ENHANCED RECOVERY OF OIL FROM SUBSURFACE RESERVOIRS WITH CARBON DIOXIDE

Final Report

By

J. S. Osoba

December 1984
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DISPLACEMENT OF CRUDE OIL FROM POROUS ROCK
USING CARBON DIOXIDE

ABSTRACT

This report details the studies made of the displacement of crude oil by carbon dioxide (CO₂) from consolidated sandpacks. The sandpacks were 20, 60, and 240 inches long and the diameter was 5/8 inch. With the sandpack in a vertical position, the CO₂ was always injected into the top. The objectives of the research were to determine procedures for predicting the pressure at which CO₂ displaces crudemiscibly and the influence of rate on the displacement of crude with CO₂.

The determination of the miscibility pressure appeared to be the same with the 20 inch long sandpack as with the 60 or 240 inch long sandpack. The total recovery at each pressure was higher with the longer sandpacks. The oil recovery was higher at low rates with the sandpack column in a vertical position. The oil recovery at low rates was lower with the sandpack column in a horizontal position.

The optimum CO₂ slug size was found to be 30% of the hydrocarbon pore volume. Water was found to be more efficient than nitrogen at driving the CO₂ to displace crude oil. The recovery of oil from a composite core of various permeabilities was slightly less than the recovery from a more homogeneous core.

Measurements of the crude oil viscosity from the Foster Field decreased as CO₂ miscibility pressure was increased. On the other hand, the viscosity of the SACROC crude oil from West Texas was found to have a minimum value at a CO₂ miscibility pressure of approximately 1600 psig. As the pressure increased, the viscosity of the oil with CO₂ increased.

Values of the permeability of dolomite cores were found to increase when flooded with CO₂ at a high pressure. When the effluent from a core with CO₂ at a high pressure was flowed through a second dolomite core as the pressure was decreased, the permeability of the second core was decreased.

Photographs showed that some of the dolomite core was dissolved by the CO₂ at high pressures, and that crystal precipitates were formed in the second core as the CO₂ miscibility pressure was reduced.
INTRODUCTION

Petroleum is an important energy resource. Even though more oil will be found, the increasing world energy consumption may cause oil demand to exceed its supply. Primary production methods and waterflooding often leave as much as 60 to 65 percent of the original oil in the ground. Hence, there is a need to develop a method that can increase oil recovery.

The three most promising enhanced oil recovery methods involve the injection of heat, surfactant, or carbon dioxide (CO₂). Thermal methods are limited to shallow reservoirs with viscous oils. Surfactant flooding has been effective in the laboratory, but tests in the field have indicated that the cost will be too high for most proposed applications. Long range forecasts indicate that the injection of carbon dioxide will be the most efficient method of increasing oil recovery from underground reservoirs.

The main reason for the effectiveness of carbon dioxide in displacing oil from reservoir rock is that oil and CO₂ may become miscible at elevated pressures. When the two are miscible, all the oil is displaced from the portion of the reservoir contacted by CO₂. Some benefits are derived from injecting CO₂ to displace oil even at pressures not sufficiently high for the oil and CO₂ to become miscible.

1. Oil viscosity is reduced.
2. Residual oil is increased in volume.
3. Some residual oil is vaporized.
4. A residual gas phase will decrease the residual oil.

A major factor in CO₂ flooding is the minimum CO₂ - crude oil miscibility pressure. Some of the parameters that could affect the miscibility pressure have been reported in the literature. During CO₂ miscible flooding, the length of the CO₂ - crude oil transition zone is influenced by the presence of fingering and fluid displacement rate. High rates lead to long transition zones while lower rates give rise to shorter transition zones. The oil recovery efficiency may be adversely affected when the length of the transition zone is comparable to, or longer than that of the core/sandpack. Since oil recovery is the basis for selecting the minimum miscibility pressure, the result of laboratory determination of this pressure may be affected by the length of the core/sandpack used.

Gravity segregation is known to occur in displacement processes when the density of the displaced and displacing fluids are different. CO₂ is usually less dense than the displaced crude oil at flooding
conditions, hence gravity segregation will influence the sweep efficiency of CO₂. The effect of gravity segregation depends on the fluid displacement rate. Since gravity segregation and fluid displacement rate are concomitant factors, they are expected to affect CO₂ flooding.

The limited supply of carbon dioxide has necessitated its use for displacing oil from underground reservoirs as a bank which can be pushed through the reservoir by a less expensive scavenging fluid. Laboratory tests³⁴⁵ have indicated that it is not necessary to inject CO₂ continuously to achieve maximum oil recovery from porous rocks. A bank of CO₂ followed by a cheap scavenging fluid may be as effective in displacing oil from underground reservoirs as continuous CO₂ injection. A recent study reported by Wang⁶ showed that injecting CO₂ in excess of an optimum bank size is wasteful.

Contact between the scavenging fluid and the reservoir oil which may occur when the scavenging fluid penetrates the CO₂ bank, is detrimental to the success of CO₂ flooding. Scavenging fluid-oil contact is promoted by fingering which is caused by adverse mobility ratio and reservoir heterogeneities. The contact is enhanced by gravity overriding or underriding in horizontal systems depending on whether the density of the scavenging fluid is lower or higher than that of CO₂. Such contact may result in immiscible oil displacement and reduced oil recovery. Contact between the scavenging fluid and the in-place oil can be prevented if the CO₂ slug bank size is large enough.

Results of studies on the size of a solvent slug bank required for displacing crude oil miscibility by fluids other than CO₂ have been published in the literature.⁷⁸⁹ Because CO₂ interacts differently with the crude oil and the scavenging fluid than with the solvents used in other miscible displacement processes, there is a need for studying the optimum CO₂ bank size required for CO₂ flooding in a porous media.

When a bank of CO₂ is propelled by a cheaper scavenging fluid, miscibility conditions must be maintained at the CO₂ - crude oil contact zone and it may be helpful to maintain miscibility conditions at the scavenging fluid - CO₂ contact zone. Achieving miscibility at both contact zones may enhance displacement efficiency and project economics, provided the sweep efficiency is not significantly impaired.

Presently, the two most viable CO₂ slug propellants are water and nitrogen because they are both readily available and inexpensive. Differences, however, in the densities and viscosities of the two fluids cause inherent differences in their sweep efficiencies when used as CO₂ slug propellants. While the displacement of CO₂ by water is immiscible, displacement by nitrogen is miscible. Therefore, a better understanding of the effectiveness of the two fluids as CO₂ slug
propellants is necessary.

The efficiency of an oil recovery process will be affected when any of the injected fluids react chemically with the reservoir rock. Chemical reaction between the rock and the injected fluids could be in the form of fluid absorption onto the rock surfaces or rock dissolution by the injected fluid. In flooding with surfactants, the efficiency of the process is affected by surfactant absorption onto the rock surface.

Holm\(^5\) reported a study in which the permeability of a dolomite core increased threefold after about nine pore volumes of carbon dioxide slug and carbonated water were injected through the core. This is a case of rock dissolution by the injected fluid. Crawford, et al.\(^12\) reported a case history in which the use of carbonated water as a post-fracture treating fluid resulted in rapid and complete well clean-up. Formation of stalactite and stalagmite in caverns shows that although carbon dioxide dissolves carbonate rocks in the presence of water, the reaction is reversible in nature. This phenomenon can be extrapolated to the reaction between CO\(_2\) and the rock during CO\(_2\) flooding of carbonate reservoirs. Since many dolomite reservoirs are potential candidates for CO\(_2\) flooding, there is a need for an in-depth study of the reaction between CO\(_2\) and dolomite rock.

The Objectives of this Laboratory Study are the Following:

1. Determine the effect of the length of the laboratory sandpack on the determination of the miscibility pressure and the effects of rate and gravity on the displacement of oil by CO\(_2\).

2. Compare the efficiency of water and of nitrogen as CO\(_2\) slug propellants during the displacement of crude oil by CO\(_2\) from horizontal consolidated cores and from a sample with a variety of permeabilities.

3. Determine the optimum CO\(_2\) bank size required for displacing crude oil from horizontal consolidated cores.

4. Study CO\(_2\) - dolomite rock interaction and the effect of pressure on the interaction.

5. Measure some of the physical properties of crude oil - CO\(_2\) miscibility pressure.

Effect of Column Length on Miscibility Pressure

In laboratory miscible flooding experiments, the length of the core used and the length of the transition zone between the displaced and the displacing fluid may affect the recovery efficiency. Perrine
and Dunmore have demonstrated that stability at the fluid displacement front will result in short transition zone, while instability will cause the transition zone to be longer. Some of the factors that affect the stability, (and hence, the length of the transition zone,) are mobility ratio, fluid displacement rate, gravity segregation and the degree of reservoir heterogeneity.

Menzie and Nielsen \(^\text{20}\) and others studied the mechanism by which CO\(_2\) generates miscibility with crude oil. They showed that the process is due to the ability of CO\(_2\) to extract heavy end hydrocarbons (C\(_5\) through C\(_{30}\)) from crude oils. The factors that affect CO\(_2\) - crude oil miscibility pressure have been described in the literature as temperature, crude oil composition and the purity of the injected carbon dioxide. Holm and Josenda\(^{10}\) showed that the length of the CO\(_2\) - crude oil transition zone is a function of the flooding pressure. Low flooding pressures are less efficient and will produce long transition zones, while high flooding pressures (near the miscibility pressures) are more efficient and will result in shorter transition zones. Adamson and Flock reported a study which indicated that the length of the CO\(_2\) - crude oil transition zone (as in other miscible displacement processes) depends on the stability of the transition zone. The transition zone is stable if it is devoid of viscous fingers and if there is a gradual change in fluid properties from that of the in-place reservoir oil to that of the CO\(_2\) throughout the flooding period.

**Effect of Gravity Segregation and Displacement Rate on Oil Recovery**

Gravity segregation is a dynamic phenomenon which may be undesirable or beneficial to the success of a miscible flooding process depending on the reservoir geometry and the flooding direction. In frontal drive operations, differences in the densities of the reservoir oil and the displacing fluid will promote their segregation. Gravity segregation will cause the gas to override the dense crude oil in immiscible external drive operations, and water to underride the less dense crude oil in water flooding operations. These effects will result in early gas and water breakthrough and, consequently, poor oil recovery efficiencies in immiscible oil displacement operations in horizontal systems. On the other hand, oil recovery efficiencies in vertical systems could be improved by injecting the gas at the crest or injecting water at the bottom of the structure at low rates.

The degree to which the effect of gravity segregation is manifested during a displacement process is a function of the displacement rate. In horizontal systems, the CO\(_2\) injection rate should be high enough to overcome the adverse effect of gravity segregation, but not so high as to cause viscous forces (fingering) to dominate. On the other hand, when CO\(_2\) injection rate is low and crude oil is moving downdip, gravity will stabilize the displacement front, resulting in a short transition zone and enhance the efficiency of the
The fact that the CO₂ viscosity is less than that of the crude oil will result in adverse mobility ratio and formation of viscous fingers at the flood front. The presence of viscous fingers at the displacement front will result in bypassing of crude oil and will adversely affect the efficiency of the miscibility process. This may result in poor oil recovery efficiency.

Comparison of the Efficiencies of Nitrogen and Water as CO₂ Slug Propellants

It is important that the fluid used to push the slug of CO₂ through the reservoir does not penetrate the slug and contact the crude oil directly. Penetration of the slug may be caused by gravity override or gravity underride, fingering, or incomplete displacement of CO₂ by the scavenging fluid.

Nitrogen is less dense than carbon dioxide at 110°F and 1500 psi. Nitrogen, therefore, will override the CO₂ when used to displace the slug. Carbon dioxide is less dense than water, hence, water will underride the CO₂ when used as a propellant. The CO₂ - nitrogen density difference is greater than the CO₂ - water density difference. Consequently, the tendency of nitrogen to override carbon dioxide will be greater than of water to underride CO₂.

Carbon dioxide is more viscous than nitrogen, but is less viscous than water at 110°F and at pressures above 1500 psi. Thus, the mobility ratio at the water - CO₂ front will be favorable, while the corresponding ratio will be unfavorable at the nitrogen - CO₂ front. When water is used as the CO₂ slug propellant, it will tend to follow previously created CO₂ fingers which will have resulted from the adverse mobility ratio at the CO₂ - crude oil front. A reduction in viscous fingering will occur inside the existing fingers. On the other hand, nitrogen will increase fingering through the CO₂ due to the nitrogen's greater mobility. This may result in a poorer sweep efficiency in the nitrogen - CO₂ - crude oil system.

