Chapter 1: Introduction and Background Material

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Strategies to mitigate man-made input of carbon dioxide into the atmosphere will involve a portfolio of strategies, such as fuel switching, energy conservation, and terrestrial sequestration (tillage practices, tree planting, wetlands reestablishment, etc.). Because fossil fuels will continue to be the principal source of energy in the near-term, mitigating the input of CO_2 into the atmosphere resulting from fossil-fuel usage is critical. The U.S. Department of Energy has determined that one of the most promising mitigation technologies is geologic carbon sequestration (U.S. Department of Energy, 1999, 2004). Geologic sequestration injects captured carbon dioxide into subsurface rock reservoirs deep beneath the earth's surface.

Data on the potential for geologic carbon storage in Kentucky and surrounding areas have been gathered by the Kentucky Geological Survey as part of a series of research projects in cooperation with DOE. In 2000, Kentucky joined four other states in establishing the Midcontinent Interactive Digital Carbon Atlas and Relational Database (MIDCARB), which was initially a 2-year compilation of data on carbon emissions and potential sinks, housed on data servers, and accessed through a common Web portal (www.midcarb.org). MIDCARB was subsequently expanded to be included in a collection of regionally managed databases called NatCarb, which contains information on CO_2 storage options and storage potential nationwide (www.natcarb.org). Next, KGS participated in two partnership projects, the Midwest Geological Sequestration Consortium and the Midwest Regional Carbon Sequestration Partnership, both part of the DOE Regional Carbon Sequestration Program. Phase I (2001–05) of the partnerships concentrated on regional assessments of potential geologic reservoirs (sinks) and seals, and determined potential sites for future small-scale demonstration projects. Work by the Midwest Geological Sequestration Consortium focused on the Illinois Basin, which includes much of western Kentucky (Frailey and others, 2005), whereas work by the Midwest Regional Carbon Sequestration Partnership focused on the eastern Midcontinent and northern Appalachians, including central and eastern Kentucky (Wickstrom and others, 2005).

Research in phase II (2005–09) of the regional partnerships is focused on implementing small-scale (thousands of tons) CO_2 injection demonstrations; monitoring, verifying, and accounting of injected CO_2 in the demonstrations; and more detailed geologic characterization of the sinks and seals identified in phase I. One of the Midwest Regional Carbon Sequestration Partnership demonstrations is scheduled at Duke's East Bend power station in Boone County, Ky., in the summer of 2009. KGS also joined the Southeast Regional Carbon Sequestration Partnership during phase II to assess coals for sequestration and enhanced coalbed methane in the Black Warrior Basin of Alabama and the central Appalachian Basin of southwestern Virginia and southeastern Kentucky. Funding for the phase II projects was matched by grants from the Kentucky Energy and Environment Cabinet (previously the Governor's Office of Energy Policy).

The level of State-sponsored funding for KGS carbon-sequestration research dramatically increased in the summer of 2007, when the Kentucky Legislature passed House Bill 1 in a special session. HB 1 authorized $5 million for research by KGS in the areas of CO_2-enhanced oil recovery, CO_2-enhanced gas recovery, and permanent geologic sequestration of CO_2. More specifically, HB 1 required drilling research wells in Kentucky's eastern and western coal fields to assess the suitability of subsurface reservoirs for CO_2 storage, and evaluating the Devonian black shale, Kentucky's most prolific gas reservoir, for enhanced gas recovery using CO_2. HB 1 encouraged KGS to collaborate with and develop cost-sharing industry partners, who will be the beneficiaries of this important research. The collaboration led to the formation of the Kentucky Consortium for Carbon Storage (www.kyccs.org), which has ongoing research in several Kentucky counties; drilling was recently completed for a deep test hole for a carbon storage test in saline aquifers in Hancock County.

Background on Geologic Carbon Storage Characteristics of CO_2 Relative to Geologic Storage

In order to better understand the potential for geologic storage in Kentucky, some background information is needed on the basic characteristics of CO_2 (including various depth, pressure, and temperature constraints); and the basic types of geologic storage reservoirs, which influence how and where CO_2 might be injected in Kentucky. Carbon dioxide is nontoxic and at surface temperatures and pressures it is a colorless and odorless gas. Carbon dioxide has been safely used in enhanced oil and gas recovery (see, for example, Jarrell and others, 2002; Melzer and Miller, 2007). Consequently, we have a good working knowledge of the behavior of CO_2 in the subsurface, although at generally smaller volumes than are being considered for industrial-scale carbon sequestration. As temperature and pressure increase (which happens with increasing depth beneath the surface), gaseous CO_2 becomes more liquid-like and liquid CO_2 becomes more gas-like, until the critical point is reached and the two phases cannot be distinguished. Beyond this point, the CO_2 is considered supercritical. The critical temperature (87.8°F) and pressure (1,073 psia) are important because the density of CO_2 increases significantly when critical conditions are reached. The density increase allows a unit mass of CO_2 to occupy a much smaller volume at supercritical pressure and temperature than it would at surface pressure and temperature. For example, 1 short ton of CO_2 gas at surface temperature and pressure occupies a volume of 18,000 ft^3, whereas supercritical CO_2 at a depth of 2,600 ft below the surface occupies a volume of 50 ft^3 (Wickstrom and others, 2005). It is this physical property of CO_2 that makes geologic storage such an attractive technology for large-scale CO_2 reductions in which millions of tons of CO_2 may need to be sequestered annually.

