SEMI ANNUAL TECHNICAL PROGRESS REPORT
FOR THE PERIOD ENDING DECEMBER 31, 2007

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
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DOE Cost Amount:	$1,892,094
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Reporting Period: DOE	July 1, 2007 – December 31, 2007
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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 was 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, 2007, 153,760 bbls of water were injected into CO2 I-1 and 5,604 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 averaged 4.1 B/D for the period from July 1-December 31, 2007. Production from wells to the northwest of the pilot region indicates that oil displaced from carbon dioxide injection was produced from Colliver A7, Colliver A3, Colliver A14 and Graham A4 located on adjacent leases. About 11,464 bbl of incremental oil was estimated to have been produced from these wells as of December 31, 2007. 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. Estimated oil recovery attributed to the CO2 flood is 17,068 bbl which is equivalent to a gross CO2 utilization of 8.1 MCF/bbl. The pilot project is not economic.

TABLE OF CONTENTS

TITLE PAGE 1
DISCLAIMER 2
ABSTRACT 2
TABLE OF CONTENTS 3
LIST OF TABLES 3
LIST OF FIGURES 3
INTRODUCTION 5
EXECUTIVE SUMMARY 5
RESULTS AND DISCUSSION 5
TASK 5.4 - IMPLEMENT CO2 FLOOD OPERATIONS..... 5
TASK 7.0 PROJECT MANAGEMENT 15
CONCLUSIONS 15
REFERENCE.....16

LIST OF FIGURES

Figure 1: Murfin Colliver Lease in Russell County, Kansas.....6
Figure 2: Injection rates into CO2 I-1..... 7
Figure 3: Injection rates into CO2I-1, CO2#10 and CO2#18.....8
Figure 4: Average daily oil production rates from pilot area.....8
Figure 5: Average daily water production rate from pilot area.....9
Figure 6: Average water/oil ratio for the period from January 1 to December 31, 2007.....9
Figure 7: Map showing location of wells completed in the Lansing-Kansas 'City 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.....11
Figure 8: Monthly oil sales from Graham A Lease.....12

Figure 9: Colliver A lease production after C zone was opened in Colliver A7, Colliver A3 and Colliver A14.....12
Figure 10: Estimated pressure distribution on Colliver-Carter Leases in December 2007 Using Surfer.....14

LIST OF TABLES

Table 1: Estimated Incremental Oil from CO2 Injection into LKC C.....13
Table 2: Summary of Monthly Data-January 2007-December 2007.....17
Table 3: Summary of Daily Data- January 2007-December 2007 18

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, 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 with the expectation that sufficient carbon dioxide had been injected to displace the oil bank to the production wells by water injection. By December 31, 2007, 153,760 bbls of water were injected into CO2 I-1 and 5,604 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 averaged 4.1 B/D for the period from July 1- December 31, 2007. Production from wells to the northwest of the pilot region indicates that oil displaced from carbon dioxide injection was produced from Colliver A7, Colliver A3, Colliver A14 and Graham A4 located on adjacent leases. About 11,464 bbl of incremental oil was estimated to have been produced from these wells as of December 31, 2007. 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. Estimated oil recovery attributed to the CO2 flood is 17,068 bbl, which is equivalent to a gross CO2 utilization of 8.1 MCF/bbl. The pilot project is not economic.

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. Average injection rates are shown in Figure 2 for the period from January 1- December 2007. Relatively stable rates and pressures were maintained. Average injection rate for the six month period from July-December 2007 was 206

B/D.

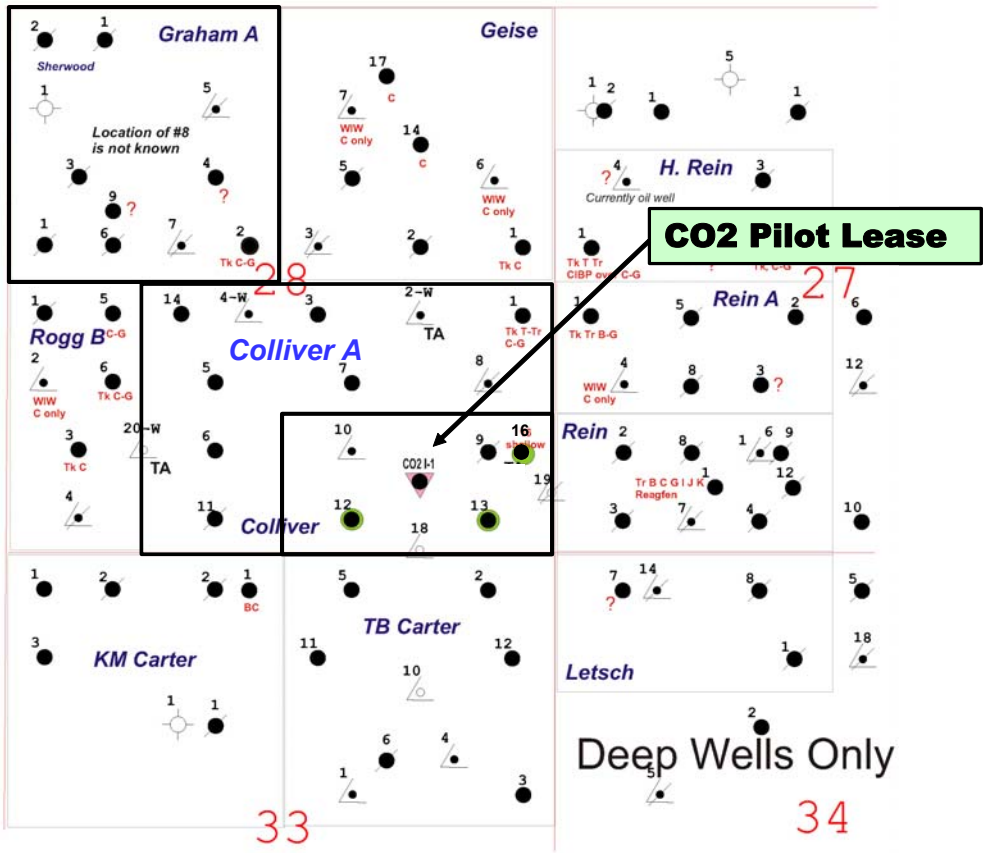

Figure 1: Murfin Colliver Lease in Russell County, Kansas

Cumulative volume of water injected into CO2I-1 was 153,760 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 injection rates for CO2I-1, CO2 #10 and CO2#18.

