SEMI ANNUAL TECHNICAL PROGRESS REPORT
FOR THE PERIOD ENDING DECEMBER 31,2005

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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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 two production wells on about 10 acre spacing. 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. Wells in the pilot area produced 100% water at the beginning of the flood. Oil production began in February 2004, increasing to an average of about 3.78 B/D for the six month period between January 1 and June 30, 2005 before declining. By the end of December 2005, 14,115 bbls of water were injected into CO2I-1 and 2,091 bbl of oil were produced from the pilot. Injection rates into CO2I-1 declined with time, dropping to an unacceptable level for the project. The injection pressure was increased to reach a stable water injection rate of 100 B/D. However, the injection rate continued to decline with time, suggesting that water was being injected into a region with limited leakoff and production. Oil production rates remained in the range of 3-3.5 B/D following conversion to water injection. There is no evidence that the oil bank generated by injection of carbon dioxide has reached either production well. Continued injection of water is planned to displace oil mobilized by carbon dioxide to the production wells and to maintain the pressure in the PPV region at a level that supports continued miscible displacement as the carbon dioxide is displaced by the injected water.

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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_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:

Continuous injection of carbon dioxide into the Lansing Kansas City C formation in the Hall Gurney Field near Russell, Kansas began on December 2, 2003. 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 two production wells on about 10 acre spacing. By the end of June 2005, about 16.19 MM lbs of carbon dioxide were injected. 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 the end of December 2005, 14,115 bbls of water were injected into CO2I-1 and 2,091 bbl of oil were produced from the pilot. Injection rates into CO2I-1 declined with time, dropping to an unacceptable level for the project. The injection pressure was increased to reach a stable water injection rate of 100 B/D. However, the injection rate continued to decline with time, suggesting that water was being injected into a region with limited leakoff and production. Oil production rates remained in the range of 3-3.5 B/D following conversion to water injection. There is no evidence that the oil bank generated by injection of carbon dioxide has reached either production well. Continued injection of water is planned to displace oil mobilized by carbon dioxide to the production wells and to maintain the pressure in the PPV region at a level that supports continued miscible displacement as the carbon dioxide is displaced by the injected water.

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 ~10 acre pilot pattern consists of one carbon dioxide injection well (CO2I-1), two production wells (CO2#12 and CO2#13) two water injection wells(CO2#10 and CO2#18) and CO2#16, an observation well. 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 from by EPCO from the ethanol plant in Russell operated by US Energy Partners where it is 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 CO2I-1.

