QUARTERLY TECHNICAL PROGRESS REPORT FOR THE PERIOD ENDING DECEMBER 31, 2001

TITLE: FIELD DEMONSTRATION OF CARBON DIOXIDE MISCIBLE FLOODING IN THE LANSING-KANSAS CITY FORMATION, CENTRAL KANSAS

DOE Contract No. DE-AC26-00BC15124

Contractor:	University of Kansas Center for Research, Inc. 2385 Irving Hill Road Lawrence, KS 66044
DOE Program:	Class II Revisited - Field Demonstrations
Award Date:	March 8, 2000
Total Project Budget:	$5,388,683
DOE Cost Amount:	$1,892,094
Program Period:	March 8, 2000 – March 8, 2006 (BP1 03/00-06/01, BP2 06/01-03/05, BP3 03/05-03/06)
Reporting Period:	October 1, 2001 – December 31, 2001
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ABSTRACT:

Progress is reported for the period from October 1, 2001 to December 31, 2001. Technical design and budget for a larger (60-acre) CO_2 demonstration project are being reviewed by the US DOE for approval. While this review process is being conducted, work is proceeding on well testing to obtain reservoir properties and on the *VIP* reservoir simulation model to improve model prediction and better understand the controls that certain parameters exert on predicted performance. Testing of present Colliver lease injection water on Lansing-Kansas City (L-KC) oomoldic rock indicates that injection brine must be filtered to < ~3-5 *u*m and <15 *u*m to prevent plugging of rocks with permeability as low as 1 md (millidarcy; 0.001 $u\text{m}^2$) and 10 md (0.01 $u\text{m}^2$), respectively. Pressure build-up testing on the Carter-Colliver #7 well is interpreted to indicate the L-KC reservoir surrounding this well is ~9 ft (2.7 m) thick having an average effective water permeability of 25-35 md (0.025-0.035 $u\text{m}^2$) that is connected to the wellbore by either a high permeability fracture, bed, or region with low skin. Reservoir simulation evaluation of gridcell size effect on model oil recovery prediction indicates that, based on the model prediction of distribution of produced oil and CO_2 volumes, oil recovery is strongly influenced by gravity segregation of CO_2 into the upper higher permeability layers and indicates the strong control that vertical permeability and permeability barriers between depositional flood cycles exert on the CO_2 flooding process. Simulations were performed on modifications of the 60-acre, two-injector pattern to evaluate oil recovery using other large-scale patterns. Simulations indicated that several 73-acre patterns with a single injector located near the Colliver #7 could provide improved economics without increasing the amount of CO_2 injected. The US Energy Partners ethanol plant in Russell, KS began operations in October ahead of schedule.

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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 40-acre (16.2 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 (03/00-03/01) involve 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 CO_2 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 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

Budget Period 1 Extended to Allow Revised Flood Design Review and Additional Reservoir Characterization

Activities in Budget Period 2 (03/02-03/05) involve implementation and monitoring of the flood:

- Task 5.1 - Remediate all wells in the flood pattern
- Task 5.2 - Re-pressure the pilot area by water injection
- Task 5.3 - Construct surface facilities
- 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 (03/05-03/06) will involve post-CO_2 flood monitoring:

- Task 6.1 – Collection and analysis of post-CO_2 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:

Progress is reported for the period from October 1, 2001 to December 30, 2001. Technical design and budget for a larger (60-acre, 24.3 ha) CO_2 demonstration project are being reviewed by the US DOE for approval. While this review process is being conducted, work is proceeding on well testing to obtain reservoir properties and on the *VIP* reservoir simulation model to improve model prediction and better understand the controls that certain parameters exert on predicted performance.

Testing of present lease injection water on Lansing-Kansas City (L-KC) oomoldic rock indicates that injection brine must be filtered to < ~3-5 *u*m and <15 *u*m to prevent plugging of rocks with permeability as low as 1 md (millidarcy; 0.001 um^2) and 10 md (0.01 um^2), respectively. If it is assumed that these particles can bridge pore throats with as few as three grains then the brine must be filtered to <1 *u*m and <5 *u*m for 1 md and 10 md rock, respectively.

Pressure build-up testing was performed on the Carter-Colliver #7 well. The pressure build-up was analyzed and interpreted to indicate a range of possible reservoir properties. General end-member models comprise: 1) a highly conductive fracture or flow channel with half-length of ~800 ft (244 m) , and skin of 4, connected to a reservoir interval of ~9 ft (2.7 m) thick having an average effective water permeability of 34 md (0.035 um^2); and 2) a ~9 foot (2.7 m) thick reservoir interval having an average effective water permeability of 25-35 md (0.025-0.035 um^2) reservoir, with a skin of -6 to -7, (representing the wellbore condition following acid treatments in the past).

Testing on the Colliver #10 was ambiguous but did not exclude possible fracture connection between the "C" and "G" zones resulting from a fracture treatment in 1960. The L-KC zone was cemented and will be 'dribble" injected during the pilot demonstration to prevent CO_2 loss.

Reservoir simulation was performed to further explore the influence of gridcell size on predicted oil recovery. Simulation results indicate that when vertical permeability is 5% of horizontal permeability oil recovery increases with decreasing gridcell size but when vertical permeability is zero oil recovery decreases. Based on the distribution of produced oil and CO_2 volumes, these results are interpreted to reflect the influence of gravity segregation of CO2 into the upper higher permeability layers and indicate the strong control that vertical permeability and permeability barriers between depositional flood cycles exert on the CO_2 flooding process.

Simulation was also performed on modifications of the 60-acre (24.3 ha), two-injector pattern to evaluate oil recovery using other large-scale patterns. Simulations indicated that several 73-acre (29.5 ha) patterns with a single injector located near the Colliver #7 could provide improved economics without increasing the amount of CO_2 injected.