Oil and water production rates are shown in Figures 4 and 5 for the period January 2007-December 2007. CO2#16 was completed and placed on pump in October 2006 on an 8-hour clock. There was a small amount of flush production and the well was pumped intermittently when the fluid level built up. CO2#16 was shut-in on May 31, 2007 following a rod part because the well was not economic to produce.

CO2#13 was shut-in on April 11, 2007 to observe pressure buildup and the effect on oil production rate from the CO2 pattern. The well was returned to production on May 17, 2007 for a total shut-in period of 36 days. During the shut-in period, the bottom hole pressure in CO2#13 increased from 62 psi prior to shut-in to 278 psi before the well was returned to production. The rate of pressure buildup in this well is small and provides further evidence of the poor reservoir

continuity between CO2I-1 and CO2#13. In contrast, fluid levels in CO2#16 buildup rapidly following shut-in of the well. Bottom hole pressure increased to about 575 psi after shut-in. CO2 #16 appears to have better hydraulic connection with CO2 I-1 than CO2#13.

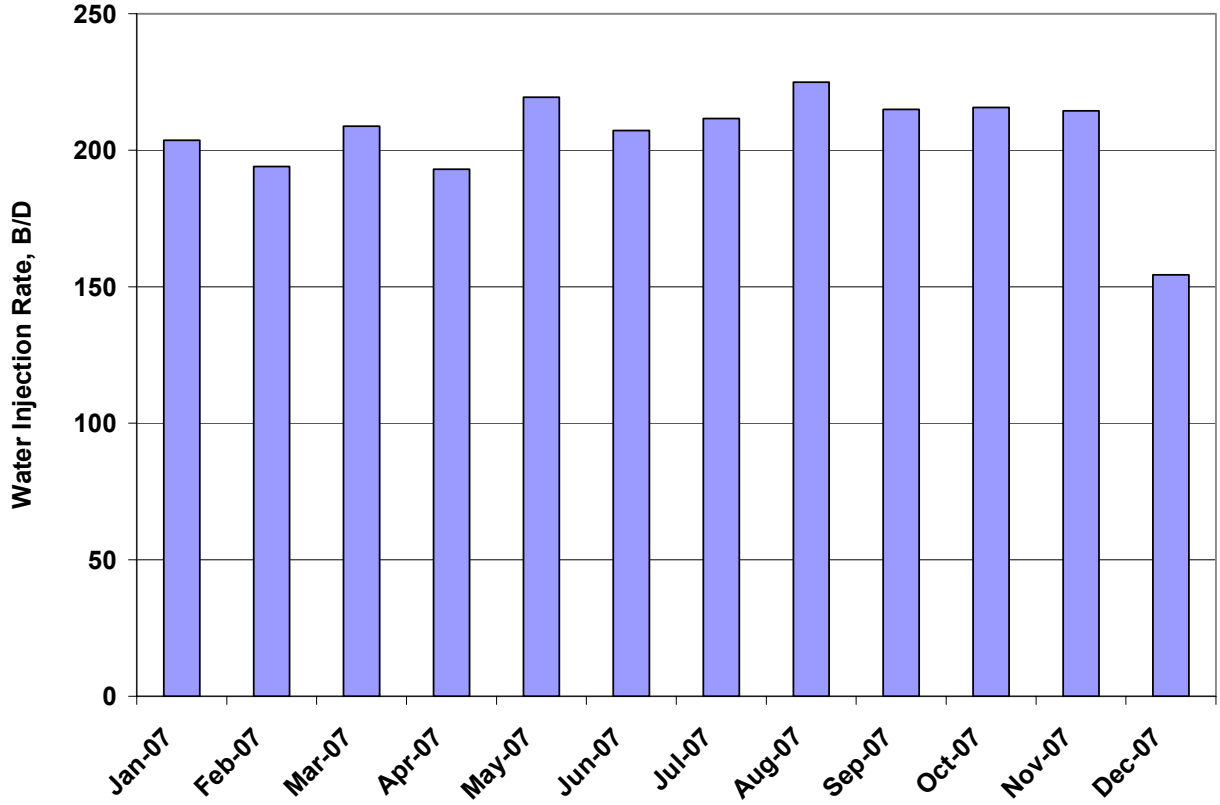

Figure 2: Water injection rate into CO2 I-1

Figures 4 and 5 show the average monthly oil and water production rates from the pilot. Meter problems persisted from July-October so water production rates were estimated based on the November rates. Average oil production rates were about 4.07B/D for the period from July 1-December 31, 2007. The entire lease was shut in for 12 days in December due to an ice storm which caused interruptions in electricity. 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 6 shows the average water-oil ratio for the same period. 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 5604 bbl. Water production from the pilot area was about 285,000 bbl

