STATEMENT OF

DR. ROBERT C. BURRUSS
RESEARCH GEOLOGIST, ENERGY RESOURCES TEAM
U.S. GEOLOGICAL SURVEY
U.S. DEPARTMENT OF THE INTERIOR
BEFORE THE
SUBCOMMITTEE ON ENVIRONMENT AND HAZARDOUS MATERIALS
HOUSE COMMITTEE ON ENERGY AND COMMERCE
HEARING ON
"CARBON SEQUESTRATION: RISKS, OPPORTUNITIES, AND PROTECTION OF DRINKING WATER"

JULY 24, 2008

Mr. Chairman and Members of the Subcommittee, thank you for the opportunity to present testimony on geological sequestration of carbon dioxide (CO_2), addressing opportunities, risks, and protection of drinking water resources within the United States. My remarks will briefly discuss some of the basic principles of geological CO_2 sequestration, provide an overview of current U.S. Geological Survey (USGS) activities on these topics, and address some of the fundamental principles of assessment of geological commodities that underlie USGS methods, including the types of uncertainties that can affect estimates of storage volume at the regional scale.

Introduction

The magnitude of addressing reductions in greenhouse gas emissions necessary to impact global climate change is significant because fossil fuel use, the major source of CO_2 emissions to the atmosphere, will continue for some time in both industrialized and developing nations. Geologic sequestration of CO_2 captured from large industrial sources of emissions is one of a number of technologies for carbon management that could be deployed to stabilize the concentration of CO_2 in the atmosphere. Although geologic sequestration is the topic of this hearing, geologic CO_2 sequestration alone cannot achieve the goal of stabilizing the atmospheric CO_2 concentration at a level that will have a meaningful impact on climate change. The magnitude of reductions needed may be on the order of 70 percent or more (IPCC, 2005), requiring all methods of carbon management in addition to geologic sequestration. These other methods include terrestrial sequestration, increased use of renewable biological sources, electricity generation by solar and wind systems, geothermal and nuclear power, increased efficiency in transportation as well as electric power generation, transmission, and end use.

Over the last nine years the USGS has engaged in several studies to evaluate geological and geochemical factors that improve our understanding of processes occurring during geologic storage of CO_2, the potential risks associated with storage of large volumes of CO_2, and some potential environmental impacts of geologic sequestration.

The USGS also collaborates with DOE on sequestration projects such as, the DOE-lead Geo-SEQ program, a consortium of National Laboratories working on monitoring technologies and simulation codes for carbon storage; the DOE-sponsored Frio Brine project in Texas; and review of the efforts by DOE to develop several large scale field projects throughout the United States.

More recently, Section 711of the Energy Independence and Security Act (P.L. 110-140), enacted into law in December 2007, authorized the Secretary of the Interior, acting through the Director of the USGS, to develop an assessment methodology and conduct a national assessment of geological storage capacity in collaboration with the Secretary of Energy, the Administrator of EPA, and the State geological surveys. USGS will collaborate with DOE to incorporate the results of the assessment into future revisions of the DOE "Carbon Sequestration Atlas of the United States and Canada". The cumulative advances from these earlier USGS studies and DOE-funded activities provide a basis for developing a methodology to assess the national capacity to store CO_2 and understand the potential impacts of large-scale deployment of geologic sequestration.

Subsequent to enactment of P.L. 110-140, the USGS received from Congress funding to initiate a new activity to develop the methodology to conduct a national assessment of carbon dioxide storage capacity in oil and gas reservoirs and saline formations. The USGS has also recently updated its website to promote the dissemination of information and research relevant to this new activity: http://energy.er.usgs.gov/health_environment/co2_sequestration/, and has assembled a project team to begin development of the methodology. The USGS will consult and collaborate with other organizations, as appropriate, including state geological surveys, the Department of Energy, the Environmental Protection Agency, other bureaus within the Department, and other stakeholders. This will help ensure, to the maximum extent possible, an efficient, effective, and coordinated effort. As with all USGS energy resource assessment methodologies, an independent non-USGS panel, consisting of individuals with relevant expertise and representing a variety of stakeholder organizations, will be convened to provide a technical review of the methodology. The full methodology is expected to be released by spring 2009