Previous work by the DOE partnerships and the Kentucky Consortium for Carbon Storage indicates that in Kentucky, CO_2 reaches critical conditions at approximately 2,500 ft below the surface (Fig. 1.1). Although a depth of 2,500 ft is a good regional estimate for supercritical conditions, variability in local pressure and temperature gradients means that determination of CO_2 phase at a given site or reservoir should be site-specific. For example, in the Illinois Basin (western Kentucky), depths of less than 2,100 ft are usually gas phase, depths of 2,100 to 2,900 ft are near supercritical (or could be either), and depths of more

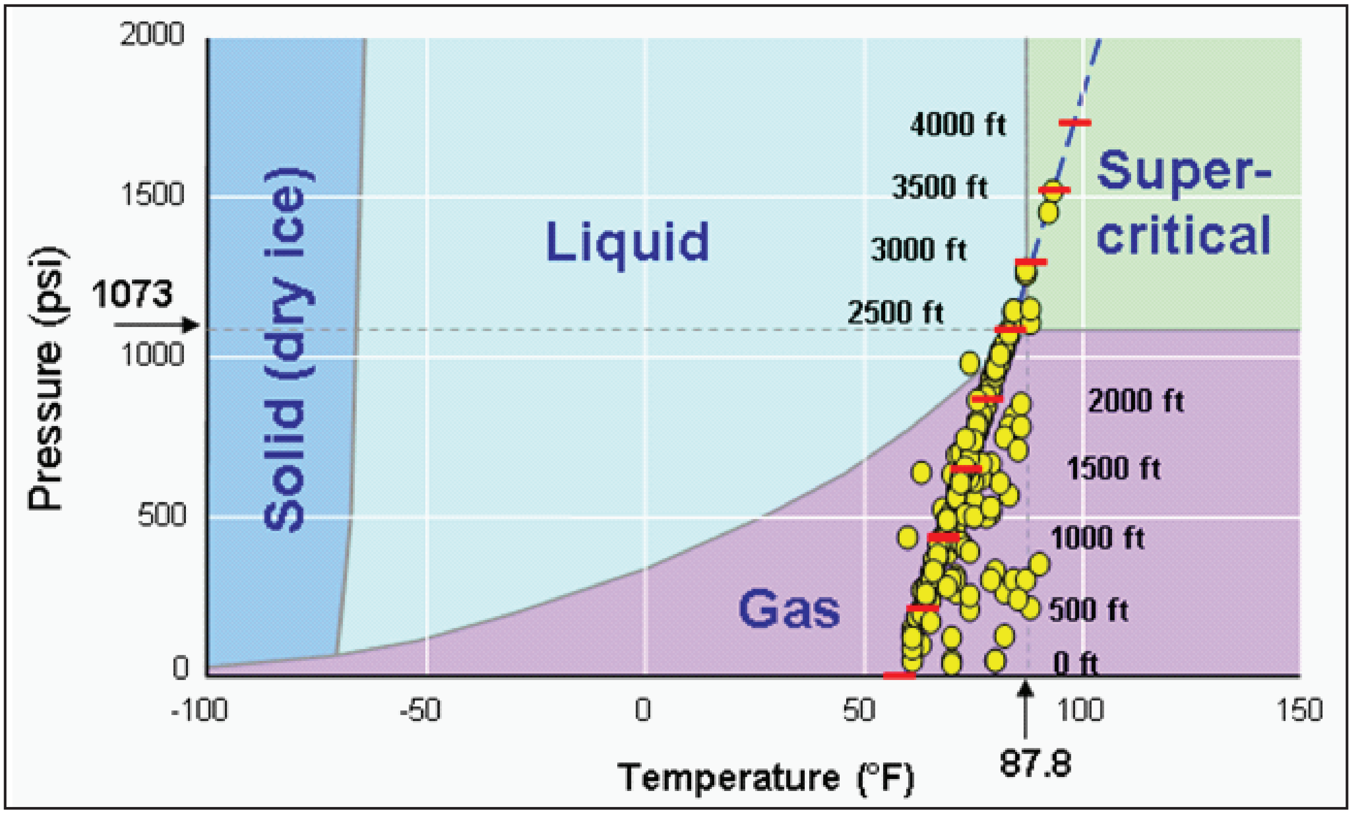

Figure 1.1. Temperature-pressure phase diagram showing fields in which solid, liquid, gas, and supercritical forms of CO_2 are stable. Data from Kentucky oil and gas wells (yellow dots) at increasing depth (red lines) plot primarily in the gas stability field (data compiled by B. Nuttall). This plot indicates that storage of dense CO_2 will require injection deeper than most oil and gas fields. Note that the supercritical phase of CO_2 is reached between 2,500 and 2,900 ft.

than 2,900 ft are considered supercritical (Frailey and others, 2005).