Nitrogen is readily miscible with carbon dioxide. The displacement of carbon dioxide in the portion of the reservoir contacted by nitrogen will be complete. However, the displacement of carbon dioxide by water is an imbibition-immiscible process which will leave approximately thirty percent of the CO₂ pore volume as free gas. Hence, a poorer displacement of CO₂ in the swept part of the reservoir will result with brine than when nitrogen displaces carbon dioxide.

Thus, nitrogen will displace carbon dioxide miscibly but will result in poor sweep efficiency. Water will displace carbon dioxide immiscibly, but may result in a better sweep efficiency.
If the carbon dioxide saturated water penetrates the CO₂ bank and contacts the crude oil, the oil displaced will be less than that which would have been displaced by the miscible CO₂ bank alone. However, water is more efficient in displacing crude oil than nitrogen at low pressures. Therefore, if nitrogen penetrates the bank of CO₂, the oil recovery would be expected to be lower than the oil recovery when water penetrates the CO₂ bank.

Determination of the Optimum CO₂ Volume Required for CO₂ Flooding

The optimum CO₂ bank size was determined from a series of tests in which two crude oils were miscibly displaced from horizontal consolidated Berea sandstone cores. Various sized CO₂ slugs were driven through the cores by water or by nitrogen. Similar cores were used in the tests in which two crude oils were displaced by carbon dioxide at pressures just above the CO₂ - crude oil miscibility pressures.

CO₂ - Dolomite Interaction During CO₂ Flooding

Carbon dioxide dissolves in water to form carbonic acid according to the following reversible reaction:

\[ \text{H}_2\text{O} + \text{CO}_2 = \text{H}_2\text{CO}_3 \]  

(1)

Dolomite rocks contain mainly CaCO₃ and MgCO₃. The metal carbonates will react with carbon dioxide in the presence of water to form water soluble bicarbonates. The stoichiometric equations of the reactions are shown below:

\[ \text{H}_2\text{O} + \text{CO}_2 + \text{CaCO}_3 = \text{Ca(HCO}_3\text{)}_2 \]  

(2a)

\[ \text{H}_2\text{O} + \text{CO}_2 + \text{MgCO}_3 = \text{Mg(HCO}_3\text{)}_2 \]  

(2b)

The factors that affect the equilibrium of Equations 2a and 2b are change in the concentrations of the reactants and the products, pressure, and temperature. In Equations 2a and 2b, the concentration of carbon dioxide determines how much of the bicarbonate will be produced. The CO₂ concentration is the determining factor because the concentration of water and the bicarbonates (rock) can be considered to be infinite in a carbonate reservoir. The solubility of carbon dioxide in water and, hence, its concentration, increases with an increase in pressure. This property decreases with an increase in temperature. The solubility is further reduced if the water contains some dissolved solids.

Treatise on the effect of pressure on rate of reaction showed that:

\[ \frac{\delta \ln k}{\delta P} = \frac{-\Delta V}{RT} \]  

(3)
$K = \text{rate of reaction}$

$P = \text{pressure}$

$\Delta V = \text{change in molal volume between that of the products and the reactants.}$

$R = \text{Universal gas constant}$

$T = \text{Absolute temperature}$

Integration of Equation 3 at constant temperature yields:

$$RT \ln \left( \frac{k}{k_0} \right) = \Delta V$$  \hspace{1cm} (4)

where $k_0$ is the rate of reaction at zero pressure. Equation 4 shows that the change of rate of reaction with pressure at constant temperature is directly proportional to the change in molal volume between that of the reactants and the products. This equation implies that a reaction proceeds at constant temperature such that the total molal volume of the products is less than that of the reactants. Also, an increase in pressure will favor formation of the reaction, and vice versa.

Since CO$_2$ miscible flooding is conducted at high pressures, the combined effect of increased solubility of CO$_2$ in water and the effect of pressure on rate of reaction will lead to the formation of the water soluble bicarbonates around the CO$_2$ injection wells. The pore linings of the carbonate rock will be eroded, and consequently, the permeability of the rock will increase in this region. At some distance away from the injection well where pressure drops become significant, the combined effect of the reduced pressure in Equation 4, the reduced concentration of carbon dioxide, and the increased concentration of bicarbonates will shift the equilibrium of Equation 3 to the left. Hence, insoluble carbonates will be formed. The precipitates will cause pore throat restriction and, will thereby, decrease the permeability of the rock.

The reservoir temperature can be considered to be constant during CO$_2$ flooding. Hence, its effect on Equation 3 is not important in this case.

**Review of Literature**

In the 1950's and early 1960's, hydrocarbon gas and chemical injection were proposed for achieving miscible oil displacement. A miscible fluid is capable of displacing oil completely from the portion
of the reservoir it contacts.

Kock and Slobod\textsuperscript{15} conducted a laboratory study in which crude oil was displaced miscibly by LPG slugs pushed with natural gas. The result of the study indicated that high oil recoveries were obtained because the solvent slug was miscible with the reservoir oil and the propellant. Components controlling the size of the slug required for efficient miscible displacement of the crude oil were reported to be approximately C\textsubscript{5} through C\textsubscript{30} constituents from the crude oil. These heavy hydrocarbons formed the transition zone separating the injected CO\textsubscript{2} from the oil in place. The transition zone then displaced the crude oil miscibly.

Yellig, et al.\textsuperscript{21} conducted laboratory studies on the displacement of crude oil from porous media by carbon dioxide at various pressures. The results of the studies showed that CO\textsubscript{2} displaced some crude oil miscibly at pressures as low as 1300 psi.

MacFarlane\textsuperscript{3} and Holm\textsuperscript{5} have studied the efficiency of the displacement of crude oil by small CO\textsubscript{2} slugs propelled with water and carbonated water. The studies demonstrated that high oil displacement efficiency can be attained by injecting a small slug of carbon dioxide into an oil reservoir and driving it with plain or carbonated water. The researchers found that carbonated water was more efficient than plain water.

O'Leary, et al.\textsuperscript{22} reported a study in which crude oil was displaced by CO\textsubscript{2} slugs propelled with nitrogen. This method has been proposed as a means of reducing the cost of CO\textsubscript{2} flooding projects.

Henderson\textsuperscript{23} and others have developed numerical models to study CO\textsubscript{2} - crude oil miscible displacement processes. The models need accurate laboratory data to simulate the process numerically.

Several field pilot projects designs in which CO\textsubscript{2} was to be used to displace crude oil miscibly have been reported. Even though the economics were unfavorable in most of the field tests, there were increases in oil recoveries over those obtained by conventional production methods.

One of the critical factors in carbon dioxide miscible flooding projects is the limited supply of carbon dioxide. Presently, there is not enough CO\textsubscript{2} to meet the amount required by all the reservoirs that are candidates for CO\textsubscript{2} flooding. The potential sources of CO\textsubscript{2} discussed in detail by Vândenhengel and Stalkup are listed below:

(1) Power plant stack gas
(2) By-product from ammonia plants
(3) Chemical plants
(4) Oil field acid gas separation
(5) Natural CO\textsubscript{2} deposits
In 1959, Holm reported some observed changes in the absolute permeability of dolomite cores after CO$_2$-carbonated water flooding. There was a threefold increase in the core permeability after flowing seven to eight pore volumes of CO$_2$ and carbonated water through the core. Crawford, et al. discussed the use of carbon dioxide as an effective well stimulating agent. The effectiveness of carbon dioxide as a well stimulant is due to the acidic nature of carbon dioxide when dissolved in water.
LABORATORY EQUIPMENT

Sandpaks

Stainless steel pipe with an O.D. of one inch and an I.D. of 5/8 inch were packed with 20 - 200 mesh sand. Monel screens were placed across the ends to retain the sand and a courser sand was placed next to the screen at each end to prevent the finer sand from reaching the screen. The pipes were designed to withstand 20,000 psi. The lengths of pipe used were twenty inches and twenty feet.

Cores

Dolomite cores 12 inches long and 2 ¼ inches in diameter were used for the investigation. The cores were obtained from J. E. Baker company and were quarried in Millersville, Sandusky County, Ohio, a primary, sedimentary dolomite formed in a warm shallow marine environment. The dolomite is from the Niagara group, Guelph formation, upper Silurian Epoch, Paleozoic era and is considered to be 400 - 450 million years old.

Filters

Filters were prepared from 10 inch long sections from a sandstone core and three dolomite cores. Each of the cores was fitted with a stainless steel endplates adaptable to 1/8 inch stainless steel tubing attached at one end. The core was coated with two layers of epoxy (resin) with the other end left open. The open end was the intake (high pressure) end. Each of the cores was housed in a 3 inch diameter, 14 inch long high pressure steel casing. The filters were placed in the oil flow line, in the CO₂ flow line, and in the nitrogen flow line.

Liquid Pump

A Whitey laboratory feed pump was used to inject brine, diesel oil, crude oil or toluene into the cores. The pump rate was controlled by adjusting the stroke length.

High Pressure Cylinders

Two 2000 cc high pressure stainless steel cylinders were placed in a vertical position, connected at the bottom end, and were completely filled with mercury. The top of one cylinder was connected to a Ruska pump which supplied antifreeze. The top of the second cylinder was filled with CO₂ which was used for the displacement tests. The mercury served to isolate the CO₂ from the antifreeze.
Ruska Pumps

Ruska pumps were used in the study. One Ruska pump was used to inject CO₂ into the cores. The pump injected antifreeze into a stainless steel cylinder to displace mercury which in turn displaced CO₂ into the cores at a constant rate. The same pump was later used to inject nitrogen into some of the core. Antifreeze was injected by the pump into the bottom of a high pressure stainless steel cylinder to move nitrogen into the cores at a constant rate. One cylinder of the second Ruska pump was used to exert confining pressure on the cores while the other cylinder was used to inject a KCl solution into the cores.

Vacuum Pump

A Harshaw Scientific vacuum pump was used to evacuate the cores to ensure that the cores were one hundred percent saturated with the KCl solution initially.

Temperature Control System

The temperature of the sandstone cores was maintained at a constant value by electric heating tapes connected to a rheostat-temperature-controller.

Backpressure Regulator

A Tescom backpressure regulator was used to maintain the desired pressures on the cores.

Transducer

A Validyne pressure transducer was used to monitor pressure drops across the dolomite cores.

Pressure Gauges

Pressure gauges were used to monitor the inlet and the outlet pressures of the sandstone cores and the inlet pressures of the dolomite cores.

Gas Flow Meter

A wet test meter was used to measure the volume of gas produced during the displacement tests.

Ruska Viscosimeter

A Ruska rolling ball viscosimeter, as well as necessary pressure gauges and pressure screens, were used for measuring viscosity, density and solubility of CO₂ in oil as functions of pressure.
EXPERIMENTAL PROCEDURE

Sandpack Preparation

The sandpacks were prepared from cylindrical stainless steel pipes with an inside diameter of 5/8 in. and lengths of 20 inches, 60 inches and 240 inches. The pipes were designed to withstand 20,000 psi. Each of the pipes was equipped with swagelok fittings at each end and was adapted to 1/8 inch stainless steel tubing. The ends of the sandpacks were equipped with screens to prevent sand production during flooding experiments. The columns were packed with Halliburtons 20-200 wet sand. The 20 inch and the 60 inch columns were wrapped with copper tubing such that water from a constant temperature bath was circulated through the tubing to regulate the temperature of the columns. The systems were wrapped with 2 inch thick fiber glass insulation. The 240 inch long column was heated with electrical heating tape and fiberglass insulation was wrapped around the column to reduce heat loss.

The sandpacks were evacuated and were saturated with fresh water. The hydrocarbon pore volume was established by displacing the fresh water with mineral oil. The irreducible water saturation and the initial oil saturation were determined by material balance methods.

Core Preparation

The investigations using consolidated cores was divided into six parts which included seventy-two displacement experiments in nineteen different cores. The properties and composition of the two crude oils, CO₂ and nitrogen used in the study are listed in Tables 1-4.

A 5 foot long consolidated sandstone core (Core #1) was prepared from a section of 2 inch x 2 inch, 5 foot long consolidated Berea sandstone core. Stainless steel endplates with fittings adaptable to 1/8 inch stainless steel tubing were placed at either end of the core. The core set-up was clamped together and was coated with four layers of epoxy resin. The core was evacuated and was allowed to stand for about twelve hours to ensure that the core had no leaks. The core was placed in a 4 1/2 inch diameter, 7 foot long high pressure steel casing in which water maintained a confining pressure in excess of the sample's internal working pressure on the outside of the core. The core was evacuated and was saturated with 0.1 N KCl solution. The volume of KCl solution used to saturate the core was recorded as pore volume. The permeability of the core was determined. The core assembly was heated by electrical heating tapes wrapped round the high pressure steel casing. The temperature of the core assembly was maintained at the desired level by a thermostat. The core assembly was insulated by 2 inch thick fiberglass. Diesel oil was used to displace the KCl solution from the core until the KCl solution saturation was reduced to essentially its irreducible value.

