**WEEKS ISLAND "S" SAND RESERVOIR B
GRAVITY STABLE MISCIBLE CO₂ DISPLACEMENT,
IBERIA PARISH, LOUISIANA**

Fourth Annual Report, June 1980-June 1981

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FOURTH ANNUAL REPORT
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ABSTRACT

Shell, in conjunction with the United States of America Department of Energy, is conducting a gravity stable displacement field test of the miscible CO₂ process. The test is being conducted in the portion of a fault sealed reservoir lying below a subsea depth of -12,750 feet. Injection of the CO₂ slug at the producing gas-oil contact commenced in October 1978. Injection of the 860 MM cubic foot slug was completed in February of 1980. The slug of CO₂ was moved downward through the watered out sand by production of downdip water. The leading edge of the displacement has reached the producing perforations and production of the oil column commenced on January 26, 1981.

Conventional cores and the log-inject-log technique were used to determine residual oil saturation in a well drilled as the pilot producer. Pulsed neutron logging devices have been used to detect the CO₂ slug and monitor its subsequent movements in the vicinity of the production well. The monitor logs indicate the thickness of the oil column had increased during the displacement to the production perforations located 130 feet below the level of CO₂ injection. The 23 foot oil column remaining at initiation of the project had apparently grown to 57 feet.

PVT samples and production data indicate CO₂ has penetrated the oil column and free gas is being produced with the oil. However, the qualitative measurements of the logs do not indicate a large gas or CO₂ content in the oil column.

INTRODUCTION

The "S" Sand Reservoir B CO₂ pilot is designed to field test a downward CO₂ displacement in a steeply dipping, high temperature, high pressure Gulf Coast reservoir. Reservoirs of this type typically are produced by natural water drives which leave a significant residual oil volume. Other major watered-out reservoirs in the Weeks Island Field have an estimated tertiary potential of 26 million barrels of oil which could be recovered by CO₂ displacement.

Reservoirs of this type are not suitable for surfactant flooding as the temperature and water salinities are too high for currently available chemical systems, while the depth and usually good oil mobilities preclude any additional recovery by thermal stimulation. The downward CO₂ displacement is designed to utilize gravity forces to stabilize the displacement and increase the sweep of the injected CO₂.

Following an evaluation of the residual oil saturation, injection of the CO₂ slug commenced on October 4, 1978. Injection averaged 106 tons of CO₂ per day and injection of the 50,000-ton slug was completed on February 27, 1980.

Neutron devices have been used to monitor the CO₂ in the vicinity of the new downdip observation and production well. The CO₂ which was initially detected in the top of the sand has been found to be invading the watered-out sand. Appearance of oil at the production perforations in the new well indicates the oil column had increased in thickness. Flowing production was initiated from the oil column on January 26, 1981.

SUMMARY OF FOURTH YEAR OPERATIONS

During the fourth year of operations, the displacement was continued with the production of downdip water. Progress of the CO₂ front was monitored with four pulse neutron logs. Since the oil-water contact could not be determined with logs, periodic tests were used to detect the arrival of the oil at the producing perforations located 130 feet below the point of CO₂ injection. A trace of oil was first detected on October 22, 1980, and continuous production was initiated on January 26, 1981. Through June of 1981, production averaged 149 barrels of oil per day with an overall water cut of 57 percent.

During the year, additional core flood experiments were conducted at the Bellaire Research Center and mathematical simulations of the core floods were attempted. Although both nitrogen and CO₂ are indicated to be immiscible with the crude oil at Weeks Island conditions, the nitrogen core floods displaced less than one-fifth of the waterflood residual oil recovered by the CO₂ core floods. The mathematical simulation of the core floods

failed to match the experimental fractional flow curves and the oil recovery indicated by the simulator was lower than that experienced in the core floods. The results of the BRC research are reported in Attachment A.

PROJECT SETTING

The Weeks Island Field is located on a Gulf Coast piercement type salt dome. Hydrocarbon shows have been found in sands of the Pleistocene to Lower Miocene age at depths from 1,000 to 17,000 feet. Commercial production has been established in 37 Lower Miocene sands, predominately below a depth of 9,500 feet. The bulk of the original in-place oil (87%) was trapped in the downthrown fault block on the north flank of the field, where hydrocarbon column heights of up to 2,600 feet have been proven in sands that are inclined against the intruding salt and sheath. The majority of these reservoirs are driven by a strong water influx.

The "S" Sand Reservoir B occurs in a fault block on the north flank of the dome with the reservoir sealed against the dome by radial and peripheral faults. The "S" Sand Reservoir B contained two oil columns with over 3 million barrels of original in-place oil overlain by a 1,300-foot gas column which contained 24 BCF of wet gas. The CO₂ displacement is being undertaken in the west flank oil column which contained all but 200,000 barrels of the original in-place oil. A structure map and dip cross section of the west flank oil column is shown on Figure 1. Prior to CO₂ displacement, the west flank oil column was flooded with fresh water. The water was injected into Smith-State Unit G-2 which penetrated the reservoir below the oil-water contact.