The poster at the 2001 American Association of Petroleum Geologists Annual meeting, June 3-6, Denver, CO, by Martin K. Dubois, Alan P. Byrnes, and W. Lynn Watney entitled "Field Development and Renewed Reservoir Characterization for CO_2 Flooding of the Hall-Gurney Field, Central Kansas", awarded the Jules Braunstein award for best poster at the national

meeting was placed on the project website at: www.kgs.ukans.edu/PRS/publication/OFR2001-38/toc1.html

The US Energy Partners ethanol plant in Russell, KS began operations in October ahead of schedule. In the next quarter business arrangement for CO_2 delivery to the Pilot will be negotiated.

RESULTS AND DISCUSSION:

TASK 2.1 TESTING OF CO_2 INJECTION WELL

Injection Water Filtration

Equipment for injectivity testing of both the Carter-Colliver CO2 I#1 and the Colliver #7 were brought to the site. The present brine to be used for injection contains FeS and FeS_2 precipitates. To evaluate the possible influence of precipitate fines on plugging of the formation, pore capillary pressure data were analyzed for principal pore throat size. In addition, several core flood tests were performed with brine filtered to <25 *u*m (micron) and to <6 *u*m.

Principal pore throat diameter was calculated from previously measured mercury intrusion capillary pressure analysis data using the Washburn equation. The relationship between permeability and pore throat diameters for the Lansing-Kansas City (L-KC) is generally consistent with that exhibited by other sandstones and carbonates (Figure 1). This correlation would indicate that the injection brine must be filtered to < ~3-5 *u*m and <15 *u*m to prevent plugging of rocks with permeability as low as 1 md (millidarcy; 0.001 $u\text{m}^2$) and 10 md (0.01 $u\text{m}^2$), respectively. If it is assumed that these particles can bridge pore throats with as few as three grains then the brine must be filtered to <1 *u*m and <5 *u*m for 1 md and 10 md rock, respectively.

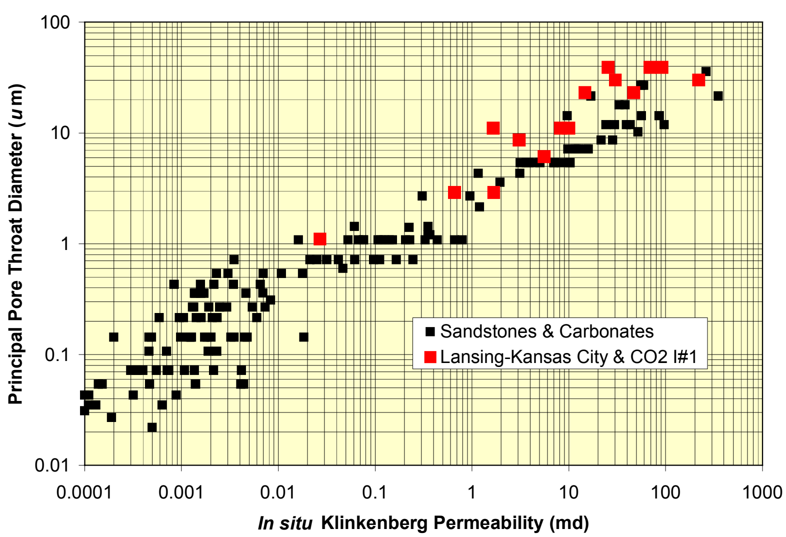


Figure 1. Cross-plot of principal pore throat diameter and permeability for Lansing-Kansas City oomoldic limestones and other carbonate and sandstone rocks. Pore throat diameters provide information on brine filtration requirements.

The concentration and size of particulates in the injection brine is strongly influenced by such variables as chemistry of the brines being mixed for injection, relative abundance of sulfur reducing bacteria, the nature of the tubulars, exposure to oxygen, residence time and mixing in tanks, and other environmental variables. Because of the complex influence of these variables, accurate analysis of the concentration and size of particulates is best done in the field. To provide an approximate test of the influence of fines on permeability, injection brine being used at the Colliver lease was collected and brought back to the Kansas Geological Survey for permeability tests. The brine was exposed to the air and contained fine black FeS and FeS_2 particulates. Two subsamples of brine were created, one filtered to <25 *u*m and the second filtered to <6 *u*m. These were used in flow through tests on two Carter-Colliver CO2 I#1 core plugs. Flow through testing of water filtered to <25um was conducted on the Carter-Colliver CO2 I#1 sample 2894.5 ft (porosity = 33.6%, *in situ* Klinkenberg permeability = 30.2 md (0.03 um^2), starting water saturation = 76.6% at residual oil saturation of 24.4%). After an initial increase in water effective permeability due to slight oil displacement, introduction of 25 *u*m filtered brine resulted in a continuous decrease in effective brine permeability (Figure 2) through the termination of the test.

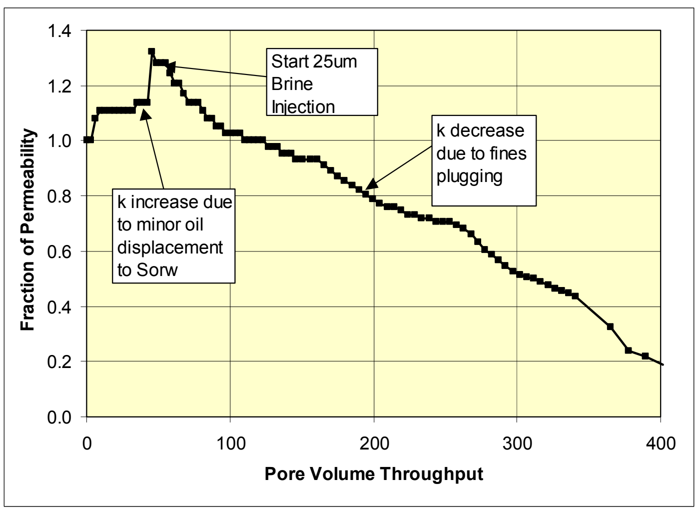


Figure 2. Influence of brine filtered to < 25um on effective brine permeability as a function of the pore volume of brine throughput for Colliver-Carter CO2I#1 sample 2894.5 ft (882 m), oomoldic limestone.

