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**CYCLIC CO₂ INJECTION FOR LIGHT OIL RECOVERY:
PERFORMANCE OF A COST SHARED FIELD TEST IN LOUISIANA**

FINAL REPORT

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ABSTRACT

The ultimate objectives of the research were to provide a base of knowledge on the cyclic CO₂ stimulation (or CO₂ huff 'n' puff) process for the enhanced recovery of Louisiana crude oil, and to demonstrate the utility of the process to the small independent producer. The project was divided into four subtasks: laboratory coreflood experiments, computer simulation, field testing, and technology transfer. Laboratory corefloods were performed to investigate important process parameters. Computer simulation was used to confirm and expand laboratory coreflood results. A field-test data base was constructed and analyzed to facilitate target reservoir screening and to identify successful operational practices. The laboratory coreflood results and data base evaluations were used in the design and implementation of a field test that was conducted in conjunction with the private sector. The results of laboratory and field studies were disseminated to the industry through presentations at technical conferences and publications in technical journals.

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PROJECT SUMMARY

Cyclic CO₂ injection, or CO₂ huff 'n' puff, is a single-well method of enhanced oil recovery that is suited to Louisiana reservoirs. The process was investigated using laboratory coreflood experiments, computer simulation, analysis of a field-test data base, and performance of a field test.

Laboratory coreflood experiments were conducted to investigate the effects of important reservoir and operational parameters on process performance. Coreflood results indicated that the process performed adequately at immiscible and near-miscible conditions, but that miscible conditions were disadvantageous. Utilization of impure CO₂ sources did not handicap overall process performance provided a second cycle of CO₂ was injected. Process performance was benefitted by water-influx, larger CO₂ slugs, a higher oil saturation, the use of a drive (or chase) gas, a well-distributed initial gas saturation, and gravity segregation. The presence of a gas cap was not detrimental, but injecting CO₂ into the top of a steeply inclined core impaired process performance. Although a second cycle of CO₂ injection recovered additional oil, process performance typically declined. A soak period was required for maximum oil recovery.

A compositional reservoir simulator was calibrated by history matching laboratory coreflood results. The tuned simulator was used to analyze the effects of important reservoir and operational parameters on process performance. Model results at simulated miscible conditions indicated that a minimum soak time was required for optimum process performance, and that oil-wet conditions were more favorable than other wettability states. In addition, model results suggested that there were optimum values for the CO₂ slug size, and residual, as well as remaining, oil saturations. Examination of oil recovery mechanisms revealed that, at miscible conditions, CO₂ efficiently mobilized oil during the injection stage and drove it away from the injection/production site which made it more difficult to produce.

An extensive field test data base which documented over one-hundred cyclic CO₂ stimulation projects was constructed and analyzed. Analysis of the data base revealed that cyclic CO₂ stimulation could be successfully implemented in diverse reservoir environments. Approximately 90% of the tests included in the data base produced incremental oil, and 82% were considered to be economic successes. Most of the failures were attributed to mechanical difficulties during CO₂ injection. Analysis of successful tests indicated that incremental oil recovery was proportional to the mass of CO₂ injected, that estimation of the optimum slug size was the most important factor in process design, that there was some decline for a second cycle of CO₂ injection,

and that operating at miscible conditions was detrimental to process performance. Diffusion, phase behavior, and relative permeability effects were the primary oil recovery mechanisms.

Performance of a field test of the cyclic CO₂ stimulation process in conjunction with a small independent oil producer demonstrated that project costs were within the realm of a small operator with limited financial resources. Waiver of the unitization requirement by the Louisiana Department of Conservation reduced the cost of the test and set a precedent for similar projects in the future. Test results indicated that injection of CO₂ could substantially reduce water cut in wells experiencing high pre-CO₂ water cuts. CO₂ injection appeared to contribute to the formation of an oil/water/CO₂ foam/emulsion and a carbonate scale which inhibited production. Production rates were improved by treatment of the well with an anti-foam agent and dilute acid. The environmental impact of the process was assessed and found to be minimal.

PROJECT PERSONNEL

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INTRODUCTION

Cyclic CO₂ injection (or CO₂ huff 'n' puff) is a single-well process that involves the injection of CO₂ into an oil well. After injection, the well is shut-in for a "soak" period to allow time for the gas to diffuse through the reservoir and dissolve into the oil, then the well is reopened for production. The process was initially proposed as an alternative to cyclic steam stimulation for the recovery of heavy crude.^{1,2} Application of this process to the recovery of light oil was initiated in the early 1980s.³⁻⁷

There are several advantages to using cyclic CO₂ stimulation over more conventional well-to-well processes. First, the economic risk is less than large-scale EOR processes, which typically require much higher upfront investments and which experience much longer project lives. Also, the environmental impact is negligible with cyclic CO₂ stimulation since relatively small slugs of a non-toxic gas are employed, and equipment requirements are minimal. In addition, a single-well process may be the only EOR option for small or discontinuous reservoirs.

State and federal agencies have been concerned as few EOR projects have been implemented in Louisiana, and state oil reserves are being lost due to well closures. The scarcity of EOR projects has been attributed to financial, geological and environmental considerations. A majority of the state oil reserves are controlled by small oil companies that cannot afford to implement expensive or high-risk projects. Numerous reservoirs in the state are not suited to large-scale projects because the mobilization of oil from injection to production wells is inefficient, if not impossible, in the discontinuous, highly faulted, and often single-well reservoirs associated with Gulf Coast salt dome geology. In addition, many reservoirs are located in environmentally sensitive areas.

Since cyclic CO₂ injection is one of few EOR options suitable for wide-scale implementation in Louisiana reservoirs, the Department of Petroleum Engineering at Louisiana State University in conjunction with the U.S. Department of Energy decided to investigate the feasibility of introducing this process to independent operators. The ultimate goals of the proposed project were to provide a base of knowledge on the CO₂ huff 'n' puff process for the enhanced recovery of Louisiana crude oil, and to demonstrate the utility of the process to the small independent oil producer. Previous field tests of this process, conducted in Louisiana, were performed by private companies that seldom made test results accessible to the general public. Extending the information available to the public domain would facilitate implementation of the process by small companies that did not have

sufficient revenues to invest in research but were responsible for a large proportion of oil production in the state.

The proposed project was a continuation of an ongoing research program initiated by Professor Teresa Monger in 1981. In 1985, when plummeting oil prices jeopardized the economic viability of full-scale processes, the research focus shifted from full-scale, miscible CO₂-flooding to the single-well cyclic stimulation process. The initial thrust of the cyclic stimulation process was to extend existing technology to include light oils and low-pressure reservoirs. Process feasibility was assessed using laboratory corefloods.

DOE funding allowed the project to be expanded to encompass four subtasks: laboratory coreflood experiments, numerical simulation, field testing, and technology transfer. Laboratory corefloods would be performed to investigate important process parameters. Numerical simulation (computer modeling) would be used to confirm and expand coreflood results. A field-test data base would be constructed and analyzed to facilitate target reservoir screening and to identify sensitive operational parameters. The information from laboratory corefloods and data-base evaluations would be used in the design and implementation of a field test that would be conducted in conjunction with the private sector. The results of all laboratory and field evaluations would be disseminated to the industry through presentations at technical conferences and publications in technical journals.

I. LABORATORY COREFLOODS

Laboratory coreflood experiments were performed to investigate the influences of important process and reservoir parameters on process performance. Although extrapolation of laboratory coreflood results to the field is seldom direct, a comprehensive evaluation of the CO₂ huff 'n' puff process from field-test results alone would be difficult, even if results were plentiful. Since numerous reservoir and operational parameters are variables in field testing, it is difficult to isolate the influence of a particular parameter from field-test results. Laboratory corefloods provide controlled conditions and the opportunity to vary one parameter at a time. Moreover, the use of watered-out cores allowed the process to be evaluated on its ability to recover oil that is undeniably tertiary.

EXPERIMENTAL METHODS AND MATERIALS

Most of the laboratory corefloods were performed using a 31.2 °API stock tank oil (STO) obtained from the Timbalier Bay Field located in Lafourche Parish, Louisiana. A few of the early studies employed another light oil from the Appalachian Basin in eastern Kentucky. The physical properties of both oils are listed in Table 1. Reconstituted reservoir oil (RRO) was prepared by mixing Timbalier Bay STO with 99.97 mol% pure methane in a gas-oil ratio of 400 scf/STB. The CO₂ employed in the experiments was 99.5 mol% pure. The water used in the corefloods was NaCl brine. The oil and brine were filtered prior to injection into the core.

Coreflood experiments were conducted in the apparatus illustrated in Figure 1. Berea sandstone cores (6 ft long, 2 in. diameter) were coated with epoxy resin prior to installation in a stainless steel coreholder. The annulus of the coreholder contained hydraulic oil which was maintained at a pressure approximately 1000 psi greater than core pressure to insure the integrity of the epoxy coating. The temperature of the core was controlled by circulating heated ethylene glycol-water through stainless steel tubes wrapped around the core assembly. The core was connected at both ends to floating piston transfer vessels. These vessels, in conjunction with positive displacement pumps, were used to displace fluids into the core. Both ends of the core were connected to high pressure sight glasses which allowed observation of the injected and displaced fluids. Backpressure regulators were used to maintain core pressure. The outlet end of the core was connected to a production panel. Oil and water were collected in a calibrated separator and gas was measured using a

The figures and tables referenced in this chapter are located at the end of the chapter.

gasometer. Pressures upstream and downstream were monitored by digital-meters and Bourdon tube gauges. Both horizontal and vertical coreflood assemblies were available. The horizontal assembly was mounted on a core rotating device capable of 360° rotation about its longitudinal axis. The type of setup chosen for a particular experiment depended on the nature of the parameter to be investigated.

New cores were initially evacuated and saturated with 50,000 ppm brine. The core pore volume was measured at room temperature and 1000 psig. After each experiment, the core was thoroughly cleaned to return it to near-virgin conditions. Brine (50,000 ppm) was initially flushed through the core until gas production ceased. Solvents were then flushed through the core in the following order: 20,000 ppm brine, isopropyl alcohol (IPA), xylene, IPA, 20,000 ppm brine, 50,000 ppm brine. The brine concentration was reduced to 20,000 ppm because the mixing of 50,000 ppm brine with IPA may cause salt to precipitate. The xylene flush was preceded and followed by IPA flushes to inhibit the formation of a second liquid phase within the core. Xylene was poorly soluble in brine, but IPA was miscible with both water and xylene.

Prior to CO₂-flooding, the brine-saturated core was flooded with oil to near-irreducible brine saturation, and waterflooded with 50,000 ppm brine to near-irreducible oil saturation to simulate a watered-out reservoir before injection of CO₂. A typical cyclic CO₂ stimulation experiment was performed by injecting a slug of liquid CO₂ into the core at the desired temperature and using pressures of 1640 psig or above (CO₂ was in the liquid state during injection). The slug size was designed so that no oil was displaced into the transfer vessel connected to the core outlet. During CO₂ injection, the core pressure was maintained by bleeding hydraulic oil from the transfer vessel connected to the core outlet. Following CO₂ injection, the core pressure was either maintained over a 10-hour soak period, or was slowly decreased to the desired pressure and then shut-in for a 10-hour soak period. Following the soak period, the core was produced by pumping brine into the core from the transfer vessel located at the end of the core opposite the injection site. CO₂ and brine were typically injected at a rate of 60 cm³/hr. Produced fluids were routed to the production panel. After oil production ceased, a second cycle of CO₂ was injected. Similar procedures were typically used for both cycles; however, the CO₂ injection procedures for the first and second cycle low-pressure runs (500 psig) slightly differed. For the second cycle runs performed at 500 psig, the CO₂ transfer vessel was maintained at 1640 psig, as in the first cycle, but the CO₂ was flashed through a needle valve into a short transfer line connected to the core that was maintained at 500 psig. Cyclic CO₂ and waterflood oil recovery efficiencies were calculated by volumetric material balance.

The following evaluation parameters were used to assess process performance:

Overall Recovery Efficiency (E_{R1}) =
volume of oil recovered divided by volume of oil initially in place, cm^3/cm^3

Huff 'n' Puff Recovery Efficiency (E_{Rp}) =
volume of oil recovered divided by volume of waterflood residual oil, cm^3/cm^3

CO_2 Utilization =
Volume of CO_2 injected divided by the incremental oil recovered, Mscf/bbl

Studies performed in this laboratory have addressed the following reservoir/operational parameters: reservoir pressure, CO_2 slug size, multiple injection cycles, water influx, soak duration, reservoir gas, impure CO_2 , gravity segregation, gas cap, drive fluids, remaining oil saturation, residual oil saturation, CO_2 injection rate, and reservoir dip.

PRELIMINARY STUDIES

Preliminary studies performed prior to receipt of DOE funding demonstrated that cyclic CO_2 stimulation was capable of displacing waterflood residual oil. Experiments performed at miscible and near-miscible conditions also examined the effects of CO_2 slug size, multiple injection cycles, water influx, soak duration, and reservoir pressure on process performance.⁸ Oil recovery was found to improve linearly as CO_2 slug size increased. The linear relationship was considered to be reasonable because the flow geometry was linear. A second cycle of CO_2 injection was found to recover additional oil, but a decline in process performance was noted. Corefloods also suggested that water influx and a soak period were required to maximize oil recovery.

RESERVOIR PRESSURE

Reservoir conditions with respect to CO_2 flooding may be divided into three regimes depending on the degree of miscibility: miscible, near-miscible, and immiscible. Miscible means that the reservoir pressure is above the minimum miscibility pressure (MMP). Near-miscible indicates that the CO_2 density is high, ranging up to 0.6 kg/m^3 , but that reservoir pressure is below the MMP. Immiscible means that the reservoir pressure is not only below the MMP, but is also below the vapor pressure of CO_2 .

Preliminary studies conducted in this laboratory addressed reservoir conditions in the miscible and near-miscible regimes, and suggested that operating at the MMP was not beneficial to incremental oil recovery.⁸ CO_2 retention was higher, CO_2

utilization was improved, and oil recovery was enhanced at near-miscible as compared to miscible conditions.

Additional corefloods were performed in the horizontal core at 500 psig and room temperature to investigate the applicability of cyclic CO_2 stimulation to pressure depleted reservoirs. The experimental conditions and results are listed in Tables 2 and 3, respectively.

Coreflood results demonstrated that cyclic CO_2 stimulation could displace waterflood residual oil at immiscible conditions. Oil recovery efficiencies and CO_2 utilization depended on slug size and cycle number, as was noted at higher pressures. Figure 2 illustrates the relationships between CO_2 utilization, oil recovery efficiency, and CO_2 density. CO_2 utilization improved as CO_2 density (or pressure) decreased; however, recovery efficiency increased as the CO_2 density rose until the system became miscible. At pressures above the MMP, recovery efficiency decreased as pressure increased.

