SEMI ANNUAL TECHNICAL PROGRESS REPORT
FOR THE PERIOD ENDING JUNE 30, 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
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Reporting Period: DOE	January 1, 2006 – June 30, 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 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 June 30, 2006, 41,566 bbls of water were injected into CO2I-1 and 2,726 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. Oil rates increased from about 3.3 B/D for the period from January through March to about 4.7 B/D for the period from April through June. If the oil rate is sustained, this may be the first indication of the arrival of the oil bank mobilized by carbon dioxide injection. 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. There is no evidence that the oil bank generated by injection of carbon dioxide has reached either production well. Water injection will continue 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:

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. In February 2006, injection was switched to produced water to reduced operating costs. By June 30, 2006, 41,566 bbls of water were injected into CO2I-1 and 2,723 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. Oil rates increased from about 3.3 B/D for the period from January through March to about 4.7 B/D for the period from April through June. If the oil rate is sustained, this may be the first indication of the arrival of the oil bank mobilized by carbon dioxide injection. 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. There is no evidence that the oil bank generated by injection of carbon dioxide has reached either production well. Water injection will continue 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.

Carbon dioxide injection into CO2I-1 terminated on June 17, 2005 and water injection began on June 21. Water injection continued into CO2I-1 with changes implemented to reduce operating costs. Figure 2 summarizes injection rates and bottomhole pressures for this period. 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. The injection rate of produced water was about the same as fresh water, but the injection pressure was about 200 psi less than observed during fresh water injection. Injection pressure was increased by increasing the injection rate. Bottomhole pressure increased about 200 psi when the injection rate was increased from about 100 B/D to about 220 B/D. This indicates that the fracture opening pressure is between 2000 and 2200 psi.

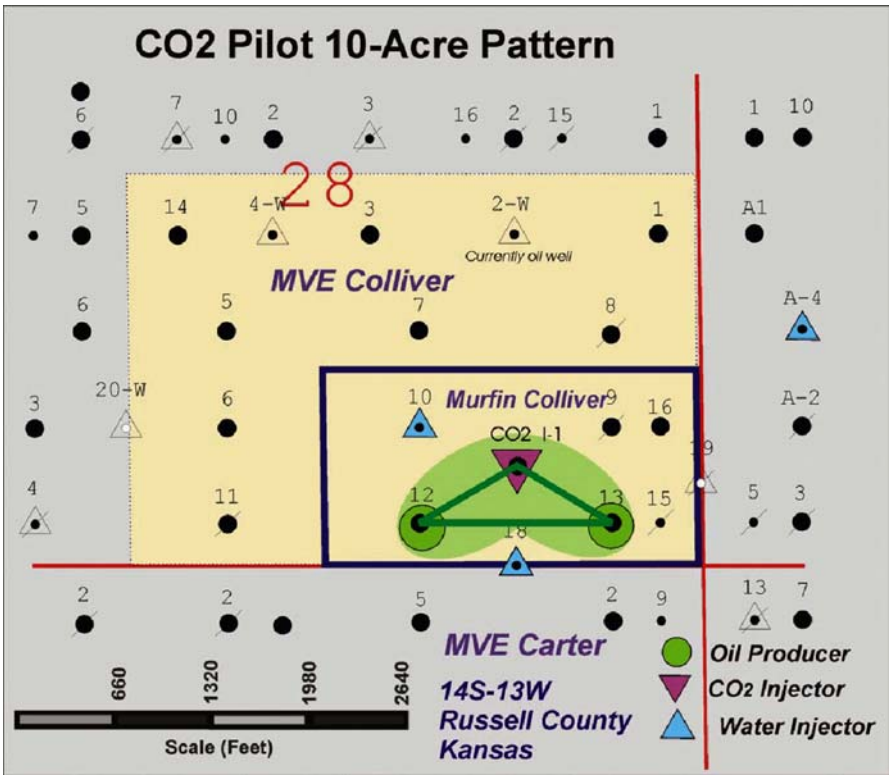

Figure 1: Murfin Colliver Lease in Russell County, Kansas

Cumulative volume of water injected was 41,566 bbls. The injection rate of produced water into CO2#10 was reduced at the same time that the injection was switched to produced water into CO2I-1. Figure 3 shows the injection rate data from CO2#10.

Oil and water production rates are shown in Figure 4 for the period January 1-June 7. Water production rates declined from 200 B/D to 150 B/D until mid April. Oil production rate during this period remained essentially constant at ~3.3 B/D. A small amount of carbon dioxide was produced. The pump in CO2#12 was found to be worn and replaced in mid April. CO2#12 continued to gas lock occasionally resulting in lower production rates than desired. Pumps in both CO2#12 and CO2#13 were replaced in May.

