Potential sinks for geologic storage of carbon dioxide generated by power plants in North and South Carolina

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Final Report

**Potential Sinks for Geologic Storage of Carbon Dioxide
Generated by Power Plants in North and South Carolina**

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Preface from power company representatives:

A consortium of four power companies in the Carolinas (Duke Energy, Progress Energy, Santee Cooper Power, and South Carolina Electric and Gas) has funded this project in cooperation with the Electric Power Research Institute (EPRI) and the Southern States Energy Board (SSEB) to take an active role in finding solutions to climate change issues. This is our first step on the path toward understanding the opportunities and constraints of carbon storage. Our motivation is to seek information that will enable application of this technology.

This document summarizes a scoping study of the current state of knowledge of carbon storage options for our geographic area. The focus is on one aspect of carbon capture and storage— identification of deep saline reservoirs in which carbon dioxide (CO_2) generated in the Carolinas might be stored. The study does not address other aspects of CO_2 storage projects, such as capture and compression of the gas, well construction and development, or injection. Transport of CO_2 is touched upon in this study but has not been fully addressed.

The information contained in this document is primarily from review of published geologic literature and unpublished data. No field data collection has been completed as part of this study. Further work will be necessary to increase confidence in the suitability of the potential CO_2 storage sites identified in this report. This study does not address the regulatory, environmental, or public policy issues associated with carbon storage, which are under development at this time.

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Executive Summary

Introduction

Options for reduction of atmospheric emissions of greenhouse gases (GHG) are currently under consideration by both government (Federal and State) and industry, and interest will continue to expand (e.g., Herzog, 2001; DOE, 2005; Hoffman, 2006). Carbon dioxide (CO_2) occurs naturally in the atmosphere, but over the past few centuries concentrations have increased as a result of emissions from anthropogenic sources. At this time CO_2 emissions are not regulated in the U.S.; however, discussions on reducing the intensity of GHG emissions are under way. Technologies to separate, capture, and concentrate CO_2 from industrial emissions are under development but are not yet ready for commercial use.

Geologic storage is a process whereby concentrated CO_2, captured from industrial sources, will be injected into suitable subsurface strata or geologic "sinks" and stored for significant periods of time (thousands of years) through physical or chemical trapping (Bachu et al., 1994). The combination of carbon capture and storage is known by the acronym CCS. According to a recently released report by researchers at Massachusetts Institute of Technology (MIT) (Deutch et al., 2007), "CCS is the critically enabling technology to help reduce CO_2 emissions significantly while also allowing coal to meet the world's pressing energy needs."

The study summarized here updates and supersedes previous CO_2 source-sink matching analyses (Hovorka et al., 2000) used in Phase I of the Southeast Regional Carbon Sequestration Partnership (SECARB), which was funded by the Department of Energy (DOE) through the Southern States Energy Board (SSEB). Funding for this study is from Carolinas power companies Duke Energy, Progress Energy, Santee Cooper Power, and South Carolina Electric and Gas, in cooperation with the Electric Power Research Institute (EPRI) and SSEB. A goal of the study is to increase understanding of the technical feasibility of subsurface geologic storage of CO_2 in order that informed decisions may be made regarding GHG issues in the region.

The focus here is to identify geologic units containing deep saline reservoirs, or sinks, that might be suitable for effective, large-volume geologic storage of CO_2 generated by power plants in North and South Carolina. All data used to evaluate the suitability of the potential geologic sinks are from preexisting geologic studies, the majority from published literature. Geologic units underlying most of North and South Carolina do not meet minimum suitability criteria necessary for long-term storage of CO_2. Hence, in order to match potential sources of CO_2 with potential sinks, a process known as *source-sink matching*, CO_2 will have to be transported before it can be injected into the subsurface and isolated from the atmosphere and freshwater resources.

Evaluation of the constraints to transport CO_2 generated in the Carolinas, including pipeline costs, was conducted by the MIT Laboratory for Energy and the Environment in late 2006. The pipeline cost estimates (in 2006 dollar equivalents for materials) include neither the cost of capture/separation at the plant nor cost of compression or injection at the CO_2 storage site, which are beyond the scope of this assessment. In recent work to evaluate costs of CCS, MIT researchers (Deutch et al., 2007) estimated that the cost of CO_2 capture and pressurization will greatly exceed the cost of CO_2 transportation and storage.

Background

Minimum suitability criteria for geologic sinks include (1) continuity and integrity of an overlying seal; (2) depth sufficient to maintain CO_2 at high density (which corresponds to depths greater than 800 m (>2,400 ft) below the surface); (3) depth below underground sources of drinking water (USDW), where total dissolved solids exceed 10,000 parts per million (ppm); and (4) storage capacity sufficient to prevent displacement of saline water into overlying freshwater-bearing units.

Estimates of the capacity of potential geologic sinks presented in this report have been provided by coworkers at Massachusetts Institute of Technology (MIT). The MIT methodology assumes that if requirements 1 and 2 above are satisfied, the CO_2 storage capacity of a saline reservoir can be calculated using the following formula:

$$Q_{aqui} = V_{aqui} * p * e * \rho_{CO2} \qquad (1)$$

where Q_{aqui} = storage capacity of entire reservoir (Mt CO_2)

V_{aqui} = total volume of entire reservoir (km^3)

p = reservoir porosity (%)

e = CO_2 storage efficiency (%)

ρ_{CO2} = CO_2 density at reservoir conditions (kg/m^3)

If accurate spatial data are available for a reservoir, then the reservoir volume used in equation 1 can be calculated as an integral of the surface area and thickness of the reservoir:

$$V_{aqui} = \sum_i S_i T_i \qquad (2)$$

where S_i is the area of the raster cell and

T_i is the thickness of the cell

The term "CO_2 storage efficiency" refers to the fraction of the reservoir pore volume that can be filled with CO_2. For a saline reservoir in which CO_2 can be trapped by a physical barrier (overlying seal), the storage efficiency is estimated at 2% (Holloway, 1996).

Large areas of the southeastern U.S. either are unsuitable or have low potential for geologic storage of CO_2 (figure ES-1). This suitability is related to geologic processes that have formed the present-day substrate of the southeastern U.S. over millions of years. A schematic cross section depicting the subsurface of the southeastern U.S. is shown in figure ES-2. Western portions of the Carolinas are underlain by highly fractured crystalline (igneous and metamorphic) rocks of the Blue Ridge and Piedmont physiographic provinces of the Appalachian Mountains (figs. ES-1, ES-2). Fractured crystalline rocks can serve as limited-capacity fluid reservoirs but are unsuitable for large-volume CO_2 storage if they lack laterally extensive overlying sedimentary seals. Rocks in the Blue Ridge and Piedmont provinces lack suitable seals throughout the Central and Southern Appalachian Mountains.

Exposed Mesozoic-age rift basins within the Piedmont province (fig. ES-1) might be considered for CO_2 storage on a site-specific basis. However, they do not meet the minimum suitability criteria used in this study. Rocks in the Valley and Ridge province have low potential for geologic storage because they are extensively folded and faulted. Limited capacity sinks are likely present in isolated areas beneath the Valley and Ridge province (fig. ES-1), but drilling and testing will be required to document storage integrity at specific locations.
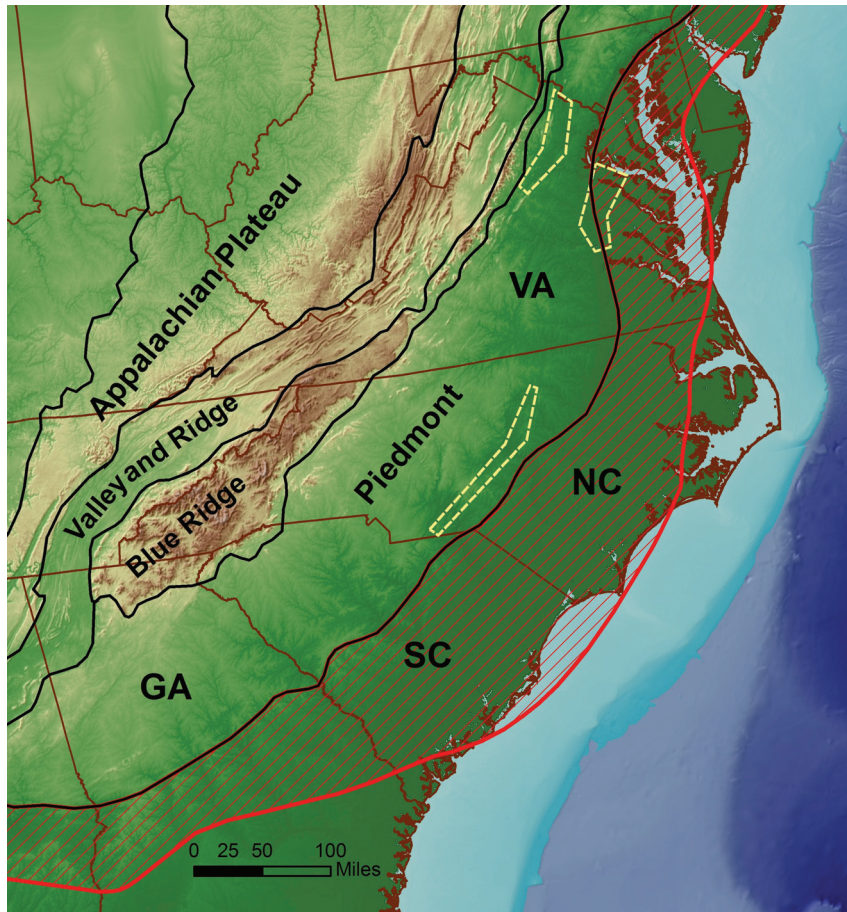
Figure ES-1. Physiographic provinces of the Appalachian Mountains and portions of the Coastal Plain where sediments are less than 800 m thick (outlined in red). Sources: Physiographic provinces of Appalachian Mountains modified from Fenneman and Johnson (1946); exposed Mesozoic rift basins (dashed yellow lines) modified from Olsen et al. (1991); and digital elevation models from NOAA (2006) (land) and Scripps (2006) (ocean floor). Depth to seafloor increases with darker shades of blue. Elevation of land surface increases from green to yellow to brown.
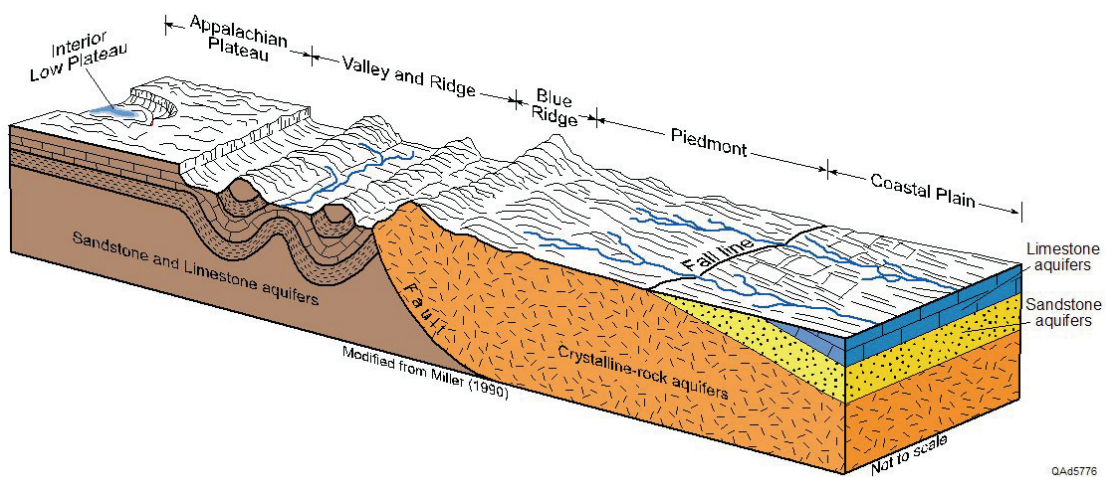
Figure ES-2. Schematic cross section from NW Alabama to south Georgia Coastal Plain.

Data compiled for this study show that much of the Coastal Plain province of the Carolinas is underlain by sedimentary sequences too thin for emplacement of CO_2 at sufficient pressure or at depths far enough below freshwater resources (figs. ES-1, ES-2). Sedimentary rocks within the area outlined in red in figure ES-1 are less than 800 m (<2,400 ft) thick, and they are underlain by Piedmont crystalline rocks (fig. ES-2). Because the coastal-plain sediments are saturated with relatively fresh groundwater, injection of CO_2 would not be possible under the criteria of this study.

Potential Sinks

Prospective geologic sinks (i.e., those subsurface units that *do* meet minimum suitability criteria) underlie areas located in (1) isolated basins along Atlantic coastlines of North Carolina, South Carolina, and Georgia (Hatteras and South Georgia Basin [SGB] sinks); (2) offshore ~1 km below the Atlantic seafloor (Unit 90 and Unit 120 sinks); and (3) nearby states (Tuscaloosa, Mt. Simon, and Knox sinks) (fig. ES-3).
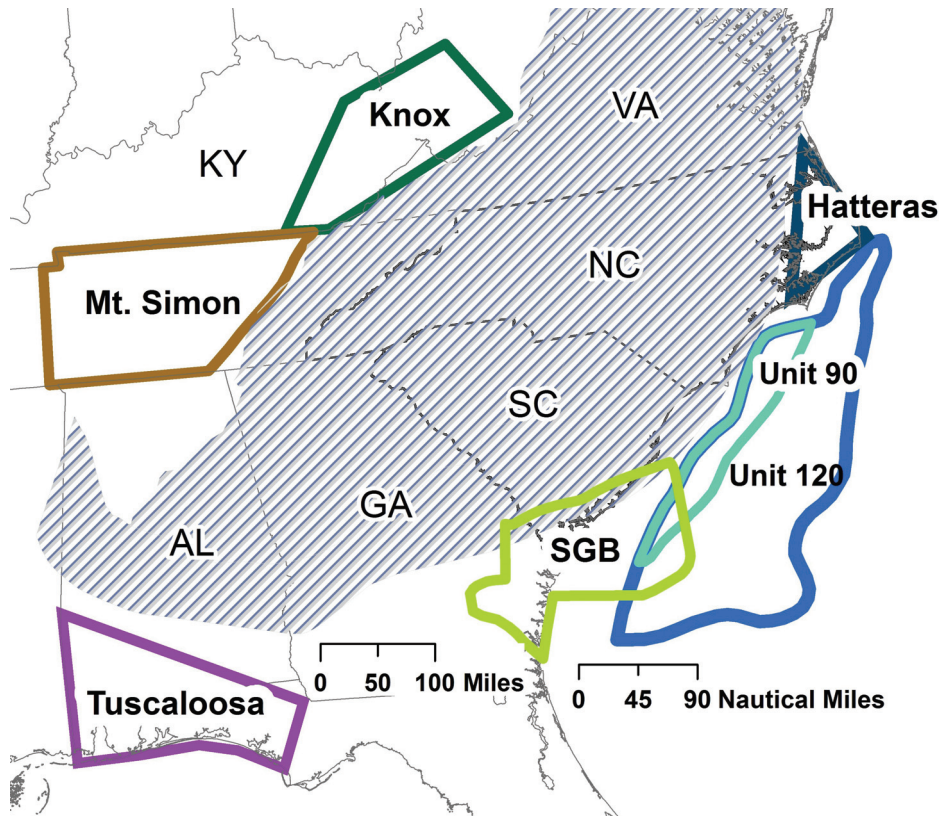
Figure ES-3. Location of low-potential regions (stippled area) and high-potential geologic sinks. SGB = Cretaceous- and Triassic-age geologic units in South Georgia Basin.

Sinks with potential for long-term storage of CO_2 generated in the Carolinas are all deep saline reservoirs within host geologic strata. All sinks presented here have been chosen through study of existing and, in most cases, published data. Additional field-data collection and verification will be required to test the suitability of specific injection sites and refine the generalized capacity estimates presented herein. This initial assessment of geologic sinks with potential for long-term storage of CO_2 is unencumbered. That is, it is

based solely on the suitability of subsurface units to store CO_2; it does not take into account environmental, economic, or socio/political issues that will need to be balanced with geologic suitability.

Potential sinks within the Carolinas are Hatteras and SGB (fig. ES-3). Sediments west of Cape Hatteras attain a thickness of 2.7 km (1.7 mi) (fig. ES-4), which is sufficient to contain potential CO_2 sinks. However, literature review to obtain hydraulic properties and other data needed to estimate capacity of specific stratigraphic units was not performed for this study.
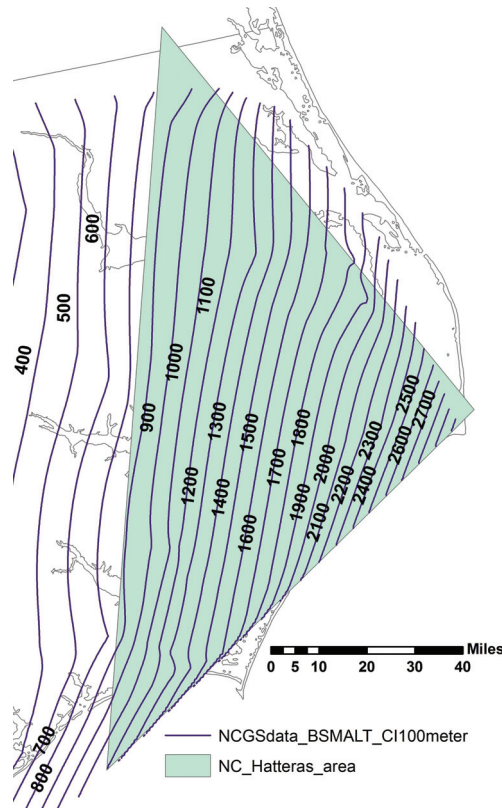
Figure ES-4. Depth (m) to crystalline basement rocks in the Hatteras area. Contours generated from North Carolina Geological Survey well data provided by Dr. Paul Thayer.

The South Georgia Basin is the east end of a series of structural basins spanning from Alabama across south-central Georgia, southern South Carolina, and eastward onto the Atlantic continental shelf. Through previous work associated with SECARB, and what is reported herein, we have identified three potential sinks in the South Georgia Basin: (1) Late Cretaceous-age Cape Fear Formation from previous SECARB work, (2) Late Cretaceous-age Tuscaloosa/Atkinson units in Georgia, and (3) Triassic-age units that are buried beneath coastal-plain sediments and extend offshore from South Carolina and Georgia (fig. ES-5). These three potential sinks partly overlap in map view but span different depth horizons between 800 and 1,300 m (2,600 and 4,300 ft); they are represented as one geologic sink, SGB, in figure ES-3. The combined estimate of capacity for these three contiguous, vertically stacked sinks is approximately 15 gigatons (Gt).
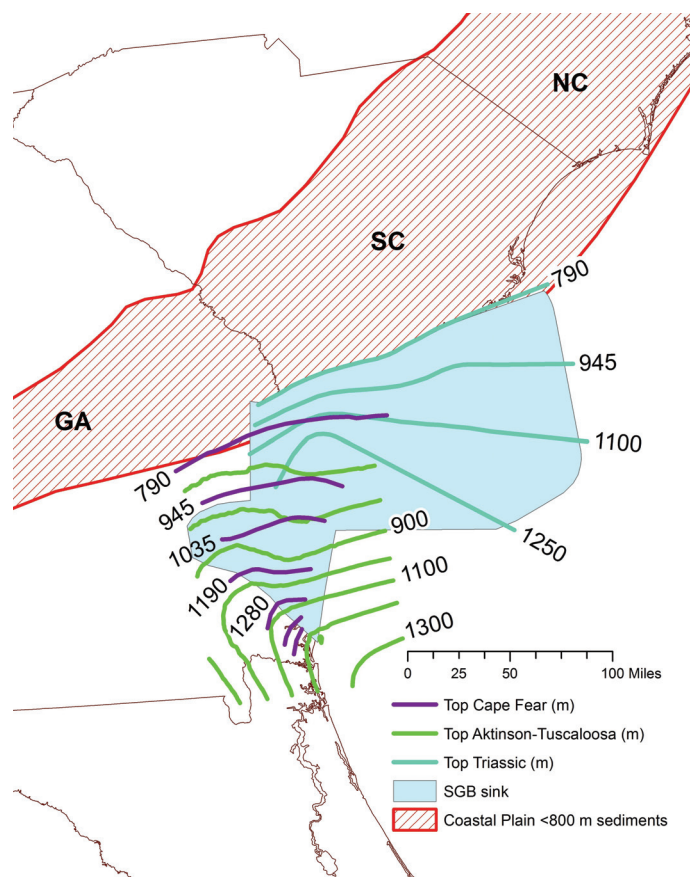
Figure ES-5. Three geologic sinks within the South Georgia Basin. Modified from Hovorka et al. (2000), Temples (pers. comm., 2006), Gohn et al. (1980), and Renkin et al. (1989).

