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APPLICATIONS OF ADVANCED PETROLEUM PRODUCTION
TECHNOLOGY AND WATER ALTERNATING GAS INJECTION FOR
ENHANCED OIL RECOVERY - MATTOON OIL FIELD, ILLINOIS

Final Report

By
M. Baroni

September 1995

Performed Under Contract No. DE-FC22-93BC14955

American Oil Recovery, Inc.
Decatur, Illinois

**Bartlesville Project Office
U. S. DEPARTMENT OF ENERGY
Bartlesville, Oklahoma**

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Oil Recovery - Mattoon Oil Field, Illinois

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Prepared for
U.S. Department of Energy
Assistant Secretary for Fossil Energy

Edith Allison, Project Manager
Bartlesville Project Office
P.O. Box 1398
Bartlesville, OK 74005

Prepared by
American Oil Recovery, Inc.
4666 Faries Parkway
Decatur, IL 62525

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EXECUTIVE SUMMARY

Phase I results of a CO₂-assisted oil recovery demonstration project in selected Cypress Sandstone reservoirs at Mattoon Field, Illinois are reported. The design and scope of this project included CO₂ injectivity testing in the Pinnell and Sawyer units, well stimulation treatments with CO₂ in the Strong unit, and infill well drilling, completion and oil production. The field activities were supported by extensive CO₂-oil-water coreflood experiments, CO₂-oil phase interaction experiments, and integrated geologic modeling and reservoir simulations. The progress of the project was made public through presentations at an industry meeting and a DOE's contractors' symposium, through quarterly reports and one-to-one consultations with interested operators. Phase II of this project was not implemented. It would have been a water-alternating-gas (WAG) project of longer duration.

Five Cypress Sandstone layers ("A", "B", "C", "D", "E") were identified within the study area in Mattoon Field. 3-D geologic models, created from well data, were used to interpret the location, size and continuity of the productive intervals. The CO₂ injectivity tests were performed in the "A" interval in the Pinnell unit, "E" interval in the Sawyer unit and "D" interval in the Strong unit.

Poor inter-well communication and limited areal extent of the Cypress Sandstone "A" interval at the Pinnell unit were confirmed by CO₂ injectivity tests and reservoir simulation. Inefficient displacement of reservoir crude oil by the injected CO₂ was caused by reservoir heterogeneity and attendant gas channelling.

Injectivity tests in the Sawyer unit showed good inter-well communication. An infill well, the No. 15 AOR/Seaman, was drilled, cored, completed and produced. Results of core sample analyses from the project infill well verified the isolation of the target "E"-sandstone interval from the extensively waterflooded lower "B" and "C" sandstone intervals. Reservoir simulation results indicated that a significant amount of

additional oil may be recovered by the implementation of a water alternating gas (WAG) injection program.

Injectivity tests in the Strong unit consisted of "huff and puff" treatments with CO₂ in two wells. Initial results from one of the wells were very encouraging. No significant response was obtained from the other. Simulated results of "huff and puff" treatments with CO₂ in the Cypress Sandstone demonstrated that the "rule of thumb" volume of 20 tons of CO₂ per perforated foot of pay constituted overtreatment. Slug sizes of 5% hydrocarbon pore volume (HCPV) and 10% HCPV improved simulated oil production rates above the decline curve while 20 tons/per perforated foot (73% HCPV) reduced oil production rates below the pre-injection levels. The injectivity tests in the Strong unit demonstrated that single well "huff and puff" well treatments may be the most cost-effective in mature fields like the Mattoon field where the well integrity is questionable and where well re-completion costs are high.

A minimum miscibility pressure (MMP) test indicated that implementation of a miscible CO₂ flood was not be possible in the project area. However, field injectivity tests with CO₂ showed that oil recovery was significant at pressures below miscibility conditions.

Fluid compatibility tests showed that Cypress sandstones at Mattoon Field are freshwater sensitive and that permeability was reduced when contacted with fresh water. However, pre-treatment with brines containing 2% potassium chloride was shown to prevent permeability reduction in a Cypress core sample. Several CO₂-water, CO₂-oil and water-oil relative permeability curves, interpreted from unsteady state experiments with these fluids, were reported and also used in the reservoir simulation models. Furthermore, compositional and pressure-volume-temperature (PVT) analyses of Mattoon crude oil and CO₂ mixture were reported and used for reservoir simulation.

Technology transfer activities included presentations at the Illinois Oil and Gas Association (IOGA) annual meeting in Evansville, Indiana, and a DOE-sponsored Contractors' Review Conference in

Checotah, Oklahoma. Five quarterly reports were written. Reviews were also conducted on one-to-one basis with interested independent operators in the basin.

INTRODUCTION

Brief History

This project, supported by a cost-shared agreement (Cooperative Agreement No. DE-FC22-93BC14955) between the United States Department of Energy and American Oil Recovery, Inc. (AOR), is part of a larger DOE program designed to recover bypassed oil from fluvial deltaic "Class I" reservoirs. Cypress Sandstone fluvial deltaic reservoirs in Mattoon Field, Coles County, Illinois were selected for demonstration of CO₂ utilization in improved oil recovery from a partially depleted mature field.

The Mattoon Field, Illinois (Fig. 1), was discovered in June, 1940. Development included approximately 420 producing wells and 90 dry holes drilled on ten-acre spacing. Oil production from Mattoon Field was principally from Cypress, Rosiclare and Aux Vases Sandstone reservoirs of the Mississippian system. Secondary waterflood recovery from several Mattoon reservoirs was initiated in 1952. At March 1993, the cumulative oil production from Mattoon Field was 21 million barrels. Fig. 1 shows the locations of the CO₂ injection project areas and wells within the Mattoon Field.

General Characteristics of Cypress Sandstone Reservoirs

Cypress sandstones have produced more than 1 billion barrels of oil in the Illinois Basin. These Chesterian (late Mississippian) sandstones are the most widespread, thickest, and productive sandstones in the Basin (Howard, 1990). Cypress sandstones can be 200 feet thick locally.

Earlier work described the Cypress sediments as fluvial-deltaic in origin (Potter 1962 1963, Potter and Pryor 1961, Swann 1963, 1964, Seyler 1982a, 1982b). Recent work (Oltz, 1994, McGee, in prep.)

showed that deposition varies from deltaic to coastal to offshore marine. The depositional system is complex and environmental interpretations are hindered by rapid lateral and vertical changes, a characteristic of low-slope, stable, intracratonic basins (Leighton et al, 1990).

Recent studies of Cypress reservoir sandstones show that they may consist of up to five or more stacked sandbodies or layers (Oltz, 1994, Whitaker, et al., 1992, Grube, 1992 and Udegbumam and Grube, 1993). Because of the variations in reservoir quality, some layers are not as efficiently swept as others during waterflooding. Such layers will contain more bypassed mobile oil than others. Typical ultimate recovery factors in Cypress reservoirs after waterflooding may approach or even exceed 40% (Udegbumam and Grube, 1993, and Lewis, 1949). The bypassed mobile oil volume may be relatively low. However, the immobile oil saturation is typically high. Udegbumam and Grube (1993) determined that over 45% of the original oil-in-place in the Cypress sandstone reservoirs at Lawrence Field are immobile and cannot be recovered by waterflooding. CO₂ injection can improve recovery of both remaining mobile and immobile oil.

Project Objectives

Project objectives include:

- characterize the Cypress Sandstone reservoirs
- identify and map facies-defined waterflood subunits (FDWS)
- design and implement an improved oil recovery program utilizing carbon dioxide in the field, and
- transfer the technology to the oil and gas industry.

Phase I of the project, which included site selection, CO₂ injectivity testing, computer-assisted generation of geological and reservoir simulation models of the Mattoon Field, drilling, completion and production of AOR-Seaman No. 15 infill well, and laboratory experiments, is reported.

Phase II of the project, a demonstration of field implementation of WAG technology, was not implemented.

Division of labor for the project

The initial design of this project and the field maps were done by Sigma Consultants of Mattoon, Illinois. All laboratory experiments, geological modeling and numerical reservoir simulation of CO₂ injection processes reported herein were conducted at the Illinois State Geological Survey. All field activities - selection of project areas, design of CO₂ displacement processes and CO₂ injection volumes, well preparations and completions, oil production, data gathering and interpretations - were carried out by American Oil Recovery, Inc. Bretagne, Inc. provided the technical support for the CO₂ field injectivity tests.

SITE SELECTION

General Geology

The following descriptions of Cypress sandstone bodies are excerpted from McGee (in prep.) and from the DOE final contract report, "Improved and Enhanced Oil Recovery in Illinois Through Reservoir Characterization", (Oltz, 1994).

The Cypress sandstones in Mattoon Field range in thickness from 64 feet in the northeast to 103 feet in the south. The Cypress was divided into separate intervals for interpretation and mapping. In ascending order, these are the "A", "B", "C" or "B/C", "D", and "E" intervals (fig. 2). Reservoirs within these intervals are not uniformly present across the field. These reservoirs can range from 5 feet to greater than 40 feet thick, ½ to ¾ mile wide, and up to 2½ miles long. They exist as single, multiple, en echelon, stacked

or coalesced, north-south-oriented, lenticular sandstone bodies encased in shale.

