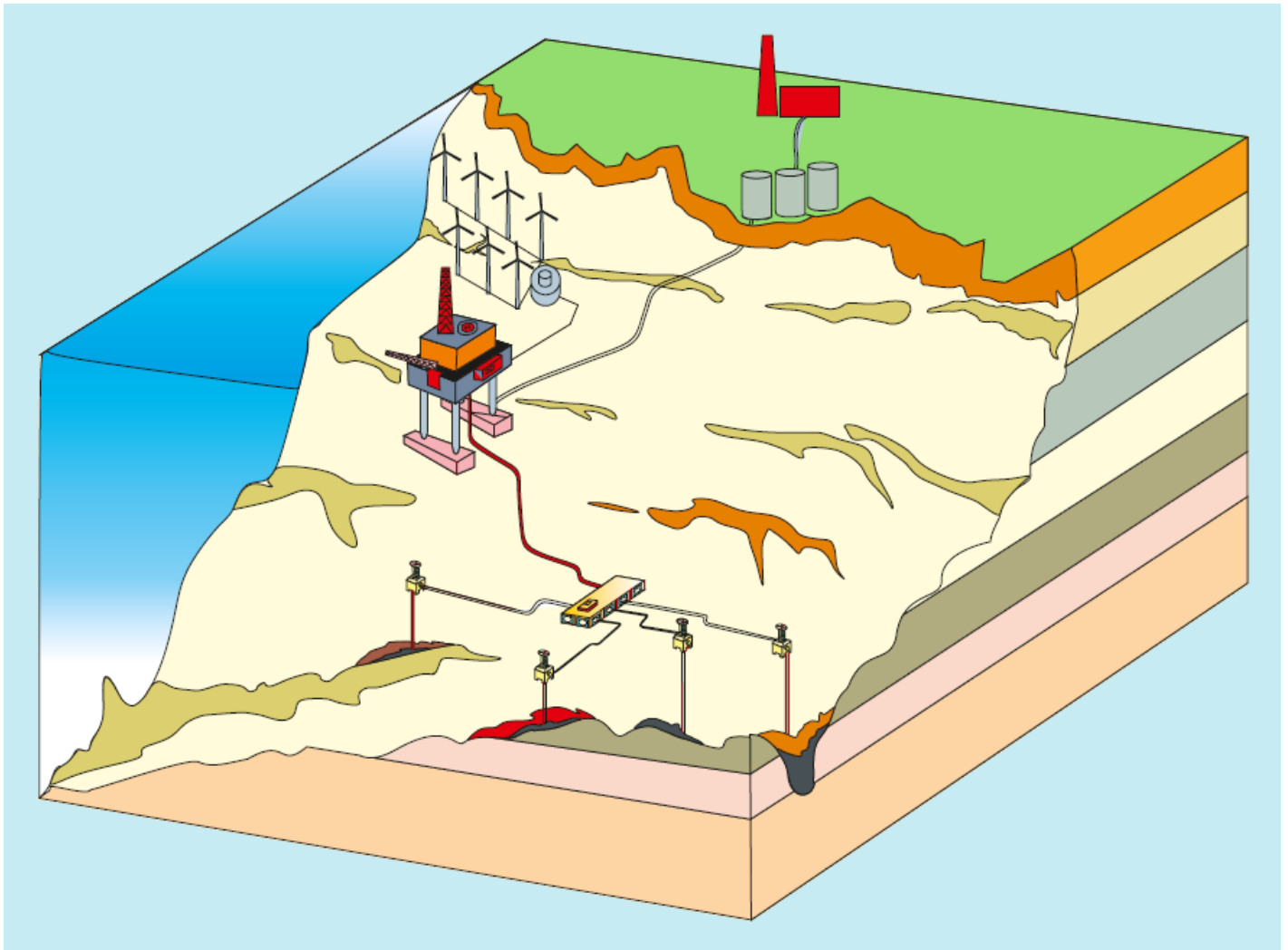


# Offshore Renewable Energy Powered CO<sub>2</sub> Injection

A Small Carbon Footprint Solution



Authors: Aichun Feng, Taeyoung Kim, Xiaojun Li, Zeeshan Riaz and Justin Wee

Series Editors: R A Shenoj, P A Wilson

# OFFSHORE RENEWABLE ENERGY POWERED CO<sub>2</sub> INJECTION

Aichun Feng

Taeyoung Kim

Xiaojun Li

Zeeshan Riaz

Justin Wee

Titles in this series:

---

## **Carbon Capture and Storage in Deep Ocean Space for the 21st Century: Guidelines for Implementation in China**

Elizabeth Livermont, YongJie Koh, Mahesa Bhawanin, Taurai Mlambo & BinBin Zhao

ISBN 978-0-854-32927-4

## **Offshore Thermal Power with CCS: An Alternative to CO<sub>2</sub> Transportation**

Björn Windén, Mingsheng Chen, Naoya Okamoto, Do Kyun Kim & Elizabeth McCaig

ISBN 978-0-854-32928-1

## **The Key to Successful Carbon Capture and Storage: Engaging the Public**

Ning Cheng, Mirjam Fürth, Michael Charles Johnson & Zhi Yung Tay

ISBN 978-0-854-32929-8

## **Offshore Renewable Energy Powered CO<sub>2</sub> Injection: A Small Carbon Footprint Solution**

Aichun Feng, Taeyoung Kim, Xiaojun Li, Zeeshan Riaz & Justin Wee

ISBN 978-0-854-32930-4

**University of Southampton**  
Highfield, Southampton  
SO17 1BJ, England

© University of Southampton, 2011

All rights reserved; no part of this publication may be reproduced, stored in any retrieval system, or transmitted in any form or by any means, electronic, mechanical, photocopying, recording, or otherwise without either the prior written permission of the Publishers or a licence permitting restricted copying in the United Kingdom issued by the Copyright Licensing Agency Ltd, 90 Tottenham Court Road, London W1P 9HE.

First published 2011

**British Library Cataloguing in Publication Data**

A catalogue entry for this title is available from the British Library

**ISBN 9780854329304**

Printed in Great Britain by Henry Ling Ltd, at the Dorset Press,  
Dorchester, Dorset

## FOREWARD

The Lloyd's Register Educational Trust (The LRET) in collaboration with the University of Southampton instituted a research collegium in Advanced Ship and Maritime Systems Design in Southampton between 11 July and 2 September 2011.

The LRET is an independent charity that was established in 2004. Its principal purpose is to support advances in transportation, science, engineering and technology education, training and research worldwide for the benefit of all. It also funds work that enhances the safety of life and property at sea, on land and in the air. The LRET focuses on four categories:

**Pre-university education:** through appropriate organisations (but not individual schools), promotes careers in science, engineering and technology to young people, their parents and teachers

**University education:** provides funding for undergraduate and post-graduate scholarships and awards at selected universities and colleges (does not fund students directly)

**Vocational training and professional development:** supports professional institutions, educational and training establishments working with people of all ages.

**Research:** funds existing or new centres of excellence at institutes and universities.

This collegium has focused on The LRET's research-led education agenda. Successful ship and maritime systems design depends on the collaborative application of a broad range of engineering competences as the drive for improved efficiency and environmental performance places greater demand on the design community. This aspect needs to be reflected in the education of naval architects, marine engineers and others who are the active contributors to the ship design processes.

The aim of the research collegium has been to provide an environment where young people in their formative post-graduate years can learn and work in a small, mixed discipline group drawn from the maritime community to develop their skills whilst completing a project in advanced maritime systems design. The project brief that initiates each project will set challenging user requirements which will encourage each team to develop an imaginative solution, using their individual knowledge and experience, together with learning derived from teaching which will form a common element of the early part of the programme.

The collegium format provided adequate time for the young people to enhance their knowledge through a structured programme of taught modules which will focus on the design process, advanced technologies, emerging technologies and novel marine solutions, regulatory and commercial issues, design challenges (such as environmental performance and climate change mitigation and adaptation) and engineering systems integration. Lecturers have been drawn from academic research and industry communities to provide a mind-broadening opportunity for the young people, whatever their original specialisation.

The subject of the 2011 collegium has been systems underpinning carbon capture and sequestration (CCS) in ocean space. The 19 scholars attending the 2011 collegium were teamed into four groups. The project brief included: (a) quantification of the environmental challenge; (b) understanding of the geo-political legal-social context; (c) possible techniques for sequestration; (d) one engineering system to achieve carbon storage in ocean space; (e) economics and logistics challenges. While all the groups addressed the items (a) to (c), each team focused on just one engineering system in dealing with items (d) and (e). This volume presents the findings of one of the four groups.

Mr. Michael Franklin (The LRET) and Professors Ajit Shenoi and Philip Wilson (University of Southampton)

Southampton

22 August 2011

## PREFACE

The work contained herein is the culmination of two months of research and development (R and D). It represents an amalgamation of thoughts and multi-disciplinary expertise from individuals of varied technical backgrounds. It is the fourth of a four volume series, each volume being the work of a group of researchers.

This fourth volume represents the work of the fourth team, which took the name of team ScarF, an acronym that stands for Small Carbon Footprint designers. The task was to develop a concept design and to propose a solution that would address some of the many challenges associated with CCS. The team comprised a naval architect, an offshore engineer, a hydrodynamicist, a mariner/seafarer and a structural engineer. It was hoped that this would bring a fresh, new and unencumbered perspective to the topic.

Carbon Capture and Storage (CCS) has been a field of vigorous R and D for some 30 years now. This book contains a novel concept design proposal that provides a means to effect this carbon storage in an environmentally friendly and safe manner. A high level overview of the concept design can be described thus - the concept entails offshore geological storage of carbon dioxide and the means to effect this storage is powered by marine renewable energy.

A holistic approach was adopted by the group in addressing the subject of CCS. Division of labor and sharing of workload among team members made this complex and daunting topic surmountable. This book is intended primarily for those actively involved in research into the field of CCS. The intent is to put forth a compelling case and to provide a progressive outlook that veteran researchers on this topic may not commonly think about. It is equally relevant and readable by legislators, policy makers and anyone with a vested interest in issues pertaining to greenhouse gas (GHG) emissions arising from the use of fossil fuels. Indeed, CCS has a strong association with the continued use of fossil fuels. Engineers and scientists in this field have a duty to eloquently and charismatically convince decision makers and the public about the pressing need for CCS.

The authors wish to express their gratitude to, first and foremost, Mr. Michael Franklin, Director of the Lloyd's Register Education Trust (LRET). Mr. Franklin is a tireless champion of the LRET's cause. We thank him and the Board of Trustees for making this collegium a reality. We applaud the noble goals of the LRET to further the art and science of engineering and technology education, training and research, worldwide *for the benefit of all*.

The authors gratefully acknowledge the guidance of the collegium academic mentors from the Fluid Structure Interactions Research Group in the Faculty of Engineering Sciences and the Environment, namely, Professor Ajit Sheno, Professor Philip Wilson, Professor Stephen Turnock and Dr. Dominic Hudson.

Gratitude must also be extended to Mrs. Aparna Subaiah-Varma, who was the principal administrative facilitator throughout the collegium. Indeed, the entire Fluid Structure Interactions Research Group would grind to a halt in her absence. She is the oil that keeps the place running, a fine example of British efficiency. We thank her for facilitating our work. We also wish to commend the resident LRET Scholars at Southampton who made us feel welcome in our new working environment, a testament to British hospitality. We convey our appreciation to Professor Sheno and Professor Wilson. The two fellows were an integral part of the success of this collegium, guiding us and inspiring us as we went along. Lastly, we dedicate this work to those close to our hearts. Though many of us missed home while working at the collegium, we took comfort in knowing that those we love are always in our hearts.

*Aichun Feng, Taeyoung Kim, Xiaojun Li, Zeeshan Riaz and Justin Wee  
August 2011*

## Contents

FOREWARD .....	III
PREFACE .....	IV
LIST OF FIGURES .....	IX
LIST OF TABLES .....	XI
1 MOTIVATION FOR CARBON CAPTURE AND STORAGE .....	1
1.1 Greenhouse effect .....	1
1.2 Sources of carbon dioxide .....	2
2 INTRODUCTION TO CARBON CAPTURE AND STORAGE .....	5
2.1 What is CCS .....	5
2.2 CO <sub>2</sub> capture .....	5
2.2.1 Post-combustion capture .....	5
2.2.2 Pre-combustion capture .....	6
2.2.3 Oxy-fuel combustion capture .....	6
2.2.4 Cost of capturing CO <sub>2</sub> .....	7
2.3 CO <sub>2</sub> transportation .....	8
2.3.1 Pipelines .....	8
2.3.2 Ships .....	11
2.3.3 Road and rail tankers .....	12
2.3.4 Comparison between pipelines and ships .....	12
2.4 CO <sub>2</sub> storage .....	12
2.4.1 Geological storage .....	13
2.4.2 Ocean storage .....	13
2.4.3 Mineral carbonation .....	14
2.4.4 Other options .....	15
2.4.5 Risk assessment for CO <sub>2</sub> storage .....	15
2.4.6 Case studies .....	16
2.5 Philosophical discussions on CCS .....	18
2.5.1 On the credibility of CO <sub>2</sub> emission scenarios .....	18
2.5.2 On the controversy surrounding the global participation in CCS .....	18
2.5.3 On the need to provide incentives for CCS in order to make it cost competitive .....	19
2.6 CCS non-technical issues .....	19
2.6.1 CCS from a political aspect .....	20
2.6.2 CCS from a legal perspective .....	20
2.6.3 CCS in a social context .....	21
3 CONCEPT PROPOSALS AND DESCRIPTIONS .....	23
3.1 CO <sub>2</sub> capture .....	23
3.1.1 Controlled algae blooms in ocean space consuming vast amounts of CO <sub>2</sub> .....	23
3.2 CO <sub>2</sub> transportation .....	23
3.2.1 Feasibility study of a large combined LPG/CO <sub>2</sub> carrier .....	23
3.2.2 A novel concept for a CO <sub>2</sub> carrier with CO <sub>2</sub> micro-bubble hull lubrication .....	23

3.2.3	Design of a CO <sub>2</sub> carrier and dedicated offshore reception facility .....	23
3.3	CO <sub>2</sub> storage .....	23
3.3.1	Locking CO <sub>2</sub> in ice as carbonic acid or dry ice .....	23
3.3.2	Using CO <sub>2</sub> to create building materials .....	23
3.3.3	Using CO <sub>2</sub> to produce zirconia (diamonds) .....	24
3.3.4	Using torpedo anchors to lodge CO <sub>2</sub> filled cylinders into sea-bed .....	24
3.3.5	Injecting CO <sub>2</sub> and biomass into depleted oil wells and other geological formations .....	24
3.3.6	Creating stable solid carbonates to make artificial reefs .....	24
3.3.7	Corrective measures for cap rock fracture of carbon storage reservoirs .....	24
3.3.8	Storage of CO <sub>2</sub> beneath permafrost .....	24
3.3.9	Carbonic acid hydro-jetting to create underground caverns for CO <sub>2</sub> storage .....	25
3.3.10	Storing CO <sub>2</sub> ‘soup’ in an underwater lake .....	25
3.3.11	CO <sub>2</sub> storage and injection platform wholly powered by marine renewable energy .....	25
3.3.12	Producing methanol from CO <sub>2</sub> wholly powered by marine renewable energy .....	25
3.3.13	Design of an artificial island for carbon storage .....	25
3.3.14	CCS technology stepping into ultra-deep water .....	26
4	CONCEPT SELECTION .....	27
4.1	Shortlisted concepts .....	27
4.2	Definition of performance factors .....	27
4.3	Scoring method for decision matrix .....	27
4.4	Evaluation of each concept .....	27
4.5	Final selected concept .....	30
5	CONCEPT DEVELOPMENT .....	31
5.1	Mind map and outline of key considerations .....	31
5.2	Selection of sources and sinks .....	31
5.2.1	Selection of power plant .....	31
5.2.2	Background information on Drax power station .....	32
5.2.3	Selection of type of geological formation for storage .....	33
5.2.4	Identification of sinks .....	33
5.2.5	Carbon storage activities and opportunities in the North Sea .....	34
5.2.6	Selection of storage location .....	34
5.2.7	Matching sources and sinks .....	36
5.2.8	Offshore installation considerations .....	39
5.3	Scenarios .....	39
5.3.1	General scenario .....	39
5.3.2	Scenario A .....	40
5.3.3	Scenario B .....	41
5.3.4	Scenario C .....	41
5.3.5	Scenario D .....	42
5.3.6	Scenario E .....	43
5.3.7	Decision making process .....	44

5.4	Key subsystems .....	45
5.4.1	Identification of key sub-systems .....	45
5.5	Renewable power system .....	47
5.5.1	Profile of Sheringham Shoal wind farm .....	47
5.5.2	Profile of Thanet wind farm.....	50
5.5.3	Profile of London Array wind farm .....	52
5.5.4	Selection of electrical power source to drive equipment for CO <sub>2</sub> injection activities .....	55
5.6	Onshore system .....	56
5.7	Offshore system.....	57
5.7.1	Offshore CO <sub>2</sub> pipelines .....	57
5.7.2	Existing oil and gas pipelines .....	57
5.7.3	Purpose built CO <sub>2</sub> pipelines .....	58
5.7.4	Offshore CO <sub>2</sub> pipeline route .....	58
5.7.5	Provision for future expansion – hub and satellite technique .....	60
5.7.6	Modelling offshore pipeline transport .....	62
5.7.7	Preliminary CO <sub>2</sub> pipe sizing .....	62
5.7.8	Laying offshore pipelines .....	64
5.7.9	Offshore platform selection .....	66
5.7.10	CO <sub>2</sub> injection pumps and required power supply .....	71
5.7.11	Subsea manifold.....	72
5.7.12	Heating equipment .....	72
5.7.13	Offshore geotechnical survey .....	72
5.8	Design considerations .....	74
5.8.1	On the use of indigenous fossil fuel resources in the UK.....	74
5.8.2	On the use of legacy systems and relic infrastructure for CCS projects.....	75
5.8.3	On the use of booster pumps in pipeline transport .....	76
5.8.4	On the use of electric motor driven pumps for CO <sub>2</sub> injection .....	76
5.8.5	On the need for offshore platforms in CO <sub>2</sub> geological injection. ....	80
5.8.6	On the use of depleted oil and gas reservoirs .....	80
5.8.7	On the rationale for the decision to have an onshore temporary storage hub.....	80
5.8.8	On the laying of subsea copper cables from wind farm to injection site.....	81
5.8.9	On the transportation and injection phase of CO <sub>2</sub> .....	81
5.8.10	On the issues with dense phase CO <sub>2</sub> transportation.....	81
5.9	Preliminary cost estimate of proposed CCS project.....	82
5.10	Legal issues.....	83
5.10.1	Anticipated legislative and statutory bodies involved .....	83
5.10.2	Relevant international conventions and protocols pertaining to CCS .....	84
5.10.3	Relevant European laws pertaining to CCS.....	84
5.10.4	Legal visibility of CCS in the UK.....	84
5.11	Assessment of public perception of CCS in the UK .....	85
5.11.1	Main opinions of CCS in the UK.....	85



5.11.2	Public concerns about CCS in the UK.....	85
5.11.3	The need for a fundamental acceptance of CCS in the UK .....	86
5.12	Risk and monitoring .....	86
5.12.1	Risk considerations and risk-based design .....	86
5.12.2	Risk assessment for CCS .....	86
5.12.3	Monitoring and verification for CCS .....	88
6	CONCLUSION AND RECOMMENDATIONS FOR FUTURE WORK.....	89
	BIBLIOGRAPHY .....	90
	APPENDIX A – FLOW RATES AND STORAGE CAPACITY CALCULATIONS .....	94
	APPENDIX B – A BRIEF TREATISE ON PIPE HEAD LOSSES .....	98
	APPENDIX C – DECISION MATRICES .....	100
	APPENDIX D – STORAGE CAPACITIES IN THE SOUTHERN NORTH SEA.....	103
	APPENDIX E – WIND FARMS IN THE UK SECTOR OF THE NORTH SEA.....	105
	INDEX .....	108

## LIST OF FIGURES

Figure 1.1 - Global temperature anomalies (1880-2010).....	1
Figure 1.2 - The change of carbon dioxide concentration in the last 50 years .....	3
Figure 1.3 - Sources of carbon dioxide emissions .....	3
Figure 1.4 - Carbon dioxide emissions for three kinds of fossil fuels .....	4
Figure 2.1 - Simplified illustration of Post-Combustion CO <sub>2</sub> capture .....	6
Figure 2.2 - Simplified illustration of Pre-Combustion CO <sub>2</sub> capture.....	6
Figure 2.3 - Simplified illustration of Oxy-Fuel CO <sub>2</sub> capture.....	7
Figure 2.4 - Distribution of CO <sub>2</sub> pipeline projects in North America .....	8
Figure 2.5 - CO <sub>2</sub> transport chain using pipelines .....	9
Figure 2.6 - Example of hydrate forming inside pipe .....	10
Figure 2.7 - CO <sub>2</sub> phase diagram.....	11
Figure 2.8 - CO <sub>2</sub> transport chain using ships .....	11
Figure 2.9 - Location of Sleipner field.....	16
Figure 2.10 - Illustration of Sleipner field .....	17
Figure 2.11 - Location of Weyburn field .....	17
Figure 2.12 - Principle of EOR in Weyburn field.....	18
Figure 3.1 - Artificial island for CO <sub>2</sub> storage .....	25
Figure 4.1 - Comparison of different concepts for technical feasibility .....	28
Figure 4.2 - Comparison of different concepts for environmental friendliness.....	28
Figure 4.3 - Comparison of different concepts for economic viability.....	28
Figure 4.4 - Comparison of different concepts for public acceptance .....	29
Figure 4.5 - Comparison of different concepts for political support and government funding .....	29
Figure 4.6 - Comparison of different concepts for legal visibility .....	29
Figure 4.7 - Comparison of different concepts for safety .....	30
Figure 5.1 - Mind map for selected concept .....	31
Figure 5.2 - Coal fired power stations in the UK.....	32
Figure 5.3 - Bathymetry of the North Sea.....	34
Figure 5.4 - Oil and gas fields in the North Sea.....	35
Figure 5.5 - Cluster of five major power plants in the Midlands of the UK.....	37
Figure 5.6 - Installed generating capacity of the six power plants .....	38
Figure 5.7 - Schematic showing CO <sub>2</sub> injection into a single reservoir from multiple injection sites ...	39
Figure 5.8 - General scenario.....	40
Figure 5.9 - Scenario A (Pipelines and existing platform retrofitted with CO <sub>2</sub> injection plant) .....	40
Figure 5.10 - Scenario B (Pipelines and new dedicated platform for CO <sub>2</sub> injection plant) .....	41
Figure 5.11 - Scenario C (Ships and platform retrofitted with CO <sub>2</sub> storage and injection plant).....	42
Figure 5.12 - Scenario D (Ships and new dedicated platform for CO <sub>2</sub> storage and injection plant).....	42
Figure 5.13 - Scenario E (Pipelines and subsea manifold for CO <sub>2</sub> injection plant).....	43

Figure 5.14 - Subsea manifold system .....	44
Figure 5.15 - Visualisation of adopted concept .....	45
Figure 5.16 - Key sub-systems identified .....	46
Figure 5.17 - Location of Sheringham Shoal wind farm .....	48
Figure 5.18 - Spatial layout of Sheringham Shoal wind farm .....	50
Figure 5.19 - Location of Thanet wind farm.....	51
Figure 5.20 - Spatial layout of Thanet wind farm.....	52
Figure 5.21 - Location of London Array wind farm.....	52
Figure 5.22 - Spatial layout of London Array wind farm .....	54
Figure 5.23 - Selected nearby wind farms for renewable power supply .....	55
Figure 5.24 - M/V Mozah .....	57
Figure 5.25 - Gas fields in the Southern North Sea gas basin .....	58
Figure 5.26 - Existing gas pipeline network in the Southern North Sea gas basin.....	59
Figure 5.27 - Approximate routing of pipeline .....	60
Figure 5.28 - Location of Audrey gas field and proposed pipeline routing.....	61
Figure 5.29 - Hub and Satellite technique applied to the Southern North Sea gas basin .....	61
Figure 5.30 - The boundaries, inputs and outputs of the pipeline model.....	62
Figure 5.31 - Diameter as a function of CO <sub>2</sub> mass flow rate .....	63
Figure 5.32 - Typical pipeline transport window.....	64
Figure 5.33 - Study of alternative routes .....	66
Figure 5.34 - Breakdown of platform types in the North Sea.....	67
Figure 5.35 - Removing and installing deck platform .....	69
Figure 5.36 - Cost comparison for three platforms (Excluding cost of Platform hibernation).....	70
Figure 5.37 - Subsea manifold and injection flow lines .....	72
Figure 5.38 - Leased blocks in the Southern North Sea gas basin.....	73
Figure 5.39 - Submersible pump.....	77
Figure 5.40 - Artist's impression of subsea infrastructure.....	78
Figure 5.41 - Subsea manifold and associated equipment.....	79
Figure 5.42 - Various pumps .....	79

**LIST OF TABLES**

Table 2.1 - Estimate of cost escalation for selected carbon capture technology .....	7
Table 2.2 - Estimate of CCS costs at different stages of development.....	8
Table 2.3 - Summary of existing long distance CO <sub>2</sub> pipelines .....	9
Table 2.4 - Existing projects of CO <sub>2</sub> transport for CCS in the North Sea .....	9
Table 2.5 - Temperature and pressure window for supercritical CO <sub>2</sub> transportation .....	10
Table 2.6 - Comparison between ships and offshore pipelines .....	12
Table 2.7 - Safety concerns related to CCS .....	22
Table 4.1 - Scoring scheme.....	27
Table 4.2 - Decision matrix .....	30
Table 5.1 - Basic information on the North Sea .....	33
Table 5.2 - Summary of scenarios .....	45
Table 5.3 - Dimensions of existing offshore gas pipelines .....	63
Table 5.4 - Decommissioned facilities before 2001 .....	68
Table 5.5 - Cost estimates for retrofitting and new building platform (unit: million euros) .....	70
Table 5.6 - Annual CO <sub>2</sub> injection rates of current projects.....	71
Table 5.7 - Commercial pumps for CO <sub>2</sub> injection (Sulzer pumps).....	71
Table 5.8 - Cost comparison of various carbon capture technologies .....	82
Table 5.9 - Cost decrease as a function of technology maturity .....	82
Table 5.10 - International laws relevant to CO <sub>2</sub> geological storage in the marine environment .....	84
Table 5.11 - European Directives relevant to CO <sub>2</sub> geological storage in the marine environment .....	84
Table C. 1 - Conversion of an existing offshore oil platform to store CO <sub>2</sub> .....	100
Table C. 2 - Modification of existing oil and gas pipelines to transport CO <sub>2</sub> .....	100
Table C. 3 - Controlled algae blooms in ocean space consuming vast amounts of CO <sub>2</sub> .....	100
Table C. 4 - CO <sub>2</sub> storage and injection platform wholly powered by marine renewable energy .....	101
Table C. 5 - Using CO <sub>2</sub> as a raw material to produce methanol powered by renewable energy .....	101
Table C. 6 - Design of an artificial island for carbon storage and utilization.....	101
Table C. 7 - Concept determination .....	102
Table C. 8 - Average scoring of each concept .....	102
Table C. 9 - Application of each performance factor on concept evaluation .....	102



## 1 MOTIVATION FOR CARBON CAPTURE AND STORAGE

### 1.1 Greenhouse effect

The greenhouse effect is a process by which thermal radiation from a planetary surface is absorbed by atmospheric greenhouse gases, and is re-radiated back to earth. As part of this re-radiation is back towards the surface, energy is transferred to the surface and the lower atmosphere. As a result, the temperature is getting higher than it would be if direct heating by solar radiation were the only warming mechanism (Greenhouse effect, 2011).

Specifically, the sun radiates energy to earth at very short wavelengths, predominately in the visible or near-visible part of the spectrum. Roughly 1/3 of the solar energy that reaches the top of Earth's atmosphere is reflected directly back to space. The remaining 2/3 is absorbed by the surface and, to a lesser extent, by the atmosphere. To balance the absorbed incoming energy, the Earth must, on average, radiate the same amount of energy back to space. Because the Earth is rather colder than the Sun, it radiates at much longer wavelengths. Much of this thermal radiation emitted by the land and ocean is absorbed by greenhouse gases, and reradiated back to Earth. The glass walls in a greenhouse reduce airflow and increase the temperature of the air inside. Earth's greenhouse effect warms the surface of the planet. Without the natural greenhouse effect, life on this planet would probably not exist as the average temperature of the Earth would be a chilly -18° C, rather than the present 15° C.

However, during the period 1880-2010, global temperature has increased by approximately 0.8 °C, as shown in Figure 1.1. Furthermore, models referenced by the Intergovernmental Panel on Climate Change (IPCC) predict that global temperatures are likely to increase by 1.1 to 6.4 °C from 1990 to 2100. This global warming phenomenon is the result of human activity such as the burning of fossil fuels (oil, coal, and natural gas), land clearing, and agriculture. Other phenomena such as solar variation and volcanoes also affect global mean temperature since, but such effects are less pronounced than those due to anthropogenic activities.

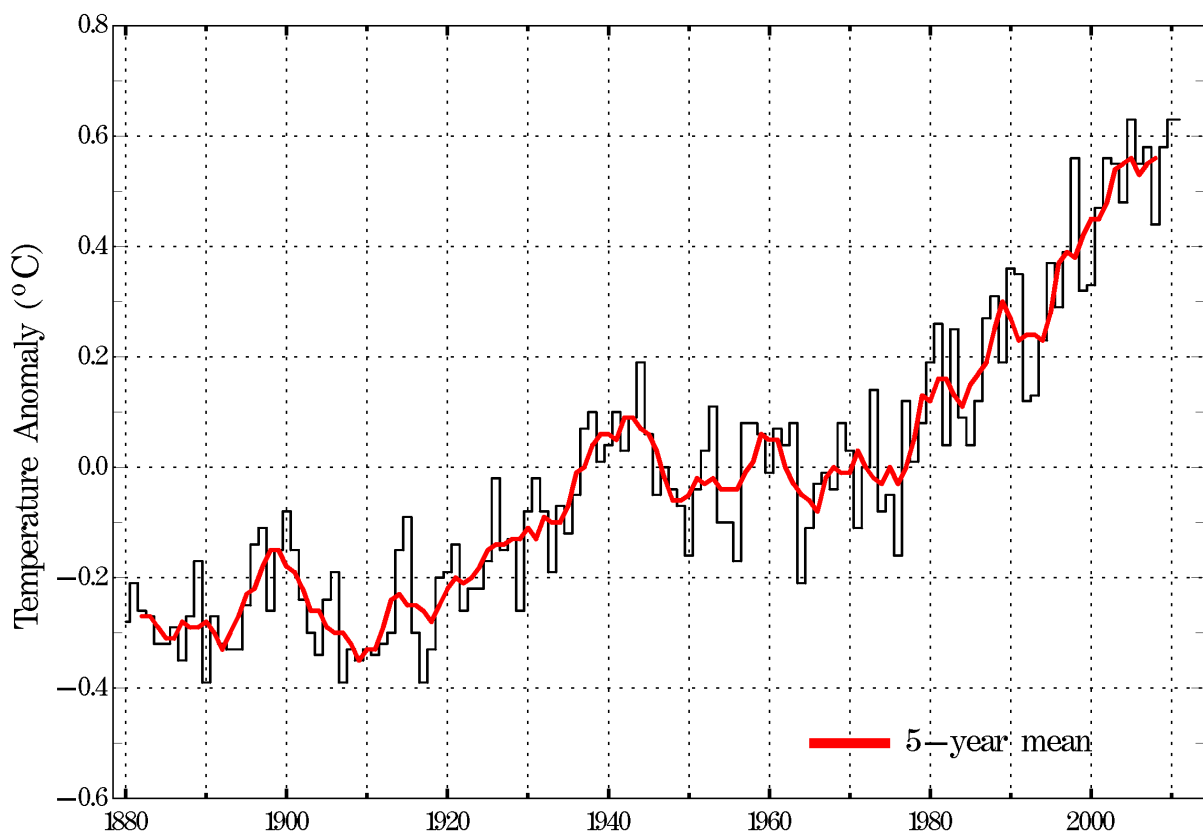


Figure 1.1 - Global temperature anomalies (1880-2010)  
(Source: Hansen et al, 2010)

There are mainly three types of gases contributing to global warming - water vapour or cloud cover, carbon dioxide and other gases (O<sub>3</sub>, CH<sub>4</sub>, N<sub>2</sub>O etc.). Methane is a particularly nasty greenhouse gas. Arctic scientists predict that the release of methane locked in ice may have knock on effects and accelerate global warming. About 70-80% of the earth's natural greenhouse effect is due to water vapour and cloud—a strong greenhouse gas. The remainder is due to carbon dioxide, methane, and a few other minor gases. However, the concentration of water in the atmosphere is quite stable, human-activity-caused water emissions have only a slight effect on climate change. If we exclude the influence of water vapour (cloud), the percentage contribution of CO<sub>2</sub> will increase to 60~70%. Human activity has greatly increased the concentration of CO<sub>2</sub> in the atmosphere. The concentration of CO<sub>2</sub> in parts per million (ppm) in the atmosphere has increased 28% over the last fifty years. Scientists agree that carbon dioxide is the principal contributor to global warming.

In light of the evidence mentioned above, there is a pressing need for us to control the emission of CO<sub>2</sub> in order to mitigate the potential disasters caused by global warming. Future carbon dioxide levels are expected to rise due to on-going burning of fossil fuels. The rate of rise will depend on uncertain economic, sociological and technological developments, but may ultimately be limited by the availability of fossil fuels. The IPCC Special Report on Emissions Scenarios gives a wide range of future carbon dioxide scenarios, ranging from 541 to 970 parts per million by the year 2100. Fossil fuel reserves are sufficient to sustain world energy demand until this time with continued emissions past 2100 anticipated. If coal, tar sands and methane catharses are exploited, the duration of CO<sub>2</sub> emission is expected to last even longer. This puts forth a compelling case and urgent necessity to develop Carbon Capture and Storage (CCS) technology.

## ***1.2 Sources of carbon dioxide***

Since the Industrial Revolution, anthropogenic activities such as the burning of oil, coal and gas, as well as, deforestation have greatly increased carbon dioxide concentrations in the atmosphere. As is shown in Figure 1.2, the concentration of carbon dioxide has increased 27% from 300 to 380ppm (parts per million) over the past half century. Although the amount of carbon dioxide emission varies with geographical location, the effect is observed world-wide. It thus becomes a global issue to control the amount of carbon dioxide in the atmosphere. Pollution respects no boundaries. It is a global problem. With current technology, it is technically very challenging to seek to control the amount of carbon dioxide in the atmosphere. This is a geo-engineering problem and involves 'scrubbing' the CO<sub>2</sub> from the air. Thus, due to this technological limitation in the present time, the bulk of Research and Development (R & D) effort focuses on reducing the emission of carbon dioxide into the atmosphere. The objective is not to allow the CO<sub>2</sub> to enter the atmosphere. As long as this is accomplished, for example if the CO<sub>2</sub> is stored in a geological formation, then that CO<sub>2</sub> has no impact in causing global warming.

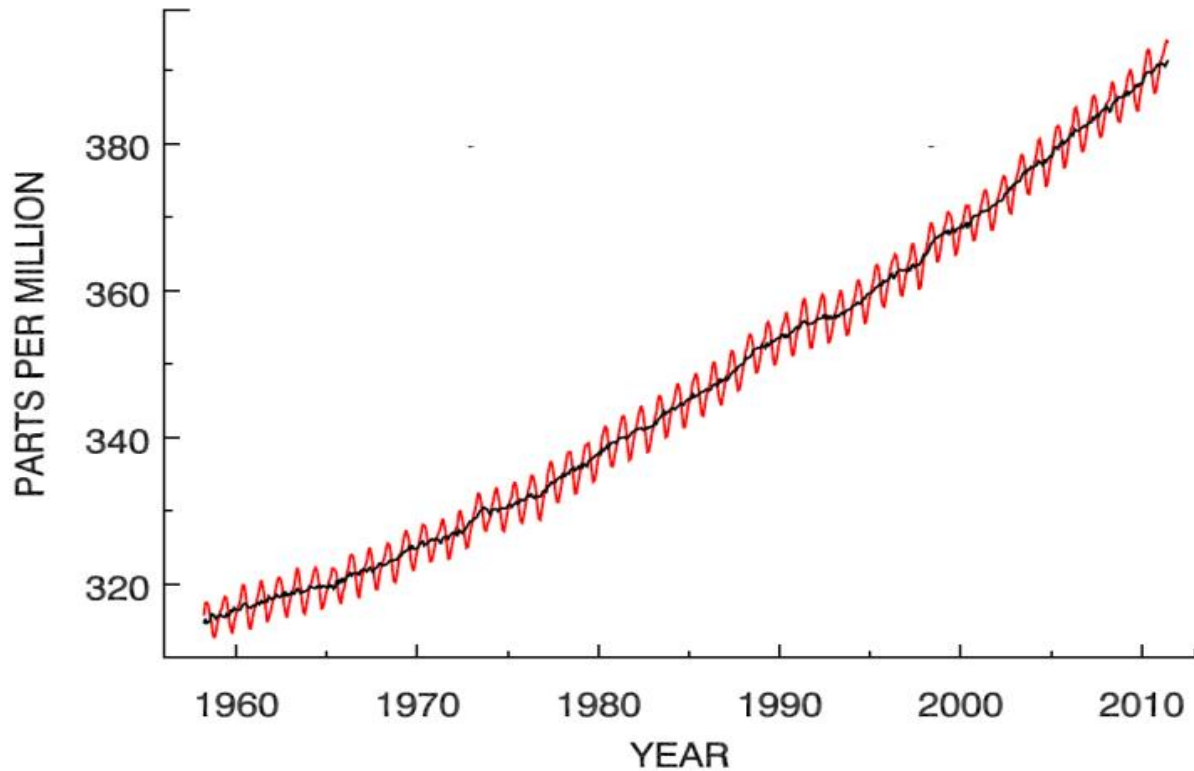


Figure 1.2 - The change of carbon dioxide concentration in the last 50 years  
(Source: Tans & Keeling. Last retrieved on 20 Jul 2011)

To reduce carbon dioxide emissions, large point sources such as coal fired power plants should be identified and arrested. According to the report from the U.S. Environmental Protection Agency (EPA, 2010), nearly 85% of carbon dioxide is emitted from fossil fuel combustion (see Figure 1.3).

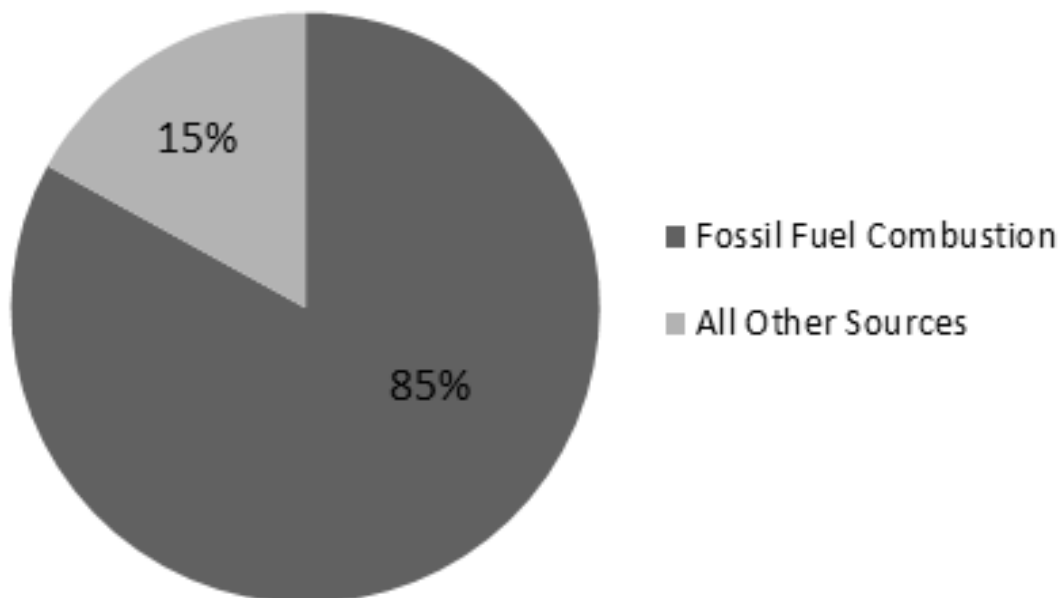


Figure 1.3 - Sources of carbon dioxide emissions

When fossil fuels are combusted, the stored carbon is emitted almost entirely as carbon dioxide. The other large sources include heavy industries such as steel-works, shipyards and petroleum refineries. However, the contribution from these industrial processes is relatively small compared to power plants. Hence, reducing carbon dioxide emission is most effectively achieved by reducing fossil fuel combustion. Despite the perception that humanity is making great strides in reducing the amount of CO<sub>2</sub> emitted, the amount of emissions has not decreased. The world still very much operates on a fossil fuelled energy system. Figure 1.4 indicates that the carbon dioxide emission from three major sources of fossil fuel - coal, oil and natural gas, has increased nearly two-fold during the past 37 years from 1971 to 2008 (IEA, 2010). With internationally recognised regulations in force such as the



Kyoto Protocol, nations whom are a party to the convention have an obligation to reduce the emission of carbon dioxide. One possible solution as part of a mix of measures that is widely discussed is Carbon Capture and Storage (CCS).

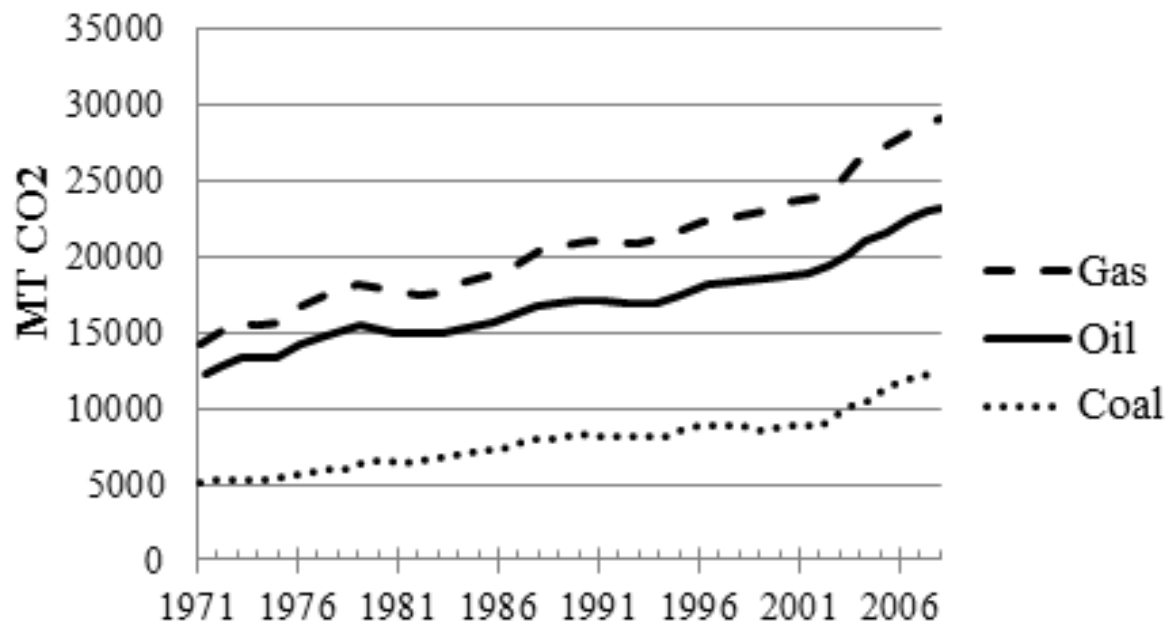


Figure 1.4 - Carbon dioxide emissions for three kinds of fossil fuels

## 2 INTRODUCTION TO CARBON CAPTURE AND STORAGE

### 2.1 What is CCS

According to the Intergovernmental Panel on Climate Change (IPCC) special report on carbon dioxide capture and storage (IPCC, 2005):

*“Carbon dioxide (CO<sub>2</sub>) capture and storage (CCS) is a process consisting of the separation of CO<sub>2</sub> from industrial and energy-related sources, transport to a storage location and long-term isolation from the atmosphere. This report considers CCS as an option in the portfolio of mitigation actions for stabilization of atmospheric greenhouse gas concentrations.”*

Owing to the dependence on fossil fuels for at least the next 50 to 60 years, CCS seems to be a promising solution to mitigate the problem in the near future. Other options to lessen the dependence on fossil fuels are still in their embryonic stage and their output is still not sufficient to effectively replace the existing energy demands. These options include renewable energy sources, less carbon intensive fuels, nuclear energy etc. The undeniable truth is that the world still operates on a fossil fuelled energy system.

This chapter starts off with a brief treatment of CO<sub>2</sub> capture, followed by a discussion of the various means of CO<sub>2</sub> transport and rounds up with a description of CO<sub>2</sub> storage possibilities. This chapter also covers non-technical issues and ends of with some philosophical discussions on CCS.

### 2.2 CO<sub>2</sub> capture

CO<sub>2</sub> capture is the process of removing CO<sub>2</sub> (carbon dioxide) produced by hydrocarbon combustion (coal, oil and gas) before it enters the atmosphere. The process will be most cost effective when it is used on large point sources of CO<sub>2</sub> such as power plants. These currently make up nearly half of all man-made CO<sub>2</sub> emissions.

CO<sub>2</sub> capture is an existing industrial technology widely used. The main challenge for any capture process is the low concentration of CO<sub>2</sub> in the flue gas. Depending on the industrial source, CO<sub>2</sub> content can vary from a few percent up to over fifty percent. Other contaminant gases such as oxygen, sulphur oxides, water vapour and oxides of nitrogen can also be present in flue gases. For reasons of both economic and energy costs, it would be impossible to compress and store all of the gases. Therefore CO<sub>2</sub> must be preferentially separated from the other flue gases by a capturing process.

In most carbon sequestration systems, the cost of capturing CO<sub>2</sub> is the largest component, possibly accounting for as much as 80% of the total.

Basically there are three types of CO<sub>2</sub> capture, namely post-combustion, pre-combustion and oxy-fuel combustion capture.

#### 2.2.1 Post-combustion capture

This process involves removing the CO<sub>2</sub> from exhaust gases following hydrocarbon combustion. It can be typically built in to existing power plants (known as retro-fitting) without significant modifications. Several commercial technologies can be used to capture large quantities of CO<sub>2</sub>. Use of these capture technologies is encouraged by the UK government and oftentimes receive state support. Listed below are the pros and cons of the post-combustion method of capture. Figure 2.1 shows a simplified process flow diagram of this process.

Pros:

- a. Feasible to retrofit to existing power plants
- b. Mature technology - decades of research and operational experience
- c. Successful commercial systems in service
- d. Potential to capture large volumes of CO<sub>2</sub>

Cons:

- a. High operating costs – requires constant replenishment of absorber solvents
- b. Limited large scale operating experience

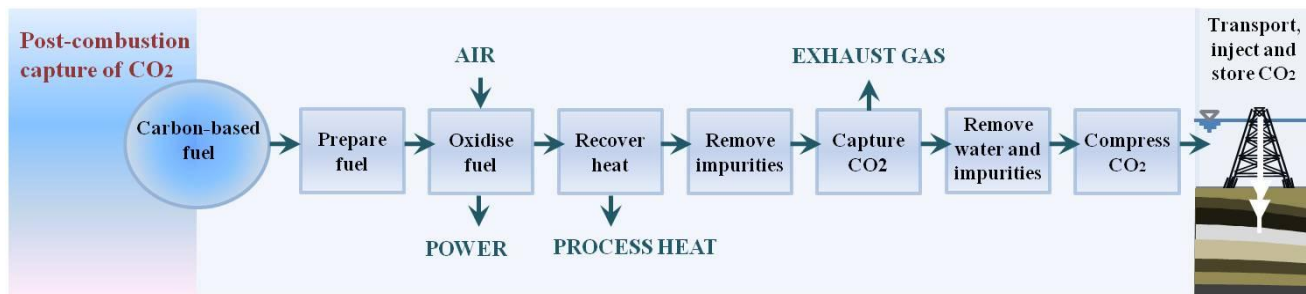


Figure 2.1 - Simplified illustration of Post-Combustion CO<sub>2</sub> capture

### 2.2.2 Pre-combustion capture

Pre-combustion capture involves removal of CO<sub>2</sub> from the hydrocarbon before combustion, to produce hydrogen. Hydrogen combustion produces no CO<sub>2</sub> emissions, with water vapour being the main by-product. Provided that this technology is used with carbon storage it could provide a CO<sub>2</sub> emission free fuel for the future. Listed below are the pros and cons of the pre-combustion method of capture. Figure 2.2 shows a simplified illustration of this process.