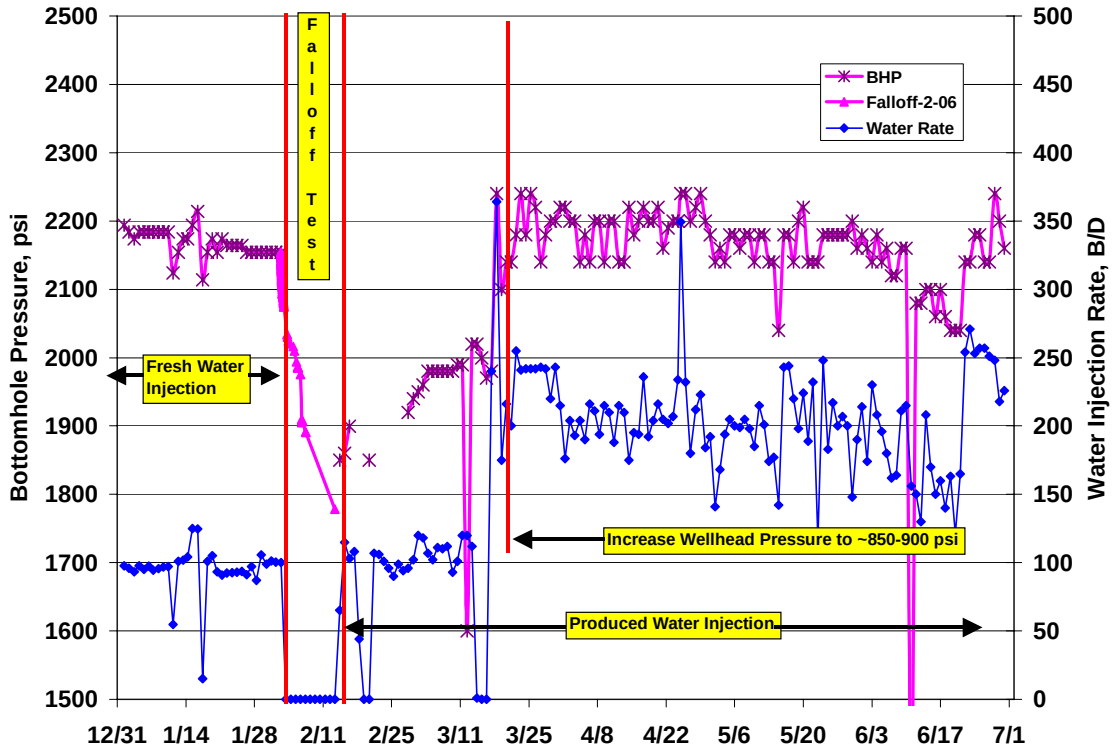

Figure 2: Injection rate and bottomhole pressure during injection into CO2I-1

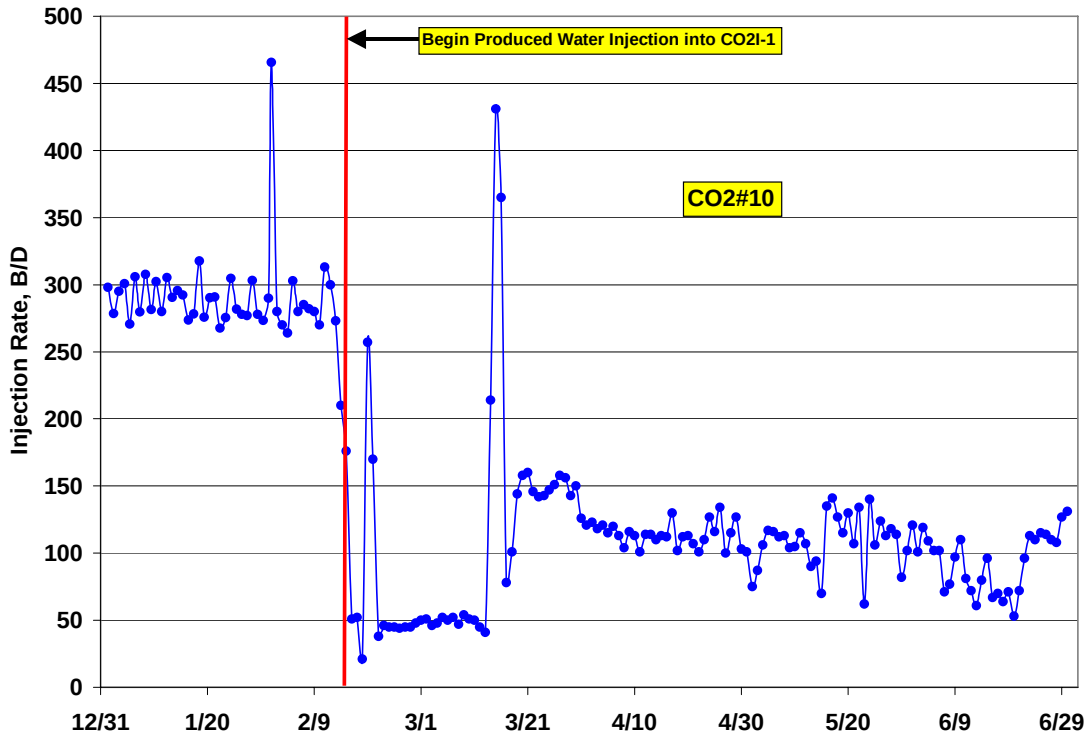

Figure 3: Injection rate into CO2#10-rate reduced when produced water injection began

in CO2I-1

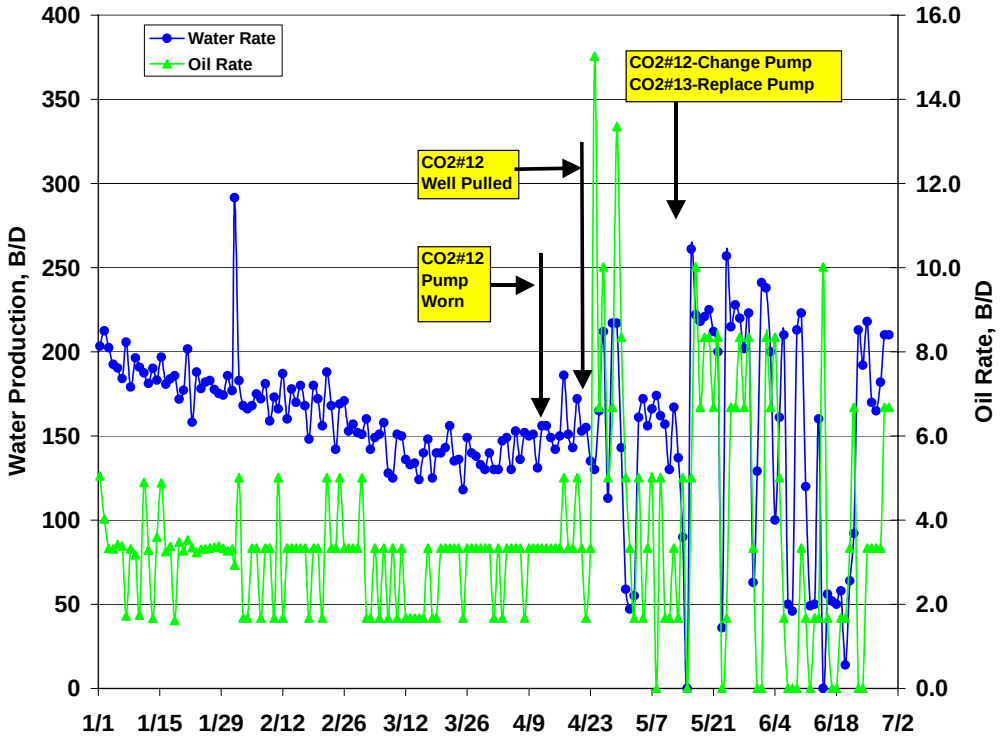

Figure 4: Oil and water production rates from pilot area.

Oil production rates ranged from 0-15 B/D for several days after water was produced at rates greater or equal to 200 B/D. CO2#12 continues to experience occasional gas lock problems, the well stops pumping and oil rates drop to 0-1 B/D. Oil rates appear to increase substantially when the total water production rate is about 200 B/D. At the present time, there has been too much fluctuation in production rates to attribute the increased oil production rates to response to the carbon dioxide flood. Additional production with minimal down time in the production wells is needed to determine if the increased oil rate is due to the CO2 flood or caused by intermittent operation of the production wells.

Figures 5 and 6 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 January through March to about 4.7 B/D for the period from April through June. If the oil rate is sustained, this may be the first indication of the arrival of the oil bank mobilized by carbon dioxide injection. 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 7 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. There is a definite downward trend in WOR beginning in March. Cumulative oil production from the pilot area is 2726 bbl. Water production is about 159,000 bbl.