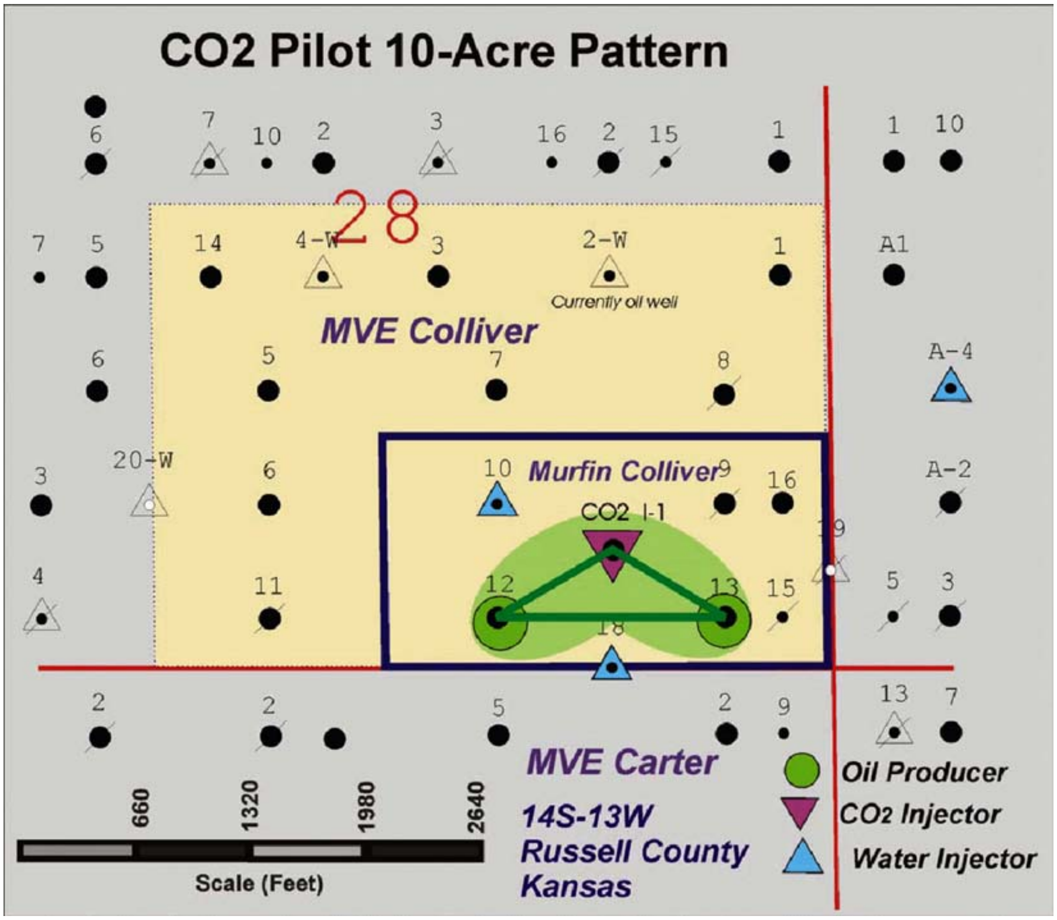

Figure 1: Murfin Colliver Lease in Russell County, Kansas

Carbon dioxide injection into CO2I-1 terminated on June 17, 2005 and water injection began on June 21. Cumulative water injection into CO2I-1 through December 31 was 14,115 bbls. Oil production since the beginning of water injection was 625 bbl and the water production was 32,259 bbl. Average monthly oil production rates are shown in Figure 2 for the period from February 2005 through December 2005. Oil rates were declining in the period before conversion to water injection and stabilized at about 3.1 B/D after water injection began. There is a small increase in oil production rate associated with the increased water production rate following the increase in injection pressure in October. There is no evidence that the oil bank generated by carbon dioxide injection has reached either CO2#12 or CO2#13. Short term production tests on both wells occasionally extrapolate to higher production rates that do not appear in the 24 hour measurements based on the stock tank oil. Production rates in CO2#13 are erratic, possibly due to presence of gas saturation in the vicinity of the well. Increased water production is coming from CO2#12.

