SEMI ANNUAL TECHNICAL PROGRESS REPORT
FOR THE PERIOD ENDING DECEMBER 31, 2006

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

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DOE Cost Amount: $1,892,094

Program Period: March 8, 2000 – March 7, 2010 (BP1 03/00-2/04, BP2 2/04-12/08, BP3 1/09-03/10)

Reporting Period: DOE July 1, 2006 – December 31, 2006

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DISCLAIMER:

ABSTRACT:

A pilot carbon dioxide miscible flood was initiated in the Lansing Kansas City C formation in the Hall Gurney Field, Russell County, Kansas. The reservoir zone is an oomoldic carbonate located at a depth of about 2900 feet. The pilot consists of one carbon dioxide injection well and three production wells. Continuous carbon dioxide injection began on December 2, 2003. By the end of June 2005, 16.19 MM lb of carbon dioxide were injected into the pilot area. Injection was converted to water on June 21, 2005 to reduce operating costs to a breakeven level with the expectation that sufficient carbon dioxide has been injected to displace the oil bank to the production wells by water injection. By December 31, 2006, 79,072 bbls of water were injected into CO2 I-1 and 3,923 bbl of oil were produced from the pilot. Water injection rates into CO2 I-1, CO2#10 and CO2#18 were stabilized during this period. Oil production rates increased from 4.7 B/D to 5.5 to 6 B/D confirming the arrival of an oil bank at CO2#12. Production from wells to the northwest of the pilot region indicates that oil displaced from carbon dioxide injection was produced from Colliver #7, Colliver #3 and possibly Graham A4 located on an adjacent property. There is evidence of a directional permeability trend toward the NW through the pilot region. The majority of the injected carbon dioxide remains in the pilot region, which has been maintained at a pressure at or above the minimum miscibility pressure. Our management plan is to continue water injection maintaining oil displacement by displacing the carbon dioxide remaining in the C zone,. If the decline rate of production from the Colliver Lease remains as estimated and the oil rate from the pilot region remains constant, we estimate that the oil production attributed to carbon dioxide injection will be about 12,000 bbl by December 31, 2007. Oil recovery would be equivalent to 12 MCF/bbl, which is consistent with field experience in established West Texas carbon dioxide floods. The project is not economic.

TABLE OF CONTENTS

LIST OF FIGURES

LIST OF TABLES

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_2 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 (03/00-2/04) involved 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 CO2 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 CO2 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 (2/04-12/08) involve implementation and monitoring of the flood:

- Task 5.4 - Implement CO_2 flood operations
- Task 5.5 - Analyze CO_2 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 (1/09-03/10) will involve post-CO2 flood monitoring:

- Task 6.1 – Collection and analysis of post-CO2 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:

Injection was converted to water on June 21, 2005 to reduce operating costs to a breakeven level with the expectation that sufficient carbon dioxide has been injected to displace the oil bank to the production wells by water injection. By December 31, 2006, 79,072 bbls of water were injected into CO2 I-1 and 3,923 bbl of oil were produced from the pilot. Water injection rates into CO2 I-1, CO2#10 and CO2#18 were stabilized during this period. Oil production rates increased from 4.7 B/D to 5.5 to 6 B/D confirming the arrival of an oil bank at CO2#12. Production from wells to the northwest of the pilot region indicates that oil displaced from carbon dioxide injection was produced from Colliver #7, Colliver #3 and possibly Graham A4 on an adjacent property. There is evidence of a directional permeability trend from NW toward the pilot region. The majority of the injected carbon dioxide remains in the pilot region, which has been maintained at a pressure at or above the minimum miscibility pressure. Our management plan is to continue water injection to maintain oil displacement by displacing the carbon dioxide remaining in the C zone, If the decline rate of production from the Colliver Lease remains as estimated and the oil rate from the pilot region remains constant, we estimate that the oil production attributed to carbon dioxide injection will be about 12,000 bbl by December 31, 2007. Oil recovery would be equivalent to 12 MCF/bbl, which is consistent with field experience in established West Texas carbon dioxide floods.

RESULTS AND DISCUSSION:

Task 5.4 - IMPLEMENT CO2 FLOOD OPERATIONS

Figure 1 shows the CO2 pilot pattern located on the Colliver Lease in Russell County Kansas. The pilot pattern is confined within the 70 acre lease owned and operated by Murfin Drilling Company and WI partners. The original ~10 acre pilot pattern consisted of one carbon dioxide injection well (CO2 I-1), two production wells (CO2#12 and CO2#13) two water injection wells(CO2#10 and CO2#18) and CO2#16, an observation well. In October 2006, CO2#16 was converted to a production well and placed on an 8 hour clock. The pilot pattern was designed recognizing that there would be loss of carbon dioxide to the region north of the injection well. This portion of the LKC "C" zone contains one active production well on the Colliver Lease (Colliver #1) which is open in the LKC "C" and "G" zones as well as several zones up hole. CO2#16 was recompleted as a potential production well in 2003 in the LKC "C" zone. Core data indicated that the permeability-thickness product of the LKC "C" in this well was inadequate to support including this well in the pattern.

Liquid carbon dioxide (250 psi and ~***-10F***) was trucked to the lease by EPCO from an ethanol plant in Russell operated by US Energy Partners where it was stored in a 50-ton storage tank provided by FLOCO2. Operational problems were encountered on startup that delayed continuous injection until December 2, 2003. In the next seventeen months, 16.19 MM lbs (138.05 MM SCF) of carbon dioxide were injected into CO2 I-1.

Carbon dioxide injection into CO2 I-1 terminated on June 17, 2005 and water injection began on June 21. Water injection continued into CO2 I-1. Fresh water injection ended on February 3, 2006 when the well was shut-in for a pressure falloff test. Injection of produced water commenced on February 14 to reduce operating costs. Injection rate and bottomhole pressure are shown in Figure 2 for the period from July 1-December 31. Relatively stable rates and pressures were maintained.

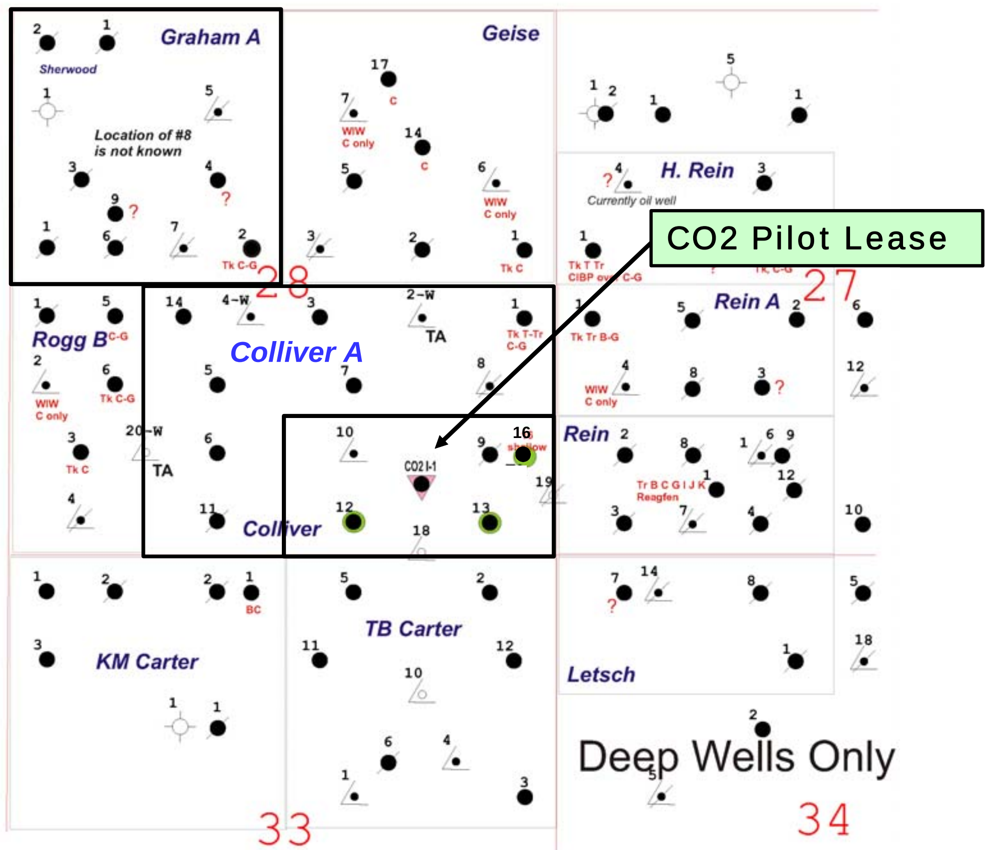

Figure 1: Murfin Colliver Lease in Russell County, Kansas

Cumulative volume of water injected was 79,072 bbls.   Injection of water was maintained in CO2#10 and CO2 #18 to maintain the pressure the pilot above the estimated minimum miscibility pressure and to reduce loss of oil and carbon dioxide from the pilot pattern. Figure 3 shows the injection rate data for CO2 #10 and CO2#18.

