SEMI ANNUAL TECHNICAL PROGRESS REPORT
FOR THE PERIOD ENDING December 31, 2008

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 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, 2008, 231,017 bbls of water were injected into CO2 I-1 and 7,204 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 4.2 B/D for the period from July 1-December 31, 2008. 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. This conclusion is supported by the discovery that carbon dioxide concentration in the casing gas from Colliver A7 increased from 1.1% to 11% between September 2006 and December 2008. About 14,260 bbl of incremental oil was estimated to have been produced from these wells as of December 2008. 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 21,464 bbl which is equivalent to a gross CO2 utilization of 6.4 MCF/bbl. The pilot project is not economic. The geologic model used to simulate CO2 injection into the C Zone (Plattsburg Limestone) reservoir at Hall-Gurney is being refined. The revised geologic model will be used in the reservoir simulator. The revision of the geomodel and re-simulation are important for future considerations and planning for CO2-IOR in Kansas and other mature producing areas like Kansas.

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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, 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, 2008, 231,017 bbl of water were injected into CO2 I-1 and 7,204 bbl of oil were produced from the pilot. Oil production rates averaged 4.2 B/D for the period from July 1- December 31, 2008. 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. This conclusion is supported by the discovery that carbon dioxide concentration in the casing gas from Colliver A7 increased from 1.1% to 11.1% between September 2006 and December 2008. About 14,260 bbl of incremental oil was estimated to have been produced from these wells as of December 31, 2008. 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 21,464 bbl, which is equivalent to a gross CO2 utilization of 6.4 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 31, 2008. Relatively stable rates and pressures were

maintained. Average injection rate for the six month period from July 1-December 31, 2008 was 218 B/D.

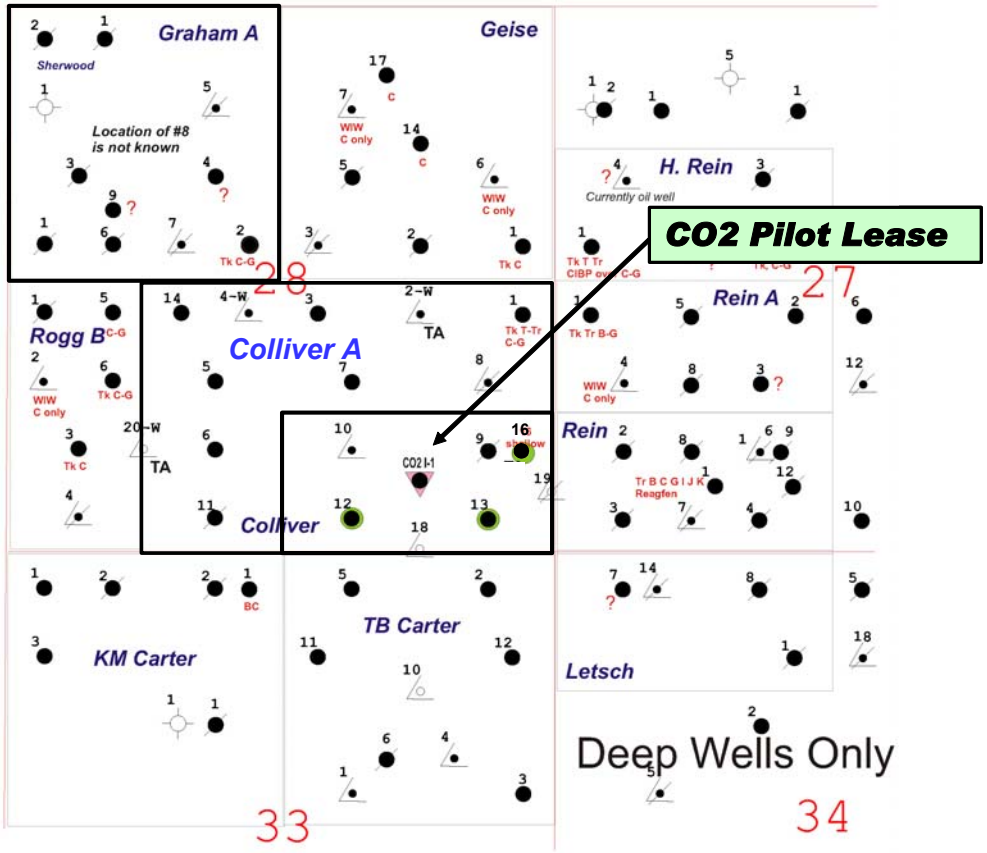


Figure 1: Murfin Colliver Lease in Russell County, Kansas

Cumulative volume of water injected into CO2I-1 was 231,017 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 1-December 31, 2008. Average oil production rates were about 4.2 B/D for the period from July 1-December 31, 2008. Figure 6 shows the average water-oil ratio for the same period. Cumulative oil production from the pilot area is 7,204 bbl. Water production from the pilot area was about 512,000 bbl.