A schematic drawing of the equipment that was used in initially saturating the cores and sandpacks is presented in Figure 1. This same equipment was used to inject CO₂, to displace the oil, and also to
inject either brine or nitrogen to push the \( \text{CO}_2 \) slug in the consolidated cores.

The volume of KCl solution produced was recorded as the core hydrocarbon pore volume (HPV). The dead volume in the system was insignificant. The diesel was injected into the core at a rate of 6 cc/min and the pressure drop across the core was noted. The pressure drop was denoted as the "initial diesel oil pressure drop". This pressure drop was compared with values in later runs to determine if the permeability of the core was changing. All other 5 foot long Berea cores were prepared in a similar manner.

The 15 foot long consolidated sandstone core (Core #2) was prepared from three sections of 2 inch x 2 inch, 5 foot long consolidated Berea sandstone cores. The three sections were arranged end to end and stainless steel plates with fittings adaptable to \( \frac{1}{8} \) inch stainless steel tubing were placed at either end of the core. Epoxy resin was applied lightly on three of the four sides and at the two points where the 5 foot long core sections were butted together. Strips of fiberglass cloth were pressed into the epoxy in order to strengthen the core at these points. The resin was allowed to set. To insure capillary continuity at the butting points, they were packed through the fourth side with fine sand obtained by grinding sandstone chips from another core section. Epoxy resin with fiberglass cloth pressed into it was applied to the fourth side at each of the two butting points. The core was coated with 4 layers of epoxy resin. The core was evacuated and was allowed to stand for twelve hours to ensure that the core had no leaks. The core was housed in a 4-1/2 inch diameter, 22 foot long high pressure steel casing containing water to provide external confining pressure on the core. The core volume, permeability, hydrocarbon pore volume and "initial diesel oil pressure drop" were established for the core in the same manner as for the 5 foot long consolidated core (Core #1). The second and the third 15 foot long consolidated Berea cores (Core #3 and #4) were prepared in the same manner as Core #2. The permeability of each of the six sections used in Core #2 and Core #3 was 275 md. Two of the three 5 foot long sections used to prepare Core #4 had a permeability of 560 md. The 275 md permeability section was placed in the middle of the 15 foot long consolidated core (Core #4).

The dolomite cores (Core #5 - 6d) were prepared in the same manner as described for the 5 foot long consolidated core. The cores were saturated with 0.1 N KCl solutions. The temperature of the cores was maintained at 80°F by setting the laboratory room temperature to that value.

Core Cleaning Procedure

Cores were cleaned at the end of each run by injection of 0.8 - 1 hydrocarbon pore volumes (HPV) of toluene followed by 1.5 HPV of diesel oil. The diesel oil was allowed to circulate through the core. Diesel oil was taken from the outflow end and returned through the cores until the pressure drop across the core equaled the "initial diesel oil pressure drop" across the core that was established initially. Crude
1. Core
2. Filter
3. Oil pump
4. Mercury-antifreeze vessel
5. Pressure gage
6. Oil reservoir
7. CO₂ source
8. Nitrogen source
9. Ruska pump
10. Pressure regulator
11. Wet test meter
12. Buret
13. Rheostat
14. Temperature control
15. Circuit breaker

FIGURE 1--Schematic of the Equipment Used for CO₂ Flooding in the Consolidated Sandstone Cores
(1) Ruska pump (6,7,8) Pressure gages
(2) Core #1 (first core) (9) Buret
(3) Core #2 (second core) (10) Wet test meter
(4,5) Pressure transducers V--valve

FIGURE 2--Schematic for flooding dolomite

Table 1

Physical Properties of the Crude Oil

Foster Crude Oil

API Gravity: 34 at 78 F
Density: 0.8537 gm/cc
Absolute Viscosity: 17.8 cp at 69 F

SACROC Crude Oil

API Gravity: 44 at 78 F
Density: 0.8062 gm/cc
Absolute Viscosity: 10.8 cp at 69 F
### TABLE 1 (Continued)

Compositional Analysis of the Crude Oils (Mole %)

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<thead>
<tr>
<th></th>
<th>Foster Crude</th>
<th>SACROC Crude</th>
<th>Foster Crude</th>
<th>SACROC Crude</th>
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</thead>
<tbody>
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<td>Trace</td>
<td>C₂₄</td>
<td>2.627</td>
</tr>
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<td>0.593</td>
<td>0.280</td>
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</tr>
<tr>
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<td>4.952</td>
<td>C₃₆</td>
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<td>C₁₄</td>
<td>4.746</td>
<td>Pristane/Phytane</td>
<td>0.559</td>
<td>1.018</td>
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### Table 2

**Compositional Analysis of the Crude Oils (Mole %)**

<table>
<thead>
<tr>
<th>Foster Crude</th>
<th>SACROC Crude</th>
<th>Foster Crude</th>
<th>SACROC Crude</th>
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</thead>
<tbody>
<tr>
<td>C</td>
<td>0.085</td>
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<tr>
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</tr>
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<td>1.610</td>
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<td>Trace</td>
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<td>3.644</td>
<td>C</td>
<td>Trace</td>
</tr>
<tr>
<td>C</td>
<td>4.407</td>
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<td>C</td>
<td>5.254</td>
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<td>Trace</td>
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<td>C</td>
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<td>Pristane/Phytane</td>
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<tr>
<td>C</td>
<td>3.390</td>
<td>1.962</td>
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</tr>
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### Table 3

**Oil Analysis**

<table>
<thead>
<tr>
<th>Foster Crude Oil (Percent)</th>
<th>SACROC Crude Oil (Percent)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Grammetric Analysis</td>
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<tr>
<td>Aliphatics</td>
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</tr>
<tr>
<td>Aromatics</td>
<td>10.0</td>
</tr>
<tr>
<td>NSO's</td>
<td>2.3</td>
</tr>
<tr>
<td>Asphaltenes</td>
<td>1.5</td>
</tr>
<tr>
<td>Volatilized</td>
<td>25.7</td>
</tr>
<tr>
<td>Retained</td>
<td>11.5</td>
</tr>
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</table>

| Elemental Analysis         |                             |
| Sulfur                     | 1.74                        | 0.19                        |
Table 4
Physical Properties of CO₂ and Nitrogen

Properties of Carbon Dioxide

<table>
<thead>
<tr>
<th>Property</th>
<th>Value</th>
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</thead>
<tbody>
<tr>
<td>Critical Pressure</td>
<td>1069.4 psia</td>
</tr>
<tr>
<td>Critical Temperature</td>
<td>547.7 R</td>
</tr>
<tr>
<td>Molecular Weight</td>
<td>44.01</td>
</tr>
<tr>
<td>Purity</td>
<td>99.9%</td>
</tr>
<tr>
<td>Viscosity at 110 F, 2500 psig</td>
<td>0.06615 cp</td>
</tr>
<tr>
<td>Viscosity at 110 F, 1500 psig</td>
<td>0.05733 cp</td>
</tr>
<tr>
<td>Density at 110 F, 2500 psia</td>
<td>50 lb/ft</td>
</tr>
<tr>
<td>Density at 110 F, 1500 psia</td>
<td>37 lb/ft</td>
</tr>
</tbody>
</table>

Properties of Nitrogen

<table>
<thead>
<tr>
<th>Property</th>
<th>Value</th>
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</thead>
<tbody>
<tr>
<td>Critical Pressure</td>
<td>492.45 psia</td>
</tr>
<tr>
<td>Critical Temperature</td>
<td>226.9 R</td>
</tr>
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<td>Molecular Weight</td>
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<tr>
<td>Purity</td>
<td>99.9%</td>
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<tr>
<td>Viscosity at 110 F, 2500 psia:</td>
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</tr>
<tr>
<td>Viscosity at 110 F, 1500 psia:</td>
<td>0.0198 cp</td>
</tr>
<tr>
<td>Density at 110 F, 2500 psia:</td>
<td>10.922 lb/ft</td>
</tr>
<tr>
<td>Density at 110 F, 1500 psia:</td>
<td>6.732 lb/ft</td>
</tr>
</tbody>
</table>
oil was injected to displace the diesel oil until the density and viscosity of the intake fluid and the oil produced was the same. The schematic of the equipment used is shown in Figures 1 and 2.

Determination of CO₂ - SACROC Crude Oil Miscibility Pressure

To determine the CO₂ - SACROC crude oil miscibility pressure, Core #1 (5 foot long consolidated sandstone core) was saturated with SACROC crude oil. The core was placed in a horizontal position. SACROC crude oil was displaced from the core with 1.7 HPV CO₂ at pressures of 260 psig, 520 psig, 740 psig, 940 psig, 1250 psig, 1550 psig, 1750 psig, 2190 psig and 2390 psig (Runs #1 - 9); 1.6 HPV of CO₂ was used to displace SACROC crude oil from Core #1 at pressures of 2413 psig, 2569 psig and 2650 psig (Runs #10 - 12). In all the runs, CO₂ was injected into the core at a rate of 1.7 cc/min and the temperature of the system was maintained at 120°F. All of these displacements can be considered primary displacements. The core was cleaned at the end of every run as outlined in the core cleaning procedure.

The CO₂ - SACROC crude oil miscibility pressure was determined from a plot of oil recovery vs CO₂ injection pressure.

Comparison of the Efficiencies of Water and Nitrogen as CO₂ Slug Propellants During CO₂ Flooding

The efficiencies of water and nitrogen as CO₂ slug propellants were compared by conducting four sets of displacement tests on Core #2 and two sets of displacement tests on Core #1 (a total of 34 runs). SACROC crude oil was displaced from Core #1 and Core #2 in four sets of runs (two sets each for each core), and Foster Field crude oil was displaced from Core #2 in two sets of runs. Each of the cores was placed in a horizontal position during the tests.

In 10 runs, SACROC crude oil was displaced from Core #2 (15 foot long consolidated core) by CO₂ slugs propelled through the core with 0.1 N KCl solution at pressures near 2560 psi. In the next set of 8 runs, SACROC crude oil was displaced from Core #2 by CO₂ slugs driven through the core with nitrogen at pressures near 2560 psi.

Foster Field crude oil was displaced from Core #2 by CO₂ slugs propelled through the core with 0.1 N KCl solution at pressures near 1560 psig. This test was conducted in five runs.

In the next five runs, Foster Field crude oil was displaced from Core #2 by CO₂ slugs propelled through the core with nitrogen at pressures near 1560 psig. The fluids (CO₂, brine and nitrogen) were injected into the core at a rate of 6 cc/min. and the temperature of the core was maintained at 110°F during all the tests.

SACROC crude oil was displaced from Core #1 (horizontal five foot long consolidated sandstone core) by CO₂ slugs pushed through the core with nitrogen at pressures near 2560 psig. CO₂ slugs propelled with brine were then used to displace SACROC crude oil from Core #1 at pressures near 2540 psig. The fluids were injected into the core at a
rate of 6 cc/min. and the temperature of the system was maintained at 120°F.

The cores were cleaned at the end of each run as outlined in the section on Core Cleaning Procedure.

The results of the displacement tests were used to compare the efficiencies of water and nitrogen as CO₂ slug propellants.

Determination of the Optimum CO₂ Slug Size Required for CO₂ Flooding

The optimum CO₂ slug size required for miscible flooding was determined from a set of runs conducted on Core #3 (15 foot long consolidated sandstone core), on Core #2 and on Core #1. All cores were tested in a horizontal position.

Core #3 was saturated with SACROC crude oil and the oil was displaced with CO₂ slugs propelled with brine at pressures near 2603 psig. The temperature of the system was maintained at 120°F. The CO₂ and the brine were injected into the core at a rate of 6 cc/min. Brine was injected after breakthrough until the water-oil ratio exceeded 100. The core was cleaned as outlined in the section on Core Cleaning Procedure at the end of every run, and it was saturated with SACROC crude oil in preparation for the next run.

Effect of Reservoir Heterogeneity (Horizontal Permeability Variation on Oil Recovery During CO₂ Flooding)

The effect of horizontal permeability variation on CO₂ flooding was studied by displacing SACROC crude oil from Core #4 (15 foot long consolidated sandstone core made up of three core sections having different permeabilities), and comparing the result with similar runs in Core #2 (15 feet long consolidated sandstone core with uniform permeability all along its length). Cores were in a horizontal position.

