland, based on our current understanding, may be summarised as follows:

TOTAL QUANTIFIED CAPACITY 93,115 Mt

comprising:

- **Theoretical Capacity: 88,770 Mt**
- **Effective Capacity 3,507 Mt**
    - ***667Mt subset of theoretical capacity;***
    - ***2,840 Mt additional to theoretical capacity***
- **Practical Capacity 1,505 Mt**

It must be stated that storage capacity estimates in this study are calculated using data of variable quantity and quality and significant further detailed geological assessment will be required prior to implementing an operational CCS project.

3.5 Recommendations: Geological Storage Capacity

It is recommended that this study is used to focus on a site(s) or basin(s) to undertake specific studies involving:

(i) Detailed analysis of seismic and well data to reduce uncertainty in the storage capability and estimated storage capacity.

(ii) More reservoir data needs to be acquired to assist in detailed modelling of selected Priority 1 basins, to include analysis of seals, fault, gas leakage (if any), geochemical reactions of CO_2 at depth/ pressures of each storage site and the stability of old well completions (where occurring).

(iii) Detailed and comprehensive hydrodynamic and reservoir simulations will be required for each selected storage site.

(iv) Modelling of the down hole phase behaviour of injected CO_2, and

(v) Detailed simulations of CO_2 host rock reactions.

Detailed characterisation & risk assessment of selected basins

Given the strategic position and geological understanding of the only producing gas field in Ireland to date, Kinsale Head has been assessed in more detail than any other basin in this study. Additionally, the provision of large amounts of geological and production data from the operators, Marathon (Ireland)[61], considerably enhanced the team's ability to model the basin in detail to assess its suitability for containment of CO_2 and the likelihood of its escape.

[61] Special thanks to Mr Fergal Murphy, MD Marathon (Ireland) for release of data to the study.

Geological data and understanding to date permit risk assessment of only two other proposed storage sites: namely the Portpatrick Basin in the North Channel and the Kish Basin in the Irish Sea, respectively.

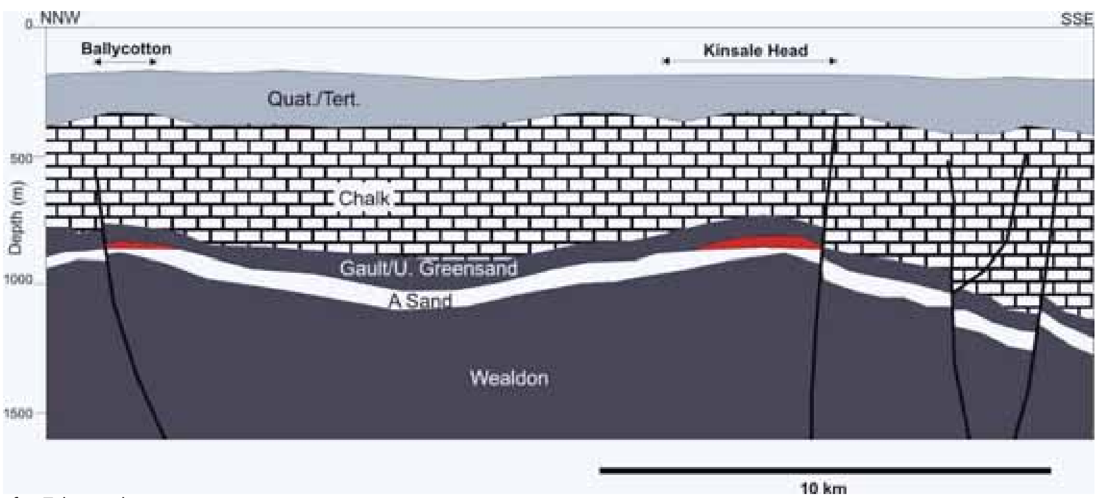
The following presents the core hydrodynamic (Kinsale) and risk analyses (Kinsale, Kish and Portpatrick) carried out by the team, using the qualitative Frequencies, Events, Processes (FEPs) methodology. To carry out full quantitative risk assessments using RISQUE methodology would require detailed hydrogeological and reservoir engineering parameters to run reservoir simulations, data which are currently lacking.

3.6 Hydrogeological Assessment of the Kinsale Head Gas Field

3.6.1 Hydrostratigraphic Framework

The reservoir units in the Kinsale Gas Field are Cretaceous channel sandstones which are embedded in low-permeability Wealden and Greensand mudstones, the latter also forming the reservoir seal (Figure 8). The overlying Upper Cretaceous Chalk does not contain any hydrocarbon reservoirs in the Celtic Sea and generally appears to have aquitard characteristics. (Please refer to the geological model of the Kinsale Head gas field in Annexe 1 for details on the lithology, depths and thicknesses of the various stratigraphic units).

Figure 8: Regional cross-section showing location of the Kinsale Head and Ballycotton gas fields

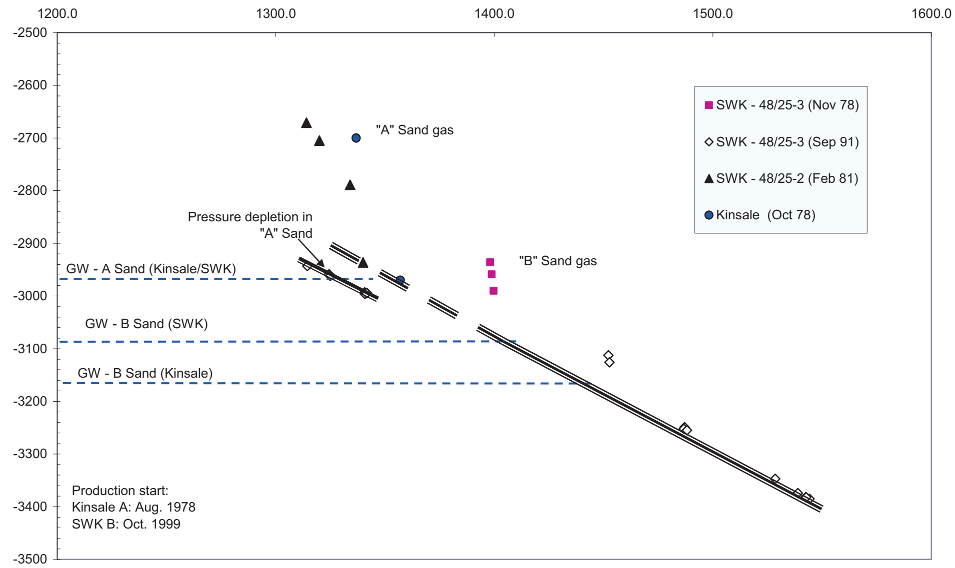


after Taber et al. 1995

3.6.2 Pressure Regime

Pressure data from drill stem tests (DSTs) and repeat formation tests (RFTs) are available only for the reservoir sandstones (Wealden, Greensand) at Kinsale Head (Figure 9). Generally, the Cretaceous sandstone aquifer system is nearly hydrostatically pressured with a typical freshwater hydraulic head value of 50m. The lateral flow of formation water could not be determined due to the lack of data from surrounding wells. Still, in an offshore environment it can be assumed that the main driving mechanism for formation water flow is sediment compaction. Minor thermal subsidence of the Celtic Sea Basin since the Late Tertiary (Shannon, 1991) probably is expressed by relatively flow rates and faults may form lateral barriers to formation water flow due to the vertical offset of aquifers.

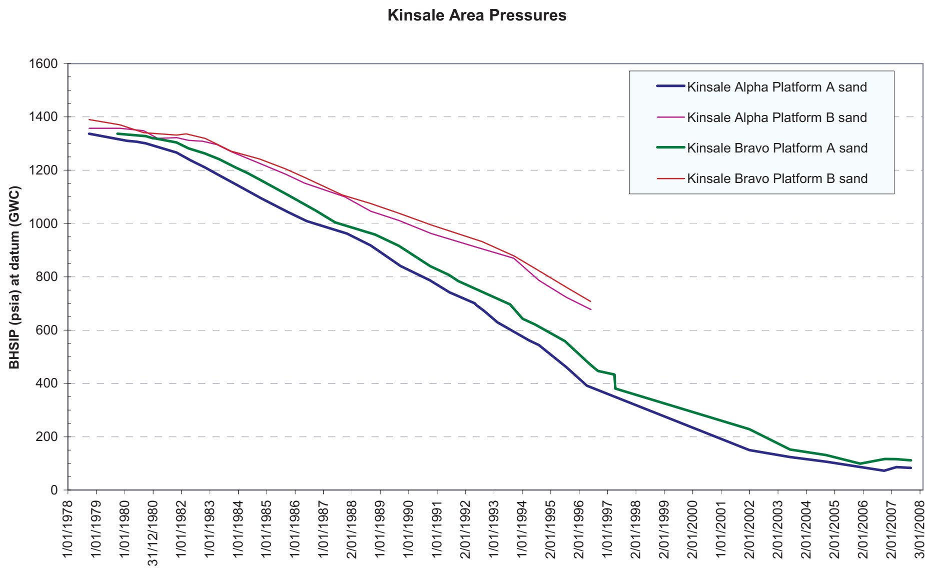
Figure 9: Formation pressures and gas-water contacts in the Kinsale Head sandstone reservoirs



The gas-water contact in the Greensand ("A" Sand) lies at 2967 ft TVDss at both Kinsale Head and South West Kinsale. The gas-water contact in the Wealden ("B" Sand) is different at Kinsale Head (3167 ft TVDss) and SW Kinsale (3084 ft TVDss). This suggests that the two "B" sand reservoirs are hydraulically separated from each other, whereas the "A" sand forms a contiguous reservoir over Kinsale Head and SW Kinsale (O'Sullivan, 2001). Measurements in the 48/25-3 well from September 91 show pressure depletion of the "A" sand reservoir at SW Kinsale, which can be attributed to production from the main Kinsale Head field. In contrast, pressures in the "B" Sand measured in the same well are close to virgin hydrostatic pressures.

The severe production-induced underpressuring of the Kinsale Head reservoirs (Figure 10) suggests weak pressure support from the aquifer below. The recovery of reservoir pressures should be monitored after abandonment of the gas field to better assess the hydraulic communication between reservoir and underlying water leg.

Figure 10: History of bottom hole reservoir pressures at Kinsale Head



3.6.3 Fluid Chemistry

No information on the formation water chemistry was available for the study area.

3.6.4 Injection Process

Anticipated injection pressures may be estimated by applying basic reservoir engineering equations to average reservoir and injection parameters. This should not substitute actual reservoir modelling[62].

In the following, two end-member cases for conditions at Kinsale will be considered (Figure 11) a) depleted reservoir pressures during injection start up and b) initial reservoir pressures which should not be exceeded.

Assumptions (Kinsale Head A Sand):

k = 382 mD (from Marathon reservoir model, Bravo platform)
h = 20m = 65.6 ft (net pay from Marathon contour maps)
P_r = 1336.8 psia (~ 100 psia at depletion)
T = 29.4 °C = 544.6 °R (Colley et al. 1981)
z = 0.26 (calculated)
• = 0.064 cP (calculated, Span & Wagner)
Re = 1000 ft (effective well radius, estimated)
Rw = 0.292 ft (well radius, estimated based on 177.8 mm casing assumption)

q = -5,000,000 Sm3/d (estimated, equivalent to ~ 3 Mt/year)

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[62] Note that multi-phase reservoir simulation and assessment of site-specific thermodynamic behaviour of CO_2 will be required prior to injection to Kinsale.

1. Sandface Injection Pressure

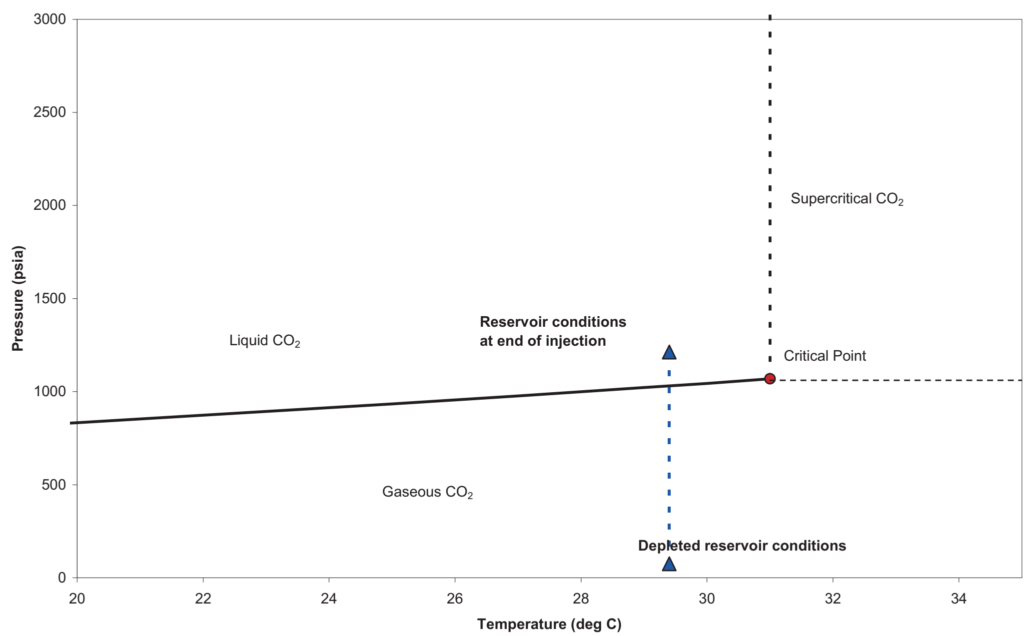
a) Depleted reservoir pressure (P_r = 100 psia):

$$P_{sf} = \left[P_r^{\,2} - \frac{q \cdot \mu \cdot T \cdot z \cdot \ln(r_e/r_w)}{703 \cdot k \cdot h} \right]^{0.5} = 809\, psia$$

b) Initial reservoir pressure (Pr = 1336 psia)

$$P_{sf} = \left[P_r^{\,2} - \frac{q \cdot \mu \cdot T \cdot z \cdot \ln(r_e/r_w)}{703 \cdot k \cdot h} \right]^{0.5} = 1588\, psia$$

Figure 11: Anticipated P,T conditions in the reservoir at injection start up and end of injection



2. Wellhead Injection Pressure

The wellhead injection pressure may be estimated by:

$P_{wh} = P_{sf} + P_f - P_h$

Where P_f = Tubing friction pressure loss (assumed to be 500 kPa) and P_h = hydrostatic pressure of a CO_2 column in the well with an average density of 12.5 kg/m^3 and 758 kg/m^3 for the depleted and initial reservoir conditions, respectively.

(a) depleted reservoir pressure: P_{wh} = 867 psia (5975 kPa)
(b) initial reservoir pressure: P_{wh} = 790 psia (5450 kPa)

The injection stream will consist mainly of pressurised gaseous CO_2 during the lifetime of injection. However, with the expected injection rates and reservoir conditions, CO_2 phase changes will occur within the injection well and in the reservoir, particularly in the later stages of the injection process when approaching initial reservoir pressures. At the end of the operation, CO_2 in the reservoir will be in a high-density (~ 750 kg/m^3) liquid phase (Figure 11). The CO_2 phase changes in the injection well make it difficult to predict the downhole density distribution and friction losses; hence calculation of the wellhead injection pressure. The calculated wellhead injection pressure of 6000 kPa for the case of the depleted reservoir should be considered as a conservative value, because it assumes gaseous CO_2 with a constant density throughout the wellbore (actual density should be higher) and relatively high friction losses (should be lower for gas phase). In comparison, numerical modelling, ignoring friction losses, results in 4.36 MPa at the wellhead. The reservoir simulator runs into difficulties calculating accurate friction losses, because an injection rate of 3 Mt/year would result into 2-phase conditions down the borehole. For a flow rate of 2 Mt/year the numerical model predicts 5.3 MPa at the wellhead, which compares relatively well with the results above. For non-depleted, initial reservoir conditions, the numerical model calculates 5.4 MPa at the wellhead, again ignoring friction losses[63].

In summary, a range of wellhead injection pressures between 4000 and 6000 kPa (40-60 bar) can be expected during the life of CO_2 injection at Kinsale Head.

In comparison, wellhead and bottom hole pressure at the SW Kinsale gas storage site (depth = 895 m) range from 775 psig to 1290 psig and from 868 psig to 1405 psig, respectively.

3. Formation Fracturing Pressure

The injection pressure should be below the rock fracturing pressure at the reservoir level. With the absence of measured data and assuming a relatively conservative fracture gradient of 18 kPa/m, the fracture pressure P_f at the top of the A Sand (825m) is approximately 14,850 kPa (2155 psia). Under the assumed reservoir conditions and injection rate, bottom hole injection pressures would be well below the fracturing pressure. However, the injection pressure is very sensitive to k and h, and for example a decrease in permeability to k = 100mD would result in a sandface injection pressure of P_f = 2150 psia. **Therefore, it is critical to conduct an injectivity test and reservoir modelling before the start of CO_2 injection, and to monitor injection pressures during the life of the injection operation.**

The injection pressures can be controlled at the surface mainly by the rate of CO_2 injection. Considering the large anticipated injection rates of approximately 3 Mt/year, it would be advisable to have at least two injection wells. Primarily, the second injector would act as a backup in case of technical problems with the main injection well. However, in cases of decreasing injectivity and increasing injection pressures, the second well could be used to take part of the injection load without having to compromise the overall CO_2 injection volume. If the injection rate is increased, then more injection wells will be required (see economic analysis in Chapter 7).

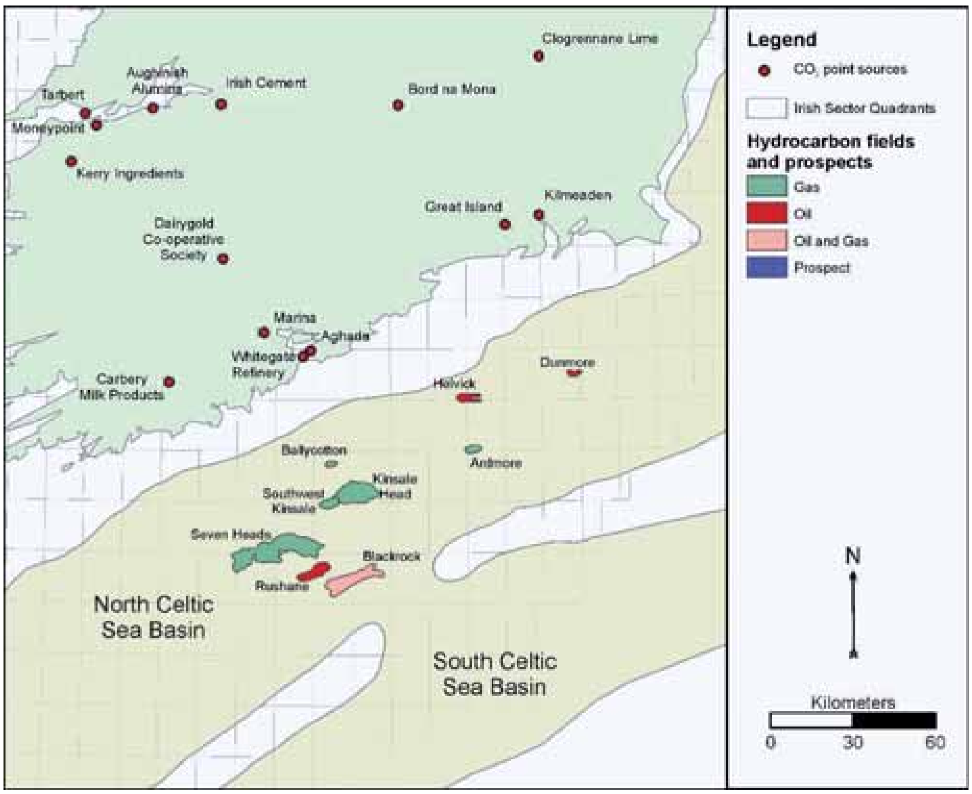
See Section 3.7 below for a more detailed risk assessment of CO_2 storage at Kinsale Head.

[63] The expected wellhead injection pressures will range between 750 psi and 1070psi (approx. supercritical pressure), but prior to detailed simulation, it is anticipated that the wellhead pressure will have to about 900 psi to achieve the required bottomhole pressures to ensure injectivity at Kinsale. CO_2 phase changes, and possibly Joule Thomson effect, can be anticipated down the borehole, but it is expected that the phase changes will become more stable with time (overall higher densities in the fluid column), as the reservoir pressure builds up. However, detailed modelling of the thermodynamics will be required.

3.7 Risk Assessment of the Kinsale Head Gas Field

The Kinsale Head gas field lies some 60km south of Ireland (Figure 12) in water depths of around 90m. The field was discovered in 1971, with a vertical gas column of 84 metres (well 48/25-2), and came on-stream in 1978. The main reservoir units are Lower Cretaceous channel sands (the Greensand 'A' Sand and the underlying Wealden 'B' Sand) embedded in low permeability Wealden and 'Gault' mudstones (see Figure 8 above).

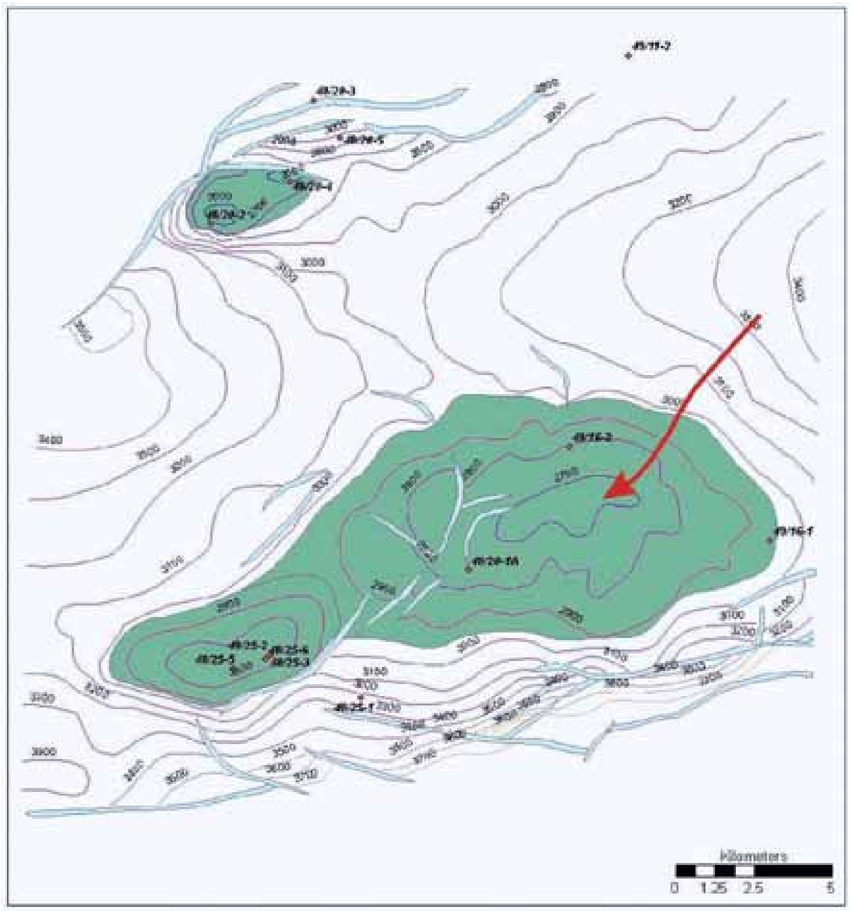
Figure 12: Location map of the Kinsale Head gas field



The gas field forms a broad, elongate, four-way dip-closed anticline structure with minor faulting to the south (Figure 13). Depths[64] to the tops of the 'A' Sands and the 'B' Sands are around 838 metres and 905 metres respectively (Colley et al. 1981). Recoverable reserves were initially estimated at 42.45 billion m^3 (Taber et al.1995), but by the end of 2002, 45.3 billion m^3 had been produced and production is expected to continue until at least 2011/ 2012 (Lansdowne Oil and Gas website, November 2007). Reservoir properties are summarised in Table 8.

[64] Depths cited are "sub-sea", i.e. measured from Mean Sea Level

Figure 13: Structural map of the Kinsale Head and SW Kinsale gas fields



Contours denote depth (in feet) to the top of the 'A' Sand. The red arrow denotes the schematic flow path for putative injection point on the NE flank of the structure.

The compositions of the dry gas in both 'A' and 'B' Sands are similar with high methane content, suggestive of a common source, thought to be the Jurassic (Colley et al. 1981; Murphy et al. 1995).

Table 8: Average reservoir characteristics for the Kinsale Head gas field

	'A' Sand	'B' Sand
Depth to reservoir (m sub-sea)	838	905
Gross sand thickness (m)	38	-
Net pay (m)	31	7
Porosity (%)	20	22
Permeability (mD)	420	280
Sw (%)	24.6	29.9
Temperature (°C)	29.4	32.2
Gas-Water contact (m sub-sea)	902	966-944

(after Colley et al. 1981)

3.7.1 SW Kinsale Gas Field

The SW Kinsale gas field forms a low-relief anticline, adjacent to the main Kinsale Head field (Figure 12). The reservoirs are similar to those at Kinsale Head, but gas-water contacts and production pressure data (see Section 3.6 above) suggest that whereas the 'A' Sand is hydraulically connected through the two fields, the 'B' Sand is hydraulically discontinuous. Estimated gas initially in place at SW Kinsale is 1.1 – 1.4 billion m^3 with recoverable reserves of 0.85 billion m^3 (O'Sullivan 2001). The first gas was produced in late 1999. There was initial interest in this field as a gas storage site to be utilized for peak-shaving, and studies carried out on the Wealden ('B' Sands) shows favourable potential for this scenario (O'Sullivan 2001).

3.7.2 Kinsale Head Gas Field

This risk assessment has been restricted to the Kinsale Head gas field, but similar arguments would apply to CO_2 storage at SW Kinsale. A review of the main containment risks was carried out, followed by a discussion of possible injection strategies.

Containment Risks

The Kinsale Head gas field culminates at a depth of about 820m below sea-level, some 730m below seabed[65]. These depths are comparable to those in the Utsira Sand at Sleipner and represent the shallow end of the viable storage window. Generally speaking, storage at these depths would be considered more risky than deeper storage, simply on the basis that a smaller column of overburden is available to contain the CO_2. Storage at Sleipner involves containing CO_2 in the dense phase (densities typically in the range 600 – 750 kgm^{-3}), whereas CO_2 stored at Kinsale Head, would, at least initially, be in a gaseous state, with higher buoyancy and mobility than at Sleipner.

Geological Seals

The immediate geological seal is formed by Lower Cretaceous mudstones (Gault equivalent) that overlie the 'A' sand (Figure 8). These are typically about 45m (150') thick and are overlain by a further 35m (110') of claystones and siltstones. The overlying Upper Cretaceous Chalk, though thick, would likely have relatively poor sealing characteristics. A caprock sequence of such thickness and stratigraphy would generally be expected to form an adequate seal, provided that capillary entry pressures are sufficiently high. This would be normally established by sample testing. In the case of Kinsale Head, the fact that the seal has trapped natural gas for long periods indicates that the caprock has formed an effective seal on geological timescales. In particular, in its intact form, the immediate topseal lithology is likely to form an effective capillary seal. However, the potential reaction of CO_2 with carbonate cements and other minerals, such as glauconite and clays, will require detailed modelling prior to injection.

A number of relatively small faults cut the top of the reservoir at Kinsale Head and some of these lie close to the structural culmination of the field (Figure 13). Faults are generally perceived to present significant containment risks, and fault geometry, linkage and sealing properties would need to be evaluated. As above, the fact that the seal has trapped natural gas for long periods indicates that the faults, prior to gas production, did not compromise caprock integrity.

Geomechanical effects triggered by the injection process have the potential to induce structural perturbations within the caprock, including the reactivation of old faults and the formation of new fractures. Simplified evaluations of CO_2 injection into the 'A' Sand have been carried out. In the course of this study (see Section 3.6 above), it was assumed that CO_2 was injected at 3 Mt/year via a single well, into a reservoir 20m thick, of 382 mD permeability and with an initial (depleted) formation pressure of 0.7 MPa. A calculated initial sandface pressure (i.e. at the wellbore perforations) of 5.5 MPa would increase progressively to 10.9 MPa, as overall formation pressures returned to hydrostatic (9.2 MPa). This is safely below the estimated fracture pressure of 14.8 MPa. However, if formation permeability were only 100mD, the sandface pressure would match the fracture pressure, with a consequent risk to caprock stability. In a fluviatile reservoir facies, such variation in permeability may well be realistic, so injectivity testing and reservoir modelling prior to CO_2 injection, and downhole pressure monitoring during injection would be critical.

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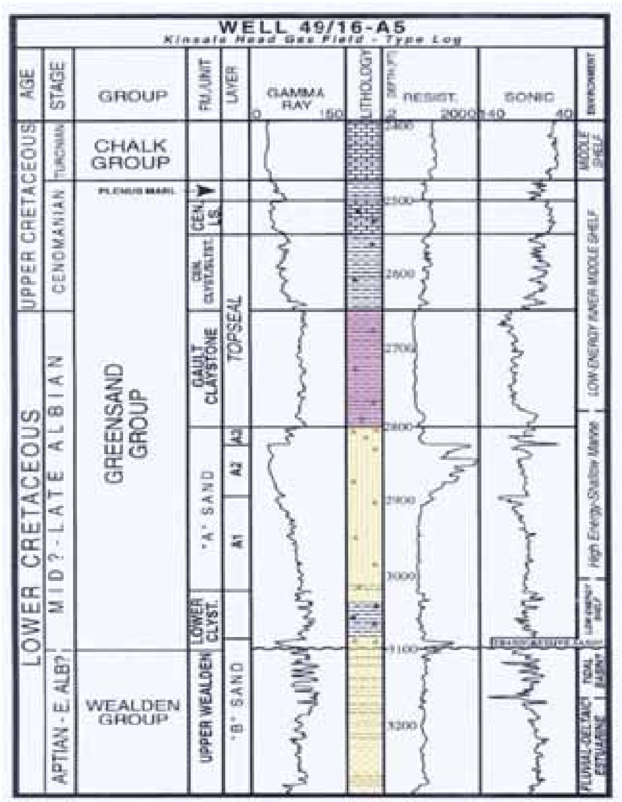
[65] The 90m water column from mean sea level to seabed will exert a hydrostatic pressure, thus contributing to the overall pressure regime for storage, but will not provide sealing capacity for injected CO_2.

Figure 14: Stratigraphy of the Kinsale Head gas field from well 49/16-A5



modified from Tarber et al. 1995 –
(yellow denotes reservoir units, purple the immediate reservoir topseal)

Longer-term pressure increases associated with filling up the available storage space should not be a problem at Kinsale Head, unless injected amounts approach the theoretical capacity of 330Mt.

In addition to geomechanical effects directly induced by CO_2 injection, in assessing the future efficacy of the geological seals at Kinsale Head, it is important to take into account the severe reservoir pressure depletion during gas production. From an initial near-hydrostatic pressure of 9.2 MPa, reservoir pressure has fallen to a current value around 0.7 MPa, increasing effective stress on the reservoir framework by 8.5 MPa. Such a change in the effective stress can result in reservoir compaction and structural disturbance of the overburden. During injection of CO_2, as pressures return towards the initial formation pressure, any newly induced or rejuvenated structural weaknesses may act as migration pathways, with a consequent reduction of seal efficacy. Practical assessment of any depletion effects could be had from subsidence measurements at the A and B platforms and by time-lapse imaging of the seabed, seeking evidence of changed sea-bottom topography, or recent gas escape (new gas-blanking, new pock-marks etc).

A possible longer-term effect on caprock efficacy is posed by chemical reaction of the CO_2-water-system with the caprock lithologies. Modelling and experimental studies elsewhere suggest that these are likely to be small, particularly if migration of CO_2 into the caprock is purely diffusive. On the other hand, induced migration pathways may allow capillary access of free CO_2 to the caprock, which could pose a more significant containment risk. However, where caprock lithologies are dominantly clay minerals and siliciclastics, any minor geochemical reactions that do occur commonly tend to reduce overall permeability (Chadwick et al. 2008). In areas of carbonate cements and glauconite in caprock lithologies, modelling must be effected.

Man-made Seals (Wells)
Wells are generally perceived to pose the greatest containment risk in geologically well-characterised storage reservoirs[66]. They commonly have imperfect completions, with poor bonding between the borehole casing and the surrounding country-rock. This is likely to be exacerbated if the overburden has suffered subsidence during gas production (see above), with induced differential movements (shear) between the wellbore and the country-rock. Poor completions pose a significant short, medium and long-term containment risk, particularly with such a shallow reservoir, where CO_2 would not have to migrate very far up the wellbore before passing into the gaseous state where mobility and buoyancy increase markedly.

The number and position of wells in the Kinsale Head field is uncertain. Up to eight wells are indicated on Figure 13, but Taber et al. indicate more are also present. With storage in a closed structure such as this, updip wells will essentially sit in a pool of stored CO_2 for very long time-scales, and suffer long-term exposure. On the plus side, in a depleted gas field such as this, the only water remaining in the pore-space will be immobile residual water (occupying a minor proportion of the pore-space). This means that the pool of CO_2 around the wellbores may be relatively dry and, in consequence, non-corrosive (although a small amount of the residual water will dissolve into the CO_2 over time). To assess these issues, careful reservoir characterisation and flow simulation will be required.

Irrespective of specific processes and scenarios, thorough evaluation of well integrity will be required, with possible pre-emptive remediation of the wellbores as appropriate. Suggested CO_2-safe completion strategies such as removing tubing and casing within the reservoir and immediate caprock and constructing multiple cement and mechanical barriers in the wellbore can be proposed.

