

**QUARTERLY TECHNICAL PROGRESS REPORT  
FOR THE PERIOD ENDING JUNE 30, 2003**

**TITLE: FIELD DEMONSTRATION OF CARBON DIOXIDE MISCIBLE FLOODING  
IN THE LANSING-KANSAS CITY FORMATION, CENTRAL KANSAS**

**DOE Contract No. DE-AC26-00BC15124**

**Contractor:** University of Kansas Center for Research, Inc.  
2385 Irving Hill Road  
Lawrence, KS 66044

**DOE Program:** Class II Revisited - Field Demonstrations

**Award Date:** March 8, 2000

**Total Project Budget:** \$5,388,683

**DOE Cost Amount:** \$1,892,094

**Program Period:** March 8, 2000 – March 7, 2009 (BP1 03/00-10/03, BP2 10/03-03/08, BP3 03/08-03/09)

**Reporting Period:** April 1, 2003 – June 30, 2003

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**ABSTRACT:**

Progress is reported for the period from April 1, 2003 to June 30, 2003. The pilot water injection plant became operational 4/18/03 and began long-term injection in the CO2I#1 on 4/23/03. The CO2I#1 exhibits sufficient injectivity for pilot requirements with average absolute permeability surrounding this well equal to ~85 millidarcies. Response to injection in the CO2I#1 has established that conductivity between CO2I#1 and CO2#12, #10, #18 and TB Carter #5 is sufficient for the demonstration. Workovers of the CO2#16 and CO2#13 were completed in April and May, respectively. Pressure response indicates #16 communicates with the flood pattern area but core, swab-test, and pressure response data indicate permeability surrounding #16 is not adequate to maintain the production rates needed to support the original pattern as the well is presently completed. Decisions concerning possible further testing and stimulation have been postponed until after testing of the #13 is complete. Production rates for the #13 are consistent with a surrounding reservoir average absolute permeability of ~80 md. However, pressure and rate tests results, partially due to the nature of the testing conducted to date, have not confirmed the nature of the CO2I#1-CO2#13 conductivity. A build-up test and conductivity test are planned to begin the first weeks of the next quarter to obtain reservoir properties data and establish the connectivity and conductivity between CO2 I-1 and CO2 #13. A new geomodel of the pattern area has been developed based on core from #16 and the new wireline logs from the #10, #12, #16, and #13. The new geomodel is currently being incorporated into the basic calculations of reservoir volume and flood design and predicted response as well as the reservoir simulators. Murfin signed a letter agreement with FLOCO2 of Odessa, TX for supply of CO2 storage and injection equipment. Technology transfer activities have included presentations to the Environmental Protection Agency, Prof. Accountants Soc. of KS, Am. Assoc. of Petroleum Geologists, and a US Congressional aide staff member. The Associated Press also released a story concerning the project that was picked up by many Kansas newspapers.

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## **INTRODUCTION**

**Objectives** - The objective of this Class II Revisited project is to demonstrate the viability of carbon dioxide miscible flooding in the Lansing-Kansas City formation on the Central Kansas Uplift and to obtain data concerning reservoir properties, flood performance, and operating costs and methods to aid operators in future floods. The project addresses the producibility problem that these Class II shallow-shelf carbonate reservoirs have been depleted by effective waterflooding leaving significant trapped oil reserves. The objective is to be addressed by performing a CO<sub>2</sub> miscible flood in a 10-acre (4.05 ha) pilot in a representative oomoldic limestone reservoir in the Hall-Gurney Field, Russell County, Kansas. At the demonstration site, the Kansas team will characterize the reservoir geologic and engineering properties, model the flood using reservoir simulation, design and construct facilities and remediate existing wells, implement the planned flood, and monitor the flood process. The results of this project will be disseminated through various technology transfer activities.