Similar testing on the Carter-Colliver CO2 I#1 sample 2893.1 ft (porosity = 27.5%, *in situ* Klinkenberg permeability = 46.9 md, starting water saturation = 81.4% at residual oil saturation of 18.6%) using <6 *u*m brine resulted in a decrease in effective water permeability of 39% after 566 pore volumes throughput. These results would indicate that fines in the filtered field brines are plugging the L-KC oomoldic limestone pore throats. If unfiltered or partially filtered brines were used during the original waterflood it is possible that plugging occurred and that injection water was progressively forced into lower permeability rock as the higher permeability rock was plugged. Plugging may also have resulted in the use of higher injection pressures and successive fracturing of the formation as the exposed surface was plugged. For short-term injection testing, series cartridge filters will be employed to filter injected brine to <25 *u*m. Injection into the Colliver #7 and #10 using this filtering system will evaluate the impact using 25 *u*m-filtered brine. Evaluation of the viability of using 1 *u*m and 5 *u*m cartridge filters or using different filtering system will be conducted. A final source for pilot injection water has not been arranged. When this source is identified, testing will be performed to evaluate possible fines damage.

Colliver #7 Tracer and Injection Test

The properties of the reservoir to the northwest of the Carter-Colliver CO2 I#1 and near the proposed second CO_2 injection well site were investigated by tracer and injection testing on the Colliver #7. Following removal of a plug at 2855 ft (870 m), a tracer survey, conducted on September 21, with a packer set in casing at 2892 ft (881.5 m) indicated 100% of the fluid went into the Lansing-Kansas City "C" zone open hole interval at 2894-2904' and no fluid traveled below 2906 ft. A pressure buildup in Colliver #7 was conducted from October 9-11, 2001 as part of a planned buildup/falloff test to characterize the reservoir interval permeability-height (***k-h***) around the well. Water injection began at 10AM on October 9 at a rate of 450 barrels per day (bbl/D; 71.5 m^3/d). The well was shut-in at 10AM on October 11 after injecting 914 barrels (145 m^3)of water. Injection rate was constant during the test and there was no buildup of surface pressure. Bottom hole pressure, measured by a pressure bomb at 2899 ft, at the start of the test was 604 psia. Although the pressure test was planned to include a four-day falloff test, the pressure bomb program incorrectly terminated data collection after ~48 hours at the end of the buildup period. Pressure data from the buildup test are shown in Figure 3. The data in Figure 3 were matched by several models using commercial well test analysis software. Models that successfully matched the data exhibited a range of permeability and bedding configurations that were all generally consistent with a general model comprising a 9-ft thick reservoir interval with 25-35 md permeability that is connected to the well bore by a high permeability fracture, flow channel, or low skin region. General end-member models comprise: 1) a highly conductive fracture or flow channel with half-length of ~766 ft, and skin of 4, connected to a reservoir interval of~9 ft-thick (2.7 m) having an effective water permeability of 34 md(0.034 *u*m^2); and 2) a 25-35 md reservoir, with a skin of -6 to –7, representing the wellbore condition following acid treatments in the past constituting up to 1,000 gal acid/ft (1.15 m^3/m). Following testing the well was returned to production from the L-KC and shallower intervals.

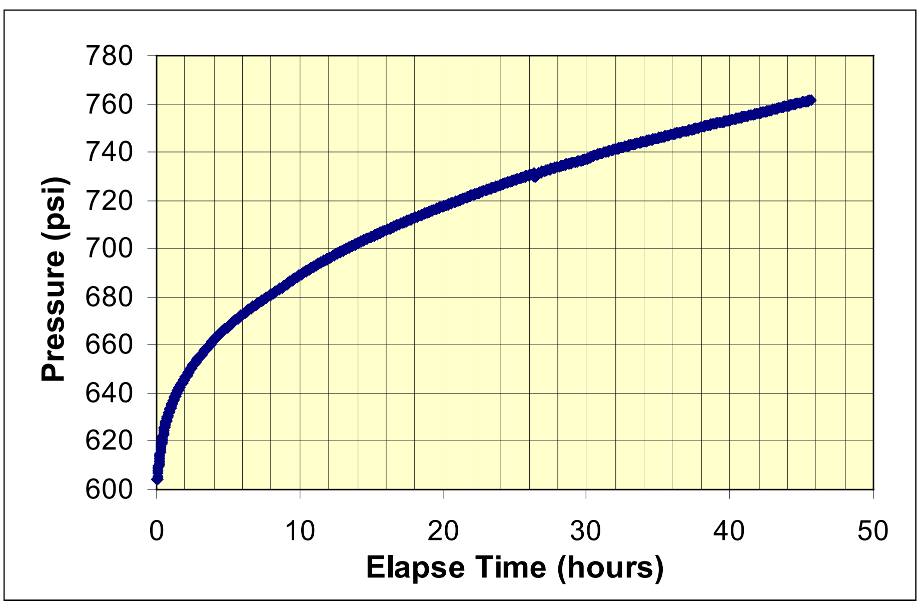


Figure 3. Bottom hole pressure build-up during water injection into Colliver #7 at a rate of 450 bbl/D (71.5 m^3/d).