"A" Interval Reservoirs in this interval are characteristically less porous and permeable than reservoirs in other Cypress intervals. Reservoirs in the "A" interval are a diversity of mixed carbonate-siliciclastic lithofacies; cement and fossil assemblages differentiate them from reservoirs in other Cypress intervals in Mattoon Field. The separate, elongate sand bodies are 2 to 3 miles long, $\frac{3}{4}$ mile wide, and 3 to 13 feet thick. Smaller (10–40 acre) isolated pods are oriented in various directions. Where they occur, A sandstone bodies typically have clean sandstone lithology in the central core and laterally grade into mixed clastic/bioclastic and fossiliferous limestone along their edges. The average thickness ranges from 5 to 9 feet in the sandstone facies, 4 to 10 feet in the calcareous sandstone facies, 6 to 8 feet in the sandy limestone facies, and 3 to 4 feet in the limestone facies. Several isolated and untested sandstone bodies in the "A" interval offer potential for oil discovery.

In the project area, the "A" interval occurs on the Pinnell lease, and on two areas along the western margin of the Uphoff and Seaman leases (fig. 3). Over 60% of the project area does not contain the "A"-interval. CO₂ was injected into this interval in the Pinnell lease.

"B" Interval The B interval (fig. 4) occurs throughout most of the project area, with the exception of a limited area in the Pinnell lease, and elsewhere in a few other small shaded-out areas. The "B" interval is interpreted as a delta-fringe sandstone. The sandstone typically has fair permeability and attains a thickness of more than twenty-five feet at one location in the southwestern part of the field. However, it is commonly less than fifteen feet thick in the project area. CO₂ was not injected into this interval.

"C" Interval Geologic mapping indicates that the "C" reservoir (fig. 5) occurs as two thick (20–25 feet) southward trending sandstone bodies interpreted to be distributary channel fill and overbank deposits - one lying parallel to the eastern margin of the Mattoon project area and a second channel-fill deposit extending

across the western one-third of the area. The channels appear not to be deeply incised into adjacent interdistributary delta clay deposits. These deposits grade laterally into deltaic strand plain sandstone deposits which are much thinner and occur in the central part of the project area. The "C" sandstone is entirely replaced by siltstone and shale on the northern part of the Pinnell lease. CO₂ was not injected into this interval.

"D" Interval Sandstone bodies in this interval have excellent porosity and permeability in the northern half of the field (fig. 6). Reservoir quality in this interval deteriorates in the southern half of the field where interbedded shale and siltstones predominate. Depending on geographic location in Mattoon Field, this interval may be completely shale or appear as a single sandstone characterized by a coarsening-upward (progradational) grain-size profile. The "D" interval occurs in the Strong lease area of the project. CO₂ were injected into the "D" interval in the Strong lease.

"E" Interval This Cypress interval consists of two sandstones separated by shale and mapped individually as the upper and lower "E" intervals. Depending on geographic location in the field, either the upper or lower sandstone body may be replaced by shale or the two sandstones may coalesce with the intervening shale absent (figs. 2 and 7). Sandstones of the lower "E" interval are best developed in the southern half of Mattoon Field, whereas sandstones within the upper "E" interval extend throughout the length of the field. Where developed, sandstones within both intervals may have basal coarsening-upward profiles commonly capped by a fining-upward sequence. These elongate sandstone bodies are encased and generally compartmentalized by interbedded shales. They are typically well sorted, silty to very fine grained quartz arenites, but generally form the lowest quality reservoirs in the Cypress Sandstone because of the abundance of interbedded shale layers in the interval. The "E" sandstone was the target interval for the CO₂ injection in the Sawyer unit. The E sandstone was previously thought to contain mainly unswept

mobile oil.

Geological Modeling and 3-D visualization

A three-dimensional geologic model of the Cypress Sandstone of the project area in Mattoon field was created using the Stratigraphic Geocellular Modeling (SGM™) software. This model used data from 230 wells in the Pinnell, Sawyer, and Strong project areas as well as other leases in Mattoon Field. The geologic models of the Mattoon Field formed the stratigraphic framework for reservoir simulation of the CO₂ injectivity testing, and subsequent predictions of oil recoveries from various CO₂-assisted recovery processes.

The 3-D visualizations produced by SGM assisted in the interpretation of the location, continuity and size of the productive intervals. Distribution of the "A", "B", "C", "D" and "E" intervals are shown in Figs. 8, 9 & 10.

Pinnell unit The "A" sandstone (lowest) can be seen in the project area of the Pinnell unit (figs. 8 & 9). The "A" sandstone is compartmentalized and is not continuous throughout the Pinnell unit. The "B" sandstone is present between the No. 3-W Pinnell (gas injection well) and No. 1 Pinnell-Uphoff (oil-producing well). Records show that the "B" sandstone was completed by fracturing and produced prior to this project (David Blake, American Oil Recovery, Inc., personal communication). The "A" sandstone was not open to the wellbore and was perforated during this project.

Sawyer unit The target interval for CO₂ injectivity testing in the Sawyer unit was the "E" sandstone (topmost interval - figs. 8 & 10). The "B" and "C" intervals vary from 20 feet to more than 40 feet in the project area of the Sawyer unit but have been extensively produced and waterflooded. There is no information to indicate whether the "E" interval was open or not in the Sawyer unit wells.

Strong unit The target interval for CO₂ injectivity testing in the Strong unit was the "D" interval

sandstone (fig. 8). The Strong unit is directly east of the Sawyer unit. The "D" interval had not been opened in the project area prior to project onset.

FIELD CO₂ INJECTIVITY TESTING

STANDARD WELL WORKOVER PROCEDURE

Many wells in the Mattoon Field lacked mechanical integrity. This may be true of wells in other mature fields. The cost of re-working every well in a given project area is prohibitive. Consequently, only wells vital to the operation of the project were re-worked.

The standard well workover procedure adopted in the project included the following:

- A. Isolate the target pays with retrievable plugs
- B. Check for communication with other intervals
- C. Clean out well and establish injectivity into target pay(s)
- D. Inject CO₂.

Wells that were not open to the target pay(s) were perforated. In every case, the tubing was pulled, inspected, pressure-tested, replaced if leaky, and re-installed before CO₂ injection. The workover procedure for CO₂ injection involved replacement of wellhead equipment and valves when necessary. Costs for reworking a typical well for CO₂ injection are discussed in Appendix A.

PINNELL CO₂ INJECTION UNIT

Prior to the injectivity testing, the "A" sandstone in the No. 3W Pinnell (fig. 11) was perforated, acid-cleaned and isolated from other sandstones with a packer. Approximately 2800 tons of liquefied CO₂ was injected into the "A" sandstone in the Pinnell Lease from 12 April, 1993 to 14 May, 1993 at an average rate of 11.27 tons per hour or 1.2 BPM. The average CO₂ injection pressure was 597.8 psig. Shut-in surface pressure after 45 days was 740 psig. The estimated bottom hole pressure was 850 psig. The CO₂ was

injected into the 3W Pinnell well while the No. 1 Pinnell Uphoff well was monitored. Gas chromatographic analyses of the produced gas from the No. 1 Pinnell Uphoff well showed 5.6 percent CO₂ on 29 April, 1993 and 72.9% CO₂ on 17 May, 1993, indicating gas breakthrough and thus establishing connectivity between the No. 3-W Pinnell and No. 1 Pinnell-Uphoff wells in the "A" interval. Throughout the injectivity testing, the annulus and tubing pressures of the No.3W Pinnell well continued to rise. Daily oil production reached a peak of 64 BO/D during the injectivity testing (fig. 12). The oil production decline was precipitous when gas injection ceased.

No. 14 H. Uphoff well Following CO₂ injectivity testing of the No. 3-W Pinnell and No. 1 Pinnell wells, the No. 14 H. Uphoff well was also tested. About 184 tons of liquefied CO₂ was injected into the Cypress sandstones at No. 14 H. Uphoff well (fig. 11). After a shut-in period of 12 days, well head pressure decreased from the post injection pressure of 600 to 325 psig. The average oil production rate between January 3, 1994 to February 28, 1994 was 4.0 BOPD of which 2.0 BOPD was estimated as incremental due to CO₂ injection (fig. 13). The average oil production rate increased to about 6.0 BOPD in March and April 1994. These results show that CO₂ injection can stimulate oil production from Cypress wells. CO₂ was injected at a slug size of 20 tons per perforated foot, a "rule of thumb" previously determined by Miller (Bretagne, Inc.) from several CO₂-assisted well stimulation projects performed by the Institut Francais du Petrole and Bretagne, Inc (Bardon et al, 1991).

SAWYER "E" CO2 INJECTION UNIT

Approximately 2000 tons of liquefied CO₂ were injected into the No. 1 Sawyer Community 3 well (fig. 14) from 19 May, 1993 until 30 June, 1993 at an average rate of 10.50 tons per hour for twelve hours per day. The No. 2 Morris, No. 18 ICCR and No. 19 ICCR wells (fig. 14) were monitored for CO₂ during that time. Produced gas monitored at No. 18 and No. 19 ICCR wells showed 95.5% and 97.9% CO₂

respectively within 20 days after the onset of CO₂ injection. The produced gas from the No. 1 Sawyer Community 2 well (directly west of the injection well, fig. 14) was also tested and found to contain 61.2% CO₂ on June 11, 1993. On June 29, 1993, the CO₂ content of the produced gas from No. 1 Sawyer Community 2 well had increased to 73.03%. The increased CO₂ content of the produced gases in the adjacent project wells demonstrated the continuity of the "E" interval within the Sawyer project area.