As pressure decreased, the reservoir volume occupied by a fixed mass of CO_2 increased due to expansion of the gas, thus a larger volume of oil was contacted by CO_2 . Alternatively, as pressure increased, the solubility of CO_2 in the oil increased, and thus the efficiency of oil displacement improved. At miscible conditions, the displacement of oil was so efficient that oil was displaced away from the injection site during CO_2 injection, and was difficult to recover during the production phase. At near-miscible conditions, CO_2 /oil interactions were less extensive, and CO_2 bypassed oil during the injection phase. The CO_2 dissolved in the oil during the soak phase, and oil was efficiently recovered. The overall process performance was, therefore, assessed to be adequate at near-miscible and immiscible conditions, but poor at miscible conditions.

RESERVOIR GAS

A series of horizontal corefloods was performed using pure CO_2 and a reconstituted reservoir oil at conditions above and below the bubble point pressure of the oil to study the influence of initial reservoir gas saturation. The experimental conditions and results are presented in Tables 4 and 5, respectively.

Decreasing the run pressure was found to improve cyclic CO_2 oil recovery for both the first and second cycles. In first cycle runs below the bubble point, a sharp improvement in waterflood residual oil recovery was observed, while second-cycle recovery displayed only a moderate increase.

Besides providing an initial reservoir gas saturation, lowering the run pressure below the bubble point expanded the reservoir volume occupied by a fixed mass of CO_2 . Lowering the run

pressure also shifted run conditions from miscible toward the near-miscible regime. Although both of these consequences of decreasing pressure favored oil recovery, as discussed earlier, they could not explain the differences observed in first- and second-cycle recovery response.

Since the core was completely watered out after the first cycle and before injection of CO_2 for the second cycle, the initial gas saturation established prior to the first cycle was flushed out of the core before the second cycle. The differences in the first- and second-cycle recovery responses could, therefore, be attributed to an initial gas saturation that was present during the first cycle, yet absent during the second cycle. It is presumed that an initial gas saturation favored oil recovery by providing a flow path for CO_2 , thus allowing deeper penetration into the core.

IMPURE CO_2

The potential of impure CO_2 sources was investigated because CO_2 availability and project costs would benefit from expanding the amenable sources of CO_2 to include recycled gas from CO_2 floods, natural gas rich in CO_2 , and stack gases. The influences of methane contamination were examined by varying the ratio of CO_2 to methane in a constant slug size (0.253 scf at standard conditions) of injected gas. Corefloods were performed in the horizontal core at immiscible conditions, and the injected gas composition was varied from 100% CO_2 to 100% methane. The experimental conditions and results are presented in Tables 6 and 7, respectively. Waterflood residual oil recoveries for first and second cycles are plotted as a function of the CO_2 content of the injected gas in Figure 3. The reservoir volume of the constant mass gas slug, which increased by approximately 20% as the slug composition changed from pure CO_2 to pure methane, is also illustrated in Figure 3.

The results indicated that CO_2 /methane mixtures could displace waterflood residual oil with a favorable overall CO_2 utilization factor; however, a second gas injection cycle was required. Oil recovery for the first cycle of gas injection increased as the slug was enriched in CO_2 , despite the fact that the reservoir volume occupied by the slug was reduced. This effect may be explained by the fact that gas solubility in oil, and subsequent oil swelling, were approximately two fold greater at the soak conditions for CO_2 as compared to methane.

The results also showed that second-cycle oil recovery was significantly enhanced as the methane content of the injection gas increased. This improvement in oil recovery was attributed to the initial reservoir gas saturation effect described earlier. Since cores were watered out prior to injection of a second gas slug and methane solubility in oil or water was low at run conditions of 500 psig, a residual gas saturation likely remained in the core after

completion of the first cycle. This hypothesis was supported by coreflood production profiles which showed that gas retention in the first cycle increased as methane content of the injected gas increased. In contrast, there was no initial gas saturation in the first cycle as dead oils were employed in this study. Low-pressure reservoirs would be expected to contain some residual gas; therefore, the magnitude of differences between first and second cycles noted in this study would be unlikely in the field.

GRAVITY SEGREGATION

At reservoir conditions, CO₂ is typically lighter than oil or water. The lower density of CO₂ may result in a migration of CO₂ to the top of the reservoir. This process has been found to be detrimental to full-scale, or well-to-well CO₂ floods, because a large portion of the reservoir oil is not contacted by CO₂.⁹

Gravity override effects in cyclic CO₂ processes were probed by either rotating the horizontal core, or allowing it to remain stationary for all or part of a run. Three scenarios were investigated: continuous rotation, no rotation, and no rotation during CO₂ injection followed by continuous rotation during the soak and production phases. Experimental conditions and results are listed in Tables 8 and 9, respectively.

A comparison of the stationary and continuously rotating corefloods indicated that gravity override benefitted process performance. At run conditions, the density of CO₂ was an order of magnitude smaller than that of oil or water. In stationary corefloods, the lower density of the CO₂ allowed it to migrate along the top of the core during injection. This apparently resulted in effective bypassing of oil by CO₂ during CO₂ injection, which produced a deeper distribution of CO₂ in the core. Rotation of the core reduced this tonguing.

The preceding hypothesis indicated that it might be advantageous to keep the core stationary during CO₂ injection, and rotate during the soak and production periods. When this procedure was performed, the oil recoveries were found to be similar to those obtained from the stationary corefloods. The results indicated that gravity segregation effects only impacted the process during CO₂ injection. Rotation of the core during CO₂ injection minimized gravity segregation, and inhibited deeper penetration of CO₂ into the core, which ultimately resulted in less oil being contacted and altered by CO₂.

GAS CAP

The influence of a gas cap on cyclic CO₂ performance was investigated as numerous target reservoirs for enhanced oil recovery are saturated and have existing gas caps. Corefloods were performed in a vertical berea core using pure CO₂ and a

reconstituted reservoir oil. Experimental results from corefloods conducted at 3300 psig (above bubble-point pressure) were contrasted with those performed at 2600 psig (below bubble-point pressure) to gauge the effects of a gas cap. A gas cap was formed by initially saturating the core with oil at pressures above the bubble point of the oil. After waterflooding, the pressure was reduced below the bubble point, and the core was shut-in for six days prior to CO₂ injection to allow gas to evolve from the oil and migrate upward to form a gas cap.

In two sets of experiments, one above and one below the bubble point pressure, CO₂ was injected from the bottom to the top of the core. This represented injection of CO₂ below the gas cap.

In a third set of experiments, conducted below the bubble point, CO₂ was injected directly into the gas cap at the top of the core. This is an exception that may occur due to migration of CO₂ into the gas cap through broken tubing or casing. The experimental conditions and results are presented in Tables 10 and 11, respectively.

Oil recoveries and CO₂ utilization factors were similar for both low-pressure runs, indicating that accidental injection of CO₂ into the gas cap was neither detrimental nor advantageous to process performance. When corefloods conducted above and below the bubble point were compared, first-cycle performance was found to be poorer above the bubble point, which suggests that the process is less favorable in the absence of a gas cap. These results, however, were influenced by other factors in addition to gas cap effects. Calculations indicated that only partial separation of the gas cap occurred; thus gas was distributed throughout the core, and a well-distributed gas saturation has been shown to be favorable to process performance. Also, because equal masses of CO₂ were injected and CO₂ occupied a larger volume of the pore space at lower pressures, some of the improved response below the bubble point could be attributed to the larger CO₂ pore volume.

Second-cycle efficiencies were similar for both saturated and undersaturated conditions. Since the second cycle of CO₂ was performed after the core had been watered out following the first-cycle run, gas was effectively removed from the core prior to the second cycle and could not influence recovery. The second-cycle results, therefore, indicated that improved response at lower pressures was primarily due to gas effects.

DRIVE GAS

Previous laboratory coreflood and field-test results have indicated that process performance improved when CO₂ penetrated more deeply into the reservoir. Deeper penetration of CO₂ may be achieved by increasing the CO₂ slug size or by use of a drive (or chase) gas. Since nitrogen has been successfully employed as a

drive gas in well-to-well CO₂ floods¹⁰, and nitrogen may be less expensive than CO₂, the feasibility of using a nitrogen drive gas was investigated.

Three sets of first- and second-cycle corefloods were performed to test the utility of employing a drive gas in cyclic CO₂ stimulation. Corefloods were conducted in the horizontal Berea core using Timbalier Bay STO. The benefits of a nitrogen drive were evaluated by comparing the results of injecting 16 cm³ CO₂, followed by 16 cm³ nitrogen with that of injecting 16 cm³ CO₂ or nitrogen alone. Gases were injected at 1640 psig and 78 °F; the pressure of the core was slowly reduced at constant temperature to 500 psig; and the core was shut-in for a soak period before oil production commenced.

Although equal volumes of CO₂ and N₂ were injected, the masses injected were quite different as the gas densities were not the same at injection conditions. Subsequently, the gas volumes at soak conditions differed substantially. Comparisons of injected CO₂ and N₂ masses and volumes, as well as reservoir pore volumes are presented in Table 12. The experimental conditions are listed in Table 13.

The coreflood results listed in Table 14 indicated that a nitrogen drive dramatically benefitted process performance. When CO₂ injection was followed by N₂, oil recoveries were substantially improved in comparison to injection of CO₂ or N₂ alone. The recoveries achieved with the drive gas were even greater than the sum of the recoveries of the separate processes ($E_{R,CO_2} + E_{R,N_2}$) or injection of a 32 cm³ slug of CO₂. As previous cyclic CO₂ stimulation coreflood experiments have shown that incremental oil recovery was linearly related to the amount of CO₂ injected⁸, a 32 cm³ CO₂ slug would be expected to yield twice the incremental oil recovered by a 16 cm³ slug. The first cycle run 107 (CO₂-N₂), however, recovered more than twice the oil produced by run 81 (CO₂), while the second cycle run 108 (CO₂-N₂) recovered nearly three times as much oil as run 82 (CO₂).

The magnitude of benefits derived from the nitrogen-drive gas was unexpected and is difficult to explain. Nitrogen has a very low solubility in oil at the low pressures employed in this set of experiments, and it was anticipated that nitrogen would act primarily as an inert medium for the transport of CO₂. The oil recoveries and gas utilization factors for the nitrogen floods, however, were much better than expected; thus nitrogen itself served to enhance oil recovery. However, since the oil recovered by the drive gas experiment was greater than the sum of the oil recovered by CO₂ and N₂ separately, the enhanced recovery effects of the separate CO₂ and N₂ processes could not solely account for the observed results. Additional experiments are planned to investigate the mechanisms responsible for oil recovery in the drive gas and nitrogen processes.

REMAINING OIL SATURATION

A series of horizontal cyclic CO₂ corefloods was performed at immiscible conditions to investigate the effects of remaining (or target oil) saturation. In the field, most EOR methods are applied before well production has reached its economic limit. This limit is frequently based on the produced water/oil ratio, and, in many cases, is defined as the point at which the reservoir becomes "watered out".

In this study, remaining oil saturation was varied by either partially or completely waterflooding the horizontal core prior to CO₂ injection. The following percent of oil saturations were investigated: 38.4% (watered-out core), 39.6%, 45.9%, and 50.4%. In the first phase of the study, water and CO₂ were injected in the same direction. Another set of experiments was performed to investigate the effects of injecting CO₂ and water in opposite directions. Experimental procedures and results are presented in Tables 15 and 16, respectively.

In each of the corefloods performed above residual oil saturation, significant quantities of oil were displaced from the core into the transfer vessel during CO₂ injection. This unrecoverable oil was included as waterflood production when calculating remaining oil saturations. As the quantity of unrecoverable oil was constant, any change in the oil recovery or CO₂ utilization factor was attributed to the remaining oil saturation prior to CO₂ injection.

CO₂ oil recovery efficiency and CO₂ utilization were found to increase with remaining oil saturation for both the first and second cycles. Total recovery efficiencies (waterflood plus CO₂ recovery efficiencies) however were essentially constant. In laboratory corefloods, calculations of recoveries based solely on a waterflood residual oil saturation represented recovery that was undeniably tertiary, and could be solely attributed to CO₂ stimulation. Partial waterflooding followed by CO₂ injection resulted in a higher oil recovery; however, some of the oil recovered could have been mobilized by an extended waterflood. Process performance, therefore, could not be gauged from oil recovery efficiencies alone.

When all of the aspects of the process were taken into consideration, an increase in remaining oil saturation was still found to benefit process performance. Since the time frame of a waterflood is typically much longer than that of a cyclic CO₂ flood, early application of CO₂ would be economically beneficial, as a fixed quantity of oil would be recovered in a shorter period of time. In addition, the trend in CO₂ utilization factors indicated that a fixed quantity of CO₂ was more effective at higher oil saturations.

In the initial experiments, cores were waterflooded and CO₂ flooded in the same direction. As partial waterflooding of a core was expected to produce a non-uniform oil saturation profile, two corefloods were performed in which water and oil were injected from opposite directions to determine the effect of oil saturation profile. Experimental results (Table 16) showed that flow direction did not appreciably affect oil recovery.

RESIDUAL OIL SATURATION

The effects of residual oil saturation on process performance at near-miscible and immiscible conditions were examined to determine the differences, if any, between remaining and residual oil saturation effects. In this study, remaining oil was defined as the oil left in the core after partial waterflooding; thus, a portion of the remaining oil could be mobilized by waterflooding. Residual oil was defined as oil that could not be mobilized by waterflooding.

The coreflood experiments were performed in the horizontal core at conditions of 78 °F and 500 psig (immiscible conditions) or 1600 psig (near-miscible conditions). A range of residual oil saturations was simulated by thoroughly waterflooding the core after each CO₂ cycle to remove all trapped CO₂ from the core. This procedure returned the core to its pre-CO₂ state with only water and oil present in the core; however, the residual oil saturation was reduced to a lower level since some of the oil had been recovered by the prior cyclic CO₂ injection.

The experimental conditions and results are listed in Tables 17 and 18, respectively. As anticipated, the oil recovery efficiency was found to decline with decreasing residual oil saturation as depicted in Figure 4 (immiscible conditions).

