**QUARTERLY TECHNICAL PROGRESS REPORT**
**FOR THE PERIOD ENDING SEPTEMBER 30, 2003**

# 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 7, 2009 (BP1 03/00-02/04, BP2 02/04-02/09, BP3 02/09-02/10)

**Reporting Period:** July 1, 2003 – September 30, 2003

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**ABSTRACT:**

Progress is reported for the period from July 1, 2003 to September 30, 2003. Conductivity testing between the CO2I#1 and CO2#13 was performed over the period 08/20/03 through 09/05/03. Observed response in CO2#13 production rates to changes in CO2I#1 injection rates are consistent with sufficient permeability between CO2I#1 and CO2#13 for a viable CO2 flood with a sufficient Process Pore Volume Rate (PPV). Based on the permeabilities near the CO2#16, a 2-producing well pattern has been determined to be optimal but may be changed during the flood depending on the response observed in the CO2#16. Present inter-well test results indicate there is greater permeability architecture complexity than originally predicted and that a low-permeability region or barrier that restricts but does stop flow may exist between the CO2I#1 and the CO2#13. Pilot area repressurization began on 09/05/03, immediately after CO2I#1-CO2#13 conductivity testing was complete, by increasing injection in the CO2I#1, CO2#10, and CO2#18. Adequate reservoir pressure in the portion of the pilot area needed to be above minimum miscibility pressure should be reached in November at which time initial CO2 injection could begin. It is estimated the 2- producing well, 10+-acre (4.05 ha) producing pattern will produce 18,000-21,000 BO (barrels oil; 2,880-3,360 $m^3$). Depending primarily on surface facilities costs, operating expenses, and the price of oil, for the predicted range of oil recovery the pilot is estimated to either break-even or be profitable from this point forward. Final arrangements and agreements for CO2 supply and delivery are being worked on and will be finalized in the next month.

## TABLE OF CONTENTS



## LIST OF FIGURES



## LIST OF TABLES

## INTRODUCTION

**Objectives -** The objective of this Class II Revisited project is to demonstrate the viability of carbon dioxide miscible flooding in the Lansing-Kansas City formation on the Central Kansas Uplift and to obtain data concerning reservoir properties, flood performance, and operating costs and methods to aid operators in future floods. The project addresses the producibility problem that these Class II shallow-shelf carbonate reservoirs have been depleted by effective waterflooding leaving significant trapped oil reserves. The objective is to be addressed by performing a $CO_2$ miscible flood in a 10-acre (4.05 ha) pilot in a representative oomoldic limestone reservoir in the Hall-Gurney Field, Russell County, Kansas. At the demonstration site, the Kansas team will characterize the reservoir geologic and engineering properties, model the flood using reservoir simulation, design and construct facilities and remediate existing wells, implement the planned flood, and monitor the flood process. The results of this project will be disseminated through various technology transfer activities.

**Project Task Overview -**

**Activities in Budget Period 1 (03/00-02/04)** 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 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 (02/04-02/09)** 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 (02/09-02/10)** 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:

Progress is reported for the period from July 1, 2003 to September 30, 2003. Conductivity testing between the CO2I#1 and CO2#13 was performed over the period 08/20/03 through 09/05/03. Observed response in CO2#13 production rates to changes in CO2I#1 injection rates are consistent with sufficient permeability between CO2I#1 and CO2#13 for a viable CO2 flood with a sufficient Process Pore Volume Rate (PPV). Based on the permeabilities near the CO2#16, a 2-producing well pattern has been determined to be optimal but may be changed during the flood depending on the response observed in the CO2#16. Present inter-well test results indicate there is greater permeability architecture complexity than originally predicted and that a low-permeability region or barrier that restricts but does stop flow may exist between the CO2I#1 and the CO2#13. Pilot area repressurization began on 09/05/03, immediately after CO2I#1-CO2#13 conductivity testing was complete, by increasing injection in the CO2I#1, CO2#10, and CO2#18. Adequate reservoir pressure in the portion of the pilot area needed to be above minimum miscibility pressure should be reached in November at which time initial CO2 injection could begin. It is estimated the 2- producing well, 10+-acre (4.05 ha) producing pattern will produce 18,000-21,000 BO (barrels oil; 2,880-3,360 $m^3$). Depending primarily on surface facilities costs, operating expenses, and the price of oil, for the predicted range of oil recovery the pilot is estimated to either break-even or be profitable from this point forward. Final arrangements and agreements for CO2 supply and delivery are being worked on and will be finalized in the next month.

