Asia-Pacific
Economic Cooperation

BUILDING CAPACITY FOR CO_2 CAPTURE AND STORAGE IN THE APEC REGION

A training manual for policy makers and practitioners

APEC Energy Working Group

October 2009

This training manual was prepared by

The Delphi Group
428 Gilmour St.
Ottawa, ON K2P 0R8
CANADA
www.delphi.ca

Alberta Research Council
250 Karl Clark Road
Edmonton, Alberta
T6N 1E4
CANADA
www.arc.ab.ca

This training manual was updated by

Cooperative Research Centre for
Greenhouse Gas Technologies
GPO Box 463
Canberra ACT 2601
AUSTRALIA
www.co2crc.com.au

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Prepared for
APEC Secretariat
35 Heng Mui Keng Terrace Singapore 119616
Tel: (65) 68919 600 Fax: (65) 68919 690
Email: info@apec.org Website: www.apec.org

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TRAINING MANUAL AUTHORS

Dr. Stefan Bachu, Alberta Geological Survey
Dr. Rick Chalaturnyk, University of Alberta Kyle Durocher, Alberta Research Council
Mike Gerbis, The Delphi Group
Dr. Bill Gunter, Alberta Research Council
Jennifer Harwood, The Delphi Group
Dr. David Keith, University of Calgary
Lael Morgan, The Delphi Group
Dr. Ernie Perkins, Alberta Research Council
Jennie Stephens, University of Calgary
Sam Wong, Alberta Research Council

Editor: Jennifer Harwood, The Delphi Group
Editorial assistance: Brent Lakeman, Alberta Research Council

PROJECT EXPERT COMMITTEE MEMBERS

Ms. Melissa Chan, U.S. Department of Energy, USA
Ms. Jette Findsen, SAIC, USA
Mr. John Gale, IEA Greenhouse Gas R&D Program, UK
Mr. Michiaki Harada, Center for Coal Utiization, JAPAN
Mr. Bill Reynen, Environment Canada, CANADA
Mr. Andy Rigg, CO2CRC, AUSTRALIA
Dr. Xu Shisen, New Power Generation Department, TPRI, CHINA
Mr. Ohsumi Takashi, Research Institute of Innovative Technology for the Earth, JAPAN
Dr. Kelly Thambimuthu, Natural Resources Canada and IEA Greenhouse Gas R&D Program, CANADA
Dr. Malcolm Wilson, Department of Energy & Environment, University of Regina, CANADA

Contributions to CO2CRC 2009 updates by:

Mrs Anni Bartlett, CO2CRC
Dr Peter Cook, CO2CRC
Dr Tess Dance, CSIRO/CO2CRC
Dr Alexandra Golab, CO2CRC
Assoc. Prof. Sue Golding, UQ/CO2CRC
Mr Barry Hooper, CO2CRC
Dr Charles Jenkins, CSIRO/CO2CRC
Dr Lincoln Paterson, CSIRO/CO2CRC
Dr Peter Neal, UNSW/CO2CRC and the UNSW Economics team

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- Issue Briefing: Climate change and CO_2 capture and storage

Overview

This APEC training package is designed to assist APEC member economies to understand the potential of CO_2 Capture and Storage (CCS), as well as the science and process involved in identifying and implementing a CCS project. It must be noted that CCS is an emerging field and in many areas of the world very little is known about the topic. It is therefore essential to properly plan and prepare your workshop in light of the needs and level of understanding of your audience. The purpose of this Note to Trainers is to provide you with guidance and suggestions on how to effectively employ the training tools and materials at your disposal.

The goal of these training materials is to:

- Increase the capacity of APEC economies to undertake their own detailed technical and site analysis of CO_2 capture and geo-sequestration potential;
- Provide the tools, procedures and understanding to undertake technical and site analysis in their respective economies;
- Assist project developer to understand the importance of effective communication with communities affected by the CCS project and provide them with an outreach strategy and sample outreach materials;
- Build upon existing technical knowledge in participating economies, with a special emphasis on the needs and requirements of developing economies.

Principles for Effectively Using the Training Materials

- **Choose the right audience.** There are a variety of stakeholders that will need to be involved in order to support and promote CCS as a viable technology within the economy in which you are providing the training. The ideal audience would include a mix of senior level policy makers, policy advisors, technical experts and researchers and from the government, research institutions and the private sector. Each workshop will have to meet a variety of needs, which makes matching the workshop agenda with the audience very important. In addition, working with a well established, well connected local contact will be essential for identifying and properly preparing the audience for the workshop.
- **Match the workshop agenda with the audience**. The training materials are divided into three main sections
- The **Introduction** – **CO_2 capture and geological storage in energy and climate policy -** provides a high-level overview of the technology, its potential and importance to an economy's energy production/supply and climate change strategy;
- The thirteen technical **Modules and Two Case Studies** develop key areas of CCS technology and practice at a very technical, in-depth level;

The **Community Outreach Strategy and Materials** are designed as a practical guide for developers seeking to implement CCS and requiring guidance on working with affected communities to enhance the project.

It is recommended that the workshop begin with a half day (2-3 hours) high-level overview of the field, including a general introduction to CCS, an the broad context in which it can be implemented and employed to complement an economy's energy production and climate change strategies. Much of this information is contained within the Introduction – An Overview for Policy Makers module. However, some basic information from Modules 1, 5, 8, 10, 11 and 13 may also be relevant in providing this overview. The exact combination of information present will have to be determined on a case-by-case basis.

The workshop should then dedicate the remainder of its time on the more technical aspects of the material contained within the thirteen modules, two case studies, and community outreach strategy and materials. This workshop should not be any longer than a day and a half, making the entire combined workshop two days maximum. It is important to understand the level of knowledge that your audience has with the topic area, in order to determine the level of detail appropriate for the audience. The training modules which have been prepared are fairly technical in nature, and it is very likely that your workshop audience will not have as high a technical literacy of the field. The most important points in the modules are always summarized at the end of the module. These represent a minimum of what you would provide through your training.

- **Include economy specific examples and information.** Economy specific information will be critical to linking the material being presented to the local context, and enabling the audience to appreciate the relevance and opportunity of CCS to their situation. This economy specific information should include any research or policy work that has occurred around the potential or attractiveness of CCS to date, high potential sources of CO_2 and basins which should be considered, climate change and Clean Development Mechanism policy and potential opportunities, etc.

Provide a number of means for interaction and dialogue. An interactive workshop with a variety of session formats is most ideal for providing lots of opportunity for discussion and interaction. However, this type of workshop will only work in some cultural contexts. It is important to know the culture in which you are working and orient the workshop accordingly so that participants receive information that they need in a manner that is culturally appropriate.

- **Administer a post-workshop questionnaire.** Always prepare a post-workshop questionnaire to determine how well the audience related to the material presented. This will assist you with the next training and provide valuable feedback to others in the economy wishing to advance the technology.
- **Include international and local experts in the presentation and discussion panels.** Local experts, senior policy makers, researchers or technical experts, will provide much needed local expertise, perspective and affirmation of the technology and its application to the economy in which you are training.

Introduction

CO_2 capture and geological storage in energy and climate policy

M. Gerbis, W.D. Gunter and J. Harwood, APEC Capacity Building in the APEC Region, Phase II
Revised and updated by CO2CRC

Overview

CO_2 capture and storage (CCS) involves the injection and containment of CO_2 in geological structures such as depleted oil and gas reservoirs, onshore and offshore saline aquifers located deep in the earth's crust, salt caverns or unmineable coalbeds. It is both an approach to improve energy production from existing fossil fuel operations as well as a means of reducing greenhouse gas emissions. This introduction is designed to provide answers to questions important to policy makers and those interested in investigating the potential of CCS to enhance energy production and reduce greenhouse gases.

This introduction answers the following questions:

- What is CO_2 capture and storage?
- How could CO_2 capture and storage fit into an economy's climate change strategy?
- How does CO_2 capture and storage form part of an economy's overall energy supply and production?
- What are the benefits of CO_2 capture and storage?
- Where can we capture CO_2?
- How do we transport CO_2?
- How safely can CO_2 be stored?
- What is the potential of CO_2 capture and storage?
- How can the potential of CO_2 capture and storage be tapped?
- What is the future outlook for CO_2 capture and storage technology?
- How can I learn more about CO_2 capture and storage?

What is CO_2 capture and storage?

CO_2 capture and storage involves the capture, transport, injection and containment of CO_2 in geological structures such as depleted oil and gas reservoirs, onshore and offshore saline aquifers located deep in the earth's crust and unmineable coalbeds. It is technically feasible. Many economies have pilot and demonstration projects. A map of those projects can be found in Appendix 1.

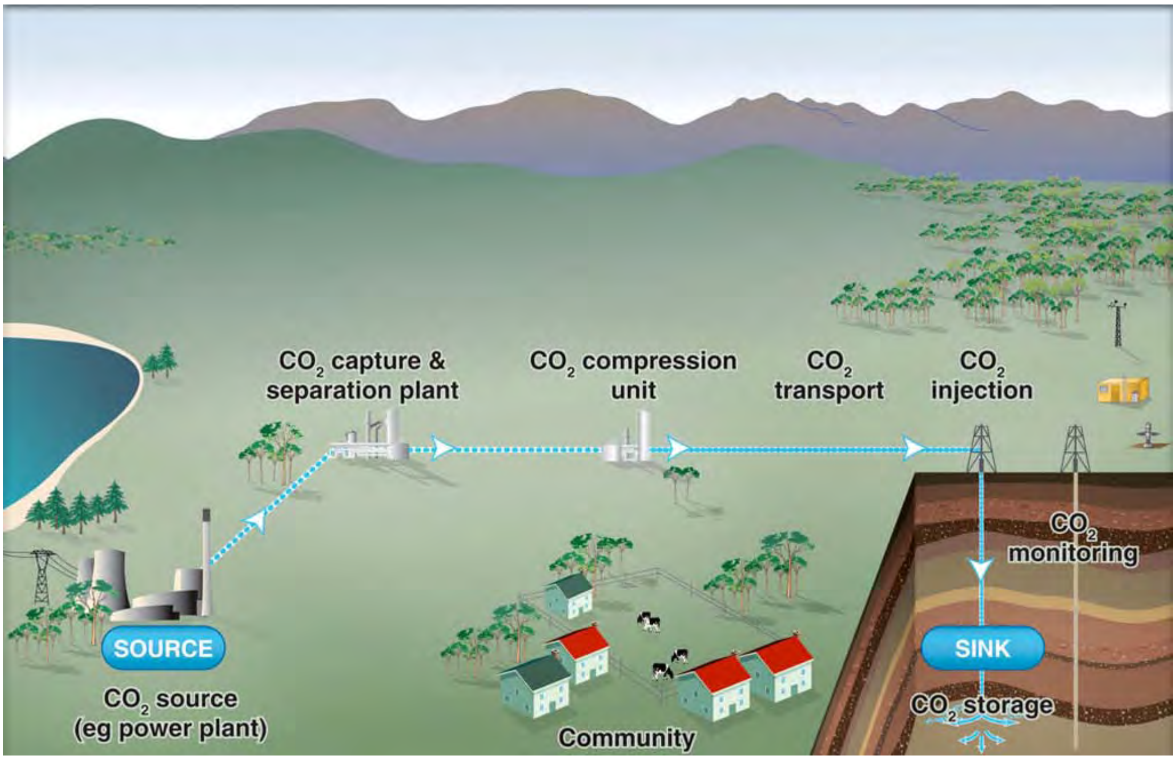

Figure 1: Overview of the components of carbon dioxide capture and storage (courtesy of CO2CRC).

How could CO_2 capture and storage fit into an economy's climate change strategy?

CO_2 is produced from a number of sources, including the burning of oil, coal and gas. CO_2 also is a "greenhouse gas" (GHG). When greenhouse gases are released into the atmosphere, they trap heat much like the glass in a greenhouse. Trapped heat can trigger climate change - a change in the weather typically experienced in a region. At a global level, such changes could impact the Earth's climate balance. It can result in warmer temperatures, an increased number of floods, droughts, hurricanes and other intense storms, and impact on human and ecological health.

Economies from around the world have developed an international agreement and strategy for dealing with climate change called the *United Nations Framework Convention on Climate Change* (UNFCCC). The UNFCCC outlines the need for more understanding about how global climate systems operate, an international effort to reduce greenhouse gas emissions (through an agreement called the *Kyoto Protocol*), public education to improve understanding of climate change, and evaluation of what how economies and regions can adapt to any climate changes that might occur. Negotiations are underway on a replacement to the *Kyoto Protocol*, which is due to expire in 2012.

CO_2 emissions are a function of several factors. Population and the standard of living are two key variables that will not be discussed in this document as reductions in either of these variables are contrary to the public policies of most governments. Therefore, greenhouse gases can be reduced through several means:

- **Lowering the energy intensity of the economy** – by increasing the energy efficiency of energy production, conversion and end use;
- **Lowering the carbon intensity of the energy system -** by substituting lower-carbon or carbon-free energy sources, such as renewable energy. for the current sources; or
- Increasing the capacity and capture rate of carbon sinks to store CO_2.

Short of revolutionary, large-scale new technological advances and major expenditures, greenhouse gas emissions are likely to continue to rise as the GDP rises and economies expand. Energy from fossil fuels currently accounts for about 65% of greenhouse gas emissions, with 28.8Gt of energy-related CO_2 emitted in 2007(IEA, 2009). Fossil fuels will likely remain a major component of world's energy supply for at least this century because of their inherent advantages, such as availability, competitive cost, ease of transport and storage, and large resources. This leaves the option of increasing carbon sinks as one of the major means of reducing net carbon emissions into the atmosphere in the short to medium term.

The International Energy Agency (IEA) has prepared a scenario of policy objectives aimed at stabilizing the long-term level of CO_2 concentration in the atmosphere at 450 parts per million which is expected limit the increase in global temperature to 2°C. To achieve this, an estimated 1.4 $GtCO_2$ would need to be captured and stored from energy-related sources annually by 2030 (IEA, 2009).

In the longer term, as the use of carbon-based fossil fuels decreases due to diminishing reserves and replacement by other renewable or carbon-free energy forms, storage of CO_2 may no longer be as integral a part of the strategy.

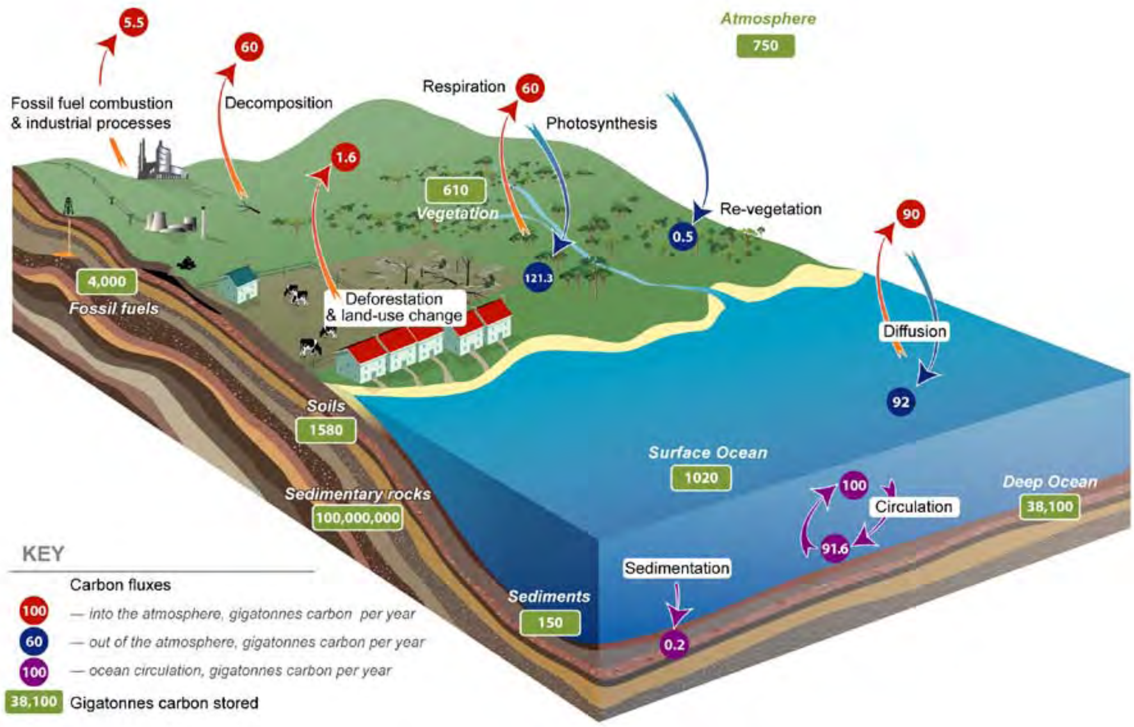

Figure 2: Representation of the carbon cycle (courtesy of CO2CRC).

Carbon dioxide sinks can be grouped into three broad classes based on the nature, location and ultimate fate of CO_2:

- **Biosphere sinks -** are active, environmentally sensitive, natural reservoirs for CO_2. The oceans, forests, and soils (agricultural) ecosystems are members of this class. These sinks (excluding oceans) are probably most suitable for offsetting the emissions from diffuse sources of CO_2 that could not otherwise be captured, but could also be applied as offset mechanisms for industrial CO_2 sources. However, using these sinks as emission reduction mechanisms can result in considerable risk as these sinks are subject to natural CO_2 releasing processes and it can be difficult to validate the amount of CO_2 actually stored.
- **Material sinks** – Carbon that has been absorbed into various living systems such as trees can be stored as a material sink when the living system is created into a material product. Material sinks include durable wood-based products (furniture, paper, etc.), chemicals and plastics. These store carbon for different lengths of times depending on the life of the product. However, outside of extensive research, it is unlikely that carbon storage in material sinks will anything but a very minor role in greenhouse gas mitigation strategies.
- **Geosphere sinks -** are natural reservoirs for CO_2 found in deep geological sedimentary basins. Human activity is required to store carbon in this type of sink. These sinks include depleted oil and gas reservoirs, deep aquifers, oil reservoirs suitable for enhanced oil recovery (EOR), and coal beds. Currently, one of the most significant issues that limits the use of geologic sinks as mitigation options is cost. The cost of disposing of CO_2 is made up of three factors: separation costs (i.e., capture/separation of CO_2 from other combustion gases), transportation costs (i.e., compression, pipelines) and injection costs (compression, injection wells). Efficient, cost-effective transportation and capture/separation technologies will need to be developed to allow large-scale use of geologic sinks. Currently, capture/separation costs represent the largest financial impediment. The financial drivers for CCS are currently not widely in place and an absence of regulatory frameworks makes investment difficult. Other issues such as community understanding and acceptance of the technology also need to be addressed.

A number of factors will need to be considered when evaluating the use of a given sink in an integrated portfolio of emissions reduction mechanisms. These factors include: environmental impact of the proposed sink mechanism; sink CO_2 capacity; retention/residence time of CO_2 in the sink; potential for accelerated leakage of CO_2; rate of CO_2 uptake by the sink; validation of storage in the sink; suitability of the sink/match to the emission source and type; and cost of implementation/utilization of the sink mechanism.

Of the types of carbon management activities, oceans are unlikely to be approved for large scale CO_2 storage because of environmental concerns, and the biosphere, which depends on land-use, is difficult to control for long periods of time. Only geological media can offer environmental benign repository for storage of CO_2 over long periods of time. In the sedimentary basins during fossil fuel production from geological media, pore space that was occupied by oil and gas for geological time can be refilled with anthropogenic CO_2, a key to reducing atmospheric GHG emissions.

How does CO_2 capture and storage form part of an economy's overall energy supply and production?

Fossil fuels – coal, gas and oil, dominate as the world's primary energy sources to meet the current energy demands. Based on current use and estimates of future demand, energy use will only grow in the future. This will place extra burden on economies to maximize opportunities for energy production.

Typically, oil and gas reservoirs cannot be economically mined to all of their capacity and some coalbed mines are at depths which prevent them from being mined economically. As a result, significant amounts of energy resources remain untapped in these reservoirs. The work involved in surveying, purchasing and constructing sites for future oil, gas and coalbed energy production operations is costly and time consuming. A solution which permits these resources to be further mined economically is beneficial for a variety of reasons.

CO_2 can be used successfully to increase resource extraction potential and revenues from existing or known reservoirs and mines.

- **Enhanced Oil Recovery (EOR)** – CO_2 is injected in miscible floods into depleted oil reservoirs. CO_2 dissolves in the oil, reduces its viscosity and moves the oil towards the producing well. An additional 10-12% of oil reserves can be tapped through this process. This use of CO_2 is a proven technology. A portion of the CO_2 will remain in the reservoir, effectively “stored” from being released into the atmosphere. Use of this sink is restricted to economies that have oil reservoirs suitable for EOR–CO_2 recovery techniques and its economic potential must be weighed against the cost of oil, the cost of CO_2 to inject into the reservoir and reservoir characteristics. EOR is being conducted in 70 locations around the world.
- **Enhanced Gas Recovery (EGR) –** CO_2 can be injected into the base of a depleted homogenous natural gas reservoir to push natural gas to the top of the reservoir for production. Computer simulation has confirmed that this could be an attractive technology for suitable gas reservoirs, however, EGR is unproven in practice as gas reservoirs can traditionally be tapped up to 90% of their total potential production through primary production methods.
- **Enhanced Coalbed Methane Recovery (ECBM) –** Coal beds have significant amounts of methane gas adsorbed in the coal which is called ***coalbed methane*** (CBM). By injecting CO_2 into coal beds, the CO_2 is adsorbed in the coal pore matrix, releasing the methane for energy production which could not otherwise have been mined economically. This method is still in a piloting stage, with several research projects completed or underway in USA, Canada, Poland and China. The bulk of the world’s coalbed methane resource occurs in People’s Republic of China, the Asian portion of Russia, Kazahkstan, and India. Australia, portions of Africa, and Central Europe, as well as the United States and Canada also contain varying amounts of this resource.

What are the benefits of CO_2 capture and storage?

CCS provides an additional alternative in the utilization of fossil-fuel based energy, while gaining a transition time to move to carbon-reduced or zero carbon fuels, such as renewables. In addition there are a number of economic and social benefits of CCS such as:

- Innovation, access to state-of-the-art technologies, job creation and continued and more sustainable economic development;
- Secondary revenue stream as emissions of GHGs that are captured and stored can be converted into a tradeable commodity that can be sold on the international market;
- Reduction in air pollution as processes tend to remove other potentially harmful pollutants;
- Opportunity for enhanced oil recovery.

Where can we capture CO_2?

CO_2 can be captured from large stationary sources, such as natural gas production facilities (where CO_2 is already separated from other gases) fossil fuel fired power stations, iron and steel plants, cement plants and some chemical plants. The technology to capture CO_2 from these sources is being adapted from the CO_2 separation technology currently used in industries such as the natural gas industry and ammonia production and also from the technology used in the air separation industry. New technologies are being developed. While there are other major sources of CO_2 (for example emissions from cars and planes) current technology is not practical for capture from those sources.

Challenges that currently exist for capturing CO_2 are reducing the cost of capture (including the amount of energy used by the capture equipment) and deploying the technology at scale.

How do we transport CO_2?

CO_2 has been transported by pipeline on a large scale in the US for over 30 years for use in EOR operations, the longest pipeline being the Cortez pipeline which is over 800 km long. CO_2 for small-scale commercial use is transported by truck and there has been some ship transport of CO_2.

Major pipeline infrastructure will need to be built to implement CCS on a large scale, and this presents challenges particularly in the area of public acceptance if pipelines are to traverse densely populated areas.

How safely can CO_2 be stored?

The safety of CO_2 storage is of prime importance to the field. Local scale risks of CO_2 storage include CO_2 leakage from the storage location; alteration of ground and drinking water chemistry and displacement of potentially hazardous fluids formerly occupying the pore space being used to store the CO_2. The appropriateness of a site for CO_2 storage is the single biggest factor determining the likelihood and magnitude of the risk. There are no existing studies that estimate storage effectiveness for different types of sites. Rough quantitative estimates of storage effectiveness and risk potential must be undertaken on a site-by-site basis.

A specific methodology is being developed for the identification, screening and prioritization of geological basins suited to CO_2 storage which also present very low possibilities for leakage. Many of these geological basins have contained oil and gas for geological timeframes and thus have proven that they are low risk options. Each storage site is unique and requires a specific technical and operational approach. These approaches are being catalogued through experience to standardise practice in the field and ensure safety. Leakage that does occur tends to be from isolated spots such as faults, fractures and wells which can be directly monitored.

Natural analogues and current industrial experience in natural gas storage indicate that it is possible to achieve very low risks of leakage from well designed storage facilities. It is reasonable to expect that more than 99% of CO_2 would be retained for over 1,000 years. Furthermore, experience suggests that it is improbable that releases of CO_2 from storage facilities will pose a threat to humans or ecosystems. Industrial experience with the injection of other fluids suggests that hazards associated with groundwater contamination would be rare. Cumulative past injection of over 30 million tons of CO_2 for enhanced oil recovery has not triggered any significant seismic activity. Therefore its risk is considered very low.

What is the potential of CO_2 capture and storage?

Several studies have been conducted over the past decade to estimate the amount of CO_2 that can be stored in sedimentary basins. Theoretical global storage capacity is estimated to be in the range of 8,000 to 15,000 $GtCO_2$ (IEA, 2009). This suggests that we have the capacity to store most, if not all, of the CO_2 needed to prevent the build-up of harmful levels of CO_2 in the atmosphere.

The potential for CO_2 capture and storage of any region and at any scale is based on the following two broad criteria:

- Availability of CO_2 sources - the current and forecasted existence of large, stationary CO_2 sources, such as thermal power generation, refineries, cement plants, petrochemical plants and large industrial complexes, that will allow CO_2 capture on a large scale is needed to supply CO_2 to storage sites.
- Availability of economically suitable storage reservoirs - The existence of geological media (sedimentary basins) suitable for CO_2 storage within economically viable distance that meet the criteria of capacity and safety is also required.

Circum-Pacific sedimentary basins are less favourable for CO_2 storage because they are located in tectonically unstable areas with faults and have generally smaller capacity for storage. The highest potential for CO_2 storage in the APEC region is in large, continental-sized economies. The most promising sites would be in areas away from the Pacific Rim. This would include: Australia, Canada, Mexico, the People's Republic of China, Russia and the United States.

The potential of industrialized economies within the APEC region is generally known. Australia, Canada, New Zealand and the United States have the most potential for storage. These economies are also generally leaders in the field and have strong research and implementation programs in place to support CO_2 capture and storage. Sedimentary basins in Russia (the Asian part), the Republic of Korea, the People's Republic of China, Chinese Taipei, Viet Nam, the Philippines, Thailand, Malaysia, Indonesia and Mexico hold the most potential of non-industrialized economies (see Figure 3 and Table 1).

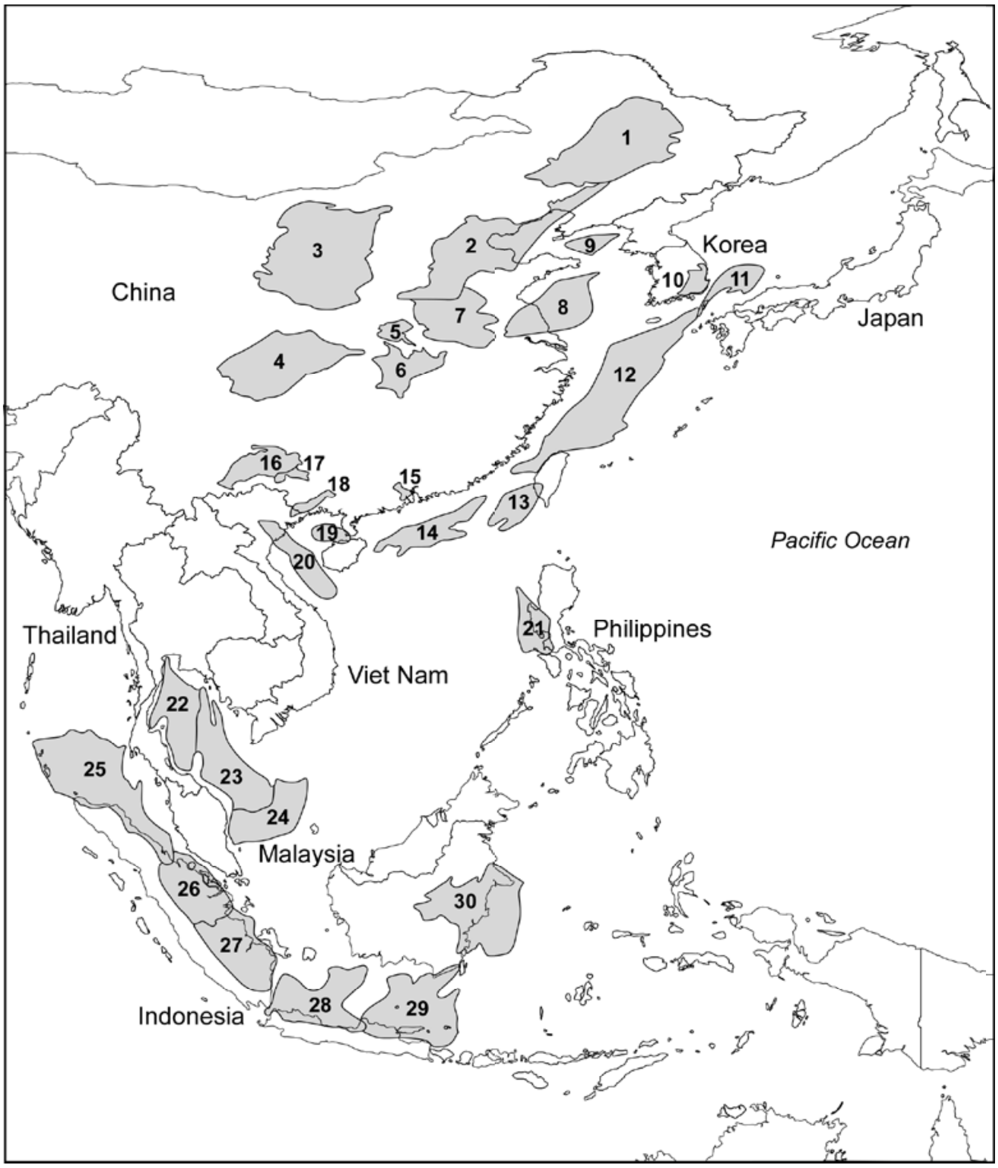

Figure 3: Sedimentary basins in East and Southeast Asian APEC economies that would potentially be primary targets for CO_2 geological storage based on their proximity to major CO_2 sources (modified from Bradshaw et. al., October 2004, see Table 3 for basin names).

#	Basin Name	#	Basin Name	#	Basin Name
1	Songliao	11	Tsushima	21	Zambalez/Central Luzon
2	Bohaiwan	12	East China Sea	22	Thai
3	Ordos	13	Taixinan	23	Malay
4	Sichuan	14	Pearl River Mouth	24	Penyu/West Natuna
5	Nanyang	15	Sanshui	25	North Sumatra
6	Jianghan	16	Nanpanjiang	26	Central Sumatra
7	Taikang Hefei	17	Bose	27	South Sumatra
8	Subei Yellow Sea	18	Shiwan Dashan	28	Northwest Java
9	Korea Bay	19	Beibuwan	29	East Java
10	Gyeongsang	20	Yinggehai	30	Kutei

Table 1: Sedimentary basins in Asian APEC economies that would potentially be primary targets for CO_2 geological storage based on their proximity to major CO_2 sources (modified from Bradshaw et. al., August 2004 (for location see Figure 3).

How can the potential of CO_2 capture and storage be tapped?

In order to tap into this opportunity and increase the likelihood of acceptance of CO_2 capture and storage, a number of activities must be conducted:

- **Education and outreach -** The notion of capturing and storing CO_2 is relatively new, and many people are unaware of its role as a GHG reduction strategy. Increased education and awareness are needed to achieve acceptance of carbon storage by the general public, regulatory agencies, policy makers, and industry and thus enable future commercial deployment of this advanced technology.
- **Risk/Performance Assessment -** Risk models need to be established for the leakage of CO_2 (slowly and rapidly) from the storage reservoir through breaks in the seals and along well bores, both in the short (during the injection period) and in the long (over the storage period) term. Safety issues and verification strategies are key components of risk/performance assessment.
- **Life Cycle Analysis -** The life cycle must be identified in the context of geological storage in the evaluation of GHG emissions throughout the full product or service system life cycle.
- **Economics of CO_2 Storage -** Avoided CO_2 as well as changing regulations must be accounted for.
- **Regulatory/Legal Framework -** This may have to be modified in order to address the long-term issues inherent in geological storage.

What is the future outlook for CO_2 capture and storage technology?

The global energy mix is becoming increasingly environmentally constrained. It is anticipated future energy sources will be required to evolve to minimize the release of pollutants. End-of-pipe solutions for fossil fuel conversion will gradually be replaced by cleaner conversion technologies. These, in turn, will be replaced by renewable forms of energy. CO_2 capture and storage is likely to play an important role in this transition.

Reducing GHG emissions to the atmosphere by storage of carbon dioxide in geological formations is a potential bridging technology to allow the continued use of fossil fuels while minimizing their effect on the environment. The world is moving from the current GHG emission-intensive fossil energy-based economy toward a GHG emission-free renewable-based energy economy. Given that energy use will increase in the future, that the current percentage of clean renewable energy in the energy mix is small, a significant amount of time will be needed to make the transition from a predominantly fossil-fuel energy-based world to a renewable energy-based one. However, given the advent of climate change and the serious implications it could have to global environmental and human health, we cannot continue to use fossil fuels, particularly coal, as we have been using it in the past.

The concept of ***storing CO_2*** (capturing it and storing it in geological formations) permits a transition to be realized between current energy use patterns and those that must dominate in the future. Thus ***zero emission fossil fuels*** (ZEFF) can be generated with lower GHG emissions.

This transition is likely to occur in three sequential steps as illustrated in Figure 4.

- **The first transition is from business as usual to CO_2 storage**. ***Business as usual*** depicts what we are doing today: conventional burning of fossil fuels to produce heat and electricity with emissions released to the atmosphere. During the first transition, business as usual is modified by the addition of downstream technologies for the diffuse storage of the CO_2 into biomass; or by CO_2 capture through upstream (oxyfuel combustion) or downstream (post-combustion) separation techniques and injected into deep geological formations for long-term storage. Both options will be utilized. In the former case, the additional cost is low; land-use constraints are the determining factor. In the latter case, the additional cost is much higher, driven by the expense of capturing a pure CO_2 stream from the emission stream or due to the expense of oxygen production from air.
- In the second transition, the fossil fuel is gasified rather than burned, eliminating upstream or downstream separation techniques, before CO_2 storage occurs. This process energy for heat, electricity and hydrogen, and a pure CO_2 waste stream which can be stored in biomass or geological reservoirs. Gasification of fossil fuels also produces additional environmental benefits. The hydrogen is used to power fuel cells, to make electricity in stationary plants or to power vehicles.
- **In the third transition, the energy mix is dominated by the renewable energy sources: solar, hydro and wind.** Fuel cells will still dominate the transportation market, requiring a hydrogen source but generated from renewables instead of fossil fuels.

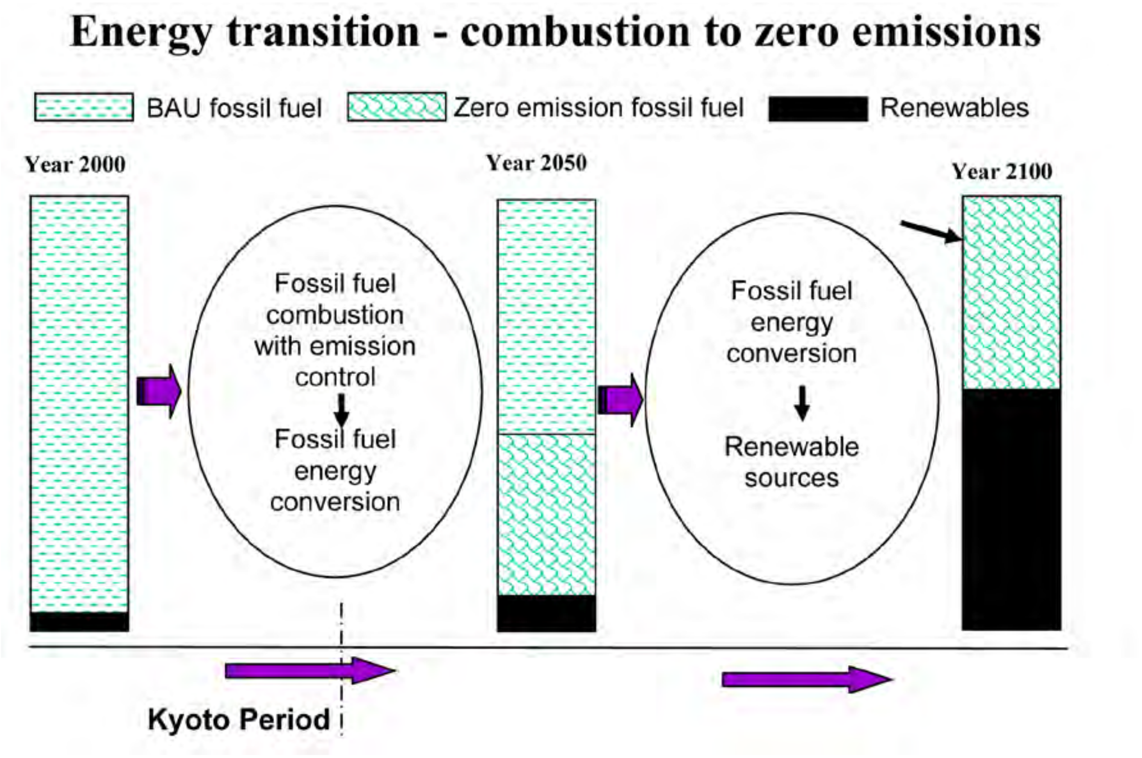

Figure 4: CCS provides an opportunity for low emission fossil fuel combustion in the transition to renewable energy.

The whole process is driven financially by emission trading in the storage transition stages where CO_2 emission permits are sold by the government and traded on the open market. A portion of the profits from the sale of these permits could be used to fund renewable energy research, development, demonstration and deployment. This would allow orderly capacity-building of renewable energy sources without severely affecting our economy and standard of living. If this scenario is correct, geological storage in sedimentary basins of emissions from power plants and other industries will have an important role to play in the future as one of several bridging technologies.

How can I learn more about CO_2 capture and storage?

CCS is an emerging field. To assist APEC member economies to understand the potential of CCS, as well as the science and process involved in identifying and implementing a CCS project, the APEC Energy Working Group commissioned the development of a training package and series of workshops on CCS.

These training materials have been designed to:

- Increase the capacity of APEC economies to undertake their own detailed technical and site analysis of CO_2 capture and geological storage potential;
- Provide the tools, procedures and understanding to undertake technical and site analysis in their respective economies;
- Assist project developer to understand the importance of effective communication with communities affected by the CCS project and provide them with an outreach strategy and sample outreach materials;
- Build upon existing technical knowledge in participating economies, with a special emphasis on the needs and requirements of developing economies.

The training modules provide a more in-depth, technical discussion on the following topics:

- Module 1 – CO_2 capture and geological storage: Overview
- Module 2 – CO_2 capture: Post-combustion flue gas separation
- Module 3 – CO_2 capture: Pre-combustion (decarbonisation) and oxyfuel technologies
- Module 4 – CO_2 compression and transportation to storage site
- Module 5 –CO_2 storage options and trapping mechanisms
- Module 6 – Identification and selection of CO_2 storage sites
- Module 7 – Key steps involved in developing and implementing a CO_2 capture and storage project
- Module 8 – Health, safety and environmental risks of CO_2 storage
- Module 9 – Risk assessment, measuring, monitoring and verification in CO_2 storage projects
- Module 10 – Regulatory and legal aspects of CO_2 storage
- Module 11 – The Clean Development Mechanism
- Module 12 – Economics of CO_2 capture and storage
- Module 13 – Public awareness and community consultation
- Module 14 – Potential for CO_2 capture and storage in the APEC region.
- Case Study #1 - The Saline Aquifer CO_2 Storage Project: Case study of CO_2 storage in an underground salt aquifer
- Case Study #2 - The Weyburn CO_2 Monitoring and Storage Project: Case Study of a CO_2 –EOR Storage Project

Community outreach documents:

- Community Outreach Strategy for CO_2 Capture and Storage Projects: A strategy for successfully working with local communities to enhance your CO_2 capture and storage project.
- Frequently Asked Questions about CO_2 capture and storage
- Issue Briefing: What is CO_2 capture and storage?
- Issue Briefing: Climate change and CO_2 capture and storage

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Appendix 1

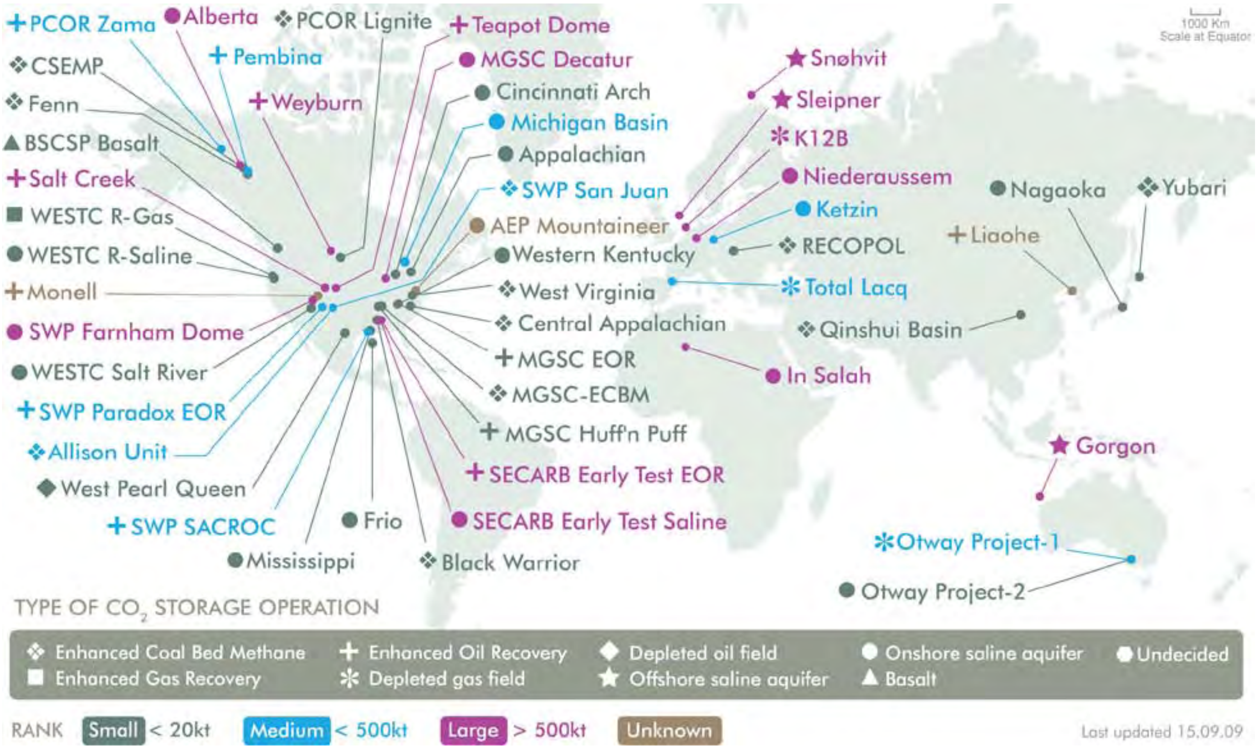

Figure 5: CO$_2$ storage demonstration projects around the world: active projects (courtesy of CO2CRC).

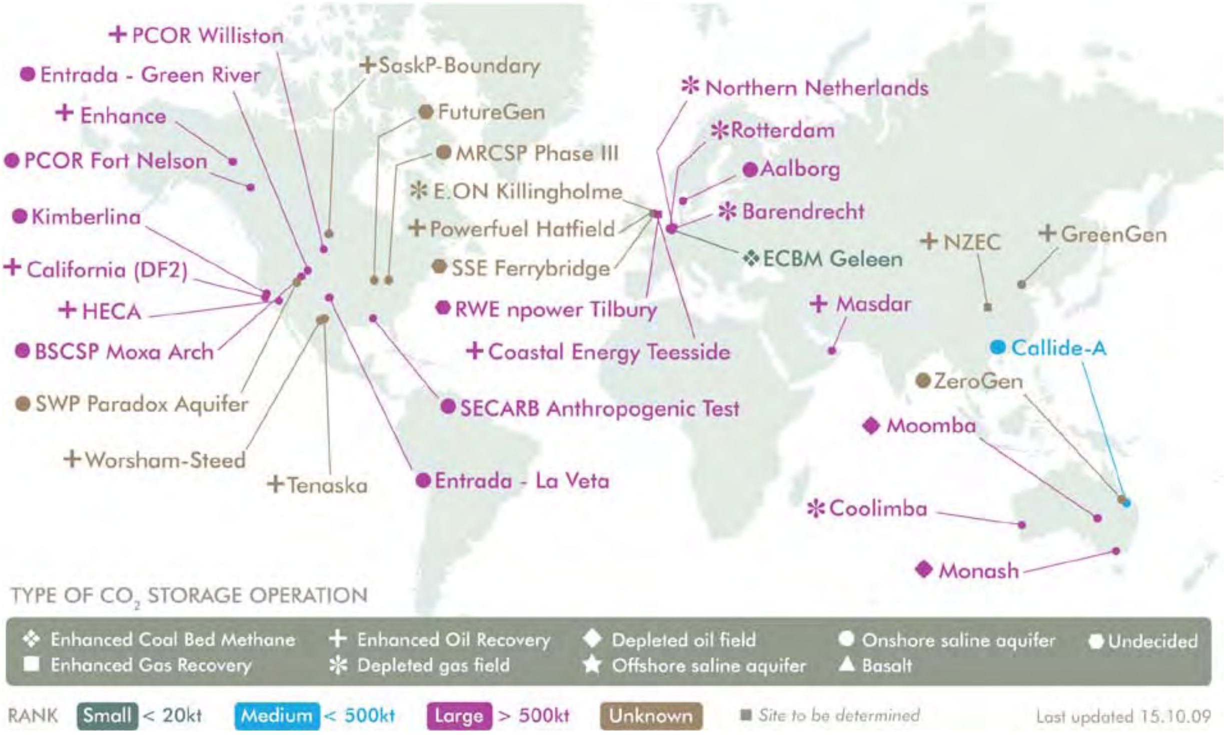

Figure 6: CO$_2$ storage demonstration projects around the world: proposed projects (courtesy of CO2CRC).

Figure 7: CO_2 capture demonstration projects around the world (courtesy of CO2CRC).

Module 1

CO_2 capture and storage overview

Original text: W. Gunter, APEC Capacity Building in the APEC Region, Phase II
Revised and updated by CO2CRC

Overview

The introduction to this training manual outlines the role of CO_2 capture and storage (CCS) in a range of measures to reduce greenhouse gas emissions and thereby avoid dangerous climate change. CO_2 capture and storage represents an interim option to reducing CO_2 emissions – the main greenhouse gas. This module introduces these technologies.

Learning objectives

By the end of this module you will:

- Be familiar with general climate change science and the various technologies available to reduce greenhouse gases;
- Understand how CO_2 capture and storage can reduce greenhouse gas emissions; and
- Understand the current status of CO_2 capture and storage technology.

The science of climate change

The climate of planet earth is very comfortable and hospitable. Actual measurements averaged over the year and over all latitudes indicate that the mean temperature is about 15^oC. Calculations show that this is about thirty five degrees warmer than if there was no atmosphere when the mean temperature would be $–20^oC$. The difference is due to the “greenhouse effect”.

The ***greenhouse effect*** is a natural phenomenon. Most of the solar radiation hitting the earth is lost to space by reflection from the surface and the atmosphere. However, certain gases in the atmosphere, the so-called ***greenhouse gases*** (GHGs), absorb and then quickly re-emit the infrared or heat radiation. In effect, these gases trap heat in the atmosphere, resulting in a rise in the Earth’s surface temperature. The most important greenhouse gases are water vapour (H_2O), carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), tropospheric ozone (O_3) and chloroflorocarbons (CFCs such as $CFCl_3$ and CF_2Cl_2) – the latter are strictly man-made or anthropogenic.

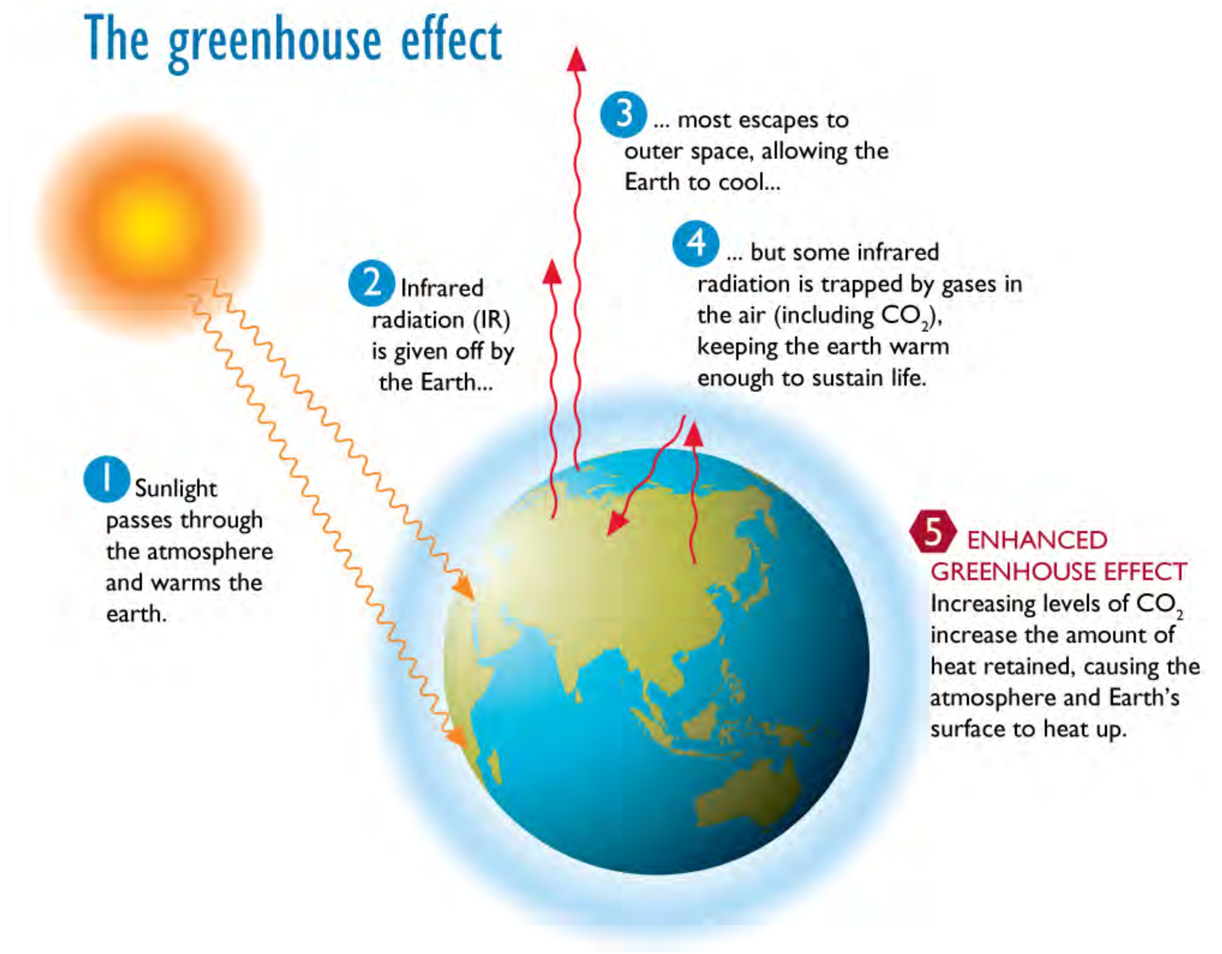

Figure 1.1 Carbon dioxide emissions are enhancing the greenhouse effect of the atmosphere.

It is anticipated that an increase of greenhouse gases in the atmosphere will increase the atmosphere's natural warming capacity. Global warming is the term commonly used for this process. This increase of GHGs is human-induced. Fossil fuel consumption, cement production, land-use changes and forest fires (natural and man-made) are the main causes of the accumulation of carbon dioxide. The accumulated methane largely comes as a by-product of digestion by livestock, agriculture production practices, garbage decomposition, and the production of fossil fuels.

Climate scientists predict that global warming will trigger changes in the average weather experienced in a region. At a global level, such changes in weather could impact the Earth's climate balance – a phenomena called climate change. A change in the Earth's climate does not require a very large increase in greenhouse gases in the atmosphere; and it is highly likely that the accumulated GHGs that are now in the atmosphere, and that will remain in the atmosphere for decades to come, could trigger these reactions.

Although there is far from unanimous agreement, the Intergovernmental Panel on Climate Change (IPCC), which is made up of some of the world's leading climate scientists, produced a major scientific assessment of climate change and concluded that, despite uncertainties, the model simulations of a warming due to increased concentrations of greenhouse gases are broadly consistent with observations of global temperature changes. Further, carbon dioxide is the most important GHG because of its abundance and longevity. It contributes more than half of the enhanced greenhouse effect – the rest being mainly due to increases in methane and CFCs.

There has been an increase in global mean temperature over the past century, most likely due to increased introduction of carbon dioxide into the atmosphere from the burning of fossil fuels (although in the scientific community other theories are debated). The effects of climate change, while by no means known precisely, are such that they will likely be major deleterious social and economic consequences if the warming trend is not slowed, or even reversed. For example, low-lying areas and entire economies could be threatened by flooding, and crops would be affected by the change in climate. The IPCC Predicts an average global temperature rise of about 0.4°C by 2020 and a rise of between 2°C and 6°C by the end of the 21st century. Sea level could rise by 20cm to 60cm by 2099 under the influence of these temperature rises (IPCC, 2007).

Sources of anthropogenic CO_2 can be centralized, as in a power generating station, or diffuse, as in the use of motor vehicles. No single method of CO_2 emissions reductions will be adequate to meet reduction objectives, since no single method can address the issues related to both large central and diffuse emission generators.

Technologies to reduce CO_2 emissions to the atmosphere

CO_2 emissions are a function of several factors. Population and the standard of living are two key variables that will not be discussed in this document as reductions in either of these variables are contrary to the public policies of most governments.

Reducing anthropogenic CO_2 emissions into the atmosphere involves basically three approaches, as shown by the equation below, (Kaya, 1995; Bachu, 2003). These involve relationships beween carbon emissions (C), energy (E) and economic growth as indicated by Gross Domestic Product (GDP):

$$NetC = GDP \times \frac{E}{GDP} \times \frac{C}{E} - S$$

In this equation, E/GDP is the “energy intensity” of the economy, C/E is the “carbon emission intensity” of the energy system, and S represents carbon removed from the atmosphere through ***carbon sinks***. Carbon sinks are reviewed in more detail later in this module.

As a general trend, historical evidence shows that:

- The emissions intensity (C/E) has decreased continuously since the beginning of the industrial revolution;
- The carbon removed from the atmosphere (S) decreased slightly as a result of deforestation and agricultural practices; and
- The net carbon emissions (C) increased at a faster rate than the decrease in emissions intensity, mainly as a result of the increase in economic growth (GDP).

Since the general trend in GDP is to increase, a reduction in net CO_2 emissions into the atmosphere can only be achieved by:

Lowering the energy intensity of the economy E/GDP – by increasing the efficiency of primary energy conversion and end use. A very attractive and cost effective solution (which will reduce **energy intensity**) is energy conservation, although it will require tough policy measures. Solutions include improving energy and material efficiency or modifying industrial processes, which will lead to a lowering of the rate of CO_2 generation. This could be a promising solution in the short- to medium-term.

Lowering the carbon intensity C/E of the energy system - by substituting lower-carbon or carbon-free energy sources for the current sources. An option to reduce carbon intensity is to increase the use of renewable resources. However, until such energy sources can be developed and applied on a large scale, fossil energy resources will continue to be the primary energy sources around the globe. During this period, reduction in carbon intensity could be achieved by switching to low carbon alternative fuels (for example switching to natural gas). Again, this is a long-term solution.

Artificially increasing the capacity and capture rate of carbon sinks. The issue of emissions reduction is a complex one, and will only be solved by innovative responses that include both reducing the quantities of these gases emitted by anthropogenic activities, and enhancing and using greenhouse gas sinks by carbon sequestration in the biosphere, in materials and in the geosphere. These create short and medium term solutions to deal with the problem of increasing CO_2 emissions.

However, short of revolutionary, large-scale new technological advances and major expenditures, the energy intensity of the economy will continue to decrease at a lower rate than the rate of GDP increase and mitigation strategies will have a limited impact (Turkenburg 1997). Similarly, fossil fuels, which currently provide more than 80% of the world's energy (88% according to the BP Statistical Review of World Energy, June 2009), will likely remain a major component of world's energy supply for at least this century because of their inherent advantages, such as availability, competitive cost, ease of transport and storage, and large resources. Thus, the carbon intensity of the energy system is not likely to decrease in any significant way in the medium term. This leaves the increase of carbon sinks and of their capture rate in a significant way as one of the major means of reducing net carbon emissions into the atmosphere in the short to medium term.

The IEA projects that more than 2.5 Gt of CO_2 will need to be captured and stored annually by 2030 to meet the Blue Map Scenario of reducing CO_2 emissions to 50% of 2005 levels (IEA, 2009). Several studies have been conducted over the past decade to estimate the amount of CO_2 that can be stored in sedimentary basins. The IEA puts the estimates of global storage capacity at between 8,000 and 15,000 $GtCO_2$ (IEA, 2009). This suggests that we have the capacity to store most, if not all, of the CO_2 needed to prevent the build-up of harmful levels of CO_2 in the atmosphere.

CO_2 capture and storage

Capture

CO_2 is best captured from large stationary sources of CO_2.

These sources include:

- Fossil fuel power plants
- Petroleum refineries
- Oil and gas production
- Iron and steel mills
- Cement plants
- Chemical plants

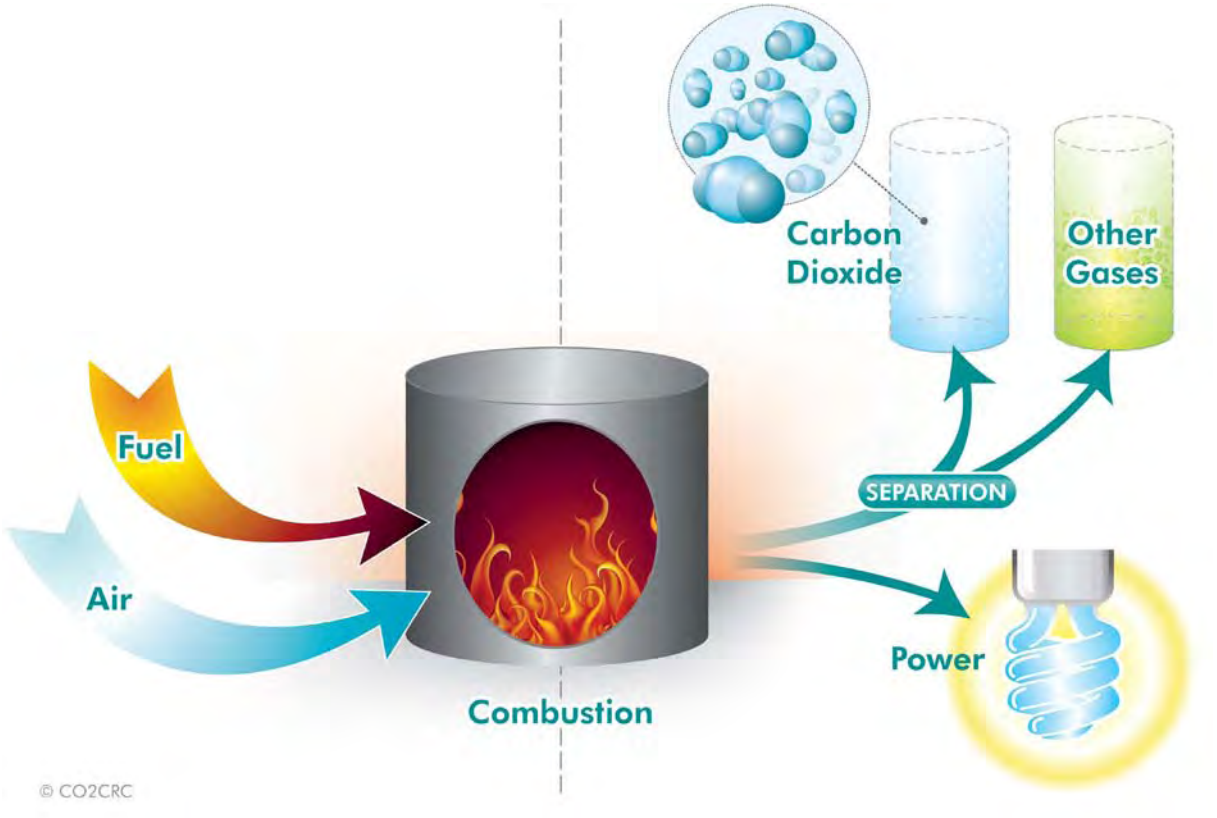

Figure 1.2: Options for capturing CO_2 emissions: Natural gas separation, combustion of fossil fuels for power, chemical industries (courtesy of CO2CRC).

Early opportunities for CCS projects exist in the natural gas industry. CO_2 occurs with methane underground and it must be removed from the methane prior to sending to customers. Normally, the CO_2 is released into the atmosphere. The Sleipner Project in Norway has been storing CO_2 stripped from the natural gas in a saline reservoir deep beneath the seabed since 1988. More recent projects at In Salah in Algeria and Snøhvit in Norway are also storing CO_2 in this way as will the recently approved Gorgon Project on the North West Shelf of Western Australia. The Gorgon Project will become the largest CCS storage project in the world when it commences injection in 2014.

Carbon dioxide is also captured as part of the manufacture of ammonia and other chemicals and/or fuels.. Ammonia is most commonly manufactured by converting methane gas into a syngas (largely carbon monoxide (CO), CO_2 and hydrogen). The CO is converted to CO_2 and removed. Ammonia is made from the hydrogen. Urea, an important fertilizer, is manufactured from ammonia and CO_2. Several plants around the world capture CO_2 for this purpose.

Iron and cement production creates large amounts of CO_2 from the use of raw materials and from the energy to fuel the process. In the case of iron and steel, the CO_2 is released from the use of coking coal and limestone to reduce iron ore and to remove excess carbon to form steel. In the case of cement, CO_2 emissions come from the use of calcium carbonate to form clinker as well as from the large amounts of energy used in the process.

However, if significant reductions are to be made in the amount of CO_2 released to the atmosphere, then the emissions from coal-fired power plants must be captured and stored too. This will mean adapting the technology to retrofit existing power stations to capture the CO_2 after the coal is burnt (post-combustion capture) or build new higher efficiency power stations with CCS. Another technology is to apply new gasification technology to power production in which coal is "gasified" using oxygen or air to create a combustible gas then capture the CO_2 before burning the gas for power (pre-combustion capture). There are operating gasification plants which capture carbon dioxide, but it is not the preferred method for power production. A further new power production technology is to capture CO_2 by first separating oxygen from air and burning coal in an oxygen-rich gas. This is called “oxyfuel”, ‘oxy-combustion’ or “oxy-firing”. The resulting gases contain largely CO_2 and water which simplifies the capture process.

The major separations technologies for capturing CO_2 currently are:

- using a liquid solvent to absorb the CO_2. (absorption);
- using solid materials to attract the CO_2 to the surface, where it becomes separated from other gases (adsorption); and
- using membranes to separate the CO_2 from the other gases.

Other technologies include chemical looping technology (a metal oxide reacts with the fuel, creating metal particles, carbon dioxide and water vapour), low temperature or cryogenic separation processes (which rely on different phase change temperatures for various gases to separate them) and dry regenerable solid processes.

Compression and transport

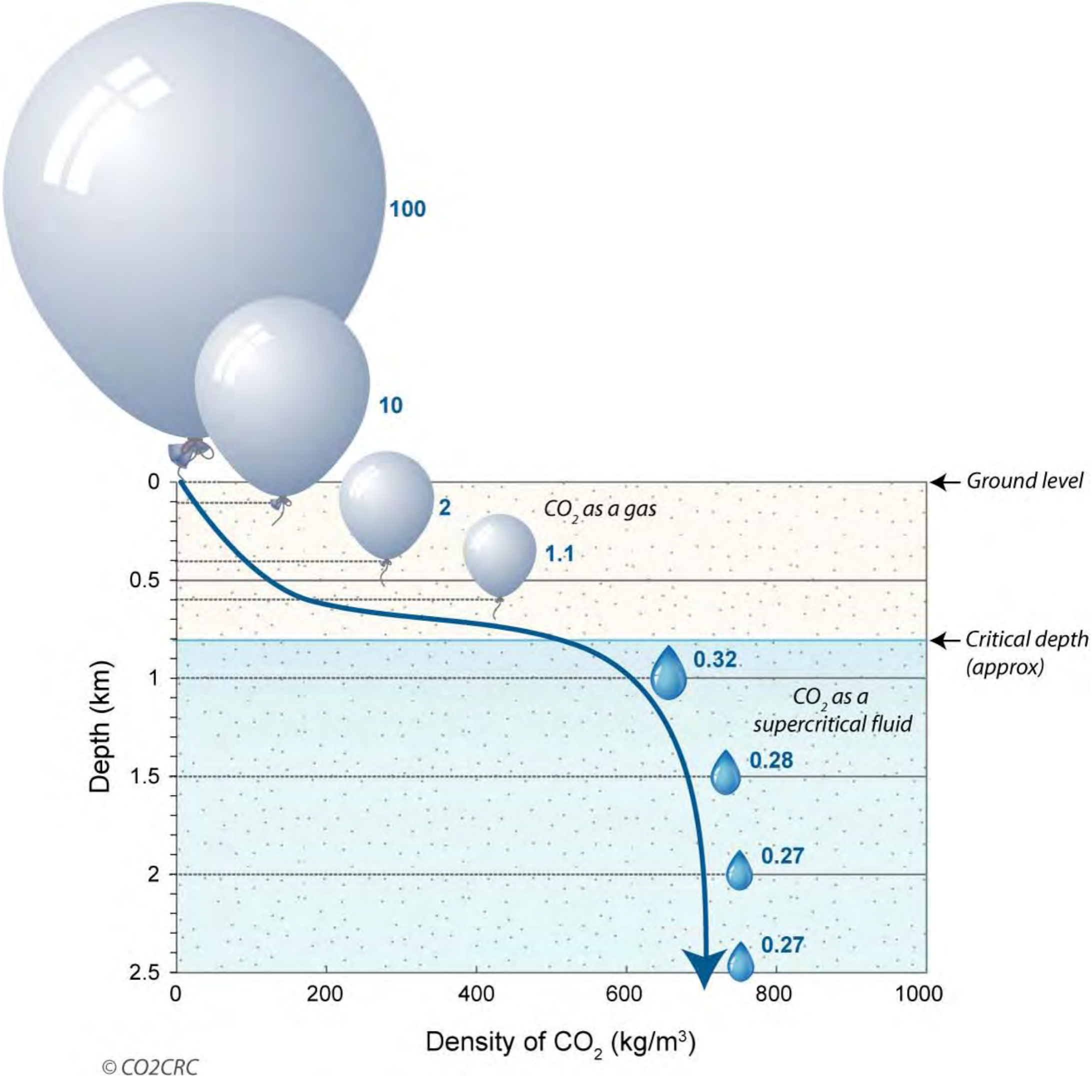

Figure 1.3: Once the CO_2 has been captured, it is compressed to a supercritical state, a very dense gas with liquid-like properties (courtesy of CO2CRC).

The CO_2 is usually dried and compressed before being transported to storage. The compression makes transporting the gas more efficient. CO_2 is used commercially in a number of industries, notably the beverage industry, and it has been transported on a large scale in the US for use in recovering oil from reservoirs (enhanced oil recovery). While much of this CO_2 is from natural sources (CO_2 is formed as a result of geological processes and can remain trapped in sedimentary basins). CO_2 captured from a variety of man-made sources will contain differing levels and types of impurities, which affects the compression and transport.

