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WEEKS ISLAND "S" SAND RESERVOIR B GRAVITY STABLE MISCIBLE CO_2 DISPLACEMENT IBERIA PARISH, LOUISIANA

Third Annual Report, June 1979 – June 1980

Date Published – November 1980

Work Performed for the U.S. Department of Energy
Under Contract No. EF-77-C-05-5232

Shell Oil Company
Houston, Texas

National Petroleum Technology Office
U.S. DEPARTMENT OF ENERGY
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Third Annual Report, June 1979 — June 1980

G. E. Perry
Project Coordinator
Shell Oil Company
P.O. Box 481
Houston, Texas 77001

R. J. Watts
Technical Project Officer
Morgantown Energy Technology Center
P.O. Box 880
Morgantown, West Virginia 26505

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U.S. DEPARTMENT OF ENERGY

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GRAVITY STABLE MISCIBLE CO2 DISPLACEMENT
IBERIA PARISH, LOUISIANA

Shell Oil Company
P. O. Box 60123
New Orleans, Louisiana 70160

Shell Development Company
P. O. Box 481
Houston, Texas 77001

ABSTRACT

Shell, in conjunction with the Department of Energy is conducting a gravity stable displacement field test of the miscible CO_2 process. The test is being conducted in a 12,800-foot deep Gulf Coast reservoir. Injection of the CO_2 slug at the producing gas-oil contact commenced in October 1978. The slug of CO_2 is being moved downward by production of downdip water. Injection of the 50,000-ton slug was completed in February of 1980, and production is projected to start in the third quarter of 1980.

Conventional cores and the log-inject-log technique were used to determine residual oil saturation in a well drilled as the pilot producer. The new well is being used to monitor the downdip displacement. Pulsed neutron logging devices have been used to monitor the CO_2 movement in the vicinity of the observation well. The logs have been successful in detecting the CO_2 slug and its subsequent movement.

Production tests of the log-inject-log perforations, located in a previously watered-out portion of the sand, 48 feet below the point of CO_2 injection in the offset well, have indicated an oil column has passed the observation perforations. Further tests and logs indicated CO_2 had reached the observation perforations in November, 1979. These perforations were then squeezed off and new production perforations were placed at the final completion depth 130 feet below the level of CO_2 injection.

Prepared for the Department of Energy under Contract EF (77-05-5232).

INTRODUCTION

The "S" Sand Reservoir B CO_2 pilot is designed to field test a downward CO_2 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 CO_2 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 CO_2 displacement is designed to utilize gravity forces to stabilize the displacement and increase the sweep of the injected CO_2.

Following an evaluation of the residual oil saturation, injection of the CO_2 slug commenced on October 4, 1978. Injection has averaged 106 tons of CO_2 per day and injection of the 50,000-ton slug was completed on February 27, 1980.

Neutron devices have been used to monitor the CO_2 in the vicinity of the new downdip observation and future production well. The CO_2 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 observation perforations in the new well indicates the remaining oil column (oil rim remaining from waterflood) is being displaced into the watered-out sand.

SUMMARY OF THIRD YEAR OPERATIONS

Injection of the 50,000-ton CO_2 slug, Project Phase II, was completed on February 27, 1980. The CO_2 slug was injected at a position just above the producing gas-oil contact. Because of its density, the slug spread between the less dense gas cap and the more dense oil column. During the 9 months of injection that occurred during the report year, 23,874 tons of CO_2 were received and injected.

Gravity forces displaced the CO_2 slug and oil column downward into the voidage created in the watered-out sand by the production of downdip water. During and following the CO_2 injection, the displacement was maintained by the production of approximately 1000 barrels of water per day. During the report year, 328,187 barrels of water were produced from the downdip well.

The initial placement and subsequent movement of the CO_2 in the vicinity of the observation and future producing well, Weeks Island, State Unit A, Well No. 17, was monitored with four pulsed neutron logs. The logs indicated a continuous downdip advancement of the CO_2 front. The latest log run on May 21, 1980, indicated the CO_2 front in the vicinity of the observation well had advanced to a depth 66 feet below the point of CO_2 injection.

Because of the water salinity, it has been impossible to ascertain the oil column location or size with neutron logs. However, tests of the observation perforations found a producible oil column preceding the downdip movement of the CO_2 front. A July 1979 production test found CO_2 was dissolved in the oil ahead of CO_2 front, while an October 1979 production test indicated the CO_2 front had invaded to a depth equivalent to the observation perforations. The observation interval was located 48 feet deeper than the interval of CO_2 injection. Since the observation perforations had served their purpose, the interval was squeezed off in November of 1979.

During February of 1980, a deeper perforated completion was made in the observation and future producing well. The new completion which is located 130 feet below the interval of CO_2 injection will be used to produce the oil bank generated by the displacement. The new interval is being tested on a semi-monthly basis to determine the arrival time of the oil bank at the producing interval. No CO_2 or hydrocarbons have been detected by the tests of the producing interval. We have estimated that the oil bank should arrive in the producing interval on or about the end of the third quarter of 1980. However, the estimate is based on limited test data and very subtle changes in the pulse neutron response seen in this well.

During the year, mathematical simulation efforts at the Bellaire Research Center found that the shape of the 3-phase relative permeability curves have a large effect on the predicted recovery from the S Sand Reservoir B. Moreover, 3-phase relative permeability measurements performed by the laboratory found that Stone's[1, 2] 3-phase relative permeability model did not apply to the Weeks Island "S" Sand Reservoir B Sandstone. The use of Stone's relative permeability model in prior simulations probably resulted in a pessimistic forecasts of "S" Sand Reservoir B pilot performance.

During the report year. the laboratory finished the construction of an apparatus that permits CO_2 displacements of core material at field conditions. CO_2 displacements have been performed on actual "S" Sand Reservoir B core material which had been water displaced to a live oil residual. The displacements generated an oil bank and resulted in substantial recovery from the limited size core. Detailed reports of the laboratory effort are contained in Appendix 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 at 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 CO_2 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 CO_2 displacement, the west flank oil column was flooded with freshwater. The water was injected into Smith-State Unit G-2 which penetrated the reservoir below the oil-water contact.

Prior to CO_2 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.

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 CO_2 injection, are illustrated on Figure 2, the "S" Sand Reservoir B oil column production and injection history.

PREFLOOD RESERVOIR EVALUATION

Prior to initiating the CO_2 injection, a new well, Weeks Island State Unit A-17, was drilled at the location illustrated in Figure 1. This well, which was drilled to evaluate the reservoir parameters, is being used to monitor the displacement and will ultimately serve as a downdip producer.

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 8. The comparative calculations were done in the interval of the LIL perforations which are illustrated on the Figure 1 cross section. On the Figure 8 comparison, the points represent our best estimate of each method, while the arrow bars represent our confidence limits on the individual residual oil determinations.

The residual oil saturation determined from LIL (.221± .025) is in good agreement with oil saturations measured in the core and calculated from open-hole logs (.23± .042 and .243± .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 8.7% 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 900 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 CO_2 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 CO_2 was reduced by the addition of 5 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 5 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 CO_2 slug should spread between the less dense gas cap and the more dense oil column. Gravity forces should displace the remaining oil column and CO_2 slug into the watered-out sand as the water column is produced. Water column voidage in the sealed reservoir is being created by the production of the downdip well, Smith-State Unit G No. 2.

Continuous CO_2 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 CO_2. 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 CO_2 since no plugging occurred during the short gas injection periods which preceded the CO_2 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 CO_2 supply and short maintenance shutdowns of the CO_2 injection plant, continuous CO_2 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:

Month	Length	Reason
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. Although the injection rate was less than the planned 130-ton per day rate, we did not resize the plungers because a smooth operating balance was established between the CO_2 injection and the CO_2 supply which had to be trucked 135 miles.

DOWNDIP WATER PRODUCTION

Production of the downdip water creates the voidage necessary for a displacement of the watered out sand. Since the reservoir is indicated to be sealed, the rate of CO_2 displacement should be a function of the water withdrawals.

Water column voidage is being created by the production of the downdip South State Unit G Well No. 2. The location of the downdip well is illustrated on Figure 1. During the period of CO_2 injection, the water production rate was limited to 1,000 barrels per day to approximately match the CO_2 slug injection rate at reservoir conditions. The rates of water production and CO_2 injection were coordinated to maintain the top of the CO_2 slug in the vicinity of the injection perforations. The reservoir volume of the CO_2 slug injection and the downdip water production are illustrated on Figure 2, "The 'S' Sand Reservoir B Oil Column Production and Injection History".

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 CO_2 invasion was in the gas cap. Subsequent logs indicated the CO_2 had moved downward at this location while production tests of the observation perforations during 1979 show that oil is resaturating the previously watered-out sand below the CO_2 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 CO_2 saturation to a well depth of 12,866 feet. This initial CO_2 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 CO_2 has invaded the oil column down to the lower quality sand interval from 12,882 to 12,888 feet. No downward movement of CO_2 was detected between February and April of 1979.

The column of CO_2 found by the February 21, 1979 log of Weeks Island State Unit A-17 indicated the injected CO_2 was concentrated at this location and had not spread uniformly over the gas-oil contact. The February 21, 1979 logs indicated CO_2 was present in the 38-foot interval from the top of the sand to the poorly developed porosity at 12,882 feet. A uniform distribution of the CO_2 injected through February 22 in a 38-foot column over the entire 6.9-acre area of the gas-oil contact would have resulted in an average CO_2 concentration of 25 percent.

Monitor logs subsequent to February 21, 1979, show a marked reduction in the rate of CO_2 movement. Figure 6 compares the neutron porosity recorded on July 17, 1979, February 8, 1980, and May 21, 1980, with that recorded on February 21, 1979. As illustrated in Figure 7, the rate of CO_2 movement since February of 1979 has been consistent with the downdip water withdrawals. Although the advancement rate indicates CO_2 is filling only 56 percent of the pore space, the steady rate would imply a uniform conformance. Moreover, the space available to CO_2 would be reduced by an 8.6 percent residual gas saturation and immobile water. The April 1979 monitor log does not dispute the steady advancment of CO_2, since the CO_2 front would have been in the poorer porosity of the log interval from 12,822 to 12,888 feet. The logs indicate CO_2 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 displacment.

The pulsed neutron logs could not be used to define the oil column below the CO_2 front. Since the hydrogen index of the water and oil are nearly equal, the technique to monitor the CO_2 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, freshwater 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 ohmmeter, 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 indicate a producible oil column is being displaced ahead of the CO_2 column indicated by the logs. The production tests have been 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 CO_2 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 CO_2. Samples of the separator oil and gas were recombined at the separator ratio using reservoir temperature of 225 degrees. The oil and gas recombined into a single-phase liquid containing 24 mol percent CO_2. 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 CO_2 was dissolved in the oil at the perforations which were 12 feet below a substantial CO_2 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 CO_2 content with a specific gravity of 1.3426 when compared to air. A pulsed neutron log run on November 8, 1979 confirmed that the CO_2 front had reached the observation perforations.

Since the October 26, 1979 test data indicated the CO_2 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 will be obtained from the new interval which is located 130 feet below the original gas-oil contact.

The new perforations are being tested on a semimonthly interval to determine the arrival time of the oil bank. Production tests of this future producing interval through May 27, 1978, had detected no produced hydrocarbons or CO_2. Chromatographic analysis indicated the composition of the returned lift gas was essentially that of the plant residue used to gas lift the well. However, chlorine titrations indicate the salinity of the produced water is declining with time. The water produced on May 27, 1980, was found to have a chlorine content of 22,580 ppm. Since the water salinity is known to increase with reservoir depth, the decrease in chlorine content is a further indication of the downdip flood movement in the reservoir.

ECONOMICS

The in-place waterflood residual target oil in the S Sand Reservoir B has been defined as 288 barrels per acre foot. Moreover, the oil in-place could have been as high as 390 barrels per acre foot if a residual gas saturation had not been created by the partial pressure depletion of this isolated reservoir.

In displacing 900 acre feet of the reservoir with 862 MCF of CO_2 and 1.5 BCF of natural gas, the project will utilize 3.34 MCF of CO_2 and 5.83 MCF of natural gas per barrel of target oil. A meaningful economic evaluation of the process will require completion of the project operation to determine the amount of target oil recoverable.

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2. Dietrich, J. K, and Bondor, P. L., "Three-Phase Oil Relative Permeability Models," SPE Preprint 6044 51st Fall Meeting, New Orleans, Oct. 3-6, 1977.

3. Dewan, J. T., Johnstone, C. W., Jacobson, L. A., Wall, W. B., and Alger, R. P.: "Thermal Neutron Decay Time Logging Using Dual Detection," SPWLA Symposium, May 6-9, 1973.

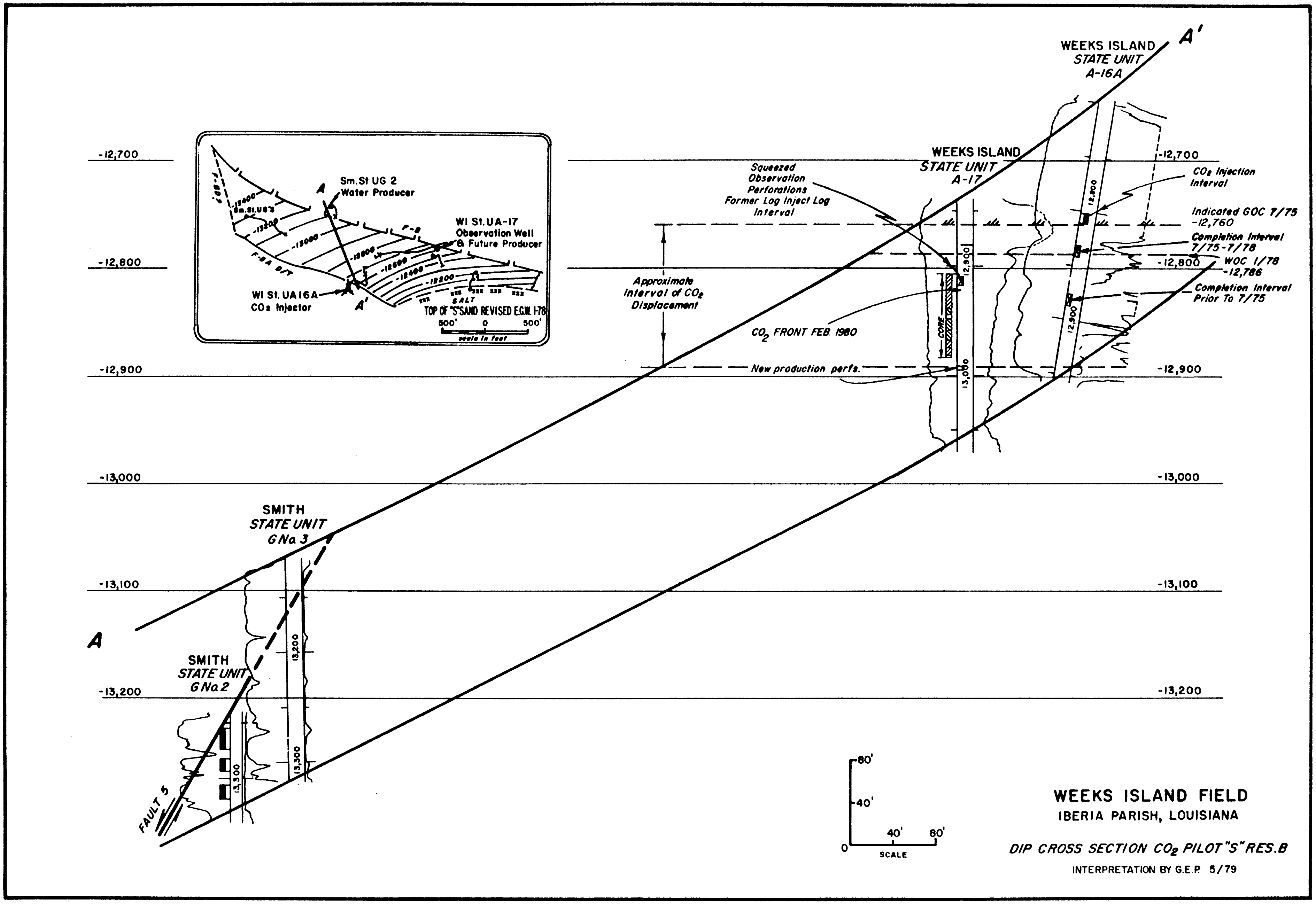
WEEKS ISLAND FIELD
IBERIA PARISH, LOUISIANA
DIP CROSS SECTION CO_2 PILOT "S" RES. B
INTERPRETATION BY G.E.P. 5/79
WEEKS ISLAND STATE UNIT A-16A
WEEKS ISLAND STATE UNIT A-17
SMITH STATE UNIT G No. 3
SMITH STATE UNIT G No. 2
A
A'
-12,700
-12,800
-12,900
-13,000
-13,100
-13,200
CO_2 Injection Interval
Indicated GOC 7/75 -12,760
Completion Interval 7/75-7/78
WOC 1/78 -12,786
Completion Interval Prior To 7/75
Squeezed Observation Perforations Former Log Inject Log Interval
Approximate Interval of CO_2 Displacement
CO_2 FRONT FEB. 1980
New production perfs.
CORE
FAULT 5
SCALE
Sm. St UG 2 Water Producer
WI St. UA-17 Observation Well & Future Producer
WI St. UA16A CO_2 Injector
TOP OF "S" SAND REVISED E.G.W. 1-78
scale in feet