Pros:

- a. High percentages of CO<sub>2</sub> emissions can be captured
- b. Low technology risk
- c. Can produce transportable and clean energy H<sub>2</sub>

Cons:

- a. High investment costs of equipment
- b. High NO<sub>x</sub> emissions
- c. Low efficiency of H<sub>2</sub> burning turbines
- d. No commercial experience

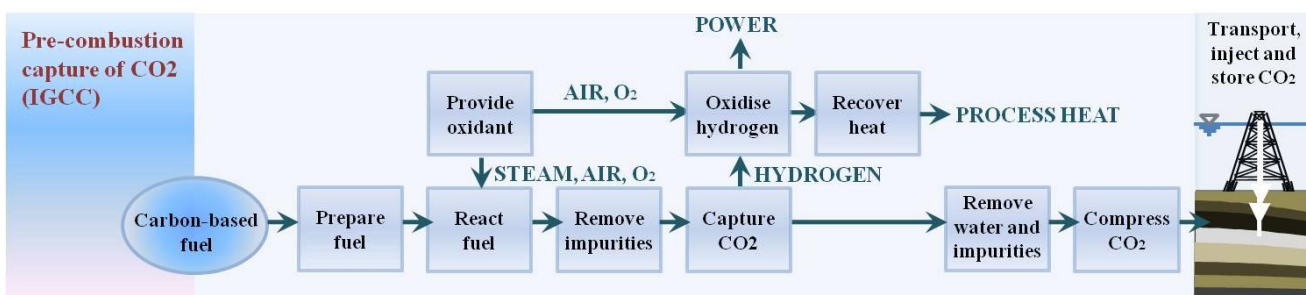


Figure 2.2 - Simplified illustration of Pre-Combustion CO<sub>2</sub> capture

### 2.2.3 Oxy-fuel combustion capture

This process uses pure oxygen instead of air for combustion and results in a more complete combustion. The exhaust stream consists of almost pure CO<sub>2</sub> (typically 90%) and water vapour, which can be easily separated from the CO<sub>2</sub> by condensation. Listed below are the pros and cons of the oxy-fuel combustion method of capture. Figure 2.3 shows a simplified illustration of this process.

Pros:

- a. Potential for 100% CO<sub>2</sub> capture
- b. Few other harmful emissions due to more complete combustion
- c. May be possible to retro-fit the oxy-fuel burners onto modified existing coal power plants

Cons:

- High energy consumption to produce pure O<sub>2</sub>
- High temperature requirement for combustion
- No mature technology and commercial experiences

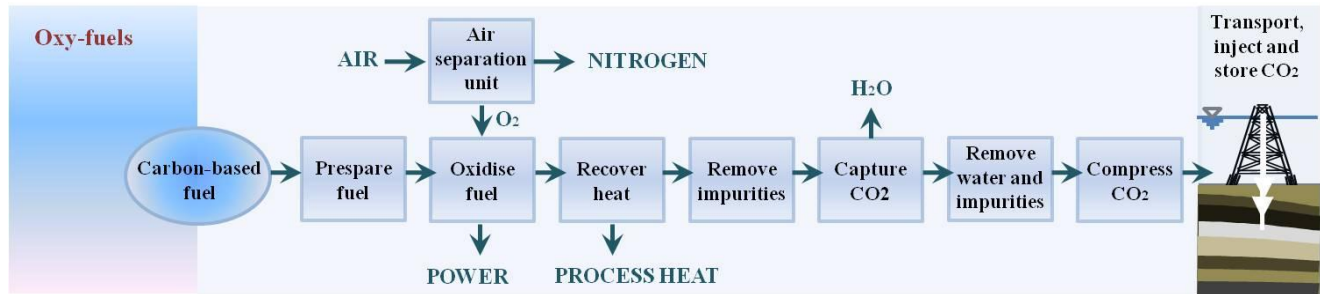


Figure 2.3 - Simplified illustration of Oxy-Fuel CO<sub>2</sub> capture

#### 2.2.4 Cost of capturing CO<sub>2</sub>

Cost estimates for CCS projects typically present a range of values and depend on many variables, such as the type of capture technology (post-combustion, pre-combustion, oxy-fuel), whether the plant represents a new construction or is a retrofit to an existing plant, whether the CCS project is in a demonstration or a commercial stage, and a variety of other factors. Part of the difficulty in estimating costs is the lack of any operating, commercial-scale electricity-generating power plants that capture and sequester their CO<sub>2</sub> emissions. Thus, there are no real-world examples to draw from. In addition, there is neither a market price for CO<sub>2</sub> emitted nor a regulatory requirement to capture CO<sub>2</sub> i.e. a market demand which would likely shape cost estimates. All observers and industry insiders, however, agree that installing CO<sub>2</sub> capture technology will increase the cost of generating electricity from fossil fuel power plants. As a result, few companies are likely to commit to the extra expense of installing technology to capture CO<sub>2</sub>, or for that matter installing the infrastructure to transport and store it, until they are required to do so. Table 2.1 shows the cost increase of different capture methods for hypothetical new construction and retrofit projects (Bernard, 2011).

Table 2.1 - Estimate of cost escalation for selected carbon capture technology

Method	New Construction	Retrofitting
Post-combustion	60%-70%	220%-250%
Pre-combustion	22%-25%	Not applicable
Oxy-fuel	46%	170%-206%

The MIT and McKinsey studies both suggest that retrofitting power plants would lead to more expensive CCS costs compared to new plants on a levelled basis. There are four reasons the associated higher costs and these are summarized in point form below:

- The added expense of adapting the existing plant configuration for the capture unit
- A shorter lifespan for the capture unit compared to purpose built new plants
- A higher energy efficiency penalty compared to a new plant that incorporates CO<sub>2</sub> capture from the design stage
- The lost generating time and lucrative revenue earning capability when an existing plant is taken offline for the retrofit

In short, retrofitted plants are more expensive. If capture technology is installed on new “capture ready” plants, these would be less expensive. (McKinsey & Company, 2008).

In most carbon sequestration systems, the cost of capturing CO<sub>2</sub> is the largest component, possibly accounting for as much as 80% of the total cost. In a 2008 study by McKinsey and Company, capture costs accounted for the majority of CCS costs estimated for demonstration plants and early commercial plants. Table 2.2 shows the McKinsey & Company estimates for three different stages of CCS development for new, coal-fired power plants.

Table 2.2 - Estimate of CCS costs at different stages of development

	Capture	Transport	Storage	Total
Initial demonstration	\$73-\$94	\$7-\$22	\$6-\$17	\$86-\$133
Early commercial	\$36-46	\$6-\$9	\$6-\$17	\$48-\$73
Post-early commercial	Not applicable	Not applicable	Not applicable	\$44-\$65

In addition, geological storage of CO<sub>2</sub> in saline formations or depleted oil and gas fields typically cost between US\$0.50–8.00 per tonne of CO<sub>2</sub> injected, plus an additional US\$0.10–0.30 for monitoring costs. However, when CO<sub>2</sub> storage is combined with enhanced oil recovery to extract extra oil from an aging oil field, the CO<sub>2</sub> storage could yield net benefits of US\$10–16 per tonne of CO<sub>2</sub> injected, based on 2003 oil prices.

### 2.3 CO<sub>2</sub> transportation

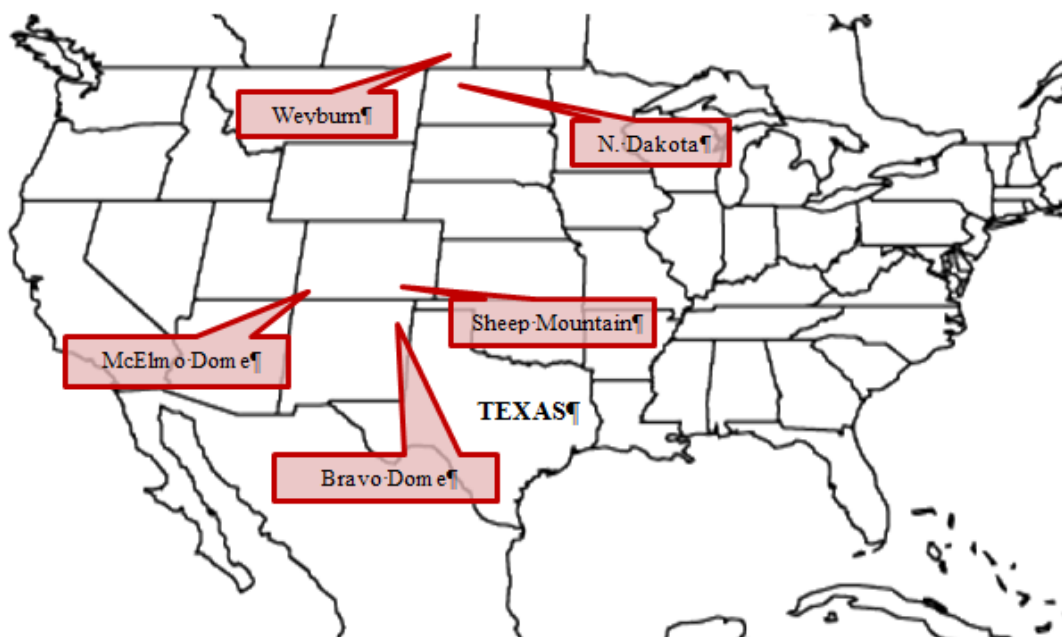
CO<sub>2</sub> can be transported in gaseous, liquid or rarely, solid phase. Being advantageous to transport in dense phased liquid form (IEA GHG, 2005), CO<sub>2</sub> thus needs to be cooled down. Lowering temperature at atmospheric pressure will change the form of CO<sub>2</sub> from gaseous to solid ‘dry ice’. In order to achieve liquefied CO<sub>2</sub>, a combination of temperature and pressure is required. Thus arises the necessity of a large scale facility to convert CO<sub>2</sub> to a medium suitable for transportation (Khan, 2006). There exist three principle means of transportation of CO<sub>2</sub>.

- High pressure pipelines
- Ship transportation
- Rail and road tankers

A large amount of research has been carried out in exploring the feasibility of these three modes of transport and a substantial amount of material is available on the web discussing the benefits and drawbacks of these modes. The technical paper found in the bibliography by Svensson, Odenberger, Johnsson and Stromberg gives a good account in explaining the infrastructure for transportation and the expected development of each of these modes of transportation. The reader is referred to this reference for further information. Extracts from their work are summarized below.

#### 2.3.1 Pipelines

CO<sub>2</sub> transport has been carried out for over 30 years for Enhanced Oil Recovery (EOR) purposes. Hence, it is well established and technically proven. In North America (see Figure 2.4), over 30 million metric tonnes of natural and man-made CO<sub>2</sub> is transported per year through 6,200 km of CO<sub>2</sub> pipelines (Carbon Sequestration Leadership Forum (CSLF), 2009).

Figure 2.4 - Distribution of CO<sub>2</sub> pipeline projects in North America

The first long distance CO<sub>2</sub> pipeline came into operation in early 1970 (Rubin, Meyer, & de Coninck, 2005). A summary of existing CO<sub>2</sub> pipelines in the US is given in Table 2.3 (Coleman, Davison, Hendriks, Kaarstad, & Ozaki, 2005) and in Table 2.4.

Table 2.3 - Summary of existing long distance CO<sub>2</sub> pipelines

Pipeline	Location	Length (km)	Capacity (MtCO <sub>2</sub> /year)	Year Finished	Origin of CO <sub>2</sub>	Operator
Cortez	USA	808	19.3	1984	McElmoDome	Kinder Morgan
Sheep Mountain	USA	660	9.5	-	Sheep Mountain	BP Amoco
Bravo	USA	350	7.3	1984	Bravo Dome	BP Amoco
Canyon Reef Carriers	USA	225	5.2	1972	Gasification Plant	Kinder Morgan
Val Verde	USA	130	2.5	1998	Vel Verde Gas Plant	Petrosource
Bati Raman	Turkey	90	1.1	1983	Dodan Field	Turkish Petroleum
Weyburn	USA and Canada	328	5	2000	Gasification Plant	North Dakota Gasification plant
<b>Total</b>		<b>2591</b>	<b>49.9</b>			

Table 2.4 - Existing projects of CO<sub>2</sub> transport for CCS in the North Sea (Seevam, Race, & Downie, 2007)

Pipeline	Location	Length (km)	Capacity (MtCO <sub>2</sub> /year)	Year Finished	Origin of CO <sub>2</sub>	Operator
Sleipner	North Sea	160	1	1996	Separation from Natural Gas	Statoil
Snøhvit	North Sea	153	0.7	2006	Amine CO <sub>2</sub> Separation/ natural Gas	Statoil

Recognizing the large number of potential offshore storage reservoirs for CO<sub>2</sub>, subsea pipelines represent a viable means to transport CO<sub>2</sub> from onshore sources to offshore sinks. Experience in offshore CO<sub>2</sub> pipelines is still immature. This is not due to a lack of technical feasibility but primarily due to the lack of demand for CO<sub>2</sub> offshore pipelines. At the time of this writing, the only existing example of an offshore pipeline for CO<sub>2</sub> is the Snøhvit project. The next paragraph describes the technical difficulties faced when transporting CO<sub>2</sub> via pipeline. A typical CO<sub>2</sub> transport chain is shown below (Joana , Joris, & Evangelos, 2011):

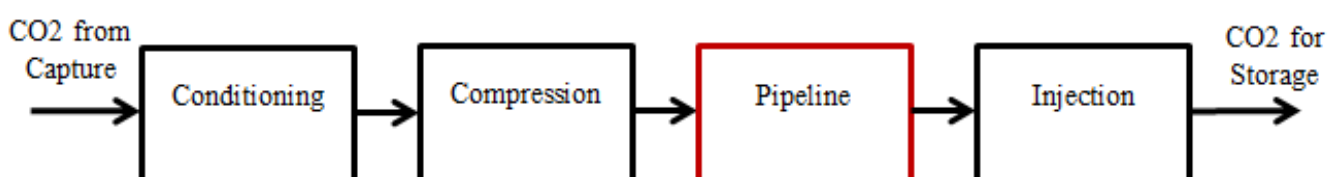


Figure 2.5 - CO<sub>2</sub> transport chain using pipelines



Captured CO<sub>2</sub> is contaminated with a number of toxic gases and is very hot in nature. Its composition depends upon the source type, the implemented CO<sub>2</sub> capture technology and the type of fuel used. This makes it very difficult to transport via pipelines. Small amounts of impurities affect the physical properties of CO<sub>2</sub> and this consequently influences pipeline design, compressor power, re-compression distance and pipeline capacity (Seevam, Race, & Downie, 2007). These impurities are normally CH<sub>4</sub>, H<sub>2</sub>S, N<sub>2</sub>, O<sub>2</sub> and water. Therefore, as far as practicable, impurity levels should be minimized so that CO<sub>2</sub> can be amenable to pipeline transport. The presence of water in CO<sub>2</sub> may result in the formation of hydrates (solid ice-like crystals) which can plug the flow line (Figure 2.6). Corrosion can also occur due to the moisture content in CO<sub>2</sub> (Wallace, 1985). Hence, there is need to dehydrate the CO<sub>2</sub> to reduce the water particles to an allowable limit ( $0.4 \times 10^{-3} \text{ kg/m}^3$ ) (King, 1981).

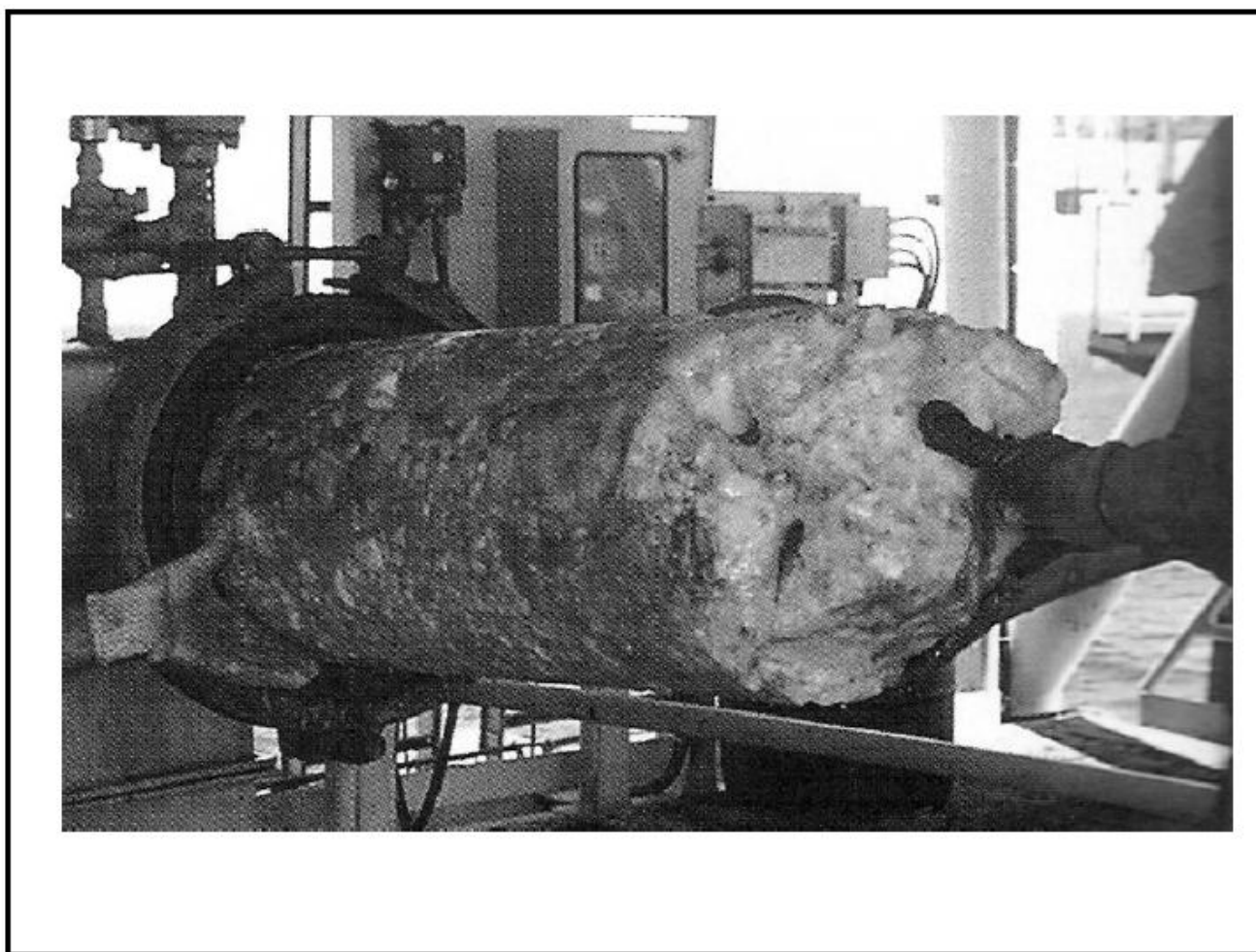


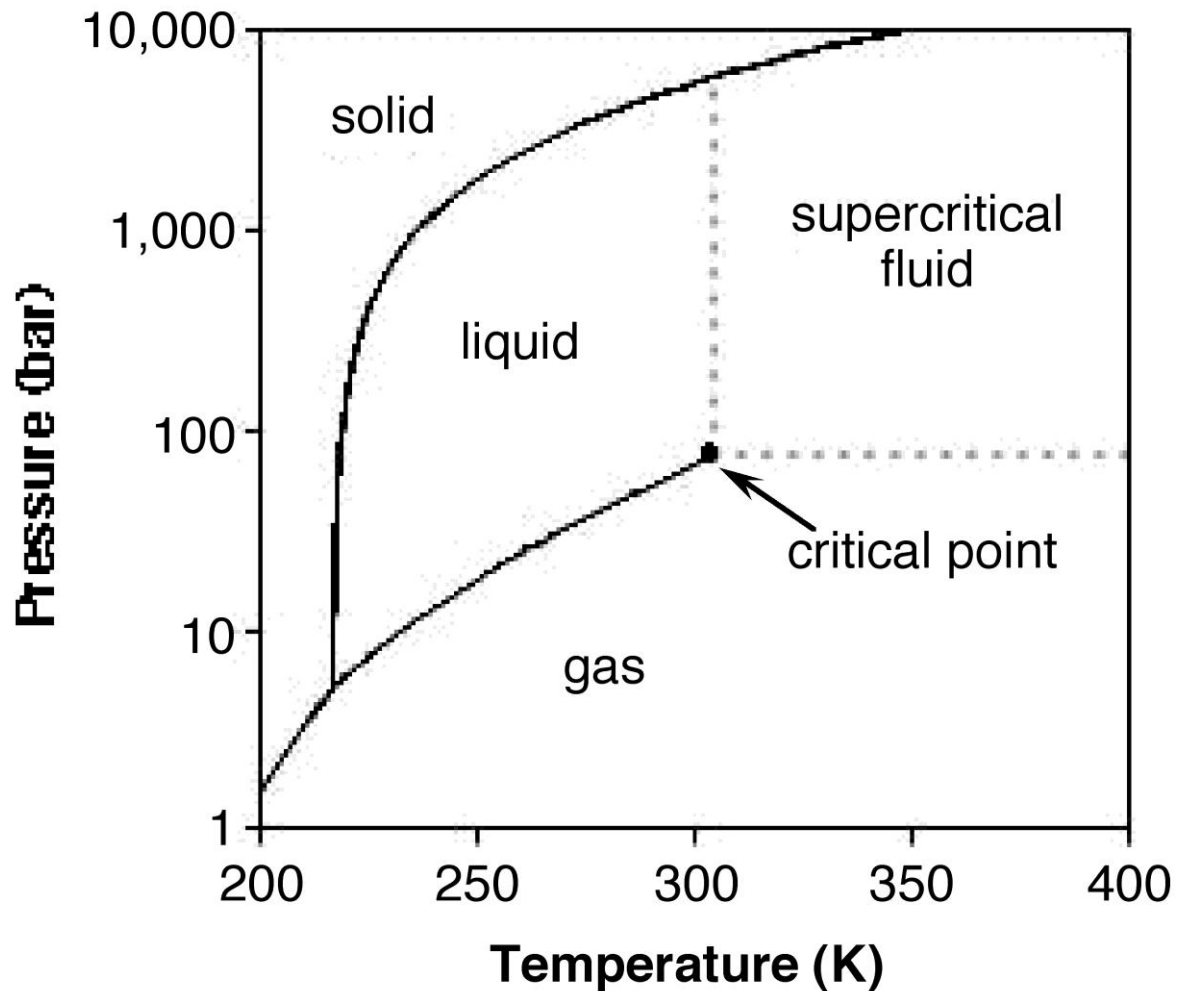
Figure 2.6 - Example of hydrate forming inside pipe

(Source: <http://www.itp-interpipe.com/products/subsea-production-flowlines/heat-traced-flowlines.php>. Last retrieved on 28 Jul 2011)

As mentioned in (IEA GHG, 2005), the most efficient way of transporting CO<sub>2</sub> is in the supercritical phase (see Figure 2.7). The upper and lower limits of temperature and pressure are given below:

Table 2.5 - Temperature and pressure window for supercritical CO<sub>2</sub> transportation  
(Morbee, Correia Serpa dos Santos, & Tzimas, 2010)

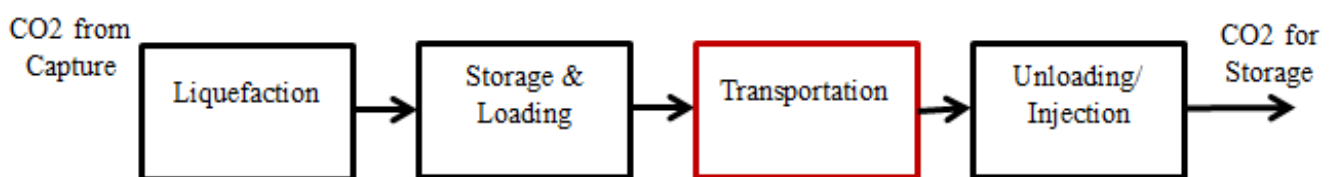
	Temperature (°C)	Pressure (bar)
Lower Limit	12	85
Higher Limit	44	150

Figure 2.7 - CO<sub>2</sub> phase diagram

(Source: [http://upload.wikimedia.org/wikipedia/commons/0/01/Carbon\\_dioxide\\_pressure-temperature\\_phase\\_diagram.jpg](http://upload.wikimedia.org/wikipedia/commons/0/01/Carbon_dioxide_pressure-temperature_phase_diagram.jpg). Last retrieved on 21 Jul 2011)

### 2.3.2 Ships

Transportation of CO<sub>2</sub> by ships is still technologically immature. There are only in service world-wide about four small ships which carry food-grade CO<sub>2</sub>. Some conceptual designing is also being carried out for large capacity CO<sub>2</sub> carriers notably in Japan and Norway. Liquefied petroleum gases (LPG), principally propane and butane, are transported on a large commercial scale by LPG carriers. CO<sub>2</sub> can be transported by ship in much the same way (typically at 0.7 MPa gauge pressure), but this currently takes place on a small scale because of limited demand. Due to the similarity in the properties of liquefied CO<sub>2</sub> with those of LPG, there is potential to convert existing LPG carriers into CO<sub>2</sub> carriers. A typical transportation chain using ships is shown Figure 2.8.

Figure 2.8 - CO<sub>2</sub> transport chain using ships

The following are the processes required for ship transportation of CO<sub>2</sub> (Khan, 2006):

- a. CO<sub>2</sub> liquefaction plant
- b. Intermediate storage and port loading facilities



- c. Ship transportation
- d. Unloading facilities offshore, preferably with buffer storage included

### 2.3.3 Road and rail tankers

The transportation of CO<sub>2</sub> using road and rail tankers is also practicable and is being used on a limited basis due to very small demand. This system requires CO<sub>2</sub> to be transported at -20 °C and at 2 MPa. However, it is not as economical a solution as compared to pipelines or ships except if the requirement is for small parcels and for transportation over short distances only.

### 2.3.4 Comparison between pipelines and ships

The table below summarizes the comparison between offshore pipelines and ships for transporting CO<sub>2</sub>.

Table 2.6 - Comparison between ships and offshore pipelines

	Ships	Offshore Pipelines
Flexibility	Ships provide more flexibility as they can mobilize fast and can operate between multiple sources and sinks	Pipelines are fixed and one pipeline system can only serve one source and sink. As pipeline design depends heavily on capture technique due to the impurities involved, therefore, it is still challenging to condition the CO <sub>2</sub> , captured from different sources to a specific handling level and then transported via a single pipeline to the storage site.
Economy	<p>a. It depends mainly on the distance to be transported. It is typically cheaper than pipelines for distances greater than approximately 1000 km (Rubin, Meyer, &amp; de Coninck, 2005) .</p> <p>b. If the capacity of the sink is very large (30 -35 years), then operating ships may result in an expensive solution.</p>	<p>a. It is cheaper to transport using pipelines when the distance is less than 1000 km.</p> <p>b. Pipelines can be a cheaper solution if the sink capacity is very high.</p>
Deep Seas	It is cheaper to use ships when storage reservoirs lie in deep ocean.	Offshore pipelines could become expensive with increasing hydrostatic pressures of large water depths.
Maturity of Technology	There are small CO <sub>2</sub> carriers but their mission function is not CCS. Design and construction of large ships is technically feasible but is impeded by a lack of demand.	Onshore CO <sub>2</sub> pipeline is quite mature. However, the concept of using onshore CO <sub>2</sub> pipelines for CCS purposes is still quite new. Again technology is not the hurdle. It is the large scale commercial requirement or rather the lack thereof. A substantial demand is needed to drive the offshore CO <sub>2</sub> pipeline industry.

## 2.4 CO<sub>2</sub> storage

Strictly speaking, carbon sequestration is the long-term storage of carbon dioxide or other forms of carbon to either mitigate or defer global warming. What is defined as 'long-term' is a subject of vigorous debate. Whereas geological disposal can be thought of as being permanent, certain forms of ocean storage are regarded as temporary storage solutions whereby the CO<sub>2</sub> will eventually enter the atmosphere after a substantial period of time. CO<sub>2</sub> sequestration can broadly be divided into three

categories. These are geological storage, ocean storage and mineral carbonation. The following paragraphs give a description of these three categories of storage.

#### 2.4.1 *Geological storage*

Also known as geo-sequestration, this method involves injecting carbon dioxide, typically in supercritical form, directly into an underground geological formation. Oil and gas fields, saline formations and un-mineable coal seams have been suggested as storage sites. Various physical (e.g. highly impermeable cap-rock) and geochemical trapping mechanisms would prevent the CO<sub>2</sub> from escaping to the surface. CO<sub>2</sub> is sometimes injected into declining oil fields for the purpose of enhanced oil recovery (EOR). Approximately 30 to 50 million metric tonnes of CO<sub>2</sub> are injected annually in the United States into declining oil reservoirs (IPCC, 2005). This option is attractive because the geology of hydrocarbon reservoirs is generally well understood and storage costs may be partly offset by the sale of additional oil that is recovered. Disadvantages of aging oil fields are their geographic distribution and their limited capacity, as well as the fact that subsequent burning of the additional oil so recovered will offset much or all of the reduction in CO<sub>2</sub> emissions.

Saline formations contain highly mineralized brines, and have so far been considered of no benefit to humans. Saline aquifers have been used for storage of chemical waste in a few cases. The main advantage of saline aquifers is their large potential storage volume and their common occurrence. The major disadvantage of saline aquifers is that relatively little is known about them, especially compared to oil fields. To keep the cost of storage acceptable, the geophysical exploration may be limited, resulting in larger uncertainty about the aquifer structure. Unlike storage in oil fields or coal beds, no side products will offset the storage cost. Leakage of CO<sub>2</sub> back into the atmosphere may be a problem in saline aquifer storage. Current research shows, however, that several trapping mechanisms immobilize the CO<sub>2</sub> underground, reducing the risk of leakage.

Un-mineable coal seams can also be used to store CO<sub>2</sub> because the CO<sub>2</sub> molecules attach to the surface of coal. The technical feasibility, however, depends on the permeability of the coal bed. In the process of absorption, the coal releases previously absorbed methane, and the methane can be recovered. The sale of the methane can be used to offset a portion of the cost of the CO<sub>2</sub> storage. Burning the resultant methane, however, would produce CO<sub>2</sub>, which would negate some of the benefit of sequestering the original CO<sub>2</sub>.

For well-selected, designed and managed geological storage sites, the IPCC estimates that CO<sub>2</sub> could be trapped for millions of years, and the sites are likely to retain over 99% of the injected CO<sub>2</sub> over 1,000 years (IPCC, 2005). It was reported that scientists had mapped 6,000 square miles (16,000 km<sup>2</sup>) of rock formations in the U.S. that could be used to store 500 years' worth of U.S. carbon dioxide emissions (LiveScience, 2009).

#### 2.4.2 *Ocean storage*

Another proposed form of carbon storage is in the oceans. Several concepts have been proposed:

- a. *Dissolution* injects CO<sub>2</sub> by ship or pipeline into the ocean water column at depths of 1000 to 3000 m, forming an upward-plume and the CO<sub>2</sub> subsequently dissolves into the seawater.
- b. Through *lake deposits*, by injecting CO<sub>2</sub> directly into the sea at depths greater than 3000m, where high-pressure liquefies CO<sub>2</sub>, making it denser than water, and forms a downward-plume that may accumulate on the sea floor as a 'lake', and is expected to delay dissolution of CO<sub>2</sub> into the ocean and atmosphere, possibly for millennia.
- c. Use a *chemical reaction* to combine CO<sub>2</sub> with a carbonate mineral, e.g. limestone, to form bicarbonates, for example,  $\text{CO}_2 + \text{CaCO}_3 + \text{H}_2\text{O} \rightarrow \text{Ca}(\text{HCO}_3)_2$ . However, the aqueous bicarbonate solution must not be allowed to dry out; otherwise, the reaction will reverse.
- d. Store the CO<sub>2</sub> in solid clathrate hydrates already existing on the ocean floor, or growing more solid clathrate.

The time it takes water in the deeper oceans to circulate to the surface has been estimated to be approximately 1600 years, depending on currents and other changing conditions. Costs for deep ocean disposal of liquid CO<sub>2</sub> are estimated at US\$40–80 per tonne of CO<sub>2</sub> (USD in 2002). This figure covers the cost of sequestration at the power plant and marine transport to the disposal site (IPCC, 2005).

The environmental effects of oceanic storage are generally negative and poorly understood. Large concentrations of CO<sub>2</sub> could kill ocean organisms, but another problem is that dissolved CO<sub>2</sub> would eventually equilibrate with the atmosphere, so the storage would not be permanent. In addition, as part of the CO<sub>2</sub> reacts with the water to form carbonic acid, H<sub>2</sub>CO<sub>3</sub>, the acidity of the ocean water increases. The resulting environmental effects on benthic life forms of the bathypelagic, abyssopelagic and hadopelagic zones are poorly understood. Even though life appears to be rather sparse in the deep ocean basins, energy and chemical effects in these deep basins could have far reaching implications. In addition, the wake structures of deep-water seabed and potential hazards caused by earthquakes and slides could undermine the stability of CO<sub>2</sub> storage. Much more work, therefore, is needed to define the extent of the potential problems.

An additional method of long term ocean based sequestration is to gather crop residue such as corn stalks or excess hay into large weighted bales of biomass and deposit it in the alluvial fan areas of the deep ocean basin. Dropping these residues in alluvial fans would cause the residues to be quickly buried in silt on the sea floor, sequestering the biomass for very long time spans. Alluvial fans exist in all of the world's oceans and seas where river deltas fall off the edge of the continental shelf, such as the Mississippi alluvial fan in the Gulf of Mexico and the Nile alluvial fan in the Mediterranean Sea.

Unfortunately, biomass and crop residues form an extremely important and valuable component of topsoil and sustainable agriculture. Removing them from the terrestrial equation is fraught with problems. If fertilized crops were used, it would exacerbate nutrient depletion and increase dependence on chemical fertilizers and, therefore, petrochemicals, thus defeating the original intentions of reducing CO<sub>2</sub> in the atmosphere. However, it is more likely that less-expensive cellulosic energy-crops would be used, and these are typically unfertilized; although, it is likely that petrochemicals would still be used for harvesting and transport.

#### 2.4.3 Mineral carbonation

In this process, CO<sub>2</sub> is exothermically reacted with available metal oxides, which in turn produces stable carbonates. This process occurs naturally over many years and is responsible for a great amount of surface limestone. The reaction rate can be made faster, for example, by reacting at higher temperatures and/or pressures, or by pre-treatment of the minerals, although this method can require additional energy. It is estimated that a power plant equipped with CCS using mineral storage will need 60-180% more energy than a power plant without CCS (IPCC, 2005).

In particular, igneous silicate rocks are globally abundant and contain important silicate minerals such as olivine, wollastonite, and serpentine which are potential feedstocks for mineral carbonation. The reactions typically require ~2 tonnes of silicate mineral per tonne of CO<sub>2</sub> captured, so application of mineral carbonation would entail very large scale mining and disposal operations. For example, a 100 kilo-tonne per day mining operation would be able to support capture of ~18Mt-CO<sub>2</sub> per year and could serve about five 500 MW coal-fired power stations. In addition, backfilling operations would need to accommodate an excess of 500-1000 kilo-tonne per day of carbonation products.

Apart from this type of large-scale application, the alkaline waste from many industrial processes is also suitable as feedstock for mineral carbonation, providing the opportunity for smaller-scale application. Wastes such as ash from municipal waste incineration, coal combustion, and cement production, as well as slag from steel making and asbestos mine tailings, are potential feedstocks. Some of these wastes after mineral carbonation generally have a higher value, offering an economic incentive to plant owners.

A study on mineral sequestration in North America states: carbon sequestration by reacting naturally occurring Mg and Ca containing minerals with CO<sub>2</sub> to form carbonates has many unique advantages. Most notable is the fact that carbonates have a lower energy state than CO<sub>2</sub>, which is why mineral carbonation is thermodynamically favorable and occurs naturally (e.g., the weathering of rock over geologic time periods). Secondly, the raw materials such as magnesium based minerals are abundant. Finally, the produced carbonates are unarguably stable and thus re-release of CO<sub>2</sub> into the atmosphere is not an issue. However, conventional carbonation pathways are slow under ambient temperatures and pressures. The significant challenge being addressed by this effort is to identify an industrially and environmentally viable carbonation route that will allow mineral sequestration to be implemented with acceptable economics (Goldberg, Chen, Connor, Walters, & Ziock, 1998).

#### 2.4.4 *Other options*

The use of CO<sub>2</sub> as an industrial feedstock is dominated by the production of urea as a nitrogen fertilizer, which currently consumes ~65Mt of industrially produced CO<sub>2</sub> per year. Other uses include the production of methanol, polyurethanes, and the food industry, and total industrial use is estimated at ~120 Mt-CO<sub>2</sub> per year.

Although this is a significant quantity against the scale of current capture and storage projects, the scope to increase this usage is limited by the demand for the end of products. Also, the retention time of carbon in these products is very limited; it is less than a year for urea, which quickly hydrolyzes to ammonia and CO<sub>2</sub> when applied. The relevance of these uses for material long-term storage is therefore very limited.

Two potential applications that could have a significant impact are the production of precipitated calcium carbonate (PCC) for use in the paper and cement industries, and the direct use of cooled flue gas as a CO<sub>2</sub> source for microalga photosynthesis, generating biomass for biofuel. The biomass is subsequently burned without capture. Furthermore, net emissions would be reduced if the CO<sub>2</sub> is also captured in the biofuel combustion process.

#### 2.4.5 *Risk assessment for CO<sub>2</sub> storage*

The most significant risk from geologic carbon sequestration is leakage of CO<sub>2</sub>. Two types of CO<sub>2</sub> releases are possible—atmospheric and subsurface. These may be caused by slow leaks through slightly permeable cap rock or catastrophic releases due to rupture of a pipeline, failure of a field well, or opening of a fault. In general, CO<sub>2</sub> is not classified as a toxic material. However, high concentrations of atmospheric releases pose health risks to humans and animals. Additional risks are attributable to subsurface release of injected CO<sub>2</sub>. Although methodologies have been developed to estimate and report leakage from storage sites, further development is needed.

One tool that can be used to achieve acceptance of CO<sub>2</sub> sequestration is risk assessment, an essential step in risk management. Risk management involves selecting appropriate prevention and control options, policies, and processes to manage risks. Evaluating risk is a proven method to manage hazards objectively in facilities such as oil and natural gas fields, refineries, chemical and pharmaceutical plants. Although probabilistic risk assessment (PRA) has been applied in these areas, its application to geologic CO<sub>2</sub> sequestration is still in its infancy. A PRA evaluates both the likelihood and the impact of an unplanned event. Use of PRAs allows decisions to be made on the most cost effective risk reduction and management options. Very loosely, there are environmental risks, health and safety risks and economic risks to consider.

Prudent handling and management of CO<sub>2</sub> are required to offset potential health hazards. Implementation of CO<sub>2</sub> sequestration is being approached in a series of phases. This should ensure that potential sources of leakage are identified, consequences are quantified, events with the potential to cause harm are analysed to estimate their frequency and associated risk, and safeguards are put in place to reduce risk to an acceptable level.

Risk = Frequency × Consequences

Thus, one can have the same level of risk for a frequent event with a low level of damage as for a rare event with a very high level of damage. Therefore, in developing a risk assessment, one must evaluate both frequency and potential damage from an event. Risk assessment can address public safety, employee safety, property damage, revenue loss, and environmental damage. This methodology, called probabilistic risk assessment (PRA), is the industry standard.

PRAs use probability distributions to characterize variability or uncertainty in risk estimates. In a PRA, one or more variables in the risk equation are defined as probability distributions rather than as single values. Similarly, the output of a PRA is a range or probability distribution of risks. Geologic storage of CO<sub>2</sub> is well suited to analysis using PRAs because sequestration is a process-driven problem occurring over a long period of time.

#### 2.4.6 Case studies

Below are summarized two case studies where carbon dioxide has been successfully disposed of in geological formations. The first is a true carbon capture and storage project in the conventional sense. The second is an example of a CO<sub>2</sub> injection project with dual function – to store carbon in an oil reservoir whilst simultaneously achieving Enhanced Oil Recovery (EOR) as shown in Figure 2.9.

<b>Case study 1:</b>	The Sleipner field
Location:	Norway, North Sea
Start date:	1996
Storage rate:	one million metric tonnes per year
CO <sub>2</sub> source:	Natural gas processing
Storage:	Deep saline reservoir 1000 m below sea floor
Motivation for demo project:	Evade tax and test technology (not for altruistic reasons)
Comment:	First commercial pilot project, no CO <sub>2</sub> leakage thus far. It has so far stored nine million metric tonnes of CO <sub>2</sub> effectively capturing 2% of CO <sub>2</sub> emitted by Norway per year.



Figure 2.9 - Location of Sleipner field

(Source: <http://www.planetseed.com/node/15252>. Last retrieved 1 Aug 2011)

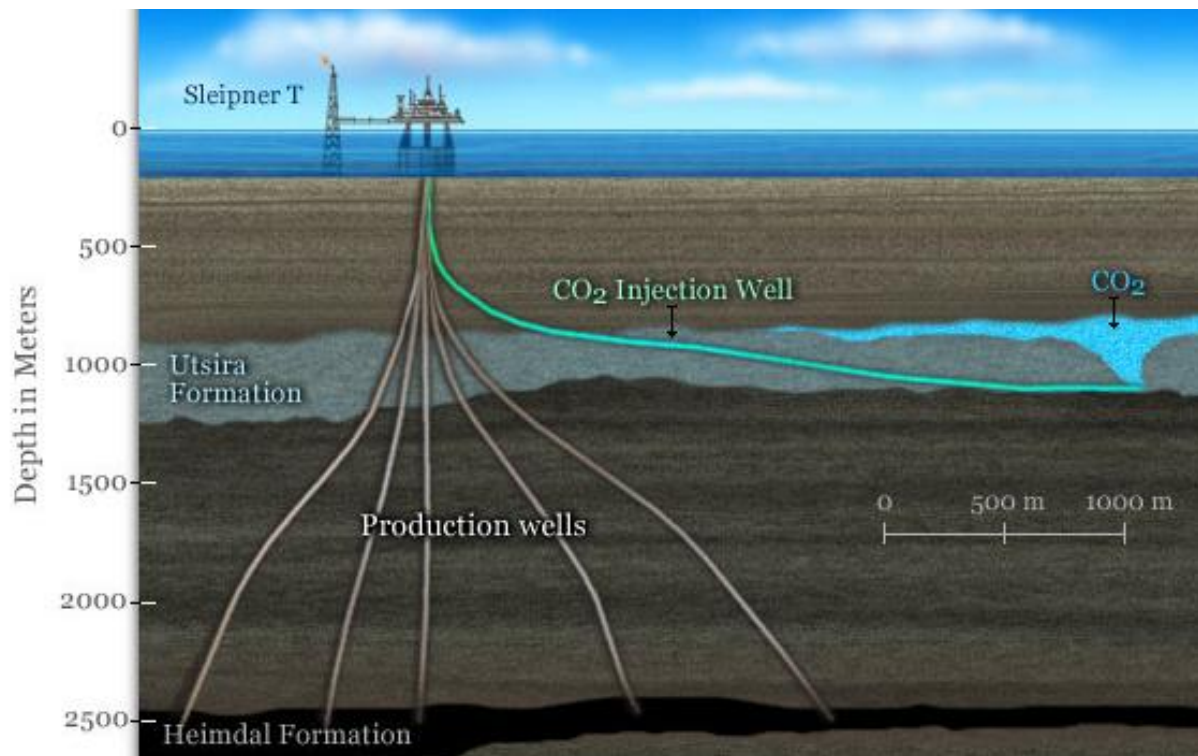


Figure 2.10 - Illustration of Sleipner field

(Source: <http://www.ens-newswire.com/ens/nov2007/2007-11-08-10.asp>. Last retrieved 1 Aug 2011)

<b>Case study 2:</b>	The Weyburn Oil Field - Enhanced Oil Recovery
Location:	Canada
Start date:	2000
Storage rate:	0.2 million metric tonnes per year
CO <sub>2</sub> source:	Exhaust gas from nearby plant
Storage:	Oil reservoir
Motivation behind project:	Increase production and extend productive life of oil field
Comment:	First onshore commercial project largely with purpose to extend field life (not for altruistic reasons). No CO <sub>2</sub> leakage monitored so far.

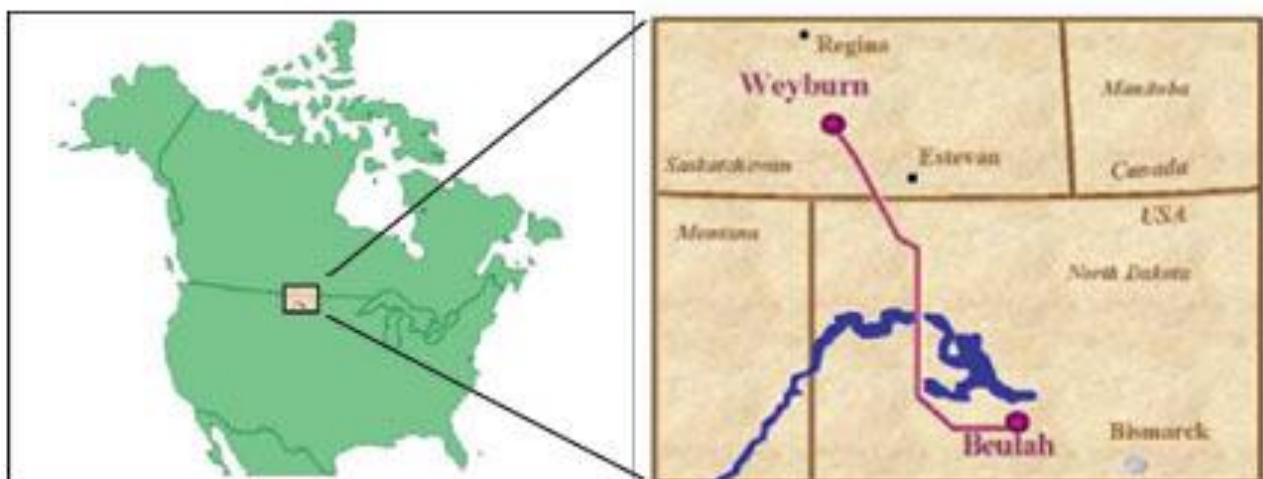


Figure 2.11 - Location of Weyburn field

(Source: <http://www.theoil drum.com/story/2005/12/12/18171/178>. Last retrieved 1 Aug 2011)



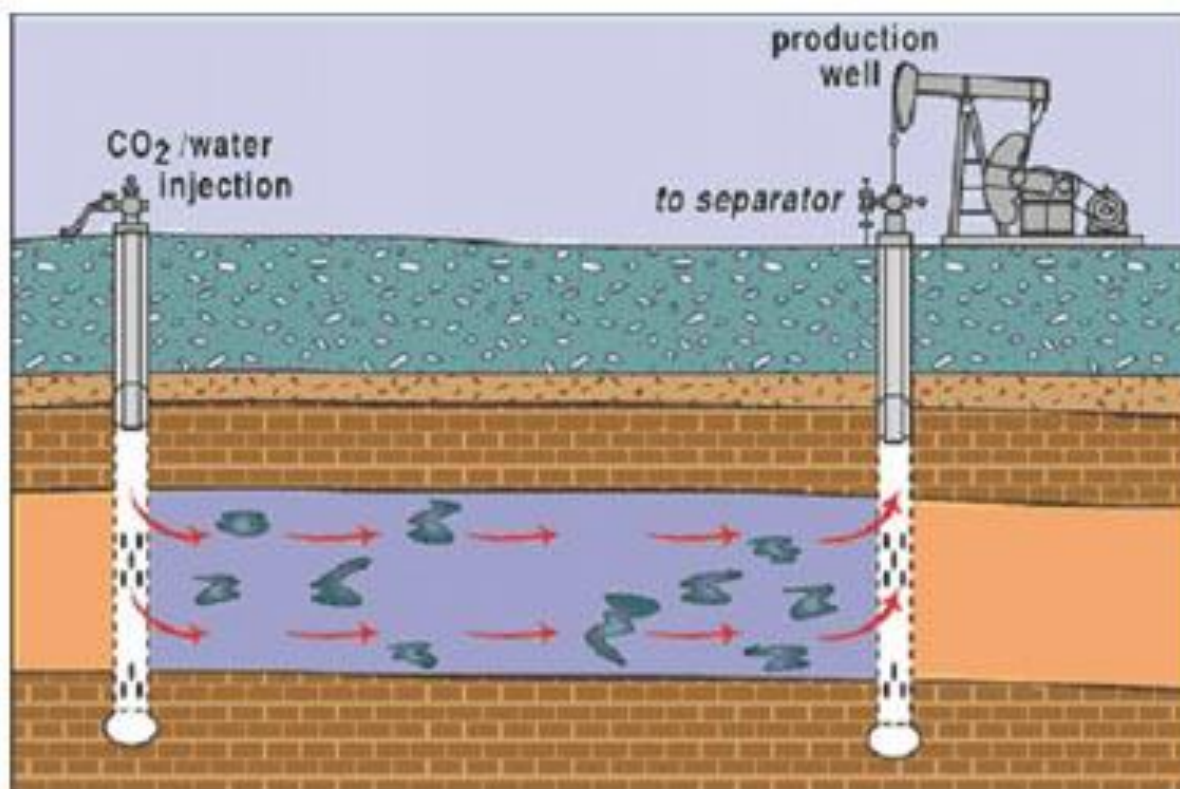


Figure 2.12 - Principle of EOR in Weyburn field

(Source: <http://www.energyindustryphotos.com/whatiseor.htm>. Last retrieved 1 Aug 2011)

## 2.5 Philosophical discussions on CCS

### 2.5.1 On the credibility of CO<sub>2</sub> emission scenarios

Recognizing that pollution respects no boundaries, the general consensus is that the emission of Green House Gases (GHG) is a global problem. Feasibility studies undertaken by the International Energy Agency (IEA) commonly refer to a baseline reference scenario which denotes the 'business as usual' case. When analysing emission scenarios, a discerning reader would exercise a degree of caution and scepticism. Ultimately, all emission scenarios are nothing more than prognostication and conjecture, albeit an informed one. Emission scenarios are estimates or predictions of how the future will be, i.e. forecasts based on hind cast. There is always uncertainty associated with forecast for who can gaze 10, 20 let alone 100 years into the future? That said, we can, with the benefit of hindsight, claim that very accurate predictions have been made in the past. Nonetheless, we must always be wary of those 'black swans' of uncertainty. The key to crafting credible emission scenarios is to be realistic. A valid case in point would be the hydrogen, ammonia and methanol economies which were touted as alternative fuels of the future. Ten years down the road since these future scenarios were proposed and we have still yet to see such visions materialize. Perhaps we are all waiting for that radical 'game changing' technology to come along and surprise us. Until then, we have to concede that the world operates on a fossil fuel energy system.

