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TECHNICAL GROUP

DRAFT

Discussion Paper from the Task Force for Identifying Gaps in CO_2 Monitoring and Verification of Storage (Revised Version)

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Note by the Secretariat

Background

At the meeting of the Technical Group in Melbourne, Australia on September 15, 2004, a Task Force was created to identify gaps in CO_2 monitoring and verification of storage. This Task Force consists of Canada (lead), the European Commission, France, Norway, and the United Kingdom. It was instructed to produce a Discussion Paper that would then undergo review and be presented at a full Technical Group meeting. A first version of this Discussion Paper was presented at the meeting of the Technical Group in Oviedo, Spain, on April 30, 2005. This revised version of the Discussion Paper is a continuation of the Task Force's activities.

Action Requested

The Technical Group is requested to review and consider the second version of the Discussion Paper presented by the Task Force for Identifying Gaps in CO_2 Monitoring and Verification of Storage.

Conclusions

The Technical Group is invited to note in the Minutes of its next meeting that:

> "The Technical Group reviewed and considered the Discussion Paper presented by the Task Force Task Force for Identifying Gaps in CO_2 Monitoring and Verification of Storage."

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CSLF Technical Group Task Force to Identify Gaps in Monitoring and Verification of Storage

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Abstract:

Monitoring of CO_2 injection for enhanced oil recovery as well as the monitoring of a variety of other underground fluid storage operations has been ongoing for some decades.

Volumes of CO_2 injected underground will increase significantly in the future compared to present and historic levels if fossil fuel use is going to continue to increase in a carbon constrained world. The injection of CO_2 will differ from the injection of oil field waste in the sense that CO_2 is a buoyant fluid. CO_2 dissolved in water is also an acid and, therefore, chemically reactive. In the longer term, the solubility and reactivity of the CO_2 will increase the permanence of the storage. Provided the storage is undertaken in suitable geological environments, the most likely pathway for leakage will be the engineered infrastructure (the wellbores or other human intrusions).

There will need to be modification of, or addition to, current regulations to ensure human and ecosystem health and safety and to prevent the CO_2 from entering the atmosphere. These regulations will require monitoring regimes to ensure that the performance of the injection site meets the predicted performance for licensing.

This paper evaluates the monitoring techniques currently in use in underground fluid injection and storage operations. Where gaps exist, for reasons of cost, resolution or other factors, these gaps are identified. Finally, recommendations are made for ongoing work to improve the cost, resolution and reliability of the techniques. Ultimately, it will be the regulator, assessing the risk of given sites, that will determine the nature of the monitoring to be undertaken and the length of time over which monitoring must occur. The recommendations in this paper do not call for technologies to be dropped from the slate of technologies we have available, rather the need for more work in many areas ensure that appropriate monitoring technologies are available to meet most monitoring requirements. The subsurface is an extremely variable natural system. Consequently, the geology of potential storage sites is site-specific, so the expectation is that different sites may well require different monitoring regimes.

Introduction:

The purpose of this paper is to provide commentary on the currently available technology for the monitoring and verification of carbon dioxide stored in the subsurface and to identify gaps or weaknesses in the available technologies. Based on this gap analysis, needs have been identified and recommendations for meeting the identified needs are proposed.

The term "geological storage" is used deliberately in this paper (and in much common usage) to distinguish the removal of CO_2 from contact with the atmosphere using capture and storage as opposed to the chemical removal of CO_2 by plants and soils. In this latter context, sink means the sequestration of carbon in organic form. Geological sink refers to the underground storage of CO_2, initially partially or completely in a free phase, in the rocks below the earth's surface.

The purpose of geological storage is to remove the CO_2 from contact with the atmosphere for extended periods of time. The work of Stenhouse et al. (2005) suggests two basic time frames for this storage. The fist is a performance based time period, in the order of hundreds of years, until the emissions to the atmosphere from fossil fuel use have dropped significantly and constraining CO_2 concentration in the atmosphere becomes less of an issue. Having stored the CO_2, there are some issues around human and ecosystem health and safety. This will be an issue as long as the CO_2 has some positive buoyancy and there is a risk of leakage to the surface. This will be effectively eliminated once the CO_2 has dissolved in subsurface fluids and there is no longer a buoyancy concern. This may take hundreds or thousands of years. Monitoring is not considered to be necessary for this entire period, but for long enough to determine the performance of the storage system.

The injection of CO_2 into the subsurface is not a new concept. There are many projects globally, particularly in the Permian Basin of West Texas, where CO_2 injection for the purposes of enhanced oil recovery (EOR) has been underway for several decades. There has also been significant experience with underground storage of natural gas and, prior to natural gas storage, the storage of town gas (CO and H_2) in the subsurface. Large natural reservoirs of CO_2 have been exploited for several decades for commercial purposes. All such operations can provide useful insight into the engineering of CO_2 storage sites.

Additionally, there has been widespread and large scale injection of other fluids into the subsurface, especially in the oil and gas industry. For example, hydrocarbon gases are widely injected for miscible enhanced oil recovery, and the re-injection of oil field liquid waste, particularly oil field brines and, more recently, acid gas injection for the storage of H_2S (Hydrogen Sulphide) is common practice. In short, there is much experience globally with the safe injection of liquids and gases into the subsurface for long-term storage.

There are also prescriptive regulations in place in many countries concerning the completion of injection wells and the abandonment procedures required when these wells are no longer needed.