The pressure-temperature-depth properties of CO_2 also influence how injected CO_2 will interact with naturally occurring fluids (e.g., brine, oil) or other gases filling the pore spaces in subsurface rock units. At its supercritical phase, CO_2 should be partly miscible; that is, it should react with the fluids and gases in the pore space. In contrast, gaseous-phase CO_2 should be mostly immiscible; that is, it should largely remain as a distinct gas phase even as it displaces and interacts with other reservoir fluids and gases. In reality, even supercritical CO_2 will likely displace fluids and gases in reservoirs and migrate as a separate phase, and only part of the injected volume will actually dissolve in the pore fluids in the short term (see, for example, Johnson and others, 2004). Over longer periods, supercritical CO_2 would continue to slowly dissolve in formation brines as it migrates into pore space undersaturated with CO_2. In an unusual case in Louisville in the 1980's, a bubble of supercritical CO_2 formed deep in a Knox Dolomite reservoir, after injected waste acid dissolved a cavern in the host carbonate rock. This supercritical CO_2 was completely dissolved by pumping fresh water into the reservoir over a period of 3 yr (Clark and others, 2005). Dissolution of CO_2 in saline brines will be slower, and controlled by the solubility factors discussed below.

Another property that will influence geologic carbon storage is the solubility of CO_2 in water. CO_2 solubility tends to decrease with increasing temperature, and tends to increase as pressure increases (Fig. 1.2) (Carr and others, 2003). For lower pressures and temperatures, as are common in many Kentucky reservoirs, the increased solubility from increasing pressure should more than offset the temperature effects.

The solubility of CO_2 is also decreased by higher salinity (Fig. 1.3), which is significant since the salinity of water in rock pores generally increases with depth (Frailey and others, 2005; Wickstrom and others, 2005). Deep saline reservoirs represent the largest potential sequestration target in Kentucky and worldwide (U.S. Department of Energy, 2004, 2008a; Frailey and others, 2005; Wickstrom and others, 2005).