Injection Issues
The simplest injection strategy, and lowest risk in terms of injectivity, would be to inject into the top of the Kinsale Head structure either via a new injection well (preferred) or a modified production well (perhaps cheaper). On the downside, it would subject the topmost part of the structure, exposed to the greatest geomechanical effects during pressure depletion, to the elevated pressures around the injection well. It would also maximise the amount of free, mobile (and buoyant) CO_2 trapped at the top of the structure by minimising CO_2 dissolution and residual phase trapping – again an unfavourable scenario.

An alternative approach would be to site the injection well downdip, for example on the NE flank of the structure (Figure 13). This strategy has risks in terms of uncertain injectivity and in exposing areas of caprock not proven to be gas-tight, but it also unlocks significant benefits. One would be in keeping elevated near-wellbore pressures away from the potentially vulnerable structural culmination. It may also be possible to avoid exposing most of the old wells to CO_2 by careful siting of the injection well. Another important benefit of injecting downdip is the consequence that the CO_2 would migrate a considerable distance through the reservoir (5km or more). This process exposes the CO_2 plume to considerable volumes of formation water (depending on where the current gas-water contact is) allowing dissolution and residual phase trapping. These two processes would work to immobilise CO_2 in the reservoir and ultimately reduce the amount of free CO_2 accumulating high in the structural closure (where well infrastructures are most vulnerable). Clearly such an approach would carry a heavier characterisation and performance assessment burden than injecting at the structural crest.

A recent report[67] on the potential for CCS at Kinsale Head, privately commissioned by Marathon (Ireland) and released to the project team, identified the following areas of risk which must be addressed: fluid chemistry/ wall rock / carbonate reactions; well bore linings/ casings/ cement in prior wells; potential for downhole Joule Thomson thermodynamic effects and identification of the

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[66] A recent study of the Der Lier gas field in Holland demonstrated that abandoned wells (although done in accordance with Dutch law) may pose a threat to effective carbon storage where the injection zone lies above the previously producing zone, and where a cement plug or quality cement sheath are not present at the level of the CO_2 injection zone. Additionally, the CO_2 may corrode the steel casing and cement in the presence of water, causing CO_2 to enter the well column and displace the brine therein. Convection streams may be set up due to variable densities and temperatures, thus increasing the risk of sustained corrosion and potentially high pressure leaks to shallower horizons (see Hofstee et al. *first break*, vol 26, January 2008. www.firstbreak.org).

[67] *Kinsale Head: Screening for Potential CO_2 Storage*. Internal Report prepared by Senergy Ltd. for Marathon Oil (Ireland) Ltd. (December 2007).

most effective injection regime. Concern was also expressed concerning the potential for CO_2 reaction with areas of carbonate cements and glauconitic sands.

3.7.3 Kinsale: Suggestions for Future Work

Currently available data allows for an adequate characterisation of the reservoir units in the Kinsale Head gas field with respect to CO_2 storage capacity and injectivity. Based on these, reservoir modelling of CO_2 injection at Kinsale Head should be conducted to confirm static capacity calculations and investigate reservoir behaviour (injectivity, bottom hole injection pressures, CO_2 phase changes) for the time of injection operations (~ 10 – 30 years).

Although containment of injected CO_2 appears to be established based on the previous trapping of natural gas, the possible gas leakage above the Kinsale Head gas field and gas chimneys on seismic cross-sections should be further investigated through fault and top seal capacity analysis. Also, no data exist for the stratigraphic units overlying the reservoir, and particularly the Upper Cretaceous Chalk should be investigated with respect to the possible occurrence of aquifers. Considering the entire stratigraphic succession from the reservoir to the surface, a more regional hydrodynamic numerical model should be created to assess the long-term (100s to 1000s of years) containment of injected CO_2.

In summary, the following aspects need further investigation:

- In order to better assess the sealing capacity of the Gault/Greensand mudstones and overlying Chalk, additional data is needed from these units, particularly pressure data and porosity/permeability data from core measurements, mercury injection capillary pressure measurements on the seal, Shale Gouge Ratio and juxtaposition determinations on the faults, in situ stress from borehole breakouts and leak off tests, and fault reactivation potential.
- Pressure and formation water chemistry data from neighbouring wells and gas fields should be looked at to assess the lateral continuity of the Upper Wealden-Greensand aquifer system.
- The potential leakage along faults has to be investigated in reference to the current stress regime. Leakage indicators from seismic and sea-bed methods should be pursued.
- Determine the fracture gradient in this area of the Celtic Sea.
- Reservoir modelling (local, short-term) & Hydrodynamic modelling (regional, long-term).
- Detailed multiphase reservoir simulation and modelling of the likely thermodynamic behaviour of CO_2 downhole and in the reservoir, particularly in the early stages of injection, are requisite prior to injection.

Due to its production history and known geological characteristics; the hydrodynamic and risk modelling carried out for this study, as well as the recent evaluation by Marathon that there are no major barriers to safe storage, the team's experience suggests that the Kinsale field has a 70% probability of providing a 'matched capacity' (as per the CLSF Resource Pyramid 2007, Fig. 3.2) safe, long term containment site. To move the Kinsale field to the apex of the pyramid, we estimate that for a costed study of €15 million, to include injectivity and reservoir simulation, the basin could be moved to a 90% probability of safe containment, within two years of study commencement.

If we assume that the Kinsale Head facilities may have a multiple role with natural gas storage, CO_2 storage and possible tie back of new satellite gas discoveries up to 2020, when the platform may need replacement, then the following work programme would be required:

A gross estimate of likely costs to define 'matched capacity' (to a probability of P90) of the existing Kinsale Gas Field is as follows:

Table 9: Gross estimate of likely costs of the existing Kinsale Gas Field

Test Item - Kinsale	*(€m)*
Reprocess existing seismic to pick optimum location for exploratory/injection wells	1.00
Evaluation of existing core and cuttings to assess integrity of the seal	0.05
Drilling of two (2) new exploratory deviated wells from the platform to obtain core over the cap rock	10.00
Geotechnical and geochemical study of the cap rock	0.04
Study of stress field and fault sealing based on core and seismic	0.03
Evaluate existing well completions for integrity – recomplete if necessary	3.00
Injection tests based on core data of the reservoir to simulate effect of CO_2 phase change	0.10
Other Studies/ Contingency	0.8
Total	**€15 million**

However, further reservoir simulation and injectivity testing to determine reservoir behaviour (injectivity, bottom hole injection pressures, CO_2 phase changes, site specific thermodynamic behaviour of CO_2) for the time of injection operations, fault seal analysis (to assess potential gas seepage), new seismic acquisition and more extensive drilling may be required to fully evaluate the storage suitability of the Kinsale Head Field and to investigate the hydraulic integrity of the reservoir seal. A total budget (including the initial €15 million) of €80 million, based on current hydrocarbon exploratory costs, has thus been applied in the economic analysis.

3.7.4 Kinsale Head: Conclusions

- Kinsale Head gas field poses an attractive option for CO_2 storage, based on current geological knowledge, and could be considered as a suitable sink to match the point source emissions from Moneypoint and/or Cork.

  - Kinsale offers 330 Mt of effective/ practical storage which could provide a sink for Moneypoint and/or Cork emissions theoretically for 50 years.
  - Detailed reservoir simulation and modelling is required and it is calculated that this could be achieved by completing the above proposed programme for €15 million, within two years of commencement.
  - Capacity is more than adequate and injectivity, constrained by gas production performance, appears to be satisfactory at expected injection rates. The field is quite shallow, however, and because of this careful attention should be paid to the identified containment risks.
  - In terms of injectivity, a range of wellhead injection pressures between 4000 and 6000 kPa (40 – 60 bar) could be expected during the life of CO_2 injection at Kinsale Head. This may vary with changes in permeability, which is currently estimated at 382 mD (Marathon data).
  - The geological seals, in intact form, appear to be satisfactory, but the possibility of their recent modification during pressure depletion should be evaluated.
  - The fact that gas is trapped in the structure of the Kinsale Gas field suggests that the mudstones form an effective seal on top of the sandstone reservoirs. As long as the volume of injected CO_2 will not exceed the produced volume of natural gas, the CO_2 should also be laterally contained within the Kinsale Head structure. Gas leakage is confirmed by gas chimneys visible on seismic cross-sections over the Kinsale Head field (P. Croker, PAD, *pers comm.* March 2008). However, the leakage rate or the timing of leakage has not been quantified. Possible conduits for seepage of gas from the reservoir could be faults that extend through the reservoir seal into the overlying Chalk.
  - Basin inversion and reactivation of Cretaceous and Jurassic faults during the Tertiary (Shannon, 1991) could have affected the hydraulic integrity of the reservoirs seal. In

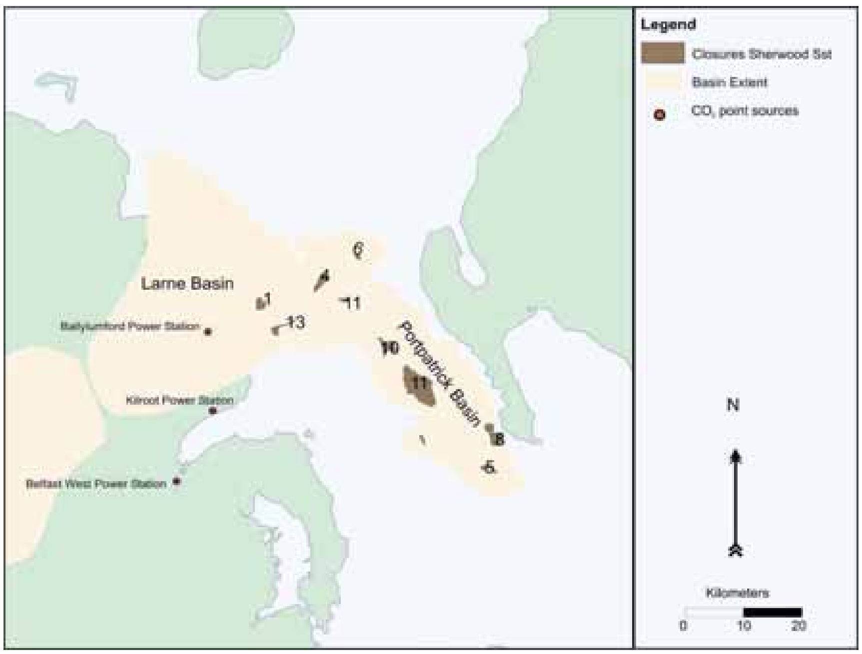
addition, depletion of the reservoir pressures would have put additional stress on the rock framework and might have weakened the overlying seal or re-activated existing faults. If CO_2 actually escaped from the reservoir, it would undergo a phase change at the p,T conditions in the overlying Chalk, and further upward migration would be accelerated due to CO_2 being in a buoyant gas phase.

- Wells pose the clearest containment risk, and a suitable risk management, monitoring and remediation strategy must be developed.

3.8 Risk Assessment of the SSG Saline Aquifer of the Larne/Portpatrick Basin

The Larne Basin is located on the east coast of Northern Ireland and extends offshore where it is known as the Portpatrick Basin (Figure 15).

Figure 15: Location of the Larne and Portpatrick Basins and identified closed structures



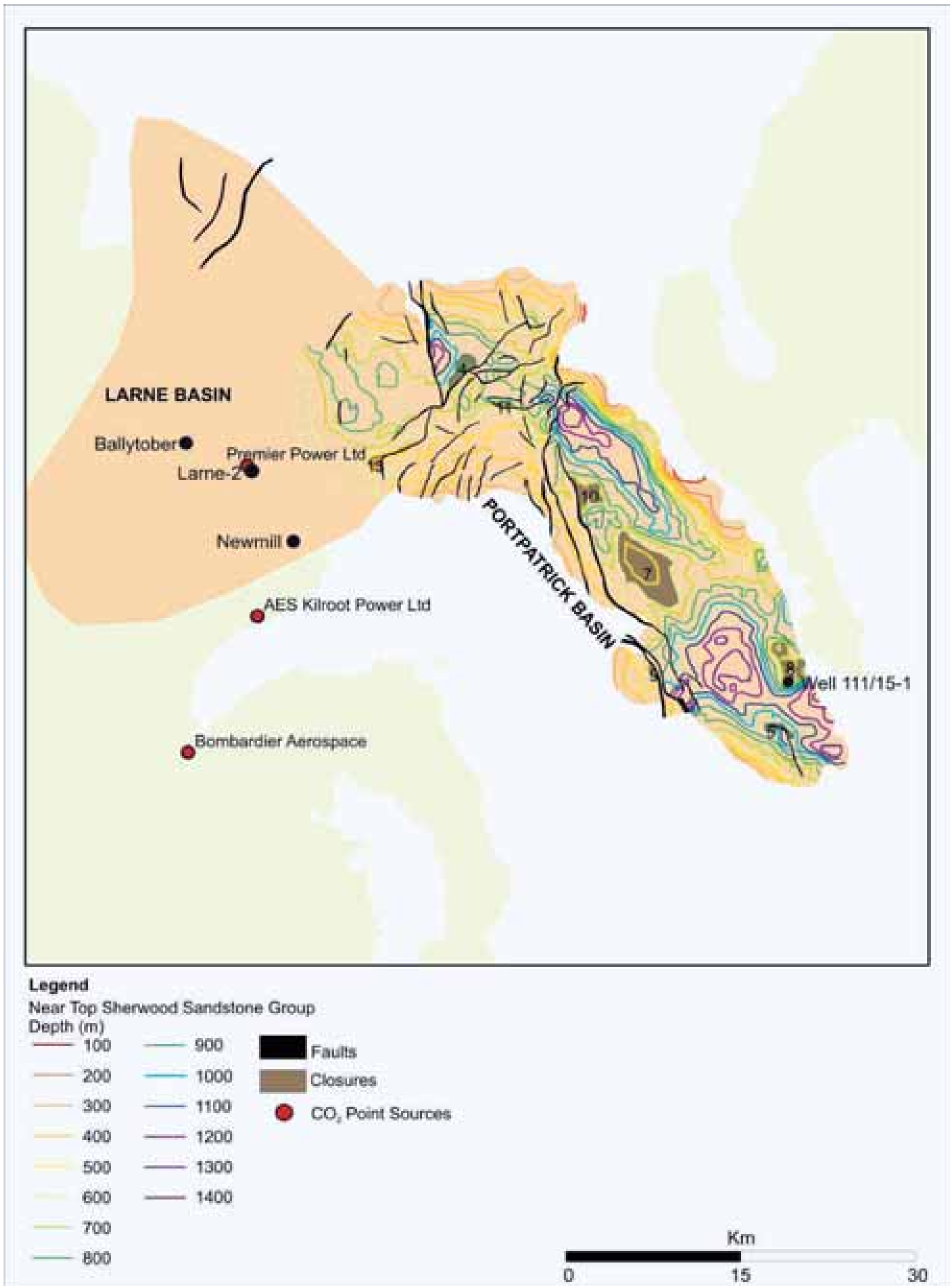
The Portpatrick Basin is filled with predominantly Permo-Triassic sedimentary rocks, and, onshore, partly overlain by the Antrim Lava Group. The Larne Basin is bisected by the NE-SW Sixmilewater Fault which defines the main structural trend of the basin, along with NNW-SSE faulting which is common to the Permo-Triassic basins in the area (Mitchell 2004). Three boreholes have been drilled in the Larne Basin that penetrate the Sherwood Sandstone Group (SSG): Larne-2, Newmill and Ballytober respectively (Figure 16).

The Portpatrick Basin is located in water depths of 120 to 200m, and forms a simple east-dipping half graben trending NNW-SSE, some 17 x 65 km in extent. The depocentre of the basin is in the hanging-wall of the Portpatrick Fault which forms the eastern basin margin (Maddox et al. 1997).

Only one well has been drilled in the Portpatrick Basin, UK 111/15-1, which targeted a rollover anticline but was plugged and abandoned as a dry hole. 2D seismic data has been interpreted for the Portpatrick Basin (Figure 16).

The main potential storage reservoirs include the Triassic Sherwood Sandstone Group sealed by the overlying Mercia Mudstone Group and the sandstones of the Permian Enler Group sealed by the Belfast Harbour Group.

Figure 16: Depth map of the near top Sherwood Sandstone Group in the Portpatrick Basin



(data courtesy of Martyn Quinn, BGS)

Table 10: Reservoir properties of the Sherwood Sandstone Group - Larne and Portpatrick Basins

	Onshore	Offshore (well UK 111/15-1)
Porosity	18 %	13 %
Permeability	300mD	45 mD
Average thickness of reservoir	600m	634 m
Average depth to top of reservoir	500m	716 m
Average thickness of seal	740m	518 m
Net to Gross reservoir		~87%

Closed structures were identified in the Portpatrick Basin using depth maps produced by interpretation of 2D seismic data (Figure 16). The structures at depths greater than 750m were estimated to have a total CO_2 storage capacity of around 37 Mt (Table 11below).

Table 11: Estimated CO_2 storage capacity for the Larne and Portpatrick Basins

Closure ID	Mapped Depth (m)	Theoretical storage capacity at 40% pore space saturation (Mt)
4	800	23
5	900	9
7	500	no estimate
8	600	no estimate
9	800	5
10	600	no estimate
11	700	no estimate
13	400	no estimate
	Total	**37**

3.8.1 Risk Assessment for the Larne and Portpatrick Basins

Containment Risks

The depth of the top of the Sherwood Sandstone Group in the Larne Basin ranges from 559 m in the Ballytober borehole, to 695 m in Newmill and 986 m in Larne-2. Storage at depths less than 700m would generally be considered risky due to the higher buoyancy and mobility of gaseous CO_2 at these shallower depths, and also the smaller overburden column available to contain the CO_2.

Only in the area surrounding the Larne-2 borehole would the reservoir be deep enough to be considered for CO_2 storage onshore therefore. In fact no closed structures have currently been identified in the vicinity of Larne-2, in part due to a lack of data. If CO_2 were to be stored in the unconfined aquifer outside of a closed structure, it could migrate laterally along high permeability pathways and, depending on the tortuosity of these features could potentially leak to the surface, where the Sherwood Sandstone Group outcrops at the surface, as it does in the Belfast area.

In addition, the Sherwood Sandstone is used as an aquifer for potable water in the Belfast area (Robins 1996) and the Larne Basin has some potable water aquifer potential. Consequently saline water displacement resulting from CO_2 injection may pose a risk to future water supply in this area. Without further data the Sherwood Sandstone Group in the Larne Basin is considered to be medium to high risk for CO_2 storage. Monitory efficacy may also pose a serious problem in the Larne Basin. Where the Antrim Lava Group crop out, seismic data are generally of poor quality due to the unfavourable acoustic properties of the thick basalt lava pile. This could seriously impair the ability of time-lapse seismic to track a migrating CO_2 plume.

The depth to the top of the Sherwood Sandstone Group in the Portpatrick Basin ranges up to 1400m in the basin centre. The crests of closures 4, 5 and 9 are at depths greater than 750m. Of these, closures 4 and 9 lie at a depth of about 800m, at the shallow end of the viable storage window, whereas closure 5 is at 900m depth and could be considered more suitable for CO_2 storage.

Geological Seals
The immediate topseal to the Sherwood Sandstone reservoir in the Larne and Portpartick Basins is formed by the Mercia Mudstone Group. This comprises a succession of interbedded halites and shales, with, in the Larne Basin, an average thickness of around 500m. Comparison with the East Irish Sea Basin, where a 300m thickness of Mercia Mudstone Group has formed a long-term seal to hydrocarbons, suggests that it will form an effective seal for CO_2 storage. Halite is considered to be an excellent seal to CO_2 as it has little or no permeability and has ductile physical properties that would tend to anneal (seal) any faults that may cut the succession. Halite is recorded in the Mercia Mudstone Group in the Larne-2 borehole interbedded with mudstones, siltstones and thin sandstones. Localised coarser clastics interbedded within the Mercia Mudstone Group may affect the sealing capacity if the halites at the base of the unit are breached. No halites are present within the Mercia Mudstone Group of the Newmill borehole south of the Sixmilewater Fault; here the unit is dominated by claystones (Maddox et al 1997). The total thickness of the Mercia Mudstone Group in the Newmill borehole is 540m, and in Ballytober 358 m are recorded. These thicknesses and lithologies are likely to be sufficient to contain CO_2, the caprock sequence likely forming an adequate seal in its <u>intact state</u>. However in areas where halite is absent, sandstones are interbedded and/or the unit is thinner, the risk of impaired caprock sealing is higher.

Offshore, only one well penetrates the Portpatrick Basin (UK 111/15-1). In this well the Mercia Mudstone Group is over 500m thick (at depths between 198 and 727m) and comprises mainly siltstones interbedded with halite. A diorite sill intrusion is recorded at 543m and thin sandstones are present at about 503m depth. The base of the Mercia Mudstone Group is formed by dolomites, sandstones and claystones which are overlain by the 72m thick Ballyboley Halite Member. This type of caprock sequence would very likely form an adequate seal in its <u>intact state.</u>

Faulting
There is too little data available for this study to establish the effects of faulting on geological containment of CO_2 in the Larne Basin.

The Portpatrick Basin forms a simple east dipping half graben trending NNW-SSE, structural details can be seen in Figure 16. Of the closures identified, only 7 and 8 do are not fault blocks; the remaining closures are bounded by one or more faults. If these faults are not sealed by clay minerals or halite along the fault plane they may act as permeable CO_2 migration pathways. Faults are generally perceived to be a risk to storage and their integrity would have to be tested as well as the geometry and linkage for each structure before CO_2 could be injected. The faults in the Portpatrick Basin have only been mapped using 2D seismic data and as a result minor faults between the lines may have been missed. 3D seismic data would enable much smaller faults to be identified. As mentioned above, it is worth bearing in mind that, where present, halite units of the Mercia Mudstone Group would be expected to generally seal faults by virtue of the inherently ductile behaviour of salt. So, particularly where the faults can be shown to be small, the chances of their posing a significant containment risk is probably quite low.

Geomechanical
Pressure increase produced by the injection process has the potential to induce structural perturbations within the caprock, including the reactivation of old faults and the formation of new fractures. In aquifer storage, as would be the case here, the necessity to displace *in situ* formation waters by injected CO_2 has the potential to increase reservoir pressures significantly. Pressure increase under CO_2 injection is primarily a function of reservoir thickness and permeability. In the case of the Sherwood Sandstone, thickness (600m) is not an issue. Measured permeabilities range from 45 mD to 300mD (Table 10), but it is not clear to what extent these are representative of regional reservoir properties – Mitchell (2004) quotes values in the range 10mD to 100mD for the Larne Basin.

If the true reservoir permeability lies towards the higher end of the measured range (300mD), then pressure increase for injection rates of 1- 5 Mt per year or thereabouts should not be an issue. If effective reservoir permeabilities are towards the lower end of the range however, pressure increase may be significant, particularly if the basin faults contribute to reservoir flow compartmentalisation. Because of this uncertainty, prior to full injection, both core and dynamic permeability data should be acquired via a test well and test injections. Numerical flow simulation of injection pressures linked to a geomechanical assessment should also be carried out.

Geochemical
A possible longer-term effect on caprock efficacy arises from chemical reaction of the CO_2-water system with the caprock lithologies. Modelling and experimental studies elsewhere, suggest that these are likely to be small, particularly if migration of CO_2 into the caprock is purely diffusive. On the other hand, induced migration pathways may allow capillary access of free CO_2 to the caprock, which could pose a more significant containment risk. However, where caprock lithologies are dominantly clay minerals and siliciclastics, (as in the case at Ballytober and Newmill) any minor geochemical reactions that might occur would commonly tend to reduce overall permeability (Chadwick et al. 2008). The immediate caprock in well Larne-2 and UK111/15-1 is halite. The potential geochemical effects of CO_2 on evaporites (including halite) in the caprock are addressed in Chadwick et al. (2008). Modelling studies indicate that CO_2-rich formation waters will not dissolve halite, indeed, the general reactive tendency is for minor net mineral precipitation which would tend to seal potential fluid pathways.

Man-made Seals (wells)
Wells are generally perceived to pose the greatest containment risk in geologically well-characterised storage reservoirs. They commonly have imperfect completions, with poor bonding between the borehole casing and the surrounding country-rock. Poor completions pose a significant short, medium and long-term containment risk, particularly in a shallow reservoir, where CO_2 would not have to migrate very far up the well bore before passing into the gaseous state where mobility and buoyancy increase markedly.

Only three wells (believed to be the case) have been drilled into the Sherwood Sandstone Group of the Larne Basin (Ballytober, Larne-2 and Newmill). In the Portpatrick Basin only one well has been drilled UK111/15-1. Provided that injection strategies are planned such that these are avoided, the risk of CO_2 migration via existing wells is considered to be low.

3.8.2 Injection Issues

The simplest injection strategy into a closed structure would be to inject into the crest of the structure. The downside of this would be subjecting the caprock to the high dynamic injection pressures around the injection well. It would also maximise the amount of free, mobile (and buoyant) CO_2 trapped at the top of the structure by minimising CO_2 dissolution and residual phase trapping – again an unfavourable scenario.

An alternative injection strategy would be to inject into the flank of the structure via a new injection well, and allow the CO_2 to migrate up-dip to fill the closure. This avoids the risk of compromising the topseal by installing a well at the highest point of the structure. Additional benefits include keeping elevated near-well bore pressures away from the potentially vulnerable structural culmination. Another important benefit of injecting downdip is the consequence that the CO_2 would migrate a larger distance through the reservoir. This process exposes the CO_2 plume to increased volumes of formation water allowing dissolution and residual phase trapping. These two processes would work to immobilise CO_2 in the reservoir and ultimately reduce the amount of free CO_2 accumulating high in the structural closure. Clearly such an approach would carry a heavier characterisation and performance assessment burden than injecting at the structural crest.

The Sherwood Sandstone Group in the Larne Basin has an estimated average porosity of 15% – 25% and permeabilities between 10mD and 100mD (Mitchell 2004). The basin has been compartmentalised by faults and dykes, which would reduce regional permeability still further and may make injection more difficult. Injection testing would be required to assess these effects.

Many of the closures identified in the Portpatrick Basin are bounded by faults. If these were to completely surround a storage closure, and were impermeable, preventing formation water from being expelled from the structure during CO_2 injection, this may well result in an unacceptable pressure increase during injection, preventing further CO_2 injection into the closure. In fact, because the Sherwood Sandstone Group is dominantly composed of a thick, quite clean sandstone, in all likelihood, most small to medium-sized faults in the reservoir would be reasonably permeable and would not constitute a strong risk to injectivity. There are no permeability or injectivity data available for this study, so the injectivity of the Sherwood Sandstone Formation in closures with and without significant bounding faults should be further assessed prior to CO_2 injection.

3.8.3 Conclusions: Larne/ Portpatrick

The Larne Basin may have a significant theoretical CO_2 storage potential, but major risks include the depth of the Sherwood Sandstone across the basin, the possible lack of suitable closed structures and possible interference of injected CO_2 with potential potable water supplies. In addition, key monitoring datasets (4D seismic) may be severely compromised by geological conditions. Further major data acquisition and analysis would have to be undertaken to reduce uncertainty before onshore storage could be contemplated.

In the Portpatrick Basin closed structures filled in the Sherwood Sandstone Group of the have potential theoretical storage capacity, limited by the restricted dimensions of the structures. The Mercia Mudstone caprock, where intact, is likely to form an effective seal to stored CO_2. If injectivity can be successfully demonstrated, CO_2 storage may be viable. Individual storage sites in the basin would have to be studied more closely via a detailed site characterisation, with particular reference to fault seal capacity and injectivity.

Subject to the caveats of the risk analysis above, the geological analysis indicates that a storage site(s) at Portpatrick in the North Channel could provide 2200 Mt theoretical storage capacity, with 37 Mt of effective storage capacity in closed structures in the Sherwood Sandtone saline aquifer. Portpatrick could theoretically service Kilroot for 10 years in the effective capacity in the closed structures or up to 50 years if say, 10% of the theoretical storage capacity could be proven up.

Risks were considered for Portpatrick using FEPs (frequency, events, processes) analysis, but at present is significantly less well understood than Kinsale and its associated risks of ineffective containment are therefore considerably higher. Significant and costly studies, including drilling, will be required to move it up the techno-economic resource pyramid to 'matched capacity'. Our economic modelling in Chapter 7/ Annexe 2 allows for €100 milllion to conduct such studies.

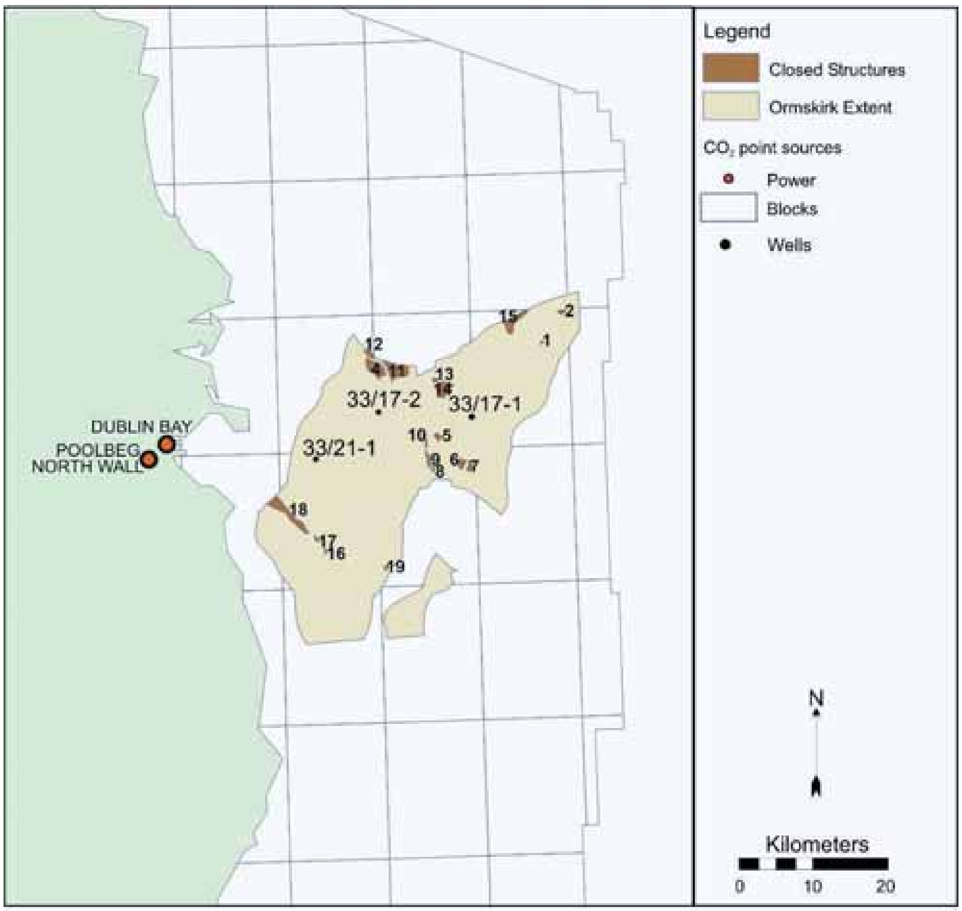
3.9 Outline Risk Assessment of the SSG Saline Aquifer of the Kish Basin

The Kish Bank Basin is located offshore approximately 20km east of Dublin in the western Irish Sea (Figure 17), in water depths of up to 100m.

Some 30 by 40km in extent, it is one of a series of basins likely to be remnants of a larger Permo-Triassic basin system, termed the Greater Irish Sea Basin (Dunford et al. 2001), that may have extended across the whole of the Irish Sea. The basin forms a NW-dipping half graben divided by the Codling Fault Zone and separated from the Central Irish Sea Basin by an area of outcropping Carboniferous strata. The basin is bounded to the NW by the NE-SW trending Bray and Lambay faults.

Triassic rocks can be correlated from the Kish Bank Basin to the East Irish Sea Basin, both basins having a similar depositional and tectonic history. In consequence, the Kish Bank Basin could be expected to have a similar potential for oil and gas as the East Irish Sea Basin.

Figure 17: Location of the Kish Bank Basin, defined by the extent of the Ormskirk Sandstone



The main reservoir is the Early Triassic Sherwood Sandstone Group (comprising the Ormskirk Sandstone and St. Bees Sandstone formations), sealed by the overlying Mercia Mudstone Group. The St. Bees Sandstone Formation contains mainly sandstone with some pebble beds and conglomerates. The Ormskirk Sandstone Formation consists of aeolian and fluvial sandstone with interbedded shales. No gas has been discovered in the Kish Bank Basin, so the Sherwood Sandstone Group provides potential for saline aquifer CO_2 storage. Other potential reservoirs include the Permian Collyhurst Sandstone and Carboniferous sandstones.

Table 12: Known reservoir properties of the Sherwood Sandstone Group in the Kish Bank Basin

Porosity	14-18 (silicified zone 8%)
Permeability	No data
Average thickness reservoir	240 m
Typical thickness seal	535.7 – 1122 m
Average depth to the top of the reservoir	1166 m
Net to Gross reservoir	66 – 88 %

In total 19 closed structures were identified by BGS across the Kish Bank Basin (Figure 17), filled with saline pore waters (Bentham et al. 2008). These structures were estimated to have a total storage capacity of 267 Mt (Table 13).