Oil and water production rates are shown in Figure 4 for the period July 1-December 31, 2006. Water production rates fluctuated around 200 B/D until October when a larger pumping unit was installed at CO2#12. CO2#16 was completed and placed on pump in October on an 8 hour clock. There was a small amount of production and the well was pumped intermittently when the fluid level built up. Increased water production is due primarily to the larger pumping unit on CO2#12. Oil production rate during this period remained essentially constant at ~5.5-6 B/D. A small amount of carbon dioxide was produced but was not measured. Most of the oil production is attributed to CO2#12. Figure 5 shows the oil and water production rates for the 2006 calendar year. An increase in oil rate from 3.3 B/D to 5.5-6 B/D began in April, but was not sustained until after pump problems were solved in June.

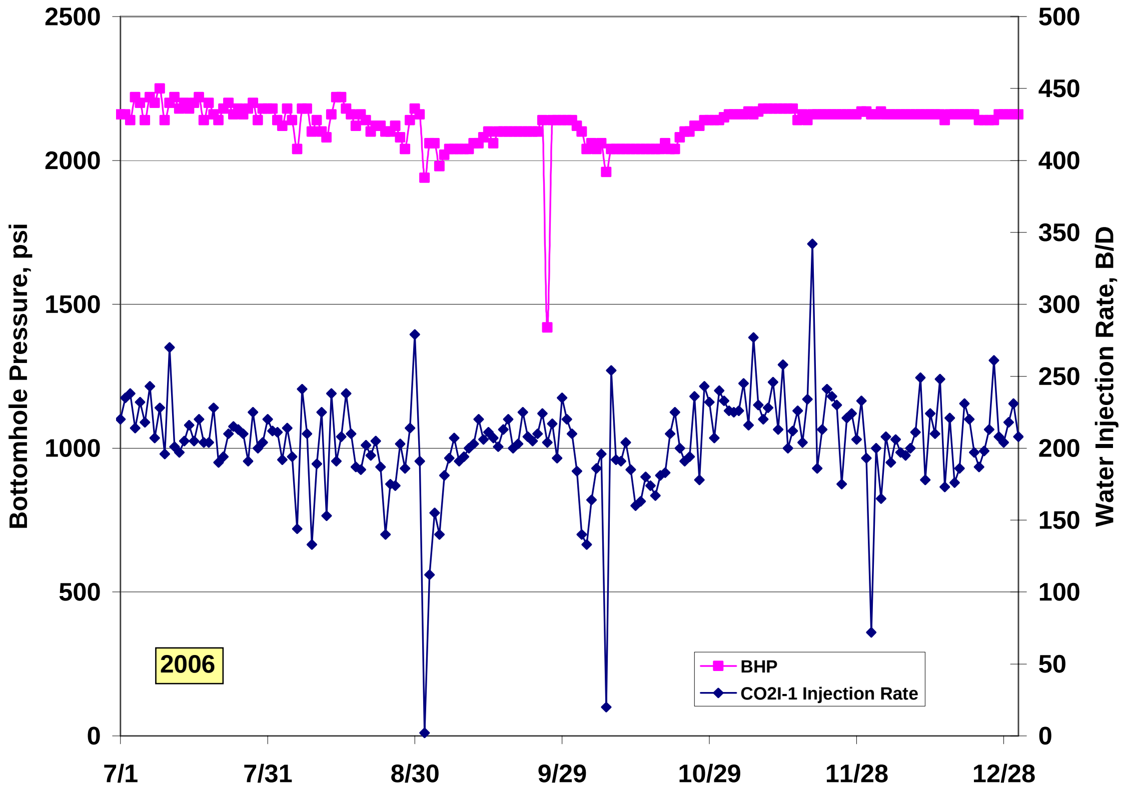

Figure 2: Injection rate and bottomhole pressure during injection into CO2 I-1

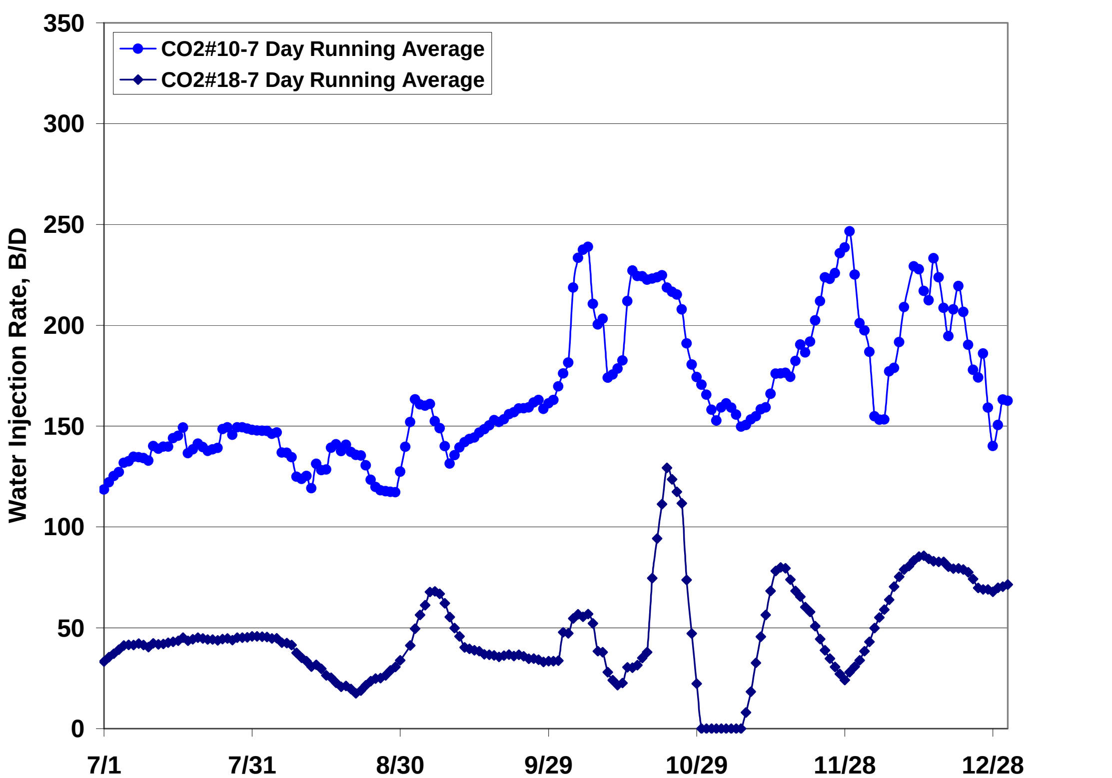

Figure 3: Injection rates into CO2#10 and CO2#18

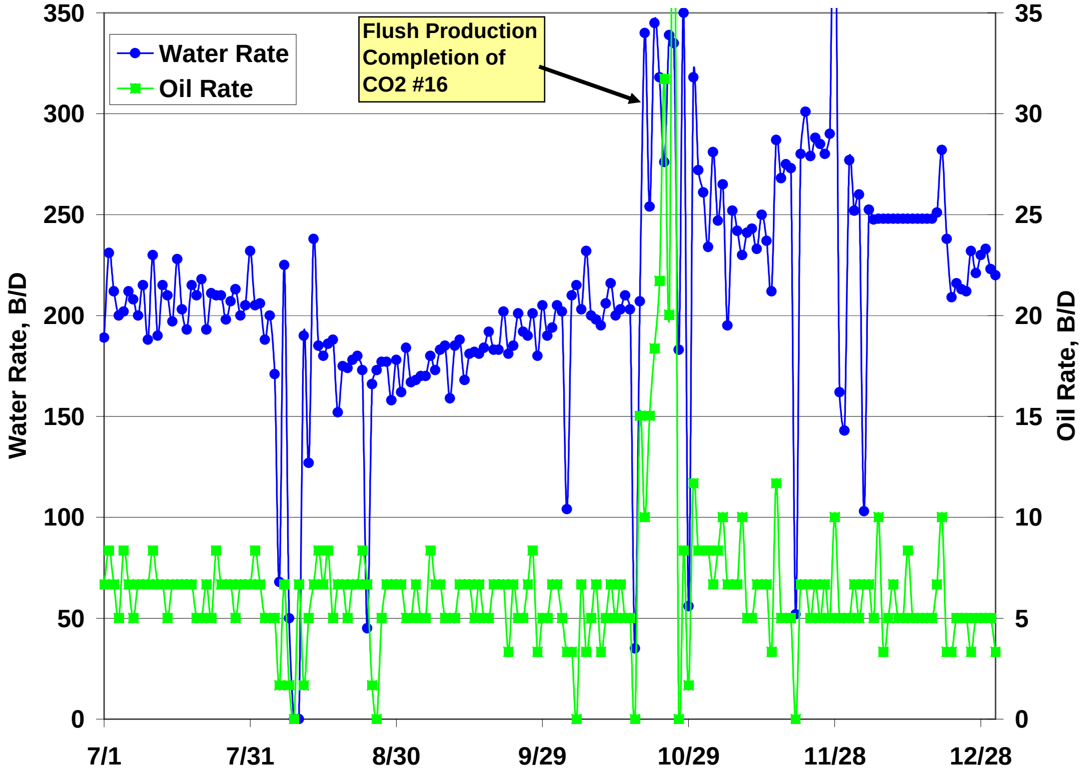

Figure 4: Oil and water production rates from pilot area.

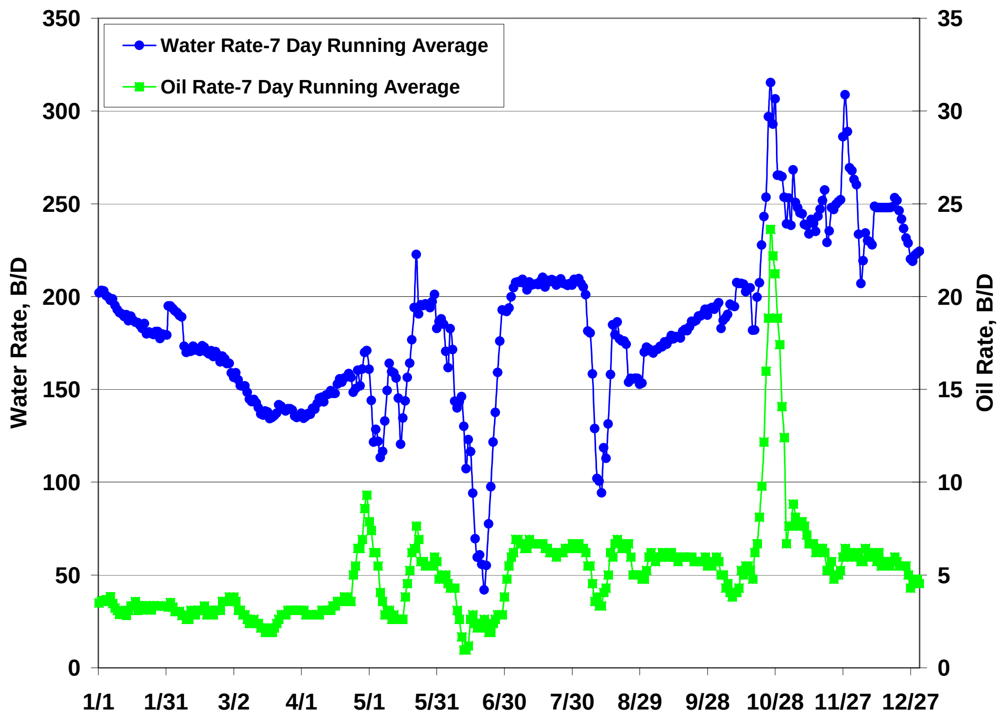