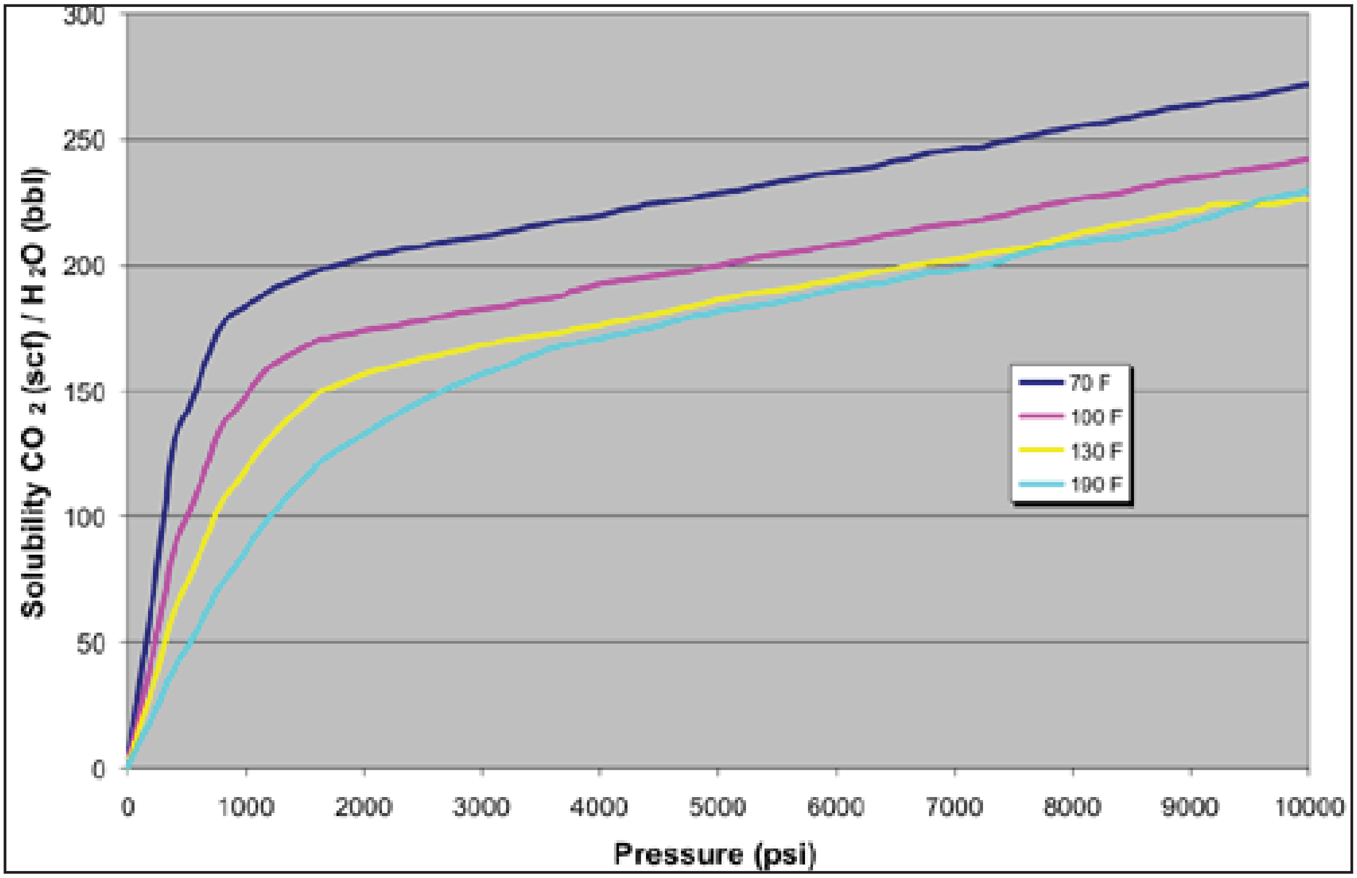

Figure 1.2. Solubility of CO_2 as a function of pressure at different temperatures (colored lines). From Carr and others (2003).

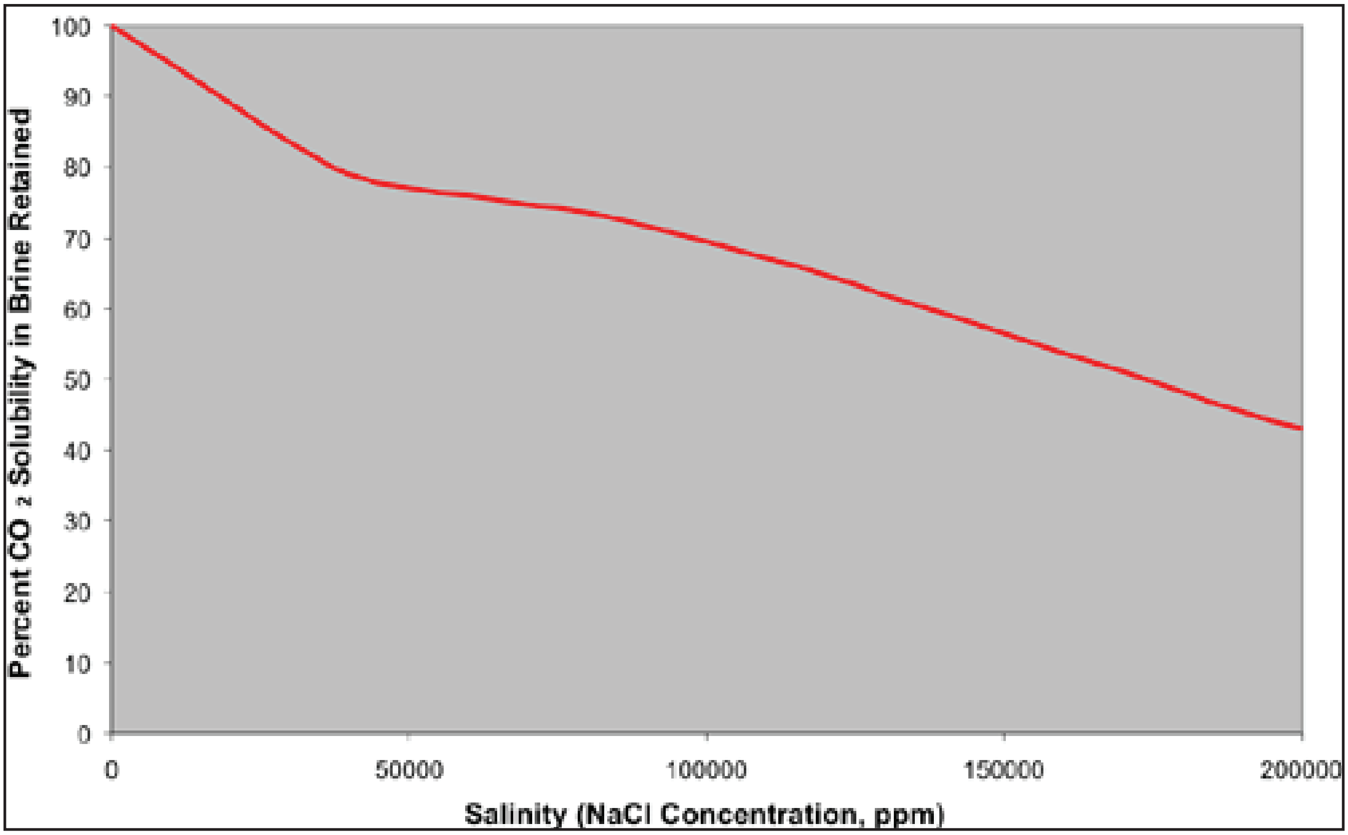

Figure 1.3. Solubility of CO_2 as a function of salinity. From Carr and others (2003).

More information about properties of CO_2 relative to carbon storage can be found at DOE's carbon sequestration Web site, www.fossil.energy.gov/programs/sequestration/, in the phase I reports of the regional partnerships (Frailey and others, 2005; Wickstrom and others, 2005), at the MIDCARB Web site (Carr and others, 2003), and at the EPA's geologic sequestration Web site, www.epa.gov/safewater/uic/wells_sequestration.html.