### 2.5.2 On the controversy surrounding the global participation in CCS

The differentiated responsibility of nations to mitigate CO<sub>2</sub> emissions is a very controversial issue with on-going heated debate. The lofty aims of the Climate Change Conference in Copenhagen (COP15) could be said to be overly ambitious and an elusive general consensus was not reached. Developed nations should recall that they were once developing nations. Perhaps such a reminder strikes raw nerves by pointing out that there was once a time when these nations were less sophisticated than they are today. Having progressed on to the status of a developed nation, it is easy to take the moral high ground by pointing out to less developed countries that they have an obligation to mitigate their CO<sub>2</sub> emissions. Developed nations, with the requisite technology at their disposal, are more adeptly able to implement such mitigative measures whereas the developing nations struggle to abate their CO<sub>2</sub> emissions and are reluctant to do so as such effort is seen to impede their economic

development. Thus, the need for differentiated responsibility whereby the developed world leads the way by example. Through this exemplary behaviour, the less developed countries would gradually be inclined to follow suit. It would not be prudent for the developed world to attempt to ram their ambitious emission reduction targets down the throats of their developing cousins. In the author's opinion, the dead-lock in reaching consensus can be broken when all parties involved come together in a spirit of compromise, empathy, tolerance and mutual understanding.

### 2.5.3 *On the need to provide incentives for CCS in order to make it cost competitive*

Oftentimes, economic viability trumps technical feasibility. In the real world, no project, however noble, can be expected to be implemented purely based on altruistic reasons. Venture capitalists and financiers are aware of the immense risk they take on when contemplating a CCS project. It does not make economic sense to launch a pilot project for the sake of merely demonstrating proof of concept. A compelling business case has to be put forth to garner financial support. Perhaps governments are the only entities which can implement a CCS pilot project 'regardless of cost'. But even then, governments have to be mindful of the prudent use of tax payer's money. The question thus arises: Why can't CCS stand on its own? Why does it require subsidies upon itself and dis-incentives upon others (carbon taxes) in order to promote it? Although much of the literature is upbeat about the prospects of CCS, there is always that caveat expressing cautious optimism: CCS can be economically feasible 'provided' or 'on condition that' or 'subject to'.

There is no clear cut solution to this conundrum. It would appear that CCS requires incentives and concessions in order to proliferate. Perhaps the answer lies in how CCS is postured and marketed. CCS must be promoted as a green initiative and thus more palatable to the public. CCS can be associated with Enhanced Oil Recovery (EOR) thereby providing a service to oil majors. The strategic positioning as a service provider makes CCS relevant. Ultimately, the success of CCS would depend on whether CCS is able to create a compelling need for itself, thereby future-proofing its existence.

## 2.6 *CCS non-technical issues*

Carbon Capture and Storage (CCS) represents a means to curb CO<sub>2</sub> emissions to the atmosphere. Whilst many papers have examined the engineering challenges and technical issues associated with CCS, this paper seeks to examine the legal and social aspects entailed with the realization of CCS. Sometimes associated with CCS, is Enhanced Oil Recovery (EOR) which is a means to boost production from aging wells by injection of CO<sub>2</sub>. EOR is a proven technology with some operational experience from which we can draw insights from. The legal framework for EOR can be used as a basis for the development of instruments of law for CCS.

When framing CCS in a legal-social-political context, a good starting point would be to consider the various stakeholders involved from the on-set. Very loosely, these entities are:

- a. Fossil fuel power plant operators
- b. The public
- c. The government and policy makers
- d. Legislators and relevant regulatory bodies
- e. Insurers, bankers and financiers
- f. CO<sub>2</sub> storage facility operators
- g. Vendors and subcontractors from support sub-industries
- h. The oil major or energy company (where applicable)

Among the various stakeholders, one immediately sees the balance of power amongst the various entities, most notably the oil major who represents an important potential source of funding for a CCS project. It is the author's opinion that for any proposed CCS project, it is highly desirable that an oil major joins the band wagon. Such an influential partner would have the financial clout to get CCS projects into the water and facilitate the maturation of CCS technology.



### 2.6.1 *CCS from a political aspect*

The climate change we are experiencing is caused by the greenhouse effect and is a common problem. Most nations agree on the necessity of reducing the emission of greenhouse gases. However, the view point about CCS is quite different.

The crucial role of CCS in cost-effective climate change mitigation is well established by many international studies and reports. But overcoming perceived and real risks, higher costs and financing barriers, and low public acceptance is proving difficult and time consuming, resulting in slower progress on CCS development. CCS technology is still immature. Commitment and a long term support plan are necessary from governments. This support requires a large amount of finance, which could be a great burden for a developing country.

From the perspective of a developing country, the immediate agenda is economic and technological progress. The effort poured into CCS technology development would be a barrier to this quest for prosperity. Furthermore, a developing country would have less experience in CCS technology and fewer resources to mobilize and bring to bear in furthering this technology. Moreover, the major portion of emitted carbon dioxide is from developed countries. Although the portion from developing countries has also increased, developing countries do not feel the same responsibility as developed countries. The geo-politics surrounding CCS is a delicate game of chess where governments wait on one another to hitch a ride. No one wishes to take the first step. The authors share the opinion that it would take a truly advanced nation such as UK to take the initiative and lead the way.

There is still ongoing debate between developed and developing countries about who should bear the burden of environmental stewardship. Encouragingly, most nations agree on the necessity of CCS technology. Therefore, a technology road map backed by political support should be spear-headed by governments with a commitment to see it through to fruition. Where there is a change of political parties heading the government, the incoming party must be willing to take on the mantle of their incumbent predecessors and continue the work forward.

### 2.6.2 *CCS from a legal perspective*

One must never underestimate the influence of international and regional laws in shaping CCS development. The difficulty is that there is not a large amount of existing legislature to bring to bear or to act as a legal basis for CCS. Legal uncertainty and the absence of a definitive internationally recognized regulatory framework underpin the high risk of new ventures. In all likelihood, CCS projects will most probably initially be undertaken by governments or with extensive government funding. These pilot demonstration projects will then pave the way for new entrants from the private sector. Not surprisingly, the legal scene for CCS is also extremely complex. Questions arise as to the applicable laws governing CCS projects. Notable legislature relevant to CCS is listed below:

- a. EU : CCS Directive (2009/31/EC)
- b. International : The London Protocol and The Oslo-Paris Convention (OSPAR)

Furthermore, legislature and statutory requirements enacted by governments are largely determined by the inclinations of that particular government towards the concept of CCS. For instance, given that CCS is related to the burning of fossil fuels, the general consensus in Germany is not to go down that path as effort to develop CCS is seen as ‘encouraging’ the burning of fossil fuels. Research effort is thus directed towards alternative energy sources. Where governments are not receptive to the concept of CCS, the legal framework surrounding CCS suffers. With Germany’s recent announcement that it intends to scale down nuclear power generation activities, the nation’s choices appear limited.

This brings the author to his next point. With Germany’s stated intention to gradually phase out and decommission the nation’s nuclear power plants in the wake of the Fukushima Daiichi incident, questions arise as to the plant operator’s legal obligations and liabilities. This highlights an important consideration for CCS projects – any newly formulated laws should be crafted with a ‘cradle to grave’ mentality and a holistic approach to law-making must be taken. Law-makers and regulators must engage the public in consultation together with engineers and scientists so as to make an informed decision on the practicality and enforceability of legal obligations. With such upheaval of the legal

system, law-makers will be forced to re-think definitions and formulate new laws. For example, is CO<sub>2</sub> defined as a waste or as a pollutant? Should governments be the sole environmental stewards of the stored carbon? Must the permitting process necessarily be bureaucratically protracted and characterized by a cautious stance or can the permitting process be more streamlined and expedited.

The roles, responsibilities and legal obligations of all stakeholders should be clearly defined. The legal implications flowing from any potential accidents should also be well understood. Custody transfer of the CO<sub>2</sub> and the penalties for accidental spillage must be transparent and uniform. In short, the various regional laws surrounding CCS should be harmonized globally.

Recognizing that fossil-fired electricity generation will continue to dominate on the world stage in the immediate future, CCS is touted as a means to use fossil fuels in a sustainable manner that is palatable to society with a robust legal framework envisaged in-place. This brings us to our next section – CCS in a social context.

### 2.6.3 *CCS in a social context*

With heightened societal awareness of global warming and climate change, proponents of CCS would argue that the need for CCS is compelling. Conversely, sceptics have voiced concerns that CCS is a solution that has come too little-too late with countries scaling back dependence on fossil fuels and looking towards alternative energy sources. CCS cynics are of the opinion that R and D effort should be directed elsewhere. Whichever expert opinion wins out, society's views are sadly often shaped by the loudest voices, not the most rational one.

Understandably, public perception of CCS is contentious and controversial. Public perception is to a large extent shaped by media coverage. Sensationalist media reporting has placed CCS in a negative light and it is dismaying that such media have not reported responsibly and objectively. A valid case in point would be the CO<sub>2</sub> incident at Lake Cameroon in 1986 which resulted in 1700 fatalities from asphyxiation (suffocation). Although such a geological occurrence is rare, the perception as to the safety of CCS has already been marred.

Of great concern to the public is that of stewardship of the stored CO<sub>2</sub>. Long time-scales make future visibility unpredictable. It is difficult to anticipate the longevity and integrity of the carbon storage facility. The public has to trust that any proposed CCS scheme is safe. Gaining public trust and confidence remains one of the great challenges of CCS. Engineers and scientists need to assure the public that any carbon storage facility in their vicinity is handled by a 'competent authority' with measures taken to mitigate and manage risk.

Oftentimes, public perception trumps other considerations as it is society that constitutes the electorate. Political parties that form the government need the strong mandate of the people for CCS to proliferate. The government will not, in its best interest, oppose the views of the public and thus these two stakeholders' views are closely aligned. An example of how public perception on safety can influence CCS projects is the Barendrecht project onshore Netherlands. The project was stopped due to public outcry. The Dutch government subsequently banned CO<sub>2</sub> storage.

It thus falls upon the engineers and scientist who are proponents of CCS to charismatically communicate and influence at the highest levels that the pursuit of CCS is a worthy endeavour. Proponents must be able to eloquently convince and persuade the public about the merits of CCS. Only then can CCS be whole heartedly embraced and spur further development of CCS technology and know-how.

Of greatest concern to the public is that of safety and how CCS will affect their lives. Sound Front End Engineering and Design (FEED) decisions must be clearly communicated to the public to allay fears. The table below argues for and against CCS being safe.

Table 2.7 - Safety concerns related to CCS

Viewed as safe	Viewed as unsafe
<ul style="list-style-type: none"> <li>• Current storage sites do not leak</li> <li>• Good track record thus-far</li> <li>• Probability of leakage very low</li> <li>• Engineering tools available to simulate and monitor CO<sub>2</sub> behaviour underground</li> <li>• Envisaged rigorous regulation of storage sites</li> </ul>	<ul style="list-style-type: none"> <li>• Very few storage sites mean lack of operational experience</li> <li>• Technological infancy and immature know-how</li> <li>• Knowledge and tools not developed enough</li> <li>• Time scales involved extremely long</li> <li>• Murphy's law</li> </ul>

When the concept of CCS is clearly explained and described to the public, the average layman with no technical background typically agrees that CCS is beneficial to mankind. However, the peculiar behaviour of society is such that society is likely to condone and endorse a novel concept but Not In My Back Yard (NIMBY). This reluctant tendency to embrace anything new can be attributed to xenophobia (the fear of anything foreign). When conveying a description of CCS to the general public, it is important that technical personnel convey the information in a simple and easy to understand manner whilst at the same time not to talk down or belittle the average man on the street.

The public also have a right to know how tax payer's money is spent. With CCS projects anticipated to involve massive public funding, is it acceptable to the tax payer that resources are allocated to CCS? The European Union has put forth ambitious environmental targets for the reduction of greenhouse gases. CCS forms part of a 'cocktail mix' of mitigation measures. The goal is to have CCS commercially viable by 2020. Society needs to question then if the public is comfortable with bearing the burden of the high CAPEX and OPEX costs, recognizing that future generations will be the beneficiaries of their efforts. The EU's pledge of EURO 1 billion in economic stimulus packages and grants is indicative of Europe's commitment. The public needs to question if such funding can be construed as 'irrational exuberance'.

The pros and cons of CCS need to be conveyed to society in an objective manner so that public awareness is not marred by preconceived notions. The legal and social issues should be explored in detail prior to implementation of any CCS project. Public consultation and engagement, together with sound legal advice from law practitioners are essential elements of such projects. Often times what may be technologically feasible is not socially acceptable or legally tenable.

### 3 CONCEPT PROPOSALS AND DESCRIPTIONS

This section provides brief summaries of the various concept proposals that were put forth by the authors. The concept proposals are categorized according to proposals related to carbon capture, transportation and storage.

#### 3.1 CO<sub>2</sub> capture

##### 3.1.1 *Controlled algae blooms in ocean space consuming vast amounts of CO<sub>2</sub>*

This concept involves saturating a body of nutrient-rich water with CO<sub>2</sub> containing anaerobic algae. Under these conditions, the algae are expected to multiply rapidly. The growth in bio-mass is then harvested and processed into fish feed or bio-diesel. The CO<sub>2</sub> absorbed by the anaerobic algae helps to mitigate emissions to the atmosphere. This concept involves the instigation of controlled algae blooms in ocean space resulting in the consumption of vast amounts of CO<sub>2</sub>.

#### 3.2 CO<sub>2</sub> transportation

##### 3.2.1 *Feasibility study of a large combined LPG/CO<sub>2</sub> carrier*

This concept proposes the design of a bespoke very large combined LPG/CO<sub>2</sub> carrier. Recognizing that the containment system, cryogenic pumps and piping systems on-board an LPG carrier is quite similar to the few CO<sub>2</sub> carriers in service, existing LPG carrier designs can be adapted to transport CO<sub>2</sub> as cargo. The vessel should be sufficiently large to capitalize on economies of scale so as to make the transport of cargo more cost effective. A combined carrier also affords versatility as the vessel is able to operate in the lucrative LPG trade or undertake CO<sub>2</sub> transport missions.

##### 3.2.2 *A novel concept for a CO<sub>2</sub> carrier with CO<sub>2</sub> micro-bubble hull lubrication*

This concept proposes to use boil off gas from the liquefied CO<sub>2</sub> as the working fluid for micro-bubble hull lubrication. The vaporized CO<sub>2</sub> is pushed through a compressor and expelled through several shell openings. It is envisaged that the CO<sub>2</sub> micro-bubbles will lower hull frictional resistance resulting in lower fuel consumption. Assuming a boil-off of 10% of the liquefied CO<sub>2</sub> cargo during the voyage and that this amount is expelled through the shell plating, the reduction in CO<sub>2</sub> emissions arising from reduced fuel consumption must offset the amount of CO<sub>2</sub> expelled in the micro-bubble operation to be viable. The CO<sub>2</sub> bubbles will rise to the surface and enter the atmosphere. A carbon neutral target may be optimistic. The powering requirements of the micro-bubble compressor must also be considered. Questions arise as to the effects the micro-bubbles will have in ocean acidification and corrosion/pitting damage on the hull plating.

##### 3.2.3 *Design of a CO<sub>2</sub> carrier and dedicated offshore reception facility*

This proposal seeks to develop a better way for the interface of the offloading CO<sub>2</sub> carrier and dedicated offshore reception facility. The CO<sub>2</sub> carrier can be framed as a transportation problem and the offshore installation can be framed as a processing, injection and storage problem. Rather than considered the two problems in isolation, an integrated solution can be sought whereby CO<sub>2</sub> transport interfaces seamlessly with CO<sub>2</sub> injection and storage.

#### 3.3 CO<sub>2</sub> storage

##### 3.3.1 *Locking CO<sub>2</sub> in ice as carbonic acid or dry ice*

This concept involves the locking of carbon dioxide in solid form as dry ice or dissolving carbon dioxide in water to form carbonic acid and then freezing it. Large blocks of solid carbon dioxide can thus be created which is then towed to the Polar Regions for storage where the blocks will remain frozen all year round. To accomplish this, the dry ice will need to be pressurized. The energy required in cooling large amounts of carbon dioxide is anticipated to be substantial.

##### 3.3.2 *Using CO<sub>2</sub> to create building materials*

This concept involves subjecting carbon dioxide to a chemical reaction with abundantly available metal oxides forming stable carbonates. The stable carbonates can then be used as building materials

in roads, buildings etc. In this way, carbon dioxide is prevented from escaping into the atmosphere. The amount of heat supplied to the chemical reaction is expected to be substantial. Energy will also need to be expended in the extraction of the metal oxides which will introduce carbon dioxide into the atmosphere and may not be commensurate with the carbon dioxide mitigation process. Concerns arise as to the susceptibility of the stable carbonates to erosion and corrosion. Lastly, the load bearing capacity and mechanical properties of the stable carbonate must be verified adequate for construction purposes.

### 3.3.3 *Using CO<sub>2</sub> to produce zirconia (diamonds)*

Recognizing that diamond is an allotrope of carbon, the reduction of carbon dioxide will yield carbon which if subjected to suitable conditions of pressure and temperature, can result in the formation of low grade diamonds (zirconia). The process of diamond formation occurs over millions of years. However, geological conditions can be recreated in a laboratory without the long timescales. This may be one plausible way of utilizing captured carbon dioxide.

### 3.3.4 *Using torpedo anchors to lodge CO<sub>2</sub> filled cylinders into sea-bed*

Torpedo anchors are a means to effect station keeping. While not the conventional mooring solution, torpedo anchors have been proven satisfactory in service, particularly in Brazil. The missile-shaped anchor is released from the water surface and allowed to free-fall under the action of gravity to the sea-bed. The trajectory of the projectile is vertically downwards. Upon impact with the sea-bed, the torpedo anchor lodges itself into the soil. This concept proposes scaling up the size of current torpedo anchors. Solid iron ore ballast occupies the tip while the internal volume of the body is used to store a substantial amount of liquefied carbon dioxide in a pressure vessel. The massive body will accelerate towards the depths picking up momentum. Penetration and lodging into the sea-floor may be one plausible means to store carbon dioxide.

### 3.3.5 *Injecting CO<sub>2</sub> and biomass into depleted oil wells and other geological formations*

In the Deep-water Horizon maritime casualty, BP attempted to pump golf balls into the leaking well in an effort to plug the well. They failed miserably. Thus, one may wonder if it is possible to inject biomass into depleted oil wells and geological formations. Rather than incinerating biomass such as leaves, organic waste and biodegradable garbage which pollutes the atmosphere with CO<sub>2</sub>, the biomass can be mixed with liquefied CO<sub>2</sub> to form slurry which is injected into depleted wells. It is anticipated that over millions of years, this slurry mixture will form fossil fuels. Alternatively, the bio-mass can be bundled into large bales and dropped into the alluvial fans of river estuaries. The bundled biomass will quickly sink into the mud obviating the need for polluting incineration.

### 3.3.6 *Creating stable solid carbonates to make artificial reefs*

This concept proposes that stable solid carbonates be dumped onto the seabed where the material will promote the development of artificial reefs. These artificial reefs are a haven for fish and will serve as a sheltered conducive environment for fish to reproduce and replenish fish stock. Alternatively, the stable carbonates may be laid at the base of wind turbine monopile foundations to serve as scour protection.

### 3.3.7 *Corrective measures for cap rock fracture of carbon storage reservoirs*

This proposal seeks to develop well-thought-out measures in the event of cap rock fracture due to geological activity. The design team will seek to conceive a comprehensive set of actions to be taken in the event of such a calamity.

### 3.3.8 *Storage of CO<sub>2</sub> beneath permafrost*

The Arctic and Antarctic regions have a thick, continuous layer of permafrost. In the extreme Polar Regions, this layer of frozen ground remains frozen all-year-round. The storage of CO<sub>2</sub> beneath the permafrost under these circumstances is plausible. The concept will seek to develop a system in which to effect this storage recognizing the harsh polar environment.

### 3.3.9 Carbonic acid hydro-jetting to create underground caverns for CO<sub>2</sub> storage

This concept involves the dissolving of gaseous CO<sub>2</sub> into water to form concentrated carbonic acid. The concentrate is then used to hydro-blast limestone, effectively eating away at the rock. Through the erosion and corrosion of rock, a large underground cavern can be created which is then used for CO<sub>2</sub> storage.

### 3.3.10 Storing CO<sub>2</sub> 'soup' in an underwater lake

This concept involves forming two stratified layers of fluid in ocean space. Liquefied CO<sub>2</sub> which is denser than seawater will form an 'underwater lake' at great depths. This may prove an effective way of carbon storage.

### 3.3.11 CO<sub>2</sub> storage and injection platform wholly powered by marine renewable energy

This concept proposes a floating (self-propelled or non-self-propelled) CO<sub>2</sub> re-liquefaction and re-gasification plant. The floating offshore installation will serve the function as a platform for CO<sub>2</sub> injection and storage into depleted oil wells. The vessel will be able to be redeployed once the reservoir is filled to capacity. All the on-board machinery and equipment will be powered wholly by marine renewable energy. Thus, operations will have a small carbon footprint and not add to the problem of GHG emissions.

### 3.3.12 Producing methanol from CO<sub>2</sub> wholly powered by marine renewable energy

This concept is an extension of the previous concept. The floater will serve as a platform to house the requisite on-board machinery. An energy storage plant will be provided on-board to store excess energy from marine renewable sources during periods of high ambient energy. This energy store will be drawn upon when required during periods of high demand. The energy storage plant is envisaged to be a flywheel in a vacuum. Rotational kinetic energy is drawn upon when needed. Water is hydrolysed to produce oxygen and hydrogen. The hydrogen is reacted with carbon dioxide in a standard industrial process to produce methanol. The methanol is stored on-board for export to chemical tankers. Methanol and hydrogen engines may also be provided onboard.

### 3.3.13 Design of an artificial island for carbon storage

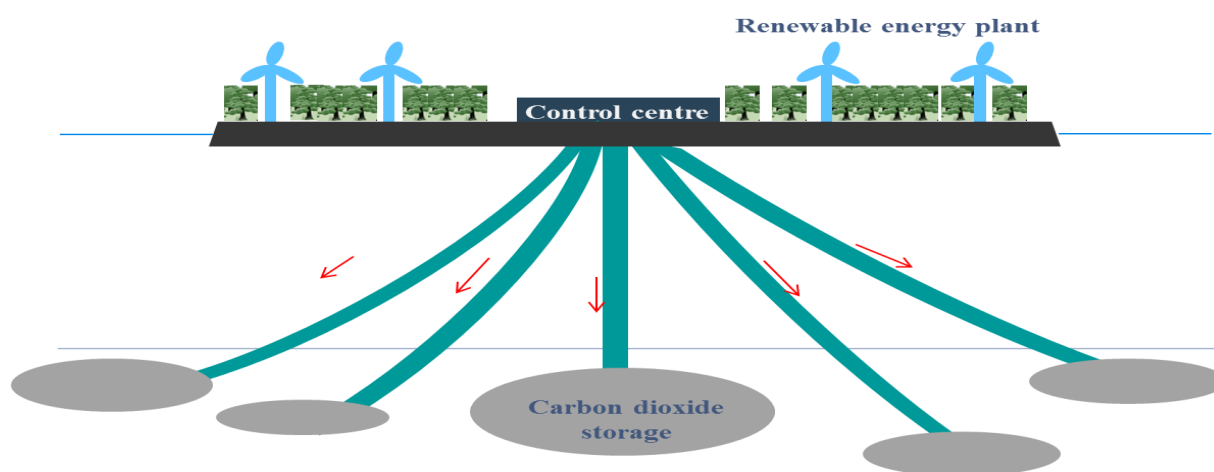


Figure 3.1 - Artificial island for CO<sub>2</sub> storage

A carbon storage and monitoring facility is not welcomed on land because of its probable danger. An installation at sea would be less opposed by the public. However, a possible candidate for storage and its capacity is not verified clearly. Therefore, this proposal suggests the installation of a floating island, where carbon capture and monitoring facilities are installed onboard. One expected effect is that this island can move to another storage site when one storage location is filled to capacity. A renewable energy plant will be considered for supplying the energy as a means to carry out the storage.

#### 3.3.14 *CCS technology stepping into ultra-deep water*

Carbon dioxide injection into deep sea sediments below 3000m water depth and a few hundred meters of sediments may provide permanent geologic storage by gravitational trapping. With high pressure and low temperatures common in deep sea sediments a few hundred meters below the sea floor, CO<sub>2</sub> will be in its liquid phase and will be denser than the overlying pore fluid. The lower density of the pore fluid also provides a cap to the denser CO<sub>2</sub>. Furthermore, the dissemination of CO<sub>2</sub> in the sediments and potential chemical reactions between CO<sub>2</sub>, pore fluid and sediments will enhance its storage into the seabed.

The overall storage capacity for CO<sub>2</sub> in such deep sea formations below the ocean floor is primarily determined by the permeability, and will vary with seafloor depth, geothermal gradient, porosity, and pore water salinity. Hence site investigation will be a significant challenge faced by the deep-sea engineers.

## 4 CONCEPT SELECTION

Of the 18 proposed concepts, six were shortlisted and deemed worthy of further consideration. These six concepts were subjected to a rational decision making process. Through a process of elimination and exercising our engineering judgment, a single most promising concept was selected to be pursued further in the concept development phase. The section below shows the decision making process in graphical form. The numerical scoring for each concept is provided in Appendix C.

### 4.1 *Shortlisted concepts*

The six concept titles are reproduced below:

1. Conversion of an existing offshore oil platform to store CO<sub>2</sub>
2. Modification of existing oil and gas pipelines to transport CO<sub>2</sub>
3. Controlled algae blooms in ocean space consuming vast amounts of CO<sub>2</sub>
4. A CO<sub>2</sub> injection platform wholly powered by marine renewable energy
5. Producing methanol from CO<sub>2</sub> wholly powered by marine renewable energy
6. Design of an artificial island for carbon storage and utilization

### 4.2 *Definition of performance factors*

Seven performance factors were developed to represent the key considerations in determining concept feasibility. They are as follows (not in order of importance):

- a. Technical feasibility
- b. Environmental friendliness
- c. Economic viability
- d. Expected public acceptance
- e. Political support and governmental funding
- f. Legal visibility
- g. Safety

### 4.3 *Scoring method for decision matrix*

Each member of the group exercised their professional engineering judgement in the scoring of each concept. Based on the results, the concept with the highest score was deemed most feasible to implement. The scoring scheme shown below is self-explanatory.

Table 4.1 - Scoring scheme

Excellent	Good	Average	Poor	Very Poor
5	4	3	2	1

### 4.4 *Evaluation of each concept*

The results of the decision making process are summarized in the graphs below. The scoring for each concept is provided in Appendix C.



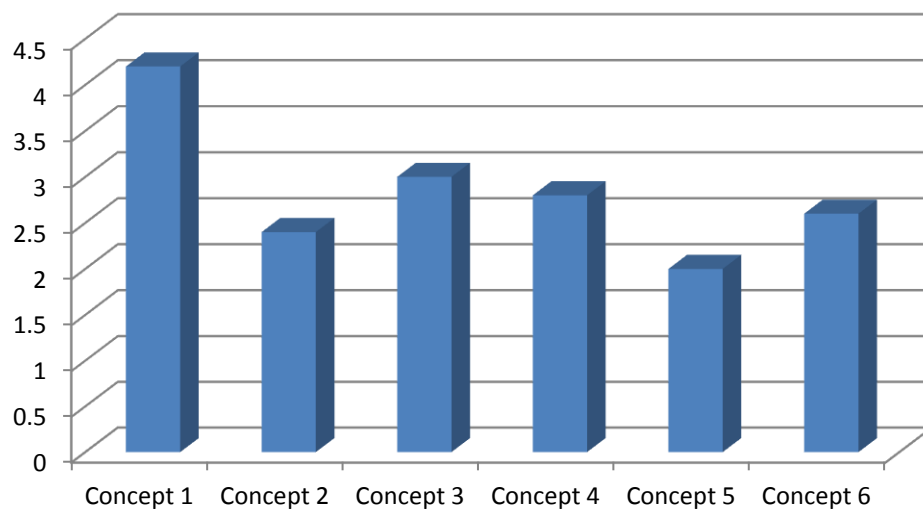


Figure 4.1 - Comparison of different concepts for technical feasibility

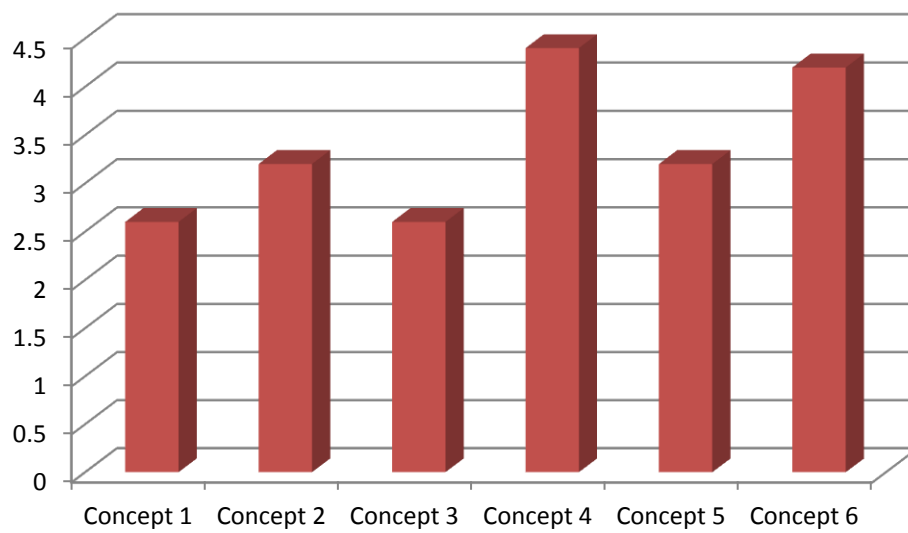


Figure 4.2 - Comparison of different concepts for environmental friendliness

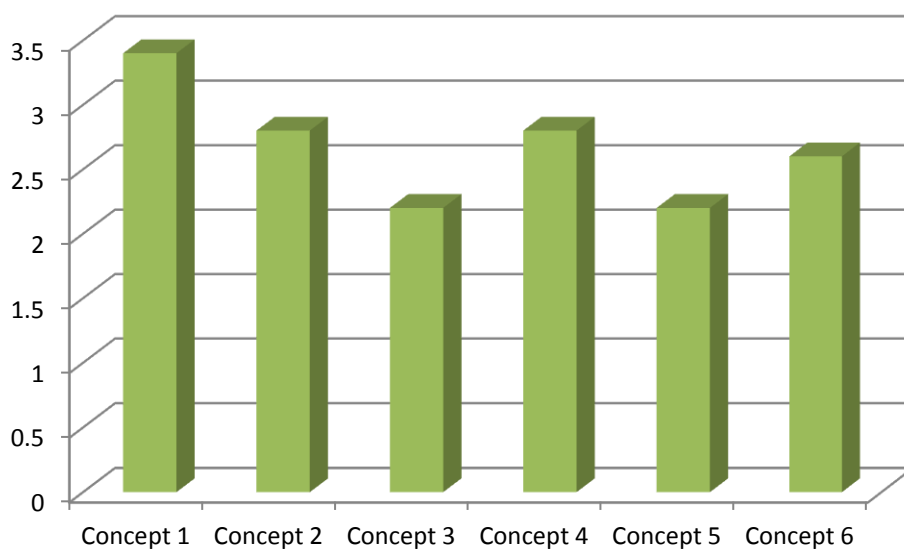


Figure 4.3 - Comparison of different concepts for economic viability

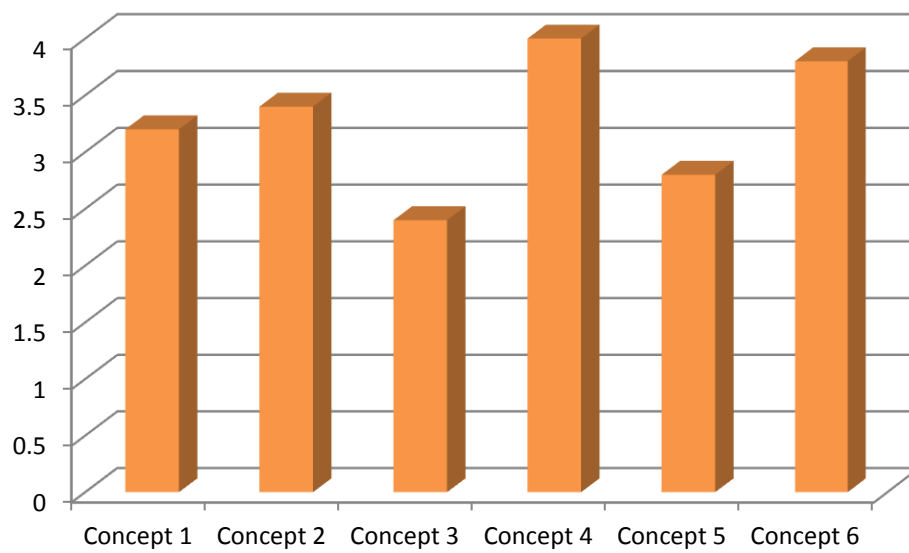


Figure 4.4 - Comparison of different concepts for public acceptance

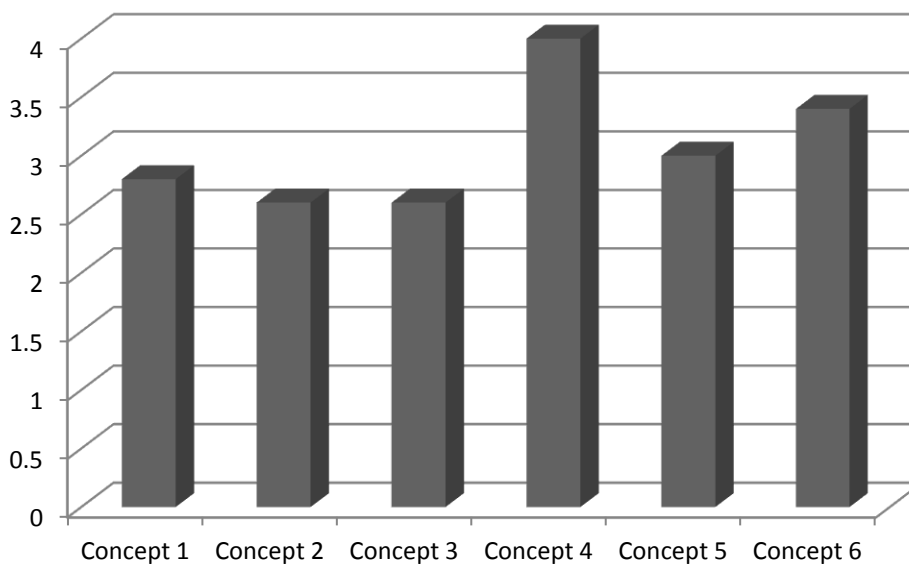


Figure 4.5 - Comparison of different concepts for political support and government funding

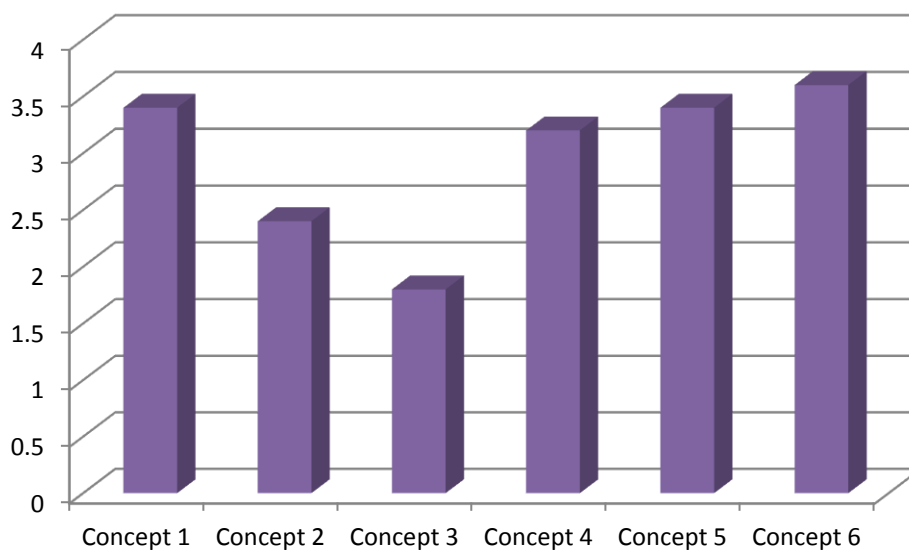


Figure 4.6 - Comparison of different concepts for legal visibility

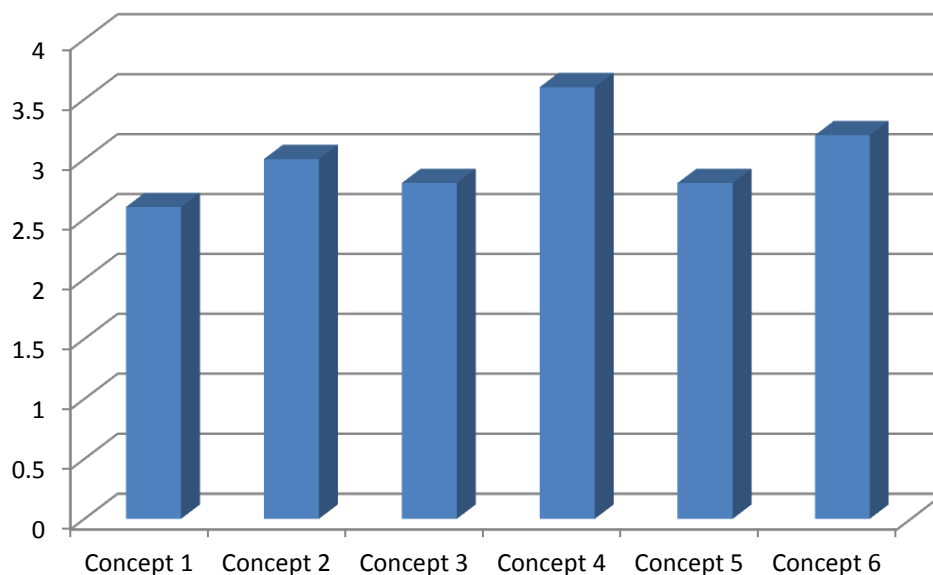


Figure 4.7 - Comparison of different concepts for safety

#### 4.5 Final selected concept

The six proposed concepts were subjected to a rational process of elimination. Selection criteria were used to evaluate overall feasibility of a proposed concept. These criteria include, but are not limited to, technical feasibility, environmental friendliness, economic viability, expected public acceptance, envisaged political support and government funding, legal visibility and safety.

To aid in the decision making process, a decision matrix was constructed and the six proposed concepts were subjected to a scoring system. The proposed concept with the highest score was deemed to be most feasible to implement. The decision matrix table is reproduced below.

Table 4.2 - Decision matrix

	Concept 1	Concept 2	Concept 3	Concept 4	Concept 5	Concept 6
Technical feasibility	4	2	3	3	2	3
Environmental friendliness	3	3	3	4	3	4
Economic viability	3	3	2	3	2	3
Expected public acceptance	3	3	2	4	3	4
Political support and governmental funding	3	3	3	4	3	3
Legal visibility	3	2	2	3	3	4
Safety	3	3	3	4	3	3
SUM	22	20	17	25	19	23

The selected concept is entitled, “A novel concept for offshore CO<sub>2</sub> injection and geological storage wholly powered by marine renewable energy.”

## 5 CONCEPT DEVELOPMENT

### 5.1 Mind map and outline of key considerations

As a good starting point for the concept development phase a mind map capturing the various important design considerations was crafted. This provided the design team with a framework from which to pursue the concept development and to serve as a guide. The mind map is reproduced below.



Figure 5.1 - Mind map for selected concept

### 5.2 Selection of sources and sinks

Before embarking on concept development, the design team contemplated on which nation or region was in the best position to lead the way with a pilot CCS project. Through a survey of countries such as UK, continental Europe, the USA, China, Russia, India, Africa, South East Asia, Australia, Japan and the UAE, it was recognized that UK and Europe were the most suitable candidates for a pilot CCS project. This conclusion was arrived at by considering various key performance indicators such as political willingness, financial clout, public receptivity, safety track record, technological capabilities, etc. Having selected Europe as the region for a CCS pilot project, the design team proceeded to frame the problem in the context of UK.

In line with the Lloyd's Register Education Trust mission statement:

*The LRET works to achieve advances in transportation, science, engineering and technology education, training and research worldwide for the benefit of all.*

In this spirit, the design team sought to produce a meaningful body of work during the duration of the collegium that would benefit the world at large, with UK as the primary beneficiary.

The subsequent paragraphs describe the selection process.

#### 5.2.1 Selection of power plant

The first step in the design process spiral is to identify sources and sinks. This involves a survey of appropriate sites and the selection of an injection location. When considering large point sources,

power plants, petroleum refineries and heavy industries were taken to account. The focus was on large coal-fired power plants near the Yorkshire coal fields in the Midlands of England. The figure below shows the coal fired power stations currently operating within the UK.



Figure 5.2 - Coal fired power stations in the UK

(Source: <http://www.ukqaa.org.uk/PowerStation.html>. Last retrieved 1 Aug 2011)

Very fortuitously, we note the relatively close cluster of coal-fired power plants along the northern bank of the Humber River. Also note the two power plants south of the Humber – West Burton and Cottam. These five plants – Ferrybridge, Eggborough, Drax, West Burton and Cottam are strategically located near the Yorkshire coal fields. Due to their close proximity, these five plants represent a valuable source of CO<sub>2</sub> for capture. These five plants out of the total 18 plants currently in operation comprise nearly a third of all the UK's large point sources. The next logical progression would be to select a single plant among the five for the pilot CCS project, with provision for future expansion to incorporate capture of CO<sub>2</sub> from other nearby plants. The selected power plant is the Drax power station. A profile of Drax power station follows in the subsequent section.

### 5.2.2 Background information on Drax power station

Drax is a coal-fired power plant in North Yorkshire, UK. It has a generating capacity of 3960 MW, the highest of any power station in the United Kingdom, providing about 7% of the country's electricity supply. Drax is the UK's single largest emitter of carbon dioxide. Drax generates around 24 terawatt-hours (TWh) of electricity annually and produces around 22.8 million tonnes of carbon dioxide per year. As well as burning coal, Drax power station also co-fires biomass and petroleum coke ('petcoke').

The environmental effects of coal burning are well documented, the most significant of which is global warming, caused by the release of carbon dioxide into the Earth's atmosphere. Coal is considered to be "easily the most carbon-intensive and polluting form of energy generation available". In 2007 Drax produced 22,160,000 tonnes of CO<sub>2</sub>, making it the largest single source of CO<sub>2</sub> in the UK.

On 17 June 2009, Secretary of State for Energy and Climate Change Ed Miliband announced that all UK coal-fired power stations may be fitted with carbon capture and storage (CCS) technology by the early 2020s or face closure. Due to the outcome of the 2010 general election, it is unclear if this remains government policy. Drax currently has made no statement on the viability of CCS technology at the power station. If it was necessary to install CCS technology at Drax, it would require the construction of new turbines and boilers, and a secure way of transporting captured CO<sub>2</sub> 64 km to the Yorkshire coast. The next section deals with the identification of sinks.

### 5.2.3 Selection of type of geological formation for storage

This section explains the decision to use aging or depleted oil and gas fields instead of saline aquifers for CO<sub>2</sub> geological storage. The rationale to use geological formations such as cavernous oil and gas reservoirs as opposed to saline aquifers was based on the fact that our understanding of known oil and gas fields is much more sophisticated than saline aquifers. Extensive 3D seismic surveys and geo-technical investigations have been carried out by oil majors on known oil and gas fields whereas our understanding of saline aquifers is relatively immature. Although the potential storage capacity of saline aquifers is estimated to substantially exceed that of oil and gas fields, there is much uncertainty associated with saline aquifers which represents risk. The information collected by oil majors on the geometry and capacity of their fields represents a repository of knowledge which can be tapped on, provided the oil majors are willing to release such proprietary information. Based on offshore Exploration and Production (E and P) activities, we can estimate based on appraisal well flow rates the capacity of an oil or gas reservoir. Likewise, based on the amount of oil or gas that was extracted, we can estimate the amount of CO<sub>2</sub> that can be injected. It is a less risky proposition than having to deal with the uncertainty associated with saline aquifers. We can also bring to bear our comprehensive understanding of reservoir engineering in the case of oil and gas fields. The techniques of flow assurance such as hydrochloric acid injection can be applied. In short, we can lean on more than thirty years of offshore engineering experience.

### 5.2.4 Identification of sinks

The table below summarizes basic information on the North Sea. Note the relatively shallow water depths which suggest that the use of fixed steel jacket template structures is feasible. However, the harsh North Sea marine environment means the jacket will be subjected to storm loadings. Following the old adage, when in doubt, make it stout, the jacket structure will have to be robust with substantial scantlings to resist wave loadings.

The table below shows water depths in the North Sea. The Southern North Sea gas basin has water depths less than 50 m. This revelation is encouraging because it means we do not have to deal with the technical challenges associated with deep and ultra-deep waters.