Colliver #10 Tracer Test

On February 12, 1960 a sand fracture/acid treatment was performed on the open hole L-KC "C" and "G" interval (2884-2894 ft; 879-882 m) of the Colliver #10. The treatment consisted of a Dowell *Duo-frac* consisting of 19,000 pounds (862 kg) of sand and 15,000 gallons (56.8 m^3) of Dowell 3% "slick acid" with maximum and minimum injection rates of 23 bbls/min @800 psi (3.7 m^3/min @ 5.5 MPa) and 21 bbls/min @1050 psi(3.3 m^3/min @ 7.2 MPa), respectively. Based on records studied, this was the only fracture stimulation performed on the L-KC in the Colliver lease. Preliminary fracture analysis using available injection data and general reservoir rock properties was performed by Stim-Lab, Inc. of Duncan, Oklahoma (A Core Laboratories Company) using the commercial fracture simulation software *WinGOPHER 2000*. Preliminary analysis, based on the general data available, indicated that it was possible that the fracture stimulation treatment in the open-hole interval containing both the L-KC "C" and "G" may have created a fracture connecting the "C" and "G" zones with an interval extending up to 10's of feet from the wellbore containing proppant. To test the possible fracture connection between the L-KC "C" and "G" intervals, from October 17-25 the well was re-entered, 90-ft (30 m) of PVC pipe was drilled out and a tracer survey conducted. The tracer survey indicated flow down into the "G" zone but could not be unambiguously interpreted to indicate the presence or absence of a fracture connecting the "C" and "G" zones. Based on all results it was decided that this well would be "dribble" injected with water to prevent possible loss of CO2 into the "G" zone. The open-hole interval, exposing both the "C" and "G" zones, was cemented and the "C" zone will be drilled out in the future. Shallower interval water injection was resumed until the well is needed for the L-KC demonstration.

TASK 3.1 RESERVOIR SIMULATION

The *VIP* reservoir simulation model, utilized for predicting CO_2 oil recovery, is being continuously refined to provide better prediction of the CO_2 flood process. In this quarter the influence of gridcell size/layering/vertical permeability on predicted recovery was further investigated.

Simulation was also performed on modifications of the 60-acre (24.3 ha), two-injector pattern to evaluate oil recovery using other large-scale patterns. Simulations indicated that several 73-acre (29.5 ha) patterns with a single injector located near the Colliver #7 could provide improved economics without increasing the amount of CO_2 injected.

Influence of Gridcell Size on Model Recovery

The principal reservoir simulation model for the pilot uses gridcells of approximately 110 ft x 110 ft (33.5 m x 33.5 m) in the x and y directions and 1 ft (0.30 m) in the vertical direction. This represents a minimum of six gridcells between wells in the x and y directions. *VIP* simulations to investigate the influence of gridcell size on oil recovery were performed on a vertical 2-D model. The 2D-20 layer model was used with a 7% pre-slug injection of CO_2 followed by 3% HCPV 1:1 water-alternating-gas (WAG) slug pattern. Total CO_2 injected was ~37% of hydrocarbon pore volume (HCPV). The simulator compositional module binary interaction parameter (BIP) was set to 0.08. Figure 4 presents permeability distribution of the model representing the distribution measured on core. Simulations with gridcell x-dimensions of 10 ft, 20 ft, 41ft, 62 ft, 81 ft, and 106 ft were investigated. Simulation results (Figure 5) indicate that when vertical permeability is 5% of horizontal permeability (Kv =5%) oil recovery (expressed as percent of original oil in place, OOIP) increases with decreasing gridcell size but when vertical permeability is zero (Kv = 0%) oil recovery decreases.

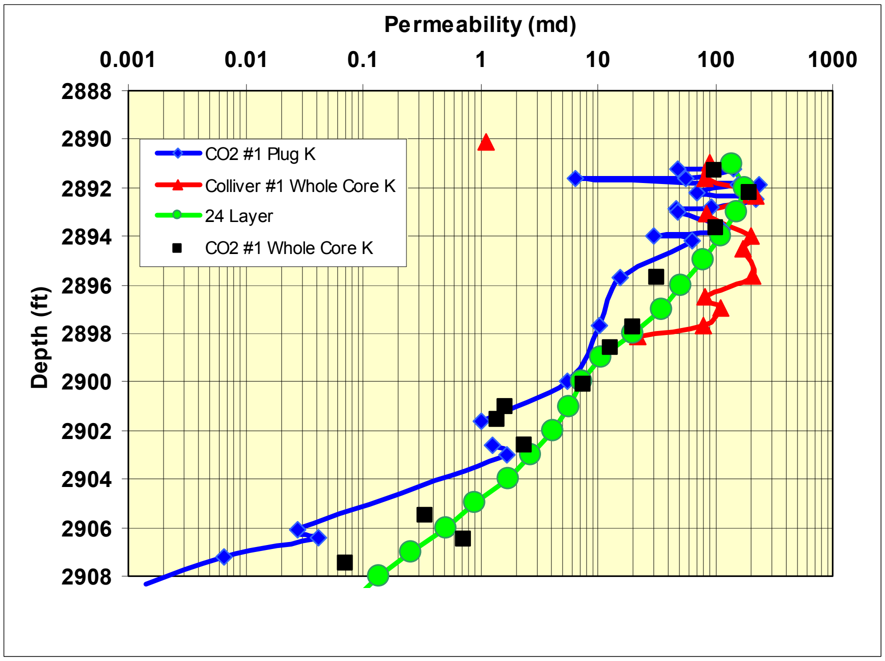


Figure 4. Vertical profile of horizontal permeability in 20-layer model and Carter-Colliver CO_2 I#1 well (1 ft = 0.305 m; 1 md = 0.001um^2).