FIGURE 1

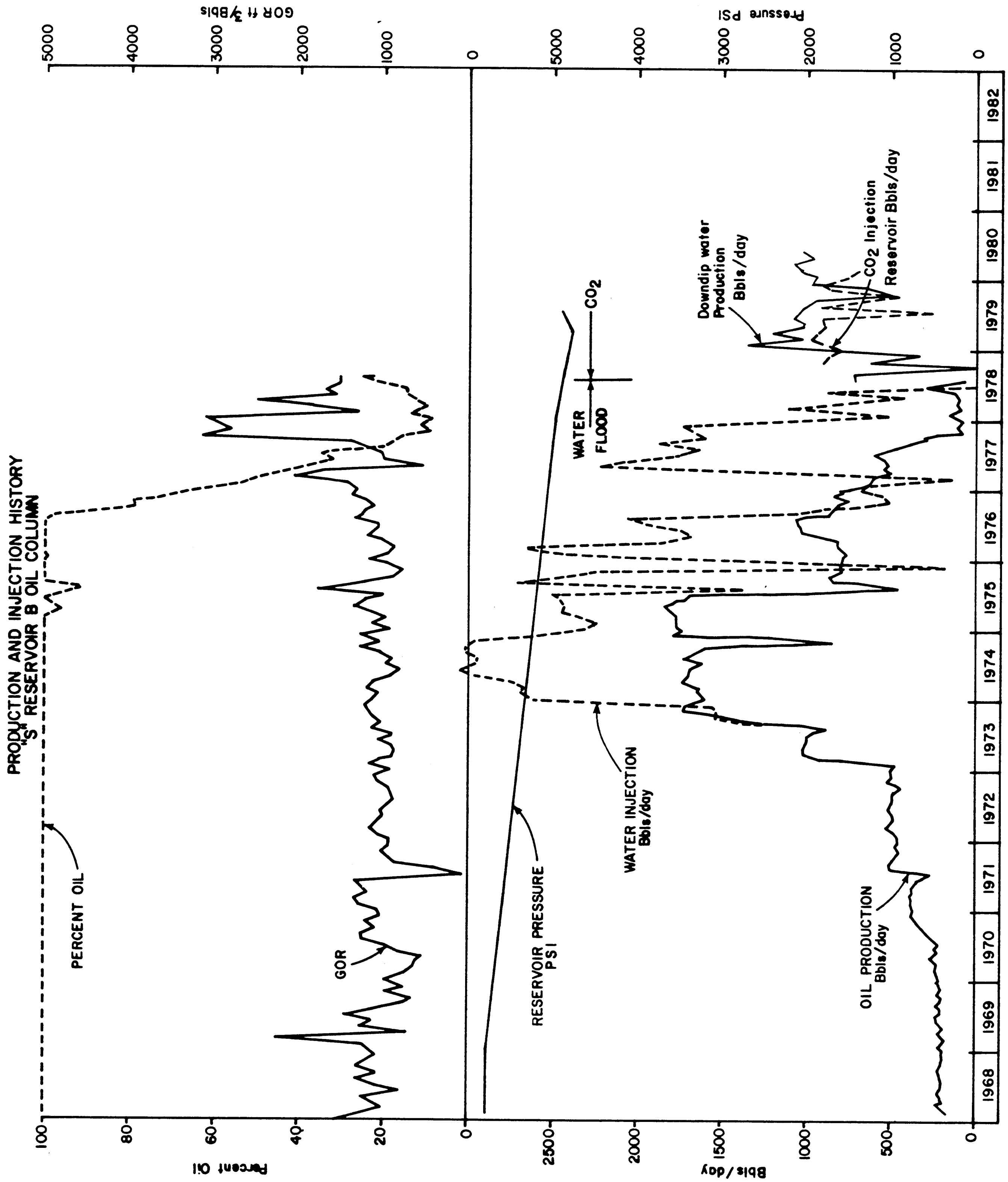
PRODUCTION AND INJECTION HISTORY
"S" RESERVOIR B OIL COLUMN
PERCENT OIL
GOR
RESERVOIR PRESSURE
PSI
WATER INJECTION
Bbls/day
OIL PRODUCTION
Bbls/day
WATER
FLOOD
CO_2
Downdip water
Production
Bbls/day
CO_2 Injection
Reservoir Bbls/day
Percent Oil
Bbls/day
GOR ft ^{3}/Bbls
Pressure PSI
100
80
60
40
20
0
2500
2000
1500
1000
500
0
5000
4000
3000
2000
1000
0
5000
4000
3000
2000
1000
0
1968
1969
1970
1971
1972
1973
1974
1975
1976
1977
1978
1979
1980
1981
1982