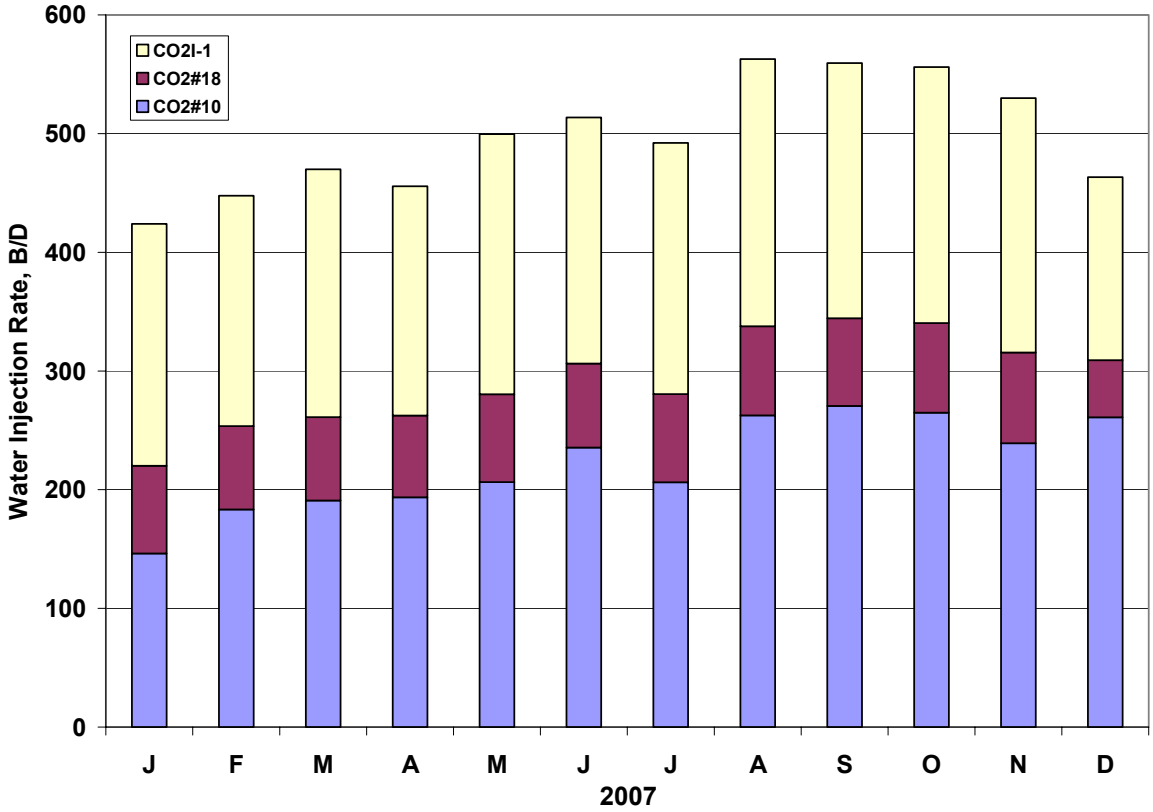

Figure 3: Injection rates into CO2I-1, CO2#18 and CO2#10

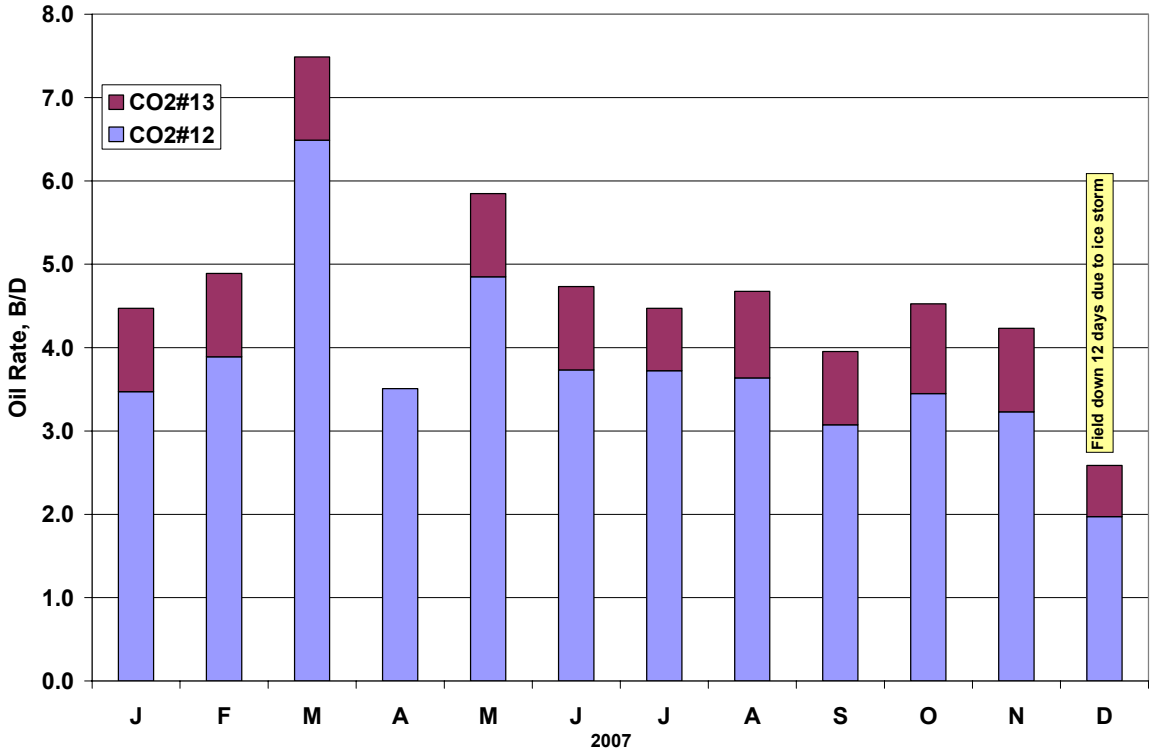

Figure 4: Average daily oil production rates from pilot area

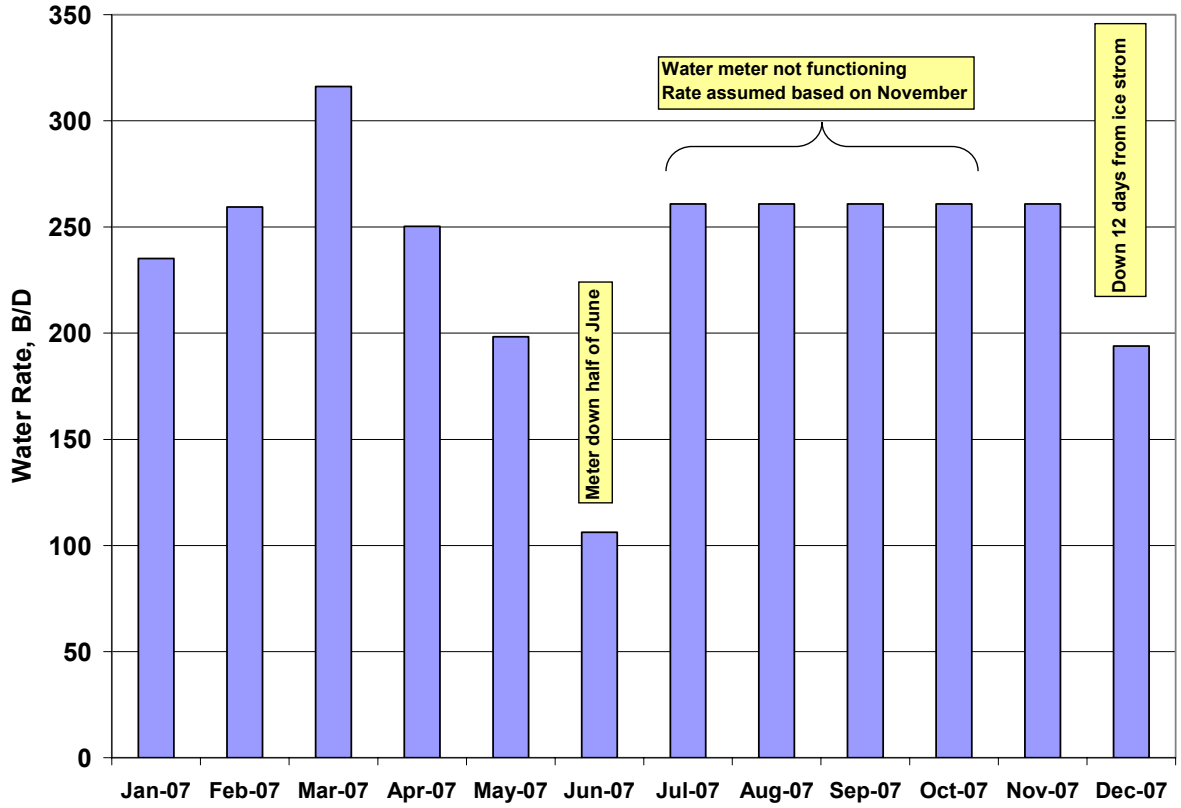

Figure 5: Average daily water production rate from pilot

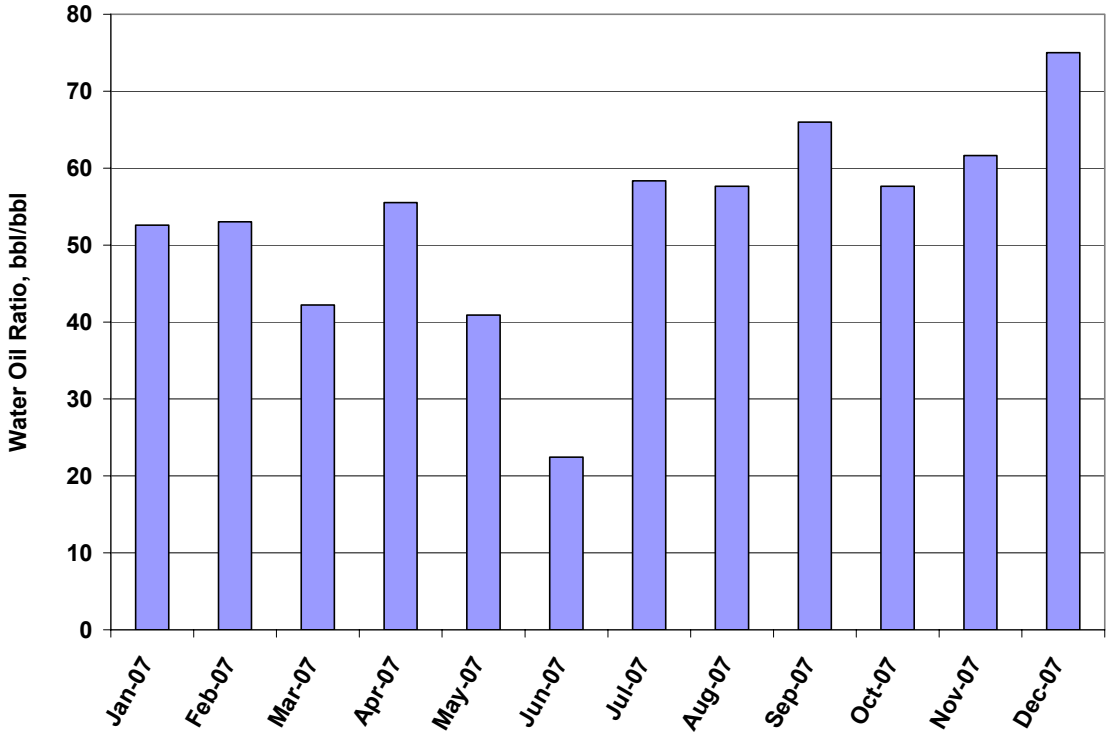

Figure 6: Average water/oil ratio for the period from January 1 to December 31, 2007

Production from Surrounding Leases

In the December 2006 Semi Annual Report, data were presented demonstrating that oil displaced from the CO2 Pilot Area had been displaced to the Graham A and Colliver A leases, on a trend northwest of the pilot.