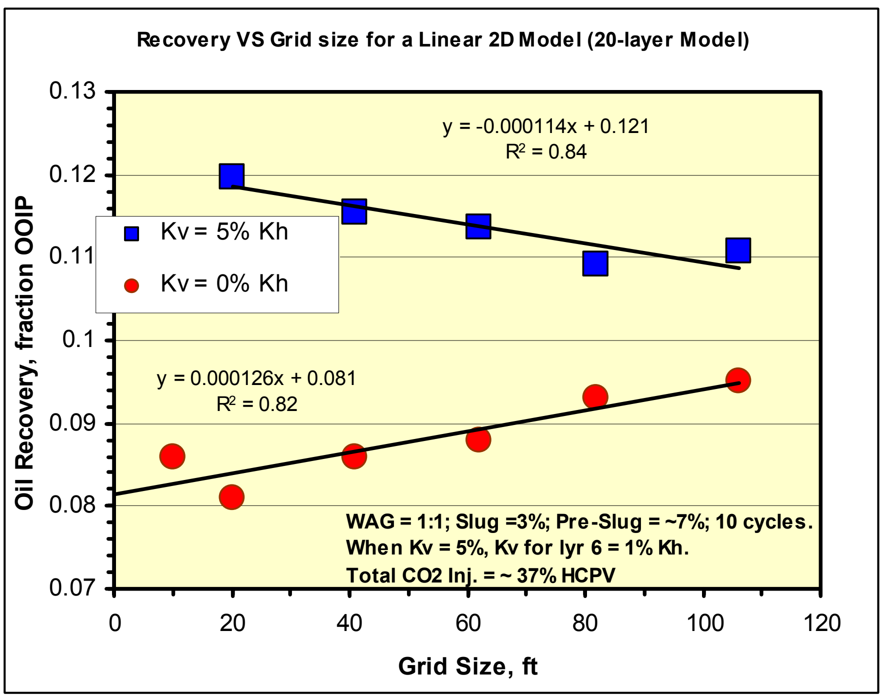


Figure 5. Simulation model-predicted oil recovery versus gridcell size for model with no vertical permeability between layers and model with vertical permeability = 5% of horizontal permeability (1 ft = 0.305 m).

Analysis indicates that oil recovery was reduced by gas cross-flow between layers enhanced by gravity segregation as grid cell length was reduced (Figure 6). When even minor vertical permeability is present vertical migration of CO_2 to the upper-most layers results in reduced oil recovery. This increases the importance of bedding architecture. Present understanding of reservoir bedding architecture indicates that either one of two flooding cycles may be present in the pilot area. The basal portion of these flooding cycles is prone to comprise mudstone and wackestone and have low vertical permeability. The possible presence of vertical permeability barriers (allowing isolated processing of the middle flood cycle), and the role of small-scale bedding architecture such as cross-bedding or stylolites would act to limit gravity override. There are many unknowns concerning lateral heterogeneity within the flood cycles such as shingling, weathering, and other diagenetic processes that might result in minimizing gravity override and promote more uniform sweep efficiency. The role that bedding architecture plays in improving vertical conformance is difficult to further quantify with available data but will be addressed by pilot flood response.

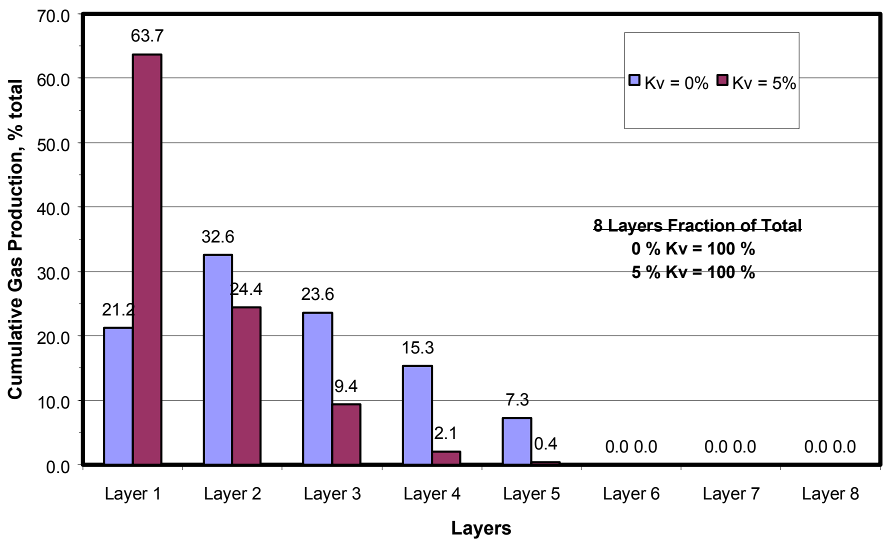
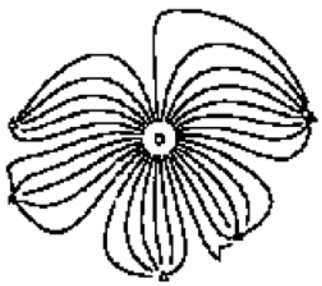


Figure 6. Model-predicted cumulative CO_2 gas produced by layer showing high gas volumes in upper layer (Layer 1) due to vertical gas migration.

