The critical role of monitoring, verification, and accounting for geologic carbon dioxide storage projects

Sean I. Plasynski, John T. Litynski, Howard G. McIlvried, Derek M. Vikara, and Rameshwar D. Srivastava

ABSTRACT

A growing concern that increasing levels of greenhouse gases in the atmosphere are contributing to global climate change has led to a search for economical and environmentally sound ways to reduce carbon dioxide (CO_2) emissions. One promising approach is CO_2 capture and permanent storage in deep geologic formations, such as depleted oil and gas reservoirs, unminable coal seams, and deep brine-containing (saline) formations. However, successful implementation of geologic storage projects will require robust monitoring, verification, and accounting (MVA) tools. This article deals with all aspects of MVA activities associated with such geologic CO_2 storage projects, including site characterization, CO_2 plume tracking, CO_2 flow rate and injection pressure monitoring, leak detection, cap-rock integrity analysis, and long-term postinjection monitoring. Improved detailed decision tree diagrams are presented covering the five stages of a geologic storage project. These diagrams provide guidance from the point of site selection through construction and operations to closure and postclosure monitoring. Monitoring, verification, and accounting techniques (both well-established and promising new developments) appropriate for various project stages are discussed. Accomplishments of the Department of Energy (DOE) Regional Carbon Sequestration Partnerships field projects serve as examples of the development and application to geologic storage of MVA tools, such as two-dimensional and three-dimensional seismic and microseismic, as well as the testing of new cost-effective monitoring technologies. Although it is important that MVA and computer simulation efforts be carefully integrated to ensure long-term success of geologic storage projects, this article is limited to a discussion of MVA activities.

This article is an extension of a report published in 2009 by the DOE National Energy Technology Laboratory titled, "Best Practices for Monitoring, Verification, and Accounting of CO_2 Stored in Deep Geologic Formations," to which interested readers are referred for

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AUTHORS

SEAN I. PLASYNSKI ~ *National Energy Technology Laboratory, U.S. Department of Energy, 626 Cochrans Mill Road, Pittsburgh, Pennsylvania 15236; sean.plasynski@netl.doe.gov*

Sean I. Plasynski received his B.S. and M.S. degrees and Ph.D. in chemical engineering from the University of Pittsburgh and a Master of Business Administration from the University of Pittsburgh Katz Graduate School of Business. He is currently the director of the Office of Coal and Power R&D within the Strategic Center for Coal at the Department of Energy National Energy Technology Laboratory.

JOHN T. LITYNSKI ~ *National Energy Technology Laboratory, U.S. Department of Energy, 626 Cochrans Mill Road, Pittsburgh, Pennsylvania 15236*

John T. Litynski received his B.S. degree in civil engineering from Virginia Polytechnic Institute and State University and an M.S. degree from Johns Hopkins University in environmental engineering and science. He currently serves as the carbon sequestration sequestration technology manager in the Strategic Center for Coal at the Department of Energy National Energy Technology Laboratory. John is a registered professional engineer and project management professional.

HOWARD G. MCILVRIED ~ *KeyLogic Systems, National Energy Technology Laboratory, Pittsburgh, Pennsylvania 15236; howard.mcilvried@kl.netl.doe.gov*

Howard G. McIlvried received his B.S. and M.S. degrees and Ph.D. in chemical engineering from Carnegie Mellon University. He currently serves as principal engineer for KeyLogic Systems at the National Energy Technology Laboratory. He has more than 50 yr of experience in petroleum refining, synthetic fuel production, and carbon capture and storage.

DEREK M. VIKARA ~ *KeyLogic Systems, National Energy Technology Laboratory, Pittsburgh, Pennsylvania 15236*

Derek M. Vikara received his B.S. degree in environmental science from Allegheny College and his M.S. degree in environmental engineering from the University of Connecticut. He is currently an environmental engineer with

KeyLogic Systems at the Department of Energy National Energy Technology Laboratory. He has 8 yr experience in environmental engineering and carbon capture and storage. He is a registered professional engineer in Pennsylvania.

RAMESHWAR D. SRIVASTAVA ~ *KeyLogic Systems, National Energy Technology Laboratory, Pittsburgh, Pennsylvania 15236*

Rameshwar D. Srivastava, Ph.D., is currently the principal engineer supervisor at KeyLogic Systems at the Department of Energy National Energy Technology Laboratory, where he has served for more than 20 yr. Previously, he was a visiting professor in the Chemical Engineering Department at the University of Delaware and the Swiss Federal Institute of Technology and professor and chairman of chemical engineering at the Indian Institute of Technology.

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more details on MVA tools. Ultimately, a robust MVA program will be critical for establishing carbon capture and storage as a viable greenhouse gas mitigation strategy.

INTRODUCTION

A growing concern that increasing levels of greenhouse gases in the atmosphere, particularly carbon dioxide (CO_2), are contributing to global climate change exists. Atmospheric levels of CO_2 have risen significantly from preindustrial levels of 280 ppm to present levels of 384 ppm (Tans, 2008). Evidence suggests that this is the result of expanded use of fossil fuels for energy production. Predictions of increased global fossil energy use imply a continued increase in carbon emissions (EIA, 2007) and a rising CO_2 level in the atmosphere, unless a major change is made in the way energy is produced and used, in particular, how carbon is managed (Greenblatt and Sarmiento, 2004; Socolow et al., 2004).

Carbon dioxide circulates through, and accumulates in, the atmosphere, surface waters (lakes, rivers, streams, and the oceans), and the land; these CO_2 sinks are a natural part of the carbon cycle. Unfortunately, natural sinks are unable to absorb all of the anthropogenic CO_2 currently being emitted, so that carbon is accumulating in the atmosphere at a rate of about 3.2 Gt of carbon per year (NASA, 2009). This has led to efforts to enhance natural sinks and to provide artificial ones. Natural sinks investigated include terrestrial and oceanic; but for various reasons, neither of these sinks is an option that can store the carbon required to make a major impact on the buildup of greenhouse gases in the atmosphere. This article is concerned with another option that is receiving considerable attention: the capture of CO_2 from large point sources and subsequent injection into deep geologic formations for permanent storage (Metz et al., 2005). This option is typically referred to as carbon capture and storage, commonly shortened to simply CCS (Plasynski et al., 2010).

A growing interest in CCS as a way of mitigating the buildup of CO_2 in the atmosphere has led to a significant effort by governments, academic institutions, and the private sector to develop the necessary procedures and technology to demonstrate that this approach to greenhouse gas control can be implemented safely, effectively, and at an acceptable cost. A variety of geologic formations, such as depleted oil and gas reservoirs, unminable coal seams, and deep brine-containing (saline) formations, are being considered as potential storage locations (Plasynski et al., 2010). Table 1 (NETL, 2008) shows the estimated storage capacity in the United States for these three options. Of these potential geologic storage options, it is clear that only deep saline formations have enough potential capacity to store at least 100 yr's worth of CO_2 emissions from stationary sources in the United States (3.8 Gt per year in 2006). For this reason, this article emphasizes monitoring, verification, and accounting (MVA) activities related to CO_2 storage in deep saline formations. However, CO_2 storage in oil

Table 1. Estimated Carbon Dioxide Storage Capacity of Geologic Formations in the United States

Type of Geologic Formation	Estimated CO_2 Storage Capacity (Gt)	Years of Capacity at Current Emissions Rate*
Oil and/or gas reservoir	138	36
Unminable coal seam	157–178	41–47
Deep saline formation	3297–12,618	867–3320

Modified from NETL, 2008.
*Current (2006) emission rate is 3.8 Gt per year of carbon dioxide (CO_2) from stationary sources in the United States.

and gas reservoirs and unminable coal seams has the potential for enhanced oil and/or gas production as a value-added benefit and could have a major impact during the early stages of CCS technology development. Therefore, CO_2 storage experience with Department of Energy (DOE)–supported enhanced oil recovery, storage in depleted oil reservoirs, and enhanced coal bed methane production are also discussed.

