Southeast Regional Carbon Sequestration Partnership

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Phase II

Final Report for Gulf Coast Stacked-Storage Project
SECARB Phase II at Cranfield

Prepared for:

Southeast Regional Carbon Sequestration Partnership

led by

Southern States Energy Board

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Abstract

Phase I regional geologic characterization found that in the Gulf Coast, abundant geologic sequestration targets are found in many areas. The idea of stacked storage, developed for the current (Phase II) study, included use of multiple hydrologically isolated injection zones beneath a common surface area to produce large capacity yet minimize the monitoring infrastructure footprint and increase public acceptance. Stacked zones include use of CO_2 for enhanced oil production (EOR), which was the focus of the Phase II study. An EOR project provided an opportunity to monitor injection at a higher rate and over a more prolonged injection period than an earlier test in brine (Frio Brine Pilot). The downdip water leg of the same field was then used for Phase III to assess geologic storage capacity beyond the use of CO_2 for EOR (Hovorka and others, 2010).

At the end of regional study of options, the site selected was a four-way structural closure at a depth of 10,300 ft (3100 m) below the surface at Cranfield, Mississippi. The field produced oil, gas condensate, and methane gas from the lower Tuscaloosa Formation “D-E” sandstones during the period 1944 through 1966. The field was then pressure depleted and wells plugged and abandoned. The field was purchased by Denbury Onshore, LLC, to be flooded with large volumes of CO_2 transported via pipeline from CO_2 produced from a geologic accumulation at Jackson Dome, Mississippi. Project design focused on coordination of the monitoring design with Denbury’s commercial plans for injection, infrastructure development, and permitting in the Phase II area on the north side of Cranfield field. Phase II provided an opportunity to test innovative monitoring approaches that may be needed in the future to document that either EOR or brine storage is performing correctly in terms of permanence of storage (Hovorka and others, 2010).

Injection started July 15, 2008, in 2 wells but increased over the study period to 16 wells over an area of several square miles. Half the wells were updip injectors at the gas-oil contact, and half were downdip injectors injecting CO_2 at the oil–water contact. The monitored injection was commercial (½ million metric tons per year) scale, and was sustained over a multiyear time frame, with the end of the Phase II project defined as September 30, 2010. In the report period, 23,640 MMSCF (1,229,510 metric tons) of CO_2 was stored under Phase II. Injection and monitoring continued in the Phase II area; however, these were logistically connected to ongoing Phase III injection, which was conducted on the east side of Cranfield.

The key Phase II reservoir surveillance technique was a central dedicated observation well collecting high-frequency pressure and temperature data in the injection zone and in an above-zone monitoring interval (AZMI). The AZMI was designed to assess the performance of the lower part of the confining system in the study area, an area with many well penetrations. In addition, we intermittently collected data including pressure, temperature, and saturated thickness, both at injection wells and at future production wells. We propose that such an approach might be part of a commercial monitoring for brine storage (and possibly for EOR) to track both the performance of the reservoir and the effectiveness of the confining system.

Objectives of the reservoir modeling were to integrate a number of diverse subsurface measurements to simulate the likely reservoir response to injection. Steps taken included (1) optimizing the approach to modeling reservoir response to CO_2 injection at the Canfield site via simplified case studies, (2) constructing a quantitative static model of the distribution of rock and fluid properties using reservoir data available at project start, (3) generating a fluid-flow model integrating an upscaled quantitative static model incorporating injection data, and (4) matching pressure measurements at several wells, including a dedicated observation well. The constructed model showed a reasonable match with the monitoring data.

Ecosystem monitoring was conducted in the shallow aquifer system over the field and in soils near plugged and abandoned wells. To extend the monitoring period, repeat monitoring was conducted as part of Phase III even in the Phase II area. During preinjection assessment, a localized methane anomaly was discovered beneath another Cranfield field well pad. Surveillance of the site has been a Phase III activity. It is not clear at this time whether the anomaly is caused by subsurface leakage, and, if so, by what mechanism and from what depth. No other soil-gas anomalies were noted in repeat surveys. Groundwater assessment has been conducted in an array of 200- to 300-ft-deep water make-up wells drilled near every injection well. No change that would indicate leakage has been detected. However, the monitoring period has been short, and extreme local and seasonal variables would most likely mask any signal. More detailed study undertaken in Phase III will be needed to determine what tools are best suited to demonstrate that no leakage is being detected in this setting.

Introduction

This final report summarizes Phase II design, field activities, and results of a monitoring program for a CO_2 injection associated with enhanced oil recovery (EOR) conducted by the SECARB field test 1 at the Cranfield unit near Natchez, Mississippi, during the period from October 2005 through September 2010. The study took advantage of a concept known as *stacked storage* because it assessed the commercial EOR flood in preparation for subsequent injection. The injection accessed large volumes of capacity below the oil reservoir, in this case the downdip "water leg" of the same stratigraphic unit containing the oil. The downdip injection was then conducted as the Phase III study, starting April 1, 2009. The injection zone is the Middle Cretaceous Tuscaloosa "D-E" sandstones and conglomerate.

The initial 2 years of the project focused on negotiating for a site suitable for hosting a stacked-storage test with a supply of CO_2 and an injection formation available during the project timeframe. A number of attractive options were considered, including injection into Gillock field near Houston, Texas, using industrial CO_2 from the Praxair reformer at the BP hydrogen refinery at Texas City, Texas. Also considered was a study of an EOR-CO_2 flood (using nonanthropogenic CO_2) at Lockhart Crossing field near Baton Rouge, Louisiana. Ultimately, a business decision was made by Praxair not to increase CO_2 capture at Texas City to levels that would support pipeline transport. DOE management determined that the fault monitoring proposed at Lockhart Crossing did not fit the profile of "best available" storage formations required by the Phase II program. At the end of the selection process, the Cranfield unit, operated by Denbury Onshore, LLC, near Natchez was selected.

Cranfield field, in an anticline with four-way closure, was discovered in 1943. It had a large methane gas cap, an oil rim, and good water drive. The oil rim was rapidly produced by Chevron (then the California Company). A gas-recycling program was developed early in the field's production history to support pressure. In response to declining oil production, Chevron produced the gas cap in 1965–66, dropping pressure and ending oil production. Most wells were shut in and plugged and abandoned during the same period. At the end of gas production, the field was considered depleted.

During the previous decade, Denbury had purchased a number of oil fields in Mississippi with declining production and successfully returned them to production by flooding them with CO_2 produced from a natural accumulation at Jackson Dome, Mississippi, and shipped via a pipeline network. At project start, Denbury had completed purchase and unitization of Cranfield field, and conversion of a Sonat natural gas pipeline to transport CO_2 was under way to provide large volumes (1 million tones/year) to the field. Denbury constructed a new separation facility at the center of the field to increase pipeline pressure to field pressure and to separate oil, gas, and water. Oil was sent to market, water was reinjected through a saltwater disposal well, and CO_2 was repressurized and commingled with new pipeline CO_2 for return to the EOR flood. At the time of field selection (late fall of 2007) Denbury was nearly ready to start CO_2 injection for EOR in the north part of Cranfield. The SECARB monitoring team moved rapidly to develop the needed contracts with Denbury; select a field service provider (Sandia Technologies); develop partnerships with the University of Mississippi and Mississippi State University; compile and integrate historical rock, log, and production data; and develop a site-specific monitoring program. Because a Phase III proposal focusing on downdip water-leg injection at Cranfield was in preparation at the same time as the Phase II project was in final design, the team took advantage of some efficiencies. For example the groundwater monitoring program for the whole flood area, under the University of Mississippi and Mississippi State, was incorporated into Phase III to assure a long period of monitoring and reduce administrative costs. Also, fieldwide geochemical sampling by USGS was conducted as part of Phase III over the whole field to support both Phase II and Phase III.

Monitoring began in the month prior to the start of injection, July 15, 2008. Injection was continuous and increased, except in the fall of 2008, when Hurricane Gustav passed over the site and power loss stopped injection and created a 6-day pressure fall-off. The pause was ultimately useful in assessment of reservoir response.

Commercial injection at Cranfield will continue beyond the project period, perhaps for decades. Monitoring under Phase II continued as planned through October of 2009. At that time the SECARB team received permission to extend the monitoring period under Phase II through September 30, 2010, providing a period of observation >27 months long, a significant scientific advantage. Monitoring in the dedicated observation well will continue beyond the Phase II time period until the real-time monitoring equipment is removed from the dedicated observation well, providing a longer history match, which will be reported as part of Phase III.

The current final report reviews how the project completed the tasks set in the Statement of Project Objectives (SOPO). Tasks were conducted close to the original plan and budget, with two deviations. The original project scope included the proposal to monitor a small injection of 7,500 to 15,000 metric tons CO_2. Source-sink optimization completed in task 1 located the best match at Denbury's Cranfield field, where commercial quantities of CO_2 were to be injected during the project timeframe. In the 27-month period—July 15, 2008, through September 30, 2010—2,381,597 metric tons was transported to Cranfield, slightly more than half of which, 1,229,510 metric tons, was stored in the Phase II area (the rest was stored in the Phase III area). In addition, the selected reservoir, at a depth of 10,300 ft (3100 m) below the surface, was deeper than initially planned. Increased injection-zone depth concomitantly and significantly increased field costs. However, costs were offset by use of Denbury's production wells as monitoring points.

Subtask 1.1: Project Definition

Under this subtask were grouped two elements that continued through the life of the project: (1) outreach and stakeholder involvement and (2) crosscutting relationships linking this project to sister projects in the Regional Carbon Sequestration Partnerships program. In addition, this subtask included an assessment of CO_2 sources and geologic sinks, including costs and feasibility of completing the study at the selected site.

Outreach and Stakeholder Involvement

For the public to understand CO_2 storage as a viable means of reducing emissions of CO_2 to the atmosphere, the project team developed and maintained a communication network. Outreach was not formally structured as a new venture but used preexisting communication pathways to provide current and technically grounded information to diverse stakeholders. Previous high-profile work, such as the Frio Brine Pilot, provided access to media and to invited talks that then supported distribution of SECARB results. A number of main communication-pathway descriptions follow.

The Bureau of Economic Geology as the State Geological Survey and a part of the Jackson School of Geosciences has a mission that provided a platform for both technical and public communication. The SECARB team used traditional institutional mechanisms to support communication. These included topical oral and poster presentations at local, state, U.S. and international venues; technical paper publications; project overviews in institutional venues, for example, the Bureau's *Annual Report*; and content on the web (www.beg.utexas.edu). The Director of the Bureau, Dr. Scott Tinker, and Associate Director, Dr. Ian Duncan, included reports of project results in numerous talks given to represent the Bureau.

The Gulf Coast Carbon Center (GCCC), an industry/academic partnership (www.gulfcoastcarbon.org), provided an industry-review panel. GCCC members incentivized development of the stacked-storage project and provided review several times a year.

For the stacked-storage project, GCCC staff collaborated with the Environmental Defense Fund (EDF) contact Scott Anderson, Natural Resources Defense Council (NRDC) contact George Peridas, Houston Sierra Club contacts Brandt Mannchen and Julia Jorgensen, World Resources International (WRI) principal contact Sarah Forbes, and Clean Air Task Force (CATF) contact Bruce Hill to keep environmental nongovernmental organizations (NGO) informed about regional progress on geologic storage, to answer questions posed by NGO communities, and to be informed about the evolution of concerns in these communities. This information exchange occurred through e-mail and telephone exchanges, face-to-face meetings, site visits, and GCCC staff participation in NGO-sponsored meetings. EDF and NRDC expressed two major concerns with CCS: (1) that it be part of a portfolio of carbon-reduction options and (2) that implementation proceed rapidly. The Houston Sierra Club expressed more concern about the competition of Federal spending between CCS and the preservation and expansion of forest. GCCC participated in workshops, writing a review for a WRI workshop on "Public Acceptability of Carbon Capture and Storage," and served as reviewers for the WRI best-practices manual.

GCCC engagement of elected officials took many forms, including providing information to Federal officials through meetings arranged by RCSP and by NGO's. Contact with Mississippi, Louisiana, and Texas officials occurred through contacts at public and private meetings and providing follow-up information upon staff request. Much of GCCC's outreach during the first two quarters of the Phase II project overlapped with the separate, but thematically allied, project—developing a response to the Request for Proposal by the FutureGen Alliance. Texas FutureGen was funded by the Texas Legislature with a $2 million grant to the Bureau to develop content for the proposal. GCCC staff members Dr. Ian Duncan, Bill Ambrose, Dr. Susan Hovorka, Mark Holtz, Dr. J.-P. Nicot, and Vanessa Nuñez provided substantive technical input into this process and contributed to preparation of outreach materials. Although the Texas proposal was ultimately unsuccessful in attracting FutureGen to the project site in Texas, potential for high-dollar Federal investment in this innovative power plant and associated geologic storage resulted in a wide range of questions about geologic sequestration from policy makers, the public, and the press. Those related specifically to Texas FutureGen were answered by the Future Gen leads; those of a more general nature were answered by GCCC staff. Collaboration with Texas FutureGen opened many lines of communications with elected officials in the State.

GCCC presented SECARB Phase II results at >100 technical and public information forums, including Regional Carbon Sequestration Partnership (RCSP) review meetings, SECARB stakeholder meetings, the Pittsburg Conference on Carbon Capture and Storage, and other technical meetings. Appendix 1 lists the GCCC presentations made that contained significant SECARB Phase II content.

Project results have been submitted for publication in publicly available literature throughout the project, and more publications are in preparation. The goal of this activity is to make information available to the geotechnical and engineering community and to obtain peer review of the interpretation of the results. Appendix 2 lists completed publications that contain significant Phase II results. Contact reports are inventoried in section 1.5.

Crosscutting Relationships

GCCC staff participated in Environmental Protection Agency (EPA) stakeholder panels, providing presentations and technical input on panels and through verbal and written comment and review of numerous preliminary documents as EPA developed Class VI rules and guidance documents.

During Phase II the GCCC staff provided data to improve mapping and quantification of sinks for CO_2 and regulatory practices across regional, state and local boundaries. Updated data were supplied to NATCARB. The Southern States Energy Board (SSEB) obtained additional funding for a study of sequestration options in the Carolinas.

With regard to collaboration on capacity assessment in Mexico, BEG Associate Director Eric Potter presented SECARB December 2–3, 2008, in Houston, Texas, on “Experiences in Data Gathering and Sharing Across Jurisdictions” to the North American Energy Working Group Experts Group on Energy S&T. This group is composed of officials from Federal energy departments from Canada (Natural Resources Canada), Mexico (Secretaria de Energia), and the United States (Department of Energy), as part of an ongoing exchange of information and exploration opportunities for joint collaboration in carbon dioxide (CO_2) capture and storage (CCS) to mitigate greenhouse-gas emissions. As a follow-up, Ramon Treviño represented SECARB at the 3rd North America Carbon Atlas Partnership (NACAP) meeting March 9–10, 2010, in Cuernavaca, Mexico

During Phase II GCCC completed a preliminary evaluation of suitable saline reservoir sinks in Florida. Two sinks assessed were the Tuscaloosa Formation extending from southwestern Alabama to the Florida Panhandle (Smyth and others, 2007) and the Cedar Key/Lawson Dolomite (Hovorka and others, 2003) in the southern two-thirds of the Florida peninsula (figure 1.1-1).

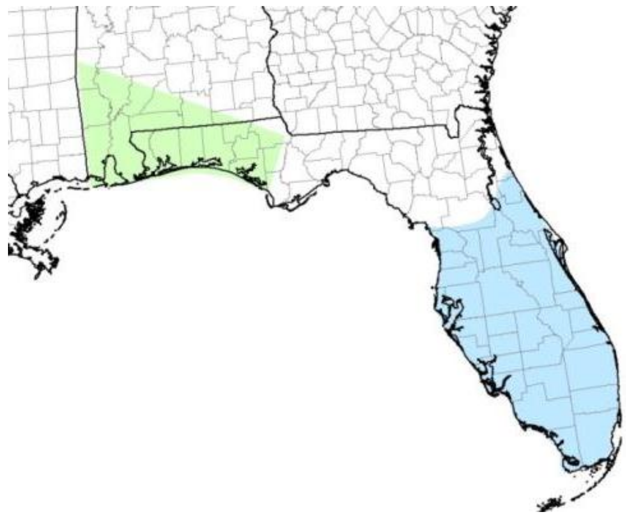


Figure 1.1-1. Two potential geologic sinks identified to date in Florida. Green shading identifies area underlain by Tuscaloosa sink. Blue shading identifies area underlain by the Cedar Keys/Lawson sink.

Minimum suitability criteria for geologic sinks include (1) continuity and integrity of an overlying seal; (2) depth sufficient to maintain CO_2 at high density (that corresponds to depths >2,400 ft [>800 m]) below the surface); (3) depth below underground sources of drinking water (USDW), where total dissolved solids exceed 10,000 parts per million (ppm); and (4) storage capacity sufficient to prevent displacement of saline water into overlying freshwater-bearing units. The Cedar Keys/Lawson sink is composed of carbonate rocks (limestone, dolomite, mudstone, and evaporites), whereas the Tuscaloosa sink is a clastic reservoir.

The Late Cretaceous-age Tuscaloosa Formation in southwestern Alabama and the Florida Panhandle is a potential geologic sink with the capacity to store ~10 gigatons (Gt) of CO_2 in the subsurface. Approximately 50% of this geologic sink with an assumed estimated ~5 Gt of capacity underlies the Florida Panhandle. Sandstones in the lower part of the Tuscaloosa, including the informally named Massive and Pilot intervals, are the most favorable host strata. The primary sources of information on the geometry, composition, and thickness of the Lower Tuscaloosa strata are geophysical logs of wells drilled for oil and gas exploration and production, as well as produced water and industrial waste disposal (Mancini and others, 1987; Renkin and others, 1989; Miller, 1997) and unpublished information provided by the Florida Geological Survey (personal comm., 2006). Depth to the top of the Tuscaloosa sink in the Florida Panhandle ranges from 3,600 ft (1100 m) in the northeast to >6,900 ft (2100 m) to the southwest (figure 1.1-2).

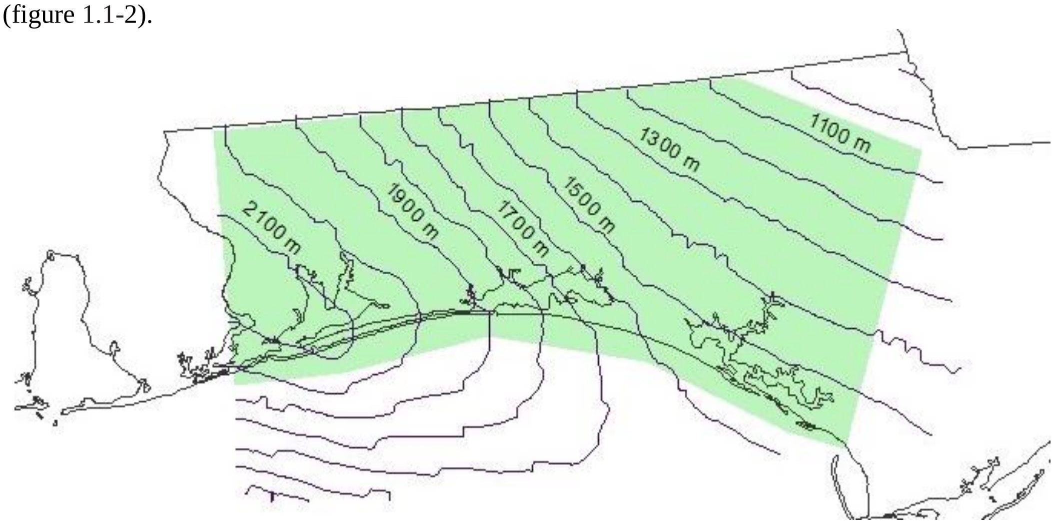


Figure 1.1-2. Extent (green shading) and depth to top (m) of assessed Tuscaloosa sink in Florida.

Depth to the top of the Cedar Keys/Lawson sink ranges from ~3,000 ft (900 m) in central Florida to >5000 ft

(1500 m) in southern Florida (figure1.1-3). The Cedar Keys/Lawson sink is overlain by a confining unit composed of dolomite and evaporite layers that range to as much as 2,300 ft (700 m) in thickness.

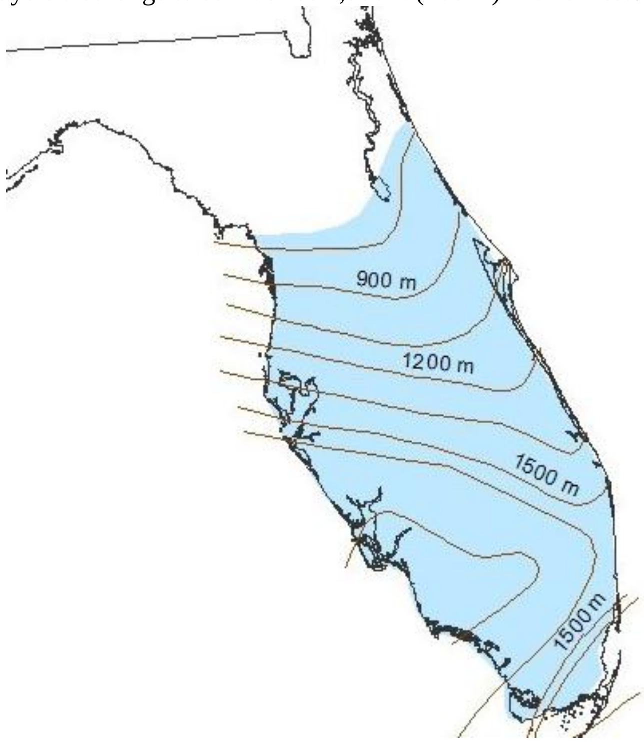


Figure 1.1-3. Depth (m) to the top of the Cedar Keys/Lawson sink in Florida.

Within a younger and shallower part of this carbonate sequence (Floridan aquifer), a brackish-water-bearing interval has been used for disposal of municipal and industrial wastewater since the late 1980's (Miller, 1997). Upward leakage from the shallower interval has been documented (e.g., Walsh, 2006, in the Miami-Dade County area) and may cause negative sentiment toward CO_2 storage in carbonate rocks in Florida. However, the Cedar Keys/Lawson sink is not only much deeper (e.g., 5000 ft versus 3000 ft in Miami-Dade County), but it is also overlain by a thicker seal (e.g., up to 2300 ft versus 500 ft in Miami-Dade County). The seal overlying the potential Cedar Keys/Lawson sink is composed of bedded anhydrite, which is demonstrated to be good geologic seal material by its retention of hydrocarbons in south Florida. Additional characterization will be required to prove the quality of this injection zone, but available data are favorable.

Additional capacity assessment in South Georgia and the offshore Gulf of Mexico was conducted under Phase III.

Costs and Feasibility of Source-Sink Options

Because a decision matching the best sink (injection site) and source of CO_2 for the stacked storage test was not made at the time the Phase II project was proposed, it became one of the project tasks. The decision process conducted prior to signing agreements with the selected operator and the CO_2 supplier is herein reviewed. In this task leading to site selection and finalizing the project definition, we evaluated the options for matching a source of CO_2 with a sink in which storage could be monitored. The major factors limiting sites for the Phase II project were cost and availability of CO_2, as well as associated injection and transportation costs. The GCCC team evaluated potential field sites for the Phase II test and worked with potential CO_2 suppliers to identify delivery processes for significant volumes of CO_2 that minimized cost. Subsurface reservoir evaluation was also used to determine that prospective sites volumes were suitable and surface-access logistical issues could be solved.

The key element guiding the decision was a sufficient supply of CO_2 that could be obtained and shipped within budget and project timeframe. We explored several options, including capture from currently underutilized

CO_2 sources at hydrogen and ammonia plants, natural CO_2 from Jackson Dome, and the possibility that other new sources may become available within the project timeframe. Shipping options considered include truck, barge, low-volume pipeline, or commercial pipeline. Source and sinks were evaluated concurrently, with increased focus where a favorable finding was made; however, sinks are reviewed first herein, followed by sources.

Sink options

Phase II SECARB Field project 1: Stacked Storage was designed to be an EOR flood associated with a large volume of deeper "stacked" saline aquifer(s). The starting point for the site search was an inventory of 767 fields in the SECARB area conducted for Phase I. Prospective fields were those determined to have conditions in which CO_2 would be miscible. Initial contact with operators during preparation of the Phase II proposal showed that about 1 out of every 10 operators contacted was interested in consideration of CO_2 –EOR in the near term, so probably ~70 fields could be identified to host the Phase II test if this search had been conducted to the maximum.

The major components to be considered were (1) suitability of injection site to accomplish the project scope of work, (2) willingness of subsurface and surface owners to host the test, (3) cost of preparations to ready the site for the project scope of work (injection well, observation well, wireline logs, core, core-plug analysis, 2-D or 3- D seismic), (4) availability of CO_2 in large amounts—>250 tons/day (4.8 MMSCFD) for 30 days during the project period (2006–2008), (5) cost of CO_2 delivery to the field site (product cost, compression, transportation, (6) cost of injection, and (7) cost of oversight and holder of liability.

Initial simulations showed that because CO_2 is dissolved in oil, much larger volumes of CO_2 are needed in an EOR context than in a saline aquifer context. Scoping scenarios with sandstones of 10 ft thickness and porosity of 30% indicated that a 30-day injection period at 250 metric tons/day (7,500 tones) would be a minimum for a viable experiment and that because of uncertainties of remaining oil saturation, larger volumes would lower experiment risk. Our assessment then moved to consideration of available sources of CO_2 at adequate volumes.

Source options

The *Carbon Sequestration Atlas of the United States and Canada* (DOE–NETL, 2010) shows 800 large stationary sources of CO_2 in the region. On the basis of numerous inquiries during project planning, a number of power plants in the region were considering capture from dilute stack gas or installation of capture-ready combustion processes; however, none of those identified planned for completion in the Phase II timeframe. An inventory of potential intermediate-volume, high-concentration, potential sources, including refineries, chemical plants, and fertilizer plants, was prepared to guide inquires for CO_2 sources. During Phase I and Phase II, ~30 of these potential large-volume sources were contacted by team members to inquire about potential for capture. Many of these source industries were willing to learn more about the potential for geologic sequestration. In many cases, the discussion did not mature beyond initial contact. Table 1 shows an inventory of the more developed CO_2-source discussions and the outcome of the discussion. The most interested source was the Praxair hydrogen plant at Texas City, Texas, and was tentatively proposed as a source for the Phase II study. Smith Energy explored the possibility of purchase of an existing low-pressure gas pipeline to ship large volumes of CO_2 from the Praxair plant to Gillock field. However, changing operations at the Praxair hydrogen plant in response to the hydrogen market (accident at BP refinery) and additional cost analysis by Praxair decreased its interest in supplying CO_2 at this time, and this option was dropped.

The number of large-volume sources of CO_2 that is really available for development of a Phase II project timeframe proved to be limited. Only two options emerged as viable: (1) CO_2 from a natural source at Jackson Dome shipped via Denbury pipeline and (2) cold-compressed CO_2 purchased on the commodity market and shipped via truck. Pipeline CO_2 was determined to be more available, more reliable, and less expensive than all other prospective sources. A downside to use of natural CO_2 in that that this project does not show the integration of the whole system, including capture, shipping, and sequestration, ; other projects in the Regional Carbon Sequestration Partnerships will advance this aspect.

Table 1. CO_2 source options considered during Phase II.

Initial contact	Source	Location	Status of CO_2 availability	Shipping method
2000	BP refinery/Praxair H_2 plant	Texas City	Praxair proposed providing discounted CO_2 to the project in the Texas City area, but research into the plant processes, combined with H_2 demand related to the BP refinery damage in 2005, determined that Praxair could not make large volumes of CO_2 available to the project within the project timeline. Costs assessed in the $75/metric ton range for retrofit.	Dedicated low-pressure retrofit pipeline proposed; would require purchase by investors and retrofit.
2003	Shell–Motiva	St. Charles, LA	Small volumes; interest in commodity sales.	NA
2004	Commodity CO_2	Baytown, TX; Donaldsonville, OK, other sources	Purchase as commodity by truckload, although availability is spotty. Quotes of price of cold compressed liquid CO_2 delivered to site range from $82 to $110/ metric ton.	Trucked
2004	Dow	Freeport, TX	Dow makes an array of gas products, interested in future; however, no near term plan to sell CO_2.	NA
2004	Valero	Lake Charles, Texas City, Corpus Christi, Port Arthur, TX	Not available in project period.	NA
2004	Denbury	Jackson Dome	Large volumes available—Denbury has 11 fields under flood or planned.	High-pressure pipeline
2006	Chevron	Pascagoula, MS	CO_2 is not all captured. Chevron CO_2 group is interested in CO_2 supply; however, refinery has no near-term plans to capture and compress.	NA

Selected Source-Sink pair

Source-sink pairs were subjected to detailed analysis of 10 possibilities of suitable sites with operator interest, and cost and benefit options were considered. The option of using the Denbury's Cranfield field as the site for the study was strongly favored for the Phase II study considering the following factors:

- For the Phase II work, CO_2 cost is zero at Denbury's sites, as compared with cost of > $1 million for CO_2 from other sources. We used an estimated product cost from Praxair of $75/ton, discounted by 50% and shipped by a retrofit of an existing pipeline. The availability of this CO_2 is uncertain; however, it provides a base cost for comparison. An alternate basis for comparison is CO_2 shipped by truck as cold compressed liquid, which would yield higher total costs. Denbury injected CO_2 as part of its commercial EOR operation; SECARB test added a monitoring component to this new flood.
- For the Phase II work, Denbury drilled new injection wells at its cost. In other sites, SECARB would have had to provide substantive funding for retrofit of an existing well as an injector, in addition to monitoring-well costs. Denbury also provided new baseline logs and a 3-D seismic survey, which are high value to the project and not available at other sites.
- Denbury provided oversight and assumed overall liability for field activities— a large benefit to the SECARB project because we would otherwise have had to subcontract these services separately at a cost of ~15% of the cost of the services subcontracted. However, as part of giving us access, Denbury requires oversight to assure that the work was done to its standards and that no unacceptable liability remains, and it requires liability wavers for personnel working on site.

Cranfield Unit is located within a 3-mile radius of the unincorporated town of Cranfield, Mississippi, about 10 miles east of the town of Natchez (figure 1.1-4). It is located mostly in Adams County, but the east edge extends into Franklin County.

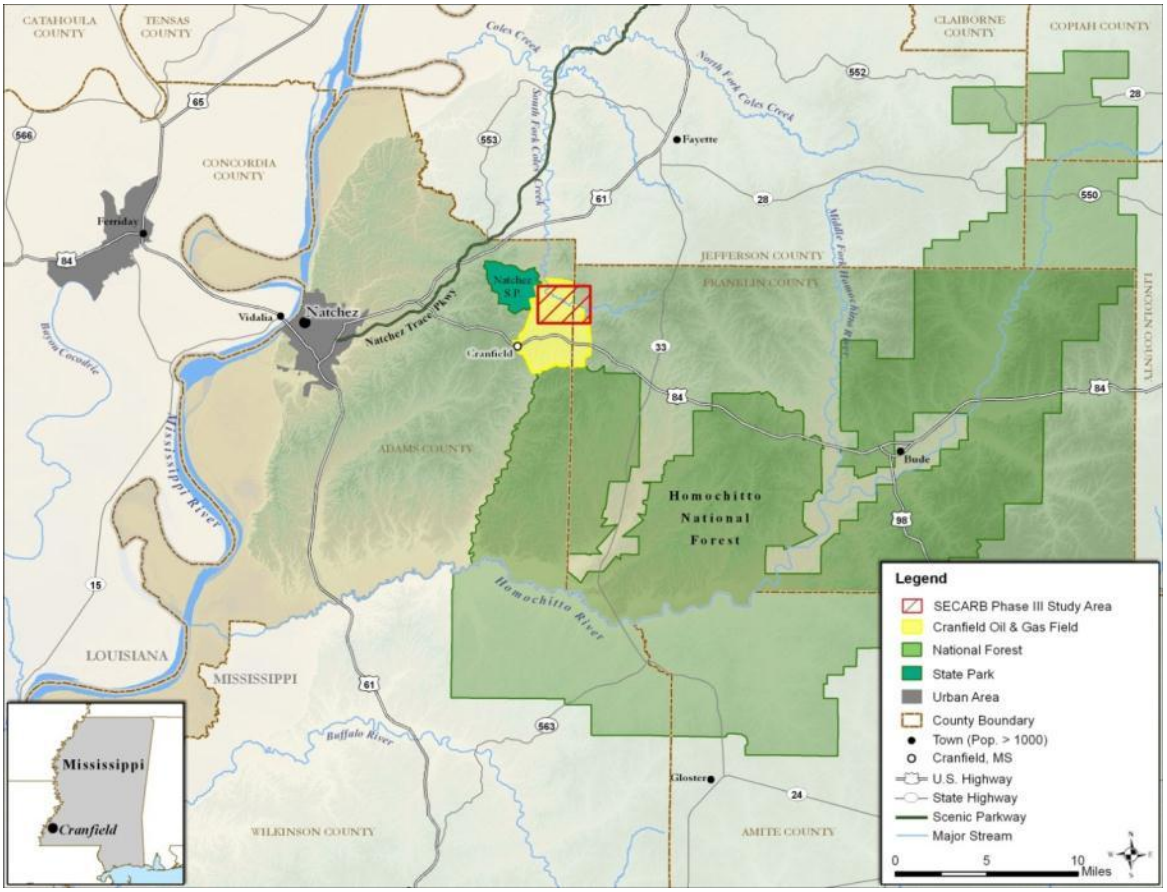


Figure 1.1-4. Location of Cranfield field (map prepared for Phase III EA).

Stacked storage implies assessment of a site that is suitable for economically based CO_2 enhanced oil recovery (CO_2 EOR), followed by use of large volumes of brine- filled storage below and/or laterally equivalent to the reservoir in which oil recovery was conducted. The value of "stacked storage" is that (1) the infrastructure and in-depth site characterization developed for the EOR phase can be used for the storage phase, (2) ownership and mineral rights also will have been resolved during the EOR phase, (3) the seal quality is known because oil is trapped, and (4) public acceptance is likely to be favorable. The Phase II study was focused in the oil ring, where Denbury started CO_2 injection during the Phase II project timeframe. A large-volume saline aquifer in the downdip Tuscaloosa Formation was assessed as part of Phase III.

Subtask 1.2: Characterization, Design, and Permitting

This subtask consisted of site characterization, technical design, and permitting. A detailed design package for monitoring activities was prepared and reviewed. A separate environmental, safety, and health (ES&H) plan was submitted to guide field activities.

Site Characterization

Site characterization plays an essential role in assuring that the site and the operational plans are suitable to for permanent storage of CO_2. This section merges data collected at the start of the study with data collected during the Phase II study; some Phase III data have also been included when they provide essential clarification. Essentially the same data used for this study have been collected by Denbury to model and optimize the EOR project. Characteristics of the injection zone are used to predict through numerical simulation how CO_2 will flow into the reservoir, especially the lateral extent of free-phase CO_2 migration during injection and postinjection stabilization, and determine the rate of injection that can be sustained without exceeding the mechanical strength of the reservoir and seal. As planned in the scope of work, modeling was conducted through the course of the study; however, in this final report an overview of model preparation through results is not presented until the last section.

At the selected site, diverse data were integrated to create a quantitative static geologic model of the reservoir. Historic data, including about 56 wireline logs, core analysis, and integrated production data were used. For Phase II characterization we did not attempt a well-by-well history match of historic production data, nor could we create a fully deterministic permeability model of the field. Historic data were substantively augmented by a 3-D seismic survey collected by Denbury in 2007 and were provided to the project as an in-kind match, a cored well (CFU28-12) with associated porosity and permeability data, and modern log suites from newly drilled injectors. The reservoir simulation based on characterization was then used in monitoring design and in interpretation of the history match between observed and modeled reservoir response. In addition, data were collected from literature, along with a database describing the confining system that isolates the injection zone from overlying resources, including underground sources of drinking water (USDW). Surface characterization was used to assess the feasibility of detection, should containment fail and CO_2 or brine migrate to the surface.

In overview: the injection interval selected for the test was the lower Tuscaloosa Cranfield Unit (figure 1.2-1). The reservoir into which injection occurred is the lower Tuscaloosa Formation, of Late Cretaceous (Cenomanian) age (Mancini and others, 1999, Mancini and Puckett, 2005). The structure of the reservoir interval is anticlinal four-way closure, with the crest of the anticline at a reservoir depth of 9,550 ft (2900 m) below sea level. The regional confining zone overlying the injection interval is 200 ft (60 m) of middle Tuscaloosa “marine” mudstone and associated low-permeability facies. Overburden includes diverse units and isolates the injection zone from shallow gas resources and underground sources of drinking water (USDW), which occur at depths of 100 to 2,000 ft (30–600 m) below land surface. The field was discovered in 1943 and produced though 1966; at this time the field was plugged and abandoned.