## RESULTS AND DISCUSSION:

### TASK 2.3. Remediate and Test Wells and Pattern
*2.3.2 Workover and Test Producing Wells in Pilot Area –*

CO2 Project #13 – Production rate tests last quarter were consistent with an average reservoir absolute permeability of ~80 md (millidarcy; 0.079 $\mu m^2$) surrounding the CO2#13 but did not confirm sufficient conductivity between the CO2I#1 and the CO2#13 wells for adequate flood rates for the demonstration. To confirm adequate conductivity between the CO2 I#1 and CO2 #13 wells, a conductivity test was conducted over the period 08/20/03 through 09/05/03 in which the injection rate of CO2 I-1 was reduced from ~140 BWPD to ~70 BWPD (barrels water per day; 22.4-11.2 $m^3$/d) while continuing to produce and pump-off CO2 #13. The test for conductivity was based on observation of production rate falling below the pre-test hyperbolic production rate decline trend defined for CO2#13 at CO2I#1 injection rates of ~140 BWPD (22.4 $m^3$/d). Figure 1 shows that production rates from the CO2#13 decreased from ~ 72 BPD (barrels per day) to ~ 63 BPD (11.5-10.0 $m^3$/d) over a 2 week period. This observed production rate decline trend for the CO2#13 fell preceded the trend predicted by reservoir modeling, indicating slightly better conductivity. Rates are consistent with sufficient permeability between CO2I#1 and CO2#13 for a viable CO2 flood with a sufficient Process Pore Volume Rate (PPV).