Prior to CO₂ injection, the remaining oil column had been produced to an estimated thickness of 23 feet. The oil column height was estimated from the water level logged at -12,786 in the new well, Weeks Island State Unit A-17, on January 1, 1978, while the gas-oil contact on January 1, 1978 was estimated at -12,760 from the production characteristics of Weeks Island State Unit A-16-A. An additional six months of production after the drilling of Weeks Island State Unit A-17 and prior to initiation of the CO₂ project is calculated to have reduced the 26-foot oil column to a 23-foot thickness.

The producing gas-oil contact was confirmed when the new injection perforations in Weeks Island State Unit A-16-A, located at a subsea depth from -12,750 to -12,760, backflowed gas and condensate in August of 1978. Both excess gas and water were being produced from the final preflood completion in Weeks Island A-16-A, which was located at a subsea depth of -12,777 to -12,787 feet. The production of Weeks Island State Unit A-16-A and the water injection into Smith-State Unit G-2, prior to CO₂ injection, are illustrated on Figure 2, the "S" Sand Reservoir B oil column production and injection history.

PREFLOOD RESERVOIR EVALUATION

Prior to initiating the CO₂ injection, a new well, Weeks Island State Unit A-17 (A17), was drilled at the location illustrated in Figure 1. This well, which was drilled to evaluate the reservoir parameters, now serves as a downdip producer. Since (A17) penetrated the entire 130-foot vertical section of the displacement, the well has been used to monitor the placement and movement of the CO₂ slug.

The reservoir was found to have an average stressed porosity of 26 percent and a stressed permeability of 1.8 darcys. The sand was calculated to contain a waterflood residual oil saturation of 22 percent or 288 barrels per acre foot. The residual oil saturation was calculated by the following three methods:

Log-Inject-Log (LIL)
Core Analysis
Open-Hole Log Analysis

The residual oil measurements obtained by the different methods appear consistent and are illustrated on Figure 11. The comparative calculations were done in the interval of the LIL perforations which are illustrated on the Figure 1 cross section. On the Figure 11 comparison, the points represent our best estimate of each method, while the error bars represent our confidence limits on the individual residual oil determinations.

The residual oil saturation determined from LIL ($.221 \pm .025$) is in good agreement with oil saturations measured in the core and calculated from open-hole logs ($.23 \pm .042$ and $.243 \pm .054$, respectively). The residual hydrocarbon saturation measured on the open hole logs in this interval was .33. However, the FDC-CNL indicates a free gas saturation of 8 to 9% and, hence, must be subtracted from the total hydrocarbon saturation to arrive at the residual oil saturation. The residual gas saturation was present because a 900 psi decline in the reservoir pressure had released solution gas from the initially gas saturated crude.

The average residual oil saturation as determined from Counter Current Imbibition (CCI) data in the LIL interval is .293. Values determined from this method are believed to be a good estimate of the expected residual hydrocarbon saturation assuming the rock is 100 percent water wet. In the case of Weeks Island Reservoir B, this number should be equal to or less than the total hydrocarbon saturation calculated from the open-hole logs, but higher than the residual oil saturation due to the existence of a gas saturation.

CO₂ INJECTION

The project will displace approximately 965 acre feet of the reservoir which is illustrated as the 130-foot vertical displacement interval on the Figure 1 cross section. A 50,000-ton slug of CO₂ has been injected into Weeks Island State Unit A-16-A at a position just above the producing gas-oil contact. Density of the injected CO₂ was reduced by the addition of five percent natural gas. Although our equilibrium experiments indicate the slug density will be reduced by methane absorbed from the oil and gas contacted in the reservoir, the five percent dilution reduced the initial slug density to approximately 95 percent of the in-place density of the S Reservoir B oil.

Because of its density, the CO₂ slug should spread between the less dense gas cap and the more dense oil column. Gravity forces should displace the remaining oil column and CO₂ slug into the watered-out sand as the water column is produced. Water column voidage in the sealed reservoir was created by the production of the downdip well, Smith-State Unit G No. 2.

Continuous CO₂ injection was commenced on October 4, 1978. Injection was delayed two months by plugging of the injection well and a maintenance shutdown of the ammonia plant which supplies the CO₂. The well plugging was attributed to lubricating oil deposits in the injection line. The deposits had accumulated in approximately one mile of former gas injection line which was reused by the project. It appears that the deposits were mobilized by the CO₂ since no plugging occurred during the short gas injection periods which preceded the CO₂ injection. No plugging problems occurred after the line was thoroughly cleaned and a wellhead filter was installed. The line was heated with steam and treated with hydrocarbon solvent and acid, which were displaced by line pigs. The wellhead filter was field fabricated to accept a 10-micron filter element.