CO₂ INJECTION RATE

In field applications, it is common practice to inject CO₂ as fast as the formation allows.¹¹ The advisability of this practice was examined by performing corefloods designed to investigate the influence of CO₂ injection rate on process performance. The coreflood experiments were conducted at both near-miscible and immiscible conditions using Timbalier Bay oil and the horizontal Berea core. The near-miscible runs were performed at 1600 psig and 130 °F. For the immiscible runs, CO₂ was injected at 1600 psig and 78 °F. The pressure was then dropped to 500 psig, and the core was shut-in for a period of time before producing oil. The production rate was maintained at the usual 60 cm³/hr. Experimental conditions are listed in Table 19.

The results for the near-miscible experiments (Table 20) indicated that process performance was maximized at moderate injection rates. Both the 10 cm³/hr and 200 cm³/hr runs resulted

in lower oil recovery efficiencies and less favorable CO₂ utilizations than the 60 cm³/hr run. The first-cycle 60 cm³/hr run involved a larger CO₂ slug, however, and oil recovery has been shown to increase with slug size. (The near-miscible runs were conducted early in the program, before the equipment had been modified for precise control of injected CO₂.) Some portion of the additional oil recovery at 60 cm³/hr could, therefore, be attributed to differences in slug size rather than injection rate alone. However, because CO₂ utilization factors, which were not dependent on slug size due to a linear relationship between oil recovery and amount of CO₂ injected, also exhibited a maximum at 60 cm³/hr, the original hypothesis was confirmed.

Production profiles showed that the 10 cm³/hr and 200 cm³/hr runs produced larger initial slugs of water than the 60 cm³/hr runs, suggesting that both the slower and faster rates were not as effective in displacing water away from the core inlet. At the faster injection rate, water influx breakthrough was also significantly early, implying that CO₂ channeled an appreciable distance into the core without pushing away water. Moreover, the faster injection rate generated a larger pressure gradient, which may have mobilized residual oil during the huff. After the 200 cm³/hr run, a second-cycle injection was performed using the typical CO₂ injection rate of 60 cm³/hr. This second-cycle run further confirmed the detrimental nature of the faster injection rate. Despite the second-cycle handicap and a smaller CO₂ slug, oil recovery and CO₂ utilization were higher than for the 200 cm³/hr run.

The results of the experiments performed at immiscible conditions were inconclusive. First-cycle performance was maximized at 140 cm³/hr (run 117); however, as run 117 did not conform to the trend of the other first-cycle runs, the results were suspect. Second-cycle recovery was uniformly low at the lower injection rates, but increased dramatically at 160 and 200 cm³/hr, where second cycle response was more favorable than that of the first cycle. At the higher rates, CO₂ presumably penetrated the core more deeply and altered oil located at a greater distance from the injection/production port. It is conceivable that oil contacted by CO₂ during the first cycle was not produced until the second cycle. As the core employed in these experiments had been in use for an extended period of time and had suffered permeability damage, it was believed that the results were not reliable. Additional studies are currently underway to determine the effects, if any, of injection rate at immiscible conditions.

RESERVOIR DIP

Numerous reservoirs, particularly those flanking salt domes, are inclined at a steep angle. Since, under most reservoir conditions, CO₂ is lighter than oil or water, the CO₂ would be expected to migrate upward to the highest portion of the reservoir.

It was, therefore, assumed that CO₂ migration would impair cyclic CO₂ process performance in wells located along the lower flank of the reservoir.

A series of corefloods was performed to examine the effects of reservoir dip. Dip angles of 0°, 45°, and 90° were investigated by inclining the core at the desired angle. The effect of injection site location was examined by injecting CO₂ into either the top or the bottom of the core after it was inclined at either 45° or 90°. The experimental conditions and results are presented in Tables 21 and 22, respectively.

In the first set of experiments performed at 45° and 90°, CO₂ was injected into the bottom of the core. First-cycle process performance improved slightly when the core angle of inclination was changed from the horizontal base case (run 125) to 45° (run 119). Similar results were obtained for runs 119 (45°) and 121 (90°), indicating that an additional increase in dip angle did not yield extra benefits. Previous experiments have shown that gravity override benefitted process performance. The favorable effect of gravity override was attributed to deeper channeling of CO₂ into the core. At experimental conditions, the density of CO₂ was an order of magnitude smaller than that of oil or water. When the core was inclined at 45° or 90°, the lower density of CO₂ facilitated upward migration of the gas and deeper penetration into the core, which ultimately resulted in more oil being contacted by CO₂.

Process performance declined in the second-cycle horizontal flood (run 126), as was typical of horizontal corefloods performed in the past.⁸ However, in the second-cycle runs 120 (45°) and 122 (90°), oil recovery showed substantial improvement over first-cycle results. In the horizontal coreflood, a large portion (approximately 50%) of the injected CO₂ was produced during the first-cycle production phase. No gas was produced however in first-cycle runs 119 and 121 (45° and 90°, respectively). First-cycle production profiles for runs 125 (0°) and 121 (90°) are compared in Figure 5. The second-cycle corefloods, therefore, had more CO₂ available for interaction with oil (the CO₂ injected in the second cycle, as well as that remaining from the first cycle). As previous studies⁸ have shown that oil recovery improved with the amount of available CO₂, the atypical second-cycle response was attributed to retention of CO₂ injected in the first cycle.

A second set of experiments was performed by injecting CO₂ into the top of the core when it was in the 45° or 90° position. This represents injection at the top of a steeply inclined reservoir. The overall process performance was significantly impaired in these experiments in comparison to the horizontal corefloods or to those runs in which CO₂ was injected at the bottom of tilted cores. The first-cycle production profiles for runs 125 (0°) and 127 (90°) are compared in Figure 5. In runs 131 (45°) and 127 (90°), CO₂ production occurred earlier, and larger volumes were

ultimately produced than in run 125 (0°). The CO₂ slug apparently remained near the injection site and did not effectively penetrate the core. Less oil was contacted by CO₂; therefore, less oil was recovered.

CONCLUSIONS

Laboratory corefloods have demonstrated that the cyclic CO₂ stimulation process was more favorable at near-miscible or immiscible conditions than at miscible conditions, and that impure CO₂ sources can be utilized. Process performance benefitted by water influx, larger CO₂ slugs, higher oil saturation, use of a drive (or chase) gas, a well-distributed initial gas saturation, and gravity segregation. The presence of a gas cap was not detrimental to the process, but injecting CO₂ into the top of a steeply inclined core impaired process performance. A second cycle recovered additional oil, but a decline in process performance was noted. A soak period was required to maximize oil recovery.

TABLE 1

CRUDE OIL PROPERTIES

	TIMBALIER BAY	APPALACHIAN BASIN
FIELD LOCATION	SOUTH LA	EASTERN KY
MOLECULAR WEIGHT ^a	225	220
DENSITY (60 °F, 1 atm.), °API	31.2	31.6
VISCOSITY (75 °F, 1 atm.), cp	13	6
COMPOSITION, wt%		
SATURATES	48.1	54.0
AROMATICS	31.4	32.0
RESINS	18.7	12.6
ASPHALTENES	1.8	1.4
C ₁₅₊	55.5	57.3

a. measured by freezing point depression

TABLE 2CONDITIONS OF CYCLIC CO₂ COREFLOODS: IMMISCIBLE CONDITIONS^a

Run (s)	Permeability (md)	S _{oi}	S _{orw}	E _{ri} ^b	Slug Size (scf)	Size (V _{rp})	Cycle No.
35	180	.663	.411	.379	1.01	.88	1
41,42	152	.698	.441	.369	1.01	.88	1,2
43,44	155	.698	.437	.375	.25	.22	1.2

a. The Appalachian Basin STO was used in this study. Run conditions were 500 psig and 78 °F.

b. Fraction of original oil-in-place recovered by waterflood.

TABLE 3

RESULTS OF COREFLOOD EXPERIMENTS: IMMISCIBLE CONDITIONS

RUN	CYCLE	E _{ri} ^a	E _{ri} ^b	GAS UTILIZATION (Mscf/bbl)
35	1	.112	.180	2.87
41	1	.080	.126	3.82
42	2	.081	.129	3.73
43	1	.049	.079	1.55
44	2	.030	.048	2.51

a. Fraction of original oil-in-place recovered by CO₂ flood.

b. Fraction of waterflood residual oil recovered by CO₂ flood.

TABLE 4CONDITIONS OF CYCLIC CO₂ COREFLOODS: RESERVOIR GAS^a

Run (s)	Permeability (md)	S _{oi}	S _{orw}	E _{ri} ^b	Pressure (psig)	Cycle No.
47, 48	404	.635	.409	.355	2,100	1, 2
53, 54	233	.591	.393	.335	2,100	1, 2
59, 60	218	.571	.366	.359	2,600	1, 2
45, 46	329	.657	.425	.353	3,300	1, 2
51, 52	305	.619	.403	.349	3,300	1, 2
57, 58	255	.569	.354	.378	3,600	1, 2

- a. The oil used in this study was RRO from Timbalier Bay STO and methane. The corefloods were performed at 130 °F. The CO₂ slug was approximately 2.09 scf. The V_{pr}s at 2100, 2600, 3300, and 3600 psig were 0.21, 0.19, 0.17 and 0.17, respectively.
- b. Fraction of original oil-in-place recovered by waterflood.

TABLE 5

RESULTS OF COREFLOOD EXPERIMENTS: RESERVOIR GAS

RUN	CYCLE	RUN CONDITIONS ^a	E _{ri} ^b	E _{ri} ^c	GAS UTILIZATION (Mscf/bbl)
47	1	Below P _b	.105	.163	6.18
48	2	Below P _b	.078	.120	8.34
53	1	Below P _b	.120	.181	5.55
54	2	Below P _b	.061	.091	11.11
59	1	Below P _b	.075	.117	9.51
60	2	Below P _b	.086	.134	8.32
45	1	Above P _b	.075	.116	8.34
46	2	Above P _b	.056	.087	11.12
51	1	Above P _b	.069	.107	9.47
52	2	Above P _b	.061	.094	10.69
57	1	Above P _b	.063	.102	11.48
58	2	Above P _b	.058	.093	12.37

- a. Run conditions with respect to oil bubble point.
- b. Fraction of original oil-in-place recovered by CO₂.
- c. Fraction of waterflood residual oil recovered by CO₂.

TABLE 6CONDITIONS OF CYCLIC CO₂ COREFLOODS: IMPURE CO₂^a

Runs	Permeability (md)	S _{oi}	S _{orw}	E _{ri} ^b	GAS (CO ₂ /CH ₄)	V _{RP}	Cycle No.
65, 66	318	.696	.412	.408	0/100	.244	1, 2
71, 72	258	.695	.414	.404	25/75	.234	1, 2
67, 68	318	.703	.407	.421	45/55	.227	1, 2
69, 70	297	.699	.402	.425	65/35	.219	1, 2
73, 74	209	.693	.409	.410	80/20	.213	1, 2
75, 76	322	.672	.400	.405	100/0	.207	1, 2

- a. The oil used in this study was Timbalier Bay STO. Run conditions were room temperature and 500 psig. The gas slug was 0.253 scf.
b. Fraction of original oil-in-place recovered by waterflood.

TABLE 7RESULTS OF COREFLOOD EXPERIMENTS: IMPURE CO₂

RUN	CYCLE	E _{ri} ^a	E _{rw} ^b	CO ₂ UTILIZATION		GAS UTILIZATION	
				CYCLE	TOTAL	CYCLE	TOTAL
65	1	.019	.032	N/A		4.03	
66	2	.108	.182	N/A	N/A	.67	1.15
71	1	.026	.043	.67		2.68	
72	2	.081	.135	.22	.34	.88	1.36
67	1	.013	.022	2.59		5.76	
68	2	.078	.135	.40	.69	.88	1.53
69	1	.020	.035	2.37		3.65	
70	2	.066	.114	.71	1.09	1.09	1.68
73	1	.009	.015	6.66		8.05	
74	2	.032	.054	1.36	2.22	1.68	2.78
75	1	.031	.053	2.37		2.37	
76	2	.025	.043	2.87	2.59	2.87	2.50

- a. Fraction of original oil-in-place recovered by CO₂.
b. Fraction of waterflood residual oil recovered by CO₂.

TABLE 8CONDITIONS OF CYCLIC CO₂ COREFLOODS: GRAVITY SEGREGATION^a

Runs	Permeability (md)	S _{oi}	S _{orw}	E _{ri} ^b	Cycle No.	RUN CONDITIONS
77,78	550	.664	.385	.420	1,2	no rotation
79,80	344	.687	.358	.479	1,2	continuous rotation
101,102	292	.713	.412	.422	1,2	rotated after injection ^c

- a. The oil used in this study was Timbalier Bay STO. Run conditions were room temperature and 500 psig. The gas slug was 0.254 scf.
- b. Fraction of original oil-in-place recovered by waterflood.
- c. The core was stationary during CO₂ injection, and was rotated during the soak and production phases of the experiment.

TABLE 9

RESULTS OF COREFLOOD EXPERIMENTS: GRAVITY SEGREGATION

RUN	CYCLE	E _{ri} ^a	E _{ri} ^b	CO ₂ UTILIZATION (Mscf/bbl)
77	1	.047	.081	1.68
78	2	.017	.029	5.03
79	1	.017	.034	4.02
80	2	.008	.016	8.04
101	1	.045	.078	1.68
102	2	.021	.036	3.67

- a. Fraction of original oil-in-place recovered by CO₂.
- b. Fraction of waterflood residual oil recovered by CO₂.

TABLE 10CONDITIONS OF CYCLIC CO₂ COREFLOODS: GAS CAP^a

Run (s)	Permeability (md)	S _{oi}	S _{orw}	E _{ri} ^b	Pressure (psig)	Cycle No.
83,84 _c	238	.558	.269	.518	2,600	1,2
97,98 _d	218	.538	.303	.437	2,600	1,2
99,100 ^e	196	.550	.316	.425	3,300	1,2

- a. The oil used in this study was RRO from Timbalier Bay STO and methane. The corefloods were performed at 130 °F. At 130 °F, the oil bubble point pressure (P_b) was 3100 psig. The CO₂ slug was 2.09 scf. The V_{PR}s at 2600, and 3000 psig were 0.207 and 0.187 respectively.
- b. Fraction of original oil-in-place recovered by waterflood.
- c. CO₂ was injected into the gas cap.
- d. CO₂ was injected below the gas cap.
- e. Run conditions were above P_b.

TABLE 11

RESULTS OF COREFLOOD EXPERIMENTS: GAS CAP

RUN	CYCLE	E _{RI} ^a	E _{RI} ^b	CO ₂ UTILIZATION (Mscf/bbl)
83	1	.089	.186	8.99
84	2	.034	.071	23.77
97	1	.099	.175	8.53
98 ^c	2	.009	.017	83.19
99	1	.067	.117	12.33
100	2	.040	.069	19.58

- a. Fraction of original oil-in-place recovered by CO₂.
- b. Fraction of waterflood residual oil recovered by CO₂.
- c. Experiment aborted prior to cessation of oil production due to mechanical failure of regulator.