Table 5.1 - Basic information on the North Sea

Location	Atlantic Ocean
Basin countries	Norway, Denmark, Germany, Netherlands, Belgium, France and the United Kingdom
Max length	960 km (600 mi)
Max width	580 km (360 mi)
Surface area	750,000 km <sup>2</sup> (290,000 sq. mi)
Average depth	95 m (312 ft.)
Max depth	700 m (2,300 ft.)
Water volume	94,000 km <sup>3</sup> (23,000 cu mi)
Salinity	3.4 to 3.5%
Max temperature	17 °C (63 °F)
Min temperature	6 °C (43 °F)

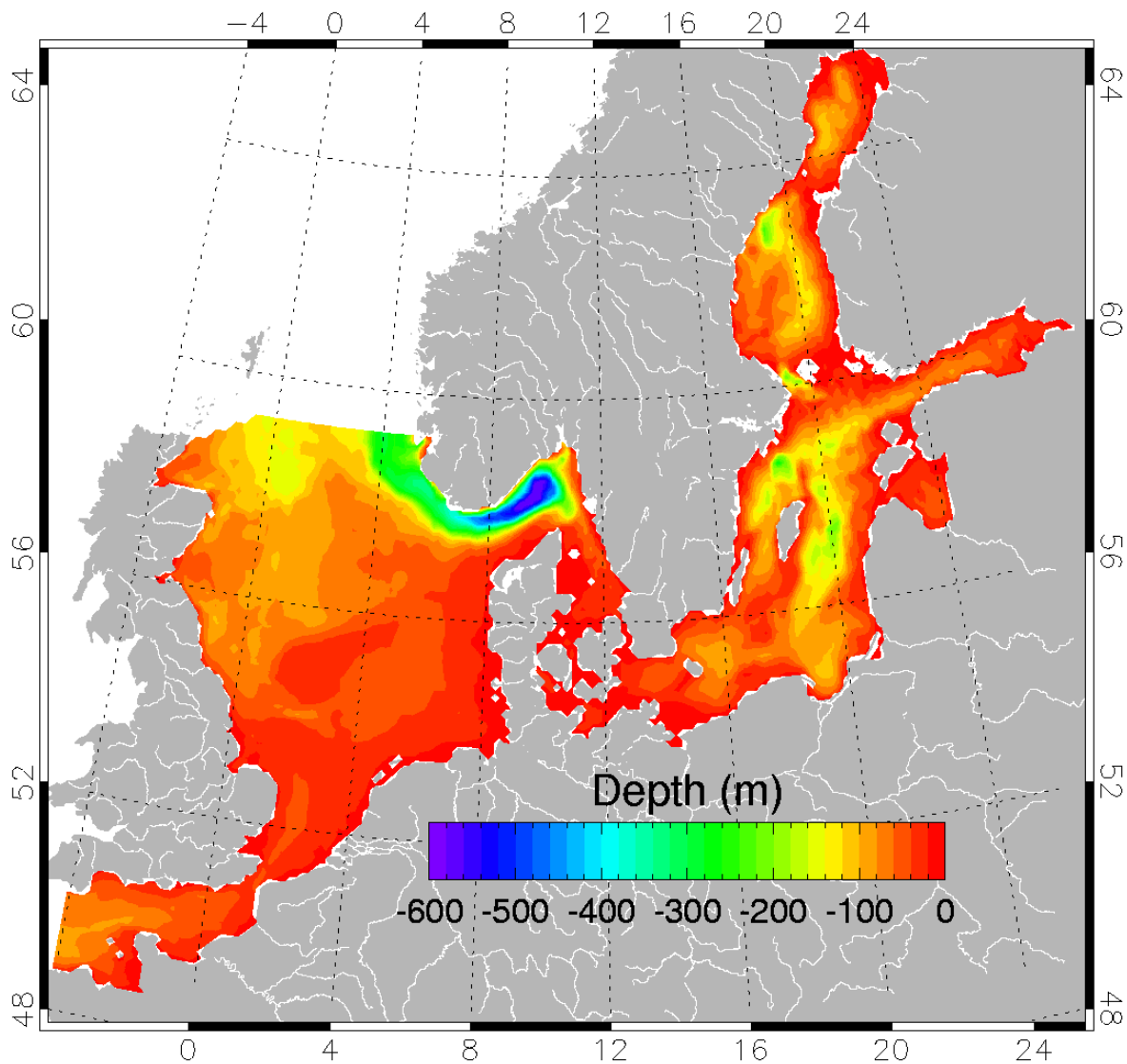


Figure 5.3 - Bathymetry of the North Sea  
(Source: <http://clasticdetritus.com/page/7/>. Last retrieved 1 Aug 2011)

#### 5.2.5 Carbon storage activities and opportunities in the North Sea

In the Norwegian sector of the North Sea, Statoil's natural-gas platform Sleipner strips carbon dioxide out of the natural gas with amine solvents and disposes of this carbon dioxide by geological sequestration. Sleipner reduces emissions of carbon dioxide by approximately one million tonnes a year. The cost of geological sequestration is minor relative to the overall running costs. As of April 2005, BP is considering a trial of large-scale sequestration of carbon dioxide stripped from power plant emissions in the Miller oilfield as its reserves are depleted.

Carbon capture and storage has the potential to be the size of the North Sea oil and gas industry. The potential exists for a CCS industry to be worth more than £2 billion per year and sustain more than 30,000 jobs by 2030. North Sea CO<sub>2</sub> storage space is estimated at more than 22 billion tonnes which is 180 years emissions from all of the UK's 20 largest point sources.

#### 5.2.6 Selection of storage location

Regarding the identification of sinks, it was decided collectively by the design team that saline aquifer geological formations would be excluded from consideration. The rationale for this decision was that scientific understanding of saline aquifers was still immature and that there was much risk and uncertainty associated with saline aquifers. This narrowed down our choice to onshore and offshore oil and gas reservoirs. Taking into account anticipated Not In My Back Yard (NIMBY) tendencies of the public, the former was further omitted. Hence, the design team, prior to deciding on the context of UK, surveyed the various offshore fields around the world. This included offshore North Western

Australia, the Gulf of Mexico, Offshore Brazil, West Africa, South East Asia and the North Sea. Of the various potential offshore oil and gas fields, the fields in the North Sea were selected; specifically the fields in the Southern North Sea Gas Basin. Figure 5.4 shows the offshore oil and gas fields within the Exclusive Economic Zone (EEZ) of the UK. In the north lies the Northern North Sea oil basin. In the south is situated the Southern North Sea gas basin. Due to the nearer proximity of the Southern North Sea gas basin to the large point sources in the Midlands, the design team focused on this region of the North Sea.



Figure 5.4 - Oil and gas fields in the North Sea

(Source: <http://www.renewbl.com/category/uncategorized> Last retrieved 1 Aug 2011)



The engineering decision and justification for selecting the North Sea as a region for a pilot CCS project is sound and logical. This is because North Atlantic sea state conditions are globally recognized as representative of unrestricted service/navigation. At first glance, the decision may seem irrational and counter intuitive. The harsh marine environment, storms, rough seas, short weather windows for offshore construction work and geo-hazards leads one to question the wisdom of selecting the North Sea as the location for a full scale pilot project. Perhaps such an undertaking for a pilot project is too ambitious? But there is a valid reason for selecting the North Sea as the trial location for a CCS project – proof of concept under the demanding North Sea conditions would suggest applicability anywhere in the world. It could potentially open the flood gates for CCS projects all around the world.

However, recognizing the concerns of risk adverse stakeholders, the design team decided to adopt a cautious stance. It is recommended that prior to the implementation of the full scale pilot project in the North Sea; a small scale demo should be trialled in the Mediterranean Sea to verify operability of the CCS system. In this report, focus is given to the description of the full scale pilot. A prelude treatment of the small scale demo is beyond the scope of this report but is highly advisable as a precursor to the full scale pilot project.

#### 5.2.7 *Matching sources and sinks*

Having identified the sources and sinks, the next step in the design process entails matching of appropriate sources and sinks. Also at this stage must be considered the means to bridge the source and the sink i.e. whether to use pipelines or ships for CO<sub>2</sub> transport. As far as practicable, it is desirable to strategically choose a source that is as close to a sink as possible such that minimal infrastructure is required for the transportation of CO<sub>2</sub>. The intent is to seek to minimize the amount of time and resources allocated for the requisite transportation chain so as to keep initial costs down.



Figure 5.5 - Cluster of five major power plants in the Midlands of the UK

The figure above shows the cluster of five power plants in the Midlands of the UK. Figure 5.6 shows the installed power of the aforementioned power plants which bears a correlation with the amount of CO<sub>2</sub> emitted.

The installed power of Drax power plant (3960MW) is approximately equivalent to the sum of any two of the other considered plants i.e. a carbon capture and storage project addressing Drax would effectively be equivalent to two separate CCS projects for the other four plants (economies of scale). The Drax power plant emits about 22.8 million tonnes of CO<sub>2</sub> per year.

On the grounds that the Drax power plant is the largest point emitter of CO<sub>2</sub> in UK, it was decided prudent to seek to arrest this largest of emitters. This is in-line with the design philosophy that when seeking to tackle a problem, go for the jugular where one can expect to make the most profound impact. The Drax power plant is located amply close to the Southern North Sea gas basin such that captured CO<sub>2</sub> is amenable to pipeline transportation.

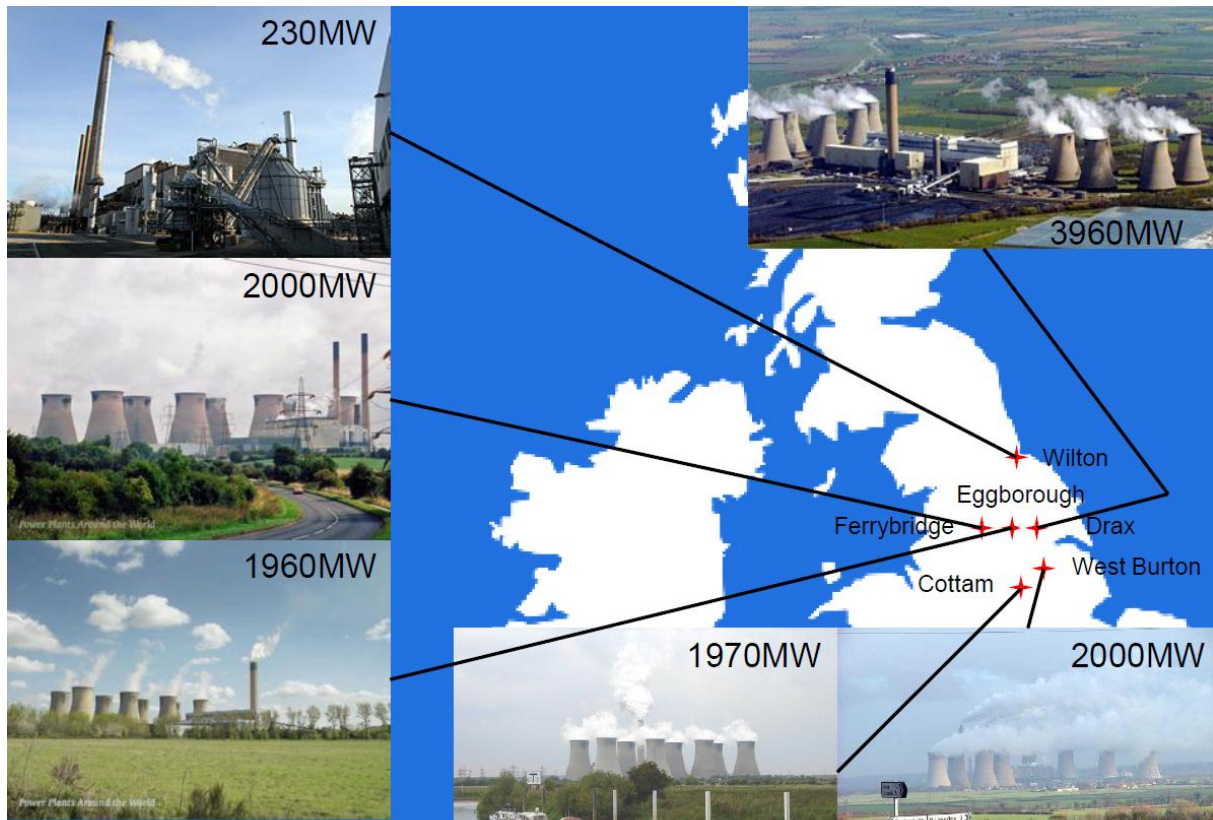


Figure 5.6 - Installed generating capacity of the six power plants

Having selected a specific source, the solution to the problem now shifts to selecting an appropriate sink. The design team identified two plausible scenarios for pipeline routes – we can take the gas north to the Argyll field and associated nearby fields (lower rim of Northern North Sea oil basin) or we can take the gas south to the Southern North Sea gas basin. The design team opted for the latter based on the following reasons:

- a. Anticipated better environmental conditions
- b. Larger potential storage capacity and possibilities

A survey of the various oil and gas fields in the Southern North Sea gas basin revealed that the Audrey field was located more or less at the geometrical centre of the basin. This was an important engineering consideration as the plan was to run a pipeline right into the heart of the Southern North Sea gas basin. With the Audrey field centrally located, the plan was for the injection platform at Audrey to serve as a hub for injection into satellite wells serving other reservoirs nearby the Audrey field. The figure below shows that it is possible to have multiple injection sites serving a single reservoir.

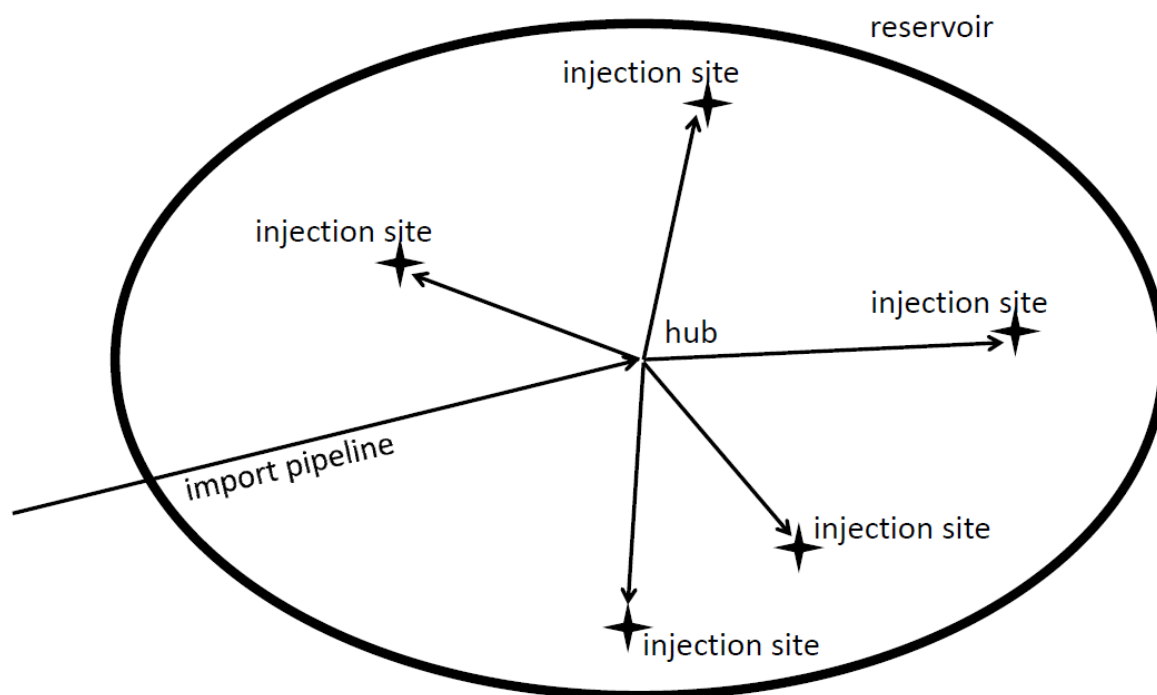


Figure 5.7 - Schematic showing CO<sub>2</sub> injection into a single reservoir from multiple injection sites

#### 5.2.8 Offshore installation considerations

Having negotiated the selection of sources and sinks, the design team reached an important milestone in the concept design phase of the project. The team members had to take into account the implications that flow from the engineering decisions made up to this point. One of these important engineering considerations is offshore installation and what it entails. By having a hub injection platform at Audrey field, this would involve retrofitting the existing Audrey platform and reconfiguring it for CO<sub>2</sub> injection. The Audrey field is still producing gas which means that the platform cannot be retrofitted to serve the sole purpose of CO<sub>2</sub> injection. The concept evolved from this realization and it was proposed that a modular add-on injection module be heavy lifted onto the platform to support the planned CCS activities. A crane barge would have to be chartered for this offshore installation work and the charter rates for such vessels tend to be high.

The decision to retrofit an existing platform instead of new build fabrication was borne out of the necessity to keep capital expenditure (CAPEX) low. However, the drawback of this approach is that CAPEX is never considered in isolation, but must be considered together with OPEX (operational expenditure) to ascertain through life cost. In the case of the utilization of an existing platform, steel renewal and lifetime structural integrity assessment needs to be undertaken. More maintenance can be expected for aging infrastructure than for a new build. A preliminary cost comparison of the two schemes revealed that the retrofit option would be more cost effective and the design team thus decided to pursue this route.

### 5.3 Scenarios

This section describes the various scenarios of the same general concept which may be implemented. The general concept is to capture CO<sub>2</sub> at Drax power station, transport the CO<sub>2</sub> to the Southern North Sea gas basin and inject it into hydrocarbon reservoirs. Now we delve further into the details and discuss the various ways in which we can carry out this plan.

#### 5.3.1 General scenario

A generic scenario is shown in the figure below. It involves the transportation of CO<sub>2</sub> by pipeline or ship from the onshore CO<sub>2</sub> temporary storage facility to a depleted gas field in the centre of the Southern North Sea gas basin. Secondary transportation links will then radiate outwards from this central hub to satellite injection sites. The existing gas production platform (fixed steel jacket) may be

retrofitted or a new purpose built platform will be fabricated and put in place. The platform may be of the fixed or floating type. The use of subsea manifolds for injection into satellite wells is a possibility. The injection platform will draw power from a nearby offshore wind farm.

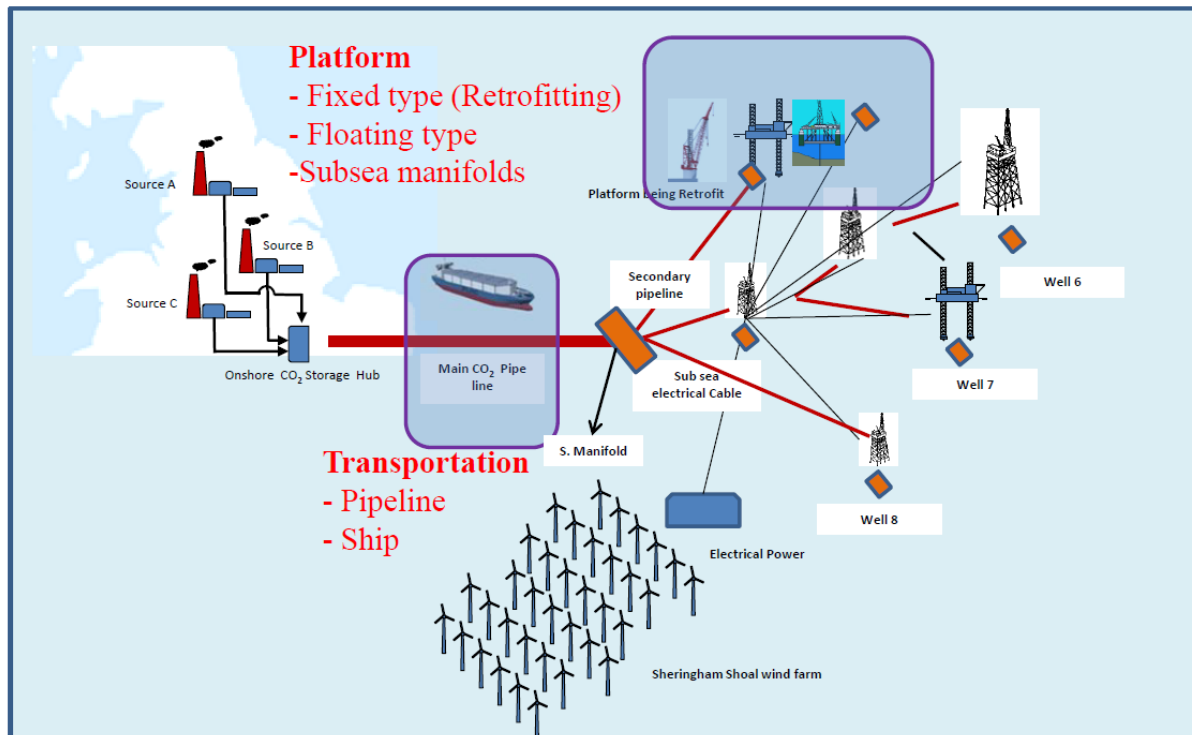


Figure 5.8 - General scenario

### 5.3.2 Scenario A

This variant as shown in Figure 5.9 involves constructing a main CO<sub>2</sub> offshore pipeline from the onshore CO<sub>2</sub> temporary storage facility to a depleted gas field in the centre of the Southern North Sea gas basin. Secondary CO<sub>2</sub> offshore pipelines will then radiate outwards from this central hub to satellite injection sites. The existing gas production platform (fixed steel jacket) will be retrofitted. Topside production modules will be removed and the injection modules will be put in place.

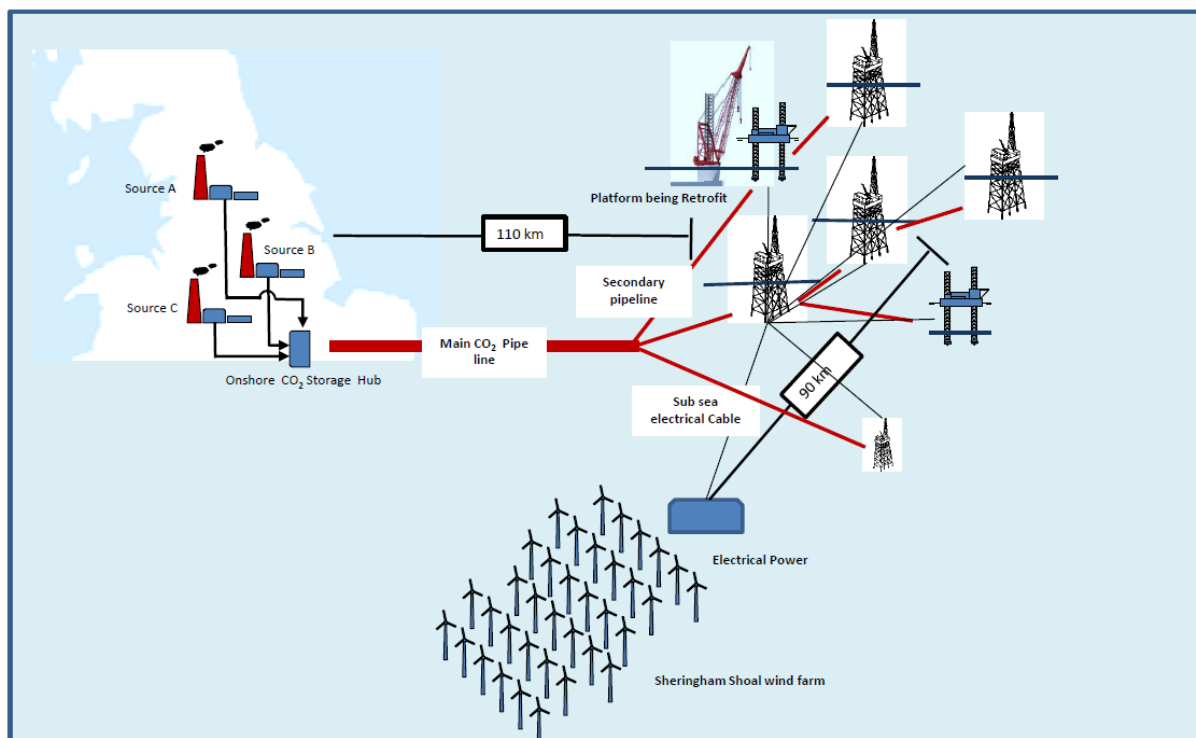


Figure 5.9 - Scenario A (Pipelines and existing platform retrofitted with CO<sub>2</sub> injection plant)

### 5.3.3 Scenario B

This variant as shown in Figure 5.10 involves constructing a primary CO<sub>2</sub> offshore pipeline from the onshore CO<sub>2</sub> temporary storage facility to a depleted gas field in the centre of the Southern North Sea gas basin. Secondary CO<sub>2</sub> offshore pipelines will then radiate outwards from this central hub to satellite injection sites. A new purpose built CO<sub>2</sub> injection platform will be fabricated and installed at the site, preferably a self-elevating jack-up which can be redeployed and relocated to the next injection site once the current site is filled to capacity.

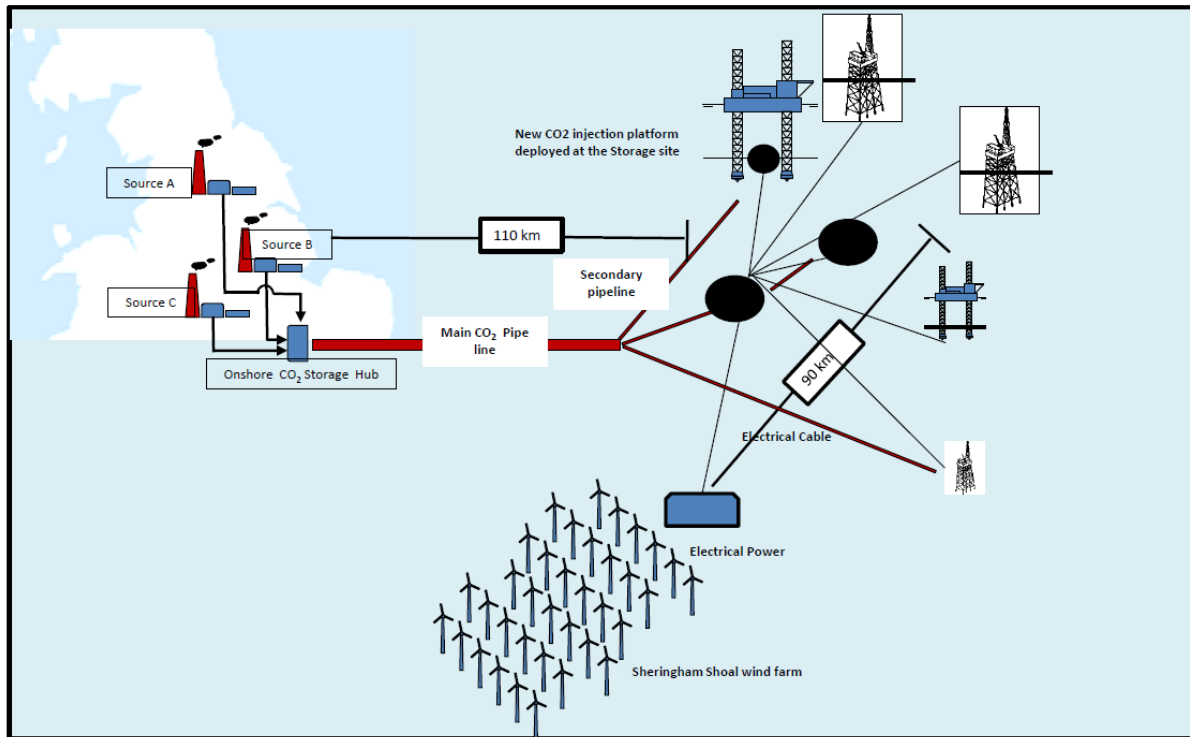


Figure 5.10 - Scenario B (Pipelines and new dedicated platform for CO<sub>2</sub> injection plant)

### 5.3.4 Scenario C

This variant as shown in Figure 5.11 involves the use of CO<sub>2</sub> carriers. A CO<sub>2</sub> carrier will transport CO<sub>2</sub> in liquefied form from the coastal CO<sub>2</sub> temporary storage facility to the offshore injection site. The coastal temporary storage facility will be fitted with liquefaction equipment. An existing fixed platform will undergo conversion into a CO<sub>2</sub> injection platform and will act as a hub. The CO<sub>2</sub> carrier will offload onto the injection platform which will inject the CO<sub>2</sub> directly into the depleted reservoir. Subsequent existing platforms will be modified and reconfigured for CO<sub>2</sub> injection. These will be fed by shuttle CO<sub>2</sub> carriers.

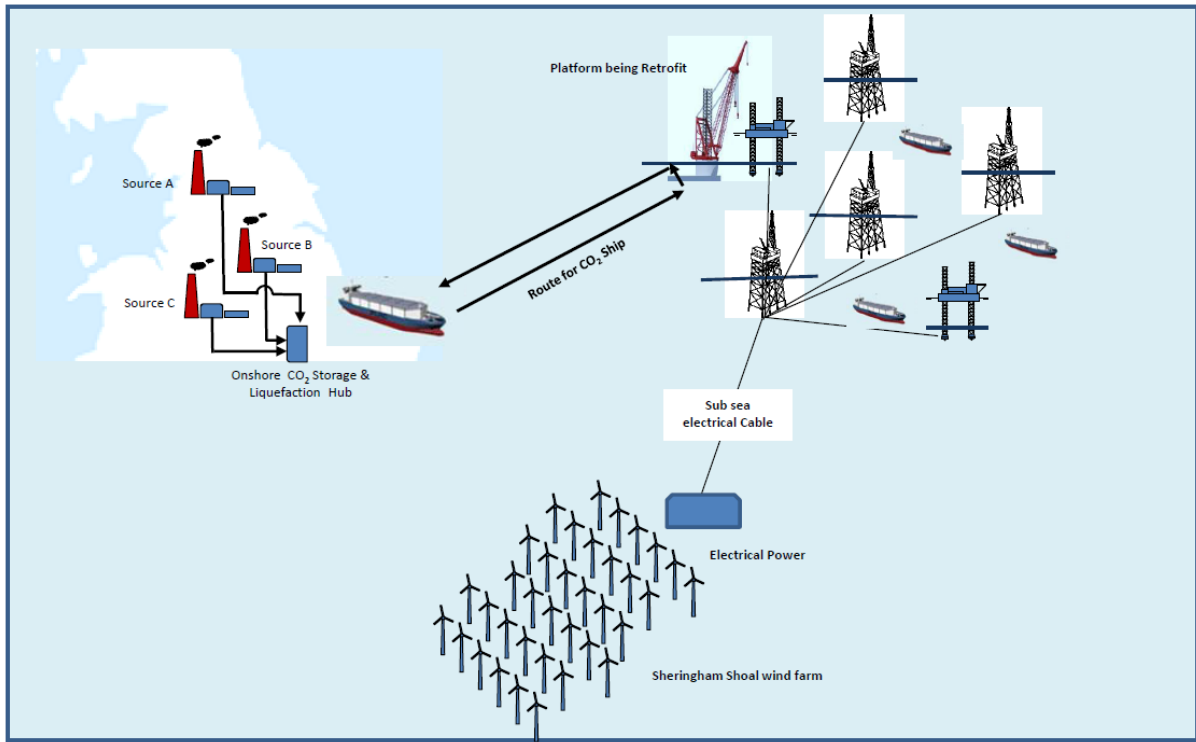


Figure 5.11 - Scenario C (Ships and platform retrofitted with CO<sub>2</sub> storage and injection plant)

### 5.3.5 Scenario D

This variant as shown in Figure 5.12 involves the use of CO<sub>2</sub> carriers. A CO<sub>2</sub> carrier will transport CO<sub>2</sub> in liquefied form from the coastal CO<sub>2</sub> temporary storage facility to the offshore injection site. The coastal temporary storage facility will be fitted with liquefaction equipment. A new CO<sub>2</sub> injection platform of the floating type will be fabricated and installed at the site. This floating platform will be able to temporarily store CO<sub>2</sub> and is re-deployable.

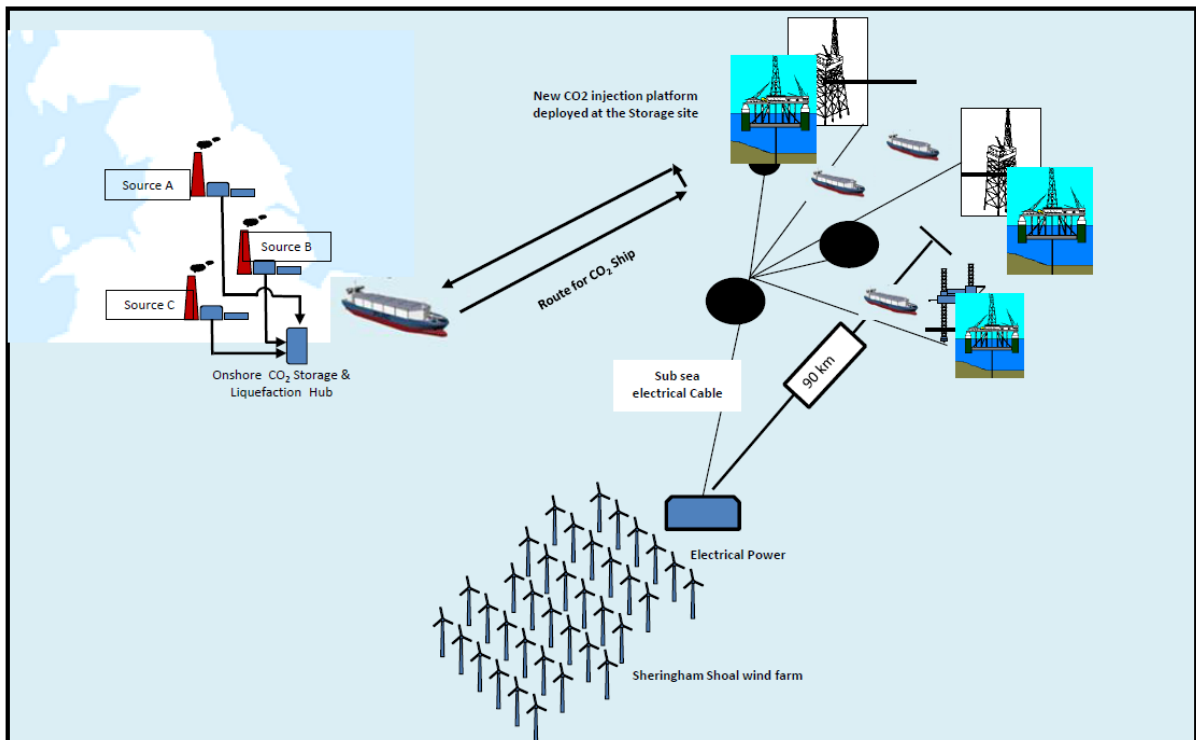


Figure 5.12 - Scenario D (Ships and new dedicated platform for CO<sub>2</sub> storage and injection plant)



### 5.3.6 Scenario E

In this scenario, the use of an injection platform is omitted. The CO<sub>2</sub> is piped to a remotely controlled subsea manifold which diverts the flow into several well heads for injection as shown in the figure below.

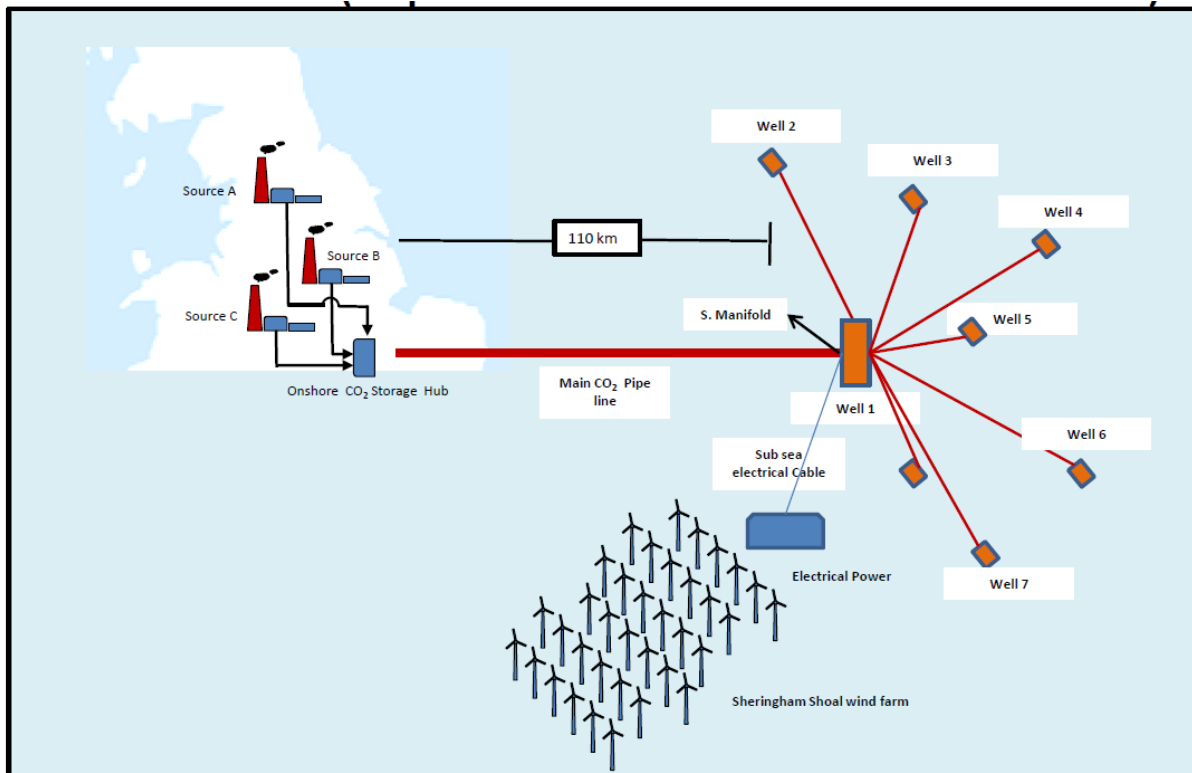


Figure 5.13 - Scenario E (Pipelines and subsea manifold for CO<sub>2</sub> injection plant)

The figure below gives a visualization of the subsea infrastructure required.



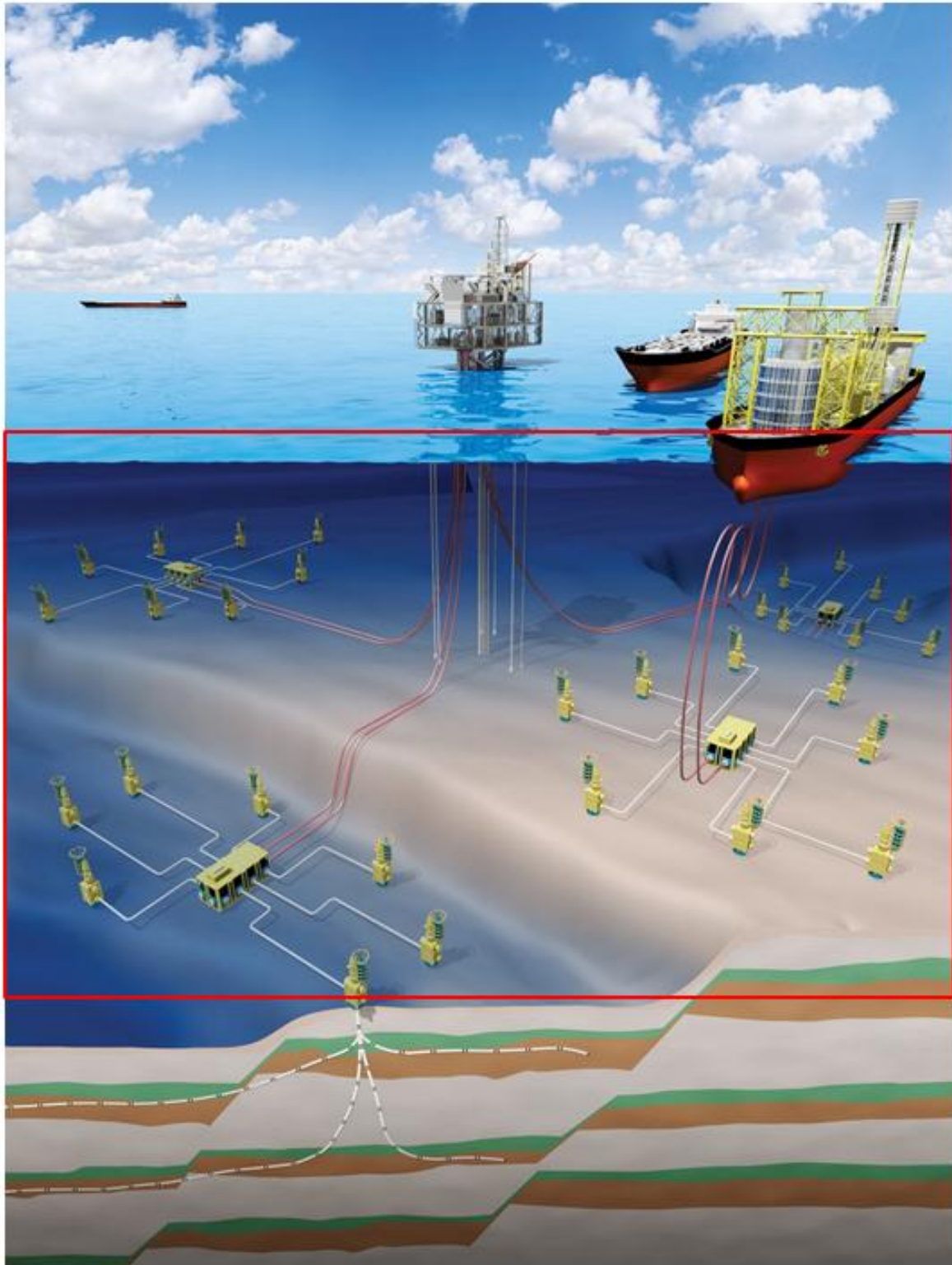


Figure 5.14 - Subsea manifold system  
(Source: Petroleum Engineering, 2011)

### 5.3.7 Decision making process

Summarized below are the five variants of the general scenario. After careful consideration by the design team, it was agreed collectively that a slight modification of scenario A was deemed most feasible. Effectively, scenario A and scenario E were combined to draw on the merits of both. Thus the design team was able to have a clear direction of the concept development path ahead. The plan was to transport the captured CO<sub>2</sub> from Drax power plant by onshore pipeline to a temporary onshore storage hub at Easington. From there, the CO<sub>2</sub> would be transported on its second leg to the injection platform located in the Audrey field. The Audrey field is strategically located at the geometric centre of the Southern North Sea gas basin. The existing fixed production platform at the Audrey field would

be retrofitted and reconfigured for CO<sub>2</sub> injection. From the offshore hub platform, subsea manifolds would transport CO<sub>2</sub> to satellite injection wells. Figure 5.15 shows the adopted scheme.

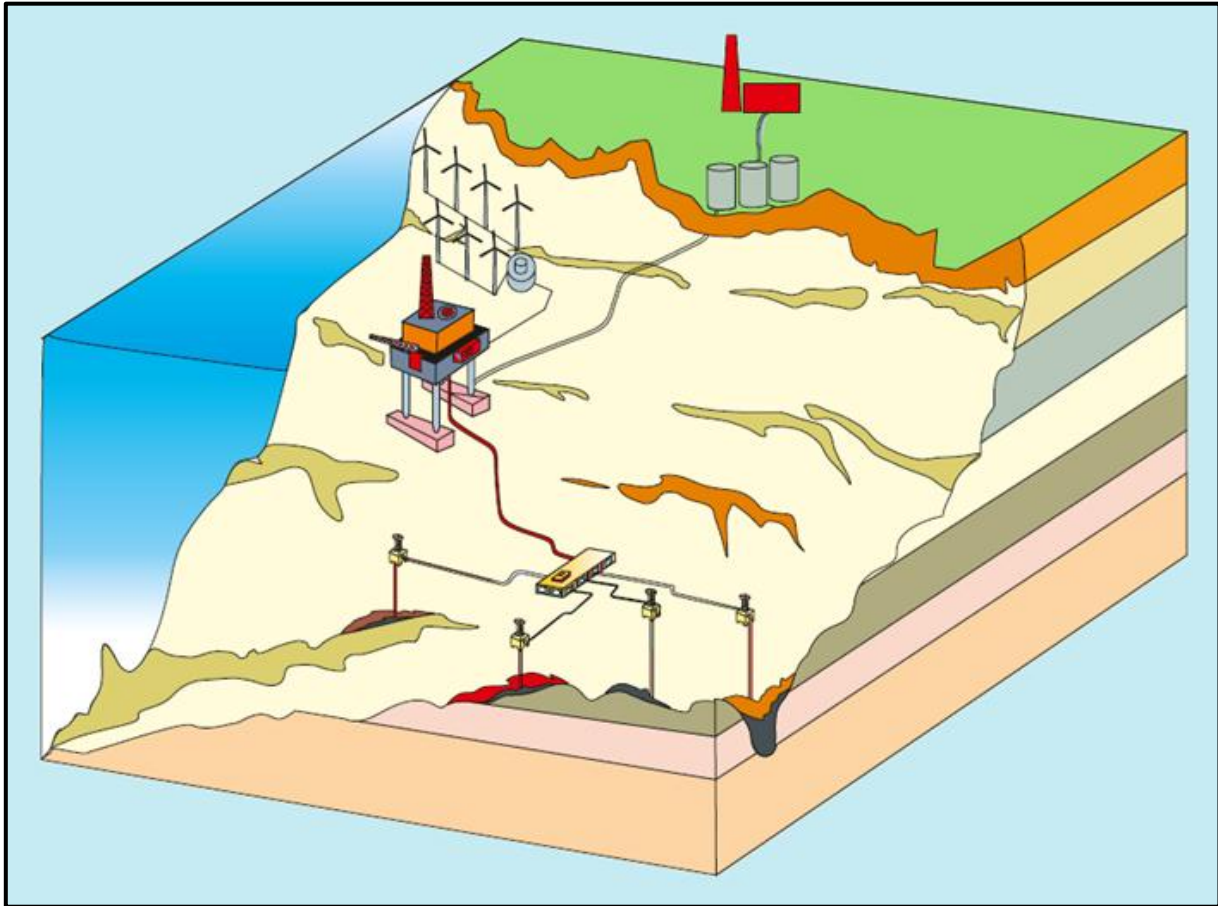


Figure 5.15 - Visualisation of adopted concept

Table 5.2 - Summary of scenarios

Scenario	Onshore transport	Temporary storage hub	Offshore transport	Storage on platform provided?	Platform	Platform type
A	Pipeline	Onshore	Pipeline	N	Retrofit existing	Fixed
B	Pipeline	Onshore	Pipeline	N	Newbuild	Floating
C	Pipeline	Onshore	Ship	Y	Retrofit existing	Fixed
D	Pipeline	Onshore	Ship	Y	Newbuild	Floating
E	Pipeline	Onshore	Pipeline	N	N/A	N/A

## 5.4 Key subsystems

### 5.4.1 Identification of key sub-systems

With the design philosophy that a system comprises several sub-systems, we can apply systems engineering principles in the design process spiral. By framing the problem in this manner, the overall system can be thought of as a 'system of systems' and system complexity can be broken down into manageable components or chunks. This is especially useful in the concept design phase as making the right decisions in the early stages of design would result in less rework in later stages. A well-thought-out concept design would effectively reduce design cycle time in the preliminary, detailed and contract design phase.

Systems engineering brings structure, discipline and teamwork to any complex project. The many risks and inter-dependencies are addressed within a systems engineering framework that brings together all the disciplines involved and represents a single unified view of the project. Oftentimes, teams of engineers are working concurrently on a project with information exchange between teams. For example, in an offshore engineering project, the mooring engineer works concurrently with the riser engineer. The decision each engineer makes affects the other. The riser engineer needs to know the vessel motion offset limits in order to design the riser and the mooring engineer needs to know the offset limits the riser can withstand in order to size the mooring. This is the proverbial chicken and egg problem. Systems engineering requires that the engineer in charge of each system have their goals aligned so as to ensure the success of the project.

Whether the emphasis is on project management, operations, structural design, equipment configurations or environmental sustainability, the many variables can be captured within a coherent framework that is readily understood by everybody involved i.e. there is alignment of goals among all members in the group. Based on a sound understanding of the system requirements, multiple concepts can be developed with lifecycle management, safety and environmental issues fully integrated from the start. Systems engineering principles optimally utilizes the available manpower, time and resources in a project.

Systems engineering doctrine advocates that a complex system be broken down into sub-systems. The key to successful implementation is not to be caught in the ‘paralysis of the analysis’ by seeking to isolate all the sub-systems, but rather to identify the critical sub-systems. Below is a list of the key sub-systems that warrant careful consideration in the concept design phase. Figure 5.16 gives a broad overview of the key sub-systems identified. It is important to note that, in the context of CCS projects, there is no ‘one size fits all’. CCS projects are by nature site specific. CO<sub>2</sub> capture system at power plant.