Types of Geologic Storage

Several broad categories of geologic reservoirs are being investigated by DOE for potential carbon storage: (1) deep saline formations, (2) depleted or abandoned oil and gas fields, (3) unmineable coal beds, (4) organic-rich shales, and (5) basalts (U.S. Department of Energy, 1999, 2004). All occur in Kentucky, although the first four have the greatest potential for carbon storage, as inferred from a relatively long history of investigation and exploitation.

Deep saline formations, also known as saline reservoirs or aquifers, are rock units that contain natural waters in the pore spaces between the mineral grains and in fractures within the rock. Also called brines, the saline waters typically have high enough salinity (greater than 10,000 ppm) that they are considered nonpotable. Some saline formations are regionally widespread; consequently, they have large potential storage volumes, which is why they are attractive targets for carbon storage. The amount of pore space in aquifers considered to have storage potential typically ranges from 5 to 20 percent of the total rock volume.

Phase I of the DOE regional partnership research determined that deep saline formations have the greatest potential for large-volume carbon storage. Hence, they are a major focus of geologic carbon storage investigations. In Kentucky, the potential total storage volumes may exceed 6.6 billion short tons (Frailey and others, 2005; Wickstrom and others, 2005). Not all of the saline aquifer capacity will be accessible, however. It is important to understand that no deep rock unit is completely homogenous or open to injection of fluids and gases. Factors such as reservoir heterogeneity, CO_2 buoyancy, sweep efficiency, and rock and water chemistry are likely to reduce the theoretical capacity to an "effective capacity" (Bachu and others, 2007). The effective capacity is then further reduced by a variety of regulatory, economic, and social issues to produce a "practical capacity."

In deep saline formations, injection would likely be done under supercritical conditions. As a dense phase, however, the pressurized CO_2 that is injected into a porous rock unit will likely displace the water within the pore space. Over a long period, the CO_2 will dissolve into the formation fluids. The amount of CO_2 that dissolves will be a function of brine-water chemistry, salinity, permeability, pressure, and temperature.

Deep saline reservoirs are only suitable for CO_2 storage if one or more overlying nonporous formations are present to serve as a vertical seal, preventing upward movement of the buoyant CO_2. Reservoirs within deep saline formations can be laterally unrestricted (regionally widespread permeability) or restricted by stratigraphic and structural barriers. Most reports of carbon storage that discuss saline aquifers assume that low fluid velocities under unconfined conditions will produce hydrodynamic trapping (Bachu and others, 2007). But as in natural gas (methane) storage fields, some degree of structural trapping may be beneficial for containment and monitoring of injected CO_2.

Confirmation of the potential for industrial-scale injection of CO_2 into saline aquifers (at least in some areas) is provided by Statoil's Sleipner Field in Norway. Approximately 1.1 million short tons of CO_2 have been injected annually into a brine-bearing sandstone at depths of approximately 3,000 ft beneath the North Sea since 1996 (Zweigel and others, 2004). The Sleipner project continues to be a focus of research on the practical aspects of large-volume injections, including post-injection chemical changes of the saline reservoir and its overlying seals (see, for example, Johnson and others, 2004), and methods for monitoring subsurface CO_2 plumes (see, for example, Chadwick and others, 2006) in deep saline rock units.

In the United States, the first DOE-sponsored experimental injection into a deep saline rock unit was the Frio project near Houston, Texas. In 2004, small amounts of CO_2 (1,764 short tons) were injected into a 70-ft-thick porosity zone in the Frio Sandstone at a depth of 5,700 ft (Hovorka and others, 2005, 2006; Kharaka and others, 2006). Data from this project continue to be collected, but the project demonstrated that CO_2 can be safely injected and the fate of the CO_2 in the subsurface successfully monitored. Additional deep saline reservoir tests are being planned around the United States as part of the DOE-sponsored regional carbon sequestration partnerships.

Several DOE-sponsored phase II demonstration tests by the Midwest Geologic Sequestration Consortium and Midwest Regional Carbon Sequestration Partnership are planned in our region. The Midwest Geologic Sequestration Consortium recently completed a test of sequestration into coal beds in central Illinois, although results have not yet been made public. The Midwest Regional Carbon Sequestration Partnership recently completed a test of sequestration into a deep saline aquifer in northern Michigan (Gupta, 2008; U.S. Department of Energy, 2008b). The Midwest Regional Carbon Sequestration Partnership completed another deep saline test in Kentucky in 2009. Approximately 1,100 short tons of CO_2 were injected into the Cambrian Mount Simon Sandstone at depths of 3,230 to 3,530 ft beneath the East Bend power station in Boone County (Midwest Regional Carbon Sequestration Partnership, 2008a; U.S. Department of Energy, 2009). As with the Frio experiment, various aspects of modeling and monitoring are continuing.

The Kentucky Consortium for Carbon Storage also drilled a deep saline test well in 2009. This test is an outgrowth of Kentucky House Bill 1 (2007) funding. The well tested the Knox Group carbonates and sandstones in Hancock County, Kentucky. Results of this project can be found at the KYCCS Web site (www.kyccs.org). Data from both of these tests will be important for understanding carbon storage potential in Kentucky.

