Frio Pilot in CO_2 Sequestration in Brine-Bearing Sandstones

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Report to the Texas Commission on Environmental Quality
to Accompany a Class V Application
for an Experimental Technology Pilot Injection Well

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Executive Summary

Carbon dioxide (CO_2), the waste product of burning carbon-based fuels, can also result from a number of other industrial processes. Unlike many industrial wastes, however, CO_2 is an intrinsic component of many natural systems, including the atmosphere, and it is produced during respiration and fixed during photosynthesis. Analysis has shown that CO_2 concentrations in the atmosphere are increasing. This trend has raised concerns about the potential for negative environmental and economic impacts that may result from this buildup—mainly because of the effect that CO_2 has on retaining solar energy as heat, a process commonly referred to as global warming.

Texas is a major U.S. source of CO_2, both as a producer and as a consumer of fossil fuel, including oil, gas, and coal. As such, the State needs to be aware of and engaged in evolving CO_2 mitigation options.

During this project we will conduct an experiment into the feasibility of using subsurface disposal/reuse as a method of decreasing CO_2 emission to the atmosphere. This method is known as “geologic sequestration.” In this process, rather than being emitted to the atmosphere, CO_2 is captured, compressed, and injected into subsurface environments, where it is isolated (sequestered) from returning to the atmosphere long enough to reduce atmospheric concentrations.

Our experiment is designed such that the performance of the subsurface in retaining CO_2 can be measured by close monitoring with the use of diverse tools. We have selected a small-volume, limited-time test to reduce risks of any unforeseeable health, safety, or environmental impacts, as well as to optimize any increase in scientific or practical knowledge about this process while keeping infrastructure costs at a minimum.

Because carbon dioxide has been injected for decades into the subsurface of oil reservoirs, mostly in West Texas, for the purpose of enhanced oil recovery (EOR), associated engineering practices are well known. In addition, excellent opportunities exist for expanding this process to the Gulf Coast and elsewhere in the United States. The costs of decreasing atmospheric releases could therefore be offset by revenue derived from the “beneficial use” of CO_2 during disposal. Tapping this opportunity, however, would require incremental expansion of technical knowledge about this process to ensure that (1) the CO_2 is retained in the subsurface for periods long enough to have the desired impact on the atmosphere and (2) expanding EOR over larger areas and into more populated areas and areas more ecologically diverse than West Texas poses no significant risk to human or natural systems.

In our experiment, we have chosen not to move directly to injection into an oil reservoir because multiple phases in the surface make modeling flow systems and measuring plume geometries too complex. We have instead selected a brine-bearing interval above the oil-production interval, where CO_2 will be introduced into a simplified and unperturbed system of rock and brine. Were we to have selected an oil-producing interval, we would have applied for a Class II injection permit. Because we are avoiding oil for the purpose of the experiments, however, we are ineligible for this class of permit and are instead applying for a Class 5 experimental permit.

We request a Class 5 permit rather than a Class I nonhazardous injection permit because

- the injection period will be brief and concluded within a few months,
- the volume injected will be small (3,000 tons),
- the substance to be injected is benign (food-grade CO_2),
- the purpose of the experiment involves extremely close monitoring,
- the area selected for the study is not suitable for a normal Class I injection because it is faulted and penetrated by many oil wells, and
- it is of benefit to all stakeholders to quickly, safely, and economically obtain information that will be useful in moving to a larger scale test, which is likely to be undertaken within the next few years. Information and experience obtained during this Federally funded experiment should be of substantive use in designing permit and monitoring strategies for that test.

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I. General Information

I.1. Purpose, Goals, and Background of the Experiment

The planned injection is the central element of an experiment collecting needed basic data on the benefits and risks of using subsurface disposal as a method of decreasing carbon dioxide (CO_2) emission to the atmosphere. The purposes of the experiment are to

(1) demonstrate that this type of injection can be done without environmental, health, or safety risks;

(2) demonstrate that we are able to document the distribution of CO_2 in the subsurface through monitoring;

(3) document that our technical understanding of the subsurface behavior of CO_2 is adequate by matching distribution modeled by numerical simulation of the reservoir to the actual measured distribution of CO_2 in the subsurface; and

(4) gain experience for all stakeholders in permitting and conducting this type of injection.

Carbon dioxide is produced as a waste product from combustion of carbon-based fuels, as well as other industrial processes such as reforming hydrocarbons into products such as ethylene and hydrogen or calcining limestone to make cement (Hendriks and others, 2002). Currently a small fraction of the CO_2 produced by reforming is captured and sold as a commodity and chemical feedstock; the rest is vented to the atmosphere.

Over the past several decades, concern has been growing that the rate of release of CO_2 exceeds the global assimilative capacity, resulting in increasing atmospheric CO_2 concentrations. This increased concentration presents risks of forcing global climate toward a new condition, warmer on average, commonly known as global warming, which in turn can have profound impacts on diverse natural and man-made systems (see Intergovernmental Panel on Climate Change, 2003 for extensive background on this topic). The U.S. Department of Energy (DOE) has been funding a broad spectrum of research projects investigating options to respond to these risks (see carbon sequestration program overview of the U.S. Department of Energy, 2003). One of the options to reduce atmospheric emissions is that CO_2 produced by industrial and power-generation activities be captured, compressed, and injected into subsurface environments where it will be isolated (sequestered) from returning to the atmosphere for time periods that will have the desired impact of reducing the atmospheric concentrations. Subsurface disposal of CO_2 is known as “geologic sequestration.”

Under the right geologic and economic circumstances, subsurface disposal can be combined with beneficial use during a process known as CO_2 enhanced oil recovery (EOR). In the EOR process, CO_2 in a supercritical state is injected into an oil field in which production is declining. The CO_2 is dissolved in the oil, causing it to swell and become less viscous and move more rapidly to the production well. This technique is widely applied in the Permian Basin of West Texas and New Mexico. Engineering practices such as alternation of CO_2 injection with water injection (water after gas, or WAG) are used to limit the amount of CO_2 that breaks through to the producing well, and CO_2 produced with the oil is usually stripped and recycled into the injection stream.

In the past 5 years, the Bureau of Economic Geology has been conducting a search for the optimal geologic environments to apply geologic sequestration to reduce atmospheric emissions of CO_2 (see an overview of these activities at Bureau of Economic Geology, 2003, www.beg.utexas.edu/CO2). We ranked the Gulf Coast high relative to other prospective sequestration sites because this region is both a major source of CO_2 emissions and a site of excellent-quality, well-characterized subsurface environments that can be developed as sinks. We identified the Frio Formation as a high-quality target because it is very well characterized on a regional and reservoir scale and has been previously used for hazardous and nonhazardous waste disposal under underground injection control (UIC) rules. We were also attracted to the Frio Formation because of the quality of the injection interval top seal, the Anahuac Formation. We identified a number of refinery sources in the region that could supply quantities of CO_2 suitable for conducting the test.

Selection of the test plan and test site took into consideration several factors. The experiment needs to achieve the objectives listed under conditions that minimize costs and risks. Through a series of conversations with stakeholders, including DOE personnel, Texas Commission on Environmental Quality (TCEQ) staff, Railroad Commission of Texas (RRC) staff, field operators, CO_2 and UIC injection specialists, and research partners at Lawrence Berkeley National Lab (LBNL), Lawrence Livermore National Lab

(LLNL), Oak Ridge National Lab (ORNL), and National Energy Technology Laboratory (NETL), we developed the following criteria for the test site:

(1) Injection will be within an oil field. This site will allow us to obtain existing high-quality, high-density subsurface data (well logs, 3-D seismic imagery, and production history) that are needed for the experiment without the high cost of collecting data at a new site. We can use existing infrastructure, such as roads and wells, to access the site and deploy monitoring at minimal cost and with minimal additional disturbance to the environment. This approach is selected also to increase acceptability of the project by the local community because impact and field activity will be minimized.

(2) The injection interval will be within a brine-bearing sandstone below and separated from potable water. Although we are working in an oil field and injection into a Gulf Coast oil reservoir would benefit the DOE sequestration program, oil adds a degree of complexity that limits the chances of success in achieving the objectives of this study. Oil reacts with CO_2 in a complex way, which adds excessive variables to matching the modeled and observed distribution of CO_2. In addition, imaging and measuring change are more difficult in a complex system and in a system that has already been perturbed by production. A relatively simple subsurface condition in which CO_2 is introduced into a brine-rock system has greater potential for producing good results than injection into a productive interval.

(3) Although Frio sandstones are thick and regionally extensive, the best site for the pilot test is a relatively thin sandstone in a fault-bounded compartment. This setting has two advantages. For one thing, a thin, laterally discontinuous sandstone will allow measurements to be made using a small volume of CO_2 over a short time; a similar volume injected into a thick sandstone might have no measurable impact. A second advantage is that the area of impact of the injection is limited by the extent of the compartment. Because the regulatory and legal environment of CO_2 disposal with or without enhanced oil recovery is immature, this assurance of limited impact is desirable to several stakeholders. Initial model runs were conducted using probabilistic data to define the range of thickness, the acceptable pressure buildup, and the potential for successfully applying various monitoring technologies. Results were used for selecting the injection site.

We then screened a number of sites to identify the best available site for conducting the experiment and proposed this site to DOE. We selected the idle wells operated in South Liberty oil field by Texas American Resources Company (TARC). These wells have produced oil from the Yegua Formation at a depth of about 8,000 ft and pass through the upper Frio Formation at about 5,000 ft. A recent 3-D seismic survey was made available by TARC to assess the site, as well as a set of wireline logs from the field. The seismic survey shows that faulting on the northwest and southeast side and the salt dome on the northeast side segment the Frio near the selected wells into a small block on the three updip sides. On the basis of modeling, we determined that drilling a new injection well 100 ft due south of Sun-Gulf Humble Fee No. 4 will provide the best experimental conditions. Sun-Gulf Humble Fee No. 4 will be recompleted as a monitoring well in the upper Frio by plugging back the lower producing interval and perforating the upper Frio. Figure I-1 shows a scale overview of the injection relative to geologic and cultural features.

The project is funded solely by DOE under phase III of the project Optimal Geological Environments for Carbon Dioxide Disposal in Brine Formations (Saline Aquifers) in the United States—Pilot Experiment in the Frio Formation, Houston Area, and the research described in this report is its only purpose. An assessment of environmental impact of this experiment has been prepared for the DOE and is available for review (U.S. Department of Energy National Energy Technology Laboratory, 2003).

The permitting strategy for the injection well was initially unclear. The well is within an oil field, and such wells are normally permitted under RRC rules. However, the new well is not intended to enhance oil production or dispose of prerefinery oil field waste and is, therefore, not eligible for a Class II permit. The site is within an oil field having numerous well penetrations and nearby faults. Although this setting was selected deliberately to optimize this experiment, it is not the type of environment that would normally be selected for siting a Class I nonhazardous disposal well. The Class I construction and plug and abandon protocols are also costly relative to the brief duration of the injection period and may not be a careful use of public moneys that are expended to support this project. The benign character of the injectate (food-grade CO_2), the experimental nature of the project, the close monitoring using multiple measurements, and the careful experimental design to minimize risk to health, safety, and the environment led to the proposal for a Class 5 experimental injection application. In addition to the Class 5 application, we provide this report, which reviews relevant information and well engineering following the outline of a Class I permit to demonstrate adequate well design.

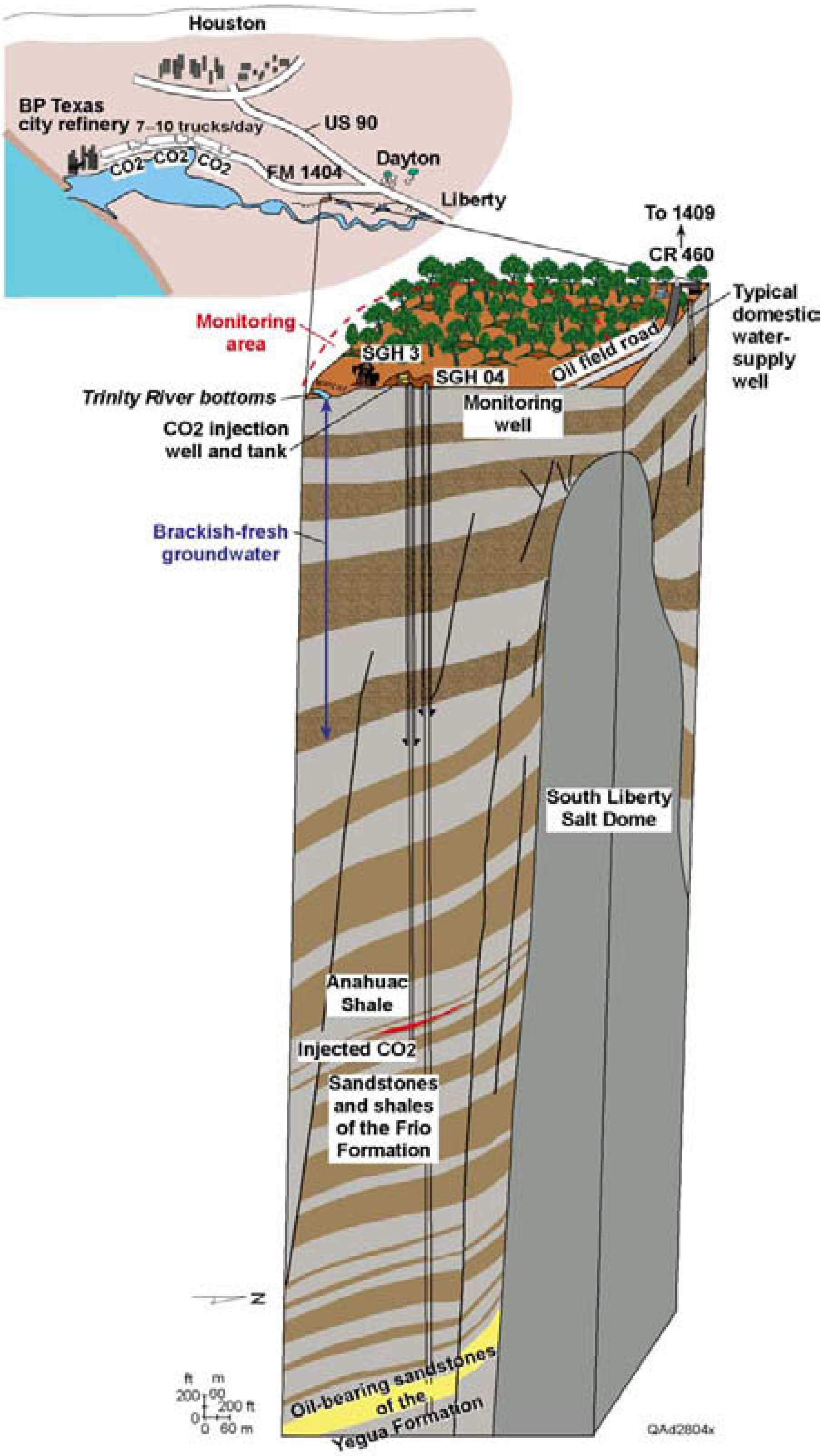


Figure I-1. True-scale overview of the CO_2 injection relative to geologic and cultural features.

I.2. Well Location

The well is located 4.7 miles south-southwest of the town of Dayton, Texas, and 5.5 miles south-southeast of Liberty, Texas, in Liberty County, on the Sun-Gulf Humble Fee Tract No. 1, Wm. D. Smith League A-106, in the South Liberty oil field, at latitude 29° 59' 24.36" north and longitude 94° 50' 39.84". Figure I-2 shows the regional location, and figures I-3, I-4, and I-5 provide detailed location information.

The injection well will be drilled by the Bureau of Economic Geology, The University of Texas at Austin. The Sun-Gulf-Humble No. 4 fee well that will be converted to a monitoring well is owned by Texas American Resources. Subsurface rights belong to Texas American Resources.

The project is led by the Bureau of Economic Geology. The experiment has been designed by a team that includes members of the GEOSEQ project (LBNL, LLNL, ORNL), NETL, Schlumberger–Doll Research Center, and Transpetco. Sandia Technologies is the field service provider and has designed the injection well, has provided support for development of the experimental procedures, and will subcontract and supervise all the injection well activities.

The injection interval for the experiment will be into the lower half of an 80-ft-thick sandstone of the upper Frio Formation at a depth 5,030 ft below surface. The injection will be 3,000 tons of food-grade CO_2, including environmentally benign perfluorocarbon tracers (PFT), which will allow accurate determination of the extent to which the CO_2 was retained within zone. The injection will be completed within a 3-month period. The experiment will be monitored by gas and brine sampling in the injection zone, sampling in the sandstone above the injection zone, monitoring change before and after injection with cross-well geophysics, and collection of a pre- and postinjection vertical seismic profile (VSP). As part of the experiment, groundwater, soil gas, and air will be monitored for changes in CO_2 concentration and presence of tracer before, during, and after the experiment, focusing on areas identified as leakage risks. After postinjection monitoring is completed, the injection and monitoring wells will be plugged and abandoned following RRC rules.

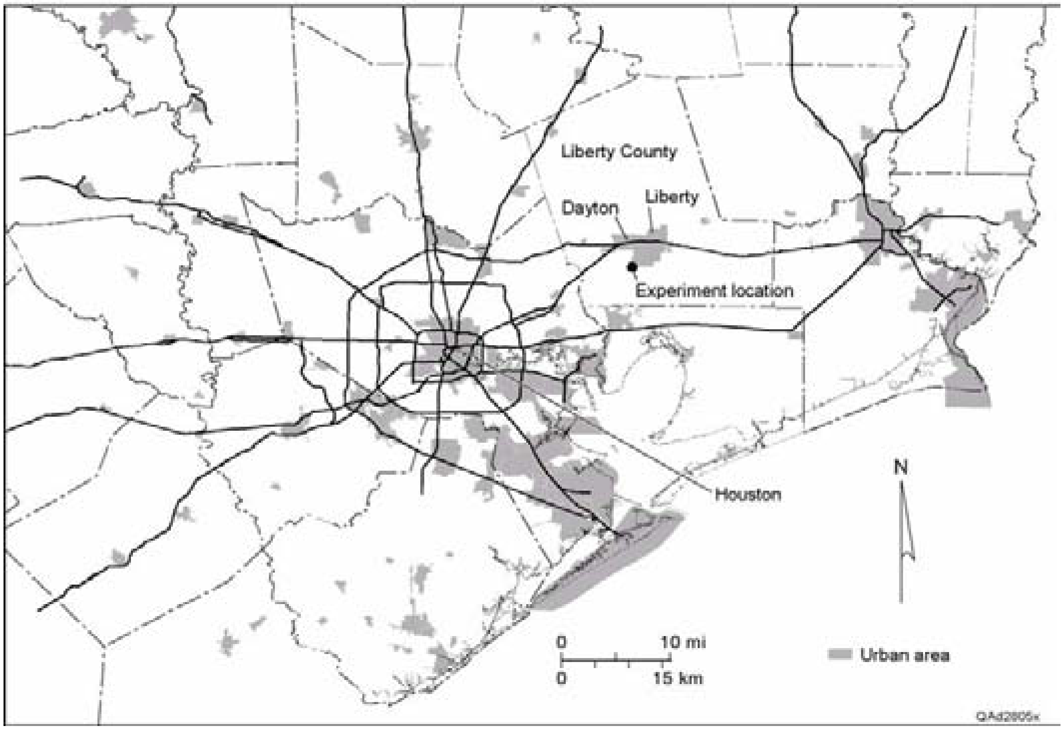


Figure I-2. Regional location of the site detailed location information.

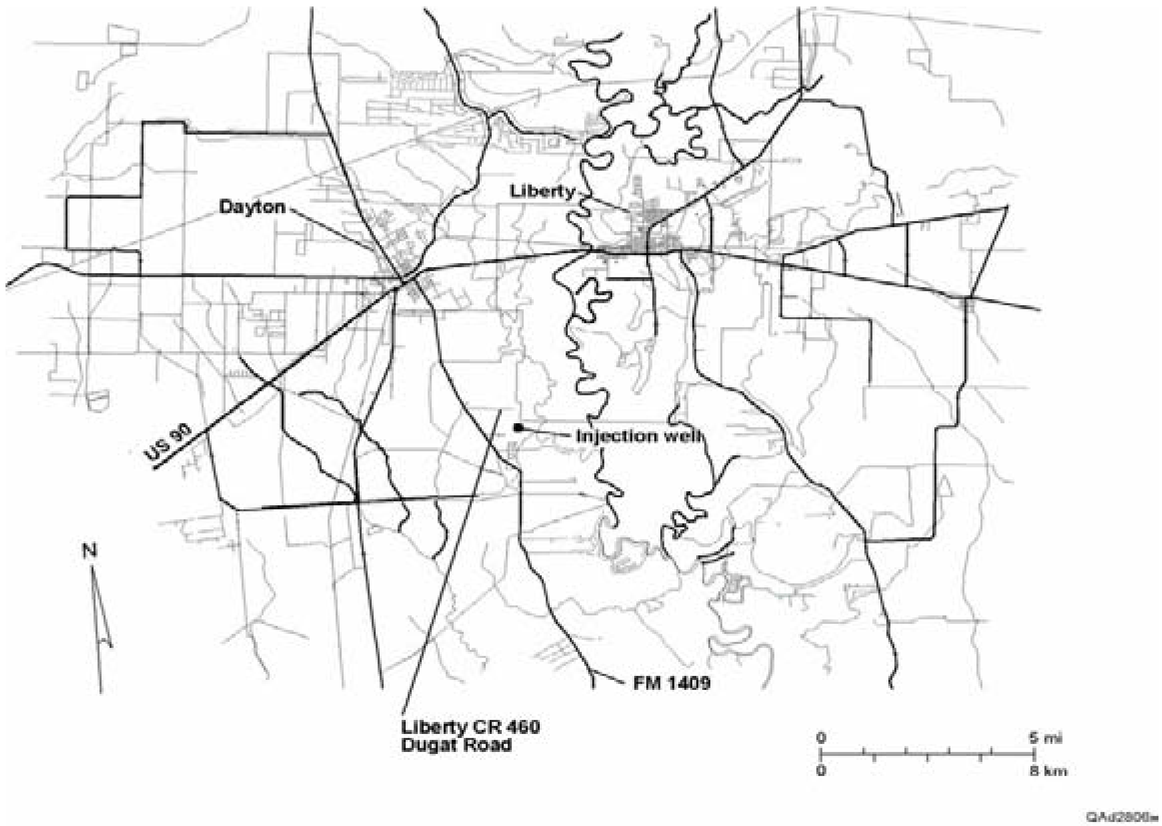


Figure I-3. Site location detail.

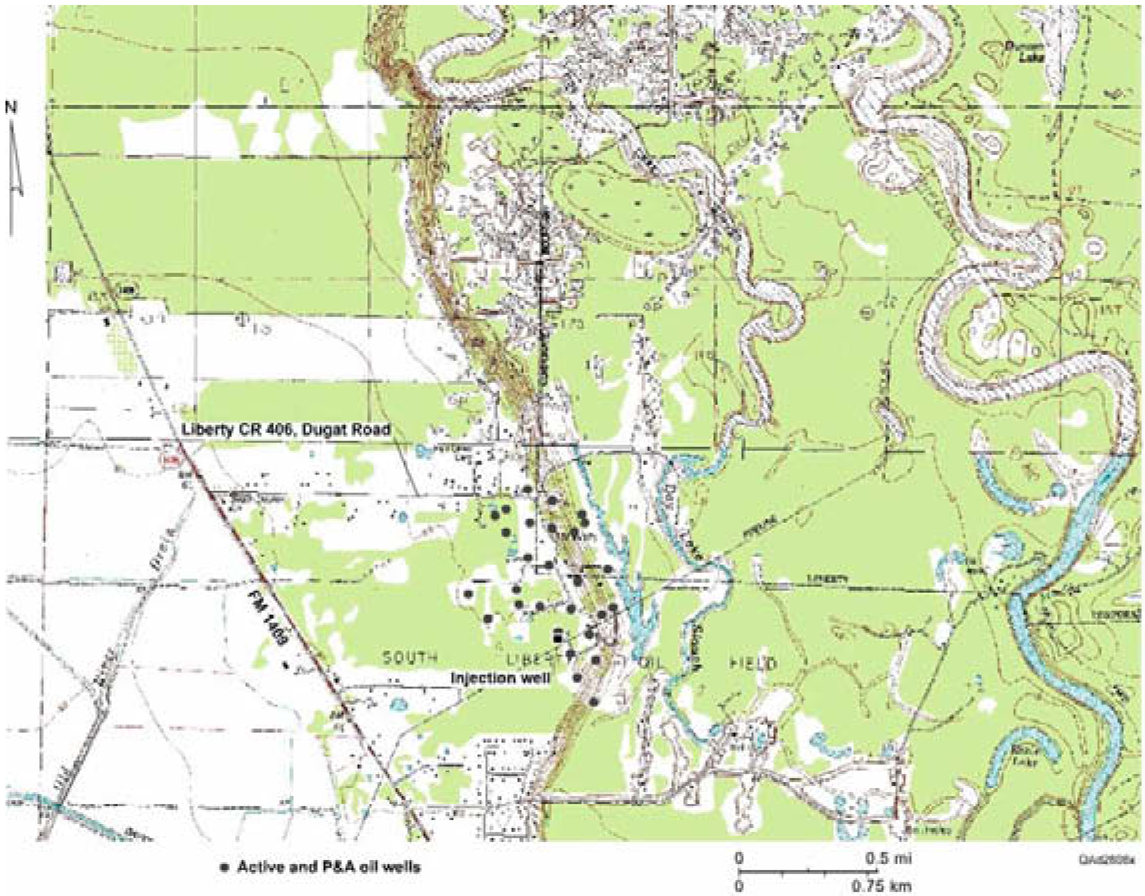


Figure I-4. Topographic map of the experiment site showing oil well locations and bluff to east of the site and a small lake (stippled area) within the Trinity River valley. Note also locations of existing well to be converted to monitor wells, SGH 4, and location of the new CO_2 injection well, about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

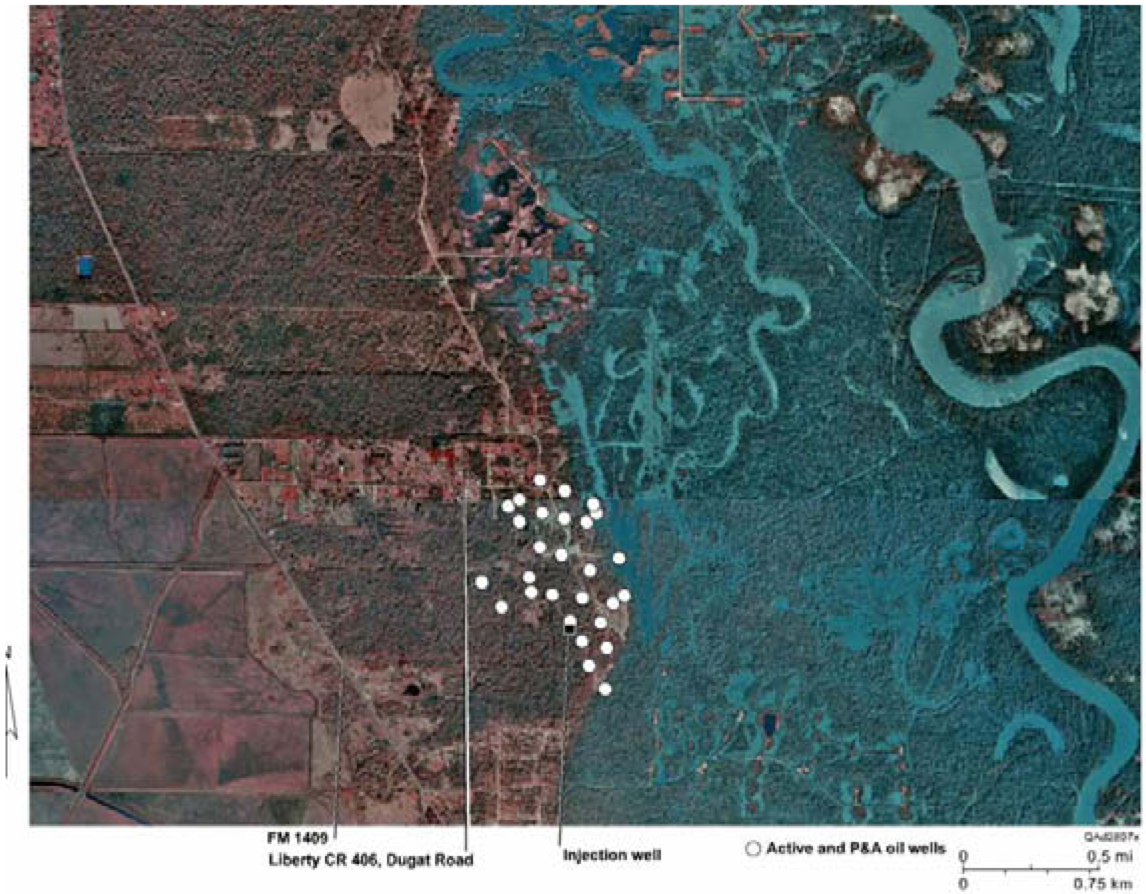


Figure I-5. Air photograph of the site, showing land uses and location of the oil wells.

II. Public Information

A central part of this project is providing information to the public about the option of using geologic sequestration to reduce CO_2 emissions to the atmosphere. We have attempted to engage the public through all phases of the project, and the results will be made publicly available through technical and nontechnical presentations and publications. The team has made numerous presentations and has developed a publicly available Web site reviewing project progress (www.beg.utexas.edu/CO_2). During the site-selection process, we gave a talk and paper to the Houston Geological Society (Knox and Hovorka, 2001), and have made numerous technical publications and presentation (Hovorka and others, 2001, 2002, in press; Hovorka and Knox, 2002, 2003; Holtz, 2003; Knox and others 2003). After the site was selected, Dayton city manager Robert Ewart hosted a meeting May 1, 2003, to provide information to local officials (table II-1). Hovorka presented an overview of the project to Dayton community leaders and to the local press June 19, 2003, at the Dayton Rotary Club and did a walking canvass of the neighborhood along CR 460 (Dugat Road) to provide information to residents. Surface and mineral rights owners (fig. II-1; table II-2) will be contacted to obtain access for seismic data acquisition. Additional presentations by Bureau staff and other team members are scheduled during and after the injection.

Table II-1. Local officials informed about the Frio Brine Project by letter April 28, 2003, and by meeting May 3, 2003.

Last Name	First Name	Agency	Position	Address1	Address3	Phone
Iverson	Neal	City of Dayton	Attorney	104 E. Clayton	Dayton, TX, 77535	(936) 258-8025
Ewart	Robert	City of Dayton	Manager	111 North Church Street	Dayton, TX 77535	(936) 258-2642
Conner	Alan	Central Appraisal District	Chief Appraiser	P.O. Box 10016	Liberty, TX	(936) 336-5722
Brown	Norman	Precinct 4	Commissioner	P.O. Box 88	Dayton, TX 77535	(936) 258-5202
Kirkham	Lloyd	Liberty County	County Judge	1923 Sam Houston	Liberty, TX, 77575	(936) 336-4665
Harris	Guy	City of Dayton	Mayor	111 North Church Road	Dayton, TX 77535	(936) 258-7605
Halstead	Bruce	City of Liberty	Mayor	1829 Sam Houston	Liberty, TX 77575	(936) 336-7361
Fontenot	Todd	Precinct 1	Commissioner	1923 Sam Houston	Liberty, TX 77575	(936) 336-4638

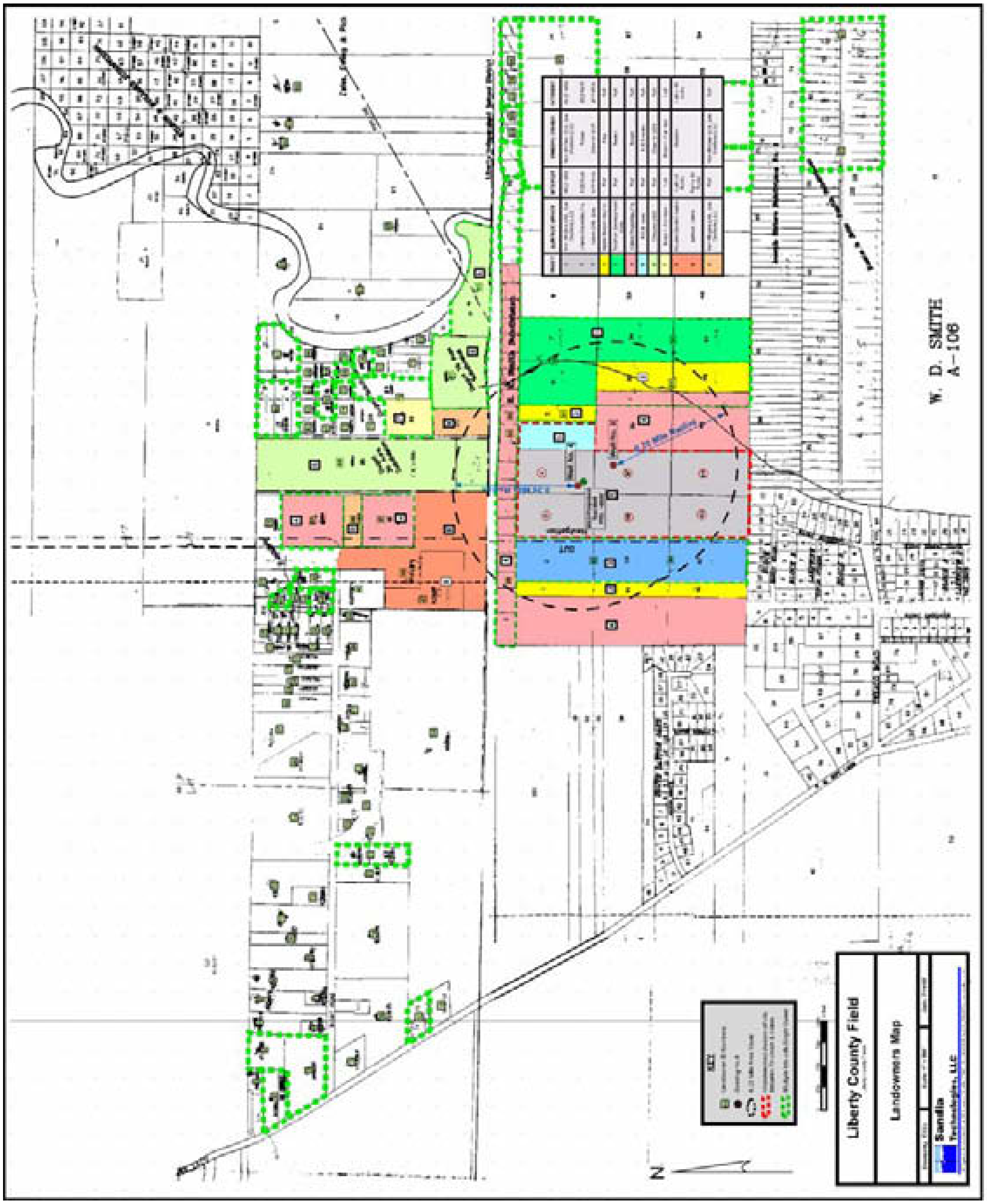


Figure II-1. Surface ownership and mineral rights, numbers keyed to table II-2.

Table II-2. Surface ownership.

Tract	Surface owner	Mineral owner
1	Kerr McGee O&G Onshore LLC Dallas, Texas Alders Properties, Inc. (3/22) P.O. Drawer 10 Dayton, Texas 77535 Odum O&G (3/22) 4705 Osage Drive Boulder, Colorado 80303	Kerr McGee O&G Onshore LLC Dallas, Texas Exxon (3/22) P.O. Box 53 Houston, Texas 77001-0053 Chevron (3/22) P.O. Box 285 Houston, Texas 77001-0285
2	Vastar Resources Property Tax Dept. P.O. Box 3092 Houston, Texas 77253-3092	ARCO Property Tax Dept. P.O. Box 3092 Houston, Texas 77253-3092
3	Tri-Union Development Corp. c/o Cochran & Co. Walters Road Houston, Texas 77268-1093	Texaco c/o Chevron P.O. Box 285 Houston, Texas 77001-0285
4	Alders Properties, Inc. P.O. Drawer 10 Dayton, Texas 77535	Exxon P.O. Box 53 Houston, Texas 77001-0053
5	R. E. Brooks	R. E. Brooks
6	Chevron P.O. Box 285 Houston, Texas 77001-0285	Chevron P.O. Box 285 Houston, Texas 77001-0285
7	B. F. Harrison c/o Texas Commerce Bank Bldg. 707 Travis, Suite 1900 Houston, Texas 77002-3299	B. F. Harrison c/o Texas Commerce Bank Bldg. 707 Travis, Suite 1900 Houston, Texas 77002-3299
8	Houston Daniel Trustee (9 acres) P.O. Box 1 Liberty, Texas 77535 Weldon Alders (30 acres) P.O. Drawer 10 Dayton, Texas 77535	Houston Daniel Trustee P.O. Box 1 Liberty, Texas 77535
9	Kerr McGee O&G Onshore LLC Dallas, Texas	Kerr McGee O&G Onshore LLC Dallas, Texas

III. Impact of Injection on Gas and on Oil Production

The injection will occur within an oil field, raising the question of impact on oil and gas resources. The injection site will be an unproductive, brine-bearing sandstone near the top of the Frio Formation. Resistivity and SP log character indicate that the interval lacks oil and gas. The Frio Formation historically produced oil in structurally higher areas on the flank of the dome (fig. III-1). Two or three Frio production wells lie within the same fault block as the injection. Migration of CO_2 the half-mile updip into oil-bearing parts of the formation is unlikely to occur because the injected volume is small. Modeling predicts that the maximum updip extent that the CO_2 will move under Frio-like conditions is about 300 ft from the injection well. Observation during the experiment will document the validity of this assessment. If the CO_2 moves farther updip than predicted and interacts with oil, it will not damage resources but most likely will mobilize minor amounts of additional resource, as is done in enhanced oil recovery. Because CO_2 is buoyant relative to brine at injection interval conditions, risk of CO_2 interaction with resources in deeper intervals (Yegua production at 8,000 ft) near the injection site is unlikely. Additionally the Vicksburg Formation, containing multiple shales and sandstone bodies, lies between the Frio and the Yegua, forming a formidable barrier.

In a field undergoing a CO_2 flood, well casings, tubings, and other equipment are usually replaced by equipment designed to be corrosion resistant. Because of the small volume and short injection for this experiment, we do not plan to replace well casings. Geochemical reactive transport modeling using Frio rock and brine composition (Knauss and others, in press) shows that pH near the CO_2 front can fall as low as 5.28; however, within a distance of 120 ft, pH rises to near ambient values of 6.74 because of buffering by calcite and other reactive phases in the rock. This natural buffering limits the risk of damage that might otherwise result if corrosive brine encountered other well casings in the field. Long-term interaction with CO_2 might weaken cements; however, because of the small volume and short duration of the injection and the buffering capacity of the rock, we see minimal risk of long-term weakening of cement. The experiment will critically evaluate the validity of these assessments and provide needed information to assure the safety of larger scale, longer term projects.

We have requested a letter from RRC that this injection experiment will not damage resources.

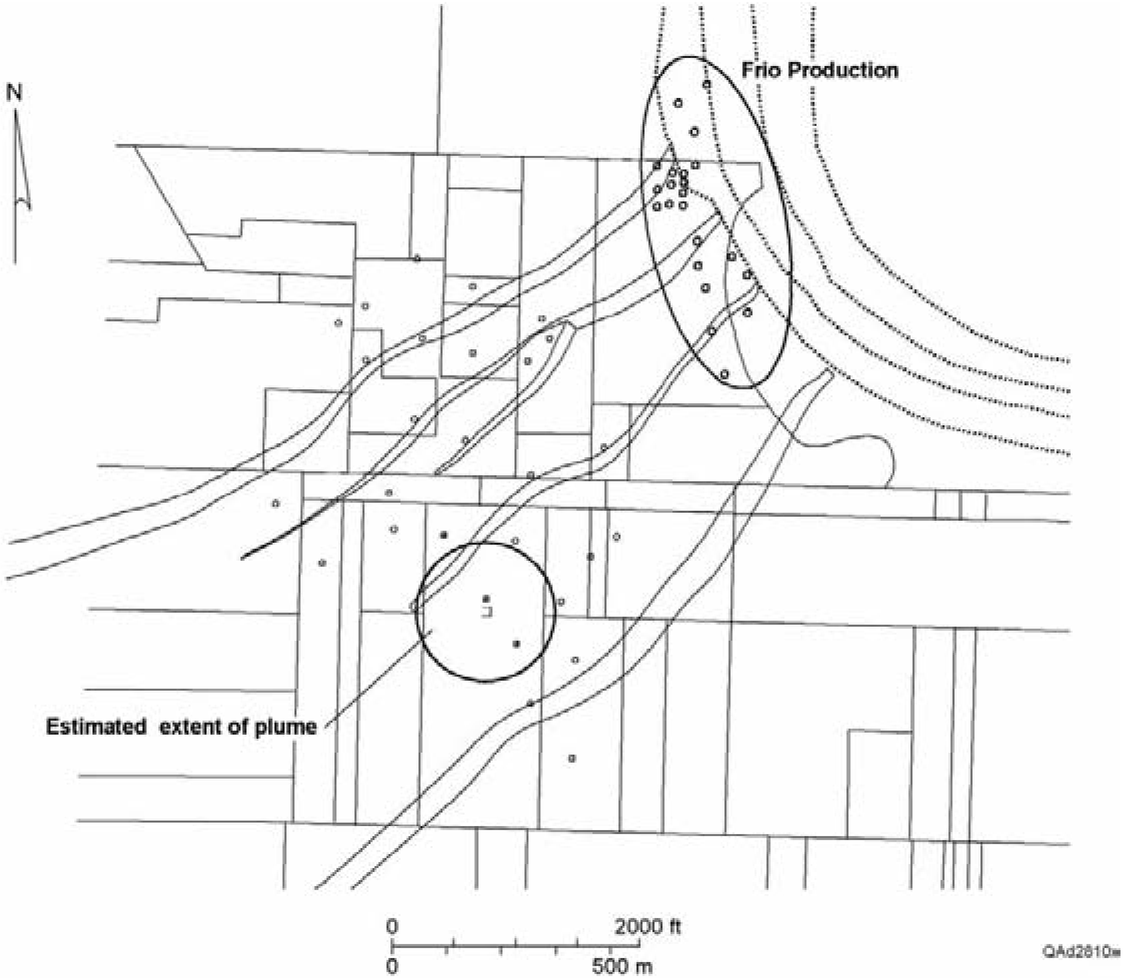


Figure III-1. Historical production in South Liberty oil field. Historical Frio production well locations extracted from Halbouty (1962). Overlaid is TOUGH2 simulation of maximum extent of CO_2 plume under Frio-like conditions. Details and discussion of TOUGH2 simulations done for this project in section VII.

IV. Financial Assurance

The injection well will be plugged and abandoned at the end of the pilot project under Federal funding during the period that the Bureau is still under contract to DOE.

V. Geology and Hydrology

V.1. Regional Geology—Overview

The stratigraphy and hydrogeology of the Gulf Coast have been studied intensively and are well known. In this report we provide a brief overview of the elements relevant to the injection.

During the Late Triassic to Early Jurassic Period, early phases of continental rifting resulted in the deposition of nonmarine red-bed and deltaic sediments overlain by a thick sequence of anhydrite and salt beds (Werner Anhydrite and Louann Salt) in the ancestral Gulf of Mexico. Shallow-water carbonate and clastic rocks of the Smackover, Buckner, and Haynesville Formations and Cotton Valley Group were deposited from the Late Jurassic into the Late Cretaceous. Tertiary sandstones and shales were deposited in progradational wedges in continental, marginal-marine, nearshore marine, shelf, and basinal environments, forming a complex depositional system along the Texas Gulf Coast. Tertiary sediments accumulated to great thickness where the continental platform began to build toward the Gulf of Mexico, beyond the underlying Mesozoic shelf margin and onto transitional oceanic crust. Rapid loading of sand on water-saturated prodelta and continental slope muds resulted in contemporaneous growth faulting (Loucks and others, 1986). The effect of this syndepositional faulting was a significant expansion of the sedimentary section on the downthrown side of the faults. Sediment loading also led to salt diapirism, with its associated faulting and formation of large salt-withdrawal basins (Galloway and others, 1982). Major transgressive and regressive episodes of the Tertiary section and the consistent pattern of Gulfward thickening are illustrated in figures V-1 and V-2. Overlying the Tertiary progradational wedges are the Pleistocene and Holocene sediments of the Quaternary Period. Pleistocene sedimentation occurred during a period of complex glacial activity and corresponding sea-level changes. As the glaciers made their final retreat, Holocene sediments were deposited under the influence of an irregular, but rising, sea level. Quaternary sedimentation along the Texas Gulf Coast occurred in fluvial, marginal-marine, and marine environments. Recent sediments are found in flood plains and coastal environments.

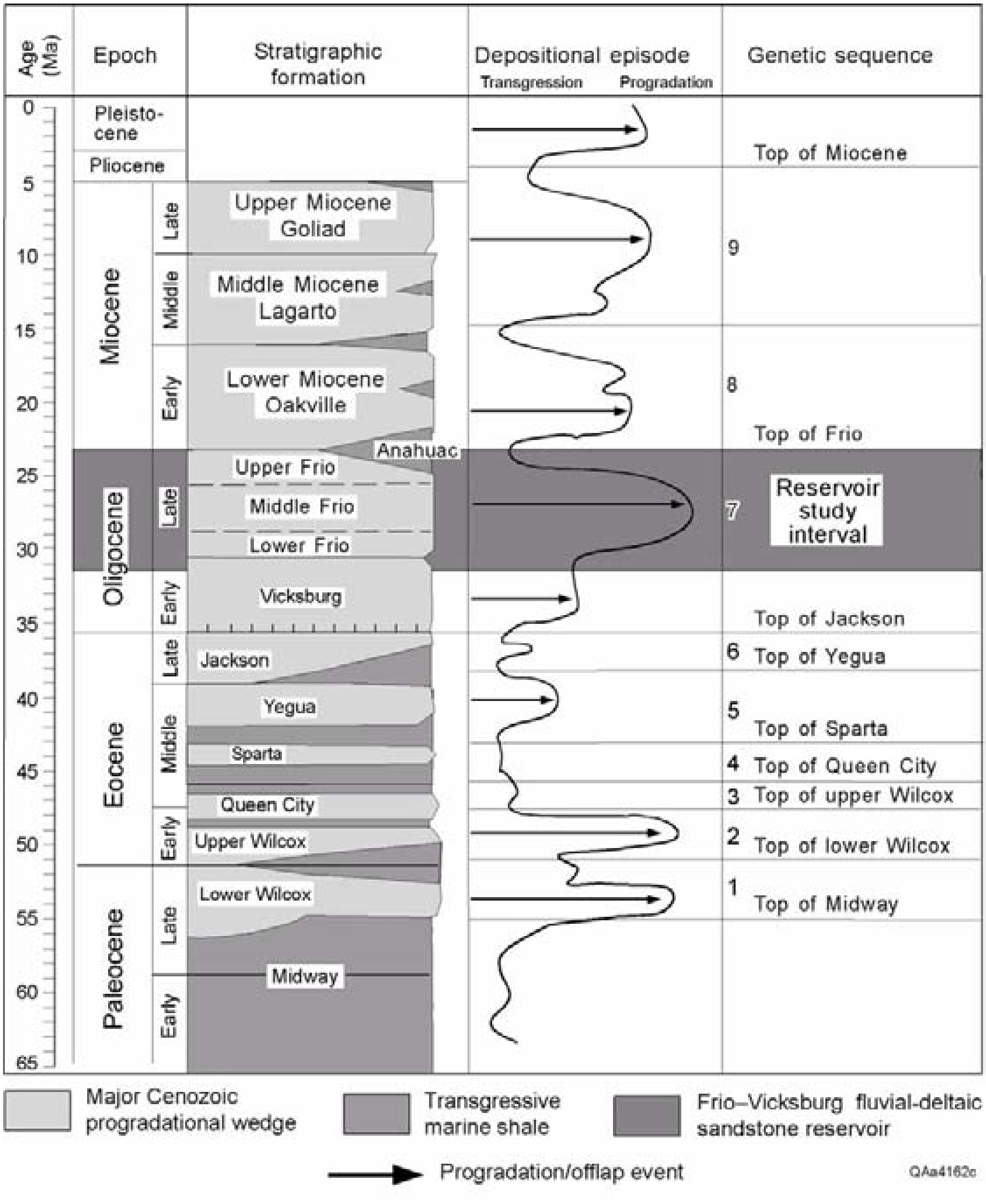


Figure V-1. Generalized stratigraphic section of the Gulf Coast.