One disadvantage of deep saline formations is that, in general, the presence of containment (seals) is not demonstrated as it is for oil and gas reservoirs, which have held hydrocarbons in place for millions of years. Injection sites targeting saline formations need to be characterized on an individual basis to ensure that they are suitable for long-term storage and overlain by the necessary seals. For hundreds to thousands of years, some fraction (possibly all) of the injected CO_2 is expected to dissolve in native formation fluids; and some of the dissolved CO_2 may react and become part of the solid mineral matrix. Once dissolved or reacted to form minerals, CO_2 is no longer buoyant and would not rapidly rise to the surface, even in the absence of a suitable geologic seal (Benson and Myer, 2002). However, these reactions typically occur during a very long time and do not lessen the need for a tight geologic seal because any leakage would most likely happen before there has been time for significant dissolution and mineralization to occur.

For every geologic CO_2 storage project, MVA of the stored CO_2 will be critical. MVA refers to monitoring the movement and impact of CO_2 injection on the geology of the site, verifying that the CO_2 is permanently stored and not leaking or migrating into undesired strata, and accounting for the amount of CO_2 that has been stored. A major goal of the DOE carbon sequestration program is the development of accounting protocols that can demonstrate the retention of essentially all the CO_2 injected. Geologic carbon storage projects will not be feasible without robust MVA protocols. The data obtained from MVA activities will be instrumental in making geologic storage a safe, effective, and environmentally acceptable method for greenhouse gas control. This article is an extension of a report published by the DOE National Energy Technology Laboratory (NETL, 2009), to which interested readers are referred for more details on MVA tools. Also included here is a description of several large-scale field projects that are testing a variety of MVA tools. Although MVA-related activities exist worldwide, this article covers only MVA activities in North America.

An activity closely related to MVA is computer simulation, which can guide site selection, follow the injected CO_2 plume, and determine if the project is performing as planned. Although it is important that MVA and computer simulation efforts be carefully integrated to ensure long-term success of geologic storage projects, computer simulation is too large a topic to be covered in this article, which is limited to a discussion of MVA activities.

STAGES OF A GEOLOGIC CARBON DIOXIDE STORAGE PROJECT

A geologic CO_2 storage project can be divided into five stages: (1) site selection and characterization; (2) site preparation and construction; (3) operations, that is, CO_2 injection; (4) site closure; and (5) postclosure surveillance. Monitoring is a critical aspect of all stages (LBNL, 2004). In the context of this article, monitoring is used in a broad sense to include the entire spectrum of technologies used to characterize a site, follow construction and operations, and observe postclosure conditions. A list of monitoring tools with a brief description of each is presented in the Appendix. For more detailed information on MVA tools for geologic storage projects, refer to the NETL (2009) report.

Stage 1: Site Selection and Characterization

Defining the characteristics of a proposed geologic storage site is the first step in developing a monitoring program for the project. Site selection and characterization involve evaluating the geology at a candidate CO_2 storage site, determining the physical properties of the target formation and the confining cap rock, and establishing baseline conditions so that any changes that result from the injection of CO_2 can be recognized. Characterization includes analysis of fluids and gases in the formation, the vadose zone, and at the surface, as well as identification

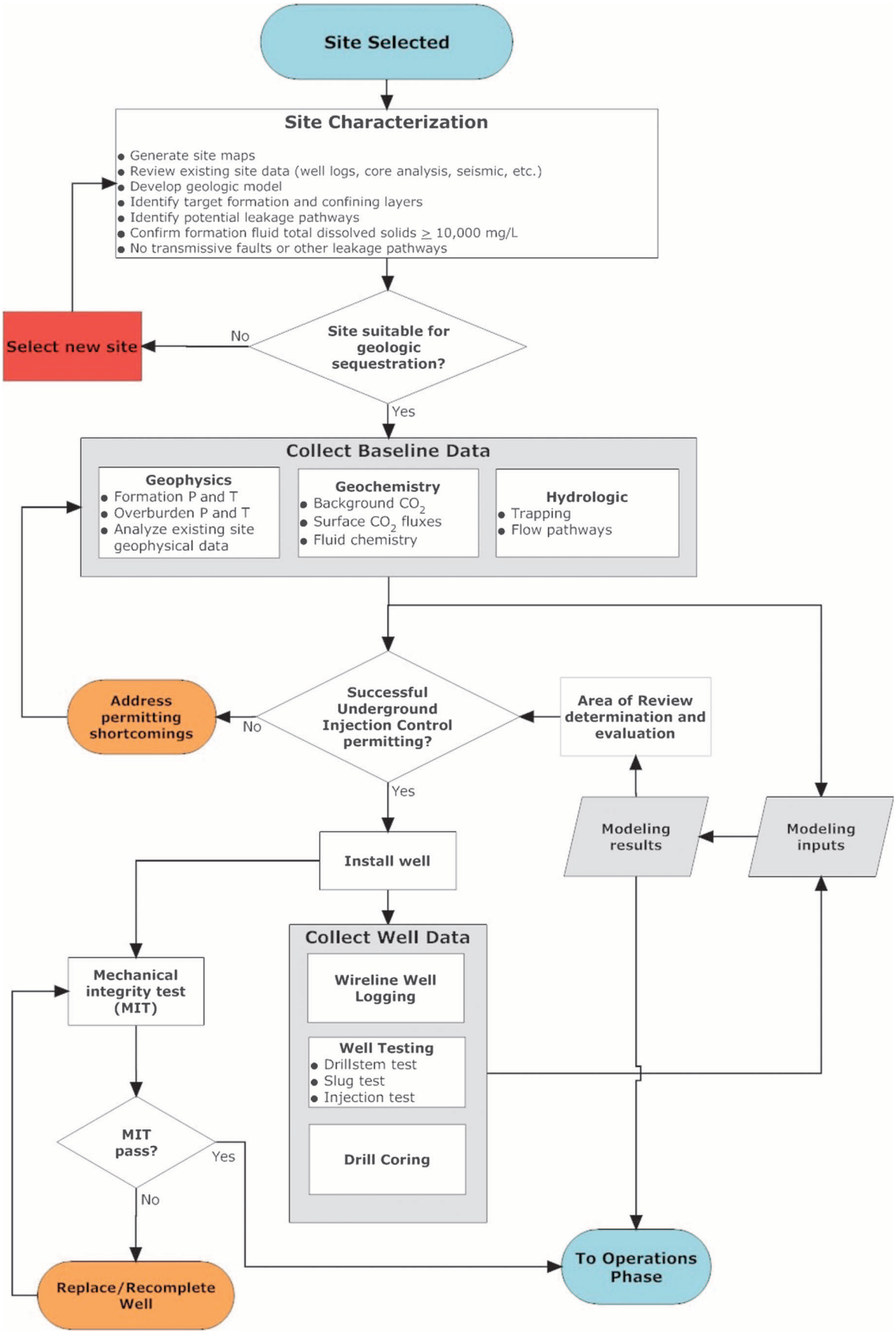

Figure 1. Decision tree showing the flow of activities during stages 1 and 2 of a geologic carbon dioxide (CO_2) storage project.

of potential leakage pathways, such as faults, fractures, and abandoned wells. Also included is developing mathematical models of the proposed project to help ensure that the site has the capacity to accept the planned amount of CO_2 at the design injection rate and to forecast plume movement, both during injection and after site closure.