### **Project Task Overview -**

**Activities in Budget Period 1 (03/00-10/03)** involve reservoir characterization, modeling, and assessment:

- Task 1.1- Acquisition and consolidation of data into a web-based accessible database
- Task 1.2 - Geologic, petrophysical, and engineering reservoir characterization at the proposed demonstration site to understand the reservoir system
- Task 1.3 - Develop descriptive and numerical models of the reservoir
- Task 1.4 - Multiphase numerical flow simulation of oil recovery and prediction of the optimum location for a new injector well based on the numerical reservoir model
- Task 2.1 - Drilling, sponge coring, logging and testing a new CO<sub>2</sub> injection well to obtain better reservoir data
- Task 2.2 - Measurement of residual oil and advanced rock properties for improved reservoir characterization and to address decisions concerning the resource base
- Task 2.3 – Remediate and test wells and patterns, re-pressure pilot area by water injection and evaluate inter-well properties, perform initial CO<sub>2</sub> injection to test for premature breakthrough
- Task 3.1 - Advanced flow simulation based on the data provided by the improved characterization
- Task 3.2 - Assessment of the condition of existing wellbores, and evaluation of the economics of carbon dioxide flooding based on the improved reservoir characterization, advanced flow simulation, and engineering analyses
- Task 4.1 – Review of Budget Period 1 activities and assessment of flood implementation

**Activities in Budget Period 2 (10/03-03/08)** involve implementation and monitoring of the flood:

- Task 5.4 - Implement CO<sub>2</sub> flood operations
- Task 5.5 - Analyze CO<sub>2</sub> flooding progress - carbon dioxide injection will be terminated at the end of Budget Period 2 and the project will be converted to continuous water injection.

**Activities in Budget Period 3 (03/08-03/09)** will involve post-CO<sub>2</sub> flood monitoring:

- Task 6.1 – Collection and analysis of post-CO<sub>2</sub> production and injection data

**Activities that occur over all budget periods include:**

- Task 7.0 – Management of geologic, engineering, and operations activities
- Task 8.0 – Technology transfer and fulfillment of reporting requirements

## **EXECUTIVE SUMMARY:**

The pilot water injection plant became operational 4/18/03 and began long-term injection in the CO2I#1 on 4/23/03. The CO2I#1 exhibits sufficient injectivity for pilot requirements with average absolute permeability surrounding this well equal to ~85 millidarcies. Response to injection in the CO2I#1 has established that conductivity between CO2I#1 and CO2#12, #10, #18 and TB Carter #5 is sufficient for the demonstration. Workovers of the CO2#16 and CO2#13 were completed in April and May, respectively. Pressure response indicates #16 communicates with the flood pattern area but core, swab-test, and pressure response data indicate permeability surrounding #16 is not adequate to maintain the production rates needed to support the original pattern as the well is presently completed. Decisions concerning possible further testing and stimulation have been postponed until after testing of the #13 is complete. Production rates for the #13 are consistent with a surrounding reservoir average absolute permeability of ~80 md. However, pressure and rate tests results, partially due to the nature of the testing conducted to date, have not confirmed the nature of the CO2I#1-CO2#13 conductivity. A build-up test and conductivity test are planned to begin the first weeks of the next quarter to obtain reservoir properties data and establish the connectivity and conductivity between CO2 I-1 and CO2 #13. A new geomodel of the pattern area has been developed based on core from #16 and the new wireline logs from the #10, #12, #16, and #13. The new geomodel is currently being incorporated into the basic calculations of reservoir volume and flood design and predicted response as well as the reservoir simulators. Murfin signed a letter agreement with FLOCO2 of Odessa, TX for supply of CO2 storage and injection equipment. Technology transfer activities have included presentations to the Environmental Protection Agency, Prof. Accountants Soc. of KS, Am. Assoc. of Petroleum Geologists, and a US Congressional aide staff member. The Associated Press also released a story concerning the project that was picked up by many Kansas newspapers.

