QUARTERLY TECHNICAL PROGRESS REPORT
FOR THE PERIOD ENDING SEPTEMBER 30, 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:	July 1, 2001 – September 30, 2001
DOE Project Manager:	Daniel J. Ferguson, NPTO Tulsa, Oklahoma
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ABSTRACT:

Progress is reported for the period from July 1, 2001 to September 30, 2001. Technical design and budget for a larger (60-acre) CO2 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.

Pressure build-up testing was performed on the Carter-Colliver CO2 I#1 well. Results of the test are still being interpreted but are consistent with either a layered reservoir with significant permeability differences between layers or with a high permeability region or fracture connected to a low permeability region.

Reservoir simulation using presently understood reservoir properties indicates that some or all containment wells may not be required to contain the flood or maintain pressures above the minimum miscibility pressure. The economics of diminished oil recovery versus the cost of reworking and operating the containment wells is being evaluated. Simulation study indicates that, given the vertical distribution of horizontal permeability evident in the CO2 I#1 well, increasing the number of layers in the simulation model results in a decrease in predicted oil recovery. The decrease is attributed to preferential flow of CO2 through upper high permeability layers and the migration of CO2 to upper layers due to gravity. This effect is more pronounced with increasing vertical permeability.

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 CO2 Flooding of the Hall-Gurney Field, Central Kansas" was awarded the Jules Braunstein award for best poster at the national meeting. The award will be presented at the 2002 meeting in Houston, TX.

Construction of the US Energy Partners ethanol plant in Russell, KS is near complete with start-up in October.

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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 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 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-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:

Progress is reported for the period from July 1, 2001 to September 30, 2001. Technical design and budget for a larger (60-acre, 24.3 ha) CO2 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.

Pressure build-up testing was performed on the Carter-Colliver CO2 I#1 well. Results of the test are still being interpreted but are consistent with either a layered reservoir with significant permeability differences between layers or with a high permeability region or fracture connected to a low permeability region.

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Construction of the US Energy Partners ethanol plant in Russell, KS is near complete. In the next quarter the plant will start up and attention will be able to be focused on CO2 delivery to the Pilot.

RESULTS AND DISCUSSION:

TASK 2.1 TESTING OF CO2 INJECTION WELL

Previous testing on the Carter-Colliver CO2 I#1 indicated lower permeabilities than predicted and indicated by the core. Based on these results it was decided to: 1) Acid stimulate Carter-Colliver CO2 I#1, 2) Perform a build-up test, and 3) Perform fall-off test at a later date when facilities are in place. The goals of this work were to 1) Clean-up near-wellbore damage for entire L-KC 'C' interval without unduly affecting native reservoir properties, 2) Measure reservoir permeability-height and wellbore skin, 3) Avoid fracturing the reservoir during

treatment and testing so that testing can reveal if native fractures exist, and 4) Prepare the well for its future role as an injector. Important considerations included: 1) Treat entire reservoir interval, 2) Break-down each set of perforations, 3) Recommend >150 gallons acid/ft, 4) Block perforations by rock salt or balls or use PPI tool, and 5) Avoid fracturing the reservoir since we want to determine presence of fractures.

The Carter-Colliver CO2 I#1 was treated with 400 gallons (1.5 m^3) 15% HCl acid on July 13 and another 1000 gallons (4.5 m^3) on July 16. The well responded to the stimulation with a pre-stimulation swab rate of +/- 2.5 bph (barrels per hour; $1.1*10^{-4}$ m^3/s) and a swab rate after the second acid job of 18 bph ($7.9*10^{-4}$ m^3/s). Treating pressures never exceeded 200 psig (1.38 MPa) at the surface. An attempt was made to use the PPI tool to breakdown individual perfs but the tool failed to work and had to be pulled out of the hole. The well was treated using a packer.