Stage 2: Site Preparation and Construction

Monitoring, verification, and accounting activities during stage 2, site preparation and construction, include completing all baseline testing plus additional testing to detect any changes resulting from construction activities. In particular, monitoring of well drilling is critical. During this stage, monitoring protocols for the operational stage are finalized. Detailed examination of all abandoned wells in the vicinity of the site and remediating any that appear to be potential leak sites are also involved. This is particularly critical for CO_2 storage in depleted oil and gas fields, which tend to have many abandoned wells. Figure 1 is a decision tree for the characterization and construction stages of a geologic storage project.

The decision tree depicted in Figure 1 begins after a site has been selected after the initial site screening process. Typically, the selected site is subjected to extensive characterization aimed at fully understanding the site's geology (reservoir, cap rock, and/or seal layer, etc.), baseline conditions, and key features to generate information needed for a successful geologic carbon storage project. Data can be obtained from existing regional sources, such as well logs, seismic surveys, geopotential data, and existing wells, or through implementing MVA methods to acquire new data. Sites may not have existing seismic data, but all onshore U.S. sites will have gravity or aeromagnetic data. The Appendix provides a detailed list of available MVA tools. Existing and newly acquired site data can (1) be used to develop a computer simulation for the site, (2) be incorporated into the necessary operational and injection well permitting, and (3) be used to determine optimal site operational and logistical procedures. Detailed subsurface geologic data, including insight into site lithology and geophysical and geochemical information, can be acquired from wireline well logging and sample cores taken from newly drilled boreholes or acquired from existing wells. Borehole measurements only provide data at a specific location. Implications about subsurface geology over large areas can be acquired through various seismic survey methods (see Appendix) that are calibrated based on specific wellbore measurements (wireline logs, cores, etc.).

Stage 3: Site Operations

After stages 1 and 2, an important activity in stage 3 is the development of theoretical models of the site that describe mechanisms controlling the behavior of injected CO_2. As additional data become available, these models are continuously updated. It is during stage 3, site operations, that the bulk of the MVA activities occurs, the most critical being following the movement of the underground CO_2 plume, monitoring to ensure safe operating conditions, detecting leaks, and ensuring that underground sources of drinking water (USDW) are not compromised. Monitoring the plume will determine whether the injected CO_2 is behaving as predicted. If not, modifications to the operating procedure may be required. If a leak is detected, remedial action may be necessary. The risk analysis performed early in the project will have developed appropriate actions to mitigate various leak scenarios should a leak occur, either during operation or after project closure.

Figure 2 is a decision tree for the operations stage of a geologic storage project. Monitoring activities conducted under the operational stage are critical to ensuring the safety and success of the project. Several mandatory monitoring requirements under the U.S. Environmental Protection Agency (EPA) Underground Injection Control (UIC) Program (see UIC Regulatory Requirements) concern monitoring pressure in the operational equipment, including injection pressure, wellhead pressure, and well annulus pressure. Changes in formation pressure (decrease in target formation or increase in overburden formations) may indicate formation or well leakage. Should pressure increase in overburden formations and/or decrease in the target formation, leakage pathways may exist, and other monitoring approaches may be necessary to assess if CO_2 has remained entirely in the target reservoir or if mitigation is needed.

Monitoring requirements for stage 3 are based on rapid detection of a range of risk factors, such as the potential for damage to mineral deposits in the vicinity, leakage of CO_2 into unintended strata, leakage to the surface, interference with water supplies, surface deformation, and microseismicity, thus allowing immediate remedial action.

Another important activity during site operations through postclosure monitoring (stages 3 through 5) is accounting for stored CO_2. This activity has two aspects: (1) determining the amount of CO_2 injected underground and (2) determining that the injected CO_2 remains within the target formation. The first of these is mainly a metering activity at the wellhead. The second involves tracking the CO_2 plume and verifying that the amount

Figure 2. Decision tree showing the flow of activities during stage 3 of a geologic carbon dioxide (CO_2) storage project. LIDAR = Light Detection and Ranging.

of CO_2 in the target formation is consistent with the amount injected by confirming that no leakage from the target formation, either into other formations or to the surface, has occurred. The accounting activity is vital for ensuring that proper credit is obtained for the CO_2 sequestered and for initiating remediation should a leak be detected.

A major issue with the accounting function is quantifying the CO_2 underground. It is relatively straightforward to measure the quantity of CO_2 being injected, but current monitoring tools, such as seismic, are not able to quantify the CO_2 in the target formation with sufficient accuracy to detect small leaks. Efforts are continuing to improve accounting protocols.

Stage 4: Project Closure

Stage 4 relates to project closure. When formation capacity at the site has been achieved and a decision has been reached to terminate the project, the injection well(s) will be plugged, equipment will be removed, and the site will be closed. Monitoring, verification, and accounting activities during stage 4 involve following well plugging to ensure that it is done properly and