After the cessation of CO₂ injection on June 30, 1993, the injection well, (No. 1 Sawyer Community 3,) No. 18 ICCR and No. 19 ICCR wells were used to monitor reservoir pressure (fig. 15). There was a general pressure decline in all three wells. Similarity of pressure responses over time further confirm communication among these wells in the "E" interval.

Daily oil production rates from May 27, 1993 to April 30, 1994 are shown in fig. 16. It can be seen that the CO₂ injection into the No. 1 Sawyer Community 3 well increased oil production. The producing wells were No. 2 Morris and No. 1 Sawyer Community 2. Oil production rate rose from a baseline of 9.0 BOPD to over 45 BOPD during the injection period. The average production rate was 20 BOPD within the test period while the average water production rate was 159 barrels per day within the same period.

Corrosion coupons were installed in the flow lines. Subsequent analyses showed no apparent significant corrosion problems. Consequently, production was handled with standard well equipment.

An extensive search for well information in this unit revealed that twelve wells were previously completed for oil production from the E interval at various times between June 1946 and February 1962. Furthermore, four wells including the No. 18 ICCR well, previously used as water injectors, were open in the E interval. Only three wells - No. 1 Sawyer Community 3, No. 1 Sawyer Community 2 and ICRR No. 19 (fig. 14) - were perforated in the "E" interval during the current project.

STRONG "D" CO₂ INJECTION UNIT

Injectivity tests in the Strong Unit consisted of the injection of 243 tons of CO₂ into the No. 8 Strong well and 1001 tons into the No. 6 Strong (fig. 17) well between October 22, 1993 and November 17, 1993. The wells were treated at the rate of 20 tons of liquefied CO₂ per perforated foot as suggested by Bretagne, Inc. (Bernie Miller, personal communication, 1993) and Bardon et al. (1991) and produced back to investigate the potential of cyclic CO₂ injection process. Oil production rate increased in the No. 8 Strong well from about 0.5 BOPD to a steady rate of over 3 BOPD during the month of December, 1993. However, oil production decreased to an average of 2.5 BOPD in January, 1994 and 1 BOPD for February and March of 1994. No significant oil production response was obtained from the No. 6 Strong well.

LABORATORY STUDIES

Several laboratory experiments were designed to support the field demonstration project. The laboratory experiments were sub-contracted to the Illinois State Geological Survey. They include:

- compositional analysis of Mattoon stock tank oil and wellhead gas
- phase behavior of CO₂ and Mattoon crude oil mixtures
- determination of the CO₂-Mattoon crude oil minimum miscibility pressure (MMP)
- determination of relative permeability data from unsteady state displacements
- compatibility of Cypress sandstones with water (from various water sources) to be used in WAG demonstration tests.
- advanced core analyses of core samples from the No. 15 AOR-Seaman well.

The advanced core analyses of the No. 15 AOR-Seaman Cypress core samples were performed by Geocore, Inc. of Boulder, Co. and are discussed under "Drilling, Coring and Completion of No. 15 AOR-Seaman well".

Compositional Analysis of Mattoon Stock Tank Oil and Wellhead Gas

A sample of crude oil taken from the No. 1 Pinnell Uphoff (fig. 1) was shipped to Core Laboratories, Carrelton, Texas, for compositional analysis. This analysis was performed by programmed temperature gas chromatography to a triacontanes plus (C30+) fraction (Table 1). Wellhead gases sampled from four wells in the Sawyer and Strong units (fig. 1) - No. 10 ICCR, No. 8 Strong, No. 1 Strohl well and No. 2 J.I. Sawyer wells - were analyzed in the Illinois State Geological Survey's gas chromatographic laboratory. A typical test result (Table 2) shows that the pre-injection compositions of wellhead gases contained very little CO₂. An increase in CO₂ composition during subsequent tests was used as evidence that the injected CO₂ reached the producing or observation wells.

Compositional analyses of Mattoon crude oil and wellhead gas mixtures (Tables 1 and 2) provide input for the compositional reservoir simulation discussed later.

Phase Behavior of Mattoon Crude Oil and CO₂

A crude oil sample collected from the tubing head of the No. 1 Pinnell Uphoff well was combined with CO₂ in a PVT visual cell. Four-step differential vaporization tests were carried out with CO₂-saturated oil samples at 500 psig and 1000 psig at the reservoir temperature of 85°F. Equilibrium gas volumes were measured at cell and standard conditions, and also analyzed by gas chromatographic techniques.

The variations of density, viscosity, solution gas to oil ratios (GOR) and oil formation volume factor (B_o) of the CO₂-saturated Mattoon crude oil with pressure were determined during the differential vaporization experiments (Tables 3 and 4). The results in Tables 3 and 4 were used for initialization of the black oil simulation models described in this work.

These results also show that the reservoir crude oil swelled by 1.55 times its original volume (fig. 18) and its viscosity decreased from 4.71 centipoise to 0.81 centipoise as a result of carbon dioxide

injection (fig. 19). These phenomena help to improve oil recovery by increasing the relative permeability of the oil phase as well as reducing residual oil saturation. The equilibrium gas mixtures evolving from CO₂-saturated Mattoon crude oil (Tables 5 and 6) contain less and less CO₂ fractions as the reservoir pressure increases.

Minimum Miscibility Pressure of Mattoon Cypress Crude Oil and CO₂ mixture

CO₂-crude oil miscibility tests were conducted in a slim-tube apparatus using Cypress crude oil sampled from the No. 8 Strong well (fig. 1). The test conditions were 85 °F and pressure ranges of 1250 psig to 2500 psig. The slim-tube properties are summarized in Table 7; the test results are summarized in Table 8. The plot of oil recovery at 1.2 pore volumes (PV) of injected CO₂ versus pressure is illustrated in figure 20. The minimum miscibility pressure of the Mattoon crude oil with CO₂ was determined to be 1780 psig using the method of Yellig and Metcalf (1978).

The above result implies that only immiscible CO₂ displacement of oil is possible from the Cypress reservoirs at Mattoon field since the formation parting pressure is about 1,800 psig (at formation parting pressure gradient of 1 psi/foot).

Relative Permeability Curves

Experimental relative permeability curves were determined at the Illinois State Geological Survey. These data served as input to the reservoir simulation models used for the selection of CO₂ displacement processes to be implemented in subsequent phases of this project.

Two-inch Cypress core plugs from No. 15 AOR-Seaman well, routinely cleaned with toluene and CO₂, and oven-dried, were subjected to unsteady state relative permeability measurements at pre-selected overburden pressures of 500 psig and 1,000 psig. To avoid formation damage, the brine solution contained 2% by weight of potassium chloride (KCl). The saturation history of the reservoir is simulated in

each displacement test except in the CO₂-crude oil displacement experiments. The unsteady state displacement data were analyzed using the method of Jones and Roszelle (1978). The following runs were conducted:

- (a) brine displacing refined oil at 1000 psig (Table 9).
- (b) brine displacing CO₂-saturated Mattoon crude oil at 1000 psig (Table 10)
- (c) CO₂-saturated Mattoon crude oil displacing brine at 1000 psig (Table 11)
- (d) CO₂ displacing CO₂-saturated Mattoon crude oil at 1000 psig (Table 12)
- (e) CO₂-saturated Mattoon crude oil displacing CO₂ at 1000 psig (Table 13)
- (f). Brine displacing CO₂-saturated Mattoon crude oil at 500 psig (Table 14)
- (g). CO₂-saturated Mattoon crude oil displacing brine at 500 psig (Table 15)
- (h). CO₂ displacing CO₂-saturated Mattoon crude oil at 500 psig (Table 16)
- (i). CO₂-saturated Mattoon crude oil displacing CO₂ at 500 psig (Table 17)

Tables 14 - 17 are also shown as curves figs. 21 - 24.

Cypress Sandstone-Injected brine compatibility tests

Core samples from the E interval in No. 15 AOR/Seaman well were tested for compatibility with Mattoon city water and field brines consisting of (1) Cypress formation brine from the No. 1 Strohl well (fig. 1), (2) produced brine from the Pennsylvanian formations in the field, and (3) pit brine containing rain water and produced water from Rosiclare, Cypress (Mississippian) and Pennsylvanian formations. The resistivity and pH of the various test brines were measured at room temperatures ranging from 74.9°F to 77.3°F (Table 18).

Tests with field brines All field brines were first passed through a Whatman filter paper (No. 4) prior to injection into the core plug. The brines retained a yellowish tint after this filtration step. The order of brine

injection was (1) Cypress formation brine (2) Pennsylvanian formation brine and (3) Pit brine (a mixture of commingled effluents from Cypress and Pennsylvanian formations and rain water). Liquid permeability was observed to decrease from 14 md to 8.50 md as the field brines were consecutively injected into the core plug (Table 19). The core effluents were colorless, suggesting that the plugs filtered out the yellow color. A dark-brown solid buildup was also observed on the inlet face of the core plugs.

Finally, the Cypress formation brine was injected in a reverse direction. Brine permeability temporarily increased from 8.5 md to 19.3 md. This indicated that particle plugging occurred in the core sample (Gray and Rex, 1990). These observations suggested that the tested field brines would impair formation permeability if injected into the reservoir without adequate filtration.