Two potential CO_2 sinks are present in geologic strata below the Atlantic seafloor, offshore from Cape Hatteras, North Carolina, to Brunswick, Georgia (units 90 and 120 on fig. ES-3). Offshore settings involve initially higher pressures (beneath the water column) and lower temperatures at the seafloor, both of which favor denser CO_2 phases throughout subseafloor storage depths when compared with terrestrial settings. It is important to note that potential offshore activities involve injections at thousands of meters below the seafloor and should not be misinterpreted to include injection (dissolution) into circulating seawater.

The subseafloor sinks are located between 25 and 175 km offshore from the Carolinas in Upper (unit 90) and Lower (unit 120) Cretaceous strata between approximately 500 and 3,000 m (1,650 and 9,850 ft) beneath the seafloor in water depths between 50 and 1,000 m (165 and 3,280 ft) (figs. ES-3, ES-6). Both of these potential sinks are overlain by low-permeability seal layers, the shallowest of which lies between 200 m (660 ft) (landward) and 2,000 m (6,600 ft) seaward below the seafloor (Hutchinson et al., 1996, 1997). Lack of extensive drilling in the Atlantic offshore from the Carolinas means that seal integrity should be excellent, but results in few available hydraulic property data. Using core data collected at other western Atlantic drill sites, we have estimated capacities of about 16 Gt for the shallower (unit 90) and up to 175 Gt for the deeper (unit 120) potential subseafloor sinks.

At present, the only subseafloor geologic storage site for CO_2 is operated by Statoil in the Norwegian North Sea. The sinks identified offshore from the Carolinas are not as well characterized as the North Sea example and would require investigation to determine suitability and to refine capacity estimates. Legal, regulatory, and policy implications of subseafloor geologic storage of CO_2 are unresolved at this time. However, in November 2006, a resolution was adopted by members of the 1996 Protocol of the London Convention to "establish the legality of storing CO_2 in sub-seabed geologic formations." Guidelines for scientific assessment of the potential for subseafloor CO_2 storage will be finalized and presented to the international community soon (IEA, 2006).
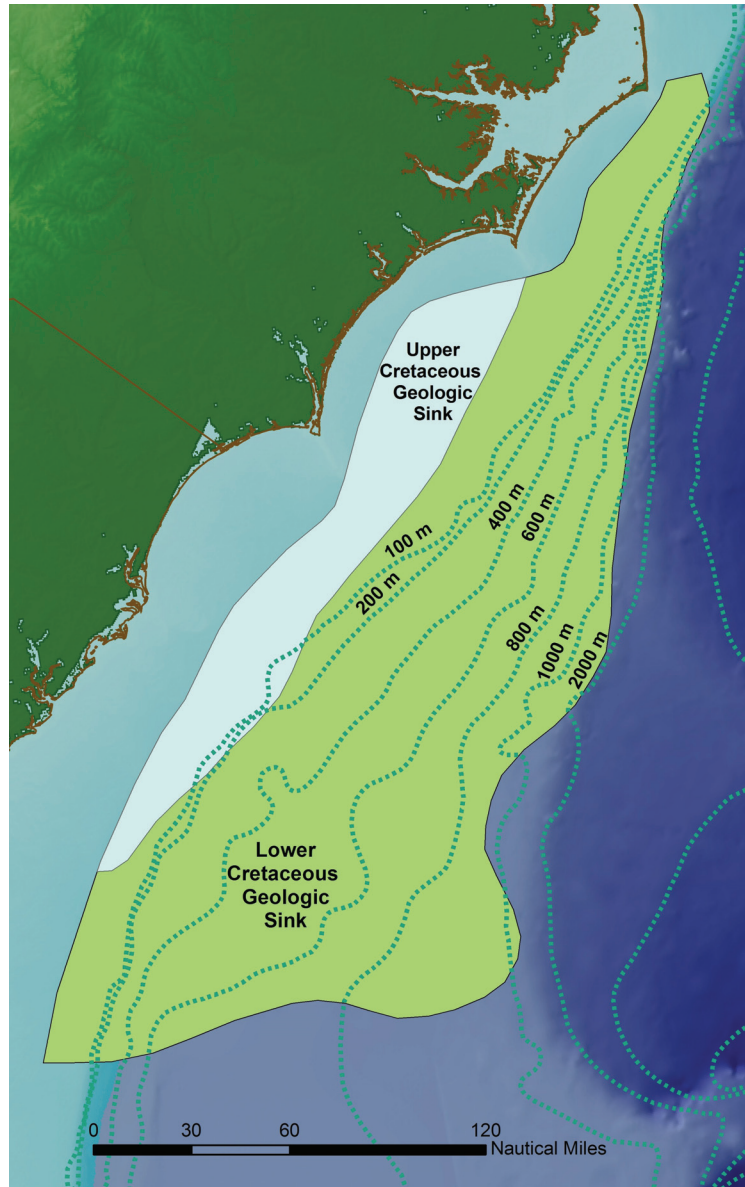
Figure ES-6. Upper and Lower Cretaceous Atlantic subseafloor sinks. (modified from Hutchinson et al., 1996, 1997). Contoured water depth (m) shown in blue dashed lines (irregular contour interval). Depth from sea level to seafloor increases with darker shades of blue.

Because subsurface units underlying much of the Carolinas are unsuitable for long-term storage of CO_2, we looked outside the states for other potential geologic sinks. Two geologic units within the Appalachian Plateau province contain potential CO_2 sinks (1) the Mt. Simon Formation and (2) the Knox Group (fig. ES-3). Data for the Mt. Simon unit in Tennessee are from Advanced Resources International, Inc. (ARI). Depth to base of Mt. Simon ranges from 1,200 to 2,400 m (4000 to 8,000 ft) (fig. ES-7), and thickness throughout is approximately 30 m (~100 ft). Capacity of the Mt. Simon unit is estimated at 2.5 Gt. Additional storage in this unit may extend into adjacent states, but this possibility has not yet been assessed.
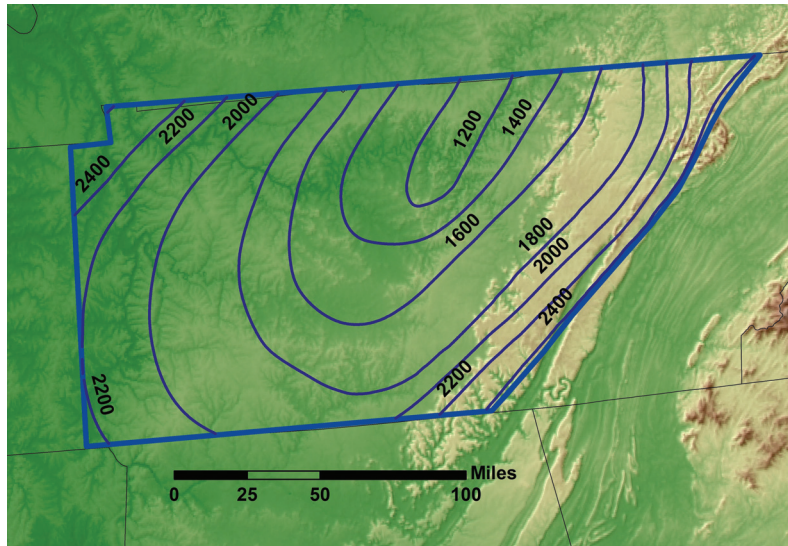
Figure ES-7. Base of Mt. Simon Formation in meters. Modified from ARI data on the Mt. Simon Formation (Maria Fonkin, pers. comm., 2005).

Hydrocarbons (primarily gas) have been produced from Knox Group rocks since the early 1960's, and the potential for future natural gas production from the Knox Group is great within eastern Kentucky and West Virginia (Baranoski et al., 1996). The Knox Group also has great potential for storage of greenhouse gasses. Depth below ground to the top of the Knox Group sink ranges from 800 m (2,600 ft) in eastern Kentucky to 2,600 m (8,500 ft) in southern West Virginia (fig. ES-8a). Thickness of strata in the Knox Group in this area ranges from 500 to 1,200 m (1,650 to 3,950 ft) (fig. ES-8b). Capacity of the Knox Group is estimated at about 30 Gt.

The Upper Cretaceous Tuscaloosa Formation in southwestern Alabama and the Florida panhandle is another out-of-state, potential CO_2 sink (fig. ES-3). Primary sources of information on the geometry, composition, and thickness of the Lower Tuscaloosa strata are geophysical logs of wells drilled for (1) oil and gas exploration and production, (2) disposal of co-produced saline water, and (3) industrial waste disposal. Depth to the top of the Tuscaloosa sink ranges from about 1 to 3 km (0.6 to 2 mi); thickness ranges from 20 to 60 m (70 to 200 ft) (Miller, 1979, 1990; Mancini et al., 1987; Renkin et al., 1989), and unpublished information was provided by the Florida Geological Survey (pers. comm., 2006). A capacity of 9.8 Gt is estimated for this area. Additional assessment of the Tuscaloosa in Mississippi is now under way as part of SECARB studies.

(a)   (b)

Figure ES-8. Potential Knox Group geologic sink; (a) structure contour on top of Knox (m) and (b) thickness of Knox (m). From Baranoski et al. (1996); Shumaker (1996). Elevation of land surface increases from green to yellow to brown.

The Upper Cretaceous Tuscaloosa Formation in southwestern Alabama and the Florida panhandle is another out-of-state, potential CO_2 sink (fig. ES-3). Primary sources of information on the geometry, composition, and thickness of the Lower Tuscaloosa strata are geophysical logs of wells drilled for (1) oil and gas exploration and production, (2) disposal of co-produced saline water, and (3) industrial waste disposal. Depth to the top of the Tuscaloosa sink ranges from about 1 to 3 km (0.6 to 2 mi); thickness ranges from 20 to 60 m (70 to 200 ft) (Miller, 1979, 1990; Mancini et al., 1987; Renkin et al., 1989), and unpublished information was provided by the Florida Geological Survey (pers. comm., 2006). A capacity of 9.8 Gt is estimated for this area. Additional assessment of the Tuscaloosa in Mississippi is now under way as part of SECARB studies.

Source-Sink Matching Constraints

Part of the source-sink matching process requires estimates of the cost of CO_2 transport to a specific potential geologic sink. For purposes of this discussion, we focused on the potential for transportation by pipeline. Estimates of pipeline costs for this study were conducted by the MIT Laboratory for Energy and the Environment in late 2006. Pipeline cost estimates (in 2006 dollar equivalents for materials) include pipeline construction, right-of-way acquisition, and operation. Cost estimates for CO_2 pipeline construction are based on cost data for natural gas pipelines. This may have resulted in an underestimate of costs to build CO_2 pipelines because of the greater CO_2 wall thickness required to contain supercritical (high pressure and temperature) CO_2. Neither the cost of capture/separation at the plant nor the cost of compression and injection at the CO_2 storage site are included. These elements are beyond the scope of this assessment, which

is to match sources with sinks and provide a relative index of cost escalation as the distance between sources and sinks increases.

After identifying CO_2 sources in the Carolinas and using the potential geologic sinks identified by the Bureau of Economic Geology (BEG), MIT workers evaluated source-sink matching over an assumed 25-yr project lifetime. They used a Geographic Information System (GIS) method of matching sources and sinks that considers optimal pipeline route selection and capacity constraints of individual sinks. Because pipeline construction costs vary considerably according to local terrain, number of crossings (waterway, railway, highway), and the traversing of populated places, wetlands, and national or state parks, the group constructed a digital terrain map that allows ranking of these factors.

MIT generated pipeline-transport algorithms using the Carnegie Mellon University (CMU) correlation (McCoy, 2006). Because the MIT source sink matching program develops a minimum cost curve, it favors sinks that are closer to potential sources and automatically excludes more distant sinks. In order to obtain pipeline estimates for all potential sinks presented in this study, MIT used a multiple scenario approach that alternatively excluded nearby sinks so as to force utilization of more distant sinks. Following are constraints for the five possible scenarios:

- Scenario 1 includes all potential sinks,
- Scenario 2 considers all sinks except the Hatteras area,
- Scenario 3 considers all sinks except the Hatteras area and subseafloor Unit 90 (Upper Cretaceous) in order to force pipeline estimates for subseafloor Unit 120 (Lower Cretaceous),
- Scenario 4 excludes the Hatteras area, subseafloor Unit 90 (Upper Cretaceous), and SGB to force pipeline estimates for Mt. Simon sink,
- Scenario 5 excludes the Hatteras area, subseafloor Unit 90 (Upper Cretaceous), SGB, and Mt. Simon to force pipeline estimates for Tuscaloosa sink in Alabama/Florida.

Summaries of estimated costs (in 2006 dollar equivalents for materials) for pipelines between selected sources and potential target sinks are presented for each of the five scenarios (table ES-1). Total power output of the plants served ranges from 25.8 gigawatts (GW) for Scenario 1 to 24.5 GW for Scenario 5. Total pipeline construction costs range from $3.8 billion for Scenario 1 to $4.3 billion for Scenario 5. Average transportation costs vary from $3.56 to $4.21 per metric ton of CO_2.

Costs for Scenario 1 are lowest because only those potential sinks closest to the Carolinas power plants—Hatteras, Knox, Unit 90, and SGB—are utilized (table ES-1, fig. ES-3). The purpose of running MIT's GIS algorithms using scenarios 3, 4, and 5 was to obtain estimated costs for utilizing the more distant potential sinks—subseafloor unit 120, Mt. Simon, and Tuscaloosa—for geologic storage of CO_2.

Table ES-1. Estimated cost summary (in 2006 dollar equivalents for materials) for five sink scenarios (for power plants with transportation cost <10$/t CO_2).

SINK OPTIONS	TOTAL CONSTRUCTION COST (BILLION $)	TOTAL CO_2 STORED IN 25 YEARS (GT[1])	TOTAL DESIGN CAPACITY (GW)	AVERAGE COST ($/TON CO_2)	AVERAGE DISTANCE[2] (km)	TARGET SINKS
Scenario 1	3.8	4.2	25.8	3.56	299	Hatteras, Knox, Unit 90, SGB
Scenario 2	3.8	4.1	25.3	3.63	322	Knox, Unit 90, SGB
Scenario 3	4.0	4.1	24.8	3.84	344	Knox, Unit 120, SGB
Scenario 4	4.2	4.0	24.5	4.17	370	Knox, Mt. Simon, Unit 120
Scenario 5	4.3	4.0	24.5	4.21	373	Knox, Unit 120, Tuscaloosa

[1]Gt = 1 billion metric tons

[2]Flow-rate-weighted-average pipeline distance

Discussion

Most of the power plants in the Carolinas are underlain by geologic units that are not suitable for long-term storage of large volumes of CO_2. The Blue Ridge and Piedmont physiographic provinces of the Appalachian Mountains in western portions of the Carolinas are underlain by crystalline rocks that lack sufficient overlying seals to (1) trap CO_2 in the subsurface or (2) keep it from interacting with fresh groundwater. Sediments of the Atlantic Coastal Plain are not thick enough to host CO_2 sinks and contain deep freshwater aquifers. An exception within the Carolinas is an isolated sedimentary basin encompassing the southernmost part of South Carolina that lies within the South Georgia Basin.

Subsurface storage of CO_2 generated in the Carolinas will probably require construction of pipelines to geologic sinks located some distance away from the power plants. The most likely potential geologic sinks for CO_2 generated in the Carolinas are located in (1) the South Georgia Basin (southernmost South Carolina, eastern Georgia, and extending offshore 50 to 75 mi (80 to 120 km), (2) the offshore in strata approximately 0.6 to 1.9 mi (~1 to 3 km) below the Atlantic seafloor, and (3) the Knox Formation in eastern Kentucky and southwestern West Virginia. The CO_2 storage potential for the offshore Atlantic margin is unexplored, but preliminary considerations suggest that CO_2 sequestration options are significant along the entire eastern seaboard. Given the limited sink availability in onshore locations of the eastern U.S., and the potentially promising offshore locations, subseafloor injection warrants further evaluation.

Estimates of storage capacity of the potential geologic units are summarized in table ES-2. These estimates are based on limited and generalized data sets, which are primarily from published literature. More accurate estimates of capacity for geologic sinks will require site-specific, detailed geologic investigations. In addition, assessment

of the potential geologic sinks is based solely on geologic suitability. Environmental, economic, and socio-political issues will need to be considered before determining which geologic sinks are most suitable for CO_2 storage.

Table ES-2. MIT estimates of CO_2 storage capacity.

POTENTIAL SINK	CAPACITY ESTIMATES[1] (Gt)

SGB
    Triassic units
    Atkinson-Tuscaloosa
    Cape Fear
	~15

Offshore Sinks
    Unit 120
    Unit 90
	~178[2]
	~16[2]

Hatteras Area	n.a.[3]
Mt. Simon	~3
Knox	~32
Tuscaloosa	~10

Notes:
1. CO_2 storage efficiency estimated as 2 percent and all the aquifers are assumed closed.
2. CO_2 density in the offshore sites assumed to be 700 kg/m³.
3. Detailed data are not available.

Costs associated with CCS can be separated into two categories—(1) those associated with CO_2 capture and separation and (2) those associated with transportation and storage. Deutch et al. (2007) estimated that the cost of CO_2 capture and pressurization will greatly exceed the cost of CO_2 transportation and storage. The cost estimates presented in this summary report represent possible scenarios for pipeline transport of CO_2 from power plants in the Carolinas to potentially suitable geologic sinks.

Pipeline construction costs are the primary cost factor in the various scenarios, and they vary according to type of terrain that must be traversed. CO_2 transport costs are estimated in terms of $/ton CO_2, which is the total cost divided by the CO_2 flow rate. Hence, transporting CO_2 at a higher flow rate results in lower transportation costs. Average transportation costs estimated by MIT for the five different scenarios vary from $3.56 to $4.21 per metric ton of CO_2 in 2006 equivalent dollars. These costs might be low because (1) MIT based pipeline construction costs on those required to build natural gas pipelines; CO_2 pipelines might be more expensive because of the greater wall thickness needed to contain supercritical (high temperature and high pressure) CO_2, (2) fluctuations in the price of steel, (3) uncertainty in the cost escalation factor for building offshore pipelines.

Introduction

Options for reduction of atmospheric emissions of greenhouse gases (GHG) are currently under consideration by both government (Federal and State) and industry, and interest will continue to expand (e.g., Herzog, 2001; DOE, 2005; Hoffman, 2006). Carbon dioxide (CO_2) occurs naturally in the atmosphere, but over the past few centuries concentrations have increased as a result of emissions from anthropogenic sources. At this time CO_2 emissions are not regulated in the U.S.; however, discussions on reducing the intensity of GHG emissions are under way. Technologies to separate, capture, and concentrate CO_2 from industrial emissions are under development but are not yet ready for commercial use.

Geologic storage is a process whereby concentrated CO_2, captured from industrial sources, will be injected into suitable subsurface strata or geologic "sinks" and stored for significant periods of time (thousands of years) through physical or chemical trapping (Bachu et al., 1994). The combination of carbon capture and storage is known by the acronym CCS. According to a recently released report by researchers at Massachusetts Institute of Technology (MIT) (Deutch et al., 2007), "CCS is the critically enabling technology to help reduce CO_2 emissions significantly while also allowing coal to meet the world's pressing energy needs."

Results presented here update and supersede previous CO_2 source-sink matching analyses (Hovorka et al., 2000) used in Phase I of the Southeast Regional Carbon Sequestration Partnership (SECARB), which was funded by the Department of Energy (DOE) through the Southern States Energy Board (SSEB). Funding for this study has been provided by Carolinas power companies Duke Energy, Progress Energy, Santee Cooper Power, and South Carolina Electric and Gas, in cooperation with the Electric Power Research Institute (EPRI) and SSEB.

The focus of this study is to identify geologic units containing deep saline reservoirs (brine-filled formations), or geologic sinks that might be suitable for effective, large-volume geologic storage of CO_2 generated in North and South Carolina. An additional objective is to provide information in a format that can be used to guide policy makers and educate the public about geologic storage options for North and South Carolina.

CO_2 Storage Requirements

Deep saline reservoirs are one type of geologic sink. These require (1) continuity and integrity of an overlying seal; (2) depth sufficient to maintain CO_2 at high density (which corresponds to depths greater than 800 m (>2,400 ft) below the surface); (3) depth below underground sources of drinking water (USDW), where total dissolved solids exceed 10,000 parts per million (ppm); and (4) storage capacity sufficient to prevent displacement of saline water into overlying freshwater-bearing units. Accurate prediction of the storage properties of geologic units will permit semiquantitative analysis of CO_2 capacity and will allow site-specific assessment to proceed more readily.