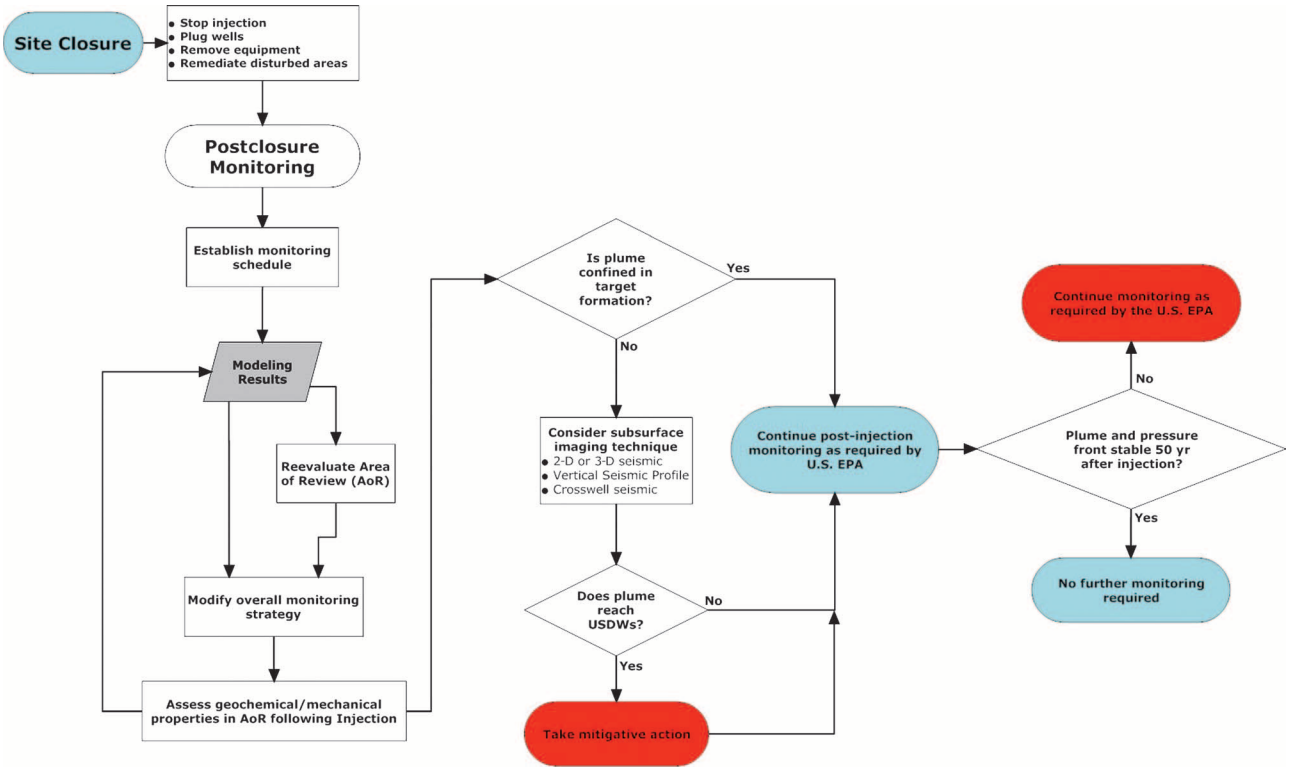

Figure 3. Decision tree showing the flow of activities during stages 4 and 5 of a geologic carbon dioxide (CO_2) storage project. EPA = Environmental Protection Agency.

establishing the location of the CO_2 plume at the time of project completion for later comparison purposes.

Stage 5: Postclosure Surveillance

During stage 5, postclosure surveillance, the site will need to be monitored to ensure that no problems exist, such as CO_2 leakage to the atmosphere or contamination of groundwater, and to identify the lateral plume extent. The duration of postclosure monitoring and the determination of the party responsible for postclosure care are site-specific issues that will depend upon who has jurisdiction (federal or state) and regulations that are yet to be promulgated. The regulations that are eventually put in place will rely heavily on the MVA experience gained from early demonstration projects. Figure 3 is a decision tree for the postclosure monitoring stage.

The overall success and safety of the project is predicated on CO_2 remaining in the intended target formation. Postclosure monitoring is critical to determining the extent of the CO_2 plume once injection has ceased. Figure 3 indicates that the overall postclosure monitoring strategy (i.e., location of monitoring wells and monitoring equipment) is influenced by site computer simulation results based on data acquired through MVA activities from the site characterization, construction, and operational stages. Computer simulation can be used to estimate the area of review (AoR) for the site, which not only is a requirement under the proposed UIC class VI wells, but also allows for a more narrow and focused monitoring plan.

Subsurface imaging techniques can be used both as a time-lapse imaging method to assess the formation's status between baseline and postinjection and as an observation technique to determine if CO_2 has breached the cap rock. Postinjection monitoring is required until key conditions, such as plume and pressure stability or requirements from the governing body, are met, as outlined by the site-specific UIC permit.

CATEGORIES OF MONITORING TOOLS (PRIMARY, SECONDARY, AND POTENTIAL)

It is convenient to classify monitoring tools into one of three categories based on application, function, and stage of development, as follows:

Primary Tools: Proven mature tools or applications that are (1) capable of providing the information required

to meet permitting requirements under the U.S. EPA UIC program for classes I, II, and V injection wells and (2) applicable and deployable in all settings (atmospheric, near surface, or deep subsurface, depending on the tool type and function) regardless of project location. Primary tools can also provide information on CO_2 containment and movement of the CO_2 plume. Not all available primary tools will be used on every project; primary tools will be selected based on site geology, permitting requirements, operator preference, and other site-specific factors.

Secondary Tools: Available tools/protocols that can aid in accounting for injected CO_2 and can provide insight into the behavior of CO_2 by refining results obtained from primary tools. Secondary tools are typically more advanced and are complimentary to primary tools. However, they are typically not required to satisfy existing UIC (classes I, II, and V) monitoring requirements. Secondary tools are evaluated on a case-by-case basis to determine which ones are useful and economically justifiable for a particular project.

Potential Tools: Tools and protocols that are technologically advanced and may help answer fundamental questions concerning the behavior of CO_2 in the subsurface and may prove useful as monitoring tools after further development and/or field testing. These tools are capable of providing more advanced and detailed insight into atmospheric and geologic features compared with primary and secondary tools, but because of their general complexity, they may not be ideal or accurate monitoring tools across all atmospheric and geologic settings.

A comprehensive listing of primary, secondary, and potential monitoring tools is presented in the Appendix (NETL, 2009).

LARGE-SCALE FIELD PROJECTS TESTING MONITORING, VERIFICATION, AND ACCOUNTING TOOLS

A wide array of advanced monitoring technologies is being evaluated by various projects, including the Weyburn-Midale project (Monea et al., 2009) and the DOE regional carbon sequestration partnerships (RCSPs) initiative. The RCSPs have had a major impact on the development of robust MVA protocols through a series of demonstration projects. The RCSPs were formed because of growing concern over the impact of CO_2 on global climate change. This led the DOE to form a nationwide network of seven RCSPs, which are tasked with determining the most suitable technologies, regulations, and infrastructure for carbon capture, transport, and storage in their respective areas of North America. The seven partnerships include more than 350 organizations (state agencies, universities, national laboratories, private companies, and environmental organizations) spanning 43 states and 4 Canadian provinces.

The RCSP initiative is being implemented in three phases: (1) the characterization phase (2003–2005) that focused on collecting data on CO_2 sources and potential sinks and developing the human capital to support and enable future carbon sequestration field tests (Litynski et al., 2006); (2) the validation phase (2005–2009) that focused on implementing small-scale CO_2 storage field tests (Litynski et al., 2008); and (3) the development phase (2008–2017) that focused on implementing large-scale geologic storage projects (injection of one million metric tons of CO_2 or more) to demonstrate that large volumes of CO_2 can be safely, permanently, and economically injected into representative geologic formations having large potential storage capacity.

Currently, the partnerships are conducting more than 20 small-scale geologic and 11 terrestrial field tests and have initiated 9 large-scale tests. Each field test incorporates extensive characterization, permitting reservoir simulation, site monitoring, risk assessment, public outreach, and technology transfer efforts aimed at ensuring safe and permanent carbon storage and wide dissemination of the information developed (NETL, 2010; Plasynski et al., 2009). At each of their field projects, the RCSPs are using extensive research-based MVA protocols that include a variety of primary, secondary, and potential MVA tools. Each site-specific MVA plan under the RCSP program has as its objective fully understanding the fundamentals of geologic carbon sequestration, not merely satisfying mandatory monitoring requirements.