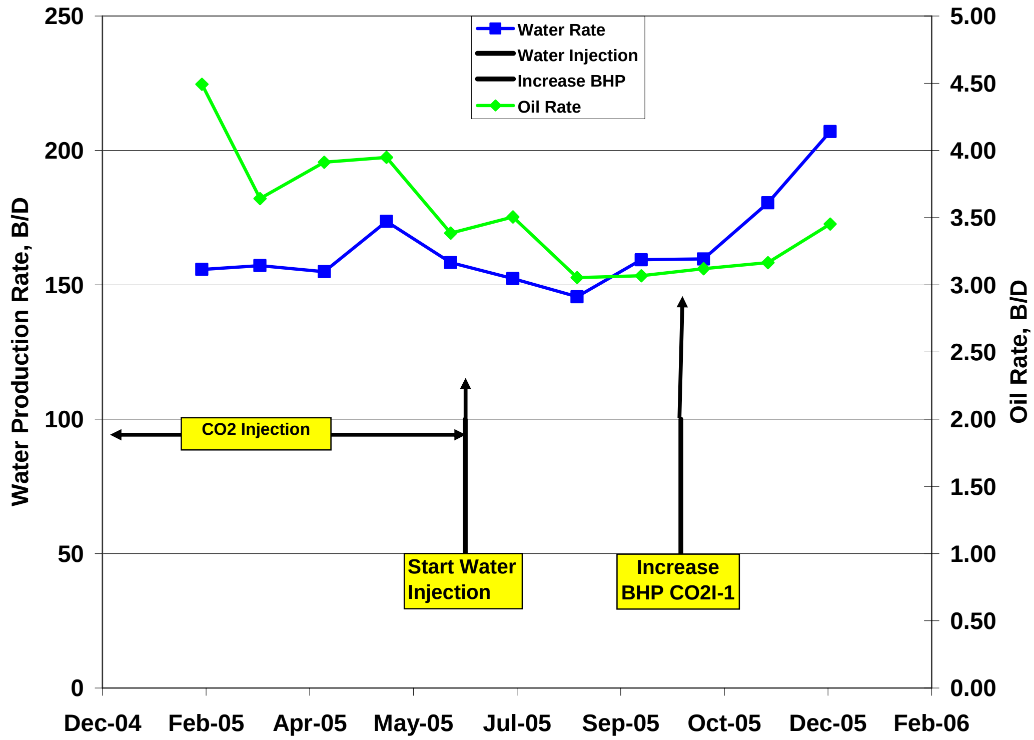

Figure 2: Oil and water production rates-CO2 Project, February to December 2005

Carbon dioxide production rates declined from ~16 MCFD to 3-4 MCFD following cessation of carbon dioxide injection. This suggests that about 12 MCFD was flowing directly from CO2 I-1 to CO2#12. Total amount of carbon dioxide produced is approximately 6.3 MMSCF. This is about 5% of the total amount of carbon dioxide injected into the reservoir. Thus, 95% of the carbon dioxide that was injected remains in the reservoir.

When the project was planned, carbon dioxide losses to the north were anticipated and estimated in designing, managing and interpreting the pilot performance. Our initial estimates were based 30% loss. Water injection into CO2#10 is managed to minimize carbon dioxide loss to the north and injection into CO2#18 is managed to minimize carbon dioxide loss to the south. However, there is substantial uncertainty in the actual loss. Interpretation of 4D seismic data suggest that some carbon dioxide moved as far north as ~600-1000 ft. The uncertainty is tempered by other information. Colliver #1 is open in the C zone and has been pumped off during the entire time the project has been ongoing. Carbon dioxide has not broken into that well in observable quantities.

The injection rate into CO2I-1 must be sufficient to:1) maintain minimum miscibility pressure in the pilot region containing carbon dioxide, 2) complete the project within the time frame of the DOE project, 3) replace fluid production in CO2#12 and CO2#13 from the pilot region and 4)compensate for fluid loss to the north. Our project design assumes that 29 % of the production from CO2#12 comes from the pilot region and 87% of the production from CO2#13 is from the pilot region. As noted earlier, loss to the north is estimated at 30% of the fluid injected into CO2I-1.

Figure 3 shows water production rates and water injection rates for the period from June 21 through December 31, 2005. Water production averaged about 150 B/D from CO2#12(100 B/D) and #13(50 B/D) during the period from June 22 through October 1. Using the above percentages, the volume of fluid produced from the pilot region is about 73 B/D. Considering the loss to the north at 30% the design injection rate for CO2I-1 is about 105 B/D to maintain fluid volume balance and thus pressure stability in the pilot region.

Water injection rates into CO2I-1 declined rapidly with time during the period from June 22 through mid September reaching rates of less than 45 B/D. Wellhead pressure remained constant during this time period so that the declining rate was attributed to either a buildup of wellbore damage or the detection of a change in the reservoir continuity. We concluded that this rate was too low to meet project goals and implemented plans to increase the injection rate to approximately 100 B/D. CO2I-1 was given an acid treatment on September 27 to remove wellbore damage if present. Upon resumption of injection at the same wellhead pressure, the same trend of declining injection rates resumed, indicating that the decline in injection rate was not caused by damage in the vicinity of the wellbore.