- a. Onshore pipeline transport system to temporary onshore storage hub
- b. Offshore primary pipeline transport system to offshore platform (hub injection site)
- c. Offshore secondary pipeline transport system to satellite injection sites
- d. Injection conduit system
- e. Modular processing and injection systems comprising components such as pressure vessels, pumps and compressors
- f. Renewable energy power supply system

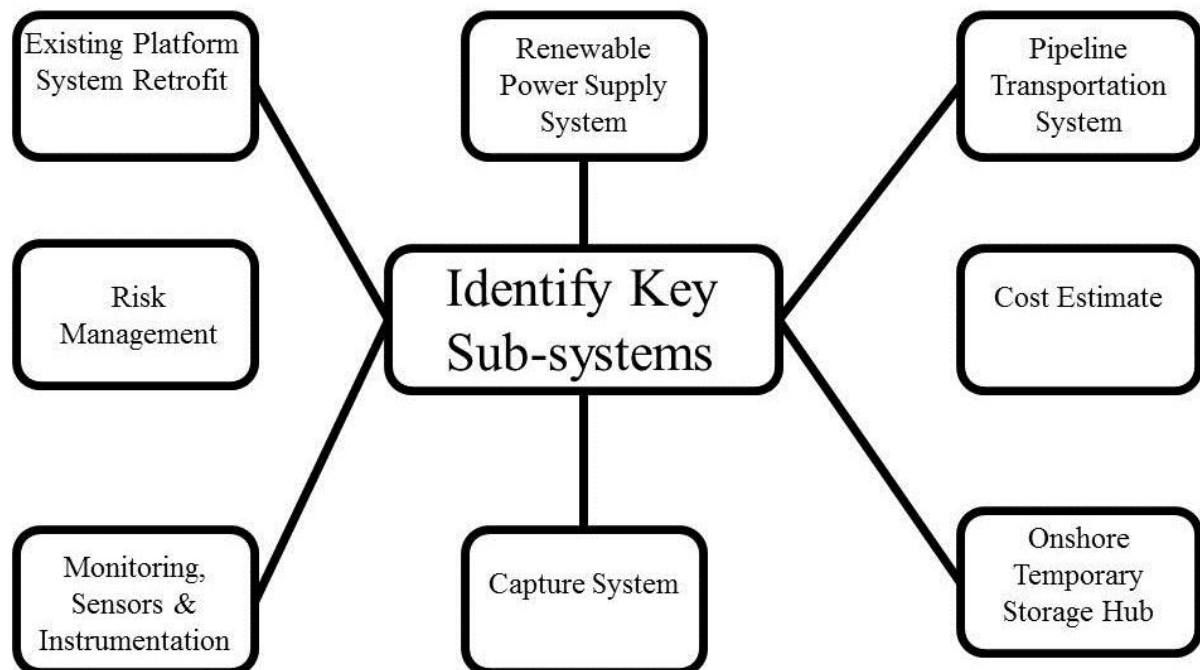


Figure 5.16 - Key sub-systems identified

## 5.5 *Renewable power system*

Part of the concept design plan is to secure a renewable energy power supply for purposes of CO<sub>2</sub> injection from nearby wind farms. In this manner, the CO<sub>2</sub> geological storage activity does not add to the problem as the operation is emission free. The small carbon footprint of the storage process is an important part of the concept design. The requirement thus is to prove that the renewable power supply, specifically offshore wind power supply, is sufficient to power the injection equipment. The intermittent nature of offshore wind would also have to be taken into account. The design team thus set out to prove the feasibility of using offshore wind power. This section profiles three nearby wind farms situated relatively close to the planned injection site. This is subsequently followed by a discussion of the applicability of offshore wind power for the intended purpose.

### 5.5.1 *Profile of Sheringham Shoal wind farm*

With around 40% of the EU's entire wind resources available in British waters, it makes sense to harness the wind. The 317 MW Sheringham Shoal offshore wind farm, located between 17 and 23 km off the coast of North Norfolk in the UK, will comprise 88 wind turbines and generate around 1.1 TWh per annum. This is enough clean energy to power almost 220,000 British homes. Compared to fossil fuels, that is a reduction of 500,000 tonnes of CO<sub>2</sub> emissions every year. The site was chosen because it lies within a government approved area for development, enjoys high wind speeds, has favourable water depths and has relatively low levels of fishing activity. The project will be fully-operational by early 2012.

The wind farm is owned equally by Statoil and Statkraft through a joint-venture company - Scira Offshore Energy Limited. The lease for the diamond-shaped 35 square kilometre site was granted as part of The Crown Estate's Round Two leasing in 2004. It is located in the Greater Wash north of the seaside town of Sheringham. Waters here are comparatively shallow at between 17 to 22 metres. Wind speeds are high and consistent and access is good for construction, operation and maintenance.

The wind farm will have two offshore substations and two 132 kV submarine export cables of about 22 km each as well as a 21.6 km onshore cable and new inland substation. The turbines will be positioned less than a kilometre apart and will be supported by foundations secured to the seabed. The figure below shows the wind farm location.



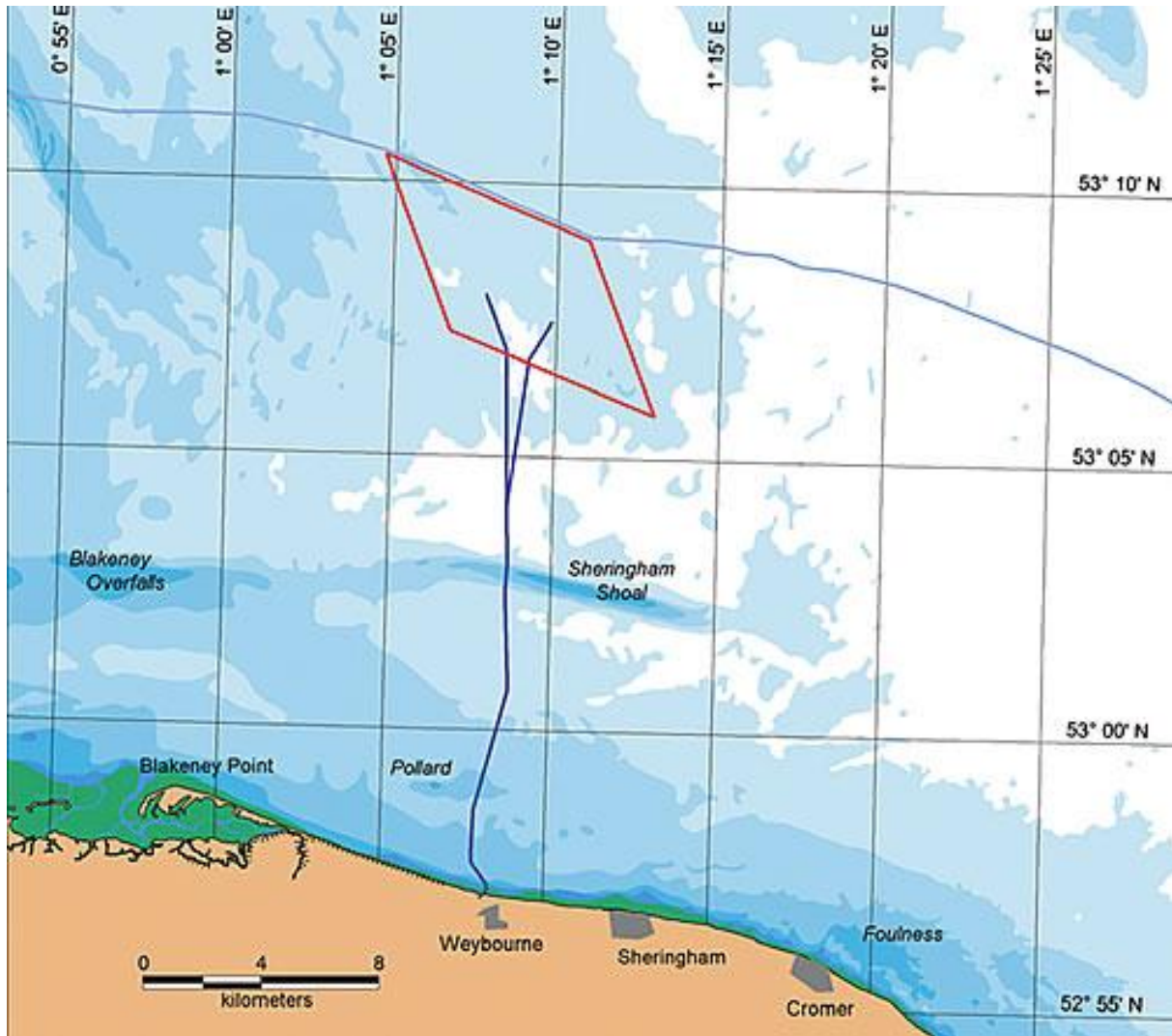


Figure 5.17 - Location of Sheringham Shoal wind farm

(Source: <http://www.scira.co.uk/about/location.html>. Last retrieved 1 Aug 2011)

Each turbine will have a capacity of 3.6 MW. Turbine blade length is 52 metres and turbine tower height is 80 metres. Two 900 tonne topsides for the offshore substations are planned. The two 132 kV marine cables will come ashore at Weybourne.

The availability of the turbines will depend on how the turbines are operated and maintained. Experience from the wind industry has shown an availability of around 95%. The wind turbines operate automatically, self-starting when the wind reaches an average speed of 3–5 metres per second (m/s). The output increases with the wind speed until it reaches 13–14 m/s. If the average wind speed exceeds the operational limit of 25 m/s, the rotor is parked and the turbine stops. When the wind drops back below the restart speed, the safety systems reset automatically.

Wind turbines are developed to produce the maximum energy yield at minimum cost. Theoretically, it is possible to have a wind turbine that always produces power: a very high tower and a very small rotor that rotates in even the faintest breeze. However, the energy yield would be very small for such a turbine. Similarly, a very strong turbine with a very large rotor would allow maximum power production during a year's worst storm, but it would be standing still during the rest of the year. The optimum is in-between these two extremes: a wind turbine that generates quite some power during most of the year, a lot during strong winds, and nothing during the worst storms.

The electrical concept is the reliable a-synchronous, squirrel cage generator without slip rings. The generator is grid connected through a full power electronic convertor (AC-DC-AC) and operates at variable speed, fully decoupled from the system frequency. The sequence described above is called the cut-in sequence (wind speed increases to 3-5 m/s) and is managed by the wind turbine controller, where the power electronics allow the complete control of the active and reactive output of the turbine. This controller automatically synchronises the turbine with the grid. The electricity produced will be

transported to a new substation at Salle, near Cawston, and then enter EDF Energy's regional grid, eventually connecting to the National Grid in Norwich for general use by British consumers.

The offshore wind turbines will be connected via a network of marine cables linking to one or two offshore transformer stations within the wind farm. From these, power will be exported via two 132 kV marine cables reaching landfall close to the site of the Muckleborough Collection Museum near Weybourne. The route of these export cables was agreed with the Department for Business Enterprise and Regulatory Reform (DBERR) and Marine and Fisheries Agency (MFA) as part of the wind farm's licence conditions. Factors considered included engineering feasibility, seabed geological conditions, sediment movements and the location of sensitive marine organisms and their habitats.

The asset infrastructure of the wind farm comprises turbines, foundations, offshore substations and electrical cables. The Siemens wind turbines selected for the site are of 3.6 MW ratings. The rotor is a three-blade cantilevered construction, mounted upwind of the tower while the 52 m blades are made of fibreglass-reinforced epoxy resin and manufactured in a single operation representing state-of-the-art technology. The turbine is mounted on an 80 m high tapered tubular steel tower with an internal ascent. These 90 giant monopile structures, as well as the transition pieces which join the turbines to them, will be fabricated by a tubular structure specialist. Each foundation is made to individual specifications and will be between 44 and 61 metres long, with a 4.2-5.2m diameter and weighing from 375 to 530 tonnes. The wind farm will include two 1000 tonne offshore substations. Offshore construction specialist Heerema will fabricate and load out two substation platform topsides from its yard in Hartlepool, County Durham, following the award of a contract by AREVA T&D UK. Each of the Sheringham Shoal substations will be 30.5 metres long, 17.7 metres wide and 16 metres high. They are scheduled to be installed at the wind farm early 2011. The offshore cables are being produced by global cable experts, Nexans. The power and optical cables will be bundled together into one unit. There will be two long export cables carrying the power from the wind farm to landfall - one 23 kilometres and one 21 kilometres in length, with a weight of 77 kilograms per metre. That's a total weight of 3,388 tonnes! There will be two different types of infield cables connecting the turbines and the offshore substations. Type one (27kg/m) has a total length of 26 kilometres and will be used to connect the turbines closest to the substations, while type two (18kg/m) has a total length of 56 kilometres and will connect the turbines further out. Both cable types will be cut into actual lengths during installation. The figure below shows the wind farm cable routing.

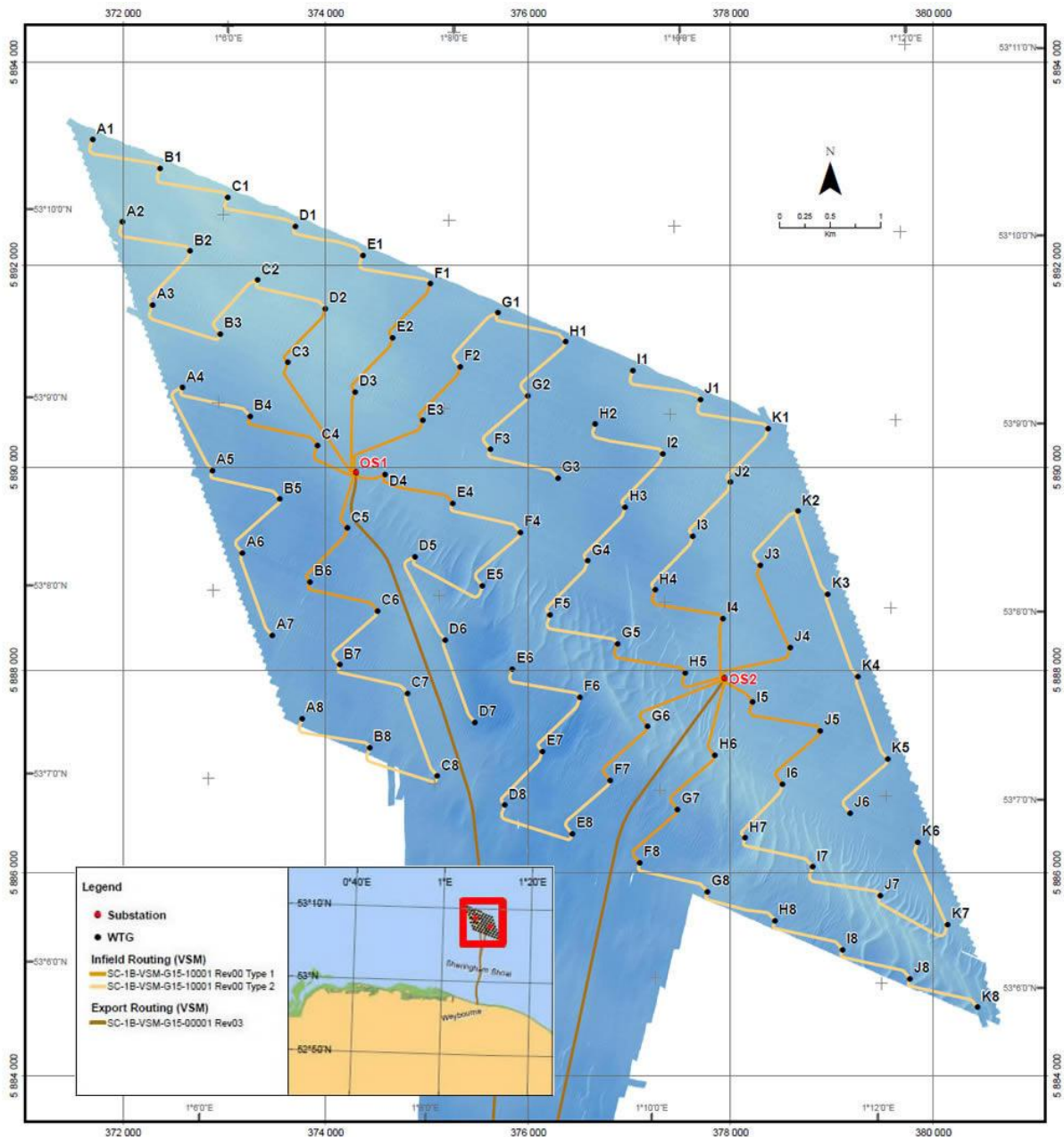


Figure 5.18 - Spatial layout of Sheringham Shoal wind farm

(Source: <http://www.scira.co.uk/offshore/FoundationsMap.html>. Last retrieved 13 Aug 2011)

### 5.5.2 Profile of Thanet wind farm

Surrounded as it is by sea, the UK has the largest offshore wind energy resource in the world, estimated to be more than a third of the total European potential. This is equivalent to three times the nation's annual electricity consumption. Conservative calculations show that offshore wind alone could meet the latest government target of producing 15% of its energy needs from inexhaustible renewable sources by 2020. Every unit of electricity generated from the wind saves a unit generated from fossil fuels, thereby reducing CO<sub>2</sub> emissions as well as reliance on international supplies of coal, gas and oil. Britain's relatively shallow waters and strong winds extend far into the North Sea. This unlimited natural resource, combined with government support and an established offshore regime puts the UK in a good position to achieve its renewable targets.

Vattenfall acquired the Thanet offshore wind farm project in November 2008. Construction was completed in September 2010. There are 100 Vestas V90 wind turbines that have a total capacity of 300 MW. This is sufficient to supply more than 200,000 homes per year with clean energy. It is the largest operational offshore wind farm anywhere in the world. It will make a significant contribution to the Government's national and regional renewable energy targets. The Thanet project is located approximately 12 km off Foreness Point, the most eastern part of Kent. Some elements of the onshore

construction work commenced at the former Richborough power station in January 2008 where the onshore substation is located. The map below shows the location of Thanet.

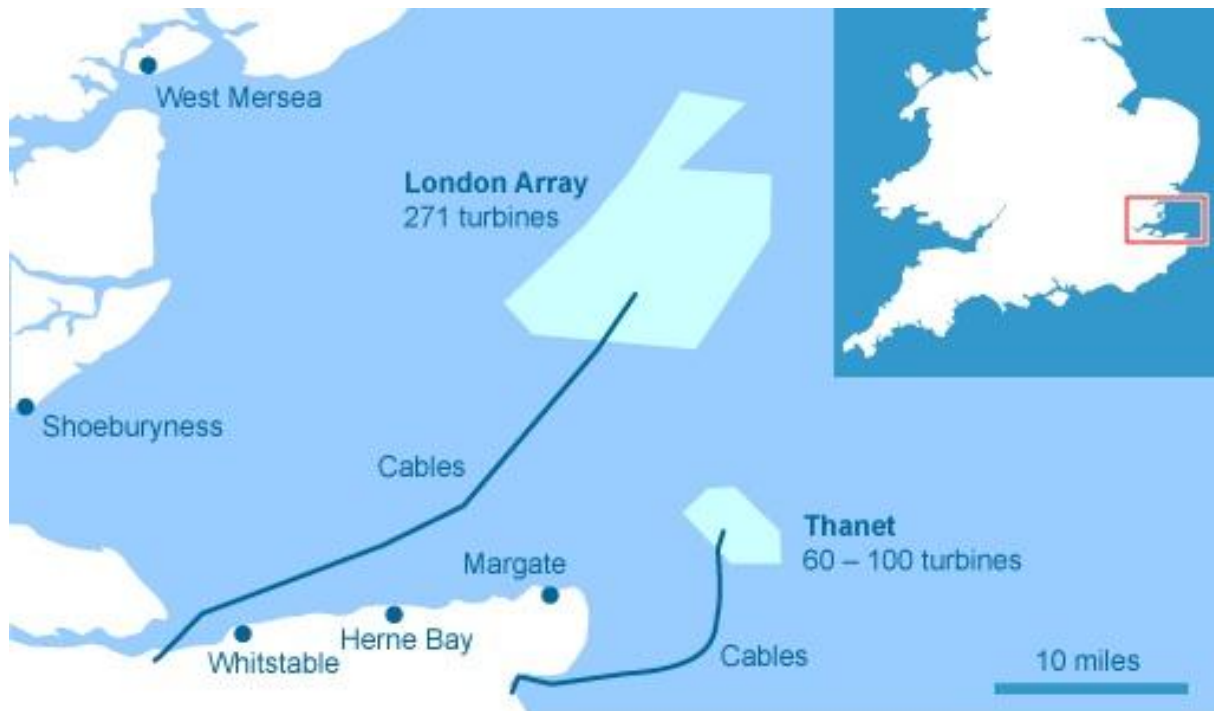


Figure 5.19 - Location of Thanet wind farm

(Source: <http://www.guardian.co.uk/graphic/0,,1974793,00.html>. Last retrieved 3 Aug 2011)

An Environmental Impact Assessment has been prepared to determine the effects on the local environment. The scope of these studies has been agreed with the appropriate government and environmental bodies. The connection of Thanet's 300MW of capacity in 2010 has boosted the UK's offshore wind capacity by more than 30% and will produce on average enough electricity to supply more than 200,000 homes with clean electricity. The wind farm is located in water depths of 20-25m and covers an area of 35km<sup>2</sup>. There are 100 turbines generating a total of 300MW of renewable electricity, enough to power more than 200,000 homes. The nearest turbine is located approximately 12km north east of Foreness Point. Each turbine is 115m tall at its highest point, with a minimum clearance above sea level of 22m. The distance between turbines is approximately 500m along rows and 800m between rows. The figure below shows the spatial layout of Thanet wind farm.





The project is composed of two phases and phase I is expected to be completed by the end of 2012 at a cost of £1.9 billion. London Array is arguably the most widely known UK offshore wind farm. Its sheer scale and proximity to Greater London has picked up much attention from politicians and in the press. At 1000MW, the project is currently the world's largest consented wind farm and will be built in two phases.

The London Array project was born in 2001, when a series of environmental studies in the outer Thames Estuary confirmed the area is a suitable wind farm site. Two years later, the Crown Estate gave London Array Ltd a 50 year lease for the site and cable route to shore. Planning consent for a 1 GW offshore wind farm was granted in 2006, and permission was granted for the onshore works in 2007. Work on Phase I started in July 2009 when construction began on the onshore substation at Cleve Hill in Kent.

The wind farm will occupy an offshore area of 100km<sup>2</sup>. It will comprise 175 wind turbines and two offshore substations. The project will involve nearly 450km of offshore cabling. The wind farm will be capable of generating 630MW of electricity, enough power for around 480,000 homes a year (two thirds of the homes in Kent). This translates to CO<sub>2</sub> savings of 925,000 tonnes a year. Construction will be completed by the end of 2012, with the project handed over to the Operations and Maintenance team in 2013.

When complete, London Array's will reduce carbon emissions by 1.4 million tonnes each year. Phase One alone will enable 925,000 tonnes of CO<sub>2</sub> to be offset each year, helping to tackle the effects of climate change and global warming. London Array will have a total capacity of 1,000 MW and will generate enough electricity for up to 750,000 homes – equivalent to a quarter of households in Greater London, or all the homes in Kent and East Sussex. Phase One's capacity of 630MW is enough to power around 480,000 homes, or two thirds of all homes in Kent. Thus helping to build a secure energy future for the UK.

Located on the outer Thames Estuary, the location was chosen due to the following reasons:

- a. High wind speeds
- b. Variable water depths
- c. Nearby ports to enable construction, operation and maintenance
- d. Suitable ground conditions
- e. A suitable electricity network connection
- f. Local power demand (south east England has the UK's highest electricity demand). Using the electricity locally reduces transmission losses

The turbines will be arranged in rows and columns aligned according to the prevailing south-westerly wind. The turbines will be placed 650m to 1,200m apart and connected to each other and to the offshore substations by array cables buried in the seabed. Figure 5.22 shows the wind farm's spatial layout.



Figure 5.22 - Spatial layout of London Array wind farm

(Source: <http://www.londonarray.com/the-project/key-facts/location/>. Last retrieved 10 Aug 2011)

Two offshore substations have been installed as part of the first 630MW phase of London Array. These will collect power from groups of wind turbines before feeding it to shore using the main export cables. Each topside consists of three levels, with an area of around 20m x 20m. Each assembled and fully equipped substation topside weighs around 1,250 tonnes.

The offshore substations consist of the following components:

- a. Transformers to step up the power to a higher voltage before being brought ashore. This helps reduce the amount of electricity that's lost during transmission.
- b. Switchgear and emergency equipment that make it safe for us to operate the wind farm.
- c. A back-up electrical generator and batteries.

The array cables will connect the wind turbines to each other and to the offshore substations. They'll each measure between 650m and 1,200m in length. The export cables will run from the offshore substations to the onshore substation at Cleve Hill, where the power will be flowed into the national electricity network. The cables will be buried in trenches dug into the seabed using a special cable installation barge and plow. As well as transporting electricity, the export cables will hold vital fiber optic wires to communicate remotely with the wind turbines. It is planned to lay 220km of export



cabling in Phase One and each of the four cables will be installed in one continuous length of over 50 km.

#### 5.5.4 Selection of electrical power source to drive equipment for CO<sub>2</sub> injection activities

As per our concept title, “A novel concept for offshore CO<sub>2</sub> injection and geological storage wholly powered by marine renewable energy”, the renewable energy source is an integral part of our concept. This agrees with our design philosophy of having CO<sub>2</sub> injection operations with a small carbon footprint. The design team strove to develop a concept whereby in the process of capturing carbon and storing it, we are not adding to the problem by further emitting CO<sub>2</sub> to the atmosphere whilst endeavouring to inject and store the CO<sub>2</sub>. Hence the renewable energy element of our concept is an important feature.

The plan is to tap a small proportion of the electricity generated from three offshore wind farms - Sheringham Shoal wind farm, Thanet wind farm and London Array wind farm. The tapped electricity will supply power to electric motor driven pumps for the injection of CO<sub>2</sub>. The CO<sub>2</sub> injection field operator would enter into a reciprocal agreement with the three wind farm operators to buy a portion of the electricity generated, say 2.5% of the total installed generating capacity from each farm. Rather than having to incorporate into the concept design renewable energy capturing devices, it was deemed more practical to sub-contract this aspect to an experienced wind farm operator. Effectively, electricity is purchased from the wind farm operator on a pence per kWh basis at prevailing rates to power CO<sub>2</sub> injection activities. The figure below depicts the location of the three selected wind farms.



Figure 5.23 - Selected nearby wind farms for renewable power supply

(Source: <http://www.londonarray.com/the-project/key-facts/location/>. Last retrieved 10 Aug 2011)

Considering a wind farm with an installed capacity of 200MW, 5% represents a supply of 10MW. If we assume that a wind farm typically on average operates at a quarter of maximum rating, this translates to 5MW. 5MW is no small amount and the design team's preliminary hand calculations on power requirements seem to indicate that this is sufficient, though a detailed electrical load analysis should be undertaken in subsequent stages of the design process.

The reason for selecting three separate wind farms to supply power was for purposes of redundancy. The decision represents an attempt to overcome the intermittent nature of offshore wind power. In the event that one electrical supply source faces down time, the injection platform is able to draw on the electrical power supply from the other two electrical power sources. This would assure energy security and availability for CO<sub>2</sub> injection operations. Tapping two or more offshore wind power sources facilitates in 'smoothing out' the intermittent nature of offshore wind – i.e. when one wind farm is in the doldrums, the other wind farm can pick up the slack.

Tapping the renewable energy would involve laying a subsea electrical cable from the transformer sub-station at the wind farm to the injection platform. The transformer will step up the voltage and transmit in HVDC so as to minimize transmission losses. Upon reaching the injection platform, the electricity is conditioned for use by the machinery. The laying of sheathed submarine copper cables

represents a long term investment with expected Return On Investment (ROI) around thirty years. Subsea cables can be retrieved from the seabed and the copper recycled.

In this section, we have walked through the concept development phase. CO<sub>2</sub> sources and sinks were identified. The aforementioned sources and sinks were then matched appropriately. Engineering considerations revolving around the injection platform were discussed and the planned renewable sources of electrical power were described. Systems engineering principles were applied to further develop the concept. At this juncture, it would be an opportune moment to summarize our concept design. The plan is to:

- a. Pipe CO<sub>2</sub> gas from Drax power plant to Audrey offshore field in the Southern North Sea gas basin.
- b. Lay subsea electrical cables from Sheringham Shoal, Thanet and London Array wind farm to the injection platform to supply electrical power to injection equipment.
- c. Retrofit the existing Audrey platform and reconfigure it for CCS activities.

### 5.6 Onshore system

The onshore system, or more accurately, onshore sub-system comprises pipelines from the Drax power plant to the temporary storage hub situated at Easington. The power plant operator at Drax is currently in the process of putting in place CO<sub>2</sub> capture infrastructure. Easington is already an established hub for export gas pipelines originating from the North Sea. With such infrastructure already in place, it is fairly easy to adapt the hub in Easington to serve as a temporary CO<sub>2</sub> storage hub. Thus, the most effort, in terms of time and resources, would be expended in the construction of the onshore CO<sub>2</sub> pipeline linking these two places. The route of the pipeline must be as unobtrusive as is practicable and consent must be obtained from those parties whose land the pipeline will run through.

An onshore temporary CO<sub>2</sub> storage facility is necessary because of:

- a. Possible down time of injection platform (6 days reserve capacity)
- b. Possible rupture pipeline transporting CO<sub>2</sub> to storage site (3 days reserve capacity)
- c. Excessive emission of CO<sub>2</sub> by plant (2 days reserve capacity)
- d. Maintenance of pipeline or HVDC cabling or injection plant (3 days reserve capacity)

Depending upon the duration unavailability, a cumulative down time of 7 days for the plant is envisaged. This implies that onshore storage should have a capability to store liquefied CO<sub>2</sub> for at least 7 days. A simple hand calculation for required temporary storage capacity is given below. It should be recognized that a more detailed calculation should be undertaken in the later stages of design when more information is available.

Taking the density of liquefied CO<sub>2</sub> to be  $770\text{kgm}^{-3}$ , and given that the capture rate of CO<sub>2</sub> per day is 24000 tonnes, the captured CO<sub>2</sub> for 7 days will be 168000 tonnes. Therefore the volume of the onshore storage will be approximately 220,000 cubic meters, which is comparable to the capacity of the world's largest LNG carrier (M/V Mozah, 266,000 cubic meters (see Figure 5.24)).



Figure 5.24 - M/V Mozah

(Source: [http://www.largestshipintheworld.com/\\_Media/mozah2\\_3\\_large.jpg](http://www.largestshipintheworld.com/_Media/mozah2_3_large.jpg). Last retrieved 9 Aug 2011)

## 5.7 Offshore system

### 5.7.1 Offshore CO<sub>2</sub> pipelines

As previously discussed, there exists two major means of transportation of CO<sub>2</sub> i.e. pipelines and ships. Prohibitive costs associated with the shipping mode of transportation for short distances were the major factor for our decision to utilize pipelines. Additionally, the energy penalties involved in the liquefaction of CO<sub>2</sub> for transport will increase the cost further. There were two paths we could take in adopting the pipeline option. First is to re-use the existing subsea gas pipeline infrastructure (LNG) in the North Sea and second is to construct a new purpose-built CO<sub>2</sub> pipeline system.

### 5.7.2 Existing oil and gas pipelines

An existing network of oil and gas pipelines in the North Sea presents opportunities for their use in CO<sub>2</sub> transportation. These pipelines include the main trunk lines between shore and offshore hydrocarbon fields, as well as many smaller in-field and inter-field pipelines which connect into trunk lines. As per (Elementenergy, 2010), most of the existing pipelines are made of carbon steel and thus are suitable for transporting CO<sub>2</sub> provided that the impurity level is kept within pre-defined limits. The main advantage of re-using existing oil and gas pipelines is the lower capital cost compared to developing the infrastructure for new pipelines.

Despite being a cost effective solution, there are challenges associated with adopting existing oil and gas pipelines. These difficulties, as explained in (Elementenergy, 2010) are summarized below:

- a. As compared to purpose-built pipelines, transportation capacity of old pipelines will reduce due to the aging factor and this happens due to the reduction in maximum allowable operating pressures.
- b. It will be very difficult to judge at which point in time, a certain hydrocarbon pipeline will cease its lucrative trade and become available for CO<sub>2</sub> transportation.
- c. Even if there is information about the availability of a specific interlink, it will be difficult to match a required source and sink with the available pipelines because it is highly unlikely that



all the required trunk pipelines and inter-pipelines for a required source and sink become available at the same time.

- d. Another issue will be the remaining life of an old hydrocarbon pipeline for CO<sub>2</sub> transportation and it will vary for different pipelines depending upon their working history and maintenance conditions.
- e. Owner/operator willingness to handover pipelines for re-use is another concern.

### 5.7.3 Purpose built CO<sub>2</sub> pipelines

Though it is not economically advantageous to construct new pipelines for CO<sub>2</sub> transportation, the challenges discussed above seems sufficient to rule out the use of existing pipelines for CO<sub>2</sub> transportation at this point in time. More rigorous and detailed feasibility studies are required to ascertain the usability of inactive hydrocarbon pipelines.

### 5.7.4 Offshore CO<sub>2</sub> pipeline route

Figure 5.25 shows the gas fields in the Southern North Sea gas basin that are within the Exclusive Economic Zone (EEZ) of the UK. From the figure, one may see the network of existing pipelines emanating from onshore hubs at Easington on the northern bank of the Humber River and Bacton. Use of existing gas pipelines for CO<sub>2</sub> transport is technical feasible though fraught with engineering challenges. The fields on the left hand side of the black line are designated UK fields. The black line demarcates the boundary of the UK's EEZ.

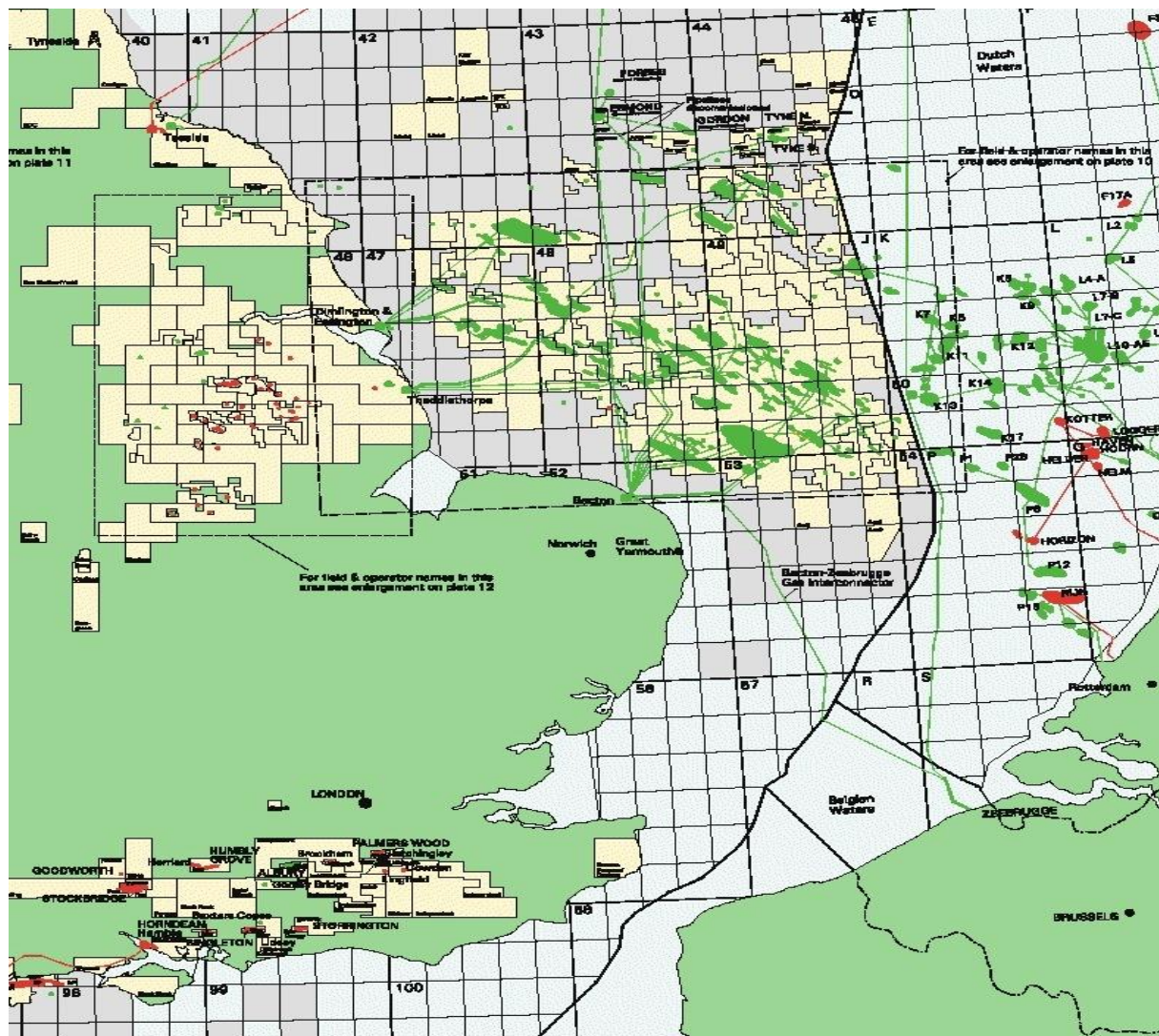


Figure 5.25 - Gas fields in the Southern North Sea gas basin

(Source: <http://www.dbd-data.co.uk/bb2001/book.htm>. Last retrieved 20 Aug 2011)

Incidentally, and perhaps very fortuitously, Bacton is close to the Sheringham Shoal wind farm which suggests the possibility of integrating the CO<sub>2</sub> transport pipeline and subsea electrical cable. But that would mean that the CO<sub>2</sub> from Drax power plant would have to be piped to Bacton and then routed to the offshore injection site. This idea was subsequently scrapped by the design team as it was found that cost turned out to be prohibitive in this case. The figure below shows the existing gas pipeline network. Note the onshore hubs at Easington, Theddlethorpe and Bacton. In our concept design, we decided that it was apt that the captured CO<sub>2</sub> from Drax power plant be temporarily stored at Easington.

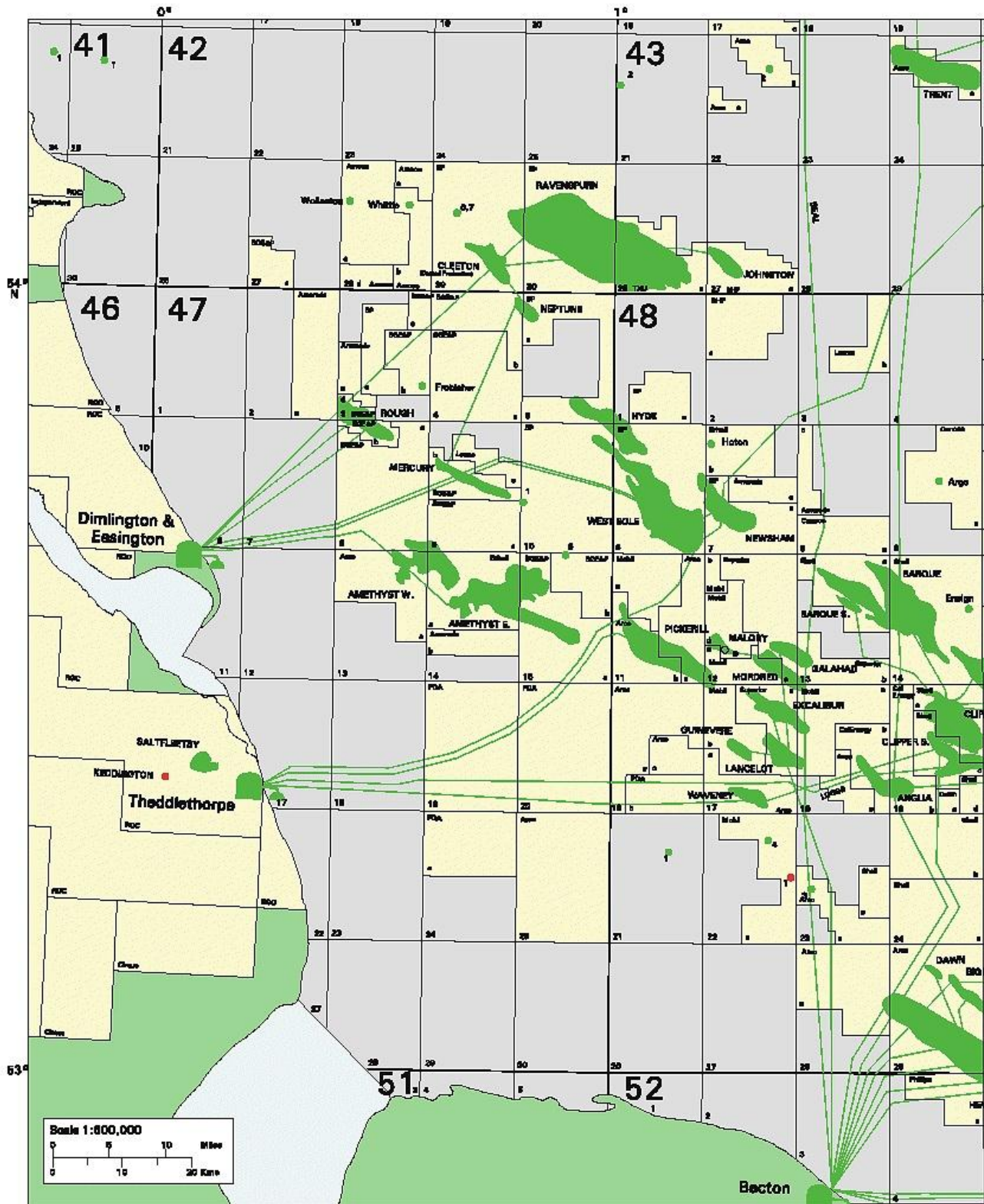


Figure 5.26 - Existing gas pipeline network in the Southern North Sea gas basin  
(Source: <http://www.dbd-data.co.uk/bb2001/book.htm>. Last retrieved 20 Aug 2011)





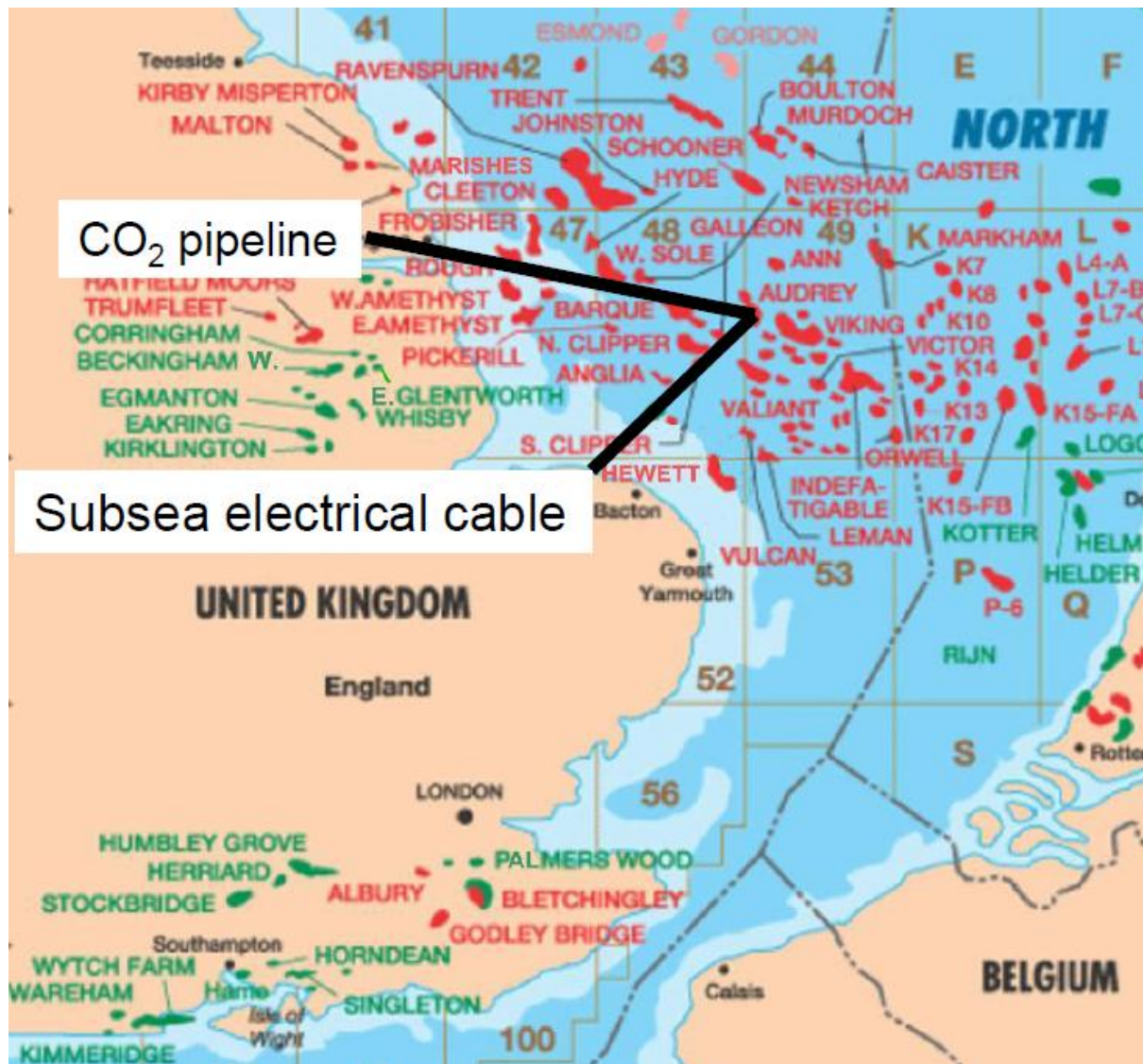


Figure 5.28 - Location of Audrey gas field and proposed pipeline routing

The concept design incorporates provision for future expansion by designating the injection platform at Audrey field as an injection hub platform with future secondary pipelines to be put in place emanating from the hub to satellite injection sites. In this manner, the entire Southern North Sea gas basin can potentially and eventually be filled to capacity. The basis for this concept is a well-known logistics principle termed the Hub and Spoke technique where the logistics supply chain centres around a hub with subsidiary lines to satellites feeding off the hub. The figure below shows a schematic as applied to this concept design.

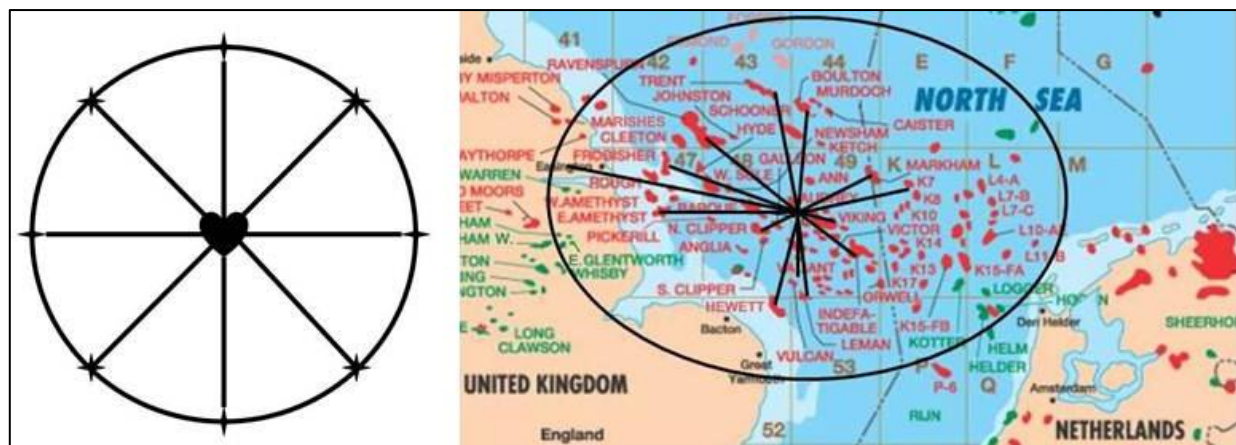


Figure 5.29 - Hub and Satellite technique applied to the Southern North Sea gas basin



### 5.7.6 Modelling offshore pipeline transport

Work has been done by (Bock, Rhudy, & Herzog, 2003) and later on by (Sean & Edward, 2005) to develop pipeline models for CO<sub>2</sub> transportation. Inputs to their models are the factors required to be considered when designing the pipeline. Typical inputs and outputs of these models are shown in Figure 5.30.