Oil and gas fields are accumulations of hydrocarbons that have been trapped in porous rock units for millennia. Oil and gas flow through the formation to wells pumped from the surface. Because oil and gas were produced (indicating permeability), CO_2 (as a gas or liquid) should flow back into the pore space vacated by the extracted oil or gas. The mechanisms responsible for trapping the hydrocarbons should likewise trap most injected CO_2.

As demonstrated in West Texas since the early 1960's and in the Weyburn Oil Field of Saskatchewan, CO_2 can be used to enhance oil (CO_2-EOR) or gas (CO_2-EGR) recovery in depleted fields (see, for example, Plasynski and others, 2008a). In West Texas, for example, CO_2-EOR has resulted in the additional recovery of 7 to 25 percent of the original oil in place (Melzer and Miller, 2007). In this process, the CO_2 either displaces oil or gas in the reservoir (immiscible) or mixes with the oil and gas (miscible) to enhance recovery. As discussed in chapter 2, the shallow depth of most Kentucky oil fields will lead to immiscible conditions for most of our existing oil and gas fields. It is possible that revenue generated from increased production in enhanced recovery projects could be used to help offset the cost of carbon storage. Elsewhere, including the Midwest, the high cost of commercially available CO_2 has limited the use of this technology. This economic restriction is likely to change in the near future when limits are placed on carbon emissions and carbon-capture technology results in greater availability of CO_2.

In oil and gas reservoir scenarios, it is important to make the distinction between enhanced recovery using CO_2 and permanent carbon storage. In general, smaller amounts of CO_2 are needed for enhanced recovery (at least initially) because some of the injected CO_2 is produced with the oil or gas and can then be reinjected. Some of the CO_2 also remains trapped in the reservoir, where it dissolves in water or is trapped by capillary forces. The amount of CO_2 necessary to produce a barrel of oil is called the "utilization factor." Integrated over the life of EOR projects in West Texas, the net utilization factor—measured in thousand cubic feet of CO_2 per barrel of oil—equals 5 to 6 (Melzer, 2005). As with saline aquifers, the effective capacities of an oil or gas reservoir to store CO_2 will be less than the theoretical capacity. Moreover, as less oil is produced and a field becomes uneconomic for EOR, it is anticipated that many fields will transition into strictly carbon sequestration projects if there are economic benefits for CO_2 mitigation.

Unmineable coal beds are another possibility for carbon storage, with potential benefits for enhanced coalbed-methane recovery (ECBM) (Gale and Freund, 2001; Schroeder and others, 2001; Reeves, 2003). The storage process is fundamentally different from that in oil and gas fields or in saline aquifers because rather than displacing fluids in pore spaces, CO_2 adsorbs (sticks) onto the surfaces of organic matter in the coal bed. One attractive feature of the adsorption mechanism in coal is that CO_2 has a greater affinity for organic matter in the coal matrix than does methane (CH_4). Thus, injected CO_2 should preferentially displace methane, thereby enhancing CH_4 production. Ratios of 3:1 to 6:1 have been determined for CO_2-to-CH_4 displacement in some Illinois coals (Frailey and others, 2005). Like EOR or EGR, ECBM with CO_2 will be more feasible when lower-cost CO_2 becomes available, helping to offset the cost of carbon capture. Kentucky currently has no economic coalbed-methane production, so injection of CO_2 into coal beds would be strictly for long-term storage.

The adsorption mechanism also means that CO_2 injection into coals would not necessarily have to be at supercritical depths for storage or ECBM. Storage would have to be at depths below the level of surface fracturing to prevent leakage of injected CO_2. Beyond that, the depth of coals used for injection would be more related to their mineability. If CO_2 is injected into a coal for permanent storage, then the coal ideally would never be mined, since mining would release the injected CO_2. For this reason, DOE has used the term "unmineable coals" when describing this carbon-storage option. Although there is no single definition of "unmineable," various DOE-sponsored partnerships have inferred that coals more than 1,000 ft deep (below lowest drainage) would be considered uneconomic to mine with foreseeable technology and might be considered for carbon storage (Frailey and others, 2005; Wickstrom and others, 2005). In the Illinois Basin, the Midwest Geologic Sequestration Consortium considered coals at 300 to 500 ft depth as potentially suitable for ECBM; coals at 500 to 1,000 ft as suitable for permanent carbon storage if thin (1.5 to 3.5 ft thick—but thicker coals would be potentially mineable); and coals at 1,000 ft or more depth as unmineable regardless of thickness, and suitable for either permanent storage or ECBM (Frailey and others, 2005). The Southeast Regional Carbon Sequestration Partnership, which KGS joined during phase II, also used a depth of 1,000 ft or more as unmineable.

Field and laboratory studies show, however, that carbon storage in coal beds faces a number of technical challenges. Laboratory experiments on coal core and crushed coal, for example, have indicated that (1) there are variable limits to the amount that CO_2 may enhance CH_4 recovery, (2) at low pressures, CH_4 may actually readsorb into the coal matrix during CO_2 injection, and (3) CO_2 adsorption causes swelling of the coal matrix, which lowers the coal bed's permeability, and therefore limits the amount of CO_2 that can be injected or stored (Levine, 1996; Frailey and others, 2005). There has been limited testing of the effects of swelling on injection in the field, although a pilot test of CO_2 injection for enhanced coalbed methane recovery in the Burlington Resources Allison unit, San Juan Basin, in New Mexico documented large decreases in coal permeability in CO_2 injection wells (Pekot and Reeves, 2002, 2003).