Buoyancy-driven flow in the absence of immobilization of CO_2 from dissolution into brine or trapping as a result of mineral-fluid interactions makes integrity of seal rocks a critical issue (e.g., Hovorka et al., 2004). The critical point of CO_2 is at a temperature of 31°C (87.9 °F) and pressure of 73.8 bars (1070.7 psi). Above this temperature and pressure, CO_2 is not liquid or gas but exists in supercritical phase, which

has properties of both liquid and gas (Jarrell et al., 2002). Supercritical CO_2 will partially dissolve into brine held in pore spaces of a deep saline reservoir. The remaining CO_2 will form a free (immiscible) supercritical phase that will displace brine (Doughty and Pruess, 2003). Temperature and pressure sufficient for keeping CO_2 in supercritical phase generally corresponds to depths greater than 800 m (2,400 ft) below the land surface.

Monitoring for CO_2 leakage into groundwater is an essential part of the overall strategy for assessing suitability of geologic sinks (Doughty et al., 2004; Nance and others, 2005; Hovorka, 2006; Hovorka and others, 2006). CO_2 could migrate into groundwater through improperly plugged boreholes, through faults or joints that penetrate seals and intermediate strata, and by flow through the seals and intermediate strata where cross-formational permeable pathways are encountered by CO_2 injectate plumes.

In 1974 the Safe Drinking Water Act was passed in the U.S. Congress (U.S. House of Representatives, 1974) and is enforced by the Environmental Protection Agency (EPA). In this Act, USDWs are defined as water-bearing units with less than 10,000 ppm or milligrams per liter (mg/L) total dissolved solids (TDS). Water-bearing units with less than 10,000 ppm TDS cannot be used to store injected wastes. CO_2 is not a waste according to the Safe Drinking Water Act, but it is prudent to utilize reservoirs for storage of it in geologic sinks that are deeper than the deepest USDW in any given area.

Procedures for estimating volume of CO_2 that can be injected into a particular saline reservoir (known as capacity of the reservoir) are still being debated among U.S. and international researchers engaged in CO_2 storage issues. In subsequent sections we provide details of data used as input to capacity estimates for each potential geologic sink identified during this study.

Part of the assessment of a potential geologic sink is estimation of CO_2 capacity and the cost of pipeline transport to a specific site. Estimates of pipeline costs (cost of pipeline construction, right-of-way acquisition, and operation—but not CO_2 injection) and potential storage capacity of geologic sinks were conducted in 2006 at Massachusetts Institute of Technology (MIT) Laboratory for Energy and the Environment by Howard Herzog and his research team in late 2006. The pipeline cost estimates (in 2006 dollar equivalents for materials) include neither the cost of capture/separation at the plant nor cost of compression or injection at the CO_2 storage site, which are beyond the scope of this assessment.

In recent work to evaluate costs of CCS, MIT researchers (Deutch et al., 2007) estimated that the cost of CO_2 capture and pressurization will greatly exceed the cost of CO_2 transportation and storage. Herzog's MIT group has developed a Carbon Management Geographic Information System (GIS) tool that utilizes ArcGIS$^{©}$ (software developed by Environmental Systems Research Institute). We converted data needed to estimate reservoir capacity into GIS format and provided it to the MIT group. This simplified data management, analysis, and presentation of information. For example, many of the figures in this report were generated in ArcGIS$^{©}$.

Geologic Framework and Storage Constraints

In western portions of North Carolina and South Carolina, highly fractured, crystalline and metamorphic rocks of the Blue Ridge and Piedmont physiographic provinces of the Appalachian Mountains are present at the surface. Fractured crystalline

rocks can serve as limited-capacity fluid reservoirs, but in this area the rocks are unsuitable for CO_2 storage owing to absence of overlying sedimentary seals that would prevent escape of injected gas to the atmosphere. In the eastern portions of North and South Carolina, sedimentary rocks of the Coastal Plain physiographic province are underlain by Piedmont-like fractured crystalline rocks. However, sediment thicknesses over much of the Coastal Plain are insufficient to allow emplacement of CO_2 at adequate pressure, or at depths far enough below freshwater resources to provide good environments for geologic sequestration. Consequently, there are few options for geologic storage of CO_2 within the Carolinas (fig. 1).

This report begins with a brief discussion of the geologic history of the southeastern U.S. because that history is fundamental to understanding the suitability of different areas to CO_2 storage. This discussion is followed by description of areas that are unsuitable or that have low potential for geologic storage. Further on we present data acquired *to date* for assessment of sinks identified for potential geologic storage of CO_2 generated in the Carolinas. The sinks are primarily located outside of the Carolinas underlying adjoining states to the northwest and southwest, and below the Atlantic seafloor offshore from the Carolinas and Georgia (fig. 1). Initial estimates of sink capacities and costs to build pipelines from power plants in North and South Carolina to the potential geologic sinks have been completed by MIT and are summarized the end of this report.
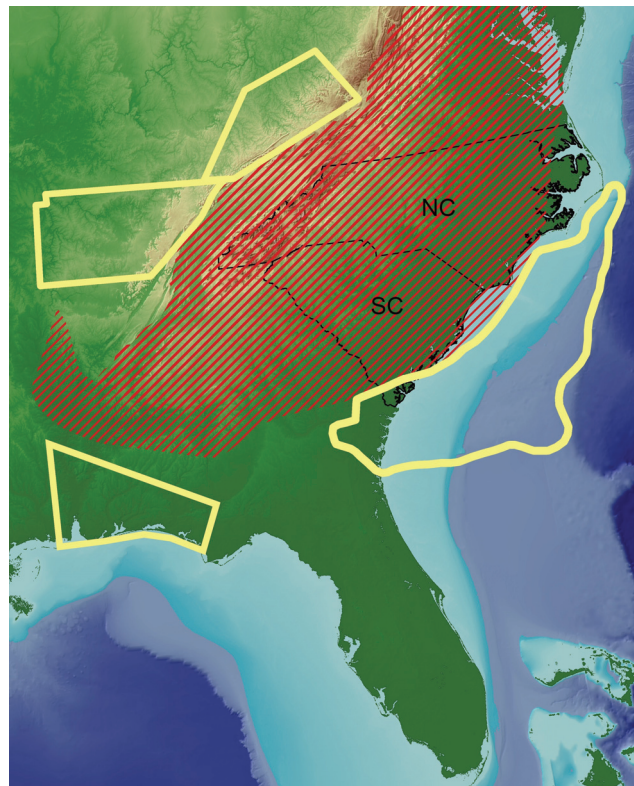

Figure 1. Location of areas considered for potential geologic storage of CO_2 generated in North and South Carolina outlined in yellow. Areas unsuitable for geologic storage of CO_2 (red stippled pattern).

All data used to evaluate the suitability of the potential geologic sinks are from preexisting geologic studies, the majority are from published literature. During this reconnaissance level study we have gathered information sufficient to identify geologic sinks that warrant further detailed assessment. Target sinks reported here should be viewed as candidate sites that passed an initial screening process and not final recommendations for geologic storage of CO_2. This initial assessment of geologic sinks with potential for long-term storage of CO_2 is unencumbered: it is based solely on the suitability of subsurface units to store CO_2; it does not take into account environmental, economic, or socio/political issues that would need to be balanced with geologic suitability.

Geologic History of the Southeastern United States

Properties that control the suitability of geologic units for storage of CO_2 in the southeastern U.S. are directly related to geologic history of the southeastern edge of the North American continent. The Atlantic Ocean has opened and closed repeatedly over geologic periods of time as a result of continental drift and seafloor spreading. Tectonism, or mountain building, which is often a result of continental collision and rifting (tearing apart), has occurred in the Appalachian Basin along the Atlantic margin of North America twice since early Paleozoic time, around 500 to 600 million years ago (ca. 500–600 Ma) (Wilson, 1966). The present-day Appalachian Mountains were formed during most recent continental collision in late Paleozoic time (ca. 250–300 Ma), resulting in formation of the supercontinent Pangaea. Fragmentation of Pangaea, with accompanied seafloor spreading and opening of the present-day Atlantic Ocean, began in late Paleozoic to early Mesozoic (ca. 200 Ma) time (King, 1959; Wilson, 1966; Milici, 1996; Shumaker, 1996). Figure 2 shows relative positions of the North American and African continents after breakup of Pangaea.
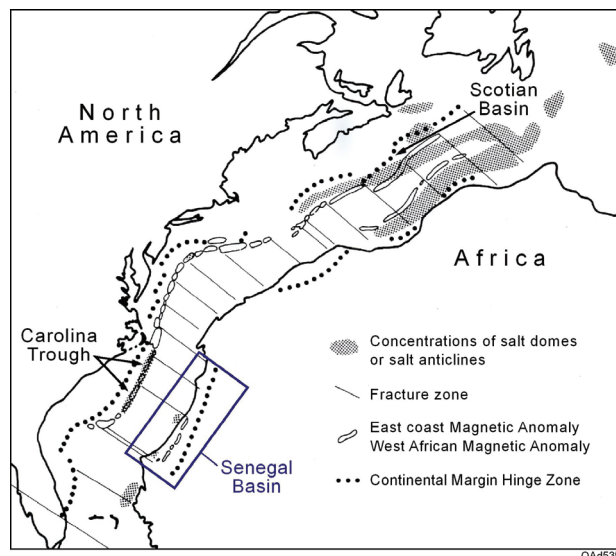
Figure 2. Relative positions of North American and African continents in Middle Jurassic time (~175 Ma), after initial opening of the present-day Atlantic Ocean. Modified from Hutchinson et al. (1982).

The present-day Appalachian Mountains extend from Newfoundland to Alabama roughly parallel to the U.S. Atlantic coast. Except for the portion in Newfoundland, the mountains are divided into three sections—northern, central, and southern. Only the southern Appalachians, which extend from Roanoke, Virginia, southwestward into Alabama, are pertinent to CO_2 source-sink studies in the southeastern U.S. The Southern Appalachian Mountains are subdivided longitudinally from northwest to southeast, into the Appalachian Plateau, the Appalachian Valley and Ridge, the Blue Ridge, and Piedmont provinces (fig. 3). A schematic diagram showing the subsurface relationship of rocks in the Southern Appalachian Mountains in cross section is depicted in figure 4.
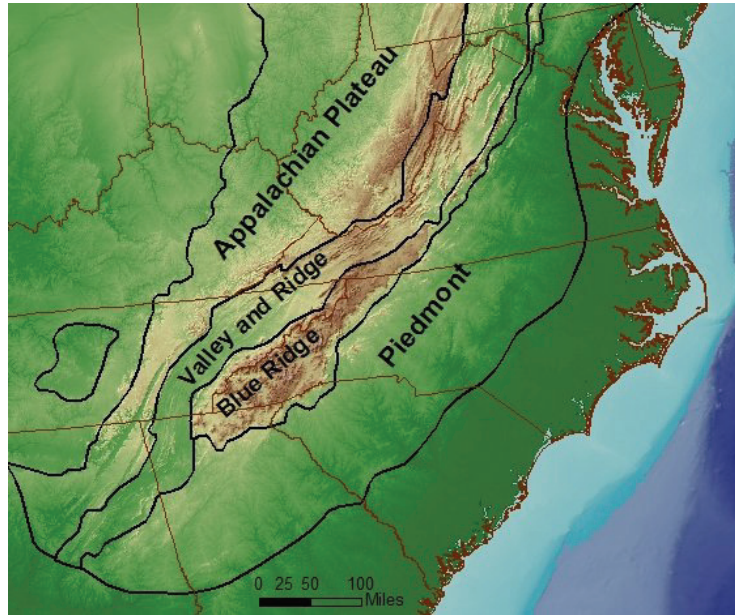
Figure 3. Physiographic provinces of present-day Appalachian Mountains. Physiographic provinces of Appalachian Mountains modified from Fenneman and Johnson (1946); digital elevation models from NOAA (2006) (land) and Scripps (2006) (ocean floor). Elevation of land surface increases from green to yellow to brown.
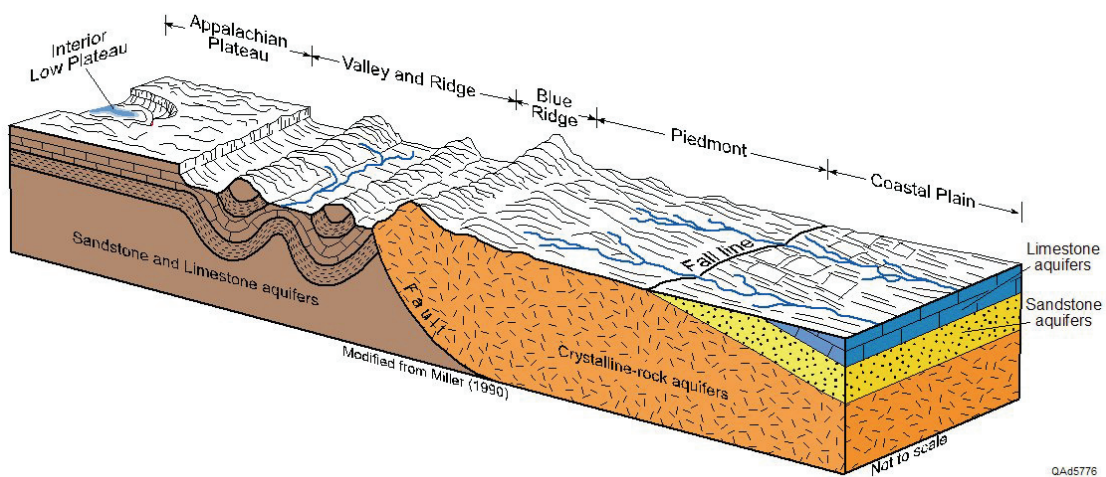
Figure 4. Schematic cross section from NW Alabama to south Georgia Coastal Plain.

The two potential sinks west of the Carolinas (fig. 1) lie within nearly flat-lying sediments of the Appalachian Plateau that were only mildly deformed during regional tectonicm. Coastal Plain deposits, which are seaward of the Appalachian Mountains (eastward from the Carolinas and in southern portions of Georgia and Alabama) are composed of detritus eroded from the Appalachian Mountains. All the other potential sinks introduced in this document lie within the seaward dipping sediments of the Coastal Plain.

Crystalline rocks of the Piedmont region are younger than those of the Blue Ridge and represent metasedimentary and granitic to ultramafic plutonic (intrusive igneous) rocks that were pasted to the eastern edge of the North American continent in middle to late Paleozoic (ca. 400 Ma) time during closing of the proto-Atlantic Ocean (King, 1959; Milici, 1996). These regions are composed of highly deformed rocks that are not suitable for subsurface storage of CO_2.

Rift basins provide a record of the earliest stages of continental breakup. A belt of rift basins parallels the Atlantic coast of North America from Nova Scotia to southern South Carolina, where it curves westward through southern Georgia, Alabama, and Mississippi. The basins were formed by tensional forces associated with breakup of the supercontinent Pangea beginning in late Paleozoic time (ca. 250–300 Ma) (Klitgord et al., 1988; Ziegler, 1988) (fig. 5). All of the basins are floored by Piedmont crystalline basement rocks and filled with Triassic to Jurassic-age (ca. 150–250 Ma) clastic (sand, silt, and clay) sedimentary rocks.

Figure 5. Mesozoic basins of the southeastern U.S. (yellow). Modified from Klitgord and Behrendt (1979); Olsen et al. (1991); Hutchinson et al. (1997). Fall line marked in blue.

The Fall Line is a boundary corresponding with the landward extent of Atlantic coastal plain sediments; this name arose from the abundant water falls or rapids that form along rivers as they cross from resistant Pie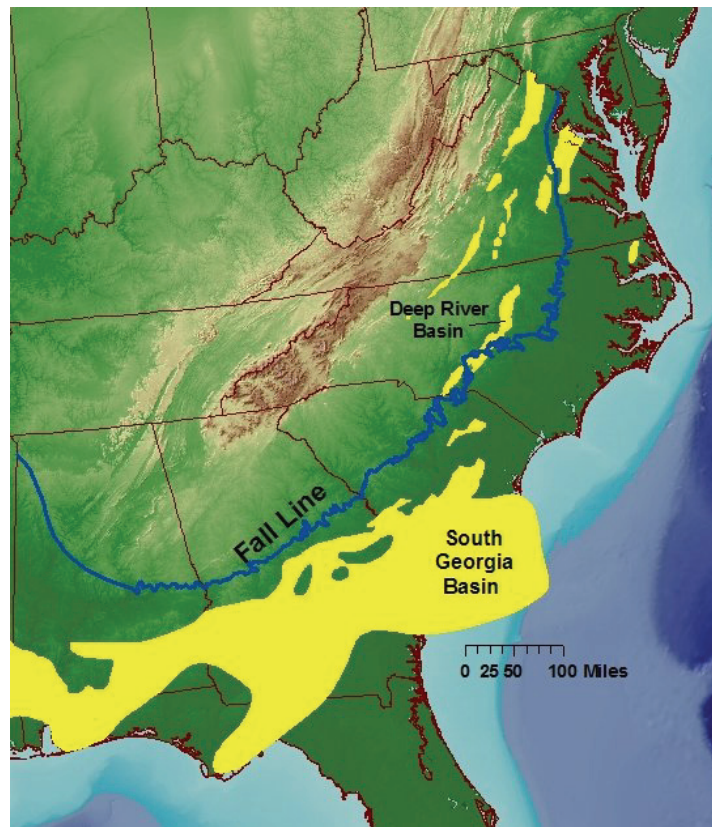dmont crystalline rocks to softer sedimentary rocks of the coastal plain. Triassic-age rocks in rift basins west of the Fall Line crop out at the surface and are often deformed and slightly metamorphosed. The rocks within the exposed rift basins are not suitable for subsurface storage of CO_2. Triassic rift basins seaward of the Fall Line are buried by varying thicknesses of coastal plain sediments (Klitgord and Behrendt, 1979; Olsen et al., 1991).

The South Georgia Basin is a northeast-southwest trending buried Triassic rift basin hypothesized to represent the pre-Appalachian Mountain continental margin of North America. It reportedly received 5-6 km thickness of sediments eroded from the Appalachian Mountains (Nelson et al., 1985). Present day Florida southeast of this basin, called Suwannee terrane, is thought to be a fragment of continental crust originally attached to Gondwanaland (ancestral African and South American continents). The Suwannee terrane (also known as a microcontinent) merged with ancestral North America during closing of the proto-Atlantic Ocean (earlier phases of Appalachian tectonism) in Permian time (ca. 260 Ma) (Horton et al., 1989; King, 1959; McBride et al., 1989; Nelson et al., 1985; Thomas, 2006).

A thick wedge-shaped accumulation of terrigineous material eroded from the Appalachian Mountains filled the South Georgia Basin rift. The sediments thicken southeastward from the Fall Line in central South Carolina and Georgia toward the southeast (Barker and Pernik, 1994). These strata become more carbonate-rich and thicken from north to south along the coast, reaching maximum thicknesses of 1400 m or more in the axis of the South Georgia Basin (Brown et al., 1979; Gohn et al., 1980). This thick sequence of strata hosts three vertically stacked geologic sinks. South of the embayment, stratigraphically equivalent units are dominantly carbonates of the Florida platform (Gohn et al., 1980).

Areas Unsuitable for Geologic Storage

Vast areas of the Appalachian Mountains in southeastern U.S. are either unsuitable or have low potential for geologic storage of CO_2. Rocks in the Valley and Ridge are less favorable for geologic storage because they are extensively folded and faulted. Nor are the fractured crystalline rocks of the Blue Ridge and Piedmont provinces (Rogers, 1949; Shumaker, 1996) suitable for CO_2 storage. Much of the Atlantic Coastal Plain is unsuitable for storage of CO_2 because sequences of sedimentary rocks are too thin to host CO_2 storage. In addition, groundwater close to the coast retains total dissolved solids (TDS) content as low as 1,300 ppm to depths as great as 200 m (660 ft) near Cape Fear, South Carolina (Kohout et al., 1988), which is well below the EPA cutoff of 10,000 ppm TDS for drinking water.

Valley and Ridge Province

As discussed in Shumaker (1996), the Precambrian-age rocks present at the surface in the Blue Ridge form the basement beneath the Appalachian Plateau and Valley and Ridge provinces. Rocks composing the Valley and Ridge represent a block of Appalachian basin sediments that was thrust westward during the most recent episode of trans-Atlantic continental collision (e.g., Shumaker, 1996). Not only are strata in the

Valley and Ridge province of the Southern Appalachian Mountains folded and faulted, drilling has revealed the presence of complex buried structures that show little surface expression. Less-competent layers of shale, salt, and thinly bedded carbonates, which acted as décollement or detachment zones for large-scale thrust faults, contain soft-sediment deformation features (Rogers, 1949; Spencer, 1972).