Table 13: Closures identified in the Sherwood Sandstone Group of the Kish Bank Basin, with the depth to the crest of the closure and the estimated CO2 storage capacity

Closure ID	Mapped Depth (m)	Theoretical storage capacity at 40% pore space saturation (MT)
1	500	0.27
2	500	1.03
4	750	41.07
5	2000	6.59
6	1000	11.78
7	1250	7.35
8	500	0.47
9	250	0.81
10	500	0.47
11	1750	52.52
12	2000	8.91
13	1750	3.09
14	1250	34.52
15	1500	36.33
16	1750	1.50
17	1750	2.77
18	1750	57.23
19	250	0.22
	Total	**266.94**

3.9.1 Risk Assessment for the Kish Bank Basin

Containment risks

The depth of the Sherwood Sandstone Group across the Kish Basin varies between 250m – 3250m below the seabed, with a large area lying at depths less than that at which CO_2 would remain in its liquid phase, approximately 700m dependant on the reservoir conditions. In the Kish Bank Basin the density of CO_2 at a depth of 250m is calculated to be around 63 kgm^{-3}, compared with a calculated density of ~744 kgm^{-3} at 750m.

Storage at depths less than 700m would therefore be considered risky due to the higher buoyancy and mobility of CO_2 at these shallower depths, and also the smaller overburden column available to contain the CO_2.

Following this reasoning, closures 1, 2, 8, 9 and 10 (Table 13), in the Sherwood Sandstone Group are probably too shallow for CO_2 storage to be considered at these sites. In any case, estimated storage capacities for these closures are low, reflecting the low density of the CO_2 at these depths. Closure 4 would be considered to lie at the shallow end of the viable storage window, comparable to the depths of storage in the Utsira Sand at Sleipner (Chadwick et al. 2004).

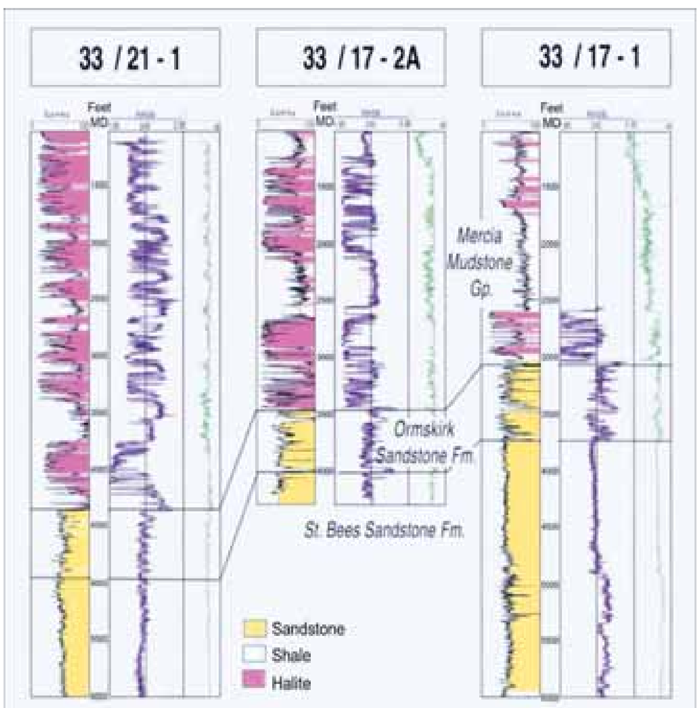
Geological Seals

The immediate topseal of the Sherwood Sandstone Group is formed by the Mercia Mudstone Group (Figure 19). It comprises interbedded halites and shales of the Lower Keuper Marl, Lower Saliferous Beds, Middle Keuper Marl, Upper Saliferous Beds and the Upper Keuper Marl. The unit shows significant lateral thickness variation, being much thinner in well 33/17-1 (535.2 m) than in well 33/21-1 (1122 m) to the south (Figure 18).

The shale units of the Mercia Mudstone Group would be considered likely to form an effective seal by themselves. In addition, halite is considered to be an excellent seal to CO_2 as it has little or no permeability and has ductile physical properties that would tend to anneal (seal) any faults which may cut the succession. Halite contents of the Mercia Mudstone Group vary from 33 % in well 33/21-1, through 30 % in well 33/17-2A to 16% in 33/17-1 (Dunford et al. 2001). In the latter well, where the halite content of the section is less, the halite beds are concentrated towards the base of the section and would therefore still act as an effective topseal to the Sherwood Sandstone Group. The stratigraphy of the Mercia Mudstone Group in the Kish Bank Basin can be correlated with that of the East Irish Sea Basin, where it forms an effective seal for oil and gas in the Ormskirk Sandstone Formation and has presumably done so on geological timescales.

It is therefore concluded that, at least in an intact (unfaulted) state, the Mercia Mudstone Group would form an effective seal to CO_2 stored in the Sherwood Sandstone aquifer of the Kish Bank Basin.

Figure 18: Kish Basin: Log correlation of the Mercia Mudstone Group and Ormskirk Sandstone Formation section from three wells



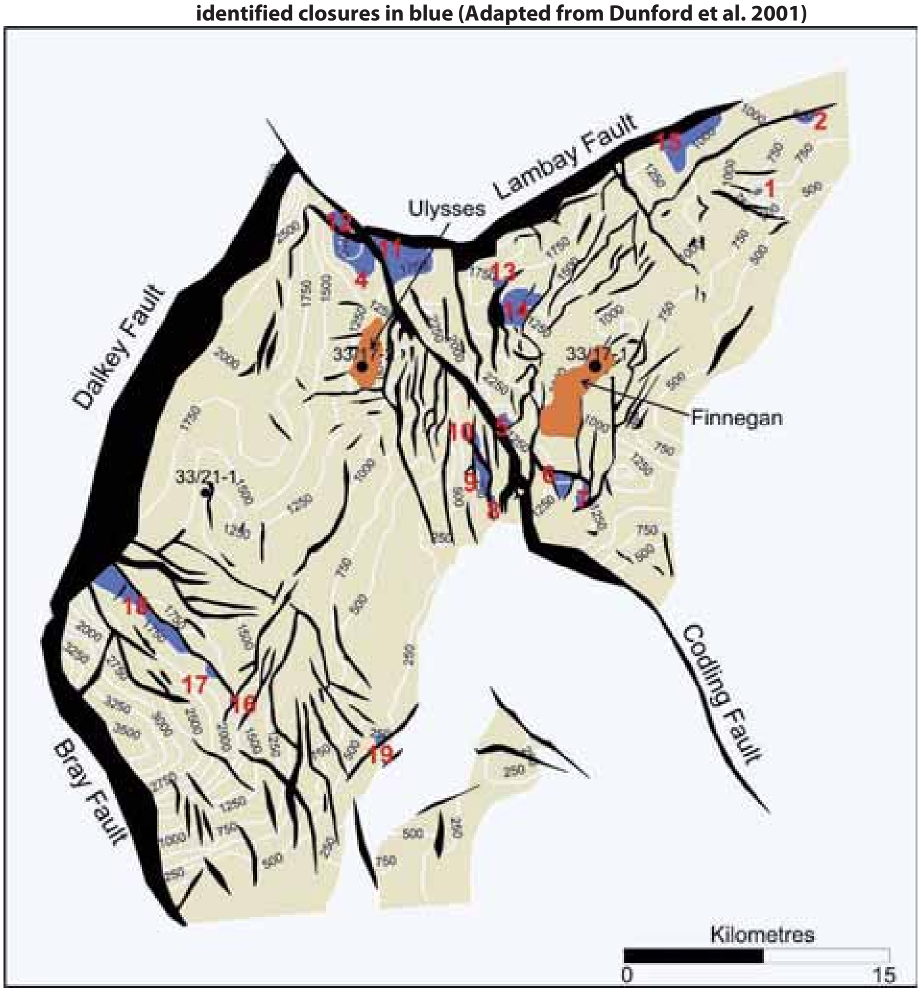
The Mercia Mudstone has a 33% halite content in wells west of the Codling fault and 16% in well 33/17-1. Shale content in the Ormskirk Sandstone increases from west to east. *Adapted from (Dunford et al. 2001)*

Faulting

The Kish Bank Basin forms a faulted northwest-dipping half-graben (Figure 18). The basin is bounded to the northwest by the Dalkey Fault, to the southwest by the Bray Fault and to the northeast by the Lambay Fault. To the southeast, the basin limit is formed by stratigraphical onlap against the Mid-Irish Sea Uplift. The northwest-trending, strike-slip Codling Fault divides the basin into two (Figure 19).

There are numerous minor faults in the southwest part of the basin, roughly parallel and antithetic to the Bray Fault. The central part of the basin is relatively unfaulted, except for scattered faults antithetic to the Dalkey Fault. The eastern part of the basin has closely spaced, north-south trending faults on both sides of the Codling Fault, which form tilted fault block closures tested by wells 33/17-2A and 33/17-1.

Figure 19: Structure of the top Sherwood Sandstone Formation in the Kish Bank Basin with identified closures in blue (Adapted from Dunford et al. 2001)



Croker et al. (2005) have documented evidence of gas seepage in the area of the Codling Fault Zone. The study used detailed shallow surveys including multibeam echosounding, sidescan sonar, video truthing and seabed sampling, combined with conventional seismic data to find evidence of gas migration in the Kish Bank Basin. Multibeam echosounding images the Codling Fault as a well-defined east-facing scarp, with a number of mound-like structures in its the central part. The mounds appear to be aligned along a curvilinear fault trend, with in total, 23 mounds identified. ROV video surveys and seabed sampling showed the mounds to be composed of carbonate-cemented sandstones. Contemporary gas seepage has been documented from some mounds on echosounder records. Vertical gas migrations via faulting has been confirmed by high resolution seismic data and have been linked to some of the mounds on the seabed. The epicentres of two minor earthquakes were recorded in the Codling Fault area in 1982, suggesting that some parts of the fault system are still active (Croker et al 2005). Evidence of gas seepage on the Lambay Fault and on other large faults in the basin has also been recorded but not fully investigated. Croker et al. concluded that evidence from the combined datasets suggests a strong link between mounds and gas migration along faults. However the provenance of the migrating gas has not been established, whether it has a shallow biogenic origin, or has a deeper source, indicative of migration from reservoir depths. The conclusion of Croker et al. is that the evidence points towards a thermogenic source for the gas since the distribution of gas leakage is not confined to any particular sediment type: in the north of the area most of the gas escape features are situated where Carboniferous subcrops the Quaternary or where migration routes from the Carboniferous via faults are present. In the south of the area, gas seepage seems to occur where migration pathways, commonly faults, exist in the Jurassic or possibly Carboniferous source rocks. Geochemical testing of the escaping gas would help confirm the source.

Irrespective of the gas provenance, it would be prudent to avoid utilising storage sites close to or associated with the Codling Fault Zone, due to the potential risk of the faults acting as migration pathways for gas to the sea bed. CO_2 storage in the central part of the Kish Bank Basin where density of faulting is low may be less of a risk in terms gas migration and leakage via faults.

As most of the closures identified for this study are fault-traps, they would need to be subjected to a rigorous site investigation to ensure there is no risk of CO_2 leakage via the faults forming the structural closures. As mentioned above, it is worth bearing in mind that the thick halite units of the Mercia Mudstone Group would be expected to generally seal faults by virtue of the inherently ductile behaviour of salt. So, particularly where the faults can be shown to be small, the chances of their posing a significant containment risk is probably quite low.

Geomechanical

Pressure increase produced by the injection process has the potential to induce structural perturbations within the caprock, including the reactivation of old faults and the formation of new fractures. In aquifer storage, as would be the case at Kish Bank, the necessity to displace *in situ* formation waters by injected CO_2 has the potential to increase reservoir pressures significantly. Pressure increase under CO_2 injection is primarily a function of reservoir thickness and permeability. In the case of the Sherwood Sandstone, thickness (> 200 m) is not an issue, but permeability may well be. This study does not have access to measured permeability data for the Kish Bank Basin, but porosity data is available and this can be used to derive a rough estimate of permeability. Porosity-permeability relationships from the Sherwood Sandstone in the UK (BGS data) indicate that porosities in the range 14 – 18% (Table 12) would be roughly consistent with permeabilities in the range 5 – 100mD. A cautionary lower limit for large-scale aquifer injection is generally reckoned to be around 100mD, so the likely permeability range in the Kish Bank Basin would require careful consideration. For permeabilities towards the lower end of the putative range, it is likely that the injection of CO_2 at industrial rates (> 1 Mt/year or so) would raise formation pressures significantly, possibly close to the fracture pressure. Prior to full injection therefore, both core and dynamic permeability data should be acquired via a test well and test injections. Numerical flow simulation of injection pressures linked to a geomechanical assessment should also be carried out.

Geochemical

A possible longer-term effect on caprock efficacy results from chemical reaction of the CO_2-water-system with the caprock lithologies. Modelling and experimental studies elsewhere, suggest that these are likely to be small, particularly if migration of CO_2 into the caprock is purely diffusive. On the other hand, induced migration pathways may allow capillary access of free CO_2 to the caprock, which could pose a more significant containment risk. However, where caprock lithologies are dominantly clay minerals and siliciclastics, (as is the case in well 33/17-1) any minor geochemical reactions that might occur would commonly tend to reduce overall permeability (Chadwick et al. 2008). The immediate reservoir topseal in wells 33/17-2A and 33/21-1 is in fact halite. The potential geochemical effects of CO_2 on evaporites (including halite) in the caprock are addressed in Chadwick et al. (2008). Modelling studies indicate that CO_2-rich formation waters will not dissolve halite, indeed, the general reactive tendency is for minor net mineral precipitation which would tend to seal potential fluid pathways.

Man-made Seals (wells)

Wells are generally perceived to pose the greatest containment risk in geologically well-characterised storage reservoirs. They commonly have imperfect completions, with poor bonding between the borehole casing and the surrounding country-rock. Poor completions pose a significant short, medium and long-term containment risk, particularly within a shallow reservoir, where CO_2 would not have to migrate very far up the wellbore before passing into the gaseous state where mobility and buoyancy increase markedly.

Only three wells (believed to be the case) have been drilled into structures within the Kish Bank Basin. Provided that injection strategies are planned such that these are avoided, the risk of CO_2 migration via existing wells is considered to be low.

3.9.2 Injection Issues

The simplest injection strategy into a closed structure would be to inject into the crest of the structure. The downside of this would be subjecting the caprock to the high dynamic injection pressures around the injection well. It would also maximise the amount of free, mobile (and buoyant) CO_2 trapped at the top of the structure by minimising CO_2 dissolution and residual phase trapping – again an unfavourable scenario.

An alternative injection strategy would be to inject into the flank of the structure via a new injection well, and allow the CO_2 to migrate up-dip to fill the closure. This also avoids the risk of compromising the topseal by installing a well at the highest point of the structure. Additional benefits include keeping elevated near-wellbore pressures away from the potentially vulnerable structural culmination. Another important benefit of injecting downdip is the consequence that the CO_2 would migrate a larger distance through the reservoir. This process exposes the CO_2 plume to increased volumes of formation water allowing dissolution and residual phase trapping. These two processes would work to immobilise CO_2 in the reservoir and ultimately reduce the amount of free CO_2 accumulating high in the structural closure. Clearly such an approach would carry a heavier characterisation and performance assessment burden than injecting at the structural crest.

Many of the closures identified are bounded by faults. If these were to completely surround a storage closure, and were impermeable, preventing formation water from being expelled from the structure during CO_2 injection, this may well result in an unacceptable pressure increase during injection, preventing further CO_2 injection into the closure. In fact, because the Sherwood Sandstone Group is dominantly composed of a thick, quite clean sandstone, in all likelihood, most small to medium-sized faults in the reservoir would be reasonably permeable and would not constitute a strong risk to injectivity. There are no permeability or injectivity data available for this study, so the injectivity of the Sherwood Sandstone Formation in closures with and without significant bounding faults should be further assessed prior to CO_2 injection.

3.9.3 Conclusions : Kish Bank

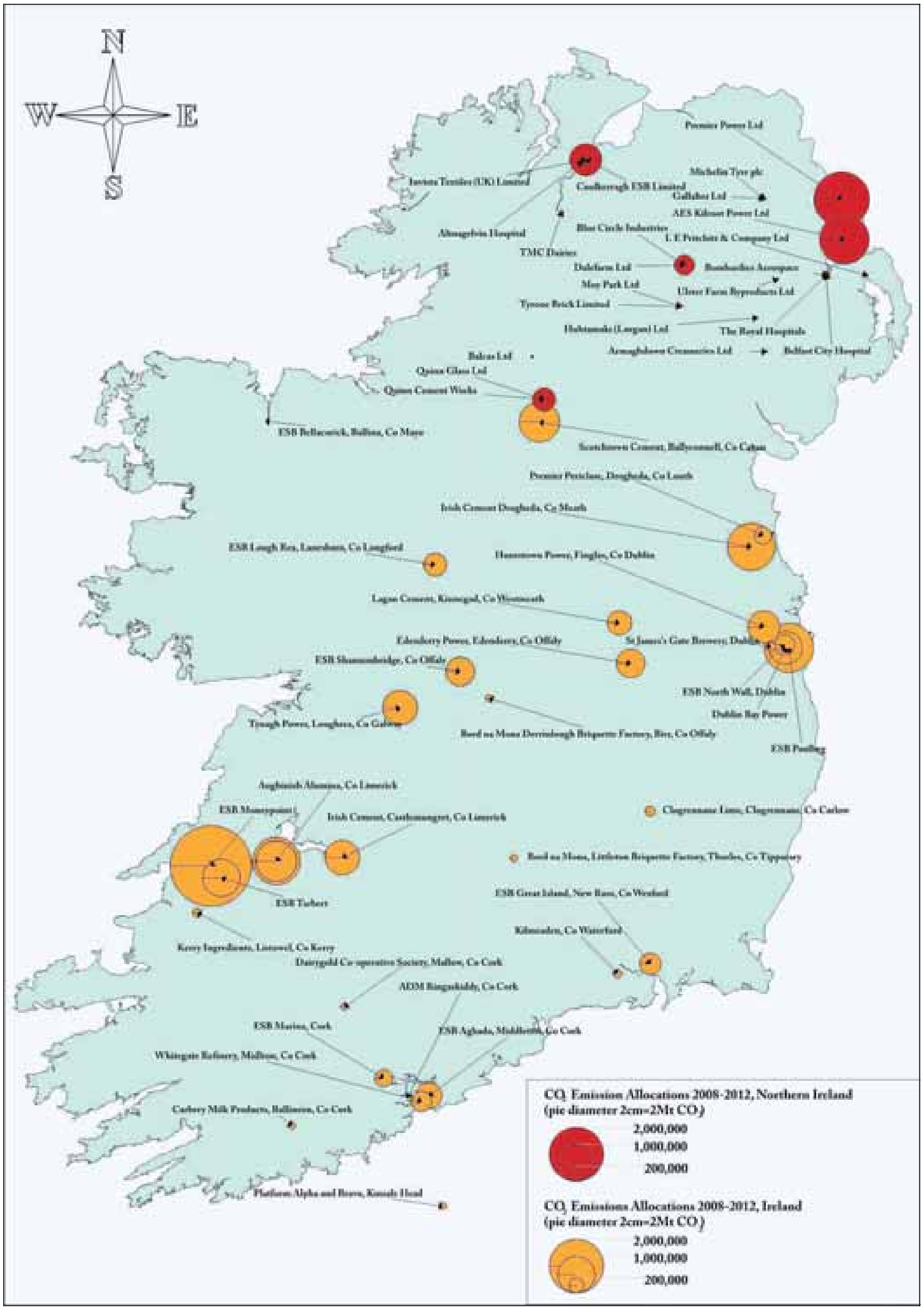
Closed structures filled with saline pore fluid in the Sherwood Sandstone Group of the Kish Bank Basin have a significant potential theoretical storage capacity. The Mercia Mudstone caprock, where it is intact, is likely to form an effective seal to CO_2.

Many of the structures however lie in close proximity to the Codling Fault Zone, along which there is evidence of contemporary gas seepage, suggesting it may act as a potential migration pathway for CO_2 stored in its vicinity.

If injectivity can be successfully modelled and verified through testing, storage of CO_2 in the relatively unfaulted areas of the basin may be a viable option.

- Individual storage sites in the basin would have to be studied more closely with a full site investigation before the risks of storage in the Kish Bank Basin can be fully understood.

Figure 20: National CO_2 Emissions Allocations (2008 to 2012)



4 POLICY & ECONOMICS OF CARBON CAPTURE

4.1 Policy Context

The drivers for considering reducing CO_2 emissions in Ireland using carbon capture and storage are self evident. The context for the study has been discussed in Section 1.3 of this report.

Technologies and costs which would be involved in building CCS infrastructure, including carbon capture technology, are examined below. An overview of the economic evaluation (Chapter 7/ Annexe 2) is presented below, based on best current evidence to evaluate whether on economic grounds the Governments should consider CCS as a valid part of future climate change strategy.

The starting point of this analysis takes the view that if CCS is to be viable then it must be proven to be economic at the largest single point sources on the Island to take advantage of economies of scale. This is turn suggests that the power sector is the primary target for CCS evaluation.

There is constant growth in electricity demand. The projected All Island demand by 2014 is 45,000 GWh, representing a growth rate of ~ 3% from now to 2014. Thereafter further demand growth of 2 to 3% pa from 2014 to 2020 is expected according to recent discussions with CER. Thus on an all-island basis electricity demand by 2020 is likely to be in the range 50,000 to 54,000 GWhrs.

4.2 Clean Coal vs. Other Options

In order to make any serious inroads into the CO_2 emissions from power generation there are a number of options:

(a) Greatly increase the % of electricity consumed which is manufactured from renewable resources;

(b) Reduce electricity demand by aggressive conservation measures in the domestic, commercial and industrial sectors of the economies both North and South. However conservation efforts have been ongoing for several years and it is likely that some element of conservation is likely to have been factored into the business as usual growth projections by CER and in the Generation Adequacy Reports.

(c) Increase the amount of gas fired electricity on the generation portfolio and close coal fired stations;

(d) Install carbon capture and storage to decarbonise power generation.

(e) Import power from UK interconnectors.

Plans are in well hand to ensure that objective (a) is progressed. The projection is that 15% of electricity in the Republic will be generated from renewables by 2010.

It is noteworthy that the option to deploy significant additional offshore wind and wave resources is being actively incentivised by the Government in Ireland and in our view the incentive prices being offered for electricity from these new technologies are very pertinent when examining the likely economic cost of power from clean coal plants with CCS and the economics of CCS in Ireland.

Energy conservation initiatives are also ongoing and are likely to intensify as the price for carbon emissions is set to increase progressively and this route may contribute significantly to tempering demand and arresting growth.

Option (c) - a policy of increasing the Island's dependency on gas fired power stations - is seen as posing a major security of supply challenge in the absence of new indigenous natural gas finds.

Clean coal thus presents an interesting alternative to the Governments. Currently the Island has 1300 MWe of installed coal fired power plant situated at two locations one North and one South. These plants are seen as critical to ensuring a continued diversity of fuel sources for power generation and have recently been upgraded with flue gas desulphurisation technology and are reported to be capable of operating up to 2020 and for 4-5 year beyond. Up to recently coal was also the most economic fuel for power generation, but coal prices have begun to escalate recently.

Hence, depending on the relative cost of coal to gas, coal-based CCS projects have the potential, on the face of it, to help to decarbonise power production while at the same time maintaining or even enhancing fuel diversity in the power generation fuel mix. The purpose of this section is to examine what costs might be incurred by the economies by incorporating CCS into all-island Ireland's plans for the power and possibly then for other sectors.

4.3 Matching the Scale of any CCS project to Ireland's needs

The three sectors which have the largest emissions (see Table 14, Figures 21, 22, 23) are as follows:

- The power sector (15 Mt in Ireland and ~4.5 Mt in Northern Ireland)
- The cement sector (4.1 Mt in Ireland and ~ 0.7 Mt in Northern Ireland)
- Alumina Production (1.6 Mt in Ireland)

Table 14: Concentration of Point Source CO_2 Emissions by Region, all-island Ireland

Concentration of Point Sources of CO_2 by Region	***Source Sectors***	***Million Tonnes CO_2 per year (Mt actual)***	***Nearest Potential Storage Basin (not geologically ranked)***
Shannon Estuary	Power Sector, Cement and Alumina Industry	9.7	Clare Basin (on/offshore) Kinsale Basin
Dublin City and Huntstown	Power Sector and Industry	5.5	Kish Basin East Irish Sea Basin
Belfast	Power Sectors and Industry	4.8	Larne/ Portpatrick (on/offshore)
ROI Midlands	Power Sector and cement	3.2	Northwest Basin (onshore)
Cork & Cork Harbour	Power sector and Oil Refining	1.8	Kinsale (offshore)
Drogheda / Platin	Cement and Periclase	1.6	Peel Basin (offshore) Kish Basin (offshore)
Cavan Monaghan	Cement	1.1	Northwest Basin (onshore)
Londonderry	Power and industry	0.6	Donegal – Malin Rathlin – Foyle (offshore)
Fermanagh Tyrone	Industry	0.5	Northwest Basin (onshore)
TOTAL all-Island Ireland		**28.8 Mt**	

Figure 21: Carbon Emissions Allocations 2008-2012, Northern Ireland (Source: DEFRA)

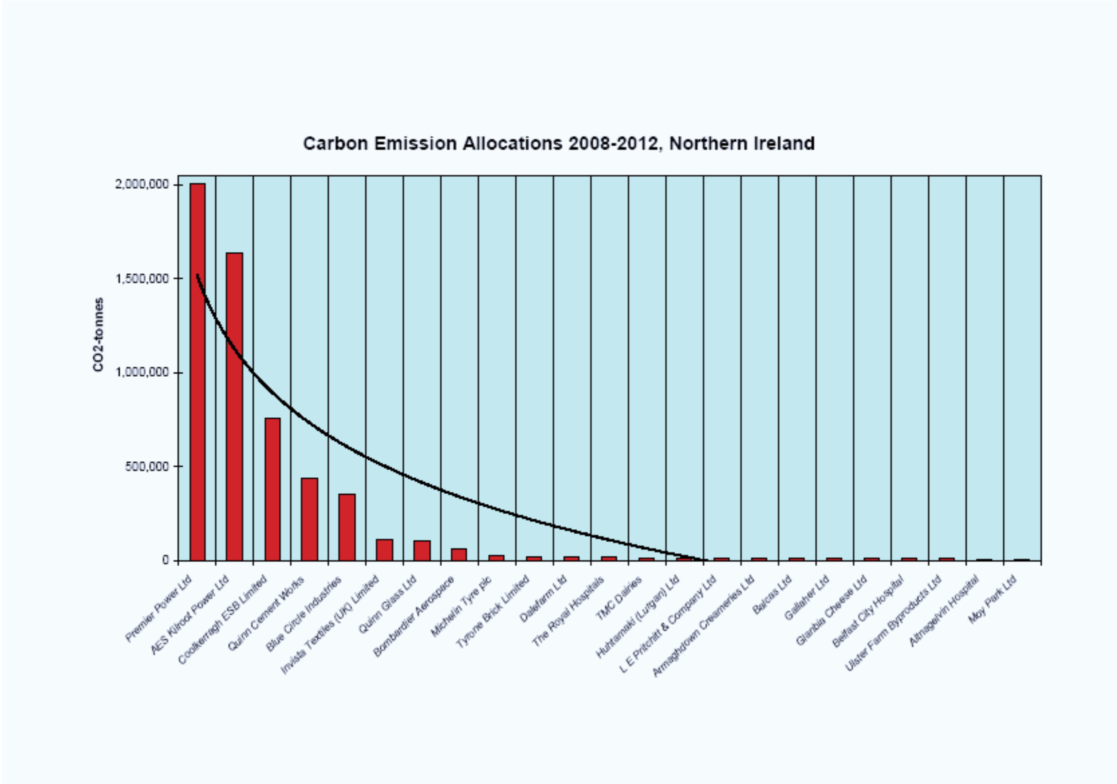
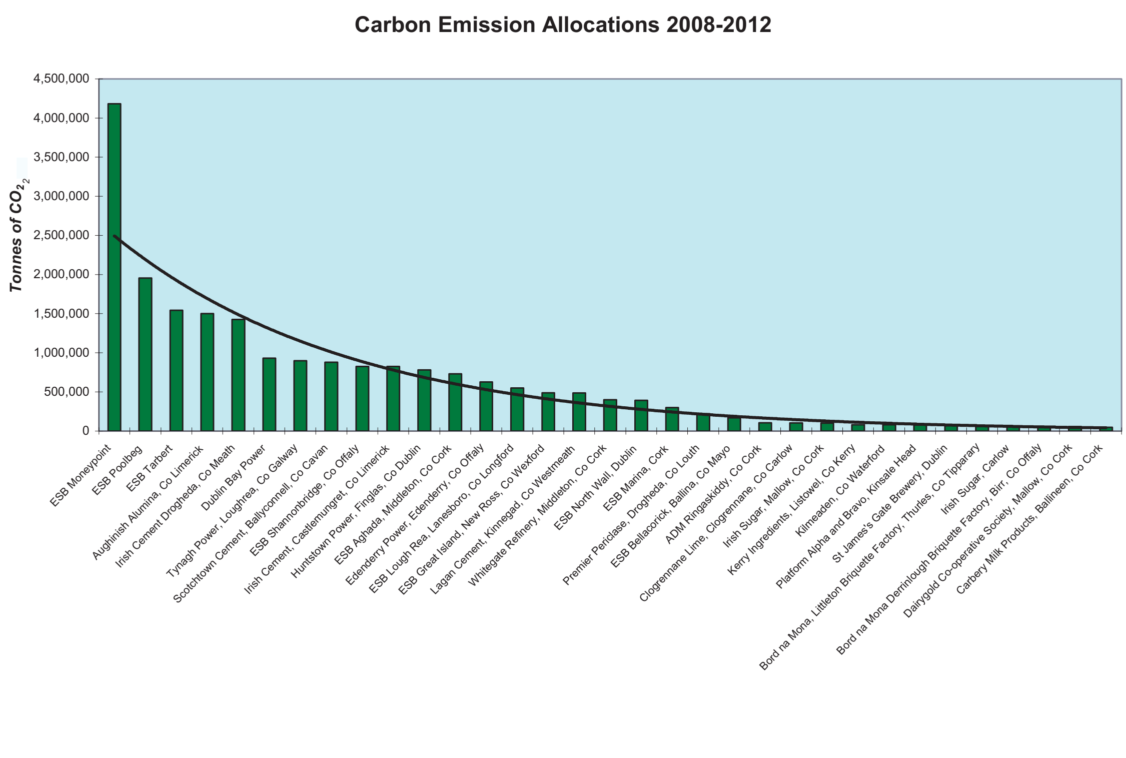


Figure 22: Carbon Emissions Allocations 2008-2012, Republic of Ireland (Source: EPA)



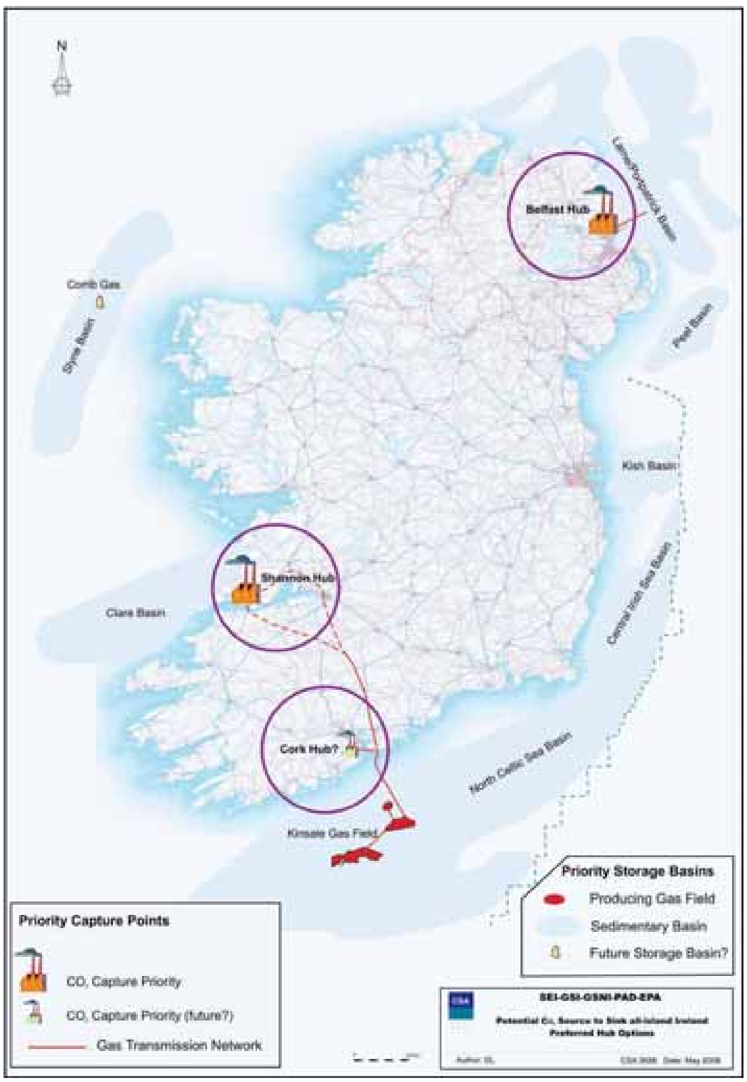
Based on economies of scale the two major emission points considered initially are Moneypoint and Kilroot with 5.0 Mt and 2.4 Mt of CO_2 emissions from their respective coal fired power plants.

Initially scenarios for new build coal fired power plants located at Moneypoint and Kilroot were considered with their electricity outputs sized to match the existing export transmission capacity.