Injection and storage

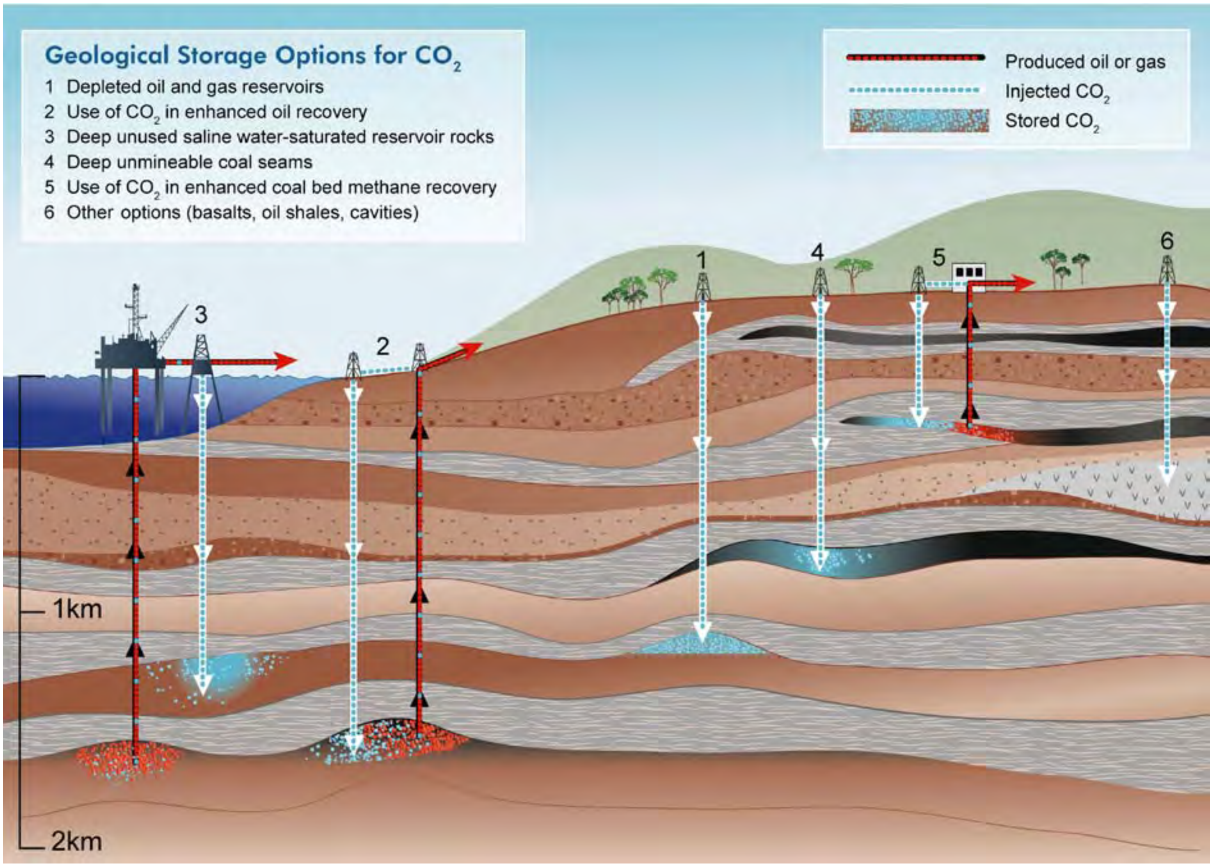

Figure 1.4: Options for storing CO_2 in geological formations (courtesy of CO2CRC).

There are a variety of types of geological formations that can be used to store CO_2. These are found in sedimentary basins. Sedimentary basins are subsiding regions of the Earth's crust that, by their shape, permit the net accumulation of sediments that result from various processes, such as: a) erosion of pre-existing rocks exposed on land (e.g., sands and muds); b) deposition of organic material; c) precipitation from water (e.g., salts); and d) volcanism (deposition of volcanic ash). As these sediments are piled and buried, they undergo a process of lithification and become sedimentary rocks, such as sandstones, carbonates, shales, coal, salt rock, tuffs and bentonites.

Deep saline aquifers-One of the more promising avenues of research has been the storage of carbon dioxide into aquifers deep in sedimentary basins. Of the various methods that have been suggested for the storage of carbon dioxide in sedimentary basins, aquifers have the largest capacity (Figure 1.4).

Oil and Gas Reservoirs-One of the most obvious, though not necessarily the best or largest, sinks for carbon dioxide in sedimentary basins are oil and gas reservoirs. There are four key reasons why the injection of CO_2 into oil and gas reservoirs may occur:

- **CO_2 can be injected into depleted oil and gas reservoirs**. The CO_2 may be injected into depleted oil and gas reservoirs, in which case the principle is that the conditions that allowed the hydrocarbons to accumulate in the first place, will also permit the accumulation of CO_2 in the pore space vacated by the produced hydrocarbons. Intuitively, the carbon taken out as oil and gas can be returned as CO_2.

- **Recoveries of oil can be increased**. Under the right conditions, CO_2 is a miscible solvent for oil, and recoveries can be increased substantially through miscible flooding of the reservoir (termed ***enhanced oil recovery***, or EOR). In effect, the residual oil is washed from the reservoir rock by the CO_2 solvent. Some of the CO_2 is returned to the surface with the crude oil production, but this is recycled to recover further oil.
- **Recoveries of natural gas can be increased**. CO_2 may be used to displace residual natural gas in depleted gas reservoirs, in a process known as ***enhanced gas recovery*** (EGR).

Coalbeds-CO_2 may be used to produce additional methane from coalbeds. This is a process known as ***enhanced coalbed methane recovery*** (ECBMR).

A number of conditions need to be met to store CO_2 geologically. In general they are:

- Porosity **-** pore space to store the CO_2 ;
- Permeability – pathways for the CO_2 to move through the rocks;
- Sealing rock – to prevent upward movement of buoyant CO_2; and
- Depth – adequate to keep the CO_2 as a supercritical fluid.

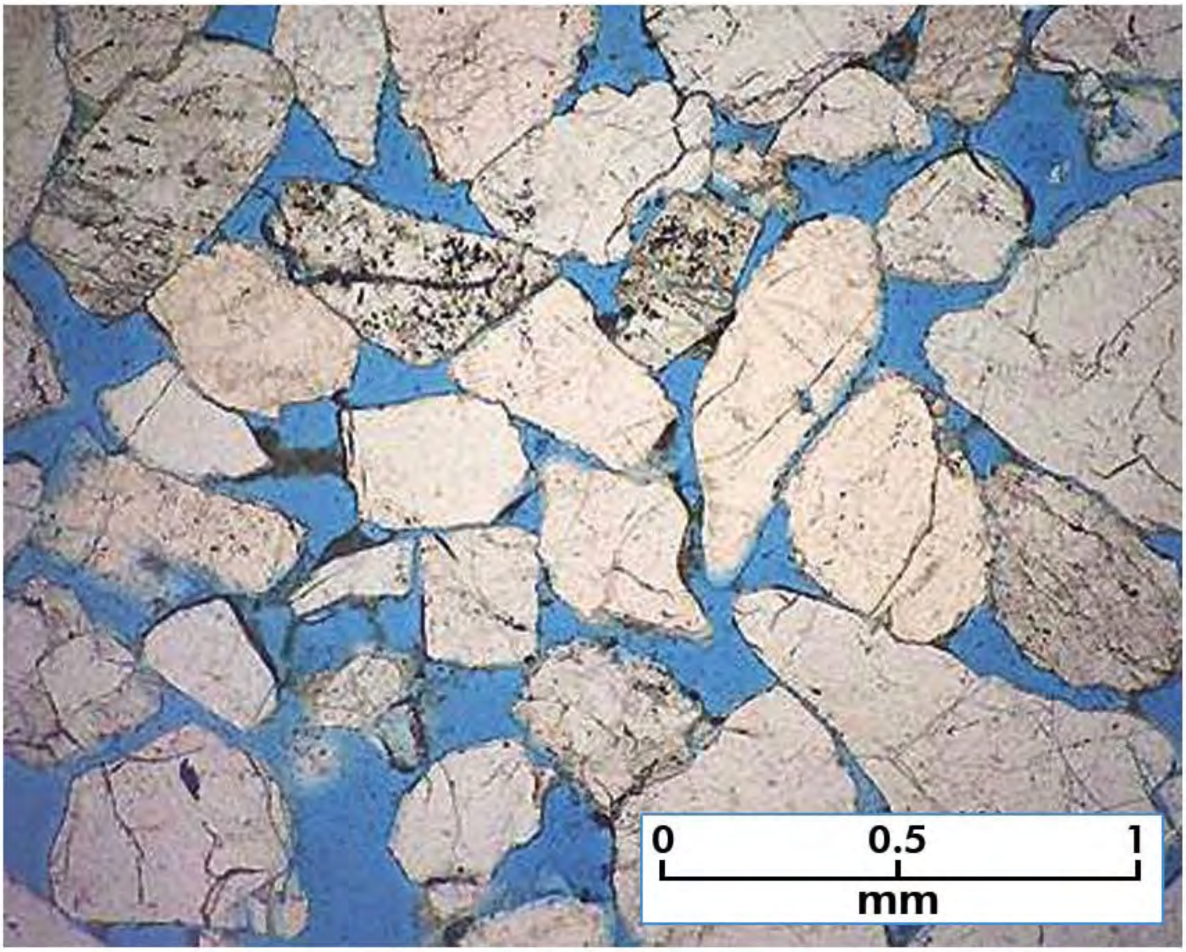

Figure 1.5: Tiny pore spaces in the storage rock shown by the blue spaces between the white grains of quartz in this photograph of a microscopic section of sandstone (courtesy of CO2CRC).

Sedimentary basins are suitable for CO_2 storage because they possess the right type of porous and permeable rocks for storage and injection, such as sandstones and carbonates, and the low permeability-to-impermeable rocks needed for sealing, such as shales and evaporitic beds.

When CO_2 is injected, it is not dissolved in formation water. It is free-phase, or immiscible. At reservoir temperatures it is less dense than the formation water and rises upwards. So that the CO_2 does not migrate to the surface there needs to be a trapping mechanism that keeps the CO_2 in the subsurface for thousands of years or longer.

There are several ways in which dense carbon dioxide can be trapped at 800 m or deeper in saline formations or fossil fuel reservoirs in sedimentary basins.

- **Structural/stratigraphic trapping -** traps CO_2 as a buoyant fluid within geological structures and flow system *(Also known as physical trapping or hydrogeological trapping*).
- **Residual trapping-** CO_2 is trapped as small droplets by interfacial (or surface) tension.
- **Solubility trapping -** the CO_2 dissolves into the surrounding formation water making that water about 1% more dense.
- **Mineral trapping -** dissolved CO_2 reacts with the reservoir rock, forming solid carbonate minerals

In coal beds, the CO_2 is adsorbed onto the coal bed (also known as adsorption trapping).

Choosing a site for storing CO_2 is an extensive process. It begins with screening for sedimentary basins, then screening those basins for suitable formations. Site characterisation examines all aspects of a storage site, such as the geological characteristics together with engineering, economic, community and regulatory considerations. It is time consuming and expensive, but a well-designed project is essential to meet the objective of storing CO_2 safely and securely.

Monitoring the stored CO_2

Once the CO_2 is injected, the storage site is monitored to show that the CO_2 remains in the reservoir. The monitoring program begins before injection to establish baseline data. Monitoring during the operational phase of the project records the dynamic behaviour of the CO_2 as it is injected and within the reservoir. After the injection ceases, the monitoring program is designed to ensure that the CO_2 storage meets the environmental and safety conditions required.

A monitoring program covers three monitoring domains:

- The sub-surface domain (the reservoir);
- The near-surface domain (shallow zones and soil); and
- The atmospheric domain

Many of the technologies for monitoring a storage project have been used by the oil and gas industries and are being adapted for CO_2 storage and are used for site characterization. Geophysical and remote sensing uses seismic, electromagnetic, gravity, microseismic and displacement sensors and petrophysical logging measurements. Geochemical monitoring involves geochemical analysis of fluids, gases, rock/soil, groundwater, surface water and the atmosphere. Environmental sensing techniques include atmospheric gas detection and dispersion modelling, remote sensing techniques including multi spectral analysis.

Outlook

Sedimentary basins, fossil fuel resources, and deleterious greenhouse gas emissions are all closely associated. To exploit the fossil fuels is to produce the greenhouse gases. This does not have to be so. The main greenhouse gas produced by the burning of fossil fuels is carbon dioxide. Rather than discharge carbon dioxide to the atmosphere, it can be stored in deep aquifers in the same sedimentary basins from which the fuel was extracted - some of the strata can be hydrocarbon-bearing (reservoirs) with the carbon dioxide enhancing oil or gas production.

Injection and storage technologies, developed by the oil and gas industry, are fairly mature. The volume of storage depends on the current and ultimate pressures of the reservoir or aquifer. Experience in injection of CO_2 has been gained from repressurizing oil reservoirs using CO_2 in enhanced oil recovery and from acid gas re-injection. Similar technology is being developed for production of methane from coal beds (i.e.

coalbed methane or CBM). The ultimate capacity of geological storage of carbon dioxide is likely huge, contingent upon identifying secure traps in sedimentary basins. However, there are still significant challenges ahead in making the technology commercial.

Major challenges for the deployment of CO_2 capture and storage

Some of the challenges ahead for CCS include:

- Reducing the cost of capture and scaling up the capture processes;
- Identifying the environmental impact of capture;
- Determining the implications of pressure build-up in a storage formation;
- Determining where the displaced water goes in a large scale injection and what the risk is to ground water;
- How to reliably predict the size of the CO_2 plume and where it migrates;
- How to gain confidence in site selection;
- Developing cost effective monitoring strategies and detection limits;
- Engaging finance and insurance industries;
- Greater regulatory and political certainty at all levels of government;
- Training a workforce for large scale deployment;
- Improve public awareness and acceptance (GHGT-9 conference summary).

Summary

The greenhouse effect is a natural phenomenon. Greenhouse gases trap heat in the earth’s atmosphere maintaining a climate hospitable for life. Global warming is expected to result when too many greenhouse gases collect, increasing the warming potential of the atmosphere. Increased average temperatures could trigger climate change.

Climate change is a change in the weather – meaning temperature, wind and precipitation - typically experienced in a region. At a global level, such changes could impact the Earth’s climate balance. Climate change has been labelled by some as the most significant threat facing our ecosystems and economy. Reducing anthropogenic greenhouse gases – gases that help to trap heat in the earth’s atmosphere – could help to reduce potential climate change effects. Changes in complex systems such as the global climate are very difficult to predict with any accuracy.

Possible climate responses to a rise in temperature are: increased desertification of semi-arid regions; higher levels of precipitation and flooding in other regions; the possibility of more intense storms such as hurricanes; and sea level rise.

As a general trend, emissions intensity has been decreasing, carbon sinks have been decreasing and net carbon emissions have been rapidly increasing. All of these have contributed to global warming and climate change.

There are three main approaches that can be used to reduce GHGs:

- energy conservation;
- reduction of carbon intensity; and
- carbon sequestration.

In order to arrest climate change, very large reductions in the amount of GHGs emitted to the atmosphere would need to be made. Geological storage is currently one of few greenhouse gas reduction technologies available that can reduce large enough amounts of GHGs.

A reduction in net CO_2 emissions into the atmosphere can only be achieved by:

Lowering the energy intensity of the economy E/GDP – by increasing the efficiency of primary energy conversion and end use;

Lowering the carbon intensity C/E of the energy system - by substituting lower-carbon or carbon-free energy sources for the current sources; or

Artificially increasing the capacity and capture rate of carbon sinks – through measures such as CO_2 capture and storage.

CO_2 can be captured from natural gas processing facilities, fossil fuel-fired power plants, cement plants, chemical plants and iron and steel manufacturing facilities. It can be captured before or after the combustion of fossil fuel depending on the process for combustion. The most common separation method is using a liquid solvent to absorb the CO_2.

The captured CO2 is compressed and transported to a geological storage site.

The geological storage of CO_2 requires access to large subsurface volumes in the rock pore space which can act as sealed pressurized containers. Aquifers have the largest capacity for all feasible sedimentary basins for CO_2 storage. The volume of pore space in aquifers far exceeds that of oil, gas and coal bed reservoirs.

The storage site is monitored before, during and after injection to show that the CO_2 remains stored.

While the technology need for CCS can be adapted from other applications, there are still challenges ahead to making the technology commercial.

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Module 2

CO_2 capture: Post combustion flue gas separation

Original text: S. Wong, APEC Capacity Building in the APEC Region, Phase II
Revised and updated by CO2CRC

Overview

CO_2 capture is the first and most expensive step in a CO_2 capture and storage project. CO_2 can be sourced from the waste gas from post-combustion or pre-combustion (decarbonization) and oxy-fuel combustion technologies.

Carbon dioxide emissions from burning fossil fuels for power and industry together contribute the largest proportion of CO_2 emissions worldwide. Much of this combustion occurs in air, and the resulting flue gas typically contains low concentrations of CO_2 (<20%). This module focuses on approaches currently used or being developed to separate CO_2 from these post-combustion flue gases. Pre-combustion and oxy-fuel combustion technologies are covered in Module 3.

Learning objectives

By the end of this module you will:

- Be able to identify sources of post combustion flue gas suited to CO_2 capture;
- Understand the various approaches that have been developed to separate CO_2 from post combustion flue gas, including their advantages, disadvantages and commercial readiness; and
- Be familiar with emerging research to improve CO_2 separation and make it more economically viable.

Sources of post combustion flue gas suited to CO_2 separation

CO_2 can be sourced from the waste gas from post-combustion or pre-combustion (decarbonization) and oxy-fuel combustion technologies. Carbon dioxide emissions from burning fossil fuels for power and industry together contribute the largest proportion of CO_2 emissions worldwide (47.8% in 2006 (WEO, 2008)). Much of this combustion occurs in air, and the resulting flue gas typically contains low concentrations of CO_2 (<20%).

Capture of CO_2 is best carried out at large point sources of emissions, such as power stations, oil refineries, petrochemical and gas plants, steel works and large cement works. CO_2 can be captured either from combustion flue gases or from process streams before combustion. Typical CO_2 concentrations in process streams are shown in Table 2.1 below:

Source type	Carbon dioxide concentration in waste gas(% of dry volume)	Pressure of gas stream (kPa)
Coal-fired thermal	12-14	100
Natural gas thermal	7-10	100
Natural gas turbine	3-4	100
Iron blast furnace	Up to 27	200-300 before combustion 100 after combustion
Cement Kilns	14-33	100
Sugar fermentation	100	100
Ammonia production	18	2800
Natural gas	2-65	900-8000

Table 2.1: Flue gas concentrations from various stationary sources (IPCC, 2005).

There are four main approaches which can be used for post combustion CO_2 separation from flue gas:

- Chemical and physical absorption;
- Solid physical adsorption;
- Low temperature distillation (cryogenic separation); and
- Membrane separation.

Each of these has different benefits and drawbacks, as well as applicability in different situations. These will be reviewed in the following sections. Other separation techniques include chemical looping which effectively removes oxygen from air prior to combustion.

Chemical and physical absorption

Chemical absorption

Chemical absorption involves one or more reversible chemical reactions between CO_2 and an aqueous solution of an absorbent, such as an alkanolamine or potassium carbonate (explained below). Upon heating the product, the bond between the absorbent and CO_2 can be broken, yielding a stream enriched in CO_2. The chemical absorption process for separating CO_2 from flue gas is borrowed from the gas processing industry. Amine based processes have been used commercially for the removal of acid gas impurities (CO_2 and H_2S) from process gas streams. It is therefore a proven and well-known technology.

Amine is a group of organic compounds, which can be considered as derived from ammonia (NH_3) by replacement of one or more hydrogen molecules by organic radicals. Amines are classified according to the number of hydrogens of ammonia that have been replaced by radicals as follows:

- Primary amine (RNH_2) - one hydrogen molecule has been replaced;
- Secondary amine (R_2NH) - two hydrogen molecules have been replaced; and
- Tertiary amine (R_3N) – all three hydrogen molecules have been replaced.

The substitute groups (R) may be alkyl, aryl or aralykl. When the (R) is an alkyl, the amine is called alkanolamine. In general, it can be considered that a hydroxyl group serves to reduce the vapor pressure and increase the water solubility, while the amino group provides the necessary alkalinity in water solution to absorb the acid gases. Akanolamines remove CO_2 from the waste gas streams through an exothermic reaction of CO_2 with the amine functionality of the alkanolamine. The amines of commercial interest to capture CO_2 are water-soluble.

A typical chemical absorption unit is shown in Figure 2.1. During the amine absorption operation the waste gas stream and liquid amine solution are contacted by countercurrent flow in an absorption tower (or absorber, see the left hand side of Figure 2.1).

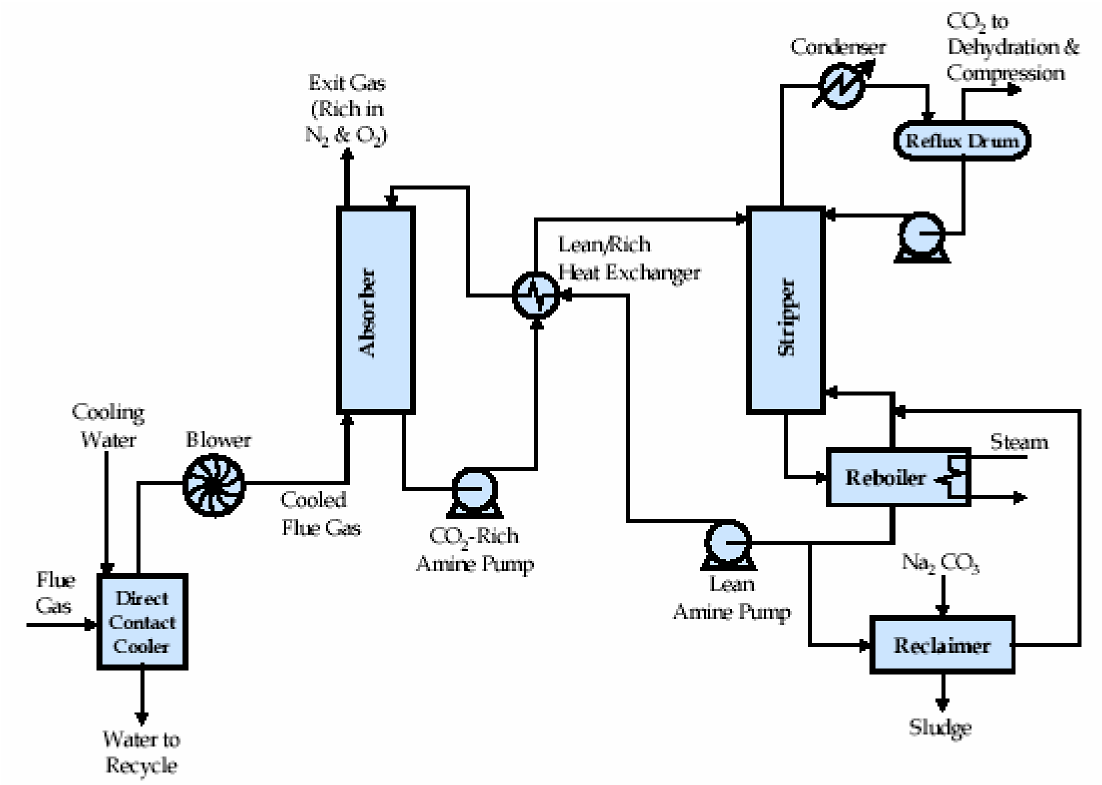


Figure 2.1: Typical chemical absorption unit for CO_2 recovery from flue gas.

The combustion flue gas coming out of the stack is hot (~ 232°C), and at atmospheric pressure. The flue gas needs to be cooled, before entering the absorber, which usually operates at less than 50°C. This is achieved by spraying cooling water in a direct contact cooler, as shown in bottom left hand side of Figure 2.1. A blower is installed to give the flue gas enough pressure for it to go through the absorption-desorption system. Conventionally, the waste gas to be scrubbed of the CO_2 enters the absorber at the bottom, flows up, and leaves at the top, whereas the solvent enters the top of the absorber, flows down (contacting the gas), and emerges at the bottom. Dilution of the circulating amine with water is undertaken to reduce viscosity of the circulating fluid. A higher viscosity fluid would require more power to pump and provide circulation. The liquid amine solution containing the absorbed gas then flows to a regeneration unit (stripper) where it is heated and the acid gases liberated. The solvent regeneration can be carried out at low pressures to enhance desorption of CO_2 from the liquid. Some amine solution is typically carried over in the acid gas stream from the regeneration step and the amine solution is recovered using a condenser, in order to avoid excessive solvent losses. The hot lean amine solution then flows through a heat exchanger where it is contacted with the rich amine solution from the contact tower and from there the lean amine solution is returned to the gas contact tower, i.e. absorber.

Figure 2.2: A solvent capture rig (background) retrofitted to International Power's Hazelwood coal-fired power plant in Australia to capture carbon dioxide from post-combustion flue gases (courtesy of CO2CRC).

Types of alkanolamines

There are three main groups of Alkanolamines: primary, secondary and tertiary amines.

Primary amines include monoethanol amine (MEA) and diglycolamine (DGA). MEA has been the traditional solvent of choice for carbon dioxide absorption and acid gas removal in general. MEA is the least expensive of the alkanolamines; its reaction kinetic is fast and it works well at low pressure, and low CO_2 concentration. However, there are several disadvantages. First, it has a high heat of reaction with CO_2, which means high level of energy has to be supplied in the regeneration step. Second, the absorptivity of MEA with CO_2 is not great. In the case of primary and secondary alkanolamines the formation of carbamate (RNHCOO-) is the main reaction.

$$CO_2 + 2RNH_2 = RNHCOO^- + RNH_3^+$$

In this reaction, two moles of MEA must be used to capture 1 mole of CO_2. Third, the full upper absorption capacity of MEA is not realized in practice due to corrosion problems. The corrosion effect is due to dissolved CO_2 and varies with the amines used. The concentration of MEA in the aqueous phase in the presence of O_2 is limited to 20-wt% (weight percent). In addition, MEA has the highest vapor pressure of any of the alkanolamines and high solvent carryover can occur during CO_2 removal from the gas stream and in the regeneration step. To reduce solvent losses, a water wash of the purified gas stream is usually required. In addition, MEA reacts irreversibly with minor impurities such as COS and CS_2 resulting in solvent degradation. Foaming of the absorbing liquid MEA due to the build-up of impurities can also be a concern.

There is considerable industrial experience with MEA and most systems at present use an aqueous solution with only 15-25-wt% MEA, due to corrosion issues (GPSA, 1998). Corrosion inhibitors may be added to MEA solution, and this results in an increase in solution strength. The inhibitors are usually not disclosed, as these will distinguish one commercial MEA process from another. In the commercial Fluor Daniel ECONAMINE FG process, a concentration of MEA up to 30-wt% has been employed successfully to remove 80% - 90% of the carbon dioxide from the feed gas (Mariz, 1998). Another commercial process from ABB LUMMUS, which uses 20% MEA with inhibitors, is also offered for CO_2 capture (Barchas, 1992).

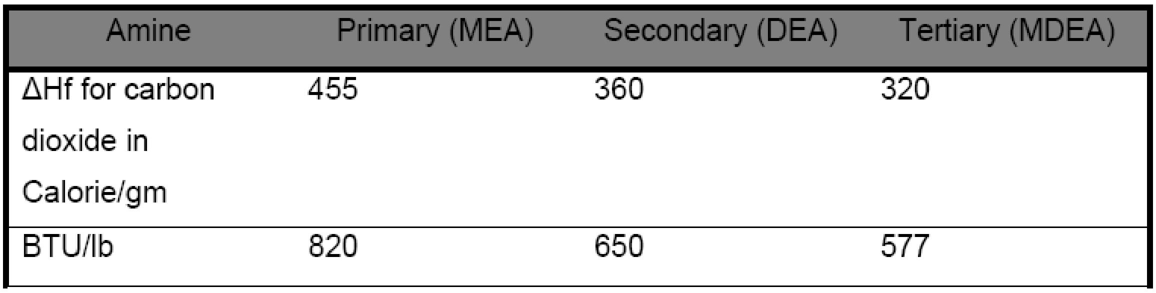
For the current MEA absorber systems, the adsorption and desorption rates are reasonably high, hence good reaction kinetics. However, the packing in the absorber (contactors, to facilitate efficient mass transfer) represents a significant cost, and its energy consumption is also significant for CO_2 capture from flue gas. In addition, the stripping temperature should not be too high (~ 150°C). Otherwise, dimerization of carbamate may take place, deteriorating the sorption capability of MEA.

Secondary amines include diethanolamine (DEA), di-isopropylamine (DIPA). Secondary amines have advantages over primary amines. Their heat of reaction with carbon dioxide is lower (360 calorie/g (650 BTU/lb) versus 455 calorie/g (820 BTU/lb) for primary amines). This means that the secondary amines require less heat in the regeneration step than primary amines. However, it has all the other problems of primary amines.

Tertiary amines include triethanolamine (TEA) and methyl-diethanolamine (MDEA). Tertiary amines react more slowly with carbon dioxide than primary and secondary amines thus require higher circulation rate of liquid to remove carbon dioxide compared to primary and secondary amines. This can be improved through the use of promoters. A major advantage of tertiary amines is their lower heat requirements for carbon dioxide liberation from the carbon dioxide containing solvent.

Tertiary amines show a lower tendency to form degradation products in use than primary and secondary amines, and are more easily regenerated. In addition, tertiary amines have lower corrosion rates compared to primary and secondary amines. The main drawback is its reaction rate is too slow.

Table 2.2 compares the heat of reaction between the three amine and carbon dioxide.



Amine	Primary (MEA)	Secondary (DEA)	Tertiary (MDEA)
ΔHf for carbon dioxide in Calorie/gm	455	360	320
BTU/lb	820	650	577

Table 2.2: Heat of reaction between three amines and carbon dioxide (Skinner et al, 1995).

Corrosion has been a serious issue in amine processes. In general, alkanolamines themselves are not corrosive to carbon steel; it is the dissolved CO_2 that is the primary corroding agent. The alkanolamines indirectly influence the corrosion rate when they absorb CO_2. The observed corrosivity of alkanolamines to carbon steel is generally from primary (most corrosive) to tertiary (least corrosive).

Operator	Location	Capacity (t/day CO_2)	Fuel source	CO_2 use	Technology	Status
Sumitomo Chemicals	Chiba, Japan	165	Gas boiler	Food grade	Fluor Econoamine MEA	Operational since 1994
Luzhou Natural Gas	Sichuan, China	160	NH_3 plant reformer	Urea	Fluor Econoamine MEA	
Prosint	Rio de Janeiro, Brazil	90	Gas boiler	Food grade	Fluor Daniel	Operational since 1997
Mitsubishi Heavy Industries	Keda, Malaysia	160	Steam reformer flue gas	Urea	MHI KS-1	Operational since 1999
Mitsubishi Heavy Industries	Aonala & Phulpur India	450 (x 2 units)	Gas boiler & steam reformer	Urea	MHI KS-1	Operational 2007

Table 2.3: Some commercial CO_2 recovery plants worldwide.

Limitations of amine-based processes and technological advances

Much of the amine scrubbing technology in the past has focused on the removal of hydrogen sulfide for the natural gas sector. However, the requirements are different for the recovery of CO_2 from power plant flue gas. One challenge is the low pressure of the flue gas for absorption of CO_2. In addition, impurities in flue gas such as oxygen, sulfur oxides, nitrogen oxides, and particulate matter create special challenges during the separation process.

Low pressure – the greatest limitation for CO_2 recovery from flue gas is the low pressure of the flue gas. CO_2 is absorbed much more easily into solvents at high pressure. The only commercially available solvents that can absorb a reasonable amount of CO_2 from dilute atmospheric pressure gas are primary and sterically hindered amines, such as MEA, DGA and the KS-1 series of solvents (Chapel et al., 1999). These solvents can absorb CO_2 at low pressures because they have high reaction energies. This results in high-energy requirements to regenerate the rich solvent. However, energy costs may be reduced if the process can be fully integrated with a power plant where significant amount of low-grade heat may be available. (see Heat Integration)

Oxygen – most amine solvents degrade to varying degrees in oxidizing atmospheres. This leads to either high solvent losses or expensive reclaiming processes. Oxygen also causes corrosion problems in the process equipment, which can lead to failures or more expensive materials of construction. The use of inhibitors in the solvent to reduce degradation and corrosion appears to work well and produces very good results.

Sulphur oxides – (SO_2, SO_3) react with MEA to form heat-stable corrosive salts that cannot be reclaimed. Some commercial MEA processes require a sulphur oxides limit of less than 10 ppm level. It is generally accepted that installing a flue gas desulfurization unit before the absorber is the best way to alleviate the problem.

Nitrogen oxides – a typical flue gas contains some amount of NOx. NOx generally consists of NO and NO_2 in a ratio of from 95:5 to 90:10. The main component NO performs as inert gas and will not affect the solvent. However, NO_2 will partially lead to the formation of a heat stable salt. Generally some solvent degradation is acceptable in order to avoid the cost of removing the NO_2.

Particulate matter – fly ash in the flue gas can cause foaming and degradation of the solvent, as well as plugging and scaling of the process equipment. A wash operation has been recommended to reduce the fly ash content to appropriate levels to abate the aforementioned problems.

Flue gas entering the absorber at high temperatures can lead to solvent degradation and decreased absorption efficiency. The flue gas must be cooled to a water dew point of 50°C, which can be accomplished in the desulfurization unit or with a direct contact water cooler.

In summary, the recovery of CO_2 from combustion flue gas requires a significant amount of pre-treatment processing in order to avoid any foul-up in the solvent absorption step. This will add to the cost of CO_2 capture. However, significant improvements can be made in the solvent absorption process in terms of optimizing the compositions of the absorbing amines and the gas-liquid contactors, in order to manage this.

Specialty amines

Considerable work is ongoing on improved amines and processes for the specific task of carbon dioxide capture. Specialty amines such as hindered amines are being developed to solve some of these issues. The idea behind hindered amines is based on attaching a bulky substitute to the nitrogen atom of the amine molecule. This molecular configuration plays an important role in process performance, by affecting the capacity of absorption and the desorption temperature. In the case of CO_2 removal, the capacity of the solvent can be greatly enhanced if one of the intermediate reactions, such as the carbamate formation reaction, can be slowed down by providing steric hindrance to the reacting CO_2. A 2006 study at a pilot plant in Osaka compared MEA, KS-1, a hindered amine and DEA found that the hindered amine performed well, with the highest effective CO_2 loading of the solvents (Yagi et al, 2006).

In addition to slowing down the overall reaction, bulkier substitutes give rise to less stable carbamates. By making the amine carbamate unstable, one can theoretically double the capacity of the solvent (Chakma, 1994).

In this case the bicarbonate formation becomes the dominant reaction.

$$RNH_2 + CO_2 + H_2O = RNH_3^+ + HCO_3^-$$

The advantage of sterically hindered amines over the alkanolamines is that in the bicarbonate reaction only 1 mole of hindered amine instead of 2 moles of alkanolamine is required to react with 1 mole of CO_2. In addition, sterically hindered amine systems can have lower heats of absorption/regeneration as compared with MEA.

The International CO_2 Capture Center in Regina, Saskatchewan, Canada also has developed a series of proprietary designer solvents designated as PSR solvents (Veawab et al., 2001). The PSR solvents have been designed specifically for the separation of CO_2 from flue gas streams. The PSR solvents may be used at higher amine concentration than conventional MEA solvents and at a higher loading of CO_2. The key features claimed for the PSR solvents are lower regeneration temperature, lower solvent circulation rate, lower solvent degeneration rate, and lower corrosion rate.

Further developments in amine solvents

Mistusbishi Heavy Industries (MHI) and KANSIA have a commercially developed propriety solvent KS-1, which is used to strip CO_2 from flue gas from natural gas boilers and steam reformers. The plants operating with this technology are in Malaysia, Japan and India (two plants) (Kishimoto et al, 2009). There have been trials of the solvent with coal fired boilers in a 10 t/d slip steam from J-Power's 2x500MW units in Matushima, Japan. The CO_2 recovery efficiency is 90%. The heat consumption was 730 – 820 kcal/kg CO_2, but with improvements to the process, the steam consumption could be reduced by 15%.

An EU project, CASTOR, involves trials of novel blended amine solvents CASTOR- 1 and CASTOR-2 at a 24t/d absorption pilot plant at Esbjerg power station, Denmark. Knudsen et al report that CASTOR -2 has a lower steam demand than MEA and is more chemically stable (Knudsen et al, 2009).

Chilled ammonia

The CO_2 in the flue gas is cooled before entering the absorber where it reacts with ammonium carbonate to form ammonium bicarbonate. Ammonia is released as a gas from the solvent solution when the CO_2 is absorbed, and the temperature is kept low to minimize this. Gases exiting the absorber pass through a water wash to remove ammonia.

The ammonium bicarbonate is heated in the regenerator, separating the CO_2. The ammonium carbonate solvent is returned to the absorber. Water and ammonia are removed from the CO_2 stream exiting the stripper column.

Alstom's Chilled Ammonia Process has been piloted at the We Energies Pleasant Prairie Power Station. A larger demonstration (100,000 tonnes per annum) including sequestration in a saline formation is planned for the AEP Mountaineer coal-fired Power Station in the US.

Chemical absorption with potassium carbonate

Many alkaline salt–based processes have been developed for carbon dioxide removal. These utilize the alkali salts of various weak acids. The most popular salts in the industry have been sodium carbonate and potassium carbonate. Low cost and minimal degradation of the solvent are the primary reasons.

The major commercial processes that have been developed for H_2S and CO_2 absorption are aqueous solutions of sodium or potassium compounds. Potassium carbonate can absorb CO_2 at high temperatures, an advantage over amine-based solvents. The principal technologies employed are processes based on hot potassium carbonate (K_2CO_3) solutions that are used for the removal of CO_2 from high-pressure gas streams, among other applications.

The hot potassium carbonate process is used in many ammonia, hydrogen, ethylene oxide and natural gas plants. Potassium carbonate has a low rate of reaction. To improve CO_2 absorption mass transfer promoters such as piperazine, diethanolamine and arsenic trioxide have been used. Less toxic promoters such as borate are currently being investigated for used with flue gas streams (Ghosh et al, 2009). To limit corrosion, inhibitors are added. These systems are known as activated hot potassium carbonate systems.

Studies indicated that presence of flue gas impurities SO_x and NO_x reduces the operational efficiency of the potassium carbonate as a solvent. SO_2 and NO_2 are not able to be released from the solvent under industrial conditions. Current research is investigating the selective precipitation of the impurity salts formed by SO_x and NO_x so that they can be removed (Smith et al, 2009).

Some licensed hot, activated potassium carbonate systems are the Benfield and the Catacarb process. The processes are designed for bulk CO_2 removal from high-pressure streams, but also produce high-purity CO_2.

Contactors in solvent systems

Various column packings are used to increase mass transfer rates. Examples include Pall rings (a random packing), Mellapak (a structured packing). Novel packings, such as SMR, are being trialled and significant improvements in mass transfer have been reported (Smith et al 2009).

Capture plant process optimisation and heat integration

Careful design of the post combustion capture plant and of the capture plant within a power plant can reduce the energy cost of adding a capture unit to a power plant. Tests by MHI have shown that using lean solvent and steam condensate heat for regeneration inside the stripper can achieve a 15% reduction in the heat required for capture (Kishimoto et al, 2009). In addition, integration of heat between the power plant and the capture plant has been studied, and improvements in design show that further reductions in the energy required are possible.

Studies of a lignite power station have shown that through proper integration of CCS into the plant, particularly through the use of energy in the flue gas, the energy penalty of the plant can be reduced to approximately 15%. Further reductions are possible if the coal is pre-dried (Harkin et al, 2009).

Physical absorption

For physical absorption, CO_2 is physically absorbed in a solvent according to Henry's Law. The absorption capacity of organic or inorganic solvents for CO_2 increases with increasing pressure and with decreasing temperatures. Absorption of CO_2 occurs at high partial pressures of CO_2 and low temperatures. The solvents are then regenerated by either heating or pressure reduction. The advantage of this method is that it requires relatively little energy; but the CO_2 must be at high partial pressure. Hence, it is suitable for recovering CO_2 from "Integrated Gasification Combined Cycle" (a pre-combustion technology – see Module 3), where the exhaust CO_2 would leave the gasifier at elevated pressures. Some physical solvent processes are the Selexol process (dimethylether of polyethylene glycol), the Rectisol process (cold methanol), the Fluor Solvent process (Propylene Carbonate) and Purisol process (N-Methyl-2-Pyrrolidone). The Purisol and Selexol processes have a high selectivity for H_2S, while the Flour Solvent is best used with feed gases with low levels of H_2S.

Selexol has been used since 1969 to sweeten natural gas, both for bulk CO_2 removal and H_2S removal. Absorption takes place at low temperature (0 - 5°C). Desorption of the rich Selexol solvent can be accomplished either by letting down the pressure (CO_2 removal) or by stripping with air, inert gas or steam. Hydrocarbons, COS, CS_2 and mercaptans are also removed by the solvent. Additionally, the low absorption temperature used requires that the lean solvent be returned to the absorber via a refrigeration unit. The Exxon gas plant at La Barge, Wyoming, USA uses two Selexol processes in series, one for removing H_2S and other for removing CO_2.

Rectisol has mainly been used to treat synthesis gas, hydrogen and town gas streams and removes most impurities. The Great Plains Synfuels Plant in North Dakota, USA - a coal gasification plant - uses a Rectisol process to separate CO_2 from a mixture of H_2, CO and CO_2. More than $3Mt/CO_2$ per year is captured at this plant. Chilled methanol is used in the North Dakota plant, however, in general, other solvents are also available for special applications.

Because the partial pressure of CO_2 in the combustion flue gas is low and the temperature is relatively high, the physical absorption approach does not appear competitive compared to chemical absorption for post-combustion capture.

Solid physical adsorption

An adsorption process consists of two major steps: adsorption and desorption. The technical feasibility of a process is dictated by the adsorption step, whereas the desorption step controls its economic viability. Adsorption requires a strong affinity between an adsorbent and the component to be removed from a gas mixture (in this case, CO_2). However, the stronger the affinity, the more difficult it is to desorb the CO_2 and the higher the energy consumed in regenerating the adsorbent for reuse in the next cycle. The desorption step, therefore, has to be very carefully balanced against the adsorption step for the overall process to be successful.

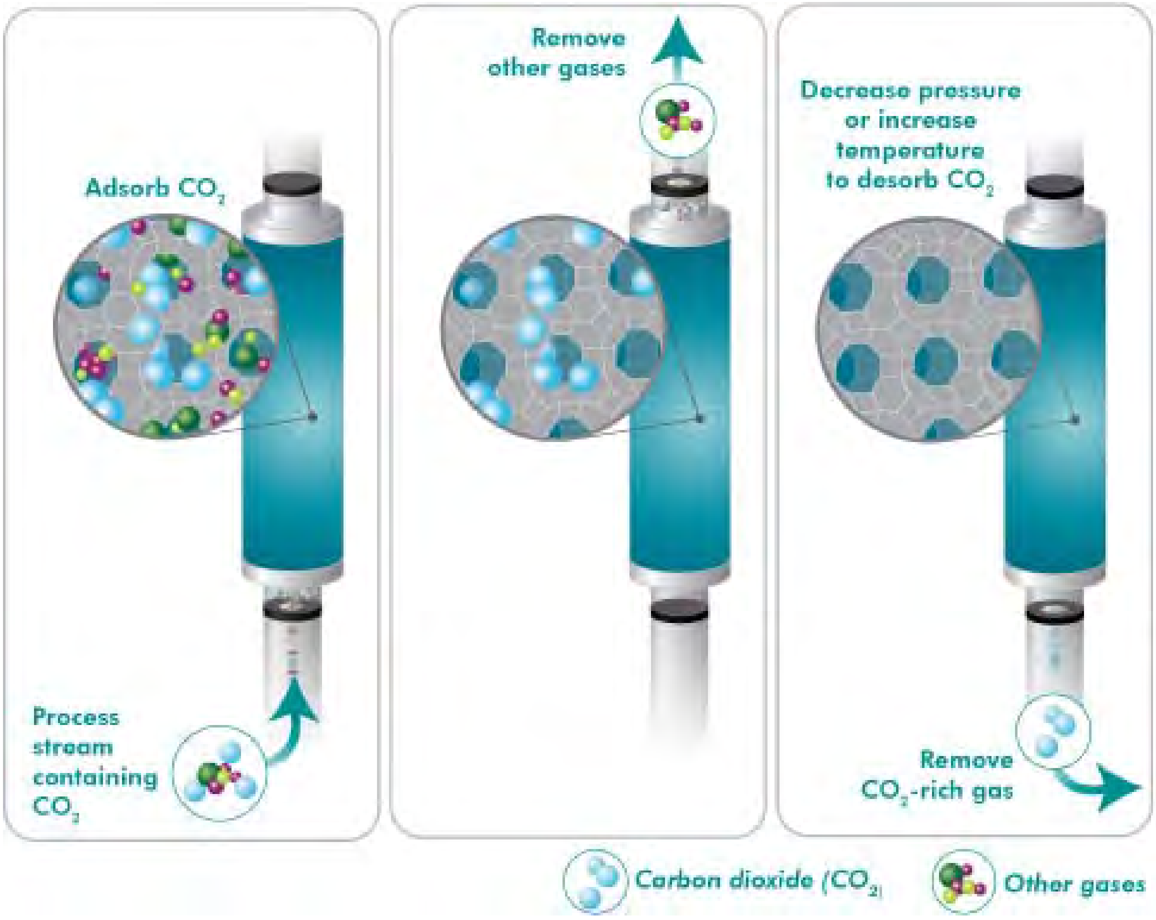


Figure 2.3: The principle of adsorption capture (courtesy of CO2CRC).

The main advantage of physical adsorption over chemical absorption is its simple and energy efficient operation and regeneration, which can be achieved with a pressure swing or temperature swing cycle (a swing in pressure or temperature as the process goes through an absorption-desorption cycle in order to achieve separation). These separations processes are known as pressure swing adsorption (PSA) and temperature swing adsorption (TSA). Where the regeneration of the adsorbent bed is achieved through a pressure reduction to near-vacuum pressure, it is known as vacuum swing adsorption (VSA). Pressure swing adsorption is a commercial process for hydrogen separation from H_2 and CO_2 mixtures in hydrogen production.

There have been significant advances in the development of adsorbents for CO_2 removal from flue gases. The primary adsorption material used has been zeolites. Zeolites are more effective for CO_2 separation from species which are less polar than CO_2, so the presence of water and SOx in flue gas streams poses a problem (Ram Reddy et al, 2008).

New adsorbents have been considered and developed such as carbons, mesoporous silico-aluminates (eg zeolitic imidazolate frameworks, ZIFs) and metal organic frameworks (MOFs). Carbon-based adsorbents have the potential to be regenerated by applying a electrical voltage, (electrical swing adsorption), or ESA. New materials being investigated include layered double hydroxide derivatives (LDHs and LDOs). Other advances include functionalising the pores of the adsorbent material by incorporating amines to increase CO_2 loading. In this case, the CO_2 is separated through a chemisorption process (Chaffee et al, 2006).

New processes are being developed for dealing with high humidity flue gas streams and impurities. These include multilayered adsorbent beds. Multilayered beds enable the use of adsorbents with high CO_2 selectivity but which degrade significantly in the presence of water.

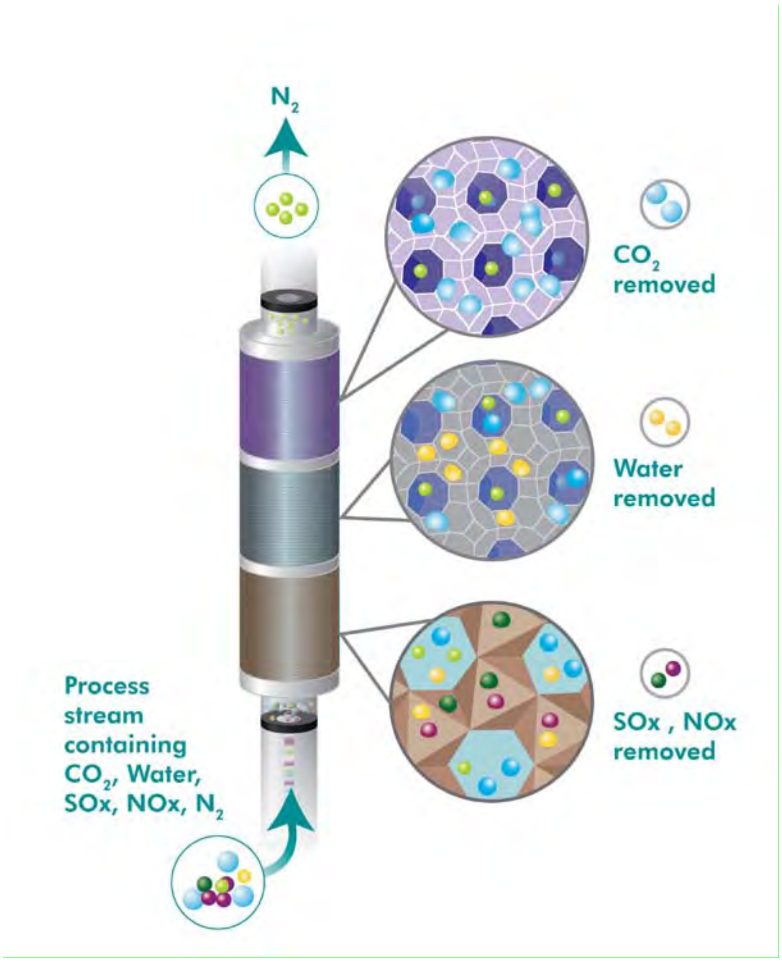


Figure 2.4: Multilayered adsorption beds for separating carbon dioxide (courtesy of CO2CRC).

Low temperature distillation (cryogenic separation)

Low temperature distillation, or cryogenic separation, is a commercial process commonly used to liquefy and purify CO_2 from relatively high purity (> 90%) sources. It involves cooling the gases to a very low temperature so that the CO_2 can be liquefied and separated.

Distillation generally has good economies of scale. This method is worth considering where there is a high concentration of CO_2 in the waste gas. The advantage is that it produces a liquid CO_2 ready for transportation by pipeline. The major disadvantages of this process are the amount of energy required to provide the refrigeration and the necessary removal of components that have freezing points above normal operating temperatures to avoid freezing and eventual blockage of process equipment.

For post combustion flue gases, the waste streams contain water and other trace combustion by-products such as NOx and SOx several of which must be removed before the stream is introduced to the low temperature section. Moreover, these by-products are usually generated near atmospheric pressure. These tend to make cryogenic process less economical than others in separating CO_2 from flue gas. However, it is a serious contender for high-pressure gases such as in pre-combustion decarbonization processes. (see Module 3).

Membrane separation

Separation membranes are thin barriers that allow selective permeation of certain gases. They are predominately based on polymeric materials. Membranes for gas separation are usually formed as hollow fibers arranged in the tube-and-shell configuration, or as flat sheets, which are typically packaged as spiral-wound modules (Figure 2.5).

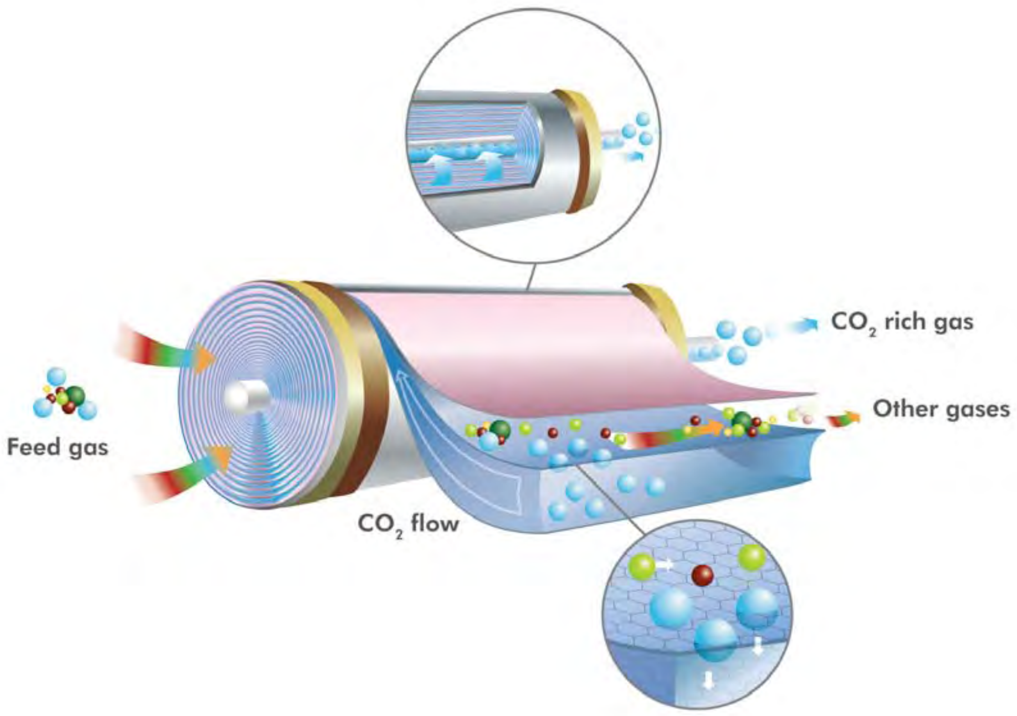


Figure 2.5: A spiral wound module showing the separation of carbon dioxide from other gases (courtesy of CO2CRC).

The membrane process has been widely used on a commercial scale for hydrogen recovery from purge gases in ammonia synthesis, refinery and natural gas dehydration, sour gas removal from natural gas, and nitrogen production from air.

The advantages of the membrane process are:

- It does not require a separating agent, thus no regeneration is required;
- The systems are compact and lightweight, and can be positioned either horizontally or vertically, which is especially suitable for retrofitting applications;
- Modular design allows optimization of process arrangement by using multi-stage operation; and
- Low maintenance requirements because there are no moving parts in the membrane unit.

A number of solid polymer membranes are commercially available for the separation of CO_2 from gas streams, primarily for natural gas sweetening. These membranes selectively transmit CO_2 versus CH_4. The driving force for the separation is pressure differential across the membrane. As such, compression is required for the feed gas in order to provide the driving force for permeation. In addition, the separated CO_2 is at low pressure and requires additional compression to meet pipeline pressure requirements. The energy required for gas compression is significant when a very high pressure is required.

The commercial membranes for CO_2 separation are mainly prepared from cellulose acetate, polysulfone, and polyimide. These membranes are primarily tailor-made for natural gas processing. Condensable components in a flue gas, particularly water, will reduce the CO_2 permeability and affect the selectivity of the membrane (by making a glassy polymer more rubbery). Laboratory trials mimicking real flue gas have been carried out at CO2CRC’s laboratories, and trials on post-combustion and pre-combustion flue gas streams are being undertaken at pilot plants (Scholes et al, 2009).

The selectivity of CO_2/N_2 of these membranes is generally in the range of 1:20 ~ 1:40 depending on the operating temperature. Because of the specific characteristics of flue gas composition, and the specific features of the separation (i.e. large volumetric flow rate, low source pressure, high temperature, and the relatively low commodity value of CO_2), further development is being undertaken for economically capturing CO_2 from flue gas on a large scale. These developments aim to improve the selectivity of CO_2/N_2 and the permeability of the membranes. New composite polymeric membranes have been developed. Some of these combine membranes with high selectivity with membranes with high permeability. Others improve separation performance by blending polymides.

Membrane research includes work on inorganic membranes which can operate at high temperatures (eg for H_2/CO_2 separation in pre-combustion gas streams – see Module 3). Inorganic membranes can contain functionalized pores which increase the selectivity above what can be achieved by molecular sieving alone. Research is being undertaken into mixed matrix membranes (inorganic particles in a polymeric matrix) and facilitated transport membranes (where a chemical reaction occurs between the gas and the membrane). Facilitated transport membranes rely on a reversible reaction occurring with the membrane to transport the CO_2 through the membrane. A pressure difference is still required to drive separation. (Scholes et al, 2008)

Membrane gas absorption – a hybrid membrane/chemical absorption process

Some efficiencies could be realized by developing amine and membrane technologies in tandem, thereby forming a hybrid process to capture CO_2 from flue gas. Micro-porous hollow fiber membranes are evolving as a new technology for CO_2 separation using amine-based chemical absorption processes. Micro-porous membranes are used in the gas-liquid unit where the amine solution is contacted with the CO_2 containing flue gas. The principle advantage of the micro-porous membrane is the reduction in the physical size and weight of the gas-liquid contacting unit.

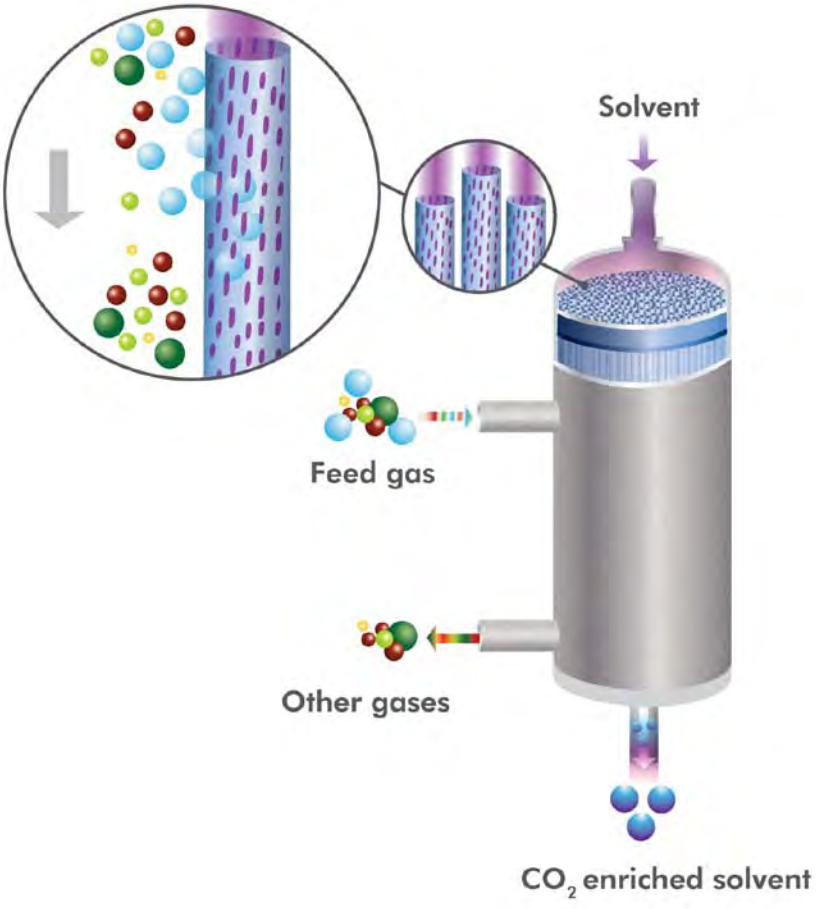


Figure 2.6: Membrane gas absorption: hollow fibre module (courtesy of CO2CRC).

Unlike conventional membrane separation, the micro-porous hollow fiber membrane separation is based on reversible chemical reaction, and mass transfer occurs by diffusion of the gas through the gas/liquid interface just as in the traditional contacting columns.

The hollow fiber membrane itself does not contribute to the separation but instead acts as a contacting medium between the gases and the liquid. There are a number of advantages to using the gas-liquid membrane contactors, including:

High gas/liquid contact area due to the high packing density of the hollow fibers (500 to 1,500 m^2/m^3, versus 100~250 m^2/m^3 for a conventional column);

Foaming is eliminated since the gas flow does not impact the solvent and there is no convective dispersion of gas in the liquid;

The membrane acts as a partition between the gas and liquid, and the gas/liquid flow rate ratio may vary widely without causing flooding problems;

The available gas/liquid contact area is not disturbed by variations in flow rates. This means the process can tolerate a wider range of process condition variations;

Solvent degradation is minimized as oxygen (a degradation agent to amines) is prevented from intimate contact with the solvents; and

Unlike the absorption column that can only be operated vertically, the hollow fiber membrane contactor may be operated in any orientation to suit the overall plant layout.

Challenges ahead for post-combustion capture

A summary from GHGT-9

Cost and scale are two significant issues for CO_2 capture. Advances are being made to reduce the cost of capturing CO_2, but these advances may be overrun by higher plant construction costs. The focus should be on reducing the energy penalty for solvents, including adapting current solvents and developing new solvents

While there are new pilot plants for post-combustion capture, demonstration of the technology for these applications at the scale of 2-4 Mt CO_2 year on a coal-fired power plant has not yet taken place.

Other issues are water usage, environmental impact, and the feasibility of retrofitting capture plants.

Summary

Capture of CO_2 is best carried out at large point sources of emissions, such as power stations, oil refineries, petrochemical and gas plants, steel works and large cement works. CO_2 can be captured either from combustion flue gases or from process streams before combustion. CO_2 in combustion flue gas has low partial pressure. CO_2 is absorbed much more easily into solvents at high pressure. Commercially available solvents that can absorb a reasonable amount of CO_2 from dilute atmospheric pressure gas are primary and sterically hindered amines. These solvents have high reaction energies. This results in high-energy requirements to regenerate the rich solvent.

CO_2 scrubbing with amines has been borrowed from the natural gas processing industry. Much of the amine scrubbing technology in the past has focused on the removal of hydrogen sulfide; however, for the recovery of carbon dioxide from power plant flue gas, the requirements are different. Other impurities such as oxygen, sulfur oxides, nitrogen oxides, and particulate matter are present in flue gas and these substances must be removed before the chemical absorption step. These add to the cost of CO_2 separation.

In the short term, significant improvements can be made to the chemical absorption process in optimizing the compositions of the absorbing amines; and improving the performance of the gas-liquid contactors and the overall heat utilization by better heat integration with the CO_2 source plant. With further improvements, cost is expected to fall.

Hybrid membrane/amine process is promising. Micro-porous hollow fiber membranes are evolving as a new technology for CO_2 separation using amine-based chemical absorption processes. Other separation processes such as physical adsorption and low temperature distillation are being developed. The advantages of physical adsorption over chemical adsorption is that it is simpler and more energy efficient. Low temperature distillation is a commercial process commonly used to liquefy and purify CO_2 from relatively pure sources. Distillation is suited to situations where there is a high concentration of CO_2 in the waste gas. It creates transport-ready liquid CO_2, but draws a high amount of energy.

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Module 3

CO_2 capture: Pre-combustion (decarbonisation) and oxy-fuel technologies

Original text: S. Wong, APEC Capacity Building in the APEC Region, Phase II
Revised and updated by CO2CRC

Overview

In Module 2, the different methods of capturing CO_2 from post-combustion flue gas were discussed. However, if the CO_2 concentration in the waste gases increases or pressure increases or both, this could provide for easier CO_2 capture. By rethinking the entire “combustion process”, it is possible to design energy conversion processes with a high CO_2 concentration waste gas stream. This can be achieved with pre-combustion (decarbonisation) and oxy-fuel combustion technologies.

Learning objectives

By the end of this module you will:

- Understand the various approaches that have been developed to separate CO_2 from pre-combustion processes, including their advantages, disadvantages and commercial readiness;
- Understand the application of oxy-fuel technologies including their advantages, disadvantages and commercial readiness; and
- Be able to determine appropriate applications of each of these technologies to different CO_2 capture scenarios.

Introduction

There are three approaches to capturing CO_2 from fossil fuels: post-combustion capture, pre-combustion capture and oxy-fuel combustion. Post-combustion capture processes were outlined in Module 2. If the CO_2 concentration in the waste gases increases or pressure increases or both, CO_2 capture could become easier than it is in post-combustion processes. Thus, by rethinking the entire “combustion process” for converting fossil fuels to energy, it is possible to design energy conversion processes, which also generate a high CO_2 concentration waste gas stream. This can be achieved with pre-combustion (decarbonisation) and oxy-fuel combustion technologies. A schematic showing the three approaches to fossil fuel combustion and capture is depicted in Figure 3.1.

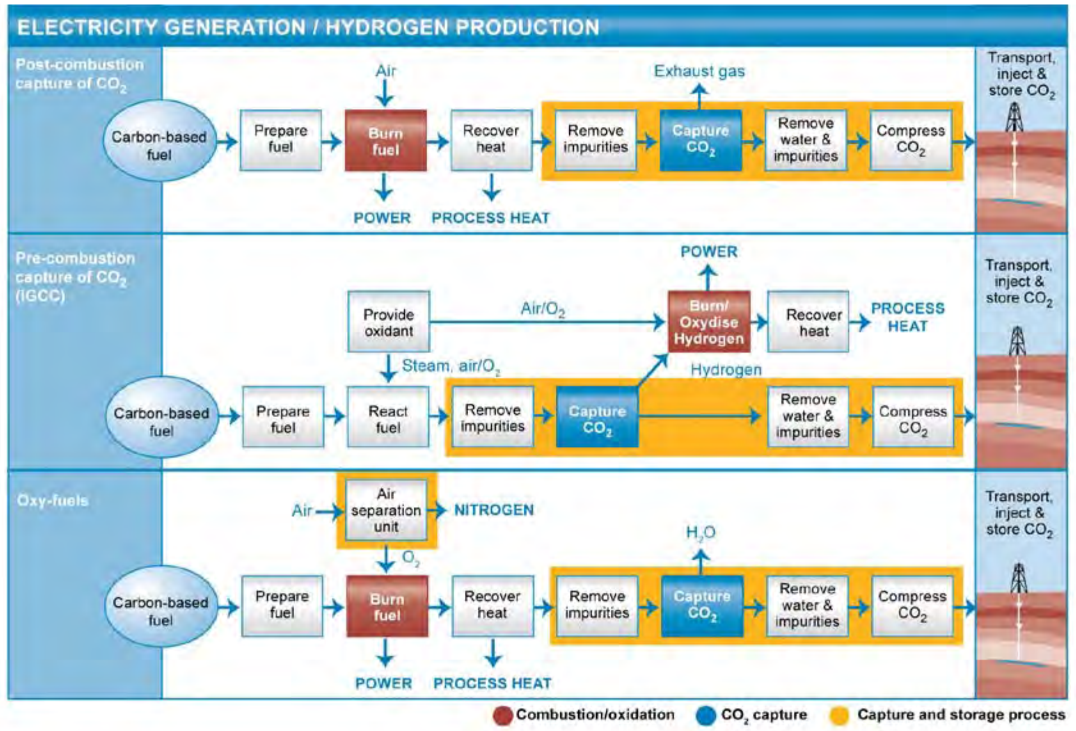

Figure 3.1: A diagram of three approaches to capturing carbon dioxide. Note that the oxidation in IGCC can be through either air or oxygen from an air separation unit (courtesy of CO2CRC).

In this module, the pre-combustion capture and oxy-fuel combustion technologies are discussed.

Pre-combustion CO_2 capture (decarbonisation)

Pre-combustion processes involve removing pollutants and CO_2 in the upstream treatment of fossil fuels prior to their combustion for the recovery of heat (via steam), or the production of electric power or hydrogen (Kreutz et al. 2003, Williams 2002). These technologies are at or near the commercial demonstration stage for coal feed material and could offer a wide range of energy products, such as electric power, heat (via steam), hydrogen and chemicals.

The pre-combustion process is not a new concept. Globally, coal is the most abundant fossil fuel. However, the burning of coal to produce energy also generates some undesirable pollutants such as sulphur oxides, NOx, particulates and mercury. In an effort to reduce the pollutants generated from the burning of coal, several economies including the US, Canada and Australia instigated clean coal programs. One of the elements of these clean coal programs is the gasification of coal. The gasification technologies could produce a waste gas stream, which is high in CO_2 and at moderate pressure, in addition to a range of energy products. This offers an opportunity to capture the CO_2 at low cost; however, it should be noted that CO_2 capture is not a process requirement, but could be easily implemented if warranted.

One-way to accomplish pre-combustion capture is through the gasification of a hydrocarbon fuel with oxygen (or air) to produce a syngas. Syngas is a gas mixture consisting predominantly of hydrogen (H_2), carbon monoxide (CO) and CO_2. The syngas is an intermediate product, which can then be converted to produce:

- Hydrogen;
- Integrated electric power; or
- Polygeneration – where a range of energy products including power, heat, hydrogen and synfuels and other chemicals.
- The process involved with each of these end energy products is described below.

Hydrogen (with excess fuel gas to generate steam/electric power)

Methane reforming

The most widely used method today for producing hydrogen is by catalytic steam reforming of methane (CH_4). The reforming reaction of converting CH_4 and H_2O to CO and H_2 is endothermic. The reaction is carried out over a nickel catalyst at a high temperature in a direct-fired furnace fuelled by methane. The catalyst is poisoned by sulphur, so any sulphur present in the feed must be removed. The synthesis gas is in turn passed through a catalytic shift converter, where the CO is reacted exothermically with steam to produce H_2 and a CO_2 by-product. These by-products are then removed from the system. The exhaust gas still contains significant heating value, so it is burned to produce steam or electric power.

Coal gasification

Alternatively, hydrogen can be produced via the gasification of coal, residual fuel oil or petroleum coke. For the case of coal, the feed coal is gasified in oxygen (or air) to produce a syngas. The syngas is cooled to 200°C in syngas coolers generating high- and low-temperature steams. It is then shifted further in a low temperature water gas shift reactor. The water gas shift reactor is a catalytic reactor where the CO is reacted with steam to produce more H_2 and CO_2. The gas is then cooled to 35°C in preparation for acid gas removal. Roughly 99% of the H_2S is removed from the syngas by physical absorption and converted to elemental sulphur via Claus and tail gas clean-up plants. A pressure swing adsorption (PSA) unit can be used to separate 85% of the H_2 from the sulphur-free syngas. The H_2 exits at about 60 bars and high purity (>99.99%). The CO_2 can be scrubbed from the syngas downstream of the sulphur capture system. The PSA purge gas is compressed and burned in a gas turbine combine cycle to produce electric power.

Gasification technologies are well established for hydrogen production. Commercial plants have been built and successfully operated to produce hydrogen for refinery applications and chemical manufacture (for example, ammonia and methanol production) based on a range of hydrocarbon feedstock. Experience with gasification technology has been growing rapidly.

Integrated electric power

Before H_2 separation, the H_2-rich syngas can be burned in a turbo expander to produce electric power in a combined cycle setting (Figure 3.2). This scheme is called integrated gasification combined cycle (IGCC). IGCC enables electricity to be generated at high efficiency. Because the gas must be cleaned to prevent damage to the gas turbine, IGCC has very low environmental emissions. In addition, IGCC plants use less water.