Figure 5: Oil and water production rates for calendar year 2006-seven day running average

Figures 6 and 7 show the average monthly oil and water production rates from the pilot. Average water production rates are consistent with the trends shown in Figure 4. Average oil production rates increased from about 3.3 B/D for the period from June to about 4.7 B/D for the period from July through December. This indicates that a small oil bank mobilized by carbon dioxide injection arrived at CO2#12, possibly as early as mid April. A sustained fluid withdrawal rate of about 200 B/D from CO2#12 and CO2#13 appears to be necessary to obtain higher oil rates. Figure 8 shows the average water-oil ratio for the same period. Data were averaged over the previous six days to dampen the effect of fluctuations in rates. The water oil ratio was stable for much of the period, increasing toward the end of the year possibly due to increased injection into CO2#18. Cumulative oil production from the pilot area is 3,927 bbl. Water production is about 197,431 bbl.

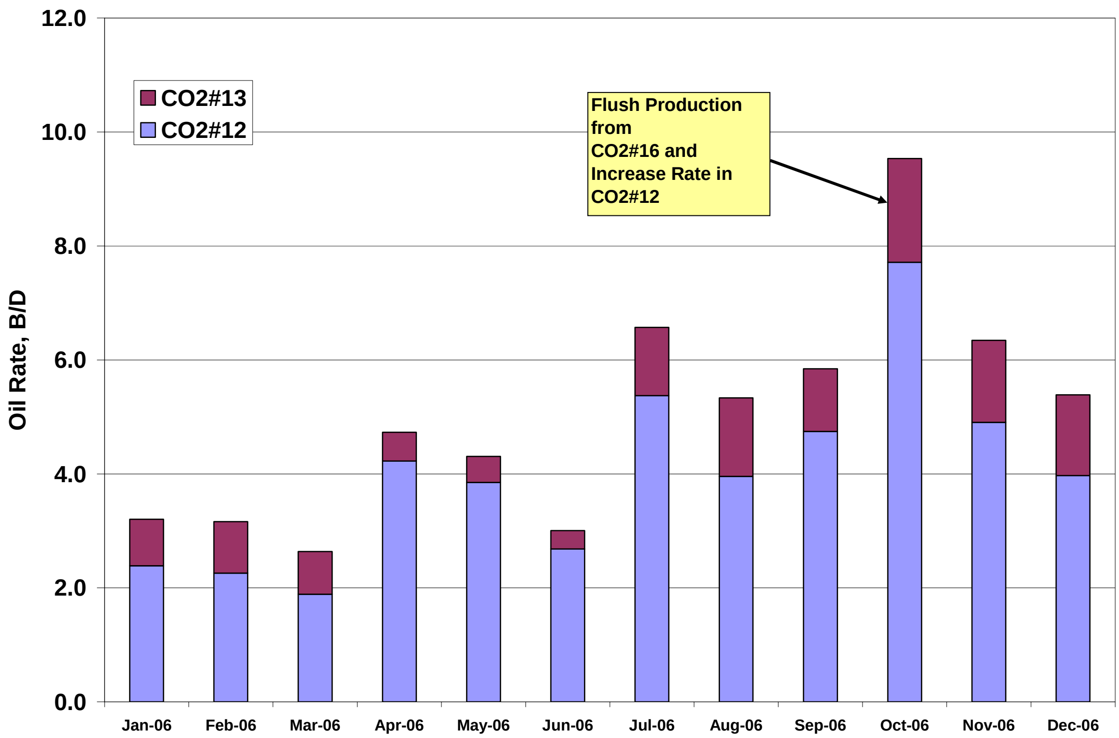

Figure 6: Average monthly oil production rate from pilot area

Figure 9 shows the cumulative oil production since the beginning of the project.