Tests with Mattoon City Water Two Cypress Sandstone core samples from the "E" interval of the No. 15 AOR-Seaman well were tested for compatibility with Mattoon city water. Mattoon city water, was under consideration as supply for the Phase II water-alternating-gas (WAG) injection program in the Sawyer unit. The tests were performed in a Hassler-type core holder at an injection rate of 1 cc/min with a back pressure of 100 psig and a confining pressure of 1,000 psig. In the first test, water containing 2% sodium chloride (NaCl) brine was injected; this was followed by the city water. The initial 2% NaCl brine injected into the core represented the saline aqueous environment existing in Cypress reservoirs. A minimum of 20 pore volumes of each water sample was injected before changeover and the permeability of the core plug to each water sample was also measured. Following this, brine containing 2% potassium chloride (KCl) was injected into the core sample.

The results (Table 20) show that the core sample permeability decreased by 6.5% after Mattoon city water was injected. This reduction indicates that the Cypress at Mattoon field is fresh-water sensitive. The injection of 2% potassium chloride (KCl) halted the permeability reduction. This is because potassium

ions stabilize fresh water sensitive clays by flocculating them (Scheuerman and Bergersen, 1990).

Permeability reduction resumed, however, when the injection of the city water was resumed (Table 20).

Altogether, use of Mattoon city water caused an 11.1% reduction in permeability of the core sample by the end of the experiment.

In subsequent tests, brine containing 2% KCl was injected into the core samples prior to the injection of the Mattoon city water. The purpose of these tests was to investigate whether brine containing 2% KCl, acting as a clay stabilizing agent, would prevent permeability reduction if injected into the core sample prior to the injection of fresh water. The results show that, within the limits of experimental error, permeability reduction did not occur (Tables 21 - 22).

These experiments show that clays within the Cypress Sandstone at Mattoon field are fresh water sensitive. They will swell and reduce rock permeability if contacted with fresh water such as Mattoon city water. However injection of a clay stabilizing agent prior to fresh water injection, may inhibit permeability reduction caused by clay swelling, dislodgement and migration.

DRILLING, CORING, COMPLETION AND PRODUCTION OF No. 15 AOR/SEAMAN WELL

An infill well, No. 15 AOR/Seaman, was drilled from September 12, 1993 to September 22, 1993 as part of the statement of work. The location of the well, Section 35, T12N R7E, was chosen on the basis of the isopach of the target facies-defined subunit ("E" interval) in the Sawyer Unit and information from surrounding wells (figs. 7 and 14).

The whole core samples recovered from 1738' to 1822.5' contained live oil in the "B", "C", "D" and "E" intervals of the Cypress Formation (fig. 25). Core analyses performed by GeoCore, Inc. of Boulder Colorado, showed that the "E" interval has a higher average porosity and permeability than the "B" - and "C"

intervals respectively (Table 23). A suite of geophysical logs was run by Western Atlas International and consisted of the following logs: dual induction focus, natural gamma ray, compensated densilog/caliper, compensated neutron, minilog, dielectric analysis and epillog - complex reservoir analyses.

Well completion and Stimulation In January, 1994, the No. 15 AOR Seaman was perforated and acidized. Halliburton Energy Services, Inc. performed CO₂ foam fracturing in the "E", "B" and "C" intervals of the Cypress Formation. A CO₂ foam system was chosen for fracturing to provide quick cleanup with minimal formation damage from the treatment fluids. A 70% CO₂ foam was used to place 16,000 lbs of proppant in the Cypress "B/C" intervals and 8,000 lbs of proppant in the "E" interval.

Oil and Gas Production Average oil production rate for the No. 15 AOR/Seaman well was 4 BOPD and 2.5 BOPD during February and March of 1994 respectively with approximately 50-70% water-cut. The produced gas sampled on March 11, 1994 was analyzed and found to contain 13.22% carbon dioxide (Table 24). Since the pre-injection gas associated with the Mattoon crude oil contained less than 1% carbon dioxide, this result indicated that injected carbon dioxide from the No 1 Sawyer Community well had reached the new well.

No. 15 AOR-Seaman Cypress Sandstone Samples Eighty five (85) feet of 3.5 inch diameter Cypress core sample were recovered from the No. 15 AOR-Seaman well. A geologic core description is detailed in fig. 25. Eight (8) core plugs were submitted to a commercial laboratory for special core analyses which included determination of the following petrophysical properties: in situ porosity (Table 25), in situ Klinkenberg permeability (Table 25), saturation versus capillary pressure (Table 26), in situ formation resistivity factor (Table 25) and cementation exponent "m" (Table 25), and saturation exponent "n" (Table 25).

The main purpose of these experiments was to determine Cypress "m" and "n" values used in

estimation of remaining oil and water saturations from log interpretations. Capillary pressure-saturation data, determined by the porous plate method, is also useful as input to the reservoir simulation model. **Atlas Wireline Service** provided interpretations of the *Dielectric logs* and *Complex Reservoir Analysis* (CRA) from the "E", "C" and "B" intervals of the Cypress Sandstone at Mattoon field. The porosity and permeability values evaluated from the *Dielectric logs* and *Complex Reservoir Analysis* using a sand density of 2.68 matched the core-derived values satisfactorily. However, water saturation values determined from input of site-specific and empirical values of brine resistivity (R_w), cementation factor (m), adjustable constant (A) and saturation exponent (n), varied widely but remained high despite the field evidence showing water-free oil production during well completion. Even with site-specific values for " m " ($A=1$) and " n ", the log interpretations still indicated "water-filled and not oil-filled pore space" (Atlas Wireline Report to American Oil Recovery, 1994). The calculated water saturation values are in the following range:

"E" sand	52 - 75%
"C" sand	70 - 82%
"B" sand	60 - 82%

The dielectric log reported low resistivity values in the sand intervals - an anomaly that may result from the presence of water bound between clay layers.

RESERVOIR SIMULATION

Reservoir simulation models of the Mattoon CO₂ Project were developed to enhance and verify reservoir characterization, and to predict optimum CO₂-assisted oil recovery processes. The three major models were: the Sawyer CO₂ Injection unit, the Pinnell CO₂ Injection unit, and the "huff 'n' puff" (cyclic CO₂ injection using data from the No. 15 AOR/Seaman well) models.

Reservoir simulation of Sawyer CO₂ Injection unit

A water alternating gas (WAG) process in the "E" interval at Sawyer unit was investigated with the aid of a reservoir simulation model. The model contained three oil producers (fig. 14) - No. 2 Morris, No. 1 Sawyer Community 2 and the new well No. 15 AOR/Seaman. The model was calibrated by history matching oil and water productions and pressure data from May 1993 to March 1994.

The following options were investigated for the potential WAG implementation in the Sawyer unit

- (a) optimum CO₂ slug sizes (fig. 26);
- (b) optimum water to CO₂ gas (WAG) ratios (fig. 27);
- (c) comparison of performances of straight CO₂ injection and WAG (fig. 28).

The model calculations showed that the optimum predicted slug size was 10% HCPV at a WAG ratio of 1:1 (fig. 26). Higher CO₂ slug sizes (> 10% HCPV) do not increase the predicted cumulative oil recovery appreciably. Higher gas volumes yielded higher cumulative oil production and higher mscf CO₂ injected/barrel of oil produced while higher water volumes give lower cumulative oil production and lower mscf CO₂ injected/barrel of oil produced (fig. 27).

Fig. 28 compares cumulative oil recovery from straight CO₂ injection at 150 mscf/day to cumulative oil recovery from a 1:1 ratio water alternating CO₂ gas (WAG) injection. In each case, oil production is slightly higher with straight CO₂ injection. However, the cost of CO₂ injection could diminish the incremental discounted revenue from the additional oil recovered by straight CO₂ injection process.

Reservoir Simulation of CO₂ WAG Project at Pinnell unit

The reservoir simulation study of the Pinnell CO₂-WAG project was performed using a black-oil model. CO₂-oil properties used in the initialization of this model are shown in Tables 3 and 4. The model was calibrated by matching oil production and pressure history between April 20 1993 and March 31 1994.

Performance of various CO₂ injection scenarios were investigated with No. 1 Pinnell-Uphoff (oil producer) and 3-W Pinnell (injector) wells. The options considered were:

- (1) Base Case: No CO₂ injection but oil production from No. 1 Pinnell-Uphoff well;
- (2) Straight CO₂ injection: continuous CO₂ injection at a rate of 500 MCF per day;
- (3) Straight water injection: continuous water injection at a rate of 125 barrels per day.
- (4) Water alternating CO₂ injection (WAG) at various brine-to-CO₂ slug ratios.

The following conclusions can be drawn from the results of the model (Table 27):

- (a) Oil production from a WAG injection is higher than that obtained from a straight CO₂ flood or water flood alone.
- (b) Higher oil recovery was obtained with a WAG ratio higher than 1 MCF of CO₂ per barrel of brine.
- (c) Oil recovery by immiscible CO₂ displacement of oil is sensitive to the mixing ratio of CO₂ with crude oil. Oil recovery from a straight CO₂ flood is poor when the mixing ratio is low (< 20%).

One of the shortcomings of attempting a Phase II WAG project in the "A" interval of the Pinnell unit is the low well density. Only the No. 1 Pinnell-Uphoff well produces from this FDWS. A WAG pilot would require three additional strategically-located producing wells. As demonstrated by the CO₂ injectivity test, none of the wells to the east, north or south of the No. 3-W Pinnell well is in communication. Furthermore, drilling of infill wells on five-acre spacing within this FDWS would be economically constrained.