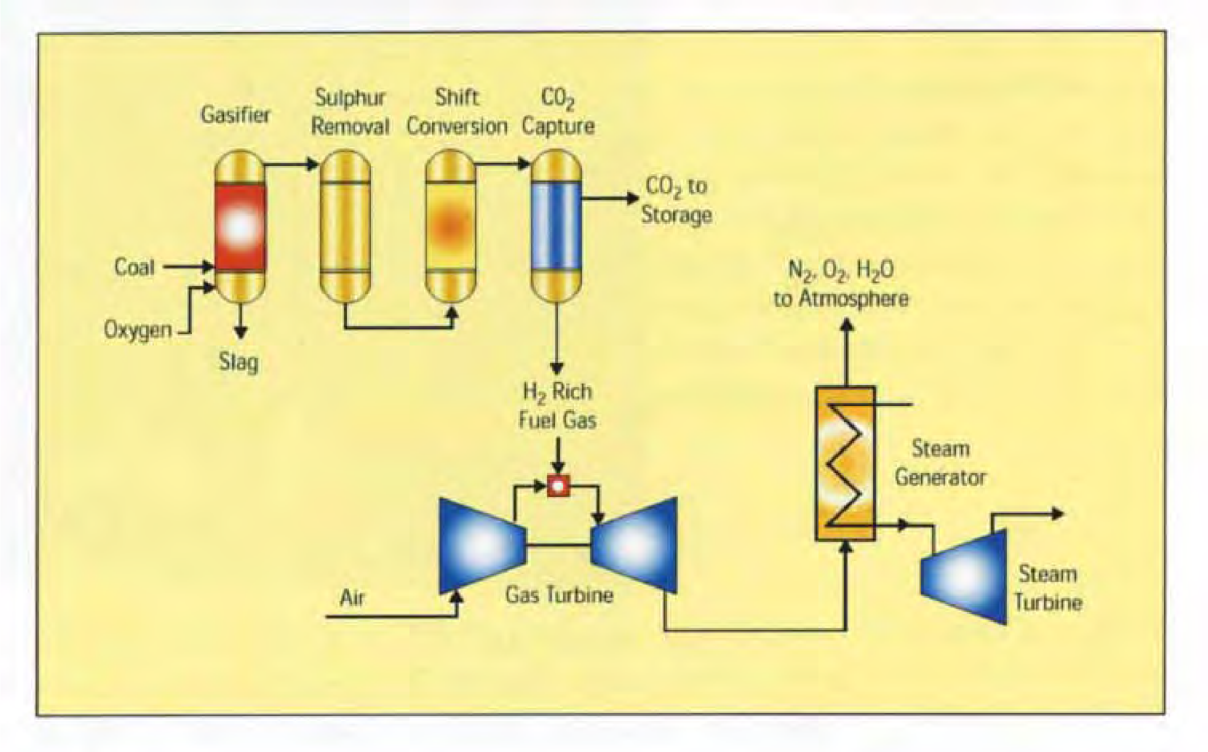

Figure 3.2: Coal fired IGCC with pre-combustion capture of CO_2.

IGCC is currently being used commercially in many plants worldwide by gasification of petroleum residuals to provide power, steam and hydrogen. The 140 MW Shell Pernis plant has been operating since 1998 at high availability on heavy residual fuel oils.

The three main types of coal gasifiers are moving bed, fluidized bed and entrained flow. These are described in Barnes (2009).

The commercial application of coal-based IGCC has been limited by its relatively high costs, poor plant availability (the percentage of a year that the plant is up and available for production, meaning not in unscheduled shut down) and competition from pulverized coal generation plants and low price natural gas. Cost estimates vary for coal-fired IGCC plants, often above 3500 (Harvard) $US /kW.

The ChevronTexaco gasifiers (slurry feed) and the Shell gasifiers (dry feed) are popular. These are both oxygen-blown, entrained-flow gasifiers. Figure 3.3 shows the internal of a Shell gasifier and a Texaco gasifier.

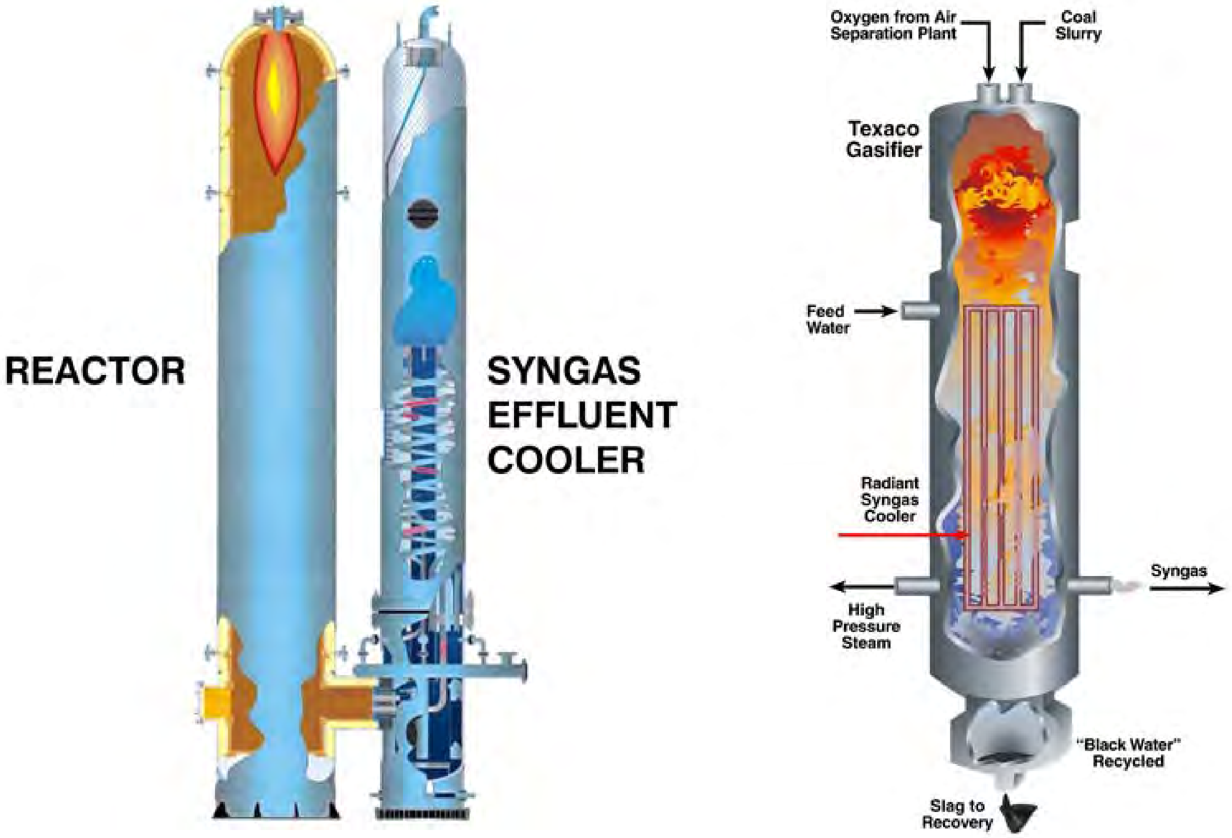

Figure 3.3: Pictorials showing the internal structure of (left) a Shell Gasifier and (right) a ChevronTexaco Gasifier (courtesy of Shell and ChevronTexaco).

For the slurry feed ChevronTexaco gasifier, without CO_2 capture, the coal is ground and slurried with water and then pumped to the gasifier vessels where it reacts with oxygen. The products from gasification are quenched with water and the saturated gas is cooled. Condensed water and minor impurities are removed. The gas is then passed through a COS hydrolysis reactor and fed to an acid gas removal plant for removal of sulphur compounds. The clean fuel gas is passed through a turbo-expander and fed to the gas turbine combined cycle plant. For CO_2 capture, the quenched gas from the gasifier is fed to a CO-shift converter prior to cooling. The acid gas removal unit removes CO_2 as well as sulphur compounds. Oxygen is supplied to the gasifier via a cryogenic air separation unit.

For the dry feed Shell gasifier, the coal is dried and ground and fed to the gasifier vessels via lock hoppers. The gasifier product gas is cooled in a waste heat boiler, which generates high-pressure saturated steam. The gas is further cooled and scrubbed with water, passed through a COS hydrolysis reactor and an acid gas removal plant. The clean fuel gas is fed to the gas turbine combined cycle plant. For CO_2 capture, the wet syngas is fed to a shift converter and the CO_2 separated. Oxygen to the gasifier is produced by cryogenic air separation.

Through IGCC, sulphur is typically removed from the syngas and produced as sulphur or sulphuric acid for sale. NOx emissions are controlled by firing temperature modulations in the gas turbine. Particulates are removed from the syngas by filters and a water wash prior to combustion so emissions are negligible.

The cost of CO_2 capture in IGCC depends strongly on the type of gasifier. The ChevronTexaco gasifiers are expected to show lower incremental energy penalties and lower cost for CO_2 capture than the Shell gasifiers. Slurry feed/quench gasifiers also tend to have lower capital costs but they have lower thermal efficiencies, either with or without CO_2 capture (Thambimuthu et al., 2002).

To enable CO_2 to be captured, the fuel gas has to be fed to a catalytic shift reactor where most of the CO is reacted to steam to give H_2 and CO_2. For the slurry feed gasifier, sufficient steam is already present in the fuel gas from evaporation of the coal slurry water and from the quench cooling of the gasifier product gas. However, for the dry feed gasifier, steam has to be taken from the steam cycle and added to the fuel gas feed to the shift converter (it needs steam for the water gas shift reaction). Therefore, slurry feed gasifier has lower incremental energy penalty for CO_2 capture than dry feed gasifier.

Slurry feed gasifier based IGCC has a lower capital cost than dry feed based IGCC as lock hopper feed systems and fuel gas recovery boilers are relatively expensive. The lower cost of the slurry feed gasifier more than compensates for the high thermal efficiency of the dry feed gasifier.

Through IGCC, sulphur is typically removed from the syngas and produced as sulphur or sulphuric acid for sale. NOx emissions are controlled by firing temperature modulations in the gas turbine. Particulates are removed from the syngas by filters and a water wash prior to combustions.

For coal-based IGCC, SO_2 emissions are very low and NOx and particulates emissions are below recent pulverized coal plants permit limits, so there are environmental benefits from IGCC. It should be noted that IGCC is more expensive for the generation of electricity than conventional pulverized coal combustion, with no CO_2 capture in both cases.

Polygeneration

Syngas is a great strategic building block, as it can be used to produce a wide range of energy products. The greatest flexibility offered is coal polygeneration, in which ‘syngas’ based steam, electric power, hydrogen and chemicals (such as methanol, Fischer-Tropsch liquids) are produced in a single plant complex. This is particularly appealing to developing economies, because of the range of energy products produced. An example of a coal polygeneration scheme is shown in Figure 3.4. Similar to the other schemes in pre-combustion CO_2 capture, CO_2 capture will occur after the water gas shift reactor. The

CO_2 captured can be deployed for geologic storage.

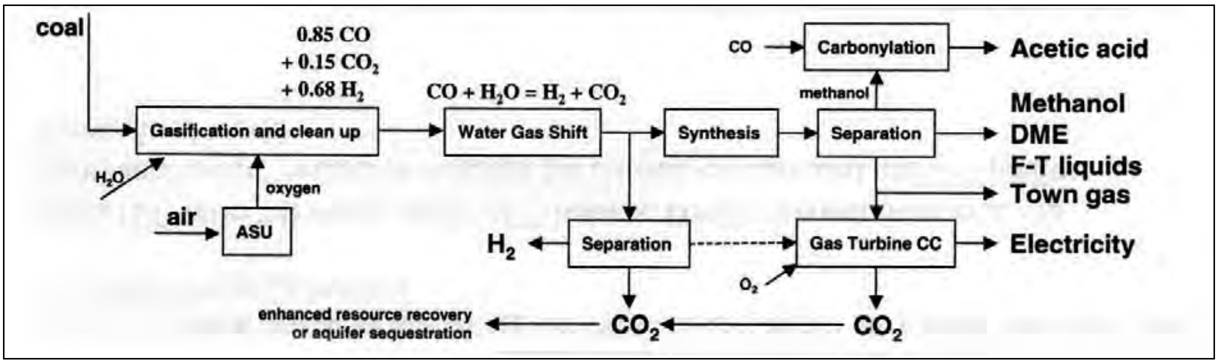

Figure 3.4: An example of a schematic for coal polygeneration (Williams, 2003).

Pre-combustion capture technologies

A number of different separation technologies including solvent, adsorbent and membrane technologies can be applied to separate CO_2 from the products of gasificiation.

Absorption

The conventional technology is physical absorption (e.g. using Selexol) in a two-stage process which removes hydrogen sulphide and then captures CO_2. Solvent units are available at scale. However, the gas needs to be cooled after the water gas shift reaction and then reheated before generating power. This reduces efficiency and increases cost.

Adsorption

Adsorbents can be used to separate CO_2 from post-combustion flue gas streams downstream of the water gas shift reaction. Adsorbents under investigation include Hydrotalcites (HTC) and 13X (a zeolite). Both temperature swing adsorption (TSA) and vacuum/pressure swing adsorption (VSA/PSA) can be used to recover the CO_2 from the adsorbent.

Xiao et al (2009) report on the design of a process to capture CO_2 from an air-blown lignite gasifier. Some advantages of the process include:

- No need for a supply of N_2 for use in the gas turbine.
- The water content of the lignite reduces the need for steam injection into the water gas shift reactor.

The CO_2 is at low pressure when recovered via VSA/PSA and needs to be compressed for storage.

Current studies suggest that the advantages over TSA are simplicity, less adsorbent required and reduced cycle time. Trials on real synthesis gas are currently underway in Australia.

Membranes

Advanced membrane-based gas separation systems are currently being developed to combine the gas shift reaction and hydrogen separation in one step. The membrane-based systems employ a water gas shift H_2 separation membrane reactor (HSMR) to shift the syngas and extract the H_2 (see Figure 3.5). The maximum temperature of ~ 475°C insures fast chemical kinetics and good water gas shift equilibrium performance is obtained by continuous removal of the H_2 product.

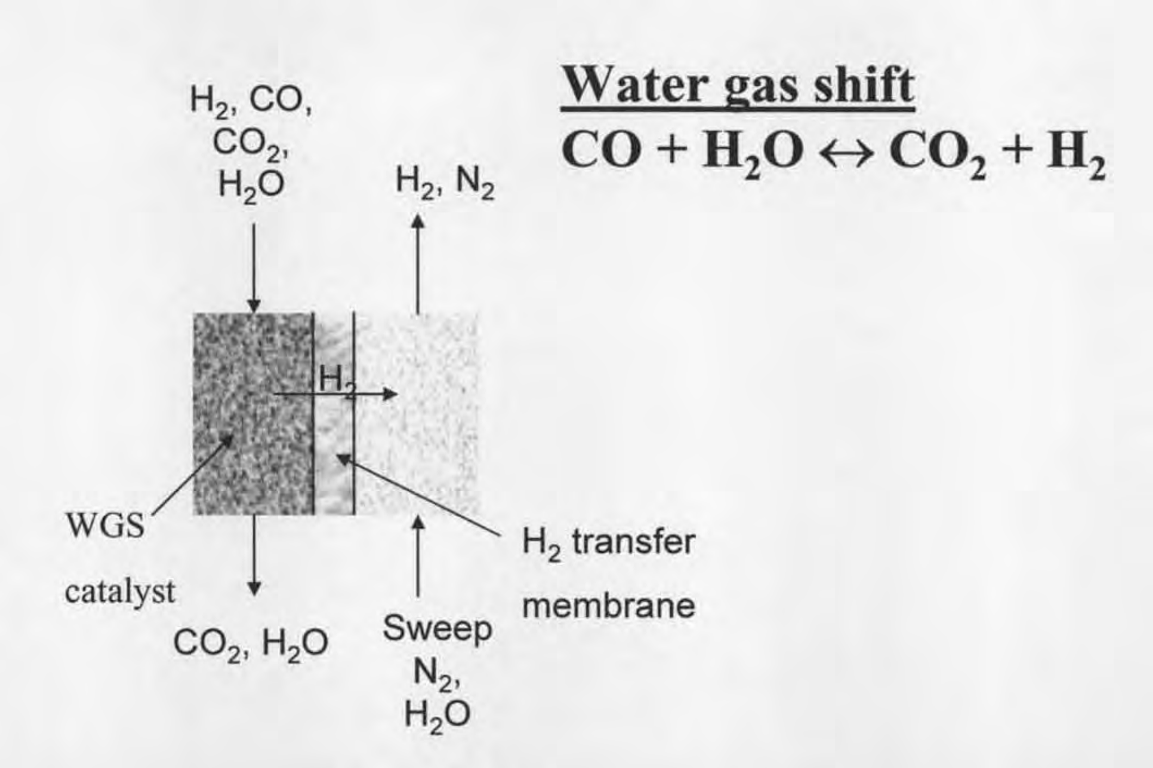

Figure 3.5: Schematic of a Hydrogen Separation Membrane Reactor (HSMR).

There are three major classes of inorganic H_2 permeable membranes:

- ceramic molecular sieving;
- dense ceramic ion transport; and
- dense metal.

One example of the dense metal membranes is 1-3 um Palladium/silver (Pd/Ag) alloy foil (dense) sputtered on single crystal silicon developed by SINTEF (Lowe and Andersen, 2004). Palladium (Pd) membranes have been studied for potential application of H_2 separation from fuel gas mixtures (Buxbaum and Kinney, 1996), as it will leave behind a gas residue enriched in CO_2. Pd is an active oxidation catalyst and therefore is not suitable for H_2 streams that contain O_2. Because of the high material cost of Pd, many researchers have turned to thin films of Pd.

Alloying Pd with Ag increases the permeability for H_2 and reduces H_2 embrittlement (H_2 can attack the material making it brittle and causing failure). Thin film Pd alloy membranes look very promising. This development could significantly reduce capital cost and improve the efficiency of CO_2 capture.

Other developments in polymide membrane systems applicable to IGCC were outlined in Module 2.

Advantages and disadvantages of pre-combustion (decarbonisation)

The advantages of pre-combustion (decarbonisation) are:

- CO_2 separation via solvent absorption or PSA is proven. The exhaust gas comes at elevated pressures and high CO_2 concentrations will significantly reduce capture costs;
- The compression costs are lower than post-combustion sources as the CO_2 can be produced at moderate pressures;
- The technology offers low SOx and NOx emissions;
- The main product is syngas, which can be used for other commercial applications or products; and
- A wide range of hydrocarbon fuels can be used as feedstock, such as gas, oil, coal petroleum coke, etc.
- The disadvantages are:
- The feed fuel must convert fuel to syngas first;
- Gas turbines, heaters, boilers must be modified for hydrogen firing; and
- It requires major modifications to existing plants for retrofit.

Oxy-fuel combustion

Oxy-fuel combustion represents an emerging novel approach to near zero-emission and cleaner fossil fuel combustion. It is accomplished by burning the fuel in pure oxygen (O_2) instead of air (O_2 and N_2). By eliminating nitrogen in the combustion process, the exhaust of the flue gas stream would be composed mainly of CO_2. High purity CO_2 can be recovered by condensation. However, when fuel is burnt in pure oxygen, the flame temperature is much higher than that in a normal air-blown combustor and the conventional material of construction for the combustor would not be able to withstand this high temperature. Therefore, either the material of construction has to be improved or the flame temperature has to be lowered. The development of high temperature resistant materials has been slow because it is a major R&D undertaking. There are a number of methods, which could be used to moderate the flame temperature, the most common being CO_2 recycling. In CO_2 recycling, a portion of the CO_2 rich flue gas stream is recycled back to the combustor to lower the flame temperature similar to that in a normal air-blown combustor. A simplified schematic of the oxy-combustion/CO_2 recycle process is shown in Figure 3.6. Another method is to use water injection rather than CO_2 recycling to control the flame temperature. This is often referred to as “hydroxyfuel” combustion. Effectively these would allow the continual use of conventional refractory material until new high temperature resistant material can be developed.

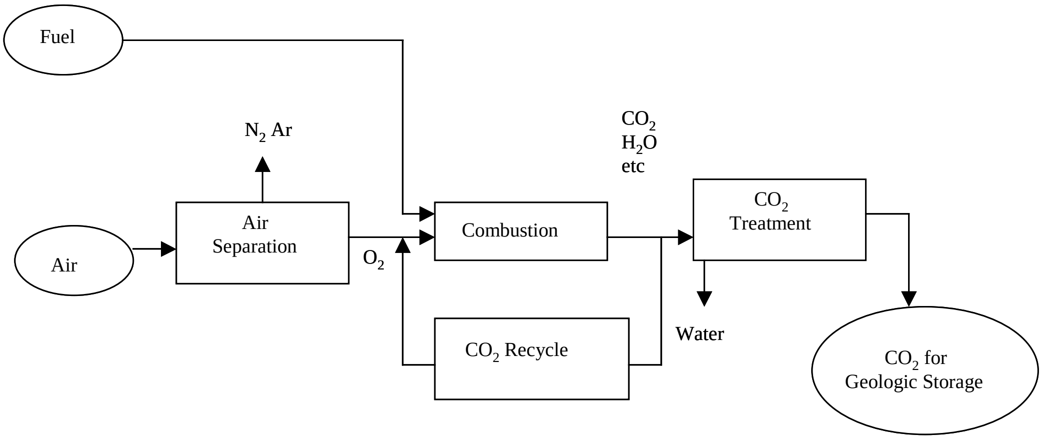

Figure 3.6: A schematic of oxy-fuel combustion with CO_2 recycle.

A primary benefit of oxy-fuel combustion is the very high-purity CO_2 stream that is produced during combustion. After trace contaminants are removed, this CO_2 stream is more easily purified and removed than post-combustion capture. Other benefits also are apparent. For instance, when the scheme is implemented with 70% recycle of the predominantly CO_2 flue gas back to the combustor, NOx formation is reduced by up to 80%. This is possible because of the reduction in thermal NOx due to the absence of N_2 in the flame and also part of the recycled NO is reduced to molecular nitrogen in the flame. When burning oil or coal, only two unit operations are needed for the combined removal of all other pollutants: an electrostatic precipitator (ESP) or bag filter and a condensing heat exchanger (CHX)/reagent system. It is also possible to simplify the reagent system in the CHX to achieve total removal of SO_2 with the CO_2 stream for geologic storage. This further reduces the cost of unit operations for pollution abatement. The CHX increases the thermal efficiency of the boiler depending on the type of fossil fuel combusted, being the lowest for high rank bituminous coal and highest for natural gas.

Another benefit is the significant reduction in the size and capital cost of all plant equipment compared to conventional air-based combustion systems. This is due to the almost 5-fold decrease in the fire box volume and exit flue gas flow rates as nitrogen is eliminated in the combustion process.

Oxy-fuel combustion could be an attractive option for retrofit of existing steam cycle power stations (McDonald et al., 1999). The modifications that would need to be made at the power station would be relatively minor. One issue that must be dealt with is the potential for air leakage into the furnace, as the retrofit unit cannot be sealed to 100% airtight. This would impact on the CO_2 concentration in the flue gas stream and hence reduce CO_2 purity. It is found that as little as 3% air leakage is possible, which would result in a flue gas with about 95% CO_2 purity. Many applications do not require 100% pure CO_2. If a 95-98% purity CO_2 product is acceptable (for geologic storage, this CO_2 purity would not be a problem), 95% purity oxygen could be used and this would substantially reduce the cost of oxygen.

Singh et al. (2003a, 2003b) presented a techno-economic comparison of the performance of a CO_2 capture using MEA amine and O_2/ CO_2 recycle combustion from an existing coal-fired power plant. Their scenario involved the power plant maintaining its original output to the power grid. As a considerable amount of supplementary energy must be supplied to the CO_2 separation processes, in this scenario supplementary energy was generated using gas turbine combined cycles, gas turbines and steam boilers. These “auxiliary” units are fuelled with natural gas. The CO_2 generated by the combustion of natural gas was not captured in this study. The results showed that both processes were expensive options to capture CO_2 from coal power plants.

Oxy-fuel combustion for power generation is an emerging technology. To date, no commercial unit has been built. However, large-scale oxy-combustion has been used in glass and steel melting furnaces for high temperature application in these industries. Oxy-fuel for coal-fired plants with carbon capture is being demonstrated in a 30 MW pilot plant at Schwarze Pumpe in Germany. Other demonstrations are at Callide (Australia) and Ciuden (Spain) and Lacq (France). Development of tail-end CO_2 purification and hybrid turbines is still required for commercial demonstration.

The major disadvantage of oxy-fuel combustion is the high capital cost and large electric power requirement inherent in conventional cryogenic air separation units required to generate oxygen. Cryogenic air separation is a mature technology. Different consortia are developing ionic transport membranes for air separation with U.S. Department of Energy and European Union (EU) funding for commercialization by 2010. The ionic transport membranes with oxygen permeable ceramics use multi-component metallic oxides with vacancies built into the oxide by ion substitution. Oxygen permeates at a high flux and 100% selectivity. This technology can substantially reduce the cost of oxygen and the energy requirement compared to cryogenic air separation.

The challenge faced in the development of oxy-fuel systems is the design configurations and material of construction of combustors, boilers and turbo-machineries to take advantage of the higher temperature with burning the fuel in oxygen. Operating at higher temperature generally means higher thermodynamic cycle efficiency. The full potential can only be realized with the development of new combustor/boiler designs that are made with high temperature-tolerant materials. In turbine applications, one proponent of “hydroxyfuel” combustion is Clean Energy Systems Inc. (CES), of California. The CES technology is currently at the demonstration stage. In the form that it is being developed, oxygen is added to gaseous fuel and the oxy-fuel mixture ignited to produce combustion gases which drive a turbine for power generation. This technology is developed from the rocket propulsion industry. With current materials, the product gas stream must be cooled and this is accomplished by injection of water or steam. The result is a proprietary "steam generator". The working fluid for the turbine would be a combined steam/CO_2 gas mixture.

Oxy-fuel combustion is not currently used in typical large combustion systems because:

- The air separation system is expensive; and
- Flue gas recycling must be practiced in order to moderate flame temperature;

Oxy-fuel combustion has a unique advantage over other methods of CO_2 capture, in that it generates an exhaust gas stream almost exclusively composed of CO_2 and H_2O. CO_2 capture from this waste stream is cheap and easy. It also enables an order of magnitude (90%) reduction of NOx emissions to be achieved.

Oxy-fuel combustion could currently be practised using conventional cryogenic air separation along with CO_2 recycle in retrofit or new plant boilers and heaters.

Summary

- Pre-combustion (decarbonisation) and oxy-fuel combustion technologies offer very attractive waste gas streams for CO_2 capture.
- For pre-combustion technologies, the exhaust gas comes at elevated pressures and high CO_2 concentrations, which will significantly reduce capture costs. Compression costs can be reduced when CO_2 can be produced at moderate pressures. This technology also offers low SOx and NOx emissions. CO_2 separation via solvent absorption or PSA is proven.
- Oxy-fuel combustion technology generates an exhaust gas stream almost exclusively composed of CO_2 and H_2O. CO_2 capture from this waste stream is cheap and easy, using condensing heat exchangers. It also enables an order of magnitude (90%) reduction of NOx emissions to be achieved.
- The availability of such waste streams for CO_2 capture depends on the timing of the commercialization of the technologies.
- Gasification technology is commercial. Hydrogen and chemical production from gasification and from natural gas reforming are commercial. These plants have produced some very attractive waste gas stream for CO_2 capture. IGCC plant gasifier exhaust would also be attractive, if these plants were available. The exhaust would be further processed in a water gas shift reactor to produce an exhaust stream suitable for CO_2 capture with solvent absorption or PSA.
- Oxy-fuel combustion technology is not commercial.

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US gasification plant :

http://www.gasification.org/what_is_gasification/pop/us-gasification-plants-table.aspx

IEA Clean Coal Centre - information on gasification: http://www.iea-coal.org.uk/site/ieacoal_old/clean-coal-technologies-pages/clean-coal-technologies-integrated-gasification-combined-cycle-igcc?

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CSIRO: http://www.csiro.au/science/ps3m.html

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IEA GHG http://www.co2captureandstorage.info/networks/oxyfuel.htm

CS energy http://www.csenergy.com.au/research_and_development/oxy_fuel.aspx

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Callide. http://www.callideoxyfuel.com/

Clean Energy Systems: http://www.cleanenergysystems.com/overview/dev_testing.html

Total Lacq Project http://www.total.com/en/corporate-social-responsibility/special-reports/capture/

Module 4

CO_2 compression and transportation to storage site

Original text: S. Wong, APEC Capacity Building in the APEC Region, Phase II
Revised and updated by CO2CRC

Overview

After capture, CO_2 needs to be transported under pressure to a long-term geologic storage site. This module addresses compression and transportation systems for CO_2.

Learning objectives

By the end of this module you will:

Understand CO_2 compression technologies and the main operating issues pertinent to CO_2;

Know the key considerations which must be taken to compress CO_2 for transport;

Be able to determine optimal CO_2 pressure for transport;

Appreciate the various operational issues association with CO_2 compression;

Understand the factors which influence costs for CO_2 compression; and

Be able to assess the various options for transporting CO_2.

CO_2 compression

Gas compression is well developed in the natural gas industry around the globe and it uses matured technologies. CO_2 compression uses the same equipment as natural gas compression, with some modifications to suit the properties of CO_2. Avoiding corrosion and hydrate formation are the main additional operating issues when dealing with CO_2. Compressors come in many different types (e.g. centrifugal, reciprocating and others), makes and sizes. Centrifugal compressors are usually the preferred type for large volume applications because of their ability to handle large flow rate (to hundred thousands of cubic feet per minute). In 2002, 490,000 hp of compression was installed in the USA, with a capital investment of over $ 635 million (True, W., 2003).

In 1998, more than 25 million tonnes of CO_2 were captured, compressed, transported and injected in the Permian basin in the USA to recover nearly 150,000 barrels/day of oil through CO_2 enhanced oil recovery (EOR) schemes (Stevens et al., 2000). The longest CO_2 pipeline is the Cortez pipeline (808km) which has been delivering 20 million tones of naturally sourced CO_2 per annum since 1972 (WRI, 2008). This illustrates that in some areas of the world there is more than adequate operating experience in compressing and handling CO_2 in large-scale applications. In addition, there is significant experience in Western Canada in acid gas (CO_2 and H_2S) compression and injection into geologic reservoirs for disposal, and some pipelines in the US also carry CO_2 from anthropogenic sources. As the oil reservoirs are maturing, for example, those in China and Indonesia, the prospect of injecting CO_2 to enhance the oil production or for storage can be technically and economically feasible. If these projects are to be implemented, large-scale handling of CO_2 is required.

Compressing CO_2 for transport

CO_2 is compressed to make it more efficient to transport. The amount of compression needed for transport can be calculated through use of a phase diagram. Figure 4.1 shows the phase diagram of CO_2. A phase diagram is a pressure-temperature relationship in graphic form, which shows the boundaries of the three phases – solid, liquid and gas phases. There are two important points to note on the phase diagram – the triple point and the critical point.

The triple point occurs at a pressure of 0.52 MPa and a temperature of -56°C. At this point, solid, liquid and gaseous phases of CO_2 coexist together. Below this pressure and temperature, CO_2 can only exist in either the gaseous or the solid phase. The critical point occurs at a pressure of 7.38 MPa and a temperature of 31.4°C. Above this critical pressure and at higher temperatures than –60°C, only one condition exists: that of the supercritical/dense phase. This kind of data can be found in engineering data handbook, for example, Gas Processors Suppliers Association (GPSA) Engineering Data book.

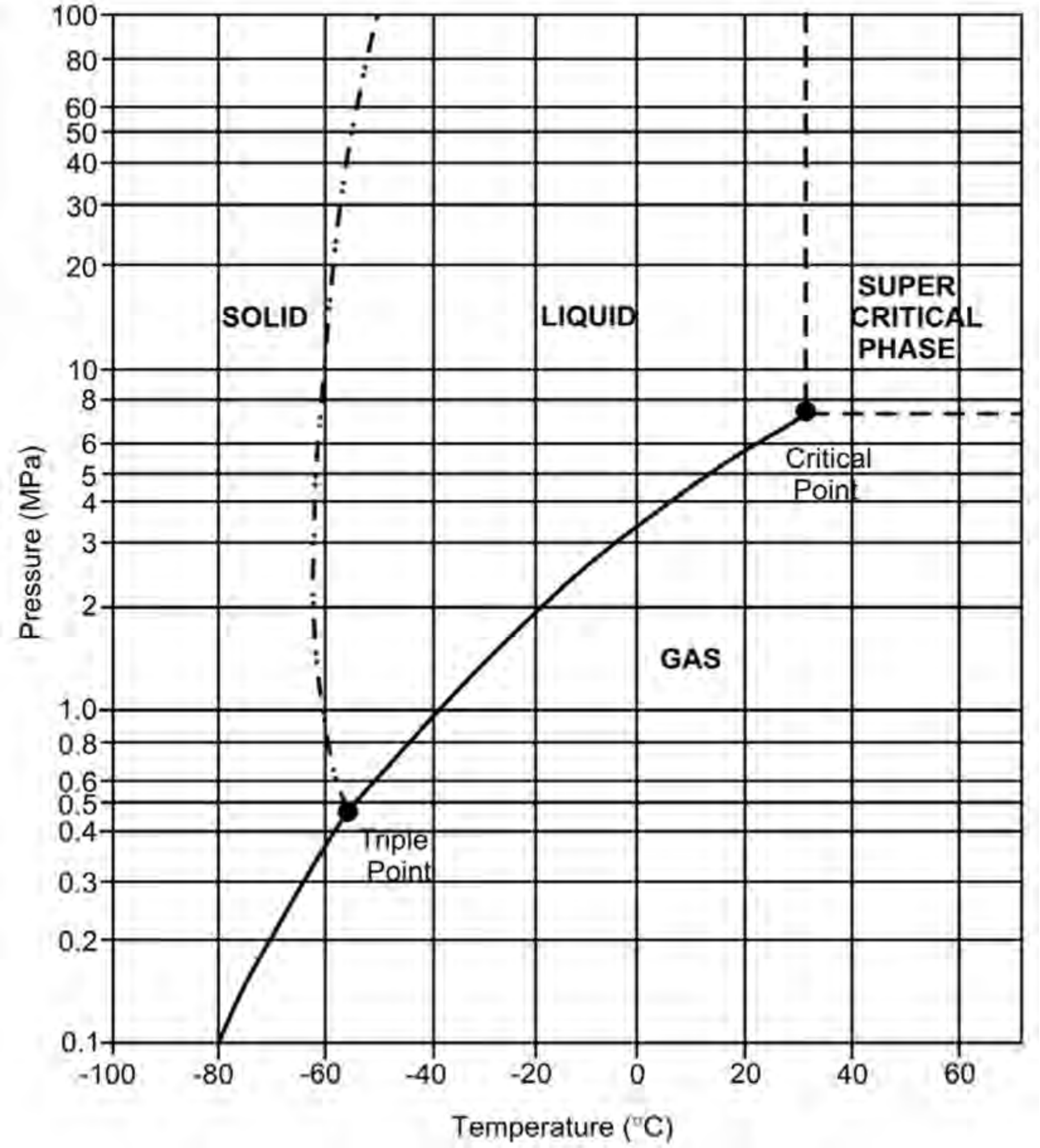

Figure 4.1: Phase diagram of carbon dioxide.

Figure 4.2 shows the density of CO_2 as the pressures and temperatures vary. Above the critical pressure of 7.38 MPa and at temperatures lower than 20°C, CO_2 would have a density between 800 to 1,200 kg/m^3 (compare this to the density of water which is 1,000 kg/m^3). A higher density is favourable when transporting liquid CO_2, as it is easier to move a dense liquid than a gas. Therefore it is typical to compress CO_2 to above 7.38 MPa for efficient transport.

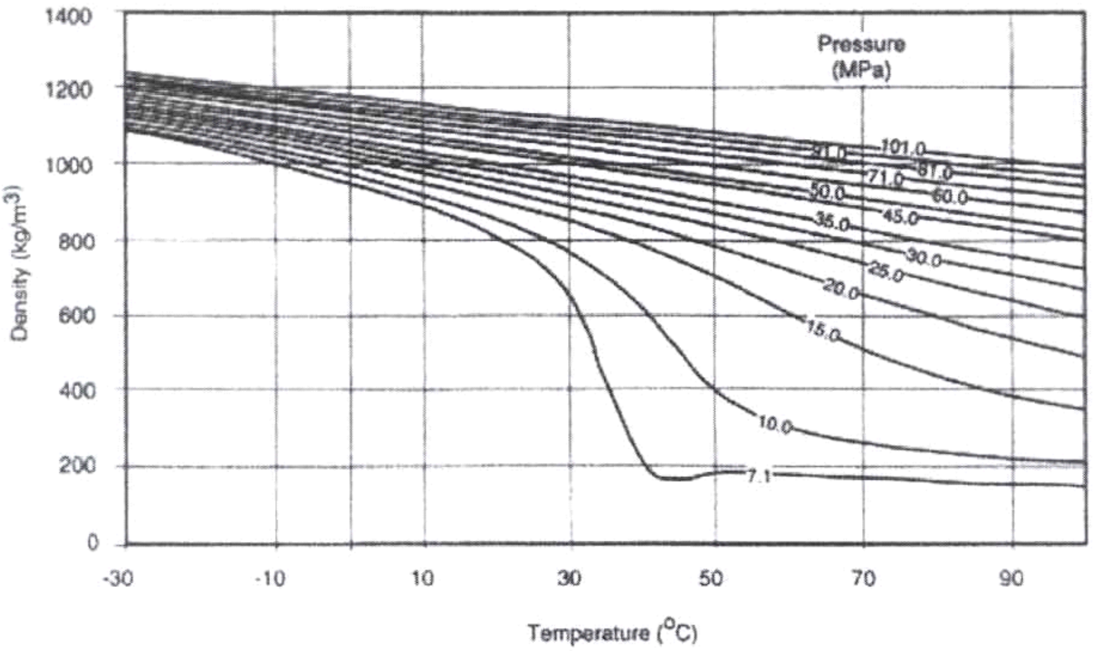

Figure 4.2: Density diagram of carbon dioxide.

There is frictional loss as the CO_2 flows through a pipeline. Typically the frictional loss can range from 4 to 50 kPa per km, depending on the pipe diameter, mass, CO_2 flow rate and the pipe roughness factor. As a rule, the larger the pipeline diameter, the lower the frictional loss. Hence, in order to maintain the CO_2 in the dense phase for the whole pipeline, we would either maintain the inlet pressure to the pipeline at a high enough pressure to overcome all the losses while still above 7.38 MPa or install booster stations every 100 to 150 km to make up the pressure losses. Industry preference is to operate the pipeline at greater than 10.3 MPa at the inlet (i.e. the compressor discharge pressure) so that the CO_2 would remain in the supercritical phase throughout the pipeline. It should be noted that when CO_2 remains in the dense phase, we could revert to pumping rather than compression to achieve the higher pressure needed.

Getting to the CO_2 pressure for transport

A number of stages of compression will be required before an optimal pressure is achieved for transport of the CO_2. This is because, from engineering principle, it is impossible to raise the pressure of a gas such as CO_2 ten to twenty fold in one step, as this would result in too high a temperature rise in the gas. Therefore, compression generally occurs in a number of steps or stages.

To determine the number of stages of compression, it is first necessary to select the acceptable compression ratio per stage. This ratio is generally in the order of 3 or 4. Table 4.1 shows the suction and discharge pressures and temperatures of a four-stage compressor with a compression ratio of 3. If needed, a fifth stage of compression can also be added.

As can be noted in Table 4.1, there is a considerable rise in the gas temperature during each stage. Aerial coolers are generally used to cool the process CO_2 stream to the appropriate suction temperature between stages. There are also line and intercooler pressure losses at each stage. With a reciprocating compressor capable of a compression ratio of 4 per stage, a discharge pressure as high as 33 MPa can be achieved for a four-stage compressor.

Stage No.	Suction Pressure kPa	Suction Temp. °C	Discharge Pressure kPa	Discharge Temp. °C
1	150	40	455	156
2	385	35	1160	149
3	1090	35	3270	150
4	3200	35	9600	152

Table 4.1: Suction and discharge pressures and temperatures as compiled through the computer model simulation.

Four to five stages of compression are required to obtain CO_2 at optimal transport pressure. The compression ratio is used to determine this.

Typically the CO_2 compression efficiency is about 80%. For example, the energy required for compressing CO_2 to 14 MPa would be about 119 kWh per tonne of CO_2.

Operational issues associated with CO_2 compression

Preventing corrosion

Since CO_2 dissolves in water and forms carbonic acid, which is corrosive, strict control of the water content in the CO_2 stream is essential for safe and efficient operation of the compressor. A glycol dehydrator is often installed ahead of the CO_2 compression stream to control water content to an acceptable level. Glycol dehydration is a standard unit operation in the oil and gas industry. For smaller scale operation, the dehydration unit may be eliminated if the temperatures of the gas stream at the intercooler stages can be controlled to drop off the water. This technique is widely practised in acid gas compression in Western Canada.

Optimizing metallurgy

When dehydration is included, the metallurgy of the compressor piping can be relaxed. However, whether to switch back and forth between carbon steel and stainless steel or whether to make all piping around the compressor out of stainless steel depends on the cost difference. If the cost difference is small, it may be more practical to use all stainless steel in all the piping, coolers and suction scrubbers. Even though there may not be any water present in certain lengths of the piping, H_2S (when present) reacts with carbon steel to form a thin film of iron sulphide on the surface of carbon steel. The iron sulphide may be dislodged at times and coat the inside surface of the stainless steel aerial coolers, thus decreasing the heat transfer efficiency. To avoid this potential heat exchanger problem, it may be advisable to use stainless steel throughout the compressor piping if H_2S is present in the CO_2 stream.

Sealing materials and gaskets

In addition, some petroleum based and synthetic lubricants can harden and become ineffective in the presence of CO_2, so specific sealing materials and gaskets are typically specified in the USA for CO_2 compressors and pipelines. CO_2 cools dramatically during decompression so pressure and temperature must be controlled during routine maintenance (Gale et al., 2003).

Impurities

Depending on the source of the flue gas, the CO_2 stream recovered from it may contain trace concentrations such as H_2S, SOx, NOx, O_2, N_2 and Ar. These impurities might have an impact on the physical state of the rich CO_2 stream and hence the operation of the compressors, pipelines and storage tanks. The impact of impurities on CO_2 transport is current topic of research.

A recent study from the University of Newcastle highlights the effect of impurities present from different sources (Seevam et al, 2008). Repressurisation distance depends on composition defined for the pipeline and the resulting thermodynamic properties (see Table 4.2).

Capture technology	Critical temperature °C	Critical pressure (bar)	Repressurisation distance (km)
Post combustion	31	74	300
Pre combustion	29	83	105
Oxyfuel	27	93	35

Table 4.2: Properties of various capture streams (Seevam et al, 2008).

Care must be taken to carefully integrate capture and storage specifications to get effective overall capture costs down. Furthermore poor selection of pipeline compositions can dramatically affect storage effectiveness through lower CO_2 density – approx halved between 85-90%.

This demonstrates that if gas composition is not considered in transportation design considerable extra costs will result. Source to sink thinking is vital to CCS economics. While screening will be required for all installations it is highly likely higher concentrations will be indicated for all capture technologies. See Module 12 for further discussion on costs and source-sink economics.

CO_2 transport

CO_2 can be transported by land via pipelines, motor carriers or railway, or by ocean via ships.

Land-based transport

Three potential systems can be considered for land-based CO_2 transport, namely: motor carriers, railway and pipeline.

Pipelining is currently the most economical method of transporting large quantities of CO_2, and therefore the preferred option. There are currently some 6,200 km of CO_2 pipelines in operation in the USA and Canada, transporting 30Mt per year of CO_2 (IEA, 2009). These pipelines transport CO_2 in the supercritical or dense phase.

Pipeline costs come from: material, labour, right-of-way access and miscellaneous. The average cost per mile shows few clear-cut trends related to either length or geologic area. In general, however, the cost per mile within a given diameter indicates that the longer the pipeline, the lower the unit cost (per mile) for construction. And, lines built near populated areas tend to have higher unit costs. Additionally, road, highway, river or channel crossings and marshy or rocky terrain each strongly affects the pipeline construction costs (True, 2003).

Liquefied CO_2 can be transported in motor carriers such as tank trucks with trailers and stored in cryogenic vessels. The tanks have an inner vessels or “liquid container” which is surrounded and supported by an outer vessel or “vacuum jacket”. The space between the two is filled with a natural material that provides insulation. The delivery system includes piping which carries gas from the vessel through the vacuum jacket to the outside, controlled by gauges and valves mounted outside the tank. These vessels are available in various sizes ranging from 2 to 30 tonnes, to suit customers’ requirements. The conditions of the liquid CO_2 is typically at 1.7 MPa, -30°C. Currently these are used to transport CO_2 for the food and beverage industries, but the volumes are very small compared with what will be required for CCS.

This kind of vessel offers flexibility, adaptability and reliability. This is the most common form of bulk CO_2 transport for retail purposes. Figures 4.4 and 4.5 show a fleet of the CO_2 tanker trucks and refilling a truck with CO_2.

Figure 4.4: A fleet of CO_2 tanker trucks for oil field applications in China.

Figure 4.5: Refilling a CO_2 tanker truck.

The railway system has a large carrying capacity that enables it to handle large volumes of bulk commodities over long distances. CO_2 can be transported in specially developed tank cars that are approved to transport liquid CO_2 at a pressure of 2.6 MPa. At this pressure, the net weight of liquid CO_2 that a single tank car can load is about 60 tonnes. CO_2 has been shipped by rail in two or three tank cars at a time. The tank cars can be left at the siding and serve as a storage tank until the next shipment arrives. However, there is no large scale CO_2 transport by railway at this point. Rail transport will only become a competitive transport option if the logistics can fit the volumes in the existing railway system. However, loading and unloading infrastructure and temporary CO_2 storage would also have to be included in calculating the cost.

Ocean transport

Ships can be used for long distance transport of CO_2 across oceans. Smaller dedicated CO_2 ships are in operation today. The size of these ships is up to 1,500 m^3, and the transport pressure is about 1.4 to 2 MPa. These ships are not suitable for large-scale ship-based transport of CO_2 because at these pressures, the ship must be constructed as pressure vessel, which will make costs very high. Lower pressure is required for enlarged storage and ship tanks. However, this should not be a major problem, as tankers are currently used for shipping liquefied petroleum gas (LPG) and tankers similar to these could be used for CO_2. Figure 4.6 shows a LPG tanker.

Figure 4.6: A LPG tanker – CO_2 could be transported in a similar way. Courtesy of Mitsubishi Heavy Industries.

The Weyburn pipeline: case study of a compression and transport system ***Drawn from the work of Hattenbach et al, 1999***

The Weyburn Pipeline is a 320 km CO_2 pipeline, which stretches from the Great Plains Synfuels Plant (GPSP) near Beulah, ND to EnCana's oil field in Weyburn, Saskatchewan, Canada (see Figure 4.7).

Figure 4.7: Location of the EnCana Weyburn CO_2 Pipeline (in white).

The pipeline is sized to handle the entire waste gas output of the Rectisol unit from GPSP (about 5 million tonnes of CO_2 per year). Phase 1 of the pipeline consists of a 356 mm (14 inch) diameter section from the plant to near Tiogas, ND followed by a 305 mm (12 inch) diameter section from Tioga north to Weyburn field. Initial pressure of the CO_2 leaving the plant is 17 MPa (2,500 psig) and the delivery pressure at Weyburn is 14.8 MPa (2,175 psig). Phase 1 is designed to deliver approximately 5,000 tonnes/day of CO_2 to the Weyburn oil fields. As the pipeline diameter is sized much bigger than the initial delivery volume, the frictional loss is very low at 7 kPa per km. For this pipeline, there is no booster station for the entire 320 km pipeline.

For compression, a dual compressor train (Figure 4.8) was designed to handle the initial throughput of the 5,000 tonnes per day for the Weyburn EOR project. Each compressor train (3 stage compressor) has an initial capacity to handle more than 2,500 tonnes/day of CO_2. A CO_2 pump is used to boost the pressure to 17 MPa for pipeline delivery. More capacity can be added later by either adding the additional compressor trains or by installing booster compressors on one or more existing trains. Adding pumping stations on the pipeline would allow increased flow to be achieved in the pipeline itself.

The pipeline has been in operation since year 2000. The IEA launched an international research program, the IEA Weyburn CO_2 Monitoring and Storage Project in 2001. This program considers how best to combine oil recovery and long term storage. In 2005, the Midale field nearby (operated by Apache Canada) became part of the project known as the IEA GHG Weyburn-Midale CO_2 Monitoring and Storage Project and is in its final phase. EnCana is injecting 7000 tonnes/day and Apache is injecting 1800 tonnes/day (PTRC website).

Summary

Gas compression is a well-developed industry in North America, using matured technologies. Basically, CO_2 compression uses the same equipment as natural gas compression, with some modifications to suit the properties of CO_2. Avoiding corrosion and hydrate formation are the main additional operating issues involved with CO_2.

The water content in the CO_2 stream must be strictly controlled to prevent corrosion. A glycol dehydrator can be used for this purpose. To avoid potential heat exchanger problems, it is advisable to use stainless steel throughout the compressor piping if H_2S is present in the CO_2 stream.

Special sealing materials and gaskets are recommended in order to avoid hardening of some petroleum based and synthetic lubricants in compressors and pipelines. Impurities in the rich CO_2 streams may impact on the compressor and pipeline operations. Their impact is currently being researched.

Pipelining is the most economical method to transport large quantities of CO_2. Rail transport would be competitive if the logistics can fit the volumes in the existing railway system. However, loading and unloading infrastructure and temporary CO_2 storage would have to be included and would be costly. Tanker truck transport would not be viable to transport large quantities of CO_2, because of cost and volume considerations.

It is more efficient and economical to ship CO_2 in the supercritical/dense phase. For pipeline transport, that means keeping the pressure at above 7.38 MPa.

In North America, we have adequate experience in compressing, pipelining and handling CO_2 in a large scale. This experience can be easily transferred to APEC economies, should such a need arise. However each project should be considered in a full source to sink way.

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Module 5

CO_2 storage options and trapping mechanisms

Original text: W. D Gunter, for APEC Capacity Building in the APEC Region, Phase II

Revised and updated by CO2CRC

Overview

Geological storage is one option for storing CO_2 from the atmosphere as a means of combating climate change. These sinks are most suitable for utilization by large CO_2 emission point sources with relatively pure CO_2 waste streams.

This training module outlines the major types of formations which can store CO_2 geologically and the way in which the CO_2 is trapped in these formations.

Learning objectives

By the end of this module you will:

- Understand the concept of geological carbon storage;
- Be familiar with the various CO_2 storage options in sedimentary basins and their potential for storage;
- Be familiar with current practices and special issues related to each of these storage options;
- Know the techniques used for trapping CO_2 in sedimentary basins and their relative security; and
- Understand the technical challenges for CO_2 storage in sedimentary basins.

Geological storage

Geosphere sinks are naturally occurring reservoirs that historically, on a geologic time basis, have been sinks for carbon. Humans have extracted carbon from these sinks in the form of oil, gas and coal, to use for energy. These same reservoirs, including deep aquifers, can be used to store carbon dioxide, reducing the amount of CO_2 available in the global carbon balance.

Carbon dioxide storage in sedimentary basins

The geological storage of CO_2 requires access to large subsurface volumes, mainly in the rock pore space, which can act as sealed pressurized containers. The pore space is initially occupied by formation fluids such as brines, hydrocarbons and other gases (e.g., H_2S and CO_2). These fluids are displaced in CO_2 storage operations. The pressure to keep CO_2 at a liquid-like density is found at depths usually below 800 metres.

Only sedimentary basins, which hold the largest pore-based volumes, are generally suitable for geological storage of CO_2. Sedimentary basins are subsiding regions of the Earth's crust that, by their shape, permit the net accumulation of sediments that result from various processes, such as:

erosion of pre-existing rocks exposed on land (e.g., sands and muds);

deposition of organic material;

precipitation from water (e.g., salts); and

volcanism (deposition of volcanic ash).

As these sediments are piled and buried, they undergo a process of lithification and become sedimentary rocks, such as sandstones, carbonates, shales, coal, salt rock, tuffs and bentonites. Sedimentary basins are suitable for CO_2 storage because they possess the right type of porous and permeable rocks for storage and injection, such as sandstones and carbonates, and the low permeability-to-impermeable rocks needed for sealing, such as shales and evaporitic beds.

Other types of rocks are igneous and metamorphic rocks. Igneous rocks are rocks that crystallized from magma, and are of two types: plutonic (have crystallized at great depth, such as granite), and volcanic (have crystallized at surface, such as basalts). Metamorphic rocks are formed by re-crystallization of existing rocks at great pressure and temperature (e.g., slate, gneiss and schist). Igneous and metamorphic rocks generally are not suitable for CO_2 storage because they do not possess the necessary porosity and permeability would allow injection and storage.

Theoretical global storage capacity is estimated to be in the range of 8,000 to 15,000 $GtCO_2$ (IEA, 2009). This suggests that we have the capacity to store most, if not all, of the CO_2 needed to prevent the build-up of harmful levels of CO_2 in the atmosphere.

Carbon dioxide storage options

Currently considered storage options for CO_2 in geological media include:

- Injection into depleted oil and gas fields;
- Deep aquifers;
- Using CO_2 for enhanced oil recovery (EOR);
- Enhanced coal bed methane recovery (ECBM);
- Deep unmineable coal seams; and
- Enhanced gas recovery (EGR).

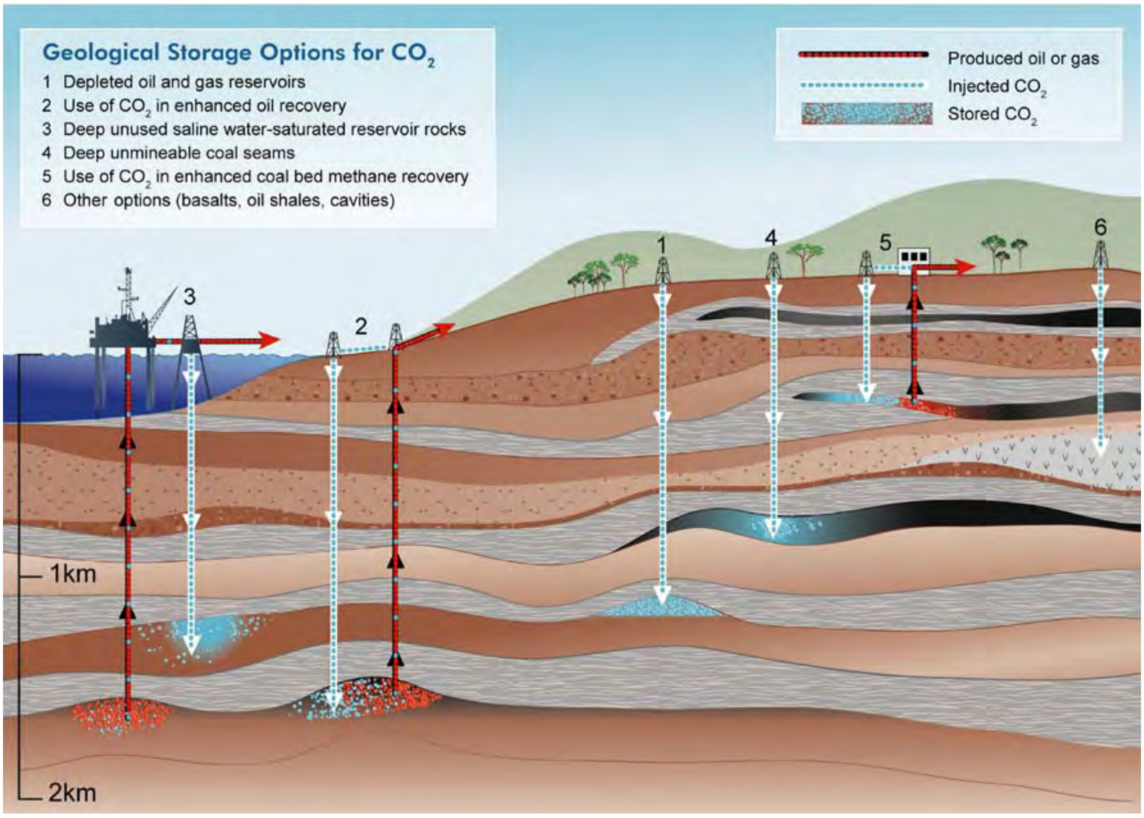

Figure 5.1: There are a range of geological storage opportunities (courtesy of CO2CRC).

Storage options EOR, ECBM and EGR have the added benefit of direct economic incentives. They are reservoirs that typically begin as a commercially developed site to enhance recovery of fossil fuel fluids and have a secondary benefit of providing a storage site for CO_2. These are considered most likely to be implemented in regions with an absence of any carbon cap and trade system. However, some might argue a disadvantage of these options is that the fuels recovered will result in a net gain in CO_2 released into the atmosphere.

Depleted oil & gas reservoirs

There are advantages for using depleted oil and gas reservoirs as CO_2 sinks, as the trapping mechanisms and reservoir properties are well known and some of the existing infrastructure can be utilized (Figure 5.8).

An abandoned oil reservoir can often have a large quantity of oil remaining in it. As such, it is very unlikely that it will be used as a storage facility unless some form of enhanced oil recovery is incorporated into the CO_2 storage scheme. This can be contrasted with an exhausted gas reservoir, where normally up to 90% of the original content would have been removed and the reservoir can genuinely be regarded as depleted and available for CO_2 storage.

The total global storage potential of all oil and gas fields in the world is estimated to be 670 Gt of CO_2 (180 Gt C) assuming the entire volume can be displaced with CO_2 at some time in the future. The distribution between oil and gas is 150 Gt CO_2 (40 Gt C) and 520 Gt CO_2 (140 Gt C) respectively. This is comparable to the estimates in the Second Assessment Report of the Intergovernmental Panel on Climate Change (IPCC).

Appropriate CO_2 capture techniques will be needed for the CO_2 purification and pressurization steps in order to develop the best approach. This is because impurities in the CO_2 can significantly reduce the amount which can be stored, enhance corrosion and increase capital costs. Legal questions also need to be resolved regarding ownership of the residual hydrocarbons.

Deep aquifers

Carbon dioxide storage into low to high permeability deep aquifers in sedimentary basins has been shown to be a technically feasible storage option. Carbon dioxide is an ideal candidate for aquifer storage because of its high density and high solubility in water at the relatively high pressures which exist in deeper aquifers. Deep aquifers have the largest potential capacity for CO_2 storage

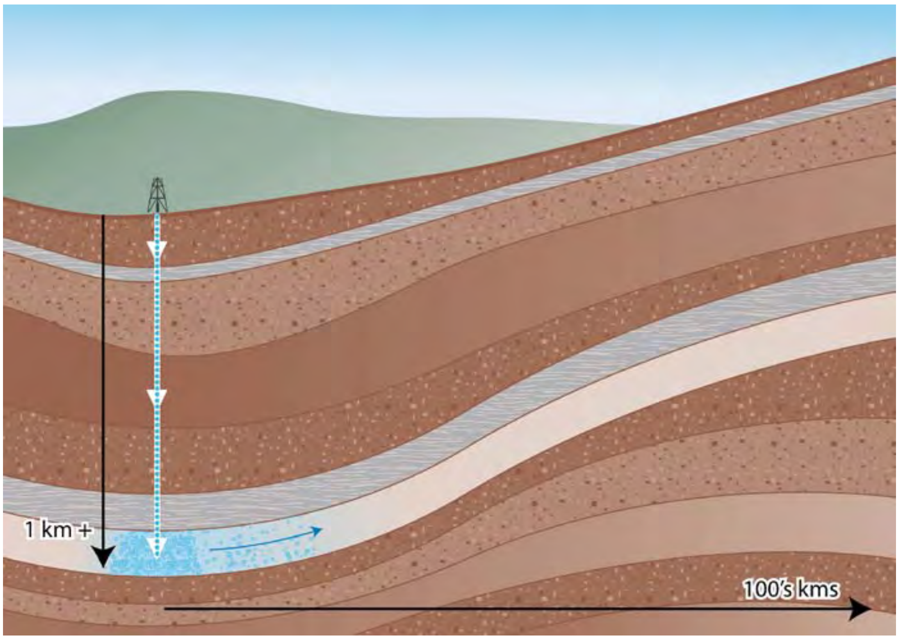

Figure 5.2: Storage in deep aquifers (courtesy of CO2CRC).

Deep aquifers contain high salinity water and could host large amounts of CO_2 trapped by the formation pressure. The determining factors are pressure and temperature in the reservoir and the integrity of the reservoir. At depths of 800 metres and greater, the temperature and pressure of the CO_2 would be above the supercritical condition, which is desirable from a storage perspective. Global estimates of the capacity of this storage option vary greatly due to different assumptions with respect to aquifer volumes, percent of the reservoir filled, density of CO_2 under reservoir conditions, and the volume suitable for storage. It ranges from 87 Gt C to 14,000 Gt C if structural traps are not required for secure storage.

Enhanced Oil Recovery (EOR)

Enhanced oil recovery refers to those methods that are used to increase the recovery of oil above the amounts that could be recovered during primary or secondary recovery. The carbon dioxide may be injected into the gas cap of an oil reservoir in order to provide additional pressure drive for oil recovery. Alternatively, the CO_2 may be injected as a flood and used to "sweep" the residual oil. The use of CO_2 in miscible floods is a proven technology (Figure 5.3), and its activity continues to increase in the U.S.. When CO_2 is injected into the reservoir, it dissolves in the oil, thus reducing its viscosity and moves the oil towards the producing well. Inherently, there is always CO_2 co-produced with the oil. However, it will be captured and reinjected into the reservoir. For immiscible floods, significantly more CO_2 may be left in the reservoir.

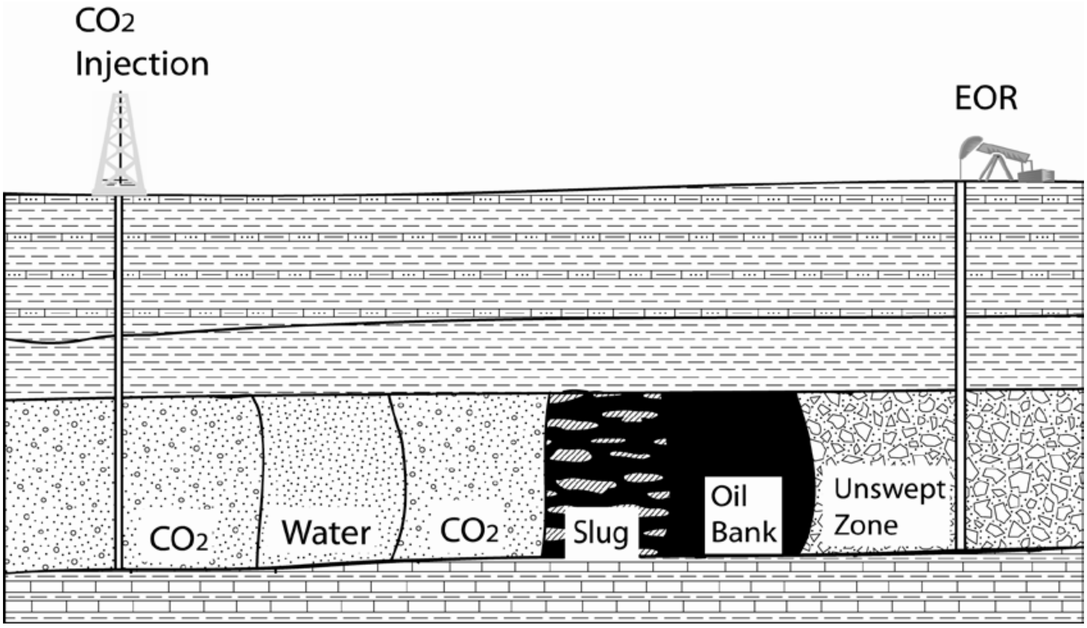

Figure 5.3: Schematic of a miscible CO_2 flood for enhanced oil recovery, EOR (courtesy of ARC).

In the case of EOR, the oil-carbon dioxide mixture is separated at the surface and the oil is used as fuel in the normal way. While this produces more carbon dioxide, the solution to that problem is clear. The carbon dioxide that is returned to the surface could be re-used for more oil recovery or disposed of in deep aquifers. It should be noted that EOR is likely the first and most economic line of carbon dioxide mitigation processes, though other methods will become more viable as technology develops. The recycling of gases in EOR and EGR is possible because there is a close association of the fossil fuel resources of sedimentary basins and the greenhouse gas emitting industry that is based on those fuels.

Globally, the EOR–CO_2 sink has an estimated capacity of 20 to 65 Gt C. It must be noted that not all operations are equally suited for EOR. Use of this sink is restricted to economies that have oil reservoirs suitable for EOR–CO_2 recovery techniques. Use of CO_2 for EOR is capable of storing a large quantity of CO_2, resulting in a net reduction in CO_2, but the overall return on investment (either positive or negative) is highly dependent on factors such as the price of oil, price of CO_2 and individual reservoir characteristics. The specific criteria which should be considered when screening reservoirs for suitability to CO_2 storage are outlined in detail in Module 6.

Figure 5.4: EOR operations in Weyburn, Saskatchewan, Canada (courtesy of EnCana).

In Canada, EnCana Ltd. of Calgary, Alberta is buying carbon dioxide from the Great Plains coal-gasification plant at Beulah, North Dakota, USA. The plant produces pipeline quality synthetic natural gas, and other products, by gasification of lignite from local mines. The carbon is piped 320 km to be used for EOR in the Weyburn Field, Saskatchewan. In 2005, the Midale field nearby (operated by Apache Canada) became part of the project known as the IEA GHG Weyburn-Midale CO_2 Monitoring and Storage Project and is in its final phase. EnCana is injecting 7000 tonnes/day and Apache is injecting 1800 tonnes/day (PTRC website). In 2008, the total of stored CO_2 was more than 12 million tonnes (Preston et al., 2009).

This association of available waste carbon dioxide and a distant oil field using carbon dioxide for enhanced oil recovery is economically viable after expenditures of more than a billion dollars.

The advantages of using carbon dioxide for EOR operations and injecting it into depleted oil and gas reservoirs are:

Opportunity to increase production – the main attraction to using CO_2 storage techniques for oil and gas is the higher recovery of the fuel from a reservoir. The use of CO_2 can aid in the recovery of up to approximately 10 – 12% of the remaining fuel;

Cost effectiveness – following from increased opportunity to produce additional hydrocarbon resources, EOR provides an economically attractive way to increase production from operational oil reservoirs. This revenue stream can offset the cost of capture, transport and injection of carbon dioxide;

Availability of secure storage – there is an opportunistic association between hydrocarbon production and the presence of reservoirs suitable for CO_2 injection. The geological processes that allowed the accumulation of hydrocarbons also permit the secure storing of injected carbon dioxide; and

Availability of supporting infrastructure - the technology and infrastructure for oil and gas production can be readily adapted for carbon dioxide injection; this ranges from knowledge of exploration for and production from reservoirs, through all aspects of gas separation, the handling of high pressure fluids and pipelining, to ensuring safe operations and appropriate environmental studies.

Enhanced Gas Recovery

The much higher densities and viscosities of CO_2 compared to a natural gas composed predominately of methane imply that injection of CO_2 into the base of a depleted homogenous natural gas reservoir would act as a push gas (Figure 5.5). This would mean that if CO_2 is injected down dip in the reservoir the natural gas could be produced from the top of the reservoir. Simulation has confirmed that this could be an attractive technology for certain gas reservoirs. In the case of heterogeneous reservoirs, there is a risk that CO_2 may preferentially follow higher permeability paths and early breakthrough of the CO_2 to the production well may occur. For these cases, more complex reservoir management strategies will be required.

Approximately 90% of the gas in a given reservoir can be extracted through primary processes. The reason for a much higher rate of extraction through primary processes (as compared with oil) is due to the fuel's high compressibility and lower viscosity.

Oil is less compressible and does not expand as much as gas. It therefore requires a secondary or tertiary recover process to provide sufficient pressure for extraction. For these reasons, CO_2 has been used for EOR in practice but is still being tested for EGR.

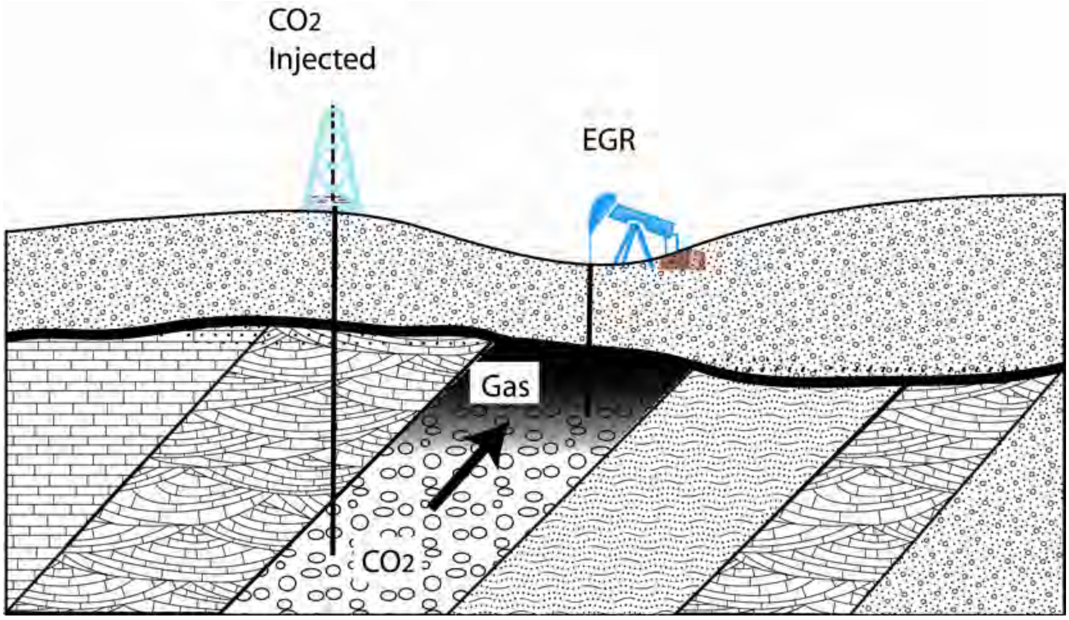

Figure 5.5: Schematic of enhanced gas recovery using CO_2 to displace the natural gas (EGR) (courtesy of ARC).