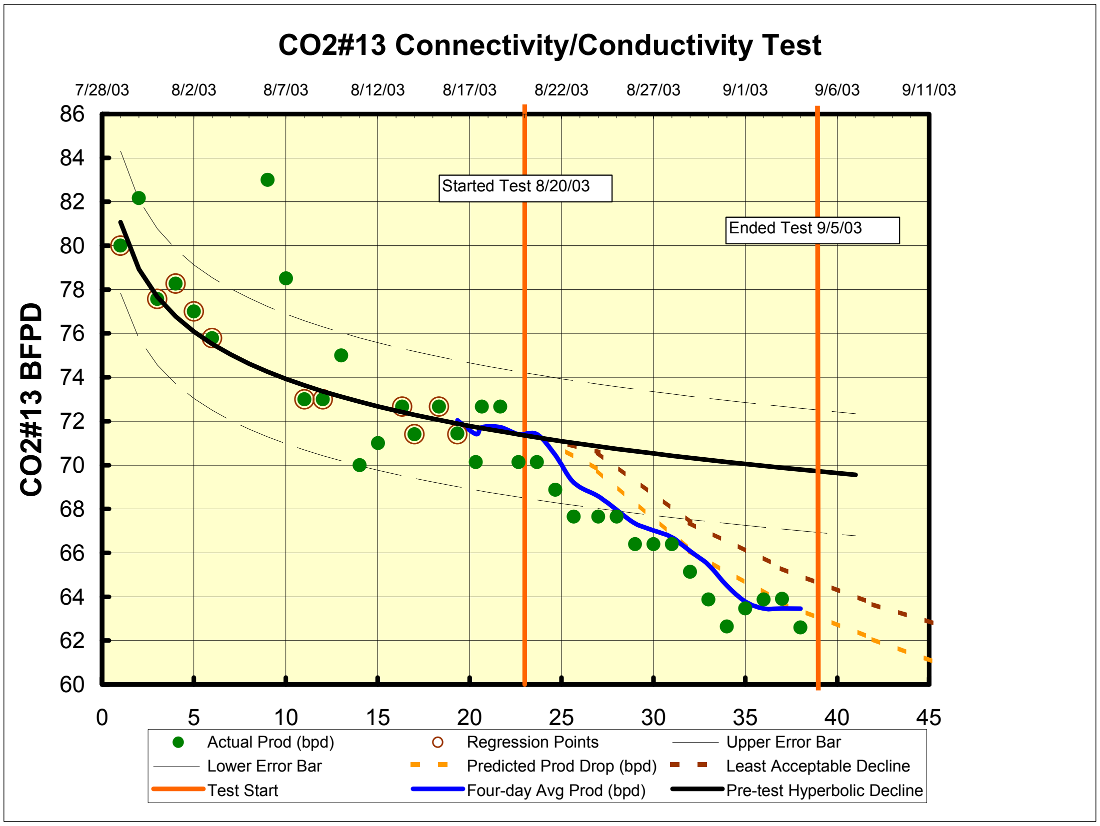


**Figure 1.** Production rates for the CO2#13 well prior to start of CO2I#1-CO2#13 conductivity test and during test. The change in CO2#13 production confirmed sufficient conductivity for adequate flood rates between the wells. (1bwpd = 0.16 $m^3$/d, 1 bbl = 0.16 $m^3$, 1 psig = 6.89 kPa)

<u>*2.3.5 Construct Surface Facilities –*</u> Between 09/09/03 and 09/15/03 a 350-foot (107 m) trench was dug from the water production plant to the CO2#10 wellhead and 330-foot (100 m) new Centron 2" (5 cm) 1,500 psi (pounds per square inch; 10.3 MPa) fiberglass pipe were laid. The line was pressure tested to 1,000 psi (6.9 MPa) using water and three very small seeps were repaired (Figure 2).

**Figure 2.** Laying fiberglass injection line from the water supply plant to the CO2#10 water injection containment well. View is looking to the northwest.

Between 09/15/03 and 09/16/03 a 240-foot trench was dug from the CO2 pump site SE to the lease road crossing and a 735-foot (224 m) trench was dug from the lease road to the CO2I#1 wellhead. Lines to the Colliver #7 and the CO2#13 were cut and modified. 980-feet (300 m) of 2" (5 cm) SCH 80 CO2 steel injection pipe were welded and pressure tested to 1,550 psi (10.7 MPa) using water and placed in the ditch and the ditch back-filled to near the CO2I#1 wellhead.

On 09/16/03 the CO2#18 was treated with 500 gallons (1,890 L) of 15% NE-FE acid containing 5% solvent to improve injectivity.

On 09/30/03 Murfin ordered a 3-phase separator from McDonald Tank of Great Bend, Kansas. The separator will be used to individually measure the oil, water, and gas production.

2.3.6 Pattern Repressurization and Analysis – Following completion of the CO2I#1-CO2#13 conductivity test and confirmation of adequate conductivity between these wells the injection rate in CO2I#1 was increased to 140 BWPD (barrels water per day; 22.4 $m^3$) on 09/05/03 to begin repressuring the pilot area in preparation for CO2 injection. Water injection began in the CO2#10 and CO2#18 containment wells on 09/15/03 and 09/16/03, respectively. Pilot area reservoir pressure is increasing and is predicted to reach sufficient pressure for CO2 injection in November. With increasing reservoir pressure and injection in the CO2#10 and CO2#18 injection rates in the CO2I#1 will decrease (Figure 2). Injection water for CO2 #18 is supplied by the existing produced-water injection system. Water injection into CO2#18 is cyclic due to a shortage of produced water at that plant. Maximum injection pressures of 640 psig (pounds per square inch gauge; 4.4 MPa), 500 psig (3.5 MPa), and 560 psig (3.9 MPa) have been set for CO2I#1, CO2#10, and CO2#18, respectively. Pressure relief valves are used to regulate the individual injection pressures (water is circulated back to the injection tank to maintain the desired pressure).

