

CHAPTER 5

CARBON DIOXIDE TRANSPORT, INJECTION AND GEOLOGICAL STORAGE

Authors

Sam Holloway (UK), Anhar Karimjee (USA),
Makoto Akai (Japan), Riitta Pipatti (Finland), and Kristin Rypdal (Norway)

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5 CARBON DIOXIDE TRANSPORT, INJECTION AND GEOLOGICAL STORAGE

5.1 INTRODUCTION

Carbon dioxide (CO_2) capture and storage (CCS) is an option in the portfolio of actions that could be used to reduce greenhouse gas emissions from the continued use of fossil fuels.

At its simplest, the CCS process is a chain consisting of three major steps: the capture and compression of CO_2 (usually at a large industrial installation¹), its transport to a storage location and its long-term isolation from the atmosphere. IPCC (2005) has produced a Special Report on Carbon Dioxide Capture and Storage (SRCCS), from which additional information on CCS can be obtained. The material in these Guidelines has been produced in consultation with the authors of the SRCCS.

Geological storage can take place in natural underground reservoirs such as oil and gas fields, coal seams and saline water-bearing formations utilizing natural geological barriers to isolate the CO_2 from the atmosphere. A description of the storage processes involved is given in Chapter 5 of the SRCCS. Geological CO_2 storage may take place either at sites where the sole purpose is CO_2 storage, or in tandem with enhanced oil recovery, enhanced gas recovery or enhanced coalbed methane recovery operations (EOR, EGR and ECBM respectively).

These Guidelines provide emission estimation guidance for carbon dioxide transport, injection and geological storage (CCGS) only. No emissions estimation methods are provided for any other type of storage option such as ocean storage or conversion of CO_2 into inert inorganic carbonates. With the exception of the mineral carbonation of certain waste materials, these technologies are at the research stage rather than the demonstration or later stages of technological development IPCC (2005). If and when they reach later stages of development, guidance for compiling inventories of emissions from these technologies may be given in future revisions of the Guidelines.

Emissions resulting from fossil fuels used for capture, compression, transport, and injection of CO_2 , are not addressed in this chapter. Those emissions are included and reported in the national inventory as energy use in the appropriate stationary or mobile energy use categories. Fuel use by ships engaged in international transport will be excluded where necessary by the bunker rules, whatever the cargo, and it is undesirable to extend the bunker provisions to emissions from any energy used in operating pipelines.

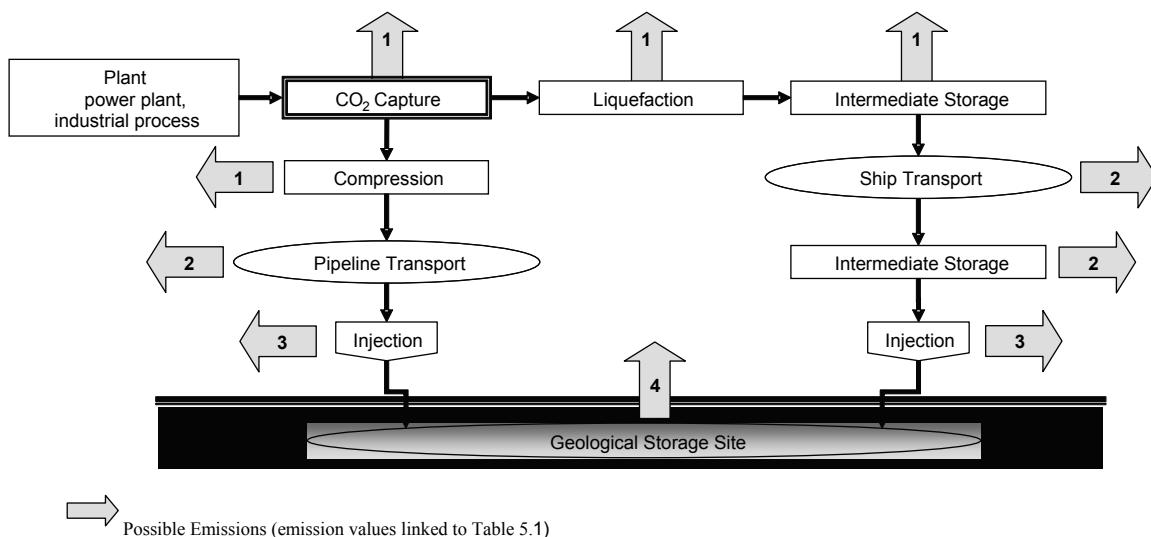
5.2 OVERVIEW

In these Guidelines, the CO_2 capture and geological storage chain is subdivided into four systems (Figure 5.1)

1. Capture and compression system. The systems boundary includes capture, compression and, where necessary, conditioning, for transport.
2. Transport system. Pipelines and ships are considered the most likely means of large-scale CO_2 transport. The upstream systems boundary is the outlet of the compression / conditioning plant in the capture and compression system. The downstream systems boundary is the downstream end of a transport pipeline, or a ship offloading facility. It should be noted that there may be compressor stations located along the pipeline system, which would be additional to any compression in System 1 or System 3.
3. Injection system. The injection system comprises surface facilities at the injection site, e.g. storage facilities, distribution manifold at end of transport pipeline, distribution pipelines to wells, additional compression facilities, measurement and control systems, wellhead(s) and the injection wells. The upstream systems boundary is the downstream end of transport pipeline, or ship offloading facility. The downstream systems boundary is the geological storage reservoir.
4. Storage system. The storage system comprises the geological storage reservoir.

¹ Examples of large point sources of CO_2 where capture is possible include power generation, iron and steel manufacturing, natural gas processing, cement manufacture, ammonia production, hydrogen production and ethanol manufacturing plants.

Figure 5.1 Schematic representation of the carbon capture and storage process with numbering linked to systems discussion above.



This chapter does not include guidance for CO₂ capture and compression. A brief summary and information on where to find emissions estimation guidelines for CO₂ capture and compression can be found in Section 5.3. Guidelines for compiling inventories of emissions from the CO₂ transport, injection and storage systems of the CCGS chain are given in Sections 5.4, 5.5 and 5.6 of this Chapter, respectively. Fugitive emissions from surface facilities at EOR, EGR and ECBM site (with or without CO₂ storage) are classified as oil and gas operations and Volume 2, Chapter 4 provides guidance on estimating these emissions. Emissions from underground storage reservoirs at EOR, EGR and ECBM sites are classified as emissions from geological storage sites and Section 5.7 of this Chapter provides guidance on estimating these emissions.

Table 5.1 shows the categories in which the emissions from the CO₂ transport, injection and storage systems are reported.

5.3 CO₂ CAPTURE

Anthropogenic carbon dioxide emissions arise mainly from combustion of fossil fuels (and biomass) in the power generation, industrial, buildings and transport sectors. CO₂ is also emitted from non-combustion sources in certain industrial processes such as cement manufacture, natural gas processing and hydrogen production.

CO₂ capture produces a concentrated stream of CO₂ at high pressure that can be transported to a storage site and stored. In these Guidelines, the systems boundary for capture includes compression and any dehydration or other conditioning of the CO₂ that takes place before transportation.

Electric power plants and other large industrial facilities are the primary candidates for CO₂ capture, although it is the high purity streams of CO₂ separated from natural gas in the gas processing industry that have been captured and stored to date. Available technology is generally deployed in a way that captures around 85-95 percent of the CO₂ processed in a capture plant IPCC (2005). Figure 5.2, taken from the SRCCS provides an overview of the relevant processes. The main techniques are briefly described below. Further detail is available in Chapter 3 of the SRCCS:

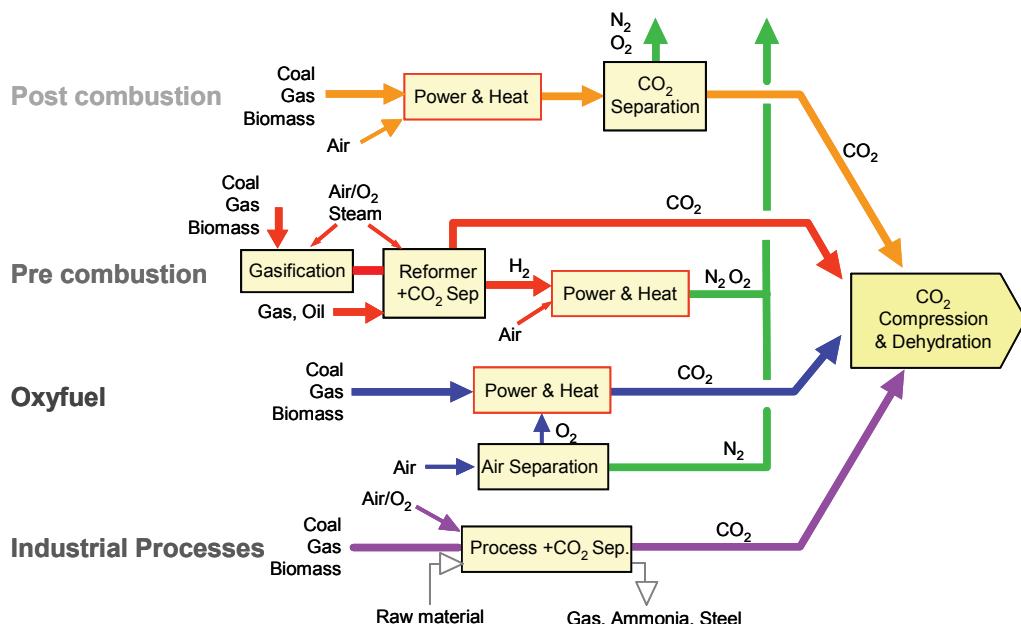
- Post-combustion capture: CO₂ can be separated from the flue gases of the combustion plant or from natural gas streams and fed into a compression and dehydration unit to deliver a relatively clean and dry CO₂ stream to a transportation system. These systems normally use a liquid solvent to capture the CO₂.
- Pre-combustion capture: This involves reacting a fuel with oxygen or air, and/or steam to produce a ‘synthesis gas’ or ‘fuel gas’ composed mainly of carbon monoxide and hydrogen. The carbon monoxide is reacted with steam in a catalytic reactor, called a shift converter, to give CO₂ and more hydrogen. CO₂ is then separated from the gas mixture, usually by a physical or chemical absorption process, resulting in a hydrogen-rich fuel which can be used in many applications, such as boilers, furnaces, gas turbines and fuel cells. This technology is widely used in hydrogen production, which is used mainly for ammonia and fertilizer manufacture, and in petroleum refining operations. Guidance on how to estimate and report emissions from this process is provided in Chapter 2, section 2.3.4 of this Volume.