A 900 MWe unit operating at 85% load factor at Moneypoint would contribute ~ 6700 GWh of electricity annually or some 12% of all island demand in 2020 with a 540 MWe unit at Kilroot contributing 7%.

If our analysis were to show that under these scenarios CCS proved to be uneconomic then, in our view, it is highly unlikely that smaller CCS projects would be economic at other sites on the Island. Thus the study focussed on three possible key scenarios: Moneypoint and Cork to Kinsale basin, and Kilroot to the Portpatrick Basin.

Figure 23: Potential CO_2 source to sink all- island Ireland preferred hub options



4.4 Investment Timescale for CCS and Implications for Technology

The ESB Moneypoint Power Station with its 845 MWe export capacity (following the installation of flue gas desulphurisation) will continue to be the largest single point CO_2 emission point on the island of Ireland with the average emissions projected to be in the region 5.0 Mt CO_2 per year for the foreseeable future out to 2020 and beyond.

The coal fired power plant at Kilroot has a capacity of 404 MWe when firing coal and its anticipated CO_2 emissions from the coal fired units will be ~ 2.4 million tonnes per annum.

These two existing coal fired power stations are the most likely sites in the medium term for locating viable carbon capture projects post-2020, primarily due to the existing coal importation facilities and the electricity transmission lines in place for an aggregate of 1444 MWe of export to the grid.

Notwithstanding this view, it is possible that smaller demonstration projects (albeit with somewhat inferior economics) on these sites or on other sites elsewhere on the Island could be considered by the Governments at an earlier date than 2020. Other site options could include, for example, CCS at the new CCGT power stations in Cork area or a new gasification project at Whitegate Refinery based on future pet coke production or a new coal fired plant in the Cork area. The project timescale for any project is likely to be ~ 8 years.

All projects at Moneypoint or Cork Harbour would be contingent on proving up the Kinsale Basin as a viable storage location. Section 3.7.3 above outlines a work programme costing €15 million, which would be needed to move Kinsale from its current probability status of 70% (P70) of containing CO_2 safely in the long term to a probablility status of 90% (P90), where investment plans for infrastructure costing up to €3.0 billion could be contemplated.

In a similar manner if the storage site at Portpatrick can be proven up at an earlier date than 2020 a demonstration scale project could be examined for Kilroot area. However the logic of Ireland investing in a sub economic demonstration project would need to be debated.

4.5 Optimum Capture Technology for Ireland

There are several variants of the CO_2 capture technology.

The most technically proven at this time could be said to be Post Combustion capture using solvent absorption as a means of separation. This technology has been used in a very similar format for CO_2 separation in fertiliser production plants for 40 years. It has not however been applied to large scale power plants. There are several process licensors promoting this technology and it is the one most familiar to and favoured in Australia as the basis for assessing CCS projects (see Section 2.5, Figure 3: Carbon Capture, Transport & Storage projects, Australia (by end -2007)

Integrated Gasification and Carbon Capture (IGCC) technology is developing rapidly. It has the advantage of producing the CO_2 at the back end of the process at a much higher pressure than the Post Combustion capture processes which operate at ambient pressure. Because of this IGCC has the potential for much lower energy penalty than Post Combustion and it is likely that this will provide added impetus to this route.

Given the EU's plans for 12 demonstration plants it is likely that most or all capture technology variants will be progressed over the next 5-7 years.

It is not imperative that Ireland selects a "winner in capture technology" at this precise time in the process. Ireland does not need to demonstrate a commercial scale CCS technology before the selected technology has been proven at a commercial scale and is thus ready to be deployed on a commercial and economic scale worldwide. This hurdle probably means a need for a proven demonstration on a power plant of > 400 MWe net output after capture. It is noted that the EU has a stated objective to have ~ 12 such projects running by 2015 to demonstrate different technologies in

the carbon capture chain. It should be noted that, even if this is achieved, not all of these plants or elements of the CCS chain will have application in Ireland.
There may be a case for Ireland to elect to become one of the dozen pre-2015 EU Demo projects. However, this would need careful assessment, given the high costs and risks involved in committing major (either public or private) funding to a research project to optimise capture technology prior to clear definition of suitable geological storage space in Ireland (see also Section 1.3.3 above).

4.6 Cost Build-up of CCS Projects in Ireland

The ESB has recently announced plans to consider a 700 MWe clean coal plant at Moneypoint sometime post 2025 i.e. once the existing plants are at the end of their useful life. The cost indicated was €1 billion. This is in the range of costs identified by this study for the power station element of a given project (see Chapter 7 below).

4.6.1 Retrofitting vs. New Build

Based on team discussions with IEA in Q1 2008, it was advised that retrofitting of capture to the older generation of existing coal fired power plants such as those at Moneypoint and Kilroot is considered very unlikely to prove economic due to lower efficiency of these older plants compared to the modern coal plants now being built.

When taking into account the energy penalties for the capture technology (see Tables 15, 16 below) and the energy for CO_2 compression, it is understood from the IEA's recent work that retrofitting carbon capture to existing older coal fired plant is likely to be double the projected cost per tonne of CO_2 of new build coal plants.

However, a caveat must be added that the IEA work on which these views were based predated the recent rapid escalation in the cost of coal, oil and natural gas. Thus, it may be prudent, if the Government wishes to pursue CCS on an ongoing basis, to periodically test these broad assumptions by more detailed engineering studies for both new build and retrofit.

4.6.2 Costs for New Build Clean Coal Projects

For the present, this study has focussed on new build, large scale, coal fired power plants which, in our view, will provide the best prospect for achieving an economic CCS project, subject to the many other factors which impinge on project feasibility. The most important immediate factor appears to be the geological viability of injection and storage in a location on or offshore the Island. Kinsale presents the best short term (<10 years) option, subject to further geological analysis and full reservoir simulation.

Following discussions with IEA on the subject of retrofitting, this study has focussed on the economics of CO_2 capture at three locations, as follows:

- a new build 900 MWe coal fired power station at Moneypoint with storage at Kinsale,
- a 540 MWe power plant at Kilroot with storage at Portpatrick, and
- a 900 MWe power station in the Cork region (not site specific) and with storage at Kinsale.

It should be noted that the power station itself is only one element of the capital cost of the CCS overall project.

The capital cost of an integrated CCS project from source to storage includes:

- The cost of proving up the storage site (speculative up front expenditure)
- The cost of the power plant,
- The cost of the capture plant
- The cost of the plant for compression of CO2 to pipeline pressure.
- The onshore transmission pipelines
- The offshore transmission pipelines
- The Injection and Monitoring Infrastructure

- Decommissioning

For a clean coal power plant exporting 900 MWe to the grid at Moneypoint and fitted with carbon capture technology with storage at Kinsale Head, the indicative project cost build-up is shown in Table 15 (total costs) :

Table 15: Indicative Cost Breakdown of 900 MWe Export Plant at Moneypoint (total)

Project Element	Costs in 2008 Euros (millions)	% of Total Project	% by Segment
Coal Fired Power Plant (1160 MWe)	1590	55.0%	71% Capture
Carbon Capture Plant	372	12.9%	
CO_2 Compression	74	2.6%	
Overland Pipeline	159	8.0%	8% Transport
Offshore Pipeline	72		
Storage Site Evaluation Costs [68]at Kinsale Basin	80	2.8%	4.3% Storage
Injection and Monitoring Infrastructure	37	1.3%	
Decommissioning (Abandonment costs)	101	3.5%	3.5% Decommission
Contingency	247	8.5%	8.5% Contingency
Owners Costs	161	5.6%	5.6% Other
Total	2893	100.20%	**100%**

Source: This study - CO2CRC Technologies & UNSW Rpt 08-1063, Annexe 2, unless otherwise specified

The cost breakdown for a new build 540 MWe power plant at Kilroot with storage at Portpatrick Basin is shown in Table 16 (total costs):

Table 16: Indicative Cost Breakdown of 540 MWe Export Plant at Kilroot (total)

Project Element	Costs in 2008 Euros (millions)	% of Total Project	% by Segment
Coal Fired Power Plant (697 MWe)	1033	48.9%	62.4% Capture
Carbon Capture Plant	220	10.4%	
CO_2 Compression	65	3.1%	
Overland Pipeline	0	3.1%	3.1% Transport
Offshore Pipeline	65		
Storage Site Evaluation Costs[69] Portpatrick Basin	100	4.7%	16.3% Storage
Injection and Monitoring Infrastructure (new platforms)	246	11.6%	
Decommissioning (Abandonment costs)	101	4.8%	4.8% Decommission
Contingency	174	8.24%	8.2% Contingency
Owners Costs	113	5.4%	5.4% Other
Total	**2117**	**100%**	**100%**

Source: This study - CO2CRC Technologies & UNSW Rpt 08-1063, Annexe 2, unless otherwise specified

According to the international literature the economics of CCS are dominated by the power plant and capture investments. This is consistent with the findings of the CO2CRC costing model in the above Tables which show that ~ 62-70% of the capital costs relate to the power station, capture plant and CO_2 compression.

[68] Based on estimates of 2007 hydrocarbon industry exploratory programmes and costs, Ireland and UK.
[69] See Note above

On this basis we would expect that the economics outlined for Moneypoint and Kilroot scenarios would be closely mirrored at other locations for coal based plants of a similar scale. It would be expected that there could be somewhat higher costs at some sites for the provision of new electricity transmission lines and a coal importation berth for a new power plant in Cork, but this could be countered by shorter onshore pipelines to the Kinsale storage site than would be the case for Moneypoint.

The differences between the main project elements can be seen by examining Table 15 and Table 16 above for the Moneypoint 900 MWe clean coal plant (which assumes using the existing Marathon Platforms and the 540 MWe (export capacity) Kilroot to Portpatrick project. As can be seen, the Kilroot project requires significant investment in new offshore platforms at the Portpatrick basin, as well as deeper investigation of geological storage sites, which are not required for the Kinsale storage options.

4.6.3 Moneypoint/Kinsale Storage Scenario

The scale of new a build plant considered as a base case scenario at Moneypoint was a power plant with an export capacity of 900 MWe. This matches the current transmission export capacity. The most likely current storage location for CO_2 from Moneypoint is considered to be the Kinsale Gas Field based on the data availability.

It should be noted that the Clare Basin is much closer to Moneypoint and, were that basin to be proven as a viable storage location in the longer term (10 years plus), there would be savings on pipelining costs. Piping to Kinsale will require 185km of underground pipeline and ~ 55 km of offshore pipeline. Storage in the Clare Basin (assuming onshore injection) would represent a saving of some €200 million on pipelines compared to a Kinsale storage scenario. However, the geological analysis (Annexe 1) suggests that much of the onshore portion of the Clare Basin may be too shallow for effective supercritical storage of CO_2. Further deep geological studies are required to ascertain its capacity.

4.6.4 Kilroot / Portpatrick Scenario

The scale of projects considered for Kilroot is in the range of 540 MWe. The captured CO_2 from Kilroot would be stored in the Portpatrick Basin (yet to be proven) located a distance of ~ 30 km from Kilroot and requiring an undersea pipeline for its entire route.

The need for extensive evaluation expenditure is also highlighted by the cost tables above.

The scale of the individual elements of the CCS chain (as shown above) means that these relative costs are very important considerations in framing Government decisions on how best to progress CCS on the Island of Ireland, as well as on where to deploy public resources to develop the data needed to progress the concept.

4.7 Benchmarking the costs for CO_2 Avoided

Post-2012, the EU will require 100% auctioning of allowances for the power sector and so we expect that post-2012 power producers in Ireland will be competing with other EU power plants for the purchase of auctioned CO_2 allowances.

The anticipation is that the price of CO_2 allowances will increase from the current price of €26.4 per tonne CO_2 for December 2008 delivery. The expected trend of rising CO_2 cost will we believe provide a powerful driver for CCS depending on the price of CO_2 reached.

One recent EU reference suggests that economic evaluations should be based on €39 per tonne of CO_2 in the period to 2020. A recent survey by Point Carbon in 2008 indicated that many commentators expect a price in the region of €35 per tonne by 2020. This latter lower value of €35 per tonne has been used in this analysis.

In order to compute the true costs of CO_2 capture and storage on the island of Ireland, the Governments need to compare the costs for the full CCS chain with some logical alternative.

Traditionally, organisations such as the IEA and US DOE have computed the costs of CO_2 emissions avoided by computing the extra cost of CCS over and above the cost of the equivalent modern coal fired power station with the same export of power as the clean coal plant. Traditionally, however, the baseline analysis for these non-CCS plants did not include a cost for CO_2.

It is apparent that a coal fired plant without penalty for CO_2 is not a realistic baseline for the island of Ireland post-2012. Rather, the benchmark which this study uses to compare CCS scenarios is the cost of electricity generation from the CCS-based power plant with the power costs from a coal fired power station of the same export capacity as the CCS project, based at either Moneypoint or Kilroot, but assuming 100% purchasing of allowances for both the non-CCS plant and the residual emissions to atmosphere from the CCS project. Costs for CCS-based power with other electricity cost benchmarks in the Irish power system have been included.

It is assumed that by 2020 any fossil fuel based power station will have to purchase carbon allowances for the full CO_2 emissions. This situation may be compared with a requirement to purchase only 25% of emissions in the 2008-2012 (1st Kyoto Period) and so the cost of electricity is set to increase post-2012 to reflect the cost of CO_2 in the market place.

This study has computed the cost per MWh of electricity for a number of CCS scenarios and compared these with a variety of electricity costs in the Single Electricity Market.

4.8 Economic analysis

The key factors and assumptions which can impact upon the price of electricity from a clean coal CCS facility are as follows.

- The capital costs
- The price of coal in US$ per tonne delivered
- US$ to € exchange rates
- The reservoir permeability which determines the injectivity, hence the number of wells and capital cost of injection
- Fracture gradient
- Evaluation costs (costs to prove up storage viability)
- Project life (a function of basin capacity and annual injection rate).

The economic analysis was undertaken using a standardised IEA economic approach, using a standard coal LHV, standard discount rate etc.

4.8.1 Coal Price Assumed

The main analysis is based on a mid range delivered coal price of $90 per tonne. This is much higher (+50%) than the prices at which IEA and US DOE conducted their most recent assessment of the cost of CO_2 abatement by CCS, but nonetheless is well below the price which the staff at both Moneypoint and Kilroot indicated was the market price in Q1 2008 ($120 per tonne). In fact, prices as high as $150 per tonne have been quoted in coal trade literature in April 2008. In view of the recent oil prices of > $130 per barrel and the continuing current trend of rising coal prices, there is considerable uncertainty as to the appropriate coal price on which to base the core CCS scenarios[70]. To account for the current uncertainty in coal and other energy price trends, sensitivity analysis has been conducted over a wide range of coal prices from $60 to $175 per tonne. (See detailed economic case studies in Chapter 7 and Annexe 2).

4.8.2 CCS Power Prices vs. Prevailing Electricity Prices in Ireland

The comparative findings of the study on carbon capture are presented below (see Table 17).

---

[70] A recent study by Deutsche Bank in June 2008 utilised commodity price projections of Coal $90 per tonne; Oil $85 and Gas €8.9 per GJ to assess the likely future price of traded carbon. Thus the CSA study is utilising industry standards, but in recognition of the current volatility of commodity prices, sensitivity analyses have been built into the economic models for each Case Study (see Annexe 3 for full details).

Over a 25 year project life and using standard IEA economic analysis, a new 900 MWe pulverized coal fired power plant based at Moneypoint and storing 6.7 Mt CO_2 at Kinsale (with 4.71 Mt avoided) could deliver power to the grid at €91.6 per MWh based on coal at $90/ tonne with €35/ tonne price for carbon. A similar assessment for an equivalent sized new Integrated Gasification Combined Cycle coal fueled power plant could deliver power to the grid at €84.6 per MWh giving a reduction in operating costs due to the lower costs associated with the gas compression process. The costs for a pulverized coal and IGCC plant operating without CCS at Moneypoint with the full cost of carbon emissions applied at €35 per tonne would be €82.9 per MWh and €86.9 per MWh respectively. This indicates that an IGCC option for Moneypoint with CCS applied, with subsequent storage of emissions in Kinsale ,could be competitively priced in the future energy market. In applying this solution, Ireland could eliminate 4.25Mt of CO_2 per annum. Therefore a single project of this scale (900 MW either IGCC or PC based) could reduce national GHG emissions by 6%, which is equivalent to reducing Irelands CO_2 emissions from fossil fuel energy usage by 9%. Before any investment of this nature could be made, detailed assessment of geological storage sites is required and capture technology development must proceed and detailed design studies undertaken for the various scenarios, together with the development of new environmental regulations to provide sufficient certainty for would-be investors.

At present power stations are required to participate in the EU-ETS for the period 2008-2012 with allocations to each power generator decided by the EPA. Under the current Phase II of this scheme (2008 – 2012) power plants are given free allowances for ~ 83.5% of their projected CO_2 emissions over the period 2008-2012. Any emissions above this level must be purchased from another producer who has a surplus of credits via the EU-ETS trading scheme. The current price for these credits for delivery in December 2008 is €22 per tonne.

The long term goal of the EU-ETS is to ensure that eventually all emitters will pay the full price for their CO_2 emissions. Some commentators expect the price of CO_2 to rise to €35 per tonne by 2020. The results of this CCS study show that the avoided cost of CO_2 could range from €28 to €56 per tonne depending on the technology option chosen. These figures indicate that as power stations are eventually faced with the full burden of cost for their carbon emissions, it may be more cost effective for them to choose CCS rather than pay the price of their emissions.

The comparative cost of electricity (COE) including the cost of carbon credits, at a price of €35/t CO_2, with and without CCS, was modelled for nine cases in Table 37 below.

The COE for a power plant with CCS and no carbon price ranges from €80 - €109 / MWh, while COE with a carbon price ranges from €82 - €114/ MWh.

The study found these results promising for CCS as an option for the Governments.

As an interesting cross-comparison, ESB have reported that their blended cost of electricity generation in 2007 was €104 per MWh (per April 2008 press conference on €22 billion investment strategy). At the same press conference the delivered price including system use charges for distribution and transmission was given as ~ €151 per MWh.

The SEI April 2008 price for electricity to medium size industry was €144.8 per MWh.

Electricity from offshore wind will attract a price of €140 per MWh while the incentive price for wave power is €220 per MWh.

CCS-based power from Moneypoint is projected to cost significantly less than the price per MWh than that being offered to incentivise wave power and considerably below the incentive price of €140 per MWh for offshore wind power incentive price, which is highly significant. It is lower than the ESB's average 2007 generation price of €104 per MWh, which in itself does not reflect the full cost of CO_2 emissions, as a high percentage of emissions in 2007 were allocated free under the EU-ETS for that period.

Notwithstanding the uncertainties in relation to coal prices and capital costs this outcome appears to be a positive outcome for CCS given the huge infrastructural investments involved - some €2.9 billion

for the full power generation, CO_2 capture and compression, long distance pipelining and injection and storage at Kinsale.
Please note for the following table and discussion:

> *Calculation of Present Value (PV)*
>
> Many authors use the annualised specific cost, which is the equivalent annual cost divided by the annual tonnes avoided.
>
> In contrast, this study calculates the specific costs by dividing the present value of the costs by the present value of the tonnes avoided.
>
> The two approaches give identical answers.
>
> If the present value of the costs is calculated, then the present value of the tonnes avoided must also be calculated before one can be divided by the other. Given this approach, as an intermediate step in calculating the cost per tonne avoided, the present value of the tonnes avoided must be calculated.

Table 17: CCS Cost Estimate Summary of Selected Case Studies - *See Annexe 2 for Detailed Analysis and breakdown of costs*

	Moneypoint 900 MW_e PC	Moneypoint 900 MW_e PC Route B	Moneypoint 900 MW_e IGCC	Moneypoint & Cork Retrofit	Cork 900 MW_e PC	Cork 900 MW_e PC Offshore Pipe	Cork 900 MW_e IGCC	Cork 540 MW_e PC	Kilroot 540 MW_e PC
Case number	1A	1B	1C	1D	2A	2B	2C	2D	3A
Annual CO_2 avoided (million tonnes)	4.71	4.71	4.25	6.50	4.70	4.70	4.25	2.85	2.83
PV** of CO_2 avoided (Mt)	45	45	40	62	45	45	40	27	27
Total capital cost (€ million)	2,712	2,688	2,656	3,679	2,516	2,516	2,497	1,665	1,908
Operating Cost (€ million)	343	343	309	399	340	340	306	208	209
Abandonment cost (€ million)	101	94	87	162	54	54	50	50	108
PV of capital costs (€ million)	2,325	2,305	2,279	3,139	2,161	2,161	2,145	1,429	1,634
PV of operating costs (€ million)	3,262	3,265	2,935	3,795	3,235	3,235	2,909	1,975	1,992
PV of abandonment costs (€ million)	14	13	12	23	8	8	7	7	15
PV of power generated (TWh)	64	64	64	64	64	64	64	38	38
COE exported with CCS and no carbon credits (€/MWh)	87.9	87.6	81.9	109*	85	85	79.5	88.8	95.2
COE exported with CCS and carbon credits (€/MWh)	91.6	90.8	84.6	113.8	88.6	88.6	82.2	92.4	98.9
Comparative COE exported with no CCS but with carbon credits (€/MWh)	82.9	82.9	86.9	93.4	82.9	82.9	87.0	85.0	84.3

*This is the aggregated cost of electricity for four power plants.
** Present Value (PV)

The prices for power generation at Moneypoint are compared with other prices in the Irish market in Table 18.

Table 18: Comparative Prices for non-CCS Power Generation at Moneypoint with other elements in the Irish Energy Market

Technological Option	Price to Grid	Price Basis
Wave Power	€220	Incentive price from DCENR
Offshore Wind	€140	Incentive price from DCENR
Mixed power portfolio ESB	€104	Average ESB cost of generation in 2007 per press release
900 MWe CCS new build project at Moneypoint – storage in Kinsale	€91.6	This study Annexe 2: Price Model Coal at $90 per tonne, CO_2 @ €35 per tonne
900 MWe new build project at Moneypoint – no CCS	€81.9	This study Annexe 2: Price Model Coal at $90 per tonne, CO_2 @ €35 per tonne

The only caveat in comparing the CCS-based power with renewables may be that the high incentive prices reported recently for renewables (at €140 and €220 per MWh) could have serious implications for competitiveness of Irish industry if these prices for renewables formed a significant portion of Ireland's electricity portfolio.

4.8.3 Next Steps in Investigating CCS Viability

The economic analysis strongly suggests that CCS could be a valuable component of Ireland's climate change strategy on an all Island basis. However, in the case of all the geological basins examined, the data available on priority storage sites is insufficient to provide definitive *matched storage capacity* (see Figure 5, Table 7)). Kinsale is an attractive option, but will require further geological studies in order to guarantee the technical feasibility of a CCS project in the short term.

The economic analysis undertaken suggests that up to €80 million[71] may be required to provide sufficient confidence in Kinsale as a geological storage option, allowing for detailed modelling to include multi-phase reservoir simulation and assessment of site-specific thermodynamic behaviour of CO_2, new seismic acquisition and up to5 new wells to be drilled to optimise injectivity of the modelled 900MWe Moneypoint's 6.7 Mt CO_2 emissions.

By contrast, the authors feel confident that the technology in relation to capture, compression and pipelining, whilst not installed at commercial scale power plants to date, is all based on well known processes and mechanical engineering principles which, within a short number of years could be made available with little technical risk of failure.

It is very likely that by 2015 it would be possible to purchase power station technology fitted with CO_2 capture and compression equipment with a high certainty that the technology will function. However there would be no logic in investing in this technology unless a proven geological storage site within acceptable risk parameters was available on or near the Island to take the CO_2 into safe, long term storage.

As outlined above, the study can conclude that the economics of CCS look sufficiently promising compared to sustainable alternatives (taking security of supply into account i.e. assuming that indefinite expansion of gas fired CCGT is not a prudent approach), that the Governments would be fully justified in expending the significant public funds needed to prove up storage sites.

[71] Data modelled on analysis of infrastructural commissioning, decommissioning, conversion and new build costs in the hydrocarbon exploration and production sectors, UK and Ireland (2006-2007)

Initially the Kinsale and Portpatrick Basins are the locations where priority geological evaluations should focus (see Chapter 3 and Annexe 1 for geological rationale). Kinsale is the most attractive in the short term (<10 years) due to its known geological characteristics with 330 Mt of effective storage capacity; is a gas field which has trapped methane gas for millions of years; has infrastructure in place; and the current gas extraction operations are due to be completed within a decade.

In Northern Ireland, the most likely contender, but with significantly less certainty than Kinsale, is the offshore Portpatrick Basin, with 37 Mt of effective capacity and 2200 Mt of theoretical capacity. It would require considerable and costly proving up before injection could commence.

The forthcoming Clare Basin CO_2 Storage Study should give sufficient confidence to Government to make a decision as to whether a deep saline aquifer could be used for storage for Moneypoint emissions. However, at the time of writing, the authors have insufficient information about the sub-surface geology and physical parameters such as porosity and permeability of the deeper part of the Clare Basin.

4.9 Key Conclusions to date on Capture Aspects

1. The cost of a clean coal power plant exporting 900 MWe to the grid and including carbon capture, compression, pipelining, injection and storage may cost up to €3.0 billion. The power plant capture and compression comprise the most costly part of the system (~ 70%), while transportation/storage and monitoring chain can comprise up to 30% when owners costs and contingencies are applied.

   Under Irish conditions and prices, the case study work by team members has indicated that the cost of power from a power station capturing 90% of the CO_2 emissions would be €91 per MWh. This is very competitive in the current Irish situation and is lower than the ESB average generation cost for 2007.

2. The economics in Ireland are clearly very different to those in the USA where power stations are not exposed to the EU-ETS and where shorter pipelines have been factored into economic assessments. The price of power in Ireland is thus projected to be much higher than that demonstrated in studies in the US or by IEA, but are nonetheless competitive.

3. There is very little difference in the cost per MWh between the capture technologies (PC, IGCC) evaluated at this stage, although the modelled cost of retrofit at Cork significantly increases the cost of electricity sent out with CCS (in €/MWh). This suggests that Ireland does not need to elect for a specific technology at this stage. Given the overall timescales involved (minimum 8 year project from start of the EIS process), Ireland should perhaps await the outcome of 12 EU supported demonstration projects before deciding on which capture technology suits Ireland needs. one of the 12 demo projects, following careful consideration of the upfront risks and cost commitments.

4. The economics outlined above appear robust and suggest that CCS may well be more economic in an Irish context than in some other economies. However, all depends on the definition of a viable and safe, long term, geological storage facility. In this case there is a strong case to pursue the research into the geological and technical viability in further phases.

5 TRANSPORT ISSUES FOR CCS

CO_2 can be moved by both pipeline and marine tanker. These two methods are being assessed as to their suitability for Ireland.

5.1 Onshore Pipelines

It is pertinent to review international experience to determine the optimal transport solution for movement of CO_2 in Ireland.

5.1.1 The US Experience

There is substantial experience of the movement of CO_2 by pipeline in North America, where it is used for Enhanced Oil Recovery (EOR). Since the early 1980s over 2,500km of new CO_2 pipelines have been constructed to move (mainly) naturally occurring CO_2 from its source to the oil fields where it is to be injected. These range from relatively short distances of under 100km to the Cortez system which is over 800km long. One 9km pipeline also operates in Turkey for EOR:

Table 19: Movement of CO2 by Pipeline in North America

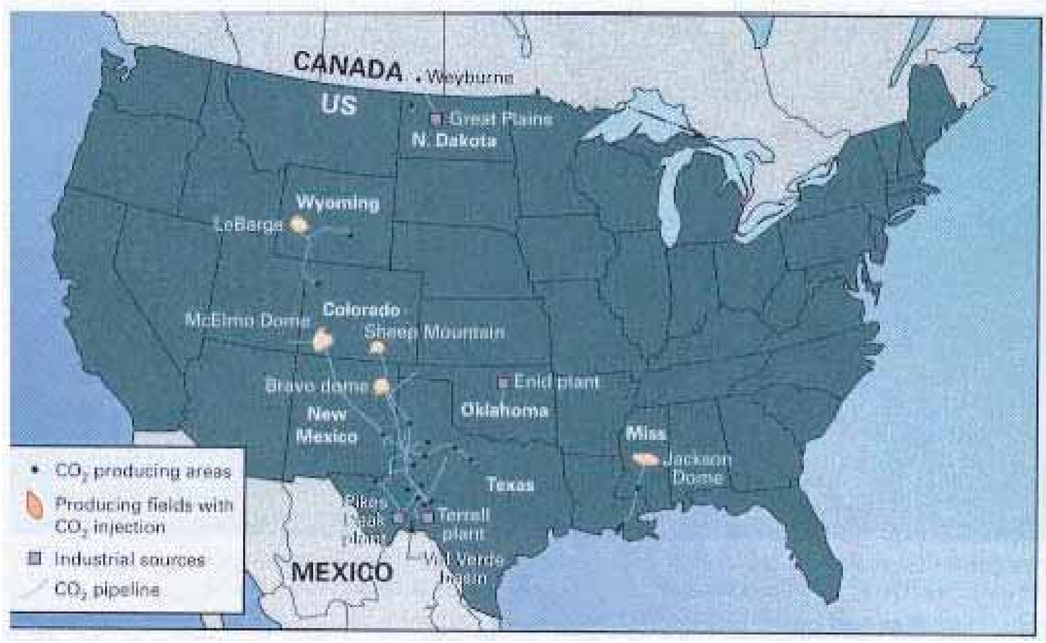
Name	Operator	CO_2 Capacity Mt pa	Diameter inch /	mm	Length miles /	km	Year Completed
Cortez	Kinder Morgan	19.3	30	762	505	+808	1984
Sheep Mountain	BP Amoco	9.5	20/24	610	412	660	
Bravo	BP Amoco	7.3	20	508	219	350	1984
Canyon Reef	Kinder Morgan	5.2	16	406	141	225	1772
Val Verde	Petrosource	2.5			81	130	1998
Bati Raman	Turkish Petroleum	1.1			56	90	1983
Weyburn	North Dakota Gasification	5.0	12/14		205	328	2000
Total		**49.9**			**1,619**	**2,591**	

The pipeline network extends from the south of the US (from the Texas/Mexican border) through the mid west and in the case of the Weyburn project up into Canada (see Figure 24 overleaf):

Although much of the experience derived from the longstanding efficient and safe operation of these pipelines in the US is of considerable value to Europe, there are also a number of significant differences that need to be taken into account.

- The majority of these US lines have been constructed in open lightly populated rural areas with generally 'easy' pipelining characteristics. This lowers the construction cost and also reduces the risk of exposure to people in the event of failure.
- With regard to construction costs, it is evident that these may not be directly relevant to the European situation in general and Ireland in particular. In many instances, the three main components of integrated carbon capture, transportation and storage projects are broken down into the percentages for each function. The relatively low capital cost of transportation in the US, compared with the other two components, results in this often being as low as 10% of the overall project and this is sometimes then transposed to the European situation. These comparisons need to be treated with considerable caution.

Figure 24: North American CO2 Pipeline Network



The CO_2 transported in US pipelines has to comply with strict specifications in order to minimise the possibility of corrosion of the pipeline, and maximise safety and enhanced production. A typical simplified CO_2 specification is that of the SACROC[72] which requires that gas delivered to the delivery meter meets the following specifications:

Table 20: SACROC Specification of the CO_2 Gas Delivered

Product	Specification
CO_2	Product shall contain at least 95% of CO_2
Water	Product shall contain no free water, and shall not contain more than 0.48 9 cu m in the vapour phase.
H2S	Product shall not contain more than 1,500 ppm by weight.
Total Sulphur	Product shall not contain 1,450 ppm by weight.
Temperature	Product shall not exceed a temperature of 48.9ºC.
Nitrogen	Product shall not contain more than 4%.
Hydrocarbons	Product shall not contain more than 5%, and the dew point shall not exceed -28.9C.
Oxygen	Product shall not contain more that 10 ppm, by weight.
Glycol	Product shall not contain more than 4 x 10^{-5} L cu metre and at no time shall the glycol be present in a liquid state at the pressure and temperature conditions of the pipeline.

Other than in the Weyburn project, all the CO_2 that is transported in these pipelines is derived from naturally occurring CO_2 reservoirs and there is little difficulty in meeting this type of specification that is relatively benign with regard to the steel - in particular with regard to the water content. For example, the final SACROC design conforms to the ANSI B31.8 code for gas pipelines and the US Department of Transportation regulations applicable at the time. The main 290 km section is 406.4mm (16") outside diameter with 9.53mm wall made from grade X65 pipe with minimum yield stress of 448MPa. These specifications are roughly equivalent to those of much of the UK and Irish transmission systems.

[72] Scurry Area Canyon Reef Operators Committee

CO_2 in gaseous and refrigerated liquid forms are classified in the US by the Department of Transportation as a non-flammable, non-toxic gas, even though it is heavier than air and is an asphyxiate at concentrations above about 10%. Generally it is considered less potentially dangerous that natural gas under high pressure and there is little public concern regarding the construction of high pressure CO_2 pipes in the US.

It is desirable for operational reasons to move CO_2 in either gaseous or supercritical form and to avoid the mid pressure, two-phase regime. All CO_2 pipelines in the US operate at the supercritical level.

Thus, experience in the US has indicated that it is cost effective to build long distance CO_2 pipelines and operate them safely. In the period 1990-2002 there were only 10 incidents with total property damage of under $0.5 million and no injuries or fatalities[73]. However, when transposing the US record of CO_2 transportation for EOR into the Irish context of CO_2 transportation for CCS, particular account has to be taken of a number of key differences including inter alia the composition of the CO_2, the different terrain and population densities , as well as the different political and regulatory attitudes towards risk.

