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

Second Annual Report, June 1978-June 1979

Date Published—November 1979

Work Performed for the Department of Energy
Under Contract EF-77-C-05-5232

Shell Oil Company
Houston, Texas



**National Petroleum Technology Office
U.S. DEPARTMENT OF ENERGY
Tulsa, Oklahoma**

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IBERIA PARISH, LOUISIANA**

Second Annual Report, June 1978-June 1979

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U.S. DEPARTMENT OF ENERGY

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

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PURPOSE AND SCOPE

The "S" sand Reservoir B CO₂ pilot was designed to demonstrate the feasibility of a downward CO₂ displacement in a steeply dipping, high temperature and 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 Weeks Island Field have an estimated tertiary potential of 26 million barrels of oil which could be recovered by a CO₂ displacement.

Reservoirs of this type are not suitable for surfactant flooding as the temperatures and water salinities are too high for currently available chemical systems; while the depth, and unusually good oil mobilities preclude any additional recovery by thermal stimulation. The major reservoirs in the Weeks Island Field have high permeabilities such that if the CO₂ were injected down-dip, the CO₂ would tend to float to the top of the watered-out reservoirs. This is because the viscous forces are small when compared to gravity forces. The downward CO₂ displacement is designed to utilize gravity forces to stabilize the displacement and increase the sweep efficiency of the injected CO₂.

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 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 freshwater. 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.

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 pre-flood completion in Weeks Island A-16-A, which was located at a subsea depth of -12,777 to 12,878. The production of Weeks Island State Unit A-16 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.

SECOND-YEAR OBJECTIVES

In the second year of the project, we had planned to initiate the Phase II (CO₂ injection) portion of the project. The original Phase II objectives of the project were to inject a 50,000-ton slug of CO₂ and to monitor the displacement with logging observations in the new well as the slug was displaced by downdip water production.

Although the Phase I sand pack displacement experiments indicated it could be possible to recover a substantial portion of the residual oil saturation, the sand pack displacements and phase behavior experiments indicated the displacement would be initially immiscible and could remain immiscible. As a result of the Phase I work, Shell recommended that the natural gas dilution of the CO₂ slug be reduced to 5 percent from the initially proposed 15 percent.