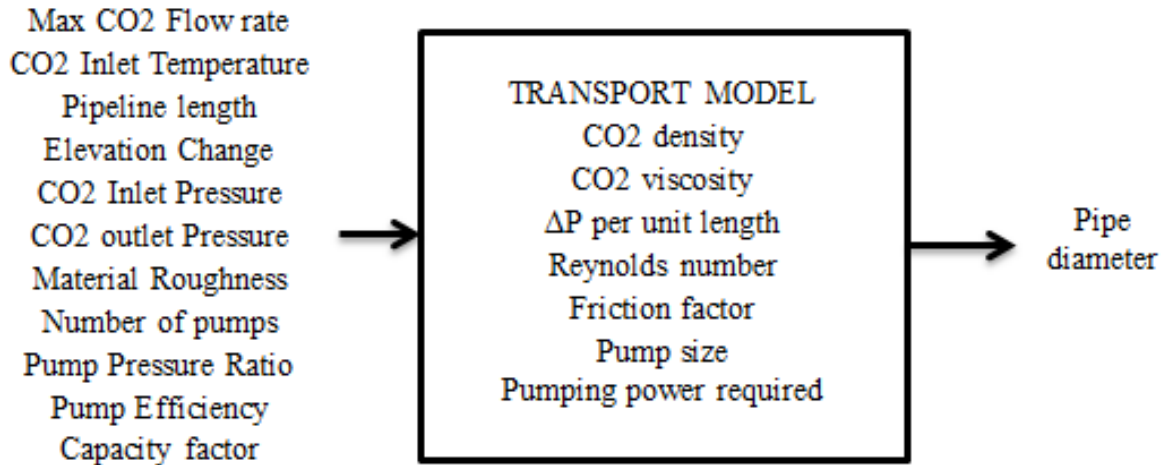


Figure 5.30 - The boundaries, inputs and outputs of the pipeline model

### 5.7.7 Preliminary CO<sub>2</sub> pipe sizing

Pipe diameter can be calculated using the equation (Manual, 2007) below for corrosive fluids as

$$d = \frac{1.03 \sqrt{\frac{Q}{Sg}}}{\rho^{0.33}} \quad (5.1)$$

where

$d$  = pipe inner diameter, inch

$Q$  = CO<sub>2</sub> Flow rate, gal/min

$Sg$  = Dense CO<sub>2</sub> specific gravity

$\rho$  = Density of dense CO<sub>2</sub>

And from Appendix A, for dense phase CO<sub>2</sub>,

$$\rho = 770 \text{ kgm}^{-3} = 48 \frac{\text{lb}}{\text{ft}^3}, \text{volumetric flow rate, } Q = 0.43 \text{ m}^3/\text{s}$$

$$Sg = 0.75$$

This is approximately equal to 5675 gallons/minute.

Plugging these values in Equation 5.1 gives the required internal diameter of pipe as 24 inches or 0.63 meters. This is only a rough approximate. A more accurate estimation involves calculating the pipeline diameter as a function of pressure drop allowance per unit length, friction, CO<sub>2</sub> density and CO<sub>2</sub> mass flow rate. Simplified formula from (Heddle, Herzog, & Klett, 2003) combining maximum allowable pressure drop ( $\Delta P/\Delta L$ ), CO<sub>2</sub> mass flow rate ( $\dot{m}$ ), CO<sub>2</sub> density ( $\rho$ ), and the Fanning friction pressure ( $f$ ) is given by:

$$\frac{\Delta P}{\Delta L} = \frac{32f\dot{m}^2}{\pi^2\rho D^5} \quad (5.2)$$

Based on this formula, the plot which is shown in Figure 5.31 can be obtained. This plot is based on the IGCC power plant CO<sub>2</sub> emission. The formula provides a good starting point to have an idea about the required pipeline diameter.

From Appendix A, the minimum mass flow rate per annum for the Drax power plant is approximately 10 M tonnes/year while the maximum value could be around 16 M tonnes/year depending upon the percentage of CO<sub>2</sub> captured.

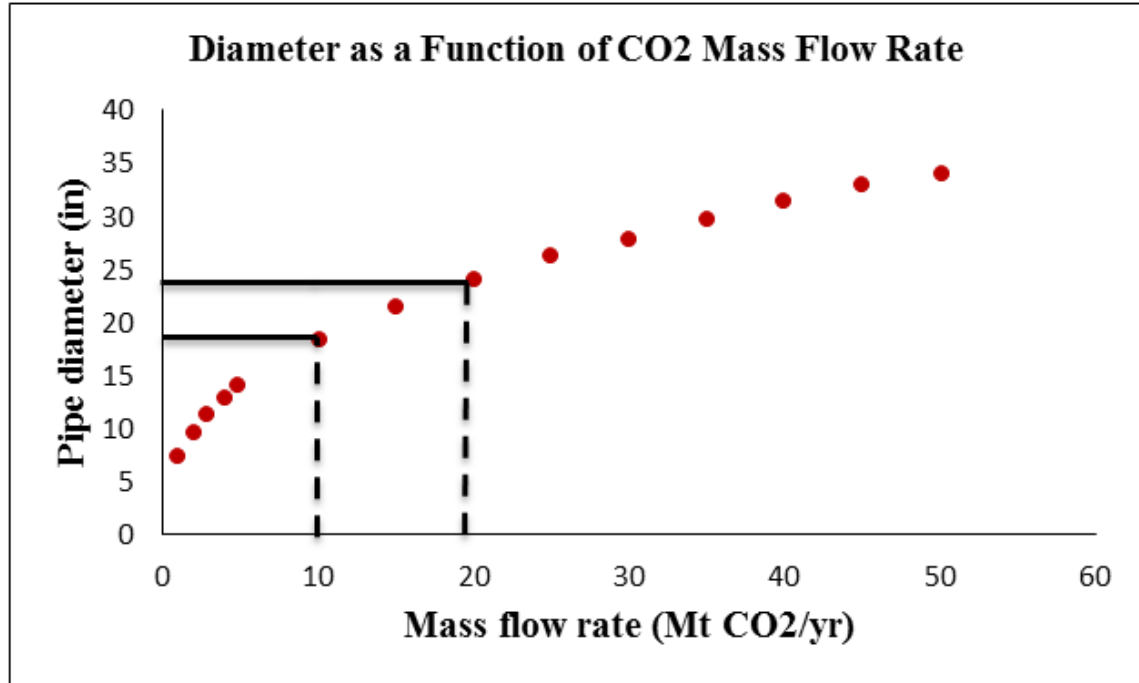


Figure 5.31 - Diameter as a function of CO<sub>2</sub> mass flow rate

Figure 5.31 gives the upper and lower values of pipeline diameters which are 24 and 18 inches respectively. Looking at the typical values of diameters of different existing natural gas pipelines as shown in Table 5.3, estimated figures in our case seem reasonable.

Table 5.3 - Dimensions of existing offshore gas pipelines

Offshore pipeline	Length (km)	Diameter (inches)
Erawan-Rayong Gas Separation Plant	415	34
Plathong Field - The first pipeline	42	24
Bongkot Field - Erawan Pipeline	171	32
Erawan - Khanom Power plant	161	24
Erawan - Rayong Gas Separation Plant	418	36
Tantawan Field - the second pipeline	54	24
Benchamas Field - the second pipeline	55	18
Pailin Field - Erawan Field	53	24
N.Pailin to existing Pailin Pipeline	10	24
Erawan-Rayong Gas Separation Plant	414	42
Arthit Field to Arthit PLEM	18.5	42
Arthit PLEM to Erawan	173	42

The wall thickness of the pipe can be calculated using Barlow's formula ("Transportation." Title 49 Code of Federal Regulations, Pt. 195, 2005), which is given by:

$$t = \frac{p_{mop} D_o}{2S \times E \times F} \quad (5.3)$$

Where,  $p_{mop}$  is the maximum operating pressure of the pipeline (Pa),  $D_o$  is the outside pipe diameter (m),  $S$  is the specified minimum yield stress for the pipe material (Pa),  $E$  is the longitudinal joint factors and  $F$  is the design factor (McCoy, 2008).

To avoid some of the difficulties associated with operation of CO<sub>2</sub> pipelines; it is generally recommended that a CO<sub>2</sub> pipeline operate at pressure greater than 8.6 MPa. This is to avoid compressibility issues with CO<sub>2</sub> at different temperatures (See Figure 5.32).

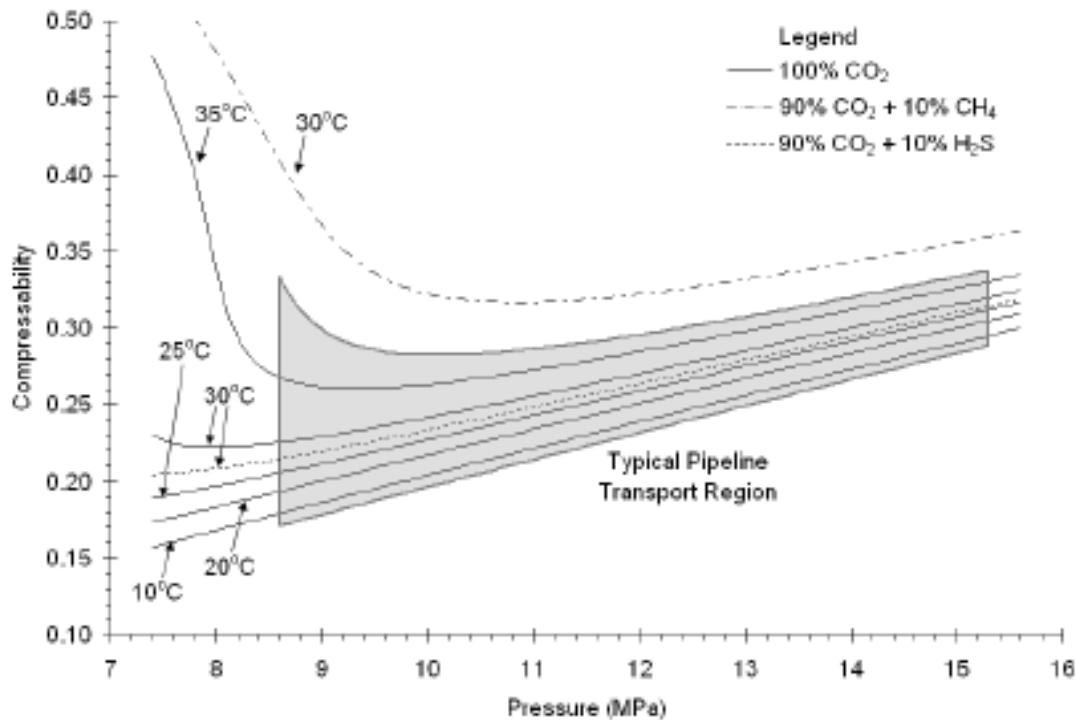


Figure 5.32 - Typical pipeline transport window  
(Source: McCoy, 2008)

Assuming the value for  $p_{mop}$  equals to 10 MPa.

Longitudinal joint factor = 1.0

Design factor = 0.72

Minimum yield stress depends upon the specification of the material of the pipe selected. In this case, the minimum yield stress is taken as 483 MPa which is the value for API<sup>1</sup> 5L X-70 line pipe. For a pipe of nominal diameter of 24 inches, the required wall thickness will be 8.7 mm (0.35 inches).

#### 5.7.8 Laying offshore pipelines

Prior to laying of offshore pipelines, route surveys are carried out to collect geotechnical data such as seabed soil profile (soil coring), bathymetry and subsea topography. This survey will facilitate pipeline routing decisions.

There are three typical techniques of laying offshore pipelines:

- Pipe laying by lay barge
- Pipe laying by reel barge
- Pipe laying by towing

<sup>1</sup> API refers to American Petroleum Institute

The laying of the proposed CO<sub>2</sub> pipeline can easily be undertaken by a pipe laying vessel. The know-how and expertise on offshore pipelines is extensive in the North Sea. The seabed of the North Sea is practically littered with pipelines, a testament to their ubiquitous use in the region.

There are a set of prescribed rules with regards to pipeline routing which every offshore pipeline engineer would be familiar with. Very broadly, pipeline routing depends upon the following factors:

- a. Physical factors
  - i. Depth
    - (a). Avoid very deep and shallow waters
  - ii. Waves
    - (a). Avoid high waves
  - iii. Currents
    - (a). Avoid high currents
  - iv. Seabed
    - (a). Avoid very soft & hard bottom
    - (b). Avoid rough bottom
- b. Other users

Other users may include other pipelines, platforms, mooring systems for FPS, wellheads, manifolds, cables, fishing, military gunning practice area, dumping area, navigation, archaeology etc.
- c. Marine Environment

Medium depths do not offer much problem in terms of environmental considerations. However for shallow waters close to the shore, care must be taken not to unduly affect the lives of marine mammals, birds, fish and coral reefs. A near-shore pipeline should be as unobtrusive as practicable.
- d. Politics

Politics involves the other operator's blocks, other's jurisdiction and the EEZ of other countries.

Figure 5.33 shows an example of a route selection study from Algeria to Spain.

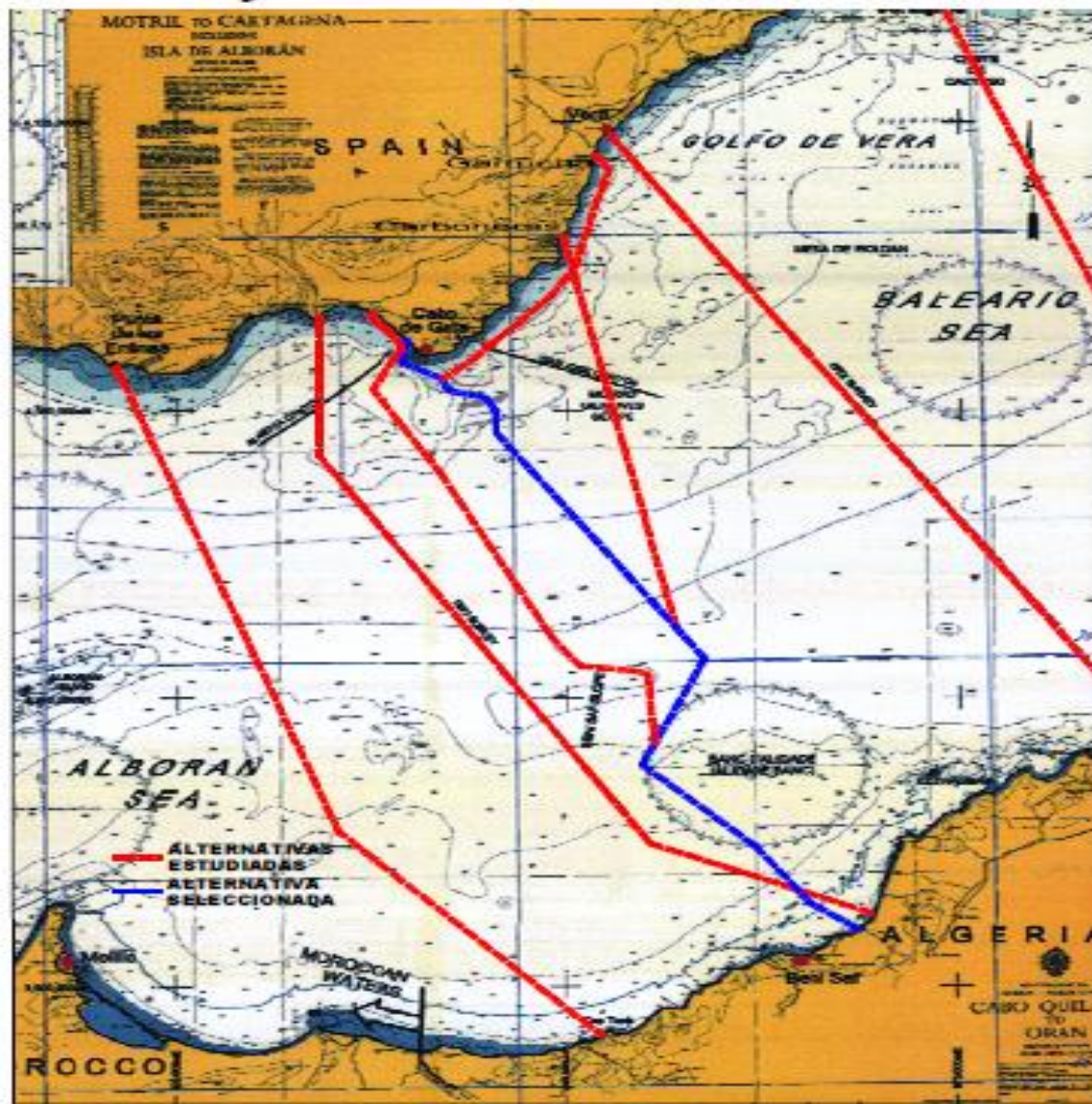


Figure 5.33 - Study of alternative routes

(Source: <http://earwilde.bligoo.com/algeria-gas-pipeline>. Last retrieved on 22 Aug 2011)

#### 5.7.9 Offshore platform selection

A support substructure to house the injection equipment needed to be selected. The design team had to make the difficult decision of whether to select a fixed or floating platform. A survey of platform types in the UK sector of the North Sea was undertaken.

As part of our concept design, retrofitting of existing platforms was proposed as a way of saving on initial costs. According to (Development of UK Oil and Gas Resources, 2001), production platforms distributed in the North Sea comprise fixed steel platforms (FSP), floating production facilities (FPF), concrete gravity based structures (CGBS), tensioned leg platforms (TLP) and floating production, storage and offloading units (FPSO), of which the fixed type platforms account for ~80%, as shown in Figure 5.34. The reason for the widespread use of fixed platforms is that the average depth of the North Sea is approximately 90m. Thus fixed platforms are the economical choice for oil and gas companies except for some remote regions where the FPSO or TLP platform option is exercised. The graph below shows the breakdown.

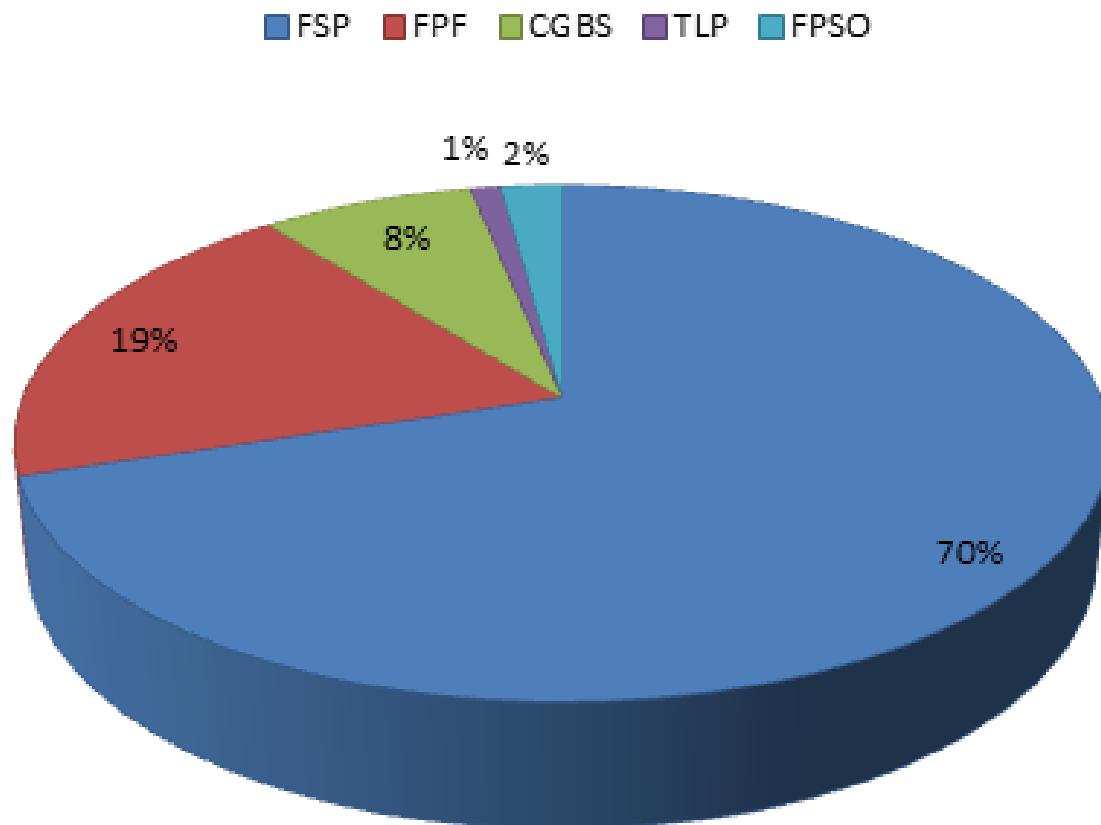


Figure 5.34 - Breakdown of platform types in the North Sea

Where

FSP	Fixed Steel Platform
FPF	Floating Production Facility
CGBS	Concrete Gravity Based Structure
TLP	Tension Leg Platform
FPSO	Floating Production Storage and Offloading Unit

Our research indicated that about 78% of production platforms in the UK sector of the North Sea are fixed platforms. Due to the level of expertise and know-how on fixed platforms in the region, a fixed platform was deemed to be the preferred choice for our project.

Having agreed on the use of a fixed platform, the design team then proceeded to decide on whether to retrofit a decommissioned production platform or to utilize a newbuild fabrication. Our research revealed that it was common in the North Sea to re-use decommissioned production platforms for other purposes and the more cost effective 'retrofit existing' option was selected. Appendix D contains a sample of decommissioned fixed platforms.

The evidence suggests that it is plausible to use decommissioned platforms as stations for CO<sub>2</sub> injection. The reader is referred to the last column of the table in Appendix D for more information on typical methods of de-commissioning. These include toppling of platform to create an artificial reef, removal of the jacket to shore, or re-use for alternative functions.

Based on this information, a simple cost-benefit analysis was carried out to gauge which option was more attractive. The retrofitting of an existing platform was deemed more cost-effective and the design team agreed that this was the more frugal path to take.

Table 5.4 summarizes some decommissioned offshore facilities in the UK.



Table 5.4 - Decommissioned facilities before 2001

Field	Operator	Decommissioned Part	Year
Piper Alpha	Occidental	Fixed Steel Platform	1988
Crawford	Hamilton	Floating Production, Facility (FPF)	1991
		Catenary Anchor Leg Mooring (CALM) Buoy	
		Subsea Facilities	
Argyll, Duncan and Innes	Hamilton	Floating Production, Facility (FPF)	1992
		Catenary Anchor Leg Mooring (CALM) Buoy	
Blair	Sun Oil	Subsea	1992
Angus	Amerada Hess	Floating Production, Storage and Offloading (FPSO) Vessel	1993
Forbes AW	Hamilton	Fixed Steel Platform	1993
Esmond CP and CW	BHP	2 x Fixed Steel Platform	1995
Gordon BW	BHP	Fixed Steel Platform	1995
Emerald	MSR	FPSO	1996
Frigg FP	Elf Norge	Flare Column	1996
Leman BK	Shell	Fixed Steel Platform	1996
Staffa	Lasmo	Subsea	1996
Viking AC, AD, AP and FD	Conoco	4 x Fixed Steel Platform	1996
Brent Spar	Shell	Oil Storage and Loading Facility	1998
Donan	BP	FPSO	1998
Fulmar SALM	Shell	Single Anchor Leg Mooring Buoy	1998
Blenheim and Bladon	Talisman	FPSO	2000
Durward and Dauntless	Amerada Hess	FPSO	2000
		Subsea Facilities	
Maureen and Moira	Phillips	Large Steel Gravity Platform	2000
		Concrete Loading Column	
Camelot CB	Mobil	Fixed Steel Platform	2001

Although it is typical for decommissioned fixed platforms to be removed, there are some instances where a platform is reused for purposes other than oil/gas production. There exists the possibility of platform conversion from oil/gas production to CO<sub>2</sub> injection. Comparing the required equipment for carbon dioxide injection to the existing equipment on a typical offshore platform indicates that reuse of equipment will be limited to some auxiliary and utility items only (VermeulenT., 2009). Items that may be reused for carbon dioxide injection include wellhead control panels and manifolds. In other words, rather than stripping out the topside equipment and machinery, it may be more cost effective to heavy-lift off the topside module and install a purpose-built injection module in place.

The process of retrofitting can be divided into 4 steps (VermeulenT., 2009).

- a. Platform shut-down and cleaning
- b. Platform hibernation
- c. Platform modifications for carbon dioxide injection
- d. Start-up of carbon dioxide injection operations

In the platform shut-down and cleaning stage, the platform stops production activities and preserves equipment for a later stage. Wells, pipelines and manifolds are isolated. Equipment is drained and cleaned. Platform hibernation process is the period of waiting for future technological development. As per the requirements of the owning company and relevant authority, activity is reduced to the minimum and safety is checked.

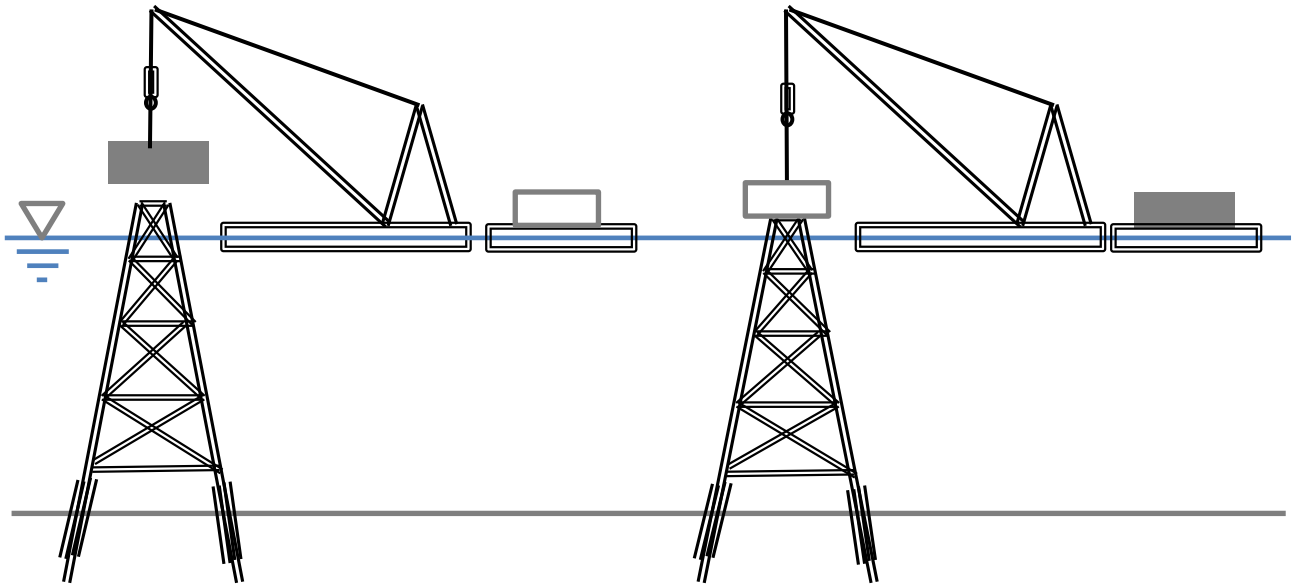


Figure 5.35 - Removing and installing deck platform

The platform modification for carbon dioxide injection is divided into two steps: removing the existing equipment and installing a new one. The precise procedure of removing and reinstalling the platform cannot be determined because there are many kinds of fixed type platforms. Their dimensions, structural configurations and inner machineries are quite different. Therefore, this project aims to fabricate a new deck structure. The new upper deck platform with carbon dioxide injection facility can be constructed in a fabrication yard. The existing deck platform is removed by a floating crane barge, which is widely used in the deck installation of offshore platforms. The offshore crane lifts and installs the upper deck onto the supporting structure (see Figure 5.35). Then, pipelines and injection equipment are connected for operation. Then, carbon dioxide injection activities can be initiated in the final stage.

The desirability of retrofitting can be determined from economic benefit compared to building a new platform. There is no clear-cut answer to this problem because the platform type and operating condition is broadly distributed. The report written by Tebodin (VermeulenT., 2009) gives a rough estimation about retrofitting of SEP (Sales Export Platform) and SAT (Satellite Platform) and building of a new mono-tower platform. Table 5.5 shows the estimated cost of retrofitting a platform for each step and of building a new one. The cost of modification is expected to be smaller than that of building a new platform. However, platform hibernation needs to be minimized for economic merit. The costs of carbon dioxide injection show high dependence on the platform type. In these cases, SEP requires 3~4 times larger injection cost per year. The expected cost is plotted in Figure 5.36, where the cost of platform hibernation is not added. Within 20 years, SAT is expected to be economically viable.

Table 5.5 - Cost estimates for retrofitting and new building platform (unit: million euros)

Platform type	Retrofitting SEP	Retrofitting SAT	Building new mono-tower
Platform shut-down and cleaning	4.6	2.6	39.5
Platform hibernation	1.5 (per year)	0.7 (per year)	
Platform modifications for carbon dioxide injection	20.9	13.2	
Carbon dioxide injection	11.4 (per year)	3.2 (per year)	2.99 (per year)

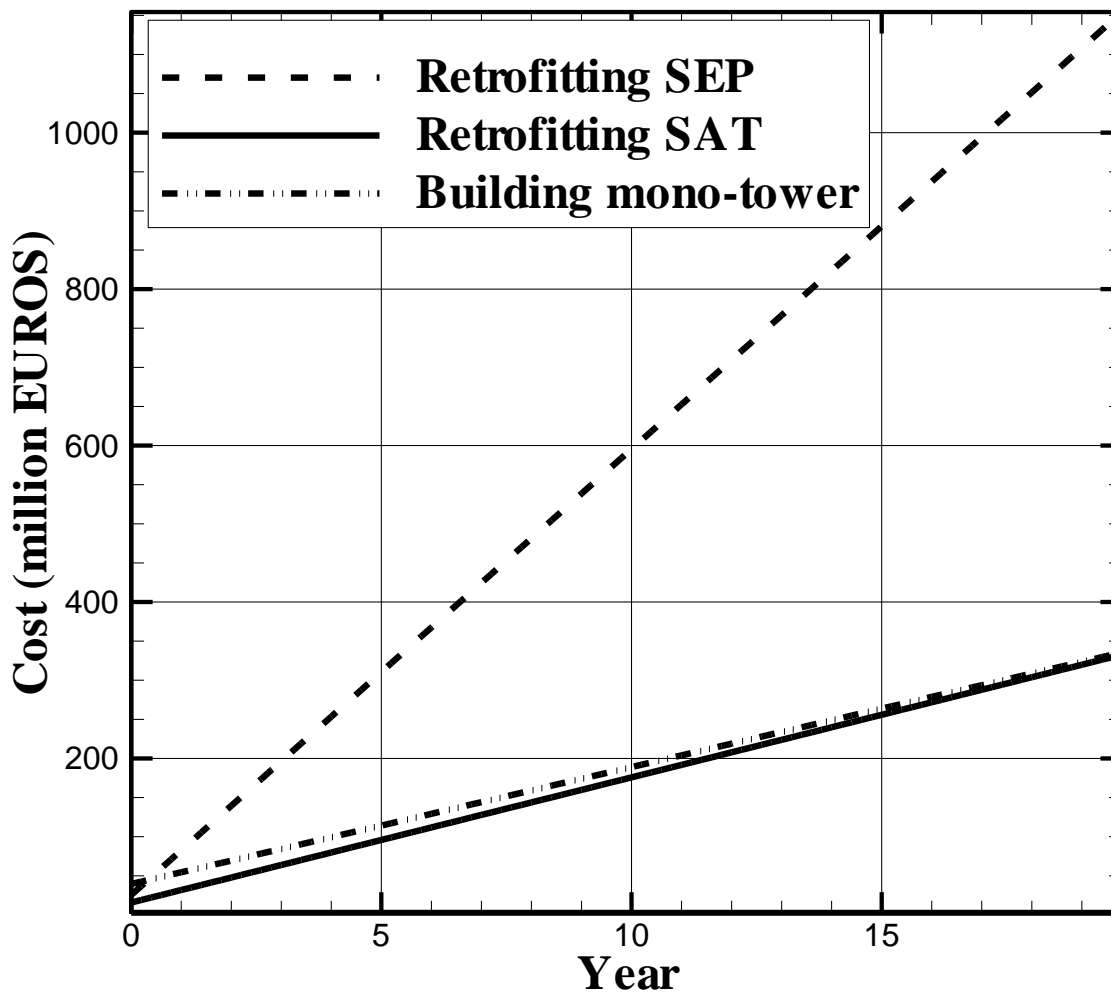


Figure 5.36 - Cost comparison for three platforms (Excluding cost of Platform hibernation)

The cost is highly dependent upon the platform type, capacities, years in service, well location and operating conditions. The example is merely a rough estimation and more thorough research is required for a specific project. However, a cost benefit of retrofitting is positively expected and this benefit could be larger as technology becomes mature.

A generic offshore platform can be divided into an upper deck and a lower supporting platform. The upper deck is called the topsides and the lower supporting platform is called the support sub-structure. The platform is designed such that it is possible to remove the upper deck and replace it. The new

upper deck platform with modular CO<sub>2</sub> injection facility can be constructed in a fabrication yard. Quayside testing and commissioning of the topside deck is often undertaken. The topside deck is transported by floating barge to the offshore installation site. An offshore crane barge lifts and installs the topside deck onto the support sub-structure. Then, pipelines, electrical cables and CO<sub>2</sub> injection equipment are hooked up for operation.

#### 5.7.10 CO<sub>2</sub> injection pumps and required power supply

The primary mission function of the offshore system is the injection of carbon dioxide and the control of flows. In the case of injection machinery, the pump is the essential device. The delivered carbon dioxide is in the supercritical state, which has a high pressure and dense phase. To maintain the state of the carbon dioxide, the injection machinery must have sufficient power to sustain the high pressures. In this project, the detailed machinery is not selected because it depends on precise well location, exact distance from well to manifold and target value of injecting rate. However, the required electrical power supply from the nearby wind farm, which is used to operate electric motors to drive the injection equipment, is estimated to be sufficient.

Table 5.6 - Annual CO<sub>2</sub> injection rates of current projects  
(Gale, Dixon, Beck, & Haines, 2009)

Projects	Sleipner	Snohvit	Salah	Rangeley	Weyburn	This project
Annual CO <sub>2</sub> injecting rate (Mt/year)	1.0	0.7	0.8	0.8	1.6	17.5

Table 5.6 shows annual injection rates of carbon dioxide in real world projects. In comparison with the injection rates of real world projects, the target injection rate value of this project is an order of magnitude higher. To satisfy the target injection rate, two possible avenues may be pursued - designing a pump with a high capacity or combining several pumps. It could be more viable to combine several pumps when considering actual operation. Because the offshore hub platform and associated manifolds cover several wells, appropriate numbers of pumps are operated simultaneously serving several injection wellheads.

The capacity of each reservoir is required to find an optimal combination of pumps. At this early stage of the concept design phase, it is not possible to determine the capacity for each individual reservoir. Therefore, a general approach is adopted where the main imported CO<sub>2</sub> flow-line reaching the offshore hub platform is diverted into several secondary flow-lines serving multiple injection sites. The aggregate injection capacity is the sum of the capacities of each pump. The characteristics of two readily available commercial pumps are shown in Table 5.7. The operating power is taken as the maximum pump power rating.

Table 5.7 - Commercial pumps for CO<sub>2</sub> injection (Sulzer pumps)

Pump type	Injecting capacity	Maximum pressure	Temperature	Power
Type BB5 Barrel Pump	1,000 (m <sup>3</sup> /h)	250 bar	-60°C ~ 425°C	13 MW
Multi-Stage Dual Volute Pump	2,700 (m <sup>3</sup> /h)	300 bar	-29°C ~ 205°C	13 MW

Because the two pumps are operated by different working principles, the capacity and operating condition is different. However, the two pumps have similar maximum pressure and power ratings. In the super-critical state, the pressure is larger than 73.7 bars and the temperature is more than 30.95°C. The two pumps satisfy the working requirement of pressure and temperature. To deliver the target capacity of 3,150 m<sup>3</sup> /h, the combination of the two pumps may be considered. Then, the required

power becomes 26 MW. This value is the design power which should be delivered from the renewable energy plant.

#### 5.7.11 Subsea manifold

From the platform, the carbon dioxide is transferred to a subsea manifold. The manifold contains several booster injection pumps and control valve mechanisms. The booster injection pumps are used to supply enough pressure for carrying the carbon dioxide into each well and pushing it into depleted hydrocarbon reservoir. The control system is actuated remotely from the offshore platform. The figure below provides a visualization of a subsea manifold.

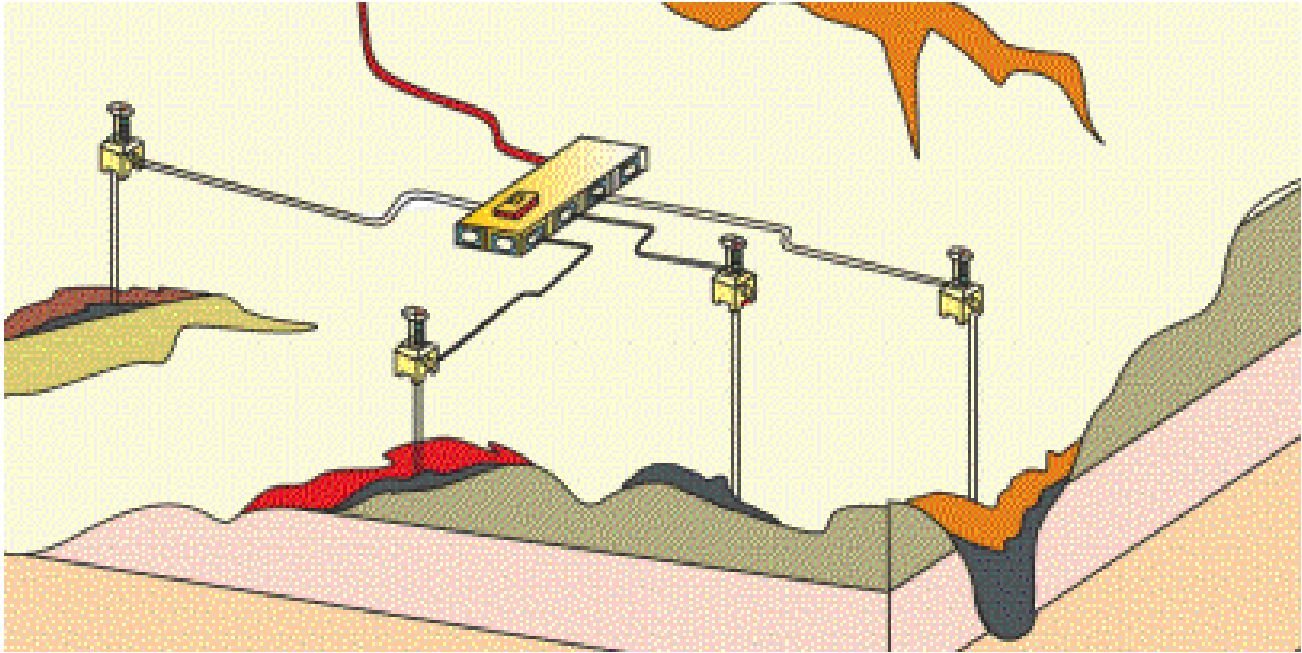


Figure 5.37 - Subsea manifold and injection flow lines

#### 5.7.12 Heating equipment

In the CO<sub>2</sub> injection system, the pressure and temperature changes are one of the major concerns because carbon dioxide in the injection conduit can change its phase. The report written by Tebodin (VermeulenT., 2009) gives several examples of injection rates for different pressures and temperatures. According to the report, heating equipment for controlling the temperature at each well is an essential part of the injection system. The reader is referred to this reference for further instruction.

The type of heater to be installed depends on the available heat sources. There are four kinds of heaters categorized by combustion type and working principle - direct fired radiant heater, direct fired convective heater, in-direct fired water bath heater and submersed combustion vaporizer. The detailed treatment of heater types is described in the report from Tebodin (VermeulenT., 2009). Generally, the most obvious source of heat comes from the combustion of recovered natural gas. If the platform is producing natural gas and injecting carbon dioxide simultaneously, the heat source is easily acquired. However, natural gas is not envisaged to be supplied from gas field in this project because we are considering depleted oil and gas reservoirs for storage. Therefore, electrical heating coils may be a plausible solution as electrical power may be utilized from wind farms. A more detailed study is required to select the optimum heater configuration.

#### 5.7.13 Offshore geotechnical survey

The Southern North Sea gas basin lies to the east of England (Figure 5.38). The basin contains three major reservoir rocks - the Bunter sandstone formation of the Triassic age, the Leman sandstone formation of the early Permian age and the Carboniferous sandstone formation of the Silesian age (Bentham M. , 2006). Thus far, the most attractive CO<sub>2</sub> storage option for the Southern North Sea gas basin lies principally in its gas fields, since the CO<sub>2</sub> storage potential of underground aquifers in this location has not been investigated in detail. There is insufficient data available on the distribution and structure of these aquifers to make a meaningful analysis. Additionally, most of the hydrocarbons

produced in the Southern North Sea gas basin are from gas fields, which provide indications as to the amount of CO<sub>2</sub> that can be stored.

The first gas to come ashore from the UK sector of the Southern North Sea was from the West Sole gas field in 1967. Most of the major natural gas discoveries have been in the Lower Permian, Upper Carboniferous and Triassic sandstone reservoirs. Gas has also been found in the Upper Permian carbonate reservoir, e.g. in the Hewett field (Cameron, et al., 1992). The major source of natural gas in the Southern North Sea is coal seams in the Upper Carboniferous coal measures. The Permian Leman sandstone formation contains the majority of the gas in the Southern North Sea and as a result has the greatest potential for CO<sub>2</sub> storage.

This report discusses the potential for storing CO<sub>2</sub> in gas fields in the UK sector of the Southern North Sea gas basin. The estimated storage potential is 2,811 million tonnes of CO<sub>2</sub>. Many of the Southern North Sea gas fields are produced by depletion drive with very little aquifer support during production. This makes them particularly favourable for CO<sub>2</sub> storage, as the reservoir pressure after production is low making CO<sub>2</sub> injection less costly. The gas fields also have proven gas seals over geological timescales. Most of the closed structures in the Bunter sandstone formation have not stored gas and the injectivity of the Bunter sandstone formation is largely unknown. As a result, storage in this aquifer carries more uncertainties than in the gas fields. It is important that before CO<sub>2</sub> injection takes place at any geological storage site, a full site investigation, characterisation and testing should be carried out. The storage sites identified in this study were used to produce some injection scenarios, outlined in this report. The purpose of the scenarios is to present stakeholders with a range of options and possibilities for using geological storage of CO<sub>2</sub>.

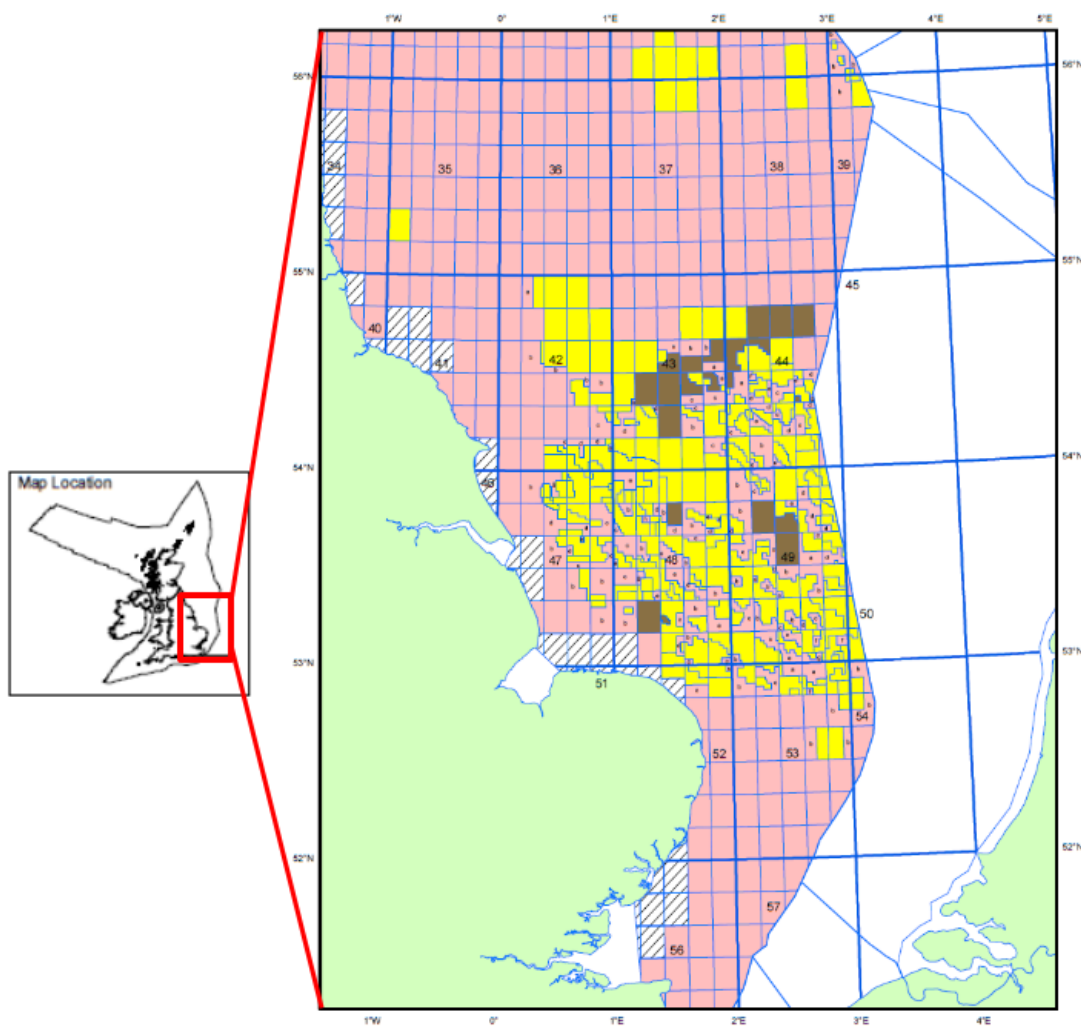


Figure 5.38 - Leased blocks in the Southern North Sea gas basin

As mentioned in the previous paragraph, the Southern North Sea basin has the largest concentration of gas fields in the UK sector of the North Sea. These gas fields provide the most promising location for

CO<sub>2</sub> injection. However, the difficulty lies in how to estimate the potential storage capacity in the UK sector of the Southern North Sea gas basin. In the GESTCO study (ChristensenN. & HollowayS., 2004), the storage capacities of the Southern North Sea gas fields were calculated. The calculation assumed that all the gas produced from the field could be replaced by CO<sub>2</sub> (Fields are summarized in Appendix D). The equation below gives an estimate of the potential CO<sub>2</sub> storage capacity.

$$V_{CO_2} = \frac{V_{Gas(STP)}}{B_g} \rho_{CO_2} \quad (5.4)$$

Where:

$V_{CO_2}$  = CO<sub>2</sub> storage capacity (m<sup>3</sup>)

$STP$  = standard temperature and pressure

$V_{Gas(STP)}$  = volume of ultimately recoverable gas at  $STP$  (m<sup>3</sup>)

$B_g$  = gas expansion factor (from reservoir conditions to  $STP$ )

$\rho_{CO_2}$  = density of CO<sub>2</sub> at reservoir conditions (kg/ m<sup>3</sup>)

The phenomenon of water invasion into the reservoir after gas production will affect the amount of CO<sub>2</sub> that can be injected back into the gas field. This was not factored into the GESTCO calculations. The effect of this can be most accurately modelled by using reservoir simulation software. However, for this concept design, no reservoir simulations are available. In the absence of simulation the following simplifying assumptions have been used to augment Equation 5.4. (BachuS. & ShawJ., Evaluation of the CO<sub>2</sub> sequestration capacity in Alberta' s oil and gas reservoirs at depletion and the effect of underlying aquifers, 2003).