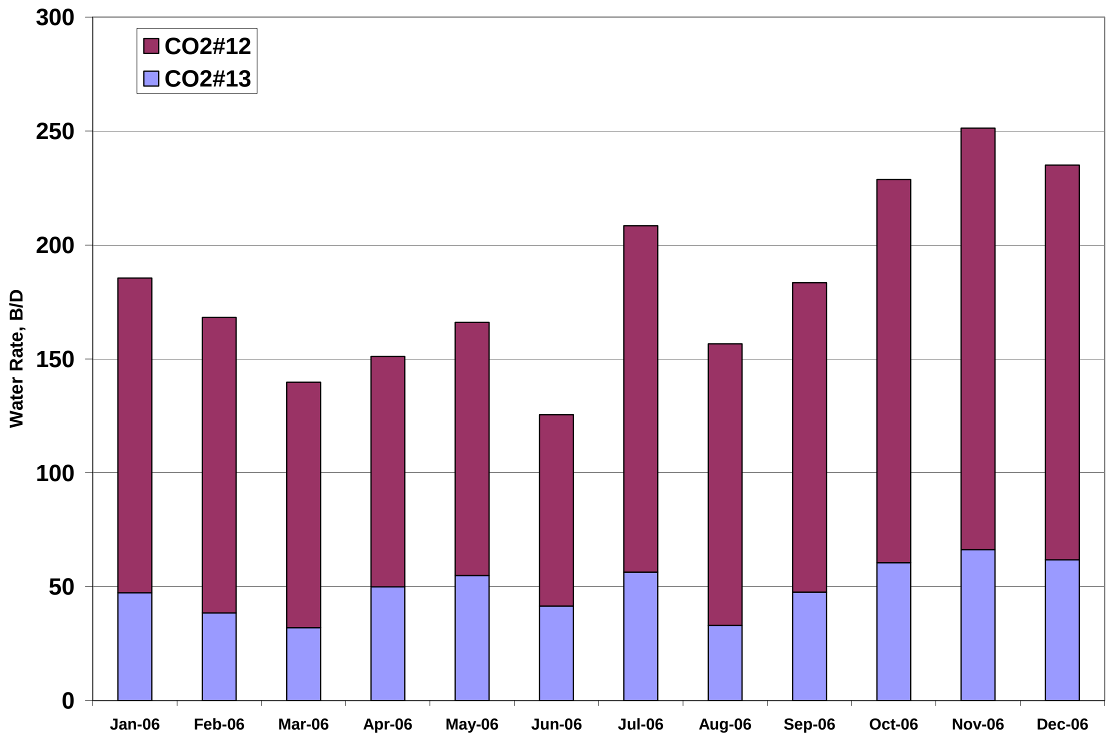

Figure 7: Average monthly water production rate from pilot area

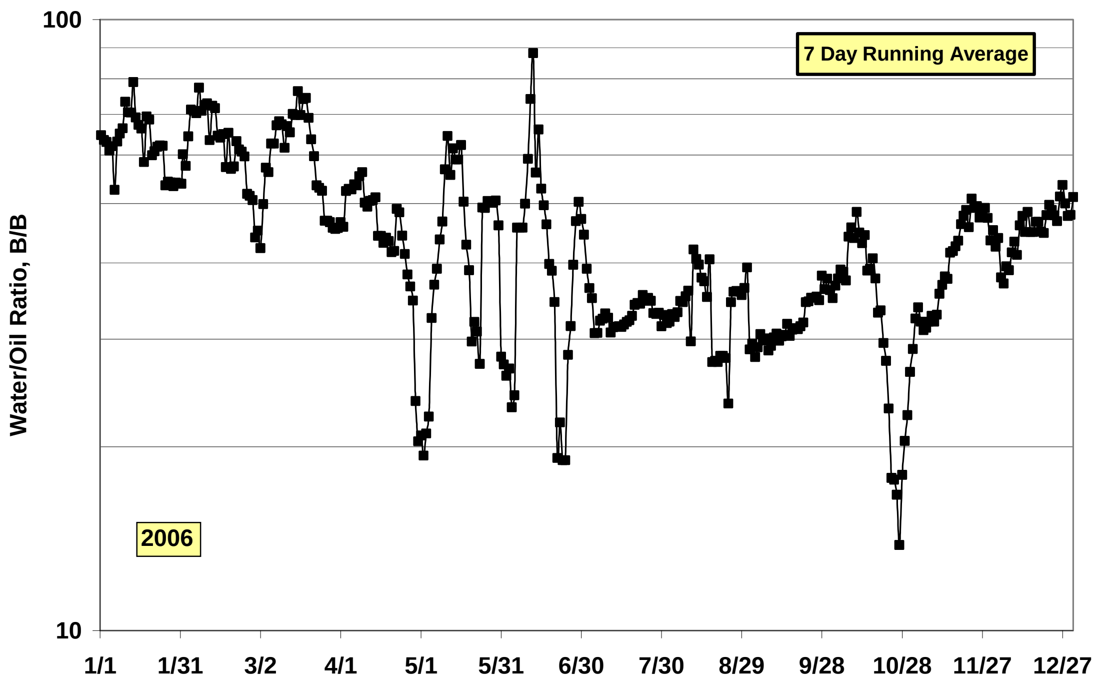

Figure 8: Average water/oil ratio for the period from January 1, 2006 to December 31, 2006

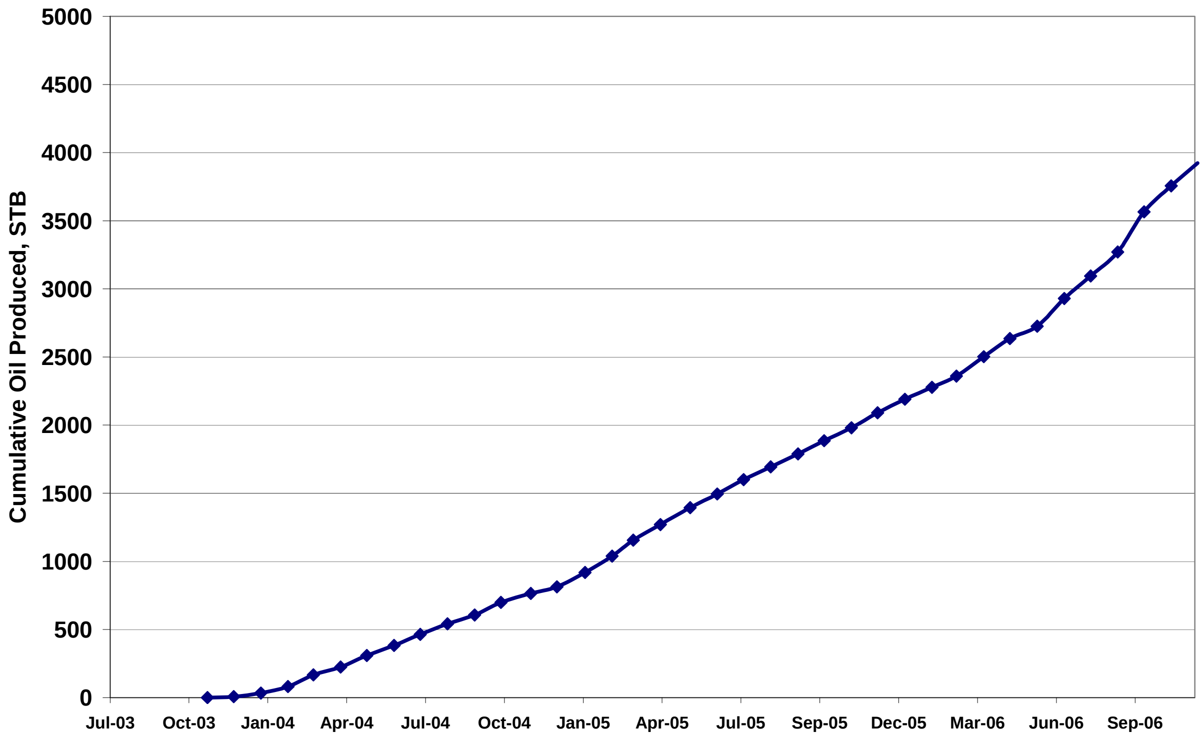

Figure 9: Cumulative oil production from the CO2 pilot

Production from Surrounding Leases

Project personnel monitored production from the Colliver Lease (north of the pilot), Carter Lease(south of pilot), Rein Lease(east of pilot) and Letsch Lease(southeast of the pilot) periodically since the beginning of carbon dioxide injection to determine if oil or carbon dioxide was produced that could be attributed to the CO2 Project. Colliver #1 and Rein A-1, north east of the pilot region and Colliver #6, west of the pilot region have been pumped off since the beginning of the project and were checked frequently. Until August 2006, there was no evidence of effects of the project on surrounding leases.