FIGURE 2

INJECTION HISTORY
GRAVITY STABLE MISCIBLE CO_2 DISPLACEMENT
"S" SAND RES. B - WEEKS ISLAND FIELD

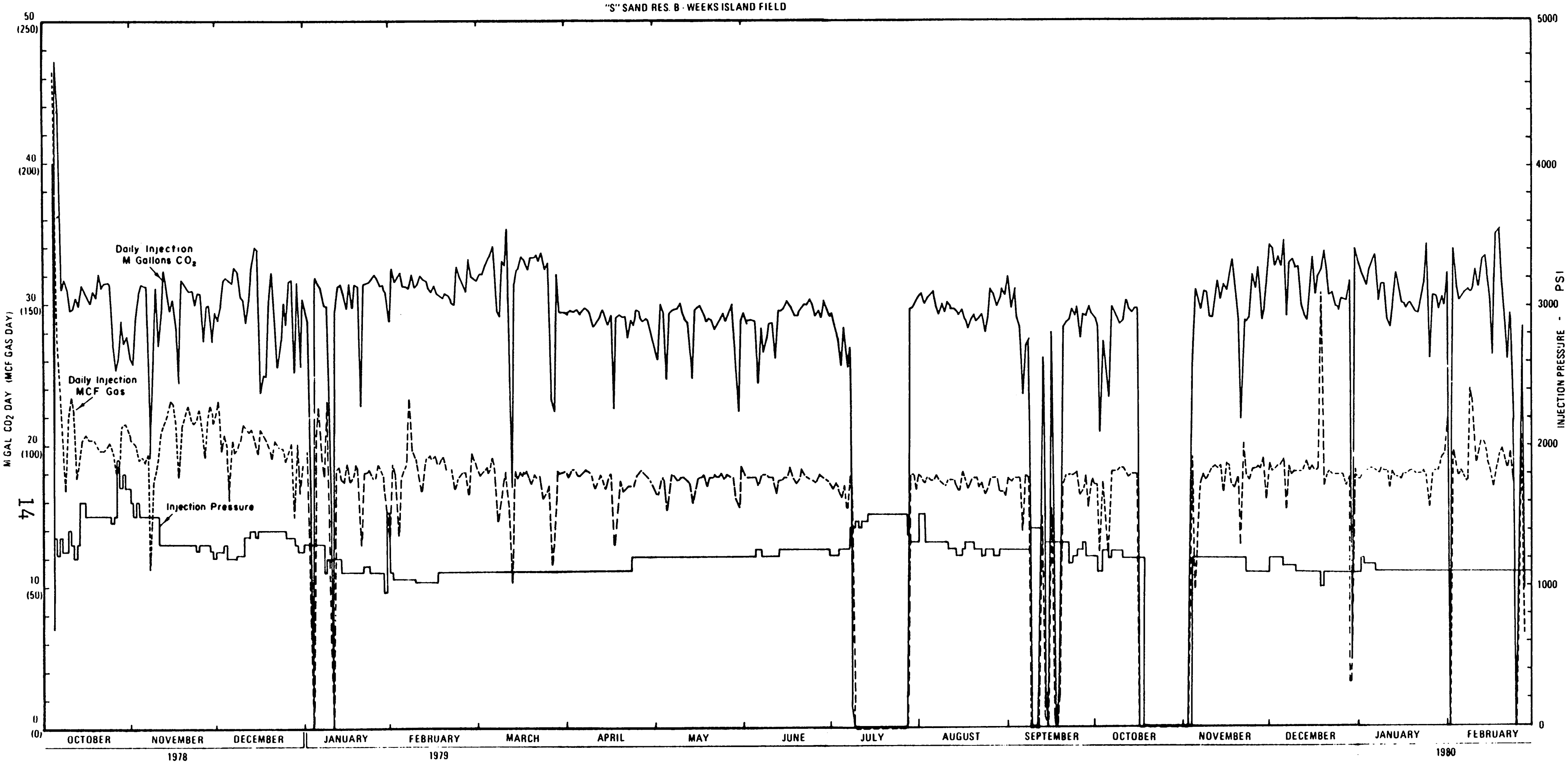

FIGURE 3

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

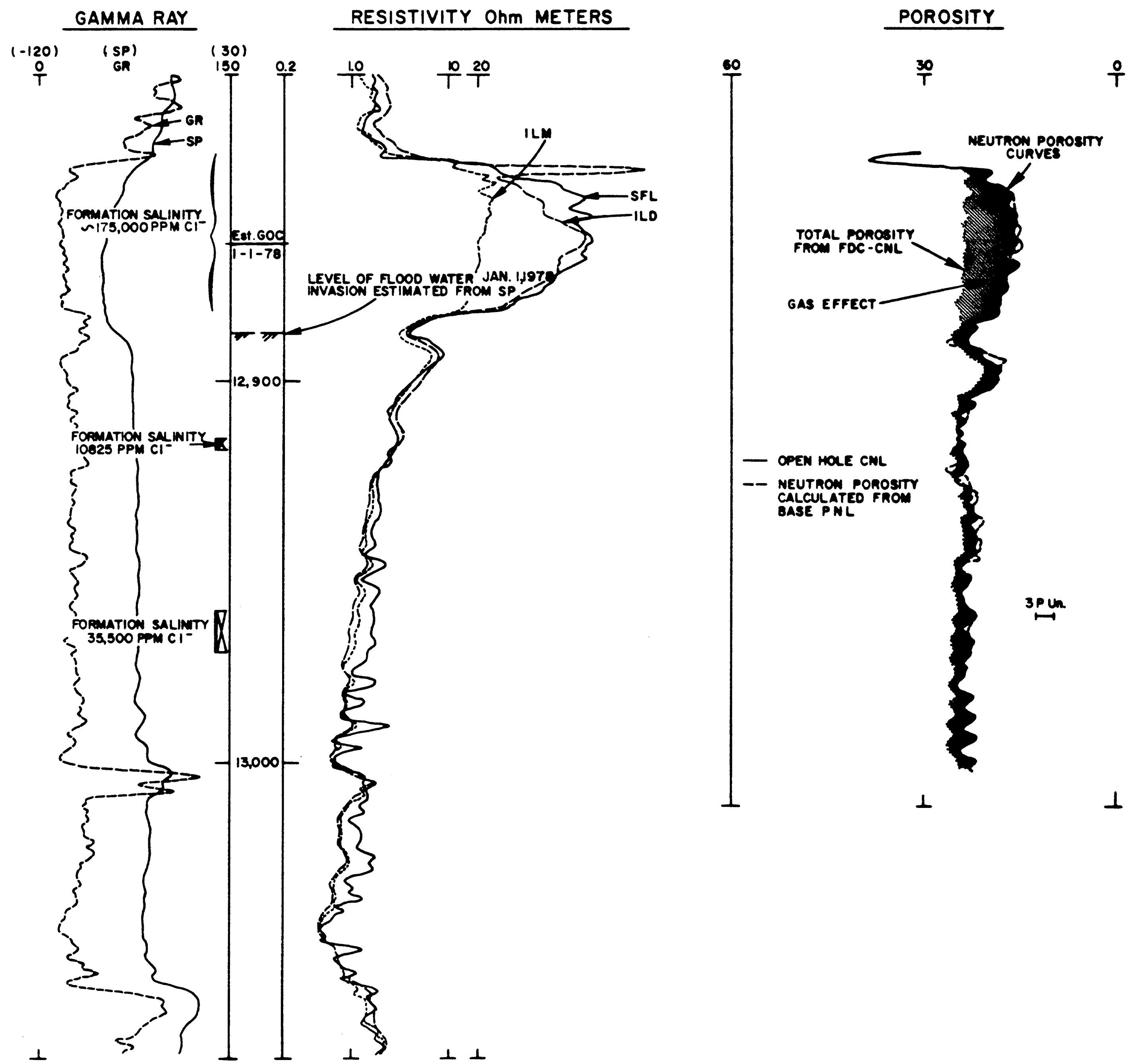

FIGURE 4

INITIAL NEUTRON POROSITY MONITORING OF CO_2 FLOOD FRONT

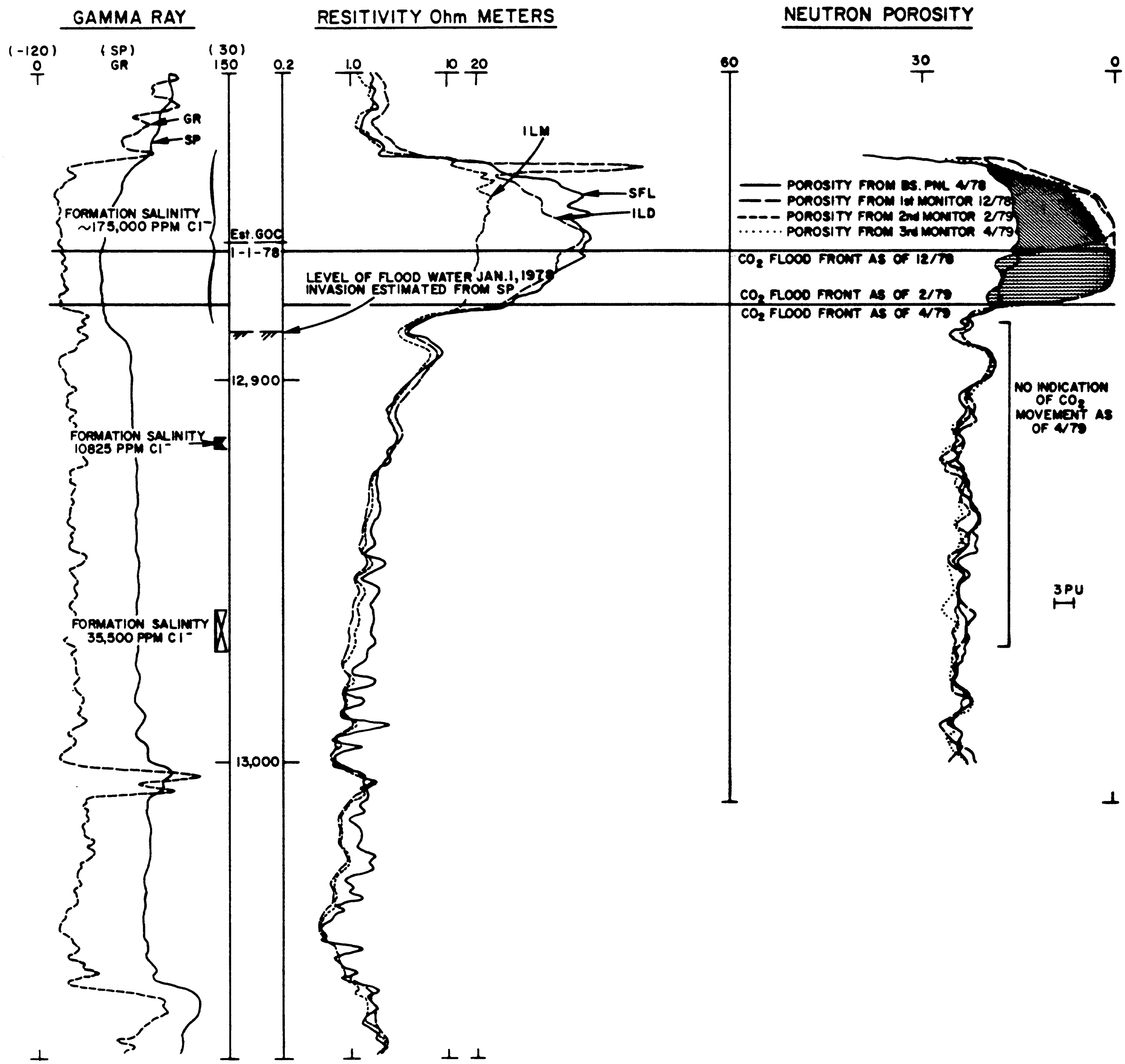

FIGURE 5

NEUTRON POROSITY MONITORING OF CO_2 FLOOD FRONT MOVEMENT

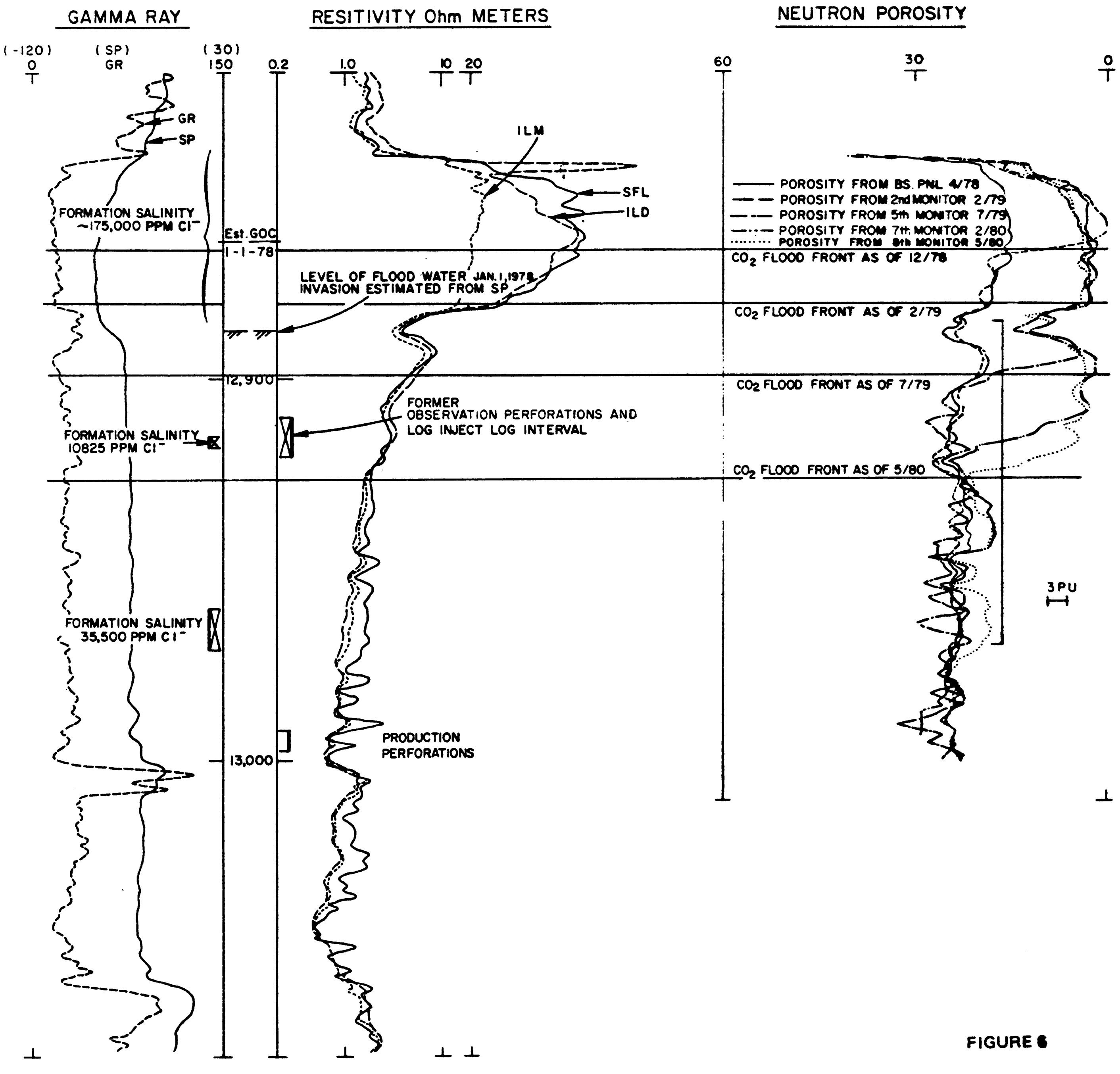

FIGURE 6

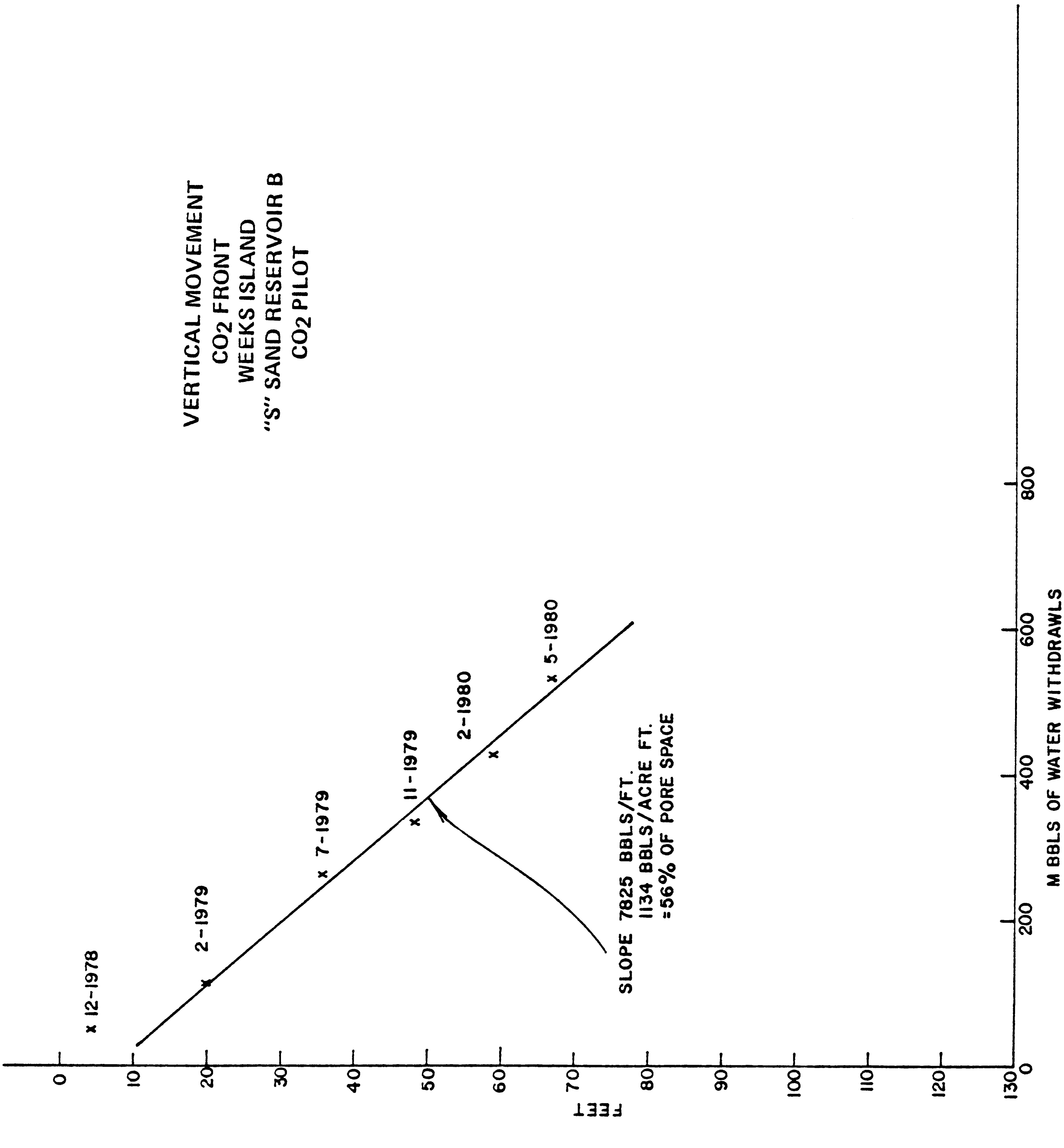
VERTICAL MOVEMENT
CO_2 FRONT
WEEKS ISLAND
"S" SAND RESERVOIR B
CO_2 PILOT
x 12-1978
2-1979
x 7-1979
11-1979
2-1980
x 5-1980
SLOPE 7825 BBLS/FT.
1134 BBLS/ACRE FT.
=56% OF PORE SPACE
FEET
0
10
20
30
40
50
60
70
80
90
100
110
120
130
200
400
600
800
M BBLS OF WATER WITHDRAWLS

FIGURE 7

COMPARISON

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

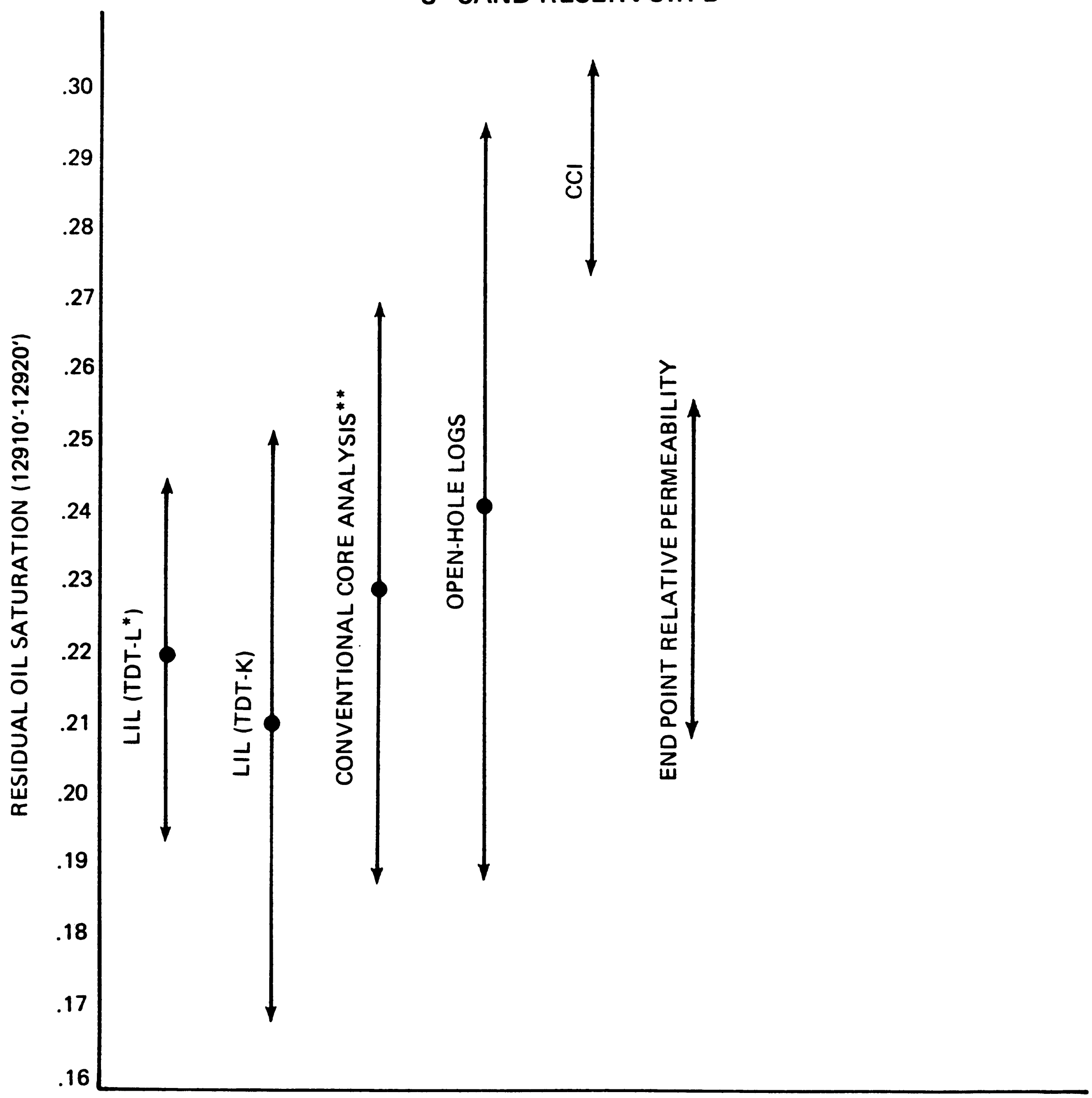

FIGURE 8

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.