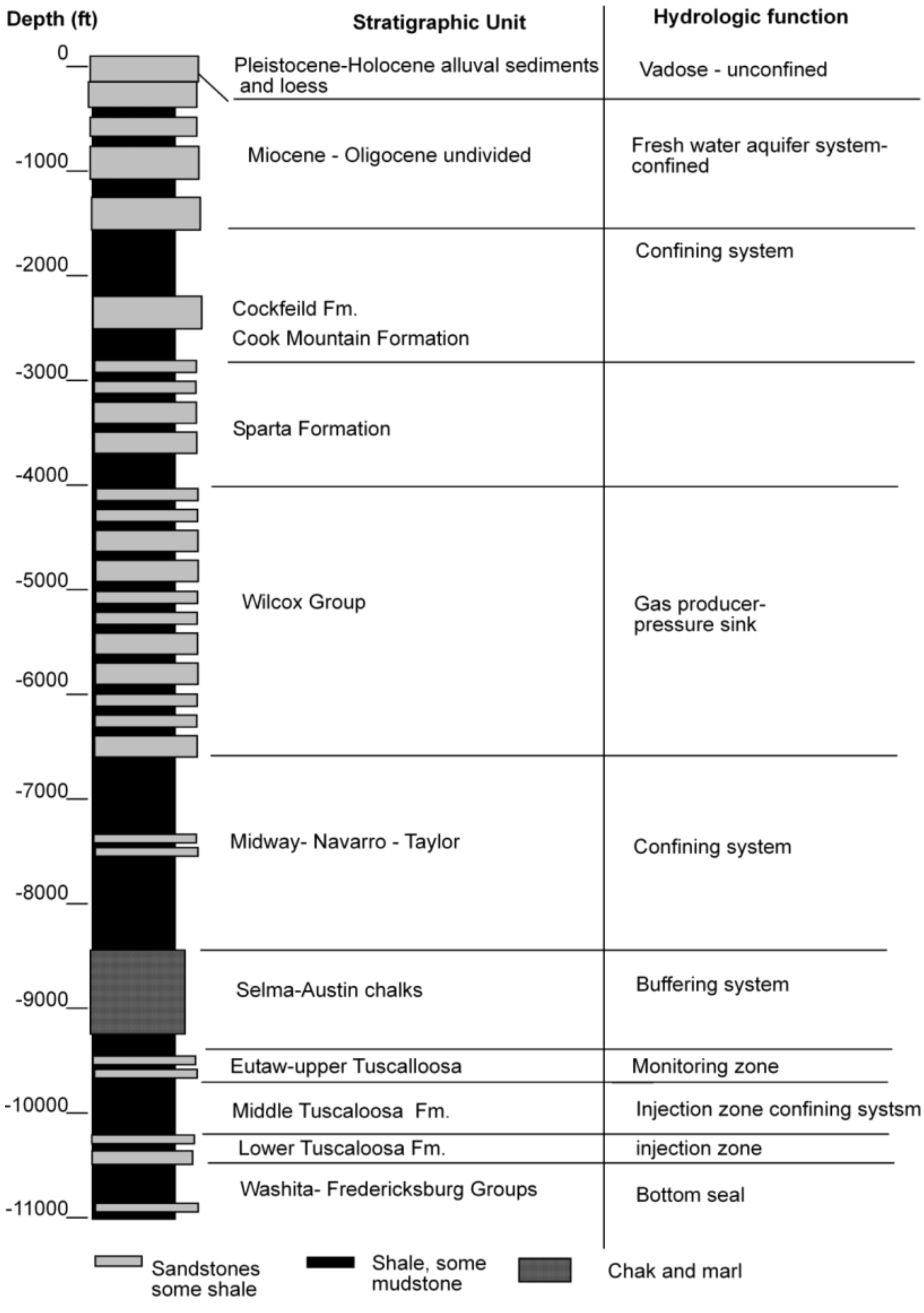


Figure 1.2-1. Stratigraphic section for Cranfield area developed from literature and adjusted to site-specific conditions.

Reservoir Characterization

Production history

Detailed records of historical field management have been published, providing an unusually good quantitative record of operations (Williams, 1945; Hines, 1950a, b, c; Mississippi Oil and Gas Board, 1966) on which to base the assessment of initial conditions for the CO_2 flood. The gas cap of the lower Tuscaloosa reservoir was discovered in 1943. Shortly after discovery, an oil rim was discovered below the gas cap. The field was unitized and a pressure maintenance program established in 1947 (Hines, 1950 a). Gas produced in the gas cap was stripped of condensate, and the less-valuable methane was reinjected through gas-cap wells to support pressure in the oil rim. Some methane was produced from the underlying Paluxy and Washita-Fredericksburg units and reinjected into the Tuscaloosa Formation (Mississippi Oil and Gas Board, 1966); therefore, some cross-formational contamination of organics occurred. Water injection was undertaken briefly on the west side of the field in 1958–59 (Mississippi Oil and Gas Board, 1966) but was considered unsuccessful and abandoned; the fluid perturbation by extensive waterfloods by diverse fluids common in EOR was avoided, increasing the value of geochemical data from this site. Shallow Sparta and Cockfield sandstones were used for saltwater disposal (Mississippi Oil and Gas Board, 1966). The field was produced by recycled gas drive until gas cut and water invasion reduced production to subeconomic. Starting in 1958, gas was produced to economic limit by deep pressure drop following gas-cap blow down. At the end of production in 1965, 93 producers and 5 dry holes had been drilled in the field. A total of 37,590,000 stock tank barrels of blended oil and condensate had been produced, along with 672,470,000 MSCF (19 km^3) of gas (Mississippi Oil and Gas Board, 1966). Most wells were plugged and abandoned (P&A) in 1965, and remaining wells were idle. However, production of shallower Wilcox reservoirs continued, and it continues today in a few wells.

Postabandonment, aquifer drive returned the reservoir to hydrostatic pressure prior to resumption of production in late 2008 (Denbury Onshore Resources LLC, 2011, written communication). This situation was optimal for the monitoring program because unlike most EOR fields that begin CO_2 injection following a prolonged period of complex pressure depletion by production and pressure maintenance by injection, Cranfield CO_2 injection was preceded by >40 years of re-equilibration. Mineral rights were purchased by Denbury in preparation for a new CO_2-EOR flood under gas drive (no water injection) with gas lift (no pumping). New injectors were drilled, as well as a few offsets for damaged producers; these provided opportunities to collect modern log suites, sidewall cores, and several other core samples. A preinjection 3-D seismic survey was collected. All these factors created a favorable data-dense experimental setting for measuring reservoir response to a large-volume CO_2 injection.

Fluid saturation prior to injection was constrained by only sparse data. Sidewall cores confirmed local oil saturation, swabbed production data showed that oil was not mobile, and examination of oil fluorescence of the initial cored CFU29-12 well showed no evidence of massive oil migration into the gas cap. Additional information about preinjection-fluid composition was calculated on the basis of modeling.

Since July 2008, the reservoir has been under CO_2 flood by Denbury Onshore LLC to sweep bypassed and residual oil. All injections occur in the lower Tuscaloosa Formation, and average CO_2 injection rate for each injector has been approximately ~5 MMSCFPD, with some variations. Phase II monitoring has focused on reservoir response to this CO_2 flood. Field development started in the northwest quadrant of the field and moved systematically clockwise around the oil ring. The SECARB Phase II program was developed in the northwest quadrant and was focused on the center of the flood in the oil ring. The later Phase III program was coordinated with development in the northeast quadrant of the field, focusing on the downdip water leg. Figure 1.2-2 shows the geometry of the field development at the time of writing of this report.

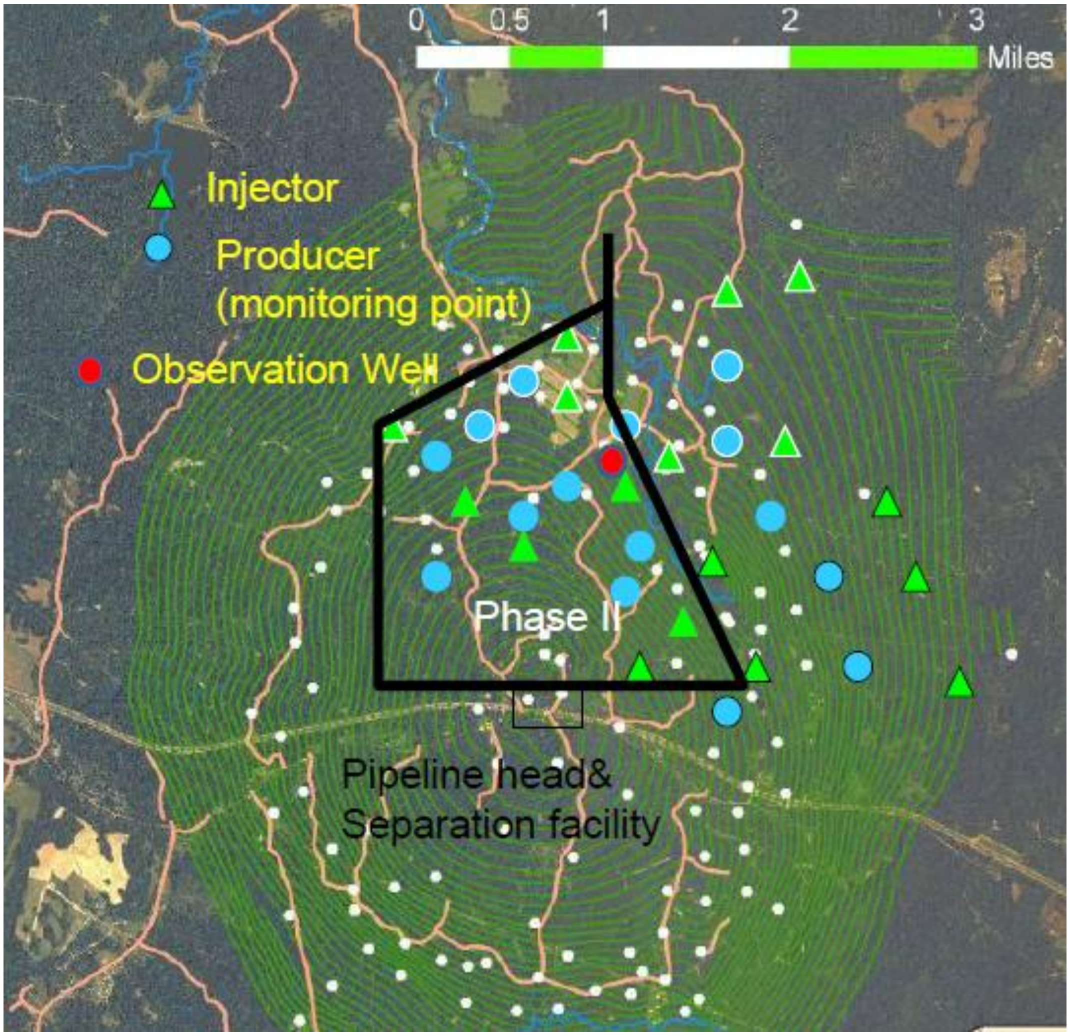


Figure 1.2-2. Geometry of Cranfield field development. Original production wells shown as white dots. New injection wells shown as triangles. Current producers shown as circles; most of these are workovers of historic producers.

Sedimentology

Regional sedimentology of the Tuscaloosa Formation is well known (example, Spooner, 1964; Stancliffe and Adams, 1986; Klieman et al., 1988; Mancini and others, 1999; Mancini and Puckett, 2005); however, prior to the current study, detailed analysis of the stratigraphy of the unit at Cranfield had not been assessed from a sedimentologic standpoint. Data used from the historic production period are principally wireline logs, many of which do not fully penetrate the lower Tuscaloosa Formation. A search conducted for core and sidewall core plugs reported to have been collected during field development (Mississippi Oil and Gas Board, 1966) was unsuccessful in obtaining useful information from Cranfield. New data, including a new 3-D seismic survey, a whole core (CFU28-12) through the entire reservoir zone of the Tuscaloosa Formation, a modern log suite, standard core-plume analysis, and brine geochemistry, were contributed by Denbury as part of cost share and provided high-value additional data to support reservoir characterization. Additional analysis and data from three additional cores assessed during Phase III further support the description provided here. A new regional sedimentological assessment currently under way (Kurtus Woolf, Jackson School of Geosciences, personal communication, 2011) also augments the updated field-scale sedimentology reviewed here.

The Tuscaloosa Formation overlies a regional unconformity on top of shales and sandstones of the Dantzler Formation of the Washita-Fredericksburg Group. The oil and gas productive reservoir and injection zone at

Cranfield is locally referred to as the “D” and “E” units of the lower Tuscaloosa Formation. The porous “D-E” unit, 45 to 80 ft (14–24 m) thick, has a relatively blocky natural gamma-ray log signature (figure 1.2-3). One to three thin, higher, natural gamma-ray breaks occur within the sandstone, the correlation of these units between wells not easily determined (figure1.2-4). In this study, we lump the “D-E” as one flow unit that has not been systematically subdivided. In core, we observe that this interval is composed of crossbedded conglomerates, sandstones, and muddy sandstones, with depositional-unit thickness typically 3 to 10 ft (figure1.2-5). Thin, ½-ft-thick, dark mudstones are identified as a cause of high gamma-ray zones isolating sandbodies. Several sequences of upward-decreasing grain size from conglomerate to sandstone to fine sandstones are noted; however, it is not clear the extent to which these are fieldwide stratigraphic units or recurrent incised-channel patterns. The relatively small scale of the observed channel-size indicators (bed thickness, lateral changes over short horizontal distances) favors the former interpretation. The top of the “D-E” unit is marked by gradual increase in natural gamma-ray, which in core is observed to be red, muddy sandstone and mudstones with disturbed fabrics interpreted as soil textures (figure 1.2-6).

Although resolution of the 3-D survey is not adequate to resolve uniquely channeled architecture and thickness variations within the “D-E” interval, textures suggest arcuate forms, as well as zones of thin sandstones, some of which may be mud-filled channel-abandonment features (figure 1.2-7). Interpretation of seismic characteristics of the “D-E” sandstone in cross section shows high-frequency lateral heterogeneity that can be interpreted to support the incised-channel model of origin of the “D-E” sandbodies (figure1.2-8).

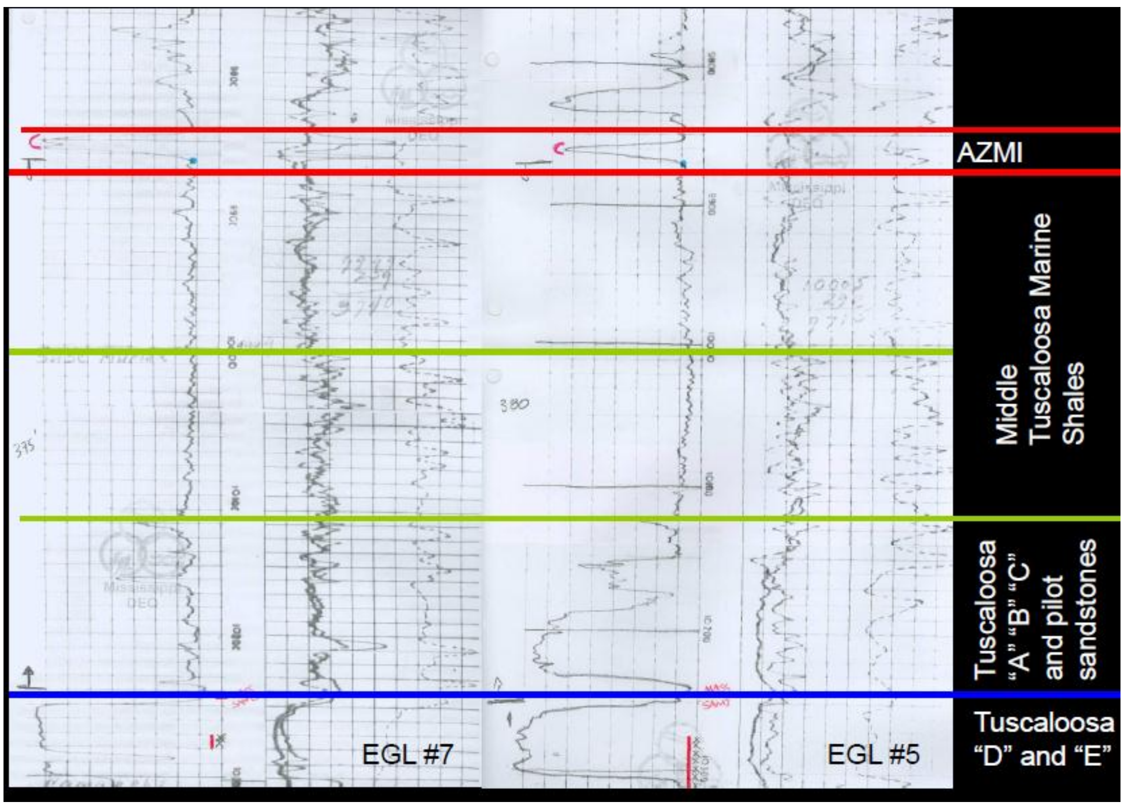


Figure 1.2-3. Type logs of the Tuscaloosa Formation

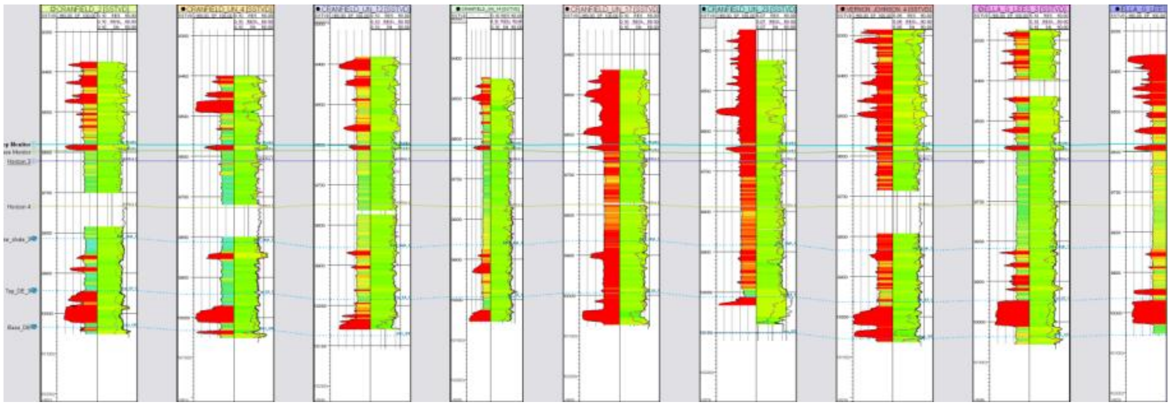


Figure 1.2-4. East-west stratigraphic cross section of Cranfield field.

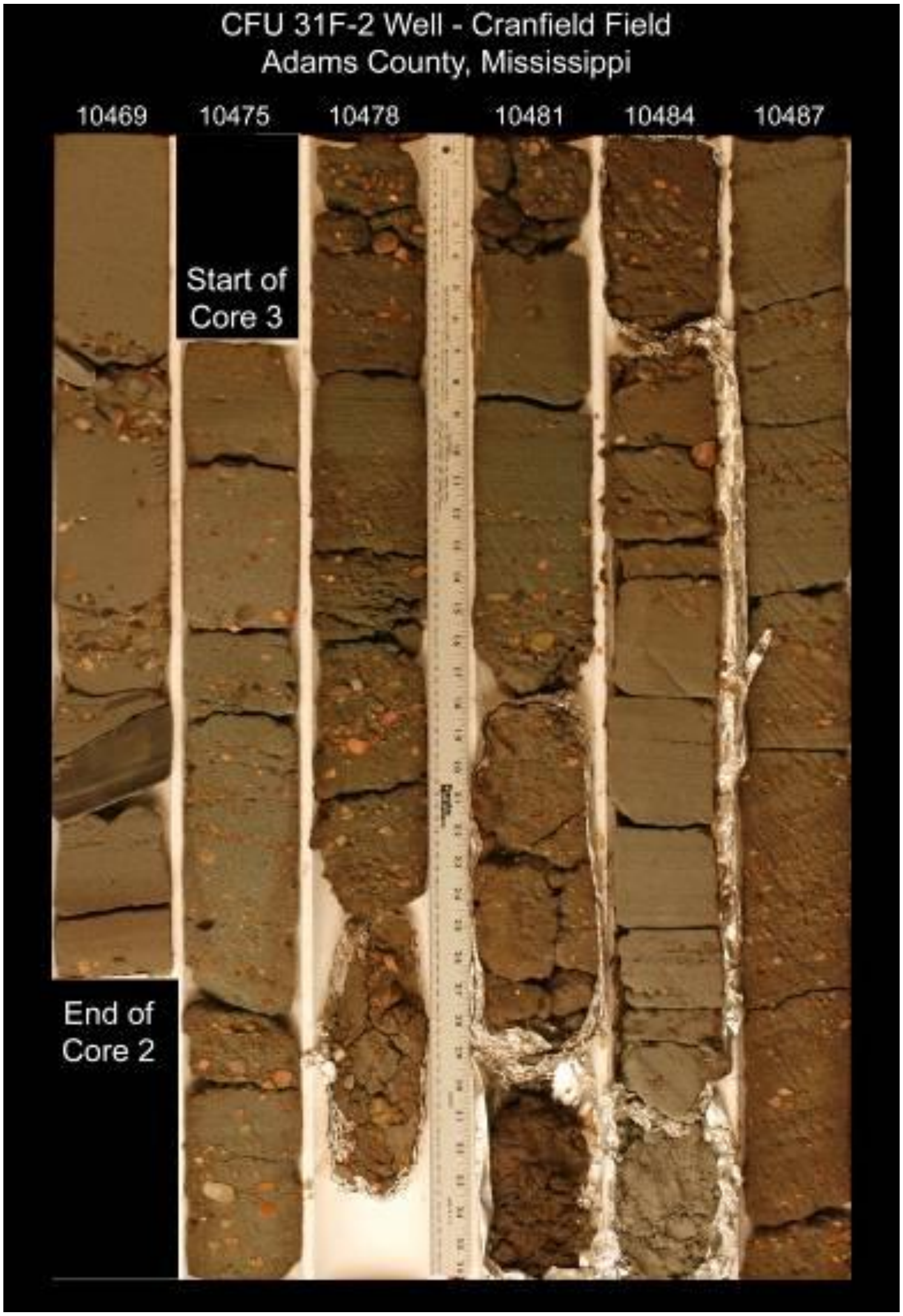


Figure 1.2-5. Typical reservoir-interval core showing conglomerate and sandstone interbeds.

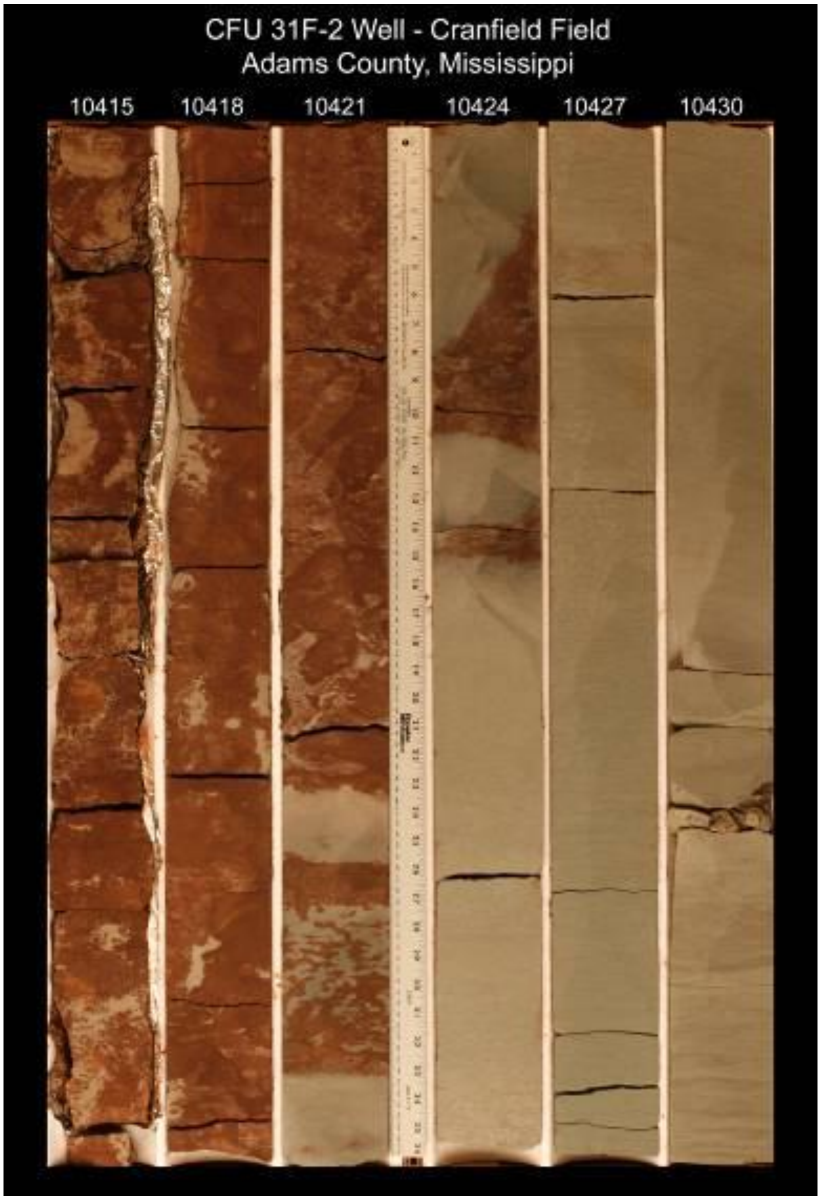


Figure 1.2-6. Overbank mudstone deposits in slabbed core from the top of the reservoir interval.

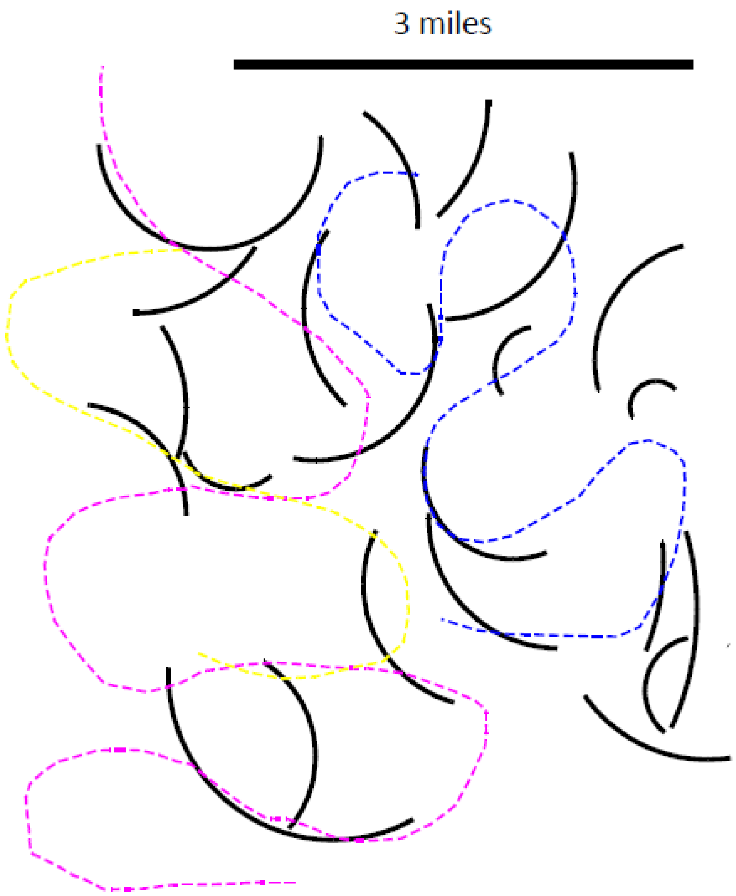


Figure 1.2-7. Interpreted channel morphologies from stratal slicing of the baseline 3-D survey (approximately equivalent to the Tuscaloosa "D-E" interval).

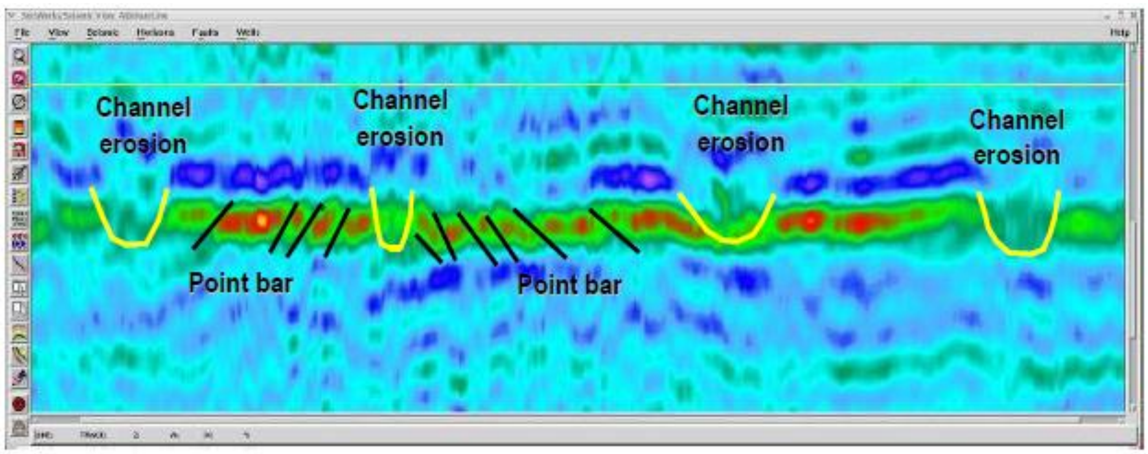


Figure 1.2-8. Interpreted channel morphologies in cross section of the baseline 3-D survey.

Analysis of percussion sidewall core, including both historical data and modern samples, revealed sustained damage and was found to be poorly matched to whole-core analysis, in which average porosities for flow units were measured at 25% and permeability averaging 50 millidarcys (mD), ranging to 1 darcy (D). Attempts to develop an accurate porosity estimate from modern logs were moderately successful. However, no method was developed to extract accurate porosity from historic natural gamma-ray-resistivity logs, even during the extended work performed as part of Phase III. Transforms from porosity to permeability were only moderately correlated, so further error was introduced with an attempt to derive permeability for models from logs.

Complex diagenesis is a likely cause of complex relationships between porosity measured on core samples and porosity measured by modern logs, as well as poor differentiation on historic logs. Thin-section and SEM analysis of core samples (Kordi and others, 2010) shows diagenetic overprints on the highly heterogeneous depositional fabrics. Chlorite is the major cement in in the “D-E” sandstones, giving the core a greenish appearance (Kordi and others, 2010). Chlorite appears to have both preserved porosity, where it forms thick grain rims and suppressed compaction and quartz cements, and occluded permeability by narrowing grain throats. A general trend of increase in quartz cement toward the upper part of the “D-E” sandstone is linked to decreased chlorite-rim thickness in finer grained sandstones. Ankerite-cemented nodules in sandstones and conglomerates are noted, as well as roles for grain dissolution, grain compaction, grain fracturing, and other minor cements. Detailed results from the petrographic study were reported in Phase III.

Reservoir-fluid characterization

Reservoir temperature was 257°F (125°C), and reservoir pressure at a depth of 9,976 ft (3040 m) was 4,701 psi (32 MPa) in 1947 prior to development (Mississippi Oil and Gas Board, 1966). API gravity of the oil was measured early in production at 39°; at the start of CO_2 flood a similar value was obtained. Original fluids were a large gas cap (column height >120 ft) underlain by up to 90 ft of oil saturation. Original gas composition was high in higher hydrocarbons, with recovery condensate approaching 20% at the end of production (Hines, 1950a). Original gas was 2.8% CO_2 (Hines, 1950a). Reservoir fluids were further characterized during Phase III (Thordsen and others, 2010).

Structural characterization

The injection zone selected in the lower Tuscaloosa Formation is located at a depth 9,976 ft (3040 m) subsea in a near-circular four-way anticline with a diameter of 4 miles (6.4 km). Gravity data show that structure is created by a deep-seated salt dome (Mississippi Oil and Gas Board, 1966), and structural complexity seen on 3-D seismic increases with depth. At the Tuscaloosa interval, dip of the formation ranges from 1 to 3°, with a structural closure of ~250 ft (76 m). The structural spill point interpreted from 3-D seismic occurs on the northwest flank of the anticline. The major complexity in this gentle structure in the Tuscaloosa is a wide, northwest-oriented, fault-bounded graben with maximum fault throw determined from historic logs of ~80 ft **(**figure 1.2-9).The southwest fault bounding the graben intersects the injection interval downdip of the oil–water contact and is distant from the Phase II study area; it was not assessed. The northeast fault bounding the graben intersects the injection reservoir to form the east margin of the Phase II study area. Following recommendations provided by a review by the International Energy Agency Greenhouse Gas Research & Development program of monitoring plans in 2008, a study of the response of this fault to injection was added to both Phase II and Phase III plans.

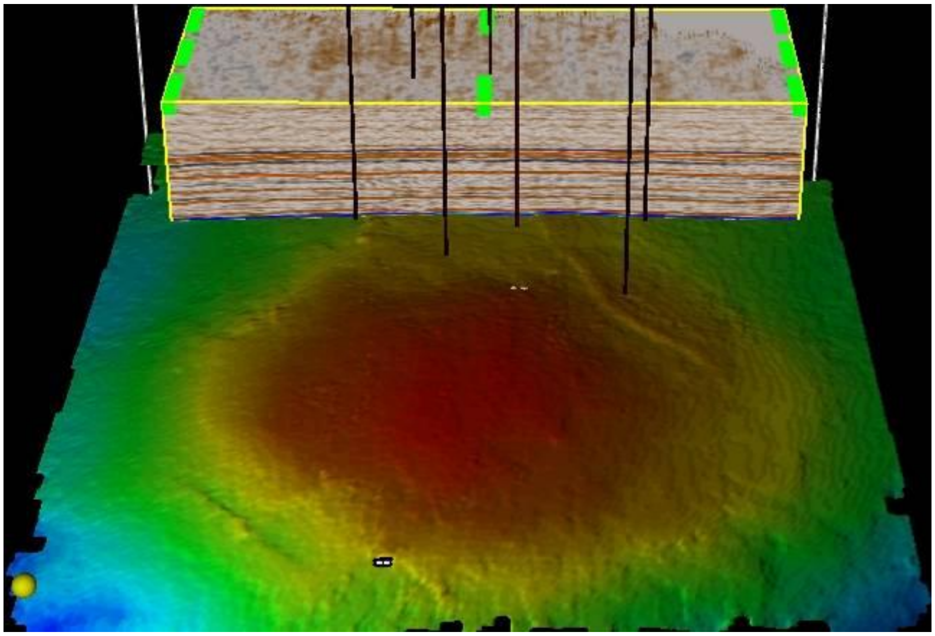


Figure 1.2-9. Structure at the top of the lower Tuscaloosa Formation “D-E” sandstone.

Mapping of the extent of the fault shows that it is elliptical, dying out by gradual decrease in throw north, south, and upward to becoming seismically nondetectable. The diminution occurs near the oil–water contact in the north part of fault, but south of the oil–water contact to the south, so that this contact was mapped as offset. Offset along the fault disappears in the 3-D seismic survey upward at the level of the Midway Formation, a thick mudrock interval that is a typical interval in the Gulf Coast for attenuation of fault throw. The oil–water contact was traditionally mapped as flat at a subsea elevation of 10,066 ft (3070 m) across the fault (Hines, 1950), suggesting that the fault may be somewhat transmissive at some point in the structure. A probable location for increased transmissivity would be at the north end, where throw is diminished. During historic production, reservoir response indicated that the center part of the fault was nontransmissive (Mississippi Oil and Gas Board, 1966). Phase III drilling of downdip wells suggest that the oil–water contact may be deeper on the northeast side of the fault, suggesting noncommunication over geologic time with at least some parts of the field, although downdip displacement of oil by gas recycling is also a possible interpretation.

During Phase II, no cross-fault pressure communication was observed in the reservoir interval. This response is discussed further in the section on operations.

Overburden characterization

The project team compiled data from published reports, historical logs, modern logs, and 3-D seismic to develop a description of above-injection stratigraphy and rock properties. These data were used in monitoring design to select the location for installation of an above-zone pressure gauge and perforated interval for time-lapse geochemical sampling, as well as for part of the certification framework for risk assessment conducted during Phase III (Nicot and others, 2011).

Overlying the injection zone in the lower Tuscaloosa “D-E” sandstones is a sequence of mudstones and muddy sandstones given a number of names, including, locally “C,” “B,” “A,” and “Pilot.” These units were not examined in core at Cranfield, but intermittent occurrence in logs (figure 1.2-4) and sinuosity in stratal slices of the 3-D volume (figure 1.2-10) suggest that they are fluvial at Cranfield but with strongly aggradational characteristics, in that they are not amalgamated and form more discontinuous, sand-rich horizons across the field. Regionally, upper sandstones of the lower Tuscaloosa Formation show increasingly marine character upward, as interpreted from shells and glauconite, suggesting that marine reworking during a regional transgression was an important influence on them (Stancliffe and Adams, 1986). Lower Tuscaloosa sandstones above the “D-E” were not perforated for oil production; however cross-section interpretations (Hines, 1950; Mississippi Oil and Gas Board 1966) show these sandstone bodies to be continuous across the top of the anticline, suggesting that production engineers interpreted them as gas charged and, in some locations, hydrologically connected. The red mudstones observed in core overlying the Tuscaloosa “D-E” are therefore interpreted as the local base of the confining system, although it is uncertain the extent to which they are isolated from injection at the field scale.