73-Acre Single-Injector Patterns

The present proposed pilot design under review by the USDOE uses two CO_2 injectors, six producers, and five water-injection containment wells. Simulations performed last quarter indicate that proved reservoir properties are suitable, fewer containment wells might be needed to maintain pilot area pressure resulting in cost-savings. Simulations performed in this quarter explored the optimum location for the second CO_2 injection well and the possibility of limiting injection to just the new well. Based on available well data the proposed second CO2 injection well can be located between the Colliver #7 and Colliver #10 wells, where data indicate injectivity is high. For an injector in this location with the injection rates possible for this location the Carter-Colliver CO2 I#1 well can be used as a producer. Single-injector patterns (Figure 7 shows B002 pattern) decrease injection and production capital and operating costs while providing for flooding of a 73-acre (29.5 ha) area. Oil recovery from single-injector, 73-acre patterns was analyzed by the Tertiary Oil Recovery Project using the *VIP* reservoir simulation model and by Transpetco Engineering, Inc.using displacement calculations and fractional pattern modeling using general Colliver properties and assuming a 20% Process Pore Volume (PPV) CO2 slug size, 40% PPV total slug, and PPV rates ranging from 7.2-9.9% for the B00 pattern and 6.3-8.67% PPV for the B002 pattern.



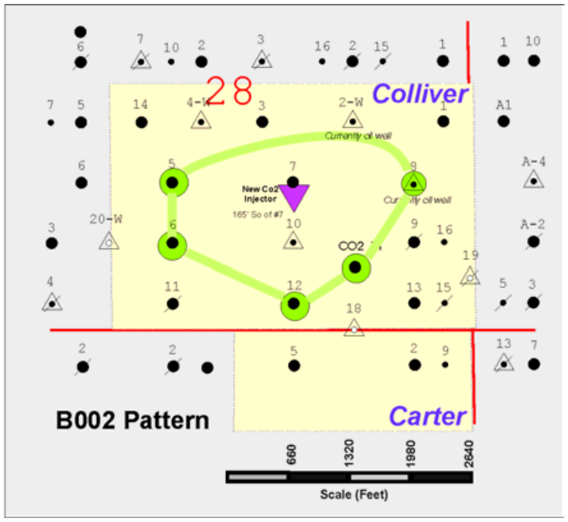


Figure 7. Example pattern (B002) for single-injector, 73-acre (29.5 ha) pattern.

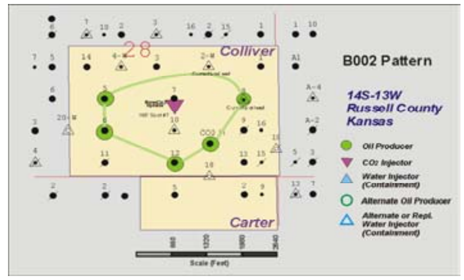
Using the above methods for predicting oil recovery the B002 pattern is predicted to recover between 71,200 and 83,800 stock tank barrels (STB; 11,310-13,320 m^3) over a period of 10 years (with >80% in first 7 years). High-side potential exceeds 89,000 STB (14,140 m^3) assuming effective flooding of the middle flood cycle, and low-side potential approaches 58,000 STB (9,220 m^3) assuming that the high permeability intervals have been efficiently waterflooded and exhibit residual oil saturations near 17%. Oil recovery estimates for the timetable of the project are strongly influenced by: 1) assumed residual oil saturation to waterflood; vertical distribution of horizontal permeability (permeability differences between upper, middle, and lower C flood cycles); the lateral distribution of permeability; and the presence or absence of vertical permeability barriers (flood cycle bounding bioclastic-rich layers); and the process rate. Without vertical permeability barriers between depositional flood cycles or shingling of ooid shoal deposits, gravity override of CO_2 acts to decrease oil recovery. The density ratio of ρ_{CO2}/ρ_{oil} = 0.6-0.8 (varying with pressure and oil density) for this pilot compared to density ratios in West Texas CO_2 floods that are often near $\rho_{CO2}/\rho_{oil} = 0.9$.

TASK 3.2 ECONOMIC AND RECOVERY ANALYSIS OF PILOT

Approximate economics have been calculated for a variety of flood patterns, assumed reservoir properties, process rates, and operation plans. Previous analysis indicated that the 60-acre two-injector pilot pattern could be CO_2 flooded at break-even or at a projected loss of less than \$44,000. By decreasing the number of surrounding water injection containment wells and the number of CO_2 injection wells the single-injector 73-acre patterns decrease capital and operating expenses but slow down the flood (increasing operating expenses) and lose some oil due to limited containment. Example economics for the B002 73-acre single-injector pattern project a potential profit ranging from -\$138,000 to \$80,000, depending highly on process rate and the price of oil. Table 1 illustrates B002 pattern economics for a high process rate and a \$20/barrel oil price.

Hall-Gurney Pilot CO2 Flood
Colliver-Carter BOO2 73-acre Pattern

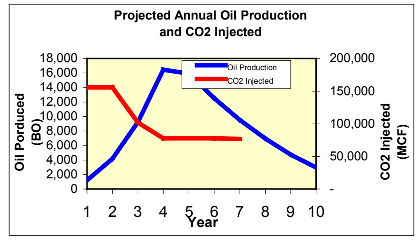
Location: Sec 28-14S-13W, Russell County, Kansas



Data Input Variables

Economic Measures	
ROR (Mid Yr Discount)	**3.17%**
NPV (Mid Yr Discount)	($135,527)
ROR (End Yr Discount)	2.84%
NPV (End Yr Discount)	($154,893)
Profit (BFIT)	$80,662
Profit/Capital	16%
Net Ultimate Rec **(BO)**	**73,317**
Cost/Net BBL Capital	$6.00
LOE	$10.70
Purchased CO2	$0.00
Recycle CO2	$0.00
Total Cost/Net BBL	**$16.70**
Gross CO2 Utilization	**8.6**
Net CO2 Utilization	**8.6**