With the exception of interruptions in the CO₂ supply and short maintenance shutdowns of the CO₂ injection plant, continuous CO₂ injection was maintained at an average rate of 106 tons per day. Daily injection volumes and pressures are illustrated in Figure 3. Notable interruptions are listed as follows:

<u>Month</u>	<u>Length</u>	<u>Reason</u>
July 1979	19 days	Ammonia plant maintenance (CO ₂ source.)
September 1979	4 days	Injection charge pump failure.
October 1979	16 days	Maintenance at ammonia plant and Weeks Island Gas Plant.

The injection rate was limited only by plunger size of the constant speed injection pump.

DOWNDIP WATER PRODUCTION

Production of the downdip water created the voidage necessary for a displacement of the watered out sand. Since the reservoir is indicated to be sealed, the rate of CO₂ displacement should be a function of the water withdrawals.

Water column voidage was created by the production of the downdip Smith State Unit G Well No. 2. The location of the downdip well is illustrated on Figure 1. During the period of CO₂ injection, the water production rate was limited to 1,000 barrels per day to approximately match the CO₂ slug injection rate at reservoir conditions. The rates of water production and CO₂ injection were coordinated to maintain the top of the CO₂ slug in the vicinity of the injection perforations. The reservoir volume of the CO₂ slug injection and the downdip water production are illustrated on Figure 2, "The 'S' Sand Reservoir B Oil Column Production and Injection History." The reduced downdip water production during July and August of 1980 resulted from unplanned maintenance of the field gas compression plant. A 51-day interruption in gas lift occurred during the compressor plant maintenance. Downdip water production was terminated one month after oil column production was initiated. Continued downdip water production would have accelerated CO₂ breakthrough because the additional voidage would move the CO₂ front closer to the producing perforations.

DISPLACEMENT OBSERVATIONS

Observations made in Weeks Island State Unit A-17 suggest a gravity segregated displacement is occurring in the vicinity of this well. Log analysis from the first monitor run in December 1978 indicates the initial CO₂ invasion was in the gas cap. Subsequent logs indicated the CO₂ had moved downward at this location while production tests of the observation perforations during 1979 and the new producing perforation in 1980 shows that oil is resaturating the previously watered-out sand below the CO₂ front.

LOGGING PROCEDURES USED TO MONITOR FLOOD FRONT

Pulsed neutron logs are being used to monitor the flood front. Originally, it had been planned to use both the pulsed neutron and thru-tubing compensated neutron logging device; however, the latter tool has been removed from the market due to safety requirements. A normal thru-tubing chemical source neutron device was run in conjunction with the pulsed neutron log on

the first two monitor runs; however, the quality of the chemical source neutron device data was insufficient to add to the interpretation derived from the pulsed neutron log. Present-day pulsed neutron logs are equipped with both a short-spaced and a long-spaced detector. The count rates at the two detectors are used to produce a ratio curve which is essentially a dual-spaced neutron device. (3) Unlike a normal compensated neutron device, which responds to gamma-rays of capture, the ratio is a function of salinity. By using the Σ curve which is also a function of salinity, a pseudoneutron porosity curve can be produced. Figure 4 is a comparison between the computed open-hole porosity, the open-hole compensated neutron porosity, and the computed neutron porosity from the pulsed neutron log. The apparent pulsed neutron porosity was computed using a regression analysis equation based on Schlumberger's Σ -ratio crossplot chart for the appropriate size casing and salinity.

Monitor Logs

As illustrated by the porosity curves computed from the pulsed neutron logs in Figure 5, the December 20, 1979 logs show a significant reduction in porosity in the top of the SRB indicating a high CO₂ saturation to a well depth of 12,866 feet. This initial CO₂ invasion was principally above the producing gas-oil contact which was predicted to be at a well depth of 12,862 feet in January 1978. The subsequent logs on February 21 and April 12, 1979, indicate CO₂ had invaded the oil column down to the lower quality sand interval from 12,882 to 12,888 feet. No downward movement of CO₂ was detected between February and April of 1979.

Monitor logs subsequent to February 21, 1979, show a marked reduction in the rate of CO₂ movement. Figure 6 compares the neutron porosity recorded on July 17, 1979, February 8, 1980, May 21, 1980, September 18, 1980, and January 9, 1981, with that recorded on February 21, 1979. As illustrated in Figure 7, the rate of CO₂ movement since February of 1979 has been consistent with the downdip water withdrawals. The April 1979 monitor log does not dispute the steady advancement of CO₂, since the CO₂ front would have been in the poorer porosity of the log interval from 12,822 to 12,888 feet. The logs indicate CO₂ penetration of this interval was delayed. The extent of the poorer quality sand interval is not known and the poorer quality interval does not appear to be affecting the overall displacement.