Because the Valley and Ridge province contains oil and gas reservoirs (Roen and Walker, 1996), it most likely contains geologic environments that could host CO_2 storage. However, identifying and assessing these local features requires in-depth investigation outside the scope of this regional survey. Targeting geologic sink horizons that have undergone complex structural deformation like observed in the Appalachian Valley and Ridge could require multiple drilling attempts and, hence, become prohibitively expensive (figs. 6 and 7).
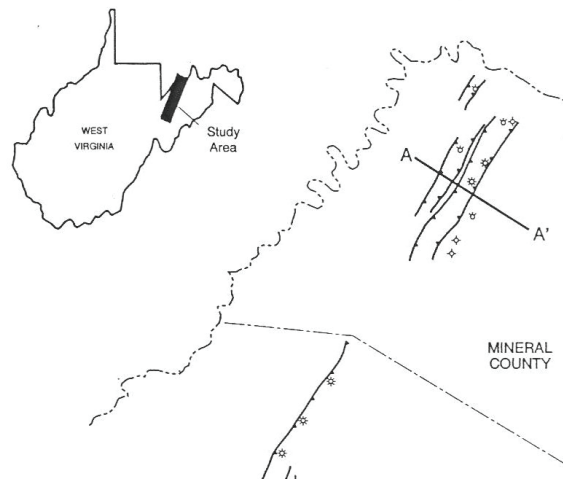

Figure 6. Location of Appalachian Plateau to Valley and Ridge cross section shown in figure 7. Source: Harper and Patchen (1996).
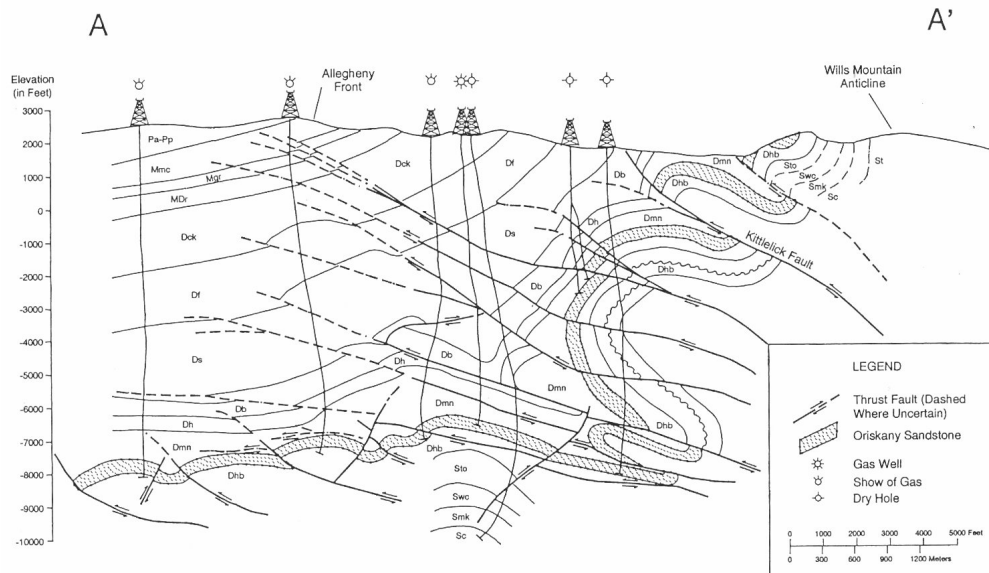

Figure 7. Cross section showing increase in structural complexity going from Appalachian Plateau (A) to Appalachian Valley and Ridge (A'). Source: Harper and Patchen (1996).

Blue Ridge and Piedmont

Fractured and metamorphosed Blue Ridge and Piedmont rocks are exposed at the surface throughout much of North and South Carolina. In late Paleozoic time (ca. 250-300 Ma), Precambrian-age crystalline rocks were thrust westward over younger Paleozoic rocks forming the Blue Ridge Mountains, resulting in brittle deformation (extensive fracturing and faulting). As stated by Spencer (1972), fractures across most of the Blue Ridge province are widely spaced (~1 ft), but near major faults fracturing becomes so intense that in some places individual crystals are shattered.

The capacity of fractured crystalline rocks to store large volumes of CO_2 is limited. Rocks that have undergone multiple episodes of brittle deformation, such as those present in the Blue Ridge and Piedmont provinces, have high permeability, if fracture networks are connected, but low matrix porosity. They therefore have limited potential for CO_2 to be dissolved or stored in pore systems trapped as a residual phase by capillary forces. The distribution of CO_2 injected into these rocks would most likely be difficult to predict and therefore expensive to monitor. Most importantly, there are no overlying sedimentary rocks to provide a seal, so injected CO_2 would not be isolated from the atmosphere. We therefore rule out the extensively fractured crystalline (plutonic and metamorphic rocks of the Blue Ridge and Piedmont physiographic provinces of the Appalachian Mountains—not just in the Carolinas) as attractive candidates for large-volume CO_2 storage.

Coastal Plain

The Fall line, which separates the eastern Piedmont province from the Coastal Plain (blue line in fig. 5), represents the landward extent of sediments deposited on crystalline basement rocks (Horton and Zullo, 1991). These sediments become thicker toward the Atlantic coast but only reach thicknesses greater than the 800 m required to create sufficient pressure for geologic storage of CO_2 in (1) Cape Hatteras area of eastern North Carolina and (2) southernmost South Carolina. Figure 8 shows that portion of the Atlantic coastal plain of the southeastern U.S. where sedimentary cover is too thin to provide CO_2 storage.

Throughout most of the Coastal Plain younger sedimentary rocks host fresh groundwater (e.g., Aucott, 1988). Groundwater close to the coast retains TDS content as low as 1,300 ppm to depths as great as 200 m (660 ft) near Cape Fear, South Carolina (Kohout et al., 1988), which is well below the EPA cutoff of 10,000 ppm TDS for drinking water. Injection of CO_2 into freshwater is generally proscribed because of the potential to damage these resources. Water resources of the Coastal Plain have been moderately characterized, but deep aquifers are poorly known because shallow aquifers generally provide sufficient water. There is very little potential for hydrocarbon production along coastal South Carolina, and because the state currently has laws prohibiting subsurface liquid waste disposal, there has been little subsurface research related to petroleum exploration or subsurface disposal of industrial liquid wastes.
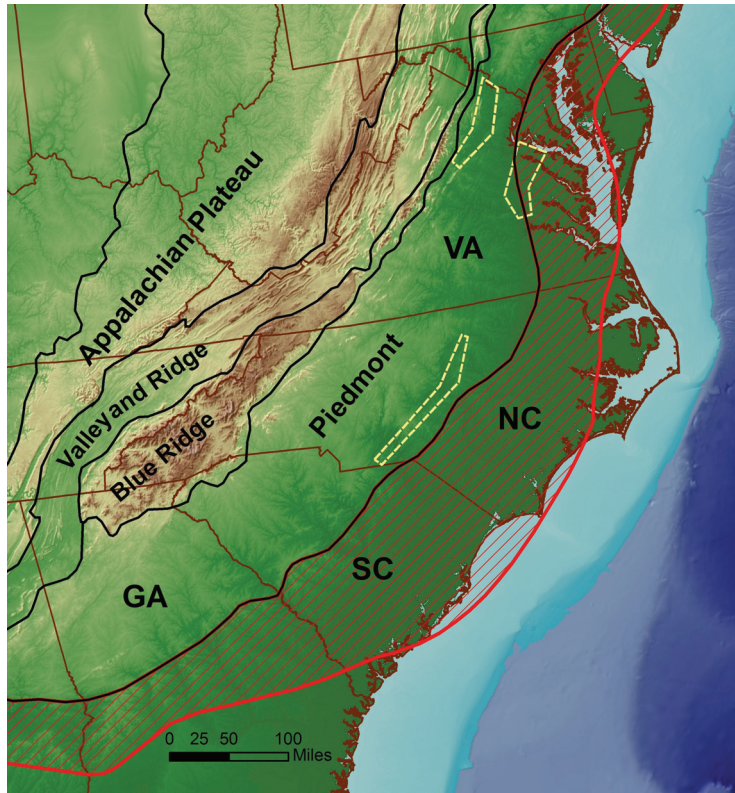
Figure 8. Area of coastal plain (outlined in red) where sediments are too thin for suitable storage of CO_2. Exposed Mesozoic rift basins shown by yellow stippled line.

Exposed Mesozoic Rift Basins

Two major basins in which Mesozoic sediments are present at the surface, the Deep River and the Dan River Basins, lie within North Carolina. The Dan River Basin occurs farther to the west and extends northeastward into Virginia (fig. 8). Surface dimensions of the Dan River basin are ~80 km (~50 mi) long by an average 8 km (5 mi) wide. Thickness of sediments in this basin ranges to as much as 3 km (~1.8 mi); however, they dip steeply (to 65°) to the west and are very brittle (i.e., lots of fractures) (Olsen et al., 1991). This basin is not suitable for storage because many of the fractures extend from deep into the basin to the surface.

Triassic-aged rocks of the Deep River Basin in central North Carolina also occur at the surface. This basin stretches from ~ 25 mi northwest of Raleigh southwestward just across the South Carolina border (fig. 8). The Deep River Basin is divided into three separate subbasins, which are, from northeast to southwest, the Durham, Sanford, and Wadesboro Basins. Approximate dimensions of surface exposure of the three subbasins are: Durham—80 km (50 mi) long × 15 km (9 mi) wide; Sanford—40 km (25 mi) long × 15 km (9 mi) wide; Wadesboro—80 km (50 mi) long × 15 km (9 mi) wide. Approximate depth of the Durham subbasin is 2 km (1.2 mi); both the Sanford and Wadesboro subbasins are thought to be ~3 km (1.8 mi) deep (Olsen et al., 1991). On the basis of detailed review of Deep River Basin studies, we conclude it to be a less favorable location for geologic storage of CO_2. All three subbasins of the Deep River Basin have deep-seated fractures exposed at the surface. In addition, they are characterized by heterogeneous, poorly sorted (lots of clay mixed in with the sand and gravel) sediments

that were deposited rapidly (Marine and Simple, 1974). The porosity and permeability of these units are difficult to predict and most likely very low.

A detailed description of the Deep River Basin, provided by Dr. Paul Thayer of the University of North Carolina at Wilmington, is included in Appendix A of this report. Excerpts from Dr. Thayer's report that are directly pertinent to storage of CO_2 in the Deep River basin follow:

> *There are few distinctive beds within the Sanford Formation and no consistently mappable subdivisions (Reinemund, 1955). Fluvial sandstone and mudrock grade into conglomerate toward the Jonesboro fault zone, which forms the southeastern border of the Sanford subbasin. Poorly sorted, matrix-supported conglomerates suggest debris flow deposition, and interbedded clast-supported, imbricated conglomerates indicate braided stream deposition on alluvial fans (Olsen et al., 1991).*

> *Two sets of faults have been identified in Deep River basin (Reinemund, 1955). The dominant set strikes northeast-southwest, parallel to the Jonesboro fault zone, and cuts the basin into a series of fault blocks that locally duplicate parts of the basin section. The other set strikes northwest-southeast, nearly perpendicular to the major set, and served as a conduit for many of the diabase dikes. Reinemund (1955) mapped a number of transverse folds in the Sanford subbasin, which are common in Newark Supergroup basins. The axes of the transverse folds trend northwest-southeast in the Sanford subbasin.*

> *Sedimentary rocks of the Deep River basin have been intruded and metamorphosed by sheets and dikes of dominantly olivine-normative diabase of probable Jurassic age (Reinemund, 1955; King, 1961, 1971; Burt et al., 1978; Ragland, 1991; Ragland et al., 1968, 1969, 1981, 1983, 1992, 1998). Most dikes trend north and northwest and cut Triassic and pre-Triassic metamorphic rocks. Although overlapped by Cretaceous and younger strata, the dikes have been traced beneath Coastal Plain cover using aeromagnetic data (USGS, 1976a, 1976b; Daniels et al., 1983; Bond and Phillips, 1988).*

As with portions of the Valley and Ridge province, exposed rift basins—all along the east coast—might be considered for storage on a site-specific, case-by-case basis. However, for the purpose of this study, we are not considering them as large-volume, potential CO_2 storage targets.

Potential Geologic Sinks

Sinks with potential for long-term storage of CO_2 generated in the Carolinas are all deep saline reservoirs within host geologic strata. All sinks presented here have been chosen through study of existing and, in most cases, published data. Additional field-data collection and verification will be required to test the suitability of specific injection sites and refine the generalized capacity estimates presented in subsequent questions.

Potential geologic sinks for subsurface storage of CO_2 generated in the Carolinas are located in (1) central Tennessee—Mt. Simon Formation, (2) eastern Kentucky and southern West Virginia—Knox Group, (3) eastern North Carolina—subsurface strata west of Cape Hatteras, (4) southern South Carolina and Georgia coasts—Triassic- and Upper Cretaceous-age units in the South Georgia Basin, (5) Florida panhandle and southwestern Alabama—Upper Cretaceous Tuscaloosa Formation, and (6) Atlantic

subseafloor strata offshore from Cape Hatteras, North Carolina, south to Brunswick, Georgia—Lower Cretaceous unit 120 and Upper Cretaceous unit 90 (fig. 9).

Three of the sinks were previously identified. The Mt. Simon Formation sink was described by workers at Advance Resources International (ARI 2005, digital communication). The Knox Dolomite was assessed during SECARB phase I (Hovorka et al., 2005 unpublished report to SSEB). The Tuscaloosa Formation in Alabama was assessed by Hovorka et al. (2000). Here we have converted data covering portions of the Mt. Simon and Knox areas, which are within reasonable distances from the Carolinas, into GIS format. We have also identified an additional area of the Tuscaloosa Formation in Florida and merged it with previous Alabama Tuscaloosa data.

Suitability criteria for geologic storage in deep saline reservoirs include (1) continuity and integrity of an overlying seal; (2) depth sufficient to maintain CO_2 at high density (which corresponds to depths greater than 800 m (>2,400 ft) below the surface); (3) depth below underground sources of drinking water (USDW), where total dissolved solids exceed 10,000 parts per million (ppm); and (4) storage capacity sufficient to prevent displacement of saline water into overlying freshwater-bearing units. In subsequent sections we provide details of data used to estimate capacity for each potential geologic sink.
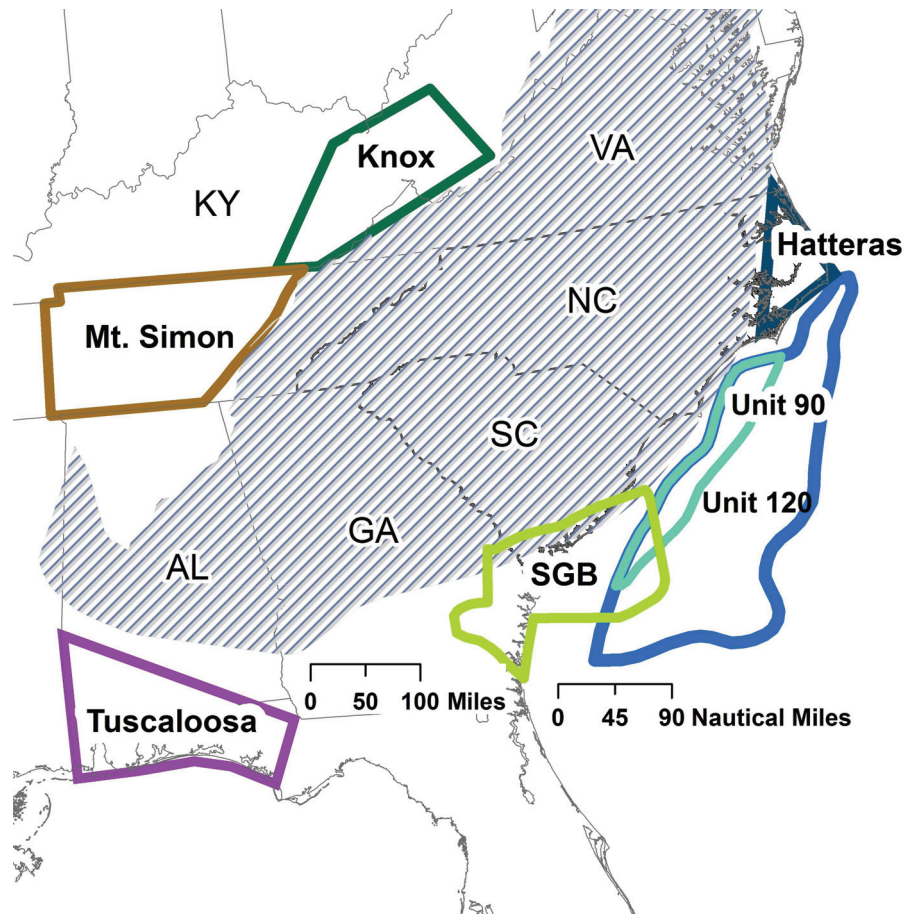
Figure 9. Location of areas considered for potential geologic storage of CO_2 generated in North and South Carolina. SGB = Cretaceous-age units in the South Georgia Basin.

Sinks Closer to the Carolinas

Potential sinks relatively near the Carolinas are located west of Cape Hatteras, NC, in the South Georgia Basin, and offshore below the Atlantic seafloor. Sites farther from the Carolinas are those located in Florida-Alabama, Tennessee, and Kentucky-West Virginia (fig. 9).

Of the three sinks located closest to the Carolinas, we have most extensively evaluated the South Georgia Basin (SGB) and offshore below the Atlantic seafloor. SGB and the area west of Cape Hatteras, NC (Hatteras area), contain thicker accumulations of sedimentary rocks than that found elsewhere along the Carolina Coastal Plain.

Hatteras Area, North Carolina

Sediments west of Cape Hatteras attain a thickness of 2.7 km (1.7 mi) (figures 9 and 10), which is sufficient to contain potential CO_2 sinks. However, literature review to obtain hydraulic properties and other data needed to estimate capacity of specific stratigraphic units was not performed for this study. Developed land use patterns in this ecologically sensitive area negate realistic expectations for obtaining pipeline and drilling permits.

Figure 10. Depth (m) to crystalline basement rocks in the Hatteras area. Contours generated from NCGS well data provided by Dr. Paul Thayer.

South Georgia Basin Sinks

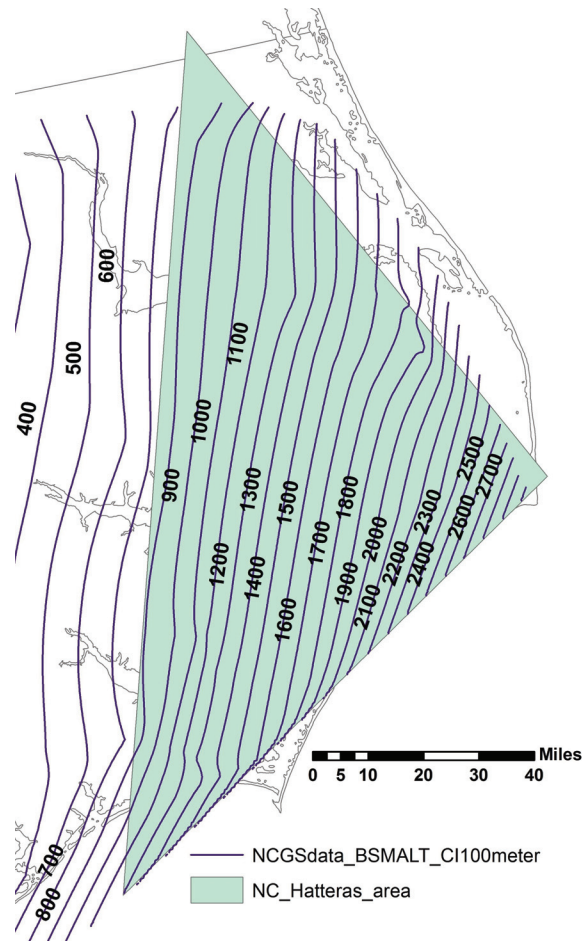The South Georgia Basin (fig. 9) is the east end of a series of structural basins spanning from Alabama across south-central Georgia, southern South Carolina, and eastward onto the Atlantic continental shelf (fig. 5). The entire series of basins are buried beneath coastal-plain sediments.