Reservoir Simulation of Single Well Stimulation with CO₂ Projects

A compositional reservoir simulation model consisting of six pseudo-components (Table 28) was developed to evaluate huff 'n' puff well stimulation projects.

Simulated results of the cyclic CO₂ injection process using data from No. 15 AOR/Seaman well demonstrated that a "rule of thumb" value of 20 tons of CO₂ per perforated foot of pay is too large. Twenty

tons of CO₂ per perforated foot constitute 73% of the HCPV (hydrocarbon pore volume) in the simulated well having 35 feet of pay at an average porosity of 17%. The simulated recovery rate is 166 MSCF/BO. On the other hand, lower amounts of CO₂ resulted in lower values of MSCF/BO (figs. 29 - 30). The simulated recovery rate is 2.8 MSCF/BO at a slug size of 5% HCPV (fig. 29) and 5.23 MSCF/BO at a slug size of 10% HCPV (fig. 30). At 50% HCPV, the simulated recovery rate is 108.4 MSCF/BO; the oil production rate returns to the pre-injection level after a very short interval (fig. 31). However at a slug size of 73% HCPV (or 20 tons/perforated foot), the oil production rate becomes lower than the pre-injection levels.

Importance of cyclic CO₂ injection in mature fields

Cyclic CO₂ injection or "huff and puff" programs are particularly suited for mature fields with stripper oil production like the Mattoon field for the following reasons:

- Economics

- Operators of small leases and stripper wells may not afford the cost of facilities, planning, and operation of a multi-well CO₂ WAG process. Many operators, however, have demonstrated interest in single-well cyclic CO₂-injection treatments.
- A great potential for demonstration of the single-well cyclic CO₂ injection process exists in the Illinois basin. Many wells like the No. 8 Strong well which are vulnerable to abandonment can be stimulated with the cyclic CO₂ injection treatment.

- Reservoir Properties

- With a MMP of 1780 psia, CO₂-crude oil miscibility cannot be achieved in this project. Consequently, it is impossible to mobilize residual (immobile) oil in the FDWS.

- ▶ Because many leases may exist on the same geological structure within a field, it may be more feasible to treat single wells unless unitization and participatory roles can be worked out among operators in the field.

TECHNOLOGY TRANSFER

Technology transfer activities during Phase I of the project included:

1. Presentation at the DOE Contractors' Review Meeting, Fountainhead Resort and Conference Center, Oklahoma, July 19 - 22, 1993. Applications of Advanced Petroleum production Technology and Water Alternating Gas Injection for Enhanced Oil Recovery from Mattoon Oil Field, Illinois.

The site selection process and the reservoir characterization of the target Cypress subunits was reviewed. We also reviewed CO₂ injectivity tests in Sawyer "E" and Pinnell "A" intervals, the injection rates and the resulting pressure responses and oil production. As a reservoir characterization tool, the CO₂ field injectivity tests were used to confirm communication between wells in a given subunit.

2. Presentation at the Illinois Oil and Gas Association Annual Meeting, Evansville, Indiana, March 2 - 4, 1994.

A talk entitled "Enhanced Recovery Opportunities in Illinois Basin Using Carbon Dioxide" was presented at the IOGA Annual Meeting (March 2-4, 1994). The history of the progress of this demonstration project, problems encountered, lessons learned, and advantages of CO₂ applications were discussed. The presentation also provided opportunities for one-to-one consultations with several independent oil operators.

3. Five quarterly reports were submitted to the U.S. DOE during the project period. Each report summarized the progress of the project.

CONCLUSIONS

- This report outlines the results of laboratory experimentation, integrated geologic modeling and reservoir simulations, field testing and the technology transfer activities associated with Phase I of a demonstration project of CO₂ assisted oil recovery on the Cypress Sandstone reservoirs at Mattoon Field, Illinois.
- Within the area of study in the Mattoon Field, five sandstone intervals ("A", "B", "C", "D", "E") have been identified. Well location maps, structure maps and net pay maps of the individual sandstones within these these intervals, as well as three dimensional geologic models were constructed and used in the interpretation of the location, continuity and geometry of the productive sandstones. The "B" and "C" sandstones are the principal oil producing reservoirs and are more or less continuous throughout the project area and have been extensively developed by both primary production and water flooding. The "A", "D" and "E" sandstones are thinner and are relatively discontinuous. They have been only partially developed in the project area.
- The "A" sandstone of the Pinnell unit, the "E" sandstone of Sawyer unit and the "D" sandstone of the Strong lease were chosen for CO₂ injectivity tests during Phase I of this project.
- The minimum miscibility pressure (MMP) of the Mattoon crude oil-CO₂ mixture, determined by slim tube experiments, is 1780 psia. This result implies that a miscible CO₂ flood would not be possible at Mattoon field because the MMP is very close to the Cypress formation parting pressure (1800 psia). However, production from the CO₂ injectivity tests show that oil recovery can be significantly enhanced even at pressure below miscibility conditions.
- Reservoir simulation studies and injectivity tests on the Pinnell unit of the project area indicate poor inter-well communication and limited areal extent of the "A" sandstone at the Pinnell unit.

Inefficient displacement of reservoir crude oil by the injected CO₂ was also indicated from production tests.

- Injectivity tests on the Sawyer unit of the project area show good inter-well communication. Results from analyses of core samples from the newly drilled infill well within this unit confirm the isolation of the target "E" sandstone from the extensively waterflooded lower "B" and "C" sandstones.
- Both injectivity tests at the Pinnell unit and the Sawyer unit resulted in rapid CO₂ breakthrough from the injectors to the producers. Improvement of CO₂ sweep efficiency by injection of water is necessary to maintain oil recovery. Reservoir simulation results indicate that a significant amount of additional oil can be recovered by the implementation of a water-alternating-gas (WAG) injection program.
- Simulated results of the cyclic CO₂ injection process in the Cypress Sandstone demonstrate that a "rule of thumb" value of 20 tons of CO₂ per perforated foot of pay can be too large. Slug sizes of 5% HCPV and 10% HCPV improved oil production rates above the decline curve while 20 tons/per perforated foot (73% HCPV) reduced oil production rates below the pre-injection levels.
- The uncertainty and expense of verifying the integrity of wells in mature fields like Mattoon field, favor single well "huff and puff" operations for CO₂ utilization.

APPENDIX A

WORK AND COSTS FOR CO₂ INJECTION AT MATTOON FIELD

The work and costs discussed below are general. They are based on our work in the Cypress reservoirs at Mattoon Field. The equipment requirement and pressure rating will vary from field to field. Costs will vary from one geographical area to another and on the basis of well depth.

PROCEDURE AND COSTS OF PREPARING WELLS FOR CO₂ INJECTION INTO AN EXISTING ZONE

1. Inspect casing head. Test to a minimum pressure of 1,500 psig.
2. Install 2 gate valves rated at 1,500 psig.
3. Install 1 inline check valve.
4. Install gauge and valve to monitor back pressure.
5. Provide miscellaneous nipples and tees for connections.
6. Inspect rod packing box.

Cost of well preparation without wellbore cleanout = \$2,000.00

Cost of well preparation with wellbore cleanout = \$3,500.00

PROCEDURE AND COSTS OF PREPARING WELLS FOR CO₂ INJECTION INTO A NEW ZONE

(Note: These zones have been produced elsewhere within the field but not in this particular well)

1. Inspect cement records to make sure zone is cemented
2. Perforate the zone at 4 shots per foot (\$100/foot).
3. Acidize and clean out wellbore (\$1,500.00)
4. Design and implement small frac. (\$5,000.00)
5. Estimate 3 days rig time at \$500.00/day
6. Prepare the wellhead (\$2,000.00)

Preparation cost for a new zone per well with 10 feet of pay = \$10,000.0

COST OF CARBON DIOXIDE (CO₂)

Carbon dioxide is a commodity; its price varies with the market price. Also CO₂ costs are transportation-sensitive. Generally a 20-ton CO₂ treatment injected directly from tank truck will cost at least \$2,000.00. A larger pump may be required for CO₂ injection if the well back pressure exceeds 225 psig. This can increase costs significantly.