In August 2006, 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 7.

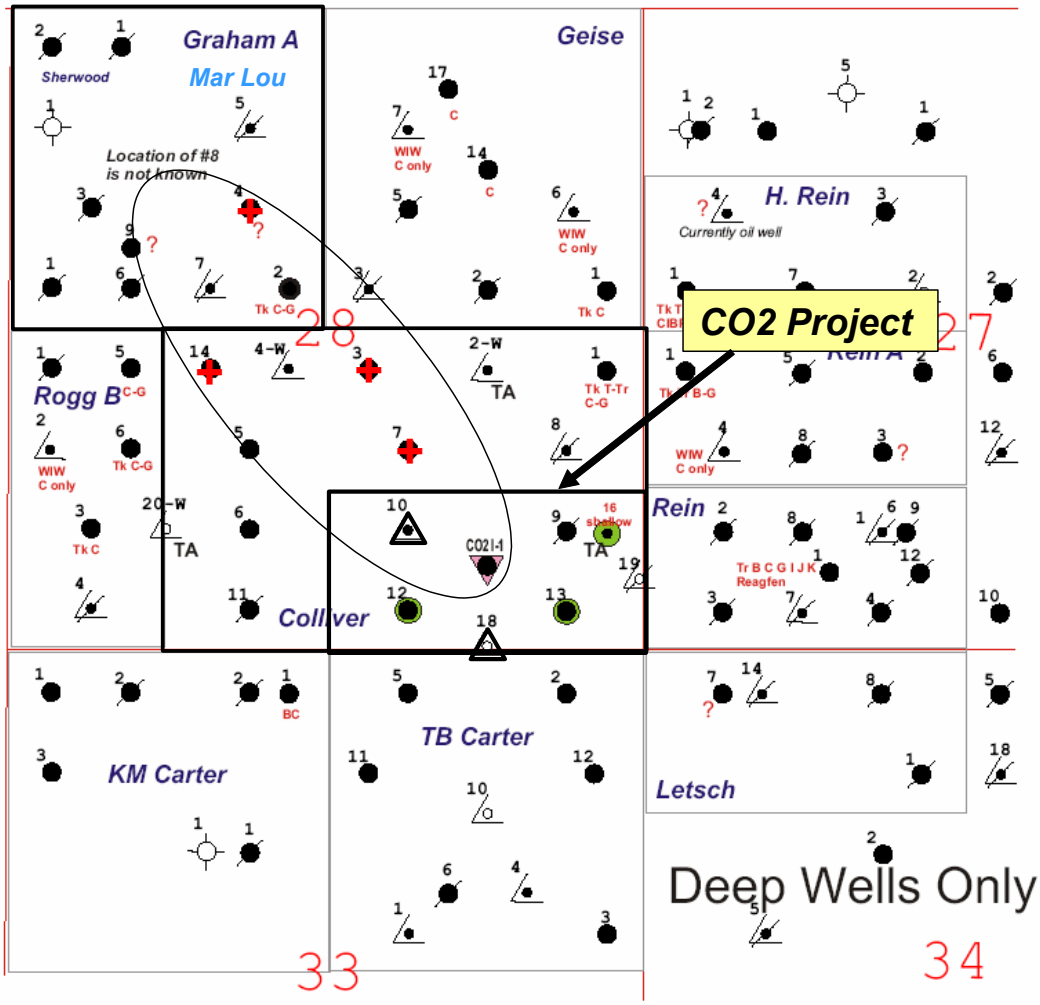

Figure 7: Map showing location of wells completed in the Lansing-Kansas C zone in the area of the CO2 pilot. The elliptical region includes wells marked with a + that appear to have produced oil displaced from the CO2 pilot area.

Figure 8 shows monthly oil sales from the Graham A4 lease for 2004-2007. There is no explanation for the decline in monthly oil sales in July 2004 that persisted until May 2006. 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. The amount of incremental oil attributed to the CO2 project from the Graham A lease is uncertain because of the fluctuations in monthly oil sales in Figure 8 which persisted into 2007.

Based on monthly oil sales, we estimate about 920 bbl of incremental oil was produced from the Graham A lease. 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. Production declined on the Graham A Lease after Colliver A7 and Colliver A3 were placed on production from the LKC ***C*** zone.