- a. In gas fields with depletion drive, i.e. those where the wells are opened up and the pressure in the gas field simply depletes, as it would if the gas were being produced from a sealed tank, it is assumed that 90% of the pore space could be occupied by CO<sub>2</sub>.
- b. In gas fields with water drive, i.e. those where water encroaches/ingresses into the pore space formerly occupied by the produced natural gas reserves, it is assumed that 65% of the pore space could be occupied by CO<sub>2</sub>.
- c. In gas fields where the drive mechanism is both pressure depletion and water drive it has been assumed that each mechanism is acting equally on the reservoir and that 77.5% of the pore space could be occupied by CO<sub>2</sub>.

Where the drive mechanism is unknown, the following assumptions may be made. If the reservoir rock for the gas field is the Leman sandstone the drive mechanism is depletion drive. This assumption has been made on the basis that most of the Leman sandstone fields are depletion-produced fields. If the reservoir is in the Triassic or Carboniferous sandstone formation, it has been conservatively assumed that the field is acting under water drive, as are most of the fields within these reservoirs.

## 5.8 Design considerations

### 5.8.1 On the use of indigenous fossil fuel resources in the UK

The UK's fossil fuel resources comprise primarily coal mines in the Yorkshire coal fields, gas fields in the Southern North Sea Gas Basin and oil fields in the Northern North Sea Oil Basin. The offshore oil and gas fields are located within the Exclusive Economic Zone (EEZ). The UK thus has the sovereign right to exploit the natural resources within her territory. Over the past three decades, exhaustive Exploration and Production (E and P) activities have been undertaken in the UK's North Sea EEZ.

A nation will always seek to exploit the natural resources within her boundaries for purposes of self-sufficiency. But as these resources gradually become exhausted, the nation will no longer be able to meet fossil fuel demand locally and will become a net importer of fossil fuels. This throws the whole notion of energy security into question and places the nation in a precarious situation. History has shown us that wars have broken out due to disputes over water and fuel. Hence, as far as practicable, a

nation should always seek to have a self-dependent energy supply and not have to deal with the geopolitics of reliance on neighbours.

However, the situation is not all that bleak. What is termed ‘proven’ reserves refers to all those oil and gas reserves which can feasibly be exploited. Typically, this excludes shale gas which is viewed as a form of ‘stranded’ gas. It can be anticipated that with technological developments, previously inaccessible oil and gas resources in remote locations can be viably exploited.

#### 5.8.2 *On the use of legacy systems and relic infrastructure for CCS projects*

The doctrine of Carbon Capture and Storage is to arrest the very large point sources of CO<sub>2</sub> emissions. This seems logical as it is easier to tackle a few large point sources than several small dispersed sources. When going about carbon capture, it would make more sense to go for the jugular i.e. large coal fired power plants. With the envisaged advent of electric cars, more of those sporadic dispersed sources can be pushed to the large point sources. Thus the design philosophy is clear – capture emissions from the largest emitters. Addressing the biggest polluters is a worthwhile endeavour with expected substantial and palpable impact. In this manner, CCS projects would be able to capitalize on economies of scale by capturing vast amounts of CO<sub>2</sub>.

With such large scale capture involved, it can be expected that high CAPEX and OPEX cost will be required. The challenge then is to devise ways and schemes to make CCS as cost effective as practicable. One of the means to affect this is to seek to utilize existing legacy infrastructure as opposed to fabricating new constructions. This would significantly help to drive down initial costs but may detrimentally influence operating cost as more inspection and maintenance would be required for the aging infrastructure.

When considering the use of existing gas pipelines for CO<sub>2</sub> transport to the injection site, a cost-benefit analysis would have to be undertaken to weigh the pros and cons of using existing inactive gas pipelines versus laying a new pipeline. If the gas pipeline is engaged in lucrative trade transporting natural gas, it is unlikely that the pipeline would be redeployed to transport CO<sub>2</sub> as such a move would not make economic sense. The intent is to modify and reconfigure existing pipelines previously used in the natural gas transportation trade but no longer in service for CO<sub>2</sub> transport. This would obviate the high start-up cost attached to laying new pipelines. However, lifetime structural integrity assessments and life extension initiatives would be required to be carried out on the converted pipelines to ascertain suitability for intended purpose. Pipeline wastage and steel renewal would have to be undertaken before the next leg of the pipeline’s service life. Lastly, specifications as to the purity of the transported CO<sub>2</sub> would have to be adhered to particularly with regards to moisture content. Moist CO<sub>2</sub> is corrosive in nature and should be avoided so as to preserve the longevity of the CO<sub>2</sub> pipeline.

When considering the use of existing platforms at the injection site, a cost-benefit analysis would have to be carried out to access the various trade-offs between retrofitting an existing decommissioned platform versus fabricating and installing a new platform. When an oil reservoir becomes depleted, the offshore oil and gas field is abandoned and the oil well plugged. The support substructure (production platform) is decommissioned. There are various ways in which a platform may be decommissioned. The platform may be toppled and left as an artificial reef. It may be heavy lifted onto a vessel and removed to shore or it may be reused to serve as a hub platform for satellite wells. The use of an existing inactive platform would involve removal of the topside production modules and refurbishment with injection modules for CO<sub>2</sub> storage in depleted reservoirs. Offshore installation of the injection modules would involve offshore lifting which is subject to the constraints of calm sea states and limited weather windows. The chartering of heavy lift crane vessels is also costly which means that effective time management and planning is imperative. Substantial savings would be gained from reconfiguring an existing platform as opposed to constructing a newbuild platform in a fabrication yard. However, a proportion of the savings obtained would have to be expended in platform conversion, modification and refurbishment. It is expected that this would still be less costly than a purposed-built bespoke injection platform though a detailed cost analysis would have to be carried out in order to confirm this. A detailed cost analysis undertaking is beyond the scope of this concept design project.



Lastly, when estimating cost, a holistic approach encompassing through life cost would likely give the most accurate indication. Life cycle cost goes beyond initial and operating cost. It considers the period over which the injection machinery and equipment is amortized and takes into account such parameters as depreciation, inflation and net present value.

#### 5.8.3 *On the use of booster pumps in pipeline transport*

The transportation of CO<sub>2</sub> via pipeline will inevitably involve head losses. Whereas the civil engineer is accustomed to open-channel flow, the mechanical engineer finds himself on familiar grounds when dealing with pipe flow. Recalling knowledge from Fluid Mechanics, we know that frictional losses occur in pipes and at elbows, tees and bends. Booster pumps will doubtless be required at regular intervals along the length of the pipeline. The Darcy-Weisbach equation can be used to calculate pipe losses. A brief treatise on pipe losses is included in the Appendix B. A detailed analysis of pipe losses and requisite booster pump sizing is beyond the scope of this concept design. Suffice to say that booster pumps will be required and that the design team are aware of and have the knowhow to calculate pipe losses if the details such as loss coefficients are furnished.

#### 5.8.4 *On the use of electric motor driven pumps for CO<sub>2</sub> injection*

When considering offshore CO<sub>2</sub> injection into geological formations in the super-critical phase, one invariably has to deal with pumps. The question thus arises: Is there an electrically driven pump that is of sufficient capacity to achieve the target flow rates given that injection is to be powered by marine renewable energy? The idea is to draw on electricity generated by offshore wind to power electric motor driven pumps to achieve injection. There will be at least two pumps for this purpose for reasons of redundancy so that functionality is maintained in the event of a breakdown.

In the case of injection pumps mounted on steel base frames at subsea manifolds, these will be submersible pumps. The drawback of having submersible pumps is that they are less accessible in the event of a breakdown. Downtime and maintenance costs for this equipment are thus higher. Having the pump machinery on the topside of a platform would suggest easier accessibility and ease of maintenance. This would be the preferred choice though it is envisaged that the use of submersible pumps will most likely be unavoidable. Satellite injection wells some distance from the hub platform would typically require a submersible pump close to the wellhead. The figure below shows a submersible pump being lowered to the seabed.



Figure 5.39 - Submersible pump

(Source: <http://www.offshoreenergytoday.com/wp-content/uploads/2011/08/Malaysia-Aker-Solutions-Wins-Contract-to-Deliver-Subsea-Production-System-for-Kikeh-Project.jpg>. Last retrieved on 2 Aug 2011)

Thus far, we have been discussing about subsea infrastructure and submersible pumps. We can thus bring to bear the whole apparatus of subsea engineering know-how. The figures below depict artist's impressions of subsea infrastructure.

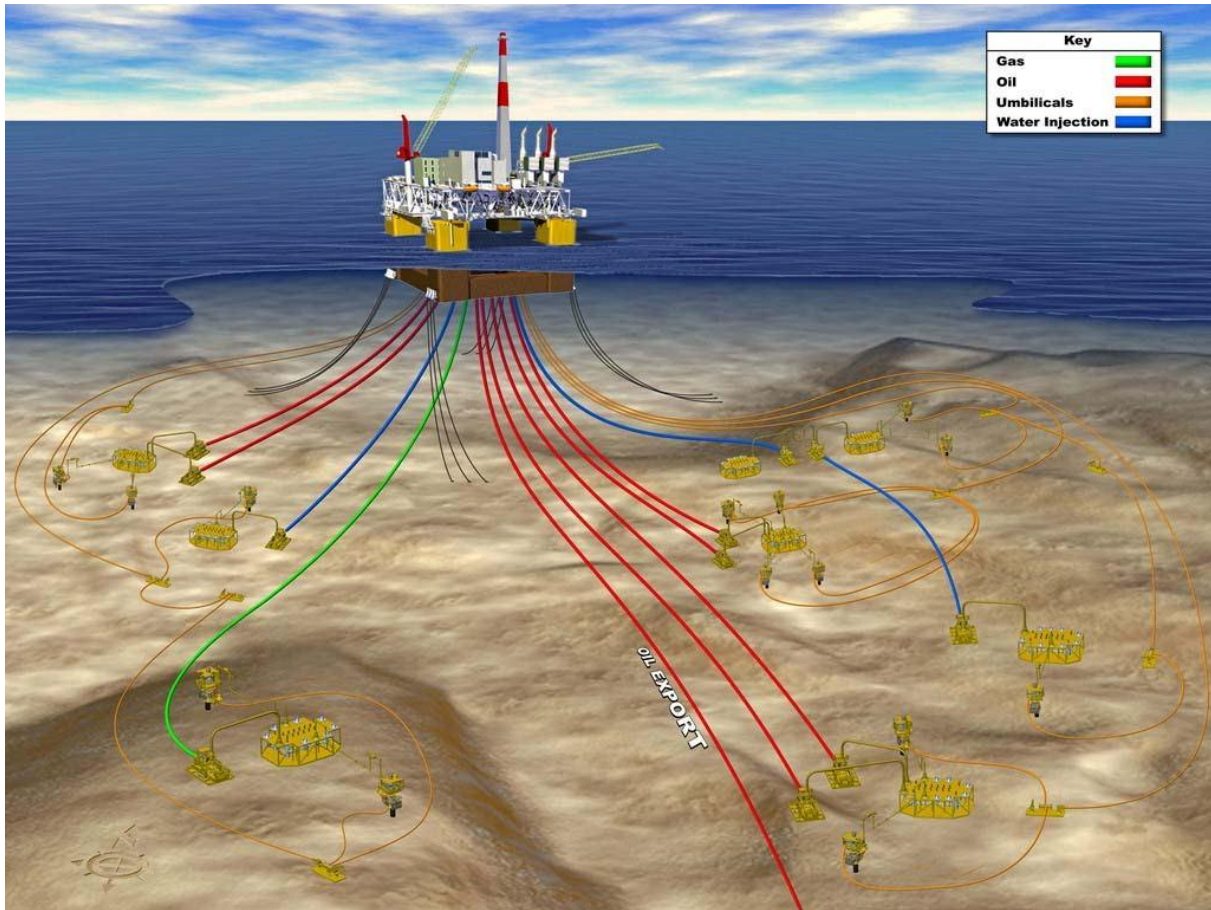


Figure 5.40 - Artist's impression of subsea infrastructure

(Source: <http://www.bornemann.com/assets/galleries/Branchen/Subsea-Pumpe-groer-Ausschnitt.jpg>.  
Last retrieved on 11 Aug 2011)

Oil and gas exploration and production is not dissimilar to CO<sub>2</sub> injection and geological storage. Indeed the two bear several similarities. Very loosely, one may think of CO<sub>2</sub> injection as oil and gas production in reverse. The technology developed for oil and gas production can be transferred to CO<sub>2</sub> injection. Below is a visualization of subsea infrastructure. Try to visualize the flow in reverse.



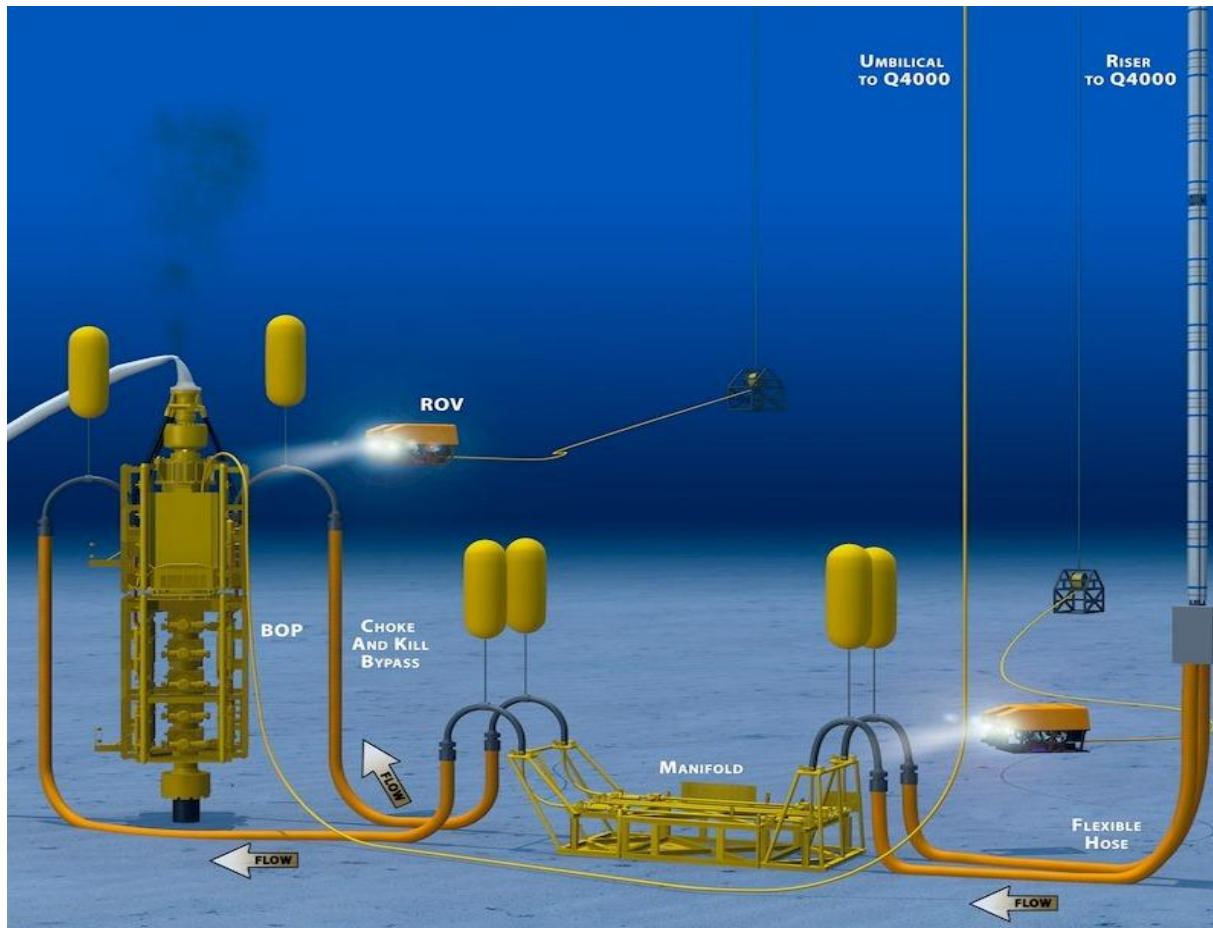


Figure 5.41 - Subsea manifold and associated equipment

(Source: [http://www.upstreamonline.com/multimedia/archive/00034/BP\\_riser\\_diag\\_34599a.jpg](http://www.upstreamonline.com/multimedia/archive/00034/BP_riser_diag_34599a.jpg). Last retrieved on 11 Aug 2011)

A survey of industry literature revealed that substantially large injection rates of supercritical CO<sub>2</sub> can be achieved with commercially available submersible pumps. This evidence emboldens and instils confidence as to the technical feasibility of the concept design. The figure below shows a collection of commercially available pumps.



Figure 5.42 - Various pumps

(Source: [http://www.epmag.com/Images/april2008/SUBSEA-SYSTEMS-KING\\_men-prepare-pump.jpg](http://www.epmag.com/Images/april2008/SUBSEA-SYSTEMS-KING_men-prepare-pump.jpg). Last retrieved on 11 Aug 2011)

Having allayed concerns as to the injection capabilities of commercially available pumps, the next step involves checking if the renewable power supply can meet injection power requirements. Shown below is a simple mental exercise to obtain some ball-park figures for matching demand and supply power requirements.

Consider electric driven pumps with motors to have a power range from 250 kW to 10MW.

Assume conservatively a 5 MW power requirement for injection.

Consider offshore wind farms with installed power from 60 MW to 300 MW.

Assume a typical wind farm with 200 MW max. generating capacity.

Assume on average operating at 25% of max. generating capacity (50 MW)

Assume 10% of electricity generated tapped for CO<sub>2</sub> injection purpose (5 MW)

Power requirement = Renewable power supply

At this juncture, one may ask how much exactly is 5 MW to get an inkling of magnitude. We can put things in perspective by making comparisons:

- a. Five MW can power 1000 British homes.
- b. A typical 59 m Offshore Support Vessel has an installed power of 6 MW.
- c. *Oasis of the Seas*, the world's largest cruise ship has an installed power of 100 MW.

#### 5.8.5 *On the need for offshore platforms in CO<sub>2</sub> geological injection.*

There are four main arguments that put forth a convincing case that an offshore platform is not required. Firstly, some existing CO<sub>2</sub> injection projects indicate no platforms are used at the injection end. For example, Sleipner, Snøhvit, K12B and Gorgon. Secondly, the primary difficulties for CO<sub>2</sub> injection focus on the vicinity of well head i.e. the large pressure jump from pipeline to wellbore. CO<sub>2</sub> injection rate control requires pumps mounted near the well head (Hrvoje, Steve, Simon, Steve, & Frederic, 2009). Thirdly, injection facilities which may include pumps, valves and conduits are not massive. Thus a platform is not essential. Fourthly, rough weather conditions and relatively shallow water also make subsea manifolds the preferred choice for CO<sub>2</sub> injection.

However, the one overriding consideration is that CO<sub>2</sub> injection will be powered by marine renewable energy, specifically offshore wind power. This means that a platform housing a transformer sub-station to receive the incoming subsea electrical cable is necessary. This requirement trumps the previous four arguments in favour of doing away with an offshore platform.

#### 5.8.6 *On the use of depleted oil and gas reservoirs*

Oil and gas reservoirs are not evacuated. The porous media is permeated with seawater. The injected CO<sub>2</sub> in supercritical phase effectively displaces the seawater. A portion of injected CO<sub>2</sub> will vaporize upon entering the reservoir as heat from the earth's mantle will cause CO<sub>2</sub> boil off.

The advantage of using depleted oil and gas reservoirs is that there is available extensive information about the geometry and capacity of these geological formations. Comprehensive geotechnical and seismic 3D surveys have been undertaken by oil companies to ascertain reservoir characteristics. We can thus draw on this knowledge. There is less uncertainty associated with oil and gas reservoirs than saline aquifers. Based on the amount of oil or gas extracted, by a simple method of triangulation, we can estimate the amount of CO<sub>2</sub> that can be stored. There is less inherent risk in using oil and gas reservoirs rather than saline aquifers in the geological storage of CO<sub>2</sub>.

#### 5.8.7 *On the rationale for the decision to have an onshore temporary storage hub*

The engineering judgement to have an onshore temporary storage hub for captured CO<sub>2</sub> is justified. This hub will provide room for future expansion such that captured CO<sub>2</sub> from other point sources can

be routed to this location. In the pilot phase, the hub will serve CO<sub>2</sub> captured from a single power plant. In future, more power plants could route their CO<sub>2</sub> to this hub. It was deemed more economically feasible to have an onshore temporary storage hub than an offshore one.

Another reason for the onshore temporary storage hub is the need to have a buffer for overload and transients. Operating on the basis that supply will meet demand, the concept design envisages that the amount of captured CO<sub>2</sub> supplied to the injection site can be directly injected into the depleted reservoir with minimal requirement for offshore temporary storage. This puts the spotlight on injection capabilities – the injection rate must be able to match the CO<sub>2</sub> supply. The temporary storage of CO<sub>2</sub> involves pressurization and refrigeration which are energy intensive processes. This is to be avoided as far as practicable because pressure vessels and cryogenic equipment are expensive. The high cost of pressure vessels is largely due to the thick scantlings required. Thus the intended purpose of the onshore temporary storage hub becomes apparent. It is to provide reserve capacity in the event of break down or equipment downtime. On any particular day, the plant may emit and capture more than the daily injection rate. Supply would exceed demand (injection capability) and equilibrium is upset. Hence it is imperative that an onshore temporary storage hub be provided to cater for such fluctuations.

#### 5.8.8 *On the laying of subsea copper cables from wind farm to injection site*

A subsea electrical cable, preferably entrenched, will have to be laid from the wind farm to the injection site. This represents a substantial initial cost for the project. However, the thing to note about subsea copper cables is that they are retrievable from the sea bed and recyclable. Hence we can expect some Return On Investment (ROI). A cost comparison between pipeline and subsea electrical cable revealed that the relative cost of the pipeline is higher.

#### 5.8.9 *On the transportation and injection phase of CO<sub>2</sub>*

From the previous sections, we have established that a CCS pilot project in the UK with geological storage in the North Sea would entail:

- a. CO<sub>2</sub> capture and temporary storage at a major coal fired power plant (liquefaction).
- b. CO<sub>2</sub> transportation in gaseous state via pipelines (regasification).
- c. Re-liquefaction at an offshore injection site.
- d. Injection into geological formation in supercritical phase.

Perhaps worthy of note is that the process of liquefaction involves refrigeration and pressurization which is energy intensive. Ideally, the aim would be to transport CO<sub>2</sub> in the supercritical phase with direct injection into the geological formation (oil and gas reservoir). In this way, we are effectively dealing with CO<sub>2</sub> in the supercritical phase only. Recognizing that the temporary storage of CO<sub>2</sub> at an onshore hub inevitably involves CO<sub>2</sub> being stored in the liquid phase, we know that such storage in cryogenic form is unavoidable. The objective then is to maintain CO<sub>2</sub> in the supercritical phase from the transportation leg onwards up until injection into the geological formation which obviates the need for re-liquefaction at the offshore injection site. The reason being that the offshore injection platform will be wholly powered by marine renewable energy, specifically offshore wind power. The energy intensive cooling and re-liquefaction process would put a heavy burden on the renewable electricity supply. There is a high likelihood that the electrical power supply would not be able to meet the energy demand in this case. To clarify in this regard, the plan is to power the injection platform from renewable sources. This does not include the onshore temporary storage hub which will be powered by alternative means.

#### 5.8.10 *On the issues with dense phase CO<sub>2</sub> transportation*

One of the design features of our concept proposal is to transport the CO<sub>2</sub> in the so called dense phase. Although preferable over transportation in the purely gaseous state, transportation in the dense phase is not without its difficulties. Listed below are the main issues with dense phase CO<sub>2</sub> transportation.

- a. Dense phase CO<sub>2</sub> is highly invasive and capable of dissolving materials. Therefore, great precaution is required while selecting the materials for seals, valve seats, sensor instrumentation, control actuators, etc.

- b. CO<sub>2</sub> dissolves in water and forms carbonic acid which can corrode pipeline materials.
- c. Hydrate formation may clog the pipelines. However, it is not very clear that dense phase CO<sub>2</sub> will form hydrates with moisture before carbonic acid. Ultimately it depends upon the specific local conditions of pressure and temperature at that particular point along the pipeline and the percentage of moisture content. In case of high pressure, there is a higher risk of forming hydrates and for low pressure, the likelihood of corrosion gets higher.

### 5.9 Preliminary cost estimate of proposed CCS project

Cost estimates for CCS projects depend upon several variables such as:

- a. The type of capture technology (post-combustion, pre-combustion, oxy-fuel)
- b. Whether the plant is a new construction or is a retrofit of an existing plant
- c. Whether the CCS project is in the demonstration or commercial stage

Part of the difficulty in coming up with reliable cost estimates is the lack of any operating commercial-scale power plants that capture and sequester CO<sub>2</sub> emissions. In addition, there is neither a market demand for emitted CO<sub>2</sub> nor a regulatory requirement to capture CO<sub>2</sub>. Hence the cost estimates vary significantly from one report to another. However, the general consensus with regard to CCS projects is that:

- a. Capital expenditure is much larger than operating expenditure
- b. Capture is the most expensive component of CCS
- c. Transport costs rely heavily on the mode of transportation selected
- d. Overall cost will decrease as the technology matures

Among the literature for cost estimation available, the report published by (McKinsey & Company, 2008) is perhaps the most widely accepted. This report was based on information gathered from many industrial CCS stakeholders. The cost estimation for our project is principally based on this report with some minor modifications. The table below provides a cost comparison of various carbon capture technologies. It shows the percentage increase in cost when different carbon capture schemes are implemented.

Table 5.8 - Cost comparison of various carbon capture technologies

	New Construction	Retrofit
Post-combustion	60%-70%	220%-250%
Pre-combustion	22%-25%	N/A
Oxy-fuel	46%	170%-206%

Many studies suggest that retrofitting an existing power plant is more expensive than designing and constructing a purpose built 'capture ready' plant; this comparison being made on a levelized basis. There are four main reasons for the higher cost.

- a. The added capital expense of adapting the existing plant configuration for the capture equipment.
- b. A shorter lifespan for the capture unit compared to new plants
- c. A sub-optimal efficiency penalty compared to a new plant that incorporates CO<sub>2</sub> capture from the design stage
- d. The revenue earning time lost when an existing plant is taken offline for the retrofit.

Table 5.9 - Cost decrease as a function of technology maturity

	Capture	Transport	Storage	Total
Initial Demo. (2015~)	\$73-\$94	\$7-\$22	\$6-\$17	\$86-\$133
Early Com. (2020~)	\$36-46	\$6-\$9	\$6-\$17	\$48-\$73
Mature Com. (2030~)	N/A	N/A	N/A	\$44-\$65

In most carbon sequestration systems, capture costs account for the majority of CCS costs, especially in demonstration and early commercial stages. Table 5.9 shows the variation in cost (dollars per metric tonne of CO<sub>2</sub>) for three different stages of CCS development for new, coal-fired power plants.

Our project aims to capture 50,000 tonnes of CO<sub>2</sub> per day for an early commercial project such that every year the amount of CO<sub>2</sub> captured is:

$$50,000 \times 365 = 18,250,000 \text{ Ton} = 18.25 \text{ MT}$$

Therefore,

For capture:  $18.25 \times 41 \times 10^6 = 748,250,000 \text{ USD}$

For transport:  $18.25 \times 7.5 \times 10^6 = 136,875,000 \text{ USD}$

For storage:  $18.25 \times 11.5 \times 10^6 = 209,875,000 \text{ USD}$

Totally the cost is:

$$748,250,000 + 136,875,000 + 209,875,000 = 1,095,000,000 \text{ USD}$$

In addition, an extra US\$0.10–0.30 per tonne is needed for monitoring costs, that is:

$$18.25 \times 0.2 \times 10^6 = 3,650,000 \text{ USD}$$

Hence the cost estimation for this project is approximately USD 1.1 billion, the price estimation based on the middle value of given cost range.

However if the storage is combined with enhanced oil recovery to extract extra oil/gas the storage could yield net benefits of US\$ 40–64 per tonne of CO<sub>2</sub> injected (based on 2011 oil prices).

## 5.10 Legal issues

### 5.10.1 Anticipated legislative and statutory bodies involved

The design team recognized that certain legislative and statutory matters would have to be dealt with in the course of implementing a pilot CCS project. An in-depth treatment of the various legal implications that may flow from a pilot CCS project is beyond the scope of this report but the team members have endeavoured to list the probable bodies involved. The expected entities involved are reproduced below:

- a. The UK Maritime and Coastguard Agency (MCA)
- b. The UK Marine Accident and Investigation Branch (MAIB)
- c. The UK Department of Energy and Climate Change (DECC)
- d. The UK Health and Safety Executive (HSE)
- e. The UK Crown Estate
- f. HM Revenues and Customs
- g. The IMO SOLAS and MARPOL statutes (if applicable)
- h. The IMO MODU code (if applicable)
- i. Classification Society Rules (if applicable)

Legal acceptance is an essential pre-requisite of any CCS project. Although legal uncertainty remains a problem within the legal framework, a conceptual or hypothetical CCS project should seek to achieve full legal acceptance under current legal obligation at national and international level. Despite future anticipated legal visibility being obscure, CCS technology developers should seek to satisfy all current legal requirements nonetheless.

When considering to operate in the UK, CCS developers must consider the applicable laws in the UK pertaining to CCS. The UK is a signatory of many international maritime laws which are potentially related to carbon dioxide storage. The UK is also a European community member and is thus inclined



to adopt much of the legislature in force within continental Europe. In short, any CCS project managed by the UK will be covered by international, European community and national legal regimes.

Strictly speaking, no current legislation or law available specifically covers the legal issues surrounding CO<sub>2</sub> storage. CO<sub>2</sub> storage is very much in a 'legal limbo' or grey area of the law. This is because large scale CO<sub>2</sub> storage has yet to be widely implemented and hence laws have yet to be crafted to provide legal direction to this budding industry.

#### 5.10.2 *Relevant international conventions and protocols pertaining to CCS*

Some international laws should be taken into consideration when offshore CO<sub>2</sub> geological storage takes place. These laws operate together, not separately, in ensuring the protection of the marine environment as well as safeguarding property and life at sea. Many of these statutory requirements have been implemented into national law in contracting government countries i.e. countries who are a party to the convention in question (Wall, Bernstone, Olvstam, SwedPower AB, & Utveckling AB, 2004). Table 5.10 summarizes the relevant maritime laws (Gough & Shackley, An Integrated Assessment of Carbon Dioxide Capture and Storage in the UK, 2005).

Among these laws, the UNCLOS is the most important and internationally recognized convention which aims to regulate all aspects of maritime activity including shipping, scientific research, exploration, avoidance of pollution and environment protection. This convention establishes the basic legal framework for maritime activities. This law requires all contracting nations to issue laws and take measures to regulate marine pollution. The legal obligations for environmental protection are further augmented by conventions such as the 1996 Protocol to the London Convention. Clearly, in view of the protection of our environment, CCS is a promising solution to reduce greenhouse gas emissions and should be embraced, promoted and encouraged on a global level.

Table 5.10 - International laws relevant to CO<sub>2</sub> geological storage in the marine environment

Convention	Purpose	Enforced
London Convention (1972)	Marine Environment. Protection	Yes
U.N. Convention on the law of the Sea (1982)	Marine Regulation	Yes
Framework Convention on Climate Change (1992)	Climate Change	Yes
Protocol to the London Convention (1996)	Marine Environment Protection	No
Kyoto Protocol to the Climate Change Convention (1997)	Climate Change	Yes
Kiev Strategic Environment Assessment Protocol (2003)	Environment Assessment	No

#### 5.10.3 *Relevant European laws pertaining to CCS*

There are three European Community Directives which appears related to our CCS project. These are outlined in Table 5.11. It is not clear whether these directives have any legal application in the marine environment, but it implies that the European Community Treaty can extend to areas within the jurisdiction of Member States.

Within the European community, many on-going projects exist where CO<sub>2</sub> storage is being tested. This has been ongoing for several years. From a legal viewpoint, these projects are all storing CO<sub>2</sub> as part of an industrial process where the motivation to store CO<sub>2</sub> is driven by economic reasons.

Table 5.11 - European Directives relevant to CO<sub>2</sub> geological storage in the marine environment

Directive	Purpose	Enforced
Habitats Directive (1994)	Habitat protection	Yes
Environmental Impact Assessment Directive (1999)	Environmental. Assessment	Yes
Strategic Environmental Assessment Directive (2004)	Environmental. Assessment	Yes

#### 5.10.4 *Legal visibility of CCS in the UK*

Our project takes the Southern North Sea gas basin as the storage site for CO<sub>2</sub> sequestration. The site is 120 km beyond the coasts of the UK, which is located within the nation's Exclusive Economic

Zone (EEZ). The EEZ was legally recognized by the United Nations Convention on the Law of the Sea (UNCLOS) in 1981 and other international maritime laws such as the London Convention and its 1996 protocol thereof. According to UNCLOS, the UK has sovereign rights of exploration, exploitation and management of the natural resources in both the seabed and column of water above it. Therefore, with UNCLOS as the basis, it would seem to indicate that the UK could claim the right to exploit the geological formations in its EEZ for CO<sub>2</sub> storage purposes.

In addition, if CO<sub>2</sub> is injected by the offshore industry for an industrial purpose like EOR, it would not be construed as dumping and would be permissible according to the London Convention.

In summary, we have a fairly high level of confidence that our proposed project will be approved by the UK government and accepted internationally from a legal viewpoint in the coming future, on condition that all the requisite legislative provisions are met.

### ***5.11 Assessment of public perception of CCS in the UK***

The public's opinion and perceived acceptability has a significant influence on the feasibility of our planned project. As a pioneering CCS solution, No similar information about public acceptance is available at the time of this writing. The statement and conclusion in this section are based on the technical report released by Tydall Centre for Climate Change Research. (Gough & Shackley, An Integrated Assessment of Carbon Dioxide Capture and Storage in the UK, 2005).

Currently, surveys on public opinion about carbon capture and sequestration have enjoyed little attention from society. This could be attributable to:

- a. The immature technology with limited experience has not drawn much attention from the public domain.
- b. Few people are able to relate to the concept of CCS and thus are unable to formulate opinions about the subject.

In Tydall's report, an in-depth investigative approach was applied to understanding public perceptions about CCS in the UK. The research was carried out and garnered 212 respondents during 2002 and 2003. The findings from the respondent sample is taken as representative of the population's opinion.

#### ***5.11.1 Main opinions of CCS in the UK***

None of the respondents were familiar with the concept before the interview. On first contact with the idea and without any supporting information, about half the people were neither for nor against CCS. Some had no inkling whatsoever. One third of respondents held an attitude of strong reservation. The remainder of respondents voluntarily supported the idea.

However, after more detailed information was provided on the motivation and rationale for CCS, the number of supporters increased substantially. Half of the respondents became more receptive and positive towards the idea, although still one third held their former attitudes towards CCS. Perhaps what is interesting is that those who initially had strong reservations about CCS became more negative (sceptical and cynical) when furnished with more detailed information.

In addition the survey reflected that CCS is more favourably accepted when it is compared with other low or zero carbon energy options such as wind, solar, wave, tidal and nuclear energy. Overall, support for CCS can best be described as moderate compared to strong support for wind, and solar energy. However, there is less disdain for CCS compared to nuclear power.

#### ***5.11.2 Public concerns about CCS in the UK***

As to what were the public's main concerns, 49% of respondents choose leakage. The next most frequently voiced concern was for the ecosystem (31%). This was followed by the new and untested nature of the technology (23%) and human health impact (18%).

When asked for any perceived positive effects of CCS, the most frequent answer was its function to reduce climate change and the next item was to "buy time". The former takes up 58% while the latter occupies 7%.

The survey also indicated that people tend to make clearer decisions about the desirability of CCS if more certainty is available about environmental and safety risks in the long-term. Many people expressed the desire for more information about CCS.

### 5.11.3 *The need for a fundamental acceptance of CCS in the UK*

Two so called "citizen panels" were integrated into the aforementioned investigation for further in-depth research; one group was based in Manchester and another in York.

Based on the survey and citizen panels, some fundamental agreement on the need for CCS can help formulate public opinion to regard CCS as a necessary option, namely:

- a. Acceptance of the underlying fact that climate change is the result of anthropogenic activity.
- b. Acceptance of the potential seriousness of threat due to climate change in the UK.
- c. Acceptance of the urgent need to reduce carbon emissions on a large scale in the coming decades.

Therefore, if CCS can be promoted such that it is perceived as highly advantageous, the worthy cause for CCS would undoubtedly galvanize public acceptance. In order for this to occur, the public must be able to easily access information on CCS. Ideally, by explaining CCS in a text book for school education, more support is expected to be obtained for CCS. Furthermore, if the risk associated with CCS can be properly managed and conveyed to the public in an easy to understand manner, then acceptance for CCS will no doubt be easily garnered from the public. The challenge thus lies in tirelessly promoting the merits of CCS to win public support.

## 5.12 *Risk and monitoring*

### 5.12.1 *Risk considerations and risk-based design*

All throughout the concept development phase, the design team was mindful of risk. The team members recognized that risk is inherent in any engineering project and that stakeholders are typically adverse to risk. Where applicable, risk mitigating measures were incorporated into the concept design. Although a detailed risk identification and management assessment is beyond the scope of this report, the design team strongly advocates that such an undertaking be carried out in the post-concept design phase. However, at this stage in the concept design phase, a quick listing of potential areas of risk would suffice to highlight the importance of risk assessment.

- a. Investment risk
- b. Geohazards e.g. subsea mudslides
- c. Pipeline leakage
- d. Pressure vessel rupture
- e. Fire
- f. Vessel collision with injection platform
- g. Maritime terrorism and piracy
- h. Occupational health and safety
- i. Damage to property, death and personnel injury

### 5.12.2 *Risk assessment for CCS*

Risk assessment is a powerful tool to enhance the confidence of stakeholders and achieve public acceptance. The identification of hazards and risk is the first step in the risk management process. Risk management involves the selection of appropriate prevention and control measures. The definition of risk in both qualitative and quantitative terms is difficult especially for new and untried projects.

#### CO<sub>2</sub> capture risk assessment

For the capture stage of the CCS process, the adopted post-combustion method is a proven technology with mature experience. This report will not go into a detailed discussion about the inherent risks of the post-combustion capture method. A few technical papers have presented comprehensive investigations on the risks of CO<sub>2</sub> capture like (Lathrop, Gates, Massie, & D., 2006), (Botten,

Morrison, & Solomon, 1983), (Eydeland & Wolyniec, 2003), et al. The reader is referred to these for further information.

### CO<sub>2</sub> transportation risk assessment

Our proposed concept design uses offshore pipelines as the mode of transportation. Offshore pipelines endear more risk than onshore pipelines. With an average failure rate of 0.6 per 1000 km years for onshore pipelines (SINTEF, 1987), failure rates for offshore pipelines can typically reach up to one order of magnitude higher as most of their length are laid underwater and are thus less accessible. Generally, offshore pipelines are far less susceptible to third party damage. However, there is the occasional fishing trawler that rakes up a pipeline or a jack-up's leg that stabs a pipeline. Offshore pipelines may also be gouged by ice-bergs. The sources of hazards for offshore pipelines are summarized in (Willcocks & Bai, 2000):

#### Harsh marine environment loads

- a. Earthquake
- b. Wave and current loading
- c. Seabed movement and instability

#### Process deviations

- a. Over/under-pressure
- b. Over/under-temperature

#### Internal/external corrosion/erosion

#### Marine traffic

- a. Dropped anchors
- b. Dragged by trawling vessels
- c. Sinking vessels
- d. Grounding vessels

#### Fishing/Trawling

- a. Impact loading
- b. Pull over loads
- c. Hooking

The result of the aforementioned hazards is pipeline rupture. Although the probability of pipeline leakage is considered low, if this occurs, severe consequences will arise:

- a. Hard to identify the location of the leak and repair it

The dense phase CO<sub>2</sub> will quickly become CO<sub>2</sub> gas and the CO<sub>2</sub> flowing in the pipeline will leak undetected. CO<sub>2</sub> is a colourless and odourless gas. Hence it is quite difficult to identify the leakage location by tracing the CO<sub>2</sub>. Pressure sensors would likely have to be located at regular intervals along the pipeline to detect pressure drops in the event of a leakage.

- b. Pollution of the marine environment

The leaked CO<sub>2</sub> would bubble up to the water surface and enter the atmosphere. This negates the effort to sequester CO<sub>2</sub> and the leakage itself becomes a CO<sub>2</sub> source. In addition the leaked CO<sub>2</sub> into the marine environment could change ocean chemistry characteristics and have a potential threat for marine life nearby.

- c. Occupational health and safety

Human exposure to elevated levels of CO<sub>2</sub> is hazardous. The reduction in the oxygen content of the ambient air causes hypoxia or CO<sub>2</sub> toxicity. After O<sub>2</sub> concentration drops below 17 percent, severe

physiological effects occur and less than six percent O<sub>2</sub>, loss of consciousness is rapid, and death takes place within minutes (Deel, 2006). The area in the vicinity of the leak should be cordoned off and personnel should not be allowed to enter this designated hazard zone until remedial action on the leak has been carried out.

#### CO<sub>2</sub> storage risk assessment

The risk assessment for CO<sub>2</sub> storage mainly focuses on the leakage of CO<sub>2</sub> after many years of storage in geologic formations. The biggest risks for leakage come from:

- a. Leakage through poor quality or aging injection well completions
- b. Leakage up abandoned wells
- c. Leakage due to inadequate cap rock characterization
- d. Leakage because of inconsistent or inadequate monitoring

Once CO<sub>2</sub> leakage occurs, the potential damage to the ocean environment and human health is identical to leakage in the transportation process.

The offshore oil and gas industry has developed the technology and expertise to take remedial actions in the event of leaked wells. We can thus, to a certain extent, lean on the offshore sector for this know-how. The technology for handling leaking wells is fairly advanced and the repairing of depleted or active wells is a very common practice in oil and gas industry. These techniques can therefore be adapted to handle damaged or leaking wells storing CO<sub>2</sub>. These techniques are explained in (Benson & Hepple, 2005) and (Melissa, 2010).

#### *5.12.3 Monitoring and verification for CCS*

After identification of potential risks, effective monitoring is essential to assure the safety and integrity of the entire CCS system. Instrumentation such as pressure gauges, temperature sensors etc. should be installed at appropriate locations along the CCS process chain. The fit-out of sensors is not a problem technically and the commercial instrumentation for monitoring is readily available.

During the capture and transportation stages, flows of super critical CO<sub>2</sub> would be measured as a normal part of operations. At the offshore oil and gas production sites, metering facilities have been used to measure oil and gas production. Very accurate flow meters are used in custody transfer of hydrocarbon products. Similar flow meters could be used to measure the amount of CO<sub>2</sub> injected into geological storage sites. Currently, a couple of methods are available to trace gas flow in underground reservoirs in the offshore oil and gas industry. These methods can be adapted to monitor trapped CO<sub>2</sub>. However the monitoring time spans and verification process lasts much longer in CCS projects than current engineering practice (we are talking about geological timescales in this instance). Therefore, actual field tests as well as further research and development in this area are still needed. It can be expected that the remaining technical difficulties with regards to sensors and instrumentation will eventually yield to R and D efforts.

As for the responsible body in charge of long term monitoring, the UK government, on behalf of society, should carry the liability for a project of this nature in the demonstration and early commercial stage. After more industry players become engaged in the later stages, a commercial entity may be nominated to bear the responsibility for monitoring and verification. Whether this will truly happen remains to be seen. Only time will tell. But for the time being, it is reasonable to assume that governments will be vested with the responsibility to monitor geological storage sites.

## 6 CONCLUSION AND RECOMMENDATIONS FOR FUTURE WORK

In the development of this concept design, several design philosophies were applied or considered. As far as practicable, the use of proven technology, as opposed to emerging technology, was specified. When considering transportation flow rates and injection rates, the use of Commercial Of The Shelf (COTS) equipment and machinery in the form of pumps and compressors were specified. The design team sought to develop an integrated solution which would seamlessly interface CO<sub>2</sub> capture, transportation and storage. Systems engineering principles were applied in the design. Risk was considered and a risk based design assessment was undertaken. Logistics supply chain principles were applied (Hub and Satellite technique). One of the design goals was to create a self-contained system that was robust and with system redundancy incorporated. The designers also took into account the possibility of having environmentally friendly operations with a small carbon footprint.

Very broadly, the plan was to inject CO<sub>2</sub> into aging or depleted oil and gas reservoirs using offshore wind energy to power the electric motor driven injection machinery (pumps). The design methodology can be summarized in five steps:

- a. Select geographical location for CCS project
- b. Identify sources and sinks
- c. Select a source and a sink
- d. Match source (point emitter) capture capacity with sink (reservoir) storage capacity
- e. Decide on a means to bridge the source and the sink i.e. transportation via pipeline or ship

Having gone through one iteration of the design process spiral, the design team has come to the conclusion that this scheme is technically feasible. However, the economics of CCS projects remain fraught with difficulties and the design team is of the opinion that the proposed concept design would almost certainly require government funding and incentives.

As to recommendations for future work, the design team strongly advocates that this concept design be taken forward into the preliminary, detailed and contract design phases. It is hoped that through this body of work produced, other teams of engineers can further develop on the groundwork laid and bring this concept design to commercialization and eventually to fruition.

The use of the Southern North Sea gas fields for CO<sub>2</sub> disposal is a sensible solution for UK. The concept design we have proposed is simple and elegant. The execution of the proposed concept is straightforward. Simplicity in design is always preferred over complexity. Over the course of this eight week collegium, we have come-up with a plan that is cost effective and gets the job done. Although many aspects of the concept design remain to be ironed out, the concept is sound. All that remains is the commitment, political will and financial clout to see the realization of this project.

A CCS project like the one expounded in this book would infuse UK's economy. It would lead to the creation of jobs and increased employment opportunities in the towns of Drax and Easington. It would bring industry and commerce to local suppliers of equipment and materials. Ultimately, the benefits that stand to be gained far outweigh the drawbacks. It is sincerely hoped that more engineers will pursue this noble cause to seek to further the art and science of CCS technology. The design team vows to tirelessly promote and promulgate this concept design so that more engineering teams will take up the mantle of enabling UK to be the pioneer in carbon capture and sequestration.



## BIBLIOGRAPHY

- 26th Seaward Licensing Round*. (n.d.). Retrieved from [https://itportal.decc.gov.uk/upstream/licensing/26\\_rnd/index.htm](https://itportal.decc.gov.uk/upstream/licensing/26_rnd/index.htm)
- Development of UK Oil and Gas Resources*. (2001). Retrieved from <http://www.dbd-data.co.uk/bb2001/book.htm>
- (2005). *"Transportation." Title 49 Code of Federal Regulations, Pt. 195.*
- (2009). *Carbon Sequestration Leadership Forum (CSLF).*
- (2009). *Strategic Analysis of the Global Status of Carbon Capture and Storage.*
- (2009). *Technology Roadmap Carbon capture and storage.* International Energy Agency.
- Announced carbon dioxide capture and storage projects*. (2011, August 9). Retrieved August 19, 2011, from Carbon capture & sequestration technologies @ MIT: [http://sequestration.mit.edu/tools/projects/index\\_projects\\_announced.html](http://sequestration.mit.edu/tools/projects/index_projects_announced.html)
- Greenhouse effect*. (2011, July 19). Retrieved August 22, 2011, from Wikipedia (the free encyclopedia): [http://en.wikipedia.org/wiki/Greenhouse\\_effect](http://en.wikipedia.org/wiki/Greenhouse_effect)
- North Sea*. (2011, August 14). Retrieved August 20, 2011, from Wikipedia (The free encyclopedia): [http://en.wikipedia.org/wiki/North\\_Sea](http://en.wikipedia.org/wiki/North_Sea)
- Petroleum Engineering*. (2011, May 25). Retrieved August 1, 2011, from <http://ilmumigas.blogspot.com/>
- Sulzerpumps*. (2011). Retrieved 8 19, 2011, from Sulzer: <http://www.sulzerpumps.com>
- Bachu, S., & Shaw, J. (2003). Evaluation of the CO<sub>2</sub> sequestration capacity in Alberta's oil and gas reservoirs at depletion and the effect of underlying aquifers. *Journal of Canadian Petroleum Technology*, 51-61.
- Bachu, S., & Shaw, J. (2003). Evaluation of the CO<sub>2</sub> Sequestration Capacity in Alberta's Oil and Gas Reservoirs at Depletion and the effect of Underlying Aquifers. *Energy Conservation and Management*, 42, 51-61.
- Benson, S., & Hepple, R. (2005). Detection and options for remediation of leakage from underground CO<sub>2</sub> storage projects. *Carbon Dioxide Capture for Storage in Deep Geologic Formations*, 2.
- Bentham, M. (2006). *An assessment of carbon sequestration potential in the UK– Southern North Sea case study*. Tyndall Centre for Climate Change Research Working Paper No. 85.
- Bentham, M. (2006). *An assessment of carbon sequestration potential in the UK? Southern North Sea case study*. Tyndall Centre Working Papers.
- Bernard, P. J. (2011). *Technological issues in carbon capture*. Newyork: Nova science publishers, Inc.
- Bock, B., Rhudy, R., & Herzog, H. (2003). *Economic Evaluation of CO<sub>2</sub> Storage and Sink Enhancement Options [Final Report to USDOE]*. Muscle Shoals, TN: TVA Public Power Institute.
- Botten, J. G., Morrison, P. F., & Solomon, K. A. (1983). *Risk-Cost Assessment Methodology for Toxic Pollutants from Fossil Fuel power Plants*. Electric Power Research Institute, Inc.
- Brook, M., Holloway, S., Shaw, K., & Vincent. (2003). *GESTCO case study 2a-1: storage potential of the Bunter Sandstone Formation in the UK sector of the southern North Sea and adjacent area of Eastern England*. British Geological Survey Commissioned Report CR/03/154.

