EPA Technical Workshop on Geologic Sequestration: Measurement, Monitoring, and Verification (MMV)
January 16, 2008; New Orleans, Louisiana

Summary Notes of the Workshop

EPA and the Ground Water Protection Council (GWPC) co-sponsored a technical workshop in New Orleans, Louisiana on January 16, 2008 to discuss measurement, monitoring, and verification (MMV) issues associated with geologic sequestration (GS) of carbon dioxide (CO_2). About 100 representatives of the electric utilities and oil and gas industries, oil field service companies, academia, consulting firms, U.S. Department of Energy (DOE) National Laboratories and Regional Partnerships for Carbon Sequestration, the Interstate Oil and Gas Compact Commission (IOGCC), State and Federal geological surveys, States, and EPA Headquarters and Regional staff attended the workshop.

The workshop format consisted of two sessions in which industry and government experts described current research on MMV of CO_2 covering the periods during and after closure of a GS project. Following each set of presentations, workshop participants split into separate "breakout" groups to discuss research needs and provide inputs related to the presentation topics and questions relating to MMV from prior workshops. During the concluding session in the afternoon, a panel of experts representing the Regional GS Partnerships, State regulators, oil field service companies, environmental groups, and DOE national laboratories responded to questions from the other workshop participants. Summary notes on the workshop introductions, presentations, and panel questions and discussions are presented below.

Appendix 1 to these summary notes presents the list of workshop participants. Appendix 2 includes the questions written by workshop participants and presented to the panel for discussion. Appendix 3 includes a list of questions from EPA presented to the workshop participants and includes responses to the questions. The workshop agenda is included as a separate file (Attachment 1), as are copies of the presentations (Attachment 2).

Welcome and Introductions

Mike Paque of GWPC welcomed the workshop participants and thanked them for their attendance. He noted that continuous discussion on GS will be held during GWPC's March 2008 Policy Meeting in Washington, DC and the September Annual forum.

Bruce Kobelski, EPA Office of Ground Water and Drinking Water (OGWDW), welcomed the group and provided an overview of the rulemaking activities at EPA and EPA's collaboration with DOE. He noted that DOE is taking the lead on GS research and development through the Regional Partnerships. EPA's role is to focus on the impacts of GS on human health and the environment, and to protect underground sources of drinking water (USDWs). He further noted that there were many other meetings on the MMV (monitoring) issues (e.g., the International Energy Agency (IEA) Monitoring Network meeting held in Edmonton, Alberta, Canada on November 7 to 9, 2007; the American Geophysical Union (AGU) special session on monitoring and modeling held on December 10, 2007 during the annual conference held in San Francisco, California; and the DOE/National Energy Technology Laboratory (NETL) Regional Partnership 2007 Annual Meeting held on December 14, 2007). Bruce indicated that monitoring would cover CO_2 plume tracking, ground water monitoring, and atmospheric monitoring. Demonstrated success in measurement, monitoring and verification regimes is crucial for gaining public acceptance of GS, but many technical challenges remain. Because monitoring techniques such as seismic surveys are very expensive, it is essential to optimize monitoring objectives and establish reliable baseline conditions to verify the secure sequestration of CO_2.

Session 1: Subsurface MMV Issues

The first session of the workshop explored issues related to MMV in the subsurface environment. The speakers' presentations are found in a separate file (Attachment 2).

John Litynski, DOE NETL, provided an overview of the Regional Carbon Sequestration Partnerships and ongoing activities at DOE in response to existing and proposed legislation. He indicated that the 2007 American Climate Security Act has played an important role in steering research activities at DOE. He also pointed out that the Characterization Phase of the Regional Carbon Sequestration Partnerships went from 2003 to 2005, with DOE funding of about \$16M. The Validation Phase started in 2005 and will end in 2009, with a total of seven Partnerships across 41 States, 24 field validation tests, and \$112M in DOE funds. The Deployment Phase will span from 2008 to 2017, with four projects awarded, seven projects expected, and a total of about \$460M in DOE funds. He also provided brief descriptions of a number of projects during Phases II and III.

Jean-Philippe (JP) Nicot of the Gulf Coast Carbon Center, Bureau of Economic Geology, Jackson School of Geosciences of the University of Texas at Austin, provided a presentation on the role of geochemical monitoring in GS. He concluded that the monitoring approach depends on the phase of deployment; dense monitoring is needed in the research phase to increase confidence, and more parsimonious monitoring can be used in the commercial phase. He noted that parsimonious (but effective) monitoring will work well only with thorough upfront site characterization and process understanding. Furthermore, geochemical monitoring plays a major role in providing a comprehensive understanding of the GS process.

Andrew Duguid of Schlumberger Carbon Services presented "MMV Technologies for Effective and Efficient Monitoring of Geologic Carbon Capture and Storage Projects." He noted that a secondary cap rock and monitoring between the two cap rocks would be an effective approach to verify the fate of the injected CO_2. The collection of baseline information is extremely important because there will not be a second chance to collect such information. He stressed that cost effectiveness of MMV will be gained through careful and detailed site characterization. He also noted that MMV is site-specific and models will help identify MMV needs. Andrew Duguid concluded that all phases of MMV operations should be based on performance criteria.

Session 2: Surface and Near Surface MMV Issues

The second session of the workshop explored issues on MMV in the surface and near surface environments. The speakers' presentations are found in a separate file (Attachment 2).

Lee H. Spangler, Director of the Zero Emissions Research and Technology (ZERT) Collaborative at Montana State University, Bozeman, Montana provided a discussion on the development of a new facility for testing near-surface CO_2 detection. The objectives for developing such a facility are 1) to provide a site with known injection rates for testing near-surface monitoring techniques, 2) to establish detection limits for monitoring technologies, 3) to improve models for groundwater, vadose zone, and atmospheric dispersion, and 4) to provide an accessible and available site for multiple seasons/years. At this time, the ZERT Center is made up of researchers from Montana State University, Los Alamos National Laboratory, Pacific Northwest National Laboratory, West Virginia University, Lawrence Berkeley National Laboratory, NETL, and Lawrence Livermore National Laboratory.