- Oxy-fuel capture: In oxy-fuel combustion, nearly pure oxygen is used for combustion instead of air, resulting in a flue gas that is mainly CO₂ and H₂O. This flue gas stream can directly be fed into a CO₂ compression and dehydration unit. This technology is at the demonstration stage. Guidance on how to estimate and report emissions from this process is provided in Chapter 2, section 2.3.4 of this volume.

TABLE 5.1
SOURCE CATEGORIES FOR CCS

1	C			Carbon dioxide Transport and Storage	Carbon dioxide (CO ₂) capture and storage (CCS) involves the capture of CO ₂ , its transport to a storage location and its long-term isolation from the atmosphere. Emissions associated with CO ₂ transport, injection and storage are covered under category 1C. Emissions (and reductions) associated with CO ₂ capture should be reported under the IPCC sector in which capture takes place (e.g. Stationary Combustion or Industrial Activities).
1	C	1		<i>Transport of CO₂</i>	Fugitive emissions from the systems used to transport captured CO ₂ from the source to the injection site. These emissions may comprise fugitive losses due to equipment leaks, venting and releases due to pipeline ruptures or other accidental releases (e.g. temporary storage).
1	C	1	a	Pipelines	Fugitive emissions from the pipeline system used to transport CO ₂ to the injection site.
1	C	1	b	Ships	Fugitive emissions from the ships used to transport CO ₂ to the injection site.
1	C	1	c	Other (please specify)	Fugitive emissions from other systems used to transport CO ₂ to the injection site and temporary storage.
1	C	2		<i>Injection and Storage</i>	Fugitive emissions from activities and equipment at the injection site and those from the end containment once the CO ₂ is placed in storage.
1	C	2	a	Injection	Fugitive emissions from activities and equipment at the injection site.
1	C	2	b	Storage	Fugitive emissions from the end containment once the CO ₂ is placed in storage.
1	C	3		<i>Other</i>	Any other emissions from CCS not reported elsewhere.

Figure 5.2 CO₂ capture systems (After the SRCCS):



As already mentioned in a number of industrial processes, chemical reactions lead to the formation of CO₂ in quantities and concentrations that allow for direct capture or separation of the CO₂ from their off gases, for example: ammonia production, cement manufacture, ethanol manufacture, hydrogen manufacture, iron and steel manufacture, and natural gas processing plant.

The location of guidelines for compiling inventories of emissions from the CO₂ capture and compression system depends on the nature of the CO₂ source:

- Stationary combustion systems (mainly electric power and heat production plants): Volume 2, Chapter 2, Section 2.3.4.
- Natural gas processing plants: Volume 2, Section 4.2.1.
- Hydrogen production plants: Volume 2, Section 4.2.1.
- Capture from other industrial processes: Volume 3 (IPPU) Chapter 1, Section 1.2.2, and specifically for
 - (i) Cement manufacture: IPPU Volume, Section 2.2
 - (ii) Methanol manufacture: IPPU Volume, Section 3.9
 - (iii) Ammonia production: IPPU Volume, Section 3.2
 - (iv) Iron and steel manufacture: IPPU Volume section 4.2

Negative emissions may arise from the capture and compression system if CO₂ generated by biomass combustion is captured. This is a correct procedure and negative emissions should be reported as such.

Although many of the potential emissions pathways are common to all types of geological storage, some of the emission pathways in enhanced hydrocarbon recovery operations differ from those for geological CO₂ storage without enhanced hydrocarbon recovery. In EOR operations, CO₂ is injected into the oil reservoir, but a proportion of the amount injected is commonly produced along with oil, hydrocarbon gas and water at the production wells. The CO₂-hydrocarbon gas mixture is separated from the crude oil and may be reinjected into the oil reservoir, used as fuel gas on site or sent to a gas processing plant for separation into CO₂ and hydrocarbon gas, depending upon its hydrocarbon content. EGR and ECBM processes attempt to avoid CO₂ production because it is costly to separate the CO₂ from a produced gas mixture. CO₂ separated from the hydrocarbon gas may be recycled and re-injected in the EOR operation, or vented; depending on the economics of recycling versus injecting imported CO₂. CO₂-rich gas is also released from the crude oil storage tanks at the EOR operation. This vapour may be vented, flared or used as fuel gas depending upon its hydrocarbon content. Thus there are possibilities for additional sources of fugitive emissions from the venting of CO₂ and the flaring or combustion of CO₂-rich hydrocarbon gas, and also from any injected CO₂ exported with the incremental hydrocarbons. These emissions along with fugitive emissions from surface operations at EOR, and EGR and ECBM sites (from the injection of CO₂, and/or the production, recycling, venting, flaring or combustion of CO₂-rich hydrocarbon gas), and including any injected CO₂ exported with the incremental hydrocarbons, can be estimated and reported using the higher methods described guidance given in Volume 2 Chapter 4.

5.4 CO₂ TRANSPORT

Fugitive emissions may arise e.g. from pipeline breaks, seals and valves, intermediate compressor stations on pipelines, intermediate storage facilities, ships transporting low temperature liquefied CO₂, and ship loading and offloading facilities. Emissions from transport of captured CO₂ are reported under category 1C (see Table 5.1). CO₂ pipelines are the most prevalent means of bulk CO₂ transport and are a mature market technology in operation today. Bulk transport of CO₂ by ship also already takes place, though on a relatively minor scale. This occurs in insulated containers at temperatures well below ambient, and much lower pressures than pipeline transport. Transport by truck and rail is possible for small quantities of CO₂, but unlikely to be significant in CCS because of the very large masses likely to be captured. Therefore no methods of calculating emissions from truck and rail transport are given here. Further information on CO₂ transport is available in Chapter 4 of the SRCCS (IPCC 2005).

5.4.1 CO₂ transport by pipeline

To estimate emissions from pipeline transport of CO₂, default emission factors can be derived from the emission factors for transmission (pipeline transport) of natural gas as provided in section 4.2 of this volume. The Tier 1 emission factors for natural gas pipeline transport, presented in, Tables 4.2.4 and 4.2.5 are provided on the basis of gas throughput primarily because pipeline length is not a national statistic that is commonly available. However, fugitive emissions from pipeline transport are largely independent of the throughput, but depend on the size of and the equipment installed in the pipeline systems. Since it is assumed that there exists a relationship between the size of the systems and natural gas used, such an approach is acceptable as Tier 1 method for natural gas transport.

The above might not be true for the transport of CO₂ in CCS applications. Since it is *good practice* to treat both capture and storage in a per plant or facility basis, the length of the transporting CO₂ pipeline system will be known and should be used to estimate emissions from transport.

BOX 5.1

DERIVATION OF DEFAULT EMISSION FACTORS FOR CO₂ PIPELINE TRANSPORT

The pressure drop of a gas over any geometry is described by:

$$\Delta P = \frac{f}{2} \rho * v^2 \frac{l}{D}$$

in which

- v is the linear velocity of the gas through the leak and, with the same size of the leak, is proportional to the leaking volume;
- ρ is the density of the gas;
- f is the dimensionless friction number
- l/D (length divided by diameter) is characterizing the physical size of the system.

For leaks, $f = 1$ and independent on the nature of the gas. So assuming the internal pressure of the pipe-line and the physical dimensions being the same for CO₂ and CH₄ transport, the leak-velocity is inversely proportional to the root of the density of the gas and hence proportional to the root of the molecular mass.

So when ΔP is the same for methane and carbon dioxide

$$v \sim \frac{1}{\sqrt{\rho}}$$

The molecule mass of CO₂ is 44 and of CH₄ is 16. So on a mass-basis the CO₂-emission rate is $\sqrt{\frac{44}{16}} = 1.66$ times the CH₄-emission rate.

From this the default emission factors for CO₂ pipeline transport are obtained by multiplying the relevant default emission factors^a in Table 4.2.8 for natural gas (is mainly CH₄) by a factor of 1.66.

Notes:

^a to convert the factors expressed in m³ to mass units, a specific mass of 0.7 kg/m³ for methane is applied.

See chapter 5 in: R.H. Perry, D. Green, *Perry's chemical engineers handbook*, 6th edition, McGraw Hill Book Company - New York, 1984.

Table 4.2.8 in section 4.2 of this volume provides indicative leakage factors for natural gas pipeline transport. To obtain Tier 1 default emission factors for CO₂ transport by pipeline these values should be converted from cubic metres to mass units and multiplied by 1.66 (see Box 1). The resulting default emission factors are given in Table 5.2.

TABLE 5.2
DEFAULT TIER 1 EMISSION FACTORS FOR PIPELINE TRANSPORT OF CO₂ FROM A CO₂ CAPTURE SITE TO THE FINAL STORAGE SITE

Emission Source	Value			Uncertainty	Units of Measure
	Low	Medium	High		
Fugitive emissions from CO ₂ transportation by pipeline	0.00014	0.0014	0.014	± a factor of 2	Gg per year and per km of transmission pipeline

Although the leakage emissions from pipeline transport are independent of throughput, the number of leaks is not necessarily correlated to the length of the pipeline. The best correlation will be between the number and type of equipment components and the type of service. Most of the equipment tends to occur at the facilities connected to the pipeline rather than with the pipeline itself. In fact, unless the CO₂ is being transported over very large distances and intermediate compressor stations are required, virtually all of the fugitive emissions from a CCS system will be associated with the initial CO₂ capture and compression facilities at the start of the pipeline and the injection facilities at the end of the pipeline, with essentially no emissions from the pipeline itself. In Tier 3 approach, the leakage emissions from the transport pipeline could be obtained from data on number and type of equipment and equipment-specific emission factors.