TABLE 12**GAS VOLUMES AT INJECTION AND SOAK CONDITIONS**

GAS	CO ₂	N ₂
Volume (cm ³)		
1640 psig, 78 °F	16	16
500 psig, 78 °F	169	52
Density (g/cm ³)		
1640 psig, 78 °F	.834	.130
500 psig, 78 °F	.079	.040
Mass Injected (g)	13.35	2.08
Gas Fractional Pore Volume		
500 psig, 78 °F	.225	.069

TABLE 13CONDITIONS OF CYCLIC CO₂ COREFLOODS: DRIVE GAS^a

Runs	Permeability (md)	S _{oi}	S _{orw}	E _{ri} ^b	Fluid Injected	Cycle No.
81,82	491	.687	.384	.441	CO ₂	1,2
107,108	282	.697	.408	.405	CO ₂ + N ₂	1,2
111,112	260	.703	.393	.440	N ₂	1,2

a. The oil used in this study was Timbalier Bay STO. The corefloods were performed at 78 °F and 500 psig.

b. Fraction of original oil-in-place recovered by waterflood.

TABLE 14

RESULTS OF COREFLOOD EXPERIMENTS: DRIVE GAS

RUN	CYCLE	E _{ri} ^a		CO ₂ UTILIZATION		GAS UTILIZATION	
		Cycle	Total	Cycle	Total	Cycle	Total
81	1	.073		1.92		1.92	
82	2	.028	.101	5.05	2.79	5.05	2.79
107	1	.163		.81		1.01	
108	2	.082	.245	1.62	1.08	2.01	1.34
111	1	.044		--		.77	
112	2	.013	.057	--	--	2.49	1.17

a. Fraction of waterflood residual oil recovered by cyclic stimulation.

TABLE 15CONDITIONS OF CYCLIC CO₂ COREFLOODS: REMAINING OIL SATURATION^a

Runs	Permeability (md)	S _{oi}	S _{orw}	E _{ri} ^b	Cycle No.
81,82	491	.687	.384	.441	1,2
85,86	326	.716	.476	.335	1,2
87,88	303	.708	.548	.226	1,2
91,92	131	.696	.593	.148	1,2
103,104	306	.696	.571	.180	1,2
105,106	278	.692	.395	.430	1,2

- a. The oil used in this study was Timbalier Bay STO. The corefloods were performed at 78 °F and 500 psig. The CO₂ slug was 0.254 scf. In runs 81, 82, 85, 86, 87, 88, 91 and 92, water and CO₂ were injected in the same direction. In runs 103-106, water and CO₂ were injected into opposite ends of the core.
- b. Fraction of original oil-in-place recovered by waterflood.

TABLE 16

RESULTS OF COREFLOOD EXPERIMENTS: REMAINING OIL SATURATION

RUN	CYCLE	E _{ri} ^a	E _{ri} ^b	CO ₂ UTILIZATION	
				Cycle	Total
81	1	.041	.073	1.92	
82	2	.016	.028	2.79	2.79
85	1	.063	.114	1.19	
86	2	.020	.037	3.67	1.79
87	1	.085	.131	.90	
88	2	.053	.081	1.44	1.11
91	1	.161	.222	.48	
92	2	.059	.082	1.30	.70
103	1	.276	.336	.28	
104	2	.052	.063	1.50	.47
105	1	.031	.054	2.52	
106	2	.058	.101	1.35	1.76

- a. Fraction of original oil-in-place recovered by CO₂.
- b. Fraction of waterflood residual oil recovered by CO₂.

TABLE 17CONDITIONS OF CYCLIC CO₂ COREFLOODS: RESIDUAL OIL SATURATION^a

Run	Permeability (md)	S _{oi}	Pressure (psig)	Slug Size (scf)	(V _{RP})
129a-e	245	.707	500	.254	.224
130a-c	253	.681	1600	.947	.080

- a. The oil used in this study was Timbalier Bay STO. The corefloods were performed in the horizontal core at 78 °F.

TABLE 18RESULTS OF COREFLOOD EXPERIMENTS: RESIDUAL OIL SATURATION^a

RUN	Cycle No.	S _{ORW}	E _{RI} ^b	E _{RI} ^c	CO ₂ UTILIZATION (Mscf/bbl)
129a	1	.401	.030	.053	2.52
129b	2	.380	.024	.043	3.11
129c	3	.363	.015	.027	5.05
129d	4	.352	.009	.017	8.08
129e	5	.345	.004	.007	20.19
130a	1	.353	.035	.068	8.36
130b	2	.329	.004	.008	75.26
130c	3	.327	.002	.004	150.53

- a. A range of residual oil saturations was simulated by thoroughly waterflooding the core after each CO₂ cycle to remove all trapped CO₂ from the core. This procedure returned the core to its pre-CO₂ state, with only water and oil present in the core. The residual oil saturation, however, was reduced to a lower level as some of the oil had been recovered by the preceding cyclic CO₂ stimulation experiment.
- b. Fraction of original oil-in-place recovered by CO₂.
- c. Fraction of waterflood residual oil recovered by CO₂.

TABLE 19CONDITIONS OF CYCLIC CO₂ COREFLOODS: CO₂ INJECTION RATE^a

Run (s)	Permeability (md)	S _{oi}	S _{orw}	Cycle No.	Injection Rate, cc/hr
17 ^b	192	.661	.399	1	10
29 ^b	192	.716	.443	1	60
22 ^b	189	.683	.417	1	200
23 ^b	189	.683	.417	2	60
113, 114 ^c	180	.644	.290	1, 2	60
133, 134 ^c	230	.656	.330	1, 2	100
117, 118 ^c	190	.691	.394	1, 2	140
123, 124 ^c	267	.667	.348	1, 2	160
115, 116 ^c	235	.682	.362	1, 2	200

- a. The oil used in this study was Timbalier Bay STO.
- b. Run conditions were 130 °F and 1600 psig. The following CO₂ slugs were used: 2.06 (runs 17 and 22), 2.64 (run 29), and 1.74 scf (run 23).
- c. Run conditions were 78 °F and 500 psig. The CO₂ slug was 0.254 scf.

TABLE 20RESULTS OF COREFLOOD EXPERIMENTS: CO₂ INJECTION RATE

RUN	CYCLE	Injection Rate, cm ³ /hr	E _{RI} ^a		CO ₂ UTILIZATION	
			Cycle	Total	Cycle	Total
17	1	10	.096		4.02	
29	1	60	.188		2.96	
22	1	200	.089		11.76	
23	2	60	.114		7.50	
113	1	60	.052		3.85	
114	2	60	.010	.062	16.15	6.21
133	1	100	.012		13.46	
134	2	100	.011	.023	16.15	14.68
117	1	140	.091		1.55	
118	2	140	.010	.101	13.46	2.78
123	1	160	.008		20.19	
124	2	160	.024	.032	6.73	10.10
115	1	200	.029		5.38	
116	2	200	.042	.071	3.67	4.37

- a. Fraction of waterflood residual oil recovered by CO₂.

TABLE 21CONDITIONS OF CYCLIC CO₂ COREFLOODS: RESERVOIR DIP^a

Run	Permeability (md)	S _{oi}	S _{orw}	Cycle No.	Dip Angle (degrees)	Injection Site
119,120	199	.743	.438	1,2	45	bottom
121,122	222	.723	.405	1,2	90	bottom
125,126	267	.698	.362	1,2	0	horizontal
127,128	211	.697	.373	1,2	90	top
131,132	214	.683	.353	1,2	45	top

- a. The oil used in this study was Timbalier Bay STO. Run conditions were 78 °F and 500 psig. The CO₂ slug was 0.253 scf. The dip angle was varied by inclining the core at the desired angle. The effect of injection site was examined by injecting CO₂ into either the top or the bottom of the core.

TABLE 22

RESULTS OF COREFLOOD EXPERIMENTS: RESERVOIR DIP

RUN	CYCLE	Dip Angle (degrees)	Injection Site	Cycle	E _{kr} ^a	CO ₂ UTILIZATION	
					Total	Cycle	Total
119	1	45	bottom	.027		4.49	
120	2	45	bottom	.050	.077	2.52	3.23
121	1	90	bottom	.025		5.77	
122	2	90	bottom	.069	.094	2.38	3.23
125	1	0	--	.019		8.08	
126	2	0	--	.011	.030	13.46	10.10
127	1	90	top	.011		13.46	
128	2	90	top	.008	.019	20.19	16.15
131	1	45	top	.011		13.46	
132	2	45	top	.009	.020	20.19	16.15

- a. Fraction of waterflood residual oil recovered by CO₂.

FIGURE 1

COREFLOOD APPARATUS

- V - Digital Display Meter**
W - Cleaning Fluids
 1. 50,000 ppm Brine
 2. 20,000 ppm Brine
 3. Isopropyl Alcohol
 4. Xylenes
X - Cleaning Pump
Y - Set Pressure Control Switch
Z - Hand Pump

FIGURE 2. EFFECT OF RESERVOIR PRESSURE ON PROCESS PERFORMANCE

FIGURE 3
OIL RECOVERY AND GAS SLUG SIZE
VS. CO₂ MOLE% IN GAS SLUG

FIGURE 4

**WATERFLOOD RESIDUAL OIL RECOVERY EFFICIENCY
CORE FLOODS**

**FIGURE 5. PRODUCTION PROFILES -
RESERVOIR DIP**

II. COMPUTER SIMULATION

Computer simulation studies were performed to complement and extend the investigation of important operational and reservoir parameters initiated in the coreflood study. Laboratory coreflood experiments were time consuming and certain parameters were difficult, if not impossible, to duplicate in the laboratory. Simulation allowed analysis of reservoir or operational parameters that could not be readily analyzed in the laboratory due to time or other constraints. In addition, simulation provided a means of examining the recovery process in detail and illuminating the relative importance of various oil recovery mechanisms.

Laboratory studies of cyclic CO₂ injection for light oil recovery have provided an extensive coreflood data base which was used to tune a compositional reservoir simulator. The calibrated model was then used to predict the results of the CO₂ huff 'n' puff process under different reservoir and operating conditions. The following reservoir/operational parameters were investigated: soak duration, CO₂ slug size, CO₂ injection rate, remaining oil saturation, residual oil saturation, and reservoir relative permeability.

HISTORY MATCH

J.S. NOLAN AND ASSOCIATES SIMULATOR

A compositional simulator was donated to the research program by J.S. Nolan and Associates (EOS-PAK, VIP-CORE, and VIP-EXEC). It was installed on the University's IBM mainframe computer. The initial effort focused on predicting the results of one cyclic CO₂ coreflood performed at conditions above the bubble point of a reconstituted reservoir oil (RRO). Three steps were required to perform the simulation. First, the equation of state package was used to model the phase properties of the RRO. Second, initial core conditions were established using a linear, one-dimensional 20-block grid to represent the 6 ft Berea core. Grid No. 1 was a CO₂ injection well for the huff, was shut-in for the soak, and then converted to a production well for the puff phase. Grid No. 20 was a production well for the huff, was shut-in for the soak, and then converted to a water injection well for the puff phase. Third, flow conditions were adopted to model cyclic CO₂ injection. Measured data were used for numerical simulation parameters (with the exception of relative permeability curves which were adjusted to optimize the match between predicted and experimental production profiles).

The figures and tables referenced in this chapter are located at the end of the chapter.

The experiment modeled in the initial simulation was a first-cycle cyclic CO_2 injection using pure CO_2 and a live oil at undersaturated conditions. The live oil was Timbalier bay stock tank oil reconstituted with methane at a Gas/Oil Ratio (GOR) of 400 scf/STB. The bubble point at run temperature was 3100 psia, and the run was performed at 3300 psig. Other experimental data used in the simulation are listed in Table 23. Eight pseudocomponents were used to describe the reservoir oil composition. The mole fractions and binary interaction coefficients used in the equation of state package are provided in Table 24. The simulation results are illustrated in Figures 6-9.

The model indicated that during the huff 91% of the fluid displaced from the core into the transfer vessel was brine, and the remainder was 10 cm^3 of stock tank oil. Although this oil was recovered during experimental runs, simulator restrictions prevented its recovery during model runs. Nonetheless, there was fair agreement between the simulated and measured puff production profiles (Figure 6). The simulator predicted earlier gas production and ultimately higher gas retention. Oil production was underestimated by 14 cm^3 , which was approximately the volume of oil lost during the huff.

Saturation profiles for gas (Figure 7), oil (Figure 8), and water (Figure 9) were also generated. The gas saturation profile showed a high saturation extending two ft from the core inlet. The oil saturation profile showed that an oil bank was formed during the huff, and that oil was preferentially produced from the same region of the core that contained the high gas saturation. The water saturation profile showed that water was efficiently displaced from the core inlet but that no water bank was formed.

The major discrepancy in the simulator and coreflood results was the sequence of oil and water production. In laboratory corefloods, oil production preceded water production and was actually curtailed by the breakthrough of water influx. In the simulation, oil and water were produced simultaneously. The simulator also predicted incremental oil recovery from portions of the core that were not contacted by CO_2 . It is plausible that these shortcomings stemmed from the limitation of one set of relative permeability curves to describe both the huff and puff phases.

WELLDRIILL SIMULATOR

Due to the limitations of the J.S. Nolan and Associates simulator, a second simulator was acquired from Welldrill Limited. The SIMCO simulator, developed by Continental Computer Bureau, Ltd. was a three-phase, three-dimensional multicomponent reservoir simulator like the one obtained from J.S. Nolan and Associates. In addition, it was capable of incorporating two sets of relative permeability curves to describe the drainage and imbibition stages

of the cyclic CO₂ injection process. The simulator was installed on the University's VAX-8800 mainframe computer.

A rectangular grid-block geometry was used to describe the 6-ft-long core with 20 blocks. Each block was 0.3 ft long, 0.1477 ft wide and 0.1477 ft high. This corresponded to the volume of the core. Four additional blocks were used to model the transfer vessel connected to the outlet end of the core.

The following grid-block configuration was used to model the cyclic CO₂ process.

Block #1

Block #24

CO₂ injection well for huff
Shut-in during soak
Production well for puff

Production well for huff
Shut-in during Soak
Water injection well for puff

Measured values of porosity, absolute permeability, initial pressure, and initial fluid saturations were assigned to each block. Eight pseudo-components were used to describe the reservoir oil (Timbalier Bay oil reconstituted with methane to give a GOR of 400 scf/STB). Molar compositions, critical temperatures and pressures, acentric factors, and binary interaction coefficients of the pseudocomponents were input and used to tune the Peng-Robinson equation of state. The properties of the oil pseudocomponents and experimental conditions are listed in Tables 25 and 26, respectively. Binary interaction coefficients were the same as used in the previous modelling study.