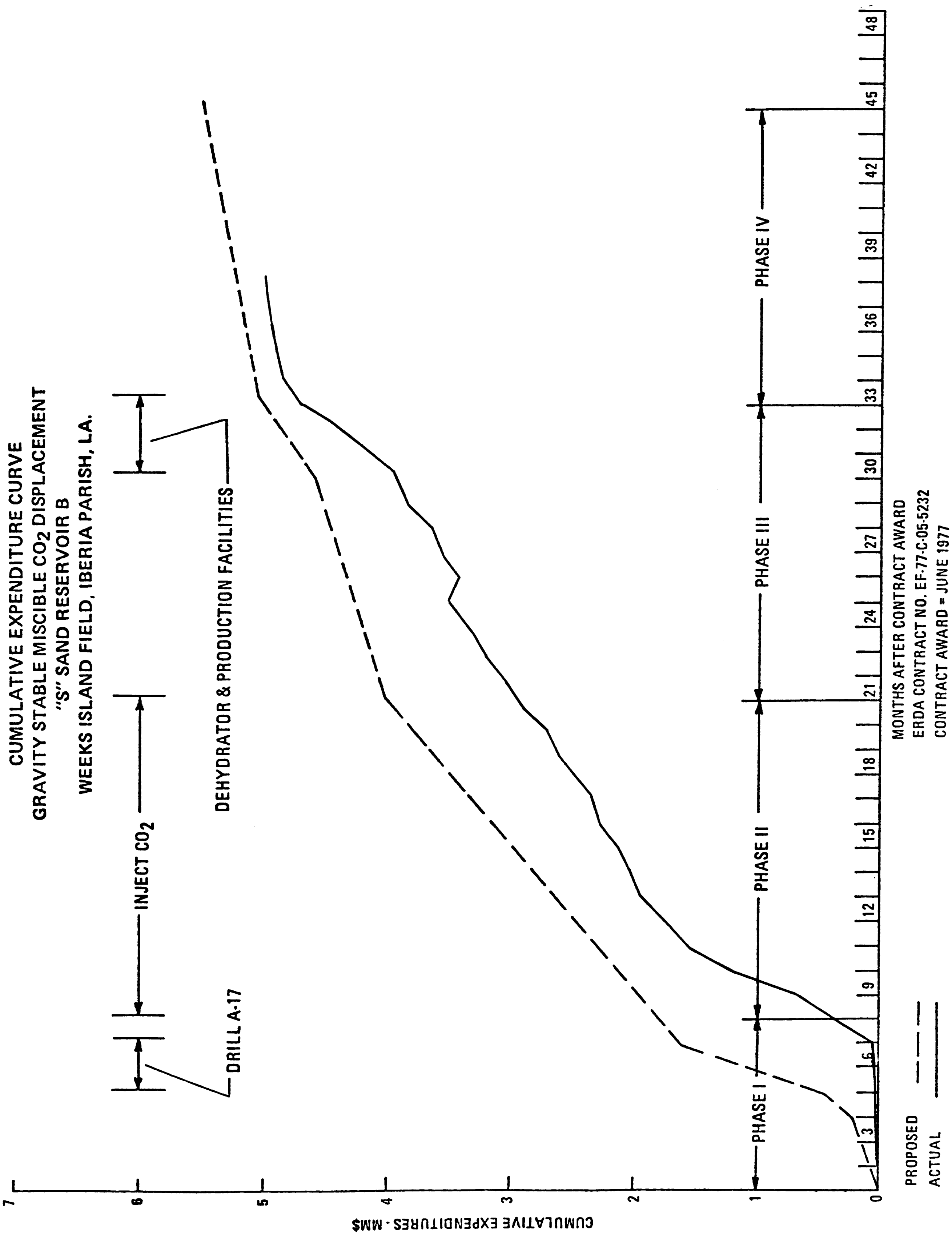
SHELL OIL COMPANY
CUMULATIVE EXPENDITURE CURVE
GRAVITY STABLE MISCIBLE CO_2 DISPLACEMENT
"S" SAND RESERVOIR B
WEEKS ISLAND FIELD, IBERIA PARISH, LA.
INJECT CO_2
DRILL A-17
DEHYDRATOR & PRODUCTION FACILITIES
CUMULATIVE EXPENDITURES - MM$
0
1
2
3
4
5
6
7
PHASE I
PHASE II
PHASE III
PHASE IV
3
6
9
12
15
18
21
24
27
30
33
36
39
42
45
48
MONTHS AFTER CONTRACT AWARD
ERDA CONTRACT NO. EF-77-C-05-5232
CONTRACT AWARD = JUNE 1977
PROPOSED
ACTUAL

FIGURE 9

REVISED PARAMETERS
"S" SAND RESERVOIR B CO_2 DISPLACEMENT

PARAMETER	ORIGINAL DESIGN	REVISED VALUE	DATA SOURCE FOR REVISION	REMARKS
Porosity*	.23	.26	Stressed Core Analysis	
Water Drive Residual Oil Saturation	.27%	.22%	Residual Oil Measurements Log-Inject-Log Analysis	Total Hydrocarbons Saturation Approximates 30% which includes $\pm$8% Residual Gas Saturation.
Absolute Permeability	1000md	1800md	Stressed Core Analysis	
Slug Composition**	85% CO_2 15% Natural Gas	95% CO_2 5% Natural Gas		
Slug Volume	36%	26%		Slug size ratio reduced by increased porosity* and reduced Natural Gas Dilution** of CO_2 Slug.
Original Water Salinity	240,000 PPM Total dissolved solids	175,000 PPMCl^- 283,000 PPM Tot. dissolved solids	Produced water Sm. St. Un. G Well 2	

TABLE 1

Technical Information Record BRC-364

Weeks Island CO_2 Pilot Project

Annual Report - Research Results

June 1979 - June 1980

Project 36-81894

By

R. H. Hite and M. I. Kuhlman

Participants: C. F. VanEgmond
J. J. Evans
W. O. Lease

Shell Development Company
Bellaire Research Center
Houston, Texas

Purpose and Scope

The purpose of this report is to document research results for the period June, 1979, to June, 1980, on the Weeks Island CO_2 pilot 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 tertiary oil in the Weeks Island CO_2 pilot project. Two main areas of research have been investigated during the last year — mathematical modeling of the process using compositional simulation and laboratory core floods approximating Weeks Island reservoir conditions. The mathematical modeling is a continuation of the model studies begun in 1978[1] and is discussed in Appendixes A and B. In 1979, a high pressure and temperature core flood apparatus recently made operational at Bellaire Research Center, was utilized to conduct a number of core floods at pressure and temperature conditions of the Weeks Island SRB CO_2 Pilot (5100 psig and 225°F). These are documented in Appendix C.

Results

One of the major concerns with the previous mathematical modeling had been the low oil recoveries; only 20 - 30% of the stock tank oil was recovered after 1.0 total pore volume injection. Model runs, identical to those reported earlier[1] except that a different three-phase oil relative permeability model was used, predicted recoveries of 70 - 80%. In the new three-phase oil relative permeability model, much of the oil recovery can be attributed to development of an oil bank, whereas the earlier runs with the traditional three-phase oil relative permeability models of Stone[2,3] and Hirasaki[3] only recovered stock tank oil by vaporization. Besides establishing the sensitivity of the model to three-phase relative permeability, a better understanding of the relationship between the circulation cell and the CO_2 slumping below the well has been gained. The model work in the past year has clearly indicated the need for additional experimental data if the mathematical models are to be used with any confidence in the Weeks Island CO_2 project.

Experimental effort during this reporting period has taken two forms — first some actual measurements of the three-phase oil relative permeabilities and secondly laboratory core floods at reservoir conditions. Three-phase oil permeabilities were measured in Weeks Island rock using the centrifuge.[4] The resulting oil permeabilities were more like the new linear interpolate model than the traditional models, but the two-phase oil-gas curve that was used earlier was too optimistic. The recoveries in the model are estimated to be 50 - 60% at 1.0 total pore volume injection with the experimental three-phase relative permeabilities.

A second, more direct approach to understanding the Weeks Island CO_2 process is core flooding in the laboratory. In all, five core floods are reported in Appendix C. Of most direct application was a flood at Weeks Island conditions which recovered more than 80% of the stock tank oil after 1.5 movable pore volumes injection. In this coreflood, an oil bank formed, which contained up to 65% of the oil, and the remainder of the recovery was by vaporization. Thus, not only does the oil become mobile but phase behavior also contributes to oil recovery. Two additional core floods are planned — one with CO_2 and Weeks Island crude at a slower rate and one with nitrogen and Weeks Island crude to obtain a better understanding of the role of phase behavior.

There are significant differences between the laboratory core floods and the field scale mathematical models that preclude direct comparison of the recovery curves. A major effort of the future model work will be simulations of the core floods with the best phase behavior and three-phase relative permeability data available.

Acknowledgement

The authors would like to acknowledge their colleague, Engel van Spronsen, of Koninklijke/Shell Exploratie en Produktie Laboratorium, Rijswijk, The Netherlands, who was the chief developer of the centrifuge technique for measuring the three-phase oil relative permeabilities while at BRC as an exchange scientist. We would also like to express our appreciation to Russell Ueber of Bellaire Research Center, Houston, for his part in initiating the measurements of three-phase oil relative permeabilities and to John Musters, who actually made the measurements.

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APPENDIX A

MODELING THE WEEKS ISLAND CO_2 FLOOD: EFFECTS OF THREE-PHASE RELATIVE PERMEATILITY

Introduction

In earlier reports on the compositional modeling of the Weeks Island CO_2 flood,[1] the phase behavior aspects of the process mechanism were emphasized. The two major features that were attributed to phase behavior were the slumping of the CO_2 directly beneath the injector and the circulation cell arising from the interchange of CO_2 and the light ends of the crude oil when CO_2 contacted the saturated crude oil. In addition, only 30 percent of the stock tank oil in the 120 foot target zone was recovered at 1.0 pore volume throughput. Relative permeability was recognized as an important factor in the modeling, and this report documents the degree of importance.

Summary and Conclusions

1) For the Weeks Island CO_2 flood, the three-phase relative permeability curves are an important factor in the predicted recovery of stock tank oil. Both historically used three-phase relative permeability models, Stone and Hirasaki, predict 20-30 percent recoveries; a new model, the linear interpolate model, predicts 70-80 percent recovery.

2) Since the three-phase relative permeability model has such a significant effect on the nature and efficiency of the process, laboratory corefloods at Weeks Island conditions are essential to our understanding of the process. Initial results of such laboratory corefloods are included in Appendix C.

3) The slumping phenomenon and circulation cell reported earlier are better understood. There seems to be little relationship between the two. The circulation cell occurred in all Weeks Island simulations, regardless of the simulator or permeability model used. The cell arises when a denser vapor is injected above a less dense one. The slumping phenomenon occurs because the reservoir liquid phase becomes immobile, but is gradually vaporized by the injected CO_2.

4) The relative significance of phase behavior depends on the three-phase relative permeability model used. For Stone's model, over 80 percent of the stock tank oil recovered was from phase behavior (vaporization); for the linear interpolate model, all of the recovery can be attributed to oil bank formation. If the three-phase model is found to be intermediate between Stone's and the linear interpolate model, both phase behavior and three-phase relative permeability may be major determinants of the process efficiency.

Three-Phase Relative Permeability

Reservoir engineers are well aware of the importance of relative permeability on the predicted performance of a recovery process.[5] For most situations, the user provides oil-water relative permeability curves (at zero gas saturation) and the gas-oil curves (at connate water). It is assumed that the water and gas relative permeabilities depend only on their own saturation, but the oil relative permeability depends not only on its own saturation, but also on the saturation of the other phases as well. If the gas saturation is nonzero and the water saturation is greater than connate, some model must be used for the oil relative permeability in this three phase region. In this study, the sensitivity of the Weeks Island CO_2 flood to the choice of three-phase model has been investigated.

In Figure A-1, the two-phase relative permeability curves used in most of the Weeks Island simulations are plotted.* Figure A-2 is the ternary saturation diagram showing oil isopermeability lines for Stone's three-phase model and for a newly proposed model. All of the earlier Weeks Island simulations had used Stone's model, one of the two commonly accepted three-phase relative permeability models.[2,3] The extreme curvature of the zero isoperm line for Stone's model is worth noting. Although residual oil to water at zero gas saturation is 27 percent, at 30 percent gas saturation the oil is immobile below 45 percent saturation. Even though residual oil to gas at connate water is zero, at 11 percent water saturation (only 4 percent above connate), the residual oil is greater than the residual to water alone. This large region of immobile oil seems physically unrealistic and is contrary to some limited data on gravity drainage.[4,6]

* In additional simulations, the two-phase curves of Figure A-1 were revised to reflect the conditions at Weeks Island more accurately, but all conclusions about the effects of three-phase relative permeability remain the same.

For many conventional recovery processes, the choice of the three-phase relative permeability model has historically been unimportant. In many instances all three phases do not flow simultaneously. Furthermore, the various three-phase models differ significantly only at low oil saturations. In a tertiary gas displacement process, such as the Weeks Island CO_2 flood, one can expect three simultaneously flowing phases at low oil saturations. The second set of isoperms on Figure A-2 is a newly proposed three-phase relative permeability model. For most two-phase curves, this model results in straight line isoperms. In this report, the model will be referred to as the linear interpolate model. Although the linear interpolate model is not presently validated by experimental data, its purpose was to test the hypothesis that the three-phase relative permeability model had a major effect on the process mechanisms.

Results

The simplified geometric model [1] of the Weeks Island CO_2 Flood was run on COMPOSIM with both Stone's model and the new linear interpolate model. Stone's model predicted a recovery of 30 percent of the stock tank oil versus 73 percent for the linear interpolate model. Figure A-3 is a picture from the color display system contrasting the two three-phase models at the end of the injection period. In the standard format of the color system, red is the gas saturation; green the oil; and blue is water.[7] The small triangle shows how any color translates into a particular set of saturations. The top frame showing Stone's model is analogous to Figure A-2 in the earlier report.[1] There are several observations that need to be made about Figure A-3. For Stone's model, there is an insignificant build-up of oil saturation in contrast to the linear interpolate model. Secondly, there is no slumping of the vapor phase directly beneath the injector in the linear interpolate model. The arrows are the CO_2 flux. The scale is logarithmic showing magnitudes from 0.008 - 8.0 moles/feet^2 - day. Both models predicted a circulation cell in the vapor phase, but the cell is not necessarily related to slumping beneath the injector or to poor recovery efficiencies. This is different from earlier ideas about the relationship between slumping and the circulation cell[1] and requires further explanation about the cause of slumping.

Figure A-4 dramatically shows the build-up of the oil saturation. It contrasts the same two runs as Figure A-3, but only the oil saturation on a linear color scale is shown. The arrows in this case are the oleic phase velocities from 0.01 to 0.2 feet/day, an order of magnitude less than the velocities observed in the vapor phase. The nominal frontal advance rate is 0.08 feet/day. The dark red and black indicate oil saturations below S_{orw}. In Stone's model there are oil saturations above S_{orw}, but the oil is not moving. Figure A-4 also demonstrates how much better the oil is banked up in the linear interpolate model.

