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Summary Report on

2011 CO$_2$ Geologic Sequestration & Water Resources Workshop

Berkeley, June 1–2, 2011

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With

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1. Introduction

Geologic Carbon Sequestration (GCS) is the process of injecting carbon dioxide (CO_2), captured from an industrial (e.g., steel and cement production) or energy-related source (e.g., a coal or natural gas power plant or natural gas processing facility), into deep subsurface rock formations for long-term storage. This is part of a process frequently referred to as "carbon capture and storage" or CCS. Underground injection of CO_2 for purposes such as enhanced oil recovery (EOR) and enhanced gas recovery (EGR) is a long-standing practice. CO_2 injection specifically for geologic sequestration involves different technical issues and potentially much larger volumes of CO_2, as well as larger scale projects than in the past.

In the United States, the Department of Energy's Fossil Energy program has created a network of seven Regional Carbon Sequestration Partnerships (RCSPs) to help develop the technology, infrastructure, and regulations to implement large-scale CO_2 sequestration in different regions and geologic formations within the U.S. In the current working phase of the RCSP's, the Regional Carbon Sequestration Partnerships are implementing large-scale sequestration projects that will demonstrate the long-term, effective, and safe storage of CO_2 in the major geologic formations throughout the United States and portions of Canada. DOE has also developed a core research program, with the goal of better understanding the behavior of CO_2 when stored in geologic formations. For example, studies are being funded at National Laboratories and universities to determine the extent to which the CO_2 moves within the geologic formation, and what physical and chemical changes occur to the formation when CO_2 is injected. This information is key to ensuring that storage will not impair the geologic integrity of an underground formation, and that CO_2 storage is secure and environmentally acceptable.

Meanwhile, the United States Environmental Protection Agency (EPA) has developed regulations for CO_2 geologic sequestration projects under the authority of the Safe Drinking Water Act's Underground Injection Control (UIC) Program (USEPA, 2010a). These regulations, also known as the Class VI rule (for CO_2 injection wells), are designed by the EPA's Office of Water to protect underground sources of drinking water (USDW). The Class VI rule builds on existing UIC Program requirements, with extensive tailored requirements that address carbon dioxide injection for long-term storage, to ensure that wells used for geologic sequestration are appropriately sited, constructed, tested, monitored, funded, and closed. In a complementary rulemaking under authority of the Clean Air Act, EPA's Office of Air and Radiation has finalized reporting requirements under the Greenhouse Gas Reporting Program for facilities that inject CO_2 underground for geologic sequestration, and all other facilities

that inject CO_2 underground (USEPA, 2010b). The data obtained through this rule will inform EPA policies and decisions under the Clean Air Act related to the use of CCS for mitigating greenhouse gas emissions. EPA is funding scientific studies with the goal of better understanding the potential for environmental risks of CO_2 storage in the subsurface, in particular with respect to the protection of USDWs. Many of these studies are conducted or facilitated by EPA's Office of Research and Development.

While several small-, medium-, and large-scale geologic sequestration projects worldwide have demonstrated (and continue to demonstrate) that CO_2 can be safely stored in the deep subsurface, many stakeholders agree that there are aspects of GCS that can benefit from additional research. Because of its regulatory focus, EPA is mostly interested in R&D targeting issues that are important for groundwater protection and greenhouse gas accounting. At present, EPA's Office of Research and Development is developing an R&D roadmap to prioritize EPA-sponsored research for the next five years. To help with the roadmap planning and prioritization, EPA and Lawrence Berkeley National Laboratory (LBNL) jointly hosted a workshop on "CO_2 Geologic Sequestration and Water Resources." The objective of the workshop, held at LBNL on June 1–2, 2011, was to evaluate the current status of R&D related to CO_2 storage and water resources, to identify key science gaps, and to define specific research areas with relevance to EPA's mission. This report provides a summary of the workshop discussions and results.

2. Organization of Workshop

This workshop on "CO_2 Geologic Sequestration and Water Resources," jointly organized by EPA and LBNL, brought together about 70 experts from EPA, the DOE National Laboratories, industry, and academia (see Appendix A). Participation was by invitation only. Invitation lists were initially developed by the organizing committee with the intention of covering relevant areas of expertise and having a good institutional mix. Most participants were from the United States, but three participants joined from Canada, France, and Iceland, respectively. A few participants could not attend in person and instead joined via live webcast and teleconferencing.

To facilitate discussions and interaction, participants were split into four breakout session groups (see Section 3), and ample time was provided during the two days for breakout group discussions. Before splitting into individual sessions, the workshop started with a series of introductory presentations to the full plenum (see workshop agenda in Appendix B). In the morning of Day 1, three general presentations by the organizing committee, DOE/NETL, and EPA were followed by an introductory

presentation to each breakout session topic. Breakout sessions were held in the afternoon of Day 1 and in the morning of Day 2. Participants reconvened in the main workshop room in the afternoon of Day 2, and breakout leads reported back to the entire plenum. All introductory presentations are provided in Appendices C through I.

Prior to the workshop, the organizing committee identified leads for each breakout area. The group leads were charged with: (1) planning of their respective session's focus before the workshop, (2) delivering a 30-minute presentation to lead into the topic at the workshop, (3) guiding the discussions during breakouts, (4) reporting back to the assembly, and (5) writing a summary document of the breakout discussions and recommendations. Each breakout group had at least two to three group leads, one representing a regulatory institution and the others representing academia or DOE National Laboratories.

To prepare the workshop summary report, members of the organizing committee collected the breakout session write-ups from the group leads (in draft form) and redacted them for consistency. General sections were written by the organizing committee. Before finalizing the report as an LBNL document, the draft text was sent for review to all breakout leads. While the final report provides a valuable summary of R&D issues and relevant research areas, we caution that this summary reflects the subjective opinions of a selected group of experts voiced over a two-day workshop period.

3. Topical Areas of Breakout Sessions

In line with EPA's needs, the primary technical focus of the workshop was protection of water resources related to deep storage of CO_2. Prior to the workshop, four topical areas were selected as being particularly relevant to this focus. Each of these areas is briefly introduced below. The research questions listed in Section 3.1 through 3.4 were sent to participants prior several weeks before the workshop. The questions were suggested by the organizing committee to initiate and/or guide discussion, but it was up to the breakout leads and the individual groups as to which research areas and questions of interest should be addressed.

In preparation for the workshop, participants also received several EPA draft guidance documents currently in review or in development to support the Class VI Rule regulations. These included documents on UIC Program Class VI Well Site Characterization (USEPA, 2011a), Area of Review (AoR) and Corrective Action (USEPA, 2011b), and Well Construction (USEPA, 2011c).
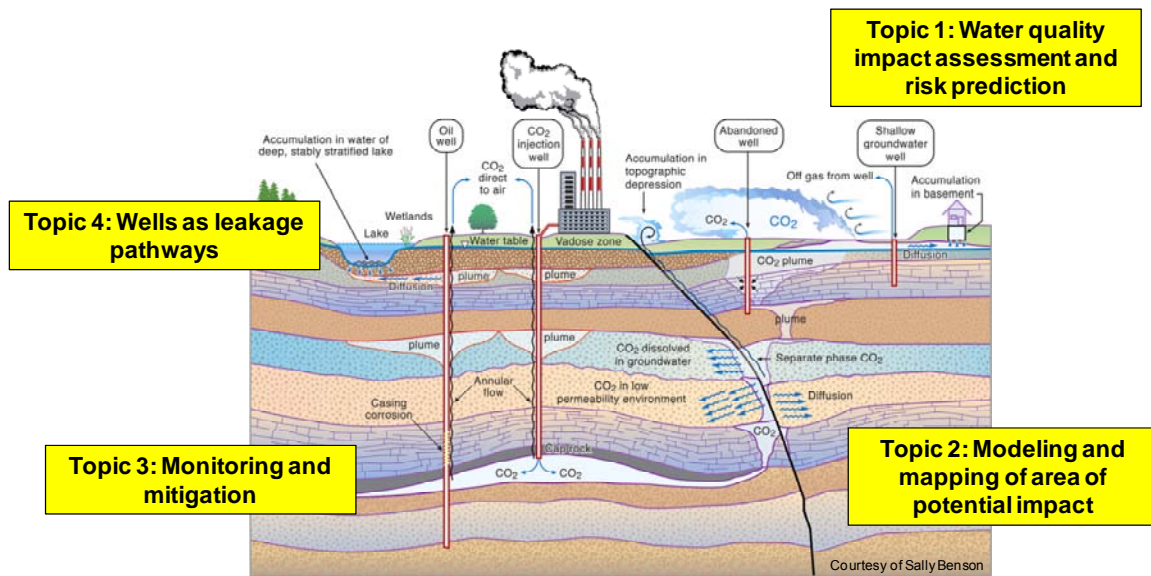
Figure 3.1 Topical Areas of Breakout Sessions

3.1 Breakout Topic 1: Water Quality and Impact Assessment/Risk Prediction

Group Leads: Susan Carroll, Rick Wilkin, Reed Maxwell

This topical area directly targets the potential for water quality changes in USDWs as a result of geologic carbon sequestration. Such changes are only expected if the containment system for CO_2 storage fails. For example, CO_2 may migrate into the shallow subsurface and atmosphere through permeable pathways—well bores, fractures, or faults. Subsurface pressure changes due to CO_2 injection can cause migration of brines from storage formations into other hydrologic units. The primary question here is whether we understand and are able to predict the consequences of leakage of CO_2, brine, and/or co-migrating constituents on water resources.

- What is the impact of CO_2 or brine intrusion on drinking water resources (e.g., mobilization of hazardous constituents from the subsurface or aquatic sediments)?
- What about co-injectants and co-contaminants?
- What are the potential ecological and health impacts?
- How accurate can these impacts be predicted with modeling or analytical tools? What is the role of system-level risk assessment models?
- What are the main risk drivers? Can these be identified based on qualitative site characteristics?

3.2 Breakout Topic 2: Modeling and Mapping of Area of Potential Impact

Group Leads: Stefan Bachu, Stephen Kraemer

EPA requires in its Class VI rule (herein, the GS Rule) that the permit application include an Area of Review (AoR) within which all potential compromises to the isolation of the injected CO_2 from the underground sources of drinking water are mapped and evaluated. These compromises include fractures and faults and artificial penetrations such as wells. This area is the projection to the surface of the zone of potential endangerment associated with GCS, and includes the influence of the separate phase CO_2 plume and the potential for pressure displacement of native fluids.

There is complex physical science, computational technology, and sophisticated and expert model building supporting the definition of a zone of potentially endangering influence and its mapping as a projected area on the land surface. We shall distinguish the state-of-the-science mapping—the area of potential impact (AoPI)—from the state-of-the-regulation mapping—the area of review (AoR); ideally, they should be the same.

The primary question here is how to best delineate the Area of Potential Impact to be practical and protective as a regulatory tool.

- How can the area of potential impact be defined such that the required site characterization and potential corrective actions (e.g., plugging of leaking abandoned wells) provide for safe storage?
- What level of model complexity is sufficient for modeling and mapping the area of potential impact?
- How might monitoring of system performance through time improve the evaluation of the area of potential impact?
- How should multiple interacting CO_2 injection operations be handled?
- What is the influence of fractures and faults on the definition of the area of potential impact?

3.3 Breakout Topic 3: Monitoring and Mitigation

Group Leads: Sue Hovorka, Dominic Digiulio, Tom Daley

Monitoring of CO_2 migration (and other subsurface processes) is an integral part of EPA's regulatory approach, both with respect to protection of water resources and greenhouse gas accounting. Mitigation involves intervention or remediation in case unplanned or unacceptable changes occur in the subsurface as a result of CO_2 storage. The primary issue here involves identifying existing or new monitoring and mitigation methodologies best suited to protecting water resources.

- What monitoring methods are best at detecting leakage into groundwater, vadose zone, or surface water bodies? What is the value of monitoring schemes to track plume migration and detect leakage at depth?
- Which current and future software tools are needed for analyses of data generated by monitoring efforts? Can the data be effectively integrated with existing water resource datasets (e.g., USGS aquifer database)?
- In the case of leakage, what mitigation measures are available to stop or limit its effect? Can water quality changes in response to leakage be remediated? What remediation technologies are available?

3.4 Breakout Topic 4: Wells as Leakage Pathways

Group Leads: Bill Carey, Randall Ross, Brian Strasizar

Wells constitute one of the most obvious potential leakage pathways for buoyant CO_2 and/or formation brine to migrate from the storage formation into USDWs. The primary question here is how to best characterize and predict well behavior/evolution to better understand leakage risks.

- What is the long-term effect of CO_2–brine exposure to well materials?
- Which tools are available to identify wells in the proximity of GS injection sites?
- What methods are best to test the mechanical integrity of injection and existing wells as well conditions change due to long-term exposure to injected fluids?
- What materials are most reliable for the construction and plugging of wells used for long-term storage of CO_2 and plugging abandoned wells in an area of concern?

4. Breakout Topic 1: Water Quality and Impact Assessment/Risk Prediction

Prepared by Susan Carroll (LLNL), Reed Maxwell (Colorado School of Mines), Rick Wilkin (EPA), and Charuleka Varadharajan (LBNL).

Portions of this report have been taken from an NRAP white paper prepared for the DoE (Hakala et al., unpublished).

4.1 Introduction

The risk of CO_2 leakage from sequestration sites that are properly selected and monitored is expected to be low. However, the potential environmental impacts of subsurface CO_2 migration are not completely understood at this time. These impacts are an important public concern with respect to the wide-scale deployment of carbon capture and storage. The objective of this breakout session was to identify and prioritize key knowledge gaps and research directions with regard to understanding and developing predictive tools for the consequences of subsurface CO_2 migration, brine, and/or co-migrating constituents on shallow water resources. Most of the discussions were centered on groundwater quality, but similar issues are also important for vadose zone and surface waters.

The impact of CO_2 release in shallow, freshwater aquifers is expected to be different from that in deep storage reservoirs, since temperatures, pressures, and salinities will be lower near the surface. CO_2 will also transition from a supercritical phase to a gaseous phase at shallow depths, where it will partially or fully dissolve into native waters. The leakage of gas (CO_2 and impurities) and brine will perturb groundwater composition. Brine leakage will introduce dissolved salts, while the reaction of supercritical CO_2 and reservoir fluids could trigger the release of metals and organics into solutions entering overlying aquifers. Furthermore, CO_2 dissolving into groundwater can increase its acidity, resulting from the formation of carbonic acid, and this in turn can mobilize naturally present hazardous constituents such as lead or arsenic.

Studies that help us understand and predict the effects of specific release pathways for CO_2 and other relevant geochemical species are necessary to determine the possible impact that CO_2 leakage may have on local and regional groundwater. The nature of the CO_2 release into the aquifer and aquifer characteristics such as hydrology, mineralogy, and water chemistry will play an important role in site selection and studies. Comparative studies across disparate aquifer types should be used to establish categories of aquifer vulnerability to CO_2 leakage, and to establish screening methodologies that would allow site-selection managers to compare potential sites in a cost-effective manner.

The UIC Program Class VI Well Site Characterization Guidance (USEPA, 2011a) describes data requirements and information that are typically used to characterize the geology and geochemistry of a site. The Guidance provides an overview of the EPA geologic sequestration rules, specifically with regard to geologic site requirements, and addresses the collection of background information for proposed project sites. Various aspects of site selection are covered, including the detailed geologic characterization of the proposed injection zone and confining zones, as well as development of sufficient geochemical sampling and analysis plans to establish baseline water quality.

The breakout group focused discussions around several major themes, including the assessment of risk to water quality, human and ecological health, the potential biogeochemical impacts of CO_2 intrusion on drinking water resources (e.g., mobilization of hazardous constituents from the subsurface or aquatic sediments), potential impact on microbial communities following CO_2 intrusion, as well as the status of predictive tools to guide site assessments and identify primary risk drivers. Understanding the impact and risk to groundwater quality also requires that we understand the potential for leakage to a groundwater resource. This is the subject of other breakout groups and will not be addressed in this section.

During the course of the discussions, it was found that there is a general need for developing a risk framework to assess the potential impact of CO_2 leakage on groundwater impact and exposure risks. This framework would need to encompass the likelihood and magnitude of leakage as well as any potential impacts. Central to the development of a risk framework is deciding/establishing the tolerance for negative impacts/risks to water quality. We presume that risk tolerance will be decided by EPA policy informed by scientific investigation.

Central to our discussion was the relative importance of determining the impact of leakage on water quality versus human health and ecological risk from the impacted water. Questions arose as to whether the EPA would define water quality impact as water composition that exceeds EPA secondary and primary drinking water standards, or if one needs to assess whether the concentrations (even if elevated above EPA standards) posed a human or ecological risk, and would a certain amount of non-zero risk be acceptable. It was generally agreed that we needed to first define what the impact of leakage is on water quality and if leakage can be detected by state-of-the-art monitoring technology. These issues are further defined below.

4.2 Key Issue 1: What chemicals are going to be introduced into USDWs through gas and brine leakage, and what are their impacts on aquifer properties?

Discussion

Potential chemicals of concern and their associated EPA primary and secondary drinking water standards are summarized in Table 1. CO_2 gas leakage into USDWs has the potential to alter water chemistry by increasing solution acidity and dissolved carbonate content. These changes can result in the release of toxic, carcinogenic metals such as lead and arsenic that are naturally present in aquifer rocks and sediments, potentially to levels close to EPA MCLs (Apps et al., 2009, Wang and Jaffe, 2004). Trace metals in aquifer materials can be adsorbed on the surfaces of carbonates, iron (oxy)hydroxides and silicates, substituted in clay interlayers, coprecipitated in secondary carbonates, or present in trace quantities of host minerals (e.g., galena or arsenopyrite). Reactions that can occur in the presence of elevated levels of CO_2 include processes such as dissolution of carbonates, sulfides, or iron (oxy)hydroxides, ion exchange from mineral surfaces, as well as competitive desorption by competing carbonate ions (Apps et al., 2010). The kinetics of the different release mechanisms will vary, with ion-exchange and desorption likely occurring sooner than dissolution from host minerals. It is important to add that some contaminants (e.g., anionic species like arsenate) can be favorably attenuated as a consequence of pH decrease.

Our ability to assess the impact of leakage on water quality requires that we have an understanding of the chemical, physical, and biological processes that control their distributions between the aqueous and solid phases. A few laboratory studies have been carried out to study the impact of CO_2 leakage into shallow aquifer settings. Little and Jackson (2010) conducted batch experiments, exposing sediments from several locations in three aquifers to CO_2 for (>)300 days, and found a decrease in pH, accompanied with increases in concentrations of some metals such as Mn, Co, Ni, and Fe by one to two orders of magnitude. However, the experiments were carried out under oxidizing conditions, potentially altering redox reactions in the batch cells. Other short-duration (2-week) batch studies have observed similar pH drops, and elevated concentrations of metals such as Ba, Ca, Mg, Fe, Mn and Sr when diverse aquifer rocks were reacted with CO_2-charged waters (Lu et al., 2010; Smyth et al., 2009). Batch experiments such as these are useful, since they provide a relatively simple and inexpensive means to determine the chemicals that can be mobilized by CO_2 leakage in a variety of aquifer settings. The studies mentioned above were conducted at atmospheric pressure (1 bar), which is much lower than typical aquifer pressures (5-15 bars); the increased pressure in the aquifer will result in enhanced CO_2 dissolution and lower pHs (Dafflon et al., 2011). Experiments using unconsolidated sediments also maximize the mineral surface area available for reactions, and can

overpredict the amount of metals released, especially in batch settings where the sediments are allowed to equilibrate with CO_2 over extended periods of time (Gilfillan and Haszeldine, 2011).

Table 1. EPA maximum contaminant levels (MCLs) and secondary drinking water standards for selected contaminants in drinking water for public supply systems. Limits in µg/L except as indicated, ND indicates no data.

Contaminant	Maximum Contaminant Level (MCL in ug/L)	Secondary Drinking Water Standards
Arsenic (As)	10	
Barium (Ba)	2000	
Cadmium (Cd)	5	
Chloride (Cl)		250000
Chromium (Cr)	100	
Copper (Cu)		1000
Iron (Fe)		300
Lead (Pb)	15	
Manganese (Mn)		50
Mercury (Hg)	2	
Nickel (Ni)	ND	ND
Nitrate (NO3 as N)	10000	
Selenium (Se)	50	
Silver (Ag)	50	
Sulfate (SO4)		250000
Thallium (Tl)	2	
Uranium	30	
Zinc		5000
Total Dissolved Solids		500000
pH		6.5-8.5 standard pH units
Benzene	5	
Ethylbenzene	700	
Benzo(a)pyrene (PAHs)	0.2	

See http://water.epa.gov/drink/contaminants/index.cfm#List

Thus, more laboratory experiments involving a range of redox conditions, pressures, means of CO_2 exposure (e.g., flow-through vs. batch modes), spatial scales, and porosities (cells vs. larger, packed column experiments) are needed to quantify the changes that could occur due to the introduction of CO_2 into USDWs. In addition, most laboratory experiments have only examined the effects of CO_2 leakage in sediments, and do not consider other co-migrating fluids/components such as brine and organics. A study exposing reservoir and cap rocks from storage formations to a supercritical CO_2-brine mixture found that metals such as As, Cd, Cr, Cu, Ni, Pb, and U could be released into the formation fluids (Carroll and Torres, 2011). A study of a natural analog in Chimayo, Mexico (Keating et al., 2010) found no evidence of trace metal mobilization caused by the high levels of CO_2 dissolved in the shallow waters; instead, increases in As, U, and Pb were found to be associated with the CO_2-brine mixture rising from deep formations. Laboratory studies are also needed to evaluate the impact of organics mobilized by supercritical CO_2 along leakage pathways. While research on organic and

metal fate and transport conducted for environmental remediation purposes can provide a valuable framework for understanding many subsurface processes, CO_2-specific studies are needed to account for its effects on reactions. Some members of the discussion group felt that the impact of brines and organics might be more significant than the changes caused by pH decrease.

Field experiments involving a controlled release of CO_2-saturated waters into shallow aquifers, simulating a leak, can help determine the changes that may occur in aquifers under more realistic conditions. In the ZERT (Zero Emissions Research and Technology) experiment in Bozeman, MT, CO_2 was released into a perforated pipe sited below the groundwater table at 2 m depth (Kharaka et al., 2009, Kharaka and Cole, 2011). Rapid and systematic changes in pH, alkalinity, and conductivity were observed, along with an increase in the concentrations of metals such as Ca, Mg, Fe, Mn, and organics (BTEX). However, measured metal and organic concentrations were below EPA MCLs (Kharaka, 2010). Similarly, elevated concentrations of major cations and trace-metals were observed in a recent 10-day field test conducted in Brandenburg, Germany, where CO_2 was injected into an aquifer at ~18 m depth (Peter et al., submitted; Peter et al., 2011). The Electric Power Research Institute (EPRI) is currently conducting a field experiment introducing dissolved CO_2 into a shallow (about 55–60 m below surface) test formation to identify the key geochemical reactions and transport processes that could lead to CO_2-induced release of metals (EPRI, 2010). In addition to helping identify elements that can be mobilized in a potential leakage scenario, the field data from both tests have been coupled with laboratory characterizations (Section 4.3, Key Issue 2) and reactive transport modeling (Section 4.4, Key Issue 3) to understand and predict the migration and impact of the CO_2 plume.

There have been large-scale CO_2 field injections for CCS-EOR, where the water quality of overlying aquifers has been monitored continuously. In SACROC, Texas, injection has now been ongoing for over 30 years; no differences have been found between freshwaters within the site and trends in regional groundwater chemistry outside of the area (Smyth et al., 2009). Similarly, no degradation of potable water has been observed so far at Weyburn, Canada (Whittaker et al., 2011). Since no leaks were reported at either site, these results could possibly reflect the safety of a properly sited CCS operation, rather than the lack of impact on USDW in the event of leakage.

Studies of natural analogs can be useful in assessing the risks associated with high levels of CO_2 dissolved in freshwaters (e.g. Keating, 2011, Kharaka and Cole, 2011). In addition, these can also yield insight into geochemical processes that can be used to monitor impacts (e.g., Sr isotopes as tracers were used to distinguish between the CO_2 and CO_2–brine source terms at Chimayo, New

Mexico). However, reactions in natural analogs may not accurately represent the changes that could result from accidental leakage of CO_2 into a freshwater aquifer, since the sediments would have equilibrated with CO_2-saturated waters over very long time scales.

The group concluded that there is a general lack of laboratory and field data on biological changes that can occur in shallow aquifers in the presence of high levels of CO_2. It is unclear whether an increase in CO_2 concentrations would slow or even reverse biologically driven reactions that typically occur in anoxic settings, where CO_2 is an end product (e.g., denitrification or iron reduction). However, this topic was not discussed in depth due to the absence of microbiological expertise within the group.

Research Needs

- More laboratory studies are needed, under a variety of redox and pressure conditions, to constrain the magnitudes of trace elements that can be mobilized due to CO_2 intrusion into an aquifer. A diverse set of aquifer materials and sample sizes must be used to determine the extent of variations that could occur in concentrations of metals and organics that are released.
- In the long term, field studies are needed to identify the water response to CO_2, brine, and other impurities to assess the spatial and temporal extent of induced changes, and to verify if lab experiments can scale up in field settings.
- Research is needed to better understand microbial responses to CO_2 leakage.
- More assessments of natural analogs could be valuable.

4.3 Key Issue 2: Can these risks/impacts be identified and predicted based on site characteristics and monitoring data?

Discussion

The GS community has recognized that geologic characterization is a critical component to selecting optimal sites for long-term storage. Similarly, characterization of the USDW is a critical component for assessing impact of leakage on water quality. The reactions that occur in the subsurface and the extent to which CO_2-leakage affects the aquifer will depend on its geological and mineralogical characteristics.

A set of standard site characteristics relevant to CO_2-leakage, and methods for quantifying them, needs to be defined. One example of a potential aquifer characterization method is to measure the buffering capacity of the aquifer, in response to changes in pH or redox potential from CO_2 and brine

leakage. (This example assumes that changes in pH and redox will drive the partitioning of metals/organics between the solids and water.) Other methods that were discussed include sequential/selective extractions (e.g., Tessier et al., 1979). Extractions have been used to identify the associations of trace elements with different sediment phases and could potentially be a risk indicator of metal mobilization from sediments. However, the relevance of these tests for conditions with high dissolved CO_2 has not yet been determined. Whenever possible, spectroscopic techniques such as micro and bulk X-ray absorption can also be used to determine mineral-metal associations, providing information complementary to wet chemical laboratory measurements (e.g., Varadharajan et al., 2011). Spectroscopy typically involves small sample sizes that may not be representative of a heterogeneous aquifer; in addition, it may be hard for research projects to get access to synchrotron facilities. Physical properties of sediments, such as grain size, cation exchange capacity, surface area, etc., are needed to provide more accurate inputs into reactive transport models. Additional mineralogical information can be obtained through other techniques such as XRD and SEM.

Central to characterization is the need for baseline studies and monitoring that capture the natural conditions, current water usage, and sampling variability. Understanding this variability is important, because leak detection, and evaluation of the magnitude and risk of impact, will be made against available baselines. Screening parameters that correlate leakage rate to the magnitude of negative impact would be useful. The selection of screening methods for the detection of CO_2 leaks should be based on detailed studies, but then applied more generally as commercial-scale geologic storage develops. Examples based on laboratory and field studies described in Key Issue 1 could include pH and alkalinity, suites of alkali/alkaline earth and trace elements (e.g., Ca, Mg, Fe, Mn, Ba, Sr, As, Pb etc.), and conductivity. However, studies in natural high-CO_2 flux settings have found that aquifer mineral buffering reactions can make it difficult to detect changes in pH or trace elements (Keating et al., 2011, Aiuppa et al., 2005). This is a topic that needs further research, since the reactions will possibly be different in USDWs where sediments have not been exposed to CO_2 over long periods of time.

Research Needs

- Identification of aquifer characteristics that define vulnerability to CO_2 intrusion.
- Identification of baseline screening parameters that need to be monitored to detect changes in water quality.

- Understanding the role of sediment buffering capacity in CO_2-driven reactions. High buffering capacities could mitigate the impacts of CO_2-intrusion, but also interfere with detection of leakage.

4.4 Key Issue 3: Modeling and Simulation

Discussion

Modeling can play a central role in understanding the potential impact of leakage on groundwater quality, provided that model development is constrained by experiments, characterization, and monitoring. Models can be used to predict impacts by testing hypothetical CO_2 leakage scenarios in aquifer settings (e.g., Carroll et al., 2009, Vong et al., 2011, Humez et al., 2011). They can also be used to develop screening technologies based on predictions of changes to aquifer geochemistry induced by CO_2 leakage (e.g., Wilkin et al., 2010). For example, geochemical modeling based on a principal component analysis of the data collected from the ZERT site suggests that the observed increases in Pb, Cu, Cd, and Zn were mostly caused by ion exchange with clays driven by Ca^{2+} from calcite dissolution, and desorption reactions with iron (oxy)hydroxides. It also suggests that the increase in anions such as arsenate was a result of competitive sorption of bicarbonate ions, whose concentrations were increased as a result of CO_2 dissolution (Apps, 2011, Zheng et al., 2011). Microbial changes were also predicted due to increased availability of Fe(II) from reduction of iron oxides and oxyhydroxides (Kirk, 2011). A similar modeling effort is being coupled with the field experiment at the EPRI test site.

The robustness and accuracy of any predictions regarding the persistence of any impacts and the reversibility of these impacts within aquifers will rely on our ability to scale these chemical and transport processes to field-scale reactive transport. Although reactive transport simulators have the capability to include a range of chemical and physical parameters, the complex chemical systems require significant computational resources. Addition of microbial and ecological processes (if needed) will add to that computation expense. Consequently, there is a desire to reduce the chemical, biological, and physical parameter space to focus on the most important parameters that relate leakage rate to groundwater quality. It is important to keep in mind that we are investigating complex systems. As such, there may be multiple explanations to laboratory and field studies. It is important that we understand the uncertainty in our conceptual models and the relative importance of the parameters used to describe our models. Towards this end, the National Risk Assessment Program for CCS is conducting simulation studies that capture both natural variability and knowledge

uncertainty regarding the effect of CO_2 leakage on groundwater quality (e.g., Carroll et al., 2011, Beacon et al., 2011)

Modeling is also an important tool for assessing system-level risk. It is needed to update risk assessment as new data becomes available and to evaluate which processes or parameters are important over time and space. These models can be used to integrate risk assessment of groundwater impacts into decision-making processes, and can aid in efforts to rank aquifer vulnerability considering several configurations, including differences in hydrogeology, mineralogy, and CO_2 leakage conditions (e.g., Siirila et al., 2010). An area of current research is aimed at determining what information is needed to inform these models and developing reduced-order models that capture the important chemical, biological, and physical processes, but can be conducted with much less expenditure of computational resources.

Research Needs

- Continued research and development of numerical models, particularly reactive transport and multiphase (supercritical CO_2) approaches that allow for treatment of uncertainty and additional processes. This could be two paths, reduced dimensionality models or approaches, which take advantage of high-performance computing.
- Research toward understanding dominant processes, contaminant pathways, and uncertainties to aid the development of simplified models.
- Development of systems-level risk models that can aid in management.

4.5 Additional Discussions

The group briefly discussed mitigation/remediation if leakage were to compromise groundwater quality. There is a general assumption that the likelihood of leakage will decrease with time once injection stops, because reservoir pressures will decay towards background. In this case, leakage is driven only by buoyancy of CO_2. Assuming this is true or that the source of the leak can be directly mitigated, then it is likely that natural attenuation will reduce negative impacts. This is a reasonable assumption, because aquifer flow will dilute the CO_2 plume, and the aquifer pH and redox state should approach its baseline. Another approach is to directly manage the reservoir pressure by using brine extraction wells. In principle, this method would limit the role that pressure has in generating leakage pathways, but it would also create new wellbores, which are potential pathways for CO_2 leakage.