APPENDIX B

STATEMENT OF WORK - CHECK LIST

PHASE ONE - PLANNING AND ANALYSIS

TASKS	PROGRESS	DOCUMENTATION
Task 1.1 Reservoir Geology		
1.1.1 Detailed Stratigraphic Cross Sections		
A. SGM cross sections	COMPLETED	1st Q. report
B. Annotated log cross sections (incorporating all data, all wells within project areas in area of interest)	COMPLETED	1st Q. report
1.1.2 Detailed Structure Map*		
A. Cypress Structure Map	COMPLETED	1st Q. report
1.1.3 Detailed Isopach Maps		
A. "A", "B-C", "D", "E" intervals	COMPLETED	2nd Q. report
1.1.4 Detailed Lithofacies Map*		
A. Stratigraphic Geocellular Modeling (SGM)	COMPLETED	2nd Q. report
1.1.5 Review Existing Core Data		
Evaluate perm., porosity & saturations	COMPLETED	Used in modeling
1.1.6 3-dimensional Fence Diagrams (SGM)	COMPLETED	2nd Q. report

Task 1.2 - Geostatistical Modelling

1.2.1 Sedimentologic and stratigraphic analysis based on logs

A. Sedimentology (depositional environment) Slab core, interpret	COMPLETED	3rd Q. report
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B. Stratigraphy	COMPLETED	
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1.2.2 A. Construct a stratigraphic 3-D geologic reservoir model

B. Determine proportion ss, sh in 106 wells	COMPLETED	2nd Q. report
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1.2.3 A. Select facies-defined subunit (FDWS) (using SGM)

	COMPLETED	2nd Q. report
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B. Project monitoring (updates to SGM)

	COMPLETED	For reservoir simulator
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1.2.4 A. Determine optimum spatial injector and producer arrangement, optimum CO₂ oil-recovery predictions (input is existing SGM model)

	COMPLETED	3rd and 4th Q. reports
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B. Update with new core and field data

	COMPLETED	In reservoir simulator
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Task 1.3 Laboratory Testing

1.3.1 A. Core tests on new core

(ϕ , K, CO₂ response and others)

(Geocore Lab will do additional testing
also)

COMPLETED	4th Q. report
COMPLETED	4th Q. report

1.3.2 A. Minimum miscibility pressure (MMP) (Slim Tube Test)

COMPLETED	3rd Q. report
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B. Reservoir rock and fluid compatibilities (check water compatibility for WAG on 3 samples)

COMPLETED	3rd Q. report
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Task 1.4 - Field Design

1.4.1 A. Plan completion and production practices

COMPLETED	
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Implemented

B. Plan location for new well	COMPLETED	3rd Q. report
C. Pick core points for well	COMPLETED	3rd Q. report
1.4.2 Select FDWS for field demonstration based on reservoir geology and engineering studies	COMPLETED	Implemented
1.4.3 Determine surface upgrade requirements for installation of demonstration project	COMPLETED	Implemented
1.4.4 Solicit bids for project installation by contacting potential contractors and service firms	COMPLETED	Implemented
1.4.5 A. Drill one new well within confines of selected FDWS		
B. Core well through Cypress interval	COMPLETED	3rd Q. report
C. Send core to commercial lab for testing	COMPLETED	3rd & 4th Q. reports
D. Run logs, pressure and production tests	COMPLETED	Implemented
E. Complete well.	COMPLETED	Implemented
Task 1.5 - Field Testing		
1.5.1 Select FDWS for CO ₂ stimulation tests	COMPLETED	1 - 5 Q. reports
1.5.2 Rework as many as 3 wells for injection testing	COMPLETED	9 wells
1.5.3 Perform injectivity test of CO ₂ in selected wells. Utilize at least 12,000 tons of CO ₂ .	COMPLETED	1 - 5 Q. reports
1.5.4 Redundant with 1.5.5		
1.5.5 Perform reservoir interference testing between wells with CO ₂ to test interwell communication (Pinnell and Sawyer Units)	COMPLETED	1 - 5 Q. reports

APPENDIX C

SUMMARY OF WORK AND FINDINGS DURING FIELD TESTING

SAWYER UNIT

- No. 1 Sawyer Comm. 3, No. 1 Sawyer Comm. 2, No. 18 ICCR, No. 19 ICCR and No. 2 Morris wells were reworked in the Sawyer unit during this project.
- Some wells tested in the Sawyer Unit lack mechanical integrity.
- Injected 2050 tons of CO₂ into Cypress FDWS (E-interval) at Sawyer unit for the injectivity testing.
- CO₂ injectivity testing revealed the E-interval is present in the wells tested in Sawyer Unit.
- AOR/Seaman No. 15 well was drilled, logged, cored and completed.
- Three Cypress intervals ("B", "C" and "E"-intervals) were present in the new well by log and core analyses.
- Bypassed mobile oil is present in all three Cypress intervals in the new well.
- Simulations of the Sawyer unit suggest that a limited WAG project consisting of wells presently active in this project and the new well would be feasible, if Phase II proceeds.

PINNELL UNIT

- Injected 5,200 tons of CO₂ into Cypress FDWS ("A"-interval) at Pinnell unit.
- CO₂ injectivity testing reveals A-interval is continuous between 3-W Pinnell and No. 1 Pinnell-Uphoff (west) wells but is not continuous with the No. 1 Pinnell (east) well.
- The "A"-interval is not well developed in Pinnell East well which produced very poorly.
- Because of limited well density in the Pinnell Unit, this FDWS may not be suitable for a WAG demonstration. Mobile oil may likely be banked against impermeable sand pinchouts in all but the west direction where the producing well is located.
- Access to bypassed mobile oil in the Pinnell Unit is more feasible with the cyclic CO₂ injection process.

STRONG UNIT

- Injected 1,300 tons CO₂ into Cypress D-interval at Nos. 6 and 8 Strong wells.
- Initial production results from cyclic CO₂ injection into Strong No. 8 ("D"-interval) was encouraging.

OTHER

- Injected 200 tons of CO₂ into Uphoff No. 14.
- CO₂ foam fracturing accomplished in No. 15 AOR/Seaman well (new well: "B", "C" and "E" intervals)

EXPERIMENTAL WORK

- Experimental evidence shows that to prevent formation damage produced brine should be adequately filtered before re-injection.
- With a measured minimum miscibility pressure (MMP) of 1,780 psia, crude oil-CO₂ miscibility may not be achieved in these reservoirs.
- Core and core flow data were provided for improvement of reservoir models of FDWS's.
- Site-specific values of cementation factor "m" and saturation exponent "n" were provided for log interpretations.
- Compositional and PVT data of CO₂-crude oil interactions were provided for reservoir simulations and for extension to other Cypress fields at similar conditions.
- Experimental data can be used as a basis for empirical determinations in other Cypress fields.

PROCESS DESIGN

- In the absence of CO₂-crude oil miscibility, the major oil recovery mechanisms are oil swelling, viscosity reduction and possibly, pressure increase from CO₂ injection.
- Oil recovery increases with increasing CO₂-crude oil mixing ratio.
- Simulated results also show that use of small CO₂ slugs (10% HCPV or less) in cyclic CO₂ injection projects yield excellent recoveries. "Rule of thumb" values of slug sizes are not always the most efficient.
- Larger CO₂ slug sizes create excess free CO₂ phase which tends to reduce the relative permeability of crude oil.
- No. 1 Pinnell-Uphoff may not sufficiently drain the Cypress FDWS at Pinnell unit in a WAG project.

"huff and puff" may be more feasible at Pinnell unit.

- **A limited WAG in the Sawyer unit with existing producing wells, CO₂ injection well and the new well, Seaman No. 15 was simulated with encouraging results.**
- **Simulated performance of "huff and puff" treatments of multiple pay zones yield as low as 2.5 Mscf of CO₂ /barrel of oil using small CO₂ slug sizes.**
- **Simulated results demonstrate the need for further field investigations of a limited WAG project in the Sawyer unit and series of "huff and puff" in Pinnell, Strong and Sawyer units.**

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Table 1 - Compositional analysis of Mattoon Stock Tank Crude oil (Pinnell Uphoff No. 1)

<u>Component</u>	<u>Mole %</u>					
CO ₂	0.00					
C1	0.00					
C2	0.00					
C3	1.72					
C4	3.17					
i-C5	1.45					
n-C5	2.81					
C6	5.61					
C7	11.64					
C8	12.31					
C9	7.98					
C10	7.08					
C11	5.3					
C12	4.28					
C13	4.24					
C14	3.51					
C15	3.19					
C16	2.44					
C17	2.28					
C18	2.15					
C19	1.82					
C20	1.61					
C21	1.41					
C22	1.26					
C23	1.14					
C24	1.00					
C25	0.98					
C26	0.78					
C27	0.78					
C28	0.77					
C29	0.62					
C30+	<u>6.67</u>					
	100.00					
		Properties of Heavy Fractions				
		Plus Fractions Mol % Density				
		Component		gm/cc	API degree	MW gm/gmole
		C6+	90.85	0.847	35.3	219.4
		C7+	85.24	0.852	34.4	228.3
		C10+	53.31	0.880	29.2	301.3
		C11+	46.23	0.887	27.9	326.9
		C15+	28.90	0.909	24.1	423.4
		C20+	17.02	0.929	20.6	556.9
		C25+	10.60	0.945	18.0	712.0
		C30+	6.67	0.959	15.9	912.9

Total Liquid Molecular Weight (MW) 205.0

Total Liquid Density (gm/cc) 0.8374

Total Liquid API gravity 37.3

Table 2 - Report of Gas Analysis - No. 10 ICCR well, Sawyer Unit (in volume percent, normalized)

Component	Volume Percent
CO ₂	0.21
O ₂ + Ar	1.29
N ₂	85.39
C1	2.20
C2	2.88
C3	5.30
i-C4	0.43
n-C4	1.39
i-C5	0.21
n-C5	0.32
C6+	0.38

Sp. Gr. = 1.03

Table 3 - Results of differential vaporization of Mattoon crude oil saturated with carbon dioxide at 500 psig

Pressure psig	GOR (cc/cc)	GOR (scf/stb)	Bo cc/cc	Density (gm/cc)	Viscosity (cps)
500	57.0	359.8	1.160	0.822	2.03
400	45.5	255.4	1.143	0.818	2.35
300	34.0	190.9	1.108	0.825	2
200	22.9	128.6	1.075	0.830	3.35
0	0.0	0.0	1.005	0.839	4.71

Table 4 - Results from differential vaporization of Mattoon crude oil saturated with carbon dioxide at 1000 psig

Pressure psia	GOR cc/cc	GOR scf/stb	Bo cc/cc	Density gm/cc	Viscosity cp
1000	240.6	1350.7	1.546	0.851	0.82
850	201.0	1128.4	1.443	0.849	0.81
725	125.0	701.5	1.292	0.837	1.18
610	86.4	485.0	1.209	0.831	1.58

Table 5 - Composition of equilibrium gas mixture liberated from Mattoon crude oil saturated with CO₂ at 500 psig.