The second plan to increase injection rate to increase the injection pressure in increments of 50 psi until a stable injection rate of about 100 B/D was attained. This plan was implemented on October 4 and the injection rate increased to about 96 B/D for the remainder of the year, an increase of about 50 B/D from mid-September. Figure 4 shows the injection rates and bottomhole pressures for the period from September 1-December 31, 2005.

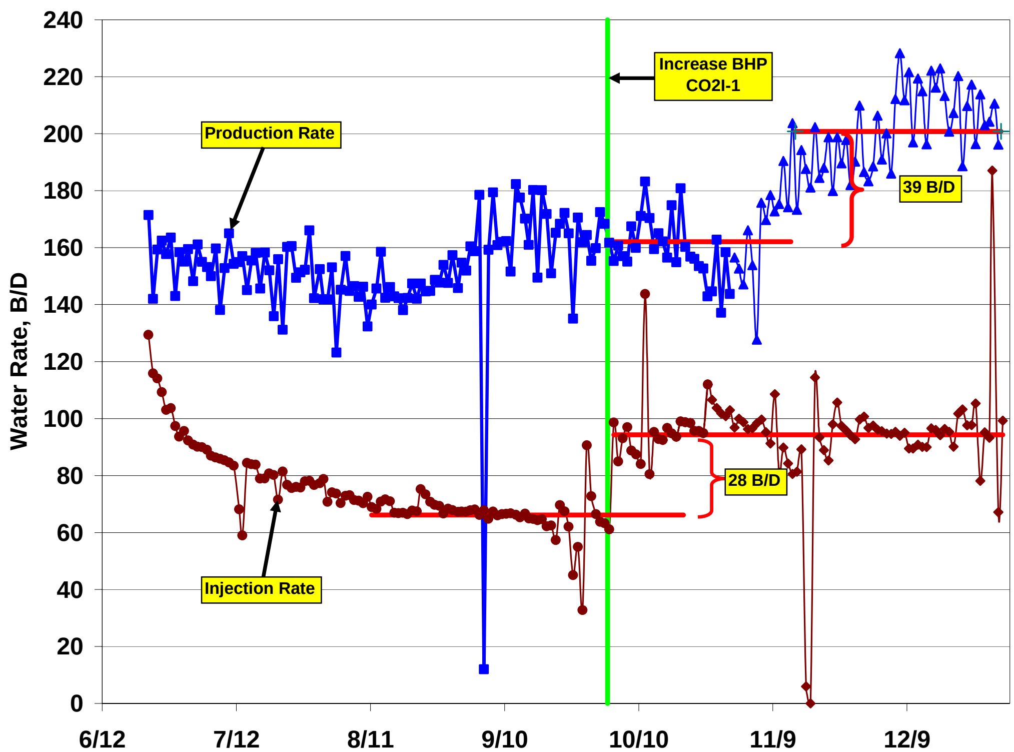

Figure 3: Comparison of injection rate in CO2I-1 with water production rate from CO2#12 and CO2#13.