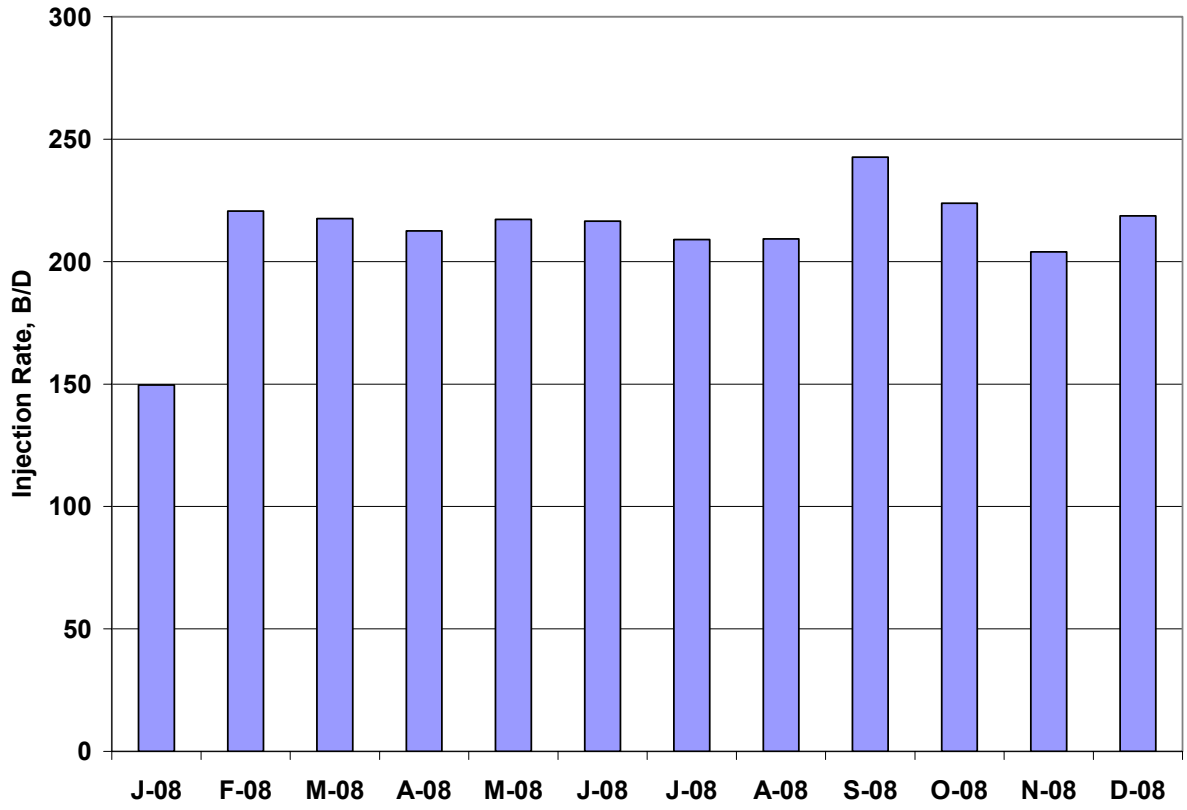


Figure 2: Water injection rate into CO2 I-1

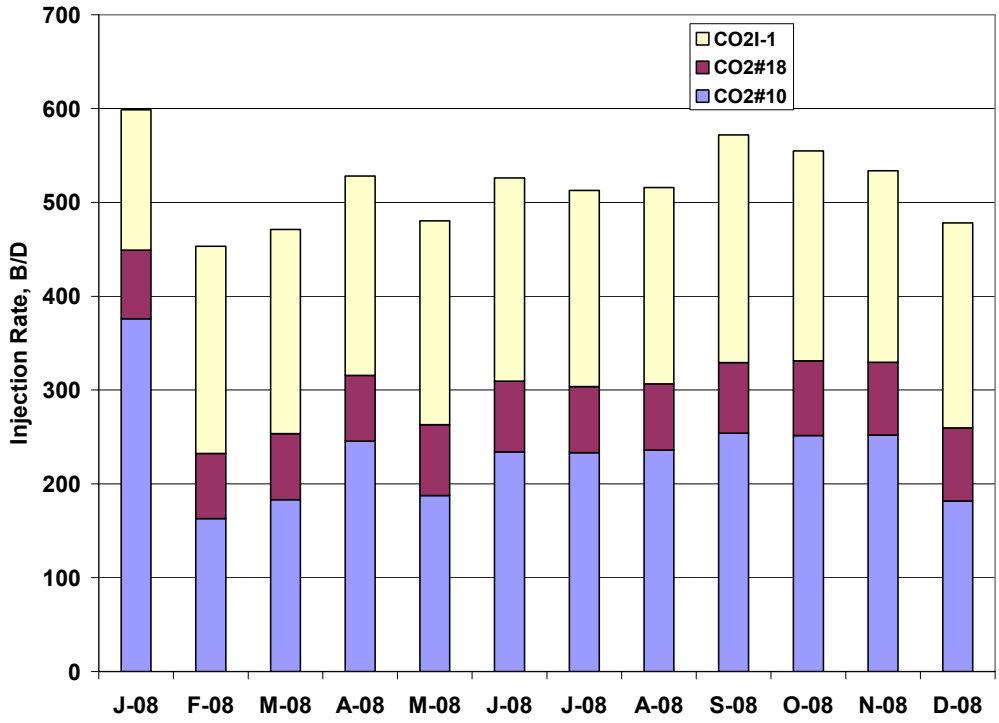


Figure 3: Injection rates into CO2I-1, CO2#18 and CO2#10

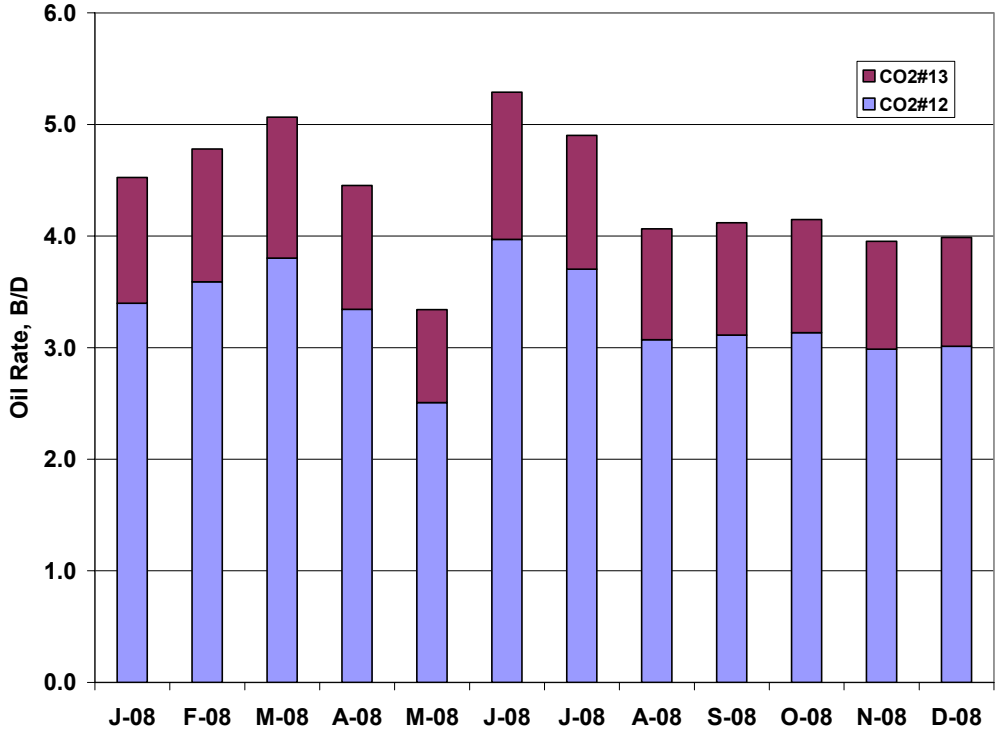


Figure 4: Average daily oil production rates from pilot area

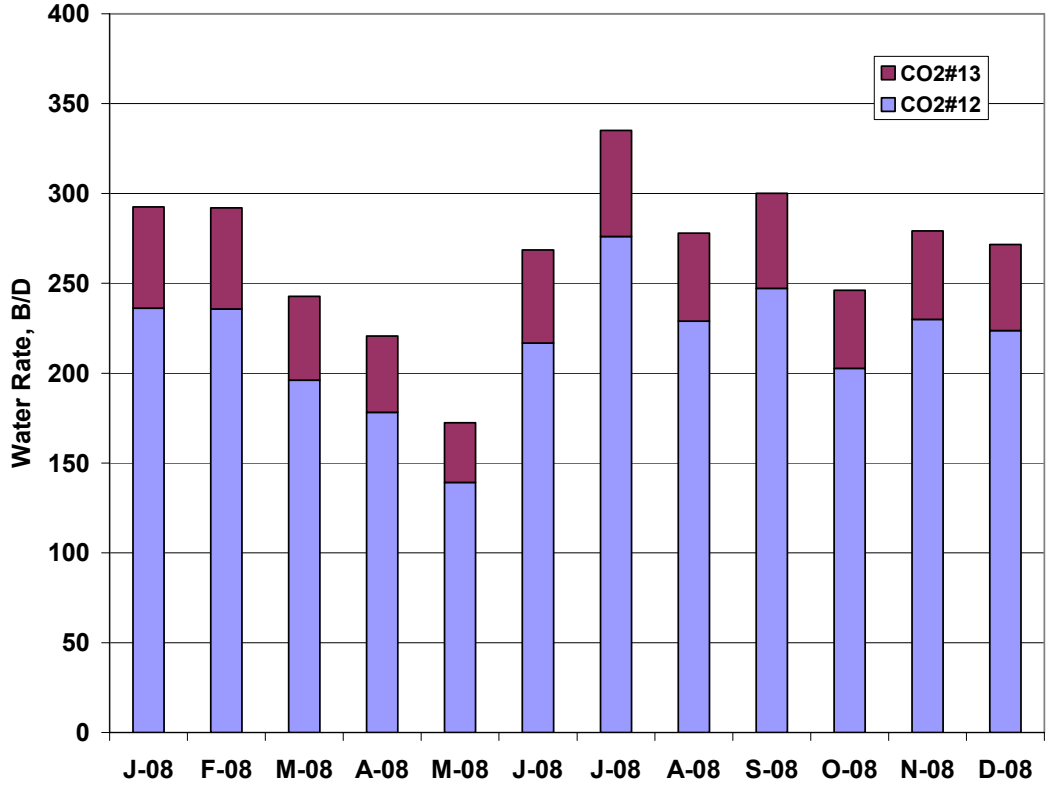


Figure 5: Average daily water production rate from pilot

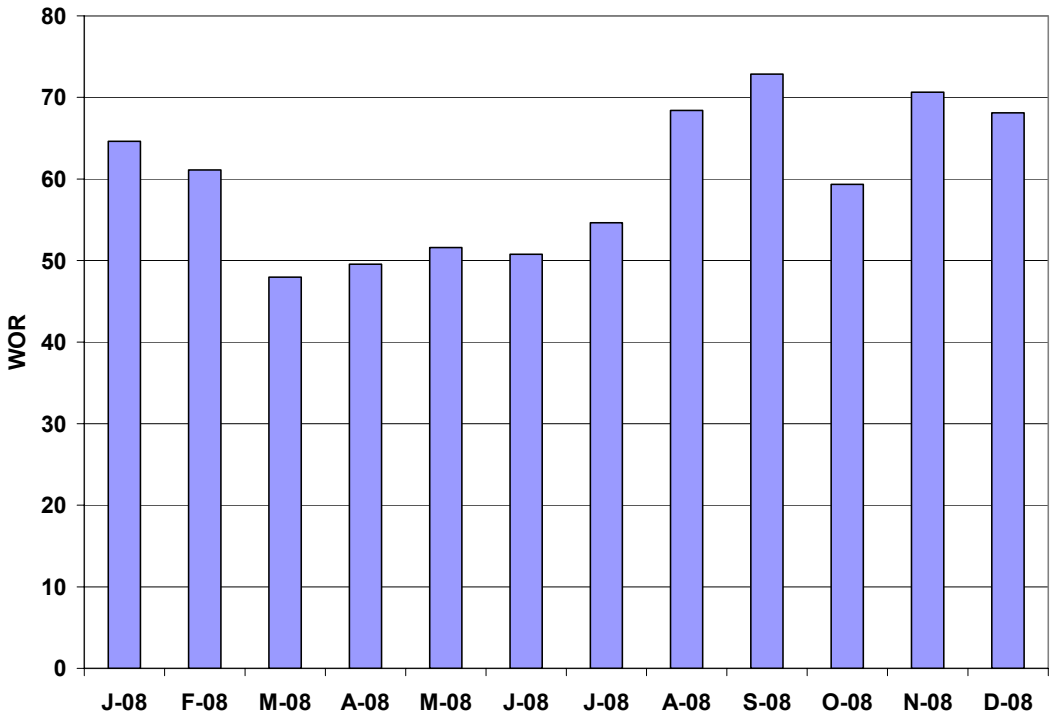


Figure 6: Average water/oil ratio for the period from Jan 1, 2008 to December 31, 2008