Basic principles of geologic sequestration of carbon dioxide

Geologic storage involves injection of liquid CO_2 into a subsurface rock unit and displacement of the fluid that initially occupied the pore space. This principle operates in all types of potential geological storage formations such as oil and gas traps, deep saline formations, coal beds, and other rock types.

At the pressures and temperatures that exist at depths in the Earth greater than about 3,000 feet, carbon dioxide is a supercritical fluid with density that ranges from 500 to about 700 kg/m^3 at the greatest depths considered for storage, about 12,000 feet below the land surface. Because the density of CO_2 is only 50 to 70 percent of the saline formation water, the CO_2 will be buoyant and rise vertically until it is retained beneath an impermeable barrier, commonly called a seal. If the structure of the seal forms a trap with both vertical and horizontal barriers (closure), CO_2 will accumulate in the same manner that other natural buoyant fluids, like crude oil and natural gas, accumulate by displacing formation water from the geologic trap. This process is commonly referred to as *physical trapping*. Physical trapping of CO_2 involves two factors critical for evaluation of storage risks: the integrity of the seal and the total volume of water displaced by injected CO_2. The volume of displaced saline water relative to the volume of CO_2 injected must be understood to fully evaluate the potential for leakage, including the potential for contamination of drinking water.

Some of the injected CO_2 will dissolve in the subsurface formation water, a process known as *solubility trapping*. The solubility of CO_2 is relatively low, however, reaching a maximum of about 5 percent of the weight of pure water, and generally less, 2 to 3 percent of the weight of saline water. This means that for complete solubility trapping, each ton of injected CO_2 must contact at least 20 tons of formation water, possibly much more.

Another consideration is that dissolved CO_2 forms a weak acid, carbonic acid, which can react with other components dissolved in formation water. Carbonic acid can also react with minerals in the geologic storage formation, either dissolving them, or precipitating new minerals, a process known as *mineral trapping*. The acidified formation water may dissolve coatings on mineral grains, releasing trace metals and residual organic components to the formation water and to the supercritical CO_2, raising the possibility of mobilizing potentially hazardous, naturally occurring materials. This process increases the potential for saline water that is displaced from a geologic storage formation to contaminate shallower, potable water supplies if the displaced water can migrate to shallower depths.

If residual oil is present in a storage formation, CO_2 will dissolve in the oil as another type of solubility trapping. However, CO_2 is much more soluble in residual oil than in water. In fact, at pressures equivalent to depths of about 5000 feet in the subsurface, CO_2 is completely soluble in oil (also known as completely miscible). This fact, together with the physical effects caused by dissolution of CO_2 in oil, including the volume of oil swelling and the viscosity dropping, provides the primary mechanism for enhanced oil recovery (EOR) using CO_2. When the oil is produced from a well, the CO_2 dissolved in the oil is separated from the oil, recycled and reinjected to recover additional oil. In the overall process, some injected CO_2 remains in the geologic formation, equivalent to about 1 ton of CO_2 stored for every 2 additional barrels of oil recovered. At current prices for crude oil, this additional recovery is clearly a valuable "by-product" of potential CO_2 storage in depleted oil fields.