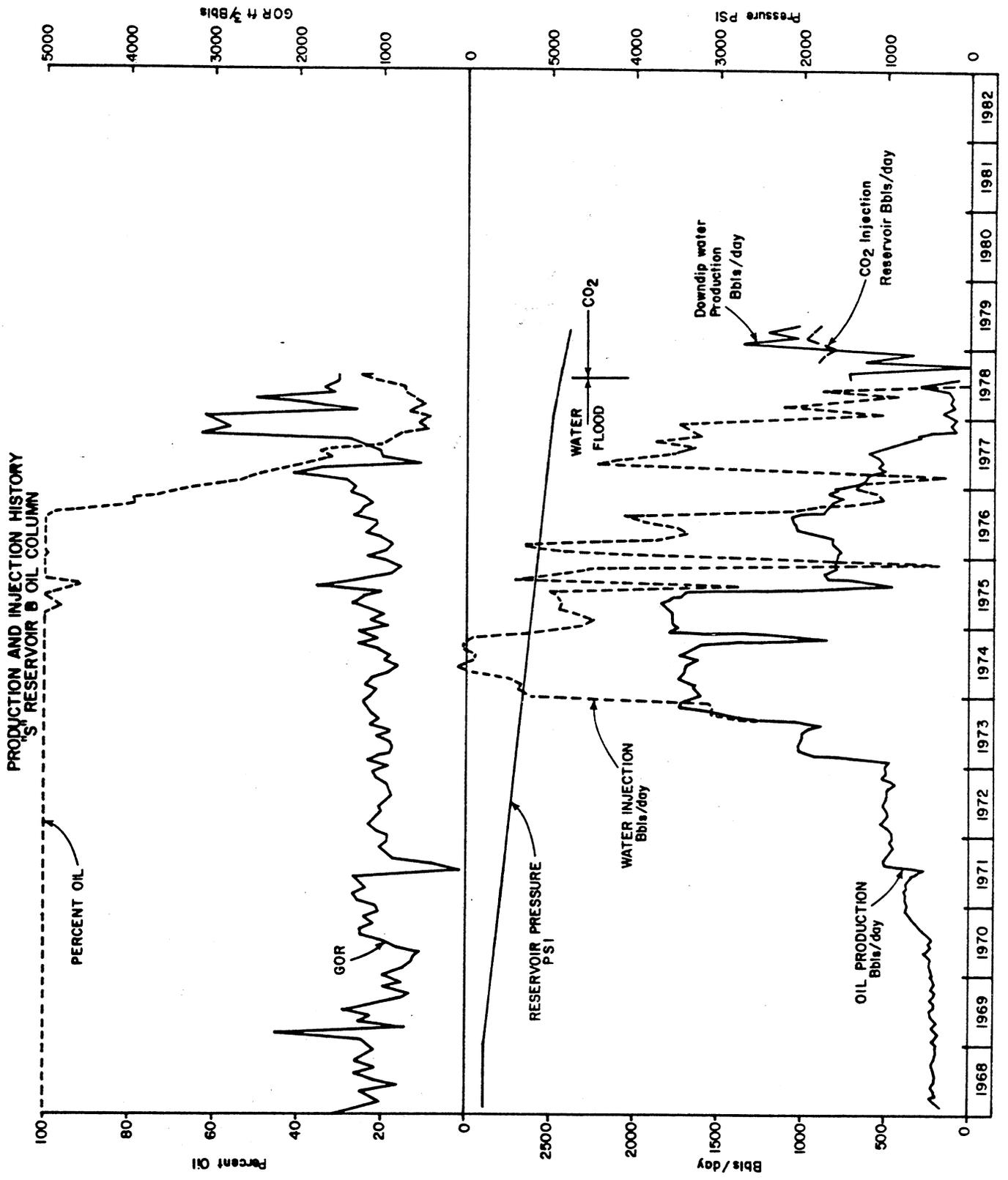


FIGURE 2

Since the process would involve the flow of both the gaseous and liquid nonaqueous phases, it was recommended that reservoir models be constructed which would include the observed compositional behavior of the fluids at reservoir conditions. To obtain samples of the displaced fluids, it was also recommended that the log-inject-log perforations located 48 feet below the level of CO₂ injection be left open and periodically sampled. Shell also proposed that² the frequency of the logging observations be increased.

SECOND YEAR RESULTS

CO₂ INJECTION

The project will displace approximately 900 acre feet of the reservoir which is illustrated as 120-foot vertical displacement interval on the Figure 1 cross section. A 50,000-ton slug of CO₂ is being injected into Weeks Island State Unit A-16-A at a position just above the producing gas-oil contact. The density of the injected CO₂ is being 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 reduces 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 is being created by the production of the down dip 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 period which preceded the CO₂ injection. Daily injection volumes and pressures are illustrated on Figure 3.

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.

