DOE/EA-0000 (DRAFT)

Environmental Assessment

Optimal Geological Environments for Carbon Dioxide Disposal in Brine Formations (Saline Aquifers) in the United States—Pilot Experiment in the Frio Formation, Houston Area

Contract DE-AC26-98FT40417 Modification A008

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1.0 INTRODUCTION

This Environmental Assessment (EA) provides the results of an evaluation of the potential environmental consequences of a field experiment and of injection of CO_2 into a subsurface brine-bearing formation, a processes known as geologic sequestration. The U.S. Department of Energy (DOE) is proposing to fund this project to determine if geologic sequestration of CO_2 is safe and effective in reducing atmospheric releases, and if the sequestration process can be modeled, measured, and monitored. If approved, DOE would provide the $3.4 million cost of the project.

This project was proposed by the Bureau of Economic Geology as Phase III of DOE-initiated competitive solicitation DE-RA26-98FT35008. Phase I and Phase II assessed the optimal geological environments for geologic sequestration in brine formations in the onshore U.S., and found that the upper Texas Gulf Coast was a regional with excellent potential for geologic sequestration. Phase III will test the Phase I and Phase II conclusions with a field experiment.

Increasing concentrations of CO_2 in the atmosphere are thought to have potential to force change toward a warmer global climate. These changes may have negative impacts on human systems as well as ecosystems. DOE is developing an understanding of the environmentally acceptable options

Geologic sequestration is one of the highly ranked technologies for stabilizing the amount of CO_2 released to the atmosphere as a waste from combustion of fossil fuel. In this method, CO_2 is captured from a stationary industrial source of CO_2, compressed, and injected into the subsurface. The injection site must be selected to have the geologic properties that will assure that the CO_2 will remain trapped in the subsurface and isolated from the atmosphere for thousands of years. The natural capacity of the subsurface to trap and retain buoyant fluids such as oil and natural gas is well known. Technologies for injection of fluids into the subsurface are widely applied both for waste disposal and for enhancing recovery of oil.

This field experiment is designed to closely monitor the performance of the subsurface in holding CO2. To reduce risks, the injection is designed using the minimum volume of CO_2 that can be measured in the subsurface using a wide variety of techniques, and to be completed over a short period of time (less than 1 year). The results obtained from monitoring a small volume will provide assurance that in a similar geologic environment, a large volume can be safely and effectively injected and monitored over a longer time frame. Monitoring and modeling tools have been designed and will be tested at this site by researchers from Lawrence Berkeley National Laboratory (LBNL), Oak Ridge National Laboratory (ORNL), Lawrence Livermore National Laboratory (LLNL), and National Energy Technology Laboratory (NETL).

2.0 PURPOSE AND NEED FOR THE PROPOSED ACTION

2.1 DOE's Purpose

The concentration of carbon dioxide (CO_2) in the atmosphere has increased 17.4% over the past 60 years (Keeling and Whorf, 2002). The Intergovernmental Panel on Climate Change (2001) has concluded that these changes result principally from accumulation of anthropogenic CO_2 emitted to the atmosphere as a result of changing land use patterns and combustion of fossil fuels, such as coal, oil, and natural gas, to produce energy. Predictions of global energy use in the next century suggest that anthropogenic carbon emissions will continue to increase, resulting in continued rising atmospheric concentrations of CO_2 unless major changes are made in the way we produce and use energy (U.S. Department of Energy, 1999, p 1-1).

Uncertainty remains in predicting the effects of this change in composition of the atmosphere. However, there is significant risk that continued increase in atmospheric concentrations could force changes in global climate, which may have a variety of serious consequences (see U.S. Climate Change Science Program / U.S. Global Change Research [2003] http://www.usgcrp.gov/usgcrp/nacc/education/default.htm for regional summaries or the Intergovernmental Panel on Climate Change http://www.ipcc.ch/ [2003]).

DOE has prepared several documents that consider U.S. energy policy and the options that can be evaluated in response to concerns over the impact of anthropogenic CO_2 releases on climate change. The National Energy Policy Development Group (2001) considered a broad spectrum of energy issues, and in chapter 3 (Protecting America's Environment) states that "Industry and the federal government are researching various new technologies that will reduce greenhouse gas emissions or sequester those emissions, in geologic formations, oceans, and elsewhere." The U.S. Department of Energy (1999) document "Carbon Sequestration" provides a detailed assessment of the role of carbon sequestration in reducing anthropogenic CO_2 emissions. Three categories of technologically driven solutions are proposed: (1) energy conservation and efficiency; (2) substituting lower carbon or carbon-free energy sources for current sources, for example switching to renewable energy sources, nuclear power, and low-carbon fuels; and (3) carbon sequestration, which removes CO_2 from combustion emissions and stores it directly underground or in the deep ocean or indirectly by enhanced uptake by soils, vegetation, and the oceans.

The purpose of the proposed action is to rigorously test the application of the third proposed technological solution, carbon sequestration, within a geologic formation. This test is a key component needed to increase scientific understanding of carbon sequestration to assure that this option is an effective method for reducing atmospheric concentrations of CO_2.

2.2 DOE's Need for Action

"The vision for the road map is to possess the scientific understanding of carbon sequestration and develop to the point of deployment those options that insure environmentally acceptable sequestration to reduce anthropogenic CO_2 emissions and/or atmospheric concentrations. The goal is to have the potential to sequester a significant fraction of the 1 Gt/year in 2025 and 4 Gt/year in 2050" (U.S. Department of Energy, 1999, p.1-1).

One option that has the potential to achieve DOE's goal is sequestration of CO_2 in geologic formations, such as oil and gas fields, coal beds, and porous brine-bearing formations (U.S. Department of Energy, 1999, p.5-1). Decades of reservoir characterization experience gained by U.S. industries in understanding the performance of the subsurface in containing gases and fluids help make geologic sequestration an attractive option. The ability of the subsurface to store oil and gas for geologically significant periods is well known, lending credibility to the concept that injected CO_2, which will be buoyant like oil and natural gas in most geological environments, could be sequestered for long periods (Hitchon, 1996). Technologies for introducing gas and fluids to the subsurface are also mature. For decades oil producers have injected CO_2 into oil reservoirs to act as a solvent and to enhance oil recovery (EOR), a process known as CO_2 EOR. In many parts of the U.S., surface water is protected from contamination by disposal of waste fluids into the subsurface. A permitting process, Underground Injection Control (UIC), assures the public that the disposal occurs in deep subsurface formations that are below and hydrologically isolated from potable water. CO_2 is already being sequestered geologically offshore in the North Sea, where approximately one million tonnes of CO_2 are stripped from natural gas and reinjected into the subsurface annually to prevent release to the atmosphere (U.S. Department of Energy, 1999, p. 5-2).

Although the processes of geologic sequestration are relatively well known, additional research is needed to fill gaps in our scientific understanding of carbon sequestration and to develop stakeholder experience with the process so that the technology is ready for deployment. Extensive laboratory and modeling studies have been completed to assess how CO_2 geologic sequestration would work in the subsurface (for example, Hitchon, 1996; U.S. Department of Energy, 1999). Comparing predictions from bench scale tests and numerical models with field results is necessary to validate the models and demonstrate that scientific understanding is correct.

Extensive experience with CO_2 injection for EOR is inadequate for this validation because the fate of the injected CO_2 is not quantified. CO_2 injected for EOR can be sorbed in the oil, held by capillary forces in pore space, trapped by buoyancy forces in stratigraphic or structural compartments, dissolved in pore water, produced and reused, or leaked from the injection zone. The absence of accounting for CO_2 fate in the complex EOR system leaves a gap in scientific understanding. It is generally assumed, but has never been demonstrated, that leakage of CO_2 from the injection zone is small relative to the other fates.

Another significant experience gap between EOR and the validation needed for full-scale CO_2 sequestration is the type of host rock. Hovorka and others (2000) (http://www.beg.utexas.edu/environqlty/co2seq/dispslsaln.htm) inventoried 21 geologic formations in the onshore U.S. that might serve as host injection intervals for CO_2 and identified areas where these formations are near numerous and large CO_2 sources. Geologic formations that could most easily receive and retain the large volumes of CO_2 (1 to 4 Gt/year) are thick, porous, and permeable sandstones. Such sandstones underlie CO_2 sources on much of the Gulf of Mexico coast. Unfortunately, most experience with EOR is in lower permeability carbonate rocks in the interior basins distant from most anthropogenic sources. In the North Sea, CO_2 is injected into a thick, porous, and permeable sandstone, but it is not feasible to closely observe reservoir performance and CO_2 fate here because it is in an offshore setting where monitoring wells are not an economic possibility.

A third significant experience gap is in the process of permitting an injection well for CO_2 sequestration. Commercial and industrial disposal wells are commonly located at sites vertically or laterally isolated from hydrocarbon reservoirs and aquifers. All wells in the cone of influence are required to be properly completed or plugged to ensure that they will not leak. In contrast, CO_2 injection wells for EOR are located within producing oilfields and are intended to increase production at as many wells as possible. Regulators need to develop processes and gain experience with combined-objective projects—CO_2 beneficial use plus CO_2 disposal. This new approach requires development of methods needed to assure stakeholders that CO_2 injected for dual purposes is retained in the subsurface and that the beneficial uses of enhanced production are safely achieved.

To address these experience gaps, we are proposing a field experiment in a high-porosity, high-permeability formation similar to those that could eventually be used to sequester large volumes of CO_2. This project will be onshore, so that it can be closely monitored to determine whether the CO_2 remains within the injection zone and so that scientific understanding can be maximized. The demonstration will be done at a small scale to (1) pioneer the permitting process, (2) ensure that health and safety and environmental risks are minimized, (3) minimize costs during this phase before stakeholders are ready for full scale deployment, and (4) obtain results quickly so that experience can be used in moving to larger scale pilots. The pilot location is ideal because the subsurface conditions are as simple as possible, maximizing the chances of matching numerical model results with field observations.

2.3 DOE's Response

A team lead by the Bureau of Economic Geology at The University of Texas at Austin proposes to conduct a well-monitored, small-scale, short-duration CO_2 injection into brine-bearing sandstone of the Frio Formation in the Gulf Coast of Texas. The site is within the South Liberty oilfield, where extensive existing geotechnical data are available, and can be used to model and predict the expected behavior of the injected CO_2. Use of existing infrastructure and location within an operating field will minimize both cost and environmental impact. This site was proposed as Phase III of DOE-initiated competitive solicitation DE-RA26-98FT35008. Phase I and Phase II assessed the optimal geological environments for geologic sequestration in brine formations in the onshore U.S. (Hovorka and others, 2000). The Frio Formation along the upper Texas Gulf Coast was identified as an area where (a) large volume sequestration is needed because of the concentration of a variety of CO_2 sources and (b) it is feasible owing to the presence of a thick widespread high-permeability formation ideal for sequestration. The project team (table 1) has identified the following objectives for the injection experiment:

- Demonstrate that CO_2 can be injected into a saline formation without adverse health, safety, or environmental effects;
- Determine the subsurface location and distribution of the CO_2 cloud;
- Demonstrate understanding of conceptual models;
- Demonstrate field-test monitoring methods developed by national laboratories; and
- Develop experience necessary for success of large-scale CO_2 injection experiments.

A small-scale injection pilot in a brine-bearing interval of the high-permeability Frio Formation was proposed and is now being planned. The project team is diverse, consisting of staff at a State geologic survey, four national laboratories, a nonprofit Canadian research company, a small independent oil and gas producer, a major oil and gas producer and refiner, a large oilfield service company, and experts in the fields of deep subsurface waste disposal and EOR operation (table 1). This group includes geologists, geophysicists, and engineers experienced in detailed subsurface characterization and numerical description as well as in waste-isolation projects; experts in geochemical tracer testing; specialists in numerical modeling of CO_2 subsurface behavior and flow simulation; engineers and petrophysicists experienced in well drilling, completion, logging, and log interpretation; and geophysicists experienced in seismic and other geophysical methods of detection of CO_2.

The pilot project will inject 3,750 tons (2 million m^3 or 71.2 million ft^3) of CO_2 into a brine-bearing Frio sandstone at a depth of about 1,500 m (5,000 ft). The site is within an existing oilfield on the flank of a salt dome approximately 56 km (35 mi) northeast of Houston, Texas. Other nearby land uses include timber production and sparse rural residences, although no dwellings lie within a 0.5-km (0.3-mi) radius of the site. The injection interval has been characterized using numerous existing geophysical well logs and a 3-D seismic survey. Engineering plans for injection and monitoring activities have been completed. A numerical simulation model created by LBNL allows prediction of subsurface results for planning purposes. Baseline surface and subsurface seismic and geochemical surveys will be completed before injection; repeat surveys will be completed during and after injection to monitor CO_2 distribution, and the integrity of structural and stratigraphic seals of the injection interval will be assessed.

Proposed activities are consistent with current land use. No endangered species occur in the study area, and no known archeological sites are located within the study area. Direct impacts include (1) clearing of as much as 2 hectares (5 acres) of upland habitat for minor expansion of the well pad and clearing of narrow pathways to allow truck-mounted drilling-rig access for the 66 seismic shot holes and 3 shallow groundwater monitoring wells; (2) transporting of 75 truckloads of CO_2 over 79.2 km (49.1 mi) of public roads through commercial, industrial, and rural areas; and (3) transporting of 30 truckloads of produced brine and 60 truckloads of drilling mud less than 32 km (<20 mi) over mostly rural roads to permitted disposal wells. Modeling studies suggest that the injected CO_2 is likely to stay within the injection zone and migrate less than 200 m (<656 ft) from the injection well. Subsurface pressure increases under maximum injection rate scenarios are expected on the basis of modeling to be 35% below fracture-pressure limitations and 22% below pressures that might result in reactivation of nearby growth faults. Monitoring of formation pressure, temperature, and near-well-bore CO_2 saturation will continue until changes become minimal, indicating significant stabilization of the subsurface physical environment. This stabilization is anticipated to occur less than 1 year after the end of injection.

Table 1. Project team.

Participant	Responsibility	Objective(s)
Bureau of Economic Geology (BEG), The University of Texas at Austin	Prime contractor. Coordination and reporting of all activities. Subsurface characterization.	Improve understanding of subsurface behavior and fate of injected CO_2.
Texas American Resources Company (TARC)	Operator of existing well and lessee of subsurface minerals.	Facilitate demonstration of additional uses for mature oil and gas fields.
Lawrence Berkeley National Laboratory (LBNL)	Model-predicted subsurfacace results. Seismic monitoring. Pressure transient testing. Noble gas tracacer modeling and monitoring.	Optimize flow-modeling software for geologic sequestration. Demonstrate use of seismic to monitor CO_2 plume.
Lawrence Livermore National Laboratory (LLNL)	Tracer geochemical modeling.	Demonstrate use of tracers in monitoring of CO_2 migration.
Oak Ridge National Laboratory (ORNL)	Tracer tests. Stable isotope and perfluorocarbon geochemistry.	Demonstrate use of introduced tracers and naturally occurring isotopes in monitoring of CO_2 migration.
National Energy Technology Laboratory (NETL)	Perfluorocarbon tracer geochemistry, surface monitoring.	Demonstrate use of tracers in monitoring of CO_2 migration.
Alberta Research Council (ARC)	Geochemical sampling plan.	Advise on basis of past subsurface experience.
Sandia Technologies, LLC	Field-services engineering, safety, oversight, and coordination.	Apply experience in deep injection of wastes to CO_2 sequestration.
W.A. Flanders, Transpetco Engineering of the Southwest, Inc.	Injection: engineering and oversight.	Apply CO_2 EOR engineering to sequestration projects.
BP	Industry advisor. Supplier of CO_2 from Texas City refinery through Praxair.	Advise on the basis of CCP JIP experience. Explore sequestration options.
Schlumberger	Industry sponsor.	Support sequestration projects and apply completion and logging techniques to sequestration.
U.S. Department of Energy, National Energy Technology Laboratory (NETL)	Project sponsor.	Demonstrate technologies for safe and effective geologic sequestration.

2.5 DOE's Decision

The decision to be made by DOE is whether to commit 100% of the $2,509,215 required to conduct the field experiment activities of the "Optimal Geological Environments for Carbon Dioxide Disposal in Brine Formations (Saline Aquifers) in the United States—Pilot Experiment in the Frio Formation, Houston Area" project in Liberty County, Texas.

3.0 ALTERNATIVES, INCLUDING PROPOSED ACTION

3.1 Overview

DOE's need for a comprehensively monitored CO_2 injection experiment could be satisfied in several ways, one of which—the proposed action—is preferable. The proposed activity is set in an oilfield, where drilling and other subsurface activities have occurred for many decades and which are familiar to the community, where well-work-over and maintenance companies are headquartered, where a mature oilfield setting provides abundant subsurface data, and where many well bores are idle and, thus, potentially available for injection or monitoring activities. The short duration (less than 1year) of field activities will minimally impact the environment and community but will return maximum amounts of scientific data needed to assess the feasibility of geologic sequestration.

Alternatives to the proposed action include: (1) conducting the same experiment at another field site in the same sedimentary basin, (2) conducting the experiment in another geographic area (different sedimentary basin), and (3) conducting the experiment in an oil- or gas-bearing interval. All are reasonable alternatives, but for various reasons are less attractive from an operational, scientific, or long-term DOE need perspective.

3.2 Proposed Action

The proposed action is for the U.S. Department of Energy (DOE) to provide funding to the team led by the Texas Bureau of Economic Geology (BEG) at the the Univeristy of Texas at Austin to prepare the site, modify two existing wells, drill a new injection well, conduct preinjection baseline monitoring and testing using numerous tools, inject 3750 metric tons of CO_2 over a period of less than 60 days, conduct numerous monitoring activities during and after the injection, monitor until subsurace conditions begin to stablize (expected within nine months of injection), and close and resore the site. The entire project will be completed in two years.