Variations in the flow of oil, gas, and water were controlled by relative permeability and capillary pressure curves for each of these fluids. Directional relative permeabilities could be assigned. Three-phase relative permeabilities were internally calculated.

Coreflood data included cumulative amounts of oil, gas, and water injected and produced during each of the oilflood, waterflood and huff 'n' puff stages. Production profiles of oil, gas, and water were obtained for the puff stage.

Since Berea sandstone is a standard porous medium for experimental research, relative permeability and capillary pressure curves for this type of sandstone with different stock-tank oils (STO) were found in the literature.¹¹ These curves were used for initial simulations of the CO₂ huff, soak, and puff stages. Minor changes were then made in the curves to history match oil and water production with time for the oilflood and waterflood stages. The refined curves were employed in a second stage simulation of the CO₂ huff, soak, and puff stages. An adequate history match was obtained, and the results are summarized in Table 27.

After the model was tuned, a sensitivity analysis was performed to determine the optimum number of grid blocks, and the reproducibility of simulator predictions was examined. Detailed descriptions of the methods employed and results obtained are presented in reference 12. Briefly, the studies found that 20 grid blocks were adequate to represent the core and that the model results were highly reproducible.

PARAMETER INVESTIGATION

The tuned Welldrill model was used to investigate the effects of key parameters on the CO₂ huff 'n' puff process at miscible conditions. Investigations of the influences of soak duration, CO₂ slug size, CO₂ injection rate, remaining oil saturation, residual oil saturation, and reservoir relative permeability have been completed. As some of these parameters had been investigated using laboratory corefloods, the accuracy of the simulator predictions could be assessed under a variety of conditions.

SOAK DURATION

Numerical simulation was performed to investigate the influence of soak duration. Soak times of 0, 3, 6, 10, 11, 15, and 17 hours were simulated, and the production process was terminated when a water cut of one was attained.

As shown in Figure 10, cumulative oil production increased and reached a maximum at an optimum soak time of 15 hours, beyond which there was no additional improvement in recovery. Analysis of the model indicated that the number of grid blocks contacted by CO₂ increased with increasing soak time, reached a maximum at 15 hours, and remained constant for longer soak times. Thus, a minimum soak time was needed for CO₂ to migrate through the porous media and interact with the crude. Although the obtained minimum soak time of 15 hours was system dependent, this investigation confirmed that a minimum soak time is required for optimum process performance.

CO₂ SLUG SIZE

The effect of CO₂ slug size on process performance was evaluated using numerical simulation. Four simulations were performed using CO₂ slug sizes of 1.25 g-moles (0.1042 scf), 2.5 g-moles (0.2083 scf), 3.75 g-moles (0.3125 scf), and 5.00 g-moles (0.4167 scf). As shown in Figure 11, oil recovery was found to increase with increasing slug size until it reached a maximum, after which there was no further improvement. Analysis of the model indicated that in the case of the largest slug CO₂ pushed oil too far away from the production outlet to be recovered. This finding was consistent with previous field-test data base analyses.¹³

CO₂ INJECTION RATE

Four simulations were performed to investigate the influence of CO₂ injection rate on process performance. Injection rates of 20, 40, 60, and 120 cm³/hr were examined. As shown in Figure 12, oil recovery appeared to decline slightly as injection rate increased. However, since the difference in recoveries for injection rates of 20 cm³/hr and 120 cm³/hr was only 0.38% of the core pore space, and no physical explanation could be gleaned from the saturation profiles of oil, gas, and water, the results were inconclusive.

This result differed significantly from results of coreflood studies conducted at near-miscible conditions. The coreflood investigations indicated that there was an optimum rate for maximum oil recovery, and that recovery decreased when injection rates higher or lower than the optimum were employed. Differences in the coreflood and simulator results could have been due to miscibility effects as simulations were performed at miscible conditions, while corefloods were conducted in the near-miscible regime. Comparisons of compatible experimental and simulator conditions are planned.

REMAINING OIL SATURATION

Since enhanced oil recovery processes are usually applied before a reservoir is completely watered out, the effect of remaining oil saturation on process performance was examined. In this study, as in the coreflood investigations, remaining oil was defined as the oil left in the core after partial waterflooding, thus a portion of the remaining oil could be mobilized by waterflooding. Residual oil was defined as oil that could not be mobilized by waterflooding.

Six simulations, one at waterflood residual oil saturation ($S_{orw} = 0.464$) and the others at various higher oil saturations ($S_{orw} = 0.500, 0.600, \text{ and } 0.625$), were performed to investigate the effect of remaining oil saturation on process performance. The results of the study are presented in Table 28. Flood performance was found to decrease at higher oil saturations. Analysis of the model indicated that at higher oil saturations CO₂ pushed moveable oil away from the injection site. This reduced the recovery efficiency of the process.

RESIDUAL OIL SATURATION

Reservoir simulations were performed to determine the influences of residual oil saturation on cyclic CO₂ process performance at miscible conditions. As shown in Figure 13, the influence of residual oil saturation at miscible conditions was quite different from that observed in the coreflood experiments conducted at immiscible conditions. In the simulation, recovery efficiency increased with increasing residual oil saturation,

reached a maximum, and then decreased with further increases in residual oil saturation at miscible conditions. The corefloods indicated that recovery efficiency steadily increased with increasing residual oil saturation.

The differences in the simulation and coreflood results were attributed to miscibility effects. At miscible conditions, CO₂ mixed with oil to a greater extent during CO₂ injection, and mobilized oil away from the injection site. At immiscible conditions, the interaction of CO₂ and oil were reduced, and CO₂ essentially bypassed the oil during injection. The combination of miscible conditions and higher oil saturations favored oil bank formation during the CO₂ injection process. If an oil bank was formed during CO₂ injection, oil would be efficiently moved away from the injection site, thus becoming more difficult to recover.

RESERVOIR RELATIVE PERMEABILITY/WETTABILITY

The effects of reservoir relative permeability on cyclic CO₂ performance could not be readily investigated in the laboratory since it was virtually impossible to physically isolate this parameter. As relative permeability is affected by mineral wettability, methods of altering the wettability of the Berea sandstone cores used in the coreflood experiments were examined. No method was found that would provide a range of wettability states without introducing additional variables. Simulation was, therefore, the only means available for examination of relative permeability effects.

Relative permeability curves characteristic of water-wet, neutral, and oil-wet states were input into the simulator to examine the effect of wettability on process performance at miscible conditions. The wettability states were defined as follows:

- 1) The water saturation at which the water relative permeability (k_{rw}) equaled the oil relative permeability after waterflooding (k_{row}) was >50% for water-wet, <50% for oil-wet, and approximately equal to 50% for neutral conditions.
- 2) The k_{rw} at residual oil saturation after waterflooding (S_{orw}) was <0.3 for water-wet, >0.5 (approaching 1.0) for oil-wet, and equal to k_{row} at neutral conditions.
- 3) The initial water saturation (S_{wi}) was 20-25% at water-wet and <15% at oil-wet conditions.

The results, shown in Figure 14, indicated that more incremental oil was recovered at oil-wet conditions than with the other wettability regimes.

CONCLUSIONS

A compositional reservoir simulator was adequately tuned to model laboratory coreflood results. Model results at simulated miscible conditions indicated that a minimum soak time was required for optimum process performance, and oil-wet conditions were more favorable than other wettability states. In addition, results suggested that there were optimum values for the slug size, and residual, as well as remaining, oil saturation. At miscible conditions, CO₂ efficiently mobilized oil during the injection stage and drove it away from the injection/production site, which made the oil more difficult to recover during the production stage.

TABLE 23**EXPERIMENTAL DATA USED FOR COMPUTER SIMULATION**

Pressure (psig)	3300
Pressure Gradient (psi/ft)	16.7
Temperature (°F)	130
Permeability (md)	329
Porosity (%)	23
Pore Volume (cc)	852
Waterflood Residual STO Volume (cc)	362
CO ₂ Slug (scf)	2.09
CO ₂ Slug (pv)	.167
Soak (hr)	10
Displacement Rate (cc/hr)	60

TABLE 24**RESERVOIR OIL COMPOSITION AND BINARY COEFFICIENTS
USED IN COMPUTER SIMULATION**

RESERVOIR OIL PSEUDOCOMPONENTS		
No.	Component	Mole Fraction
1	CO ₂	.0000
2	C1	.43500
3	C6+	.12046
4	C9+	.13453
5	C12+	.11972
6	C17	.08917
7	C25	.05539
8	C42	.04753

BINARY INTERACTION COEFFICIENTS								
	1	2	3	4	5	6	7	8
1	0	.1500	.1500	.1500	.1500	-.0511	.1877	.2467
2	.1500	0	0	0	0	.0523	.0575	.0640
3	.1500	0	0	0	0	0	0	0
4	.1500	0	0	0	0	0	0	0
5	.1500	0	0	0	0	0	0	0
6	-.0511	.0523	0	0	0	0	0	0
7	.1877	.0575	0	0	0	0	0	0
8	.2467	.0640	0	0	0	0	0	0

TABLE 25

PROPERTIES OF PSEUDOCOMPONENTS

Component	Mol. Wt.	Pc	Tc	w
CO ₂	44.01	1071.0	547.9	.2225
C1	16.04	667.8	343.9	.0126
C6+	100.12	441.8	1003.4	.2888
C9+	132.86	382.1	1122.9	.4119
C12+	181.38	318.4	1249.7	.5740
C17+	240.27	231.2	1382.4	.8000
C25+	342.82	185.0	1558.7	1.1167
C37+	464.00	178.1	1673.0	1.4993

TABLE 26

EXPERIMENTAL DATA USED FOR NUMERICAL SIMULATION

Pressure (psig)	3300
Temperature (°F)	130
Permeability (md)	305
Porosity (%)	22
CO ₂ Slug (g-mol)	2.5
CO ₂ Slug (pv)	.167
Soak (hr)	10
CO ₂ Injection Rate (cc/hr)	60
Huff Time (hr)	2
Displacement Rate (cc/hr)	60
Residual S _o	.464

TABLE 27**SUMMARY OF COREFLOOD HISTORY MATCH**

	Laboratory Coreflood	Simulation
N_p (cm ³)	35	35
G_p (scf)	1.124	1.329
W_p (cm ³)	55	52
T^a (min)	180	180

a. Time elapsed during production phase after 10-hour soak.

TABLE 28**RESULTS OF COMPUTER SIMULATION: REMAINING OIL SATURATION EFFECTS**

S_{orw}	N_p (cm ³)	G_p (scf)	W_p (cm ³)
.464	35	1.329	52
.500	37	1.373	48
.600	47	1.452	33
.625	50	1.490	29

FIGURE 6

RUN NO.45, FIRST CYCLE

FIGURE 7

FIGURE 8

FIGURE 9

FIGURE 10

CUMULATIVE OIL AND GAS PRODUCTION VS. SOAK TIME

FIGURE 11

CUMULATIVE OIL AND GAS PRODUCTION VS. CO₂ SLUG SIZE

FIGURE 12

CUMULATIVE OIL AND GAS PRODUCTION
VS. CO₂ INJECTION RATE

FIGURE 13

WATERFLOOD RESIDUAL OIL RECOVERY EFFICIENCY SIMULATION

FIGURE 14
SIMULATION RESULTS: WETTABILITY EFFECTS

III. FIELD-TEST DATA BASE

An extensive field-test data base was constructed and analyzed to facilitate reservoir screening and to identify successful operational practices. Analysis of the effects of important reservoir and operational parameters on process performance in the field also provided a basis for evaluating validity of coreflood and computer simulation results. In addition, predictive techniques were assessed to determine their ability to estimate incremental oil recovery as a result of process implementation.

DESCRIPTION OF DATA BASE

The data base documented 106 CO₂ cyclic stimulation tests performed in light-oil (23-38 °API) sandstone reservoirs under diverse reservoir conditions. These projects were conducted in fourteen different fields located in Louisiana and Kentucky. Sites on land, as well as over inland waterways, were included.

The field data employed in the study were obtained from five oil companies. Engineers at the various companies were visited periodically to obtain both updated results from past tests and new data from recent tests. Operational procedures used by the various companies were also discussed.

Operational procedures varied. CO₂ was typically transported in tanker trucks as a liquid at 300 psi and 0 °F. In many cases, CO₂ was heated prior to injection down the tubing, workstring, or annulus. Injection rates were typically as fast as pumps would allow; however, in some cases, lower rates were used to prevent damage to well completions. After injection, the CO₂ was displaced from the wellbore with a corrosion-inhibitor/lease-crude mixture. The well was then shut-in for a soak period ranging from one week to six months; one month was the typical soak period. In some cases, offset wells were also shut-in to confine CO₂. After the soak period, the well was typically reopened on a small choke to keep backpressure on the well and thus minimize CO₂ breakout. Many companies preferred to isolate cyclic CO₂ production due to the detrimental effects of CO₂.

Reservoir/operational parameters that appeared to be important to cyclic CO₂ stimulation, as based on published field studies, laboratory coreflood experiments, and computer simulation results, were included in the data base. A detailed description of the data base is provided in reference 14.

The figures and tables referenced in this chapter are located at the end of the chapter.

EVALUATION PROCEDURE

Process effectiveness was assessed on the basis of four evaluation parameters: incremental oil, CO₂ utilization, CO₂ reservoir utilization, and stimulation ratio. The incremental oil produced as a result of cyclic CO₂ injection was determined using decline curve analysis. CO₂ utilization was defined as the volume of CO₂ injected, measured at standard conditions in Mscf, divided by the estimated incremental oil production in barrels. CO₂ reservoir utilization was defined as the volume of CO₂ injected, measured in ft³ at reservoir conditions, divided by the estimated incremental oil production in barrels. Stimulation ratio was defined as the average oil production rate during the first month of post-CO₂ production divided by the average monthly oil production rate before CO₂ injection.

Incremental oil was determined by calculating the area between the predicted baseline decline curve based on pre-CO₂ injection data and the decline curve established after CO₂ injection. Both decline curves were determined by linear regression analysis of production data. If the predicted pre-CO₂ decline curve reached the well's economic limit, baseline production was held constant at the economic limit. The project life was terminated either when the post-CO₂ decline curve reached the extrapolated pre-CO₂ baseline or if the well was worked over. If necessary, the post-CO₂ decline curve was extrapolated. A sample decline curve analysis is shown in Figure 15.