The well was produced until August 30 when the well was shut in for a build-up test. Prior to the build-up test the well was producing at 2.88 BOPD (barrels oil per day, 0.46 m^3/d) and 69.12 BWPD (11 m^3/d). The response curve for the build-up test (Figure 1) does not conform easily to models available in standard commercial well test analysis software. Present interpretations are working on resolving whether the results indicate a reservoir with layers of significantly different permeability or whether the data support a model where there is a high permeability region or fracture near the wellbore surrounded by a region of low permeability.

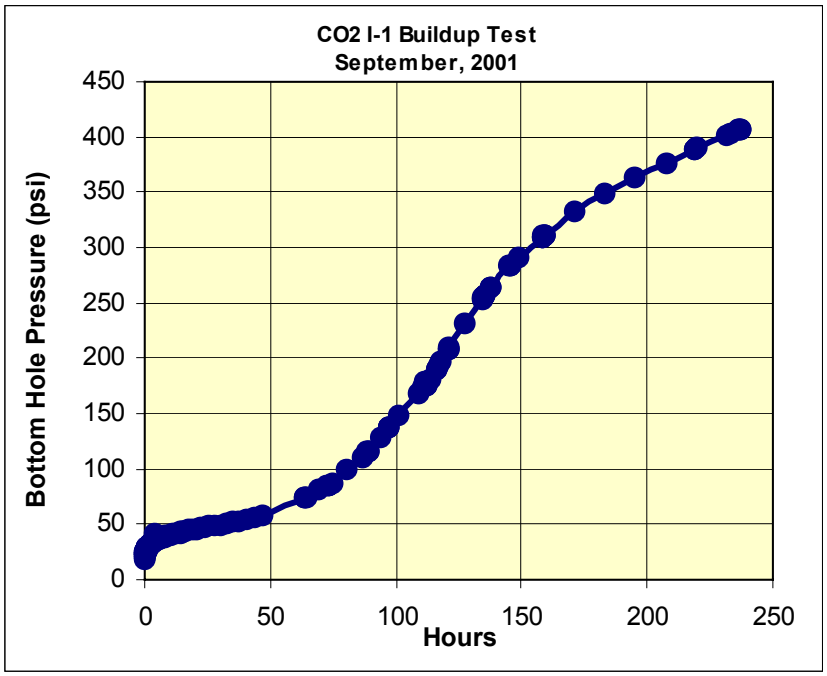

Figure 1. Pressure build-up test results for Carter-Colliver CO2 I#1 well.

TASK 3.1 RESERVOIR SIMULATION

The *VIP* reservoir simulation model, utilized for predicting CO_2 oil recovery, was refined to provide better prediction of the CO2 flood process. Aspects of the reservoir simulation model investigated include: 1) pressure containment, and 2) the influence of the number of layers and vertical distribution of permeability on CO2 recovery.

Pressure and Containment

Previous models have used water injection containment wells to both contain the oil bank and to help maintain pressures above the minimum miscibility pressure (~1,250 psi, 8.6 Mpa). Water injection wells cost approximately $40,000-$50,000 for rework and $800/month ($9,600/year) in operating expense during the flood. For a 7-year pilot the total cost of a containment well can be ~$117,000. Even if some oil is lost because of lack of containment, the lost oil revenue may not warrant the use of all containment wells. If not all injectors are needed then the project can realize a cost saving. To explore this possibility a series of simulations were performed on the 60-acre (24.3 ha) pattern and on a smaller 20-acre pattern to examine pressure distribution with fewer or no containment wells. The simulations were performed using only water injection. Because water has a significantly higher viscosity than CO2 (~0.7 centipoise compared with ~0.04 centipoise), water injection represents a limiting or "worst-case" scenario for pressure distribution created by injection.

Figures 2 and 3 illustrate the pressure distribution for the 60-acre (24.3 ha) pattern with the injection wells held at a constant bottom hole pressure (BHP) of 2,000 psi (13.8 MPa). Figure 2 illustrates pressure distribution in the period before the pattern producers are turned on and have a BHP equal to the reservoir (BHP = ~800 psi, 5.5 MPa). Figure 2 illustrates pressure distribution during the semi-steady state period later in the flood when the BHP of all producers is held at a constant pressure of 600 psi (4.1 MPa). These figures illustrate that containment wells are not necessary for pressure buildup to MMP conditions. During flood operations pressures at the outer edge of the flood drop below MMP without surrounding containment injectors. With injection of low viscosity CO2, pressures at the outer edge increase to near MMP.