3.3 Overview and Project Plan

The bulk of the time associated with the 2-year-long proposed action will consist of office activities such as geologic interpretation, engineering design, procedure planning, post-experiment analysis, and publication and presentation of results. Minimal time, amounting to perhaps 7 months, will consist of field activities with potential environmental and social impacts, followed by low-impact monitoring activities. Table 2 provides a milestone description, work breakdown structure, and timeline for the experiment. The timeline is based upon completion of NEPA review during May 2003 and depends upon State regulatory approval, CO_2 availability, favorable weather, and drilling-rig availability. Site characterization and planning began in 2002. Review by two State agencies, the Railroad Commission of Texas (RRC—petroleum resource protection) and the Texas Commission on Environmental Quality (TCEQ—groundwater protection, engineering review) will commence in the first months of 2003, and field activities will begin in May 2003. Two existing wells will be modified as monitoring wells and a new injection well will be drilled during the summer of 2003. The injection event will occur in a window between October 2003 and December 2003, with exact timing dependent upon seasonal availability of compressed food-grade CO_2 and other logistical considerations. Postinjection tests, analyses, and synthesis of results will continue through June 2004. Documentation and presentation of project results will begin in May 2004. The project is scheduled to be completed in September 2004. Site closure and restoration could begin as early as January 2004 and will be completed by September 2004.

Table 2. Milestone description and work breakdown structure.

Description*	Initiation date**	Completion date**
Task 1 – NEPA Review, Approval, and Permitting		
1. Prepare and submit Environmental Assessment	9/2002	4/2003
2. Prepare and submit UIC Class V application to TCEQ	2/2003	5/2003
3. Secure NEPA review and approval	4/2003	5/2003
4. Secure TCEQ review and approval	5/2003	6/2003
Task 2 – Pre-Field Mobilization Characterization		
1. Conduct geologic characterization of field site	3/2002	8/2002
2. Design geochemical sampling and tracer programs	6/2002	3/2003
3. Computer-simulate CO_2 subsurface behavior	6/2002	3/2003
4. Design geophysical monitoring program	6/2002	3/2003
5. Design optimal field procedure and engineering plans	6/2002	3/2003
6. Develop safety plan and training schedule	4/2003	5/2003
Task 3 – Preinjection Field Activities		
1. Prepare site	6/2003	7/2003
2. Prepare monitor wells	6/2003	7/2003
3. Drill and complete injection well	6/2003	7/2003
4. Conduct baseline geophysical survey, fluid sampling	7/2003	7/2003
5. Conduct pressure-transient test	7/2003	9/2003
Task 4 – CO_2 Injection Experiment		
1. Implement safety plan	7/2003	7/2003
2. Install CO_2 storage and injection equipment	9/2003	10/2003
3. Inject CO_2	10/2003	12/2003
4. Perform postinjection testing	1/2004	9/2004
5. Analyze and interpret results	1/2004	4/2004
6. Site closure and restoration	1/2004	9/2004
6. Synthesize observations and results	4/2004	6/2004
7. Project final reporting and technology transfer	5/2004	9/2004
* Tasks condensed from contract modification A008		
** Tentative dates, based on start of field activities in June 2003,contingent upon completion of the NEPA review, State regulatory approval, CO_2 availability, weather conditions, and rig availability.		

3.3.1 Preinjection Activities

Analysis of geologic and geophysical data acquired to characterize the site will be conducted at the Bureau of Economic Geology (BEG) in Austin, Texas (table 3). Activities include literature review, computer workstation use, and limited transportation to and from offices of team members and the field site. Geochemical tracer design, geophysical monitoring design, simulation of CO_2 subsurface behavior, and field planning/engineering design will require similar activities at Oak Ridge National Laboratory (ORNL) in Oak Ridge, Tennessee; Lawrence Berkeley National Laboratory (LBNL) in Berkeley, California; Lawrence Livermore National Laboratory (LLNL) in Livermore, California; National Energy Technology Laboratory (NETL) in Pittsburgh, Pennsylvania and Morgantown West Virgina; Alberta Research Council (ARC) in Calgary, Alberta, Canada; and Sandia Technologies, LLC in Houston, Texas. Project planning, data collection, engineering design, and administrative support will take place in Texas American Resources Company offices in Austin and Houston, Texas. Log engineering design and data interpretation will occur in the Ridgefield, Connecticut, offices of Schlumberger-Doll Research. Field-support services (well logging) will originate from the Schlumberger Oilfield Services office in Liberty, Texas, approximately 11.25 km (7 mi) from the field site. BEG's Houston Core Research Center (1611 West Little York Road, Houston, Texas) will serve as a nearby facility during field activities for office work and staging/handling of geochemical samples. BP project advisors will be located in Houston, Texas. The project will be managed from DOE National Energy Technology laboratory (NETL) offices in Pittsburgh, Pennsylvania, or Morgantown, West Virginia.

Table 3. Work sites and activities.

Location	Team member	Activity
Dayton, Texas	All	Field activities
Austin, Texas	Bureau of Economic Geology	Office activities
Berkeley, California	Lawrence Berkeley N.L.	Office activities
Livermore, California	Lawrence Livermore N.L.	Office activities
Oak Ridge, Tennessee	Oak Ridge N.L.	Office and laboratory activities
Houston, Texas	Sandia Technologies, LLC	Office activities
Houston, Texas	Bureau of Economic Geology, Houston Core Research Center	Office and laboratory activities
Austin and Houston, Texas	Texas American Resources Company	Office activities
Calgary, Alberta, Canada	Alberta Research Council	Office activities
Ridgefield, Connecticut	Schlumberger-Doll Research	Office activities
Liberty, Texas	Schlumberger Oilfield Services	Office and laboratory activities
Houston, Texas	BP	Office activities
Pittsburgh, Pennsylvania, or Morgantown, West Virginia	NETL	Office and laboratory activities
Texas City, Texas	BP, Praxair	Refinery and gas processing

The field site is located in Liberty County, Texas, about 56 km (35 mi) northeast of Houston (fig. 1), near the town of Dayton. The site lies on a 30 m × 30 m (100 ft × 100 ft) clearing within a low-relief upland area dominated by small deciduous trees and is 400 m (1,312 ft) west of wetlands of the Trinity River floodplain margin (figs. 2, 3). The area has been an active oilfield from 1951 to present and is sparsely populated. Residential neighborhoods have been developed over the past 2 decades to the north, southwest, and south of the site (fig. 2), but no residences lie within 0.5 km (0.3 mi) of the site. Approximately 250 land blocks within 2 km (3.2 mi) of the site are platted for residences. Intermittent logging has occurred in the vicinity for decades; an idle lumber mill lies about 0.4 km (0.25 mi) north of the site. The area west of highway FM 1409 (fig. 2) is primarily agricultural. The project will impact less than 2 additional hectares (5 acres) within an oilfield where oil and gas activities have impacted 6,980 hectares (17,280 acres). State and Federal records indicate no known archeological sites or endangered species at or near the site. Groundwater is within a few meters of the ground surface.

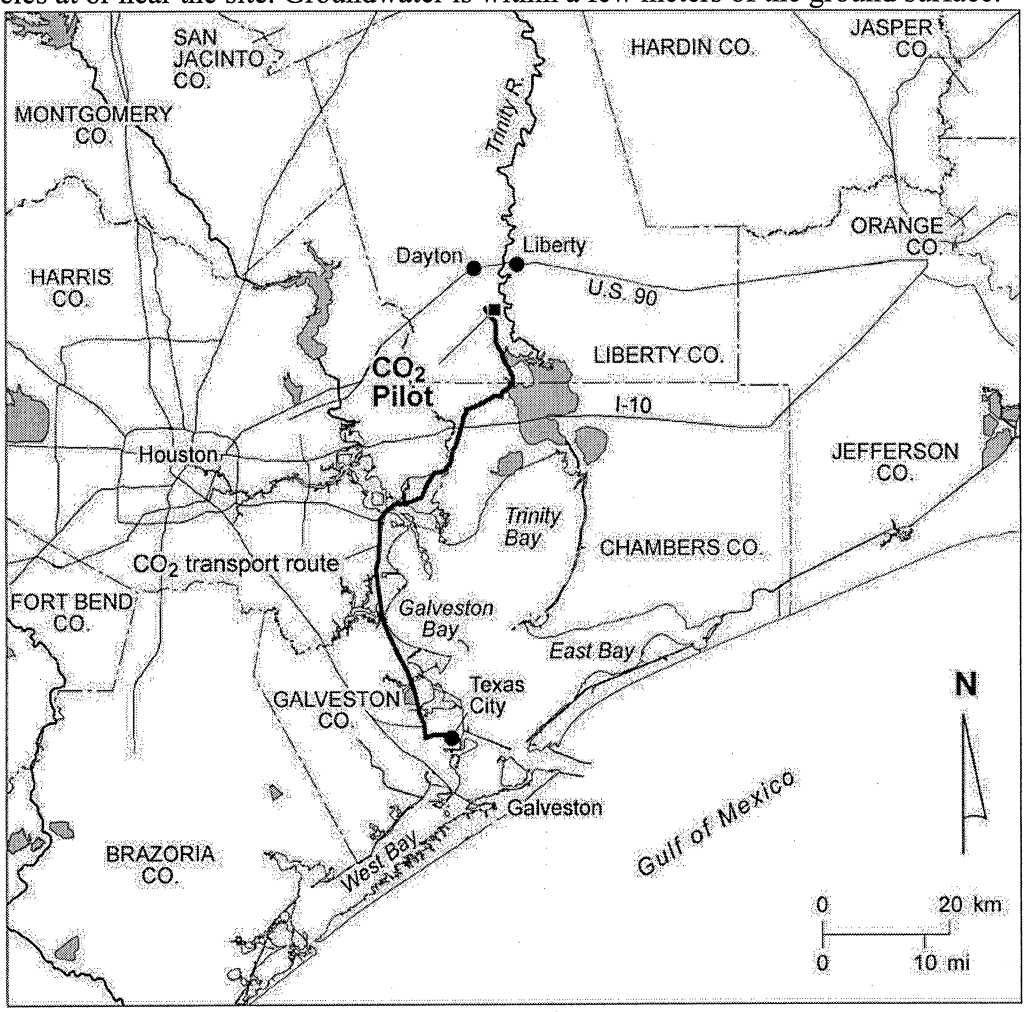


Figure 1. Map of the southeast Texas coastal region showing the location of the CO_2 pilot project, including the transportation route.

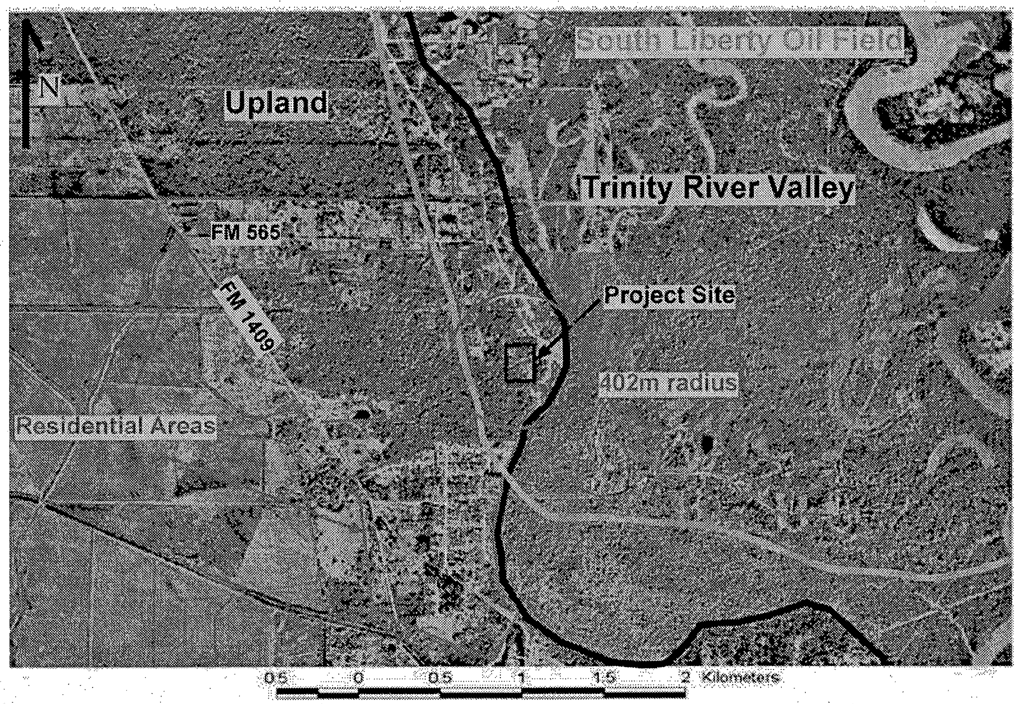


Figure 2. Aerial photograph of the area surrounding the project site showing major land features, roads, residential areas, the South Liberty oilfield outline, and the 402 m (0.25 mi) radius of the Area of Review. Aerial photo base modified from Texas Natural Resources Information System.

Site preparation will include improving about 1 km (~0.6 mi) of unpaved lease road by adding road base and grading and incrementally expanding one well pad, which will require clearing of no more than 0.4 hectares (1 acre) of vegetation. Expansion of the well pad and associated loss of vegetation has been minimized by additional expenditures to directionally drill the injection well from the margin of an existing pad, instead of clearing a new pad and building an access road within the vegetated upland.

Soil gas, pore water, and shallow groundwater will be sampled and analyzed prior to CO_2 injection to establish background CO_2 concentrations. Because background values vary seasonally with changes in biologic activity, a sample grid will be established and resampled over several months before and after injection. These points will also be monitored throughout the injection and postinjection phases. Shallow auger holes will be used to sample soil gas. Three shallow water wells will be drilled to sample groundwater following TCEQ monitoring well protocols.

Two existing wells, Sun-Gulf-Humble #4 and #3 (SGH 4, SGH 3, figs. 2, 3) will be converted to monitoring wells, requiring mobilization of a truck-mounted work-over rig to the well pad along lease roads. SGH 4 is the primary monitoring well; the new injection well will be drilled 30 m (100 ft) south of SGH 4. SGH 3 is 135 m (440 ft) southeast of SGH 4. Minor modifications will be made to this well to facilitate limited plume monitoring. Standard oilfield techniques will be implemented to determine casing condition, cement the well-bore annulus in the injection zone, and perforate that same zone to prepare for monitoring. These activities will occur at depth, within the saline aquifer, well below and isolated from potentially potable groundwater.

Standard oilfield techniques and equipment will be employed to drill and complete an injection well on the same pad as SGH 4 (fig. 2). A shallow drilling-mud pit will be constructed adjacent to the well pad and lined in accordance with TCEQ requirements to prevent subsurface infiltration. The drilling mud will be water based. The volume of well cuttings (natural earth materials extracted during well drilling) is estimated to be 400 m^3 (550 yd^3). Cuttings will be buried on site as municipal solid waste in accordance with Texas Administrative Code Chapter 330. Drilling fluids, estimated to be less than 7,000 barrels, will be trucked to an RRC-authorized disposal well within 48 km (30 mi) of the project site. The new well will be cemented and perforated according to oil-industry standards. Minor amounts of excess nonhazardous material and debris will be removed from the site to a municipal landfill.

Newly established perforations in the injection well and monitor well will undergo a Mechanical Integrity Test (MIT) to verify casing-to-formation bond and ensure that injected materials will escape from the intended zone through the well annulus. Part of the routine MIT involves injection into the perforated zone at 1,500 m (5,000 ft) depth of 20 cc of ^{131}I solution containing a total of 20 millicurries of radiation. This isotope has an 8-day half-life. The wells will sit idle for at least 2 weeks before production or injection of fluids begins, preventing return of hazardous levels of radioactivity to the surface. Radioactivity of produced fluids will be tested to assure that exposure levels conform to acceptable levels in Article 213 of the DOE Radiological Control Manual.

A series of extraction and injection tests will be conducted to evaluate subsurface fluid characteristics and pressure response within the injection interval. Brine produced during each pumping test, equaling no more than 3,000 barrels (351 m^3), will be sampled, temporarily stored on site, then reinjected with a groundwater tracer into the original well in a subsequent injection test.

Two baseline geophysical surveys, a crosswell seismic survey and a 3-D vertical seismic profile (VSP), will be conducted before injecting of CO_2. The crosswell survey will consist of a downhole seismic source (high-frequency oscillating) in the SGH 4 monitoring well and seismic detectors placed in the injection well. The 3-D VSP will employ a surface seismic source and the injection-well detectors. As many as 66 18-m-deep (60-ft) shot holes will be drilled along four lines passing through the injection well and extending up to 400 m (1,312 ft) from the well (see Direct Effects section). A small jeep-mounted rig will be used to drill the shot holes near existing lease roads wherever possible, impacting less than 0.8 hectares (<2 acres). A maximum charge of 1.5 kg (3 lb) of biodegradable explosive (Dynoseis, consisting of sodium perchlorate and diethylene glycol [MSDS in Appendix A]) will produce the seismic energy for the survey. After detonation, shot holes will be filled with soil and the area compacted.

A

B

Figure 3. Photographs of the planned project site. (A) View, looking north, of well pad where existing monitor well SHG #4 is located. New well will be drilled on a southward extension of this pad. (B) View, looking northwest, of well pad where existing monitoring well SHG #3 is located—the two water-storage tanks visible were used when the well was a salt-water disposal well.