In August, the operator of the Graham A lease, northwest of the pilot area mentioned that oil production from his lease increased in April-May with no apparent cause. Murfin staff obtained permission to test wells on this lease and determined that the additional production was coming from Graham A4, a well located 3570 feet from CO2 I-1 as shown in Figure 10.

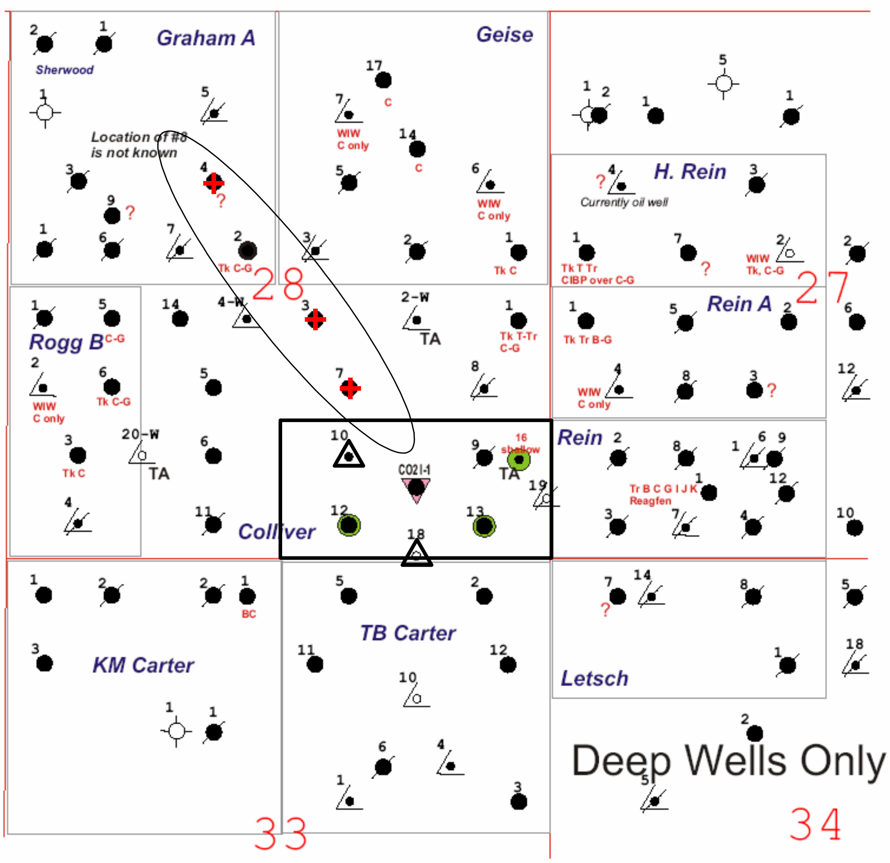

Figure 10: Map showing location of wells completed in the Lansing-Kansas C zone in the area of the CO2 pilot. The elliptical region includes wells marked with a + that appear to have produced oil displaced from the CO2 pilot area.

The discovery of increased oil production from the Graham A lease in August with no other activity in the area appeared to indicate that oil mobilized by carbon dioxide injection on the CO2 pilot lease was displaced to Graham A4. Based on monthly production, we estimate about 1000 bbl of incremental oil were produced from April through September. There is no evidence of carbon dioxide breakthrough in this well. The solubility of carbon dioxide in oil and water is so large that it is unlikely that much CO2 will show up as a flowing phase at any location some distance from the pilot region.

On August 28, 2006 the packer was released from Colliver #7 and oil production increased substantially from the Colliver A lease. Increased oil production is further evidence that that oil displaced by carbon dioxide injection moved off lease in a Northwesterly trend from the CO2 pilot region. The CIBP in Colliver A#3 was knocked out and the well was placed on production on October 11, 2006. Figure 11, shows the Colliver A production data. Colliver #3 production declined to 1 B/D by December 2006. Incremental oil production on the Colliver A Lease appears to be coming from Colliver #7. The elliptical shape on Figure 9 suggests a preferential permeability trend from the northwest toward CO2 I-1.

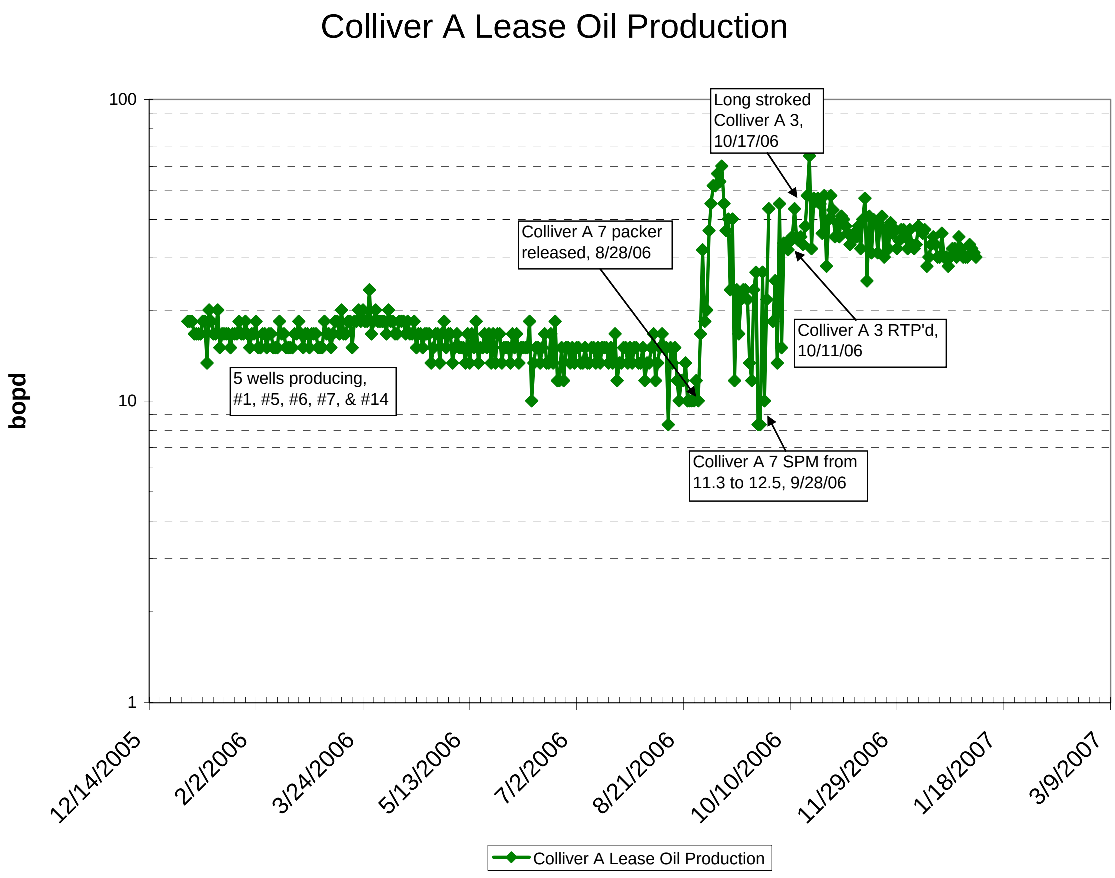

Figure 11: Colliver A lease production after C zone was opened in Colliver #7 and Colliver #3.

Colliver A Lease oil production data indicate a decline has set in. The data for the period from October 18 to December 31 were fitted with an exponential decline before and after the wells were recompleted. Decline curves were used to estimate incremental production due to CO2 injection. We have assumed that all oil production above the Colliver A Upper Zone decline can be attributed to carbon dioxide injection in the CO_2 pilot region. Table 1 contains a projection of incremental oil from CO_2 injection. Oil production from the CO_2 pilot is assumed to average 5 B/D as long as water injection into CO_2 I-1 is maintained. There is no decline on the Graham A lease, so no projections were made.