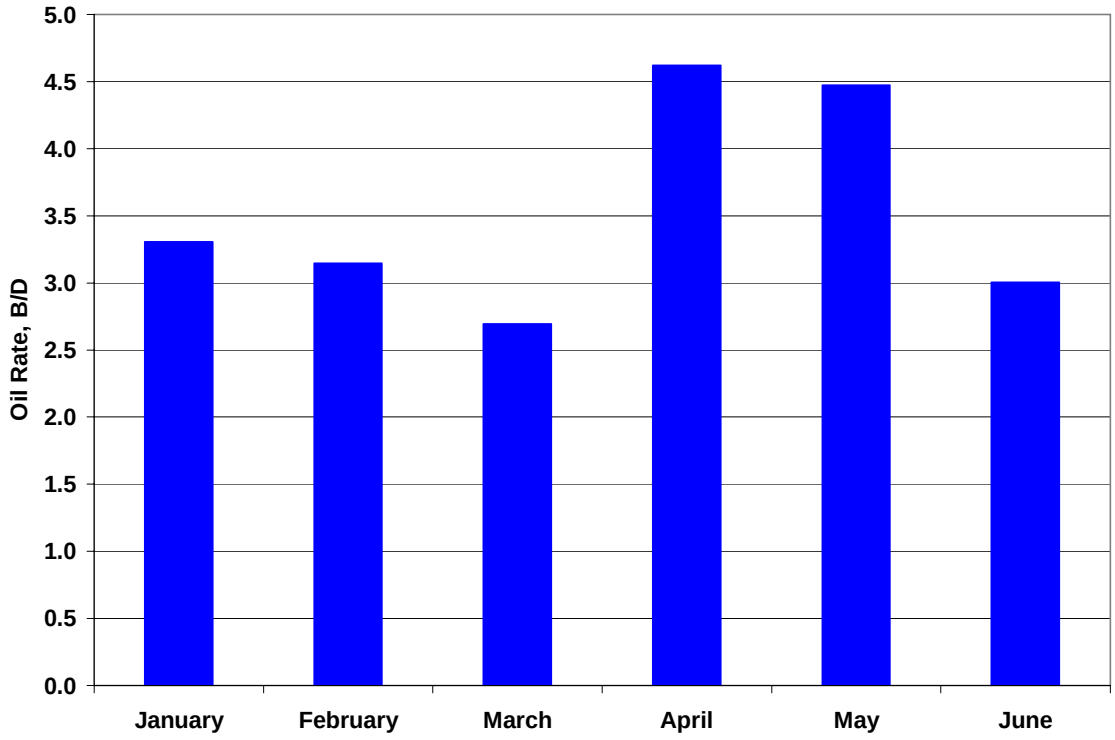

Figure 5: Average monthly oil production rate from pilot area

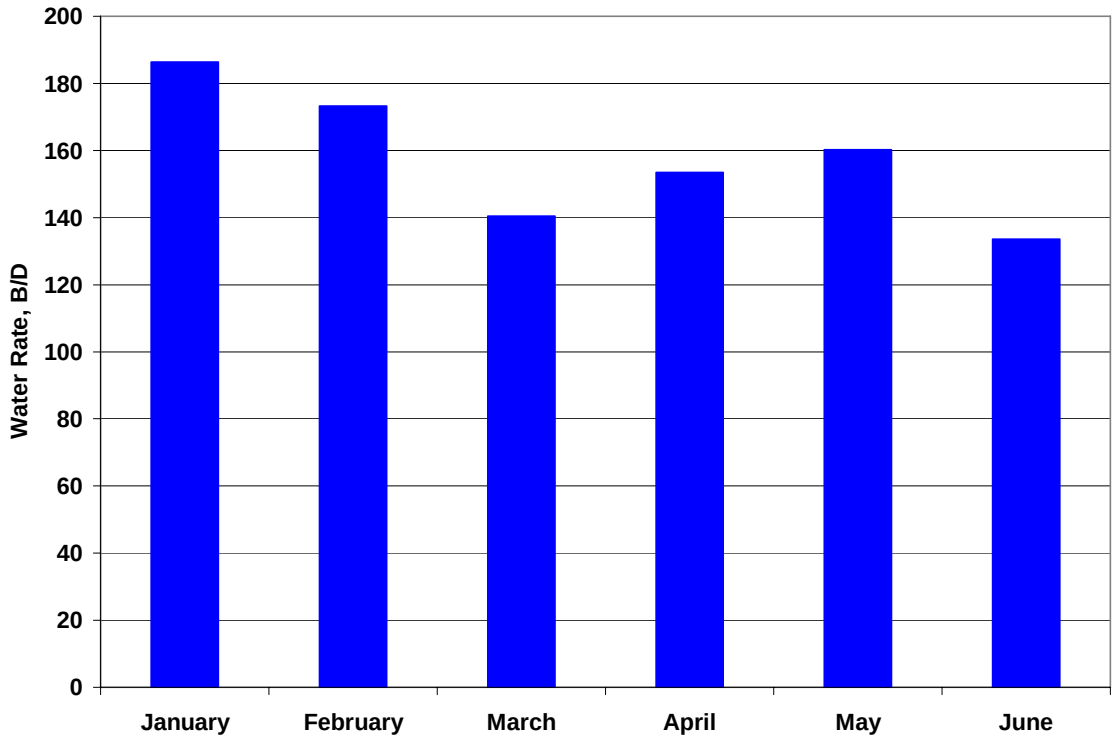

Figure 6: Average monthly water production rate from pilot area

A pressure falloff test was conducted in CO2I-1 when fresh water injection ended. The general trend of these data is shown in Figure 2. A cold front moved in shortly after the well was shut-in and the wellhead froze during the night, thawing during the day. Periods of good data are shown in Figure 8. The rapid decrease in pressure after 100 hours of shut-in may be due to damage of the transducer by freezing. Interpretation of the data to determine mobility in the region around the well was compromised by uncertainty in the pressure data.