3.3.2 Injection Activities

A maximum of 3,750 tons (71.2 MMcf) of CO_2 will be injected intermittently into the subsurface over a maximum period of 60 days at rates not exceeding about 8.5 tons/hr (161 Mcf/hr). Downhole pressure increases will not exceed 116.4 bar (1,688 psi). This pressure is established by TCEQ regulation and is about 7 bar (100 psi) below the calculated fracture pressure of the formation. TCEQ regulations also require that pressure increases within the 402-m (one-quarter-mi) radius area of review (AOR) not exceed a calculated value of 11.4 bar (165 psi), assuming a hydraulic gradient of 0.098 bar/m (0.433 psi/ft). Flow simulations by LBNL using TOUGH2 (Pruess and others, 1999; Hovorka and others, 2001) and formation-specific petrophysical properties calculated pressure response under proposed injection rates and durations. Figure 4 is a map view of the modeled pressure increase for a conservative scenario; it assumes that a slightly larger volume of 5,000 tonnes, rather than the 3,750 tonnes planned, is injected at the maximum rate over 20 days. The northeast, northwest, and southeast model boundaries are faulted and considered no-flow boundaries. The southwest boundary is open (unfaulted) and allows pressure dissipation. Maximum pressure increase at the injection well is 20.8 bar (304 psi), less than 20% of the regulated limit. Maximum pressure increase within the fault block at 402 m (0.25 mi) from the well is less than 6 bar (<87 psi), about half of the regulated limit. Subsequent models to be constructed before injection will be refined to include more detailed geologic information from an existing 3-D seismic volume, hydrologic tests of the injection formation, and information from core and log data in the new injection well. These model refinements, combined with pressure monitoring during injection, will ensure that the experiment is performed within regulatory requirements.

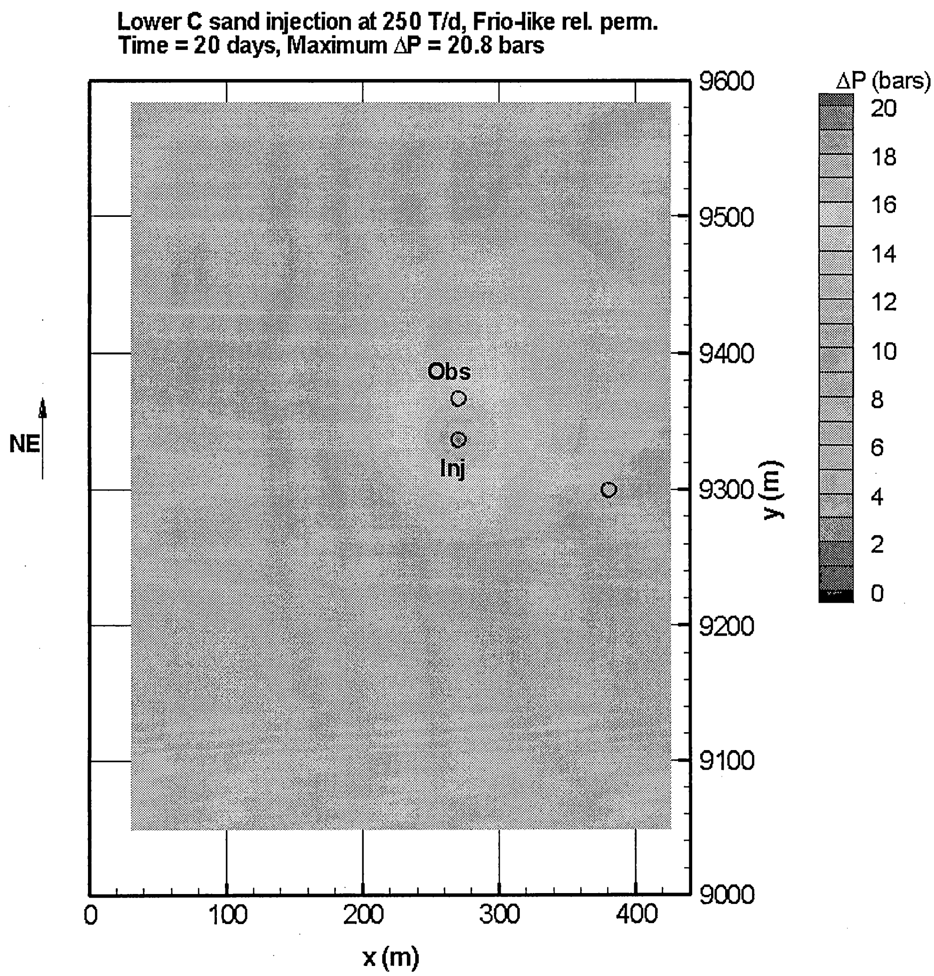


Figure 4. Map-view results of Tough2 numerical simulation showing incremental pressure increases in the injection interval after 20 days of injecting 250 tonnes per day. Note that the total injection volume modeled is 5,000 tonnes, more than the proposed 3,750 tonnes, to investigate upper limits of pressure increase, here calculated to be 20.8 bars (304 psi).

CO_2 for injection will be delivered to the site by commercial truck and temporarily stored in a 1,000-barrel pressure tank placed on a 6 ×24 m (20 ×80 ft) concrete pad. The CO_2, at 15 bar (220 psig) and –19°C (–3°F), will be compressed prior to injection by a pad- or skid-mounted pump taking up a space no more than 3 ×6 m (10 ×20 ft). Both the tank and pump will be removed following injection.

The injection of CO_2 will be suspended several times during the experiment to allow for downhole logging, sampling, and geophysical measurements. During these suspensions, produced formation brine will be injected to prevent return of CO_2 gases to the surface through the well bore. Standard oilfield procedures will be used to log and sample the well. 3-D VSP surveys will be repeated during injection to monitor CO_2 plume behavior.

The focal point of the proposed activity is monitoring of the injected CO_2 to understand its subsurface flow paths. Formation temperature and pressure will be recorded nearly constantly to determine formation response. Additionally, tracers will be injected with the CO_2 in minor amounts, and both the injection and monitoring wells will be sampled to identify the tracer and CO_2 concentrations. Geochemical tracer techniques will include (1) isotopic profiles of injected CO_2, (2) introduced noble gases, and (3) introduced perfluorocarbons. A maximum of 3,000 barrels of fluid in one monitoring well (SGH 4) will be produced by nitrogen lift during the injection period to monitor tracer and CO_2 concentration. These fluids will not be reinjected in the formation because of their potential to interfere with long-term monitoring. They will be trucked to a TCEQ-permitted UIC Class 1 nonhazardous well within 32 km (20 mi) of the site and disposed of into a subsurface formation.

3.3.3 Postinjection Activities

Following CO_2 injection, downhole fluid samples will be taken from the injection zone and the immediately overlying zone in both the injection well and primary monitoring well (SGH 4). Purging of the well bore to obtain fresh samples from the formation may yield up to 172 barrels of formation brine, which will be transported to a TCEQ-permitted disposal well.

The existing completions will remain open in the injection and monitoring wells for a period anticipated to be less than 1 year to allow extended monitoring. Monitoring will include pressure and temperature measurements and perhaps other activities that may include well logging, crosswell or surface seismic surveys, or geochemical sampling and analyses. Monitoring of CO_2 in the wells will decrease in frequency as changes in pressures and concentrations become minimal, indicating significant stabilization of the subsurface physical environment. This stabilization is anticipated to occur less than 1 year after the end of injection. Shallow-groundwater dissolved gas and soil-gas concentrations will be monitored throughout this time at sample points established during preinjection field activities. Impacts of surface seismic surveys and geochemical sampling (waste formation brine) will be treated as previously described.

Following the completion of downhole logging and sampling, the injection and monitoring zone perforations will be plugged by cement following standard oil-industry practices. The wells will either be plugged and abandoned according to RRC rules or converted to a use approved by the appropriate agency.

Other postinjection activities will include additional office work to analyze and interpret results at the various team members sites (Table 3). Results and interpretations will be synthesized by the Bureau of Economic Geology, and a final project report prepared. Technology transfer to interested parties will continue sporadically until project completion in September, 2004.

3.4 Enabled Actions

NETL will add text here

3.5 Range of Reasonable Alternatives

The proposed experiment is the culmination of 3 years of research effort in geologic sequestration in brine-bearing formations. That research progressively identified the ideal pilot setting. Reasonable alternatives, including the no-action option, are listed in table 4, along with comments on limitations of each. Alternatives range from siting the experiment in an adjacent area to conducting it in a hydrocarbon-bearing formation.

Table 4. Comparison of possible alternative actions

Alternatives	**Comments**
Alternate location in same basin	Need oilfield setting. Would need to find other operators willing to host experiment and supply data.
Injection in a different basin	Other large basins having significant CO_2 sources needing sequestration have limited subsurface data and service-industry infrastructure.
Injection in an oil or gas reservoir	Presence of hydrocarbons in even minor concentrations interferes with critical fluid flow characteristics and rock-water interactions being investigated.
No action	Large-scale sequestration efforts suffer increased risks or substantial delays, reducing U.S. options for climate change mitigation.

Considering the nomination of the Frio Formation in the upper Texas Gulf Coast as a programmatically advantageous setting, one ready alternative would be to conduct the experiment in another area of dense subsurface control, perhaps closer to a major CO_2 source. The small fault blocks associated with salt domes in this basin provide significant benefits by providing a more closed compartment. Small volumes of injected material have a larger pressure response because the pressure is not as rapidly dispersed by an unnecessarily large pore volume. Similarly, flanks of salt domes commonly have steeper dips, accentuating the response of the buoyant injected CO_2 plume to the effects of gravity—a key parameter being evaluated. There are many salt-dome settings in this area, but the proposed location is the only one in which an operator was located who was interested in hosting the experiment and providing access to idle wells.

Many other basins exist across the U.S. that contain formations suited to sequestration (Hovorka and others, 2000). Few of these basins, however, combine a high concentration of CO_2 sources with the abundance of subsurface data available in the form of well logs and 3-D seismic data. Fewer still have a robust well-servicing industry, which reduces experiment cost through a competitive business climate and relatively low mobilization costs.

Another alternative is to conduct the experiment in the same basin as that proposed but use existing infrastructure and completed wells in an oil or gas reservoir. This option would reduce well-construction costs and potentially add value by enhancing hydrocarbon production as result of the injection. Other such projects are under way, but the daily activity in such settings makes detailed scientific monitoring difficult. The background electromagnetic and seismic noise reduces the achievable resolution of geophysical surveys. Additionally, experiments require periods in which wells are idle, resulting in loss of revenue for producers. Most important, the presence of hydrocarbons substantially affects CO_2 sorption, pressure response, and flow processes that are the objectives of the project. The presence of a native gas phase in the formation significantly increases the compressibility of the formation fluid, making response to injection difficult to predict and interpret. The presence of oil in the formation fluid complicates multiphase flow effects.

3.5.1 The No-Action Alternative

No action, meaning that the proposed project is not carried out in any setting, would delay planned larger-scale sequestration pilots by perhaps several years. The increased understanding of subsurface behavior of CO_2 would not be gained, nor could an example of successful and safe sequestration, on any scale, be offered to the public in support of a larger, more expensive project. The complexities of a larger pilot might translate to long delays in public and regulatory approval, thereby jeopardizing goals of rapid action on climate change issues. A 3-year delay in initiating large-scale sequestration efforts would increase CO_2 emissions by approximately 5% and atmospheric concentrations of CO_2 would increase by as much as 6 ppm before any stabilization effort would be started.

4.0 AFFECTED ENVIRONMENT AND THE ENVIRONMENTAL CONSEQUENCES OF THE PROPOSED ACTION

4.1 Site Description

The experiment is planned for South Liberty field in southern Liberty County, Texas, a largely rural county with an estimated population of 72,620 in 2001 (U.S. Census Bureau, 2001). The site is located on an upland adjacent to the Trinity River valley on the coastal-plain physiographic province. The site and the immediately surrounding area are within an oilfield that have been active since 1951 and are sparsely populated. Low-density residential neighborhoods have been developed over the past 2 decades to the north, southwest, and south (fig. 2) of the site. No residences lie within 0.5 km (0.3 mi) of the site. Approximately 250 land blocks within 2 km (1.25 mi) of the site are platted for residences. Timber has been harvested sporadically in the vicinity for many decades; an idle lumber mill is located about 0.4 km (0.25 mi) north of the site. The area west of highway FM 1409 (fig. 2) has historically been used for agriculture.

The project site is about 25 km (~15.5 mi) upstream of Trinity Bay, 65 km (40.3 mi) inland from the Gulf of Mexico, 60 km (37 mi) northeast of downtown Houston (fig. 1), and nearest the small communities of Dayton (7.5 km, or 4.5 mi, to the northwest) and Liberty (9 km, or 5.5 mi, to the northeast). Liberty County is on the northeast margin of the heavily populated Houston metropolitan area. Harris County, home of most of Houston's citizens, had an estimated 2001 population of 3,460,589; populations estimated for adjacent counties within the regional impact area are 255,865 for Galveston County and 26,859 for Chambers County (U.S. Census Bureau, 2001).

4.1.1 Field History

South Liberty field was discovered in 1925. The first commercial production was from the Oligocene Frio Formation shallow on the east flank of a piercement salt dome, and a significant drilling boom followed (Halbouty, 1962). Attention was drawn to the area in 1901 by surface shows of sulfur, oil, and gas, and by the discovery of Spindletop Dome. South Liberty cumulative oil production for 1925 was 4,416,000 barrels of oil. Production steadily declined through the mid 1940's, but discoveries of oil in the deeper Eocene Yegua and Cockfield Formations on all flanks of the dome in 1948 and 1949 reinvigorated the field (Halbouty, 1962). A large number of the wells in the pilot area were drilled in 1950 and 1951 as a new drilling boom spread. Annual production peaked at 5,271,847 barrels in 1958 and has been gradually declining since then. Annual production for 2001 was 253,000 barrels of oil and 437 million ft^3 of gas (Railroad Commission of Texas, 2002).

No production has been found over the top of the dome (caprock area), where salt rises to within 84 m (275 ft) of the surface (Halbouty, 1962). According to a Texas Railroad Commission database, there are 654 wells in South Liberty field (fig. 5). About 55 leases are currently producing (there may be multiple oil wells per lease, but only one gas well per lease), with a large number of wells, perhaps several hundred, standing idle.

From January 1, 1998, through January 1, 2003, 11 wells have been permitted within the field, all on the east and north flanks of the dome, with at least 5 of those permits granted in 2002. Exploration for deeper oil or gas objectives continues, as evidenced by the increase in well permits in 2002 and the recent completion of a large 3-dimensional seismic reflection survey in the area.

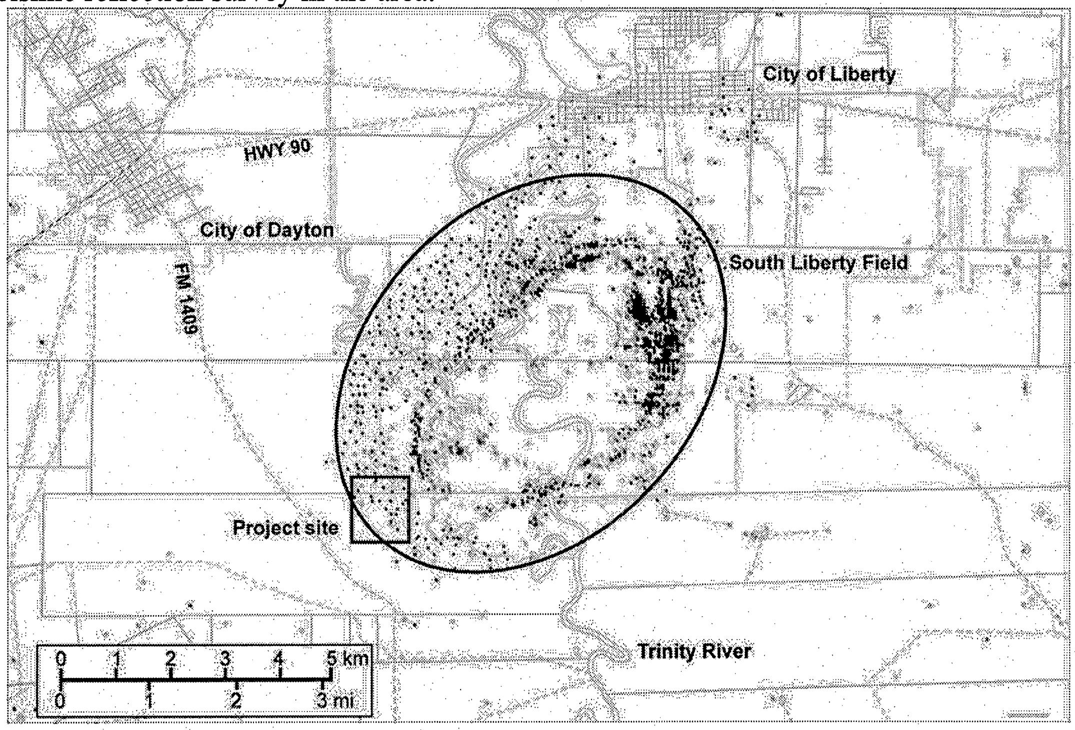


Figure 5. Map of oil and gas wells drilled in South Liberty field and surrounding area. Modified from Railroad Commission of Texas (2002).

4.1.2 Surface Geology and Soils

The proposed new CO_2 injection well and existing monitoring well are located on the Beaumont Formation (Aronow and Barnes, 1982), a Pleistocene fluvial-deltaic depositional system composed of fine sandy channels and interchannel muds. Fisher and others (1972) mapped the site as a heavily to sparsely tree-covered meander-belt sand. The site is about 300 m (~1,000 ft) west of the erosional bluff marking the geomorphic boundary between the Pleistocene upland at surface elevations of about 20 m (~66 ft) above sea level and the floodplain of the Trinity River at elevations of 2 to 6 m (6.6 to 20 ft) above sea level (fig. 6). The main channel of the Trinity River passes about 2,700 m (~1.7 mi) east of the site. Depositional units within the floodplain, mapped as Quaternary alluvium by Aronow and Barnes (1982), include tree-covered meander-belt sand, overbank flood-basin mud, and mud-filled abandoned channels (Fisher and others, 1972).