Pressure, psig	100	200	300	400
<u>Component</u>	<u>Mole fraction, %</u>			
CO ₂	98.42	98.11	97.61	96.71
N ₂	0.13	0.15	0.19	0.22
C ₁	0.12	0.35	0.61	1.10
C ₂	0.14	0.21	0.26	0.35
C ₃	0.26	0.32	0.40	0.70
IC ₄	0.06	0.08	0.09	0.11
NC ₄	0.20	0.24	0.35	0.37
NC ₅	0.11	0.11	0.10	0.09
IC ₅	0.23	0.18	0.19	0.16
C ₆₊	0.33	0.25	0.20	0.18

Table 6 - Composition of gas liberated from Mattoon crude oil saturated with CO₂ at 1000 psig

Pressure, psig	500	600	725	850
<u>Component</u>	<u>Mole fraction, %</u>			
CO ₂	98.65	98.56	98.49	98.37
N ₂	0.04	0.05	0.08	0.22
C ₁	0.17	0.20	0.24	0.33
C ₂	0.07	0.09	0.13	0.12
C ₃	0.27	0.33	0.35	0.33
IC ₄	0.03	0.05	0.05	0.05
NC ₄	0.21	0.23	0.22	0.21
NC ₅	0.07	0.06	0.06	0.06
IC ₅	0.15	0.13	0.12	0.11
C ₆₊	0.33	0.30	0.26	0.19

Table 7: SLIM TUBE PROPERTIES

Column material	316 stainless steel
Length	57 feet
Internal diameter	0.457 cm
Packing material	glass bead (100-120 mesh)
Porosity	42.1%
Pore volume	120 cc
Pressure rating	5000 psi
Permeability	4 darcies

Table 8: OIL RECOVERIES AT VARIOUS SLIM TUBE PRESSURES

Pressure (psig)	% oil recovery	% PV CO2 injected when gas oil interface/transition zone was observed
1350	74.86	72%
1500	81.67	79%
2000	90.01	91%
2500	91.40	95%

Table 9 - Imbibition Relative Permeability (Brine displacing refined oil)

	Experimental Data		Regressed Data	
Sw(%)	Kro	Krw	Kro	Krw
29.25	0.471	0.0	0.4710	0.0000
30.0			0.4572	0.0000
35.0			0.3680	0.0006
40.0			0.2841	0.0020
43.78	0.2247	0.0086	0.2246	0.0036
49.88	0.1416	0.0118	0.1370	0.0072
59.08	0.0328	0.0164	0.0310	0.0150
63.66	0.0000	0.0370	0.0005	0.0370

Table 10: Imbibition Relative Permeability (Brine displacing CO₂ saturated Mattoon oil at 1000 psig)

	Experimental		Regressed	
	Data	Data	Data	Data
Sw(%)	Kro	Krw	Kro	Krw
34.10	0.8578	0.0	0.8578	0.0000
40.0			0.5534	0.0003
45.0			0.3428	0.0031
50.0			0.1781	0.0139
55.0			0.0630	0.0416
58.97	0.0110	0.0835	0.0091	0.0771
59.80	0.0052	0.0951	0.0076	0.0831
60.15	0.0033	0.1005	0.0070	0.0857
61.40	0.0000	0.1211	0.0005	0.1211

Table 11 - Drainage Relative Permeability (CO₂ saturated Mattoon oil at 1000 psig displacing brine)

	Experimental		Regressed	
	Data	Data	Data	Data
So(%) Krw	Kro	Krw	Kro	
38.6	0.0000	0.1210	0.0000	0.1210
40.0			0.0000	0.1097
45.0			0.0000	0.0725
50.0			0.0008	0.0408
55.0			0.0256	0.0158
56.34	0.0688	0.0122	0.0540	0.0106
57.93	0.1161	0.0095	0.1220	0.0054
60.39	0.3345	0.0001	0.3815	0.0002
60.70	0.4358	0.0000	0.4358	0.0000

Table 12 - Relative Permeability (CO₂ displacing CO₂ saturated Mattoon oil at 1000 psig)

	Experimental		Regressed	
	Data	Data	Data	Data
Liquid saturation (S _w + S _o) S _w =34.1	Kro	Krg	Kro	Krg
100.0	0.4360	0.0000	0.4360	0.0000
87.22	0.2460	0.0367	0.2643	0.0418
81.92	0.1989	0.0608	0.1945	0.0571
79.13	0.1687	0.0723	0.1582	0.0650
76.74	0.1431	0.0810	0.1274	0.0716
75.05	0.1260	0.0863	0.1059	0.0763
67.80	0.0000	0.1000	0.0000	0.1000

Table 13 - Relative Permeability (CO₂ saturated Mattoon oil at 1000 psig displacing CO₂)

	Experimental		Regressed	
	Data	Data	Data	Data
Liquid saturation (S _w + S _o)	Krg	Kro	Kro	Krg
66.30	0.1000	0.0000	0.0000	0.1000
74.10			0.0020	0.0406
79.10			0.0167	0.0164
85.35	0.0020	0.0871	0.0813	0.0029
88.96	0.0018	0.1816	0.1595	0.0005
90.85	0.0015	0.2450	0.2169	0.0000
92.07	0.0012	0.2825	0.2613	0.0000
93.65	0.0000	0.3191	0.3276	0.0000

Table 14: Relative Permeability (brine displacing CO₂ saturated Mattoon oil at 500 psig)

	Experimental Data	Experimental Data	Regressed Data	Regressed Data
Water saturation (S _w) S _{wi} =37.34	K _{ro}	K _{rw}	K _{ro}	K _{rw}
37.34	0.2560	0.0000	0.2560	0.0000
40.00			0.2143	0.0041
45.00			0.1430	0.0163
50.00			0.0821	0.0314
52.84	0.0475	0.0379	0.0528	0.0409
54.58	0.0388	0.0407	0.0371	0.0469
58.00	0.0128	0.0511	0.0124	0.0594
61.16	0.0000	0.0720	0.0000	0.0714

Table 15: Relative Permeability (CO₂ saturated Mattoon oil displacing brine at 500 psig)

	Experimental Data	Experimental Data	Regressed Data	Regressed Data
Oil saturation (S _o)	K _{rw}	K _{ro}	K _{rw}	K _{ro}
38.84	0.0719	0.0000	0.0719	0.0000
45.00			0.0448	0.0000
50.00			0.0267	0.0002
55.00			0.0120	0.0066
57.00			0.0074	0.0201
59.00			0.0035	0.0544
60.00			0.0020	0.0861
61.13	0.0040	0.1480	0.0006	0.1411
61.30	0.0035	0.1780	0.0005	0.1519
62.66	0.0000	0.2150	0.0000	0.2150

Table 16: Relative Permeability (CO_2 displacing CO_2 saturated Mattoon oil at 500 psig)

	Experimental		Regressed	
	Data	Data	Data	Data
Gas saturation (S _g)	K _{ro}	K _{rg}	K _{ro}	K _{rg}
37.34	0.2682	0.0000	0.2682	0.0000
39.06	0.2065	0.0016	0.2268	0.0032
39.87	0.1916	0.0020	0.2090	0.0039
42.58	0.1494	0.0036	0.1550	0.0055
45.06	0.1160	0.0054	0.1138	0.0067
47.00	0.0922	0.0069	0.0868	0.0075
52.00			0.0362	0.0093
55.00			0.0176	0.0102
60.00			0.0023	0.0115
61.40	0.0000	0.0125	0.0000	0.0125

Table 17: Relative Permeability (CO_2 saturated Mattoon oil displacing CO_2 at 500 psig)

	Experimental		Regressed	
	Data	Data	Data	Data
Liquid saturation (S _w + S _o)	K _{rg}	K _{ro}	K _{rg}	K _{ro}
77.20	0.0730	0.0000	0.0730	0.0000
83.60			0.0591	0.0119
88.60			0.0260	0.0673
92.95	0.0134	0.1395	0.0108	0.1501
92.63	0.0001	0.1656	0.0091	0.1668
93.94	0.0000	0.3041	0.0000	0.3041

Table 18 - CHEMISTRY OF BRINE USED IN THE ROCK/BRINE COMPATIBILITY TESTS

Type of Fluid	pH	R _w , ohm/m ²	TDS, ppm	Test Temperature, F
Cypress brine	6.97	0.074	37,768	74.9
Pennsylvanian brines	7.54	0.113	20,804	77.3
Pit brine	6.85	0.110	21,652	77.0
Lab brine	7.26	0.065	42,365	77.1
Core effluent from Cypress brine	7.36	0.076	35,400	76.3

Table 19 - Effect of Formation Brines on Cypress Rock Permeability

Type of Fluid Injected	Sample Permeability, md
Cypress brine	14.04
Pennsylvanian brine	13.33
Pit brine	8.50
Reverse flow - Cypress brine	19.32

Table 20 - Compatibility testing of Sample MA 1752.4 - No. 15 AOR-Seaman well
Cypress Sandstone, Mattoon field, Coles County, Illinois

ID: MA1752.4

Length = 4.838 cm

Diameter = 2.540 cm

Porosity = 18.5%

Air permeability = 60.7 md

Fluid Injected	Permeability, md	% Reduction
2% NaCl	36.8	-
City water	34.4	6.5
2% KCl	34.8	6.5
City Water	32.7	11.1

Table 21 - Pre-injection of 2% potassium chloride prevents permeability reduction due to clay swelling caused by fresh water in a Cypress rock sample.