Major Input Parameters		
Oil Price	**$20.00**	per BBL
Purhased CO2 Cost	**$0.00**	per MCF
Recycle CO2 Cost	**$0.35**	per MCF
Discount Rate	**10.0%**	
Working Interest	100.0%	
Net Revenue Interest	87.5%	
Severance Tax	0.0%	
Ad Valorem Tax	0.0%	
EOR Tax Credit	10.0%	
LOE Cost Factor	100.0%	FO
Capital Cost Factor	100.0%	FC
Oil Price Escalator	0.0%	per year
LOE Escalator	0.0%	per year
CO2 Cost Escalator	0.0%	per year



Capital Costs

	Est. Item Cost	Factored (x FC) Item Cost	DOE	Operator	DOE	Operator	EOR Tax Credit
BP-1 Loss carried forward	$105,692	$105,692	45%	55%	$47,561	$58,131	
Rework and upgrade wells	$292,188	$292,188	45%	55%	$131,485	$160,703	
Drill & Equip CO2 I-2	$175,000	$175,000	45%	55%	$78,750	$96,250	$9,625
Drill and Equip Water SW	$35,000	$35,000	45%	55%	$15,750	$19,250	
Surface facilities	$238,136	$238,136	35%	65%	$83,348	$154,789	$15,479
total before DOE cost share and EOR credit		$846,016		*before EOR credit*	$356,894	$489,123	$25,104
				Operator Capital Expnses (excludes BP1 Loss)		**$430,992**	

EOR tax credit applied to CO2 injectors and their lines, and surface facilities

Lease Operating Expense Costs

	Est. Unit $/mo	Factored (x FO) Unit $/mo
CO2 Oil Well	1,400	1,400
Post CO2 Oil	1,100	1,100
Water Injectin Well	800	800
CO2 Injection Well	1,200	1,200
Water Supply Well	800	800
Flood Mgmt ($/pattern)	417	417
Repressure Phase	6	Months

Lease Operating Expense Calculator

Phase	Year	CO2 Oil	Post CO2 Oil	WIW	CO2 Inj	WSW	Flood Mgmt # Patterns	LOE Annual Cost	DOE Cost Share
BP2 Repressure	0	0	0	1	1	1	1	19,303	35%
BP2 CO2 WAG	1	5	0	1	1	1	1	122,605	35%
BP2 CO2 WAG	2	5	0	1	1	1	1	122,605	35%
BP2 CO2 WAG	3	5	0	1	1	1	1	122,605	35%
BP2 CO2 WAG	4	5	0	1	1	1	1	122,605	35%
BP2 CO2 WAG	5	5	0	1	1	1	1	122,605	35%
BP2 CO2 WAG	6	5	0	1	1	1	1	122,605	35%
BP3CO2 WAG	7	5	0	1	1	1	1	122,605	10%
BP3 Post WF	8	0	5	1	0	1	1	90,205	0%
Post WF	9	0	5	1	0	1	1	90,205	0%
Post WF	10	0	5	1	0	1	1	90,205	0%
	11	0	0	0	0	0	0	0	0%
	12	0	0	0	0	0	0	0	0%
	13	0	0	0	0	0	0	0	0%
	14	0	0	0	0	0	0	0	0%
	15	0	0	0	0	0	0	0	0%
					total before DOE cost share and EOR credit			1,148,153	

Projected Oil Production and CO2

Year	Annual Oil (BO) Production	CO2 in MMCF Injected	CO2 Purchased
1	1,190	155,800	155,800
2	4,184	155,800	155,800
3	9,258	101,800	101,800
4	16,441	77,900	77,900
5	15,967	77,900	77,900
6	12,548	77,900	77,900
7	9,539	76,862	76,862
8	6,940	0	0
9	4,751	0	0
10	2,973	0	0
11	0	0	0
12	0	0	0
13	0	0	0
14	0	0	0
15	0	0	0
	83,791	723,960	723,960

Annual Forecasts

Pre-CO2 Well Cap Costs 334,334
Surf Fac Cap Costs 154,789

Year	Prod (BO)	Price	Net WI Op Revenues	Sev & Adv Taxes	Lease Op Expenses	Purchased CO2 Costs	Recycled CO2 Costs	EOR Tax Credit	Cash Flow BFIT	Yr End Discount PVP @ 10.0%	Yr End Discount PV Factor 10.0%	Mid-Year Discount PVP @ 10.0%	Mid-Year Discount PV Factor 10.0%	ROR Calc. 3.17%
0	Repressure	*Lost Oil Rever*	(50,000)		12,547				(551,670)	(551,670)	1.0000	(551,670)	1.0000	(551,670)
1	1,190	$20.00	20,829	0	79,693	0	0	25,104	(33,760)	(30,691)	0.9091	(32,189)	0.9535	(33,237)
2	4,184	$20.00	73,223	0	79,693	0	0	0	(6,470)	(5,347)	0.8264	(5,608)	0.8668	(6,174)
3	9,258	$20.00	162,013	0	79,693	0	0	0	82,319	61,848	0.7513	64,866	0.7880	76,135
4	16,441	$20.00	287,720	0	79,693	0	0	0	208,026	142,085	0.6830	149,020	0.7164	186,481
5	15,967	$20.00	279,418	0	79,693	0	0	0	199,725	124,013	0.6209	130,066	0.6512	173,533
6	12,548	$20.00	219,585	0	79,693	0	0	0	139,892	78,966	0.5645	82,820	0.5920	117,808
7	9,539	$20.00	166,930	0	110,345	0	0	0	56,586	29,037	0.5132	30,455	0.5382	46,187
8	6,940	$20.00	121,452	0	90,205	0	0	0	31,247	14,577	0.4665	15,288	0.4893	24,720
9	4,751	$20.00	83,150	0	90,205	0	0	0	(7,055)	(2,992)	0.4241	(3,138)	0.4448	(5,410)
10	2,973	$20.00	52,026	0	90,205	0	0	0	(38,179)	(14,720)	0.3855	(15,438)	0.4044	(28,375)
11	0	$20.00	0	0	0	0	0	0	0	0	0.3505	0	0.3676	0
12	0	$20.00	0	0	0	0	0	0	0	0	0.3186	0	0.3342	0
13	0	$20.00	0	0	0	0	0	0	0	0	0.2897	0	0.3038	0
14	0	$20.00	0	0	0	0	0	0	0	0	0.2633	0	0.2762	0
15	0	$20.00	0	0	0	0	0	0	0	0	0.2394	0	0.2511	0
	83,791		1,416,347	0	871,666	0	0	25,104	80,662	(154,893)		(135,527)		(0)