There was also a short discussion on the indirect impacts of storage in the absence of leakage. One example might be oscillations in the groundwater table from pressure changes during injection and storage at depth that might also, under exceptional circumstances, impact surface water (streams, lakes, and rivers).

Research Needs

- Laboratory, field, and simulation studies are needed to identify primary attenuation processes that would be expected following CO_2 leakage.
- Additional studies are required to assess existing aquifer remediation technology for environmental management and evaluate usefulness in cases of CO_2-related contamination.

4.6 Summary and Priorities

Research on the potential impact and risk to groundwater quality from leakage of CO_2 into drinking water aquifers is a new and evolving area. Past research directed towards understanding how contaminants affect water resources has largely been driven by response or need to mitigate resources that have been contaminated. The research community is in a unique position to assess the impact of leakage on groundwater quality prior to commercial deployment of geologic storage of CO_2.

There was a general consensus at the end of the workshop that significant knowledge gaps exist that prevent the scientific community from bounding what the impact of CO_2 leakage would be on water quality. The group generally agreed that leakage of CO_2 and brine into an overlying aquifer will perturb organic and metal concentrations in aquifers. However, it is not known whether the perturbations would have high enough or sufficiently sustained concentrations to compromise water quality, leading to human and ecological exposure and health risk. Below, we summarize the key issues identified in the workshop. Expertise of those attending in this group included geochemistry (12), hydrology (5), and risk assessment (3). Some individuals had expertise in more than one area. The ranking below may reflect the expertise present.

Ranking (1 is the highest priority)	Research Question
1	Determine which chemicals will be introduced into USDW through gas and brine leakage
1	Determine the spatial and temporal impact of these constituents in the aquifer
3	Identify potential risk through characterization
4	Define what is acceptable risk to water quality
5	Develop a risk framework
5	Determine Indirect impacts from pressure
7	Develop systems-level risk models
7	Investigate methods to update risk assessment

5. Breakout Topic 2: Modeling and Mapping the Area of Potential Impact

Prepared by Stefan Bachu (Alberta Innovates—Technology Ventures), Stephen Kraemer (EPA), and Jens Birkholzer (LBNL)

5.1 Introduction

Area of Review (AoR) evaluations and corrective actions are long-standing permit requirements of the Underground Injection Program (UIC) of the U.S. Environmental Protection Agency (EPA). The AoR refers to the delineated region surrounding the CO_2 injection well(s) wherein the potential exists for underground sources of drinking water (USDWs) to be endangered by the leakage of CO_2 injectate and/or formation fluids. A USDW is an aquifer or portion of an aquifer that supplies any public water system or that contains a sufficient quantity of groundwater to supply a public water system, and currently supplies drinking water for human consumption, or that contains fewer than 10,000 mg/L total dissolved solids (TDS) and is not an exempted aquifer. Owners or operators of injection wells are required to identify any potential conduits for fluid movement—including artificial penetrations (e.g., abandoned wellbores) within the AoR—assess the integrity of any artificial penetrations, and perform corrective action where necessary to prevent fluid movement into a USDW.

The GS Rule (USEPA, 2010a) defines the Area of Review (AoR) as "the region surrounding the GS project where USDWs may be endangered by the injection activity" [§146.84(a)]. USDWs in the vicinity of a proposed Class VI injection well may be endangered by: (1) movement of carbon dioxide into the USDW, either in gaseous phase or dissolved in formation water, impairing drinking water quality through changes in pH, contamination by trace impurities in the injectate (e.g., mercury, hydrogen sulfide), and leaching of metals and/or organics; and (2) movement of nonpotable water (e.g., brine) out of the injection formation into a USDW as caused by elevated formation pressures induced by injection. Therefore, the AoR encompasses geographically the region overlying the extent of free-phase (i.e., supercritical, liquid, or gaseous) carbon dioxide migration, and the region overlying the extent of fluid-pressure increase sufficient to drive fluids into any USDW if flow pathways (such as defective or open-hole wells, or fractures) were available.

The GS Rule requires that "the AoR is delineated using computational modeling that accounts for the physical and chemical properties of all phases of the injected carbon dioxide stream and is based on available site characterization, monitoring, and operational data" [§146.84(a)]. Computational modeling in most cases will be conducted by multiphase multicomponent numerical solvers, but innovative analytic or semi-analytic solutions (and hybrids) are also included. Additionally, the AoR

must be reevaluated (a) periodically, at least once every five years, (b) when actual operational data differ significantly from initial estimated operational values that were used for model inputs, or (c) when monitoring data and model results differ significantly [§146.84(e)]. The purpose of GS Rule injection-well AoR reevaluation is to ensure that site monitoring data are used to update modeling results, and that the AoR delineation reflects any changed in operational conditions.

The GS Rule AoR is a regulatory concept and tool that balances science and policy. There is complex physical science, computational technology, and sophisticated and expert model building supporting the definition of a zone of potentially endangering influence, and its mapping as a projected area on the land surface. We shall distinguish the state-of-the-science mapping—the area of potential impact (AoPI)—from the state-of-the-regulation mapping—the AoR; ideally, they should be the same.

Based on the group discussions in the workshop breakout session, this chapter discusses various remaining questions related to definition and mapping of the AoPI to existing or potential underground sources of drinking water due to high-volume injection of CO_2, including understanding and characterizing both free-phase CO_2 migration and the extent of threshold pressures (see definition in Section 5.2) and associated uncertainties. A draft guidance document on AoR evaluation and corrective action was recently released by EPA (USEPA, 2011b).

5.2 Key Issue 1: How can the Area of Potential Impact (AoPI) be defined such that the required site characterization and potential corrective actions provide for safe storage?

Discussion

The consensus of the group discussion is that the area of potential impact (AoPI) encompasses: (1) the maximum extent of the separate-phase CO_2 plume at stabilization; and (2) the maximum extent of the threshold pressure that would drive brackish water or brine into the USDW (given the presence of an unplugged well), through the primary and secondary seals and traps. This approach is consistent with the recommendations in USEPA (2011b).

It is expected that the maximum pressure increase will occur at or near the end of the injection period, followed by pressure decay over time. Thus, the region of maximum extent of the threshold pressure that may drive brackish water or brine into a USDW should be established at the time of maximum pressure increase. The separate-phase CO_2 plume will migrate during the post-injection period and eventually stabilize due to capillary trapping, dissolution, and mineralization. Although generally it is

expected that the maximum extent of the plume of CO_2 will be contained within the maximum extent of the threshold pressure as defined previously, due to the CO_2 migration after cessation of injection, there might be cases when a portion of the geographical extent of the CO_2 plume will be outside of the maximum extent of the threshold pressure. In such cases, the area of potential impact (AoPI) should include both.

The definition of threshold pressures depends on the density of fluids assumed in the hypothetical conduit (unplugged well screened in injection formation and USDW) connecting the injection formation and the USDW before and during injection. Threshold pressures may be defined using static or dynamic calculations.

As explained by Birkholzer et al. (2011), an increase in pressure in the injection formation may lead to the migration of brine into and up a hypothetical conduit (unplugged well screened in the injection formation and the USDW [Figure 5.1]. However, if the brine is denser than the well fluid it displaces and the pressure increase is below a critical minimum value, upward migration stops before formation brine reaches the bottom of the USDW. The pressure change in the injection formation required to lift denser brine in the wellbore from the top of the injection formation up to the bottom of the shallow aquifer (distance D_B) can be calculated. Sustained flow of brine up the well will occur if the actual pressure change in response to CO_2 injection increases to a level larger than this threshold value. Assuming that the initial fluid pressures P_B at the top of the injection reservoir and P_W at the bottom of the shallow aquifer (both of which are measured near the wellbore) are known, the threshold pressure, ΔP_{crit}, is given by:

$$\Delta P_{crit} = \int_0^{D_B} \rho_B(z)g\,dz + P_w - P_B$$

where $\rho_B(z)$ is brine density at depth z (a function of salinity as well as temperature and pressure). The integral in the equation above can be solved numerically and represents the hydrostatic pressure of the brine column in the well after the injection brine has moved up to the bottom of the shallow aquifer. The density of brine as a function of salinity, temperature, and pressure can be calculated using equation-of-state correlations for saline water available as stand-alone or implemented in typical multiphase, multicomponent simulators. This approach is referred to as the dynamic calculation of threshold pressure.

A static calculation of threshold pressure assumes that the well-bore casing is impermeable between $z = 0$ and $z = D_B$; i.e., there is no exchange of fluids or salts between the wellbore and the intervening

formations. As a result, at and above the pressure threshold, the brine that has invaded the well bore has uniform salinity equal to the salinity of the injection reservoir. The equilibrium case assumes that the invading fluid instantaneously equilibrates with its surroundings, i.e., to an approximately linear pressure profile defined by P_W at the top and $P_B + \Delta P_{crit}$ at the bottom, and to a temperature profile defined by the initial temperature distribution in the formation. In this case, the density of the brine in the well bore varies slightly as a function of depth.

Bandilla (personal communication) shows a simple expression for a static-equilibrium threshold pressure:

$$\Delta p_{crit} = \frac{g \, D_B}{2} \left(\rho_B(D_B) - \rho_w \right)$$

assuming hydrostatic initial conditions, a linear density profile in the well after brine invasion, initial density at the bottom of the well is the same as the initial density in the injection formation, and initial density at the top of the well is the same as the USDW water density. This hydrostatic calculation of threshold pressure considers only whether flow up the well may occur, not what the flow rates or the potential impact might be; in other words, the vulnerabilities of potential environmental receptors are not taken into account. Other expressions for static-equilibrium threshold pressure are given in Nicot et al. (2009) and Bandilla et al. (2012).

As discussed previously, it is anticipated that in most scenarios, the front of threshold critical pressure will encompass a larger area than the CO_2 plume itself; consequently, the discussion of CO_2 front modeling is deferred to the model complexity section.
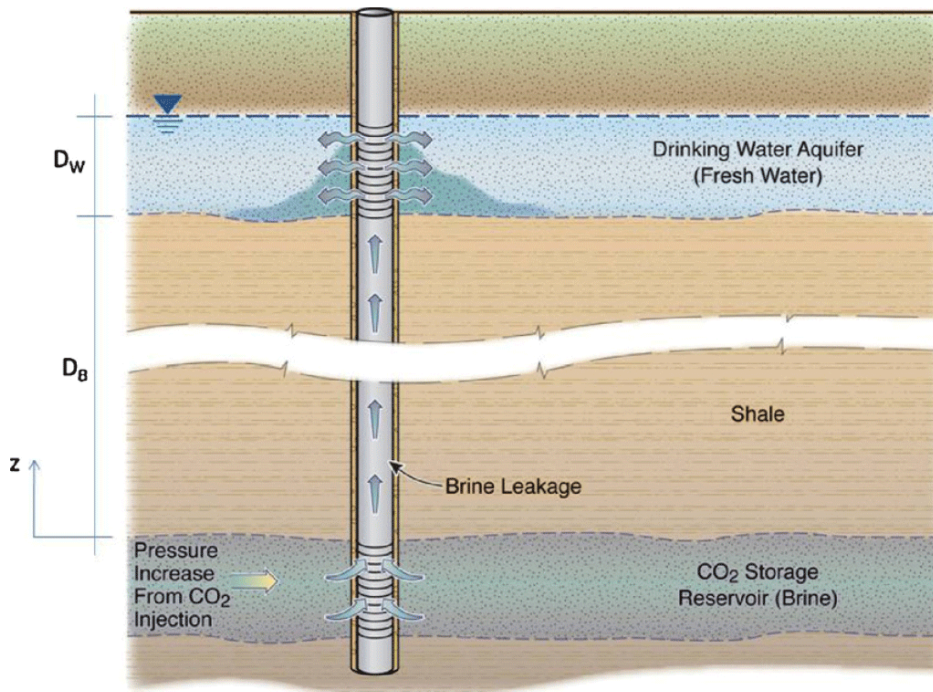
Figure 5.1. Conceptual model showing upward brine migration inside an unplugged well caused by pressurization of the reservoir (from Birkholzer et al, 2011).

Research Needs

- The definition of threshold pressure, based on the concept of density stratification (as mentioned above), needs further exploration for us to better understand whether the approach is reasonable (safe but not overly conservative) under various representative conditions. One aspect of this evaluation should be the assessment of the possible environmental impact of saline and brine-water fluxes into the USDW.

- More research is needed to evaluate and rank the integrity/condition of artificial penetrations (e.g., abandoned wellbores) within the AoPI, so that the priorities for corrective action can be assessed.

- More research is needed on understanding data sensitivity and defining monitoring priorities as a basis for periodic reevaluation of AoPIs and reduction of uncertainty involved in AoPI mapping.

5.3 Key Issue 2: What level of model complexity is sufficient for modeling and mapping the area of potential impact?

Discussion

The goal in AoPI mapping is to find the appropriate level of model complexity (conceptual representation, numerical solution technique) for representing the area of potential impact. A step-wise and progressive approach starts simple, and then adds complexity as understanding and data support increase. The appropriate level of model complexity will be problem-specific (critical threshold pressure vs. CO_2 front) and site-specific. Experience should reveal good modeling practice and rules of thumb. Analytical or semi-analytical solutions may be somewhat better positioned for characterizing uncertainty due to their computational efficiency.

In general, single-phase (pure brine) models are justified in modeling far-field pressure influence and mapping critical threshold pressure fronts (Nicot, 2008). For CO_2 front modeling, the simplest representations include three components (CO_2, H_2O, salt) and two phases (brine, and supercritical CO_2) (Schnaar and Digiulio, 2009). The focus on early time (<100 years) allows for the assumption of two-phase physics, and the discounting of bulk geochemistry and nonisothermal effects allows the assumption of constant fluid properties in each layer. Further assuming a sharp interface between CO_2 and brine, and capillary exclusion in aquitards, opens up possibilities for semi-analytical solutions as long as CO_2 is at sufficient depth to allow the assumption of constant density to be valid. Semi-analytical solutions for CO_2 front modeling have often relied on a vertical-equilibrium sharp-interface solution for two-phase flow of CO_2 and brine (e.g., Nordbotten and Celia, 2006; Nordbotten et al., 2009). It is important to explore and understand the effect of model complexity on AoPI delineation through numerical experiments, in which the importance of process representation is explored through inclusion or exclusion.

Research Needs

- Modeling frameworks with alternative levels of model complexity are needed (1) to facilitate various levels of process representation and different solution techniques, and (2) to allow for efficient quantification of uncertainty associated with predictions of threshold critical-pressure fronts and separate phase CO_2 fronts.
- More research is needed to develop a consistent definition for the maximum extent of the CO_2 front (which saturation level constitutes a "front"?) and to understand the role of capillary trapping on its definition.

5.4 Key Issue 3: What is the influence of multiple interacting CO$_2$ injection operations on areas of potential impact definition?

Discussion

The influence of multiple injections within a basin has modeling, legal, and regulatory implications. Each additional injection potentially changes the pressure boundary conditions for other Class VI wells (Birkholzer and Zhou, 2009). The influence will depend upon site-specific conditions, proximity, and whether injections are in stacked storage units. It is not clear how the sharing of data, conceptual models, and associated parameterizations will be handled (e.g., some companies may consider permeability to be proprietary information). Might there be legal complaints of "pressure trespass"? Or will seniority rights be honored in pressure-limited storage units? Also, pressure management with multiple wells extracting native brine might be a legitimate and effective corrective action (e.g., Buscheck et al., 2011).

Research Needs

- More research is needed to improve regional-scale understanding of storage complexes.
- Field data are needed to support model validation of regional-scale pressure influence, including pressure interference between multiple deep injection wells in multiple aquifers.
- Basin-scale modeling methodologies are needed for managing and optimizing storage operations and sequencing injections from multiple storage projects. Such methodologies are also important for assessing the effect of CO$_2$ storage on competing activities, such as oil and gas production, natural gas storage, and extraction of geothermal energy.

5.5 Key Issue 4: What is the influence of fractures and faults on the definition of the area of potential impact?

Discussion

The current guidance on AoPI evaluation and delineation of a threshold pressure assumes the presence of an unplugged well allowing migration of brine into a USDW. It is not entirely clear if the same threshold pressure would be applicable to brine migration through fractures or faults. Fractures and/or faults will influence pressure response and CO$_2$ transport in the storage formation, which depends in part on whether the fractures/faults are open or closed. The change in pressure might open fractures/faults, change the pattern of leakage, and change how the fractures/faults interact with the CO$_2$ plume. CO$_2$ or brine migrating up a fracture/fault pathway will interact with intervening formations, which reduces the risk of these fluids reaching USDW. The relationship between the

increases in pressure and the possibility of fault reactivation (induced seismicity) is uncertain. Pressure management might be an option to prevent fluid migration through fractures/faults (e.g., Buscheck et al., 2011).

Research Needs

- More research is needed to better characterize fractures/faults in the field, and predict their impact on pressure-induced leakage and on CO_2 plume migration.
- Methodologies are needed to determine threshold pressure for AoPI delineation specific to fracture and/or fault pathways.
- More research is needed on the subject of induced seismicity.

5.6 Additional discussions

For regulatory purposes, a practical definition for the area of potential impact is needed for effective protection of groundwater resources. The initial site-characterization phase will establish the baseline prediction of the AoPI. Ongoing monitoring is expected to reduce the band of uncertainty associated with mapping of the AoPI. The UIC Class VI requirement requires a reevaluation of the AoPI every 5 years, at minimum. AoPI mapping and reevaluations should be based on the results from models and monitoring data. The discussion group recognizes the value of comprehensive best-practice manuals for modeling and monitoring that are shared between various stakeholders. Good starting points are DOE/NETL documents on best practices for simulation and monitoring (NETL, 2009; 2011).

The group also discussed whether there were specific computational-modeling software for evaluation of AoPI that should be recommended by the scientific/technical community for use by potential Class VI owners or operators. The consensus was that it would be inappropriate to make a blanket recommendation for specific codes at this time. The UIC program should be aware of community acceptance of codes/models; the modeling community includes industry, academia, and the National Laboratories. Evidence of community acceptance includes documented testing, frequent usage, and a solid publication record. The pressures to use accepted codes and standardization should be balanced by the goal to promote innovation. Independent of the question about which software/codes should be used, the group recommends that potential users need to be trained in how to use codes and develop model applications, how to evaluate code performance, and how to ensure sufficiently accurate model results. It was also recommended to continue open/transparent benchmarking of codes.

5.7 Other recommendations and priorities

Other recommendations from the group are to:

- Continue evaluation of the AoPI definition with respect to threshold pressure, including the influence of heterogeneous storage complexes and different leakage pathways.
- Continue to advance the predictive capabilities for AoPI evaluation, ranging from complex numerical process models to more simplified analytical and semi-analytical solvers.
- Develop guidance on the minimum level of model complexity needed to define an effective and safe AoPI.
- Ensure that modeling and monitoring is tightly coupled to improve AoPI mapping and reevaluations.
- Encourage basin-scale modeling to support and coordinate individual UIC Class VI applications, and strive for consistent basin-scale geomodels and parameterization.
- Consider relaxing the rules to conduct controlled field experiments of leakage through fractures/faults that can provide data for testing of coupled hydrogeological and geomechanical models.

An online poll was conducted after the workshop to identify priorities for the key issues discussed. Eight members of the group responded as follows:

Ranking	Key Issue	High Priority	Medium Priority	Low Priority
1	How can the Area of Potential Impact (AoPI) be defined such that the required site characterization and potential corrective actions provide for safe storage?	87.5% (7)	12.5%(1)	0
2	What is the influence of multiple interacting CO_2 injection operations on the AoPI?	75% (6)	12.5% (1)	12.5% (1)
3	How might monitoring of system performance through time improve the evaluation of the AoPI	62.5% (5)	12.5% (1)	25% (2)
4	What is the influence of fractures and faults on the definition of the AoPI	37.5% (3)	50% (4)	12.5% (1)
5	What level of model complexity is sufficient for modeling and mapping the AoPI	25% (2)	62.5% (5)	12.5% (1)
5	How can National Laboratories (DOE, EPA) best assist UIC programs in evaluating modeling results	37.5% (3)	37.5% (3)	25% (2)
7	Which computational modeling software for evaluation of AoPI has been tested and recommended by the scientific community	37.5% (3)	12.5% (1)	50% (4)

6. Breakout Topic 3: Monitoring and Mitigation

Prepared by Susan Hovorka (BEG), Thomas Daley (LBNL), and Dominic DiGulio (EPA),

6.1 Introduction

The topic of monitoring and mitigation covers a wide range of applications, each with specific research needs. In the context of geologic sequestration of CO_2, monitoring involves both the direct detection of injected CO_2 through remote sensing, and the estimation of processes and properties modified by the injection of CO_2 (such as fluid-pressure increases or displaced fluids). Mitigation involves the remediation of unplanned and unacceptable changes in the subsurface induced by CO_2 injection. The Monitoring and Mitigation breakout group decided to focus on monitoring, with an emphasis on identifying gaps in knowledge and future research needs. Several members of the group had attended a recent workshop on mitigation held by the Carbon Capture Project (CCP) (Imbus and Christopher, 2011); thus, discussion about mitigation was limited, with the expectation of inclusion of material from the CCP workshop. Also, extensive reviews are available regarding the state of the art for sequestration monitoring in best practices and guidance documents, such as the National Energy Technology Laboratory (NETL) Monitoring, Verification, and Accounting (MVA) document (NETL, 2009). The information in these documents, particularly a listing of monitoring or mitigation tools, is not repeated here. An EPA guidance document on monitoring is in development, but has not been released yet.

Given the extensive nature of the topic, any discussion involving monitoring has to be broken down in some manner. For this workshop, the approach chosen was to spatially divide the monitoring environment into different zones, each with different goals for monitoring, research needs, and deployment of state-of-the-art tools. Figure 6.1 shows various settings that could be monitored, and indicates one possible spatial division of monitoring zones. The discussion group agreed on three spatial intervals—the injection zone (IZ), the above-zone monitoring interval(s) (AZMI), and the underground source(s) of drinking water (USDW)—and agreed to organize discussion based on the technologies appropriate to each zone. During the course of the breakout session, it was found that better terminology and definitions were needed to determine the boundaries of the IZ and AZMI with respect to the confining system. For example, AZMI(s) could be within or above the confining system, while generally below the USDW.

Members of the discussion group had strongly divergent views on the value of monitoring the different spatial intervals. A straw poll conducted prior to the workshop recommended allocation of discussion time (a proxy for importance/value) in the following manner: IZ = 20%; AZMI = 44% and USDW = 36%,

with one-quarter of the participants voting for little to no time spent on the IZ, considering it to be straightforward. A post-discussion poll was more balanced, with all participants recommending some time on each zone (with an average emphasis of Injection Zone = 26%, AZMI = 37%, and USDW = 37%). Biological monitoring, soil gas, and atmospheric monitoring were brought up, but then tabled without discussion, due to time constraints and the group's desire to focus on the subsurface.

In further discussion, it became apparent that the purpose for which monitoring was being carried out would influence research needs and approaches to deployment. The group developed a consensus that, from the context of the EPA, the discussion of monitoring for compliance with Underground Injection Control (UIC) Class VI permits (which is focused on the environmental risk of leakage, with respect to safeguarding USDW) (USEPA, 2010a) should be separated from reporting under the Subpart RR of EPA's Greenhouse Gas Reporting Rule (which seeks to account for stored and emitted CO_2) (USEPA, 2010b). Thus, our discussion of key issues and research needs was divided into six categories, according to the spatial zone being monitored and compliance needs (Table 6.1). Two additional topics were discussed in depth: the role of background (pre-injection) monitoring and the role of mitigation.
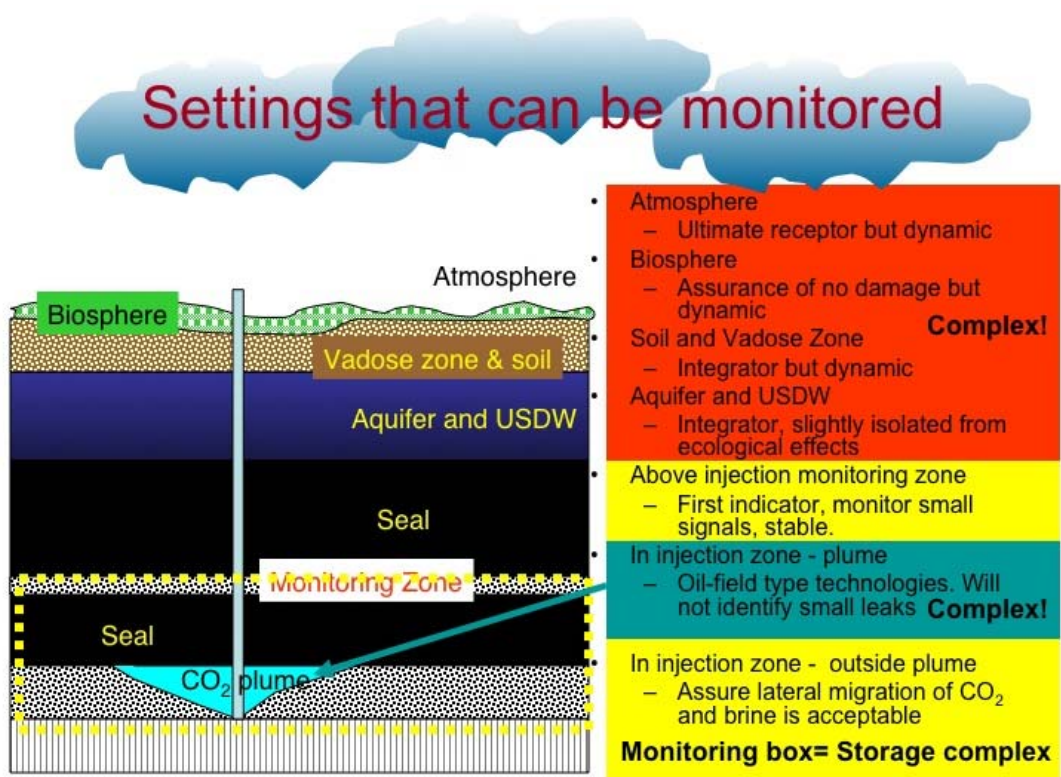
Figure 6.1. Proposed zonal separation for monitoring of different environments

Table 6.1: Division of monitoring discussions

	IZ (Deep)	AZMI (Intermediate)	USDW (Shallow)
Protection of USDW (EPA Class VI needs)	Key issues	Key issues	Key issues
Greenhouse Gas Reporting (EPA RR Needs)	Key issues	Key issues	Key issues

6.2 Injection zone (IZ) monitoring for protection of USDW

6.2.1 Key Issue 1: The composition of brine and CO_2 are the geochemical source terms for leakage potentially degrading USDW

Discussion

The majority of monitoring work for the IZ has focused on geophysical sensing of CO_2, with the goal of documenting conformance to predictions (e.g., Daley et al., 2011). The most used and most successful geophysical methodology is seismic monitoring, particularly time-lapse (or 4D) surface seismic reflection surveys (e.g. Chadwick et al., 2009). It was acknowledged that these methodologies still need improvement for CO_2-specific applications. However, geochemical monitoring of the IZ may also have value. For this purpose, it is important to know the composition of fluids within the IZ, especially when changes to the chemistry of USDW are detected. A source term would be needed to construct a mixing line that can determine whether the changes are a result of leakage of brine or gas, as well as to calculate the risk to USDW. Several end-member compositions are needed: (1) the native brine(s) and other fluids in the IZ; (2) the injectate, and (3) the reaction products of brine, CO_2, rock (inorganics) and/or organics. In particular, information is needed about the toxicity of any of these constituents. The group did not reach a consensus on identifying specific constituents or fluid properties to be measured, but decided that a site-specific methodology was important.

Sampling of IZ fluids is not simple, because of the expected depth of sequestration (> 800 m). §146.90(g) of the Class VI Rule (USEPA, 2010a) requires direct monitoring of the extent of both pressure and CO_2 plumes[1]; members of the breakout group interpreted this as a requirement for a perforated monitoring well that could be used for geochemical sampling. For the purpose of observing IZ reactions of brine, CO_2, rock, and organic components, it is important that this monitoring well be

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[1] "Testing and monitoring to track the extent of the carbon dioxide plume and the presence or absence of elevated pressure (e.g., the pressure front) by using: (1) Direct methods in the injection zone(s); and, (2) Indirect methods (e.g., seismic, electrical, gravity, or electromagnetic surveys and/or down-hole carbon dioxide detection tools), unless the Director determines, based on site specific geology, that such methods are not appropriate"

distant from the injection well(s), thereby allowing for reactions to take place. However, it is difficult to obtain accurate geochemical samples of the reaction products of CO_2 dissolved into brine and reacted with rocks (and possibly organic components) for several reasons, as demonstrated in the following examples.

Field tests at the Frio site and the Cranfield site used U-tubes (Hovorka et al., 2006; Freifeld et al., 2005; Hovorka et al., 2011) in the perforated, packer-isolated IZ to obtain samples. These tests did not observe a large bank of brine (and dissolved CO_2) pushed ahead of the CO_2 plume. However, such sampling was likely limited because of the possibility of high-mobility CO_2 fingers bypassing brine. If fingers of CO_2 intersect the perforated wellbore, CO_2 would preferentially migrate into the well, displacing brine. Therefore, brine outside the wellbore containing dissolved CO_2 would not be drawn into the well. Later on, during the period when both brine and CO_2 are in the wellbore, supercritical CO_2 will migrate upward and float on top of brine, accumulating at the top of well elements (e.g., attic under packer, top of tubing, etc.). Undersaturated brine in the wellbore will be isolated from rock, and will react with CO_2 until it is saturated and/or entirely displaced. New techniques to determine the properties of brine reacted with CO_2 in the IZ are being explored in some field studies. In one pilot study at Nagaoka, Japan, time-lapse wireline resistivity logs were obtained above the CO_2 plume, and the brine was sampled using a cased-hole formation tester that opened only one targeted perforation (Mito et al., 2008; Mito and Xue, 2011). The Decatur, Illinois, project will test the commercial Westbay system (developed for shallow groundwater applications), which compartmentalizes the wellbore with many packers and performs isolated sampling of each compartment, to see if this method can be used to capture both phases (supercritical CO_2 + impurities and brine + impurities) (e.g., Picard et al., 2011).

An additional difficulty in obtaining IZ fluid geochemistry is that gas solubility varies strongly with pressure and temperature. The mass of CO_2 or other dissolved gases will change with variations in pressure and temperature, which in turn can affect the solubility of other constituents. A number of technologies can be used to capture fluids under reservoir conditions and minimize alteration during transport to the surface—for example, evacuated devices that can be lowered to depth, opened, and resealed, isolating an aliquot of fluid; or U-tube samplers that produce high-frequency small-sample volumes. Techniques to determine the composition of fluids at given pressures and temperatures, either by calculation or experimentation, are needed to determine fluid characteristics in reservoir conditions. It is a common practice to bring fluids to the surface (where they can be easily sampled and analyzed), allow them to cool and outgas, and then back-calculate the chemistry at reservoir conditions.

Research Needs

- Improvement of methods to sample injection-zone formation fluid with intact geochemical properties
- Development of recommendations for a site- and problem-specific methodology for selecting analytes

6.2.2. Key Issue 2: Understanding the importance of CO_2 dissolution

Discussion

It is difficult to map or quantify the distribution of dissolved CO_2 in the subsurface. This is especially difficult in high-salinity brines. Changes in fluid properties (e.g., conductivity) resulting from dissolution that are detectable in fresh or brackish water become insignificant in water with high total dissolved solids (TDS), where the solubility of CO_2 decreases. Dissolution of a large amount of CO_2 could have a positive effect on pressure and stabilization of the free-phase (mobile) CO_2. However, dissolution would also result in a reduction of the volume of free-phase CO_2, which should not be mistaken as leakage losses from the IZ in detection by methods such as seismic or pressure monitoring.