As oilfield technology for oil and gas production, EOR and waste removal has developed, so has the technology to monitor the movement of injected fluids and native pore fluids in reservoir rocks. Consequently, the technologies that we now look to as techniques for monitoring the movement and potential migration/leakage of CO_2 are largely the same ones that are used for detecting and quantifying the presence of hydrocarbons within the subsurface. Additional techniques developed in the oil and gas industry can be used to ensure safety at the surface injection facilities and to avoid overpressuring in the reservoir in underground CO_2 storage.

In some regions of the world, primarily volcanic regions, natural CO_2 leaks occur, with the CO_2 moving along natural fracture systems to the surface. Most of these seeps are benign, but in a few cases potential hazard does exist for humans and animals (e.g. Ciampino, Italy). In these instances monitoring technologies are deployed to provide early warning of potentially hazardous CO_2 accumulations. These extreme examples provide confidence that monitoring of leaks in proximity to human settlement can be effectively achieved.

Why is monitoring needed and what can it achieve?

Monitoring of CO_2 injection projects is needed for:

- health, safety and environmental purposes
- verification of the mass of CO_2 stored, for emissions trading and greenhouse gas inventory purposes
- to resolve any disputes arising from conflicts over the use of the subsurface and possible contamination of underground resources.

For health, safety and environmental purposes, monitoring will be needed to ensure the safe operation of the injection processes and other processes taking place on the site, and to detect leaks from surface equipment and pipelines on the injection site. Alarms may need to be fitted, particularly in enclosed spaces such as buildings. Monitoring will also be needed to detect leaks from the storage reservoir to the near surface, ground surface or sea bed, both through natural geological discontinuities of the site and surrounding area and through wells.

For emissions trading and greenhouse gas inventory purposes, there will need to be some regulations or protocols developed to determine the net impacts of geological storage in terms of the project based emissions and corporate or national inventories. The nature of the regulations will determine the monitoring required to inform the bodies governing inventories of the net emissions to be accounted. Examples may include the severity of regulations regarding migration of the CO_2 within the subsurface, outside the injection zone, but still below any potable water zones o the surface itself. Site emissions related to the injection process itself, particularly in the case of enhanced oil recovery where recycling of CO_2 consumes a large quantity of energy. Where the recycling energy is imported (i.e. electricity purchases), it is likely that the emissions will be accounted for against the producer of the electricity. Fugitive emissions will be the responsibility of the project storing the CO_2.

At present, as far as the authors are aware, CO_2 purchased at EOR projects in the USA is not counted in the national greenhouse gas emissions inventory and CO_2 stored at the Sleipner project offshore Norway is treated in the same way (i.e. it is assumed that there are zero fugitive emissions from underground). In the case of Weyburn, because the emissions are reduced in the USA, there is currently no mechanism to provide any credit to the project storing these emissions. Fugitive emissions at Weyburn are essentially zero (tight monitoring for leaks is required at Weyburn because of the H_2S present in the gas stream). Monitoring for fugitive emissions is not a legal requirement or license condition in the US and Sleipner cases. Monitoring for CO_2 leaks in not regulated at Weyburn, except, as noted above, for worker safety issues.

It is not known whether the IPCC will include a Tier 1 (discounting) method of accounting for fugitive emissions from underground in future revisions of the guidelines for compiling national greenhouse gas inventories, or whether it will require a Tier 3 method based on monitoring. It has been proposed that the mass of CO_2 stored would be accounted within the EU Emissions Trading Scheme (EU ETS). Thus any fugitive emissions from underground would fall outside the boundaries of the scheme; they would however, be accounted for in the national greenhouse gas inventory. Government regulation would presumably ensure that the operators were held responsible and liable for any leakage.

To resolve any disputes arising from conflicts of use of the subsurface and possible contamination of underground resources the distribution of CO_2 in the subsurface may need to be determined.

In all cases it would be desirable to know the origin of any fugitive emissions of CO_2. That is, which, if any, CO_2 storage project they are derived from.

Thus, ideally, monitoring should:

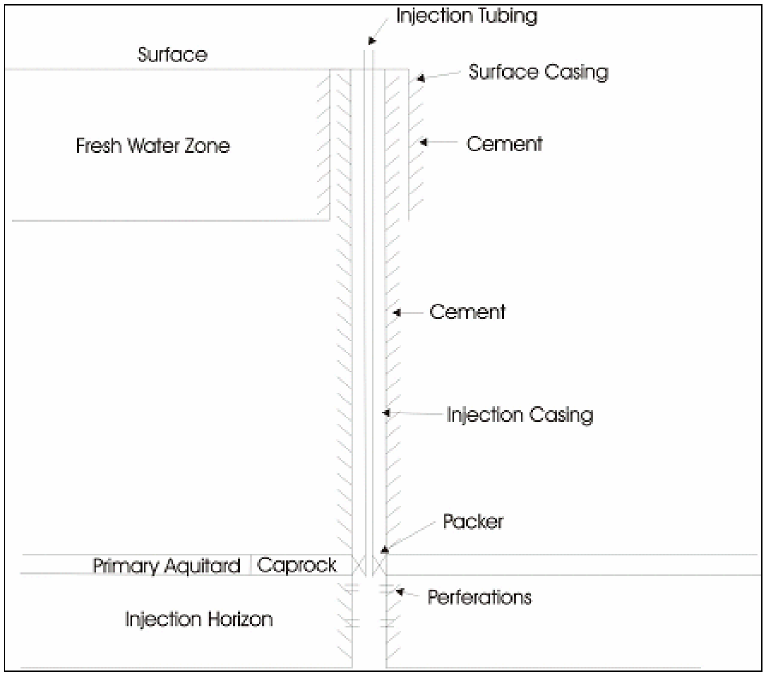
- allow the safe and stable injection of CO_2 into subsurface reservoirs
- allow the integrity of injection and monitoring wells to be assessed and monitored
- allow the location and fate of the CO_2 plume in the subsurface to be determined
- allow the project operator or regulator to assess the accuracy of performance predictions of the project
- verify that the entire mass of CO_2 that is delivered to the injection well(s) is, indeed, stored in the location that was approved for that storage
- provide early warning of migration from the intended storage reservoir or leaks to the ground surface or sea bed
- detect and measure the flux of leaks of CO_2 to the biosphere (the shallow subsurface, the ground surface, or sea bed).