It is important to note that the bottomhole pressure declined to about 1780 psi in a period of two weeks after the well was shut-in. Estimated pressure contours are shown in Figure 9. . The average pressure in the PPV region was estimated using Surfer, a mapping program. In developing Figure 9, fluid level or pressure measurements were available from CO2I-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. Also shown on Figure 9 is the outline of the region where carbon dioxide displaced reservoir oil and water.

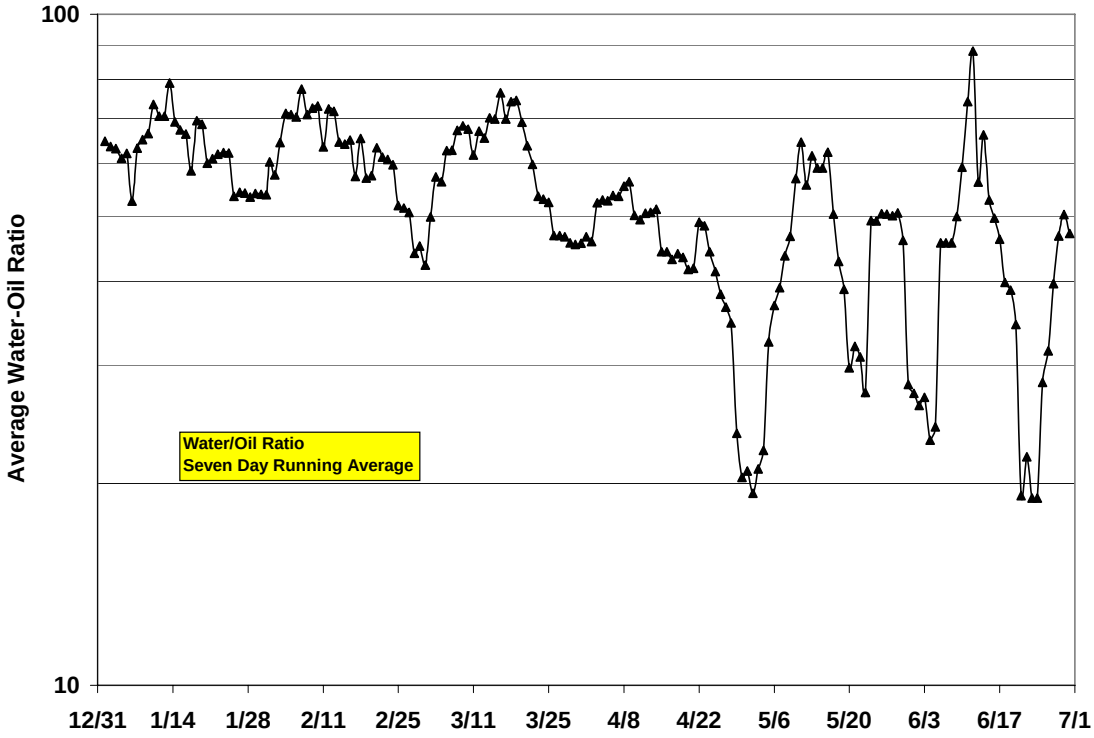

Figure 7: Average water/oil ratio for the period from January 1, 2006 to June 30,2006

The pressure in the region around CO2I-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.