The solubility of CO_2 in different types of brines at relevant pressures and temperatures is fairly well known (e.g., Spycher, 2010). The uncertainty in defining the amount of CO_2 dissolved, and the volume of the plume of the CO_2–brine mixture containing increased concentrations of any associated rock-water reaction products, stems from uncertainties in determining the surface-contact area of CO_2 and brine. The surface-contact area depends on the geometry of the CO_2–brine interface, and is often strongly affected by heterogeneity and preferential flow paths for the fluid. The total volume dissolved will also be influenced by other, potentially slow, effects such as local or regional flow of brine, and density overturn of CO_2-saturated brine. In areas with high-CO_2 saturation, such as the center of the plume, the brine will be less mobile because of relative permeability effects.

Research Needs

- Better understanding of the applicable dissolution rates for supercritical CO_2 into brine within porous media.
- More lab-scale measurements of geophysical properties (e.g., resistivity, elastic moduli) of CO_2–brine mixtures
- Investigating the value of combined seismic/electrical methods for monitoring of dissolved CO_2 via changes in pure phase saturation.

- In the long term, improvement of the monitoring tools to map supercritical CO_2 is needed for field-scale validation of model-based predictions.

6.3 Injection-zone monitoring for purposes of GHG reporting

6.3.1 Key Issue 3: How to avoid misinterpretation of volume stored in the reservoir

Discussion

The breakout group consensus was that GHG accounting using the mass of CO_2 stored in the IZ, as determined by currently available techniques, is not recommended. The precision in quantifying the total mass *in situ*, for example with seismic methods, is only moderate. For carbon trading, with a detection level of a given tool of x%, credit might have to be given for +/- x%; there is financial importance in minimizing x. Instead, the errors in measuring small-volume leakage are likely to be lower, and therefore quantifying measured leakage (rather than measuring the amount of stored CO_2) would be a preferable accounting method. Some improvements to quantification of CO_2 in the IZ may be possible—for example, by combining seismic/electrical methods. However, significant investments made in quantifying oil and gas resource volumes in hydrocarbon reservoirs have demonstrated that *in situ* quantification is not easy. Existence of a pre-injection baseline for saline-formation storage improves estimation over hydrocarbon reservoirs, for which there is often no baseline. It is important to consider that some seismically unquantifiable CO_2 may be dissolved, not escaped (as mentioned in Section 6.2.2). Nonetheless, geophysical monitoring tools, especially seismic, are the best-known methods to estimate leakage (e.g., Daley et al., 2008), and these tools require improvement in demonstrated quantification.

Research Needs

- Improvement of monitoring technologies, including tools with better detection limits, is needed for more precise quantification of supercritical CO_2 in the reservoir. Seismic monitoring is a proven tool, but requires research on quantification and issues unique to CO_2–brine mixtures.

- Improvement of methods for joint data collection and interpretation from different monitoring technologies.

6.4 Above Zone Monitoring Interval(s) (AZMI)

An AZMI is a selected permeable zone, within or above the confining system, that is expected to be hydrologically isolated from pressure and fluids in the injection zone (Figure 6.1). The AZMI should be selected based on risk assessment, so as to detect leakage signals if features such as wells, faults, and fractures are or become transmissive, and before impacts to USDW or other environmental concerns become an issue. The monitoring instrumentation deployed in this zone should be site specific and fit-to-purpose. For Class VI purposes, AZMI are below the USDW, unless a waiver to inject above the lowermost USDW has been granted, since RR shallow zones closer to the land-surface reporting horizon may be more valuable.

With regard to AZMI monitoring methods and research needs, the discussion group felt there was much overlap between the objectives of groundwater protection and greenhouse gas reporting. For the sole purpose of greenhouse gas reporting, the AZMI could be conceptually combined with the injection zone, since only emissions to the atmosphere would be of concern. It is within the AZMI that monitoring is perhaps most important—it is the last line of defense.

6.4.1 Key Issue 4: Monitoring within the AZMI—best approaches and sensitivity

Discussion

Above-zone pressure monitoring may be a promising method for detection of brine leakage and quantification of CO_2 leakage. Modeling studies have shown that the pressure response in the AZMI depends on hydrologic properties (including lateral boundary conditions, confinement by overlying confining bed, thickness, permeability, storativity), the leakage rate of the fluid, and the distance between the monitoring point and the leak (Chabora and Benson, 2009; Nogues et al., 2011). Meckel and Hovorka (2010) suggested that triangulation of pressure measurements could be used to locate the leakage location. Detection methods could also employ combinations of geophysical and geochemical techniques to test for allochthonous brine and/or CO_2 accumulation. The placement and spacing of wells would vary, depending on site-specific hydrologic conditions and the monitoring tool(s) deployed.

Although some members of the breakout group were enthusiastic about the potential of the AZMI approach, only limited field testing—e.g., geochemical monitoring at the Frio site (Kharaka et al., 2006) and pressure monitoring combined with other methods at the Cranfield site (Meckel and Hovorka, 2011)—has been completed, and moderate amounts of generic modeling has been conducted (Chabora and Benson, 2009; Nogues et al., 2011). AZMI has been widely used for many

decades to monitor the performance of gas storage reservoirs, which provides valuable background for its use in CO_2 sequestration.

The extent to which fluids could move through the AZMI without changing pressure requires assessment. The case in which an abandoned well fails in a zone not hydrologically connected to the AZMI should be considered, because it creates a scenario in which flow bypasses the AZMI, and a CO_2–brine leak would not be detected there. A similar case for fault-zone flow bypassing the AZMI should be considered. In addition, the hydrologic impact of penetrations in the confining system overlying the AZMI, for example by wells with open-rock-casing annuli, should also be considered.

Note that AZMI wells in general will be single-phase (water-well) systems, for which standard hydrologic instrumentation could be adapted. After development, the wellbore will be filled with a single-density fluid, and reasonable measurements of bottomhole pressure can be obtained by water-level measurements. Characterization of the AZMI can rely heavily on hydrologic test programs (drawdown and recovery, slug and recovery, multi-well interference, etc.) that are well-known to EPA regional regulators from other underground injection programs (UIC)—for example, those involving Class I wells. It is also possible to develop AZMI in hydrocarbon production zones overlying the CO_2 injection zone. In this case, active production of fluids will increase the sensitivity of geochemical programs, but decrease the sensitivity to pressure measurements. Use of AZMI for mitigation via pressure control was discussed. One example is water injection, thereby increasing pressure to form a water "curtain" with higher pressure, which would prevent CO_2 migration.

Research Needs

- Testing value and best practices of AZMI through modeling linked to field validation.

- Clarification on the definition of the AZMI (which horizons are included), and other terms relating to storage, confining zones, etc.

- Understanding the importance of monitoring pressure/other properties across multiple zones.

- Quantification of seismic responses to small CO_2–brine accumulations in the AZMI.

6.4.2 Key Issue 5: Brine and CO_2 can change chemistry along leakage path—reactive transport can confuse source term (Key Issue 1) of contaminant

Discussion

Fluids are essentially never transported unaltered from the injection zone to a USDW. If the nature of the changes occurring during transport is not correctly considered, the leakage source term will be estimated improperly, and both gas and brine leakage might be wrongly assessed. The risk profile could be changed by changes in fluid composition during migration.

At a minimum, CO_2 will change state from supercritical to gas, which is a complex process. Heavier organic compounds dissolved in supercritical CO_2 become immiscible and precipitate. Light compounds such as methane and benzene remain dissolved in the gas phase. As pressure decreases, gases dissolved in brine will be exsolved as free phases. Profound changes in fluid chemistry could result from the interaction of supercritical CO_2, brine, or brine plus dissolved CO_2 with rocks and formation fluids as they migrate along flow paths, while pressures and temperature change. In the AZMI, the volume ratio of rock and formation to migrating fluid during leakage would be higher than in the injection zone, so interaction effects could be increased. If there were any organic constituents in the CO_2 migration pathway, they could be dissolved by leaking supercritical CO_2. Black shales are common in sedimentary basins, as are coals and lignites; the nature of rock–CO_2 interaction with these rock types is not well known.

In some basins, methane is commonly near saturation in brines through large regions. It is hypothesized that CO_2 leaking into these brines will dissolve and in turn cause methane to be exsolved and enter the gas stream. This hypothesis, however, has not been tested through modeling, laboratory, or field experiments, other than recent results at the SECARB Cranfield DAS site (Hovorka, personal communication). If this occurs to a significant extent, the gas transported through leakage pathways would become strongly enriched in methane. Methane is a significant gas under a leakage scenario, because it is more detectable than CO_2, it is a more effective greenhouse gas, it leads to strong reduction, and it can be explosive at higher concentrations.

Research Needs

- Scoping study to assess significance of reaction of injection zone brines and supercritical CO_2 with rocks and fluids in the overburden (modeling and batch reaction experiments using rocks from diverse basins).

- Understanding geochemical reactions of CO_2 in organic-rich shales, especially with regard to damage of seals.
- Experimental determination of mobility and partitioning of organic compounds in supercritical and gas-phase CO_2, as well as in multiphase solutions (e.g., oil/gas/CO_2–brine/constituent of concern)
- Evaluation of the implications for monitoring during the transition of CO_2 from supercritical to gas phase.
- Interaction of CO_2 with various rocks along the leakage pathway (reservoir and overburden)
- Improvement of geophysical resolution and detection of CO_2-brine leakage.

6.4.3 Key Issue 6: Detection of leakage in preferred pathways (fault/fracture zones)

Discussion

The issue of leakage from the injection zone through fault/fracture pathways in the confining system could be placed in either the injection zone or the AZMI discussion; however, such leakage is likely to be detected in the AZMI. Substantial investment has already been made in detection and characterization of faults and fractures, because of the economic value of such information for hydrocarbon resource recovery. A wide variety of techniques are therefore available to map such features and assess their hydrologic functions. However, detection and characterization of faults and fractures also have widely recognized limits. Direct detection in cores is limited by the small volume of sample relative to the volume to be characterized. Seismic detection is limited by properties of materials and offsets of reflective horizons. Hydrologic detection is limited by the duration of the typical test periods and the magnitude of the pressure change induced by pumping/injection tests, which are generally much shorter and have less fluid than the actual CO_2 injection. Additionally, as pressure changes, the hydrologic properties of fractures can change.

The group recognized the need to monitor the performance of faults and fractures during injection. Conducting surveys to detect accumulation in secondary reservoirs is one of the recommended monitoring methods; this can lead to a pressure signal, a seismically imageable bright spot, or a geochemical change. The success of each of these methods can be enhanced by thorough characterization, correctly targeted modeling of the system response, and appropriate deployment of monitoring systems. Time-lapse measurements can greatly increase the sensitivity of detection for each of these methods. It may also be easier to detect CO_2 in shallower zones. If CO_2 is present as a gas, seismic detection is enhanced over the same mass compared to it being a supercritical fluid. Increased volume of gaseous CO_2 compared to the same mass of supercritical CO_2 will also create a

stronger pressure signal, if it displaces original formation fluids (although the pressure may be reduced by increased storativity). Increased solubility of CO_2 in less saline water and faster lateral flow will increase the size of geochemical perturbations, and increase geochemical detectability.

How fracture zones are connected to secondary reservoirs is cause for uncertainty. Models assuming idealized communication between fracture leakage pathways and secondary reservoirs (e.g., Nordbotten et al., 2009) may lead to false interpretations, because fractures can have skin effects or mineralization that limits their connectivity to the matrix. Capillary entry pressure into pore systems may also favor flow remaining in larger aperture pore system in the fractures.

Methods to detect displacement of one fluid by another, which would indicate whether fractures or fault zones are transmissive, are desired to increase confidence in monitoring. Detection of the active part of a fracture or fault zone would also be needed—for example, to design mitigation approaches. Geophysical techniques need to be more sensitive to fluid substitution within a fracture zone if used in time-lapse measurements; however, this has only rarely been documented (Gritto et al., 2004; Majer et al., 1997). Fluid substitution would only be relevant if CO_2 replaced brine; the important case of brine leakage caused by elevated pressure would not be easily detectable, because brine replaces a fluid of similar geophysical properties.

Microseismic hypocenter location is commercially used to track induced fracturing (e.g., in hydraulic fracturing, steam floods, and geothermal stimulation), and is studied as something that could be useful in assessment of geomechanical processes during CO_2 injection. Recent studies have attempted to identify fracture opening events from fracture closing events (Baig and Urbancic, 2010). In principle, microseismic monitoring has two uses: (1) to improve understanding of subsurface processes, and (2) to detect geomechanical damage to the reservoir and confining system. However, application of this technique to injection below fracture pressure, as would be required under the Class VI[2] regulation, has received only limited study (Rutledge, 2009; Zhou et al., 2010). More studies are needed to assess the significance of microseismic signals from the reservoir and confining system during subfracture pressure injection. In addition, a better understanding of the use of microseismic events as an indicator of damage to the confining layer is needed. Note also that public perception is a key factor with any seismicity induced by a fluid injection project, particularly in seismically active

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[2] § 146.88(a) of the Class VI rules requires that: "Except during stimulation, the owner or operator must ensure that injection pressure does not exceed 90 percent of the fracture pressure of the injection zone(s) so as to ensure that the injection does not initiate new fractures or propagate existing fractures in the injection zone(s). In no case may injection pressure initiate fractures in the confining zone(s) or cause the movement of injection or formation fluids that endangers a USDW."

areas such as California. Open and transparent reporting of seismicity is expected to be an important attribute of a monitoring program.

Fault and fracture discontinuities are key features in geomechanical studies (Zoback, 2008). Typical site characterization requires additional information to understand the geomechanical and possible geochemical response of fractures to increased pressure and changes in fluid composition. While the role of fractures in a new site is difficult to characterize, information about fracture response is needed to develop management, intervention, and mitigation plans, as well as better ongoing characterization guidance. Integration of monitoring with fracture flow modeling is an area of limited studies (e.g. Daley, et al, 2006). If fluids move to shallow zones and significantly elevate pressure there, they produce distinctive surface elevation patterns that can be detected by an array of technologies, including statellite-based methods such as InSAR, GPS, as well as surface and downhole tilt (e.g., Vasco and Ferretti, 2005; Vasco et al., 2008). This surface deformation can be interpreted for fracture properties. Gravity could also be a tool for detecting shallow gas accumulations related to preferred pathways, as could various seismic and electrical methods.

Research Needs

- Theoretical, lab and especially field studies to better understand and interpret microseismicity (particularly under subfracture pressures). High-resolution borehole monitoring could be an effective tool to study microseismicity at low levels.
- Improvement in seismic detection and imaging of gas-filled fracture zones. Field testing is needed, especially at supercritical conditions.
- Development of methodologies to predict the potential for induced seismicity, based on the history of the basin as well as known faults.
- Improvement of methodologies for determining the current stress state.
- Application of geomechanics and deformation in leakage monitoring.
- Optimization by joint or staged use of geophysical methods.

6.5 USDW monitoring for groundwater protection

Discussion

The breakout group ran low on time for complete discussion of the best approaches, roles, value, needs, and purposes of monitoring in the USDW. Some members of the group were strongly influenced by the requirements for geochemical monitoring in the USDW as required in the regulation

for Class VI wells[3]. The ensuing discussion focused on how many wells are needed, how they should be sited and completed, how they should be sampled, and what would be the minimum list of analytes that should be required. In this case, the past quality assurance experience of various EPA programs comes into play.

Other members of the breakout group argued that once CO_2 or brine entered a USDW, it would be "too late." This group recommended more focus on monitoring in deeper horizons, to allow for intervention and mitigation prior to any damage to water resources. One group member was less concerned with damage to USDWs, arguing that natural analogs and oilfield analogs suggest that health, safety, and environmental concerns should be localized and moderate. Several group members were pessimistic about success in detecting and (especially) quantifying leakage of brine, CO_2, and/or other reaction products into USDWs. Very recent results indicate potential for geophysical detection of CO_2-saturated groundwater via changes in electrical properties (Dafflon et al., 2011)

Detection may be conceptualized very simply; however, a variety of interferences can complicate the monitoring environment and swamp even clear leakage signals. Interferences include (1) complex natural processes—e.g., recharge and upwelling of various natural waters that interact with rock, sediment, fluid, and biologic systems; (2) historic strong perturbations of the USDW—e.g., from pumping, land use, and contamination; and (3) other natural perturbation of the USDW system during the long injection and post-injection period—e.g., climate change influences on hydrologic systems, natural or purposeful recovery or additional damage not related to GS, land-use changes. The issue of the role of baseline measurements (further discussed below) also enters into this discussion.

Three risks to water are noted: (1) damaging contamination of USDW by brine from depth, which may contain hazardous substances, (2) contamination of USDW by CO_2 and hazardous substances in the gas, and (3) contamination of USDW by reaction of gas with aquifer rocks or fluids *in situ*. Monitoring for each of these may require a somewhat different approach.

Pressure (often termed hydraulic "head" in shallow studies) can be an important monitoring parameter. A confined aquifer could respond to leakage with detectable pressure changes. Classic contaminated-

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[3] In particular, §146.90(d) of the Class VI rules requires that monitoring, at a minimum, include "Periodic monitoring of the ground water quality and geochemical changes above the confining zone(s) that may be a result of carbon dioxide movement through the confining zone(s) or additional identified zones including: (1) The location and number of monitoring wells based on specific information about the geologic sequestration project, including injection rate and volume, geology, the presence of artificial penetrations, and other factors; and (2) The monitoring frequency and spatial distribution of monitoring wells based on baseline geochemical data that has been collected under § 146.82(a)(6) and on any modeling results in the area of review evaluation required by § 146.84(c)."

site up-gradient/down-gradient measurements could have value and would require information about pressure heads.

The group discussed several philosophies with respect to monitoring of geochemical parameters. Some members felt that direct measurement of CO_2 (via pH, DIC, headspace gas) and TDS would meet the major needs. Others argued that reaction products (e.g., alkalinity, cations) were needed to capture rock–water CO_2 reactions. A third group suggested a fluid mixing and reactive transport approach in which the composition of the source term (i.e., leaking fluid) is compared against *in situ* reaction components by sampling of rocks and end-member (native and leaked) fluids. (See Key Issues 1 and 2 for injection-zone source terms.) A fluid mixing and reactive-transport approach would be useful in deciding the type of remediation required, depending on whether the constituents of concern were transported from depth or generated *in situ*.

Sampling methods appropriate for USDWs are generally simpler than sampling methods for deep brines. However, even in shallow systems, methods for sampling intact gas are still challenging. Methods to place slim or direct push wells are also fairly well known. The need to drill and/or develop wells using methods to reduce contamination (e.g., tagging workover fluids, producing until field parameters stabilize) was discussed.

Methods that could be used in monitoring USDWs, other than measuring changes to fluid chemistry, include electrical conductivity tools (Dafflon et al., 2011), and the same suite of geophysical methods described for the AZMI (gravity, geomechanics, electrical, seismic methods). Many of these methods are not well developed for use in shallow environments; technology transfer from the substantive investment in deep environments might be valuable. For example, the extensive deployment of 3D seismic imaging for oil and gas exploration is almost entirely focused on depths below 500–1000 m. This technology needs modification to be applicable to monitoring the 10–1000 m depths of most USDW. Until costs are reduced by technology improvements, 3D seismic will likely be prohibitive for the large-scale USDW monitoring necessary for commercial-scale sequestration. Other approaches include ground-based surveys, soundings, and airborne conductivity surveys (e.g., Paine, 2003), which have been well demonstrated for leakage assessment in flood water and natural salinization problems. These tools can be combined with magnetic surveys to locate well casings. In general, airborne-based methods seem promising. Other types of remote sensing should also be explored.

The breakout group discussed the value and use of several different types of tracers. Consensus was reached that CO_2 itself may be considered a tracer, especially if its $C^{12/13}$ signature is unique.

Consensus was also reached that pervasive tagging of all CO_2 with unique tracers is undesirable, given the limited number of suitable tracers. It is well-known from groundwater work that overuse of tracers can degrade its value as a unique signal. In addition, many tracers are strong greenhouse gases, although otherwise benign. Tracers should be developed and deployed for cases where additional data are needed to diagnose the nature of a problem. There are needs for both brine and CO_2-soluble tracers. However, gas-soluble tracers that travel with CO_2 may not be carried if the CO_2 dissolves in water. Fractionation and sorption of tracers in the multiphase fluid-rock-organic system of interest are poorly known.

Research Needs

- Development of best-practice guidance and methodology to identify the appropriate combination of site-specific geochemical measurements
- Identification of trace metals that could be released due to CO_2 leakage. Techniques used should include isotope suites (e.g., strontium).
- Development of tracers and methodologies for monitoring based on lab tests linked to field trials. Need inventories of tracers, with information about environments where they are more or less conservative.
- Development of geophysical tools for shallow groundwater, including using technology deployed for deep reservoirs. Need to find and improve geophysical monitoring tools for mapping at some distance away from boreholes. Need to develop more cost-effective seismic monitoring (e.g., Majer et al., 2006). Further research on downhole sensors is needed.
- Improvement of isotopic analyses of CO_2 sources.

6.6 USDW monitoring motivated by greenhouse gas reporting

Discussion

The group briefly discussed the value of USDW monitoring in complying with greenhouse gas reporting. At times, it may be hard to satisfy the greenhouse gas reporting expectations of annual mass accounting (at a relatively small margin of error) with the methods and concepts available to track and estimate processes in the subsurface. Reporting of leakage for greenhouse gas accounting is focused on return of sequestered CO_2 to the atmosphere, and not on the movement of CO_2 outside a subsurface confinement system. The point of applicability for the EPA greenhouse gas reporting rule is thus at the soil/atmosphere interface. The UIC Class VI rule may also require "surface air monitoring and/or soil gas monitoring to detect movement of carbon dioxide that could endanger a

USDW."[4] This is a difficult measurement point, because of the high temporal and spatial variability of surface leakage (leakage tends to be focused in small spots) (e.g., Lewicki et al., 2007; Lewicki et al., 2009). Further, this interface is the peak zone of biologic activity, which provides a highly variable respiration/photosynthesis signal. To isolate low or moderate leakage signal at this interface is difficult, and cannot be accomplished in most areas with simple measurements of CO_2.

Subpart RR EPA's Greenhouse Gas Reporting Rule requires annual reporting (as well as quarterly data collection and record retention in some cases). However, the confining system that protects a USDW is at depth. Should CO_2 migrate above the confining system, the confidence in long-term retention of CO_2 is significantly reduced, yet the travel path from depth to the surface could take decades or centuries.

Research Needs

- Evaluation of the attenuation potential of shallow horizons; i.e., would CO_2 migration into AZMI mean that it would eventually reach the surface? Under what circumstances could a USDW system attenuate or eliminate atmospheric leakage even if the deep containment system were to fail? This is important for developing crediting schemes.
- More studies of sampling strategies that will help assess the complexity of near-surface environments

6.7 Additional discussions

6.7.1 Role of baseline monitoring

Discussion

Most group members agreed that baseline monitoring prior to CO_2 injection start was essential, with some finding this so important that (in their opinion) a project could not be operated as a CO_2 storage site if a suitable set of baseline data were not collected. Time-lapse data have been used with excellent results in seismic surveys at Sleipner, Norway, and Weyburn, Canada (e.g., Chadwick et al., 2009). The absence of a high quality pre-injection seismic survey at the In Salah site, Algeria, has been an impediment to interpreting fracture flow. Geochemists also require a baseline time-series of geochemical measurements, which must include all the "right" data. Most participants agreed with the statement "Baseline is necessary but not sufficient."

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[4] §146.90(h)

One member of the group contested the breadth of the statements valuing baseline, noting that a strong reliance on measurement of change may result in an inconclusive monitoring program, for the following reasons: (1) change can occur unlinked to injection—in seismic monitoring, unlinked changes referred to as static error are known to degrade the value of time-lapse geophysics significantly (e.g., Al-Jabri et al., 2010); (2) for other tools, a series of corroborative measurements may be needed to determine whether the measured change is a result of leakage. These corroborative measurements may best be made after an anomalous measurement is observed (no baseline for follow-up measurements). It is impossible to make baseline measurements precisely where an anomaly occurs, because the location of occurrence is unknown. After detection of an anomaly, a comparison between the impacted area and adjacent nonimpacted areas can help in understanding the origin of the anomaly—for example, through developing mixing lines. Monitoring techniques that are not reliant on high-quality baseline data would be useful.

Site characterization is commonly conducted together with baseline measurements. However, it is important that these two goals are not confused. Proper site characterization and baseline data gathering on dynamic components, with full quantification of uncertainties of measurements, should drive the monitoring program. If a measurement uncertainty were to have a significant impact on meeting site performance goals, it should be a focus of any risk assessment. Note that this is a different statement than "the project proposer thinks that the site will leak at a named feature," which could cause the regulator to deny permits for the project. However, recognizing that an error stemming from a well-justified assumption might cause the project to fail can ultimately help to avoid failure. For example, it is likely that many project investigators would test the quality of a site's seal, via samples, logging, and pressure communication tests, at some point in the project. Then, any assumptions about the seal would be made and justified based on correlations and seismic interpretations over an area, over a duration, and over a pressure range. Some uncertainties in this assumption are acknowledged, and the monitoring plan would be devised so that these uncertainties were reduced over time. There is widespread agreement that it is possible to increase confidence and update the model during project development by continued site characterization over the lifetime of the project.

Research Needs

- Improved understanding of developing site-specific baseline monitoring needs, including the spatial and temporal sampling required.
- Better conceptualization of the evolution of a project, with exploration of a wide variety of unexpected scenarios and consequences regarding monitoring and mitigation. Model-based

theoretical scenarios will illuminate the key elements of baseline measurements that should be well established prior to the start of the project, as opposed to other types of monitoring that may be triggered by anomalies.

6.7.2 Mitigation

Discussion

Mitigation was considered a separate topic from monitoring, though there is some overlap, since monitoring is needed for the design of mitigation methods and the testing of mitigation success. Mitigation was not discussed in depth, because multiple attendees were at a recent CCP workshop on assessment of needs for mitigation. Some highlights of that work specific to EPA were reviewed.

Several definitions of terms involved in mitigation were discussed. One example is *active reservoir management*, which describes actions taken prior to any leakage. Reservoir management is referred to as *risk mitigation*. This seems to be different from mitigation in the sense of actions taken after leakage has occurred. As an example, the planned water extraction at the Chevron Gorgon project (see http://www.zero.no/ccs/projects/gorgon) was debated as an example of reservoir management and/or risk mitigation. *Intervention* was proposed as an alternate term for short-term actions immediately following detection of leakage. *Remediation*, which describes repair of environmental damage, was also discussed. Some group members proposed that toxic organics from oil were contaminants that could result from CO_2 leakage, for which mitigation is essentially impossible.

Mitigation of leakage through faults and fractures is difficult, and intervention techniques require further research. The research needs for this topic overlap with those of monitoring mentioned earlier (Key Issue 6). Abandoned wells were discussed briefly as a key target for monitoring and mitigation (see also discussion from the breakout group on Wells as Leakage Pathways). The feasibility of a no-action response to leakage was briefly discussed. In the case of a leakage pathway that could not be repaired, the question was raised whether the installation of atmospheric monitoring devices would be sufficient.

Assessment of the difficulty and cost of intervening and mitigating leakage through the geologic system reinforces the need for monitoring and characterization, because mitigation may be very expensive and problematic. The possible need for mitigation over a time scale much longer than the injection period was discussed. Some breakout group members believe that leakage risk increases over time.

Research Needs

- Improvement of response plans for the case in which an unexpected measurement is made during monitoring. A well-designed monitoring system should have predetermined thresholds that trigger follow-up investigation. Subsequent examination should be conducted to confirm that the measurement is accurate and to further diagnose the mechanism and location of leakage.
- Further investigation of mitigation, intervention, and remediation options for leakage cases.

6.8 Other recommendations

- Development of standardized terminology, with commonly used definitions, for important zones of monitoring with respect to the confining system.
- Lowering the cost of wells that can be used for both geophysical and geochemical measurements (e.g., Majer et al., 2006).
- Development of more cost-effective monitoring approaches.
- Monitoring planning has not comprehensively accounted for the monitoring-program response to an anomalous measurement. A method for selecting and optimizing a full range of remedies is needed, and a budget must be planned for such contingencies. A balance should be sought between (1) an exhaustive program that attempts to anticipate every measurement that might be needed and (2) an underprepared program that is not able to interpret monitoring results. For example, how do you find a leak source if you find a secondary accumulation?

6.9 Conclusions

Monitoring covers the entire range of activities associated with geologic storage of CO_2. It is only through monitoring that we can have confidence in our conceptual understanding of subsurface processes. While there have been many notable successes in monitoring (which leads to our confidence in sequestration), there are many advances to be made as sequestration grows in scale. For regulatory purposes, definitions of the zones being monitored will aid progress in development of tools for each zone. Development of site-specific monitoring strategies is needed, and will likely develop with growing commercial-scale application. Needs for development of specific monitoring tools vary with the tool and the application. For example, seismic monitoring of deep gas accumulations is fairly well developed by the oil and gas industry, but further work is needed on the quantification of CO_2–brine mixtures, including basic petrophysical measurements. Other geophysical tools, such as electro-magnetic (EM) surveys or gravity, have promise but require field testing.

Integration of different geophysical tools holds promise for improving quantification. Geochemical sampling is key for understanding mobilization and migration of contaminants from source rocks, and such sampling requires research development in both monitoring technology (especially deep well sampling) and fundamental reaction and transport processes for CO_2–brine mixtures.

7. Breakout Topic 4: Wells as Leakage Pathways

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7.1 Introduction

Potential leakage from wells is one of the key risk elements in any analysis of the long-term safety and efficacy of geologic sequestration (e.g., FutureGen 2007; EPA 2010). The risks associated with wellbore leakage include loss of carbon credits, degradation of underground sources of drinking water (USDWs), degradation of natural resources (oil and gas reservoirs), loss of productivity of agricultural lands, negative impacts to ecosystems, and harm to human life. In any given project, some of these risks may be negligible. One of the most consistent concerns is the potential for CO_2 or brine leakage resulting from CO_2 operations to impact drinking water resources.

Well leakage pathways involve failure of one or more barriers that are designed to isolate the CO_2 storage reservoir from the surface. Within the well, failure of packers, tubular joints, and hydrostatic imbalance can result in leakage in operational wells; failure of cement plugs can lead to leakage in abandoned wells. External to the well, failure of the cement sheath or the steel casing can allow fluids to escape from the reservoir. The leakage path is not necessarily an obvious single point of failure and may involve a circuitous path through many wellbore elements or via cross-well flow. In addition, wells provide isolation through an elongated length of steel, cement, and packers, and any small element of these can act as a barrier to leakage.

There are significant research efforts directed toward well integrity occurring in a number of organizations. The CO_2 Capture Project (http://www.co2captureproject.org) has sponsored research on field performance of wells exposed to CO_2 and on experiments and computational studies of wellbore integrity (e.g., Crow et al., 2010). The IEA Greenhouse Gas R&D Programme (http://www.ieaghg.org) sponsors a Wellbore Integrity Network that has met every year since 2004. This international group acts as a forum for communicating the latest research results, developing research agendas, and fostering collaboration. Reports summarizing the annual meetings are available on the website. In addition, the IEA GHG sponsors research studies. The Department of Energy sponsors a number of different research activities at several National Laboratories, including NETL, LANL, LBNL, LLNL, and PNNL. Some of this work is conducted within the National Risk Assessment Program (NRAP), which aims to develop quantitative risk measures of wellbore leakage mechanisms. In addition, there are a number of universities that have been active in wellbore issues,

including Princeton University and the University of Texas. All of the major oil companies have well-integrity divisions that have valuable experience to contribute to this research problem, and BP and Chevron have been particularly active in the sequestration community. Among oil service companies, Schlumberger is particularly active in CO_2-specific well-integrity issues. Finally, there are several risk analysis companies who have been developing CO_2-specific well-integrity analyses, including Quintessa, Oxand, and DNV.