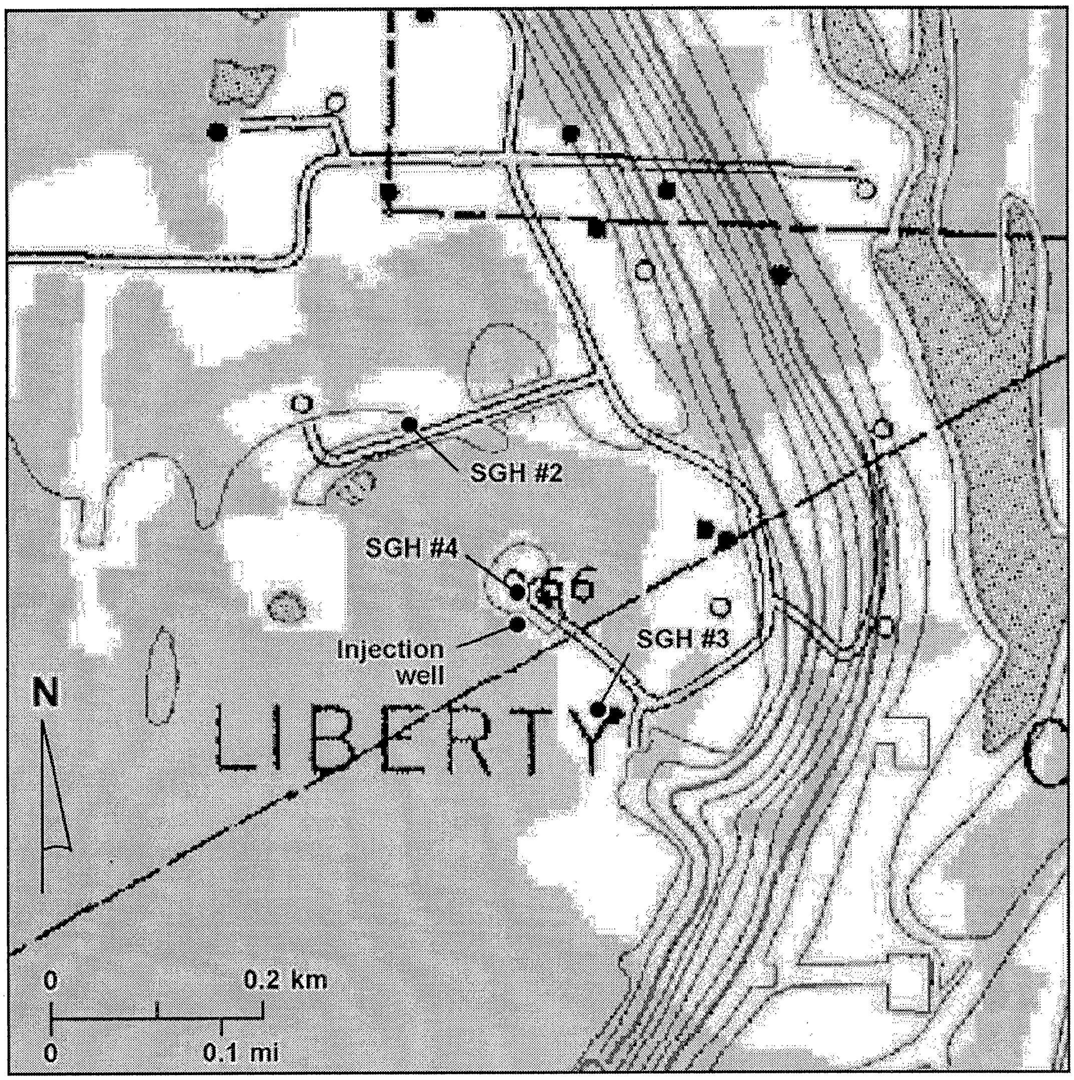


Figure 6. Topographic map of the experiment site showing bluff to east of the site and a small lake (stippled area) within the Trinity River valley. Note also locations of existing wells to be converted to monitor wells, SGH #4 and #3, and location of the new CO_2 injection well, about 30 m (100 ft) south of SGH #4. Gray shading designates vegetated areas. Contour interval is 5 ft. Modified from U.S. Geological Survey Moss Bluff 7.5-minute quadrangle.

The Natural Resources Conservation Service has mapped three soil units at and near the site (U.S. Department of Agriculture, 1996), as shown in figure 7. On the upland is the Aldine-Aris complex, a thick soil with texture ranging from very fine sandy loam to clay (Aldine) and sandy clay loam to clay (Aris). Geologic maps indicate that the dominant soil texture at the site is sandy loam rather than clay. This soil unit is considered to be very slowly permeable and has a high water-holding capacity. The depth to water, where present, is less than 1 m (<3 ft). Organic matter content is 2 percent or less.

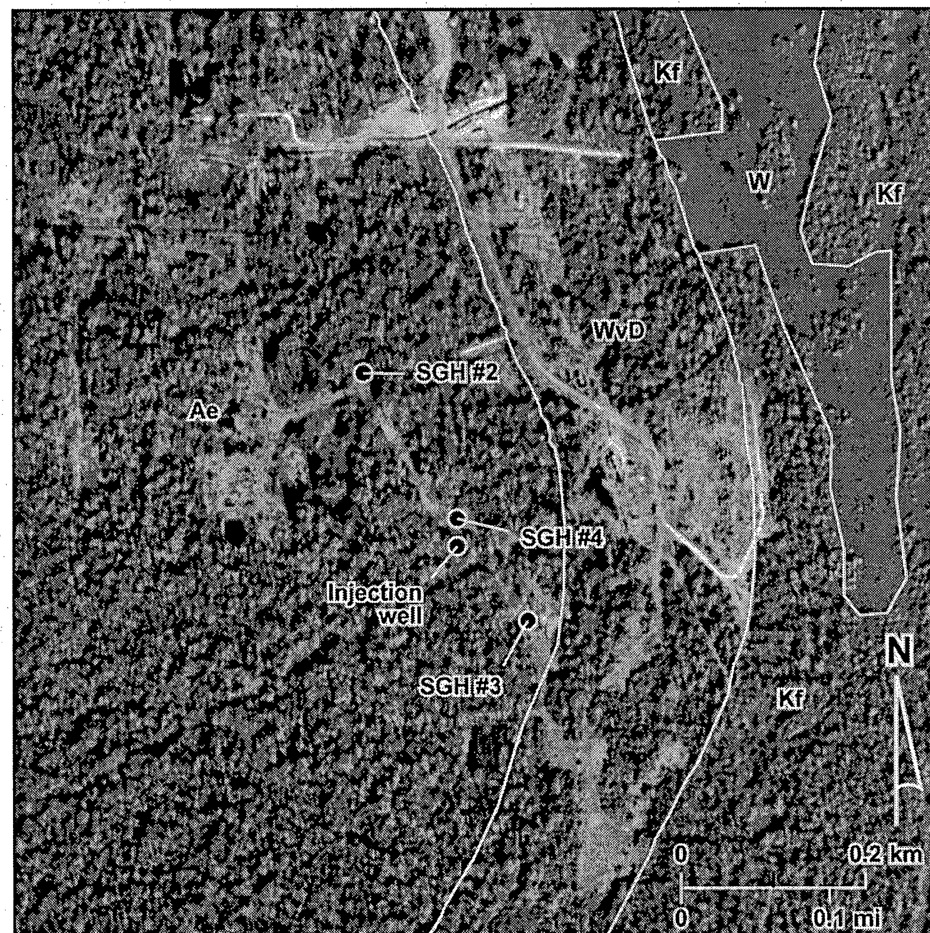


Figure 7. Distribution of soil units at the experiment site. Soil units are those of the Natural Resources Conservation Service (U.S. Department of Agriculture, 1996). W = water; Ae = Aldine-Aris complex; Kf = Kaman clay; and WvD = Woodville fine sandy loam. Aerial photo base modified from Texas Natural Resources Information System.

Soils of the Woodville fine sandy loam are mapped for the bluff separating the upland experiment site and the Trinity floodplain. This soil, with a surface slope of 5 to 8 percent, has a thin sandy surface layer overlying clay substrata. Permeability is classified as very slow; water-holding capacity is high. Depth to water, where present, is 2 m (6.6 ft) or more.

The Trinity floodplain adjacent to the site is classified as either Kaman clay or open water. The Kaman clay is a very deep, wet, and poorly drained unit that is frequently flooded. It is classified as clay to silty clay with organic content of 3 percent or less. It has high water-holding capacity.

4.1.2 Subsurface Geology

The proposed injection will take place in brine-bearing sandstones near the top of the approximately 600-m-thick (~2,000-ft) Oligocene Frio Formation at about 1,500 m

(~5,000 ft) below ground surface, on the southwest flank of the South Liberty salt dome. Hydrocarbon production in this part of the field comes from sandstones of the Eocene-age Yegua/Cockfield and Cook Mountain Formations between 2,500 and 2,750 m (8,200 and 9,000 ft) below ground level (fig. 8). The interval between the production (Yegua/Cockfield) and injection (Frio) formations is a shale-dominated section that includes the Eocene Jackson and Oligocene Vicksburg formations (fig. 8). The Frio is overlain by the 75-m-thick (250-ft) Oligocene Anahuac Shale, which, in turn, is overlain by an approximately 1,300-m-thick (~4,200-ft) interval of Miocene interbedded sandstones and shales (projected from cross sections in Morton and others, 1985). These include, in order of oldest (deepest) to youngest (shallowest), the Oakville (~470 m [~1,500 ft] thick), Fleming (~565 m [~1,850 ft] thick), and Goliad Formations (~245 m [~800 ft] thick). Above these units is the sand-dominated interval extending to the surface and including the Pliocene Willis Formation (~60 m [~200 ft] thick; Galloway and others, 1991; Guevara-Sanchez, 1974), the Pleistocene Lissie (~45 m [~150 ft] thick), and the Beaumont (~25 m [~80 ft] thick; Guevara-Sanchez, 1974) Formations.

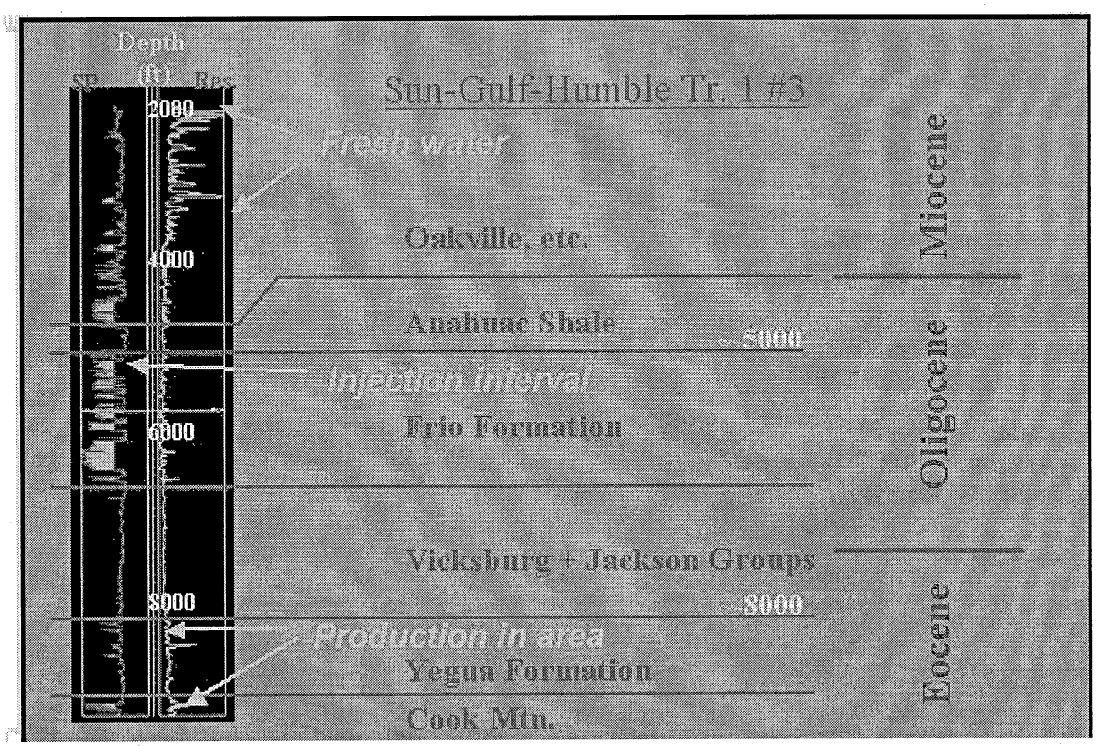


Figure 8. Type log from SGH #3 showing depth to the injection interval, underlying oil and gas production, and fresh-water aquifers substantially above the injection interval.

Typical structure within the central and upper Texas Gulf Coastal Plain dips gently toward the Gulf of Mexico and is cut every few kilometers by northeast-trending, down-to-the-coast growth faults. Along the upper Texas coast (including the study area), the growth-fault pattern is disrupted by numerous salt domes. The pilot area lies on the south flank of the South Liberty salt dome. The Frio Formation dips southerly to slightly southeasterly at high angles (greater than 30°) near the salt-dome flank, decreasing south and west of the pilot location to a dip of less than 5°. The salt flank is cut by a series of normal faults that radiate from the salt dome and typically dip and throw to the west-northwest (fig. 9). Major fault offsets vary from 90 to more than 120 m (300 to >400 ft), decreasing away from the dome as dips flatten. Minor fault offsets detectable with well logs and seismic correlation range from 15 to 45 m (50 to 150 ft), with many of these faults dying out not far south of the pilot area (fig. 9).

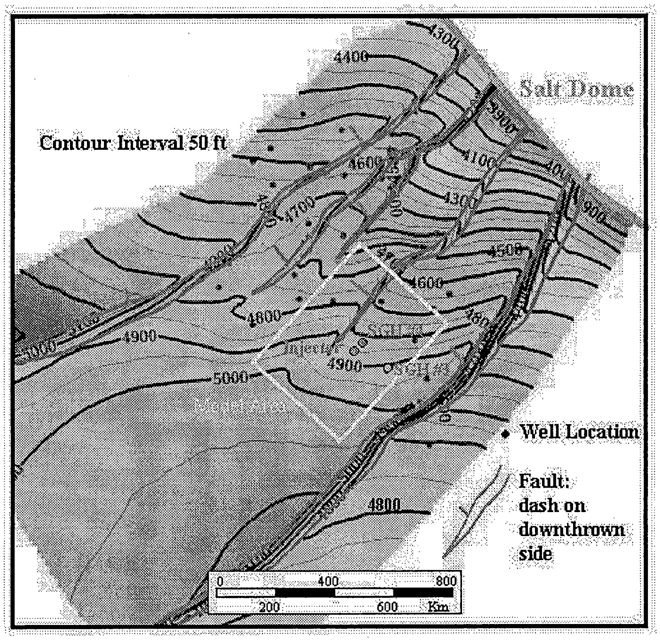


Figure 9. Structure-contour map of the southwest flank of the South Liberty salt dome, showing the relationship of experiment well locations to faults and the edge of the salt dome. White rectangle indicates the extent of the numerical model. Contour interval is 50 ft.

Individual sandstones at the top of the Frio (the injection zone) range from less than 3 to more than 15 m (<10 to >50 ft) thick and are separated by laterally continuous shale beds from 1 to more than 4 m (3 to >15 ft) thick. Sandstones at the project site have been given informal letter designations, "A" being the shallowest (fig. 10). CO_2 will be injected into the thicker "C" sandstone, and both the "C" and "B" sandstones will be monitored for response. Although hydrocarbons have been encountered in the "A" and "B" sandstones in nearby fault blocks adjacent to the salt dome, no indications of hydrocarbons have been found in logs from the "C" sandstone.

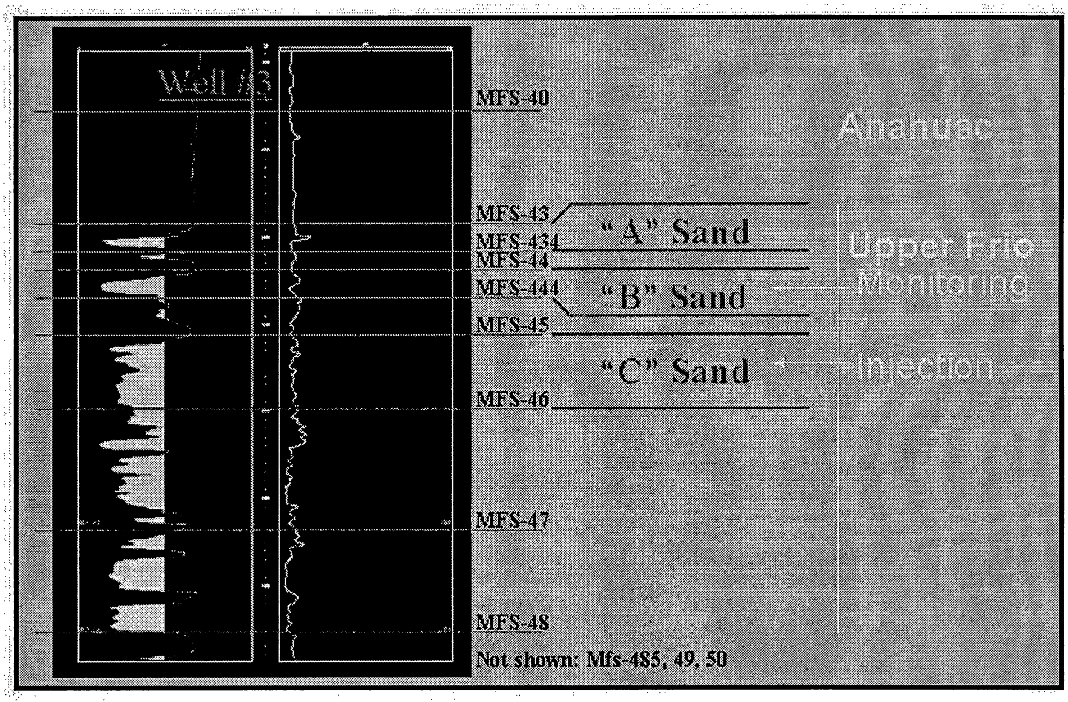


Figure 10. Detailed type log from SGH #3 showing interval nomenclature, correlated horizons (MFS), and sandstones (yellow on SP curve).