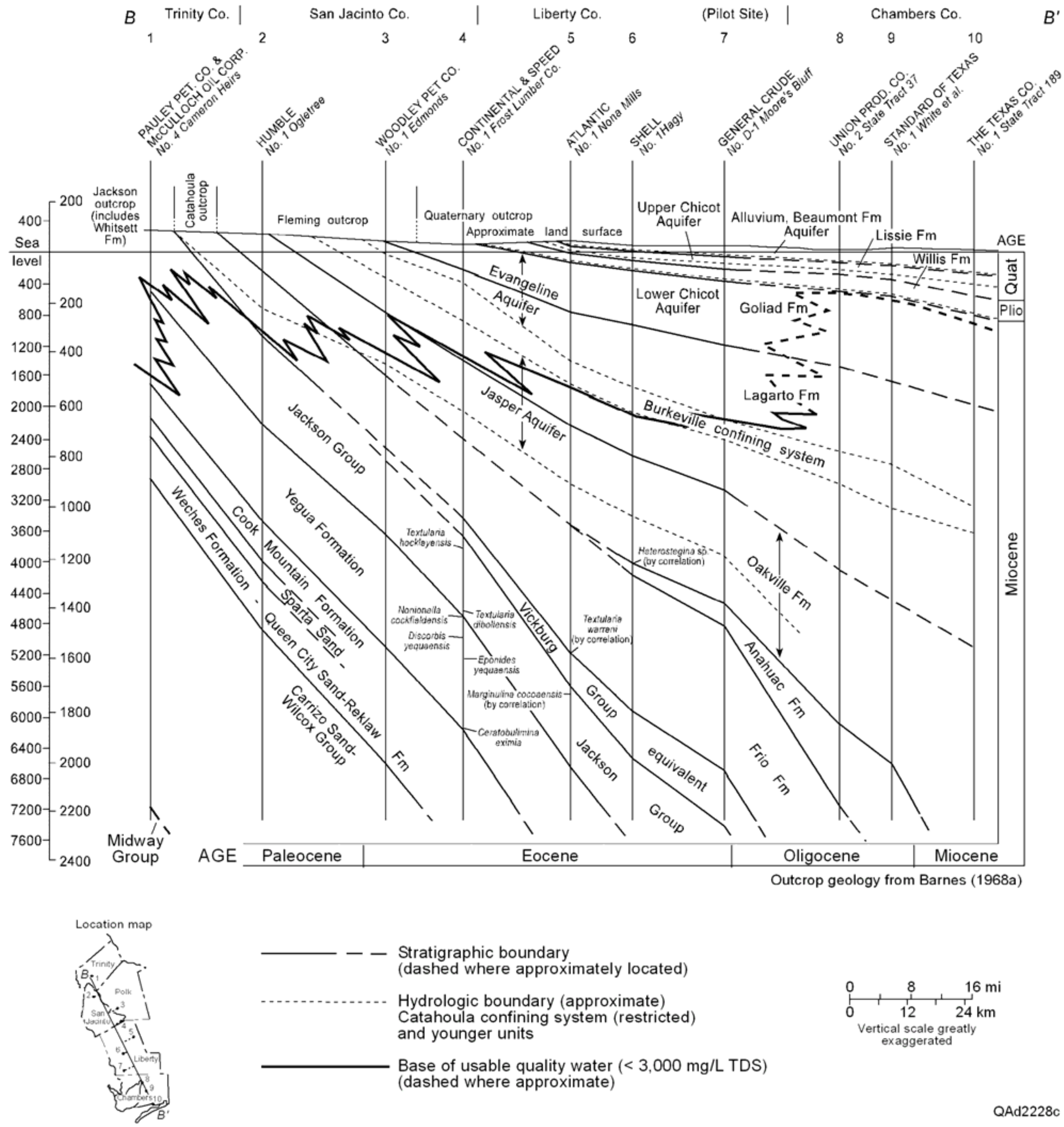


Figure V-2. Dip-oriented regional cross section through experiment site showing relationship of stratigraphic units to hydrologic units. Modified from Baker (1979). Some stratigraphy and thickness for units above the Anahuac taken from Guevara-Sanchez (1974), Morton and others (1985), and Galloway and others (1991). (QAd2228)

V.1.1. Stratigraphy

V.1.1.1. Pre-Frio Stratigraphy

Stratigraphic units below the Frio Formation were not examined in detail but should be mentioned because they are significant producing units in South Liberty field. The Eocene section includes the Claiborne Group (Cook Mountain, Yegua, and Cockfield Formations) and has significant deltaic and shore-zone sandstone facies in the region of the site (Galloway and others, 1991). Overlying Eocene Jackson and Oligocene Vicksburg groups are shale-dominated offshore and prodelta deposits in the site area that hydrologically isolate the reservoirs in the Yegua and Cook Mountain sandstones from the injection zone in the Frio Formation. Figure V-2 gives a representative overview of the complex geometries of sandstone and shale sequences in this stratigraphic interval.

V.1.1.2. Frio Formation

The regional depositional environment of the Frio Formation is described in some detail because it is the host for the injection. Figures V-3, V-4, and V-5 show the structural elevation, thickness, and net sand of the Frio Formation. Detailed regional stratigraphy and injection parameters for the Frio Formation are reviewed online at www.beg.utexas.edu/CO2.

Regional understanding of depositional environment was used to help optimize interpretation of data in the reservoir-scale model. Deposition of the progradational Frio wedge was initiated by a major global fall in sea level, with subsequent Frio sediments being deposited under the influence of a slowly rising sea (Galloway and others, 1982). On a regional scale, the Frio and Catahoula Formations can be divided into a number of distinct depositional systems that are related spatially and temporally. Two major progradational delta complexes, designated the Houston and Norias delta systems and identified by Galloway and others (1982), were centered in the Houston and Rio Grande Embayments, respectively. Separating the two delta complexes was a broad barrier island/strandplain system (Greta/Carancahua) along the south-central Texas coast. A similar but smaller barrier island/strandplain system (Buna) was deposited by longshore currents off the eastern flank of the Houston delta system (Galloway and others, 1982). Two Catahoula Formation fluvial systems, the Chita/Corrigan and the Gueydan, supplied sediment to the delta complexes. Frio sandstone of the upper Texas Gulf Coast contains a higher percentage of quartz, less feldspar, and fewer volcanic rock fragments (quartzose feldspathic volcanic litharenite), than Frio sandstone (feldspathic litharenite) of the lower Texas Gulf Coast (Bebout and others, 1978, p. 43).

The Houston delta system of East Texas underlies parts of nine counties centered on southern Harris County. The system is composed of several minor, laterally coalescent, and frequently shifting delta lobes (Galloway and others, 1982). Streams of the Chita/Corrigan fluvial system of the Catahoula Formation supplied sediment. Updip deltas exhibited wave-dominated, arcuate geometries, whereas lobate delta geometries characterized episodes of maximum progradation or an area where high subsidence rates were associated with salt-withdrawal basins (Galloway and others, 1982). As a result of switching of delta lobes, the rate of coastal progradation was slow for the Houston delta system (Galloway and others, 1982).

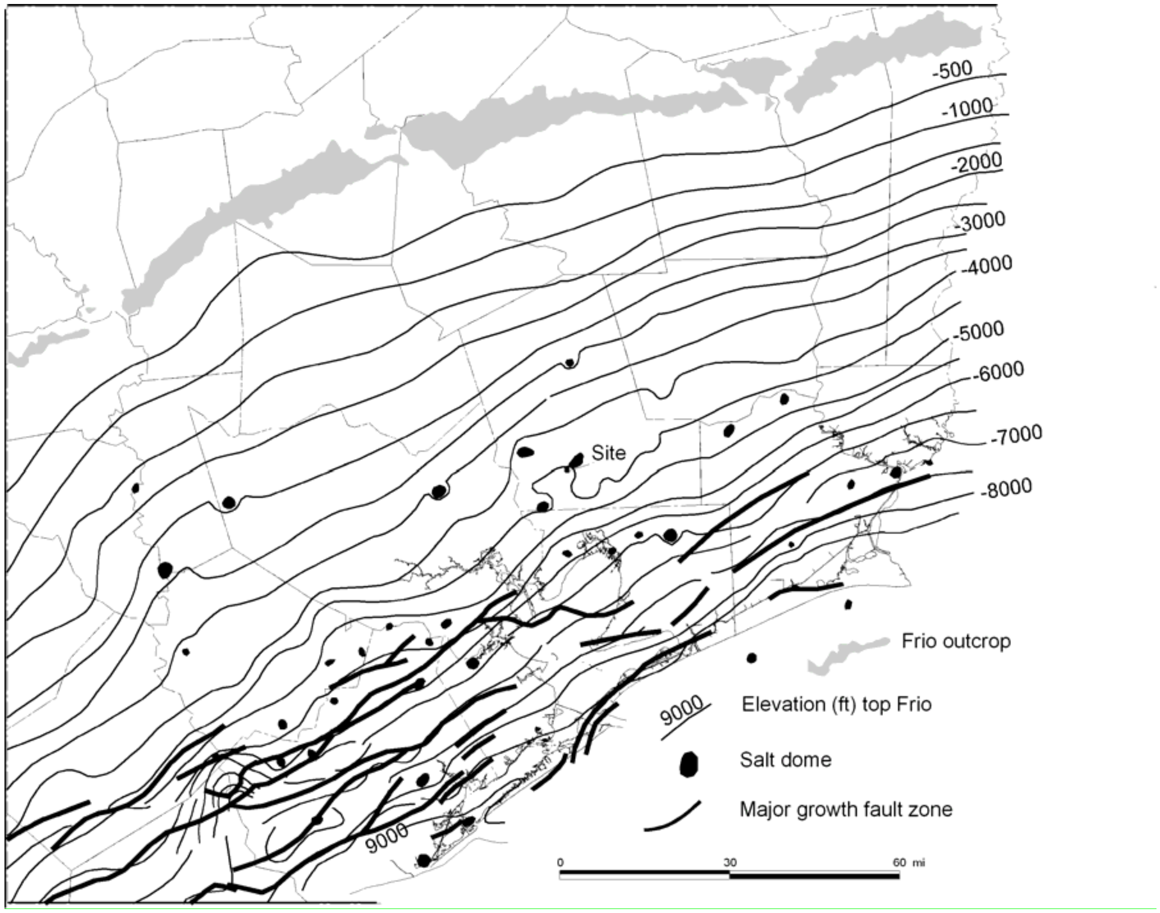


Figure V-3. Structural elevation of the top of the Frio Formation, location of major growth faults, and piercement salt domes. Compiled from Galloway and others (1982).

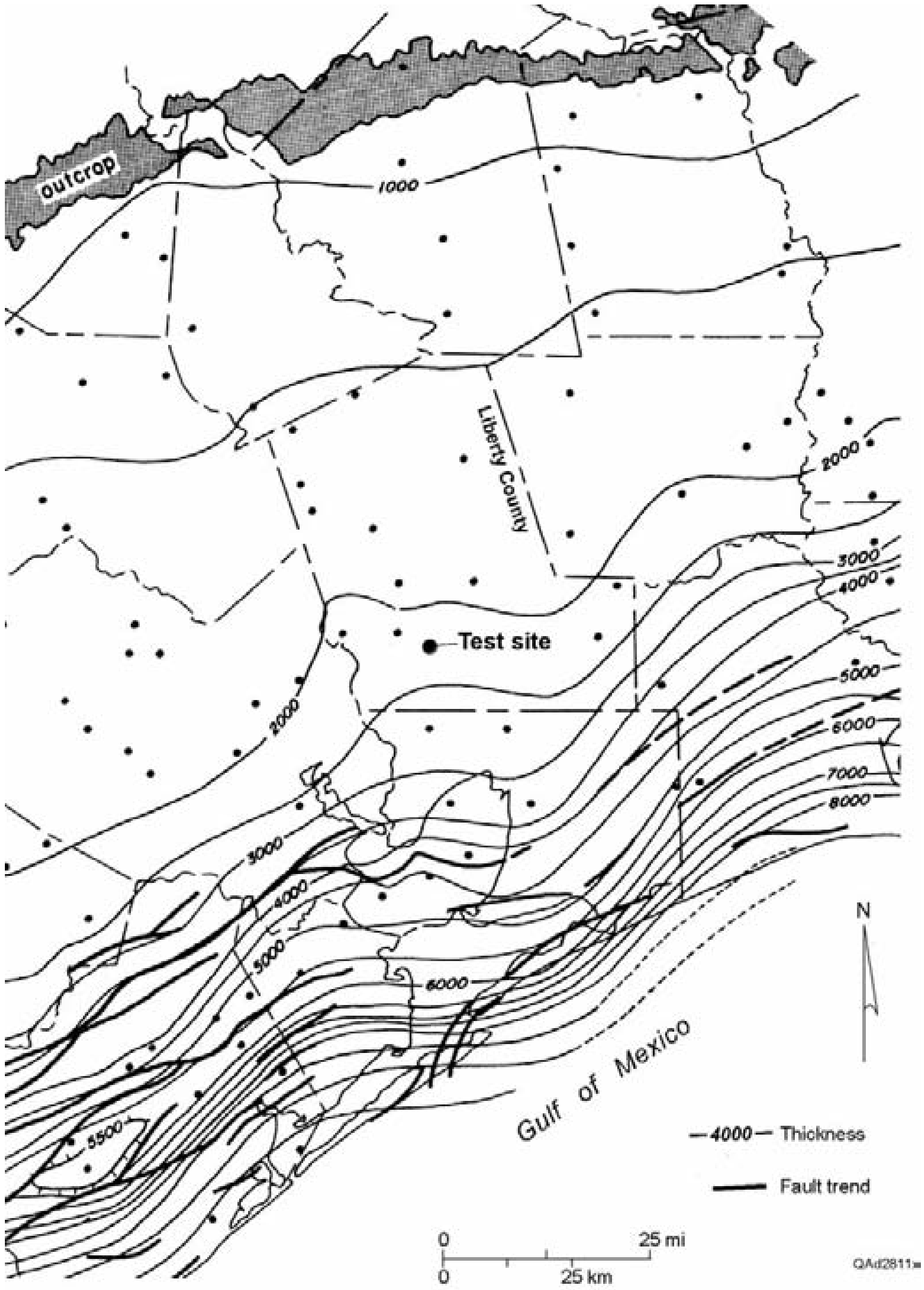


Figure V-4. Isopach of the Frio Formation, excerpted from plate III of Galloway and others (1982).

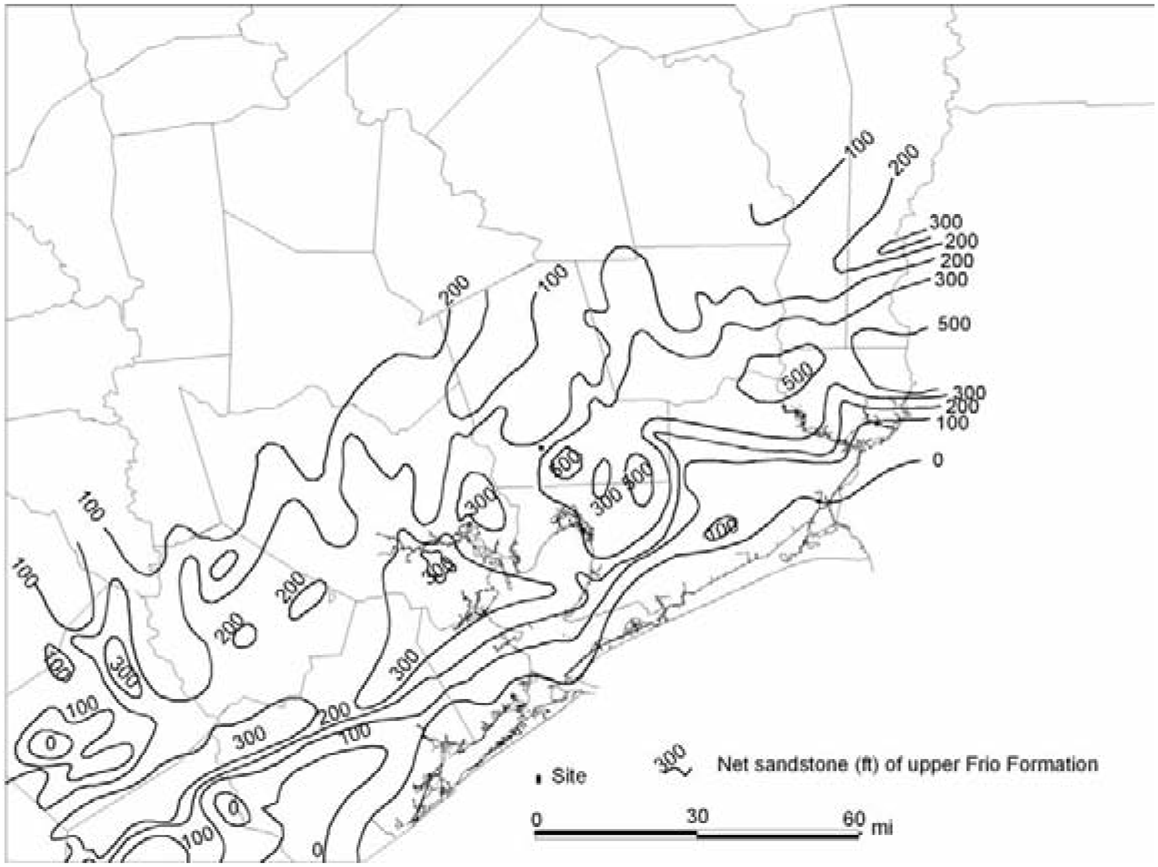


Figure V-5. Net sand of the upper unit of the Frio Formation. Modified from Galloway and others (1982).

V.1.1.3. Anahuac Formation

The Anahuac was selected as the injection interval seal because it is a regionally thick and well-known shale. It was deposited as sea level continued to rise during the late Oligocene and the underlying Frio progradational platform flooded. Wave reworking of sediment along the encroaching shoreline produced thick, time-transgressive blanket sands at the top of the Frio Formation and base of the Anahuac Formation (Marg-Frio) section. The transgressive Anahuac marine shale was deposited conformably on top of the blanket sands throughout the Texas and Louisiana coastal region. The injection is hosted by one of these reworked fluvial sands. The Anahuac Shale was deposited in an open-shelf environment and is typically composed of calcareous marine shales and localized, lenticular, micritic limestone units. The Anahuac Shale thickens from its onshore margin to nearly 2,000 ft offshore in the Gulf of Mexico (Galloway and others, 1982).

V.1.1.4. Fleming Group

The Miocene Fleming Group, which was deposited throughout the Gulf Coast, is subregionally divided into the Oakville Formation and the Lagarto Formation, separated by the Burkville confining system. Deposition of the Fleming Group occurred in relatively shallow water across the broad, submerged, shelf platform constructed during Frio and Anahuac deposition.

Along the northeastern boundary of Texas, the Newton fluvial system supplied sediment to the Calcasieu delta system of Southeast Texas and Southwest Louisiana. Sands of the Newton fluvial system are fine to medium grained and have thick, vertically and laterally amalgamated sand lithosome geometries typical of meanderbelt fluvial systems (Galloway and Cheng, 1985). Depositional patterns within the Oakville Formation (lower Fleming) of Southeast Texas show facies assemblages typical of a delta-fringing strandplain system (Galloway and Cheng, 1985). The Calcasieu delta system is best developed in Southeast Texas in the Lagarto Formation of the upper Fleming. The delta system consists of stacked delta-front, coastal-barrier, and interbedded delta-destructional shoreline sandstones that compose the main body of the delta system, with interbedded prodelta mudstones and progradational sandy sequences deposited along the distal margin of the delta (Galloway and others, 1986).

The structure on the base of the Fleming as interpreted for aquifer studies is presented in figure V-6. Regional characteristics of the lower Fleming section are presented online at www.beg.utexas.edu/CO_2 (Jasper aquifer).

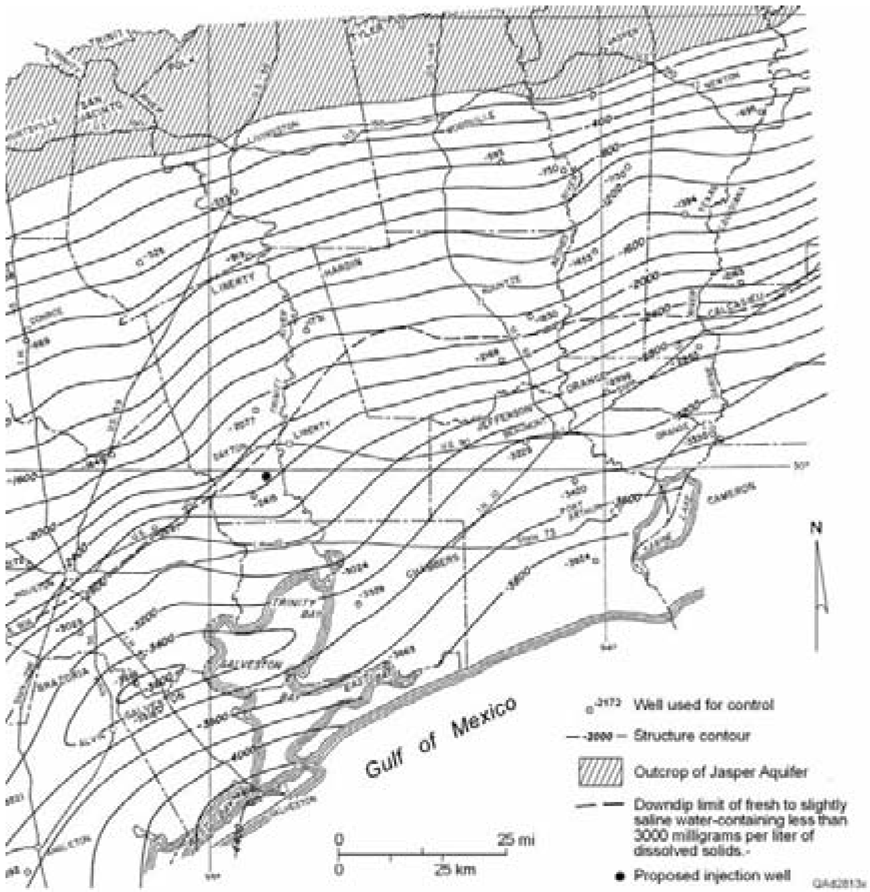


Figure V-6. Altitude of the top of the Jasper aquifer showing downdip extent of slightly saline water. Modified from Baker (1986).

V.1.1.5. Pliocene, Pleistocene, and Recent

Miocene-Pliocene-aged sediments of the Goliad Formation are composed of heterogeneous interbedded clay, silt, and sand deposited in fluvial, deltaic, and marginal-marine environments. The section thickens in a downdip direction toward the present-day coastline and has a variable thickness along strike. Sandstones of the Goliad Formation are the lowermost units containing fresh to slightly saline water at the site and from the upper part of the Evangeline aquifer. The approximate elevation of the base of the Evangeline aquifer is shown in figure V-7. Pleistocene-aged clay sand and minor siliceous gravel of the Willis and Lissie Formations were deposited in fluvial and deltaic environments (Guevara-Sanchez, 1974; Galloway and others, 1991). Pleistocene Beaumont, late Pleistocene to Holocene Deweyville, and Holocene alluvial units contain freshwater and comprise the Chicot aquifer. The approximate elevation of the base of the

Chicot aquifer is shown in figure V-8. Regional shales deposited during transgressions form a complex system of semiconfining units that impact groundwater resources (Kreitler and others, 1977). A regional geologic map showing the distribution of units at the surface is presented in figure V-9.

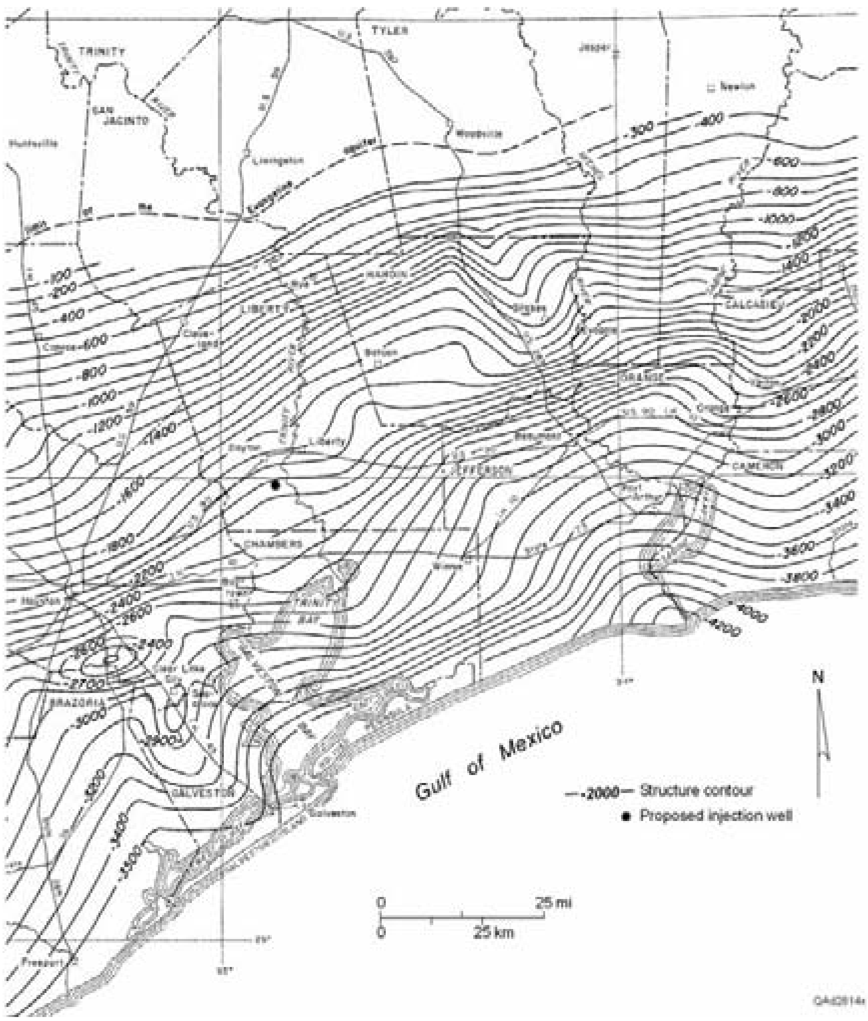


Figure V-7. Altitude of the base of the Evangeline aquifer (from Carr and others, 1985).

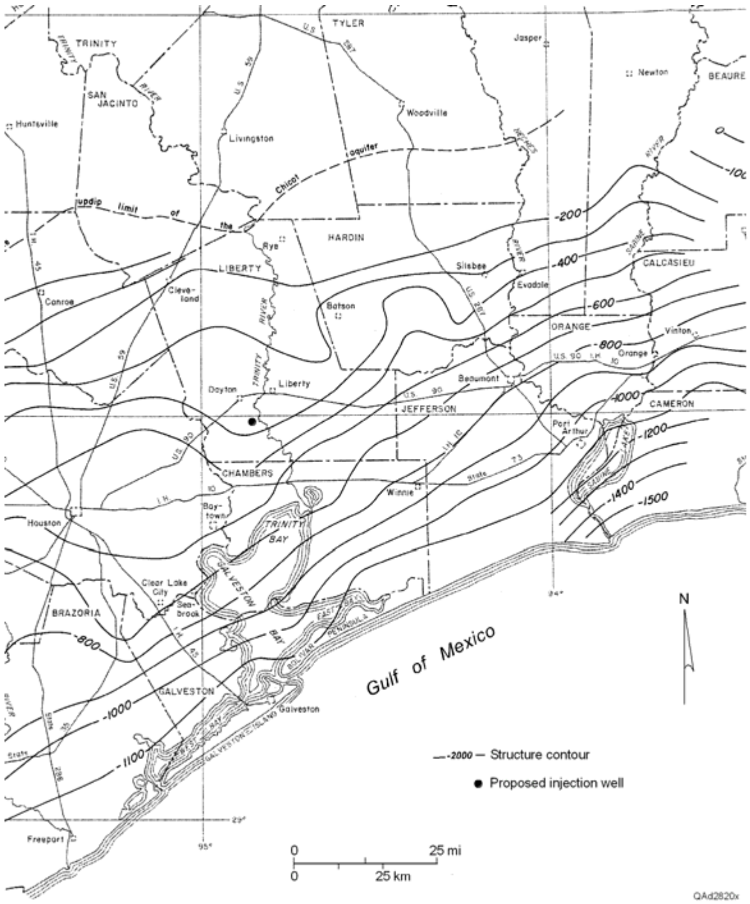


Figure V-8. Altitude of the base of the Chicot aquifer (from Carr and others, 1985).

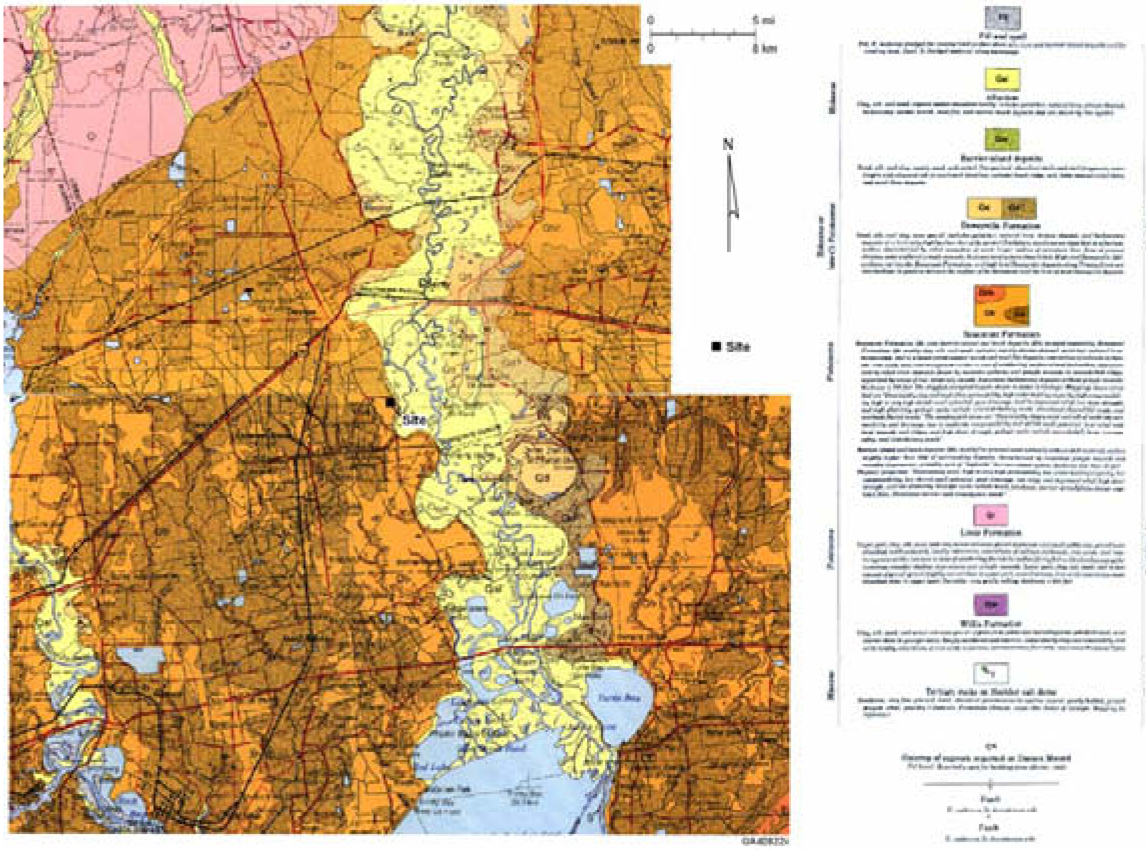


Figure V-9. Geologic atlas of Texas, Houston and Beaumont sheets, showing units that crop out at the surface.

V.1.2. Regional Hydrogeology

Miocene and younger formations that underlie the southeast Texas Coastal Plain contain usable-quality water (<3,000 mg/L TDS) and potentially usable quality water (<10,000 mg/L TDS) (base of lowermost underground source of drinking water [USDW]). Baker (1979) described four major hydrogeologic units along the Texas Coastal Plain. These are, from oldest to youngest, the Miocene-aged Jasper aquifer and the Burkeville confining system, the Miocene-Pliocene-aged Evangeline aquifer, and the Pleistocene-Holocene-aged Chicot aquifer. The Burkeville confining system forms the aquitard that restricts exchange between the Jasper aquifer and the overlying Evangeline aquifers.

The general relation of the aquifers to the stratigraphic units is shown in figure V-2. Regional structure on aquifer units in the region is shown in figures V3, V-6, V-7, and V-9. Freshwater recharge to the aquifer system is primarily from rainfall on the outcrop areas north-northwest of the Frio Brine Pilot Test Site and from rainfall on the surficial aquifer system, which in turn recharges the underlying aquifers. The hydrologic units are composed of varying proportions of gravel, sand, silt, and clay, with the aquifers containing high ratios of sand to clay.

Most of the groundwater in Liberty County is supplied by the Evangeline and Chicot aquifers. Large groundwater withdrawals for municipal, industrial, and agricultural uses from the Evangeline and Chicot aquifers began in the 1930's (Gabrysch, 1980), and in the nearby Houston area (west-southwest of the Frio Brine Pilot Test Site), withdrawal averaged 500 million gallons per day from 1969 through 1982.

V.1.2.1. Regional Fluid Flow

Regional flow in the Gulf Coast aquifers near the site was originally probably toward the Gulf of Mexico (Gabrysch, 1980). However, the large-volume water withdrawals from pumping related to both oil production and groundwater production have resulted in significant water-level perturbation seen on potentiometric surfaces of these aquifers (figs. V-10 through V-12) Regional gradients near the site in the Frio and Jasper aquifers are toward the west. The Evangeline and Chicot aquifers exhibit gradients toward the west or south as part of the regional decline in aquifers throughout Harris County (Kasmarek and Lanning-Rush, 2002), extending into the adjacent counties, including into southwest Liberty County.

Flow rates in deep saline aquifers show sluggish circulation to nearly static conditions in the deep subsurface, with flow rates less than 1 ft per year (Clark, 1988). Under natural conditions, flow responds to three driving forces: compaction expelling fluids in the deep basin, recharge from topographically high aquifer outcrops in recharge zones, and density flow resulting from salinity contrasts (Kreitler, 1986; Bethke and others, 1988). High pressure at depth, known as geopressure, is developed where sedimentary loading basinward of the Cretaceous shelf occurs under conditions where fluids are trapped within sediments that have been hydrologically isolated by alternating shales and sandstones and growth faulting (Galloway and others, 1991). Dewatering of shales and maturation of hydrocarbons also contribute to formation of geopressure at depth. Lowered sea level during the Pleistocene has caused additional perturbations in the pressure gradients. Flow directions have been strongly perturbed by fluid withdrawal as a result of oil and gas production, creating a complex pattern within depths between 4,000 and 6,000 ft relevant to the injection (fig. V-12) and perturbing the regional flow patterns away from the original southward flow. Around salt domes flow is complicated as a result of increased density because of salt dissolution, higher than background heat flux through the salt, and structural and stratigraphic heterogeneities (Ranganathan and Hanor, 1988).

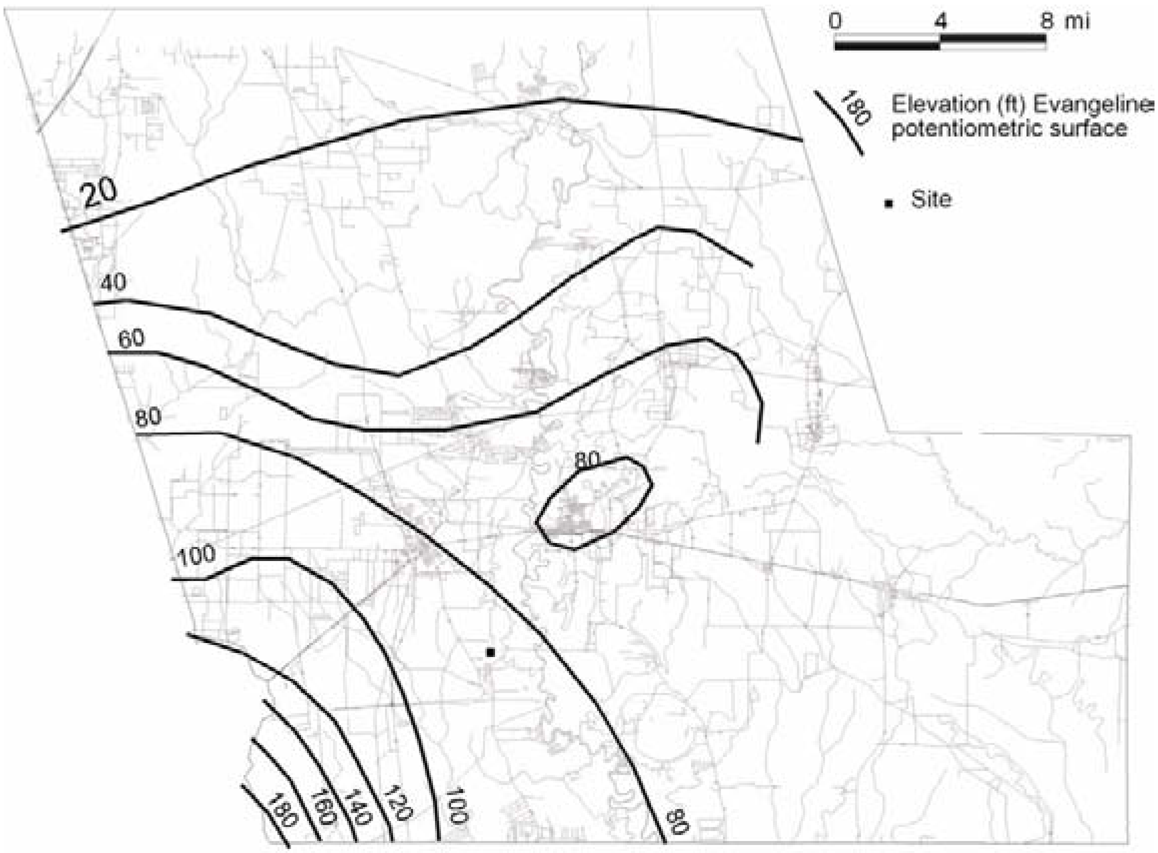


Figure V-10. Regional potentiometric surface (ft) for Evangeline aquifer, 1985. Modified from Carr and others (1985).

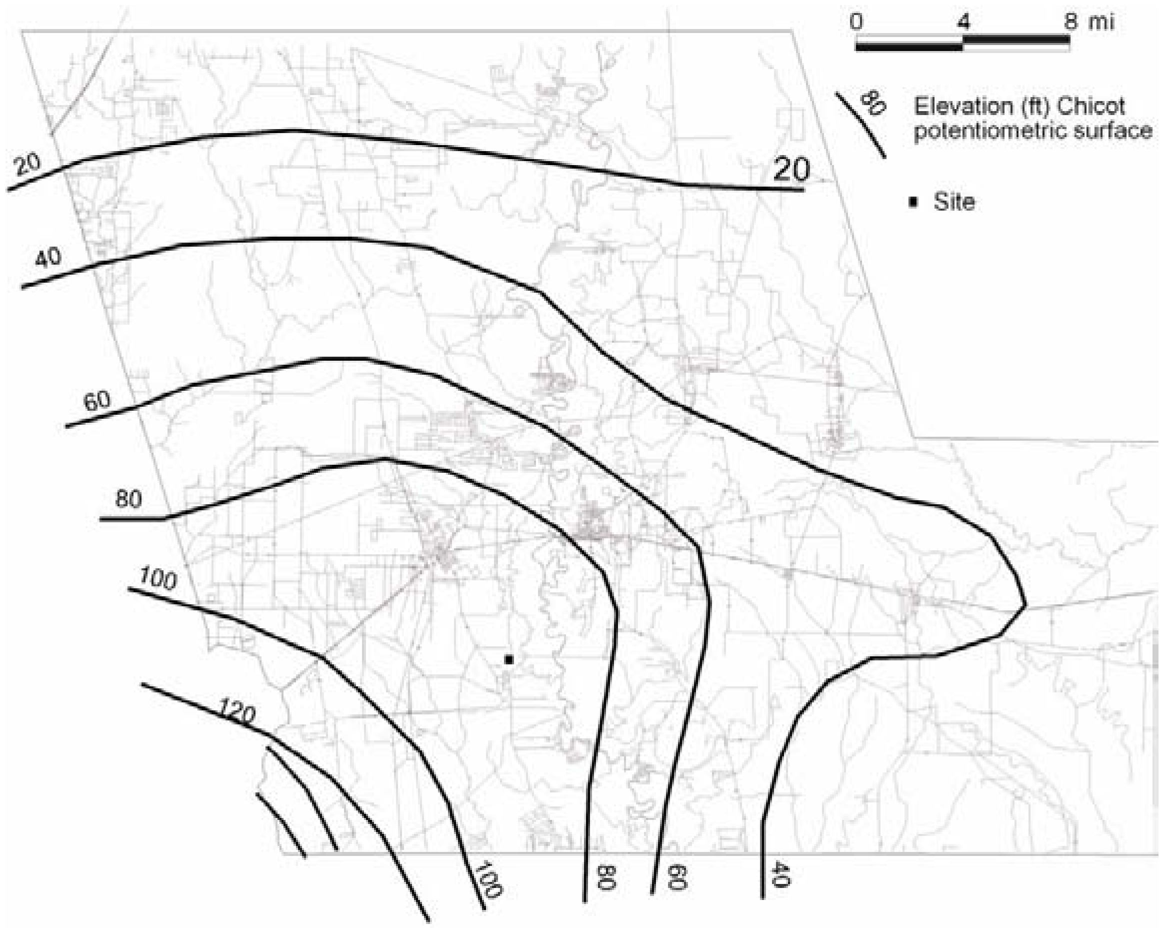


Figure V-11. Regional potentiometric surface (ft) for Chicot aquifer, 1985. Modified from Carr and others (1985).

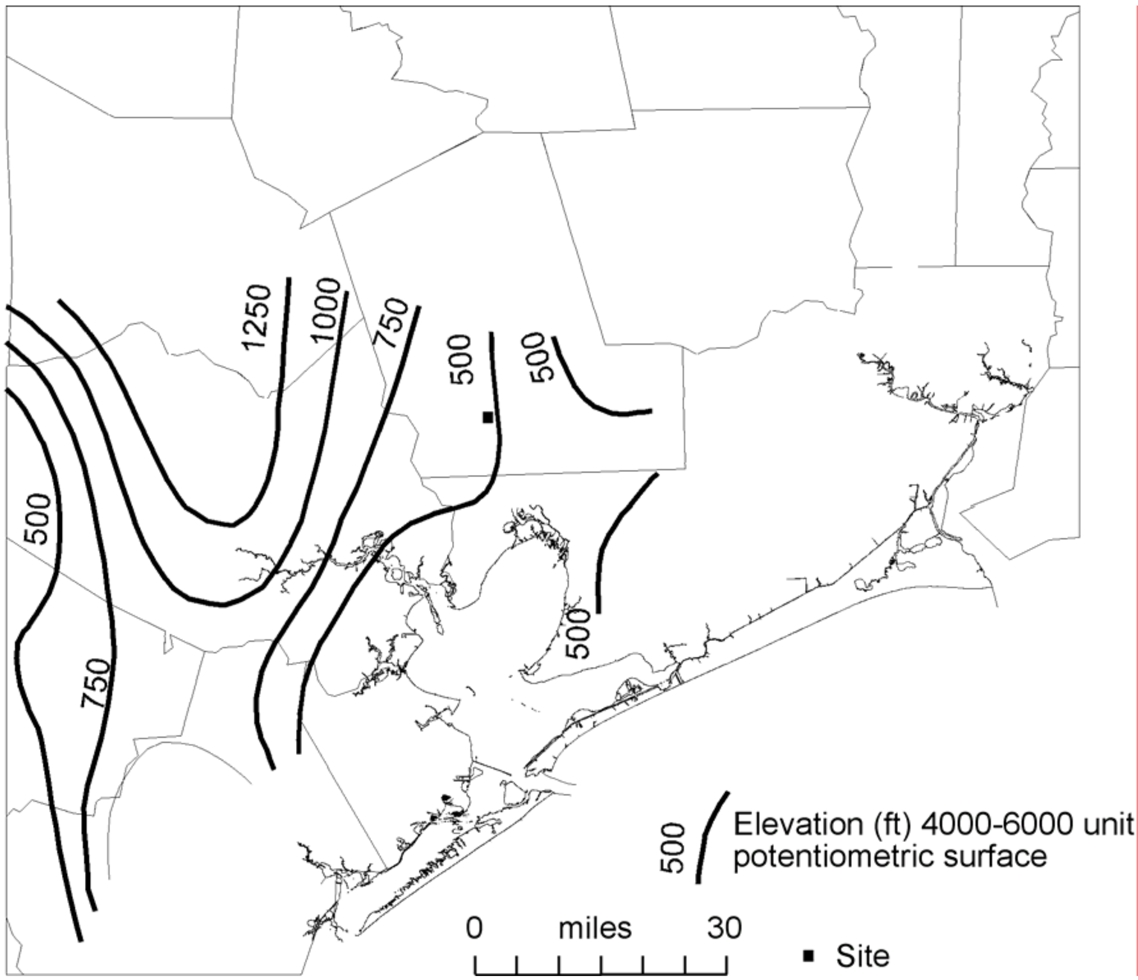


Figure V-12. Regional potentiometric surface (ft) on 4000–6000 ft depth slice (Frio interval at site) based on calculated freshwater equivalent head from drill-stem tests (DST). Modified from Kreitler and others (1988a).

V.1.3. Regional Structural Setting

The regional structure of the Gulf Coast is well known because of the abundance of well penetrations and the significance of structural closure in forming traps. Basement-controlled structures, including the Rio Grande Embayment, San Marcos Arch, East Texas Basin, and Sabine Uplift exert control on tectonics and sedimentation in the Texas Gulf Coast. The experiment site is within the Houston Salt Diapir Province. Gravity tectonic elements relevant to this study include (1) listric-normal “growth” faults formed in thick sediments deposited rapidly on heterogeneous and irregular older sediments and (2) salt structures (fig. V-3). Salt structures are complex features that form where thick salt has been loaded unevenly, and they include piercement dome, salt-withdrawal structures, and turtle structures (Jackson and Talbot, 1991; Nelson, 1991). The injection site lies on the southeast flank of a piercement salt dome. A complex structural evolution can be documented for these features, including folding and radial faulting near the structure. Sediment thickening records major episodes of salt movement. Depositional patterns little affected by salt structures record the current period of relative quiescence. Faults that formed in the later stages of formation of a piercement structure extend generally radially out from the dome, with the largest throw near the structure that decreases outward (Nelson, 1991). The salt dome is generally separated from water-bearing strata by layers of less soluble anhydrite, gypsum, and calcite known as caprock.