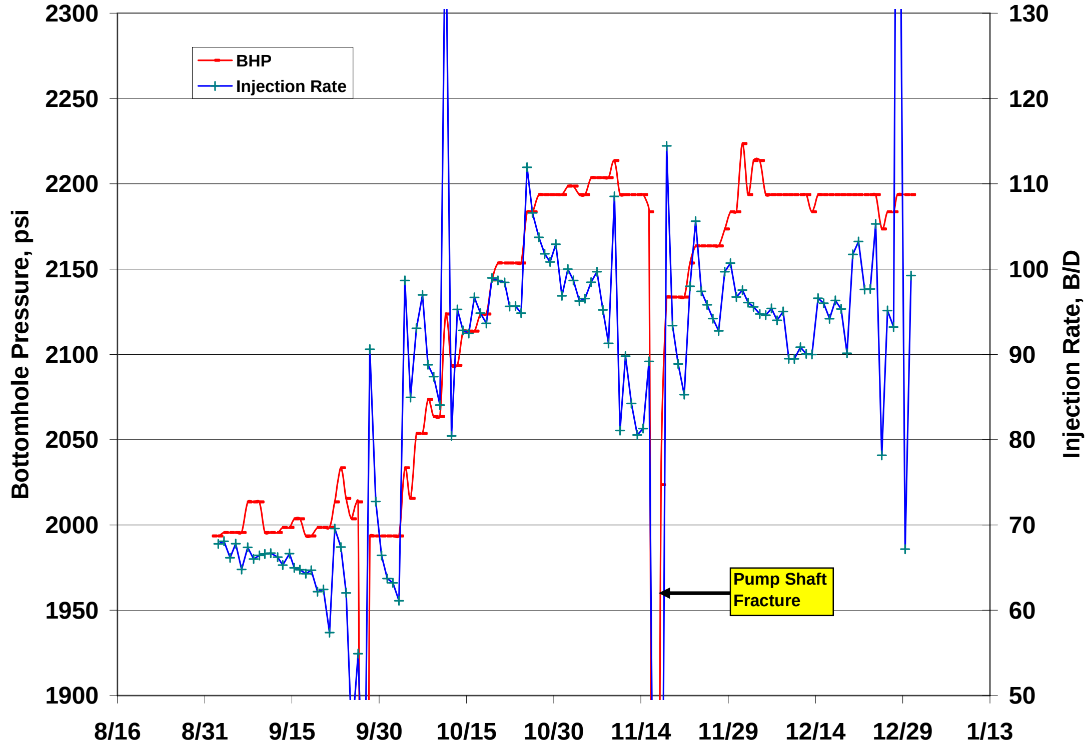

Figure 4: Injection rates and bottomhole pressures in CO2I-1

Our management plan was based on maintaining a constant wellhead pressure to determine the stabilized injection rate. However, this goal has been difficult to attain in the field. Note in Figure 4 that that the injection rate frequently declines with time when the wellhead pressure is maintained at a constant value.

Figure 5 is a plot of the bottomhole pressure in CO2I-1 and reservoir pressure at CO2#16 and Carter 2. The pressure increase in CO2I-1 is about 200 psi which is above the estimated fracture pressure. CO2#16 is open to the C zone. Carter 2 is open in the C, Tarkio and Plattsmouth zones. Reservoir pressure declined at a constant rate in CO2#16 following conversion to water injection in CO2I-1 suggesting that fluid movement toward this well was reduced before water injection started or that losses increased. Pressure in Carter 2 varied within 25 psi until the pressure was increased in CO2I-1. However, the pressure in Carter 2 increased by about 150 psi shortly after the pressure in CO2I-1 was increased and then increased slowly thereafter. These values are the highest pressures observed in Carter 2 and may indicate fluid movement toward CO2#13 following the increase in injection rate in CO2I-1. There is a possibility that the increase in pressure in Carter 2 is caused by fluid entry form Tarkio and/or Plattsmouth zones.

The declining injection rate at constant wellhead pressure is convincing evidence that the pilot region has a finite volume with limited loss to the surroundings. This means that losses to the north may be less than estimated and that the fraction of the fluid production from CO2#12 and CO2#13 from the pilot region is less than anticipated.