## **RESULTS AND DISCUSSION:**

### **TASK 2.3. Remediate and Test Wells and Pattern**

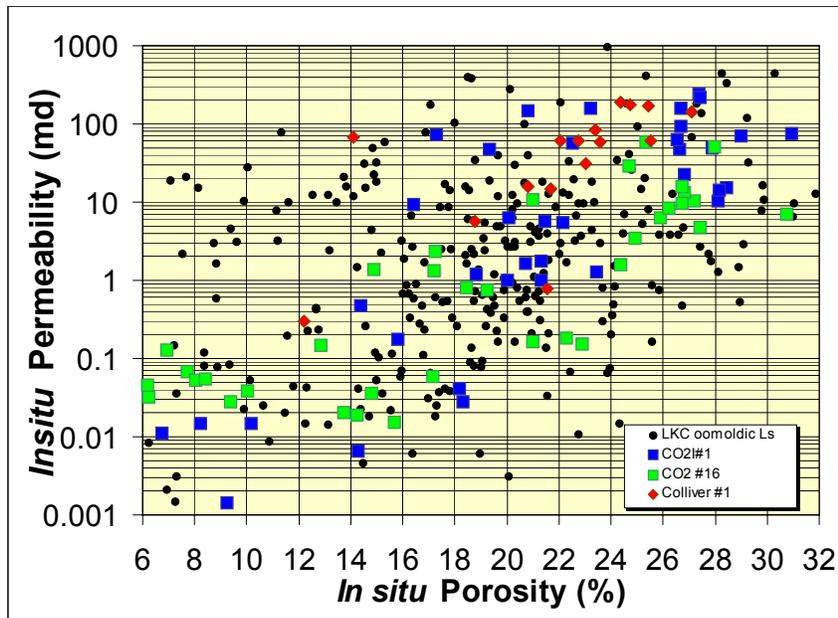
#### 2.3.2 Workover and Test Producing Wells in Pilot Area –

CO2 Project #16 – The deepening of the #16 well was completed 4/15/03 with 4-1/2 inch (0.114 m) casing set at 3,252 ft (991.2 m). Core analysis (Figure 1), log analysis, and swab rate tests indicate that the permeability in and near #16 is lower than that of the other pilot wells (Figure 1). The upper portion of the #16 LKC “C” interval is interpreted to have been more heavily micritized creating poor matrix permeability and poor oomoldic pore connectivity and consequently low permeability relative to LKC oomoldic limestones (Figure 2). It was decided to complete the well in the LKC “C” zone and sequentially stimulate the zone with acid to attempt to contact higher quality reservoir. On 4/8/03 the well was perforated in the LKC “C” from 2883-2894 ft (878.7-882.1 m) using 4 shots/ft (13 shots/m). From 4/9/03-4/11/03, the well was treated with a total of 4,500 gallons (17,032 L) acid as follows (Table 1):

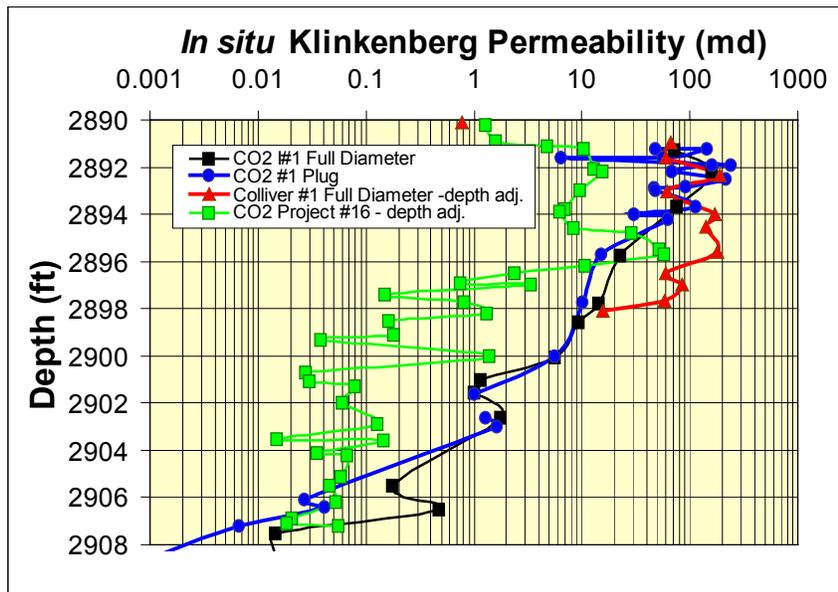
## CO2 Project #16 Acid Stimulation Program

Date	Acid Type	Acid Volume (gallons)	Maximum Rate (bpm)	Maximum Pressure (psig)	Approx. Post-treatment Swab Rate (bph)
4/9/2003	15% MCA	500	0.25	250	1.45
4/10/2003	15% MCA	1000	2.5	475	1.74
4/11/2003	XTA-15%	3000	3.2	450	3.48

(where; XTA is a retarded acid, 1 gal = 3.8 L, 1 barrel per minute bpm = 9.54 m<sup>3</sup>/h; pounds per square inch gauge, psig = 6.90 kPa; 1 barrel per hour, bph=0.159 m<sup>3</sup>/h). Based on the post-treatment swab rates, it was interpreted that the acid stimulation established sufficient communication with the surrounding reservoir to run tubing and monitor the well during long-term injection testing.