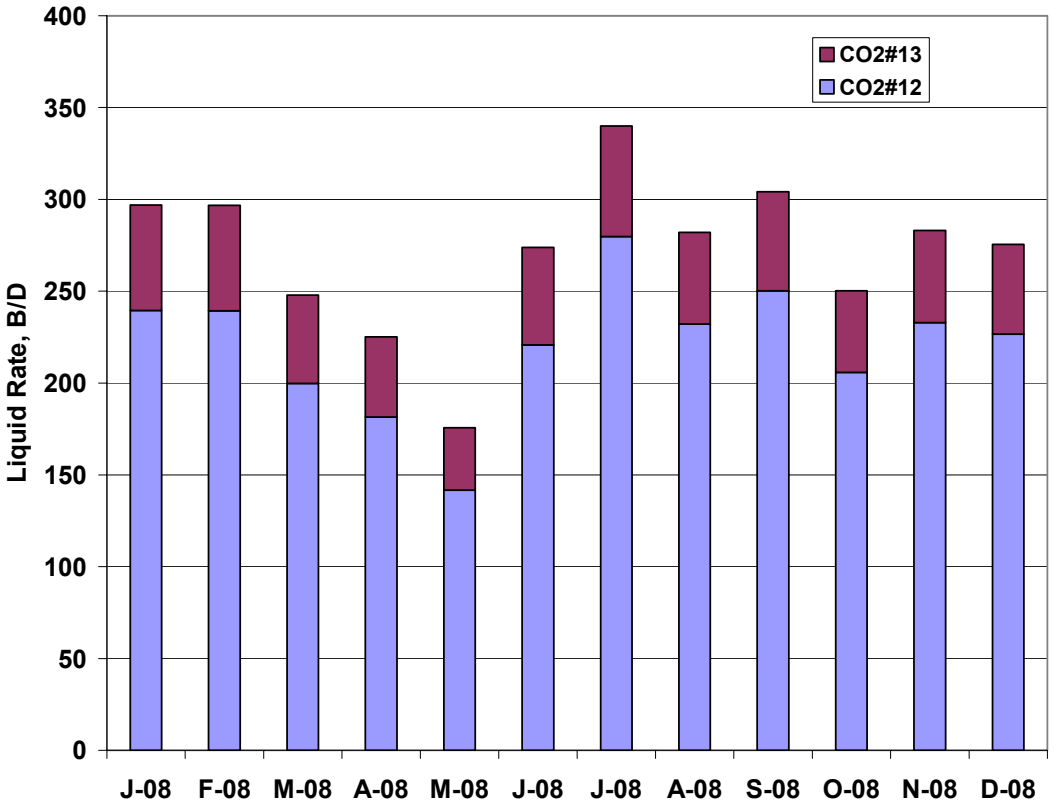


Figure 7: Total liquid production rate from CO2 pilot

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 8.

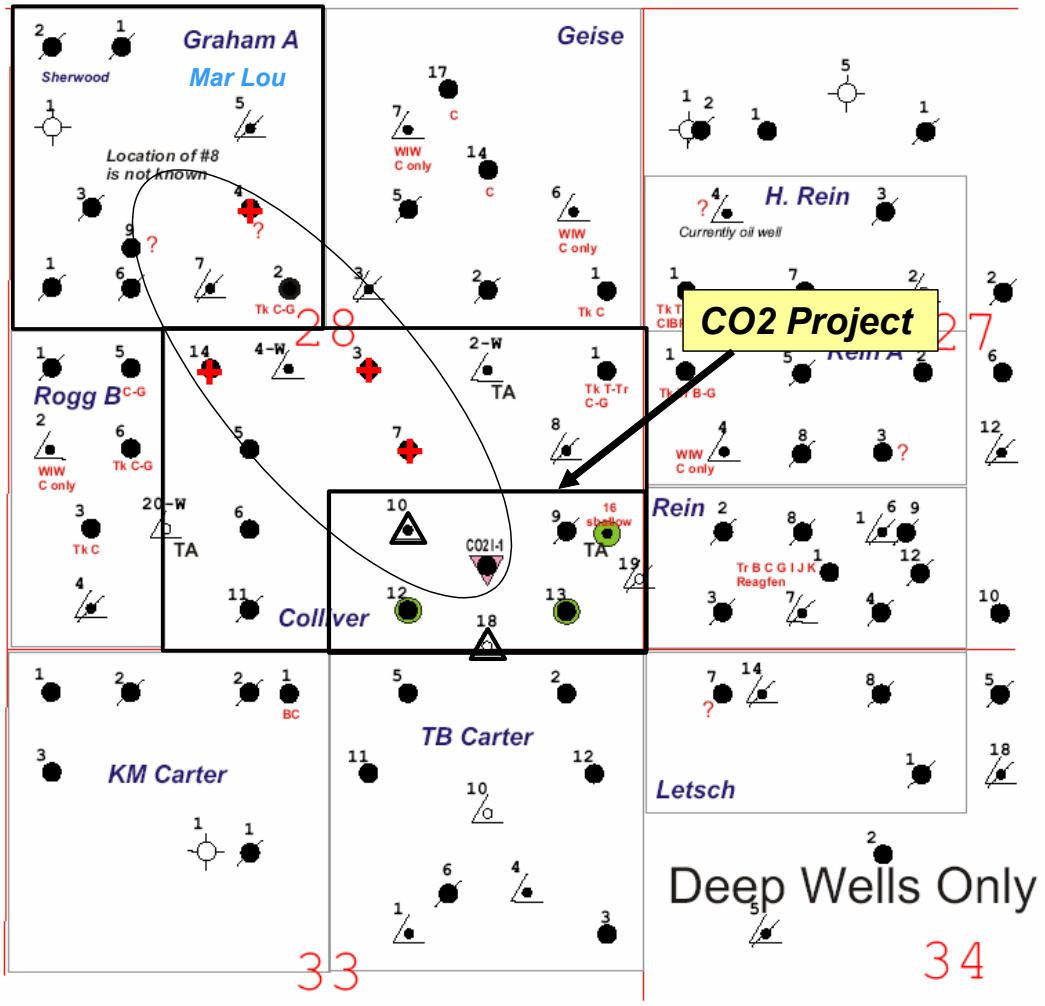


Figure 8: Map showing location of wells completed in the Lansing-Kansas C zone in the area of the CO2 pilot. The elliptical region includes wells marked with a + that appear to have produced oil displaced from the CO2 pilot area.

The discovery of increased oil production from the Graham A lease in August 2006 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 was estimated to be about 920 bbl. 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 and no further incremental oil is attributed to the Graham 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 13,340 bbls.

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. Colliver A14 has declined to about 3 B/D.

Incremental oil production from the Colliver A Lease, north of the pilot, averaged 12.8 B/D for the last six months of 2008. The carbon dioxide concentration in the casing gas from Colliver A7, the principal well producing incremental oil on the Colliver A lease, increased to about 11.1% at the end of December 2008. This confirms that carbon dioxide injected into the CO2 Pilot Pattern is associated with the incremental oil produced from Colliver A7. The incremental production from the Colliver A Lease during the past ten months is on decline which is expected.

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 8 suggests a preferential permeability trend from the northwest toward CO2 I-1. We believe that oil displaced by carbon dioxide is being produced in Colliver A7. This conclusion is supported by analysis of casing gas from Colliver A#7. Figure 10 shows the carbon dioxide concentration in the casing gas from shortly after the LKC "C" zone was opened in the well. Carbon dioxide concentration rose steadily from September 2006 through June 2008, appearing to level out around 6% until the last sample in December which jumped to 11.1%. There has been no increase in carbon dioxide concentrations in casing gas from Colliver A3 and Colliver A14. The amount of carbon dioxide produced from the Colliver A wells is negligible.

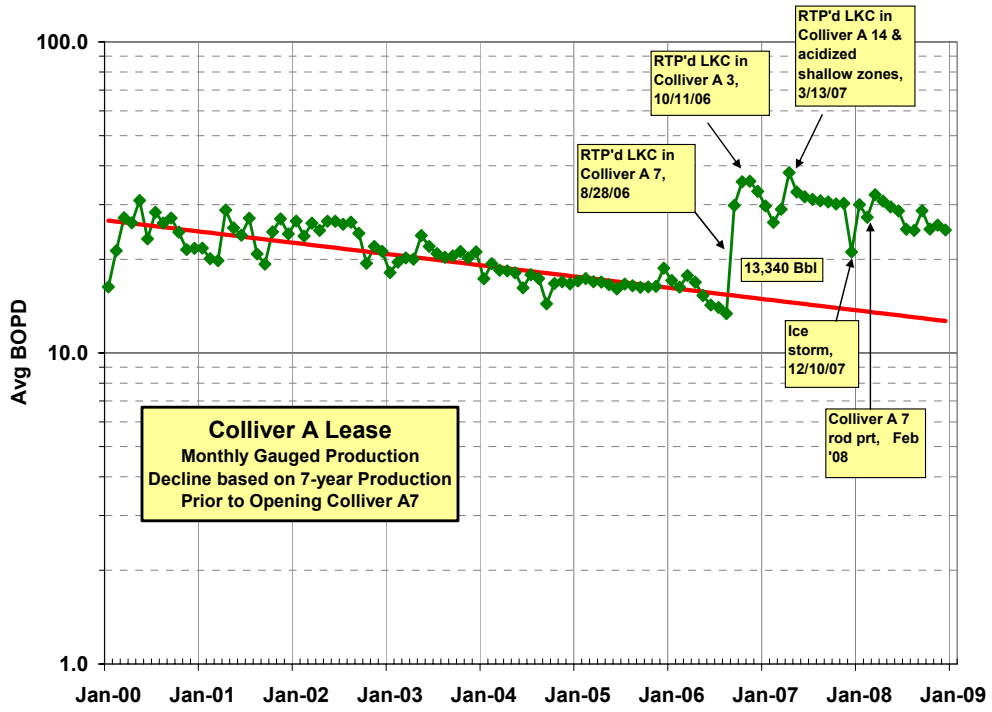


Figure 9: Colliver A lease production after C zone was opened in Colliver A #7, Colliver A#3 and Colliver A#14.