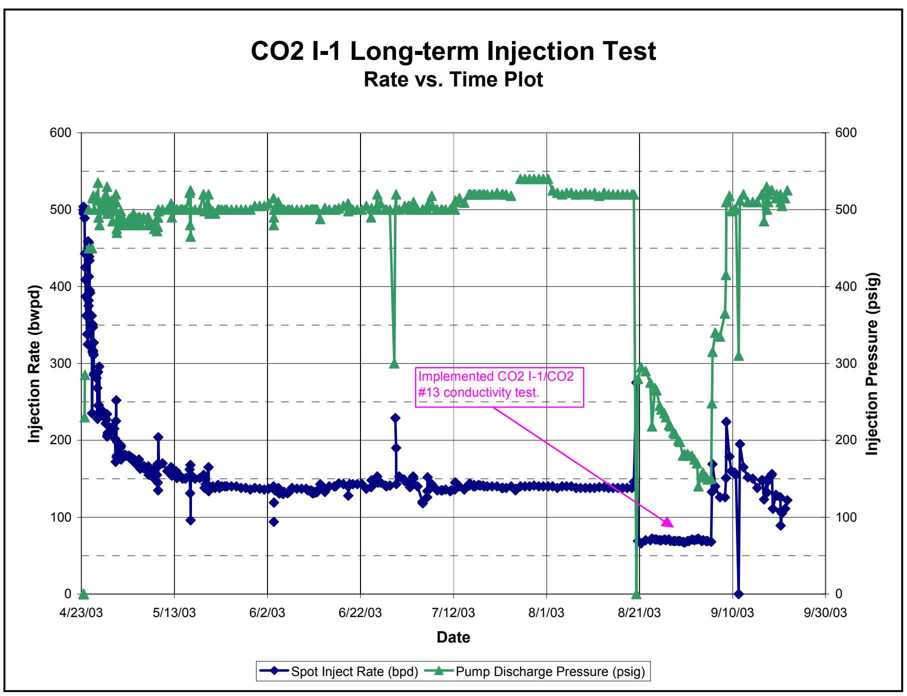


**Figure 3.** Bottom-hole pressure (BHP) and injection rate of the CO2I#1 through time and notes marking events. . (1bwpd = 0.16 $m^3$/d, 1 bbl = 0.16 $m^3$, 1 psig = 6.89 kPa)

**TASK 3.1. Reservoir Simulation (Phase 2)**
The new reservoir properties data obtained last quarter and the well test data have indicated greater permeability architectural complexity than previously modeled, a not uncommon situation. The process pore volume rate between the CO2I#1 and the CO2#16 is sufficiently low that without stimulation of the CO2#16 the PPV is too low to properly process the region within the demonstration time period. The flood is presently planned to produce only from the CO2#12 and CO2#13 and to monitor the CO2#16 (Figure 4).