ID: MA1754

Length = 4.464 cm

Diameter = 2.540 cm

Porosity = 18.5%

Air permeability = 34.4 md

Fluid Injected

2% KCl

City water

Permeability, md

22.5

22.5

Table 22 - Pre-injection of 2% potassium chloride prevents permeability reduction due to clay swelling caused by fresh water in a Cypress rock sample.

ID: MA1751.7

Length = 5.204 cm

Diameter = 2.540 cm

Porosity = 16.7%

Air permeability = 36.8 md

Fluid Injected

2% NaCl

2% KCl

City Water

Permeability, md

22.9

22.2

22.5

Table 23 - Core Analysis Summary of Cypress Sandstone Core Sample from No. 15 AOR/Seaman

DEPTH feet	Average Permeability		Average Porosity %	Saturation, %	
	Horizontal md	Vertical md		Oil	Water
1748.9-1758	61.0	57.0	19.6	15.3	25.2
1777.8-1788.3	24.0	7.1	19.5	21.7	43.4
1799.7-1810.8	11.0	11.0	16.7	10.6	37.9

Table 24 - Report of Gas Analysis: No. 15 AOR/Seaman, Mattoon field, Illinois

Component	Composition, volume % (normalized)
CO ₂	13.22
O ₂ + Ar	0.19
N ₂	3.79
C1	30.40
C2	10.08
C3	23.94
i-C4	2.81
n-C4	9.91
i-C5	Not Detected
n-C5	0.01
C6+	5.66

Table 25 - Summary of in situ porosity, permeability and electrical properties of core samples from Mississippian Cypress Sandstone No. 15 AOR/Seaman, Mattoon Field, Coles County, IL

Sample Depth (ft)	In situ Porosity (%)	Klinkenberg Permeability (FRF)	Formation Factor (m, A=1)	Cementation Exponent (n)	Saturation Cypress Exponent (depth,ft)	Interval
1751.5	19.2	76.4	26.6	1.99	2.53	
1754.0	16.0	3.08	38.2	1.99	2.58	"E"
1745.5	19.1	38.1	26.5	1.98	2.50	(1748-1758)
1778.0	18.6	8.8	26.5	1.95	2.12	
1778.1	18.6	16.6	25.2	1.92	2.21	"C"
1783.5	18.0	9.67	30.6	1.99	2.08	(1771-1784)
1802.0	17.0	7.12	37.9	2.05	2.11	"B"
1802.5	17.7	5.46	39.1	2.11	1.94	(1799-1810)

Table 26 - Summary of Capillary pressure analyses using core samples from Mississippian Cypress Sandstone at No. 15 AOR - Seaman well , Mattoon Field.

Sample Depth (ft)	Brine Saturation @ Pc=10psi	Brine Saturation @ Pc=20psi	Brine Saturation @ Pc=200
1751.5 36.6	3.4	28.6	20.5
1754.0 91.3	78.7	55.5	30.1
1754.5 49.4	41.7	34.0	20.2
1778.0 71.0	56.3	38.4	21.1
1778.1 63.7	48.8	35.9	21.4
1783.5 84.4	63.5	44.8	22.2
1802.0 85.0	60.8	42.3	26.3
1802.5 78.3	62.3	43.4	24.1

Table 27 - Cumulative oil production ratio (relative to base case cumulative oil production) at Pinnell unit (April 20, 1993 to December 30 1995)

	Mixing Ratio (% of HCPV contacted by CO ₂)		
	5%	20%	50%
CO ₂ flood	0.75	1.4	3.2
Brine flood	2.4	2.5	3.1
WAG (1:2) ¹	2.6	3.8	5.7
WAG (1:1)	2.6	3.7	5.0
WAG (2:1)	2.6	3.5	4.2
WAG (3:1)	2.6	3.2	3.8

¹WAG (1:2) means water alternating gas ratio of 15,000 barrels of water to 30,000 MCF of CO₂)

Table 28 - Properties and Composition of Pseudo-Components in Reservoir Crude Oil

Reservoir Temperature = 80°F

Pseudo-Component	Composition Mole fraction	Component in Mixture	Molecular Weight gm/gm mole	Critical temperature °F	Critical pressure psia
CO ₂	0.0004	CO ₂	44.01	87.9	1070
P2	0.0036	N ₂	28.01	-232.4	493.0
P3	0.0625	C1,C2,C3	36.11	119.8	639.2
P4	0.0817	C4,C5	65.32	342.8	518.51
P5	0.3522	C6,C7,C8,C9	103.11	553.6	435.76
P6	0.4996	C10,C33	388.53	1104.7	212.15

Fig. 2 - Type log illustrating intra-Cypress intervals in the Carter Oil No. 1 E. Tynan well, Mattoon Field (after McGee in Oltz, 1994).

Figure 6 - Net pay map of "D" Sandstone interval

Figure 7 - Net pay map of "E" Sandstone interval

Figure 9 - Fence diagram of Cypress Sandstones (A - B) showing the distribution of sandstones and shales in the Pinnell unit, Mattoon Field (white = sandstone and dark = shale). This visualization was produced by a stratigraphic modeling software.

Figure 10 - Fence diagram of Cypress Sandstones (A - E) showing the distribution of sandstones and shales in Sawyer unit, Mattoon Field (white = sandstone and dark = shale). This visualization was produced by a stratigraphic modeling software.

Figure 11 - Well location map of Pinnell and Uphoff units showing the CO₂ project wells. (Dotted outline represents the extent of the Pinnell unit project area)

Figure 12- Oil production rate from the Pinnell unit CO₂ injection project. At the Pinnell unit, CO₂ was injected into the 3-W Pinnell well from April 12 to May 14, 1993. Oil production rate increased from a baseline of about 3 BO/D to over 60 BO/D but declined at the end of the CO₂ injectivity test to pre-injection levels.

Figure 13 - Average oil production rate from the No. 14 H. Uphoff well. CO₂ Injectivity test in this well consisted of CO₂ injection and oil production from the same well (Huff and Puff). Production increased from a baseline of 3 BO/D to an average of 6 BO/D after the stimulation treatment with CO₂

Figure 14 - Well location map of Sawyer CO₂ injection unit. (Dotted outline represents the Sawyer unit project area)

Figure 15 - Wellhead pressures of the CO₂ injection well (No. 1 Sawyer Community), No. 18 ICCR and No. 19 ICCR wells.

Figure 16 - Sawyer Unit Oil Production (May 27, 1993 to April 30, 1994). The baseline oil production rate before CO₂ injectivity test was 9.0 BO/D

LOCATION MAP OF STRONG CO₂ INJECTION UNIT

Figure 17 - Well location map of Strong Injection unit

Figure 18 - Swelling factors at various saturation pressures for CO₂ -Mattoon crude oil mixture

Figure 19 - Viscosity of CO₂-Mattoon crude oil mixture at various saturation pressures

Figure 20 - Minimum miscibility pressure (MMP) of Mattoon crude oil- CO₂ mixture by slim tube tests

Figure 21 - Brine displacing CO₂-saturated oil in a Mattoon Cypress Sandstone core plug at 500 psig.

Figure 22 - CO₂ displacing saturated oil in a Mattoon Cypress Sandstone core plug at 500 psig.

Figure 23 - Brine displacing CO₂-saturated oil in a Mattoon Cypress Sandstone core plug at 1,000 psig.

Figure 24 - CO₂ displacing saturated oil in a Mattoon Cypress Sandstone core plug at 1,000 psig.

Core # 1 1738-1760
Core 22', recover 20.35'

Core # 2 1761-1791
Core 30', recover 30'

Core # 3 1792-1822.5
Core 30.5', recover 28.9'

Figure 25 - Whole core description of the Cypress interval in the No. 15 AOR-Seaman well. The core was taken from 9/16/92 to 9/18/92. Core description courtesy of B.G. Huff, ISGS.

Figure 26 - Prediction of the optimum CO₂ slug size at 1:1 WAG ratio in the Sawyer unit

Figure 27 - Prediction of the optimum water to gas (WAG) ratio using 10% HCPV slug size in the Sawyer unit

Figure 28 - Comparison between performances of straight CO₂ injection versus WAG in the Sawyer unit.

Figure 29 - Predicted incremental oil production from "Huff and Puff" treatment at CO₂ slug size of 5% HCPV

Figure 30 - Predicted incremental oil production from "Huff and Puff" treatment at CO₂ slug size of 10% HCPV

Figure 31 - Predicted incremental oil production from "Huff and Puff" treatment at CO₂ slug size of 50% HCPV