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

COOPERATIVE AGREEMENT NUMBER DE - FC22 - 93BC14955

**AMERICAN OIL RECOVERY, INC.
DECATUR, ILLINOIS**

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OBJECTIVES

The objectives of this project are to continue reservoir characterization of the Cypress Sandstone; to identify and map facies-defined waterflood units (FDWS); and to design and implement water-alternating-gas (WAG) oil recovery utilizing carbon dioxide (CO₂). The producibility problems are permeability variation and poor sweep efficiency. Phase 1 of the project focuses on the development of computer-generated geological and reservoir simulation models that will be used to select sites for the demonstration and implementation of CO₂ displacement programs in Phase 2. Included in Phase 1 is the site selection and drilling of an infill well, coring of the Cypress interval, and injectivity testing to gather information used to update the reservoir simulation model. Phase 2 involves field implementation of WAG. Technology Transfer includes outreach activity such as seminars, workshops, and field trips.

SUMMARY OF TECHNICAL PROGRESS

SPECIAL CORE ANALYSES OF SEAMAN No. 15 CYPRESS SAMPLE

Electrical Properties and other insitu core data

Eight (8) Cypress core plugs from AOR-Seaman No. 15, Mattoon field were submitted to **Geocore** for special core analysis which includes determination of the following petrophysical properties: in situ porosity (Table 1), in situ Klinkenberg permeability (Table 1), irreducible brine saturation (Table 2) and saturation versus capillary pressure (Table 2), effective Klinkenberg gas permeability at irreducible saturation (Table 1), in situ formation resistivity factor (Table 3) and cementation exponent "m" analysis (Table 3), and saturation exponent "n" analysis (Table 3).

The key 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 useful as input in the reservoir simulation model.

Atlas Wireline Service (AWS) 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 are reported to match 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 **AWS's** log interpretations still indicate "water-filled and not oil-filled pore space". 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. The log interpretations may not have included corrections for clay effects.

Relative Permeability Curves

Experimental relative permeability curves were determined at the *Illinois State Geological Survey*. These data were input into the reservoir simulation models being used for the selection of sites and CO₂ displacement processes to be implemented in Phase 2 of this project.

Two-inch Cypress core plugs from AOR-Seaman No. 15, 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 run except in the CO₂-crude oil displacement experiments. The unsteady state displacement data were analyzed using the method of Jones and Roszelle. (Jones, S.C. and Roszelle W.O.; "Graphical Techniques for determining relative Permeability From Displacement Experiments. "J. Pet Tech. (May 1978) 807-817; Trans., AIME, 265). The following runs were conducted:

- (a) brine displacing refined oil (Table 4)
- (b) brine displacing CO₂-saturated Mattoon crude oil (Table 5)
- (c) CO₂-saturated Mattoon crude oil displacing brine (Table 6)
- (d) CO₂ displacing CO₂-saturated Mattoon crude oil (Table 7)
- (e) CO₂-saturated Mattoon crude oil displacing CO₂. (Table 8)

PREDICTIVE MODELLING OF CO₂ INJECTION PROCESSES

Reservoir simulation models of the Mattoon CO₂ Project have been developed to enhance and verify reservoir characterization, and to predict optimum CO₂-assisted oil recovery processes. Predictions from the models aid in the selection of sites and the CO₂ displacement process to be implemented at given site during Phase 2 of this project.

Sawyer Unit CO₂ Injection

The possibility of an implementation of the CO₂-WAG process in the Cypress FDWS at Sawyer unit is investigated with the aid of a reservoir simulation model of the Sawyer unit. The model contained three oil producers (fig. 1) - No. 2 Morris, No. 1 M. Sawyer and the new well No. 15 AOR/Seaman. Besides the injector, No. 1 Sawyer Community, the other wells in the pilot study area (fig. 1) are not presently active. The following options are investigated for the WAG implementation in the Sawyer unit:

- (a) optimum CO₂ slug sizes (fig. 2);
- (b) optimum water to CO₂ gas (WAG) ratios (fig. 3);
- (c) comparison between performances of straight CO₂ injection versus WAG implementation (fig. 4);
- (d) effect of the location of gas and water injector (fig. 5).