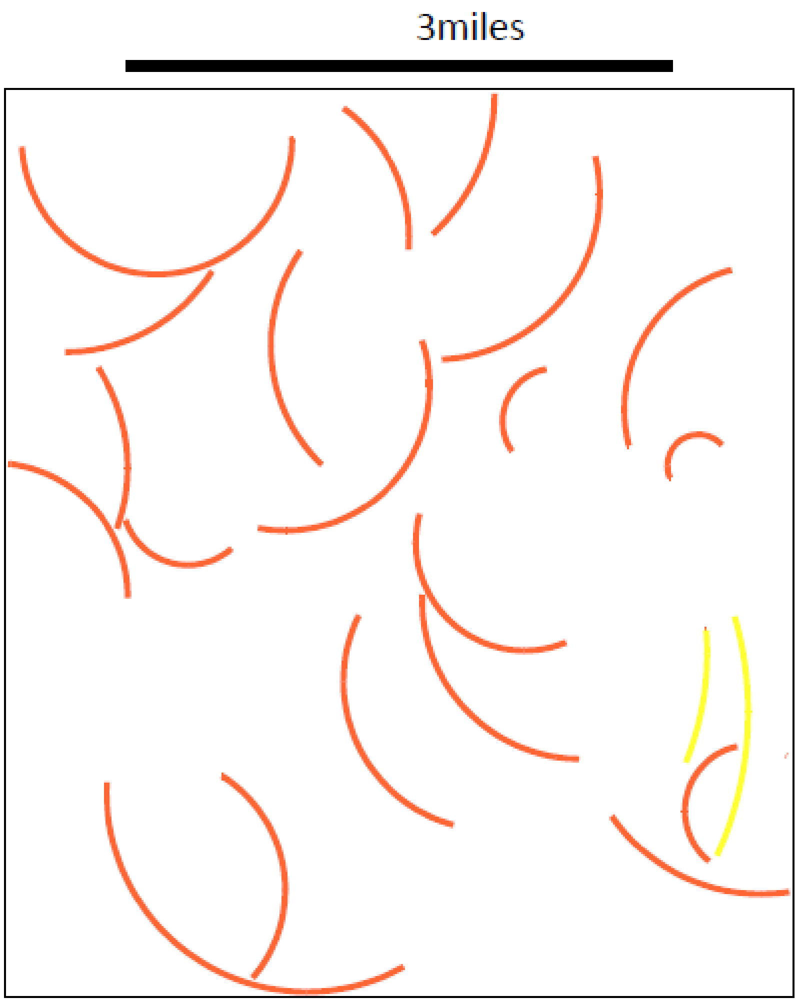


Figure 1.2-10. Map view of interpreted channel morphologies from stratal slicing of the baseline 3-D survey (approximately equivalent to the Tuscaloosa “A-B-C” intervals).

The lowest element of the regional confining system is the thick marine mudstone part of the middle Tuscaloosa (figure 1.2-4). Cuttings of the middle Tuscaloosa examined at the Mississippi Geological Survey warehouse are dominantly fissile, dark-gray to black mudstone. A regionally traceable high gamma-ray–high-resistivity zone in the middle of the mudstone interval is correlated as the maximum flooding surface. Part of this interval was cored during Phase III, recovering a diverse suite of lithologies, including mudstones and calcite-cemented fine sandstones having very low permeability (Lu and others, 2010, 2011), and it qualifies as a good capillary seal (Meckel, 2010).

The top of the middle Tuscaloosa Formation is a series of thin (10- to 25-ft-thick) sandstones. As is typical regionally, picking a zone that represents the contact between the upper Tuscaloosa and Eutaw Formations is difficult (Mancini and others, 1999). One of the lower units of this sequence above the top of the middle Tuscaloosa is correlated fieldwide in stratigraphic sections hung on the interpreted middle Tuscaloosa (figure 1.2-4). Because of its interpreted continuity, this sand was selected as the above-zone monitoring interval (AZMI). Hydrologic tests of the AZMI at the Ella G. Lees # 7 (EGL#7) well yielded permeablities of ~100 mD over a 10-ft thickness. Sidewall core plugs collected during Phase III at the new CFU 31F2 well showed clean and muddy quartzose sandstone compositions.

Above the sandstones of the upper Tuscaloosa/Eutaw Formations, the Upper Cretaceous and lower Tertiary section is relatively fine grained and low permeability (figure 1.2-1). Confining-system efficacy is demonstrated by hydrocarbon accumulation in the lower Tuscaloosa Formation (methane cap and oil rim). Notable units include chalks of the Selma and Austin equivalents and the thick, dominantly mudstone Midway Formation. These units provide ~4,000 ft (1200 m) of confining system below the Wilcox productive reservoir. Wilcox brines are dominantly Na-CL and vary from <100,000 to 150,000 ppm. Additional confinement is provided by the mudstones within the Wilcox Group and interbedded Tertiary sandstones and mudstones of the overlying units, such as the Jackson and Claiborne Groups below and at the base of underground sources of drinking water (USDW).

Surface ecosystem and freshwater-aquifer characterization

Matching the near-surface monitoring program with the characteristics of the site is important. Representative overviews of the region include Childress (1976), Marble, (1976a), Boswell and Bednar (1985), Renken (1998), and Williamson and Grub (2001).The site selected at Cranfield is hilly, with elevations between 280 ft (85 m) and 400 ft (122 m) above sea level. Highway 84 at the south end of the Phase II area is approximately on the drainage divide. The south fork of Coles Creek lies near the north part of the study area (figure 1.211). Loess cover subdues the topography of uplands dissected by alluvial valleys. Modern streams are deeply incised into the alluvial valley fills and show thick loess accumulations. Soil and vegetation are diverse and include cleared and formerly cleared fields and formerly logged and recently logged mixed hardwood forest. As is typical of the southeast region, there is no cold winter season in which biological activity is dormant; temperatures range from an average of ~50° F (10° C) in the winter to ~80° F (27° C) in the summer (U.S. Climate Data). Rainfall is frequent year-round, with monthly averages of 4.5 inches in the summer and 1.5 inches in the winter, for an annual rainfall averaging ~62 inches (1.5 m), leading to year-round root and microbial activity. Current land use includes timber production, gravel quarries, and cattle production; residential use is limited, with the greatest concentration of population in the rural village of Cranfield. U.S. highway 84 bisects the field, providing easy access. County and oil-field gravel roads provide all-weather access to the field. Gravel pits lie outside of the field boundaries to the west, as does Natchez State Park, which provides hunting, fishing, hiking, and camping. National forest bounds the field to the east (figure1.1-4).

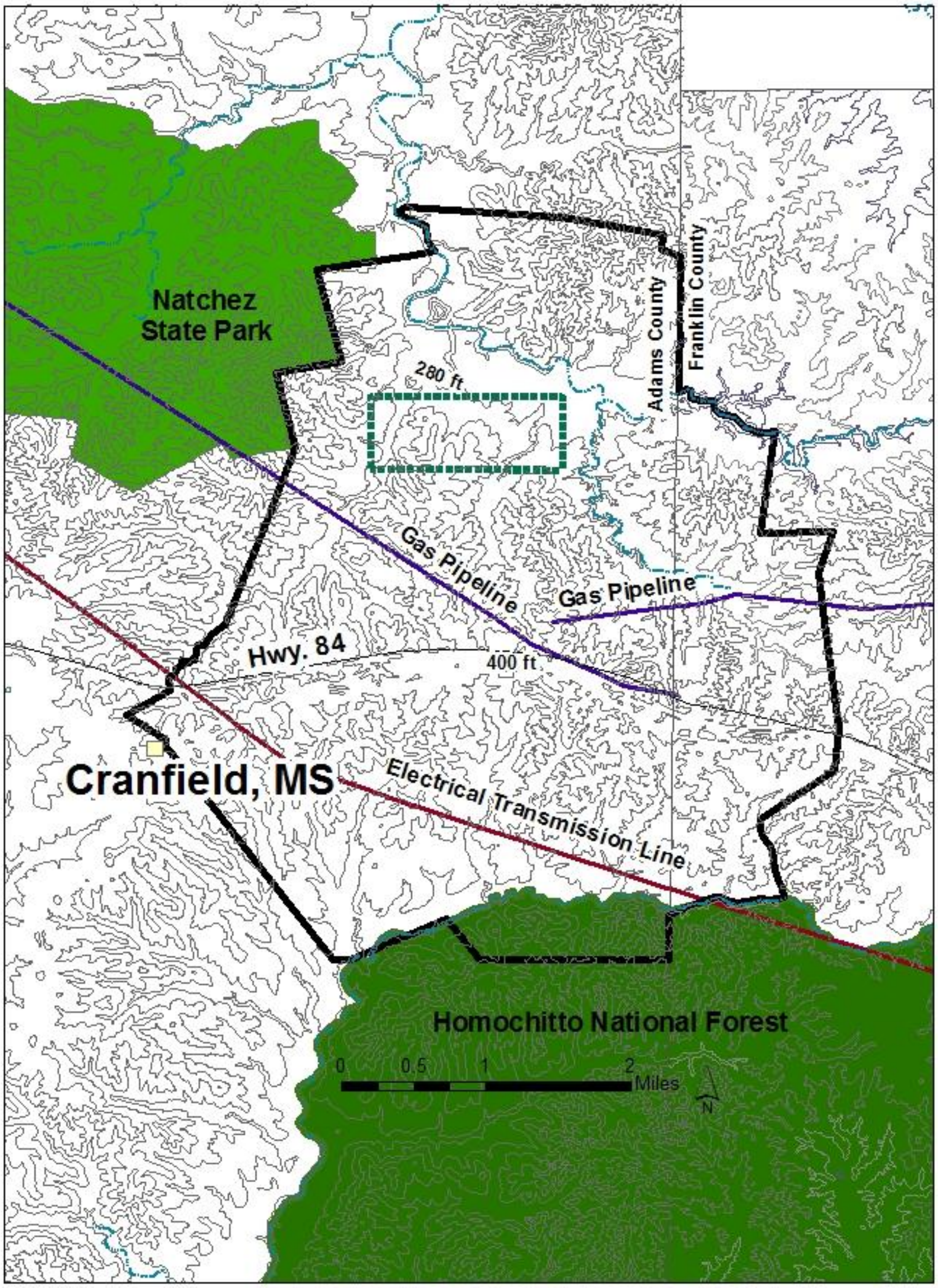


Figure 1.2-11. Physiographic setting of the Phase II study area.

Prior to current EOR activities, the area exhibited abundant evidence of historic oil-field activity, including remnants of pre-1965 Tuscaloosa production in the form of unremediated mud-pit ponds and remnants of tank batteries and equipment. A few pump jacks from stripper wells producing from Wilcox reservoirs are still scattered over the field. Infrastructure for EOR operations, in contrast, is focused in the central separation facility; modern well pads, wells, and pipelines have a low profile. Mud pits, berms, and well pads developed for new well drilling are regraded and revegetated at the end of drilling. Small well pads are maintained around wellheads for well management. Normal production is by lift using reservoir energy; no pump jacks or permanent downhole pumps are used. Of high value for monitoring are water wells drilled to depths of 200 to 300 ft (60–90 m) on each new well pad. These wells provide water for well drilling and then serve as aquifer-monitoring wells and access points for aquifer characterization.

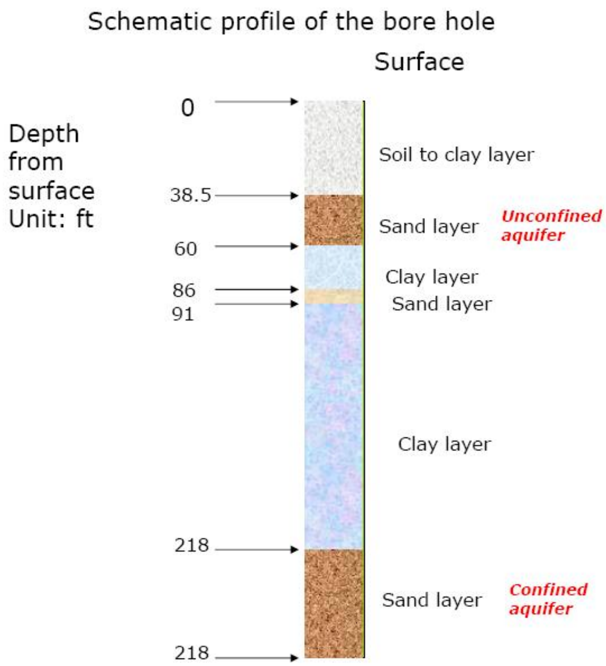
Near surface sediments at Cranfield include a surficial loess drape on top of deeply eroded and laterally heterogeneous Quaternary sands and gravels. These unconformably overlie sandstone, mudstone and conglomerate of Tertiary age. Table 2 summarizes these relationships.

Table 2. Near-surface geological units and their lithological characteristics in the Natchez area. Modified from Boswell and Bednar (1985).

System	Series	Group	Stratigraphic unit	Thickness (ft)	Physical character	Water-bearing properties
Quaternary Tertiary	Holocene		Alluvium	0-200+	Clay, silt, sand, and gravel	Deposits in tributary streams ma y yield as much as 100 gal/min; Mississippi river alluvium, 2000 gal/min or more with specific capacities of 30 to 150 gal/min/ft of drawdown; recharge to the aquifer depends partly on river stage.
	Pleistocene and Pliocene		Loess	0–50	Brown calcareous silt	Unimportant as an aquifer. Prevents recharge to aquifers, which yield to streams.
			Natchez Formation and terrace deposits	0–80	Sand and gravel, mainly chert and quartz; some grains of igneous rock	Forms Natchez aquifer. Yields up to 300 gal/min.
	Miocene and Oligocene		Hattiesburg Formation, Catahoula sandstone and Chickasawhay limestone	0–2200	Clay, sand, and gravel; pea gravel of polished black chert	Municipal and industrial supplies. Yields 100 to 800 gal/min with specific capacities of 3 to 25 gal/min/ft of drawdown. Wells in Natchez area are produced from irregular sand beds in Catahoula sandstone.
	Oligocene	Vicksburg	Bucatunna clay, Byram Formation, Glendon limestone, Marianna limestone	160	Clay, marl, and limestone	Unimportant as an aquifer
			Forest Hill sand	200	Fine sand and carbonaceous clay	Unimportant as an aquifer
	Eocene	Jackson	Yazoo clay	450	Clay	Confining aquifer
			Moody's Branch Formation	25	Sand marl	Unimportant as an aquifer
		Claiborne	Cookfield Formation	570	Sand clay	Saline water
			Cook Mountain Formation	150–250	Shale and sandy limestone	Confining aquifer
				900	Sand and shale	Saline water

Loess blown from the Mississippi Valley blankets a broad area east of the river with relatively homogenous silt-size sediment that stands in distinctive vertical cliffs. The loess is tens of feet thick in the Phase II area but thins and pinches out to the east. Thin sandstone channels within the loess are visible in outcrop, showing that the loess cover is internally heterogeneous. In fresh exposures, such as excavations for new well pads and farm erosion control features in the Cranfield area, the loess has a blue-gray color at depths of a few meters below the surface, with red and yellow hematite and limonite nodules at the contacts with overlying oxidized loess and soil. Beneath the loess and locally exposed in high-standing hills is well-indurated hematite-cemented conglomerate. Gravel deposits are mined in upland areas west of the study area that may be genetically related to heavily hematite-cemented gravel that forms cliffs in high area of the west part of the Phase II study area. The extent and relationship of these gravels have not been mapped, and they were not penetrated by water wells. These observations show that available data are inadequate to define gradient and aquifer characteristics in the Cranfield area; therefore, a near-surface characterization task was planned and started in Phase II with collection of a near-surface core by Dr. Robert Holt, University of Mississippi. Further work continued using wireline-log data collected during Phase III.

The University of Mississippi core was collected at the EGL#7 well pad for a University of Mississippi hydrogeology class project (figure 1.2-12). The upper 38.5 ft (12 m) was loess, which serves mostly as a confining layer. A sandstone aquifer that is probably at the same depth as the local creeks and recharges and discharges into them was cored at 38.5 to 60 ft. It is underlain by clay to 218 ft (66 m), with a sand zone at 86 to 91 ft, which is interpreted as weathered Tertiary sediment. A confined aquifer is found below 218 ft (66 m), which is a water-bearing zone accessed by many of the shallow wells.



1.2-12. Lithologic log of University of Mississippi near surface stratigraphic well UM-1

In our assessment, factors that will lead to change in CO_2 flux for this complex, dynamic, and perturbed ecosystem are much more variable than in other sites, such as Rangeley, Weyburn, and Otway. An attempt to provide a direct assessment of leakage by assessing ecosystem flux and human activities would require a very large effort. We therefore selected two significant parameters to focus on for monitoring in Phase II: (1) soil-gas profiles across the location of selected Tuscaloosa production wells that were plugged and abandoned in 1965 and (2) groundwater reconnaissance and baseline.

Surface casing is set to 1,800 ft (550 m), the approximate depth of USDW (Gandl, 1982; Marble, 1976a). Data on USDW for the Cranfield area were compiled by Nicot and others (2011). Brackish aquifers of the Claiborne Group lie beneath the Vicksburg-Jackson confining unit but above the Wilcox Group. The three Claiborne aquifers have total dissolved solids levels close to 10,000 ppm near Cranfield (Gandl, 1982). The chemistry of these units has not been sampled in the Cranfield area.

The two freshwater aquifer units mapped in the Cranfield area are the deeper Miocene system and the alluvial Pliocene(?) and Pleistocene system. Fresh-water zones within the Miocene Catahoula Formation have been described in the Natchez area, where they are used for water supply (Strom and others 1995). Near Natchez, the Catahoula Formation has three main sand intervals known as the 400-ft, 600-ft, and 1,000-ft sands. The total dissolved solids contents of these aquifers is 300 to 500 ppm (Boswell and Bednar, 1985). In the Natchez area, pump tests determined that conductivities were in the range of 36 to 150 ft/day and storage coefficients in the 0.0001 to 0.0004 range, for a thickness of 60 to 65 ft (Marble, 1976b, Table 12). In Natchez, as in a large area of Louisiana, groundwater pumping altered predevelopment groundwater flow so that natural upward flow in the coastal lowland aquifer system has become downward flow (Renken, 1998, Figures 56 and 57). However, the flow pattern at Cranfield has not been strongly affected by pumping. The Catahoula is a confined-aquifer system isolated from overlying alluvial aquifers by low-permeability strata within the formation. As part of the SECARB studies at Cranfield, the groundwater chemistry of available wells (200–300 ft below surface) was assessed in detail. Groundwater wells are typically drilled to confined Tertiary sandstone units at depths of 200 to 300 ft below surface. According to surface mapping, these sandstones are assigned to the Catahoula Formation. Overlying clay is mapped as Pascagoula/Hattiesburg.

The confining zone is overlain by alluvial aquifers developed in Pliocene(?) and Pleistocene alluvial aquifers consisting of sand, gravel, silt, and clay. In the area of Natchez, alluvial formations have a maximum thickness of ~200 ft (60 m; Boswell and Bednar, 1985). Abundant, but discontinuous, fine-grained beds of local extent act as confining units for the alluvial aquifer but cannot be traced over large areas. Published data from the Natchez area (Entergy, 2007) documents complex alluvial stratigraphy near the Mississippi River. In the Cranfield area, Quaternary deposits are thinner and have not been mapped in detail. A shallow unconfined-semiconfined sandstone aquifer inferred on the basis of seeps at stream banks was cored in the University of Mississippi test well (figure 1.2-12) on the EGL#7 well pad in the alluvial plain of South Coles Creek. A wedge of loess (silt partly altered to clay) that forms steep cliffs blankets the area and provides confinement but thins to the east of the study area.

Preparation for fieldwork and permitting

Preparation and permitting

Monitoring at the Cranfield site allowed the SECARB team to “piggy-back” onto Denbury commercial operation in terms of access, permitting, and logistics. During the process of unitization and prior to SECARB project development, Denbury prepared digital maps of surface and mineral ownership and historical well locations. Denbury in addition had collected information on well construction and P&A records and made commercial plans for well reentry and offsets and new drills. This information was provided to the SECARB project team and used to develop monitoring strategy and reservoir models. A follow-on study of well condition was conducted as part of the certification framework study completed for Phase III.

All wells in the field are permitted by Denbury through the Mississippi Oil and Gas Board as producers and Class II injectors. National Environmental Policy Act (NEPA) Assessment was completed and the project granted a Categorical Exclusion (CX) to the SECARB team for the monitoring work. No other permits are required because the project avoids wetlands.

Wells were renamed using a Cranfield unit (CFU) system, followed by a number denoting the lease and consecutive number within this lease. Wells in Franklin County are given an “F” in addition. To develop the dedicated observation well that formed the core of the SECARB Phase II monitoring program, the project team worked with Denbury to identify a plugged and abandoned (P&A) well in a favorable position for monitoring early stages of the flood. A suitable well, Ella G. Lees #7 (EGL#7) was located in the center of the array of early injectors and producers, and plans were made to renter it. The long string casing had not been cut off near the base of surface casing and removed, which was considered a possible cost reduction. On behalf of the SECARB project, Denbury executed a lease for the well pad from the property owner and permitted reentry, with the Mississippi Oil and Gas Board as an idle producer. Denbury was also subcontracted to employ a vendor to complete the reentry, using rig and expertise already available for commercial development, and to improve the access road and well pad as needed to support these activities. Sandia Technologies of Houston was contracted to design and deploy the monitoring system. In addition, the SECARB team worked with Denbury to collect additional wireline-log and bottom-hole pressure data, focusing on producers in the early stage of production when they serve more as passive monitoring points, prior to development of pattern flow systems that converge on producers.

Data on reservoir and fluid properties were combined with injection and production plans to create a reservoir model using CGM software, GEM. Initial models used characteristics generalized from previous models for input; these were episodically replaced by more-field-specific models. The Phase II model was developed focusing on the northern third of Cranfield, where the initial injection occurred. To increase the speed of model runs, the model was focused on the injection area, and boundary conditions were explicitly controlled by emplacing "pseudo-wells" to mimic the function of the downdip aquifer. This emplacement limits the useful model period to early stages of the flood, before CO_2 migrates near the model edge. This model was then superseded by Phase III models that included large areas of downdip aquifer for that part of the study. Results of the Phase II stage of modeling are summarized in the last section of this report.

Technical design

The Phase II research design developed at the end of the characterization phase included review of the injection plan, surface infrastructure, and determination of preproduction idle wells and production-well distribution and how each intersects with project goals. In addition, significant work during this phase was design of the dedicated observation well.

Work completed in Phase II became a case study in the process of flexible adaptation of the scope of work as additional information about the site became available. The team worked through a series of possible sites, each of which would have required its own approach. For example, if Gillock field had been selected as the storage site, a much higher percentage of effort and budget would have been spent on getting CO_2 to the site and into a well. If Lockhart Crossing had been selected, the emphasis would have been on fault performance. Operations at the elected site took advantage of near-ideal pressure conditions (recovered postproduction) to advance our understanding of this part of the CCS monitoring program. The scope of work was prepared with decision points that allowed the needed adaptions to be made while staying within the proposed scope.

A professionally written health and safety plan (HASP) was prepared by Sandia Technologies in March 2008 and has since been provided to the project team and contractors.

Injection plan

The injection plan for Phase II is the commercial plan for field flood because at this selected site, all CO_2 is provided by the EOR flood operator. Injectors were placed at the upper and lower contact of the oil rim at somewhat irregular spacings of several thousand feet. The injection wells are newly drilled, most are vertical, but some injectors are deviated several thousand feet to selected bottom-hole locations distant from the surface well pad. Wells are constructed with a conveyer pipe pounded to refusal (~100 ft), a surface casing to ~1,800 ft (550 m), 5½-inch (14-cm) diameter #17 weight steel long string cemented in and perforated across ~65 ft of the Tuscaloosa "D-E." Wells are completed with a 2⅞-inch diameter, 6.40-weight steel tubing, and 5½ × 3.00 "DB" packer set above perforations. Each commercial well is equipped with a volumetric flow meter that reports in MSF (thousand cubic feet). Flow is recorded daily by a field technician. Correction of this volume measurement to mass is sensitive to assumptions of fluid temperature and pressure in the flow line and to the amount to methane in the CO_2 stream. The daily well flow is therefore corrected to the high-precision purchase pump at the separation plant by proportional allocation. In Phase III, a coriolis flow meter was connected in series with the volumetric flow meter to assess the accuracy of the correction.

The average design flow rate for each well is 5,000 MSCFD—that is, ~260 metric tons/day. At this rate it takes 10 wells to inject 1 million tons/year. The purpose of this design is to distribute the CO_2 to contact oil, not to inject at a maximum rate. In areas with good reservoirs, injection rate is limited by a field pressure of 2,900 psi and tubing diameter; it is possible to inject at ~10,000 MSCFD (confirmed during the Phase III test). The start-up plan for the project was to start injection at a limited number of wells, with only one well in the area monitored by the observation well, so that a single well response could be measured. The pump design for efficiency limited the minimum flow rate to >10,000 MCF/day. Two wells were injected into during the first week: CFU 29-10 near the EGL#7 observation well was brought quickly to a rate of 10,500 MSCFD by July 15, 2008, and a lesser amount was injected into CFU26-1 on the east side of the field (future Phase III area), where it would be isolated from the EGL#7 observation well. Over the following weeks, six additional wells (CFU29-12, CFU25-5, CFU 24-2, CFU29-2, CFU 27-1, and CFU 28-1) began injection.

Production plan

Production wells planned as part of the original project scope are used by the operator for oil production and by the SECARB project as high-value additional surveillance points. The commercial design deployed by Denbury was near-ideal for this purpose. Because producers were selected to form five-spot patterns with the injectors, the spacing as surveillance points is good. Denbury produces by gas lift, so prior to breakthrough wells are idle and serve as passive observation points. Only after production has progressed for a sustained period does the flow field become dominated by production.

Plugged and abandoned former production wells were reentered and returned to service. Reentry includes repairing the well pad to support a rig, excavating the well with a back hoe, setting a cellar to provide a working space, testing the well cap to determine whether any pressure or methane provides a hazard, cutting off the cap placed on the well as the final step of P&A, welding on additional casing to replace casing that was cut off below ground surface, deploying a workover rig with associated equipment and expertise to drill out cement plugs, and drilling mud fill in the casing and mill-out packers and other equipment left at the well at abandonment. It is important to restore adequate casing integrity by squeezing cement or running a liner over damaged zones. Denbury producers are completed with tubing but without packers. Corrosion-inhibited oil is cycled through the casing to protect the well from damage by CO_2. Denbury constructs flow lines to the test plant, where daily production from each well is tested in rotation (at least once a month) by separation of oil, water, and CO_2 to assess progress of the flood.

Part of the subsurface monitoring plan developed was to collect, on an opportunistic basis, bottom-hole pressure and temperature, production and injection logs, and RST from idle wells prior to production. The purpose was to collect a 3-D distribution of pressure and saturation over time that was then used for history matching. Because the measurement points are wells that are in preparation for production or in the early stages of production, it was necessary to coordinate measurements with field operations. In addition, because of reservoir heterogeneity, the rate at which pressure and fluid composition will change and CO_2 migrate was variable, and times selected to sample points of significant change were responsive to indications, such as pressure increase at the wellhead. Poor well conditions, in particular incomplete penetration of the "D-E" zone and damage to casing or tubing blocking access, proved to be a significant limitation on how many wells could be logged.

Surface facilities

Denbury's surface handling facilities provided several key pieces of information to the SECARB project team. The total amount of CO_2 injected is measured at the purchase pump, which is the most accurate measurement point in the commercial operation for quantifying the total injection mass. In addition, the total amount injected, including recycle, is important to consider for history matching reservoir performance. The separation plant increases pipeline pressure to field pressure (2900 psi) on input gas and efficiently separates oil, brine, and CO_2. Oil is sent to market, brine is reinjected in the saltwater disposal well in the gas cap, and CO_2 is recompressed and returned to the field for reinjection. In the Cranfield operation, because gas is not stripped of hydrocarbons, the recycled gas includes methane and some higher hydrocarbons (analyzed during Phase III). Accounting for the recycled methane is important because it has an effect of CO_2 density at the measurement point, in the injection tubing, and downhole in the reservoir. In current CO_2 storage reporting, methane is removed from the reported stored mass. It is, however, important to record in the modeling.

Observation-well design

In this project the SECARB team designed and installed a dedicated observation well to host monitoring equipment without interference from or with injection and production activities. The design selected is a dual completion. The upper perforated zone in the AZMI sandstone occurs in the upper Tuscaloosa /lower Eutaw Formation above the major "marine" Tuscaloosa shale and mudstone (regional seal). The lower perforated zone occurs in the Tuscaloosa "D-E." Well construction attempted to isolate the zones from one another and from heating and cooling in the shallow part of the borehole by setting packers. The purpose of this installation was to conduct a first test of the feasibility of using AZMI high-frequency pressure and occasional fluid-composition data to monitor for subtle leakage signals that might have indicated that fluids were moving upward through the lowest part of the regional confining system in the middle Tuscaloosa (Meckel and Hovorka, 2010). Likely flow paths for upward flow are via wells. The plan allows for occasional fluid sampling of the AZMI. The project schedule required that the well be installed quickly in a narrow window between site selection in late 2007 and start of injection in mid-

2008. A vendor with previous experience in research-well instrumentation under CO_2 conditions, Sandia Technologies, was selected by the SECARB team and approved by Denbury.

Final design issues that were resolved in discussion between the GCCC team and Sandia Technologies in preparation for ordering completion components for the observation-well tubing and packer design:

- Chrome tubulars and packers were utilized for the completion. Stainless-steel materials were used for the wellhead. Hamilton Metals was the vendor selected for the 13 chrome tubing strings.
- Schlumberger was the vendor selected for the packers.
- Wood Group was the vendor selected for the wellhead.
- Pinnacle Technologies was the vendor selected for the downhole pressure gauges and data acquisition system. However, Pinnacle's new fiber-optic pressure gauges will not be implemented in Phase II because of cost considerations. Table 3 provides gauge specifications.
- Downhole pressure and temperature were recorded every 5 seconds at each perforation zone and transmitted via wireline to the surface. Wellhead data included pressure and temperature on the tubing and on the casing annulus and wellhead temperature and barometric pressure. An onsite recording system wirelessly linked to wellhead instrumentation and powered by a solar panel provided a robust system for recording. All five pressure and temperature sensors were synchronized using a time stamp, and the data logger was set for a sampling frequency of 1 minute. The data file was in ".csv" format. An individual file was saved every 24 hours. The data logger had 2 GB of flash memory capable of storing 5 years' worth of data at a 1- minute sample rate. The data were subsampled every 10 minutes and streamed to a satellite system, where they were served to a website address. Every several months the high-frequency data were downloaded by Sandia Technologies and archived at the Bureau of Economic Geology.
- Distributed Temperature System was not utilized as part of the instrumentation because of cost considerations but was tested in Phase III, where the instrumentation budget is larger.
- The observation well was not produced, except when baseline reservoir properties were measured with a drawdown/buildup test over 3 days prior to initiation of CO_2 injection. Downhole fluid samples will be collected from the monitoring zone near removal of instrumentation and decommission. Equipment will be added to the completion string to enable a fluid sample to be taken from the monitoring interval as a follow-on test.

Table 3. Pressure-gauge specifications.

Pressure sensor	Thickness shear-mode quartz resonator
Temperature sensor	Quartz resonator
Total system pressure accuracy	+/-0.02 of full scale (10 K), including linearity, hysteresis, and repeatability over a calibrated temperature range
Pressure repeatability	≤0.01% of full scale
Pressure resolution	0.01 psi or better
Temperature accuracy	+/-0.5º C
Temperature resolution	0.005º C

The detailed planned procedure for completing the well was developed and reported to DOE. The plan included Denbury reentering the well, drilling out existing cement plugs, cleaning out the well bore to total depth, and remediation to assure that the well bore was intact. In preparation prior to Sandia starting completion, the 7-inch production casing was scraped and pressure tested to 2,500 psi (17 MPa) using a digital gauge for a minimum of 1 hour. The 7-inch casing was logged using an Ultrasonic and Variable Density log across the cemented 7-inch casing on the bottom, an electromagnetic caliper log from total depth (TD) to surface, and a baseline differential temperature survey conducted to provide additional information about the base condition of the well bore. All logs were evaluated to ensure mechanical integrity and cement bonding/isolation behind the casing prior to completing the well and any remedial activities undertaken. The actual procedure was adjusted in consultation with the Bureau in response to additional data collected in the field, and the steps taken following this procedure have been recorded in Sandia's daily reports.

Subtask 1.3: Implementation of Plans: Preparing for Injection

The detailed design package developed to complete subtask 1.2 was used to guide test-site development, including preparation of the site, reentry, and instrumentation of the observation well. Major activities completed to prepare for injection were workover, completion, hydrologic testing and base-fluid sampling in the AZMI, instrumentation, and collection of short preinjection baseline pressure and temperature at the EGL#7 dedicated observation well. The steps to complete this work are reviewed in a later section. Prior to the start of injection, the SECARB team collected baseline hydrologic and soil-gas data, which are reviewed in this section also.

In 2007, Denbury collected a 3-D seismic survey that the SECARB project team used to assist in reservoir characterization, as reported in Task1.1. Prior to start of injection, Denbury drilled and completed five injection wells. The new wells, which allowed collection of one core, reservoir-fluid samples, and open-hole logs at the new wells, were also used in characterization by the project team. Before and shortly after injection began, Denbury completed workover of three production wells and drilled a new producer to offset one that was damaged by erosion. These wells and others completed after the start of injection provided access points for collecting pressure data and baseline-pulsed neutron-log response using the Schlumberger Reservoir Saturation tool (RST).

Preparation of the Observation Well for Injection and Collection of Baseline Data

In this project, a key goal has been to observe pressure and associated temperature and CO_2 concentration changes during injection at a point that averages the response to several nearby wells so as to verify the correctness of modeling approaches to predicting these fundamental parameters (Nicot and others, 2009). A second goal was to conduct a first test of feasibility and instrumentation for measurement of pressure and fluid change in an above-zone monitoring interval (AZMI).

As an intended cost-saving measure, we reentered a plugged and abandoned well. Because of the difficulties encountered, which were described in the previous section, the cost of this reentry approached the cost of a newly drilled well. As a corollary, collection of core and open-hole logs were conducted by Denbury in injection wells instead of the observation well as proposed in the original statement of project objectives. The fault study proposed in the original statement of project objectives was modified; in the Phase II study, the fault was east of the EGL#7 observation well, and cross-fault pressure response was the major tool used.

The purposes of the observation well are (1) to observe pressure and fluid response to injection in the Tuscaloosa "D-E" and (2) to test the feasibility of monitoring for subtle leakage signals that may indicate that fluids are moving across the lower part of the confining system, the middle Tuscaloosa "marine" mudstone, with the likely flow path being through wells. The well designed for this purpose is a dual completion with two perforated zones, so that reservoir pressure and AZMI pressure can be independently measured at a single installation and directly compared (figure 1.3-1). The upper perforated zone is in the selected 10 ft AZMI sandstone in the upper Tuscaloosa /lower Eutaw Formation above the marine Tuscaloosa shale and mudstone. The lower perforated zone is in the Tuscaloosa "D-E" injection zone.

A three-packer system was designed to isolate pressure inside the casing in each monitoring zone (in zone, above zone), as both intervals were perforated. Packers eliminated through-wellbore fluid flow and pressure communication in each part of the well and decreased well-bore storage effects. The plan left the tubing open for access of RST logging tools and included installation of a "dummy gas valve" to allow occasional fluid sampling. A pass-through that connects the casing-tubing annular in the nonperforated zone allows control and monitoring of pressure in all the isolated compartments (figure 1.3-2).

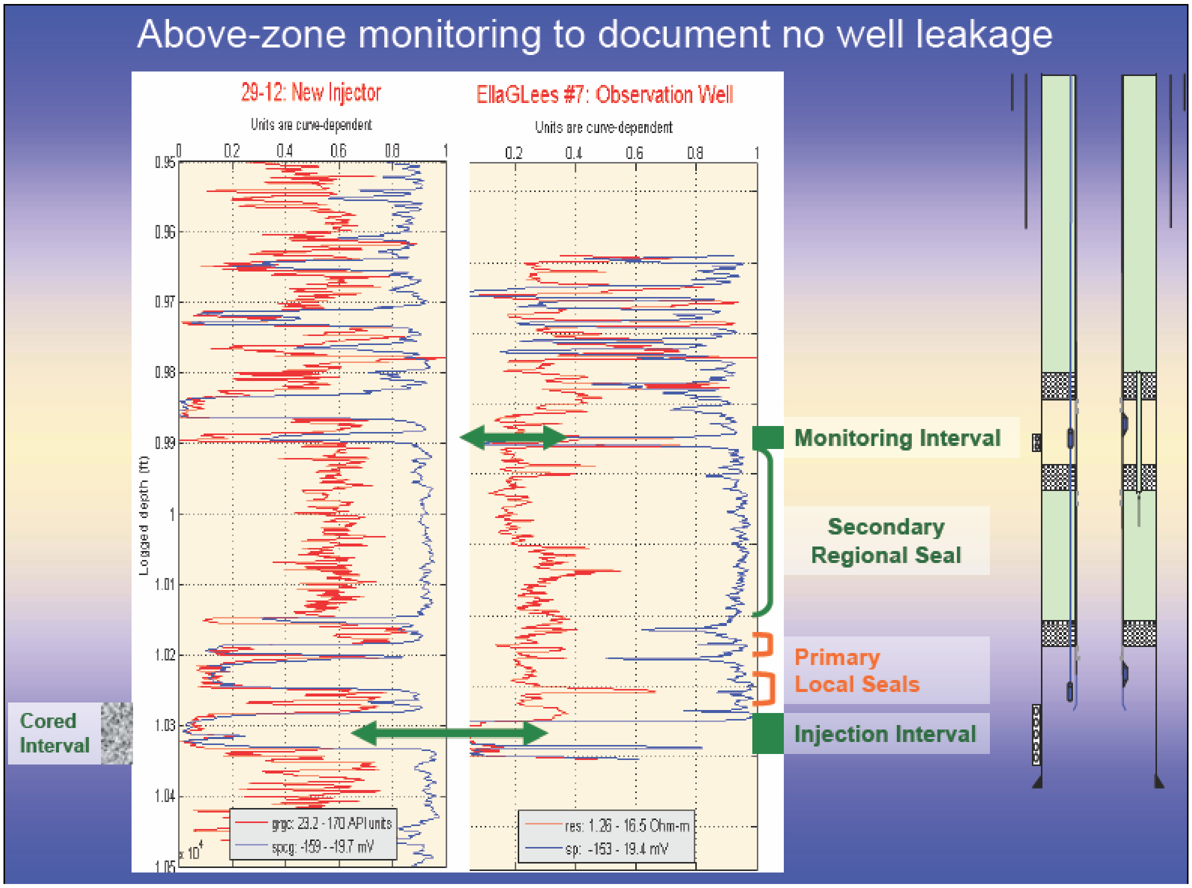


Figure 1.3-1. Well completion of Phase II observation well, Ella G. Lees #7 (EGL#7). Three packers were used to isolate injection and monitoring zones from one another and from heating and cooling in the shallow part of the borehole, respectively. Well log of nearby injection well CFU 29-12 shown for comparison purposes.