The pulsed neutron logs could not be used to define the oil column below the CO₂ front. Since the hydrogen index of the water and oil are nearly equal, the technique to monitor the CO₂ movement is not applicable for monitoring the oil bank movement. Normally, in the Gulf Coast rocks of this porosity and depth, the pulsed neutron log can discern the difference between oil and water due to the difference in the capture cross section

between the oil and salt water. However, fresh water was used in the S RB Waterflood Unit. As a result, we see wide variation in the salinity of the observation well with the water near the oil-water contact expected to be virtually fresh. Movement of the oil bank is not easily discernible since the oil and freshwater have similar capture cross sections.

The gradational water salinity is illustrated on Figure 5, where the resistivity of the January 1, 1978 open-hole logs is shown to decrease with depth below the logged water-oil contact. Swab tests of two intervals found the resistivity difference can be attributed to the varying water salinity. The first interval between 12,917 feet and 12,919 feet, which had a resistivity of 3 ohmmeters, recovered water with a measured chlorine content of 10,825 ppm, while the second interval between 12,960 feet and 12,970 feet, which had a resistivity of 1 ohmmeter, recovered water with a measured chlorine content of 35,500 ppm.

Production Tests

Since we believed we could not define the zone of oil resaturation in the formerly watered-out oil column with logs, we periodically tested the former log-inject-log perforations for producible fluids. These tests found a producible oil column was being displaced ahead of the CO₂ column indicated by the logs. The production tests were limited to 10 barrels per hour for periods of less than 15 hours to limit the distortion of the fronts in the vicinity of the observation well.

Oil was detected in the tubing in the observation well, Weeks Island State Unit A-17, following the April 12, 1979 pulsed neutron log. On May 2, 1978, the well flowed 17 barrels of oil and 32 barrels of load water on a 6-hour test. Following the test, the bottom-hole pressure survey indicated the tubing was essentially filled with oil and this previously watered-out interval had produced little or no water during the test. A chromatographic analysis of produced gas measured a normal preinjection CO₂ content of 1 percent. During a subsequent May 31, 1979 test, the well flowed oil with no detectable water and a normal solution gas-oil ratio of 859 cubic feet per barrel.

On July 27, 1979, the observation perforations in Weeks Island State Unit A-17 were tested with a separator gas-oil ratio of 1,032 cubic feet per barrel and no detectable water. Chromatographic analysis indicates the produced gas contained approximately 35 percent CO₂. Samples of the separator oil and gas were recombined at the separator ratio using the reservoir temperature of 225 degrees. The oil and gas recombined into a single-phase liquid containing 24 mol percent CO₂. The recombination occurred at a pressure within 6 psi of the measured bottom-hole pressure of 4,950 psia. The recombination results indicate the gas produced during the test was

dissolved in the oil. Moreover, it would appear that CO₂ was dissolved in the oil at the perforations which were 12 feet below a substantial CO₂ concentration indicated by a July 19, 1979 pulsed neutron log.

On October 26, 1979, tests of the observation perforations produced oil with a gas-oil ratio which increased from an initial 1,838 cubic feet per barrel to a final ratio of 4,000 cubic feet per barrel. An analysis of the gas produced during the October 26 test measured an 80 mol percent CO₂ content with a specific gravity of 1.3426 when compared to air. A pulsed neutron log run on November 8, 1979 confirmed that the CO₂ front had reached the observation perforations.

Since the October 26, 1979 test data indicated the CO₂ front had reached the observation perforations in Weeks Island State Unit A-17, a workover was undertaken to prepare the well for the production phase of pilot operations. During the workover, the observation perforations were squeezed. A new perforated interval was opened between 12,992 and 12,996 feet (-12,890 to -12,894 feet subsea). Pilot production is now obtained from the new interval which is located 130 feet below the original gas-oil contact.

The producing perforations were tested on a semimonthly interval to determine the arrival time of the oil bank. A trace of oil was produced during an October 22, 1980 test which indicated the leading edge of the displacement had reached the producing perforations. The displacement was continued through December 1980 while the producing characteristics of the well were monitored with additional semimonthly tests. Attachment 1 is a tabulation of the test results.

DISPLACEMENT ANALYSIS

Bellaire Research Findings

The Weeks Island pilot was undertaken with a concurrent effort at the Bellaire Research Center (BRC) to understand the process and develop the simulator. Because of the complexity of the system, we do not yet have a working reservoir simulator. However, BRC's concurrent effort has resulted in several findings important to the process. These findings are separately reported in detail by the investigators⁽⁴⁾ and are only briefly mentioned here.

The laboratory work has found that an immiscible gravity stable CO₂ displacement in the Weeks Island "S" Sand Reservoir B can displace substantial amounts (> 80%) of oil. A tertiary oil column has been displaced

with CO₂ from Weeks Island "S" Sand Reservoir B core material. The displacements were done at reservoir conditions, utilizing reservoir crude which had been swept to a water drive residual. However, the size of the core displacements prevent the recovery from being scaled to field operations.