Table 1: Estimated Incremental Oil from CO_2 Injection into LKC ***C***

Date	CO_2 Pilot	Colliver A Lease	Graham A Lease	Total BBL	MCF/BBL
12/31/06	3927	2703	1193	7823	17.9
6/30/07	4827	5242		10069	13.9
12/31/07	5747	6297		12044	11.6

Our projections indicate that if water injection is maintained through the end of 2007, the incremental oil attributed to carbon dioxide in the pilot region may approach what has been observed in large scale West Texas carbon dioxide floods. This would demonstrate that carbon dioxide mobilized oil in the LKC ***C*** zone, a key objective of the pilot project.

Bottom hole pressures in CO_2 I-1 and CO_2#10 have been maintained well above the minimum miscibility pressure to enhance the capability of the remaining carbon dioxide to displace oil. Production of CO_2, primarily from CO_2#12 is on the order of 5-6% of the injected CO_2. About 95% of the carbon dioxide remains in the reservoir. We believe that the CO_2 is still mobilizing oil as it is displaced by the injected water. There is the possibility that oil mobilized by carbon dioxide injection may exceed the performance of West Texas reservoirs because little carbon dioxide has been produced. The problem is that the some of the mobilized oil is not showing up in production from the pilot lease and additional oil recovery appears likely to occur on the Colliver A lease.

Demonstrating that Incremental Oil is Attributable to CO_2 Injection

An issue that has been raised is how can we demonstrate that incremental oil from Graham A and Colliver A leases is from CO_2 injection as opposed to water injection? Keep in mind that these leases were waterflooded extensively from the mid 1960's to 1987. A CIBP was installed above the LKC interval in Colliver A7 in 1989. Colliver Lease production in 1988 was 32.7 BOPD from 7 wells with 50% allocated to ***C zone***, so at most 2.3 B/D might be attributed to ***C zone*** production from Colliver A7 without the carbon dioxide flood.

Another approach to identify carbon dioxide displaced oil is to analyze carbon dioxide produced from each well to determine if the carbon dioxide originated from the EPCO plant. Carbon dioxide contains two stable carbon isotopes, C-12 and C-13. Carbon dioxide generated by ethanol production has a different ratio of C-12 to C-13 than carbon found in fossil fuels. Analysis of isotope concentrations may allow identification of the source of carbon dioxide. As noted earlier, carbon dioxide is quite soluble in oil. Oil displaced by carbon dioxide may have dissolved carbon dioxide.

Timing of Oil Production Response

Our current reservoir models do not predict the oil production rates corresponding to field results. We recognize that this is important for economic analysis and consideration of application of carbon dioxide flooding to the Hall Gurney Field in a commercial scale. Although the initial response to carbon dioxide injection resulted in an increase in oil production from 0 B/D to ~3 B/D, an oil bank has never arrived at CO2#13. The arrival of an oil bank at CO2#12 probably occurred in April or May 2006, coinciding with pump difficulties. Arrival may have been sooner if pump problems had not occurred. In addition, the increase in oil rate was less than predicted from our reservoir models.

The increase in oil production on the Graham A lease occurred in April 2006, about 850 days after the beginning of carbon dioxide injection into CO2 I-1. The common arrival time of an increase in oil production in both the pilot and the Graham A lease is probably coincidental. However, the arrival time does help estimate the velocity of the oil bank. Well Graham A4 is located about 3570 feet from CO2 I-1. An oil bank flowing through a thin high permeability streak at the top of the LKC ***C*** would need to have an average frontal velocity of 4.2 ft/D from CO2 I-1 to reach Graham A4.

Colliver A7 is about 1190 feet from CO2 I-1. At a frontal velocity of 4.2 ft/D, the oil bank that arrived at Graham A4 in April 2006 would have passed in the vicinity of Colliver A7 about 283 days after the beginning of injection or ~ September 9, 2004. It appears that the oil production response would have been substantially earlier if Colliver A7 was part of the pilot project. This well was excluded from consideration in the pilot region because of a suspected connection to the G zone (later shown to be incorrect) and the high productive capacity of this well.

It is evident from the field response that reservoir heterogeneity dominates the response of the pilot pattern to CO2 injection. There is clearly a SE-NW permeability trend that is not properly described in our reservoir model. The continuity between CO2 I-1 and CO2#13 must be less than what is currently in the model. Remediation of CO2#18 has permitted maintenance of more uniform injection rates and pressures at the south end of the CO2 pilot. This was done to enhance the productivity of CO2#12. Increase in BHP in CO2#18 has caused the fluid level in Carter 2 to increase.

Disposal of produced water began in November 2006 in Carter #4. However, the increase in fluid level in Carter #2 began well before disposal of water resumed on the Carter Lease after being discontinued for several months. There has been no effect of CO2#18 on the productivity of either CO2#12 or CO2#13 as of the end of December. This is further evidence that CO2 #13 is poorly connected to the pilot region. Colliver A1 is located 2113 feet NE of CO2 I-1. There has been no production response in this well. CO2 isotope analysis may indicate whether there is any "ethanol CO2" in the oil produced from this well.

We plan to continue to revise the reservoir model in attempt to predict rates and arrival times of oil banks as the field was operated.

Pressure in Pilot Region

Estimated pressure contours are shown in Figure 12 as of December 2006. The average pressure in the PPV region was estimated using Surfer, a mapping program. In developing Figure 12, fluid level or pressure measurements were available from CO2 I-1, CO2#10, CO2#12, CO2#13, CO2#16, Carter 2 and Carter 5. We assumed that all other wells that were open in the C zone were pumped off. No data are available in the white areas beyond the pilot area. Also shown on Figure 12 is the outline of the region where carbon dioxide is estimated to displace reservoir oil and water.

Pressure distribution in the pilot region was estimated from pressures measured in CO2 I-1, CO2#10 , CO2#18 and fluid levels measured in CO2#12, CO2#13, CO2#16 and Carter #2. Colliver #1, Carter #2, Rein A-1, Letsch #7 and Colliver #6 were assumed pumped off. The fluid head in Colliver #7 is equivalent to a pressure of 187 psi. Colliver #3 was assumed to have a pressure of 100 psi.

The average pressure in the region delineated by the solid black line is about 1435 psi. The average pressure in the pilot region has decreased due to the production of Colliver #7 and the occasional production of CO2#16.

The pressure in the region around CO2 I-1 is well above the estimated MMP pressure which was about 1250 psi. Carbon dioxide remaining in this region is either dissolved in the residual oil and water or existing as a free supercritical fluid phase.

Carbon Dioxide

The amount of carbon dioxide injected was 16,190,000 lb. The amount of carbon dioxide produced is about 766,841 lb. About 95% of the carbon dioxide remains in the reservoir. Carbon dioxide injection began in December 2003 and fluid injection has been continuous. As of December 2006, carbon dioxide has not been detected in any well outside of the project area even though Colliver #1, Rein A-1, Colliver #6, Letsch #7 and Carter #5 have been pumped off throughout the project. Thus, there appear to be no high permeability channels from the pilot region. Analysis of the 4D seismic data has not indicated presence of carbon dioxide in strata above or below the injected interval.

It is believed that much of the remaining carbon dioxide is within the boundary outlined by the solid line in Figure 12. The average pressure in the region outlined by the solid boundary is well above the critical pressure for carbon dioxide at reservoir temperature. The region of high pressure extends substantial distance to the north of the pilot area even with the pressure sink introduced by placing Colliver #7 on production. The carbon dioxide that is present in this region exists as either a supercritical fluid phase or is dissolved in the oil and water phases.