Grant Bromhal of DOE NETL provided a presentation on statistical techniques for incorporating near-surface monitoring and modeling. He explained that his project focuses on the implementation of a CO_2 transport model. The model will predict migration from different possible leakage events at a site, determine the performance characteristics of leak detection technologies for simulated leak events, combine evidence from multiple detection systems to infer the probability that a leak of a given size will be detected, and reduce the likelihood of false positive and false negative leak detections. He also indicated that future projects will include multiple monitoring techniques (e.g., soil flux measurement, perfluorocarbon (PFC) tracers, isotope analysis, ground water chemistry, and other methods).

Jennifer Lewicki of the Earth Sciences Division at Lawrence Berkeley National Laboratory presented her findings on the monitoring of surface CO_2 fluxes during two controlled shallow subsurface CO_2 releases. Fluxes were measured using chamber measurements and the eddy covariance method. The chamber measurements mapped the spatio-temporal evolution of surface CO_2 leakage and allowed for the quantification of CO_2 emissions from background soil respiration separately from leakage. She noted that because eddy covariance averages over a large area, temporal trends in background fluxes could mask leakage. In addition, the location and height of eddy covariance stations, atmospheric conditions, and background flux variability influence the ability to detect leakage. Therefore, it is important to characterize background CO_2 variability prior to CO_2 injection. Also, the area of investigation should be limited by focusing on the features most susceptible to leakage based on site characterization using a variety of complementary measurement techniques and statistical methods.

Tommy Phelps of the Oak Ridge National Laboratory presented his research on the monitoring and verification of geologically sequestered CO_2 using suites of perfluorocarbon (PFC) and other inert tracers. The project was conducted at the Frio Brine Pilot Site. Objectives were to 1) determine the chemical (organic and inorganic) and isotopic compositions of water and gases in the Frio Sandstone– baseline, during, and post injection; 2) determine the behavior of multiple suites of PFC tracers; 3) delineate the CO_2 front using on-line probes to monitor pH and conductance complemented by PFC tracers and isotopes; 4) assess water-mineral-CO_2 interactions; 5) investigate the environmental implications of post-injection results; and 6) develop procedures for use in carbon sequestration demonstrations for monitoring, modeling, and verification. He concluded his presentation by noting that despite negativity related to eventually releasing these tracers to the atmosphere, PFCs are valuable in the detection of leakage. Along with geochemistry and isotopes, PFC tracers serve multiple MMV purposes.

Session 3: Panel Discussion of MMV Questions from Participants
(The panel members were: Jean-Philippe Nicot / University of Texas at Austin; Andrew Duguid / Schlumberger Carbon Services; Jennifer Lewicki / Lawrence Berkeley National Laboratory; Grant Bromhal / DOE NETL; Ben Knape / UIC Permits Team Leader; Tommy Phelps / Oak Ridge National Laboratory, and; Scott Anderson / Environmental Defense Climate & Air Program)

<u>Questions Regarding Siting and Monitoring Regime Decisions</u>

Question: Why is monitoring required for all GS projects?

- Scott Anderson – It is important to find out if a project is working in practice and not just in theory.
- Grant Bromhal – Some level of monitoring is needed to check on the progress of the project, but such monitoring may not need to be regulated.

Question: Why should there be a requirement for a secondary cap rock if the primary cap rock is an exceptional regional seal?

- Andrew Duguid – A primary cap rock may be a regional seal. In a redundant system, a secondary cap rock that is equal to the primary cap rock may be needed. A secondary cap rock provides an additional safeguard to public health and the environment. Ideally, there should be multiple confining layers. A competent primary cap rock is crucial but a redundant system with a secondary cap rock (if available) should be encouraged.

One attendee expressed that he is not comfortable with the need for a secondary cap rock because it may not be available in all sites with a competent primary cap rock. Moreover, the commenter indicated that the term “redundant system” should be used in a careful and consistent manner. It can either imply that there is a secondary reservoir (as compared with the capacity of the primary reservoir) or a secondary cap rock (as compared with the quality of the primary cap rock).

- Andrew Duguid – The presence of a secondary cap rock would increase safety and multiple cap rocks would be ideal.
- JP Nicot – In response to the comments on secondary reservoir, most of the injected CO_2 will be trapped in the primary reservoir.

Question: How long should monitoring continue for a GS project?

- Scott Anderson – The time period for monitoring will depend on three conditions:
    - Pressure and/or brine reaching the anticipated distribution in the injection zone.
    - Confirmation of good predictability of the modeling results.
    - Proof of no leakage through “potential” pathways identified during the site characterization phase of the project.

  Monitoring can cease when these conditions are met.
- JP Nicot – Extensive instrumentation of the first commercial GS project should be done by DOE and States to obtain reliable and extensive data to educate the GS communities and researchers.

Question: Should MMV requirements be extensively evaluated before setting standards?

- Scott Anderson – An adaptive approach is preferable. As data from pilot and early projects become available, it would be feasible for us to learn and adjust. Because of the fast track of GS projects, we cannot wait until much of the data become available. We have to use what we can get and move forward.

Question: How large an area should be sampled for baseline data and at what spacing (e.g., entire ultimate plume or inclusion of a buffer)?