Foster Field crude oil was displaced from Core #4 with CO₂ slugs propelled through the core with brine at pressures near 1558 psig. Fluids (CO₂ and brine) were injected into the core at a rate of 6 cc/min. The temperature of the core was maintained at 110°F. The core was cleaned at the end of each run as outlined in the section on Core Cleaning Procedure.
Effect of CO₂ on Dolomite Rock

To study the effect of CO₂ on dolomite rock, 0.1 N KCl solution was displaced from a 9 inch long dolomite core (Core #5) by CO₂ slugs. A schematic drawing of the equipment used to measure the interaction between CO₂ and dolomite is presented in Figure 2. In three tests, 0.3, 0.59, and 0.65 PV of CO₂ were injected into the core at a rate of 10 cc/hr and at pressures of 1050 psig, 1060 psig and 1220 psig (Runs #58 - 60) to displace KCl solution. The maximum pressure difference developed across the core during any of the three tests, or during the blowdown period was less than 18 psi. At the end of each test, the core was resaturated with KCl solution and its permeability was redetermined.

In the second set of tests, dolomite Core #6, which was 9 inches long, was connected in series with Core #5 such that effluent from Core #5 passed through Core #6. Three slugs of CO₂ with volumes of 0.56, 0.59 and 0.59 PV were injected at a rate of 10 cc/hr to displace KCl solution from Core #5. The displacement pressure in all three tests was 1030 psig. The maximum pressure drop across Core #5 was less than 18 psi while pressure drops of 1030 psi, 100 psi and 750 psi were maintained across Core #6 in the three runs, respectively. At the end of each displacement test, the cores were resaturated with KCL solution and the core permeabilities were redetermined. The temperature of the system was maintained at 80°F during the tests.

In Run #64, a 0.3 PV bank of CO₂ was injected at 1050 psig to displace KCl solution from Core #7. The maximum pressure drop across the core was less than 18 psi. CO₂ was injected into the core at a rate of 10 cc/hr and the temperature of the system was maintained at 80°F. The core was resaturated with KCI solution at the end of the run and its permeability was redetermined.

Effect of Pressure on CO₂ - Dolomite Rock Interaction

Twelve 3" long dolomite cores were used to study the effect of pressure on CO₂ - dolomite rock interaction. There were two sets of four displacement tests. In the first set, KCl solution was displaced from four 3" long cores at 1050 psig, 1505 psig, 2070 psig and 2500 psig, respectively, by 0.3 PV CO₂ slugs. The four sections were cut from a single 12" long dolomite core. The CO₂ slugs were pushed with KCl solutions. CO₂ slugs and KCl driving solutions were injected into the core at a rate of 10 cc/hr. The maximum pressure drop maintained across any of the four cores was less than 5 psig. The cores were resaturated at the end of the runs and their permeabilities were redetermined.

Eight 3" long dolomite cores were used for the second set of four runs. In each run, two cores were connected in series such that the effluent from Core #5 flowed through Core #6. Cores #5a - 5d were from a 12" long dolomite core and Cores #6a - 6d were from another 12" long dolomite core. Thirty percent PV CO₂ slugs pushed with 2 PV KCl solution were injected into Cores #5a - 5d to displace connate KCl
solution from the cores at a rate of 10 cc/hr. Effluents from Cores #5a - 5d were passed through Cores #6a - 6d. A back pressure of 1060 psig was maintained on each of Cores #5a - 5d. The maximum pressure drop across Cores #5a - 5d was less than 5 psi. Pressure drops of 1050 psi, 300 psig, 500 psig and 0 psig were maintained across Cores #6a - 6d in the first, second, third and the fourth runs, respectively. The temperature of each system was maintained at 80°F during the tests.

A pressure drawdown of less than 18 psi was maintained across Core #1, and a pressure drawdown of less than 5 psi was maintained across Cores #4a - 4d and across Cores #5a - 5d. This was done to prevent carbonates precipitated in the cores from moving to clog up pore throats.

Cores #4a - 4d, #5a - 5d and #6a - 6d were cut from three different 12” long cores to determine how different cores responded to CO₂ treatment differently.

Results and Discussion

The effect of liquid carbon dioxide on the permeability of dolomite Core #5 is shown in Figure 22. After three displacement runs, the permeability of the core increased from an initial value of 90.13 md to 142.35 md. The permeability of the core finally increased to 147.87 md after a total of 3.28 PV CO₂ was injected through the core. This agrees with the findings of Hölm which showed that the permeability of a dolomite core increased three fold after about nine PV of carbonated water and CO₂ were injected through the core. It is obvious, therefore, that at high pressure, carbon dioxide in the presence of water dissolves calcium and magnesium carbonates along the pore walls, thereby increasing the pore throat size and, hence, the permeability of the core.

The permeability of dolomite Core #6 as influenced by flushing the core with the effluent from Core #5 is shown in Figure 22. The permeability of the core decreases from an initial value of 184.56 md to a final value of 143.19 md after three runs. The maximum pressure drop allowed across core #2 was 1030 psi. The result showed a relationship between pressure drawdown and permeability reduction (Figure 26).

Microscopic examination showed the untreated cores to be fine grained limestone consisting of a mosaic of rhombohedral calcite crystals. The average grain size varied from 0.1 mm to 0.2 mm. Pores were abundant and they must have resulted from calcite recrystallization. Pore spaces varied in diameter with the value of some as high as 1 mm. The pore walls were lined with crystal faces or cleavage planes of calcite (Figures 23a and 24a).

The CO₂ treated sample appeared to have some pore lining calcite crystals showing the effect of dissolution on crystal boundaries and along cleavage planes. This effect has resulted in an increase in the pore diameter to a value as high as 1.5 mm in cases. The milky
appearance of the produced fluid (and the presence of precipitates in the effluent) further confirmed that some of the rock was dissolved. This must have caused the increase in the permeability of the core (Figure 23b).

Figures 25 and 26 show the effect of pressure on the interaction between CO₂ and the dolomite rock used for this study. At 1050 psig, CO₂ flooding resulted in a 5% increase in the permeability of Core #4a. A 22% increase was observed in the permeability of Core #4d when the flooding pressure was 2500 psig. Core #6a showed about 25% reduction in permeability when the pressure drawdown across the core was 1030 psig while the permeability of core #6c was reduced to 95% of the initial value. Cores #5a-5d each showed a 5% increase in its permeability after the treatments (Figure 26).

The results indicated that more of the rock was dissolved from the pore walls as the CO₂ flooding pressure was increased, and more material precipitated from the bicarbonate solution when the pressure drawdown was increased.
Presentation of Results

Displacement from Sandpacks

The properties of the three sandpacks properties of consolidated sandstone core, including initial fluid saturations, are shown in Table 5. The porosities of the 20, 60 and the 240 inch sandpacks were 34.8%, 34.3%, and 31.8%, respectively. The permeability of the sandpacks ranged from 3478 md for the 20 inch column to 3181 md for the 240 inch column. The consolidated sandstone core had a porosity of 21.5% and a permeability of 275 md. The irreducible water saturation was 10%, 11%, and 11% for the 20 inch, 60 inch and the 240 inch sandpacks, respectively, and the initial water saturation in the 5 foot long consolidated sandstone core was 34%.

To determine the pressure at which CO₂ becomes very efficient at displacing crude oil from porous media, the first series of displacements were conducted. Foster crude was displaced from the 60 inch sandpack by carbon dioxide at 750 psig, 900 psig, 2100 psig, 1200 psig, 1400 psig, 1500 psig, 1600 psig and 1800 psig. The sandpack was placed in a vertical position. Similar tests were conducted on the 20 inch and the 240 inch vertical sandpacks. Carbon dioxide was injected into the top of the columns at a rate of 20 cc/min until the gas oil ratio exceeded 200 over a ten minute interval. The results are shown in Figure 3.

The total oil recovery from the 60 inch sandpack increased from 68.5% OIP at 750 psig to 99.0% OIP at 1800 psig. The oil recovery from the 20 inch sandpack ranged between 73.3% OIP at 740 psig and 97.7% OIP at 1800 psig. The oil recovery from the 240 inch sandpack varied from 69.3% at 750 psig to 97.14% OIP at 1800 psig. Generally, the oil recovery from the three sandpacks increased with the flooding pressure from 750 psig to 1500 psig. Increasing the flooding pressure above 1500 psig did not result in concomittant increases in oil recoveries as was observed at lower pressures.

In the second set of tests, crude oil was displaced from the 60 inch sandpack, 240 inch sandpack and the 60 inch consolidated sandstone core by carbon dioxide at various rates. Foster crude oil was displaced from the vertical 60 inch sandpack by carbon dioxide injected into the top of the column at a rate of 21 cc/min, 13 cc/min, 6.48 cc/min and 3.24 cc/min. A flooding pressure of 1500 psig was maintained on the column during the four tests. The results are shown in Figure 4. Similar tests were conducted on the 60 inch sandpack placed in a horizontal position. The results are shown in Figure 5. Foster crude oil was displaced from the vertical 240 inch sandpack at pressures of 1400 psig and 1600 psig by carbon dioxide injected into the top of the column at rates of 3.24 cc/min and 21 cc/min. The results are shown in Figure 6 and in Table 6. At a flooding pressure
<table>
<thead>
<tr>
<th></th>
<th>20</th>
<th>60</th>
<th>240</th>
</tr>
</thead>
<tbody>
<tr>
<td>Length (in.)</td>
<td>20</td>
<td>60</td>
<td>240</td>
</tr>
<tr>
<td>Grain size (mesh)</td>
<td>20-200</td>
<td>20-200</td>
<td>20-200</td>
</tr>
<tr>
<td>Pipe diameter (micr)</td>
<td>0.625</td>
<td>0.625</td>
<td>0.625</td>
</tr>
<tr>
<td>Pore volume (cc)</td>
<td>40</td>
<td>103.5</td>
<td>384</td>
</tr>
<tr>
<td>Hydrocarbon pore volume (cc)</td>
<td>36</td>
<td>92</td>
<td>343</td>
</tr>
<tr>
<td>Porosity %</td>
<td>34.8</td>
<td>34.3</td>
<td>31.8</td>
</tr>
<tr>
<td>Absolute Permeability</td>
<td>3478</td>
<td>3428</td>
<td>3181</td>
</tr>
</tbody>
</table>

**Berea Sandstone Core**

- Length: 60 in.
- Cross Section: 2 in. x 2 in.
- Porosity: 21.5%
- Permeability (md): 275
- Initial Oil Saturation: 66%
- Initial Water Saturation: 34%
Figure 3 Effect of Sandpack length on miscibility pressure. Oil recoveries from the 20 inch, 60 inch and the 240 inch sandpacks as functions of flooding pressures. (T = 110°F, CO₂ injection rate = 21 cc/min)
Figure 4  Effect of rate and gravity Segregation on CO₂ flooding. Oil (Foster crude) recovery from the vertical 60 inch sandpack as a function of displacement rate (flooding pressure = 1500 psig, T = 110°F)
Figure 5  Effect of rate and gravity Segregation on CO₂ flooding. Oil (Foster crude) recovery from the horizontal 60 inch sandpack as a function of displacement rate. (Flooding pressure = 1500 psig.  T = 110°F)
of 1400 psig, the total oil recovery was 93% OIP when the fluid injection rate was 3.24 cc/min as compared to an oil recovery of 91.5% OIP when CO₂ was injected at a rate of 21 cc/min.

In the next set of runs, Foster crude was displaced from the 240 inch sandpack at 740 psig, 900 psig, 1100 psig, 1200 psig, 1400 psig, 1500 psig, 1600 psig and at 1800 psig. The sandpack was placed in a horizontal position. The results are shown in Figure 6. The total oil recovery increased from 68.8% OIP at 740 psig to 86.8% OIP at 1800 psig. The sandpack was placed in a vertical position and the floods were repeated. At all pressures the recovery was higher in the vertical sandpack than in the horizontal sandpack.

Two runs were made at pressures near 2585 psig displacing SACROC crude oil from a 5 ft. long Berea sandstone core. When CO₂ was injected at a rate of 1.7 cc/min., the recovery of oil was 87.6% of OIP. When the rate of CO₂ injection was increased to 6 cc/min, the oil recovery was 90% of OIP. Two runs were made at pressure near 2200 psig which was a little below the miscible pressure for CO₂ - SACROC crude oil. The oil recovery was 86.4% of OIP when CO₂ was injected at a rate of 1.7 cc/min and 88% of OIP when the rate was 6 cc/min.

Measurement of Viscosity, Density and Dissolved CO₂ of Crude Oil as a Function of CO₂ Pressure

The viscosities of the Foster Crude oil and the viscosities of the SACROC crude oil were measured as functions of CO₂ miscibility pressure with a Ruska Rolling Ball Viscometer. The viscometer was first calibrated with fluids of known viscosity. The results are presented in Table 7 and in Figure 7. The physical properties of SACROC crude oil and Foster crude oil were measured and are presented in Table 8 and Figures 8 and 9.