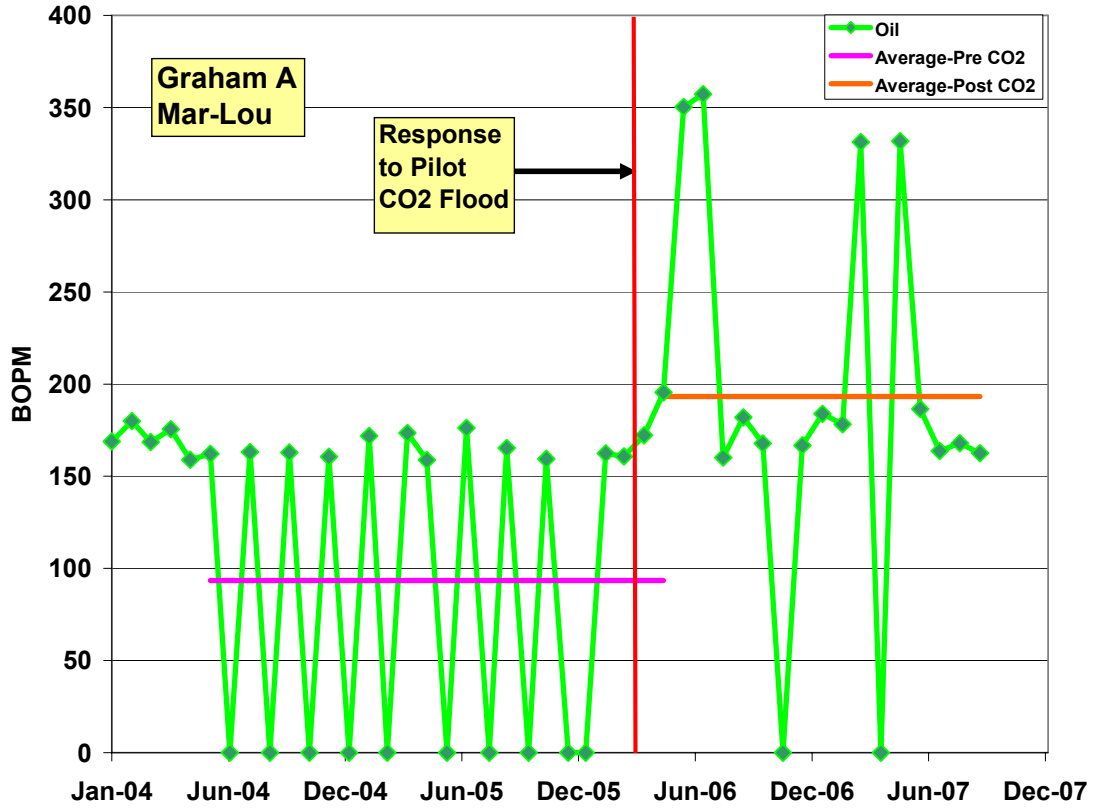

Figure 8: Monthly oil sales from the Graham A lease

On August 28, 2006 the production packer used to isolate the LKC ***C*** zone from shallow zones was released in Colliver A7 and oil production increased substantially from the Colliver A lease. The CIBP in Colliver A3 was knocked out and the well was placed on production on October 11, 2006. The CIBP in Colliver A14 was removed in March 13, 2007. Sustained increased production from the Colliver A lease is shown on Figure 9. The red line is a projection of the Colliver A lease decline before the C zone was opened in Colliver A7, A3 and A14. Incremental

oil above the estimated decline is about 22 BOPD. It is believed that opening Colliver A3 and A7 reduced the movement of oil from the Colliver A lease to the Graham A lease. Colliver A3 production declined to 1 B/D by December 2006 and remained at that level. At the present time, incremental oil production on the Colliver A Lease appears to be coming from Colliver A 7 and Colliver A 14. 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 elliptical shape on Figure 7 suggests a preferential permeability trend from the northwest toward CO2 I-1.

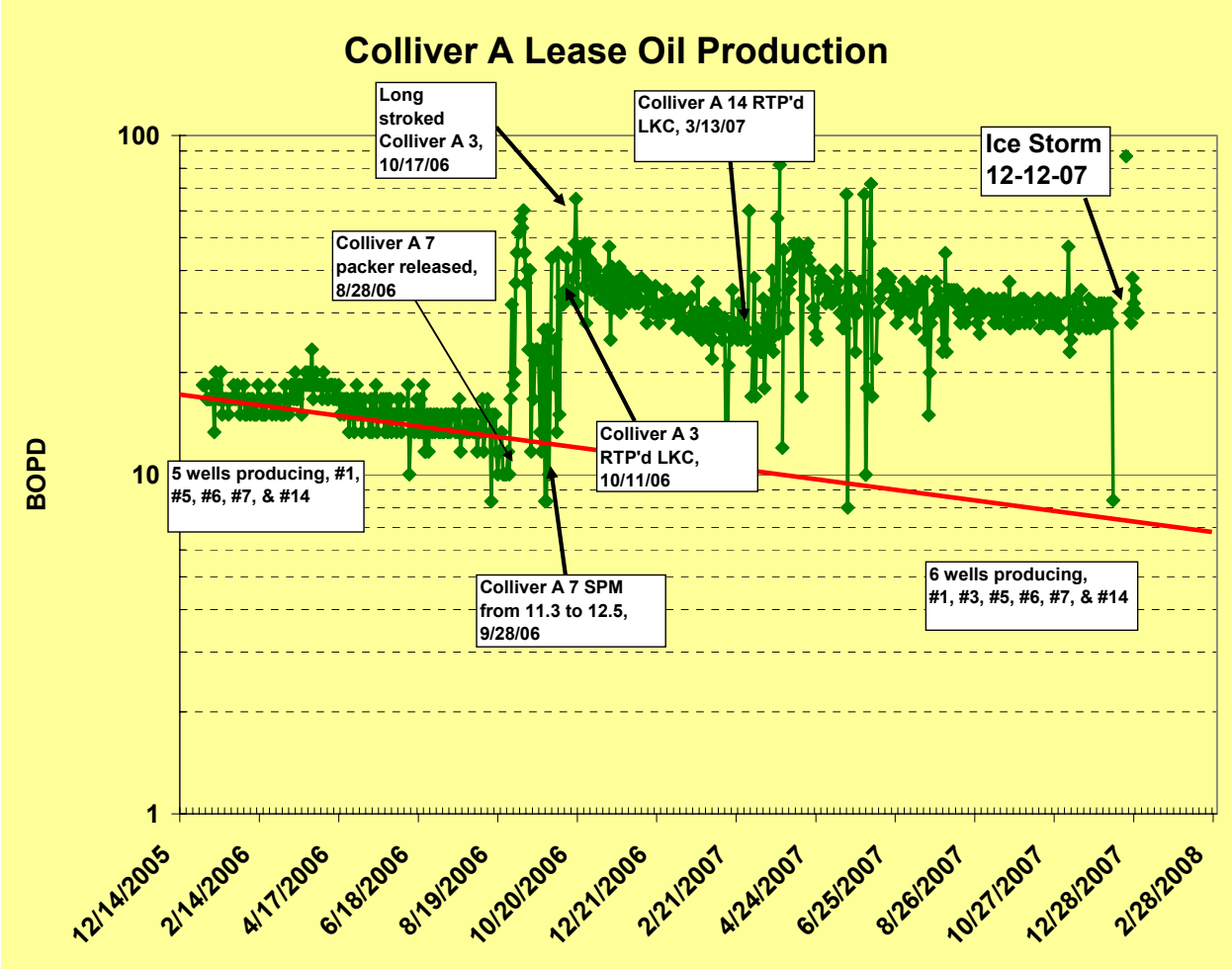

Figure 9: Colliver A lease production after C zone was opened in Colliver A #7, Colliver A#3 and Colliver A#14.