- Grant Bromhal – Spacing of sampling points in both the subsurface and near surface environments should be site-specific and determined on the basis of site characterization and simulated injection. Given that the affected area will change over time as more CO_2 is injected, it would be preferable to concentrate on sampling in a smaller area around the injection point and then move outward to include additional sampling points.
- JP Nicot – States should develop reliable baseline data and then add more data from sampling over time.
- Andrew Duguid – A progressive approach should be used to go beyond the area that is considered to be safe. It is important to identify major hazards (e.g.,

artificial penetrations in the project area). It is important to be on the safe side. For example, if CO_2 is moving faster than expected, it may hit some of the major hazards with regrettable results. Although seismic surveys would be useful, they may not be available at all locations. Therefore, solid baseline data are essential for the success of a GS project.

- Jennifer Lewicki – At the surface environment, the sampling area would depend on heterogeneity (e.g., varying ecological systems). It is often unnecessary to make thousands of measurements, but some samples that take into account temporal variation at key locations using continuous monitoring instruments would be optimal for assessing the spacing of sampling locations.
- Grant Bromhal – For a domal structure, the extent of the dome would dictate the areal extent of the sampling locations. In addition, the dips of the rock formations and other structural elements could affect the sampling design.

Brian Graves of EPA Region 6 commented that high resolution seismic (as presented by Andrew Duguid during first session) is very costly. A survey covering 100 square miles can cost about $8M to $10M. He is concerned about the cost if high resolution seismic surveys are deployed for site characterization of GS project locations.

Question: Does an adaptive performance-based MMV approach suggest that we will learn with time and that there will be a second chance to obtain baseline data?

- Andrew Duguid – In the zone immediately around the injection point, it is unlikely that a second chance is available to collect baseline data once CO_2 injection has started. At locations farther out from the injection point, it may be feasible to get a second chance to collect baseline data after the GS project has commenced.
- Ben Knape – Because the regulators do not have all the answers regarding MMV, it is more protective to the public health and the environment to apply more stringent requirements upfront. In time, the changing “baseline” and monitoring requirements may be reduced as we learn more about the GS process.
- Andrew Duguid – The amount of baseline data needed is site-specific (i.e., non-ideal sites such as old oil and gas fields with a large number of abandoned wells and sites that are not well characterized would need more baseline data).

<u>Questions Regarding Subsurface Monitoring of Pressure and Geochemistry; Well Materials</u>

Question: Does pressure rise in overlying layers indicate leakage of CO_2?

- Andrew Duguid – Pressure increase in overlying layers is indicative of leakage
- Grant Bromhal – Although pressure extends upward due to the injection of CO_2, differing signals can be associated with leakage and non-leakage situations.

Therefore, pressure monitoring can be used to detect leakage – given the inter-connection between the pore fluids and cap rock and possible leakage pathways.

Question: Should geochemical monitoring be conducted only in shallow aquifers?

- JP Nicot – Geochemical monitoring can be performed in deep or shallow formations. The bases of underground sources of drinking water (USDWs) would be good locations for geochemical monitoring. Usual parameters to be considered for such a monitoring program include pH, total dissolved solid (TDS), and ions such as calcium and sodium. As CO_2 enters an aquifer, pH will drop and thus may mobilize metals from the formation and may cause calcite precipitation. Analyses of geochemical parameters are inexpensive (i.e., running at about $100 to $200 per sample for multiple chemical indicators). Furthermore, geochemical monitoring may be used to identify abandoned wells by monitoring for brine.

Question: What is the effect of co-contaminants (e.g., hydrogen sulfide) on the detectability and leakage potential of CO_2 by seismic methods?

- Andrew Duguid – The effect of co-contaminants on the use of seismic methods should be limited because this assessment method is largely dependent on density differences. Based on observed evidences, seismic methods should perform well. [Note: He later indicated that it would be valuable to conduct a workshop on geophysics and geophysical methods due to the highly specialized nature of this subject.]

Question: Why are there claims of degradation of "well materials" (e.g., Portland cement) when field data and mechanical integrity test results do not support the claims?

- Andrew Duguid – In the scientific community, few field data are available. Because of time constraints, laboratory experiments are often conducted using the severest possible conditions. In the real world, processes may occur more slowly and be less severe. There is clear evidence of changes to cement when exposed to CO_2 in accelerated laboratory experiments.

A number of participants expressed their concerns regarding laboratory experiments and their validity as compared to processes in the real world. Items addressed by these Participants include:

- Data from the Scurry Area Canyon Reef Operators Committee (SACROC) field and West Texas indicated that there were no problems with casing, tubing, and cement.
- There are insufficient long term data to show if cement would erode due to the presence of carbonic acid or would self-heal because of the properties of calcium carbonate.

- Additional experiments should be performed to gain experience.

A workshop attendee referred to a presentation by Chuck Fox (Kinder Morgan CO2 Company) and stated that the SACROC data show examples of well integrity over time and a lack of leakage.

- Andrew Duguid – The sharing of real world data from commercial operations would be valuable to the GS community. Due to the reluctances of industries to share data, the scientific community has to rely on accelerated laboratory experiments to assess the impacts of CO2 on well construction materials. The availability of field data will allow for a reality check of the lab results.
- Grant Bromhal – Agrees with Andrew Duguid that field data would be highly valuable. CO_2 in brine will attack cement, and some evidence indicates that the action on the first few millimeters of cement is relatively quick but that the diffusion of CO_2 through the rest of the cement is very slow. Depending on the reaction rate, it is unclear if chemical changes will cause pathways to open wider or to close. In other words, the rate of change is a big issue because it may dictate if the cement will go through self healing or destruction.

Questions Regarding Tracers

Question: How are tracers used for flow path analyses?

- Tommy Phelps – By combining different levels of PFC tracers (i.e., creating different lots [or batches] that can be identified using different serial numbers), it is feasible to detect if a leak is transient or long-term in nature. Through identification of the tracers' identities, it is feasible to infer different geochemical processes (e.g., dissolution or precipitation of calcium carbonate) as the CO_2 plume front advances. In addition, a change in pH is a sign of hydrogeologic communication (per information available from the U.S. Geological Survey).