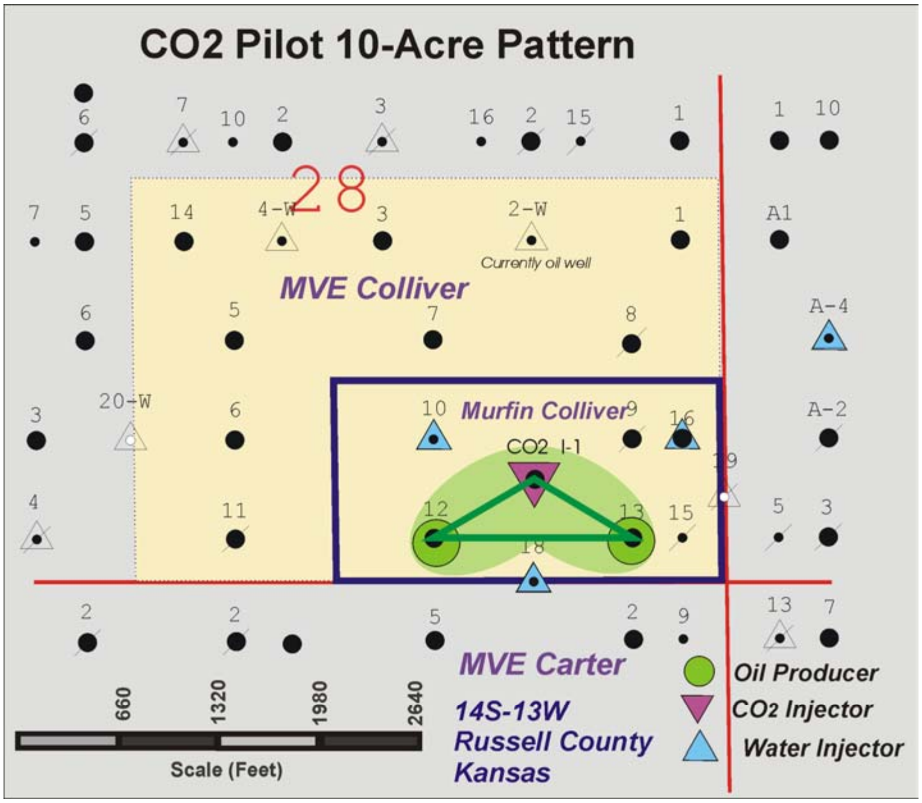


**Figure 4.** Present design of CO2 pilot comprising the CO2I#1 CO2 injection well, two containment wells (CO2#10, CO2#18), two producing wells (CO2#12, CO2#13) and an observation well that may be changed in status depending on response (CO2#16).

If the CO2#16 shows indications of the movement of an oil bank consideration will be given to well stimulation. Model-generated flowlines for the 2-producing well pattern indicate that this pattern should provide 80-85% containment (Figure 5) and is predicted to recover 18,000-21,000 BO (2,880-3,360 $m^3$). Several models have been constructed to simulate different alternate working hypotheses for reservoir permeability architecture. Table 1 illustrates predicted permeabilities at and near wellbores for leading 2-layer models and/or reservoir properties calculated from various tests interpreted by the Tertiary Oil Recovery Project (TORP) and at Transpetco Engineering (TPE; consulting for Kinder-Morgan CO2 Company). The table also shows predicted permeabilities based on porosity-permeability transforms.