Mathematical simulation efforts at BRC found that the shape of the 3-phase oil relative permeability curves have a large effect on the predicted recovery from the "S" Sand Reservoir B. Moreover, 3-phase oil relative permeability measurements performed by the laboratory found that Stone's^(1,2) 3-phase oil relative permeability model did not apply to the Weeks Island "S" Sand Reservoir B sandstone. Use of Stone's relative permeability model in early simulations resulted in pessimistic forecasts of the "S" Sand Reservoir B pilot performance when compared to the field analysis of the displacement. Substantial recoveries (50-60%) have been indicated by the present mathematical simulations when the measured Weeks Island 3-phase oil relative permeability curves are used.

FIELD ANALYSIS OF THE DISPLACEMENT

A preliminary analysis of the CO₂ displacement indicates a substantial oil column has been generated and it is probable that the gravity stable CO₂ process is displacing in excess of 75% of the water drive residual oil saturation from the watered-out "S" Sand Reservoir B.

As illustrated on Figure 7, the displacement appears to have generated a 57-foot thick oil column in the vicinity of the single well bore from which we can observe the displacement. The 57-foot oil column is implied from the extrapolated position of the CO₂ front on October 22, 1980, the date on which a production test indicated the oil column had reached the producing perforations. Although we are encouraged by the oil column thickness, we cannot yet assign an exact displacement efficiency from field measurements. However, the size of the column indicates that substantial oil has been displaced from the water-driven sand.

An exact determination of the stock tank volume of the present oil column would require the following information:

1. Reservoir volume factor of the stock tank oil.
2. Determination of the water and gas saturation in the oil column.
3. Delineation of the oil column over its entire extent.

Although the reservoir volume factor of the stock tank oil will be determined from a recombination of the separator oil and gas, we have not found a way to determine the water and gas saturations or delineate the entire oil column.

A substantial displacement can be implied if we assume the contacts were level on October 22, 1980. If we assume horizontal contacts, Figure 8 illustrates the lateral extent and acre-feet of the CO₂ swept region, the original oil column and the October 22, 1980 oil column. This overly simplified projection indicates we may have increased the oil bank 284 acre-feet during the sweep of 522 acre-feet of reservoir. However, we must caution that the increased oil bank volume also reflects an unknown water and gas saturation in the column and a yet-to-be determined oil reservoir volume factor.

PRODUCTION PERFORMANCE

Sustained oil production commenced on January 26, 1981. The initial production has contained substantial amounts of CO₂ and water. The production is illustrated by the daily tests plotted on Figure 9.

The produced gas has contained approximately 50 percent CO₂ or approximately 675 cubic feet of CO₂ per barrel of produced oil. PVT₂ measurements and production tests indicate free undissolved gas is being produced from the reservoir. On May 12, 1981 the well produced 161 barrels of oil and 207 MCF of gas for a separator gas-oil ratio of 1,286 cubic feet per barrel. A recombination of the oil and gas produced on May 12 required a 5,370 psi pressure which was 442 psi above the reservoir pressure. As illustrated on Figure 11, production tests have also found that the GOR and CO₂ content of the produced gas tend to increase with an increased production rate. Evidence of a cone has not been found by the qualitative pulsed neutron monitor logs. The log recorded on June 4, 1981 found that in the vicinity of the producing well the front of substantial CO₂ content was 38 feet above the producing perforations.

An oil column gas saturation at or just above the critical amount necessary for gas movement, could be a possible explanation for the free gas production. Our analysis of the open-hole FDC CNL log recorded in the A-17 penetration of this reservoir indicated a gas saturation existed in the watered-out oil column prior to the initiation of the project. The open-hole CNL log analysis indicates a uniform 8 to 9 percent gas saturation existed throughout the penetrated watered-out oil column. Because of its uniformity, the initial gas saturation was believed to represent a critical gas saturation created by the 900 psi pressure decline which occurred on this gas saturated crude. We have not yet determined if the initial gas saturation was instrumental in the CO₂ penetration of the oil column or if an existing gas saturation will result in an early development of excessive CO₂ production.

As illustrated on Figure 9, the water cut of the producing well has increased from 50% to 70% during the first eight months of production. This water production has continued even though the production of downdip water should have moved the oil-water contact approximately 12 feet below the producing perforations. The continued water production was unexpected, because we were able to produce water-free oil when the oil column was displaced past the observation perforations. The location of the observation perforations in the previously watered-out oil column is illustrated on Figures 1 and 6. We cannot be certain whether the water cut of the producing well is due to a water cone, a change of relative permeability in the presence of CO₂, or a poor cement job in the producing well. A casing bond log run after the casing was set found no cement bond in the vicinity of the present producing perforations. Although the casing was squeezed in the vicinity of the present perforations, we cannot be sure that it was effective in creating a casing bond.

Work has been undertaken to reinject the produced gas and replace the produced water with downdip water injection. The downdip water injection was reestablished on August 6, 1981. The water injection will be used to control downdip movement of the oil column by replacing the downdip water produced with the oil. Gas reinjection is projected to start on or about October 1, 1981. The reinjection of produced gas will enable us to maintain the 860,000,000 cubic foot slug of CO₂ with the reinjection of the produced gas. Additional production testing at higher flowing rates will be undertaken when the gas reinjection capacity has been installed.