V.2. Local Geology

The site for this experiment was selected because the local geology is well known because of production activities. The high quality of data is critical to meeting experiment goals. This information has been compiled and reanalyzed to support the experiment. Two major data sources (fig. V-13) were analyzed: 36 well logs within the field, which were used to assess the injection zone permeability structure, and a 3-D seismic survey of the relevant part of the field. Additional data refinement is expected as part of the monitoring program both in the injection zone–confining zone interval and in the near-surface freshwater system.

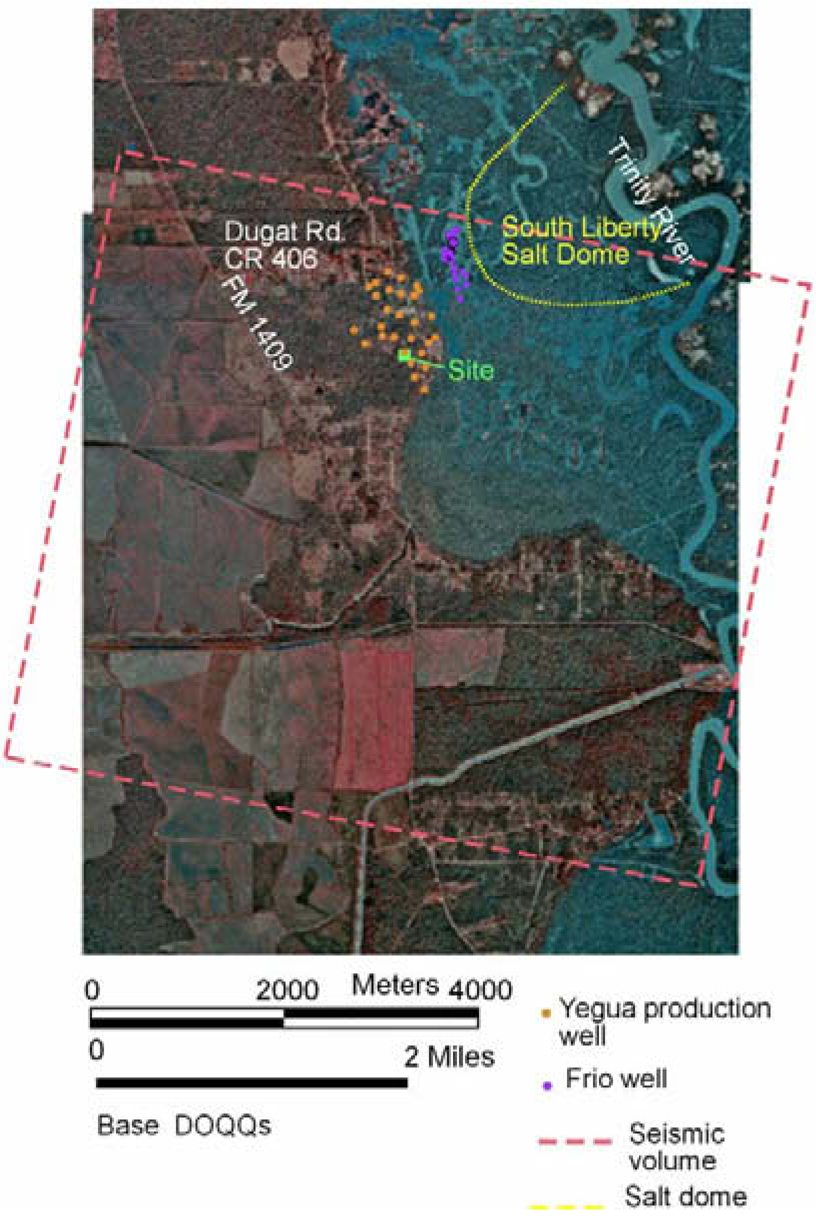


Figure V-13. Study base map displaying wells location, well spacing, and the location of the proposed monitor and test injection well.

V.2.1. Local Stratigraphy

The focus of our understanding of the local stratigraphy has been characterization of the injection zone, confining beds, and monitoring horizon.

Oil production at the site is in the Eocene-age Yegua/Cockfield and Cook Mountain Formations between 8,200 and 9,000 ft below ground level (fig. V-14). Wells near the injection well are completed at these depths. The interval between production (Yegua/Cockfield) and injection (Frio) formations is a shale-dominated section that includes the Eocene Jackson and Oligocene Vicksburg Formations. The Oligocene Frio Formation is a 1,600-ft-thick section of sandstones and shales customarily divided into informal lower, middle, and upper units. The Frio Formation is overlain by the 250-ft-thick Oligocene Anahuac Shale, which, in turn, is overlain by an approximately 4,200-ft-thick interval of Miocene interbedded sandstones that include, in order of oldest (deepest) to youngest (shallowest), the Oakville (~1,500 ft thick), Fleming (~1,850 ft thick), and Goliad Formations (~800 ft thick). Above these units is the sand-dominated interval extending to the surface and including the Pliocene Willis (200 ft thick); the Pleistocene Lissie (~150 ft thick), and the Beaumont (~80 ft thick) Formations (Guevara-Sanchez, 1974). For this study we selected the upper sands in the upper Frio Formation beneath the Anahuac Formation to be in the injection zone. These sand and shale units were divided into genetic units defined by sandstones separated by shale that can be recognized on wireline logs throughout the field and recognized in the 3-D seismic volume. Following conventional reservoir procedures, these shale stratigraphic markers were numbered. Figure V-15 shows the relationship between the numbered genetic sequences (MFS 43 to MFS 50) and traditional, lithologically described stratigraphic units within the upper Frio Formation.

Within the upper Frio Formation we informally identified three target sandstones, designated "A," "B," and "C" (fig. V-15). Units "A" and "B" contain thin (30 to 55 ft) sandstone units having log characteristics that suggest reworking of sands during the flooding preceding Anahuac deposition, which are separated by thicker shales. The shale between units B and C, which forms the seal on the injection interval, contains at least 15 ft of shale and 50 ft of shale, sand, and siltstone interbeds. Unit "C," 240 ft thick near the injection well, has more complex sandstone facies with better fluvial characteristics. Examination of wells near the injection well suggests that these units are stratified fluvial sandstones and that a thin (<5 ft) shale (MFS-46, fig. V-15) within the "C" sand may locally isolate the upper from the lower C.

To construct a model of the injection interval, we calculated log porosity for the Frio “A,” “B,” and “C” and input into a 3-D structural model constructed in Rocksar (fig. V-16). State-of-the-art geostatistics were used to interpolate porosity between wells. The experiment design is to inject into the upper half of the “C.” Monitoring will be in the “C” interval of SGH No. 4 100 ft away and updip, as well as within the “B” interval.

For this experiment, the injection interval is the Frio “C” sandstone. The experiment seal is the top “C” shale, and the injection zone includes the B and C sandstones. At the end of the experiment we plan to assess the rates, processes, and pathways of any leakage out of the injection interval by perforating the upper Frio “B” in the injection well and extracting fluids. We expect to be able to assess whether any CO_2 has moved into this zone by measuring by tracer, as well as distinctive stable isotopes of carbon and oxygen in the CO_2.

For purposes of assuring no impact to the environment, the Anahuac Formation will provide a seal, and the buffer injection zone includes the lower Miocene Oakville Formation (fig. V-14).

No site-specific information about the stratigraphy from the surface to base of surface casing was located; therefore, regional inferences are used. Prior to the injection experiment, the near-surface aquifer units will be characterized as part of the program led by the DOE National Energy Technology Laboratory Sequire group to assess potential for out-of-zone leakage using wireline logging and geophysics (VSP).

Surficial deposits near the proposed new CO_2 injection well and existing monitoring well are from 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 meanderbelt sand. The site is about 1,000 ft west of the erosional bluff marking the geomorphic boundary between the Pleistocene upland at surface elevations of about 66 ft above sea level and the floodplain of the Trinity River at elevations of 6.6 to 20 ft above sea level. The main channel of the Trinity River passes about 1.7 miles east of the site. Depositional units within the floodplain, mapped as Quaternary alluvium by Aronow and Barnes (1982), include tree-covered meanderbelt sand, overbank flood-basin mud, and mud-filled abandoned channels (Fisher and others, 1972).

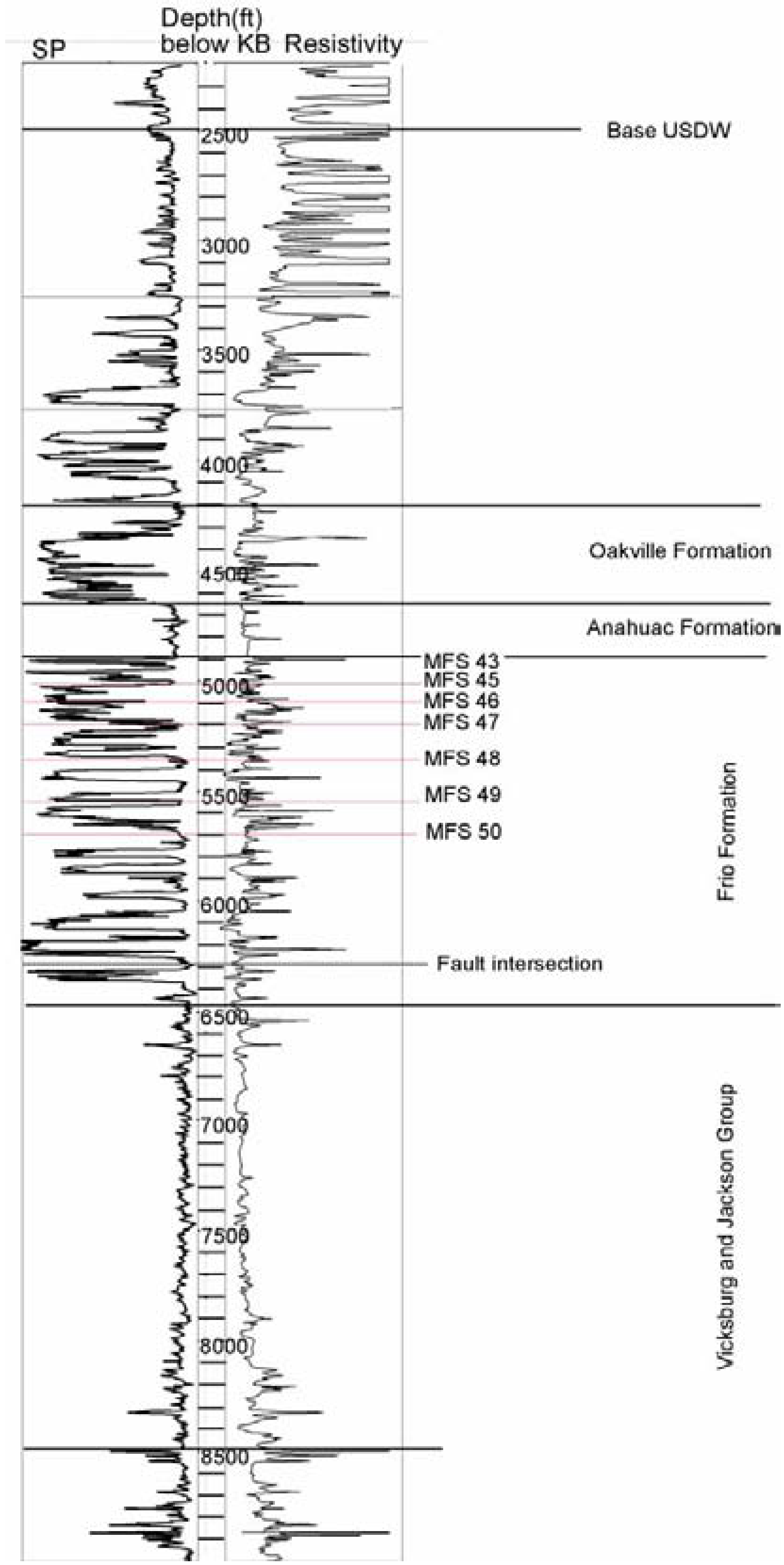


Figure V-14. Type log, South Liberty field study area, Sun-Gulf Humble Tract 1 No. 4.

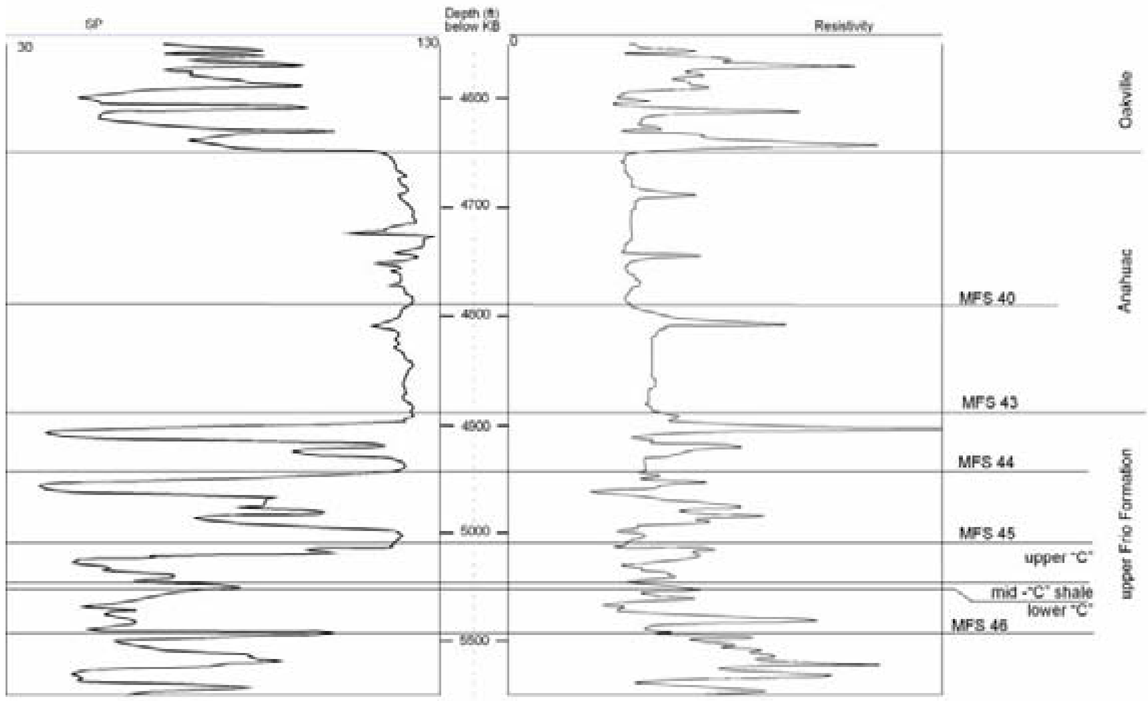


Figure V-15. Injection interval detail of the type log for South Liberty Field study area, Sun-Gulf Humble Tract 1 No. 4. MFS designates maximum flooding surface boundaries of genetic units.

V.2.2. Local Structure

Understanding of local structure in the experiment site area is excellent because of numerous previous studies (for example, Bowman, 1926; Halbouty and Hardin, 1951; Halbouty, 1979) and the availability of a 3-D seismic survey of the southwestern dome flank and high well log density for site-specific investigations. Major stratigraphic flooding surfaces were picked in both the seismic and log data. The seismic was depth-tied to the logs. These seismically and log-correlatable surfaces were then used as guiding constraints for more detailed stratigraphic correlations. These correlations were then used to develop isopach maps of the injection interval. The position of the fault planes was derived from the interpretation of 3-D seismic data. Both coherency maps and seismic lines were interpreted to delineate the position and the throw of faults. From this analysis 3-D fault planes were constructed.

The local structure was a critical component in selecting the site in order to limit the area into which the small volume of CO_2 will be injected. This process is different from that of most injection wells, which are selected to assure that pressure will remain low for the life of the injection program. In our study, we hope to see some pressure response near the monitoring well during the short injection period. A compartmentalized reservoir is also a benefit in assuring a limited extent of the injected plume during this early phase of sequestration.

The South Liberty salt dome is elliptical in map view, elongated northeast to southwest. The top of gypsum-anhydrite and minor calcite salt-dome caprock is 275 ft below the surface, beneath Pleistocene and Trinity River sediments (Seni and others, 1985; Banga and others, 2002). Around the dome, a complex pattern of radial normal faulting and associated antithetic and peripheral faults compartmentalizes the stratigraphy. A prominent salt-withdrawal syncline occurs on the north side of the dome (Geomap, 2002).

The pilot area lies on the south flank of the South Liberty salt dome. In this area, the Frio Formation dips southerly to slightly southeasterly at high angles (>30°) near the salt-dome flank, decreasing south and west of the pilot location to a dip of less than 5° (figs. V-16, V-17). 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. Coherency mapping (fig. V-15) was used to define breaks in the section relevant to delineating the compartmentalization (figs. V-18, V-19). Major fault offsets range 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. The seismic interpretation was depth-tied to the logs to best interpret the injection zone architecture in strike and dip cross sections. Plates V-1, V-2 show the whole interval, and plates V-3, V-4 focus on the details of the injection zone.

The injection well is in a small fault-bounded compartment on the southeast flank of the salt dome (fig. V-20). Two major faults (F1 and F2, fig. V-20) are mapped on the northwest and southeast sides of the compartment. Both faults dip northwest through the shallow section. Three smaller faults (FS1, FS2, and FS3) with displacements near the limit of seismic resolution are mapped near the dome. These faults are not clearly visible on a single coherency map but can be mapped when moving through the entire seismic volume. South of the injection well the throw on F2 is about 300 ft. North and updip of the injection well the throw on FS1 is about 100 ft. The northeast edge of the compartment is formed by the salt dome, which dips steeply. The seismic signal becomes indistinct in the highly fractured zone near the dome.

The capacity of the faults to seal the injection interval and limit lateral and vertical flow of fluids or gas is a complex issue and will be further investigated during the experiment using multiple monitoring strategies. Faults limit cross-fault flow for two reasons: (1) offset of permeable strata and (2) clay smearing along fault planes, creating a rock unit having high capillary entry pressure (Yielding and others, 1997). The F2 fault is most likely sealing because it juxtaposes the injection interval in the Frio “C” sandstone against the thick shale of the Vicksburg Group. The sealing capacity of the updip seal at the FS1 fault is more questionable because it juxtaposes the Frio “C” sandstone with Frio “A” and “B” intervals (plate V-4). Current techniques of reservoir analysis use shale gouge ratio (SGR) for estimating the fault seal (Yielding and others, 1997). According to this method

SGR = sum (shale bed thickness)/fault throw × 100

Shale bed thickness for Frio A and B = 40 ft

FS1 throw updip of injection well = 100 ft

SGR for that part of the FS1 fault = 40 percent.

The effectiveness of the fault seal is dependent on the pressure regime; however, from three different basins Yielding and others (1997) generalized 15 to 20 percent SGR as a threshold value, above which faults are classified as sealing. More properly, the capillary entry pressure of the shale gouge is high enough so that a high pressure increase is required to move fluids across that fault gouge. This fault-zone capillary entry pressure (FZP) can be calculated by the equations of Bretan and others (2003):

FZP (bar) = $10^{(SGR/27-C)}$ where for depths less than 3.0 km C = 0.5

FZP for the FS1 fault updip of the injection well = 9.5 bar

Early production history confirms this estimate:

> In practically every instance, each fault block has within its confines separate water levels and distinctive bottom-hole pressure, and the

production from one block does not affect the reserves in any of the adjoining blocks. (Halbouty and Hardin, 1951, p. 1956)

Because the details of the sealing characteristics of the FS1 fault are difficult to assess, we have modeled the CO_2 plume with and without this fault acting as a seal.

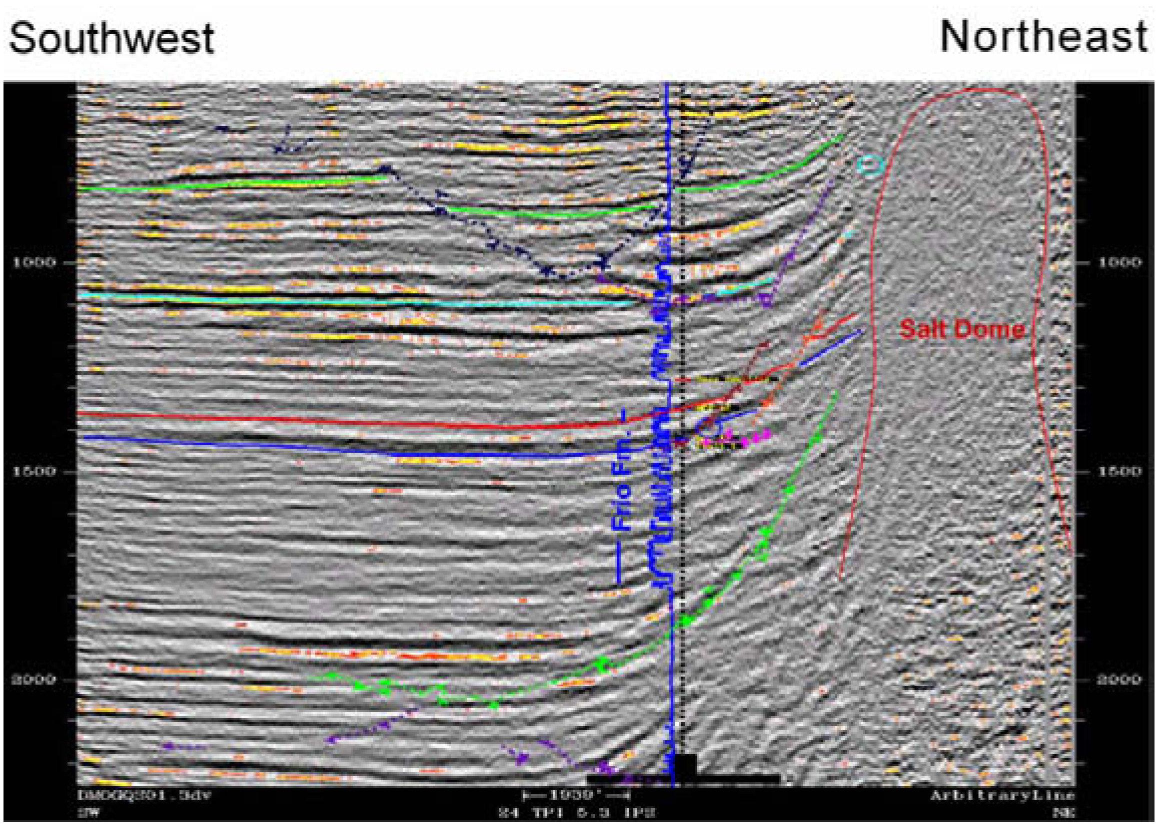


Figure V-16. Representative seismic section radial to the dome showing the dip away from dome. Stratigraphic markers are mapped, as well as the intersection of the line of section with faults.

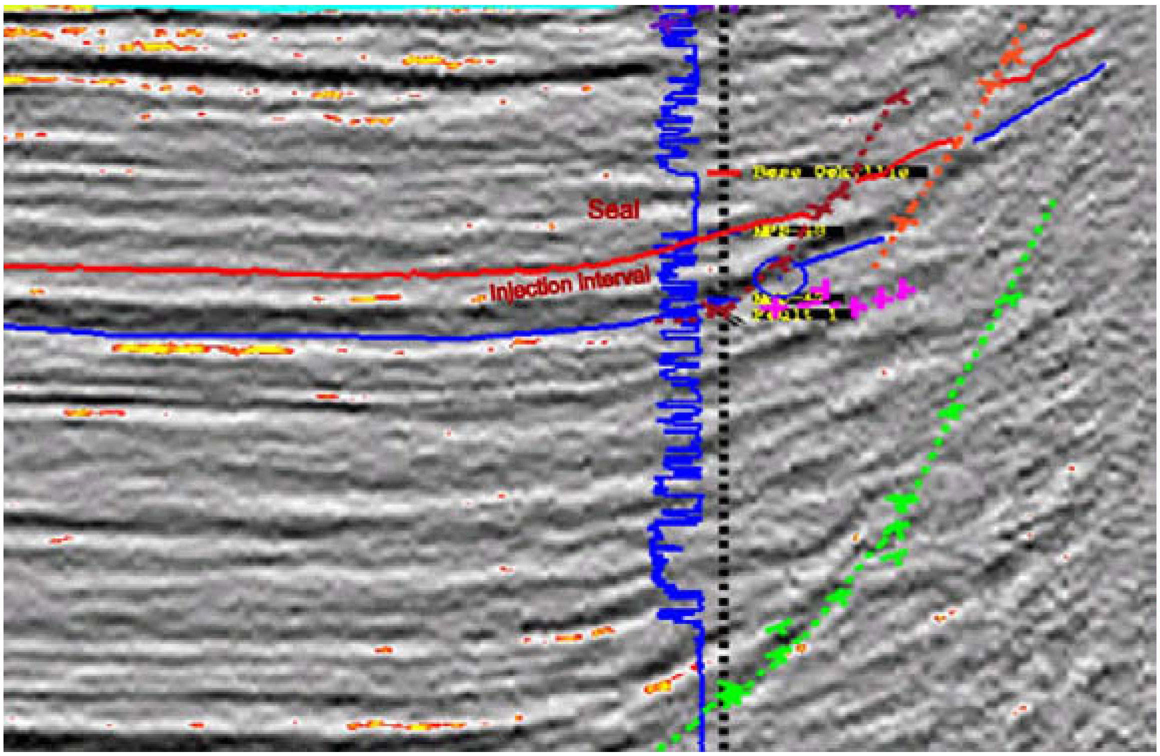


Figure V-17. Detail of the same seismic section as shown in figure V-16.

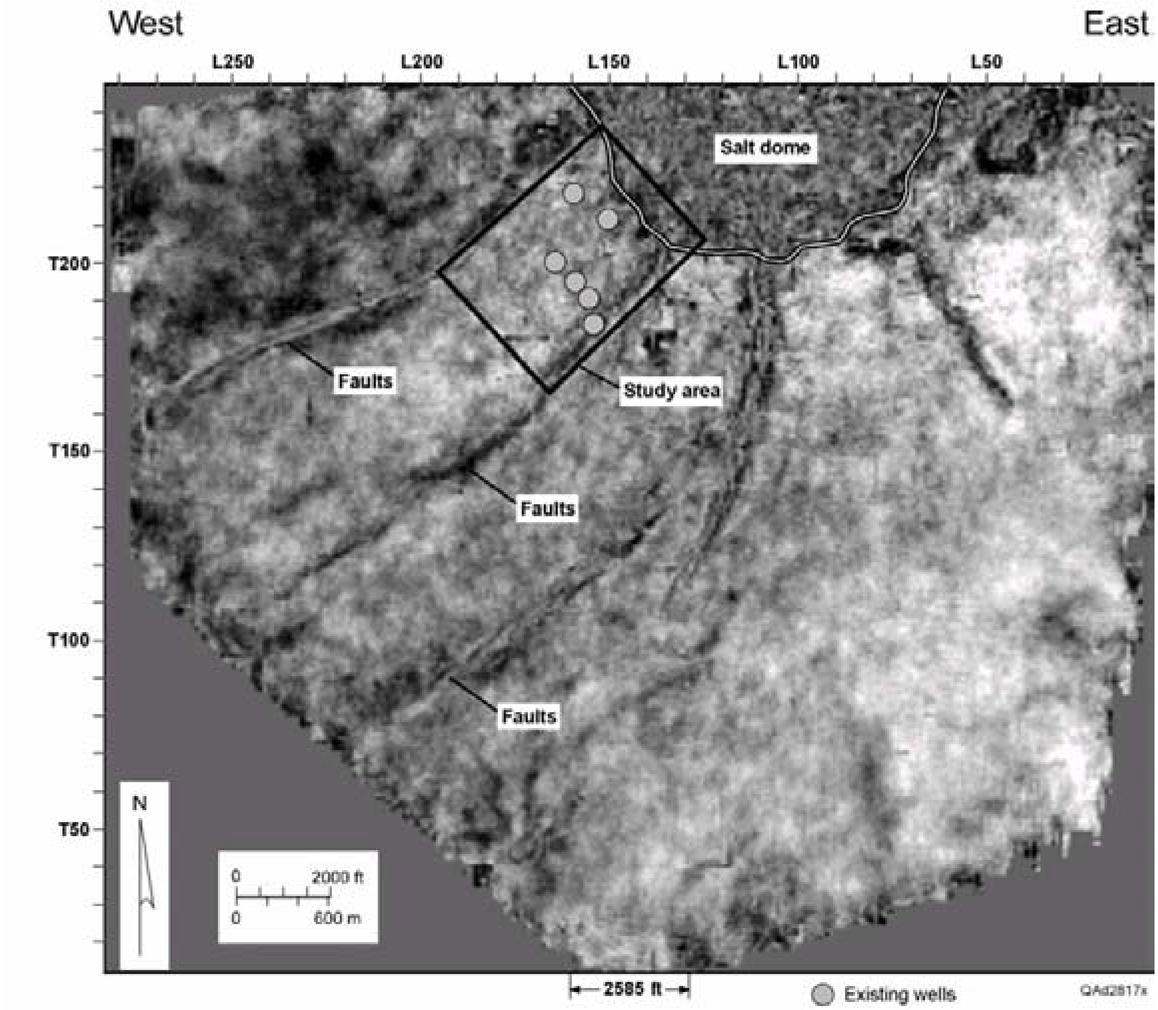


Figure V-18. Time slice at 1,450 ms in continuity cube near top MFS 43 (top Frio), showing salt diapir and radial faults.

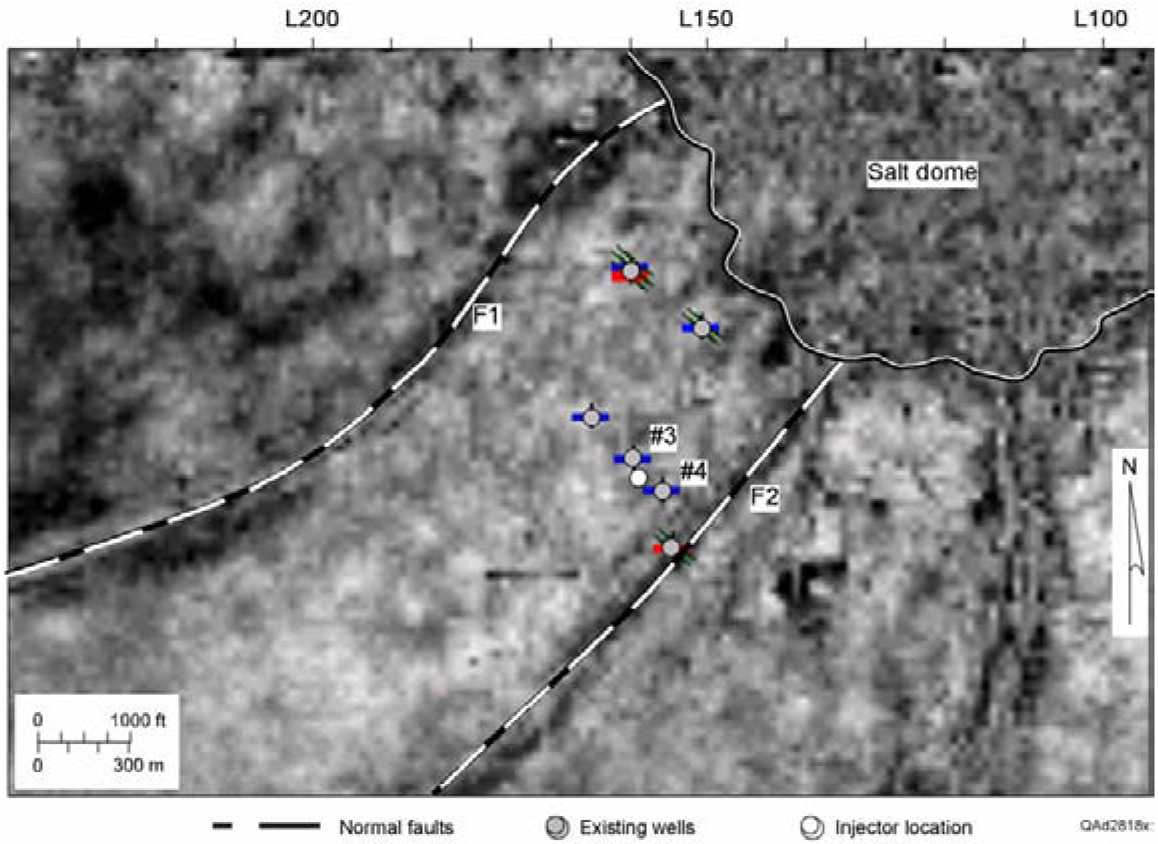


Figure V-19. Detail of figure V-18.

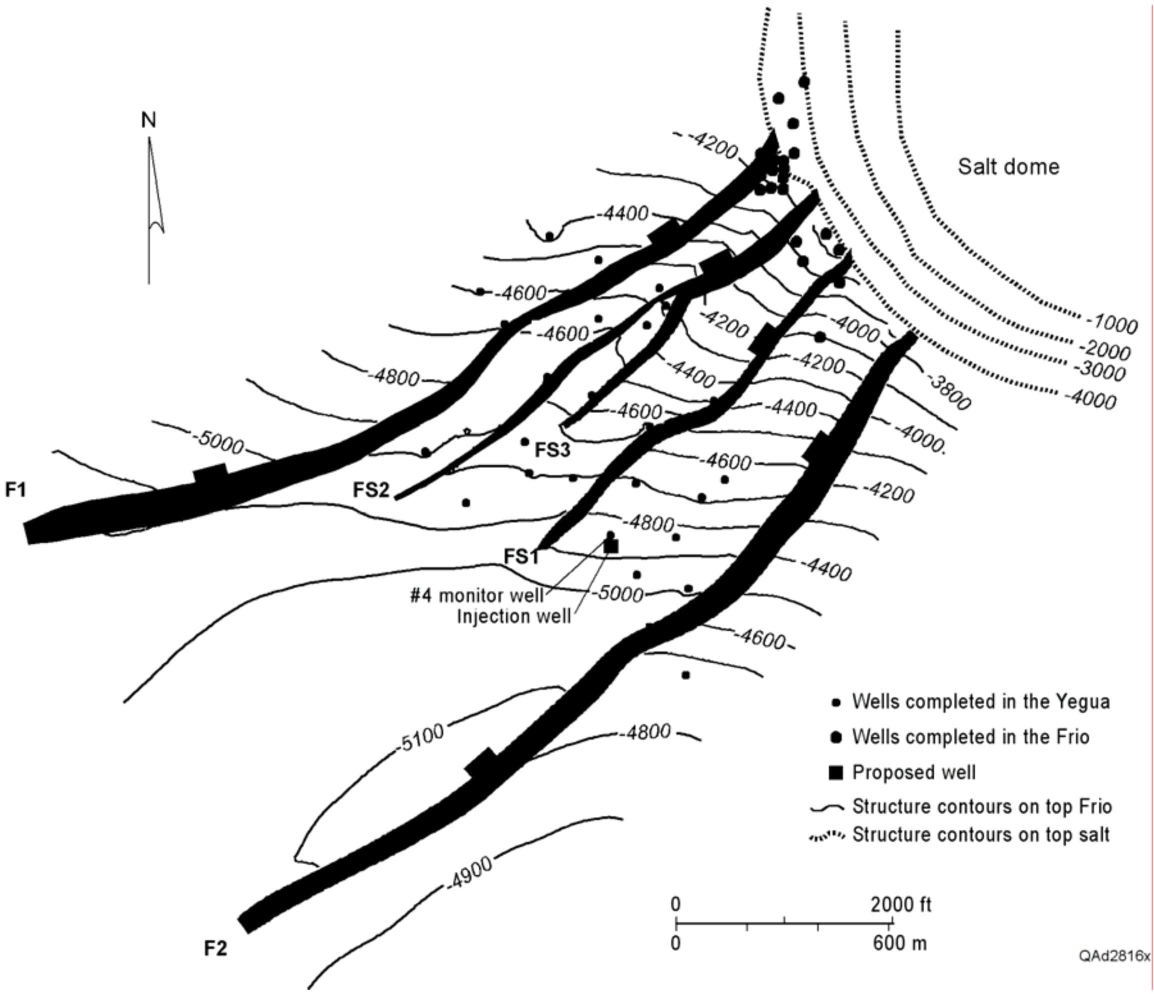


Figure V-20. Interpreted structure on top of the Frio Formation from integration of log and seismic interpretations. Structure on top of salt from Seni and others (1985).

V.2.3. Local Hydrology

Domes typically have a complex salinity field near them because of heterogeneous structures and rock properties, anomalous heat flow, and local dissolution of salt and caprock. Hydrologic and hydrochemical conditions are the cumulative product of a long history (Ranganathan and Hanor, 1988; Hanor, 1994). Salt domes were emplaced into sediments during the late Cenozoic and early Tertiary, and rock and fluid properties have been impacted by the complex process of salt movement linked to sedimentation, compaction, sea-level change, and recent pumping of both freshwater and brine.

The freshwater aquifers beneath the site are the Evangeline and Chicot. The nearest residential water well for which detailed information is available (well 64-02-102) is located about 4,100 ft northwest of the injection well. This well, drilled in 1972 to a depth of 240 ft, produces water from the Chicot aquifer. Water level in this well bore is 26 ft below ground surface. A walking survey of domestic water supply wells near the site demonstrated that this is a typical domestic well construction, with wells ranging from 180 to 258 ft in depth. The Texas Water Development Board online database for Liberty County shows that domestic water-supply wells are generally completed at depths of less than 430 ft in the Chicot aquifer, whereas most city or public water providers have wells completed between 430 and 1,560 ft, mostly in the shallower sections (fig. V-21). 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 most likely represents a perched water table. The level of standing water in the adjacent Trinity River floodplain, commonly about 30 ft below the project area, may indicate the approximate top of the saturated zone. We assume that the shallowest groundwaters probably flow toward the river valley. Depth to water will be determined during drilling of initial shot holes for seismic acquisition, and monitoring strategy will be designed as appropriate.

Local data for the deeper subsurface are abundant at the site. Because of good well control in South Liberty field, distribution of salinity can be calculated from wireline logs. This is accomplished by applying the Archie water saturation equation in a Picket plot. The gradation from fresh to saline occurs over a short vertical distance, with 3,000 mg/L TDS estimated to occur at depths of 2,200 to 2,400 ft and 10,000 mg/L TDS estimated to occur at depths of 2,500 to 3,200 ft (plates V-1, V-2). Some lateral heterogeneity is noted in these salinities, indicating that the lower part of the freshwater system is stratigraphically and/or structurally compartmentalized. In the vicinity of the dome, pressures above 5,600 ft are normal hydrostatic pressures. Those from deeper intervals are slightly higher than hydrostatic "soft" geopressure (Banga and others, 2002). The local thermal gradient derived from well logs in the same study is 18˚C/km.

Water produced from the Yegua and Frio Formations on the east side of the dome and the Yegua and Cook Mountain Formations on the north and south sides of the dome is chemically diverse over short distances, demonstrating that the reservoir has been horizontally compartmentalized by faulting (Banga and others, 2002). However, the same study measured increases in oxygen stable isotopic compositions with depth, which was interpreted as evidence that dense faults close to the dome act, or have acted in the past, as conduits for vertical fluid flow. Diagenetic studies have suggested that deep penetration by meteoric water occurred early in the basin's history (Ranganathan and Hanor, 1988); however, no data to confirm this hypothesis have been collected at the study area.

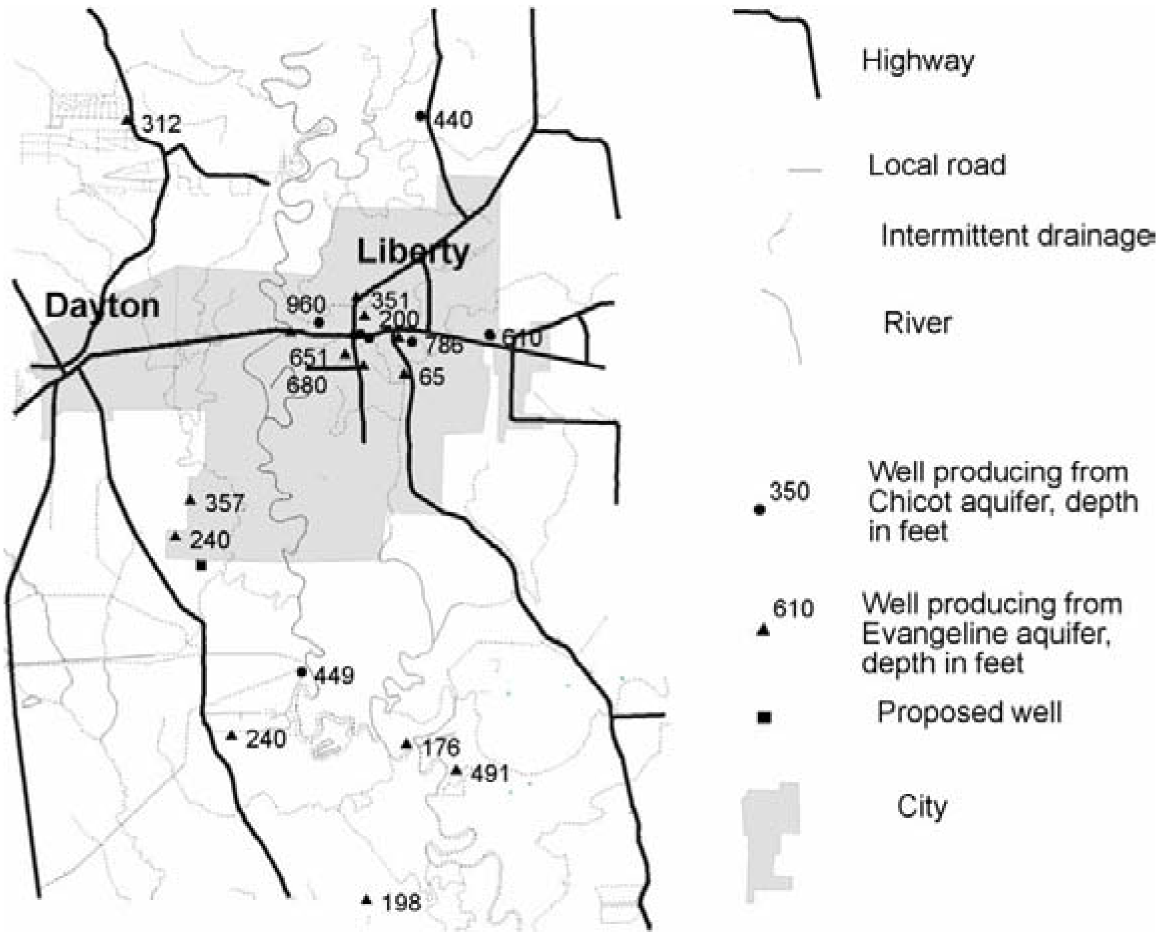


Figure V-21. Water wells from Texas Water Development Board county well database, showing aquifer produced and depth of well.

V.2.4. Injection Zone

The injection zone, including the upper Frio A, B, and C intervals was characterized in detail to support the numerical modeling of the impact of injection of CO_2 into the interval. Extension of the model to natural compartment boundaries allowed realistic assignment of boundary conditions. Boundaries selected are the F1 fault on the northwest, the F2 fault on the southwest, the dome on the northeast, and an open boundary 350 m (1,148 ft) downdip to the southwest is modeled by extending the model to 10 km (6 mi). Major flooding surfaces (MFS) marking stratigraphic boundaries were picked in both seismic and log data, and seismic was depth-tied to the logs. These seismically and log correlatable surfaces were then used as guiding constraints for more detailed stratigraphic correlations. The correlations were then used to develop structural and isopach maps of the injection interval. The position of the fault planes was derived from interpretation of the 3-D seismic data. Both coherency maps and seismic lines were interpreted to delineate position and throw of faults and to map the 3-D fault planes. Data presented here are elements of a fully developed geocellular reservoir model (fig. V-22).

The injection interval and zone isopach maps (figs. V-23, V-24) show a trend of thinning from 300 to 200 ft toward the salt dome, interpreted to be an effect of salt-dome movement during Frio deposition. In the detail areas near the injection well (figs. V-25, V-26), thickness changes are small, with injection interval thickness estimated to be about 310 ft. The injection zone “C” sand is 83 ft thick at the SGH 4 well 100 ft away from the injection well, and the isopach map shows minimal thickness changes in this area.

Detailed examination of log character in the “C” sand shows strong layering, including a consistent shale break below the limits of log resolution but most likely several feet thick in the middle of the “C” sand. Model runs with various realizations of stratigraphy (Hovorka and others, 2003) demonstrate that the distribution of CO_2 is sensitive to vertical anisotropy and effective injection interval thickness. Therefore, in addition to log-derived heterogeneity, we interpreted a distinct low-permeability bed within the “C” sand to produce conservative (maximum) plume geometries and pressures.

The petrophysical character of the injection interval was analyzed by combining wireline analysis with literature and report-derived Frio petrophysical data. To calculate porosity and permeability of the injection interval in the model, we needed to develop a relationship between the spontaneous potential (SP) log, which is the dominant log available for wells in the field, and these parameters. The bulk volume of shale (vshale) is the dominant control on the petrophysical properties. Vshale was calculated by normalizing the SP log curve to the shale-corrected neutron porosity log curve for one of the wells within the field where both logs types were available (fig. V-27). The relationship thus derived was applied to all available SP logs, and porosity for each foot was calculated. No core from the Frio Formation in South Liberty field is currently available, so we used the cored Frio well, the Jackson Felix No. 62, Chambers County, for which there were whole-core-analysis core data available to estimate permeability from porosity (fig. V-28). This well is about 20 miles south of the experiment site. From these same core data a correlation between porosity and permeability was determined. Porosity and permeability were then calculated for the entire injection interval from the vshale wireline log. The upper “C” averages 36 ft of thickness, with a high average porosity of 0.24 and a range of permeability up to 156 md and average permeability of 49 md.

Modeling has also shown that CO_2 plume extent is sensitive to both residual water saturation during drainage and residual CO_2 saturation during imbibition. On the basis of log-derived porosities and a porosity–residual-saturation relationship derived from the literature, including four values from the Frio Formation in the Felix Jackson well (fig. V-29), we anticipate residual-gas saturations for the injected CO_2 of approximately 30 percent. We estimated this amount from a cross plot of residual gas saturation and porosity for 140 data points collected from the literature + 4 data points from a Frio sandstone core recovered from the Jackson Felix No. 62 well. The accumulated points indicate a logarithmic relationship with a high correlation coefficient of 0.85. Depending on the effective residual water saturation under injection conditions, residual-gas saturations could be as low as 5 percent, which is considered in modeling to be an end-member possibility.

Detailed examination of the log character in the “C” sand shows strong layering, including a consistent shale break below the limits of log resolution but probably several feet thick in the middle of the “C” sand. Model runs with various realizations of stratigraphy (Hovorka and others, 2003) demonstrate that the distribution of CO_2 is sensitive to vertical anisotropy and effective injection interval thickness. Therefore, we mapped this middle “C” shale break within the “C” sandstone.

Table V-1. South Liberty (Frio) reservoir properties.