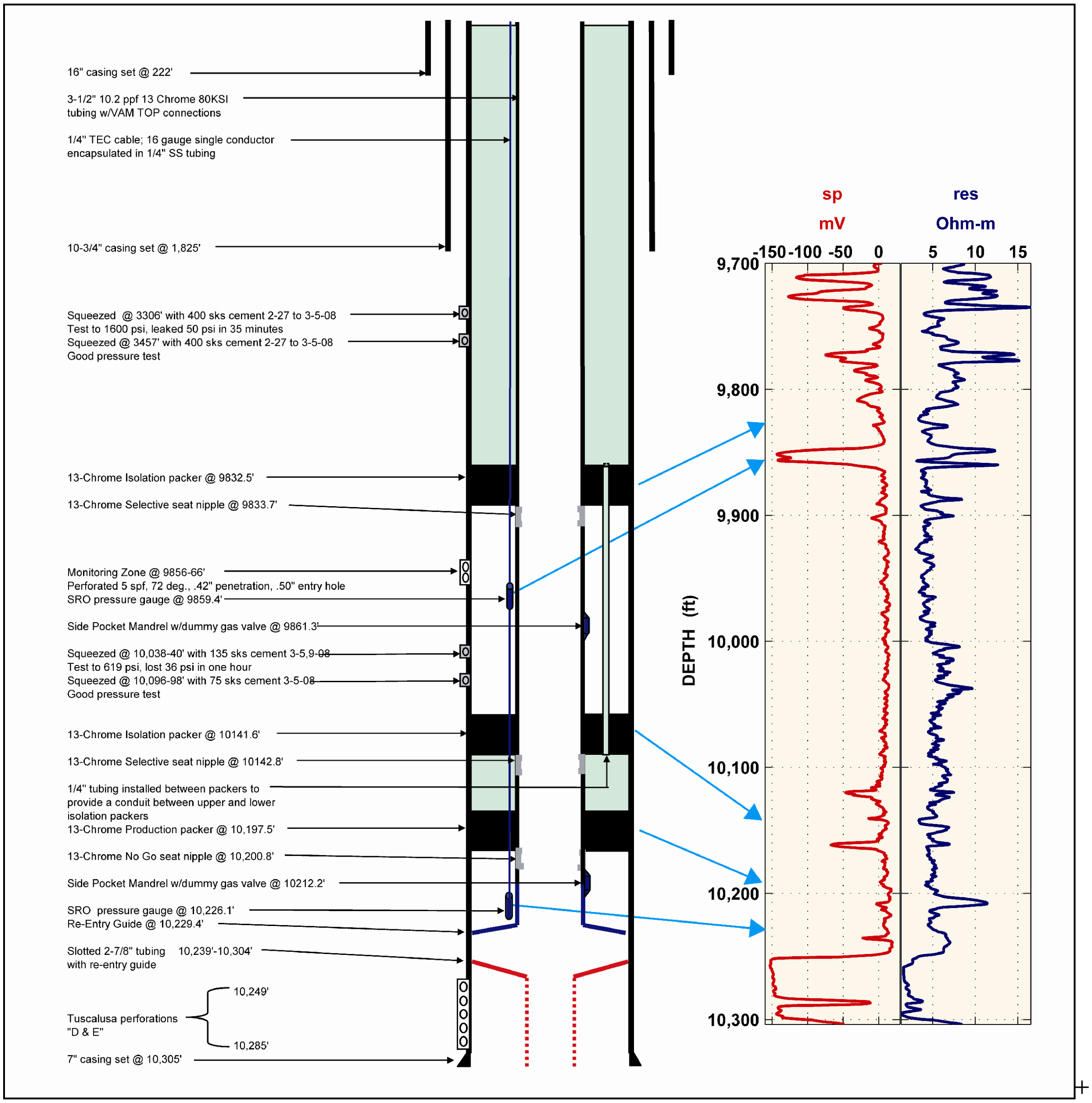


Figure 1.3-2. Design details for Phase II Ella G. Lees #7 (EGL#7) observation well

Workover of the selected EGL#7 was slower and more costly than anticipated. Damage to the long strong casing below the surface casing allowed sediment to infill the well behind the bit, threatening to cause the drill string to jam. Therefore, the casing had to be remediated prior to completion of reentry. Afterward, a several-thousand-foot-long section of heavy workover tubing was found to have been left in the lower part of the well, which required reaming drilling mud between the casing and the tubing and then removing sections of tubing. The tubing had two gas-lift valves from preabandonment operation, and these large-diameter obstructions had to be milled out before reaming could continue. In this complex operation, twice the workover tubing sections jammed, torqued, and unscrewed when unloaded, requiring “fishing” operations to extract loose elements and reconnect them to the active tubing string. Preparations on the CO_2 pipeline were also delayed, so the observation well was completed and instrumented before start of injection on July 15, 2008.

Reentry of the Phase II EGL#7 observation well EGL#7 was completed on April 4, and total depth, when reached, was measured at 10,302 ft (3140 m; measurements were from datum 8 ft above ground level). A 1-11/16-inch outer-diameter (OD) Gamma Ray/Casing Collar Locator was connected to the wireline and lowered into the well. Tools were run to the bottom of the well, and the well was logged up to 10,690 ft (3250 m) uncorrected depth. The log was compared with the original Schlumberger open-hole SP/resistivity-log run on August 31, 1945. Depths were correlated, and the corrected current total depth via wireline is 10,296 ft (3135 m). The workover rig was rigged down and released April 14, 2008.

Preparation for collection of observation-well logs was begun when Tip Meckel (Bureau) and David Freeman (Sandia Technologies) visited Rick McClung on January 31, 2008, at the Natchez Schlumberger office to prepare for both the observation-well and the production-well logging programs. After well reentry, several USIT logs were run in the observation well to assess well conditions and to determine that well conditions were adequate that the project could proceed. These data can also be used by the DOE program to study risks at old wells. For example, about 10 wells with a history similar to that of the Ella G. Lees #7 will not be reentered, and features observed in this well provide insight into what risks these wells might contribute. Although the casing was corroded (figures 1.3-3 and 1.3-4), the cement plugs and heavy mud effectively eliminated flow up the well. In its plugged and abandoned condition, this well would have a low risk of leakage. On April 9, 2008, Schlumberger connected EMIT (electromagnetic imaging and thickness), PMIT (40-arm mechanical caliper), and Gamma Ray / Casing Collar Locator tools to the wireline. The logging tools were lowered to an uncorrected depth of 10,265 ft (3130 m). The well was logged from 10,265 ft to 9,965 ft using GR / CCL and depth corrected to the original open-hole log. The bottom-hole pressure and temperature at 10,235 ft (3120 m) were recorded at 4,483 psia (31 kPa) and 252° F (122° C), respectively. The well was logged from 10,265 ft to 6,700 ft at 1,400 ft per hour. A repeat section was logged from 7,000 to 6,700 ft. The tools were raised to 3,520 ft and logged to 3,200 ft. Schlumberger connected USIT (ultrasonic imaging tool), CBL (casing bond log), VDL (variable density log), and Gamma Ray / Casing Collar Locator tools to the wireline. The logging tools were lowered into the well. The well was logged from 10,250ft to 6,800 ft (3125 to 2070 m). The tools were raised to 3,520 ft and logged up to 3,150 ft. Because the observation well used an existing well with steel casing, no open-hole logs could be collected from this well, and because of repeated infilling of the lower 30 ft (10m) of the well, RST could not be collected in this well.

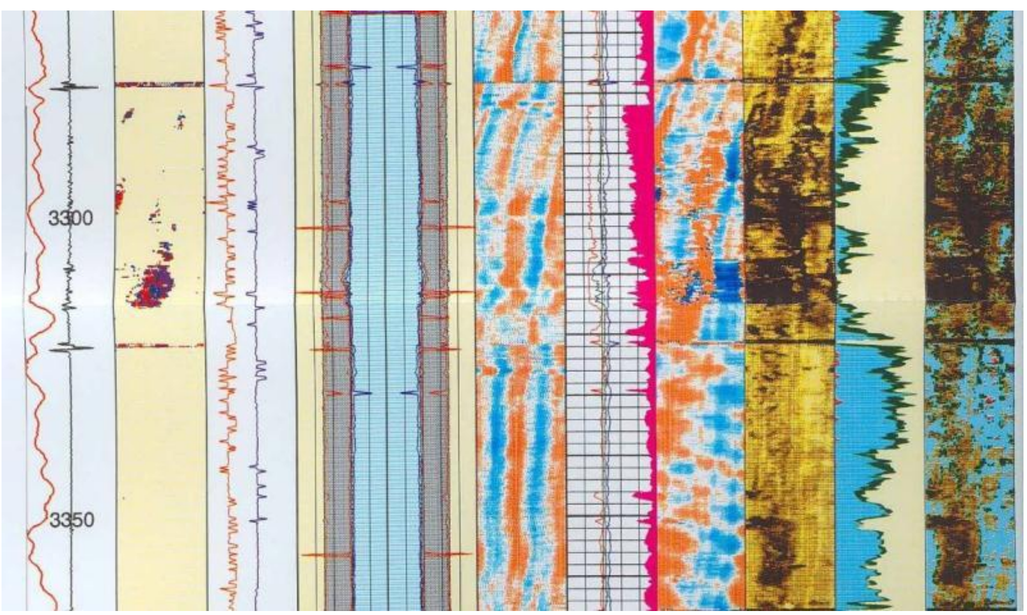


Figure 1.3-3 USIT image of corrosion in the casing in a zone with no cement. Casing was subsequently repaired with a cement squeeze and successfully held pressure.

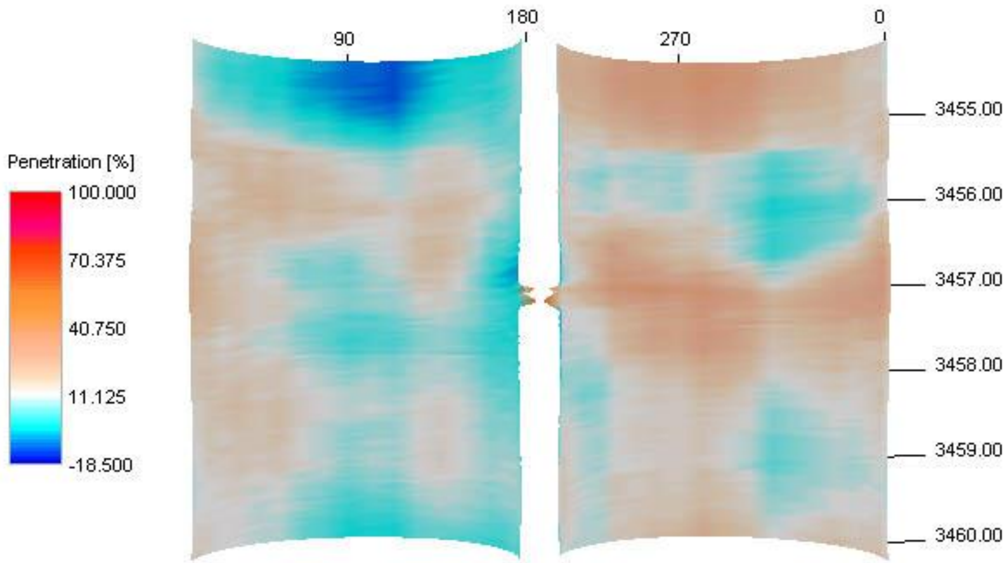


Figure 1.3-4 USIT log used to model corrosion in the casing. It was subsequently repaired with a cement squeeze and successfully held pressure.

On April 18, 2008, a meeting held at Sandia's offices with Schlumberger to interpret well-integrity logs determined that the cement might be discontinuous in the observation well between the injection zone and the AZMI. poor cement quality raised doubts about the isolation of the injection zone and the monitoring zone because of a poor cement bond behind the casing and the possibility that prolonged workover may have created a microannulus (cracked cement). Several zones with apparent 100% fill suggested that the annulus might be impermeable; however, it was difficult to rely on the quality of these intervals, because many other parts of the annulus logs showed fluid filling. Because the above-zone monitoring experiment was a unique, first-time effort, we decided to be conservative and place a cement plug by perforating the casing and placing a circulating cement squeeze behind the casing. A zone where significant annulus is observed was selected. Two squeezes were attempted. Sandia, Nabors Well Service, and Delta Oil Tools perforated the 7-inch casing from 10,096 to 98 ft through tubing for remedial cement squeeze and attempted to inject through perforations. A second set of perforations to the 7-inch casing at 10,038-40 ft were used to establish circulation behind the casing and set a cement plug between 10,095 and 9,759 ft (3077 to 2975 m). Cement was cured under pressure and then drilled out, and it held pressure with only a 2% loss. A pressure transducer hung below the cement retainer showed that there was no pressure communication past the original cement. Placing the remedial squeeze in this lower interval required, on cost grounds, foregoing the planned squeeze at the AZMI interval. During monitoring, the absence of an engineered cement squeeze and a designed perforated interval proved to create uncertainties in interpretation of subtle aspects of the AZMI pressure data because the nature of the pressure communication along the casing-rock annulus had been undetermined.

During workover, the age-weakened casing in the perforated zone in the lower Tuscaloosa was damaged, and casing, cement, and sediment fill fell into the lower part of the well. A slotted 2⅞-inch liner was placed in the injection zone (top at 10,236 ft) to attempt to provide some protection for logging through the region of damaged casing at the perforated zone in the lower part of the well. No additional perforation was undertaken in the reservoir zone.

To prepare for hydrologic testing and sampling of the monitoring sandstone, a bridge plug was temporarily set at 10,010 ft (3050 m) to isolate the lower perforations while the monitoring interval was being developed. The AZMI sandstone was perforated at 9,856 to 9,866 ft on May 22. The well was swabbed and flowed to the surface. Schlumberger and Gulf Coast Nitrogen performed a hydrologic test of the monitoring sand using a spinner at 9,800 ft, along with a producer for 12 hours at an average rate of 72 gallons (273 liters) per minute, with repeats at 30, 60, 90, and 120 ft per minute. The tools were reset at 9,800 ft, nitrogen lift stopped abruptly and pressure was allowed to recover overnight. Schlumberger then ran a PVT sampler at 9,842 and 9,856 ft, activated and pulled the sampler from the well. Repeat fluid sampling of this zone has been scheduled as part of phase III to allow a longer monitoring period.

Because of questions raised at the end of May by pressure-memory-gauge responses during development of the monitoring sandstone, on June 2–3, 2008, an additional test program was conducted to ensure that the well could be completed without communication through any part of the well between the injection zone and the monitoring sandstone. Results showed that above the emplaced cement plug, communication through the upper squeeze perforations at 10,038 and 10,040 ft and rock-casing annulus provided connection to the monitoring-sandstone perforations from 9,856 ft to 9,866 ft. Various options were considered for attaining the goal of isolation between the perforated zones. Significant cost overrun already had resulted from the remedial squeeze. On the basis of cost management and risk reduction, the team decided to forego any additional squeeze attempts and to set the middle packer below the leaking upper squeeze perforations, thereby isolating the perforated and hydrologically connected monitoring zone, which included most of the middle "marine" Tuscaloosa seal and the monitoring sandstone. Because the middle Tuscaloosa is a seal, no significant change was expected in performance. The monitoring-zone compartment therefore has the major perforated zone against the monitoring sandstone and a minor perforation against the middle Tuscaloosa shale.

Installation of the downhole instrumentation, along with tubing and packers, was begun by Sandia Technologies following completion of perforation, testing, and sampling. Table 4 shows the as-built construction. On June 4–5, 2008, the chrome-13 tubing arrived, and preparations for installing the tubing and instrument strings were completed. Corrosion-resistant 3½-inch, 10.20 lb/ft, SM13CR-80, VAM Top tubing was selected because this well would not be active in injection or production, thus making other corrosion-reduction methods impossible. The 5.72-inch outer-diameter wireline reentry guide, two 3½-inch pup joints, 3½-inch side pocket mandrel, 3½-inch pup joint, 3½-inch XN nipple, 3½-inch pup joint, Schlumberger's production packer, and 3½-inch pup joint were run in the well. Each connection was torqued to 3,550 ft-lbs and pressure tested to 5,000 psi. The ¼″ TEC line was fed through the production packer and run down to the end of the string. The Panex pressure gauge was connected to the ¼-inch TEC line and pressure tested. The gauge was attached to the bottom 3½-inch pup joint with a Cannon clamp. The ¼-inch TEC line was secured to the 3½-inch tubing with Cannon clamps across the tubing couplings. On June 6, 2008, an additional 3½-inch tubing joint, 3½-inch pup joint, X nipple, lower isolation packer, eight joints of 3½-inch tubing, 3½-inch pup joint, 3½-inch side pocket mandrel, two ½-inch pup joints, X nipple, and upper isolation packer were run in the well. Tubing was run in the well to place the packers at design depth. During running of additional tubing in the well, Bilco's PST leak-detection system was used to monitor for connection leaks; however, it failed to reliably test connections, and after a series of tests, including assessment by the tubing representative from VAM, the Bilco system was discontinued because excessive time was spent checking erroneous tests. Problems with the pressure-test system required 2 additional days to run the completion (7 actual; 5 projected).

The three mechanical packers were set. Tubing was slowly pressured to 3,500 psi (24 mPa; 27 mPa differential at the packers). Observation of data from the downhole-pressure gauges once the packer-setting pressure was achieved confirmed isolation from the packers. The pressure held for 45 minutes. Tubing pressure was released, and the digital pressure gauge was moved to the casing, which was pressure tested to 400 psi and observed for 15 minutes. The wellhead was placed on the well, and wireline instrumentation was run through the wellhead and to recording instrumentation and the transmission system.

On June 10, 2008, the bottom of the well was tagged at 10,274 ft (3130 m) inside the 2⅞-inch, slotted liner. Scale and possible sediment had filled the lower 25 ft of the well, which precluded access to the injection zone by the RST tool. Options were discussed; it was determined on the basis of research needs, cost, and timeline that we would not attempt to remove this sediment. If sediment removal had been undertaken, it would have set back the pressure-recovery process at this well and risk the pressure-observation program, as well as reduce the significance of RST measurement, and the research team had no confidence that sediment would not continue to refill the well and repeat the problem at every RST repeat. Removal of the observation well from the RST program was therefore needed to ensure that the program would not exceed budget and that good data could be collected from the pressure experiment. On June 12, 2008, the Nabors workover rig was demobilized.

On June 11, 2008, the AKS real-time system was activated (figure 1.3-5). This installation was successfully completed, and instrumentation has been functioning correctly collecting data for more than 2 years with minimal downtime.

Table 4. As-built well instrumentation, tubing, and packers.

Depth (ft)	Length (ft)	ID	OD	Description
10.69	10.69			Rotary Kelly Bushing adjustment to top of tubing hanger
12.00	1.31	2.922		Tubing hanger
44.11	32.11	2.922	3.500	3.5-inch 10.2 ppf 13CH Vam Top tubing joint #314
54.22	10.11	2.922	3.500	3.5-inch 10.2 ppf 13CH Vam Top tubing pup joint
62.37	8.15	2.922	3.500	3.5-inch 10.2 ppf 13CH Vam Top tubing pup joint
9819.18	9756.81	2.922	3.500	3.5-inch 10.2 ppf 13CH Vam Top tubing joint #313-10 (304 joints)
9832.51	13.33	2.942	5.997	Upper Isolation Packer
9833.67	1.16	2.750	3.900	2.75-inch X nipple
9843.79	10.12	2.922	3.500	3.5-inch 10.2 ppf 13CH Vam Top tubing pup joint
9853.89	10.10	2.922	3.500	3.5-inch 10.2 ppf 13CH Vam Top tubing pup joint
9861.32	7.43	2.922	5.570	Upper Side Pocket mandrel w/ 1-inch blank gas valve
9859.40				Pressure Port on upper surface readout BHP/BHT gauge
9871.49	10.17	2.922	3.500	3.5-inch 10.2 ppf 13CH Vam Top tubing pup joint w/SRO gauge externally mounted
10127.63	256.14	2.922	3.500	3.5-inch 10.2 ppf 13CH Vam Top tubing joint #9-2 (8 joints)
10141.60	13.97	2.942	5.997	Lower Isolation Packer
10142.76	1.16	2.750	3.900	2.75-inch X nipple
10152.76	10.00	2.922	3.500	3.5-inch 10.2 ppf 13CH Vam Top tubing pup joint
10184.89	32.13	2.922	3.500	3.5-inch 10.2 ppf 13CH Vam Top tubing joint #1
10197.53	12.64	2.942	5.997	Production Packer
10199.53	2.00	2.922	3.500	3.5-inch 10.2 ppf 13CH Vam Top tubing pup joint
10200.75	1.22	2.650	3.900	2.75-inch XN nipple
10204.88	4.13	2.922	3.500	3.5-inch 10.2 ppf 13CH Vam Top tubing pup joint
10212.17	7.29	2.922	5.570	Lower Side Pocket mandrel w/1-inch blank gas valve
10218.42	6.25	2.922	3.500	3.5-inch 10.2 ppf 13CH Vam Top tubing pup joint
10226.12				Pressure Port on lower surface readout BHP/BHT gauge
10228.54	10.12	2.922	3.500	3.5-inch 10.2 ppf 13CH Vam Top tubing pup joint w/SRO gauge externally mounted
10229.49	0.95	2.870	5.720	Reentry Guide
10239.66	1.74	2.380	5.875	Top of 2⅞-inch slotted liner re-entry guide
10241.40	62.33	2.380	2.875	Two joints of 2⅞-inch 6.5 ppf CS Hydril slotted liner w/16 (1/8-inch × 2-inch) slots per foot
				with closed chisel point bottom
10303.73				Bottom of 2⅞-inch CS Hydril slotted liner

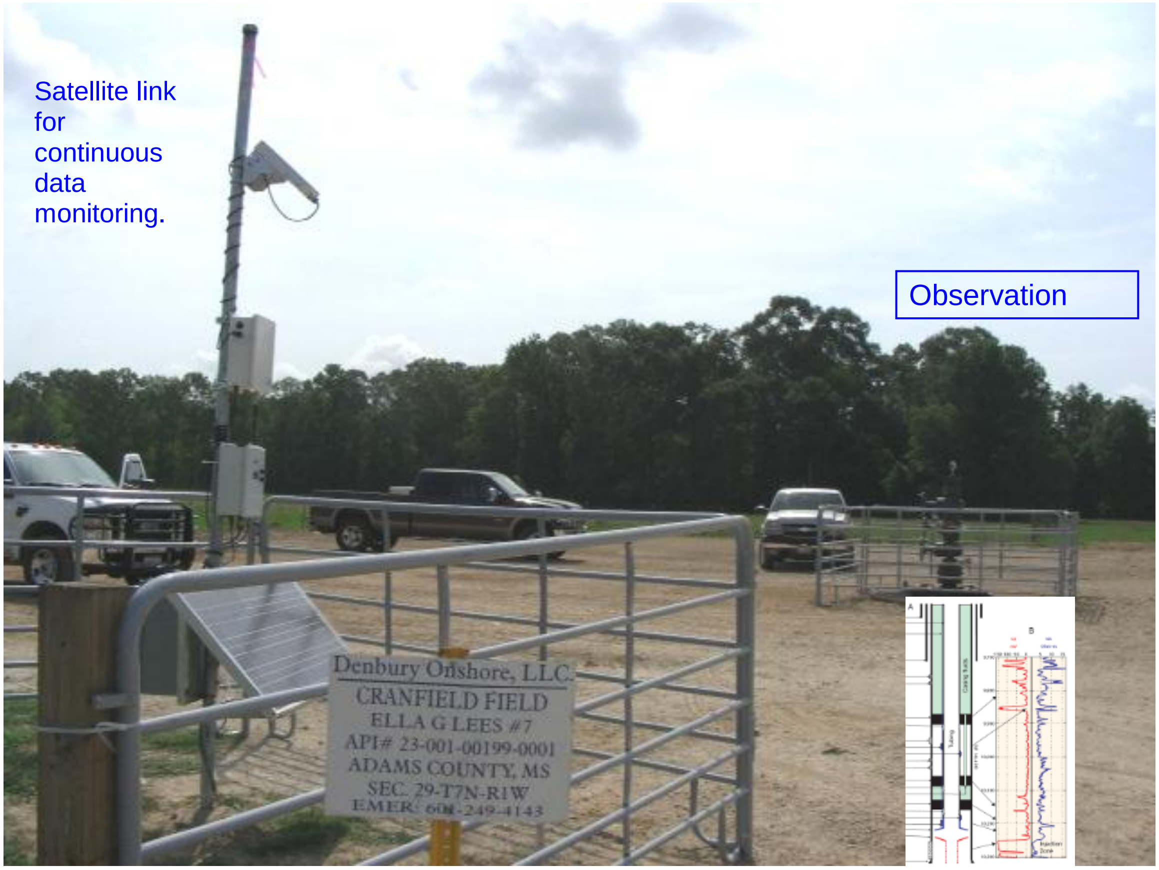


Figure 1.3-5. Surface equipment for AKS real-time satellite uplink from the dedicated observation well, Ella G. Lees #7 (EGL#7), in the background.

Collection of Preinjection Reservoir Characterization Data

Because the observation well is a workover on an existing well, injection wells provided the required new well data for characterization. Injection wells drilled by Denbury were completed, and logs and core data from CFU 29-12 were donated to the project as part of construction of the static model. Denbury has donated fluid analysis from the Phase II area. Additional reservoir-fluid analysis was completed in Phase III (Thordsen and others, 2010). SECARB funded four swab tests on injection wells to estimate variations in injectivity added to the two that Denbury completed shortly prior to completing contract negotiation. Other information collected to provide input into the static model included evaluation of new and historic wireline logs, assessment of core, petrographic analysis of thin sections, and evaluation of formation permeability Quantitative results of this analysis are included in the description of the numerical model in section 1.5.

Evaluation of integrity of all wells that penetrate the injection zone was completed to ensure storage and containment. Production wells were worked over by Denbury as designed, and preparations were completed to monitor pressure and fluid changes. The site selected for the injection project had good access via U.S. Highway 84 and Tate, Moss Grove, and Log Cabin county roads. The EGL#7 site is close to the Edwards “camp” residence, providing good roads. The gravel road to the well pad was improved for rig access and sampling. Power at the EGL#7 site was arranged using a solar panel.

Collection of Preinjection Groundwater Characterization Data

Surface monitoring undertaken for Phase II included initial groundwater monitoring through water make-up wells on injection-well pads. No additional permitting or permission, other than from Denbury was needed for this operation. Because the groundwater wells were drilled by Denbury to supply water for new well drilling, they could immediately be put to use. In Phase II the baseline data were collected by the Bureau so as to get into the field before the start of injection, while awaiting completion of subcontracts to University of Mississippi and Mississippi

State. Because of the delay, a decision was made to complete the groundwater contracts as part of Phase III. Results of monitoring are therefore reported as part of that project, thus also allowing a longer period of observation. However, in results collected so far, no systematic changes in groundwater attributed to CO_2 leakage have been noted.

In addition to the water well that supplies the Edwards camp houses, five other water-on-well pads were accessed (figure 1.3-6), and Bureau staff measured water levels in each of these wells, well depths in two of the wells, and methane concentrations in the PVC well casing upon removal of the casing caps. Water depths in the five wells ranged from 78 to 198 ft (24–60 m) below the top of the casing. Well depths ranged from 195 ft to more than 300 ft (the limit of our probe). Methane concentrations in the head space were generally a few tens of parts per million but reached 5,200 ppm at the water well near the CFU 24-2 and 25-1 wells. Methane concentrations at all wells dropped rapidly upon cap removal, suggesting that methane accumulates over time at the top of the well casing. We acquired GPS locations for all water wells.

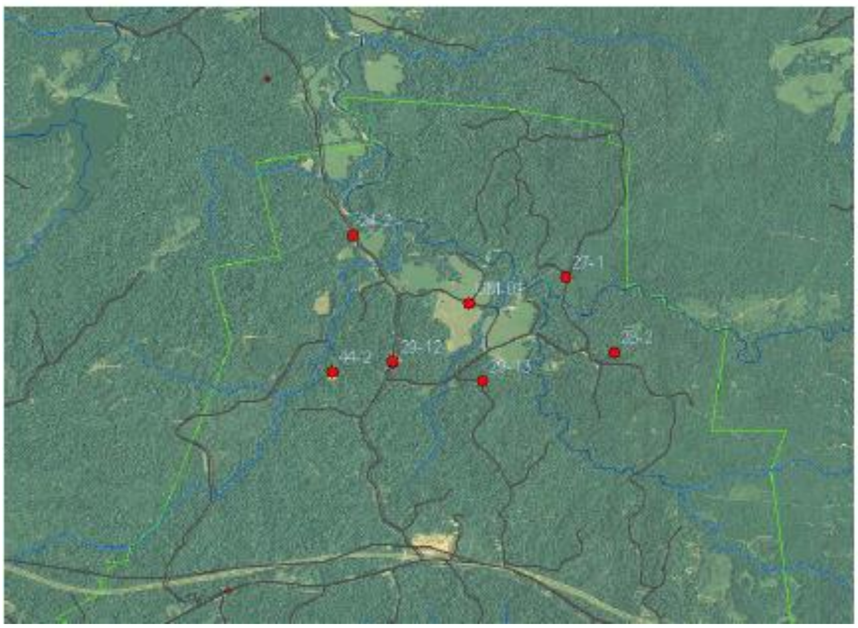


Figure 1.3-6. Locations of groundwater wells sampled during baseline near-surface sampling.

Sample analysis shows fresh water Ca-Mg-HCO3-Cl type(figure 1.3-7). As, Cr, Mo, and Se are below the detection limit of the University of Mississippi's lab. SEM and XRD results of the sediment samples taken from the University of Mississippi (UM-1) water well located within the footprint of the oil field indicate that the aquifer is free of carbonate minerals. Saturation indexes for selected minerals show that calcite, dolomite, and gypsum are undersaturated in all groundwater samples (figure 1.3-8), corroborating the petrographic analyses of cores from the same well.

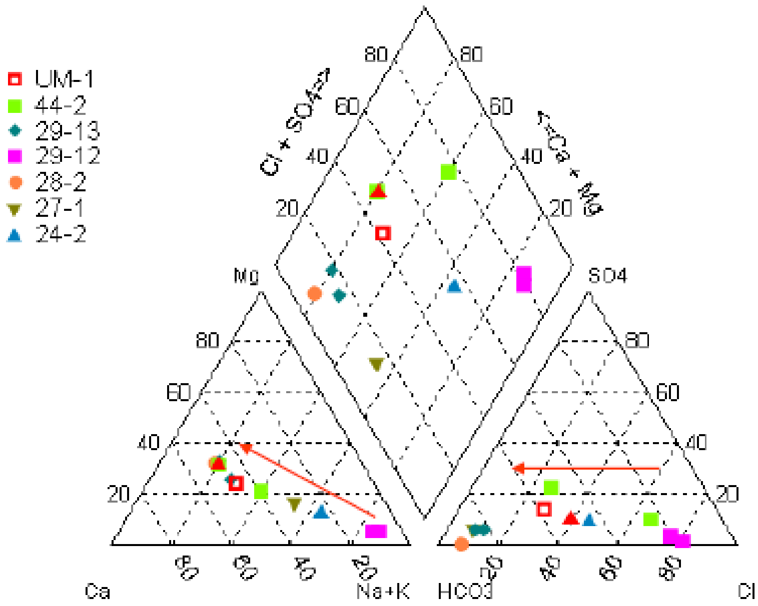


Figure 1.3-7. Groundwater composition is diverse, ranging from NaCl to CA-Mg-HCO_3 types. SO_4 is low, suggesting that EH may be low enough that sulfate is reduced.

Correlation matrix

	pH	K	Ca	Cl	Na	Mg	Fe	Mn	Ba	Zn	F	SO4	NO3	HCO3
pH	1.00	0.17	-0.25	0.45	0.48	-0.28	0.25	0.21	0.03	0.07	-0.39	-0.24	-0.21	-0.12
K		1.00	0.56	-0.02	-0.05	0.52	-0.35	-0.16	0.91	0.61	0.25	0.27	-0.66	-0.14
Ca			1.00	-0.68	-0.79	0.97	-0.33	-0.24	0.72	0.36	0.44	0.29	-0.27	0.20
Cl				1.00	0.95	-0.66	-0.19	-0.28	-0.32	-0.14	-0.19	-0.22	-0.19	-0.58
Na					1.00	-0.76	0.00	-0.06	-0.30	-0.17	-0.28	-0.34	-0.09	-0.44
Mg						1.00	-0.35	-0.25	0.70	0.18	0.51	0.19	-0.15	0.18
Fe							1.00	0.98	-0.32	-0.25	-0.25	0.02	-0.40	0.20
Mn								1.00	-0.11	-0.09	-0.24	0.13	-0.44	0.22
Ba									1.00	0.51	0.37	0.11	-0.43	0.17
Zn										1.00	-0.10	0.55	-0.35	0.08
F											1.00	-0.24	-0.61	0.35
SO4												1.00	-0.89	-0.44
NO3													1.00	0.67
HCO3														1.00

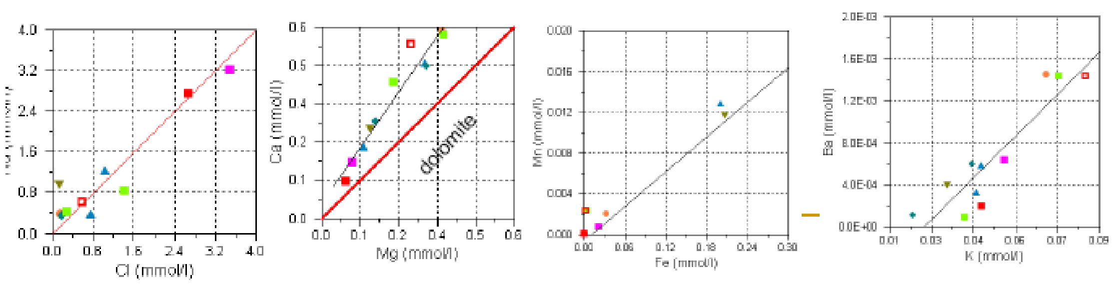


Figure 1.3-8. Groundwater-correlation matrix.

Risk assessments tell us that in EOR settings, where the seal has been proven by hydrocarbon accumulation, the highest leakage risk is at plugged and abandoned wells (e.g., Whitaker and others, 2004). Although injection wells experience the highest pressure, in Cranfield they are newly drilled and designed for the purpose, suggesting lower risk. Injection wells are also actively monitored by field technicians, and production wells are pressure sinks. Should a flaw exist in well completion, it is generally assumed that fluid flow would preferentially go up the production tubing. We therefore selected soil-gas monitoring at plugged and abandoned, idle wells as a potentially important technology for testing in Phase II. Table 5 shows the well locations assessed in the baseline soil-gas survey.

Table 5. Wells assessed in preinjection baseline soil-gas survey

Original designation	Unit name
Ella G. Lees #11	P&A
Ella G. Lees #10	P&A (well casing not found; transect acquired in the general area)
Cranfield #14	CFU 29-5
Ella G. Lees #9	CFU 24-4
Ella G. Lees #6	CFU 29-6
Ella G. Lees #17	CFU 29-7
Vernon Johnson #1	P&A south of Moss Grove Road
Cranfield #21	CFU 29-2

Bureau staff conducted preinjection baseline soil-gas sampling of the Cranfield area the week of April 14–18, 2008. A magnetometer was used to locate buried surface casings of selected plugged and abandoned (P&A) wells in the area to undergo CO_2 flood. A Landtec SEM-500 Surface Emission Monitor, calibrated using 0 ppm and 500 ppm methane-concentration standards was used to measure methane concentrations at the land surface. Surface flux was measured along 20- to 40-m-long transects (1-m sample spacing) at the eight well locations listed in table 5. Methane concentrations were at or below the practical instrument detection limit of a few parts per million at all sites.

The team acquired four soil-gas samples from a depth of about 5.5 ft at the CFU 29-6, 29-7, 24-4, and 29-2 wells (Table 6). Soil gas sampled at Cranfield using a push soil probe was brought back to the lab and analyzed on an SRI gas chromatograph equipped with a HayesQ column and FID and TCD detectors. The method used has a detection limit for CO_2 of about 0.04% and for CH_4 of about 10 ppm. All samples had CO_2 concentrations elevated from atmospheric (0.035%), and one sample from the soil near the 29-2 well had detectable methane, as well as higher-than-atmospheric CO_2 concentrations. The GC method used can also detect light hydrocarbons, but none was found in the samples analyzed. As part of the near-surface monitoring plan conducted for Phase III, the Bureau team developed this anomaly into a study site (P-site). We installed nested vadose-zone access tubes and periodically sampled and analyzed gas to better understand the distribution and genesis of hydrocarbons and CO_2. Real-time field analysis of soil gas sampled through nested gas wells is preferable to lab analysis for yielding more reliable data. Oxygen and nitrogen values are easily measured in the field and provided more insight into the origin of the elevated CO_2 reported under Phase III.