Relationships between evaluation parameters and reservoir/operational variables, as well as oil recovery mechanisms, were determined using linear regression analysis. More sophisticated analytical procedures were not employed due to data limitations and difficulties in isolating the influence of a particular property. Data analysis was complicated by several factors: use of field-wide averages or correlations where single-well data were not available, changes in numerous parameters from test to test, and difficulties in quantifying various drive mechanisms.

As one objective of the data base analysis was to correlate reservoir/operational parameters with successful test responses to determine performance trends, a preliminary evaluation of field-test response was conducted to exclude tests that may have failed due to mechanical problems. Wells that showed a limited response were evaluated separately to improve reservoir screening criteria and to establish operational guidelines. An economic criterion based on a CO₂ utilization of 3 Mscf/STB or less was adopted for screening purposes.

Out of the 106 tests in the data base, 97 recovered incremental oil. Eight of the failures were attributed to mechanical problems during CO₂ injection, and one to apparent CO₂,

migration along a fault. A summary of selected reservoir properties for fields in which cyclic CO₂ injection recovered incremental oil is given in Table 29. Table 30 lists operating conditions for the 97 projects that produced incremental oil.

Out of the 97 tests that recovered incremental oil, 87 were considered to be economic successes on the basis of CO₂ utilization. In Field G, production was frequently pooled and individual well monitoring was limited; therefore, 61 single-well tests were evaluated as six projects. The number of successful tests was thus reduced to 30 for the purposes of evaluation. Tables 31 and 32 summarize the results of the successful projects.

PRODUCTION-RESPONSE TRENDS

CO₂ SLUG SIZE

Of all the parameters examined in the study, the amount of CO₂ injected gave the best correlation with production response. The trend between incremental oil and mass of CO₂ injected is shown in Figure 16. Injection of extremely large slugs dampened response in some low pressure reservoirs. A large reservoir volume of CO₂ may have altered oil too far from the wellbore to be effectively recovered in reservoirs with poor drive mechanisms.

The mass of CO₂ injected also correlated with the post-CO₂ rise in oil production rate, as shown in Figure 17. For the 30 successful projects, the average increase in oil production rate observed during the first month of post-CO₂ production was 34 BOPD, with an average CO₂ slug of 400 tons.

DRIVE MECHANISM

The reservoir drive mechanism strongly influenced process performance, particularly in reservoirs where the process was hampered by negative factors. Strong water-drive reservoirs typically performed well in the absence of mechanical failures, while depletion or weak-water drive reservoirs performed well when other favorable factors were present to offset the negative influence of a poor drive.

The reservoir area affected by CO₂ injection was influenced by the strength of the reservoir drive. The radius of CO₂ migration for successful projects was estimated assuming uniform displacement, a reservoir CO₂ saturation of 50%, and no mixing of CO₂ with reservoir fluids. The results summarized in Table 33 indicated that the treatment radius increased with the available reservoir energy.

RESERVOIR PRESSURE

Reservoir CO₂ utilization improved as reservoir pressure increased; however, operating above the minimum miscibility

pressure appeared to be unfavorable. Laboratory coreflood and computer simulation results indicated that CO₂-contacted oil was displaced more efficiently at higher pressures. Since the CO₂ solubility in oil increased with pressure, the alteration of oil by CO₂, thus the mobility of the oil, improved as pressure increased. Miscible conditions were detrimental to process performance because CO₂ dissolved in oil during the injection process, displacing oil away from the wellbore.

Although CO₂ reservoir utilization was not optimal at lower pressures, the process economics were often favorable. At lower pressures, the reservoir volume occupied by a fixed mass of CO₂ increased, and more oil was contacted by CO₂. Incremental oil was recovered at immiscible conditions as the poorer displacement efficiency was balanced by an increase in the reservoir volume of oil contacted by CO₂. Operations at lower pressures were less expensive since a smaller mass of CO₂ was typically required for injection, and also because pumping, as well as well preparation, expenses were less.

NET PAY INTERVAL

Process response tended to improve with thicker net pay intervals when comparisons were made on an individual-field basis (Figure 18). This trend was not sufficiently strong enough to be observed on a wider basis, perhaps because it was overshadowed by variations in other factors that more strongly influenced process response. However, attempts to minimize the effects of other factors on the process by normalizing response were fruitless. The improvement in process response with net pay interval was attributed to increased CO₂/oil contact near the wellbore where recovery efficiency was high.

SOAK PERIOD

The relationship between incremental oil per unit of pay and soak duration is depicted in Figure 19. Extending the soak period up to about four weeks improved response. Minimal additional improvement was noted for longer soak periods, especially when production losses during the soak were taken into account.

OIL RECOVERY MECHANISMS

Examination of the cyclic CO₂ stimulation process by analysis of laboratory coreflood, computer simulation, and field-test results have attributed improved oil recovery to one or more of the following factors:^{4,7,8,15-17}

1. Oil viscosity reduction,
2. Oil swelling,
3. Solution-gas drive,

4. Altered relative permeability from reduced water saturations, drainage/imbibition hysteresis, and/or wettability change,
5. Hydrocarbon extraction, or
6. Interfacial tension reduction.

The contribution of oil swelling was estimated by multiplying the volume of oil contacted by CO₂ by a swelling index. The oil swelling index was determined using the Simon and Graue¹⁸ correlation. The volume of oil in the zone contacted by CO₂ was determined using the pre-CO₂ oil saturation and the estimated reservoir volume contacted by CO₂. It was assumed that CO₂ mixed with the oil present in a reservoir pore volume that was twice that of the CO₂ reservoir volume. This assumption was based on laboratory coreflood experience. Oil viscosity reduction was estimated in a similar fashion using the Simon and Graue¹⁸ correlation.

The influence of oil swelling was overshadowed by stronger effects when analyzed on a project-wide basis. As shown in Figure 20, a correlation between swelled oil and incremental oil was observed when the data was analyzed on an individual-field basis.

No trend could be discerned between viscosity reduction and process performance; however, data were limited due to the use of field-wide oil viscosity values for individual wells. Although viscosity reduction has been shown to be an important mechanism in the recovery of heavy oils, studies have indicated that it had a lesser effect on the recovery of light oils such as those included in the data base.^{1,17}

The influence of solution-gas drive was not analyzed directly; however, indirect results suggested that this mechanism was not significant. Field observations indicated that oil production cut improved when wells were opened on a small choke. Opening the well on a small choke increased the backpressure on the well, reducing CO₂ outgassing. In addition, reservoir capacity, which is inversely proportional to pressure drawdown, correlated with improved response, as shown in Figure 21.

Relative permeability appeared to be important since CO₂ injection reduced water cuts in most of the tests. Apparently, CO₂ pushed water away from the wellbore, and alteration of the water saturation in the vicinity of the wellbore impaired water flow. Additionally, the improvement of response with soak time underlined the importance of diffusion.

OTHER OBSERVATIONS

Five of the projects included in the data base were followed by a second cycle of CO₂ injection. In four cases, some decline in process performance was noted. In one case, an improvement in

second-cycle CO₂ utilization was noted. This improvement was attributed to an extended soak period.

Improved oil production and CO₂ breakthrough were noted in some wells adjacent to cyclic CO₂ stimulation tests. In one case, CO₂ production in an offset well was observed during the soak period. It was assumed that CO₂ traveled through fractures connecting the two wells.

Low pre-CO₂ water cuts did not appear to be advantageous, provided that high water production was the result of water coning. Successful tests were conducted in wells with water cuts as high as 99%.

FIELD-TEST FAILURES

Wells that showed limited or poor responses were analyzed to improve reservoir screening criteria and to establish operational guidelines. Mechanical problems were the primary cause of test failures. Examples of mechanical problems encountered were ice plug formation, CO₂ channeling behind tubing, gravel pack failure, split tubing, and excessive CO₂ injection pressure. Some failures were attributed to reservoir conditions. Reservoir failures were primarily due to migration of CO₂ either into an adjacent water zone or along a fault, as well as operating in the miscible pressure regime. Chasing CO₂ with water was also found to be detrimental.

RESERVOIR SCREENING AND OPERATIONAL GUIDELINES

The results of this analysis and the available literature suggest the following concerning reservoir parameters, well conditions, and operating procedures.

RESERVOIR PARAMETERS

Cyclic CO₂ stimulation was successfully implemented in diverse reservoir environments; however, project costs tended to increase with depth. Process performance was not sensitive to reservoir pressures below the minimum miscibility pressure, but operating above the minimum miscibility pressure appeared to be disadvantageous. Process performance was also favored by a thick pay interval, a mobile-water or free-gas saturation, and an adequate drive mechanism. In some cases, the presence of faults was disadvantageous.

WELL CONDITIONS

Candidate wells should be mechanically sound and not subject to production problems. Process performance was not sensitive to remaining oil saturation or pre-CO₂ water cut, particularly when

high water cut was the result of water coning. Since CO₂ is corrosive, it is advisable to isolate production.

OPERATING PROCEDURES

Estimation of the CO₂ slug size was the most important factor in process design. Field-test results suggested that the target treatment radius should not exceed 150 ft for optimum CO₂ utilization. Analysis of the successful tests included in the data base indicated that treatment radius was dependent on reservoir-drive energy. In most of the successful tests conducted in depletion drive reservoirs, CO₂ travelled less than 50 ft; while in strong water-drive reservoirs, CO₂ migrated up to 135 ft from the wellbore in successful tests. The average estimated radius of CO₂ migration for the 30 successful tests was 73 ft.

Although ultimate oil recovery was improved by extending the soak period, analysis of the data base indicated that there was an optimal soak period of one month when production downtime was taken into consideration. Opening the well on a small choke and managing offset wells also improved process performance.

PREDICTIVE TECHNIQUES

MULTI-VARIABLE ANALYSIS OF DATA BASE

Since numerous parameters changed from test to test, the influence of one factor was difficult to analyze. It was, therefore, determined that a multi-variable analysis might facilitate analysis of the field-test data base. Further evaluation of analytical methods indicated that the data, in most cases, did not warrant any method more sophisticated than a general linear regression model as field-wide average properties were used for many parameters, correlations were used to predict some properties that were not available, and data distributions were not uniform.

Although the non-uniform data distributions in the data base resulted in some biases, a multi-linear model was obtained by using parameters known from more controlled sources to be important to the process. It was envisioned that this method would yield a first approximation predictive technique.

The following equations were derived using swelling index (SI), the amount of CO₂ injected (MSCF), and the capacity in md-ft (KH) to predict incremental oil (IO) recovery.

All Wells:

$$IO = 1097 SI + 0.653 MSCF - 0.007 KH \quad [1]$$

Strong Water-Drive Wells:

$$IO = -5731 + 3372 SI + 0.953 MSCF + 0.0093 KH \quad [2]$$

Figures 22 and 23 show the relationships between predicted and observed incremental oil using Eq. 1 and 2 respectively. Correlation coefficients for the plots generated by using Eq. 1 and 2 were 0.865 and 0.683, respectively. A good prediction was obtained by using only the amount of CO₂ injected. This is shown in Figures 24 and 25, which were generated using Eq. 3 and 4, respectively (the correlation coefficients were 0.854 and 0.92, respectively).

All Wells:

$$IO = 0.7796 MSCF \quad [3]$$

Strong Water-Drive Wells:

$$IO = 0.8545 M \quad [4]$$

EVALUATION OF OTHER PREDICTIVE TECHNIQUES

Only two methods have been reported in the literature for the prediction of incremental oil recovery as a result of cyclic CO₂ stimulation. The method proposed by Patton, et al.¹⁷ was based on a numerical simulation study of heavy crude oils. The predictive method developed by Haskin and Alston⁷ was based on reservoir engineering principles and was applied to actual field results obtained from completed tests. These predictive techniques were evaluated to determine how well they could predict performance of selected wells in the CO₂ huff 'n' puff field-test data base. Since the tests in the data base were conducted under diverse conditions, wells from relatively similar environments were chosen for evaluation in an attempt to normalize some variables.

The method of Patton, et al. heavily underestimated the oil production response of the wells included in the study (Figure 26). This was not unexpected as the Patton, et al. correlation was generated using crude oils with viscosities ranging from 177 to 28,000 cp, while the data-base oils analyzed had viscosities ranging from 2.8 to 11.5 cp.

The Haskin and Alston method also underestimated production response; however, predictions were improved over those generated by using the Patton, et al. correlation (Figure 27). The Haskin and Alston method was developed for Texas crude oils in the 23 to 30 °API gravity range, and the data-base oils used for this study were in that same range.

The Haskin and Alston method was refined to improve fluid saturation estimates for the wells included in the study. Since the wells employed in the study were in strong water-drive

reservoirs near the bubble-point pressure, it was unlikely that an appreciable gas saturation persisted. Therefore, the Haskin and Alston gas saturation estimate of 50% movable oil saturation was reduced to 5% movable oil saturation. Initial oil saturations were obtained from welllogs or relative permeability data instead of being estimated by correlations. Finally, the change in oil saturation due to cyclic CO₂ injection was estimated by using the simple algebraic equation shown below (Eq. 5), which relates the change in oil saturation to oil viscosity reduction. S_{orco2} is the oil saturation after application of the cyclic CO₂ process; S_{orw} is the oil saturation prior to CO₂ injection; U_{oco2} is the oil viscosity with CO₂; and U_{o1} is the oil viscosity before CO₂ injection.

$$S_{orco2} = S_{orw} * (U_{oco2}/U_{o1}) \quad [5]$$

With the exception of two tests considered to be mechanical failures, the modified Haskin and Alston procedure adequately estimated the incremental oil recovery expected as a result of the CO₂ huff 'n' puff process (Figure 28). More recent studies indicated that the modified method only served as a predictive tool for reservoirs having parameters within the range of the reservoirs for which the method was originally developed. The method cannot be used to predict the cyclic CO₂ performance of either very high- or very low-pressure reservoirs, or of reservoirs with a high gas saturation.

CONCLUSIONS

The data-base analysis revealed that cyclic CO₂ stimulation could be successfully implemented in diverse reservoir environments. Approximately 90% of all the tests in the data base produced incremental oil. Most of the failures were attributed to mechanical difficulties during CO₂ injection. Incremental oil recovery was found to increase in proportion to the mass of CO₂ injected. Process efficiency appeared to depend on targeted treatment radius and showed some decline for a second cycle of CO₂ injection. Optimum CO₂ slug size depended on field conditions. Production-response trends underlined the importance of diffusion, phase behavior, and relative permeability effects on oil recovery processes.