Leaks or unintended migration out of the storage reservoir might in turn require mitigation activities to be undertaken. In the event that mitigation is required, the performance of the mitigation process itself will need to be evaluated.

Injection well technology:

The basics of deep injection well technology are straightforward. The well is drilled to a specified depth, casing is then inserted into the well and cemented in place such that a cement bond is formed between the casing and the surrounding rock. Usually, the first casing is inserted a significant distance above the target formation. Drilling then continues with a smaller bit that fits inside the casing, and at a lower specified depth more, smaller, casing is inserted and cemented in place. This process continues until the specified depth for the well is reached; in the case of vertical wells, this is most commonly slightly below the formation of interest. Cementing regulations vary greatly from place to place. Cementing may be restricted to providing a seal from the ground surface to below the lowest potable water zone (the goal being to isolate and protect potable water) and at the base of the well in the formation of interest and some metres above this. However, in many cases, the casing is cemented to the surrounding rock along its entire length to ensure effective isolation of zones in the subsurface. The well is then perforated to allow access through the casing and cement into the formation of interest (Fig. 1).

Figure 1. Schematic of a Typical Injection Well



The full diameter of the well is not generally used for injection. Instead an injection string (a smaller diameter tube) is run into the well. At the top of the formation of interest, a packer is put in place between the casing and the injection tubing to seal off the lower portion of the well. Injection then takes place. The fluid flows out of the injection tubing into the annulus between the casing and tubing and then through the casing via the perforations. The annulus, the space between the injection string and the casing itself, is sealed top and bottom. In the case of horizontal wells, there may be casing in the formation of interest (particularly when the formation consists of unconsolidated sediments), or the hole may be uncased when the formation is sufficiently consolidated to allow the hole to remain open after drilling with no artificial support.

The surface infrastructure of the injection well is designed for safety, with valves that allow isolation of the well and automatically shut off the well in the event of an emergency. This surface infrastructure also allows monitoring equipment such as pressure gauges to be installed.

Safety requirements for injection of fluids into subsurface reservoirs

Prior to any injection into the subsurface, the fracture pressure of the reservoir rock and caprock should be determined. To avoid fracturing, with the possibility of damaging the caprock (the primary seal of the storage site), the reservoir injection pressure will usually be restricted to some level below its fracture pressure. Typically, the regulator will set limits on the surface pressure and flow rates allowable into an injector to prevent any risk of damage to the reservoir or seals. In some cases however, the reservoir rock may be deliberately fractured to allow fluids to be injected more rapidly. This can be acceptable provided that any damage to the cap rock is not sufficient to allow fluids to escape from storage.

Also prior to any injection of fluids into the subsurface, the integrity of the well casing should be confirmed by pressure testing the well. In addition, cement bond logs should be used to determine the condition of the cement bond between the casing and the formation (this creates the seal between the outside of the well casing and the surrounding rock).

What might a monitoring program consist of?

Monitoring of CO_2 storage can conveniently be divided into stages:

- Preparation of a monitoring plan
- Acquisition of baseline measurements with which changes in environmental and other parameters can be compared, a critical component of any program
- Verification of well bore integrity and cement bond.
- Measurements to determine the mass of CO_2 injected, principally derived from the fluid pressure, temperature, flow rate and gas composition at the wellhead
- Monitoring of pressure during the injection process to ensure safe and stable injection
- Monitoring of well bore integrity during the injection period
- Monitoring of the migration and distribution of the CO_2 in the deep subsurface, focusing on the intended storage reservoir, but including any unintended migration out of the storage reservoir
- Monitoring of the shallow subsurface offshore to detect and quantify any CO_2 migrating out of the storage reservoir towards the sea bed
- Monitoring of the vadose zone onshore to detect and quantify any CO_2 migrating out of the storage reservoir towards the ground surface
- Monitoring of the ground surface and atmosphere to detect and quantify CO_2 leaking into the biosphere
- Monitoring of the biosphere to detect any subtle changes that might be related to increased CO_2 concentrations
- Monitoring of the sea bed and water column to detect and quantify CO_2 leaking to the marine environment or atmosphere
- Monitoring at the injection site to detect and quantify any leakage from surface infrastructure (for worker health and safety) and physical changes to the site (particularly heave), which may be indicative of problems below surface
- Monitoring of the wells, deep subsurface, shallow subsurface and ground surface or sea bed should continue for some period after the injection is terminated to confirm predictions of storage behaviour.

Such a monitoring program would not just utilize direct and indirect measurements of CO_2 itself, but would probably also include the use of tracers to pinpoint movement ahead of any advancing CO_2 front. These tracers may also help to distinguish naturally occurring CO_2 from CO_2 leaking from the injection site.