A final question is: Why does the slumping occur in Stone's three-phase model? This question may be academic if the linear interpolate model represents the actual Weeks Island conditions. On the other hand, it may be that the appropriate model is intermediate between Stone and the linear interpolate model. To try to determine the cause of the slumping, a series of runs were made with the black oil simulator, COMSIM, using the same model geometry as COMPOSIM. The relative permeability effects were still present, but not the interphase mass transfer. For Stone's model, COMSIM predicted a recovery of only 5 percent, 25 percent less than with COMPOSIM. The additional recovery, predicted by COMPOSIM, must be a result of vaporization of the stock tank oil, a phenomenon not included in COMSIM. With Stone's model in COMPOSIM, the initial oil rim is immobilized because of the adverse oil isoperms (Figure A-2), but then the CO_2 vaporizes the hydrocarbon liquid phase near the well (the region of highest CO_2 throughput). When the linear interpolate model is used, the oil does not become immobile and there is little difference between COMSIM and COMPOSIM. The slumping is therefore caused by the combination of poor oil mobility and vaporization by injected CO_2.

When all the runs that have been made on the Weeks Island Model are classified according to percentage recovery of stock tank oil at one pore volume throughput, they divide into two groups. Those that recover less than 32 percent and those that recover greater than 70 percent; this classification corresponds to which three-phase relative permeability model was used. Stone's model has never predicted recoveries greater than 32 percent for these Weeks Island Model simulations, and the linear interpolate model has never predicted less than 70 percent. The other commonly used three-phase model is Hirasaki's.[3] For the two-phase curves of Figure A-1, it predicts a region of immobile oil intermediate in size between Stone and the linear interpolate model, and indeed the predicted recoveries are also intermediate for comparable COMSIM runs. Additional laboratory work to determine the appropriate three-phase relative permeabilities for Weeks Island CO_2 pilot has subsequently been carried out and the results are reported in Appendix B.

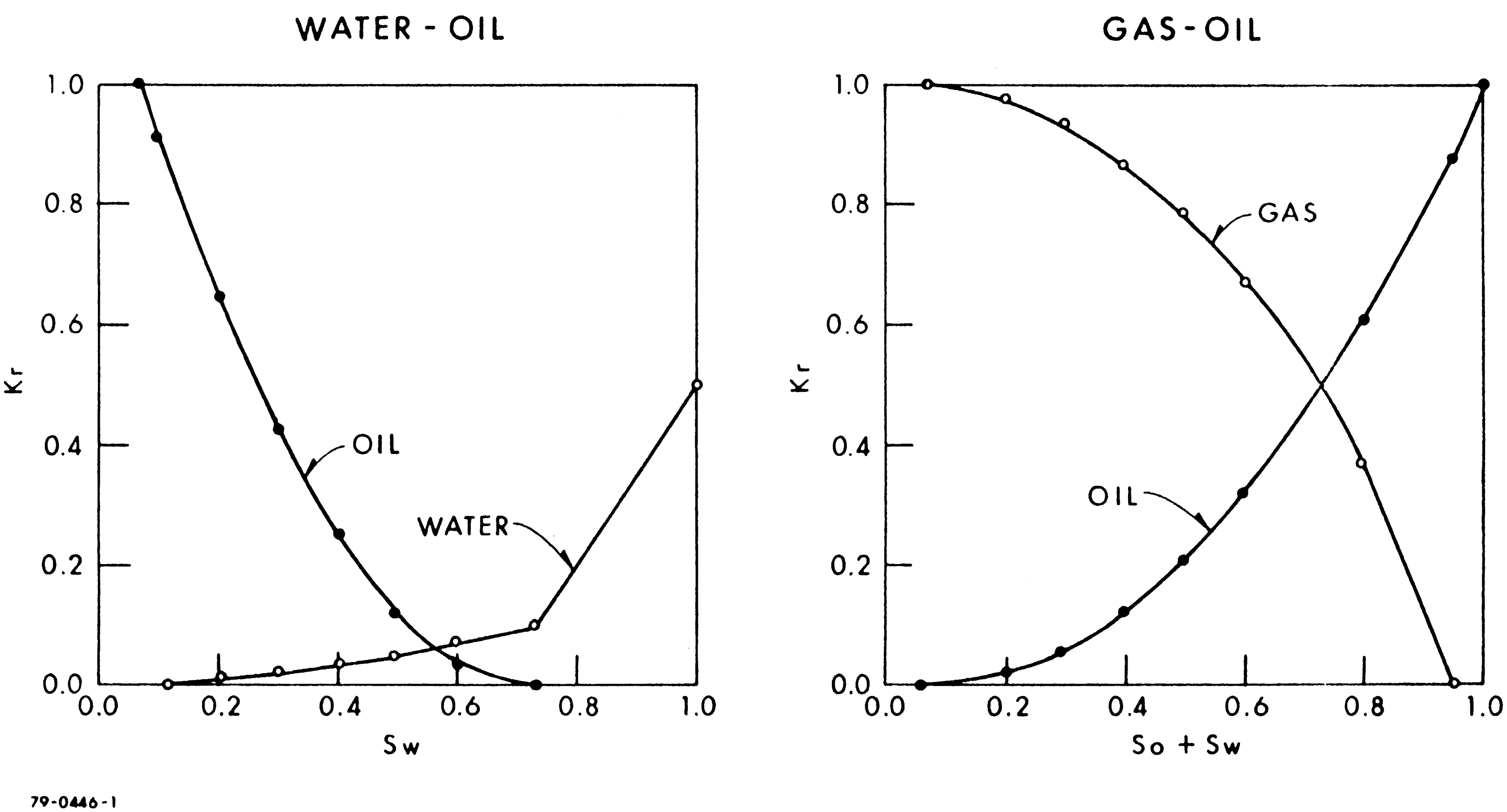

Fig. A-1 Two-phase water-oil and gas-oil relative permeability curves used in Weeks Island simulations.

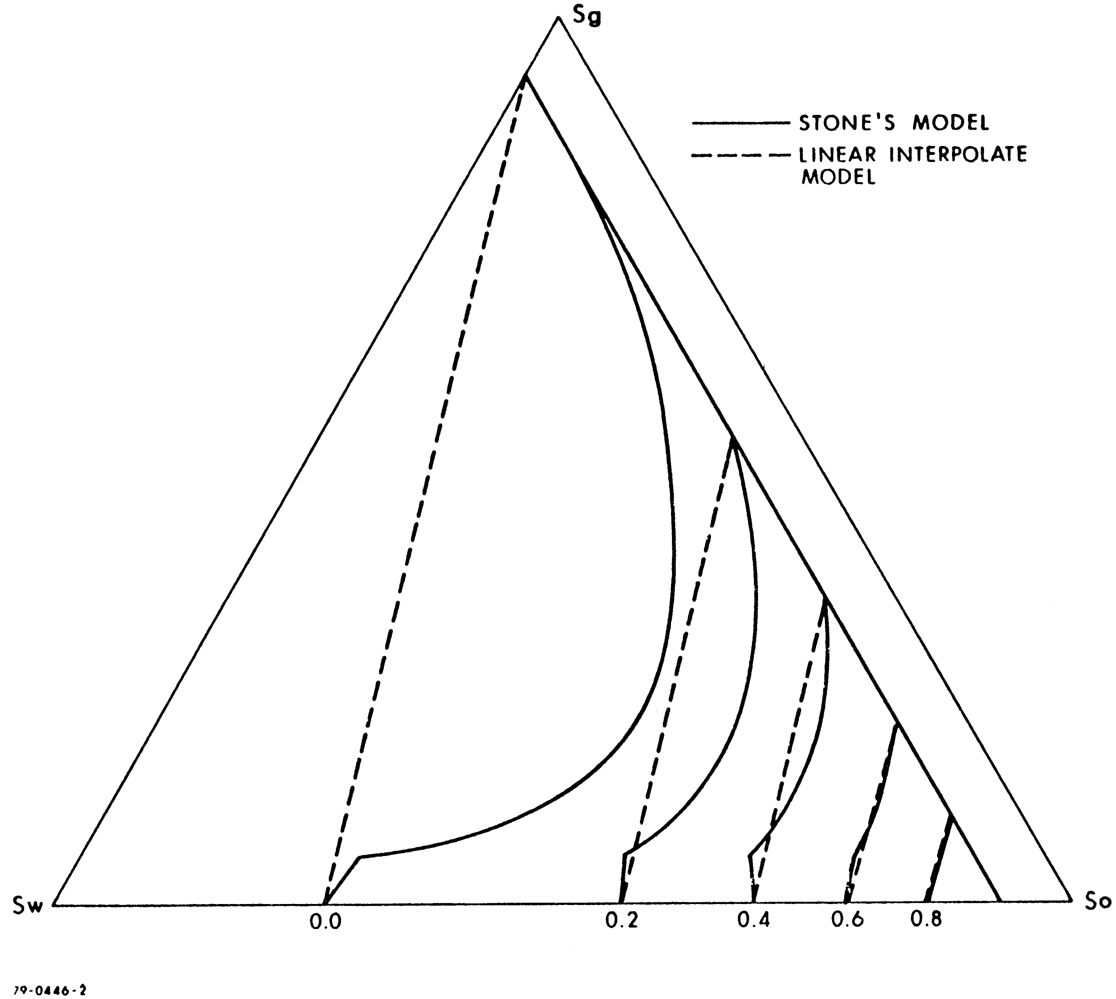

Fig. A-2 Three-phase oil isoperms for Stone's and Linear Interpolate Models used in Weeks Island simulations.

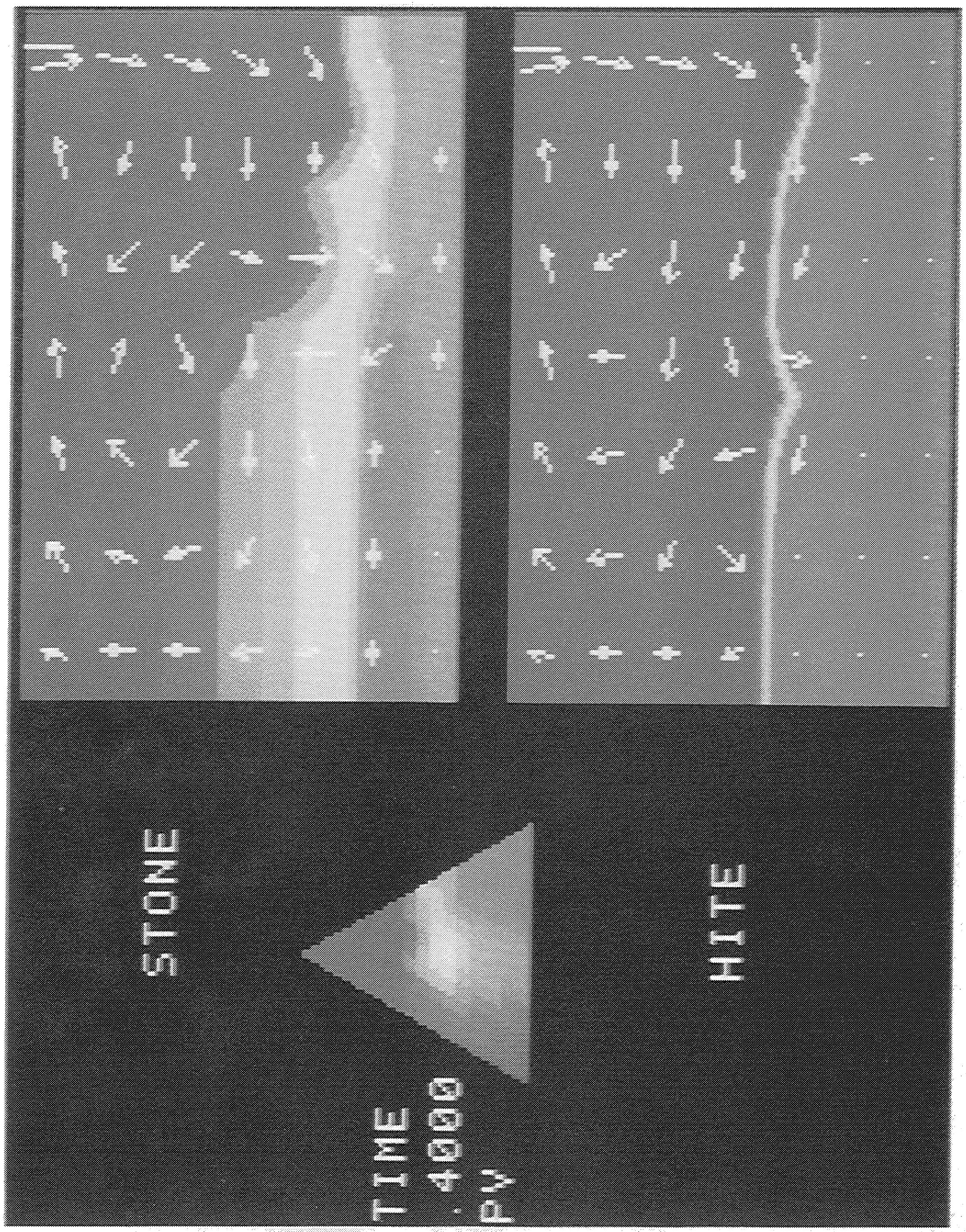

Fig. A-3 - Contrast of Stone's and Linear Interpolate (Hite's) Three-Phase Relative Permeability Models showing CO_2 flux and saturations at end of CO_2 injection.