Through previous work associated with SECARB, and current work, we have identified three potential sinks in the South Georgia Basin: (1) Late Cretaceous-age Cape Fear Formation (from previous SECARB work), (2) Late Cretaceous-age Tuscaloosa/Atkinson units in Georgia, and (3) multiple intervals in Triassic-age units that extend offshore from South Carolina and Georgia (fig. 11). These sinks partly overlap in map view but span different depth horizons between 800 and 1,300 m (2,600 and 4,300 ft). The outline of SGB in fig. 9 depicts the composite area of these three sinks projected up to land surface.
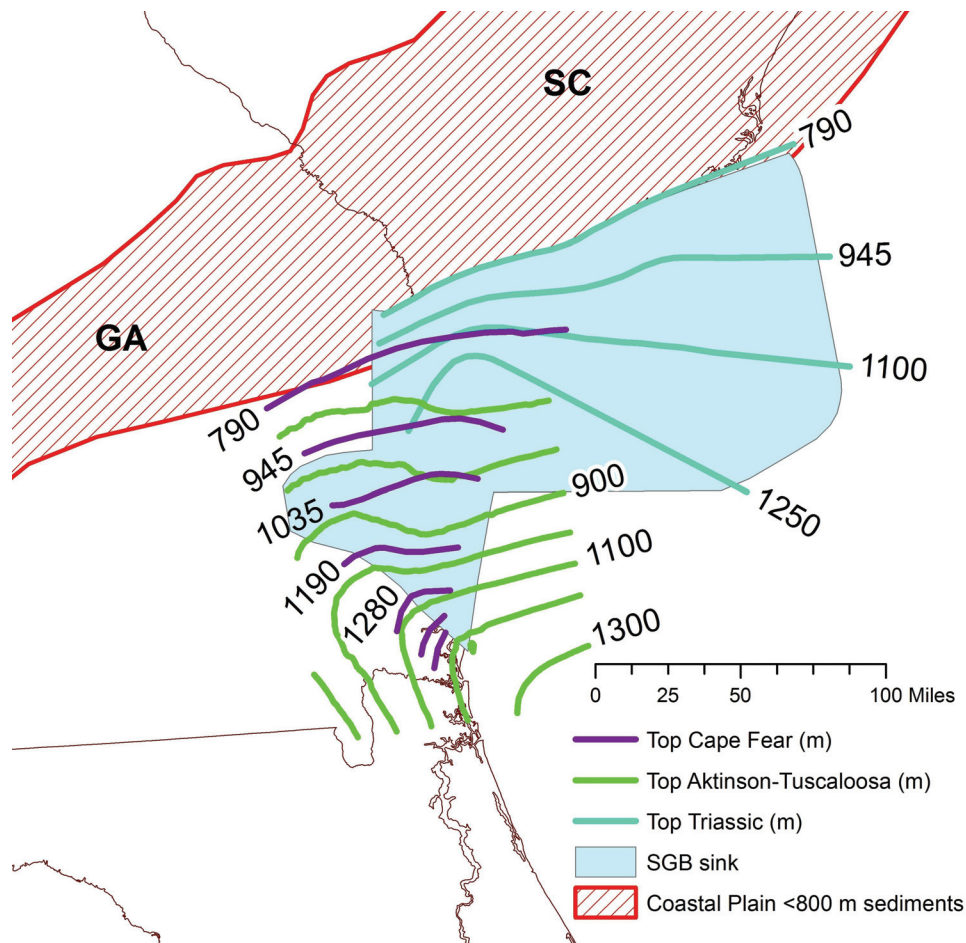
Figure 11. South Georgia Basin Sinks.

Dr. Tom Temples of the University of South Carolina at Columbia provided data interpretations and potential sink intervals for the Triassic units (figures 11 and 12). Much of the interpretation is based on a well log from the Lightsey well drilled by an oil company near Jedberg, South Carolina. BEG converted the data into GIS format and extended contours to the published extents of the SGB. Figure 12a shows top depths of

800 to 1,200 m below the surface and a thickness of 80 to 110 m (fig. 12b) for the Triassic sink intervals. We scaled thickness contours to approximate only those intervals of the Triassic section identified by Dr. Temples as good host strata (table 1).

(a)   (b)
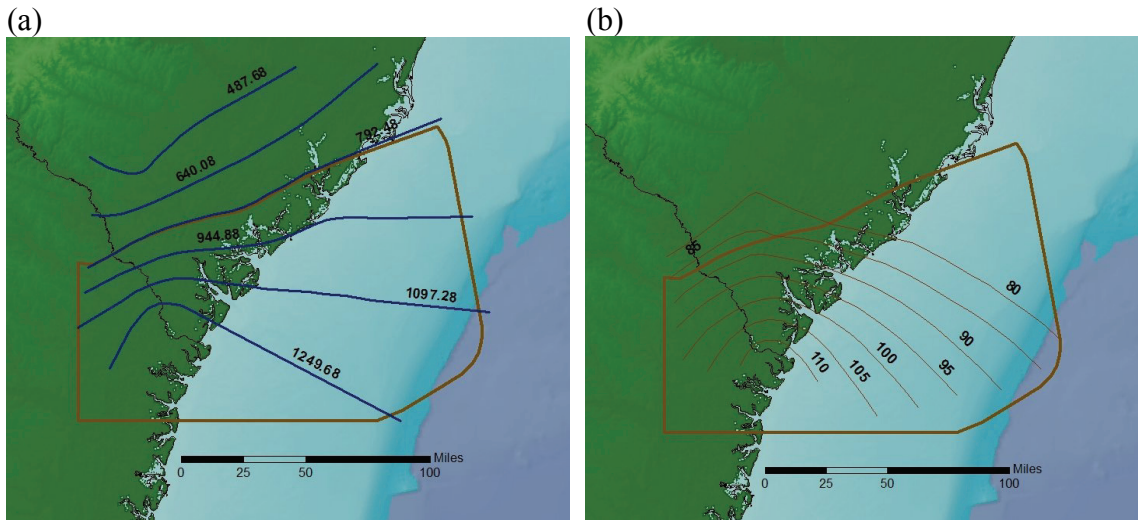
Figure 12. SGB Triassic sink (a) depth below sea level (m) to top, and (b) thickness (m) of Triassic sinks.

Table 1. Characteristics of potential sink intervals in Lightsey well.

TOP (ft)	BOTTOM (ft)	THICKNESS (ft)	LITHOLOGY
3450	3470	20	sand
7910	7930	20	sand
8440	8460	20	sand
7505	7565	60	diabase
8590	8620	30	diabase
9220	9250	30	diabase
9290	9315	25	diabase
9480	9530	50	diabase
total sand > 15% porosity			60 ft
total diabase >15 % porosity			195 ft

Interestingly, not all the sink intervals identified by Dr. Temples are composed of sedimentary rock. Two of the intervals are in basaltic igneous rock (sills) injected between layers of sediment during infilling of the SGB basin. Porosity estimated from the geophysical log is over 15 percent. Permeability was assigned a value of 100 millidarcys (md). A copy of the complete report received from Dr. Temples in appendix A.

Information on the geometry, composition, and thickness of Upper Cretaceous-age Tuscaloosa- and Atkinson-equivalent sink (figures 11 and 13) comes from geophysical logs of wells drilled during limited oil and gas exploration on the coastal plain, as well as onshore and offshore stratigraphic test wells (Brown et al., 1979; Scholle, 1979). Interpretations made from published maps and cross sections (Gohn et al.,

1978; Renkin et al., 1989) show that depth to the top of the Tuscaloosa and Atkinson equivalents increases to the south and east, from 700 m near the Georgia–South Carolina border to more than 1,200 m at the coast near the Georgia–Florida border (fig. 12a). Greatest depths follow a southeasterly trend along the axis of the southeast Georgia embayment. Geophysical logs (Gohn et al., 1980; Renkin et al., 1989) indicate sand thicknesses as great as 50 m within and along the northern flank of the embayment (fig. 12b). Coast-parallel thickness trends suggest deposition of the Upper Cretaceous sediments in transgressive strandplain, barrier-island, or destructional deltaic systems.

There are few measured values of porosity or permeability within Tuscaloosa- and Atkinson-equivalent strata on the southern Atlantic Coastal Plain. Porosities reported for onshore wells by Temples and Waddell (1996) range from 26 to 36 percent. Porosities measured in stratigraphically equivalent units on the Georgia continental shelf were at the lower end of this range (Scholle, 1979). We chose to use a representative value of 27.5 percent in this study. The permeability calculated for these strata in regional groundwater modeling studies is 3,000 md (Barker and Pernik, 1994), within the range of published site-specific measurements of 1,000 to 6,000 md (Temples and Waddell, 1996) and higher than measurements of 1 to 1,000 md made on finer grained correlative strata beneath the Georgia continental shelf (Scholle, 1979). We assumed a representative permeability of 3,000 md throughout the southeast Georgia area.
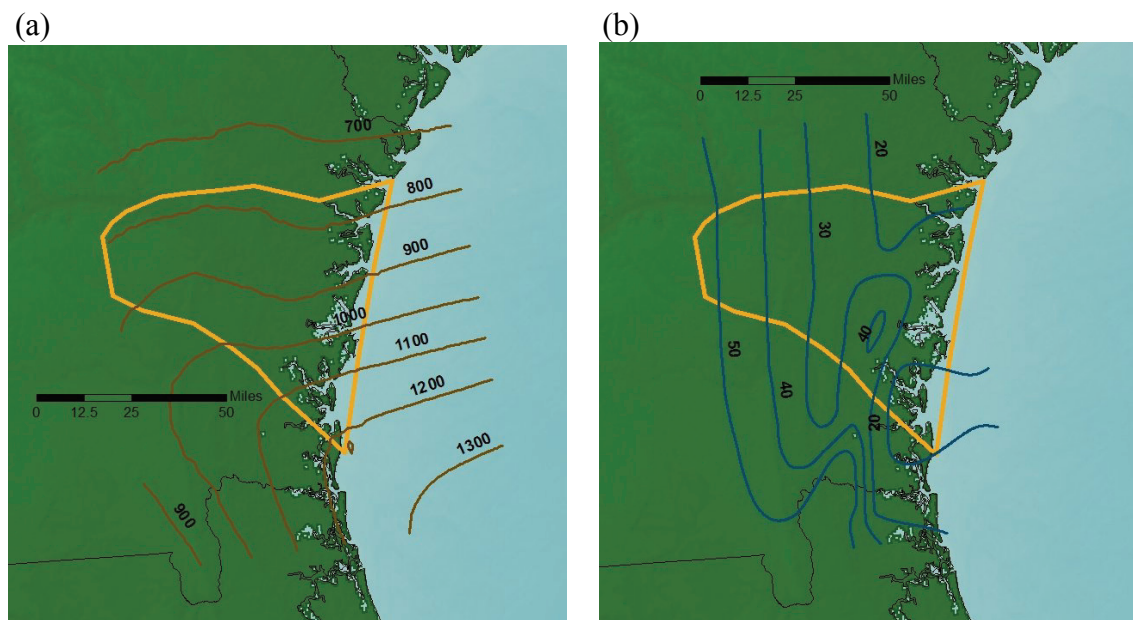
Figure 13. SGB Tuscaloosa\Atkinson Formations data in Georgia (a) depth below sea level (m) and (b) thickness (m).

The Tuscaloosa and Atkinson Formations beneath the Georgia Coastal Plain are considered to be part of the Black Warrior River (A4) aquifer, the basal and most extensive aquifer of the Southeastern Coastal Plain aquifer system (Renkin et al., 1989; Barker and Pernik, 1994). In general, Georgia's counties bordering the Atlantic Ocean are underlain by Black Warrior River aquifer strata containing groundwater with dissolved-solid concentrations greater than 10,000 mg/L, whereas more inland counties are underlain by strata containing fresher water (Miller, 1990).

Atlantic Subseafloor Sinks

Offshore geologic storage of CO_2 is fundamentally similar to onshore storage in terms of geological considerations (reservoir characteristics and trapping mechanisms). However, offshore settings involve initially higher pressures (beneath the water column) and lower temperatures at the seafloor, both of which favor denser CO_2 phases throughout subseafloor storage depths when compared with terrestrial settings. That is, CO_2 will always be denser at a given depth below sea level than in an onshore setting at a similar depth below a zero elevation land surface. Because much of the intent of drilling to great depths in terrestrial settings is to achieve dense CO_2 phases (and supercritical-phase properties) offshore operations may have reduced drilling costs. Absolute costs for drilling offshore from the Carolinas are unavailable but would be important for weighing the economic impact of the offshore sinks presented here.

It is important to note that offshore activities discussed here involve injections at hundreds to thousands of meters below the seafloor and should not be misinterpreted to include injection into (dissolution into) circulating seawater. Some researchers think that shallow subseafloor depths (< 300 m) are sufficient for permanent CO_2 storage in deep marine environments (> 3.5-km water depth; House et al., 2006). However, the shallow sedimentary environment can become unstable as a result of the release of gas from shallow gas hydrates (Lee et al., 1993) owing to pressure and temperature perturbations that may be introduced by drilling and injection. Furthermore, the logistics of transporting CO_2 many hundreds of kilometers offshore to the appropriate water depths (> 3 km or 1.9 mi) for storage in shallow sediments described by House et al. (2006) are likely to make such activity uneconomic. In contrast, we present below potential storage sites below the continental shelf in water depths between 50 and 1,000 m (165 and 3,500 ft) (fig. 14).
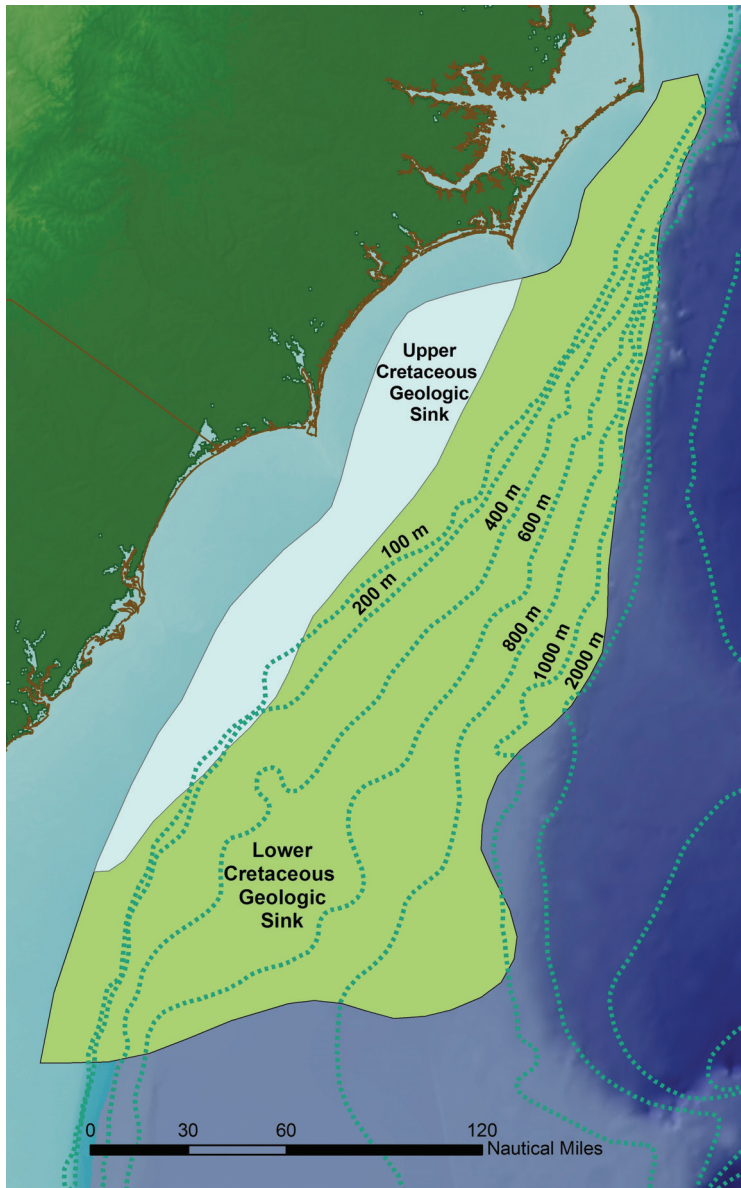
Figure 14. Upper and Lower Cretaceous Atlantic subseafloor sinks (modified from Hutchinson et al., 1996, 1997). Contoured water depth (m) shown in blue dashed lines (irregular contour interval). Depth from sea level to seafloor increases with darker shades of blue.

The potential sink (reservoir) units are the Upper and Lower Cretaceous strata beneath the seafloor located between 25 and 175 km (15 and 110 mi) offshore of the Carolinas. The Lower Cretaceous sink is Unit 120. A second, less-extensive sink is Upper Cretaceous-age Unit 90. Both units 90 and 120 have variable composition, composed of fine- to coarse-grained sediments. The deeper and more extensive Unit 120 extends over 15,000 km^2, ranging in depth from 700 to 3,200 m (2300–10,500 ft) below the seafloor (fig. 15a). Unit 120 has an extremely variable thickness, ranging from 10 (landward side) to 1,700 (seaward side) m in thickness (fig. 15b).

Figure 15. Offshore Atlantic Unit 120 (Lower Cretaceous): (a) depth below seafloor to top of unit (m); (b) contoured thickness (m). Contour data source: Hutchinson et al., 1997.

The shallower offshore Unit 90 extends over 8,000 km^2, ranging in depth from 200 to 1,000 m (66—3,300 ft) below the seafloor (fig. 16a). Thickness for Unit 90 ranges between 75 and 515 m (250 and 1,700 ft) (fig. 16b). Usable thicknesses for both prospective offshore sinks might be less than the maximum thicknesses shown.
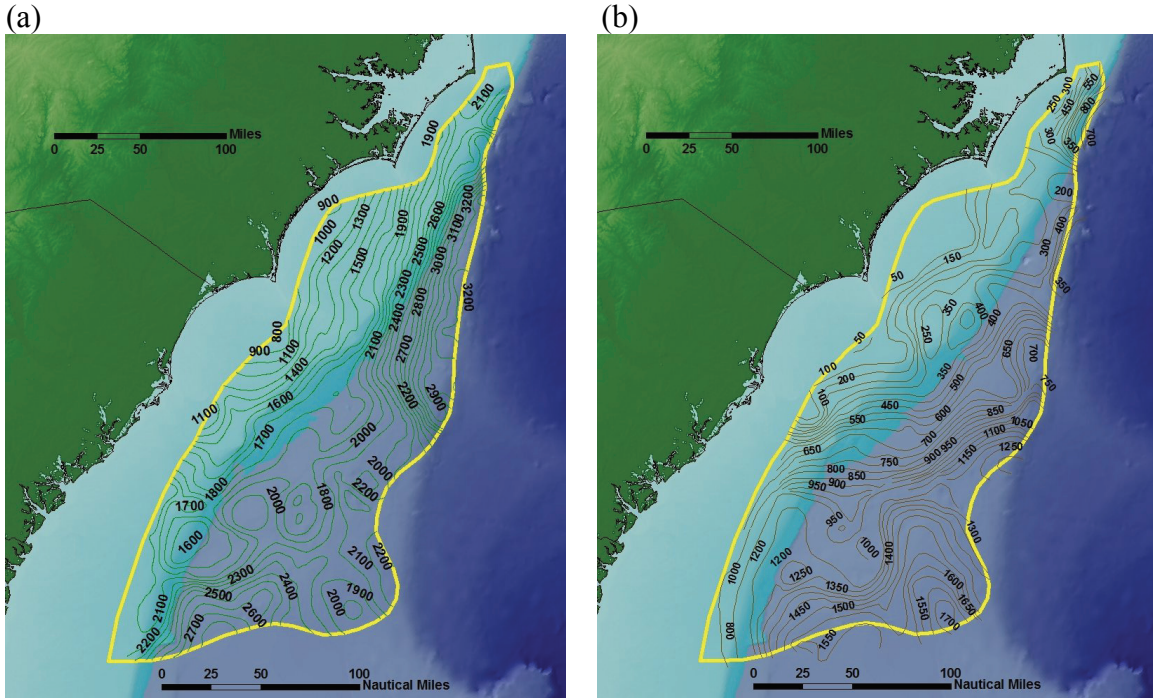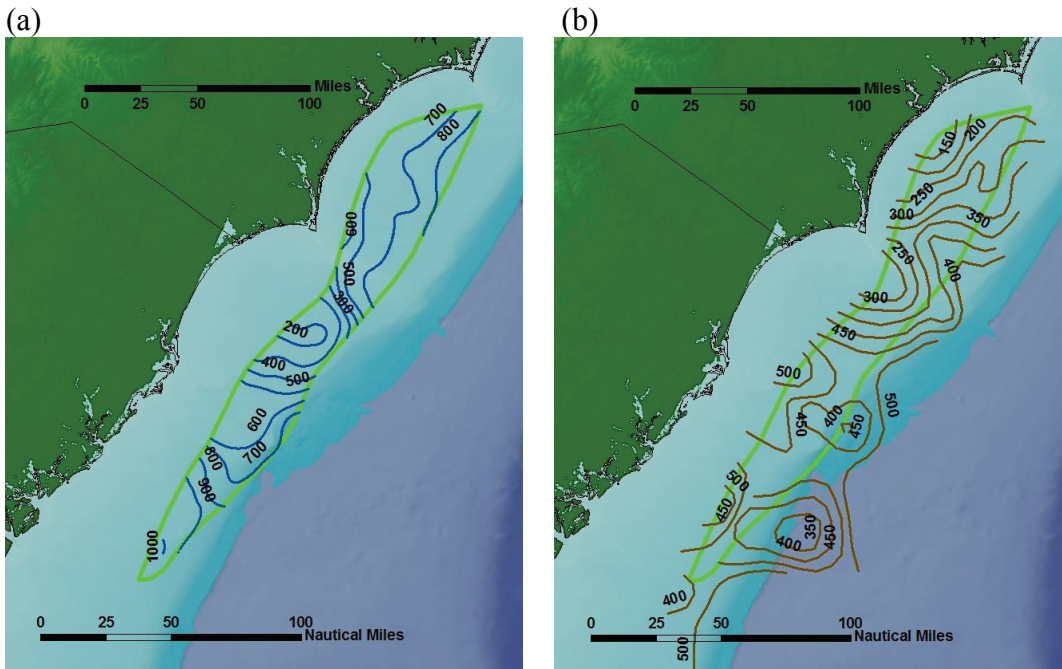

Figure 16. Offshore Atlantic Unit 90 (Upper Cretaceous): (a) depth below seafloor to top of unit (m); (b) contoured thickness (m). Contour data source: Hutchinson et al., 1997.