A pre-requisite for effective monitoring is the preparation of a monitoring plan. This is likely to be based on some form of risk assessment, which in turn will likely be based on detailed geological and hydrological site characterization and numerical simulation of CO_2 injection. This will highlight any likely migration pathways from the storage reservoir to the ground surface or sea bed, and therefore will allow appropriate monitoring technologies to be deployed at appropriate places and appropriate times.

Another pre-requisite is the acquisition of baseline surveys. They can be crucial as they will allow all subsequent surveys to be compared to the baseline to evaluate changes that have occurred as a result of the injection of CO_2. Ideally these should be undertaken prior to any injection of CO_2 into the storage formation, but this may not always be possible, for example when monitoring an existing EOR project. However, monitoring at the Rangely EOR project has highlighted the advantages of having a baseline survey. A small flux of deep-sourced CO_2 has been detected (Klusman 2003) and a baseline survey prior to injection could have enabled the question of whether this is a natural flux or a flux attributable to EOR to be resolved.

Monitoring techniques:

Detailed descriptions of monitoring techniques that have been applied to, or are potentially applicable to CO_2 storage are given by Benson et al. (2004) and Pearce et al. (2005).

Monitoring well bore integrity

A wide variety of pressure sensors can be installed to measure pressure through access points in the wellhead. Fibre-optic systems are particularly useful for pressure measurement downhole as well as at surface, giving greater control on the pressures in the entire injection well system. As noted above, emergency shutdown can be triggered if pre-set threshold levels are exceeded. The pressure and gas composition in the annulus can be continuously monitored to determine the integrity of the injection string and the packer inside the casing used to isolate the injection zone from the remainder of the well. Changes in pressure or composition can be rapidly detected using pressure sensors or infrared analysers and the well shut-in to determine the cause of the change. During well shut-in, fibre-optic temperature sensors can identify fluid exchange sites between a borehole and surrounding formations. Fibre-optic systems exist that will allow measurement along the entire wellbore in real time.

Cement bond logs can be run periodically to determine the status of the bond between the rock and the well casing.

Leaks through the casing or immediately outside well bores can be detected by, for example, passive sonic monitoring.

Monitoring of the mass of CO_2 injected

The direct measurement of volumes and composition of a gas stream flowing into an injection well will allow the operator and regulator to determine the amount of gas injected with a high degree of accuracy. The measurement of produced fluids, capture of the produced CO_2, its recompression and reinjection, will allow an accurate assessment of the gross and net storage of CO_2 in an EOR project.

Monitoring equipment to determine the mass of CO_2 being injected is generally available from commercial suppliers. Typically, control systems measure gas volume, pressure and temperature at the wellhead and transmit the collected data to a control centre. Gas composition is also measured in such systems, commonly with a gas chromatograph (e.g. Wright & Majek, 1990). A good example of a state-of-the-art system is at Weyburn where all information from monitors in buildings, at well sites, at collection sites (satellite batteries) and other key locations is received and displayed in central control facilities. This information includes both health and safety information as well as production and injection flows for economic and process operation purposes..

Monitoring of the migration and distribution of the CO_2 in the deep subsurface

The transport and fate of CO_2 in the deep subsurface can be monitored using both direct and indirect techniques. Direct techniques measure directly the changes in the pore fluids in the subsurface, sampling either from monitoring wells or (oil or gas field) production wells. Indirect techniques include the use of a variety of remote sensing technologies which principally comprise seismic and non-seismic geophysical methods. Tracers (introduced, such as SF_6, or indigenous, such as radon) can also be used to identify fluid migration routes and breakthroughs.

Direct techniques

Fluid samples can be obtained from the injection zone by collecting samples from production wells in the case of EOR operations or from monitoring wells. Changes in fluid chemistry (pH, alkalinity, HCO_3^- or resistivity levels for example) can be evaluated to determine whether or not CO_2 has reached the well. Additionally, sampling and analysis of the CO_2 itself can provide an indicator of whether it is injected or naturally occurring CO_2 (for example, in the Weyburn reservoir, the stable isotopic composition of the carbon in injected CO_2 is quite different from the that of the carbon naturally present in the subsurface, so the presence of injected CO_2 at production wells can be identified by determining isotopic ratios of the carbon).

The injection of tracers has potential to more precisely determine the route and transport rate from injector to producer or monitoring well. As noted above, tracers can be artificial gases such as perfluorocarbons or noble gases, both able to be identified at very low concentrations. Noble gases, in particular, may travel through the rock more rapidly that the CO_2 providing a proxy for the route that CO_2 might take.

Direct measurement of vertical movement of CO_2 in the stratigraphic column can also be achieved in some instances with the use of observation wells or existing injection or production wells. Tools now exist that can drill through the casing and cement to collect fluid samples from behind the casing at various levels in the subsurface, and then plug the holes to prevent leakage into the well. While this technique is expensive, it may allow for periodic testing of zones of interest above the injection zone without the drilling of monitoring wells. The fluids sampled would be analysed for CO_2 and for changes to fluid chemistry resulting from increased CO_2 levels.

Well logging can be used to determine, for example, CO_2 saturation distribution in an open section of a monitoring well. Cased hole logs can also be used to detect the presence of CO_2 behind the casing, particularly if there are pre-injection logs to allow comparison. Well logging has great potential for both detection and quantification of CO_2 in the subsurface.