Composition of Crude Oil Displaced from Slim Tube Sandpack by CO₂

A West Texas crude oil was displaced from a slim tube sandpack (100 ft. in length) with CO₂. The pressure of the displacement was above the pressure estimated to be the miscibility pressure. During the flood, three samples of produced fluid were collected. One sample was the base crude oil. Another sample was collected before CO₂ breakthrough as the produced fluid started to change color to the color of light straw. The final sample was collected just prior to CO₂ breakthrough. An analysis was made of each sample with a chromatograph. The results are presented in Figures 10 – 12.

Attempts were made to determine the composition of the mixing zone between CO₂ and crude oil during the displacement of oil from a Berea sandstone core 5 ft long and with a cross section 2 inches by 2 inches. The transition zone between crude oil CO₂ was such that during the displacement process, the properties of the effluent changed to those of CO₂ with no delectable transition zone.
Figure 6  Effect of Gravity Segregation. Comparison of oil recoveries from the 240 inch Sandpack when placed in a vertical and an horizontal position as functions of flooding pressures. (T = 110°F, CO₂ injection rate = 21 cc/min)
Figure 7 Calibration Curve for the Rolling Ball Viscosimeter
Figure 8 Determination of CO₂ - Foster Crude Oil viscosity and the Solubility of CO₂ in Foster Crude Oil at different pressures. (T = 110°F)
Figure 9 Determination of CO₂ - SACROC crude oil viscosity and the solubility of CO₂ in SACROC crude oil at different pressures. (T = 110°F)
Table 6
Displacement of Foster field crude oil from the vertical 240 inch sandpack by CO₂ (T = 110 F, injection rate = 3.24 cc/min.)

<table>
<thead>
<tr>
<th>Pressure (Psig)</th>
<th>Vol. of CO₂ Injected (APV)</th>
<th>Vol. of CO₂ Produced (ft³)</th>
<th>Breakthrough Oil Recovery (%OIP)</th>
<th>Total Oil Recovery (%OIP)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1400</td>
<td>1.24</td>
<td>4.15</td>
<td>74.3</td>
<td>93.0</td>
</tr>
<tr>
<td>1600</td>
<td>1.28</td>
<td>4.49</td>
<td>74.5</td>
<td>94.5</td>
</tr>
</tbody>
</table>

Table 7
Calibration Curve for the Rolling Ball Viscosimeter Ball Density
Inclination 23 (7.62 gm/cc)

<table>
<thead>
<tr>
<th>Viscosity (cp)</th>
<th>Roll time (Scc)</th>
<th>Density gm/cc</th>
<th>t(P - P')</th>
</tr>
</thead>
<tbody>
<tr>
<td>3.4</td>
<td>3.15</td>
<td>.8</td>
<td>21.45</td>
</tr>
<tr>
<td>6.5</td>
<td>7.6</td>
<td>.805</td>
<td>61.72</td>
</tr>
<tr>
<td>12.55</td>
<td>17.3</td>
<td>.8193</td>
<td>117.48</td>
</tr>
<tr>
<td>17.48</td>
<td>24.9</td>
<td>.835</td>
<td>168.70</td>
</tr>
<tr>
<td>23.00</td>
<td>33.9</td>
<td>.836</td>
<td>229.64</td>
</tr>
</tbody>
</table>
Table 8
Crude Oil Physical Properties as a Function of CO₂ Pressure

**Foster Crude** (T = 110°F)

<table>
<thead>
<tr>
<th>Pressure (Psig)</th>
<th>Roll time (Sec)</th>
<th>Density cc</th>
<th>t(P-P)&lt;sub&gt;1&lt;/sub&gt;</th>
<th>Viscosity (cp)</th>
<th>Weight of 70 cc Mixture</th>
<th>Produced CO₂ SCF</th>
<th>MW</th>
</tr>
</thead>
<tbody>
<tr>
<td>480</td>
<td>10.39</td>
<td>.79</td>
<td>70.90</td>
<td>8</td>
<td>55</td>
<td>159</td>
<td>633.54</td>
</tr>
<tr>
<td>830</td>
<td>7.76</td>
<td>.83</td>
<td>52.59</td>
<td>6.3</td>
<td>58.3</td>
<td>254.4</td>
<td>425.16</td>
</tr>
<tr>
<td>220</td>
<td>6.15</td>
<td>.84</td>
<td>41.61</td>
<td>5.15</td>
<td>59.1</td>
<td>383.9</td>
<td>287.73</td>
</tr>
<tr>
<td>500</td>
<td>4.55</td>
<td>.86</td>
<td>30.73</td>
<td>4.2</td>
<td>60</td>
<td>606.5</td>
<td>185.88</td>
</tr>
<tr>
<td>1800</td>
<td>3.81</td>
<td>.90</td>
<td>25.55</td>
<td>3.7</td>
<td>63.1</td>
<td>763.2</td>
<td>155.63</td>
</tr>
</tbody>
</table>

**Sacroc Crude**

<table>
<thead>
<tr>
<th>Pressure (Psig)</th>
<th>Roll time (Sec)</th>
<th>Density cc</th>
<th>t(P-P)&lt;sub&gt;1&lt;/sub&gt;</th>
<th>Viscosity (cp)</th>
<th>Weight of 70 cc Mixture</th>
<th>Produced CO₂ SCF</th>
<th>MW</th>
</tr>
</thead>
<tbody>
<tr>
<td>20</td>
<td>4.70</td>
<td>.73</td>
<td>32.32</td>
<td>4.4</td>
<td>51.4</td>
<td>202.2</td>
<td>469.09</td>
</tr>
<tr>
<td>40</td>
<td>3.81</td>
<td>.79</td>
<td>26.00</td>
<td>3.8</td>
<td>55.0</td>
<td>558.8</td>
<td>184.79</td>
</tr>
<tr>
<td>1540</td>
<td>3.51</td>
<td>0.84</td>
<td>23.75</td>
<td>3.56</td>
<td>59.1</td>
<td>929</td>
<td>119.90</td>
</tr>
<tr>
<td>10000</td>
<td>4.20</td>
<td>0.83</td>
<td>28.46</td>
<td>4.0</td>
<td>58.3</td>
<td>863.1</td>
<td>127.25</td>
</tr>
<tr>
<td>170</td>
<td>5.08</td>
<td>0.83</td>
<td>34.46</td>
<td>4.6</td>
<td>57.8</td>
<td>801.8</td>
<td>135.74</td>
</tr>
</tbody>
</table>
TABLE 9
Physical Properties of the Sandstone Cores

<table>
<thead>
<tr>
<th>Core Number</th>
<th>1</th>
<th>2</th>
<th>3</th>
<th>4</th>
</tr>
</thead>
<tbody>
<tr>
<td>Length, ft</td>
<td>52</td>
<td>152</td>
<td>153</td>
<td>153</td>
</tr>
<tr>
<td>Cross Section</td>
<td>2&quot;x2&quot;</td>
<td>2&quot;x2&quot;</td>
<td>2&quot;x2&quot;</td>
<td>2&quot;x2&quot;</td>
</tr>
<tr>
<td>Porosity or percent</td>
<td>21.1</td>
<td>21.1</td>
<td>21.1</td>
<td>24.9</td>
</tr>
<tr>
<td>Initial Water Saturation, %</td>
<td>34</td>
<td>36.5</td>
<td>36.5</td>
<td>29.5</td>
</tr>
<tr>
<td>Absolute Permeability, md</td>
<td>275</td>
<td>275</td>
<td>275</td>
<td>331</td>
</tr>
</tbody>
</table>

Table 10
Determination of CO₂ - SACROC Crude Oil Miscibility Pressure

<table>
<thead>
<tr>
<th>Pressure (psig)</th>
<th>Oil Recovery (% OIP)</th>
</tr>
</thead>
<tbody>
<tr>
<td>260</td>
<td>52.7</td>
</tr>
<tr>
<td>520</td>
<td>57.7</td>
</tr>
<tr>
<td>740</td>
<td>58.3</td>
</tr>
<tr>
<td>940</td>
<td>60.8</td>
</tr>
<tr>
<td>1250</td>
<td>68.7</td>
</tr>
<tr>
<td>1550</td>
<td>74.3</td>
</tr>
<tr>
<td>1750</td>
<td>77.0</td>
</tr>
<tr>
<td>2190</td>
<td>82.4</td>
</tr>
<tr>
<td>2390</td>
<td>84.8</td>
</tr>
<tr>
<td>2413</td>
<td>86.5</td>
</tr>
<tr>
<td>2569</td>
<td>87.6</td>
</tr>
<tr>
<td>2650</td>
<td>88.1</td>
</tr>
</tbody>
</table>
# TABLE 11

Displacement of SACROC Crude Oil from Core #2 With CO₂ Propelled With Brine

<table>
<thead>
<tr>
<th>CO₂ Bank Size (HPV)</th>
<th>Total Oil Recovery (HPV)</th>
<th>Oil Recovery at GBT (HPV)</th>
<th>Oil Recovery Blowdown (HPV)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Brine only</td>
<td>0.67</td>
<td>0.54 (WBT)</td>
<td>-</td>
</tr>
<tr>
<td>0.1</td>
<td>0.76</td>
<td>0.57</td>
<td>.017</td>
</tr>
<tr>
<td>0.2</td>
<td>0.80</td>
<td>0.51</td>
<td>.015</td>
</tr>
<tr>
<td>0.3</td>
<td>0.87</td>
<td>0.55</td>
<td>.015</td>
</tr>
<tr>
<td>0.4</td>
<td>0.90</td>
<td>0.57</td>
<td>.012</td>
</tr>
<tr>
<td>0.5</td>
<td>0.91</td>
<td>0.54</td>
<td>.007</td>
</tr>
<tr>
<td>0.6</td>
<td>0.93</td>
<td>0.56</td>
<td>.015</td>
</tr>
<tr>
<td>0.7</td>
<td>0.94</td>
<td>0.55</td>
<td>.011</td>
</tr>
</tbody>
</table>

# TABLE 12

Core #2 With CO₂ Propelled With Nitrogen

<table>
<thead>
<tr>
<th>CO₂ Bank Size (HPV)</th>
<th>Total Oil Recovery (HPV)</th>
<th>Oil Recovery at GBT (HPV)</th>
<th>Oil Recovery Blowdown (HPV)</th>
</tr>
</thead>
<tbody>
<tr>
<td>N only</td>
<td>0.57</td>
<td>0.30</td>
<td>.186</td>
</tr>
<tr>
<td>0.1</td>
<td>0.66</td>
<td>0.51</td>
<td>.012</td>
</tr>
<tr>
<td>0.2</td>
<td>0.72</td>
<td>0.52</td>
<td>.040</td>
</tr>
<tr>
<td>0.3</td>
<td>0.81</td>
<td>0.55</td>
<td>.025</td>
</tr>
<tr>
<td>0.4</td>
<td>0.88</td>
<td>0.56</td>
<td>.046</td>
</tr>
<tr>
<td>0.5</td>
<td>0.88</td>
<td>0.55</td>
<td>.030</td>
</tr>
<tr>
<td>0.6</td>
<td>0.92</td>
<td>0.55</td>
<td>.050</td>
</tr>
<tr>
<td>0.7</td>
<td>0.94</td>
<td>0.54</td>
<td>.072</td>
</tr>
</tbody>
</table>
### Table 13
Displacement of Foster Crude From Core #2
By CO₂ Propelled by Brine

<table>
<thead>
<tr>
<th>CO₂ Bank Size (HPV)</th>
<th>Total Oil Recovery (HPV)</th>
<th>Oil Recovery at GBT (HPV)</th>
<th>Oil Recovery Blowdown (HPV)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Brine Only</td>
<td>0.67</td>
<td>0.55 (WBT)</td>
<td>-</td>
</tr>
<tr>
<td>0.1</td>
<td>0.77</td>
<td>0.66</td>
<td>.057</td>
</tr>
<tr>
<td>0.3</td>
<td>0.87</td>
<td>0.60</td>
<td>.022</td>
</tr>
<tr>
<td>0.5</td>
<td>0.90</td>
<td>0.56</td>
<td>.045</td>
</tr>
<tr>
<td>0.7</td>
<td>0.91</td>
<td>0.53</td>
<td>.067</td>
</tr>
</tbody>
</table>

### Table 14
Displacement of Foster Crude Oil from Core #2
by CO₂ Propelled by Nitrogen

<table>
<thead>
<tr>
<th>CO₂ Bank Size (HPV)</th>
<th>Total Oil Recovery (HPV)</th>
<th>Oil Recovery at GBT (HPV)</th>
<th>Oil Recovery Blowdown (HPV)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Nitrogen Only</td>
<td>0.56</td>
<td>0.48</td>
<td>.050</td>
</tr>
<tr>
<td>0.1</td>
<td>0.59</td>
<td>0.50</td>
<td>.026</td>
</tr>
<tr>
<td>0.3</td>
<td>0.73</td>
<td>0.52</td>
<td>.026</td>
</tr>
<tr>
<td>0.5</td>
<td>0.72</td>
<td>0.52</td>
<td>.015</td>
</tr>
<tr>
<td>0.7</td>
<td>0.79</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

### Table 15
Displacement of SACROC Crude Oil
From Core #1 by CO₂ Propelled by Brine

<table>
<thead>
<tr>
<th>CO₂ Bank Size (HPV)</th>
<th>Total Oil Recovery (HPV)</th>
<th>Oil Recovery at GBT (HPV)</th>
<th>Oil Recovery Blowdown (HPV)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Brine only</td>
<td>0.66</td>
<td>0.61 (WBT)</td>
<td>---</td>
</tr>
<tr>
<td>0.21</td>
<td>0.80</td>
<td>0.34</td>
<td>.079</td>
</tr>
<tr>
<td>0.41</td>
<td>0.86</td>
<td>0.36</td>
<td>.069</td>
</tr>
<tr>
<td>0.82</td>
<td>0.92</td>
<td>0.36</td>
<td>.057</td>
</tr>
</tbody>
</table>
Displacement From Consolidated Sand Cores

Displacement of Crude Oil with Banks of CO₂ Pushed with Brine or Nitrogen from Sandstone Cores

Physical properties of the Berea sandstone cores that were used in the displacement experiments are presented in Table 9. In all the experiments it was assumed that the water saturation always returned to the initial value.