5.1.2 Ireland

The analyses in the previous sections have identified a number of potential emissions hubs ("sources" - Chapter 4) and a number of potential storage locations ("sinks" - Chapter 3) for CO_2 on an all-island basis (see Figure 25 below).

These include:

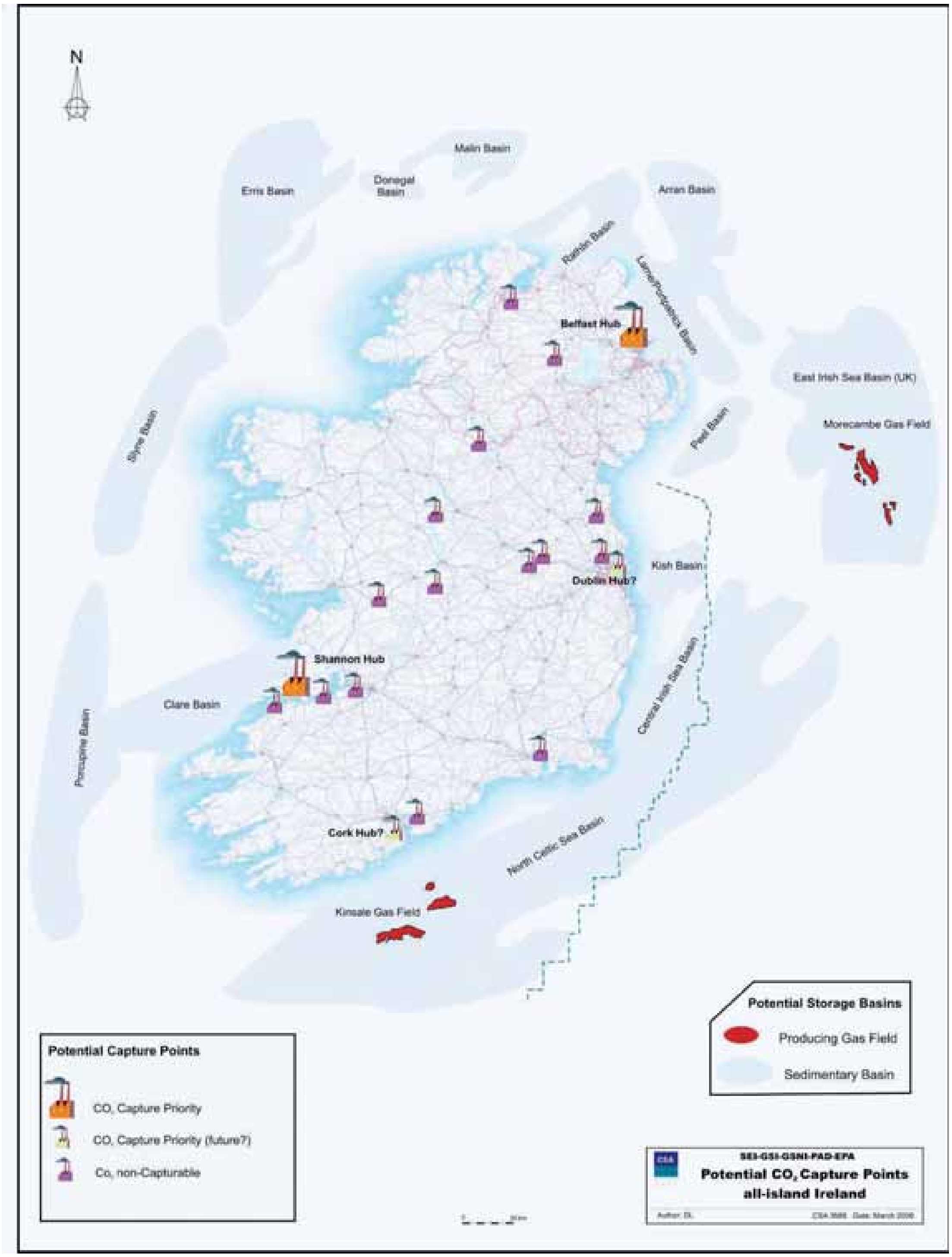
- Shannon Hub with potential sink at Kinsale (and perhaps with further geological investigation in the Clare Basin);
- Potentially an additional hub from a new power station(s) in the Cork area, with storage at Kinsale;
- Belfast Hub with potential sinks in the offshore Larne/ Portpatrick Basin (and perhaps in longer term in the Peel Basin).

With the possible exception of the Clare option, all of these routes involve both onshore and offshore pipelines to a differing degree.

The cost of constructing pipelines in Ireland (and elsewhere) will be a function of the terrain (ranging from soft agricultural soil, bog, rock high or low population areas etc), the number of crossings (railways, rivers, roads etc), number of pipe bends, as well as the length of pipe, its diameter and wall thickness, together with compression, metering valves etc and associated costs such as landowner compensation, project management etc.

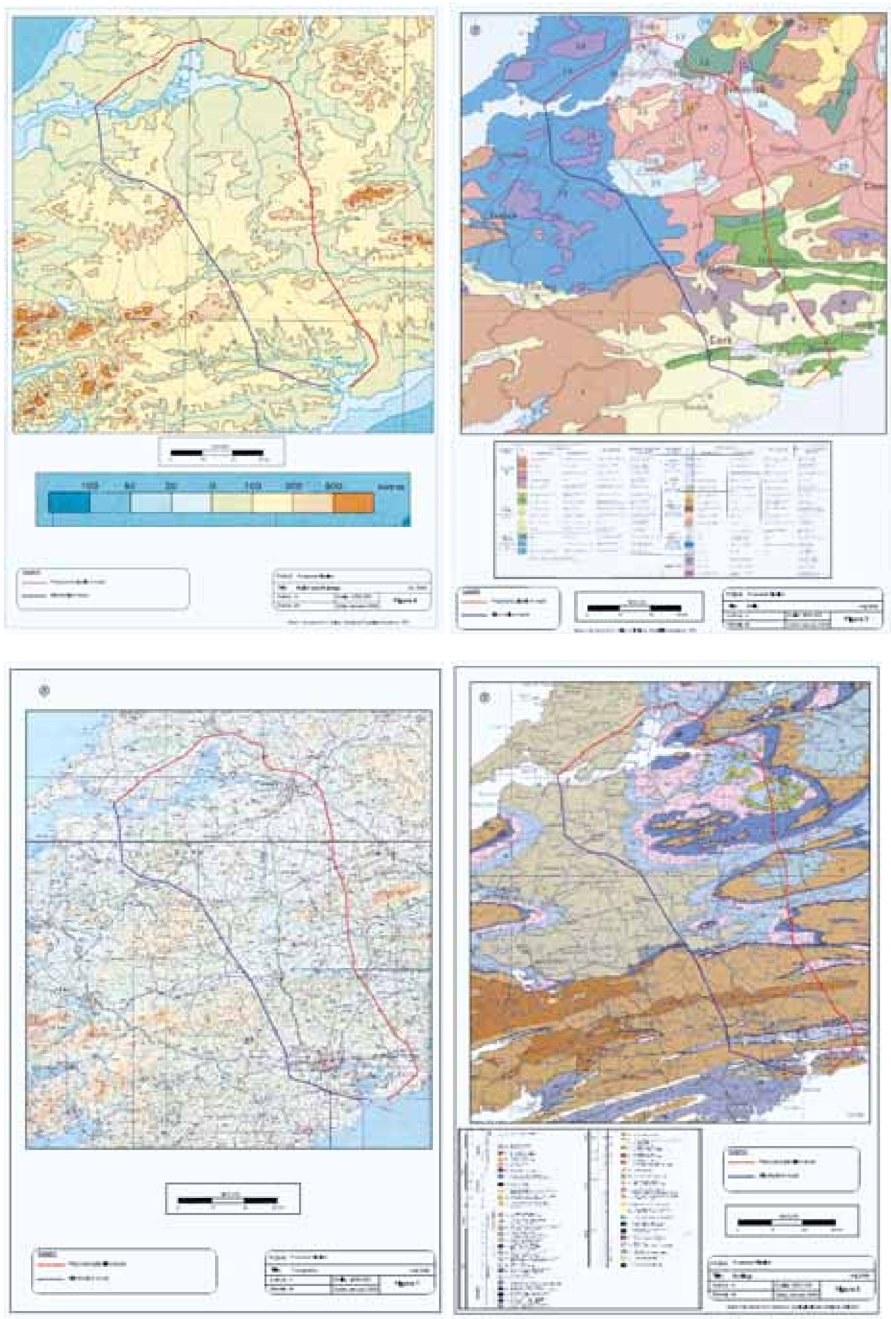
[73] Gale, J and J. Davidson, 2002: Transmission of CO_2 – Safety and Economic Considerations. GHGT-6

Figure 25: Potential Source Hubs and potential (pre-screening) Geological Storage locations for CO_2, all-island Ireland



For the source to sink scenarios identified above, potential routes were plotted on detailed maps to obtain the relevant information regarding both the type of terrain and the number of crossings. The routes chosen were designed where possible to avoid heavily populated areas. By way of example, maps of the two routes considered for the onshore Shannon/Kinsale option can be seen below:

Figure 26: Two routes considered for the onshore Shannon/Kinsale option



Initially, it was assumed that the shorter distance of the western route was more than offset by the high cost of the two deep water crossings of the Shannon and the entrance to Cork Harbour. However, the detailed economic analysis (Annexe 2) showed that the western (shorter) route was slightly cheaper and that crossing Cork Harbour may be unnecessary; the pipeline could theoretically go directly to the Kinsale field from west of the Harbour.

The relevant information on the various routes can be summarised as follows:

Table 21: Terrain/ Infrastructural Considerations in Route Selection

Source to Sink Route	Terrain Type	Km	Major Roads	Minor Roads	Railways	Major Rivers
Kilroot-Ballylumford			4	4	1	0
	Acid brown earths – drumlin-wet mineral soil	25				
	Grey brown earths – flat to undulating lowland-wet mineral soils	3				
	Total	**28**				
Ballylumford-Carrickfergus-Killough			c.24	c.60	3	1
	Acid brown earth – rolling lowland – dry mineral soils	25				
	Acid brown earths – drumlin-wet mineral sols	55				
	Acid brown earths – drumlin dry mineral to organic soils	7				
	Grey brown earths – flat to undulating lowland – wet mineral soils	2				
	Total	**89**				
Moneypoint - Doonbeg			5	6	0	1
	Acid brown earths – rolling lowland	10				
	Peaty soils	7				
	Total	**17**				
Moneypoint - Inch			C23	C93	6	C12
	Acid brown earths – rolling lowland	62				
	Brown earths – rolling lowland	40				
	Peat/peaty soils – flat to undulating lowland	18				
	Grey brown, mostly dry mineral soils – flat to undulating lowland	34				
	Mostly wet mineral soils – flat to undulating lowland and drumlin	22				
	Peaty to grey/brown earths – hill and mountain	10				
	Total	**186**				
Cork Bay – Aghada – Whitegate - Inch			6	25	1	1
	Dry mineral brown soils – rolling lowland	20				
	Dry/acid mineral soils – rolling lowland	17				
	Estuary	1				
	Total	**38**				

The size for the pipeline itself will be determined by a number of factors, the most important being the volume of CO_2 that needs to be moved. A number of cases were considered, of 5, 7.5 and 10million tons pa, respectively.

The pressure at which the CO_2 would be optimally transported is a critical parameter for pipeline design and costings, and will be fundamentally determined by optimal injectivity pressures. As mentioned above, all US CO_2 pipelines are in supercritical phase, which is also the case in Australia to date.

Given the potential sensitivity of running pipelines across Ireland containing supercritical CO_2, a number of cases were run to understand the implications of moving the three different volumes of gas in either gaseous form (20 bar & 40 bar) and supercritical (over 90 bar). The purpose of this was to size the pipeline under different scenarios and determine the number of compressors required. The results of a selected number of these can be seen below for a pipeline running the 185 km between

Moneypoint and the point where the existing offshore pipeline from Kinsale come onshore (the Inch Terminal):

Table 22: Range of Variables for Pipeline Transmission of CO_2

Inlet Pressure Bar g	Minimum Pressure Bar g	Volume Million tons pa	Diametre mm	Compressors	Compressor Spacing km
20	10	5.0	900	5	32
40	20	5.0	600	6	28
40	20	5.0	900	1	120
40	30	5.0	900	2	74
40	20	7.5	900	3	69
40	20	10.0	900	5	32
120	93.7	5.0	500	0	n/a
120	97.3	7.5	600	0	n/a
185	83.4	10.0	500	0	n/a
130	90.0	10	600	0	n/a
135	89.7	5.0	450	0	n/a
150	92.1	7.5	500	0	n/a
170	87.3	5.0	400	0	n/a

As would be expected, lowering the operating pressure and reducing the diametre of the pipe has to be offset by increasing the number of compressors. The analysis would suggest that it would be unrealistic to operate at 20 bar as it would require a 900mm diameter pipeline (approximately 36") with five compressors to move even the lowest volume of CO_2 (5 million tons pa). The option of operating at 40 bar would also appear to be expensive in that all volumes would require a 900mm pipeline and a number of compressors, other than using a smaller 600mm pipeline which would require 6 compressors to move only 5 million tonnes pa.

Thus by conventional analysis, it would appear that for the case of the Shannon/ Kinsale option, the additional cost of a large diameter pipeline, compression and construction, when taken in isolation, would probably make this option unrealistic. When operating at supercritical levels, none of the volumes considered required en-route compression and the diameters of the pipeline were significantly smaller.

However it should be pointed out that if the injection pressure at Kinsale were to remain at or below 40 bar[74] during the expected life of the plants producing the CO_2 to be stored, there could be some offsetting savings at the capture end by not having to compress the gas to supercritical levels. This saving would be in the form of a much lower MW output penalty. Alternatively, if the required injection pressure at Kinsale were to rise above the 40 bar at a later stage in the project life, and if the monetary value of the offsetting penalty was significant, it might be possible to run the pipeline system at 40 bar for a number of years and then add additional compression at the capture site to raise the pressure to the supercritical level. One advantage of this is that there may be less public concern relating to the construction and operation of a low pressure CO_2 pipeline. After it had operated safely for a number of years at low pressure, permission to increase it to supercritical might be easier. Understanding the implications of these options will need to be studied further.

[74] Modelling to date during this study indicates that optimal injection pressures will be in the order of 40-60b at Kinsale, given the current post-production, under-pressured regime in the reservoir. However, detailed simulation and modelling of injectivity, pressures and rates would be required prior to injection.

Figure 27: Cross Country Pipeline Construction in Ireland

Estimates have been made for the construction costs of the various options under consideration. These are based as if a tender had been offered for a high pressure natural gas transmission pipeline in 2007 with actual construction undertaken in the current year (2008). These include all the activities to build the pipeline including inter alia fencing the land, preparing the right of way, stripping the topsoil, stringing, bending, welding, trench excavation, lowering and laying the pipe, backfilling, all crossings and tie ins, regrading and replacing the topsoil, pre commissioning (testing, gauging and drying the pipeline), installing permanent fencing and undertaking the final trim.

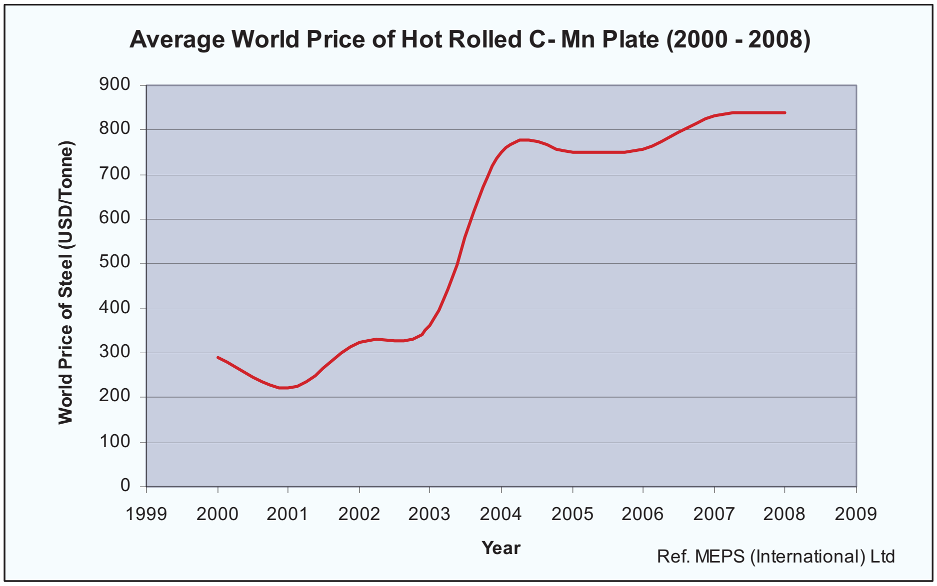
The cost ranges from about under €500,000 to over €800,000 per kilometre (see Table 23):

Table 23: Variable Construction Costs per Length/ Diameter of Pipeline (onshore)

Route	Length km	Diametre mm	Cost €million
Kilroot-Ballylumford	30	450	17
		600	18
		900	23
Ballylumford-Carrickfergus-Killough	90	450	50
		600	52
		900	67
Moneypoint-Doonbeg	17	450	10
		600	11
		900	14
Moneypoint-Inch	185	450	90
		600	94
		900	119
Cork Bay-Aghada-Whitegate-Inch	40	450	21
		600	22
		900	28

The other major cost component is that of the pipeline itself. As would be expected, there is a close correlation between the cost of pipe and its weight (length times wall thickness) and that of steel prices generally. Basic rolled plate is used for many applications as well as pipelines – for example shipbuilding and offshore oil and gas facilities, where demand has risen sharply during the last few years. Other elements contribute to the end cost and include iron ore, coal, energy, alloying elements, freights and exchange rates. The price of steel plate (in $US) has risen significantly during the last few years as can be seen below seen below:

Figure 28: Average World Price of Hot Rolled C-Mn Plate (2000-2008)



As discussed above, a number of cases were considered involving the volume of CO_2 to be moved and the pressure that the gas would move at. Different pressures require different grades of pipe – in particular regarding wall thickness. In the US, CO_2 pipelines generally follow the same specification as high pressure natural gas pipelines and a similar approach has been adopted to specify pipeline for use in Ireland – thus the requirements would likely to be similar to that required by Bord Gáis in Ireland and National Grid in the UK, both of which specify X65 grade for their high pressure gas transmission systems.

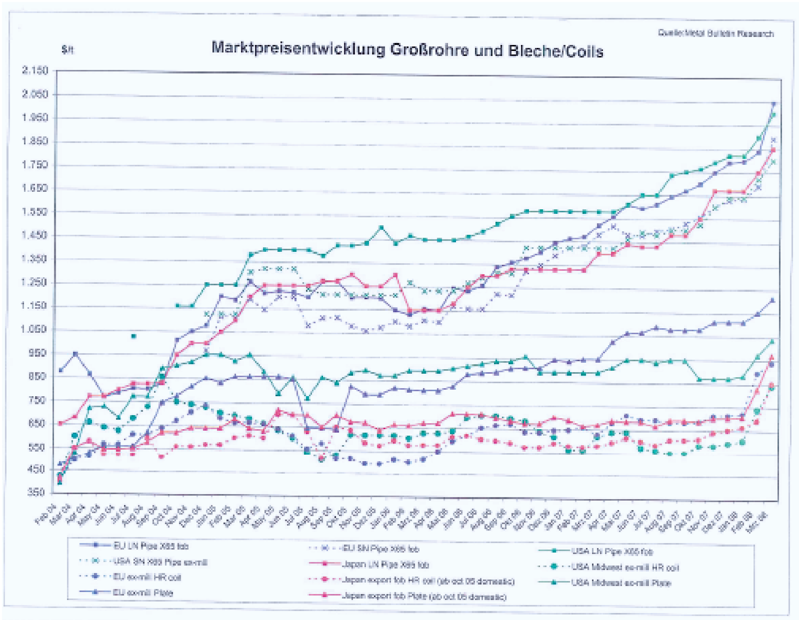
Pipeline design pressures (operational pressure +75%) so as not to exceed 70barg for the larger diameter pipelines, would result in the use of X52 and X60 grades (Table 24):

Table 24: Pipeline Steel Grade vs Diameter & Wall Thickness

Diametre mm	Steel Grade	Wall Thickness mm
450	X65	55.9
600	X52	9.5
900	X60	12.7

The price of pipe has reflected that of steel plate during the last few years – for example, as can be seen below (Figure 29), the price of X65 pipe fob Europe has more than doubled between February 2004 and March 2008:

Figure 29: Price of X65 pipe fob Europe has more than doubled – 02/ 2004 – 03/ 2008



Estimates have been obtained for these sized pipes, based on supplies ordered in 2008 for 2009 delivery and are shown below (Table 25):

Table 25: Pipeline Length vs Diameter vs Cost

Route	Length km	Diametre mm	Cost €million
Kilroot-Ballylumford	30	450	7
		600	5
		900	15
Ballylumford-Carrickfergus-Killough	90	450	23
		600	17
		900	49
Moneypoint-Doonbeg	17	450	4
		600	3
		900	9
Moneypoint-Inch	185	450	49
		600	34
		900	102
Cork Bay-Aghada-Whitegate-Inch	40	450	10
		600	7
		900	21

Some other hardware costs would need to be added, in particular Above Ground Installations (AGIs) etc, but these are not possible to determine in advance of a specific project. These costs can be summarised as follows (Table 26):

Table 26: Summary of Pipeline Costs (Diameter/ €/ km)

Route	450 mm	600 mm	900 mm	450 mm	600 mm	900 mm
	€million			€/km		
Kilroot-Ballylumford	24	23	38	0.8	0.8	1.3
Ballylumford-Carrickfergus-Killough	73	69	116	0.8	0.8	1.3
Moneypoint-Doonbeg	14	14	23	0.8	0.8	1.4
Moneypoint-Inch	139	128	221	0.8	0.7	1.2
Cork Bay-Aghada-Whitegate-Inch	31	29	49	0.8	0.7	1.2

Thus it can be seen, on the basis of these costs, and taken in isolation of other factors, it would be more cost effective to move the gas as a supercritical fluid in a 600mm pipeline. This would result in lower pipeline costs with no need for compressor stations along the route. Construction costs of the 600mm line are only marginally higher than for the 450mm line.

These costs relate to the construction of equivalent onshore natural gas pipelines. Costs in the USA of CO_2 pipelines for EOR projects are broadly similar to those of high pressure gas transmission lines, assuming that the CO_2 is similar to the SACROC specification above, in particular that the gas is dry in order to avoid corrosion. There is sometimes the need to use purpose designed pumps and compressors because of the poor lubricating properties of dry CO_2 and fracture arrestors are often installed to prevent longitudinal running fractures but the additional cost of these is considered marginal.

CO_2 is heavier than air and is an asphyxiate at concentrations above about 10%, so routes in rural lightly populated areas are preferable. Block valves may need to be installed more frequently than in natural gas pipelines especially in areas close to population in order to reduce the inventory that could escape in the event of a failure.

Gas Quality
The actual quality of CO_2 captured by an industrial process is likely to be different from that of the naturally occurring CO_2 that is moved by pipeline in the US. The addition of impurities is likely to have at least three effects:

- The volume of gas that can be moved through a pipeline could be reduced if significant amounts of impurities such as nitrogen, hydrogen or methane are present.

The presence of other impurities such as H_2S would make the gas significantly more toxic which would increase the impact of any leakage or rupture – this might for example require greater wall thickness and closer block valves in areas in proximity to population in order to minimise the risk of rupture and exposure to H_2S in the event of a rupture.
Impurities are likely to increase the corrosion rate of the pipelines themselves. In particular as noted above, it would be impractical to transport wet CO_2 in conventional pipelines generally made with low alloy carbon-manganese steel as this would react with the CO_2 to form carbonic acid causing corrosion and pitting of the steel.

It is not possible to provide generalised conclusions on the impact of impurities on the movement of CO_2 in pipelines as this will be a function of the quality of the CO_2 captured at source. This will be a function of many variables, including in particular the properties of the coal and the processes used to capture and compress the CO_2. Once this is known, site-specific studies will be needed for each project to understand the issues related to complying with a relatively pure specification (as is the case in the US - for instance a low nitrogen content is required for effective EOR that may not be an issue for CCS) or accepting the additional cost associated with moving impure CO_2.

5.2 Offshore Pipelines

In the absence of any identified safe, land based geological storage structures in Ireland and Northern Ireland, it is likely that any CCS project would store captured CO_2 offshore. This would clearly require the CO_2 to be moved offshore in a sub-sea pipeline. Offshore pipelines are common and represent no significant technical challenge. The first significant offshore pipeline is believed to have been laid by Brown and Root in the US Gulf of Mexico in 1954 and much of the subsequent technology developed for this area was transferred to the UK, beginning in the late 1960s. Since that time, over 14,000km of crude, condensate and natural gas pipelines have been laid offshore in UK waters[75]. These range from small infield gas lift lines as small as 2" to large diameter main oil and gas trunk lines which can be up to 48" (1,200mm) or larger.

As is the case with onshore pipelines, these offshore trunk lines are generally constructed with carbon steel with a wall thickness designed to cope with the internal pressure of the fluid or gas being transported and also to allow for the corrosive effect of whatever might be transported in them. Where the material being transported is particularly corrosive (e.g. high sulphur crude oil or gas with a high H_2S content), the internal surface is coated with a corrosion resistant alloy (CRA) or stainless steel is used.

Offshore pipelines are generally laid by offshore pipelines vessels which weld pipe sections together on the ship and then lower the pipe onto the sea bed, after which it is protected by trenching it into the seabed:

Figure 30: Allseas Solitaire (1); Pipeline Entering the Sea (2)

If it was decided to utilise the Kinsale field for CO_2 storage, it might be possible to reuse the existing 60km x 600mm (24") pipeline between the Alpha platform and the onshore gas terminal at Inch.

The potential reuse of redundant pipelines in the North Sea was examined in a previously referenced report[76], which concluded that there was no reason why offshore pipelines could not be used for the transportation of CO_2, provided that the gas was dry. However, it should be noted that this would require that the field be used only for CO_2 storage and that other activities currently underway including natural gas production and commercial storage and third party processing and transportation would have to have ceased by then.

If the existing pipeline was not available, or if storage was to be undertaken at another location, it would of course be possible to construct a new pipeline. It is difficult to estimate the cost of this as, unlike onshore construction, the cost will be more capital intensive given the need to utilise specialised offshore equipment. The availability and cost will be a function of the demand for the equipment at the time. This in turn will be influenced by factors such as *inter alia* the level of offshore oil and gas activity, the prevailing and expected oil and gas prices and exchange rates. The overall cost of offshore pipelines (i.e. including the pipe itself) has risen sharply in the last few years. Generally, for the UK North Sea this used to be estimated at around $1 million per mile, but a combination of the increase in the price of steel and pipe noted above (Figs. 5.3, 5.4) and the high demand for offshore equipment, has increased this significantly. The most recent pipeline laid in the North Sea (excluding major trunk lines such as the Langeled pipeline) is understood to have been a 33km x 250mm (10") oil line completed in 2007 for Venture Production plc between its Kittiwake platform and the Forties pipeline for a contract value of £65 - £70million – i.e. around £2 million per km. This would include the tie-in costs to the platforms at either end of the pipeline. In an Irish

[75] UK Department for Business Enterprise and Regulatory Reform
[76] EEEgr *The Re-Use of Offshore Oil and Gas Pipelines*, January 2006

situation, a tie-in to a platform above the storage reservoir would be needed, as well as a land fall connecting the offshore and onshore pipelines. There is no reason to believe that the cost of an equivalent pipeline in Irish waters would be significantly different (subject to exchange rates) than in UK waters.

There is very little direct experience of transporting CO_2 by subsea pipeline. In May 2008, the only long distance subsea pipeline is at the Statoil operated Snøhvit field in the Norwegian Barents Sea. This field produces natural gas with a CO_2 content of 5-8% which is stripped out and 700,000 tons pa is returned to the field in a dedicated 151km x 200mm (8") pipeline. The relatively small diameter of the pipeline has permitted it to be laid in 5 sections by a deep water reeled pipelay vessel, where the pipeline is stored in a large drum containing around 30km on the deck of the vessel, rather than having to be welded in sections offshore.

Figure 31: Skandi Navica

This method has the potential of significantly reducing the cost of offshore pipelay, assuming the required volume of CO_2 can be transported in a relatively narrow diameter pipeline.

5.3 Marine Transportation of CO_2

If a suitable storage location for captured CO_2 cannot be found around the coast of Ireland or Northern Ireland (or possibly the UK portion of the Irish Sea), it may be necessary to consider transporting CO_2 by marine tanker. In principal, this can be undertaken in tankers similar in design to those which carry liquefied petroleum products (LPG) such as butane and propane. According to the IEA_GHG, the cost of transporting CO_2 by pipeline is less than by ship for distances up to around 1,000 km, at which point ship becomes less expensive:

Figure 32: Comparative Costs of Onshore/ Offshore Pipeline & Ship Transport (US$/t CO_2)

Source: IPCC Special Report – Carbon Capture and Storage 2005

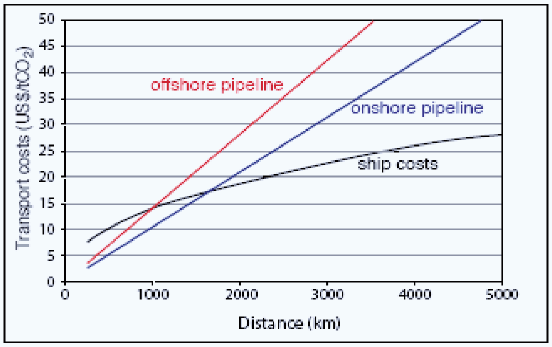


Figure TS.6. Costs, plotted as US$/t$CO_2$ transported against distance, for onshore pipelines, offshore pipelines and ship transport. Pipeline costs are given for a mass flow of 6 MtCO_2 yr^{-1}. Ship costs include intermediate storage facilities, harbour fees, fuel costs, and loading and unloading activities. Costs include also additional costs for liquefaction compared to compression.

It is most likely that any early CCS project in the UK would use one of the depleted gas fields in the southern sector of the North Sea, possibly offshore East Anglia. Many of these fields feed gas into one of the gas processing terminals located at Bacton, north of Great Yarmouth.

Thus one scenario for Ireland could be that captured CO_2 is shipped from Ireland or Northern Ireland – for example from the Shannon Hub or Belfast Hub to East Anglia and injected into a depleted gas field on a shared basis with a UK capture project. The distance between Moneypoint and Great Yarmouth is about 720 nautical miles, or approximately 1,330km and from Kilroot to Great Yarmouth 800 nautical miles (approximately 1,480km) by the southern route and 865 nautical miles (approximately 1,600km going north of Scotland. This would suggest, in particular for the relatively low volumes of CO_2 that would need to be shipped to the UK from Moneypoint or Kilroot (up to 5 -6 Mt each pa), it would be less expensive to do this by ship than construct a pipeline:

Figure 33: Moneypoint to East Coast UK (1); Kilroot to East Coast UK (2)

Up to this point in time, there has been only a limited volume of CO_2 moved by ship, in contrast to the large amounts moved by pipeline in the US. Most of the marine trade that does exist is in North West Europe and the Baltic in relatively small sized ships. This is generally for food grade CO_2 from point sources such as ammonia plants to small coastal communities where it is distributed by tanker trucks or in pressurised bottles. The limited number and small size of the ships is dictated by limited demand, rather than by any inherent technical reason. Generally these ships have a capacity of 900-1,200 tons of CO_2 each and are also used for carrying LPG. The CO_2 is cooled to about -50C to pressurise to about 7 bar.

Evidence of some upscaling is provided by the MV Coral Carbonic, the first purpose designed CO_2 carrier, which was launched in 1999. It has a capacity of nearly 1,400 tons at a maximum pressure of 18 bar and minimum temperature of -40ºC in a single tank and travels at 12.5 knots:

Figure 34: MV Coral Carbonic

Thus on the basis that small scale CO_2 tankers and much larger LPG tankers have operated successfully for many years, there would seem to be no technical reason why larger scale CO_2 tankers could not likewise be operated. These could either be conversions of existing LPG tankers or new build CO_2 tankers. This would seem to be confirmed by a number of studies, including the IPCC[77], the IEA[78] and an investigation into the possibility of using CO_2 for EOR at the Norwegian oilfield Gullfaks and the surrounding area[79].