Owing to the absence of historic or present hydrocarbon production in the reservoirs offshore of the southern Atlantic margin, few detailed data are available for rock properties. However, porosity and permeability data applicable to Units 90 and 120 may come from several possible sources: (1) core analyses from COST well GE-1, (2) oil wells drilled offshore north of Hatteras in Baltimore Canyon Trough, and (3) an analogous area offshore northwestern Africa in the Senegal Basin (fig. 2), in which oil and gas exploration began in the late 1990's (Davison, 2005). For the purpose of preliminary scoping, we used a porosity of 20 percent and a permeability of 100 md to estimate capacity of the subseafloor sinks. This is an oversimplification of the geologic environment of this setting, but it allows for order-of-magnitude capacity estimations.

The shallowest, potentially effective geologic seal for trapping CO_2 lies between 200 (landward side) and 2,000 m (660-6600 ft) below the seafloor (Unit 80; Hutchinson et al., 1997). Because Unit 80 is the first good seal encountered below the seafloor, CO_2 cannot be stored at shallower depths in these sinks. Fine-grained, low-permeability horizons (Units 105 and 80) completely overlie each of the subseafloor sinks, providing a seal between sink horizons and the seafloor.

The offshore geothermal gradient is expected to be similar to an onshore gradient because the continental crust extends offshore approximately 150 km (93 mi) (figures 17, 18). Deep Sea Drilling Project (DSDP) and petroleum industry data along the Atlantic margin suggest a temperature gradient of 1 to 2 °F per 100-ft depth (~25 °C/km) (Costain and Speer, 1988). Temperatures at the seafloor offshore the Atlantic coast are cold (0 °C or 32 °F), but if the geothermal gradient is similar to that of nearby onshore terrestrial settings, then the critical temperature of 31 °C (88 °F) will be reached at approximately 1.2 km (0.75 mi) below the seafloor. Temperature in the Hatteras Lighthouse well no. 1 at Cape Hatteras at 3,048 m (10,000 ft) is 77 °C (170 °F), suggesting a gradient of 1.7 °F per 100 ft. (~25 °C/km). Borehole temperature data from seven wells along the southern coast of North Carolina (Lambe et al., 1980) indicate supercritical temperatures around 1,000 to 1,300 m (3280 to 4265 ft) below the seafloor.
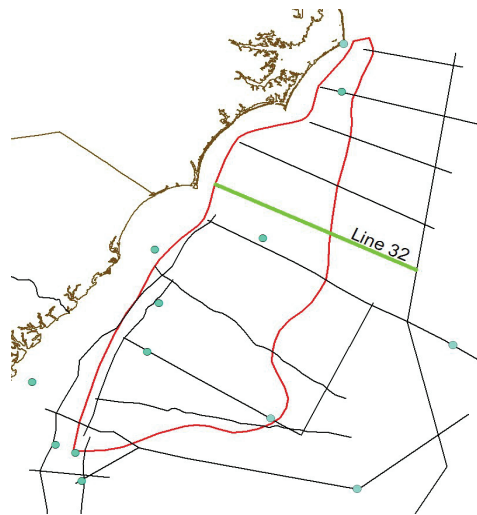

Figure 17. Location of USGS referenced (Hutchinson et al. 1996, 1997) seismic lines. Cross section in figure 18 is along line 32 offshore from Cape Fear, NC.
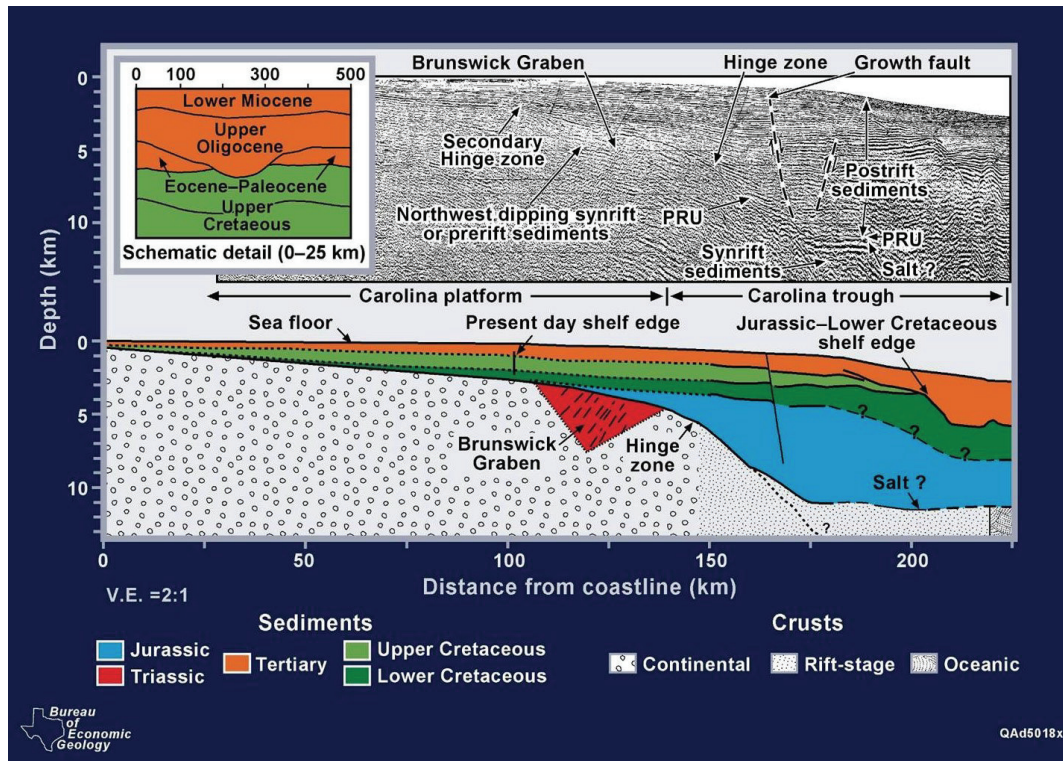
Figure 18. Schematic cross section along seismic line 32 shown in fig. 16. Modified from Grow et al. (1988); Hutchinson et al. (1982); and Hutchinson et al. (1997).

Important points illustrated by the cross section shown in fig. 18 include:

- Strata dip and thicken seaward.
- In the absence of an onshore/nearshore Triassic rift basin, post-rift sediments are not thick enough to serve as geologic sinks. Note that the Triassic age Brunswick graben is analogous to the onshore Mesozoic rift basins, but is seaward of the continental crust, offshore from the present day continental shelf edge.
- Top of Upper Cretaceous strata within 25 km (16 mi) of the coast may have been scoured during deposition of Tertiary age units and therefore might not have good seal integrity.
- The edge of North American continent crust lies approximately 150 km (93 mi) offshore from Cape Fear, North Carolina, which is underneath ~1500 m (~4900 ft) of water.

Regarding pressures, a typical terrestrial (onshore) hydrostatic gradient (pressure increase per foot of depth increase) for freshwater is 0.0097 MPa/m (0.433 psi/ft). In marine settings, a typical saltwater (88,000 ppm TDS) hydrostatic gradient is slightly higher: 0.0105 MPa/m (0.465 psi/ft). The impact is that the critical pressure for CO_2 (7.37 MPa, 1070 psi) may be encountered approximately 60 m (197 ft) shallower for offshore settings than for onshore (e.g., 700 m (2297 ft) below sea level versus 760 m (2493 ft) below a zero elevation land surface). This is not a dramatic difference, considering the total drilling depths involved. Furthermore, water becomes more saline with depth in

terrestrial settings, approaching and potentially exceeding marine salinities. Thus, the difference in depth to critical pressure is likely to be a maximum value.

Temperature-pressure regimes in the potential offshore geologic sinks are such that injected CO_2 would be very dense, but formation temperatures will not be warm enough for the supercritical conditions typically sought after in terrestrial environments. Yet successful CO_2 storage in subseafloor geologic environments can occur at pressures and temperatures below supercritical conditions. In such environments, the relatively cold temperatures and high pressures result in higher CO_2 densities (>900 km/m³, 56 lb/ft³, when compared with typical terrestrial storage conditions. A smaller volume is thus required for comparable storage efficiency in subseafloor versus subterranean sinks.

The reservoir and sealing capacity of the described units to bouyant CO_2 is essentially unknown in offshore Atlantic settings, but they should perform similarly to tested subseafloor storage examples. The best-documented offshore storage example is related to activity in the Sleipner gas field located in the Norwegian North Sea, which is operated by Statoil. There CO_2 has been injected into an exceptionally porous and permeable, poorly consolidated sand horizon 800 m (2625 ft) below the seafloor in 75 m (246 ft) of water. The geologic sink used (Utsira Formation) is 200 m (656 ft) thick and extends over 25,000 km² (9652 mi²). The overlying finer grained silts and shales are an effective top seal. It is thought that the storage capacity may be on the order of 100 times the annual European CO_2 emissions from power plants (Statoil, 2004). Since 1996, the Utsira Formation has safely received and contained approximately 1 million metric tons of CO_2 per year (Statoil, 2004).

Three caveats to offshore operations have been identified but remain to be considered in further detail: (1) the presence of freshwater below the continental margin at depths of over 1 km beneath the seafloor (Kohout et al., 1988), (2) the potential displacement (due to CO_2 injection) of subseafloor (geologic) water within potential reservoirs and discharge at the seafloor, and (3) the hazard of encountering shallow gas hydrates during pipeline and drilling operations on the continental shelf. The first issue concerns water quality and the anticipation of eventual utilization of offshore freshwater resources. The potential displacement of geologic water beneath the seafloor is of concern because potential discharge at the seafloor or the shelf edge or on the continental slope may generate conditions favorable to sediment dispersal (such as slumping or erosion). The drilling hazard of encountering hydrates is well known, and their distribution is known to some degree (e.g. fig. 19). Pipeline and well locations would need to rely on updated maps of hydrate distribution and may involve detailed surveys to further minimize risks. Expertise for these types of surveys is widespread, and hydrate studies are in a mature phase.
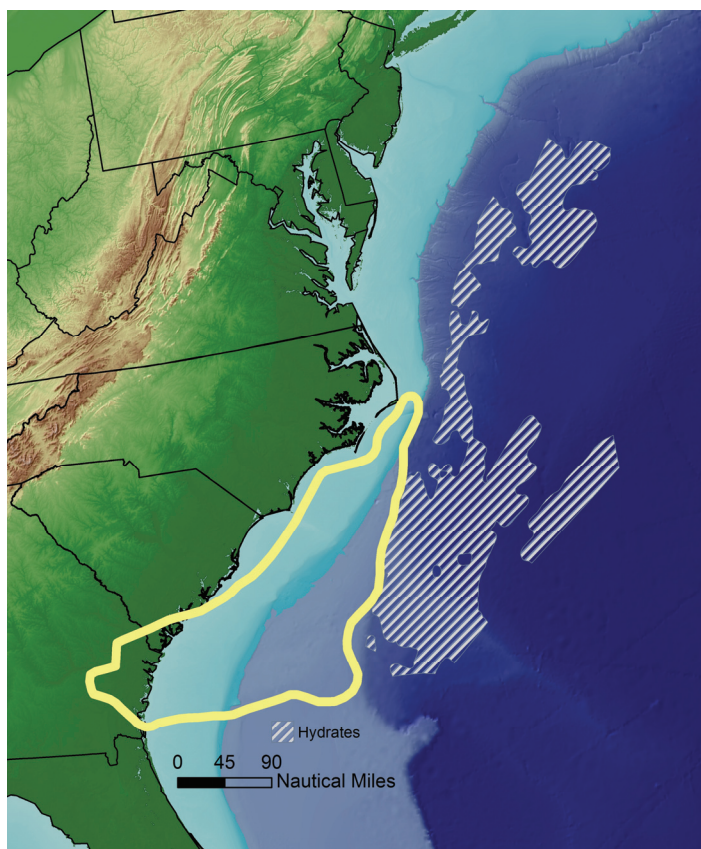
Figure 19. Location of known hydrate deposits offshore from the U.S. Atlantic east coast. Hydrate data modified from Dillon et al. 1995.

At present, the only subseafloor geologic storage site for CO_2 is operated by Statoil in the Norwegian North Sea. The sinks identified offshore from the Carolinas are not as well characterized as the North Sea example and would require investigation to determine suitability and to refine capacity estimates. Legal, regulatory, and policy implications of subseafloor geologic storage of CO_2 are unresolved at this time. However, in November 2006, a resolution was adopted by members of the 1996 Protocol of the London Convention to "establish the legality of storing CO_2 in sub-seabed geologic formations." Guidelines for scientific assessment of the potential for subseafloor CO_2 storage are due to be finalized and presented to the international community soon (IEA, 2006).

Sinks Farther from the Carolinas

Because geology within the Carolinas is generally unsuitable for long-term storage of CO_2, it is necessary to look outside the states for potential geologic sinks. This analysis is focused only on the geologic suitability of out-of-state sinks and does not address policy or environmental aspects of interstate transport. Potential geologic sinks in Tennessee and Kentucky/West Virginia (Mt. Simon and Knox, respectively) (fig. 9) lie within the Appalachian Plateau province of the Appalachian Mountains. Preliminary analysis indicates that the Tuscaloosa Group of southwestern Alabama and the panhandle of Florida (fig. 9) are also a potential sink for CO_2 geologic storage.

Mt. Simon Formation in Tennessee

The late Cambrian-age Mt. Simon Formation (fig.9) is a quartz arenite sandstone (Driese et al., 1981). Depth to base of Mt. Simon sink ranges from 1,200 to 2,400 m (fig. 20). Mt. Simon data in Tennessee are from an unpublished work compiled by Advanced Resources International (ARI). Thickness of Mt. Simon across entire areas is estimated by ARI to be 100 ft. A copy of data received from ARI is contained in appendix B.
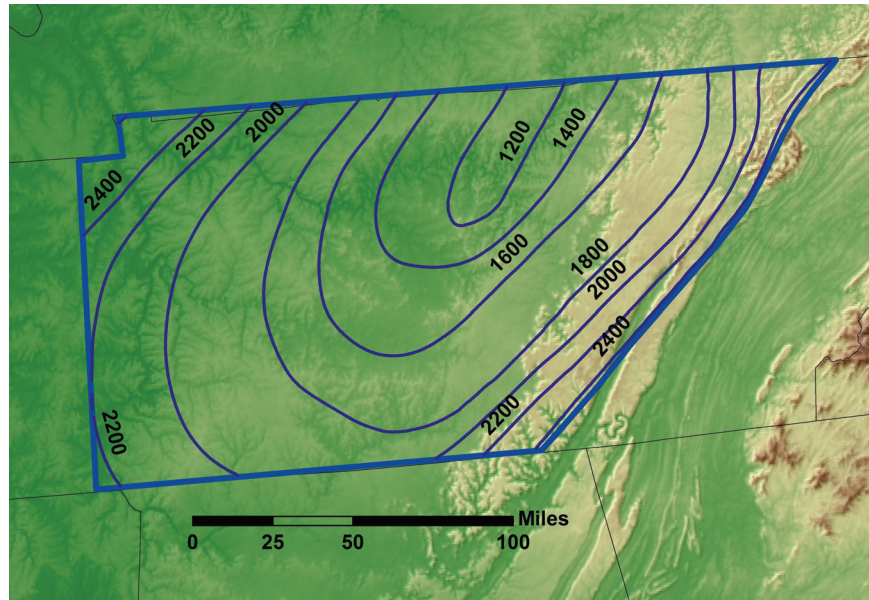
Figure 20. Base of Mt. Simon Formation in meters.

Knox Group in Kentucky and West Virginia

Since the early 1960's, hydrocarbons (primarily gas) have been produced from Knox Group paleotopographic highs along the postrift unconformity and from fractured dolomites and sandy interlayers (Baranoski et al., 1996). Although the potential for future natural gas production from the Knox Group is great within the Rome Trough of eastern Kentucky and West Virginia (Baranoski, 1996), areas within almost the entire Knox Group Play show great potential for storage of greenhouse gasses. The Knox Group Play is more expansive to the northeast and tapers to the southwest following the western boundary of the Appalachian Plateau physiographic province (fig. 21).
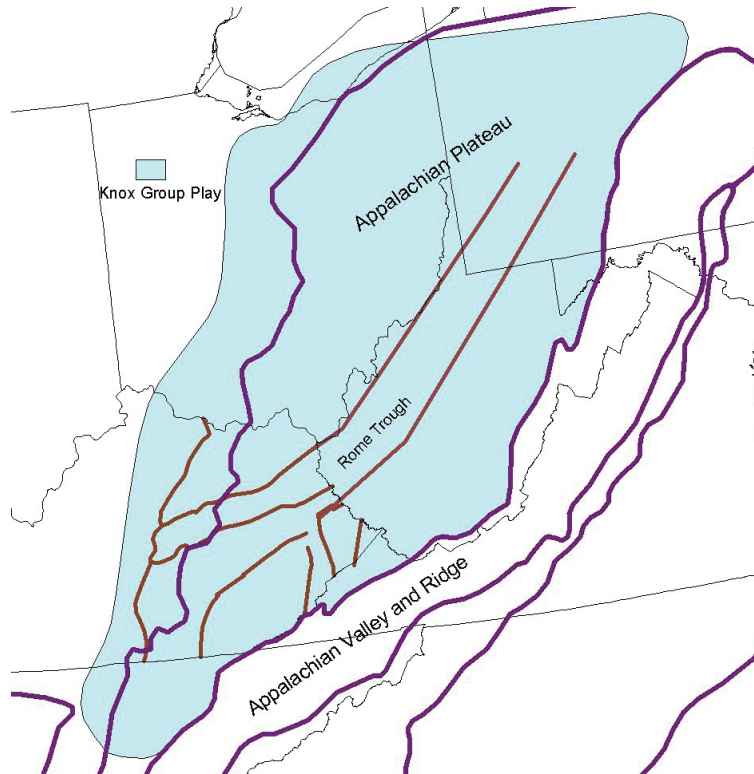
Figure 21. Knox Group play, Appalachian Plateau, southern Appalachian Mountains. Modified from Baranoski et al. (1996) and Shumaker (1996).

The Cambrian portion of the Knox Group is a gray, finely crystalline dolomite in which secondary porosity has been enhanced by recrystallization (Rodgers, 1953; Read, 1989; Milici, 1996). In the Southern and Central Appalachians, Cambrian subunits of the Knox are stacked peritidal carbonate cycles from 3 to 15 ft thick. Cycles, lime mudstone at the base, coarsen upward into pelletal oolitic grainstones, flat-pebble conglomerates, and stromatolites (Read, 1989).

The Ordovician portion of the Knox Group contains peritidal carbonates in the west to shallow, subtidal, open-marine or biohermal shelf-edge deposits in the east (Read, 1989). A Knox Group facies in Tennessee contains significant secondary porosity owing to diagenetic dolomitization and formation of solution-collapse breccias. These Ordovician-aged rocks in Tennessee contain Mississippi Valley-type sphalerite mineralization (Montanez, 1994).

Average value of porosity calculated from log analysis of the pay zone from three producing fields in Kentucky is 8 percent (10 logs evaluated), 9 percent (9 logs evaluated), and 4 percent (2 logs evaluated). These fields reported between 20 and 700 Mcf initial gas production. Overall, the average porosity for horizons within the Knox Group Play ranges from 3 to 20 percent, averaging 9 percent. Permeability in the Rose Run Sandstone ranges from 0.01 to 198 md and averages 5 md (Baranoski et al., 1996).

We mapped the elevation of the top of the Knox Group by combining published structure contours (Baranoski et al. 1996) with those inferred from a map of basement structure (Shumaker 1996). We then calculated depth to top of the formation by subtracting gridded elevation from surface topography (90-m digital elevation models

[DEM's] generated from Shuttle Radar Topography Mission [SRTM] data [http://srtm.usgs.gov/data/obtainingdata.html or http://srtm.csi.cgiar.org/]). Depth below ground to the top of the Knox Group sink ranges from 800 m in eastern Kentucky to 2,600 m in southern West Virginia (fig. 22a).