Table 1 contains an estimate of incremental oil from CO2 injection through December 31, 2007. Total incremental oil attributed to the CO2 project is 17,068 bbl. No additional incremental oil from the Graham A lease was added to the total after October 2006. There is evidence of production decline on the Colliver A Lease, but substantial additional incremental production should occur before rates decline to the red line indicating the estimated decline rate prior to opening Colliver A wells to the C zone.. By the end of 2007, the gross CO2/oil ratio was 8.1 MCF/bbl which is comparable to values observed in large scale West Texas carbon dioxide floods. This demonstrates that carbon dioxide mobilized oil in the LKC ***C*** zone, a key objective

of the pilot project.

Table 1: Estimated Incremental Oil from CO2 Injection into LKC ***C***

Date	CO2 Pilot	Colliver A Lease	Graham A Lease	Total BBL	MCF/BBL
12/31/07	5604	10544	920	17068	8.1

Although half of the planned CO2 was injected, only about 5% of the injected CO2 has been produced. Consequently, 95% of the injected CO2 remains in the C zone where it is being displaced by injected water. Pressures in much of the pilot region have remained above MMP through maintaining injection pressures in CO2I-1, CO2#10 and CO2#18. Consequently, we believe that oil continues to be displaced by carbon dioxide. Additional oil recovery appears likely to occur on the Colliver A lease and the CO2 pilot lease.

Pressure in Pilot Region

Estimated pressure contours are shown in Figure 10 as of December 2007. The average pressure in the PPV region was estimated using Surfer, a mapping program. In developing Figure 10, 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 11 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 A1, Carter #2, Rein A-1, Letsch #7 and Colliver A6 were assumed pumped off. The fluid head in Colliver A7 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 1451 psi. The average pressure in the pilot region has decreased due to the production of Colliver A7.

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 A6, Letsch #7 and Carter #5 have been pumped off