Geological Reserves, Resources, and the Role of the USGS in capacity assessment

An assessment of the geological capacity to store CO_2 must be based on fundamental principles that are analogous with any assessment of a finite geological commodity such as petroleum or coal. Within the total possible volume of storage, we must be able to distinguish potential geologic CO_2 reserves from resources (Bachu and others, 2007). The resource is the quantity that, based on geological principles and available knowledge, may exist within some portion of the Earth. The reserve is that portion of the resource for which we have more information and thus greater certainty with which we can define a volume that can be evaluated with enough detail to assign a value to the commodity. For clarification, use of the term "reserve" in this testimony is broader and distinct from the term "proved reserves" which connotes economic evaluation of a known quantity of resource. The current and most precise definitions of the terms reserve and resource as they pertain to oil and gas accumulations are provided in a 2007 joint publication of the Society of Petroleum Engineers, the American Association of Petroleum Geologists, the World Petroleum Congress, and the Society of Petroleum Evaluation Engineers (SPE, 2007). In the SPE terminology, the USGS assessment will focus on "contingent resources", a term indicating that additional economic factors must be evaluated before a value can be assigned, thereby shifting the volume of contingent resource to a reserve. In common usage "probable reserves" is synonymous with "contingent resources".

The USGS has a long history of conducting national and international assessments of natural resources. Given that geologic storage space for CO_2 in the subsurface is a finite geological commodity, USGS scientists have the necessary geological expertise to build a robust methodology for assessing geological CO_2 storage capacity. This expertise stems in part from many years of experience in conducting impartial, scientifically robust oil, gas, and coal assessments where a critical issue is the distinction between reserve and resource described previously.

Equally important in developing an assessment methodology is the significant expertise of the USGS in assessment of ground-water resources. The unique knowledge within the USGS of regional ground-water aquifer systems enables the USGS to develop methods to assess potential storage in saline water-bearing geologic formations. Although very large storage capacities can be calculated for saline formations, incorporation of geological and hydrological risk factors that affect these capacities is a challenging and difficult scientific task. These factors are essential to defining the portion of the total geologic

CO_2 storage resource that is actually technically feasible to utilize and may ultimately meet the economic definitions of a reserve.

Conceptual framework for storage assessment

USGS methods for assessment of geological resources focus on evaluations at the regional or basin scale where we can define geologically consistent assessment units (AU). The application of a consistent methodology across these scales will facilitate aggregation of results from all assessment units, providing an overview of the national endowment of storage capacity. For CO_2 storage, the description of the AU should include information from two types of geological formations, the storage unit and the overlying regional seal. The most commonly described formation types for geological storage of CO_2 are depleted oil and gas fields, saline formations, and unmineable coal beds. For each storage type, a sealing formation must accompany the storage formation to prevent the buoyant leakage of CO_2 from the storage formation to shallower levels or to the atmosphere. The geological properties of the sealing formation provide a basis for evaluating the geological risk of CO_2 leakage from the storage formation that could cause contamination of shallower aquifers for potable water supplies or limit the effectiveness of sequestration if stored CO_2 can return to the atmosphere. The geological risk factors at the scale of the AU are distinct in scale from risks specific to individual CO_2 storage sites, where additional factors such as the integrity of existing well bores and cement must be taken into consideration.

Although CO_2 storage in known oil and gas traps and saline formations are commonly considered as distinctly different types of storage, in most cases they are geologically linked. The physical traps of oil and gas fields occur within almost every saline formation under consideration for CO_2 storage. Using the distinction between reserve and resource described earlier, the physical traps that have retained buoyant oil and gas for hundreds of thousands to hundreds of millions of years are the best characterized part of the saline formation in which we understand the integrity of the seal and the injectivity of the formation. These areas are typically the most well characterized settings for CO_2 storage, and in this context can be considered analogous to a reserve and the larger area of saline formation adjacent to the trap can be considered the resource.