The model calculations showed that the optimum predicted slug size is 10% HCPV at a WAG ratio of 1:1 (fig. 2). Higher CO₂ slug sizes (> 10% HCPV) do not increase the predicted cumulative oil recovery appreciably. In fact, as reported later, very large CO₂ slug sizes may affect oil production adversely.

An investigation of water to CO₂ gas (WAG) injection ratios shows that higher gas volumes yield 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. 3). The optimum WAG ratio for the project will depend on economics.

Fig. 4 compares cumulative oil recovery from straight CO₂ injection at 150 Mscf/day to cumulative oil recovery from a WAG project at a 1:1 ratio. In each case, oil production is slightly higher with straight CO₂ injection. However, the cost of CO₂ injection may outweigh the incremental discounted revenue from the additional oil. Finally, the simulated oil recovery is better if No. 18 ICCR is used as a gas-water injector rather than the present injector, No. 1 Sawyer Community (figs. 1 and 5).

Pinnell CO₂ Injection

Simulations of the CO₂ injection and CO₂-WAG processes in the Pinnell FDWS (A-interval) were briefly discussed in the third quarterly report. One of the short comings of performing a WAG in the Pinnell FDWS is the low well density. Only one producer is available. The injectivity test has demonstrated that No. 1 Pinnell (fig. 6) is outside the FDWS. A WAG pilot in a five-spot pattern will require at least three new wells drilled within five-acre well spacings. This option is constrained by the budget of this project.

Strong CO₂ Injection

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. This amount constituted 73% of the HCPV (hydrocarbon pore volume) in

the simulated well having 35 feet of perforated pay and average porosity of 17% and resulted in 166 Mcf/BO. On the other hand, lower amounts of CO₂ resulted in lower values of Mcf/BO. Figs. 7 and 8 show the incremental oil recovery due to CO₂ injection at 5% HCPV and 10% HCPV levels of CO₂ injection respectively. These slug sizes improved oil production rates above the decline curve.

At 50% HCPV, the oil production rate returns to the pre-injection level after a very short interval (fig. 9); however at 73% (or 20 tons/perforated interval), the oil production rate becomes lower than the pre-injection levels.

Recovery Mechanisms In the absence of miscibility, the only mechanisms taking place in the cyclic CO₂ injection are oil swelling and viscosity reduction. Pressure increase from CO₂ injection is slight but could also contribute to oil recovery. Depending on the mixing conditions, the amount of CO₂ mixing with crude oil is limited by saturation pressure and diffusivity. The unmixed CO₂ gas can be detrimental to oil production as it increases the mobile gas phase saturation and hence reduces the relative permeability (mobility) of oil. Consequently, smaller CO₂ slugs can be more advantageous as less unmixed gas will remain in the reservoir.

FIELD TESTING

Strong Unit

Injectivity tests in the Strong Unit in the fourth quarter consisted of the injection of 243 tons of CO₂ into Strong No. 8 well and 1001 tons into Strong No. 6 (fig. 10) well between October 22, 1993 and November 17, 1993. The wells were produced back to investigate the potential of cyclic CO₂ injection process. The initial results were very encouraging. Oil production rate increased in Strong No. 8 from about 0.5 BO/d to a steady rate of over 3 BO/d. The result from Strong No. 6 is not yet conclusive.

Pinnell Unit

Injectivity tests continued in Pinnell FDWS. CO₂ injection was resumed into No. 3-W Pinnell to raise reservoir pressure. During the initial CO₂ injection, oil production rate from the FDWS was 60 barrel/day level at a tubinghead pressure was about 700 psi. But then, production declined at the cessation of CO₂ injection.

Furthermore, CO₂ was injected into No. 1 Pinnell well (fig. 9) in attempt to produce oil from the FDWS by the cyclic CO₂ injection. Oil production response was low showing that the A-interval is not well developed in this area.