TASK 7.0 PROJECT MANAGEMENT

Construction of the US Energy Partners ethanol plant in Russell, KS was completed and ethanol production began in October. In the first month of operations, only minor "shake-down" problems were encountered. Negotiations with prospective CO_2 purchasers have been initiated. At the present, offers from two companies for CO_2 purchase are being considered. 800 million cubic feet of CO_2 are being held by US Energy Partners, the owners of the ethanol plant, for the demonstration pilot. Arrangements for how the CO_2 will be transported and compressed for down-hole injection are being considered and will be finalized when a final CO_2 sale agreement is reached.

Two organizational meetings were held in this quarter.

A meeting was held on October 8, 2001 at the offices of Murfin Drilling Company, Inc., Wichita, KS with the following personnel present: MV Energy) James Daniels, Larry Jack, Niall Avison; TORP) Paul Willhite, Don green, Richard Pancake; KGS) Alan Byrnes, Martin Dubois; Kinder-Morgan) Donald Schnacke (rep K-M), and William Flanders (Transpetco Engineering, rep K-M). Topics covered included: 1) Revised plan approval status, 2) Colliver #7 build-up analysis, 3) well rcompletion and testing schedule, 4) Pressure containment, 5) Economics, 6) CO_2 delivery, 7) Project Schedule, and 8) Reservoir modeling.

A meeting was held on December 5, 2001, after presentations at the CO_2 Conference in Midland Texas with the following personnel present: KGS) Alan Byrnes, Martin Dubois; Kinder-Morgan) Russell Martin, William Flanders (Transpetco Engineering representing K-M). Topics covered included: 1) CO_2 project timetable.

At the onset of the pilot project the Kansas Department of Commerce & Housing provided $100,000 of support for drilling of the first CO2 injeciton well. A letter was sent in December to Lt. Governor Gary Sherrer, Director of the KDC&H, by Alan Byrnes, Paul Willhite, and Don Schanacke requesting additional funding support for the CO_2 pilot project. A meeting was planned for January, 2002.

TASK 8.0 TECHNOLOGY TRANSFER

The poster presented at the 2001 American Association of Petroleum Geologists Annual meeting, June 3-6, Denver, CO, by Martin K. Dubois, Alan P. Byrnes, and W. Lynn Watney entitled "Field Development and Renewed Reservoir Characterization for CO_2 Flooding of the Hall-Gurney Field, Central Kansas" and awarded the Jules Braunstein award for best poster at the national meeting was placed on the CO2 website at:
www.kgs.ukans.edu/PRS/publication/OFR2001-38/toc1.html
Several investigators involved with the pilot project attended the 2001 CO_2 Conference in Midland Texas, December 4-5 including Alan Byrnes, Martin Dubois and Timothy Carr from the KGS, Richard Pancake and Jyun Syung Tsau of TORP, and William Flanders and Russel Martin of Kinder-Morgan CO_2 Company. Information concerning the project was shared and discussed informally with companies involved in CO_2 flooding in the United States.

CONCLUSIONS

While the larger (60-acre) CO_2 demonstration project are being reviewed by the US DOE for approval work is proceeding on well testing to obtain reservoir properties and on the *VIP* reservoir simulation model to improve model prediction and better understand the controls that certain parameters exert on predicted performance. Testing of present Colliver lease injection water on Lansing-Kansas City (L-KC) oomoldic rock indicates that injection brine must be filtered to < ~3-5 *u*m and <15 *u*m to prevent plugging of rocks with permeability as low as 1 md (millidarcy; 0.001 $u\text{m}^2$) and 10 md (0.01 $u\text{m}^2$), respectively. Pressure build-up testing on the Carter-Colliver #7 well is interpreted to indicate the L-KC reservoir surrounding this well is ~9 ft (2.7 m) thick having an average effective water permeability of 25-35 md (0.025-0.035 $u\text{m}^2$) that is connected to the wellbore by either a high permeability fracture, bed, or region with low skin. Reservoir simulation evaluation of gridcell size effect on model oil recovery prediction indicates that, based on the model prediction of distribution of produced oil and CO_2 volumes, oil recovery is strongly influenced by gravity segregation of CO_2 into the upper higher permeability layers and indicates the strong control that vertical permeability and permeability barriers between depositional flood cycles exert on the CO_2 flooding process. Simulations were performed on modifications of the 60-acre (24.3 ha), two-injector pattern to evaluate oil recovery using other large-scale patterns. Simulations indicated that several 73-acre (29.5 ha) patterns with a single injector located near the Colliver #7 could provide improved economics without increasing the amount of CO_2 injected. The Martin K. Dubois, Alan P. Byrnes, and W. Lynn Watney poster entitled “Field Development and Renewed Reservoir Characterization for CO_2 Flooding of the Hall-Gurney Field, Central Kansas” and awarded the Jules Braunstein award for best poster at the AAPG national meeting was placed on the CO_2 Pilot website. The US Energy Partners ethanol plant in Russell, KS began operations in October ahead of schedule.