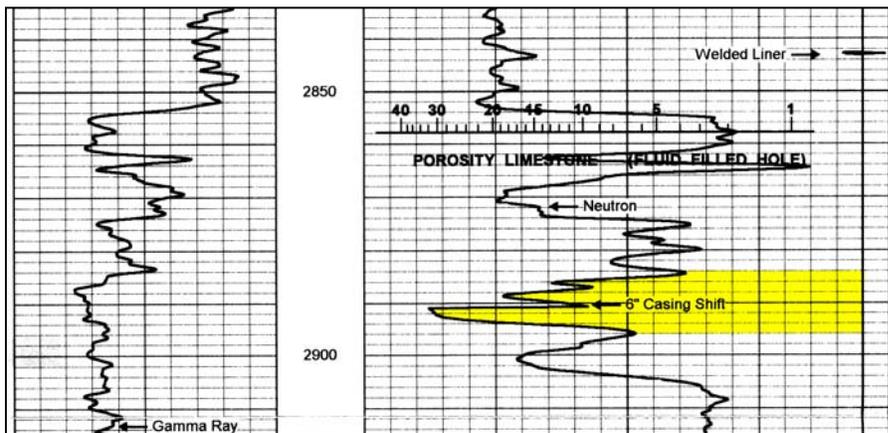


**Figure 1.** Comparison of permeability versus porosity in CO2 Project #16 compared to other LKC wells showing low permeability of the LKC “C” interval rock in the #16 well. Some routine air permeability data was converted to approximate *in situ* Klinkenberg permeability (liquid-equivalent). (md = millidarcy, 1 md =  $9.87 \times 10^{-4} \mu\text{m}^2$ )



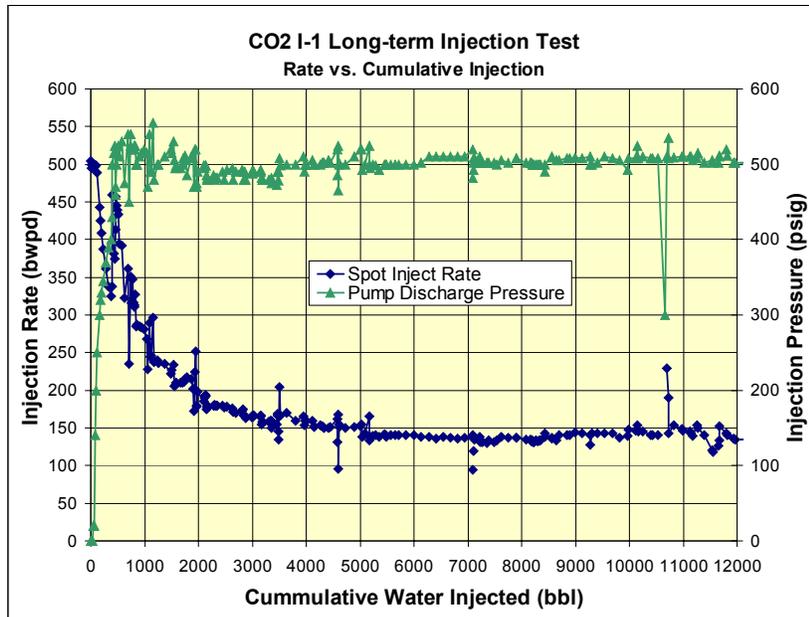
**Figure 2.** Permeability profile for CO2 Project #16 LKC “C” interval measured on full-diameter core (Kmax is shown) and plugs. Full-diameter routine air permeabilities were converted to approximate *in situ* Klinkenberg permeability.