A color copy of Figures A-3 &
A-4 can be obtained from:

G. E. Perry
Shell Oil Company
P. O. Box 60123
New Orleans, LA 70160

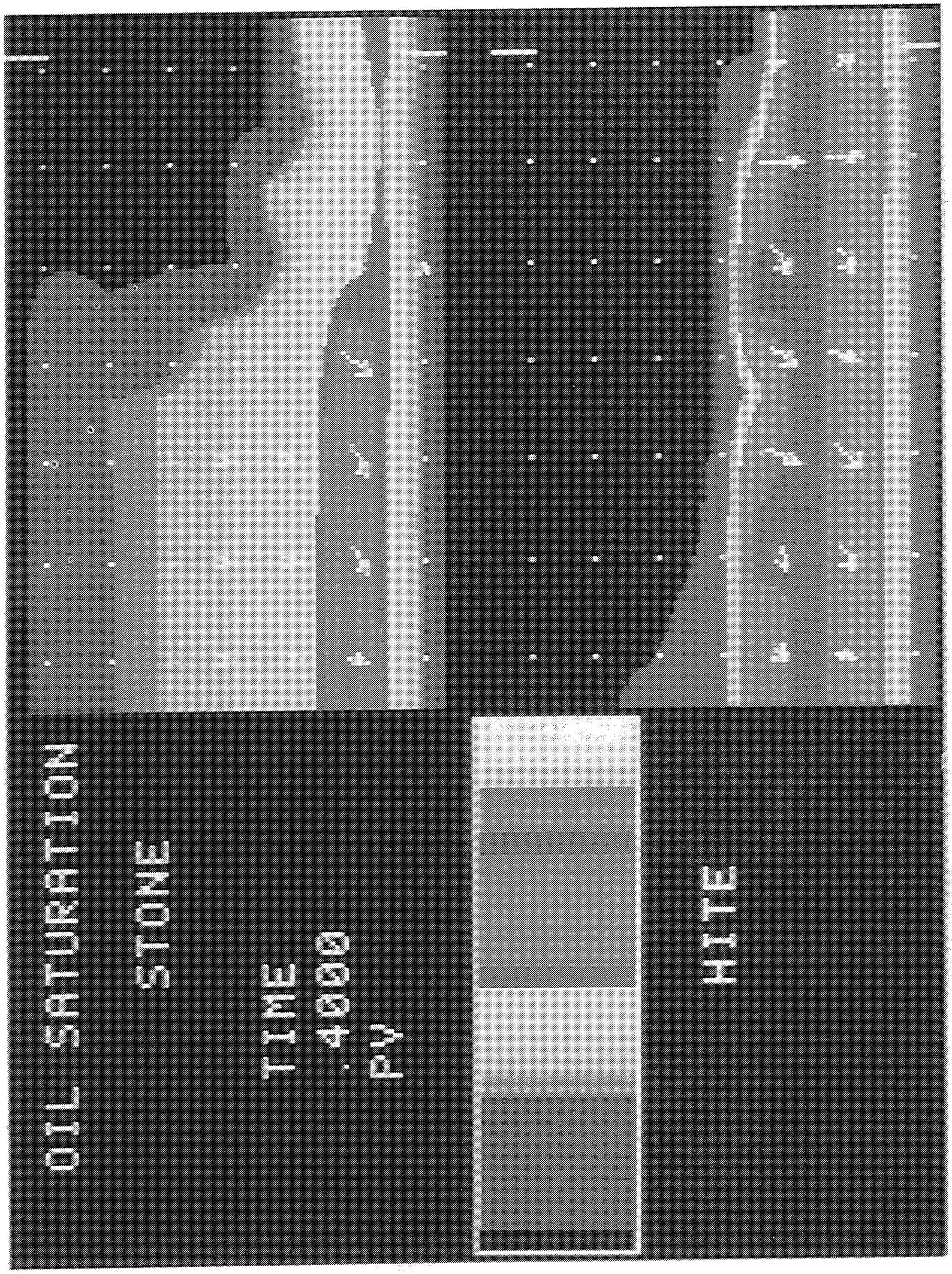

Fig. A-4 - Contrast of Stone's and Linear Interpolate (Hite's) Three-Phase Relative Permeability Models showing oil velocity and oil saturation at end of CO_2 injection.

A color copy of Figures A-3 &
A-4 can be obtained from:
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Shell Oil Company
P. O. Box 60123
New Orleans, LA 70160

APPENDIX B

WEEKS ISLAND CO_2 PILOT: EXPERIMENTAL THREE-PHASE OIL RELATIVE PERMEABILITIES

Introduction

Three-phase oil relative permeabilities have been measured in the laboratory using the centrifuge. These data show unequivocally that the traditional models of Stone and Hirasaki are not applicable to the region of low oil permeability under the Weeks Island CO_2 pilot conditions. The experimental relative permeability data have been incorporated into compositional simulation of the field scale Weeks Island CO_2 pilot. The model of the pilot with the experimental three-phase oil relative permeabilities is similar to the models described earlier[1] and in Appendix A of this report.

Summary and Conclusions

1. The three-phase oil relative permeabilities applicable to the Weeks Island CO_2 pilot have been measured in the laboratory. These data show none of the extreme curvature at low oil permeabilities exhibited by the more traditional models of Stone[2,3] and Hirasaki.[3] Therefore, the low recoveries (20-30 percent) reported in the earlier mathematical studies are too pessimistic.
2. The new experimental data have been incorporated into the compositional simulator and the mathematical model of the CO_2 pilot re-run with these new data. These simulations contain our present best estimate of both the phase behavior and relative permeabilities. This model predicts a 50 percent recovery of the stock tank oil after one total pore volume has been injected. This recovery is less than that estimated in Appendix A for the linear interpolate three-phase oil relative permeability model because the experimental oil curve at irreducible water saturation is much more pessimistic than the previous two-phase curve used with the linear interpolate model.
3. The model recovery efficiency of 50 percent is less than the 70 percent recovery efficiency obtained from the laboratory core floods at a comparable throughput (see Appendix C).* There are certainly differences between the

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* In Appendix C, recoveries are quoted at 1.5 movable pore volumes, but in this appendix the recovery at 1.1 movable pore volumes is used (1.0 total pore volumes for the field-scale mathematical models).

results that could explain the lower model recovery and one main goal of the future model work at Weeks Island will be to construct an adequate mathematical model of the laboratory core floods.

Measurement of Three-Phase Oil Relative Permeabilities

The measurement of two-phase oil relative permeabilities with the centrifuge has been described by Hagoort.[4] This technique was extended to the measurement of three-phase relative permeabilities in another research project not funded by the DOE. Since the experimental and theoretical details of the three-phase oil relative permeability measurements are considered proprietary at this time, only the results will be reported.

Figure B-1 shows the oil relative permeability contours for Weeks Island S Sand Reservoir B. The solid curves are the experimental data from the centrifuge and the dashed lines show Stone's model. Since there are large uncertainties in the centrifuge technique at low gas saturations, the oil-water curves obtained previously by a Welge method are used along the zero gas line and "meshed" with the centrifuge data. It should also be noted that the two-phase oil curve at irreducible water saturation is much more pessimistic than the two-phase curve used in Appendix A. That is, at a given liquid saturation with no movable water, the oil relative permeability is much less for the three-phase centrifuge data than for the data in Appendix A.

Incorporation Into Simulator

The mathematical model of the Weeks Island CO_2 pilot is similar to the model described in Appendix A of this report and in earlier reports about the Weeks Island CO_2 project.[1] A vertical cross-section, with gas cap and CO_2 being injected above an oil rim, was used. Both the single and multiple contact experiments were incorporated into the phase description of the compositional simulator, COMPOSIM. Below the oil rim there was a residual hydrocarbon saturation consisting of 22 percent liquid and 8 percent vapor. The experimental three-phase oil relative permeabilities were incorporated into the simulator in a tabular form. With these relative permeabilities, recovery of stock tank oil was 50 percent of the oil in the 120-foot target area at 1.0 total pore volume throughput. This contrasts to only 12 percent recovery for Stone's model with the comparable two-phase curves. On the other hand, the recovery with the experimental three-phase data is considerably less than the 70-80 percent reported in Appendix A for the linear interpolate model because the linear interpolate model used a more optimistic oil curve at irreducible water saturation.

In Appendix C of this report five laboratory core floods in Weeks Island rock are reported. The core flood using Weeks Island recombined reservoir fluid had a recovery of approximately 70 percent at a throughput equivalent to one total pore volume throughput in the mathematical model. Since the mathematical model presently simulates the field scale Weeks Island pilot, a direct comparison of the recoveries from the core flood and the present mathematical model is inappropriate. However, one of the main goals of the future Weeks Island research will be to develop an adequate laboratory-scale mathematical model.

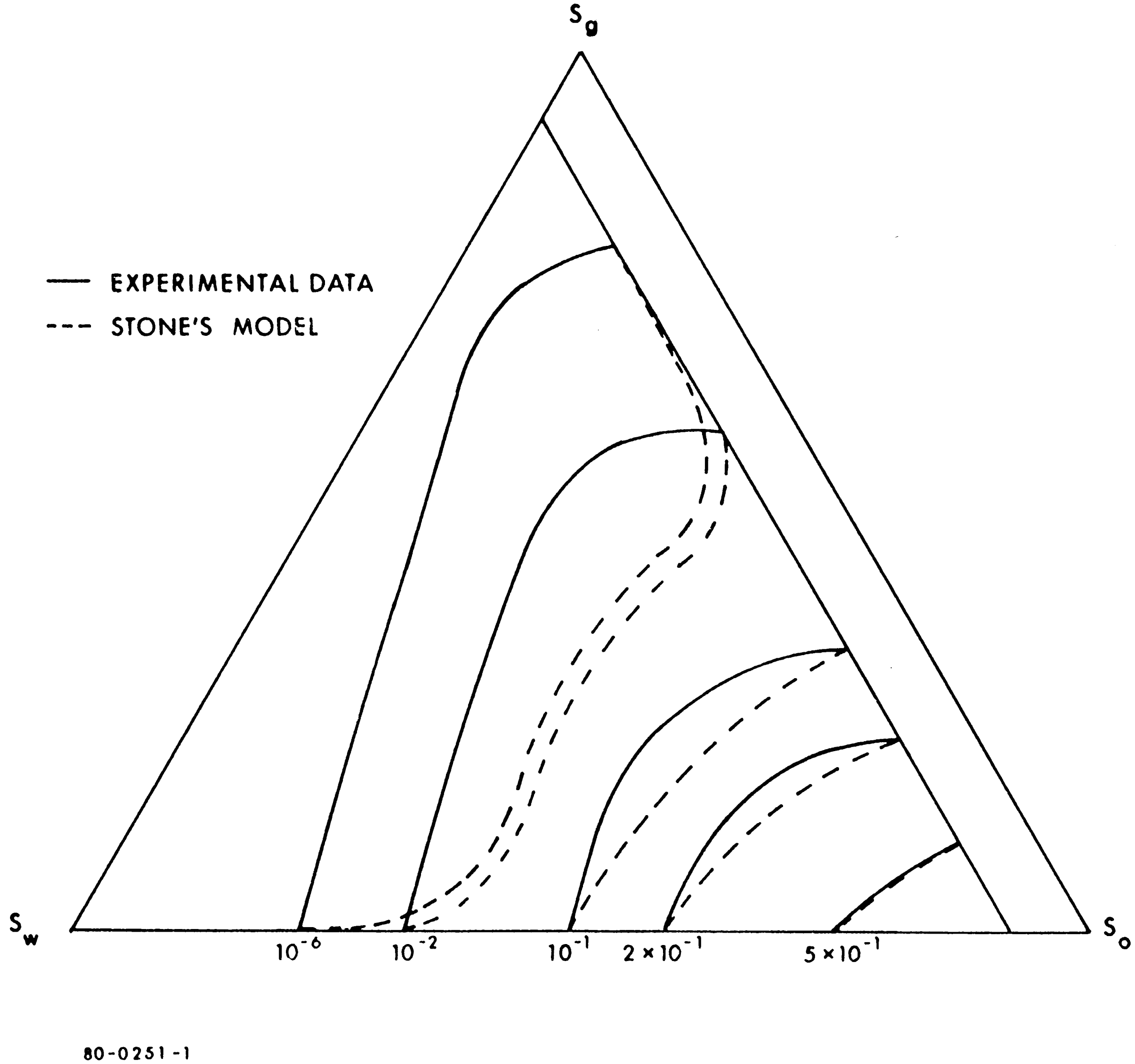

Fig. B-1 Three-phase oil isoperms for Weeks Island showing both experimental data and Stone's model.

APPENDIX C

LABORATORY COREFLOODS FOR THE WEEKS ISLAND CO_2 PROJECT

Introduction

Several corefloods have been completed which represent the conditions encountered in the ongoing CO_2 flood at Weeks Island SRB. The corefloods were conducted in the new high temperature high pressure, coreflooding apparatus recently made operational at BRC. A highly efficient recovery of waterflood residual oil was achieved. These laboratory tests also address questions raised earlier about three phase relative permeability at low oil saturations (See Appendix A) and the drainage/stripping mechanisms in vertical displacements of waterflood residual oil by CO_2.

Summary and Conclusions

Initially concerns were that an oil bank would not form in the corefloods because oil permeabilities predicted by existing three phase permeability models are zero at low gas and oil saturations. In addition it was speculated that CO_2 would finger through the oil bank because dense CO_2 rich oil forms on contact of residual oil and CO_2.

However, the experimental evidence from the first series of corefloods shows that:

1. Tertiary oil recovery is above 80 percent of the waterflood residual oil at 1.5 PV of CO_2 injected. Oil banks with oil/water ratios greater than 4 form. This would have been impossible if three phase relative permeabilities predicted by existing models were correct near the waterflood residual oil saturations in these cores.

2. While the denser CO_2-rich oil formed by stripping CH_4 at the back of the oil bank could finger into the oil bank, laboratory oil recoveries were not adversely affected by this phenomenon.

3. Stripping caused methane to lag behind the oil as predicted from earlier predictions using compositional simulation.

4. From the composition of the hydrocarbons produced, it is estimated that approximately one-third of the oil recovery results from vaporization in the CO_2.

Discussion

Characteristics of five corefloods presented in this summary are listed in Table 1. Four tertiary displacements and one secondary displacement were conducted in cores from Weeks Island SRB A-17, at 225°F. The cores were either 2 or 2-3/8 inches in diameter, had an unstressed permeability of around 5000 md, and were up to one foot long. All floods but one were conducted at 5000 psig, the approximate reservoir pressure of the Weeks Island SRB reservoir. Methane saturated brine was used to waterflood cores containing recombined oil to S_{or}. Unsaturated brine would have reduced the bubble point of the oil and a large amount of CO_2 would have been soluble in the oil. To minimize viscous fingering into any developing oil bank, frontal advance rates were kept below the stable velocities calculated by Dumore's and Chuoke's methods.

Four tertiary displacements reported in this summary include a miscible displacement of Soltrol by CO_2 (experiment 6 in Table 1), an immiscible displacement of Soltrol by N_2 (experiment 7) and two displacements of recombined Weeks Island crude oil (experiments 10, 11). The immiscible and miscible tertiary displacements of Soltrol are included so that recoveries in the CO_2 displacement of Weeks Island crude can be compared with truly miscible and immiscible displacements.

The desaturation curves in these four experiments are displayed in Figure C-1. Recovery was highest in the tertiary Soltrol/CO_2 coreflood; however, recoveries in the two tertiary displacements of recombined oil, 85 percent at 1.5 pore volumes, were nearly as high. On the other hand, oil recovery of only 38 percent was observed in the tertiary immiscible displacement of Soltrol by N_2.

The production history in the N_2 displacement differed drastically from all displacments of oil by CO_2. The rate of oil desaturation by N_2 displacement quickly decreased (Figure C-1) as the N_2 broke through. This can be contrasted in Figure C-1 to the more steady and continuous desaturations observed in both a miscible CO_2 displacement, experiment 6, and displacements of recombined crude oil by CO_2/CH_4 in experiments 10 and 11. Part of this difference is due to vaporization of oil by CO_2, to be discussed later.

The fractional flows of brine, oil and CO_2 in a tertiary displacement of recombined crude oil, experiment 11, are shown in Figure C-2. It is clear that an efficient oil bank has developed between 0.4 to 0.8 movable pore volumes of CO_2 injected. This result is not consistent with what one might expect from the commonly accepted three-phase oil relative permeability models of Stone and Hirasaki as applied to the present problem (see Figure C-3 and Appendix A). The present experimental observations are more consistent with the three-phase relative permeability data obtained using the centrifuge technique (see Appendix B).

Figure C-2 also shows that small amounts of CO_2 penetrate into the oil bank. Calculations presented later in the discussion of stripping and vaporization show that the CO_2 produced before 0.8 pore volumes was dissolved in the oil under the reservoir conditions. The penetration of CO_2 into the oil phase happens because the CO_2 rich oil which forms upon contact with the original oil is denser than the oil below it. We commonly observe an increase in density, because of nonideal mixing, when CO_2 is added to an oil above its bubble point. If the oil is at its bubble point, replacement of methane by CO_2 will certainly result in a denser oil. In our experiments, and at Weeks Island, this denser oil is formed above the original lighter oil. The situation is not stable and fingers form.