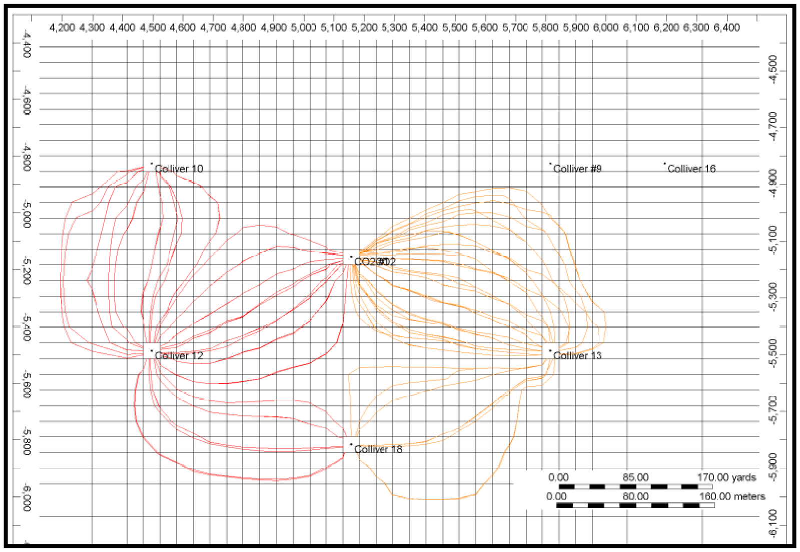


**Figure 5.** Flowlines generated by computer model of pilot area using permeability distributions shown in Table 1.

| Well | Core Perm Avg (md) | Log $\phi$ only Perm Avg (md) | TPEC Perm Avg (md) | core Layer 1 Perm (md) | log $\phi$ only Layer 1 Perm (md) | TORP Layer 1 Perm (md) | TPEC Layer 1 Perm (md) | core Layer 2 Perm (md) | log $\phi$ only Layer 2 Perm (md) | TORP Layer 2 Perm (md) | TPEC Layer 2 Perm (md) |
|---|---|---|---|---|---|---|---|---|---|---|---|
| CO2 I#1 | 88 | 72 | 85 | 115 | 94 | 117 | 134 | 20 | 47 | 117 | 35 |
| Colliver 10 | | 33 | 48 | | 55 | 117 | 80 | | 14 | 17 | 15 |
| Colliver 12 | | 66 | 60 | | 95 | 117f | 100 | | 37 | 50 | 19 |
| Colliver 13 | | 62 | 79 | | 44 | 10 | 38 | | 81 | 117 | 120 |
| Colliver 16 | 25 | 36 | 26 | 10 | 58 | 10 | 17 | 37 | 26 | 20 | 34 |
| Colliver 18 | | 133 | 30 | | 172 | 53f | 50 | | 108 | 117 | 10 |
| Main Reservoir | | | 112 | | | 117 | 188 | | | 117 | 36 |
| W of #13 | | | 72 | | | | 64 | | | | 80 |
| E of #13 | | | 110 | | | | 80 | | | | 140 |

f-indicates fracture or enhanced permeability channel may influence CO2#12-CO2#18 connection

**Table 1.** Summary of Lansing-Kansas City 'C' zone permeability in and near wells in pilot pattern measured from core and interpreted from well tests and used in computer models of the pilot. Permeabilities are shown for leading 2-layer models created by the Tertiary Oil Recovery Project (TORP) and Transpetco Engineering (TPE; consulting for Kinder-Morgan).

Conductivity test results between CO2I#1 and CO2#13 are interpreted to indicate the presence of a lower permeability region or barrier between the two wells that restricts but does stop flow. Based on the differences in permeability between the upper and middle intervals in the two wells, it is interpreted that the uppermost interval decreases in permeability from the CO2I#1 towards the CO2#13 and the middle interval increases in permeability. A lower permeability barrier between the upper and middle intervals, possibly reflecting a low-permeability bedset contact, could decrease composite permeability and explain the lower conductivity between CO2I#1 and CO2#13 compared to between the CO2I#1 and CO2#12. Further analysis is being performed.

**TASK 3.2 Economic and Recovery Analysis of Pilot**

*3.2.1 Determine CO2 Source for Pilot* – In the previous quarter Murfin signed an agreement with FLOCO2 of Odessa, Texas for FLOCO2 to provide CO2 storage and injection equipment to the pilot in exchange for Kinder-Morgan CO2. The Murfin/FLOCO2 agreement will be initiated in October. Discussion of logistics and timetables with US Energy Partners and EPCO for CO2 supply will be initiated when a decision to inject CO2 is made. Discussions were held between Murfin, USEP, and EPCO to finalize contracts for CO2 supply. Discussions were initiated with the City Council of Russell concerning possible reduction of energy surcharges to EPCO for liquid CO2 supplied to the project. Possible relief from surcharges will be considered by the City Council in the fourth quarter.

*3.2.3 Design Facilities for Pilot and Monitoring -* Facilities specifications have been designated for the 10+-acre pattern but require further quantification to be consistent with the final pattern design. Recent testing and reservoir modeling indicate that the 3-phase separator should be sized for a maximum fluid production of 250 BFPD (40 $m^3$) and gas rate of 200 mcf/D (thousand cubic feet per day; 5,660 $m^3$/d). Gas rates are expected to average 66 mcf/d and peak around 100 mcf/D (2,830 $m^3$/d). Actual production rates would not exceed the injection rates. Controlling injection rates to the 14% PPV rate would result in a maximum CO2 production rate of 125-140 mcf/D (3,540-3,960 $m^3$/d). Separators are rated based on HC gas production. Generally 2.5 times the CO2 rate is required for the HC gas design rate due to the high density of CO2 and higher affinity it has for oil.