Question: Can tracers provide any information on the quantity of leakage or just the presence/absence of leakage?

- Tommy Phelps – Rate information can be obtained using changes in the tracer regime (i.e., different combination of PFC compounds or lots with serial numbers). However, the identification of flow paths will require a longer period of injection and associated research. Items of specific interest in the use of tracers include identification of circular pathways, multiple injection sources, linkages to geophysics, surficial geophysics, and alternative pathways.
- Grant Bromhal – The use of conservative and non-conservative tracers will allow us to learn more about the GS process.

Question: Can PFC transfer to formation water and/or hydrocarbon (could you "lose" it)? Could PFCs leave the CO_2 stream and not be present in a CO_2 leak?

- Tommy Phelps – PFCs and CO_2 move together, but this is an excellent question. PFCs become more soluble with increasing non-polar CO_2 concentrations (i.e., with depth).
- Grant Bromhal – PFC tracers are not significantly attenuated in coal seams, thus indicating that PFC tracers do not tend to bind on coal fines. In addition, the use of carbon isotopes (e.g., carbon-12 and carbon-13 ratio) may identify if the source of the CO_2 is from the subsurface or biotic sources.

<u>Questions Regarding Surface Monitoring</u>

Question: Would an eddy covariance system be economical and effective for detecting leakage from abandoned wells of unknown locations (maybe in areas with suspected abandoned wells?)

- Jennifer Lewicki – The use of eddy covariance and remote sensing techniques (e.g., open path laser) are much less laborious than the chamber method. Once a leak is detected (e.g., using the eddy covariance method), a more specific method (e.g., chamber method) can be deployed to pinpoint and quantify the leak. In addition, inversion of laser/eddy covariance data is being examined as a viable approach to locate leaks.
- Grant Bromhal – For a known pathway (e.g., an improperly abandoned well) and high priority areas, surface flux monitors (i.e., solid state sensors) can be used to monitor CO_2 concentrations. In addition, certain remote sensing techniques can be used to survey potential leak sites. These techniques have been applied in the past to assess methane and radon leakages. Another remote sensing technique is the use of electromagnetic sensors to locate existing or abandoned wells. Electromagnetic Ray Tracing (ERT) has also been used to detect movement of brine into surficial aquifers.

John Veil of the Argonne National Laboratory commented that NETL has conducted fly-overs to identify abandoned wells using aerial photo techniques (based on brine spills). In addition, he noted that there are handheld sensors that can detect natural gas leaks and that a similar sensor may be developed for detection of CO_2 leaks. Bruce Kobelski of EPA pointed out that the USGS has conducted extensive magnetic surveys in the 1980s and that such surveys may be similar to the scope of MMV.

Question: What is the cost associated with the eddy covariance method, and what are some of the limitations in applying this method?

- Jennifer Lewicki – Eddy covariance is a cost effective method for detecting leakage signals from abandoned wells. The cost of deploying an eddy covariance setup would be about $20,000 to $30,000. The cost may be as high as $50,000 if other sensors are included. The effectiveness of the method depends largely on the location of the leakage source and environmental conditions because the method is strongly influenced by the background level of CO_2. At the one (1) km scale, a single eddy covariance setup may not be able to detect leakage from known sources. It is therefore very important to perform site-specific sensitivity analysis. In other words, more upfront work is needed to ensure that the eddy covariance method would be effective at the various scales of investigation.

Additional Questions and Comments

In closing the workshop, additional questions and comments were solicited from workshop participants. Kirk Hoeffner (Kansas) asked if the new GS regulations would address acid gas injection, given the fact that CO_2 streams from certain sources may contain impurities such as hydrogen sulfide. Bruce responded that it is EPA's understanding that pure CO_2 will be used by demonstration projects. Currently, acid gas injection is done through Class II wells for enhanced oil recovery (EOR) and there are between 10 to 40 acid gas injection wells in the U.S. EPA is continuing its investigation on what could be injected along with CO_2 for GS and the associated implications under the Resource Conservation and Recovery Act (RCRA). It is unlikely that the proposed rule will include acid gas injection; however, it will request information on the presence of potential impurities and their impacts on GS process.

Chin-Fu Tsang of the Lawrence Berkeley National Laboratory commented that a number of techniques were not discussed during the workshop; these techniques include tilt meters and acoustic emission. In addition, he echoed JP Nicot's concern regarding the interpretation of data (e.g., in determining how big the monitoring area should be). A site structure/description model is needed to support monitoring program design (i.e., taking into account the CO_2 plume and displaced water). As more data are collected, they can be used to refine the model. In other words, a site structure model can initially be simple, based on the site characterization process.

Next Steps/Closing

Bruce thanked the speakers and participants for their valuable input, and added that EPA will take everything discussed in the workshop under consideration as it develops the proposed GS regulation. Participants are invited to send additional ideas or comments to EPA and GWPC.

APPENDICES

1. Workshop Participants
2. Questions submitted by Workshop Participants to the Panel Members
3. EPA’s Questions for the Workshop Participants, along with Responses from the Participants (Subsurface MMV Questions; Surface & Near-Surface MMV Questions)