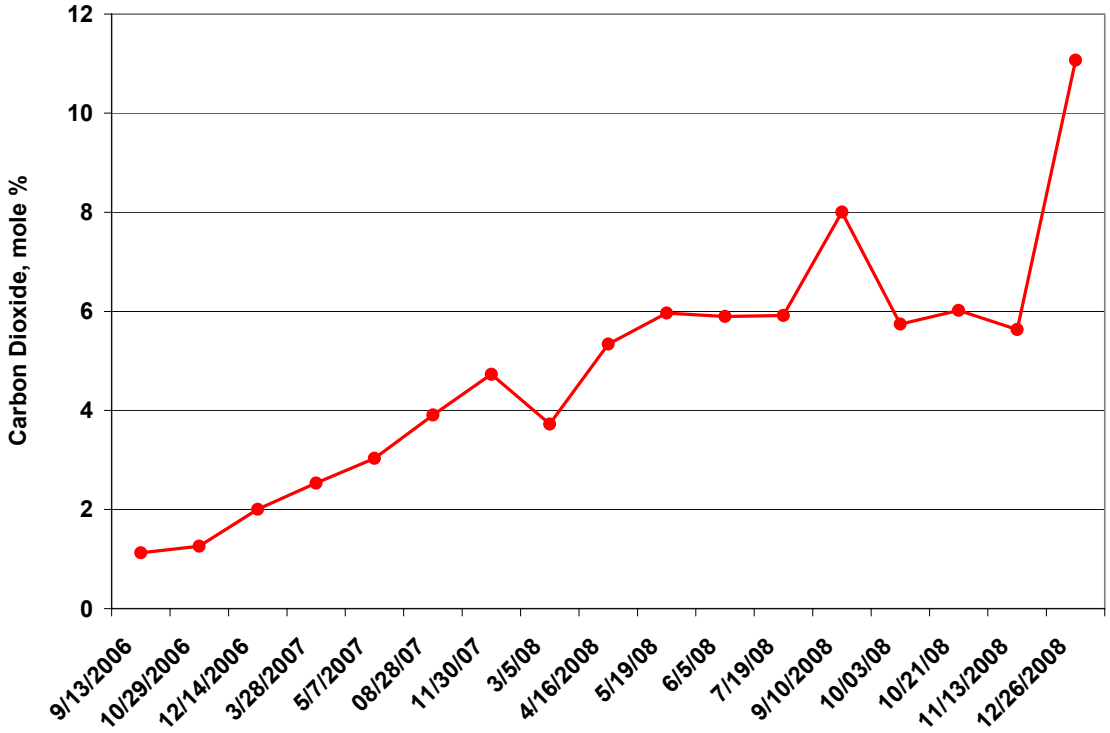


Figure 10: Carbon dioxide concentration in casing gas from Colliver A7

Table 1 contains an estimate of incremental oil from CO2 injection through December 31, 2008. Total incremental oil attributed to the CO2 project is 21,464 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 December 31, 2008, the gross CO2/oil ratio was 6.4 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
12/31/08	7,204	13,340	920	21,464	6.4

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 11 as of December 2008. The average pressure in the PPV region was estimated using Surfer, a mapping program. In developing Figure 11, fluid level or pressure measurements were available from CO2 I-1, CO2#10, CO2#12, CO2#13, CO2#16, Carter 2 and Carter 5. 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. No data are available in the white areas beyond the pilot area. The average pressure in the region delineated by the solid black line is about 1494 psi. 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. Carbon dioxide from the pilot region is being produced from Colliver A7 as shown in Figure 10. Other than Colliver A7, evidence of injected 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 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 11. 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 the region north of the pilot area is either in the vapor phase or is dissolved in the oil and water phases.

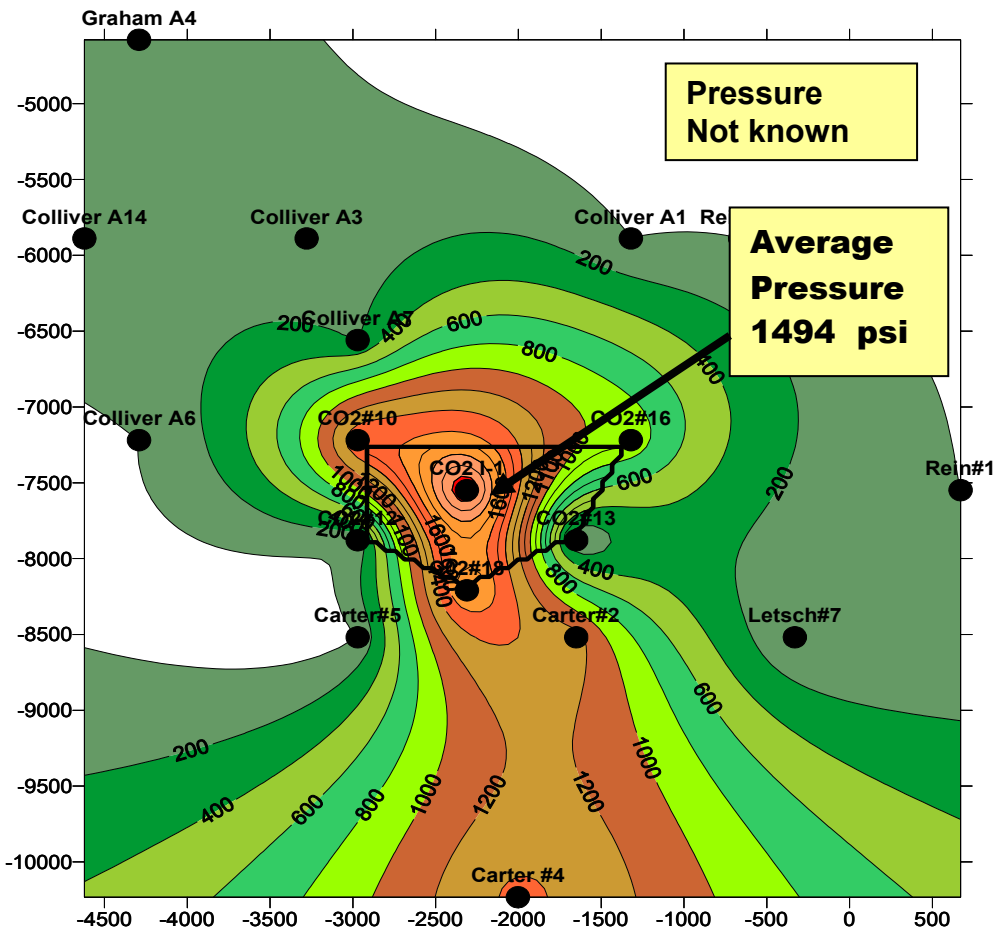


Figure 11: Estimated pressure distribution on Colliver-Carter Leases on December 31, 2008 using Surfer

Revision of Reservoir Description(W. Lynn Watney, Kansas Geological Survey)

Overview

The geologic model used to simulate CO2 injection into the C Zone (Plattsburg Limestone) reservoir at Hall-Gurney is being refined. New information acquired since the original modeling including acquisition of seismic data provided an opportunity to modify the original geologic model. Also recent work on a Modern analog for ooid shoals from the Bahama Platform was applied to this ancient oolitic limestone reservoir to help understand reservoir geometries that obtained in remapping the pilot project area. Finally, incremental oil recovered from CO2 injection has moved off pattern, northwest of the injector and has further warranted revising the geologic model. The revised geologic model will be used in the reservoir simulator. The revision of the geomodel and re-simulation are important for future considerations and planning for CO2-IOR in Kansas and other mature producing areas like Kansas.