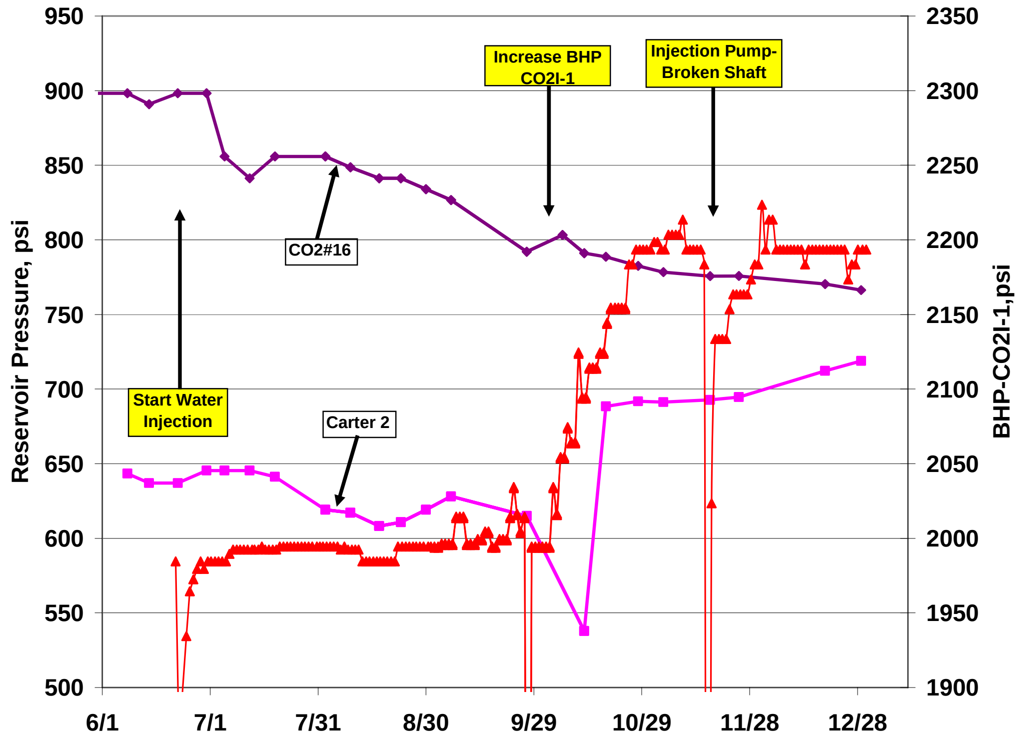

Figure 5: Pressures in CO2I-1, CO2#16 and Carter 2 before and after initiation of water injection

Effect of Injection Rate on Pattern Production

Conversion from carbon dioxide injection to water injection resulted in a decrease in the water injection rate from ~120 B/D to 64 B/D or lower in the four month period following conversion. During this period of time, the water production rate averaged 150 B/D and varied by less than ± 10 B/D. The decrease in injection rate does not correlate with the production rate. There is additional pressure drop in the water-contacted region due to the fact that the viscosity of water is about 10 times larger than supercritical carbon dioxide. This could allow the pressure in the carbon dioxide region to decrease, providing the reservoir energy needed to sustain the production rate by fluid expansion. If this was the case, fluid withdrawal could exceed injection during the time until pressure gradients stabilized. Stabilization should occur in a relatively short time, rather than months as shown in Figure 3.

The injection rate into CO2I-1 increased by an average of 28 B/D after the BHP was increased in CO2I-1. Approximately 35 days later, the average water production rate from the pattern increased by about 39 B/D, primarily from CO2#12. All of the increased production appears to come from the pattern suggesting that loss to the north diminished significantly after or before water injection started. During the last few months of carbon dioxide injection, there were indications that injection rates were dropping with time, suggesting that losses from the total pattern volume were decreasing and that the region contacted by carbon dioxide was pressuring up.

These effects may indicate that the allocation factors for the determining the loss to the north as well as the percentage of the production from CO2#12 and CO2#13 that comes from the PPV region. Further investigation is needed to reevaluate these factors.

General Observations

The pilot performance tends to indicate that the PPV region is more confined than initially estimated from reservoir data. Connectivity to both CO2#12 and CO2#13 appears to be more tortuous than modeled in our simulators. There is also a possibility that loss to the north is less than assumed since the carbon dioxide injection rate tended to decrease when the injection pressure was maintained at a constant value during the last few months of carbon dioxide injection. Continuation of water injection is planned in an attempt to displace oil mobilized by carbon dioxide injection to the production wells. Injection pressure will be maintained to sustain miscible displacement by carbon dioxide as the carbon dioxide is displaced from the region around the injection well into the reservoir by the injected water. It is planned to maintain a balance between injection and withdrawal/loss in the PPV region.