**CO2 Project #13** – A workover to isolate the LKC “C” interval and close off other producing intervals (LKC G, Douglas, Toronto, Plattsmouth, Topeka, and Tarkio) took place from 5/15/03-5/30/03. The LKC “C” interval was isolated by cementing a 4-1/2” (0.114 m) liner from TD to surface, perforating the LKC “C” interval from 2886-2894 ft (880-882.1 m), and then acidizing the “C” interval with 2,250 gallons (8,516 L) of 15% HCL acid. New wireline logs were obtained (Figure 3). Production testing of the LKC-“C” interval, beginning 6/12/03, indicated that the well produced ~45 BFPD (barrels fluid per day; 7.2 m<sup>3</sup>/d) at a bottom hole pressure (BHP) of ~417 psig (pounds per square inch gauge; 2875 kPa). Drawdown to obtain production rates for fluid levels less than 50 ft (15 m; equivalent to 23 psig, 159 kPa) above the perforations was begun on 6/27/03. Production rates at these pressures average ~93 BFPD (14.8 m<sup>3</sup>/d) and are dropping as the well approaches long-term equilibrium. These production rates are consistent with a surrounding reservoir average absolute permeability of ~80 md. Pressure and rate tests results, partially due to the nature of the testing conducted to date, have not confirmed the nature of the CO2I#1-CO2#13 conductivity. A build-up test and conductivity test are planned to begin the first weeks of the next quarter to obtain reservoir properties data and establish the connectivity and conductivity between CO2 I-1 and CO2 #13.



**Figure 3.** Wireline gamma ray and neutron log for the CO2 Project #13 well. Gamma ray in API units and porosity scaled for percent.

**2.3.4 Injection Well Testing and Analysis** – Long-term water injection began in CO2 I#1 on 4/23/03. The purpose of this long-term injection test has been to verify connectivity and sufficient conductivity between CO2 I#1 and the pilot producer and containment wells for a viable CO2 flood and to gather additional reservoir data to refine the reservoir model for improved CO2 flood design and performance prediction. The Cumulative Water Injected versus Injection Rate crossplot shows that CO2 I#1 injection approximately stabilized at rates of 140±5 barrels of water per day (BWPD; 22.3±0.8 m<sup>3</sup>/d) at 500±5 psig (3448±38 kPa) surface injection pressure after 5,000 bbls (795 m<sup>3</sup>) injected (Figure 3). These results are consistent with core- and log- and build-up test-measured average absolute permeability of ~85 millidarcies (md).



**Figure 4.** Injection rate versus cumulative injection for the CO2I#1 during ongoing long-term injectivity test. (1bwpd = 0.16 m<sup>3</sup>/d, 1 bbl = 0.16 m<sup>3</sup>, 1 psig = 6.89 kPa)

2.3.5 Construct Surface Facilities – The pilot water injection plant became operational 4/18/03 and began long-term injection in the CO2I#1 on 4/23/03. The injection facility consists of the shallow Dakota sandstone water supply well (WSW), a 200 barrel (31.8 m<sup>3</sup>) fiberglass injection tank, a triplex pump, filter cartridges, metering, valves, etc (Figures 5-7). Long-term water injection began 4/23/03. Injection water is filtered to 5 microns. The incoming shallow Dakota sandstone freshwater has a dissolved oxygen concentration of approximately 2-4.4 ppm (parts per million). After treatment with an oxygen scavenger (~2-3 quarts/d; 1.7-2.8 L/d), dissolved oxygen concentration of the injection water before the filter is 0.00-0.08 ppm. Following batch treatments using biocide WCW 5827 on 4/23/03 and 3/28/03, approximate biweekly RapidCheck™ tests have indicated no detectable levels of bacteria in the injection water before the filter.