The effect is most pronounced in the secondary displacement, experiment 2. The early breakthrough of CO_2 observed during a secondary displacement of Soltrol in a 4900 md core, experiment 2, is shown in Figure C-4. The specific gravity of mixtures of Soltrol and CO_2 is as high as 0.89 at 225°F and 5000 psig. Yet, the specific gravity of Soltrol and CO_2 are only 0.77 and 0.68 at the same conditions. The CO_2/Soltrol solution fingers down through the core since it is heavier than Soltrol.

Stripping of the oil should be an important phenomenon in displacements of light oil such as the Weeks Island crude. One way that this stripping is observed is the higher methane to stock tank oil ratio (Figure C-5) found after CO_2 breakthrough. This results when the dense CO_2-rich injection gas replaces the light methane rich gas vaporized from the oil by contact with CO_2. The circulation cell that results is a major part of the mechanism of oil recovery reported by Hite[1] in his simulations of the Weeks Island CO_2 flood. Other investigators[8-11] have reported that a methane bank leads the front. These results are consistent, since the earlier core floods were all in horizontal cores or with flood rates so high that methane rich light gas released at the displacement front could not rise and disperse behind the front.

Another way in which stripping becomes evident is the change in color and composition of the stock tank oil produced during the experiment. The change in composition is summarized in Figure C-6, where the normalized composition determined by true boiling point gas liquid chromatography of the liquids produced is displayed. Molecules smaller than C_{20} appear to be preferentially stripped from the core. After 1.9 pore volumes of CO_2 injection the core contains virtually no fractions smaller than C_{10}. In another experiment no fractions smaller than C_{18} remained after 2.5 PV.

The composition, volume and density of liquid samples and the volume and composition of the gas produced are known. From this the average composition of any sample can be computed. Using a phase equilibria computer program, the fraction of liquid and vapor flowing at any time can be computed. The calculations show that nonaqueous components form a single phase for CO_2 fractional flows below 20 percent. Above 80 percent fractional flow of CO_2, all liquids are produced by vaporization. This is shown in Figure C-7. The area between the curves corresponds to production of about 65 percent of the hydrocarbons by drainage and the remainder by vaporization.

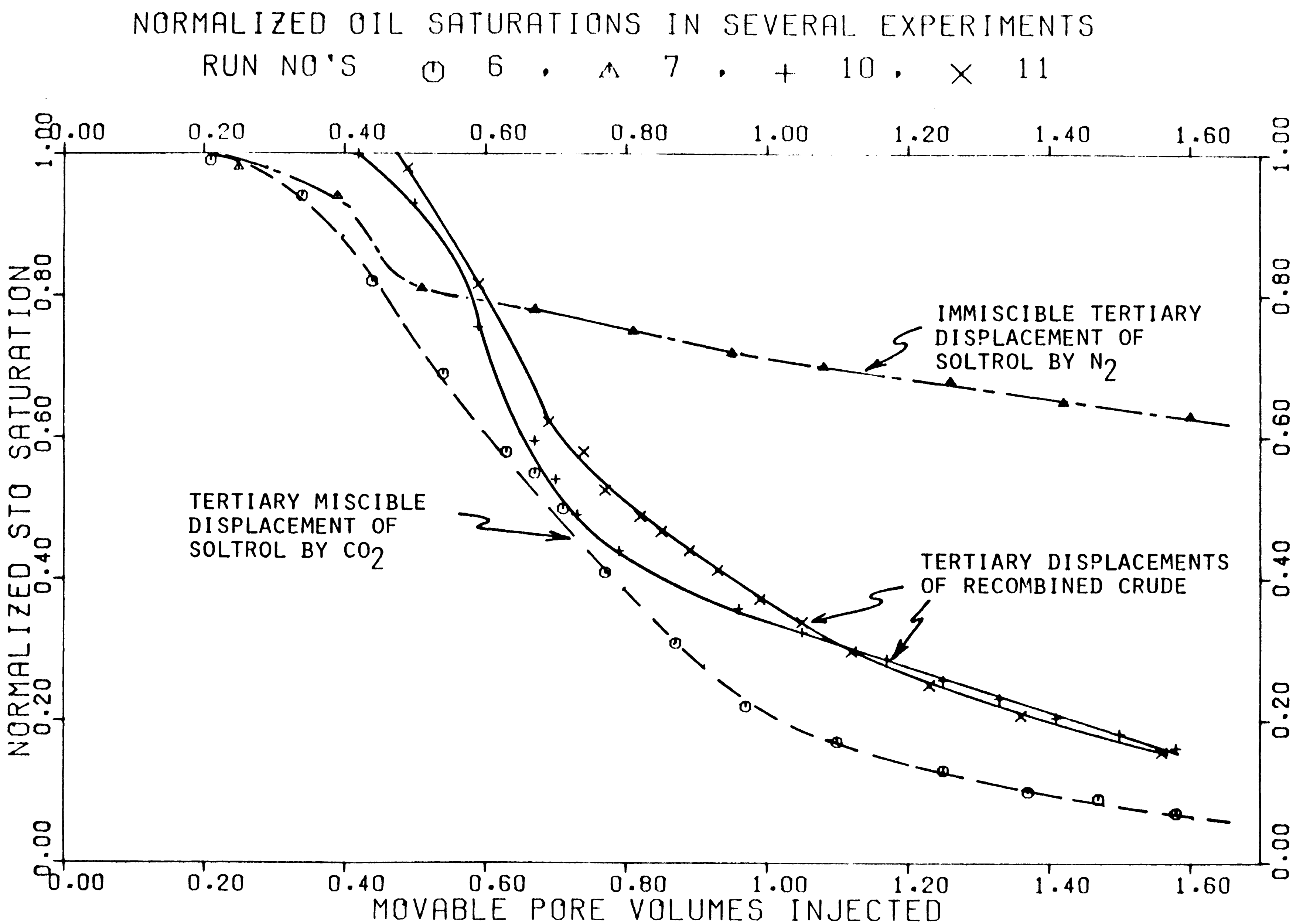

Fig. C-1 - Normalized oil saturations for miscible and immiscible displacements

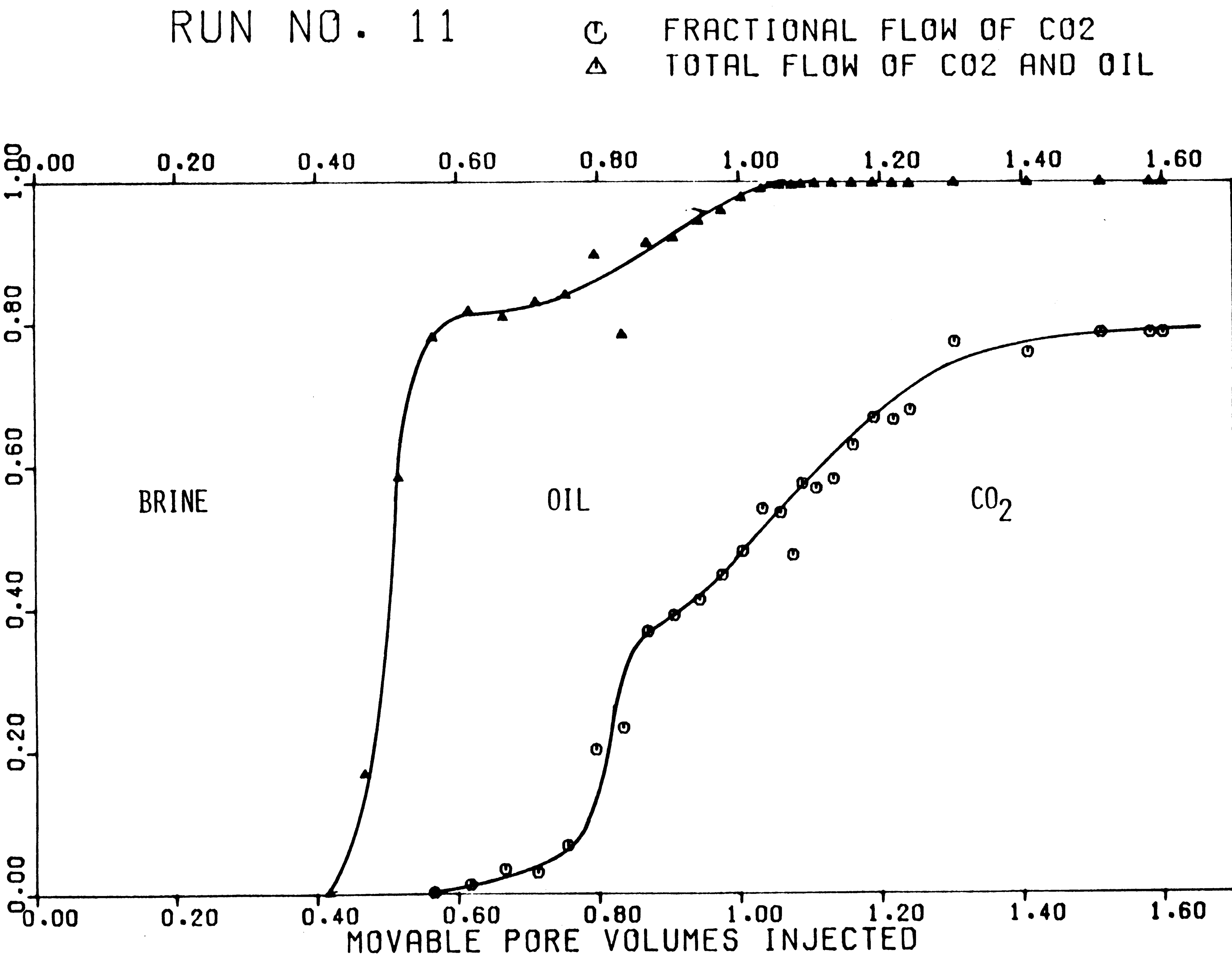

Fig. C-2 - Fractional flows in a tertiary displacement of recombined Weeks Island SRA crude by CO_2

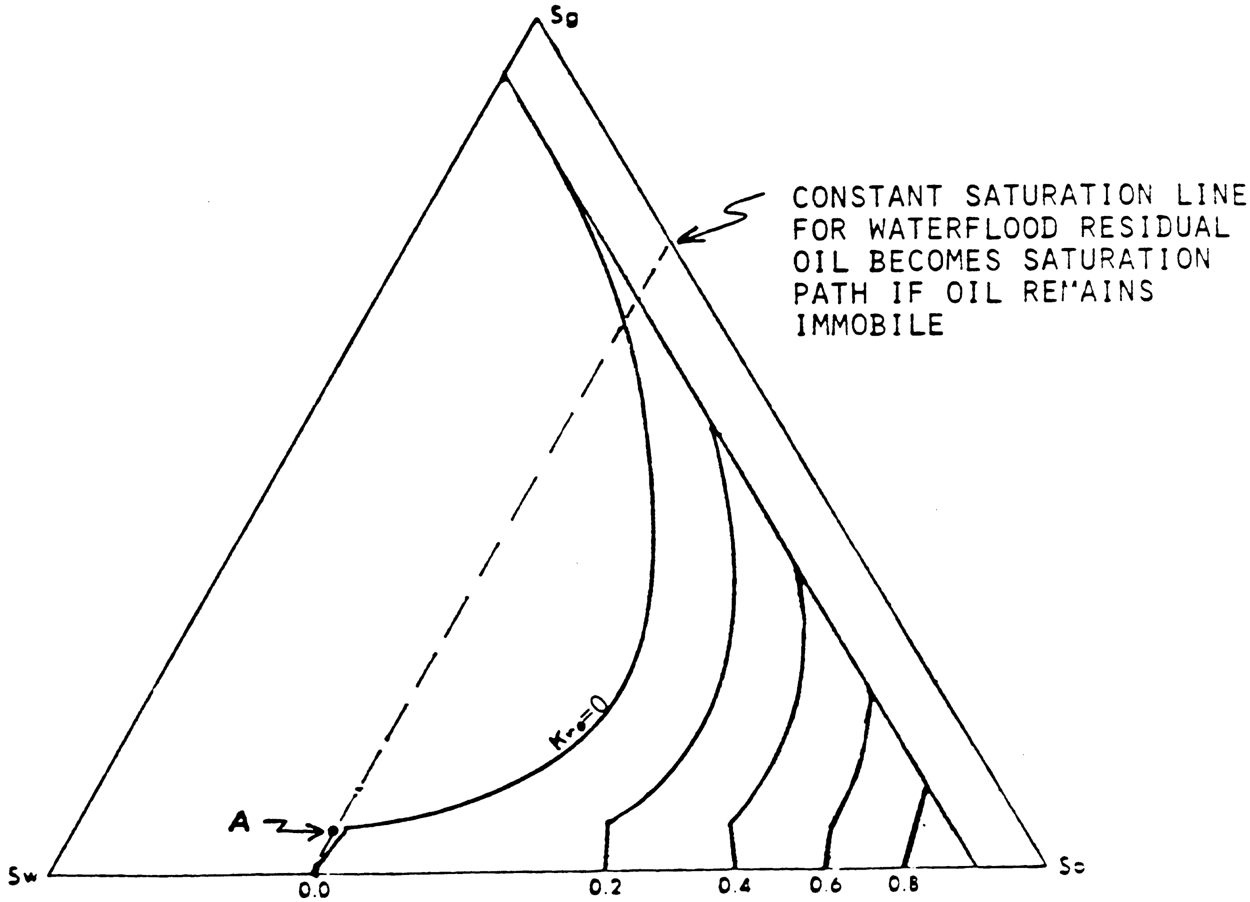

Fig. C-3 - Oil phase relative permeabilities
estimated from Stone's model (See Appendix A)