Research in the wellbore-integrity community has been oriented toward solving the following questions:

1. What is the frequency with which wells fail and leak fluids?
2. What is the rate of fluid flow in leaking wells (effective permeability and proximity to the injection well)?
3. What factors or practices correlate with increased risk of well-integrity failure?
4. How does CO_2 reaction with cement and steel impact long-term well integrity?

These questions have been examined in field studies of wells with a history of CO_2 exposure in both CO_2-EOR and natural CO_2 reservoirs (Carey et al., 2007; Crow et al., 2010). These have focused on determining whether there is evidence for CO_2 migration, analysis of material integrity, and measurement of effective permeability of wellbore systems. Other field surveys have focused on developing an understanding of the frequency and severity of well-integrity failure events, including Watson and Bachu (2007, 2008), Jordan and Benson (2008), and Duncan et al. (2009).

There have been a number of experimental studies on the behavior of wellbore materials on exposure to CO_2. Much of this work has focused on carbonation of cement, including the studies of Kutchko et al. (2007, 2008, 2009), Duguid and Scherer (2010), and the Schlumberger group (Barlet-Gouédard et al. 2006, Rimmelé et al. 2008, Fabbri et al. 2009). Corrosion of steel in wellbore environments has received less attention, but includes experimental studies by Carey et al. (2010) and Han et al. (2011b).

Computational studies of wellbore leakage have examined scales ranging from cumulative potential leakage from a large region of wells to the details of cement-CO_2 reactions. Nordbotten, Celia, and others (e.g., Gasda et al., 2004; Nordbotten et al., 2005; Nordbotten et al., 2009; Celia et al., 2011) have developed a semi-analytical model of wellbore leakage that has been applied to numerous wells as part of a hypothetical sequestration project with an assumed probability distribution of effective permeability values. The model allows calculation of the cumulative loss of CO_2 from the storage

reservoir, but lacks validated values for permeability. Similar calculations have been conducted within a risk-assessment framework, in which multiple realizations are used to develop a probability distribution of potential leakage (e.g., Viswanathan et al., 2008; Stauffer et al., 2009; Oldenburg et al., 2009). Computational models for cement carbonation at the small scale have been developed by Carey and Lichtner (2007), Carey et al. (2007), and Huet et al. (2010). Corrosion modeling in sequestration systems has been described by Han et al. (2011c). Relatively little work has been done on two-phase flow in the wellbore system (e.g., Carey and Lichtner, 2011).

In examining the current body of work, the goals of the wellbore-integrity research community are oriented toward determining the likelihood and magnitude of CO_2 leakage from *existing/older* wells that occur in the Area-of-Review. The focus has not been on purpose-built geologic sequestration wells, which are generally viewed as having significantly lower risk than older wells that were constructed without any forethought toward CO_2 sequestration. Viewed in this way, the research has been geared toward determining whether regions of oil and gas exploration, and depleted oil and gas fields in particular, would be suitable for geologic sequestration. These areas have the advantage of relatively well-known reservoir and cap-rock properties, but may have tens to thousands of pre-existing wells within the Area-of-Review.

In the following pages, we discuss the results of a group discussion on the current state, future directions, and recommendations for wellbore integrity research relevant to the Environmental Protection Agency. The group discussion focused on well-integrity issues in the context of the EPA 40 CFR "Federal Requirements Under the Underground Injection Control (UIC) for Carbon Dioxide (CO_2) Geologic Sequestration (GS) Wells," as well as the draft guidance document "Draft Underground Injection Control (UIC) Program Class VI Well Construction Guidance for Owners and Operators." The discussion was open and free ranging, which allowed the participants to brainstorm on issues and research directions.

In the following, we summarize the major discussion topics during the two days of the workshop.

7.2 Key Issue 1: Definition of well failure

Discussion

The participants found a difference between the definitions of well failure used by the wellbore-integrity community and that used in the EPA guidelines. The EPA guidelines for wellbore integrity are based on preventing deleterious impacts to USDW. However, wellbore integrity is defined as zonal

isolation of CO_2 to the storage complex regardless of impacts. Damage of USDW by leaking wells necessarily requires failure of zonal isolation; on the other hand, failure of zonal isolation does not necessarily imply damage to USDW, because leakage could occur directly to the atmosphere or USDWs may be absent.

Much wellbore-integrity work has focused on the need to determine the effective permeability of the wellbore system[5] through field measurements (e.g., Crow et al., 2010) and laboratory studies (e.g., Carey et al., 2010; Newell et al., 2010; Huerta et al., 2011) as a basis for numerical studies of wellbore leakage in risk assessment studies (e.g., Celia et al., 2011, Viswanathan et al., 2008). The results of these studies lead to estimates of CO_2 and brine flow as a function of wellbore permeability, and the pressure and saturation conditions in the CO_2 storage reservoir. These flow rates can then be used to assess impacts on USDWs. Thus, there is no direct connection between much of the existing literature on wellbore integrity and the EPA requirement for no impact to USDW.

We note that at present, there are no data on the *effective permeability* of flow external to the casing from the reservoir to receptor. There is a measurement of a 3 m section of the external annulus from a well in a CO_2-producing field that is in the range 1–10 mD (Crow et al., 2010; Gasda et al., 2011).

There are some data on the effective permeability of internal well annuli derived from studies of sustained casing pressure in Gulf of Mexico wells. Huerta (2009) studied two wells, the first of which showed a permeability of 0.1–5 mD, the second 140 mD; Wojtanowicz et al. (2001) found permeabilities of 0.001 and 0.0028 mD in two wells; Xu and Wojtanowicz (2001) found permeabilities of 0.40 and 0.94 in two other wells. Tao et al. (2010) also found permeabilities due to SCP within this range.

The group found that the EPA rule does not require "zero leakage" of wells, and thus presumably a sequestration project could be in compliance as long as USDWs are not impacted. This will require difficult decisions from EPA Project Directors—whether federal, state, or local—as to what level of well-integrity and monitoring requirements are required.

Thus, a key research need is to determine the impact of CO_2 and brine leakage on USDWs. The National Risk Assessment Program (NRAP) is conducting research on this topic through a combination of field, experiment, and computational modeling. In addition, EPRI is sponsoring a field

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[5] Effective permeability of the wellbore system is defined by applying the Darcy flow equation to rate of fluid movement through the total wellbore annular area in response to a given pressure gradient from the CO_2 reservoir to the USDW or surface.

experiment in which CO_2-saturated water will be injected in one well and withdrawn in another well as part of a study to determine impacts of CO_2 on groundwater. These results will provide some insight into how to connect CO_2 emanating from a well to USDW impacts. However, at present the group is not aware of any direct observations or experiments of wells leaking CO_2–brine to USDWs.

Research Needs

- Resolve differing perspectives on the definition of wellbore integrity failure.
- Conduct more studies on effective permeability of both internal and external well annuli.
- Evaluate impacts of CO_2 and brine leakage from wells on USDWs.

7.3 Key Issue 2: Identification of wells in the Area of Review

Discussion

Abandoned wells are generally plugged, cut-off, and buried to depths below, for example, farming activities (10–50 ft). If these wells are not found using drilling records, steel-cased wells can generally be located using electromagnetic (EM) surveys. Hammack et al. (2006) conducted an EM survey at the Salt Creek field in Wyoming as part of a CO_2 flooding operation. The survey was able to locate 95% (133 of 139 wells) within the study area (the remaining six were discovered by ground surveys). In addition, the survey included the simultaneous use of methane detectors that discovered four significant leaks derived from well heads, pipelines, and separation facilities. This monitoring method has obvious applications to locating leaking wells, although the methane leaks observed by Hammack et al. (2006) were not associated with plugged and abandoned wells. The depth to which casing top can be detected with magnetometer surveys is ~100 ft below surface.

There is general acknowledgment that older abandoned wells (e.g., pre-1950) are more likely to have well-integrity problems, based in part on anecdote and intuition (e.g., Watson and Bachu, 2007), although we have found no references that directly demonstrate this result. Some of the potential problems of older wells are mitigated by the fact that they are generally shallower and therefore less likely to penetrate the CO_2 storage reservoir (e.g., Nicot et al. 2006).

Uncased abandoned wells and sidetrack wells cannot be identified by EM methods. The lack of casing means there is no EM signal, and the sidetrack wells are generally at greater depth than EM can detect. In both of these cases, it will be necessary to rely on drilling reports or other surface

evidence to locate the wells. We note that for properly plugged, uncased, abandoned wells, Watson and Bachu (2007) found a lower probability of leakage than for cased and abandoned wells.

Research Needs

- Methods for identification of uncased abandoned wells, and wells located at depths >100 ft below the surface (that are not detectable by EM)
- Determination of well construction features that increase leakage potential

7.4 Key Issue 3: Differential treatment of injection wells and wells in the Area of Review

Discussion

The EPA guidelines have different standards for injection wells and wells in the area-of-review (AoR). Injection wells must be constructed of CO_2-resistant materials and are required to have annual internal and external mechanical integrity tests (MIT). Wells in the AoR are subject only to the requirement that the operator "determine whether they have been properly completed or plugged." Thus, these wells do not need to be constructed of CO_2-resistant materials and do not require annual monitoring.

There are important differences between injection wells and AoR wells. Injection wells require more frequent monitoring and potentially the use of specialized, materials. In particular, well components in direct contact with the injection stream (e.g., tubing) should be CO_2 resistant, and internal MITs are necessary to ensure proper operation.

However, it is unclear why an injection well requires CO_2-resistant cement and corrosion-resistant external casing coupled with annual external MIT monitoring, whereas an AoR well does not. The external components of both well types can experience the same CO_2-brine (±oil) conditions. Thus, the risk of leakage along the external annulus is presumably the same. In addition, cement formulations are designed to meet a variety of well-engineering requirements, and a focus on CO_2 resistance may not result in the optimal choice and performance of cement.

The group also considered the question of whether repeated internal MITs could lead to eventual loss of well integrity due to pressure cycling. We are not aware of any research on the possibility of fatigue of well materials due to MITs, and suggest this as a research topic.

Research Needs

- Data on possible failure of well materials due to repeated MIT tests.

- Research comparing field performance of CO_2-resistant materials with standard Portland cement and carbon steel

7.5 Key Issue 4: Will all wells in the Area of Review require remediation or intervention?

Discussion

Current EPA regulations require the operator to determine whether any wells in the AoR require intervention. The group considered the question as to whether reviews of well records alone would be adequate to establish well integrity. Well completion and abandonment records document intended practices and do not necessarily demonstrate successful placement of cement or deviations from the original drilling plan. Bond or ultrasonic logs showing good cement coverage and cement-casing contact can be used to establish wellbore integrity, but are not sufficient to establish lack of leakage. (The sensitivity of these logs to leakage is not established.) During the operating life, an external integrity evaluation log (temperature/noise/tracer) can be used to assess leakage outside the casing (Thornhill and Benefield 1990, 1992). Lack of sustained casing pressure indicates a lack of problems in cemented internal (casing-casing) annuli, but not for the external annulus. Most wells appear to have never had external mechanical-integrity studies and thus do not have documented external integrity.

These considerations led to the question as to whether, in practice, all wells in the AoR must be entered and evaluated for integrity. Operators may adopt differing strategies: some may elect to enter all wells at the start of the project and (re-)abandon them with current methods; other operators may choose to wait for evidence of leakage or impacts before conducting remediation operations. The approach may also depend greatly on the discretion of the permitting authority. We recommend that more consideration of the criteria for determining whether wells pose no risk be made. This should include examples of evidence or procedures that can be used to demonstrate integrity, possibly obtained from new field studies or pilot studies arising from suggestions in this report.

Research Needs

- More development of diagnostic logging tools, and assessment of their sensitivities to detection of CO_2 leakage

- Criteria and methodology to determine whether and how to monitor abandoned wells in the AoR
- Research on criteria that ensure abandoned wells have very low probability of leakage

7.6 Key Issue 5: Monitoring of wellbore failure

Discussion

Monitoring annular pressure is already an industry standard or requirement, and provides continuous evaluation of potential leakage within the well. Internal-mechanical-integrity tests (tests of pressure tightness) are effective at demonstrating lack of leakage within the well. Monitoring of external mechanical integrity is much less common and is not generally a requirement, except in the rules for geologic sequestration injection wells (although pressure tests on casing shoes do test the external integrity of each cemented interval). These involve the use of acoustic, temperature, or radioactive tracer logs that can detect leakage (Thornhill and Benefield, 1990; 1992). There appear to be few studies that evaluate the sensitivity of external MITs or document results of external MITs (but see McKinley 1994). Other possible methods for monitoring the external annulus include soil-gas measurements near the well or water-well monitors near the well.

Research Needs

- Development of new, more sensitive monitoring tools, and assessment of their sensitivities to CO_2 leakage
- Criteria and methodology to determine whether and how wells (including, e.g., monitoring wells) should be monitored for wellbore integrity

7.7 Key Issue 6: Injection well standards

Discussion

MIT pressure tests may actually damage the wells. The American Petroleum Institute (API) has guidelines for predicting what pressures could lead to damage. Current regulations appear to require testing at pressures equal to or greater than injection pressure. These high pressures may not be necessary to establish leak-tight internal integrity. The EPA requirement also specifies that the operator maintain a high pressure on the external annulus surrounding the injection tubing unless the operator successfully argues that it may cause harm. This requirement may cause more problems through damage to the well than mitigation of any problem that might exist. Current rules for pressure

testing do not account or allow for the possibility of stimulation of the wells (to improve reservoir permeability) at still higher pressures.

The requirement for CO_2-resistant materials for the injection wells should be considered in light of evidence of decades-long performance of wells constructed of carbon steel and ordinary Portland cement. In the case of SACROC (Carey et al., 2007), the cement was partially carbonated due to CO_2 migration external to the casing, but the hydrologic properties of the cement appeared unchanged from noncarbonated cement. The situation for steel is less clear, as field studies have not shown evidence of corrosion. In one case, the well had cathodic protection (Carey et al., 2007), and in another, the well was without cathodic protection (Crow et al., 2010). However, recent experimental studies have shown that even carbonated Portland cement provides effective protection against corrosion (Han et al., 2011a). The requirement for CO_2-resistant materials in the external components of a well might be revised to allow for operator experience and demonstrated success in the handling and injection of CO_2, such as in CO_2-EOR fields.

Research Needs

- Data on magnitudes and modes of pressure testing (at pressures lower than injection pressures) that would be adequate to establish well integrity.
- Evaluate whether CO_2-resistant materials are necessary for injection wells

7.8 Key Issue 7: Long-term performance of wells

Discussion

EPA regulations are focused on the injection phase and prescribe a nominal period of 50 years of monitoring following injection. The question of establishing long-term performance (> 50 years) as part of site closure is not addressed by the regulations and is perhaps outside of the scope of EPA's authority. Nonetheless, the regulations imply that after 50 years of compliance, the wells will no longer pose a potential problem.

Long-term performance issues center on how long cement and steel will last in the subsurface. Even for a well that provides excellent integrity for several decades and has not been exposed to CO_2 or other reactive agents, it is possible that in the long term, cement may degrade to the point that it loses mechanical and hydrologic properties (e.g., degrades to an unconsolidated powder). Steel may slowly corrode and eventually be replaced by porous iron oxide or iron carbonate. In either case, well integrity may eventually be lost when considering time periods of hundreds of years.

Another concern is the impact of slow leakage. A well may seep CO_2 and brine at very slow rates that do not impact groundwater and are otherwise difficult to detect. With time, these leaks may worsen due to dissolution of cement or corrosion of steel, and eventually the leakage pathway may be enhanced. However, there is evidence of self-healing in wells by carbonate precipitation. Several field and experimental studies have shown calcium carbonate precipitation in cement fractures and decreases in permeability (Carey et al., 2007; Huerta et al., 2008; Huerta et al., 2011), a decrease in permeability of a simulated cement-rock interface (Newell et al., 2010), and deposition of iron carbonate scale at the casing-cement interface (Carey et al., 2010).

A third consideration in long-term performance is the slow plastic deformation of cap-rock materials and Portland cement under rock pressure. Ardila et al. (2009) and Williams et al. (2009) have demonstrated zonal isolation in an uncemented external annulus achieved by plastic creep of shale caprock. As a consequence, in favorable caprocks such as soft shales, salt, or evaporites, cap-rock deformation may seal wells over the long term. Portland cement is also subject to plastic deformation. Liteanu and Spiers (2011) have conducted experimental studies of creep and fracture closure in Portland cement as a function of confining pressure, finding that defects and micro-annuli in Portland cement could self-heal through material deformation.

Finally, decreasing storage reservoir pressures mitigates the risk of wellbore leakage in the long term. In the scenarios considered here, injection pressures decay over the long term to background levels before well integrity is lost due to material degradation. At that point, the only driving force for CO_2 leakage is buoyancy (there is no hydrologic gradient driving fluid into the wells). This lower driving force will limit the potential leakage rate. Moreover, drilling creates a disturbed zone adjacent to the well that modifies the near-wellbore permeability—known as the skin effect. The skin may modify the pore structure so that the capillary entry pressure is increased in the near-wellbore region as compared to the undisturbed reservoir. This may prevent gas from migrating into the well in the absence of a hydraulic gradient that can overcome the skin barrier.

Studying the long-term performance of wells poses several difficult challenges. Laboratory experiments provide guidance on wellbore material stability, but it is difficult to reproduce downhole conditions and to extrapolate short-term laboratory data to hundreds of years. It may also be difficult to predict well-scale behavior based on laboratory-scale tests. Field studies offer the most realistic investigation of well performance, but the oldest wells available for study are perhaps 100 or 120 years in age. However, the oldest wells are not representative of more modern construction practices

(e.g., since the 1950s) and so are not representative of the longevity of today's wells. Access to wells is also severely limited by the operators' willingness to disrupt field operations for research programs.

Research Needs

- More laboratory, field, and modeling studies to understand the long-term performance of wells
- More data on the potential impacts of slow CO_2 leakage on well materials

7.9 Key Issue 8: Steel corrosion and metallurgy

Discussion

Corrosion of steel in CO_2 sequestration environments has not received as much research attention as carbonation of Portland cement. At present, we have a computational model for uniform corrosion of carbon steel that allows prediction of steel survival as a function of CO_2 pressure and brine salinity (Han et al., 2011c). Much more work is needed to correlate the vast literature on steel corrosion with the unique conditions present in the wellbore (very limited fluid movement, high-salinity brines, high-pressure CO_2, and possibly microbial activity). The problem of localized corrosion has also not been addressed, and may be important in the corrosion-resistant systems recommended by the EPA Well Construction Guidance Document. There are also impurities in the CO_2 stream (e.g., SO_2, H_2S) that could enhance corrosion rates. Work by Han et al. (2011a) shows that cement provides corrosion protection even when it has been carbonated, but more work is needed to understand the corrosion potential for fluid migration along the cement-casing interface.

Research Needs

- Studies on corrosion of steel in environments relevant to CCS, including the role of (carbonated) cement in mitigating corrosion effects

7.10 Additional discussions

At a CO_2-EOR operation's end of life, it may be desirable to convert Class II wells used for CO_2-EOR injection to Class VI wells for CO_2 storage. The group briefly discussed this. The EPA rule outlines risk-based criteria for this process, which includes increased injection-zone pressure, an increase in CO_2 injection rates, decreased production rates, distance between injection zone and USDWs, the suitability of Class II AoR, the quality of abandonments in the AoR, a CO_2 recovery plan at the end of EOR, and CO_2 properties. The EPA rule explains that these criteria are to be considered

comprehensively for a conversion to Class VI. Site review of well histories for corrosion and casing pressure could inform the conversion process regarding the suitability of existing wells (material selection and placement) for Class VI service. Monitoring the wells for potential leakage will be a key part of integrity assurance.

The group also had a brief discussion of best practices for abandonment of wells. There is the potential for inconsistency where practices are specified for injection wells that have not been applied to observation wells or to pre-existing wells. Abandonment requirements could also be tailored to reflect whether the wells are within the CO_2 plume or only within the critical pressure line. The most secure approach to abandonment is to mill out a portion of the steel casing and to place a plug of cement across the rock face. However, it is difficult to mill out this region if there is cement behind casing, and thus the practice of cementing to surface may preclude this approach to abandonment. There may be some environments in which bentonite may be an effective sealant, although the potential for CO_2-induced desiccation of bentonite should be considered.

7.11 Research recommendations and priorities

There are many research needs in well integrity. During the discussion, the group identified a number of research recommendations associated with the above topics. We have divided these into short- and long-term recommendations.

7.11.1 Short-term recommendations

1. Conduct a study of EPA records of internal and external MIT results. This could build on earlier work by Koplos et al. (2007) and would use these results to determine the likelihood that a well would have integrity problems. The external MIT results would be particularly helpful, since there is little to no work published on external casing leakage. The internal MIT data could be compared to sustained casing pressure data (e.g., Wojtanowicz et al., 2001; Xu and Wojtanowicz, 2001; Huerta, 2009), as these are related phenomena.
2. Develop a concept paper for the use of EPA's Ada, Oklahoma, research field for the study of well integrity in the context of geologic sequestration. The Ada facility has a field installation of several wells (<200 ft deep) for testing of well integrity and has been used in the past to study the efficacy of external well-integrity methods (McKinley, 1994). A description of the facility and testing capabilities is given in Thornhill and Kerr (1993). The facility is not currently in use, but could be brought back into operation with an estimated investment of $50K. The concept paper would outline a proposal for modifying the Ada facility to conduct CO_2-specific well-integrity tests. The

facility could be used to study CO_2 leakage mechanisms, CO_2 leakage detection, and monitoring technologies.

3. Conduct a study of well work-over records from a CO_2-EOR field in collaboration with an industrial partner. The idea is to identify which work-over events were likely due to wellbore-integrity issues, and to use the records as a proxy for estimating likely failure rates for wells in potential sequestration sites. The ideal field site would be an older oil and gas field with a mixture of operating and abandoned wells that have never had CO_2. The operator's experience of putting CO_2 into the field would be an analog for sequestration operations.

4. Review records of abandonment practices. IEA GHG produced a report, "Well Abandonment Review," that provides a good starting point for looking at effective practices in well abandonment. This review could be expanded to a more U.S.-centric analysis. The results could guide analysis of project risk in determining which abandoned wells are likely to fail.

5. Leakage through casing threads has received little attention, although it may be responsible for the majority of sustained casing pressure events. A review of annulus leakage obtained from sustained-casing-pressure reports would provide insight into loss of tubing connection isolation.

6. There is an urgent need for research on the long term integrity of wells. This could involve a combination of laboratory, field, and computational studies:

    a. Laboratory studies of well-defect healing or defect widening (dissolution/corrosion dominance versus precipitation dominance) in casing-cement and cement-caprock interfaces, as well as cement fractures.

    b. Field studies surveying the oldest wells (>80 or 90 years in age) for material survivability under downhole conditions.

    c. Computational studies that extrapolate laboratory and field results to very long-term performance (>100 years). These could address the long-term durability of steel, the long-term durability of cement, and the long-term durability of steel-cement interfaces.

7. Review downhole monitoring and logging techniques for wellbore integrity, particularly as they are currently applied to Class I wells. Survey the techniques that are used (or required) and determine the sensitivity and uncertainty in identifying leakage pathways. Identify current research activities aimed at developing and improving these techniques.

7.11.2 Long-term recommendations

1. Our current understanding of the potential impacts is severely limited by the fact that we do not have observations of leaking wells. A "leaking-well field experiment" would provide a real-life laboratory for studying leakage processes. The following represent some approaches to creating a field laboratory:

a. Create a leaking well by pressurizing the annulus or inducing thermal cycles that damage the cement-casing and/or cement–cap-rock bond. Inject fluids with tracers to observe and quantify leakage and determine effective permeability.

b. Use a well with sustained casing pressure or a well that has failed external MIT tests to conduct controlled leakage experiments

c. Use the Ada, Oklahoma, facility as described above to conduct leakage experiments.

d. The Rocky Mountain Oilfield Testing Center (RMOTC) could be used as a field site for the study of more complex leakage pathways, such as fluids escaping to intermediate aquifers rather than the surface.

e. We also envision an ambitious field experiment: a double-blind study involving a number of wells (e.g., 10), only one or two of which leak. One group induces leakage in these wells; an independent group attempts to detect the leaks and determine groundwater impacts.

2. Develop a large-scale laboratory facility for the study of well integrity, with the purpose of testing detection tools (logging), impact of stress/strain on well integrity, and wellbore leakage mechanisms. This could involve construction and placement of a 40 ft well. The CO_2 Capture Project is interested in this concept and could be a partner in this endeavor.

8. Crosscutting Issues

Crosscutting issues were not explicitly discussed during the workshop, but review of Sections 4 through 7 immediately allows identification of a few overarching themes across the breakout sessions. One of the breakout topical areas, Monitoring and Mitigation, is in fact itself a crosscutting theme, having direct ties with the other three breakout topical areas. For example, monitoring of CO_2 migration, pressure changes, and other related processes in the storage formation is important for the periodic reevaluation of the AoR as required by EPA's Class VI rule for CO_2 injection wells. Comparison of initial predictions with measured system behavior allows for adjusting the area that needs to be characterized and where corrective action may need to be taken. Monitoring for leakage pathways in overlying formations serves to identify conductive features such as fault/fracture zones or wells, and helps planning of intervention strategies. Finally, monitoring in USDWs or at the ground surface allows detection of possible impacts to water resources.

A crosscutting issue mentioned in several breakout sessions is the need for designated field experiments that could provide field-based understanding of leakage processes and impacts. It was recognized that most CO_2 storage demonstration experiments are conducted to demonstrate safe storage; project sites are selected that are very unlikely to "fail." However, better understanding of many key risk-related issues, such as fault leakage, well leakage, and induced seismicity, can benefit from development of a dedicated field test site (or field test facility) where failure modes can be observed, leakage processes and impacts can be studied, and monitoring as well as mitigation technology can be tested. One breakout group suggested that EPA should consider relaxing regulations for a field experiment where a controlled release of CO_2 into a leakage pathway can be evaluated.

Several breakout groups also discussed the need for improved computational modeling tools. These include mechanistic process models for basin-scale modeling of reservoir processes, for mechanical-chemical behavior of wells, and for reactive transport processes in USDWs. Improvement of joint inversion and uncertainty quantification methods was also suggested. The need for simplified or reduced-order models in addition to higher-fidelity approaches was mentioned. Improvement of site characterization and monitoring tools also came up as a crosscutting theme among breakout groups. While most of the related discussion evolved in the Monitoring and Mitigation Group, better characterization methods for uncased wells was also mentioned as a research need within the Well Leakage Group, along with the desire to have better testing approaches for well integrity.

Another crosscutting issue might be the need for considering a large range of scales in GCS, both in time and space. GCS requires that project performance can be predicted over long time periods (> 100 years), while most laboratory and field results available to date span a few years of data at best. Similarly, spatial scales important for GCS range from the grain size for reactive geochemistry and pore scale for multiphase flow, all the way up to the basin scale for evaluating pressure impacts from industrial CO_2 injection projects. Methodology for upscaling and downscaling of processes and parameters is clearly lacking to date.

As a final issue, several groups brought up the need for better definitions and clarifications, both in terms of standard terminology and/or standard procedures (or best practices). The Monitoring and Mitigation Group mentioned that storage systems (or storage complexes) are sometimes considered to include the storage formations plus the overlying primary seal, while other definitions might include additional aquifers and seals above the primary caprock. This definition immediately affects the question of what would constitute a leak. If CO_2 escapes from the storage formation through the primary cap rock but accumulates under a secondary seal, leakage would be assumed following the former definition, but not the latter. In addition to such terminology questions, groups also discussed the need for further guidance by EPA on various issues. For example, what constitutes a strong enough discrepancy between predictions and monitoring to warrant reevaluation of an AoR? What is a strong-enough monitoring signal (compared to baseline data) to conclude that leakage into a USDW must have occurred and intervention/mitigation is necessary? How is well failure defined according to EPA, i.e., is a well considered to fail if leakage occurs but no impact is seen in a USDW?

9. Summary and Conclusions

The United States Environmental Protection Agency (EPA) and Lawrence Berkeley National Laboratory (LBNL) jointly hosted a workshop on "CO_2 Geologic Sequestration and Water Resources" in Berkeley, June 1–2, 2011. The focus of the workshop was to evaluate R&D needs related to geological storage of CO_2 and potential impacts on water resources. The objectives were to assess the current status of R&D, to identify key knowledge gaps, and to define specific research areas with relevance to EPA's mission. About 70 experts from EPA, the DOE National Laboratories, industry, and academia came to Berkeley for two days of intensive discussions. Participants were split into four breakout session groups organized around the following themes:

- Water Quality and Impact Assessment/Risk Prediction
- Modeling and Mapping of Area of Potential Impact
- Monitoring and Mitigation
- Wells as Leakage Pathways

In each breakout group, participants identified and addressed several key science issues, which are summarized in Sections 4 through 7 of this report. All groups developed lists of specific research needs; some groups prioritized them, others developed short-term vs. long-term recommendations for research directions. Several crosscutting issues came up which are summarized in Section 8. Most participants agreed that the risk of CO_2 leakage from sequestration sites that are properly selected and monitored is expected to be low. However, it also became clear that more work needs to be done to be able to predict and detect potential environmental impacts of CO_2 storage in cases where the storage formation may not provide for perfect containment and leakage of CO_2–brine might occur. We hope that this workshop report will not only help to shape research directions at EPA, but also research by the broader scientific community.