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 Tom Nichols, Bill Flanders and Richard Pancake. Changes in field operations are initiated through the Operational Team. Coordination of the activities is done between Paul Willhite (Technical Team) and Bill Flanders (Operational Team). Production and injection workbooks are updated daily 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 began in CO2I-1 on June 21 to displace the oil bank generated by carbon dioxide injection to the production wells. By the end of December, 14,115 bbls of water were injected into CO2I-1 and 2,091 bbl of oil were produced from the pilot. Injection rates into CO2I-1 declined with time, dropping to an unacceptable level for the project. The injection pressure was increased to reach a stable water injection rate of 100 B/D. However, the injection rate continued to decline with time, suggesting that water was being injected into a region with limited leakoff and production. Oil production rates remained in the range of 3-3.5 B/D following conversion to water injection. There is no evidence that the oil bank generated by injection of carbon dioxide has reached either production well. Continued injection of water is planned to displace oil mobilized by carbon dioxide to the production wells and to maintain the pressure in the PPV region at a level that supports continued miscible displacement as the carbon dioxide is displaced by the injected water.

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 1
Summary of Monthly Data
January –December, 2005

Field			Jan 2005	Feb 2005	March 2005	April 2005	May 2005	June 2005	July 2005	Aug 2005	Sept 2005	Oct 2005	Nov 2005	Dec 2005	Cum
I/W With 30% North Losses			1.19	1.09	1.07	1.21	0.98	0.82							
PPV Inj CO2 I-1	%		0.314	0.335	0.356	0.379	0.401	0.42	0.42	0.42	0.42	0.42	0.42	0.42	
	Loss		0.094	0.101	0.107	0.114	0.120	0.125	0.125	0.125	0.125	0.125	0.125	0.125	
	In Pattern		0.2198	0.2345	0.249	0.265	0.281	0.29	0.29	0.29	0.29	0.29	0.29	0.29	
Production	Oil	bbl	104.9	120.3	117	114	124	101	108.13	95.61	91.07	96.46	95.63	109.38	2090.9
	Wtr	bbl	4333	4184	4926	4631	5431	4,721	4733	4529	4794	4951	5454	6424	130.65
	Gas	mcf	408.3	456.6	471	515	623	494.4	353.42	264.67	180.41	140.8	120.42	79.73	6324.55
	WOR	bbl/bbl	41	35	42	41	44	46.88	43.77	47.37	52.64	51.33	57.03	58.73	
	Cumulative Oil		919	1039	1156	1270	1394	1495	1600	1694	1789	1885	1981	2090	
Injection	Wtr	bbl	11466	10012	10618	10775	11945	12,221	13,088	13,088	13088	14194	13473	13876	289.12
	CO2	mcf	8,146	7,071	7035	7701	7281	3,787	0	0	0	0	0	0	138.05
		Mlb	950.303	824.837	820.695	989.39	849.393	441.79	0.00	0.00	0.00	0.00	0.00	0.00	16.19
CO2 Delivered		mcf	8164.9	7250.6	7211.9	8354.3	8657.8	4,193.70	0.00	0.00	0.00	0.00	0.00	0.00	154.58
		Mlb	946.9	840.8	836.4	968.8	1004	486.3	0	0	0	0	0	0	17.93
		Tons	473.4	420.4	418.2	484.4	502	243.2	0	0	0	0	0	0	8,963
Tank Vent		mcf	122.3	106	326.8	575.5	1285.6	671.7	0	0	0	0	0	0	15.63
		Mlb	14.18	12.3	37.89	66.75	149.09	77.9	0	0	0	0	0	0	1.81
		% of Injection	1.5	1.5	4.6	7.5	17.7	17.70%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	11.19%