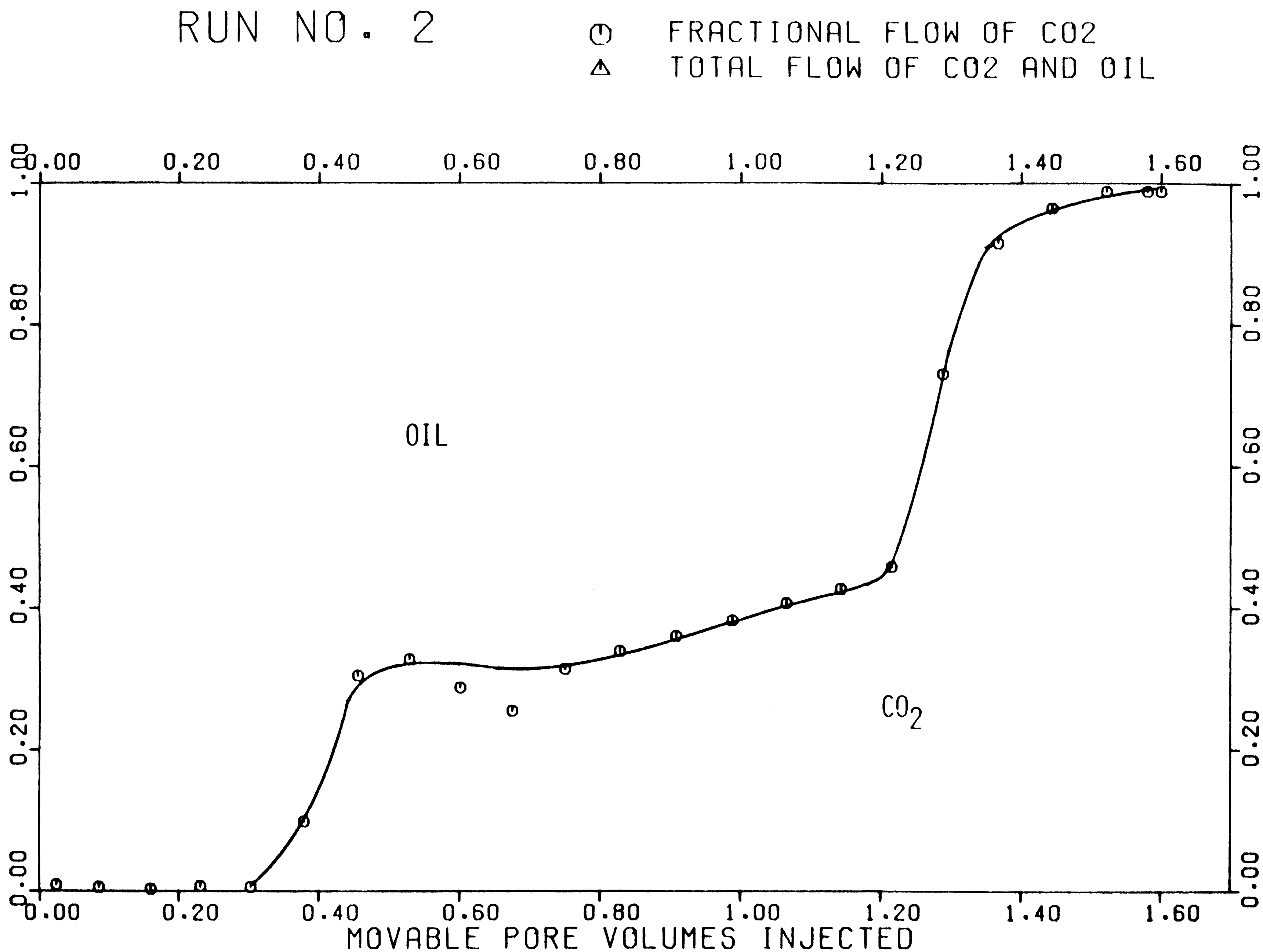

Fig. C-4 - Early breakthrough of CO_2 caused by volume decrease in mixing of Soltrol and CO_2

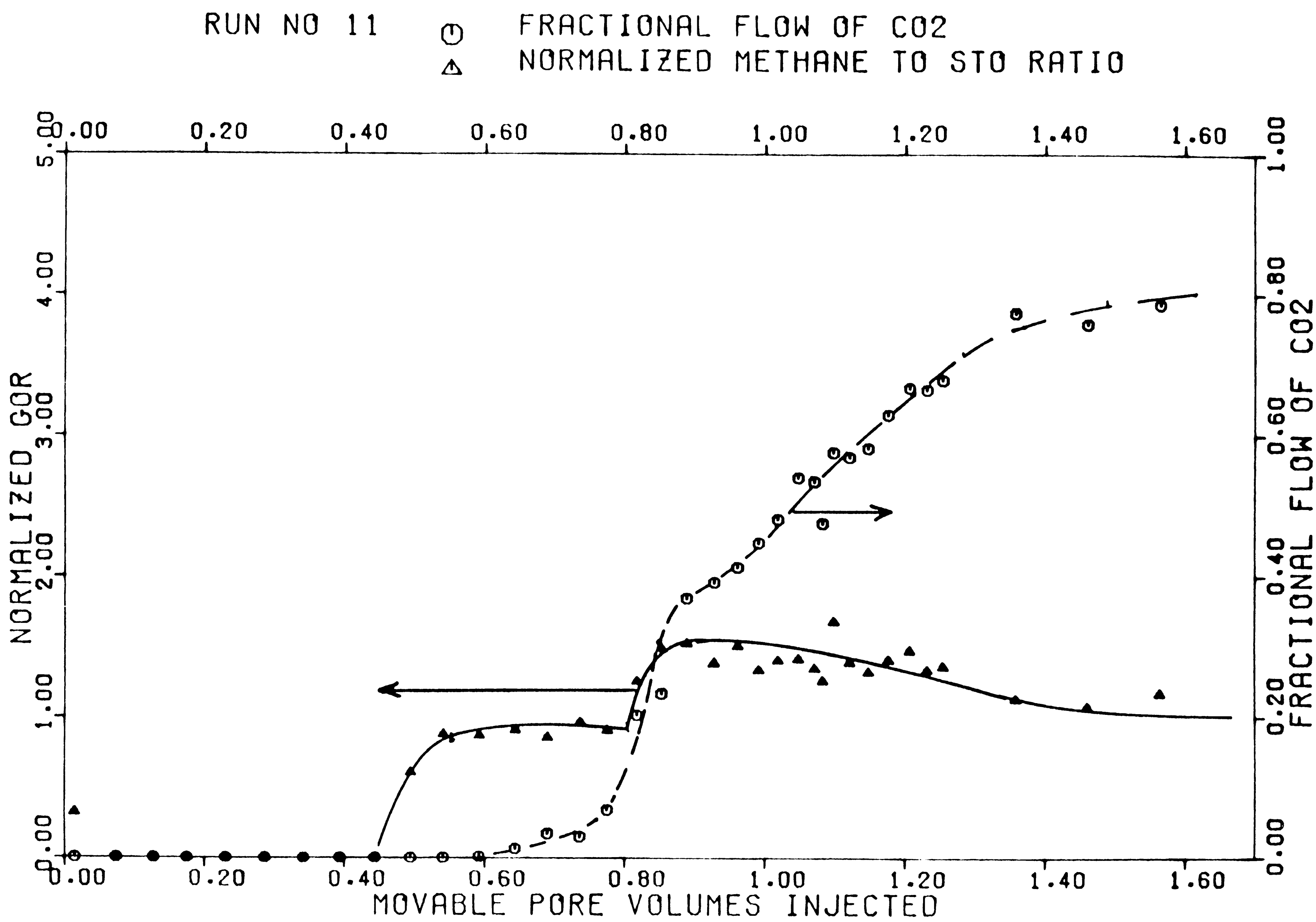

Fig. C-5 - Comparison of methane to oil ratio and fractional flow of CO_2

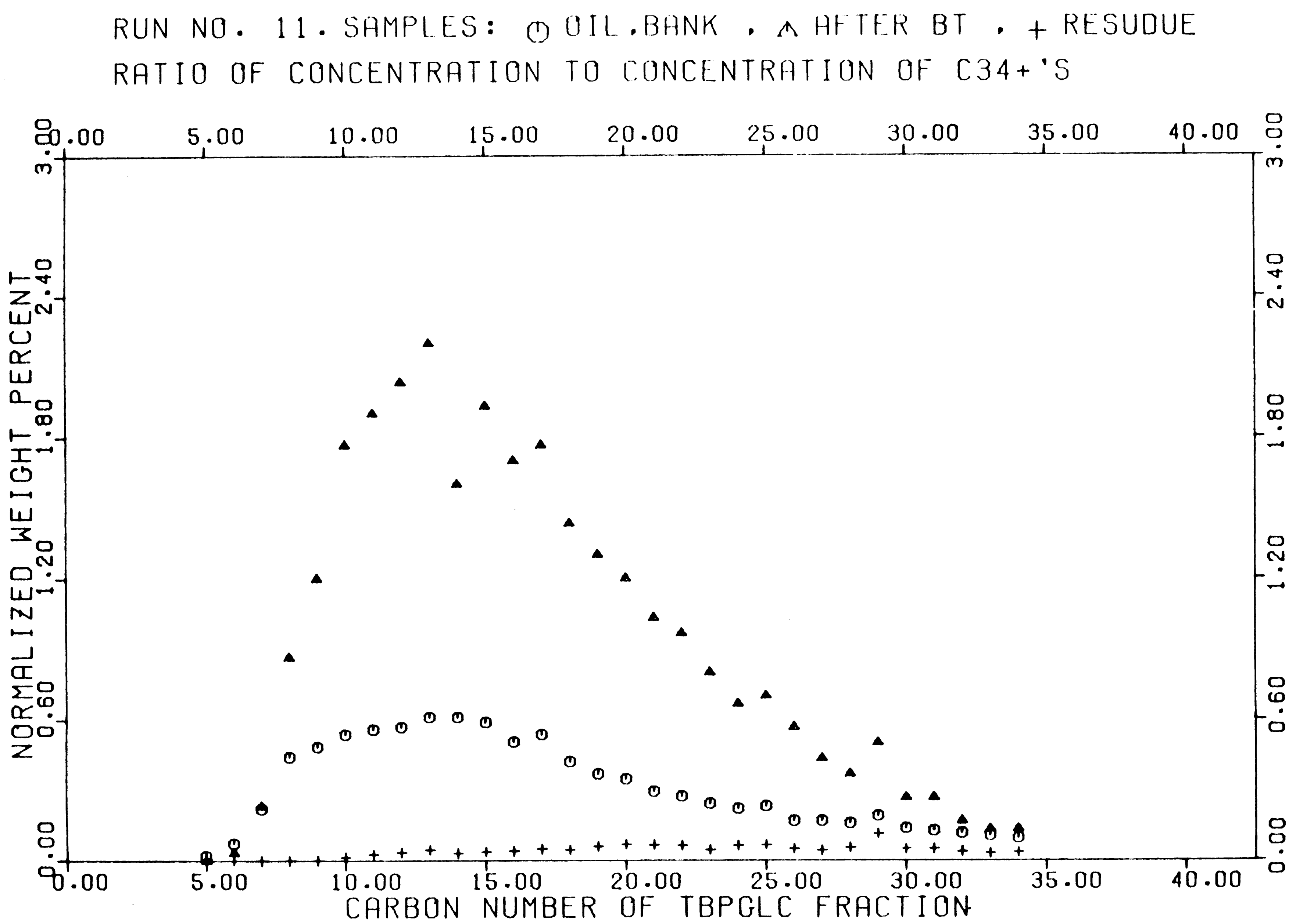

Fig. C-6 – Changes in composition of stock tank oil samples in Experiment 11 with increased CO_2 injection

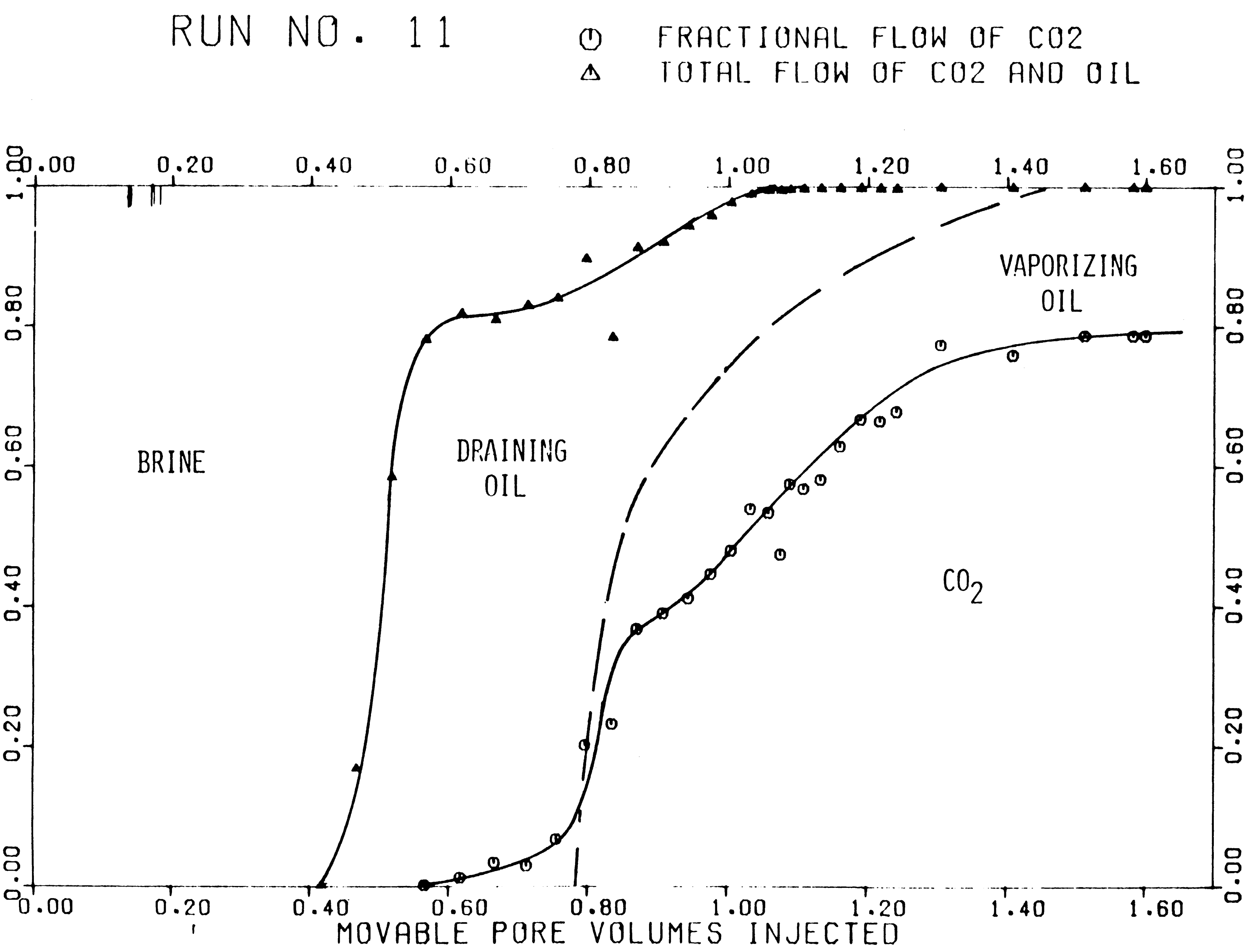

Fig. C-7- Calculated flowing fractions on nonaqueous phases in Experiment No. 11

Table 1

SUMMARY OF EXPERIMENTAL DATA*

Experiment No.	Oil Type	Oil Bubble Point	SOI	Displacement Fluid Pressure	Dimensions, in. Diameter	Length	$\Delta\rho$ g/cc	CO_2 BT-PV	% Recovery @ 1 PV	@ 1.5 PV	Displacement Type
11	Recombined Oil Batch 2	5000	31.5	CO_2/CH_4 5000	2-3/8	12.0	0.03	0.61	65	85	Tertiary Recombined Oil
10	Recombined Oil Batch 1	4000	31.5	CO_2/CH_4 4000	2	11.0	0.10	0.70	65	85	Tertiary Recombined Oil
6	Soltrol	--	28.5	CO_2 5000	2	8.3	0.09	0.40	80	92	Tertiary Miscible
2	Soltrol	--	100.0	CO_2 5000	2	8.3	0.09	0.38	80	95	Secondary Miscible
7	Soltrol	--	28.3	N_2 5000	2	8.3	0.52	0.45	32	38	Tertiary Immiscible

* All corefloods were vertical displacements of oil down by supercritical fluid at 225°F. Calculated velocities were between 0.5 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.

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