The oil recovery from Core #1 by CO₂ at several pressures is presented in Figure 13 and Table 10.

The results of the displacement of SACROC crude oil from the 15 foot long Core #2 in which banks of CO₂ were propelled by brine are presented in Table 11. The pressure was maintained at approximately 2560 psig above the value that was thought to be needed to achieve miscibility between the CO₂ and the crude oil. A plot of the oil recovery as a function of the CO₂ bank size is displayed in Figure 14. Details of the production behavior are shown in Appendix A.

SACROC crude oil was displaced by CO₂ banks pushed with nitrogen under the same conditions of pressure, temperature, and rate as were used when brine was used to push the CO₂. The oil recovered as a function of CO₂ bank size is displayed in Table 12 and in Figure 15. Details of the production behavior are shown in Appendix B.

Crude oil from the Foster Field was displaced from Core #2 by banks of CO₂ propelled by brine. The pressure was maintained at about 1,560 psig which was thought to be above the pressure that was needed to achieve miscibility. The temperature was maintained at 110°F. The oil recoveries as a function of the size of CO₂ banks are displayed in Table 13 and in Figure 16. The rate at which CO₂ was injected was 6 cc/min. Details of the production behavior are shown in Appendix C.

Nitrogen was used to push banks of CO₂ from Core #2 under the same conditions that existed when brine was used to push the CO₂. The oil recovery as a function of bank size is presented in Table 14 and in Figure 17. Details of the production behavior are shown in Appendix D.

The results of the tests in which SACROC crude oil was displaced from Core #1 at 120°F by CO₂ slugs propelled with KCl solution, are summarized in Table 15. The plot of oil recovery related to CO₂ slug size is shown in Figure 18. Total oil recovery increased from 66% OIP for a straight waterflood at 2540 psig to 92% OIP when 0.82 HPV CO₂ were propelled through the core with KCl solution. Details of the
production behavior are shown in Appendix E. The results of the tests in which SACROC crude oil was displaced with different CO₂ slugs propelled through the core by nitrogen are summarized in Table 16. Total oil recovery increased from 67% OIP when 0.21 HPV CO₂ were propelled through the core by nitrogen to 82% OIP when 0.82 HPV CO₂ were propelled with nitrogen at 2594 psig. A plot of oil recovery vs CO₂ slug size injected is presented in Figure 19. Details of the production behavior are shown in Appendix F.

The results of the tests in which SACROC crude oil was displaced from the horizontal 15 foot long consolidated sandstone core (Core #3) by different CO₂ slug sizes propelled with KCl solution are summarized in Table 17. The plot of total oil recovery vs CO₂ slug size is shown in Figure 20. The total oil recovery increased from 70% OIP when the oil was displaced from the core with 0.05 HPV CO₂ slug propelled through the core by KCl solution at 2600 psig to 86.7% OIP when 0.6 HPV CO₂ were propelled with KCl solution at 2570 psig. The results of the eight tests showed that 0.3 HPV CO₂ slug was an optimum slug size for CO₂ flooding at the conditions of the laboratory study. Details of the production behavior are shown in Appendix G.

The results of the tests in which Foster field crude oil was displaced from Core #4 (horizontal 15 foot long consolidated sandstone with variable permeability along its length) by CO₂ banks propelled with KCl solution are summarized in Table 18. The plot of total oil recovery related to CO₂ bank size is shown in Figure 21. The total oil recovery increased only slightly when the bank size was increased from 0.3 HPV to 0.5 HPV at about 1560 psig. Total oil recoveries were a little less than those obtained for similar tests (Runs #16, 17, 18) conducted in Core #2 (horizontal 15 foot long homogeneous consolidated sandstone core). Details of the production behavior are shown in Appendix H.

The Influence of CO₂ on the Permeability of Dolomite

The properties of the dolomite cores that were used to study the changes in permeability that might take place when CO₂ and brine are flowed through the cores are presented in Table 19.

In the first set of experiments CO₂ was flowed through Core #5 at high pressure, and the effluent was flowed through Core #6 as the pressure was reduced.

The effect of carbon dioxide on Core #5 (dolomite core) is demonstrated in Figure 23. The permeability of the dolomite core increased from 90.13 md after 0.3 HPV CO₂ were injected.

The effect on the permeability of core #6 by flowing the effluent from Core #5 through Core #6 is shown in Figure 24. The permeability of the core decreased from 184.56 md to 144.88 md after the first test
Figure #10
Analysis of Base Crude

Relative Abundance

Normal Paraffin Number
Figure #11
Analysis of Oil from Front of Transition Zone
Figure #12
Analysis of Oil from Back of Transition Zone

Relative Abundance

Normal Paraffin Number
FIGURE 13- Determination of CO$_2$ - SACROC crude oil miscibility pressure
FIGURE 15 - Oil (SACROC crude) recovery from the horizontal 15 foot consolidated Berea sandstone core (Core #2) as a function of CO$_2$ slug sizes. CO$_2$ slugs were propelled with nitrogen. (T = 110°F, 2500 psig < flooding pressure < 2650 psig)

FIGURE 16

Oil (Foster crude) recovery from the horizontal 15 foot consolidated Berea sandstone core (Core #2) as a function of CO$_2$ slug sizes. CO$_2$ slugs were propelled with water (brine). (T = 110°F, 1500 psig < flooding pressure < 1650 psig)
FIGURE 17
Oil (Foster crude) recovery from the horizontal 15 foot consolidated Berea sandstone core (Core #2) as a function of CO\(_2\) slug sizes. CO\(_2\) slugs were propelled with nitrogen. \((T = 110^\circ F, 1500\; \text{psig} \leq \text{flooding pressure} \leq 1650\; \text{psig})\)

FIGURE 18
Oil (SACROC crude) recovery from the horizontal 5 foot consolidated Berea sandstone core (Core #1) as a function of CO\(_2\) slug size. CO\(_2\) slugs were propelled with water (brine). \((T = 120^\circ F, 2500\; \text{psig} \leq \text{flooding pressure} \leq 2650\; \text{psig})\)
FIGURE 19
Oil (SACROC crude) recovery from the horizontal 5 foot consolidated Berea sandstone core (Core #1) as a function of CO₂ slug sizes. CO₂ slugs were propelled with nitrogen (T = 120°F, 2500 psig ≤ flooding pressure ≤ 2650 psig)

FIGURE 20
Oil (SACROC crude) recovery from the horizontal 15 foot consolidated Berea sandstone core (Core #3) as a function of CO₂ slug sizes. CO₂ slugs were propelled with water (brine) (T = 120°F, 2500 psig ≤ flooding pressure ≤ 2650 psig)
FIGURE 21 - Oil (Foster crude) recovery from the horizontal 15 foot heterogeneous consolidated Berea sandstone core (Core #4) as a function of CO₂ slug size. CO₂ slugs were propelled with water (brine). (T = 110°F, 1500 psig ≤ flooding pressure ≤ psig)
FIGURE 22 - Effect of CO₂ - dolomite rock interaction on rock permeability

\[ \frac{k}{k_0} (\%) \]

Run Number

Core #5

Core #6

\( k_0 \) = original permeability of the core

\( k \) = core permeability after CO₂ treatment
FIGURE 23a--A Section of Dolomite Core 5 Before CO₂ Treatment.

FIGURE 23b--A Section of Dolomite Core 5 After CO₂ Treatment.
FIGURE 24a--A Section of Dolomite Core No. 6 Before Treatment.

FIGURE 24b--A Section of Dolomite Core No. 6 After Flushing With Effluent From Core No. 5.
FIGURE 25 - Effect of CO₂ flooding pressure on CO₂ - dolomite rock interaction

\[ \frac{k}{k_0} \] = original permeability

\[ k \] = core permeability after CO₂ treatment
FIGURE 26—Effect of pressure drop across core on CO₂ - dolomite rock interaction

\( \frac{k}{k_0} \) = original permeability of core

\( k \) = core permeability after CO₂ treatment
in which a 0.56 PV CO₂ slug was used to displace KCl solution from Core #5 and the effluent was passed through Core #6. The permeability of Core #6 was finally reduced to 143.19 md after additional volumes of CO₂ were passed through the core.

Microscopic examination showed the untreated cores to be fine grained limestone consisting of a mosaic of rhombohedral calcite crystals. The average grain size varied from 0.1 mm to 0.2 mm. The pore walls were lined with crystal faced or cleavage planes of calcite (Figures 23a and 24a).

The CO₂ treated sample appeared to have some pore lining calcite crystals indicating the effect of dissolution on crystals boundaries and along cleavage planes, as shown in Figures 23a and 24a. The dissolution resulted in an increase in the pore diameter to a value as high as 1.5 mm in some cases. The milky appearance of the fluid produced further confirmed that some of the rock was dissolved. This must have caused the increase in the permeability of the core.

Microscopic observations of the sample flushed with effluent from Core #5 shows that the section of Core #6 had a greater amount of disintegrated fragments as shown in Figure 24b. The fragments were the calcite crystals dissolved from the pore walls of Core #5 which were precipitated in Core #6. The fragments were free to migrate to, and clog up pore throats. The clogging of the pore throats must have caused the reduction in the permeability of Core #6.

Table 16
Displacement of SACROC Crude Oil from Core #1 by CO₂ Propelled by Nitrogen

<table>
<thead>
<tr>
<th>CO₂ Bank Size (HPV)</th>
<th>Total Oil Recovery (HPV)</th>
<th>Oil Recovery at GBT (HPV)</th>
<th>Oil Recovery Blowdown (HPV)</th>
</tr>
</thead>
<tbody>
<tr>
<td>0.21</td>
<td>0.82</td>
<td>0.34</td>
<td>0.049</td>
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<tr>
<td>0.41</td>
<td>0.75</td>
<td>0.32</td>
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<td>0.82</td>
<td>0.67</td>
<td>0.30</td>
<td>0.069</td>
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</table>
Table 17

Displacement of SACROC Crude Oil From Core #3
by CO₂ Propelled with Brine

<table>
<thead>
<tr>
<th>CO₂ Bank Size (HPV)</th>
<th>Total Oil Recovery (HPV)</th>
<th>Oil Recovery at GBT (HPV)</th>
<th>Oil Recovery Blowdown (HPV)</th>
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<tr>
<td>0.05</td>
<td>0.77</td>
<td>0.53</td>
<td>0.013</td>
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<td>0.10</td>
<td>0.70</td>
<td>0.62</td>
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<td>0.20</td>
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<td>0.025</td>
</tr>
<tr>
<td>0.50</td>
<td>0.86</td>
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</tr>
<tr>
<td>0.60</td>
<td>0.87</td>
<td>0.49</td>
<td>0.031</td>
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</table>

Table 18

Displacement of Foster Crude Oil from Core #4
by CO₂ Propelled with Brine

<table>
<thead>
<tr>
<th>CO₂ Bank Size (HPV)</th>
<th>Total Oil Recovery (HPV)</th>
<th>Oil Recovery at GBT (HBT)</th>
<th>Oil Recovery Blowdown (HPV)</th>
</tr>
</thead>
<tbody>
<tr>
<td>0.3</td>
<td>0.85</td>
<td>0.52</td>
<td>0.033</td>
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<td>0.4</td>
<td>0.87</td>
<td>0.50</td>
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<tr>
<td>0.5</td>
<td>0.87</td>
<td>0.49</td>
<td>0.039</td>
</tr>
<tr>
<td>Core #</td>
<td>Length (in.)</td>
<td>Diameter (m)</td>
<td>Porosity (%)</td>
</tr>
<tr>
<td>-------</td>
<td>--------------</td>
<td>--------------</td>
<td>--------------</td>
</tr>
<tr>
<td>1</td>
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<td>24.82</td>
</tr>
<tr>
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<td>9</td>
<td>2.25</td>
<td>29.13</td>
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<td>6c</td>
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<td>26.00</td>
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<tr>
<td>6d</td>
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<td>2.25</td>
<td>26.00</td>
</tr>
</tbody>
</table>
DISCUSSION OF RESULTS

Displacement of Oil by CO₂ from Sandpack

The results of the tests in which Foster field crude oil was displaced from the 20 inch, 60 inch and 240 inch sandpacks placed in a vertical position showed that the miscibility pressure was independent of the length of the sandpacks in the range of lengths used. The total oil recovery ranged between 73.3% OIP and 97.1% OIP, 68.5% OIP and 99% OIP and between 69.3% and 97.1% OIP for the vertical 20 inch, 60 inch and vertical 240 inch sandpacks, respectively. Pressure regions of immiscible, near miscible and miscible crude oil displacement were recognized in the result obtained from each of the three sandpacks. The total oil recovery from each of the sandpacks was above 90% OIP when the flooding pressure was 1400 psig. Hence, 1500 psig was selected as the CO₂ - Foster crude oil miscible pressure, (Figure 3).