Acknowledgments

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Appendix A: Participant List

(* Participants who attended more than 1 breakout session)

Breakout Group 1: Water Quality and Impact Assessment/Risk Prediction

Susan Carroll, LLNL (Lead)	carroll6@llnl.gov
Rick Wilkin, EPA (Remote Lead)	wilkin.rick@epa.gov
Reed Maxwell, CSM (Lead)	rmaxwell@mines.edu
Alexandra Hakala, NETL	Alexandra.Hakala@netl.doe.gov
Alexis Navarre-Sitchler, CSM	aksitchler@gmail.com
Andrea McNemar, DOE*	Andrea.McNemar@netl.doe.gov
Charuleka Varadharajan, LBNL	cvaradharajan@lbl.gov
Chris Brown, PNNL	Christopher.Brown@pnl.gov
Curt Oldenburg, LBNL	cmoldenburg@lbl.gov
Ed Jones, LLNL	jones37@llnl.gov
Elizabeth Keating, LANL	ekeating@lanl.gov
Isabelle Czernichowski-Lauriol, BRGM	i.czernichowski@brgm.fr
Jim Thordsen, USGS	jthordsn@usgs.gov
John Apps, LBNL	JAApps@lbl.gov
John Kaszuba, University of Wyoming	John.Kaszuba@uwyo.edu
Liange Zheng, LBNL	lzheng@lbl.gov
Lisa Botnen, UNDEERC	lbotnen@undeerc.org
Nicolas Spycher, LBNL	nspycher@lbl.gov
Nik Qafoku, PNNL	nik.qafoku@pnl.gov
Travis McLing, INL	Travis.McLing@inl.gov

Breakout Group 2: Modeling and Mapping the Area of Potential Impact

Steve Kraemer, EPA (Lead)	kraemer.stephen@epa.gov
Stefan Bachu, AITF (Lead)	Stefan.Bachu@albertainnovates.ca
Abdullah Cihan, LBNL	ACihan@lbl.gov
Andrea McNemar, DOE*	Andrea.McNemar@netl.doe.gov
Bruce Kobelski, EPA (OW)	Kobelski.Bruce@epamail.epa.gov
Charlie Gorecki, UNDEERC	cgorecki@undeerc.org
Ed Mehnert, ISGS	mehnert@isgs.illinois.edu
George Robin, EPA (R9)	robin.george@epa.gov
Jens Birkholzer, LBNL*	jtbirkholzer@lbl.gov
JP Nicot, BEG	jp.nicot@beg.utexas.edu
Karl Bandilla, Princeton University	bandilla@princeton.edu
Kevin Ellet, Indiana University	kmellett@indiana.edu
Laura Chiaramonte, LLNL	chiaramonte2@llnl.gov
Mark Dobossy, Geological Storage Consultants	mark.dobossy@geostorageconsultants.com
Quanlin Zhou, LBNL	QZhou@lbl.gov
Rajesh Pawar, LANL	rajesh@lanl.gov

Breakout Group 3: Monitoring and Mitigation

Susan Hovorka, BEG (Lead)	susan.hovorka@beg.utexas.edu
Dom DiGiulio, EPA (Remote Lead)	Digiulio.Dominic@epamail.epa.gov
Thomas Daley, LBNL (Lead)	TMDaley@lbl.gov
Burt Thomas, USGS	burt_thomas@usgs.gov
Chi Ho Sham, Cadmus Group	ChiHo.Sham@cadmusgroup.com
Dennis Newell, LANL	dnewell@lanl.gov
Domenik Wolff-Boenisch, University of Iceland	boenisch@raunvis.hi.is
George Peridas, NRDC	gperidas@nrdc.org
Jens Birkholzer, LBNL*	jtbirkholzer@lbl.gov
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Robert Trautz, EPRI	rtrautz@epri.com
Rohit Salve, LBNL	rsalve@lbl.gov
Susan Hubbard, LBNL	sshubbard@lbl.gov
Yuxin Wu, LBNL	ywu3@lbl.gov

Breakout Group 4: Wells as Leakage Pathways

William Carey, LANL (Lead)	bcarey@lanl.gov
Randall Ross, EPA (Remote Lead)	Ross.Randall@epamail.epa.gov
Brian Strazisar, NETL (Lead)	brian.strazisar@ netl.doe.gov
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Carl Miller, EPA	
Jim Houseworth, LBNL	jehouseworth@lbl.gov
Jonathan Koplos, Cadmus Group	Jonathan.Koplos@cadmusgroup.com>
Nik Huerta, University of Texas	njhuerta@gmail.com
Preston Jordan, LBNL	pdjordan@lbl.gov
Sarah Gasda, University of North Carolina	sgasda@unc.edu
Sean Porse, EPA	Porse.Sean@epamail.epa.gov
Steven Acree, EPA	acree.steven@epa.gov
Walter Crow, BP	Walter.Crow@bp.com

Appendix B: Workshop Agenda

2011 CO$_2$ Geologic Sequestration & Water Resources Workshop

Workshop Agenda
Lawrence Berkeley National Laboratory
June 1-2, 2011

Day 1

A live webcast for the common session (8:30 am - 1:30 pm) will be available at
http://hosting2.epresence.tv/LBL/1.aspx

8:00	8:30	66-316	Registration and check-in
8:30	8:50	66 Auditorium	Welcome, introductions, objectives [Jens Birkholzer, LBNL] (Refreshments served during presentation)
8:50	9:00		Welcome and remarks by DOE senior representative [Andrea McNemar, NETL]
9:00	9:30		EPA research and technology to support regulations [Steve Kraemer (ORD), Sean Porse (OW), Lisa Bacanskas (OAR climate)]
9:30	10:10		Introduction to Breakout 1: Water Quality and Impact Assessment/Risk Prediction [Susan Carroll, LLNL and Rick Wilkin, EPA]
10:10	10:50		Introduction to Breakout 2: Modeling and Mapping the Area of Potential Impact [Stefan Bachu, Alberta Innovates - Technology Futures and Steve Kraemer, EPA]
10:50	11:30		Introduction to Breakout 3: Monitoring and Mitigation [Sue Hovorka, BEG and Dom DiGulio, EPA]
11:30	12:00		Introduction to Breakout 4: Wells as Leakage Pathways [Bill Carey, LANL and Randall Ross, EPA]
12:00	12:15		Instructions for Day 1 Breakouts [Charu Varadharajan, LBNL]
12:15	1:30	66 Auditorium	Science talk by Don De Paolo, Associate Lab Director, Energy & Environmental Sciences, LBNL (Lunch served during presentation)
1:30	4:30	67-3111 (#1) 67-2204 (#2) 67-5106 (#3) 67-6106 (#4)	Parallel Breakout Sessions: Discussion of science gaps with respect to the breakout topic - led by breakout leads. [Additional breakout leads are Reed Maxwell, CSM (#1), Tom Daley, LBNL (#3) and Brian Strazisar, NETL (#4)] (refreshments served during breakout sessions)
4:45	5:30	67-3111	Organizer meeting with breakout leads.
6:30	8:30	Downtown Berkley	Guest Speaker: Bill Collins, Climate Science Dept. Head, LBNL (Dinner served during presentation, 'Revival Bar & Kitchen', 2102 Shattuck Avenue, Berkeley)

Page 1

Workshop Agenda
Lawrence Berkeley National Laboratory
June 1-2, 2011

Day 2			
8:00	8:30	67-3111	Registration and check-in
8:30	8:45	67-3111	Instructions for Day 2 Breakouts [Varadharajan] (refreshments served during presentations)
8:45	11:30	67-3111 (#1) 67-2204 (#2) 67-5106 (#3) 67-6106 (#4)	Parallel Breakout Sessions: Discussion of research prioritization with respect to the breakout topic - led by breakout leads. Develop list of recommendations for short- and long-term R&D.
11:30	1:00	Bldg 67 outdoor seating area	Discussion/Q&A Session re: breakout session topics (lunch served during discussions [Alternate rain location: 67-3111])

A live webcast for the common session (1:00 - 3:00 pm) will be available at
http://hosting2.epresence.tv/LBL/1.aspx

1:00	2:45	66 Auditorium	Breakout leads for all sessions report back to the entire group. Summary of results and path forward recommendations - 20 minutes each with discussion.
2:45	3:00		Workshop summary [Birkholzer, Kraemer, Porse, Varadharajan] Main workshop adjourns.
3:30	4:30	66-316	Organizer team meeting - compile results and set writing assignments for final report.

Next page – Special Workshop Shuttle Info

Appendices C - I: Introductory Presentations (Separate PDF Attachment)

Appendix C: Welcome to the 2011 CO2 Geologic Sequestration and Water Resources Workshop, Jens Birkholzer and Charuleka Varadharajan (LBNL), Steve Kraemer and Sean Porse (EPA)

Appendix D: Welcome and Overview Remarks, Andrea McNemar (DOE/NETL)

Appendix E: EPA Research and Technology to Support Regulation and Program Implementation, Steve Kraemer, Sean Porse and Lisa Bacanskas (EPA)

Appendix F: Water Quality and Impact Assessment/Risk Prediction, Susan Carroll (LLNL), Rick Wilkin (EPA), Reed Maxwell (CSM)

Appendix G: Modeling and Mapping of Area of Potential Impact, Stefan Bachu (AITF), Steve Kraemer (EPA)

Appendix H: Monitoring and Mitigation, Sue Hovorka (BEG), Dominic Digiulio (EPA), Tom Daley (LBNL)

Appendix I: Wells as Leakage Pathways, Bill Carey (LANL), Randall Ross (EPA), Brian Strasizar (LBNL)

Welcome to the
2011 CO$_2$ Geologic Sequestration and Water Resources Workshop

Sponsored by U.S. Environmental Protection Agency
Hosted by Lawrence Berkeley National Laboratory

Organizing Committee:

Jens T. Birkholzer and Charuleka Varadharajan
Lawrence Berkeley National Laboratory

Stephen R. Kraemer and Sean Porse
U.S. Environmental Protection Agency

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Workshop Focus Areas

Research on geological carbon sequestration with specific attention to protection of water resources

Topic 1: Water quality impact assessment and risk prediction

Topic 4: Wells as leakage pathways

Topic 3: Monitoring and mitigation

Topic 2: Modeling and mapping of area of potential impact

Courtesy of Sally Benson
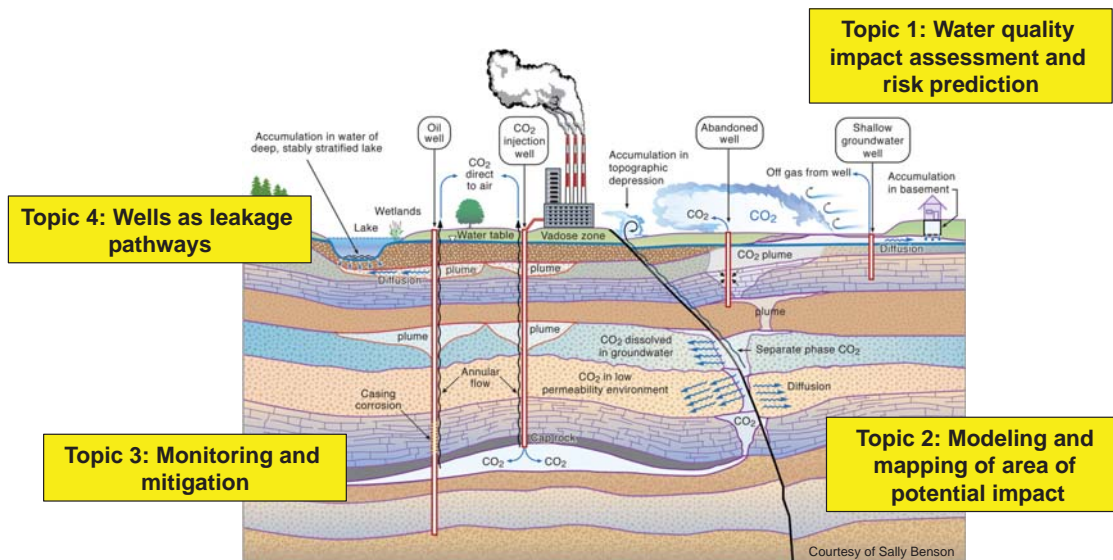
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Objective and Outcome

- **Evaluate current status of R&D related to CO_2 storage and water resources**
- **Identify key science gaps**
- **Prioritize research areas with specific relevance to EPA's mission**
- **Consider potential areas of collaboration between EPA and other institutions (DOE, labs, academia, industry…)**
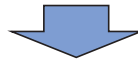
Workshop summary report (LBNL report)

EPA R&D 5-Year Research Plan

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U.S. Environmental Protection Agency

- **EPA Office of Water**
  - Regulates CO_2 Geologic Sequestration Wells (UIC Class VI Wells)
  - Final Rule December 2010; Guidance Documents in Comment Period
- **EPA Regional Offices**
  - EPA has ten regional offices, each of which is responsible for the execution of programs within several states and territories
- **EPA Office of Air and Radiation**
  - "Climate Science and Impact" group runs the Greenhouse Gas Reporting Program
  - Requires reporting from facilities that directly emit greenhouse gases to the atmosphere as well as suppliers of fuels and industrial gases
- **EPA Office of Research and Development**
  - Conducts and facilitates R&D in various areas (e.g., safe and sustainable water resources) and research centers (e.g., national risk management research lab; national exposure research lab)
  - Manages external R&D under STAR Program

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LBNL – EPA Collaboration

Conferences

Special Issue in Environmental Geology
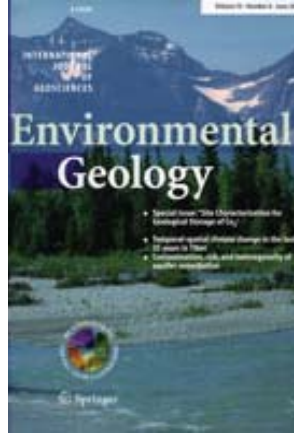
R&D in Support of UIC Program and CO$_2$ Sequestration Issues*
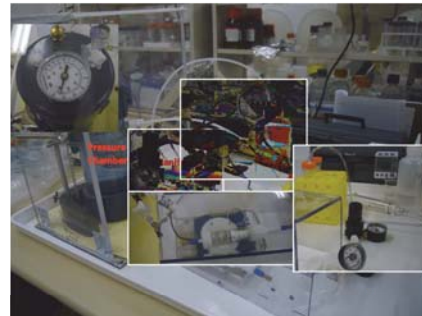
*R&D jointly coordinated between DOE's CCS program and EPA

LBNL: Current Projects Funded by EPA

- **Evaluating the Consequences of CO$_2$ Intrusion into Groundwater: Sediment Analysis with Micro-Spectroscopy, Flow Cell Experiments, and Geochemical Modeling (+ thermochemical data review)**
  Research group: Nic Spycher, Charuleka Varadharajan, Liange Zheng, Peter Nico, John Apps, Jens Birkholzer
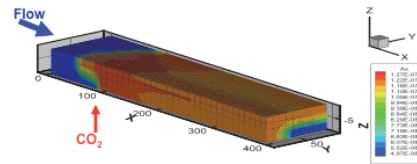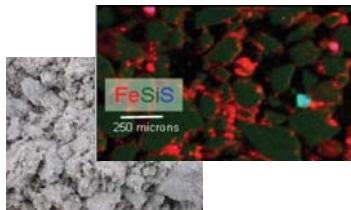
- **Analytical and Numerical Modeling in Support of Area of Review Estimates and Geological Sequestration Modeling Framework**
  Research group: Quanlin Zhou, Abdullah Cihan, Jens Birkholzer
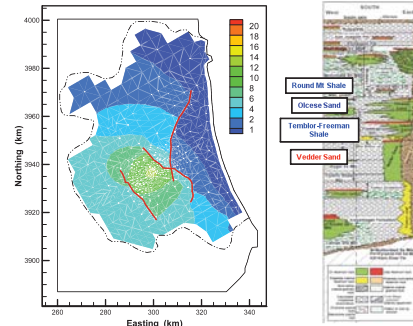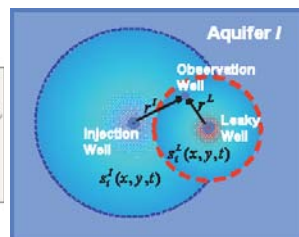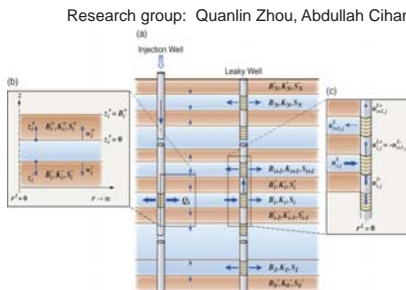
- **Use of microarray analysis to study the effect of GCS on groundwater microbial communities**
  Research group: Gary Andersen, Eric Dubinsky, Yvette Piceno

Agenda for June 1, Morning Session

8:30	8:50	66 Auditorium	Welcome, introductions, objectives [Jens Birkholzer, LBNL]
8:50	9:00		Welcome and remarks by DOE senior representative [Andrea McNemar, NETL]
9:00	9:30		EPA research and technology to support regulations [Steve Kraemer (ORD), Sean Porse (OW), Lisa Bacanskas (OAR climate)]
9:30	10:00		Introduction to Breakout 1: Water Quality and Impact Assessment/Risk Prediction [Susan Carroll, LLNL and Rick Wilkin, EPA]
10:00	10:30		Coffee Break
10:30	11:00		Introduction to Breakout 2: Modeling and Mapping the Area of Potential Impact [Stefan Bachu, Alberta Innovates - Technology Futures and Steve Kraemer, EPA]
11:00	11:30		Introduction to Breakout 3: Monitoring and Mitigation [Sue Hovorka, BEG and Dom DiGulio, EPA]
11:30	12:00		Introduction to Breakout 4: Wells as Leakage Pathways [Bill Carey, LANL and Randall Ross, EPA]
12:00	12:15		Instructions for Day 1 Breakouts [Varadharajan, LBNL]
12:15	1:30	66 Auditorium	Lunch [12:30-1:00 pm – Science talk by Don De Paolo, Associate Lab Director, Energy & Environmental Sciences, LBNL]

+ Reed Maxwell, CSM

+ Tom Daley, LBNL

+ Brian Strazisar, NETL

For the remainder of the workshop, participants split into separate breakout sessions for each topical area to facilitate discussion and interaction.

Safety

Assembly Areas
For Bldg. 66 – Floor 3

Alternate Assembly Area up stairway to B67 Assembly Area

Assembly Area by B62 C&D containers

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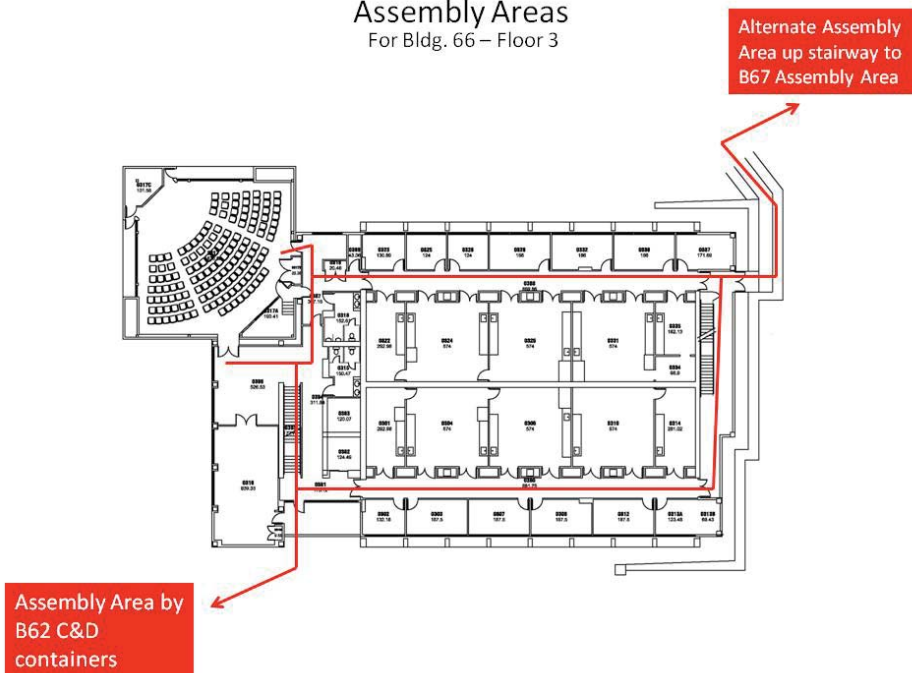
Workshop Discussion Topics

- **Topic 1: Water quality impact assessment and risk prediction**
  Understand and be able to predict the consequences of leakage of CO_2, brine, and/or co-migrating constituents on water resources
  - What is the impact of CO_2 or brine intrusion on drinking water resources (e.g., mobilization of hazardous constituents from the subsurface or aquatic sediments)?
  - What about co-injectants and co-contaminants?
  - What are the potential ecological and health impacts?
  - How accurate can these impacts be predicted with modeling or analytical tools? What is the role of system-level risk assessment models?
  - What are the main risk drivers? Can these be identified based on qualitative site characteristics?

- **Topic 2: Modeling and mapping of area of potential impact**
  Delineate the subsurface domain affected by CO_2 plume migration and pressure buildup to define site characterization needs
  - How can the area of potential impact be defined such that the required site characterization and potential corrective actions (e.g., plugging of leaking abandoned wells) provide for safe storage?
  - What level of model complexity is sufficient for modeling and mapping the area of potential impact?
  - How might monitoring of system performance through time improve the evaluation of the area of potential impact?
  - How should multiple interacting CO_2 injection operations be handled?
  - What is the influence of fractures and faults on the definition of the area of potential impact?

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Workshop Discussion Topics (II)

- **Topic 3: Monitoring and mitigation**
  Develop and utilize state-of-the-art of monitoring and mitigation methodologies related to protection of groundwater and surface water
  - What monitoring methods are best at detecting leakage into groundwater, vadose zone, or surface water bodies? What is the value of monitoring schemes to track plume migration and detect leakage at depth?
  - Which current and future software tools are needed for analyses of data generated by monitoring efforts? Can the data be effectively integrated with existing water resource datasets (e.g. USGS aquifer database)?
  - In the case of leakage, what mitigation measures are available to stop or limit its effect? Can water quality changes in response to leakage be remediated? What remediation technologies are available?

- **Topic 4: Wells as leakage pathways**
  Characterize and be able to predict well behavior and evolution to better understand leakage risks
  - What is the long-term effect of CO_2/brine exposure to well materials?
  - Which tools are available to identify wells in the proximity of GS injection sites?
  - What methods are best to test the mechanical integrity of injection and existing wells be tested as well conditions change due to long-term exposure to injected fluids?
  - What materials are most reliable for the construction and plugging of wells used for long-term storage of CO_2 and plugging abandoned wells in an area of concern?

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Welcome and Overview Remarks
Andrea McNemar
Sequestration Program Project Manager

Contents

- **DOE Research Highlights**
  - Safe, cost effective, permanent geologic storage of CO_2
  - Potential brine formation water extraction
- **Collaborations**
  - EPA and others

CCS Best Practice Manuals
Critical Requirement For Significant Wide Scale Deployment - Capturing Lessons Learned

Best Practices Manual	Version 1 (Phase II)	Version 2 (Phase III)	Final Guidelines (Post Injection)
Monitoring, Verification and Accounting	2009	2012	2020
Public Outreach and Education	2009	2016	2020
Site Characterization	**2010**	**2016**	**2020**
Geologic Storage Formation Classification	**2010**	**2016**	**2020**
**Simulation and Risk Assessment	2010	2016	2020
**Well Construction, Operations and Completion	2011	2016	2020
Terrestrial	2010	2016 – Post MVA Phase III	

**Regulatory Issues will be addressed within various Manuals

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http://www.netl.doe.gov/technologies/carbon_seq/refshelf/refshelf.html

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NETL Office of Research and Development
Geological/Environmental Sciences
**Science/engineering research of earth systems & materials
to enable the clean production & utilization of domestic fossil energy**

Predicting the Behavior of Engineered–Natural Systems

- Reservoirs & Resources
- Wellbores (Seal Integrity) & Drilling
- Water Resources
- Monitoring of Natural Systems
- Geomaterials Science (fluid & solid properties at conditions)
- Fluid–Rock Geophysics (multiphase flow; fractured material)
- Fluid–Rock Geochemistry
- Multiscale Integrated Assessments
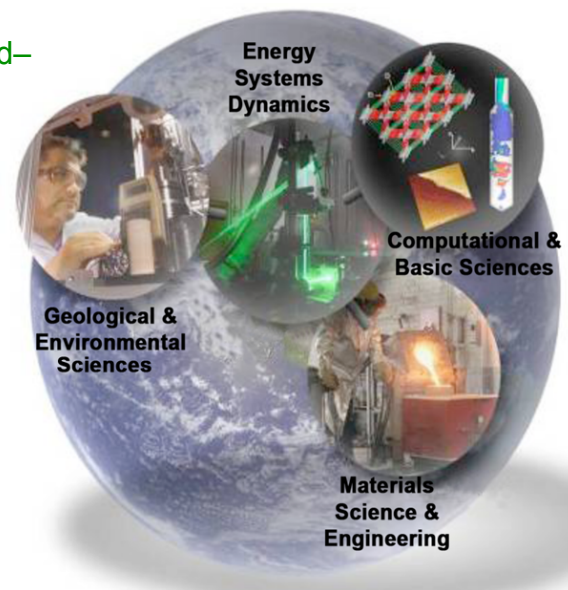
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National Risk Assessment Partnership (NRAP)
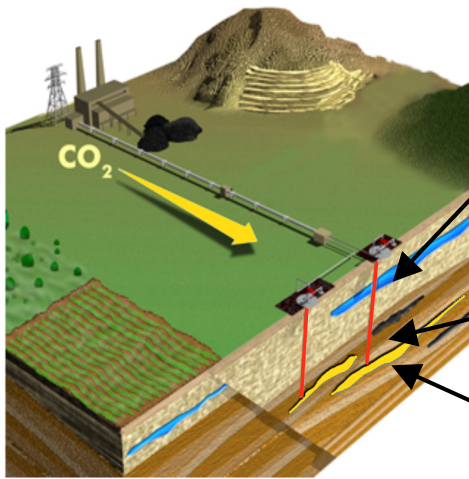
Lawrence Berkeley National Lab
Lawrence Livermore National Lab
Los Alamos National Lab
National Energy Technology Lab (lead)
Pacific Northwest National Lab

Outside of the Reservoir

- **Strategic monitoring for the site (during injection and post closure)**
- **Potential impacts of CO_2 release**
- **Protection of subsurface resources (groundwater, minerals, etc.)**

Seal

- **Seal characterization**
- **Seal (and wellbore) integrity over time**
- **Mitigation strategies**

Reservoir

- **Strategic site characterization**
- **Capacity & injectivity over time**
- **Plume movement in reservoir (CO2, brine, pressure front)**
- **Impacts from introducing CO2 into the reservoir**

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NETL Managed DOE National Laboratory Efforts Investigating Water Extraction

- **LLNL**
  - Active CO_2 Reservoir Managment
  - Brine treatment utilizing formation pressure
- **SNL**
  - Model examining integrated system for power plant CCS and formation water removal for treatment and cooling
- **ANL**
  - Life cycle assessment of environmental costs and benefits of various water extraction, treatment, and reuse options

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RCSP Water Working Group

- **Capture experiences related to CCS & water**
- **To provide a forum for brainstorming and communication on issues and opportunities**
- **Each RCSP has crosscutting challenges and opportunities but also many unique regional experiences**

9   NATIONAL ENERGY TECHNOLOGY LABORATORY

NATCARB Brine Database

10   NATIONAL ENERGY TECHNOLOGY LABORATORY
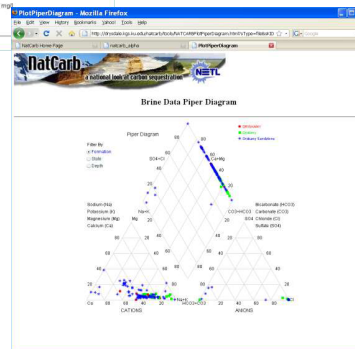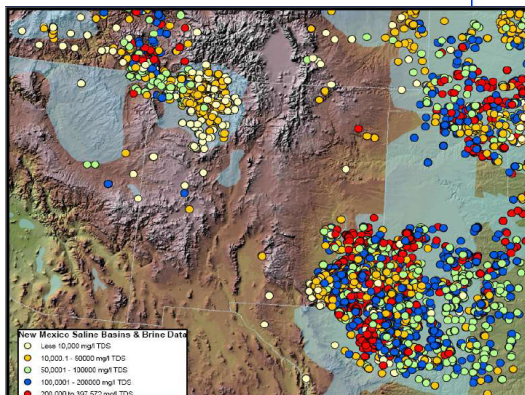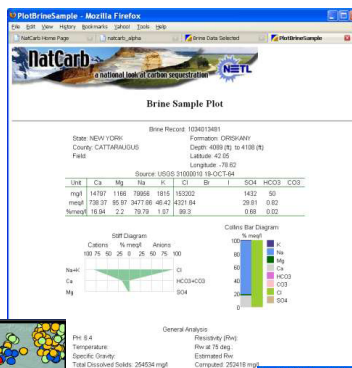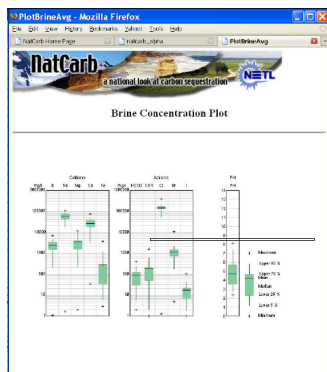
International Study

- **EERC work co-funded by DOE and IEA GHG**
  - Supplementing the average global database
  - Modeling of CO_2 storage and water extraction scenarios
  - Technical and cost feasibility analyses
  - Review of regulatory constraints
  - Case study analysis
  - Development of global recommendations for potential CO_2 storage and water extraction projects based on the effort's findings

ieaghg

EERC
Energy & Environmental Research Center

UND University of North Dakota

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11

DOE's Interagency CCS Collaborations

Issue	Agency	Authority	What is Regulated	FE Involvement
CO_2 Geologic Storage				
Injection, Monitoring, Safety	EPA/Office of Water	Safe Drinking Water Act (SDWA)	Underground injection and environmental monitoring of CO_2	EPA and FE are actively engaged in CCS regulatory and technical development. This interaction has helped to inform EPA's regulatory development process.
Injection on Federal Lands	U.S. Department of Interior (DOI)/Bureau of Land Management	Federal Land Policy and Management Act and Minerals Leasing Act	Underground injection of CO_2 on Federal Lands	FE participated in the preparation of several BLM Reports to Congress (e.g, under EPACT Sec. 369 and EISA Sec. 714).
State Role	Interstate Oil and Gas Compact Commission (IOGCC) and Ground Water Protection Council (GWPC)	State and Federal Statutes	Storage, including injection	FE is working with the IOGCC to examine the legal and regulatory framework for CO_2 storage, and the GWPC on state regulatory program data management for carbon storage.
Offshore	IOGCC	State and Federal Waters	Transport and Storage	FE is sponsoring IOGCC to conduct assessment of gaps for offshore storage.
CCS Task Force	DOE and EPA (co-chairs)	Interagency Task Force on Carbon Capture and Storage	Goal to develop a comprehensive and coordinated Federal strategy to speed the commercial development and deployment of clean coal technologies.	Task Force charged with proposing a plan to overcome the barriers to the widespread, cost-effective deployment of CCS within 10 years, with a goal of bringing 5-10 commercial demonstration projects online by 2016. Final report published in August 2010 (http://www.fe.doe.gov/programs/ sequestration/ccstf/ CCSTaskForceReport2010.pdf)

Welcome

NATIONAL ENERGY TECHNOLOGY LABORATORY
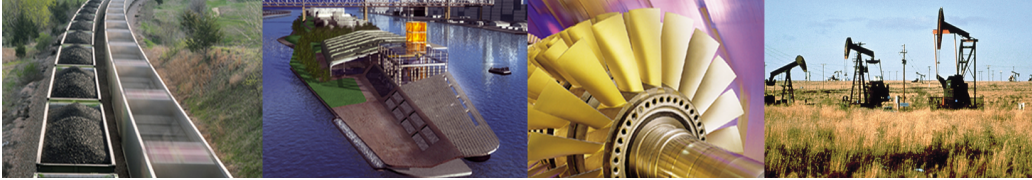
EPA Research and Technology to Support Regulation and Program Implementation

**2011 CO2 Geologic Sequestration & Water Resources Workshop
June 1, 2011**

Sean Porse, Office of Water
Washington, DC

Lisa Bacanskas, Office of Atmospheric Programs
Washington, DC

Stephen Kraemer, Office of Research and Development
Athens, Georgia

6/14/11

U.S. Environmental Protection Agency

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Outline

- Office of Water

- Office of Atmospheric Programs

- Office of Research and Development

- More Information

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Underground Injection Control Background

- 1974 Safe Drinking Water Act (SDWA; Reauthorized in 1996)
  - Federal regulations for protection of Underground Sources of Drinking Water (USDWs)
  - USDW defined:
    - Any aquifer or portion of an aquifer that contains water that is less than **10,000** ppm total dissolved solids or contains a volume of water such that it is a present, or viable future source for a Public Water Supply System

- UIC Program regulates underground injection of *all* <u>fluids</u> – liquid, gas, or slurry
  - Designation as a commodity does not change SDWA applicability
  - Natural gas storage and some hydraulic fracturing exempted

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Underground Injection Control Background

- **Class I** – Technically sophisticated, stringently regulated deep injection wells with detailed siting, monitoring, and closure requirements.