Indirect techniques

The most commonly applied indirect technique is seismic technology. The use of 2-D and 3-D seismic techniques is common. Comparison of time-lapse (4-D) surveys allow migration of CO_2 in the subsurface to be followed. Examples of this technique are from Sleipner (injection into a saline aquifer) and Weyburn (injection into an oilfield). In both cases, baseline surveys were run prior to CO_2 injection so that all subsequent surveys could be compared to the pre-injection survey.

Seismic techniques can be applied in a variety of ways. The most common is 2D seismic reflection profiling or 3D seismic reflection data acquisition, where the energy source and detectors are on the surface, measuring reflection from zones in the subsurface. Continuous seismic monitoring is a technique receiving some attention as well. This technique (for example, Bianchi et al. 2004) uses low energy sources operating for long time periods or continuously to provide a view of changes to the distribution of gas or CO2 in the subsurface. Such techniques have good temporal resolution, but lower areal resolution than conventional techniques, but may be useful for plume tracking in saline aquifer situations. Other techniques include vertical seismic profiling where the source is on the surface and the detectors are placed in vertical or horizontal wells in the subsurface. Cross-well profiling can also be used where both the source and the detectors are in the subsurface. Both vertical profiling and cross-well profiling reduce the areal extent of the survey, but the level of detail may be greater. Passive techniques (micro-seismic monitoring) may also have some potential. In this case, sensors are left in place, often in wells that are scheduled for abandonment, to measure microseismic activity in the reservoir. This activity may arise from dynamic responses to changing pore pressure or reactivation of faults or fractures. The responses to these changes result in very weak seismic events in the order of 0 to -4 magnitude.

Seismic techniques are in common use and are key components of the monitoring programs in current monitoring projects such as Weyburn, Sleipner and the recently initiated In Salah project (Algeria). They are also used in pilots such as the recent tests in the Frio sandstone in Texas and at Nagaoka in Japan. They currently provide the most accurate method of detecting CO_2 in the subsurface in areas between wells. Nonetheless surface seismic methods have limitations. They have little potential to resolve the very small impedance contrast between a reservoir rock the pores of which are filled with water containing dissolved CO_2 and one in which the pores contain water without dissolved CO_2. They also do not resolve events well below highly reflective or dispersive geological horizons such as thick evaporite deposits. Moreover their resolution deteriorates with depth as a result of frequency attenuation.

Non-seismic geophysical techniques include the use of electrical and electromagnetic (EM), self-potential (SP) and gravity techniques. Gravity techniques, marine, ground or aerially based, can detect variations in rock or fluid density in the subsurface, for example, those caused by the injection of a lighter fluid into the pore spaces of a reservoir rock. Resolution is significantly poorer than seismic.

Electrical techniques measure natural or induced electrical or magnetic fields in the Earth. An induced electrical current will provide a measurement of the resistivity of a formation. Changes to resistivity will occur, for example, with the dissolution of minerals in the formation (decrease in resistivity) or the displacement of saline fluids by CO_2 (an increase in resistivity). The measurement of natural electrical or magnetic fields can be interpreted by comparison to a pre-injection survey to determine the presence of fluids such as CO_2 that change the characteristics of these fields. Self-potential can be measured as well, this is the ability of the earth to generate its own electrical fields. The migration of CO_2 within the rock can produce an electrical potential that is measured – this technique may again be useful in measuring plume migration. It is a low cost but low resolution technique.

Monitoring of the shallow subsurface and marine environment to detect and quantify any CO_2 migrating into the water column or accumulating close to the sea bed

Echo-sounding and swath bathymetry may be used to detect changes in sea bed morphology that could be due to gas emerging at the sea bed, e.g. the development of pock marks. Echo-sounding can also detect bubble trains in sea water. Sparker and deep towed boomer surveys may be used to detect CO_2 in the shallow zone beneath the sea bed. Typical responses to shallow gas include acoustic blanking, reflector enhancement and bright spots. These techniques are routinely used in the oil and gas and marine surveying industries.

Monitoring of the vadose zone and ground surface to detect and quantify leakage of CO_2 to the ground surface

A number of techniques can be applied to determine the presence of CO_2 that might be released from a storage site into the vadose zone and thus to the ground surface and near-surface environment. CO_2 in near-surface environments may occur either as free gas or as CO_2 dissolved in water emerging, for example, as carbonated springs. Excellent accounts of monitoring and modeling techniques that can be applied at the ground surface and in the vadose zone are given by Oldenburg and Unger (2003) and Oldenburg, Lewicki and Hepple (2003).

Techniques applied include soil gas monitoring (Strutt et al. 2003; Klusman 2003) and accumulation chambers placed on the ground surface (Klusman 2003), to detect increased levels of CO_2. This can be followed up by stable carbon isotope analysis to help determine the source of any detected CO_2, and analysis for levels of the radiogenic isotope of carbon (^{14}C), which may give information about the age of the carbon atoms in the carbon dioxide molecules. Marker gases such as radon that might provide clues to the location of pathways through which gases might migrate from depth may also be detected.

The major issue here is that there is a variable natural ecological (and potentially anthropogenic) background flux of CO_2 against which very small fluxes from underground need to be detected. A second issue is that such surveys sample at grid nodes and further research is needed to define the appropriate grid spacing that will provide comprehensive coverage of an area.