5.4.2 CO₂ transport by ship

Default emission factors for fugitive emissions from CO₂ transport by ship are not available. The amounts of gas should be metered during loading and discharge using flow metering and losses reported as fugitive emissions of CO₂ resulting from transport by ship under category 1C1 b.

5.4.3 Intermediate storage facilities on CO₂ transport routes

If there is a temporal mismatch between supply and transport or storage capacity, a CO₂ buffer (above ground or underground) might be needed to temporarily store the CO₂. If the buffer is a tank, fugitive emissions should be measured and treated as part of the transport system and reported under category 1C1 c (other). If the intermediate storage facility (or buffer) is a geological storage reservoir, fugitive emissions from it can be treated in the same way as for any other geological storage reservoir (see Section 5.6 of this Chapter) and reported under category 1C3.

5.5 CO₂ INJECTION

The injection system comprises surface facilities at the injection site, e.g. storage facilities, any distribution manifold at the end of the transport pipeline, distribution pipelines to wells, additional compression facilities, measurement and control systems, wellhead(s) and the injection wells. Additional information on the design of injection wells can be found in the SRCCS, Chapter 5, Section 5.5.

Meters at the wellhead measure the flow rate, temperature and pressure of the injected fluid. The wellhead also contains safety features to prevent the blowout of the injected fluids. Safety features, such as a downhole safety valve or check valve in the tubing, may also be inserted below ground level, to prevent backflow in the event of the failure of the surface equipment. Valve and other seals may be affected by supercritical CO₂, so appropriate materials will need to be selected. Carbon steel and conventional cements may be liable to be attacked by highly saline brines and CO₂-rich fluids (Scherer et al. 2005). Moreover the integrity of CO₂ injection wells needs to be maintained for very long terms, so appropriate well construction materials and regulations will be needed. Cements used for sealing between the well and the rock formation and, after abandonment, plugging the well, must also be CO₂/salt brine resistant over long terms. Such cements have been developed but need further testing. Due to the potential for wells to act as conduits for CO₂ leakage back to the atmosphere, they should be monitored as part of a comprehensive monitoring plan as laid out in Section 5.7 of this Chapter.

The amount of CO₂ injected into a geological formation through a well can be monitored by equipment at the wellhead, just before it enters the injection well. A typical technique is described by Wright and Majek (1998). Meters at the wellhead continuously measure the pressure, temperature and flow rate of the injected gas. The

composition of the imported CO₂ commonly shows little variation and is analyzed periodically using a gas chromatograph. The mass of CO₂ passing through the wellhead can then be calculated from the measured quantities. No default method is suggested and the reporting of the mass of CO₂ injected as calculated from direct measurements is *good practice*.

If the pressure of the CO₂ arriving at the storage site is not as high as the required injection pressure, compression will be necessary. Any emissions from compression of the stored gas at the storage site should be measured and reported.

5.6 GEOLOGICAL STORAGE OF CO₂

Chapter 5 of the SRCCS (IPCC 2005) indicates that geological storage of carbon dioxide may take place onshore or offshore, in:

- **Deep saline formations.** These are porous and permeable reservoir rocks containing saline water in their pore spaces.
- **Depleted or partially depleted oil fields** - either as part of, or without, enhanced oil recovery (EOR) operations.
- **Depleted or partially depleted natural gas fields** – either with or without enhanced gas recovery (EGR) operations.
- **Coal seams** (= coal beds) – either with or without enhanced coalbed methane recovery (ECBM) operations.

Additionally, niche opportunities for storage may arise from other concepts such as storage in salt caverns, basalt formations and organic-rich shales.

Further information on these type of storage sites and the trapping mechanisms that retain CO₂ within them can be found in Chapter 5 of the SRCCS (IPCC 2005).

5.6.1 Description of emissions pathways/sources

The Introduction to the SRCCS states that >99% of the CO₂ stored in geological reservoirs is likely to remain there for over one thousand years. Therefore potential emissions pathways created or activated by slow or long-term processes need to be considered as well as those that may act in the short to medium term (decades to centuries).

In these Guidelines the term migration is defined as the movement of CO₂ within and out of a geological storage reservoir whilst remaining below the ground surface or the sea bed, and the term leakage is defined as a transfer of CO₂ from beneath the ground surface or sea bed to the atmosphere or ocean.

The only emissions pathways that need to be considered in the accounting are CO₂ leakage to the ground surface or seabed from the geological storage reservoir². Potential emission pathways from the storage reservoir are shown in Table 5.3.

There is a possibility that methane emissions, as well as CO₂ emissions, could arise from geological storage reservoirs that contain hydrocarbons. Although there is insufficient information to provide guidance for estimating methane emissions, it would be *good practice* to undertake appropriate assessment of the potential for methane emissions from such reservoirs and, if necessary, include any such emissions attributable to the CO₂ storage process in the inventory.

² Emissions of CO₂ may occur as free gas or gas dissolved in groundwater that reaches the surface e.g. at springs.

TABLE 5.3
POTENTIAL EMISSION PATHWAYS FROM GEOLOGICAL RESERVOIRS

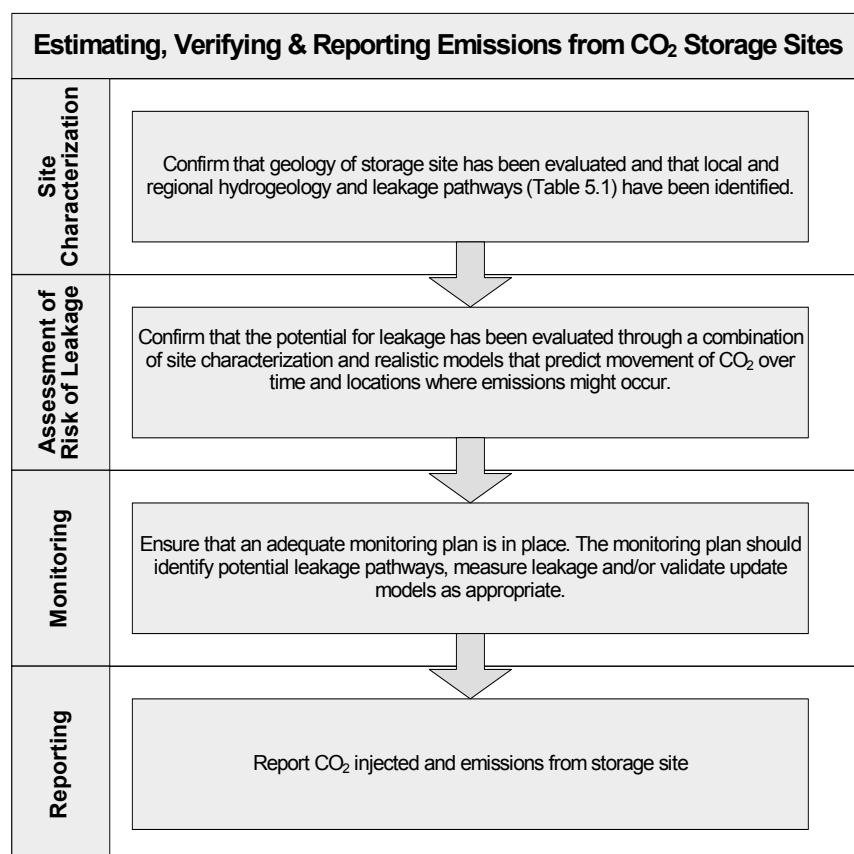
Type of emission	Potential emissions pathways/ sources	Additional comments
Direct leakage pathways created by wells and mining	<ul style="list-style-type: none"> • Operational or abandoned wells • Well blow-outs (uncontrolled emissions from injection wells) • Future mining of CO₂ reservoir 	<ul style="list-style-type: none"> • It is anticipated that every effort will be made to identify abandoned wells in and around the storage site. Inadequately constructed, sealed, and/or plugged wells may present the biggest potential risk for leakage. Techniques for remediating leaking wells have been developed and should be applied if necessary. • Possible source of high-flux leakage, usually over a short period of time. Blowouts are subject to remediation and likely to be rare as established drilling practice reduces risk. • An issue for coal bed reservoirs
Natural leakage and migration pathways (that may lead to emissions over time)	<ul style="list-style-type: none"> • Through the pore system in low permeability cap rocks if the capillary entry pressure is exceeded or the CO₂ is in solution • If the cap rock is locally absent • Via a spill point if reservoir is overfilled • Through a degraded cap rock as a result of CO₂/water/rock reactions • Via dissolution of CO₂ into pore fluid and subsequent transport out of the storage site by natural fluid flow • Via natural or induced faults and/or fractures 	<ul style="list-style-type: none"> • Proper site characterization and selection and controlled injection pressure can reduce risk of leakage. • Proper site characterization and selection can reduce risk of leakage. • Proper site characterization and selection, including an evaluation of the hydrogeology, can reduce risk of leakage. • Proper site characterization and selection can reduce risk of leakage. Detailed assessment of cap rock and relevant geochemical factors will be useful. • Proper site characterization and selection, including an evaluation of the hydrogeology, can determine/reduce risk of leakage. • Possible source of high-flux leakage. Proper site characterization and selection and controlled injection pressure can reduce risk of leakage.
Other Fugitive Emissions at the Geological Storage Site	<ul style="list-style-type: none"> • Fugitive methane emissions could result from the displacement of CH₄ by CO₂ at geological storage sites. This is particularly the case for ECBM, EOR, and depleted oil and gas reservoirs. 	Needs appropriate assessment.