Multiple demonstration tests are planned in surrounding states in the near future that should provide data on the viability of CO_2 injection into coals for storage and ECBM. This is important because differences in coal rank, chemistry, cleating, and other factors may influence coal swelling and adsorption. A well in the Springfield coal (W. Ky. No. 9) in central Illinois has been drilled and sampled as part of phase II Midwest Geologic Sequestration Consortium research (Illinois State Geological Survey, 2007; U.S. DOE Fossil Energy Techline, 2008), and test injection of CO_2 into coal occurred in the summer-fall of 2008. During this test, 111 short tons of CO_2 were injected intermittently over 200 days. Injection rates fell during the test from an initial 2.2 short tons/day to a final 0.66 short ton/day, presumably because of permeability reduction caused by swelling of the coal (D. Morse, Illinois State Geological Survey, personal communication, 2009). Elsewhere, Southeast Regional Carbon Sequestration Partnership has planned CO_2 injection tests in Alabama and southwestern Virginia (Pashin and others, 2004; Pashin and Clark, 2006; Ripepi and others, 2008). The Virginia test has been initiated, but results are not yet public. In addition, KGS, as part of the Southeast Regional Carbon Sequestration Partnership, has planned a laboratory investigation of coal swelling in eastern Kentucky coals.

An overview of the factors that influence carbon storage and use of CO_2 for enhanced methane recovery can be found in the phase I reports of the Midwest Geologic Sequestration Consortium (Frailey and others, 2005) and the Southeast Regional Carbon Sequestration Partnership project (Pashin and others, 2004). Maps of CO_2 storage and ECBM recovery possibilities for coals in the Carbondale Formation in Kentucky (and the rest of the Illinois Basin) are shown in the phase I final report of the Midwest Geologic Sequestration Consortium (Frailey and others, 2005, p. 150–153). In Kentucky, the areas are mostly limited to a narrow belt south of the Rough Creek Fault System in the Rough Creek Graben, where coals are preserved at greater depths. Likewise, a map of the general area in which coal beds of eastern Kentucky are deep enough to be considered for ECBM or carbon storage is shown in the phase I final report of the Midwest Regional Carbon Sequestration Partnership (Wickstrom and others, 2005). This area is restricted to the southern part of the Eastern Kentucky Syncline and the Middlesboro Syncline.

Organic-rich shales are a fourth possibility for geologic carbon storage in Kentucky. The Devonian black shales of Kentucky are the state's most prolific natural gas (CH_4) producer. Like coal beds, the shales have high total organic content and low matrix porosity. The reservoir similarity suggests that the adsorption mechanisms described for coals should also occur in black shales, although to a lesser degree because of the lower organic content. Likewise, injection of CO_2 into the shales should displace naturally occurring CH_4 in the shale matrix and along fractures in the shale, so that enhanced gas recovery is possible. This would allow a revenue stream to be developed to help offset the costs of carbon storage, as with carbon storage and EOR, EGR, and ECBM.

KGS (through DOE and State of Kentucky funding) is a national leader in researching the potential for carbon storage in subsurface shales (Nuttall and others, 2005). The potential of this type of reservoir is great, but remains speculative. Aside from issues discussed for injection of CO_2 in coal beds, the extremely low permeabilities of the shales (normally considered a seal or confining interval) may limit the rate at which CO_2 can be injected. The widespread distribution and thickness of the Devonian black shales in the subsurface means that they could be a very important storage option in Kentucky, however, with potential CO_2 storage capacities of more than 27.6 billion short tons (Nuttall and others, 2005; Wickstrom and others, 2005). Kentucky's House Bill 1 (2007) specifically requires applying CO_2 enhanced gas recovery technology to the Devonian black shale. For updates on this project, see the KYCCS Web site (www.kyccs.org).

Basalts are the last of the potential reservoirs that have been identified as having potential for geologic carbon storage. Basalt is an igneous rock formed from lava. Rather than by miscible, immiscible, or adsorption mechanisms, carbon could be stored in basalts through chemical trapping mechanisms. Chemical trapping, also called mineral trapping, occurs when injected CO_2 reacts with minerals and elements in the basalt to form carbonate minerals. Because the injected CO_2 is altered to a relatively stable and solid phase, CO_2 would be permanently stored (Seifritz, 1990; Goldberg and others, 2008). The injectivity of the basalt, kinetics of the reactions, and potential for precipitation of minerals and scaling at the point of injection are some of the issues that need to be evaluated before this type of mechanism can be utilized for large-scale storage. A small-scale carbon-storage demonstration test in thick basalts is planned by the Big Sky Regional Partnership as part of their phase II research, which will help answer some of the above questions (Plasynski and others, 2008b).