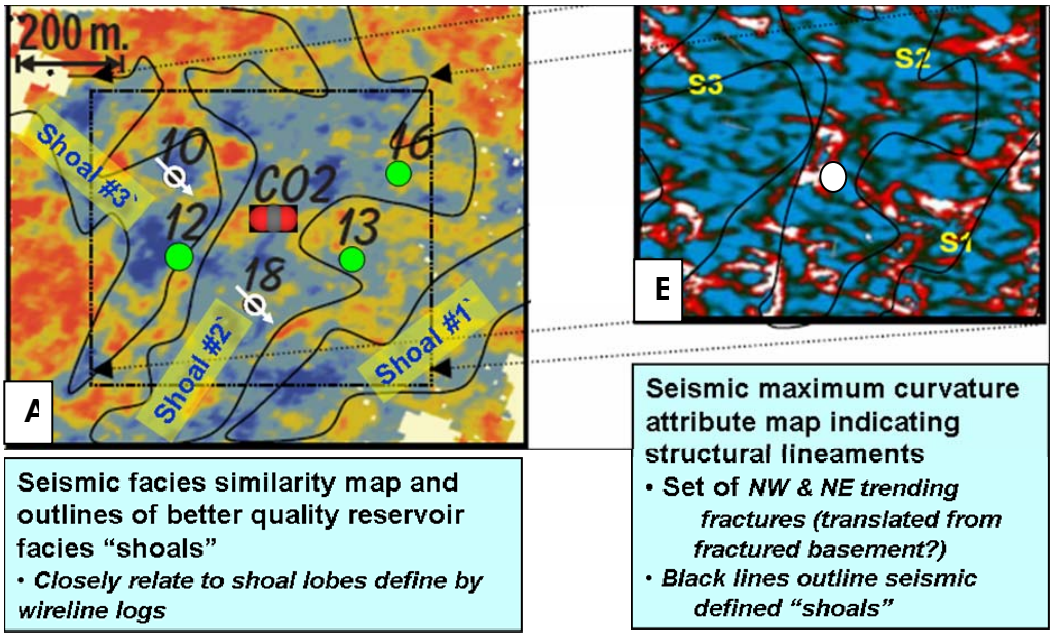
Latest Seismic Interpretation Suggest Reservoir Compartmentalization and Lineaments

The 4D seismic survey in the CO2 pilot area has identified distinct and separate areas of seismic reflection character, quantitatively defined here as seismic facies similarity (Figure 12A). A number of properties comprising seismic facies are statistical analyzed to create this map of seismic facies similarity (Raef et al., 2005; Raef et al., 2007). Areas of homogeneous seismic facies, depicted by various shades of blue and outlined by the addition of thin black lines, suggest continuity of reservoir properties including those that may be related to fluid storage or flow. Well logs and cuttings were reexamined to refine the lithofacies and stratigraphy. Latest ideas ooid shoal composition and geometries were incorporated into new maps and cross sections of the C Zone (Plattsburg Limestone) reservoir. This information was subsequently compared with the new seismic data. The results of this examination lead to identifying possible reservoir compartments in the vicinity of the CO2 pilot project. Three temporally-distinct ooid shoals are recognized, labeled in Figure 12A as Shoal #1, Shoal #2, and Shoal #3. These separate shoals become the basis to refine the geologic model as described in the next section.

A map of the seismic maximum curvature attribute is shown in Figure 12B that indicates linear areas of abrupt change in elevation of a seismic reflection horizon near the top of the ooid shoal reservoir. The discontinuous lineaments denoted by red and black areas show a preferred orientation of northeast-southwest with less continuous, but abundant northwest-trending lineaments. Superimposed are thin black lines outlining the seismic facies similarity also in Figure 12A.

The CO2 #1 well is located as a white dot on the curvature map (Figure 12B) and is located in a concentration of lineaments, mainly trending northeasterly. As a potential indicator of fractures this attribute may indicate conduits for CO2 migration. However, fractures tend to be open or closed in orthogonal directions, one direction open (usually parallel to maximum compressive stress) and the other direction closed, perpendicular to maximum compressive stress. Fracture apertures can be partially cemented to keep fractures open or fracture porosity can be lost due to cementation so there is no fast rule outside of understanding local conditions. Furthermore, local

structure can influence stress field and affect orientation of fractures and aperture widths. For example, in an analysis of seismic coherency and production data at Dickman Field in Ness County, Kansas, northwest-trending fractures are open and positively affect production (Nissen et al., 2006). This latter result is not consistent with a regional maximum compressive stress direction that trends northeast-southwest (World Stress Map, 2005).



Raef et al. (2007)

Figure 12. Seismic facies similarity map (A) on left and seismic maximum curvature attribute map on right (B)

New Geologic Information

Analysis of cuttings and wireline logs in the vicinity of the CO2 injection well was used to refine the interpretation of the geologic reservoir model. A map of average porosity in Layer #2 of the original six layer geologic reservoir model shows a strong northeast-southwest trend of higher porosity (Figure 13A). Layer #2 is the most porous of the six layers and is located at the top of the reservoir interval and presumably where the CO2 would move most readily to mobilize oil (Figure 13B). Overlain on the porosity map of Layer #2 is an outline of the CO2 plume as of 2005 delineated by a light blue line. The trend of the CO2 plume at this time was parallel to the high porosity zone of Layer #2.

Re-evaluation of core from the CO2 #1 and Colliver #16 and wireline logs and cuttings from wells in the vicinity of the CO2 #1 well led to a revision of the primary ooid shoal geometry based on an approach patterned from current studies of Modern Bahamian ooid shoals (Rankey et al., 2006). The better sorted areas of the ooid shoals tend to be located on the crests of Modern

tidally-dominated ooid bars including elongate tidal ridges and lobate bars related to incoming or outgoing tides. Petrologic and petrophysical analysis of the oomoldic reservoirs including the "C" Zone indicates that that the highest permeability appears to be located in better sorted oomolds reflecting the original hydrodynamics during deposition. The rationale is that the better sorting leads to more efficient grain contact. Then when ooids are dissolved, the dissolution is more complete in areas of better sorting. Later cements then occlude some of this pore space. Permeability tends to be best near the top of the reservoir, apparently in proximity to the subaerial exposure surface that typifies many Pennsylvanian and Permian carbonate reservoirs including the "C" zone/Plattsburg Ls. at Hall-Gurney Field.

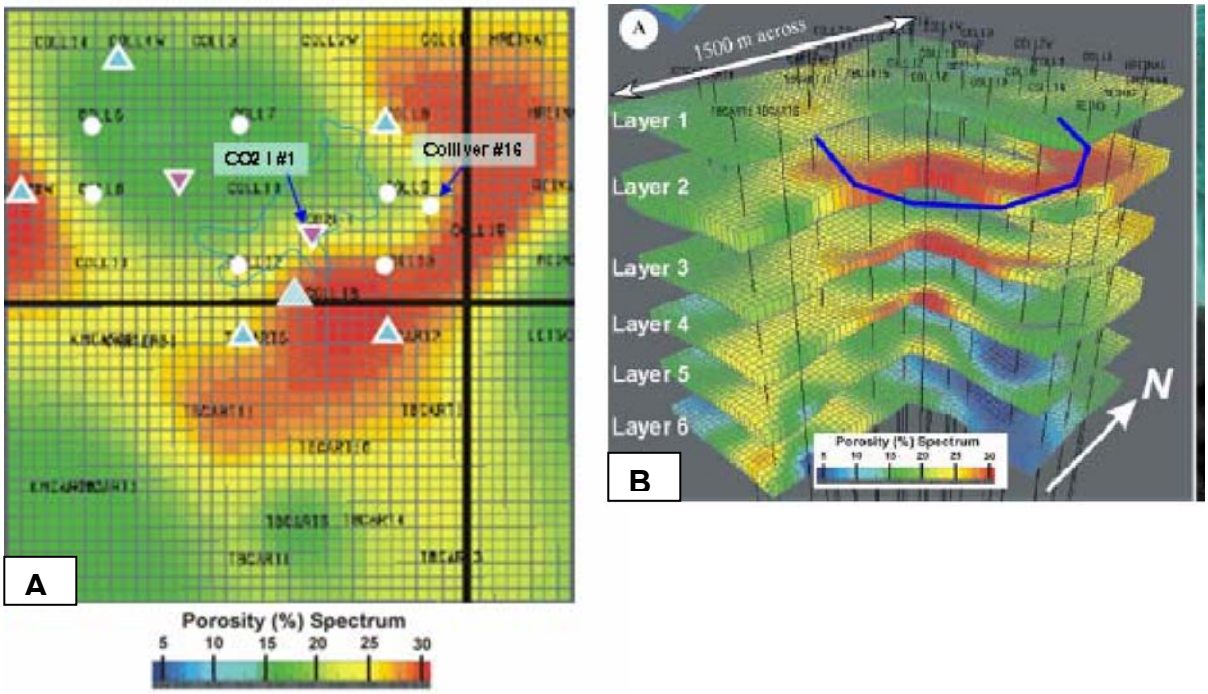


Figure 13. A. Average porosity for Layer #2 of the original six-layer geologic model shown in Figure 2 B. B. The six-layer geologic model illustrates average porosity of each layer.

Figure 14 illustrates the gamma ray, permeability, and porosity profiles obtained from core and wireline logs for the Colliver #16. The high permeability zones are located in thin (several feet thick) intervals at the tops of layer #2 and #4. Each of the more permeable beds exhibit better sorting of the ooid grainstone (now oomolds). Besides better sorting the more permeable beds have lower gamma ray (cleaner carbonate) representing cleaner carbonate that appears to typify the better sorted porous oomoldic lithofacies.