- Brown, D. A. (2011). Comparative Ethical Issue entailed in the geological disposal of radioactive waste and carbon dioxide in the light of climate change. In *Geological Disposal of Carbon Dioxide and Radioactive Waste: A Comparative Assessment* (Vol. 44). Springer.
- Cameron, D. J., Crosby, A., Balson, P. S., Jeffery, D. H., Lott, G., Bulat, J., et al. (1992). United Kingdom offshore regional report: the geology of the southern North Sea. London: HMSO for the British Geological Survey.
- Carbon capture and sequestration*. (n.d.). (COSTAIN) Retrieved August 17, 2011, from <http://www.carbon-capture-and-storage.com/?gclid=CMqb0cernKoCFcNP4Qod4RhpXg>
- Carbon services*. (n.d.). (Schlumberger) Retrieved July 24, 2011, from [http://www.slb.com/services/additional/carbon.aspx?entry=ad\\_google\\_carbon&gclid=CO-Lg4aenKoCFYcKtAodgmD7xQ](http://www.slb.com/services/additional/carbon.aspx?entry=ad_google_carbon&gclid=CO-Lg4aenKoCFYcKtAodgmD7xQ)
- Christensen, N. P., & Holloway, S. (2004). *Geological Storage of CO<sub>2</sub> from Combustion of Fossil Fuel*. European Union Fifth Framework Programme for Research & Development Project.
- Coleman, D., Davison, J., Hendriks, C., Kaarstad, O., & Ozaki, M. (2005). *IPCC Special Report on Carbon dioxide Capture and Storage*. New York: Cambridge University Press.
- Deel, D. e. (2006). Risk Assessment and management for long-term storage of CO<sub>2</sub> in geologic formations. *Journal of Systemics, Cybernetics and Informatics*, 5.
- Ducroux, R., & Bowers, J. M. (2005). *Acceptance of CCS under International Conventions and agreements*. IEA GHG Weyburn CO<sub>2</sub> Monitoring and Storage Project Summary Report 2000-2004.
- Elementenergy. (2010). *One North Sea; A study into North sea cross-border CO<sub>2</sub> transport and storage*.
- EPA. (2010). *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990 – 2008*. Washington, DC: U.S. Environmental Protection Agency.
- Eydeland, A., & Wolyniec, K. (2003). *Energy and power risk management: new developments in modeling, pricing and hedging*. John Wiley and Sons, Inc.
- Gale, J., Dixon, T., Beck, B., & Haines, M. (2009). What have we learnt to date from large CCS projects? *International Scientific Congress on Climate Change: Global Risks, Challenges and Decisions*. Copenhagen, Denmark.
- Global Offshore Wind Farms Database*. (n.d.). Retrieved 8 20, 2011, from Global Offshore Wind Farms Database: <http://www.4coffshore.com/>
- Goldberg, P., Chen, Z. Y., Connor, W. O., Walters, R., & Ziock, H. (1998). *CO<sub>2</sub> Mineral Sequestration Studies in US*. National Energy Technology Laboratory.
- Gough, C., & Shackley, S. (2005). *An Integrated Assessment of Carbon Dioxide Capture and Storage in the UK*. Tyndall Center for Climate Change Research.
- Gough, C., & Shackley, S. (2005). *An Integrated Assessment of Carbon Dioxide Capture and Storage in the UK*. Tyndall Center for Climate Change Research.
- Hansen, J., Ruedy, R., Sato, M., & Lo, K. (2010). Global surface temperature change. *Reviews of Geophysics*, Vol. 48, 29.
- Heddle, G., Herzog, H., & Klett, M. (2003). *The Economics of CO<sub>2</sub> Storage*. Massachusetts Institute of Technology, Laboratory for Energy and the Environment, MIT LEE 2003-003 RP, Cambridge.

- Hieb, M. (2007, Mar 2). *Global Warming*. Retrieved from A closer look at numbers: [http://www.geocraft.com/WVFossils/greenhouse\\_data.html](http://www.geocraft.com/WVFossils/greenhouse_data.html)
- Hrvoje, G., Steve, C., Simon, B., Steve, T., & Frederic, G. (2009). CO<sub>2</sub> injection into depleted gas reservoirs. *Society of Petroleum Engineering*.
- IEA. (2010). *CO<sub>2</sub> Emissions from fuel combustion*. IEA.
- IEA GHG. (2005). *Building the cost curves for CO<sub>2</sub> storage: European sector. Report Number 2005/02*. International Energy Agency Greenhouse Gas R&D Programme.
- IPCC. (2005). *Carbon Dioxide and storage*. Cambridge University Press.
- Joana, S., Joris, M., & Evangelos, T. (2011). *Technical and Economic Characteristics of a CO<sub>2</sub> Transmission Pipeline Infrastructure*. JRC Scientific and Technical Reports, European Commission, Joint Research Centre, Institute for Energy.
- Judith, I. M., deGroot, & Linda, S. (2011). Psychological Perspectives on the Geological Disposal of Radioactive Waste and Carbon Dioxide. In *Comparing the Geological Disposal of Carbon Dioxide and Radioactive Waste; - A comparative Assessment* (Vol. 44). London, UK: Springer.
- Khan, I. (2006). *CO<sub>2</sub> storage technologies overview; Engineering Report*. RWE Power International, Swindon.
- King, G. G. (1981, Nov). design Considerations for Carbondioxide Pipelines. *Pipe Line Industry*.
- Kurian, V. J., & Ganapathy, C. (2009). Decommissioning of offshore platforms. *Construction Industry Research Achievement International Conference*.
- Lathrop, S. D., Gates, C. L., Massie, D. D., & D., J. M. (2006). *Risk assessment of a power plant: evaluating the security of a supervisory control and data acquisition system*. ASHRAE Transactions.
- LiveScience. (2009, March 09). Rocks Found That Could Store Greenhouse Gas.
- London Array. (n.d.). Retrieved 8 20, 2011, from London Array: <http://www.londonarray.com/>
- Manual, N. (2007). *Engineering & piping design guide, Manual No. E5000*. National Oilwell Varco Company, San Antonio, Texas.
- McCoy, S. T. (2008). *The Economics of CO<sub>2</sub> Transport by Pipeline and Storage in Saline Aquifers and Oil Reservoirs, PhD Thesis*. Carnegie Mellon University, Pittsburgh, PA.
- McKinsey & Company. (2008). *Carbon capture and storage; Assessing the Economics*.
- Melin, M. (2011). *Feasibility of Danish CCS Scheme Comprised of Capture at Power Plants, Ship Transport and CO<sub>2</sub> EOR*. Copenhagen: Llyod's Register.
- Melissa, A. M. (2010). *Remediation of possible leakage from geologic CO<sub>2</sub> storage reservoirs into groundwater aquifers*. Stanford university, Department of energy resources engineering.
- Morbee, J., Correia Serpa dos Santos, J., & Tzimas, E. (2010). *The Evolution of the Extent and the Investment Requirements of a Trans-European CO<sub>2</sub> Transport Network. EUR24565 EN*. Publications Office of the European Union.
- Peak Oil News. (n.d.). Retrieved August 12, 2011, from Deep oil drilling: <http://www.peak-oil-news.info/deep-oil-drilling/>
- Reiner, D. M., & Nuttall, W. J. (2011). Public Acceptance of Geological Disposal of Carbon Dioxide and Radioactive Waste: Similarities and Differences . In *Geological Disposal of Carbon Dioxide and Radioactive Waste: A Comparative Assessment* (Vol. 44). London: Springer.

- Rubin, E., Meyer, L., & de Coninck, H. (2005). *IPCC Special Report Carbon Dioxide Capture and Storage - Technical Summary*.
- Sean, T. M., & Edward, S. R. (2005). Models of CO<sub>2</sub> Transport and Storage Costs and Their Importance in CCS Cost Estimates. *Fourth Annual Conference on Carbon Capture And Sequestration Doe/Netl*.
- Seevam, P. (2009). *Transporting the Next Generation of CO<sub>2</sub> for Carbon, Capture and Storage : The Impact of Impurities on Supercritical CO<sub>2</sub>*. Newcastle: GERG Academic Network Event.
- Seevam, P. N., Race, J. M., & Downie, M. J. (2007). Carbon dioxide pipelines for sequestration in the UK: an engineering gap analysis. *Journal of Pipeline Engineering*, 133-146.
- SINTEF. (1987). *Reliability Evaluation of SubSea Pipelines*. Norway: SINTEF Report.
- Svensson, R., Odenberger, M., Johnsson, F., & Stromberg, L. (n.d.). Transportation Infrastructure for CCS - Experiences and expected development. *Department of energy conversion, Chalmers University of Technology*.
- Tans, P., & Keeling, R. (n.d.). *NOAA/ESRL* . Retrieved from [http://www.esrl.noaa.gov/gmd/ccgg/trends/#mlo\\_full](http://www.esrl.noaa.gov/gmd/ccgg/trends/#mlo_full)
- Van der Meer, L. (1995). The CO<sub>2</sub> storage efficiency of aquifers. *Energy Conversion and Management*, 36(6-9), 513-518.
- Van der Meer, L. (1996). Computer modeling of underground CO<sub>2</sub> storage. *Energy Conversion and management*, 37(6), 1150-1160.
- Vermeulen, T. N. (2009). *Potential for CO<sub>2</sub> storage in depleted fields on the Dutch Continental shelf - Cost estimate for offshore facilities*. Tebodin Netherlands B.V.
- Wall, C., Bernstone, C., Olvstam, M.-L., SwedPower AB, & Utveckling AB, V. (2004). International and European Legal Aspects on Underground Geological Storage of CO<sub>2</sub>. *Proc. 7th International Conference on Greenhouse Gas Control Technologies*. Cheltenham, U.K.
- Wallace, C. B. (1985, June 24). Drying supercritical CO<sub>2</sub> demands care. *Oil and Gas Journal*.
- Willcocks, J., & Bai, Y. (2000). Risk based inspection and integrity management of pipeline systems. *International Society of Offshore and PolarEngineers*, 285-294.

## APPENDIX A – FLOW RATES AND STORAGE CAPACITY CALCULATIONS

### A1 CO<sub>2</sub> emission rate for Drax power plant

Consider:

“A ‘typical’ 800MW coal plant emits in the order of three to four million tonnes of CO<sub>2</sub> **per year**”

Now suppose:

“A ‘typical’ 500MW coal plant emits 10000 tonnes of CO<sub>2</sub> per day”

$$4 \times 10^6 \text{ tonnes per year for 800MW coal plant}$$

$$\frac{4 \times 10^6}{350} \text{ tonnes per day for 800MW coal plant (assuming two weeks down time per year)}$$

$$\frac{4 \times 10^6}{350 \times 800} \text{ tonnes per day per MW (availability 350 days)}$$

$$14 \text{ tonnes per day per MW}$$

$$1 \times 10^4 \text{ tonnes per day for 500MW coal plant}$$

$$\frac{1 \times 10^4}{500} \text{ tonnes per day per MW}$$

$$20 \text{ tonnes per day per MW}$$

Engineering Judgement: the numerical values are comparable and we can believe these values to be reasonable.

A ‘typical’ 500MW coal plant emits approximately 10000 tonnes of CO<sub>2</sub> per day.

Extrapolating linearly, the Drax power plant (4000MW) would emit approximately:

$$\begin{aligned} \frac{4000}{500} \times 10000 \text{ tonnes of CO}_2 \text{ **emission** per day} \\ = 80000 \text{ tonnes of CO}_2 \text{ **emission** per day} \end{aligned}$$

Of this 80000 tonnes of CO<sub>2</sub> emitted per day, assume only 30% captured.

$$80000 \times 0.3 = 24000 \text{ tonnes of CO}_2 \text{ **capture** per day} \quad (\text{supply})$$

Consider  $10 \times 10^6$  tonnes of CO<sub>2</sub> **injection and storage** per year

This translates to  $\approx 27000$  tonnes CO<sub>2</sub> **injection and storage** per day (demand)

$$\therefore \text{demand for injection} > \text{supply from captured source}$$

Let captured supply = injection capability demand (equilibrium)

Let demand for injection = 24000 tonnes per day with +3000 tonnes margin (+10% overload)

Ideal if all CO<sub>2</sub> captured and supplied via pipeline can be injected so as to minimize the need for pressure vessel storage at offshore injection location (supply chain logistics becomes important).

Consider  $10 \times 10^6$  tonnes CO<sub>2</sub> **injection and storage** per year

Assuming annual availability of 350 days i.e. 2 weeks downtime per year

$$\frac{10 \times 10^6}{350} \text{ tonnes } CO_2 \text{ injection and storage per day}$$

$$\frac{10 \times 10^6}{350 \times 24} \text{ tonnes } CO_2 \text{ injection and storage per hour}$$

$$1190 \text{ tonnes } CO_2 \text{ injection and storage per hour}$$

1 metric tonne = 1000 kg

$$1190000 \text{ kg } CO_2 \text{ injection and storage per hour}$$

$$\therefore CO_2 \text{ injection rate} \approx 1200 \text{ tonnes/hr}$$

Consider a typical fire monitor onboard a Fi-Fi OSV or Tug:

$$\text{Typical volumetric flow rates} = 1200 \text{ m}^3/\text{hr}, 2400 \text{ m}^3/\text{hr}, 3600 \text{ m}^3/\text{hr}$$

$$\rho_{\text{seawater}} = 1.025 \text{ tonnes/m}^3$$

$$\text{Typical mass flow rates} = 1230 \text{ tonnes/hr}, 2460 \text{ tonnes/hr}, 3690 \text{ tonnes/hr}$$

Engineering Judgement:

Injection of CO<sub>2</sub> can be effected by readily available Commercial-Off-The-Shelf (COTS) marine equipment and machinery.

There are cryogenic pumps and electric motors available to achieve target injection rates.

CO<sub>2</sub> injection can be carried out using currently available technologies without resorting to emerging technologies.

$$\text{Consider liquid } CO_2, \rho_{CO_2} = 0.770 \text{ gcm}^{-3} \quad @ 20^\circ\text{C} \quad \text{and} \quad 56 \text{ atm} = 770 \text{ kgm}^{-3}$$

$$\text{Consider gaseous } CO_2, \rho_{CO_2} = 1.977 \text{ gm}^{-3} \quad @ 0^\circ\text{C} \quad \text{and} \quad 1 \text{ atm} = 1.977 \text{ kgm}^{-3}$$

$$1 \text{ atm} = 1.01325 \times 10^5 \text{ Pa}$$

$$\text{For mass injection rate of } 1200 \text{ tonnes/hr} \rightarrow 333 \text{ kg/s}$$

Footnote: 1 car  $\approx$  2 tonnes.  $\therefore$  1200 tonnes/hr is like loading 600 cars!

$$300 \text{ kg is about the mass of five persons!}$$

Consider favourable scenario, injection and storage in liquid phase:

Occupies relatively small volume for a given mass

Storage space gradually used up

Consider worst case scenario, injection and storage in gaseous state:

Occupies relatively large volume for a given mass

Storage space rapidly used up

$$\text{For } \rho_{CO_2} = 770 \text{ kgm}^{-3}, \text{volumetric flow rate} = 0.43 \text{ m}^3/\text{s}$$

(achievable with commercially available electrical motor driven pump)

$$\text{For } \rho_{CO_2} = 1.977 \text{ kgm}^{-3}, \text{volumetric flow rate} = 168 \text{ m}^3/\text{s}$$

(technically challenging for an electrically driven compressor)



Implication: We must inject in the liquid (supercritical) phase.

As a comparison, a typical large engine room pump may have a rating of say

$3600 \text{ m}^3/\text{hr}$  which translates to  $1 \text{ m}^3/\text{s}$  throughput.

*Consider a demo, small scale project with  $1 \times 10^6$  tonnes per year storage.*

*Consider a pilot, full scale project with  $10 \times 10^6$  tonnes per year storage.*

*Assuming a storage capacity of  $1 \times 10^9$  tonnes,*

$$\text{For small scale project, time to fill to capacity} = \frac{1 \times 10^9 \text{ tonnes}}{1 \times 10^6 \text{ tonnes/yr}} = 1000 \text{ years}$$

$$\text{For full scale project, time to fill to capacity} = \frac{1 \times 10^9 \text{ tonnes}}{1 \times 10^7 \text{ tonnes/yr}} = 100 \text{ years}$$

Theoretical estimates of CO<sub>2</sub> disposal capacity in the UK are explained in Table A. 1.

Table A. 1 - Theoretical estimates of CO<sub>2</sub> storage capacity in the UK

Type of geological formation	Potential CO <sub>2</sub> capacity (Giga tonnes)
Gas fields	5.982
Oil fields	4.225
Saline aquifers	14.446

$$\sum \text{gas fields} + \text{oil fields} + \text{saline aquifers} \approx 24 \text{ Giga tonnes}$$

*24 Giga tonnes*

*≡ approx. 180 years worth of CO<sub>2</sub> emissions from ALL power stations in UK!*

Considering only oil and gas fields, excluding saline aquifers:

$$\frac{10}{24} \times 180 = 75 \text{ years}$$

Let the storage capacity from the UK's oil and gas fields be 70 years.

Let the UK's fields be divided equally into two regions:

Southern North Sea gas basin                      and

Northern North Sea gas basin

Considering only Southern North Sea gas basin fields:

$$\frac{1}{2} \times 70 = 35 \text{ years}$$

Implication:

Even if we **consider only Southern North Sea gas basin fields**, research findings suggest that there would be sufficient storage capacity for **ALL** of the UK's power plant emissions for 35 years!

*∴ For half of the UK's power plants, expect sufficient storage capacity for 70 years*

*∴ For a third of the UK's power plants, expect sufficient storage capacity for 105 years*

Engineering judgement/decision making:

Feasibility studies indicate that CO<sub>2</sub> storage in the Southern North Sea gas basin represents a viable proposition.

Consider CO<sub>2</sub> injection in the supercritical phase (essentially liquid phase).

$$\rho_{co_2} = 770 \text{ kgm}^{-3}$$

Mass flow rate,  $\dot{m} = \rho A v = 1200 \text{ tonnes/hr} = 333 \text{ kg/s}$

Consider a 273 mm (10" nominal) pipe CO<sub>2</sub> conduit

$$\text{Cross sectional area} = \frac{\pi d^2}{4} \text{ m}^2$$

Flow velocity,  $v = \frac{\dot{m}}{\rho A} = 7.4 \text{ ms}^{-1}$  (reasonable)

Consider CO<sub>2</sub> transportation in the gaseous phase.

$$\rho_{co_2} = 1.977 \text{ kgm}^{-3}$$

Mass flow rate,  $\dot{m} = \rho A v = 1200 \text{ tonnes/hr} = 333 \text{ kg/s}$

Consider a 1000 mm (nominal) pipe CO<sub>2</sub> conduit

$$\text{Cross sectional area} = \frac{\pi d^2}{4} \text{ m}^2$$

Flow velocity,  $v = \frac{\dot{m}}{\rho A} = 214 \text{ ms}^{-1}$  (63% the speed of sound) (Not tenable)

## APPENDIX B – A BRIEF TREATISE ON PIPE HEAD LOSSES

Total Head loss in pipe systems = Major and Minor losses

where

*Major Head loss = pressure loss due to friction in pipes*

*Minor Head loss = pressure loss due to components such as valves, bends, tees, etc*

The total head loss of a pipe can be expressed as

$$h_{loss} = \Sigma h_{major\_losses} + \Sigma h_{minor\_losses} \quad (B-1)$$

where

$$h_{loss} = \text{total head loss in the pipe system}$$

$$h_{major\_losses} = \text{major loss due to friction in the pipe system}$$

$$h_{minor\_losses} = \text{minor loss due to components in the pipe system}$$

The major head loss of a pipe system can be expressed as

$$h_{major\_loss} = \lambda (l / d_h) (v^2 / 2 g) \quad (B-2)$$

where

$$h_{loss} = \text{head loss (m)}$$

$$\lambda = \text{friction coefficient}$$

$$l = \text{length of pipe (m)}$$

$$d_h = \text{hydraulic diameter (m)}$$

$$v = \text{flow velocity (m/s)}$$

$$g = \text{acceleration due to gravity (m/s}^2\text{)}$$

The minor head loss of a pipe system can be expressed as

$$h_{minor\_loss} = \xi v^2 / 2 g \quad (B-3)$$

where

$$\xi = \text{minor loss coefficient}$$

The sum of minor losses in a pipe can be expressed as

$$\Sigma h_{minor\_losses} = \Sigma \xi (v^2 / 2 g) \quad (B-4)$$

The total head loss for a single pipe can be calculated by using equations (B-1) and (B-4).

$$h_{loss\_single} = \lambda (l / d_h) (v^2 / 2 g) + \Sigma \xi v^2 / 2 g \quad (B-5)$$

or

$$h_{loss\_single} = (\lambda (l / d_h) + \Sigma \xi) (v^2 / 2 g)$$

For pipes in series, the pressure loss is the sum of the individual losses and the mass flow rate is the same in all pipes.

$$p = p1 + p2 + ... + pn \quad (B-6)$$

$$m = m1 = m2 = .... = mn \quad (B-7)$$

where

$p$  = total pressure loss ( $Pa$ )

$p1..n$  = individual pressure loss ( $Pa$ )

$m$  = mass flow ( $kg/s$ )

For pipes in parallel, the pressure loss is the same in all pipes and the total mass flow is the sum of the flow in each pipe.

$$p = p1 = p2 = .... = pn \quad (B-8)$$

$$m = m1 + m2 + .. + mn \quad (B-9)$$

Footnote: Recall the D'Arcy-Weisbach equation from Fluid Mechanics.

Implication: Booster pumps/compressors will be required at interval distances along the pipeline to offset pipe losses and maintain flow.

## APPENDIX C – DECISION MATRICES

Table C. 1 - Conversion of an existing offshore oil platform to store CO<sub>2</sub>

	Researcher 1	Researcher 2	Researcher 3	Researcher 4	Researcher 5
Technical feasibility	5	3	4	5	4
Environmental friendliness	3	2	3	2	3
Economic viability	3	2	4	4	4
Expected public acceptance	4	3	3	3	3
Political support and governmental funding	2	4	2	3	3
Legal visibility	4	3	4	2	4
Safety	2	3	4	1	3
<b>Sum</b>	23	20	24	20	24

Table C. 2 - Modification of existing oil and gas pipelines to transport CO<sub>2</sub>

	Researcher 1	Researcher 2	Researcher 3	Researcher 4	Researcher 5
Technical feasibility	4	3	3	1	1
Environmental friendliness	4	3	3	3	3
Economic viability	4	2	4	2	2
Expected public acceptance	4	2	4	3	4
Political support and governmental funding	1	3	5	3	1
Legal visibility	2	3	3	1	3
Safety	3	4	3	1	4
<b>Sum</b>	22	20	25	14	18

Table C. 3 - Controlled algae blooms in ocean space consuming vast amounts of CO<sub>2</sub>

	Researcher 1	Researcher 2	Researcher 3	Researcher 4	Researcher 5
Technical feasibility	3	4	2	4	2
Environmental friendliness	2	4	3	2	2
Economic viability	2	3	2	1	3
Expected public acceptance	3	2	2	3	2
Political support and governmental funding	3	3	3	2	2
Legal visibility	3	2	2	1	1
Safety	4	4	2	2	2
<b>Sum</b>	20	22	16	15	14

Table C. 4 - CO<sub>2</sub> storage and injection platform wholly powered by marine renewable energy

	Researcher 1	Researcher 2	Researcher 3	Researcher 4	Researcher 5
Technical feasibility	3	3	3	2	3
Environmental friendliness	5	5	5	3	4
Economic viability	3	3	3	2	3
Expected public acceptance	4	5	3	4	4
Political support and governmental funding	4	5	4	3	4
Legal visibility	4	3	4	2	3
Safety	3	3	4	4	4
<b>Sum</b>	26	27	26	20	25

Table C. 5 - Using CO<sub>2</sub> as a raw material to produce methanol powered by renewable energy

	Researcher 1	Researcher 2	Researcher 3	Researcher 4	Researcher 5
Technical feasibility	1	4	2	2	1
Environmental friendliness	4	4	3	2	3
Economic viability	2	3	2	1	3
Expected public acceptance	1	4	3	3	3
Political support and governmental funding	2	4	3	2	4
Legal visibility	4	3	3	4	3
Safety	4	3	2	2	3
<b>Sum</b>	18	25	18	16	20

Table C. 6 - Design of an artificial island for carbon storage and utilization

	Researcher 1	Researcher 2	Researcher 3	Researcher 4	Researcher 5
Technical feasibility	1	3	3	3	3
Environmental friendliness	4	4	4	5	4
Economic viability	1	3	3	4	2
Expected public acceptance	4	4	4	3	4
Political support and governmental funding	3	3	3	4	4
Legal visibility	5	3	4	3	3
Safety	3	3	4	3	3
<b>Sum</b>	21	23	25	25	23



Table C. 7 - Concept determination

	Researcher 1	Researcher 2	Researcher 3	Researcher 4	Researcher 5	Sum	Average
Concept 1	23	20	24	20	24	111	22.2
Concept 2	22	20	25	14	18	99	19.8
Concept 3	20	22	16	15	14	87	17.4
Concept 4	26	27	26	20	25	124	24.8
Concept 5	18	25	18	16	20	97	19.4
Concept 6	21	23	25	25	23	117	23.4

Table C. 8 - Average scoring of each concept

	Concept 1	Concept 2	Concept 3	Concept 4	Concept 5	Concept 6
Technical feasibility	4.20	2.40	3.00	2.80	2.00	2.60
Environmental friendliness	2.60	3.20	2.60	4.40	3.20	4.20
Economic viability	3.40	2.80	2.20	2.80	2.20	2.60
Expected public acceptance	3.20	3.40	2.40	4.00	2.80	3.80
Political support and governmental funding	2.80	2.60	2.60	4.00	3.00	3.40
Legal visibility	3.40	2.40	1.80	3.20	3.40	3.60
Safety	2.60	3.00	2.80	3.60	2.80	3.20

Table C. 9 - Application of each performance factor on concept evaluation

	Best	Worst
Technical feasibility	Concept 1	Concept 5
Environmental friendliness	Concept 4	Concept 1, 3
Economic viability	Concept 1	Concept 3, 5
Expected public acceptance	Concept 4	Concept 3
Political support and governmental funding	Concept 4	Concept 2, 3
Legal visibility	Concept 6	Concept 3
Safety	Concept 4	Concept 1

**APPENDIX D – STORAGE CAPACITIES IN THE SOUTHERN NORTH SEA**

(Brook, Holloway, Shaw, &amp; Vincent, 2003)

Field Name	Grid Position	Status	Storage Capacity (MT)
Leman	2° 18' E 53° 13' N	Producing	869.55
Indefatigable and Indefatigable SW	2° 33' E 53° 20' N	Producing	221.55
Viking	2° 16' E 53° 32' N	Producing	214.49
West Sole	1° 06' E 53° 44' N	Producing	135.83
Galleon	1° 50' E 53° 30' N	Producing	128.66
Hewett	1° 46' E 53° 01' N	Producing	108.24
Indefatigable	2° 37' E 53° 21' N	Producing	110.69
Barque and Barque S	1° 36' E 53° 36' N	Producing	88.69
Victor	2° 21' E 53° 20' N	Producing	73.47
Ravenspurn N.	0° 54' E 54° 06' N	Producing	59.52
Vulcan	1° 58' E 53° 15' N	Producing	53.15
Audrey	2° 00' E 53° 33' N	Producing	49.49
Clipper N	1° 44' E 53° 25' N	Producing	46.10
Amethyst E and W	0° 42' E 53° 30' N	Producing	45.97
Sean N. and S.	2° 50' E 53° 13' N	Producing	44.33
Schooner	2° 05' E 54° 04' N	Producing	40.93
Pickerill Permian	1° 06' E 53° 32' N	Producing	38.72
Ravenspurn S.	1° 00' E 54° 02' N	Producing	36.57
Thames, Yare, Bure and Wensum	2° 32' E 53° 05' N	Producing	30.85
Murdoch	2° 18' E 54° 15' N	Producing	16.60
Rough	0° 27' E 53° 50' N	Producing	22.62
Skiff	2° 52' E 53° 25' N	Producing	21.47
Neptune	0° 47' E 53° 59' N	Producing	20.95
Ganymede	2° 14' E 53° 19' N	Producing	20.92
Welland	2° 41' E 53° 00' N	Producing	20.00
Excalibur	1° 21' E 53° 27' N	Producing	19.35
Cleeton		Depleted	16.28
Anglia	1° 36' E 53° 22' N	Producing	18.04
Lancelot	1° 20' E 53° 24' N	Producing	17.33
Markham	2° 52' E 53° 50' N	Producing	17.16
Camelot N, CandS	2° 09' E 52° 57' N	Producing	12.23
Gawain	2° 43' E 53° 10' N	Producing	16.37
Johnstone	1° 14' E 54° 12' N	Producing	16.03

Corvette	2° 38' E 53° 14' N	Producing	15.48
Boulton	2° 08' E 54° 14' N	Producing	9.70
Valliant S.	2° 05' E 53° 19' N	Producing	12.43
Bell	2° 25' E 53° 16' N	Producing	11.24
Galahad	1° 23' E 53° 32' N	Producing	11.24
Esmond		Depleted	9.39
Vixen	2° 14' E 53° 24' N	Producing	10.80
Sean E	2° 52' E 53° 14' N	Producing	6.57
Orwell	3° 02' E 53° 08' N	Producing	8.65
Trent	1° 42' E 54° 17' N	Producing	8.03
Valiant N.	2° 01' E 53° 22' N	Producing	7.90
Bessemer	2° 28' E 53° 12' N	Producing	7.80
Europa	2° 17' E 53° 13' N	Producing	7.58
Hyde	1° 00' E 53° 50' N	Producing	7.11
Baird	2° 31' E 53° 06' N	Producing	6.64
Ann		Producing	6.56
Guinevere	1° 16' E 53° 05' N	Producing	6.53
Vanguard	2° 06' E 53° 23' N	Producing	4.96
Gordon		Depleted	4.07
Forbes		Depleted	1.74
		Total	2816.57

**APPENDIX E – WIND FARMS IN THE UK SECTOR OF THE NORTH SEA**

(Global Offshore Wind Farms Database)

Field	Capacity (MW)	Operation
Argyll Array	1,800	Concept/Early planning
Atlantic Array	1,500	Concept/Early planning
Barrow	90	Fully Commissioned
Beatrice	920	Concept/Early planning
Beatrice Demonstration	10	Fully Commissioned
Blyth	4	Fully Commissioned
Britannia	10	Concept/Early planning
Burbo Bank	90	Fully Commissioned
Docking Shoal	540	Concept Application Submitted
Dogger Bank	6,000	Concept/Early planning
Dogger Bank Project One	1,400	Concept/Early planning
Dogger Bank Tranche A	1,600	Concept/Early planning
Dudgeon	560	Concept Application Submitted
East Anglia One	1,200	Concept/Early planning
East Anglia Two	1,200	Concept/Early planning
East Anglia Three	1,200	Concept/Early planning
East Anglia Four	1,200	Concept/Early planning
East Anglia Five	1,200	Concept/Early planning
East Anglia Six	1,200	Concept/Early planning
European Offshore Wind Development Centre - EOWDC	115	Concept Application Submitted
Firth of Forth Phase 1	1,075	Concept/Early planning
Firth of Forth Phase 2	1,820	Concept/Early planning
Firth of Forth Phase 3	790	Concept/Early planning
Galloper Wind Farm	504	Concept/Early planning
Greater Gabbard	504	Partial Generation/Under Construction
Gunfleet Sands I + II	173	Fully Commissioned
Gunfleet Sands III	20	Concept/Early planning
Gwynt y Mor	576	Consent Authorized

Hornsea	2,800	Concept/Early planning
Hornsea Project One Block 1	600	Concept/Early planning
Hornsea Project One Block 2	600	Concept/Early planning
Humber Gateway	230	Consent Authorized
Inch Cape	905	Concept/Early planning
Inner Dowsing	97	Fully Commissioned
Irish Sea	4,200	Concept/Early planning
Islay	690	Concept/Early planning
Kentish Flats	90	Fully Commissioned
Kentish Flats Extension	51	Concept/Early planning
Lincs	270	Under Construction
London Array Phase 1	630	Under Construction
London Array Phase 2	370	Concept Application Submitted
Lynn	97	Fully Commissioned
Methil	6	Concept Application Submitted
Moray Firth Eastern Development Area Edward MacColl	380	Concept/Early planning
Moray Firth Eastern Development Area Robert Stevenson	380	Concept/Early planning
Moray Firth Eastern Development Area Thomas Telford	380	Concept/Early planning
NaREC	100	Concept/Early planning
Navitus Bay Wind Park	1,200	Concept/Early planning
Neart na Gaoithe	420	Concept/Early planning
North Hoyle	60	Fully Commissioned
NOVA Project Demonstrator	10	Concept/Early planning
NOVA Project	1,000	Concept/Early planning
Ormonde	150	Under Construction
Race Bank	620	Concept Application Submitted
Rampion	665	Concept/Early planning
Rhyl Flats	90	Fully Commissioned

Robin Rigg	180	Fully Commissioned
Scroby Sands	60	Fully Commissioned
Sheringham Shoal	317	Partial Generation/Under Construction
Sloway Firth	300	Concept/Early planning
Teesside	62	Consent Authorized
Thanet	300	Fully Commissioned
Triton Knoll	1,200	Concept/Early planning
Walney Phase 1	184	Fully Commissioned
Walney Phase 2	184	Under Construction
Walney Extension	750	Concept/Early planning
West of Duddon Sands	389	Consent Authorized
Westernmost Rough	240	Concept Application Submitted
Wigtown Bay	280	Concept/Early planning



## INDEX

**A**

agriculture, 1, 14  
 Amine, 9  
 ammonia, 15, 18  
 assessment, 15, 16, 39, 86, 87, 88, 89  
 atmosphere, 1, 2, 5, 13, 14, 15, 19, 23, 24, 32, 55, 87  
 atmospheric pressure, 8

**B**

biomass, 14, 15, 24, 32  
 burning, 1, 2, 6, 13, 20, 32  
 butane, 11

**C**

C<sub>2</sub>, 10  
 calcium carbonate, 15  
 Canada, 9, 17  
 capture, 2, 4, 5, 6, 7, 8, 10, 12, 14, 15, 16, 23, 25, 32, 33, 34, 37, 46, 56, 63, 75, 81, 82, 83, 86, 88, 89  
 carbon, iii, 2, 3, 5, 6, 7, 12, 13, 15, 16, 19, 20, 21, 23, 24, 25, 27, 32, 33, 34, 37, 53, 55, 57, 68, 71, 72, 75, 82, 83, 89, 101  
 carbon dioxide, iii, 2, 3, 5, 12, 13, 16, 20, 23, 24, 25, 32, 34, 68, 71, 72, 83  
 CCS, iii, 5, 7, 8, 9, 12, 14, 18, 19, 20, 21, 22, 26, 31, 32, 33, 36, 37, 39, 46, 56, 75, 81, 82, 83, 84, 86, 89  
 cement, 14, 15  
 century, 2  
 CH<sub>4</sub>, 2, 10  
 chemical reactions, 26  
 climate change, 2, 20, 21, 53  
 cloud, 2  
 CO<sub>2</sub> carriers, 11, 12, 23, 41, 42  
 coal, 1, 2, 3, 5, 6, 7, 13, 14, 32, 33, 50, 60, 73, 74, 75, 81, 82, 94  
 combustion, 3, 5, 6, 7, 14, 15, 72, 82, 86  
 Commercial, 5, 71, 89, 95  
 component, 5, 7, 14, 82  
 composition, 10  
 concentration, 2, 3, 5, 87  
 condensation, 6  
 configuration, 7, 72, 82  
 contaminant, 5  
 contaminated, 10  
 continental shelf, 14  
 corrosion, 23, 24, 25, 82, 87  
 Corrosion, 10

cost, 5, 7, 8, 13, 14, 15, 19, 20, 23, 34, 39, 48, 53, 57, 59, 67, 75, 76, 81, 82, 83

**D**

decades, 5, 74  
 deforestation, 2  
 demonstration, 7, 8, 20, 82, 88  
 depleted, 8, 24, 25, 33, 34, 39, 40, 41, 72, 75, 80, 81, 89  
 design, iii, 7, 10, 12, 23, 24, 31, 34, 36, 37, 38, 39, 45, 46, 55, 56, 59, 60, 61, 66, 67, 72, 75, 76, 79, 81, 82, 83, 86, 89  
 developments, 2, 75  
 dry ice, 8, 23

**E**

earth, 1, 80  
 economic, 2, 5, 14, 18, 19, 22, 28, 30, 66, 75, 84  
 Efficiency, 6  
 electricity, 7, 21, 32, 48, 50, 51, 53, 54, 55, 76, 80, 81  
 emission, 2, 3, 6, 18, 19, 20, 56, 63, 94  
 emissions, 2, 5, 6, 7, 13, 15, 18, 19, 23, 25, 33, 34, 47, 50, 53, 75, 82, 96  
 energy, iii, 1, 5, 6, 7, 14, 15, 18, 19, 20, 23, 25, 27, 30, 32, 46, 47, 48, 50, 53, 55, 57, 71, 72, 74, 76, 81, 89  
 enhanced oil recovery, 8  
 environment, iii, 2, 24, 36, 51, 65, 84, 87, 88  
 Environmental Protection Agency, 3  
 EOR, 8  
 equipment, 6, 25, 41, 42, 46, 47, 54, 55, 56, 66, 68, 69, 71, 72, 76, 79, 81, 82, 89, 95  
 established, 8, 20, 50, 81  
 exhaust, 5, 6  
 existing, 5, 6, 7, 9, 11, 13, 20, 23, 27, 39, 40, 41, 56, 57, 58, 59, 60, 63, 66, 67, 68, 75, 80, 82, 100  
 expensive, 7, 12, 14, 81, 82  
 experience, 6, 19, 20, 22, 33, 86

**F**

flue gas, 5  
 food-grade CO<sub>2</sub>, 11  
 fossil, iii, 1, 2, 3, 5, 7, 18, 20, 21, 24, 47, 50, 74  
 Fossil fuel, 2, 19  
 fossil fuels. *See* fossil  
 fuels, iii, 1, 2, 3, 5, 18, 20, 21, 24, 47, 50, 74  
 future, 2, 5, 6, 18, 19, 21, 22, 32, 53, 60, 61, 80, 85, 89

**G**

gas, iii, 2, 3, 5, 8, 13, 15, 16, 17, 20, 23, 27, 33, 34, 35, 37, 38, 39, 40, 41, 50, 56, 57, 58, 59, 60, 61, 63, 66, 72, 73, 74, 75, 78, 80, 81, 83, 84, 87, 88, 89, 96, 97, 100  
 gases, 2, 5, 10, 11  
 gasification, 25  
 global warming, 2, 12, 21, 32, 53  
 greenhouse effect, 1, 2, 20  
 greenhouse gases, 1, 22  
 Gulf of Mexico, 14, 35

**H**

H<sub>2</sub>, 6  
 H<sub>2</sub>S, 10  
 Hg, 10  
 human, 1, 2, 88  
 Human activity, 2  
 hydrates, 10, 13, 82  
 hydrocarbon, 5, 6, 13, 88

**I**

ice, 8, 10, 23  
 immature, 9, 11, 20, 22, 33, 34, 86  
 impurities, 10, 12  
*industrial*, 5, 14, 15, 25, 82, 84, 85  
 infrastructure, 7, 8, 36, 39, 49, 57, 75, 77, 78, 79  
 Intergovernmental Panel on Climate Change, 1, 5  
 investment, 6, 56  
 IPCC, 1, 2, 5, 13

**K**

KYOTO Protocol, 4

**L**

leakage, 13, 15, 16, 17, 22, 85, 86, 87, 88  
 legislation, 84  
 limestone, 13, 14, 25  
 liquefaction plant, 11  
 liquefied CO<sub>2</sub>, 8, 11, 23, 24, 56, 87  
 loading, 11, 87  
 LPG, 11, 23

**M**

McKinsey and Company, 7  
 methane, 2, 13  
 methodology, 16, 89  
 Mississippi, 14

mitigate, 2, 5, 12, 18, 21, 23  
 MPa, 11, 64

**N**

N<sub>2</sub>, 10  
 natural, 1, 2, 8, 9, 15, 34, 50, 72, 74, 75  
 natural gas, 1, 15, 34, 72, 74, 75  
 Nile, 14  
 North Sea Gas Basin, 35, 74  
 Norway, 11, 16, 33  
 NO<sub>x</sub>, 6

**O**

O<sub>2</sub>, 7, 10, 87  
 oceans, 13, 14  
 offshore, iii, 9, 12, 23, 25, 27, 30, 33, 34, 36, 39, 40, 41, 42, 46, 47, 48, 49, 50, 51, 53, 54, 55, 56, 59, 60, 62, 63, 64, 68, 71, 72, 74, 75, 76, 80, 81, 84, 87, 89, 94, 100  
 oil, iii, 2, 3, 5, 8, 13, 15, 16, 17, 19, 24, 25, 27, 33, 34, 38, 50, 57, 66, 72, 74, 75, 78, 80, 81, 83, 88, 89, 96, 100  
 oxy-fuel, 6, 7, 82  
 Oxy-fuel Combustion, 5  
 oxygen, 5, 6, 25, 87

**P**

petroleum, 1, 11, 32  
 pipelines, 8, 9, 10, 12, 27, 40, 41, 57, 58, 60, 61, 62, 63, 64, 65, 71, 75, 81, 82, 87, 100  
 porous, 80  
 post-combustion, 5  
 potential, 2, 9, 11, 13, 14, 15, 16, 19, 21, 26, 33, 34, 35, 38, 50, 72, 73, 74, 83, 86, 87, 88  
 power plants, 5, 7, 20, 32, 37, 38, 75, 81, 82  
 pre-combustion, 5  
 pressure, 8, 10, 11, 12, 13, 24, 26, 46, 62, 71, 72, 73, 74, 80, 81, 82, 87, 94, 98, 99  
 prices, 8, 83  
 production, 14, 15, 17, 19, 39, 40, 48, 66, 67, 73, 74, 75, 78, 88  
 propane, 11  
 public acceptance, 20, 27, 29, 30, 85, 86, 100, 101, 102  
 pure, 6, 7

**R**

radiation, 1  
 rail, 12  
 region, 2, 31, 35, 36, 67  
 regulation, 22  
 regulatory, 7, 19, 20, 82

renewable. *See* renewable energy  
 renewable energy, 5, 55, 81  
 research, iii, 5, 8, 13, 31, 67, 84, 88, 96  
 reservoirs, 9, 12, 13, 24, 33, 34, 38, 73, 74, 75, 80, 88, 89  
 retrofit, 5, 7, 39, 67, 82  
 retro-fit. *See* retrofit  
 risk, 6, 13, 15, 16, 19, 20, 21, 33, 34, 36, 60, 80, 82, 86, 87, 88, 89  
 road, 8, 12, 18, 20

## S

saline. *See* Saline Formations  
 saline formations, 8, 13  
 sandstone, 72, 73, 74  
 sensor, 81  
 sequestration, 5, 7, 12, 13, 14, 15, 16, 34, 82, 84  
 ship, ii, 11, 13, 39, 80, 89  
 snøhvit, 9  
 sources, 2, 3, 5, 9, 12, 15, 20, 25, 31, 32, 34, 35, 36, 39, 50, 55, 56, 72, 75, 80, 81, 87, 89  
 Sources, 2  
 storage, iii, 2, 4, 5, 6, 8, 9, 12, 13, 14, 15, 16, 19, 21, 22, 23, 24, 25, 26, 27, 30, 33, 34, 37, 38, 39, 40, 41, 42, 46, 55, 56, 60, 66, 72, 73, 74, 75, 78, 80, 81, 83, 84, 85, 88, 89, 94, 96, 97, 101, 103  
 subsea pipelines, 9  
 suffocation, 21  
 supercritical, 10, 13, 81, 96, 97

systems, 5, 7, 23, 45, 46, 48, 56, 65, 71, 72, 82, 98

## T

tankers, 8, 12, 25  
 technological development, 69  
 technology, iii, 2, 5, 6, 7, 10, 12, 16, 18, 19, 20, 21, 26, 31, 33, 49, 78, 82, 86, 89  
 temperature, 1, 7, 8, 10, 24, 33, 71, 72, 74, 82, 87  
 temperatures, 1, 14, 15, 26, 72  
 thermal, 1  
*transport*, 5, 7, 8, 9, 10, 11, 12, 14, 23, 27, 41, 42, 46, 58, 59, 60, 75, 76, 81, 83, 100  
 transportation, 8, 10, 11, 12, 23, 31, 36, 37, 39, 57, 58, 60, 62, 75, 76, 81, 87, 88, 89, 97  
 Turkey, 9

## U

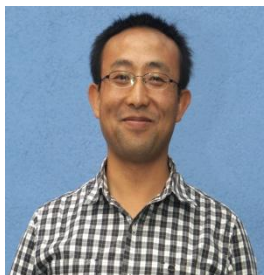
United Kingdom, i, 32, 33  
 urea, 15  
 USA, 9, 31

## V

vapour, 2, 5, 6

## W

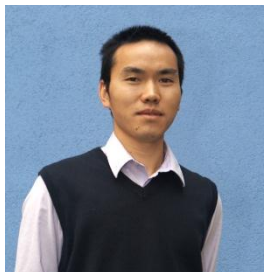
waste, 13, 14, 21, 24  
 wells, 19, 24, 25, 38, 40, 45, 71, 74, 75, 76, 88



Aichun Feng is currently a PhD student of Fluid Structure Interaction Group in the University of Southampton. Before that he received his bachelor degree in Harbin Engineering University and then master degree in Shanghai JiaoTong University in China. His research interest mainly lies in the nonlinear hydrodynamic analysis for floating structures.



Taeyoung Kim received his bachelor degree in Department of Naval Architecture and Ocean Engineering at Seoul National University, South Korea in 2008. Now he works for the PhD degree in Department of Industrial Engineering and Naval Architecture at the same university. His research field is fluid structure interaction and ship stability.



Xiaojun Li is a visiting student from Centre for Offshore Foundation System, The University of Western Australia. He received his master degree of engineering from Institute of Mechanics, Chinese Academy of Sciences in 2010. He is currently doing research on the recovery of deep-water manifold foundations.



Zeeshan Riaz graduated with a Bachelor degree in Electronics engineering from National University of Science & Technology, Pakistan in 2002. He received his Master's degree in Naval Architecture from University College London (UCL) in 2007. He is currently a research student in the Department of Mechanical Engineering at UCL in the field of submarine hydrodynamics.



Justin Wee is a research scholar at the Centre for Offshore Research and Engineering (CORE) in the National University of Singapore (NUS). He graduated with a Bachelor's degree in mechanical engineering from NUS in 2008. He is currently a PhD candidate of the Department of Civil Engineering at NUS. His area of specialization is offshore engineering. Since 2010, he has devoted his time to research into marine renewable energy.

Offshore Renewable Energy Powered CO<sub>2</sub>  
Injection: A Small Carbon Footprint  
Solution.

©University of Southampton 2011.

ISBN 978-0-854-32930-4



9 780854 329304