We can make conservative estimates of storage volume based on the amount of oil and gas recovered from the trap. That initial conservative estimate of storage volume can increase through additional recovery of residual petroleum with enhanced oil recovery. Ultimately, it may be possible to fill the trap to the maximum capacity defined by the spill point of the trap. When a trap is filled to maximum capacity, if the saline formation extending beyond the trap is adequately characterized, then injection could continue and storage would "spill" into the larger volume of the saline formation. Alternatively, storage could be initiated in an adjacent trap in the same assessment unit or in a different assessment unit. This concept of conservative definition of an initial, well-characterized volume of a geological commodity (in this case, storage volume) that can grow over time as the geologic setting of the commodity continues to be evaluated is another way to describe the fundamental definitions of reserve, resource, and reserve growth that will be implemented in the USGS assessment methodology.

Although the geological relationships between the storage properties of the physical traps of depleted oil and gas fields and the properties of the larger potential storage volumes within the saline formation of the same assessment unit are clear, developing geologically sound mathematical methods to estimate the storage volume of saline formations is difficult for several reasons. First, the number of direct measurements of the properties of the storage unit and overlying seal may be very limited. A saline formation may have only one well penetration or no penetrations at all within a 100 square mile area. Even if there is one or even several penetrations of the formation, the amount of information available for characterization of the injectivity of the formation or the integrity of the seal may be limited. The limited data availability will not preclude estimates of storage volume, but it will result in large ranges of uncertainties in the estimated storage volumes. The largest uncertainties caused by sparse data may be in the uncertainties in risk parameters such as potential for leakage and/or the injectivity of the formation.

Risk parameters can be incorporated into numerical assessments of geological commodities such as storage volume in two distinctly different ways. Values can be assigned to risks on a standardized scale, the values for all risks totaled, and then the calculated volumes can be ranked by total risk. A more rigorous method is to assign a probability to each independent risk factor, and then multiply these factors to arrive at the overall “riskiness” of the storage volume. That overall risk factor is then used to reduce the calculated volume of potential storage. This method results in probabilistic ranges of storage volumes that can be compared between assessment units within a single basin or between basins and regions. This approach is analogous to the process underlying USGS assessments of oil and gas resources that we describe as "fully risked" and is the method we will incorporate in the USGS methodology for assessment of CO_2 storage capacity.

Another aspect of CO_2 storage in saline formations that impacts our evaluation of risk factors is the scale of storage projects and the volumes of CO_2 that must be injected into storage formations as geological sequestration is fully deployed. The CO_2 emitted by a single, 1000 megawatt coal-fired electrical generating station is roughly 8 million tons per year. If that CO_2 is captured and injected into the subsurface, it will displace about 84 million barrels of formation water. Over the lifetime of a single full-scale storage project of this size, for example, for 50 years, the total volume of CO_2 injected into the subsurface, and the volume of water displaced, will be equivalent in volume to about 4.1 billion barrels of oil. This volume corresponds to a 'giant' oil field, according to terminology used in describing oil field sizes. There are physical traps of this size in the United States, but the number is limited. The geospatial mismatch between size of storage needed for sequestration projects and the location of large sources of CO_2 has been addressed in a USGS report published in 2006 (Brennan and Burruss, 2006). If geologic sequestration is deployed to the extent that the Nation is storing about 500 million tons of CO_2 per year, equivalent to emissions from 50 to 60 coal-fired power plants of 1000 megawatt size, then we must recognize that the storage process will displace about 0.6 km^3 or 172 billion gallons of formation water each year. Such large movements of saline formation water have the potential to disturb regional ground-water flow systems, possibly displacing saline formation water laterally or vertically to near-surface environments where it could contaminate shallower drinking water supplies or impact ecosystems

The size of storage projects also impacts our concepts for evaluating risks of CO_2 storage. Estimates of the total area of a geological storage site will determine the area that must be characterized geologically and hydrologically prior to injection, monitored during injection, and then continually monitored for sometime into the future once the injection phase of the project ends and long-term storage begins. However, for the same volume of total storage, there is an important difference between storage in physical traps and storage in saline formations.