Table 6. Soil-gas samples from depth assessed in initial survey

Sample-well location	Depth (ft)	CO_2 (vol %)	CH_4 (ppm)
CFU-29-6	0.51	0.1	nd
CFU-29-7	0.53	0.14	nd
CFU-29-4	1.63	0.11	nd
CFU-29-2	0.49	0.26	121
	0.49		

Subtask 1.4: Injection and Monitoring Operations

This subtask consisted of injection of CO_2 and observation of reservoir and AZMI pressure and temperature response in the EGL#7 well and in selected idle and production wells during the early stages of flood development.

Injection Operations

Denbury began filling the Sonat pipeline, pressuring field lines and getting equipment operational 1 week before injection. CO_2 injection into the Cranfield lower Tuscaloosa reservoir began on July 15, 2008. Initial rates were 11.0 MMCFPD into CFU 29-10 and 6.0 MMCFPD into CFU 26-1 at 2850 psi. The target of the test was reservoir response to injection into CFU29-10 near the observation well. Starting injection into CFU 26-1 was needed so that sufficient CO_2 would pass through the pump and operate within the engineered temperature range; it was selected because it was distant and on the other side of the nontransmissive fault. On July 18, injection was shut down to test reservoir response, and then the two wells were put back on injection. Injectors were staged individually in an attempt to monitor pressure pulses through the reservoir (figure 1.4-1). Initial injection rates (table 7) were set on the basis of permeability estimated from swab tests. All injection was at a field pressure of 2,900 psi (20 MPa; injection rate was controlled at each wellhead by opening the valve incrementally and was based on previous experience to obtain the designed flow rate).

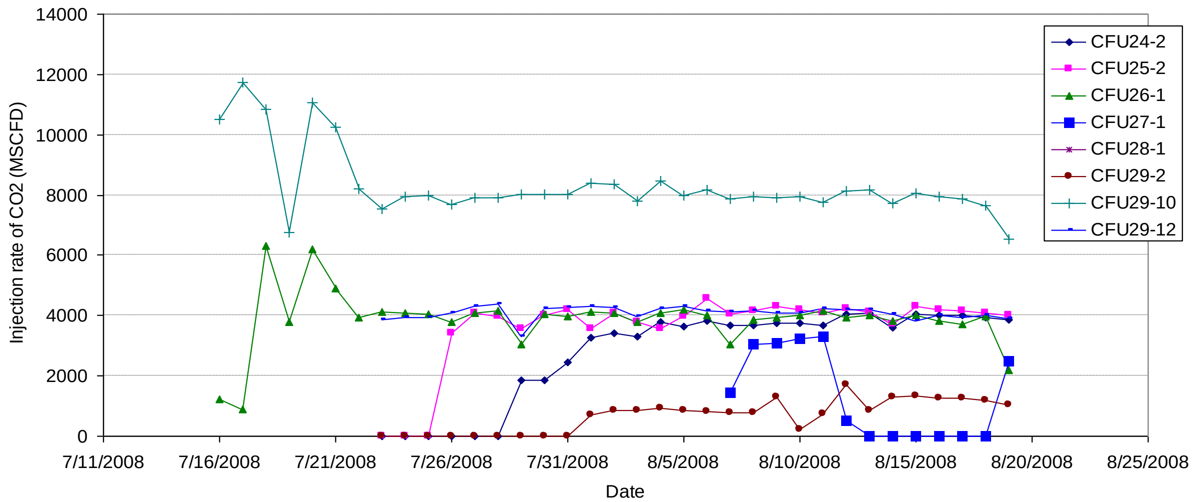


Figure 1.4-1.CO_2 injection rates per well during early stages of the CO_2 flood.

A daily inventory of injection rate (Denbury Onshore Resources LLC, 2011) is plotted in figure 1.4-2 and was used to assess pressure response to changes in injection rate. Injection was continuous except during August 2008, when hurricane Gustav passed over the field; injection was shut in because of the pumps' need to run on onsite electricity, which was not available. Other decreases were shorter shut-downs or slowdowns at the separation facility or on the pipeline that produced subtle but measurable pressure response in the field.

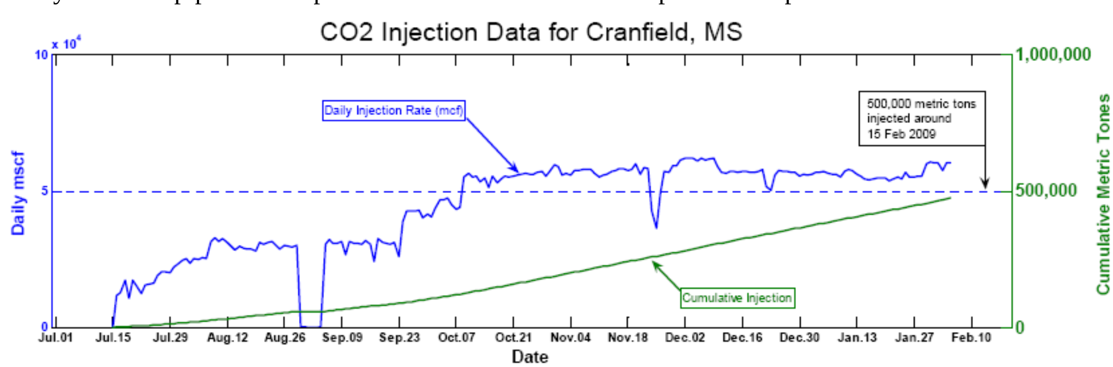


Figure 1.4-2. Daily and cumulative injection rates for the first half year.

Table 7. Initial CO_2 injection rates for individual injection wells

Well name	Injection rate (MSCFD)	Well name	Injection rate (MSCFD)
CFU 24-2	4000	CFU 28-1	4000
CFU 25-2	4000	CFU 29-2	1000
CFU 26-1	4000	CFU 29-10	8000
CFU 27-1	3200	CFU 29-12	4000

Injection continued during Phase II, with a monthly injection rate about 50,000 metric tons per month (figure 1.4-3). When Phase III started in April 2009, injection from three wells drilled in the Phase III area was transferred to the Phase III ledger. At about the same time, production began to be significant (figure 1.4-4). In the fall of 2009, additional injection wells were drilled in the Phase III area. Cumulative monthly storage (recycle volumes removed) is shown in figure 1.4-5. A spike in Phase III in March through May 2010 to test the high-volume injection test area (HiVIT) was accomplished partly through producing some of Denbury's CO_2 stored in the Phase II area and injecting it into Phase III (figures 1.4-5 and 1.4-6).

The total CO_2 mass stored in the Phase II area at the end of the Phase II project, September 30, 2010, is calculated at 1,229, 510 metric tons of CO_2. This mass is different from the mass injected that was reported previously because recycleand the 2% methane that comes from Jackson Dome have been removed. Methane has a significant effect on density, so it will continue to be included in the modeled injections. Note that methane is enriched during recycling by preferential CO_2 dissolution and co-production of field methane. A detailed document (Clift and others, 2011, in preparation) on the methods of correcting CO_2 mass stored was developed for Phase III and will be reported as part of that project.

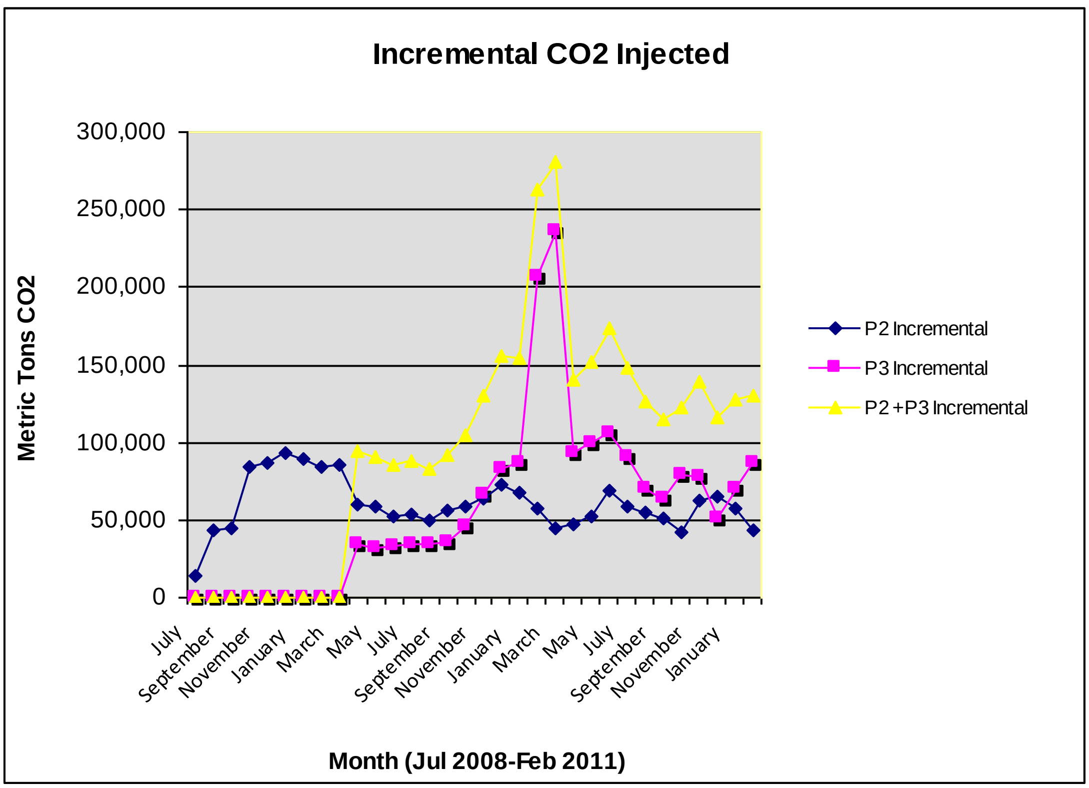


Figure 1.4-3. Monthly incremental injection rate (total).

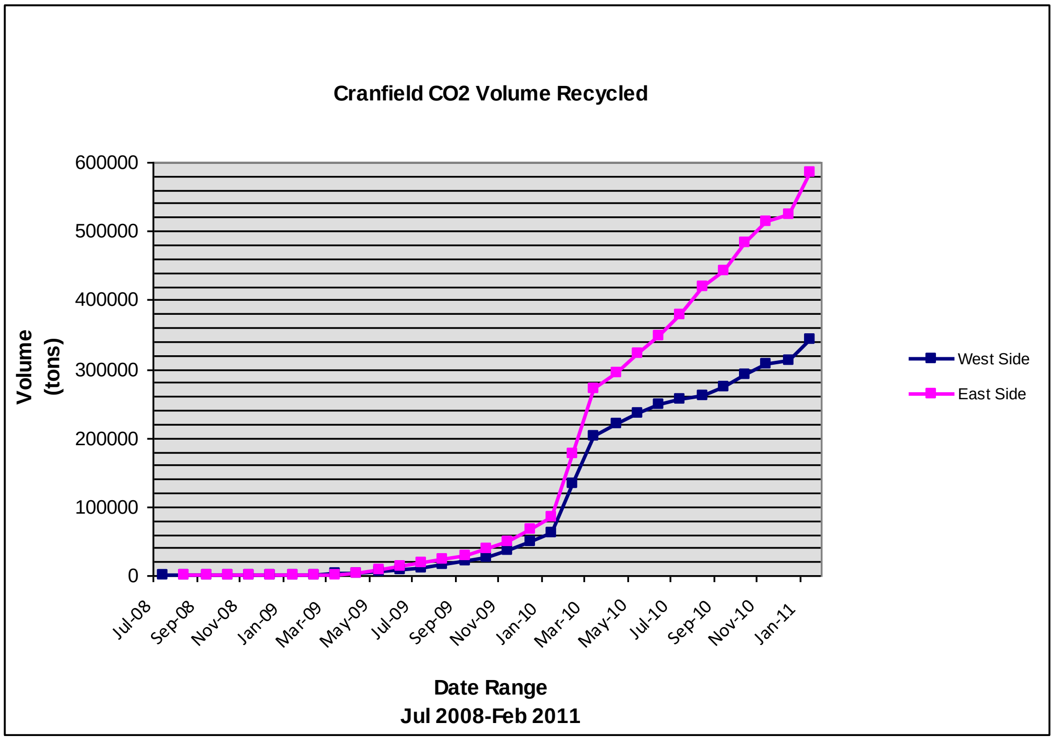


Figure 1.4-4. Cumulative CO_2 recycled, corrected for methane.

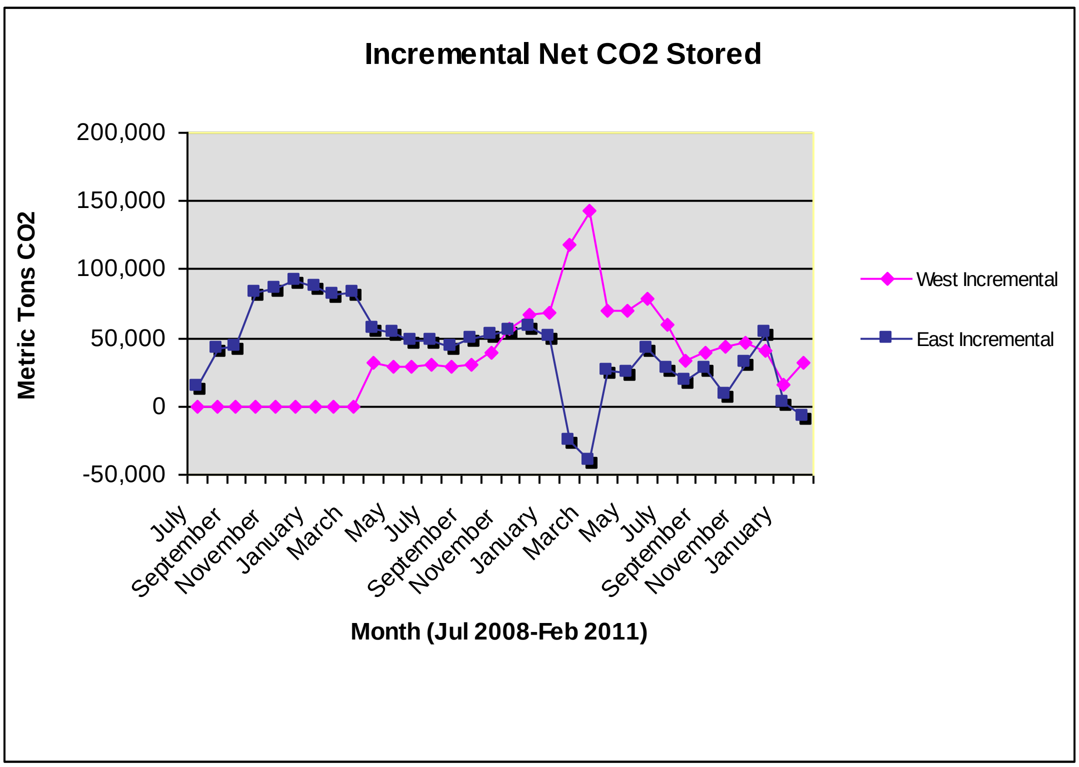


Figure 1.4-5. Incremental CO_2 stored per month, corrected for recycled CO_2 and methane.

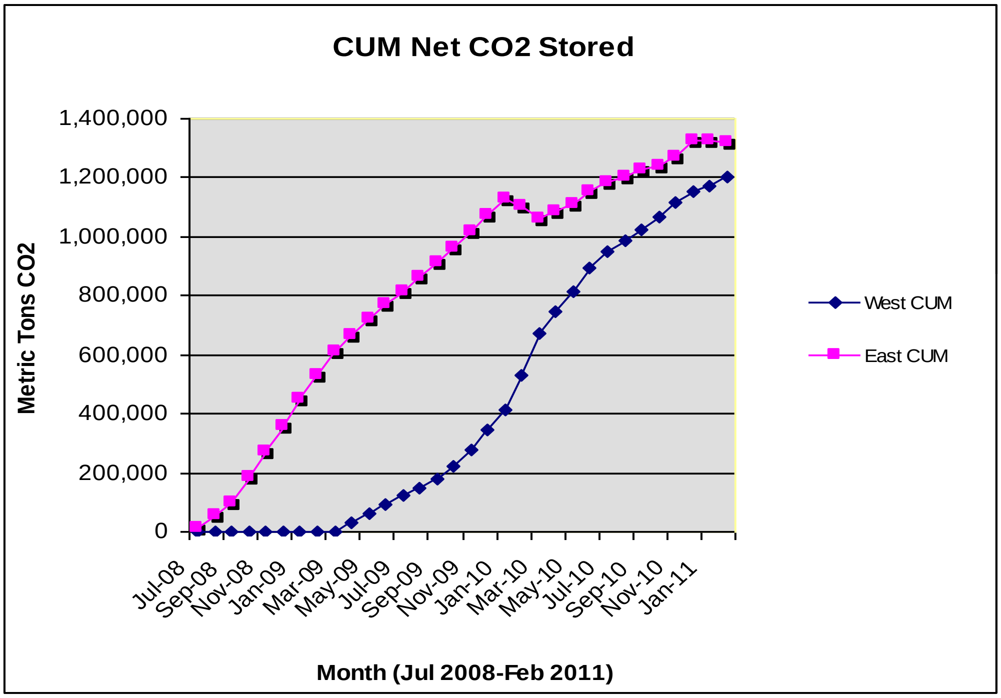


Figure 1.4-6. Monthly cumulative mass CO_2 stored (corrected for recycling and methane).

Reservoir Response in the Injection Zone Measured at Idle and Production Wells

To meet project objectives for monitoring the pressure, temperature, and fluids at idle and production wells in the injection area, several types of data were collected episodically at the start of the flood. These data were used to history match to the reservoir model. At the start of injection, wells were idle until CO_2 breakthrough caused fluids to flow to the surface. The opportunity at Cranfield is unique. In most EOR fields in tertiary recovery, the tubing would be occupied by a pump or by sucker rods, and access for logging could be done only by taking the well off production and pulling the pump. At Cranfield production tubing is available, and wells can be logged as often as funding and feasibility permit. In addition, at most fields reservoir pressure and fluid compositions and saturation are highly perturbed at the start of CO_2-EOR. At Cranfield, preinjection conditions were at the end of a multidecadal recovery and well equilibrated.

One type of monitoring that was tested was pulsed neutron logging using the Schlumberger reservoir saturation tool (RST). This tool has been used successfully to observe replacement of highly saline water by CO_2 (Sakurai and others, 2005). The large contrast between thermal capture cross section of CO_2 ($\sum_{CO2}$) and formation water ($\sum_w$) means that if CO_2 replaces water, a large change will be observed between the baseline and the repeat logging run. However, environmental correction must be made because in a perforated well, well-bore fluids are replaced by CO_2 at the same time as formation fluids are changed. Ideally, good open-hole logs are available for characterizing porosity and preinjection-fluid composition. Schlumberger log analyst Robert Butsch was responsible for analysis of the logs.

Four wells in the Phase II area were selected to monitor saturation with RST. A number of wells were eliminated from consideration because the open hole was not deep enough to allow the RST tool to measure across the injection zone or because well conditions were questionable and it was considered too risky to send an expensive tool into a compromised well. Baseline logging was conducted in June 2008 and repeated at intervals during the early stages of the flood, when the team detected change in saturation because of increase in pressure at the wellhead.

The status of RST monitoring in the Phase II area is

- CFU 29-9—Three RST logs, interpreted CO_2 breakthrough run 6 months after injection (figure 1.4-7)
- CFU 44-2—Newly drilled offset production well with a modern log suite. Two runs, interpreted gas in reservoir interval 6 months after CO_2 breakthrough (figure 1.4-8).
- CFU 29-11—Two runs, no change observed; however, fill now prevents complete RST, and production log run instead shows flow over a 15-ft interval (Figure 1.4-9).
- CFU 29-5—One run did not successfully access the zone because of fill across perforations.

Analysis of open-hole and RST logs of CFU 29-9 (figure 1.4-7) shows (in green) an estimate of original oil saturation from the 1944 log (fourth from right), then an estimated oil saturation at the preinjection baseline in a log run June 2008 (third from right). The first repeat log was collected in October 2008, shortly after the log began producing, and shows some slight variability in oil saturation (second from right), which may be an estimate of noise rather than real measurements. The final RST log run in April 2009 calculates an increase in oil, which may be an oil bank including some CO_2 dissolved in oil and some thin zones of free-phase CO_2. However, the RST shows oil and some CO_2 in most sandstones in the section, indicating that the calculation probably is not successfully corrected for well-bore changes.

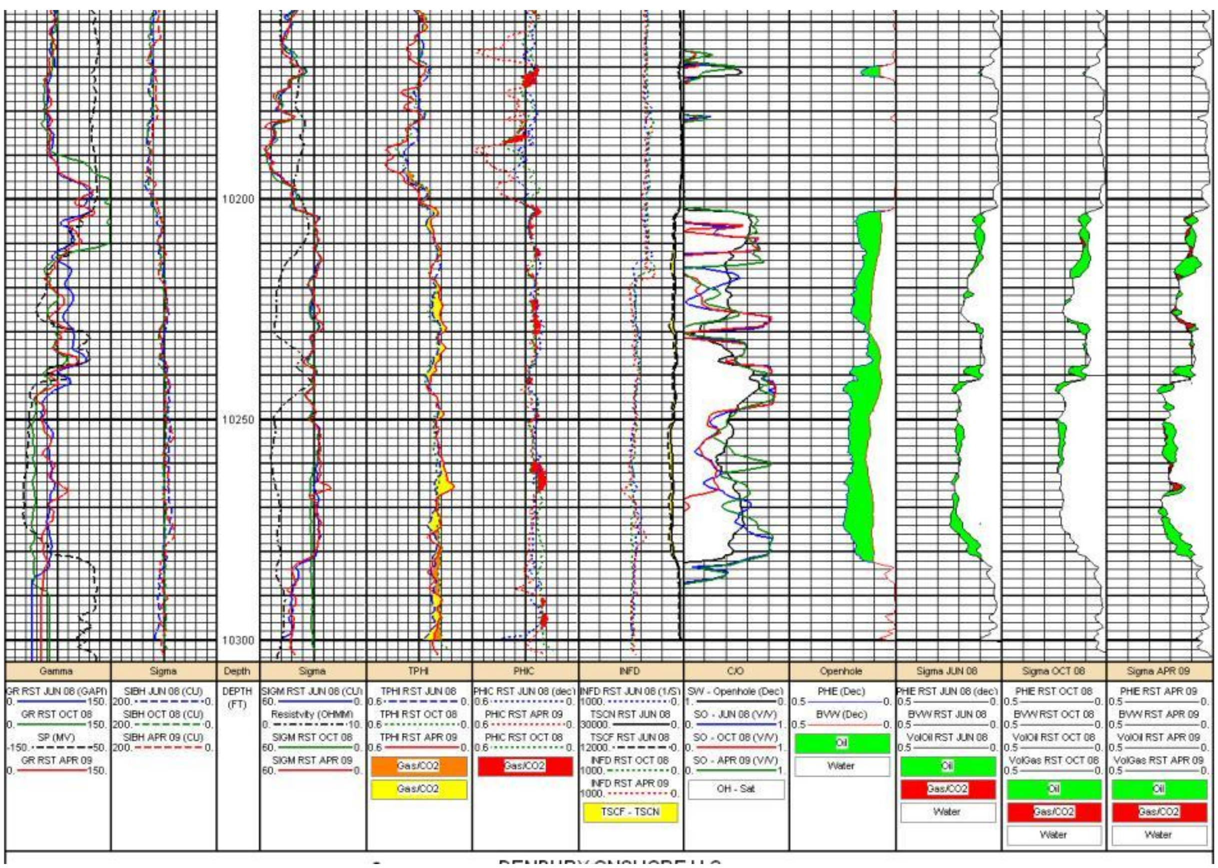


Figure 1.4-7. Time-lapse RST logs of producer CFU 29-9. “Openhole” is Schlumberger interpretation of oil saturation during initial drilling in 1944. June 2008 preinjection baseline saturation from RST shows an interpretation of depleted oil saturation. October 2008 was the first repeat, run after initial CO_2 production. Decrease in oil saturation probably shows noise in the analysis. No CO_2 was interpreted on the log. April 2009 shows a slight change in oil and gas saturation that may indicate effects from CO_2 injection and EOR.

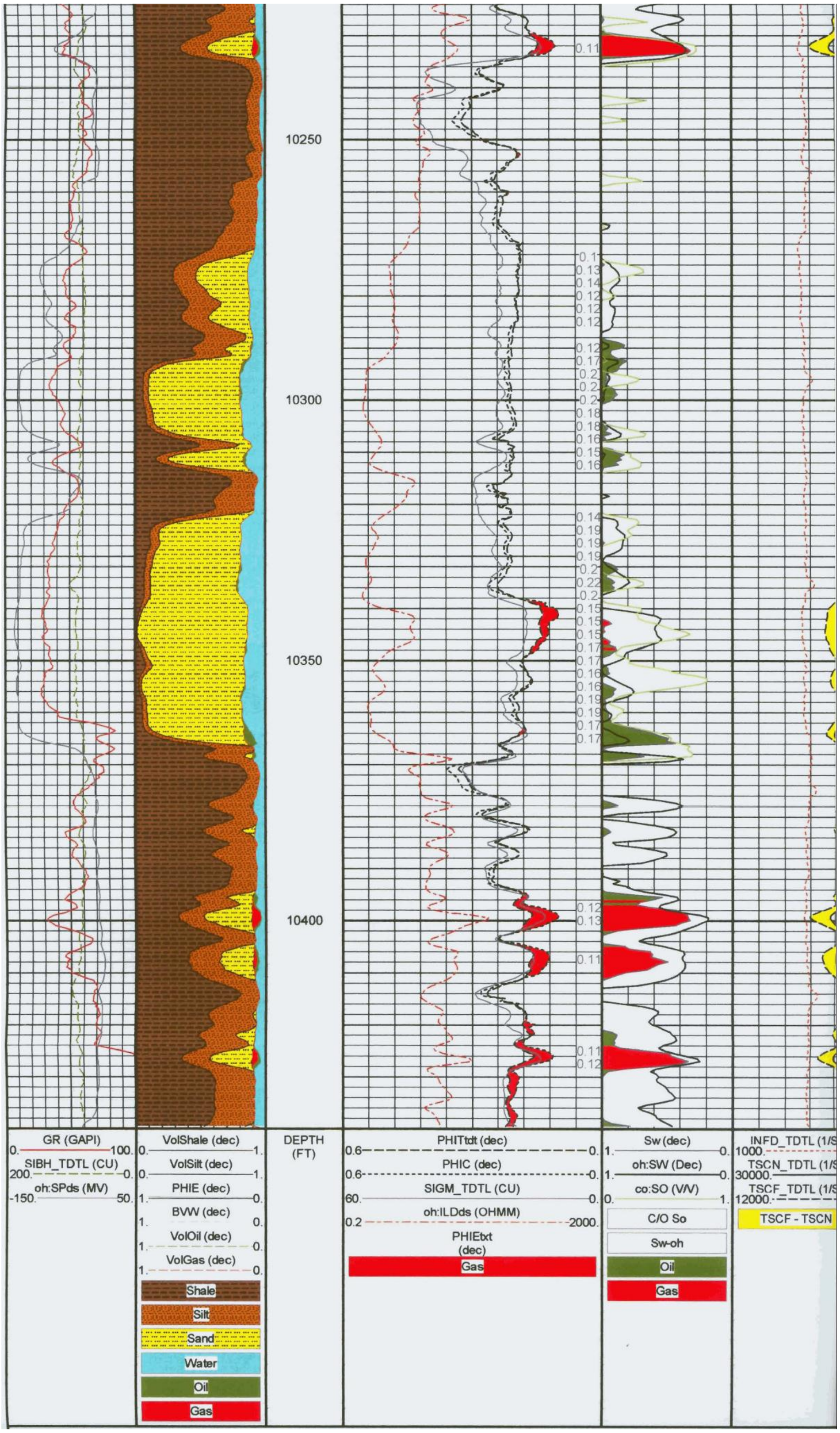


Figure 1.4-8. RST log of CFU 44-2 run in July 2009 after breakthrough in January 2009, showing Schlumberger analysis possible when modern baseline logs exist. No independent corroboration of high gas saturation in the sandstones below or above the injection zone was available. However, both zones were historically produced for gas in some parts of the field.

RST logs were less successful in Cranfield at detecting CO_2 than they were at the Frio site (Sakurai and others, 2005). A number of factors confused the interpretation, including complex fluids (brine, methane, oil, and CO_2), dominantly old wells that were problematic because of lack of modern logs, and well conditions unsuitable for running the RST tool. Interpretations of the logs consistently yielded fluid changes in zones that were outside the injection zone, adding doubt about the use of this tool in this setting to determine conformance of the flood to the injection zone. The project team therefore deemphasized this data-collection method in Phase II, although recommending a test in the simpler brine system of Phase III.

Because the planned repeat RST could not be run owing to infill in the CFU 29-11 producer, a production log was run for SECARB May 7, 2008, by Superior Energy (figure 1.4-9). Denbury uses this type of log in other CO_2 fields, and it does not have the tool length limitations that we experienced in other Cranfield wells for RST. It shows flow occurring into perforations over about 9 ft of sandstone, which is an important history-match parameter because it shows that the whole thickness of the lower Tuscaloosa “D-E” is not active at the producers.

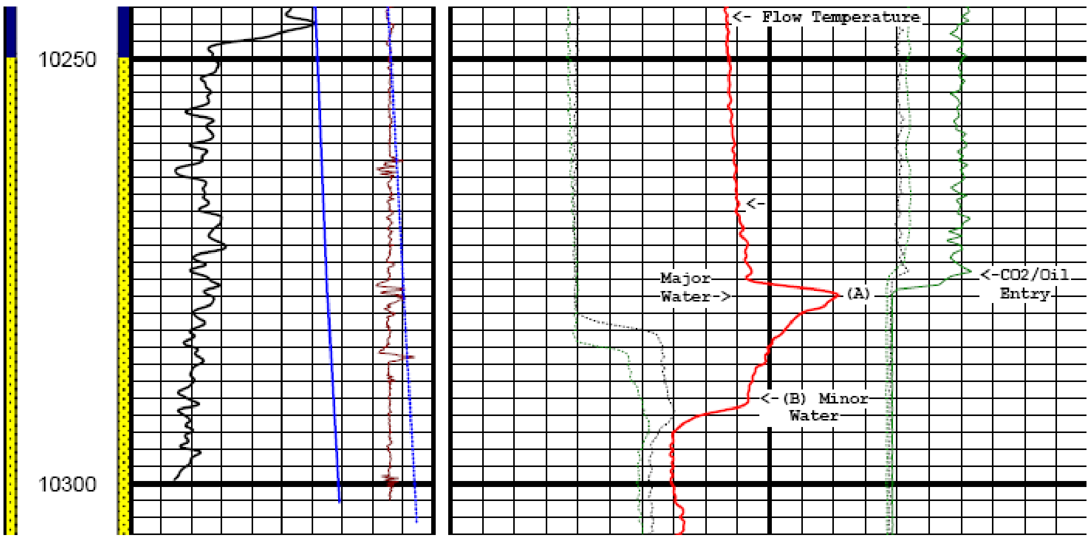


Figure 1.4-9. Production log from producer CFU 29-11 showing CO_2 breakthrough.

To calibrate the flow model and better assess when fluid change will occur at observation wells, Denbury collected injection logs from CFU 29-12 and CFU-24-2 on August 13 and 14, 2008. These logs show how fast a tracer moves out of the casing volume into the formation. CFU 29-12 received CO_2 fairly evenly over 70 ft of the perforated interval (figure 1.4-10). In contrast, CFU-24-2 has very focused flow, taking 73% of the CO_2 in the lower 20 ft (figure 1.4-11).

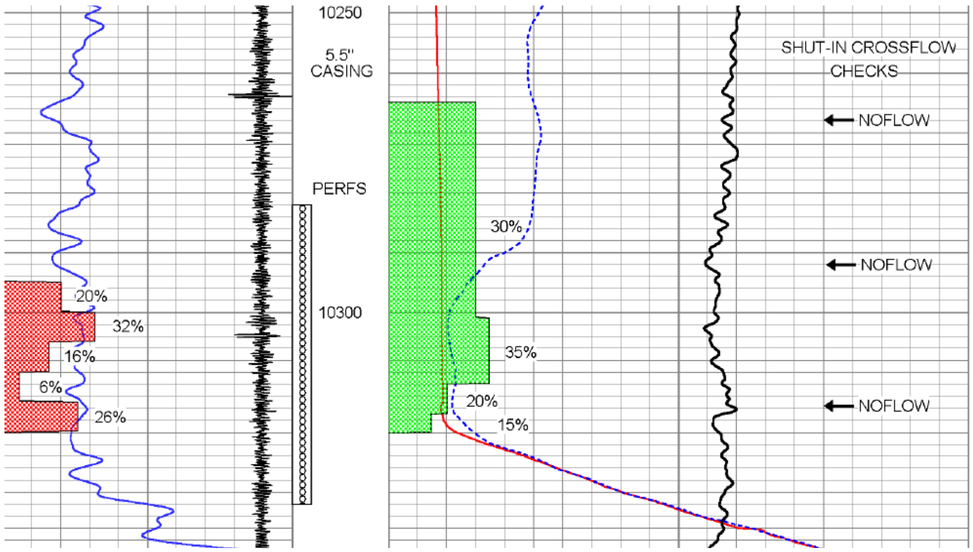


Figure 1.4-10. Injection log of CFU 29-12.

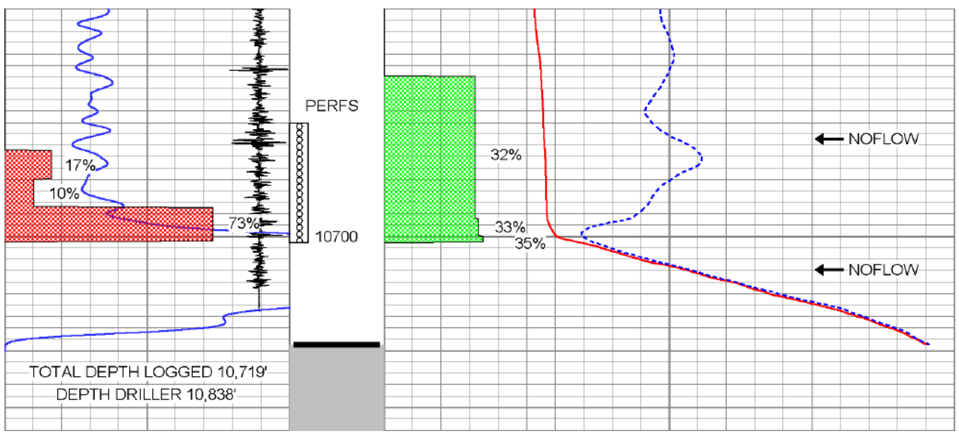


Figure 1.4-11. Injection log of CFU 24-2.

Pressure measurements in injection zone at idle wells

Bottom-hole pressure was episodically measured during development of the flood at selected production wells. A pressure gauge on slickline was lowered to the center of the perforated zone in the injection interval. Denbury with SECARB cost-share collected pressure measurements at four idle (future production) wells during the initial week of injection (figure 1.4-12). The gauges were then raised to the surface, and the pressure recorded was reported versus time. This depleted but pressure-recovered field provides a unique opportunity to observe far-field response to large-volume injection.

Areal coverage for monitoring is accomplished through dip-in pressure measurements at production wells as pressure builds. These dip-in measurements were collected episodically, some under shut-in conditions and some flowing. Results of these pressure measurements are reported in the section on modeling.