5.7 METHODOLOGICAL ISSUES

Geological conditions vary widely and only a few published studies of monitoring programmes that identify and quantify fugitive anthropogenic carbon dioxide emissions from geological storage operations currently exist (Arts et al. 2003, Wilson and Monea 2005; Klusman 2003a, b, c). Although the Summary for Policymakers of the SRCCS suggests that properly selected geological storage sites are likely to retain greater than 99 percent of the stored CO₂ over 1000 years and may retain it for up to millions of years, at the time of writing, the small number of monitored storage sites means that there is insufficient empirical evidence to produce emission factors that could be applied to leakage from geological storage reservoirs. Consequently, this guidance does not include Tier 1 or Tier 2 methodology. However, there is the possibility of developing such methodologies in the future, when more monitored storage sites are in operation and existing sites have been operating for a long time (Yoshigahara et al. 2005). However a site-specific Tier 3 approach can be developed. Monitoring technologies have been developed and refined over the past 30 years in the oil and gas, groundwater and environmental monitoring industries (also see Annex 1). The suitability and efficacy of these technologies can be strongly influenced by the geology and potential emissions pathways at individual storage sites, so the choice of monitoring technologies will need to be made on a site-by-site basis. Monitoring technologies are advancing rapidly and it would be *good practice* to keep up to date on new technologies.

Tier 3 procedures for estimating and reporting emissions from CO₂ storage sites are summarised in Figure 5.3 and discussed below.

Figure 5.3 Procedures for estimating emissions from CO₂ storage sites



In order to understand the fate of CO₂ injected into geological reservoirs over long timescales, assess its potential to be emitted back to the atmosphere or seabed via the leakage pathways identified in Table 5.3, and measure any fugitive emissions, it is necessary to:

- (a) Properly and thoroughly characterise the geology of the storage site and surrounding strata;
- (b) Model the injection of CO₂ into the storage reservoir and the future behaviour of the storage system;
- (c) Monitor the storage system;

(d) Use the results of the monitoring to validate and/or update the models of the storage system.

Proper site selection and characterization can help build confidence that there will be minimal leakage, improve modelling capabilities and results, and ultimately reduce the level of monitoring needed. Further information on site characterisation is available in the SRCCS and from the International Energy Agency Greenhouse Gas R & D Programme (IEAGHG 2005).

Monitoring technologies have been developed and refined over the past 30 years in the oil and gas, groundwater and environmental monitoring industries. The most commonly used technologies are described in Tables 5.1-5.6 in Annex I of this chapter. The suitability and efficacy of these technologies can be strongly influenced by the geology and potential emissions pathways at individual storage sites, so the choice of monitoring technologies will need to be made on a site-by-site basis. Monitoring technologies are advancing rapidly and it would be *good practice* to keep up to date on new technologies.

A range of modelling tools is available, some of which have undergone a process of code inter-comparison (Pruess et al. 2004). All models approximate and/or neglect some processes, and make simplifications. Moreover, their results are dependent on their intrinsic qualities and, especially, on the quality of the data put into them. Many of the physico-chemical factors involved (changes in temperature and pressure, mixing of the injected gas with the fluids initially present in the reservoir, the type and rate of carbon dioxide immobilization mechanisms and fluid flow through the geological environment) can be modelled successfully with numerical modelling tools known as reservoir simulators. These are widely used in the oil and gas industry and have proved effective in predicting movement of gases and liquids, including CO₂, through geological formations.

Reservoir simulation can be used to predict the likely location, timing and flux of any emissions, which, in turn, could be checked using direct monitoring techniques. Thus it can be an extremely useful technique for assessing the risk of leakage from a storage site. However, currently there is no single model that can account for all the processes involved at the scales and resolution required. Thus, sometimes, additional numerical modelling techniques may need to be used to analyze aspects of the geology. Multi-phase reaction transport models, which are normally used for the evaluation of contaminant transport can be used to model transport of CO₂ within the reservoir and CO₂/water/rock reactions, and potential geomechanical effects may need to be considered using geomechanical models. Such models may be coupled to reservoir simulators or independent of them.

Numerical simulations should be validated by direct measurements from the storage site, where possible. These measurements should be derived from a monitoring programme, and comparison between monitoring results and expectations used to improve the geological and numerical models. Expert opinion is needed to assess whether the geological and numerical modelling are valid representations of the storage site and surrounding strata and whether subsequent simulations give an adequate prediction of site performance.

Monitoring should be conducted according to a suitable plan, as described below. This should take into account the expectations from the modelling on where leakage might occur, as well as measurements made over the entire zone in which CO₂ is likely to be present. Site managers will typically be responsible for installing and operating carbon dioxide storage monitoring technologies (see Annex 1). The inventory compiler will need to ensure that it has sufficient information from each storage site to assess annual emissions in accordance with the guidance provided in this Chapter. To make this assessment, the inventory compiler should establish a formal arrangement with each site operator that will allow for annual reporting, review and verification of site-specific data.

5.7.1 Choice of method

At the time of writing, the few CO₂ storage sites that exist are part of petroleum production operations and are regulated as such. For example, acid gas storage operations in western Canada need to conform to requirements that deal with applications to operate conventional oil and gas reservoirs (Bachu and Gunter, 2005). Regulatory development for CCS is in its early stages. There are no national or international standards for performance of geological CO₂ storage sites and many countries are currently developing relevant regulations to address the risks of leakage. Demonstration of monitoring technologies is a necessary part of this development (see Annex 1). As these standards and regulatory approaches are developed and implemented, they may be able to provide emissions information with relative certainty. Therefore, as part of the annual inventory process, if one or more appropriate governing bodies that regulate carbon dioxide capture and storage exist, then the inventory compiler may obtain emissions information from those bodies. If the inventory compiler relies on this information, he/she should submit supporting documentation that explains how emissions were estimated or measured and how these methods are consistent with IPCC practice. If no such agency exists, then it would be *good practice* for the inventory compiler to follow the methodology presented below. In the methodology presented below, site characterization, modelling, assessment of the risk of leakage and monitoring activities are the responsibility of the storage project manager and/or an appropriate governing body that regulates carbon dioxide capture and

storage. In addition, the storage project manager or regulatory authority will likely develop the emission estimates that will be reported to the national inventory compiler as part of the annual inventory process. The responsibility of the national inventory compiler is to request the emissions data and seek assurance of its validity. In the case of CCS associated with ECBM recovery, the methodology should be applied both to CO₂ and CH₄ detection.

1. Identify and document all geological storage operations in the jurisdiction. The inventory compiler should keep an updated record of all geological storage operations, including all the information needed to cross-reference from this section to other elements of the CO₂ capture and storage chain for QA/QC purposes, that is for each operation:

- The location of the site;
- The type of operation (whether or not associated with EOR, EGR, ECBM);
- The year in which CO₂ storage began;
- Source(s), annual mass of CO₂ injected attributable to each source and the imputed cumulative amount in storage; and
- Associated CO₂ transport, injection and recycling infrastructure, if appropriate (i.e. on-site generation and capture facilities, pipeline connections, injection technology etc.) and emissions therefrom.

Although the inventory compiler is only responsible for reporting on the effect of operations in its jurisdiction, he/she must record cross-border transfers of CO₂ for cross-checking and QA/QC purposes (see Section 5.9).

2. Determine whether an adequate geological site characterization report has been produced for each storage site. The site characterization report should identify and characterize potential leakage pathways such as faults and pre-existing wells, and quantify the hydrogeological properties of the storage system, particularly with respect to CO₂ migration. The site characterisation report should include sufficient data to represent such features in a geological model of the site and surrounding area. It should also include all the data necessary to create a corresponding numerical model of the site and surrounding area for input into an appropriate numerical reservoir simulator.

3. Determine whether the operator has assessed the potential for leakage at the storage site. The operator should determine the likely timing, location and flux of any fugitive emissions from the storage reservoir, or demonstrate that leakage is not expected to occur. Short-term simulations of CO₂ injection should be made, to predict the performance of the site from the start of injection until significantly after injection ceases (likely to be decades). Long-term simulations should be performed to predict the fate of the CO₂ over centuries to millenia. Sensitivity analysis should be conducted to assess the range of possible emissions. The models should be used in the design of a monitoring programme that will verify whether or not the site is performing as expected. The geological model and reservoir model should be updated in future years in the light of any new data and to account for any new facilities or operational changes.

4. Determine whether each site has a suitable monitoring plan. Each site's monitoring plan should describe monitoring activities that are consistent with the leakage assessment and modelling results. Existing technologies presented in Annex 1 can measure leaks to the ground surface or seabed. The SRCCS includes detailed information on monitoring technologies and approaches (see Annex 1). In summary the monitoring programme should include provisions for:

- (i) Measurement of background fluxes of CO₂ (and if appropriate CH₄) at both the storage site and any likely emission points outside the storage site. Geological storage sites may have a natural, seasonally variable (ecological and/or industrial) background flux of emissions prior to injection. This background flux should not be included in the estimate of annual emissions. See Annex 1 for a discussion of potential methods. Isotopic analysis of any background fluxes of CO₂ is recommended, as this is likely to help distinguish between natural and injected CO₂.
- (ii) Continuous measurement of the mass of CO₂ injected at each well throughout the injection period, see Section 5.5 above.
- (iii) Monitoring to determine any CO₂ emissions from the injection system.
- (iv) Monitoring to determine any CO₂ (and if appropriate CH₄) fluxes through the seabed or ground surface, including where appropriate through wells and water sources such as springs. Periodic investigations of the entire site, and any additional area below which monitoring and modelling suggests CO₂ is distributed, should be made to detect any unpredicted leaks.
- (v) Post-injection Monitoring: The plan should provide for monitoring of the site after the injection phase. The post-injection phase of monitoring should take account of the results of

the forward modelling of CO₂ distribution to ensure that monitoring equipment is deployed at appropriate places and appropriate times. Once the CO₂ approaches its predicted long-term distribution within the reservoir and there is agreement between the models of CO₂ distribution and measurements made in accordance with the monitoring plan, it may be appropriate to decrease the frequency of (or discontinue) monitoring. Monitoring may need to be resumed if the storage site is affected by unexpected events, for example seismic events.