Enhanced Coal bed Methane Recovery

The use of coal beds as a reservoir rock for storing CO_2 is novel. Coal beds contain significant amounts of methane gas - called coal bed methane or CBM - adsorbed in the coal. Current commercial technologies first dewater the coal in order to release the adsorbed gas (Figure 5.6). On the other hand, by injecting CO_2 into the coal beds, the CO_2 is adsorbed in the coal pore matrix, releasing the methane. Experimental results show that two to ten molecules of CO_2 can be adsorbed in the coal matrix for every molecule of methane it displaces. The use of CO_2 for CBM recovery would have the same effect as enhanced oil recovery and is classified as an enhanced coal bed methane recovery (ECBM).

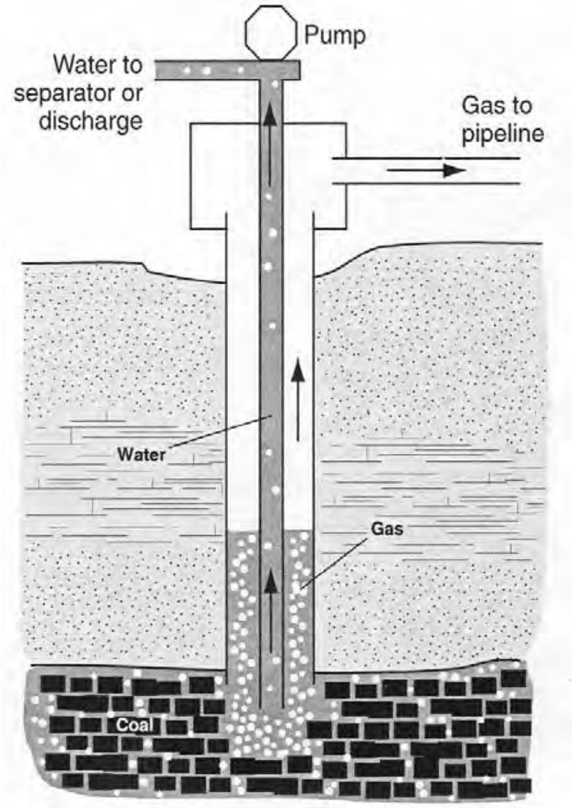

Figure 5.6: Example of a coal bed methane well (courtesy of ARC).

Burlington Resources in the US ran the world's first large scale ECBM pilot utilizing CO_2 injection located in the San Juan Basin, New Mexico. The global estimates of coal bed methane resources are on the order of 84 – 262 x 10^{12} cubic meters. Converting these estimates to CO_2 storage capacity (assuming two molecules of CO_2 displacing one molecule of CH_4) yields a potential of 82 to 263 Gt C. Other trials are in Canada and in China (the Qinshui Basin Project).

The bulk of the world's coal bed methane resource occurs in United States, China, the Asian portion of Russia, Kazahkstan, and India. Australia, portions of Africa, Central Europe, and Canada also contain varying amounts of this resource. It is too early to determine the potential global storage capacity for this application, as it is still in piloting stage. The attractiveness of disposing of CO_2 in coal beds is that it can be coupled directly with the production of methane. Carbon dioxide is much more strongly adsorbed to the coal than methane and premature breakthrough of the injected CO_2 is not expected. Therefore recycling of the CO_2 would not be necessary.

The permeability of the coal seam is a significant factor. While it is theoretically possible to sequester CO_2 in deep coal without the recovery of CBM, the permeability will be low in most cases and further reduced by the swelling that occurs when CO_2 is adsorbed to the coal. Therefore, from a reservoir engineering perspective and from and economic perspective, in most circumstances CO_2 storage would accompany or follow CBM production (Golding et al., 2008). Trials in Japan (Yubari) and Poland (Recopol) have examined the injection of CO_2 into virgin coals and the associated coal bed methane produced.

ECBM is different compared to other storage options, as a pure stream of CO_2 is not required. Separation of the gas takes place in the coal bed due to the coals varying sorption selectivity for different gases. For example if the gas (a mixture of N_2 and CO_2) is injected into a coal seam, the N_2 will pass through and be produced with the methane while the CO_2 will remain trapped in the coal seam.

Alternatively, N_2 in the flue gas can be separated and released to the atmosphere, and a pure stream of CO_2 can be directly injected into the coal seam, Figure 5.7. The choice depends on the economics of the project.

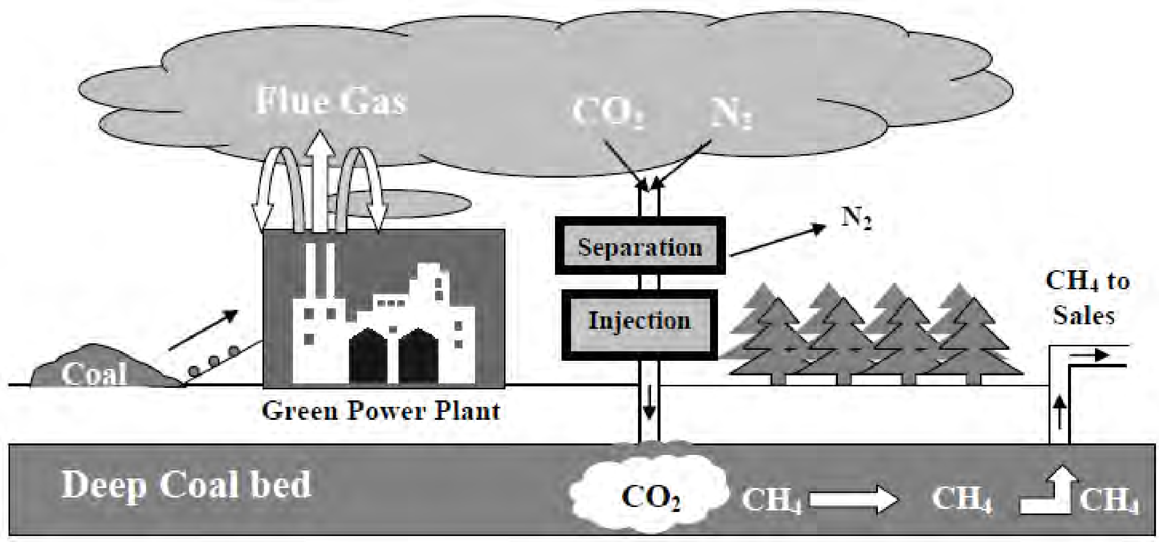

Figure 5.7: Schematic of enhanced coal bed methane recovery (ECBM) (courtesy of ARC).

Trapping carbon dioxide in sedimentary basins

When CO_2 is injected, it is not dissolved in formations water. It is free-phase, or immiscible. At reservoir temperatures it is less dense than the formation water and rises upwards. So that the CO_2 does not migrate to the surface there needs to be a trapping mechanism that keeps the CO_2 in the subsurface for thousands of years or longer.

There are several ways in which dense carbon dioxide can be trapped at 800 m or deeper in saline formations or fossil fuel reservoirs in sedimentary basins.

- **Structural/stratigraphic trapping -** traps CO_2 as a buoyant fluid within geological structures and flow system *(also known as physical trapping or hydrogeological trapping*).
- **Residual trapping -** CO_2 is trapped as small droplets by interfacial (or surface) tension.
- **Solubility trapping -** the CO_2 dissolves into the surrounding formation water making that water about 1% more dense.
- **Mineral trapping -** dissolved CO_2 reacts with the reservoir rock, forming solid carbonate minerals.

Each of these trapping mechanisms will be described in turn.

Structural/stratigraphic trapping

CO_2 must be trapped below sealing rock, such as shale or mudstone, to avoid rapid migration of CO_2 to the surface. If the top of the trap is closed, such as is the case with most oil and gas reservoirs, the CO_2 could be expected to remain in the trap for geological time periods. There are analogues for long-term storage of CO_2 in naturally occurring CO_2 reservoirs which are currently producing commercial grade CO_2 for use in industry (soft drink, dry cleaning etc.) and for EOR.

Sedimentary basins have many such closed, physically-bound traps, called reservoirs, in which the fluid is largely static. Some of these are occupied by oil and gas, and the remainder are occupied by formation water. These oil and gas occurrences were initially also filled by water. Moreover, the available volumes in petroleum reservoirs is very small compared to deep saline formations

However, most of these closed traps have held fluids securely over geological time and, obviously, would be the first targets for geological storage. In addition, the production of oil and natural gas from sedimentary basins creates low-pressure storage space that can be repressurized with CO_2. Examples of trap types are traps bounded by unconformities, facies change, anticlines and non-transmissive faults (Figure 5.8). Obviously, these would be very attractive for CO_2 storage due to their long history of containment.

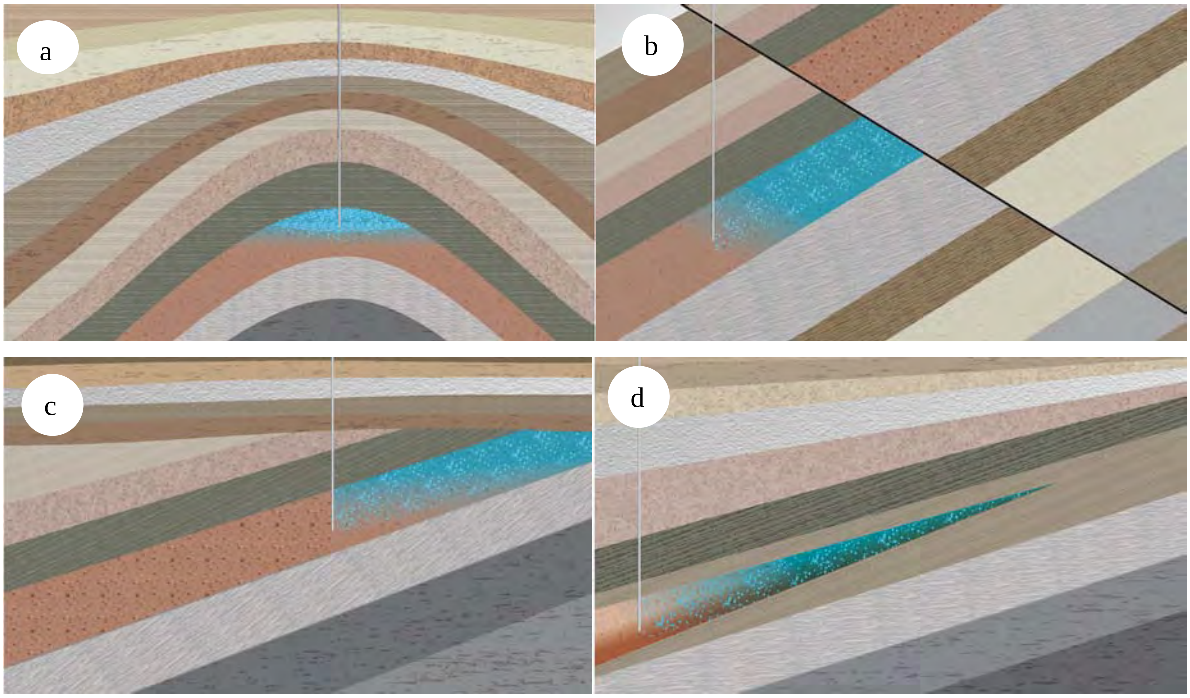

Figure 5.8: Representations of structural and stratigraphic closed traps. a) structural trap – anticline b) structural trap – fault trap c) stratigraphic trap – unconformity d) stratigraphic trap – change in rock type/pinchout (courtesy of CO2CRC).

In structural/stratigraphic trapping, CO_2 is trapped below low permeability rock which prevents it from migrating to the surface. Under these circumstances, CO_2 could be trapped for geological time periods. Often closed traps also hold oil and natural gas which could be tapped during CO_2 storage.

Storage in deep saline formations

The pore space in these formations is filled with saline water. Carbon dioxide can be injected into these deep formations by displacing the saline formation water (Hitchon, 1996). Where CO_2 is injected into horizontal or gently dipping reservoirs that are laterally unconfined, it can remain in the reservoir moving very slowly for a long time – such deep saline formations characteristically have slow groundwater flow rates of the order of cm/yr (Bachu et al., 1994). CO_2 is expected to migrate under the force of buoyancy towards the surface. The pathway that the CO_2 takes is determined by the complex plumbing of the sedimentary basin. If the aquifer is well-bounded by aquitards, migration of the CO_2 would be slowly towards the earth's surface over geologic time. A volume of CO_2 injected into such a deep open hydrogeological trap can take over a million years to travel upward in the aquifer to reach the surface and be released into the atmosphere - distances from the deep injection sites to discharge at outcrop can be of the order of 100s of kilometres. The timeframe needed to stabilize CO_2 atmospheric concentrations is of the order of hundreds of years. During that time, the CO_2 could dissolve in the formation water or be trapped as a mineral.

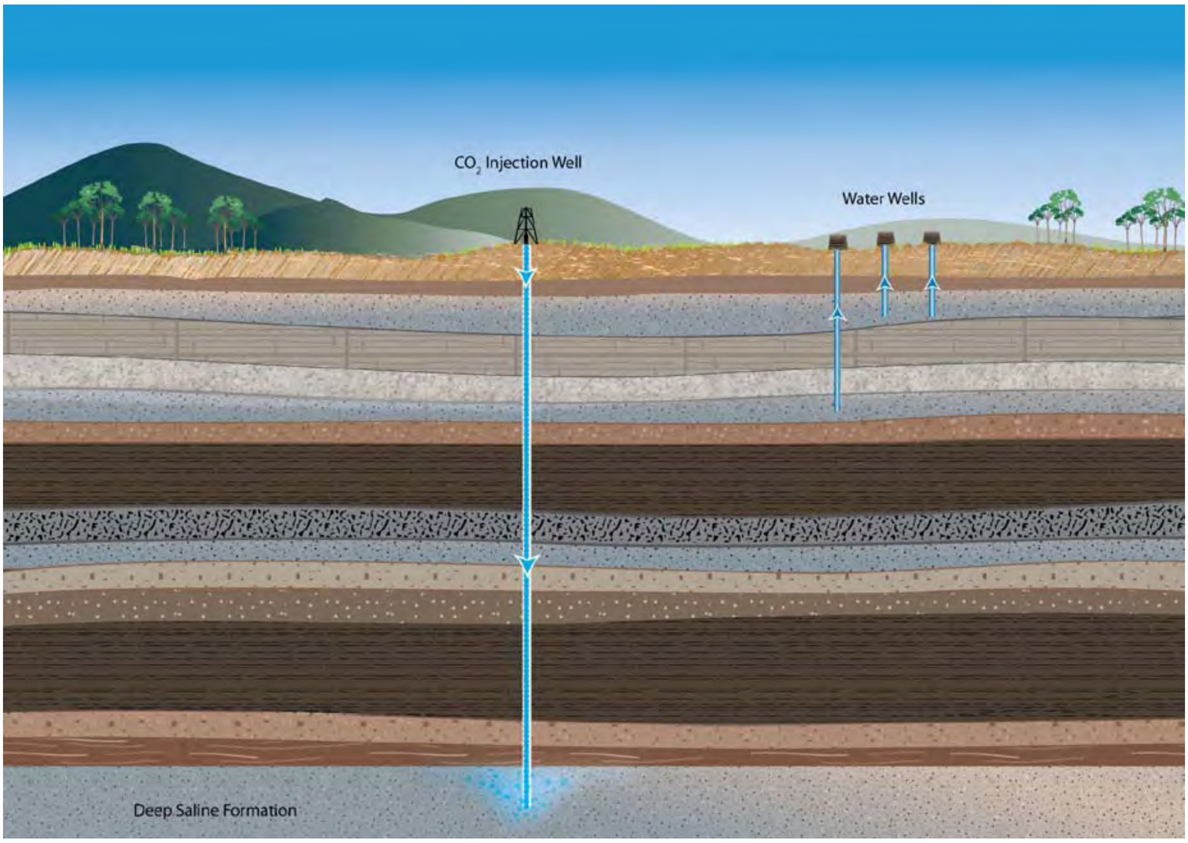

Figure 5.9: Deep saline formations can store carbon dioxide over geological timeframes (courtesy of CO2CRC).

Careful characterisation of the potential reservoir is required because buoyant CO_2 will seek out the interconnected high permeability pathways, including interconnected aquifers, faults, fractures and and wellbores. These potential leakage points will carry the CO_2 upwards where it could eventually discharge at the surface on much shorter time scales (e.g. human life).

CO_2 must be trapped in sedimentary basins in order to ensure storage for geological time periods. Only a few sedimentary basins will leak significantly over human time scales, or the time scale required to stabilize atmospheric CO_2 concentrations associated with climate change (hundreds of years).

The hydrodynamic trapping efficiency is significantly enhanced when the flow of formation waters is driven downward in the aquifer by erosional rebound, as is the case of Cretaceous aquifers in the Alberta basin (Figure 5.10).

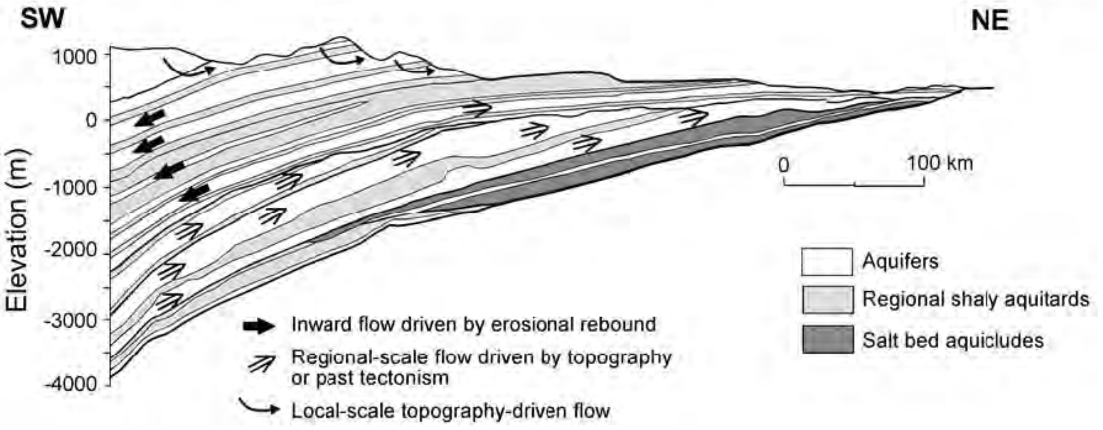

Figure 5.10: Diagrammatic cross-section through the Alberta sedimentary basin, Canada, showing main flow types and systems (after Bachu, 1995).

Residual trapping

When CO_2 is injected into a deep saline formation in a situation where it can migrate away from the injection well, it forms a plume of free-phase CO_2. This plume will migrate under the influence of gravity, displacing the formation water. When injection ceases, tail of the plume of free-phase CO_2 that is not in the final free-phase accumulation is at low saturation in the pores and trapped by interfacial tension with the formation water in the pore space between the rock. This is called residual trapping. Eventually, this residually trapped CO_2 will dissolve into the formation water up to the point where the water becomes fully saturated with CO_2.

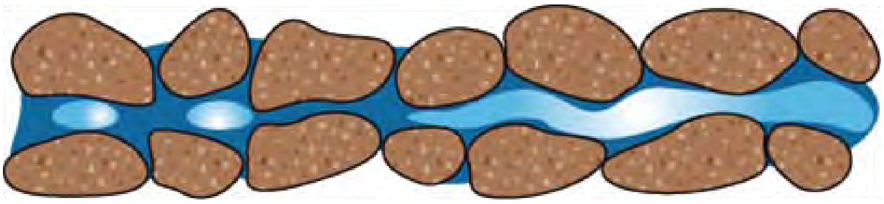

Figure 5.11: The tail of the carbon dioxide plume is snapped of and trapped residually (courtesy of CO2CRC).

Residual trapping involves trapping CO_2 at the irreducible saturation point, segregating the CO_2 bubble into droplets that become trapped in individual or groups of pores.

Geochemical trapping – solubility trapping and mineral trapping

The chemistry of formation water and rock mineralogy play an important part in determining the potential for carbon dioxide capture through geochemical reactions (see Gunter et al., 2000). More important, these reactions store the carbon dioxide as a dissolved phase (solubility trapping) or ionic complex (ionic trapping) in the formation water or in solid phases as carbonate minerals (mineral trapping). In the case of storage in unmineable coal seams, the CO_2 is trapped as an adsorbed phase in coal (adsorption trapping). In this respect, the unique feature of mineral trapping is that the carbon dioxide is sequestered in a form that is immobile.

Solubility trapping

If the CO_2 is injected into deep saline aquifers, the injected CO_2 can dissolve in the formation water on an engineering time scale (decades) (Law and Bachu, 1996). Over longer periods of time (centuries to millennia) all the injected CO_2 can dissolve (McPherson and Cole, 2000) if the structure allows it. The amount of dissolved CO_2 normally decreases with depth as a result of increasing temperature and formation-water salinity characteristic of many sedimentary basins (Bachu and Adams, 2003).

Carbon dioxide dissolves in the aqueous phase and alters the pH (acidity/alkalinity) through reactions coupled to the dissociation of water. Reactions of the following type occur when carbon dioxide dissolves in water:

$$H_2O + CO_2 \leftrightarrow H_2CO_3 \leftrightarrow HCO_3^- + H^+$$

Initially, some of the carbon dioxide is held in the aqueous phase as bicarbonate. Only minor amounts of bicarbonate ion and the proton will be produced (thereby lowering the pH), no matter how high the pressure of carbon dioxide. This is the reason that formation water alone is not an acceptable long term sink for carbon dioxide.

The proton, released when the CO_2 dissolves in the formation water, results in acid conditions in the water and, therefore, enhances the possibility of attack on the silicate and carbonate minerals present in the aquifer.

Mineral trapping

The dissolved CO_2, being acidic, can attack silicate and carbonate minerals present in the aquifer in free ions of elements such as calcium (Ca), magnesium (Mg), and iron (Fe) being released, while at the same time neutralizing the pH shift (i.e. acidity) caused by the dissolved carbon dioxide and allowing more bicarbonate ions to form. This is referred to as “ionic trapping” The reactions fix the CO_2 as an ionic species in the formation water that does not boil off when the pressure is released.

One of the fastest geochemical precipitation reactions is the precipitation of calcium carbonate, which occurs when free calcium ions exist in the presence of bicarbonate ions in supersaturated amounts, and is most effective at high pH values. The reaction produces calcite, and it is this reaction that forms the theoretical basis for the storage of carbon dioxide as the mineral calcite.

$$Ca^{2+} + HCO_3^{-} \leftrightarrow CaCO_3 + H^{+}$$

Silicate minerals such as anorthite can be transformed to kaolinite and calcite in the following reaction:

$$\underset{\text{(anorthite)}}{CaAl_2Si_2O_8} + H_2O + CO_2 \rightarrow \underset{\text{(calcite)}}{CaCO_3} + \underset{\text{(kaolinite)}}{Al_2Si_2O_5\,(OH)_4}$$

The role of the silicate minerals in the above reaction is to neutralize the acid added to the formation water by the addition of carbon dioxide. There are similar reactions for the formation of calcium-magnesium carbonate (dolomite) and iron carbonate (siderite). Thus, unlike the storage of carbon dioxide in the oceans or by other means, the reactions that may occur in the aquifer are such that the carbon dioxide is permanently fixed as a mineral—this method is called mineral trapping. For the more complex minerals commonly found in aquifers, the reaction is of the form:

$$\text{Feldspars} + \text{Clays} + CO_2 = \text{Kaolinite} + \text{Calcite} + \text{Dolomite} + \text{Siderite} + \text{Quartz}$$

where the carbon dioxide is permanently fixed as the carbonate minerals calcite, dolomite and siderite. Carbon dioxide mineral traps are most effective when the aquifer contains minerals that are proton sinks—that is, the basic silicate minerals such as the feldspars and clay minerals. Consequently, mineral trapping of carbon dioxide is favoured in aquifers containing an abundance of clay minerals—typically, siliciclastic (sandstone) aquifers are favoured over carbonate aquifers.

Relative securing of trapping methods

The most secure hydrogeological traps are closed stratigraphic or structural geologic traps, which have been well characterised during their exploitation for oil and gas. Although the capacity of these traps for CO_2 storage is small relative to open hydrodynamic traps in deep sedimentary basins, they are likely to be used first as they are known to be secure, having held oil and gas for geological time.

Storage of CO_2 as carbonate minerals is the most secure form of storage, but the reactions that trap the CO_2 in carbonate minerals are slow on the human time scale, but relatively fast on a geological time scale. Over longer time periods, mineral trapping may become a long-term stable sink for CO_2. The extent and rate at which this occurs depends on the mineralogy and brine chemistry of the sedimentary rocks contacted by CO_2.

As the capacity of closed traps is exhausted and more is learned about the rates of residual and geochemical trapping, the large storage capacity available in open hydrodynamic traps will be utilized. This will only be possible when the security of the geological storage of CO_2 can be enhanced by geochemical reactions of the CO_2 with basic silicate minerals.

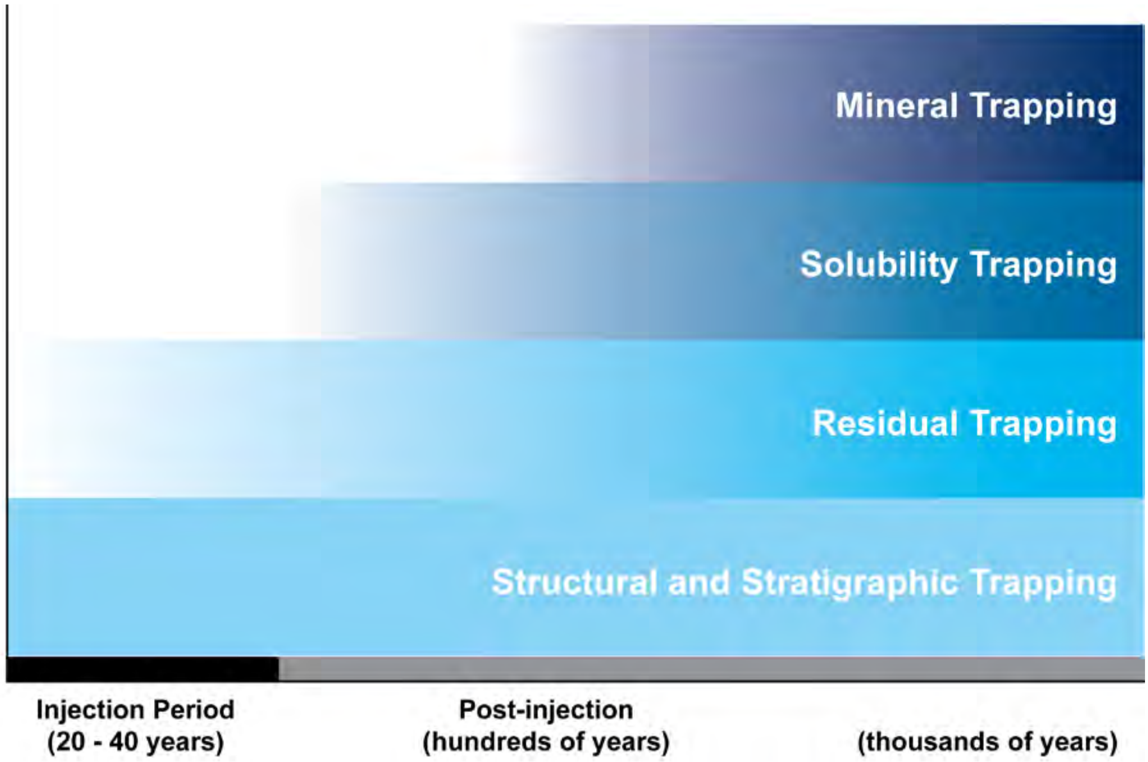

Figure 5.12: Over time, the security of the trapped CO_2 increases as different types of trapping become significant (courtesy of CO2CRC).

In the sedimentary basins, suitably located injection sites far from the basin edge and injection at depths greater the 800 m (the minimum depth for injection of carbon dioxide at liquid-like density) will result in geologically long times before any emergence of carbon dioxide at the surface occurs—if at all. By that time, if ionic or mineral trapping have not occurred, the pressure of carbon dioxide will have been reduced to such an extent (from the original injection pressure) due to solution, diffusion, dispersion and residual trapping that the emergence will be a relatively harmless event, occurring over a much longer period than the original injection period.

Outlook

Sedimentary basins, fossil fuel resources, and deleterious greenhouse gas emissions are all closely associated. To exploit the fossil fuels is to produce the greenhouse gases. This does not have to be so. The main greenhouse gas produced by the burning of fossil fuels is carbon dioxide. Rather than discharge carbon dioxide to the atmosphere, it can be stored in deep aquifers in the same sedimentary basins from which the fuel was extracted - some of the strata can be hydrocarbon-bearing (reservoirs) with the carbon dioxide enhancing oil or gas production.

Injection and storage technologies, developed by the oil and gas industry, are fairly mature. The volume of storage depends on the current and ultimate pressures of the reservoir or aquifer. Experience in injection of CO_2 has been gained from repressurizing oil reservoirs using CO_2 in enhanced oil recovery, from acid gas re-injection, and similar technology is being developed for production of methane from coal beds (i.e. coalbed methane or CBM). The ultimate capacity of geological storage of carbon dioxide is likely huge, contingent upon identifying secure traps in sedimentary basins.

At GHGT-9 in November 2008, the following short term challenges were identified:

- Determining the implications of pressure build-up in a storage formation;
- Determining where the displaced water goes in a large scale injection and what the risk is to ground water;

- How to reliably predict the size of the CO_2 plume and where it migrates;
- How to gain confidence in site selection;
- Cost effective monitoring strategies and detection limits; and
- If a leak occurs, determining how it can be fixed, the cost of fixing it and how long it will take.

Summary

The geological storage of CO_2 requires access to large subsurface volumes in the rock pore space which can act as sealed pressurized containers.

Currently considered storage options for CO_2 in geological media include:

- Injection into depleted oil and gas fields;
- Deep aquifers;
- Using CO_2 for enhanced oil recovery (EOR);
- Enhanced coal bed methane recovery (ECBM);
- Deep unmineable coal seams; and
- Enhanced gas recovery (EGR).

Aquifers have the largest capacity for all feasible sedimentary basins for CO_2 storage. The volume of pore space in aquifers far exceeds that of oil, gas and coal bed reservoirs.

Aquifer storage of CO_2, depleted oil/gas reservoir storage of CO_2 and enhanced oil recovery are currently being demonstrated. Enhanced coal-bed methane recovery is being explored. Enhanced gas recovery also being investigated.

CO_2 must be trapped in sedimentary basins in order to ensure storage for geological time periods. This trapping can be through structural/stratigraphic trapping, residual trapping, solubility/ionic trapping and/or mineral trapping.

In structural or stratigraphic trapping, CO_2 is trapped below low permeability rock which prevents it from migrating to the surface. Under these circumstances, CO_2 could be trapped for geological time periods. Often closed traps also hold oil and natural gas which could be tapped during CO_2 storage.

The most secure hydrogeological traps are closed stratigraphic or structural geologic traps, which have been well characterized during their exploitation for oil and gas. They have a smaller capacity but are likely to be used first of the options.

Trapping occurs in deep saline aquifers with slow flow rates. Injected CO_2 replaces saline formation water. It will remain in the reservoir moving very slowly for a long period of time.

Residual trapping involves trapping CO_2 at the irreducible saturation point, segregating the CO_2 bubble into droplets which become trapped in individual or groups of pores.

Injected CO_2 can dissolve in the formation water over a geological time scale. Silicate or carbonate minerals present in the aquifer will neutralize the acidic CO_2 added to the formation. These reactions fix the CO_2 as an ionic species in the formation water that does not boil off when the pressure is released.

Mineral trapping occurs when carbon dioxide reacts with the reservoir rocks to form carbonate minerals. Mineral trapping is the most secure form of storage, but reactions occur slowly on the geological time scale.

The preferential adsorption of CO_2 onto the coal matrix because of its higher affinity to coal than that of methane is a form of geochemical trapping.

The trapping mechanisms become more secure over time.

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Module 6

Identification and selection of suitable CO_2 storage sites

Adapted from: Storage Capacity Estimation, Site Selection and Characteristics for CO_2 Storage Projects, CO2CRC
Technical appendices: S. Bachu, APEC Capacity Building in the APEC Region, Phase II

Overview

The selection of potential storage sites suitable for significant volumes of CO_2 involves the consideration of geological, regulatory, environmental and social factors. It is essential that it is carried out carefully to minimise risks of leakage.

Learning objectives

By the end of this module, you will:

- Understand the main criteria for the identification of a site for a geological storage of CO_2 at the basin, regional and local scales;
- Understand the steps in selecting a site for geological storage of CO_2;
- Identify the difference in selecting sites for different types of geological storage; and
- Be aware of the skills and expertise needed for site selection.

Introduction

The initial stage in selecting possible storage sites involves screening of sedimentary basins which have the potential to store CO_2 in pore space in rock such as limestone and sandstone or via adsorption onto coal. Following the basin screening, the next stage in selecting a CO_2 storage site is a basin-scale assessment.

More detailed and localised assessments are carried out as indicated in the diagram, with the amount of data required to make a more accurate assessment of the storage capacity increasing at each stage.

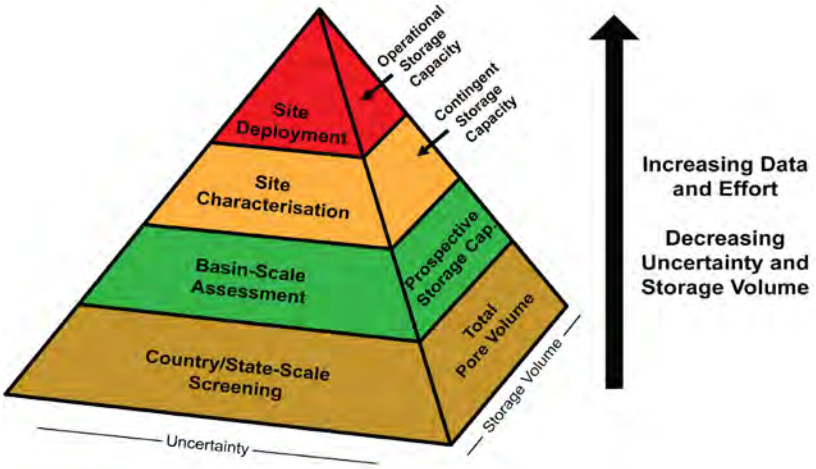

Figure 6.1: The steps in selecting a site and refining the estimates of the amount of CO_2 that can be stored at the site (courtesy of CO2CRC).

A summary of the steps required for identifying a site to store CO_2 is shown in Figure 6.2.

As each step of the site selection is carried out, the storage capacity is refined until a final figure is determined - the operational storage capacity.

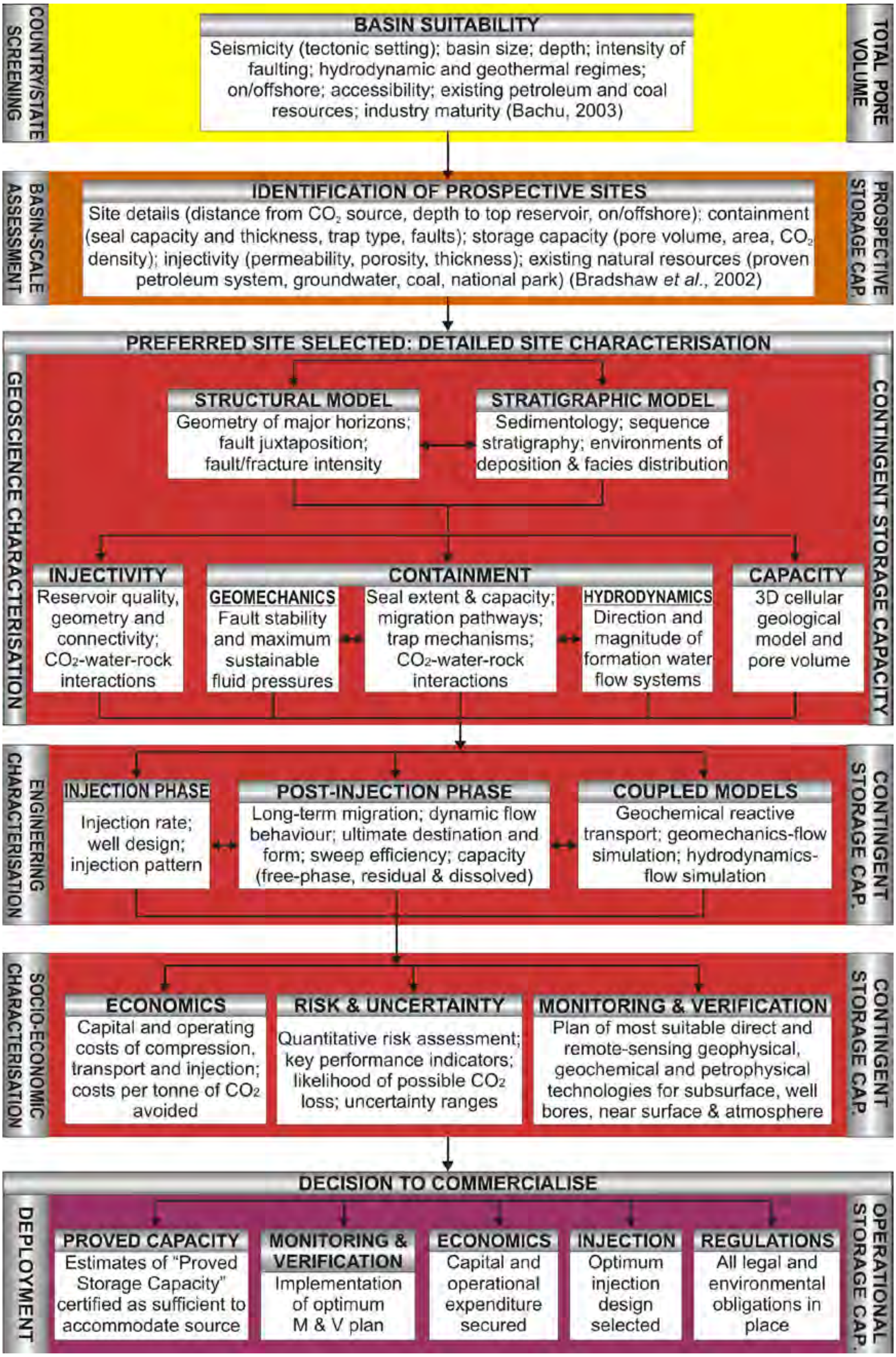

Figure 6.2: Steps in selecting a storage site (modified from Gibson-Poole, 2008).

Screening sedimentary basins

Appropriate sedimentary basins can be screened and ranked according to their suitability for CO_2 storage. Existing geological information can be used to evaluate the size and thickness of the basin, the tectonic setting of the basin and the intensity of faulting within the basin. Other factors influential in producing a list of possible sites are hydrodynamic and geothermal regimes, accessibility, the existence of petroleum and coal resources and the level of maturity of the industry.

The steps are:

- Identify sedimentary basins;
- Screen sedimentary basins - review the characteristics of sedimentary basins; and
- Qualitatively rank sedimentary basins in order of suitability.

Screening sedimentary basins

Different basins can be compared and ranked as suitable CO_2 storage basins by considering the following factors:

Tectonic setting or seismicity – the tectonic setting or seismicity of a basin should be considered because large earthquakes could lead to CO_2 escaping from the storage reservoir. Although some areas that are seismically active contain large petroleum accumulations which suggests that CO_2 storage is possible, so they should not be eliminated as potential storage areas. Instead, the site characterisation should be undertaken with particular emphasis on the impact of seismic activity (see also Appendix 1).

Basin size and depth – basin size and depth give an estimate of the overall storage volume achievable. The sedimentary basin needs to be deep enough to store CO_2 in a supercritical phase (a depth of approximately 800m is needed for this), but not so deep that injection well drilling would be excessively costly. Coal seams can be considered for storage at depths of 300-800m. Saline formations are suitable at depths between 800 and 3500m.

Faulting intensity – faulting intensity influences the capacity and the containment of the site. If an area contains extensive faults, there is the possibility that CO_2 could leak out via faults and fractures. Alternatively, faults could seal individual reservoirs, so extensive faulting can break the reservoir into compartments. Multiple wells may then need to be drilled to effectively use the storage capacity of the reservoir.

Hydrogeology/hydrodynamics – hydrogeology describes the dynamic flow system in the reservoir rock and is used to assess the potential of confined but extensive saline formations for hydrodynamic trapping. To keep the CO_2 in the reservoir for long enough to enable residual trapping, solution trapping or mineral trapping, the saline formation needs a slow flow rate and/or a long migration pathway. The permeability of the reservoir needs to be a balance between reasonable injection rates and a slow flow rate for the CO_2 once in the saline formation (see also Appendix 2).

Geothermal conditions – the geothermal conditions of a storage basin affect the density of the CO_2. In colder basins, CO_2 is denser, so that more CO_2 can be contained in the same volume of rock (see also Appendix 3).

Reservoir seal pairs – a suitable storage site will have good reservoir-seal pairs. The reservoir will have high porosity and good permeability, and the seal will have low permeability. One way to determine the possible existence of reservoir-seal pairs is through examining stratigraphic columns (see Figure 6.3). Evaporites provide the best caprock seals. They form when brackish-saline water evaporates, leaving behind a mineral sediment.

Coal seams and coal rank – coal seams can adsorb significant amounts of CO_2. Coalbed methane (CBM) production usually involves pumping groundwater from the seam to reduce the pressure and release the methane. In enhanced coalbed methane production (ECBM), a gas is used to displace methane from the coal bed. If the gas used is CO_2, CO_2 is stored by adsorption onto the surface of the coal. CO_2 would only be able to be stored in coal seams that were uneconomic to mine because of their depth or quality. While coals at a greater depth have good adsorption capacity, they generally have low permeabilities.

Hydrocarbon potential – rocks that are suitable for containing and producing oil and gas are likely to be suitable for storing CO_2. The potential for storing CO_2 will be dependent on the timing of possible hydrocarbon production.

Industry maturity – if there is a mature oil/gas industry in the area, there will be a larger amount of available geological information about the site. Most of the hydrocarbon and coal would have been discovered and there are likely to be depleted oil and gas reservoirs. Such areas are likely to have good infrastructure such as roads, pipelines and wells.

Location: onshore/offshore – onshore CO_2 storage sites have economic and technical advantages but may have land use and tenure issues.

Climate – climate affects the surface temperatures, the depth of the water table and the ease of development of storage facilities.

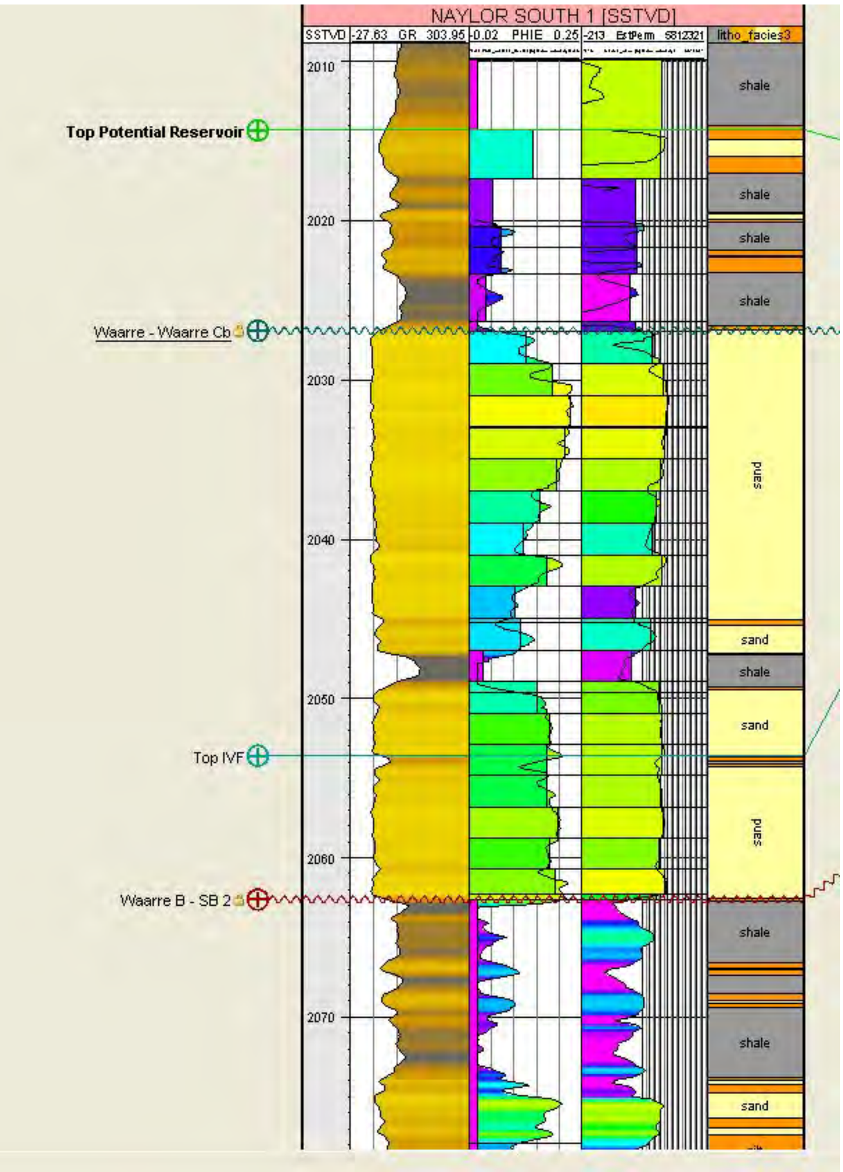

Figure 6.3: Stratigraphic column of the storage site for the CO2CRC Otway Project with reservoir/seal pairs (courtesy of CO2CRC).

Summary table of criteria for screening sedimentary basins.

	Criterion	Increasing CO_2 Storage Potential → Classes				
		1	2	3	4	5
1	Seismicity (tectonic setting)	Very high (e.g. subduction)	High (e.g. syn-rift, strike-slip	Intermediate (e.g. foreland)	Low (e.g. passive margin)	Very low (e.g. cratonic)
2	Size	Very small (<1000 km^2)	Small (1000–5000 km^2)	Medium (5000 – 25000 km^2)	Large (25000–50000 km^2)	Very large (>50000 km^2)
3	Depth	Very shallow (<300 m	Shallow (300–800 m)		Deep (>3500 m	Intermediate (800–3500 m)
4	Faulting intensity	Extensive		Moderate		Limited
5	Hydrogeology	Shallow, short flow systems, or compaction flow		Intermediate flow systems		Regional, long-range flow systems; topography or erosional flow
6	Geothermal	Warm basin (>40ºC/km)		Moderate (30–40ºC/km)		Cold basin (<30ºC/km)
7	Reservoir–seal pairs	Poor		Intermediate		Excellent
8	Coal seams	None	Very shallow (<300 m)		Deep (>800 m)	Shallow (300–800 m)
9	Coal rank	Anthracite	Lignite		Sub-bituminous	Bituminous
10	Evaporites	None		Domes		Beds
11	Hydrocarbon potential	None	Small	Medium	Large	Giant
12	Maturity	Unexplored	Exploration	Developing	Mature	Super-mature
13	Onshore/ offshore	Deep offshore		Shallow offshore		Onshore
14	Climate	Arctic	Sub-arctic	Desert	Tropical	Temperate
15	Accessibility	Inaccessible	Difficult		Acceptable	Easy
16	Infrastructure	None	Minor		Moderate	Extensive

Table 6.1: Criteria for screening sedimentary basins for geological storage of CO_2 (modified from Bachu, 2003).

Basin-scale assessment

Following the basin screening, the next stage in selecting a CO_2 storage site is a basin-scale assessment. This involves reviewing the basin stratigraphy, mapping reservoir-seal pairs and coal seam distributions and assessing CO_2 migration pathways and possible traps. At this scale, reservoir/seal pairs can be mapped using existing data such as geological and structural maps, seismic sections and well logs. The subsurface geometry of the reservoir and seal units can be determined using structural contour and isopach maps, reports on hydrocarbon resources and well completion reports.

The steps involved are:

- Review basin stratigraphy;
- Determine reservoir-seal pair and coal seam distribution;
- Assess CO_2 migration pathways and possible traps; and
- Rank prospective sites.

The elements used to rank prospective sites are:

- Storage capacity
- Injectivity potential;
- Site logistics;
- Containment; and
- Existing natural resources.

The criteria and what is considered are outlined below for storage in saline formations and storage in coal seams.

Factor	Chance Being Assessed	Considerations
Storage capacity	Will meet the volume requirements of neighbouring, currently identified CO_2 sources	Temperature, pressure, area, pore volume
Injectivity potential	Reservoir conditions viable for injection	Porosity, permeability, thickness
Site logistics	Site is economically and technically viable	Distance from CO_2 source, water depth, reservoir depth, overpressure
Containment	Seal and trap will work for CO_2	Seal capacity and thickness, trap, faults
Existing natural resources	No viable natural resources in the site that may be compromised	Proven or potential petroleum system, groundwater, coal or other natural resource (e.g. National Park)

Table 6.2: Ranking factors for saline formations and petroleum reservoirs as prospective CO_2 storage sites (modified from Bradshaw & Rigg, 2001; Rigg et al., 2001; Bradshaw et al., 2002).

Factor	Chance Being Assessed	Considerations
Storage capacity	Will meet the volume requirements of neighbouring, currently identified CO_2 sources	Temperature, pressure, rank, ash content, lithotype, seam thickness, continuity, aerial extent
Injectivity potential	Reservoir conditions are viable for injection	Permeability, stress regime, mineralisation, structure, rank, lithotype
Site logistics	Site is economically and technically viable	Distance from CO_2 source, coal seam depth, infrastructure, CSM potential
Containment	Seal and trap will work for CO_2	Seal type and thickness, hydrology, trap, fault breaches
Existing natural resources	No viable natural resources in the site that may be compromised	Proven or potential coal resource, groundwater or other natural resource (e.g. National Park)

Table 6.3: Ranking factors for coal seams as potential CO_2 storage sites (modified from Bradshaw et al., 2001).

Site characterisation – saline formations and petroleum reservoirs

Once a basin-scale assessment has been finished and a prospective storage site is identified, the site then needs to undergo increasing levels of detailed analysis in a process called site characterisation. Site characterisation is the analysis and interpretation of subsurface, surface and atmospheric data to assess whether or not an identified site is suitable to store a specific quantity of CO_2 for a defined period of time and meet all required health, safety, environmental and regulatory standards.

Site characterisation is the most time consuming and costly part of site selection. It involves skills in reservoir engineering, structural geology, sedimentology, stratigraphy, hydrodynamics and geological modelling. In addition, the social setting, the economics of operation, the risks involved in storing the CO_2 at the site and the requirements of a monitoring and verification regime need to be considered. Because of the wide range of expertise covered in a site characterisation, it is best carried out in a multidisciplinary environment. Where there is not enough existing data to successfully characterise the site, it is necessary to generate new data. The process involves:

- Geoscience characterisation – interpreting structural and stratigraphical information and building geological, geochemical, geomechanical and hydrodynamic models;
- Engineering characterisation – constructing numerical flow simulations to predict CO_2 plume migration;
- Updating all models as additional data become available; and
- Socio – economic characterization: Risk assessment, economic modelling and community concerns.

Geoscience characterisation

Sources of data can include 2D and 3D seismic surveys, well log and core data, drill cuttings, biostratigraphy, field production and fluid data. Three key factors need further evaluation at this stage: injectivity, containment and capacity.

Injectivity

Injectivity is the rate at which CO_2 can be injected into a given reservoir and the ability of the CO_2 plume to migrate away from the injection well. Factors which affect injectivity include the viscosity ratio of CO_2 to other formation fluids, the injection rate and the relative permeability of the reservoir.

Core samples can be used to determine the porosity and permeability of the reservoir rock. Wireline logs of existing wells give one dimensional data, so rock properties have to be inferred through the use of well log correlation, the use of analogues and seismic interpretation. Static reservoir models should be constructed to map reservoir distribution and horizontal and vertical connectivity.

CO_2 dissolution into formation water can result in CO_2-water-rock interactions which may alter the pore system of the rock, so the mineralogical composition of the reservoir should be included in evaluating injectivity.

In deep saline formations, which typically have low permeability, the ideal objective is high permeability near the wellbore to improve injectivity and lower permeability outside the radius of influence of the wellbore to increase residence times.

Containment

Supercritical CO_2 is less dense than water and has the tendency to be driven upward due to buoyancy forces. Loss of CO_2 can occur through migration through the top seal, faults and fractures or via wells. Factors that affect containment include:

The distribution and continuity of the seal: The top seal is called the cap rock. Good cap rock is uniform, regionally extensive, thick, strong and unlikely to be weakened though CO_2–water–rock reactions.

The seal capacity (maximum CO_2 column height retention)**:** The seal capacity is dependent on the capillary pressure properties of the sealing rock and physio-chemical properties of CO_2 and the formation water such as density, wettability and interfacial tension. Water pumping tests can be used to measure the rate of leakage across the cap rook. The sealing capacity of rock can also be estimated by mercury injection capillary pressure (MICP) analysis of core samples. This analysis determines the capillary pressure that is required to move mercury through the pore system of the sample. This pressure is converted to an equivalent CO_2 brine pressure and then used to determine CO_2 column height.

Integrity of reservoir and seal rock: When the CO_2 is injected, it increases the pressure in the formation which can potentially reactivate pre-existing faults or generate new fractures. The maximum sustainable fluid pressure for CO_2 injection can be determined through geomechanical modelling.

The potential for CO_2-water-rock interaction: The injected CO_2 may react chemically with the rock. Detailed reservoir petrology, water chemistry and pressure-temperature conditions enable mineral reactions with CO_2 to be predicted. Mineral precipitation of CO_2 can lead to mineral trapping and hence greater containment security. It can also clag pores and thereby decrease injectivity.

Migration pathways: The structural orientations and dips in the reservoir can be predicted using stratigraphic, subsurface wireline and seismic data. Because the injected CO_2 is more buoyant than water, it will migrate vertically to the top of the reservoir. Once there, the geometry of the seal will have a strong influence on the subsequent migration direction and rate. Other characteristics that need to be identified are the trapping mechanisms.

Intraformational seals which act as localised barriers: The presence of siltstones and shales within the reservoir formation can reduce the vertical flow of the CO_2 and create a more complex migration pathway. Such siltstones and shales contribute to the degree of stratigraphic heterogeneity of the formation. In a homogenous formation, the buoyant CO_2 will migrate vertically up to the top of the reservoir.

Formation water flow direction and rate: Understanding the flow system of the existing formation water within a reservoir is important to determine how effective hydrodynamic trapping will be. Using hydrodynamic models, the impact of vertical connectivity, horizontal continuity and low permeability zones on the migrating CO_2 plume can be assessed.

Capacity

CO_2 storage capacity is an estimate of the amount of CO_2 that can be stored in subsurface geological formations. It is influenced by the density of CO_2 at subsurface conditions, the amount of interconnected pore volume of the reservoir rock and the nature of the formation fluids.

Storage capacity estimation in saline formations

The mass estimate of CO_2 storage capacity is a calculation based on:

- The geographical area that defines the region for storage;
- The thickness of the saline formation;
- The average total porosity of the entire saline formation;
- The density of CO_2 at the relevant temperature and pressure;
- How much of the region has a suitable formation;
- How much of the formation meets minimum porosity and permeability requirements for injection;
- How interconnected the formation is;
- What area surrounding an injection well can be contacted by CO_2;
- Porosity and permeability variation in sub layers in the formation;
- How much of the formation will be contacted by CO_2 as CO_2 rises due to a density difference with water; and
- How much of the water will be replaced by CO_2 in the pore space.

Storage capacity estimation in depleted oil and gas formations

Unlike saline formations, oil and gas fields can be considered as discrete systems. The mass estimate of CO_2 storage capacity is a calculation based on:

- The geographical area that defines the region for storage;
- The hydrocarbon column height in the reservoir;
- The type of trap;
- The average porosity over the column height;
- The density of CO_2 at the relevant temperature and pressure; and
- The fraction of the pore volume from which oil/gas has been produced and can be filled by $CO_{2.}$

Another method of estimating the storage capacity is to estimate the volume of CO_2 which can be stored per stock tank barrel of original oil in place.

Engineering characterisation

The equipment required to inject the CO_2 into the subsurface is determined by injection rates, the presence of other gases in the CO_2 stream and the pressure required to inject the gas in supercritical state. The number of wells required for a particular storage site depends on factors such as the permeability of the reservoir and the injection rates required. Models of the injection phase are used to determine the number of wells, the well design and the injection pattern. Modelling can also optimise injection strategies and predict the migration and distribution of the CO_2. This helps to further refine the storage capacity of the reservoir.

Data sources to build and refine models and simulations

The early stage of site characterisation relies on processing and interpreting existing data, including an understanding of the uncertainty associated with the predictions based on the data. As the characterisation proceeds, gaps in the data may be filled through the acquisition of new data, a step which is costly. The sources for data include seismic data, well-log and core data and data from analogues. This final stage of site characterisation is outlined in greater detail in Module 7.

Socio- economic characterisation

The final stage of characterising a site is to determine the likely capital costs and the cost per tonne of CO_2 avoided (see Module 12), to determine the acceptability of the site by the community and to complete a risk assessment (see Module 8). Risk and uncertainty analysis are crucial in determining the suitability of a site as well as reassuring the community about the environmental impact of geological storage. A monitoring and verification program needs to be designed in such a way that it will be efficient and cost-effective. A monitoring and verification program (see Module 9), whilst fulfilling regulatory requirements, will also provide data to refine models of the behaviour of the subsurface CO_2 and contribute to community reassurance.

Site characterisation for coal seams

Storage of CO_2 in coal seams is different to storage in oil and gas reservoirs or in saline formations because CO_2 is adsorbed onto coal and this is major way the CO_2 is trapped. Solution trapping and mineral trapping are other means of trapping.

An important factor in determining the storage capacity is the ability of the coal to adsorb CO_2 at a given depth and temperature, and will depend on the rank, grade and type of the coal. Another factor to consider is whether the coal would be considered for future mining.

The parameters which describe the storage capacity and injectivity in coal seams are seam thickness, adsorption capacity and permeabililty. Permeability depends on the amount of jointing and cleating and on the mineralized condition of the cleats. It generally decreases with depth, presenting a challenge for geological storage in deep unmineable coal seams.

Coal plasicisation due to CO_2 injection may also reduce permeability, but recent research has shown that this may only occur in certain types of coal.

Engineering characterisation

The well configuration for CO_2 sequestration in coal seams is substantially different to that in other storage options. If the coal bed has not previously been degassed, when CO_2 is injected into the coal, horizontal wells collect the coalbed methane that is displaced by the CO_2.

Socio-economic characterisation

This characterisation is similar to that carried out for other storage options. There are different economics to storage and site monitoring in coal seams, particularly where coalbed methane is produced. In this case, the injection capital, operating costs are lower and site monitoring is cost-effective. The amount of CO_2 avoided through this form sequestration is also calculated differently (Golding et al., 2008)

Summary

The selection of storage sites suitable for significant volumes of CO_2 comprises mainly geological evaluation of the applicable storage system (e.g. saline formations, depleted or near-depleted oil and gas reservoirs and/or coal systems) on various levels of detail. These correspond to degrees of confidence in estimating storage capacity. Basin screening involves identification of appropriate sedimentary basins which can then be ranked as to their overall suitability for CO_2 storage. Evaluation of the size and thickness of the basin gives an indication of total pore volume it may hold. More detailed basin assessment allows the estimation of the prospective storage capacity in each of the identified storage systems and trap types.

Site characterisation is the most time-consuming and costly part of the CO_2 storage site selection process. Site characterisation typically involves collection and analysis of more detailed information than basin assessment investigations and may involve re-evaluation of regional geology and generation of new data and/or updating of existing data such as static (geologic and seismic) and dynamic (flow simulation and injection) data. The level of detail used in site characterisation allows the estimation of contingent pore capacity. The ultimate goal of a storage project is commercial site deployment, which requires all the geological, engineering, economic and regulatory considerations of a site being taken into account. Site deployment therefore requires estimation of operational storage capacity.

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IEA Greenhouse Gas R&D Programme - CO_2 Sequestration Information:
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Midcontinent Interactive Digital Carbon Atlas and Relational Database:
http://www.midcarb.org/

National Energy Technology Laboratory - Carbon Sequestration Web Site:
http://www.netl.doe.gov/technologies/carbon_seq/index.html

US Department of Energy - Carbon Sequestration Web Page:
http://www.energy.gov/sciencetech/carbonsequestration.htm

European Carbon Dioxide Thematic Network, CO_2NET: http://www.co2net.com/

The Weyburn CO_2 Monitoring Project: http://www.ptrc.ca/weyburn_overview.php

Carbon Mitigation Initiative at Princeton University: http://www.princeton.edu/%7Ecmi/

Appendix 1

Geological characteristics of sedimentary basins

S. Bachu

Sedimentary basins can be broadly classified in relation to their position in regard to plate tectonics (Figure 6.4). The suitability of a given basin depends on its location on the continental plate (Figure 6.5).

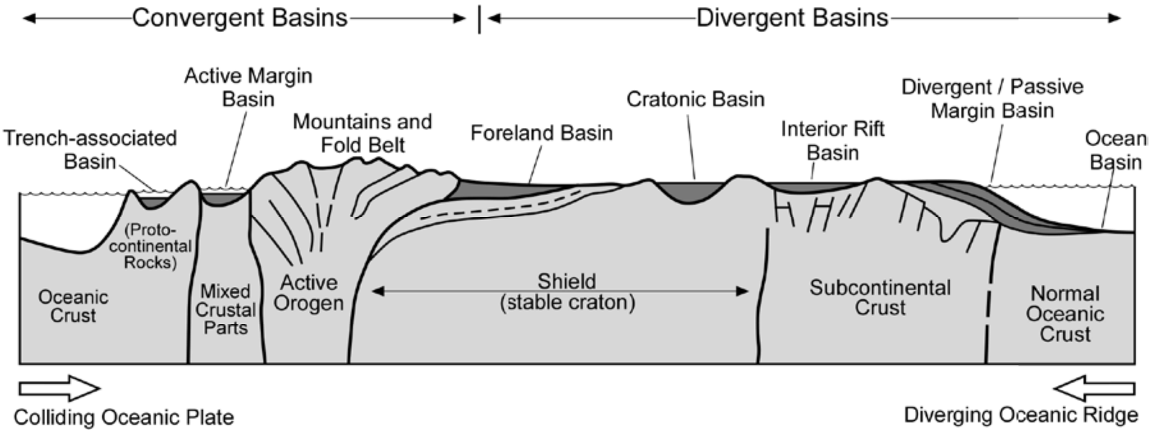

Figure 6.4: Diagrammatic representation in cross-section of the various types of sedimentary basins and their relation to the Earth's crust (from Hitchon et al., 1999).

Types of sedimentary basins

Divergent basins on the rigid lithosphere (intra-cratonic and on passive continental margins) are the most suitable for CO_2 storage as a result of their stability, reduced tectonic activity and favorable structure (Bachu, 2003). Circum-Atlantic, circum-Arctic, some Indian Ocean and many Australian marginal basins, and most intra-cratonic (mid-continent) basins are of this type. These basins are much less prone to earthquakes and other significant hazardous events that may lead to the CO_2 release back into the atmosphere.

Foreland basins, formed in areas of plate collision and mountain forming, are also favourable for CO_2 storage. These include the Rocky Mountains, the Appalachian and Andean basins in the Americas, the European basins north of the Alps and Carpathians, the basins west of the Urals in Russia, and those located south of the Zagros and Himalayas in Asia.

Convergent basins, such as circum-Pacific basins, are located in tectonically active areas, where there is subduction of oceanic plates beneath continental plates. They are generally smaller in size than divergent basins. These basins are usually subject to volcanism, earthquakes and active faulting. Thus, CO_2 storage in such basins poses higher risks because of a higher probability of accidental release along open faults and fractures as a result of local catastrophic events. Convergent basins are, by and large, not suitable for CO_2 storage and any individual sites for CO_2 storage must be selected with precaution. Convergent **intramontane basins** are strongly folded and faulted, and are therefore less likely to be suitable for storage.

Other features, such as cratonic platforms and orogenic belts (Figure 6.3) are not suitable for CO_2 storage. **Cratonic platforms**, such as the Canadian and Brazilian shields, are unsuitable for geological storage of CO_2 because their crystalline (igneous) or metamorphic rocks lack the porosity needed for storage space and the permeability needed for injection (see Module 1). **Orogenic belts** (mountain ranges) are not suitable either because of lack of continuous seals as a result of extensive faulting and fracturing during mountain forming.

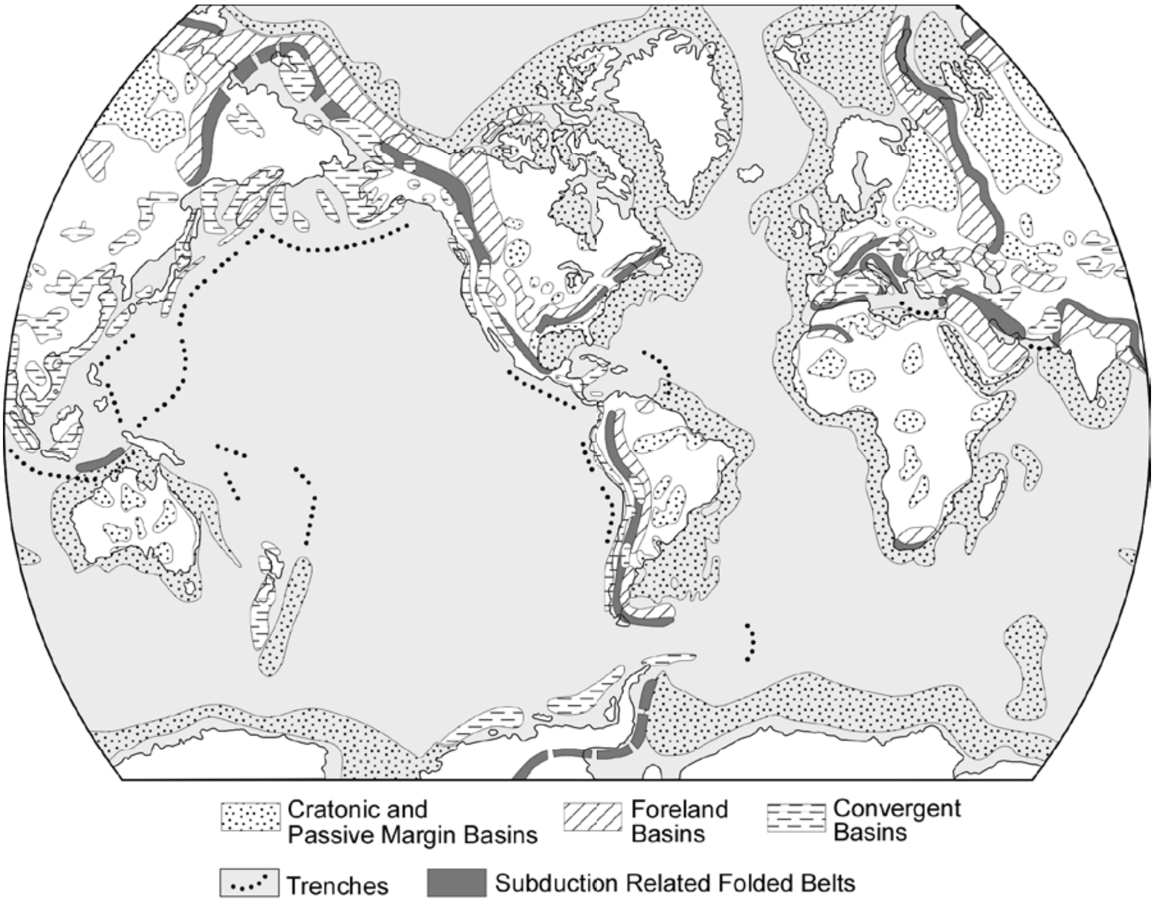

Figure 6.5: Major types and distribution of sedimentary basins around the world (based on St. John et al., 1984).

Basin characteristics important for storage

Basin characteristics that are also important for effective CO_2-storage. Basins should have the following characteristics (Bradshaw et al., 2002; 2004):

- Adequate thickness – >1000 m;
- Strong reservoir and seal relationships;
- Not highly faulted, fractured or located in fold belts;
- Strongly harmonious sequences;
- No volcanogenic sediments; and
- Have not undergone significant diagenesis.

Appendix 2

Hydrodynamic regime

S Bachu

The hydrodynamic regime of ***formation waters*** is critical for CO_2 injection and storage in depleted hydrocarbon reservoirs, coal beds and deep saline aquifers. Strata in sedimentary basins are called formations. Formation water is the water that is found in the pore space of these formations. It usually identifies saline water in deep aquifers, and this terminology differentiates this water from the shallow groundwater that is near the surface and is used for agriculture, drinking, etc.