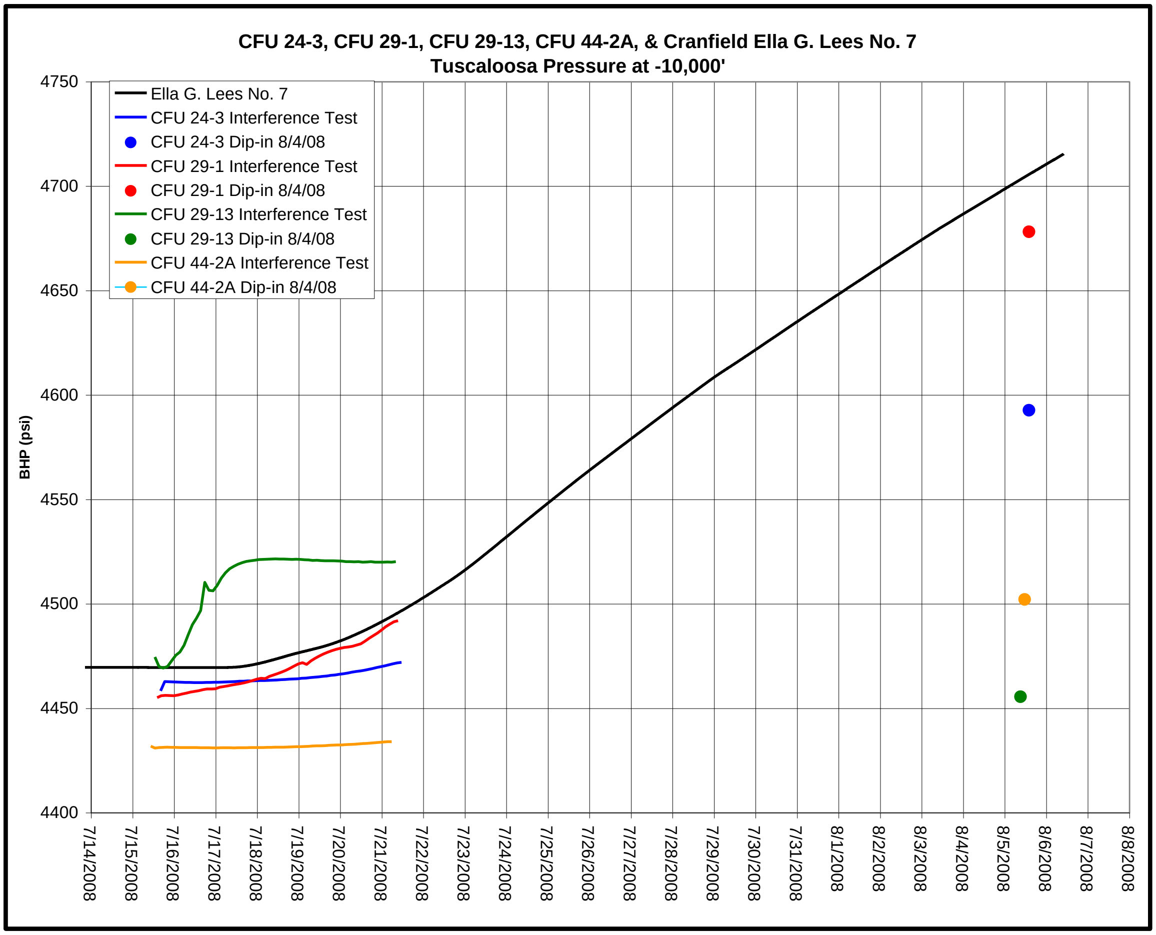


Figure 1.4-12. Pressure measurements collected from memory gauges and by ‘dip-in’ compared with those of the EGL#7 dedicated observation well. Pressures normalized to 10,000 ft.

Pressure measurements in injection zone at EGL#7

The unique surveillance tool in the Tuscaloosa “D-E” is the EGL#7 dedicated observation well that measures and reports via satellite uplink, reservoir pressure and temperature from the injection zone. This measurement was used in two ways: as a high-frequency pressure measurement in a well that is idle and therefore needs no recovery period to be representative of the reservoir, and as a high-frequency measurement giving the speed and magnitude of the response of the reservoir. Collection of these data tests the value of high-frequency data compared with those of episodic measurements obtained by conventional “dip-in” sampling. Because pressure is a broadly integrative tool, it allows monitoring of extensive areas (different directions and distances) at relatively low cost for long periods of time. Similar frequency of other observations (that is, fluid sampling, well logging, etc.) will be cost prohibitive in most situations.

Pressure response of the reservoir during the start of injection was significant because the field had equilibrated and recovered over 40 years prior to injection, and production was minimal for the first year (figure 1.4-4). During the first months, the daily injection rate at Cranfield increased to over 312,000 metric tons (6,000 MMSCFD), and 500,000 cumulative metric tons (9615 MMSCFD) of CO_2 was injected between start-up on July 15, 2008, and February 15, 2009 (~7 months after initiation). Injection initiated in two wells 1,121 (well 29-10) and 1,940 ms (well 26-1) from the observation well (EGL#7). Well 26-1 occurs on the opposite side of a sealing fault from the EGL#7 well and therefore is discounted in calculations. The injection-zone gauge in the observation well showed pressure increase within 24 hours of the start of injection and pressure in the injection zone increased continuously for 6 months, raising the ambient reservoir pressure approximately 8 MPa (1200 psi) above initial conditions. This behavior was anticipated and indicated pressure communication within the injection zone between the injection wells and the observation well. Injection zone pressure data recovery has been 90%, with data gaps relating to equipment power issues that were resolved in the field. Nine additional injectors initiated CO_2 injection at various times over the following 3 months, and average injection rates were 2 to 10 MMSCFD.

Note that pressure increases for an extended period after injection rate increases (figure 1.4-13). However, using a time derivative of rate of pressure change (Bourdet and others, 1983), we have observed that the rate of pressure increase begins rapidly to decrease. This slowing in the rate of pressure increase in this case preceded start of production. It is indicative of the interaction of a growing plume with a flow field having good lateral connectivity at the scale of pressure response (no significant interaction with a reservoir boundary).

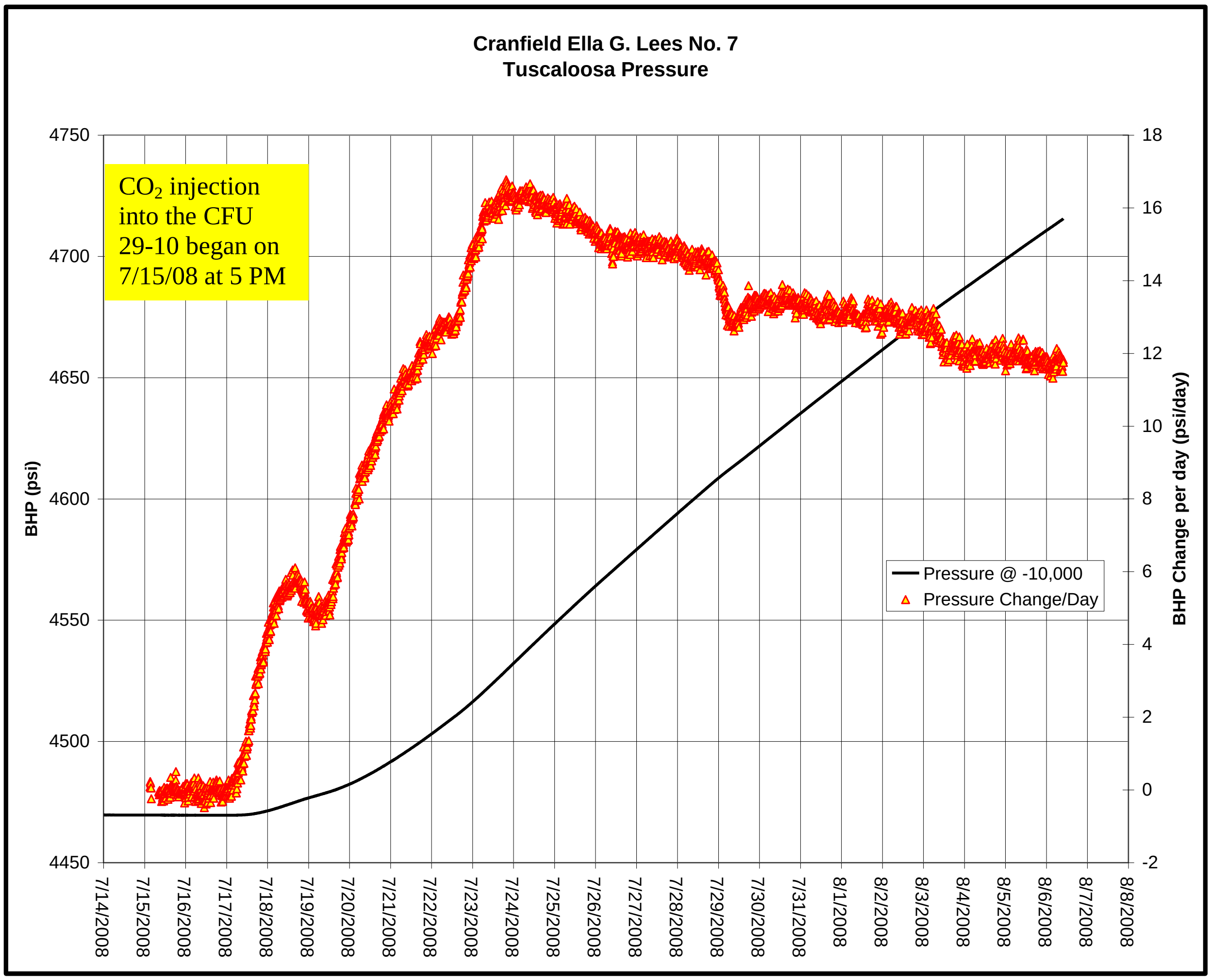


Figure 1.4-13. Bottom-hole pressure in EGL #7 observation well (black line) compared with incremental change in bottom-hole injection pressure (red symbols) at the start of injection.

Pressure-data collection and interpretation are classic reservoir-management tools. High-resolution data collection extends the traditional value placed on such methods. For the geologic conditions present at Cranfield, fluxes in injection rates of approximately 215 metric tons per day (4.1 MMSCFD) can be observed from distances of up to about 1 km. Pressure monitoring appears capable of verifying the overall conformance of an injection. Some daily injection fluxes observed at Cranfield represent less than 10% of contemporaneous fieldwide injection rates, suggesting that with proper network design incorporating multiple gauges, high percentages of injected CO_2 could be accounted for fieldwide.

The time derivative of the pressure curve (figure 1.4-14C) reveals fine details of pressure response to various injection events and is particularly powerful for understanding gauge response to distant events. In particular, changes in the rate of pressure increase are clearly observable for events such as fieldwide shut-in during Hurricane Gustav and decreased injection during Hurricane Ike, which resulted in negative rates and brief pressure decline (figure 1.4-13; table 8). Dramatic rate changes are observed in the rate of pressure change related to the initiation of individual injection wells, most notably for the 29-7 injector closest to the observation well (220 m distant). The early January increase and subsequent decrease in injection rates at the 29-2 well (525 m distant) is also clearly recorded in the injection-interval data from the observation well.

In addition, injection data can be used to characterize which injection events are not observable in the observation-well injection-zone pressure signal, helping to constrain the sensitivity of the technique. Perhaps suggestive of geologic complexity and/or limits of sensitivity, early injection activities from injectors 25-2 (898 m distant; event E in Figure 1.4-14) and 24-2 (1600 m distant; event F in figure 1.4-14) are not detectable. Given their relatively low initial injection rates compared with those of the 29-10 (figure 1.4-14 2D), these examples may illustrate the lower limit of sensitivity for that rate and distance, or they may indicate geologic barriers to pressure communication.

Figure 1.4-14C and E illustrates that injection on the east side of the fault is not being detected by the pressure gauge in the injection zone at EGL#7 on the west side of the fault, indicating the sealing nature of the fault at these timescales. For example, a response from the initiation of injector 29-4 in late September 484 m from the observation (labeled event G1 in table 8), as well as the increase in late November (labeled event G2 in table 8), would be expected, given the response observed from the initiation of the 29-7 injector 220 m from the observation well but on the same side of the fault (table 8, events C1 and C2). Finally, a decrease in injection rate at the 26-1 injector (1940 m distant) (labeled event H in table 8), as well as a similar decrease in the 27-1 injector 1450 m distant (labeled event I in table 8) probably also indicates fault sealing between the wells. No obvious pressure effects at EGL#7 are observed from initial activity at injectors 27-1 or 28-1.

Whereas we have not observed any pressure signals in the reservoir suggesting unanticipated migration out of the injection zone, the data support the capability of the observation strategy for early detection of nonconformance within the injection zone. From the sensitivity results summarized in table 8, we can infer that the initiation of significant (e.g., 10% of concurrent injection rates; hundreds to thousands of tons per day), unintentional migration of fluids (water and/or CO_2) out of the injection zone would be identifiable at timescales that would allow for dynamic modification of injection and possible mitigation (e.g., well remediation, decreased injection, abandonment). For example, initiation of injection at the injection well closest to the monitoring well 220 m away is clearly identifiable in the rate of pressure change in the injection zone. The initial injection rate at this well was approximately 5 MMSCFD (260 tons per day), or approximately 9% of total contemporaneous fieldwide CO_2 injection rates. Within 4 days the rate increased by 3.4 MMSCFD (177 tons per day), representing 6% of total fieldwide injection rates, and this response is slightly smaller (as expected) but still clearly identifiable. This figure suggests that were similar rates of migration out of zone to occur at similar timescales, they could be identified quickly as a similar magnitude but opposite sense (decrease) signal in the rate of pressure change. This fact is clearly demonstrated for larger changes in injection rates such as fieldwide shut-in for Hurricane Gustav, resulting in a decrease of about 1,000 tons/day. Event A (table 8) corresponds to a flux of -213 metric tons of CO_2 per day 3,675 ft (1121 m) from the observation well and is observable in the rate of pressure change at the gauge in the injection zone at the monitoring well. This chnage represents perhaps the highest sensitivity for the dataset and occurred early in the injection when complications of advanced pressure interference were minimized. Whereas geologic factors may complicate this sensitivity, the key observations are: (1) high-resolution changes in rate of pressure increase can be correlated with field activities to infer conformance, (2) pressure events related to injection-rate fluxes as small as about 200 tons per day are observable from distances up to about 1 km at Cranfield, and (3) events that cannot be matched to injection data would be candidates for further investigation as potentially representing unanticipated nonconformance.

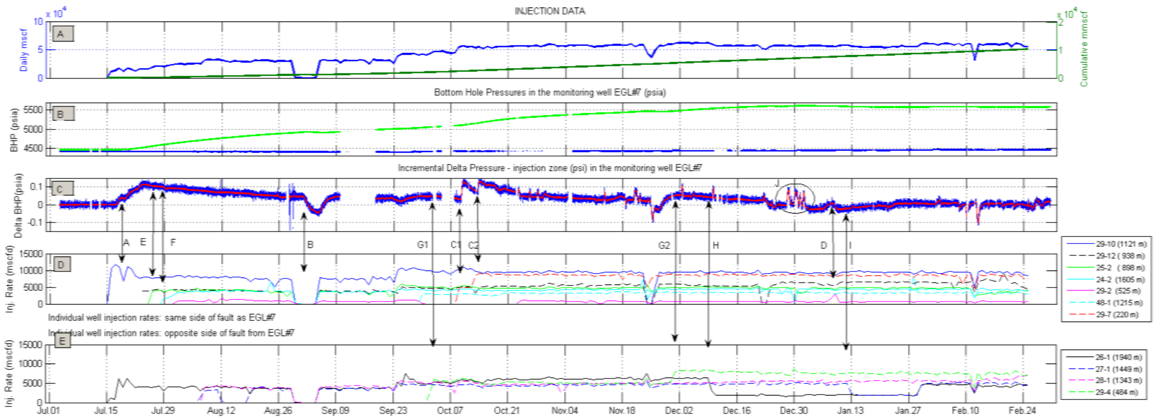


Figure 1.4-14. Fieldwide injection data and pressure response in the EGL#7 monitoring well. (A) Daily and cumulative injection data. (B) Pressure response in injection zone and overlying monitoring zone. (C) Rate of pressure change (temporal derivative) in the injection zone. Blue curve is 10-minute data. Red curve is moving average using an hourly time window. (D) Individual injection rates for injectors on the same side of the fault as the observation well. (E) Individual injection rates for injectors on the opposite side of the fault from the observation well. Injectors are labeled by name, with distance from observation well indicated in meters in parenthesis.

Table 8. Summary of sensitivity of pressure data observed in the injection zone of EGL#7 for injection events of various magnitudes and distances from the observation well. Rightmost column represents division of amplitude of response observed in Figure 2C (column 6) by flux in metric tons per day (Column 5). Other events observed in figure1.4-14C are generally related to changes in multiple-well injection rates and so are harder to evaluate. Events in the last four lines are from the opposite side of the fault from the observation well. Fault seal is demonstrated by comparing events C1 and C2 with events G1 and G2 (see figure 1.4-15 for locations).

Event	Date	Basis	Change MSCFD	Metric Tons	Amplitude of Delta-P (psi)	Effective Distance (ft)	Effective Distance (m)
(A) Hurricane Ike	7/19/2008	Individual well (29-10)	-4,099	-213	-0.006	3368	1121
(B) Hurricane Gustav	8/30/2008	Fieldwide	-19,298	-1002	-0.094	complex	
(C1) Closest injector on	10/9/2008	Individual well (29-7)	5,000	260	0.095	723	220
(C2) Closest injector increase	10/13/2008	Individual well (29-7)	3,416	177	0.057	723	220
(D) 29-2 increase	1/8/2008	Individual well (29-2)	2,397	124	0.028	525	160
(E) 25-2 startup	7/26/2008	Individual well (25-2)	3,400	176	none	2946	898
(F) 24-2 startup	7/29/2008	Individual well (24-2)	1,862	97	none	5266	1605
(G1) 29-4 startup	10/2/2008	Individual well (29-4)	2,586	134	none	1588	484
(G2) 29-4 rate increase	12/1/2008	Individual well (29-4)	2,624	136	none	1588	484
(H) 26-1 rate decrease	12/10/2008	Individual well (26-1)	-4,568	-237	none	6366	1940
(I) 27-1 rate decrease	1/13/2009	Individual well (27-1)	-2,587	-134	none	4754	1449

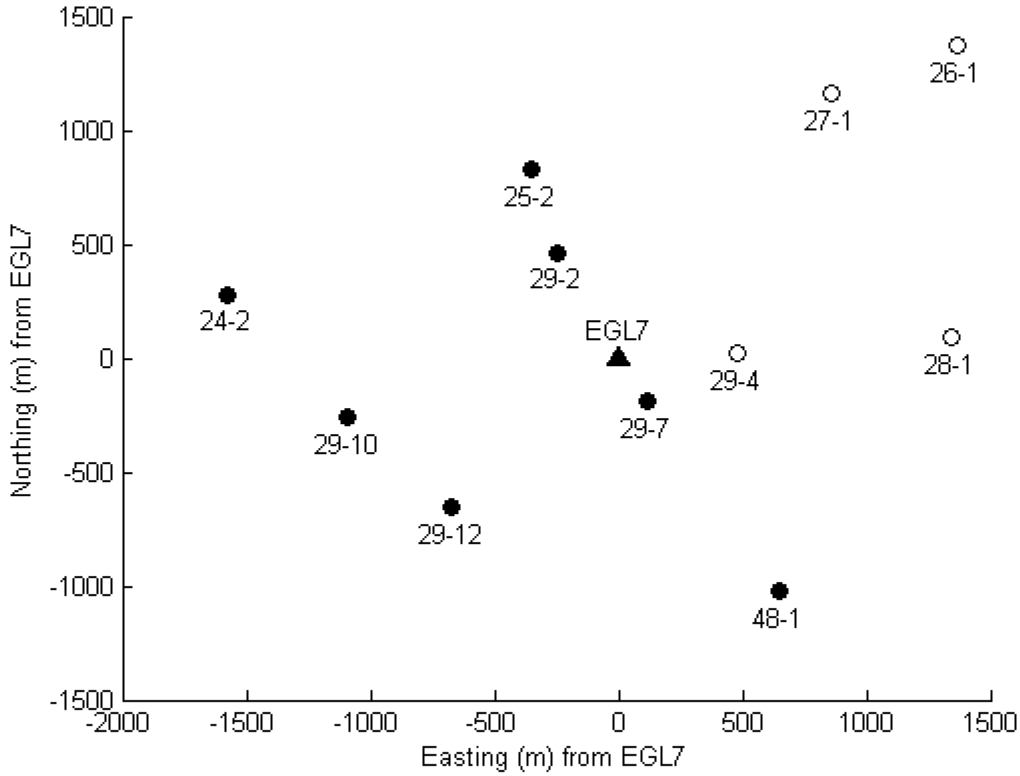


Figure 1.4-15. Phase II well locations described in figure 1.4-14 and table 8.

One difficulty in interpreting the detailed pressure response in Phase II was that injection data were not recorded at frequencies other than by a daily injection rate collected by the field technician reading the flow meter at each injection well. Downhole gauge data are sensitive to shorter timescales (minutes and hours). The use of high-frequency flow meters for quantifying temporally variable injection rates throughout the field is justified, given the potential for improved analysis using continuous gauge data. This recommendation was used to justify purchase of a MicroMotion coriolis flow meter for the Phase III test. Given the lack of detailed injection data during Phase II, we suspect that many of the pressure transient events that cannot be related directly to injection data may represent unrecorded injection activities related to minor field operations, as supported by their short duration. Availability of continuous injection data would obviously benefit reservoir-pressure analysis, but it would come at a cost that is not justified in this EOR project, although it may be for sequestration activities with stringent accounting regulations.

One drawback of cost-limited single-well deployment at the study site is that it could be challenging to identify the cause or location (distance and direction) related to an inexplicable pressure signal in the observation well (e.g., unwanted migration). Employing a suite of similar deployments in multiple wells would be useful for evaluating various scenarios to explain pressure data. Distinguishing between localized rapid (acute) well leakage and more pervasive, longer-term (chronic) failure in confining systems or fault leakage should be possible, as has been demonstrated for natural gas storage projects (University of Michigan, 1966).

For this study, a comparison was made of observations of brine-filled well-tubing pressure using a gauge at the ground surface (wellhead) with those of reservoir pressure using a downhole gauge in the same well. One reason for this analysis was to determine which events identified in the downhole gauge were observable in the surface gauge because deployment of such gauges is far less expensive, providing more opportunities for deployment. This test was done prior to breakthrough (arrival of free-phase CO_2 and mobile oil at this well).

The downhole injection reservoir gauge and surface gauge in EGL#7 are in pressure communication via the 3.5-inch well tubing. Prior to injection at the end of completion, tubing was produced so that it was filled with a single fluid at the dame salinity as that of formation brine and allowed to thermally equilibrate with the host rock. At the start of injection, water levels in the tubing were static at about 300 ft below land surface, and the top of the tubing was filled with air somewhat rich in exsolved methane. The tubing was closed at the wellhead so that, as pressure in the reservoir built, atmosphere was compressed. Under these conditions, surface tubing-pressure observations were influenced by downhole reservoir pressure, fluids in the tubing, and the temperature at the surface. In high-frequency data we can see that wellhead tubing temperature is strongly correlated with tubing wellhead pressure, as would be expected by CO_2. To eliminate these temperature effects and to isolate the component of the tubing-pressure gauge data that more accurately represents downhole reservoir conditions, a standard second-order polynomial least-squares regression was performed on the tubing temperature and tubing-pressure data, and the polynomial fit (figure 1.4-16B) was used to remove temperature effects from the tubing-pressure data. The corrected tubing-pressure data were then filtered using a 4-hour window running average to smooth random noise (other window sizes result in varying amounts of residual random noise) and compared with the downhole pressure observed. Whereas the processed surface tubing-pressure data are clearly noisier than the downhole data, a good match between measured BHP and corrected surface tubing pressure was demonstrated for this example. However, the sensitivity of such methods has important implications, especially for CCS projects that may have significant monitoring components. It is clear from this example that the surface gauge in an equilibrated, brine-filled well can essentially and instantaneously detect fluxes of hundreds of tons per day of CO_2 from hundreds of meters away. Further development of this technique in general (as well as for specific reservoirs) will enhance measurement, monitoring, and accounting procedures related to CCS.

This analysis suggests a conventional tradeoff between cost and observation resolution for pressure monitoring; more surface gauges could be deployed over a larger area at the same cost as fewer downhole gauges, with an acceptable sacrifice of pressure-event resolution. A combination of surface and downhole gauges could be deployed, but a pragmatic balance should be strived for, given the minimum magnitude of pressure perturbation that is expected to reflect a concerning pressure condition. Such conditions could be investigated prior to injection by using flow simulations incorporating unwanted migration scenarios of interest. Downhole data will always be more accurate, however much meaningful analysis related to measurement, verification, and accounting can be undertaken with surface gauges, at significant cost savings over downhole gauge deployment. A significant parameter is noted in that if the density of fluids in the well changes, bottom-hole and surface pressure are decoupled. Changes in fluid density are minimal for brine-filled wells. In wells filled with gasses, changes result from thermal effects from the surface, recovery of perturbation, or complex in-well thermal effects (Henninges et al., 2010). In reservoirs that mobility of fluids (oil, gas, CO_2) changes over time, accumulation of fluids of different density will greatly decouple reservoir pressure from surface gauges.

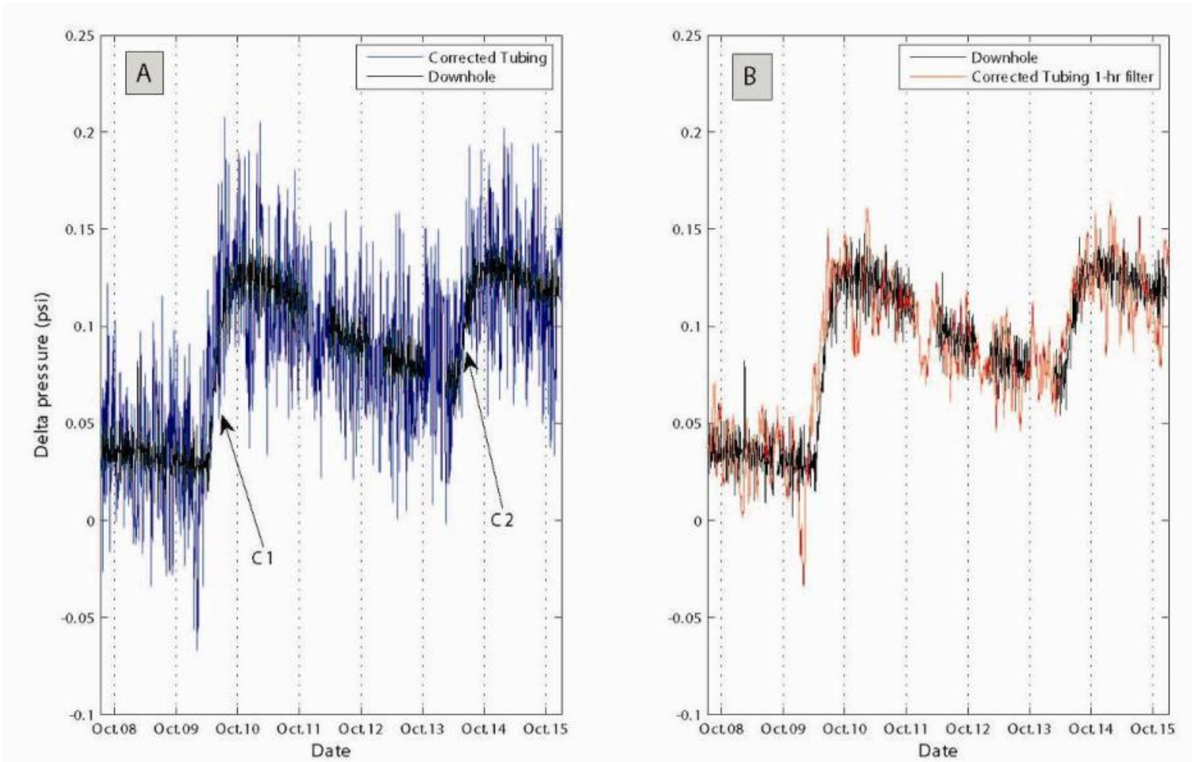


Figure 1.4-16. Processed wellhead pressure (tubing) data to remove surface temperature and random noise can be used to identify changes in reservoir pressure that are observable in downhole gauges. (A) Processed surface data compared with actual downhole data are noisier but are reasonably responsive to known events. (B) Hourly filtering of corrected tubing surface data in A indicates that accuracy above noise levels is possible.

Pressure response at EGL#7 indicative of breakthrough

The EGL#7 observation well was located at a central point in the Phase II flood so that it could monitor activities at 16 active wells (7 injection wells and 9 production wells) completed in the lower Tuscaloosa "D-E" injection zone. Models showed that we would expect CO_2 to arrive at EGL#7 about 6 months after start of injection and soon after beginning of injection at the injector 200 m to the north of EGL#7. However, by the 2-year anniversary of the beginning of the flood, July 15, 2010, no free-phase CO_2 had been observed at the injection zone in the EGL#7 well. Note that Denbury has been decreasing injection rates in this part of the field, so reservoir pressure was declining.

On July 21, 2010, a sharp change in tubing pressure at the wellhead (figure 1.4-17) signaled the start of accumulation of a less-dense phase in the tubing. This change was interpreted as arrival of free-phase CO_2 plus possible oil (breakthrough). Prior to this event, the tubing was filled with reservoir brine. Because tubing is open to the perforated interval in the injection zone, wellhead tubing pressure had been paralleling bottom-hole pressure faithfully. Arrival of CO_2 caused lightening of the density (~1.1 – 0.6 g/cc) of the fluid column, and therefore pressure at the wellhead increased. No change in either bottom-hole pressure or AZMI pressure was noted (figure 1.4-18). Arrival of CO_2 was preceded by a 0.3° F warming pulse in the reservoir (figure 1.4-18) that may be attributed to dissolution or to migration of a warmer phase, perhaps oil. The possible reasons for timing of breakthrough being delayed were due to production on the opposite (south) side of the injector nearest EGL#7, enhancing asymmetrical fluid flow toward the producer.

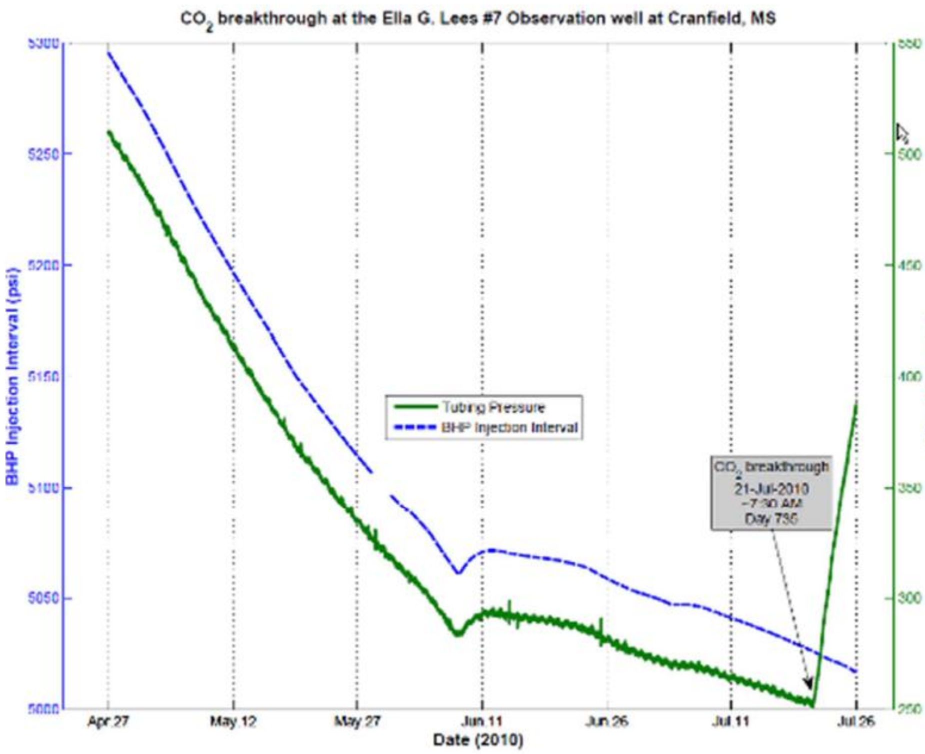


Figure 1.4-17. Indications of CO_2 breakthrough at EGL#7. Bottom-hole pressure in the injection zone (blue) tracks wellhead tubing pressure (green) until density of the well-bore fluid changed on July 21, 2010.

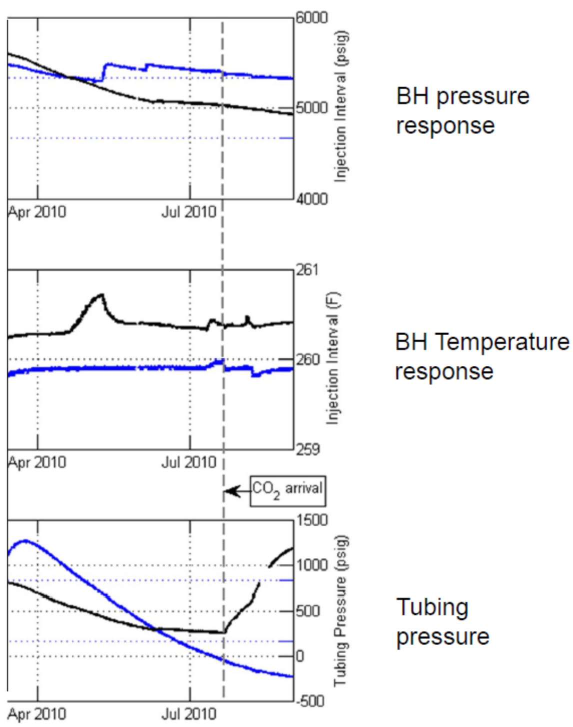


Figure 1.4-18. Detail of indications of CO_2 breakthrough at EGL#7. Top: detail of bottom-hole (black) and AZMI (blue) pressure response; middle: detail comparison of bottom-bole (black) with AZMI (blue) temperature response; and bottom: detail showing change in bottom-hole pressure in injection zone (blue) compared with measurement of tubing pressure at wellhead.

AZMI Response to Injection in the Tuscaloosa "D-E" Sand Interval

Measurements of subsurface fluid pressure in the above-zone monitoring interval (AZMI) were made during Phase II at the EGL#7 dedicated observation well. In phase III, each of the observation wells at the detailed area study (DAS), CFUF31-2 and CFUF31-3, was instrumented at the AZMI interval with a downhole pressure and temperature gauge behind casing; these wells will be integrated into an assessment of feasibility of monitoring AZMI during Phase III.

The real-time continuous pressure data system (AKS) began transmitting data after activation in June 2008, and an immediate pressure response to injection initiation on July 14 was measured in the injection interval (figure 1.4-19). Prior to initiation of injection, slight pressure changes measured in both zones were interpreted as recovery to after-well workover, with minor pressure rebuilding in the monitoring sandstone and pressure decreasing in the injection sandstone. First-order pressure response in the injection interval appears smooth, although the rate of pressure change (temporal derivative) can be correlated with injector operations (increase or decrease in injection) or shut-in periods (Meckel and Hovorka, 2009).

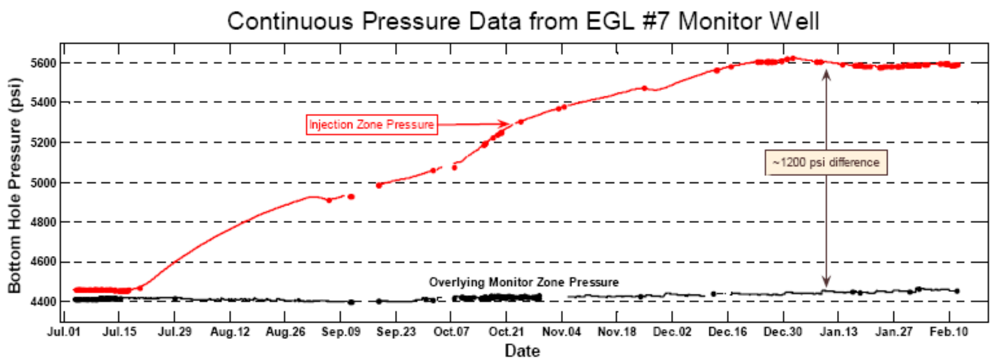


Figure 1.4-19. Continuous-pressure data from upper and lower gauges from July 2008 through February 2009.

For the entire time series, magnitude of pressure fluctuation in the monitoring sandstone is small (~+100 psi), compared with more than 1,200 psi in the injection zone (figure 1.4-19). After injection initiation, the AZMI pressure response is characterized by an initial period of minor pressure decrease (tens of psi) for about 3 months, followed by an overall pressure rise (figure 1.4-20, top). However, the sustained pressure differential of more than 1100 psi (8 MPa) indicates reasonable isolation across the geologic confining system between the two zones. In addition, temperature data do not indicate significant fluid volumes moving from the injection interval to the AZMI near the observation well because a constant temperature differential is maintained between the two observation points (reservoir and AZMI; figure1.4-20, middle).

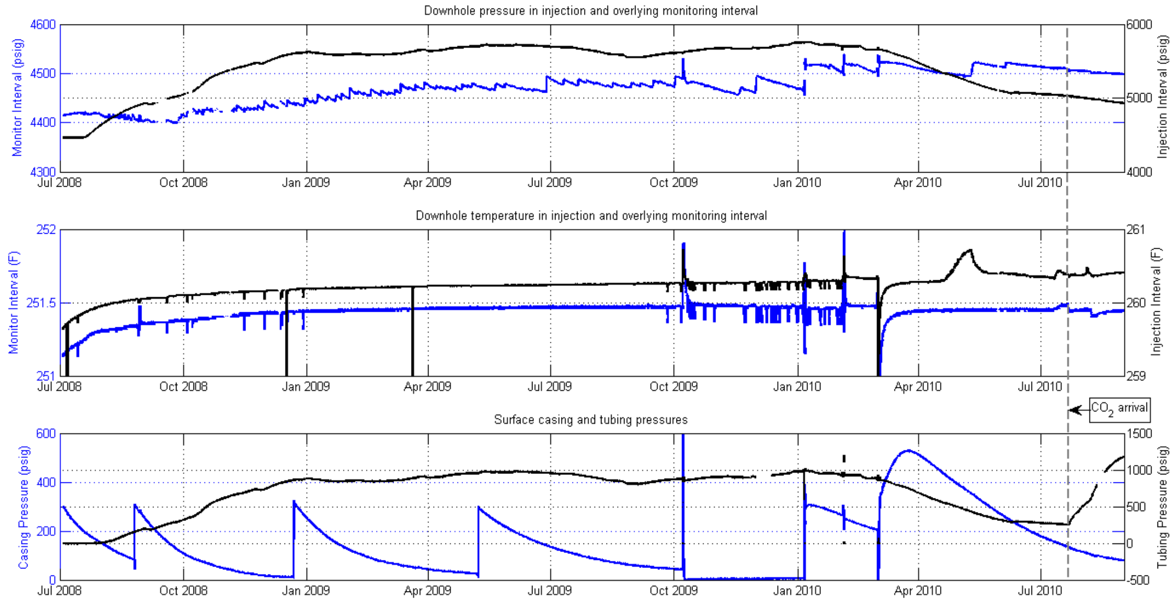


Figure 1.4-20. Long-term continuous-pressure and temperature measurements at the EGL#7 injection zone (black) and AZMI (blue). Top graph shows bottom-hole pressure adjacent to perforations in the lower Tuscaloosa D-E CO_2 injection zone (black) compared with bottom-hole pressure at the AZMI (note different vertical scales for the two gauges). The middle panel shows temperature at the injection zone (black) compared with temperature at the AZMI measured at the gauges, and the bottom graph shows casing-pressure management (pressured up with corrosion-inhibited fresh water and slowing bleed off through flaws in the casing repair). Casing-pressure changes are not correlated to pressure fluctuations in the injection interval or AZMI, demonstrating that flaws in the tubing are not responsible for observed variations.