Although our analysis indicates that we have been successful in displacing residual oil from a watered-out sand, the viability of the process will depend on the amount of oil we can economically produce from this displacement. A projection of the well performance prior to the initiation of the project is illustrated in Figure 10. This projection indicates approximately 65,000 bbls of oil remained to be economically recovered from the 23-foot oil column remaining at the initiation of the CO₂ displacement. Through June of 1981, 23,059 bbls of oil had been recovered from the displaced oil column. A 52 percent recovery of the water drive residual oil in the 130-foot displacement will require 210,000 bbls of oil production.

CONCLUSIONS

1. Confirming water drive residual oil saturations were obtained using core analysis and the log-inject-log technique.
2. Displacement observations indicate a gravity stable CO₂ displacement is occurring in the "S" Sand Reservoir B.
3. The CO₂ displacement appears to have increased the oil column thickness to 57 feet from an initial thickness of 23 feet.
4. Concurrent BRC work indicates a gravity stable immiscible CO₂ displacement can recover substantial oil from watered-out sands, which have a 3-phase oil relative permeability similar to the Weeks Island "S" Sand.
5. Stone's model⁽¹⁻²⁾ did not forecast the applicable 3-phase oil relative permeability for the "S" Sand.
6. Production has been initiated and we are now determining the amount of displaced oil that can actually be recovered.

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PRODUCTION TESTS
PRODUCING PERFORATIONS
WEEKS ISLAND STATE UNIT A, WELL 17
WEEKS ISLAND GRAVITY STABLE CO2 DISPLACEMENT

<u>DATE</u>	<u>PRODUCING METHOD</u>	<u>OIL* CUT</u>	<u>GAS-OIL RATIO FT.³/BBL.</u>	<u>CO₂ CONTENT IN GAS</u>	<u>API GRAVITY TANK OIL</u>
Original Oil			1,386	0.71%	32.7
10/22/80	Gas Lift	Trace	Unknown	1.30%**	Not Measured
11/11/80	Gas Lift	9%	Unknown	8.70%**	Not Measured
12/3/80	Gas Lift	16%	Unknown	11.90%**	Not Measured
12/17/80	Flowing	25%	Meter Failure	54.91%	Not Measured
12/31/80	Flowing	32%	2,206	55.57%	29.3

* Percent oil in total liquid recovery.

** Diluted with lift gas.

TABLE 1

FIGURE 1

WEEKS ISLAND FIELD
IBERIA PARISH, LOUISIANA
DIP CROSS SECTION CO₂ PILOT "S" RES.B
INTERPRETATION BY G.E.P. 5/79

COMPARISON OF TOTAL POROSITY COMPENSATED NEUTRON POROSITY AND COMPUTED PULSED NEUTRON BASE LOG POROSITY

FIGURE 4

INITIAL NEUTRON POROSITY MONITORING OF CO₂ FLOOD FRONT

FIGURE 5

NEUTRON POROSITY MONITORING OF CO₂ FLOOD FRONT MOVEMENT

FIGURE 6

FIGURE 7

FIGURE 8

FIGURE 9

FIGURE 10

COMPARISON
RESIDUAL OIL MEASUREMENTS
WEEKS ISLAND ST U A-17
"S" SAND RESERVOIR B

METHOD OF DETERMINATION

- This is a modified TDT-K with TDT-G electronics source-detector spacing 60 cm. Readings are taken while stationary.
- ** Saturation of core plug at 12918 is omitted. The saturation of this plug was over 2.5 standard deviations from the average.

FIGURE 11

FIGURE 12

Appendix A

Weeks Island Co₂ Pilot Project
Annual Report - Research Results

June 1980 - June 1981
Project 36-81894

By

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Appendix A

TECHNICAL INFORMATION RECORD BRC-511

WEEKS ISLAND CO₂ PILOT PROJECT ANNUAL REPORT - RESEARCH RESULTS JUNE 1980 - JUNE 1981

Purpose and Scope

The purpose of this report is to document research results for the period June 1980 to June 1981 on the Weeks Island CO₂ project for inclusion in the annual report to the United States Department of Energy. The research has been directed toward a better understanding of the complex process mechanisms governing the recovery of oil in the Weeks Island CO₂ pilot project. There has been a two-pronged approach to this research - laboratory experiments and mathematical modeling.¹

The first part of this report deals with the laboratory experiments. Two additional experiments have been completed during this report period - a nitrogen-crude run and a CO₂-crude run at a slower rate. The experimental portion of this report summarizes and interprets all of the Weeks Island related laboratory corefloods to date. The second part of the report summarizes the attempts to model the laboratory corefloods. Because this part of the project is incomplete, this report will primarily examine the problem areas in the modeling of the corefloods.