Projects conducted by the RCSPs include CO_2 injection into depleting oil and gas reservoirs, unminable coal seams, and deep saline formations. These projects are evaluating and determining which monitoring techniques are most effective and economic for specific geologic conditions, information that will be vital to the success of future geologic storage projects. Some instructive example projects are subsequently discussed.

Monitoring, Verification, and Accounting Activities Related to Carbon Dioxide Storage in Oil and Gas Reservoirs

Eight combined CO_2 storage and enhanced oil recovery projects are being conducted in conjunction with the validation phase of the RCSP initiative. Unlike projects planned for saline formations or unminable coal seams, enhanced oil recovery–related projects commonly have extensive site characterization data available from previous oil and gas exploration and production activities. Thus, an enhanced oil recovery project can combine existing data with newly acquired geologic data and predictive simulation results to fully characterize the project site and optimize injection and postinjection MVA plans.

The Southeast Regional Carbon Sequestration Partnership (SECARB) Gulf Coast stacked storage test at Cranfield is an example of a validation phase–enhanced oil recovery project using an extensive MVA effort with innovative approaches aimed at ensuring safe CO_2 storage and oil production. This test demonstrates the concept of combining initial injection of CO_2 for enhanced oil recovery followed by later injection into deeper brine formations underlying the oil reservoir. As of the end of 2009, SECARB had injected about 900,000 t (1 million tons) of CO_2.

The SECARB stacked storage test included detailed site characterization including a robust set of existing data (200 vintage wireline logs [ca. 1940s], hundreds of sidewall cores, and detailed field production records), a newly acquired three-dimensional seismic survey, and data from 10 new wells, including openhole logs, sample cores, and sidewall cores (Figure 1, site characterization). The SECARB is also using a novel test element that includes a dedicated observation well to allow monitoring of two zones: the lower Tuscaloosa injection zone and a continuous, 3.7-m (12-ft) thick, 100 md sandstone in the upper Tuscaloosa that serves as an above-zone monitoring horizon. Simulation shows that, should significant leakage occur through the reservoir seal (through conduits, such as flawed well completions or faults in the area), the leak would result in a pressure increase in the monitoring zone.

Real-time pressure and temperature data from these two zones are being acquired from in-place wireline logging. During the course of 1 yr from the time of injection, the lower Tuscaloosa injection zone pressure increased by about 8.3 MPa (1200 psi) from baseline conditions, but the above-zone monitored pressure did not correspondingly increase, suggesting that no leakage had occurred (similar to assessing pressures within and above the target formation; Figure 2).

The Southwest Regional Partnership (SWP) tested microseismic monitoring for tracking the movement and containment of CO_2 injected at the Aneth oil field located in San Juan County, Utah (Rutledge et al., 2008). A microseismic (passive) survey is one of the available monitoring tools for assessing subsurface geology; this technique has been used for about 40 yr to measure subsurface seismic activity induced by injection of fluids. The approach provides an image of fractures by detecting microseisms (microearthquakes) triggered by shear slippage. The location of the microseismic events is obtained using a downhole receiver array that is positioned at depth in a well(s) near the injection well.

The project included extensive monitoring and analysis of CO_2 migration and ultimate sequestration in conjunction with a fieldwide CO_2–enhanced oil recovery operation. Starting in March 2008, small microearthquakes (M, -1 to 0) within about 2 km (1.25 mi) of the geophone string were detected episodically at rates ranging from zero to 10 events per day. Most of these events delineated a northwest-southeast–oriented fracture zone within the reservoir. Poroelastic simulation of the Aneth reservoir indicates a correlation between fluid pressure increases, resulting from injection, and fracture and/or strain propagation that is the likely cause of the induced seismic activity.

In hydrocarbon reservoirs, passive monitoring of microseismicity, induced through fluid injection, has been widely deployed to monitor hydrofracturing in commercial oil fields and to track flow fronts and pressure waves during water injection. It is also used to confirm the location of the plume of injected CO_2 in the storage formation, to predict premature breakthrough, to monitor formations above the reservoir for evidence of CO_2 migration through the cap rock, and to assess fracture propagation.

Vertical seismic profiling (VSP) was used at the Weyburn enhanced oil recovery project (Monea et al., 2009). A potential advantage of this borehole method, relative to surface seismic methods, is higher resolution imaging. Although VSP provided higher resolution imaging of the reservoir zone than the surface time-lapse seismic images, it failed in the initial attempt to provide robust images of the distribution of injected CO_2. At least part of this failure was caused by nonrepeatability of the data. Based on lessons learned, VSP is expected to provide useful information in future tests.

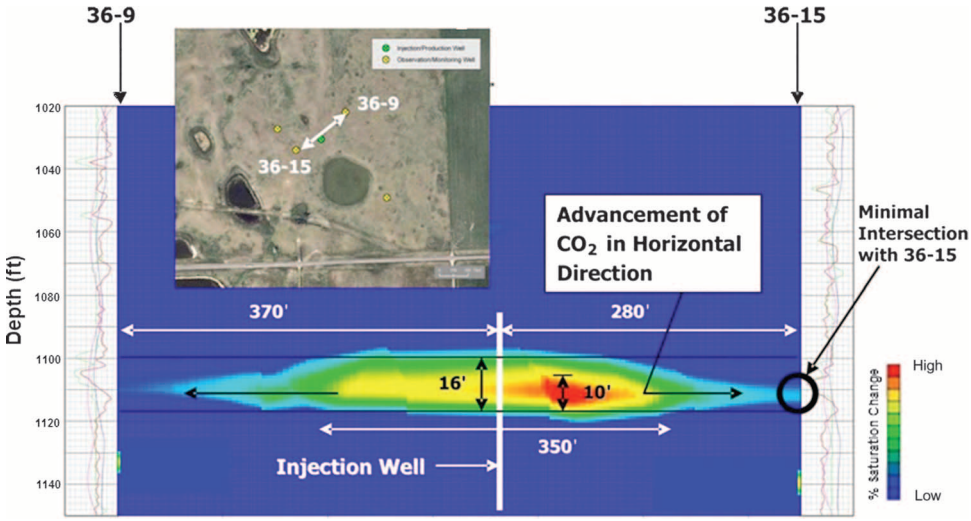

Figure 4. Seismic imaging from injection of carbon dioxide (CO_2) into a lignite seam in Plains CO_2 Reduction Partnership North Dakota lignite field test; 36-9 and 36-15 indicate the locations of monitoring wells on both the aerial photograph and seismic image. The black lines in the seismic image indicate the width of the CO_2 plume.