- **Class II** – Wells used by oil and gas operators for waste fluid disposal, enhanced recovery (ER), and hydrocarbon storage

- **Class III** – Wells associated with solution mining (e.g., extraction of uranium, copper, and salts)

- **Class IV** – Wells used to inject hazardous or radioactive waste into or above a USDW; banned by statue and regulation

- **Class V** – Any injection well that is not contained in Classes I –IV, or VI

- **Class VI** – Wells that inject carbon dioxide for long term storage, also known as geologic sequestration

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Class VI Rule Requirements
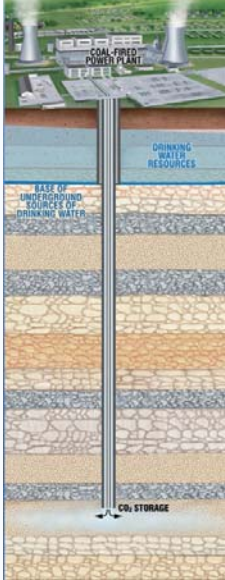
- After publishing a proposed rule in 2008, and a NODA in 2009, EPA finalized a new well class (i.e. Class VI) in December 2010
- Class VI wells will be permitted to allow for GS
- It is anticipated that CO_2 injected into Class VI wells will come from anthropogenic sources
  – Coal-fired power plants
  – Ethanol plants
  – Other facilities producing large amounts of this greenhouse gas
- Our primary goal is to protect USDWs

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Primacy Background

- Law encourages states to seek "primary enforcement authority" for the UIC program

- Depending on the well types being regulated, states have to meet specific minimum federal requirements or demonstrate that their programs are "effective"

- States can be, and often are, more stringent than minimum federal requirements

- EPA is responsible for implementing the program when a state chooses not to, or is unable to obtain federal approval, to do so

- UIC Program primacy requirements are under Sections 1421, 1422, and 1425 of the SDWA

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Primacy Background

- 33 States have primary enforcement authority (primacy) for the UIC program; EPA and States share program implementation in 7 States; EPA directly implements the entire UIC Program in 10 states

State Program
Joint State/EPA Program
Joint Tribal/EPA Program
EPA Program

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* The Fort Peck (FP) Tribes and the Navajo Nation (NN) are currently the only Tribes with UIC Primacy

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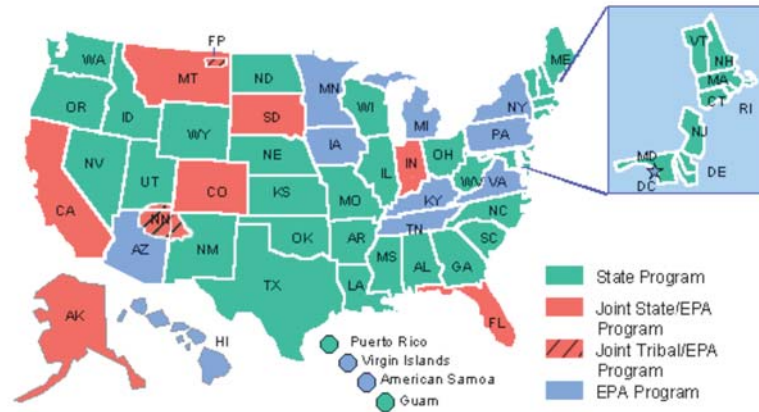
Guidance Development

In development:
- Site Characterization
- Area of Review and Corrective Action
- Well Construction
- Project Plans Development
- Testing and Monitoring
- Primacy and Implementation Manual
- Injection Well Plugging, Post-Injection Site Care, and Site Closure
- Class II – Class VI Transition
- Injection Depth Waivers
- Reporting and Recordkeeping
- UICPG #83 Class V Experimental Technology Wells Update

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EPA and DOE Interagency Agreement

- The Interagency Agreement (IA) between EPA and DOE has continued for almost 25 years

- OW, OAP, ORD, and EPA Regions have all utilized the IA for funded research

- Current and Past UIC research topics include:
  - Ultimate Fate of Hazardous Waste Injection
  - CO_2 Geological Storage and Ground Water Resources

EPA and DOE Interagency Agreement

- Current projects include:

  - Evaluating the Consequences of CO_2 Intrusion into Ground Water
  - Analytical and Numerical Modeling in Support of Zone of Potential Endangerment Estimates and GS Modeling Framework
  - Thermochemical data review and assessment to support research on geochemical impacts to ground water from GS projects
  - Use of microarray analysis to study the effect of GS on ground water microbial communities

Moving Forward

- OGWDW looks to:
  - Identify and refine research approaches for CO_2 interaction with ground water
  - Appropriately tier research goals to gain a clear path forward on conducting GS research
  - Increase potential for collaboration between EPA, LBNL and other research organizations

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Office of Atmospheric Programs
Climate Change Division

U.S. EPA GHG Reporting Program

Goal of the GHG reporting program is collect accurate and timely data on GHG emissions to inform future policy decisions.

- Generally requires facilities across certain sectors of the economy to report to EPA GHG supply and/or emissions and other related data.

- EPA estimates that over **13,000 facilities** will be reporting, accounting for 85-90% of U.S. GHG emissions.

- Reporting only, no control requirements.

# of facilities

Sector	# of facilities
Stationary Combustion	3000
Petroleum and Natural Gas Systems	2800
Municipal Landfills	2551
Fuel and Industrial GHG Suppliers	1224
Electricity Generation	1108
Pulp and Paper	425
Industrial Wastewater Treatment	358*
Vehicle and Engine Manufacturers	317
Fluorinated GHG Processes	259
Industrial Waste Landfills	200*
Petroleum Refineries	150
Underground Coal Mines	128
Iron and Steel	121
Cement	107
Other	513

*The majority of these facilities already have to report under other subparts (e.g., pulp and paper, petroleum refining)

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Electronic Reporting System

- All reporting under the GHG Reporting Program, including submissions for Subpart RR, through EPA's Electronic GHG Reporting Tool (e-GGRT).
  - Web-based system for facility/supplier to EPA reporting

Overview of Subparts RR and UU

- On December 1, 2010, EPA finalized GHG reporting mechanisms for:
  - Facilities that conduct geologic sequestration (Subpart RR)
  - All other facilities that inject carbon dioxide (CO_2) underground for enhanced oil and gas recovery or any other purpose (subpart UU)
- This rule is complementary to and builds on EPA's Underground Injection Control (UIC) permit requirements
- Information obtained through this rule will inform Agency decisions under the Clean Air Act related to the use of CCS for mitigating GHGs.

Geologic Sequestration of Carbon Dioxide (Subpart RR)

- Facilities that conduct geologic sequestration by injecting CO_2 for long-term containment in subsurface geologic formations are required to:
  - Develop and implement an EPA-approved site-specific monitoring, reporting, and verification (MRV) plan.
  - Report basic information on CO_2 received for injection, annual monitoring activities and the amount of CO_2 geologically sequestered using a mass balance approach.
- All facilities permitted as UIC Class VI must report under Subpart RR.
- Facilities that conduct enhanced oil and gas recovery are not required to report geologic sequestration under Subpart RR unless
  - The owner/operator chooses to opt-in to Subpart RR *OR* the facility holds a UIC Class VI permit for the well or group of wells used to enhance oil and gas recovery
- R&D projects will be granted an exemption from Subpart RR provided they meet the eligibility requirements

Illustrative Example of GHGs to be Reported for Subpart RR

CO$_2$ source type

CO$_2$ received

CO$_2$ injected

CO$_2$ recycled

CO$_2$ produced

CO$_2$ entrained in fluids

CO$_2$ surface leakage, if any

Facility Fence line

EL&V

EL&V

Geologic Formation
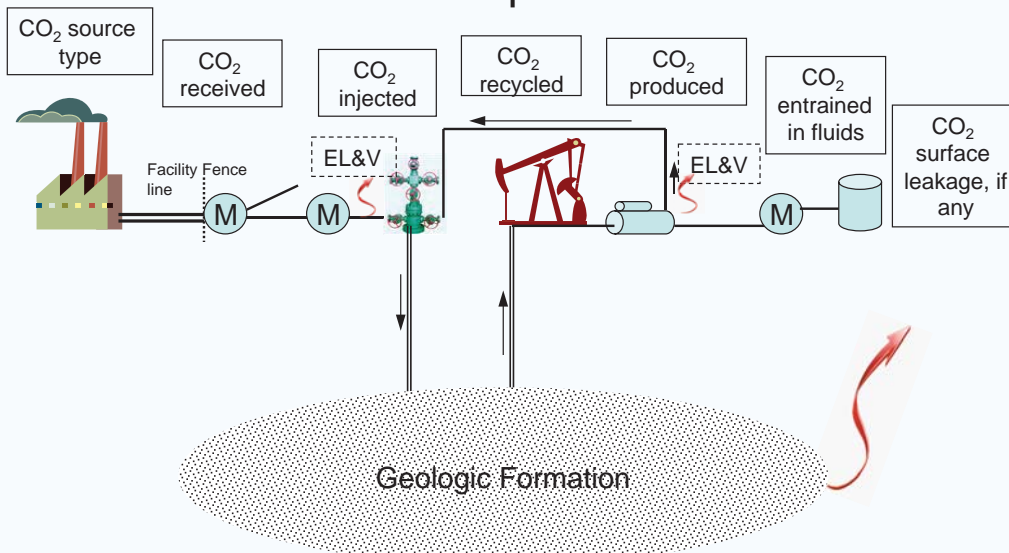
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Contents of the MRV Plan

- Delineation of monitoring areas
- Identification of potential surface leakage pathways
- Strategy for detecting and quantifying surface leakage of CO$_2$
- Strategy for establishing the expected baselines for monitoring CO$_2$ surface leakage
- Other

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Office of Research and Development

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ORD Risk Paradigm FY07-FY11

Environ. Community

Other Fed Agencies

NGOs
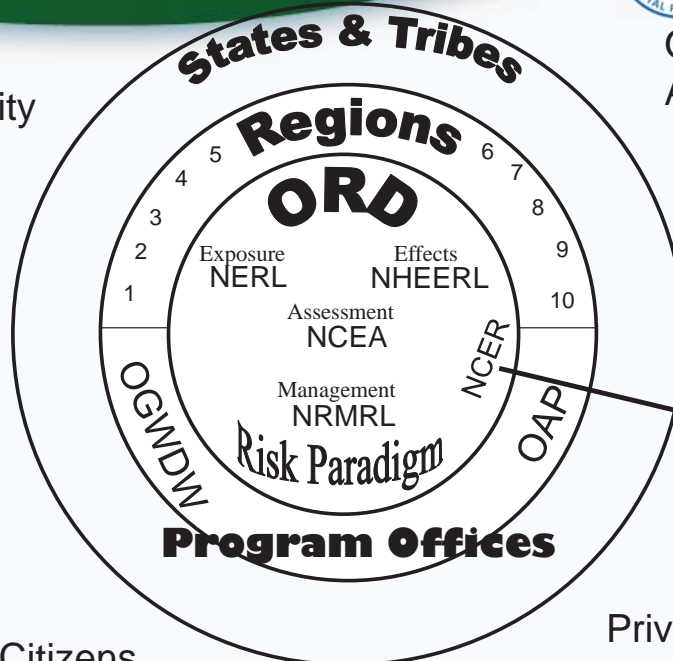
Academic community

Private Citizens

Private Industry

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ORD Intramural-lead Research

A. Levine

- Kraemer, Babendreier, NERL, modeling and mapping area of potential impact
- Wilkin, NRMRL, geochemistry
- DiGiulio, NRMRL, soil gas and gw monitoring
- Ross, Acree (new start), NRMRL, well integrity
- Ashbolt, SantoDomingo (new start), NRMRL, microbiology

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ORD Extramural Research
STAR Grants

B. Klieforth/A. Paige

- Princeton (Celia), hierarchical modeling framework
- Colorado School of Mines (McCray, Kaszuba, Maxwell, Sitchler), decision making
- U Illinois Urbana-Champaign (Roy, Benson, Berger, Krapac, Lin, Mehnert, Panno, Chittaranjan), reducing uncertainties
- Clemson U (Falta, Benson, Murdoch), understanding and managing risk
- U. Utah (McPherson, Deo, Goel, Solomon), integrated design, modeling, monitoring
- U. Texas Austin (Nicot, Hovorka), expert-based standards monitoring
- Columbia U (Goldberg, Matter, O'Mullan, Slute, Takahashi), interactions of shallow aquifer and CO2 leak

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ORD FY12 and Beyond -

Integrated, Transdisciplinary, Sustainable

J. Orme-Zaveleta

D. Costa

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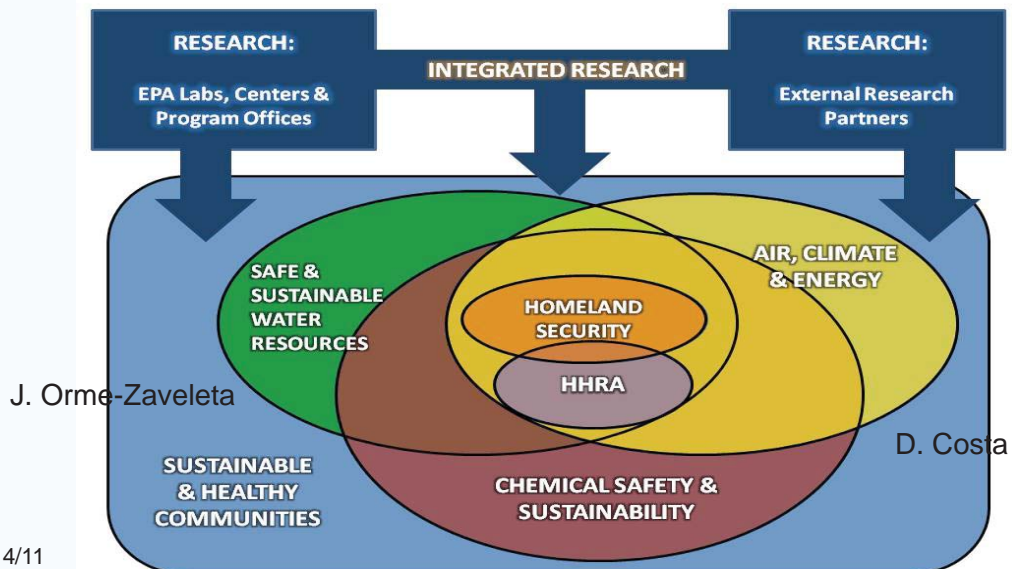
SSWR Research Problem Areas

- Water Infrastructure
- Agricultural Practices
- Chemical and Industrial Processes
- **Energy and Mineral Extraction/Injection (HF, GS, MTM)**   D. Jewett
- Nitrogen and Phosphorus Pollution
- Protecting Watersheds
- Climate component

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Framework

Key Program Needs

Problem Statement

Research Theme

1. Sustainable Water Resources
2. Sustainable Water Infrastructure

Science Question   Science Question

Proj   Proj   Proj

Output   Output   Output   Output   Output

Intended Outcome   Intended Outcome

Research Action Plan
(Oct 1, 2011)

DESIRED IMPACTS

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GS Science Questions

WQ and risk
- DW risk profiles from data ?
- impact ground water chemistry and microbiology on WQ?
- economic costs/benefits and societal impacts?
- expected time periods for permanent CO2 trapping?
- potential for leakage during injection and post- injection?

Modeling and mapping area of potential impact
- capability of models to evaluate potential leakage, including displaced native saline waters?
- , cumulative effects of multiple injections?
- effect of fractures/faults?

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GS Science Questions continued

Monitoring and mitigation
• monitoring methods best at detecting soil gases and ground water movement related to CO2 injection?
• monitoring and modeling methods to monitor/assess/predict long-term (100–1,000 years)?

Wells as leakage pathways
• mechanical integrity tests?

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For More Information

• UIC Class VI Program Information
  – http://water.epa.gov/type/groundwater/uic/wells_sequestration.cfm
  – www.regulations.gov (i.d.: EPA-HQ-OW-2008-0390)

• GHG Reporting Program Information:
  – http://www.epa.gov/climate/climatechange/emissions/ghgrulemaking.html
  – Email: GHGMRR@epa.gov

• Subpart RR Information and Help
  – http://www.epa.gov/climatechange/emissions/subpart/rr.html

• e-GGRT Information and Help
  – http://www.ccdsupport.com
  – Email: GHGreporting@epa.gov

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Water Quality and Impact Assessment/Risk Prediction

2011 CO2 Geologic Sequestration and Water Resources Workshop

Susan Carroll @ LLNL

Rick Wilkin @ EPA

Reed Maxwell @ Colorado School of Mines

LLNL-PRES-489776

Objective: Prioritize research needs to ensure USDW are protected from underlying carbon storage reservoirs

- What are the main risk drivers?

- What is the impact of CO_2/brine intrusion on drinking water resources?

- What is the role of modeling to assess impact and human and ecological risk?

- What is the role of USDW characterization and monitoring?

What are the main risk drivers ?

↓pH
↑Metals
↑CO_2 (aq)   Well

CO_2 Injection

Drinking Water Aquifer

100 m

Fault

Wellbore

CO_2 Storage reservoir

1300 m to 1800 m
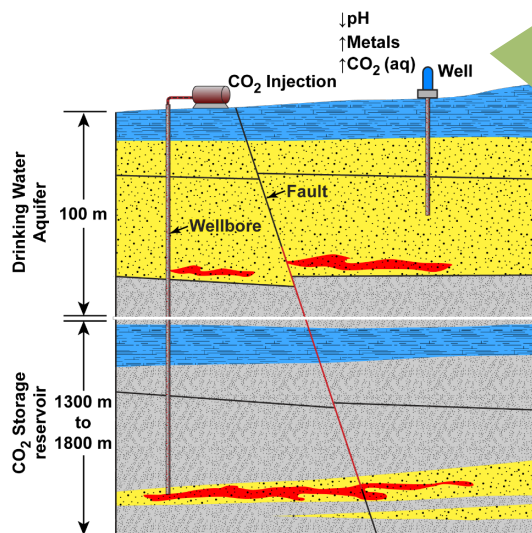
- Increase organics and metal concentrations and compromise the use of the groundwater resource

- Human and ecological exposure and health risk via multiple pathways

- Risk = f(Dose, Dose Response)
- Dose=f(Exposure)

What is the impact of CO_2/brine intrusion on drinking water resources?

- Laboratory Experiments

- Field Scale Experiments

- Reactive Transport Modeling

Experiments to identify response or source terms for regulated metals and organics within the storage reservoir and aquifer material

- Aquifers:
  - Gulf Coast Aquifers (Lu et al., 2009; Smyth et al., 2009)
  - Study of three different aquifers (Little and Jackson, 2010)
  - Experiments on sediments from the EPRI field site
    (Varadharajan et al, 2011)
- Storage Reservoirs:
  - Study of reservoir and caprocks from storage sites (Carroll and Torres 2011)
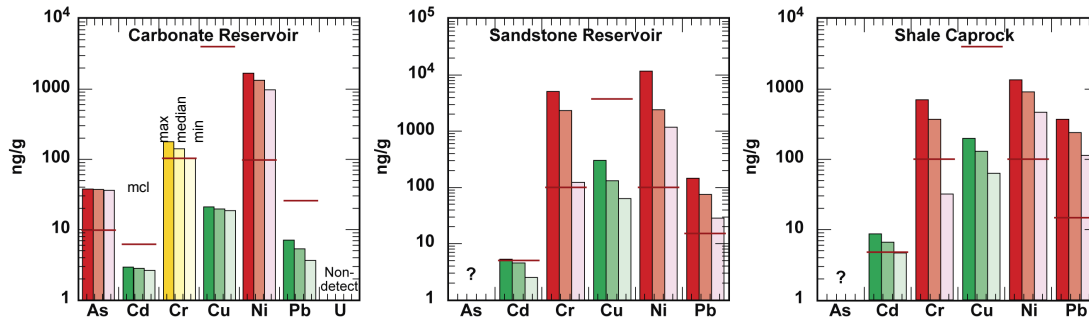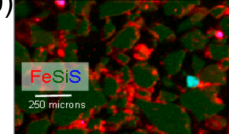
Controlled Field Studies

Southern Co Site/EPRI/ LBNL/ NRAP

- Determine how a leak of a given rate of CO_2 intrusion affects groundwater quality
  - Identify key reaction and transport processes
  - Test and improve reactive transport models and their predictive capability in a risk assessment context
  - Evaluate existing and new MVA technology for detection of CO_2 intrusion and/or related impacts

Host: Mississippi Power Co. (A Southern Company)

Location: Plant Daniel Escatawpa, Mississippi
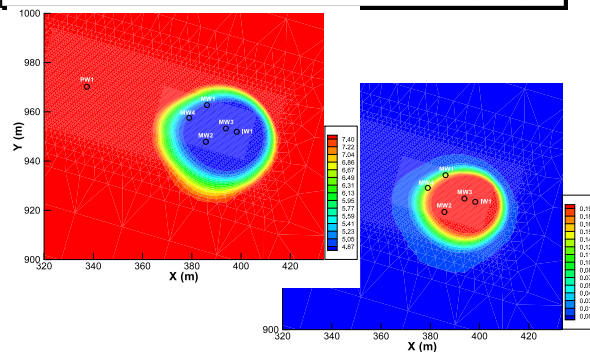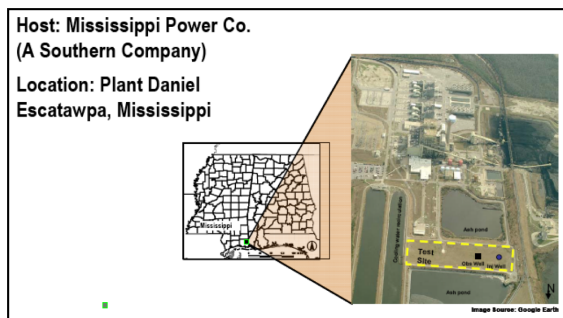
Controlled Field Studies: ZERT (Zheng et al. 2011)
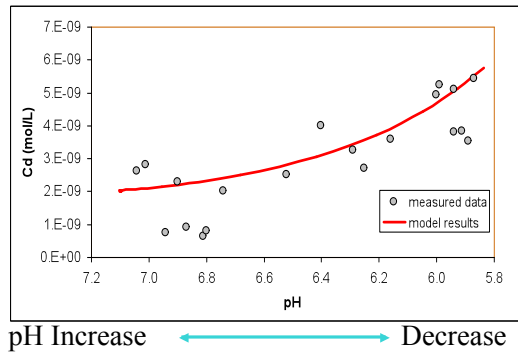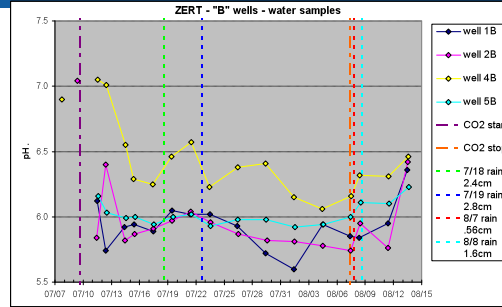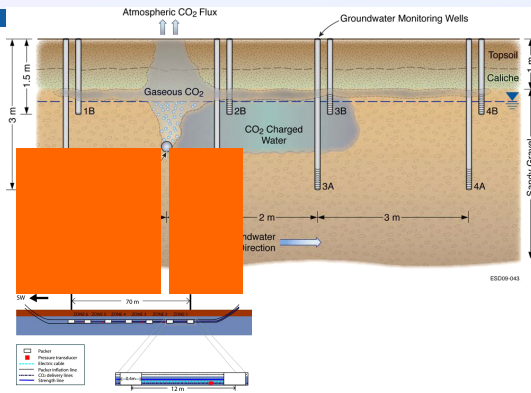
> Evaluate plausible processes responsible for the geochemical evolution of shallow groundwater in response to gaseous CO_2 injection: Ion exchange on clays driven by Ca^{+2} from calcite dissolution could lead to observed increases in Pb, Cu, Cd, and Zn

pH Increase ←——————→ Decrease

Natural Analog Sites
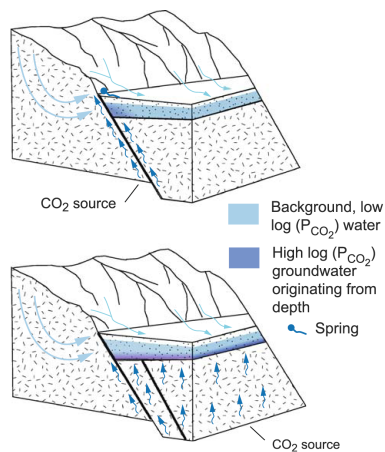
Fig. 1 Two types of natural analogs a) CO_2 rises with deep water along a fault and forms a CO_2-rich spring, b CO_2 rises with deep water along a faults and diffuses into shallow aquifer water. CO_2 degasses at springs and also along the water table to the vadose zone

Chimayo, New Mexico
(Keating et al., 2010)

• Brine leakage with CO2

• As, U, and Pb increases are associated with the brine and are not mobilized by CO2

• CO2 appears to lower F concentrations and improve water quality

How accurate can these impacts be predicted with modeling and analytical tools?

DOE, National Risk Assessment Program
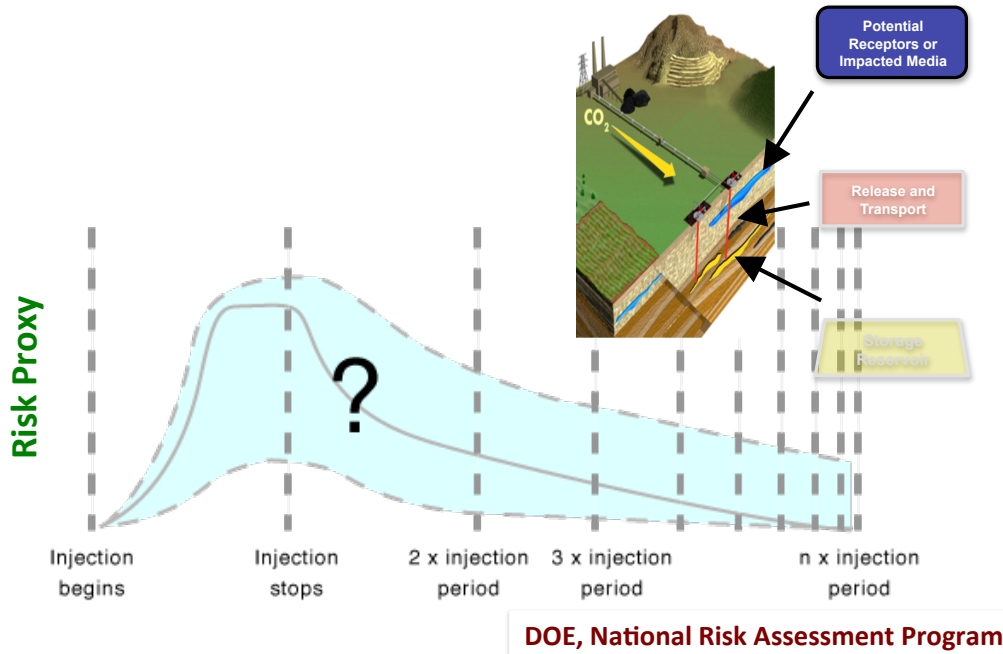
Uncertainty Quantification Analysis of High Plains Aquifer to Potential CO_2 leakage (Mansoor et al, ongoing)

Explore the spatial, temporal and 16 parametric dimensions

Structure Model	NUFT Model	
• Sand volume fraction	• Sand porosity	• van Genuchten α in sand
• Correlation length in x	• Clay porosity	• van Genuchten α in clay
• Correlation length in y	• Sand density	• Permeability in sand
• Correlation length in z	• Clay density	• Permeability in clay
	• van Genuchten m in sand	• CO_2 diffusivity
	• van Genuchten m in clay	• CO_2 leakage flux rate
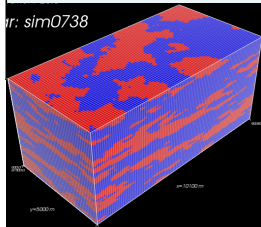
- Generated 1000 models
- Currently 590 successful model runs
- Approx. 50,000 hours CPU time
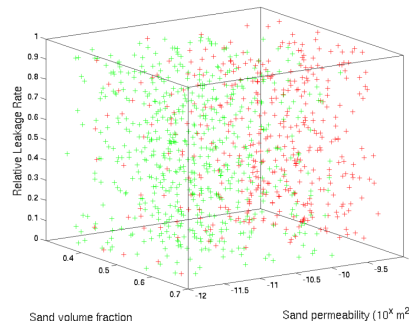
Dynamic Global Sensitivity: 10-year Base
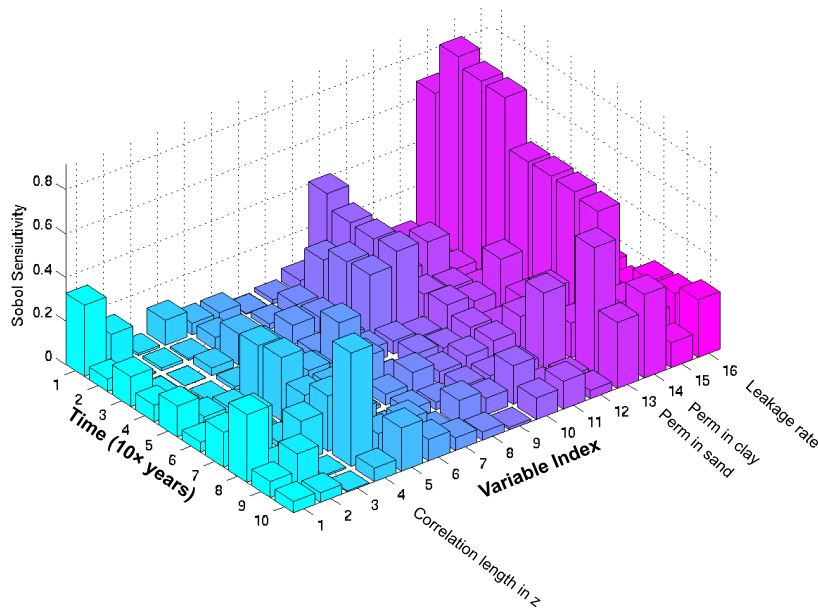
Use UQ analysis to extract risk from physics based simulations
Example: Volume Fraction of Aquifer for pH < 6.5
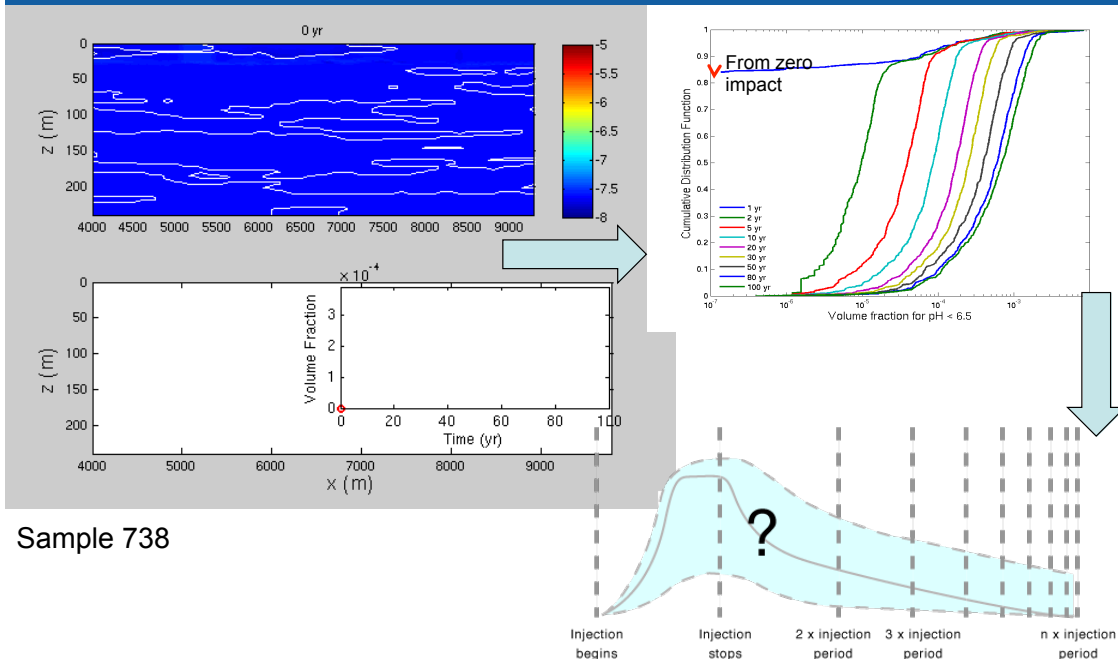
Sample 738

What are the potential ecological and health impacts?
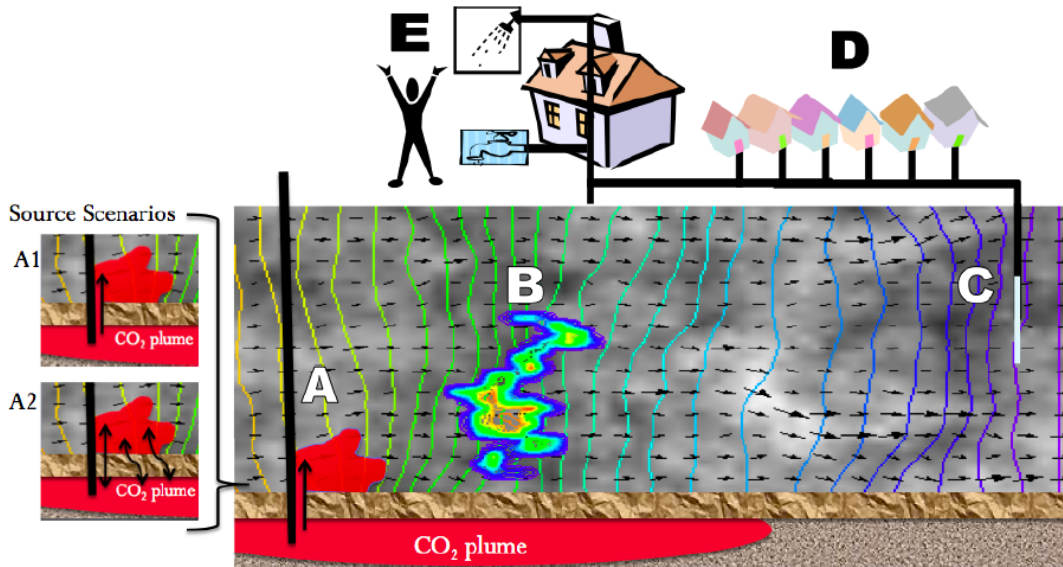
Figure 1. Schematic of the process involved in quantifying human health risk in CCS leakage (modified after Maxwell and Kastenberg [28]; Maxwell et al. [37]).