Appendix 1: Workshop Participants

Muhammadali Abbas Zadeh - exas Commission on Environmental Quality
Malcolm Anderson - Southern Calufornia Edison Company
Scott Anderson - Environmental Defense (Climate & Air Program)
J. Daniel Arthur - Arthur Langhus Layne (ALL) Consulting
Jeffrey Benegar - GeoTrans - Inc.
Amy Boyle - Wyoming Department of Environmental Quality
Grant S. Bromhal - US Department of Energy, National Energy Technology Laboratory
Richard T. Brown - Subsurface Technology, Ic.
Hugh J. Campbell - E I DuPont De Numours
Bill Carey - Los Alamos National Laboratory
Mickey W. Carter - ConocoPhillips WPC
Valerie Chan - USEPA, ORD
Elisabeth Cheney - Shell Exploration & Production Company
Ann M. Codrington - PA, OGWDW
Larry T. Cole - USEPA, Region 4
Ken Cooper - Petrotek Engineering Corporation
Patrick Costello - USEPA, Region 7 (Water, Wetlands & Pesticides Division)
Steven Crookshank - American Petroleum Institute
Walter Crow - BP America Inc. (Alternative Energy)
Elaine Darby - Quantitative Environmental Analysis (QEA), LLC
Ken E. Davis - Subsurface Technology, Inc.
Fernando De Leon - Texas Railroad Commission
Kirk Delaune - Sandia Technologies, LLC
Dominic DiGiuliio - USEPA, ORD (Robert Kerr Research Center)
Don J. Drazan - New York State Department of Environmental Conservation
Amelie Dufournet - Schlumberger Water and Carbon Services
Andrew J. Duguid - Schlumberger Carbon Services
Paris Edeburn - Trihydro Corporation
Mike H. Eisner - Maryland Deparment of Environment
Robert Ferri - USEPA, Region 2 (Water Compliance Branch)
Mark E. Fesmire - New Mexico Oil Conservation Division
Elisabeth Fleming - Shell Exploration & Production Company
Steve Fries - AAAS / USEPA, ORD
Eric Fry - Peabody Energy Company
Tom Godbold - MI Department of Environmental Quality (Office of Geological Survey)
Heather Goss - USEPA, OGWDW
Brian Graves - USEPA, Region 6
Ben Grunewald - Ground Water Protection Council
Sherri Henderson - Ground Water Protection Council
Kirk Hoeffner - Kansas Department of Health & Environment (KDHE)
Michael S. Houts - Oklahoma Department of Environmental Quality
Scott W. Imbus - Chevron Energy Technology Corporation
Steve Ingle - Wyoming Department of Environmental Quality (Water Quality Division)
Dan Jackson - USEPA, Region 8

Ed Janicki - British Columbia Gov. (Ministry of Energy, Mines, & Petroleum Resources
Paul Jehn - Ground Water Protection Council
Peter W. Jordan - Subsurface Technology Inc.
Scott R. Kell - Ohio Department of Natural Resources
Steve King - Subsurface Technology Inc.
Barbara Klieforth - USEPA, ORD/NCER
Ben Knape - UIC Permits Team Leader
Bruce Kobelski - USEPA, OGWDW
Jonathan Koplos - The Cadmus Group, Inc.
Monica Kuehling - New Mexico Oil Conservation Division
Cynthia Lane - American Water Works Association
Jennifer Lewicki - Lawrence Berkeley National Laboratory
John Litynski - US Department of Energy (National Energy Technology Laboratory)
Erica Martinson - Inside Washington Publishers (Water Policy Report)
Linda McConnell - Conestoga, Rovers & Assoc.
David Miesbach - Nebraska Department of Environmental Quality
Rich Moen - Shell Exploration & Production Company
Gregory S. Monson - Shell Exploration & Production Company
Dan Murta - T & C Consulting
Michael P. Nickolaus - Ground Water Protection Council
Jean-Philippe Nicot - Texas Bureau of Economic Geology/University of Texas
Curt Oldenberg - Lawrence Berkeley National Laboratory
Craig A. Pangburn - T & C Consulting (Manufacturing & Operating)
Mike Paque - Ground Water Protection Council
Mike Parker - Exxon Mobil
Tim Parker - Schlumberger Water Services
Leslie Patterson - USEPA, Region 5
Tommy J. Phelps - Oak Ridge National Laboratory
Derrick Placek - North Dakota Department of Health
Stephen Platt - USEPA Region 3
Theresa Pugh - American Public Power Association
David J. Rectenwald - USEPA Region 3
Kelly G. Roberts - New Mexico Oil Conservation Division
Randall Ross - USEPA, ORD (Ground Water & Ecosystem Restoration)
Claude P. Roulet - Schlumberger Carbon & Water Services
Jose Daniel Sanchez - New Mexico Oil Conservation Division
Kathy Sanford - New York State Dept. of Envir. Conservation (Division of Minerals)
Chi Ho Sham - The Cadmus Group, Inc.
Lee Spangler - ZERT, Montana State University
James O. Sparks - Mississippi Department of Environmental Quality
Donald E. Stehle - Sandia Technologies, LLC
Michael Stettner - CA Dept. of Conservation (Div of Oil, Gas & Geothermal Resources)
Ron Sweatman - Halliburton
Saba Tahmassehi - Oklahoma Department of Environmental Quality
Lindsay C. Taliaferro III - Ohio EPA (Division of Drinking & Ground Waters, UIC)
Mark Taylor - Wyoming Department of Environmental Quality (Land Quality Division)

Mark F. Thiesse - Wyoming Dept. of Environmental Quality (Water Quality Division)
Rebecca Thingelstad - Anadarko Petroleum
Thomas Tomastik - Ohio Department of Natural Resources, DMRM
Chin-Fu Tsang - Lawrence Berkeley National Laboratory
Robert Ullman - Martin Marietta Magnesia Specialties, LLC
Robert F. Van Voerhees - Bryan Cove, LLP
John A. Veil - Argonne National Laboratory
Jared Wehde - Peabody Energy Company
D. Brian Williams - BP America Inc.
James Randy Williams - Mangi Environmental Group
Lori Wrotenbery - Oklahoma Corporation Commission (Oil and Gas Division)

Appendix 2: Questions submitted by Workshop Participants to the Panel Members

Siting and Monitoring Regime Decisions

Q1: Be careful using the term "redundant systems". This implies the need for a secondary reservoir (with the capacity of the primary reservoir) and a secondary cap (with the quality of the primary cap). I am uncomfortable with insistency on a secondary cap (many primary caps are exceptional regional seals).