The pressure at which CO₂ generates miscibility with a particular crude oil depends on the temperature, crude oil composition and the purity of the carbon dioxide. The miscibility pressure is independent of the length of the columns in which the two fluids are brought into contact down to a length of 20 inches.

The total oil recovery and the recovery at breakthrough are the two parameters commonly used for determining the CO₂ - crude oil miscibility pressure. These two parameters are commonly used for determining the CO₂ - crude oil transition zone which depends on the stability of the transition zone. If the transition zone is so long that its length becomes comparable to the length of the porous media, the oil recovery at breakthrough will be low and more CO₂ will be required to achieve total oil recoveries (% OIP) as were obtained with displacements with short mixing zones; these phenomena were demonstrated in the result presented in Figure 3. The breakthrough oil recovery was between 30 and 36% OIP from the 20 inch sandpack while it was between 41 and 70% OIP from the 60 inch sandpack and between 56.3 and 77.3% OIP from the 240 inch sandpack. The volume of CO₂ required to achieve total oil recovery at flooding pressures above 900 psig was 2 - 5.6 HPV from the 20 inch sandpack, 1.39 - 2.39 HPV from the 60 inch sandpack, and 0.92 - 1.84 HPV from the 240 inch sandpack.

The oil recovery efficiency of CO₂ miscible flooding in the sandpacks and the sandstone core was found to be dependent on the fluid displacement rate. The total oil recoveries from the vertical sandpacks increased as the CO₂ injection rate was decreased. The total oil recovery from the 60 inch vertical sandpack was 95.6% OIP when CO₂ was injected at a rate of 3.24 cc/min and 92.1% OIP when the rate was 21 cc/min (Figure 4). Similar results were obtained when Foster crude oil was displaced from the vertical 240 inch sandpack at 1400 and at 1600 psig. At a flooding pressure of 1400 psig total oil recoveries
were 93.0% OIP and 91.5% OIP when CO₂ was injected at 3.24 cc/min and at 21 cc/min. Total oil recoveries at 1600 psig were 94.5% OIP and 93.1% OIP when CO₂ was injected at a rate of 3.24 cc/min and at a rate of 21 cc/min.

This result is in agreement with those reported by Terwilliger et al., and by Dumore on immiscible displacement processes. The studies showed that when gas was injected into the top of a vertical sandpack to displace brine from the system, the efficiency of the process was highest when the displacement rate was less than equal to the gravity reference rate defined as:

\[ \text{GRR} = \frac{KA}{\Delta\mu \Delta\gamma \sin\omega} \]

where:
- \( K \) = effective permeability to liquid at 100% liquid saturation
- \( A \) = cross-sectional area through which flow occurs
- \( \Delta\mu \) = viscosity difference between liquid and gas
- \( g \) = gravitational constant
- \( \Delta\gamma \) = density difference between liquid and gas
- \( \omega \) = dip angle of the system

During CO₂ flooding in vertical systems, the density and the viscosity increase from that of the pure CO₂ to that of the crude oil across the transition zone. If the transition zone is divided into small slices perpendicular to the displacement direction, every plane of adjacent slices will have some stable rate defined by the GRR based on the densities and the viscosities of the fluids in the slice. At the limit, the stable rate will depend on the densities and the viscosities of the CO₂ and the crude oil. If the displacement rate is less than or equal to the stable rate, a stable transition zone will result. The transition zone thus formed will not deteriorate and should lead to almost 100% oil recovery. Hence, the result of CO₂ flooding in vertical systems will be enhanced if the displacement rate is less than or equal to the stable rate. Above the stable rate, the oil recovery will decrease if the displacement rate is increased as was observed during this study.

The results of tests conducted on the horizontal 60 inch sandpack and on the horizontal 60 inch consolidated sandstone core demonstrated that the total oil recovery from the horizontal systems increased with the CO₂ injection rate (Figure 5). The density of CO₂ being less than that of the crude oil at experimental conditions must have caused CO₂ to override the crude oil in these systems. In horizontal systems, the displacement rate must be higher than the gravity reference rate for the effect of the latter to be minimized; the higher the displacement rate above the gravity reference rate the less the effect of overriding. However, the efficiency of a miscible displacement process may be affected at higher displacement rates by CO₂ by-passing and
transition zone deterioration due to the development of viscous fingers. Hence, it is necessary to operate in a horizontal system at a displacement rate high enough to minimize gravity segregation but not so high as to cause the efficiency of the process to be adversely affected by viscous fingering.

Results of studies conducted on the 240 inch sandpack when placed in a vertical and in an horizontal position show that gravity segregation affects CO₂ flooding gas as it does immiscible displacement processes (Figure 6). Results of the effect of varying injection rate on oil recovery also corroborated the findings.

At corresponding pressures, displacements from the horizontal sandpacks were characterized by early CO₂ breakthrough and less oil recovery than those obtained from the vertical sandpacks. Gravity segregation will occur in any displacement process if there is a difference in the densities of the displacing and the displaced fluids. Gravity segregation must have caused the less dense CO₂ to override the crude oil in the horizontal systems, hence reducing the vertical sweep efficiency of the displacement process. The effect of gravity segregation in the horizontal systems was more pronounced at lower rates. These results agree with that reported by Wang which showed that gravity segregation caused CO₂ to override crude oil during CO₂ flooding in a horizontal system. However, gravity stabilization must have enhanced the result from the vertical systems.

The results showed that fluid displacement rate and gravity segregation are concurrent factors which affected the recovery efficiency of CO₂ miscible flooding.

Physical Properties of Crude Oil and CO₂

The result of the PVT studies showed that the viscosity of the CO₂ - Foster crude oil mixture decreased with increase in pressure. The result agreed with that reported in the literature. Also, the solubility of CO₂ in the crude oil and its density as a function of pressure are displayed in Table 8 and Figure 8. The viscosity of the SACROC crude oil decreased from 4.4 cp at 510 psig to 3.56 cp at 2000 psig and finally at 2520 psig the viscosity increased to 4.6 cp. This increase of viscosity at pressures about 1,500 psig could have been one of the reasons the CO₂ - crude oil miscibility pressure of the SACROC crude oil is at variance with the CO₂ - crude oil miscibility pressure correlation presented by Holm et al. The solubility of CO₂ in the crude oil also increased from 202.2 scf/bbl at 510 psig to 929 scf/bbl at 1540 but decreased to 863.1 scf/bbl at 2500 psig and finally to 801.8 psig at 2520 psig. The crude density showed a similar behavior. The density was 0.73 gm/cc at 510 psig, 0.84 gm/cc at 1540 psig and 0.83 gm/cc at 2520 psig.
Analysis of Fluid in Transition Zone During Displacement of Oil by CO₂

The analysis of the West Texas crude oil from a 100 ft long thin sandpack showed the change in the properties of the crude oil in the transition zone between the resident crude and the CO₂. A comparison of the analysis of three samples of produced fluid are displayed in Figure 27. In Figure 27 the base fluid is M-1, the fluid just as the color starts to change is M-2, and the fluid just before CO₂ breakthrough is M-2a.

The analysis shows an increase in the carbon number from 7 to 16 as the CO₂ approaches the outflow end. The largest increase is in the range from 7 to 11. A corresponding decrease is seen in the carbon numbers from 4 to 7 and 17 to 26.

A similar analysis was attempted on samples collected from the displacement of crude oil from a consolidated core that was five feet long with a square cross section 2 by 2 inches. The fluid produced from the consolidated core did not exhibit the long transition zone that was observed in the fluids produced from the long, thin tube. The effluent from the consolidated core with the 2 by 2 inch cross section changed from the base crude to CO₂ with no measurable volume for a transition zone. It appears the fingering of the CO₂ through the crude oil results in CO₂ reaching the outflow end of the core without building up a large transition zone. If there was a transition zone it was so small that it was mixed in the outflow lines and backpressure regulator.

Displacement of Crude Oil from Consolidated Cores by CO₂

The first set of tests conducted on the horizontal five foot long consolidated core demonstrated that CO₂ was miscible with SACROC crude oil at pressures above 2500 psig and at 120°F. A previous study carried out on Foster field crude oil had established that CO₂ was miscible with the oil at pressures above 1500 psig at 110°F. Studies were conducted using the two crude oils at pressures above 1500 psig for the Foster field crude oil and at pressures above 2500 psig for the SACROC crude oil.

Investigation of the displacement of crude oils from horizontal consolidated cores by CO₂ slugs pushed through the core with KCl solution and with nitrogen showed that brine was more efficient than nitrogen as a CO₂ slug propellant in the horizontal systems used. A comparison of the SACROC crude oil recovery by CO₂ banks pushed by water and by nitrogen from the 5 foot long Berëa sandstone core is presented in Figure 28.

Almost identical results were obtained when Foster crude oil was displaced from 15 foot long consolidated core by banks of CO₂ pushed by brine and nitrogen. The results are presented in Figure 29. The
Figure 27

Compositional Analysis for Crudes M1, M2, and M2A

M1 - Base Crude
M2 - Front of Transition Zone
M2A - Last of Transition Zone

Relative Abundance

Normal Paraffin Number
displacement of SACROC crude oil by banks of CO₂ from a 15 foot long consolidated sandstone pushed by brine and by nitrogen are presented in Figure 30. The oil recovery efficiency of slugs of CO₂ pushed with brine were similar for the SACROC and the Foster Field crude oils even though the miscible flood pressure was 1500 psig for the Foster Field crude oil and 2500 psig for the SACROC crude oil. On the other hand, the recovery efficiency was found to be less for the Foster Field crude oil when nitrogen was used as the slug propellant although the operating pressure in both floods was above the minimum CO₂ - crude oil miscible pressure.

The oil recoveries for all six floods as a function of CO₂ bank size appear similar. All the floods seemed to indicate that a bank of CO₂ of 30% of a HPV was an optimum size. The first floods were made in the 5 foot long sandstone core and it was felt the core was too short with respect to the mixing zone to obtaining representative data but would provide experience for later runs. It was surprising that the displacement of SACROC crude from the 5 foot long core was very similar to the 15 foot long core except that the recovery was a little higher at all bank sizes from the 15 foot core. The mixing zone must have been shorter then was first expected. The total oil recovery was 79.18% OIP when Foster field crude oil was displaced from the horizontal 15 foot long consolidated core by 0.7 HPV of the CO₂ slug at 1565 psig. The oil recovery was 94.4% OIP when SACROC crude oil was displaced from the same core by 0.7 HPV of the CO₂ slug at 2560 psig. Nitrogen was used to propel the CO₂ slugs in both cases and results are shown in Figure 31.

The superiority of water over nitrogen as a slug propellant must have been due to the following reasons: (1) The water - CO₂ density difference being less than that of nitrogen - CO₂ at experimental conditions must have resulted in less underriding of CO₂ by water in the water - CO₂ - oil system than the overriding of the CO₂ by nitrogen in the nitrogen - CO₂ - oil system. (2) The viscosity of water is higher than that of CO₂ while that of nitrogen is less than that of CO₂ at experimental conditions. Hence, while the mobility ratio was favorable at the water - CO₂ front, it was unfavorable at the nitrogen - CO₂ front. This must have permitted the nitrogen to finger through the CO₂ slug while the slug was displaced by the water in a more efficient manner. These two reasons may explain why the nitrogen could have penetrated the CO₂ slug and contacted the in-place oil in the nitrogen - CO₂ - oil system. (3) In case either nitrogen or water penetrated the slug and contacted the in-place oil in the two systems, the carbonated water is less efficient in displacing crude oil than miscible CO₂ flooding, but it is more efficient than immiscible type displacement that resulted when nitrogen mixed with CO₂ during flooding in the nitrogen - CO₂ - oil system.