INJECTION HISTORY
GRAVITY STABLE MISCIBLE CO₂ DISPLACEMENT
"S" SAND RES. B - WEEKS ISLAND FIELD

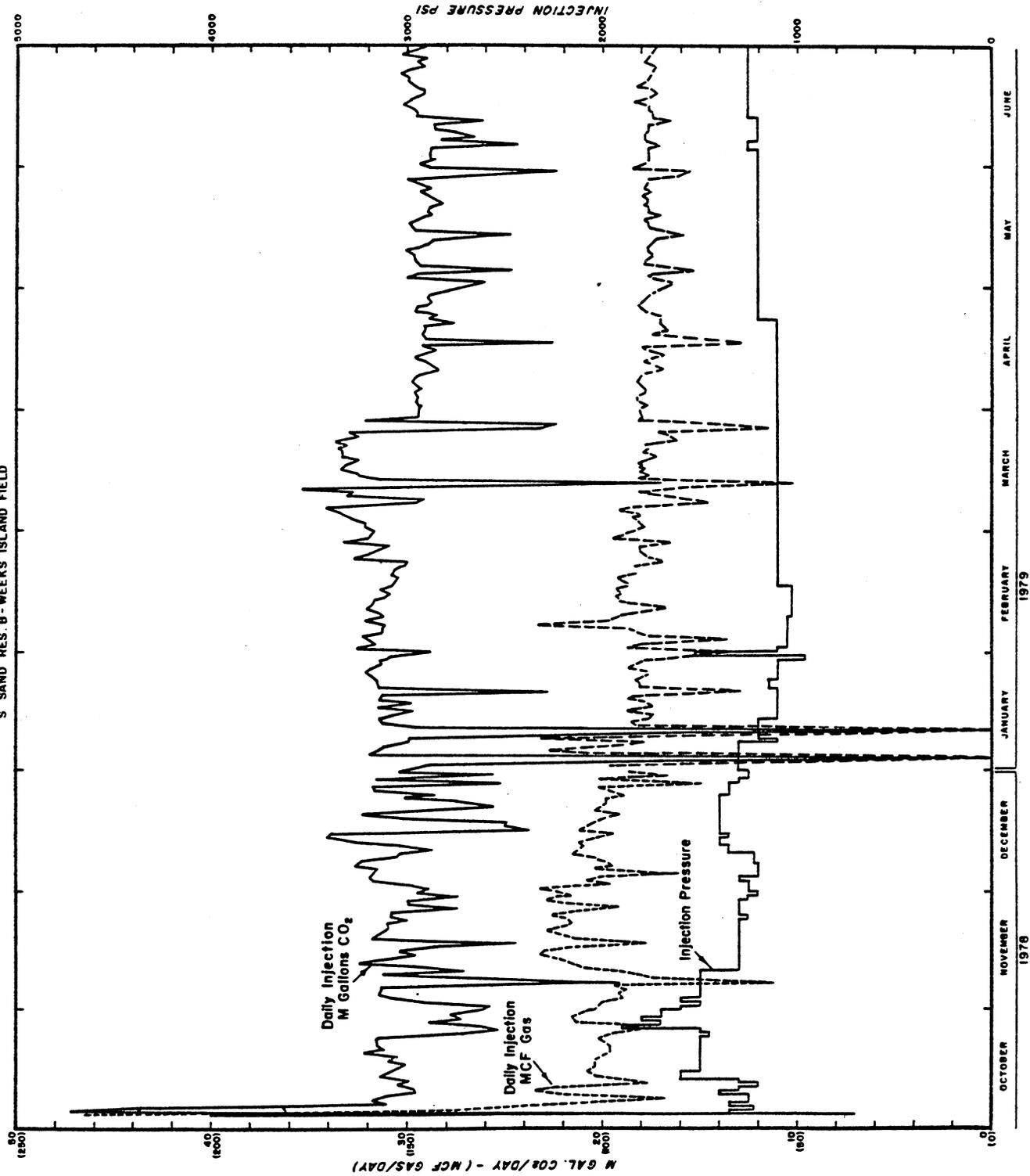
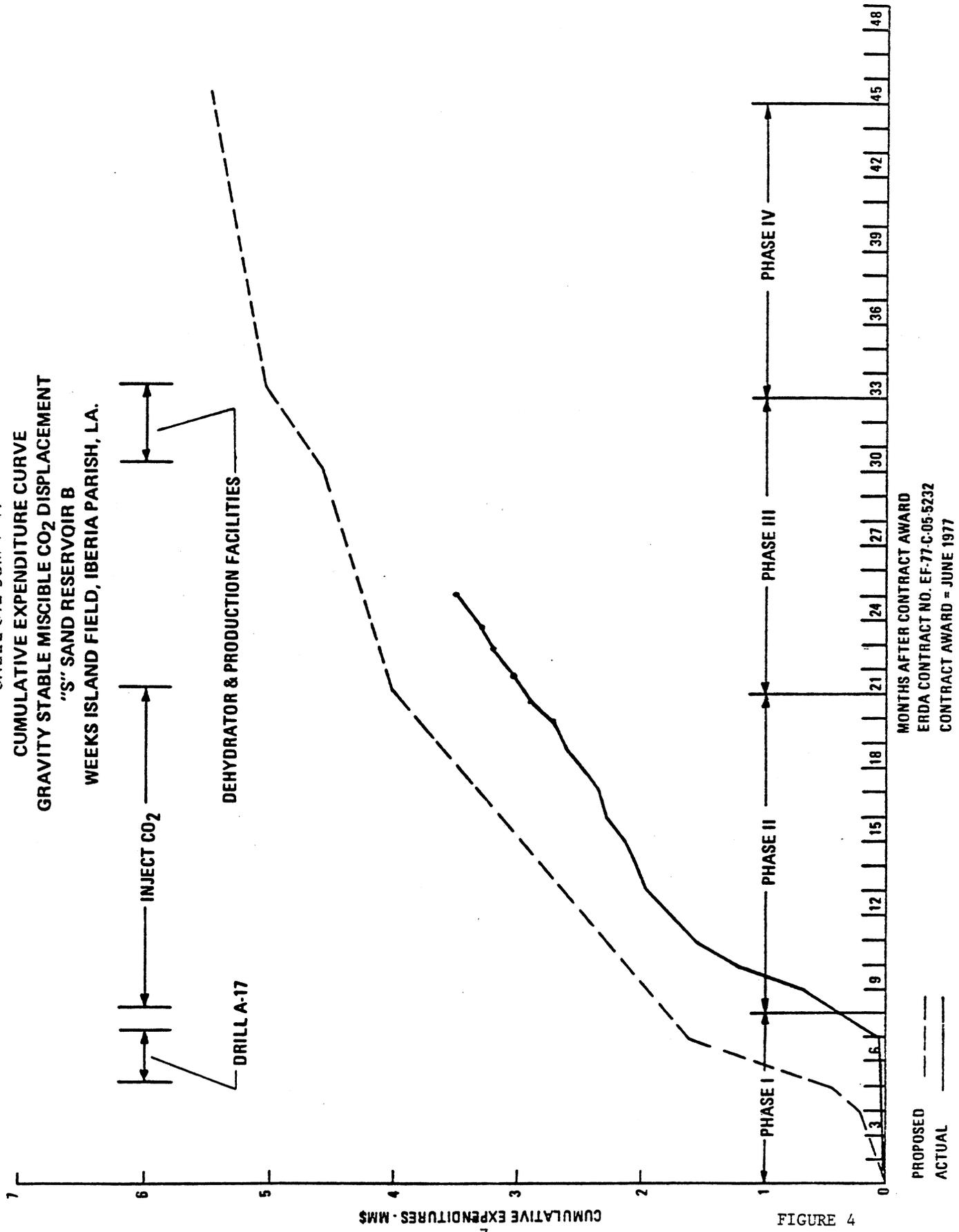