Q2: How large an area should be sampled for baseline data and at what spacing (entire ultimate plume or plume and buffer)?

Q3: What is wrong with drilling a number of groundwater monitoring wells as part of any monitoring program?

Q4: Before any serious consideration of requiring long-term MMV of any kind, shouldn't pilot and research results be collected and evaluated first?

Q5: Why is a requirement for monitoring already being assumed as necessary for all sites?

Q6: Have any "no monitoring required" regulations been contemplated?-Site Specific.

Subsurface Monitoring of Pressure, Geochemistry; Well Materials

Q7: What is the effect of co-contaminants (e.g. H_2S) on the detectability (and leakage potential) of CO_2 by seismic methods?

Q8: What is the tradeoff between installing wells to measure pressure and the potential of these wells to create leakage conduits?

Q9: Does a pressure rise in overlying layers indicate leakage of CO_2?

Q10: Is this monitoring of aquifers you mentioned, monitoring aquifers or deeper USDWs? What geochemical parameters are to be monitored? Costs?

Q11: How should spacing of geochemical sampling points be determined if an "early warning" system for leak detection is used?

Q12: If seismic is necessary, does that imply the reservoir too complex to be considered?

Q13: In terms of the cost of various established characterization and monitoring techniques, have the regional partnerships, DOE, or the national labs compiled information on estimated costs? This would include the cost of baseline seismic, geochemical, geomechanics, as well as sensor costs, how long sensors last, etc., cost of operating the sensors, etc.

Q14: In Andrew Duguid's presentation re Effective MMV, the suggestion was that lots of early data gathering should be required to develop a solid baseline. A statement was made that there are no 2nd chances. Does not having an adaptive performance-based MMV suggest we will learn with time and that there will be 2nd chance opportunities to develop a baseline? Concern: Upfront mandatory prescriptive requirements for MMV baseline data could place a large economic burden on storage.

Q15: How about getting some geophysics experts to come in and talk about what can really be detected using various seismic techniques? We really need experts that do seismic interpretation on a daily basis to tell us what it can do. Maybe also someone who is familiar with cross-well tomography?

Q16: What geophysical techniques are available and what are their limitations?

Q17: What isotope and chemistry specifically will you look at in the next phase? What would be a possible multiple indicator parameter monitoring program for sentry wells/monitoring and relative cost per sample?

Q18: Why are claims being made on "well material" degradation such as Portland cement when field MMV data such as external / internal MIT result don't support degradation claims?

Q19: What test can be conducted to evaluate the integrity of "sealed" abandoned wells prior to injection?

Q20: How would you quantitate leakage from a compromised abandoned "sealed" well?

<u>Tracers</u>

Q21: How are tracers used for flow path analyses?

Q22: Can tracers provide any information on quantity of leakage or just the presence/absence of leakage?

Q23: What is the "life" of PFTs at temperature and pressure? Do they degrade over time – 10 years, 100 years?

Q24: Can PFTs transfer to formation water and/or hydrocarbons so that you would "lose" it? Could it "leave" the CO_2, and if the CO_2 leaked there would be no PFTs in it?

Q25: What are the implications of PFTs migrating differently from CO_2, i.e. is the detection of PFTs necessarily indicative (or predictive) of CO_2 leakage?

Q26: How do we deal with surface contamination of PFTs and their indicating "false positives?"

Q27: Some research has shown that PFC compounds can cause health effects and the F-C bond leads to little degradation in the environment. Furthermore, PFC compounds have been shown to bio-accumulate at the top of the food chain. So why is it a good, safe choice for an environmental tracer for CCS?

Surface Monitoring

Q28: Are there remote sensing techniques to monitor CO_2 currently being implemented by Air Programs?

Q29: Do you think an eddy covariance system would be economical and effective for detecting leakage from abandoned wells of unknown locations (maybe in areas of suspected abandoned wells?)

Q30: What's the cost of the Lidar equipment?

Q31: What information has been collected on near surface impacts for CO_2 leakage in on-going EOR projects (West Texas)?

Q32: Given the size of the AORs for CO_2 injection, can near surface impacts be determined on a large (Sq. miles) scale?

Q33: How does this translate into rule requirements?

Q34: Discuss how eddy covariance and perhaps optical remote sensing can be used in conjunction with, not in lieu of, chamber and soil-gas sampling to identify and then quantify leakage from the vadose zone.

Other Topics

Q35: Who in State and EPA offices will have the technical expertise to review the monitoring information? Many agencies will not have he staff available to do this. What good is the information if folks can't analyze it?

Q36: How is EPA/DOE looking at their staff resource building for implementation?

Q37: Can EPA/DOE assist Academia with recruiting a new generation of early resources scientists needed over the next 10-20 years?

Appendix 3: EPA's Questions for the Workshop Participants, along with Responses from the Participants (Subsurface MMV Questions; Surface and Near Surface MMV Questions)

Subsurface MMV Questions

1. What existing or anticipated subsurface monitoring techniques are sensitive enough to: quantify CO_2 plume movement? quantify CO_2 leakage out of the injection zone?

- Seismic before and after injection.
- Seismic affiliation and processes.
- Geochemical; temperature; radioactive tracers.
- For seismic sensitivity, must consider presence of co-contaminants such as H_2S, SO_2, etc. on fluid seismic properties; difficult to quantify by seismic; detection okay - for leakage.
- Seismic under many circumstances can detect gross plume movement but not saturation; geochemical sampling most sensitive, although potential new conduits are introduced
- U-tube or in-situ pH may be enough; for the surface, CO_2 flux chambers would work but sites for monitoring would be difficult.
- Seismic techniques may be best for qualitative assessment but may be lacking with respect to quantitative assessments. Cross-hole techniques/tomography may represent a good tool for future evaluation.
- Why won't traditional monitoring techniques that are presently used in injection well technology work? Not sure I know about other monitoring techniques to provide better answer. Having monitoring wells in strategic areas will provide best way to monitor.
- 3-D seismic; horizontally drilled monitoring wells into formation above cap rock.
- I think we need experts in seismic interpretation give us presentations on what can actually be monitored with seismic. How about cross-well tomography – anybody know about this?