In groundwater, analysis of major ions (Na, K, HCO_3^- etc), alkalinity and pH, as well as searching for hydrocarbon gas and the ratio of stable carbon isotopes can determine changes to CO_2 quantity and source. In addition, contamination by trace elements such as lead and arsenic, which may be mobilized by changing water pH, may be indicators of increased CO_2 levels. As in soil gas analysis or gas analysis from accumulation chambers, isotopic analysis of the CO_2 will help to determine its source, in particular shallow biogenic sources of CO_2 will have a different isotopic composition to CO_2 from fossil sources. Artificial tracers injected with the CO_2 such as perfluorocarbons or noble gases, detectable at very low concentrations, may provide an indication of the potential for leakage from the storage zone.

Techniques such as hyperspectral imagery from airborne surveys can indicate changes to vegetation productivity that could be the result of changing conditions in the vadose zone (Pickles & Cover 2005). Due to the density difference between gaseous CO_2 and the atmosphere, the CO_2 will tend to accumulate in the vadose zone, even with low flux levels, and at high levels (for example Mammoth Mountain) can negatively impact plant growth to the point of killing the plants. Such biosphere responses are clear signals of ecosystem disturbance, drawing attention to the need for more detailed examination. Some plant responses to chronic raised atmospheric levels of CO_2, such as reduced stomatal density, could provide a low-tech way of identifying leakage and have been observed around natural seeps. Tree kills and other vegetational changes are routinely used in the identification of methane leaks from buried gas pipelines.

Measuring a change in flux of CO_2 into the atmosphere can be undertaken with a variety of infrared techniques (Schuler & Tang, 2005). Two techniques that have been used to date are accumulation chambers (Klusman 2003) and eddy covariance (Miles, Davis and Wyngaard, in press). Long open-path infrared laser gas detectors show promise for surveying large areas at low heights above ground level (Menzies et. al., 2001).

Various remote infrared techniques may be used to try to analyse for increasing CO_2 concentrations in the near surface zone of the atmosphere using airborne or even satellite based systems. In any of these techniques, the increasing flux of CO_2 would need to be very high for the analytic techniques to pick up variance. The more remote the sensor, the less likely it is to be able to pick up changing levels of CO_2. For example, the averaging effect of airborne or satellite based measurements of CO_2 through a long column of atmosphere will effectively mask most leaks of CO_2.

Monitoring ground surface movement:

Accurate tiltmeters, or satellite imagery can be used to measure heave of the ground surface or injection wellhead. This may be indicative of potential problems in the subsurface. However, this is not always the case, and under favourable circumstances, satellite-based ground elevation measurement techniques have the potential to help to identify plume migration in the subsurface.

Monitoring of air quality to ensure worker health and safety:

For worker health and safety, particularly if there are contaminants in the CO_2 stream such as H_2S (for example, acid gas injection sites in Alberta), there will be monitoring equipment sited at and around the surface facilities to directly measure any leakage. Infrared gas detectors are commonly used to determine the levels of CO_2 in the ambient air surrounding the wellhead.

Costs of monitoring:

While monitoring may appear at first glace to be expensive, with extensive 3D seismic surveys and observation wells costing hundreds of thousands to millions of dollars (depending on areal extent and location), the cost of monitoring on a *per tonne* basis for a large storage project (30 million tonnes and up) will be comparatively low. Work by Benson et al. (2004) suggests costs of less than US$1.00 per tonne. This is compared to capture costs in the range of US$25-35.00 per tonne with current technology. When dealing with the cost of storage alone, this could be, however, a significant issue still, particularly if there are no regulations in place to limit the length of time that monitoring should occur or should monitoring in higher risk storage locations become more onerous.

Gaps discussion:

The above discussion covers most of the techniques either currently being used or proposed to monitor:

the injection of CO_2 into the subsurface

the condition of wells and their bond to the surrounding rock

the migration and distribution of injected CO_2 within the intended storage reservoir

its migration out of the intended storage reservoir and subsequent distribution
its potential transport to the near surface, ground surface or sea bed
its flux through the ground surface or sea bed, into the atmosphere or sea.

These techniques vary greatly in resolution and cost. The necessary precision of measurement does not exist in all monitoring spheres and there is also a need to identify the least-cost solutions able to meet the necessary monitoring requirements. It is not yet clear how much resolution is actually required. Less sensitive techniques may well be adequate to monitor plume movement unless potential leakage points are encountered.

There are no major perceived gaps in our ability to monitor the mass of CO_2 or other gases injected into the subsurface. This is common practice in enhanced oil recovery projects.

There are no major perceived gaps in our ability to monitor CO_2 escapes from surface facilities at injection sites for health and safety reasons. This is also common practice in enhanced oil recovery projects.

There are no major perceived technology gaps in monitoring the condition of new wells and their bond to the surrounding rock. The ability to assess the condition of pre-existing abandoned wells beyond empirical observation of leaks (i.e. to determine whether they are likely to leak in the future) is, however, a major technology gap.

Shallow subsurface monitoring of CO_2 is also a mature technology in terrestrial settings, the main gaps being those of frequency and spacing, and strategies required in different terrestrial climate regimes (e.g. deserts, temperate grassland, tundra etc). In subaqueous settings, it is less clear how much CO_2 measuring devices used by marine biologists (often for mesocolumn and shallower applications) can be adapted for benthonic settings, particularly within shallow sediments. Very little is also known about the possibility of using ecosystem changes, or indicator species, as monitoring signals for CO_2 seepage into the hydrosphere. Such techniques are used to monitor pollution effects, such as nitrification from agricultural and sewage disposal activities.