Zone	Thickness (ft)	Average porosity (fraction)	Average permeability (md)	Range of permeability (md)
Upper C	36	0.24	49	0.004–156
Intervening shale	6	0.05	0.01	0.01
Lower C	47	0.28	50	3.4–105

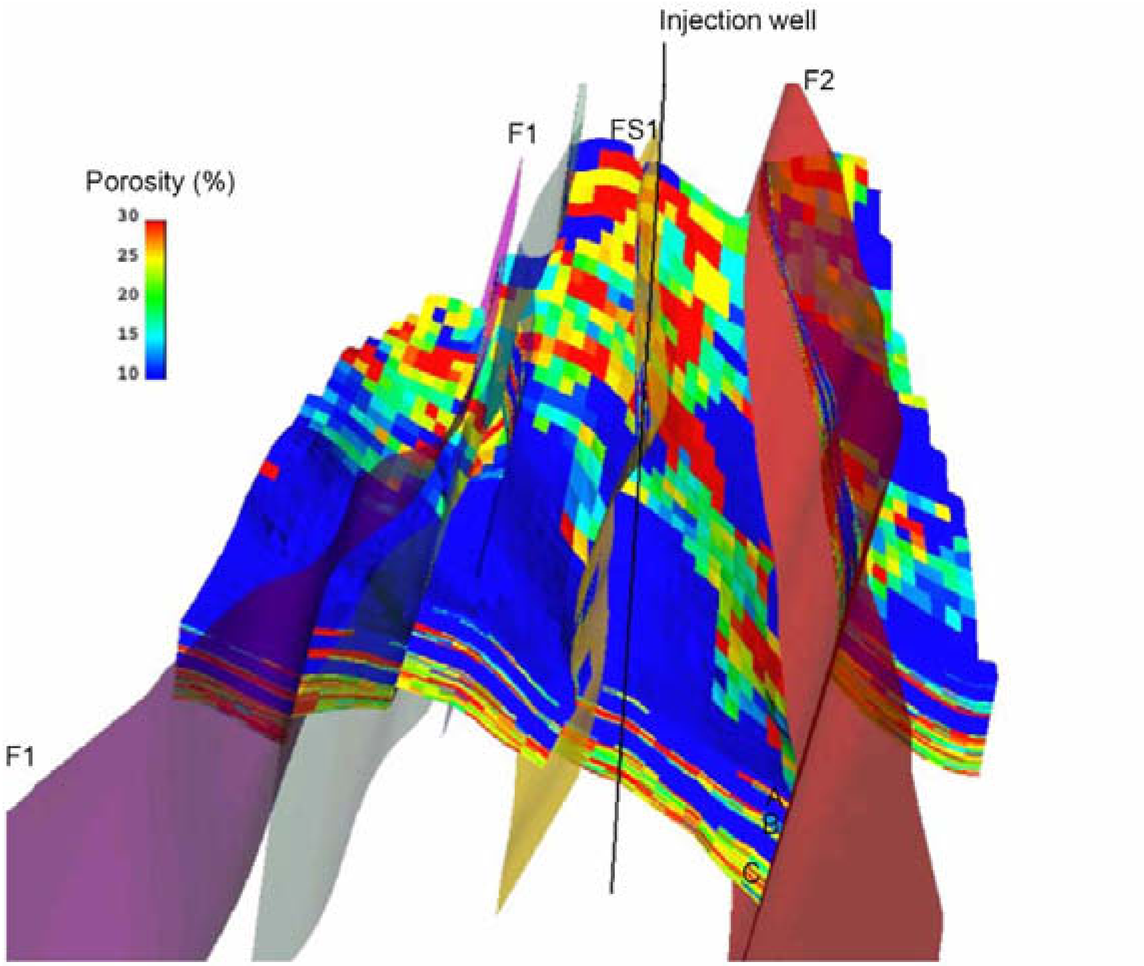


Figure V-22. Representative view of the geocellular model developed for this experiment showing the geometry of faults and the grids prepared of the rock volume.

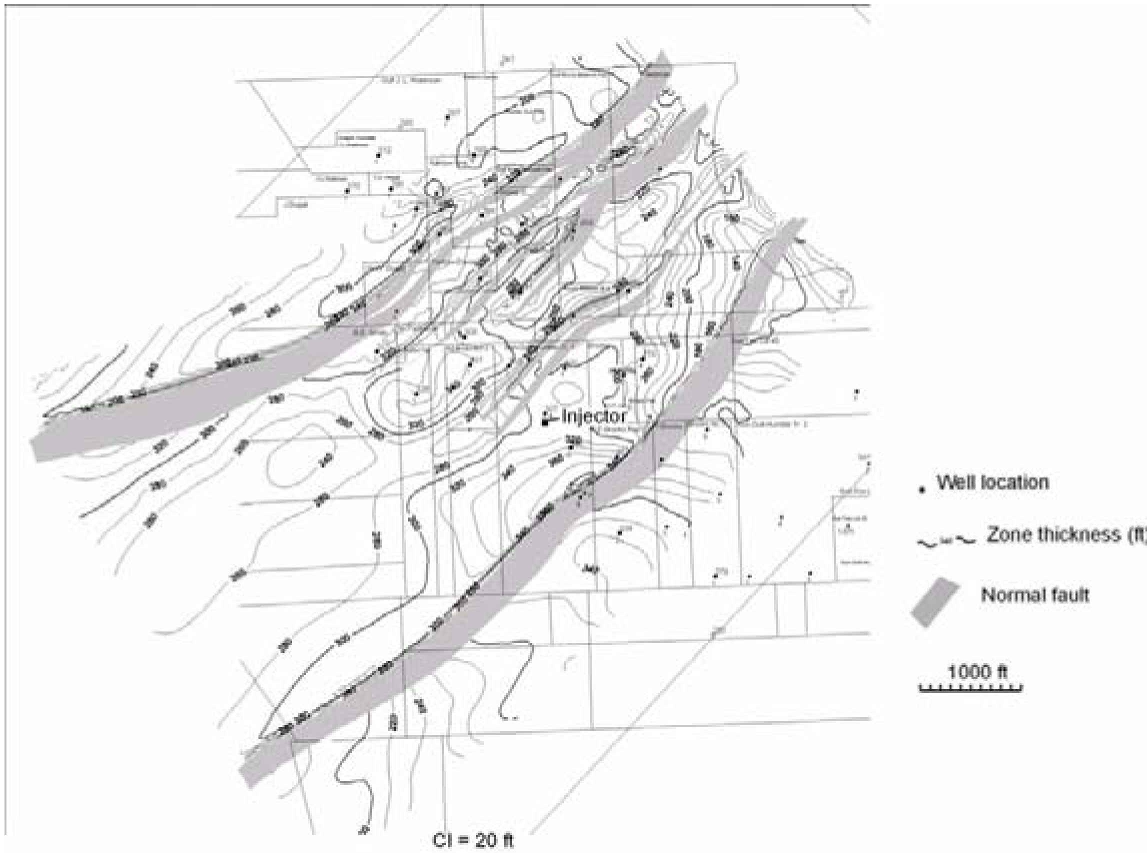


Figure V-23. Injection zone isopach map (Frio A, B, and C) mapped between MFS43 and MFS47 (fig. V-15).

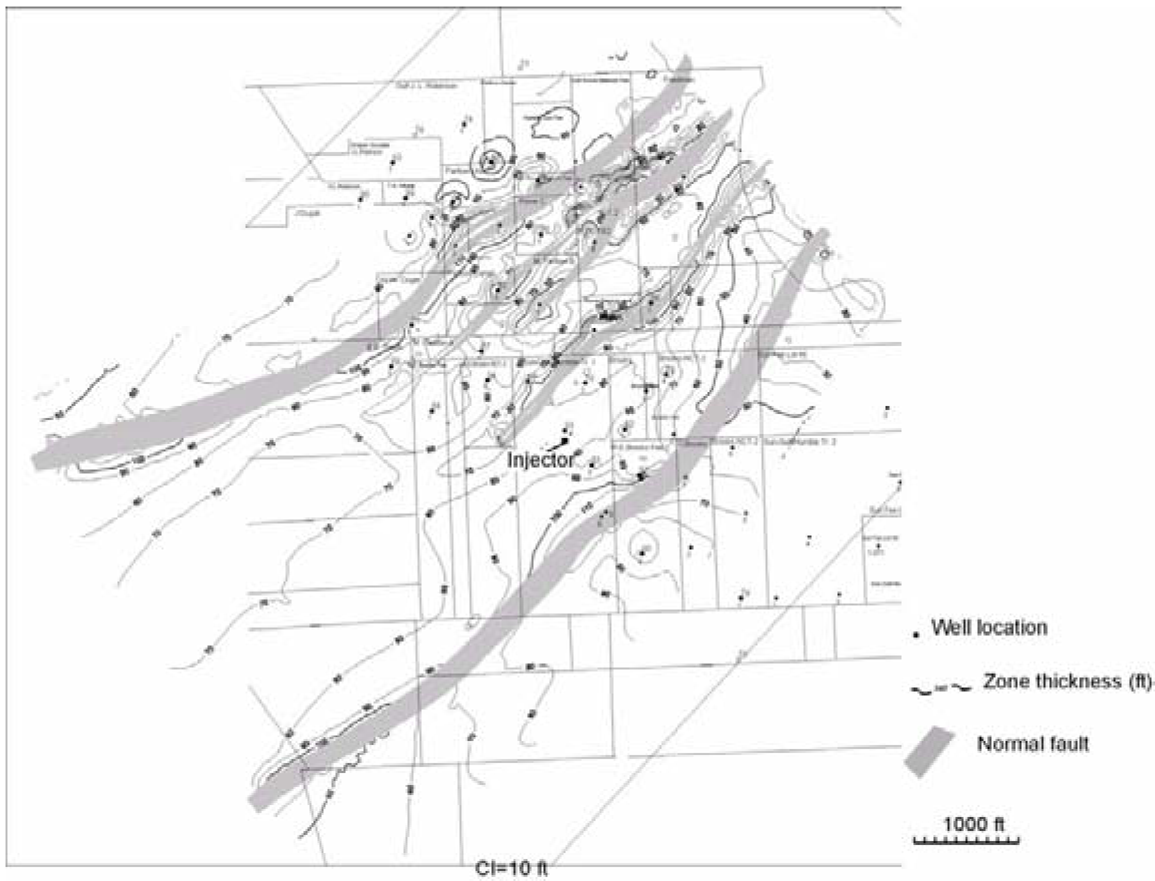


Figure V-24. Injection interval isopach map (Frio C) mapped between MFS45 and MFS46 (fig. V-15).

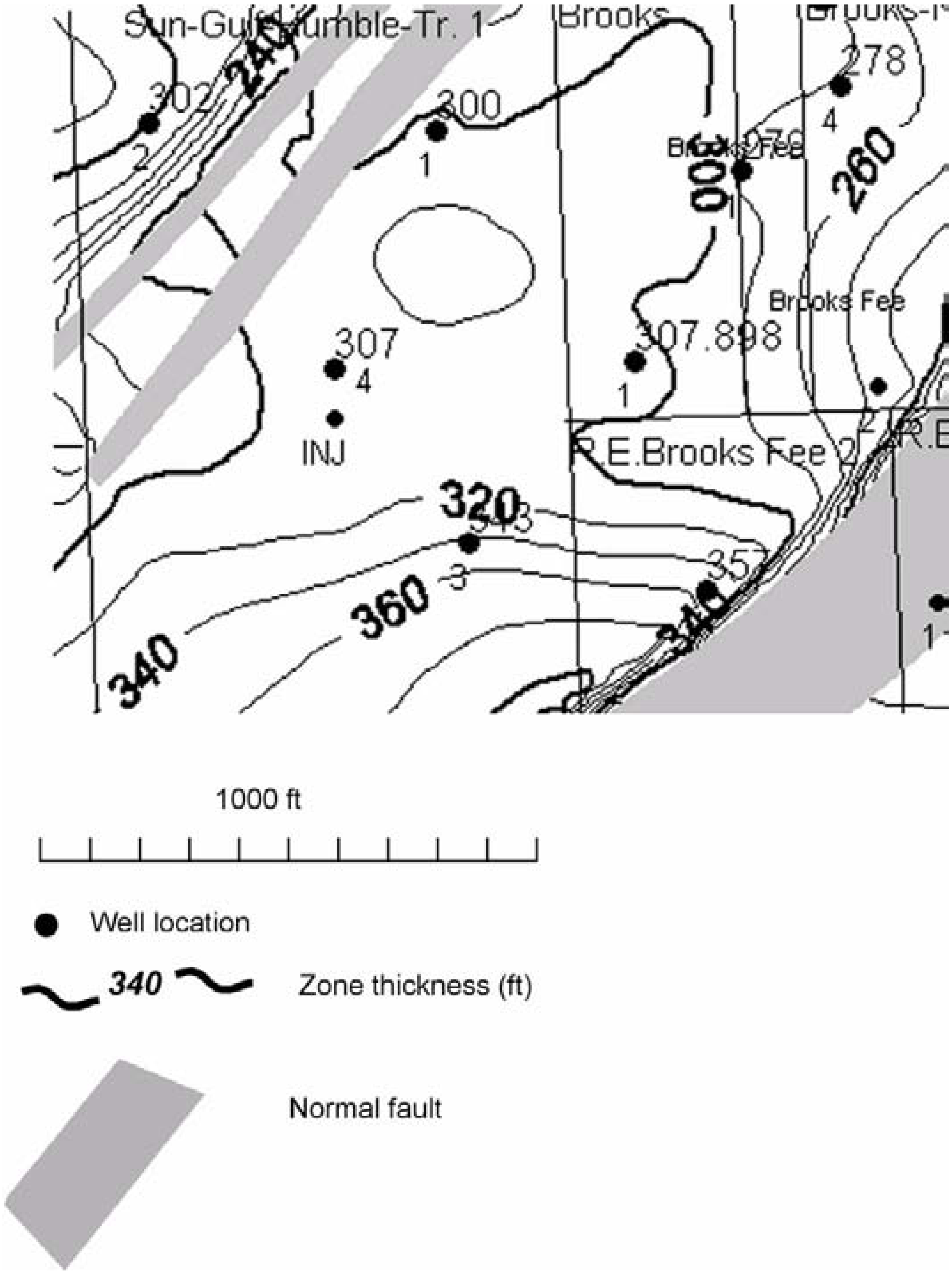


Figure V-25. Detail of figure V-23.

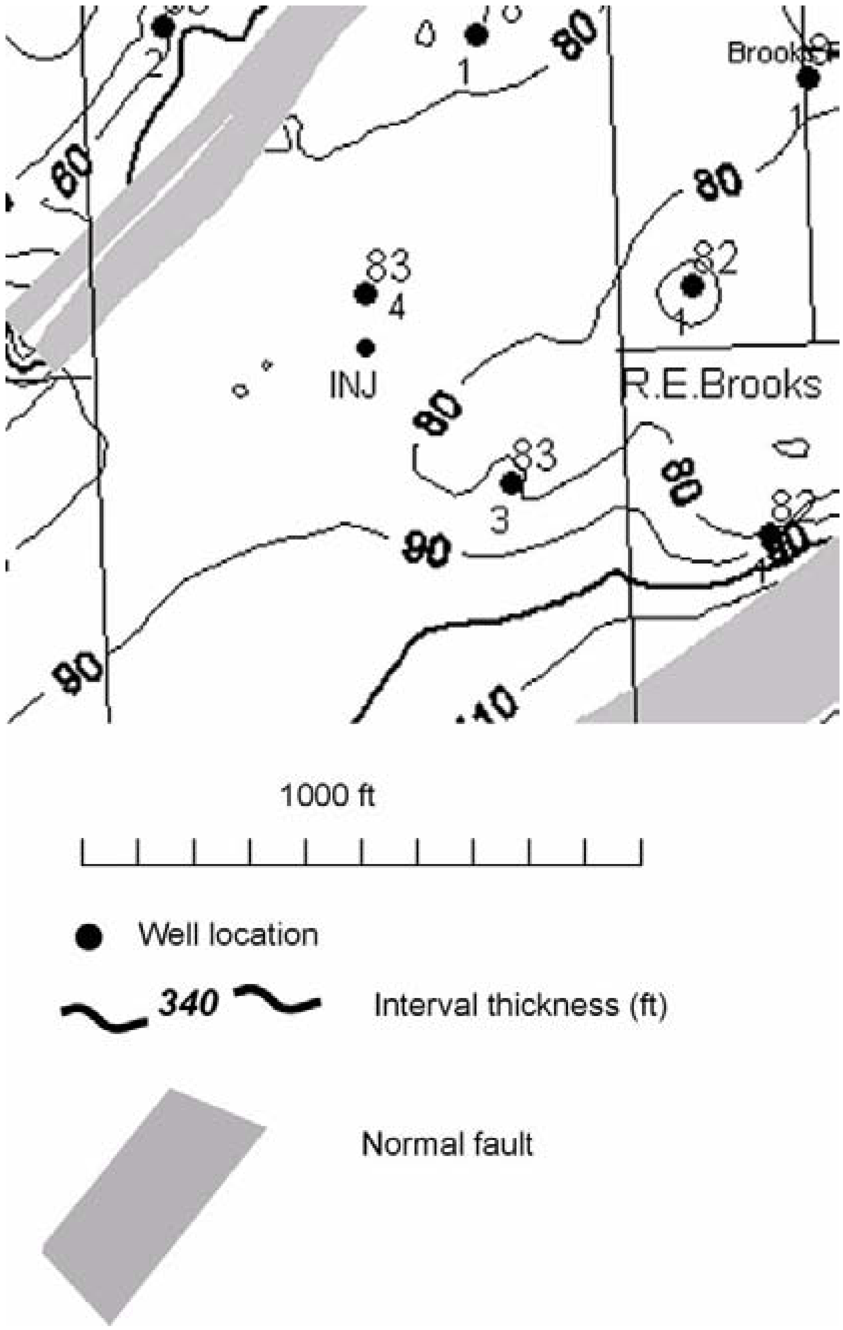


Figure V-26. Detail of figure V-24.

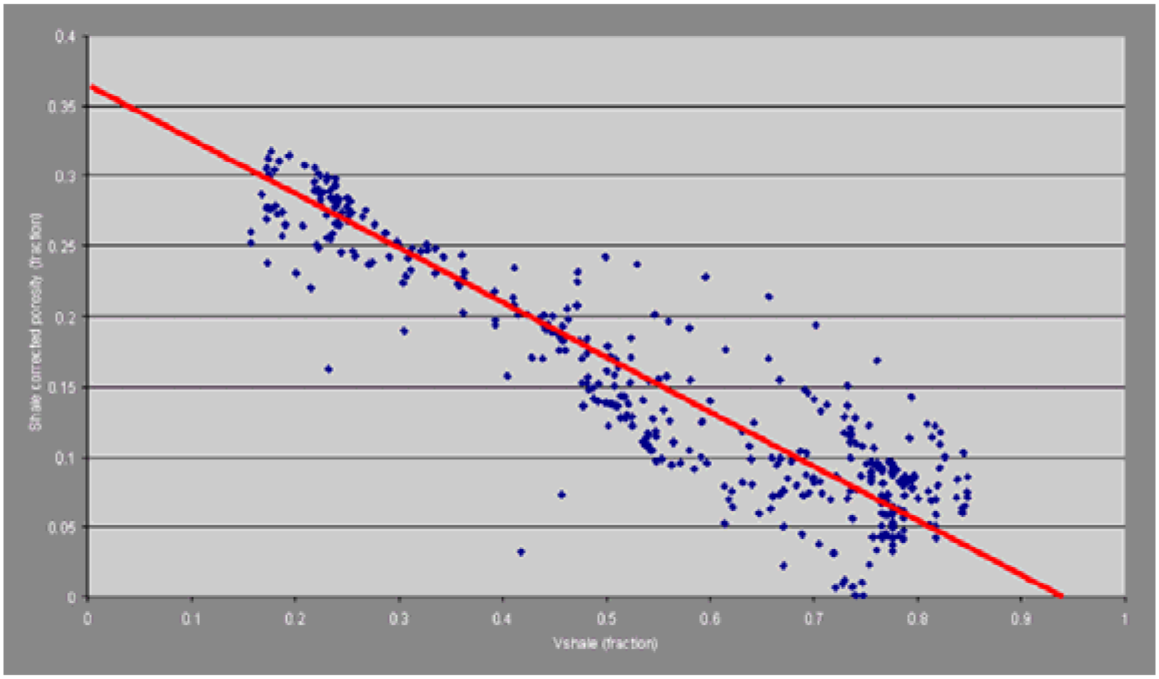


Figure V-27. Cross plot of vshale from SP log to porosity from shale-corrected neutron density log, Sun Fee Lot 45 No. 1 well, South Liberty field. Porosity = 0.357 – 0.3824 × vshale, with r = 0.91.

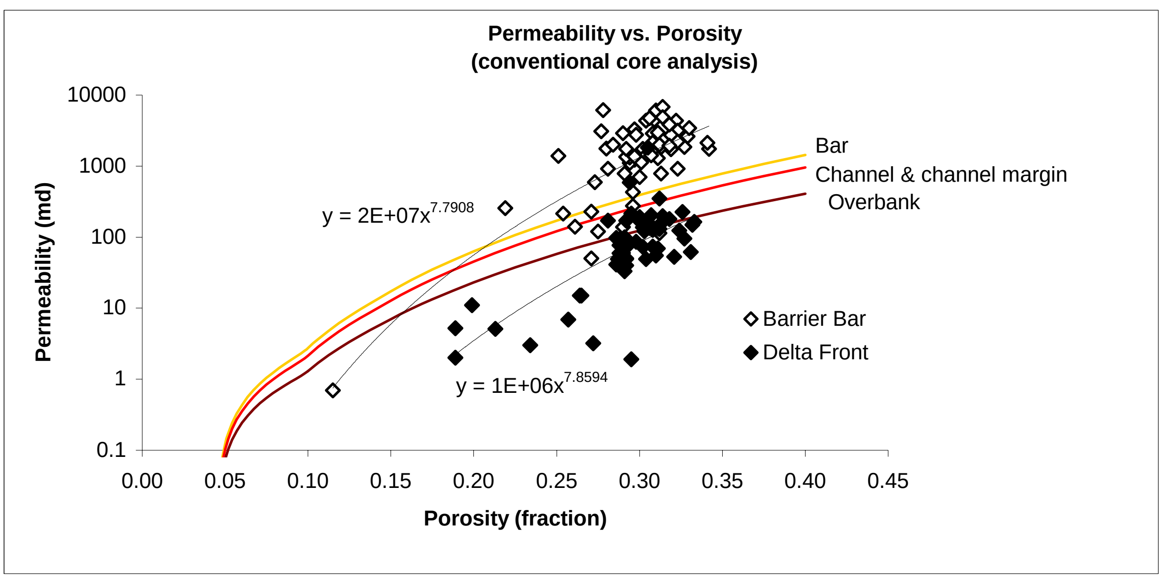


Figure V-28. Cross plot of porosity vs. permeability from conventional core analysis for the Frio, Felix Jackson No. 1 well, Chambers County. The barrier-bar values were used to estimate permeability from calculated porosity for the Frio injection zone. Bar, channel, and overbank lines presented for comparison are from a detailed study of the Frio Formation, Rincon field, South Texas (Holtz and others, 1996).

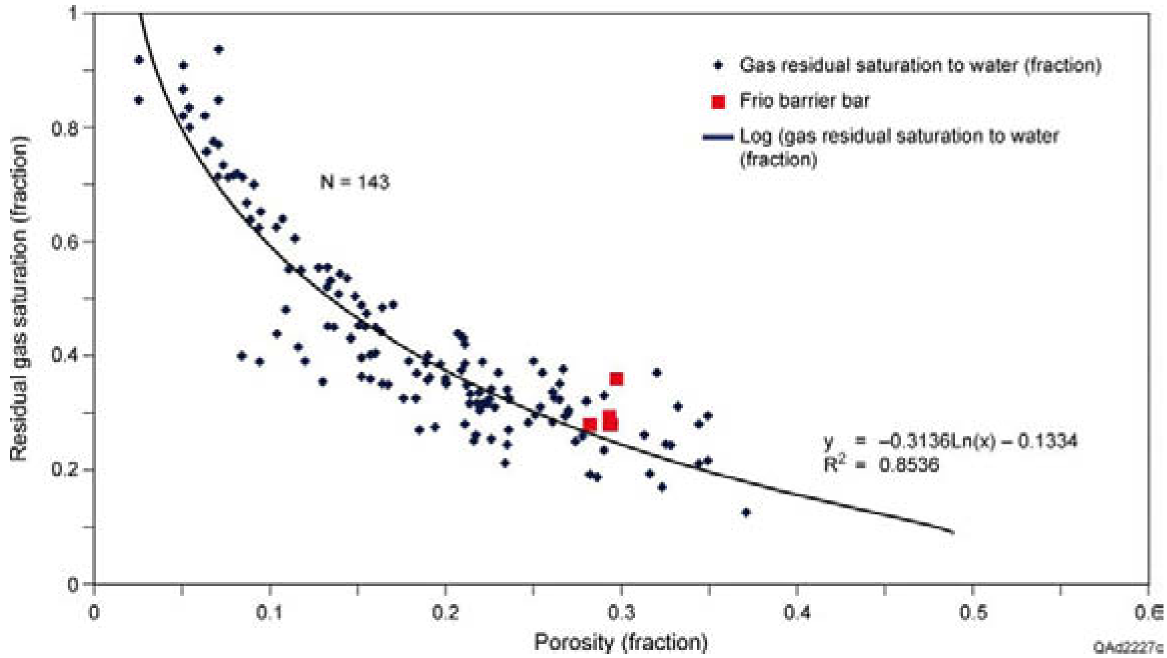


Figure V-29. Cross plot of residual gas saturation and porosity for 140 data points collected from the literature + 4 data points from a Frio sandstone core through barrier-bar facies recovered from the Felix Jackson No. 1 well.

V.2.5. Confining Strata

The main barrier to migration of the CO_2 out of the injection interval "C" Frio sandstone is the 15-ft-thick shale at the base of the "B" (fig. V-15).This unit can be traced throughout the field and is interpreted as a regionally extensive transgressive shale deposited during relative sea-level highstand. We will assess the retention of CO_2 beneath this shale by sampling in the overlying "B" sandstone for PFC tracers injected with the CO_2. If the basal "B" shale leaks, the overlying succession of the 60 ft of "B" sandstone, siltstone, and sandstone and shale, 15 ft basal "A" shale, 40 ft of "A" sandstone with an intervening shale, and 230 of Anahuac Shale will prevent flow out of the injection zone. Structure on the top of the Anahuac (fig. V-30) shows a fairly smooth dip toward the dome, similar to the injection interval. Carbon dioxide will therefore not be trapped by any structural closure. Above this 240 ft of sandstone with shale interbeds in the Oakville Formation (fig. V-31) separates the injection zone from the lowest occurrence of potable water.

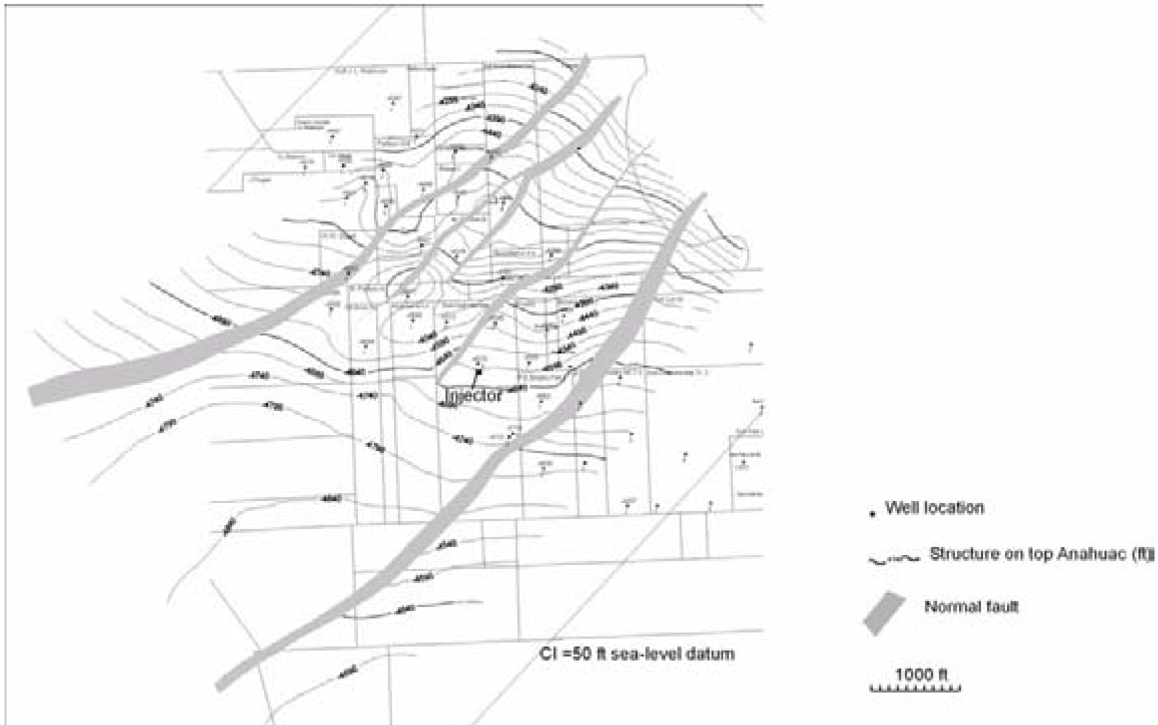


Figure V-30. Structure on the top of the Anahuac shows a fairly smooth dip toward the dome, similar to the injection interval.

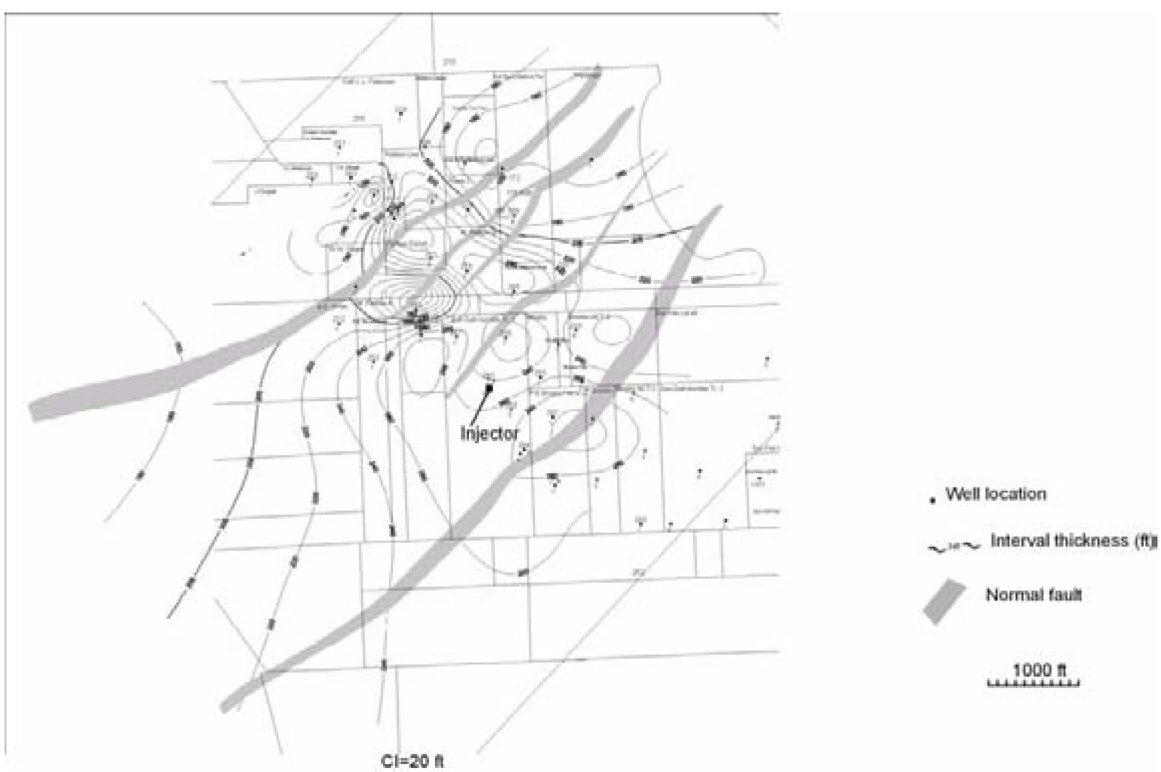


Figure V-31. Isopach map of the Anahuac Formation that separates the injection zone from the lowest occurrence of potable water.

V.2.6. Seismicity

Three types of risks are considered in this section: (1) natural seismic events that might impact the experiment, (2) induced seismicity that might impact the area, and (3) aseismic deformation.

The Gulf Coast is an area of low seismic activity (fig. V-32), as shown by the distribution of earthquake epicenters felt in Texas and the national assessment of seismic hazard. Faulting in the Gulf Coast Basin is predominantly two types: listric normal growth faulting and faulting associated with shale or salt piercement structures (diapirism) (fig. V-33). Growth faults form contemporaneously with sedimentation so that their throw increases with depth, and strata on the downthrown side of the fault are thicker than the correlative strata on the upthrown side. Although much of the displacement occurred during deposition in the Tertiary, faults remain zones of weakness. The seismic history demonstrates that regional stresses are low and extensional. The buoyant rise of shale or salt through sandstones and shale produces radial fault patterns. Diapir growth was also most rapid during earlier phases of basic development, although at some domes growth continues, resulting in maintenance of positive topographic relief over the dome. The South Liberty salt dome is beneath the Trinity River valley, suggesting that any uplift on the dome is small compared with rates of erosion or salt dissolution.

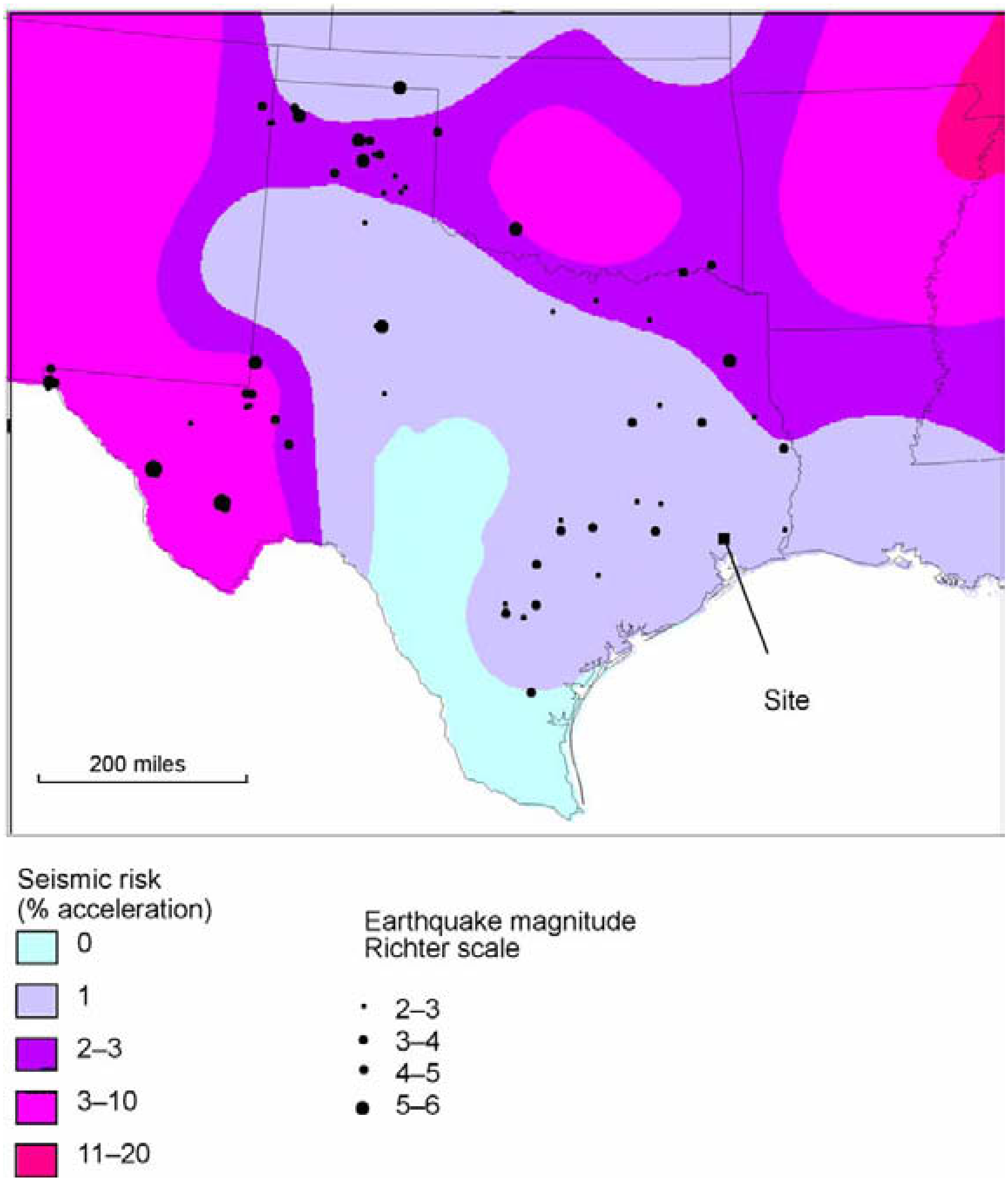


Figure V-32. Risk of seismic hazard in the United States contoured as peak horizontal ground acceleration with a 10-percent probability of exceedance in 50 years (Rukstales, 2002). Values are given in percent, where g is acceleration. Distribution of historical earthquake epicenters derived from a digital data set provided by Cliff Frohlich, The University of Texas at Austin, Institute for Geophysics (Frohlich and Davis, 2003).

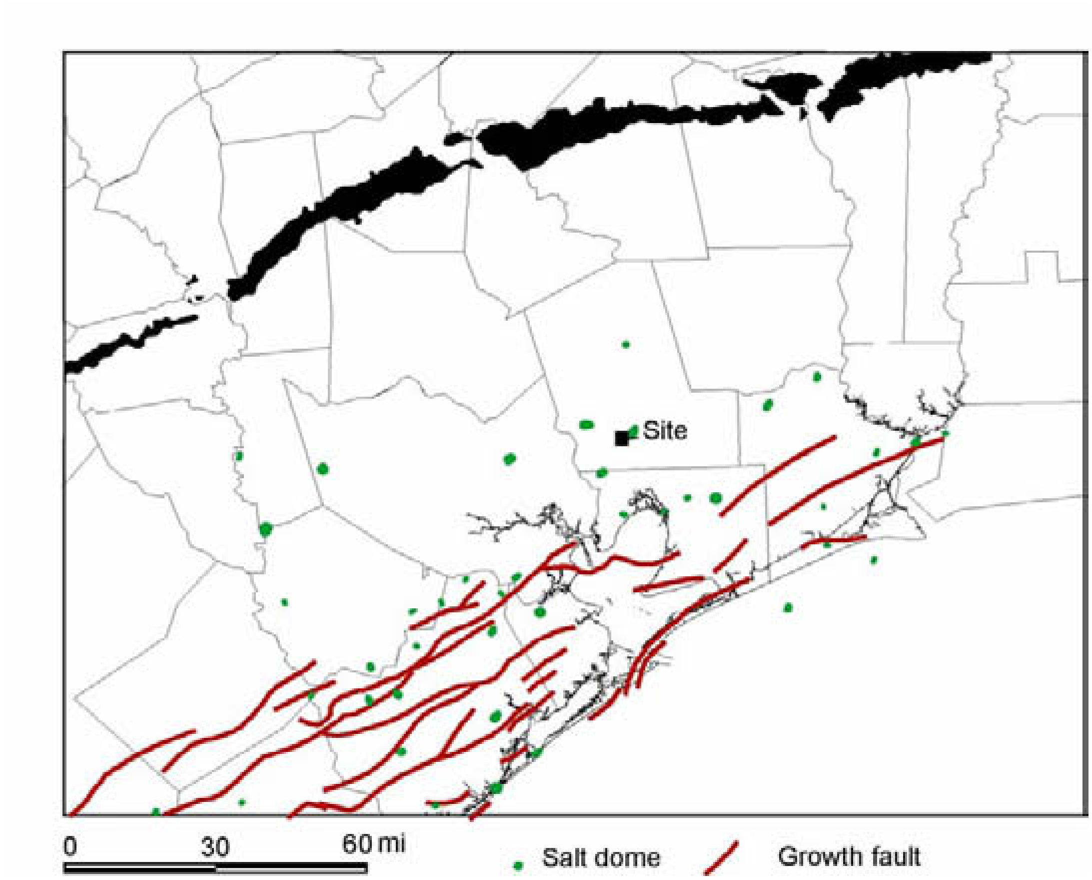


Figure V-33. Distribution of regional growth fault systems and piercement salt domes. Data extracted from Galloway and others, 1982.

V.2.6.1. Induced Seismicity

Faults bounding the injection site are interpreted to be closed to fluid flow at hydrostatic pressure because of observed variability in fluid composition and hydrocarbon production history. At depth, ambient confining pressures are expected to keep faults closed to fluid migration unless fluids are injected into the fault plane at pressures sufficient to overcome normal stress across the fault plane and cohesive strength of the clays in the fault gouge (Healy and others, 1968; Rasmussen, 1997). Injection-induced excess-fluid pressures can reactivate faults (Wesson and Nicholson, 1987), and during fault motion, fluids can be conveyed up the fault plane (Hooper, 1991). The maximum modeled pressure increase at the nearest fault is 25 bars (364 psi), which is small relative to the gravitational loading component normal to the fault. As part of the experimental program we will monitor microseismic events at the site.

Although class I wells in the Gulf Coast are typically sited away from faults, oil and gas production and fluid injection operation are common in the region. In spite of the large numbers of operations moving large volumes of fluid, only three injection-induced or fluid-withdrawal-induced earthquakes are recorded for the Gulf Coast of Texas and Louisiana (Nicholson and Wesson, 1990). Two earthquakes were recorded in an Atascosa County field as a result of strong depletion of reservoirs in Flashing and Imogene fields. Here fluid pressure was reduced from 40 to 80 percent over 30 years. Earthquakes have also been documented in Lake Charles, Louisiana, after several decades of both production and injection activity. No induced earthquakes have been known, nor are any postulated, to have been caused by relatively low-volume, low-pressure, Class I injection operations similar to those anticipated at the Frio Brine Pilot Test Site.

Increased pressure within the injection zone will cause a small but measurable increase in thickness of the injection zone that will be expressed in a slight differential change in elevation at the surface (Bill Foxall, LLNL, written communication, 2003). It is expected that this deformation will be plastic and aseismic. Maximum fluid pressures of 169 bars (2,469 psi) associated with the proposed project are below the 264 bars (3,853 psi) calculated by the Wesson and Nicholson (1987) method as likely to initiate fractures. We will install an onsite passive seismic monitoring station during the experiment to collect information relevant to seismic risks of larger volume CO_2 injection.

V.2.7. Surficial Geology

The site is about 1,000 ft west of the erosional bluff marking the geomorphic boundary between the upland at surface elevations of about 66 ft above sea level and the floodplain of the Trinity River at elevations of 6.6 to 20 ft above sea level (fig. I-4). The main channel of the Trinity River passes about 2,700 m east of the site. Outcrops in the upland are 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 meanderbelt sand. Depositional units within the floodplain, mapped as Quaternary alluvium by Aronow and Barnes (1982), include tree-covered meanderbelt sand, overbank flood-basin mud, and mud-filled abandoned channels (Fisher and others, 1972).

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 V-34. 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 slowly permeable, and it has a high water-holding capacity. The depth to water, where present, is less than 3 ft. Organic matter content is 2 percent or less.

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 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 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.

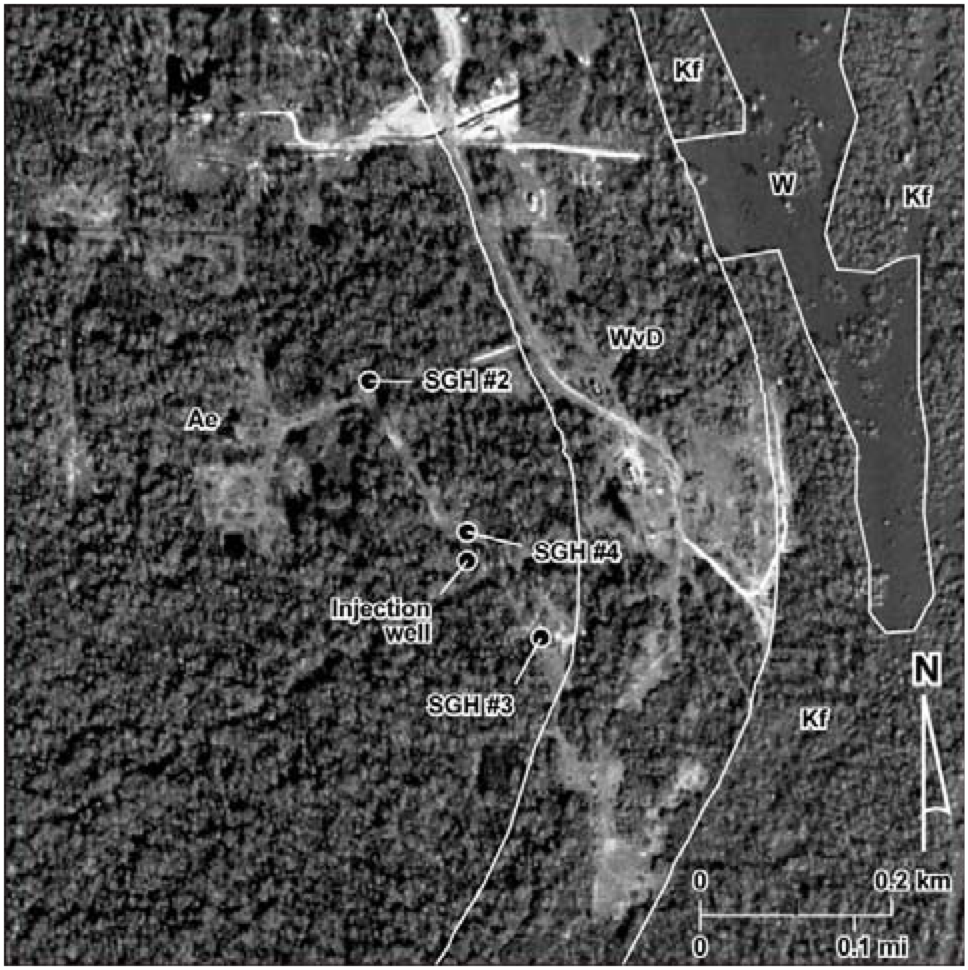


Figure V-34. Distribution of soil units at the experiment site. Soil units are those of the Natural Resources Conservation Service (U.S. Department of Agriculture, 1996). W = water; Ae = Aldine-Aris complex; Kf = Kaman clay; and WvD = Woodville fine sandy loam. Aerial photo base modified from Texas Natural Resources Information System.

VI. Injection Well Construction and Operation

The Frio Brine Pilot Test project team is submitting a Class V application to drill one injection well and a permit to convert the existing Sun-Gulf-Humble Fee No.4 well (API No. 42-291-81045) into a monitor well. The injection interval is anticipated to be the upper Frio Formation at an approximate depth of 4,885 to 5,075 ft below ground (Frio C Sand test injection interval is expected between 5,000 and 5,075 ft below ground). The wells will be constructed in general accordance, with appropriate modifications, with TAC §331.62 standards for Class I injection wells. Specific modifications to the TAC §331.62 construction standards for the proposed injection well and the converted monitor well are identified in this section. The following subsections describe the procedures that will be followed to drill, sample, complete, and test each of the wells prior to initiating the Frio Brine Pilot Test injection operations. Additionally, procedures for final disposition, including plugging and abandoning each well, are provided. Specification of maximum instantaneous rate of injection, average rate of injection, and total monthly and annual volumes requested are also included.