TABLE 29**RESERVOIR CHARACTERISTICS**

Field	Pay (ft)	Perm (md)	Porosity (%)	Depth (ft)	Pressure (psia)	Temp (°F)	Drive ^a
A	21	322	29	8140	3547	185	WF
B	46	1033	28	10330	2406	212	WF
C	20-50	139	25	12870-13140	2500	240	DD
D	12-17	2500	32	4909-16	2235	138	SWD
E	6-24	3000	32	1200-3000	560-1400	80-100	SWD
F	7-35	300-500	32	6248-525	2900	166	SWD
G	34-58	10	13-16	1300	100	68	DD
H	30	500	31	10060	1795	206	WWD
I	NA	250	27	8900	3947	185	SWD
K	15-34	252	24	9837-914	5100	192	DD

a. WF = waterflood; DD = depletion drive; SWD = strong water drive; and WWD = weak water drive.

TABLE 30**TEST CONDITIONS**

Field	No. of Tests	CO ₂ Slug (tons)	CO ₂ Volume (res ft ³)	Soak (days)	Life (months)
A	1	500	24532	31	10
B	2	960-975	80263-81266	19-21	11-13
C	3	500	46043	25-33	4-42
D	4	600-812	30578-41143	28-181	6-26
E	11	109-500	11647-182544	28-63	2-24
F	2	500	25391	20-23	7-13
G	69	20-240	49588-594696	7-38	8-71
H	1	500	63450	47	19
I	1	375	17361	17	8
K	3	845-21450	NA-60788	16-54	1-104

TABLE 31**RESULTS OF SUCCESSFUL TESTS**

Field	No. of Tests	Incremental Oil (STB)	CO ₂ Utilization (Mscf/STB)	Reservoir CO ₂ Utilization (res ft ³ /STB)	Stimulation Ratio
A	1	3233	2.67	7.6	1.7
B	2	6148-11410	1.45-2.73	7.0-13.2	4.2-4.7
C	1	29830	.29	1.54	2.1
D	4	5516-14863	0.91-1.87	2.6-5.5	4.9-11.2
E	9	2612-11051	0.72-2.68	2.2-33.8	1.6-3.7
G	66	321-6326	0.62-2.14	90-309	1.4-6.4
H	1	12115	.71	5.2	1.5
I	1	9118	.71	1.9	2.2

TABLE 32**PRODUCTION RATES OF SUCCESSFUL TESTS**

Field	No. of Tests	Pre-CO ₂ Oil ^a (B/D)	Pre-CO ₂ Water ^a (B/D)	Post-CO ₂ Oil ^b (B/D)	Post-CO ₂ Water ^b (B/D)
A	1	19	171	29	164
B	2	25-31	255-486	52-86	237-272
C	1	47	47	84	116
D	4	13-18	971-1281	64-250	167-999
E	9	9-53	76-441	18-88	19-241
G	66	1-70	4-397	2-96	4-384
H	1	54	20	74	32
I	1	72	31	83	161

a. Average rate for six months prior to CO₂ injection.

b. Average rate for first month of post-CO₂ production.

TABLE 33**INFLUENCE OF DRIVE MECHANISM ON TREATMENT RADIUS**

Drive Mechanism	Number of Projects	Number of Reservoirs	Average CO ₂ Migration Radius, ft
Strong water influx	14	3	80
Weak water influx	1	1	66
Waterflood	12	2	59
Pressure depletion	3	2	57

FIGURE 15. DECLINE CURVE ANALYSIS
 SMALL SQUARES = PRE-CO₂; LARGE SQUARES = POST-CO₂

FIGURE 16

FIGURE 17

* Production Increase = Average production during six months prior to CO₂ injection minus average during first month of post-CO₂ production

FIGURE 18

CORRELATION BETWEEN STIMULATION RATIO AND PAY THICKNESS

FIGURE 19

RELATION BETWEEN INCREMENTAL OIL PER PAY INTERVAL AND SOAK DURATION

FIGURE 20

EFFECT OF OIL SWELLING ON INCREMENTAL OIL RECOVERY

FIGURE 21

EFFECT OF RESERVOIR CAPACITY ON STIMULATION RATIO

FIGURE 22

**PREDICTED VALUE OF INCREMENTAL OIL - EQUATION 1
(ALL WELLS)**

FIGURE 23

**PREDICTED VALUE OF INCREMENTAL OIL - EQUATION 2
(STRONG WATER DRIVE WELLS)**

FIGURE 24

PREDICTED VALUE OF INCREMENTAL OIL - EQUATION 3
(ALL WELLS)

FIGURE 25

PREDICTED VALUE OF INCREMENTAL OIL - EQUATION 4
(STRONG WATER DRIVE WELLS)

FIGURE 26

FIGURE 27

FIGURE 28

**INCREMENTAL OIL - MODIFIED HASKIN AND ALSTON METHOD
(SOUTH LOUISIANA WELLS)**

IV. PERFORMANCE OF FIELD TEST

The information from field-test data base evaluations, laboratory corefloods, and numerical simulations was used in the design and implementation of a field test of the CO₂ huff 'n' puff process. The ultimate goal of the field test was to provide a public data base on implementation of the process in Louisiana. Previous field tests of this process, conducted in the State of Louisiana, were performed by private companies that seldom made test results accessible to the general public. Extending the information available in the public domain would facilitate implementation of the process by small companies that do not have sufficient revenues to invest in research but that are responsible for a large proportion of oil production in the state.

The field test involved a coordinated effort of the University and industry. An operator selected from small companies and independents provided the test site and well equipment. Department personnel were responsible for location, evaluation, and selection of test sites, as well as test design, monitoring, and evaluation.

SITE SELECTION

PRELIMINARY CONSIDERATIONS

A list of the factors to be considered in the design and implementation of a field test were compiled through a review of the available literature, analysis of the field-test data base, and discussions with industry personnel who had participated in previous field tests. Information concerning the field test was disseminated to operators with potential candidate wells through meetings, mailings, and personal communication. Interested operators were asked to provide information on reservoir conditions and history, well production history, and well production facilities and equipment. Initial screening of potential candidate wells was conducted on the basis of site location, type of operator, and quality of information provided by the operator. It was required that well sites be provided by an independent operator and located in Louisiana.

SITE SELECTION CRITERIA

1. Reservoir Considerations

Previous analyses indicated that thicker net pay intervals, higher pre-CO₂ oil saturations, and reservoir pressures below the

The figures and tables referenced in this chapter are located at the end of the chapter.

minimum miscibility pressure (MMP) contributed to a favorable response; therefore, a candidate well with these characteristics was desired. A sandstone reservoir within the range of parameters contained in the field-test data base was required to assure that the data-base analysis could be applied to the candidate well. Since migration of CO₂ into adjacent water zones or faults would impair process performance, favorable geological characteristics were also an important consideration.

2. Mechanical and Production Facility Considerations

Production facilities that allowed monitoring of individual well production were essential for the test well and desired for wells located near the test site. Monitoring of individual well production was needed to gauge test well incremental oil production and to evaluate offset well production response. Because many test failures were attributed to mechanical failures, mechanical integrity of wellbore and production equipment was required.

3. Site Requirements

A site within Louisiana was needed to fulfill contract requirements. Site location also governed cost and availability of CO₂.

4. Information Requirements

The availability of information on the reservoir, well history, equipment, and facilities was a primary consideration in the well selection process.

SCREENING OF CANDIDATE WELLS

Five wells were submitted by operators for consideration. The following information was requested from each operator in order to assess the suitability of the wells as candidates for cyclic CO₂ stimulation:

- a. current water cut,
- b. thickness of pay,
- c. oil API gravity,
- d. reservoir temperature and pressure,
- e. molecular weight of C₅ fraction,
- f. production history data (oil, water, and gas),
- g. production monitoring system,
- h. wellbore diagram,
- i. well completion date and type of completion,
- j. workover history, and
- k. oil samples.

Evaluation parameters that were estimated for each candidate well included current oil saturation, minimum miscibility pressure,

potential incremental oil recovery, and CO₂ slug size. Estimated values were rough, as sufficient data was not available. Accurate fluid properties; oil, water, and gas production rates; and cumulative volumes of these fluids were difficult to obtain. Most stripper-type wells did not produce sufficient quantities of gas to justify measurement of gas or determination of producing gas/oil ratios. Produced water volumes were typically missing or inaccurate. In addition, most operators did not have accurate measurements of the current downhole pressure.

Relatively accurate monthly oil production volumes were typically available and were used to generate production profiles. These profiles were then analyzed using linear regression to predict performance under continued operations and to predict oil recovery with current operational practices. Potential incremental oil production was predicted using the modification of the Haskin and Alston⁷ procedure described in sec. III.

The available information on reservoir conditions was utilized to estimate CO₂ properties in the reservoir. A target radius for injected CO₂ was selected based on conclusions of the data-base analysis. This target radius was used in conjunction with available rock parameters that were obtained from well logs and/or core analysis for determining an "optimal" CO₂ slug size for each of the candidate wells. CO₂ expenses for each candidate were estimated using the optimal slug size and typical CO₂ prices. The evaluation parameters estimated for each well are presented in Table 34.

SELECTION OF CANDIDATE WELL

Ranking of candidate wells was based upon two types of parameters: logistical and technical. The logistical parameters included well availability and mechanical condition. Technical parameters included such items as estimated cost per estimated incremental barrel of oil, completion type, communication between wells, reservoir pressure, and propensity for the reservoir oil to precipitate heavy hydrocarbons upon mixing with CO₂.

After the ranking process was completed, four of the five wells under consideration were eliminated from the pool of potential candidates. Candidate 4 was eliminated early in the selection process due to formation damage which restricted fluid flow. Candidate 5 was eliminated since the crude contained a high paraffin content, and it was feared that paraffin waxes might precipitate and cause plugging during the cooling associated with injection and production of CO₂. Also, the estimated reservoir pressure of this well was near the MMP. Candidates 2 and 3 were eliminated because they were located in dipping reservoirs, and it was feared that CO₂ might migrate upward and away from the wellbore in this type of formation (This decision was made prior to investigation of reservoir dip by laboratory corefloods).

Candidate 1, therefore, was selected as the primary candidate for the field test.

DESCRIPTION OF CANDIDATE WELL

The Frank J. Bollich Jr., et al. No. 5, located in Sec. 30, T7S-R1E, Acadia Parish, Louisiana (Figure 29), and operated by Southwest Gas Producing, Inc. was selected as the test well. The well was drilled in December, 1987, and completed in the 4500 ft Channel Sand of the South Bayou Mallet field. This reservoir had a 17-ft oil zone overlying an 83-ft water zone. An induction-sonic log taken after the well was drilled is shown in Figure 30.

The well initially produced 70 BOPD. Production from the well prior to injection of CO₂ was 17 BOPD and 160 BWPD, with cumulative oil production of nearly 23,000 STB. The high water cut was presumed to be due to water coning. Reservoir rock and fluid properties for the target zone are shown in Table 35.

PRE-TEST ADMINISTRATIVE PROCEDURES

Before an enhanced oil recovery (EOR) project, such as cyclic CO₂ injection, can be applied to a well, certain permits must be obtained from various regulatory agencies. The permitting process is discussed in the following paragraphs.

LOUISIANA DEPARTMENT OF NATURAL RESOURCES (DNR) - OFFICE OF CONSERVATION

The Office of Conservation DNR is responsible for overseeing all activities involving oil and gas wells (including unitization, drilling, primary production, and secondary and tertiary recovery) to ensure exploitation of the State's resources in an efficient and non-wasteful manner. The Commissioner of Conservation conducts hearings to approve proposed EOR projects.

A hearing application was filed on February 8, 1991, and an application fee of \$600 was paid by the operator. The hearing was held on April 9, 1991. Approval for the field test was granted on April 22, 1991.

At the hearing, geological and engineering data in support of the project were presented by Dr. Philip A. Schenewerk (LSU Professor of Petroleum Engineering) and Mr. E.J. Faul (well operator). The exhibits included well logs; maps of the field showing the location of wells and property lines; and lists of royalty interest owners, interested parties, overriding royalty interest owners, and working interest owners.

Since the well site was located 118 ft from a lease line, as shown in Figure 31, the CO₂ slug size was designed to limit the treatment radius to 75 ft. Letters were obtained from offset

operators and property owners stating that there were no objections to the test. A graph of slug size versus treatment radius is presented in Figure 31. The estimation of the CO₂ slug size assumed piston displacement along a radial front, reservoir CO₂ saturation of 50%, no mixing of CO₂ with fluids in place, and a CO₂ bank thickness equal to the perforation thickness.

Unitization of the field was not required. This was the first permit granted by the State of Louisiana for an enhanced oil recovery project to be conducted in a non-unitized field. Waving the unitization requirement substantially reduced the cost of the project and set a precedent for similar projects in the future.

LOUISIANA DEPARTMENT OF NATURAL RESOURCES -
UNDERGROUND INJECTION CONTROL COMMISSION

The Underground Injection Control Commission is responsible for regulating the injection of fluids into new or existing wells to prevent the contamination of freshwater supplies. An application was filed on February 14, 1991, and an application fee of \$200 was paid by the operator. The application included completion data for the test well and all wells within a 1/4 mile radius of the test well, well logs and plats, and a schematic of the surface facilities. Approval for the field test was granted on April 29, 1991.

LOUISIANA DEPARTMENT OF ENVIRONMENTAL QUALITY -
AIR QUALITY DIVISION

The Air Quality Division of the Department of Environmental Quality is responsible for monitoring emissions or venting of gases into the atmosphere during any oil well activity. On January 28, 1991, an exemption from permitting requirements was requested on the basis that the field test was considered to be a pilot project, and a \$200 application fee was paid. The exemption was granted on February 24, 1991 and a permit was issued subject to the following requirements:

1. The Acadian Regional Office must be informed within 5 days of commencement of venting.
2. Testing must be completed within three months of commencement of venting.
3. A detailed report of conditions found to exist, and other information required by regulations must be submitted within 30 days of completion.