Sandstones are generally laterally continuous over 1 km (0.6 mi) or more and were deposited in fluvial and deltaic settings (Galloway and others, 1982). Sandstone framework compositions are dominantly subarkose to lithic arkose, having quartz compositions between 45 and 80 percent (Loucks and others, 1984). Regional formation-water salinity trends (Morton and Land, 1987) and log-derived, site-specific data indicate that these sandstones contain waters with more than 120,000 ppm total dissolved solids. Log-derived porosities range from about 20 to more than 30 percent, averaging about 29 percent. Although no core from the area immediately surrounds the injection site, sandstones with similar log character but deeper depths in a cored well in adjacent Chambers County have permeabilities ranging from 50 millidarcies (md) to several darcies. We anticipate that Frio sandstones in the pilot area will have permeabilities of several hundred to nearly 1,000 md. Permeabilities will have a large impact on pressure response and distribution of the injected CO_2, as will residual gas saturations. On the basis of log-derived porosities and a porosity–residual-saturation relationship derived from the literature (fig. 11), we anticipate residual-gas saturations for the injected CO_2 of approximately 30 percent. Residual saturations could be as low as 5 percent, so this fact is being considered in modeling as an end-member possibility. Pressures and temperatures in the injection interval are expected to be about 151 bar (2,195 psi) and 66° C (151° F) on the basis of regional gradients of 0.099 bar/m (0.439 psi/ft) and 3.32° C/100 m (1.82° F/100 ft). Values will be measured in project wells during initial field activities to verify these estimates.

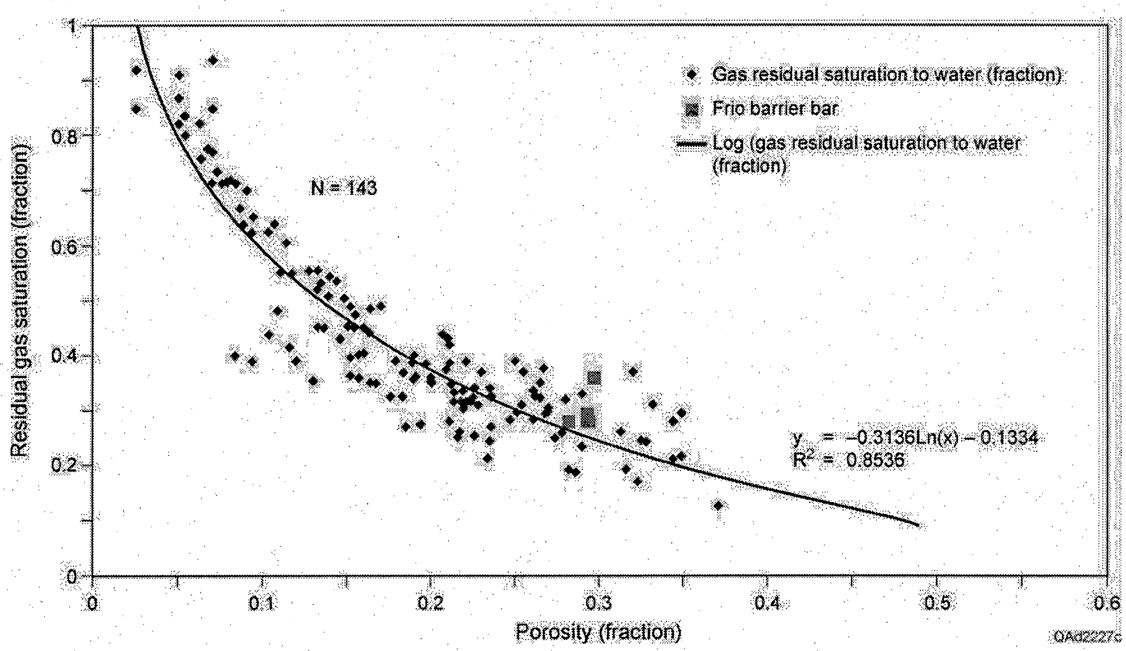


Figure 11. Cross plot of residual gas saturation and porosity for 140 data points collected from the literature and 4 data points from a Frio sandstone core recovered from a well about 32 km (~20 mi) south of the experiment site. The accumulated points indicate a logarithmic relationship with a high correlation coefficient of 0.85.

4.1.3 Groundwater

Fresh-water aquifers in the pilot area include the Alluvium and Beaumont, upper and lower Chicot, and Evangeline Formations (Dutton, 1990). The first and uppermost extends to the base of the Beaumont (see Dutton, 1990). The upper Chicot extends to the upper part of the Lissie, and the lower Chicot includes the remainder of the Lissie and Willis Formations (fig. 12; Carr and others, 1985). The Evangeline aquifer includes the Goliad and the upper part of the Fleming Formation (Dutton, 1990). The base of usable-quality water, defined as containing less than 3,000 mg/L (<3,000 ppm) total dissolved solids (TDS), is at a depth of about 670 m (~2,200 ft) (Baker, 1979). Below the Evangeline aquifer is the Burkeville confining unit near the middle of the Fleming Formation. Below this is the Jasper aquifer, which includes the lower part of the Fleming Formation and the upper part of the Oakville Formation (fig. 12; Baker, 1979). The base of potentially usable-quality water (also referred to as the base of the lowermost USDW), defined by having less than 10,000 mg/L (<10,000 ppm) TDS, is at a depth of about 1,035 m (~3,400 ft). This is about 500 m (~1,600 ft) above the injection zone and is separated from it by more than 75 m (>250 ft) of Anahuac Shale Formation.

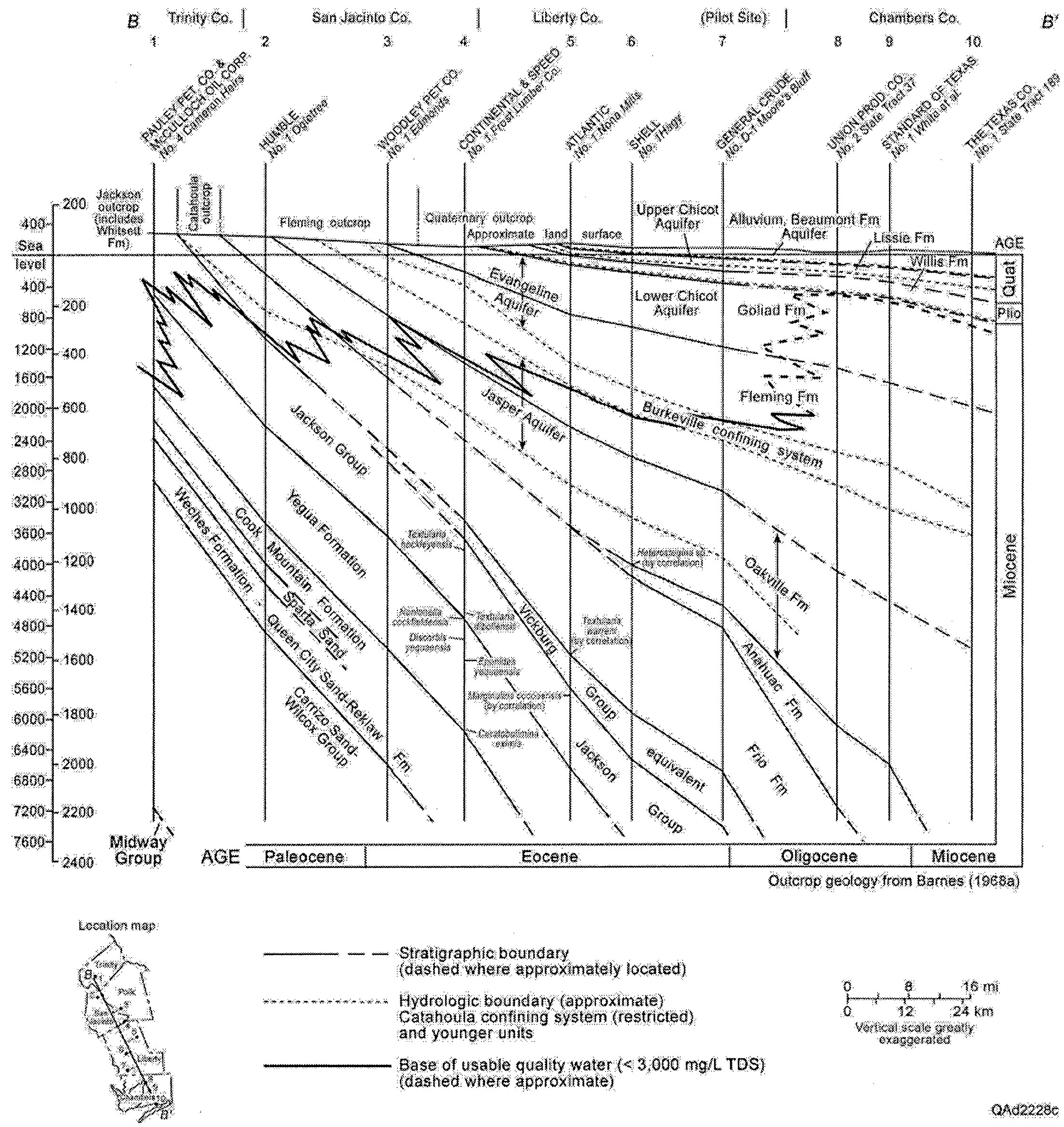


Figure 12. Dip-oriented regional cross section through experiment site showing relationship of stratigraphic units to hydrologic units. Modified from Baker (1979). Some stratigraphy and thicknesses for units above the Anahuac taken from Morton and others (1985), Galloway and others (1991), and Guevara-Sanchez (1974).

Depth to groundwater is uncertain and will be investigated prior to CO_2 injection. The amount of unsaturated section in the shallow subsurface is important because it acts as a buffer if CO_2 were to leak from the deep subsurface (see Potential Leakage Impacts). Saturation profile most likely varies across the site area depending on season, geomorphic position, and surface elevation. Information from mapped soil types suggests that water-saturated soil lies less than 1 m below ground level at the injection and monitoring wells. With the interbedded sand/clay nature of the shallow subsurface, this shallow water is likely to represent a perched water table. The nearest residential water well (well 64-02-102) is located about 1,250 m (~4,100 ft) northwest of the injection well. This well, drilled in 1972 to a depth of 73 m (240 ft), produces water from the Chicot aquifer. Water level in this well bore is 8 m (26 ft) below ground surface. If this aquifer is unconfined in this location, a substantial unsaturated zone could exist. Finally, the level of standing water in the adjacent Trinity River floodplain, commonly about 10m (~30 ft) below the project area, may indicate the approximate top of the saturated zone. Depth to water will be determined during drilling of initial shot holes for seismic acquisition.

4.1.4 Climate

As part of the upper coast climatic province (Bomar, 1983), Liberty County experiences a warm, temperate, and humid climate. In January, historically the coldest month, temperatures range from an average low of 4.9° C (41° F) to an average high of 16.6° C (62° F) (Bomar, 1983). In July, historically the warmest month, temperatures range from an average low of 22.5° C (72° F) to an average high of 34.2° C (94° F) (Bomar, 1983). Temperatures fall below the freezing point of water an average of 11 times each year between the average date of the first freeze (December 6) and the average date of the last freeze (February 15). Recorded temperature extremes are a low of –15° C (5° F) in January 1940 and a high of 41.7° C (107° F) in August 1980.

Average wind vectors are from the north-northwest at 13 km/hr (8 mi/hr) in January, from the south-southeast at 14 km/hr (8.7 mi/hr) in April, from the south at 11 km/hr (6.8 mi/hr) in June, and from the east-southeast at 10 km/hr (6.2 mi/hr) in October (Bomar, 1983). Highest wind speeds occur during the approach and passage of cold fronts, which are most common from October through March. Extreme weather conditions are associated with the occasional tropical storm, which brings torrential rains, high, sustained winds, and tornadoes to the area. Hurricane season begins on June 1 and ends on December 1. Tropical storms are most common in the months of June, August, and September.

Average annual rainfall in the Houston area is 114 cm/yr (44.5 in/yr) (Bomar, 1983). The months of May and September have the highest historical rainfall averages.

4.1.5 Access

The experiment site is located on existing well sites accessed using privately owned lease roads in the active South Liberty Oilfield. Access to the field is from Texas Farm-to-Market Road 1409 between Dayton, where FM 1409 intersects U.S. Highway 90, and Mont Belvieu. The major transportation routes in this area are Interstate Highway 10, which passes about 15 km (~9.3 mi) south of the site, and U.S. 90, which passes about 7 km (~4.3 mi) north of the site. At its nearest point, FM 1409 is about 1.3 km (~0.8 mi) southwest of the experiment site.

The planned transport route for trucks carrying CO_2 for injection at the site (fig. 1) will be from the supply plant in Texas City (Galveston County) onto Texas 146. This major state highway passes through the cities of Texas City and Kemah in Galveston County, Seabrook, La Porte, and Baytown in Harris County, and Mont Belvieu in Chambers County for a cumulative route distance of 55 km (34 mi). At Mont Belvieu, the route turns east onto Loop 207 for 1.3 km (0.8 mi) before turning east again onto FM 565 for a distance of 6 km (3.7 mi) to the intersection with FM 1409. The route turns north onto FM 1409 and continues to the lease road entrance 16.9 km (10.5 mi) from the intersection with FM 565. Total distance from plant to site is 79.2 km (49.1 mi).

4.1.5 Historical and Archeological Resources

The Texas Archeological Research Laboratory (TARL), The University of Texas at Austin, is the curator of archeological and historical sites for the State of Texas. Upon review of site maps and the location of the proposed experiment, TARL staff determined that "within one kilometer (0.6 mi) of the proposed delineated project area, there are no recorded archeological or historical sites. No sites are registered as State Archeological Landmarks or are listed in the National Register of Historic Places." Copies of the review request, accompanying site maps, and the determination response letter are included in Appendix B. The areas of the drilling pad, mud pit, and seismic shot lines will be surveyed by project archeologists before site work begins.

4.1.6 Endangered Species

Staff from the Clear Lake Ecological Services Field Office of the U.S. Fish and Wildlife Service have reviewed the experiment location and have determined that "no federally listed or proposed threatened or endangered species are likely to occur at the project site. The project site is not located within officially designated critical habitat." Copies of the review request, accompanying maps, and the determination letter are attached in Appendix B.

4.1.7 Flood Potential

The western margin of the floodplain of the Trinity River lies about 400 m (~1,300 ft) east of the experiment site. The current channel of the river itself is about 2.7 km (~1.7 mi) east of the site. The principal flood risk for the site is related to Trinity River flooding. The normal and peak stream flow of the Trinity River in this area is relatively well known because there is a stream-gauging station on the Trinity at Liberty (U.S. Geological Survey station 08067000) that has been in operation since 1940.

The drainage area for the Trinity River above the Liberty station totals 45,242 km^2 (17,644 mi^2) (Dougherty, 1980). Maximum discharge measured at the Liberty gauge was 3,230 m^3/s (114,084 ft^3/s) on May 12, 1942, which corresponded to a gauge height of 8.955 m (29.37 ft). The gauge datum is 0.68 m (2.23 ft) below mean sea level. Peak flood elevation at Liberty was 8.275 m (27.14 ft) above sea level. Dougherty (1980) stated that the 1942 discharge maximum was the greatest since at least 1903. The most recent discharge data in Dougherty (1980) are from 1975. In 1994, more recent data reported from the U.S. Geological Survey's National Water Information System (http://waterdata.usgs.gov/nwis/) show that peak discharge since 1975 was 3,823 m^3/s (135,028 ft^3/s), corresponding to a gauge height of 9.45 m (31.00 ft) and an elevation of 8.77 m (28.77 ft) above the 1929 National Geodetic Vertical Datum. Over the century represented in the pre- and post-1975 monitoring, the peak flood elevation was sufficient to inundate the floodplain adjacent to the experiment site at typical elevations of 2 to 6 m (6.5 to 20 ft) above sea level. Trinity water elevations reached during the extreme floods of 1942 and 1994 were more than 10 m (>33 ft) below the land-surface elevation of about 20 m (~66 ft) above sea level at the experiment site on the upland.

4.1.8 Wetlands

The experiment site, located in a low-relief, high-rainfall area on the upland adjacent to the Trinity River valley, is near wetlands identified both in the *Atlas of the Submerged Lands of Texas* (White and others, 1985) and on wetland maps published by the U.S. Fish and Wildlife Service. White and others (1985) depicted the experiment site as an upland environment that is about 400 m (~1,300 ft) west of the Trinity River floodplain margin and elevated 14 to 18 m (46 to 59 ft) above it. Wetlands on the modern floodplain nearest the site are classified as WL (woodlands in fluvial areas), where water-tolerant trees and shrubs are found on river floodplains and in poorly drained areas, and as FH (high marsh), where fresh-water plants make up the vegetation assemblage.