VI.1 Well Construction Information

VI.1.1 Total Well Depth

Proposed total drilling depth for the Frio Brine Pilot Test injection well is +/- 5,750' ft below kelly bushing. At total depth, the injection well will penetrate the middle Frio Formation, which will provide a rat hole sufficient for logging and testing purposes, prior to running the protection casing ("long string"). Formations penetrated are anticipated as follows:

FORMATION	DEPTH BELOW GROUND
Goliad Formation	600 ft
Fleming Group	1,000 ft
Anahuac Formation	4,635 ft
Frio Formation	4,885 ft

The Sun-Gulf-Humble Fee No.4 well will be plugged back from current completion in the Yegua Formation to a depth of approximately 6,000 ft in the lower Frio Formation.

VI.1.2 Well Casing Specifications

Prior to initiation of drilling activities, 14-inch conductor casing will be set to ±100 ft using a casing hammer or rat-hole service to set the conductor pipe to desired depth. After drilling the surface hole to approximately 2,600 ft, 9-5/8-inch surface casing will be cemented from total depth to surface. The proposed injection well will be completed with 2⅞-inch tubing, set within a 5½-inch protection casing string. The protection casing string will be set through the Frio C Sand injection reservoir to approximately 5,750 ft. Casing specifications for the proposed injection well are shown in table VI-1. The casing strings are more than adequately designed for the life of the Frio Brine Pilot Test experiment.

Table VI-1. Proposed injection well—casing specifications.

Tubular	Depth (ft)	Size (inches)	Weight (lb/ft)	Grade	Thread	Collapse/ Burst	Tensile Body/Joint (× 1,000 lb.)
Conductor	1–100	14	N/A	A-36	Welded		
Surface casing	0–2,600	9⅝	36	J-55	STC	2,020/ 3,520	564/394
Protection casing	0–5,750	5½	15.5	J-55	LTC	4,040/ 4,810	248/339

VI.1.3 Well Completion and Completion Interval Information

The proposed Injection Zone consists of sediments of the Miocene and Oligocene. The injection interval is anticipated to be the Frio Formation at an approximate depth of 4,885 to 5,075 ft below ground (Frio C Sand test injection interval is expected to be between 5,000 and 5,075 ft below ground). The proposed injection well completion is a perforated completion and injection packer system. A procedure for the completion is detailed in Section VI.1.5—Well Drilling Program. The Sun-Gulf-Humble Fee No.4 well (proposed monitor well) will also be a perforated completion in the Frio C Sand, following plug back and reconfiguration of the well. During the injection experiment, the injection and/or monitor well may also be completed into the overlying Frio B Sand and/or Frio A Sand for monitoring purposes. No direct injection of CO_2 is anticipated for either of these overlying intervals. The Frio A Sand interval is expected to be between 4,885 and 4,915 ft below ground, and the Frio B Sand interval is expected to be between 4,930 and 4,985 ft below ground.

VI.1.4 Well Construction Engineering Schematics

The proposed well design for the proposed injection well is shown in figure VI-1. The schematic shows casing information and setting depths, cement information, and completion details. Proposed wellhead information is shown in figure VI-2, and the proposed well annulus and monitoring system (WAMS) is shown in figure VI-3. The injection wellhead area will have secondary containment to collect and contain spills, leaks, and/or storm water. All liquids collected in the secondary containment will be recycled, disposed of offsite at an approved disposal facility, or held in storage for subsequent injection.

Figure VI-4 shows a current well schematic for the Sun-Gulf-Humble Fee No.4 well, and the proposed well design for the converted monitor well is shown in figure VI-5. The schematic shows casing information and setting depths and completion details. Proposed wellhead information is shown in figure VI-6. The proposed monitor well will be outfitted with a nitrogen gas lift system so that the Frio C Sand can be continuously purged during CO_2 injection operations and selectively purged for any postinjection monitoring.

VI.1.5 Well Drilling Program

The following subsection (Section VI.1.5.1) contains the general drilling and completion procedure for the proposed injection well at the Frio Brine Pilot Test site.

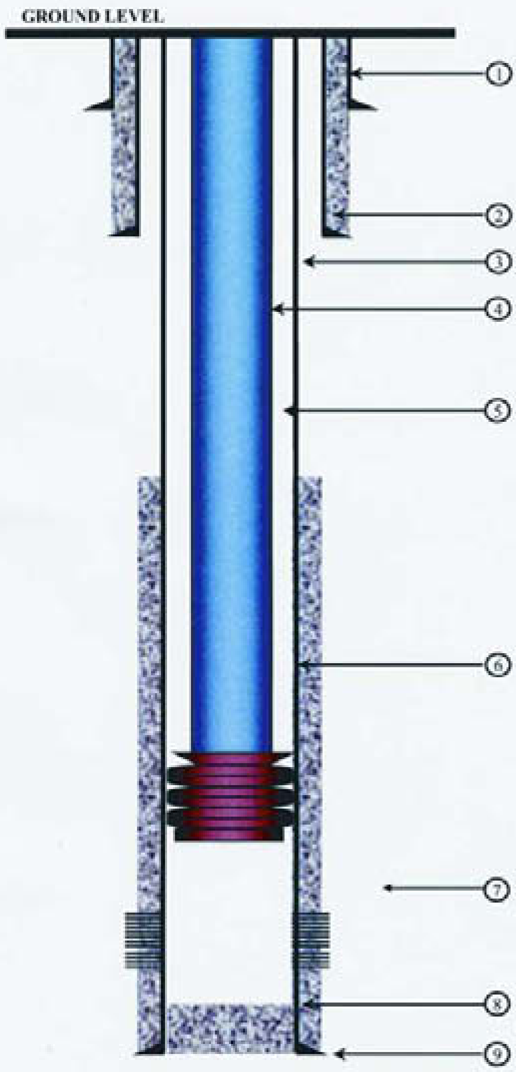
Subsection VI.1.5.2 contains the recompletion procedure for the SUN-Gulf-Humble Fee No.4 well (proposed monitor well).

VI.1.5.1 Well Drilling Program—Proposed Injection Well

The following subsections contain the proposed step-by-step program for drilling and completing the proposed injection well. The well will be used to inject the CO_2 fluid during the experiment and may be used for postinjection monitoring of the upper Frio sands.

Frio Brine Pilot Test
Proposed Injection Well

KB = 77.65 ft
GL = 65 ft
All depths RKB



COMPLETION DETAIL

1. 14" Conductor Pipe set at 80'
2. 9-5/8" Surface Casing @ 2600', set in 12.25" hole: 36 lb/ft J-55 STC; Cemented to surface with 500' tail (Class A) and 2100' lead (15:85 Pozmix) cements.
3. 5-1/2" Protection Casing @ 5750', set in 7.875" hole: 15.5 lb/ft J-55 LTC; Cemented to 3750' with 1000' tail (Class A) and 1000' lead (35:65 Pozmix) cements.
4. 2-7/8" Injection Tubing @ 5000': 6.5 lb/ft N-80 EUE 8rd.
5. Annular Fluid: 9.0 lb/gal inhibited NaCl brine.
6. Injection Packer @ 5000': 5-1/2" X 2-7/8" Weatherford I-X Mechanical Set.
7. Perforations: 5055' to 5090'.
8. Plug Back Total Depth @ 5670'
9. Total Depth @ 5750'.

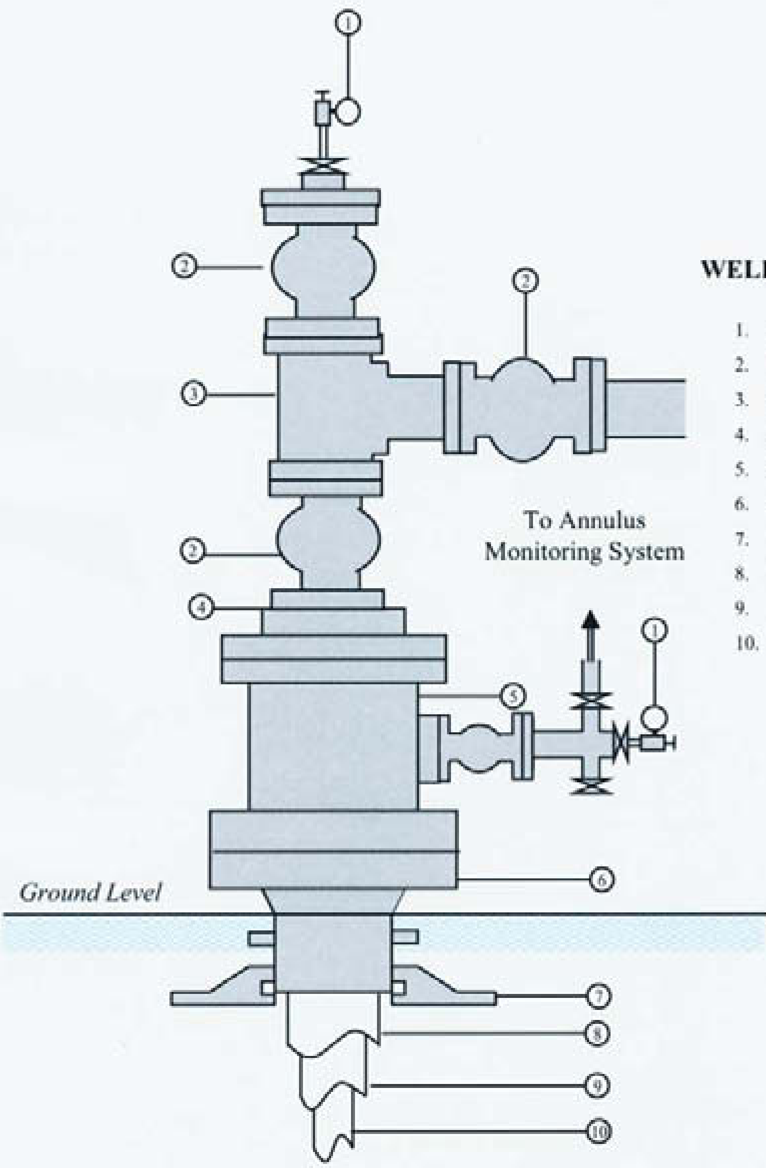
Drawn by: KFD 08/12/03
drawing not to scale

Figure VI-1: Proposed Injection Well No. 1 Completion Schematic

8/15/03

Frio Brine Pilot Test
Proposed Injection Well

KB = 77.65 ft
GL = 65 ft
All depths RKB



WELLHEAD ASSEMBLY DETAIL

1. Pressure Gauge
2. Full-Opening Gate Valve
3. Flow Tee
4. Adapter Flange
5. 5-1/2" 5000 psi Tubing Spool
6. 13-3/8" 3000 psi Casing Head
7. Base Plate, welded to 14" Conductor
8. 9-5/8" O.D. Surface Casing
9. 5-1/2" O.D. Protection Casing
10. 2-7/8" Injection Tubing

Figure VI-2: Proposed Injection Well Wellhead Schematic

8/15/03

Frio Brine Pilot Test
Proposed Injection Well - Annulus and Monitoring System

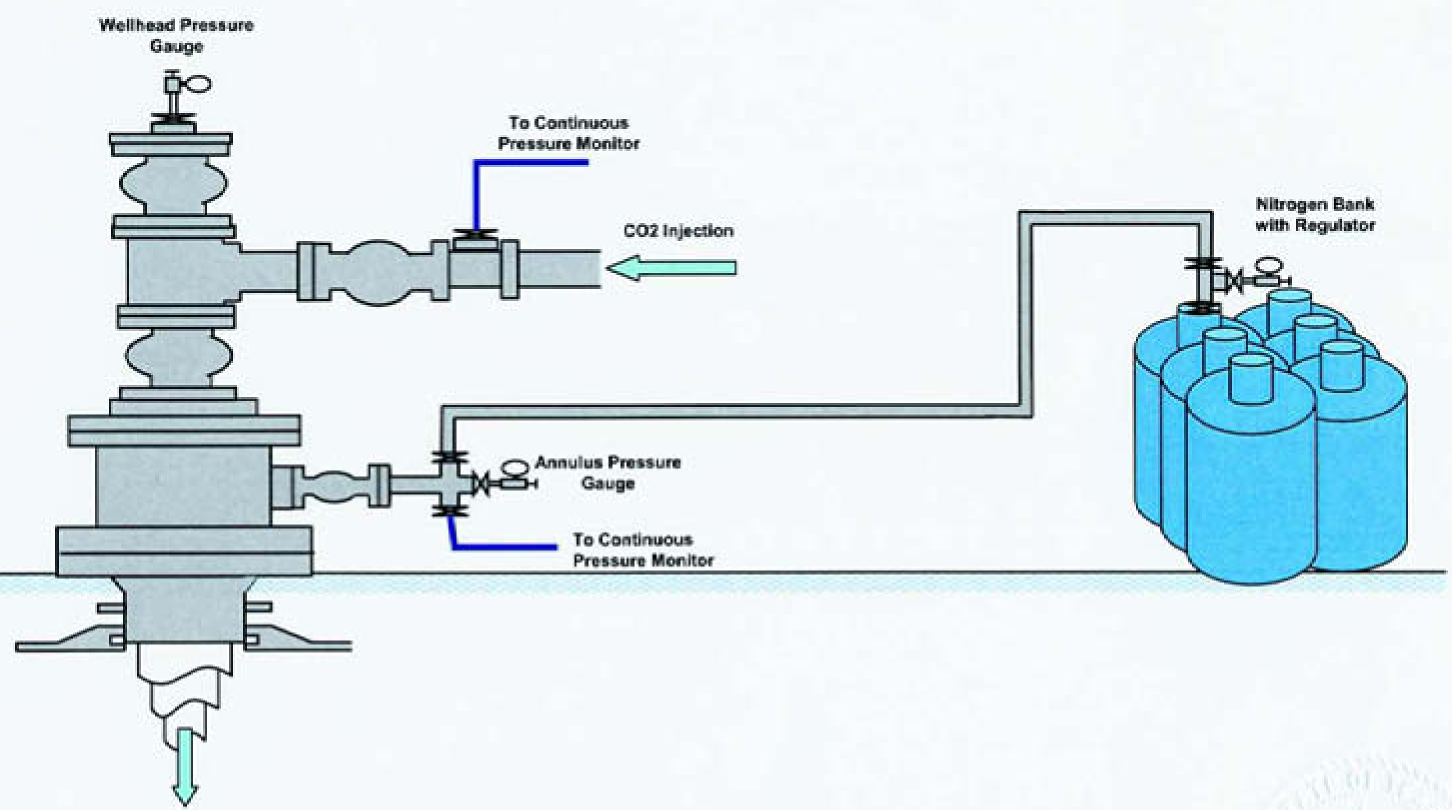
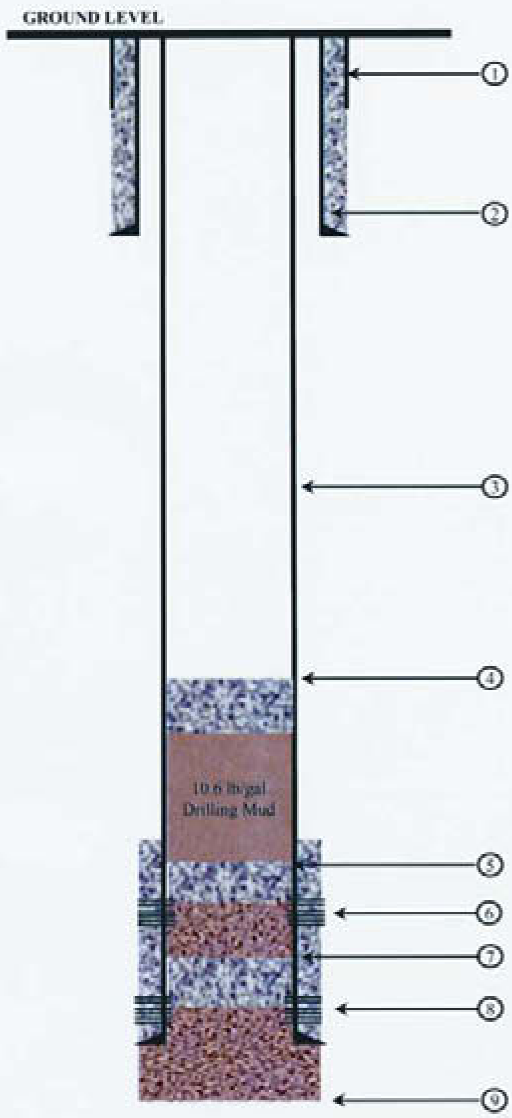


Figure VI-3: Proposed Injection Well – Well Annulus and Monitoring System Schematic

8/15/03

Sun-Gulf Humble Fee #4 Completion Schematic



KB = 77.65 ft
GL = 65 ft
All depths RKB

COMPLETION DETAIL

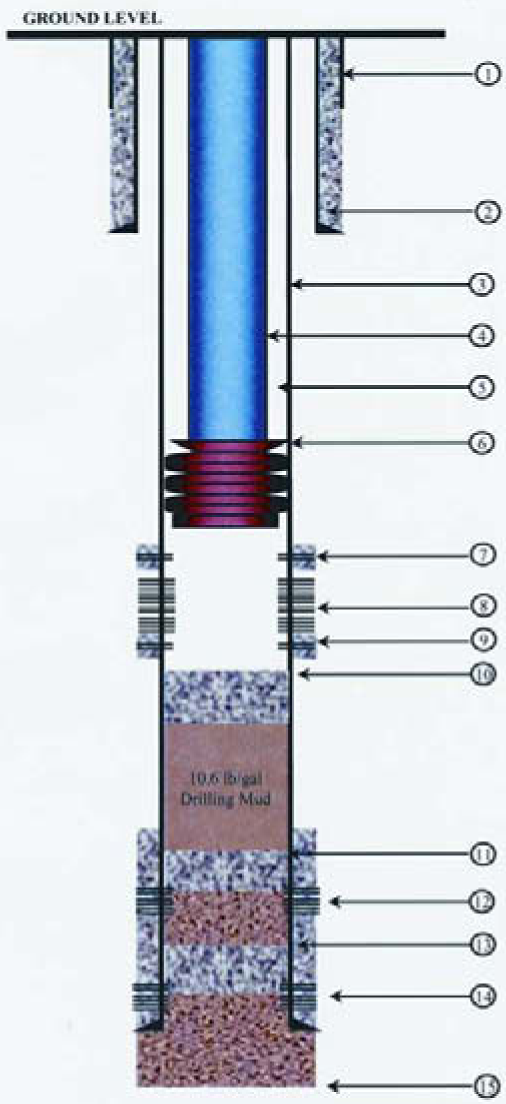
1. Conductor Pipe
2. 10-3/4" Surface Casing @ 2040'.
3. 5-1/2" Protection Casing @ 8964'.
4. Plug Back Total Depth @ 6129'. Cement Plug: 6129' to 6327'; set using 23 sx Class H.
5. Cement Plug: 7931' to 8414'; set using 57 sx Class H.
6. Abandoned Perforations: 8489' to 8501'.
7. Cement Plug Top at 8600'.
8. Abandoned Perforations: 8810' to 8914'.
9. Total Depth @ 9516'.

Drawn by: KFD 08/14/03
drawing not to scale

Figure VI-4: Current Sun-Gulf Humble Fee #4 Completion Schematic

8/15/03

Proposed Sun-Gulf Humble Fee #4 – Monitor Well - Completion Schematic



KB = 77.65 ft
GL = 65 ft
All depths RKB

COMPLETION DETAIL

1. Conductor Pipe
2. 10-3/4" Surface Casing @ 2040'.
3. 5-1/2" Protection Casing @ 8964'.
4. 2-7/8" Injection Tubing @ 5000': 6.5 lb/ft N-80 EUE 8rd.
5. Annular Fluid: 9.0 lb/gal inhibited NaCl brine.
6. Injection Packer @ 5000': 5-1/2" X 2-7/8" Weatherford I-X Mechanical Set.
7. Squeeze Perforations above Frio C Sand
8. Frio C Sand Perforations: 5055' to 5090'.
9. Squeeze Perforations below Frio C Sand
10. Plug Back Total Depth @ 6129'. Cement Plug: 6129' to 6327'; set using 23 sx Class H.
11. Cement Plug: 7931' to 8414'; set using 57 sx Class H.
12. Abandoned Perforations: 8489' to 8501'.
13. Cement Plug Top at 8600'.
14. Abandoned Perforations: 8810' to 8914'.
15. Total Depth @ 9516'.

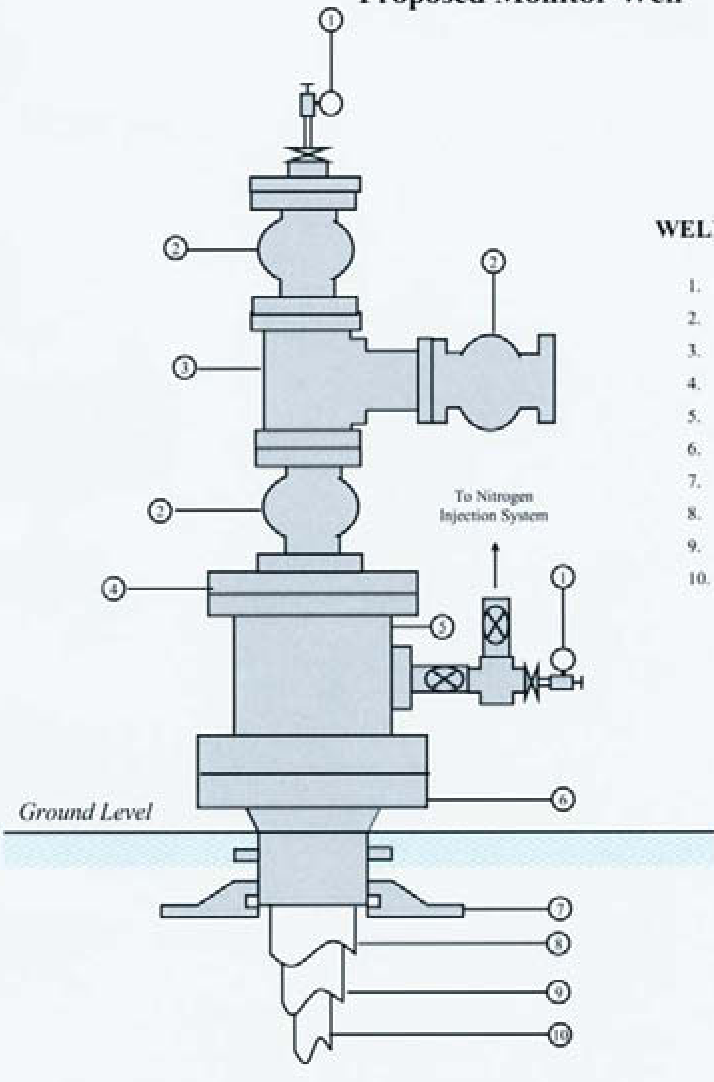
Drawn by: KFD 08/14/03
drawing not to scale

Figure VI-5: Proposed Sun-Gulf Humble Fee #4 – Monitor Well - Completion Schematic

8/15/03

Frio Brine Pilot Test
Proposed Monitor Well

KB = 77.65 ft
GL = 65 ft
All depths RKB



WELLHEAD ASSEMBLY DETAIL

1. Pressure Gauge
2. Full-Opening Gate Valve
3. Flow Tee
4. Adapter Flange
5. 5-1/2" 5000 psi Tubing Spool
6. 13-3/8" 3000 psi Casing Head
7. Base Plate, welded to 14" Conductor
8. 10-3/4" O.D. Surface Casing
9. 5-1/2" O.D. Protection Casing
10. 2-7/8" Injection Tubing

Figure VI-6: Proposed Sun-Gulf Humble Fee #4 – Monitor Well - Wellhead Schematic

8/15/03

<u>**Drilling procedure—proposed injection well**</u>

Conductor hole

Prepare surface location.

Set conductor casing to ±100 ft. Use a casing hammer to drive 14-inch conductor pipe to desired depth or when penetration rate slows to 100 blows per foot. Alternatively, a shallow drilling company may be used to drill a 17½-inch hole for the conductor casing. The casing will then be cemented in place.

Mobilize drilling rig. Perform safety audit during rig-up to ensure that equipment setup complies with project requirements.

Drill mouse hole and rat hole.

Dig hole for drilling rig "cellar," and install cellar wall material.

Install 14-inch drilling spool and well control equipment on the conductor casing.

An excavation permit may be required before any drilling is performed.

Surface hole

Pick up 12¼-inch bit and the bottom-hole assembly (BHA). Drill a 12¼-inch surface hole to ±2,600 ft using spud mud, as detailed in the Well Fluids Program section of this well plan. Take deviation surveys every 500 ft. Maximum allowable deviation from vertical is 5º, and maximum allowable deviation between surveys is 2º. After reaching surface casing setting depth, the drilling fluid will be circulated and conditioned to ensure correct fluid properties for the casing setting procedure. The final deviation survey should be taken just before pulling out of the hole.

Run 9⅝-inch surface casing to ±2,600 ft. Refer to Section VI.1.2—Well Casing Specifications for a detailed description of the casing and casing equipment.

Reduce mud levels in surface circulating system and have additional tanks on hand to recover any excess mud or cement that may circulate to the surface.

Designate a qualified person to observe the circulating system and monitor drilling fluid at all times during the cementing procedure. An accurate accounting of volumes will be critical in the event that circulation is lost.

Rig up circulating equipment and perform a pressure test on the lines. Circulate and condition the drilling fluid to ensure correct fluid properties for the cementing procedure. Reciprocate the casing continuously during the circulating of the drilling fluid.

Cement the casing in place. Details of the cement blends proposed are located in Section VI.1.8—Well Construction Cementing Program.

Be prepared to divert cement and cement-contaminated drilling-fluid returns away from circulating system and into appropriate containment. Use sugar to retard the premature setting of the cement if necessary.

If no cement returns are observed at surface, contact wireline service provider and schedule a temperature survey to determine the top of the cement.

Center the casing in the rotary table of the drilling rig after completing the cementing procedure and before the cement hardens.

Cement the annular space that does not contain cement. Fill the annulus space by pumping cement through small tubing that has been run into the annulus to the current top of cement.

After waiting for cement to harden for a minimum of 12 hours, cut off the surface and conductor pipe and install a 9⅝-inch × 3,000-psi casing head. Perform a pressure test on the casing head after installation.

Protection hole

Install 9⅝-inch (Pipe-Blind-Annular) blowout preventers (BOP) and auxiliary well control equipment. Perform a pressure test on the equipment to a low pressure of 250 and a minimum high pressure of 2,000 psig.

Test annular preventer to 70 percent of rated capacity.

Pick up a 7⅞-inch bit and BHA, and trip in the hole to the top of cement. Close pipe rams and perform a pressure test on the surface casing to 1,000 psig for at least 30 minutes. Record pressure on some type of recording device, preferably digital. The original copy of the pressure test record **MUST** be sent in to the office and made part of the well report to the State. Keep a copy of the pressure test record at the well site with other important records.

Displace the drilling fluid in the well with a low solids drilling fluid. Details of the drilling fluid characteristics are located in the Drilling Fluids Program subsection of this well plan.

Drill out casing float equipment and 20 ft of new hole.

Perform a pressure test on the casing seat and formation to leak off or a 10.5-ppg equivalent drilling fluid density.

Drill a 7⅞-inch hole from surface casing point to the first core point. Details of the coring program are located in Section VI.1.6—Well Logging, Coring and Testing. Monitor the well path as drilling proceeds.

Drill and retrieve the first core.

Pick up drilling assembly and drill 7⅞-inch hole to the second coring point.

Drill and retrieve the second core.

Pick up the drilling assembly and lower into the well. Control drill to the proposed total depth (5,750 ft true vertical depth).

After reaching total depth, circulate and condition the drilling fluid to ensure correct fluid properties for the wireline logging procedure.

Measure the drill string on the trip out to confirm well depth.

Rig up wireline equipment and run the electric logs and collect formation fluid and any sidewall core samples over the open-hole interval. Refer to Section VI.1.6—Well Logging, Coring and Testing for details.

If logging procedure is extended and/or hole becomes sticky or unstable during logging, run drill string into the well and circulate and condition the drilling fluid. Complete logging program as planned

After completing all wireline logging and sampling, go into the hole with bit, drill collars, and drill pipe to bottom. Check and note presence of fill at the bottom of the hole. Circulate hole clean, and condition the drilling fluid for running the protection casing. Note that a high-viscosity pill may be required to keep the bottom portion of the hole open.

Pull out of the hole with the drilling assembly. Lay down drill pipe and drilling assembly.

Notify TCEQ of upcoming cement job.

Rig up casing make-up and torque measuring equipment. Run the 5½-inch casing. Details of the casing program are located in Section VI.1.2—Well Casing Specifications.

Ensure that all dimensions of cementing equipment are visually inspected, measured, and drifted before running in the hole.

API Modified thread lubricant or equivalent will be used unless premium threads and/or corrosion resistant (stainless steel casing) is used.

Have a casing swedge available, on the rig floor, with circulating hoses ready, in the event that the casing must be washed to bottom or in the event that well control procedures are required.

Once the casing is on bottom, rig up and circulate the hole for a minimum of 150 percent of the hole volume to clear the floats and cool the formation sufficiently for cementing. Add water and chemicals to the drilling fluid to adjust the characteristics of the fluid to improve drilling-mud removal from the annulus during the cementing procedure.

Reciprocate the pipe slowly, but continuously, in 20-foot strokes during the circulating and cementing operations. If the movement of the pipe begins to indicate that sticking is occurring, lower the pipe to planned setting depth and discontinue pipe movement.

Reduce mud levels in surface circulating system, and have additional tanks on hand to recover any excess mud or cement that may be circulated to the surface.

Designate a qualified person to observe the circulating system and monitor drilling fluid at all times during the cementing procedure. An accurate accounting of volumes will be critical in the event that circulation is lost.

Mix and pump the cement and spacer slurries. Details of the cementing program are located in Section VI.1.8—Well Construction Cementing.

Lift the BOP stack and hang off the 5½-inch casing in tension (same hook load as when originally cemented in place). Nipple up the tubing spool, and perform a pressure test on the seals to the manufacturer's specifications.

Rig up and run a temperature or similar diagnostic survey to determine the top of cement. After the cement top is located, a procedure to fill any voids in the annular space between the actual cement depth and the proposed depth will be provided, if required.

Rig down the drilling rig and release from location. Remove and clean location of all drilling equipment.

<u>Completion procedure—proposed injection well</u>

Casing and cement evaluation

1. Mobilize a workover rig to location, and rig up the equipment.

2. Install well-control equipment and test.

3. Pick up a bit and two casing scrapers, and trip into the hole with a work string to the top of cement in the casing.

4. Circulate the fluid in the well bore to remove any solids. Pull the work string, scrapers, and bit.

5. Rig up wireline equipment and lubricator to the top of the annular BOP. Perform a 2,000-psig pressure test on the lubricator. Run cement evaluation and casing inspection/caliper logs and gyroscopic survey as detailed in Section VI.1.6—Well Logging, Coring, and Testing section of this well plan. Run cement bond log under zero pressure and at elevated pressures if necessary to remove effects from potential microannulus. Run logs approximately 500 ft above the top of annular cement. Rig down wireline equipment.

6. Perform a pressure test on the casing to 1,500 psig for at least 30 minutes. Record the pressure test on a strip, circular, or digital recording device.

Well completion

7. Pick up a bit and drilling assembly (no stabilizers), and trip into the hole.

8. Circulate the well clean, and displace well fluid with completion fluid. Pull out of the hole.

9. Rig up wireline unit and set up perforating charges. Run in hole and correlate perforation gun(s) on depth. Perforate the Frio C Sand injection reservoir as determined from the open-hole logs. It is recommended that the well be perforated **underbalanced** to aid in perforation tunnel clean up.

10. Flow formation fluid from the Frio C Sand either by pumping or nitrogen jetting. This will also aid in developing the well. Monitor formation properties (chlorides, pH, temperature, etc.). Continue flowing the well until parameters stabilize, which indicates that formation fluids are being recovered. Collect a sample for laboratory analysis.

11. Perform short-duration injection test to determine whether further well development/stimulation is required.

12. Run any preexperiment testing requiring the well to be clear of completion equipment.

13. Run in well, and set retrievable plug just below the Frio C Sand to minimize well-bore storage effects. Spot sand on top of plug.

14. Pick up completion packer and tubing. Attach any monitoring equipment and run in well. Once on bottom, circulate the well with clean brine.

15. Space out tubing string and set the packer 10 ft above the uppermost perforation in the Frio C Sand.

16. Land the tubing into the wellhead.

17. Install wellhead equipment.

18. Perform annulus pressure test.

19. Rig down the workover rig and move out associated equipment.

General notes

All depths referenced are approximate and are based on the expected log depth.

Actual depths may vary according to lithology of local formations.

<u>Contingency planning</u>

In the event that unforeseen events occur, detailed plans to remedy the specific problem will be developed, with input from all parties involved. These plans will then be implemented to solve the specific problem. The following are general contingency plans to address specific problems.

Lost circulation

Zones of moderate to severe lost circulation have not been identified by review of local offset data. Some fluid losses are anticipated during the drilling of the surface and protection hole, as part of normal operations. Permeable freshwater and saline-water sands will be penetrated during well installation operations. These will be treated as necessary by the addition of sized lost circulation material during the drilling of the hole. Low mud weights and solids concentration in the drilling fluid will help minimize losses. Lost circulation pills will be spotted in the event that losses are excessive. Lost circulation material will be stored on location to allow quick response to any loss conditions.

Overpressured zones

Area review has indicated no overpressured zones in the local subsurface geology down to the Frio Formation. Offset well data indicate that the normal hydrostatic pressure regime extends down to at least 9,000 ft. During the drilling of the injection well, the following measures will be used to control/contain formation pressure:

- Hydrostatic pressure exerted by drilling/completion fluid
- Blowout prevention (BOP) equipment

Stuck pipe

The possibility of stuck pipe exists because of the extensive permeable sand layers in the well path. Drilling jars will be used, if needed, in the drilling of the protection hole to assist in freeing stuck pipe. Fluid-loss control of the drilling fluid will be maintained to reduce the possibility of differential sticking of the work string. In the event that the work string becomes stuck in the hole, some or all of the following procedures may be utilized to free the pipe.

- Circulate a lubricating fluid in the well to assist in removal of the stuck pipe.

- Rig up wireline and run a free point survey to determine the depth of the shallowest stuck point.

- Back off the section of free pipe using wireline detonation charges.

- Engage the stuck portion of the work string with an overshot and fishing jars and attempt to jar the pipe free.

- Wash over the stuck pipe and remove it from the hole.

- Sidetrack the hole above the section of stuck pipe.

Agency notification and consent will be obtained before sidetrack operations are implemented.

Drilling fluids program

Surface hole

Depth (ft)	Mud type	Weight (lb/gal)	Viscosity (funnel-sec.)	Fluid loss (cc/30 min)
0-2,600	Freshwater gel	8.4 - 8.8	35 - 45	No control

(1) Lost circulation material (LCM) will be on location to treat for fluid losses in shallow sands. The fluid system will be pretreated with LCM before any known or suspected loss zones are encountered.
(2) High-viscosity sweeps will be used to assist hole cleaning.

Protection hole

Depth (ft)	Mud type	Weight (lb/gal)	Viscosity (funnel-sec.)	Fluid loss (cc/30 min)
2,600-3,000	Freshwater gel	8.7 - 9.2	35 - 45	NC - 10
3,000 - TD	Freshwater gel	9.2 - 9.5	30 - 50	6 - 8

Notes:
(1) Refer to vendor's Drilling Fluids Program for details.
(2) Should lost circulation and fluid seepage occur, materials designed for that problem will be used to remedy the problem on an as-needed basis.
(3) High-viscosity sweeps will be used as needed to assist hole cleaning.

Completion fluid

Potassium chloride (KCl) or Sodium Chloride (NaCl) are planned for use as completion fluid(s). Fluid weight will be maintained to contain reservoir pressures without inducing flow to the well bore.

Drilling fluid may be used as a completion fluid in the event that well-bore stability problems arise or are anticipated.

Annular completion fluid

The annular completion fluid for this well is an NaCl brine solution with a density of approximately 8.8 lb/gal. Corrosion inhibitor, biocide, and oxygen scavenger additives will be mixed with the annular completion fluid prior to pumping into the well. A conservative tracer, such as KBr, may be added to workover fluids to identify introduced materials.

Waste fluid and solids management planning

Prior to mobilizing equipment to the well location, the area beneath the drill-rig footprint and surrounding area will be cleared and graded. The area will be constructed in a manner to divert any collected liquids to the well cellar or to a sump. The liquids collected in the cellar or sump will be periodically removed and recycled within the active fluid system or disposed of in an approved facility according to their classification.

Drilling mud that is circulated out of the hole will flow through solids control equipment consisting at a minimum of a shale shaker, desander, and/or desilter to remove drill cuttings and other solids from the circulating mud system. All drill cuttings and removed solids will be contained and characterized for proper disposal according to applicable Federal and State regulations. Disposal will be either onsite or at an approved facility appropriate to receive the properly classified wastes.

Upon completion of the proposed injection well, the drilling mud will be dewatered to separate solids from liquids. The solids will be characterized and disposed of according to any and all applicable Federal and State regulations. The liquid portion may be retained and injected into the well once the permit to inject has been received. Alternately, the liquids will be characterized and disposed of according to any and all applicable Federal and State regulations at another approved facility appropriate to receive the properly classified wastes.

VI.1.5.2 Well Recompletion Program—Proposed Monitor Well

The following subsections contain proposed well conversion and completion activities for the Sun-Gulf-Humble Fee No.4 well to convert it to a monitor well during the CO_2 injection experiment. Note that because of the overall field activities, time gaps may exist between procedure steps.

The Sun-Gulf-Humble Fee No.4 well was reentered and plugged back from the current Yegua producing interval to the Frio Formation between July 28 and August 7, 2003. The rods and 2⅜-inch tubing were removed from the well, and the well was circulated clean. A cement plug was set above the producing perforations from 7,931 to

8,414 ft. Mud of 10.4-lb/gal density was circulated in the well, and a second cement plug was set from 6,129 to 6,327 ft. The 5½-inch casing was pressure tested from surface to plug-back depth of 6,129 ft. The 30-minute pressure test had an initial test pressure of 1,228.40 psig and ended at 1,213.09 psig. The test was satisfactory, with a net loss of 15.31 psi, or 1.25 percent change in during the test. Following completion of the pressure test, casing scrapers were run in the well, and the well was circulated clean with freshwater. On August 7, 2003, a Schlumberger USIT tool was run in the well to determine the current condition of the 5½-inch casing, which showed minimal wall loss.

Remedial well operations

1. Rig up workover rig and ancillary equipment.

2. Rig up wireline unit and set up perforating charges. Run in hole, and correlate perforation gun on depth. Perforate the 12-foot shale interval between the Frio C Sand injection reservoir and the overlying Frio B Sand, as determined from the open-hole logs.

3. Rig up cementing company, and perform cement isolation squeeze of the perforated interval.

4. Rig up wireline unit, and set up perforating charges. Run in hole, and correlate perforation gun on depth. Perforate the 12-foot shale interval located between the Frio C Sand and the overlying Frio B Sand, as determined from the open-hole logs.

5. Rig up cementing company, and perform cement isolation squeeze of the perforated interval.

6. Rig up wireline unit, and set up perforating charges. Run in hole, and correlate perforation gun on depth. Perforate the basal portion of the Anahuac Shale overlying the Frio A Sand, as determined from the open-hole logs.

7. Rig up cementing company, and perform cement isolation squeeze of the perforated interval.

8. Drill out any cement left inside the casing, and scrape the casing.

9. Evaluate effectiveness of the squeeze cement procedure(s).

10. Repeat squeezing until isolation is achieved.

11. Once acceptable isolation is achieved, perform pressure test on the casing and squeeze perforations.

<u>Well completion—monitor well</u>

12. Pick up a bit and drilling assembly (no stabilizers), and trip into the hole.

13. Circulate the well clean, and displace well fluid with completion fluid. Pull out of the hole.

14. Rig up wireline unit, and set up perforating charges. Run in hole and correlate perforation gun(s) on depth. Perforate the Frio C Sand injection reservoir as determined from the open-hole/cased hole logs. It is recommended that the well be perforated **<u>underbalanced</u>**, to aid in perforation tunnel clean up.

15. Flow formation fluid from the Frio C Sand either by pumping or nitrogen jetting. This will also aid in developing the well. Monitor formation properties (chlorides, pH, temperature, etc.). Continue flowing the well until parameters stabilize, indicating that formation fluids are being recovered. Collect a sample for laboratory analysis.

16. Perform short-duration injection test to determine whether further well development/stimulation is required.

17. Run any preexperiment testing requiring the well to be clear of completion equipment.

18. Run in well and set retrievable plug just below the Frio C Sand to minimize well-bore storage effects during the injection experiment.

19. Pick up completion packer and tubing with gas lift valves. Attach any monitoring equipment and run in well. Once on bottom, circulate the well with clean brine.

20. Space out tubing string, and set the packer 10 ft above the uppermost perforation in the Frio C Sand.

21. Land the tubing into the wellhead.

22. Install wellhead equipment.

23. Rig down the workover rig, and move out associated equipment.

VI.1.6 Well Logging, Coring, and Testing Program

VI.1.6.1 Proposed Injection Well Logging Program

The following geophysical well logs will be run in the open-hole section of the protection casing (long string) hole of the proposed injection well:

- Dual induction/spontaneous potential
- Natural gamma ray
- Porosity (density and neutron and/or sonic)
- Fracture finder (borehole imaging survey recommended) through injection and confining zones
- Open-hole caliper
- Formation fluid samples

Additional diagnostic logs and/or formation cores (whole core or sidewall cores) may be run at the discretion of the Frio Brine Pilot Test project team.

The following cased-hole geophysical well logs will be run after the protection casing is cemented in place:

- Cement evaluation and casing inspection log
- Gyroscopic survey
- Differential temperature survey
- Bottom-hole pressure fall-off test—static pressure determination
- Radioactive tracer survey

Additional diagnostic logs may be run at the discretion of the Frio Brine Pilot Test project team.

VI.1.6.2 Injection Zone and Confining Zone Testing

The following whole core depths are proposed for the injection well on the basis of anticipated funding. The proposed conventional cores will be supplemented with sidewall cores or horizontal rotary cores as necessary.

Conventional coring

Core size	Depth	Formation/lithology
7⅞ inches × 4 inches × 30 ft	±5,000 ft	Containment Interval Shale and Frio B Sand
7⅞ inches × 4 inches × 30 ft	±5,100 ft	Frio C Sand

Supplemental conventional coring in the injection zone may be conducted to obtain additional reservoir data. The Frio Brine Pilot Team will select actual core points during the drilling of the well. If insufficient formation core is recovered in any core run, the core run may be repeated at the discretion of the team, or sidewall coring will be conducted in the interval. Core depths will be adjusted relative to actual drilling depths encountered.

Sidewall coring/horizontal rotary coring

Sidewall coring or horizontal rotary coring may be taken in the injection zone or the confining zone during the open-hole logging of the protection hole to supplement conventional core data. On the basis of evaluation and percent recovery of the conventional cores the Frio Brine Pilot Team will select actual core depths. If sufficient whole core is recovered, sidewall cores may not be taken in the injection well.

Formation fluid sampling

Selected samples of formation fluids in the injection interval will be collected during open hole logging of the protection hole via a wireline formation testing device, or the injection well and/or monitor well will be back flowed (pumping or via nitrogen) to obtain background native formation fluids. The decision to attempt fluid samples via wireline will be made on the basis of the condition of the borehole at the time of logging operations. Fluid samples will be collected and transported to a selected laboratory for detailed analysis.

VI.1.6.3 Well Testing Program

Mechanical integrity tests will be performed during completion of the injection well and conversion of the monitor well. The following tests will be performed:

- Pressure testing of the 5½-inch protection casing.
- Radioactive tracer survey of the completed injection well following perforation of the Frio C Sand test interval.
- Annulus pressure test of the completed injection well, with tubing and packer in place.

These tests will be run in accordance with procedures contained in the *Basic Guidelines for Mechanical Integrity Tests and Related Cased Hole Wireline Logging* for Class I injection wells.

VI.1.7 Well Casing Centralizer Information

Approximately 32 hinged bow spring centralizers will be used in setting the surface casing string. Centralizers will be placed as follows:

- 1 centralizer 10 ft above the float shoe, straddling a stop collar
- 1 centralizer straddling the first casing collar above the float shoe
- 1 centralizer 10 ft above the float collar, straddling a stop collar
- 1 centralizer every other collar, up to the surface

Approximately 72 hinged bow spring centralizers will be used in setting the protection casing string. Centralizers will be placed as follows:

- Centralizer 10 ft above the float shoe, straddling a stop collar

- Centralizer straddling the first casing collar above the float shoe
- Centralizer 10 ft above the float collar, straddling a stop collar
- Centralizer every ±80 ft, straddling a casing collar

VI.1.8 Proposed Injection Well Construction Cementing Program

The following cementing program is proposed for installation of the surface casing string:

- 9⅝ inches in 12¼-inch hole at 2,600 ft
- cement to surface
- estimated 100 percent excess over bit size
- actual volume to be calculated from caliper log plus 50 percent excess

SURFACE CASING CEMENT SPECIFICS

	Weight lb./gal	Yield ft^3/sack	Water gal/sack	Volume sacks
Spacer: 40 bbl of freshwater				
Lead Cement: 2,100 ft of fill				
15:85 Poz + 8% bentonite + 3% salt	12.4	2.23	12.6	610
Tail Cement: 1,000 ft of fill				
Class A	15.6	1.18	5.22	270

The following cementing program is proposed for installation of the protection casing (long string) string:

- 5½ inches in 7⅞-inch hole at ±5,750 ft
- cement from total depth to 3,750 ft
- estimated 190 percent excess over bit size
- actual volume to be calculated from caliper log plus 20 percent excess

PROTECTION CASING CEMENT SPECIFICS

	Weight lb./gal	Yield ft^3/sack	Water gal/sack	Volume sacks
Spacer: 30 bbl of freshwater				
20 bbl of mud spacer				

Lead Cement: 1,000 ft of fill				
35:65 Poz + 6% bentonite + 3% salt	12.7	1.90	10.3	230
Tail Cement: 500 ft of fill				
Class A	16.4	1.08	4.39	215

AUXILIARY CEMENTING EQUIPMENT

Surface casing

9⅝-inch float equipment and casing equipment

1. Float shoe—8rd STC

2. Float collar, installed 1 joint above the float shoe

3. ±32 hinged bow spring centralizers

- 1 centralizer 10 ft above the float shoe, straddling a stop collar
- 1 centralizer straddling the first casing collar above the float shoe
- 1 centralizer 10 ft above the float collar, straddling a stop collar
- 1 centralizer every other collar, up to the surface

Protection casing (long string)

5½-inch float equipment and casing equipment

1. Float shoe
2. Float collar, 2 joints above the float shoe
3. Bottom wiper plug
4. Top wiper plug
5. ±72 hinged bow spring centralizers

- Centralizer 10 ft above the float shoe, straddling a stop collar
- Centralizer straddling the first casing collar above the float shoe
- Centralizer 10 ft above the float collar, straddling a stop collar
- Centralizer every ±80 ft, straddling a casing collar

VI.1.9 Proposed Completion Interval Information

The injection interval is anticipated to be the upper Frio Formation at an approximate depth of 4,885 to 5,075 ft below ground (Frio C Sand test injection interval is expected between 5,000 and 5,075 ft below ground).

The proposed completion for the injection experiment is a perforated completion into the Frio C Sand. Additionally, the Frio B Sand and/or the Frio A Sand may be perforated for monitoring purposes following CO_2 injection.

VI.1.10 Well Tubing Specifications

The proposed injection well will be completed with 2⅞-inch tubing set within a 5½-inch protection casing string. The protection casing string will be set through the Frio C Sand to approximately 5,750 ft. This will allow sufficient rate hole below the completion to run anticipated experiment monitoring equipment. Injection tubing specifications for the proposed injection well is shown in table VI-2. The tubing string is designed for the anticipated duration of the CO_2 injection experiment.