Monitoring, Verification, and Accounting Activities Related to Carbon Dioxide Storage in Unminable Coal Seams

The validation phase of the RCSP initiative includes five projects combining enhanced coal bed methane recovery with CO_2 storage. These projects use extensive MVA protocols focused on evaluating coal bed methane production efficiency, as well as assessing simultaneous CO_2 storage capacity. Monitoring, verification, and accounting accomplishments from these enhanced coal bed methane production projects can prove valuable for analogous monitoring situations in other types of projects because tracking and accounting for CO_2 plume movement are important considerations for any geologic storage project. Such tracking is necessary to demonstrate that geologic storage is safe, does not create significant adverse local environmental impacts (such as leakage to the atmosphere or encroachment into potable groundwater sources), and is effective for greenhouse gas control. Assessing plume movement allows comparison and refinement of computer simulations and provides a basis for AoR (area of review) determination.

The SWP is monitoring plume movement in the San Juan Basin enhanced coal bed methane recovery pilot test with a combination of surface tiltmeters (to detect crustal deformation) and CO_2 tracers (to distinguish existing CO_2 from injected CO_2). In this project, 16,500 t of CO_2 were injected during the course of 1 yr. To date, the tiltmeters have detected no surface deformation in the vicinity of the injection well. A short time after injection, CO_2 breakthrough was observed through the detection of tracers in two monitoring wells (Wells et al., 2007). These results provided valuable data for refining site simulation models and understanding plume extent and rate of movement.

The Plains CO_2 Reduction Partnership (PCOR) obtained favorable results using cross-well seismic surveys to track the fate of injected CO_2 in their North Dakota lignite field test. In this project, 80 t of CO_2 was injected into an unminable lignite seam in northwestern North Dakota, resulting in a plume approximately 350 ft in diameter and 16 ft thick (Figure 4).

Seismic results for this application proved to be advantageous as an indicator that CO_2 remained within the expected target interval. Movement of injected CO_2 along the center line of the lignite seam suggests that CO_2 transport is a direct function of seam properties. Absorption in a coal seam has been calculated at approximately 18.1 SCF CO_2/ton coal. Downhole measurements of pressure, temperature, and fluid pH have been used in conjunction with seismic imaging to verify model results (similar to the procedures discussed in postclosure surveillance in Figure 3). Postinjection VSP is being conducted at the SWP San Juan Basin enhanced coal bed methane recovery project as a way to assess the fate and movement of the CO_2 plume over time (similar to the PCOR North Dakota lignite test).

Monitoring, Verification, and Accounting Activities Related to Carbon Dioxide Storage in Deep Saline Formations

Recent attention and research efforts have been placed on deep saline formations as potential CO_2 storage sinks because of their extensive regional availability and large

potential storage capacity relative to oil and gas formations and unminable coal seams. Saline formations are layers of porous rock that are saturated with brine (in the United States, total dissolved solids must be greater than 10,000 mg/L for the formation to qualify for CO_2 storage). As saline formations are much more extensive than coal seams or oil and gas reservoirs, they represent an enormous potential for geologic storage of CO_2. However, much less is known about the geology of saline formations because they lack the characterization data that industry has acquired through resource recovery from oil and gas reservoirs and coal seams. Therefore, more uncertainty regarding the suitability of saline formations for CO_2 storage exists.

Critical tasks when designing an MVA program for projects intending to inject CO_2 into saline formations include (1) identifying confining cap rock and/or seals above the target formation, (2) ensuring sufficient storage capacity, and (3) determining maximum injection and reservoir pressures so that confining layer integrity will not be compromised.

The RCSP validation phase includes seven tests of CO_2 injection into saline formations (including one basalt formation test). Because of limited existing data, a major activity is extensive site characterization to ensure that the site is safe and suitable for CO_2 storage and that geologic features that can influence the fate and movement of CO_2 are identified. The Midwest Regional Carbon Sequestration Partnership (MRCSP) used an elaborate suite of MVA tools to conduct a thorough site characterization for the Cincinnati Arch validation test in Rabbit Hash, Kentucky. This test has injected 1000 t (1100 tons) of CO_2 into the Mt. Simon Sandstone Formation, a regionally extensive saline formation in the midwestern region of the United States that has historically been used for injection of liquid and hazardous wastes and is a promising formation for large-scale CO_2 storage.

Existing data for this test site were minimal because oil and gas exploration and production in the area were limited to shallower formations. No wells within a 2-mi (3.2-km) radius of the site penetrated the Mt. Simon Sandstone. Site characterization consisted of (1) a preliminary geologic assessment that included compiling available well logs and developing cross sections and delineating target storage reservoirs, (2) a two-dimensional seismic survey of the site, and (3) extensive site investigation work that included drilling a test well, rock sample analyses, wireline logging, and geochemical fluid sampling (Figure 1, site characterization). In addition, a short-term brine injection test was used to assess hydraulic properties of the storage reservoir, and a VSP was used to obtain high-resolution images near the wellbore.

Monitoring tools for CO_2 storage were selected based on the proposed injection system specifications and geologic setting. Because the injection interval is fairly thick (~90 m [~300 ft]), the monitoring approach involved tracking the upward migration (if any) of the injected CO_2. Accordingly, VSP and wireline methods were considered the most appropriate for this site. System pressure, temperature, groundwater, and brine geochemistry monitoring were also used. The MRCSP was able to build a predictive reservoir model using the STOMPCO_2 software (White and McGrail, 2005) based on acquired hydrologic and geologic parameters obtained as part of the project's MVA program. Preliminary reservoir simulation results for the Cincinnati Arch validation test indicated that the CO_2 plume extended as much as 90 m (300 ft) from the injection well after 30 days based on a CO_2 injection rate of 100 t (110 tons) per day (similar to AoR determination in Figure 1).

Microseismic monitoring was implemented as part of a comprehensive carbon sequestration monitoring program at the MRCSP geologic field test site in Otsego County, Michigan. As part of this project, real-time microseismic reservoir monitoring technologies were deployed to assist in MVA activities (Daugherty and Urbancic, 2009). The project injected approximately 54,550 t (60,000 tons) of CO_2 into a target interval containing the porous parts of the Bois Blanc and all of the Bass Islands Dolomite formation at a depth of 972 to 1071 m (3190–3515 ft). The actual target interval is located in the Bass Islands Dolomite at 1049 to 1071 m (3442–3515 ft). The primary seal is the Amherstburg Formation, which acts as a cap rock, overlying the Bois Blanc and Bass Islands Dolomite.