Weeks Island Coreflood Experiments

The results of the seven Weeks Island coreflood experiments suggest that it should be possible to conduct successful CO₂ floods in steeply dipping, high permeability Gulf Coast reservoirs.

Most significantly, oil recovery of Weeks Island reservoir fluid by CO₂ is almost as high as in miscible displacements. (See Table 1.) Even though CO₂ and nitrogen are nominally immiscible with Weeks Island reservoir fluid, recovery by CO₂ was much higher than recovery by nitrogen (85% vs. 12%).

Fractional flow curves for CO_2 and nitrogen displacements of Weeks Island reservoir crude are shown in Figures 1 and 2. In these figures it is apparent that not only is more oil displaced in the oil bank by CO_2 but more oil is vaporized by CO_2 than by nitrogen. This vaporization continues with CO_2 , but stops quickly with nitrogen.

The reason for the higher recovery by vaporization with carbon dioxide can be seen in Figure 3. There, the carbon number distribution of residual oil recovered from the core after the corefloods is plotted along with the composition of the original oil. With CO_2 , over half of all boiling point fractions below C34+ were removed. Nitrogen, however, strips little of any boiling point cut larger than C10. The result is that about 25% of the oil is vaporized by CO_2 while only 2% is vaporized by nitrogen.

One major reason for the large bank with CO_2 appears to be that the recombined reservoir fluid shrinks when exposed to nitrogen and swells in the presence of CO_2 . (See Figure 4.) Even though the recombined oil is nominally immiscible with both nitrogen and CO_2 , there is interphase mass transfer in both cases. However, nitrogen is less soluble in the oleic phase than CO_2 . The result with nitrogen is a higher oil viscosity and a lower oil saturation. The change that this reduction in oil saturation causes in oil relative permeability is displayed in Figure 5. Maximum swelling with CO_2 and shrinkage with nitrogen have been superimposed on a ternary plot of oil relative permeability for Weeks Island rock. At a water saturation of 50%, oil permeability with nitrogen and CO_2 differ by a factor of 9. Since the oil viscosity has also increased on exposure to nitrogen, initial oil mobility in the case of N_2 could be as little as 5% of that in the case of CO_2 . This probably accounts for 25% higher oil recovery in the nitrogen-Soltrol displacement, experiment 7, versus experiment 13, the nitrogen-crude coreflood.

Vaporization and shrinkage are probably the most important differences between CO_2 and nitrogen displacements of the Weeks Island reservoir fluid. However, these effects appear to account for only two thirds of the difference in oil recovery between the two types of

displacements. The observed difference is about 70% recovery of the waterflood residual oil.

Factors which might account for the remainder of the difference in oil recovery are related to the lower water displacements in nitrogen corefloods. Water desaturation was about 30% in the nitrogen displacements and 50-60% for CO₂ displacements, based on water present at the start of gas injection. A possible explanation for this lower water desaturation is significantly lower capillary pressures in CO₂-recombined crude-brine systems but this explanation is as yet unconfirmed.

Modeling Weeks Island Coreflood Experiments

As in the field scale modeling reported earlier,^{1,2} the primary modeling tool has been a fully compositional simulator.³ The primary emphasis in the modeling has been the attempt to model the CO₂ floods. At this time, the floods with nitrogen have not been modeled rigorously, primarily because of meager phase behavior data for nitrogen and Weeks Island crude. For the CO₂ runs, there are two types: one with Soltrol and one with recombined reservoir fluid. Soltrol is a refined oil totally miscible with CO₂ at Weeks Island conditions (225°F and 5100 psig). For the CO₂-Soltrol runs, both secondary (beginning with 100% oil saturation) and tertiary (beginning at waterflood residual oil saturation) experiments have been conducted. For the CO₂-crude experiments, all floods began at waterflood residual oil.

Since CO₂ and Soltrol are completely miscible, it would seem likely that this series of runs could easily be matched with a non-compositional miscible simulator. However, the CO₂-Soltrol system exhibits a large negative volume change on mixing which means that CO₂-Soltrol mixtures are more dense than the Soltrol which they are displacing. For this reason, CO₂-Soltrol corefloods can be unstable although they are run at velocities less than the nominal critical velocity (i.e., based on the densities of the pure fluids). Examination of the effluent CO₂ fractional flow in the secondary CO₂-Soltrol coreflood shows that this flood has some fingering of CO₂ through the oil. For the tertiary Soltrol flood, it is

not as clear that the flood is unstable. However, attempts to match the oil recovery curve for this case with a 1-D compositional model (including the negative volume changes on mixing) have shown that very high dispersion levels are necessary. In this case, Lantz's analogy⁴ equating numerical and physical dispersion was used and the reciprocal Peclet number was 0.25 - i.e. two grid blocks. For the velocity and length of this coreflood, the dispersion coefficient would be 10^{-3} cm²/sec. This seems high, but in the absence of measured dispersion coefficients in Weeks Island cores, one cannot be certain that the dispersion coefficient is unreasonable. At present, although the model is able to predict the oil recovery fairly accurately, the fractional flow curves are still in error for the Soltrol runs. This is additional evidence that some instability, not just dispersion, is present in the tertiary Weeks Island Soltrol corefloods.