In a physical trap with lateral barriers to flow, injected CO_2 will fill a thickness of the formation up to a maximum defined by the spill point of the trap. Within that interval, CO_2 can occupy up to 50 or 60 percent of the pore volume of the formation. In contrast, the CO_2 injected into saline formations will rise vertically to the base of the sealing formation and spread laterally. Models of this process and experience at the Sleipner project in the North Sea show that the total fraction of pore space occupied by injected CO_2 is small, on the order of 2 to 5 percent, although in some geologically heterogeneous formations this fraction could increase to 10 to 20 percent. This difference between high efficiency of storage in traps and low efficiency in saline formations means that for the same quantity of CO_2 stored, the surface area above a storage site in a saline formation that corresponds to the spatial extent of injected CO_2 in the subsurface will be at least 2 times larger to as much as 20 times larger than the area above equivalent storage in a physical trap. The larger surface area above storage sites in saline formations will increase the effort necessary to characterize risks of storage and to monitor the site during the lifetime of a sequestration project.

The focus of USGS evaluations of risks of geologic sequestration is at the regional or basin scale where the total volume of storage from deployment of multiple, full-scale projects may have the greatest impact on movement of formation water and injected CO_2. Evaluation of these risks is dependent on knowledge of the geology and hydrology of the regional assessment unit. This analysis of risks is different from the risks evaluated in the proposed EPA rules on geologic sequestration where the emphasis is on evaluation and mitigation of the risks at the scale of individual storage projects. USGS does not evaluate individual projects. However, the regional scale risks may impact individual projects. USGS collaboration with EPA on risk issues ranges from informal discussions about subsurface fluid flow and area of review with the Underground Injection Control Program, to USGS participation in the public stakeholder meetings that EPA held as part of the current rulemaking process. We look forward to closer collaboration with EPA as development of our methodology proceeds and during assessment of storage capacity.

Concluding Remarks

In this statement, I have summarized some of the basic aspects of geological CO_2 sequestration and described some of the fundamental concepts underlying resource assessments that the USGS is employing to develop a probabilistic methodology for assessment of CO_2 storage capacity in both the physical traps of depleted oil and gas fields and in saline formations. In addition, I have discussed some of the concepts of geological risk that must be incorporated into the assessment methodology. The present USGS work addresses the activity authorized under Section 711 of the Energy Independence and Security Act (P.L. 110-140) to develop an assessment methodology that can be applied consistently across the Nation. As noted above, the methodology development is being conducted in coordination with a number of organizations to maximize the usefulness of the assessment to a variety of partners and stakeholders, including the Department of Energy, the Environmental Protection Agency, other Agencies within the Department of the Interior, and State Geological Surveys.

Thank you for the opportunity to present this testimony. I will be happy to answer any questions you may have.

References:

Bachu, S., Bonijoly, D., Bradshaw, J., Burruss, R., Holloway, S., Christensen, N.P., Mathiassen, O.M., 2007, CO_2 storage capacity estimation: Methodology and gaps, International Journal of Greenhouse Gas Control, v. p. 430-443.

Brennan, S. T., and Burruss, R. C., 2006, Specific Storage Volumes: A useful tool for CO_2 storage capacity assessment, Natural Resources Research, v. 15, pp. 165 -182, DOI: 10.1007/s11053-006-9019-0

Intergovernmental Panel on Climate Change (IPCC), 2005, IPCC Special Report on Carbon Dioxide Capture and Storage. Prepared by Working Group III of the Intergovernmental Panel on Climate Change [Metz, B., O. Davidson, H. C. de Coninck, M. Loos, and L. A. Meyer (eds.)], Cambridge University Press, Cambridge, United Kingdom and New York, NY, USA, 442 pp.

Society of Petroleum Engineers (SPE), American Association of Petroleum Geologists (AAPG), World Petroleum Congress (WPC), and Society of Petroleum Evaluation Engineers (SPEE), 2007, Petroleum Resources Management System, 49 p., http://www.spe.org/spe-app/spe/industry/reserves/prms.htm, downloaded July 2, 2008.