Siirila et al Advances in Water Resources, 2011

Carcinogenic risk is defined by a **toxicity** parameter, exposure **time** parameters, and by the environmental **concentration**

$$Risk = 1 - e^{CPF_{metal,i} \times ADD_{metal,i}}$$

Toxicity Value:
Cancer Potency Factor
(CPF)

Exposure Time :
Average Daily Dose (*ADD*)

$$ADD_{metal,i} = \overline{C}_{metal}\left[\frac{IN_i}{BW}\right]\frac{ED \times EF}{AT}$$

Environmental concentration: $\overline{C}_{metal}$

Risk=*f*(uncertainty, variability)

Carcinogenic risk, As vs. Pb
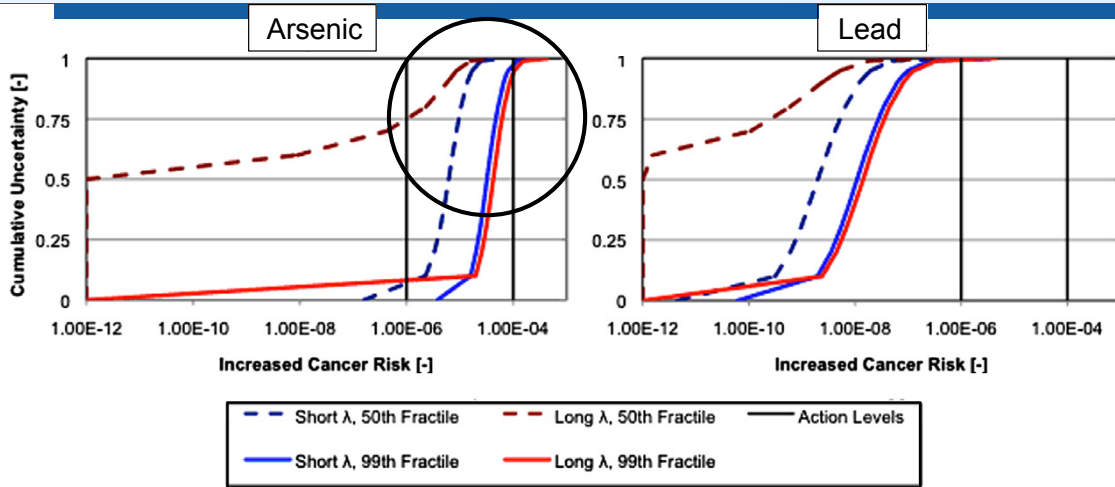
1. Because more lead sorbs in comparison to arsenic, $As_{Risk} > Pb_{Risk}$

2. A stratified domain (little macrodispersion) yields a larger distribution of uncertainty than less anisotropic domain (high macrodispersion)
   *this uncertainty propagates in overall risk

Siirila et al Advances in Water Resources, 2011

What is the role of USDW characterization and monitoring?

SACROC Field, Texas

•Over 30 years of CO2-EOR

•Sampled outside of SACROC in lieu of baseline

•Comparison yields
   •no indication of CO2 leakage
   •No change in groundwater quality

Smyth et al., 2009
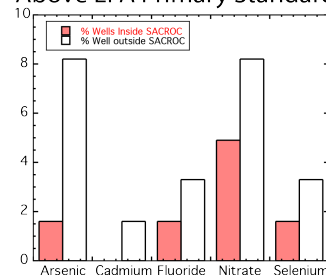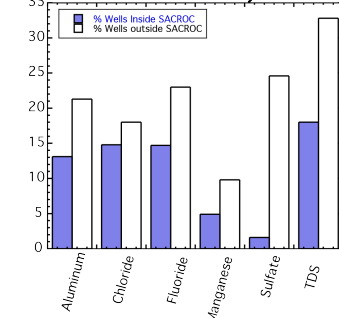
Monitoring studies above EOR-CO2 fields

Weyburn-Midale Field, Canada

•Baseline study is essential

•Sample water wells over life of the project

•No changes were observed in groundwater quality
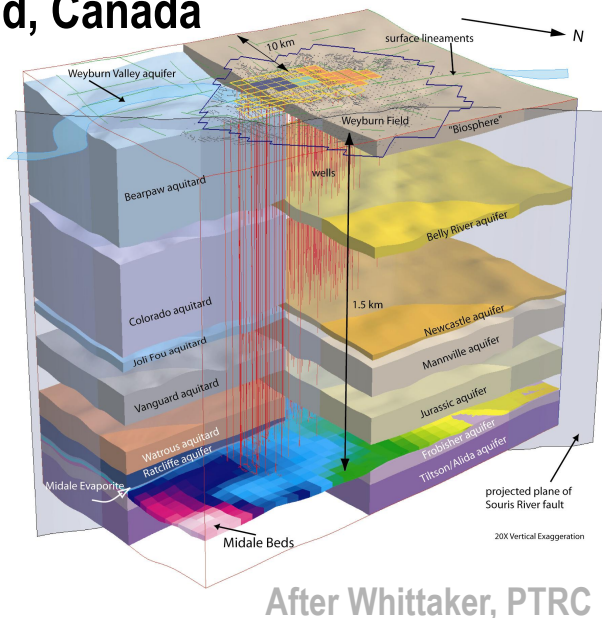
After Whittaker, PTRC

Objective: Prioritize research needs to ensure USDW are protected from underlying storage of carbon sequestration

- What are the main risk drivers?
  - Can these be identified based on qualitative site characteristics?
  - What is the role of system-level risk assessment models
- What is the impact of CO_2/brine intrusion on drinking water resources?
  - Identification of constituents of concern
  - Physics and Chemistry
- What is the role of modeling to assess impact and human and ecological risk?
- What is the role of USDW characterization and monitoring?

Objective: Prioritize research needs to ensure USDW are protected from underlying storage of carbon sequestration

- What are the main risk drivers?
  - Do we need a MCL for CO2
  - Brine leakage (TDS, metals, organics)
  - CO2 leakage (Methane, H2S, BTEX)
  - Organics
    - PAHS, Phenols,
    - BTEX
    - Organic acids, potential ligands for metals
  - Can these be identified based on qualitative site characteristics?
    - Is there a class of USDW that .
  - What is the role of system-level risk assessment models
    - Develop reduced order models
    - Investigate methods to update risk assessments
      - Use of monitoring data to reduce uncertainty
      - re-evaluate what process/parameters are important over time and space)
      - Accounting and inclusion of new data and understanding to risk assessments
- What is an acceptable risk?
  - What's important – water quality and/or human and ecological risk assessment?
- What is an acceptable leakage rate with respect to groundwater quality?

Objective: Prioritize research needs to ensure USDW are protected from underlying storage of carbon sequestration

- Mitigation
  - Natural attenuation
  - Reservoir Management
  - Can you stop the source of leakage?
    - Wellbore - yes
    - Fault - no

Objective: Prioritize research needs to ensure USDW are protected from underlying storage of carbon sequestration

- What is the impact of CO_2/brine intrusion on drinking water resources?
  - Identification of constituents of concern
  - Physics and Chemistry

Objective: Prioritize research needs to ensure USDW are protected from underlying storage of carbon sequestration

- What is the role of USDW characterization and monitoring?
  - Characterization to reduce uncertainty
  - Organics
  - Buffering capacity of rock
  - What is baseline?

Objective: Prioritize research needs to ensure USDW are protected from underlying storage of carbon sequestration

- What chemicals are going to be introduced into the aquifer through gas and brine leakage?
  - TDS
  - Metals-with brine
  - Metals-from aquifer
  - Organics
  - Methane, H2S, CO2, other gases
  - Impurities in the injected CO2
- What is the impact of the these constituents in the aquifer?
  - What are the chemical, physical, and biological processes that control the impact to the aquifer
  - Persistence of impacts, reversibility of impacts
  - Equilibrium vs kinetics (form of rate law)
- What are the indirect impacts due to changes in pressure resulting from GS operations
- What are the consequences to changes in groundwater quality
- Ability to detect in time and space
- Scaling
  - Lab scale (too short)
  - Field scale
  - Natural analogs (too long)
- Chemical processes (equilibrium, kinetics, sorption, redox)
  - What phases control the cycling of metals between solids and solution
  - Establish screening approaches based on some detailed studies
- Relative importance of reactive transport process overtime

Break-out Group #2:
Modeling and Mapping
the Area of Potential Impact

2011 Workshop on CO$_2$ Geologic Sequestration
&
Water Resources

Moderators
Stefan & Stephen   ☺
Bachu   Kraemer
AITF   EPA

Lawrence Berkeley National Laboratory, June 1-2, 2011

What is the Main Subject?

Defining, characterizing and modeling the volume of rock where CO$_2$ storage is envisaged or is already taking place, overlain by protected groundwater resources that may be negatively impacted by the CO$_2$ storage operation

Question: Does it mean that we are concerned only with onshore CCS Operations?

Although EPA Class VI well rules apply to offshore wells within state waters, there is no USDW there

Main Issues

- Understanding of what the subject of interest is
- Definition of Area of: Impact, Influence, Interest, Review…..
- Influence of natural and/or man-made conduits between the storage unit and protected groundwater in defining the Area of ?????
- Determination and characterization of such Area
- Modelling of this Area before application and permitting
- Re-evaluation of this Area as the CCS operation proceeds and new information and data become available through monitoring
- Effects of multiple, adjacent, overlapping and/or stacked CCS operations
- Is there software readily available for use by operators and regulators?
- How the national labs, DOE and EPA-ORD can support/assist UIC programs in evaluating and permitting applications, and monitoring evolution

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Useful Definitions - 1

- **Storage Unit**: The geological unit into which CO_2 is injected (depleted oil or gas reservoir, or deep saline aquifer; coal beds, shales and basalts are not considered at this time). May or may not be laterally bounded by lithological (low permeability) boundaries
- **Primary Seal**: The caprock (aquitard or aquiclude) immediately overlying the storage unit; may or may not include lateral lithological (low permeability) boundaries
- **Storage Complex:** The system comprising the storage unit and the primary seal extending laterally to natural boundaries of low permeability or to the defined limits of the effects of CO_2 storage operation(s)
- **Secondary Traps and Seals**: Succession of aquifers and aquitards/ aquicludes in the sedimentary package between the storage complex and the base of protected groundwater
- **Underground Source of Drinking Water**: An aquifer that supplies any public water system or that contains a sufficient quantity of ground water to supply a public water system, and currently supplies drinking water for human consumption, or that contains fewer than 10,000 mg/L total dissolved solids and is not an exempted aquifer.

4

Useful Definitions - 2

- **CO_2 Migration:** Movement (flow) of CO_2 within the storage unit
- **CO_2 Leakage:** Movement (flow) of CO_2 outside the storage complex
- **Brine Leakage**: Movement (flow) of displaced native brines outside the storage complex
- **Main CO_2 Plume**: The 3D region in the storage unit occupied by free-phase CO_2. Does it matter if it is mobile or immobile, or dissolved?
- **Secondary plume**: Plume of CO_2 formed in an aquifer overlying the main storage unit as a result of CO_2 leakage
- **Zone of Impact:** Surface and subsurface region where the effects of CO_2 storage may be measured either directly (e.g., geomechanical effects) or as a result of CO_2 or brine leakage into other aquifers or reservoirs, and/or protected groundwater, or CO_2 leakage to the atmosphere
- **Zone of endangering influence**: region delineated by pressures that might cause migration of the injection or formation fluids to flow into the USDW.
- **Area of Review:** region surrounding the GS project where the USDW may be endangered by the injection activity.

5

Evolution of Thinking

- **Early Thinking**
  - **Area of interest:** area occupied only by CO_2
  - **Leakage:** only of CO_2, driven by pressure forces and by buoyancy

- **Latest Thinking**
  - **Area of Interest: i**ncludes area of elevated pressure
  - **Leakage:** of CO_2 and/or formation water from the storage unit
  - **Pressure Build-up**: pressure increase as a result of injection
  - **Elevated Pressure:** pressure sufficient to lift formation water (brine) from the storage unit into protected groundwater aquifers through an open fracture or defective wells

- From the point of view of Underground Sources of Drinking Water, only leakage into protected groundwater matters. However, from the point of view of resource protection, leakage of CO_2 and/or brine into other intervening aquifers or oil or gas reservoirs matters as well

6

EPA's Underground Injection Control (UIC) Class VI Wells Regulations

- CO_2 sequestration wells (Class VI wells) are regulated under the UIC program (Safe Drinking Water Act), its main focus being the protection of groundwater resources (USDW with TDS < 10,000 mg/L)

- Applicants for a permit need to define an Area of Review (AoR), in which the presence of conductive features connecting the injection reservoir and USDW needs to be assessed

- EPA's Area-of-Review delineation considers both the possible migration of CO_2 (i.e., CO_2 plume extent) and the possible migration of brine (i.e., extent of pressure front)

- With respect to the pressure-based AoR delineation, it is suggested to determine a threshold pressure above which brine displacement could occur via a permeable pathway, such as an open wellbore, connecting the injection formation and a USDW

- According to the EPA Guidance on Area of Review Evaluation (Draft), the AoR comprises the region where the predicted pressure exceeds this threshold pressure (unless the region of maximum plume size is even larger; can this be?)

- This regulatory concepts considers only whether flow may occur or not, not what the flow rates or the potential impact might be

7

Illustration of Pressure Effects

from Birkholzer et al., 2008
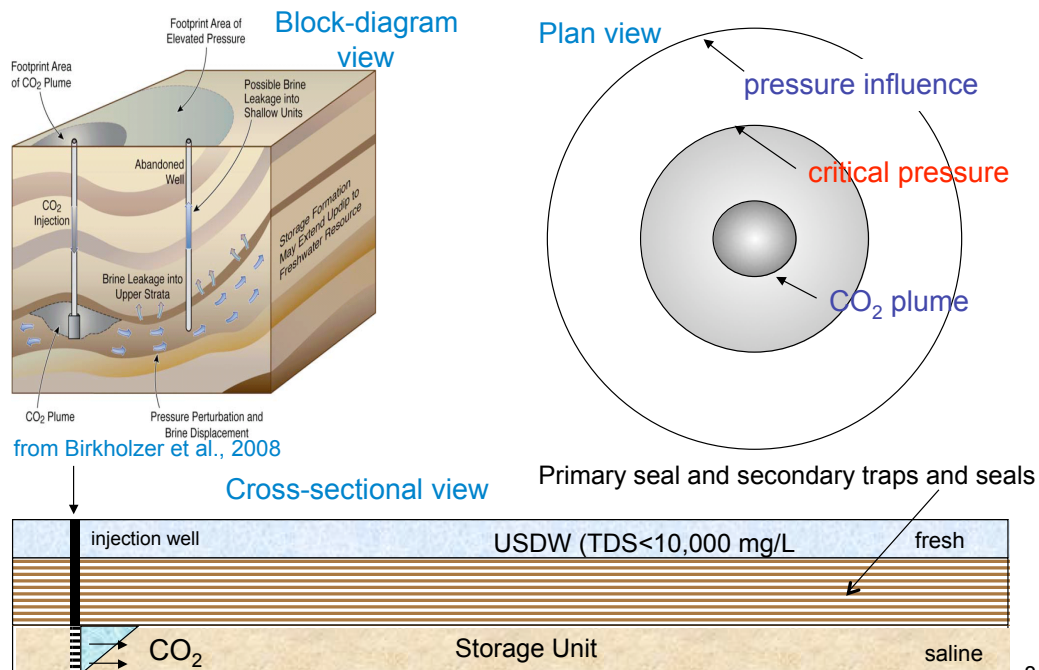
8

Critical Pressure Threshold – Equilibrium Calculations
The pressure build-up that will bring saline water up to USDW

initial

final

ρ_w

ρ_b

ρ_w

ρ_b

ρ_b

$$\Delta P_{crit} = \frac{gl}{2}\left(\rho_b - \rho_w\right)$$
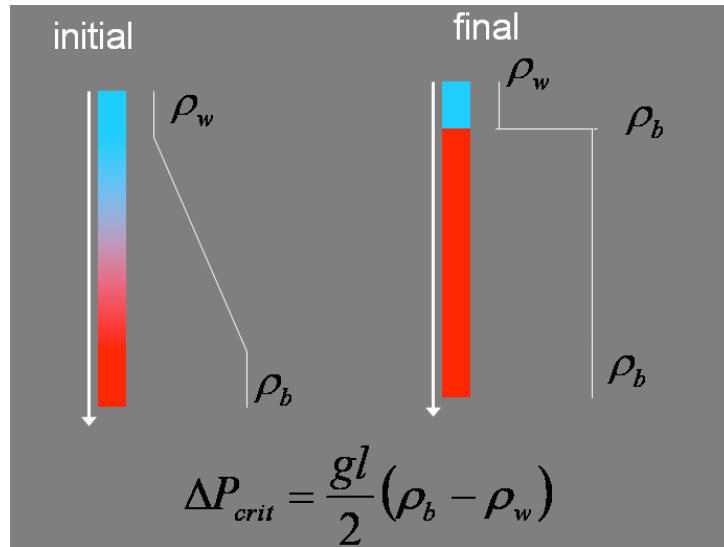
Bandilla, Kraemer, Birkholzer manuscript
Nicot et al., 2009

Water density ρ= F(p, T, S)

9

Critical pressure threshold – dynamic calculations

equilibrium critical
pressure = 2.1 bar

——	DP = 1 bar
——	DP = 2 bar
——	DP = 3 bar
——	DP = 5 bar
——	DP = 10 bar
——	DP = 15 bar

TOUGH2

Flow Rate into Aquifer (kg/s)

Time (days)

Birkholzer et al, 2011

10

EPA UIC Area of Review

CO$_2$ front

Critical pressure front

AoR = MESPOP
(maximum extent of the separate-phase plume or the pressure front)

Explanation
Injection well #1
○   Injection well
——   Pressure front (pressure great enough to cause fluid movement into USDW)
——   Maximum predicted extent of supercritical carbon dioxide plume
– – –   Delineated area of review (maximum extent of supercritical carbon dioxide or pressure front)
Source: Daniel B. Stephens & Associates, Inc.

11

EPA's GHG Reporting Rule – monitoring areas
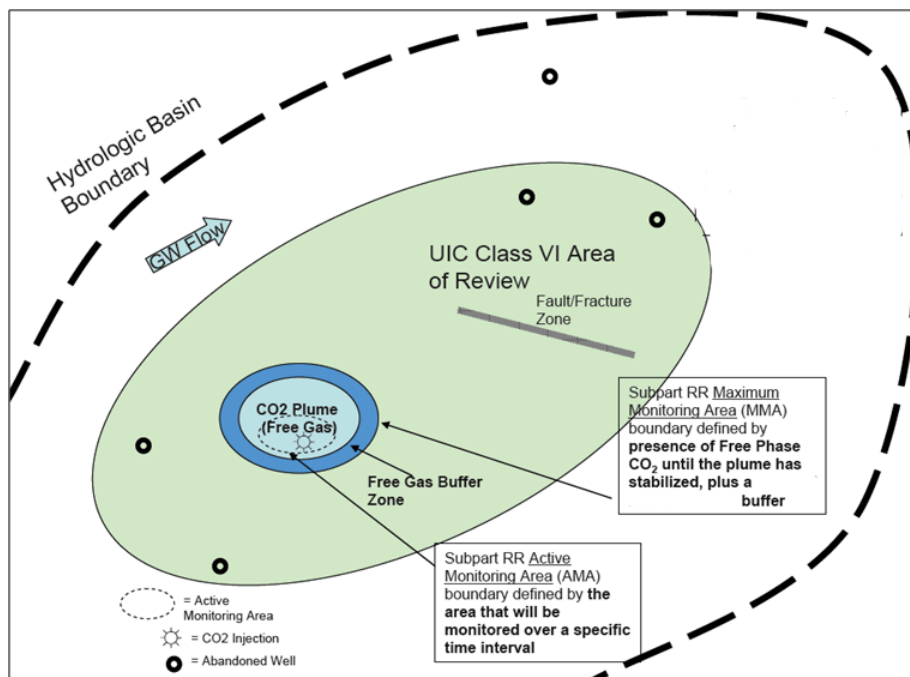
12

Some Results to Date

- The presence of secondary traps and seals reduces leakage into protected groundwater ("elevator effect"; Nordbotten et al., 2005)

- Individual CO_2 plumes in adjacent CO_2 storage operations may not coalesce and will not spread afar, but pressure effects will be felt faster and farther away, and will add up (textbooks, Birkholzer & Zhou, 2009)

- Brine and pressure diffusion through the caprock has a significant effect in elevating or dissipating pressure (texbooks, Birkholzer & Zhou, 2009)

- Impact of pressure and temperature variations along an open borehole are negligible compared with salinity effects and depth (Bandilla, 2010)

13

Princeton's Analytical Model

(from Nordbotten and Celia, *JFM*, 2006)

Princeton's Semi-analytical model
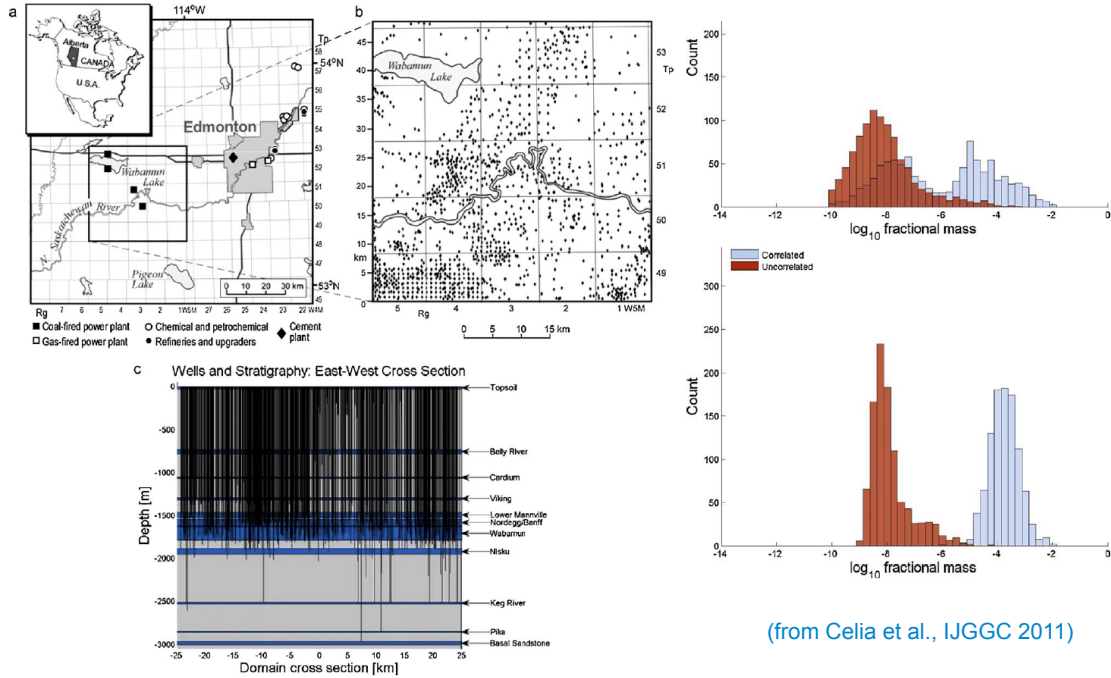
(from Celia et al., IJGGC 2011)

1146 wells, leakage into the shallow aquifer after 50 years of injection never exceeds 1%

15

Multi-Layer Semi-analytical Model
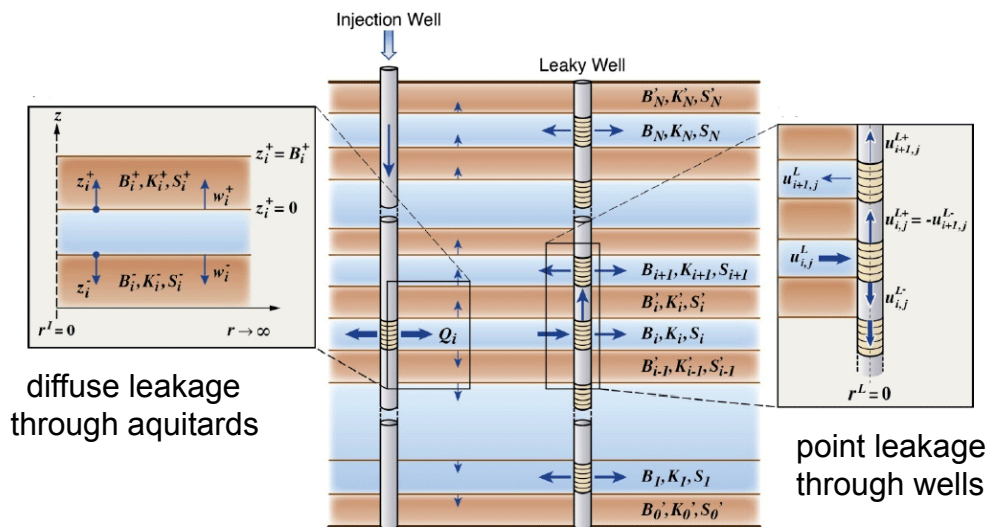
diffuse leakage through aquitards

point leakage through wells

Cihan, Zhou, Birkholzer, LBNL

Bakker, TU Delft

16

Illustration of Numerical Model
Mt. Simon Aquifer in the Illinois Basin

Birkholzer & Zhou, IJGCC 2009
Zhou et al., GW, 2010

Thickness of Mt. Simon (m)
and injection sites
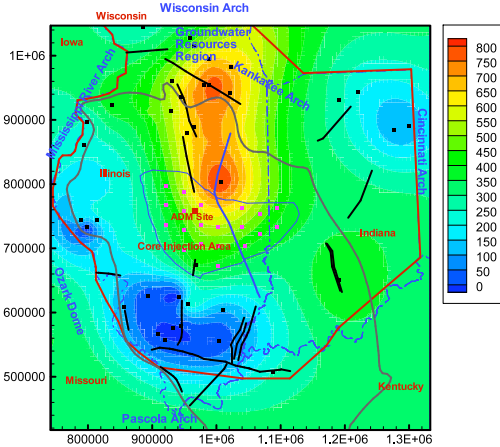
TOUGH2/ECO2N
24 node Linux supercomputer

20 hypothetical injection wells
5 Mt CO_2/yr each
Total 100 Mt/yr
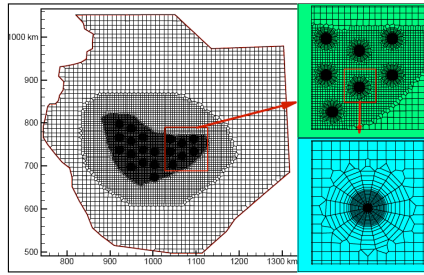
Eau Clare primary seal
Mt. Simon Sandstone

Potential Seal

Potential Sink

Potential Sink

2000 m
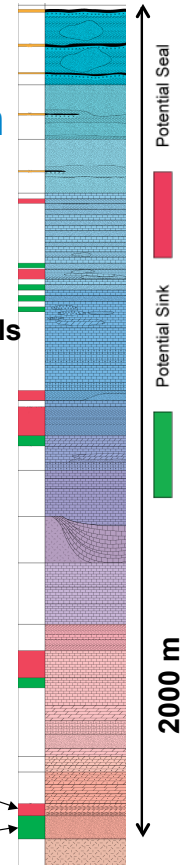
CO_2 Plumes and Pressure Build-up

Regional to basin scale

Local scale

CO_2 saturation at 50 yrs
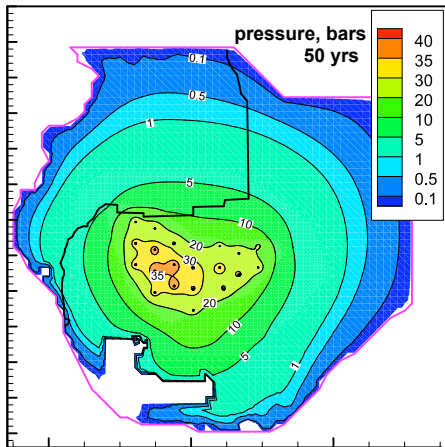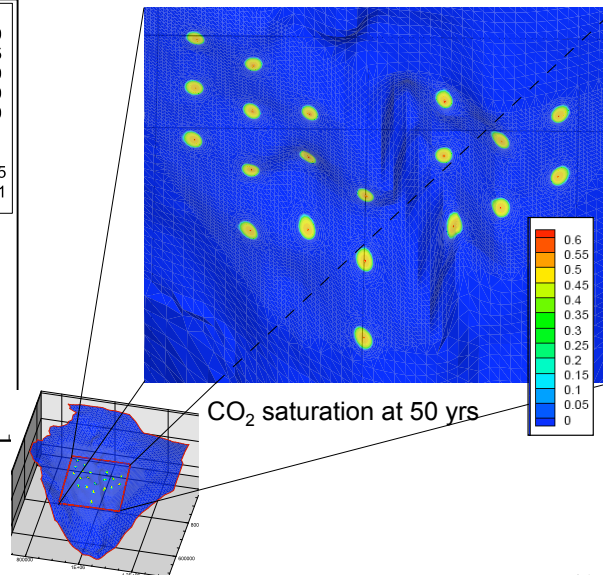
(from Birkholzer & Zhou, 2009)

18

Characterization

- **Geology:** The entire sedimentary succession from the storage unit to surface
- **Hydrochemistry:** Chemistry of all the aquifers from the storage unit to protected groundwater (inclusive of both ends)
- **Hydrogeology**: The pressure regime and flow direction and magnitude in all the aquifers from the storage unit to the surface
- **Rock Flow Properties:** porosity, permeability and relative-permeability for all the aquifers from the storage unit to the surface
- **Planar and Linear Conduits (faults, fractures and wells)**: Flow characteristics
- **Rock Mineralogy:** For all the rocks that may come in contact with CO_2 and/or CO_2-saturated water

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Models

- Analytical/Semi-Analytical:
  - Capable of handling multiple aquifers, many wells, fast
  - Require certain simplifying assumptions
  - Allow multiple realizations for various scenarios
  - Easy to use

- Numerical:
  - Capable of handling variability and heterogeneity
  - May describe better complex, coupled processes
  - More difficult to set up and use
  - Allow analysis of only few scenarios
  - Computer resource intensive and time consuming

We expect the simple semi-analytical modeling tools to complement the more complex computational/numerical reservoir simulations and help regulators evaluate applications from operators

20

Discussions

- What data and tools the operators need to perform their analysis for site selection and application?