2. What existing or anticipated monitoring techniques are appropriate for monitoring movement of displaced native fluids?

- Monitoring wells both deep and shallow.
- Observation and ground water monitoring wells (shallow and deep).
- Tracers.
- Electrical conductivity, ERT; pressure response; pressure probe in observation well in zone above injection zone.
- Pressure data from distal sites and shallower reservoirs.
- In-situ conductivity as early warning (like in USDW); pressure would give an indication of forcers moving fluids.
- Microseismic and high resolution seismic technologies may work.
- Tracer technology – inject with CO_2.
- See above [3-D seismic; horizontally drilled monitoring wells into formation above cap rock].

- Unless you drill monitoring wells into the injection zone, how are you going to monitor this movement? But do we want to have more artificial penetrations of the injection zone?
- Pressure monitoring; temperature monitoring; salinity; resistivity.

3. What existing or anticipated monitoring techniques are appropriate for monitoring the pressure front moving in advance of the CO_2 plume?

- Pressure transit and testing before and after injection.
- Pressure build-up tests within the monitoring well.
- Pressure measurements on offset wells?
- Pressure transducers in wells; InSAR; tilt meters.
- Several available.
- Well pressure sensors would work but caution should be used in creating additional penetrations.
- Existing instruments (e.g., transducers) should be capable of detecting pressure points. Main trouble may be lack of monitoring points (e.g., not enough wells).
- Again, the best way would be installation of monitor wells into the injection zone. But why would we want to do this? More artificial penetrations pose greater risk for migration out of the injection zone.

4. What existing or anticipated monitoring techniques are sufficient to detect CO_2 movement from the well bore of an injection well?

- Measured soil CO_2 fluxes.
- Running tracers and recording measurements.
- PFT; CO_2 flux – Lewicki; CO_2 transport – Spangler.
- Annulus pressure monitoring.
- Do you mean from a specific well among several? →Unique tracers.
- Visual monitoring for dead vegetation/ in AOR – Morgan Kinder indicated that CO_2 coming up a bore hole would kill surrounding vegetation; 3-D seismic; horizontally drilled monitoring wells completed in zone overlying injection zone – put instrumentation and sensors in their base location on AOR study and seismic.
- Ideally, monitoring wells in the injection zone. Same answers as #2 [Unless you drill monitoring wells into the injection zone, how are you going to monitor this movement? But do we want to have more artificial penetrations of the injection zone?] and #3 [Again, the best way would be installation of monitoring wells into the injection zone. But why would we want to do this? More artificial penetrations pose greater risk for migration out of the injection zone].

5. Should a monitoring regime include monitoring of (potentially induced) seismic activity? If so, what seismic monitor techniques would be appropriate?

- Monitoring pressure of injection well.
- 3-D seismic modeling to detect any faulting.
- Yes; passive microseismic.
- In systems with cap rock fractures and moveable faults.
- Yes: priority should be placed on uplift/subsidence as most likely danger to local population/property. Assuming seismicity was not predicted as a part of injection, re-evaluation of site should follow events.
- Yes – for mega-sink injections.
- Yes! Down hole seismic monitor. Earthquakes piss off the neighbors!
- As far as I have read, seismic events that are actually documented due to injection were caused by injection in excess of the fracture gradient. Is there documentation where it has happened during normal injection operations? If we are injecting below the fracture gradient, is there a need for seismic monitoring?
- This is site-dependent. Microseismic might be good.

6. What parameters should be monitored in ground water (e.g., some suite of water quality parameters)? For example, what should be monitored to detect anticipated impurities in the CO_2 injectate stream, or minerals or metals leached out and mobilized from native formations due to changing geochemistry, etc.?

- Geochemical monitoring.
- Taking fluid samples; geochemical monitoring.
- Brine or USDW?; pH Conductivity? TDS; Compare to baseline of major ions, RCRA metals.
- Ionic; elemental analysis; stable isotopes.
- Characteristics of water quality before injection would provide the information needed to decide what to monitor in GW and USDW. Conductivity, pH, metals of health concern (DW standards), injectate impurities (esp. H_2S and water) should be monitored. (*very different chemistry when present*).
- pH/ alkalinity/ major cations/anions/ use of radio labeled C or O as tracers.
- Would be dependent on purity of CO_2 injected, formation water chemistry, and chemical interactions between them all. Need to have rule that allows site specifics.
- Baseline geochemistry should be done on the ground water, injectate stream, and injection zone prior to start of injection activity. Only if the injectate stream changes do we need to do more sampling.
- pH, alkalinity, salinity, TDS, Ionic constituents, CO_2 conc. (H_2CO_3). HCO_3^- CO_3^{2-}

7. Can monitoring methods detect CO_2 in the subsurface without creating significant conduits for CO_2 movement out of the injection zone?

- Yes and no.
- Yes/No; open for discussion.
- Surface seismic – no conduits.
- Yes, but should be risk-based decision.
- Seismic/acoustic methods can do it, but wells are better. Issue: Do we <u>really</u> need to know where the plume is with high time and space resolution <u>or</u> do we need to make sure where it <u>isn't</u> (above primary seal; in USDW)? These wells would be shallower and not conduit for failure.
- Properly designed/constructed monitoring wells <u>should be</u> able to monitor/detect CO_2 without compromising seals and acting as conduits. Old wells are problematic, at best.
- Probably not.
- If you don't drill monitoring wells into the injection zone, you won't create those conduits.
- Yes, geophysical monitoring can detect CO_2 and CO_2 movement. Appropriately constructed wells can also do this but there is greater risk of creating a pathway.