Pressure in Pilot Region

Pressure distribution in the pilot region was estimated from pressures measured in CO2I-1,

CO2#10 and fluid levels measured in CO2#12, CO2#13, CO2#16 and Carter #2. CO2#18 takes fluid on a vacuum and has zero surface pressure. Fluid level in CO2#18 is not measured and was assumed to be near the surface. Colliver #1, Carter #2, Rein A-1, Letsch #7 and Colliver #6 were assumed pumped off.

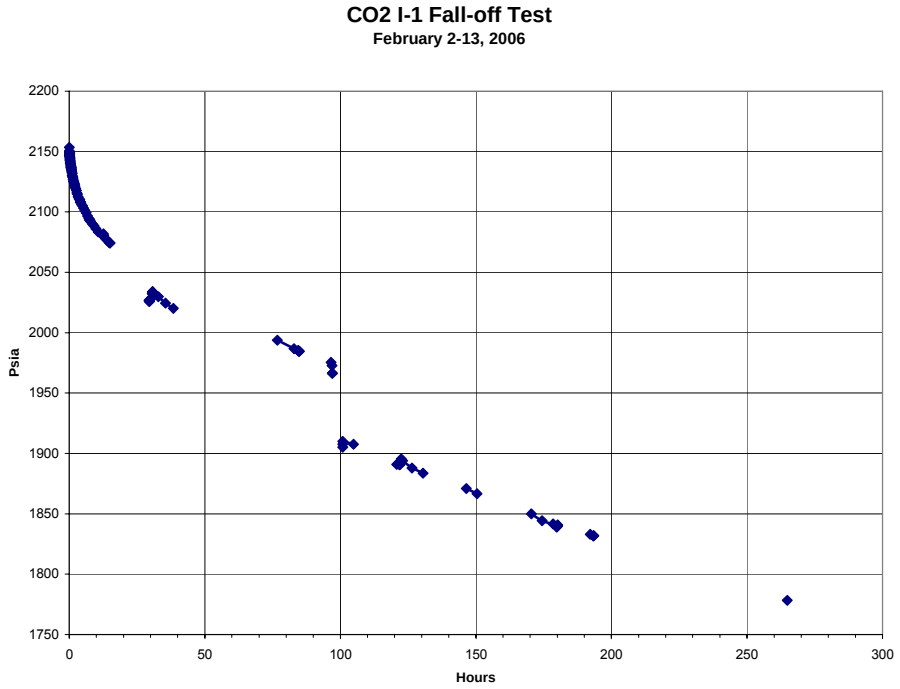

Figure 8: Bottomhole pressure data during falloff test conducted from February 2-12, 2006

Figure 9 shows the pressure contours developed from using Surfer, a commercial graphing package. Pressure contours were obtained by kriging the input data to generate a pressure surface. The average pressure in the region delineated by the solid black line is about 1435 psi.

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. 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 the remaining carbon dioxide is within the boundary outlined by the solid line. 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. 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.