Table VI-2. Injection tubing specifications—injection and monitor wells.

Tubular	Depth (ft)	Size (inches)	Weight (lb/ft)	Grade	Thread	Collapse/burst	Tensile body/joint (× 1,000 lb)
Injection tubing	0–5,000	2⅞	6.5	N-80	EUE 8rd	11,160/10,570	145/145

VI.1.11 Well Packer Information

The well packer will be set in each well to just above the Frio C Sand reservoir at a depth of approximately 5,000 ft. Proposed packer is a Weatherford I-X Mechanical Set

5½- × 2⅞-inch packer or equivalent. The packer is designed for the life of the CO_2 injection experiment.

VI.1.12 Well Stimulation Program

The proposed injection well and the converted Sun-Gulf-Humble Fee No.4 monitor well will be developed by pumping or nitrogen lift. The wells will be flowed until monitored parameters stabilize, indicating that native formation brine is being pulled from the wells. Development of the wells should result in an appropriate stimulation of the Frio C Sand interval.

Alternatively, if back-flowing the wells does not result in acceptable injection characteristics, a stimulation program consisting of an acid treatment will be performed. The purpose of the acid treatment will be solely to remove formation skin damage due to invasion of solids during the course of drilling and open flow channels in the perforation tunnels. The acid treatment will consist of the following acids, with actual volumes to be determined at the time of placement and by formation characteristics determined from core and wireline-log evaluation:

• 15 percent hydrochloric acid (HCl)

• Additional acids (HCL/HF) will be selected after mineralogical and acid solubility evaluation of the injection reservoir

• Chemicals may be added to the acid to limit clay swelling, reduce emulsions, and inhibit reaction to the carbon steel completion equipment. The type and quantity of these chemicals will be determined on the basis of formation characteristics determined from core and wireline-log evaluation

The acid fluids will be displaced from the well bore and near well-bore area by back-flowing the fluids following stimulation. Several stimulation treatments and/or backwashing events may be necessary if injectivity of well is unacceptable. Stimulation procedures will be submitted for approval prior to any additional stimulation work.

VI.1.13 Injectivity/Falloff Testing Program

Pressure-transient monitoring will play an important role in both site characterization and CO_2 plume monitoring for the Frio Brine Pilot Test. Pretest site-characterization goals include estimation of single-phase flow properties, determination of appropriate lateral boundary conditions for the subvertical faults bounding the pilot site, assessment of the integrity of intersand shale layers, and analysis of ambient phase conditions within the formation (although nominally brine saturated, the pilot-site sands may harbor immobile gas-phase or dissolved hydrocarbons). Pressure-transient monitoring during CO_2 injection will enable estimation of two-phase flow properties and help in tracking the movement of the injected CO_2 plume.

Pretest site-characterization testing will include, at a minimum, an injection/falloff transient test of the Frio C Sand injection interval. Formation fluids pumped from the wells or recovered during back-flow operations will be filtered and used as the test injection fluid. If insufficient native formation fluids are available, commercial brine cutback with freshwater may be used for injection fluids.

VI.2 Renewal Permit and Amended Permit Information

This Permit Application is for new wells, therefore Section VI.2. does not apply.

VI.3 Injection Well Operation

VI.3.1 Maximum Instantaneous Rate of Injection

The Frio Brine Pilot Team anticipates that average daily flow of CO_2 to the injection wells will be no more than 250 tons per day. Modeling presented in Section VII—Reservoir Mechanics considers this maximum injection rate to be conservative. The Frio Brine Pilot Team is requesting that the instantaneous rate of injection of CO_2 be calculated and limited as follows (rate is based on modeling presented in Section VII—Reservoir Mechanics):

INJECTION INTERVAL	INSTANTANEOUS RATE* (TONS PER DAY)
Frio Sands	***250***

*Equivalent to 41 gpm

The Frio Brine Pilot Team is requesting that the instantaneous rate of injection be calculated and limited as follows for any project generated liquids disposal:

INJECTION INTERVAL	INSTANTANEOUS RATE (GPM)
Frio Sands	***150***

VI.3.2 Average Rate of Injection, Total Monthly, and Annual Volumes

The Frio Brine Pilot Team anticipates that the flow to the injection well will be 250 tons of CO_2 per day. The CO_2 amount of CO_2 injected will be cost limited to less than 5,000 tons and will be injected over a period of less than 90 days, including pauses for experimental data collection and monitoring. Modeling presented in Section VII—Reservoir Mechanics considers this rate of injection for the duration of the injection experiment. The Frio Brine Pilot Team is requesting that the cumulative volume be calculated and limited as follows (volume based on modeling presented in Section VII—Reservoir Mechanics):

INJECTION INTERVAL	CUMULATIVE ANNUAL VOLUME** (TONS)
Experiment Cumulative Maximum*	***54,000***

* Calculated by multiplying : Rate (tpd) × 20 days of injection

The Frio Brine Pilot Team is requesting that the cumulative volume for any project-generated brines and/or fluids be calculated and limited as follows (volume based on modeling presented in Section VII—Reservoir Mechanics):

INJECTION INTERVAL	CUMULATIVE ANNUAL VOLUME** (BBL)
Cumulative Maximum*	***26,000***

* Estimated brine resulting from pumping activities

The Frio Brine Pilot Team anticipates that the flow to the injection wells will be 250 tons of CO_2 per day. The Frio Brine Pilot Team is requesting that the cumulative monthly volume be calculated and limited as follows (volume based on modeling presented in Section VII—Reservoir Mechanics):

INJECTION INTERVAL	CUMULATIVE MONTHLY VOLUME** (TONS)
Experiment Cumulative Maximum*	***5,000***

* Calculated by multiplying : Rate (tpd) ×20 days of injection

The Frio Brine Pilot Team is requesting that the cumulative volume for any project generated brines and/or fluids be calculated and limited as follows (volume based on modeling presented in Section VII—Reservoir Mechanics):

INJECTION INTERVAL	CUMULATIVE ANNUAL VOLUME** (BBL)
Cumulative Maximum*	***26,000***

* Estimated brine resulting from pumping activities

In support of this request, the Frio Brine Pilot Team has provided detailed modeling in Section VII—Reservoir Mechanics.

VI.3.3 Maximum Surface Injection Pressure

The Frio Brine Pilot Team requests the following surface injection pressure be permitted for the Frio Injection Interval:

INJECTION INTERVAL	MAXIMUM SURFACE INJECTION PRESSURE (PSI)
Frio Sands—CO_2 Injection	***2,700***
Frio Sands—Liquids Injection	***1,200***

Calculation of the Maximum Surface Injection Pressure is contained in Section VII.A.5. This request is consistent with the maximum wellhead pressure of 5,450 psig approved by the Railroad Commission of Texas for CO_2 injection for secondary recovery of oil in the Yegua for the R. E. Brooks Fee NCT 2-2 well (Artificial Penetration No. 43) and R. E. Brooks Fee NCT 2-4 well (Artificial Penetration No. 35).

VI.3.4 Range in Injection Rate and Surface Injection Pressure, Annual Volume, and Operational Life

The Frio Brine Pilot Team anticipates that daily flow to the injection well field will be 250 tons per day (approximately 41 gallons per minute) during the CO_2 injection experiment. Surface injection pressure for the injection wells is anticipated to range between 1,200 psi and 2,400 psi for the CO_2. The equivalent wellhead pressure for native brine is expected to be in the range of 50 to 350 psi, on the basis of experience at the nearby Class I injection wells. The injection well is designed for the life expectancy of the injection experiment and postinjection monitoring.

VI.3.5 Well Maintenance and Operation

The Frio Brine Pilot Team will operate the wells in compliance with provisions specified or referenced in the final Class V injection permits. The wells and surface facilities will be maintained in good working order and painted, if appropriate. A road will be installed to allow access to the injector well, the monitor well, and the associated facilities. The road will be maintained in good condition. Each well will be clearly identified by a posted sign and labeled with relevant information as appropriate (lettering will be at least 1-inch high).

Pressure gauges will be installed at the wellhead on the injection tubing and the on the annulus between the injection tubing and the long-string casing and maintained in good working order at all times. Recording devices will be installed to record at a minimum: (a) injection tubing pressure, (b) injection flow rate, (c) injection fluid temperature, (d) injection volume, and (e) tubing—long-string casing annulus pressure. All gauges, pressure sensing devices, and recording devices will be tested and calibrated at installation. Test and calibration records will be maintained for the duration of the experiment. All instruments will be housed in weatherproof enclosures.

Site personnel will monitor the above parameters while CO_2 injection activities are going on. If a monitored parameter is exceeded, the Frio Brine Pilot Team will immediately investigate and identify the cause of the problem. If, upon investigation, the subject well appears to lack mechanical integrity, the Frio Brine Pilot Team will

(a) immediately cease injection of CO_2 unless continued or resumed injection is authorized by the Executive Director,

(b) take all steps necessary to determine the presence or absence of a leak, and

(c) notify the Executive Director within 24 hours of the incident or shutdown.

If a loss of mechanical integrity is discovered during the investigation (or during mechanical integrity testing), the Frio Brine Pilot Team will

(a) immediately cease injection of CO_2,

(b) take reasonable steps necessary to determine whether there has been a release of effluent into any unauthorized zone,

(c) notify the Executive Director within 24 hours after the loss of mechanical integrity is discovered,

(d) notify the Executive Director when injection can be expected to resume, and

(e) restore and demonstrate mechanical integrity to the satisfaction of the Executive Director prior to resuming injection of effluent.

If there is evidence that there has been a release to an unauthorized zone, the Frio Brine Pilot Team will

(a) notify the Executive Director within 24 hours of obtaining such evidence,

(b) take the steps necessary to identify and characterize the extent of any release,

(c) propose a remediation plan for Executive Director review and approval,

(d) comply with any remediation plan specified by the Executive Director,

(e) implement any remediation plan specified by the Executive Director, and

(f) notify the local health authority, place a notice in a newspaper of general circulation, and send notification by mail to adjacent landowners where such a release is into a USDW or freshwater aquifer currently serving as a water supply.

VI.4 Waste Compatibility and Corrosion Monitoring

Tubing and casing materials are anticipated to be compatible with anticipated injection fluids over the anticipated duration of the injection experiment. The Frio brines are generally noncorrosive to the materials of construction, as evidenced by the condition of the 5½-inch casing in the Sun-Gulf-Humble Fee No.4 well. Dry supercritical CO_2 is relatively inert; however, it is much more reactive in the presence of water or NaCl brines. Corrosion of the carbon steel well components will be minimized during the injection experiment by a short period of injection, rapid reduction of acidity by reaction with mineral phases, and the use of pure CO_2.

Well materials and the piping to the well will be visually inspected on a daily basis for evidence/absence of corrosion. The annulus system of the injection well will be continuously monitored for indications of failure of the tubing or the packer seal.

VI.5 Well Closure and Postclosure Care Plans

Well closure procedures and postclosure care plans are detailed in the following subsections.

VI.5.1 Well Closure Plan

The closure procedure for the proposed injection well and monitor well is designed to be used at the conclusion of any relevant postinjection monitoring, when the wells have reached the end of their useful life. The procedure for each well closure is generally described below and may be modified prior to actual closure, as directed by the TCEQ:

A. The Frio Brine Pilot Test Team shall notify the TCEQ of intent to plug at least 60 days prior to closure. The following information will be provided:

   1. Type and number of plugs

   2. Placement of each plug, including elevations of both the top and bottom of the plug

   3. Type, grade, and quantity of the plugging material and additives to be used

   4. Method used to place plugs in hole

   5. Procedure used to plug and abandon the well

   6. Any information on newly constructed or discovered wells, or additional well data, within the ¼-mile Area of Review

B. Plugging operations will be conducted as follows:

   1. Record pressure decay in the injection zone for a time specified by the TCEQ

   2. Prepare location for workover rig

   3. Move workover rig onto location

   4. Remove wellhead and nipple up blow our preventers

   5. Kill well with brine or drilling fluid

   6. Remove injection tubing and injection packer

7. Place cement plug across the lower Anahuac and upper Frio, from approximately 4,800 to 5,200 ft. Tag cement plug after cement has hardened.

8. Place cement plug across the lowermost underground source of drinking water, from approximately 3,100 to 3,600 ft. If the 5½-inch protection casing is not cemented across the interval in the casing-borehole annulus, the well(s) will be perforated at the required depths and cement placed outside of the casing by squeeze cementing prior to the internal plug being paced.

9. Place cement plug at the base of surface casing. Minimum of 100 ft above and below the surface casing depth (note that the 5½-ich casing may be pulled from surface casing depth for salvage value; if casing is pulled, the cement plug will be placed in and out of the casing).

10. Top of final cement plug will be placed from 25 ft to surface.

11. Cut off casing 3 ft below ground surface and weld steel plate on top.

12. Inscribe on plate the injection well number, location, dates of use, total volume injected, and owner of well.

13. A permanent marker will be erected at the well site. The marker will contain all pertinent well information.

C. A plugging report will be filed with the Executive Director within 30 days of completion of plugging.

VI.5.1.1 Estimated Plugging Cost

An amount of $86,900 to cover plugging the wells is calculated, assuming the balance method is used to spot cement plugs.

VI.5.2 Postclosure Plan

This postclosure plan has been developed for the Frio Brine Pilot Test site in accordance with 31 TAC 331.68 (a)(4).

Regulatory information requirements

The following information is submitted in order to fulfill 31 TAC 331.68(a)(4). Pressure buildup and plume-front-location predictions were made using the TOUGH2 Model. The reservoir characteristics used in modeling are conservative in order to overpredict pressure buildup. Section VII—Reservoir Mechanics contains further details pertaining to these models.

The following postclosure plan has been developed for the Frio Brine Pilot Test site:

1. Current estimated formation pressure in the Frio C Sand Injection Interval is 150 bars (2,203.2 psi) at 5,100 ft (0.432 psi/ft original gradient).

2. Maximum modeled pressure in the Frio C Sand Injection Interval at the monitoring well at the cessation of CO_2 injection is 175 bars (2,588 psi)

   Maximum incremental pressure buildup at the monitoring well is 25 bars (363 psi). This pressure results from modeling the maximum proposed injection rate of 250 tons per day through the duration of the injection experiment. Pressure will be observed as it decreases toward initial pressure prior to plugging at the end of the experiment.

3. Wells within the Area of Review that could act as conduits for migration of the injected CO_2 because of pressure buildup are thought not to provide a risk for out-of-zone migration from the injection zone (see Section VIII). This assessment will be evaluated at the monitoring well during the test.

4. The projected maximum horizontal extent of the CO_2 plume in the Frio C Sand Injection Interval at the end of the injection experiment will not exceed a 350-foot radius (all injected CO_2 will be contained within the ¼-mile-radius Area of Review).

Other postclosure requirements

Upon closure of the injection and monitor wells, the Frio Brine Pilot Test Team will submit a survey plat to the local zoning authority that shall indicate the location of the injection wells relative to permanently surveyed benchmarks. The facility will also submit a copy of the plat to the TCEQ Underground Injection Control Unit in Austin, Texas. The Frio Brine Pilot Test Team will also notify the Railroad Commission of Texas and provide information necessary to impose appropriate conditions on subsequent drilling activities that may penetrate the well's confining or injection zone.

For a period of 5 years, the Frio Brine Pilot Test Team will retain well-plugging and abandonment records reflecting the nature, composition, and volume of all injected fluids. At the conclusion of the retention period, all records shall thereafter be maintained at a location designated by the Executive Director for that purpose. The estimated cost of postclosure care is less than $5,000.

VII. Reservoir Modeling

Injection reservoir modeling is a focus area for this experiment because through history-matching the observed CO_2 plume movement with the model plume, we will gain confidence in the model approach, assumptions, and methods of calculating input parameters. For this reason, our team has conducted extensive simulations, including analysis of the sensitivity of the model response to each parameter. All TOUGH2 simulations were done by Christine Doughty at Lawrence Berkeley National Lab.

VII.1 Model Construction and Input Data

Input data for the model were derived from a high-resolution geocellular model described in section V. Well logs and a 3-D seismic survey collected for exploration of deeper hydrocarbon reservoirs were reinterpreted for this study, focusing on the injection zone, and used to define the reservoir architecture, including finely resolved stratigraphy and structure. The model data were rebuilt within the TOUGH2 code, which has been extensively modified, as well as subjected to code intercomparison specifically for modeling subsurface migration of injected CO_2. During this project, we have experimented with two versions of the model. Version 0 models were created with minimal site-specific data but used extensively to define the sensitivity of the simulation to various uncertainties in the model inputs, as well as to optimize the experiment and monitoring design. The current model version 0.5 honors available data in the area of the plume. Simplifications and uncertainties are noted in detail in the following description. When additional site-specific data are acquired from the injection well, we will construct a fully deterministic version 1 model. Additional versions may then be prepared during following stages of model matching.

The lateral extent of the model is taken from a plan view of figure V-20, redrawn here as figure VII-1. Fault positions are constructed from the geologic interpretation but are generalized to straight lines within TOUGH2. On the basis of the reservoir understanding developed in section V, the modeled fault block is assumed to be closed along faults F1, F2 and the salt dome margin NW, NE, and SE, and extends far to the SW. Within the fault block, the fault (FS2) closest to the injection and monitoring wells is modeled as a very low permeability (shalelike and essentially impermeable) vertical, planar feature. Small inaccuracies created by simplifying this fault as planar and vertical are not significant to model performance. The sand thickness (23.24 m) and dip (17.45^{o} due south) observed at Well SGH-4 are applied to the whole model. The model thickness in the plume area is therefore representative of the observed thickness, but variations in thickness toward the salt dome are not represented. The below C shale and the Anahuac Formation are modeled as no-flow boundaries. The following model outputs are referenced to the fault compartment boundaries. Modeling was done in SI. We have converted critical results to English units only at the final result.

Horizontal mesh developed for the model is shown in figure VII-2. The vertical discretization of the model was chosen to correspond to the SP log-derived porosity profile from Well SGH-4 (fig. VII-3). The model has 16 layers.

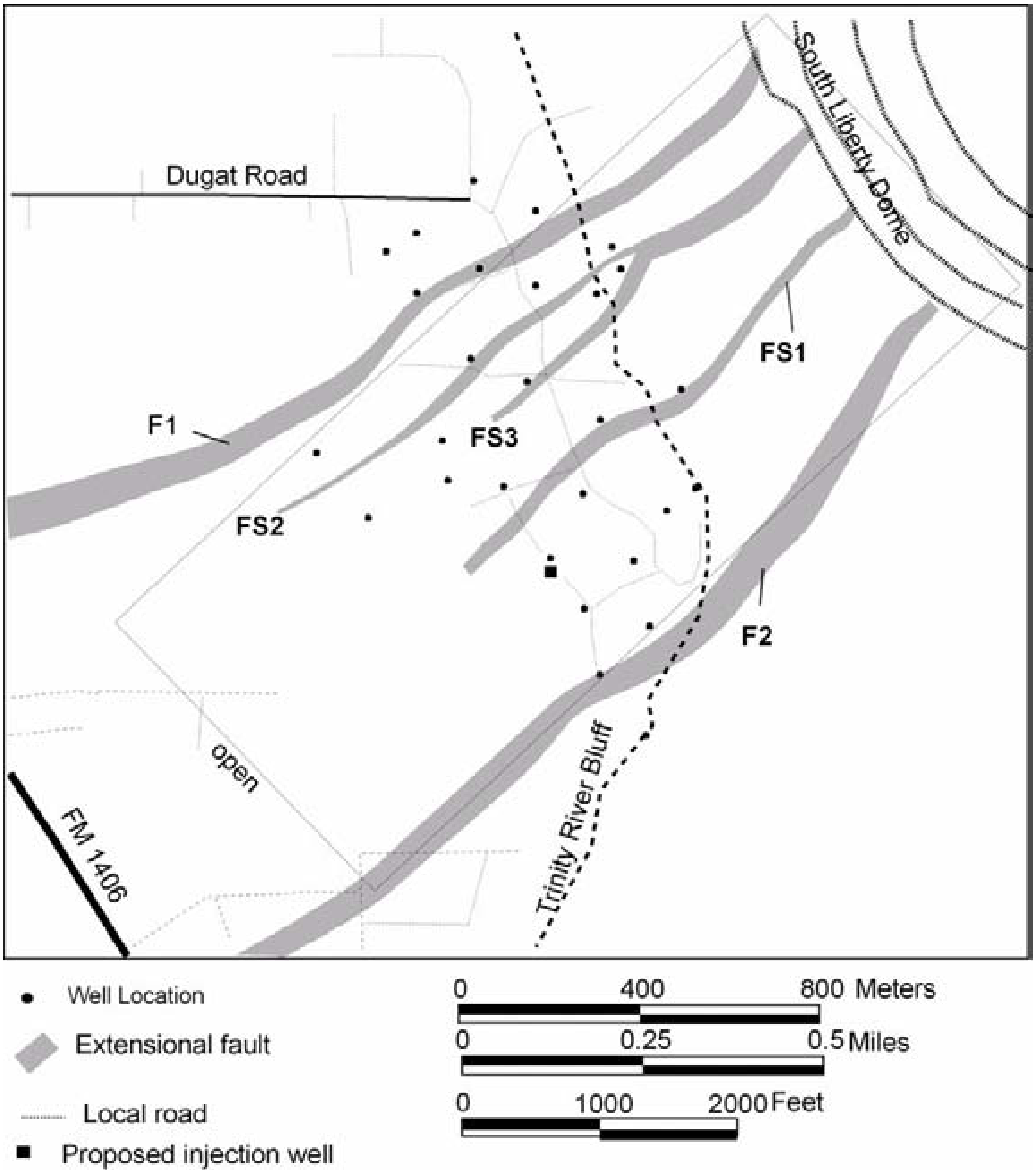


Figure VII-1. Model boundaries generalized from the detailed structural map, figure V-20.

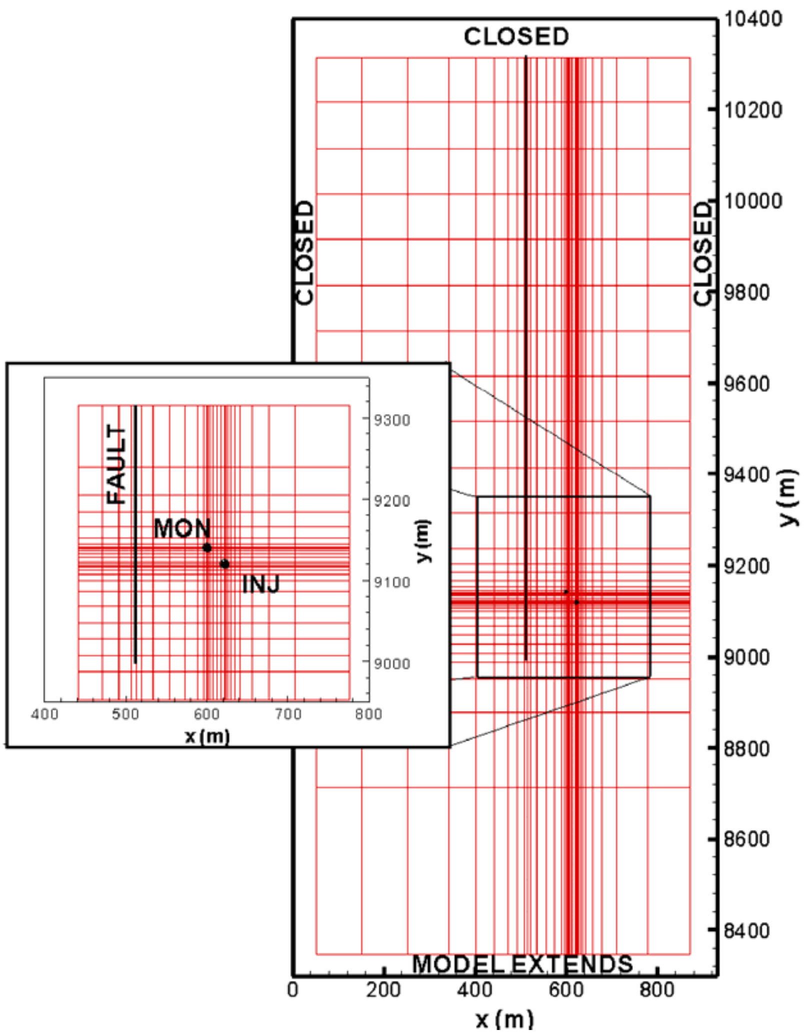


Figure VII-2. Mesh developed for the model in plan view. Model boundaries correspond to those shown in figure VII-1.

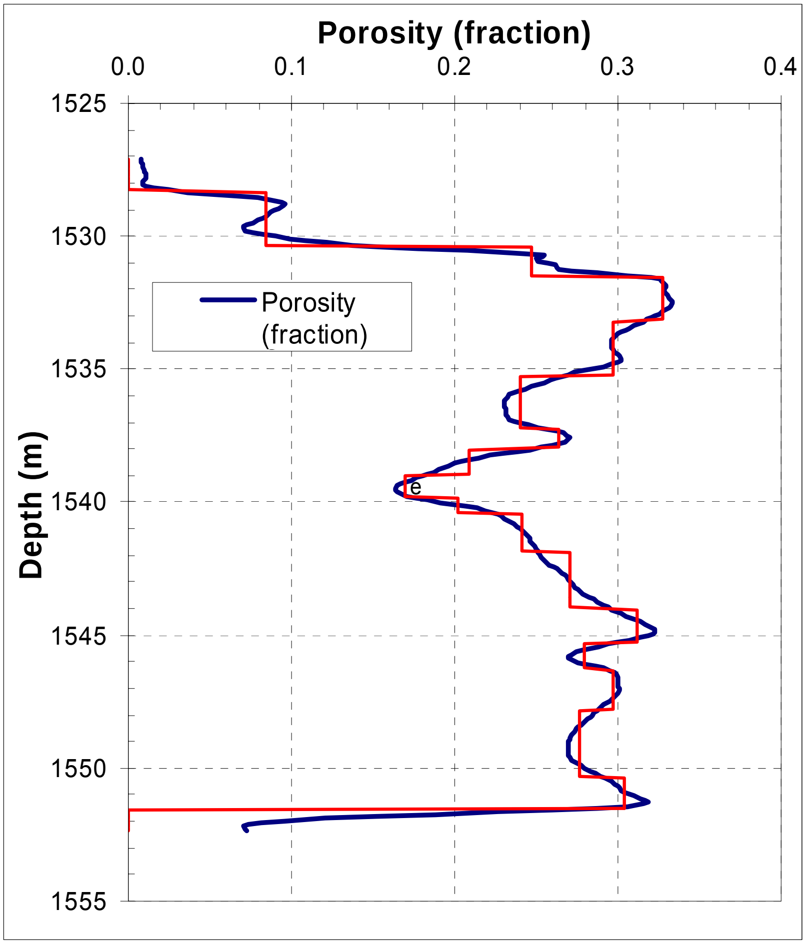


Figure VII-3. Model porosity derived from SP log porosity.

The lateral pattern of the model was chosen to provide enhanced resolution over the expected extent of the injected CO_2 plume and near the intrafault block fault. The resolution at the injection well is 1 m, which is larger than the actual well diameter (planned to be 5.5 inches); hence, modeled pressure and saturation changes shown for the injection well must be interpreted as representing the immediate neighborhood of the injection well, not actual well-bore conditions.

The rock porosity ϕ is the basic attribute taken from a local well log; other properties are derived from porosity, as described below. Properties do not vary laterally over the model, and previous experiments show that this simplification has only minor impact on plume geometry.

Horizontal permeability, k_h, is given by

$$k_h = 1 \cdot 10^6 . \phi^{7.8594}$$

where k_h is in md and ϕ is a fraction. This equation was derived from the core analysis porosity–permeability transform developed for delta-front sandstone from the Felix Jackson 62 well (see fig. V-28).

The ratio of vertical to horizontal permeability is given by

$$k_v/k_h = 22.679\phi - 5.3601,$$

with lower and upper limits of 0.1 and 1.

Capillary pressure, P_{cap}, is given by

$$\log(P_{cap}) = (1.1628 - S_L)/0.3145) - 0.3\log(k_h)$$

Rock compressibility ($3 \cdot 10^{-9}$ Pa^{-1}) is taken from well tests in the Frio Formation (Dan Collins, personal communication).

Residual liquid saturation, S_{lr}, is given by

$$S_{lr} = 0.2464 - 0.0945 \cdot \log(k_h)$$

Residual gas saturation, S_{gr}, is derived from the porosity S_{gr}, cross plot (Fig V-29) given by

$$S_{gr} = -0.3136 \cdot \ln(\phi) - 0.1334 .$$

In version 0 modeling, we found that residual liquid and gas saturation are two of the most sensitive parameters controlling model geometry.

Table VII-1. Properties of the Version 0.5 model. Layers representing the thin shale layers are shown in bold. The fault has properties comparable to layer 1.

Layer number	Porosity	Thickness (m)	Horizontal permeability (md)	Vertical permeability (md)	S_{gr}	S_{lr}
1	0.08	2.06	0.0037	0.0004	0.64	0.48
2	0.25	1.14	16.8	4.0	0.31	0.13
3	0.33	1.68	156.5	156.5	0.22	0.04
4	0.30	2.06	71.9	71.9	0.25	0.07
5	0.24	1.98	13.5	1.3	0.31	0.14
6	0.26	0.76	28.4	17.8	0.28	0.11
7	**0.05**	**0.99**	**0.01**	**0.01**	**0.36**	**0.18**
8	**0.05**	**0.84**	**0.01**	**0.01**	**0.42**	**0.25**
9	0.20	0.61	3.4	0.3	0.37	0.20
10	0.24	1.45	13.9	1.4	0.31	0.14
11	0.27	2.13	34.2	26.2	0.28	0.10
12	0.31	1.30	105.0	105.0	0.23	0.06
13	0.28	0.99	44.4	43.3	0.27	0.09
14	0.30	1.52	72.2	72.2	0.25	0.07
15	0.28	2.51	40.5	36.5	0.27	0.09
16	0.30	1.22	85.7	85.7	0.24	0.06

Initial conditions (same as Version 0 model)

Pressure: assume a hydrostatic pressure profile with a near-surface water table; P_0 = 150 bars (2,195 psi) at injection and monitoring wells at C sand depth.

Temperature: assume a geothermal gradient typical of upper Gulf Coast conditions (1.79° F/100 ft, Loucks and others, 1984); T_0 = 64° C (151° F) at C sand depth.

Salinity: based on typical Frio brine composition, TDS = 100,000 ppm (Kreitler and others, 1988; Macpherson, 1992).

Values will be measured in project wells during initial field activities to verify these estimates, which will then be input to Version 1 models. Simulation is not very sensitive to these parameters in the expected range of uncertainty.

In the simulation, CO_2 is injected at a constant rate of 250 T/day (2.89 kg/s) for a period of 15 days. The actual injection will be paused several times during injection for downhole monitoring, so this simulation is conservative with respect to pressure buildup and concentration of CO_2. The injection interval is the 9.7-m-thick (31 ft) sand above the thin shale. Injection is distributed between the model layers according to the permeability-thickness product of the layer (fig. VII-4).

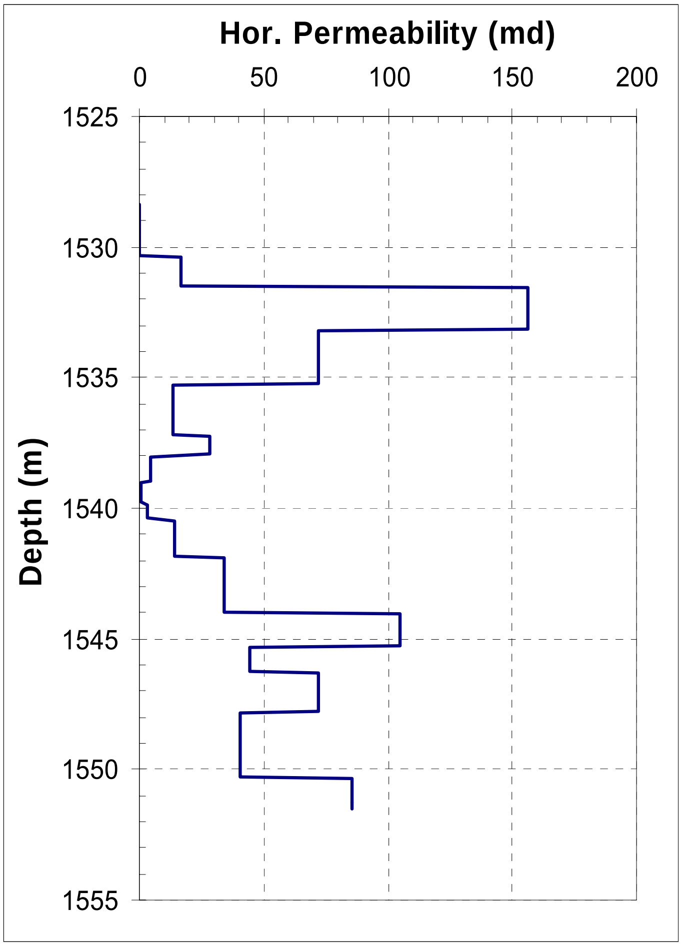


Figure VII-4. Input horizontal permeability in the injection interval.

VII.1.2 TOUGH2 Simulations

VII.1.2.1 TOUGH2 Simulator

The numerical simulations were performed with TOUGH2, a general-purpose simulator for multiphase flows in porous and fractured media (Pruess and others, 1999). TOUGH2 solves mass-balance equations (optionally also an energy balance) for multicomponent fluid mixtures in which the components can partition into several fluid and solid phases. Flow is represented with a multiphase version of Darcy's law that includes relative permeability and capillary pressure effects. The continuum equations are discretized by means of an integral finite difference method, which for systems of regularly shaped grid blocks is mathematically equivalent to conventional finite differences (Narasimhan and Witherspoon, 1976). For numerical stability, time is discretized fully implicitly as a first-order backward finite difference. Time steps are automatically adjusted (increased or reduced) during the course of a simulation, to cope with variable nonlinearities and convergence rates, especially during appearance or disappearance of phases. Discretization results in a system of coupled nonlinear algebraic equations, which are solved by Newton-Raphson iteration. The linear equations arising at each iteration step are solved by means of preconditioned conjugate gradient methods or sparse direct solvers (Moridis and Pruess, 1998).

The fluid property description is based on correlations originally developed for geothermal applications (Battistelli and others, 1997) and subsequently enhanced to more accurately represent phase partitioning and thermophysical properties of water/CO_2/NaCl mixtures at near-ambient temperatures and supercritical CO_2 pressures (Pruess and Garcia, 2001). Densities, viscosities, and enthalpies of CO_2 are calculated from correlations developed by Altunin and his associates (1975), as implemented in a computer program kindly provided to us by V. Malkovsky. Dissolution of CO_2 in NaCl brines is described with an extended version of Henry's law that accounts for effects of CO_2 fugacity, temperature, and salinity. Details of the fluid property model are given in Pruess and Garcia (2001).

VII.1.3 Results of Simulation

Subsurface behavior of the CO_2 within the upper "C" sand injection interval was modeled in three dimensions in TOUGH2. In order to show the results of this simulation we prepared output in three formats for this report: plots of change through time at the injection and monitoring wells, map views of parameters through time, and cross sections of parameters through time.

A plot of expected conditions at the injection and monitoring wells was prepared (fig. VII-5). Because pressure and CO_2 saturation increase rapidly at the beginning of injection, a semi-log plot is used to show the changes through the 15-day (4×10^{-2} year) injection period to the end of the 30-year postinjection period (3×10^{1}). Pressure in the 1-meter area around the injection well will increase through the injection period and then fall rapidly toward starting pressures. The concentration of immiscible supercritical CO_2 (labeled gas) at the monitoring well also increases during injection as a result of displacement of brine and then drying, and it then decreases as the CO_2 plume dissipates because of pressure differential and gravitational forces. At the monitoring well, 100 feet north of the injection well, pressure increased rapidly, but it takes immiscible supercritical CO_2 3 days to break through to this well. At the end of injection, pressure at this well falls along the same trajectory as that of the injection well. The concentration of immiscible supercritical CO_2 reflects the water saturation during displacement of CO_2 and will be one of the main parameters measured during the experiment. Simulation with Frio-like 30 residual gas saturation shows that gas saturation stabilizes over a year toward residual values and then slowly decreases as CO_2 enters solution.

The evolution of pressure is displayed in map view in figure VII-6. During injection, the area of increased pressure is focused around the injection well, and the effects on the rest of the compartment vary with boundary conditions and depth of the "C" sand. The rapid fall-off in pressure during preinjection hydrologic testing will prepare for and validate the observations made during injection. The extent of maximum pressure buildup is reached on the last day of injection. The distribution of maximum pressure with respect to geologic and cultural features is shown in figure VII-7.

Evolution of the plume of immiscible CO_2 through time is shown in figure VII-8. Rapid expansion of the plume is modeled during the injection period, followed by slow migration updip under gravity. The extent of the plume 1 year after injection is shown in map view in figure VII-9. Plume evolution is shown in cross section in figure VII-10. Plume expansion is limited by the trapping of immiscible phase CO_2 by capillary processes and by slow dissolution of the CO_2 into brine. The purpose of the experiment is to refine the numerical representation of these processes, which would likewise limit the risks of injection of a large volume of CO_2 over a long timeframe.

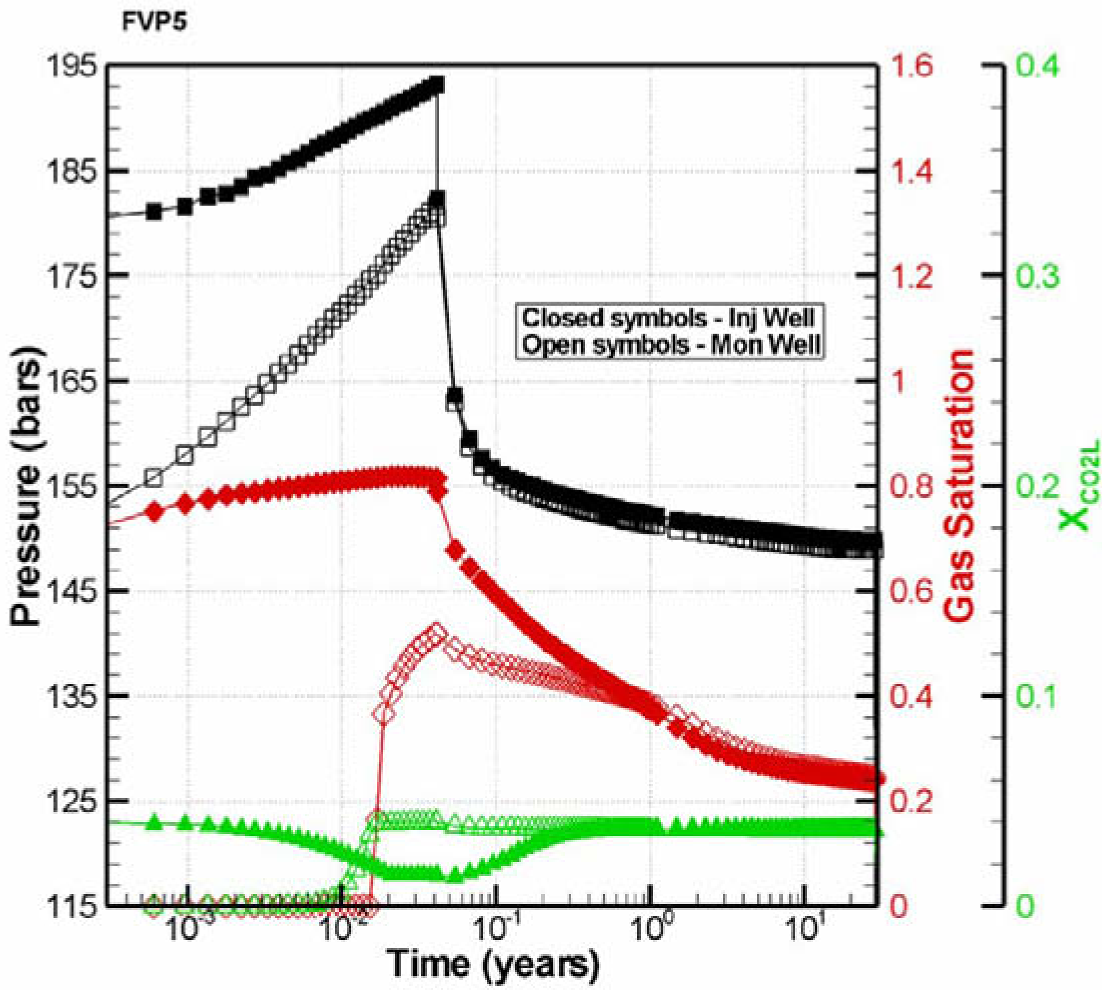


Figure VII-5. TOUGH2 output showing transient changes in pressure (black), concentration of immiscible supercritical CO_2 (red), and concentration of dissolved phase CO_2 (green).

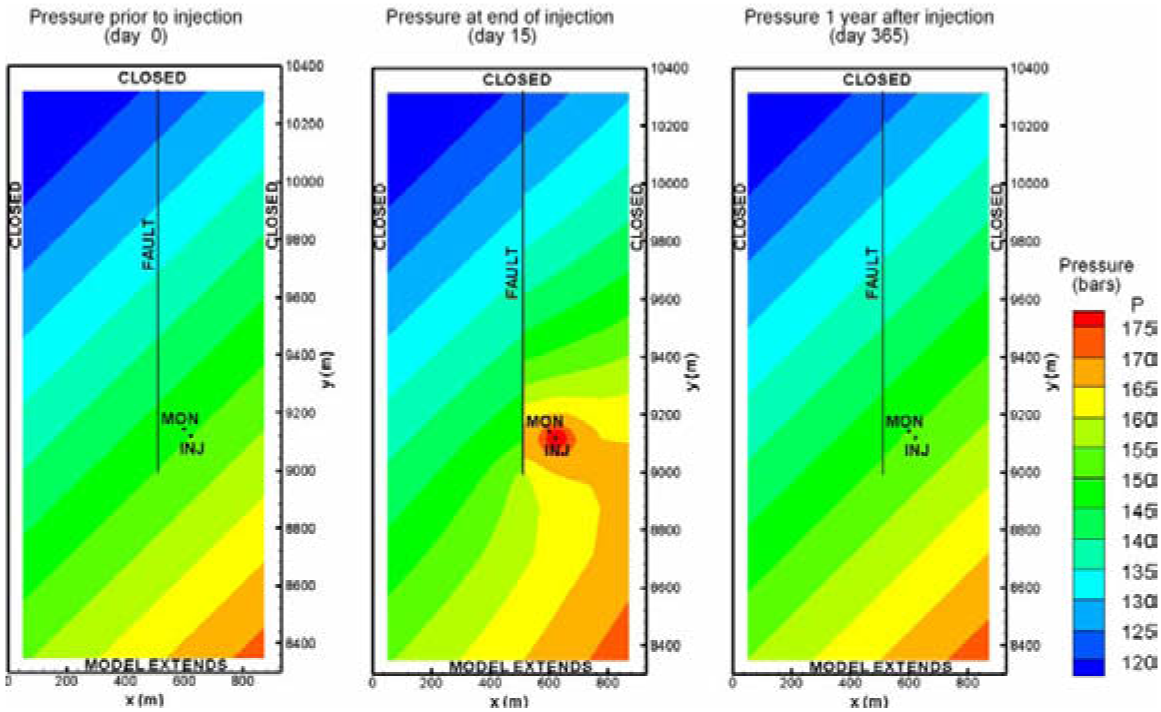


Figure VII-6. Plan view of changes in pressure distribution before (day 0), during (day 15), and after (day 365) injection at a depth of 3 m (9 ft) below the top of the "C" sand. Edges of the model area are shown in figure VII-1.

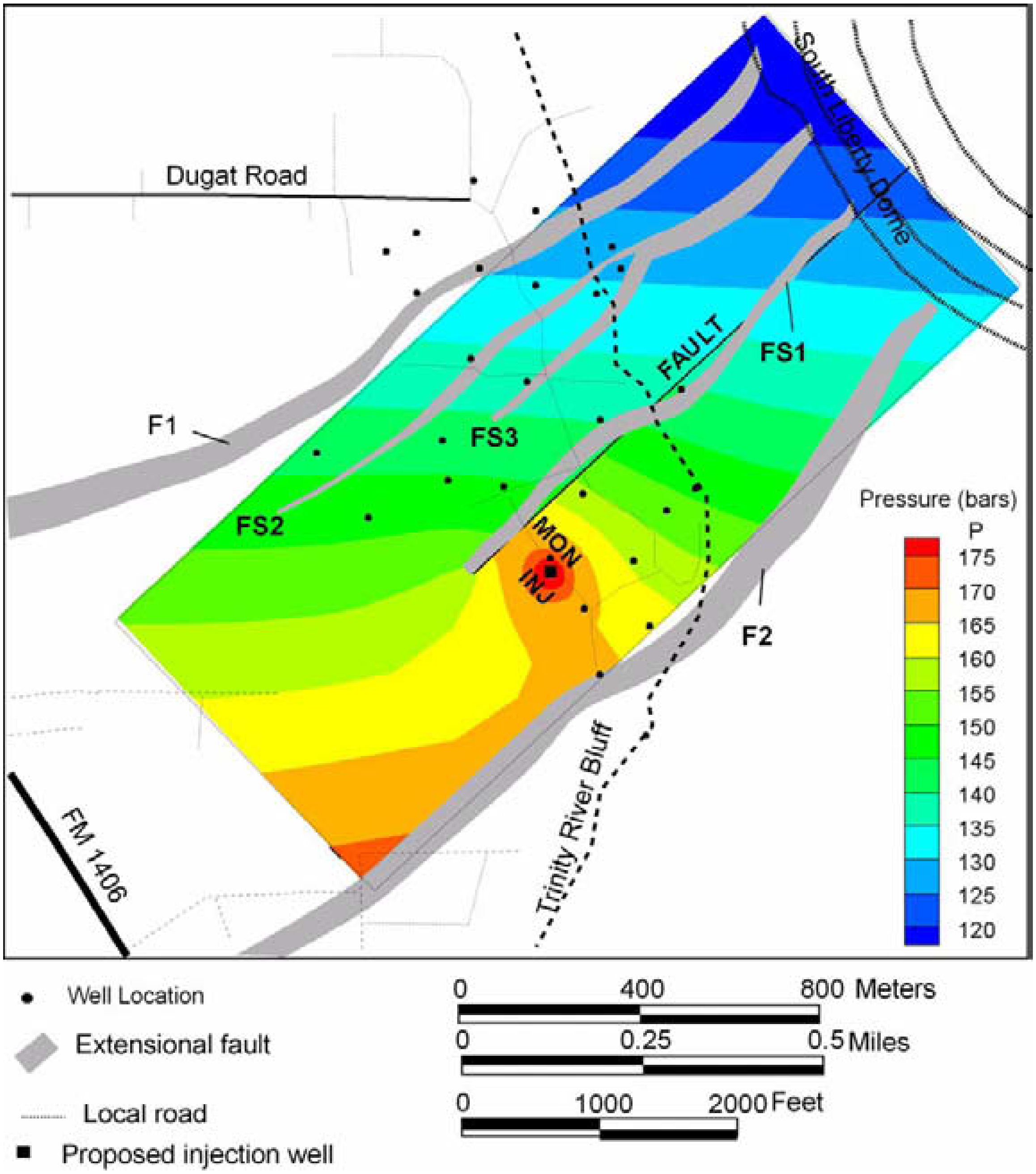


Figure VII-7. Map view of the maximum pressure distribution, reached at the end of injection at a depth of 3 m (9 ft) below the top of the "C" sand, showing relationship of the zones of elevated pressure to wells, faults, and surface roads.