The planned average injection rate was 100 to 300 t (110–330 tons) per day, with a maximum rate of 600 t (660 tons) per day. Bottomhole fracture pressure and corresponding maximum surface pressure were used as limits for injection (described in Pressure Monitoring in Figure 2). The MRCSP wanted to ensure that anticipated injection rates would not fracture the formation or breach the capping Amherstburg layer. Data from acoustical emissions created by the injection process were used to refine the geomechanical model. A temporary microseismic system was deployed for monitoring the CO_2 injection (Figure 5). Data were acquired using two eight-level dual three-component sensor arrays, spaced 15 m (50 ft) apart and deployed down two monitoring wells on retrievable bow spring clamps. Proper design and deployment of these downhole arrays resulted in

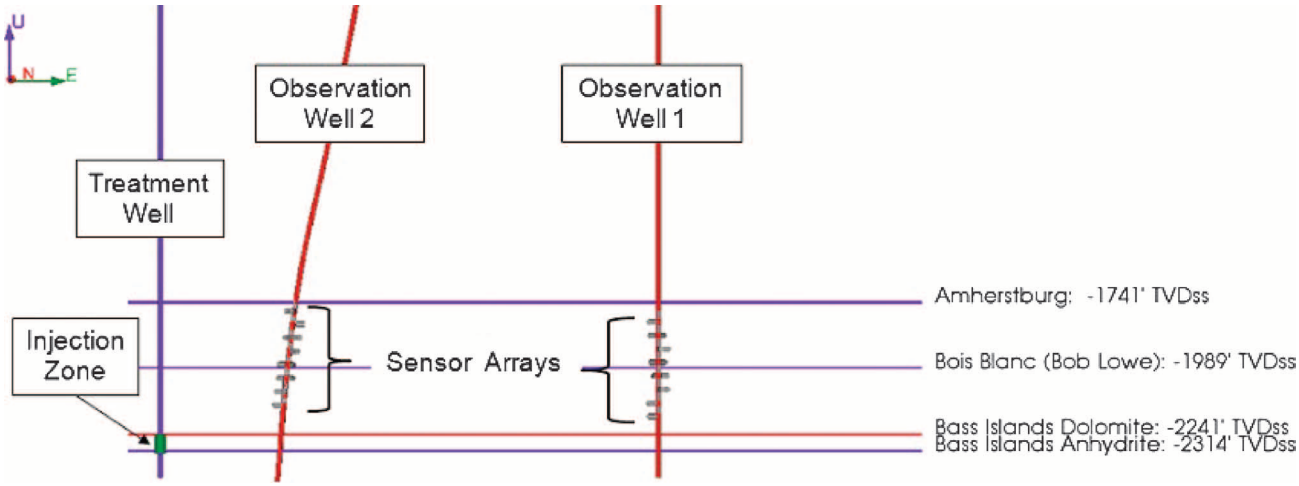

Figure 5. Michigan field test CO_2 injection site (depth view figure from Daugherty and Urbancic [2009]). TVDss total vertical distance subsea.

excellent coupling to the formation for maximum event detection.

Twenty-six microseismic events were recorded during the injection period; of particular importance was some microseismic activity captured by both arrays that occurred after an increase in the gas injection rate. This activity was located within the upper region of the Bois Blanc, immediately below the Amherstburg Formation cap rock. Because the activity was detected immediately after a period of increased injection pressure, it is probable that the injection activated a previously existing structure within the formation or that the increased injection pressure itself contributed to insignificant fracturing within the formation. Most of the events recorded lined up in an orientation that indicated the influence of a regional subsurface structure. The microseismic activity detected near the capping shale clearly indicated that injection was influencing the formation to some degree.

Table 2. Proposed Requirements for Class VI Underground Injection Control Wells*

Category	Requirement
Siting	Extensive site characterization needed, including well logs, maps, cross sections, USDW locations, injection zone porosity, location of any faults, and an assessment of the seismic history of the area.
Fluid movement	No fluid movement to USDWs.
AoR	Determined by computational model and reevaluated during the duration of the project.
Construction	Two layers of corrosion-resistant casing required, set through lowermost USDW. Cement compatible with subsurface geology.
Operation	Injection pressure may not initiate or propagate fracture into the confining zone or cause fluid movement into a USDW. Quarterly reporting on injection, injected fluids, and monitoring of USDW within the AoR. Must report changes to facility, progress on compliance schedule, loss of mechanical integrity, or noncompliance with permit conditions. Permit valid for 10 yr.
Mechanical integrity testing	Continuous internal integrity monitoring and annual external integrity testing.
Monitoring	Analysis of injectant. Continuous temperature and pressure monitoring in the target formation. Plume tracking required.
Closure	Provide 50 days' notice and flush well. Wells must be plugged to prevent injectant from contaminating USDW.
Proof of containment and postclosure care	Postclosure site care for 50 yr or until proof of nonendangerment to USDWs is demonstrated.

*AoR = area of review; USDW = underground sources of drinking water.

This information was incorporated into operating practices to help determine optimal injection rates and provide direct feedback on injection compliance to ensure overall safe and effective operations.

UNDERGROUND INJECTION CONTROL REGULATORY REQUIREMENTS

Regulatory monitoring requirements will be a major driving force for application of primary MVA tools. The U.S. EPA regulates the injection of fluids into geologic formations under the UIC program as part of the Safe Drinking Water Act. The UIC program's primary mission is to ensure that no injection operation endangers USDW or human health. Existing UIC regulations define five classes of wells (classes I–V) based on the type of fluid injected and the well's location. Wells for geologic storage of CO_2 have been permitted under class I (nonhazardous waste wells), class II (wells associated with oil and gas production), and class V (experimental wells). Each injection well class is subject to siting, construction, operating, monitoring, and closure requirements. Monitoring requirements for each well class are essentially constant across the different project stages (site characterization, construction, operation, closure, and postclosure), but monitoring frequency varies from stage to stage.

Generally, UIC injection wells for storage in saline formations are (1) sited in geologically suitable areas that are free of conduits (e.g., abandoned wells or faults) that could allow fluid movement to USDW, (2) constructed of materials that can withstand exposure to injected fluids at operating conditions for the entire injection period, and (3) closed in a manner that will prevent the well from inadvertently serving as a path for fluid migration in the future. Specific MVA-related activities under existing UIC regulations include determining maximum allowable injection pressure, characterizing the local site geologic structure, maintaining well annulus pressure and fluids, monitoring injection flow rate and volume with continuous recording devices, conducting periodic chemical analyses of the injected fluid, assessing groundwater chemistry, and periodically testing injection wells for mechanical integrity (EPA, 2008).

Primary tools are fully capable of providing information to meet existing UIC monitoring requirements for classes I, II, and V injection wells. These tools are frequently and effectively used in applications similar to geologic storage, such as oil and natural gas exploration and production. The EPA is proposing a new well designation (class VI) to cover CO_2 injection. Table 2 presents a summary of proposed requirements for class VI wells. In addition to primary tools, secondary and potential tools may be necessary to meet class VI monitoring requirements.

Table 2 clearly indicates that extensive monitoring will be required to comply with the proposed class VI well requirements. The U.S. DOE development program, including its core research and development effort, the RCSP initiative (discussed above), and its sponsorship of international projects, is helping to ensure that the necessary monitoring tools are available.

CONCLUSIONS

Concern over the buildup of greenhouse gases in the atmosphere has led to a growing interest in CCS as a method for reducing CO_2 emissions. The final step in the process is storage of CO_2 in a suitable geologic formation, such as a depleted oil or gas reservoir, an unminable coal seam, or a saline formation. However, this is relatively new technology, and if it is going to succeed, robust MVA tools need to be available for all stages of geologic storage projects from site selection to postclosure monitoring. Monitoring, verification, and accounting will be critical for site selection, well permitting, tracking the underground CO_2 plume during injection, leak detection, ensuring that no flow into USDW exists, providing an accurate accounting of the injected CO_2, and for postclosure monitoring.