By way of example, if vessels travelled between the Shannon Hub and Great Yarmouth at 15 knots and assuming one day each for loading and unloading, it would take about six days to complete a round trip. The number of ships and the amount of storage would vary depending on the carrying capacity of the vessel:

Table 27: Vessel Size vs Voyages Required for CO_2 Transport

Size of Vessel	10,000 Tons	30,000 Tons	50,000 Tons
Number of ship/voyages/year	400	133	80
Number of voyages/week	6.5	2.2	1.3
Number of ships required	8	3	2
Storage required at each port *	25,000	75,000	125,000

**** basis:2.5 times ship capacity***

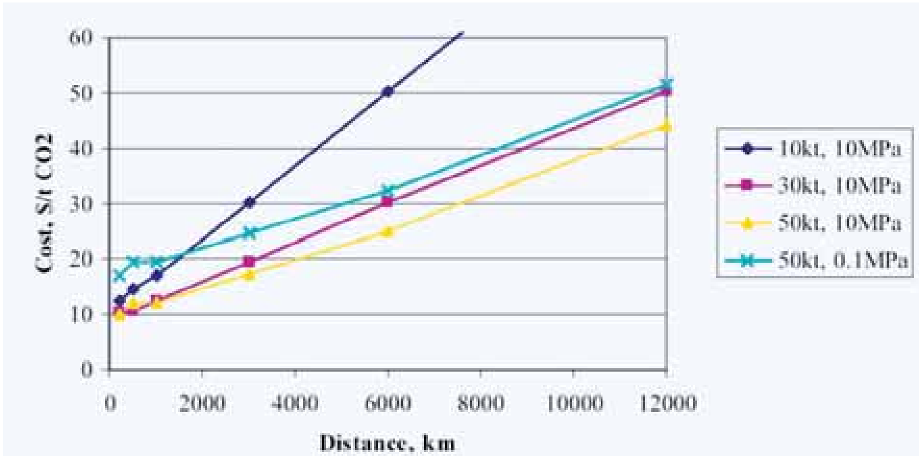
Thus, it is likely that the mid range sized vessel (30,000 tons) would probably be the most economic and practical from both a cost and operational basis.

Thus in the absence of any storage location offshore the island of Ireland, tankers could be used to move captured CO_2 to a location off the east coast of the UK for possible joint storage with a UK project. Any such project will include a number of capital and operating costs, including tanks and loading facilities at the loading terminal to store the captured CO_2 until it is loaded onto a ship and the costs of the ship transportation itself and the costs at the unloading end. These costs have been assessed by the 2004 IEA report for different distances for three sizes of vessels (10,000, 30,000 and 50,000 tons) – see

Figure 35 below:

[77] IPCC *Special Report – Carbon Capture and Storage* (2005)
[78] IEA_GHG *Ship Transport of CO_2* (2004)
[79] Elsam A/S, Kinder Morgan and New Energy, Statoil (2003)

Figure 35: Cost (US$/t CO_2) vs Distance by Shipping



(Source: *IEA_GHG 2004 study***)**

Thus it can be seen that the cost per ton for a voyage of about 1,500 km (at 15 knots) would range from about $15/ton for 30,000 and 50,000 ton vessels and about $20/ton for a 10,000 ton vessel.

It will be appreciated that these shipping costs are in 2004 US$ and may well have changed significantly since then; however whatever the actual cost is, it is clear that it is a different order of magnitude to that of moving CO_2 shorter distances by pipeline. It is difficult to see how such costs could be accommodated within an economic CCS project in Ireland or Northern Ireland at this time.

6 ENVIRONMENTAL RISK, MONITORING & REGULATION

A range of environmental, risk assessment, permitting and regulatory issues were considered by the CSA team within the context of a rapidly changing international CCS policy environment.

The IPCC (2005) estimated that CCS could be used to achieve between 15% and 55% of carbon emissions reductions necessary to avoid dangerous levels of CO_2 atmospheric concentrations. Given worldwide concerns over energy security and the policy positions being adopted by multilateral agencies such as UN, OECD (IEA) and the EU, as well as national governments (UK, USA, Australia, Norway, China, India, Canada – see Chapter 2 above), it is likely that CCS will be adopted as a widespread technology in the coming decades. Given the timeframes involved with defining suitable storage, the challenge will be to reach an international consensus on how CCS may best be managed, monitored and regulated, areas in which a consensus is already emerging.

6.1 International Legality of CCS

Prior to any commercial injection of CO_2 into sub-seabed settings, the international legality of storage had to be addressed through the London and OSPAR Conventions, which were amended in 2007.

- **London Protocol *Amended 2007***
  Ocean storage of CO_2 became legal in 2007, following international agreements to amend the London Protocol (which governs all the world's oceans) to "allow carbon dioxide streams from carbon dioxide capture processes for sequestration only if it is into a sub-seabed formation, it consists overwhelmingly of carbon dioxide and no wastes or other matter are added for the purpose of disposal". The agreement came in to effect in February 2007.

- **OSPAR Convention *Amended 2007***
  The OSPAR Convention, which governs the Northeast Atlantic Shelf, includes 15 member states and the EU. It addresses six strategic areas, of which 'Hazardous Substances' and 'Assessment & Monitoring' will directly concern CCS, in areas such as site selection, acceptable leakage, long-term monitoring, purity of waste streams and liability, as well as the political (public) message. In particular Annexes 1 and 2 would impact on CCS and required change:

Annex II: ***on the Prevention and Elimination of Pollution by Dumping or Incineration***
- Deliberate disposal in the maritime area
- Specific exceptions (e.g. dredging)
- Authorisation and regulation, associated guidelines

Annex III: ***on the Prevention and Elimination of Pollution from Offshore Sources***
- Prohibition of dumping of wastes or other matter from offshore installations
- Use of Best Available Techniques, and
- Best Environmental Practice

Technical and legal issues were tackled during the 2006/7 OSPAR meeting cycle, including risk characterisation and risk management; jurisdictional responsibility and potential for trans-boundary pollution; implementation reporting and record keeping over very long timescales[80]. In 2007, OSPAR agreed to adopt by consensus the following amendments to Annexes 1 and 2:

- OSPAR Decision 2007/1 to Prohibit the Storage of Carbon Dioxide Streams in the Water Column or on the Sea-bed
- OSPAR Decision 2007/2 on the Storage of Carbon Dioxide Streams in Geological Formations
- OSPAR Guidelines for Risk Assessment and Management of Storage of CO_2 Streams in Geological Formations, including a Framework for Risk Assessment and Management of Storage of CO_2 Streams in Geological Formations (FRAM).

[80] Dr David Johnson, Executive Secretary, OSPAR Commission/ Bonn Agreement, speaking at EU Carbon Capture & Storage Summit, London 28-29 November 2007.

OSPAR contributed to the London Convention in early November 2007, so that the two are now consistent with respect to CCS, based on establishing rules to ensure that the marine environment is not damaged, including preventing any carbon dioxide placement in either the water column or on the sea bed. Specific guidelines for assessment of CO_2 streams for disposal into sub-seabed geological formations are to be developed, and a Scientific Group will develop a standardised CCS reporting format. London will liaise with OSPAR to establish a legal and technical working group on CCS trans-boundary issues.

These guidelines will form an excellent basis on which environmental monitoring and risk assessment templates for countries such as Ireland may be built and against which CCS projects may be benchmarked.

6.2 Potential Environmental Impacts

If carbon dioxide equivalent (CO_2-e) average atmospheric concentrations are not stabilised to below 450ppm $CO_{2\text{-}e}$ by 2030, then the globe will warm to > 2°C above pre-industrial levels, with potentially catastrophic effects. CCS technologies in combination with alternative energy sources such as biomass, wind, wave etc, will offer a very significant means to reduce atmospheric emissions.

Environmental concerns about the potential impacts of CCS (focussed on surface or sub-surface leakage and groundwater / ocean quality) are high on the list of many national environmental protection agencies and non-governmental organisations, which must be addressed if public acceptance of CCS is to be gained. There is a running debate among environmental NGOs, whereby some support CCS as a pragmatic measure, while others oppose it as an avoidance of energy efficiencies and adoption of renewable energies. However, most would agree that capture and storage offer a viable 'string in the bow' of mitigative measures, with due regard to environmental risks and liabilities. The primary environmental concern is to capture and store the greatest amount of CO_2 with the <u>net</u> effect of reducing emissions.

Most environmental focus has been on carbon storage (i.e. risk of potential leakage of CO_2). However, other more specific environmental areas of concern pertain to the upstream (capture and transport) stages of CCS, but are more predictable due to their visibility and current industrial practice. Key risks at all stages include the following:

- CO_2 Capture and the Environment

Systems to cope with variable carbon streams must be developed as depending on the carbon source (power plants, cement, EGR, etc), the flue stream will react differently with materials and the physical capture process will vary accordingly. Safety and environmental requirements relating to separation technologies, depressurization, compressors etc must be addressed, with different requirements likely for onshore and offshore (EOR, EGR) capture. In the Irish context, capture is most likely to occur onshore at power generation sites (e.g. Moneypoint, Kilroot), with pipelining to offshore storage sites (e.g Kinsale, Portpatrick).

- Transport of CO_2 and the Environment

CO_2 is highly compressible and can be pipelined in liquid, gaseous or supercritical states, but the denser phase is more economically viable and can be transported in a smaller diameter pipe. The properties and heterogeneity of the captured gas stream will determine the pipeline design: the impurities will ultimately determine the full process from capture to storage. In the USA, the impurities in carbon transport are limited to 5%[81]. Transporting a particular gas stream will be determined by the both the source and storage requirements. Issues such as compressor design must be addressed to optimise fluid flow and to prevent pipeline cavitation. The reactability of CO_2 varies with temperature and pressure, depending on which state it is transported in, and may react with polymers and plastics, which will also influence the overall pipeline design, compression requirements and transfer points (see Chapter 5 above).

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[81] USA CO_2 pipeline impurity limits have been established for H_2S, N, S, total hydrocarbons, free water and glycol. CO_2 minimum is 95% mole purity.

Under the ETP ZEP[82], one of five working groups has specifically addressed the infrastructural and environmental concerns pertaining to CCS. Technologically, it has been proven in the USA for more than 30 years that CO_2 can be piped safely. US regulations[83] dictate the design and safety requirements for operators of CO_2 infrastructure, but in the EU, current regulations for e.g. hydrocarbons transport is deficient for CO_2 and modifications will be required EU-wide to ensure continuity of the carbon value chain. However, the infrastructure to combine transportation from heterogeneous, and potentially more reactive, point source flue streams (cement plants, steel mills, oil & gas refineries etc) will have to be developed.

Two CO_2 pipeline options have come onstream in the EU in the past two years: the first as an onshore-to-offshore 153km pipeline at Statoil's Snøvit LNG project in Norway, to store CO_2 removed from its LNG liquefaction plant, and the second at Linde's onshore 230km gaseous CO_2 (1Mtpa throughput) pipeline in the Netherlands.

Given the recent history of the Corrib gasfield development, one of the most strongly perceived environmental and safety hazards is likely to be transport of pressurised liquid CO_2 by pipeline in the Irish public mind. Hazards and infrastructure leak analysis, along the entire chain from capture to injection, will be required to identify risks posed by potential seepage creating CO_2 fluxes. Slow leakage is not generally considered to be a major public safety issue unless the CO_2 becomes trapped. Pipeline specifications and design and avoidance of densely populated areas will be critical. However issues of surface/ near-surface potential ground contamination will need to be addressed, both on land and on the seabed.

- CO_2 Storage and the Environment

The second working group of the ETP_ZEP[84] highlighted potential environmental impacts associated with storage, grouped by potential impact on human, terrestrial and marine ecosystems (see Table 28 below).

Geological storage risks may be simply categorised into two end members: local and global:

Geological Storage Risks:

Local

- Elevated gas-phase concentrations in the near-surface environment
- Effects of dissolved CO_2 on groundwater chemistry
- Effects that arise from the displacement of fluids by the injected CO_2

Global

- CO_2 back to the atmosphere

[82] European Technology Platform ZEFFPP, WG3: Infrastructure & Environment contribution to the European Strategic Research Agency
[83] Code of Federal Regulations Title 49 Chapter 1, Part 195 (49CFR195), Transport of Hazardous Liquids by Pipeline.
[84] Zero Emission Fossil Fuel Power Plants (ZEFFPP) WG2: *CO_2 Use and Storage – Contribution to the EU Strategic Research Agenda.* May 2006.

Table 28: Potential Environmental Impacts of Carbon Storage

Potential impact on Human Health & Safety due to leakage (either slow or catastrophic):	Even at relatively low limits (1%) the human respiratory rate will increase by 37%; at 5-8% a person will exhibit severe headaches, dizziness, confusion etc; by 10% vomiting, hypertension and loss of consciousness. Volcanology studies have assisted in determining the empirical impacts of release of carbon dioxide and other gases.
Impact on Groundwater from CO_2 leakage and brine displacement:	Hazards may include increased levels of dissolved CO_2 in potable water; mobilisation of toxic metals, acidification or infiltration of saline water into potable aquifers. All of these potential hazards will need to be identified through carefully focussed case studies and monitored over substantial periods of time. However, current projects would suggest for instance that the incursion to potable aquifers of saline water displaced from injection wells is rare, and may thus be considered unlikely to arise from large scale CO_2 storage activities.
	The thermodynamic impacts of injection of impure streams of CO_2 and residual natural gas in reservoirs.
	Likelihood of host rocks releasing heavy metals and consequent changes in metal concentrations and reactivity.
Impact on Terrestrial Ecosystems	Stored CO_2 may impact on flora & fauna, including microbes in the deep subsurface. Increased CO_2 in ambient air (due to slow leakage) or soil gases may adversely impact plant growth and fertility through root impairment, and ultimate die-off at relatively low levels (>5%).
Impact on Marine Ecoystems	Seepage may adversely impact benthic communities through seepage along geological structures, while the water column itself may inhibit upward buoyancy of CO_2 to the ocean surface. Very little is known about CO_2 impact in the deep ocean.
Cumulative effect of contaminants?	Will changes in Eh/ pH cause adverse impacts on benthic communities – how will mixing/ dilution/ gas exchange eliminate impacts? How will ecosystems adapt to changed CO_2 concentrations? How will individual species react?
Chemical reactions between CO_2 and other minerals?	Will mineral trapping happen, and if so over what time period? How will this affect connectivity for transport channels and storage reservoir? Hydrodynamic activity?

Appropriate modelling at site specific locations must address short-term and long-term impacts of these risks to offer full confidence in the environmental and human safety of CCS.

6.3 CCS Environmental Impact Assessment

Under the proposals for an EU CCS Directive, the EC considered the environmental, health and safety impacts and risks linked to CCS (see Table 30 below) and highlighted the need for a clear regulatory framework to address the likely impacts and management of associated risks[85].

The IEA has recently published a technical study[86] on the Environmental Assessment requirements for CCS. It examined the possibilities of adapting current Environmental Impact Assessment (EIA) and Strategic Environmental Assessment (SEA) procedures from over 10 countries and three international frameworks to CCS. As well as SEA, an integrated environmental, health and social impact assessment (EHSIA) approach is currently being advocated by international bodies for CCS projects[87]. The impact assessments for capture and transport elements are not very different to those being undertaken currently for major projects, but specific and additional requirements will be needed for the storage component.

While the methodologies are broadly similar, it was clear that some elements of best SEA practice are not required in law, while CCS is not specifically addressed by any of them. Existing legislation must be adapted or new legislation will be required in most cases, particularly to achieve compliance with EU Emissions Trading Scheme (EU-ETS) and the Kyoto accords.

The IEA advocates the development of a single international guideline for CCS, which would be acceptable across international storage / transport boundaries, combining aspects of health & safety, environmental and community impacts. Thus, an internationally agreed *Environmental, Safety and Health Impact Assessment (ESHIA)* is recommended to incorporate the following:

- ✓ Health & safety aspects of projects
- ✓ Risk based approach with modelling
- ✓ Incorporate full carbon balance
- ✓ Detailed guidance on each ESHIA steps
- ✓ Specify environmental resources to be covered, with minimum information requirements
- ✓ Binding commitments for monitoring, management, and site handover to authorities
- ✓ Guidance on long term liability management
- ✓ Have separate EHSIA at time of abandonment to ensure that current best practice is applied
- ✓ Include results of a Storage Performance Assessment
- ✓ Exclude High Risk projects

The ESHIA approach would encompass environmental health and probability estimates of the impacts of accidental CO_2 release and long term management of liability. The balance between local negative impacts and positive global impacts must be addressed.

Minimum standards for individual site performance assessments would have to include establishment of baseline data, identification of potential leakage paths (seal failure, faults), expected behaviour of leaked CO_2 and how uncertainty may be modelled and tracked. Reservoir simulation models and seismic profiling can be used to establish baseline conditions for the storage site, while monitoring will allow comparisons between expected and observed behaviour.

Environmental impact assessments (EIA) with dispersion models to predict likely CO_2 behaviour in the event of accidental release will need to be provided at project pre-development stages. Ireland's existing EIA monitoring framework may be modified appropriately to encompass CO_2 pipeline specification and risk management, through adaptation of the recommendations of bodies such as IEA.

A *Risk-based Environmental Impact Assessment* (EIA) approval process to CCS is currently being tested on a number of projects (e.g. Gorgon in Australia). Signatories to the Kyoto regimes need to manage

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[85] Paul Zakkour, ERM for EC-DG Environment (2007). *Technical Support for an Enabling Policy Framework for CO_2 Capture and Geological Storage: Task 2* – Discussion Paper on Choices for Regulating CO_2 Capture & Storage in the EU.
[86] IEA (March 2007). *Environmental Assessment for CO_2 Capture and Storage*. Technical Study 2007/1.
[87] IEA GHG R&D Programme: *Environmental Assessment for CCS Projects*. Project Nº 22512893

'*global risk*' in the context of commitment to Certified Emissions Reductions (CER) replacement[88]. However, adopting an EIA process will provide a strong mechanism for regulation of storage liability, while insurance could play a role in underwriting defined CCS risks.

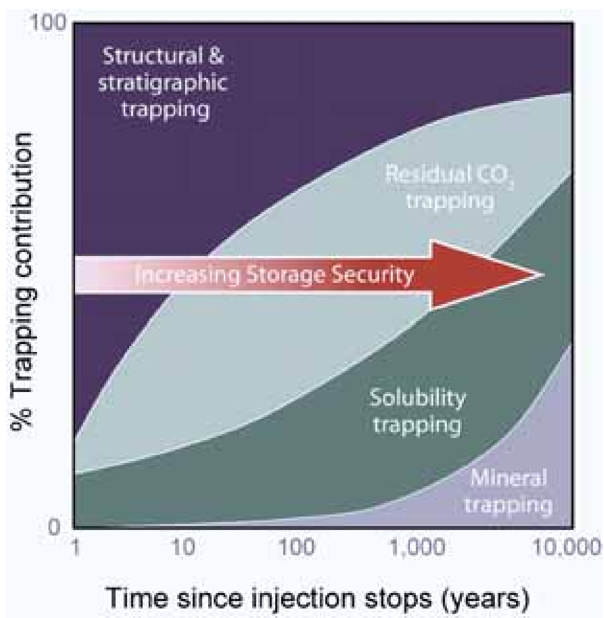
6.4 Risk Assessment & Liabilities

Clear regulatory guidance on the balance between local pollution risks versus climate change may require that some form of risk-benefit approach be adopted. However, such risks may be managed by adopting the life cycle management approach to the entire chain (as presented in Figure 36) at various international and national levels. The protection of human health and the environment must be the primary consideration of national regulators, while for the carbon emission generators, pipeline operators and storage site developers, the project must be both environmentally safe and financially viable.

Underpinning the operational and regulatory aspects of CCS will be the international and national climate regime policy makers (*shifting sands*) and the insurance and financial underwriting of any given project.

Current research and demonstration projects suggest that geological storage will become less risky with time, due to natural processes of residual, solubility and mineral trapping.

Figure 36: Long Term Trapping of CO_2 in Saline Aquifers



According to the IPCC (2005)[89], the fraction retained in appropriately selected and managed geological reservoirs (saline aquifers) is very likely to exceed 99% over 100 years, and is likely to exceed 99% over 1,000 years[90]. Local risk of geological storage can be comparable to risks of current activities such as natural gas storage in Southwest Kinsale in a local sense or EOR projects in the USA/ Canada.

To minimize and manage geological storage risks, the following have been proposed in the UK, but have not yet adopted at EU level:

88 Paul Zakkour of ERM, speaking on Clean Development Mechanism (CDM) applications to CCS at EU Summit on Carbon Capture & Storage, London, November 2007.

89 IPCC (2005). *Carbon Capture & Storage* Special Report.

90 'Likely" is a probability between 66 and 90% and "very likely" of 90 to 99%.

- CCS storage site operator must show due care in site selection with a reasonable expectation of no leakage and a rigorous risk management plan;
- Storage sites must be monitored and reported on site performance, and obtain third party verification – any CO_2 emissions from a permitted carbon storage site would have to be reported in the debit column of the host country's official national GHG inventory.
- Site licenses could be time-limited, subject to performance review, with the possibility of revocation and potential restitution of leakage via comparable CO_2 allowance purchases as an offset.
- There is a need to cap operator liability due to uncertainty over future GHG unit prices
- Very long-term liability accrues to host country, not operator**.**

There is an emerging consensus that a CCS facility operator should be liable for risks up to a point of post-closure where the site can be independently monitored and verified as safe by an international body and certified as such. However, commercially workable rules for long-term liability will be needed to incentivise investment in CCS. For long-term stewardship, common sense dictates that this must be undertaken by nation states, with long term independent monitoring and verification by an international body(s), possibly under the auspices of IEA, EU or a dedicated UN agency.

Capture Risk

All of the current carbon capture projects internationally are at demonstration stage and are unproven at commercial scale. Thus there is still a significant risk associated with the chosen capture technology, whether through pre-combustion, post-combustion or oxy-fired means. However, the central risk for any capture facility is the absolute prerequisite for a safe storage location within economically viable distance, with a reliable transmission system.

Additional R&D is needed to improve knowledge of emerging technologies for CO_2 capture, in particular to demonstrate their environmental performance on a large scale.

Clear definition of the CO_2 ownership transfer throughout the industrial process will be required, as will a stable policy regime, with clear targets and some degree of financial certainty. The latter may be addressed by power purchasing agreements or the establishment of a floor price for carbon in the longer term.

Pipeline Operational Risk

CCS cannot happen without a pipeline infrastructure (see Chapter 5 above) to transfer the CO_2 from source to sink. Based on international experience in both natural gas and CO_2 transmission, the pipeline itself can be safely engineered for the CO_2 gas/ fluid at designated pressures, but considerable risk still remains at either end of the pipeline.

Risks include:

- Gas composition and specification at the capture end;
- Pipeline costs, in particular the soaring costs of steel
- Land access and planning permission for pressurised pipelines
- Injectivity rates and pressures at the storage end
- Handover points if different operators of capture, transport and storage elements of the project
- Long term ownership of the pipeline: a privately owned common carrier approach or a public utility approach – which is best?

The latter question is critical in that depending which approach is adopted, then different levels of investment may ensue, influencing the economics of the entire carbon chain.

A generalised CCS Risk Assessment checklist (Table 29) has been compiled from a range of sources, to encompass the key areas of concern.

Table 29: Carbon Capture & Storage : Key Areas for Risk Assessment

STAGE OF PROCESS	RISKS	Yes	No
SOCIO-POLITICAL	Policy regime/ Incentives for deployment		
	Transparency of early project results		
	Effective regulatory regime: early stage modification of existing regulations, used to develop commercial scale deployment over time		
	Public engagement, education & acceptance		
CAPTURE	Technology source identified		
	Financial – capital costs & penalties		
	Sensitivity analysis		
	Environmental net balance (CO2 avoided)		
	Purity of CO2 gas stream		
	Transfer – to other operator/ same operator?		
TRANSPORT	Planning issues		
	Pipeline failure		
	Financial costs – pipeline/ compression		
	Compressor failure		
	Transfer - to other operator/ same operator?		
STORAGE	Suitable site identified		
	Site characterisation: sufficient knowledge		
	Storage capacity assessed		
	Financial costs > prove up costs		
	Reservoir model & simulation		
	Faults characterised		
	Seal efficacy		
	Old well efficacy		
	Injectivity		
	Sensitivity analysis		
	Leakage (modelled & monitored)		
	Induced seismicity		
	Fluid displacement		
	Adequacy of models		
	Financial costs		
	Transfer? to state/ international agency?		
STEWARDSHIP	Long term monitoring by whom?		
	Methodologies for long term monitoring		
	Remediation techniques		
	Costs		
	Negotiated arrangements for long term liabilities		
	Liability transfer *'pass the baton'*		
	Independent verification		
	Penalties for infringement		
NET RISK	Global vs Local risks		

In particular, the transfer (or *'pass the baton'*) stages of any project will need to be addressed, particularly where different operators may be managing different stages of the process and environmental liability needs to be clearly defined. The issue of leakage through abandoned wells has also been flagged in the international literature as an area of particular concern. In the longer term, stewardship of each storage site is likely to pass to the national state, with stringent independent monitoring of the sites carried out by internationally recognised bodies. The handover from operator to the national state will only be permitted following full adherence to those requirements as well as any necessary rehabilitative measures.

In conclusion, there is a need to learn from emerging experience in CCS internationally so as not to lock in inappropriate features; policy must be designed to be somewhat flexible. However, in the Irish context issues of long term risks and liability will need to be addressed in a meaningful way to suit local conditions, taking on board UK and wider EU developments.

6.5 Regulation of CCS – A Life Cycle Approach

Under the draft proposals for an EU Directive on CCS, it was decided that existing regulatory frameworks will be used for CCS where possible. For storage, the options to regulate risks were the EU-ETS, the IPPC and waste legislation and/or to develop a new framework. The ETS is not designed for complete regulation of the environmental risks of CCS, while the IPPC and the Waste instruments are not well adapted to regulating CO_2 storage, and could be made so only by extensive amendment. It was thus decided to adopt proposals for a new framework in January 2008 (see Section 2.3.1). The requirements for permitting of storage sites and for characterisation, monitoring and closure are essential provisions for ensuring environmental integrity and to gain public confidence from the start.

In the draft EU CCS Directive (see Section 2.3.1 above), requirements on site selection are designed to ensure that only sites with a minimal risk of leakage are chosen, and it is proposed that a review of draft permit decisions by the Commission – assisted by an independent scientific panel – will ensure that the requirements will be implemented consistently across the EU. A Monitoring Plan must be submitted by the operator, which can be inspected to verify that the injected CO_2 is behaving as expected. If the site leaks, corrective measures must be taken to return it to a safe state. Remedial measures such as e.g. abandoned well rehabilitation must be taken where specific hazards or risks are identified in the monitoring process. Appropriate levels of monitoring and verification must be adopted at critical stages of any given project, from the injection through closure and long-term post closure phases. The requirements of the Environmental Liability Directive on repairing local damage to the environment will apply in the case of leakage.

Life cycle environmental assessment for is advocated[91] to estimate the total carbon 'footprint' of CCS projects. Commercial scale CCS deployment will require an integrated policy, regulatory, legal, public perception and operational framework, which will determine the overall viability of the exercise. It is now generally agreed by IEA, EU, UNFPCC and International Risk Governance Council (IRGC) that a globally consistent system of regulation and risk governance is required, within which national deployment and site specific local considerations may be coordinated. Thus, a life cycle regulatory approach is advocated (see Figure 37) for site characterisation, injection, closure, post-closure and long term stewardship of any CCS project for an indefinite period of time.

The draft EU Directive on CCS proposes that:

> The competent authority in EU Member States must ensure that inspections are carried out to verify that the provisions of the proposed CCS Directive are observed. It is proposed that routine inspections must be carried out at least once a year, involving examination of the injection and monitoring facilities and the full range of environmental effects from the storage complex. In addition, non-routine inspections must be carried out if any leakage has been notified, if the operator's annual report to the competent authority shows that the installation is not compliant with the proposed directive, and if there is any other cause for concern.

Geological storage will extend over much longer periods than the lifespan of an average commercial entity. Thus, the draft EU Directive proposes that to ensure long-term stewardship, the storage sites must be transferred to Member State control in the long term. However, the *polluter pays* principle requires that the operator retain responsibility for a site while it presents a significant risk of leakage. The EU proposes that rules are needed to ensure that no distortion of competition arises from different Member State approaches.

Under the proposed EU directive, a storage site will only be transferred to the state when all available evidence indicates that the CO_2 will be safely contained for the indefinite future. This is the second key decision in the lifecycle of a storage site (the first being the decision to permit the site for use),

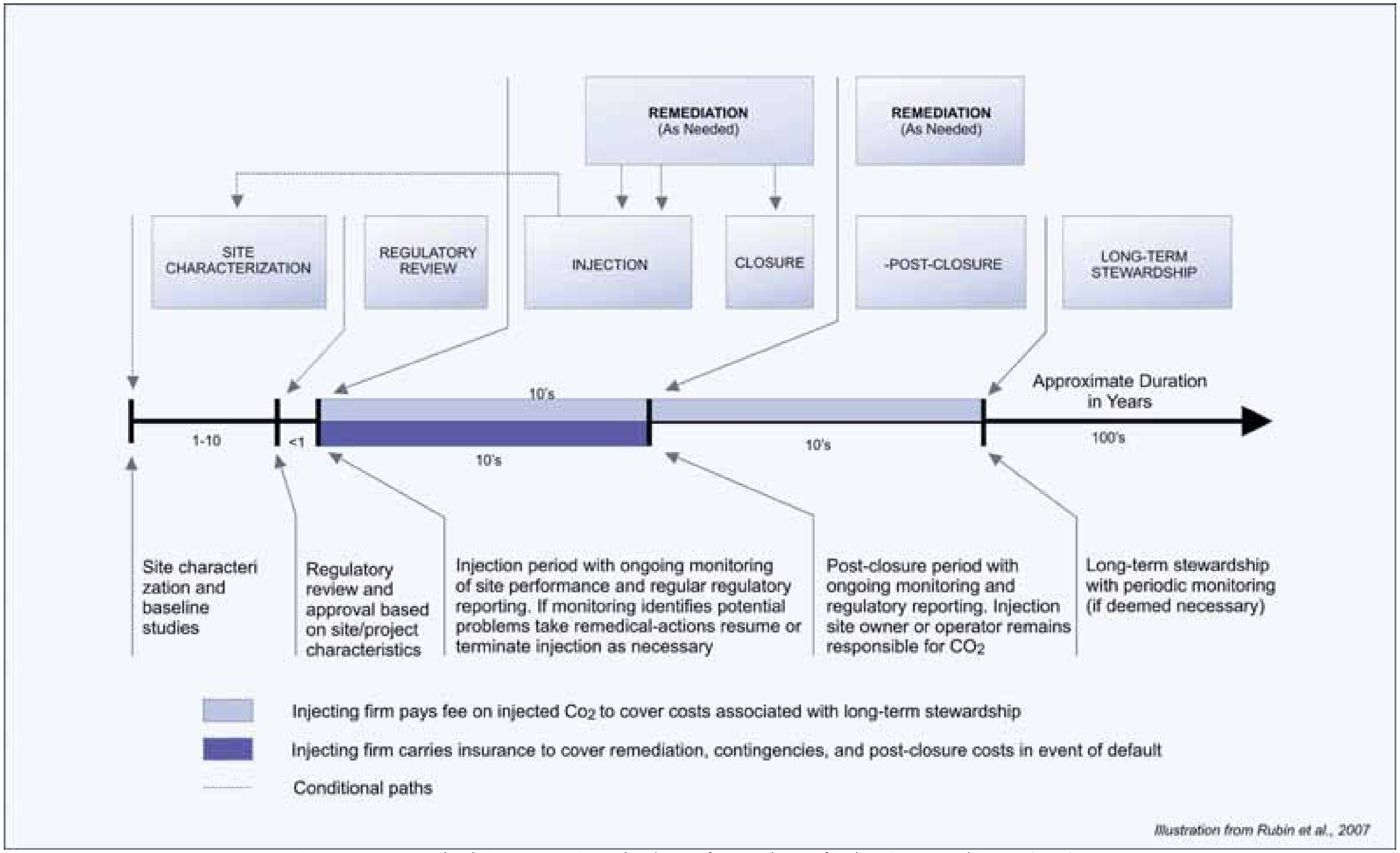
[91] EU Technology Platform for ZEFFPP: Working Group No 3 - Infrastructure & Environment (May 2006)

and independent monitoring and verification will be required. The following[92] summarises the basic regulatory requirements for a given storage site:

Project Phase	Element	Sub-Element	Notes
Project Planning & Design	Baseline Survey	Site Selection	-Identification of suitable sites, including site characteristics
		Site characterisation, fate & behaviour studies of CO2	- Factors: regional seismicity, trapping mechanisms, delimitation of storage site boundaries; potential migration pathways; secondary containment features ((storage complex paradigm); Achieved through static & dynamic reservoir simulation modelling (long & short term) - Injection Strategy: CO2 delivery rate, reservoir injectivity/ permeability - Identification of potential receptors (for humans, ecosystems; commercially important resources)
		Estimation of potential impacts (risk-based assessment)	- Range of hazard scenarios (leakage; induced seismicity); displacement of formation fluids; mobilisation of metals) - Estimation of likelihood, probability potential for frequencies for such scenarios - Consequence of analysis - Acceptability of risks
	Risk Management & Liability Regime	Design of risk management system including financial securities	- Injection strategy & design (linked to delivery rate & injectivity) - Monitoring scheme design for injected CO_2 plume & surrounding zones and receptors Remediation strategies & technologies - *A priori* financial provisions to cover costs of remediation, after-care, esp. in case of operator insolvency
		Application of appropriate QA/QC & external assurance	- Appropriate use of data sources; modelling assumptions; application of expert judgement, external expert committee; consultation & verification
Project Operation	Implement of Risk Management System	Operation of above-ground installations	Siting of above ground installations Good operational practice Operator competency
		Monitoring of CO2 flows and emissions above and below ground	- Early detection of CO_2 seepage or un-intended migration - For chain of custody & GHG accounting obligations - Need to match & calibrate models; adaptive learning to improve continuously sub-surface knowledge
		Remediation options	Need to ensure liability allocated for remediation of any damage caused (local or global)
		Monitoring of CO2 purity	needed for GHG accounting - Ensure that storage site is not compromised by impurities - Ensure operators do not use CCS to co-inject other hazardous substances.
Project Cessation & Closure	Legal Consideration	Conditions upon which site closure might commence	May need to specify conditions under which site closure would commence (P, volumes etc) - Need for enforced closure procedure for unsatisfactory sites.
	Technical Decommissioning Considerations	Well plugging & abandonment techniques	Based on best available techniques at time of decommissioning
Post-Closure	Site Stewardship (long term)	Ongoing monitoring obligations	To ensure c long term safe storage. Assess long term storage stability
	Liability	Ongoing liability provisions & transfer	Need to consider conditions for which satisfactory evidence that secure storage is achieved, where monitoring may cease or be reduced, and liability transferred from operator to host government.