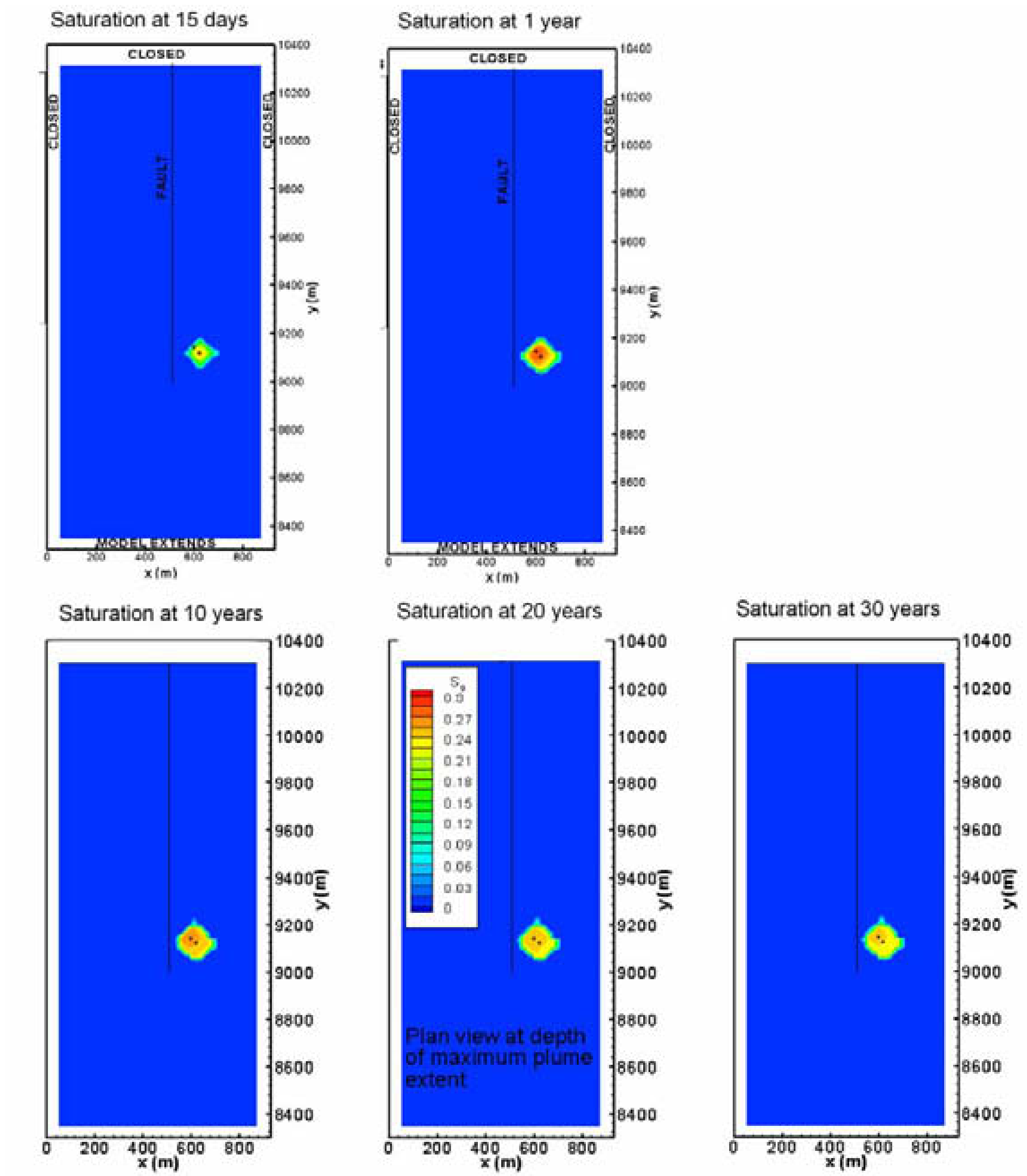


Figure VII-8. Plan view of the saturation of immiscible supercritical CO_2 at a depth of 3 m (9 ft) below the top of the "C" sand at end of injection (15 days) and 1, 10, 20, and 30 years. Edges of the model area are shown in figure VII-1.

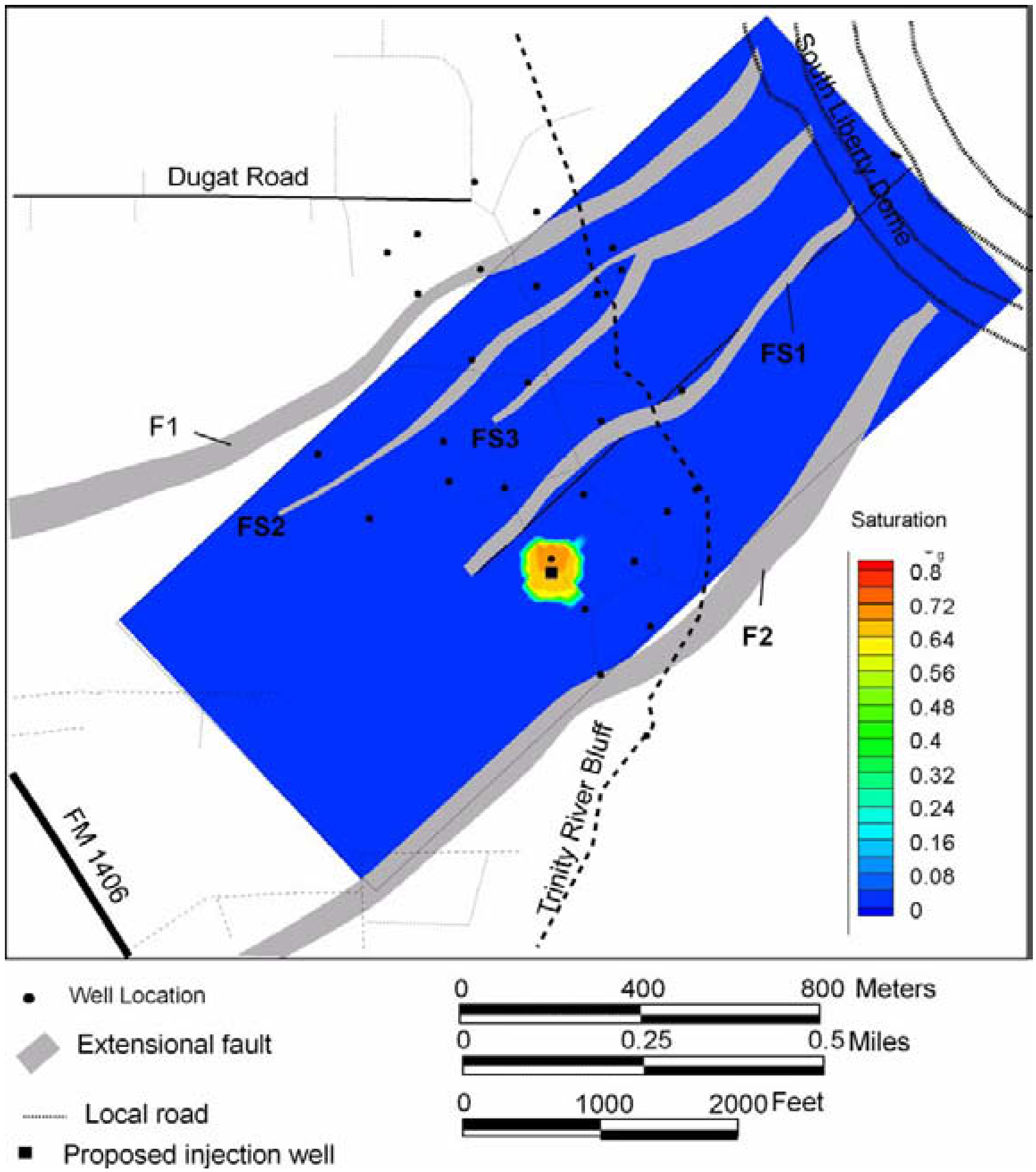


Figure VII-9. Map view of the saturation of immiscible supercritical CO_2 at a depth of 3 m (9 ft) below the top of the "C" sand (maximum aerial extent), showing the extent of the plume after 10 years in relation to wells and faults.

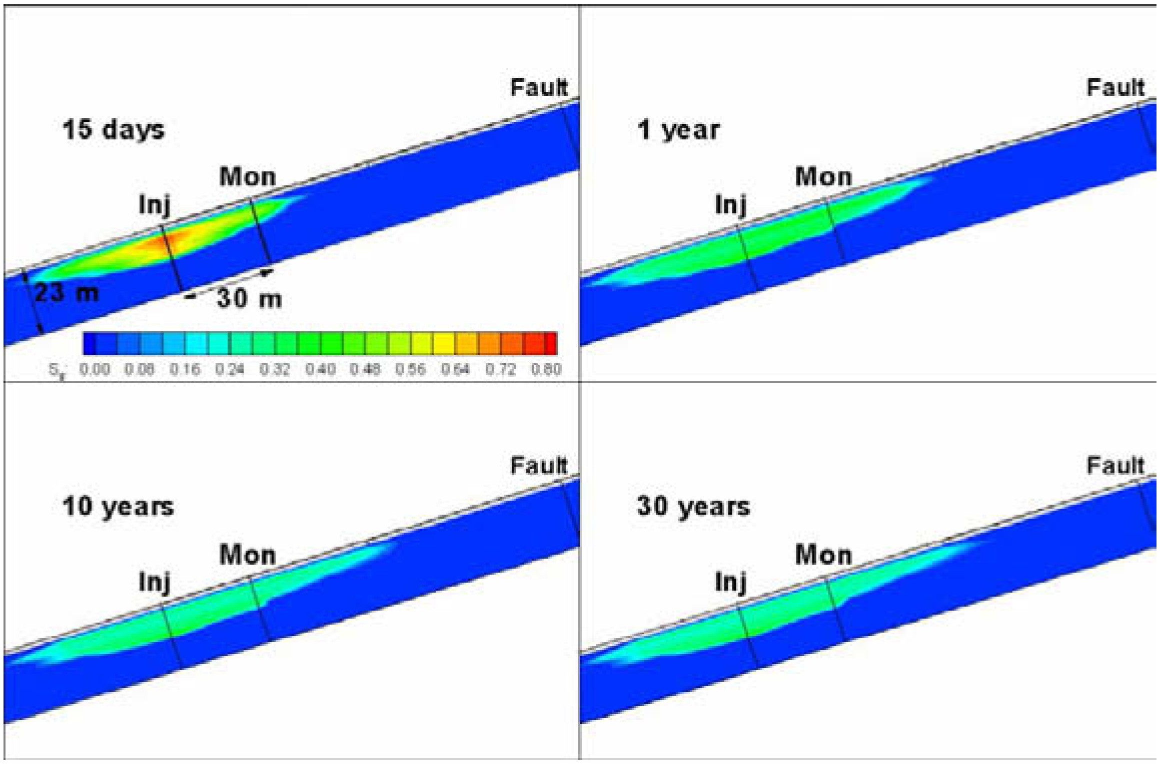


Figure VII-10. Cross-section view of changes in saturation of immiscible supercritical CO_2 along a line between the injection and monitoring wells at 15 days and 1, 10, and 30 years.

VII.1.4 Static Fluid Level and Regional Gradients

VII.1.4.1 Static Fluid Level

The original formation pressure of the Frio C Sand Injection Interval is estimated from nearby Class I injection wells completed into the Frio Formation in Harris County, Texas. Measured formation pressure gradients from Class I wells located near the Houston Ship Channel and from Atofina's Crosby Plant (located on the western flank of the nearby Esperson Dome) indicate that the average static pressure gradient in the Frio Formation is 0.432 psi/ft.

The static fluid level (hydraulic head) for the Frio C Injection Interval Sand, using sea level as the datum, can be calculated from the following equation:

$$h = Z + \frac{P}{pg},$$

where:

h	=	hydraulic head (ft)
Z	=	elevation relative to datum (ft)
P	=	fluid pressure at point Z (psi)
pg	=	weight density of fluid (psi/ft)

Using the inputs for the Frio E and F sand and substituting:

Z	=	–5,000 ft (datum sea level, top of sand)
P	=	2,160 psi - (top of Frio E and F 5,000 ft × 0.432 psi/ft)
pg	=	0.465 psi/ft - (0.433 psi/ft x specific gravity of 1.074)
		0.433 is weight density of pure water
		1.074 is specific gravity of Frio Formation fluid

h	=	–5,000 ft + 2,160 psi/0.465 psi/ft
	=	–5,000 ft + 4,645 ft
	=	–354 ft

The calculation is in good agreement with measured original static fluid levels of –400 ft in the Houston area wells.

VII.1.4.2 Regional Gradients in the Frio Formation

We do not anticipate migration of impacted brine away from the site because of selection of a vertically and horizontally compartmentalized injection site. Immiscible CO_2 will slowly dissolve into brine (fig. VII-5). The resulting bicarbonate-enriched brine is estimated to be slightly denser than brine that has not dissolved CO_2; therefore, it will tend to sink. Dissolved carbonate and bicarbonate will react readily with minerals in the rock, such as calcite and feldspar, which will limit the impact of the dissolved phase plume. Geochemical sampling conducted during this test will assess the short-term CO_2–water-rock interactions that take place under natural conditions and help to validate ongoing modeling of these processes and their effectiveness in stabilizing injected CO_2. Modern regional hydrologic gradients within the Frio Formation at relevant depths are low (15 ft/mi) and toward the east (fig. V-12).

Original formation pressure-gradient data for the Frio Formation in the Houston area substantiate the lack of a large hydraulic gradient within the Frio sands. Original formation pressure gradients from Lyondell Chemical Company, Plant Well 1 (WDW-148), from Equistar Plant Well 1 (WDW-36), from Atofina Plant Well 1 (WDW-122), and from the Merisol Plant Well 1 (WDW-147) are nearly identical ($\pm$0.001 psi/ft).

VII.1.5 Estimation of Fracture Pressure

The fracture gradient for the injection interval sands can be estimated by Eaton's Method, following the procedure outlined in Moore (1974):

$$FG = \frac{(P_{ob} - P_r)e}{(1 - e)} + P_r ,$$

where:

FG	=	fracture gradient
P_{ob}	=	overburden gradient (figure 11-11 in Moore, 1979)
P_r	=	reservoir pressure gradient (original)
e	=	Poisson's ratio (figure 11-12 in Moore, 1979)

The nomographs presented in Moore (1979) are solved for a below-ground depth of 5,000 ft (top of the Frio C Sand in the Proposed Injection Well). For the Frio C Sand Injection Interval:

$$FG = \frac{(0.907 - 0.432) * 0.416}{(1 - 0.416)} + 0.432$$

$$= 0.770 \text{ psi/ft}$$

Using the calculated fracture gradient of 0.770 psi/ft, the fracture pressure for the Frio C Sand Injection Interval is estimated to equal 3,851 psi at 5,000 ft bgl (top of the sand). The calculated fracture gradient and fracture pressure for the Frio C Sand Injection Interval Sand is shown below:

Sand	Fracture Gradient (psi/ft)	Top of Sand (ft bgl)	Formation Fracture Pressure (psi)
Frio C Sand	0.770	5,000	3,851

VII.1.5.1 Maximum Allowable Surface Injection Pressure Calculation

The calculation of maximum surface injection pressure is as follows:

$$MASIP = P_{frac} - P_{hydro} - 100 \text{ psi},$$

where:

P_{frac} = fracture pressure (psi)
P_{hydro} = hydrostatic column pressure (psi)

and

$$P_{hydro} = (0.433 \times SG_{effluent}) \times \text{Depth}.$$

For the Frio C Sand Injection Interval, the Maximum Surface Injection Pressure (calculated at a depth of 5,000 ft and using a supercritical CO_2 specific gravity of 0.470) is as follows:

$$MASIP = P_{frac} - P_{hydro} - 100 \text{ psi},$$

where:

P_{frac} = fracture pressure (3,851 psi)
P_{hydro} = hydrostatic column pressure (1,017.6 psi)

$$MASIP = 3{,}851 \text{ psi} - 1{,}017.6 \text{ psi} - 100 \text{ psi}$$

$$MASIP = 2{,}733 \text{ psi}$$

A similar calculation is made for anticipated brine injection, using a conservative specific gravity of 1.1 for the brine fluids. The calculation is summarized below:

CALCULATED MAXIMUM SURFACE INJECTION PRESSURE

SAND	DEPTH (ft)	EFFLUENT SPECIFIC GRAVITY	ORIGINAL FORMATION PRESSURE GRADIENT (psi/ft)	CALCULATED FRACTURE GRADIENT (psi/ft)	CALCULATED MAXIMUM SURFACE INJECTION PRESSURE (psi)
Frio C—CO_2	5,000	0.47	0.432	0.770	2,733
Frio C—Brines	5,000	1.10	0.432	0.770	1,370

The maximum surface injection pressure being requested for the Frio C Sand Injection Interval is shown below (conservatively set to a lower value than the calculated MASIP).

Injection Interval	Maximum Requested Surface Injection Pressure
Frio C Sand—CO_2	2,500 psi
Frio C Sand—Brine fluids	1,200 psi

These wellhead pressures are well below that required to actually fracture the formation because the flow inefficiency down the injection tubing and the flow inefficiency at the completion (friction losses or well skin) are discounted in this calculation.

VII.1.6 Predictions of Increase in Reservoir Pressure Due to Injection

Modeling shows that reservoir pressure will increase during the injection period and then decrease rapidly at the end of injection (fig. VII-5). Pressures are highest near the injection well and decrease with distance. Boundary conditions have an effect on pressure increase and pressure distribution, and these have been documented by modeling the compartment within various geometries, including completely closed, smaller, and completely open. The volume of the compartment is large relative to the volume of the injected CO_2, so the range of pressures for any reasonable boundary conditions is similar to those presented here in figures VII-5, VII-6, and VII-7.

VII.1.7 Determination of the Cone of Influence

Under the Texas Administrative Code (TAC) §331.42(b)(4) standard, the Area of Review for a Class V injection well corresponds to the area determined by a radius of at least ¼ mile of the injection well. The radius of the area of review may be based on the calculated "cone of influence" of the injection well, if it extends out to a greater radius. The "cone of influence" is defined as "the potentiometric surface area around the injection well within which increased injection zone pressures caused by injection of wastes would be sufficient to drive fluids into a USDW or freshwater aquifer" (TAC §331.2). It is apparent from the definition language that the pressure increase of concern in the Area of Review determination is the pressure increment, over the preexisting static background conditions, resulting from the regulated injection activity. The "cone of influence" concept was, therefore, developed specifically to preclude consideration of extraneous factors not resulting from the injection activity itself. The methodology used in this permit application for calculating the cone of influence for the Frio Brine Pilot Test Site is generally consistent with previous methods (Johnston and Greene, 1979; Barker, 1981; Collins, 1986; Davis, 1986; Johnston and Knape, 1986; Warner and Syed, 1986; Clark and others, 1987; Warner, 1988). The basic underlying assumption in this approach is that in the absence of naturally occurring, vertically transmissive conduits (faults and fractures) between the injection interval and any USDW, the only potential pathway between the injection zone and any USDW is through an artificial penetration (active or inactive oil and gas well(s)). In order to pose a potential threat to a USDW (i.e., pressure buildup from injection sufficient to drive fluids into a USDW), the pressure increase in the injection interval would have to be greater than the pressure necessary to displace the material residing within the borehole. This pressure is defined as the *allowable buildup pressure*. Therefore, the cone of influence is the area within which injection interval pressures are greater than the allowable buildup pressure required to displace the fluid within the borehole.

A static mud column exerts pressure. For an abandoned well to provide a pathway for fluid movement, the pressures acting on the static mud column (pressure due to injection plus original formation pressure) must be greater than the static mud column pressure. In a static fluid column, the gel strength of the mud must also be considered.

In this case, for upward fluid movement to begin, original formation pressure (P_f) plus the pressure due to injection (P_i) must be greater than the static fluid column pressure plus the gel strength of the mud. This relationship is based on a simple balance of forces (Davis, 1986):

$$P_f + P_i > P_s + P_g \ ,$$

where:

P_f = original formation pressure (psi)

P_i = formation pressure increase due to injection (psi)

P_s = static fluid column pressure (psi)

P_g = gel strength pressure (psi)

Therefore, pressure increase due to injection must be greater than static fluid column pressure minus original formation pressure:

$$P_i > P_s + P_g - P_f \ .$$

The initial step in calculating the allowable buildup pressure (cone of influence) for the Frio injection reservoir at the Frio Brine Pilot Test Site facility involved determining the maximum pressure buildup gradient. This gradient was derived by first calculating the mud column gradient from the very conservative 9.0-lb/gal mud and subtracting from it the original formation pressure gradient of the injection interval sand.

In iteration, the maximum pressure buildup gradient is calculated by subtracting the original formation pressure gradient from the 9.0-lb/gal mud column gradient, as is demonstrated for the Frio C Sand Injection Interval by the following:

0.052×9.0 lb./gal = 0.468 psi/ft	(mud column gradient, modified from Barker, 1981)
	0.052 is a conversion factor and has units of gal/ft-in^2
–0.432	(Frio formation pressure gradient – Houston Area)
0.036 psi/ft	(maximum pressure buildup gradient, based on 9.0-lb/gal mud)

Thus, 0.036 psi/ft is the maximum pressure buildup gradient allowed in the Frio Injection Interval sands prior to possible fluid movement.

Multiplying the maximum pressure buildup gradient by depth to the injection reservoir yields allowable pressure buildup due to the mud column pressure. Additionally, a minimum gel pressure was determined using a conservative value of 20 lb/100 ft^2 for the gel strength and a borehole radius of 12¼ inches (largest surface casing size in the area, to be conservative). As an additional measure of conservatism, a 50-foot fallback of the mud column from the surface is utilized in the calculations.

Figure VII-11 summarizes the calculation of the cone of influence for the Frio C Sand injection interval at the Frio Brine Pilot Test Site. Note that no Cone of Influence is developed outside of the ¼-mile radius Area of Review.

It is important to note that the current calculations of Area of Review are very conservative and contain significant, additional safety factors. These factors include actual weight of the mud in the borehole, actual gel strength of the drilling mud, and borehole closure, which have not been included in the conservative assessment.

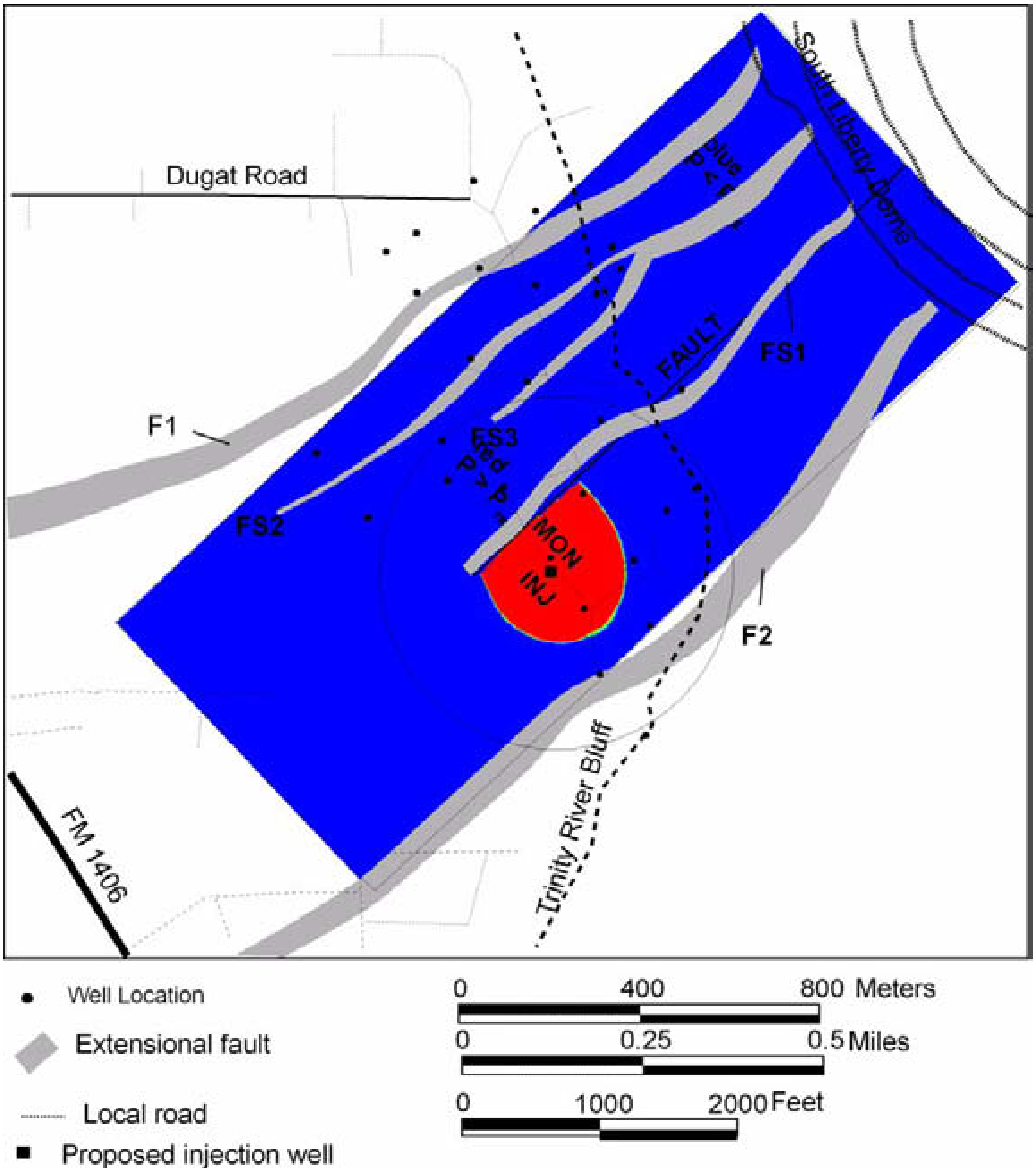


Figure VII-11. Calculated cone of influence. P = modeled pressure and P_{reg} = calculated pressure at each depth when pressure increase per foot is set equal to 0.468.

VII.2 Other Subsurface Disposal Operation in the Area

The Sun-Gulf-Humble #2 well just southeast of the site has been used as a disposal well for produced oil-field brine. Well records indicate that the injection was above the Anahuac Formation into the Oakville.

VIII. Area of Review

Under Texas Administrative Code §331.42 and Environmental Protection Agency (EPA) 40 CFR 144 regulations, the Area of Review is the area within which the owner or operator of a Class I injection well must identify all artificial penetrations that penetrate the confining zone and/or injection zone and determine whether they have been completed or plugged so that they do not provide conduits for fluid movement. Artificial penetrations constitute a possible threat to human health or the environment because of their potential for conveying injected effluent and formation fluid out of the injection zone and/or conveying fluid (injected effluent or formation brine) into an underground source of drinking water (USDW) (nonendangerment standard).

Under the Texas Administrative Code (TAC) §331.42(b)(4) standard, the Area of Review for a Class V injection well corresponds to the area within a fixed 0.25-mile radius of the injection well or that based on the calculated cone of influence of the injection well, whichever is greater. The cone of influence is defined as “the potentiometric surface area around the injection well within which increased injection zone pressures caused by injection of effluent would be sufficient to drive fluids into a USDW or freshwater aquifer” (TAC §331.2). For the Frio Brine Pilot Test, the cone of influence in the Frio C Sand Injection Interval is less than 0.25 mile; therefore the fixed 0.25-mile radius for the Area of Review applies.

Nineteen artificial penetrations are identified in the Area of Review for the Frio Brine Pilot Test site (table VIII-1). Each of these wells was evaluated for nonendangerment. All of the wells penetrate the injection and/or confining zone. Of the artificial penetrations, only Map ID Nos. 637, 40, and 45 are plugged with cement below the lowermost USDW (note that Map ID No. 41 will be squeezed in the injection interval and used as an experiment monitor well—see Section VI). The remaining wells were conservatively modeled to determine whether predicted pressure in the Frio C Sand exceeds the hydrostatic pressure present within the well bores. On the basis of projected maximum injection rates (250 tons of CO_2/day) at the Frio Brine Pilot Test, the modeling projection determined that interformational fluid flow would not occur in any of the boreholes. Judging by the results of the evaluation, no corrective action is necessary for any of the wells in the 0.25-mile radius Area of Review under the conditions requested in this Permit Application. Natural borehole closure has not been quantified but would add significantly to the safety of these artificial penetrations (most of these wells were drilled in the 1950’s).

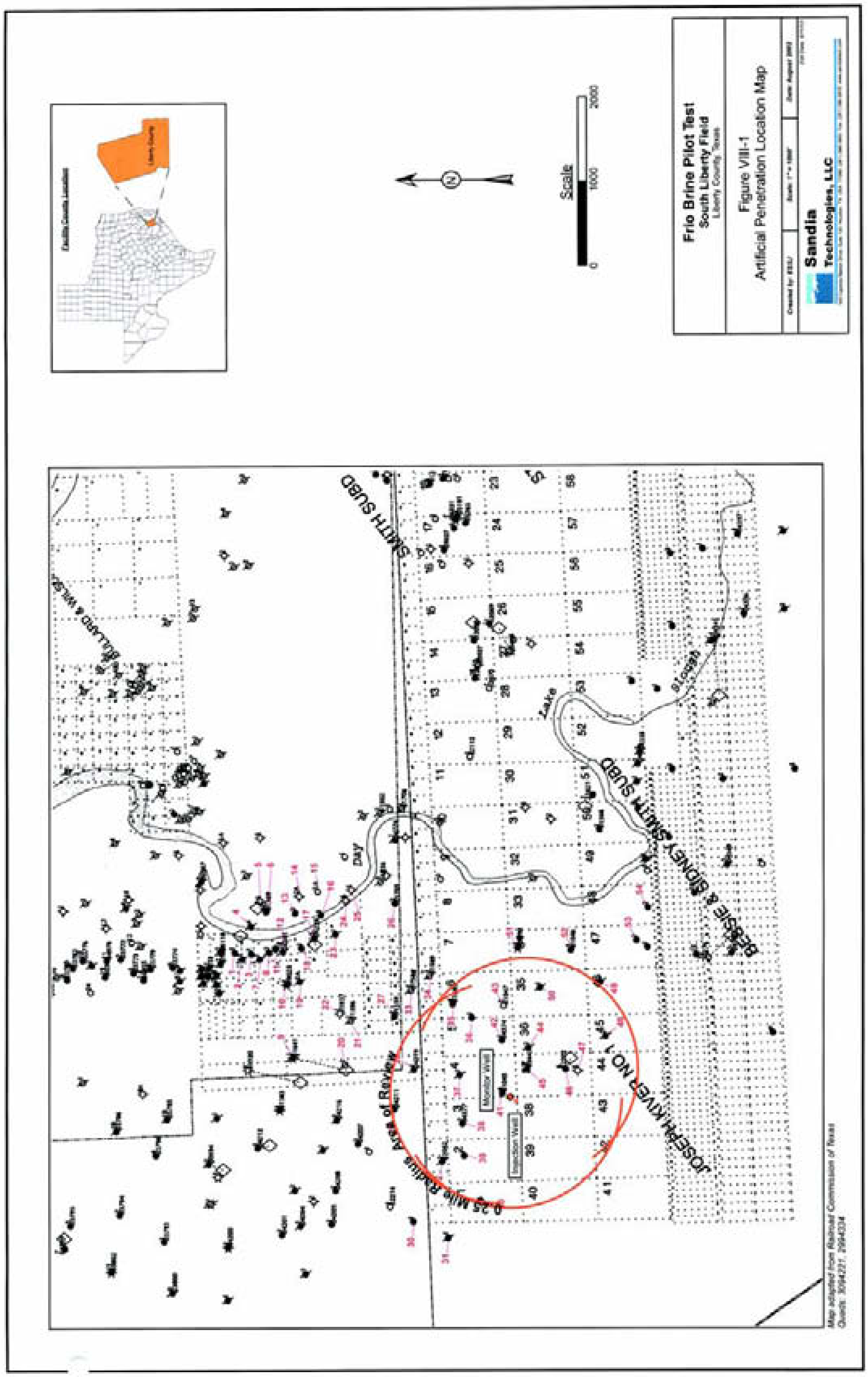
TABLE VIII-1
FRIO BRINE PILOT TEST
ARTIFICIAL PENETRATIONS WITHIN THE 0.25-MILE RADIUS AREA OF REVIEW

Artificial Penetration Map ID #	Operator	Lease and Well #	Ground Elevation (feet)	Kelly Bushing Elevation (feet)	Well Spud Date	Status	Date Plugged	Well Depth (feet)	P&A Mud Wt. (ppg)	Log** Mud Wt. (ppg)	Depth Top of Inj Zone* (feet)	Depth Top of Inj Interval* (feet)	Depth Base of USDW* (feet)	Depth of CMT Plugs (feet)	Surface Casing Size (inch)	Surface Casing Depth (feet)	Protection Casing Size (inch)	Casing Depth (feet)	Protection Casing Cutoff (feet)	Hole Size (inch)	Properly Plugged For Non-Endangerment
28	Gulf Oil Corp.	Rowe-Baldwin et al Unit #1	63	82	10/23/51	Active	–	9,602	–	11.8	3,940	4,890	3,100	–	8 5/8	2,495	5 1/2	8,345	0	7 7/8	NO
29	Gulf Oil Corp.	M. Partlow #1	66	85	03/19/51	P&A	08/14/68	9,009	9.5	11.1	3,930	4,860	3,175	0 - 155' 2,000 - 2,132' 2,355 - 2,575' 4,326 - 7,304'	10 3/4	2,320	5 1/2 2 3/8	8,810 8,134	1 4,317	9 7/8	NO
32	Gulf Oil Corp.	M. Partlow et al. Unit "A" #1	66	80	06/22/52	P&A	12/20/70	9,500	9.8	N/A	4,030	4,980	3,150	0 - 23' 2,453 - 2,605' 8,175 - 8,300'	10 3/4	2,908	5 1/2	9,033	2,545	N/A	NO
33	The Texas Company	R. L. Brooks Fee NCT-2 #4	11	32	03/09/52	Active	–	8,700	–	N/A	3,960	4,770	3,150	–	10 3/4	2,118	5 1/2	7,611	0	9 7/8	NO
36	Sinclair O&G Co.	Brooks Fee #1	44	58	06/30/52	P&A	03/30/78	9,310	9.5	11.8	4,017	4,843	3,175	5 - 19' 2,124 - 2,234' 6,377 - 6,477' 7,522 - 7,622'	8 5/8	2,222	5 1/2	8,758	2,389	8 3/4	NO
37	F. L. Karsten	Sun Gulf Humble Fee Tract #1	63	77	06/15/51	P&A	10/26/71	9,366	9.9	12.4	4,055	4,880	3,150	0 - 30' 1,700 - 1,801' 3,700 - 3,800'	10 3/4	1,117	7 2 3/8	8,583 7,052	0 4,263	8 3/4	YES - Plug Below USDW
38	F. L. Karsten	Sun Gulf Humble Fee Tract #2	63	78	09/05/51	Active - SP	–	9,050	–	12.8	4,030	4,980	3,150	–	10 3/4	1,018	5 1/2	8,380	0	8 3/4	NO
39	The Texas Company	R. L. Brooks Fee NCT-3 #1	63	79	02/23/52	P&A	06/07/61	9,800	MUD	N/A	4,030	4,980	3,150	0 - 10' 1,857 - 1,957' 8,560 - 8,660'	10 3/4	2,207	5 1/2	9,029	1,907	8 5/8	NO
40	Humble O&R Co.	R. E. Brooks Fee "B" #1	63	76	06/10/52	P&A	07/17/52	10,000	MUD	9.7	4,340	4,990	3,370	3,380 - 3,680' 8,400 - 8,600'	9 5/8	3,514	N/A	N/A	N/A	8 3/4	YES - Plug Below USDW
41	F. L. Karsten	Sun Gulf Humble Fee Tract #4	63	78	01/12/52	Active - SP	–	9,336	–	11.4	4,150	5,010	3,250	–	10 3/4	2040	5 1/2	8,964	0	8 3/4	Convert to Monitor Well
42	King & Heyne, Inc.	Brooks et al. #1	63	78	02/08/52	Active - SP	–	8,830	–	11.9	4,130	5,000	3,270	–	10 3/4	2,245	5 1/2	8,360	0	8 3/4	NO
43	The Texas Company	R. L. Brooks Fee NCT-2 #2	24	38	12/29/52	Active - OG	–	8,853	–	11.6	4,075	4,967	3,127	–	10 3/4	2,137	5 1/2	8,823	0	9 7/8	NO
44	Humble O&R Co.	R. E. Brooks Fee #1	60	75	10/21/51	P&A	09/23/72	9,107	9.5	10.2	4,225	5,155	3,170	0 - 50' 2,867 - 3,021' 8,056 - 8,300'	9 5/8	3,064	5 1/2	9,002	0	8 3/4	NO
45	F. L. Karsten	Sun Gulf Humble Fee Tract #3	63	76	11/09/51	Shut-in	–	9,397	–	12.2	4,210	5,105	3,310	–	10 3/4	2,015	7	8,650	0	8 3/4	YES
46	TARC	Sun Gulf Humble Fee Tract #6	63	80	12/20/97	Active	–	9,659	–	N/A	4,240	5,250	3,190	–	9 5/8	2,535	5 1/2	9,650	0	8 3/4	NO
47	F. L. Karsten	Sun Gulf Humble Fee Tract #5	63	77	06/05/52	P&A	07/04/52	9,427	MUD	11.6	4,260	5,250	3,218	0 - 30' 1,950 - 2,075' 8,600 - 8,760'	10 3/4	2,011	N/A	N/A	N/A	8 3/4	NO
48	Humble O&R Co.	R. E. Brooks Fee #2	14	27	08/26/55	P&A	09/18/72	9,020	9.5	N/A	4,260	5,250	3,230	0 - 30' 3,066 - 3,492' 8,313 - 8,650'	9 5/8	3,494	5 1/2	8,800	0	8 3/4	YES - USDW Behind SC
49	Sinclair O&G Co.	R. E. Brooks Unit #2	44	58	04/01/55	P&A	02/27/76	9,229	9.9	11.6	3,860	4,880	3,260	0 - 25' 8,172 - 8,387'	9 5/8	2,166	5 1/2	8,785	0	8 3/4	NO
50	Sinclair O&G Co.	R. E. Brooks Unit #1	13	34	09/07/52	P&A	02/24/76	9,121	9.6	11.2	4,180	FO***	3,150	0 - 30' 7,855 - 8,070'	9 5/8	2,266	5 1/2	9,004	0	8 3/4	NO

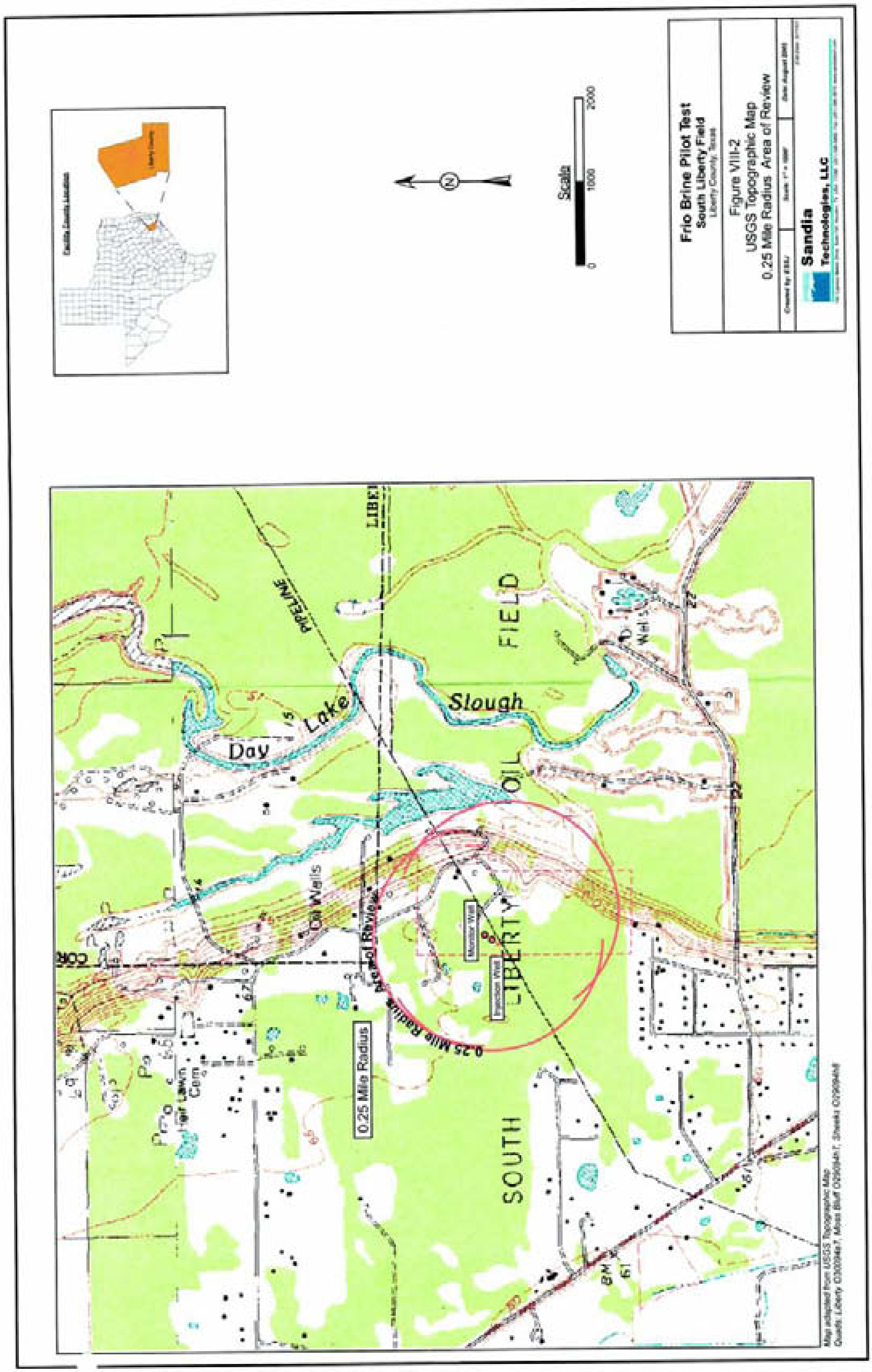
*Top of Injection Zone, Top of Injection Interval, and Base of Lowermost USDW given in feet below kelly bushing

** Log Mud Weight is the weight of fluid present across the Injection Zone

*** Wells Improperly constructed or plugged for Non-Endangerment may require further evaluation



Frio Brine Pilot Test
South Liberty Field
Liberty County, Texas
Figure VIII-1
Artificial Penetration Location Map
Sandia
Technologies, LLC
Scale
0
1000
2000
N
Facility County Location
Liberty County
Monitor Well
Injection Well
0.25 Mile Radius Area of Review
JOSEPH KIVER NO 1
BESSIE & SIDNEY SMITH SUBD
SMITH SUBD
Lake
Slough
Day
Map adapted from Railroad Commission of Texas
Quads: 3094221, 2994334



Frio Brine Pilot Test
South Liberty Field
Liberty County, Texas
Figure VIII-2
USGS Topographic Map
0.25 Mile Radius Area of Review
Sandia Technologies, LLC
Scale
0
1000
2000
N
0.25 Mile Radius
Area of Review
Monitor Well
Injection Well
Day Lake Slough
SOUTH LIBERTY OIL FIELD
PIPELINE
Oil Wells
Map adapted from USGS Topographic Map

VIII.1 Area of Review Map

A base map showing the permit application identification number, location, and well number of the artificial penetrations in the 0.25-mile radius Area of Review is included as figure VIII-1. This map was prepared from a Railroad Commission of Texas field map and shows the location of the test site, the injection well, surface bodies of water, and other pertinent surface features. No surface faults are known to occur in the Area of Review. Figure VIII-2 shows the 0.25-mile radius Area of Review superimposed on a USGS topographic quadrangle map. This figure (fig. VIII-2) shows the location of all surface bodies of water, springs, mines, quarries, and other pertinent surface features.

VIII.2 Artificial Penetrations in the Area of Review

A thorough record search was conducted during preparation of this Permit Application by a records research company (D&B Associates, Austin, Texas) in accordance with 30 TAC §331.121(a)(2)(A) in order to locate all artificial penetrations that lie within the 0.25-mile radius Area of Review. A total of 19 artificial penetrations were identified. The following sections describe the protocol used to conduct the artificial penetration search.

VIII.2.1 Artificial Penetration Protocol

As used in current regulations, the Area of Review pertains to the area within which the owner or operator of an injection well must identify all artificial penetrations that penetrate the site-specific confining and/or injection zone. These artificial penetrations constitute a possible threat to Underground Sources of Drinking Water (USDW) because of their potential for conveying fluid from an injection reservoir to the overlying USDW (nonendangerment standard). The Area of Review for the nonendangerment standard is defined as a fixed 0.25-mile radius around the injection well (Class V well) unless the calculated cone of influence of the injection well warrants a larger Area of Review (TAC §331.42(b)(4)). State regulations require, in the Area of Review phase of the permitting process, identification and evaluation of artificial penetrations followed by appropriate action to mitigate any potentially threatening situation. Following is an outline of the steps that were taken to identify and evaluate an artificial penetration in the Area of Review pursuant to permit requirements.

VIII.2.2 Well Identification

VIII.2.2.1 Data Sources

A specific and consistent methodology was used to identify all artificial penetrations within the Area of Review surrounding the Frio Brine Pilot Test site. Several data sources were utilized to locate pertinent information regarding each artificial penetration. A field base map from the Railroad Commission of Texas, checked against a Tobin Surveys, Inc., base map and a regional Geomap, Inc., map was utilized initially to identify and establish a general background on the wells in the Area of Review. State agency files, along with State libraries, were researched by D&B Associates of Austin, Texas for descriptive well documentation. The regional libraries of Geomap, a commercial log service company, were researched for well logs applicable to each well identified in the Area of Review. Where discrepancies existed among data sources, State form data were considered to be the most accurate. The following discussion is a synopsis of the procedures used to procure these State form data.

VIII.2.2.1.1 File Search and Research Procedures for the Railroad Commission of Texas

The well record filing system of the Railroad Commission of Texas is cumbersome owing to changes in filing procedures implemented through the years. The enormous amount of information contained within the system has often been reorganized when directors of the Railroad Commission of Texas have changed. The following discussion on file searches and research procedures for the Railroad Commission of Texas outlines the steps necessary to retrieve oil and gas well records to be used in researching each well within a given area.

VIII.2.2.1.2 Maps

Before the retrieval process can begin, it is necessary to know the operator, lease name, county, and survey in which the well is located. This information is normally found on commercially prepared oil and gas base maps. The Railroad Commission of Texas maintains two types of maps, which are used by the researcher to determine operator, well name, approximate drilling date, and field name. The two types of maps on file at the Railroad Commission of Texas are:

County maps

These maps are produced by commercial firms who obtained the data to build the oil and gas bases from scout tickets, completion data obtained from individual oil companies in the early years and then, in later years, from the Railroad Commission of Texas itself. The Railroad Commission of Texas purchases these maps and utilizes them as base maps, plotting incoming information filed by oil and gas operators. Changes in the status of existing wells are noted, as well as factual material on new wells.

Field maps

These maps are prepared by Railroad Commission of Texas personnel from commercial base maps. Field maps are prepared when there is an extremely high well concentration in an area and it is necessary to expand the scale of the area so that wells can be properly identified. All data, including survey name, fee name, acreage and configuration of tracts of land, operator name, and well location data, are taken from the county map and transposed onto the field map. Once the field map is prepared, any wells drilled, deepened, plugged back, or plugged in the area encompassed are spotted on this map.