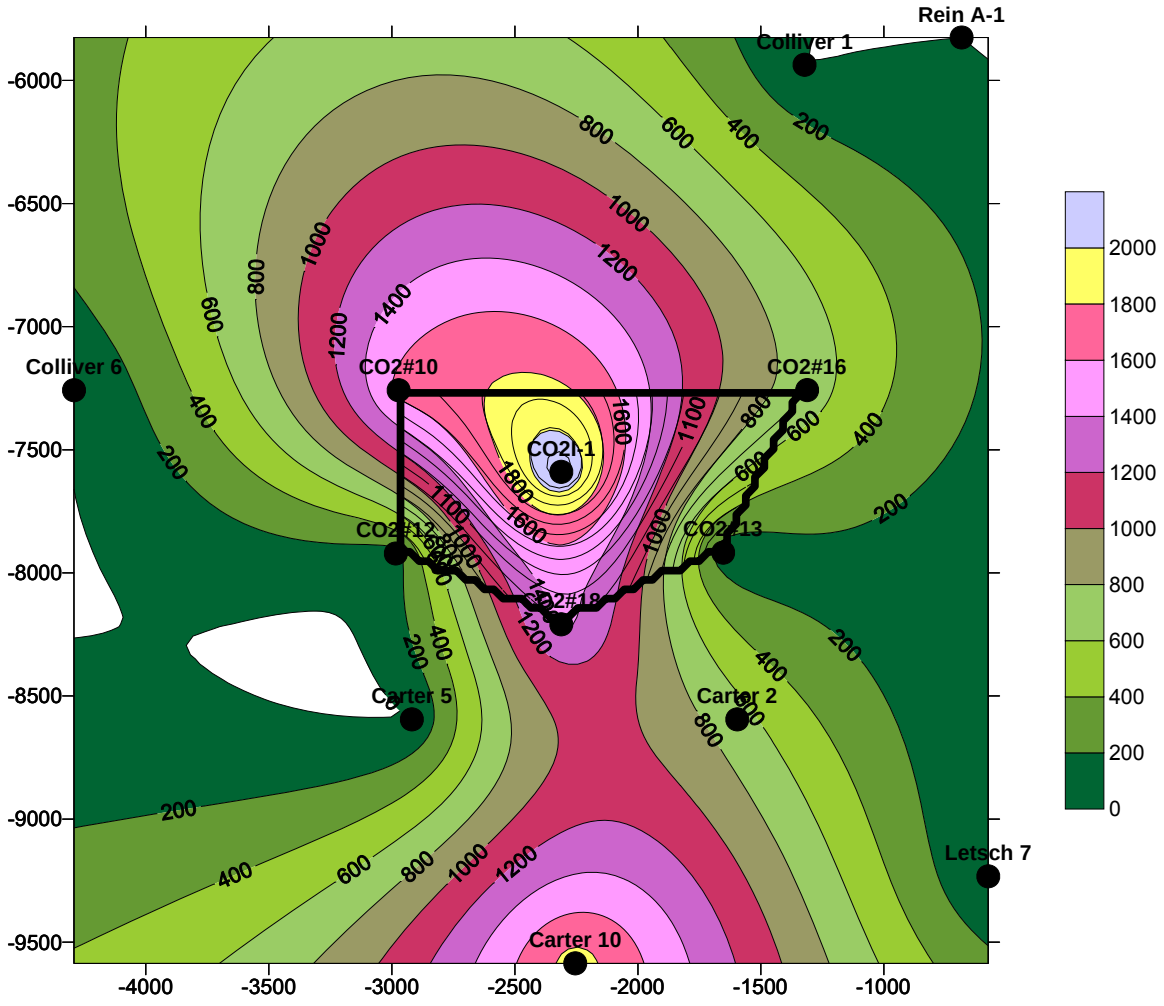

Figure 9: Estimated pressure distribution on Colliver-Carter Leases on February 2, 2006 using Surfer

We examined the possibility that the remaining carbon dioxide is dissolved in the oil and water saturations within the closed boundary in Figure 9. This region has an area of about 25.35 acres. Reservoir volume corresponding to this area (h=8 ft, φ=0.25) is 393,331 RB. Volume of oil in this volume at the beginning of the displacement process is estimated to be 118,000 RB assuming the residual oil saturation is 0.30.

The solubility of carbon dioxide in oil is about 1686 SCF/STB at 1400 psi and the formation volume factor for oil is 1.75 RB/STB. The solubility of carbon dioxide in water is about 146 SCF/STB at 1400 psi and the water formation volume factor is assumed to be 1.0 RB/STB. If the remaining carbon dioxide is completely dissolved in oil and water saturations, the swollen oil

saturation would be ~0.5, and an equivalent water saturation would be displaced (0.2 or 47,885 RB). The reservoir volume required to accommodate the remaining carbon dioxide is 239,427 RB which is 61% of the reservoir volume within the boundary shown in Figure 9. Thus, if the reservoir heterogeneity restricted displacement of oil by carbon dioxide, the carbon dioxide could be dissolved in the fluids in the pilot region producing a carbon dioxide rich oil phase (S_o~0.5) and a carbon dioxide saturated water phase in 61% of the volume within the boundary shown in Figure 9.

If this occurred, subsequent water injection would simply be a conventional waterflood at a high initial water saturation. Water injection would reduce the saturation of the carbon dioxide rich oil phase from 0.5 to ~0.3 and progressively strip out the dissolved carbon dioxide leaving a residual oil saturation of 0.17 as the carbon dioxide rich oil residual oil saturation shrinks when carbon dioxide is stripped out by the water phase. Some of the displaced oil will eventually flow to CO2#12 and CO2#13 with a corresponding decrease in water oil ratio.

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. Water injection will continue 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 continued in CO2I-1 to displace the oil bank generated by carbon dioxide

injection to the production wells. In February, injection was converted to produced water to reduce operating expenses. By June 30, 2006 , 41,566 bbl of water were injected into CO2I-1 and 2726 bbl of oil were produced. 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. Injection rates were increased to maintain a BHP pressure of about 2200 psi in CO2I-1.