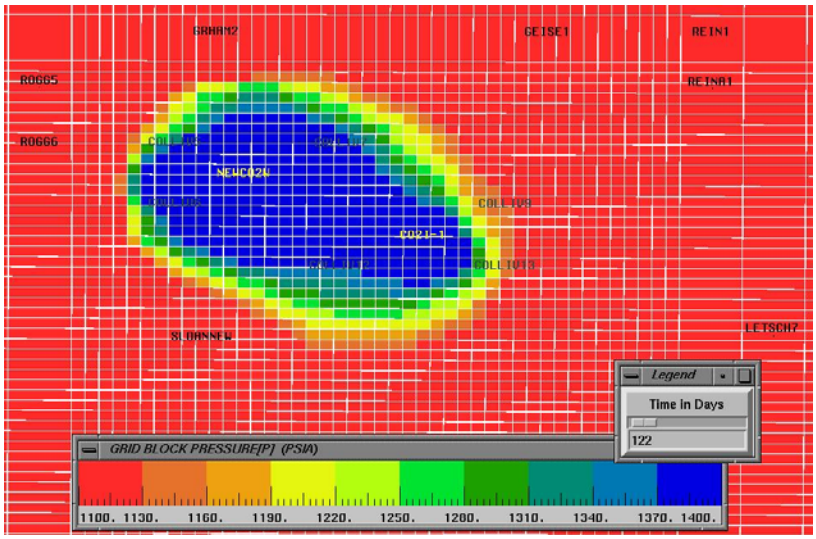

Figure 2. Pressure distribution for 60-acre pattern with no containment wells active. Injection well BHP= 2,000 psi, 13.8 MPa) producing wells are inactive during this pressure buildup phase. Note red indicates pressures of 1,130 psi (7.8 MPa) or less.

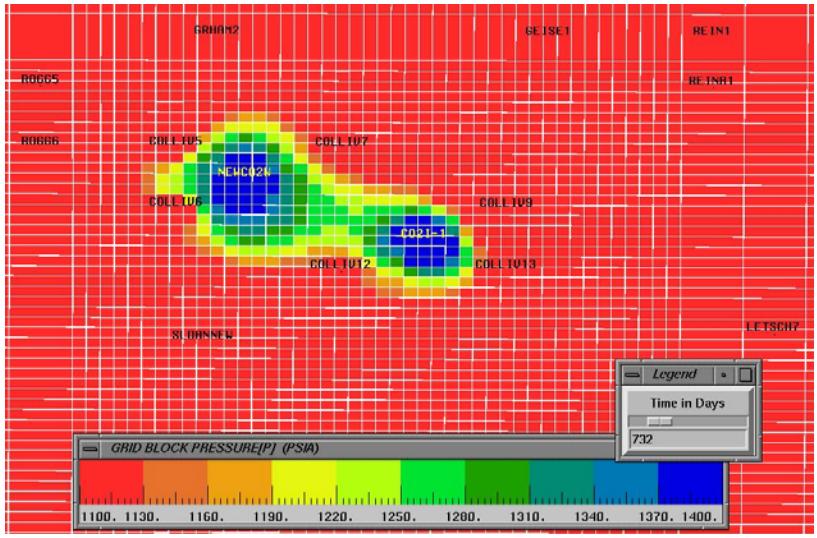

Figure 3. Pressure distribution during flood operations with producers at 600 psi BHP (4.1 MPa) and with only water injection. Note red indicates pressures of 1,130 psi (7.8 MPa) or less.

The exact pressure distribution is a function of the permeability distribution which must still be assessed more accurately by well injection testing.