Sawyer Unit

There was no field test in the Sawyer Unit during third quarter. The No. 2 Morris and No

1 M. Sawyer oil producers were still responding to the previous CO₂ injection into No. 1 Sawyer Community well (fig. 1).

TABLE 1 - SUMMARY OF CORE ANALYSIS RESULTS
Mississippian Cypress Sandstone
American Recovery - Seaman No. 15
Mattoon Field, Coles County, IL

Sample Depth (ft)	Ambient Porosity (%)	In situ Porosity (%)	Routine Air Permeability (md)	In situ Klinkenberg Permeability (md)
1751.5	19.9	19.2	98.2	76.4
1754.0	16.7	16.0	4.92	3.08
1745.5	19.6	19.1	44.8	38.1
1778.0	19.7	18.6	11.3	8.8
1778.1	19.4	18.6	18.7	16.6
1783.5	18.9	18.0	11.0	9.67
1802.0	17.4	17.0	8.7	7.12
1802.5	18.4	17.7	7.5	5.46

TABLE 2 - SUMMARY OF CAPILLARY PRESSURE ANALYSES
Mississippian Cypress Sandstone
American Recovery - Seaman No. 15
Mattoon Field, Coles County, IL

Sample Depth (ft)	Brine Saturation @ Pc=10psi	Brine Saturation @ Pc=20psi	Brine Saturation @ Pc=200psi	Brine Sat. @ Pc=600psi
1751.5	36.6	33.4	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 3 - SUMMARY OF ELECTRICAL PROPERTIES ANALYSES
Mississippian Cypress Sandstone
American Recovery - Seaman No. 15
Mattoon Field, Coles County, IL

Sample Depth (ft)	In situ Porosity (%)	In situ Formation Factor (FRF)	In situ Cementation Exponent (m, A=1)	Average Saturation Exponent (n)	Sand (depth)
1751.5	19.2	26.6	1.99	2.53	1748'-1758'
1754.0	35.5	38.2	1.99	2.58	
1754.5	25.2	26.5	1.98	2.50	
1778.0	18.6	26.5	1.95	2.12	1771' - 1784'
1778.1	18.6	25.2	1.92	2.21	
1783.5	18.0	30.6	1.99	2.08	
1802.0	17.0	37.9	2.05	2.11	1799'-1810'
1802.5	17.7	39.1	2.11	1.94	"B"

TABLE 4: Imbibition Relative Permeability
(Brine displacing refined oil)

Sw(%)	Experimental Data		Regressed Data	
	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 5: 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 6: Drainage Relative Permeability
(CO₂ saturated Mattoon oil at 1000 psig displacing brine)

	Experimental		Regressed	
	Data	Data	Data	Data
So(%)	Kro	Krw	Kro	Krw
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 7: Relative Permeability
(CO₂ displacing CO₂ saturated Mattoon oil at 1000 psig)

	Experimental		Regressed	
	Data	Data	Data	Data
liquid saturation (Swi + So) swi=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 8: Relative Permeability
(CO₂ saturated Mattoon oil at 1000 psig displacing CO₂)

	Experimental		Regressed	
	Data	Data	Data	Data
liquid saturation (Swi + So)	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

FIGURE 1 -

LOCATION MAP OF SAWYER CO₂ INJECTION UNIT

FIGURE 2 - Prediction of the optimum CO₂ slug size at 1:1 WAG ratio in the Sawyer Unit

FIGURE 3 - Prediction of the optimum water to gas (WAG) ratio using 10% HCPV slug size in the Sawyer Unit

FIGURE 4 - Comparison between performances of straight CO₂ injection versus WAG implementation in the Sawyer Unit

FIGURE 5 - Effect of Injection well location (Sawyer Unit) on oil recovery performance

FIGURE 6 -
LOCATION MAP OF PINNELL CO₂ INJECTION UNIT

FIGURE 7 - Predicted incremental oil production from "huff and puff" treatment at CO₂ slug size of 5% HCPV.

FIGURE 8 - Predicted incremental oil production from "huff and puff" treatment at CO₂ slug size of 10% HCPV.

FIGURE 9 - A slug size of 50% HCPV yields no sustainable gain in oil production

FIGURE 10 -

LOCATION MAP OF STRONG CO₂ INJECTION UNIT

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