FIGURE 3

SMALL COMPANY
CUMULATIVE EXPENDITURE CURVE
GRAVITY STABLE MISCIBLE CO₂ DISPLACEMENT
"S" SAND RESERVOIR B
WEEKS ISLAND FIELD, IBERIA PARISH, LA.



MONTHS AFTER CONTRACT AWARD
 ERDA CONTRACT NO. EF-77-C-05-5232
 CONTRACT AWARD = JUNE 1977

PROPOSED (---)
 ACTUAL (—)

FIGURE 4

CUMULATIVE EXPENDITURES - MM\$

With the exception of minor interruptions in the CO₂ supply and short maintenance shut down of the injection plant, continuous CO₂ injection has been maintained at an average rate of 107 tons per day. At the present rate of injection Phase II (CO₂ injection) will be extended by approximately two months. Injection of the 50,000-ton CO₂ slug should be completed on or about the first of 1980.

The injection rate is limited only by the plunger size in the constant speed injection pump. We have not proposed the purchase of new plungers because a smooth operating balance has been established between the CO₂ injection system and the CO₂ supply which must be trucked 135 miles.

DOWNDIP WATER PRODUCTION

The additional gravity head created by the production of un-anticipated 280,000 part ppm salt water limited the initial gas lift capacity of the downdip well Smith State Unit G-2 to approximately 800 barrels per day. During late November and early December 1978, the nominal 2" downhole tubing in the well was replaced with nominal 2 1/2" tubing which increased the gas lift capacity of the well to 1,500 barrels per day.

The production rate of the downdip well is now restricted to approximately 1,000 barrels per day to match the rate of CO₂ slug injection and maintain the top of the CO₂ slug in the vicinity of the injection perforations. However, the additional producing capacity of the downdip well will allow us to increase the displacement rate to 1,500 barrels per day after the CO₂ slug has been injected.

LOGGING PROCEDURES USED TO MONITOR FLOOD FRONT

In monitoring the Weeks Island SRB, we are attempting to observe two things:

- (1) The movement of the CO₂ front down through the reservoir.
- (2) The movement of the oil bank ahead of the CO₂.