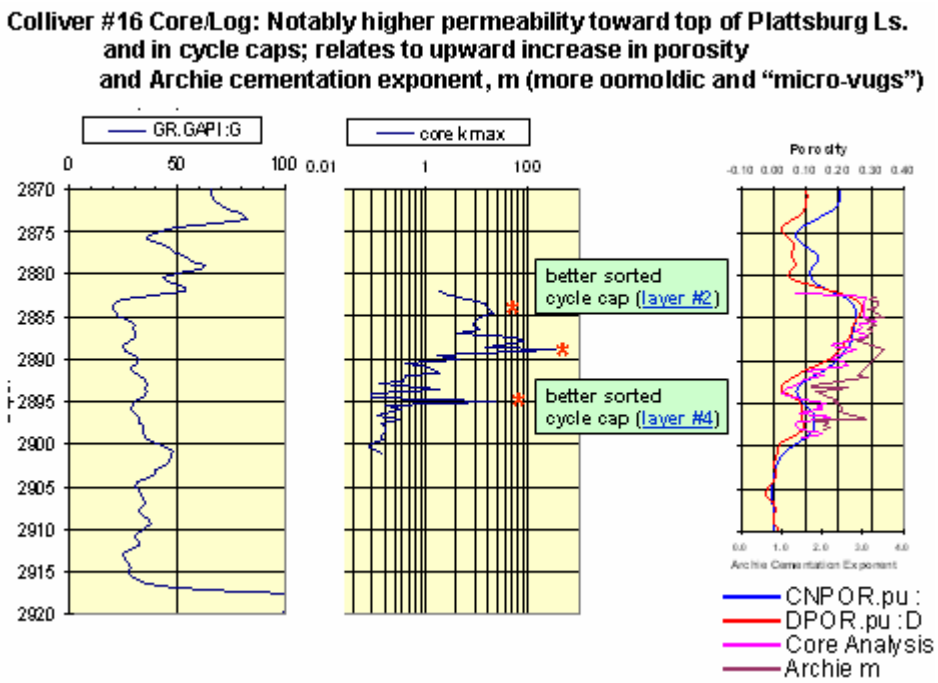


Figure 14. Depth profile of the "C" zone showing gamma ray, maximum permeability, and Archie cementation exponent, m, compared to various measures of porosity. Note that m increases upward from around 2 to near 3.5. Higher m indicates more tortuous paths for fluid to move as m increases.

A cross plot of the permeability vs. gamma ray in the Colliver #16 well indicates that samples with permeability in excess of 10 md also have natural gamma ray below 30 API. The porosity-gamma ray cross plot also indicates that highly porous oomoldic rocks with intermediate gamma ray values (>30 and <40 API) have a significant range in permeability (0.1 to 100 md, but generally less than 10 md).

Estimating permeability from a porosity-permeability cross plot is fraught with uncertainty due orders of magnitude variation in permeability at a given porosity value. Also, lack of core analyses further limit correlations. Thus, delineation of intervals of both high porosity and low gamma ray appears to be important in estimating whether the interval is sufficiently permeable.

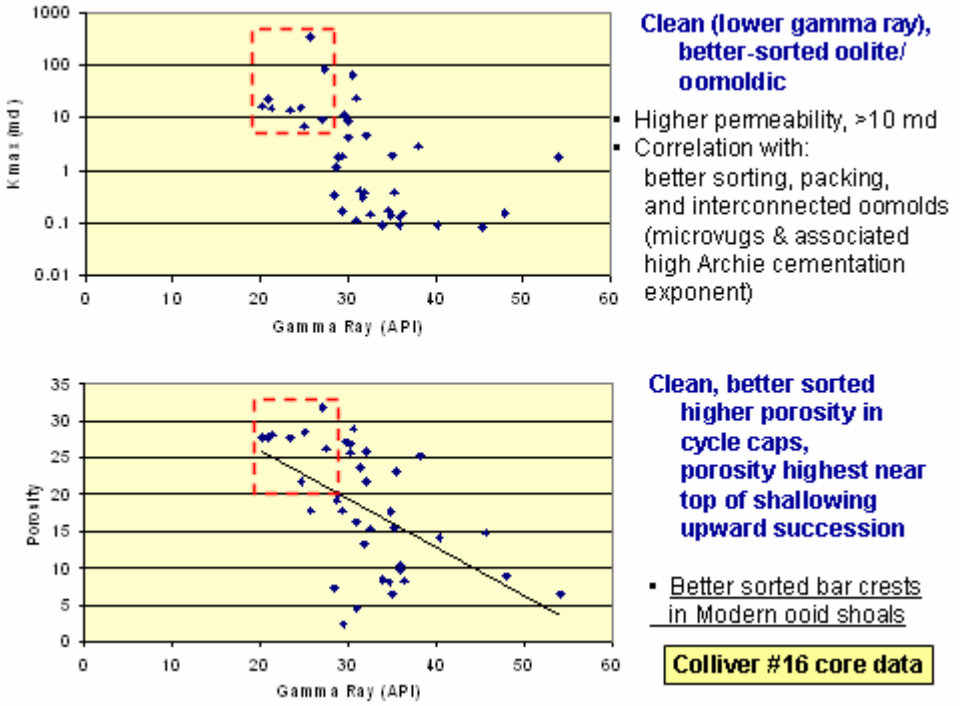


Figure 15. Cross plots of porosity and permeability vs. gamma ray for analyzed core taken from "C" zone/Plattsburg Limestone in Colliver #16.

An isopachous map of net thickness of porous interval in Layer #2 with low gamma ray shows clear northeast-southwest and northwest-southeast orientations (Figure 16). The CO2 injection well, CO2 #1 is located in the northeast-trending segment. The initial CO2 plume (imaged in early 2005) defined by 4D seismic (dark blue lined area around CO2 #1) conforms closely with the area of thick low gamma ray in layer #2. The general pattern of this map resembles the porosity map in layer #2 (Figure 13), but departs in detail.

The lime green lines on this map are lineaments drawn manually from the current day structure as shown in Figure 17, corresponding to dominant ridges and their edges along a gently northwesterly plunging anticline. These lineaments closely correspond to the trend and locations of low gamma ray. Correspondence of low gamma ray (better sorted) portions of the oolitic grainstone reservoir with current structure suggests that paleotopography may have been associated with contemporaneous structural deformation along trends paralleling current structure (Watney et al., 2008). Underlying paleotopography in Modern ooid shoals (created by Pleistocene islands and shoals) is very important in channeling ocean currents that led to formation of the ooid shoals.

The maps also include the location of wells currently producing incremental oil northwest of CO2 #1. This apparent response from CO2 injection falls outside of the low gamma ray areas including wells with marginal porosity and extends well beyond the confines of the initial CO2 plume that was seismically imaged. While perplexing, additional factors are also contributing to the movement of the CO2 beyond what was seismically imaged and initially modeled. These additional factors should be considered in a revised geologic model.

Individual ooid shoals in the Modern environment are often imbedded within a shoal complex, developed in response to an equilibrium hydrodynamic configuration. In spite of frequent storms and hurricanes, the basic distribution of Modern shoals is maintained that conforms to day-to-day processes such as tides and trade winds (Rankey et al., 2006). The controls on the shoals include pre-existing topography, sea level, landward-basinward orientation, and prevailing wind direction. In ancient rocks, the delineation of individual shoals is difficult especially in the subsurface outside of generally locating the complex of shoals when present.

To add to the complexity, meter-scale thick high-frequency cycles typify Pennsylvanian carbonate reservoirs, believed to reflect temporally distinct variations in sea level. Each sea level stand will likely invoke a different response as to location and type of ooid shoal that is deposited. A preliminary methodology was developed to discriminate between separate shoals of oolite in the vicinity of the CO2 #1 injection well in an attempt to examine their possible roll in reservoir compartmentalization. The approach taken is to establish the elevation of the base of the oolitic strata comprising the "C" Zone with respect to the elevation of the base of the "C" Zone carbonate. The base of the "C" is the subtidal, low energy portion of the cycle. This lowermost subtidal carbonate interval accumulated slowly in deeper water, so effectively, it was a blanket deposit. The ooid shoal was deposited during a lower stand in sea level, since ooid shoals are formed at depths under a couple of meters. It is probable that the lower the elevation of the base of the porous oolitic strata, a distinctive contact on wireline logs, the earlier the formation of the ooid shoal. This may reflect a site with higher elevation (paleotopographically higher and shallower) or in closer proximity to focused currents and waves needed in the formation of oolite.

When abrupt changes are noted in the relative elevation of the base of the shoal to the base of the underlying subtidal limestone between adjoining wells, the wells may be part of different bar/shoals of oolite. Alternatively, when the relative base of the oolite stays the same or slowly changes between wells, these wells may be part of the same ooid shoal. Shoals forming at distinctly different times would have contrasting elevation of their lower stratigraphic contact relative to the base of the subtidal carbonate.

As we have seen elsewhere in Kansas' Pennsylvanian oolites, subsequent sea levels can place ooid shoals in juxtaposition, i.e., a shoal of oolite building upward or laterally from an older shoal/shoal (French and Watney, 1993) or filling in the space between exiting shoals if the later sea level is lower.

Applying the relative elevation of the base of the oolite to delineate the ooid shoals was substantiated by describing sample cuttings of wells in each of the presumably separate shoals. In the Modern, besides the decline in sorting of ooids with distance from shoal crest, the ooids also contain increasing skeletal grains and micrite mud when energy has significantly declined. In the ancient record, temporally distinct ooid shoals in a complex may have characteristic and contrasting compositions that might reflect variations in climate conditions, energy level, or water circulation. These changes might be detected in the well cuttings to substantiate the interpretations from well logs.

The result of comparing the log correlations and cuttings appear to be consistent in resolving three separate oolite shoals in the are of the CO2 pilot as identified as light red dotted and dashed lines on the maps of the low gamma ray in the porous layer #2 and the top of the Plattsburg Limestone

(Figures 16 and 17). Two cross sections follow (Figures 18 and 19), using the low gamma ray map as an index map, to illustrate the nature of the lateral boundaries of the oolite shoals defined by abrupt changes in elevation of the base of the oolite shoal, distinctly different shapes in of the well profiles, and contrasting composition of grains and oolite content based on sample cuttings.