For the CO₂-crude corefloods, the process is more complicated because phase behavior and three-phase oil relative permeability are also involved. For these runs the major drawback of the present models is almost the reverse of the Soltrol runs. Here the model predicts too little oil recovery even with 20 grid blocks. As with the Soltrol runs, attempts to match the fractional flow data fared worse than the production data.

The first modeling efforts with CO₂ and Weeks Island crude used a two-dimensional model because of anticipated problems with density inversions.^{1,2} However, with this fine grid system, it was found that the time-step size was severely limited by the explicit capillary pressure. With the 200 grid block model being used, over 100,000 time-steps would have been required to inject 1.6 pore volumes of CO₂. However, reassessment of the need to use a 2-D model showed that a 1-D model would suffice. Therefore, the time-step limitation for explicit capillary pressure is not as restrictive as once was thought. This capillary pressure time-step limitation could pose a problem if 2-D coreflood models are required in the future. As was discussed in the section on experimental results, the capillary pressure is uncertain and the level of interfacial tension is used as an adjustable parameter in the modeling to

obtain the correct water recovery curve. The validity of this approach is in doubt as long as there is no satisfactory match of all of the experimental data.

In summary, the model of the CO₂-Soltrol runs presently falls short in that the level of dispersion seems too high and the fractional flows are not predicted very well. With fingering through the Soltrol being the likely culprit, it does not seem that our present 1-D models can match these runs in significant detail. For the CO₂-crude experiments, the present major deficiencies too low recovery of oil and the shape of the fractional flow curves. At the present time, these deficiencies are not understood well enough to speculate about the eventual results of modeling the CO₂-crude corefloods.

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TABLE 1

SUMMARY OF EXPERIMENTAL DATA*

Experiment No.	Oil Type	Oil Bubble Point	S _o At Start of Gas Flood	Displacement Fluid	Dimensions, in.		$\Delta\rho$ g/cc	CO ₂ BT-PV	% Recovery		Displacement Type
					Diameter	Length			@ 1 PV	@ 1.5 PV	
12	Recombined Oil Batch 2	4800	26.9	CO ₂ /CH ₄	2-3/8	11.5	0.05	0.49	65	86	Tertiary Recombined Oil .15ft/D
11	Recombined Oil Batch 2	4950	31.5	CO ₂ /CH ₄	2-3/8	12.0	0.03	0.61	65	84	Tertiary Recombined Oil .6ft/D
10	Recombined Oil Batch 1	4000	31.5	CO ₂ /CH ₄	2	11.0	0.10	0.70	65	82	Tertiary Recombined Oil .6ft/D
5,6	Soltrol	--	28.5	CO ₂	2	8.3	0.09	0.40	75,81	92,92	Tertiary Miscible .6ft/D
2	Soltrol	--	100.0	CO ₂	2	8.3	0.09	0.38	80	95	Secondary Miscible .6ft/D
7	Soltrol	--	28.3	N ₂	2	8.3	0.52	0.45	32	34	Tertiary Immiscible .6ft/D
13	Recombined Oil Batch 3	4800	28.0	N ₂	2-3/8	10.4	0.45	0.30	12.5	--	Tertiary Recombined Oil .6ft/D

*All corefloods were vertical displacements of oil down by supercritical fluid at 225°F. Calculated velocities were between 0.15 and 0.6 ft/day. These are below stable velocities calculated by Chuoke's or Dumore's methods. Thus no viscous fingers were expected to develop.

RUN NO. 11

○ FRACTIONAL FLOW OF CO₂
 △ TOTAL FLOW OF CO₂ AND OIL

Figure 1: Oil, Brine and Gas Fractional Flows at Reservoir Conditions in Experiment 11
 Calculated from Composition of Oil and Gas Produced

RLN NO. 13

○ FRACTIONAL FLOW OF N₂
 ▲ TOTAL FLOW OF N₂ AND OIL

Figure 2: Oil, Brine and Gas Fractional Flows at Reservoir Conditions in Experiment 13
 Calculated from Composition of Oil and Gas Produced

FIGURE 3: COMPARISON OF ORIGINAL OIL COMPOSITION WITH THE COMPOSITION OF RESIDUES COLLECTED AFTER EXPERIMENTS 11 AND 13

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Figure 4: RELATIVE VOLUME OF LIQUID AS FUNCTION OF DISPLACING FLUID CONTENT

- CO₂ - 5000 PSIG 225°F Equation of State Calculation
- Volumes Calculated From Hite's and Orr's Data 5100 PSIG
- × N₂ - 5000 PSIG 225°F Equation of State Calculation

Figure 5: Effect of Phase Behavior or Initial Oil Relative Permeability at Weeks Island