We felt that the neutron porosity device would be an excellent monitoring tool to detect the movement of the CO₂, since CO₂ should significantly reduce the apparent porosity reading. The neutron log responds directly as a function of the Hydrogen Index of the formation. The neutron response porosity equation may be expressed as follows:

$$\phi_N = \phi(H_w S_{wo} + H_h S_h + H_{CO_2} S_{CO_2}) \quad (1)$$

where ϕ_N = Neutron apparent porosity

H_w = Hydrogen index of the water in zone of investigation of the neutron tool

H_{CO_2} = Hydrogen index of the CO_2

H_h = Hydrogen index of the hydrocarbon

S_h = Hydrocarbon Saturation

S_{X^o} = Water Saturation in zone of investigation of the neutron tool

S_{CO_2} = CO_2 Saturation

Via personal communication between Shell's Bellaire Research Center and Dr. L. L. Raymer of the Schlumberger-Doll Research Center, it was suggested that a value of 0.0 be used as the Hydrogen Index of CO_2 . Therefore, as can be shown from equation (1), a CO_2 saturation causes a much lower apparent neutron porosity. (Modeling studies done by Dr. Raymer show that 100% CO_2 saturation at a density of 1 g/cc would result in a compensated neutron porosity of a negative 2-3 porosity percent.)

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 this data was insufficient to add to the interpretation derived from the pulsed neutron log. Thus far, four monitor runs have been made since December 1978. Plans are to continue frequent monitoring through the remainder of 1979.

The pulsed neutron log records a time value indicating the rate of decay of thermal neutrons in the formation. This decay is a function of the capture cross section (Σ) of the formation. The capture cross section recorded by the tool may be expressed by the following simplified equation in terms of formation properties:

$$\Sigma_{Log} = \Sigma_{ma} (1-\phi) + S_w \Sigma_w \phi + (1-S_w) \Sigma_h \phi + K \quad (2)$$

where Σ_{LOG} = Capture Cross Section Recorded by Logging Device

Σ_{ma} = Capture Cross Section of the Matrix

- Σ_w = Capture Cross Section of the water
- ϕ = Porosity
- S_w = Water Saturation
- Σ_h = Capture Cross Section of the hydrocarbon
- K = Diffusion Correction

The capture cross section for oil typically runs between 20-22 units, or about the same as freshwater. Hydrocarbon gas typically runs between 8-12 units but may vary considerably due to temperature, pressure, and composition. The capture cross section for water varies greatly with salinity and runs between 20 units for freshwater to approximately 130 units for salt saturated brines.

Present day pulsed neutron logs are equipped with 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. (1) Unlike a normal compensated neutron, since it is responding 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 pseudo neutron porosity curve can be produced. Figure 5 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.

An estimate of the CO₂ saturation can be derived from the neutron response equations. An equivalent saturation based on hydrogen indices can be calculated from the following:

$$S_{wH} = (S_{\chi_o} H_w) + (H_h S_h) + H_{CO_2} S_{CO_2} \quad (3)$$

Using this equation in conjunction with equation (1) and solving these equations simultaneously with the equation for the "excavation effect" provided by Segesman and Liu (2), an estimate of CO₂ saturation can be calculated.