From well testing, the Carter-Colliver CO2 I#1 well appears to exhibit lower permeability (~800 md-ft; 0.24 um^2-m) than the area surrounding the New CO2 I well to the northwest. Simulation of a 20-acre pattern using only the Carter-Colliver CO2I#1 well as an injector, without a second injector, exhibits a smaller region with pressure above MMP than the two-injector pattern because of the limited injectivity in the CO2 I#1 well (Figures 4 and 5). In this simulation the Carter-Colliver CO2I#1 injection well BHP was 2,000 psi (13.8 MPa). In Figure 3 the producing wells (Colliver #10, #12, #13, and #8) are not on and have a bottom hole pressure of ~800 psi (5.5 MPa), equal to the reservoir pressure. In Figure 5 the producing wells are on and maintain a BHP of 600 psi (4.1 MPa). As with the larger pattern, injection of low-viscosity CO2 would enlarge the area of high pressure. The exact size and distribution of pressure is still not well delineated until data are obtained from well testing and interference testing.

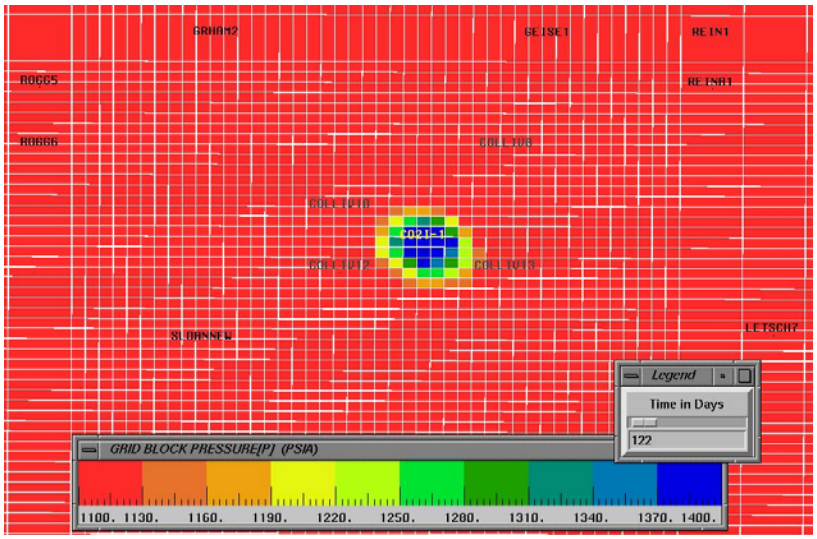

Figure 4. Pressure distribution around Carter-Colliver CO2 I#1 using only water injection in the pressure-up period before the producing wells are turned on. Note red indicates pressures of 1,130 psi (7.8 MPa) or less.

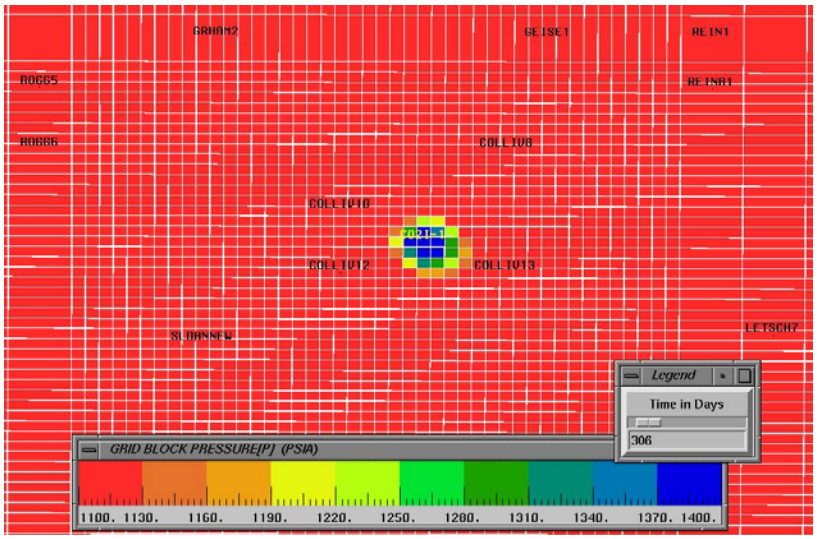

Figure 5. Pressure distribution of 30-acre flood pattern with Colliver #10, #12, #13, and #8 BHP equal to 600 psi (4.1 MPa). Note red indicates pressures of 1,130 psi (7.8 MPa) or less.