ENVIRONMENTAL IMPACT

Specific environmental impacts associated with cyclic CO₂ enhanced oil recovery were assessed to address the concerns of

Louisiana's DEQ and to comply with the National Environmental Policy Act (NEPA). The conclusions of the environmental assessment were as follows:

1. The available information indicated that minimal environmental impact was anticipated as a consequence of the proposed test.
2. No new surface-disturbing activities were proposed in association with the test. Existing access roads and production equipment would be utilized.
3. Impacts associated with water quality were expected to be negligible. Tubing would be pressure tested with nitrogen prior to CO₂ injection to insure mechanical integrity, and to reduce the risk of contaminating fresh water supplies. The current practice of reinjecting produced waters into brine-containing formations would be continued.
4. Air quality impacts were assessed to be minimal. Some CO₂ and produced hydrocarbon gases would be vented into the atmosphere, but these emissions were not expected to influence the environment due to the small quantities involved. Hydrocarbon gas production was negligible prior to CO₂ injection, and was not expected to significantly increase during the production phase of the test. Fluid production rates would be limited in the initial phases of production. Gas production rates would be 250 Mcf/day or less, since previous studies had shown that producing the well on a small choke, thus maintaining a backpressure in the reservoir, was beneficial to ultimate oil recovery. If CO₂ alone was initially produced, the daily production rate of CO₂ would correspond to the amount of CO₂ released in 1.5 minutes from the operation of a typical coal-fired power plant.¹⁹
5. No adverse effects on flora and fauna in the area were anticipated. The candidate well site was located within an isolated area of oil production activity that was surrounded by a large agricultural area consisting primarily of soybean and rice fields. CO₂ is a colorless, odorless, non-combustible gas that is a natural constituent of air (0.036%).⁴ Elevated concentrations of CO₂ have been shown to be beneficial to plants.⁵ Extremely high concentrations of the gas have been shown to be harmful to humans, but these levels are usually only found in enclosed areas with poor ventilation.^{20,21}
6. Recently, there has been considerable concern about the contribution of elevated global CO₂ concentrations to the "greenhouse effect". CO₂ huff 'n' puff processes as a whole are not expected to significantly contribute to global CO₂ concentrations as the CO₂ quantities involved are relatively small compared to other industrial processes. Also, since the

CO₂ used in the process is not generated, but is purchased as CO₂ which would have been released into the atmosphere through some other process, the net concentration of CO₂ in the global atmosphere is not increased. In fact, studies have shown that 20 to 23% of the injected CO₂ remains in the reservoir and is not produced; therefore, the net concentration of CO₂ in the global atmosphere is reduced.^{3,8}

PERFORMANCE OF FIELD TEST

PREPARATION OF WELL

Before injection of CO₂ could begin, it was necessary to workover the well to comply with State of Louisiana Underground Injection Control (UIC) requirements. This workover was performed June 17-19, 1991. It consisted of the removal of the sucker rods, rod pump, and 2-7/8 inch tubing. This equipment was replaced with a tubing conveyed packer and 2-3/8 inch tubing. The new tubing was pressure tested with nitrogen gas to insure tubing integrity.

PERFORMANCE OF FIELD TEST

The initial test design called for the injection of approximately 120 tons of CO₂ at rates ranging from 0.5 to 4.0 barrels per minute. Wellhead pressure was not expected to exceed 1200 psi at any time during the injection of the CO₂. Plans were to heat the CO₂ to 80 °F prior to injection, since previous field tests⁴ had shown that heating CO₂ prevented excessive contraction of the wellbore tubulars and formation of ice plugs in the injection lines.

CO₂ was delivered to the well site in 20-Ton tankloads and stored on site in two 60-Ton portable storage units. A specially designed CO₂ injection unit operated by Liquid Carbonics was used to perform the injection. This particular injection unit contained a National triplex pump rated at 1.75 BPM @ 5000 psi along with a diesel burning indirect line heater capable of generating 1 MMBTU.

Injection operations began on July 1, 1991 and were completed within six hours. Injection rates increased from 0.5 barrels per minute at the beginning to 2.1 barrels per minute at the end of injection. Surface injection pressures were higher than anticipated and ranged from 1500 to 1900 psi. The injection heaters were unable to maintain the desired 80 °F wellhead injection temperature. The injection temperature varied from 58 to 70 °F, which proved to be more than adequate for this test. Total injection time was 6.6 hours. The project costs through the injection stage are detailed in Table 36.

After CO₂ injection, the well was shut-in for a period of 28 days to allow time CO₂ to diffuse through the reservoir and interact with the oil. The well was reopened on July 29, 1991.

During the first three days, only gas was produced. The produced gas was primarily CO₂ with 0.5-5% methane and traces of higher molecular weight hydrocarbons. The methane concentration increased with time. After three days and approximately 440 MCF of gas production, the well died with fluid 20 ft from the surface. The well was placed on a pump, and produced approximately 15 bbl fluid per day (10 STB oil and 5 bbl water).

The fluid produced at the surface appeared to be a CO₂-oil-water foam/emulsion which readily broke at surface conditions. Production impairment was attributed to poor mobility of the viscous emulsion within the formation. Discussions with operators revealed that the well had foamed during initial production. Apparently, this particular crude had a propensity to foam in the presence of any gas.

Samples of produced fluids were submitted to Petrolite Corporation for evaluation. Petrolite Corporation suggested that the well be treated with a mixture of de-emulsifier and asphaltene/paraffin remover to restore lost production.

Before implementing the treatment suggested by Petrolite Corporation, it was decided to determine if fluid flow could be improved by lowering the pump. When the well was originally placed on a pump, the pump was set at approximately 3,000 ft. It was decided to lower the pump to 4,000 ft. The initial results were encouraging when the pump was lowered; however, fluid production rapidly decreased.

When the pump was pulled in preparation for lowering it to 4,000 ft, a scale that appeared to be calcium carbonate was noted on the pump. Later, when the tubing was pulled prior to implementation of the treatment recommended by Petrolite Corporation, a large quantity of scale was found in the lower 20 ft of the mud anchor and in the perforated sub. It was, therefore, decided to treat the well with 15% HCl to dissolve the scale after injecting the treatment mix recommended by Petrolite.

The well was treated with de-emulsifier and acid in July 1992. Although fluid production was constrained by the pump, daily production rose to approximately 40 B/D with oil cuts as high as 22 STB/D. Within a month following the treatment, the pump developed mechanical problems that had not yet been resolved at the time of this report. A graph of pre- and post-test production data is presented in Figure 33.

The Frank J. Bollich Jr., et al. No.7, which is located approximately 120 ft from the No. 5 well, was recompleted in the 4500 ft sand on October 1, 1992. Initial production from the 4500 ft sand zone was 82 BOPD. The produced fluid was in the form of a foam, similar in appearance to the foam produced by the No. 5 well after CO₂ treatment. It was noted, however, that the gas produced

from the No. 7 well was burnable. The gas produced from the No. 5 well, during the same time frame, still contained too much CO₂ to allow it to burn.

A sample of the gas produced by the No. 7 well was analyzed and found to contain 0.3% CO₂. The low concentration of CO₂ suggested that little, if any, of the CO₂ injected in the No. 5 well migrated as far as the No. 7 well. The slug design which restricted CO₂ migration to a 75 ft radius and the assumptions on which the estimated migration radius was based were, therefore, considered to be adequate for this test.

AIR QUALITY TESTS

The air quality at the test site was monitored to determine the impact of the field test. Base-level measurements were made at the well site one week prior to CO₂ injection. Air emissions were monitored during CO₂ injection and during the production stage.

Air samples were monitored using a Microsensor Technology, Inc. Microgas Analyzer Model P200D. The instrument is a portable gas chromatographic system with two columns. The Haysep A column is used to analyze fixed gases such as nitrogen, carbon dioxide, hydrogen sulfide, methane, and ethane. The OV-1 column is used to analyze hydrocarbon contaminants such as propane, butane, pentane, benzene, etc. Certified Master Standard gas mixtures are used to calibrate the instrument response.

Air samples were taken from five locations around the well site on June 20, 1991. All of these samples had CO₂ levels of 0.036%, and no other air contaminants were detected. On July 1, 1991, air samples were monitored during CO₂ injection. A total of 30 samples were taken in a circular pattern around the CO₂ sources at distances of 20 to 50 ft over a period of seven hours. Of the 30 samples, 14 had CO₂ levels less than 0.05%; six had CO₂ levels in the range 0.05 to 0.1%; three had CO₂ levels in the range of 0.2 to 0.6%, and one sample, taken in the cab of the pumping truck, had a level of 3.74%.

On July 29, 1991, the ambient CO₂ level was 0.034% immediately prior to opening the well. Six samples were taken downwind of the vent at distances of 20 to 100 ft over a two-hour period after production resumed. Only two samples had CO₂ values (0.094 and 0.141% CO₂) that were significantly elevated over pre-production levels. The other samples were in the range 0.034 to 0.040% CO₂.

On July 30, 1991, six air samples were analyzed. The samples were taken at 12-60 ft downwind of the vent. CO₂ levels were measured as follows: 0.066, 0.057, 1.26, 0.110, 0.182, and 0.040%. The sample containing 1.26% CO₂ was taken directly in the path of the plume and 12 ft from the vent. Air samples taken on July 31,

August 1, and September 3, 1991, at distances of 5 to 30 ft downwind of the vent, contained pre-test concentrations of CO₂.

The environmental impact of the process was minimal. Atmospheric CO₂ levels were elevated for a relatively short period of time during CO₂ injection and during the first two days of production. CO₂ concentrations declined rapidly with distance from the source and when outside of the visible plume (Note: CO₂ is not visible, but when it expands, it cools the air which causes watervapor to condense and form a visible fog.). N-pentane was the only contaminant other than CO₂ that was detected in air samples, and the concentration was barely above detection limit (<0.001%). Samples taken from the wellhead and inside the vent indicated that the produced gas was primarily CO₂ with 1 to 13% methane, and trace quantities of ethane, propane, and n-pentane. None of the samples contained detectable amounts of benzene (The detection limit was 10 ppm.). Butane was not included in the analysis.

CONCLUSIONS

1. Performance of the field test demonstrated that a cyclic CO₂ stimulation project could be implemented by a small independent operator with limited financial resources.
2. Waiver of the unitization requirement by the Louisiana Department of Conservation substantially reduced the cost of the project and set a precedent for similar projects in the future.
3. Injection of CO₂ can substantially reduce water cut in wells experiencing high pre-CO₂ water cuts.
4. Wells that produce foams during the early stages of production should be subjected to laboratory testing prior to CO₂ injection to determine if anti-foaming agents should be included in the process design.
5. Injection of CO₂ appeared to have contributed to the formation of a calcium carbonate scale which was dissolved by dilute acid.
6. The CO₂ slug migration radius was adequately estimated using simple assumptions.
7. The environmental impact of the process appeared to be minimal.

TABLE 34
CANDIDATE WELL SUMMARY

WELL DESCRIPTION	CANDIDATE					
	1	2	3	4	5	5 ^a
Reservoir Temperature, °F	140	120	120	140	180	180
Est. Reservoir Pressure, psia	1300	1300	1300	1000	2000	3580
Oil Gravity, °API	28	26	26	27	32	32
Est. MMP Range ^b , psi	4289 3930	2623 2422	2679 2315	3753 3067	3451 3189	3451 3189
Oil Zone Thickness, ft	17	72	130	37	18	20
Oil Zone Porosity, %	33	28	31	30	30	25
Top of Perforations, ft	4523	4404	4402	4764	9652	9652
Perforated Interval, ft	6	42	30	16	8	8
Current Production						
Oil, BPD	25	32	16	<1	20	20
Water, BPD	150	0	144	NA	360	360
Water Cut, %	86	0	90	NA	95	95
Cumulative, bbl	16,909	59,300	109,500	35,000	526,000	526,000
CO ₂ Required ^c , Tons	119	953	753	201	241	370
Est. CO ₂ Cost @ \$75/Ton, \$	8,847	71,500	56,504	15,074	18,041	27,743
Predicted Recovery, bbl	1,583	5,166	6,168	2,539	1,690	
CO ₂ Utilization, Mcf/STB	1.3	3.2	2.1	1.4	2.4	
CO ₂ Costs ^d , \$/bbl	5.65	13.84	9.16	5.94	10.67	

- a. Two estimates were made for Candidate #5 because of the magnitude of the uncertainty in the estimated current reservoir pressure.
- b. The MMP was estimated to cover a range of pressures due to the uncertainties in several of the parameters required for the correlation.
- c. The CO₂ treatment radius was designed to be 75 feet. The assumptions used in the estimation of gas slug size are listed in Table 3-H.
- e. CO₂ costs were estimated at \$75/Ton or \$4.37/Mcf.

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TABLE 35

TEST WELL RESERVOIR AND FLUID PROPERTIES

Initial Reservoir Pressure, psia	2000
Current Reservoir Pressure, psia	1300
Reservoir Temperature, °F	148
Reservoir Thickness, ft	100
Oil Zone Thickness, ft	17
Porosity, %	33
Water Saturation, %	40
Permeability, md	2000
Oil Gravity, °API	28
Gas Oil Ratio	nil
Initial Oil Production Rate, BOPD	70
Current Oil Production Rate, BOPD	17
Current Water Production Rate, BWPD	160

TABLE 36

PROJECT COSTS

Permits	\$ 1,000
Workover	\$10,800
Tubing	\$12,600
Tubing Test	\$ 2,400
CO ₂	\$ 5,400
Storage Tanks	\$ 2,100
Injection	\$ 6,400
Miscellaneous	<u>\$ 1,300</u>
Total	\$42,000

FIGURE 29. LOCATION OF TEST WELL

FIGURE 30

INDUCTION-SONIC LOG

FIGURE 31. MAP OF WELL SITE

FIGURE 32

COMPARISON OF SLUG SIZE VS. TREATMENT RADIUS

FIGURE 33

MONTHLY PRODUCTION PRE- AND POST-CO₂ INJECTION

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ABBREVIATIONS AND SYMBOLS

CO ₂ Utilization	Volume of CO ₂ slug at standard conditions divided by volume of oil recovered, Mscf/bbl
CO ₂ Reservoir Utilization	Volume of CO ₂ slug at reservoir conditions divided by volume of oil recovered, res ft ³ /bbl
E _{R1}	Recovery efficiency in terms of original oil-in-place, volume of oil recovered divided by volume of oil initially in core, cm ³ /cm ³
E _{Rr}	Recovery efficiency in terms of waterflood residual oil, volume of oil recovered divided by volume of oil in core after waterflood, cm ³ /cm ³
G _p	Produced gas
Gas Utilization	Volume of gas slug divided by volume of oil recovered, Mscf/bbl
GOR	Gas/oil ratio
IPA	Isopropyl alcohol
k _{rw}	water relative permeability
k _{row}	oil relative permeability after waterflooding
MMP	Minimum miscibility pressure
N _p	Produced oil
P _b	Bubble point pressure
RRO	Reconstituted reservoir oil
S _{oi}	Initial oil saturation
S _{orw}	Oil saturation after waterflood
S _{wi}	Initial water saturation
STO	Stock-tank oil
W _p	Produced water

APPENDIX

PRESENTATIONS AND PUBLISHED PAPERS

PRESENTATION AND PUBLISHED PAPERS

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