- (vi) Incorporating improvements in monitoring techniques/technologies over time.
- (vii) Periodic verification of emissions estimates. The necessary periodicity is a function of project design, implementation and early determination of risk potential. During the injection period, verification at least every five years or after significant change in site operation is suggested.

Continuous monitoring of the injection pressure and periodic monitoring of the distribution of CO₂ in the subsurface would be useful as part of the monitoring plan. Monitoring the injection pressure is necessary to control the injection process, e.g. to prevent excess pore fluid pressure building up in the reservoir. It can provide valuable information on the reservoir characteristics and early warning of leakage. This is already common practice and can be a regulatory requirement for current underground injection operations. Periodically monitoring the distribution of CO₂ in the subsurface, either directly or remotely would also be useful because it can provide evidence of any migration of CO₂ out of the storage reservoir and early warning of potential leaks to the atmosphere or seabed.

5. Collect and verify annual emissions from each site: The operators of each storage site should, on an annual basis, provide the inventory compiler with annual emissions estimates, which will be made publicly available. The emissions recorded from the site and any leaks that may occur inside or outside the site in any year will be the emissions as estimated from the modelling (which may be zero), adjusted to take account of the annual monitoring results. If a sudden release occurs, e.g. from a well blowout, the amount of CO₂ emitted should be estimated in the inventory. To simplify accounting for offshore geological storage, leakage to the seabed should be considered as emissions to the atmosphere for the purposes of compiling the inventory. In addition to total annual emissions, background data should include the total amount of CO₂ injected, the source of the injected CO₂, the cumulative total amount of CO₂ stored to date, the technologies used to estimate emissions, and any verification procedures undertaken by the site operators in accordance with the monitoring plan as indicated under 4(iii) and 4(iv) above. To verify emissions, the inventory compiler should request and review documentation of the monitoring data, including the frequency of monitoring, technology detection limits, and the share of emissions coming from the various pathways identified in the emission monitoring plan and any changes introduced as a result of verification. If a model was used to estimate emissions during years in which direct monitoring did not take place, the inventory compiler should compare modelled results against the most recent monitoring data. Steps 2, 3, and 4 above should indicate the potential for, and likely timing of future leaks and the need for direct monitoring.

Total national emissions for geological carbon dioxide storage will be the sum of the site-specific emission estimates:

EQUATION 5.1
TOTAL NATIONAL EMISSIONS

$$\text{National Emissions from geological carbon dioxide storage} = \sum \text{carbon dioxide storage site emissions}$$

Further guidance on reporting emissions where more than one country is involved in CO₂ capture, storage, and/or emissions is provided in Section 5.10: Reporting and Documentation.

5.7.2 Choice of emission factors and activity data

Tier 1 or 2 emission factors are not currently available for carbon dioxide storage sites, but may be developed in the future (see Section 5.7). However, as part of a Tier 3 emissions estimation process, the inventory compiler should collect activity data from the operator on annual and cumulative CO₂ stored. These data can be easily monitored at the injection wellhead or in adjacent pipework.

Monitoring in early projects may help obtain useful data that could be used to develop Tier 1 or 2 methodologies in the future. Examples of the application of monitoring technologies are provided by the monitoring programmes at the enhanced oil recovery projects at Rangely in Colorado, USA (Klusman, 2003a, b, c) Weyburn in Saskatchewan, Canada (Wilson and Monea, 2005), and the Sleipner CO₂ storage project, North Sea (Arts et al., 2003; also see Annex 5.1). None of the other CO₂-injection projects around the world have yet published the results of systematic monitoring for leaking CO₂.

The Rangely enhanced oil recovery project started injecting CO₂ into the Weber Sand Unit oil reservoir in the Rangely field in 1986. Cumulative CO₂ injection to 2003 was approximately 23 million tonnes. A monitoring programme was undertaken (Klusman 2003a, b, c), based on 41 measurement locations scattered across a 78 km² site. No pre-injection background measurements were available (which, at a new site, would be determined at step 4 (i) in the monitoring plan outlined above). In lieu of a pre-injection baseline, 16 measurement locations in a control area outside the field were sampled. The results of the monitoring programme indicate an annual deep-sourced CO₂ emission of less than 3 800 tonnes/yr from the ground surface above the oil field. It is likely that at least part, if not all, of this flux is due to the oxidation of deep-sourced methane derived from the oil reservoir or overlying strata, but it is possible that part of it could be fugitive emissions of CO₂ injected into the oil reservoir. The absence of pre-injection baseline measurements prevents definitive identification of its source.

CO₂ has been injected at the Weyburn oil field (Saskatchewan, Canada) for EOR since September 2000. Soil gas sampling, with the primary aims of determining background concentrations and whether there have been any leaks of CO₂ or associated tracer gases from the reservoir, took place in three periods from July 2001 and October 2003. There is no evidence to date for escape of injected CO₂. However, further monitoring of soil gases is necessary to verify that this remains the case in the future and more detailed work is necessary to understand the causes of variation in soil gas contents, and to investigate further possible conduits for gas escape (Wilson and Monea 2005).

The Sleipner CO₂ storage site in the North Sea, offshore Norway (Chadwick et al. 2003) has been injecting approximately 1 million tonnes of CO₂ per year into the Utsira Sand, a saline formation, since 1996. Cumulative CO₂ injection to 2004 was >7 million tonnes. The distribution of CO₂ in the subsurface is being monitored by means of repeated 3-D seismic surveys (pre-injection and two repeat surveys are available publicly to date) and, latterly, by gravity surveys (only one survey has been acquired to date). The results of the 3D seismic surveys indicate no evidence of leakage (Arts et al. 2003).

Taken together, these studies show that a Tier 3 methodology can be implemented so as to support not only zero emissions estimates but also to detect leakage, even at low levels, if it occurs.

There has been only one large-scale trial of enhanced coalbed methane (ECBM) production using CO₂ as an injectant; the Allison project in the San Juan Basin, USA (Reeves, 2005). There was sufficient information derived from the Allison project to indicate that CO₂ was sequestered securely in the coal seams. Pressure and compositional data from 4 injection wells and 15 production wells indicated no leakage. Some CO₂ was recovered from the production wells after approximately five years. However, this was expected and, for inventory purposes, it would be accounted as an emission (if it was not separated from the produced coalbed methane and recycled). No monitoring of the ground surface for CO₂ or methane leakage was undertaken.

5.7.3 Completeness

All emissions (CO₂ and if relevant, CH₄) from all CO₂ storage sites should be included in the inventory. In cases where CO₂ capture occurs in a different country from CO₂ storage, arrangements to ensure that there is no double accounting of storage should be made between the relevant national inventory compilers.

The site characterization and monitoring plans should identify possible sources of emissions outside the site (e.g., lateral migration, groundwater, etc.). Alternatively, a reactive strategy to locations outside the site could be deployed, based on information from inside it. If the emissions are predicted and/or occur outside the country where the storage operation (CO₂ injection) takes place, arrangements should be made between the relevant national inventory compilers to monitor and account these emissions. (see Section 5.10 below).

Estimates of CO₂ dissolved in oil and emitted to the atmosphere as a result of surface processing are covered under the methodologies for oil and gas production. The inventory compiler should ensure that information on these emissions collected from CO₂ storage sites is consistent with estimates under those source categories.

5.7.4 Developing a consistent time series

If the detection capabilities of monitoring equipment improve over time, or if previously unrecorded emissions are identified, or if updating of models suggests that unidentified emissions have occurred, and an updated monitoring programme corroborates this, appropriate recalculation of emissions will be necessary. This is particularly important given the generally low precision associated with current monitoring suites, even using the most advanced current technologies. Establishment of the background flux and variability is also critical. For dedicated CO₂ storage sites, anthropogenic emissions prior to injection and storage will be zero. For some enhanced oil recovery operations, there may be anthropogenic emissions prior to conversion to a CO₂ storage site.

5.8 UNCERTAINTY ASSESSMENT

It is a part of *good practice* that an uncertainty assessment is included when using Tier 3 methods. Uncertainty in the emissions estimates will depend on the precision of the monitoring techniques used to verify and measure any emissions and the modelling used to predict leakage from the storage site. The concept of percentage uncertainties may not be applicable for this sector and therefore confidence intervals and/or probability curves could be given.

The uncertainty in field measurements is most important and will depend on the sampling density and frequency of measurement and can be determined using standard statistical methods.

An effective reservoir simulation should address the issues of variability and uncertainty in the physical characteristics, especially reservoir rock and reservoir fluid properties, because reservoir models are designed to predict fluid movements over a long timescale and because geological reservoirs are inherently heterogeneous and variable. The uncertainty in estimates derived from modelling will therefore depend on:

- The completeness of the primary data used during the site assessment;
- The correspondence between the geological model and critical aspects of the geology of the site and surrounding area, in particular the treatment of possible migration pathways;

The accuracy of critical data that support the model:

- Its subsequent numerical representation by grid blocks
- Adequate representation of the processes in the physico-chemical numerical and analytical models

Uncertainty estimates are typically made by varying the model input parameters and undertaking multiple simulations to determine the impact on short-term model results and long-term predictions. The uncertainty in field measurements will depend on the sampling density and frequency of measurement and can be determined using standard statistical methods. Where model estimates and measurements are both available, the best estimate of emissions will be made by validating the model, and then estimating emissions with the updated model. Multiple realizations using the history-matched model can address uncertainty in these estimates. These data may be used to modify original monitoring requirements (e.g. add new locations or technology, increase or reduce frequency) and ultimately comprise the basis of an informed decision to decommission the facility.