All hydrocarbon reservoirs are the result of secondary migration of hydrocarbons through aquifers, and subsequent trapping. As a result, more often than not hydrocarbons are in contact with underlying formation water. Injection of CO_2 in active or disused reservoirs may affect or be influenced by the flow of formation waters. Formation water is also present, sometimes in abundance, in coal beds. Injection of CO_2 in coal beds will affect the pressure, flow regime and salinity of formation waters and ***produced waters*** (the term to denote formation water that is produced at the pump together with hydrocarbons such as oil and/or gas). Formation water flow paths could provide a means of leakage for CO_2 stored in the reservoir.

Basin hydrodynamics and flow-driving mechanisms are essential in establishing strategies with regard to CO_2 injection and storage in various geological media. There is a close link between the type of sedimentary basin and the flow of formation waters (Bachu, 2000). See Figure 6.6.

Hydrodynamics and flow-driving mechanisms for different basins:

In basins located on marine shelves, such as the Gulf Coast and the North Sea, the flow of formation water is driven by compaction. Flow occurs vertically out of shales (aquitards), and laterally outward toward the basin margin in the intervening aquifers. Shaley aquitards and aquifers are usually much overpressured. CO_2 injection in overpressured aquifers may raise technological and safety issues because of the high pressure needed for injection and because of the increased potential for a well blow out.

In basins adjacent to active orogenic belts, formation water is driven laterally out in the basin and toward its margin by tectonic compression. Waters expelled from underneath orogenic belts are usually overpressured, hot and very saline, thus these aquifers are not well suited for CO_2 storage.

In foreland and intracratonic basins that have undergone recent significant uplift and erosion, flow is driven by erosional rebound vertically into thick shales and laterally inward in thin adjacent aquifers. The aquitards and adjacent aquifers are underpressured, as observed in the Alberta basin. Such aquifers are the best suited for the long-term (geological time) confinement and storage of CO_2 (hydrodynamic trapping). In some foreland and intracratonic basins, such as the Alberta and Williston basins in Canada, deep saline water has the tendency to stagnate or flow with extremely low velocity (< 1 cm/y or < 10 km/My). This water is generally isolated from fresh, shallow groundwater of meteoric origin. Injection of CO_2 in such aquifers ensures hydrodynamic trapping on a geological time scale. The long residence time associated with hydrodynamic entrapment enhances the mineral storage of CO_2.

In continental basins most flow systems are driven by topography from recharge areas at high elevations to discharge areas at low elevations. Aquifer pressures are usually close to hydrostatic with slight over- or underpressuring being controlled by permeability distributions. In such cases it is better to inject CO_2 in the recharge areas, to increase the length of the flow path and residence time (hydrodynamic trapping).

Zones of active hydrocarbon generation, regardless of the basin and flow types, are overpressured, and may pose a risk for CO_2 disposal. In addition, CO_2 may “contaminate” these resources, destroying their potential to produce useable hydrocarbons.

Selecting an injection strategy that is consistent with the hydrodymanic regime of the formation, you will reduces the potential for CO_2 leakage. However, it is important to keep in mind that, as a basin evolves on a geological time scale, the pattern of formation water flow changes from a mainly vertical component in the early stages of basin compaction, to mainly horizontal, topographically-controlled flow in a mature basin. Figure 6.6 classifies the basin types in terms of the degree of sediment compaction over the life of the basin and fluid flow type. Both of these parameters are related to the risk of CO_2 leakage. As will be noted, foreland and cratonic basins have the least risk of leakage over time. Basins undergoing active compaction are likely to be more prone to leakage. Of course, highly faulted and fractured basins, regardless of type, are the most unsuited for CO_2 storage because of the higher risk of CO_2 leakage.

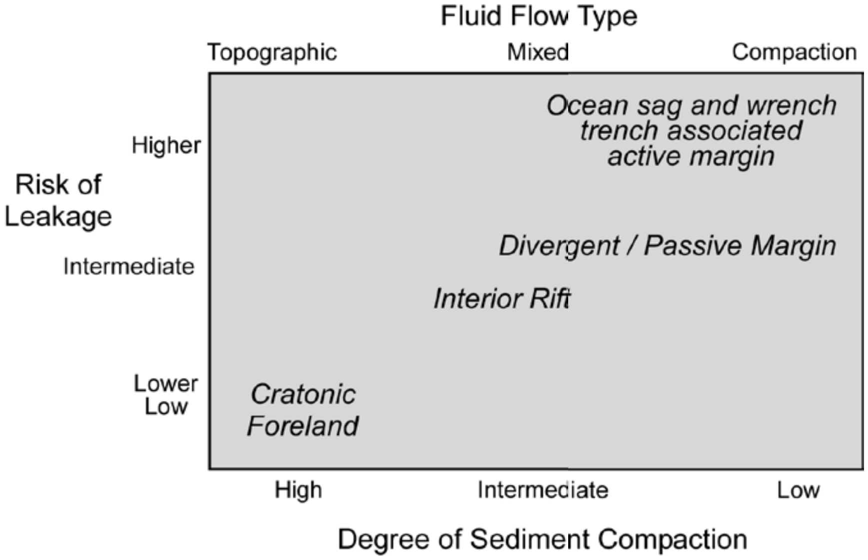

Figure 6.6: Sedimentary basins classified by degree of sediment compaction, type of fluid flow, and risk of leakage (from Hitchon et al., 1999).

All basins have a point of lowest hydraulic head, ranging from the lowest topographic elevation in the case of a consolidated basin, to the sea bed in the case of a basin still undergoing compaction. A short flow path, for example to the sea bed, means that the carbon dioxide may not be confined for geological periods of time. Hence, the higher the risk of leakage, the greater the need for a hydrogeological evaluation of the basin around the injection site.

Appendix 3

Geothermal regime

S. Bachu

The geothermal regime in the basin impacts the type and depth of CO_2 injection and storage. The geothermal regime in sedimentary basins depends on:

- Basin type, age and tectonism;
- Proximity to crustal heat sources, such as magma chambers, intrusives and volcanoes;
- Basement heat flow – this is the heat that comes from the interior of the earth, at the base of the sedimentary basin;
- Thermal conductivity and heat production in the sedimentary succession, which depend on the lithology and porosity of the sedimentary rocks; and
- Temperature at the top of the sedimentary succession.

Geothermal characteristics of basins located in different regions:

- For continental basins located in tropical-to-temperate regions, the ground surface temperature depends on climatic conditions (geographic position, altitude and local climate), varying from 25-27 ^{o}C in a tropical basin, to 4-7 ^{o}C in a temperate basin.
- In tropical and sub-tropical low-altitude basins, CO_2 can be injected only as a gas or in supercritical state because the 31.1 ^{o}C isotherm is reached at shallow depths varying between 150 and 500m.
- For oceanic basins, the temperature at the top of the sedimentary succession (bottom of the ocean) is around 3-4 ^{o}C.
- In temperate and oceanic basins, CO_2 can be injected and stored as a gas, a liquid or in supercritical state, depending on pressure, geothermal regime and depth of the 31.1 ^{o}C isotherm.
- For sedimentary basins located in arctic regions, the temperature at the top of the sedimentary succession (bottom of the permafrost zone) is around -2 ^{o}C.

Temperature and CO_2 density

The efficiency of CO_2 storage in geological media, defined as the amount of CO_2 stored per unit volume, increases with increasing CO_2 density.

‘Cold’ sedimentary basins are characterized by low surface temperatures and/or low geothermal gradients (Bachu, 2000, 2003). They are more favorable for CO_2 storage because CO_2 attains higher density at shallower depths than in ‘warm’ sedimentary basins.

‘Warm’ sedimentary basins are characterized by high surface temperatures and geothermal gradients (Bachu, 2000, 2003). Thus, depending on geothermal gradients, the top of the injection unit must be at a depth of greater than 600-900 m for CO_2 to be in a dense fluid phase (liquid or supercritical) (Bachu, 2003).

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Module 7

Key steps involved in developing and implementing a CO_2 capture and storage project

Original text: S. Bachu & W. D. Gunter, APEC Capacity Building in the APEC Region, Phase II

Revised and updated by CO2CRC

Overview

Carbon dioxide capture and storage projects are complex undertakings. By following a specific decision-making process, is possible to improve the CO_2 source and storage site selection process, and manage costs. This module lays out a series of recommended steps for project proponents to follow to ensure that CO_2 capture and storage project selection, design, implementation, operation and decommissioning are optimized.

Learning objectives

By the end of this module you will:

- Be familiar the steps which must be undertaken in developing and implementing a CO_2 capture and storage project, and what is involved in each step;
- Understand how to establish a sequence and timelines for the various steps involved;
- Know the type of expertise needed and potential partnerships; and
- Know which major firms and economies can provide the expertise needed.

Steps to be undertaken in developing and implementing a CO_2 geological storage project

The steps that should be undertaken to develop and implement a CO_2 capture and storage project must ensure that the storage site:

- Has the necessary capacity for storage;
- Meets the conditions necessary for injectivity to introduce CO_2 in the subsurface at the desired rate;
- Provides for safe injection such that CO_2 leakage is avoided, or, if it happens, it is minimized and benign;
- Is economically viable - from cost effectiveness and life-cycle points of view the site has to store more CO_2 than it is produced by the capture and storage operation itself, and must either produce a profit or avoid a regulatory penalty;
- Is acceptable to the public;
- Is constructed and operated in a safe manner; and
- Is decommissioned in a safe manner.

There is a sequence of steps and actions in developing and implementing a CO_2 capture and storage project (illustrated in Figure 7.1) that can be broadly split into:

- **Site selection** – this comprises all the steps necessary up to obtaining approval for construction of facilities, including in many cases data collection and analysis of suitable storage sites and CO_2 sources;

- **Site construction** – this occurs after all permits and leases have been secured and actual construction commences. During this phase, the capture, transportation, injection, and trapping methods and technologies will be implemented;
- **Site operation –** during which active capture, compression, transportation and injection of CO_2 occurs; and
- **Post-operation –** comprising of preparing the CO_2 storage site for decommissioning and abandonment, and preparing and implementing a long-term monitoring strategy.

Different organizations are best suited to undertake these various steps:

- **Government organizations,** such as geological surveys and regulatory agencies**,** have a responsibility and natural capacity to undertake the work in identification and characterisation of sites (inventory of CO_2 sources; basin-scale and regional-scale suitability analyses), broad identification of potential geological sinks for CO_2, determination of immediate and ultimate capacity for CO_2 storage, and broad screening of potential sites based mainly on safety criteria.
- **Research institutes and universities** are the natural place for development of methods, tools and technology for the prediction and monitoring of the fate of the injected CO_2 in the sub-surface.
- **Industry** would be involved in the following steps: local-scale screening and selection of potential sites in the vicinity of the planned CO_2 source(s) (this may include identification and characterisation of CO_2 sources); specific site selection and detailed characterisation using geoscience, engineering, economic and safety methods and criteria; engineering and construction; site operation; and post-operation decommissioning and monitoring of CO_2 fate. Development of monitoring methods and technology may be also be undertaken by industry.

These roles and the requirements of each step of the process are outlined in the following sections.

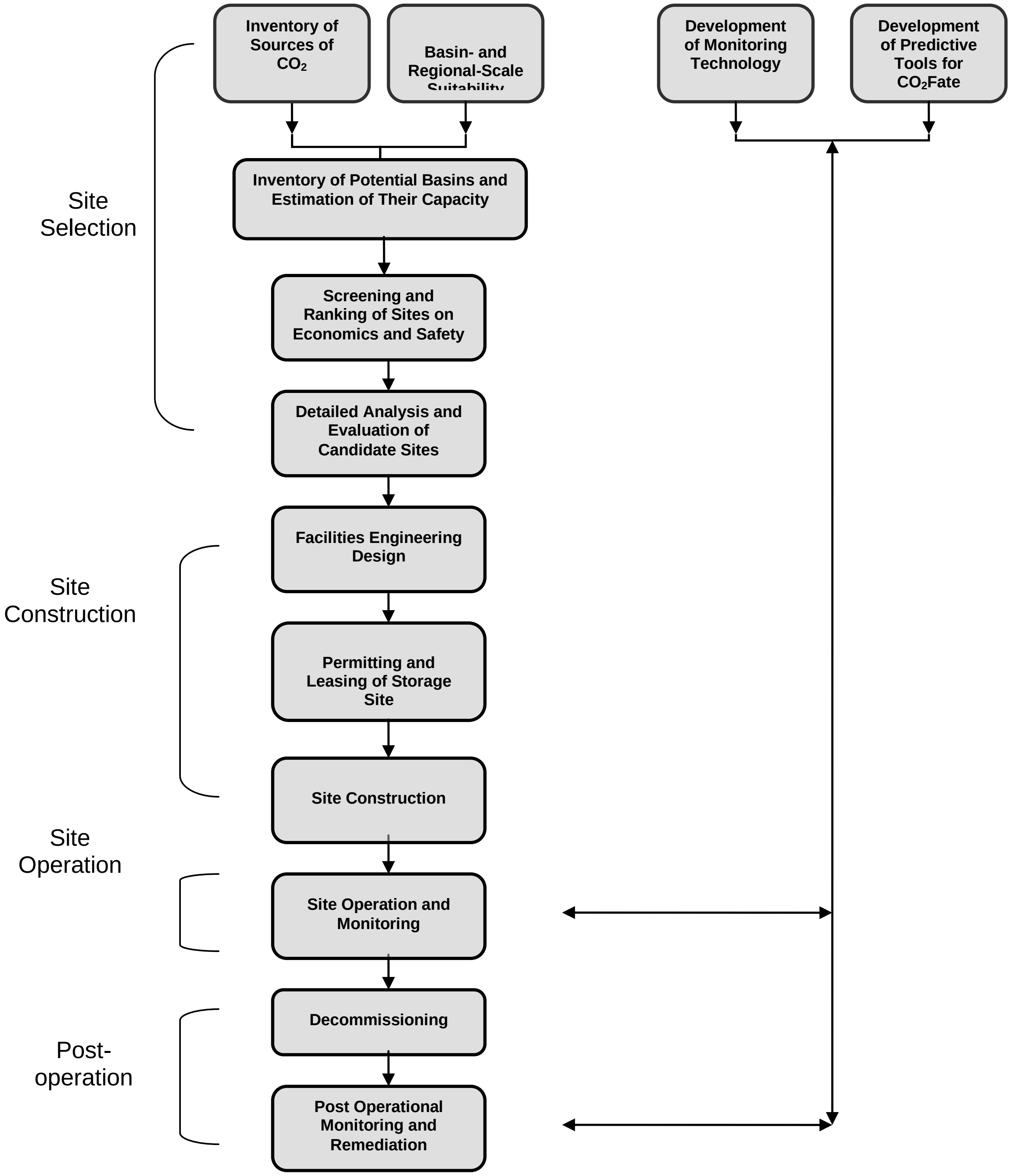

Figure 7.1: Flow chart of recommended steps to be taken in developing and implementing a CO_2 capture and storage project (adapted from Bachu, 2002).

Site selection

The site-selection sequence comprises all the steps necessary up to obtaining approval for construction of facilities. This involves the following key steps:

- Inventory of CO_2 sources;
- Basin-scale and regional-scale suitability analysis of potential CO_2 storage sites within reach of CO_2 sources (see Module 6);
- Inventory of potential basins and estimation of their immediate and ultimate capacity (see Module 6);
- Screening and ranking of sites based on economics and safety (see Modules 8 and 12);
- Detailed analysis and evaluation of candidate sites;
- Facilities engineering design; and
- Permitting and leasing of storage site.

These are each described in more detail below; others are covered in more detail in Modules 8 and 12 as indicated.

Inventory of CO_2 sources

This step involves analysis of both quantity and quality of the source CO_2. Parameters to analyze include CO_2 purity, and other components in the emission stream.

- **If the company has already identified a source**, this step consists of characterising the CO_2 source.
- **If the company has not identified a source**, an inventory of potential sources needs to either be identified and purchased, or performed. In some jurisdictions, mandatory GHG reporting may facilitate the identification of sources. Where available, the company could purchase the reports of potential CO_2 sources developed by the government.
- **When no inventory exists**, creation of an inventory of CO_2 sources is required. Fertilizer plants, petrochemical plants, gas processing plants, refineries, hydrogen plants and ethanol plants are attractive sources of CO_2 because they have relatively pure waste streams of CO_2 compared to coal-fired power plants, cogeneration plants and cement plants. In these latter plants, CO_2 waste streams have CO_2 concentrations less than 25%. The inventory of CO_2 sources is a government responsibility, although this task can be contracted or delegated to various agencies or even the private sector. Occasionally, this step may involve conducting a broad economic analysis of capturing CO_2 from large stationary sources, transporting it and injecting it into geological sinks, and this analysis may be performed either by government for establishing policy and regulations, or by the private sector.

The presence of impurities in the CO_2 gas stream affects the engineering processes of capture, transportation and injection, as well as the trapping mechanisms and capacity for CO_2 storage in geological media. Some contaminants in the CO_2 stream, such as SO_x, NO_x and H_2S, may classify the CO_2 as hazardous. This would impose different requirements for injection and disposal than if the stream were pure (Bergman et al., 1997). In all cases, gas impurities in the CO_2 stream affect the compressibility of the injected CO_2, and hence the volume needed for storing a given amount. Gas impurities also reduce the capacity for storage in free phase in depleted hydrocarbon reservoirs and deep saline formations as some of the storage space is taken by these gases.

In addition, depending on the type of storage, the presence of impurities may have other, additional specific effects. For example:

- In **EOR operations**, impurities affect the minimum miscibility pressure and oil recovery because they affect the solubility of CO_2 in oil and the ability of CO_2 to vaporize oil components (Metcalfe, 1982). Methane and nitrogen increase the minimum miscibility pressure and decrease oil recovery. Hydrogen sulphide, propane, and heavier hydrocarbons have opposite effects. However, the presence of SO_x and NO_x is unlikely to affect significantly oil recovery and/or well injectivity (Bryant and Lake, 2004).

- In **deep saline formations**, the presence of gas impurities affects the rate and amount of CO_2 storage through dissolution and precipitation. In addition, leaching of heavy metals from the minerals in the rock matrix by SO_2 or O_2 contaminants is possible.
- In **coal seams**, impurities may have a positive or negative effect, similarly to EOR operations. If a stream of gas containing H_2S or SO_2 is injected into coal beds, these will likely be preferentially adsorbed because of higher affinity to coal than CO_2. This would act to reduce the storage capacity for CO_2 (Chikatamarla and Bustin, 2003). If oxygen is present, it will react irreversibly with the coal, thus reducing the sorption surface and, hence, the adsorption capacity. On the other hand, some impure CO_2 waste streams, such as coal-fired flue gas (i.e., primarily N_2 + CO_2), may be used for ECBMR because the CO_2 is stripped out (retained) by the coal reservoir due to its higher sorption selectivity compared to N_2 and CH_4 (Mavor *et al*., 2002).

Basin-scale and regional-scale suitability analysis of potential CO_2 storage sites within reach of CO_2 sources

Project proponents should next review the geological environment within economical distance of the CO_2 source(s) to establish its suitability for CO_2 geological storage. This step involves identification of suitable geological media according to the basin-scale criteria described in Module 6.

At this stage it is important to identify if the storage is going to be onshore or offshore, because different jurisdictional and legal issues apply to the two cases (see Module 11).

Where available, project proponents can purchase the maps and reports of the storage resource assessments from government agencies or research organizations. Where no assessments have been done, determination of basin and regional-scale suitability for CO_2 storage is required. This is a broad responsibility of government agencies, but it may be performed also by research organizations, including universities.

From the basin-scale and regional-scale storage assessment, CO_2 storage sites within the reach of CO_2 sources can be inventoried. This analysis includes the storage capacity of all known storage reservoirs based on adsorption calculations (coal beds) or dissolution calculations (saline aquifers/depleted oil and gas reservoirs) depending on the type of storage project (see Module 6).

Inventory of potential sites and estimation of their storage capacity

At this point, an inventory of CO_2 source and sink options and the capacity of these reservoirs can be compiled. Only the most feasible sites with the highest potential should be retained. After the inventory is compiled, local-scale characterisation needs to be done for *in situ* pressure and temperature, oil and/or gas composition, water salinity, reservoir or aquifer porosity and permeability, stress regime and fracturing threshold and gas content (for coal beds).

Geological surveys and research organizations are best suited for developing the methodology and conducting the assessment of immediate and ultimate capacity for CO_2 storage as outlined in Module 6, the capacity determination needs to be performed on a site-specific basis:

- For EOR operations and depleted oil and gas reservoirs, the reservoir pore volume and spill point, the degree of water invasion as a result of production, and CO_2 solubility are determining factors in estimating the CO_2 storage capacity.
- For deep saline aquifers, the critical parameters are CO_2 solubility in brine and the migration path to determine how much will be dissolved in solution and how much will override at the top of the aquifer as a separate phase.
- For coal beds, the coal thickness and adsorption capacity at the in situ conditions are the critical elements in estimating coal bed storage capacity.

Screening and ranking of sites based on economics and safety

The **economic viability** of a CO_2 capture and storage project should be assessed by industry. This would include: source-sink matching, transportation options for the CO_2, compression, and infrastructure requirements.

- **Source-Sink Matching (SSM)**. The resource assessments for storage are compared to the specifics of the emissions at sources and distance to an appropriate storage site. Included in this analysis, the capture technology must be considered. Currently, commercially available technology is solvent capture for post-combustion applications. For new plants, oxyfuel combustion or gasification might be chosen as they produce a purer CO_2 waste stream but at the expense of requiring a pure oxygen stream in the process. These technologies also lower other harmful emissions such as NOx, SOx and particulate matter emissions. In an emission-constrained world, they are may be more competitive economically to the more conventional end post-combustion solutions.
- A **broad economic analysis**, of the source-sink matching type, should be applied to rank the potential candidates based on the cost of CO_2 storage. When a cluster of acceptable storage sites has been identified, the economic benefits of synergies with transportation and environment and economic factors should be considered.
- **Evaluating transportation options** from the capture site to the storage site can be an important consideration. For example, some CO_2 sources are located on the margins of the sedimentary basins or far away from any basin storage opportunities. In such cases, transportation costs can be a significant portion of the total capture and storage costs, and may help determine that a closer CO_2 stream be selected even though it is more costly to purify. Offshore storage sites will have different economic considerations than land-based ones. See Module 4 for more detail.
- **Compression of the CO_2** is required in order to transport it in a dense liquid form and in order to inject it into deep storage reservoir. Compression to pressures in the order of 14 MPa (2000 psi) are required. This represents a significant expense. Process integration may reduce costs if the high compression required for transportation and injection can be utilized in the capture technology so that the purified CO_2 stream is already at high pressure (instead of atmospheric pressure) after capture. See Module 4 for more detail.
- **Infrastructure requirements**. Much of the infrastructure for a commercial CO_2 geological storage industry will have to be built. This is particularly the case for sedimentary basins which have stranded assets or are immature or barren with respect to their production of oil and gas. In mature sedimentary basins which are in a depletion stage with respect to oil and gas, it is possible that there will be existing pipelines which are not at full capacity. These could be used for transporting the CO_2. Sites with no pre-existing infrastructure will face significant expenses in building facilities for injection and monitoring.
- **Evaluation of storage safety** through an analysis of the long-term fate of the stored CO_2 is a critical step at this stage. This assessment helps to narrow down potential sites to a small number of possible candidates for CO_2 storage. It should be based on the methodology already developed or in process of development by research organizations for predicting the long-term fate of the injected CO_2. If no such methodology exists, one should be developed by the project proponents in collaboration with appropriate government agencies and research organizations.

The screening process should be based on local-scale criteria (see Module 6). Unsafe sites automatically should be rejected. Currently, such analysis has been applied on a continental scale (see Bradshaw et al. 2003 for Australia, and Dooley et al., 2005 for North America), but it can be applied on a regional and local scale as well. Government and research organizations should develop the methodology for the safety assessment of CO_2 storage sites.

The immediate and ultimate safety of CO_2 storage operations needs to be established on a case-by-case basis. Lack of safety will automatically exclude a site from consideration even if all other criteria are being met and the economics are favourable.

- **Immediate safety** refers to the potential for CO_2 upward migration and escape into other strata during or immediately after injection. This could happen through open faults and natural or man induced fractures, or through improperly completed and/or abandoned wells (Celia and Bachu, 2003).
- **Ultimate safety** refers to CO_2 lateral migration in aquifers with potential for cross formational flow, or in flow systems with a short residence time. Carbon dioxide could reach aquifers either directly, as a result of injection into deep saline aquifers, or indirectly, by exceeding the level of the spill point in hydrocarbon reservoirs and flowing into the underlying aquifers.

In both cases, CO_2 may contaminate existing energy, mineral and water resources, and may even reach the surface. The assessment of storage site safety needs to be done on the basis of a better understanding of the *in situ* physical and chemical processes associated with CO_2 injection and storage, improved numerical modelling of CO_2 fate, and detailed knowledge of relevant site characteristics. The process of safety evaluation will further reduce the number of sites suitable for CO_2 storage.

Detailed analysis and evaluation of candidate sites

After selection, based on transportation and other costs, the detailed characterisation includes site geology, hydrogeology, fluid characteristics (oil, gas, water/brine), geomechanical properties of the injection unit and confining strata, and running sophisticated models to predict the fate of the injected $CO_{2.}$

Facilities Engineering Design

Design of the capture, transportation (often by pipeline) and injection facilities must be made. The capture facilities may be end of the pipe where the flue gas is purified so that a pure CO_2 steam is available for pipelining (see Module 2 and Module 3 for more detail). Alternatively, a pure CO_2 stream may already be available.

Pipeline design depends on the CO_2 capacity and compression required for delivery to the injection site. Right of ways must be obtained, and the terrain to be crossed by the pipeline will affect the design (e.g. rivers, mountains) (see Module 4 for more detail).

A level of detail for the injection site must be developed sufficient to analyze the costs, economics and safety of the storage reservoir options, and satisfy the application requirements for licensing and approval. This phase may involve some back and forth with regulators and changes may need to be incorporated into the site plan. Only after approval is granted should the company proceed with more detailed site engineering design. Additional compression may be required at the injection site depending on the difference between the pipeline and reservoir pressures. Nominally, the pipeline gas may not require further treatment unless injection will be at reservoir temperatures. In this case, a heater would be required. If more than one well is used for injection, a distribution system is needed to partition the CO_2 between the injection wells. If the project involves enhanced recovery, then an independent collection system is needed for the produced oil or gas, as well as a separate compression station to place the oil or gas in a pipeline to market.

Permitting and leasing of storage site

The final step in the site selection process is obtaining regulatory approval and public acceptance for the project. In some jurisdictions the two are inseparable because the public is involved in the regulatory process (see Module 13 and APEC publication entitled: *Community Outreach Strategy for CO_2 Capture and Storage* for more information on proactively working with the public to enhance the CO_2 capture project and gain their acceptance). The project proponents have to meet all the regulatory requirements within the respective jurisdiction, which may include intervention by third parties. Obtaining regulatory approval involves site-specific analysis and engineering; however, this is still at a pre-construction level.

Just as industry pays for leases and royalties for the production of oil and gas, it is assumed that the companies that want to develop an CO_2 geological storage site would have to pay the owner of the mineral rights (usually, but not always, the government) some type of fee or royalty for the use or rental of the subsurface pore space in the reservoir into which they plan to inject the CO_2. In addition, companies will need to obtain the right of way for new pipelines to be built, or enter into a contact with an existing pipeline company to transport the CO_2 from the point of capture to the point of storage.

Site construction

Having obtained all the necessary permits and leases, construction of the CO_2 capture and storage project can begin. The capture plant will need to be installed at the source (see Module 2 for more details).

For the pipeline, as well as compression at the plant gate for introduction of the CO_2 into the pipeline, booster compressor stations would have to be built at regular intervals to maintain pressure for pipelines of extended length (i.e. tens to hundreds of kilometers) (see Module 4 for more details).

Roads have to be built and electric power has to be delivered to the storage site. Assuming an enhanced oil, gas or coalbed methane recovery project, both injection and production wells have to be drilled, completed and plumbed into the distribution or gathering system after it is built. Pumps have to be installed on the production wells and separators have to be built for separation of the produced oil, gas and water. The gas may be flared if produced in small quantities and the produced water would be injected into a deep waste disposal zone through a separate injection well.

For offshore storage sites, all operations take place from platforms, pipelines are under water and can be short if the oil is transported by tanker; and the number of wells are fewer than land-based storage sites because of their higher costs.

Permanent or non-permanent monitoring facilities must be installed to track the fate of the CO_2. Dedicated monitoring wells may be drilled with provisions for sampling reservoir fluids, collecting seismic data and tiltmeter data. These tools may be cemented in or just hung in the casing or tubing of the monitoring well. In addition, periodic monitoring data may be collected by running wireline logs in the injection or producing wells as well as fluid chemistry from the production wells. Surface seismic, groundwater monitoring and atmospheric monitoring can be used to detect any movement of the CO_2 from the storage depth to the surface (see Module 9 for more detail).

Site operation

Site operation involves all the activities involved in transporting, compressing and injecting CO_2 into the storage reservoir.

Injection of CO_2 into the storage reservoir can take place after the surface facilities have been constructed. The number of injection wells to be drilled depends on existing wells which are suitable for injection and the desired rate of injection. For a project planned to store a megatonne of CO_2 per year, the daily rate of injection would be approximately 3000 tonnes (55MMcf) of CO_2, requiring on the order of two to 20 injection wells, depending on permeability and reservoir thickness. Compression may or may not be needed, depending on the magnitude of the difference between the pipeline delivered pressure and reservoir pressure. If the storage reservoir is an EOR project, recycling of CO_2 will be involved and the CO_2 stored will be a fraction of the total CO_2 injected. The net, or creditable CO_2 will be even less as the additional energy used to capture the CO_2, and compress it for reuse has to be subtracted from that stored. This is not a simple calculation, as the oil produced can be considered as an offset for oil that would have to be produced elsewhere if this supply wasn't available. However, if the reservoir is not being produced, and the CO_2 is simply being injected into a depleted oil and gas reservoir or a deep saline aquifer, the calculation is straightforward. In this case, the injection operation consists of a distribution system to the injection wells and some means of monitoring the amount of CO_2 injected at each well and for leakage.

Monitoring the fate of CO_2. There are three levels of monitoring:

- **Operational monitoring** is only carried out during injection of the CO_2 and consists of measurements that are normally done in any oil or gas production and/or injection operation. They consist mainly of measuring temperature, pressure and fluid composition (including tracers) for the injection and producing wells, and wireline logs. These measurements are used to estimate the amount and rate of CO_2 that is injected and/or produced, and to assess the movement of the CO_2 front between injection wells and producers;
- **Verification monitoring**, tracks the migration of the CO_2 plume away from the wells either in the target storage zone or through leakage across the caprock. This can be through observation wells, geophysical methods and tiltmeters; and

- **Environmental monitoring** is used to detect surface seepage into the shallow groundwater zone or into the atmosphere. The tools used here are water sampling in shallow groundwater wells, soil gas, and laser surface atmospheric analyses.

Project proponents may use one or a combination of operational monitoring, operational and verification, or all three levels during the site operational phase depending on the perceived risk. Module 9 provides more detail on risk assessment.

Post-operation (closure and post-closure)

After the reservoir reaches a predetermined pressure (the fill pressure) and/or capacity (depending on the licensing parameters), injection ceases and the post operational phase commences. If the site is to be abandoned, the wells will be cemented to act as a permanent seal at their entry into the reservoir, so that CO_2 cannot escape.

Regulatory agencies will likely require a long-term monitoring phase of the project to be put in place as part of the closure plans. Research organizations and/or industry should develop the methodology for predicting the long-term fate of the injected CO_2.

Monitoring of the CO_2 fate is the responsibility of industry, utilizing technology which is being developed by research organizations and industry, and regulated by government. However, with time monitoring will likely become the responsibility of the government as it is the only agency which is assured of being in existence over such a long timeframe. Currently, these long-term liability issues have not been widely addressed.

The technologies used for monitoring would probably be some combination of surface seismic, vertical seismic in dedicated abandoned cemented observation wells, and aerial scans for anomalous CO_2 concentrations in the atmosphere, together with sampling of formation water and groundwater where possible as deemed necessary. The frequency of the monitoring will most likely decrease with time. If a leak is observed, remedial measures will have to be taken.

The predictive modeling of the movement of CO_2 plume using a reservoir simulator should be benchmarked against the monitoring data at periodic intervals. If the model predicts a different position of the plume than that estimated from the monitoring, then the model should be changed or improved, and/or the monitoring data reinterpreted. Once agreement is reached between predictions through modeling and observed data through monitoring, confidence can be gained that the position of the CO_2 plume is known accurately (see Module 9).

If it is detected that the plume has broken through the caprock, the leak point should be determined and identified as a fracture/fault or a well, and a mitigation plan formulated. This usually takes one of two forms:

- **Faulty wellbore**. If the leak is thought to be through a faulty wellbore, then a remedial cement job may be effective in plugging the well; and
- **Opening of fracture or fault by pressure build up**. If the leak is thought to be caused by opening of a fracture or fault due to a buildup of pressure, then the pressure in the storage reservoir can be reduced to a pressure low enough that the fracture or fault closes back. If the position of the leak is accurately located, then a new well may be drilled down to the leakage point and the weak point in the caprock cemented. Alternatively, it may be decided to allow the storage reservoir to leak across the caprock into an adjacent deep aquifer, if that aquifer is known to have hydrodynamic or geologic trapping capacity.

If the CO_2 manages to seep to the surface before it is discovered, it can be pumped out through shallow wells and reinjected. In most cases, if site selection, site construction and site operation are properly done, leakage or seepage of CO_2 is unlikely.

Needed expertise and potential partnerships

The expertise needed for the development and implementation of a CO_2 geological storage project is very vast. A more detailed enumeration of the expertise is provided in Appendix 2. The needed expertise can be broadly grouped into the following categories:

- Geoscience (geology, hydrogeology, geochemistry, geophysics, etc.);
- Engineering (reservoir engineering, facilities engineering, pipeline engineering, chemical engineering, mechanical engineering, etc.);
- Economics;
- Legal and regulatory; and
- Public relations.

New projects are often proposed by industry partners to provide all of the expertise required for a CO_2 capture and storage project. Typically, in today's business world, three types of companies would be involved: the producers of fossil fuels (oil and gas companies, coal producers), transporters (pipeline and shipping companies), and users of fossil fuels (power generating, refineries, cement plants, large industrial plants). The latter have potentially the highest liability with regard to CO_2 emissions and would be the group that would be driving the search for opportunities to sell CO_2 for capture and storage. Albeit, the former also would seek such opportunities.

Major firms and economies with expertise in developing a CO_2 storage project

Currently the firms that possess the expertise and capacity for developing and implementing a large CO_2 geological storage project are large energy companies with experience in oil and gas production, enhanced oil recovery, and disposal of acid gases. Firms active in CCS projects include Schlumberger, Chevron, Exxon Mobil, Total, Statoil, BP, Halliburton and Santos. Some associations with various projects are:

- In **Norway**, Statoil which operates the Sleipner CO_2 aquifer storage project in the North Sea;
- In the **United Kingdom**, BP which operates the In-Salah gas field in Algeria;
- In the **United States**: Chevron, Exxon, Penn West, Apache, Anadarko, Devon Energy, Kinder Morgan, Burlington Resources, and others, which operate CO_2 EOR and acid gas disposal operations;
- In **Canada**: Encana, Penn West, Apache, Devon Energy, Anadarko, Keyspan, ChevronTexaco, and others, which operate CO_2 EOR and acid gas disposal operations; and
- In **Australia**, Chevron which operates the offshore Gorgon LNG project, where the separated CO_2 will be injected into an offshore aquifer beneath Barrow Island.

Summary

Effective site selection ensures that the storage site will meet all the required conditions:

- Necessary capacity;
- Injectivity at the desired rate;
- Short and long-term safety;
- Economic viability;
- Acceptable to the public;
- Safe operation; and
- Safe decommissioning.

It is unlikely that any one organization will have all the expertise to undertake all the steps involved in a CO_2 capture and storage project. Government organizations, research institutes and universities, and industry are each best suited to undertake different tasks.

Identifying a CO_2 source is the first step to undertake. Potential CO_2 sources must be analyzed for impurities (quality). Impurities will have specific affects on different types of storage options.

It is recommended that project proponents identify potential storage basins within an economical distance from the CO_2 source early on in this process. Onshore and offshore storage options will have different jurisdictional and legal issues that must be considered.

From the basin-scale and regional-scale storage assessment, CO_2 storage sites within the reach of CO_2 sources can be inventoried. This analysis includes the storage capacity of all known storage reservoirs based on adsorption or dissolution calculations depending on the type of storage project.

After a short list of potential sites is established, local-scale characterisation of priority sites should be completed. Assessments of capacity for CO_2 storage need to be performed on a site-specific basis (see Module 6).

Economic viability should consider source-sink matching, CO_2 transportation options, compression of the CO_2, and infrastructure requirements.

Both the immediate and ultimate safety of stored CO_2 are important considerations. Immediate safety is the potential for leakage after injection. Ultimate safety is the potential for leakage over longer time periods. Both must be carefully considered to ensure that existing energy, mineral, water resources are not contaminated, or human or ecosystem life compromised.

Capture, transportation (often by pipeline) and injection facilities must be constructed. Capture design depends on the source CO_2 stream. Pipeline design depends on the CO_2 capacity and compression required for delivery to the injection site. A level of detail for the injection site must be developed sufficient to analyze the costs, economics and safety of the storage reservoir options, and satisfy the application requirements for licensing and approval.

A number of licenses and approvals will need to be obtained. This includes all jurisdictional regulatory approvals and may include leasing fees for rental of subsurface pore space for storage. Site construction will then put in place the compression, transport and injection facilities required.

Construction of injection and monitoring facilities is now required. Operational monitoring must be carried out during CO_2 injection. Verification and environmental monitoring may also be performed during CO_2 injection.

Regulatory agencies will most likely require a long-term monitoring plan to be in place to ensure the safety of CO_2 storage after site decommissioning. Monitoring will be the responsibility of the project proponents, but given the long lifetime of CCS projects, it is likely that the government will eventually be required to take over monitoring in the long-term.

A range of monitoring technologies will be required. The frequency of the monitoring will most likely decrease with time. Predictive modeling of the movement of the CO_2 plume should be benchmarked against collected monitoring data periodically to verify its accuracy. Leaks must be addressed immediately. When done properly, site selection, construction and operation make the likelihood of any leaks very minimal.

It is likely that a team of qualified experts will need to be involved to ensure the needed expertise is available for the project undertaking. Expertise will be required in:

- Geoscience (geology, hydrogeology, geochemistry, geophysics, etc.);
- Reservoir, facilities, pipeline, chemical, mechanical, etc. engineering;
- Economics;
- Legal and regulatory; and
- Public relations.

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The Weyburn CO_2 Monitoring Project: www.ptrc.ca/weyburn_overview.php

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Module 8

Health, safety and environmental risks of CCS projects

Original text: J. Stephens & D. Keith, APEC Capacity Building in the APEC Region, Phase II

Revised and updated by CO2CRC

Overview

Understanding the health, safety and environmental risks associated with geological storage of CO_2 involves consideration of both the potential hazards of the technology, and the likelihood that those hazards will occur. The storage project can then be designed to control the risks. The potential hazards of a poorly designed CCS project can be understood through the examination of natural CO_2 leakage events, although discussion must emphasize the difference between these events and the expected behavior of CO_2 in long-term geological storage. This module mainly covers the hazards associated with CO_2 storage, although some mention is made of transporting CO_2.

Learning objectives

By the end of this module you will:

- Understand the types and scales of risks associated with CO_2 storage in geological reservoirs;
- Be aware of the potential human and ecological health hazards which could result from CO_2 leakage;
- Gain an appreciation of how to assess the likelihood of hazard occurrence; and
- Know the level of current risk attributed to CO_2 storage leakage.

Types and scales of risk associated with CO_2 storage

The risks associated with storing CO_2 underground can be considered on two different scales: local and global (Figure 8.1).

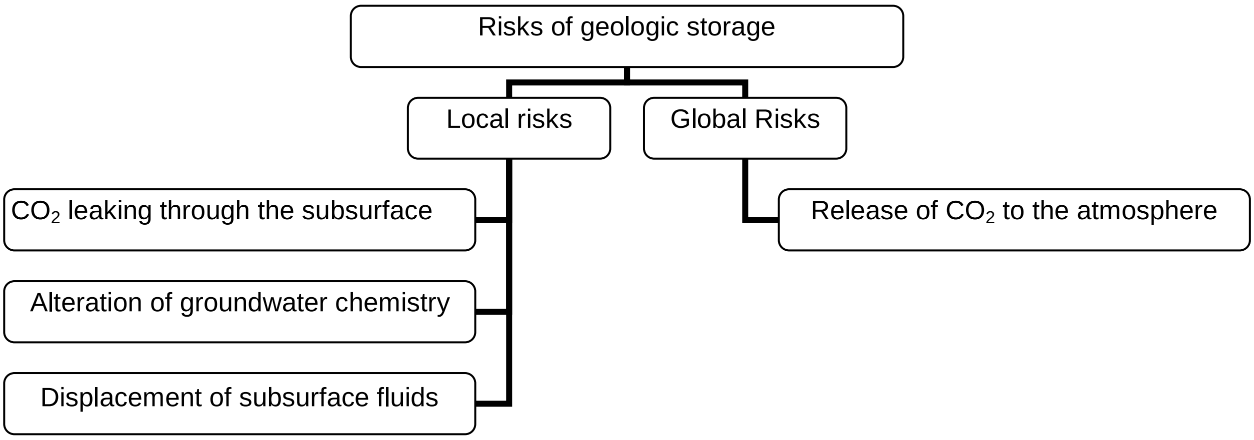

Figure 8.1 Risks associated with storing CO_2 underground.

At the local scale, potentially hazardous impacts may result from three mechanisms:

Leakage of CO_2 from the storage location through the subsurface into the atmosphere – this leakage could occur through isolated, catastrophic events - such as an earthquake - or through sustained, slow venting of CO_2 due to improper storage site selection or preparation. Either of these forms of leakage would result in elevated CO_2 concentrations at the surface or in the shallow sub-surface that could negatively impact human health and safety as well as that of plants and animals living in the area. Figure 8.2 demonstrates the various pathways for CO_2 leakage.

Alteration of groundwater chemistry resulting from CO_2 dissolving in it – such a chemical change in groundwater that is used for drinking water could impact human health. Alterations in groundwater not used for human consumption may have impacts on the ecosystem it is in contact with.

Displacement of fluids previously occupying the underground space where the CO_2 is injected – by injecting CO_2 gas underground, salty brine water could be forced out into drinking water reserves. The increased pressure of this type of displacement could cause fractures or other physical changes in the subsurface rock.

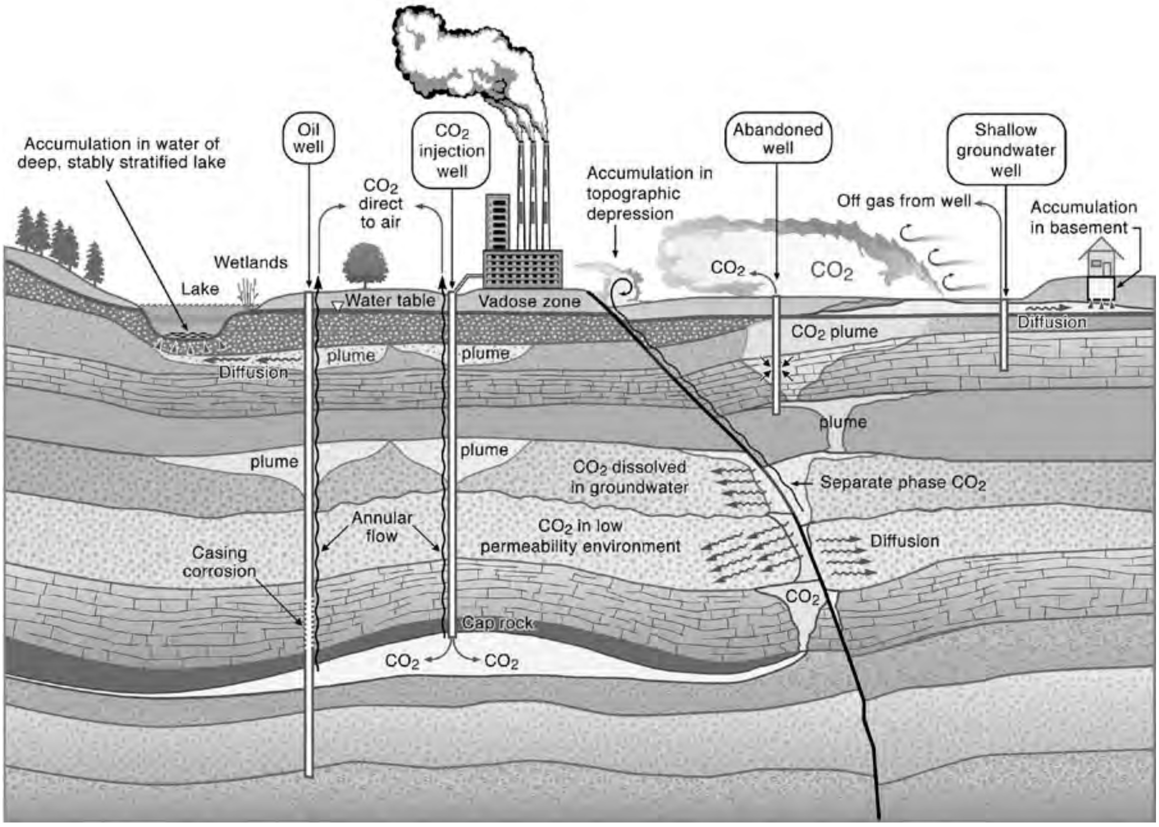

Figure 8.2: Schematic diagram of possible pathways by which CO_2 might leak to the surface (courtesy of Sally Benson).

The local risks of leakage are dependent on the location and timing of the leak. Continued and dispersed leakage will have very different impacts than episodic and isolated leakage events. For example, while slow but sustained leakage could gradually alter long-term soil ecosystems, a sudden, distinct leakage event could cause instantaneous disruption.

At a global scale, the major risk is that leakage of CO_2 injected into geologic formations will limit the effectiveness of the initiative in reducing the global atmospheric CO_2 concentration. This global risk, therefore, can be alternatively viewed as uncertainty in the effectiveness of CO_2 containment and of CO_2 storage as a climate change solution.

The global risk of leakage is dependent only on the average quantity of CO_2 released from the storage site over time. This will be a reflection of the contribution of the project to reducing atmospheric CO_2 emissions.

Finally, because of the energy penalty, the additional energy required to capture and store CO_2, more fuel will be required per unit of delivered energy if CO_2 is captured. Everything else being equal, therefore, there will be a corresponding increase in the various environmental impacts and risks associated with fuel production.

Potential human and ecological health hazards associated with leaked CO_2

Both human health and safety impacts, as well as ecosystem impacts, must be considered in evaluating the potential risks associated with CO_2 leaking from an underground storage site. In addition to the possibility of catastrophic leaks such as well blowouts or pipeline ruptures where large amounts are CO_2 suddenly released, slow, less-obvious leaks also need to be considered.

Although there is currently minimal experience with engineered CO_2 storage and no examples of leakage from existing projects to draw from, several naturally occurring CO_2 underground reservoirs (natural analogues) that have released CO_2 provide valuable insight into the types of hazards that could be anticipated at engineered sites. The primary natural analogues that have been studied are on the flanks of Mammoth Mountain, California (Fig. 8.3), at several locations in Italy and at Lake Nyos in Cameroon. Lake Nyos waters had been gradually saturated with CO_2 from volcanic vents over a period of time. They suddenly released a huge amount of CO_2 during the night which blanketed a local town killing 1,700 people. A fluctuating but constant flux of CO_2 has been flowing from underground at Mammoth Mountain into the atmosphere for about 15 years, killing the trees in several distinct areas and altering the soil and water chemistry in the region. As case studies, they provide a useful basis for understanding both the ecosystem and human health hazards associated with CO_2 leakage. It is important to note that these natural analogues are very different to the deep stable subsurface sedimentary storage basins that would be the preferred locations for engineered CO_2 storage. Natural analogues are located in highly fractured volcanic zones and are not well suited to understanding the likelihood of leakage from a CO_2 storage site.

In addition to these natural analogues, additional information relevant to both the potential hazards and the likelihood of occurrence can be gained through industrial experience of underground injection and in situations of humans operating in closed environments such as submarines and aircraft. This industrial experience includes the underground injection of CO_2 to enhance oil recovery, store natural gas, and dispose of hazardous and non-hazardous waste.

Figure 8.3. Aerial view of Mammoth Mountain, California where a natural source of underground CO_2 has been leaking through the soil into the atmosphere. The venting CO_2 has killed the trees in several distinct areas, visible in the above photograph as the non-green areas close to the lake (courtesy of USGS).

Potential human health and safety hazards

Elevated CO_2 concentrations in confined areas

The most serious human health and safety hazard associated with leaking CO_2 from an underground storage site is injury or death caused by elevated CO_2 concentrations in confined areas. Although CO_2 gas generally disperses quickly in the open atmosphere, CO_2 is denser than air so it will accumulate in confined environments including basements, tents, under snow-packs and in depressions or pits in the ground. Humans will suffer from unconsciousness and even death at CO_2 concentrations above 10%. CO_2 also causes significant respiratory and physiological effects in humans at concentrations over 2%. No adverse effects have been observed at concentrations below 1%.

Contamination of drinking water

Storage projects need to be designed to ensure that there is adequate protection of drinking water. The direct effects of dissolved CO_2 in drinking water are probably minor, because drinking water is often carbonated with CO_2 without any adverse health impacts. Dissolving CO_2 in water, however, will increase the acidity of the water which could cause indirect effects including increased mobilization of toxic metals, sulfate or chloride and changes in the odor, color or taste of the water. Groundwater used for drinking water could also be contaminated by saline brine water that is displaced by the CO_2 injection. This process could potentially render the drinking water too salty to drink. The infiltration of saline water into groundwater or the shallow subsurface also could pollute surface water and restrict or eliminate the use of some land for agricultural use.

Local heave and seismicity

A well charaterised storage site will consider the seismicity of the area as part of the site selection process (see Module 6). Underground injection of CO_2 into porous rock under pressure can induce fracturing and movement of faults. This could cause potentially damaging earthquakes and could result in the creation of additional pathways for CO_2 leakage. Several examples of induced seismicity resulting from the industrial practice of underground injection exist including the 1967 Denver earthquake and 1986 and 1987 Ohio earthquakes that are believed to have been induced from deep well injection of waste fluids.

Other potential hazards

A major pressure loss of dense phase CO_2 could result in cryogenic burns, embrittlement of equipment and damage from dry ice. It is important to understand how CO_2 will behave following a sudden release from pressurised containment. In assessing the safety hazards for pipelines to the storage site, fracture propagation in a pipeline needs to be considered.

Potential ecosystem hazards from CO_2 storage

Elevated concentrations of CO_2

Potential ecosystem impacts associated with CO_2 storage and potential leakage from an underground storage reservoir include effects on plants and animals both below-ground and above-ground. Throughout the underground environment, even in the deep storage sites where CO_2 could be injected, there are thriving microbial communities which rely on very specific conditions to live. Drastic changes, such as those associated with injecting CO_2, would alter these ecosystems. In the shallower underground environment, elevated concentrations of CO_2 could kill or weaken insects and burrowing animals as well as inhibit root respiration by displacing the soil oxygen needed for the roots of plants to function.

Acidification of soils and enhanced weathering

Other potential ecosystem hazards include the acidification of soils as CO_2 gas forms an acid when it combines with water. This acidification may directly impact some wildlife, but a potentially more serious indirect impact is the increased release of toxic metals that can result from the enhanced mineral weathering rate as the result of increased acidity.

Alteration of groundwater chemistry

The infiltration of saline brines into groundwater or the subsurface caused by displacement from the CO_2 injection also could impact many plants and animals who rely, directly or indirectly, on fresh rather than salty water.

Induced seismicity or ground heave

Ground heave and induced seismicity could also impact local ecosystems by the disruptions associated with earthquakes, including fractures and movement of the ground.

Impacts to off-shore benthic environments

Leakage from offshore geologic storage sites could impact benthic environments as the CO_2 moves from deep geologic structures through benthic sediments to the ocean waters. Minimal research has been conducted to assess the potential impacts to benthic communities; however plants and animals in the benthic region that rely on specific CO_2 concentrations could be threatened.

Evaluating the risks

To evaluate the risks associated with CO_2 storage, the potential hazards associated with a specific event must be considered in conjunction with the probability of the event happening. This section describes what is known about the likelihood of leakage and the likelihood of the hazards associated with it.

Likelihood of hazards associated with leakage

Understanding the probability of CO_2 leakage primarily involves assessing the effectiveness of the storage site being considered. Storage effectiveness is dependent on many different site specific factors including geological characteristics, the injection system being adopted, and the methods used to seal and contain CO_2 within the injection site. There are no existing studies that systematically estimate storage effectiveness across a sample of different storage sites. Therefore, rough quantitative estimates of achievable storage effectiveness must be attempted drawing from other relevant knowledge and experience of the site.

Data from natural systems, such as natural analogues, demonstrate that large quantities of CO_2, methane and oil can be trapped underground for geological timescales. CO_2 trapped underground in the Jackson Dome in Mississippi, for example, is thought to have been generated more than 65 million years ago. This demonstrates that reservoir seals exist that are able to provide almost perfect confinement of CO_2.

Engineered natural gas storage facilities provide additional insight into the likelihood of leakage. Among the approximately 470 natural gas storage facilities in the US and Canada, there have been nine incidents of significant leakage. Five of these were related to well bore integrity, three arose from leaks in the cap rocks, and the other was caused by early abandonment due to poor site selection. The performance of natural gas storage systems in North America suggests that the annual average gas leak rate is less than 0.01% of the stored gas. The leakage rates of natural gas storage facilities are expected to be higher than leakage from CO_2 storage because natural gas systems are designed for rapid pressure/volume cycling. As such, it is anticipated that the risk of CO_2 leakage is relatively small.

Off-shore geological storage leakage poses a less significant threat to the health and safety of humans because of its distance from human habitation. The probability of leakage in off-shore storage sites would also be reduced because there are fewer old abandoned wells off-shore than on-shore. Leakage off-shore also may not reduce overall CO_2 storage effectiveness as much as it does on-shore because some of the CO_2 that leaks out of an off-shore storage site will diffuse in the ocean rather than being re-released to the atmosphere. Although CO_2 leakage into the oceans could have some impacts on the local area, the oceans are capable of naturally dissolving and absorbing large quantities of CO_2 so leakage into ocean water does not pose the same risks as leakage into the atmosphere. **Taken together, the experience with natural and engineered systems suggests that amount of leakage from well designed CO_2 storage facilities will be very small**. It is reasonable to expect that more than 99% of the CO_2 would be retained for over 1,000 years. The ability to assess the health risks of a CCS project accurately is an area of rapid development.

Likelihood of hazards associated with groundwater contamination

The cumulative industrial experience with underground injection of other fluids (eg: oil, natural gas and waste) provides an empirical basis for assessing the likelihood of groundwater contamination and induced seismicity resulting from displacement caused by CO_2 injection. The current rates of injection of these other fluids into the deep subsurface are roughly comparable to the rates at which CO_2 would be injected if CO_2 capture and storage technologies were widely adopted. Contamination of groundwater by brines displaced from injection wells is rare, so it is reasonable to assume contamination resulting from CO_2 injection also would be rare.

Likelihood of hazards associated with seismicity

The injection of CO_2 for enhanced oil recovery provides a direct basis for estimating seismic risk. Current experience suggests that the risks are very low, as no significant seismic effects have been attributed to the over 30 million tons per year of CO_2 that is currently injected for enhanced oil recovery. Only a handful of individual seismic events have been associated with underground injection of other fluids suggesting that the risks of induced seismicity are generally low.

Risk assessment must be an integral component of CO_2 storage site selection, site characterisation, storage system design, monitoring and, if necessary, remediation. Current risk assessment methodologies are being adapted to the meet the unique risks posed by CCS projects. Module 9 outlines some of the methodologies that are being applied to commercial and demonstration CCS projects.

The IEA GHG Risk Assessment Network as established in 2005 to address what the regulators are expecting and whether risk assessment can provide the answers they require. The Network is divided into a number of smaller and more specific subject areas, Data Management and Risk Analysis, Regulatory Engagement and Environmental Impacts. The CSLF has a Risk Assessment Taskforce. Another body set up to share expertise on risk assessment is the International Performance Assessment Centre for Geologic Storage of Carbon Dioxide (IPAC- CO_2), managed from the University of Regina, Canada.

Summary

The risks associated with storing CO_2 underground can be considered on two different scales: local and global and can affect both human health and safety, as well as that of ecosystems. Without direct experience to draw from, studies of natural analogues and engineered storage sites have largely provided the basis for understanding and quantifying the health, safety and environmental risks that could arise from CO_2 that seeps from the shallow subsurface to the atmosphere.

Local scale risks include CO_2 leakage from the storage location; alteration of ground and drinking water chemistry and displacement of potentially hazardous fluids formerly occupying the pore space being used to store the CO_2.

At a global scale, CO_2 storage could be a major contributor to reducing atmospheric levels of CO_2 – one of the precursors to climate change. CO_2 leakage into the atmosphere would limit the effectiveness of CO_2 storage as a climate change solution.

Potential hazards of CO_2 storage to human health include:

- risk of death or unconsciousness from elevated CO_2 concentrations;
- contamination of drinking water as a result of increased acidity and mobilization of toxic metals; and
- local ground heave and induced seismicity through fracturing.

Experience with natural analogues and engineered sites suggest that the likelihood of these risks occurring will be minimal.

Off-shore CO_2 storage could cause risks to individuals on nearby ships or drilling rigs. However, there are no published studies on the issue and experience with industrial injection of other fuels suggests the risks will be minimal.

Ecosystems also face negative impacts from CO_2 leakage including:

- Damage or death from elevated CO_2 concentrations;
- Acidification of soils and enhanced weathering;
- Alteration of groundwater chemistry;
- Induced seismicity or ground heave; and
- Impacts to off-shore benthic environments.

Proper site selection for CO_2 storage is the single biggest factor determining the likelihood and magnitude of the risk. Risk evaluation is a young field and improvement in our understanding of these risks, as well as development of a methodology for risk evaluation on a site-by-site basis, are critical. Although natural analogues and the industrial practice of underground injection have provided valuable insight about potential risks, experience with and analysis of actual CO_2 storage projects is needed to allow for accurate risk evaluation. In addition to pointing out the need for better understanding of the risks, it should be pointed out that recent efforts in developing effective tools for monitoring, verification and leakage remediation provide improved approaches for managing, and therefore minimizing, the risks associated with CO_2 storage.

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IEAGHG Risk Assessment Network: www.co2captureandstorage.info/networks/riskassess.htm

Module 9

Risk management, measurement, monitoring and verification in CO_2 storage projects

Original text: R.J. Chalaturnyk & W.D. Gunter, APEC Capacity Building in the APEC Region, Phase II.
Revised and updated by CO2CRC

Overview

When a CO_2 storage project is being proposed, measurements are taken for site characterisation and the risks are assessed. The scientific methods used for site characterisation are also applicable to monitoring the storage site during various stages of the project. A comprehensive measurement, monitoring and verification plan forms part of and contributes to a risk management program and to demonstrating that a CO_2 storage project is meeting its objectives and complying with the regulations in place.

Learning objectives

By the end of this module you will be able to:

- Be familiar with the concept performance assessment for CO_2 storage projects;
- Be familiar with risk assessment for geological storage projects;
- Be familiar with stages in a CO_2 storage project and the type of monitoring for each stage;
- Be familiar with monitoring techniques; and
- Know where to go to for detail on the topic of risk assessment and monitoring and verification.

Background

Performance assessment refers to the process of evaluating the behaviour or performance of an element of a geological storage project relative to one or more performance standards. Performance incorporates both engineering and safety aspects into the assessment. Thus, performance is essentially the ability of the reservoir to retain stored CO_2 over time.

In order to assess such performance, the long-term fate of CO_2 initially injected into a geologic formation must be determined. Ultimately, if the CO_2 migrates far enough to reach the biosphere, but the flux of CO_2 to this environment is sufficiently low comparison to an acceptable flux performance standard, it does not pose a potential safety hazard.

Performance assessment forms a key component of a risk assessment for any geological storage project and ultimately feeds into the entire risk management process. In some processes such as EOR, there are elements of the performance assessment that are not contained in the risk management process. Prior to discussing some specific details of the performance assessment process, it is important to review the risk management process as it pertains to geological storage projects.

Risk management provides a comprehensive decision-making process that aids decision-makers in identifying, analyzing, evaluating and controlling all types of risks, including risks to health and safety. The objective of risk management is to ensure that significant risks are identified and that appropriate action is taken to minimize these risks. Such actions are determined based on a balance of risk control strategies, their effectiveness and cost, and the needs, issues and concerns of stakeholders. Communication among stakeholders throughout the process is a critical element of this risk management process. Decisions made with respect to risk issues must balance the technical aspects of risk with the social and moral considerations in the project.

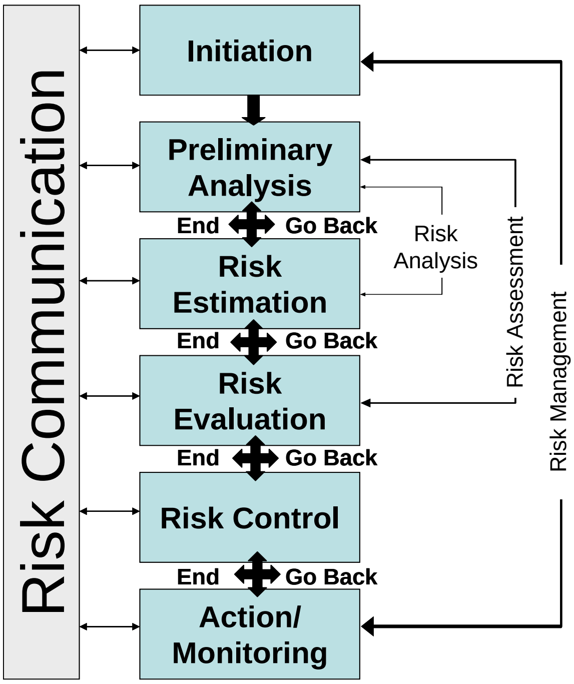


Figure 9.1: Risk management decision making process (after CSA, 1997).

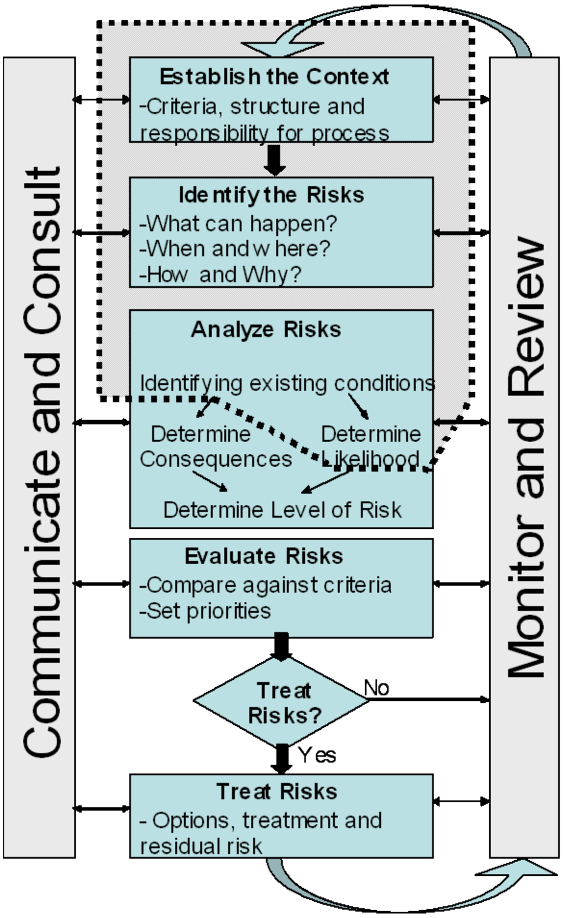


Figure 9.2: Risk management process (after HB 436:2004.)

The region outlined within the dotted line in Figure 9.2 generally describes the activities associated with performance assessment within the context of a full risk assessment.

Establishing the context for the performance assessment

The first step in a performance assessment should define the basic parameters within which the performance assessment should be conducted. These are the administrative details of the process and involve defining the:

- **Organizations or groups involved** (stakeholders) and the processes to be followed for the performance assessment;
- **Performance assessment team** which provides technical expertise and advice to decision makers. As such, this team is best formed from a multidisciplinary group of experts with specific knowledge and experience concerning the storage project currently being examined; and
- **Scope of the performance assessment.** This should include descriptions of the storage project; the potential areas of risk associated with the storage project; decisions that may have to be made;

stakeholders who may be affected by the project; and the risks and any assumptions that will be adopted at the outset of the performance assessment. This must include a description of the spatial extent of the storage project that will be assessed, as well as the timeframe of the assessment.

For geological storage projects, the most crucial components of performance assessment are (Wildenborg at al., 2004):

- **Assessment criteria:** quantitative criteria that relate to acceptable levels of CO_2 exposure and acceptable consequences for health, safety and environment. Examples are: the maximum acceptable CO_2 concentration, heavy metal concentrations, or the maximum individual lethality risk;
- **Storage concept:** a clear description of the concept of underground CO_2 storage must be provided; and
- **Setting of the storage site:** this involves a detailed description of the geological and geographical setting of the storage system including previous underground human activities in the area.

Perhaps the most difficult task among these components, *a priori*, is the establishment of the criteria against which the assessment results will be evaluated. To illustrate, wells (either injection or production) represent a subset or subsystem within the geological storage project that must perform satisfactorily. However, there must be criteria in place to assess the wellbores' performance. Experience in the oil and gas field demonstrates that most wells perform well during their operational life (10 to 15 years). For geological storage, satisfactory performance is required not only over the operational life but over much longer timeframes (in the order of 100 to 5,000 years). Current research and field demonstration activity on measurement, monitoring and verification is focussing much of their activities to assist in the establishment and assessment of these criteria.

Bowden and Rigg (2004) conducted a risk assessment study to assess reservoir risk in CO_2 storage projects in Australia as part of the GEODISC project. For the technical assessment context, their study included both containment issues (the ability of the reservoir to contain most of the injected CO_2) and effectiveness issues (the ability of the reservoir to receive the planned CO_2 injection volumes). Their risk assessment criteria, which could be helpful as a guideposts for future assessments, was:

- A 99% chance that the total injection will be held within the system for 1000 years;
- Acceptable containment will be achieved, if one can be 80% confident that 99% of the injected mass will be contained within the system for 1000 years; and
- It would be acceptable if there was less than a 20% chance that a reduction and/or delay of CO_2 mass stored within a geological storage site would result in a zero or negative net greenhouse value.

For each geological storage project, the performance assessment team would be required to develop these types of criteria for evaluating the performance assessment results.

The methodology used by Bowden and Rigg to undertake and qualitative risk assessment by use of an expert panel to establish the likelihood and consequesnces of risks has been also applied to the Weyburn-Midale project. (Preston et al, 2009).

Wildenborg et al. (2004) have developed a methodology for risk assessment of CO_2 storage that consists of three major steps, scenario analysis, model development, and consequence analysis, Figure 9.3. Performance assessment is embedded into this methodology. This method is based on risk assessment studies on the storage of radioactive waste, but it has been adapted to the particularities and challenges that geological storage present.

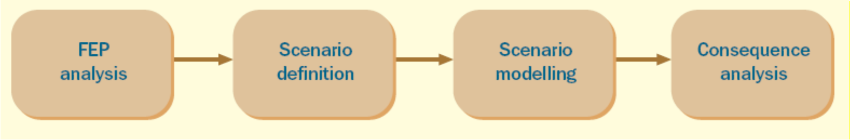


Figure 9.3: The scenario approach for safety assessment (from Wildenborg et al., 2004)

CO_2 storage risk assessment methodologies include RISQUE, Structured What if Technique (SWIFT), Screening Risk Assessment (SRA) and TESLA (a decision making tool).

Identify the risks

For most current geologic storage projects, risk identification has been completed following a systems analysis approach. This approach recognizes that a geologic storage project includes several systems - wells, reservoir, surface facilities and others, which interact with each other. Systems analysis consists of several inter-related elements:

- **Development of a list of features, events and processes** (FEPs) which together describe the geological storage system;
- **Identification of how FEPs interact** within the geological storage system;
- **Construction of scenarios** which describe the most likely set of FEP interactions; and
- **Description of how these interactions will be accommodated** in the performance assessment modeling to be undertaken for each scenario.

Each of these will be described in more detail below.

Development of a list of features, events and processes (FEP) for geological storage

Features, events and processes can be described in the following way:

- **Features** are physical characteristics or properties of the system such as lithologies, porosity, permeability, wells, faults and nearby communities;
- **Events** are discrete occurrences affecting one or more components of the system, such as earthquakes, subsidence, drilling, borehole casing leak and pipe fracture; and
- **Processes** are physico-chemical processes often marked by gradual or continuous changes that influence the evolution of the system such as precipitation of minerals, groundwater flow, CO_2 phase behaviour and corrosion of borehole casing.