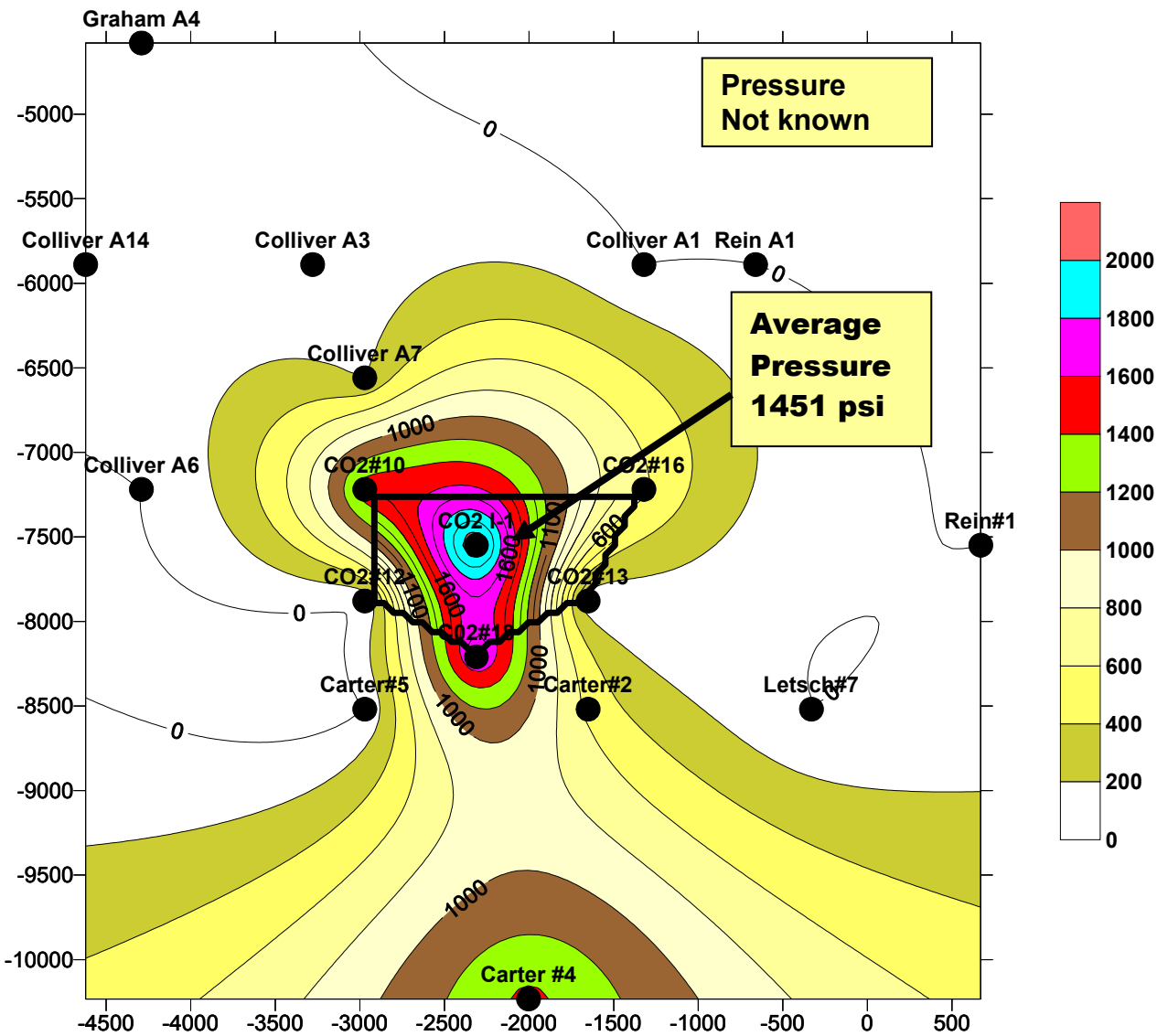

Figure 10: Estimated pressure distribution on Colliver-Carter Leases on December 31, 2007 using Surfer

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 10. 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 A7 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.

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. 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.

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 A7, Colliver A3, Colliver A14 and Graham A4.

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.

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 member is Richard Pancake. 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 monthly 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, 2007, 153,760 bbl of water were injected into CO2 I-1 and 5,604 bbl of oil were produced from the pilot pattern. Oil production rates increased from averaged 4.1 B/D during the period from July 1-December 31. Production from wells to the northwest of the pilot region indicates that oil displaced from carbon dioxide injection was

produced from Colliver A7, Colliver A3, Colliver A14 and Graham A4. The amount of incremental oil produced from adjacent leases is about 11,464 bbl. Total oil production attributed to CO2 injection is 17,068 bbl. This is equivalent to a gross CO2 utilization of 8.1 MCF/bbl. 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 – December 2007

Field			N	Jan 2007	Feb 2007	Mar 2007	April 2007	May 2007	June 2007	July** 2007	Aug** 2007	Sept** 2007	Oct** 2007	Nov 2007	Dec* 2007	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	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	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	0.29	
Production	Oil	bbl		139	137	232	135	150	142	139	140	119	140	127	80	5604	bbl
	Wtr	bbl		7290	7262	9801	7509	6148	3187	8086	8086	7825	8086	7825	6012	285	Mbbl
	Gas	mcf		NM	NM	NM	NM	NM	NM	NM	NM	NM	NM	NM	NM	6815	mcf
	WOR	bbl/bbl		52.59	53.03	42.22	55.51	40.90	22.45	58.34	57.64	65.99	57.64	61.65	75.00		
	Cumulative Oil	bbl		4062	4199	4431	4566	4717	4858	4997	5137	5256	5396	5523	5603		
Injection	Wtr	bbl		6315	5432	6471	5793	6801	6217	6560	6747	6447	6685	6434	6434	501.31	Mbbl
	CO2	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
CO2 Delivered																	
		mcf		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	155	mmcf
		Mlb		0	0	0	0	0	0	0	0	0	0	0	0	17.93	MMlb
		Tons		0	0	0	0	0	0	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%	

***Field shut-in 12 days in December from ice storm**
****Water meter out July-October. November average water rate assumed**

Table 3
Summary of Daily Average Data
January –December 2007

Field			Jan 2007	Feb 2007	Mar 2007	April 2007	May 2007	June 2007	July 2007	August 2007	Sept 2007	Oct 2007	Nov 2007	Dec* 2007	Average July-Dec
Production															
	Oil	bbl	4.5	4.9	7.5	4.5	4.8	4.7	4.5	4.7	4.0	4.5	4.2	2.6	4.07
	Wtr	bbl	235	259	316	250	198	106	***261***	***261***	***261***	***261***	261	194	250
	Gas	mcf	NM	NM	NM	NM	NM	NM	NM	NM	NM	NM	NM	NM	NM
Injection															
	Wtr	bbl	204	194	209	193	219	207	212	225	215	216	214	154	206
	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	3.5	3.9	6.5	3.5	4.8	3.7	3.7	3.6	3.1	3.4	3.2	2.0	3.2
	Wtr	bbl	184	208	265	199	198	55	217	203	203	199	199	148	195
	Gas	mcf	NM	NM	NM	NM	NM	NM	NM	NM	NM	NM	NM	NM	NM
	Total Liquid(bbl)		188	212	272	203	203	59	221	207	206	202	202	150	198
	GOR		NM	NM	NM	NM	NM	NM	NM	NM	NM	NM	NM	NM	NM
CO2 13	Oil	bbl	1.00	1.00	1.00	0.00	1.00	1.00	0.75	1.04	0.88	1.08	1.00	0.61	1
	Wtr	bbl	51	51	51	0	51	51	44	58	58	62	62	46	55
	Gas	mcf	NM	NM	NM	NM	NM	NM	NM	NM	NM	NM	NM	NM	NM
	Total Liquid(bbl)		52	52	52	0	52	52	44	59	59	63	63	47	43.33
	GOR	bbl/bbl	NM	NM	NM	NM	NM	NM	NM	NM	NM	NM	NM	NM	NM
Total Liquid-Pattern		bbl	240	264	324	203	255	111	265	266	265	265	265	197	254
Total Gas_pattern		mcf	NM	NM	NM	NM	NM	NM	NM	NM	NM	NM	NM	NM	NM
GOR-Pattern		mcf/bbl	NM	NM	NM	NM	NM	NM	NM	NM	NM	NM	NM	NM	NM
Injection															
CO2 10	Wtr	bbl	146	183	191	194	206	235	206	263	271	265	239	261	251
CO2 18	Wtr	bbl	74	70	70	69	74	71	74	75	74	75	76	48	71
CO2 I-1	Wtr	bbl	204	194	209	193	219	207	212	225	215	216	214	154	206

Note: Field shut-in for 12 days in December from ice storm