General Questions – Subsurface MMV

8. What do researchers, industry, or regulators consider as the primary shortcomings or gaps in existing or anticipated monitoring techniques or approaches?

- Adequate monitoring subsurface and surface. Liability.
- Will they actual reduce the long term liability factors that will be faced in the future?
- Need to exploit natural/industrial analogues more for their long-term response records; Heterogeneity, uncertainty.
- How much/how little to do – technology is available.
- Coverage and monitoring site selection, including depth. <u>If</u> models provide information to determine these parameters, then model performance is of primary concern.
- Need to go to West Texas and do studies to see where leakage occurred there and how to detect it. Morgan Kinder in talks pointed mainly to temporarily abandoned boreholes.
- There are a lot of unknowns because it hasn't been done before. Isn't this what the demonstration projects are supposed to do?
- Additional cross-hole techniques for pre & post injection monitoring.

9. Should a monitoring regime include monitoring techniques for screening (determining presence/absence) and for quantifying CO_2 leakage? If so, what screening techniques would be appropriate?

- Yes, strive for both; seismic tends to be better for detection.
- Deep – quantify and locate.
- Why? It's leaky or not. Question then becomes what to do about it.
- How can you identify injected CO_2 vs. other naturally-occurring CO_2 sources? Tracers?

Surface and Near Surface MMV Questions

1. What existing or anticipated surface (soil gas/surface air) monitoring techniques are sensitive enough to quantify CO_2 leakage?

- Gas chromatograph surveys; tracer surveys.
- CO_2 flux, MMV technologies.
- If leakage fluxes are as small as background fluxes, must use filtering and statistical analyses to enhance signal to noise ratio regardless of technique. EC has advantage of low labor, broad areal coverage. Laser IR approaches.
- This type of monitoring should not be required to be included routinely in MMV plans, and should not be required unless the initial site characterization indentifies extremely unusual circumstances or features/areas that prompt unusual concerns. These techniques can be explored further in RD&D projects to see if there are reasons to after this approach.
- Tracers – but may have different phase behavior than CO_2.
- Best "easy" way is group of eddy flux towers (overlap high wind footprints). Surface flux chambers for select/suspect sites.
- Seems to me chamber method would be useful for measuring pipeline leakage not necessarily injection well leakage.
- If you have surface CO_2 leakage, what does monitoring do to resolve the problem? It's already too late! How do you remediate this?
- You need to be able to see an effect or measure from airplane or car. You are dealing with large AORs and putting in fixed soil sensors is impractical.
- Still some debate about some, depends on size of leakage; Surface flux; Eddy covariance; Isotopic analysis; Tracer monitoring.

2. What existing or anticipated monitoring techniques are sufficient to detect CO_2 movement from an abandoned well in the Area of Review?

- Tracer surveys, water sampling, isotope studies.
- PFTs.
- Depends on leakage rate. If low, EC (see no. 1). If well location known, could set up instruments near (or top of) the well. If traces are used, monitor for tracers.
- Logging, annulus pressure.
- CO_2 air sensors (both at old head and on site). Couple with tracer additions to increase sensitivity.
- Why would you want to detect fluid movement (CO_2) in an abandoned well? Hopefully, it's been plugged or if not is being used for monitoring already. Water chemistry change pH.
- You can monitor an abandoned well for CO_2 breakthrough by monitoring with CO-air detection type equipment. It would need to be set up around the existing wellhead or area of the abandoned well if the casing has been cut off below grade.
- See dead vegetation?
- See #1 [Still some debate about some, depends on size of leakage; surface flux; eddy covariance; isotopic analysis; tracer monitoring.]

General Questions – Near Surface/Surface MMV

3. What do researchers, industry, or regulators consider as the primary shortcomings or gaps in existing or anticipated monitoring techniques or approaches?

- Baseline data; fuzziness of data – confused with baseline.
- Difficulty detecting signal above noise. Appear to need to know <u>where</u> seepage is occurring. Must distinguish detecting, locating, or quantifying – these are separate objectives.
- Detailed site-characterization – what is enough? Risk-based approaches are needed. Relate risk to financial factors. Integration of groundwater resources and saline aquifers into CO_2 characterization is needed.
- Seismic – depth/saturation level.
- Reliance on wells is dangerous due to the expanding number of artificial penetrations. Balance between number of sites and extent of MMV. Expense does not equate prudence in deciding (this balance).
- Most of the proposed techniques are not proven technologies for CO_2 detection. Hopefully, the demonstration projects will help us with this problem.
- Need to go to West Texas and ask companies there. How do they measure loss of CO_2? How do they know when there is an effect at the surface?
- It isn't clear whether multiple monitoring programs will be necessary, or if that only adds a redundant and costly additional activity. Also, for monitoring of the injection well itself – which mechanical integrity tests are appropriate?
- Individual monitors have a small footprint; need for >1 year of background data.

4. Should a monitoring regime include monitoring techniques for screening (determining presence/absence) and for quantifying CO_2 leakage? If so, what screening techniques would be appropriate?

- Isotope studies.
- Yes. Detection is primary goal. Largely a question of scale. Detection can be done potentially using large (high) EC towers, but location of seep will be appropriate.
- Yes. O^{18}, C^{13}/CO_2; pH, alkalinity, CO_2 tracers.
- No, not unless there are extremely unusual circumstances indentified in the site characterization. Then, the plan should include carefully targeted approaches.
- Screening is much higher priority than concentration. Many techniques can discriminate between events and established baseline.
- Same answer as #9 under Session 1 [How would you identify the injected CO_2 vs. other naturally-occurring CO_2 sources? Add a tracer?]
- Soil monitoring – just presence/absence at most.
- Yes.