National Wetlands Inventory maps (U.S. Fish and Wildlife Service, 1997; see Cowardin and others, 1979, for basis) depict the wetlands habitats at the experiment site at the 7.5-minute quadrangle scale (fig. 13). Mapped units at the site are classified as U (upland); adjacent and nearby mapped units are PFO1A, PEM1C, and PUBFx on the upland, PFO1C on the bluff, and PFO1/2F and PEM1F on the Trinity floodplain adjacent to the site. The "U" classification, which encompasses the actual experiment site (fig. 14a), denotes an upland environment (nonwetland). Unit PFO1A is mapped on the topographic upland adjacent to the "U" (upland) unit but is classified as a palustrine forested unit with broad-leaved deciduous trees (fig. 14b). The Palustrine System designation (units beginning with the letter P) includes "all nontidal wetlands dominated by trees, shrubs, persistent emergents, emergent mosses or lichens" (Cowardin and others, 1979). Unit PEM1C, located 100 m (325 ft) west of the site, is classified as a palustrine, emergent, persistent, and seasonally flooded wetland. Unit PUBFx, located about 200 m (~650 ft) west of the site, is classified as an excavated, semipermanently flooded palustrine wetland with an unconsolidated bottom.

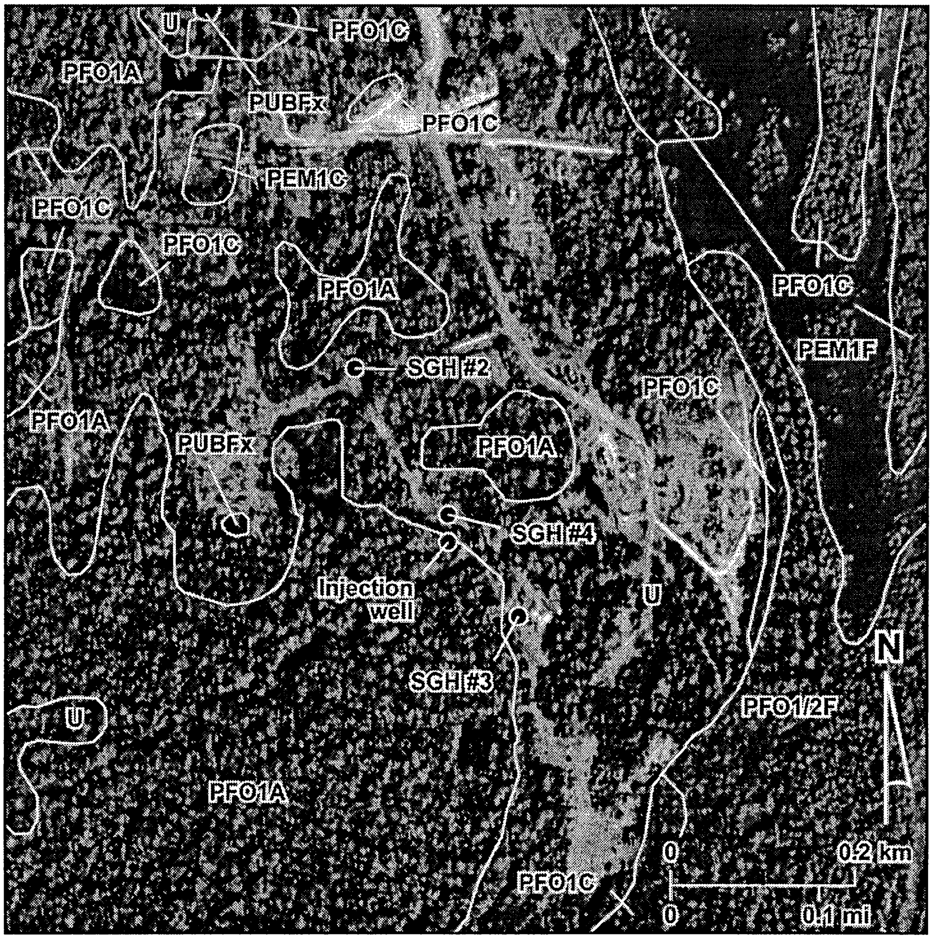
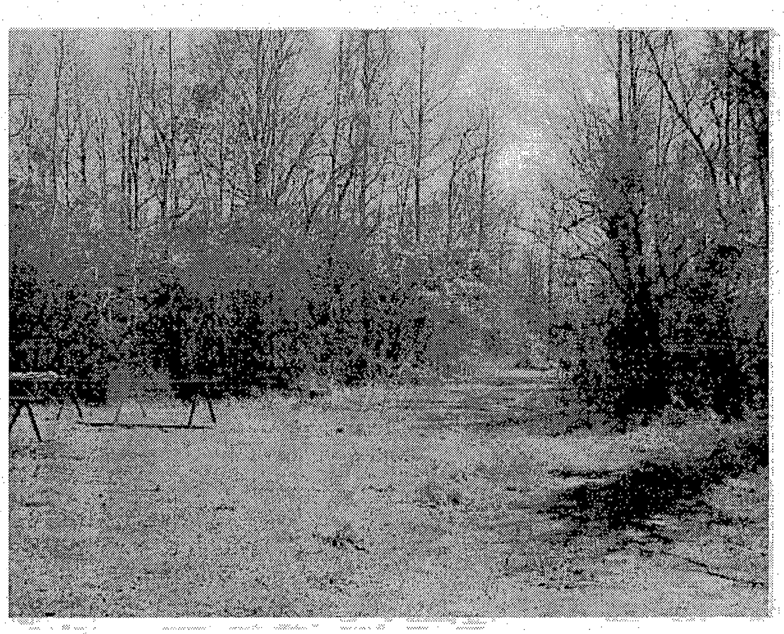


Figure 13. Distribution of mapped wetlands units at the experiment site. Wetlands units are those of the National Wetlands Inventory (U.S. Fish and Wildlife Service, 1997). PEM1C = palustrine, emergent, seasonally flooded; PEM1F = palustrine, emergent, semipermanently flooded; PFO1A = palustrine, forested, broad-leaved deciduous trees; PFO1C = palustrine, forested, broad-leaved deciduous trees, seasonally flooded; PFO1/2F = palustrine, forested, broad- and needle-leaved deciduous trees, semipermanently flooded; PUBFx = palustrine, excavated, semipermanently flooded, unconsolidated bottom; and U = upland (nonwetland). Aerial photo base modified from Texas Natural Resources Information System.

A



B

Figure 14. Representative photographs of upland vegetation assemblages from the experiment site and surroundings. (A) Upland environment ("U" classification) at the injection site. (B) Mixture of broad-leaved deciduous trees and evergreen trees (Unit PF01A) about 100 m (~330 ft) north of the experiment site. Photos taken during February 2002.

A

B

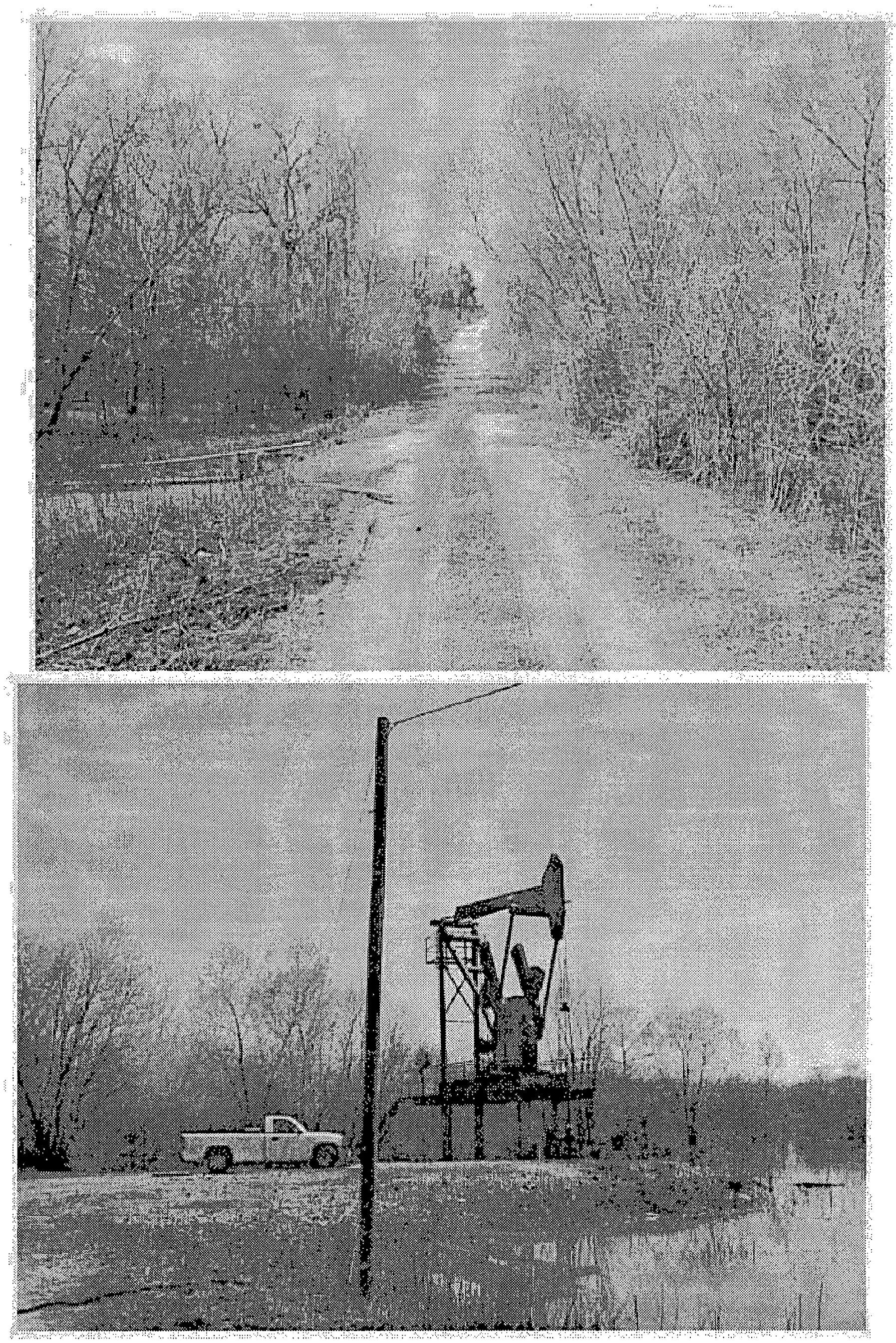


Figure 15. Representative photographs of lowland vegetation assemblages near the experiment site. (A) Unit PF01C, a palustrine wetland on the bluff between the upland area of the experiment site and the Trinity River floodplain. (B) Unit PEM1F, a semipermanent flooded palustrine emergent habitat within the Trinity River floodplain, at the Sun Fee Lot 45 #1 well pad. Raised well platform accommodates occasional flooding. Photos taken during February 2002.

On the bluff between the upland and the Trinity floodplain, unit PFO1C designates a palustrine wetland composed of broad-leaved deciduous trees that is seasonally flooded (fig. 15a). On the Trinity floodplain, unit PFO1/2F designates a forested palustrine wetland with broad- and needle-leaved deciduous vegetation that is semipermanently flooded. The other nearby floodplain unit, PEM1F, denotes a persistent, semipermanently flooded palustrine emergent habitat (fig. 15b).

4.2 Direct Effects

Direct environmental effects from the proposed action include (1) surface impacts, (2) agents introduced into the subsurface, and (3) leakage of introduced agents back to the surface or groundwater. Risks of unacceptable impacts from proposed activities are low.

4.2.1 Surface Impacts

As noted previously, construction impacts on archeological sites, endangered species, and wetlands are nonexistent or negligible. Traffic impacts from delivery of CO_2 to the site and removal of wastes to disposal facilities are minor. Risks of significant surface leaks of CO_2 are minor, but effects on human health could be significant. The presence of large volumes of compressed CO_2 during the 30-day-or-less injection phase represents a significant health and safety concern because of the high injection pressures (up to 168 bar or 2,454 psi) and asphyxiation hazard posed.

CO_2 is a nontoxic inert gas that is essential for fundamental biological processes in all living things (Benson and others, 2003). Exposure to elevated concentrations can cause adverse reactions. At concentrations between 3 and 5% (30,000 and 50,000 ppm), humans experience discomfort and impacts on respiratory rate. Loss of consciousness can occur above 5% (50,000 ppm) and occurs within seconds at concentrations above 25 to 30%, at which point death is imminent (Benson and others., 2003). CO_2 is denser than air and can concentrate in low-lying or confined areas if not dispersed or mixed with air by winds. Contingency plans for large-scale CO_2 leaks will be prepared by Sandia Technologies, complete with an audible and visual warning system, escape procedures, and emergency notification plans. A site-safety training plan designed by a safety expert with substantial experience in CO_2 EOR operations will be administered to all on-site personnel. In addition, the site will be staffed by trained personnel at all times during the time when CO_2 is being stored or injected at the site. Relevant health and safety procedures, such as the Emergency Planning and Community Right-to-Know Act (EPCRA, or SARA Title III), will be followed.

4.2.2 Subsurface Impacts

Direct effects to the subsurface environment from introduction of CO_2 will have minimal environmental impact because of the relatively small volume introduced and the isolated nature of the setting. Introduced tracer materials will have negligible impacts because of the small volumes and benign nature of the materials. Table 5 lists the chemicals selected as tracers, along with any potential harmful impacts. These include perfluorocarbons and noble gases. MSDS sheets for these materials are provided in Appendix A. None of these materials is listed in 40 CFR 261 Subpart D.

Table 5. Tracer materials to be used and their concentrations.

Tracer	Concentration (Injectate)	Concentration (Produced Fluids)	Maximum total weight	Comments
FLUTEC-TG PMCH (perfluoromethylcyclohexane)	30 ug/mL (30 ppm)	1 ng/mL (1 ppb)	Maximum total Perfluoro-carbons: 60 kg.	No known human- or eco-toxicity
FLUTEC-TG PTMCH (perfluoro-1,3,5-trimethylcyclohexane)	30 ug/mL (30 ppm)	1 ng/mL (1 ppb)	Maximum total Perfluoro-carbons: 60 kg.	No known human- or eco-toxicity
FLUTEC-TG o-PDMCH (perfluoro-1,2-dimethylcyclohexane)	30 ug/mL (30 ppm)	1 ng/mL (1 ppb)	Maximum total Perfluoro-carbons: 60 kg.	No known human- or eco-toxicity
FLUTEC-TG m-PDMCH (perfluoro-1,3-dimethylcyclohexane)	7 ug/mL (7 ppm)	0.2 ng/mL (0.2 ppb)	Maximum total Perfluoro-carbons: 60 kg.	No known human- or eco-toxicity
FLUTEC-TG p-PDMCH (perfluoro-1,4-dimethylcyclohexane)	7 ug/mL (7 ppm)	0.2 ng/mL (0.2 ppb)	Maximum total Perfluoro-carbons: 60 kg.	No known human- or eco-toxicity
FLUTEC-TG PMCP (perfluoromethylcyclopentane)	30 ug/mL (30 ppm)	1 ng/mL (1 ppb)	Maximum total Perfluoro-carbons: 60 kg.	No known human- or eco-toxicity
FLUTEC-TG PDMCB (perfluorodimethylcyclobutane)	7 ug/mL (7 ppm)	0.2 ng/mL (0.2 ppb)	Maximum total Perfluoro-carbons: 60 kg.	No known human- or eco-toxicity
FLUTEC-TG PECH (perfluoroethylcyclohexane)	7 ug/mL (7 ppm)	0.2 ng/mL (0.2 ppb)	Maximum total Perfluoro-carbons: 60 kg.	No known human- or eco-toxicity
^{20}Ne (Neon 20)	30.3 ppm	Variable	0.63 kg	No known human- or eco-toxicity
^{36}Ar (Argon 36)	164 ppm	Variable	3.42 kg	No known human- or eco-toxicity
^{84}Kr (Krypton 84)	7.64 ppm	Variable	0.16 kg	No known human- or eco-toxicity
^{132}Xe (Xenon 132)	0.4 ppm	Variable	0.01 kg	No known human- or eco-toxicity
Eosin	1 ppm	5 ppb	10kg	No known human- or eco-toxicity

Perfluorocarbons are used in human medical treatments, and noble gases are chemically inactive. A maximum total of 60 kg (132 lb) of perfluorocarbon tracers will be used during the experiment, with maximum concentrations in the injectate of 30 ug/mL (30 ppm) and those at the monitoring well at the radial distance of 30 m (100 ft) lower than 1 ng/mL (1 ppb). A maximum of 4.22 kg (9.33 lb) of noble gases will be used. Concentrations in the injectate will range from 0.04 to 164 ppm, depending on the gas type. Concentrations at the monitor well will vary from 100 % of the gas phase initially to no concentration several days after injected gases reach the monitor well. Eosin fluorescent dye approved for use in groundwater tracing and has been widely used in drinking water and environmentally sensitive areas. Less then 10 kg will be added to the hydrologic test brine before reinjection to the subsurface, produding concentrations in the ppm range.

Shot holes for the 3-D VSP will leave minor amounts of residue within shallow saturated zones. A biodegradable explosive such as Dynoseis®, which contains sodium perchlorate and diethylene glycol, will be used instead of more traditional and less expensive, but potentially more harmful, explosives such as Pentalite. Shot holes will be filled following use, and the soil compacted.

4.2.3 Potential Leakage Impacts

Risks associated with return of injected CO_2 to groundwater or the surface are low. The injection zone is overlain by a 75-m-thick (250-ft) shale and approximately 1,375 m (~4,500 ft) of interbedded sandstone and shale that serve as alternating barriers to vertical migration and sinks for any escaped CO_2. Incremental pressures throughout the injection phase will be controlled and below regulatory limits established by TCEQ in adherence to U.S. Environmental Protection Agency rules. Limits are designed to prevent migration of injected fluids out of the injection zone over a 10,000-year period. Numerical modeling indicates that CO_2 will not travel more than 200 m (>650 ft) from the injection well. Under experiment conditions, faults will not be conduits for fluid or gas escape. Monitoring, which is the central focus of this experiment, will provide assurance that the CO_2 in the subsurface is performing as predicted. Preinjection engineering and during-injection monitoring will provide assurance that the wells are not leaking fluids or gasses.