A range of tools are available for monitoring the migration and distribution of injected CO_2 within the storage reservoir and its potential migration out of the storage reservoir and subsequent distribution. However, these are at best semi-quantitative and their performance will be highly site-specific and dependent on the local geology. In general, detection of CO_2 in the subsurface is better than quantification. Seismic reflection surveying is commonly a good method of detecting free gas phase or supercritical CO_2, but it may be of limited effectiveness beneath, for example, thick salt horizons. Also it will not detect dissolved CO_2. Well logging and direct sampling can provide a better understanding of CO_2 saturation distribution in the reservoir and certain tools may be able to detect dissolved CO_2 from changes in resistivity, pH or direct sampling. In general, there is a major gap in our ability to independently and accurately verify the mass of CO_2 stored in a subsurface reservoir.

Tools are available to detect CO_2 in the vadose zone onshore and in the shallow subsurface offshore. However, there is a technology gap in quantification of the mass of CO_2 present in shallow accumulations in offshore areas.

Tools and methodologies are available for detecting and monitoring CO_2 fluxes from the vadose zone to the atmosphere. These require further field trials to identify best practice. There is room for technology research and development in this field.

Technologies exist that can detect bubble trains in seawater. These provide a means of detecting CO_2 fluxes through the sea bed. However they will not detect dissolved CO_2 and some cost-effective means of direct detection in the marine environment such as sea water sampling needs to be developed.

The real gaps in the technology for monitoring fall into the areas of cost and level of accuracy. While there is some discussion around the ability to quantify results, the key is the accuracy and repeatability of results.

From another perspective, if it can be shown that there is little or no leakage from the subsurface container, the ability to quantify the amount of CO_2 in the reservoir or saline aquifer based on remote sensing techniques is largely irrelevant, the inflow metering will be quite adequate. The discussion resides, therefore around several other factors:

- The ability to identify leaks in the subsurface.
- The ability to determine the risk of leakage along wellbores.
- The ability to identify faults or fractures that may be encountered by the expanding CO_2 plume that may be open or could be opened to provide a conduit out of the subsurface storage container.
- The ability to identify surface or near-surface leaks of CO_2.
- The ability to define what thresholds and types of leakage are acceptable/unacceptable with respect to the different requirements of carbon trading, health and safety and environmental protection. These thresholds have to be measurable/quantifiable by appropriate monitoring technologies and strategies

These issues and the gaps will be discussed below:

Leaks in the subsurface: The current work on storage projects is providing increasing confidence that under favourable circumstances migration out of the storage reservoir may be identified on 3D seismic surveys before large volumes of CO_2 have escaped. Work at Lawrence Berkeley National Laboratories suggests that volumes as small as 10,000 tonnes of CO_2 could be consistently resolved in the subsurface. In the instance of Weyburn, this resolvable volume may be as low as 2,500 tonnes. The work at Sleipner suggests that zones as thin as 1 metre vertically with high concentrations of CO_2 can be resolved in the subsurface. This generally assumes that the CO_2 spreads out in an overlying aquifer; vertical or sub-vertical migration of CO_2 along a fault or fracture may be more difficult to identify.

Some of the current work at Sleipner (e.g. Chadwick et al. 2005) is aimed at refining estimates of the quantity of CO_2 in the reservoir obtained from the seismic surveys. A model of the CO_2 saturation within the plume at Sleipner that satisfies both the the observed plume reflectivity and pushdown contains approximately 85% of the known mass of the injected CO_2. There are significant uncertainties that account for the shortfall, including the possibility of significant CO_2 dissolution, which is likely to increase with time. A pre-requisite for improved quantification is good site evaluation to establish rock properties and reservoir temperature and pressure.

As noted above, the key question is the identification of leaks rather than assessing the volume stored. There is also a question of leak identification in the absence of a baseline survey, for example in the EOR projects of West Texas where no baseline surveys were undertaken. The other element of the seismic survey is the cost of undertaking repeat surveys. While seismic surveys are expensive, they represent only a small proportion of a total storage project cost. There is still, however, a need to continue to bring down the cost of surveys and the ensuing data processing.

It is currently not possible to use the non-seismic geophysical techniques to identify leaks in the subsurface, unless they are very large, probably several orders of magnitude larger than might be seen by seismic techniques. The use of observation wells with permanent or periodic sampling points in horizons overlying the injection zone would be able to identify leaks in the area close to the well by means of geochemical monitoring or direct recognition of CO_2 in the zone of interest. There has been no evaluation of permanent or semi-permanent sampling points in an observation well to determine leakage into overlying zones.

Leakage along the wellbore: One of the gaps remaining is a better understanding of wellbore integrity over the long-term, including the steel of the casing and any physical or chemical changes to the cement. There is a need to better understand the interpretation of cement bond logs to determine what these logs are indicating about the quality of the cement and bonding outside the casing. Effective log interpretation may result in the provision of an indication of potential problem areas or identify degradation and leakage along the wellbore following injection of CO_2 into a storage zone. It is likely that some invasive testing will be required as well as laboratory work to provide verification of the log interpretation.

Measurement at the surface of CO_2 in the vadose zone or leaking across the soil-atmosphere interface should be relatively straightforward using soil gas surveys, accumulation chambers and infrared analysis.