Oil production rates remained in the range of 3-3.5 B/D following conversion to water injection in June 2005. Oil rates increased from about 3.3 B/D for the period from January through March to about 4.7 B/D for the period from April through June. If the oil rate is sustained, this may be the first indication of the arrival of the oil bank mobilized by carbon dioxide injection. 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. There is no evidence that the oil bank generated by injection of carbon dioxide has reached either production well. Water injection will continue 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
July 2005 –June 2006

			Jul-05	Aug-05	Sep-05	Oct-05	Nov-05	Dec-05	Jan-06	Feb-06	Mar-06	Apr-06	May-06	Jun-06	
Field			July 2005	Aug 2005	Sept 2005	Oct 2005	Nov 2005	Dec 2005	Jan 2006	Feb 2006	March 2006	April 2006	May 2006	June 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	108.13	95.61	91.07	96.46	95.63	109.38	99.36	88.51	81.83	141.95	133.6	90.18	2726 bbl
	Wtr	bbl	4733	4529	4794	4951	5454	6424	5748	4710	4333	4533	5147	3766	158.888 Mbbl
	Gas	mcf	353.42	264.67	180.41	140.8	120.42	79.73	105.35	60.98	128.5	117.67	78.29		6815 mcf
	WOR	bbl/bbl	43.77	47.37	52.64	51.33	57.03	58.73	57.85	53.21	52.95	31.93	38.53	41.76	
	Cumulative Oil		1600	1694	1789	1885	1981	2090	2190	2278	2360	2502	2636	2726	
Injection	Wtr	bbl	13,088	13,088	13088	14194	13473	13876	12589	7711	10497	10166	10024	9,029	349.13 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%

Table 2
Summary of Daily Average Data
July 2005-June 2006

Field			July 2005	August 2005	Sept 2005	Oct 2005	Nov 2005	Dec 2005	Jan 2006	Feb 2006	Mar 2006	April 2006	May 2006	June 2006	Average Jan-June
Production															
	Oil	bbl	3.5	3.1	3.1	3.1	3.2	3.5	3.2	3.2	2.6	4.7	4.3	3.0	3.51
	Wtr	bbl	152.3	145.7	159.3	159.7	181.8	207.2	185.4	168.2	139.8	151.1	166.0	125.5	156
	Gas	mcf	11.6	8.6	6.1	4.5	4.0	2.6	3.4	2.2	4.1	3.9	2.5	NM	3.23
Injection															
	Wtr	bbl	436.3	436.3	436	458	449	448	406	275	339	339	323	301	331
	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	0	0	0	0	0							0.00
Wells															
Production															
CO2 12	Oil	bbl	2.3	2.1	2.2	1.8	1.8	2.4	2.4	2.3	1.9	4.2	3.8	2.7	2.88
	Wtr	bbl	109.9	107.6	132.8	114.6	142.1	152.2	138.1	129.7	107.8	101.1	111.1	84.0	112
	Gas	mcf	7.1	5.3	3.8	2.8	2.5	1.6	2.1	1.4	2.6	2.5	1.6		2.02
	Total Liquid(bbl)		112.2	109.7	135.0	116.5	143.9	154.5	140.4	131.9	109.6	105.4	115.0	86.7	115
	GOR		3116	2532	1710	1565	1406	677	890	603	1374	580	410	NM	771
CO2 13	Oil	bbl	1.21	0.99	0.90	1.30	1.40	1.16	0.82	0.90	0.75	0.51	0.46	0.32	0.63
	Wtr	bbl	42.4	38.1	26.5	45.1	39.7	55.1	47.4	38.5	32.0	50.0	54.9	41.5	44.05
	Gas	mcf	4.3	3.2	2.3	1.7	1.5	1.0	1.3	0.8	1.6	1.5	0.9		1.21
	Total Liquid(bbl)		43.6	39.1	27.4	46.4	41.1	56.2	48.2	39.4	32.8	50.5	55.4	41.8	44.68
	GOR	bbl/bbl	3524	3227	2502	1313	1073	835	1557	905	2063	2906	2054		1897.02
Total Liquid-Pattern		bbl	155.8	148.8	162.4	162.8	185.0	210.8	188.6	171.4	142.4	155.8	170.3	128.5	159.52
Total Gas_pattern		mcf	11.4	8.5	6.0	4.54	4.01	2.57	3.40	2.18	4.15	3.92	2.53	NM	3.23
GOR-Pattern		mcf/bbl	3257	2754	1940	1460	1259	729	1060	689	1570	829	586	NM	947
Injection															
CO2 10	Wtr	bbl	357.4	356.2	350.3	337.6	336.4	311.7	287.5	169.3	121.6	113.5	109.1	90.0	148
CO2 18	Wtr	bbl	21.2	22	21.7	24.9	24.2	40.4	24.0	55.1	53.0	20.5	18.2	21.4	32
CO2 I-1	Wtr	bbl	81.4	69.9	64.3	95.4	88.5	95.5	94.6	50.9	164.0	204.9	196.1	189.6	150