**Figure 5.** CO2 Injection plant near CO2 Project tank battery.



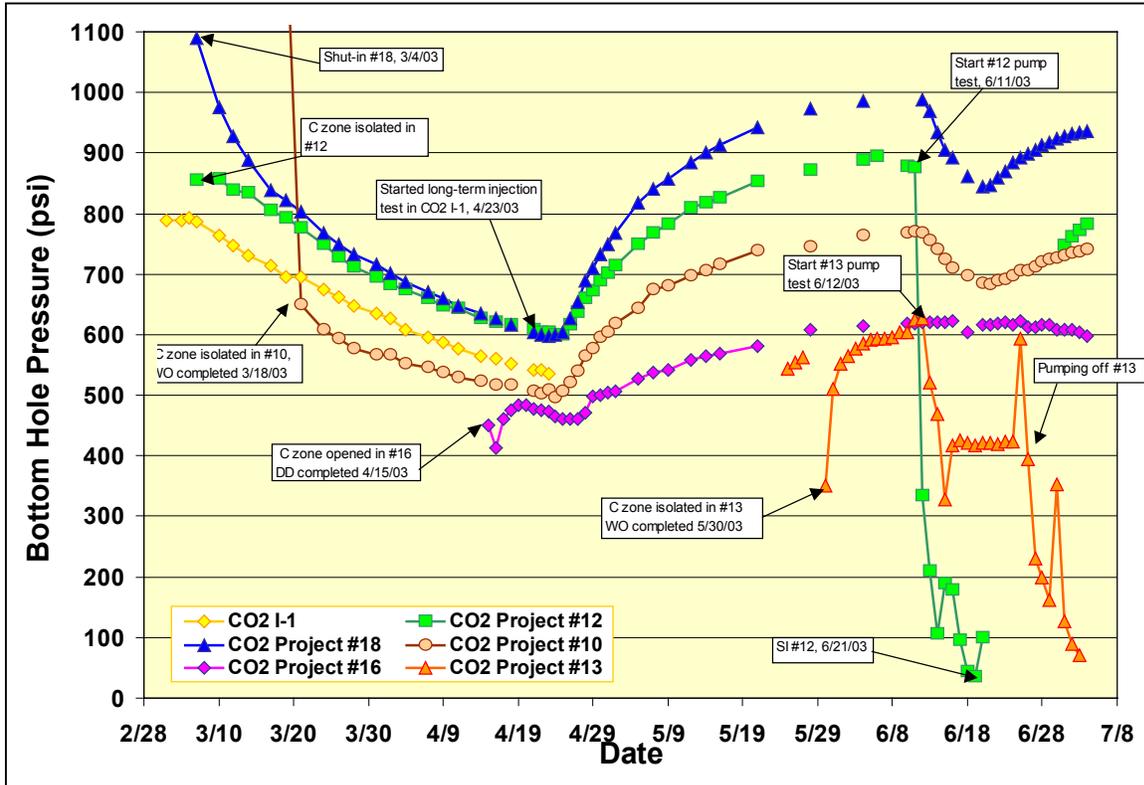
**Figure 6.** CO2 pilot water injection tanks with treatment chemicals.



**Figure 7.** CO2 Pilot injection pump and filters.

2.3.6 Pattern Repressurization and Analysis – Beginning on 3/7/03 the CO2 Project #18 injection well was shut-in and a program of measuring fluid levels in the pattern wells was initiated. Bottom-hole pressures were calculated from the fluid levels. Long-term injection in the CO2I#1 began on 4/23/03 (Figure 8). Based on first arrival times of 3-5 days for pressure response in the #10, #12, #18, #16, and Carter #5 to injection in CO2I#1, the absolute average permeability between the CO2I#1 and the #10, #12, and #18 is interpreted to range from 50-80 md. Average permeability near the CO2I #16 is ~25-35 md. Pressure response to injection in CO2I#1 give clear indication that the #10, #12, #18 and Carter #5 wells are well connected to CO2I#1. A drawdown and buildup test on the CO2#12 provided permeability values that are consistent with first arrival times from the CO2I#1. Response of the #18 to changes in the #12 indicates that these wells may have enhanced interwell conductivity.

Pressure response indicates #16 communicates with flood pattern area but permeabilities in this well and the surrounding area are significantly lower than in the rest of flood pattern area. Low pressure in the #16 may result from production in the region to east. Based on these permeabilities, the rate at which the #16 would process the pore volume between the CO2I#1 and the #16 is too low to use this well effectively in the time period of the demonstration without additional stimulation. Decisions about additional testing or stimulation of this well have been delayed until after completion and testing of the CO2#13 well is complete. The CO2#13 exhibits low pressure similar to the CO2#16. This is presently interpreted to reflect pressure drawdown from the pumped-off Rein #1 and Letsch #7 wells in adjoining leases to the east and southeast.