5.9 INVENTORY QUALITY ASSURANCE/QUALITY CONTROL (QA/QC)

QA/QC for the whole CCS system

CO₂ capture should not be reported without linking it to long-term storage.

A check should be made that the mass of CO₂ captured does not exceed the mass of CO₂ stored plus the reported fugitive emissions in the inventory year (Table 5.4).

There has been limited experience with CCS to date, but it is expected that experience will increase over the next few years. Therefore, it would be *good practice* to compare monitoring methods and possible leakage scenarios between comparable sites internationally. International cooperation will also be advantageous in developing monitoring methodologies and technologies.

TABLE 5.4 OVERVIEW TABLE: OVERVIEW OF CO₂ CAPTURE, TRANSPORT, INJECTION AND CO₂ FOR LONG-TERM STORAGE			
Category	Activity		CO₂ (Gg)¹
	Data Source	Unit	
Total amount captured for storage (A)	Summed from all relevant categories	Gg	
Total amount of import for storage (B)	Data from pipeline companies, or statistical agencies	Gg	
Total amount of export for storage (C)	Data from pipeline companies, or statistical agencies	Gg	
Total amount of CO ₂ injected at storage sites (D)	Data from storage sites provided by operators, as described in Chapter 5	Gg	
Total amount of leakage during transport (E1)	Summed from IPCC reporting category 1 C 1	Gg	
Total amount of leakage during injection (E2)	Summed from IPCC reporting category 1 C 2 a	Gg	
Total amount of leakage from storage sites (E3)	Summed from IPCC reporting category 1 C 2 b	Gg	
Total leakage (E4)	E1 + E2 + E3	Gg	
Capture + Imports (F)	A + B	Gg	
Injection + Leakage + Exports (G)	D + E4 + C	Gg	
Discrepancy	F - G	Gg	

¹ Once captured, there is no differentiated treatment between biogenic carbon and fossil carbon: emissions and storage of both will be estimated and reported.

Ideally, (Capture + Imports) = (Injection + Exports + Leakage)

If (Capture + Imports) < (Injection + Exports + Leakage) then there is need to check that

Exports are not overestimated

Imports are not underestimated

Data for CO₂ injection does not include EOR operations not associated with storage

If (Capture + Imports) > (Injection + Exports + Leakage) then need to check that

Exports are not under-estimated

Imports are not overestimated

CO₂ capture designated as ‘for long-term storage’ is actually going to other short-term emissive uses (e.g., products, EOR without storage)

Site QA/QC

On-site QA/QC will be achieved by regular inspection of monitoring equipment and site infrastructure by the operator. Monitoring equipment and programmes will be subject to independent scrutiny by the inventory compiler and/or regulatory agency.

All data including the site characterization reports, geological models, simulations of CO₂ injection, predictive modelling of the site, risk assessments, injection plans, licence applications, monitoring strategies and results and verification should be retained by the operator and forwarded to the inventory compiler for QA/QC.

The inventory compiler should compare (benchmark) the leak rates of a given storage facility against analogous storage sites and explain the reasons for differences in performance.

Where applicable, the relevant regulatory body can provide verification of emissions estimates and/or the monitoring plan described above. If no such body exists, the site operator should at the outset provide the inventory compiler with the results of peer review by a competent third party confirming that the geological and numerical models are representative, the reservoir simulator is suitable, the modelling realistic and the monitoring plan suitable. As they become available, the site operator should compare the results of the monitoring programme with the predictive models and adjust models, monitoring programme and/or injection strategy appropriately. The site operator should inform the inventory compiler of changes made.

5.10 REPORTING AND DOCUMENTATION

Guidelines for reporting emissions from geological storage:

Prior to the start of the geological storage operation, the national inventory compiler where storage takes place should obtain and archive the following:

- Report on the methods and results of the site characterization
- Report on the methods and results of modelling
- A description of the proposed monitoring programme including appropriate background measurements
- The year in which CO₂ storage began or will begin
- The proposed sources of the CO₂ and the infrastructure involved in the whole CCGS chain between source and storage reservoir

The same national inventory compiler should receive annually from each site:

- The mass of CO₂ injected during the reporting year
- The mass of CO₂ stored during the reporting year
- The cumulative mass of CO₂ stored at the site
- The source (s) of the CO₂ and the infrastructure involved in the whole CCGS chain between source and storage reservoir
- A report detailing the rationale, methodology, monitoring frequency and results of the monitoring programme - to include the mass of any fugitive emissions of CO₂ and any other greenhouse gases to the atmosphere or sea bed from the storage site during the reporting year
- A report on any adjustment of the modelling and forward modelling of the site that was necessary in the light of the monitoring results
- The mass of any fugitive emissions of CO₂ and any other greenhouse gases to the atmosphere or sea bed from the storage site during the reporting year
- Descriptions of the monitoring programmes and monitoring methods used, the monitoring frequency and their results
- Results of third party verification of the monitoring programme and methods

There may be additional reporting requirements at the project level where the site is part of an emissions trading scheme.

Reporting of cross-border CCS operations

CO₂ may be captured in one country, Country A, and exported for storage in a different country, Country B. Under this scenario, Country A should report the amount of CO₂ captured, any emissions from transport and/or temporary storage that takes place in Country A, and the amount of CO₂ exported to Country B. Country B should report the amount of CO₂ imported, any emissions from transport and/or temporary storage (that takes place in Country B), and any emissions from injection and geological storage sites.

If CO₂ is injected in one country, Country A, and travels from the storage site and leaks in a different country, Country B, Country A is responsible for reporting the emissions from the geological storage site. If such leakage is anticipated based on site characterization and modelling, Country A should make an arrangement with Country B to ensure that appropriate standards for long-term storage and monitoring and/or estimation of

emissions are applied (relevant regulatory bodies may have existing arrangements to address cross-border issues with regard to groundwater protection and/or oil and gas recovery).

If more than one country utilizes a common storage site, the country where the geological storage takes place is responsible for reporting emissions from that site. If the emissions occur outside of that country, they are still responsible for reporting those emissions as described above. In the case where a storage site occurs in more than one country, the countries concerned should make an arrangement whereby each reports an agreed fraction of the total emissions.

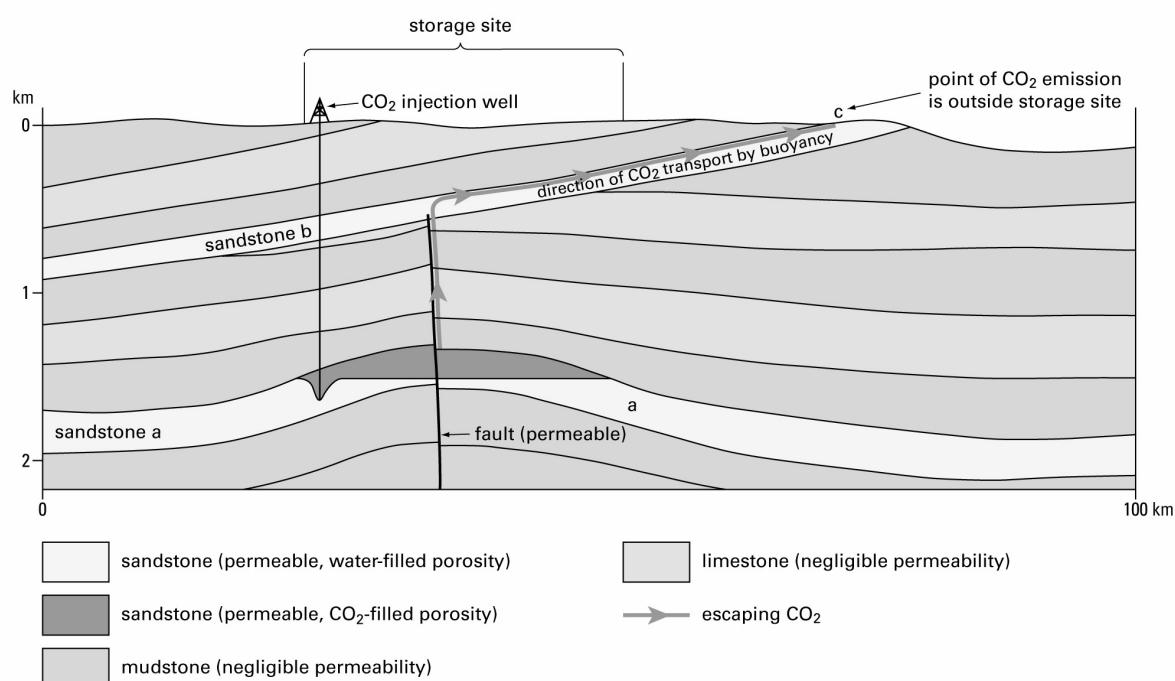
Annex 5.1 Summary description of potential monitoring technologies for geological CO₂ storage sites

Introduction

Monitoring of the geological storage of CO₂ requires the use of a range of techniques that can define the distribution, phase and mass of the injected CO₂ anywhere along any path from the injection point in the geological storage reservoir to the ground surface or seabed. This will commonly require the application of several different techniques concurrently.

The geology of the storage site and its surrounding area should be characterized to identify features, events and processes that could lead to an escape of CO₂ from the storage reservoir, and also to model potential CO₂ transport routes and fluxes in case there should be an escape of CO₂ from a storage reservoir, as this will not necessarily be on the injection site (Figure A1).

Figure A1 An illustration of the potential for leakage of CO₂ from a geological storage reservoir to occur outside the storage site.



If CO₂ migrates from a storage reservoir (a) via an undetected fault into porous and permeable reservoir rock (b), it may be transported by buoyancy towards the ground surface at point (c). This may result in the emission of CO₂ at the ground surface several kilometres from the site itself at an unknown time in the future. Characterization of the geology of the storage site and surrounding area and numerical modelling of potential leakage scenarios and processes can provide the information needed to correctly site surface and subsurface monitoring equipment during and after the injection process.