Influence of the Number of Layers

The reservoir simulation model was constructed with six (6) layers representing the subdivision of three flood cycles into an upper and lower layer. In this model average layer thicknesses range from 1.5 to 3.7 ft (0.45-1.1 m). Because of the higher mobility ratio of CO2:oil compared to water:oil, the vertical distribution of horizontal permeability exerts greater influence on flood performance and on CO2 breakthrough. Vertical permeability distribution for the flood pattern area is not well defined. The only available data is the core analysis from the Carter-Colliver CO2 I#1 well and core analysis data measured in 1936 on the Colliver #1 in the northeast corner of the lease. The lateral distribution of permeability between wells is not known. To investigate the possible influence of thin, high permeability layers on CO2 flood performance simulations were performed to compare flood performance for models ranging from 6 layers to 20 layers. The distribution of permeability

A model for investigating the influence of layering in the region of the CO2 #1 was constructed. Using permeability and porosity data from the Colliver #1 and the Carter-Colliver CO2 I#1 wells analysis of the permeability data indicated that permeability is both a function of porosity and is a function of depth below the unconformity surface at the top of the Lansing-Kansas City C zone. A multivariate equation was developed that predicted permeability in the CO2 I #1 well:

$$\log_{10}\boldsymbol{k} = -0.18\ \text{Depth} + 0.0036\ \text{Porosity} + 2.23$$

Where k = permeability (md), depth = depth below top of L-KC C zone (ft), and porosity is in percent (%). This equation gives significant weight to depth and is not considered applicable to all L-KC reservoirs but does provide good prediction in this well.

Wireline log porosities, which have been shown to correlate well with core porosities, were obtained at intervals of one-half foot. Permeabilities were predicted from the log porosities for every half-foot. To scale these data up to coarser layers porosity and permeability were

successively averaged to obtained layer values for a 40, 20, 10, 6, and 3-layer model. Permeabilities for each of these models are compared in Figure 6. For each of these models the total and layer-specific average porosity (ϕ), permeability (k), porosity-height (ϕ-h), and permeability-height (k-h) were the same. The models assigned relative permeabilities to each layer based on the layer absolute permeability.

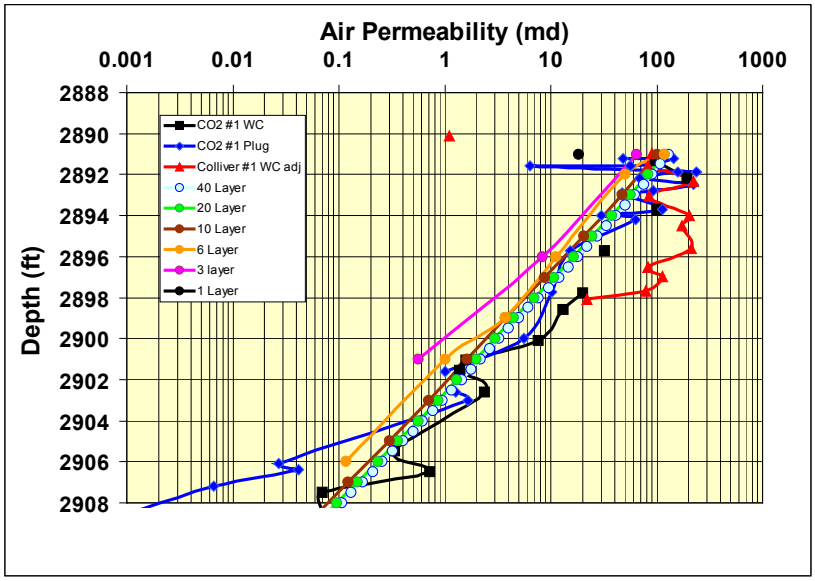

Figure 6. Comparison of permeability distribution for layer models and measured data.