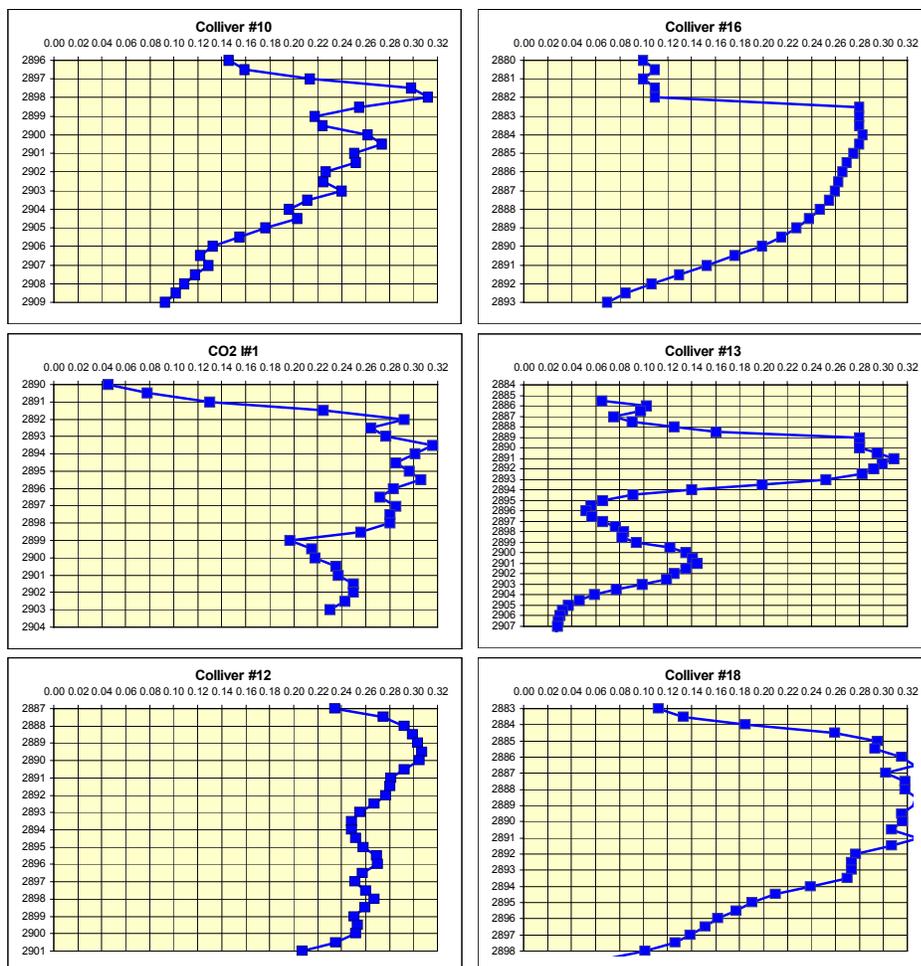


**Figure 8.** Bottom-hole pressures (BHP) through time and notes marking events. BHP values calculated from measured fluid levels. (1 psi = 6.89 kPa)

### TASK 3.1. Reservoir Simulation (Phase 2)

A new geomodel of the pattern area has been developed based on the “C” interval core from the CO2 #16 and wireline logs from the #12, #13, and #16. Using the new logs, old unscaled neutron logs in the pattern area were rescaled to provide consistent porosity values. In general, rescaling increased interpreted porosities from previous analysis (Figure 9). The new porosities were used in the *Petra* mapping software package to construct new porosity maps for six layers in the LKC “C” interval. This model has been used to estimate the pattern pore volumes that can be processed provided #12 and #13 are used as producing wells. The new geomodel is currently being incorporated into the basic calculations of reservoir volume and flood design and predicted response as well as the reservoir simulators.

Low permeabilities in and around #16 were not predicted. Existing models have been modified to be consistent with the present understanding of this portion of the pattern. In addition, new reservoir simulation models have been constructed using the Computer Modeling Group *CMG-IMEX* reservoir simulator and are being modified to accurately predict previous and recent production and pressure histories. These models will be further refined when testing on the CO2#13 is complete.