Identification of faults and fractures: One of the keys for assessing the risk of storage, particularly in saline aquifers where the amount of drilling will be small and the knowledge of the reservoir consequently fairly limited will be the understanding of the nature of any fracture system. Seismic surveys, may be able to detect large open fracture networks (Lonergan et al. 1998), sandstone dykes (Huuse et al. 2005) or gas chimneys that might be intersected by an expanding CO_2 plume. To maximize the rate of dissolution of CO_2 in reservoir fluids, particularly in saline aquifers, the faster and further the CO_2 plume expands the better. In other words, the more rapidly the CO_2 encounters unsaturated water the quicker is will dissolve and remove the buoyancy effect. However, this has the negative effect in terms of risk in the sense that the “slippery” CO_2 plume (*sensu* Benson et al, 2004) will migrate further and this increases the chance of encountering fractures that may be conduits to surface. Careful geochemical analysis and geological interpretation prior to use of the site may help alleviate this concern by identifying geochemically separate fluids in the injection zone and overlying zones, which would suggest hydrodynamic isolation for extended periods.

The use of cheaper, but lower resolution, techniques to follow the plume may be adequate to identify plume migration. These techniques will not, however, allow identification of potentially problematic fractures.

Surface and near-surface leaks: Direct sampling of gases in the vadose zone for appropriate isotopically distinct carbon or for precursor or indicator gases is undoubtedly the most effective way. In the freshwater zone, changes to geochemistry in the water, perhaps with mobilization of some heavy metals, is also indicative of increased flux of CO_2 from below. Remote sensing of CO_2 flux across the geosphere-atmosphere interface is a lot more problematic and will require some additional work to develop techniques that can measure low flux increases. Analysis of vegetational changes by hyperspectral surveys could show changes to gas levels in the vadose zone quite effectively, but more work will be required to determine optimal times for surveys in different climatic zones, a better understanding of the influence of soil type, etc.

Needs analysis:

- Reduced cost to seismic surveys and the interpretation of seismic data.
- Improved vertical resolution of seismic surveys.
- Improved quantification of seismic results as a means of determining leaks in the subsurface.
- Improvements in the resolution of non-seismic geophysical techniques.
- Improved recognition and interpretation of the nature of faults and fractures with seismic, non-seismic or the combination of techniques.
- Improved remote sensing to allow identification of increased CO_2 fluxes at surface that might be from deeper sources.
- Development of improved wellbore monitoring techniques to allow interpretation of activity outside the casing, but in the immediate wellbore area.
- Development of guidelines to assist in the determination of effective pre-injection surveys, particularly in saline aquifer examples. In particular to help in the determination of hydrodynamic isolation of the proposed injection zone.
- Improved interpretation of cased hole logs to determine potential activity outside the casing or identification of problems with cement bonding.
- Improved integration of monitoring techniques and the results of the application of these techniques.
- Improved methods for detecting CO_2 seeps into subaqueous settings, particularly dissolved CO_2.
- Identify thresholds of leakage that can be measured and the implications of these on formulating regulation of sites.

Conclusions and recommendations:

In conclusion, there are a wide variety of techniques available to examine all phases of CO_2 injection into the subsurface and to monitor its fate and transport in the subsurface. The more direct the technique, the more certain the results in terms of the level of confidence placed on the outcomes. The ability to use direct techniques is limited by the cost, for example the drilling of observation wells for direct sampling, and the risk that these holes will become leakage pathways will limit their application. Direct techniques also have some limitations in terms of the areal extent of the information gained.

Remote interpretation techniques to determine what is happening to the CO_2 in the subsurface currently have resolution issues, particularly in respect of dissolved CO_2. Seismic techniques are the best suited, but still have some limitations regarding resolution, cost and quantification. Non-seismic geophysical techniques show some promise, but require more work to improve resolution. There is likely to be some improvements in the integration of results from these various techniques to improve overall effectiveness of interpretation. Remote sensing of CO_2 fluxes from the surface may never be effective, but some additional work in this area could be undertaken.

The most promising is the use of hyperspectral imagery to identify changes to vegetation that might be related back to CO_2-induced changes to plant growth as the level of CO_2 in the vadose zone changes.

Ultimately it will be the level of risk associated with a given site that will determine the amount and type of monitoring that is undertaken. In what might be considered as safe sites, based on effective pre-injection surveys of the geology, the nature of the caprock etc., the need to improve monitoring techniques might well be minimal. In areas with a higher real or perceived risk, the need to establish a more complex monitoring program may well require ongoing improvements to the resolution of the techniques under examination. The nature of the techniques will also change depending on the level of knowledge available for the site, for example, oil fields may use slightly different techniques than saline aquifers where there is less information available at the start of operations.

In short, further work is required. This should be a continued research effort to improve the interpretation of the variety of remote sensing techniques being employed. While not all avenues will be required, it is not clear that any techniques should be abandoned at this point. The work to improve monitoring techniques should progress with risk assessment work – the level of risk acceptable to the public and regulator will determine the requirements of the monitoring program (level of accuracy, length of time monitoring must continue, etc.). Ideally, there will be more integration of research effort and the use of sites with extensive geological knowledge to provide the best chances for success in improvement of techniques in these early stages. Activities such as the IEA Greenhouse Gas R&D Programme networks on monitoring and verification, risk assessment and wellbore integrity will be important to overall success of this effort and should be encouraged. Better integration of major projects should also be encouraged to optimize results in these early stages.

Finally, well logging has great potential for monitoring many aspects of CO_2 storage in the subsurface. It is recommended that submissions be invited from well logging companies on the functionality and resolution of available logging tools that might have relevance to the monitoring of CO_2 storage sites.

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