The solubility of nitrogen in crude oil increases as the pressure is increased and it is miscible with crude oils at pressures above 3600
FIGURE 28 - Comparison of the efficiencies of water and nitrogen as CO₂ slug propellants. Oil (SACROC crude) recovery from the horizontal 15 foot long consolidated Berea sandstone core as a function of CO₂ slug size (T = 110°F, 2500 psig ≤ pressure ≤ 2650 psig)
FIGURE 29 - Comparison of the efficiencies of water and nitrogen as CO₂ slug propellants. Oil (Foster crude) recovery from the horizontal 15 foot long consolidated Berea sandstone core as a function of CO₂ slug size (T = 110°F, 1500 psig ≤ pressure ≤ 1650 psig)
FIGURE 30 - Comparison of the efficiencies of water and nitrogen as CO₂ slug propellants. Oil (SACROC crude) recovery from the horizontal 5 foot long consolidated Berea sandstone core as a function of CO₂ slug size (T = 120°F, 2500 psig ≤ flooding pressure ≤ 2650 psig)
psig. Nitrogen is more efficient at displacing crude oil as the pressure is increased. Therefore, if nitrogen penetrated the CO$_2$ slug and contacted the crude oils, it displaced the SACROC crude oil at pressures above 2500 psig more efficiently than it did the Foster Field crude oil at pressures above 1500 psig. Thus, the high oil recovery for each bank size at the higher pressure may have been due to the higher oil recovery that can be effected by nitrogen at higher pressure. The increase in the efficiency of nitrogen as a CO$_2$ slug propellant at high pressures showed that it could be used as the scavenging fluid instead of natural gas in high pressure CO$_2$ flooding pilot tests to improve project economics.

The results indicated that at high pressure, nitrogen may be as efficient as water in pushing large CO$_2$ banks. While the total oil recovery was 94.2% OIP when SACROC crude oil was displaced from Core #2 by a 0.7 HPV CO$_2$ slug propelled with KCl solution, the total oil recovery was 94.4% OIP from a similar run in which the CO$_2$ slug was pushed with nitrogen at pressures about 2600 psig.

Of all the tests in which crude oils were displaced with CO$_2$ slugs propelled with brine, 0.3 HPV of CO$_2$ was established as the optimum bank size required for CO$_2$ flooding in the cores used. The total recovery increased as the CO$_2$ slug size was increased from 0.0 to 0.3 HPV. Increasing the CO$_2$ slug size in excess of 0.3 HPV however did not result in a concurrent increase in the total oil recovery as was obtained when smaller slug sizes were increased. In fact, the slope of the plot of the "total oil recovery" vs "CO$_2$ slug size" (Figure 31) was almost zero at CO$_2$ slug sizes above 0.3 HPV in most cases.

The total oil recovery was higher in tests conducted at 110°F than those conducted at 120°F (Figure 32) with water as the CO$_2$ slug propellant. This is due to the effect of temperature on CO$_2$-crude oil miscibility pressure. CO$_2$ is more soluble in oil at low temperatures and it generates miscibility with the crude oil at lower pressures when the temperature is low than when the temperature is high. The minimum miscibility pressures is, therefore, less at 110°F than at 120°F. Thus, the total oil recovery will be higher at 110°F than at 120°F for similar flooding pressures.

The result of studies on the effect of horizontal permeability variation on CO$_2$ flooding in horizontal systems demonstrated that the total oil recovery was not very sensitive to horizontal permeability variation. The total oil recoveries were a little less from the core with variable permeability along its length than from a similar core with uniform permeability when similar CO$_2$ slug sizes propelled with brine were used to displace the oil from the cores. A comparison may be made using Figure 34. This could have been due to the different rate of gravity segregation along the length of the core with variable permeability as compared to the uniform rate of segregation in the homogenous core.
From the result of the tests on the heterogeneous core, the optimum slug size required for CO₂ flooding was affected very little by horizontal permeability variation. Horizontal permeability variation may not be as detrimental to any form of displacement process as is vertical permeability variation when the degree of the variation is comparable in both cores. If a reservoir contains large variations in permeability in vertical strata, bypassing of a large fraction of the oil will result because the CO₂ will move oil from the high permeability zone long before oil is moved from the tight zones.

Studies conducted on CO₂ - dolomite rock interaction during CO₂ flooding showed that carbon dioxide in the presence of water dissolved the rock at high pressures. This effect is depicted in Figures 35, 36, and 37. The permeability of Core #5 increased from 90.13 md to 147.76 md after a 3.28 PV CO₂ slug was passed through it. This was confirmed by the milky appearance and the presence of precipitates in the produced fluid, and by comparing microscopic observations of the treated and the untreated cores. The CO₂ - treated sample showed some effect of rock dissolution on the crystal boundaries and a concomitant increase in pore diameter (Figures 23a and 23b). The result agrees with that reported by Holm and others. They stated that the permeability of carbonate rocks increased after they were flushed with liquid CO₂ and/or carbonated water.

The effect of flushing Core #6 with effluent from the CO₂ treated core established that carbonates were precipitated when the flooding pressure was reduced. The permeability of Core #6 decreased from 184.56 md to 143.19 md after three consecutive runs. The result was confirmed by comparing the microscopic observations of the fresh core to that of the core flushed with effluent from Core #5. Microscopic observations of Core #6 showed that it had disintegrated fragments in its pore spaces as seen in Figure 24b. The fragments were the calcite crystals dissolved from the pore walls of Core #5 which were precipitated in Core #6 after the flooding pressure was reduced. The fragments were free to migrate to and clog up pore throats. The clogging of the pore throats could have caused the reduction in the core permeability.

Studies of the effect of pressure on CO₂ - dolomite rock interaction indicated that more of the rock was dissolved from the rock pore walls as the CO₂ flooding pressure was increased and more of it was precipitated from the bicarbonate solution when the pressure drawdown was increased (Figures 36 and 37).

Results of the measurements in this study indicated that the dolomite cores used for this investigation varied in their degree of homogeneity. This was inferred from the analysis of their physical properties and from variations in the reaction of the cores to CO₂ flushing. A case in point was that of two 9 inch long cores having slightly different porosities and permeabilities (Cores #5 and 7, Table
FIGURE 31 - Efficiency of the nitrogen CO₂ slug propellant as a function of the flooding pressure. Oil (SACROC and Foster crudes) recoveries as a function of the CO₂ slug size. (T = 110°F; 1500 psig ≤ pressure ≤ 1650 psig, 2500 psig ≤ pressure ≤ 2650 psig)
FIGURE 32 - Determination of the optimum CO₂ bank size (water propellant). Oil recoveries from the two horizontal 15 foot and the 5 foot long consolidated Berea sandstone cores as functions of CO₂ slug size. (T = 110°F, 120°F; 1500 psig ≤ pressure ≤ 1650 psig, 2500 psig ≤ pressure ≤ 2650 psig)
FIGURE 33 - Effect of the flooding temperature on oil recovery. Oil (SACROC crude) recovery from horizontal 15 foot consolidated Berea sandstone cores (Cores #2 and 3) as a function of CO₂ slug size. CO₂ slugs propelled with water (brine) (2500 psig ≤ flooding pressure ≤ 2650 psig).
FIGURE 34 - Effect of horizontal permeability variations on oil recovery. Oil (Foster crude) recoveries horizontal homogeneous 15 foot and heterogeneous 15 foot long consolidated Berea sandstone cores as functions of CO₂ slug size (water propellant). (T = 110°F; 1500 psig ≤ pressure ≤ 1650 psig)
FIGURE 35 - Effect of $CO_2$-Dolomite rock interaction on rock permeability

$k_o$ = original permeability of the core
$k$ = core permeability after $CO_2$ treatment
FIGURE 36 - Effect of CO$_2$ flooding pressure on CO$_2$ - dolomite rock interaction (Dolomite)

$\frac{k}{k_0}$ = original permeability

$k$ = core permeability after CO$_2$ treatment
Figure 37 - Effect of pressure drop across core on CO₂ - dolomite rock interaction (Dolomite)

\[ k/ k_0 \%
\]

- \( k_0 \) = original permeability of core
- \( k \) = core permeability after CO₂ treatment

Pressure Drop Across Core (psi)
After similar CO₂ treatments, the permeability of Core #5 increased by 3.5 percent while that of Core #7 increased by 5 percent. Howard, et al. showed that the variation in solubility of carbonate rocks in acid solution depends upon the distribution of the rock crystals (aragonite, calcite, dolomite and magnesite). The difference in the responses of the cores to similar CO₂ treatments must have been due to the difference in their physical properties.

The solubility of CO₂, and hence, its concentration in brine, increases as the pressure is increased. Equations that can describe the interaction between CO₂ and dolomite rock in the presence of brine are:

\[ \text{H}_2\text{O} + \text{CO}_2 + \text{CaCO}_3 = \text{Ca(HCO}_3)_2 \] \hspace{1cm} (2a)

\[ \text{H}_2\text{O} + \text{CO}_2 + \text{MgCO}_3 = \text{Mg(HCO}_3)_2 \] \hspace{1cm} (2b)

The factors that could disturb the equilibrium of the equations are the concentration of the reactants and the products, pressure and temperature. In a dolomite reservoir, the metal carbonates are in abundance and the temperature is constant during CO₂ flooding in most cases. As the pressure is increased at an injection well, the concentration of CO₂ in the brine will force the equilibrium of Equation 2a to the right forming more of the soluble bicarbonates. The effect of pressure on the rate of reaction can be predicted by the following equation:

\[ \frac{\delta (\ln K)}{\delta P} = -\frac{\Delta V}{RT} \] \hspace{1cm} (3)

K = reaction rate constant

P = pressure

\(\Delta V\) = change in molal volume between that of the reactant and the product

R = universal gas constant

T = temperature

Equation 3 predicts that if a reaction proceeds such that the total number of moles of the reactants is more than the total number of moles of the products, an increase in pressure will favor formation of the products and vice-versa. The equation favors formation of the right-hand side of Equation 2a at high pressures because for every three moles of the reactants, only one mole of the product is formed. Hence, high pressure caused formation of more of the soluble
bicarbonates and the resulting increase in the permeabilities of the cores. Pressure reduction cause the reversal of the these efforts leading to precipitation of the insoluble carbonates and the reduction in the permeabilities of the cores.

The result of studies on CO$_2$- dolomite rock interaction has the following implications concerning CO$_2$ flooding in carbonate reservoirs:

(1). When the CO$_2$- crude oil miscibility pressure is high, more of the rock is expected to be dissolved around the CO$_2$ injection well, and the chance of carbonate precipitation caused by pressure drawdown will be high.

(2). Pressure reduction during flooding may cause some of the dissolved rock to be precipitated and reduce the permeability of the formation.

(3). Pressure drawdown between injectors and producers should not be excessive to avoid possible productivity problems.
CONCLUSIONS

The following conclusions were drawn from the results of this laboratory study:

(1). The minimum pressure at which CO$_2$ appeared to achieve miscibility with a crude oil was the same in a 20 inch long sandpack as in a 60 and 240 inch long sandpack.

(2). The fraction of oil displaced from a sandpack in a vertical position increased as the rate of injection decreased.

(3). The fraction of oil displaced from a sandpack in a horizontal position increased as the rate of injection increased.

(4). Banks of CO$_2$ displaced a larger fraction of oil from horizontal consolidated cores 15 foot long and 2 x 2 in cross section when pushed with water than when pushed with nitrogen.

(5). The efficiency of the nitrogen solvent slug propellant increased with the flooding pressure while that of the brine propellant was almost unaffected by flooding pressure.

(6). A 0.3 HPV CO$_2$ bank was found to be the optimum size for displacing crude oil from horizontal 15 ft. long consolidated cores with 2 x 2 inch cross section.

(7). The total oil recoveries from a core with variable horizontal permeability was only a little lower than those from homogeneous cores at similar flooding conditions.

(8). The total oil recoveries showed a slight decrease as the flooding temperature was increased for all slug sizes.

(9). Studies of CO$_2$ - dolomite rock interaction showed that CO$_2$ dissolved part of the rock at high pressures, thus increasing the permeability. The enhancement of the permeability of the rock increased with the flooding pressure.

(10). Pressure drawdown along the flow path caused dissolved carbonates to be precipitated and decreased the permeability of the rock. There was a larger reduction in permeability when the pressure reduction was larger.
REFERENCES