*3.2.5 Economic Forecasts-* Economic forecasts for the pilot project have been run but will be modified with improved reservoir characterization and modeling. Based on current predicted oil recovery estimates for the 2-producer pattern (CO2#12 and CO2#13 producing) economics are primarily influenced by remaining surface facilities costs, operating costs, and oil price. Table 1 shows estimated costs from this point forward for assumed remaining surface facilities and lease operating expenses and at an oil price of $23/barrel. These estimates indicate that the project could show profit from this point forward if lease costs can be kept low. At projected surface facilities and lease costs but with only 18,000 BO (2,880 $m^3$). recovery the project will show a slight loss.

| Wells in Operation | Oil Recovery BO (BO) | Surface Facilities Costs ($) | Lease Operating Expense Factor (%) | Profit (BFIT) ($) |
|---|---|---|---|---|
| 12,13 | 21,000 | $82,613 | 90 | $93,152 |
| 12,13 | 21,000 | $82,613 | 100 | $65,767 |
| 12,13 | 21,000 | $118,019 | 90 | $51,162 |
| 12,13 | 18,000 | $118,019 | 100 | ($2,224) |

blue indicates modified lower cost conditions

**Table 2.** Estimated economics from this point forward for various oil recovery, surface facilities, and lease operating expense scenarios and for an oil price of $23/BO. (1bwpd = 0.16 $m^3$/d, 1 bbl = 0.16 $m^3$, 1 psig = 6.89 kPa)

## TASK 7.0 PROJECT MANAGEMENT

Various members of the Kansas CO2 Team communicated on a nearly daily basis by telephone and email over specific technical or business issues. Group conference calls were held on April 07/11/03, 08/19/03, 09/11/03, 09/03/03 and meetings were held in Wichita, KS and Lawrence, KS on 07/24/03 and 09/03/03, respectively. The following personnel have participated in one or more calls, emails, and meetings: Murfin Drilling) James Daniels; Stan Froetschner, Kevin Axelson, Tom Nichols; Tertiary Oil Recovery Project) Paul Willhite, Richard Pancake; Kansas Geological Survey) Alan Byrnes, Martin Dubois; Kinder-Morgan) William Flanders, Don Schnacke. Topics covered have included: 1) Water supply quality, 2) Well test analysis procedures and results, 3) CO2 supply, storage and injection facilities, 4) Reservoir properties, 5) Project economics, and 6) project management. A meeting was held at the USDOE office in Tulsa, OK on 07/25/03 with the following participants; Tertiary Oil Recovery Project) Paul Willhite; Kansas Geological Survey) Alan Byrnes; USDOE) Dexter Sutterfield, Paul West, Rhonda Lindsey, Dan Ferguson, and Gary Walker. The project status and plans were reviewed and discussed.

## TASK 8.0 TECHNOLOGY TRANSFER

An article by Pam Stoedart appeared in the Russell Daily News on Friday, Sept 26, 2003. The article reviewed the project, present status, and potential impact to Russell and the state of Kansas.

# CONCLUSIONS

Conductivity testing between the CO2I#1 and CO2#13 has completed the inter-well testing needed to confirm the flood pattern will provide a viable demonstration. Based on the permeabilities near the CO2#16, a 2-producing well pattern has been determined to be optimal but may be changed during the flood depending on the response observed in the CO2#16. Present inter-well tests results indicate there is greater permeability architecture complexity than originally predicted. Present injection in the CO2I#1, CO2#10, and CO2#18 should increase reservoir pressure in the necessary portion of the pilot area above minimum miscibility pressure by November at which time initial CO2 injection could begin. It is estimated the 2-well, 10+-acre (4.05 ha) producing pattern will produce 18,000-21,000 BO (2,880-3,360 $m^3$). . Depending primarily on surface facilities costs, operating expenses, and the price of oil, for the predicted range of oil recovery the pilot is estimated to either break-even or be profitable from this point forward.