**Figure 9.** Wireline log porosity profiles for wells in CO2 Pilot pattern. CO2 Project #18 neutron porosity was rescaled from previous analyses to match new well log responses.

### **TASK 3.2 Economic and Recovery Analysis of Pilot**

**3.2.1 Determine CO2 Source for Pilot** – Murfin has signed an agreement with FLOCO2 of Odessa, Texas for FLOCO2 to provide CO2 storage and injection equipment to the pilot in exchange for Kinder-Morgan CO2. The Murfin/FLOCO2 agreement will be initiated once a decision is made to inject CO2. Discussion of logistics and timetables with US Energy Partners and EPCO for CO2 supply will be initiated when a decision to inject CO2 is made.

### **TASK 7.0 PROJECT MANAGEMENT**

Various members of the Kansas CO2 Team communicated on a nearly daily basis by telephone and email over specific technical or business issues. A conference call was held on April 14, 2003. The following personnel have participated in one or more calls and emails: Murfin Drilling) James Daniels; Stan Froetschner, Kevin Axelson, Tom Nichols; Tertiary Oil Recovery Project) Paul Willhite, Richard Pancake; Kansas Geological Survey) Alan Byrnes, Martin Dubois; Kinder-Morgan) William Flanders, Don Schnacke. Topics covered have included: 1) Water supply quality, 2) Well completion procedures and results, 3) Rework scheduling and preparation, 4) build-up and drawdown testing, 5) CO2 supply, storage and injection facilities, and 6) Project management. The project was granted a no-cost time extension to October 7, 2003 by the U.S. DOE to complete necessary Budget Period 1 activities.

## **TASK 8.0 TECHNOLOGY TRANSFER**

A talk was presented at the Environmental Protection Agency sponsored Underground Injection Committee meeting in Kansas City, MO on April 1, 2003 entitled:

“Update on the Field Demonstration of CO<sub>2</sub> Miscible Flooding in the Lansing-Kansas City Formation, Central Kansas & Carbon Sequestration“, by Alan P. Byrnes, Timothy Carr, Martin Dubois, and Scott White

Two talks were presented at the Petroleum Accountants Society of Kansas (PASOK) in Wichita, KS, May 6, 2003. Titles of the talks were:

“Field Demonstration of CO<sub>2</sub> Miscible Flooding in the Lansing-Kansas City Formation, Central Kansas“, by Alan P. Byrnes  
“CO<sub>2</sub> Project“, by James Daniels

Caroline Walling, an aide to Senator Pat Roberts, visited the Kansas Geological Survey on April 24, 2003. As part of a technical review session, Alan P. Byrnes made a brief presentation concerning CO<sub>2</sub> projects in Kansas involving the KGS. This included the field demonstration project.

The Associate Press released an article concerning the CO<sub>2</sub> Demonstration project on June 7, 2003 entitled “Program Aims to Boost Oil Production” by Carl Manning. The article was picked-up by numerous newspapers in Kansas.

A poster talk was presented by Byrnes, Alan P., Franseen, Evan, K., Watney, W.L., and Dubois, M.K., entitled; "The Role of Moldic Porosity in Paleozoic Kansas Reservoirs and the Association of Original Diagenesis with Reservoir Properties" at the American Association of Petroleum Geologists Annual meeting in Salt Lake City, Utah, May 11-14, 2003. This poster presented some information obtained under this project. The poster was the recipient of the Jules Braunstein Award for best poster presentation at the AAPG Annual meeting.

## **CONCLUSIONS**

Surface injection facilities construction and well workovers have been completed successfully. Adequate conductivity exists between CO<sub>2</sub> I#1 and the #10, #12, and #18 wells. Conductivity to #16 is, in its present state, not sufficient for this well to be used as a producer in the pilot without testing or production performance indicating that further stimulation would provide connection between the wellbore and better quality reservoir. The #13 well and CO<sub>2</sub> I#1 are connected but results of the tests performed to date have not defined the conductivity sufficiently. Testing in the next quarter will establish the nature of the CO<sub>2</sub>I#1-CO<sub>2</sub>#13 conductivity. Once the #16 and #13 conductivity and general properties are established, possible flood patterns, designs, and general response and economics can be estimated and decisions can be made concerning how to proceed with project implementation.