Within the AZMI data exists high-frequency, serrated behavior characterized by sharp increases in pressure lasting minutes to hours, followed by linear pressure decline lasting days to weeks (figure 1.4-20, top). Statistics of these events indicate that they occur at random intervals and that the pressure increase and subsequent decreases are generally of similar magnitude but very different duration. The frequency of these events decreases moving forward in the time series toward present. This serrated signal is not yet well understood; however, it does not seem to be a leakage signal from the injection zone because it is not at all correlated to monotonic pressure increase in that zone and there is no temperature increase that would be expected to accompany hotter fluid moving upward.

Further evaluation of the serrated AZMI pressure signal was undertaken at the end of August 2008. We speculate that the monitoring zone is hydrologically connected to a source of relative underpressure. This underpressure could be natural; however, we suspect that it may be related to production from much higher in the stratigraphic interval and could be either a zone in the Tuscaloosa that has not recovered or a zone that is being depressured in the Wilcox. Additionally, the spikes could be interpreted as a small, intermittent leakage (a matter of a few ounces) upward from the injection zone, and we thought that it was important to evaluate this possibility. In consultation with Sandia Technologies, we developed a plan to further assess the signal, which was conducted August 25–26, 2010.

Because the noise signal is sharp, we hypothesized that pressure change is occurring near the Panex gauge in the monitoring interval (not, for example, at another distant well in the field), and therefore we focused our assessment on the EGL#7 well at depth. Cost was a key consideration because the phase II budget is essentially committed.

Initially repressurization of the casing annulus, (pressure had gradually declined from 250 to 100 psi [1.7 to 0.7 MPa]), introduced a strong signal into the engineered system. No response in the pressure transducers in the monitoring zone or in the injection zone was observed, demonstrating that tubing or casing leakage is not the cause.

Next, a through-tubing temperature log was used as a standard tool to assess behind-casing flow. Because of the geothermal gradient, this tool will locate flow of fluid from one zone to another, which would focus the investigation. No anomaly was observed, suggesting either that flow is not near the well or that the volumes transferred are small and thermally equilibrated.

Subsequently an acoustic log was used to locate noise that could indicate flow behind casing. No significant source of noise was located in the depth survey, in which data were collected at numerous depths between the injection interval and AZMI. The acoustic sensor was placed to sit stationary at selected points above the monitoring sand, at squeeze perforations below the monitoring sand, and in the zone between the lower two packers. This test detected some intermittent noise (figure 1.4-21). Because noise is conducted efficiently through water, it is important to consider that it may not originate where it is detected.

We interpret these tests as an indication that any flow processes near the well are small and produce no thermal or continuous flow. We will continue to observe as the fluid composition changes as CO_2 breaks through. If there is any leakage from the injection zone this testing? should give a clear signal.

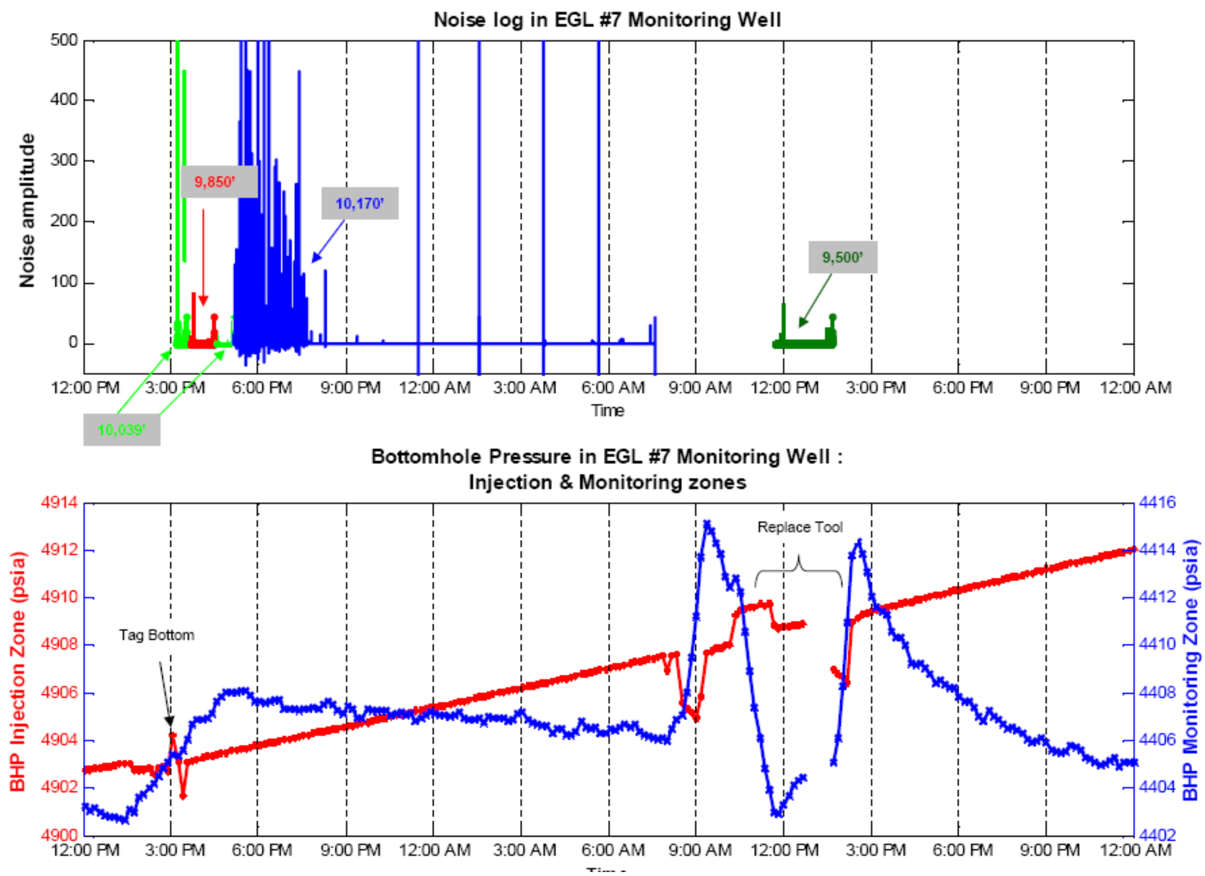


Figure 1.4-21. August 2008 acoustic-log summary (top) compared with pressure response in injection and monitoring zones (bottom).

In early 2009 AZMI pressure measurements were duplicated by deployment of a gauge at the dummy gas valve with a blanking plug in the tubing. This repeat measurement confirmed the correct pressure at the AMZI. The minor disruption of the well bore seems to have reduced the saw-tooth fluctuation on the original gauge, confirming a local perturbation source at the gauge or in the well geometry.

Simulation of pressure response using an analytical approach to coupled abandoned well-bore communication allows potential contributions to the above-zone pressure signal from existing and recently drilled wells to be evaluated. Specifically, measured pressure data have been used to constrain the sensitivity of pressure for detecting cross-formational communication via well bores and to determine possible scenarios that can explain the observed above-zone pressure time series. Modeling results indicate that pressure data from the above-zone gauge can be matched with variable fidelity to a variety of plausible coupled well-bore-flow scenarios. The small magnitude of above-zone pressure increase can be matched to both local and distant minor communication between the injection interval and the AZMI via existing well bores. High-frequency detail apparent in the above-zone data suggests that fluid flow local to this well was detected by continuous pressure measurement but below the detection limit of noise, temperature, and cement bond logs tested. We will continue observation now that CO_2 has arrived at this well, which may reduce the number of credible scenarios. We also plan to repeat fluid sampling of the AZMI, which will test whether any fluid from the injection zone has migrated to the AZMI. Analysis of this long-term pressure record continues into Phase III.

Three primary observations suggest that interformational (injection reservoir to AZMI) communication at the site due to large-volume CO_2 injection is negligible: (1) A significant pressure differential is sustained for the period of injection (currently >2 years), reaching a maximum of approximately 1,200 psi (>8 MPa), (2) temperature data do not indicate significant fluid volumes moving from the injection interval to the AZMI near the observation well, and (3) pressure trends and transients created in the injection interval by variable CO_2 injection rates are not apparent in the AZMI data.

Several recommendations can be made from this experiment. Deconvolution of the pressure response at two zones has been more complex than anticipated because of dual completion. Open perforations in both the injection zone and monitoring interval separated by packers and tubing have introduced thermal and pressure transients into the system. In addition, retrofit of the EGL#7 original production well into an observation well introduced a number of uncertainties. Distribution of cement in the well bore and location and effectiveness of sloughed material in limiting behind-casing flow along the uncemented borehole limit utility of interpreting pressure response. We have no certainty that the borehole is closed above the AZMI. We also recognize that past pressure transients must be fully evaluated to design for successful measurement. For example, could the rapid pressure drops observed in the AZMI be related to a low pressure zone, relict from maximum historic field production? The complexity would not be as apparent without high-frequency data. On the basis of this observation of complexity, we recommend, and are planning, simpler completions at future sites, with one zone open per well and known cement distribution providing isolation. Doing so would increase well cost, but would reduce completion costs and should lead to cleaner and more uniquely interpretable data.

Downhole-pressure gauges provide a valuable means of monitoring the performance of carbon-sequestration projects. Continuous data as compared with intermittent measurements provide much more information on process and are recommended for the next steps of tool evolution. Real-time data have potential as a tool, with value for public acceptance. Our deployment of this technique at EGL#7 and in two other wells at Cranfield provides the following insights for consideration in future deployments:

1. Monitoring with high-resolution gauges requires good well completions to ensure high data quality. Complex dual completions such as we used present interference issues. In our EGL#7 deployment, interpretation is complicated by engineering-related contributions to the observed pressure signal associated with remediation and complex dual completion of the 60-year-old observation well. When possible, simple completions utilizing newly drilled wells are recommended for data collection used for regulatory purposes.
2. Continuous data from high-resolution gauges will attain highest value when other field data (e.g. injection rate, workover activities, etc.) are acquired with similar temporal precision, even if less frequently. This fact is particularly true for CCS sites for which higher standards for demonstrating containment are likely. High-resolution pressure data are capable of recording subtle transients that may indicate a variety of processes and events; distinguishing routine and benign events from those that are potentially more problematic for storage integrity will be difficult without equally comprehensive and accurate complementary data.
3. Redundancy, flexibility, and simplicity in deployment are extremely desirable. Monitoring that relies on a single technology or deployment risks data loss. Our well design included side-pocket mandrels for memory-gauge deployment in the event of permanent downhole gauge failure. In addition, tubing pressure measured at the surface was determined to be useful when corrected for tubing fluids and surface conditions. A simple piezometer-style tubing deployment for measuring pressure may also be economical and highly reliable.

EGL#7 may be an interesting well to consider for evaluating the impact of CO_2 on historic wells. This activity is outside of both Phase II and Phase III goals, but has been a long-term objectives of several programs, such as CCP. Well-condition assessment was recommended to RCSP as part of the 2008 IEA review.

Surface Ecosystem Monitoring

Surface ecosystem monitoring, including groundwater monitoring and soil-gas monitoring, focused on follow-up assessment, and the methane anomaly at the "P-site" was transferred to Phase III. The reasons for grouping surface monitoring are (1) efficiency in management and execution because the two areas are adjacent, (2) greater data coverage because more sample points are included in each set and (3) longer duration of sampling because Phase III continues past the end of Phase II.

Groundwater monitoring

Detailed analysis of groundwater data is under way as part of Phase III. Some damages to water quality tentatively attributed to past oil-field activities were noted during baseline. In this section, preliminary data are reported to show absence of a systematic trend attributed to CO_2 leakage. A total of 6 field trips were conducted to collect groundwater samples from 10 "makeup" wells at Cranfield oil field, which were completed from July 2008 to December 2010. Values of groundwater pH were measured in the field and in the lab (figure 1.4-22). Values of pH measured in the lab are more consistent than values measured in the field but may not reflect equilibrated gasses. There are significant differences for the groundwater samples taken in April 2009, July 2010, and November 2010. Alkalinity measurements show a slightly increased trend with time (figure 1.4-23). An increasing trend might be an effect of rock-water interaction with CO_2 and therefore indicative of leakage from the reservoir. However, testing this hypothesis by looking at values of stable carbon isotopes of dissolved inorganic carbon (figure 1.4-24) fails to support the hypothesis. Stable carbon isotopes do not show significant increase and therefore are unlikely to have been caused by allochthonous, heavy CO_2 from Jackson Dome. Measurements of water conductivity do not show any increasing trend (figure 1.4-25). Further modeling during Phase III will reevaluate these initial assessments.

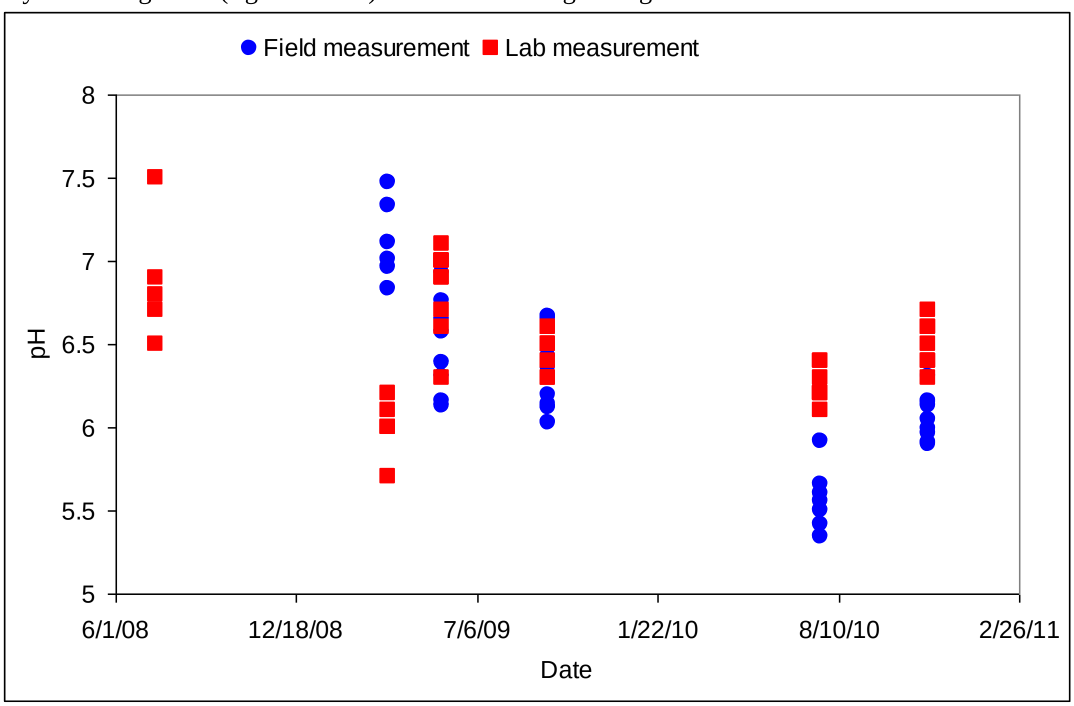


Figure 1.4-22. Field and lab measurements of groundwater pH from shallow (200–300 ft) wells at Cranfield for the six sampling trips since 2008.

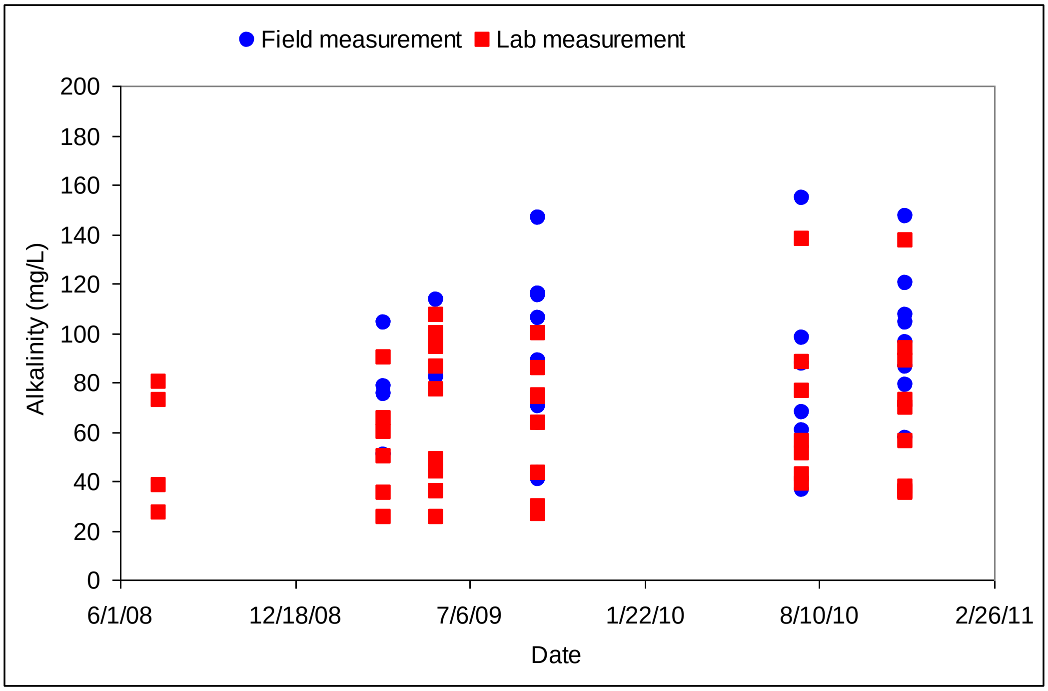


Figure 1.4-23. Field and lab measurements of groundwater alkalinity from shallow (200–300 ft) wells at Cranfield for the six sampling trips since 2008.

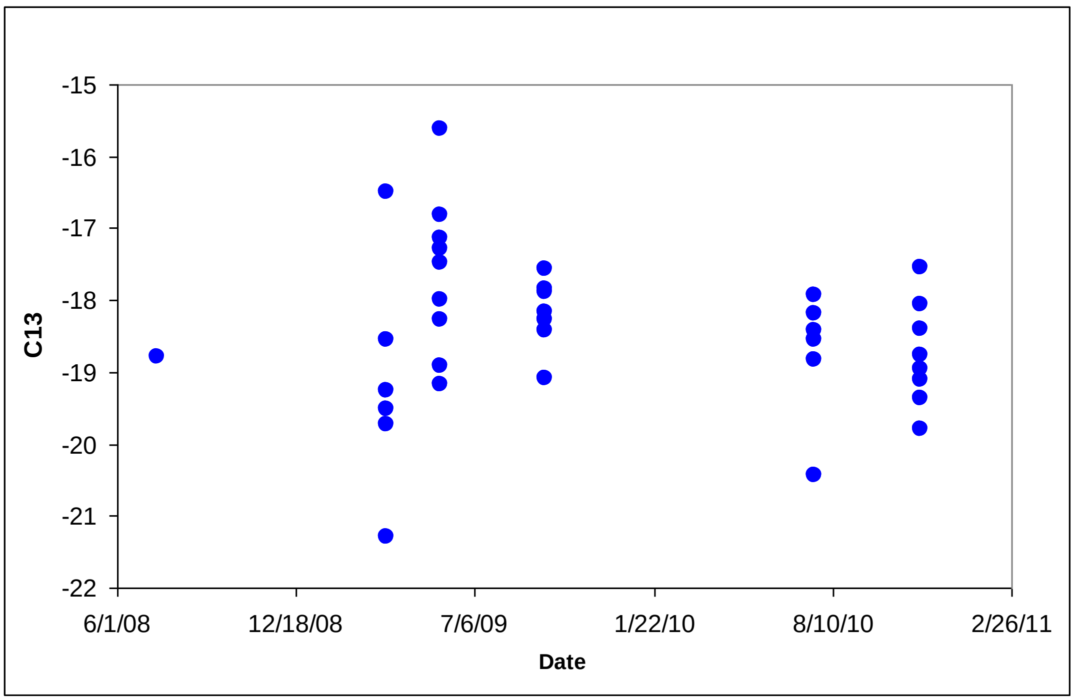


Figure 1.4-24. Stable carbon isotope of dissolved, inorganic carbon of groundwater from shallow (200–300 ft) wells at Cranfield field for the six sampling trips since 2008.

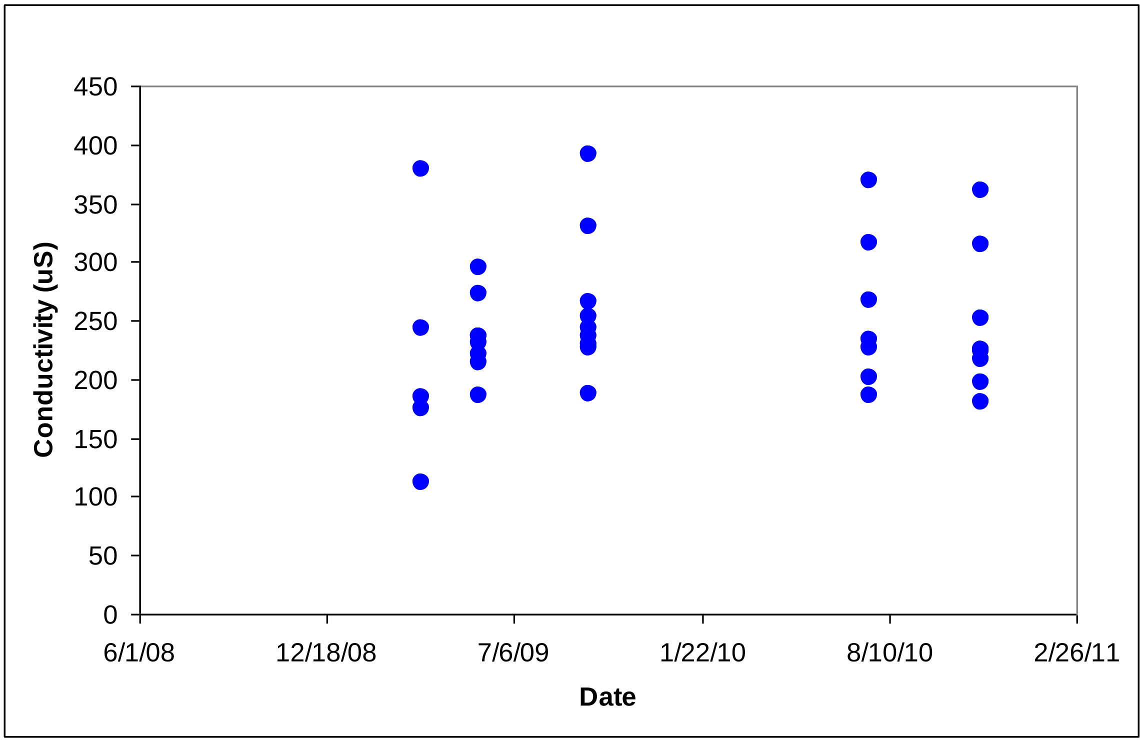


Figure 1.4-25. Groundwater conductivity at shallow (200–300 ft) wells at Cranfield field for the six sampling trips since 2008.

Soil-gas monitoring

Repeat ecosystem monitoring was conducted October 20 and 21, 2009, by Bureau staff member Katherine Romanak at the same wells surveyed before CO_2 injection. Gas concentrations of CO_2, CH_4, O_2+Ar, and N_2 were measured at the ground surface along 20- to 40-m-long transects (10- to 5-m sample spacing) using a field-portable gas chromatograph. Field analyses were also conducted on soil-gas samples collected from 23-cm depths at CFU 29-6, 29-7, 24-4, and 29-2. No CH_4 was detected, and CO_2 concentrations were near atmospheric (table 9), indicating no widespread significant flux of deep gases is occurring at the site.

Table 9. Summary of select gas components monitored in October 2009 at Cranfield.

Analysis date	Analysis time	Location notes	Lat	Long	CO_2 (vol. %)	CH_4 (vol. %)
10/20/2009	14:46:29	N end of gas transect near Johnson 1 well	31.57233	91.16125	0.036	0.00
10/20/2009	14:52:36	Gas transect near Johnson 1 well, 5 m	31.57227	91.16123	0.036	0.00
10/20/2009	14:58:51	Gas transect near Johnson 1 well, 10 m	31.57214	91.16115	0.068	0.00
10/20/2009	15:06:27	Gas transect near Johnson 1 well, 15 m	31.57225	91.16120	0.031	0.00
10/20/2009	15:09:54	Gas transect near Johnson 1 well, 20 m	31.57213	91.16115	0.033	0.00
10/20/2009	15:14:01	Gas transect near Johnson 1 well, 25 m	31.57207	91.16116	0.031	0.00
10/20/2009	15:18:40	S end of gas transect near Johnson 1 well, 30 m	31.57207	91.16135	0.056	0.00
10/20/2009	16:13:30	NE end of gas transect near Cranfield 29-5 well	31.58158	91.17986	0.064	0.00
10/20/2009	16:17:02	Gas transect near Cranfield 29-5 well, 5 m	31.58142	91.17980	0.032	0.00

10/20/2009	16:22:16	Gas transect near Cranfield 29-5 well, 10 m	31.58131	91.17973	0.065	0.00
10/20/2009	16:26:03	Gas transect near Cranfield 29-5 well, 15 m	31.58139	91.17970	0.065	0.00
10/20/2009	16:29:22	SW end of gas transect near Cranfield 29-5 well, 20m	31.58129	91.17971	0.030	0.00
10/20/2009	17:04:15	W end of gas transect near Ella G Lees 11 well	31.57971	91.17304	0.056	0.00
10/20/2009	17:07:23	Gas transect near Ella G Lees 11 well, 10 m	31.57969	91.17298	0.043	0.00
10/20/2009	17:13:25	Gas transect near Ella G Lees 11 well, 20 m	31.57966	91.17283	0.032	0.00
10/20/2009	17:17:58	E end of gas transect near Ella G Lees 11 well	31.57962	91.17276	0.037	0.00
10/20/2009	17:34:33	S end of gas transect near Cranfield 29-2 well	31.58272	91.17213	0.061	0.00
10/20/2009	17:37:38	Gas transect near Cranfield 29-2 well, 5 m	31.58276	91.17217	0.059	0.00
10/20/2009	17:41:07	Gas transect near Cranfield 29-2 well, 10 m	31.58281	91.17223	0.030	0.00
10/20/2009	17:45:47	Gas transect near Cranfield 29-2 well, 15 m	31.58283	91.17224	0.055	0.00
10/20/2009	17:48:59	N end of gas transect near Cranfield 29-2 well, 20 m	31.58288	91.17226	0.029	0.00
10/21/2009	17:46:11	soil gas sample 9 inches depth near 29-2 well	31.58261	91.17205	0.028	0.00
10/21/2009	17:49:29	soil gas sample 9 inches depth near 29-2 well	31.58261	91.17205	0.032	0.00
10/21/2009	17:53:24	soil gas sample 9 inches depth near 29-2 well	31.58261	91.17205	0.065	0.00
10/20/2009	18:07:09	N end of gas transect near Cranfield 29-6 well	31.57676	91.17288	0.030	0.00
10/20/2009	18:11:41	Gas transect near Cranfield 29-6 well, 5 m	31.57672	91.17290	0.031	0.00
10/20/2009	18:14:43	Gas transect near Cranfield 29-6 well, 10 m	31.57671	91.17287	0.030	0.00
10/20/2009	18:17:45	Gas transect near Cranfield 29-6 well, 15 m	31.57672	91.17289	0.034	0.00
10/20/2009	18:20:37	Gas transect near Cranfield 29-6 well, 20 m	31.57668	91.17279	0.033	0.00
10/20/2009	18:23:34	Gas transect near Cranfield 29-6 well, 25 m	31.57674	91.17293	0.034	0.00
10/20/2009	18:27:06	S end of gas transect near Cranfield 29-6 well, 30 m	31.57682	91.17292	0.031	0.00
10/21/2009	18:09:34	soil gas sample 9 inches depth near 29-6 well	31.57701	91.17278	0.064	0.00
10/21/2009	18:12:26	soil gas sample 9 inches depth near 29-6 well	31.57701	91.17278	0.030	0.00
10/21/2009	15:54:19	N end of gas transect near Cranfield 29-7 well	31.57622	91.16757	0.035	0.00
10/21/2009	15:58:50	Gas transect near Cranfield 29-7 well, 5 m	31.5762	91.16753	0.035	0.00
10/21/2009	16:02:04	Gas transect near Cranfield 29-7 well, 10 m	31.57617	91.16753	0.031	0.00
10/21/2009	16:05:13	Gas transect near Cranfield 29-7 well, 15 m	31.57614	91.16756	0.031	0.00
10/21/2009	16:08:47	Gas transect near Cranfield 29-7 well, 20 m	31.57613	91.16757	0.057	0.00
10/21/2009	16:12:47	Gas transect near Cranfield 29-7 well, 25 m	31.57608	91.16756	0.030	0.00
10/21/2009	16:17:45	S end of gas transect near Cranfield 29-7 well, 30m	31.57603	91.16753	0.052	0.00

10/21/2009	16:24:07	soil gas sample 9 inches depth near 29-7 well	31.575 97	91.167 53	0.029	0.00
10/21/2009	16:27:18	soil gas sample 9 inches depth near 29-7 well	31.575 97	91.167 53	0.030	0.00
10/21/2009	16:51:27	S end of gas transect near Cranfield 29-4 well	31.578 37	91.164 58	0.030	0.00
10/21/2009	16:54:40	Gas transect near Cranfield 29-4 well, 5m	31.578 45	91.164 60	0.054	0.00
10/21/2009	16:57:29	Gas transect near Cranfield 29-4 well, 10m	31.578 46	91.164 56	0.028	0.00
10/21/2009	17:00:49	Gas transect near Cranfield 29-4 well, 15m	31.578 5	91.164 54	0.029	0.00
10/21/2009	17:04:44	Gas transect near Cranfield 29-4 well, 20m	31.578 55	91.164 57	0.028	0.00
10/21/2009	17:07:36	Gas transect near Cranfield 29-4 well, 25m	31.578 58	91.164 60	0.027	0.00
10/21/2009	17:10:58	N end of gas transect near Cranfield 29-4 well	31.578 62	91.164 56	0.027	0.00
10/21/2009	17:15:55	Soil-gas sample 9 inches depth near 29-4 well	31.578 72	91.164 51	0.028	0.00
10/21/2009	17:18:56	Soil-gas sample 9 inches depth near 29-4 well	31.578 72	91.164 51	0.030	0.00

Follow-on work at the high-methane –high-CO_2 soil-gas location near well CFU 29-9 is being conducted as part of Phase III. CO_2 at this site is interpreted as a product of biodegradation of methane, and no CO_2 attributed to a Jackson Dome source has been sampled. A source of the methane has not been uniquely determined, although an extensive test program is in progress to attempt to determine the source and mechanism of migration.

Subtask 1.5: Project Summary: Modeling, Reporting, and Closeout

Modeling

Modeling provides an integration of a number of types of data collected during the project (Nicot and others, 2009a). The Phase II model was developed through 2009. More recent modeling has been focused on Phase III, which includes a large number of refinements in response to Phase II learning, although use of the Phase II model continues as a test bed for refinements and other assessments.

The model area includes the northern third of the Cranfield reservoir, where Phase II activities were conducted (figure 1.5-1b). The location of each injection well modeled is shown in Figure 1.5-1a. During EOR operations (injection of CO_2), pressure was measured continuously in the EGL # 7 observation well. The Phase II observation is centrally located relative to injection operations. Periodic pressure measurements using pressure dip-in were collected for four wells: CFU 24-3, CFU 29- 1, CFU 29-13, and CFU 44-2. Locations of the wells used for pressure monitoring are shown in Figure 1.5-1b.

Charge history, production history, and pressure response during injection show that the NW-SE fault cross-cutting the reservoir is a sealing fault. Thus, there is no fluid flow or propagation of pressure perturbation across the fault.

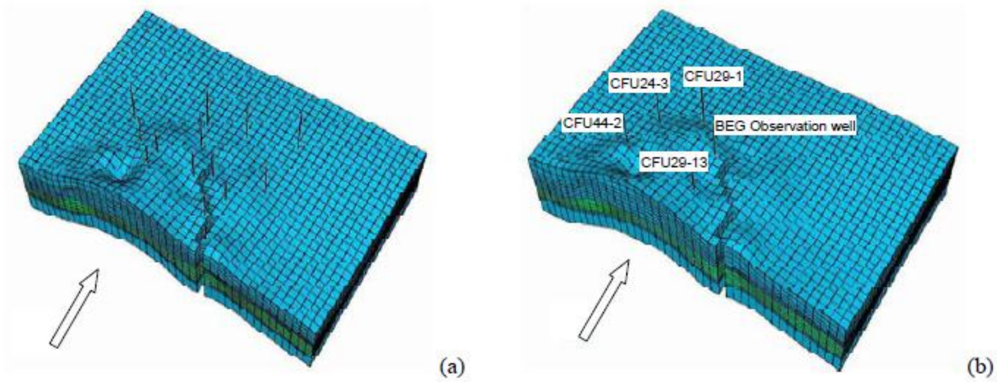


Figure 1.5-1. Location of wells in the fluid-flow model: (a) CO_2 injection wells and (b) wells where pressure is measured. Arrow in figures points north.

Model design and initial condition

CMG-GEM, a multiphase compositional-flow simulator, is used for Phase II modeling. It enables us to predict volumetric behavior and phase equilibrium composition of pure components and mixtures, as well as their properties, such as densities and viscosities. In this work, water is treated as an individual aqueous phase (Kumar and others, 2005; Choi and others, 2008). Three phases (oil, gas, water) coexist in the reservoir. As a consequence, partitioning of water into the other phases and of the other phase components present in the model into the aqueous phase is not modeled.

The structure of our static model is created on the basis of both seismic data and well logs using Petrel software. Maximum and minimum elevations are 9,741 ft (2969 m) and 10,207 ft (3111 m) subsea, given the depth to the middle of cells, respectively. The average dip is 2° in an approximate radial fashion toward the apex of the anticline structure. Other reservoir parameters are given in Table 10.The model is composed of two rock types: “sand” and “shale.” For each of the two rock types, we developed two correlated sets of two-phase permeability curves: water–oil and fluid (water and/or oil)–gas (Figure 1.5-2). Both relative permeability sets used in this model assume a Brooks-Corey (BC) formalism.

Table 10. Parameters of the Cranfield reservoir (Mississippi Oil and Gas Board, 1966).

Parameter	Value
Average horizontal permeability	2.76×10-13 m2 (280 md)
Average porosity	0.255
Anisotropy ratio	0.01
Temperature of reservoir	125°C (257°F)
Initial pressure at 9,976 ft (3040 m) subsea	32 MPa (4701 psi)

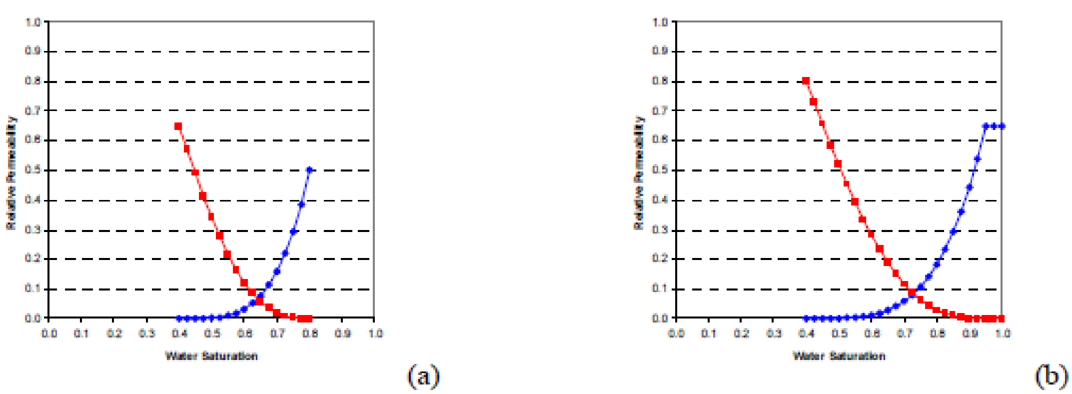


Figure 1.5-2. Relative permeability curves for “sand”: (a) oil–water and (b) liquid–gas.