- What data and tools the regulators need to assess applications?

- How the research community can help?

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Topic 3: Monitoring and Mitigation
for protection of groundwater and surface

water resources

- State-of-the-art of monitoring methodologies
- State-of-the-art of mitigation methodologies
- Identify future research needs

⭐ = topic highlighted in pre-meeting discussion

Components for discussion

- Location of targets monitored – Deep vs. shallow
- Scale of monitoring
- Frequency of monitoring
- Quantification of stored/leaked
- Role of modeling
- Mitigation
- Remediation

Settings that can be monitored

Atmosphere

Biosphere

Vadose zone & soil

Aquifer and USDW

Seal

Monitoring Zone

Seal

CO_2 plume

- Atmosphere
  - Ultimate receptor but dynamic
- Biosphere
  - Assurance of no damage but dynamic
- Soil and Vadose Zone **Complex!**
  - Integrator but dynamic
- Aquifer and USDW
  - Integrator, slightly isolated from ecological effects
- Above Zone monitoring interval **AZMI**
  - First indicator, monitor small signals, stable.
- In injection zone - plume
  - Oil-field type technologies. Will not identify small leaks **Complex!**
- In injection zone - outside plume
  - Assure lateral migration of CO_2 and brine is acceptable

Monitoring box= Storage complex =MESPOP= AoR

Spatial Scale of Investigation: What Tools? What Resolution?

Scale of Investigation

Regional ~10 to 10^4 m

Local ~10^{-2} to 10^2 m

Lab ~10^{-4} to 10^{-1} m

Satellite (InSAR)

Surface Seismic

Borehole Seismic VSP, Crosswell

Well Logs

Core Tests

~10^{-3} to 1 m   ~10^{-1} to 10 m   ~10 to 10^3 m

Approximate Spatial Resolution
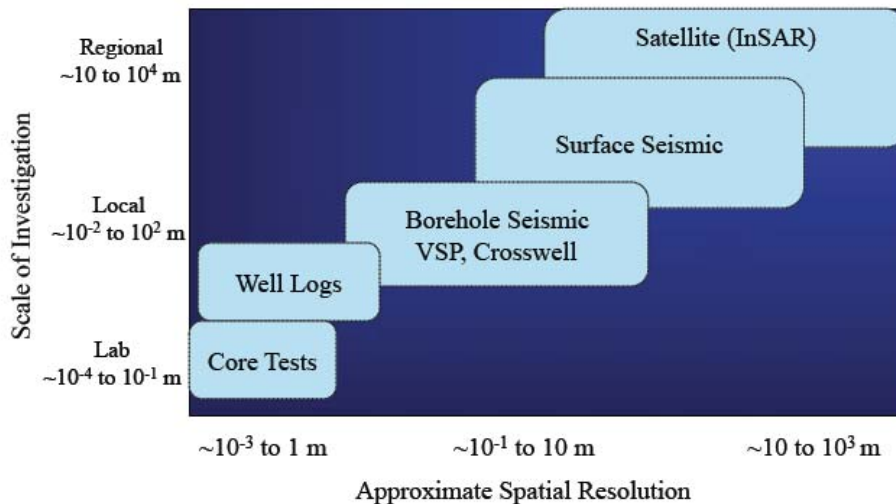
T.M Daley

Temporal Sampling:
'Snapshot' versus Continuous Monitoring

- **Time Lapse Snapshots** - Constrain model at specific times with good spatial resolution
  - 3D Surface Seismic
  - Vertical Seismic Profile (VSP)*
  - Crosswell Tomography/Imaging (Seismic, Electrical)*
  - Well Logging
    - RST, Sonic*, Resistivity
- **Continuous Monitoring** – Constrain model dynamics
  - U-Tube Fluid Sampling
  - CASSM (Continuous Active-Source Seismic Monitoring)*
  - ERT (Electrical Resistance Tomography)
  - DTPS (Distributed Temperature Perturbation Sensing)
  - Deep Borehole Microseismic

T.M Daley

Assessment of Deep Targets

- Track two phase plume and pressure migration

Detect leakage out of storage complex

— Quantification??

— Non-invasive vs. well based

State –of-art monitoring **State –of-art-mitigation** **Future research**

Shallow Monitoring Technologies

- What monitoring methods are best at detecting leakage to resource:
  - groundwater
  - vadose zone
  - surface water bodies?
- Which indicators can be used to detect drinking water issues arising from
  - Reservoir fluids themselves: injectate constituents, brine, organics
  - hydrogeochemical reactions in the aquifer
- Which monitoring methods give reliable results?
  - Background, thresholds of concern
  - Frequency, methods, spatial coverage
  - Role of tracers
  - Quantification

Modeling

- What current and future software tools are needed for analyses of data generated by monitoring efforts?
  - How to history match?
  - What defines conformant response?
- Can data be effectively integrated with existing water resource datasets (e.g. USGS aquifer database)?

State –of-art monitoring **State –of-art-mitigation** **Future research**

Mitigation

- Short term response to leakage detection to stop or limit leakage amount
    - Limit plume migration
    - Subsurface pressure management
    - Reduction of permeability of leakage pathways
    - Barrier implementation

State –of-art monitoring State –of-art-mitigation Future research

Remediation

- Longer term than mitigation -- engineered repair of environmental damage
- What remediation technologies are available?
- Can water quality changes in response to leakage be remediated?
    - Groundwater
    - vadose zone
    - surface water

State –of-art monitoring State –of-art-mitigation Future research

View from Field: Linking Parts Together

Detailed site characterization
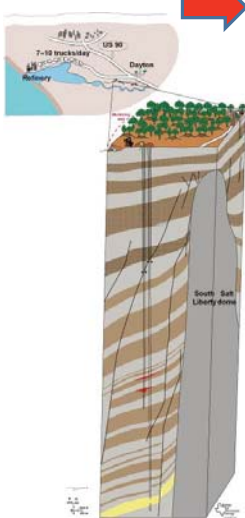
Model plume and pressure with range of uncertainties
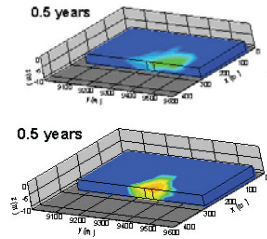
Risk Assessment= low risk, find no significant [material]*uncertainties

* That might lead to failure to meet performance standard

0.5 years

0.5 years

Operate and monitor as permitted
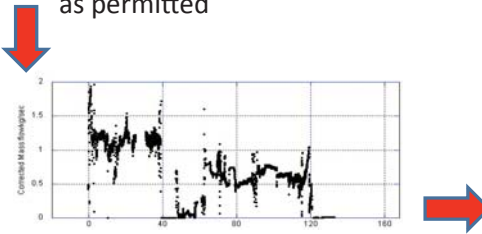
Linking monitoring to actions

Something unexpected is observed

Something obvious or drastic
 Dripping or roaring
Climbing injection pressure, etc.

Fix

Remediate

Positive leakage indicators
Something caused by injection, cause unclear:
AZMI Elevated pressure, fluid change, T change
Bright spot AZ in seismic
Salinity increase in USDW

Test plan to diagnose

Monitoring?

False indicators
Something likely not caused by injection, cause unclear:
AZMI Elevated pressure, fluid change, T change
Bright spot AZ in seismic
Salinity increase in USDW

?!*

What is the solution?

- Elegant monitoring approaches that lead to simple answers

- "Research-like" approaches that test multiple hypotheses – how are these deployed in a regulatory environment?

Comments

- Geochemical contamination implicit in sampling
- Detecting migration of CO_2 and brine along fault and fracture systems?
- Role of background measurements
- Can leakage be quantified?
- What would be the margin of safety regarding leakage?
- Thresholds of concern – for example if a leak is suspected based on a list of monitored constituents but primary and secondary EPA standards are not exceeded, when is action required?

Comments con't.

- Explore the use of optimization techniques (e.g., location/allocation methods) for the design of the monitoring network. Number of wells sufficient?
- The use of sensors for in situ "non-invasive" monitoring is preferable

Topic 4: Wells as Leakage Pathways

Group Members:
- Bill Carey, LANL
- Randall Ross, EPA
- Brian Strazisar, NETL
- Andrew Duguid, Schlumberger
- Sarah Gasda, University of North Carolina
- Preston Jordan, LBNL
- Nik Huerta, UT
- Walter Crow, BP
- Jonathan Koplos, Cadmus Group
- Jim Houseworth, LBNL
- Sean Porse, EPA
- Steve Acree, EPA
- Carl Miller, EPA

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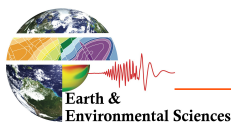
LA-UR-11-10919

Los Alamos

Title and Abstract

Wells as Leakage Pathways
J. William Carey (bcarey@lanl.gov; Earth & Environmental Sciences Division, Los Alamos National Laboratory, Los Alamos, NM 87545)

In EPA guidance documents for the geologic sequestration of CO_2, wells are one of the primary risks to a successful CO_2 storage programs. In this presentation, I review basic concepts in wellbore integrity and discuss the latest experimental, field, and computational studies. Experimental studies show that wellbore materials react with CO_2 (carbonation of cement and corrosion of steel) but the impact on zonal isolation is unclear. Field studies of wells in CO_2-bearing fields show that CO_2 does migrate external to the casing, however rates and amounts of CO_2 have not been quantified. Computational studies have emphasized Darcy flow, although the applicability to flow along defects in wellbore systems is not well known. I conclude by examining the question of long-term (500 year) performance of wells and a series of key research questions for the coming years.

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Los Alamos
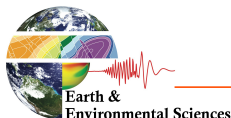
What Does Wellbore Failure Look Like?

Crystal Geyser: CO_2 from abandoned well
http://www.4x4now.com/cg.htm

Deep Horizon Blowout
Natural gas and oil
http://whistleblowersblog.org
Credit: US. Coast Guard

Slow casing leak
Natural gas
Watson and Bachu 2007

How Is Wellbore Integrity Achieved?

- **Operational measures**
  - **Adequate weight drilling mud**
  - **Monitoring pressure for gas intrusion ("gas kick")**
  - **Blowout preventers**
- **Design measures**
  - **Steel**
  - **Portland cement**

www.theoildrum.com

Production design

Conductor Casing
Surface Casing
Cement
Production Casing
Cement Top
Production Tubing
CO2
Perforations

Abandonment

Conductor Casing
Cement Plug
Surface Casing
Cement
Production Casing
Cement Top
Cement Plug
CO2
Cement Plug
Perforations
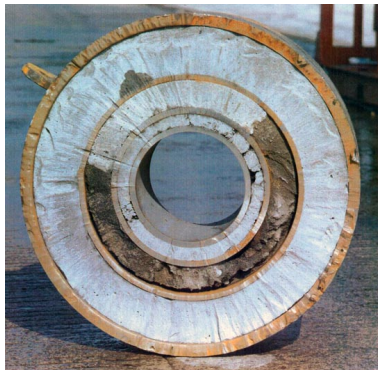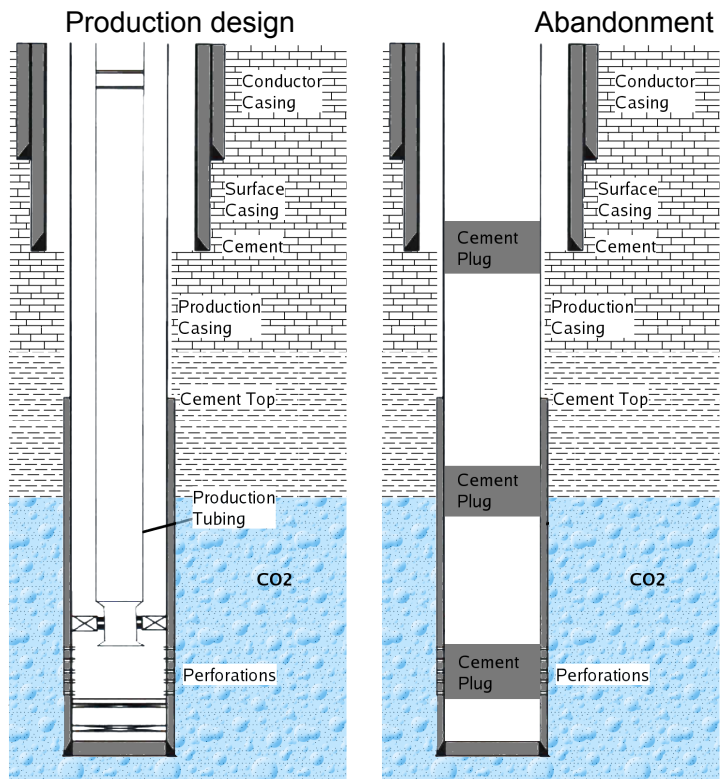
Wellbore Integrity: What can go wrong?

Pre-production
- Formation damage during drilling (caving)
- Casing centralization (incomplete cementing)
- Adequate drilling mud removal
- Incomplete cement placement (pockets)
- Inadequate cement-formation bond
- Inadequate cement-casing bond
- Cement shrinkage
- Contamination of cement by mud or formation fluids

Production
- Mechanical stress/strain
  - Formation of micro-annulus at casing-cement interface
  - disruption of cement-formation bond
  - Fracture formation within cement
- Geochemical attack
  - Corrosion of casing
  - Degradation of cement
    - Carbonation
    - Sulfate attack
    - Acid attack

Oil and Gas Production
Wellhead Not to Scale
-80'
Cement
Steel Casing
Cement
-2500'
Steel Casing
Drilling Mud
Cement
Production Tubing
Packer
Perforations
Cement
Steel Production Casing
Wellbore Not to Scale

State of Alaska Oil and Gas Division
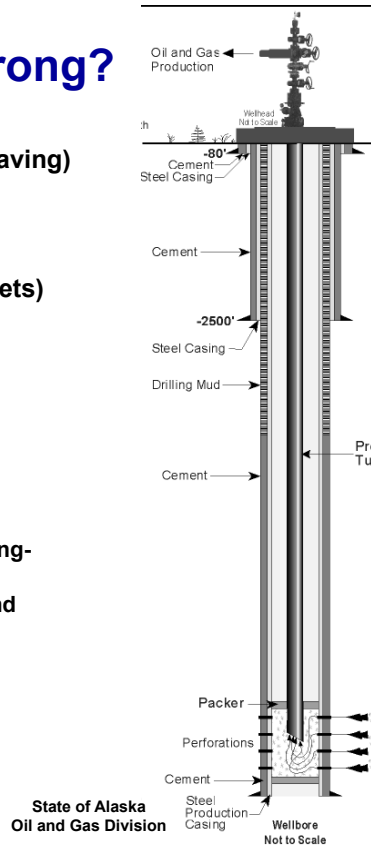
Old Wells vs. New Wells

- **New wells for carbon storage sites are likely to be purpose-built and may contain novel, CO_2-resistant construction materials**
- **Old wells were designed for a limited service life (40-50 years)**
  - **Wells above the storage reservoir could provide a path upward**
- **The construction practices and abandonment conditions of old wells may be unknown**
- **Uncertainties with old wells drives some project to areas (or depths) without significant well penetrations**
- **However, this means giving up on some of the most economically feasible and well studied potential reservoirs**
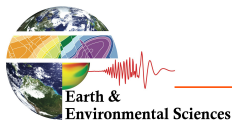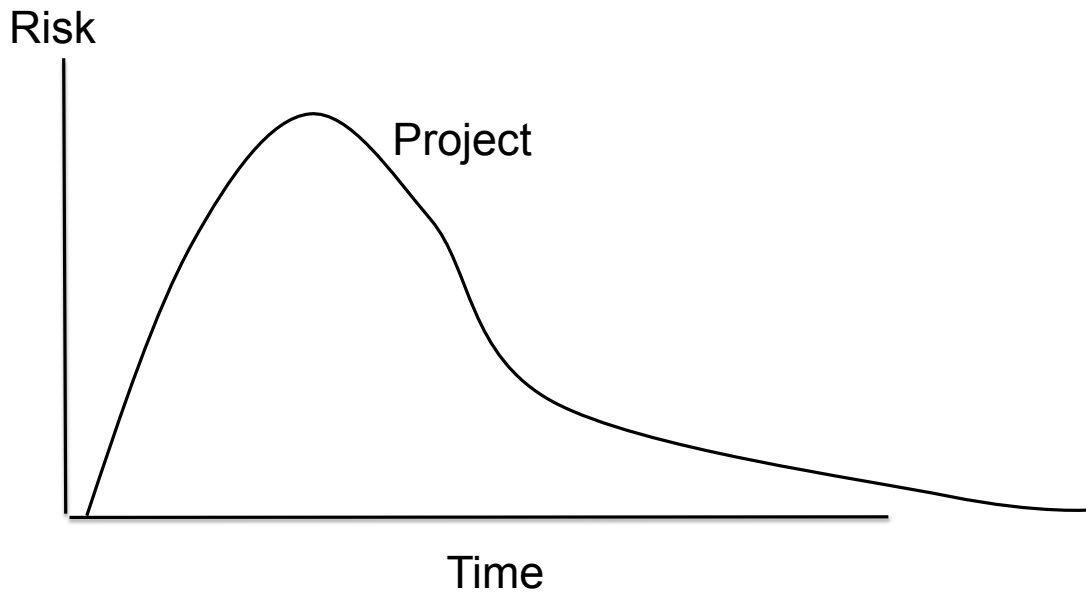
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Long-term Risk and Wellbore Integrity

Long-term Risk and Wellbore Integrity

Long-term Risk and Wellbore Integrity

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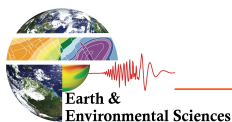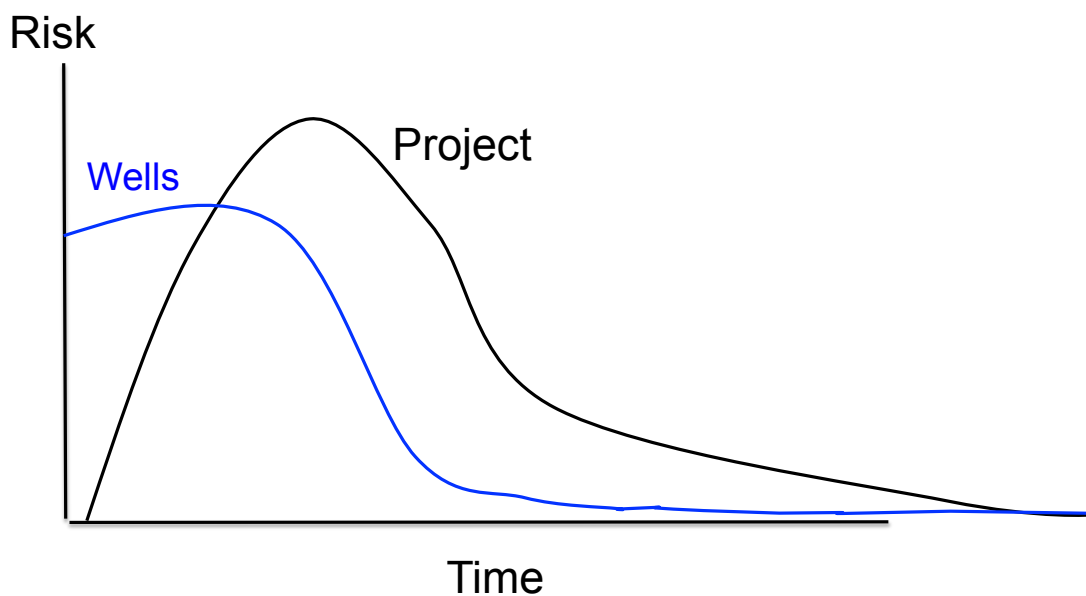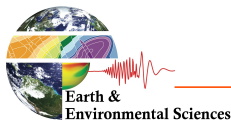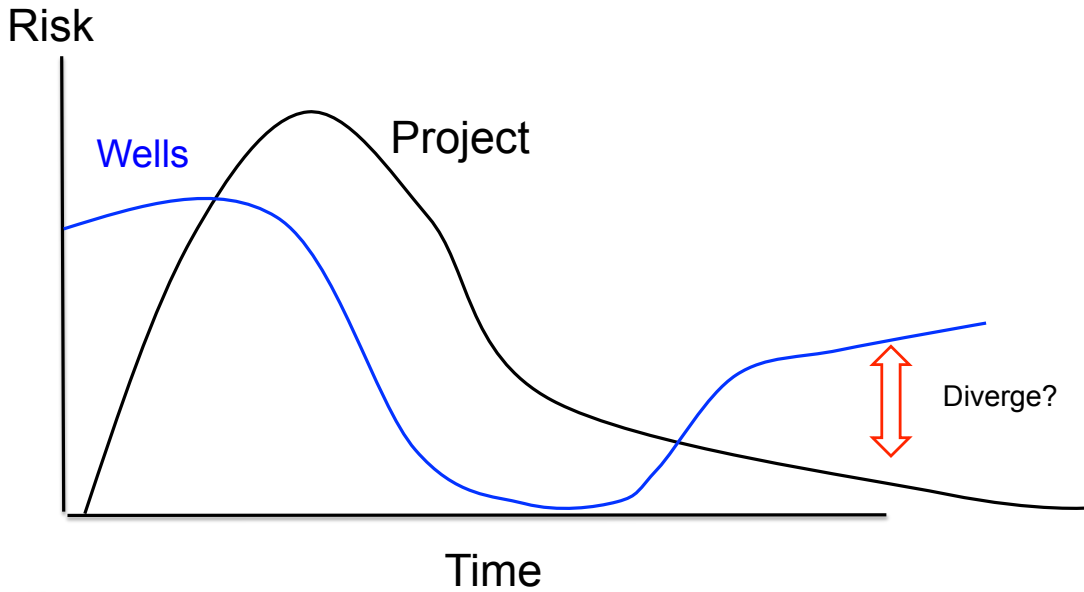
How Do Wells Leak? Long-Term Integrity and Leakage Pathways and Deterioration Mechanisms

Earth & Environmental Sciences
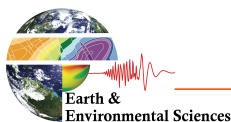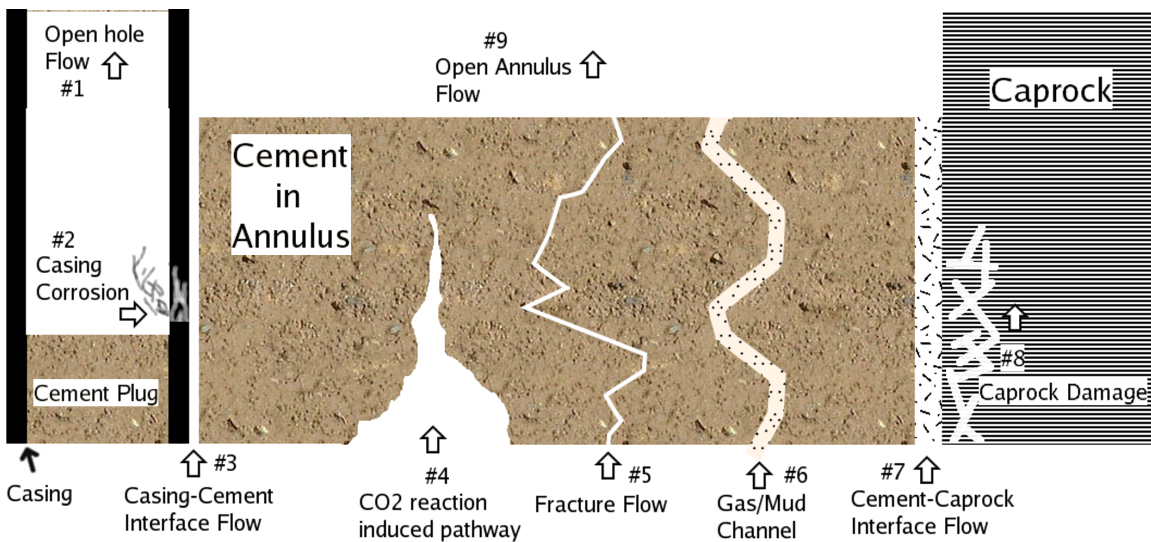
Not to scale

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Research in Wellbore Integrity

Field Studies

Experimental Studies

Computational Studies
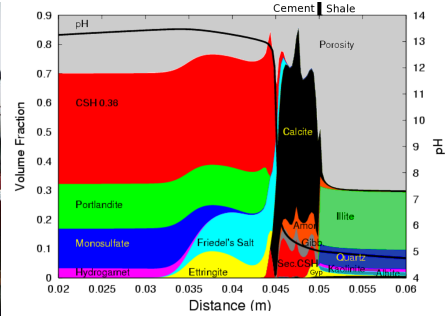
Much work has focused on wellbore material stability; fewer studies have evaluated field performance of wells

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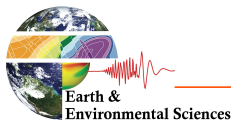
Wells in Context: Risk Assessment

Storage System
- Capacity
- Injectivity

Containment
- Caprock
- Fault
- Wellbore

Potential Receptors

Potential Consequences

Development of a probabilistic system model (e.g., Stauffer, Pawar, et al.; Oldenburg et al.)

$P_{wellbore\ failure}$

time
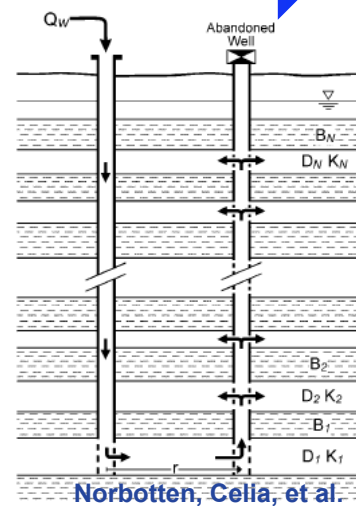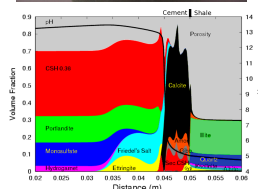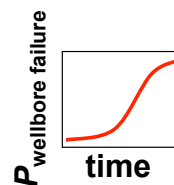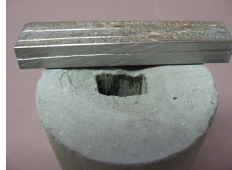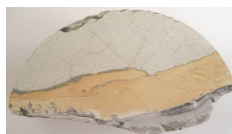
Norbotten, Celia, et al.

EPA guideline issues/questions

- **No established connection between CO_2-resistant materials and long-term, well integrity (external well leakage)**
- **External mechanical integrity tests are specified, but little CO_2-specific research exists on this topic!**
- **What materials comply with guidelines for CO_2-resistant wells?**
- **How are non-injection wells within the area-of-review different/same in design/monitoring requirements?**
  - **How do you demonstrate that an abandoned well is not a risk?**

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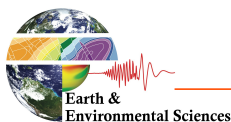
Other Issues

- **Historical records of well performance based on falling reservoir pressures**
- **Focus of leakage concerns has been CO_2, but brine may be much more significant in terms of impact and number of wells affected**
- **Is it conceivable (or even permissible) to allow unremediated wells in the Area-of-Review?**

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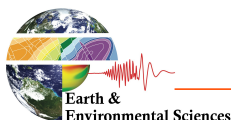
Key RA Topics in Wellbore Integrity

- **Frequency of well failure**
  - **Acute versus chronic events**
  - **Impact of wellbore leakage**
- **Relationship of wellbore construction and operational history to leakage potential**
- **Detection and monitoring of wellbore leakage**
- **Mitigation and prevention of wellbore leakage**
- **Effective permeability of wells including time-dependent leakage rates**
- **Long-term performance of wells**

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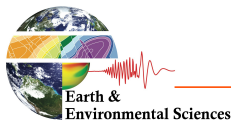
Questions (1)

- **How do we approach the long-term performance question when we do not have experience with well performance that extends past the 70-80 year period.**

- **In risk assessment, how do we identify likely-to-fail wells**

- **Are mechanical integrity tests of the type used by regulation adequate to prove well integrity and over what period of time?**

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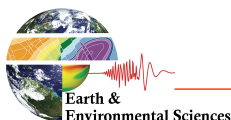
Questions (2)

- **Should well integrity requirements differ for wells within the plume versus wells outside the plume but in the area-of-review?**

- **How do we integrate laboratory studies and field observations of well behavior into a model of well leakage risk?**

- **How do we capture the fact that a well can be full of defects but still be protected by a single, 1-m section of good material?**

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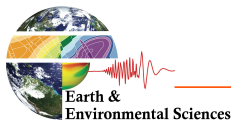
Questions (3)

- In assessing the potential for wellbore leakage, what are the relative significances of original construction, use of CO_2-vulnerable materials, geochemical deterioration, and geomechanical deterioration,

- How much effort should we place on developing guidelines for new, CO_2-storage specific wells and must these wells be constructed of stainless steel and CO_2-resistant cement?

- What post-completion monitoring technique demonstrates (proves) that wells don't leak?

- Can wells with carbon steel and ordinary Portland cement that have proven integrity today be considered adequate in a CO_2 sequestration area-of-review?

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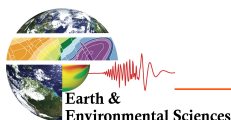
Questions (4)

- **Will a full wellbore leakage model require a coupled multiphase fluid flow, geochemistry, and geomechanics model?**
- **Are wellbore leaks primarily confined to the internal casing, the external annulus, or do they mostly disperse into shallow groundwater systems before reaching the surface?**
- **How do we obtain effective permeability data for leaking wells?**
- **What remediation activities and what costs are associated with typical CO_2-EOR development in older fields?**

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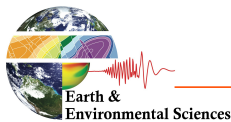
Questions (5)

- **Should all wells have cathodic protection in a CO_2 sequestration region? For how long?**
- **Do all wells leak?**
- **The pressure pulse will generally be much larger in area than the CO_2 plume and therefore there may be many more wells at risk from brine leakage. What should the focus be in terms of risk?**
- **What is the leakage significance of cement carbonation?**

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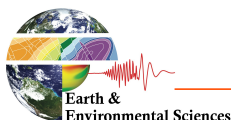
Questions (6)

- **How do you find/identify abandoned, uncased wells?**

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