The entire Knox Group is quite thick, ranging from 305 to over 1220 m (1,000 to over 4,000 ft) in thickness within the play (Baranoski et al., 1996). Thickness isopachs increase to the northeast in West Virginia and southwestern Pennsylvania and to the southwest toward Tennessee. Thickness in the Knox Group sink ranges from 500 to 1,200 m (1640 to 3940 ft) (fig. 22b).

(a)   (b)
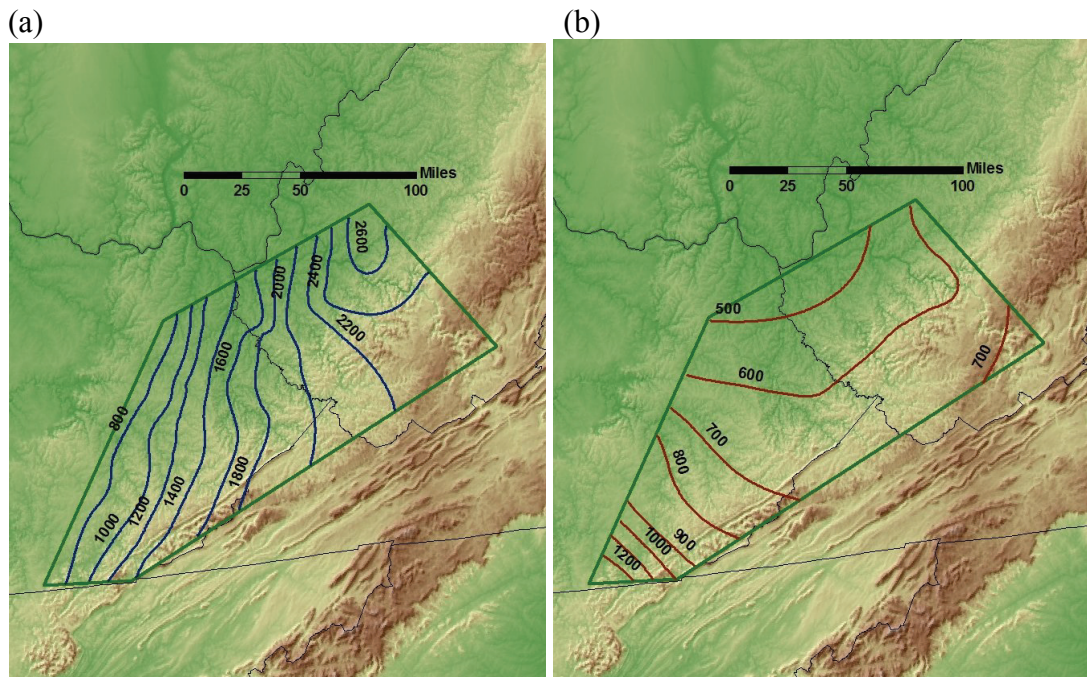
Figure 22. Potential Knox Group geologic sink, (a) structure contour on top of Knox (m), and (b) thickness of Knox (m).

Tuscaloosa Formation in Alabama and Florida

Preliminary analysis indicates that the Tuscaloosa Group of southwestern Alabama and the panhandle of Florida (fig. 9) is a potential host for CO_2 geologic storage. Sandstones in the lower part of the Tuscaloosa, including the informally named Massive and Pilot intervals, are the most favorable host strata. These units have been interpreted to represent a transgressive sequence that includes fluvial, deltaic, and coastal barrier or strandplain environments (Mancini et al., 1987).

The primary sources of information on the geometry, composition, and thickness of the Lower Tuscaloosa strata are geophysical logs of wells drilled for oil and gas exploration and production, as well as produced water and industrial waste disposal. Interpretations made from published maps and logs (Miller, 1979; Mancini et al., 1987; and Renkin et al., 1989) and unpublished information provided by the Florida Geological Survey (pers. comm., 2006) show that depth to the top of the lower Tuscaloosa sand intervals increases from zero where lower Tuscaloosa equivalents crop out northeast of the study area to more than 2,500 m (8200 ft) southwest of Mobile Bay (fig. 23). These

strata dip to the south-southwest toward the axis of the Mississippi embayment, transitioning to a more westerly dip component farther northward. Thickness of dominantly sandy lower Tuscaloosa strata can approach or exceed 100 m (328 ft). Contoured maps depict a general trend of thickness increasing southwestward from 10 m (33 ft) or less in the northeastern part of the subject area to more than 70 m (230 ft) along the Florida shoreline and southwest of Mobile Bay (fig. 23).

There is relatively little published information on the porosity and permeability distribution within lower Tuscaloosa Group strata. Lower Tuscaloosa porosities reported for Alabama wells by Tucker and Kidd (1973) range from 30 to 33 percent, slightly higher than values of 25 to 30 percent quoted for Tuscaloosa brine-injection wells in Jay field (Florida Geological Survey, pers. comm., 2006). The conservative, representative value that we chose for this study is 27.5 percent. Quoted Lower Tuscaloosa permeabilities range from 50 to 1,000 md in Alabama (Tucker and Kidd, 1973) and from 500 to 1,000 md in lower Tuscaloosa Massive unit injection wells in Florida's Jay field (Florida Geological Survey, pers. comm., 2006). We assumed a representative permeability of 750 md throughout the Tuscaloosa area. SECARB research groups will be collecting additional data for the Tuscaloosa in Alabama and Mississippi beginning in spring of 2008.

The Lower Tuscaloosa Group is part of the Black Warrior River aquifer, the basal and most extensive aquifer in the Southeastern Coastal Plain aquifer system (Renkin et al., 1989; Barker and Pernik, 1994). At depths suitable for CO_2 storage, dissolved-solid concentrations of pore water exceed 10,000 mg/L TDS (Miller, 1979; Barker and Pernik, 1994).
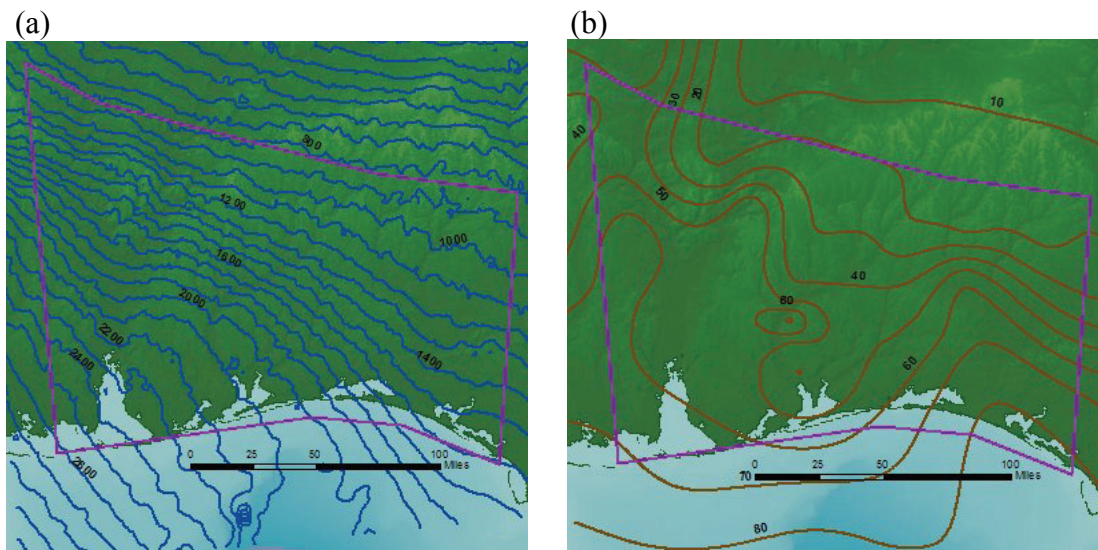
(a) (b)

Figure 23. Tuscaloosa sink data: (a) structure contours (m) indicating depth to top of Tuscaloosa sink in Alabama and Florida. (b) isopach (thickness in m) for the same sink.

Estimates of Sink Capacity and Pipeline Costs

Geologic units underlying most of North and South Carolina do not meet minimum suitability criteria necessary for long-term storage of CO_2. Hence, in order to match potential sources of CO_2 with potential sinks, CO_2 will have to be transported before it can be injected into the subsurface and isolated from the atmosphere and freshwater resources.

Massachusetts Institute of Technology (MIT) Laboratory for Energy and the Environment has developed a Carbon Management Geographic Information System (GIS) tool that utilizes ArcGIS© (software developed by Environmental Systems Research Institute) to evaluate CO_2 sources and sinks. This section contains the geologic sink capacity estimates and GIS analysis of the pipeline calculations completed by the Carbon Capture and Sequestration Technologies Program at MIT. Multiple pipeline scenarios are presented in order to provide CO_2 transport estimates to all potential geologic sinks. The MIT methodology is provided in appendices C-1, C-2, and C-3. Additional MIT data tables and plots are provided in Appendix D.

Capacity

MIT capacity estimates are based on limited and generalized data sets, which are primarily from published literature. More accurate estimates of capacity for the specific geologic sinks included in this study will require site-specific, detailed geologic investigations.

The MIT methodology assumes that if the suitability criteria (1) continuity and integrity of an overlying seal and (2) pressure and temperature conditions sufficient to maintain CO2 at high density are met, the CO_2 storage capacity of a saline reservoir can be calculated using the following formula:

$$Q_{aqui} = V_{aqui} * p * e * \rho_{CO2} \qquad (1)$$

where Q_{aqui} = storage capacity of entire reservoir (Mt CO_2)
$\quad$ V_{aqui} = total volume of entire reservoir (km^3)
$\quad$ p = reservoir porosity (%)
$\quad$ e = CO_2 storage efficiency (%)
$\quad$ ρCO_2 = CO_2 density at reservoir conditions (kg/m^3)

If accurate spatial data are available for a reservoir, then the reservoir volume used in equation 1 can be calculated as an integral of the surface area and thickness of the reservoir:

$$V_{aqui} = \sum_i S_i T_i \qquad (2)$$

where S_i is the area of the raster cell and
$\quad$ T_i is the thickness of the cell

The term "CO_2 storage efficiency" refers to the fraction of the reservoir pore volume that can be filled with CO_2. For a saline reservoir in which CO_2 can be trapped by a physical barrier (overlying seal), the storage efficiency is estimated at 2% (Holloway, 1996).

Estimates of storage capacity of the potential geologic sinks located in (1) South Georgia Basin (SGB), (2) offshore Atlantic subseafloor (units 90 and 120), (3) Tennessee (Mt. Simon), (4) Kentucky and West Virginia (Knox), and (5) Alabama and Florida (Tuscaloosa) are summarized in table 2.

Table 2. MIT estimates of CO_2 storage capacity.

POTENTIAL SINK	CAPACITY ESTIMATES[1] (Gt)

SGB
  Triassic units
  Atkinson-Tuscaloosa
  Cape Fear
	~15

Offshore Sinks
  Unit 120
  Unit 90
	~178[2]
	~16[2]

Hatteras Area	n.a.[3]
Mt. Simon	~3
Knox	~32
Tuscaloosa	~10

Notes:
1. CO_2 storage efficiency estimated as 2 percent and all the aquifers are assumed closed.
2. CO_2 density in the offshore sites assumed to be 700 kg/m³.
3. Detailed data are not available.

Pipeline Cost Methodology

Part of the source-sink matching process requires estimates of the cost of CO_2 transport to a specific geologic sink. For purposes of this discussion, we focused on the potential for transportation by pipeline. Estimates of pipeline costs for this study were conducted by the MIT Laboratory for Energy and the Environment in late 2006. Pipeline cost estimates (in 2006 dollar equivalents for materials) include pipeline construction, right-of-way acquisition, and operation. Cost estimates for CO_2 pipeline construction are based on cost data for natural gas pipelines. This may have resulted in an underestimate of costs to build CO_2 pipelines because of the greater CO_2 wall thickness required to contain supercritical (high pressure and temperature) CO_2. Neither the cost of capture/separation at the plant nor the cost of compression and injection at the CO_2 storage site are included. These elements are beyond the scope of this assessment, which is to match sources with sinks and provide a relative index of cost escalation as the distance between sources and sinks increases.

MIT started this process using data for the CO_2 generated by fossil-fuel power plants in North and South Carolina. They used the USEPA eGRID 2002 (data for 2000) database to estimate the adjusted CO_2 emissions and annual flow rates, assuming 80

percent operating factor and 90 percent capture efficiency. Owing to economies of scale, they included only power plants with a design capacity greater than 100MW (fig. 24 and table 3).
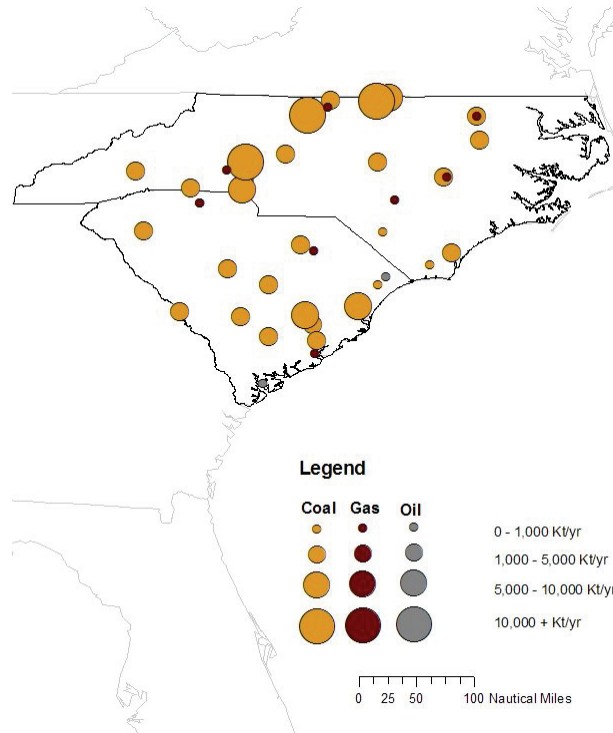

Figure 24. Power plant data used in MIT pipeline cost estimates.

Table 3. Fossil-fuel power plants by fuel type (design capacity>100MW)

FUEL TYPE	Coal-Fired PP	Gas-Fired PP	Oil-Fired PP	Total
Numbe of Power Plants (PP)	29	9	2	40
Total Design Capacity (MWe)	21,651	5,565	229	27,446
2000 Average Operating Factor[a]	0.63	0.05	0.02	0.51
Actual 2000 Total CO_2 Emission (Mt)[b]	117	2	0	119
Adjusted Total Annual CO_2 Emission (Mt)[c]	153	32	3	188
Estimated 25-year CO_2 Flow (Mt)[d]	3,441	729	61	4,231

Notes: [a]Weighted (by design capacity) average operating factor

[b]eGRID published 2000 CO_2 emission based on actual plant operating factor

[c]Estimated plant CO_2 emission at 80% operating factor

[d]Estimated CO_2 flow rate assuming 90% capture efficiency

After identifying CO_2 sources in the Carolinas and using the geologic sink data provided by BEG, MIT workers evaluated source-sink matching over an assumed 25-yr project lifetime. They used a GIS method of matching sources and sinks that considers optimal pipeline route selection and capacity constraints of individual sinks. Because pipeline construction costs vary considerably according to local terrain, number of

crossings (waterway, railway, highway), and the traversing of populated places, wetlands, and national or state parks, the group constructed a digital terrain map that allows ranking of these factors (fig. 25). MIT used the digital terrain map to generate a grid of transportation cost factor, which appears in figures 26 through 30.
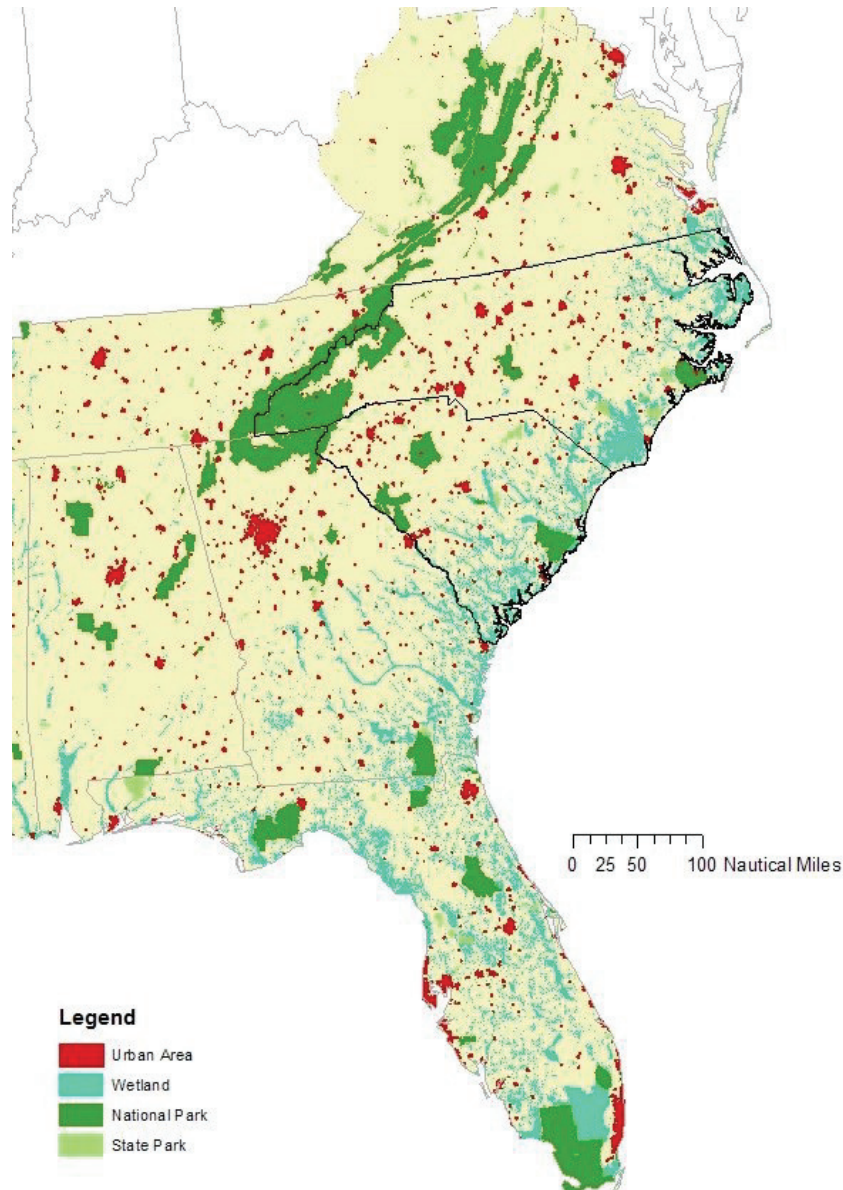
Figure 25. Terrain classification used in MIT pipeline cost estimates.

MIT generated pipeline-transport algorithms using the Carnegie Mellon University (CMU) correlation (McCoy, 2006). Because the MIT source sink matching program develops a minimum cost curve, it favors sinks that are closer to potential sources and automatically excludes more distant sinks. In order to obtain pipeline estimates for all potential sinks presented in this study, MIT used a multiple scenario

approach that alternatively excluded nearby sinks so as to force utilization of more distant sinks. Following are constraints for the five possible scenarios:

- Scenario 1 includes all potential sinks,
- Scenario 2 considers all sinks except the Hatteras area,
- Scenario 3 considers all sinks except the Hatteras area and subseafloor Unit 90 (Upper Cretaceous) in order to force pipeline estimates for subseafloor Unit 120 (Lower Cretaceous),
- Scenario 4 excludes the Hatteras area, subseafloor Unit 90 (Upper Cretaceous), and SGB to force pipeline estimates for Mt. Simon sink,
- Scenario 5 excludes the Hatteras area, subseafloor Unit 90 (Upper Cretaceous), SGB, and Mt. Simon to force pipeline estimates for Tuscaloosa sink in Alabama/Florida.

Summaries of estimated costs (in 2006 dollar equivalents for materials) for pipelines between selected sources and potential target sinks are presented for each of the five scenarios (table 4). The pipeline construction costs are composed of two components, the basic pipeline construction cost, which is diameter-dependant, and the additional obstacle cost (independent of diameter), which is represented by the transportation cost factor grid shown in figures 26 through 30. The model output used to generate values in table 4 are summarized in Appendix E. Total power output (design capacity) of the plants served ranges from 25.8 gigawatts (GW) for Scenario 1 to 24.5 GW for Scenario 5. Total pipeline construction costs range from \$3.8 billion for Scenario 1 to \$4.3 billion for Scenario 5. Average transportation costs vary from \$3.56 to \$4.21 per metric ton of CO_2. The costs presented here are in 2006 dollar equivalents for materials.

Table 4. Estimated cost summary (in 2006 dollar equivalents for materials) for five sink scenarios (for power plants with transportation cost <10\$/t CO_2).