A European Commission funded study conducted as part of the Weyburn CO_2 Monitoring and Storage Project (Maul et al., 2004) has developed an online FEP database specifically for geological storage projects. The database is internet-enabled incorporating hyperlinks to other relevant sources of information (reports, websites, maps, photographs, videos, etc.), and is searchable in a variety of ways. It includes FEPs relevant to the long-term safety and performance of storage systems after injection of CO_2 has been completed and the injection boreholes have been sealed. Some FEPs associated with the injection phase are nevertheless considered where these could affect long-term performance. For any particular geological storage system, it can be utilized to identify an applicable, comprehensive list of FEPs. Moreover, the development of this lists can drawn a vast amount of information from natural analogues such as natural CO_2 reservoir, and industrial analogues such as deep injection of wastes, or underground gas storage.

Classification of FEPs

The assessment context for the performance assessment helps to determine which FEPs need to be considered in an analysis and which can be considered irrelevant to the scope of the assessment in a given specific project. To provide a sense of the character of the FEPs identified for a geological storage project, Figure 9.4 provides a list of FEPs developed for the IEA Weyburn CO_2 Monitoring and Storage Project (Stenhouse and Zhou, 2001).

Utilizing the definition of the storage system set out in the assessment basis or context, the FEPs are ranked and screened in order to identify the FEPs that are likely or very likely to occur. These FEPs are grouped and assigned to specific zones within the geological storage system (compartments). A combination of interrelated events and processes for a group may include (Wildenborg et al., 2004):

- The integrity of the reservoir, seal, fault and well completions;
- The migration of CO_2 through the overburden; and
- Health, safety and environmental impacts in the shallow subsurface or atmosphere.

Category	WEYBURN FEP TITLE	Category	WEYBURN FEP TITLE
SYSTEM FEPs		**SYSTEM FEPs (continued)**	
Rock properties		**Other gas**	
	Mechanical properties of rock (including stress field)		Gas pressure (bulk gas)
	Mineralogy		Release and transport of other gases
	Organic matter (solid)		
	Presence and nature (properties) of faults / lineaments	**Geology**	
	Presence and nature (properties) of fractures		Seismicity (local)
	Cap-rock integrity		Temperature / thermal field
			Uplift and subsidence (local)
Hydrogeological properties			
	Cross-formation flow	**Abandoned Wells**	
	Fluid characteristics of rock		Annular space (quality / integrity)
	Geometry and driving force of groundwater flow system		Boreholes - unsealed (extreme case)
	Groundwater flow (including rate and direction)		Corrosion of metal casing (abandoned wells)
	Hydraulic pressure		Expansion of corrosion products (abandoned well metal casing)
	Hydrogeological properties of rock		Incomplete borehole sealing / Early seal failure
	Pore blockage		Incomplete records of abandonment / sealing
	Saline (or fresh) groundwater intrusion		
	Transport pathways	**NON-SYSTEM FEPs**	
		EFEPs	
Chemical/Geochemical			Artificial CO2 mobility controls
	Carbonation		Climate change
	Colloid generation		Cross-formation flow (fast pathways)
	Degradation of borehole seal (cement / concrete)		Depth of future wells drilled
	Dissolution of minerals/precipitates/organic matter		Earthquakes
	Dissolution / exsolution of CO2		EOR-induced seismicity
	Dissolved organic material		Exreme erosion
	Groundwater chemistry (basic properties)		Fault activation
	Methanogenesis		Future drilling activities
	Microbial activity		Glaciation
	Mineral surface processes (including sorption/desorption)		Hazardous nature of other gases
	Precipitation/Coprecipitation/Mineralisation		Hydraulic fracturing (EFEP?)
	Reactive gaseous contaminants		Hydrothermal activity
	Redox environment / heterogeneities		Igneous activity
	Salinity gradient		Major rock movement
			Metamorphic processes
CO2 Properties and Transport			Mining and other underground activities
	Advective flow of CO2		Monitoring (future)
	Colloid transport		Regional uplift and subsidence (e.g. orogenic, isostatic)
	Diffusion of CO2		Rock properties - undetected features
	Dispersion of CO2		(e.g. faults, fracture networks, shear zone, etc.)
	Gas flow		Sea-level change
	Source term (CO2 distribution)		Seismic pumping
	Thermodynamic state of CO2		Seismicity (EXTERNAL)
	Transport of CO2 (including multiphase flow)		

Figure 9.4: Examples of features, events and processes associated with a CO_2–EOR project (after Stenhouse, 2001).

Scenario development

Scenario development is concerned with the identification, broad description and selection of potential futures relevant to performance (and safety) assessment of the geological storage site. Scenario development includes the identification of relevant FEPs, synthesis of broad models of scientific understanding and selection of calculational cases to be performed. Scenarios provide the structure for discussing the likelihood and consequences of CO_2 leakage from a storage reservoir and the framework for presenting any biases or shortcomings in the performance (and safety) assessment. Guidelines for Carbon Dioxide Capture, Transport and Storage (World Resources Institute, 2008), contains a set of possible risk scenarios together with mitigation/remediation options.

In general, experts begin with gaining knowledge of how the system has evolved in the past and then determine how the system might operate in the future if not disrupted. After this, they then consider the likelihood and consequences of different perturbations and disruptions. Expert judgment will also make use of the goals and objectives of the risk assessment, and, especially, current modeling capability and data availability.

Based on the above, the next step for geological storage projects is the development of different, plausible and credible ways in which the geological CO_2 storage system might evolve over decades to hundreds to thousands of years. These scenarios essentially explore “what if…?” type questions.

Scenarios are the starting points for the development of conceptual physical/chemical models for which performance assessment analyses are conducted. In identifying possible scenarios, it is generally accepted that there is one most likely way in which the geological storage system would be expected to evolve. This is generally referred to as the Base Scenario. The Base Scenario is defined as the expected evolution of the system being assessed while recognizing that there will be uncertainties associated with this Base Scenario. These uncertainties are typically explored using variants of the Base Scenario called Alternative Scenarios.

The following describes some issues associated with scenario development:

- Challenges in making predictions about the future behaviour of humans interacting with the storage site;
- Confidence concerning the longevity of expert consensus views;
- Estimates of probability; and
- Possible omissions in FEP lists.

As an illustration, the base scenario and alternative scenarios developed for the IEA Weyburn CO_2 Monitoring and Storage Project are presented in Figures 9.5 and 9.6 respectively.

Base Scenario

- System model domain: the Weyburn 75 well patterns and a 10-km zone surrounding it.
- Time frame: inception of EOR using injected CO_2 and with an nominal end time taken as the earlier of 5000 years or the time at which there is 50% loss (to the biosphere) of CO_2 that was in place within the geosphere at the end of EOR.
- The caprock may have natural fractures or discontinuities but all are isolated or sealed such that caprock integrity is not impaired.
- There are a series of aquifer/aquitards above and below the reservoir horizon. These media may contain fractures and fissures.
- Will consider physical trapping features, which have naturally contained the oil/gas within the reservoir.
- Will consider geochemical effects (formation of carbonate minerals and CO_2 removal by solubility and ionic trapping) in the aqueous phase of all aquifers.
- The biosphere starts from the deepest possible potable aquifer and technically includes all of the glacial till and surficial deposits (i.e. it extends to a depth of about 300 m below ground surface). It includes soil, surface water, atmosphere, flora and fauna.
- Includes the presence of all wells found within the system model domain.
- All wells assumed to have been abandoned following current field abandonment procedures applicable at the time of abandonment. Note that this includes wells that may have been sealed in earlier years according to different abandonment procedures and regulations.
- Well seals may degrade after abandonment. Well seals are primarily the cement used to fill the annulus between the casing and borehole, cement and metallic plugs used to fill the casing bore, and the cap welded onto the casing approximately 4 m below ground surface. Consideration should also be given to degradation of the casing itself within the reservoir and all aquifers and aquitards penetrated by the casing.
- The base scenario includes consideration of FEPs that could affect the storage and movement of CO_2. These include, but are limited to, processes such as hydrodynamics, geochemistry, buoyancy and density driven flow, dissolution of CO_2 in water and residual oil, and pressure-temperature changes occurring within the geologic formations.

Figure 9.5: Elements constituting the Base Scenario definition (after Jazrawi et al., 2004).

Alternative Scenario Name	Unique characteristics
Engineering options for EOR (a) Maximize CO_2 storage (b) Water flush at the end of EOR	Option (a) involves larger reservoir pressures; over-pressurisation and caprock fractures are possible problems. Option (b) would result in changes to CO_2 distributions in the reservoir and could also decrease CO_2 storage
Well abandonment options	Emphasis on improved long-term sealing capabilities
Salt dissolution of underlying formations	Dissolution and subsidence may lead to development of fractures
Leaking wells	Involves extreme failures only as the Base Scenario has 'normal' leakage
Fault movement or reactivation, including undetected faults	Could represent a new and fast CO_2 transport pathway; could affect several formations
Tectonic activity	Low probability but possible
Deliberate & accidental human intrusion (a) Destruction of surface casing (b) Resource extraction	Likely scenario involves intrusion into the reservoir in search for CO_2 or petroleum. Option (a) could affect the uppermost seal in one or more wells. Option (b) likely involves extraction of some shallower resource, but could lead to CO_2 blow-out from CO_2 trapped in formations above the reservoir

Figure 9.6: Alternative Scenario descriptions developed for the Weyburn CO_2 Monitoring and Storage Project (after Jazrawi et al., 2004)

Guidelines for Carbon Dioxide Capture, Transport and Storage (World Resources Institute, 2008), contains a set of possible risk scenarios together with mitigation/remediation options for a CO_2 storage project. The list deals with leakage through faults, fractures, spill points and well, leakage into the soils and groundwater and surface water, CO_2 accumulating in indoor environments and large releases to the atmosphere.

Analyze performance

Based on the scenario development and the features, events and processes included in these scenarios, an analysis strategy must be chosen to establish the likelihood of exceeding criteria established in the assessment context stage. This is a critical step in analyzing the geological storage site performance. The choice of analysis method will reflect the accuracy needed (in the results), cost, available data, level of expertise on the team and the acceptability of the analysis method to the stakeholders. The analyses may be qualitative, semi-quantitative or quantitative or a combination of these, depending on the circumstances.

Current performance analysis uses numerical modeling to provide a forecast of the behaviour of scenarios. The results, although in essence quantitative, can be used both in a quantitative or qualitative manner depending on the certainty about the model itself and its parameters. This modeling exercise not only provides a forecast, but also helps to better understand what FEPs are critical to the successful development of the project, as well as helping to identify uncertainties in both FEPs and scenarios.

Qualitative analyses use words to describe the magnitude of potential consequences and the likelihood that those consequences will occur. For geological storage projects, qualitative analyses serve well as an initial screening activity to identify risks which require more detailed analyses. Expert opinion and judgment are important ingredients of qualitative studies. They ensure that all pertinent guidelines, environmental risk indices, and processes have been addressed, and can assist in recommending appropriate comparative guidelines when specific data are unavailable. Moreover, the knowledge and experience of experts have a major influence on the quality of the assessment and on the real and perceived confidence in the results. This last factor actually applies to all risk assessment methods, and can be one of the most important considerations for assessments that are sensitive to members of the public. Qualitative methods for analyzing performance include evaluation using multi-disciplinary groups; specialist and expert judgment; and structure interviews and questionnaires.

In **semi-quantitative analysis**, qualitative scales are given values, as illustrated in Figure 9.7. The objective is to produce a more expanded ranking scale than is usually achieved in qualitative analyses. Care must be taken with the use of semi-quantitative analyses because the numbers chosen may not properly reflect relativities and this can lead to inconsistent, anomalous or inappropriate conclusions (HB 436:2004).

These can also be used as an initial screening tool. Figure 9.7 provides consequence tables and likelihood tables used in assembling the results into an estimate of the risk for any particular scenario chosen for the geological storage project.

Quantitative analyses adopt numerical or analytical models to quantify both consequence and likelihood. In general, this has been the method adopted for most early risk assessment studies for geological storage projects. Performance assessments conducted in the IEA Weyburn CO_2 Monitoring and Storage Project adopted both deterministic and probabilistic methods. A sophisticated reservoir simulator was utilized for deterministic analyses and an analytical model was constructed to permit probabilistic performance analyses to be conducted. The quantitative approach can use both natural and industrial analogues as a tool to validate both the numerical and analytical models to be used. Such validation is a fundamental step whenever new approaches are being taken and/or the experience with certain analytical methods is limited and the confidence in them not very high.

For deterministic performance assessments, single point estimates for each parameter are used in the analyses. In contrast, a probabilistic performance assessment generates a coherent set of consequence estimates that reflect the effects of parameter uncertainty. As in the deterministic assessment, a set of parameter values is passed to the computational model, which then generates an estimate of consequence. However, this simulation process is repeated, often thousands of times but with different sets of parameter values.

Consequences

	People	Environment	Financial	Public	
4	◆Fatality; **OR** ◆Serious long term health impact **OR** ◆Permanent Disability	◆Permanent environmental damage **OR** ◆Effects widespread (outside Storage Project areas)	◆Production and equipment loss **>$z**	◆National/ International attention **OR** ◆Evacuation of **N** or more people	Major
3	◆Lost time injury	◆Severe environmental damage **OR** ◆Effects within Storage Project operating areas	◆Production and equipment loss **>$y** but **<$z**	◆Provincial attention **OR** ◆Evacuation of **M** to **N** people	Serious
2	◆Medical aid injury **OR** Restricted work	◆Moderate environmental damage **OR** ◆Effects off lease but localised	◆Production and equipment loss **>$x** But **<$y**	◆Local or community attention **OR** ◆Evacuation of less than **M** people	Moderate
1	◆Minor injury **OR** ◆Illness ◆**OR** First Aid	◆Minor environmental damage **OR** ◆Effects continued to lease	◆Production and equipment loss **<$x**	◆Individual concern **OR** ◆Minor inconvenience to a few people **OR** ◆No evacuations	Minor

Liklehood

A-Remote	B-Occasional	C-Probable	D-Frequent
◆Not likely to occur during life cycle **OR** ◆None expected for the system being assessed and only a few occurrences industry or worldwide	◆Likely to occur sometime during life cycle **OR** ◆**x** to **y** occurrences a over a z year life cycle	◆Likely to occur several times during life cycle **OR** ◆x_1 to y_1 occurrences a z year life cycle	◆Happens often and might be expected during life cycle **OR** ◆x_2 or more occurrences over a z year life cycle

Level of Risk

	A	B	C	D
4	🟥	🟩	🟩	🟩
3	⬜	🟪	🟩	🟩
2	⬜	⬜	🟪	🟪
1	⬜	⬜	⬜	⬜

🟩	**Extreme risk**
🟥	**High impact risk**
🟪	**Moderate risk**
⬜	**Low risk**

Figure 9.7: Semi-quantitative analysis categories for the combination of consequence and likelihood, which defines levels of risk.

Quantitative methods employed in performance (risk) assessment include (HB 436:2004):

- Consequence analysis;
- Statistical analysis of historical data;
- Fault-tree and event-tree analysis;
- Influence diagrams;
- Simulation and computer modeling;

- Statistical and numerical analysis; and
- Probability analysis.

Measurement, monitoring and verification

Measurement, monitoring and verification (MMV) activities provide the confidence that CO_2 has been injected and stored in an environmentally sound and safe manner. It also provides verification to both numerical modeling and performance assessment and provides the necessary accounting metrics for emissions trading scenarios (such as those under the Kyoto Protocol) based on geological storage.

The following terms are important to the discussion on monitoring the fate of injected CO_2:

- **Migration -** refers to movement of fluids (including injected CO_2) within the injection formation. This can involve movement both vertically and horizontally within the designated injection horizon. The fluids remain “trapped” by both the upper and lower bounding seal layers;
- **Leakage -** refers to movement of fluids (including injected CO_2) outside the injection formation. This can involve movement through the upper and lower bounding seals or through wellbore pathways. Leakage includes all pertinent pathways through the geosphere. Monitoring for leakage is important as it includes all processes leading to CO_2 movement towards and possibly into the biosphere; and
- **Seepage -** refers to movement of fluids (including injected CO_2) from the geosphere to the biosphere. Monitoring programs aimed at seepage processes are primarily focused on limiting any health, safety or environmental issues.

CO_2 storage projects are generally considered in four phases. These phases are referred to in new and developing legislation for CCS:

- Pre-operation phase– design, site characterisation, establishing baseline monitoring conditions, risk identification;
- Operation phase– CO_2 injection;
- Closure phase – Period after injection has stopped and when wells are abandoned, facilities removed and site remediated while monitoring continues; and
- Post-closure phase – Ongoing monitoring takes place until no longer required (the site is stable). (DOE, 2009).

(Note: The last two phases are also called the “Post-operational phase”)

The monitoring required at each phase varies and each project will have specific monitoring programs to reflect the project’s geology and objectives. Appendix 1 outlines a methodology for planning a monitoring program.

A monitoring program covers three monitoring domains:

- The sub-surface domain (the reservoir);
- The near-surface domain (shallow zones and soil); and
- The atmospheric domain.

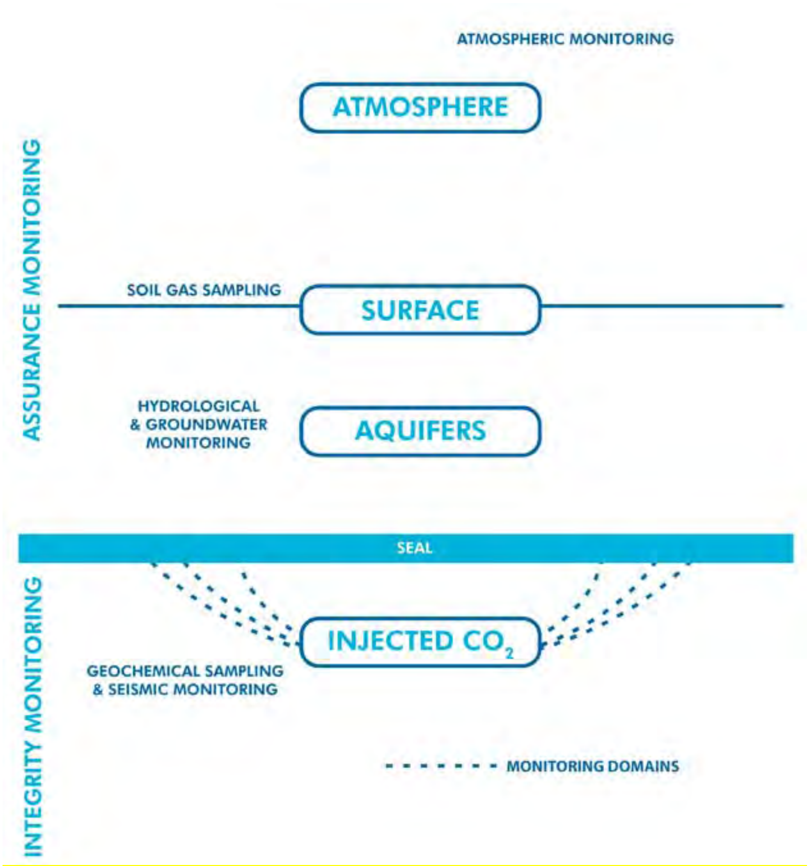


Figure 9.8: Monitoring domains (courtesy of CO2CRC).

The first two domains (subsurface and near-surface) involve monitoring using information obtained from fluid sampling and geophysical sensing in addition to remote monitoring from the surface or related boreholes.

The monitoring in the pre-operation phase is known as baseline monitoring. It establishes the initial condition of the storage system and the environment surrounding the storage site.

Monitoring during the operational phase of the project records the dynamic behaviour of the CO_2 as it is injected and within the reservoir. Measurements include surface and downhole pressures, flow rates and the geochemical profile of the injected fluids. Together with tracer sampling, seismic surveys, and well log data, these measurements verify and update the pre-injection models used to predict the behaviour of the CO_2 within the reservoir. Atmospheric, groundwater and soil samples are used to monitor the local environment for seepage that could pose a health, safety or environmental risk.

Monitoring technologies

Many of the technologies for monitoring a storage project have been used by the oil and gas industries and are being adapted for CO_2 storage. Many of techniques are used for site characterisation, and the data obtained is used for design of the project, for identifying risks and providing the baseline measurements. New techniques, applicable to environmental programs (air, soil and water sampling), are also being adapted for use in CO_2 storage projects.

Geophysical and remote sensing uses seismic, electromagnetic, gravity, microseismic and displacement sensors and petrophysical logging measurements.

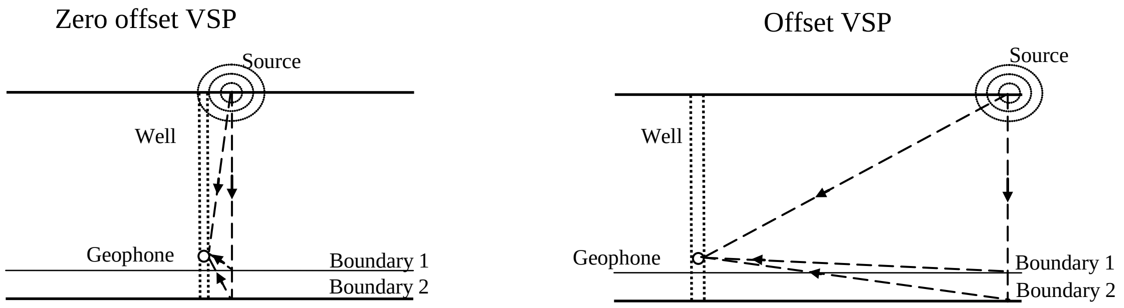
One of the most common methods used is seismic monitoring. It is used to detect subtle changes associated with the presence of the injected CO_2 and map the migration pathways.

Surface seismic monitoring maps the migration path of CO_2 plume from injector to producer. The initial surveys carried out before injection need to be repeated during and after the CO_2 injection to show the distribution of carbon dioxide over time.

Vertical Seismic Profiling (VSP) provides a high resolution geological image in the immediate vicinity of the boreholes. Seismic sources are located at the surface and receivers are positioned in the boreholes.

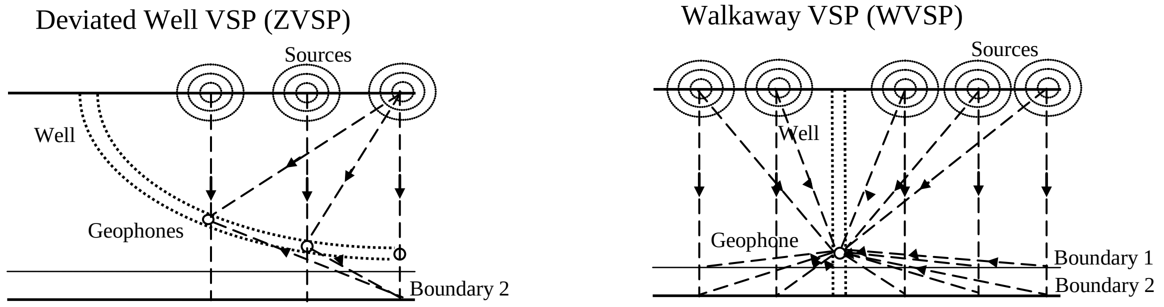
High Resolution Travel Time seismic enables monitoring of fine changes in fluid level and can verify the volume of CO_2 injected.

Microseismic surveys are used to monitor for fractures or fault reactivation as a result of the injection of CO_2.



The source is close to the well.

The source is some distance from the well.



Multiple geophones are located in the well, with multiple source positions.

The source is moved away from the well and signals are generated at regular spacings.

Figure 9.9: Typical arrangements for vertical seismic profiling (VSP) (courtesy of CO2CRC).

Figure 9.10: A field view of a seismic survey underway at the CO2CRC Otway Project (courtesy of CO2CRC).

Gravity measurements have been used to monitor CO_2 movement in the Sleipner project. These measurements show changes in density in a vertical column of rock and can detect the displacement of saline water by CO_2.

A recent development in remote monitoring is satellite air-born radar interferometry (InSAR) which detects subtle ground deformation above the injection wells. This technology has been used to determine the level of uplift of the surface in the In Salah CO_2 injection areas. This surface uplift is around 5mm/year. (Ringrose et al, 2009).

Geochemical monitoring involves geochemical analysis of fluids, gases, rock/soil, groundwater, surface water and the atmosphere.

CO_2 in the injection stream can be tagged using chemical tracers in order to verify the plume behaviour. Water levels and the chemistry of shallow aquifers can be monitored to detect any injected CO_2 leakage into these aquifers. Seasonal variation, flow rate and direction of water flows are recorded from deep water bores. Groundwater sampling using a low flow pump will help to detect any chemical changes in the unlikely event of CO_2 leakage. High quality well bore fluid and gas samples can be collected at reservoir pressure from multiple levels in a monitoring well and analysed for their chemical and isotopic composition to detect the CO_2 arrival.

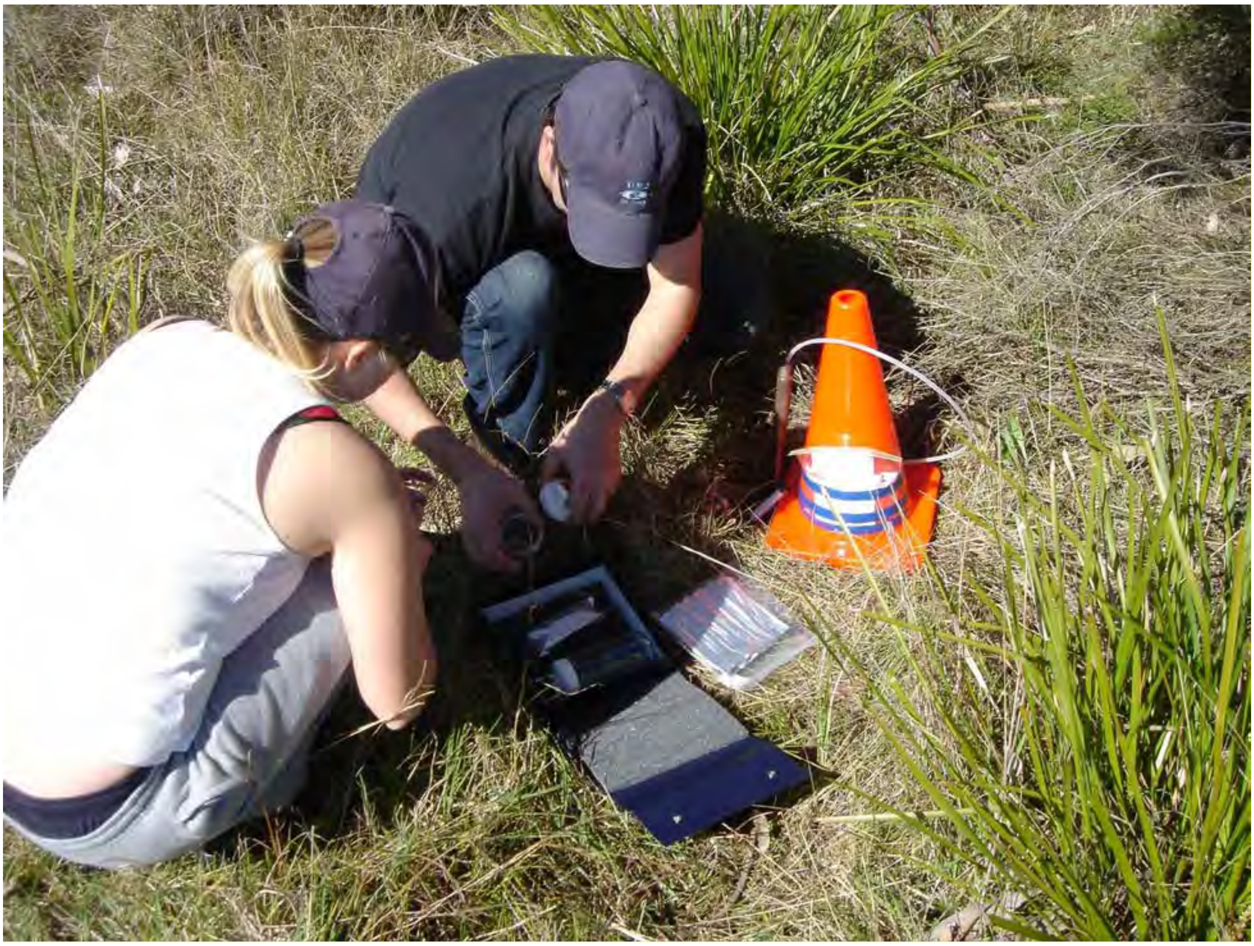


Figure 9.11: Soil gas sampling at the CO2CRC Otway project (courtesy of CO2CRC).

Environmental sensing techniques include atmospheric gas detection and dispersion modelling, remote sensing techniques including multi spectral analysis

Atmospheric stations can continuously measure concentrations of CO_2. A CO_2 flux tower can continuously measures surface-air CO_2 movement. Soil CO_2 flux measurements can be taken at many locations in the project area. Measurement of tracers and isotopes can establish the origin of CO_2 emissions to the local atmosphere quantify emissions.

Figure 9.12: CO_2 flux station (courtesy of CO2CRC).

Project monitoring and verification results help to confirm the modelling predictions that there is no migration of CO_2 beyond the containment site.

Information about the monitoring programs in place at active storage projects sites is shared through networks such as the IEA GHG monitoring network and CO2NET.

The IEA GHG has developed an online monitoring selection tool to identify and prioritise techniques that could form part of a monitoring program.

A Technical Basis for Carbon Dioxide Storage, prepared by members of the CO_2 Capture Project, has a chapter devoted to various monitoring techniques and their limitations and applications. The chapter also includes several case studies.

In January 2009, the US Department of Energy published a comprehensive best practices module for monitoring geological storage projects. The report, *Monitoring, Verification, and Accounting of CO_2 stored in Deep Geologic Formations*, includes a comprehensive list of monitoring techniques including a description of each, the benefits of using each technique and the challenges. It also categorises technologies into the monitoring domains.

Outline of steps in performance assessments

The following generalizes an approach for conducting performance assessments of a geological storage site:

1. Define the characteristics of the project and establish the assessment context.

Some of the issues that need to be considered within the assessment context are:

- Environmental impact of the proposed sink mechanism;
- CO_2 capacity;
- Retention/residence time of CO_2 in the storage site;
- Potential for accelerated leakage of CO_2;
- Rate of CO_2 uptake by the storage site;
- Validation of storage in the sink; suitability of the sink/match to the emission source and type; and
- Cost of implementation/utilization of the sink mechanism.

2. Utilize online resources to identify and rank the important features, events and processes for the project.

- Establish plausible scenarios for the long term evolution of the geological storage site;
- Make use of qualitative assessment studies to appropriately rank the scenarios for subsequent performance assessment analyses. Qualitative studies can be used to identify where further, more detailed studies will be most beneficial and can assist in identify whether deterministic and/or probabilistic assessments should be adopted. The choice will depend on the nature of the questions which in turn determines the nature of the mathematical models used to describe the system; and
- Conduct appropriate quantitative analyses on scenarios to confirm performance of the geological storage site will meet the criteria developed within the assessment context. If a performance criterion is not met, the design is reiterated until a satisfactory design is achieved or a new site must be found.

There are some important decisions that should be made before evolving the performance assessment towards risk evaluation. These questions relate primarily to the adequacy of the data, the methods used in the analyses, and the uncertainties associated with the analysis. Some of these decisions are listed below. While this list was not meant to be exhaustive it should provide the reader with a good overview of the types of questions to be asked at the end of any component of the performance assessment.

- Is the performance (risks) much lower than initially estimated or is there no longer an issue of concern with stakeholders? If so, end the performance assessment here.
- Have new issues developed? If so, return to establishing the context for the project.
- Should new scenarios be considered? If so, return to identifying the risks.
- Are the methods used in the analyses appropriate? If not, return and redo analyses using different methods.
- Are the results of the analyses considered reasonable? If not, return and redo analyses using different methods.
- Is the level of uncertainty associated with the estimates considered acceptable? If not, acquire better data and redo analyses using new data or better techniques.

Summary

Performance assessment evaluates the performance of an element of a storage project against one or more performance standards. It includes engineering and safety aspects of the initiative and is one aspect of the risk management process.

Risk management provides a comprehensive decision-making process that aids decision-makers in identifying, analyzing, evaluating and controlling all types of risks, including risks to health and safety.

A performance assessment should begin with defining the basic parameters for the study. This includes determining the key stakeholders and process to be followed, developing a performance assessment team and defining the scope for the study. The most crucial components to consider are selection of assessment criteria, description of the storage concept and describing the storage site. The most difficult component to undertake is selection of assessment criteria for the evaluation. This is the focus of much of the activity in current research and field demonstration in measurement, monitoring and verification.

Current practice for most geologic storage project is to use a systems analysis approach for determining and evaluating risks. This involves developing a list of features, events and processes and how they interact and will managed within the storage system. An *online features, events and processes (FEPs) database* has been developed to help with their identification. It includes FEPs that are relevant to long-term safety and performance of geological storage systems. Classification of FEPs occurs against the context for the performance assessment. This helps to determine which FEPs are important to consider. After FEP classification, scenarios are developed to identify, describe and select futures relevant to the performance assessment of the site. This provides the overall framework for the performance assessment and FEP selection. Base Scenarios (the expected evolution of the storage system) and Alternative Scenarios (those that illustrate the potential outcomes of uncertainties) are typically produced.

An analysis strategy is chosen to establish the likelihood of exceeding criteria established in the assessment context stage. Different analysis methods will be chosen based on accuracy needed in the results, cost, data available, level of team’s expertise and the acceptability of the analysis method to stakeholders. The main tool for these analyses is numerical modeling of the conceptual physical/chemical models in different scenarios. This produces quantitative results which can be used for qualitative, semi-qualitative or quantitative analyses.

Measuring, monitoring and verification ensure that CO_2 injection has been environmentally safe and sound. It also provides some of the necessary CO_2 accounting required under emission trading scenarios such as the Kyoto Protocol. Monitoring the fate of CO_2 involves monitoring migration, leakage and seepage and is carried out in the subsurface, near-surface and the atmosphere. Monitoring programs are developed for each distinct phase of a project – pre-operation, operation, closure and post-closure.

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Society for Risk Analysis (SRA): http://www.sra.org/

Crystal Ball: http://www.decisioneering.com/

@RISK: http://www.palisade.com/

RISQUE http://www.ap.urscorp.com/Services/A-Z/?BusinessRiskStrategies

TESLA decision making tool http://www.quintessa-online.com/downloads.php

Interactive Design of Monitoring Programmes for the Geological Storage of CO_2

http://www.co2captureandstorage.info/co2tool_v2.2.1/index.php

CO_2 Capture Project: http://www.co2captureproject.org/ccp2_storage.html and

http://www.co2captureproject.org/co2_storage_technical_book.html

The US Department of Energy/National Energy Technology Laboratory guide to best practice for Monitoring and Verification: http://www.netl.doe.gov/technologies/carbon_seq/core_rd/mva.html

IEA GHG Monitoring Network: http://www.co2captureandstorage.info/networks/monitoring.htm

The Weyburn-Midale project: http://www.ptrc.ca/weyburn_overview.php

The report from the first phase of the Weyburn-Midale CO_2 monitoring and storage project:

http://www.ptrc.ca/publications.php

A Technical basis for carbon dioxide storage. Publication available online from the CO_2 Capture project once logged in as a user.: http://www.co2captureproject.org/co2_storage_technical_book.html

Appendix 1

Methodology for planning a monitoring program

R.J. Chalaturnyk & W.D. Gunter, APEC Capacity Building in the APEC Region, Phase II

Monitored decision framework

A monitored decision framework is a planned approach to decision making over time that draws on long-term field measurements for input, with planned analysis of the measurements and appropriate contingent actions (D'Appolonia, 1990). The framework is designed to deal with uncertainties in the geological storage system and making project design decisions with the knowledge that planned long-term observations and their interpretation will provide information to decrease these uncertainties. The framework is also designed to provide contingencies for all envisioned outcomes of the monitoring program.

Some elements of the monitored decision framework are already implemented as normal practice in subsurface waste disposal or oil and gas activities. The difference in the context of geological storage of CO_2 is the need (and likely a requirement soon) to confirm the "science" of storage and to ensure adequate storage permanence. These drivers demand monitoring programs that inform operating practices but provide value-added knowledge on the evolution of the CO_2 storage processes.

Systematic approach to planning monitoring programs

The purpose of geological storage monitoring is to:

- "Truth" the predictive capability of the simulators;
- Validate the physics of the storage process;
- Reduce uncertainty associated with reservoir parameters;
- Identify and validate hydrodynamic, ionic, mineral, solution or residual gas storage mechanisms in oil and gas reservoirs and aquifers;
- Correlate operational issues with aquifer and caprock behavior (e.g., high injection pressures leading to caprock hydraulic fracture); and
- Satisfy regulatory and public safety concerns.

These general attributes of monitoring can be classed into three distinct mandates:

- **Operations** – involve monitoring / controlling actual *in situ* processes by changes in the injection/production strategy based on the measured variables. There are minimal regulatory requirements; and the need for additional operations monitoring is determined by the complexity of the injection/production scenario. Operational monitoring is generally concerned with migration;
- **Scientific or Verification** – involves measurements that improve the understanding of complex processes occurring *in situ*. Scientific or verification monitoring is generally concerned with migration and leakage. This currently is a major focus of effort in geological storage research; and
- **Environmental** – involves monitoring aimed at safeguarding against health, safety and environmental risks. Depending on the risk level of the project, aspects of environmental monitoring may be part of operational monitoring scenarios. Environmental monitoring is generally concerned with seepage.

Figure 9.13 provides a schematic illustration showing the progression from operational monitoring through to environmental monitoring. Inherent within the monitored decision framework, is an effective fully integrated monitoring program, whether for operational, verification or environmental reasons. Planning a monitoring program should be a logical and comprehensive engineering process that begins with defining an objective and ends with planning how the measurement data will be implemented (Dunnicliff, 1998). The following sections provide a brief description of the steps that should be followed in developing the monitoring programs embodied within the monitored decision framework.

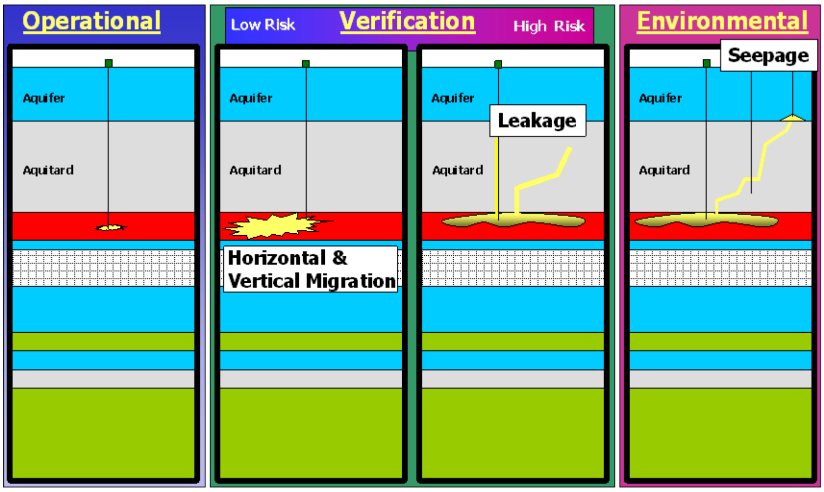

Figure 9:13: Operational, verification and environmental monitoring levels (after Chalaturnyk and Gunter, 2004).

There are a number of steps involved in designing a systematic approach to planning monitoring programs:

- Defining project conditions;
- Predicting mechanisms that control behaviour;
- Answering technical questions;
- Selecting parameters to be measured and identifying their role in answering technical questions;
- Determining the magnitude of expected change in parameters;
- Selecting instrumentation and monitoring approaches/systems;
- Selecting instrument or monitoring locations; and
- Determining timeframes and the depth for monitoring.

Each of these will be explained in more detail below.

Definition of project conditions

In the context of geological storage projects, defining project conditions is a necessary first step in the regulatory application process. For example, in Alberta, applications for acid gas injection operations must conform to a set of specific requirements given in Chapter 4.2 of EUB Guide 65 (2000). These requirements include geological interpretation of the acid gas disposal formation and bounding formations; analysis of reservoir fluids and injected stream; geological properties of the formations, and so on. In essence, the regulatory process can provide the majority of the information required to plan the monitoring program. Depending on the reasons for monitoring, however, additional information may be required and should be collected at this stage in the planning process.

Prediction of mechanisms that control behaviour

This second step involves developing working hypotheses about the important mechanisms that control the behaviour of injected CO_2. This has been studied extensively over the last decade and from a risk assessment perspective. This step is similar to the features, events and processes (FEPs) identification stage prior to performing risk analyses.

Technical questions to be answered

This step is perhaps the most critical step in the systematic development of a monitoring program for a particular geological storage project. This is because selection of an appropriate measurement method and/or the selection of instrumentation is based on whether it can provide the data necessary to answer a particular technical question. If there is no question to answer, there should be no instrumentation. This applies equally to all three monitoring scenarios: operations, verification and environmental. For example:

- **Operational questions** can be as simple as “what are the wellhead injection pressures?” or “what is the distribution of CO_2 within the reservoir?”
- **Verification questions** may pose the identical question, for example “what is the distribution of CO_2 within the reservoir?”, with the only distinction being the degree of resolution required to answer the question.

Select parameters to be measured and their role in answering technical questions

The range of physical processes active in geological storage is large and identifying measurable parameters to help explain these processes is difficult. Parameters such as pressure, temperature, load, deformation, acoustic velocity, and resistivity are commonly selected. Rock-fluid parameters such as conductivity, pH, ionic strength, stable isotopes, and mineralogy begin to identify more complex parameters that aid in answering specific questions. These parameters are referred to as ***performance measures***.

Determining the magnitude of change expected in parameters

Predictions or estimates of the maximum possible value of a parameter provide limits on the instrument range and an estimation of the minimum value of a parameter. This makes possible the selection of appropriate instrument sensitivity or accuracy. Parametric studies with the models or analysis tools that will be used throughout the project can provide valuable input to assist in establishing the range, accuracy and sensitivity required of an instrument. The uncertainty and variability expected in a performance measure must also be quantified.

Select instrumentation and monitoring approaches/systems

Instrument selection should recognize any limitations in skill or quantity of available personnel and should consider the implications of construction, installation and long-term needs and conditions. Criteria established for operations monitoring may be quite different from environmental monitoring and may entail selection of two different monitoring methods. Monitoring approaches or systems refers to the selection of techniques, rather than instruments, within a particular approach. However, instrument selection remains an important step.

Timeframes and Depth of Monitoring

The previous discussion raises a number of outstanding issues which must be addressed, namely:

- How should monitoring tools be assessed (geophysical versus geochemical)?;
- At what depth should monitoring occur?;
- How should the type of monitoring be identified (remote versus *in situ*)?; and
- How should the frequency of monitoring be defined?

The focus of monitoring depends on the phase of monitoring (operational, verification or environmental) and the particular mechanism (migration, leakage or seepage correlating with depth in the subsurface) being measured. Risks in all three have consequences.

The frequency with which monitoring is undertaken is also an important design element in the monitored decision framework. Currently, regulatory agencies focus mostly on 25 years. This is the time period approved for waste fluid injection (of which CO_2 would be an example) into depleted hydrocarbon reservoirs or deep saline aquifers. The lifetime of the injection operation is limited by the reservoir capacity and the injection rate. During injection and abandonment, issues are safety, well integrity, caprock integrity and monitoring. Operating, shut-in and abandoned wells in the vicinity of the injection well which may be contacted by the waste fluids have to be identified and assessed for leakage potential both in the short-term (during injection) and the long-term (after abandonment of the reservoir or aquifer). The definition of ‘long-term’ is based on perceived risk of leakage, which is expected to decrease towards a stable condition as the pressure decays after injection ceases. TNO and ECN (2003) provide certain guidelines to approach the time framework for monitoring, as illustrated in Figure 9.14.

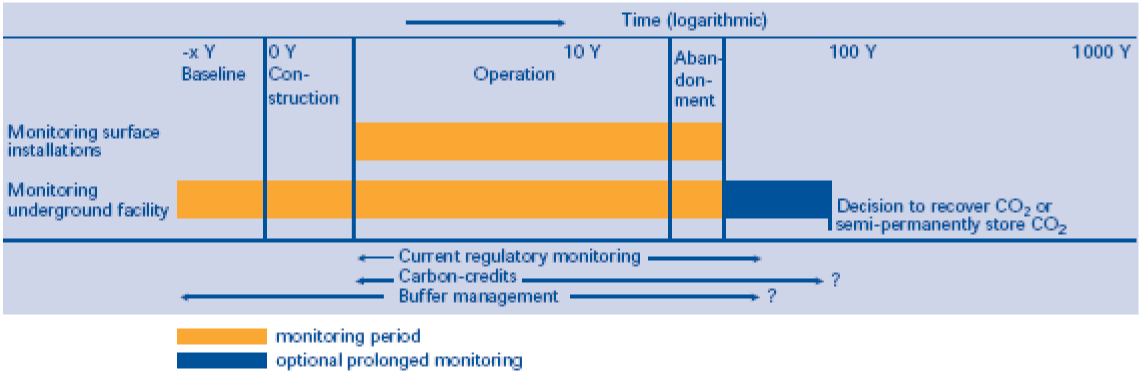

Figure 9.14: Timeframe of monitoring (after TNO and ECN, 2003).

Remediation

Most of the knowledge in remediation for geological storage comes from experiences in underground gas storage. If gas leaks, appropriate remediation measures should be taken to stop or reduce the leaks. Generally repairing or plugging the leaking wells is sufficient to eliminate the problem. If the leaks are not related to well damage (i.e., they are caused by high storage pressures or an inadequate geological framework), the pressure in the storage aquifer or reservoir might have to be reduced (Benson et al., 2002). Similar actions will be used in the case of a leaking CO_2 storage project.

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Module 10

Regulatory and legal aspects of CO_2 storage

Original text by J. Stephens & D. Keith, APEC Capacity Building in the APEC Region, Phase ll
Revised and updated by CO2CRC

Overview

Injecting large quantities of CO_2 into subsurface reservoirs creates a host of new risks that need to be addressed within a regulatory framework. Module 8 discussed the nature of these risks and this module discusses regulatory approaches to management of them. These risks occur at two scales: local risks associated with human or ecosystem health and global risks relating to re-release of CO_2 into the atmosphere.

Learning objectives

By the end of this module you will:

- Understand the role of regulation in both managing the risks of CO_2 storage as well as promoting or discouraging uptake of the technology;
- Understand the requirements of effective regulation related to CO_2 injection and storage;
- Be familiar with international legislation or agreements which could have relevance to CO_2 injection and storage; and
- Appreciate some of the challenges of regulating CO_2 injection and storage.

Regulation as a tool for managing risk

As discussed in Module 8, health and safety risks associated with CO_2 storage may occur at local and global scales. The local health, safety or environmental risks in the region where the CO_2 is being stored can be appropriately managed through regulations. Global risks may require the development of an international regulatory regime to ensure consistent monitoring practices and accurate reporting of reduced or avoided global CO_2 emissions associated with each CO_2 storage project. International regulation may also be required to manage the risks associated with storing CO_2 in geologic formation beneath the sea floor in areas where no single economy has jurisdiction.

In addition to serving as a tool to manage risk, regulation also will play a critical role to promote or frustrate CO_2 storage projects. While many CO_2 storage projects are already underway, the initiators of current projects each have unique research goals and/or funding opportunities which have provided the incentive for their projects. Before CO_2 storage becomes common or widespread on a scale that would be required to actually reduce or stabilize the atmospheric CO_2 concentration, regulation designed to put a real cost on CO_2 emissions will need to be in place. Only when governments impose restrictions on CO_2 emissions, through economic mechanisms such as taxes, tradable permits or credits, will the additional costs associated with capturing and storing CO_2 be incurred by industry on a large scale.

Regulation in APEC economies

Several APEC economies are currently developing or have passed regulation relating specifically to CO_2 injection and storage, including addressing the issue of long-term liability (Hoversten, 2009).

In Canada, injection of CO_2 for EOR and acid gas injection is allowed in some states. These CCS operations have been in place for some time under legislation for petroleum, mining and natural resources. Suggestions for new CCS regulations have been proposed in the by the EcoENERGY CCS Task Force.

In the United States, the Safe Drinking Water Act regulates all underground injection activities (Underground Injection Control (UIC)). The activities must ensure zero movement of the injected material into underground sources of drinking water. The EPA has developed a draft rule for CO_2 storage based on the UIC and has created a new category of injection well for compressed CO_2 for storage. The draft rule covers site characterisation to post-injection site care and closure. The rule will be enacted in late 2010. Various US states are developing legal frameworks for CCS including New York State, North Dakota, Montana, Illinois and Texas Wyoming and Washington State. Wyoming was the first state to pass specific legislation for storage of CO_2 for within the UIC (Kerr et al, 2009). In addition, there is a proposed Federal bill to allow commercial demonstration of CCS which has provisions for the Secretary of Energy to be responsible in the long term for the injection site including monitoring and remediation, and the possibility of indemnifying the project owner from liability.

Australia has adopted the Offshore Petroleum Amendment and GHG Storage Act (2008). The Act provides provisions for greenhouse gas leases, greenhouse gas pipelines, and injection licences for offshore storage of GHGs. The injection licences will cover comprehensive site plans, monitoring, measurement and verification. At the end of injection, the licence holder must assess the migratory behavior of the GHG and recommend an approach to monitoring the stored GHG. A Site Closure Certificate is then issued and after a minimum of fifteen years long-term liability can be transferred to the government if the GHG is safely stored and behaving as predicted. The Act also deals with the potential impacts of greenhouse gas storage on petroleum title holders.

Individual Australian states have passed laws allowing storage of CO_2 onshore

- The Victorian Greenhouse Gas Geological Sequestration Act 2008 permits storage of greenhouse gas substances subject to environmental and public health considerations and with monitoring and verification requirements. Once the government is satisfied that the GHG is behaving as predicted, the government will take over monitoring and verification, but the issue of liability is uncertain.
- The Greenhouse Gas Storage Act 2009 covers onshore storage in Queensland with provisions for exploration permits to assess potential storage formations and injection and storage leases. After injection, the lease is surrendered once an extensive monitoring report has been approved. Long-term liability potentially rests with the leaseholder.
- The South Australian government amended the Petroleum act to allow storage of CO_2 but the issue of long term liability is not covered.
- Western Australia has specific legislation for the Gorgon Project, which will store CO_2 from the Gorgon LNG Project The Australian Government announced that it would share long term liability for the stored CO_2 with the Western Australian Government on the basis of a 80:20 Federal-State ratio.

Japan has offshore CCS activities regulated by amendments to an existing law – the Law Relating to the Prevention of Marine Pollution and Maritime Disaster.

In the **European Union**, a series of directives on CCS have been passed. These allow for CCS under the IPCC GHG Guidelines and OSPAR (see below) with the objective of permanently storing CO_2. The directives cover access to transport networks, site selection, characterisation, risk assessment, monitoring, corrective measures, post-closure, financial security and liability.

CCS is carried out offshore in **Norway** as part of the Sleipner and Snøhvit projects under the Norwegian Petroleum Act and the Pollution Control Act.

In economies without specific legislation for CCS, laws relating to underground injections provide experience that can help in the development of appropriate regulations for CO_2 storage, and/or act as an existing framework within which CO_2-specific regulations can be instituted within that economy. In some economies around the world, injection of waste underground is a regulated method for waste disposal. A common practice for disposing of acid gas, a mixture of H_2S and CO_2, involves injecting it underground. In addition to waste disposal, CO_2 is currently being injected into the subsurface to enhance oil recovery (EOR). While some monitoring of the injected gas is required in some instances, existing laws do not require the same extent of monitoring and storage assurances that would be required for CO_2 storage.

Guidelines for building an effective regulatory system

An effective regulatory system must take into consideration the additional attributes of CO_2 injection and storage as well as the evolving nature of the technology.

Although CO_2 injection and storage is similar in some respects to common practices that are regulated, they also have unique attributes that must be reflected in regulation. These unique attributes include:

The scale of the activity – CO_2 projects will be larger in scale than most activities currently covered under legislation;

The need to monitor and verify containment and leakage of the buoyant fluid – not all existing regulations require monitoring and verification of containment to take place, many regulations for underground disposal were designed to manage liquids rather than buoyant gasses; and

Different risk management requirements - CO_2 storage poses risks that are different from many of the other fluids that are now disposed of underground.

Regulation needs to be responsive to the evolving nature of the technology. Some of the key issues related to the degree of development of the technology are:

Uncertainties associated with containment – This is a key factor associated with the effectiveness of geological storage. Regulation designed to manage CO_2 storage should be adaptive and should emphasize learning-by-doing;

Be flexible to ensure safety but enable learning to take place - In the near term, a regulatory framework for managing geological storage must ensure projects provide acceptably safe CO_2 storage while maximizing the ability to learn through experience. Regulations must also be flexible to enable effective management of the diverse array of possible storage projects, accommodating both diversity in scale and diversity in the geological setting ;

Provide access to data - Provisions related to access to data, including the ability to gather new data, could be built into the rules under which existing facilities should be incorporated into a CO_2 storage protocol; and

Enable public input and comment - Strong public concerns about the local and global risks of CO_2 storage and also about the wisdom of using CO_2 storage as a means to continue the use of fossil fuels should be anticipated. As such, another critical condition is that the management of CO_2 storage should be transparent Information about all projects should be made available to the public and input from the public should be facilitated.

Existing international laws

An economy's regulation relevant to CO_2 storage should be consistent with international laws related to CO_2 injection and storage. This section outlines existing international regimes and explains their relevance to CCS. International laws are particularly critical for managing the risks associated with CO_2 storage in geologic areas underneath oceans where no single economy has complete jurisdiction.

- **The United Nations Framework Convention on Climate Change (UNFCCC)** and the **Kyoto Protocol** place requirements on signatories to reduce greenhouse gases, among other commitments. Both agreements anticipate, and could encourage, the practice of CO_2 storage. Nonetheless, neither the text of the Convention or the Protocol explicitly provide for storage to be used in order to meet greenhouse gas emission reduction commitments at this time (see Module 11).
- The **London Convention** and is an international treaty that entered into force in 1975. It prohibits "dumping" in the ocean, defined as: "any deliberate disposal at sea of wastes or other matter from vessels, aircraft, platforms or other man-made structures". **The London Protocol** has succeeded the London Convention in March 2006 and expands the definition of "dumping" to apply to all marine waters and the seabed and subsoil thereof. It was amended in 2006 to cover CO_2 streams from CO_2 capture processes for sequestration. The amendment allows sub seabed geological

storage, injected matter must be overwhelmingly CO_2 and there should be no other wastes added. However, some other substances are allowed to be in the CO_2 stream if they are derived from the source or the process or they enable or improve the CCS process. There are issues still to be resolved in relation to transport of CO_2 across boundaries and subsurface migration of CO_2 (Dixon, 2009).

- The **Convention for the Protection of the Marine Environment of the North-East Atlantic** (OSPAR Convention) is a regional convention that could be relevant to geological CO_2 storage. OSPAR requires its Contracting Parties to take all possible steps to prevent and eliminate pollution from land-based sources of dumping or from offshore sources. In 2007, amendments were adopted to allow for CO_2 storage in sub-seabed reservoirs (Kerr et al, 2009).
- **The Basel Convention** is designed to control the transboundary movement of hazardous wastes and other wastes by requesting consent from both the economy of origin and the destination economy. Within this convention, the transboundary movement of hazardous wastes and other wastes from OECD economies to non-OECD economies for the purpose of disposal and recovery and recycling is prohibited. The current language of the Convention does not provide any indication that CO_2 captured from fossil fuel combustion sources would be defined as hazardous waste, and only if it were would the restrictions of the Basil Convention apply.
- **The Convention on Biological Diversity** requires its Contracting Parties to take measures toward the conservation and sustainable use of marine biological diversity. Leakage from CO_2 storage sites could affect marine biological diversity, and therefore could be seen as opposing the Convention. When undertaking a geological CO_2 storage project in a economy that has signed the Convention, or promoting its use, proponents would be obliged to review the components identified by their economy as important for conservation and sustainable use, identify how CO_2 capture and storage projects might have significant adverse impacts on the conservation and sustainable use of significant biological diversity, and monitor its effects.
- **The United Nations Convention on the Law of the Sea** (UNCLOS) (1994). UNCLOS is a global framework convention that has, among other things, established areas of coastal jurisdiction for coastal States. Several articles of UNCLOS define States' obligations to protect the marine environment, making it possibly relevant to geological CO_2 storage in offshore subsurface geological reservoirs. Under UNCLOS, States must take measures to prevent, reduce and control pollution of the marine environment. An additional section of UNCLOS specifies that marine scientific research must be conducted in compliance with all relevant regulations, which could restrict the research and demonstration of CO_2 storage in off-shore environments. Freedom of navigation, the laying of cables and pipelines, and the construction of artificial islands and other installations are allowed provided that have regard for the interests of the other states.

International guidelines

Consistent international methodologies to estimate monitor and report physical leakage from CO_2 storage sites still need to be developed and adopted at the within an economy's legislation. Aiming for a storage performance of more than 99% of the stored CO_2 likely to be retained over the first 1000 years (IPCC, 2005) presents a regulatory challenge.

The Intergovernmental Panel on Climate Change (IPCC) 2006 Guidelines for GHG Inventories provides reporting guidelines and standards for actual annual emissions of greenhouse gases by gas and by sector. These guidelines also include a methodology for CCS which covers site characterisation, risk assessment, monitoring and reporting (see Module 9).

Both the London Protocol and OSPAR have guidelines for risk assessment and management.

Summary

Regulation is an important tool in managing the risks from CO_2 storage. Regulations at all levels of government will be required. In addition, regulation will serve as a means of promoting or frustrating CO_2

storage projects. The technology cannot be successfully widely applied without an effective regulatory system.

The scale of CO_2 storage activities, the timeframe under which they operate, their need for long-term monitoring and their potential impacts make CO_2 storage a unique regulatory challenge.

Economies such as Canada, the United States, Japan and Australia, as well as the European Union and Norway are some of the economies that have established regulations or are currently developing regulations relating to geologic CO_2 storage.

To account for the unique attributes of CO_2 storage, regulation must:

- Take the scale of activity into account;
- Provide provisions for monitoring and verification of CO_2 containment; and
- Address the increased risks.

CO_2 storage regulation should:

- Be highly adaptive;
- Take a “learning by doing” approach;
- Ensure CO_2 storage meets acceptable safety standards;
- Enable access to data;
- Apply to diverse scales and geological settings;
- Be highly transparent; and
- Provide for public input and comment.

Commitments made through international treaties, agreements and regulations must be reflected, or not compromised, in internal CO_2 storage regulation. International treaties with text relevant to CO_2 injection and storage are:

- The United Nations Framework Convention on Climate Change (UNFCCC) and the Kyoto Protocol;
- The London Convention and London Protocol; and
- The Convention for the Protection of the Marine Environment of the North-East Atlantic (OSPAR).

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OSPAR Guidelines for Risk Assessment and Management of Storage of CO_2 Streams in Geological Formations (Document on CD)

University College London's Carbon Capture Legal Programme website: www.ucl.ac.uk/cclp/ccsprotcol.php

Basel convention http://www.basel.int/convention/about.html

Convention on Biological Diversity http://www.cbd.int/

Module 11

The Clean Development Mechanism

Original text: L. Morgan, APEC Capacity Building in the APEC Region, Phase II
Update on CCS in the CDM by CO2CRC

Overview

The Clean Development Mechanism (CDM) is an instrument under the Kyoto Protocol which could enable CO_2 capture and storage projects to receive an additional revenue stream and become more economically viable. This module will assist the reader to gain familiarity with the CDM and associated components.

Learning objectives

By the end of this module you will:

- Be familiar with the Kyoto Protocol and the Clean Development Mechanism;
- Know the eligibility requirements for a project to become a CDM project;
- Understand the partners needed to undertake a CDM project;
- Have an understanding the CDM project cycle and its various requirements; and
- Understand the current progress to recognising CO_2 capture and storage as a CDM project.

Introduction to the Kyoto protocol and the Clean Development Mechanism

In 1992, international collaboration on climate change reached a new level when 186 economies agreed in Rio de Janeiro to limit or reduce greenhouse gas (GHG) emissions by ratifying the ***United Nations Framework Convention on Climate Change*** ***(UNFCCC)***. This was in response to growing evidence that human activity was contributing to global warming. The Framework Convention on Climate Change sets an overall framework for intergovernmental efforts to tackle the challenge posed by climate change. The Convention also provides for the dissemination of educational materials for the general public, assistance to developing economies to adapt to climate change, and a forum to quantify and report on emissions.

After several years of negotiations, the international community came together again in Kyoto, Japan in December 1997 and reached agreement on the ***Kyoto Protocol***. The Kyoto Protocol is the instrument under the UNFCCC that set legally binding targets for reducing ***greenhouse gas (GHG)*** emissions, and put in place mechanisms to realize the objectives of the UNFCCC. Only industrialized economies (referred to in this module as "***Annex 1 economies***") that ratify the Protocol commit themselves to limiting their emissions of six greenhouse gases:

- Carbon Dioxide (CO_2);
- Methane (CH_4);
- Nitrous Oxide (N_2O);
- Hydrofluorocarbons (HFCs);
- Perfluorocarbon (PFC); and
- Sulfur hexafluoride (SF_6).

Taken together, all Annex 1 economies are obliged to reduce their combined GHG emissions by 5.2% compared to 1990 levels in the period 2008-2012. This time period is known as the First Commitment Period. Developing economies (referred to in this module as "Non-Annex 1 economies") do not have emission reduction targets for the First Commitment Period. The Kyoto Protocol came into force on February 16th, 2005.

Formal negotiations are taking place under UNFCCC on finding a replacement for the Kyoto Protocol as the commitment period for the Kyoto Protocol will end in 2012. A series of UNFCCC meetings have taken place throughout 2009, prior to the United Nations Climate Change Conference (COP 15) in Copenhagen, 7-18 December, 2009. In addition, there are parallel initiatives led by governments and research institutes to develop the new agreement on global cooperation to reduce GHG emissions.

The Clean Development Mechanism

The Kyoto Protocol includes three flexibility mechanisms to enable its implementation. These mechanisms provide economically efficient alternatives for Annex 1 economies to reduce GHG emissions and meet their Kyoto targets. This module focuses on only one of these flexibility mechanisms: the Clean Development Mechanism (CDM). CDM projects are initiatives that result in a reduction of greenhouse gases. These projects must be implemented by Annex 1 economies in Non-Annex 1 economies where both parties have ratified the Kyoto Protocol. It also may be possible for Non-annex 1 economies to develop CDM projects to sell the credits they generate. This concept – called "unilateral CDM" is under debate. Article 12 of the Kyoto Protocol says that the CDM is intended to:

- Assist developing economies to achieve sustainable development;
- Assist industrialized economies to fulfill their emission reduction obligations under the Kyoto Protocol; and
- Contribute to global greenhouse gas reductions.

CDM projects allow companies or organizations in Annex 1 economies another option outside of domestic action for meeting their emission reduction target. They offer companies or organizations in Non-Annex 1 economies with access to more efficient technology and processes, and the opportunity to reach sustainable development goals. By investing in CDM projects in Non-Annex 1 economies, investors from Annex 1 economies can buy the ownership of Certified Emission Reductions (CERs) from the Non-Annex 1 economy project partner that owns them. CERs can used to meet the GHG reduction commitments of Annex 1 economies under the Kyoto Protocol. Thus, CDM projects help both developed and developing economies to work together to achieve sustainable development and decrease GHG emissions.

The mechanism has already registered more than 1,000 projects since becoming operational at the beginning of 2006 and is anticipated to produce certified emission reductions amounting to more than 2.7 billion tonnes of CO_2 equivalent in the first commitment period of the Kyoto Protocol, 2008–2012. (UNFCCC website)

CO_2 capture and storage as a CDM option

The status of CO_2 capture and storage (CCS) projects under the CDM is still under review. A decision was due at Poznan in 2008 but the move to include CCS in the CDM was blocked. The matter is still under consideration.

The debate about whether CCS should form part of the CDM is centered around issues including:

- the role CCS plays in climate change mitigation;
- long-term liability;
- potential leakage;
- the impact of CCS projects on the CDM market; and
- how CCS will affect sustainable development by continuing the use of fossil fuels

The Conference of the Parties serving as the Meeting of the Parties (COP/MOP) to the Kyoto Protocol (CMP) invited intergovernmental organisations (IGOs) and non-governmental organisations (NGOs) to provide to the secretariat, by 31 May 2007, information on the following issues relevant to the consideration of CCS under the clean development mechanism (CDM):

Technical issues considered in relation to CCS projects as CDM projects

- Long-term physical leakage (seepage) levels of risks and uncertainty.
- Project boundary issues (such as reservoirs in international waters or several projects using one reservoir) and projects with operations across boundaries.
- Long-term responsibility for monitoring the reservoir and any remediation measures that may be necessary after the end of the crediting period.
- Long-term liability for storage sites.
- Accounting options for any long-term leakage (seepage) from reservoirs.
- Criteria and steps for the selection of suitable storage sites with respect to the potential for leakage of greenhouse gases (GHGs).
- Potential leakage paths and site characteristics and monitoring methodologies for physical leakage (seepage) from the storage site and related infrastructure, for example, transportation.
- Operation of reservoirs (for example, well-sealing and abandonment procedures), dynamics of carbon dioxide (CO_2) distribution within the reservoir and remediation issues.
- Any other relevant matters, including environmental impacts.

The first synthesis report, prepared in response to this request, was considered by the Subsidiary Body for Scientific and Technological Advice (SBSTA) at its twenty-eighth session. In addition, the SBSTA, at its twenty-seventh session, invited Parties, IGOs and accredited NGOs to submit to the secretariat, by 16 June 2008, their views on technological, methodological, legal, policy and financial issues additional to those listed above. The synthesis report was presented at Poznan in December 2008.

Summary of the report: (available at http://unfccc.int/resource/docs/2008/sbsta/eng/inf03.pdf)

Technical issues

- Broad agreement that understanding potential leakage paths, including consideration of potential leakage pathways beyond the near-term project boundaries, is critical.
- Conflicting views on whether there is sufficient experience with CCS, particularly relating to risks of leakage.

Methodological issues

- Broad agreement that emissions associated with the energy required for CCS should be included within the project boundary, that strict site selection criteria are critical and that site selection processes should draw on the 2006 IPCC Guidelines and the SRCCS for information on site selection and site characterisation methods.
- Conflicting views on whether sites can be selected to isolate CO_2 from the atmosphere safely over very long periods of time, whether project boundaries can be practically defined for CCS and whether the current CDM modalities and procedures could be applicable to CCS.

Legal issues

Broad agreement that robust legal frameworks and legislation are necessary, that regulations are needed for post-closure obligations, that capacity-building is needed for non-Annex I Parties on various aspects of CCS project approvals and that there are several key types of liabilities (e.g. for any local damage from CO_2 seepage, or climate damage from release of CO_2 to the atmosphere).

Conflicting views on whether CCS activities fit within the modalities and procedures of the CDM, whether CCS activities fulfill the purpose of the Convention and Kyoto Protocol, whether the CDM institutional structures are sufficient for CCS projects and the size of financial liabilities potentially posed by CCS projects.

Policy issues

- Broad agreement that CCS is an important part of the overall portfolio of GHG mitigation options, whether it is in the CDM or not.
- Conflicting views on who should undertake CCS demonstration, whether there should be a pilot phase for inclusion of CCS as a CDM project activity, how to account for potential long-term seepage, the probability of major seepage events and whether it is necessary or possible to manage the risk of seepage over the long term.

Financial issues

- Broad agreement that additional financing is required for projects with CCS as compared with equivalent projects without CCS.
- Conflicting views on whether inclusion of CCS as a CDM project activity will adversely affect carbon market prices, the degree to which CCS will develop without carbon market incentives, whether the CDM is the appropriate vehicle to provide seed finance for emerging technologies such as CCS, the degree to which CCS inclusion as a CDM project activity could result in more fossil fuel consumption and whether CCS will negatively affect the equitable distribution of CDM projects.

There was general agreement that capacity-building is required for CCS projects for non-Annex I Parties in the areas of technical assistance, and design and implementation of effective regulations.

No agreement was apparent on the degree to which CCS contributes to sustainable development; whether the current CDM institutional structure is sufficient to handle CCS; or whether CCS would result in coal and gas displacing less-carbon-intensive fuels.

The Executive Board of the CDM is still considering the issues relating to the inclusion of CCS into the CDM.

Eligibility requirements for the CDM

In order to be eligible to qualify under the Kyoto Protocol, a CDM project must meet the following requirements:

- **Generate real, measurable and verifiable GHG reductions**. The project must be able to measure and report the amount of GHGs it reduces (in tonnes). The process used for doing this must be verifiable by an independent party. The project also can not cause GHGs to increase in another location. For example, the project cannot displace emissions across a border **-** this is known as "***leakage***".
- **Gain approval from the host economy that is a party to the Kyoto Protocol**. Each Non-Annex 1 economy that has ratified the Kyoto Protocol has a ***Designated National Authority*** (DNA) that is authorized to accept or reject proposed CDM projects. In order to secure this approval, project developers will be required to demonstrate how the project contributes toward the sustainable development objectives of the Host Economy. The DNA should publish information on which sustainable development objectives it requires projects to meet.
- **Projects must contribute to emissions reductions above and beyond business-as-usual.** This is called ***additionality***. The Kyoto Protocol specifies that only those "reductions in emissions that are additional to any that would occur in the absence of the certified project activity" will be eligible to earn CERs (UNFCCC (4), 1998). To receive credits for a carbon offset project, it will be necessary to demonstrate that the project would not have been undertaken were it not for its emission reduction benefits.