In Kentucky, basalts are not widespread, and are encountered in association with the Precambrian Middle Run Formation. Basalt has been encountered in only two wells, and detailed petrographic and geochemical data are available for these intervals (Walker, 1991). Petrographic analysis of these basalts indicates they have been highly altered, both by a mild metamorphism and by surface weathering (Walker, 1991). The resulting mineralogic changes may affect how these basalts react with injected CO_2. These limitations, as well as the potential limitations to injection rates and sequestration volumes, will probably eliminate basalts as an option in Kentucky at this time.

Subsurface Area Required for Carbon Storage

One of the most important issues concerning geologic carbon sequestration is the large volume of CO_2 that will likely need to be sequestered. A 500-MW, bituminous-coal-fired power plant produces 2.2 to 4.4 million short tons of CO_2/yr. How much of that CO_2 will be required to be stored remains uncertain, but the FutureGen initiative based its proposals on annual storage volumes of 1.1 million short tons.

The area that will be required to store an industrial-scale volume of 1.1 million short tons of CO_2 (1 million metric tons) was calculated, based on some model criteria, for a Kentucky deep injection well. Table 1.1 shows the calculated areas of an injected CO_2 plume of 1.1 million short tons at different thicknesses and porosities of reservoir rock, using the MidCarb solubil-

Table 1.1. Calculations for a model western Kentucky CO_2 injection well to illustrate range of surface injection areas required using the MidCarb (2003) saline storage calculator (www.kgs.ku.edu/Magellan/Midcarb/aquifer.html).

Reservoir Thickness	*Porosity*	*Area Needed for 1.1 Million Short Tons of CO_2*	
(ft)	*(percent)*	*(acres)*	*(mi^2)*
5	5	106,225	165.92
	10	53,112	82.96
	15	35,408	55.31
	20	26,556	41.48
10	5	53,112	82.96
	10	26,556	41.48
	15	17,704	27.65
	20	13,278	20.74
20	5	26,556	41.48
	10	13,278	20.74
	15	8,852	13.83
	20	6,639	10.37
50	5	10,622	16.59
	10	5,311	8.30
	15	3,541	5.53
	20	2,656	4.15
100	5	5,311	8.30
	10	2,656	4.15
	15	1,770	2.76
	20	1,328	2.07

ity of CO_2 and volumetrics calculator for a saline reservoir (MidCarb, 2003). The calculation is based on a western Kentucky reservoir at 4,000 ft depth, a temperature of 90°F, a pressure of 1,700 psi, and a salinity of 170,000 ppm. Differences in temperature, pressure, salinity, rock heterogeneity, actual permeability, and other factors could also influence area estimates. Obviously, the best reservoirs would be 100 ft or more in thickness with porosities of 20 percent or more. Unfortunately, most known oil and gas and saline reservoirs in Kentucky are less than 20 ft thick, with average porosities of less than 15 percent. Only the Mount Simon Sandstone and Rome Formation have porosities of more than 10 percent in intervals more than 100 ft thick.

Contents of This Report

This report documents the results of a multifaceted regional evaluation of carbon storage potential in Kentucky funded by the Energy and Environment Cabinet (formerly the Governor's Office of Energy Policy). Four separate tasks were defined as part of this project, each of which contributes to the goal of implementing future geologic sequestration projects in the state. The individual tasks range from regional stratigraphic summaries to site-specific evaluations. Significant new data have resulted from this work, including reservoir parameters important for CO_2-enhanced oil recovery and chemical constituents of subsurface brines.

Task 1 evaluated and characterized major oil fields in Kentucky for their suitability in CO_2-enhanced oil recovery techniques. Oil fields were evaluated for EOR suitability using KGS reservoir data. Results of this work are presented in chapter 2.

Task 2, as originally proposed, involved sampling and chemical analysis of subsurface formation waters (brines) in two oil fields being considered for CO_2-EOR. Soon after this work began, a wealth of brine geochemistry data from across the state was located at KGS. These older data, in paper format, had never been entered into a computer database to allow analysis of regional or depth-related trends. These 356 analyses from wells in 23 counties across the state were determined to be of more value than new brine data collected from only two sites. Chapter 3 presents the results of this effort, and provides a valuable new data set for use in modeling the geochemical effects of CO_2 injection.

Task 3 evaluated the geology of the commonwealth to identify areas and geologic formations best suited for CO_2 storage. This study continued an appraisal started as part of Kentucky's effort to prepare a proposal for the Department of Energy FutureGen project (www.futuregenalliance.org). This work has focused on the major river corridors in the state, because there are existing coal-burning power plants in these areas, which will also be the likely sites of new gasification facilities. A new series of cross sections paralleling the river corridors is an important contribution, and is discussed in chapter 4.

Task 4 was more site-specific, and has provided preliminary CO_2 storage evaluations of sites nominated for coal gasification projects in the Kentucky site bank program (www.energy.ky.gov/efsb.htm). These CO_2 evaluations were included as part of the overall site rankings published by the Energy and Environment Cabinet, and are also included in chapter 5 of this report.

Appendix A of this report includes a discussion on the various types of geologic data required to evaluate the CO_2 storage potential of a site. The appendix also includes a new map of commercial reflection seismic data coverage for Kentucky. Seismic data are important for geologic characterization of an area prior to injection, and this map identifies the locations of seismic lines that are available for purchase at lower cost than acquiring new data.

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