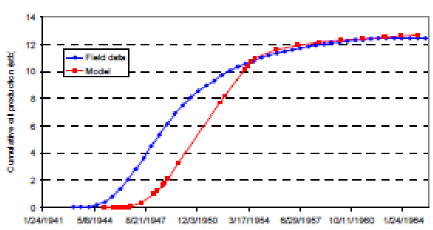
The dimensions of the model are 20,000 ft × 14,000 ft × 300 ft (6.1 km × 4.3 km × 0.09 km), for a total of 18,368 (= 41×28×16) cells. Average cell size is 500 ft × 500 ft × 20 ft (152 m × 152 m × 6 m). Numbering of the 16 layers starts at the top. Several simplifications were made: the system is modeled as isothermal, which is justified because measured heating and cooling are minor. Chemical reactions with minerals of the reservoir-rock matrix are not modeled. Geochemical work in Phase III (Karamalidis, 2010) shows that rock-water CO_2 reaction at Cranfield is minor and can be discounted in this decade-duration model.

Although CMG-GEM can handle faults in a more sophisticated way, for this study we modeled the fault by rendering cells along the trace of the fault inactive and, in effect, by eliminating these cells from the model. Well skin is assumed to be zero.

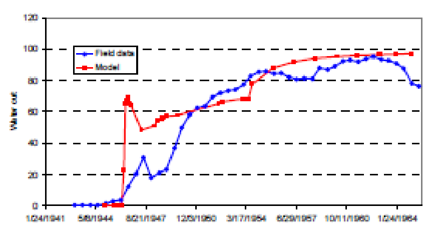
Porosity data input for the Phase II reservoir was collected from well logs ground-truthed with core plugs and full core measurements and then interpolated and upscaled within Petrel. The permeability-porosity transform used in this model is derived directly from preliminary work and has not been updated with results of Phase III work. Both porosity and permeability are upscaled within Petrel then exported into the GEM grid. Permeability of the Cranfield model ranges from 5.6 to 1620 md, and we assume a value of 0.01 for the ratio of vertical:horizontal permeabilities.

Oil composition has not varied since the historical production period (1945–1965). We used the Peng-Robinson model for EOS. The PVT data of C2+ oil components were those internally available within CMG, whereas PVT data for CO_2 and CH_4 were independently tuned.

Oil/water/gas saturation data needed to establish model initial conditions just prior CO_2 flood and were essentially nonexistent. We decided to model the likely distribution of oil, gas, and water prior to the start of CO_2 flood by including the historical period into the modeling. Basic parameters such as original oil in place, integrated field-scale production histories (Mississippi Oil and Gas Board, 1966), and original gas–oil (3040 m)/oil–water (3068 m) contact depth (Mississippi Oil and Gas Board, 1966) are known. By numerically producing hydrocarbon according to the production histories (1945–1965), we obtained an assumed saturation distribution prior to CO_2 injection period that started in July 2008. Figure 1.5-3 shows results of the production-history match during the historical period. Early production histories (before 1954) for cumulative oil production (Figure 1.5-3a) and water cut (Figure 1.5-3b) show mismatches between field data and model owing to the lack of well-by-well calibration to production data. However, cumulative oil production (Figure 1.5-3a) matches well at the end of production (1964), suggesting that our model reasonably simulates the saturation distribution in the reservoir before CO_2 injection. To obtain this relatively good match, we needed both to include the produced-gas reinjection program (Mississippi Oil and Gas Board, 1966) and to make use of the strong water drive. Water drive was modeled with constant bottom-hole pressure (5000 psi) along the boundaries of the model.



(a)



(b)

Figure 1.5-3. History matching during historical period (1940’s–1960’s): (a) cumulative oil production and (b) water cut.

Results of injection-period modeling

The numerical model constructed on the basis of this information is called the “base case.” Results of the pressure-history match for the “base case” are presented in Figure 1.5-4 for four nonproducing wells (24-3, 29-1, 29-13, and 44-2) and the observation well. Calculated pressure histories at the four wells show a good match with the field data (Figure 1.5-4d). However, comparison between field and modeled pressure histories at the EGL#7 observation well shows noticeable deviations (Figure 1.5-4e), although calculated histories trend as field data.

Differences come from uncertainties in key parameters in our model, particularly permeability distribution. Note that the observation well behaved anomalously in terms of slow breakthrough.

To investigate the impact of key parameter uncertainties, we conducted a series of sensitivity tests on boundary conditions (Nicot and others, 2009) and permeability distribution. In contrast to the open-boundary "base case," we ran a case with a closed boundary (that is, imaginary boundary wells shut-in). Comparison of pressure histories of "closed boundary" and "base case" cases shows that the impact of boundary conditions on pressure histories is not significant (Figure 1.5-5). This result can be explained by the time period modeled and by the existence of production wells. There are 14 injection wells and 13 production wells in the model, and the distance between neighboring production and injection wells ranges from 500 ft (152 m) to 3,000 ft (914 m), whereas the distance between the production wells and boundary of the model is between 2,500 ft (762 m) and 7,000 ft (2133 m). Consequently, all fluids (oil, gas, and water) preferentially flow toward the production wells rather than toward the model boundaries. Calculated pressure histories from the "base case" are slightly greater than those from the "closed boundary" case because the "base case" has boundary (injection) wells to simulate water drive. Although the difference between the two cases is not large, it indicates that measuring and prediction of reservoir pressure can be useful tools for monitoring the response of reservoirs under CO_2 injection. That is, the boundary condition of a reservoir has an impact on reservoir-pressure change, and the boundary condition directly determines the movement of the CO_2 plume, although its impact is not dominant in an EOR project (Hovorka and others, 2009).

To test the impact of permeability uncertainties, we present a case in which we increased permeability of all cells within sand layers by a factor of five. The calculated pressure histories for the "permeability" case are then significantly reduced compared with those for the "base case" (Figure 1.5-5). Because permeability, oil, gas, and water production rates are increased significantly, reservoir pressure decreases substantially. This example, in addition to similar tests, validates our permeability-distribution choice.

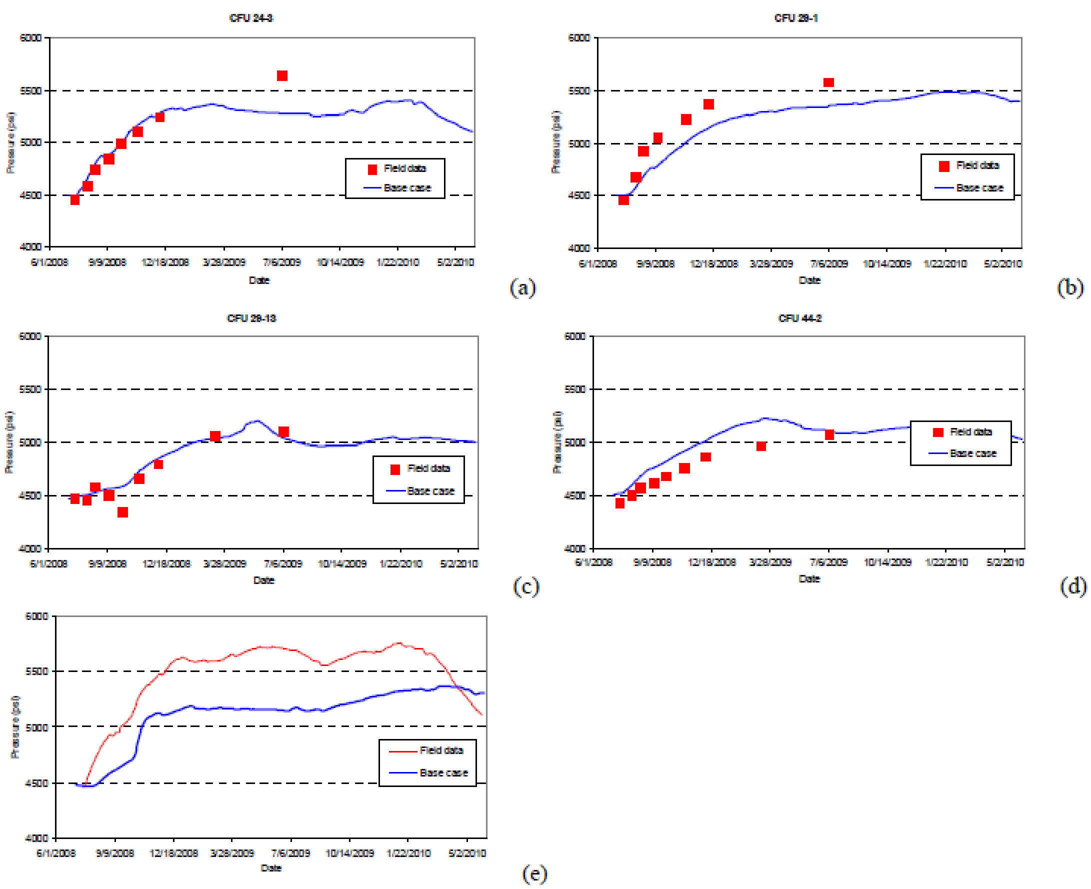


Figure 1.5-4. Comparison of calculated-pressure histories for the "base case" with field measurements: (a) CFU 24-3, (b) CFU 29-1, (c) CFU 29-13, (d) CFU 44-2, and (e) EGL#7 observation well.

Results of pressure-history matching show that our "base case" model can reasonably reproduce field-pressure histories with some deviations owing to uncertainties in key parameters. We have presented a few sensitivity tests on boundary conditions and permeability distribution to illustrate the behavior of the field under varying conditions. Sensitivity tests suggest that the system (during the CO_2 injection phase) is controlled by production wells rather than by boundary conditions. Although the difference of calculated-pressure histories between the "base case" and the "closed boundary" case is not large, boundary conditions do have an impact on reservoir-pressure histories, which may be a good indicator of reservoir response. This result demonstrates the importance of monitoring of reservoir pressure. Note that, because production wells are not generally used in saline water-injection projects, the impact of boundary condition would be more prominent for CO_2 injection into brine aquifers.

Sensitivity-test results also demonstrate, not surprisingly, that permeability has a significant impact on model pressure histories. Thus, our permeability model is probably most responsible for the differences between calculated histories and field data. Several issues are related to the permeability in our model. We used cells with a large average size (500 ft × 500 ft × 20 ft) for numerical efficiency. Such a large cell would certainly be heterogeneous in the field, but it is not the case in our model. This fact may lead to failure of capturing lower permeability stringers or domains. Another important issue is the evaluation of permeability values on the basis of porosity measurements. This model was created on the basis of data available prior to early 2008, and considerably more data have been collected in Phase III that may improve model performance. This a new model will be tested as part of Phase III.

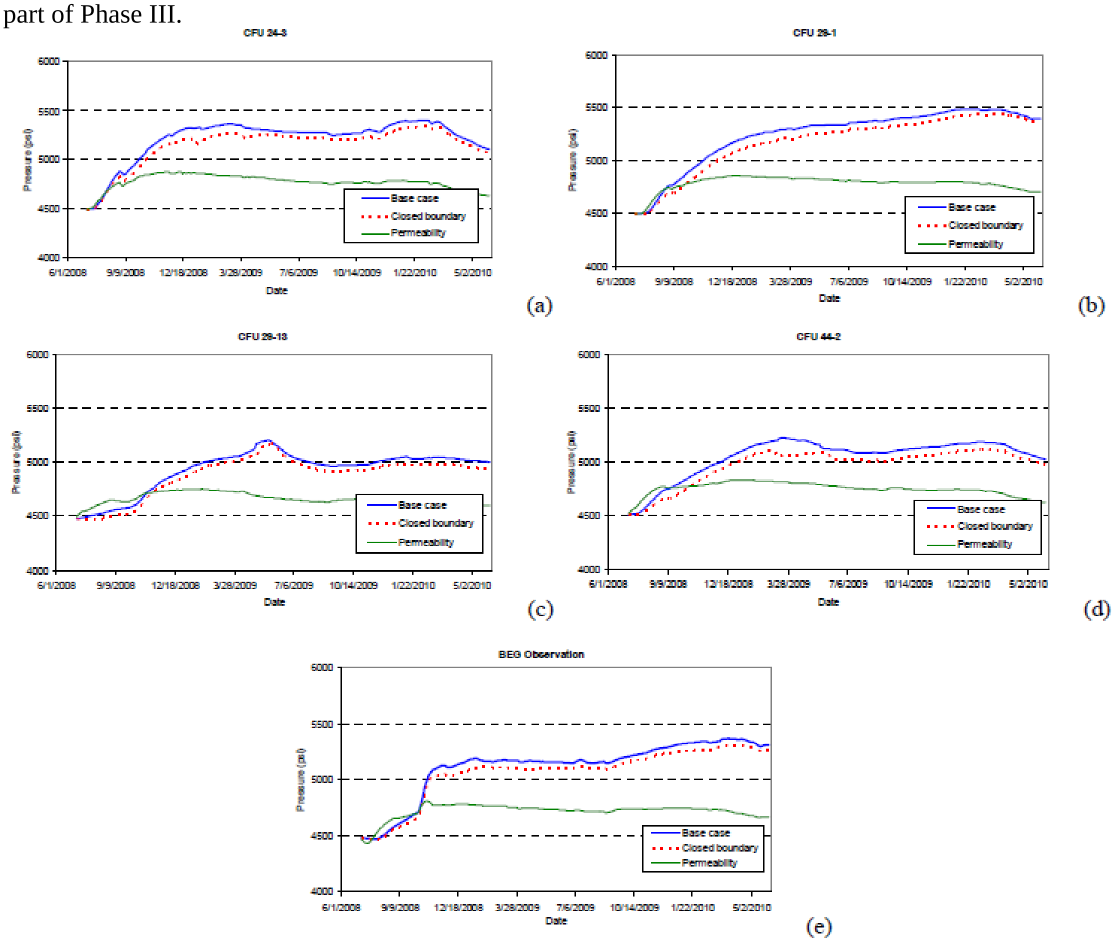


Figure 1.5-5 Comparison of calculated-pressure histories for "closed boundary" and "permeability" cases with those for the "base case": (a) CFU 24-3, (b) CFU 29-1, (c) CFU 29-13, (d) CFU 44-2, and (e) EGL#7 observation well.

Reporting

Progress of the Phase II study has been presented systematically through monthly and quarterly reports and summarized thematically through a series of topical reports (table 11). This final report completes the reporting requirements.

Table 11. Topical reports submitted.

Task	Title	Report type	Date of last version	Pages
1.1	Project Definition Status Report for Gulf Coast Stacked Storage, Subtask 1.1	Letter report and request for extension	June 25, 2006	5
1.1	Project Implementation Status Report	Letter report	April 3, 2007	7
1.1	SECARB Field Test 1: Stacked Storage Selection of Optimized Field/Source/Monitoring 1.1	Letter report to complete Subtask 1.1.2.4	August 3, 2007	4
1.2	Project Design Status Report for Gulf Coast Stacked Storage, Phase II, Subtask 1.2	Report and documentation of milestone completion	April 1, 2008	24
1.2	Detailed Project Design Package for Gulf Coast Stacked Storage Phase II, Subtask 1.2	Report and documentation of milestone completion (includes HASP)	March 28, 2008	Variably paginated
1.2	Permitting report	Requested spreadsheet	July 18, 2008	3
1.3	Status Report on SECARB Observation Well: Ella G. Lees #7, Task 1.3.1: Installation of Observation Well	Informal progress report	Feb 18, 2008	4
1.3	Phase II Field Test 1: Gulf Coast Stacked Storage Project—Status Report Prior to Injection	Report and documentation of milestone completion	May 10, 2008	13
1.3	Health and Safety Plan, Cranfield Phase II Monitor Well, Adams County, Mississippi	Report and documentation of milestone completion	July 2, 2008	Variably paginated
1.4	Quick-Look Report for Gulf Coast Stacked Storage Project, Subtask 1.4	Report and documentation of milestone completion	August 13, 2009	24
1.4	Project Operations Status Report for Gulf Coast Stacked Storage Project Phase II, Subtask 1.4	Report and documentation of milestone completion	August 13, 2008	44
1.5	Project Closeout Report for Gulf Coast Stacked Storage Project Phase II, Subtask 1.5	Report and documentation of milestone completion	March 30, 2011	14

Closure

The project test site selected at Cranfield is a commercial EOR site and does not close at the end of the SECARB Phase II project. Denbury is the legal owner of the EGL #7 observation well, and at cessation of SECARB activities it will take responsibility for this well. The period of the Phase II operation was extended 1 year through 2010 to acquire long-term data more relevant to a commercial site. Operation of EGL#7 downhole pressure and repeat geochemical monitoring were rolled into Phase III to allow an even longer monitoring period. No field activities by the SECARB team are therefore required to conclude Phase II.

Conclusions

This recently concluded SECARB Phase II project provides a first test of long-term, commercial-type surveillance techniques at an EOR project. Injection started July 15, 2008, into the lower Tuscaloosa "D-E" sandstone at the Cranfield unit, in southwestern Mississippi. The injection has been a commercial operation conducted by Denbury Onshore LLC that has stored more than 1.2 million metric tons of CO_2 in the Phase II area.

The lower Tuscaloosa "D-E" injection zone at Cranfield is a highly heterogeneous complex of fluvial-channel sandstones and conglomerates that were assessed using core, 3-D seismic, and wireline logs. Basal Tuscaloosa conglomerates are incised into marine shales and sandstones of the Washita-Fredericksburg Group. Overlying lithic arkoses are poorly sorted and show sinuous patterns, with amalgamated crossbedded channel-fill and point-bar deposits, forming a fairly continuous sand-rich zone across the field. Fe-chlorite, quartz, and ankerite cements further complicate the flow system developed in these rocks. Red overbank mudstones serve as seals on the oil-producing interval. A sequence of dark mudstones of the middle Tuscaloosa "marine" member is identified as the lowest part of the regional confining system.

The monitoring program for Phase II began in the spring of 2008 prior to CO_2 injection and continues as part of Phase III, representing 30 months of continuous monitoring with subsurface pressure gauges—the longest available record in the United States currently for a CO_2 injection project. A plugged and abandoned former production well, the Ella G. Lees #7 (EGL#7), was reentered and repaired to serve as a dedicated observation well prior to the start of injection. A novel test element was a dual completed observation well to allow monitoring pressure in two zones: the lower Tuscaloosa "D-E" injection zone and an aerially continuous, 10-ft-thick, 100-md sandstone above the thick middle Tuscaloosa mudstone serving as an above-zone monitoring interval (AZMI). The test assessed the adequacy of established Mississippi well-integrity standards for retaining CO_2 for greenhouse-gas mitigation. Modeling shows that, should significant leakage occur through the reservoir seal through conduits such as flawed well completions, pressure would increase in the monitoring zone. Pressure and temperature data from both the injection zone and AZMI are transmitted via wireline to a satellite uplink, providing real-time access to data at 10-minute increments, with higher frequency data stored at the well site. Over 27 months, pressure in the injection zone increased as much as 8 MPa (1200 psi). Pressure measurement at an idle well completed in the injection zone proved to be an effective tool for injection surveillance. Pressure at the observation well responded rapidly and with high sensitivity to injection and shut-in at distant wells documenting hydrologic continuity of the reservoir, as well as the corroborating effective cross-fault sealing performance predicted on the basis of production history of one of the crestal graben-bounding faults. High-frequency data from the idle observation well shows major events in the reservoir, such as start or cessation of injection, production, and areas of good or poor pressure communication, at resolution greater than the daily information about injection rate. Signal in this reservoir is detected over areas of 1 kilometer, with resolution and noise response of the gauges at EGL#7.

Additional monitoring undertaken to constrain the model and thereby document the capacity under conditions at the site included (1) intermittent flowing and shut-in pressure measurements at selected producers using memory gauges,(2) selected injection and production profiles, and (3)wireline behind-casing estimates of fluid changes measured with Schlumberger's Reservoir Saturation Tool (RST) at selected observation wells. Change in wellhead pressure because of lower fluid column density was effective in documenting arrival of CO_2 at the observation well, where breakthrough of CO_2 occurred in 2010, about 1 year later than predicted by modeling.

Surveillance of pressure in the above-zone monitoring interval (AZMI), a standard technique for gas storage, was tested for the first time under EOR conditions. Pressure changes in the AZMI showed a more complex response than predicted but document that the AZMI is mostly isolated from the injection zone. A slight decrease at the start of injection, followed by an increase, is attributed to a combination of near-well bore effects, geomechanical effects, and minor fluid migration along well completions. It is difficult to isolate the effects of these similarly trending processes. Observation continues now that CO_2 has arrived at this well. In future projects we plan to reduce complexity by installing single-use AZMI wells to reduce near-well bore effects. At project end, fluid sampling to test the AZMI for geochemical evidence of leakage is planned.

A soil-gas and groundwater program to assess the value of such monitoring at the Cranfield site is under way and continues as part of Phase III. No anomalies attributed to CO_2 leakage have been observed.

Experience from this test is being used to design the next generation of monitoring programs for injection of CO_2 into other reservoirs for EOR.

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Appendix 1

Date	Presentation title/subject	Meeting title	Location (city, state)	Presenter(s)
December 11, 2011	Monitoring the behavior of CO_2 in shallow environments: Evidence from one natural and two industrial carbon-storage analogue sites	Bureau of Economic Geology Fall Technical Seminar Series	Austin, TX	Katherine D. Romanak
November 9, 2011	Technical support to Gerald Hill at a meeting with regard to CCS options in Florida	Director of Environmental Affairs, Florida Electric Power Coordinating Group	Tampa, FL	Ramon H. Trevino Rebecca C. Smyth
October 26, 2011	Fundamentals of carbon capture and storage	QUEST Program, Osher Lifelong Learning Institute, The University of Texas at Austin	Austin, TX	Rebecca C. Smyth
June 9, 2011	Sequence stratigraphy of the Tuscaloosa at Cranfield field, Mississippi: A carbon sequestration study in an enhanced oil recovery operation	AAPG / SEPM Annual Convention	Denver, CO	Ramon H. Trevino
June 9, 2011	Continuous real-time pressure monitoring during a CO_2-EOR project from Cranfield, MS, and relevance for geologic sequestration	AAPG / SEPM Annual Convention	Denver, CO	Timothy A. Meckel
June 9, 2011	Risks and benefits of geologic sequestration of carbon dioxide: How do the pieces fit?	AAPG / SEPM Annual Convention	Denver, CO	Susan D. Hovorka
May 11, 2011	U-tube geochemical sampling at SECARB Cranfield DAS project	NETL CCS meeting	Pittsburgh, PA	Paul Cook (LBNL)
May 11, 2011	Seismic monitoring and reservoir modeling at SECARB's Phase-III Cranfield site	NETL CCS meeting	Pittsburgh, PA	Thomas M. Daley (LBNL)
May 11, 2011	Novel research: Well design implementing six sets of instrumentation, SECARB partnership, Phase III Cranfield project	NETL CCS meeting	Pittsburgh, PA	David Freeman (Sandia Technologies)
May 11, 2011	U-tube geochemical sampling: Successes, limitations, and lessons learned from 5 years of field deployments	NETL CCS meeting	Pittsburgh, PA	Barry M. Freifeld (LBNL)
May 11, 2011	Seal heterogeneity and sealing capacity for CO_2 injection at Cranfield field, Mississippi, USA	NETL CCS meeting	Pittsburgh, PA	Jiemin Lu
May 11, 2011	Update on results of SECARB test of monitoring large volume injection at Cranfield	NETL CCS meeting	Pittsburgh, PA	Susan D. Hovorka

May 11, 2011	Evaluation of CO_2, C1-C5 gaseous hydrocarbons at an engineered CO_2 injection, Cranfield, Mississippi	NETL CCS meeting	Pittsburgh, PA	Katherine D. Romanak
May 11, 2011	Targeted soil-gas methodologies for monitoring an engineered plugged and abandoned well site, Cranfield, Mississippi	NETL CCS meeting	Pittsburgh, PA	Katherine D. Romanak
May 11, 2011	Chemical composition of brine and gas in the Tuscaloosa formation: Preliminary baseline and post-CO_2 injection results from SECARB-III test at Cranfield, MS	NETL CCS meeting	Pittsburgh, PA	Jim Thordsen (USGS)
May 11, 2011	Geochemical characterization of shallow groundwater at the Cranfield aquifer and numerical simulation: Can pH and carbonate parameters be used to detect potential CO_2 leakage at geological CO_2 sequestration sites?	NETL CCS meeting	Pittsburgh, PA	Changbing Yang
March 19, 2011	SECARB stacked storage at Cranfield	SECARB Stakeholders Briefing	Atlanta, GA	Timothy A. Meckel
March 19, 2011	Carolinas study update	SECARB Stakeholders Briefing	Atlanta, GA	Timothy A. Meckel (for Rebecca Smyth)
September 19–23, 2010	History-match of CO_2 injection into a typical U.S. Gulf Coast anticline structure	GHGT 10	Amsterdam	Jean-Philippe Nicot
September 19–23, 2010	Monitoring a large volume injection, year two results—SECARB project at Denbury's Cranfield, Mississippi, USA	GHGT 10	Amsterdam	Susan D. Hovorka
September 7, 2010	Above-zone pressure monitoring as a surveillance tool for carbon sequestration projects	SPE CCS workshop	New Orleans, LA	Timothy A. Meckel
July 23, 2010	EOR as sequestration: Geotechnical perspective	Symposium on the Role of Enhanced Oil Recovery in Accelerating the Deployment of Carbon Capture and Storage	Boston, MA	Susan D. Hovorka
June 10, 2010	Ensuring monitoring and storage security in carbon capture and sequestration	Public workshop sponsored by the Environmental Defense Fund and the National Resources Defense Council	Sacramento, CA	Susan D. Hovorka
May 8, 2010	Early results of SECARB Cranfield project	IEAGHG R&D Program Monitoring Network	Natchez, MS	Susan D. Hovorka

May 8, 2010	Overview of geology of Cranfield	IEAGHG R&D Program monitoring network field trip	Cranfield, MS	Timothy A. Meckel
May 8, 2010	U-tube demonstration	IEAGHG R&D Program monitoring Network field trip	Cranfield, MS	Katherine D. Romanak
May 8, 2010	Results of geophysics program	IEAGHG R&D Program Monitoring network field trip	Cranfield, MS	Tom Daley (LBNL)
May 8, 2010	Results of wireline program	IEAGHG R&D Program Monitoring Network field trip	Cranfield, MS	Bob Butsch (Schlumberger)
May 8, 2010	Results of P-site	IEAGHG R&D Program Monitoring Network field trip	Cranfield, MS	Katherine D. Romanak
May 8, 2010	Core program	IEAGHG R&D Program Monitoring Network field trip	Cranfield, MS	Jiemin Lu
May 8, 2010	Well construction	IEAGHG R&D Program Monitoring Network field trip	Cranfield, MS	David Freeman
May11-12, 2010	Using pulsed neutron measurements to monitor CO_2 movement postinjection	NETL CCS meeting	Pittsburgh, PA	Bob Butsch (Schlumberger)
April 1, 2010	Deep and near-surface monitoring for enhanced CO_2 storage security	AAPG	New Orleans, LA	Susan D. Hovorka
April 1, 2010	Across-fault pressure perturbation induced by CO_2 injection	AAPG	New Orleans, LA	Kyung Won Chang
April 1, 2010	Organic compounds in produced brine from Tuscaloosa Formation following CO_2 injection in the Cranfield oil field, Mississippi	AAPG	New Orleans, LA	Pamela Campbell
April 1, 2010	Downhole passive microseismic observations during continuous CO_2 injection at Cranfield, Mississippi	AAPG	New Orleans	Timothy A. Meckel
March 9-10, 2010	Gulf Coast Stacked Storage Project	Fifth Annual SECARB Stakeholders Briefing	Atlanta, GA	Ian J. Duncan
December 15, 2009	Natural and anthropogenic fluxes of CO_2 from subsurface formations: Natural analogues of geologic carbon sequestration	American Geophysical Union (AGU) Fall Meeting	San Francisco, CA	Katherine D. Romanak Changbing Yang
November 17, 2009	Update on SECARB Phase II	Regional Carbon Sequestration Partnerships Annual Review	Pittsburgh, PA	Susan D. Hovorka

October 29, 2009	The ‘S’ in carbon capture and storage: An overview of CCS technology and politics in the U.S., with emphasis on geologic storage	University of Texas LAMP (Learning Activities for Mature People) part of the Osher Lifelong Learning Institute	Austin, TX	Rebecca C. Smyth
October 4, 2009	Managing risk to groundwater from large volume CO_2 sequestration	National Ground Water Association Theis Conference: Groundwater and Climate Change	Boulder, CO	Susan D. Hovorka
September 29, 2009	Questions from CO_2 injection field tests	Center for Frontiers of Subsurface Energy Security (UT - ACES, telecom with Sandia National Lab)	Austin, TX	Susan D. Hovorka
September 25, 2009	Overview of field projects	Public meeting on Carbon Capture and Storage, California State University	Bakersfield, CA	Susan D. Hovorka
September 11, 2009	Monitoring of carbon sequestration	University of Texas, Institute for Geophysics	Austin, TX	Timothy A. Meckel
September 11, 2009	Big science and big funding - BEG research addressing CO_2 injection and retention in the deep subsurface	Bureau of Economic Geology Fall Seminar Series	Austin, TX	Susan D. Hovorka
August 21, 2009	Connectivity of a CO_2 reservoir verified by fluid-pressure monitoring and 3D seismic survey	Hedburg Conference	Vancouver, Alberta, Canada	Timothy A. Meckel
June 2, 2009	U.S. regional carbon sequestration partnerships	Presented to IEAGHG R&D Programme Monitoring Network Tokyo, Japan	Tokyo, Japan	Susan D. Hovorka
May 29, 2009	The Cranfield, MS, CO_2 injection test site	2009 NGWA Ground Water Expo and Annual Meeting, December 10–13, 2009	New Orleans, LA	Jean-Philippe Nicot
May 28, 2009	How is monitoring sequestration in an EOR site different from monitoring sequestration in a storage-only site?	2009 SPE International Conference on CO_2 Capture, Storage, & Utilization, Nov. 2–4, 2009	San Diego, CA	Susan D. Hovorka
March 3–3, 2009	Phase II—stacked storage	SECARB stakeholders briefing	Atlanta, GA	Ramon H. Trevino
February 9, 2009	Too much carbon in our atmosphere? Geologic sequestration—one option	Coastal Bend Bays Foundation, Corpus Christi, TX—Texas A&M University.	Corpus Christi, TX	Ramon H. Trevino

December 8, 2008	GCCC field projects	Hart Energy's 6th Annual EOR Carbon Management Conference	Houston, TX	Timothy A. Meckel
December 8, 2008	Public acceptance	Hart Energy's 6th Annual EOR Carbon Management Conference	Houston, TX	Susan D. Hovorka
December 8, 2008	Overview of MVA	NETL-AWWA Webinar	Via web	Susan D. Hovorka
November 13, 2008	Comparing carbon sequestration in an oil reservoir to sequestration in a brine formation: Field study	GHGT-9	Washington, D.C.	Susan D. Hovorka Jong-Won Choi Timothy A. Meckel Ramon H. Trevino Hongliu Zeng Masoumeh Kordi Fred P. Wang
November 10-14, 2008	Continuous pressure monitoring for large volume CO_2 injections	GHGT-9	Washington, D.C.	Timothy A. Meckel Susan D. Hovorka Nishanth Kalyanaraman
October 9, 2008	Update on SECARB modeling activities at Cranfield, MS	RCSP Annual Meeting	Pittsburgh, PA	Jean-Philippe Nicot
October 6, 2008	SECARB Phase II stacked storage at Cranfield	RCSP annual meeting	Pittsburgh, PA	Susan D. Hovorka
September 17, 2008	Preliminary results of numerical investigations at SECARB Cranfield, MS, field test site	American Geophysical Union	San Francisco, CA	Jong-Won Choi
September 8, 2008	Use of geochemical tracers	Second Petrobras Conference on CCS	Salvador, Bahia, Brazil	Susan D. Hovorka
August 11, 2008	Strategies for monitoring a CO_2 storage project: Test program to full-scale deployment	Southern Company Review	Birmingham , AL	Susan D. Hovorka
May 30, 2008	What to do with CO_2: The knowns and unknowns of geologic sequestration and CO_2 EOR in greenhouse gas context	Austin Professional Landmen's Association (APLA)	Austin, TX	Susan D. Hovorka
May 7, 2008	Southeast Partnership "early test" update, Cranfield field, Mississippi	NETL CCS	Pittsburgh, PA	Susan D. Hovorka Ramon H. Trevino Timothy A. Meckel Hongliu Zeng Masoumeh Kordi Jong-Won Choi Jean-Philippe Nicot
May 5–8, 2008	Integrated monitoring design for a large volume commercial injection	NETL Annual CCS meeting	Pittsburgh, PA	Timothy A. Meckel
May 5–8, 2008	Strategies for monitoring a large volume commercial injection—a hypothesis and a test program	7th Annual Conference of Carbon Capture and Sequestration	Pittsburgh, PA	Susan D. Hovorka

April 30, 2008	Monitoring a large volume injection	TCEQ Trade Fair, UIC track	Austin, TX	Susan D. Hovorka
April 22, 2008	What to do about CO_2: outreach demo	UT Earth Day Sustainability Fair	Austin, TX	Ramon H. Trevino Susan D. Hovorka Jong-Won Choi Joseph Essandoh-Yeddu
April 17, 2008	Case study: monitoring an EOR project to document sequestration value	American Conference Institute (ACI)	Houston, TX	Susan D. Hovorka
April 17, 2008	Monitoring a large volume injection	Austin Geological Society poster session	Austin, TX	Susan D. Hovorka
February 23, 2008	Design of research well instrumentation for a long-duration CO_2 flood, Southeast Carbon Sequestration Partnership (SECARB) Phase II Cranfield Project	NETL CCS conference	Pittsburgh, PA	Daniel Collins David Freeman Donald Stehle (Sandia) Susan D. Hovorka Timothy A. Meckel
February 23, 2008	Strategies for monitoring a large volume commercial injection—a test program	NETL Annual CCS meeting	Pittsburgh, PA	Susan D. Hovorka Ramon H. Trevino Timothy A. Meckel
February 23, 2008 (abstract submitted)	Integrated monitoring design for a large volume commercial injection	NETL Annual CCS meeting	Pittsburgh, PA	Timothy A. Meckel Susan D. Hovorka
February 22, 2008 (abstract submitted)	Geologic carbon storage	TCEQ Tradefair	Austin, TX	Jean-Philippe Nicot
February 22, 2008 (abstract submitted)	Leakage risks and impacts on groundwater	TCEQ Tradefair	Austin, TX	Jean-Philippe Nicot
February 22, 2008 (abstract submitted)	Geologic sequestration of CO_2: strategies for monitoring a large volume commercial injection	TCEQ Tradefair	Austin, TX	Susan D. Hovorka Ramon H. Trevino Timothy A. Meckel
January 14–16, 2008	What to verify?	Ground Water Protection Council meeting	New Orleans, LA	Scott Anderson Susan Hovorka
January 11, 2008	Recent progress and big ideas on geologic sequestration U.S./international perspective	Department of Chemical Engineering, Luminant (formerly TXU) Carbon Management Program	Austin, TX	Susan D. Hovorka
December 4, 2007	Perspectives and considerations for approaching proposed regulations for geologic sequestration of carbon dioxide	PUC conference	Charleston, SC	Ian J. Duncan
December 11–14, 2007	Overview of Phase II Cranfield	RCSP Annual Meeting	Pittsburgh, PA	Susan D. Hovorka
December 11–14, 2007	Outreach workshop	RCSP Annual Meeting	Pittsburgh, PA	Susan D. Hovorka
December 11–14, 2007	Discussion on geochemical tools at the combined monitoring modeling workshop	RCSP Annual Meeting	Pittsburgh, PA	Susan D. Hovorka

December 3-4,2007	Panel presentation	EPA Public Workshop to discuss management of underground injection of carbon dioxide for geologic sequestration under the safe drinking water act	Washington, D.C.	Jean-Philippe Nicot
December 3–4,2007	Panel presentation: Potential risks and technical challenges to protecting underground sources of drinking water for geologic sequestration of carbon dioxide	EPA Public Workshop to discuss Management of Underground Injection of Carbon Dioxide for Geologic Sequestration Under the Safe Drinking Water Act	Washington, D.C.	Susan D. Hovorka
November 26, 2007	Review of SECARB	RCSP Annual meeting	Pittsburgh, PA	Gerald Hill
November 16, 2007	Overview of GCCC research	Greater Houston Partnership Energy Collaborative R&D Committee	Houston, TX	Ramon H. Trevino
November 16, 2007	What to do about CO_2	Hot Science– Cool Talks Outreach Lecture Series	Austin, TX	Susan D. Hovorka
November 12–13, 2007	"FutureGen-like" opportunities in Texas	Texas Clean Coal	Austin, TX	Timothy A. Meckel
November 8–10, 2007	Frio results and introduced SECARB Phase II Cranfield and Phase III project goals	IEA MMV workshop	Edmonton, Alberta, Canada	Susan D. Hovorka
November 1–7, 2007	Frio test results and introduction to SECARB Phase II Cranfield and Phase III project goals	30th Course of the International School of Geophysics on CO_2 Capture and Storage	Erice, Italy	Susan D. Hovorka
June 14, 2007	Considering faults in CCS	Outreach working group, via phone	Via phone	Timothy A. Meckel
May 7, 2007	Gulf Coast Stacked Storage Field Test	NETL CCS conference	Pittsburgh, PA	Timothy A. Meckel
May 7, 2007	Potential saline reservoir sinks for storage of CO_2 generated in North and South Carolina	NETL CCS conference	Pittsburgh, PA	Rebecca C. Smyth
May 1–3, 2007	Update of carbon storage field projects	TCEQ Environmental Trade Fair	Austin, TX	Susan D. Hovorka
January 25, 2007	Introduction to geologic sequestration of CO_2	U.S. Senate Committee on Energy and Natural Resources	Washington, D.C.	Susan D. Hovorka

Appendix 2

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