Table 2
Summary of Daily Average Data
January-December, 2005

Field			Jan 2005	Feb 2005	Mar 2005	April 2005	May 2005	June 2005	July 2005	August 2005	Sept 2005	Oct 2005	Nov 2005	Dec 2005	Average July-Dec
Production															
	Oil	bbl	3.4	4.3	3.8	3.8	4	3.4	3.5	3.1	3.1	3.1	3.2	3.5	3.25
	Wtr	bbl	139.8	149.4	158.9	154.4	172.3	157.4	152.3	145.7	159.3	159.7	181.8	207.2	167.67
	Gas	mcf	13.2	16.3	15.2	17.2	20.1	16.5	11.6	8.6	6.1	4.5	4.0	2.6	6.24
Injection															
	Wtr	bbl	369.9	357.6	342.5	359.2	385.3	407.4	436.267	436.3	436	458	449	448	443.90
	CO2	mcf	262.8	252.5	226.9	256.7	234.9	126.2	0	0	0	0	0	0	0.00
		Mlb	30.7	29.5	26.5	29.9	27.4	14.7	0	0	0	0	0	0	0.00
CO2 Delivered															
		mcf	263.4	258.9	232.6	278.5	279.3	139.8	0	0	0	0	0	0	0.00
		Mlb	30.5	30	27	32.3	32.4	16.2	0	0	0	0	0	0	0.00
Tank Vent															
		mcf	3.9	3.8	10.5	19.2	41.5	22.4	0	0	0	0	0	0	0.00
		Mlb	0.5	0.4	1.2	2.2	4.8	2.6	0	0	0	0	0	0	0.00
		% of Injection	1.5	1.5	4.6	7.5	17.7	17.7	0	0	0	0	0	0	0.00
Wells															
Production															
CO2 12	Oil	bbl	0.7	1.26	3.1	3.1	2.5	2	2.3	2.1	2.2	1.8	1.8	2.4	2.09
	Wtr	bbl	83.4	97.1	117.5	124.7	123.4	100.7	109.914	107.6	132.8	114.6	142.1	152.2	126.54
	Gas	mcf	9.2	5.7	9.4	12.3	13	12.0	7.1	5.3	3.8	2.8	2.5	1.6	3.86
	Total Liquid(bbl)		84.08	98.36	120.6	127.8	125.9	102.7	112.2	109.7	135.0	116.5	143.9	154.5	128.63
	GOR		13529	4524	3032	3968	5200	6000	3116	2532	1710	1565	1406	677	1834.17
CO2 13	Oil	bbl	2.7	3.1	0.6	0.7	1.5	1.4	1.21	0.99	0.90	1.30	1.40	1.16	1.16
	Wtr	bbl	56.4	52.3	41.2	38.7	48.9	56.7	42.4	38.1	26.5	45.1	39.7	55.1	41.14
	Gas	mcf	4	10.6	5.9	4.9	7.1	4.4	4.3	3.2	2.3	1.7	1.5	1.0	2.32
	Total Liquid(bbl)		59.1	55.4	41.8	39.4	50.4	58.1	43.6	39.1	27.4	46.4	41.1	56.2	42.30
	GOR	bbl/bbl	1481	3419	9833	7000	4733	3143	3524	3227	2502	1313	1073	835	2078.78
Total Liquid-Pattern		bbl	143.18	153.76	162.4	167.2	176.3	160.8	155.8	148.8	162.4	162.8	185.0	210.8	170.93
Total Gas_pattern		mcf	13.2	16.3	15.3	17.2	20.1	16.5	11.4006	8.5	6.0	4.54	4.01	2.57	6.18
GOR-Pattern		mcf/bbl	3882	3791	4026	4526	5025	4853	3257	2754	1940	1460	1259	729	1900
Injection															
CO2 10	Wtr	bbl	350.1	334.8	342.5	345.1	356.6	353.8	357.355	356.2	350.3	337.6	336.4	311.7	342
CO2 18	Wtr	bbl	19.8	22.8	0	14.1	28.7	19	21.2	22	21.7	24.9	24.2	40.4	26
CO2 I-1	Wtr	bbl	0	0	0	0	0	34.5	81.4	69.9	64.3	95.4	88.5	95.5	82.47