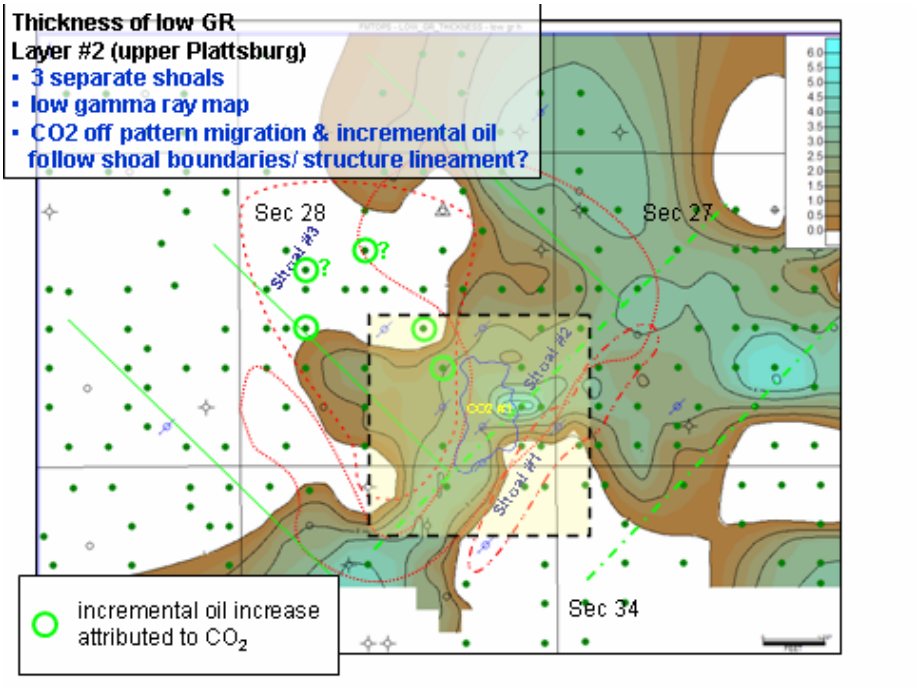


Figure 16. Thickness of low gamma ray in Layer #2 of the "C" zone/Plattsburg Limestone. Black lines delimit squares, one mile on a side.

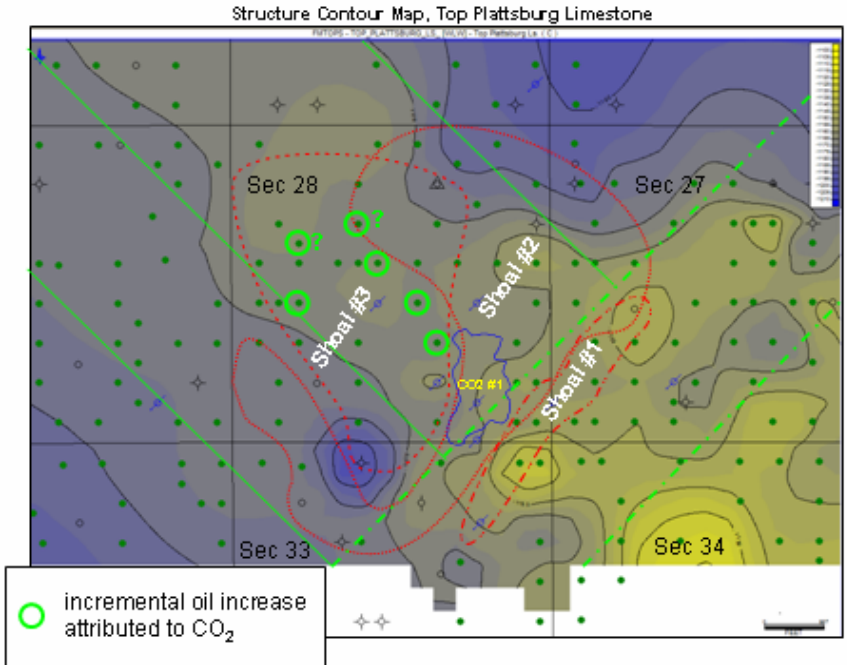


Figure 17. Structure contour map of the top of the Plattsburg Limestone.

The red dashed and dotted lines define separate ooid shoals. The green circles define wells that have responded to CO2 flooding with incremental oil recovered (Willhite, 2008). These wells all are inside the shoal #3 lying northwest of the CO2 injection well. The quality of the reservoir in shoal #3 is not as good as in shoal #2, the latter with overall lower gamma ray. The boundaries of shoal #3 appear to serve as barriers to flow.

It appears that shoal #3 and #1 began earlier that shoal #2 based on their lower elevations with respect to the base of the subtidal interval. Shoal #3 is at the structurally lowest position but is still along the regional structural saddle within this large field. Shoal #3 is also more poorly sorted as suggested by cuttings, but still has thin intervals of clean (low gamma ray) that are porous, that could be the preferred conduits for the injected CO2 and the resulting oil bank.

The injection well is in shoal #2, while the oil recovery is all located in shoal #3. The initial CO2 plume as imaged seismically is all within shoal #2, so that some other factor such as structure may have contributed to directing the CO2 to eventually cross between shoal #2 into shoal #3. Fracturing may have allowed the CO2 to breach the shoal boundaries that initially limited the flow of CO2. This may be been a matter of reaching adequate parting pressure of existing fractures. The general linear nature of the wells with incremental oil recovery may indicate a fracture contribution to the overall flow and recovery direction. Additionally, a preferred lineament direction based on the structure map is northwest-trending paralleling the general direction of this oil recovery.

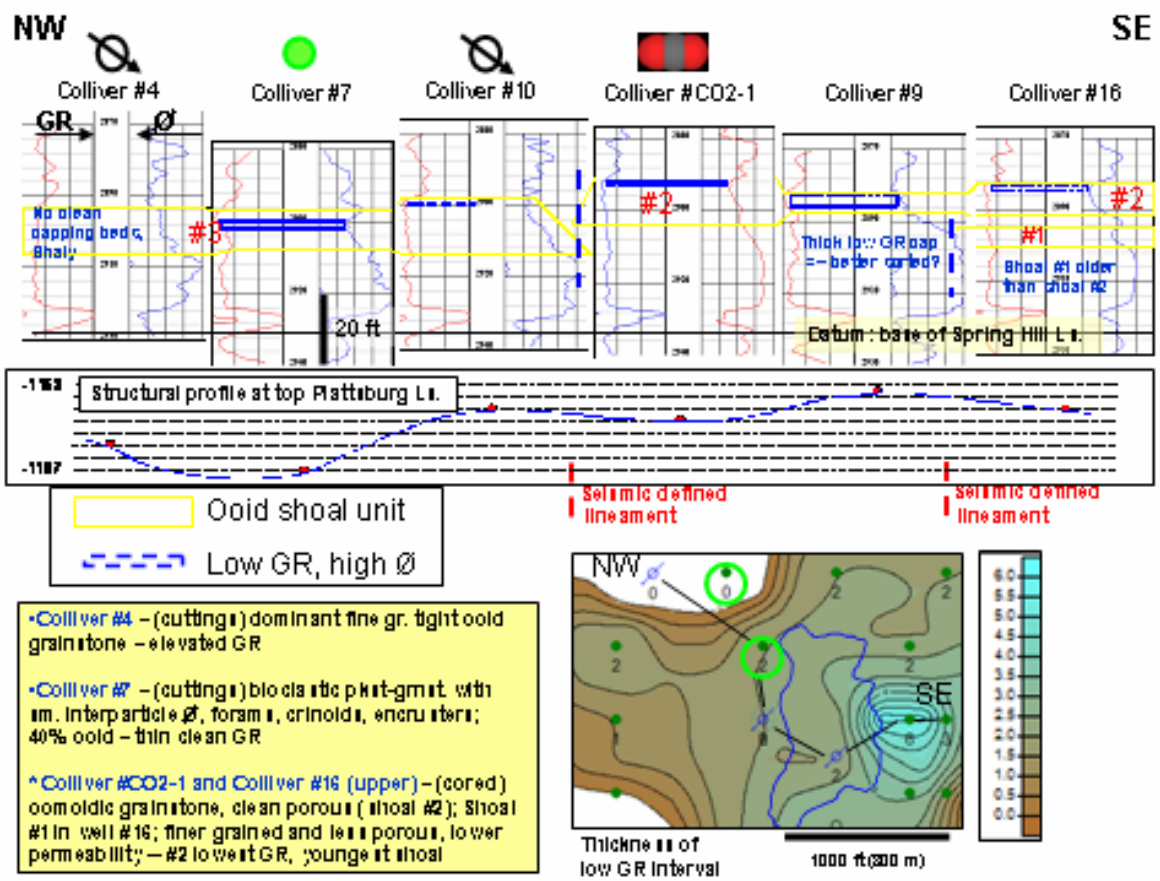


Figure 18. Northwest-southeast stratigraphic cross section crossing the CO2 #1 well that delineates three shoals #1, #2, and #3 (light yellow lines). The higher porosity and low gamma ray

are outlined on the logs by blue bars. The sample descriptions are highlighted in the yellow box. A structural profile is shown in the middle of the graphic.