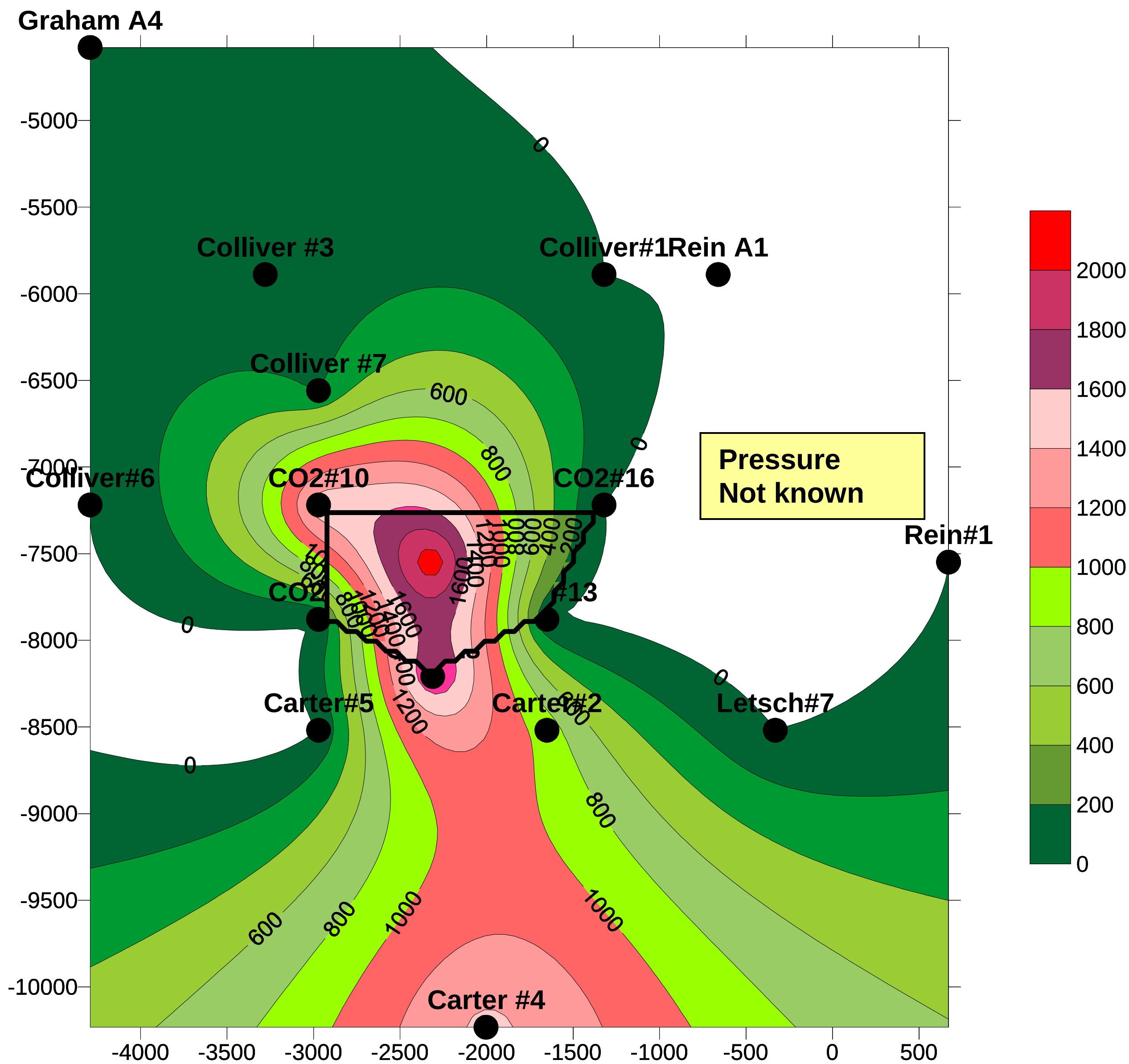

Figure 12: Estimated pressure distribution on Colliver-Carter Leases in December 2006 using Surfer

General Observations

The CO2 Pilot was designed and operated on the basis that oil produced from the pilot wells (CO2 #12 and CO2#13) would come from displacement of oil by carbon dioxide in the PPV (processed pore volume) region indicated on Figure 13. Injection of water into CO2#10 was done to restrict the loss of carbon dioxide north of the PPV area to 30%. Reservoir simulations were consistent with this assumption.

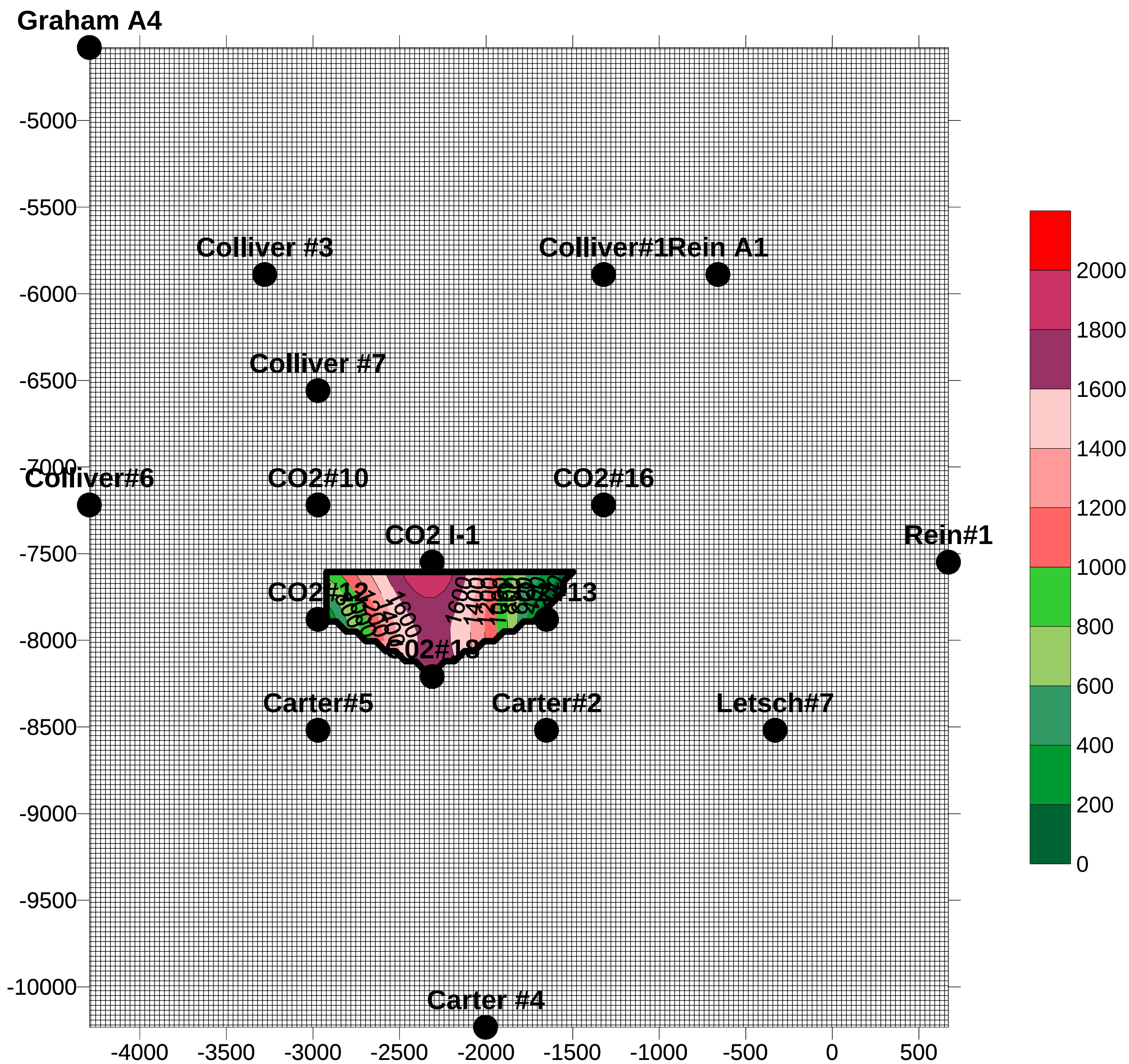

Figure 13: Pressure distribution in the PPV region in CO2 pilot

Oil production from pattern wells is significantly less than estimated and at slower rates than predicted. Much of the oil attributed to CO2 injection has been produced from CO2#12. Oil produced from CO2#13 averaged 1 B/D. CO2#13 is poorly connected to the pilot region and has not experienced the arrival of an oil bank created by carbon dioxide injection. Results indicate that the pilot area is more heterogeneous than represented in the reservoir model. Production from wells to the northwest of the pilot region indicates that there is a directional permeability trend from NW toward the pilot region and that oil displaced from carbon dioxide injection was produced from Colliver #7, Colliver #3 and possibly Graham A4.