[92] EC-DG Environment – Task 2 Discussion: *Choices for Regulation of CO_2 Capture and Storage in the EU*, 2007.

Figure 37: Life Cycle Stages of a CCS Project (after IRGC 2008)



Source: International Risk Governance Council: *Policy Brief on Regulation of Carbon Capture and Storage* (2008). www.irgc.org

6.6 Monitoring & Regulation

One of the critical environmental tools to be developed across all CCS projects will be effective environmental monitoring tools. Accurate and verifiable life cycle monitoring systems must be developed in tandem with capture, transport and storage technologies, to the highest standards, if public acceptance is to be achieved as recommended below (Table 30; Figure 38: Recommended Monitoring Techniques for Carbon Storage Projects below).[93]:

6.6.1 Regulation & Monitoring - a Practical Approach under EU-ETS

Under the EU-ETS (Section 2.3.2 above), Article 14 of the ETS Directive required the EC to elaborate guidelines for Monitoring and Reporting (MRG) of greenhouse gas emissions under ETS. MRG were adopted in January 2004, but have been amended by EU-wide consultation through 2006-2007. The current MRG 2007 were adopted under decision C(2007)3416, to take effect from 1 January 2008. Article 14 requests that member states ensure that emissions are monitored in accordance with these legally binding guidelines. MRG 2007 contains a new Annex XII to specify approaches for continuous emissions monitoring systems. It also establishes a recommended sequence and key actions for monitoring as follows:

Permitting
Monitoring Plans
Monitoring
Reporting
Verification (*to include strategic analysis; risk analyses; materiality balance; internal & external verifications)*

For monitoring purposes, the MRG also set out practical means by which the mass balance of CO_2 **emissions may be defined and from which portion of a CCS installation.** The ETS Directive also contains specific definitions for capture and transport elements of the CO_2 network.

Capture includes all parts of an installation's activities connected to the purpose of capturing CO2, intermediate storage and transfer to the CO_2 network. All emissions from combustion, production and other capture-related processes must be accounted for, including fuel and material inputs. Fugitive emissions from capture, intermediate storage and transfer to the starting point of the transport network must be accounted for, while a mass balance approach to calculating CO_2 emissions is advocated:

$$CO_{2\text{-emissions}}\,[tCO_2] = CO_{2\ \text{installation activities}} - CO_{2\ \text{transferred to transport}}$$

Where: $CO_{2\ \text{installation activities}}$ = amount produced, unrelated to CCS, determined by measurement
$CO_{2\ \text{transferred to transport}}$ = determined by continuous emissions measurement

Transport of CO_2 will be defined under the transport network's permit and will include all installations connected to the pipeline for geological storage of CO_2, including booster stations. Every transport network has defined 'start' and 'end' points (S&E) which must be legally defined under the ETS Directive, connected to the other CCS components. S&E points can include bifurcations of the pipeline and national boundaries where relevant. The mass balance approach must be applied (as per capture component and including fugitive elements) by verifiable mass flow measurements:

$$CO_{2\text{-emissions}}\,[tCO_2] = L\ (km) \times EF\ tCO_2/\ km$$

Where: L = length of pipe / EF = Emissions Factor = [tCO_2/ km]

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[93] Zero Emission Fossil Fuel Power Plants (ZEFFPP) WG2: *CO_2 Use and Storage – Contribution to the EU Strategic Research Agenda.* May 2006.

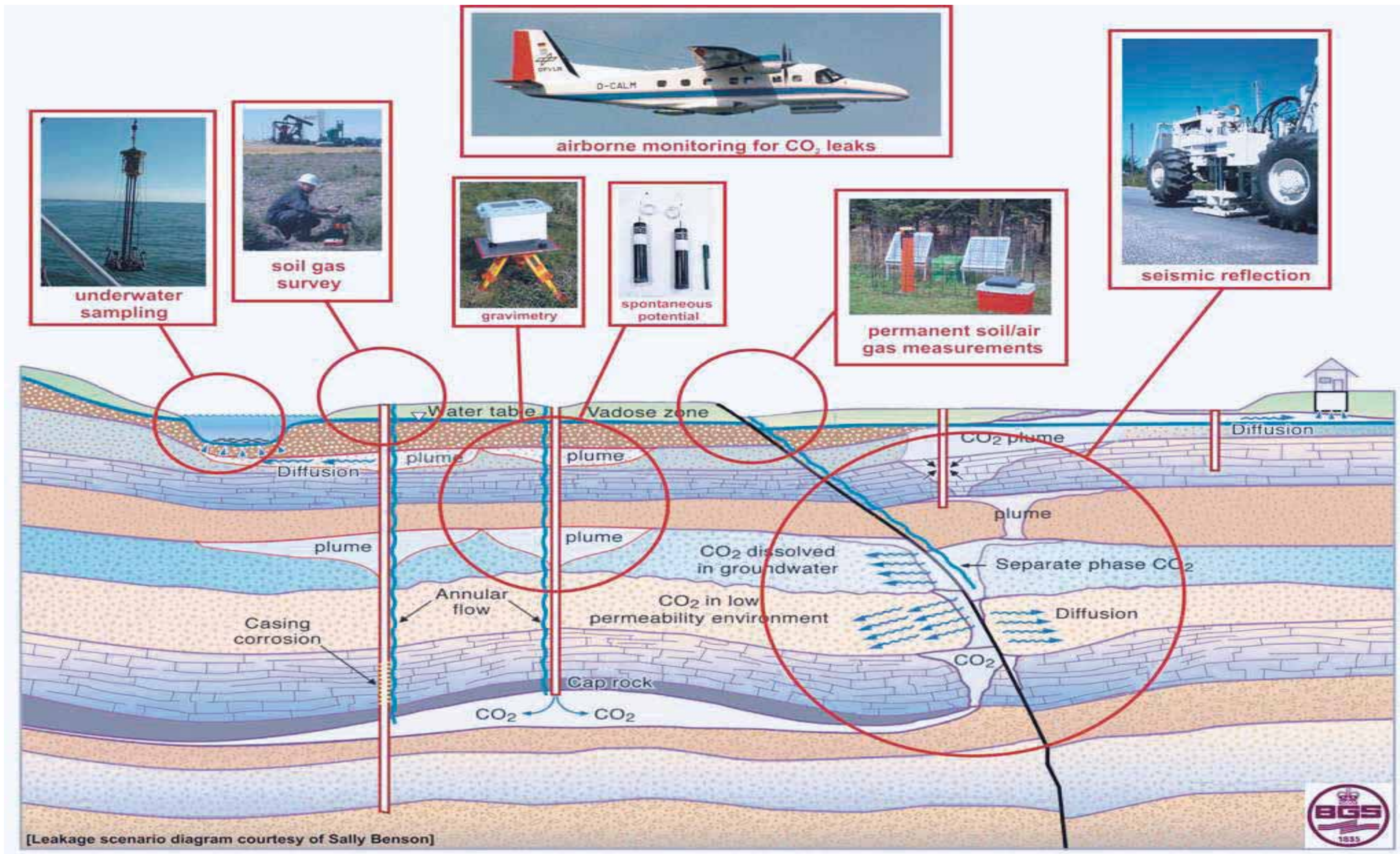
If there are no losses / fugitive leaks, this must be proven by verification using representative Pressure (P) and Temperature (T) measurements, critical in establishing the overall mass balance, from the transport networks. The overall mass balance can then be compared with the emissions calculated, as set out in Annex 1 of the ETS Directive.

Monitoring of carbon storage sites will be less unequivocal and will require rigorous monitoring through each site's specific Monitoring Plan to assess the mass balance of the system. Within the EU, the most likely first contender for full commercial CCS from point source emissions will be the North Sea, where demonstration projects such as Sleipner will be critical in verification of CO_2 dispersion modelling and overall safety of CCS systems. The following steps are proposed to monitor storage sites (Table 31), as illustrated in Figure 38 below:

Table 30: Monitoring Requirements of Carbon Storage Projects

Develop site specific Monitoring Plan	***The Monitoring Plan should be guided by performance and risk analyses to benchmark the overall CCS performance. Local regulatory framework and public acceptance may mean additional requirements (and costs)***
Operational Monitoring *Standard techniques used in hydrocarbon industry*	Control of the injection operation Gas volume, composition, pressure, temperature measured & data transmitted to control centre
	Microseismicity – allows real-time imaging of fracture extensions to control injection parameters (as used in the petroleum industry) and avoid fracturing the cap (seal) rock. Comparing of modeled and actual behaviour of fractures.
Verification Monitoring *May require new technological inputs to develop systematic and comparative monitoring tools*	Location, distribution & migration of CO_2 in the storage reservoir: gravimetric techniques- detection of variations in rock / fluid densities. 2-D/ 3-D/ 4-D seismic techniques to characterize the sub-surface & migration of CO_2. Vertical imaging & cross-well measurements may also be applied for more detail on site specifics. Electro-magnetic (EM)/ Magneto-telluric (MT) sensing will allow measurement of saline fluid displacements as well as dissolution of minerals through variations in resistivity. Migration of CO_2 may produce an electric potential which can be tracked to image the CO_2 plume migration.
Verification of ground surface movement	Tiltmeters or ground elevation measurements can assist in monitoring the CO_2 sub-surface plume by monitoring surface movement or displacements due to shear or creep.
Verification of Geochemical Integrity	Reservoir fluid geochemistry (if samples can be taken from the injection wells) can be monitored to determine whether chemical reactions are taking place and can provide information on acidity, alkalinity, temperature, pressure etc.
Well Integrity *Much concern about potential for leakage at injection sites, since this is where the storage facility has been 'punctured' (as well as at older production wells (if a depleted hydrocarbon field).*	Pressure & gas composition in the well annulus must be monitored continuously (drill string; casing etc), with pressure & temperature sensors. Cement bond logs can determine the integrity of the bond between the rock and the well casing. Casing corrosion can be monitored by ultrasonic or EM logging tools.
Caprock (Seal) Integrity	Microseismics can allow imaging of fault movements through the vertical profile above the injection site.
Monitoring of Leakages *Define measurement grid – establish controls*	Analyses of soil-gas fluxes and concentrations in space/ time (generally related to deep seated faults). Multivariable geochemical analyses should allow monitoring of the quality of containment over time. Fault-pathfinder trace gas elements and isotopic soil gas surveys will detect leakage routes before and during injection. Other geophysical techniques can be applied in tandem in case specific measures.
Monitoring of Contamination	Measuring of major ion concentrations, alkalinity, pH, ratio of stable carbon isotopes etc can assist in determining changes to shallow aquifers. Vegetational changes through airborne/ satellite surveys can be highlighted over short to prolonged periods.

Figure 38: Recommended Monitoring Techniques for Carbon Storage Projects



6.7 Conclusions

Environmental liability and responsibility of CCS need to be defined very carefully by regulators, as the establishment of causal links to negative impacts, either to single party or among multiple operators, will be exceedingly difficult[94] particularly with the time scales involved.

As well as assessment, monitoring and validation techniques, technologies for mitigation of damages and site remediation may also be necessary in the longer term as CCS becomes more 'mainstreamed'. Internationally, most regulation will likely be modelled on existing hydrocarbons/ landfill industry regulations at the outset (as is happening in USA), but effective regulatory and legal mechanisms for CCS will need to evolve more quickly in line with increased deployment of CCS projects.

The London/ OSPAR accords and planned guidelines, especially the FRAM, may be especially useful in this regard (see Section 6.1 above).

- All stages of the CCS chain have specific associated risks and a life cycle approach to regulation, monitoring and verification must be taken.
- An integrated EHSIA approach should be taken to assess the likely and specific impacts of CCS on the environment, human and animal health and communities.
- No country has a comprehensive program for the role of CCS in its energy or climate change strategies to date, although an emerging consensus is emerging on how CCS may best be operated and regulated, particularly in Australia, USA and Europe.
- Commercially workable rules for long-term liability may be needed to incentivise investment in CCS. The issue of who gains/ loses carbon credits (the operator or the state) based on independently assessed site performance reviews will need to be addressed.
- Long term liability is likely to pass from the facility operator to the state once an independently verified performance certificate has been issued by an international body, likely an IEA or UN agency.
- CCS rules need to provide legal and regulatory clarity, thus ensuring a clear and stable business environment.

[94] Wilson, EJ; Friedmann SJ; Pollak MF (2007). Research for Deployment: Incorporating Risk, Regulation & Liability for Carbon Capture and Sequestration. Envir. Science & Technology, V. 41, Nº 17.

7 ECONOMIC MODELLING OF SELECTED CASE STUDIES

The cost and engineering estimates shown in this report are generated using a techno-economic model developed in-house at the University of New South Wales, study partners of CO2CRC of Australia. The full details of the study are presented in Annexe 2.

Three key source-to-sink scenarios emerged from the geological and economic assessment of the potential for storage of carbon dioxide on the island of Ireland, within the context of the all-island and broader international energy policy frameworks and commodity prices. This section presents the summary results of a screening study of the economics of three carbon capture and storage (CCS) case studies.

Each scenario has been analysed by the team, with sensitivity analyses, for consideration (see Table 31 below). The three sources are new build power plants at Moneypoint, Cork and Kilroot. It is assumed that Kinsale Head is used to store CO_2 from Moneypoint and Cork in Ireland, while the Portpatrick Basin is used to store CO_2 from Kilroot in Northern Ireland.

7.1 Aims and Methodology

The capital, operating and abandonment costs have been estimated, as well as the costs per tonne of CO_2 avoided for CO_2 separation, transport and injection. The cost of electricity is reported as € per MWh for projects with and without CCS. The costs are presented in before tax real €2008 terms. They are based on limited processing, cost and reservoir data and have a margin of error of ± 50%[95].

The cost of the CCS projects has been estimated excluding tax effects and the impact of how the European Emissions Trading Scheme (ETS) might affect the economics has not been considered.

Table 31: Summary of Economic Cases Examined

Number	Power plant type	Source location	Sink	Sensitivity Analysis
Case 1A	900 MW_e pulverised coal	Moneypoint	Kinsale Head	Yes
Case 1B	900 MW_e pulverised coal	Moneypoint	Kinsale Head using alternative onshore route	No
Case 1C	900 MW_e IGCC	Moneypoint	Kinsale Head	No
Case 1D	900 MW_e pulverised coal and retrofit natural gas power plants	Moneypoint and Cork	Kinsale Head	No
Case 2A	900 MW_e pulverised coal	Cork	Kinsale Head	Yes
Case 2B	900 MW_e pulverised coal	Cork	Kinsale Head with alternative offshore route	No
Case 2C	900 MW_e plant	Cork	Kinsale Head	No
Case 2D	540 MW_e pulverised coal	Cork	Kinsale Head	No
Case 3A	540 MW_e pulverised coal	Kilroot	Portpatrick Basin	Yes

[95] 50% error is an indicator of the accuracy of these estimate as appropriate to a scoping report.

7.1.1 Definition of CO_2 Avoided

The net reduction of CO_2 emissions as a result of CCS can be referred to as the amount of CO_2 avoided:

$$\left[\mathrm{CO_2\ avoided}\right] = \left[\mathrm{CO_2\ emitted\ without\ CCS}\right] - \left[\mathrm{CO_2\ emitted\ with\ CCS}\right]$$

The amount of CO_2 avoided is different from the amount of CO_2 stored, which represents the quantity of CO_2 that is injected into a geological reservoir.

For example, the amount of CO2 avoided and stored in million tonnes per year for the Kilroot project is shown in below.

Figure 39: Mass of CO_2 avoided in the Kilroot to Portpatrick Basin Base Case Study

A. Without CCS			
CO_2 generated	3.25 Mt/yr		
CO_2 captured and stored	0 Mt/yr		
CO_2 emitted	3.25 Mt/yr		
B. With CCS			
CO_2 generated	4.19 Mt/yr		
CO_2 captured and stored		3.77 Mt/yr	
CO_2 emitted (CCS)	0.42 Mt/yr		
C. Increment = (B) - (A)			
CO_2 generated			0.95 Mt/yr
CO_2 captured and stored		3.7 Mt/yr	
CO_2 avoided		2.83 Mt/yr	

7.1.2 Process Modelling

The model determines the characteristics of the equipment, estimates the costs and the total energy consumption. The CO_2 separation, transport and injection phases of the CCS process (but not the power plant cycle) are modelled.

As regards to CO_2 separation, the energy required for cooling and compressing the feed gas, pumping and regenerating the solvent is included.

The CO_2 compression and transport costs are influenced by a combination of the required down-hole injection pressure, the static head and frictional losses in the wells and flowlines.

For the Kilroot to Portpatrick Basin study, it is assumed that a minimum pressure of 86 bar (1,250 psia) and maximum pipeline pressure of 152 bar (2,200 psia). For the Moneypoint and Cork to Kinsale Head, a minimum pipeline pressure of 1 bar (15 psia) and a maximum pressure of 100 bar (1480 psia) are assumed. The pipelines are made from X65 carbon-steel line pipe, but the effects of terrain and land use on pipeline construction costs are not included.

In this analysis, many simplifications have been made. Short cut correlations and simplified process models have been used. In addition, simulation of the separation processes or the reservoir has not been attempted.

7.1.3 Economic Modelling & Assumptions

The techno-economic model estimates the individual equipment, operating, abandonment and the total costs of carbon capture and storage. The main output from the model is the before-tax real specific cost of CO_2 avoided.

This is defined as:

$$J = \frac{\mathrm{PV}(\mathrm{Capex}) + \mathrm{PV}(\mathrm{Opex}) + \mathrm{PV}(\mathrm{Abex})}{\mathrm{PV}(\mathrm{CO_2\ Avoided})} = \frac{\mathrm{PV}(\mathrm{Total\ Cost})}{\mathrm{PV}(\mathrm{CO_2\ Avoided})} \quad (1)$$

where, PV represents the present value of the capital cost (Capex) in € million, operating costs (Opex) € million, the abandonment costs (Abex) in € million and the mass of CO_2 avoided.

The specific cost real cost of CCS for power plants can be calculated as:

$$J = \frac{\Delta COE}{\Delta EI_{CO2}} = \frac{COE_{CCS} - COE_0}{EI_{CO2,0} - EI_{CO2,CCS}} \quad (2)$$

where COE is the cost of net electricity in € per MWh. EI represents the emission intensity of CO_2 in tonne per MWh. The subscripts 0 and CCS denote without and with CO_2 capture respectively.

It was assumed that the specific cost of CCS is the difference between the costs of a power plant with CCS and one without. This methodology reflects IEA and US DOE guidelines[96]. The effect of a carbon price from EU Emissions Trading Scheme in determining the cost of CCS or the sent out cost of electricity have not been included in this study. (Appendix 1 in Annexe 2 briefly describes how this can be calculated).

[96] The results presented in this report can be used to determine the CCS cost of CO_2 avoided in relation to different reference points. For example, the reference point could be a new best entrant power plant such as a CCGT plant without CCS. The CCGT plant has a COE of €60/MWh and an emission intensity of 0.4 ton/MWh CO_2. If we assume that a new power plant with CCS has a COE of €90/MWh and a CO_2 emission intensity of 0.1 ton/MWh, the specific cost of CCS can be calculated as (90-60) €/MWh ÷ (0.4-0.1)ton/MWh = €100/ t CO_2 avoided.

The change in cost of electricity can be calculated as:

$$\Delta COE = COE_{CCS} - COE_0 = \frac{\mathrm{PV(Total\ Cost)}_{\mathrm{CCS}} - \mathrm{PV(Total\ Cost)}_0}{\mathrm{PV(NESO)}} \quad (3)$$

NESO is the Net Electricity Sent Out (TWh). This is the same both with and without CCS.

The costs of CO_2 injected are not presented. However, this can be calculated using Equation (2) by replacing CO_2 avoided with the amount of CO_2 injected.

It is assumed that for the offshore component of CCS, the abandonment cost is 25% of the sum of capital costs of the CO_2 compressor, pipeline and injection wells and platforms. For the power plant and separation plant, it is assumed that the abandonment costs are offset by the salvage value of the process equipment.

Table 32 below lists the economic assumptions used in this analysis. The costs are in €2008 terms. The exchange rate is assumed to be 1.25 US per € based on the average daily exchange rate from January 2003 to May 2008.

Table 32: Economic Assumptions of Base Cases

Property	Value	Units
Cost year	2008	
Currency	Euro	€
Exchange rate	1.25	US$ per €
Discount rate	7	% real *(*based on IEA standard*)
Project life (injection period)	25	Years
Construction period	2 (CCS) 3 (Power station)	Years
Capital cost phasing	40:60 (CCS) 20:45:35 (Power station)	%
Load factor	85	%
Fuel cost (bituminous coal)	90	US$/tonne, equivalent to €2.5/GJ[97] LHV[98]
Fuel cost (natural gas)	10	$/GJ, equivalent to €8/GJ
Unit power station capital cost (IEA-GHG, 2006)	1,560 pulverised coal 1,860 IGCC 890 CCGT	€/kW

[97] The cost of coal as $ per tonne is converted to $ per GJ assuming the thermal energy of bituminous coal is 27.9 GJ per tonne.
[98] LHV represents the lower heating or calorific value, which is a measurement of the amount of heat released by burning a fuel at 25°C and returning the temperature of the product to 150 °C.

The baseline coal prices assumed in this study are calculated in the mid-range of the IEA long term coal price of US$60 per tonne and the US€120 per tonne being paid by Kilroot (AES) and Moneypoint (ESB) power stations in Q1/ 2008. To reflect rapidly rising oil and coal prices, sensitivity analyses were conducted on coal prices over a wide range of US$60 - $175. References were also made to US Department of Energy, Queensland coal statistics and the Australian Energy Regulator forecasts[99].

There are two ways of calculating the specific cost of CO_2 avoided and the cost of electricity.

1. The first way is by annualising the costs of capital and abandonment, adding them to the (constant) operating - this total annual cost is then dividing them by either the annual CO_2 avoided or the annual electricity sent out. This version requires that the operating cost and the CO_2 or electricity is the same for the entire operating period.

2. The second way is to calculate the present value of all costs and divide them by the present value of the CO_2 avoided or the electricity sent out.

It can be demonstrated mathematically that the two methods give the same answer. The second method was used in this study because it is simpler and more flexible.

Individual cases studies are presented below in summary. The reader is referred to Annexe 2 for full economic analysis.

[99] See also for coal pricing forecasts:
1. http://www.eia.doe.gov/cneaf/coal/page/coalnews/coalmar.html
2. http://www.aer.gov.au/content/index.phtml/itemId/713232
3. http://www.dme.qld.gov.au/mines/coal_statistics.cfm

7.2 Case 1 – Moneypoint Power Station to Kinsale Head Gas Field

7.2.1 CCS for a Pulverised Coal Power Station

This case study examines the CCS costs of a new-build 900 MW_e sent-out pulverised coal power plant in the Shannon Estuary at Moneypoint. The total capacity of the power plant excluding the power required for auxiliaries is 1,160 MW. Of this total, 260 MW_e (22%) is used for CCS.

Table 33: CCS costs for Moneypoint to Kinsale Head

Moneypoint to Kinsale Head	Reference power station without CCS (A)	Power station with CCS (B)	Incremental effect of CCS (B - A)
Capital Cost (€ million)[100]	1,509	2,712	1,203
Annual operating cost (€ million/yr)	229	343	114
Abandonment cost (€ million)	0	101	101
Annual CO_2 emissions (million tonnes)	5.41	0.70	(4.71)[#]
PV** of costs (€ million)	3,480	5,601	2,121
PV of CO_2 Avoided (Mt)	–	–	44.8
PV of Power Sent Out (TWh)	64	64	0.0
Cost of Net Electricity Sent Out (€/MWh)	**54.6**	**87.9**	**33.3**
Specific CCS Cost (€/t CO_2 avoided)	**–**	**–**	**47.4**

[#] A total of 6.27 Mt is injected and 4.71 Mt is avoided each year
** Present Value

CO_2 is separated from the flue gas of the power plant using solvent absorption. The CO_2 is compressed, transported 185 km onshore and 50km offshore. It is then injected at <u>sub-critical</u> state into the subsurface into Kinsale Head depleted gas field. The amount of CO_2 avoided annually is 4.71 million tonnes.

The capital cost of the CCS project including the cost of the power plant is €2,712 million. The annual operating cost is over €343 million. The effect of changing the onshore pipeline route to include a 2.5km water crossing at the Shannon Estuary and reducing the onshore distance from 185km to 130km is marginal.

The study's best estimate of the specific cost of CCS at Moneypoint is €47 per tonne CO_2 avoided.

7.2.2 Sensitivity Analyses

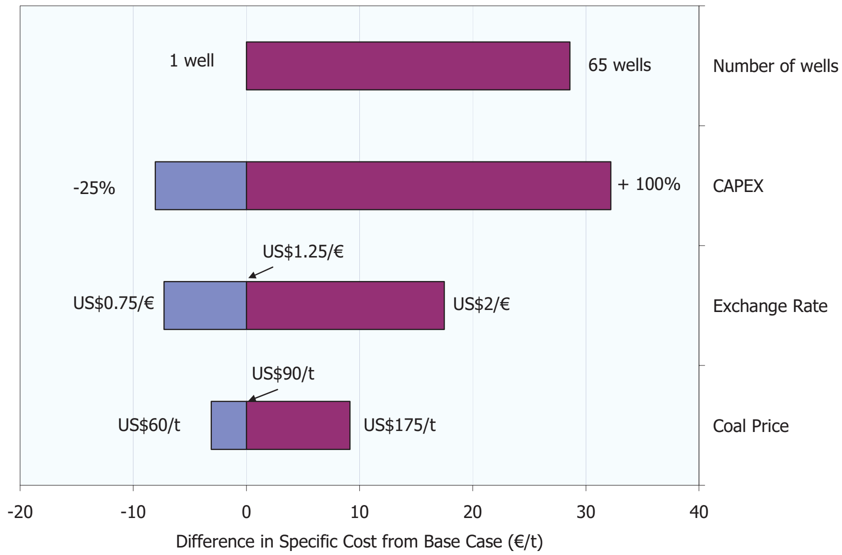
The figure below gives a summary of the sensitivity of the base case estimates to changes in the exchange rate, coal price, capital costs and the number of injection wells. The central cost estimates are most sensitive to changes in the capital cost. Doubling the capital cost can increase the CCS cost estimates by almost €35 per tonne CO_2 avoided.

Reflecting uncertainties in injection conditions at Kinsale (see Section 3.7 above), the effect of increasing the number of wells to take into account well interference and pressure build-up in the reservoir was examined; increasing the number of wells from an estimate of 1 to 65 increases the specific cost of CCS by over €25 per tonne CO_2 avoided.

[100] A more detailed breakdown of Capital and Operating Costs is presented in Annexe 3.

Variations in the exchange rate and coal price increase the costs by, less than €20 and €10 per tonne CO_2 avoided respectively.

Figure 40: Summary of Sensitivity Analyses for Case 1A Moneypoint



The costs set out above (Figure 40) exclude the costs of appraising the injection site before the CCS project is established. Additional sensitivity analyses show that such costs increase the specific costs of CCS by less than €1 per tonne CO_2 avoided. This is small because evaluation costs are considerably smaller than the costs of CCS itself.

7.2.3 CCS for an Integrated Gasification Combined Cycle (IGCC) plant

The specific cost of CCS for an IGCC power plant at Moneypoint was estimated. The total capacity is 980 MW_e, including the power required for CCS. The capital, operating and specific costs are estimated to be €2,656 million, €309 million per year and €31 per tonne CO_2 avoided respectively.

CO_2 is separated from the synthesis gas produced by the power plant. The CCS energy penalty is estimated to be 8%. With a higher energy penalty of 16%, the total capacity of the power plant would be 1,090 MW_e and the specific cost of CO_2 avoided would be over €40 per tonne.

7.2.4 CCS for both Money Point and Cork

An additional possibility is establishing CCS at Moneypoint and at the two existing natural gas fired power plants at Cork. The costs of CCS for the combined projects are €3,680 million for capital costs, €400 million per year for annual operating costs and €162 million for abandonment costs. In other words, this adds approximately €970 to the total capital costs compared to CCS for Moneypoint alone.

The specific cost of CCS increases to €56 per tonne CO_2 avoided.

7.3 Case 2 – Cork Power Station to Kinsale Head Gas Field

This case study envisages a hypothetical new-build power plant in the Cork Harbour area. The analysis estimates only the costs of establishing CCS facilities. It does not include the cost of increasing the transmission capacity from Cork or of constructing and operating a coal port.

7.3.1 CCS for a Pulverised Coal Power Station

Another potential CCS project involves capturing CO_2 from a new 900 MW_e sent out supercritical pulverised coal power plant at Cork. CO_2 is separated from flue gas, compressed and transported 6km onshore followed by a 50km offshore pipeline. The CO_2 is injected in a subcritical state at Kinsale Head.

The total capacity of the new power plant is 1,154 MW_e, with 254 MW_e consumed for CCS. The amount of CO_2 avoided is 4.7 million tonnes annually (see Table 34).

Table 34: CCS costs for Cork to Kinsale Head

Cork to Kinsale Head	Reference power station without CCS (A)	Power station with CCS (B)	Incremental effect of CCS (B - A)
Capital Cost (€ million)[101]	1,507	2,516	1,009
Annual operating cost (€ million/yr)	228	340	112
Abandonment cost (€ million)	0	54	54
Annual CO_2 emissions (million tonnes)	5.40	0.70	(4.70) ##
PV** of costs (€ million)	3,475	5,404	1,930
PV of CO_2 Avoided (Mt)	–	–	44.7
PV of Power Sent Out (TWh)	64	64	0.0
Cost of Net Electricity Sent Out (€/MWh)	54.6	85.0	30.3
Specific CCS Cost (€/t CO_2 avoided)	–	–	43.1

A total of 6.24 Mt is injected, and 4.70 Mt is avoided each year

**** Present Value**

The total capital cost of the project is €2,516 million including the cost of building the power plant. The operating costs are estimated to be €340 million per year and the specific cost of CO_2 avoided is €43 per tonne. Constructing a new pulverised coal power plant at Cork saves €4per tonne CO_2 avoided compared to Moneypoint.

Changing the transport route and thereby increasing the offshore pipeline distance from 50km to 60km does not significantly change the cost estimates.

7.3.2 Sensitivity analyses

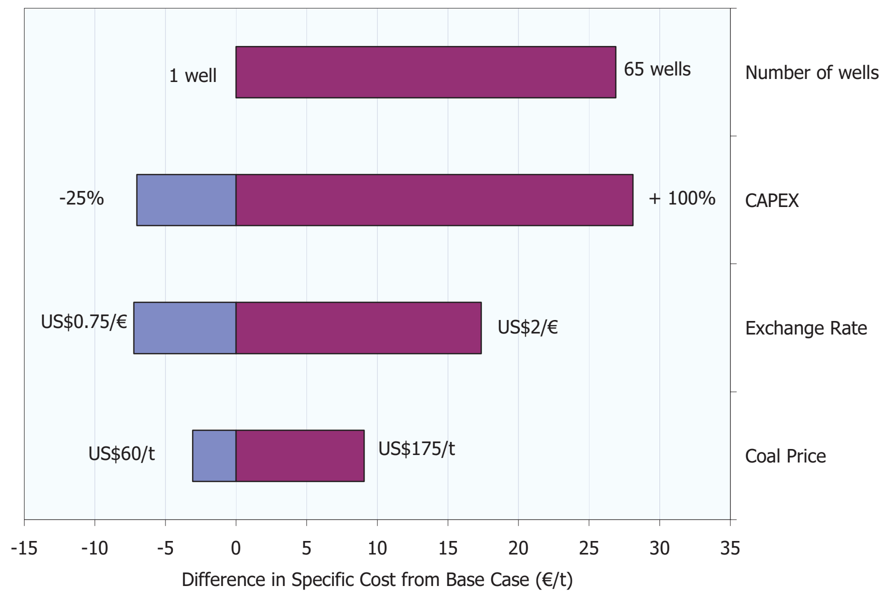
The specific cost is again most sensitive to the capital cost estimates and the number of wells. If capital costs' estimates are doubled, the cost of CO_2 avoided increases by almost €30 per tonne. Increasing the number of wells from 1 to 65 increases the specific cost of CO_2 avoided by more than €25 per tonne of CO_2 avoided compared to the base case (Figure 41below).

The project is less sensitive to the exchange rate and coal price variations. If the US dollar exchange rate increases to $US2 per €, the specific cost increases by almost €18 per tonne CO_2 avoided.

If the coal price increases to $175 from €90 per tonne, the CCS cost rises by €10 per tonne CO_2 avoided.

[101] A more detailed breakdown of Capital and Operating Costs is presented in Annexe 3.

Figure 41: Summary of sensitivity analyses for Case 2A



7.3.3 CCS for an Integrated Gasification Combined Cycle (IGCC) plant

The specific cost of CCS for a 900 MWe sent out coal integrated gasification combined cycle (IGCC) power plant at Cork is estimated to be €28 per tonne CO_2 avoided.

The total capital and annual operating costs are €2,497 million and €306 million respectively.

The total capacity of the plant is 973 MWe.