Tables A5.1 - A5.6 list the more common monitoring techniques and measurement tools that can be used for monitoring CO₂ in the deep subsurface (here considered to be the zone approximately 200 metres to 5 000 metres below the ground surface or sea bed), the shallow subsurface (approximately the top 200 metres below the ground surface or sea bed) and the near surface (regions less than 10 metres above and below the ground surface or sea bed).

The techniques that will produce the most accurate results given the circumstances should be used. The appropriate techniques will usually be apparent to specialists, but different techniques can also be assessed for relative suitability. There are no sharply defined detection limits for most techniques. In the field, their ability to measure the distribution, phase and mass of CO₂ in a subsurface reservoir will be site-specific. It will be determined as much by the geology of the site and surrounding area, and ambient conditions of temperature, pressure and water saturation underground as by the theoretical sensitivity of the techniques or measurement instruments themselves.

Similarly, the detection limits of surface monitoring techniques are determined by environmental parameters as well as the sensitivity of the monitoring instruments themselves. In near-surface systems on land, CO₂ fluxes and concentrations are determined by uptake of CO₂ by plants during photosynthesis, root respiration, microbial respiration in soil, deep outgassing of CO₂ and exchange of CO₂ between the soil and atmosphere [Oldenburg and Unger 2003]. Any outgassing of CO₂ from a man-made CO₂ storage reservoir needs to be distinguished from the variable natural background (Oldenburg and Unger 2003, Klusman 2003a, c). Analysis of stable and radiogenic carbon isotope ratios in detected CO₂ can help this process.

Most techniques require calibration or comparison with baseline surveys made before injection starts, e.g. to determine background fluxes of CO₂. Strategies for monitoring in the deep subsurface have been applied at the Weyburn oil field and Sleipner CO₂ storage site (Wilson and Monea 2005, Arts et al. 2003). Interpretation of 4D seismic surveys has been highly successful in both cases. In the Weyburn field, geochemical information obtained from some of the many wells has also proved extremely useful.

Strategies for monitoring the surface and near-surface onshore have been proposed (Oldenburg and Unger 2003) and applied (Klusman 2003a, c; Wilson and Monea 2005). Soil gas surveys and surface gas flux measurements have been used. To date there has been no application of shallow subsurface or seabed monitoring specifically for CO₂ offshore. However, monitoring of natural gas seepage and its effects on the shallow subsurface and seabed has been undertaken and considered as an analogue for CO₂ seepage [e.g., Schroot and Schüttenhelm 2003a, b].

TABLE A 5.1
POTENTIAL DEEP SUBSURFACE MONITORING TECHNOLOGIES AND THEIR LIKELY APPLICATION

Technique	Capabilities	Detection limits	Where applicable, costs	Limitations	Current technology status
2D, 3D and 4D (time-lapse) and multi-component seismic reflection surveys	Images geological structure of site and surrounding area; structure, distribution and thickness of the reservoir rock and cap rock; distribution (and with time-lapse surveys movement) of CO ₂ in reservoir. May verify (within limits) mass of CO ₂ in reservoir. Permanent seismic arrays can be installed (but are not necessary) for time-lapse (4D) acquisition.	Site-specific. Optimum depth of target commonly 500-3000 m. At Sleipner, which is close to optimum for the technique, detection limit in Utsira Sand is c. 2800 tonnes CO ₂ . At Weyburn, detection limit is c. 2500 - 7500 tonnes CO ₂ (White et al. 2004). Likely that dispersed CO ₂ in overlying strata could be detected - shallow natural gas pockets imaged as bright spots and dispersed methane in gas chimneys can be well imaged.	Onshore and offshore. Imaging poorer through karst, beneath salt, beneath gas, in general resolution decreases with depth	Cannot image dissolved CO ₂ (insufficient impedance contrast between CO ₂ -saturated pore fluid and native pore fluid). Cannot image well in cases in which there is little impedance contrast between fluid and CO ₂ -saturated rock. These will be fairly common (Wang, 1997)	Highly developed with full commercial deployment in oil and gas industry
Crosshole seismic	Images velocity distribution between wells. Provides 2D information about rocks and their contained fluids.	Site specific. Resolution could be higher than surface seismic reflection surveys but coverage more restricted	Onshore and offshore	As above, and limited to area between wells	Highly developed with full commercial deployment in oil and gas industry
Vertical seismic profile	Image velocity distribution around a single well. Map fluid pressure distribution around well. Potential early warning of leakage around well.	Site specific	Onshore and offshore	As above and limited to small area around a single well	Highly developed with full commercial deployment in oil and gas industry

TABLE A.5.1(CONTINUED)
POTENTIAL DEEP SUBSURFACE MONITORING TECHNOLOGIES AND THEIR LIKELY APPLICATION

Technique	Capabilities	Detection limits	Where applicable, costs	Limitations	Current technology status
Microseismic monitoring	Detects and triangulates location of microfractures in the reservoir rock and surrounding strata. Provides an indication of location of injected fluid fronts. Assesses induced seismic hazard.	Site specific. Depends on background noise amongst other factors. More receivers in more wells provides greater accuracy in location of events	Onshore and offshore	Requires wells for deployment	Well developed with some commercial deployment
Monitoring wells	Many potential functions including measurement of CO ₂ saturation, fluid pressure, temperature. Cement and/or casing degradation or failure. Well logging. Tracer detection - fast-moving tracers might provide an opportunity to intervene in the leakage prevention by modifying operating parameters. Detection of geochemical changes in formation fluids. Physical sampling of rocks and fluids. In-well tilt meters for detecting ground movement caused by CO ₂ injection. Monitoring formations overlying the storage reservoir for signs of leakage from the reservoir.	Downhole geochemical samples can be analyzed by Inductively Coupled Plasma Mass Spectrometer (has resolution of parts per billion). Perfluorocarbon tracers can be detected in parts per 10 ¹² . Well logs provide accurate measurement of many parameters (porosity, resistivity, density, etc.).	Onshore and offshore. More expensive to access offshore.	Certain functions can only be performed before the well is cased. Others require the perforation of certain intervals of the casing. Cost is a limitation, especially offshore	Monitoring wells deployed e.g. in natural gas storage industry. Many tools highly developed and routinely deployed in oil and gas industry, others under development
Wellhead pressure monitoring during injection, formation pressure testing	Injection pressure can be continuously monitored at the wellhead by meters (Wright & Majek 1998). Downhole pressure can be monitored with gauges. Injection pressure tests and production tests applied in well to determine permeability, presence of barriers in reservoir, ability of cap rocks to retain fluids.	Proven technology for oil and gas field reservoir engineering and reserves estimation. ICP-MS used to detect subtle changes in elemental composition due to CO ₂ injection.	Onshore and offshore. More expensive offshore		Highly developed with full commercial deployment in oil and gas industry
Gravity surveys	Determine mass and approximate distribution of CO ₂ injected from minute change in gravity caused by injected CO ₂ displacing the original pore fluid from the reservoir. Can detect vertical CO ₂ migration from repeat surveys, especially where phase change from supercritical fluid to gas is involved because of change in density. Detection limit is poor and site-specific.	Minimum amounts detectable in the order of hundreds of thousands to low millions of tonnes (Benson et al. 2004; Chadwick et al 2003). Actual amounts detectable are site-specific. The greater the porosity and the density contrast between the native pore fluid and the injected CO ₂ , the better the resolution	Onshore and offshore. Cheap onshore.	Cannot image dissolved CO ₂ (insufficient density contrast with native pore fluid).	Highly developed with full commercial deployment in oil and gas industry. Widely used in geophysical research

TABLE A 5.2
POTENTIAL SHALLOW SUBSURFACE MONITORING TECHNOLOGIES AND THEIR LIKELY APPLICATION

Technique	Capabilities	Detection limits	Where applicable, costs	Limitations	Current technology status
Sparker: Seismic source with central frequency around 0.1 to 1.2 kHz is towed generally at shallow depth.	Image (changes in) gas distribution in the shallow subsurface (typically represented by acoustic blanking, bright spots, reflector enhancement).	Generally free gas concentrations >2% identified by acoustic blanking. Vertical resolution >1m	Offshore	Greater penetration but less resolution than deep towed boomer Gas quantification can be difficult when concentrations above 5%	Highly developed, widely deployed commercially, in sea bed and shallow seismic survey industry, also in marine research
Deep towed boomer: Seismic source generating a broad band sound pulse with a central frequency around 2.5 kHz is towed at depth.	Image (changes in) shallow gas distribution in sediments (typically represented by acoustic blanking, bright spots, etc.). Image the morphology of the sea bed. Image bubble streams in sea water	Generally free gas concentrations >2% identified by acoustic blanking. Resolution of sea bed morphology typically less than 1 metre. Penetration can be up to about 200 m below sea bed but generally less.	Offshore	Bubble streams more soluble than methane bubbles therefore may dissolve in relatively shallow water columns (approximately 50 m). Bubble streams may be intermittent and missed by a single survey. Accurate positioning of boomer is critical	Highly developed, widely deployed commercially, in sea bed and shallow seismic survey industry, also in marine research
Sidescan sonar	Image the morphology of the sea bed. Image bubble streams in sea water Characterisation of sea bed lithology eg carbonate cementation	Optimum method for detecting gas bubbles.	Offshore	As above. Accurate positioning of side scan sonar fish is critical.	Highly developed, widely deployed commercially in sea bed survey industry, also in marine research
Multi-beam echo-sounding (Swath bathymetry)	Image the morphology of the sea bed. Repeat surveys allow quantification of morphological change. Sea bed lithology identified from backscatter.	Can identify changes in sea bed morphology of as little as 10 cm.	Offshore	As above. Greater coverage in shorter time	Widely deployed in marine research
Electrical methods	May detect change in resistivity due to replacement of native pore fluid with CO ₂ , especially when the CO ₂ is supercritical. EM and electrical methods potentially could map the spread of CO ₂ in a storage reservoir. Surface EM may have potential to map CO ₂ saturation changes within the reservoir.	Relatively low cost and low resolution	Onshore and offshore	Resolution - Needs development and further demonstration	At research stage