The effect of subdividing the Colliver Carter "C" zone into thinner layers was studied by simulating carbon dioxide miscible flooding in a ¼ 5-spot with an area of 5 acres (2 ha). The dimensions of the ¼ 5-spot were 660 ft (201 m) in the east-west direction and 330 ft (100 m) in the north-south direction (area of exactly 5 acres). There was no flow across the pattern boundaries. The reservoir interval simulated was 20 feet (6.1 m) thick. The reservoir model was subdivided into 3, 6, 10, 20 and 40 layers. Each layer was 0.5 ft (0.15 m) thick in the 40 layer model, 1 foot thick in the 20 layer model and 2 feet thick in the 10 layer model. A 6 layer model corresponding to that used in earlier simulations was assigned thickness of 1 ft, 4 ft, 3 ft, 2 ft, 5 ft, and 5 ft (0.3, 1.2, 0.9, 0.6, 1.5, an 1.5 m) for layers 1 to 6 respectively. Thicknesses of individual layers in the 3 layer model were respectively; 5 ft, 5 ft, and 10 ft (1.5, 1.5, 3.0 m) respectively. Permeabilities were constant in each layer. The ratio of vertical to horizontal permeability was 0.05. Residual oil saturations were assigned to each layer based on the present simulation model. The hydrocarbon pore volume (HCPV) and original oil in place (OOIP) of the model at connate water saturation were ~122.03 MRB (thousand reservoir barrels; $19.4*10^3$ m^3). The oil at the beginning of carbon dioxide flooding was 65.4 MRB ($10.4 *10^3$ m^3) so that primary and secondary recovery was 54 %. Average residual oil saturation was 46%. The bottom hole pressure of the producer was set at 1,000 psia (6.9 MPa) with the following injection sequence: 5 months of CO_2 slug, WAG ratio of 1:1, 10 cycles of WAG injection, and a 3 % HCPV slug size (3,661 RB; 582 m^3).

Comparison of flood results (Figure 7) shows the recovery decreasing with increasing number of layers. A detailed analysis of production from individual layers indicates that the top three zones

corresponding to about 8 feet of reservoir are the most productive (i.e., zones correspond to existing 'C' layers 1,2, and 3, respectively). The thickness of Zone 1 is 1 foot (0.3 m) , Zone 2 is 4 feet (1.2 m) , and Zone 3 is 3 feet (0.9 m).

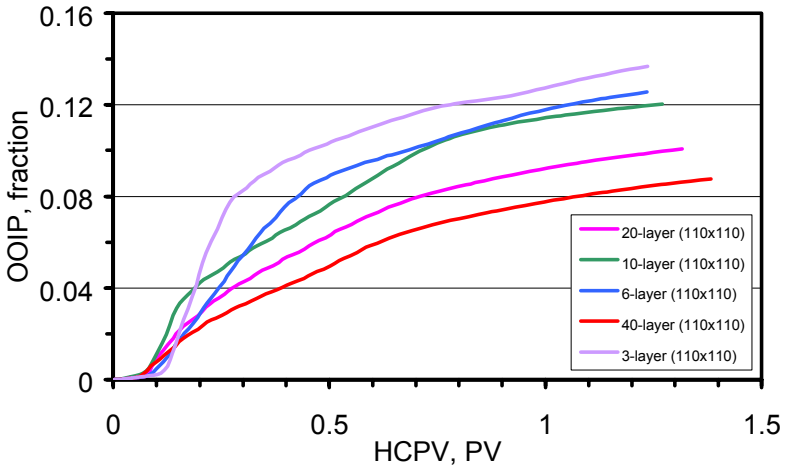

Figure 7. Comparison of oil recovery for different layer models showing decreasing recovery with increasing number of layers.

The effect of vertical permeability on oil recovery from these three zones was investigated by varying the vertical permeability from 0% of the horizontal permeability to 50% of the horizontal permeability. Figure 8 summarizes oil recovery (% residual oil saturation for each zone) at 1 HCPV of fluid injected into the reservoir. Simulation results indicate that recovery decreases when vertical permeability is greater than zero. This is believed to be due to cross-flow and CO2 migration to the top of the interval due to gravity segregation.