In addition, participation in CDM requires that:

- Both participating economies have an assigned authority for the CDM;

- Both parties undertake the initiative voluntarily;
- CDM projects must include the participation of stakeholders;
- The project must not cause any degradation in local social, economic or environmental domains;
- Any technologies that are transferred during the project to developing economies must be appropriate to their needs and business environment; and
- Parties must be able to prove that the CERs generated are owned by the party selling them. The owner of the credits needs to be identified and involved in all contract negotiations around transferring ownership of the CERs.

If a proposed CDM project does not meet these basic criteria, it will not be officially classified as a CDM project, nor will it be eligible under the Kyoto Protocol to earn CERs.

Who is involved in a CDM project?

There are numerous organizations that will be involved in process of developing and approving a CDM project. A quick snapshot of key players and their roles is listed below:

- **Project developers** are the owners and managers of companies looking to develop and operate a project that will result in CERs. These will include parties from both the Non-Annex 1 economy (the seller) and the Annex-1 economy (the buyer).
- **Technology providers** are suppliers of environmental and support technologies and services that provide technology, support or expertise that will lead to reductions of GHGs.
- **CDM experts** provide essential insight into the development of various components of the project such as baselines, preparation of the ***Project Design Document*** (PDD), ensuring project design will meet host economy approval requirements, public engagement, etc. This will be covered in more detail in the section entitled: Overview of the CDM Cycle.
- **The public** includes individuals, groups or communities that are affected or likely to be affected by the proposed project. There is a specific requirement for a CDM project to consult local stakeholders for input and comment.
- **Investors** support CDM projects through the investment of capital. They will typically be located in an Annex 1 economy, but not always. CDM initiatives may provide new options that are attractive to investors. Some investors will require that all or a portion of the CERs are transferred to them as part of their investment.
- The **Designated National Authority (DNA)** is a governmental agency or department which handles all matters relating to the development of CDM projects in the host economy. The DNA takes part in the validation process and must officially approve any CDM project that takes place in the economy. It also is responsible for administering CDM implementation. The UNFCCC website maintains a list of Designated National Authority contacts.
- The **CDM Executive Board** is part of the UNFCCC process. It oversees the development of rules and procedures supporting the CDM such as emission monitoring methodologies, baseline methodologies, and emission reduction verification procedures. It also is responsible for approving CDM methodologies, registering approved projects as CDM projects, and accrediting Operational Entities (described below). It is responsible to report back to the Parties on its decisions. This board consists of 10 members, plus 10 alternates.
- **Operational Entities** (OEs) are domestic or international legal companies that carry out the verification and validation of a registered CDM project activity. OE’s must first become designated by the CDM Executive Board before they are able to officially carry out these functions. A list of approved operational entities is maintained on the UNFCCC website.

Overview of the CDM project cycle

CDM projects have a formalized series of protocols for project proponents to follow if they who wish to have their projects declared CDM eligible under the Kyoto Protocol and want be able to sell their emission reduction credits on the international market. The steps required for this certification can be simplified into five major steps (Figure 11.1):

- Project design and the project design document;
- Host economy approval;
- Validation and registration;
- Implementation and monitoring;
- Verification and certification; and
- Issuance of CERs.

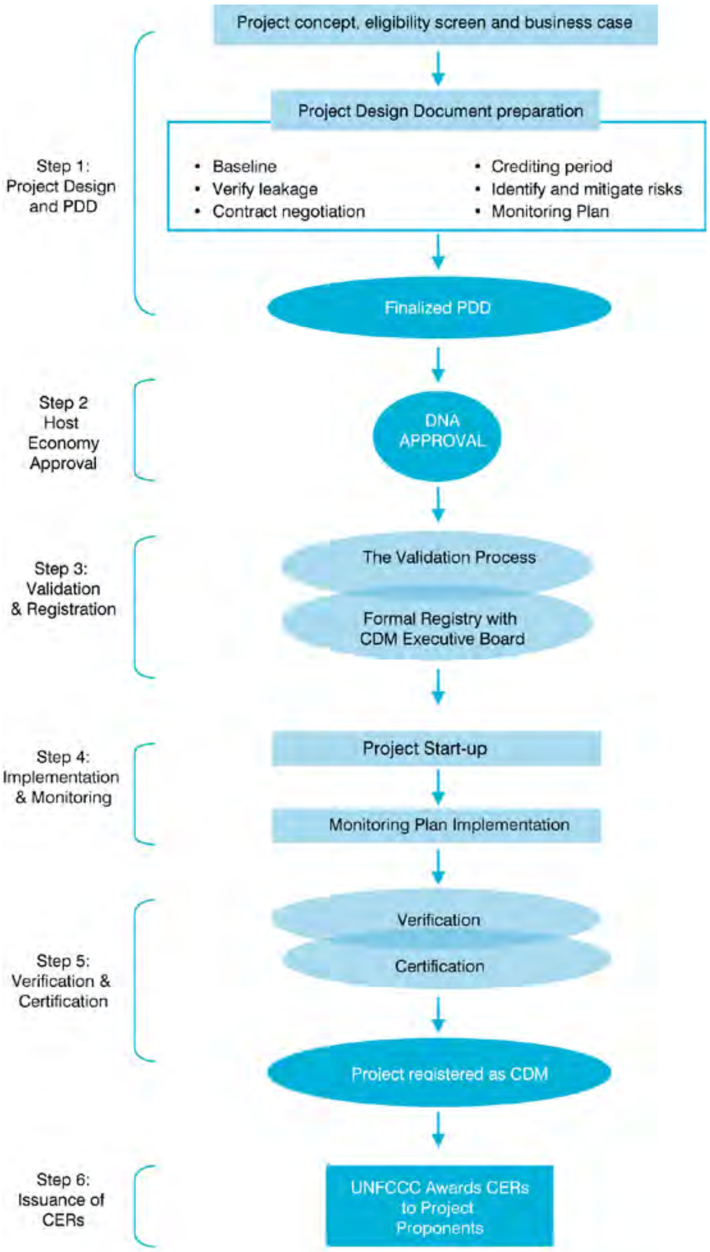

Figure 11. 1: The CDM project cycle.

Step 1: Project design and the project design document

Design of a CDM project involves a number of specific steps which help proponents to evaluate the potential of the project to gain host economy and CDM Executive Board approval, its economic and technical feasibility, and risks and monitoring issues of importance. All of this also is necessary to prepare the Project Design Document (PDD). The PDD is the principle document required to gain approval for a CDM project.

After identifying a potential project, the following must be undertaken:

- **Establish the baseline** – this is one of the most important stages of CDM project development. The project ***baseline*** represents the projected GHG emissions of a company, business unit or activity over a defined period of time under business-as-usual conditions. The business-as-usual forecast takes into consideration the economic, political, and technological conditions within which the implementing entity - a company, village or public utility for instance – would have operated within the established timeframe of the project if the project had not taken place. Comparing the established baseline to the estimated (or actual) GHG emission reductions generated by the project will provide an indication of the number of GHG reduction credits that might be generated annually by the project or over the life of the project. The project developer must document in a clear, logical fashion the rationale, parameters, assumptions and processes used to establish the projected emissions under the business-as-usual scenario. This will help facilitate future validation and certification of emissions reductions.

  Calculating the baseline includes defining the project boundaries. These boundaries clearly identify the sources and sinks of all GHGs that the project will reduce, and set the physical limits of the area in which the emissions will be reduced. All GHG emissions that are significant and reasonably attributable to the project activity must be included.

  The principal responsibility for defining the baseline lies with the project developer. However, the underlying assumptions and data that support a baseline definition must be derived from national or international entities and archives.

  Overall, the baseline development methods will depend on a number of influential factors such as the accessibility and reliability of relevant data; the location, type and size of project; existing and planned policies, and available resources. In all cases the calculation must be project-specific and take into consideration economic, political, and technological conditions under which the entity implementing the CDM project would have operated over the established timeframe had the project not been undertaken. It also must consider all GHGs within the project boundary from the sectors and sources that will be positively or negatively affected by the proposed CDM project. Emissions are calculated using data sets such as actual or historical emissions, emission profiles of proven technologies that have been or are likely to be introduced, and/or average emissions for similar projects.

  Establishing the baseline is a complex undertaking and should be done in consultation with an expert. The expert will know how other issues such as the chemical composition of the fuel used, the efficiency of fuel conversion, technology characteristics, company operations, coefficients and other elements will influence the resultant baseline.

- **Verify against leakage** – leakage refers to a net change of GHG emissions that occur outside of the project boundary but which are the result of the CDM project. In essence, leakage occurs when CDM projects do not reduce emissions, but rather displace them somewhere outside the project boundary. CDM projects must be able to demonstrate that they will not create leakage of GHG emissions in this way.

- **Negotiation of contractual agreements** – the CDM and the buying and selling of carbon credits are new phenomena. This can increase project risks. Having a legal contract agreement among the main project parties is essential for all proponents. These risks, as well as lost opportunities, are minimized when the key stakeholders in a project, particularly the buyer and seller, negotiate and sign legally binding contracts early in the process that address:

    - Collection, transfer and ownership of the data and information required to establish a baseline and generate monitoring reports;
    - Ownership of rights, title and interest in future GHG reductions;
    - Responsibility for verification;
    - Timelines, quantity, price setting procedures and future credit payments; and
    - Technology transfer and intellectual property.
- Select the crediting period − the project proponent should recognize that the time period during which credits arising from the project can be claimed is not necessary equal to the operational lifetime of the project activity. There are two options for the crediting period:

  A ***fixed crediting period*** has a maximum of 10 years after which CERs will be awarded. The starting date for a fixed crediting period is determined once for a project activity with no possibility of renewal or extension once the project activity has been registered.

  A ***renewable crediting period*** has an initial period of 7 years after which CERs are awarded. This may be renewed a maximum of two times for a total of 21 years. For each renewal, a designated operational entity must determine that the original baseline is still valid or has been updated taking in account new data where applicable.

  Selection of a crediting period should take into consideration:

    - The technical and/or economic lifetime of the technology installation;
    - Project payback time for the investor; and
    - Period during which the project is considered to be additional (technology is not yet a business-as-usual investment).
- **Identification and mitigation of risks** − CDM projects, like any projects, face certain risks. These can be associated with a broad range of issues and conditions, for example:
    - Project and technology performance;
    - Force majeure (unforeseeable events, such as an earthquake, that excuse a party from fulfilling a contract);
    - Management and team skills;
    - Changing market forces; and
    - Political, social and economic instability in the host economy.

Identification of all possible risks and opportunities, and addressing them appropriately in the project agreement, is key to ensuring current uncertainties are manageable under the future regulatory setting.

- Establish a monitoring plan − an effective monitoring plan will have a clear, concise and transparent GHG reduction report providing the necessary information required by the operational entity to verify that the project is proceeding as planned. Project proponents should include a description of the project activities and emission sources to be monitored, the key parameters involved, and the specific monitoring process that is to be undertaken. The monitoring plan should identify and describe:
    - The data sources (type and quality) used to calculate project baselines and estimate emissions removed by the project during the crediting period;
    - All sources of GHGs outside the project boundary that might increase total emission reductions attributed to the project;
    - Environmental impacts that have been addressed by the organization implementing the project;

    - Processes and procedures for collecting required data, measuring all emissions, effectively reporting information on a timely basis and maintaining a high level of quality control;
    - Roles and responsibilities of all those who will take part in the monitoring process; and
    - Quality assurance and control procedures for the monitoring process, and procedures documenting the calculations used to determine leakage.
- Prepare the project design document − all of the elements outlined above are important components of the Project Design Document. The resultant PDD should include the following information:
    - A general description of the project;
    - A baseline derived from an approved baseline methodology;
    - The estimated lifetime of the project and the crediting period;
    - A demonstration of how the project generates emission reductions that are additional to what would have occurred without the CDM;
    - An analysis of the environmental impacts;
    - A discussion of the stakeholder consultation process and how stakeholder comments were taken into account; and
    - A monitoring and verification plan that uses an approved monitoring methodology.

Step 2: Host economy approval

Host economy approval by a Designated National Authority (DNA) is a mandatory step for CDM project proponents before the project can be submitted to the CDM Executive Board for consideration and accreditation as an official CDM project. Each host economy is responsible for setting and publishing criteria against which it will base its approval process. Many, but not all, host economy have finalized this process of criteria selection and publication

Host economy DNAs will typically wish to see that:

The project meets sustainable development objectives, and provides local benefits including benefits to local project partners;

The project is appropriate (e.g.: transfers appropriate technology), desirable and represents positive development, The project is in-line with current and future policies and programs which may influence how the project's baseline is established and how additionality is determined;

Emission reductions achieved through the project are not the lowest cost reductions (referred to as 'low-hanging fruit'), nor are they achievable by the host economy through local technology or know-how; and

Issues surrounding the ownership, rights, title and interest in future GHG reductions, and all related technology transfer and intellectual property issues have been negotiated and agreed upon as outlined in the CDM project's PDD.

Step 3: Validation and registration

Validation involves an independent evaluation of the activities described in the PDD. It is undertaken by an Operational Entity (OE) that has been designated by the CDM Executive Board. Once the PDD has been completed and host economy approval has been received, the PDD is then submitted to an OE for review and approval. Typically this process will involve a detailed examination of the stakeholders involved, calculations of the GHGs mitigated by the project, review of the system used for monitoring, and verification that all the relevant government approvals have been obtained.

The OE will confirm that:

- The Kyoto Protocol participation requirements have been satisfied, including voluntary participation of both parties, DNA involvement, and Kyoto Protocol eligibility;
- Comments by stakeholders have been invited and summarized, and there is an account of the proponent's response to those comments;
- Proper attention has been given to possible environmental impacts from the project;
- Provisions for baselines, monitoring, reporting and verification are in accordance with current standards and approved by the Executive Board; and
- A quantifiable GHG reduction will result from the project.

When submitting a project for validation and registration a project proponent is required to submit information on their proposed CDM project using the approved PDD format and glossary of terms. Project proponents must either:

- Submit a proposal of a new baseline and/or monitoring methodology; or
- Use a methodology that has already been approved by the Executive Board.

In both of these cases the project proponent must submit the PDD to either a designated OE or an applicant entity (from the approved UNFCCC list) for validation. If a previously approved methodology is submitted, the designated OE may proceed directly with the validation process and submit the PDD for registration.

If a new methodology is submitted, the OE will submit the PDD to the Executive Board for their consideration. This includes the following sequential steps:

- The UNFCCC Secretariat makes the proposed new methodology publicly available on the UNFCCC CDM web site and invites public inputs for a period of 15 working days;
- Two members of the Methodology Panel are chosen and responsible for compiling desk reviews of the project and preparing draft recommendations within 10 working days to the Methodology Panel;
- The Methodology Panel prepares recommendations regarding the approval of the proposed new methodology to the Executive Board. The recommendations could be approved with minor changes; approved subject to more major changes; or not approved. The Methodology Panel's recommendations can be technically revised by the Chair & Vice Chair of the panel;
- Return of methodologies that have been approved subject to major changes or not approved. Where changes must be made, the methodology can be resubmitted to the Panel for reconsideration; and
- Submission of methodologies approved by the Methodology Panel to the CDM Executive Board. The Board makes a decision on proposed new methodology and, if approved, will register the project.

Step 4: Project start-up & monitoring

Once the project has been registered with the CDM Executive Board, it can be implemented. While project implementation is underway, the project proponents are required to monitor and measure emissions emitted and reduced on an on-going basis. The monitoring component of a CDM project is an extremely important step and not one to be overlooked or taken lightly. It must be based on the parameters set-out in the Monitoring Plan established in the project design stage and approved by the OE. Project participants are required to maintain internal monitoring and tracking systems to demonstrate that they are achieving the emission reductions specified in the PDD. This includes collecting and archiving data for the duration of the project.

According to the Kyoto Protocol, GHG emissions may be monitored:

- Directly using dedicated monitoring devices, and/or;
- Indirectly using predictive methods such as models or conversion of fuel inputs.

Information from the monitoring procedures will need to be complete, comprehensive and based on established fact. Assumptions, measurements, calculations, models and methodologies must be well documented. Throughout the project, the project managers must collect data exactly as specified in the monitoring plan. Any changes to the monitoring plan will need to be approved by a validating Operational Entity once the project has started.

Step 5: Verification & certification

The verification process confirms the total number of CERs resulting from the CDM project during a specific period of time. At this stage, the project developer is responsible for finding a designated operational entity to carry out the verification. This should be a different OE than the one that initially validated the CDM project. It is the responsibility of the OE to verify that the data collected by the project developer is what was proposed in the monitoring plan. This may involve an on-site inspection or interviewing of appropriate personnel.

Once the quantity of GHG reductions from the project has been verified, the OE will issue a certification report that will include the following information:

- The quantity of GHG reductions generated, and confirmation that they were real and measurable over the identified period of time;
- Ownership of the GHG reductions; and
- An indication that no further analysis is required.

The certification report is submitted to the CDM Executive Board by the OE and certifies in writing that the project has achieved the verified amount of GHG reductions. The certification report constitutes a request that the board issue CERs equal to the verified amount of GHG reductions.

Step 6: Issuance of CERs

Once the CDM Executive Board receives the verification and certification report from the OE, it will review it and may have additional questions to pose of the OE or CDM project proponents. If the CDM Executive Board believes no further review of the project is required, the registry administrator will issue the CERs into the CDM Executive Board’s pending account. Credits are subsequently distributed according to the contracts negotiated by the project participants. The issuance of CERs will be considered final fifteen days after the date of receipt of the request for issuance. The administrator will hold back a share of the CERs for administrative expenses as well as an additional 2% for an adaptation fund to help less developed economies mitigate the impact of climate change in their economy.

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Module 12

Economics of CO_2 capture and storage

Guy Allinson, Peter Neal, Minh Ho, Dianne Wiley and Geoffrey McKee
Adapted from CO2CRC Report Number RPT 06-0080

Overview

This module sets out the methods and assumptions used in carrying out economic analyses of carbon dioxide capture and storage (CCS) projects. It describes the methods and assumptions used when making generic cost estimates of CCS projects. For analyses of specific sites for special purposes, we might chose to adopt different methods and assumptions.

This module contains hypothetical examples to illustrate the methods we employ. The examples are not intended to represent any actual CCS project or opportunity.

Economics is an essential aspect of the evaluation of CCS projects. This module provides an overview of the economic considerations required to establish a CCS project.

Learning objectives

By the end of this module, you will have an understanding of -

How the costs of CCS are derived.

The concepts of CO_2 avoided, $ per tonne avoided and injected and $ per MWh in the context of CCS.

The pitfalls of estimating the costs of CCS.

Summary

Cost estimates

The inputs to our cost estimates of CO_2 capture and storage are the physical characteristics of the source of CO_2 and the injection site as well as the unit costs of equipment and services in today’s markets.

The estimates are subject to uncertainties because we cannot predict accurately storage reservoir parameters, gas compositions, capture equipment performance, unit costs and so on.

Costs per tonne of CO_2 avoided

The total costs of CCS consist of capital, operating and decommissioning costs. We estimate these, phase them over time, calculate the present value and divide by the present value of the annual CO_2 avoided. This gives the costs in $ per tonne of CO_2 avoided.

CO_2 avoided is the difference between amount of CO_2 emitted without capture and the amount of CO_2 emitted with capture.

Annualised costs

In much of the literature on the economics of CCS, authors derive annualised costs per tonne of CO_2 avoided. This gives the same result as the costs based on present values as described above. However, it is only easily applicable if the capital costs are incurred at time zero and if the operating costs and the CO_2 avoided are the same each year. These conditions are very restrictive.

Sometimes annualised costs are referred to as "levelised" costs.

Adding costs per tonne avoided

It is not valid to add together the costs of CO_2 avoided in the capture process and the costs of CO_2 avoided in the storage process. The costs per tonne of CO_2 avoided in the CCS process as a whole must be calculated using the total CO_2 avoided in the whole process.

Reference plant

Very often, the amount of CO_2 avoided is calculated by reference to the same plant from which we capture the CO_2. We also calculate CO_2 avoided with reference to other possible sources of CO_2. In general, we calculate CO_2 avoided by reference to (a) the same plant (b) a black coal power station, (c) a brown coal power station and a (d) natural gas combined cycle power station as appropriate. In some cases, for instance capture from a natural gas processing plant, it is not appropriate to calculate CO_2 avoided by reference to other sources of CO_2.

Generic capital costs

Our estimates of real capital costs for generic cases are built up using the following cost categories –

Costs of equipment and materials
International freight (if applicable)
Local freight
Construction and installation costs
Engineering and project management costs
Owners' costs

The main text sets out how we estimate these costs in these categories.

Generic operating costs

For generic cases, we estimate real annual fixed operating costs as a percentage of real capital costs. The percentage varies depending on the equipment.

Generic decommissioning costs

For generic cases, we assume that real decommissioning costs are 25% of the real capital costs.

Cost translations

Our costs estimates are for local conditions and are expressed in local currency. Our procedure for translating these into US conditions expressed in US$ is set out in the main text.

Assumptions

The following table contains the assumptions the CO2CRC adopts in making generic cost estimates. For purposes of comparison, we adopt a similar list as the International Energy Agency. A full comparison between the CO2CRC's assumptions and the IEA assumptions is given in the main text.

Table 12.1 Summary of assumptions

Capture plant size
Power stations – 500 MW

Other plant – depends on the situation

Capture plant design and construction period
2 years

40% of capital costs spent in year 1 and 60% in year 2.

Plant life
25 years

Load factors
Pulverised coal power stations **-** 85%

Natural gas power stations **-** 90%

Other plants – to be determined later

Cost of debt
No debt. Fully equity financed

Discount rate
7% real for capture from oil and gas facilities

Fees and owners' costs
7% of engineering, procurement and construction (EPC) costs

Contingency
10% of engineering, procurement, construction and owners' (EPCO) costs

Commissioning and working capital
We make no separate allowances for commissioning and working capital. These are taken into account in our capital cost phasing assumptions.

Decommissioning
We assume that decommissioning costs are 25% of the original real capital costs.

Maintenance
Maintenance costs are part of our estimates of operating costs

Labour
Labour costs are part of our estimates of operating costs

Fuels and raw materials
We assume that electric power used for CCS equipment is generated using natural gas costing A$3.50 per GJ.

Water
A$20 per megalitre

Effluent/emissions and solids disposal
We assume that the costs of these are part of the operating costs.

Site conditions
Ambient air temperature – 25°C onshore and 17°C offshore

Ambient air relative humidity **-** 60%

Ambient air pressure 1.01325 bar

Lower Heating Value is used in all efficiency calculations

Heat content
We assume that a super-critical black pulverised coal plant has a thermal efficiency of 40%.

We assume that a natural gas combined cycle (NGCC) power plant has a thermal efficiency of 56%.

Gas composition and CO_2 recovery
CO_2 recovery = 90%.

Gas compositions are shown in the following table –

Black coal plant	**Brown coal plant**	**NGCC plant**
Carbon dioxide = 13% Nitrogen = 75% Oxygen = 5% Water = 12% SOx = 200 ppm	Carbon dioxide = 12% Nitrogen = 60% Oxygen = 3% Water = 24% SOx = 200 ppm	Carbon dioxide = 9% Nitrogen = 83% Oxygen = 5% Water = 3% SOx = 2 ppm

Methodology

The CO_2 capture and storage system consists of –

1. Extracting CO_2 from a mixed gas stream in an industrial process. The industrial process might be electric power generation, natural gas processing, furnaces, boilers and so on. The capture technology might be chemical or physical absorption, gas separation membranes, pressure swing adsorption (including vacuum swing adsorption) and low temperature cryogenic separation.
2. Compressing CO_2 from capture (atmospheric) pressure to a pressure required for CO_2 transport in a pipeline. We need to compress the CO_2 to more than 8.3 megapascals (MPa) (approximately 1,200 pounds per square inch - psi) so that it is in a supercritical state ready for transport. This initial compression occurs at the source of the CO_2 after the capture process or as part of the capture process.
3. Transporting the CO_2 in a pipeline from the source to the point of injection.
4. Recompressing the CO_2, as required, along the transport route and possibly at the storage location before it is injected.
5. In the case of injection offshore, constructing and installing platforms to support the injection wells and equipment. In the case of injection onshore, constructing and installing infrastructure to support the injection wells and equipment.
6. Injection wells and flowlines connecting the wells to the pipeline used to transport the CO_2.

Inputs to cost estimates

The inputs to the estimates of capital and operating costs are –

1. Engineering estimates of the size and number of different pieces of equipment and the number and features of the wells required. These estimates depend on a range of inputs such as the following (not a complete list) –
    - The mixed gas composition at the source.
    - The mixed gas flow rate.
    - The capture technology.
    - The extracted CO_2 flow rate.
    - The period of injection.
    - The CO_2 pressure at the input to the pipeline.
    - The distance from the source to the injection site (the sink).
    - The relative elevation between source and sink.
    - The water depth (if the reservoir is offshore).
    - The depth of the storage reservoir beneath the surface of the earth.
    - The reservoir temperature and pressure.
    - The reservoir net thickness.
    - The reservoir permeability
2. Estimates of the unit costs of equipment and services in today's markets. These depend on the type of equipment and hardware and their unit costs at market prices.

We first make preliminary estimates of the size and number of pieces of hardware required. We then apply estimates of unit costs to derive the total capital and operating costs of the CCS project.

All cost estimates are usually preliminary. They cannot be made firm until a particular site is specified, designed and engineered in detail and until quotations are received for the equipment required. The purpose of estimates is to give broad-brush estimates as inputs to economic and business planning.

All cost estimates apply at a particular point in time. The costs of equipment and services change over time because of market forces.

Uncertainties

Both the engineering and the economic data are subject to uncertainties. In some cases these are potentially large. For instance, there are difficulties in predicting accurately the nature of the reservoir and its behaviour during the injection process. Uncertainties can arise with variations of CO_2 flow rates and the level of impurities. There are also uncertainties in unit costs because different providers of equipment and services will in general quote different costs. In addition, the costs of labour materials and energy can fluctuate considerably.

Uncertainties for the capture technologies are related to the different technologies and the range of data available from which to estimate performance for a given source. For instance, relatively mature technologies, such as amine adsorption that have already been applied at different scales in different international locations, will have fewer uncertainties than newer technologies that have limited or no industrial application.

Capital, operating and decommissioning costs

Estimating the costs of CCS involves estimating the capital, operating and decommissioning costs of each of the components of the system. The capital costs are the costs of constructing and installing equipment and are incurred at the beginning of the project. The operating costs are the costs of running and maintaining the system on a regular basis after it is constructed. The decommissioning costs are the costs of disposing of the equipment in an environmentally safe manner at the end of the project.

As an illustration, we might estimate the real capital costs (capex), the real operating costs (opex) and the real decommissioning costs of a hypothetical CCS project to be as shown in Table 12.2 below.

Real costs are the costs at today's prices for the components of the system (steel, materials, labour etc). For Table 2, we assume that the construction period is from year 1 to year 2 inclusive and that CO_2 storage begins in year 3 and finishes in year 27. Therefore CO_2 capture and storage lasts for 25 years. The project is abandoned in year 28.

In the case of enhanced oil or gas (for example enhanced coal bed methane recovery) projects there will be an annual revenue stream in addition to the costs shown in Table 12.2. These revenues clearly will offset the costs shown in the table. Moreover, if there is a carbon trading regime, the benefits of selling carbon credits would also offset the costs. In any commercial CCS operation, the revenues from trading CO_2 credits plus any extra revenues from enhanced recovery would exceed the costs of CCS and yield a profit.

Table 12.2 Illustrative real costs of a CCS project in $million

		Years						
	Totals	1	2	3	4	…	27	28
Real capex	2,500	500	2,000					
Real opex	7,500			300	300	…	300	
Real decommissioning costs	625					…		625
Real total costs	10,625	500	2,000	300	300	…	300	625

The present value of costs

Based on the example costs set out in Table 12.2, we calculate the present value (PV) of the costs as shown in Table 12.3.

Table 12.3 Calculating the present value of real capital and operating costs in $million

		Years				
	Totals	1	2	…	27	28
Real total costs	10,625	500	2,000	…	300	625
Discount factor		$1/(1+7\%)^1$	$1/(1+7\%)^2$	…	$1/(1+7\%)^{27}$	$1/(1+7\%)^{28}$
PV of costs	5,362	467.3	1,746.9	…	48.3	94.0

This calculation is based on a real discount rate 7%, our default assumption for the discount rate as discussed later. We assume end-year discounting.

The PV of real costs in this example is the amount of money which would need to be placed in an alternative investment today to allow the investment to pay the capital and operating costs of the CO_2 storage project as they become due at the end of each year. The alternative investment yields a real return of 7% per year. The PV is therefore the equivalent cost of the project as at today.

An example of the calculation of power station costs before and after capture is given in Appendix 1.

CO_2 avoided

In the CCS system CO_2 is captured from a mixed gas stream and injected into the subsurface. However, not all of the CO_2 is extracted from the mixed gas stream. It is emitted. CO_2 is also generated and emitted in the CCS process itself, for instance in compressing the CO_2 before and during transport and injection.

Of course, additional CO_2 is also generated in the process of manufacturing the equipment forming part of the CO_2 storage system. However, this is not included in our calculations.

To take into account the CO_2 emitted in the CCS process, we calculate the "CO_2 avoided". This is calculated below with example data –

Table 12.4 CO_2 avoided

	Without CCS	With CCS	Change
CO_2 generated (million tonnes/year)	10	14.3	4.3
CO_2 captured and stored (million tonnes/year)	0	12.9	12.9
CO_2 emitted (million tonnes/year)	10	1.4	8.6

* Assumes a CO_2 recovery rate of 90%

In the example in Table 12.4 we assume that the CCS process itself generates CO_2 emissions. For coal fired power stations the energy penalty (the extra energy required to capture and store CO_2) might be as much as 30% as is assumed in this case. The CCS process would then capture and store a percentage of the original CO_2 emitted plus the CO_2 emitted from the capture plant. This percentage is the rate of CO_2 recovery and is assumed to be 90% in Table 12.4.

An example of how we determine the CO_2 avoided in the case of a power station is given is Appendix 2.

Specific costs per tonne of CO_2 avoided

Based on the example costs set out in Table 2, and assuming that the CO_2 avoided is 8.6 million tonnes per year, we can calculate the specific costs per tonne of CO_2 avoided and per tonne of CO_2 injected as shown below.

Table 12.5 Specific costs

Present value of costs =	$5,362 million
Present value of CO_2 avoided = Specific costs = PV costs/PV tonnes avoided =	87.2 million tonnes $61.5 per tonne of CO_2 avoided
Present value of CO_2 injected = Specific costs = PV costs/PV tonnes injected =	130.9 million tonnes $41.0 per tonne of CO_2 injected

We divide by the present value of the CO_2 avoided (or injected) because then the CO_2 avoided (or injected) is in the same terms as the present value of the costs so that the ratio represents a valid comparison.

The present value of the CO_2 avoided in the example shown above is calculated as shown in Table 12.6. The present value of tonnes injected is calculated in a similar way.

Table 12.6 Calculating the present value of CO_2 avoided in million tonnes

		Years				
	Totals	3	4	…	27	28
CO_2 avoided	214	8.6	8.6	…	8.6	0
Discount factor		1/(1+7%)3	1/(1+7%)4		$1/(1+7\%)^{27}$	$1/(1+7\%)^{28}$
PV of CO_2 avoided	87.2	7.0	6.5		1.4	0

Annualised costs

Another way in which we might represent the costs of CCS per tonne of CO_2 avoided is to calculate "specific annualised costs". In fact, this is the representation most often used in the literature.

Appendix 3 demonstrates that the specific annualised costs are exactly the same as the specific present value of costs when we make simplifying assumptions. However, the assumptions made in calculating specific annualised costs are restrictive and when any one of the assumptions does not apply, then the calculation becomes complex. It is simpler and more appropriate to use the specific present value of costs, which is a much less restrictive approach.

Our preference is to use the present value of project costs rather than annualised costs because it allows more flexibility. It allows us to spread capital expenditure over several years. It also allows us to have different operating costs in different years of the project. Further, it allows us to incorporate inflation. Finally, if we are deriving costs per unit of production, it allows us to vary the units of production each year. Additionally, if we need to incorporate tax and the receipt of carbon credits in the calculation, then this is relatively easy to do.

In contrast, annualised cost calculations rely on a simplification of project costs and might not be helpful if we want to represent costs accurately. The difficulties with using annualised costs are –

1. If capital costs are spread over time, then we need to express them in terms of their present value before calculating their annualised equivalent using a "capital recovery factor" (see Appendix 3).
2. It does not allow us easily to vary fixed or operating costs to over the life of the project. To do this, we would need to calculate the present value of operating costs and derive an "operating cost recovery factor" in a manner similar to the way in which we derive a capital recovery factor.
3. It does not allow us easily to incorporate inflation. To do this, we would need to derive an operating cost recovery factor as mentioned above.
4. It does not enable us to calculate costs per unit of production when production varies over the life of the project.
5. It does not allow us easily to incorporate tax into the cost calculations. To do this, we would need to work out the taxes each year, calculate the present value of those taxes and derive a "tax recovery factor" in a similar way to the way in which we derive a operating cost recovery factor.
6. It does not allow us easily to incorporate varying revenues, for instance from receipts of carbon credits or enhanced oil or gas recovery. To do this we would need to calculate the present value of revenues and derive an annual revenue equivalent in a manner similar to the way in which we derive a capital recovery factor.

Adding specific costs

In much of the literature, specific costs are quoted separately for capture on the one hand and transport and injection (= storage) on the other. However, that the CO_2 avoided used to calculate the specific costs of capture is not the same as the CO_2 avoided used in calculating the specific costs of storage. Therefore, to estimate the costs per tonne of CO_2 avoided for the combined process, we cannot simply add the specific costs of capture and the specific costs of storage. We must adjust the calculations to derive the correct specific costs of the combined capture and storage process.

Table 12.7 shows the calculation of CO_2 avoided using hypothetical, illustrative data.

Table 12.7 CO_2 avoided for capture and storage in million tonnes per year

CO_2 capture separately		CO_2 storage separately		Capture & storage combined	
Emitted before capture (a)	10.0	Stored (c)	12.9	Emitted before CCS	10.0
Emitted after capture (b)	0.9	Emitted during storage	0.5	Emitted after CCS	1.4
CO_2 avoided per year	9.1	CO_2 avoided	12.4	CO_2 avoided	8.6

Footnotes
(a) Data assumed - CO_2 emitted from the original (reference) plant before capture
(b) Data assumed - CO_2 emitted after capture from the original plant and the capture plant.
(c) Data assumed - CO_2 captured and stored from the original plant and the capture plant.

Given these data and relationships, we can now calculate the specific costs per tonne of CO_2 avoided. Table 12.8 illustrates the calculation.

Table 12.8 Specific costs of CCS in $ per tonne of CO_2 avoided

Cost of capture (a)	344	Cost of injection (a)	123	Cost of CCS (a)	467
CO_2 avoided (b)	9.1	CO_2 avoided (b)	12.4	CO_2 avoided (b)	8.6
Costs per tonne	$37.8	Costs per tonne	$9.9	Costs per tonne	$54.3

Footnotes
(a) Assumed annualised costs in $ million and (b) CO_2 avoided in million tonnes per year

Table 12.7 and Table 12.8 show that the correct specific cost of the combined capture and storage process is $54.3 per tonne of CO_2 avoided. It is not the sum of $37.8 plus $9.9 equals $47.7 per tonne avoided. The example demonstrates that we cannot simply add the specific costs of capture and the specific costs of storage to derive the correct specific costs of the combined capture and storage process.

Reference plant

CO_2 avoided is the difference between the original CO_2 emitted and the CO_2 generated or lost during the CCS process. In the examples above, the original CO_2 emitted is that from the industrial process that hosts the CCS project, but before CCS is applied. In other words, the reference plant is the same plant as is used for CCS. This is the assumption used in most of the CCS literature.

However, this is not the only assumption that we might make. We might instead assume that the reference plant is a different industrial process and, if so, this would give a different value for the CO_2 avoided and also the specific cost. This is illustrated in the examples below.

In the first hypothetical example, we calculate the specific costs for a pulverised coal (PC) power station. The calculations are per megawatt hour (MWh) of electricity output. The reference plant is the same plant.

Table 12.9 PC power station - Reference plant = same plant

Pulverised coal power station. Per MWh	PC with no capture	PC with capture	Difference	Comments
Cost in $	45	77	32	Increase in cost in $
CO_2 emitted in tonnes	0.807	0.107	0.700	CO_2 avoided in tonnes
Cost per tonne			46	$ per tonne avoided

In the second hypothetical example, we calculate the specific costs for a natural gas combined cycle (NGCC) power station. Again, the calculations are per megawatt hour (MWh) of electricity output and the reference plant is the same plant.

Table 12.10 NGCC power station - Reference plant = same plant

NGCC power station. Per MWh	NGCC with no capture	NGCC with capture	Difference	Comments
Cost in $	31	46	15	Increase in cost in $
CO_2 emitted in tonnes	0.358	0.050	0.308	CO_2 avoided in tonnes
Cost per tonne			49	$ per tonne avoided

Comparing the NGCC plant with the PC plant, the cost of CCS per tonne of CO_2 avoided is higher for the NGCC plant.

However, from a comparison between Table 12.9 and Table 12.10, it is clear that the NGCC plant has lower emissions and is less expensive than the PC plant. If we recast the specific costs of the NGCC plant using the PC plant as a reference, then the costs of NGCC even without capture will be very different. The calculations are shown in Table 12.11.

Table 12.11 NGCC plant with no capture - Reference plant = PC plant

NGCC power station. Per MW	PC with no capture	NGCC with no capture	Difference	Comments
Cost in $	45	31	-14	Increase in cost in $
CO_2 emitted in tonnes	0.807	0.358	0.449	CO_2 avoided in tonnes
Cost per tonne			-31	$ per tonne avoided

Table 12.11 shows that, by comparison with a PC reference plant, an NGCC plant avoids almost 0.5 tonnes of CO_2 and is cheaper by $14 per MWh. The cost per tonne avoided is therefore negative $31, by comparison with $49 when the reference plant for NGCC was the same plant.

If we now include the costs of capture for the NGCC plant and calculate the costs of capture for the NGCC plant with the PC plant as a reference, then we avoid even more CO_2 than we do without capture, but the costs are higher. The net result is a specific cost of $1.3 per tonne of CO_2 avoided.

In some cases (for instance, natural gas processing plants), it might not be appropriate to show specific costs with a reference plant other than the same plant.

Table 12.12 NGCC plant with capture - Reference plant = PC plant

NGCC power station. Per MW	PC with no capture	NGCC with capture	Difference	Comments
Cost in \$	45	46	1	Increase in cost in \$
CO_2 emitted in tonnes	0.807	0.050	0.757	CO_2 avoided in tonnes
Cost per tonne			1.3	\$ per tonne avoided

Capital costs

This section illustrates the general way in which we can make estimates of capital costs. An example of the build up of a generic compressor cost estimate is given in Appendix 4.

(a) Equipment and Materials costs (Procurement)

This is either the Free-On-Board (FOB) cost in local currency of importing equipment and materials from overseas or the cost of purchasing the equipment locally. These costs exclude both international and local freight.

(b) International freight

This is the cost of transporting the equipment and materials from the overseas location to the country hosting the CCS plant. When a specific estimate is not available, we assume that this is 10% of the FOB cost described in (a) above.

(c) Local freight

This is the cost of transporting the equipment and materials to the location of the CCS project from the loading port (for imported items) or the point of purchase (for items purchased locally). We estimate these costs depending on the project.

(d) Costs including freight (CIF)

These are the sum of the FOB cost plus the cost of international freight (where appropriate) plus the costs of local freight. In other words, it is the sum of (a) + (b) + (c) above.

(e) Construction and installation costs

Construction and installation costs are different for different items of equipment and are estimated using different methods.

(f) Base Plant Costs = Direct Costs

These are the sum of the cost including freight and the construction and installation costs. In other words, they are the sum of (d) + (e) above.

(g) Engineering and project management costs

These are the costs of designing and overseeing the construction of the CCS project. We generally assume that engineering and project management costs are 15% of the Base Plant Cost or the Direct Costs.

(h) Engineering, procurement and construction costs (EPC)

These are the sum of Base Plant costs (or Direct Costs) and Engineering and Project Management costs. In other words, they are the sum of (f) + (g) above.

(i) Owners' costs

These are the costs of obtaining approvals, including environmental approvals, land purchase, and of negotiations and legal processes. We assume that these are 7% of the EPC costs described above. This is the same assumption as is recommended by the IEA (reference 1).

(j) Total EPCO costs

These are the sum of EPC costs plus Owners' costs. In other words, they are the sum of (h) + (i) above.

(k) Contingency

This covers the costs of miscellaneous items not included in (j) above. We assume that these are 10% of the total Direct plus Indirect Costs in (j) above.

(l) Total plant/project capital cost

This is the final total cost and is the sum of items (j) + (k) above.

Generic fixed operating costs

The operating costs of a CCS process have fixed and variable components. The variable component consists of fuel or power costs and this is discussed in a later section. As regards fixed operating costs, for generic cases and as defaults in our economic model, we adopt the following rules of thumb set out in Table 12.13. For specific cases where we have better data, we use that better data.

Our rules of thumb for estimating operating costs are set out in Table 12.13 below.

Table 12.13 Fixed operating cost rules of thumb

Item	Rule of thumb
Compressors and capture equipment	4% of EPC
Platforms	2% of EPC
Injection wells	2% of EPC
Pipelines	1% of EPC

Generic decommissioning costs

Unless we have better estimates, as a rule of thumb we assume that the real costs of decommissioning are 25% of the real EPC.

Cost translations

Our cost estimates are US$ dollars ($). The way in which we build up capital, operating and decommissioning costs estimates is described in above.

We adopt the following rules of thumb when translating local costs to costs in another country in a foreign currency. The rules of thumb used when translating to US$ are given in Table 12.14 below. Appendix 4 shows an example of a translation of compressor costs to US$.

Table 12.14 Cost translation rules of thumb for translation to costs in USA in US$

Item	Translation factor
Procurement of equipment and materials	Translation factor = Exchange rate
International freight	Translation factor = zero if equipment is manufactured in the USA. Exchange rate if not.
Local freight	Translation factor = 1 provisionally
Construction and installation costs	Translation factor = 0.9 based on relative skilled labour wage rates and the productivity of skilled labour
Engineering and project management costs	Translation factor = 1 provisionally
Owners' costs	Not translated. Estimated as a 7% of EPC
Contingency	Not translated. Estimated as a 10% of EPCO

Assumptions

In this section we discuss the assumptions and conventions used in making estimates of the costs of CCS generally. We also make a comparison between our assumptions and those adopted by the International Energy Agency (IEA) in a paper called "Technical and Financial Assessment Criteria", May 2003, which makes recommendations for studies carried out in the IEA Greenhouse Gas R&D programme. This paper is referred to the "IEA Assumptions" in this report and is reproduced in Appendix 5. We follow the list of assumptions used in the IEA report.

Development status This refers to the stage of development of the capture technology for which cost estimates are being made. We state the stage of development associated with cost estimates made in our economic modelling.	**IEA Assumptions** For commercially available technology current ‘state-of-the-art’ cost and performance figures will be assumed. Where technology has only reached the demonstration stage or earlier stages of development, 1st (commercial) generation costs and performance will be assumed and compared with ‘state-of-the-art’ current figures. The cost vs. installed capacity relationship assumed should be presented in the results.
Power plant size We assume a power station with a net power output of 500 megawatts (MW). We adopt a smaller size than the IEA (750 MW) because the smaller size is more typical of local conditions. This means that IEA unit costs will tend to be smaller than ours taking into account economies of scale.	**IEA Assumptions** The net power output after deducting ancillary power requirements will be 750 MW. There will be cases (e.g. gas turbines which have fixed sizes) where it is not possible or advisable to match the required net power output. In such cases the power output will be agreed with IEA GHG.
Location For generic costs estimates, we assume a Greenfield location on. Our estimates include the costs of making the site self sufficient in services.	**IEA Assumptions** A green field site with no special civil works implications will be assumed. Unless otherwise specified, the plant will be assumed to be on the NE coast of The Netherlands. Adequate plant and facilities to make the plant self sufficient in site services will be included in the investment costs. Alternative and/or multiple sites will be specified for some studies.
Currency We make costs estimates for local conditions and convert them to USA costs in US$ using the cost translation factors described above.	**IEA Assumptions** The results of the studies will be expressed in US $ applicable to a specific year. Data obtained in other currencies will be converted at rates to be agreed.

Design and Construction Period We assume that the CCS project will be constructed in 2 years and that the construction costs are phased 40% in year 1 and 60% in year 2. We do not make estimates of power station costs and therefore do not need phasing assumptions for such plant.	**IEA Assumptions** Coal fired power generation plant - 3 years. Natural gas fired combined cycle plant - 2 years. CO_2 capture plant and 'chemical plants' in general - 2 years. Underground CO_2 storage - 2 years Ocean storage: 4 years (assuming a long pipeline to the disposal point) Modular renewable technologies such as wind turbines - 1 year. Typical `S' curves of expenditure during construction will be used. These are- Coal-fired plant Year 1 =20%, Year 2 = 45%, Year 3 = 35%. Natural gas fired plant Year 1 = 40%, Year 2 = 60% Chemical plant Year 1 = 40%, Year 2 = 60%
Plant life We assume a CCS project life of 25 years. This corresponds approximately to the useful life of equipment with moving parts. After approximately 25 years, the CCS equipment would need to be replaced.	**IEA Assumptions** Twenty-five years. Where for technical reasons this is regarded as excessive, provision will be made for the cost of any major maintenance/refurbishment or a shorter life will be assumed.
Load Factor We adopt IEA assumptions and use the following power station load factors. For coal and oil power stations we assume 60% in the first year of the CCS project and 85% thereafter. For natural gas power stations we assume 90% in all years.	**IEA Assumptions** For coal, other solids, and liquid processing plants; 1st. year: 60% of rated capacity; subsequent years: 85% of rated capacity. For natural gas fuelled plants (and other plants solely processing gases) 90% of rated capacity for all operating years. Renewable technologies on a case-by-case basis. Allowance should be made for sufficient installed duplicate/spare capacity to meet required load factor taking into account maintenance requirements and reliability. No allowance for decline as plant ages.

Cost of debt We see it as important that all costs estimates are made on an equity finance basis and exclude the cost of debt. Financing arrangements can vary tremendously from one project to the next and simply introduce unnecessary noise into the cost estimates. This matter should not be confused with discounting which is used to assess present values. The discount rate represents the return that can be obtained on an alternative investment. It is not the cost of debt.	**IEA Assumptions** For simplicity, all capital requirements will be treated as debt at the same discount rate used to derive capital charges. No allowance for grants, cheap loans etc. (More complex financial modelling might be considered for certain studies.) Specific capital cost figures should be presented without including an allowance for funds used during construction (i.e. independent of discount rate).
Capital charges/inflation In the literature on CCS costs estimates, capital charges and the discount rate are used in annuity calculations to derive the annualised costs. These are discussed in above and Appendix 3. We employ the discount rate to derive the present values of costs as discussed above and in Appendix 3. The discount rate is the cost of capital for the company undertaking the CCS project. This varies from company to company and from sector to sector. We assume a nominal discount rate of 10%, which is representative of discount rates adopted by the international oil and gas industry. This corresponds to a real discount rate of approximately 7% assuming inflation of 3% per year. Our economic model also calculates costs using a range of real discount rates between 5% and 15% to take into account the different circumstances of different companies and sectors. We make cost estimates in real terms before tax ignoring inflation. However, after tax real cost estimates necessarily require an inflation assumption. The real after tax costs are a function of inflation. When calculating real after tax costs, we assume inflation at 3% per year.	**IEA Assumptions** Discounted cash flow calculations will be expressed at a discount rate of 10% and, to illustrate sensitivity, at 5%; the resulting capital charge rate will be quoted. All annual expenditures will be assumed to be incurred at the end of the year. Inflation assumptions will not be made. No allowance will be made for escalation of fuel, labour, or other costs relative to each other.

Contingency As discussed above, we assume a contingency of 10% of EPCO costs. This is included to cover unforseen items that are not already included in the estimate of EPCO costs. It is not intended to take into account uncertainties in estimating parameters that are included in our estimates of EPCO. These are handled separately by probability analyses.	**IEA Assumptions** A contingency will be added to the capital cost to give a 50% probability of a cost over-run or under-run. In the absence of a more detailed assessment, the default value for the contingency should be 10% of the installed plant cost (overnight construction). All plant should be assumed to be built on a turnkey basis, i.e.; the cost of risk should be built into the contractor's fees.
Fees and other owners' costs Owners' costs consist of land purchase, environmental approvals, legal fees and related costs. We assume that owners' costs are 7% of EPC costs as defined in above. This agrees with the IEA assumption. These costs are assessed before contingencies are added.	**IEA Assumptions** A total of 7% of the installed plant cost (overnight construction, excluding contingency) will be included to cover these owners costs. A separate statement of the cost should be made where any proprietary technology or other technology license fee exceeds 2% of the plant cost.
Commissioning and working capital Commissioning and working capital are taken into account in our capital cost phasing assumptions.	**IEA Assumptions** A 3 month commissioning period will be allowed for all plant. Sufficient storage for 30 days operation at rated capacity will be allowed for raw materials, products, and consumables (except for natural gas and other gaseous fuels in which case provision should be made for an alternative supply of fuel). No allowance will be made for receipts from sales in this period.
Decommissioning Decommissioning or decommissioning costs can be significant compared to the original cost of a CCS system. This is especially the case for abandoning offshore injection systems. However, they can vary significantly from one case to the next. As a rule of thumb, we assume that real decommissioning costs are 25% of the original real construction costs.	**IEA Assumptions** This will be included to facilitate comparison with technologies where decommissioning can be a significant proportion of project cost.

Taxation and insurance Sales and local taxes and insurance are included as part of our estimates of the EPC costs.	**IEA Assumptions** Allow 1% per year of the installed plant cost (overnight construction, excluding contingency and fees) to cover specific services e.g. local rates. Taxation on profits will not be included in the assessments. Allow 1% per year of the installed plant cost (overnight construction excluding contingency and fees) to cover insurance.
Maintenance Maintenance costs are part of our estimates of operating costs as described in above.	**IEA Assumptions** Routine and breakdown maintenance will be allowed for at: 4% per year of installed plant cost (overnight construction excluding contingency and fees) for solids handling plant and at 2% per year for plants handling gases and liquids and services plant.
Labour Labour costs are part of our estimates of operating costs as described in above.	**IEA Assumptions** The cost of maintenance labour is assumed to be covered by item 15 [Maintenance]. Operating labour only will be identified and assumed to work in a 5 shift pattern. If not estimated in detail, an allowance of 20% of the operating labour direct costs will be included to cover supervision. A further 30% of direct labour costs will be included to cover administration and general overheads. (ie; total cost = (direct operating labour cost x 1.2) x 1.3)

Fuels and raw materials For our generic cost estimates, we assume that electric power is used for CCS equipment. In our modelling we can account for electricity supply in one of three ways - Parasitic power (CCS for power plants) – electricity required by CCS reduces the total electricity to the grid from the power plant, Upgrade power (CCS for power plants) – the power plant is upgraded to produce enough electricity to supply the CCS project and maintain the same output to the grid. This can be achieved either by (a) the addition of a new capture plant to an existing power plant or (b) by building a new enhanced power plant that includes capture. Purchase - electricity is purchased from the grid to supply the CCS project. Our default for power stations is method (b) above. For other CCS applications and for transport and injection, we assume that electricity is purchased from the grid and that this electricity is generated using natural gas at a price of A$3.50 per gigajoule (GJ). Site specific studies might employ different assumptions about the fuel used and its price.	**IEA Assumptions** Typical' bituminous coal and natural gas are used as a standards. Their specifications are given on the last page of this document. Where appropriate the analysis of alternative fossil fuels fuel will be supplied. The cost of coal delivered to site is to be assumed to be US$1.5/GJ (LHV basis). The cost of natural gas delivered by pipeline to site is to be assumed to be US$3/GJ (LHV basis). The studies will show the cost of power generated for a range of fuel prices (0-3 US $/GJ for coal and 0-6 US $/GJ for gas).
Water We assume that the costs of water are in addition to the fixed operating costs mentioned in above. We assume that water costs A$20 per megalitre. It is assumed that the cooling water system is closed circuit. Cooling water conditions are: Average inlet temperature 25 °C; maximum temperature rise of 10 °C.	**IEA Assumptions** The use of sea water cooling will be assumed for the site in the Netherlands and other coastal sites. Direct cooling will be used for the steam turbine condenser and large compressor intercoolers and an indirect cooling system will be used for other process coolers. Unless otherwise stated, any inland sites will be assumed to use closed circuit cooling water systems. Sea-water cooling conditions are: Average inlet temperature 12 °C; maximum temperature rise 7 °C; salinity 22 grams/litre.

Effluent/Emissions and Solids Disposal We assume that the cost of waste disposal is part of the operating costs discussed in above.	**IEA Assumptions** The plant will be assumed to have effluent abatement and treatment facilities sufficient to meet achievable reductions, e.g. Particulate matter < 25 mg/Nm^3 NOx < 200 mg/Nm^3 SO2 < 200 mg/Nm^3 Where disposal of waste is required the cost of appropriate plant and methods will be included in the assessments. The cost of ash disposal, value of by-products e.g. sulphur, etc., will be treated on a case-by-case basis. Unless otherwise specified, the minimum CO$_2$ capture level is to be 80%; and the preferred level 85%. Unless otherwise specified, CO$_2$ is to be compressed to 110 bar before injection into the transfer pipeline. Note will be taken of possible emissions arising from CO$_2$ processing, eg, amine scrubbing.
Site conditions We assume standard conditions of temperature and pressure at the capture and storage site. These are set out below. Ambient air temperature – 25 °C onshore and 17 °C offshore Ambient air relative humidity - 60% Ambient air pressure 1.01325 bar Lower Heating Value is used in all efficiency calculations.	**IEA Assumptions** Ambient air temperature: 9 °C Ambient air relative humidity: 60% Ambient air pressure: 1.013 bar Lower Heating Value will be used in all efficiency calculations.

Heat content	**IEA Assumptions**
We assume that a super-critical black pulverised coal plant has a thermal efficiency of 40%. We assume that a natural gas combined cycle (NGCC) power plant has a thermal efficiency of 56%.	Lower Heating Value will be used in all efficiency calculations.

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Gas composition and CO_2 recovery

We assume a 90% recovery of CO_2 from chemical absorption and the following feed gas composition –

Gas compositions

Black coal plant	**Brown coal plant**	**NGCC plant**
Carbon dioxide = 13% Nitrogen = 75% Oxygen = 5% Water = 12% SOx = 200 ppm	Carbon dioxide = 12% Nitrogen = 60% Oxygen = 3% Water = 24% SOx = 200 ppm	Carbon dioxide = 9% Nitrogen = 83% Oxygen = 5% Water = 3% SOx = 2 ppm

Footnote
NO_x is not included in this table because we assume that it has been pre-treated prior to capture.

If SO_x pre-treatment is included in the analysis, we assume that the SO_x content in the flue gas is 10 ppm.

Appendix 1. Example calculation of costs for hypothetical pulverised coal power station

A) Cost of electricity (COE) from a hypothetical 500MW super-critical power plant

Example calculation		Value	Explanation
Discount rate	%	7%	Data assumed
Load factor	%	85%	Data assumed
Plant life	years	25	Data assumed
Net capacity	MW	500	Data assumed
Electricity produced per year	MWh / yr	3,723,000	Production = 500 MW capacity * 85% load factor * 365 days * 24 hours
Thermal efficiency	%	40%	Data assumed
Unit cost for 500 MW plant	A$/kW	1,050	Data assumed
Annual fixed opex	% of capex	4%	Data assumed
Annual variable opex	% of capex	0.5%	Data assumed
Fuel cost	A$/GJ	1.00	Data assumed
Capex	A$ million	525	Capital cost for building the power plant = 500 MW * 1,050 A$/kW
Annual opex	A$ million / yr	23.6	Annual fixed & variable opex = 4.5% * A$525 million
Annual fuel cost	A$ million / yr	33.5	Annual fuel cost = 3,723,000 MWh / 40% * 3.6 GJ/MWh * A$1.00/GJ
PV capex	A$ million	475	PV of initial capital cost
PV opex	A$ million	560	PV of operating cost for lifetime of project
PV of electricity produced	MWh	35,450,973	PV of total energy generated for the life of the power plant
Cost of Electricity (COE)			
COE to cover capex	A$/MWh	13.39	PV of capital cost divided by PV of total energy generated per MWh
COE to cover opex	A$/MWh	15.78	PV of total opex divided by PV of total energy generated per MWh
COE total	A$/MWh	29.17	Sum of COE Capex + COE Opex

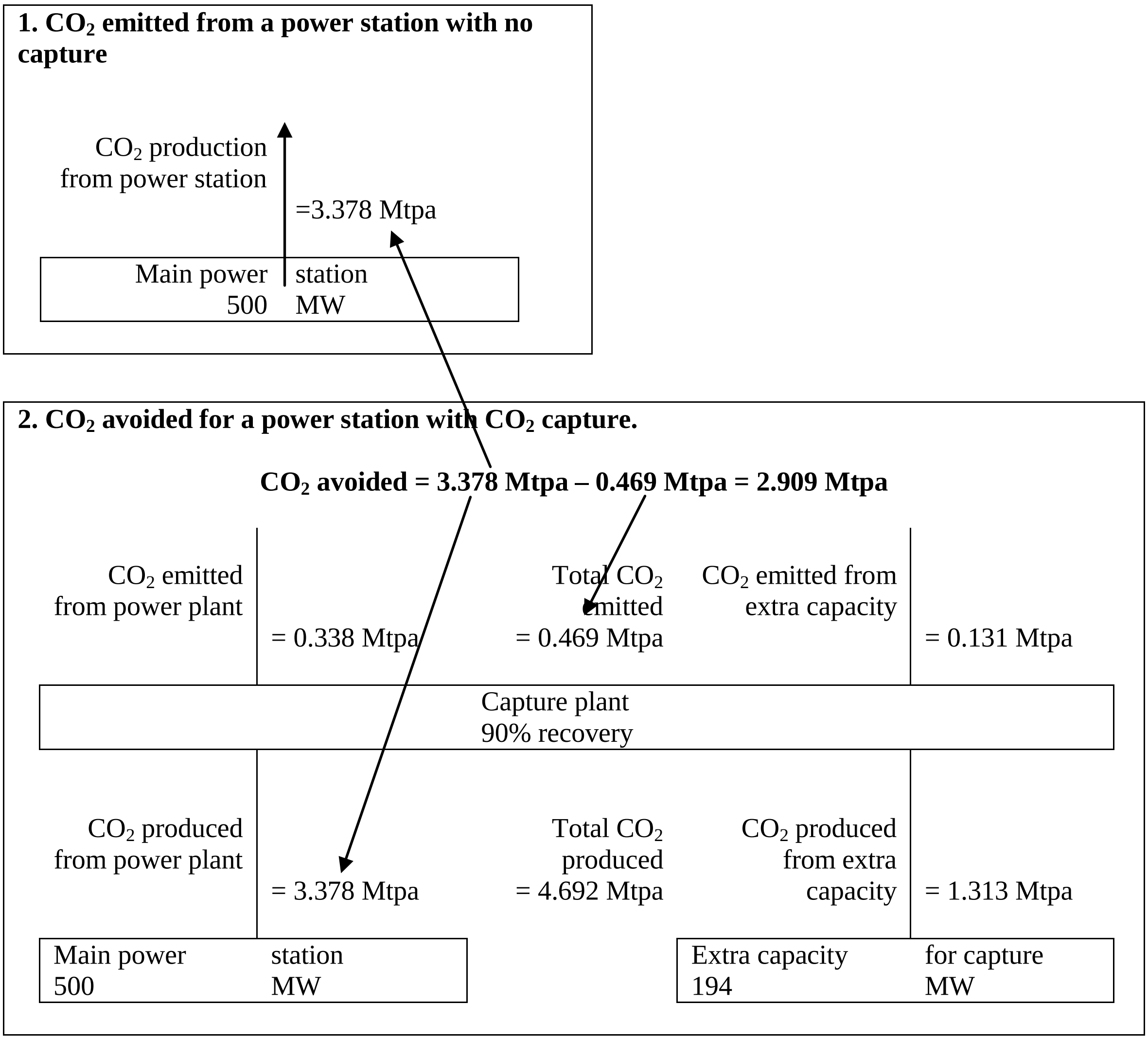
B) Cost of electricity for a hypothetical new-build pulverised coal power plant with extra capacity to provide energy for CO$_2$ capture.

Example calculation		**Value**	**Explanation**
Discount rate	%	7%	Data assumed
Load factor	%	85%	Data assumed
Plant life	years	25	Data assumed
Energy penalty for capture	%	28%	Data assumed
Total capacity of enhanced plant	MW	694	Total capacity = 500 MW net capacity / (1 – 28% energy penalty)
Extra capacity for capture	MW	194	Capacity needed to operate the capture facility = 694 MW * 28% penalty
Net capacity	MW	500	Remaining capacity for the grid after capture
Electricity produced per year	MWh / yr	5,167,524	Production = 694 MW capacity * 85% load factor * 365 days * 24 hours
Thermal efficiency	%	40%	Data assumed
Fixed opex	% of capex	4%	Data assumed
Variable opex	% of capex	0.5%	Data assumed
Fuel cost	A$/GJ	1.00	Data assumed
Capex for enhanced plant	A$ million	660	Capex = A$525MM * (694 MW/500 MW$^{0.7}$)
Fixed opex for enhanced plant	A$ million/yr	29.7	Annual fixed & variable opex = 4.5% * A$660 million
Fuel cost for enhanced plant	A$ million/yr	46.5	Annual fuel cost = 5,167,524 MWh / 40% * 3.6 GJ/MWh * A$1.00/GJ
Capex for capture facility only	A$ million	350	Data assumed - Capex for the capture separation and compression facility
Opex for capture facility only	A$ million/yr	40	Data assumed - Opex for the capture separation and compression facility
NPV of capex	A$ million	913	NPV of total capex (enhanced power plant + capture plant)
NPV of opex	A$ million	1,153	NPV of total opex (enhanced plant + capture plant) for the life of the project
NPV of electricity produced	MWh	35,450,973	NPV of total electricity generated over the life of the power plant
Cost of electricity (COE)			
COE to cover capex	A$/MWh	25.77	NPV of capital cost divided by NPV of total energy generated per MWh
COE to cover opex	A$/MWh	32.51	NPV of total opex divided by NPV of total energy generated per MWh
COE total	A$/MWh	58.28	Sum of COE capex + COE opex

Appendix 2. Example calculation of CO_2 avoided for power stations

The following is an illustration of the calculation of CO_2 avoided for CO_2 capture from a hypothetical power station. For this simple illustration, the extra capacity providing energy to the capture plant could be from a retrofit power generation plant, a new and separate power generation plant or an expansion of the existing power station.

For this illustration, we capture the CO_2 from the extra capacity needed for the capture plant as well as from the power station.



The detailed calculations on which this diagram is based are given in the table below.

Example CO_2 avoided calculations	**Units**	**Values**	**Explanation**
Power station with no CO_2 capture			
Original power station capacity	MW	500	Hypothetical data assumed
Original power station load factor	%	90%	Hypothetical data assumed
CO_2 production rate at power station	t/MWh	0.857	Hypothetical data assumed
Power station with CO_2 capture			
Energy penalty(a)	%	28%	Hypothetical data assumed
Total capacity needed including capture (a)	MW	694	= Original power station capacity (500 MW) / (1 - 28% penalty)
Total plant load factor	%	90%	Assume same as for original power station
Total plant annual power output	MWh	5,475,000	Capacity (694 MW) * Load factor (90%) * 365 days * 24 hours
CO_2 production rate from total plant	t/MWh	0.857	Hypothetical data assumed = same as for power station
CO_2 recovery from total plant	%	90%	Hypothetical data assumed
CO_2 produced from total plant	Mtpa	4.692	Total plant annual power output * CO_2 production rate per MWh/10^6
CO_2 captured from total plant	Mtpa	4.223	CO_2 produced * CO_2 recovery
CO_2 emitted from total plant	Mtpa	0.469	CO_2 produced less CO_2 captured
Electricity production with no capture	MWh	3,942,000	Capacity (500 MW) * Load factor (90%) * 365 days * 24 hours
CO_2 emitted from station with no capture	Mtpa	3.378	Power station output * CO_2 production rate per MWh/10^6
Total CO_2 emitted	Mtpa	0.469	= 0.338 + 0.131
CO_2 avoided	Mtpa	2.909	= CO_2 output with no capture - total CO_2 emitted

Footnote
(a) The energy penalty is the percentage of the total plant capacity required for capture. In this example, the original power station capacity is 500 MW. The total plant capacity is 694 MW, because 694 = 500 + 694 * 28%. Alternatively, we can write 694 = 500 / (1 – 28%).

Appendix 3. Specific project costs

This appendix discusses the methods by which we can represent project costs as a single number. Project costs basically consist of -

- Capital expenditure or construction costs spent in the early years of a project before CO_2 capture and injection starts
- Operating expenditure spent each year during capture and injection.
- Taxes paid during capture and injection.

One way to represent total costs as a single number is to calculate the “annualised cost”. In order to calculate this, we need first to determine the capital expenditure in terms of its annual equivalents – “annuities” and then add the annual operating costs. Usually annualised costs are calculated before tax – that is, taxes are not included. In fact, it is difficult to incorporate taxes in annualised cost calculations because taxes almost always vary over the life of the project.

Another way to represent total costs is by adding the present value of the capital expenditure to the present value of the operating costs and taxes incurred each year. This gives the total present value of the project. We discuss these methods in the following.

1 Annualised project costs

The annualised cost of a project is a single number incorporating both capital and operating costs. It is the same for each year of the project and is derived as set out in the following.

1.1 Annuities

The first step in calculating annualised costs is to translate the capital expenditure at the beginning of the project into annual equivalents. We achieve this by converting capital expenditure into annuities as set out below.

In Table 1, the capital expenditure of a project at time = 0 is $K million (MM). We can translate this into equivalent annual payments (annuities) of $A million per year. These are paid at the end of each year starting at the end of year 1 and ending in year n.

Table 1 - Calculating annuities

	Total	Time 0	End yr 1	End yr 2	End yr 3	…	End yr n
Capital expenditure $MM	K	K					
Annuities $MM	A*n		A	A	A	…	A

We can work out the value of A by making the present value of all of the annuities the same as the present value of the capital expenditure. The present value of the capital expenditure is $K million, because it is incurred at time = 0 (today). Note that we do not necessarily need to assume that the capital expenditure occurs at time = 0. If it is spread over several years, we can calculate and use the present value of the capital expenditure, which is its equivalent value today.

The present value of the annuities is calculated in Table 2. The discount rate is r% per year.

Table 2 - Discounted annuities

	End yr 1	End yr 2	End yr 3	…	End yr n
Discounted annuities = $MM per year	$\frac{\$A\text{ MM}}{(1+r)^1}$	$\frac{\$A\text{ MM}}{(1+r)^2}$	$\frac{\$A\text{ MM}}{(1+r)^3}$	…	$\frac{\$A\text{ MM}}{(1+r)^n}$

We want to know the discounted annuities which give a present value of $K million. These are given by A in the following equation -

$$\$K\text{ MM} = \frac{\$A\text{ MM}}{(1+r)^1} + \frac{\$A\text{ MM}}{(1+r)^2} + \frac{\$A\text{ MM}}{(1+r)^3} \dots + \frac{\$A\text{ MM}}{(1+r)^n}$$

Multiply all terms in the equation by 1 / (1+r %). This gives -

$$\frac{\$K\text{ MM}}{(1+r)^1} = \frac{\$A\text{ MM}}{(1+r)^2} + \frac{\$A\text{ MM}}{(1+r)^3} + \frac{\$A\text{ MM}}{(1+r)^4} \dots + \frac{\$A\text{ MM}}{(1+r)^{n+1}}$$

Subtracting the second equation from the first equation gives -

$$\$K\text{ MM} - \frac{\$K\text{ MM}}{(1+r)^1} = \frac{\$A\text{ MM}}{(1+r)^1} - \frac{\$A\text{ MM}}{(1+r)^{n+1}}$$

Multiplying all terms by $(1+r)^{n+1}$ gives -

$$\mathbf{\$K\text{ MM} *(1+r)^{n+1} - \$K\text{ MM} * (1+r)^n = \$A\text{ MM} *(1+r)^n - \$A\text{ MM}}$$

Rearranging to obtain an equation for A gives the annuity equation as shown in Equation 1 –

Equation 1 Annuity equation

$$\textbf{Annuity} = \frac{K\,r(1+r)^n}{((1+r)^n - 1)} = \frac{KrDn}{(Dn - 1)}$$

Where	A = Annuity in each year
and	K = capital expenditure at time = 0
and	r = the discount rate
and	D = (1 + r)
and	n = the number of years for the annuity

1.2 Capital recovery factor

The “capital recovery factor” (or the “capital charge rate”) is calculated by dividing the annuity by the capital expenditure. It is the annuity as a fraction of the capital expenditure. Therefore, the capital recovery factor is defined as set out in Equation 2.

Equation 2 Capital recovery factor (CRF)

$$\textbf{CRF} = \frac{r(1+r)^n}{(1+r)^n - 1}$$

or

$$\text{CRF} \qquad \frac{rD^{n}}{D^{n\,-1}}$$

where r = the discount rate
and $D = (1 + r)$
and n = the number of years for the annuity

Therefore, the annuity is the total capital expenditure of a project at time zero multiplied by the capital recovery factor.