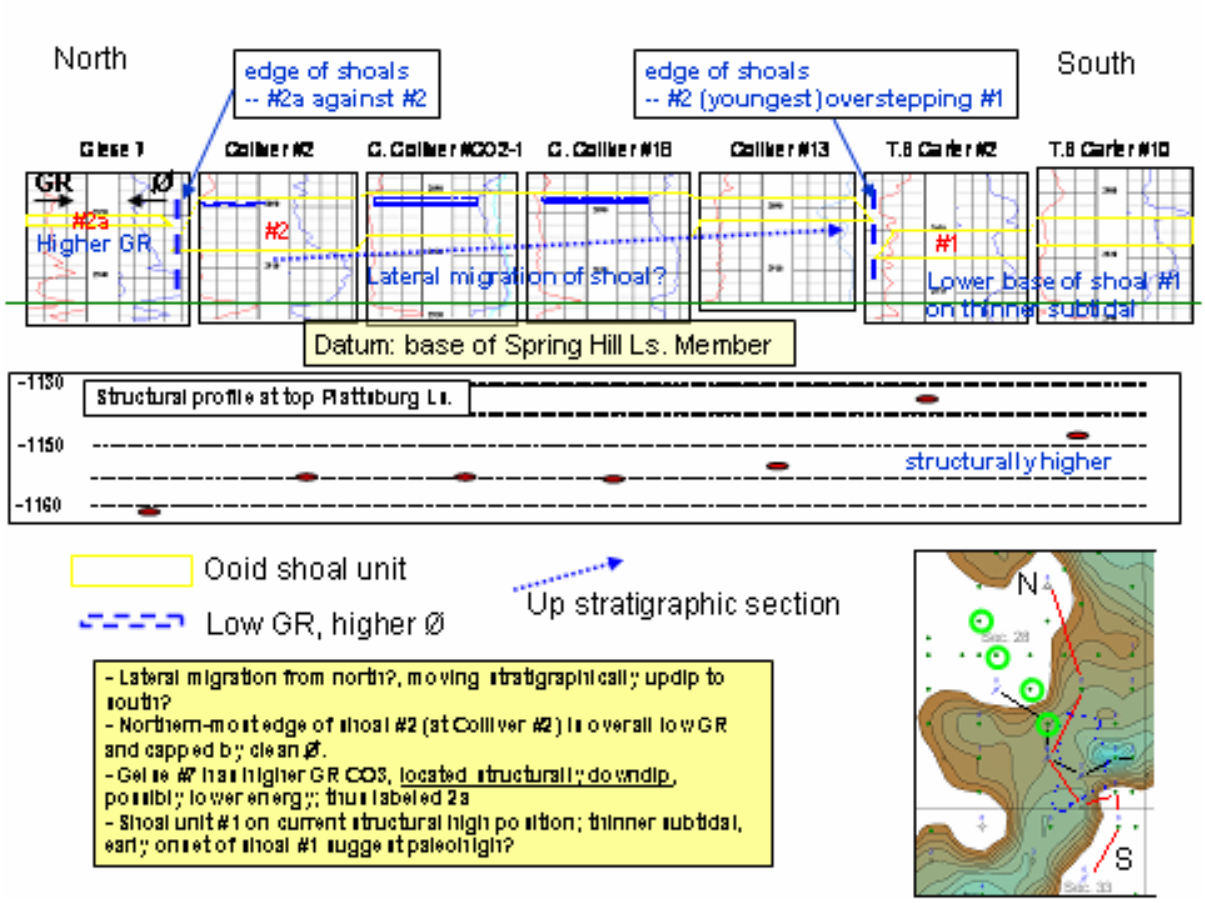


Figure 19. North-south stratigraphic cross section crossing the CO2 #1 well that delineates three shoals #1, #2, and #3 (light yellow lines). The higher porosity and low gamma ray are outlined on the logs by blue bars. The sample descriptions are highlighted in the yellow box. A structural profile is shown in the middle of the graphic.

Revised Geological Model(Continuation of Phase 2)

A revised geologic model of the "C" Zone (Plattsburg Limestone) reservoir will be developed for reservoir simulation using the methodologies described above. The delineation of permeability will reflect new mapping of high permeable zones based on correlation of low gamma ray porous intervals primarily in layer #2 of the reservoir. Also, addition of permeability anisotropy will be considered with a biased higher permeable northwesterly trend representing possible open fractures that are suggested by the pattern of wells experiencing incremental oil recovery in shoal #3. These wells are located on the western (northwest-trending) ridge extension of the mapped structure (Figure 17). It might also be the case that northeast-trending fractures are more sealing since incremental oil has not been observed east of the CO2 injector. These observations are consistent with interpretations by Nissen et al. (2006) in Dickman Field (one fracture direction open and the other closed). Introducing directional permeability was recommended by Willhite

(2008) based on fluid production history of the project and this analysis supports that conclusion. It may also be necessary to refine this model as considerations are taken for pore volume actually swept by the CO2 and recovered as incremental oil.

An improved simulation model will help understand the nature of the CO2 recovery process here that will also have wide implications for the future of CO2-IOR in Kansas and elsewhere. Refined parameters obtained here will help to model oil recovery in new fields that contain these types of ooid shoals, e.g., much of the Pennsylvanian of the upper Midcontinent.

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 Tsau and Lynn Watney. 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.

Budget Period 2 was completed for field operations and Budget Period 3 began on January 1, 2009. Development of a revised reservoir description and simulation of the carbon dioxide flood will continue under a no-cost extension of Budget Period 2 to June 30, 2009.

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, 2008, 231,017 bbl of water were injected into CO2 I-1 and 7.204 bbl of oil were produced from the pilot pattern. Oil production rates increased from averaged 4.2 B/D during the period from July 1-December 31, 2008. 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 14,260 bbl. Total oil production attributed to CO2 injection is 21,464 bbl. This is equivalent to a gross CO2 utilization of 6.4 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.

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Table 2
Summary of Monthly Data
January to December 2008

Field				Jan 2008	Feb 2008	Mar 2008	April 2008	May 2008	June 2008	July 2008	Aug 2008	Sept 2008	Oct 2008	Nov 2008	Dec 2008	Cumulative	
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	140	139	157	134	104	159	152	122	124	129	118.57	124	7204	bbl
	Wtr		bbl	9066	8468	7528	6619	5342	8057	8302	8339	9002	7630	8374	8417	512	Mbbl
	Gas		mcf	NM	NM	NM	NM	NM	NM	NM	NM	NM	NM	NM	NM	6815	mcf
	WOR		bbl/bbl	64.63	61.09	47.96	49.54	51.59	50.78	54.63	68.40	72.84	59.34	70.62	68.11	71.01	
	Cumulative Oil		bbl	5744	5882	6039	6173	6276	6435	6587	6709	6832	6961	7080	7203		
Injection	Wtr		bbl	18473	13143	14604	15842	14887	15783	15894	15473	17159	17201	16010	14491	1,392	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 3

Summary of Daily Average Data
January to December 2008

Field			Jan 2008	Feb 2008	Mar 2008	April 2008	May 2008	June 2008	July 2008	August 2008	Sept 2008	Oct 2008	Nov 2008	Dec 2008	Average Jul-Dec
Production															
	Oil	bbl	4.5	4.8	5.1	4.5	3.3	5.3	4.9	4.1	4.1	4.1	4.0	4.0	4.20
	Wtr	bbl	292	292	243	221	172	269	335	278	300	246	279	272	285
	Gas	mcf	NM	NM	NM	NM	NM	NM	NM	NM	NM	NM	NM	NM	NM
Injection															
	Wtr	bbl	150	221	218	213	217	217	209	209	243	224	204	219	212
	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	3.4	3.6	3.8	3.3	2.5	4.0	3.7	3.1	3.1	3.1	3.0	3.0	3.3
	Wtr	bbl	236	236	196	178	139	217	276	229	247	203	230	224	217.5
	Gas	mcf	NM	NM	NM	NM	NM	NM	NM	NM	NM	NM	NM	NM	NM
	Total Liquid(bbl)		240	239	200	181	142	221	280	232	250	206	233	227	221
	GOR		NM	NM	NM	NM	NM	NM	NM	NM	NM	NM	NM	NM	NM
CO2 13	Oil	bbl	1.13	1.19	1.26	1.11	0.83	1.32	1.20	0.99	1.01	1.01	0.97	0.97	1
	Wtr	bbl	56	56	47	43	33	52	59	49	53	43	49	48	49
	Gas	mcf													NM
	Total Liquid(bbl)		57	57	48	44	34	53	60	50	54	44	50	49	50.09
	GOR	bbl/bbl	NM	NM	NM	NM	NM	NM	NM	NM	NM	NM	NM	NM	NM
Total Liquid-Pattern		bbl	297	297	248	225	176	274	340	282	304	250	283	276	271
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	376	163	183	245	188	234	233	236	254	251	252	182	233
CO2 18	Wtr	bbl	73	70	70	70	75	75	70	71	75	80	78	78	74
CO2 I-1	Wtr	bbl	150	221	218	213	217	217	209	209	243	224	204	219	212