To evaluate the potential impact of a leak at a theoretical site where these assurances are not present, we have investigated the fate and transport of a release from the injection interval equivalent to 10% of the total CO_2 injected. The most likely case is that the rising gas would be retained in the pores of the sandstones through which it ascends by capillary forces and residual saturation effects. If the gas were to rise along a conduit in which it had little contact with porous rock, a significant percentage could reach either the groundwater or the ground surface.

If the CO_2 were to ascend into an aquifer, impacts would be minor. Dissolution of CO_2 in water decreases pH (increases acidity) slightly. Chemical reactions between the acid waters and the surrounding rock moderate this reaction, limiting pH changes. Modeling by LLNL (K. Knauss, LLNL, personal communication) indicates that pH would be reduced from 6.74 to 5.28 for a radial distance of less than 20 m (<65 ft) from the leak point, assuming an aquifer of 6-m (20-ft) thickness, salinity of <1,000 ppm, and rate of leakage equivalent to rate of injection. A statewide database of water well locations maintained by the Texas Water Development Board records no water wells within 1 km (0.6 mi) of the proposed injection well. The nearest known residential water well (well 64-02-102) is located on the Pleistocene upland about 1,250 m (~4,100 ft) northwest of the injection well. This well, drilled in 1972 to a depth of 73.2 m (240 ft), produces water from the Chicot aquifer. A field survey will be conducted prior to injection operations to locate undocumented water wells within a 402-m (0.25 mi) radius of the injection well. Any wells within this area will be monitored for changes in pH during the experiment. We willdrill three monitoring wells near the injection well to monitor shallow groundwater.

In the unlikely event that CO_2 were to ascend to ground surface, impacts would be minor. Numerical modeling by Oldenburg and others (2002a, b) demonstrates that CO_2 rising from the subsurface will collect in the unsaturated zone and spread laterally, accumulating to nearly 100% vapor concentration in the shallow soil because its density is greater than that of air. Only when the unsaturated-zone pore space is filled with CO_2 would significant flux to the atmosphere occur (Oldenburg, 2002a). Under conditions of significant leakage, topographic lows and enclosed subsurface structures such as basements could accumulate significant concentrations of CO_2 from the unsaturated zone. Any such points within 400 m (0.25 mi) of the experiment site will be identified and monitored during and following CO_2 injection.

Increasing concentrations of CO_2 in soil gas could forewarn of a potential flux to the atmosphere. The grid of groundwater and soil-gas sample points established on the well pad and at other potential leak sites (see Preinjection Activities section) will be monitored throughout the injection and postinjection phases.

At the end of a long chain of unlikely events is the possibility that CO_2 might seep into the atmosphere because high flux rates through groundwater or limited pore space in the unsaturated zone fills the unsaturated zone, creating flux to the surface. Oldenburg and others (2002a) modeled a scenario where subsurface flux rates equivalent to 10% of project volumes returned to the surface over a 1-year period. CO_2 concentrations at ground level near the leak site would be nearly 100%, but would dissipate to background atmospheric concentrations within about 28 m (~90 ft) in wind speeds typical of the experiment location (7.2 km/hr).

Impacts of introduced agents that might leak to the groundwater or surface are negligible. As shown in table 5, perfluorocarbon and noble gas tracers to be used have no known toxicity.

5.0 REGULATORY COMPLIANCE

5.1 State Permitting Requirements

State permitting requirements have been discussed with the two Texas agencies that have possible jurisdiction over the drilling and injection activities envisioned for this experiment. Discussions regarding State regulatory requirements have been held with Richard Ginn, Director of Underground Injection Control (UIC) at the Railroad Commission of Texas (RRC) and Ben Knape, Team Leader, UIC Permits, Texas Commission on Environmental Quality (TCEQ).

The UIC program consists of five classes of wells, from I to V, each generally requiring a permit for operation under Texas Water Code, Chapter 27, and Texas Health and Safety Code, Chapter 361 (Class II wells fall under different codes). Federal guidelines for UIC wells have been established by the Environmental Protection Agency (EPA). The Texas Commission on Environmental Quality (TCEQ) and the Texas Railroad Commission (RRC) have been delegated authority by EPA under delegated programs to administer UIC programs in Texas that are at least as stringent as those adopted by EPA. Additional rules governing the various classes can be found in Title 30 of the Texas Administrative Code, Chapter 331, with supporting information and rules in Chapters 1–100, 281, and 305. Class I wells are used for long-term injection of hazardous and nonhazardous wastes and are permitted by the State environmental quality agency (TCEQ). Class II wells are designated for injection of water or other chemicals into existing oil and gas reservoirs or injection of oilfield wastes into nonreservoir intervals and are permitted by the State oil and gas regulatory agency (RRC). UIC Class III is reserved for wells that inject fluids for extraction of minerals other than oil and gas. The Class IV category applies to wells that dispose of hazardous wastes above formations that contain underground sources of drinking water and are generally prohibited. Class V wells are those that are not included in Classes I through IV. Class V wells have numerous purposes ranging from disposal of storm runoff and motor vehicle waste to aquifer recharge and remediation. One Class V category is "experimental" wells for subsurface fluid distribution, under which this project will be permitted.

Because the injection interval is not an oil or gas reservoir, and because the source of the injected CO_2 is postrefinery, the project falls under the jurisdiction of the UIC program at TCEQ. Further discussions with TCEQ regarding the short duration of the experiment and the small volume of gas injected resulted in a request for us to submit an application for a Class V well, accompanied by a report providing relevant additional information typically required in Class I filings. A public information meeting will also be held in the community, hosted by the Bureau of Economic Geology, wherein local citizens, public officials, local and regional political representatives, and other interested stakeholders are invited to review the project plan and provide nonbinding comment. Public comment will be considered, and any appropriate adjustments to the field plan will be made.

The TCEQ Class V application includes responsible-party contact information, well-site information, downhole design, and a review of hydrogeological data, including information about formation water chemistry, relationship to aquifers, and locations of injection or water wells within a one-quarter-mile radius. The additional report to be delivered to TCEQ will include

- a detailed land-ownership map with contact information,
- additional detailed site information (relationship of the site to government entities and jurisdictions),
- contact information for local government agencies and political representatives,
- financial assurance for site closure,
- a concise description of the geologic and hydrogeologic setting,
- engineering drawings and plans for surface and subsurface equipment approved by a registered professional engineer,
- a discussion of injection zone mechanics that includes flow-simulation model results indicating expected changes in pressure and injectate saturations through time,
- an Area-Of-Review (AOR) study documenting all wells and their current condition within 402 m (0.25 mi) of the pilot wells,
- a discussion of injected fluids and their expected reactivity with formation and construction materials, and
- a letter from the RRC indicating that activities will not adversely affect any known hydrocarbon accumulations.

6.0 CUMULATIVE AND INDIRECT EFFECTS AND LONG-TERM ENVIRONMENTAL CONSEQUENCES

Cumulative impacts are those that result from the incremental impact of the proposed project when added to other past, present, and reasonably foreseeable future actions. They include direct impacts caused by the proposed action and that occur at the same time and place as the project and indirect impacts that can reasonably be foreseen that result from the proposed project and that occur later in time or farther in distance from the project site. Direct cumulative effects of this proposed project are limited because of the short duration of field activities, and are expected to span only several months, with the injection phase lasting less than 1 month. Indirect cumulative effects predominantly relate to long-term fate of the injected CO_2 and the risk of it escaping from the injection zone, as well as the difficult-to-foresee impacts of project success on the number of active domestic sequestration projects.

6.1 Direct Cumulative Effects

Direct cumulative effects considered include traffic impacts of CO_2 transportation, traffic and capacity impacts associated with disposal of produced water, impacts on flora and fauna of proposed field activities, and noise- and light-pollution impacts of nighttime operations.

Cumulative transportation impacts are minimal, and specific actions will be taken to mitigate anticipated effects. The 10 CO_2 truckloads per day during the comparatively short injection phase are minor in comparison to moderate to heavy commercial, agricultural, industrial, and private traffic on planned routes. Transport during typical commuting hours will be avoided along Highway 146 between Seabrook and the east end of Baytown.

Disposal of less than 30 truckloads of produced brine, a nonhazardous material, will entail an approximately 22.5-km (~14-mi) drive along public rural roads over 4 days and will not result in significant cumulative effects. A maximum of 595 barrels (5 truckloads) of produced water will be disposed of each day into a commercial UIC Class I nonhazardous disposal well with capacity for up to 950,000 gallons per day that typically receives other deliveries amounting to less than 150,000 gallons per day. A maximum of 7,000 barrels (bbl) (60 truckloads) of drilling fluids will be disposed of at a TCEQ-permitted disposal facility approximately 48 km (30 mi) from the field site. Drilling-fluid disposal will be spread over at least 6 days, reducing traffic impacts. The disposal well has a capacity of 20,000 bbl/day with a typical use of 1,200 bbl/day. Delivery of about 1,000 bbl/day should have no cumulative impact on the facility.

Cumulative effects to flora and fauna will be minor and local. The project will impact less than 2 additional hectares (5 acres) of habitat in an oilfield where exploration and development activities span an area of 6,980 hectares (17,280 acres).

Drilling, work-over, and CO_2 injection activities may occur at night. Associated light and noise impacts are minimized by the 0.6-km (0.35-mi) distance between the well site and the nearest residence and the limited duration of intensive drilling and injection activities.

6.2 Indirect and Indirect-Cumulative Effects

Indirect and indirect-cumulative effects include the long-term fate of injected CO_2, the postproject disposition of the three wells used, the potential for increased drilling and land use in the project area associated with potential project success, and the impacts of increased sequestration activities throughout the U.S.

6.2.1 Fate of Injected CO_2

A primary goal of the project is to document the fate of injected CO_2. Numerical modeling and accumulated knowledge of behavior of fluids and gases in the subsurface suggest that the CO_2 will stay within the injection zone and travel less than 200 m (650 ft) from the injection well (Doughty and Pruess, 2003). Alternative models have been constructed to investigate possible but unexpected scenarios, including leaks upward such as (1) through overlying formations, (2) along well-bore annuli, and (3) along faults. Factors that diminish the escape risk include (1) the presence of the 75-m-thick (250-ft) Anahuac Shale with documented capability to retain gases for geologic time spans above the injection zone and the overlying 1,475-m-thick (4,500-ft) section of interbedded sandstones and shales, (2) the presence of remnant drilling mud in well-bore annuli of a density sufficient to contain anticipated pressure increases outside the 402-m (0.25-mi) Area of Review (AOR) established by TCEQ, and (3) planned maximum fluid pressures 22 percent below those calculated to induce seismicity and fault leakage. No significant identifiable risks to human health, safety, or the environment have resulted from these alternative scenarios. Discussions in the Direct Effects section address impacts of an unlikely release of all CO_2 to the surface or an aquifer. Numerical models will be refined using site-specific data after field activities begin but before any CO_2 is injected.

Subsurface numerical models were constructed at Lawrence Berkeley National Laboratory using TOUGH2 code (Doughty and Pruess, 2003). The models incorporate reasonable scientific assumptions (Pruess and others, 1999; Holtz, 2003) and geologic assessments based on regional knowledge of the injection horizon (Doughty and others, 2000; Hovorka and others, 2000; Doughty and Pruess, 2003) and site-specific geotechnical data derived from well logs and a 3-D seismic survey (fig. 16). Knowledge of subsurface fluid behavior comes from the multitude of engineering and geologic studies done of subsurface-oil and gas-reservoir characteristics.

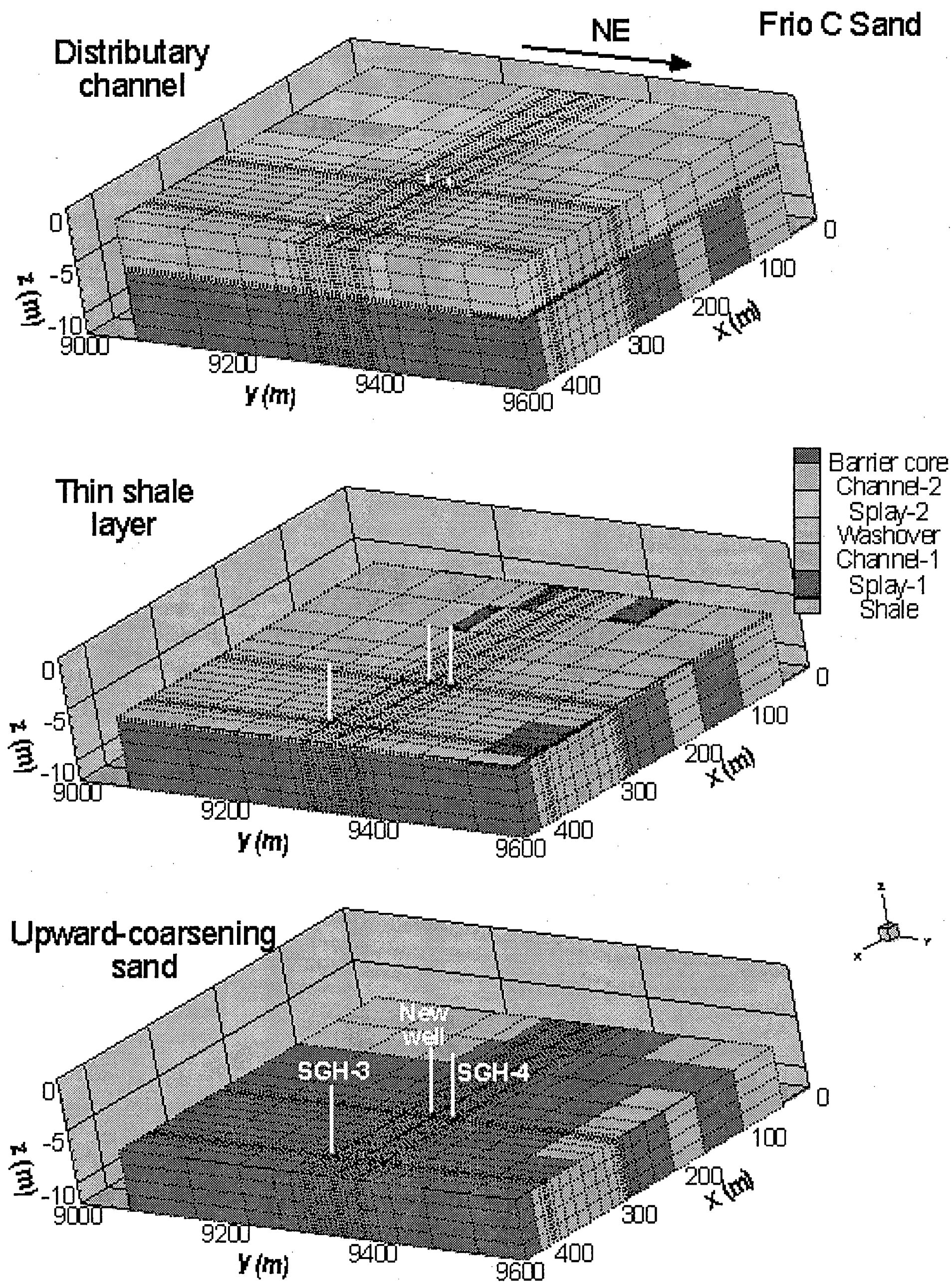


Figure 16. Numerical simulation model construction parameters for the "C" sand (injection interval). A thin shale in the middle of the sandstone separates a lower upward-coarsening sandstone deposited in a probable delta front setting from a dominantly upward-fining sandstone deposited in a distributary channel. North is toward the right side of the images. Grid refinement around well bores allows greater detail in imaging injection response. Simulation grid prepared by Christine Doughty, LBNL.

Models show that the CO_2 injected into the subsurface during the experiment will behave buoyantly because of its low density (0.6 grams/cm^3) compared with that of native formation brines (1.075 grams/cm^3). The buoyant plume of concentrated immiscible CO_2 will migrate updip within the injected stratigraphic interval toward the salt dome (fig. 9). Some percentage of the CO_2 will be left behind the migrating plume as it is trapped in rock pores by capillary behavior and relative permeability effects (Wardlaw, 1982; Holtz, 2002). Holtz (2003) indicated that, for the ranges of porosities in the injection interval, as much as 30% of the pore space will sequester the CO_2 in what is termed *residual saturation*. Numerical flow simulation models constructed on this basis suggest that the plume will stop moving entirely within 5 years after moving less than 200 m (<650 ft) updip (fig. 17). The CO_2 will remain in place at least until local geologic conditions change significantly, a time period expected to exceed 1,000 years.