Oil production from the CO2 pilot region appears to be at a steady rate with no indication of decline. Cumulative oil production is 3923 bbl. The majority of the injected carbon dioxide remains in the pilot region, which has been maintained at a pressure at or above the minimum miscibility pressure. Our management plan is to continue water injection to maintaining oil displacement by displacing the carbon dioxide remaining in the C zone.

If the decline rate of production from the Colliver Lease remains as estimated and the oil rate from the pilot region remains constant, we estimate that the oil production attributed to carbon dioxide injection will be about 12,000 bbl by December 31, 2007. Oil recovery would be equivalent to 12 MCF/bbl, which is consistent with field experience in established West Texas carbon dioxide floods. The project is uneconomic.

Work continues to revise our reservoir model to reflect the complex heterogeneity indicated by field performance.

TASK 7.0 PROJECT MANAGEMENT

A project management plan was developed consisting of a Technical Team and an Operational Team. Technical Team members include Paul Willhite, Don Green, Jyun Syung and Alan Byrnes. The Operational Team members include Richard Pancake and Susan Sears. Changes in field operations are initiated through the Operational Team. Coordination of the activities is done between Paul Willhite (Technical Team) and Richard Pancake (Operational Team). Production and injection workbooks are updated biweekly by personnel in Murfin's office in Russell and transmitted electronically to members of the Technical and Operational Team. These Excel workbooks are archived periodically in an FTP site accessible to members of the Technical and Operational Teams.

Various members of the Kansas CO2 Team communicate primarily by email over specific technical or business issues. Conference calls are arranged when the discussion involves more than two members of a team.

CONCLUSIONS

Water injection continued in CO2 I-1 to displace the oil bank generated by carbon dioxide injection to the production wells. By December 31, 2006, 79,072 bbl of water were injected into CO2 I-1 and 3,923 bbl of oil were produced. Oil production rates increased from 4.7 B/D to 5.5 to 6 B/D confirming the arrival of an oil bank mobilized by carbon dioxide injection at CO2#12. Production from wells to the northwest of the pilot region indicates that oil displaced from carbon dioxide injection was produced from Colliver #7, Colliver #3 and Graham A4. There is evidence of a directional permeability trend from NW to SE through the pilot region. The majority of the injected carbon dioxide remains in the pilot region, which has been maintained at a pressure at or above the minimum miscibility pressure. Our management plan is to continue water injection to maintaining oil displacement by displacing the carbon dioxide remaining in the C zone.

REFERENCE

1. "Field Demonstration of Carbon Dioxide Miscible Flooding in the Lansing Kansas City Formation, Central Kansas", Semi Annual Report July 1, 2004-December 31, 2004, DOE Contract No. DE-AC26-00BC15124.

Table 2
Summary of Monthly Data
January 2006-December 2006

Field			Jan 2006	Feb 2006	March 2006	April 2006	May 2006	June 2006	July 2006	Aug 2006	Sept 2006	Oct 2006	Nov 2006	Dec 2006	Cum	
I/W With 30% North Losses																
PPV Inj CO2 I-1		%	0.42	0.42	0.42	0.42	0.42	0.42	0.42	0.42	0.42	0.42	0.42	0.42		
		Loss	0.125	0.125	0.125	0.125	0.125	0.125	0.125	0.125	0.125	0.125	0.125	0.125		
		In Pattern	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29		
Production	Oil	bbl	99.36	88.51	81.83	141.95	133.6	90	204	165	175	296	190	167	3924	bbl
	Wtr	bbl	5748	4710	4333	4533	5147	3766	6461	4854	5503	7091	7540	7286	277.777	Mbbl
	Gas	mcf	105.35	60.98	128.5	117.67	78.29	NM	NM	NM	NM	NM	NM	NM	6815	mcf
	WOR	bbl/bbl	57.85	53.21	52.95	31.93	38.53	42	31.71	29.36	31.38	23.99	39.61	43.63		
	Cumulative Oil	bbl	2190	2278	2360	2502	2636	2726	2930	3095	3270	3566	3756	3923		
Injection	Wtr	bbl	12589	7711	10497	10166	10024	9,029	12417	11108	11757	13602	12484	14473	424.98	Mbbl
	CO_2	mcf	0	0	0	0	0	0	0	0	0	0	0	0	138.05	mmcf
		Mlb	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	16.19	MMlb
CO_2 Delivered																
		mcf	0.00	0.00	0.00	0.00	0.00	0.00							155	mmcf
		Mlb	0	0	0	0	0	0							17.93	MMlb
		Tons	0	0	0	0	0	0							8,963	Tons
Tank Vent																
		mcf	0	0	0	0	0	0	0	0	0	0	0	0	15.63	mmcf
		Mlb	0	0	0	0	0	0	0	0	0	0	0	0	1.81	MMlb
		% of Injection	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	11.19%	

Table 3
Summary of Daily Average Data
January –December 2006

Field			Jan 2006	Feb 2006	Mar 2006	April 2006	May 2006	June 2006	July 2006	August 2006	Sept 2006	Oct 2006	Nov 2006	Dec 2006	Average July-Dec
Production															
	Oil	bbl	3.2	3.2	2.6	4.7	4.3	3.0	6.6	5.3	5.8	9.5	6.3	5.4	6.50
	Wtr	bbl	185.4	168.2	139.8	151.1	166.0	126	208	157	183	229	251	235	211
	Gas	mcf	3.4	2.2	4.1	3.9	2.5	NM	NM	NM	NM	NM	NM	NM	NM
Injection															
	Wtr	bbl	406	275	339	339	323	301	401	358	392	439	416	467	412
	CO2	mcf	0	0	0	0	0	0	0	0	0	0	0	0	0.00
		Mlb	0	0	0	0	0	0	0	0	0	0	0	0	0.00
CO2 Delivered															
		mcf	0	0	0	0	0	0	0	0	0	0	0	0	0.00
		Mlb	0	0	0	0	0	0	0	0	0	0	0	0	0.00
Tank Vent															
		mcf	0	0	0	0	0	0	0	0	0	0	0	0	0.00
		Mlb	0	0	0	0	0	0	0	0	0	0	0	0	0.00
		% of Injection													0.00
Wells															
Production															
CO2 12	Oil	bbl	2.4	2.3	1.9	4.2	3.8	2.7	5.4	4.0	4.7	7.7	4.9	4.0	5.1
	Wtr	bbl	138	130	108	101	111	84	152	124	136	168	185	173	156
	Gas	mcf	2.1	1.4	2.6	2.5	1.6	NM	NM	NM	NM	NM	NM	NM	NM
	Total Liquid(bbl)		140.4	131.9	109.6	105.4	115.0	86.7	157	127	140	176	190	177	161
	GOR		890	603	1374	580	410	NM	NM	NM	NM	NM	NM	NM	NM
CO2 13	Oil	bbl	0.82	0.90	0.75	0.51	0.46	0.32	1.20	1.37	1.10	1.82	1.44	1.41	1
	Wtr	bbl	47.4	38.5	32.0	50.0	54.9	42	56	33	48	61	66	62	54
	Gas	mcf	1.3	0.8	1.6	1.5	0.9	NM	NM	NM	NM	NM	NM	NM	NM
	Total Liquid(bbl)		48	39	33	50	55	42	58	34	49	62	68	63	44.68
	GOR	bbl/bbl	1557	905	2063	2906	2054	NM	NM	NM	NM	NM	NM	NM	NM
Total Liquid-Pattern		bbl	188.6	171.4	142.4	155.8	170.3	128.5	215	162	189	238	258	240	217
Total Gas_pattern		mcf	3.40	2.18	4.15	3.92	2.53	NM	NM	NM	NM	NM	NM	NM	NM
GOR-Pattern		mcf/bbl	1060	689	1570	829	586	NM	NM	NM	NM	NM	NM	NM	NM
Injection															
CO2 10	Wtr	bbl	287.5	169.3	121.6	113.5	109.1	90	142	135	150	201	186	184	166
CO2 18	Wtr	bbl	24.0	55.1	53.0	20.5	18.2	21.4	44	33	42	49	8	75	42
CO2 I-1	Wtr	bbl	94.6	50.9	164.0	204.9	196.1	189.6	214	191	200	189	222	207	204