7.3.4 CCS for a 540 MW_e power plant at Cork

The capital, abandonment and annual operating costs for a new build 540 MWe pulverised coal power at Cork are €1,665 million, €50 million and €208 million respectively.

Compared to the base 900 MWe power plant, the CCS and sent electricity costs increases by 5% to €45 per tonne CO_2 avoided and €89 per MWh respectively.

The total capacity of the plant is 692 MWe, including 152 MWe for CCS.

7.4 Case 3 – Kilroot Power station to Portpatrick Basin

The costs of CCS in Northern Ireland have also been estimated. It is assumed that the CO_2 is captured from a new power plant at Kilroot. The CO_2 is then compressed, transported 40 km offshore and injected into the subsurface in the Portpatrick Basin.

The total capacity of the new power plant at Kilroot is 698 MW_e including the power required for CCS. The power sent out is 540 MW_e, which is the power requirement without CCS.

Table 35: CCS cost for Kilroot to Portpatrick

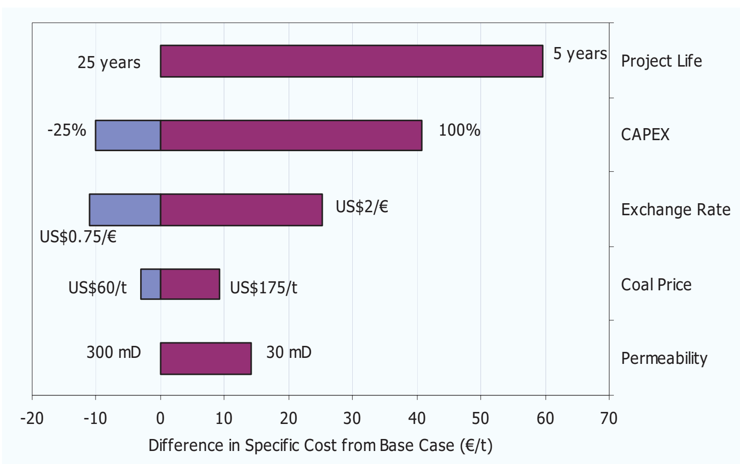
Kilroot to Portpatrick	Reference power station without CCS (A)	Power station with CCS (B)	Incremental effect of CCS (B - A)
Capital Cost (€ million)[102]	978	1,908	930
Annual operating cost (€ million/yr)	136	209	73
Abandonment cost (€ million)	–	108	108
Annual CO_2 emissions (million tonnes)	3.25	0.42	(2.83)###
PV** of costs (€ million)	2,144	3,641	1,497
PV of tonnes avoided (Mt)	–	–	27
PV of power sent out (TWh)	38	38	0
Cost of Net Electricity Sent Out (€/MWh)	56.1	95.2	39.2
Specific CCS Cost (€/t CO_2 avoided)	–	–	56

A total of 3.77 Mt is injected and 2.83 Mt is avoided each year
**** Present Value**

7.4.1 Sensitivity analyses

The effects of changes in the coal price, capital costs, reservoir permeability and project life on the cost of CO_2 avoided have been analysed (see Figure 42 below).

Figure 42: Summary of sensitivity analyses for Case 3A



The storage capacity of the Portpatrick reservoir is uncertain. The costs in Table 35 assume that the reservoir has a capacity to inject over 100 million tonnes or 3.8 millions tonnes annually for 25 years. However this could be as low as 37 million tonnes. As far as the cost estimates are concerned, these uncertainties affect the injection period.

If the injected period is reduced from 25 to 5 years, the specific cost of CCS increases by €60 per tonne CO_2 avoided.

In addition, increases in the capital costs estimates can raise the specific cost of CCS by over €40 per tonne CO_2 avoided. Changes in the coal price and reservoir permeability also affect the costs, but to a lesser extent.

[102] A more detailed breakdown of Capital and Operating Costs is presented in Annexe 3.

Again, evaluation costs were shown to have only a small effect on the estimate costs. Changes to the fracture gradient also have little effect.

7.5 Cost Comparisons

Table 36 shows the breakdown for all cases of the total base plus incremental costs, as well as the incremental specific costs per tonne CO_2 avoided.

Table 36: Cost Comparisons of Project Base Cases

	Money-point PC	Money-point IGCC	Money-point + Cork Retrofit	Cork PC	Cork IGCC	Cork PC	Kilroot PC
Case Number	**1A**	**1C**	**1D**	**2A**	**2C**	**2D**	**3A**
Sent Out Power (MWe)	900	900	900	900	900	540	540
Total capital cost (€ million)[103]	2,712	2,656	3,679	2,516	2,497	1,665	1,908
Annual operating cost (€ million/yr)	343	309	399	340	306	208	209
Abandonment cost (€ million)	101	87	162	54	50	50	108
Cost of Electricity Sent Out with CCS (€/MWh)	88	82	109	85	80	89	95
Specific Cost of CO_2 avoided (€/t CO_2 avoided)							
Separation	29.7	15.1	35.7	29.6	15.0	29.5	29.8
Transport	13.3	12.4	14.9	9.8	9.1	11.2	11.7
Injection	0.9	1.0	1.0	0.9	1.0	1.4	9.8
On Costs	3.5	2.9	4.5	2.9	2.4	3.3	4.5
Total	**47.4**	**31.3**	**56.1**	**43.1**	**27.5**	**45.4**	**55.7**

The lowest cost estimate of €28 per tonne CO_2 avoided is for an IGCC power plant with CCS at Cork with storage in Kinsale Head. This cost is up to €30 per tonne CO_2 avoided less than the other source - sink combinations.

The costs of CCS for IGCC power plants are approximately €15 per tonne less than those for pulverised coal power plants. This reflects the lower energy penalty of recovering CO_2 from high pressure gasification systems, reducing the operating costs of the power plant and the amount of total CO_2 generated.

The project with the lowest capital and operating costs is the 540 MW_e pulverised coal power plant with CCS at Cork with storage in Kinsale Head. This is because the power plant is smaller and the transport distance is shorter. CCS for Kilroot to Portpatrick has slightly higher capital costs, even though the size of the power plants and the transport distances are similar. The higher capital cost reflects the more expensive platform costs for deep water. This increases the specific cost to €56 from €43 per tonne CO_2 avoided.

The project with the highest cost is retrofitting the existing natural gas fired power plants at Cork for CCS and connecting it to the CCS project from Moneypoint power plant to Kinsale Head (Case 1D). The capital costs are larger than the other projects because of the costs for separating CO_2 at four different

[103] A more detailed breakdown of Capital and Operating Costs is presented in Annexe 3.

power plants. The operating costs per MWh are also higher for this project because using natural gas is three times more expensive than coal. Although economies of scale are achieved for transporting a large volume of CO_2 in the offshore pipeline, the high costs of the four separate CO_2 recovery processes and the large operating costs result in a high CCS project cost.

The comparative cost of electricity including the cost of carbon credits, with and without CCS, for seven modelled cases is reported in Table 37. In this analysis a carbon credit price of €35/t is assumed.

Table 37: Cost of Electricity including the Cost for Carbon at a Price of €35/t

	Money-point 900 MW PC	**Money-point 900 MW IGCC**	**Money-point PC with Cork Retrofit**	**Cork 900 MW PC**	**Cork 900 MW IGCC**	**Cork 540 MW PC**	**Kilroot 540 MW PC**
Reference power plant without CCS (A)							
PV of all costs (€MM)	3,480	3,961	3,487	3,475	3,952	2,182	2,144
PV of CO_2 emitted (Mt)	51.4	45.4	70.6	51.3	45.3	31.0	30.9
PV of electricity sent out (TWh)	64	64	64	64	64	38	38
COE with no carbon price (€/MWh)	54.6	62.1	54.6	54.6	62.1	56.8	56.1
PV of carbon credits (€MM)	1,800	1,588	2,472	1,797	1,584	1,086	1,081
PV of costs incl. carbon (€MM)	5,280	5,548	5,958	5,272	5,536	3,268	3,224
COE with carbon price (€/MWh)	82.9	86.9	93.4	82.9	87.0	85.0	84.3
Power plant with CCS (B)							
PV of all costs (€MM)	5,601	5,226	6,958	5,404	5,061	3,411	3,641
PV of CO_2 emitted (Mt)	6.6	4.9	8.7	6.6	4.9	4.0	4.0
PV of electricity sent out (TWh)	64	64	64	64	64	38	38
COE with no carbon price (€/MWh)	87.9	81.9	109.0	85.0	79.5	88.8	95.2
PV of carbon credits (€MM)	232	173	305	231	172	139	140
PV of costs incl. carbon (€MM)	5,833	5,399	7,262	5,635	5,233	3,550	3,781
COE with carbon price (€/MWh)	91.6	84.6	113.8	88.6	82.2	92.4	98.9
Incremental effect of CCS (B-A)							
PV of all costs (€MM)	2,121	1,266	3,471	1,929	1,109	1,229	1,498
PV of CO_2 emitted (Mt)	-44.8	-40.4	-61.9	-44.7	-40.4	-27.1	-26.9
PV of electricity sent out (TWh)	0	0	0	0	0	0	0
COE with no carbon price (€/MWh**)**	**33.3**	**19.8**	**54.4**	**30.3**	**17.4**	**32.0**	**39.2**
PV of carbon credits (€MM)	-1,568	-1,415	-2,167	-1,566	-1,412	-947	-941
PV of costs incl. carbon (€MM)	553	-149	1,304	364	-303	281	557
COE with carbon price (€/MWh)	**8.7**	**-2.3**	**20.4**	**5.7**	**-4.8**	**7.3**	**14.6**

* The Present Value (PV) of all costs is the sum of the PV of project capital, operating and abandonment costs.

7.6 Conclusions: Economic Analysis

The economic assessment of CCS on the island of Ireland concludes that:

- In a reference power plant without CCS (A), the Cost of Electricity (COE) with no carbon price ranges from €54.6 - €62.1 /MWh, while with carbon price, ranges from €82.9 - €93.4/ MWh.

- In a power plant with CCS (B), the COE with no carbon price ranges from €79.5 - €109 /MWh, while COE with the carbon price ranges from €82.2 - €113.8 /MWh.

- Significantly, the incremental effect of CCS (A-B)-based COE with no carbon price is a range from €17.4 - €54.4/ MWh, but with a carbon price of €35/t CO_2, lies in the range of -€4.8 to +€20.4/ MWh.

The costs of CCS range from €28 to over €56 per tonne CO_2 avoided. The costs are highly dependent on the source of CO_2 and the conditions and location of the storage reservoirs.

The cost of electricity sent out with CCS for new build pulverised coal power plants is €85 to €95 per MWh. For IGCC power plants with CCS, the cost of electricity sent out is €80 to €82 per MWh.

The source to sink combination with the lowest cost (€28 per tonne CO_2 avoided) involves capturing CO_2 from a 900 MW_e IGCC located at Cork, with subsequent storage in Kinsale Head. CCS from an IGCC power plant located at Moneypoint with storage in Kinsale Head has a slightly higher cost (€31 per tonne CO_2 avoided). The costs of capturing CO_2 from pulverised coal power plants at the same location is approximately €16 per tonne CO_2 avoided higher. A cost of €56 per tonne CO_2 avoided for capturing CO_2 from at Kilroot with storage in the Portpatrick Basin is estimated.

The sensitivity results show that cost estimates are strongly affected by capital cost estimates. Doubling the capital costs increases the specific cost of CCS by €30 to €40 per tonne CO_2 avoided. The CCS costs are also affected by reservoir and fluid behaviour uncertainties, which in turn affect the number of wells required. The cost estimates increase by up to €30 per tonne CO_2 avoided if the number of wells increase from 1 to 65. Changes in the US dollar to Euro exchange rate and the coal price have a smaller impact increasing the costs of CCS by up to €20 per tonne CO_2 avoided. Site evaluation costs have a small effect on the total costs.

The comparative analysis indicates that a capture-ready power plant, which includes the cost of carbon pricing at €35/t CO_2, could be highly competitive in the all-island energy market place. With price incentives similar to those currently on offer to offshore wind and wave power generators, this would be particularly so.

This report is a preliminary analysis based on limited process and cost data. Rules of thumb and simple equations have been used to model the cases. Detailed process or reservoir simulations have not been carried out. As such, the results of this report are indicative with a margin of error of ±50%. Furthermore, the effect of tax and any effects of the European Emissions Trading Scheme have been excluded.

7.7 Recommendations: Economic Analysis

It is recommended that:

- More reservoir data be acquired to assist in characterising the storage sites;
- The geological modelling of the Kinsale and Portpatrick Basin formations be expanded;
- Detailed and comprehensive reservoir simulations are carried out for each storage site;
- The behaviour of the CO_2 injected at Kinsale over time is modelled in detail;
- Local vendor quotes for capital and operating expenses be obtained; and
- Process simulation of the power plant cycle is carried out, in particular for the IGCC power plant.

An economic feasibility assessment, including full geological, engineering design and costing should be undertaken to address the considerable uncertainties identified in this report.

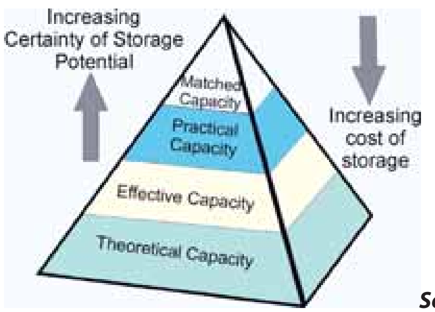
8 Conclusions

The following conclusions may be drawn as a result of this study.

8.1 Geological Assessment of Storage Capacity

An integrated assessment of the geological storage capacity of the island of Ireland was carried out for suitable onshore and offshore geological basins and structures. The study estimated, using the techno-economic resource pyramid recommended by the international Carbon Sequestration Leadership Forum (2007), that the island has a total storage capacity volume of **93,115 Mt.**

Figure 43: Techno Economic Resource Pyramid



Source: CSLF 2007

This storage volume may be subdivided as follows:

TOTAL:	**93,115 Mt**
• **Theoretical Capacity:**	**88,770 Mt**
• **Effective Capacity (subset of Theoretical):**	**667 Mt**
• **Effective Capacity (additional to Theoretical)**	**2,840 Mt**
• **Practical Capacity (additional to Effective)**	**1,505 Mt**

A number of sites are proposed for geological storage of CO_2 including the Kinsale Head depleted gas field in the North Celtic Sea Basin, the Portpatrick Basin in the North Channel and potentially the Clare Basin off the west coast. Significantly, the geological assessment and economic analysis indicate that:

The **Kinsale depleting gas field** offers **330 Mt** of effective storage capacity. In hydrocarbon exploration terms, the Kinsale Head Gasfield is low risk with proven reservoir potential and the appropriate depths. The only risk applies to containment. The drilling of two exploration wells from the existing platforms would provide sufficient geological data to allow a comprehensive reservoir simulation to model the effect of injecting CO_2. A number of injectivity tests at different pressures could be carried out to better understand the stress regime and any potential leak points. The biggest risk of containment is existing production wells that can be recompleted with appropriate cement barriers to flow of CO_2.

The Portpatrick and Clare Basins are not well explored and there is a paucity of well data to assess their potential for CO_2 storage.

The **Portpatrick saline aquifer** (closed structures) offers **37 Mt** of effective storage capacity and a further **2200 Mt** of theoretical storage capacity. The Portpatrick Basin has adequate 2D seismic coverage and one exploration well. However the potential for CO_2 storage is better than in the Clare Basin because the permeable and porous Sherwood Sandstone Group has been identified in structural traps at the appropriate depth in the Portpatrick Basin. The drilling of two exploration wells on the identified structural traps would provide the additional information to prove up the potential of the Basin to store CO_2.

The **Clare Basin, which comprises a westward-plunging syncline,** was evaluated geologically and based on one borehole and some 2D seismic data, the study found that the onshore Carboniferous sandstones of the Basin are too shallow to be a viable storage reservoir for CO_2. Exploration in the 1960s for oil and gas concluded that there are no appropriate reservoir rocks to contain gas. However, additional exploration with modern technologies might identify potential storage for CO_2 in karstified or fractured limestones below the Carboniferous sandstones, but the volumes will be difficult to quantify in these subtle traps. In exploration terms the onshore Clare Basin is high risk with low probability of proving CO_2 storage potential. However, the geological data available at the time of the study did not permit the quantification of the theoretical storage capacity either on- or offshore. Further work is required to evaluate the deeper offshore portion of the Clare Basin, as well as deeper part of the onshore basin, given its strategic proximity to Moneypoint.

Saline aquifer storage in e.g. the **Peel Basin** (68,000 Mt theoretical) and other offshore basins could offer enormous storage capacity in the longer term, but will require significant and costly proving up and to do so. The **East Irish Sea Basin** may offer a very significant sink (**1060 Mt** effective/practical capacity in depleted gas reservoirs), but would require a collaborative approach with the UK Government.

If such capacities can be proven up to offer 'matched capacity' storage, then the island of Ireland could actively reduce its contribution to atmospheric carbon emissions and become a small but significant contributor to mitigation of climate change. However, the considerable geological data constraints must be addressed if CCS is to play a part in the island's future climate strategy.

8.2 Assessment of all-Island Ireland's Emissions

The study concludes that the island's major point source emissions of 28.8 Mt CO_2 per annum are derived from the power, alumina and cement industries distributed across the island. If CCS is to be viable then it must be proven to be economic at the largest point sources to take advantage of economies of scale. This suggests that the power sector is the primary target for CCS evaluation, centred on the two key generators at Moneypoint (ESB) and Kilroot (AES), with current emissions of 5.0 Mt and 2.4 Mt CO_2 respectively from their coal fired power plants. Planned CCGT power generating capacity in the Cork Harbour area, as well as proximity to Kinsale, suggested that Cork too should be considered as a potential capture point.

The technology of CO_2 capture from cement plants is in its infancy internationally, while other industrial / power plants are either too small or too distributed to economically justify CCS at this point in time. Thus, while the study considered the concept of developing capture 'hubs' at e.g. Shannon Estuary (power, alumina, cement) and Belfast (Kilroot and Ballylumford power), in the final analysis it focussed on capture from three single power generation sources: Moneypoint, Kilroot and Cork.

8.3 Carbon Capture and Storage

The three components of CCS were considered integrally in the study.

Capture: Three main technologies exist for capture of CO_2: post-combustion, pre-combustion and oxy-firing. Currently, the most technically proven is post combustion capture using solvent absorption as a means of separation, which was chosen for the study. The three priority sites identified for detailed economic analysis were Moneypoint, Kilroot and Cork, due to their economies of scale. Base cases were taken for each site with variable coal and gas fuel sources, while sensitivity analyses were applied to arrive at seven cost comparative scenarios.

Storage: The geological analysis indicated that two main storage sites at Kinsale and Portpatrick in the North Channel could be considered as suitable sinks to match the selected point source emission outputs, as follows:

- Kinsale: 330 Mt of effective/ practical storage which could provide a sink for Moneypoint and Cork theoretically for 50 years.
- Portpatrick: 2200 Mt theoretical storage capacity, with 37 Mt of effective storage capacity in closed structures, which could service Kilroot for 10 years in the closed structures or for > 50 years if say, 10% of the theoretical capacity were proven up.

Transport: Transport options for Moneypoint to Cork-Kinsale, Cork to Kinsale and Kilroot to Portpatrick were considered. International pipeline specifications (steel grade, pipe diameters, materials, pressures) for transport of CO_2 were assessed and applied using variable economic scenarios. Shipping of CO_2 offshore to the east coast UK was considered to be sub-economic given the short distances involved.

The study suggests that the most efficacious transport option is to compress the captured gas at point source and transmit it supercritically in dense liquid phase by pipeline to the storage destination. In the case of Moneypoint, this requires c. 185km onshore and 55km offshore pipelining. Modelling suggested that it should be decompressed and injected subcritically (40-60bar) at Kinsale due to the post-production under-pressuring of the reservoir (although this would require detailed modelling to prevent thermodynamic instability in the well bore), at least in the early stages of injection. Injection pressures may be increased as the reservoir pressure increases over time. Detailed modelling of injectivity and reservoir simulation is required.

At Portpatrick, a similar model was applied, with pipelining from Belfast Harbour offshore for 50km to the Portpatrick saline aquifer storage sites. This model can apply supercritical pressures throughout to optimise injectivity into the (already pressurised) aquifer at depth.

8.3.1 Risk Assessment of Storage Sites

The risk of leakage of CO_2 from a deep storage structure decreases up the resource pyramid with increasing certainty of storage potential. The lowest risk basin identified was that of the gas field at Kinsale in the North Celtic Sea, lying in the 'practical capacity' field.

Risks were considered for Kinsale using FEPs (frequency, events, and processes) analysis and although issues such as seal efficacy, faulting, gas chimneys, CO_2:host rock interaction and injectivity require to be modelled in detail, the structure offers an attractive storage site.

Due to the sum of its production history and known geological characteristics; the hydrodynamic and risk modelling carried out for this study, as well as a recent evaluation by Marathon (Ireland) that there are no major barriers to safe storage, the team's experience suggests that the Kinsale field has a 70% probability of providing a 'matched capacity' storage site. To move the Kinsale field towards the apex of the pyramid, the study estimates that for a costed study of €15 million, to include injectivity and reservoir simulation, the basin could be moved to a 90% probability of safe containment, within two years of study commencement.

Portpatrick was also risk assessed, but at present is significantly less well understood than Kinsale and its associated risks of ineffective containment are therefore considerably higher.

8.4 Economics of Carbon Capture & Storage

The technologies and costs involved in building a complete CCS infrastructural chain, including carbon capture technology, transport and storage elements, were examined in this study. An economic evaluation is presented, based on best current evidence, to evaluate whether the Governments should consider CCS as a valid part of future climate change strategy.

The lowest cost estimate of €28 per tonne CO_2 avoided is for an IGCC power plant with CCS at Cork with storage in Kinsale Head. This cost is up to €30 per tonne CO_2 avoided less than the other source - sink combinations.

The costs of CCS for IGCC power plants are approximately €15 per tonne less than those for pulverised coal power plants. This reflects the lower energy penalty of recovering CO_2 from high pressure gasification systems, reducing the operating costs of the power plant and the amount of total CO_2 generated.

The project with the lowest capital and operating costs is the 540 MW_e pulverised coal power plant with CCS at Cork with storage in Kinsale Head. This is because the power plant is smaller and the transport distance is shorter. CCS for Kilroot to Portpatrick has slightly higher capital costs, even though the size of the power plants and the transport distances are similar. The higher capital cost reflects the more expensive platform costs for deep water. This increases the specific cost to €56 from €43 per tonne CO_2 avoided.

The project with the highest cost is retrofitting the existing natural gas fired power plants at Cork for CCS and connecting it to the CCS project from Moneypoint power plant to Kinsale Head. The capital costs are larger than the other projects because of the costs for separating CO_2 at four different power plants. The operating costs per MWh are also higher for this project because using natural gas is three times more expensive than coal. Although economies of scale are achieved for transporting a large volume of CO_2 in the offshore pipeline, the high costs of the four separate CO_2 recovery processes and the large operating costs result in a high CCS project cost.

The comparative cost of electricity including the cost of carbon credits, with and without CCS, for seven model cases is reported in Chapter 7 (see Table 7.7), where a carbon credit price of €35/t is assumed. The incremental effect of CCS (A-B)-based COE with no carbon price is a range from €17.4 - €54.4/ MWh, but with a carbon price of €35/t CO_2, lies in the range of -€4.8 to +€20.4/ MWh.

The following overall conclusions may be reached:

- The cost of a clean coal power plant exporting 900 MWe to the grid and including carbon capture, compression, pipelining, injection and storage may cost up to €3.0 billion. The capital cost of power plant, capture and compression comprise the most costly part of the system (~ 70%), while transportation/storage and monitoring chain can comprise up to 30% when owners costs and contingencies are applied.

- Under Irish conditions and prices, the case study work has indicated that the cost of power from a power station capturing 90% of the CO_2 emissions would be €91 per MWh. This is very competitive in the current Irish situation and is lower than the ESB average generation cost for 2007.

- The economics in Ireland are very different to those in the USA where power stations are not exposed to the EU-ETS and where shorter pipelines have been factored into economic assessments. The price of power in Ireland is thus projected to be much higher than that demonstrated in studies in the US or by IEA, but are nonetheless competitive.

- There is very little difference in the cost per MWh between the three capture technologies evaluated at this stage. This suggests that Ireland does not need to elect for a specific technology at this stage. Given the overall timescales involved (minimum 8 year project from start of the EIS process), Ireland could await the outcome of 12 EU supported demonstration projects before deciding on which capture technology suits Ireland needs. Alternatively, Ireland could elect to become one of the 12 demo projects, following assessment of the upfront risk and cost commitments. However, a window of opportunity linked to the cessation of natural gas production at Kinsale within the next decade could be optimised to demonstrate that basin's CO_2 storage capacity in the shorter (<10 years) term.

- The comparative analysis indicates that a power plant with CCS, which includes the cost of carbon pricing at €35/t CO_2, could be highly competitive in the all-island energy market place.

8.5 Pricing Policy

If CCS is to be viable then it must be proven to be economic at the largest single point sources on the Island to take advantage of economies of scale. Thus the power sector is the primary target for CCS evaluation and this study indicates that clean coal presents an interesting alternative to the Governments.

The option to deploy significant additional offshore wind and wave resources is being actively incentivised by the Government in Ireland and the incentive prices being offered for electricity from these new technologies are very pertinent when examining the likely economic cost of power from clean coal plants with CCS in Ireland. Energy conservation initiatives are likely to intensify as the price for carbon emissions (modelled at €35/t in this study) is set to increase progressively, which may contribute significantly to tempering demand and arresting growth. A policy of increasing the Island's dependency on gas fired power stations is seen as posing a major security of supply challenge in the absence of new indigenous natural gas finds.

The economic analysis undertaken in this study strongly suggests that CCS could be a valuable component of Ireland's climate change strategy on an all Island basis. The modelled cost of electricity sent out varies from €80 - €109 /MWh, while the specific cost of CO_2 avoided varies from €27.5 - €56.1/t CO_2. Furthermore, the model indicates that the incremental effect of CCS-based cost of electricity with no carbon price ranges from €17.4 - €54.4/ MWh, but with a carbon price of €35/t CO_2, the increment lies in the range of -€4.8 to +€20.4/ MWh.

As an interesting cross-comparison, ESB have reported that their blended cost of electricity generation in 2007 was €104 per MWh. (per April 2008 press conference on €22 billion investment strategy). The SEI April 2008 price for electricity to medium size industry was €144.8 per MWh. Electricity from offshore wind will attract a price of €140 per MWh while the incentive price for wave power is €220 per MWh. Incentives for other renewable energy sources range from €57 per MWh (large onshore wind) to micro-hydroelectricity of €72 per MWh. The CER Best New Entrant 2007 price is quoted at €86 per MWh.

Notwithstanding the uncertainties in relation to coal prices and capital costs this outcome is seen as very positive for CCS given the huge infrastructural investments involved - some €2.9 billion for the full power generation at Moneypoint, CO_2 capture and compression, long distance pipelining and injection and storage at Kinsale. The technology in relation to capture, compression and pipelining, whilst not installed at commercial scale power plants to date, is all based on well known processes and mechanical engineering principles which, within a short number of years could be made available with little technical risk of failure.

However, in the case of all the geological basins examined, the data available on priority storage sites is insufficient to provide definitive *matched storage capacity*. Kinsale is an attractive option, but will require further geological studies in order to guarantee the technical feasibility of a CCS project in the short term. The economic analysis suggests that while €15 million may increase the probability of Kinsale offering an 'matched capacity' storage site to 90%, up to €80 million may be required to provide sufficient confidence in Kinsale as a long term geological storage option, allowing for 5 new wells to be drilled to optimise injectivity of e.g. the modelled 900MWe Moneypoint's 6.7 Mtpa CO_2 emissions. A figure of €100 million has been modelled to bring Portpatrick to a sufficient level of geological confidence in its storage capacity.

It is possible that by 2015 power station technology fitted with CO_2 capture and compression equipment will be available. For a CCS project to proceed, it is also necessary that a geological storage site within acceptable risk parameters is available to take the CO_2 into safe, long term storage. Alternatively, Ireland could elect to become one of the 12 EU pre-2015 demo projects, following careful consideration of the upfront risks and cost commitments. However, a window of opportunity linked to the cessation of natural gas production at Kinsale, within the next decade, with its infrastructure and storage capacity, could be optimised to confirm the viability of that basin as safe storage site for some of Ireland's major power-derived point source CO_2 emissions.

8.6 Environmental Considerations

Current international aspects of environmental management, risk analysis, monitoring and regulation for CCS, although in a developmental state, were considered in this study.

The London and OSPAR Accords have been recently amended to allow under-sea carbon storage and an emerging international consensus is developing on how best to apply rigorous standards of environmental management of storage sites, as well as long term monitoring and verification methodologies. Risk and liability issues are being addressed at various forums such as EU, IEA, IGRC and London/ OSPAR, as well as in individual states, and it is likely that internationally approved guidelines and standards will emerge in the near term.

It is likely that long term stewardship of carbon storage sites will be carried out by individual states' regulatory bodies (following post-closure handover of the site by the operator), while it is likely that long term monitoring and verification will likely be carried out by an internationally approved body.

The fact that CCS-based power from Moneypoint is projected to cost significantly less than the price per MWh being offered to incentivise wave power and considerably below the incentive price of €140 per MWh for offshore wind power incentive price is highly significant. It is lower than the ESB's average 2007 generation price of €104 per MWh, which in itself does not reflect the full cost of CO_2 emissions, as a high percentage of emissions in 2007 were allocated free under the EU-ETS for that period.

The expected cost of €35/t CO_2 used in this study is well within the modelled range of CO_2 avoided (€27.5 - €56.1/t CO_2). The incremental effect on cost of electricity of CCS based power generation with a carbon price of €35/t is modelled at -€4.8 to +€20.4/ MWh.

The study found that the economics of CCS look sufficiently promising compared to alternatives, taking security of supply issues into account, and that the Governments would be fully justified in expending the significant public funds needed to prove up storage sites.

9 Recommendations

The following recommendations may be made:

Recommendation 1: - Storage:

Priority 1.1 Kinsale That given the geological uncertainties and in order to match modelled CO_2 emissions of up to 6.27Mt per annum from new-build power stations at Moneypoint or Cork, selected work be undertaken to include reprocessing of seismics, deviated drilling, petrophysical and geochemical test work, followed by reservoir simulation and injectivity modelling) for a cost of approximately €15 million to move the Kinsale depleted gas field from a probability of 70% (P70) to 90% (P90) that it could provide a safe, long term carbon storage site. These studies may determine that further drilling of wells would be required to achieve optimal injectivities and to confirm overall seal integrity, whereby up to €80 million (inclusive of the initial €15 million) may be required. These studies could be achieved within 2-4 years.

Priority 1.2 Portpatrick That further geological studies be undertaken to include acquisition of seismics, drilling and geological studies to prove up a suitable and safe carbon storage site for the modelled emissions of 3.77 Mt CO_2 per annum from a new build Kilroot power station. It is anticipated that the defined closed structures of 37Mt effective storage capacity will require detailed reservoir simulation and modelling of injectivity parameters to reduce defined risks. To move a portion of the 2200 Mt theoretical capacity to 'matched capacity' will require significant inputs. Such studies will be costly in terms of time and resources, up to €100 million over up to 10 years.

Priority 1.3 Clare Basin That further geological studies be undertaken to include reprocessing and acquisition of seismics, drilling and geological studies to prove up a suitable and safe carbon storage site for the modelled emissions of 6.27 Mt CO_2 per annum from a new build Moneypoint power station. The study notes that planned early investigations are planned by the EPA with GSI, which work is to be welcomed in the light of the findings of this study. However, it is likely that the onshore portion of the Clare Basin may be too shallow to provide supercritical conditions for storage of CO_2. And work may have to be directed to the deeper offshore.

Priority 1.4 Irish Sea Task Force That an Irish Sea Task Force be established between the Irish and UK Governments (akin to the UK-Norway-Netherlands *North Sea Task Force*) to examine the suitability in the shorter term of the East Irish Sea Basin as a joint CO_2 storage site due to its very considerable effective/ practical modelled capacity (1060 Mt). In the longer term, the Kish, Peel, Central Irish Sea Basins could be examined in a similar light, under the same Task Force.

Recommendation 2: EU Demonstration Project for Ireland

Given that this study concludes that clean coal potentially offers the island of Ireland an economic option to address the considerable security of supply issues, and that the Kinsale Gas Field storage opportunity is projected to be depleted of gas within the next ten years, that Ireland take an early lead and elect to undertake one of the EU pre-2015 CCS demonstration projects.

Recommendation 3: Pricing Support

That a price support be offered to CCS in the range offered to other low carbon power generation options to incentivise operators. The price would need to be significantly above that offered to large onshore wind (€57per MWh), but below that offered to offshore wind (€140 per MWh) and wave (€220 per MWh).

Recommendation 4: Environmental Monitoring

It is recommended that emerging international guidelines (from IEA/ EU/ IGRC/ OSPAR) on monitoring, verification and risk analysis of the environmental, safety, health and social impacts of CCS be adapted to site specific conditions for Irish carbon storage projects.

[Please note that the Annexes 1 and 2 are supplied in an accompanying CD-ROM]

ANNEXE 1: Basin-by-Basin Analysis of CO2 Storage Potential of all-island Ireland

British Geological Survey: Final Report (May 2008)

ANNEXE 2 Economic Analysis of the Potential for Carbon Capture and Storage in all-Island Ireland

CO2CRC Australia: Final Report (May 2008)

ANNEXE 3: References

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