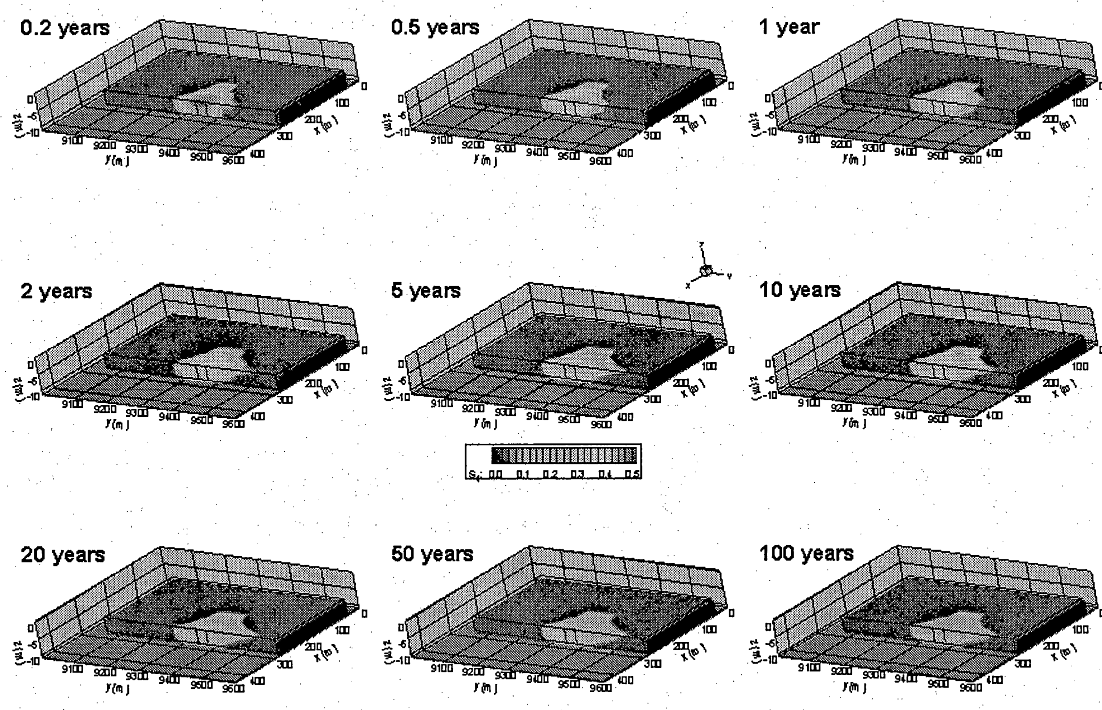


Figure 17. CO_2 saturation distributions around the injection well from 0.2 to 100 years after injection begins. Model uses best estimates of porosity and residual gas saturation. The model block is tilted up toward the northeast. Note that very little movement of the plume occurs after the initial injection period. Simulation results from TOUGH2 prepared by Christine Doughty, LBNL.

If the current understanding of residual saturation behavior or subsurface pressure conditions is inaccurate, the CO_2 could continue migrating updip to the north within the injection interval. The faults to the northwest and southeast of the injection well would focus the plume as it moves up and is trapped against the salt dome. Such a scenario could be produced, as shown by numerical modeling, if residual saturation were actually 5%, as opposed to the 30% estimated (figs. 18, 19).

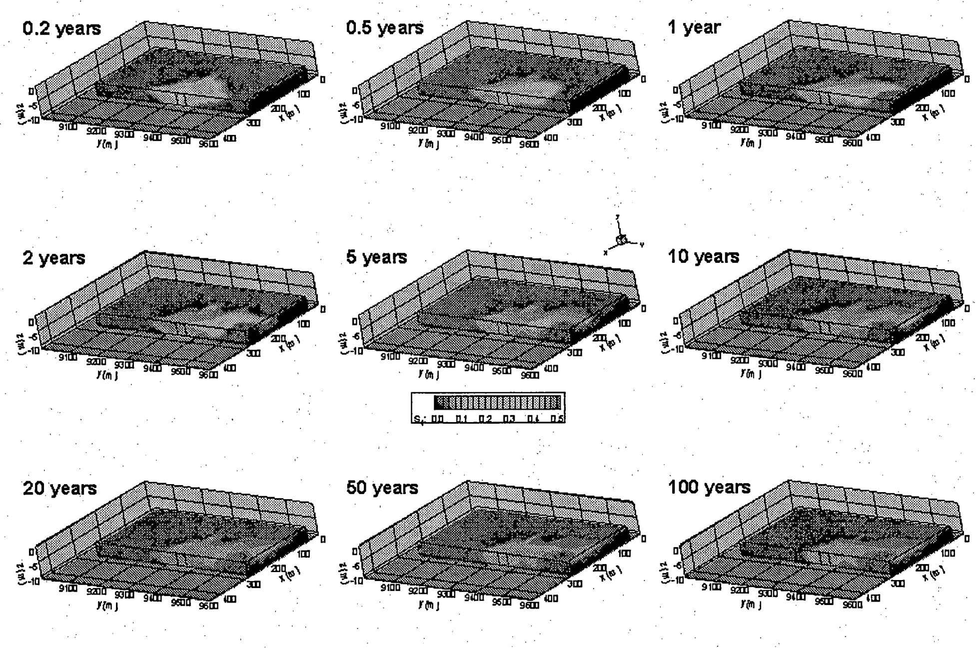


Figure 18. CO_2 saturation distributions around the injection well for low-residual gas saturation case from 0.2 to 100 years after injection begins. Model uses best estimates of porosity and a maximum of 5% residual gas saturation. The model block is tilted up toward the northeast. Note that the plume continues to migrate updip for perhaps 10 years before being immobilized by the residual gas saturation effect. Simulation results from TOUGH2 prepared by Christine Doughty, LBNL

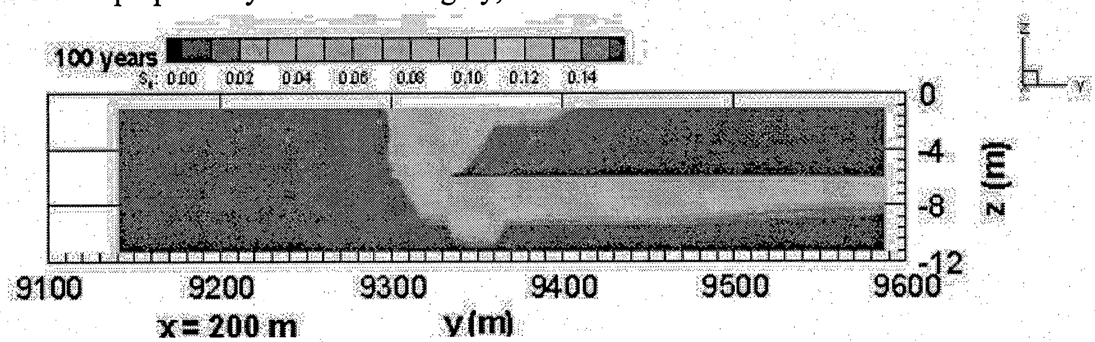


Figure 19. CO_2 saturation distributions in northeast-southwest (dip) section cross-sectional view of injection zone for low residual gas saturation case at 100 years after injection begins. Updip is to the right in this section through the center axis of the model. CO_2 has escaped from the lower half of the "C" sandstone through a theoretical break in a thin shale midway up the sandstone body. Only the plume in this half of the sandstone has sufficient volume to continue migrating to the updip end of the model. Simulation results from TOUGH2 prepared by Christine Doughty, LBNL.

. In such a mobile plume, the dominant risk is that the plume might encounter a conduit leading up and out of the injection zone. Possible conduits include (1) cross-formational flow (discontinuous seal), (2) well-bore annuli, and (3) faults, including the interface between the formation and the salt dome. Each is unlikely, for the following reasons:

- In addition to the two 3-m-thick (10-ft) laterally continuous shales separating the injection zone from overlying sandstones in the Frio Formation, the injection zone is overlain by the 75-m-thick (250-ft) Anahuac Shale. This shale has retained both oil and gas over geologic periods of time at the South Liberty Salt Dome, as evidenced by the presence of oil and gas reservoirs in the uppermost Frio sandstones (Halbouty, 1962). Additionally, maximum subsurface pressures, on the basis of LBNL models, during the experiment of 169 bar (2,469 psi) are 35% below the fracture pressure as calculated by the Eaton method (Eaton, 1969).
- Well bores within the 402-m (0.25-mi) Area of Review (AOR) established by the TCEQ will be assessed for proper completion or abandonment using RRC file data and will be remediated if found to be noncompliant. Annuli of surrounding wells outside the AOR are filled with 9 lb/gal drilling mud present in the well before emplacement of casing. Incremental formation pressures outside the AOR during the experiment of less than 10 bar or 141 psi are 12% below the Critical Incremental Pressure of 11.4 bar (166.4 psi) required to overcome the hydrostatic head of the mud column. This rationale for assessment of upward leakage potential was established by TCEQ for UIC operations. Adherence to these conditions is a prerequisite of the Class V application approval. For a Class V well to qualify for a TCEQ permit, wells within the AOR must have cemented casing emplaced below the base of Usable Quality Groundwater (TDS < 3,000 ppm). In the unlikely event that CO_2 did overcome mud-column heads in the annulus, the cemented casing would prevent the gas from entering aquifers.
- ambient confining pressures keep faults at depths greater than 1 km (~ 3,000 ft) closed to fluid migration unless fluids are injected into the fault plane at excessive fluid pressures (Rasmussen, 1997) or unless the fault slips (Hooper, 1991). A lack of fault scarps at the surface indicates that faults in the area have not been active in the recent geologic past. Injection-induced excess fluid pressures can reactivate faults (Wesson and Nicholson, 1987). Maximum fluid pressures of 169 bar (2,469 psi) associated with the proposed project are 22% below the 264 bar (3,853 psi) calculated by the Wesson and Nicholoson (1987) method as likely to induce seismicity.
- If unforeseen events were to occur and the CO_2 gradually escaped to an aquifer or to the surface, impacts would be minor and limited in geographic extent. The conditions of immediate escape of CO_2 have been addressed previously in the Direct Effects section. Cumulative or indirect impacts, by definition, would occur over longer periods of time and have less impact than that described previously. Following completion of injection, subsurface pressure anomalies will decay as the pressure pulse is absorbed by the surrounding formation volume. Potential for rapid leakage is reduced as the plume spreads and pressures decline. Gradual leakage would be at substantially reduced rates, increasing chances for broad, slow dispersion in water-saturated sediments or near-surface soils and preventing buildup of dangerous levels of CO_2 in the air around the experiment site.

As discussed previously in the Direct Effects section, groundwater-dissolved gases and soil gases will be monitored for increases in CO_2 above baseline values. This and other monitoring will decrease in frequency as measurable pressure and temperature effects in the subsurface decay over time. Monitoring will cease when asymptotic values of change occur, which is anticipated within 1 year after the end of injection.

6.2.2 Postproject Well Disposition

Following project completion, the three wells used in the project will be abandoned in, accordance with Rule 14, section 3.14 of the RRC "Statewide Rules for Oil, Gas, and Geothermal Operations," or converted to another use authorized by DOE, RRC, and TCEQ. Neither of these alternatives would have significant cumulative effect on the South Liberty oilfield, where similar activities are routine for the hundreds of existing wells in the field.

6.2.3 Increase in Sequestration Activities in the Pilot Area

The pilot site was not selected because of any perceived potential for larger-scale operations in the same area, but because it possessed suitable technical attributes for a small-scale project. Success of the pilot may increase interest in larger projects, perhaps in the same general area. Any such project would require considerable further study, including assessing potential environmental impact and obtaining disposal permits.

6.2.4 Increase in Domestic Sequestration Activities

With the success of this and other sequestration experiments, government and industry will have the option to manage atmospheric CO_2 concentrations through geologic sequestration. Operation costs will dictate that sequestration will be distributed in many areas near major CO_2 sources. Many of these areas are likely to be existing oil and gas fields, where impacts would be incremental and minimal. Where CO_2 sources are present but oil and gas fields absent, sequestration options include (1) piping or trucking to some distant location where an existing oil or gas field can be used or (2) drilling a well to inject CO_2 into a brine-bearing formation locally. Economic and logistical lessons learned from the proposed experiment will help determine which of these approaches is most feasible.

7.0 IRREVERSIBLE AND IRRETRIEVABLE COMMITMENTS OF RESOURCES

Principal resources employed in the proposed CO_2 injection and monitoring experiment are: (1) the materials (steel, water, and cement) required to drill a new injection well and refit the existing monitoring well; (2) the CO_2 required to create the subsurface plume; (3) the fossil fuels consumed in drilling, refitting, and sampling wells and in transporting CO_2 and wastes; and (4) minor amounts of timber cleared during extension of well pads and drilling of shot holes for the 3-D VSP. For the new injection well, several truckloads of caliche road base will be needed to expand the existing well pad to drill a new well, up to 6,000 barrels of water for drilling mud will be needed to advance the drill bit to an estimated depth of 1,820 m (6,000 ft) and return cuttings to the surface, steel surface and injection casing will be installed to protect shallow, fresh groundwater and permit injection at the selected stratigraphic interval, and steel wellhead valves and pipes will be installed to allow CO_2 injection. The 3,750 tons of CO_2 to be consumed represents a commercial market value of approximately $375,000. CO_2 to be used for the project would otherwise have been vented to the atmosphere as a waste. Fossil fuels, primarily diesel, will be used by the drilling and work-over rigs and by the trucks hauling 165 loads of CO_2, produced water, and drilling fluids.

8.0 ENVIRONMENTAL CONSEQUENCES OF THE NO- ACTION ALTERNATIVE

Under the No- Action Alternative, there would be no change in current hydrocarbon extraction activities or other uses at the South Liberty Oilfield. The minimal local environmental consequences associated with drilling a new well (well-pad expansion, mud-pit excavation, and well drilling) would be avoided. The experiment to inject 3,750 tons of CO_2 into a subsurface saline aquifer, monitor the lateral migration of the CO_2 plume, and assess the performance of stratigraphic sealing horizons in sequestering CO_2 underground would not be conducted. The 3,750 tons of CO_2 that would have been injected into the subsurface would be released to the atmosphere. Underground CO_2 sequestration in saline aquifers is one of the viable approaches being evaluated for maintaining or reducing climate-altering greenhouse gas concentrations in the atmosphere. In addition to losing the opportunity to sequester a small amount of CO_2 in a geological repository, we lose the opportunity to evaluate the technical approach and feasibility of CO_2 sequestration in a saline aquifer specifically selected for its favorable sequestration potential.

9.0 SIMILAR ACTIONS AND ACTIONS BEING CONSIDERED UNDER OTHER NATIONAL ENVIRONMENTAL POLICY ACT REVIEWS

The proposed action, for DOE support in evaluating the suitability of CO_2 sequestration in deep saline aquifers, is not similar to any other action being considered (or currently being implemented) by DOE.

This action is not a segment of any other action for which review under NEPA would be required. This project will help provide information for a large-scale geologic sequestration project being planned for West Virginia. The West Virginia project, supported by DOE and being conducted by American Electric Power Company (AEP) and Battelle Memorial Institute, is in the data-collection phase, which does not require NEPA review.

10.0 RELATIONSHIP OF THE PROPOSED ACTION TO APPLICABLE FEDERAL, STATE, REGIONAL, OR LOCAL LAND USE PLANS AND POLICIES

The proposed project requires no substantive change in the current land use as an operating oilfield. The proposed incremental enlargement of an existing well pad, the drilling of a new well, and monitoring of CO_2 at an existing well represent no substantive change to the current use of the land. Similar drilling and fluid-extraction activities have been ongoing in the area since hydrocarbon production began in the 1920's.

11.0 CONSULTATION AND PUBLIC PARTICIPATION

11.1 Consultation

The agencies and organizations contacted during environmental assessment of the proposed project are identified in table 6. Copies of correspondence exchanged with those agencies and organizations are provided in Appendix B.

Table 6. Agency and organization contacts.

No.	Agency contacted	Date	Author	Response Date	Author
1	Texas Archeological Research Laboratory	10/4/2002	Paine	10/7/2002	Azulay
2	U.S. Fish and Wildlife Service	10/9/2002	Paine	10/30/2002	Morgan
3	U.S. Army Corps of Engineers	10/9/2002	Paine	10/9/2002	Dunn
4	Texas Commission on Environmental Quality (Underground Injection Control Section)	Many	Knox	Many	Fred Duffy
5	Texas Commission on Environmental Quality (surface casing and groundwater protection)	12/6/2002	Paine, Knox		Traylor
6	Railroad Commission of Texas	Many	Hovorka, Knox	Many	Ginn
7	Liberty County		Knox		
8	City of Dayton		Knox		
9	City of Liberty		Knox		
10	Texas Department of Health (Radiation Control Section)	3/24/03	Knox	3/24/03	R. Cortez

11.2 Public Participation

A draft Environmental Assessment was issued on and made available for public review and comment. Copies of the document were provided for review at area libraries and on the Department of Energy/NEGL Web page at www.netl.doe.gov. An announcement of availability (Public Notice) was published in area newspapers.

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Appendix A

BOC Gases Material Safety Data Sheet: Krypton

BOC Gases Material Safety Data Sheet: Argon

Dyno Nobel Inc. Material Safety Data Sheet: DYNOSEIS

Fisher Scientific Material Safety Data Sheet: Eosin Y

MDS Nordion Material Safety Data Sheet: Sodium Iodide Iodine 131

F2 Chemicals Ltd. Material Safety Data Sheet: FLUTEC-TG o-PDMCH

F2 Chemicals Ltd. Material Safety Data Sheet: FLUTEC-TG PMCH

F2 Chemicals Ltd. Material Safety Data Sheet: FLUTEC-TG PMCP

F2 Chemicals Ltd. Material Safety Data Sheet: FLUTEC-TG PTMCH

BOC Gases Material Safety Data Sheet: Neon

A. Johnson Matthey Company, Inc. Material Safety Data Sheet: Perfluorodimethyl-cyclobutane

F2 Chemicals Ltd. Material Safety Data Sheet: FLUTEC-TG m-PDMCH

F2 Chemicals Ltd. Material Safety Data Sheet: FLUTEC-TG PECH

F2 Chemicals Ltd. Material Safety Data Sheet: FLUTEC-TG p-PDMCH

BOC Gases Material Safety Data Sheet: Xenon

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Gulf Coast Carbon Center

Appendix B

Letter from Texas Archeological Research Laboratory

Letter to U.S. Fish and Wildlife Service