Current research utilized both types of maps on file with the Railroad Commission of Texas, as well as other available commercial oil and gas base maps. The information found on these various base maps is used to proceed into the next step of the research process.

VIII.2.2.1.3 Microfilm Records

All records filed with the Railroad Commission of Texas prior to 1973 are found on microfiche and microfilm. Records in some Railroad Commission of Texas districts are filmed through 1980. These microfiche and microfilm records are organized in several different systems: operator and lease name; district, field, and operator name; or district, field, and lease number. +Within the aforementioned filing systems, there are a large number of exceptions to the filing procedures, which create additional filing systems within these categories. The various types of standard film sets are as follows:

Unit cards

These are microfiche records for wells, which had records filed with the Railroad Commission of Texas prior to 1962. These units are filed sequentially by an operator number assigned by the Railroad Commission of Texas when the operator filed the required organization report with the agency. The operator number can be referenced in either the county book or the county microfiche. A county book is maintained for each county within the state. Within the county book, the information is organized alphabetically by lease name, which cross references to the operator name and corresponding operator number. The county microfiche are a recent addition to the Railroad Commission of Texas filing system. The agency took the county books and reorganized the leases into alphabetical order and microfilmed the information. Although the county books are not organized as neatly as the county microfiche, they are the original system and are more accurate owing to unintentional omissions made when reorganizing the listings.

Operator numbers can also be obtained from old copies of organization ledgers maintained by the Railroad Commission of Texas. These ledgers are in five separate sets, which correspond to various time periods from the 1920's through the 1960's. They list only operator names, addresses, and numbers assigned by the agency and are used as a last resort because they do not indicate lease names and often list multiple operators with the same name.

Once the operator name is matched to a lease name and an operator number is given, the unit card, if available, is pulled. The lease names are filed alphabetically within each operator number. Because there are exceptions to the filing system, if the desired information is not available or only partially available on the unit card, then the researcher must proceed to the next set of microfilms.

Well records—folder rolls

Duplicate copies of unit cards, which sometimes contain information that was not included in the initial filming of the unit cards, are referenced on the folder rolls. The folder rolls are organized by operator number and folder number, which appear on the unit card jacket. In addition, some folder rolls do not have a folder number given, but only an operator number. These rolls are called “add-on rolls” and also contain records not included in the initial filming of the unit cards.

Well records—runs 20 to 30 and A to I

These rolls are organized by operator number and by specific periods of years. They encompass the time period from 1945 through 1960 and commonly have three to five rolls for a specific year and operator number. When information is not available on the unit cards, these are the next set of films to be researched for records.

Well records—major runs

This is a special set of films that contains information on records filed only by major operators. These rolls are organized by operator and then alphabetically by lease name. It should be noted that there are few unit cards for major companies and that, if any information had been filed on a lease or well, it would be found on this set of films. It should also be noted that major operators, even in the early years of the oil business, were prudent about filing completions and plugs for wells, which they operated.

Well records—old warehouse film

This set of films contains some of the earliest information filed with the Railroad Commission of Texas and includes oil and gas well records filed from 1919 through 1939. There are only five rolls of this film, with three rolls organized numerically by operator number and two rolls organized alphabetically by operator name.

Well records—K, L, and M film

In March 1966, the Railroad Commission of Texas instituted a new filing system. However, before the system could be fully implemented, many well records, which were filed during the period of transition, were placed onto the K, L, and M film. The K Run covers portions of records filed from 1963 through 1964, the L Run covers portions of records filed from 1964 through 1965, and the M Run covers portions of records filed from 1965 through March 1966. The K, L, and M films are organized by operator number, with leases listed alphabetically within operator number.

Potential film

In March of 1966, the Railroad Commission of Texas filing system was converted to the potential filing system, which is currently used. This film contains records of all wells that produced oil and/or gas and were placed in a designated oil or gas field. This film is organized by Railroad Commission of Texas District, field name, and oil lease number or gas well identification number.

Wildcat and suspense film

This film contains records of all wells with applications to drill in wildcat fields or new leases in designated fields that were on leases that did not have a lease identification number previously assigned because no producing wells were on the lease in the field. This film is organized by district, county, and/or American Petroleum Institute (API) number. The API number system has been in effect since April 1966. The numbers have been stored within the Railroad Commission of Texas computer system, as well as being noted on all forms filed for the well. The system allows information to be retrieved by computer showing drilling status, operator, lease name, oil lease number or gas identification number, and field name. This is a very efficient system and allows quick and accurate retrieval of data filed since 1978.

Well record files

These are the hardcopy files of data not yet placed on microfilm. These files are organized by district, field name, and oil lease number or gas identification number. These files contain the most recent data processed by the Central Records staff of the Railroad Commission of Texas. Inside these folders are references to data that have been placed onto potential film.

Suspense files

These files contain the most recent information to be filed with the Central Records Department. This is the holding area for information to be placed into existing well record files or to have new oil lease or gas identification files prepared. The information is filed by district and API number. To obtain API numbers assigned to these records, it is necessary to search suspense cards that are filed by district, county, and alphabetically by lease name. Records that have not been placed in suspense files are usually found on the map where they are held until data are placed onto the county oil and gas base maps or onto field maps.

The aforementioned record sets are the primary file systems utilized to access records at the Railroad Commission of Texas. In retrieving information from the Railroad Commission of Texas, the researcher often has to examine every file system available in search of a particular piece of information.

VIII.2.2.1.4 Research Procedures for Geophysical Well Logs

A commercial log library (Geomap) was contacted for information concerning the wells within the Area of Review. Log libraries maintain extensive geophysical well log collections, as well as scout ticket files. Geophysical well logs were requested for all of the artificial penetrations within the Area of Review.

VIII.2.3 Artificial Penetration Evaluation

After information was compiled from the various data sources, a critical review of each artificial penetration was undertaken. All artificial penetration records were examined to identify improperly constructed and/or plugged wells, along with other disposal operations, which may exist in the Area of Review. Once identified, the artificial penetrations were then subdivided into wells that are abandoned and wells that are active. An abandoned well is a well whose use has been permanently discontinued or is in disrepair such that it cannot be used for its intended purposes. These types of wells include dry holes, abandoned production (oil and gas) wells, and injection wells. An active well is a well that is currently operating, including production and injection (saltwater disposal, enhanced recovery, or other) wells. Well evaluation included current status, confining zone/injection zone penetration, nature of the strata penetrated, and drilling methods.

VIII.2.3.1 Well Status

Each artificial penetration (active/abandoned) was evaluated as to adequacy of construction and plugging to determine the potential of penetration to convey fluid from an injection zone into the overlying USDW's (nonendangerment) and the potential of penetration to convey injected effluent out of the injection zone (no migration). Potential problem wells were identified and were subsequently evaluated or modeled to determine need for corrective action.

VIII.2.3.2 Confining/Injection Zone Penetration

Wells that penetrate the confining and/or injection zone may have the potential for conveying fluid from the injection zone to an overlying formation or from the injection zone to an overlying USDW. Available geophysical well logs from artificial penetrations within the Area of Review were correlated to determine which of the wells penetrate the confining/injection zone. Wells that do not penetrate this interval do not provide potential avenues for fluid movement and need not be evaluated further.

VIII.2.3.3 Rock Types

Unconsolidated rock formations, such as the geologically young shales in the Gulf Coastal Plain, have hydration (expanding clays-smectites) and plastic properties, which result in natural closure of man-made boreholes (Johnson and Greene, 1979; Davis, 1986). After interviewing several experienced drilling engineers, Johnson and Knape (1986) reported that the geologically young and unconsolidated sediments of the Gulf Coast tend to slough and swell and an uncased borehole will commonly squeeze shut within a matter of hours, resulting in natural borehole closure. AIC (1987) examined improperly plugged abandoned wells in over 46,500 Texas oil and gas fields in both unconsolidated and consolidated regions and documented natural closure as an important mechanism in preventing upward fluid movement in the unconsolidated rock areas (Clark and others, 1987). Borehole closure has also been verified in the day-to-day experience of field engineers or petroleum consultants who encounter difficulty in keeping boreholes open while drilling and running casing and sometimes find boreholes closed when reentry is attempted for plugging. Experience from reentering and plugging abandoned wells near E. I. du Pont de Nemours and Company injection facilities confirmed that the boreholes are closed by natural processes in the Texas Gulf Coastal Plain (Meers, personal communication, 1987; Klotzman, personal communication, 1986).

These observations explain why abandoned well boreholes without production/long-string casing are normally sealed by natural phenomena. Although closure of the borehole by caving sands and swelling shales would provide a significant obstacle to vertical fluid movement in the well, the approach used to model the potential for fluid movement in abandoned boreholes assumes that borehole closure will not occur. The resulting modeling calculations thus include a large safety factor. The monitoring program implemented in SGH#4 will help to test and validate these assumptions.

VIII.2.3.4 Drilling Methods and the Mud Column

The artificial penetrations were classified by their drilling methods (rotary vs. cable). Because boreholes tend to close in unconsolidated rock formations, such as the geologically young sands and hydrated shales of the Gulf Coastal Plain, rotary drilling has been the most preferred drilling method. Generally drilling mud is carefully balanced to keep caving sands and sloughing shales from entering the borehole. Rotary drilled dry holes (wells without economically recoverable hydrocarbons) without proper plugging records can be assumed to have been left mud filled as a minimum condition because there is no economic reason to recover the drilling mud prior to abandonment (Johnston and Knape, 1986). Exceptions are wells drilled with polymer or oil-based muds, which are economical to extract from the well; however, the hole during extraction is filled with a less expensive bentonite mud. Mud characteristics (density, viscosity, type, and pH) were obtained from geophysical well logs and State and operator records when available. Rotary drilled dry holes with protection and/or production casing strings were reviewed for perforations because a well that has been production tested by perforating usually has the drilling mud replaced by a water cushion.

Mud plugs provide an effective barrier to vertical fluid flow in the abandoned well bore. The permeability of the mud plug is usually less than that of the surrounding formations, which, in combination with the hydrostatic head of an overbalanced mud column that is sufficient to counterbalance increased formation pressure due to injection, creates an effective barrier to vertical fluid flow. These factors, combined with borehole closure, minimize the chance of encountering a truly open conduit in an artificial penetration that was drilled in unconsolidated regions.

VIII.3 Tabulation of Artificial Penetrations in the Area of Review

A tabulation of data on all artificial penetrations within the 0.25-mile-radius Area of Review is included in table VIII-1. These data include permit application identification number, operator information, well lease name, status, casing information, key hydrologic and geologic datums, and cement plugging depths. The permit application identification number is keyed to figure VIII-1.

VIII.4 Schematics, Records for Artificial Penetrations in the Area of Review

Schematics and records data (State forms and scout tickets) for all artificial penetrations within the 0.25-mile-radius Area of Review are included in Appendix VIII-1. Information included on the well schematics are permit application identification number, operator information, well lease name, status, casing information, key hydrologic and geologic datums, and cement plugging depths.

VIII.5 Improperly Constructed or Abandoned Artificial Penetrations

For purposes of evaluating artificial penetrations, the Statewide Rules for Oil, Gas and Geothermal Operations (1986), from the State of Texas was used to determine proper plugging requirements for the protocol because the rules are very specific and stringent. The Railroad Commission of Texas, under Statewide Rule 14, (1967), demands all formations bearing USDW's, oil, gas or geothermal resources be protected with type-specific cement plugs and mud-laden fluid. Uncemented areas in the abandoned well bore must be filled with a mud-laden fluid weighing at least 9.5 lb/gal (Railroad Commission of Texas, 1986). Setting depths for cement plugs depend on construction of the well and geological environment. Wells abandoned with only surface casing should be plugged across the base of the lowermost USDW regardless of casing depth. When insufficient surface casing is set to protect all USDW's and such strata are exposed to the open well bore, a cement plug must be placed across the exposed strata with an additional cement plug set across the surface casing shoe (Railroad Commission of Texas, 1986). When sufficient surface casing has been set to protect all USDW's, a cement plug must be set across the surface casing shoe (Railroad Commission of Texas, 1986).

For wells abandoned with protection and/or production casing that have been cemented through all underground sources of drinking water strata, all productive horizons must have cement plugs placed inside the casing and cement plugs centered opposite the base of the lowermost USDW (Railroad Commission of Texas, 1986). For wells abandoned with protection and/or production casing set back to surface, the casing must be perforated at the depths required to protect all productive horizons and the lowermost USDW with cement placed outside of the casing by squeeze cementing (Railroad Commission of Texas, 1986). Wells determined to be improperly plugged by the above criteria were labeled as "potential problem well" and were evaluated or modeled for potential upward movement of fluids.

For the purpose of this protocol, a properly constructed active well is defined as a well in which the annulus between the borehole and a casing string has been effectively sealed by cement across and/or above the correlated injection interval(s), thereby preventing vertical fluid movement. Wells that were drilled into or through the injection interval and abandoned with protection and/or production casing left in the hole pose potential problems. If cement were not circulated to a depth above the correlated injection interval, only drilling fluid would be present in the annulus. Although the drilling fluid in the annulus would provide the same resistance to vertical fluid movement as a mud plug in the well bore, active wells that were constructed improperly were also listed as potential problem wells and evaluated or modeled for possible vertical fluid movement.

Cement volume calculations were made on each well that has full protection and/or production casing left intact in the well. Only conservative data values were used in the calculations. One inch was added to the borehole diameter, and all slurry volumes were calculated using Class H cement with 0 percent Gel (1.06 ft^3/sack-slurry volume).

VIII.5.1 Incomplete Records

Most of the data on the artificial penetrations in each Area of Review were obtained from State records kept on file at each specific State agency. When public records were missing or inadequate, private record searches were conducted to locate pertinent data. Many current operators or well owners have ceased operation or have changed names, making it difficult to locate records. Many of these operators did not keep records on older wells that were dry holes, making it increasingly difficult to document the present status of the well. Wells that were identified as having been drilled but missing the necessary records to document adequacy of plugging and/or construction were considered potential problem wells and evaluated or modeled for possible vertical fluid movement utilizing the known data.

VIII.5.2 Modeling Improperly Constructed or Plugged Wells

Within the 0.25-mile-radius Area of Review of the Frio Brine Pilot Test site, only Map ID. Nos. 37, 40, and 45 are identified as either properly constructed or properly plugged, using the nonendangerment criteria outlined above. The remaining wells are all in communication with the Frio C Sand Injection Interval, with the exception of Map ID No. 50, where the sand is faulted out. These wells were put through a modeling evaluation by comparing the conservatively predicted pressure increases from Section VII-reservoir mechanics at maximum rates of injection with the calculated allowable pressure buildup (static column pressure plus minimum gel strength) at the top of the Frio C Sand Injection Interval, using well-specific information (mud weight, borehole diameter, formation depth, etc.). In cases where information was not available, conservative assumptions were made in the model calculations. These assumptions are summarized below:

(a) For purposes of calculating the pressure due to gel strength, in cases where the borehole diameter across the injection interval sands was unknown, the surface casing diameter was used as a surrogate for the bit size. This is conservative because the actual bit diameter **must** be less than the outer diameter of the surface casing string.

(b) For purposes of calculating the pressure due to gel strength, a conservative ultimate gel strength of 20 lb/100 ft^2 was used. This is conservative because studies indicate that with time, the gel strength of “set” mud may be more than an order of magnitude higher (Pierce, 1989). Additionally, in order for the calculation to be conservative, 1 inch was added to the bit diameter to account for potential borehole washout.

(c) For purposes of calculating the static mud column pressure, in cases where the weight of the mud in contact with the injection intervals could not be found, a conservative drilling mud weight of 9.0 lb/gal was used. This is conservative because the available drilling information from area well logs indicates that the mud weight was always higher than 9.0 lb/gal for wells in the immediate area (lowest mud weight was 9.7 lb/gal).

(d) In order to be extremely conservative in calculating the static column pressure, a fallback of 50 ft in the mud column was assumed in the calculations. This is conservative because State regulations require that all uncemented intervals in a well be filled with mud. Additionally, mud to surface is required to support the surface plug; otherwise, the plug would not set properly and would fall down the hole.

Calculations used in the modeling analysis are presented below.

A static fluid column exerts pressure. The pressures acting on the static fluid column (pressure due to injection plus original formation pressure) must be greater than the static fluid column pressure before fluid movement will start. In this case, for upward fluid movement to begin, original formation pressure (P_f) plus the pressure due to injection (P_i) must be greater than the static fluid column pressure:

$$P_f + P_i > P_s \ ,$$

where:

P_f = original formation pressure (psig)

P_i = formation pressure increase due to injection (psi)

P_s = static fluid column pressure (psig)

In other words, pressure increase due to injection must be greater than static fluid column pressure minus original formation pressure:

$$P_i > P_s - P_f \ .$$

Static fluid column pressure is calculated using the equation:

$$P_s = 0.052 \times h \times M \ ,$$

where:

P_s = pressure of static mud column (psi)

h = depth to the injection reservoir from the 50 foot fallback (ft)

M = fluid weight (lb/gal)

and 0.052 is the conversion factor so that P_s is in psi.

In an artificial penetration filled with a column of drilling mud, the gel strength of the mud must also be considered. In this case, for upward fluid movement to begin, original formation pressure (P_f) plus the pressure due to injection (P_i) must be greater than the static fluid column pressure plus the gel strength of the mud. This relationship is based on a simple balance of forces (Davis, 1986):

$$P_f + P_i > P_s + P_g \ ,$$

where:

P_f = original formation pressure (psig)

P_i = formation pressure increase due to injection (psi)

P_s = static fluid column pressure (psig)

P_g = gel strength pressure (psi)

Therefore, pressure increase due to injection must be greater than static fluid column pressure plus the pressure due to gel strength minus original formation pressure:

$P_i > P_s + P_g - P_f$.

The pressure due to gel strength (G) in an open borehole can be calculated from the following equation:

$$P_g = \frac{0.00333 \times G \times h}{d} ,$$

where:

P_g = pressure due to gel strength (psi)

G = gel strength (lb/100 ft^2)

h = depth to the injection reservoir from the 50-foot fallback (ft)

d = borehole diameter (inches)

where 0.00333 is the conversion factor, such that P_g is in psi.

For a hypothetical open borehole, the added resistance due to gel strength for a mud with a conservative ultimate gel strength of 20 lb/100 ft^2, in a 10-inch borehole, is approximately 6.7 psi for every 1,000 ft of depth.

For a cased hole, pressure due to gel strength (G) can be calculated from:

$$P_g = \frac{0.00333 \times G \times h}{d_b - d_c}$$

where:

P_g = pressure due to gel strength (psi)

G = gel strength (lb/100 ft^2)

h = depth to the injection reservoir from the 50-foot fallback (ft)

d_b = borehole diameter (inches)

d_c = outside casing diameter (inches)

For a hypothetical cased borehole, the added resistance due to gel strength for a mud with a conservative ultimate gel strength of 20 lb/100 ft^2, in a 10-inch borehole with 7-inch casing is approximately 22.4 psi for every 1,000 ft of depth.

As the above calculations show, gel strength provides a significant additional resistance to fluid movement due to injection. Additional conservatism is added owing to borehole rugosity, which can increase the contribution in pressure due to gel strength by a factor of 3 to 5 (Collins and Kortum, 1989). Using the above formulas for an open borehole and a cased borehole, average measured gel strength from the Nora Schulze No. 2 well (267 lb/100 ft^2) (Pierce, 1989) and a factor of 3 contribution in gel strength due to borehole rugosity, the added resistance due to gel strength could reasonably be expected to be 266 psi per 1,000 ft of depth in an open borehole and 889 psi per 1,000 ft of depth in a cased well.

In order to add an additional measure of conservatism in the calculation, a fallback of 50 ft in the mud column was assumed.

Modeling results for wells requiring further evaluation are shown in table VIII-2, and the input parameters into the calculation are shown in table VIII-3. Additionally, other artificial penetrations are also listed in this table, along with their evaluation result. The table shows that the predicted worst-case pressure increase in the Frio C Sand Injection Interval at each evaluated well is significantly less than the minimum allowable pressure increase at that artificial penetration. Because all of the wells pass the evaluation demonstration, no corrective action is required for any of the artificial penetrations located in the Area of Review.

Table VIII-2. Modeling results for the wells requiring further evaluation.

Artificial Penetration Map ID #	Operator	Lease and Well #	Injection Well Number	Allowable Incremental Pressure (psi) Frio C Sand	Modeled Incremental Pressure (psi) Frio C Sand	Safety Margin (psi) Frio C Sand
28	Gulf Oil Corp.	Rowe-Baldwin et al. Unit #1	Frio Brine Pilot Well	912	0	912
29	Gulf Oil Corp.	M. Partlow #1	Frio Brine Pilot Well	732	0	732
32	Gulf Oil Corp.	M. Partlow et al. Unit "A" #1	Frio Brine Pilot Well	214	0	214
35	The Texas Co.	R. E. Brooks Fee NCT-2 #4	Frio Brine Pilot Well	204	0	204
36	Sinclair O&G Co.	Brooks Fee #1	Frio Brine Pilot Well	904	0	904
38	F. L. Karsten	Sun Gulf Humble Fee Tract #2	Frio Brine Pilot Well	1,186	0	1,186
39	The Texas Co.	R. E. Brooks Fee NCT-3 #1	Frio Brine Pilot Well	214	73	142
41	F. L. Karsten	Sun Gulf Humble Fee Tract #4	Frio Brine Pilot Well	851	377	425
42	King & Heyne, Inc.	Brooks et al. #1	Frio Brine Pilot Well	977	145	832
43	The Texas Co.	R. E. Brooks Fee NCT-2 #2	Frio Brine Pilot Well	878	0	878
44	Humble O&R Co.	R. E Brooks Fee #1	Frio Brine Pilot Well	635	109	526
45	F. L. Karsten	Sun Gulf Humble Fee Tract #3	Frio Brine Pilot Well	1,122	290	696
46	TARC	Sun Gulf Humble Fee Tract #6	Frio Brine Pilot Well	243	145	98
47	F. L. Karsten	Sun Gulf Humble Fee Tract #5	Frio Brine Pilot Well	898	145	753
49	Sinclair O&G Co.	R. E. Brooks Unit #2	Frio Brine Pilot Well	880	0	880
50	Sinclair O&G Co.	R. E. Brooks Unit #1	Frio Brine Pilot Well	N/A*	N/A*	N/A*

*Not modeled for Frio C Sand; sand faulted out.

Table VIII-3. Input parameters into the modeling calculation.

Artificial Penetration Map ID #	Operator	Lease and Well #	Top of Frio C Sand II Depth BGL (feet)	Protection Casing Present (Y/N)	Protection Casing Diameter (inches)	Borehole Diameter (inches)	Equivalent Borehole Diameter (inches)	Mud* Weight (lb/gal)
28	Gulf Oil Corp.	Rowe-Baldwin et al. Unit #1	4,871	Yes	5 1/2	7 7/8	5 1/2	11.8
29	Gulf Oil Corp.	M. Partlow #1	4,841	Yes	5 1/2	9 7/8	5 1/2	11.1
32	Gulf Oil Corp.	M. Partlow et al. Unit "A" #1	4,966	Yes	5 1/2	10 3/4	5 1/2	9.0
35	The Texas Company	R. E. Brooks Fee NCT-2 #4	4,756	Yes	5 1/2	9 7/8	5 1/2	9.0
36	Sinclair O&G Co.	Brooks Fee #1	4,829	Yes	5 1/2	8 3/4	5 1/2	11.8
38	F. L. Karsten	Sun Gulf Humble Fee Tract #2	4,967	Yes	5 1/2	8 3/4	5 1/2	12.8
39	The Texas Company	R. E. Brooks Fee NCT-3 #1	4,966	Yes	5 1/2	8 5/8	5 1/2	9.0
41	F. L. Karsten	Sun Gulf Humble Fee Tract #4	4,997	Yes	5 1/2	8 3/4	4 1/4	11.4
42	King & Heyne, Inc.	Brooks et al. #1	4,987	Yes	5 1/2	8 3/4	4 1/4	11.9
43	The Texas Company	R. E. Brooks Fee NCT-2 #2	4,953	Yes	5 1/2	9 7/8	5 3/8	11.6
44	Humble O&R Co.	R. E Brooks Fee #1	5,120	Yes	5 1/2	8 3/4	4 1/4	10.5
45	F. L. Karsten	Sun Gulf Humble Fee Tract #3	5,102	Yes	7	8 3/4	2 3/4	12.2
46	TARC	Sun Gulf Humble Fee Tract #6	5,193	Yes	5 1/2	8 3/4	4 1/4	9.0
47	F. L. Karsten	Sun Gulf Humble Fee Tract #5	5,216	No	0	8 3/4	9 3/4	11.6
49	Sinclair O&G Co.	R. E. Brooks Unit #2	4,876	Yes	5 1/2	8 3/4	4 1/4	11.6
50	Sinclair O&G Co.	R. E. Brooks Unit #1	F/O	Yes	5 1/2	8 3/4	4 1/4	11.2

* Wells modeled with 9.0 lb/gal mud where logging weight unknown.
** Injection interval sand depths listed as below ground depths.

VIII.6 Corrective Action Plan for Improperly Constructed or Abandoned Artificial Penetrations

No improperly constructed or improperly plugged wells fail the conservative modeling evaluation. Therefore, a corrective action program is not warranted because all of the artificial penetrations are properly constructed, plugged or abandoned, or they have a sufficient hydrostatic column so as to prevent the movement of fluids into or between USDW's.

IX. Waste and Waste Management

This section discusses the test fluid(s) to be injected and how those fluids will be managed at the Frio Brine Pilot Test site.

IX.1 Waste Generation and Management Activities

IX.1.1 Waste Management Information

Table IX.1 has been completed for the anticipated streams to be injected.

IX.1.2 Injected Waste Stream(s) Information

Table IX.2 has been completed for the anticipated streams to be injected.

IX.1.3 Waste Stream Analysis Plan

Table IX.3 has been completed for anticipated project sampling to be conducted during the injection experiment. Representative samples of the "food-grade" CO_2 will be taken at the source or from the on-site storage tanks and analyzed for chemical characteristics (purity). The recovered Frio brines will be analyzed for both chemical and physical properties for site characterization.

IX.1.4 Hazardous Waste(s) Subject to Federal Land Ban Disposal Restrictions

All of the streams anticipated for injection are nonhazardous. None of the streams are subject to Federal Land Ban Disposal Restrictions under 40 CFR 148 Subpart B.

IX.1.5 Hazardous Waste(s) Not Subject to Federal Land Ban Disposal Restrictions

All of the streams anticipated for injection are nonhazardous.

IX.1.6 Chemical and Physical Characteristics of the Waste Stream(s)

CO_2 is anticipated to be in a supercritical state when injected into the Frio Formation [conditions above 31.1 ^{o}C (87.9 ^{o}F) and 72.8 atm pressure (1,070.6 psi)]. A supercritical fluid possesses the characteristics of a fluid and a gas in that although it is compressible, it has liquidlike densities.

It is anticipated that a limited volume of formation brine may be produced during the experiment. Activities that may produce brine include (1) back-flowing the well(s) during initial development of completion, (2) fluids generated during pump testing of the wells, and (3) fluids generated during nitrogen lift activities required for fluid sampling (purging of the wells).

Typical native Frio Formation fluid compositions, from the nearby Class I UIC injection wells, are tabulated below. The Frio Formation fluid at the Frio Brine Pilot Test site is expected to be similar.

	Merisol WDW-147 mg/L	Merisol WDW-319 mg/L	Equistar WDW-36 mg/L	GNI WDW-169 mg/L	Hampshire WDW-222 mg/L	Hampshire WDW-223 mg/L
Calcium	2,250	1,610	6,400	2,400	2,200	2,160
Magnesium	475	214	1,440	480	457	455
Barium	66	494	190	60	63	46
Strontium	150	853	-	112	113	-
Sodium	55,664	45,700	43,000	39,400	41,200	-
Chloride	60,247	82,000	63,548	70,400	$\pm$70,520	$\pm$70,872
Sulfate	-	654	18	12	<100	-
Iron	-	1,170	5	35	60.5	53.4
Alkalinity Bicarbonate	-	<5	99	463.6	80.1	109.1
pH	7.0	4.5	6.7	6.85	6.7	6.5
Specific gravity	1.073	-	1.074	1.0836	1.082	1.087
Total solids	-	135,000	127,318	119,018	113,400	115,400

IX.1.7 Waste Stream(s) pH and Specific Gravity

At a supercritical state, CO_2 has a density of 29.2 lb/ft^3, for a specific gravity of 0.47 (assuming a pure water density of 62.29 lb/ft^3. Although dry supercritical CO_2 is inert, it is much more reactive in the presence of water or NaCl brines, forming carbonic acid when the injected CO_2 goes into solution. Preliminary geochemical modeling for the Frio Brine Pilot Test Site indicates that the pH in the formation brine should not drop below a value of about pH 5.3. This is due to the buffering provided by naturally occurring carbonates and other reactive minerals in the formation.

The tabulation included in Section IX.1.6 shows anticipated properties of the produced Frio brine. The pH of the Frio is in the neutral range of 6.5 to 7.0 standard units (note that the fluid from Merisol's WDW-319 was taken just after an acid stimulation of the interval), and the specific gravity of the brine ranges from 1.073 to 1.087.

IX.1.8 Injection Well Checklist

Table IX.4 has been completed for the anticipated site wells.

IX.2 Hazardous Waste Management

Hazardous wastes will not be injected at this site. Any wastes generated during site activities that are classified as hazardous will be appropriately handled and transported to an approved facility for disposal.

IX.3 RCRA Permit

Hazardous wastes will not be stored or injected at this site. An RCRA permit is not required for the injection experiment.

Table IX.1. Waste management information.

Waste	Source	Volume (gallons/year)
Food-grade CO_2	Local commercial sources	4,000 tons
Brine water	On site or commercial sources	1,092,000 gallons
Experiment tracers	Oak Ridge National Lab	Small amounts mixed with CO_2

Table IX.2. Injected waste streams.

Waste number	Waste	EPA waste codes	EPA hazard codes (I, C, R, E, H, T)	TNRCC waste classifications[1] (IH, I, II, III or H, 1, 2, 3)	TNRCC waste codes
1	Food-grade CO_2	N/A—Non-hazardous	N/A—Nonhazardous	IW Class 2	0001-701-2
2	Brine water	N/A—Non-hazardous	N/A—Nonhazardous	IW Class 1	0002-199-1

[1]For newly generated wastes classified after 1/01/93. Existing wastes must be reclassified by 1/01/95.

Table IX.3. Waste analysis plan.

Waste number (from table IX.B)	**Sampling location**	**Sampling method**	**Frequency**	**Parameter**	**Test method**	**Desired accuracy level**
1	Source	Canister	As needed	Chemical characteristics		PQL
		Probe	Continuous	Injection temperature		±1 °F
2	Storage/Frac Tank	Grab		Physical characteristics	EPA 625-16-74-003	
				Metals	EPA 625-16-74-003	PQL

Table IX.4. Injection well checklist.

WDW number	**Status[1]**	**Injected volume[2]**	**Maximum permitted injection rate[3]**	**Number of years utilized**	**Date in Service**
Injection well	Proposed	None to date	250 tons/day CO_2/ 150 gpm brine	N/A	N/A
Monitor well	Proposed—conversion	None to date	150 gpm brine	N/A	N/A

[1]Indicate only one of the following: Active, Inactive, Closed, or Proposed
[2]Total volume (gallons) injected into the well
[3]Gallons per year

X. WASTE COMPATABILITY

This section demonstrates that the injected CO_2 stream and its anticipated reaction products, and any necessary well stimulation fluids, which may be required to increase well performance during the experiment, will not significantly alter the permeability or other relevant characteristics of the injection zone strata or the confining zone strata. The major hydrogeologic elements involved in this compatibility demonstration are the injection zone formation fluid and the injection zone reservoir rock interaction with injected fluids.

X.1 Injected Effluent—Injection Interval Compatibility

The Injection Zone is composed of fine-grained to very fine grained sandstones with interbedded shales. Judging by X-ray diffraction tests run on whole core recovered from the Frio Formation by Atofina (Plant Well 2 (WDW-230)), which is located on the western flank of nearby Esperson Dome, sandstones at the Frio Brine Pilot Test Site are likely to be composed of the following minerals:

- Quartz—83 to 96 percent
- Potassium feldspars—2 to 14 percent
- Plagioclase feldspars—0 to 3 percent
- Calcite—minor amounts
- Clays—2 to 6 percent (primarily illite, kaolinite, and illite/smectite)

Although the injected CO_2 may initially act as an immiscible phase, it can react with the native formation brine, and it is expected that carbonic acid will be formed when the injected CO_2 goes into solution. The coupled reaction can be expressed by the following equation:

$$CO_2\,(g) + H_2O \leftrightarrow CO_2\,(aq) + H_2O \leftrightarrow HCO_3^- + H^+$$

The reduced pH conditions in the formation brine-CO_2 mixture near the injection well will result in conditions capable of dissolving silicate and carbonate minerals. Preliminary geochemical modeling for the Frio Brine Pilot Test Site indicates that the pH in the formation brine should not drop below a value of about pH 5.3. This is due to the buffering provided by naturally occurring carbonates in the formation.

Dissolved CO_2 can further react with or form mineral phases once it has dissociated into bicarbonate or carbonate aqueous species. This interaction of CO_2 with the native formation brine and the formation materials is the basis for the geologic sequestration process of solubility trapping (as carbonate aqueous species) and mineral trapping (as carbonate minerals). These are critical aspects of the Frio Brine Pilot Test, which will be studied and monitored during this experiment.

In feldspathic sandstones, such as are expected at the Frio Brine Pilot Test Site, dissolution of the potassium feldspars is expected to occur in the slightly acidic environment resulting from the CO_2 going into solution. As aluminum is released from the dissolving potassium feldspars, it can combine with sodium provided in the formation brine and dissolved CO_2 to form the mixed hydroxycarbonate mineral dawsonite (Knauss and others, 2001). The formation of dawsonite is sequestering CO_2 via mineral trapping. Mineral trapping will also occur from the formation of calcite-group carbonates, most significantly as siderite, magnesite, and calcite. Silica released from the dissolving potassium feldspars is also expected to be precipitated in the formation, as both the silica polymorph chalcedony and additional quartz (Knauss and others, 2001).

The mineral trapping of CO_2 is expected to be a long-term, on-going process that evolves as the solution chemistry evolves over time and minerals evolve in response to fluid chemistry changes.

X.2 Injected Effluent—Aquiclude Layer Compatibility

Shales of the confining layers within the injection zone and/or the confining zone are primarily alumino-silicates (clays), with quartz and minor amounts of feldspar, carbonates, and miscellaneous oxides. These materials are generally unreactive or very slowly reactive with weak acids and bases and aqueous organics. The permeability of the confining shales at the Frio Brine Pilot Test Site is at least six orders of magnitude less permeable than the injection interval sands. In a practical sense, the large permeability difference between these lithologic intervals means that the injected CO_2 has the highest potential to contact and react with the injection interval material, not the overlying or underlying aquiclude shale material. Because of the low permeability of the aquiclude shales, only reactions near or at the shale/sand interface can occur.

Studies of clays indicate that chemical reactions may take place between injected waste streams and clay, mainly by cation exchange, clay dissolution, and new mineral formation (zeolites) (Mohnot and others, 1984). Clays (especially illites and smectites) are known to be efficient ion exchange materials. These clays have a structure consisting of alternating layers of tetrahedral SiO_4 and octahedral AlO_6, in which oxygens are shared between the structural units. Generally, clay minerals have undergone isomorphic substitution for either the Si or Al by ions of lower valence. This results in a negative lattice charge that can be neutralized by exchangeable cations. Clays are known to preferentially adsorb heavy metal ions (nickel, lead, chromium) onto their surfaces and release sodium or calcium ions into solution.

The principal effect of acids on clays is to leach metal ions from the clay lattice sites, leaving behind the silica framework. In laboratory X-ray diffraction experiments, diffraction patterns for the tested clays reacted similarly as metal ions are leached out by acid, indicating that the clay structure remains essentially constant. The metal ions are leached from montmorillonites as follows:

$$(12\ SiO_2) \cdot (2\ MgO + 5\ Al_2O_3) \cdot (12\ SiO_2) \cdot Na_2O \cdot (6\ H_2O) + 36\ H^+$$

$$\rightarrow 2\ Na^+ + 2\ Mg^{+2} + 10\ Al^{+3} + 24\ SiO_2 + 24\ H_2O$$

The metal ions are leached from illites as follows:

$$(Al_2O_3 + 6\ SiO_2) \cdot (4\ Al_2O_3) \cdot (Al_2O_3 + 6\ SiO_2) \cdot (2\ Na_2O) \cdot (4\ H_2O)$$

$$+ 40\ H^+ \rightarrow 4\ Na^+ + 12\ Al^{+3} + 12\ SiO_2 + 24\ H_2O$$

The metal ions are leached from kaolinites as follows:

$$(2\ Al_2O_3) \cdot (4\ SiO_2) \cdot (4\ H_2O) + 12\ H^+ \rightarrow 4\ Al^{+3} + SiO_2 + 10\ H_2O$$

As the reactive components react, permeability and diffusivity of the shale at the injection interval-aquiclude layer interface will gradually increase; however, the acid will need to disperse ever further to find reactive material, resulting in a self-limiting reaction. Additionally, aside from reacting with the acid, clays in the aquiclude layers will slow the movement of positively charged ions (such as H^+) by ion exchange, again limiting the reaction.

X.3 Effects of Well Stimulations on the Injection Interval Sand Layers

The effects of potential remedial stimulations on the Frio C Sand Injection Interval material are dependent on the acid used. The large permeability difference between the injection interval and the overlying and underlying confining aquiclude layers results in the stimulation fluid having the highest potential to contact and react with materials within the injection interval, not the overlying or underlying aquiclude layers. Once the stimulation procedure is complete, injection of brine buffers or CO_2 will be initiated. Thus, any "live" acid will be quickly swept deeper into the injection interval, where it will continue to be neutralized.

Acid HCl will rapidly react with the carbonates in the injection interval and formation fluids. The typical chemical reaction is as follows:

$$(4\text{-}s)\ HCl + CaCO_3 \rightarrow Ca^{+2} + (4\text{-}s)\ Cl^- + s\ HCO_3 +$$

$$(1\text{-}s)\ H_2O + (1\text{-}s)\ CO_2 \text{ aqueous,}$$

where:

s ranges from 1 to 0

Silica can be solubilized by acid as follows:

$$SiO_2 + H_2O + H^+ \rightarrow Si(OH)_3^+$$

However, the rate of silica dissolution is quite slow, especially in low pH environments (Iler, 1979).

Acid HF is extremely reactive with siliceous materials. In combination with HCl, HF is so reactive with siliceous materials that the HF is completely spent within a radial distance of 3 to 4 ft of the well bore (Jorda, 1978; Empack, 1990). The reaction that takes place is as follows:

$$6\ HF + SiO_2 \rightarrow 2\ H_2O + H_2SiF_6$$

Because the reaction kinetics are so rapid, there is minimal potential for the acid to remain active in the formation for any appreciable length of time. Therefore, overlying containment shale layers will not be impacted.

Waste compatibility

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 less than 1,000 ppm, and rate of leakage equivalent to rate of injection.

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 X-1 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.

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 µg/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 percent 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 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, producing concentrations in the ppm range.

Table X-1. Tracer materials to be used and their concentrations.

Tracer	Concen-tration (injectate)	Concen-tration (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

XI. SURFACE INSTALLATIONS

XI.1 Surface Facilities General Flow

This section provides a description of the proposed surface installations for the Frio Brine Pilot Test. A flow diagram for the proposed surface facilities is provided as figure XI-1.

XI.2 Deep Well Preinjection Facilities

The deep well preinjection facilities will provide liquid carbon dioxide (CO_2) storage tanks, necessary pumping facilities, CO_2 temperature control, and various elements needed for system control and quality assurance for the CO_2 injection. The Proposed Injection Well Preinjection Facilities will consist of:

- CO_2 storage tanks
- Injection pump
- Inline temperature monitor
- Inline flow meter
- CO_2 heater
- Annulus monitoring system
- Surge protection system

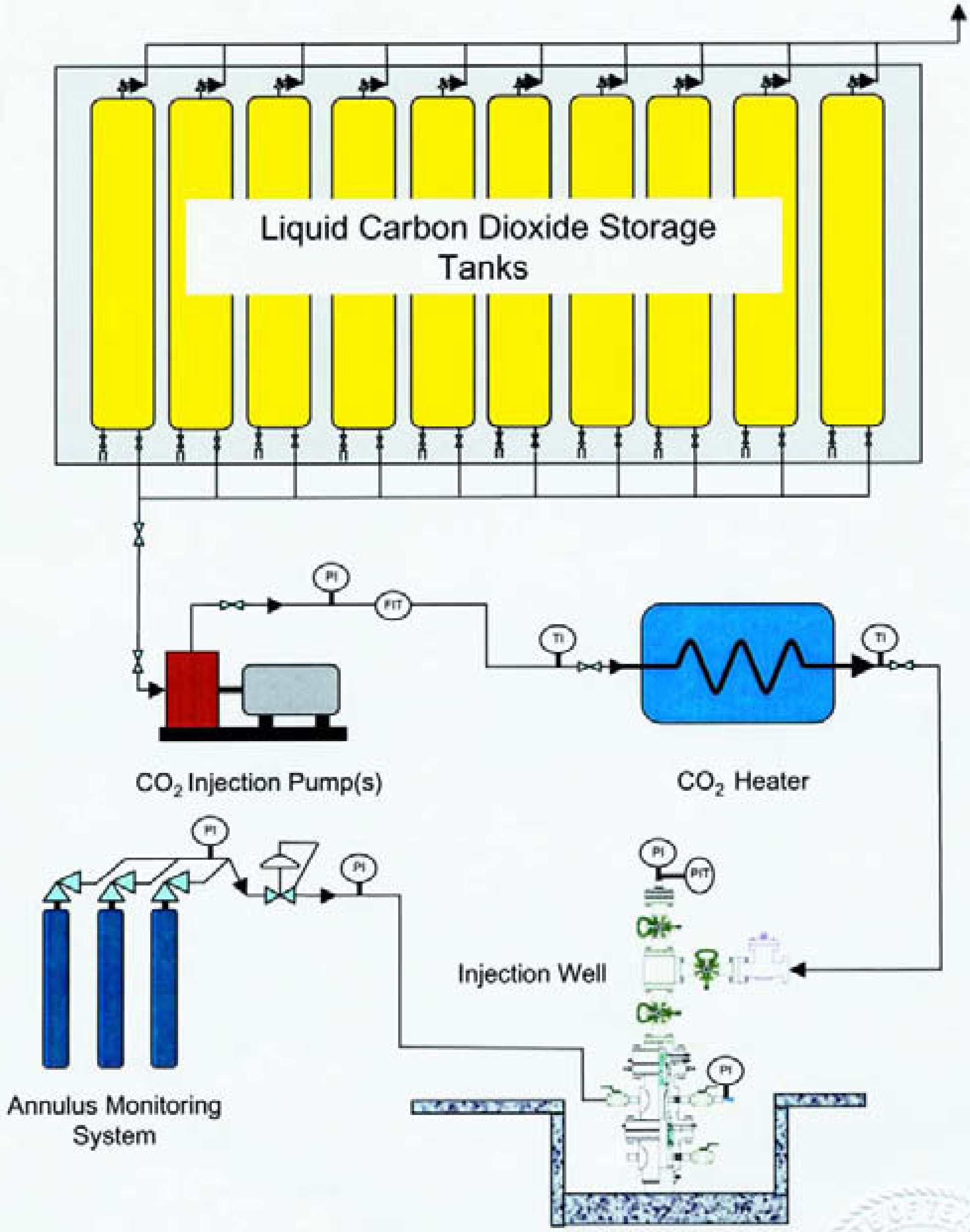


Figure XI-1: Proposed Surface Facilities

8/15/03

XI.3 Carbon Dioxide Storage Tanks

The liquid carbon dioxide will be hauled to the Frio Brine Pilot Test location by commercial haulers and transferred to the liquid carbon dioxide storage tanks. The temporary storage facility will be designed for storage of approximately 500 tons (131,234 gallons) of liquid CO_2, in 10 storage vessels. Horizontal 50-ton vessels, with a maximum working pressure of 350 psig with safety valves and pressure vent system, will be used for onsite CO_2 storage. This volume will provide approximately 48 hours storage under average flow conditions of 250 tons per day, to address planned test injection periods. Soil under the storage vessels will be stabilized to support the load of the 10 storage vessels.

XI.4 Injection Pump(s)

One or more injection pump(s) will be installed for the testing program. The injection pump(s) will have a maximum capacity of at least 42 gpm and a maximum injection pressure of 3,500 psig. The injection pump(s) will be designed for pumping liquid CO_2 under the conditions for the injection tests scheduled during the project. The CO_2 provider or a third-party vendor will supply the injection pumps.

XI.5 Inline Temperature Monitors

Temperature will be monitored and recorded continuously immediately downstream of the injection pump(s) and immediately downstream of the CO_2 heater. The inline temperature monitors will be used to control the temperature of the CO_2 injected during the project.

XI.6 Carbon Dioxide Heater

A carbon dioxide heater will be installed between the injection pump(s) and the injection well. The carbon dioxide heater will be used to regulate the temperature of the CO_2 to approximately 70 °F. Diesel fuel, natural gas, or electricity will be used as the energy source for the heater. The heater will be adjusted to regulate the discharge temperature of the CO_2 to the desired temperature.

XI.7 Annulus Monitoring System

See figure VI-3 of for a schematic drawing of the annulus monitoring system.

XI.8 Proposed Injection Well

The proposed injection well will be located within a separate containment sump, approximately 6 ft in diameter by 3 ft in depth. Rainwater or spillage around the wellhead will drain to a sump that will be used for containment. A pressure transducer will be mounted on the wellhead to log injection pressure and a pressure gauge mounted on the wellhead annulus valve to monitor the annulus pressure.

XI.9 General Construction Items

A sign shall be posted at the well site that shall show the name of the company, company well number, and commission permit number. The sign and identification shall be in the English language, clearly legible, and shall be in numbers and letters at least 1 inch high.

An all-weather road shall be installed and maintained during the experiment to allow access to the proposed injection well, the proposed monitor well, and related facilities.

XI.10 Inspections, Record Keeping, and Reporting

XI.10.1 Operation and Inspections

A minimum of one full-time operator per shift will be on location during the experiment injection periods. Additional staffing will be provided as needed. The facilities will be staffed 24 hours per day, 7 days per week during active injection periods. The operator(s) will complete daily inspections of all components and complete a daily operations report showing critical operation and maintenance data, including but not limited to:

- CO_2 flows
- CO_2 temperature

- Component integrity
- Maintenance actions
- Maintenance needs

The wellhead and associated facilities will be maintained in good working order without leaks.

XI.10.2 Monitoring and Testing

All gauges, pressure sensing, and recording devices will be tested and calibrated prior to the beginning of CO_2 injection and as needed or recommended by the manufacturer.

The integrity of the long-string casing, injection tubing, and annular seal will be tested by means of an approved pressure test with a liquid or gas prior to injection into the well and whenever a well workover or change in the completion configuration occurs. A radioactive tracer survey may be run prior to initiation of injection or after workovers that have the potential to damage the cement within the injection zone.

Pressure buildup in the injection zone will be monitored frequently during the injection experiment, including at a minimum, an initial injection/falloff test for determination of injection interval properties. A final static bottom-hole pressure will be obtained prior to final closure of the wells.

A casing inspection, casing evaluation, or other approved log will be run following installation of the proposed injection well and whenever a workover is conducted that could damage the protection casing string.

XI.10.3 Record Keeping and Reporting

The Frio Brine Pilot Test Team will keep complete and accurate records as required by 30 TAC 305 and 331.

All reports will be submitted in strict accordance with TCEQ requirements. A Texas registered professional engineer will certify all reports.