The DOE, together with its national and international partners, has an active program to ensure that the required monitoring and simulation tools will be available when needed. This program has several aspects, including field tests to determine which MVA tools are most effective in particular situations, improvement of mathematical models that rely on data from MVA activities, and development and testing of potential tools. Providing vital information necessary to design, construct, operate, and close a geologic storage project will help assure the public that such projects are safe and environmentally sound. An efficient suite of MVA tools will be the key to successful implementation of CCS on a commercial scale and will have a significant impact on the development of legal and regulatory protocols covering the geologic storage of CO_2.

APPENDIX: COMPREHENSIVE LIST OF MONITORING METHODS AVAILABLE FOR GEOLOGIC CARBON DIOXIDE STORAGE PROJECTS**

Monitoring Technique	Technology Type*	Description
Atmospheric Monitoring Techniques		
CO_2 detectors	Secondary	Sensors for monitoring CO_2 either intermittently or continuously in air.
Laser systems and LIDAR	Secondary	Open-path device that uses a laser to shine a beam, with a wavelength that CO_2 absorbs over many meters. Used to assess CO_2 fluxes over large spatial scales.
Eddy covariance	Potential	Atmospheric flux measurement technique to measure atmospheric CO_2 concentrations at a height above the ground surface.
Advanced leak detection systems	Potential	Sensitive multigas detector (CH_4, total HC, and CO_2) with a GPS mapping system carried by aircraft or terrestrial vehicles. Technology being evaluated by DOE.
Tracers (isotopes)	Potential	Natural isotopic composition and/or compounds injected into the target formation along with the CO_2 that allows for detection of leakage and provides indication of plume flow direction.
Near-Surface Monitoring Techniques		
Groundwater monitoring	Primary	Sampling of water or vadose zone/soil (near surface) for basic chemical analysis.
Ecosystem stress monitoring	Secondary	Satellite or airplane-based optical method that can be used in a time-lapse manner to assess changes in vegetation integrity that could signify a CO_2 leakage location.
Flux accumulation chamber	Secondary	Quantifies the CO_2 flux from the soil, but only from a small, predetermined area.
Tracers	Secondary	CO_2 soluble compounds injected along with the CO_2 into the target formation used to determine hydrologic properties, flow direction, and low-mass leak detection.
Soil and vadose zone gas monitoring	Secondary	Sampling of gas in vadose zone/soil (near surface) for CO_2.
Shallow 2-D seismic	Secondary	Closely spaced geophones along a 2-D seismic line that can provide high-resolution images of the subsurface, including changes in lithology and the location of CO_2 plumes.
Thermal hyperspectral imaging	Potential	An aerial remote-sensing approach primarily for enhanced coal bed methane recovery and sequestration as a means to detect surface deformation changes resulting from CO_2 injection.
Synthetic aperture radar (SAR and InSAR)	Potential	A satellite-based technology in which radar waves are sent to the ground to detect surface deformation.
Color infrared transparency films	Potential	A vegetative stress technology deployed on satellites or aerially that can be an indicator of CO_2 or brine leakage.
Tiltmeter	Potential	Measures small changes in elevation via mapping tilt, either on the surface or in subsurface.
Induced polarization	Potential	Geophysical imaging technology commonly used in conjunction with DC resistivity to distinguish metallic minerals and conductive aquifers from clay minerals in subsurface materials.
Spontaneous (self) potential	Potential	Measurement of natural potential differences resulting from electrochemical reactions in the subsurface. Typically used in groundwater investigations and in geotechnical engineering applications for seepage studies.
Deep-Subsurface Monitoring Techniques		
Injection well logging (wireline logging)	Primary	Wellbore measurement using a rock parameter, such as resistivity or temperature, to monitor fluid composition in wellbore and to assess geologic characteristics as a function of well depth.
Annulus pressure monitoring	Primary	A mechanical integrity test on the annular volume of a well to detect leakage from the casing, packer, or tubing. Can be done constantly.
Pulsed neutron capture	Primary	A wireline tool capable of depicting oil saturation, lithology, porosity, oil, gas, and water by implementing pulsed neutron techniques.
Sonic (acoustic) logging	Primary	A wireline log used to characterize lithology and determine porosity and traveltime of the reservoir rock.
Density logging (RHOB log)	Primary	Continuous record of a formation bulk density as a function of depth by accounting for both the density of matrix and density of liquid in the pore space. Allows for assessment of formation density and porosity at varying depths.
Cement bond log (ultrasonic well logging)	Primary	Implements sonic attenuation and traveltime to determine whether casing is cemented or free. The more cement which is bonded to casing, the greater will be the attenuation of sounds transmitted along the casing. Used to evaluate the integrity of the casing cement and assessing the possibility of flow outside of casing.
Gamma-ray logging	Primary	Use of natural gamma radiation to characterize the rock or sediment in a borehole.
Aqueous geochemistry	Primary	Chemical measurement of saline brine in or above the target storage reservoir.
Multicomponent 3-D surface seismic time-lapse survey	Secondary	Surface 3-D seismic surveys covering the CCS reservoir that can provide high-quality information on distribution and migration of CO_2 and identification of subsurface features. Best technique for map view coverage. Can be used in multicomponent form (e.g., three, four, or nine components) to account for both compression waves (P-waves) and shear waves (S-waves).

APPENDIX: Continued

Monitoring Technique	Technology Type*	Description
Vertical seismic profile	Secondary	Repeated seismic surveys source in a wellbore, receiver at surface. Can be implemented in a "walk-away" manner to monitor the footprint of the plume as it migrates away from the injection well and in time-lapse application. VSP provides a very detailed survey because of the close spacing of the geophones.
2-D seismic survey	Secondary	Acoustic energy, delivered by explosive charges or vibroseis trucks (at the surface) is reflected back to a straight line of recorders (geophones). After processing, the reflected acoustic signature of various lithologies is presented as a 2-D graphical display.
Optical logging	Secondary	Device equipped with optical imaging tools is lowered down the length of the wellbore to provide detailed digital images of the well casing.
Magnetotelluric sounding	Potential	Changes in electromagnetic field resulting from variations in electrical properties of CO_2 and formation fluids.
Electromagnetic resistivity	Potential	Measures the electrical conductivity of the subsurface including soil, groundwater, and rock.
Electromagnetic induction tomography	Potential	Uses differences in how electromagnetic fields are induced within various materials as a means to identify subsurface lithology and geologic features.
Time-lapse gravity	Potential	Use of gravity to monitor changes in density of fluid resulting from injection of CO_2.
Microseismic (passive) survey	Potential	Provides real-time information on hydraulic and geomechanical processes taking place within the reservoir in the interwell region, remote from wellbores by implementing surface or subsurface geophones to monitor earth movement.
Crosswell seismic survey	Potential	Seismic survey between two wellbores in which transmitters and receivers are placed in opposite wells. Enables subsurface characterization between those wells. Can be used for time-lapse studies.
Resistivity log	Potential	Log of the resistivity of the formation, expressed in ohm meter, to characterize the fluids and rock or sediment in a borehole.

*See Categories of Monitoring Tools for definitions of primary, secondary, and potential.
**2-D = two-dimensional; 3-D = three-dimensional; CO_2 = carbon dioxide; DOE = Department of Energy; CCS = carbon capture and storage; GPS = global positioning system; LIDAR = Light Detection and Ranging; HC = hydrocarbons; DC = direct current.

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