TABLE A 5.3
TECHNOLOGIES FOR DETERMINING FLUXES FROM GROUND OR WATER TO ATMOSPHERE, AND THEIR LIKELY APPLICATION

Technique	Capabilities	Detection limits	Where applicable, costs	Limitations	Current technology status
Eddy covariance technique (Miles, Davis and Wyngaard 2005).	Measures CO ₂ fluxes in air from a mathematically-defined footprint upwind of the detection equipment. Equipment is mounted on a platform or tower. Gas analysis data, usually from fixed open- or closed-path infra-red CO ₂ detectors, is integrated with wind speed and direction to define footprint and calculate flux.	Realistic flux detectable in a biologically active area with hourly measurements = $4.4 \times 10^7 \text{ kg m}^{-2} \text{ s}^{-1} = 13870 \text{ t km}^{-2}/\text{year}$ (Miles, Davis and Wyngaard 2005)	Can only be used onshore. Proven technology. Relatively cheap. Potential to survey relatively large areas to determine fluxes and detect leaks. Once a leak is detected likely to require detailed (portable IR CO ₂ detector or soil gas) survey of footprint to pinpoint it.	Several instrument towers may be needed to cover a whole site. With a detector mounted on a 10 m tower a footprint in the order of 10 ⁴ -10 ⁶ m ² is likely. Development may be desirable to automate measurement. Quantitative determination of fluxes may be limited to regions of flat terrain.	Deployed by research community
Accumulation chambers technique, using field IR or lab analysis of sampled gas to measure flux (Klusman 2003).	Accumulation chambers of known volume are placed on the ground and loosely connected to the ground surface, e.g. by building up soil around them, or placed on collars inserted into the ground. Gas in chambers is sampled periodically and analysed e.g. by portable IR gas detectors, and then returned to chamber to monitor build-up over time. Detects any fluxes through the soil.	Easily capable of detecting fluxes of 0.04g CO ₂ m ⁻² day ⁻¹ = 14.6 t/km ² /year (Klusman 2003a). Main issue is detection of genuine underground leak against varying biogenic background levels (potentially, tracers could help with this). Works better in winter because the seasonal variation in biological activity is suppressed during winter.	Technology proven at Rangely (Klusman 2003a, b, c). Powerful tool when used in combination with analysis of other gases and stable and radioactive carbon isotope analysis -these help in identify the source of the collected CO ₂ . Tracer gases added to the injected CO ₂ could also help with this – detection of fast-moving tracers might provide an opportunity to intervene in the leakage prevention by modifying operating parameters (i.e., avoid remediation).	Gaps between sample points allow theoretical possibility of undetected leaks. In oil and gas fields the possibility exists that CO ₂ may be microbially oxidised CH ₄ rather than leaking CO ₂ from a repository.	Deployed by research community
Groundwater and surface water gas analysis.	Samples and measures gas content of groundwater and surface water such as springs. Could: a) Place a partial vacuum over the liquid and extract dissolved gases. Analyse for gases by gas chromatography, mass spectrometry etc. b) For a fresh sample, analyse for bicarbonate content. This is essentially what was done at Weyburn in the field and at the well-head (Shevill et al. 2004). As dissolved CO ₂ and bicarbonate contents are linked, then analysis of bicarbonate can be directly related to dissolved CO ₂ content (assuming equilibrium conditions).	Background levels likely to be in low ppm range. Detection limit for bicarbonate in <2 ppm range	Onshore. Should be used in combination with ground to atmosphere flux measurements as provides an alternative pathway for CO ₂ emissions. Measurement techniques well developed and relatively straightforward (e.g. Evans et al., 2002) but care should be taken to account for rapid degassing of CO ₂ from the water (Gambardella et al., 2004).	Should take account of varying water flux.	Commercially deployed

TABLE A 5.4
TECHNOLOGIES FOR DETECTION OF RAISED CO₂ LEVELS IN AIR AND SOIL (LEAKAGE DETECTION)

Technique	Capabilities	Detection limits	Where applicable, costs	Limitations	Current technology status
Long open path infra-red laser gas analysis	Measures absorption by CO ₂ in air of a specific part of the infra-red spectrum along the path of a laser beam, and thus CO ₂ levels in air near ground level. It is possible to construct a tomographic map from the measurements but little track record of converting this to a flux through the ground.	Needs development but estimate potential at ±3% of ambient (c. 11 ppm) or better	Onshore. Probably has the best near-term potential to cover several km ² with one device, therefore whole fields with a few devices. Costs estimated at \$1000's per unit, therefore potential to survey whole fields relatively cheaply. Once a leak is detected may require more detailed (portable IR CO ₂ detector or soil gas) survey to pinpoint it.	Technology still under development. Measures CO ₂ concentration over long path, so interpretation of tomography or more detailed survey necessary to locate leaks precisely. Difficult to calculate fluxes or detect low level leaks against relatively high and varying natural background.	At demonstration and development stage
Soil gas analysis	Establishment of the background flux from the ground surface and its variation is critical. Technique measures CO ₂ levels and fluxes in soil using probes, commonly hammered into soil to a depth of 50-100 cm but can also sample from wells. Sampling usually on a grid. Lower part of probe or tube inserted in well is perforated and soil gas is drawn up for on-site analysis using a portable IR laser detector or into gas canisters for lab analysis.	Portable infra-red detectors used in soil gas surveys can resolve changes in CO ₂ concentration down to at least ± 1-2 ppm. Absolute values of CO ₂ in soil gas (0.2-4%) are higher than in air, but background flux variations are less below ground than above so low fluxes from underground are easier to detect. A range of gases may be measured - ratios of other gases and isotopes can provide clues to origin of CO ₂ .	Onshore. Technology proven at Weyburn and Ranger fields and volcanic/geothermal areas. Useful for detailed measurements, especially around detected low flux leakage points.	Each measurement may take several minutes. Surveying large areas accurately is relatively costly and time consuming. In oil and gas fields the possibility exists that CO ₂ may be microbially oxidised CH ₄ rather than leaking CO ₂ from repository	Deployed by research community
Portable personal safety-oriented hand-held infra-red gas analyzers	Measures CO ₂ levels in air	Resolution of small hand-held devices for personal protection is typically c. 100 ppm.	Can be used onshore and on offshore infrastructure such as platforms. Proven technology. Small hand-held devices for personal protection typically <\$1000 per unit. Could also be useful for pinpointing high-concentration leaks detected by wider search methods.	Not sufficiently accurate for monitoring CO ₂ leakage	Widely deployed commercially
Airborne infra-red laser gas analysis	Helicopter or aeroplane-mounted open or closed-path infra-red laser gas detectors have potential to take measurements of CO ₂ in air every ~10m.	Brantley and Koepenick (1995) quote a ±1 ppm above ambient detection limit for the equipment used in airborne closed path technique. Less information is available on the open path technique, though it is likely to be ±1% or less.	Onshore. Proven technology for detecting methane leaks from pipelines and CO ₂ from very large point sources. Possible application for detecting CO ₂ leaks from pipelines and infrastructure or concentrated leaks from underground.	Measurements are made a minimum of hundred(s) metres above ground, and concentrations at ground level likely to be much higher than minimum detectable at these levels. CO ₂ is heavier than air, so will hug the ground and not be so easily detectable as methane by airborne methods	Commercially deployed in natural gas pipeline applications, not in CO ₂ detection applications

Notes: Data partly from Schuler & Tang (2005) included by permission of the CO₂ Capture Project.

TABLE A 5.5
PROXY MEASUREMENTS TO DETECT LEAKAGE FROM GEOLOGICAL CO₂ STORAGE SITES

Technique	Capabilities	Detection limits	Where applicable, costs	Limitations	Current technology status
Satellite or airborne hyperspectral imaging	Detects anomalous changes in the health of vegetation that could be due to leakage of CO ₂ to ground surface. Can also detect subtle or hidden faults that may be pathways for gases emerging at the ground surface. Uses parts of visible and infra-red spectrum.	Spatial resolution of satellite and airborne images 1-3m. Not calibrated in terms of flux or volume fraction of CO ₂ in air or soil gas, but may give indications of areas that should be sampled in detail.	Onshore	Research required to determine levels of CO ₂ in soil that will produce detectable changes in vegetation health and distribution. Many repeat surveys needed to establish (seasonal) responses to variations in weather. Not useful in arid areas	At research stage
Satellite interferometry	Repeated satellite radar surveys detect changes in ground surface elevation potentially caused by CO ₂ injection, if absidence (ground uplift) occurs	InSAR (Interferometric Synthetic Aperture Radar) can detect millimetre-scale changes in elevation	Onshore	Changes in elevation may not occur, or may occur seasonally, e.g. due to freezing/thawing. Local atmospheric and topographic conditions may interfere.	At research stage, not yet deployed for CO ₂ storage

TABLE A 5.6
TECHNOLOGIES FOR MONITORING CO₂ LEVELS IN SEA WATER AND THEIR LIKELY APPLICATION

Technique	Capabilities	Detection limits	Where applicable, costs	Limitations	Current technology status
Sediment gas analysis	Samples and, in laboratory, measure gas content of sea bed sediments.	Uncertain how measured gas contents relate to in situ gas contents.	Offshore. Ship time costly.	Pressure correction of data will be necessary unless pressurised sample is collected. ROV's and divers could be used for sampling if necessary. Ship time costly.	Deployed by research community for methane gas analysis offshore
Sea water gas analysis	Sample and, in laboratory, measure gas content of sea water. Protocols exist for analysis of sea water samples.	Detection limits of analytical equipment likely to be in low ppm range or better. Detection limit for bicarbonate in <2 ppm range. Ability to detect leaks in field unproven. Minimum size of leak that could be detected in practice unproven.	Offshore. Ship time costly.	As above	Deployed in near surface waters in research community, not widely used at depth.

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