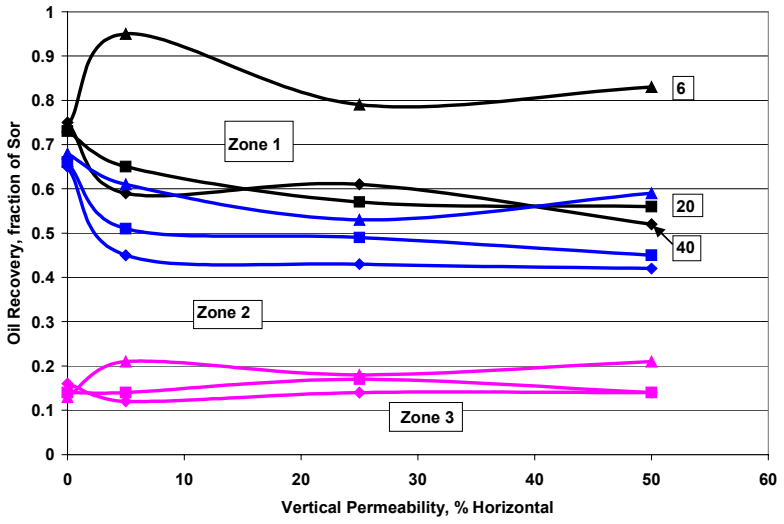

Figure 8. Influence of vertical permeability on oil recovery.

TASK 3.2 ECONOMIC AND RECOVERY ANALYSIS OF PILOT

Economics of the pilot are being reevaluated based on the possibility of lower oil recovery predicted by a reservoir simulation model that uses a greater number of layers.

TASK 7.0 PROJECT MANAGEMENT

Construction of the US Energy Partners ethanol plant in Russell, KS is near complete. In the next quarter the plant will start up and attention will be able to be focused on CO2 delivery to the Pilot.

Two organizational meetings were held in this quarter.

A meeting was held on September 11, 2001 at the Kansas geological Survey the following personnel were present: MV Energy) James Daniels; TORP) Paul Willhite; KGS) Alan Byrnes, Martin Dubois;. Topics covered included: 1) CO2 I#1 build-up analysis, 2) Colliver #7 testing, 3) 60-acre pattern considerations, 4) Project Schedule, and 5) Arbuckle gas composition data.

A teleconference meeting was held on September 14, 2001, the following personnel were present: MV Energy) James Daniels; TORP) Paul Willhite, Don Green, Richard Pancake; KGS) Alan Byrnes, Martin Dubois; Kinder-Morgan) William Flanders, Don Schnacke. Topics covered included: 1) Arbuckle oil and gas sampling; 2) CO2I#1 build-up analysis, 3) layering in the 'C' zone, 4) arrangement for project meeting in October.

TASK 8.0 TECHNOLOGY TRANSFER

1) 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 CO2 Flooding of the Hall-Gurney Field, Central Kansas" was awarded the Jules Braunstein award for best poster at the national meeting. The award will be presented at the 2002 meeting in Houston, TX.

2) The CO2 Demonstration website was updated and the format changed slightly. http://www.kgs.ukans.edu/CO2/index.html

CONCLUSIONS

Build-up analysis of the Carter-Colliver CO2 I#1 indicates lower permeabilities than originally predicted. Present interpretation would indicate that it should have sufficient injectivity for the demonstration but injectivity testing must be performed to confirm this. Refined reservoir simulations, incorporating more layers, indicate that not all containment well will be necessary for the demonstration, which will provide a cost savings. Predicted oil recovery for models with 15, 20, and 40 layers is lower than the present six-layer model and would indicate that if lateral heterogeneity does not exist oil recovery and economics will be lowered. Alternate flood patterns are being investigated that could improve economics. Testing of injection water requirements to prepare for injection in the CO2 I#1 is proceeding and testing of the Colliver #7 and Colliver #10 is being initiated to obtain better understanding of reservoir properties.