1.3 Total annualised costs

We can express the total costs of a project as the annualised costs as defined in Equation 3. Equation 3 is valid only when operating costs do not change over time.

Equation 3 – Annualised project costs

Annualised project costs in $MM per year =

Capital recovery factor * capital expenditure
\+ Annual fixed operation and maintenance costs
\+ Annual variable operating costs (eg energy costs)

In algebraic form –

$$AC = \frac{Kr(1 + r)^{n}}{((1 + r)^{n} - 1)} + O = \frac{KrD^{n}}{(D^{n} - 1)} + O$$

where AC = annualised costs
and O = total annual fixed plus variable operating costs
and D = (1+r)

1.4 Specific annualised costs

In order to determine the specific annualised cost - that is the annualised costs per unit of production, or tonne of CO_2 avoided, or per tonne of CO_2 injected, etc - we must assume that the production, or the CO_2 avoided or the CO_2 injected is the same each year. With this assumption, all we need to do is divide the annualised cost by the annual rate of production, of CO_2 avoided, or CO_2 injected. This is set out in Equation 4.

Equation 4 – Specific annualised project costs

Specific annualised project costs =

$$\frac{\text{Annualised cost in \$MM}}{\text{Annual rate of production, or } CO_2 \text{ avoided, or } CO_2 \text{ injected}}$$

in $ per KWh, or $ per tonne, etc

In algebraic form -

$$AC_s = \frac{KrDn}{P(Dn - 1)} + \frac{O}{P}$$

where P = annual production in MM units (the same each year)
and other symbols have the same meaning as given above

2 Present value of project costs

As its name implies, the present value of costs is the equivalent value of the project today. It represents the amount of money we would need to invest today earning interest at r% per year (the discount rate) to enable us to meet the costs of the project as they fall due during project life.

2.1 Definition

We can express the total costs of a project as the total present value of its different components as set out in Equation 5. This characterisation of project costs allows us to incorporate capital costs spread over time, varying operating costs over time, inflation and taxes.

Equation 5 – Present value of project costs

Present value (P_V)of project costs =

P_V of capital expenditure
\+ P_V of fixed operation and maintenance costs
\+ P_V of variable operating costs (eg energy costs)
\+ P_V of taxes

In algebraic form and excluding taxes -

$$P_VC = P_VK + P_VO$$

If K occurs at time = 0 and O is the same each year and we exclude tax,

$$P_VC = K + \frac{O(D^n - 1)}{rD^n}$$

We can deduce that the present value of equal annual operating costs is $O(D^n - 1)/ D^nr$ from the annuity equation above (Equation 2). This is because O is effectively the annuity that gives a present value of $O(D^n - 1)/ D^nr$.

2.2 Specific present value of project costs

The specific present value of project costs is the revenue per unit of production we would need to receive to ensure that the present value of that revenue equals the present value of the project costs. Alternatively, it is the revenue we would need to receive to ensure that the present value of net cash flow (that is, revenues less costs) equals zero.

Equation 6 – Specific present value of project costs

Assuming constant revenues, production, operating costs and no taxes -

	Time = 0	End yr 1	End yr 2	…	End yr n
Zero =	$\frac{-K}{(1+r\%)^0}$	$\frac{RP-O}{(1+r\%)^1}$	$\frac{RP-O}{(1+r\%)^2}$	…	$\frac{RP-O}{(1+r\%)^n}$

where K = capital costs in \$MM

and R = revenue per unit in \$ per unit

and P = annual production in million units

and O = annual operating costs in \$MM

and r = discount rate in % per year

Alternatively, using P_V to represent present value,

$$0 = - P_VK + P_VRP - P_VO$$

Therefore - $$P_VRP = P_VK + P_VO$$

If R is constant $$RP_VP = P_VK + P_VO$$

and $$R = \frac{P_VC}{P_VP} = \frac{P_VK + P_VO}{P_VP} = \frac{P_V(K + O)}{P_VP}$$

Therefore, the revenue per unit required to cover project costs, or alternatively the specific present value of project costs, is equal to -

$$\frac{\text{Present value of capital and operating costs}}{\text{Present value of production}}$$

In algebraic form -

$$P_VC_s = \frac{P_VC}{P_VP} = \frac{K + \frac{O(D^n - 1)}{rD^n}}{\frac{P(D^n - 1)}{rD^n}}$$

$$P_VC_s = \frac{K\, rD^n}{P(D^n - 1)} + \frac{O}{P}$$

This is a special case because it assumes that operating costs and production are the same each year and that there are no taxes.

Of course, when we calculate the specific present value of costs we do not have to restrict the timing of capital expenditure to time = zero. We can easily incorporate capital costs incurred in any year of the project. Similarly, we do not need to assume that operating costs and production are the same each year and it is straightforward to incorporate taxes.

3 Comparison

3.1 Relationship between AC and P_VC

If we assume that –

7. capital costs occur at time zero, or we use the present value of capital costs in the annualised cost calculation,
8. operating costs start in year 1 and do not change over time,
9. there is no inflation, or we carry out the analyses only in real terms,
10. production does not change over time and
11. there are no taxes,

then there is an algebraic connection between AC and P_VC. Table 3 shows this connection.

Table 3 – AC and P_VC

From equation 3 above -

$$AC = \quad = \frac{KrD^n}{(D^n-1)} + O$$

Re-arranging -

$$\frac{AC(D^n-1)}{rD^n} = \frac{K + O(D^n - 1)}{rD^n}$$

This is the same as P_VC in equation 5

Therefore

$$\frac{AC(D^n-1)}{rD^n} = P_VC$$

or $$AC = \frac{P_VC\ rD^n}{(D^n-1)}$$

This makes sense because the annualised cost is effectively an annuity based on the present value of the costs (also see Equation 1).

In addition, when the conditions above apply then specific annualised costs per unit of production (AC_s) will give the same answers as the specific present value of costs per unit of production (PVC_s). Table 5 shows that AC_s and P_VC_s are the same under these conditions.

Table 4 ACs and P_VCs

As stated above -

$$P_VC_s = \frac{P_VC}{P_VP}$$

Therefore

$$P_VC_s = \frac{P_VC}{\frac{P(D^n - 1)}{rD^n}} = \frac{P_VC\ rD^n}{P(D^n - 1)}$$

The right hand side of this equation is equal to AC_s, the specific annualised costs as shown in Table 3

Therefore

$$P_VC_s = AC_s$$

Table 4 shows that the specific annualised costs are the same as the specific present value of costs when we make simplifying assumptions. However, these assumptions are restrictive and when any one of the assumptions does not apply, then it is difficult to calculate specific annualised costs. We are therefore drawn to use the specific present value of costs.

Using the present value of project costs rather than annualised costs gives more flexibility. It allows us incorporate capital expenditure that is spread over several years. It allows us to have different operating costs in different years of the project. It allows us to incorporate inflation. If we are deriving costs per unit of production, it allows us to vary the units of production each year. If we need to incorporate tax in different years into the calculation, then this is relatively easy to do.

In contrast, annualised cost calculations rely on a simplification of project costs and might not be helpful if we want to represent costs accurately. The difficulties with using annualised costs are –

12. If capital costs are spread over time, then we need to express them in terms of their present value.
13. It does not allow us easily to vary fixed or operating costs to over the life of the project. To do this, we would need to calculate the present value of operating costs and derive an “operating cost recovery factor” in a similar way to the way in which we derived a “capital recovery factor”.
14. It does not allow us easily to incorporate inflation. To do this, we would need to derive an operating cost recovery factor as mentioned above.
15. It does not enable us to calculate costs per unit of production when production varies over the life of the project.

16. It does not allow us easily to incorporate tax into the cost calculations. To do this, we would need to work out the taxes each year, calculate the present value of those taxes and derive a “tax recovery factor” in a similar way to the way in which we derived a capital recovery factor.
17. It does not allow us easily to incorporate varying revenues, for instance from receipts of carbon credits or from enhanced oil or gas production. To do this we would need to calculate the present value of revenues and derive an annual revenue equivalent in a manner similar to the way in which we derive a capital recovery factor.

Appendix 4. Cost translations

The table that follows, shows the way in which we translate costs in local currency into costs in another country. The example is for a compressor purchased in Germany and installed as part of a CCS project in Australia. In this example, we translate the costs in Australia in A$ into costs in the USA in US$. We adopt a similar approach for converting costs in Australia into costs in countries other than the USA.

The cost translations in the table are described below (refer to the row numbers in the table).

18. We use a currency exchange rate to convert of purchasing equipment and materials.
19. There is no international freight because, for a CCS project in the USA, the equipment would be purchased in the USA.
20. We assume that the local freight costs in Australia in A$ are the same as the local freight costs in the USA in US$. The cost translation factor is therefore 1.
21. The cost including freight is the sum of the costs of items 1, 2 and 3.
22. Based on the relative wage rates of skilled labour and the relative productivity of skilled labour in Australia compared to the USA, the cost translation factor is 0.9 for construction and installation.
23. The Base Plant Cost, or Direct cost, is the sum of the costs of items 4 and 5.
24. Based on the relative salaries of professional engineers and their productivity, we assume a cost translation factor of 1.
25. The total Engineering, Procurement and Construction cost (“EPC”) is the sum of items 6 and 7. This is the total of Direct and Indirect costs.
26. We assume that Owners’ Costs (environmental approvals and related costs) are 7% of the EPC cost.
27. EPC plus the Owners’ (EPCO) costs. This is the sum of items 8 and 9 and applies to the whole CCS project.
28. Contingency represents the cost of miscellaneous unknown items. We assume that this is 10% of the EPCO costs.
29. Total project cost is the sum of items 10 and 11.

Conversion of costs in Australia to costs in USA — compressor example

Cost items	Cost in Australia A$MM	Translation Factor US$/A$	Cost in USA US$MM	Basis for Translation Factor
1. Equipment & materials cost	39.3	0.75	29.5	Exchange rate
2. International freight	3.9	0	0.0	Equipt manufactured in USA – no international freight
3. Local freight	2.0	1	2.0	Translation Factor - Assume 1 provisionally
4. Cost including freight	45.2	na	31.5	
5. Construction/Installation	16.7	0.9	15.0	Relative skilled labour wages & productivity
6. Base Plant Cost = Direct costs	61.9	na	46.5	Total of 4 and 5
7. Engineering & Project Management	9.3	1	9.3	Assume 1 for the Translation Factor.
8. EPC Cost	71.2	na	55.8	Total of 6 and 7
9. Owners costs	3.6	na	3.9	7% of EPC cost
10. Total EPC and O costs	74.8	na	59.7	Total of 8 and 9
11. Contingency	7.5	na	6.0	10% of total Direct and Indirect costs
12. Total Project cost	82.2	na	65.7	

Compressor specification

Manufacturer	Siemens	
Source	FOB German North Sea Port	
Required capacity	2	Mtpa
Train capacity	0.51	Mtpa/Train
Number of units required	4	Trains
Exchange rate	0.58	€/A$
Unit cost, original currency	5.7	€MM/Train
Equipment cost, original	22.8	€MM
Equipment cost, Australia	39.3	A$MM

Appendix 5. IEA Technical and Financial Assessment Criteria

CRITERIA FOR APPRAISAL STUDIES

Technical/Financial Factor (notes)	Assessment Convention
1. <u>Development Status</u> ***(It is well documented that the cost of technology decreases and its performance improves as experience is gained.)***	***For commercially available technology current 'state-of-the-art' cost and performance figures will be assumed.*** ***Where technology has only reached the demonstration stage or earlier stages of development, 1st (commercial) generation costs and performance will be assumed and compared with 'state-of-the-art' current figures. The cost vs. installed capacity relationship assumed should be presented in the results.***
2. <u>Plant Size</u> ***(Significant economics of scale can apply up to the size at which increases can only be obtained by using plant modules and/or the cost of working capital due to extended construction periods outweighs benefits of scale.)***	***The net power output after deducting ancillary power requirements will be 750 MW. There will be cases (e.g. gas turbines which have fixed sizes) where it is not possible or advisable to match the required net power output. In such cases the power output will be agreed with IEA GHG.***
3. <u>Location</u> ***(The standard site for IEAGHG studies is on the NE coast of The Netherlands; this appears to give costs which are in the middle of the range for OECD member countries.)***	***A green field site with no special civil works implications will be assumed. Unless otherwise specified, the plant will be assumed to be on the NE coast of The Netherlands. Adequate plant and facilities to make the plant self sufficient in site services will be included in the investment costs.*** ***Alternative and/or multiple sites will be specified for some studies.***
4. <u>Currency</u> ***(Converting US$ costs to a local currency equivalent involves more than using the current exchange rate; members of the IEA GHG programme will need to take their own views on appropriate rates.)***	***The results of the studies will be expressed in US $ applicable to a specific year. Data obtained in other currencies will be converted at rates to be agreed.***

<table>
<tr><th>Technical/Financial Factor (notes)</th><th>Assessment Convention</th></tr>
<tr><td>5. <u>Design and Construction Period</u>
(Project finances can be sensitive to the time required to erect the plant.)</td><td>Coal fired power generation plant: 3 years.
Natural gas fired combined cycle plant: 2 years.
CO_2 capture plant and ‘chemical plants’ in general: 2 years.
Underground CO_2 storage: 2 years
Ocean storage: 4 years (assuming a long pipeline to the disposal point)
Modular renewable technologies such as wind turbines: 1 year

Typical `S' curves of expenditure during construction will be used, viz:
<table>
<tr><th>Year</th><th>Coal-fired Power Plant %</th><th>Natural gas fired Power Plant %</th><th>`Chemical' Plant %</th></tr>
<tr><td>1</td><td>20</td><td>40</td><td>40</td></tr>
<tr><td>2</td><td>45</td><td>60</td><td>60</td></tr>
<tr><td>3</td><td>35</td><td></td><td></td></tr>
</table></td></tr>
<tr><td>6. <u>Plant Life</u>
(Design life to be used as a basis for economic appraisal. A financial assessment convention; actual life is frequently extended.)</td><td>Twenty-five years. Where for technical reasons this is regarded as excessive, provision will be made for the cost of any major maintenance/refurbishment or a shorter life will be assumed.</td></tr>
<tr><td>7. <u>Load Factor</u>
(Achieved output as a percentage of rated/nameplate capacity. Appropriate to the ranking of technical options; in practice, because of system limitations, many power plants achieve considerably less output.)</td><td>For coal, other solids, and liquid processing plants; 1st. year: 60% of rated capacity; subsequent years: 85% of rated capacity. For natural gas fuelled plants (and other plants solely processing gases) 90% of rated capacity for all operating years. Renewable technologies on a case-by-case basis.

Allowance should be made for sufficient installed duplicate/spare capacity to meet required load factor taking into account maintenance requirements and reliability. No allowance for decline as plant ages.</td></tr>
</table>

Technical/Financial Factor (notes)	Assessment Convention
8. <u>Cost of Debt</u> ***(Note that money is required during design, construction and commissioning i.e. before any returns on sales are achieved.)***	***For simplicity, all capital requirements will be treated as debt at the same discount rate used to derive capital charges. No allowance for grants, cheap loans etc. (More complex financial modelling might be considered for certain studies.)*** ***Specific capital cost figures should be presented without including an allowance for funds used during construction (i.e. independent of discount rate).***
9. <u>Capital charges; inflation</u> ***(In the event of the reduction in carbon emissions being achieved at a significantly later date than the expenditure, the investment costs should be projected forwards.)***	***Discounted cash flow calculations will be expressed at a discount rate of 10% and, to illustrate sensitivity, at 5%; the resulting capital charge rate will be quoted. All annual expenditures will be assumed to be incurred at the end of the year.*** ***Inflation assumptions will not be made. No allowance will be made for escalation of fuel, labour, or other costs relative to each other.***
10. <u>Contingencies</u> ***(A contingency is added to the capital cost to allow for unforeseen set-backs, cost under-estimates, programme overruns etc.)***	***A contingency will be added to the capital cost to give a 50% probability of a cost over-run or under-run. In the absence of a more detailed assessment, the default value for the contingency should be 10% of the installed plant cost (overnight construction).*** ***All plant should be assumed to be built on a turnkey basis, ie; the cost of risk should be built into the contractor's fees.***
11. <u>Fees and other owners costs</u> ***(The contractor's fees for design and build will form part of the basic plant cost estimate; additional fees and costs covered here include:- process/patent fees, fees for agents or consultants, legal and planning costs, land purchase, surveys and general site preparation etc. Start-up costs are not included here as they are calculated separately)***	***A total of 7% of the installed plant cost (overnight construction, excluding contingency) will be included to cover these owners costs.*** ***A separate statement of the cost should be made where any proprietary technology or other technology license fee exceeds 2% of the plant cost.***

Technical/Financial Factor (notes)	Assessment Convention
12. <u>Commissioning and Working Capital</u> ***(Commissioning is defined as the period between the construction period [item 3] and the start of the 1st year of operation [item 4]. Working capital includes raw materials in store, catalysts, chemicals etc.)***	***A 3 month commissioning period will be allowed for all plant. Sufficient storage for 30 days operation at rated capacity will be allowed for raw materials, products, and consumables (except for natural gas and other gaseous fuels in which case provision should be made for an alternative supply of fuel). No allowance will be made for receipts from sales in this period.***
13. <u>Decommissioning</u> ***(Costs associated with final shut down of the plant, long term provisions and 'making good' the Site).***	***This will be included to facilitate comparison with technologies where decommissioning can be a significant proportion of project cost.***
14. <u>Taxation and Insurance</u> ***(The treatment of these items will differ markedly from country to country. Therefore, a simple treatment is used which can be readily adapted to suit the circumstances of individual members.)***	***Allow 1% per year of the installed plant cost (overnight construction, excluding contingency and fees) to cover specific services e.g. local rates. Taxation on profits will not be included in the assessments.*** ***Allow 1% per year of the installed plant cost (overnight construction excluding contingency and fees) to cover insurance.***
15. <u>Maintenance</u> ***(To include labour, materials and contract maintenance costs)***	***Routine and breakdown maintenance will be allowed for at: 4% per year of installed plant cost (overnight construction excluding contingency and fees) for solids handling plant and at 2% per year for plants handling gases and liquids and services plant.***
16. <u>Labour</u> ***(Agreed conventions are required for the treatment of operating, supervising, maintenance and other labour elements; including administrative, other general overheads and items such as social security payments.)***	***The cost of maintenance labour is assumed to be covered by item 15.*** ***Operating labour only will be identified and assumed to work in a 5 shift pattern. If not estimated in detail, an allowance of 20% of the operating labour direct costs will be included to cover supervision. A further 30% of direct labour costs will be included to cover administration and general overheads. (ie; total cost = (direct operating labour cost x 1.2) x 1.3)***

Technical/Financial Factor (notes)	**Assessment Convention**
17. Fuels and Raw Materials ***(Where a range of fossil fuels could be used, coal and natural gas will normally be specified as they span the range of H:C ratios for fossil fuels.)***	***'Typical' bituminous coal and natural gas are used as a standards. Their specifications are given on the last page of this document.*** ***Where appropriate the analysis of alternative fossil fuels fuel will be supplied.*** ***The cost of coal delivered to site is to be assumed to be US$1.5/GJ (LHV basis).*** ***The cost of natural gas delivered by pipeline to site is to be assumed to be US$3/GJ (LHV basis).*** ***The studies will show the cost of power generated for a range of fuel prices (0-3 US $/GJ for coal and 0-6 US $/GJ for gas).***
18. Water.	***The use of sea water cooling will be assumed for the site in the Netherlands and other coastal sites. Direct cooling will be used for the steam turbine condenser and large compressor intercoolers and an indirect cooling system will be used for other process coolers. Unless otherwise stated, any inland sites will be assumed to use closed circuit cooling water systems.*** ***Sea-water cooling conditions are: Average inlet temperature 12C; maximum temperature rise 7C; salinity 22grams/litre.***

Technical/Financial Factor (notes)	**Assessment Convention**
19. Effluent/Emissions and Solids Disposal ***(a) Sulphur, ash, oils and tars, NO_x, SO_x etc (other than CO_2)***	***The plant will be assumed to have effluent abatement and treatment facilities sufficient to meet achievable reductions, eg*** ***Particulate matter < 25 mg/Nm^3*** ***NO_x < 200 mg/Nm^3*** ***SO_2 < 200 mg/Nm^3*** ***Where disposal of waste is required the cost of appropriate plant and methods will be included in the assessments. The cost of ash disposal, value of by-products e.g. sulphur, etc., will be treated on a case-by-case basis.***
(b) CO_2 processing.	***Unless otherwise specified, minimum CO_2 capture level is to be 80%; and the preferred level 85%.*** ***Unless otherwise specified, CO_2 is to be compressed to 110 bar before injection into the transfer pipeline.*** ***Note will be taken of possible emissions arising from CO_2 processing, eg, amine scrubbing.***
20. Site Conditions	***Ambient air temperature: 9C*** ***Ambient air relative humidity: 60%*** ***Ambient air pressure: 1.013 bar***
21. Heat Content	***Lower Heating Value will be used in all efficiency calculations***

FUEL SPECIFICATIONS

1. Natural gas specification

Component	**volume %**
Methane	83.9
Ethane	9.2
Propane	3.3
Butane +	1.4
CO_2	1.8
Nitrogen	0.4
Sulphur (as H_2S)	4 mg/Nm^3
Lower heating value	46.9 MJ/kg

The gas specification is based on a pipeline quality gas from the southern part of the Norwegian off-shore reserves.

2. Coal specification

Proximate analysis:	**weight %**
coal (dry, ash-free)	78.3
ash	12.2
moisture	9.5
Ultimate analysis:	
Carbon	82.5
Hydrogen	5.6
Oxygen	9.0
Nitrogen	1.8
Sulphur	1.1
Chlorine	0.03
Ash analysis:	
SiO_2	50.0
Al_2O_3	30.0
TiO_2	2.0
Fe_2O_3	9.7
CaO	3.9
MgO	0.4
Na_2O	0.1
K_2O	0.1
P_2O_5	1.7
SO_3	1.7
Gross CV	27.06 MJ/kg
Net CV	25.87 MJ/kg
Hardgrove Index	45
Ash fusion point (reducing atmosphere)	1350 C

The coal specification is based on an open-cut coal from Eastern Australia.

Module 13

Public awareness and community consultation

A.Bartlett

Overview

For CCS to be implemented on the scale needed to avoid dangerous climate change, work needs to be undertaken to inform and engage communities. The two aspects are broad public awareness about CCS and engaging the communities where CCS projects will be undertaken.

Learning objectives

By the end of this module you will:

- Understand the difference between public awareness and community consultation;
- Be familiar with the conclusions of current social research into awareness about CCS; and
- Be familiar with the principles for effective community engagement

Background

Governments around the world now regard CCS as a one of the measures needed to reduce greenhouse gas emissions and avoid dangerous climate change. Energy producers and other industries are beginning to look towards scaling up the technology. Consequently, the need to develop public awareness and acceptance of CCS as a climate change mitigation measure is now urgent. Already there are some projects that are unable to proceed due to community opposition.

Onshore CCS infrastructure and storage sites will be vital for implementing the technology in the time frame required. This may mean pipelines through and storage under populated areas. As the science and technology involved is complex, the messages about the need for CCS and the risks of CCS in the context of climate change need to be easily understandable and, most importantly, delivered by groups that communities trust.

There are two aspects to developing public awareness about CCS and working with communities where CCS projects are located. These are social research and communication. Social research is important to inform governments, develop policy and formulate communication strategies. Good communication is vital to a CCS project and whether that project proceeds.

Groups that have been active in the area of developing social research principles behind engaging the public and the community on CCS include:

- WRI - World Resources Institute;
- C3 – Climate Change Central;
- C2S2RN – Carbon Capture and Storage Social Research Network – an informal group; and
- CSIRO – Commonwealth Scientific and Industrial Research Organisation.

There have been a number of studies into the public awareness of CCS and public acceptance of CCS, as well as case studies in public consultation for various projects.

The APEC materials “Community Outreach Strategy for CO_2 Capture and Storage Projects”, which accompany this APEC training manual, are developed to provide a step-by-step strategy for community engagement.

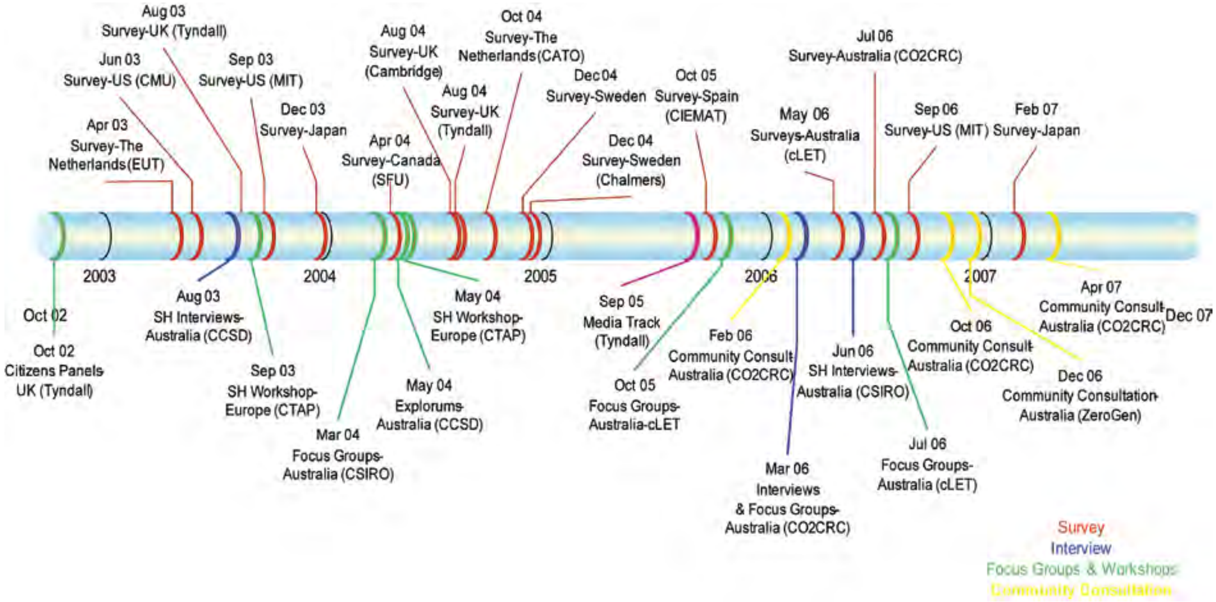


Figure 13.1: A timeline showing social research and communications activities. From An integrated roadmap of communications activities in Australia and beyond (CLET/CSIRO Report No:P2007/975).

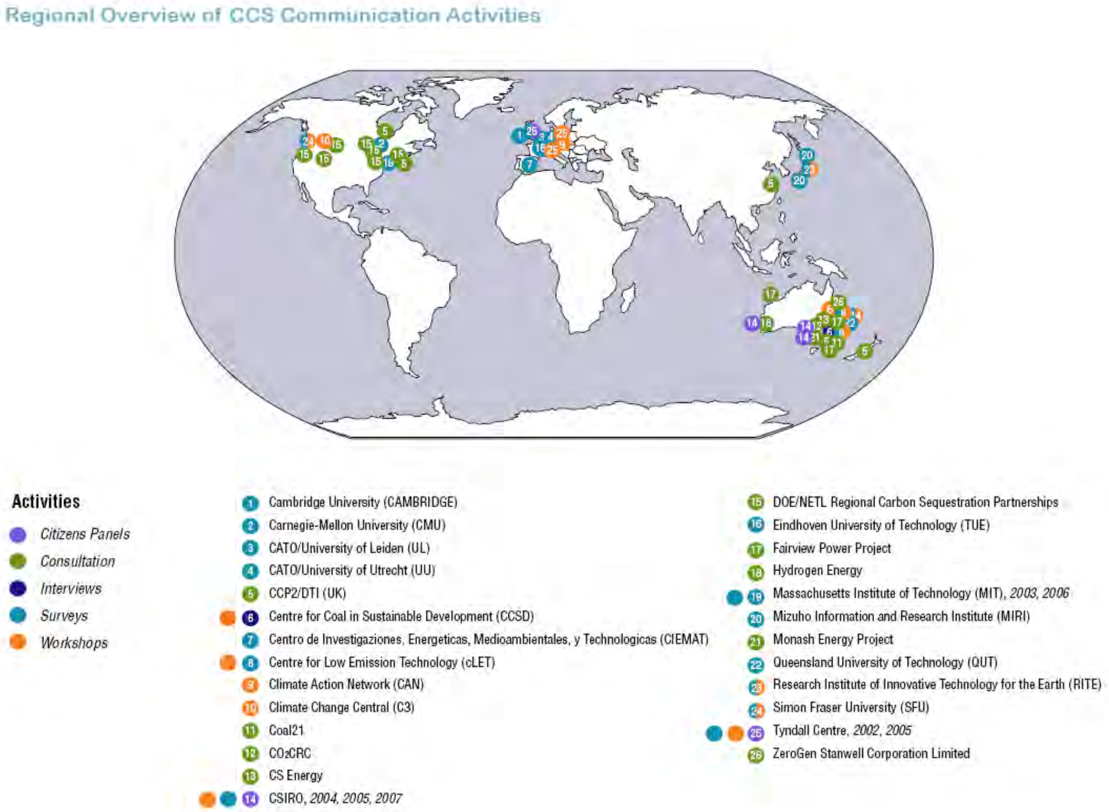


Figure 13.2: CCS communication activities. From An integrated roadmap of communications activities in Australia and beyond (CLET/CSIRO Report No: P2007/975).

Public awareness

The Carbon Dioxide Capture and Storage Social Research Network (C2S2RN) is an informal network set in up in January 2006. A major workshop, the Carbon Capture and Storage Communication Workshop, was held in September 2007 in Canada, hosted by Climate Change Central (C3). The key research findings were that:

- Once formed, opinions can be slow to change;
- Understanding of CCS remains low;
- There is a need to collaboratively provide balanced, valid and accessible information from a range of sources (i.e. industry, government and NGO);
- Face-to-face dialogue is the most effective way to communicate;
- Communication must be set in the context of climate change;
- Stringent regulation and monitoring should be an integral component of any CCS project; and
- CCS should not be implemented at the expense of investments in renewable energy (from Carbon Capture and Storage Communication Workshops Final Report.)

Surveys on knowledge of CCS were conducted in Japan in 2003 and 2007. The researchers found that few people know about CCS, and those that did know about CCS generally supported it. Some of the questionnaires contained additional information. Reports of concerns about CCS which were included in the questionnaire were found to have a negative influence on acceptance of CCS. Information on industrial activities and natural analogues for CO_2 storage impacted positively on groups' opinions about CCS. In addition, understanding the effectiveness of CCS was highly influential (Itaoka et al, 2009).

Stephens et al (2009) reported on a seminar on a CCS educational workshop held in the US in which the participants were surveyed about their attitude to CCS prior to the seminar, and then again after the seminar. In general, they found that the level of support for advancing CCS increased particularly amongst younger and more educated stakeholders.

Public concerns about CCS and its perceived benefits, found throughout various communications activities, have common themes, as outlined below (Ashworth et al, 2007).

Concerns:

- Safety risks of a CO_2 leak.
- The risk of contamination of ground water.
- Any harm to plants and animals near storage sites.
- Assumption CO_2 is explosive.
- Is it the wrong solution for climate change, a bandaid?
- Are there enough available storage sites?
- It appears to require a large infrastructure which does not necessarily exist today.
- Long term liability issues.
- Cost – economic efficiency.
- Scale required for successful CO_2 mitigation.
- It is an unknown technology.
- Should not be pursued at the expense of renewable energy sources.

Benefits:

- It could provide a good bridge to the future.
- If successful can reduce large quantities of CO_2 from the atmosphere.
- Allows continued use of fossil fuels which provides an economic advantage for some economies.
- Energy security around the world.
- Helps to clean up coal-fired power plants for developing economies that need access to energy.
- Allows emissions to be reduced without having to change lifestyles too much.

Communicating CCS in Italy

As an example of a long-term communication project, Instituto Nazionale di Geofisica e Vulcanologia, INGV, has communicated about CCS to the public in Italy and surrounding regions as part of the EU ZEP program over the period 2000-2008. Activities included attending science festivals with an interactive CCS scaled model, participation in debates and conferences and meeting with NGOs.

Italy is geodynamically active with CO_2 being naturally diffusely degassed (that is, emerging over time in small amounts over large areas). INGV have over 500 continuous monitoring stations to measure CO_2-related parameters and micro-seismicity throughout Italy and surrounding regions. Their message was that despite billions of tonnes of CO_2 being located underground in Italy, and strong seismic events throughout history, there have not been any large CO_2 bursts. One of the areas with diffuse degassing structures (DDS) is a WWF bird reserve. They also examined the naturally occurring CO_2-rich mineral waters as an analogue for storage in aquifers (Quatrocchi, 2009).

Public acceptance of CCS in Norway

Norway has the world's first commercial CCS project, the Sleipner Project. It also has an active NGO community who are involved in issues of conservation and the environment, including marine protection and climate policy. One of these, the Bellona Foundation, is a multidisciplinary international environmental NGO based in Oslo. It hosts a comprehensive website on CCS. Others NGOs such as Greenpeace Norway oppose CCS.

As the Sleipner Project raised no significant debate, the offshore and remote location is considered to be a key part of the public and NGO acceptance of CCS. Indeed, the attention drawn to the technology has led to calls for further CCS projects in Norway (IEA, 2007).

Project-based community engagement (community consultation)

World Resources Institute principles

Recent events in Germany and the Netherlands have highlighted the importance of involving the community in CCS projects from the early stages. The World Resources Institute (WRI) published a report – Breaking Ground: Engaging Communities in Extractive and Infrastructure Projects in 2009 (following on from the 2007 publication Development without Conflict: The Business Case for Community Consent). This report describes the broad principles required for industries such as the mining and petroleum industry to conduct meaningful community engagement in projects. WRI is following this up with Guidelines for Community Engagement regarding Carbon Dioxide Capture and Storage (CCS) Projects to be published later this year.

People living near a proposed CCS project who are potentially impacted by the project should be engaged as part of the CCS project and it is this group that is referred to as "community". Apart from the issues of social justice, there is evidence that community engagement during the development of projects, while adding to the initial costs, significantly reduces the costs incurred through lost project time or even cancellation of projects.

The WRI principles for effective community engagement are:

- Prepare communities before engaging;
- Determine what level of engagement is needed;
- Integrate community engagement into each phase of the project cycle;
- Include traditionally excluded stakeholders;
- Gain free, prior and informed consent;
- Resolve community grievances through dialogue; and
- Promote participatory monitoring by local communities.

Prepare communities before engaging

While communities have their own decision-making structures, they may need time to prepare for engagement in a CCS project. Aspects of this preparation include training community representatives, site visits to CCS projects and access to legal and technical advisors. Project proponents could benefit from cultural training and identifying decision makers through participatory mapping.

Determine what level of engagement is needed

Levels of engagement are informing, consulting and negotiating. Informing communities that decisions have been taken is not appropriate in the early stages of a project. Access to information should be provided before main activities relating to community engagement begin, communities should be engaged before taking decisions and the project proponents should respond to community input by demonstrating how the input has affected decision making. Negotiations may need to take place prior to project commencement (e.g. if land needs to be purchased or access rights are required).

Integrate community engagement into each phase of the project cycle

Engaging the community at all stages of the project (pre-feasibility, feasibility, construction, operation and closure and ongoing monitoring) is important to ensure that the community can prepare for and respond to the changing stages in the project. Site selection for CO_2 storage should include a social impact assessment along with environmental impact assessments.

Include traditionally excluded stakeholders

It may be necessary to identify marginalized groups within a community. Separate meetings may need to be held to enable groups to speak comfortably. Identifying communities outside the immediate vicinity of the project which may be affected is also important.

Gain free, prior and informed consent

This can be a challenge in communities with a mix of indigenous and non-indigenous people, or when several groups have right to the same land/resources or when the government does not to recognise the rights of various groups. However, one effective way of obtaining consent is by negotiating an impact benefit statement at the end of the feasibility phase.

Resolve community grievances through dialogue

A formal grievance mechanism can help to detect systemic problems in projects, avoid issues with personnel changes and help to meet the needs of diverse communities. These grievance mechanisms should be low-cost, inclusive of all stakeholders and record and track progress.

Promote participatory monitoring by local communities

The community should have access to information about the project. In addition, there is an opportunity with CCS projects to involve the local community in scientific sampling. A CCS project which will require ongoing monitoring and the involvement of trained members of the local community in this can build the skill base of the community and improve their understanding of the project.

Seven steps to community engagement

The APEC *Community Outreach Strategy for CO_2 Capture and Storage Projects* guides projects through seven steps to engage the community in a project.

These are

Step 1: Develop a team and a plan to communicate with the public about your planned CO_2 storage project

Step 2: Identify and prioritize community groups relevant to the project

Step 3: Define and test the interests, priorities and concerns of community groups

Step 4: Prepare communications plan, messages and materials

Step 5: Delivering the messages and listening to community groups

Step 6: Measuring the effectiveness of the outreach

Step 7: Develop a long-term communication plan with community groups

Figure 13.3: Local residents are briefed by project leaders in a community reference group meeting for the CO2CRC Otway Project (courtesy of CO2CRC).

Examples of CCS community engagement

A number of existing CCS projects developed community engagement strategies which include the use of focus groups and community consultations.

Three of the US DOE’s Regional Carbon Sequestration Partnerships, West Coast (WESTCARB), Southwest (SWP) and Midwest (MRSCP) have conducted a series of focus groups. They found that social factors including past experience with government were of greater concern than concerns about the risks of the technology itself. Key questions that the public are likely to raise and should be considered by project proponents before beginning community consultation concern

- who is responsible for the project;
- will they take care of the community if things go wrong;
- will the community have any say in the project and; and
- what are the benefits to the community of the project (Bradbury et al, 2009).

Bielicki and Stephens (2008) outline four examples of public engagement on CCS in the US. The examples serve to illustrate that there are many different groups for which communications strategies can be designed and the questions that the public raise are instrumental in shaping those strategies.

At the C3 CCS Communication Workshops in Canada, Mary Griffiths of the Pembina Institute provided advice about engaging local communities.

- Provide poster displays with general information on CCS and its geological aspects prior to talks.
- Have an experienced facilitator and clear ground rules.
- Have speakers who are good communicators, but have technical experts available.
- Use relevant examples (e.g. the Weyburn Enhanced Oil Recovery project, or acid gas injection).
- Have opportunities for a question and answer session.
- Record the information and put posters, presentations, questions and answers on a website so that the wider public can learn as well (from Carbon Capture and Storage Communication Workshops Final Report).

The CO2CRC Otway Project – community consultation in action

The CO2CRC Otway Project in south-western Victoria, Australia, is a research demonstration project of the injection, storage monitoring and verification of CO_2. The project commenced in 2003 and injection began in April 2008. To date, in Stage 1 of the project, 65,000 tonnes of CO_2 has been injected into a depleted gas field 2.25 km below dairy-farming paddocks. The first discussion with the landowners and local council took place in early 2004. Further community consultation for the Project was developed and modified on the results of social research carried out in 2006, comprising qualitative research and a quantitative survey. Community consultation meetings have been held with the local community throughout 2006 and 2007 and since injection began to the present. The community meetings include landholders, local businesses, environmental groups, government officials, the local media and the general community.

Figure 13.4: The CO2CRC Otway Project community reference group meets on the first birthday of the Project to discuss the next stage of research (courtesy of CO2CRC).

Fact sheets and community newsletters also underpin the community consultation process. CO2CRC has a local Community Liaison Officer who lives in the area. She personally visits landowners to inform them of upcoming activities such as seismic monitoring. The community liaison officer is able to bring concerns of individual landowners and the community to the project manager for resolution.

Scientific monitoring of the stored CO_2 is carried out in a community-friendly way. The visiting scientists are briefed on the concerns of residents and landowners and how to conduct their experiments with consideration for the needs of the community. In addition, local university students are involved in the collection of water samples as part of the monitoring program.

A community reference group of landowners, regulators, local NGOs and project management was established in the early stages of the project. Initially, meetings were held frequently and are now held prior to major changes in the project's operation and when significant results are obtained.

The Otway Project has general community acceptance and mainly positive media coverage. A second stage of the Project will begin shortly to research CO_2 storage in saline aquifers.

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Websites

World Resources Institute: www.wri.org/climate

CO2CRC Otway Project: www.co2crc.com.au/otway/

C2S2RN: www.climatechangecentral.com/ccs/

Module 14

Potential for CO_2 capture and storage in the APEC region

Original text: S. Bachu, APEC Capacity Building in the APEC Region, Phase II
Revised and updated by CO2CRC

Overview

A number of economies in the APEC region have strong potential for CO_2 capture and storage. The potential of industrialized economies is generally well known, and most of these economies are considered international leaders in the field. The potential of developing economies in the APEC region is generally less well known. This module gives an indication of CCS potential in the APEC region as a whole, based on a study in 2004. Updates from work completed in individual economies is included.

Learning Objectives

By the end of this module you will:

- Have a broad understanding of the potential for CO_2 capture and storage in the APEC region in industrialized and developing economies;
- Be able to identify specific basins or regions in APEC economies which should be considered for further research and analysis; and
- Be aware of the general process that can be used to short-list potential basins for analysis of their potential for CO_2 storage.

Global-Scale Potential for CO_2 Capture and Geological Storage in the APEC Region

The potential for CO_2 capture and geological storage of any region and at any scale is based on the following two broad criteria:

- **Availability of CO_2 sources -** the current and forecasted existence of large, stationary CO_2 sources, such as thermal power generation, refineries, cement plants, petrochemical plants and large industrial complexes, that will allow CO_2 capture on a large scale is needed to supply CO_2 to storage sites.
- **Availability of economically suitable storage reservoirs -** The existence of geological media (sedimentary basins) suitable for CO_2 storage within economically viable distance that meet the criteria of capacity and safety is also required.

The criteria for selecting a CO_2 source and storage basin are provided in Module 6. These criteria apply as well to the APEC region, which currently comprises the following economies: Australia, Brunei, Canada, Chile, People's Republic of China, Hong Kong (China), Indonesia, Japan, Republic of Korea, Malaysia, Mexico, New Zealand, Papua New Guinea, Peru, Philippines, Russia, Singapore, Chinese Taipei, Thailand, United States and Viet Nam (Figure 14.1).

Figure 14.1: Geographic location of APEC economies.

In general terms, the potential for CO_2 storage in geological media in the APEC region can be defined as:

Likely small in small- and medium-sized economies along the Pacific Rim - this is because circum-Pacific sedimentary basins are located in a region of plate subduction, active tectonism and volcanism, are faulted, and are generally smaller in size than divergent sedimentary basins on the stable continental lithosphere (Bachu, 2003).

Large in continental-sized economies, with storage sites located in areas away from the Pacific Rim - such as Australia, Canada, People's Republic of China, Russia and the United States. For these economies, as well as for Mexico, the greatest potential for CO_2 storage is in regions that are farther away from the Pacific Ocean. For example, in the case of Canada, United States and Mexico, the potential is largely on the Eastern side of the Rocky Mountains and along the coasts of the Atlantic Ocean and the Gulf of Mexico. In Australia, significant potential exists for storage in offshore oil and gas reservoirs in Western Australia along the Indian Ocean. In China and Russia, it is assumed that significant potential exists in the inland portion of the Asian continent and in European part of Russia.

This analysis is based on global-scale tectonism and geology, only. It will need to be complemented by a more detailed analysis of sedimentary basins, and of CO_2 sources and emissions, before the potential for CO_2 storage in the APEC region can be fully evaluated.

Sedimentary basins with greatest potential for CO_2 storage in industrialized economies of the APEC region

The industrialized economies in the APEC region are Australia, Canada, Japan, New Zealand and the United States. These economies are leaders in the field of CO_2 capture and storage (CCS) and their potential for storage is better known. All these economies have vigorous programs in CCS, a strong research program, and roadmaps for CCS implementation. By and large, each of these economies has completed the initial steps of creating an inventory of CO_2 sources and estimating CO_2 capacity. They are now at various stages of source-sink matching (see, for example, Bradshaw et al., 2004; Dooley et al., 2005).

The potential of each of these economies is as follows.

Canada and the **United States –** a Carbon Sequestration Atlas of the United States and Canada has been published. It is the first coordinated assessment of carbon capture and storage (CCS) potential across the majority of the U.S. and portions of western Canada. The total storage capacity in oil and gas fields is estimated to be approximately 138 $GtCO_2$ The total CO_2 storage capacity in deep saline aquifers is the estimated to lie between 3,297 $GtCO_2$ and 12,618 $GtCO_2$. Unmineable coal seams are estimated to have a storage potential of between 157 and 178 $GtCO_2$ (DOE/NETL, 2008).

Australia's sedimentary basins have the potential to store more than a century of Australia's CO_2 emissions (Bradshaw et al., 2004). Since Australia is not a major hydrocarbon producer, its CO_2 storage capacity in depleted reservoirs is likely small, but will contribute to Australia's needs. There are only niche opportunities for CO_2-EOR, due to the high primary recovery and very good reservoir quality, and to the light oils that are present (Bradshaw and Rigg, 2001; Bradshaw *et al*., 2002). In regard to deep saline aquifers, an initial storage capacity estimate of 740 $GtCO_2$ was determined. (Bradshaw *et al*., 2004). Regional studies focusing on various basins in Australia have been carried out by CO2CRC over the past several years, Queensland has published a storage atlas, and an atlas for NSW is forthcoming.

New Zealand's CO_2 emissions are small; however, the northern island most likely has potential to meet its requirements. The southern island has some potential in the foreland basin; however, generally there are no major CO_2 sources. A "satellite study" was carried out in 2006/2007 and further regional studies followed this.

Japan's total capacity has been estimated to 146.1 $GtCO_2$ (RITE, 2007) in deep saline aquifers mostly in offshore basins (CO_2 geological storage project being implemented by the Research Institute of Innovative Technology for the Earth (RITE)). Japan has no storage capacity in hydrocarbon reservoirs and minimal sedimentary basins that would meet the criteria for geological storage of CO_2. Although a leader in the field of CO_2 capture and storage, initial indications are that geological storage capacity will be limited in Japan.

The circum-Arctic basins in the United States and Canada are considered to have lower potential because of the distances involved to reach these basins, the harsh conditions, and the lack of close CO_2 sources and infrastructure to support CO_2 capture and storage (Bachu, 2003).

Sedimentary basins with greatest potential for CO_2 storage in developing economies of the APEC region

There are 400 identified sedimentary basins in all the APEC economies, including those in their offshore territorial waters (St. John et al., 1984; USGS, 2000). The potential for CO_2 storage in sedimentary basins under the jurisdiction of developing economies of the APEC region is less well known. A study was commissioned by the Asia-Pacific Economic Cooperation to undertake the first broad analysis of the potential of these basins (Bradshaw et. al., August 2004 and Bradshaw et. al., October 2004).

The authors of the study undertook a series of analyses to prioritize further research and characterisation of sedimentary basins suitable for CO_2 storage in developing economies of the APEC region. This was required for this study in particular, due to time and budgetary constraints. Further analysis will be required before a fully representative list of potential storage basins and specific sites can be finalized. In the first step of the prioritization exercise, the following economies and/or regions were excluded or considered of low potential or priority for the stated reasons:

- **The circum-Polar region of Russia –** is considered as having low potential for the same reasons as the circum-Polar regions of Canada and the United States.
- **European Russia -** was excluded because of the significant distances involved, and of the different conditions that apply in European Russia than in the rest of the APEC region.
- **City states –** such as Singapore and Hong Kong, China have relatively small CO_2 emissions. In addition, their potential for CO_2 geological storage theoretically lies offshore, where international law and issues of jurisdiction, territorial waters, and right of passage apply.
- **Brunei –** although an oil producer, similarly has small emissions. Its potential likely lies offshore.
- **APEC economies with low CO_2 emissions** – were considered a lower priority for the analysis. These economies include: Ecuador, Peru, and Chile along the Andes Mountains in South America, and Papua New Guinea in Asia. Sedimentary basins in these economies are mostly intramontane, with difficult access and far from CO_2 sources, or offshore.
- **Mexico –** its potential for CO_2 geological storage lies on the Atlantic side rather than on the Pacific side, east of the mountain ranges and in the Gulf of Mexico.
- **Sedimentary basins of poor potential for CO_2 storage –** exclusion of abyssal sediments on oceanic crust, areas of folded platforms, and basins composed largely of volcanogenic sediments.

Excluding the above economies and basins, 170 of the 400 existing basins in the APEC region are deemed to be of interest currently for assessing their potential, suitability and capacity for CO_2 geological storage. The sedimentary basins in Asian APEC economies considered in the current study are shown in Figure 14.2. Basins in the following APEC economies were retained for further analysis: (counterclockwise starting from northeast Asia, see Figure 14.1): Russia (Asian part), the Republic of Korea, the Peoples' Republic of China, Chinese Taipei, Viet Nam, the Philippines, Thailand, Malaysia and Indonesia.

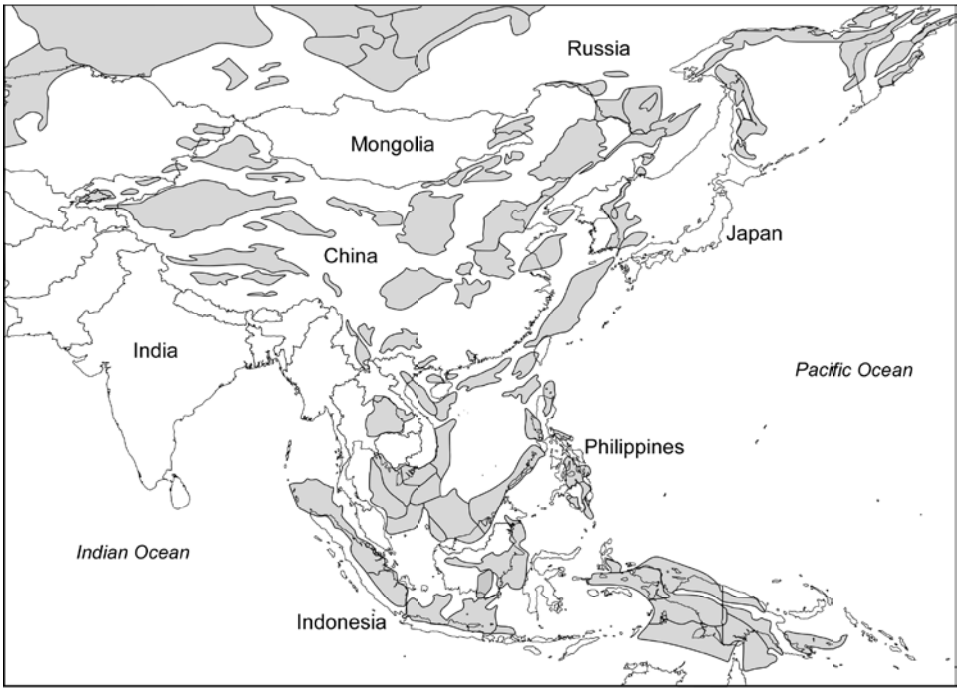

Figure 14.2: Sedimentary basins in Asian APEC economies (modified from Bradshaw et. al., August 2004).

In an attempt to further prioritize sedimentary basins to be considered for this analysis, the CO_2 emissions in these economies were taken into account based on the report “1998 CO_2 Emissions of East and South-East Asia” (IEA GHG Programme, 2002). The CO_2 sources in Asia can be consolidated into CO_2 nodes, whose distribution is shown in Figure 14.3. As illustrated, developing APEC economies in Asia, with significant CO_2 emissions are: the Republic of Korea, the People’s Republic of China, Thailand, Malaysia, Indonesia and the Philippines.

Note there has been significant growth in China’s use of fossil fuel energy since these emissions map was produced. There are estimated to be over 1,620 large stationary point sources which emit over 3.8 $GtCO_2$ (Li et al, 2009). Those point sources are distributed mainly in the East and South Central Administrative Regions. A map of the emission sources can be found in Dahowski et al. This paper also includes a map of potential storage formation in China. The majority of storage in China (99%) is in deep saline formations – capacity estimates are 2,300 $GtCO_2$ onshore and 780 $GtCO_2$ offshore.

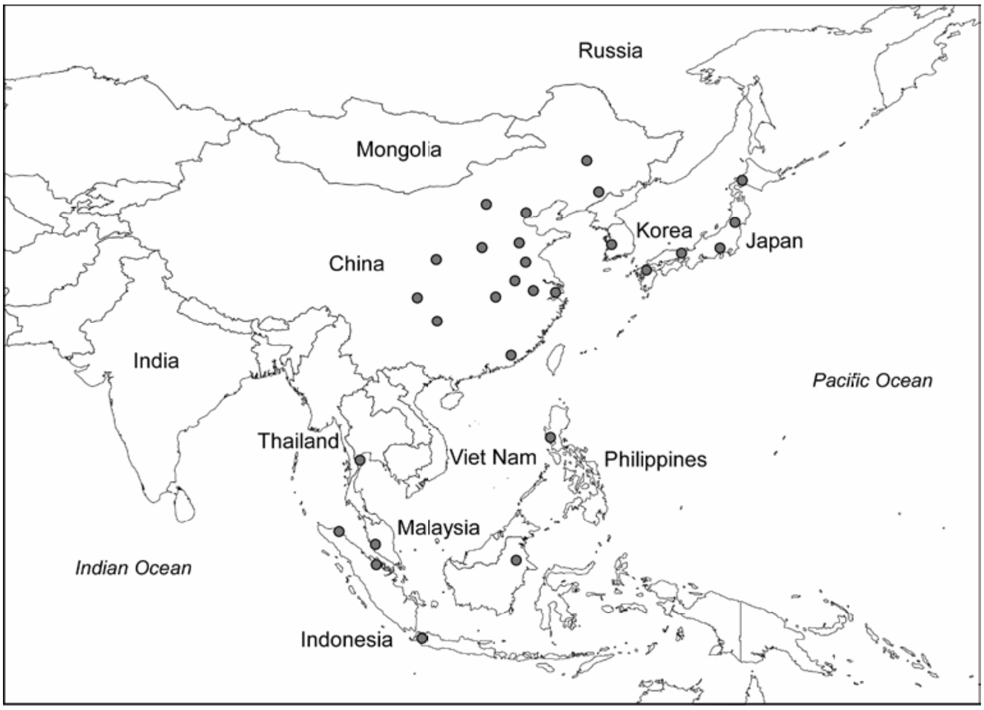

Figure 14.3: Asian APEC economies with significant CO_2 emissions and location of major CO_2- nodes (modified from Bradshaw et. al., August 2004).

All source-sink matching studies to date (also called “cost-curves for CO_2 capture and storage”) have used an arbitrary radius of 300 km around a CO_2 node. This is based on the premise that this represents an appropriate (economic) distance for a pipeline to be run, although, much longer pipelines are likely to be utilized in some future projects. If this limit of 300 km is used, then the number of sedimentary basins of interest in the APEC region in Asia is further reduced, as shown in Figure 14.4.

In China, 91% of large stationary sources of CO_2 are within 161km of a candidate storage formation. However, there are many sources in the east and south central regions that are more than 240km from potentially suitable storage basins (Dahowski et al, 2009).

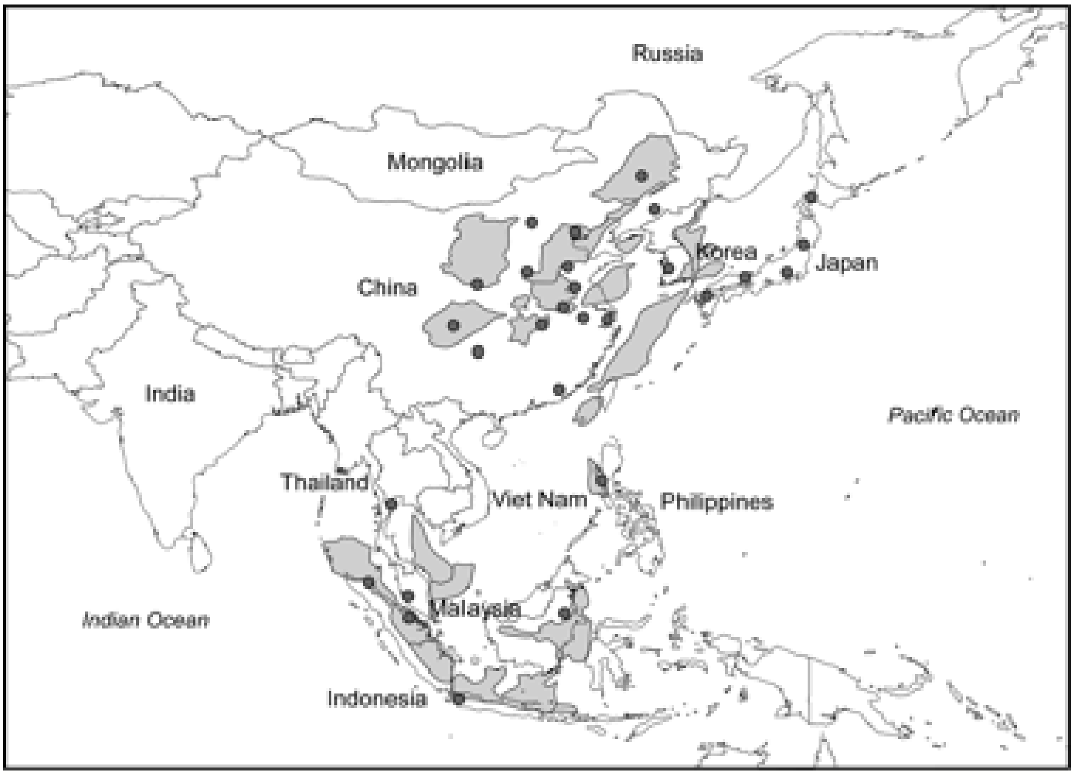

Figure 14.4: Sedimentary basins in Asian APEC economies within 300 km distance from major CO_2 nodes (modified from Bradshaw et. al., August 2004).

It should be noted that there are CO_2 sources that have an extremely high purity (close to 100%), outside these CO_2 nodes. These are very economically attractive for CO_2 storage. Most of these are produced from hydrogen production in refineries and ammonia plants. The location of these high-purity CO_2 sources is shown in Figure 14.5.

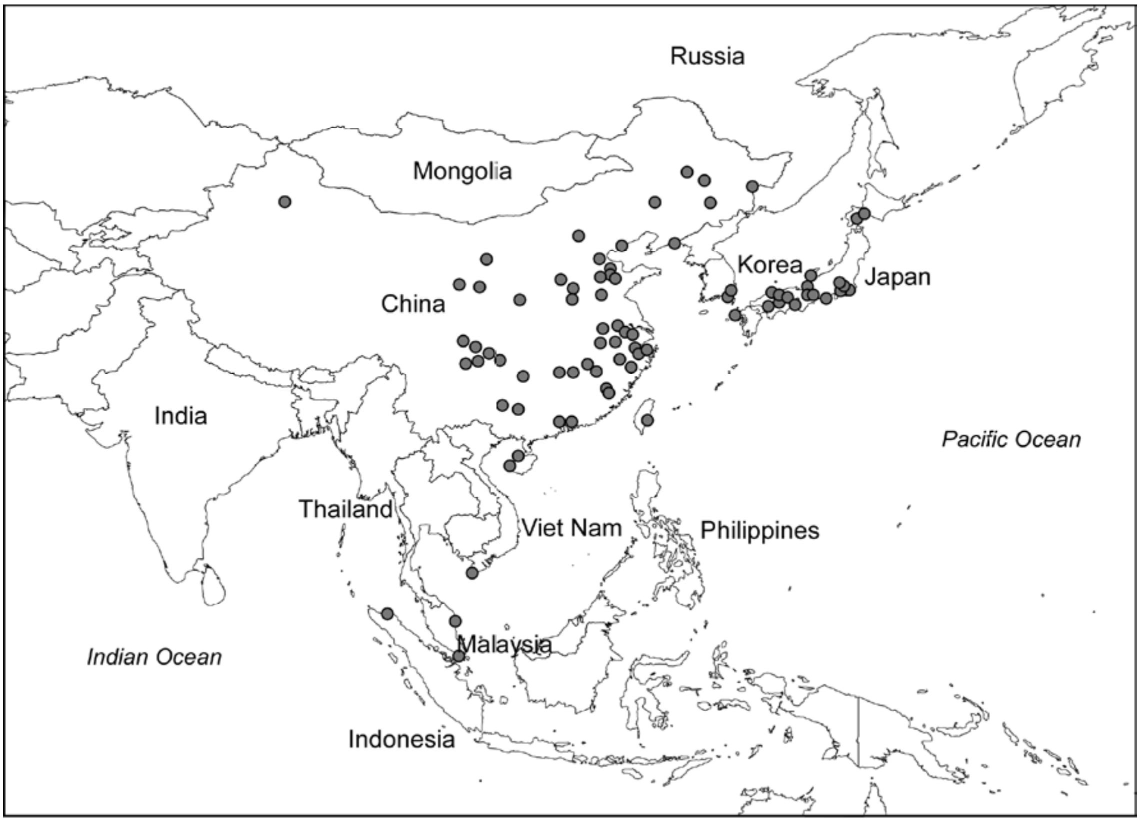

Figure 14.5 Location of high-purity CO_2 sources in Asian APEC economies (modified from Bradshaw et. al., October 2004).

If only the general CO_2 nodes and the location of high-purity CO_2 sources are taken into account, the number of sedimentary basins that should be considered for CO_2 geological storage in APEC economies in east and south-east Asia is reduced to 30, as shown in Figure 14.6. These basins are listed in Table 14.1.

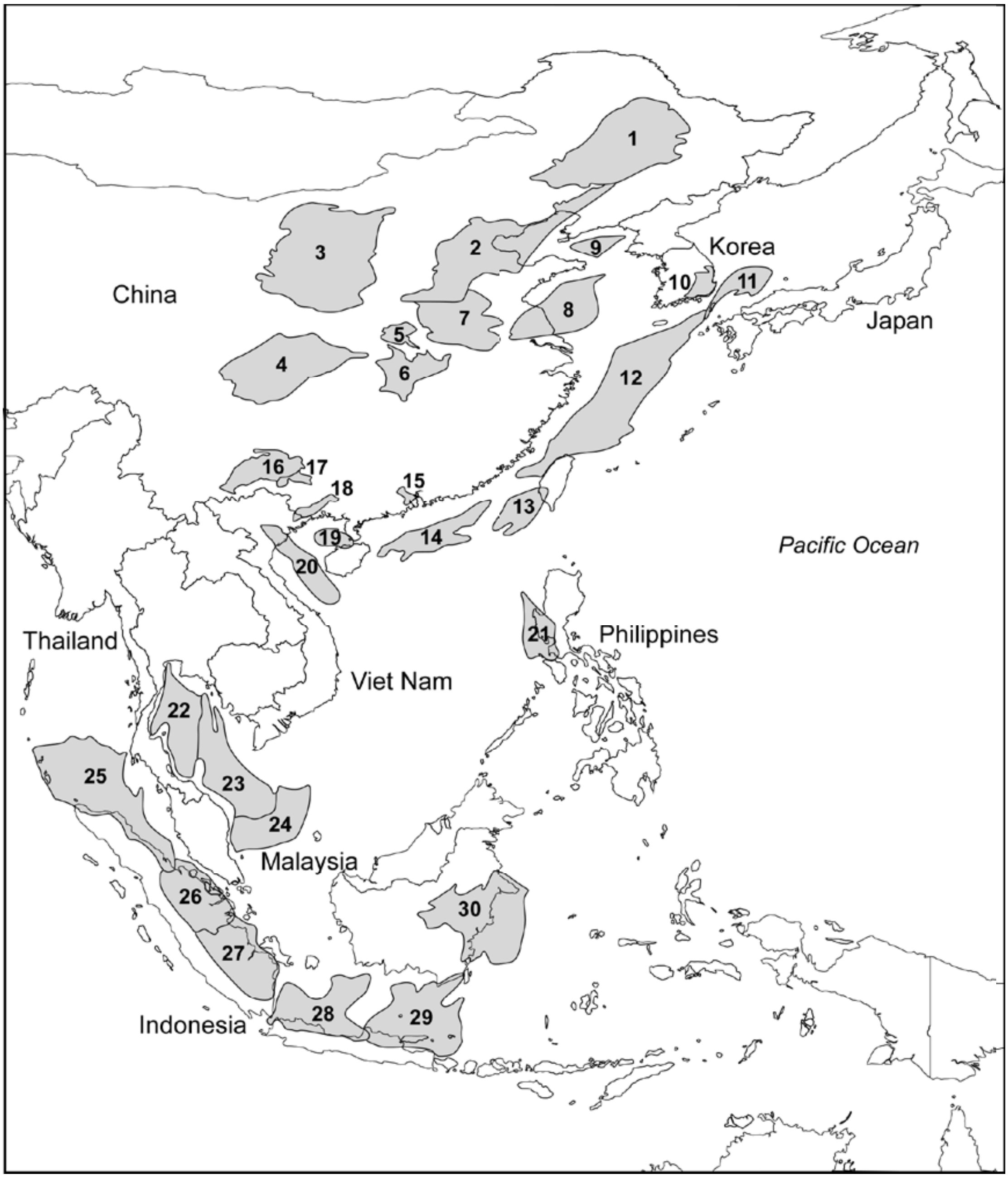

Figure 14.6: Sedimentary basins in East and Southeast Asian APEC economies that would potentially be primary targets for CO_2 geological storage based on their proximity to major CO_2 sources (modified from Bradshaw et. al., October 2004, see Table 14.1 for basin names).

#	Basin Name	#	Basin Name	#	Basin Name
1	Songliao	11	Tsushima	21	Zambalez/Central Luzon
2	Bohaiwan	12	East China Sea	22	Thai
3	Ordos	13	Taixinan	23	Malay
4	Sichuan	14	Pearl River Mouth	24	Penyu/West Natuna
5	Nanyang	15	Sanshui	25	North Sumatra
6	Jianghan	16	Nanpanjiang	26	Central Sumatra
7	Taikang Hefei	17	Bose	27	South Sumatra
8	Subei Yellow Sea	18	Shiwan Dashan	28	Northwest Java
9	Korea Bay	19	Beibuwan	29	East Java
10	Gyeongsang	20	Yinggehai	30	Kutei

Table 14.1: Sedimentary basins in Asian APEC economies that would potentially be primary targets for CO_2 geological storage based on their proximity to major CO_2 sources (modified from Bradshaw et. al., August 2004. For location see figure 14.6).

Some of the sedimentary basins that were identified as top priority for further detailed analysis in the APEC commissioned study have specific challenges associated with their development for CO_2 geological storage. This is particularly true for those that are located off-shore, indicating that the probability of implementing CO_2 geological storage is not equal for all the short-listed basins. This is true even if they are within 300 km distance from major CO_2 emission centers and/or sources of high-purity CO_2.

According to general principles of customary international law, States can exercise their sovereignty in their territories and, therefore, could engage in activities such as CO_2 geological storage in those areas under their jurisdiction, particularly onshore. However, if such storage causes transboundary impacts, States have the responsibility to ensure that activities within their jurisdiction or control do not cause damage to the environment of other States or of areas beyond the limits of an economy's jurisdiction. More specifically, there exist a number of global and regional environmental treaties, notably those on climate change and the law of the sea and marine environment which, as presently drafted, could be interpreted so as to indicate the permissibility or otherwise of CO_2 geological storage.

A series of off-shore basins in East and Southeast Asia are found in international waters or straddle the territorial waters of more than one economy. Regulations regarding the storage of CO_2 offshore are still underdevelopment (see Module 10).

In addition, if the location of these basins (on-or offshore), accessibility and possible lack of infrastructure (particularly for offshore basins) are taken into account, it is likely that offshore basins will be used for CO_2 geological storage much later than onshore basins, if at all (Bachu, 2003; see Module 6 for more discussion on this topic). Among the 30 selected basins, the ones that would fall into this category are: Korea Bay, Tsushima, East China Sea, Taixinian, Pearl River Mouth, Beibuwan, Yinggehai, Thai, Malay, Penyu/West Natuna, North Sumatra, Northwest Java and East Java. The remaining 17 basins should be the focus of more detailed studies for determination of their suitability and capacity for CO_2 geological storage.

Summary

Circum-Pacific sedimentary basins are less favorable for CO_2 storage because they are located in tectonically unstable areas with faults and have generally smaller capacity for storage. The highest potential for CO_2 storage in the APEC region is in large, continental-sized economies. The most promising sites would be in areas away from the Pacific Rim. This would include: Australia, Canada, Mexico, the Peoples' Republic of China, Russia and the United States.

The potential of industrialized economies within the APEC region is generally known. Australia, Canada, New Zealand and the United States have the most potential for storage. These economies are also generally leaders in the field and have strong research and implementation programs in place to support CO_2 capture and storage.

There are 400 known sedimentary basins in APEC economies. The potential of these basins in developing economies of the APEC region is generally unknown, although significant moves have been made to map storage basins in some economies.

A number of regions or economies in developing areas of APEC can be excluded from this analysis as they have low potential or priority for CO_2 storage. As a result, sedimentary basins in Russia (the Asian part), the Republic of Korea, the Peoples' Republic of China, Chinese Taipei, Viet Nam, the Philippines, Thailand, Malaysia, Indonesia and Mexico have the most potential.

Sufficiently high CO_2 emissions are important criteria for prioritizing basins in APEC developing economies. Without adequate CO_2 emissions, sufficient CO_2 capture for storage is not possible or economically prohibitive.

A distance of 300 km from a CO_2 node (source) is generally accepted as the economic limit for feasibility. However, sources of extremely high CO_2 purity outside of these limits should also be considered.

Some of the basins that resulted from the APEC commissioned study are located in offshore areas. These will be subject to international laws and treaties and could raise the coasts of developing them.

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