SINK OPTIONS	TOTAL CONSTRUCTION COST (BILLION \$)	TOTAL CO_2 STORED IN 25 YEARS (GT[1])	TOTAL DESIGN CAPACITY (GW)	AVERAGE COST (\$/TON CO_2)	AVERAGE DISTANCE[2] (km)	TARGET SINKS
Scenario 1	3.8	4.2	25.8	3.56	299	Hatteras, Knox, Unit 90, SGB
Scenario 2	3.8	4.1	25.3	3.63	322	Knox, Unit 90, SGB
Scenario 3	4.0	4.1	24.8	3.84	344	Knox, Unit 120, SGB
Scenario 4	4.2	4.0	24.5	4.17	370	Knox, Mt. Simon, Unit 120
Scenario 5	4.3	4.0	24.5	4.21	373	Knox, Unit 120, Tuscaloosa

[1]Gt = 1 billion metric tons

[2]Flow-rate-weighted-average pipeline distance

Costs for Sink Option Scenario 1 are lowest because only those potential sinks closest to the Carolinas power plants—Hatteras, Knox, Unit 90, and SGB—are utilized (table 4, fig. 25). Scenario 2 is may be more likely because it excludes the Hatteras sink; we do not think it is likely that there will be drilling allowed in the Cape Hatteras, NC area. The purpose of running MIT's GIS algorithms using scenarios 3, 4, and 5 was to obtain estimated costs for utilizing the more distant potential sinks—subseafloor unit 120, Mt. Simon, and Tuscaloosa—for geologic storage of CO_2.

Results from the individual source-sink matching hypothetical scenarios are summarized in the following sections and figures 26 through 30. Each section contains a map showing location of the power plants with a design capacity greater than 100MW (red triangles); the same power plants shown in fig. 24 and described in table 3 are used in all scenarios. The blue lines represent pipeline routes. The saline reservoir sinks are the same as those discussed in previous sections of this report with the exception of the South Georgia Basin. Recall from figure 11 that this area contains three partially overlapping saline reservoir horizons that are suitable geologic sinks. The three sink horizons are from shallowest to deepest the (1) Atkinson-Tuscaloosa (fig. 13 and GA in figures 26 through 30), (2) Cape Fear, and (3) Triassic-age intervals (SGB in figures 26 through 30). The transportation cost factor grid shown in figures 26 through 30 was generated from a combination of (1) land slope, (2) presence of absence of protected areas (populated areas, wetlands, State or National parks), and (3) crossings (waterway, highway, or railroad).

Source-Sink Matching for Pipeline Scenario 1

Scenario 1 used all potential sinks included in this study as possible locations for subsurface storage of CO_2 generated by power plants in the Carolinas with a design capacity greater than 100MW. The MIT optimal pipeline network solution for Scenario 1 (fig. 26) utilized the Knox, Hatteras, subseafloor unit 90, SGB, and GA sinks. CO_2 generated by most of the power plants in western North Carolina (NC) could be transported via pipeline across the Appalachian Mountains to the Knox sink. CO_2 generated by most of the power plants in eastern NC could be transported to the Hatteras sink. CO_2 from a few of the plants in southern NC and northeastern South Carolina (SC) could be transported to the subseafloor unit 90 sink. CO_2 from most of the power plants in SC could be sent to the South Georgia Basin (SGB and GA in fig. 26).
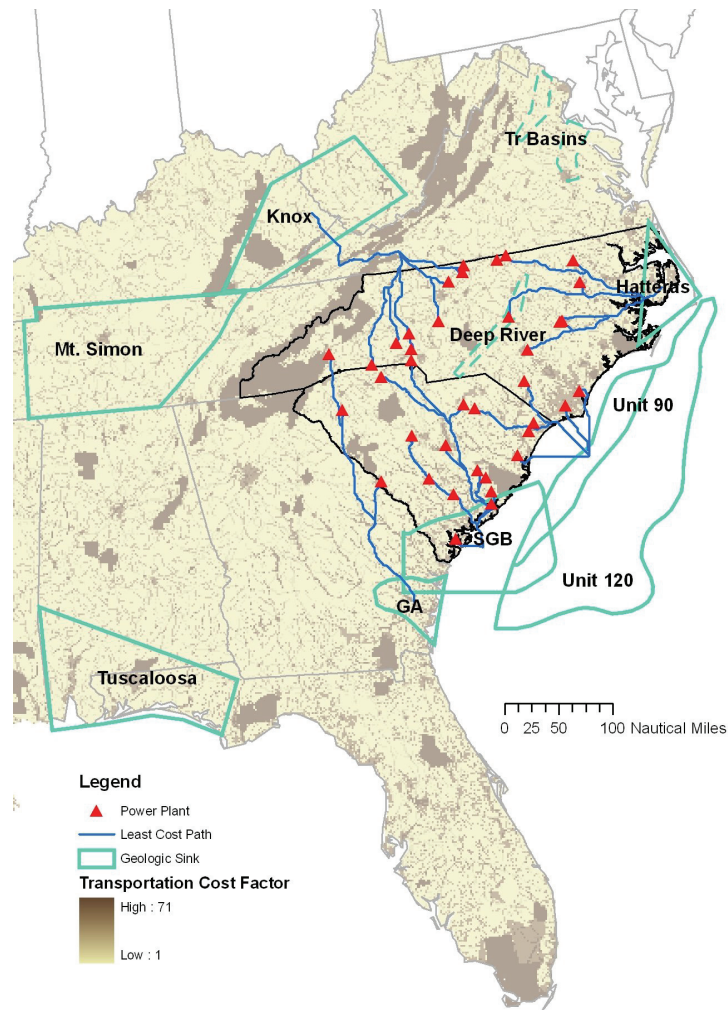
Figure 26. MIT Scenario 1 optimal pipeline network solution.

Source-Sink Matching for Pipeline Scenario 2

In this scenario all the potential sinks except for Hatteras were used as possible locations for subsurface storage of CO_2 generated by power plants in the Carolinas with a design capacity greater than 100MW. The MIT optimal pipeline network solution for Scenario 2 (fig. 27) utilizes the Knox, subseafloor unit 90, SGB, and GA sinks. The difference in Scenario 2 is that CO_2 could be transported to the unit 90 subseafloor sink rather than being transported to the Hatteras sink as in Scenario 1. CO_2 generated by most of the power plants in western NC could still be transported to the Knox sink. CO_2 from most of the power plants in SC could still be sent to the South Georgia Basin (SGB and GA in fig. 27).

Figure 27. MIT Scenario 2 optimal pipeline network solution.

Source-Sink Matching for Pipeline Scenario 3

In Scenario 3 all the potential sinks except for Hatteras and subseafloor unit 90 were used as possible locations for subsurface storage of CO_2 generated by power plants in the Carolinas with a design capacity greater than 100MW. The MIT optimal pipeline network solution for Scenario 3 (fig. 28) utilizes the Knox, subseafloor unit 120, SGB, and GA sinks. The objective of this scenario was to force utilization of subseafloor unit 120, which would require a longer offshore pipeline and hence increase cost. Otherwise the transport network solution matches the one in Scenario 2.
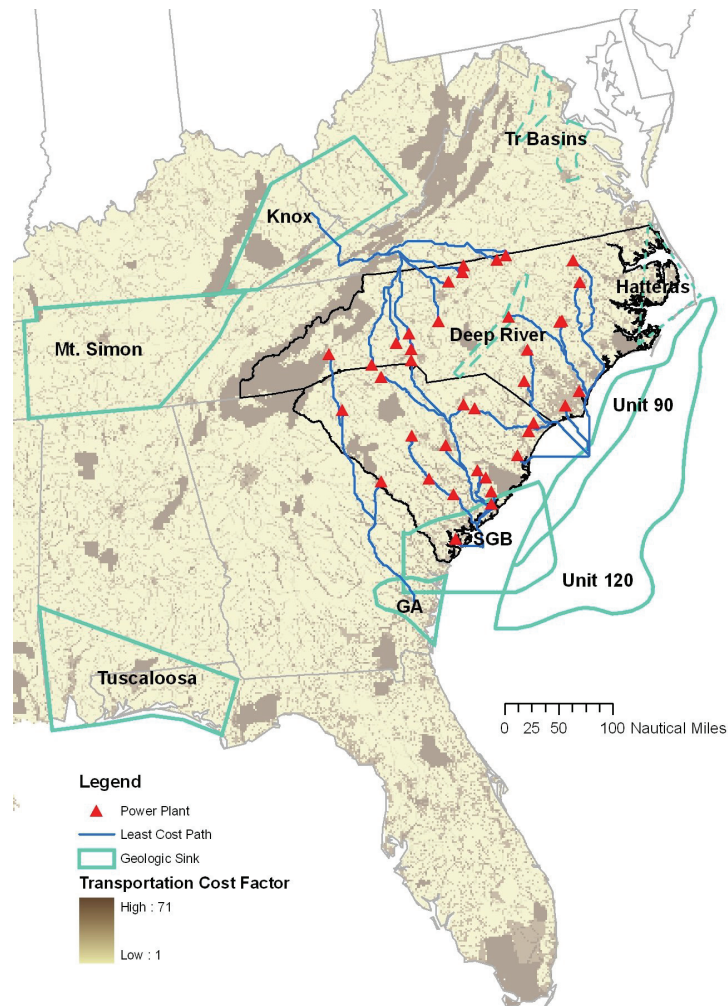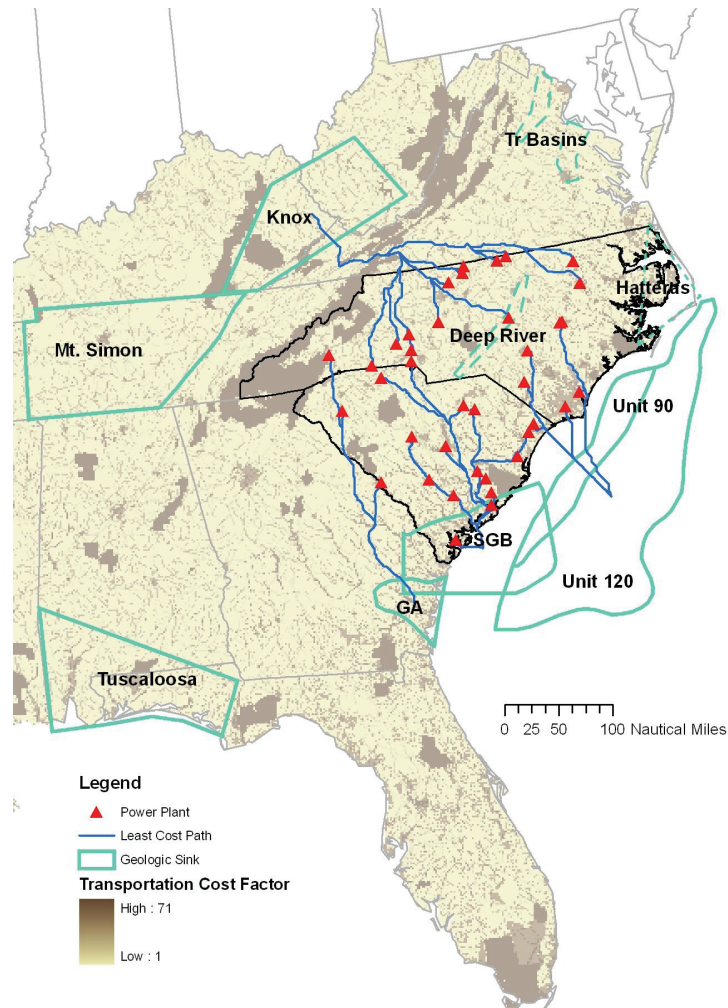
Figure 28. MIT Scenario 3 optimal pipeline network solution.

Source-Sink Matching for Pipeline Scenario 4

In Scenario 4 all the potential sinks except for Hatteras and subseafloor unit 90, and the two South Georgia Basin sinks were used as possible locations for subsurface storage of CO_2 generated by power plants in the Carolinas with a design capacity greater than 100MW. The MIT optimal pipeline network solution for Scenario 4 (fig. 29) utilizes the Knox, subseafloor unit 120, and the Mt. Simon sinks. The objective of this scenario was to force utilization of subseafloor unit 120 by excluding unit 90, and force utilization of Mt. Simon by excluding the SGB sinks. Only two of the power plants in southern SC would utilize the Mt. Simon sink most likely because of the long distance of pipeline required. CO_2 from all of the other power plants that previously utilized the SGB sinks could be transported to the subseafloor unit 120 sink in this scenario. CO_2 generated by most of the power plants in western NC could still be transported to the Knox sink.
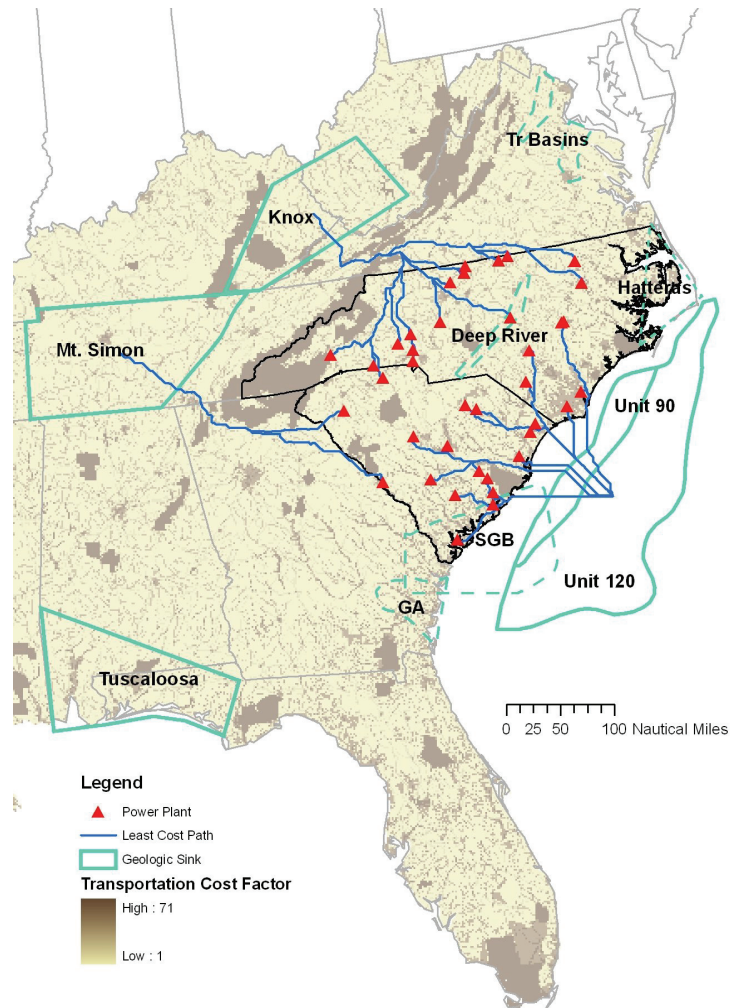
Figure 29. MIT Scenario 4 optimal pipeline network solution.

Source-Sink Matching for Pipeline Scenario 5

In Scenario 5 the Hatteras, subseafloor unit 90, SGB sinks, and Mt. Simon sinks were excluded from consideration. The MIT optimal pipeline network solution for Scenario 5 (fig. 30) utilizes the Knox, subseafloor unit 120, and the Tuscaloosa sinks. The objective of this scenario was to force utilization of subseafloor unit 120 by excluding unit 90 and force utilization of the Tuscaloosa sink by excluding the SGB and Mt. Simon sinks. Only one of the >100MW power plants in southern SC would utilize the Tuscaloosa sink most likely because of the long distance of pipeline required. CO_2 from all of the other power plants that previously utilized the SGB sinks could still be transported to the subseafloor unit 120 sink in this scenario. CO_2 generated by most of the power plants in western NC could still be transported to the Knox sink.
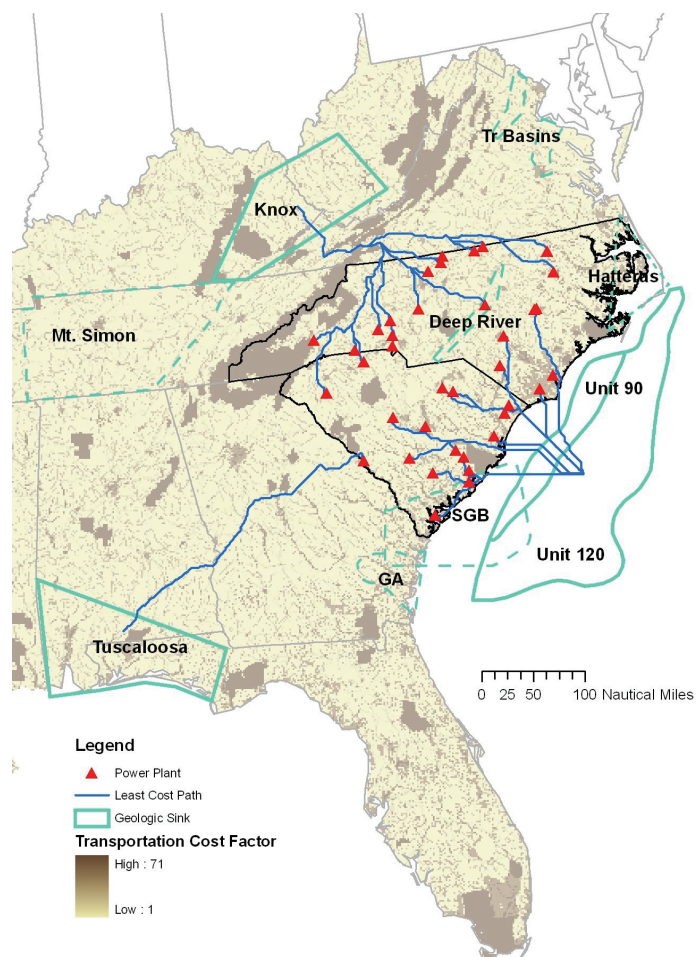
Figure 30. MIT Scenario 5 optimal pipeline network solution.

Conclusions

Most of the power plants in the Carolinas are underlain by geologic units that are not suitable for long-term storage of large volumes of CO_2. The Blue Ridge and Piedmont physiographic provinces of the Appalachian Mountains in western portions of the Carolinas are underlain by crystalline rocks that lack sufficient overlying seals to (1) trap CO_2 in the subsurface or (2) keep it from interacting with fresh groundwater. Sediments of the Atlantic Coastal Plain are not thick enough to host CO_2 sinks and contain deep freshwater aquifers. A potential exception within the Carolinas is an isolated sedimentary basin encompassing the southernmost part of South Carolina that lies within the South Georgia Basin.

Subsurface storage of CO_2 generated in the Carolinas will probably require construction of pipelines to geologic sinks located some distance away from the power plants. The most likely potential geologic sinks for CO_2 generated in the Carolinas are located in (1) the South Georgia Basin (southernmost South Carolina, eastern Georgia, and extending offshore 50 to 75 mi (80 to 120 km), (2) the offshore in strata approximately 0.6 to 1.9 mi (~1 to 3 km) below the Atlantic seafloor, and (3) the Knox Formation in eastern Kentucky and southwestern West Virginia. The CO_2 storage

potential for the offshore Atlantic margin is unexplored, but preliminary considerations suggest that CO_2 sequestration options are significant along the entire eastern seaboard. The CO_2 storage potential for the offshore Atlantic margin is unexplored, but preliminary considerations suggest that CO_2 sequestration options are significant along the entire eastern seaboard. Given the limited sink availability in onshore locations of the eastern U.S., and the potentially promising offshore locations, subseafloor injection warrants further evaluated.

Estimates of storage capacity of the potential geologic units identified in this document range from approximately three (Mt. Simon sink in Tennessee) to over 175 gigatons (offshore Atlantic subseafloor sinks). These estimates are based on limited and generalized data sets, which are primarily from published literature. More accurate estimates of capacity for geologic sinks will require site-specific, detailed geologic investigations. Less favorable locations could be considered for storage of small amounts of CO_2, (less than 1 million tons of CO_2 per year) but the economic considerations of subsurface storage requires sinks capable of storing larger volumes. In addition, assessment of the potential geologic sinks is based solely on geologic suitability. Environmental, economic, and socio-political issues will need to be considered before determining which geologic sinks are most suitable for CO_2 storage.

Costs associated with CCS can be separated into two categories—(1) those associated with CO_2 capture and separation and (2) those associated with transportation and storage. Pipeline construction costs are the primary cost factor in the various scenarios, and they vary according to type of terrain that must be traversed. CO_2 transport costs are estimated in terms of $/ton CO_2, which is the total cost divided by the CO_2 flow rate. Hence, transporting CO_2 at a higher flow rate results in lower transportation costs. Average transportation costs estimated by MIT for the five different scenarios vary from $3.56 to $4.21 per metric ton of CO_2 in 2006 equivalent dollars. These costs might be low because (1) MIT based pipeline construction costs on those required to build natural gas pipelines; CO_2 pipelines might be more expensive because of the greater wall thickness needed to contain supercritical (high temperature and high pressure) CO_2, (2) fluctuations in the price of steel, (3) uncertainty in the cost escalation factor for building offshore pipelines.

Acknowledgments

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