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

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

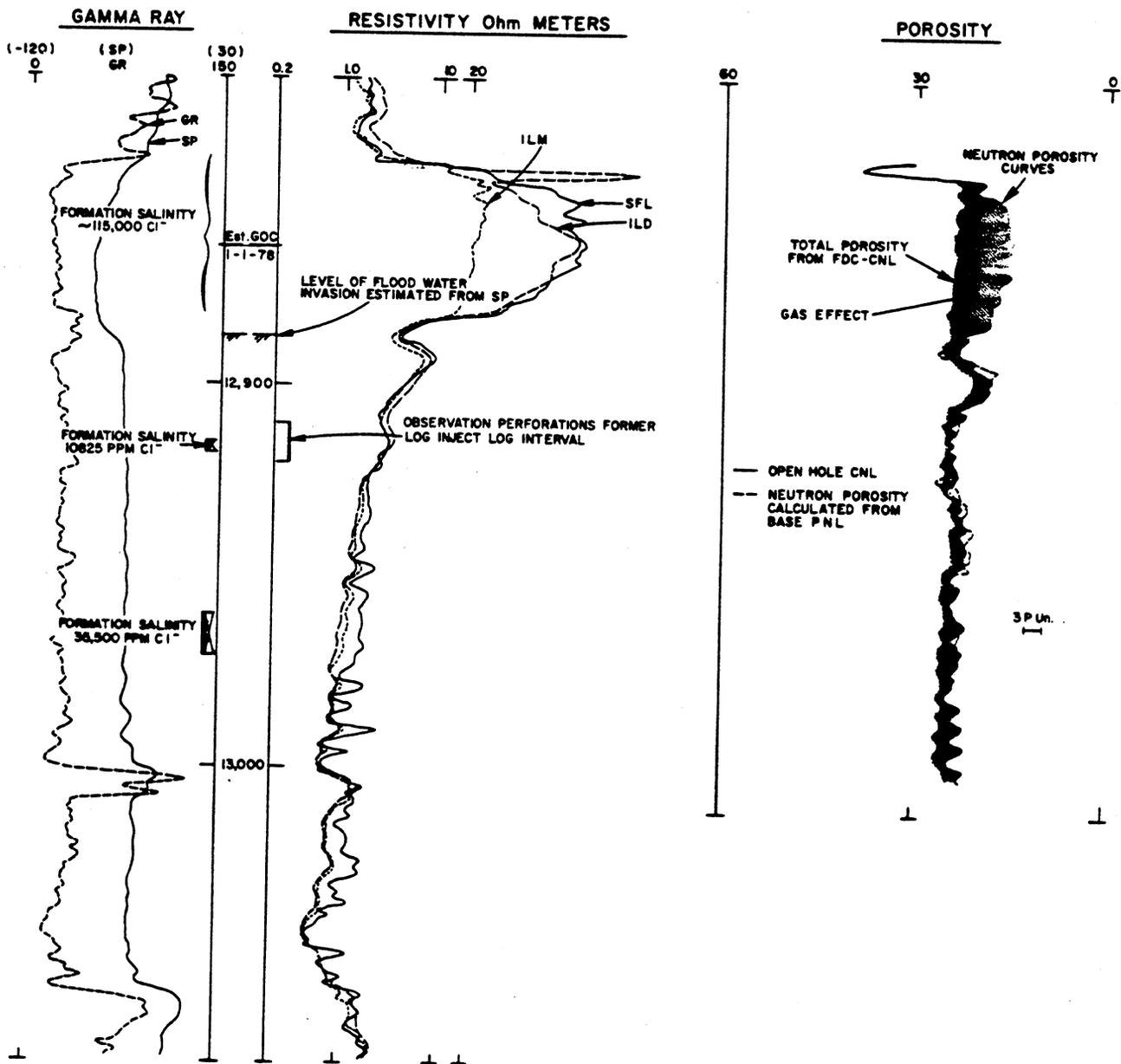


FIGURE 5

water. However, as discussed in last year's report, freshwater was used in the SRB waterflood unit. As a result, we see a wide variation in salinity in the observation well with the water near the present day oil-water contact expected to be virtually fresh. Early movement of the oil bank is not easily discernable since the oil and water have similar capture cross sections. As the oil bank moves lower in the interval where the water becomes salty, we may be able to monitor the oil movement with the capture cross section curve. Present devices capable of discerning the differences between oil and freshwater such as the Carbon/Oxygen Log⁽³⁾ can not be run through tubing.

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 displaced the oil column at this location. An April 1979 production test of the observation perforations, 28 feet below the CO₂ level indicated by the log analysis, shows that oil is resaturating the previously watered-out sand.

As illustrated by the porosity curves computed from the pulsed neutron logs in Figure 6, the December 20, 1978 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 has invaded the oil column down to the lower quality sand interval from 12,882 to 12,888. No downward movement of CO₂ was detected between February and April.

The column of CO₂ logged in Weeks Island State Unit A-17 indicates the injected CO₂ was concentrated at this location and had not spread uniformly over the gas-oil contact. The February 21, 1979 logs indicated CO₂ 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 CO₂ 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 CO₂ concentration of 25 percent. Over much of this interval, the neutron porosity is 0.0% (actual porosity is 25%). The minimum CO₂ saturation necessary to produce this apparent porosity is greater than 65%. The bell shape of the neutron porosity (the apparent decrease of neutron porosity with depth) computed from the April 1979 log is an indication that the CO₂ saturation is decreasing in the upper portion of the sand at the Weeks Island State Unit A-17 location. Possible reasons for the decrease in CO₂ concentration could be spreading of the CO₂ or additional

NEUTRON POROSITY MONITORING OF CO₂ FLOOD FRONT MOVEMENT

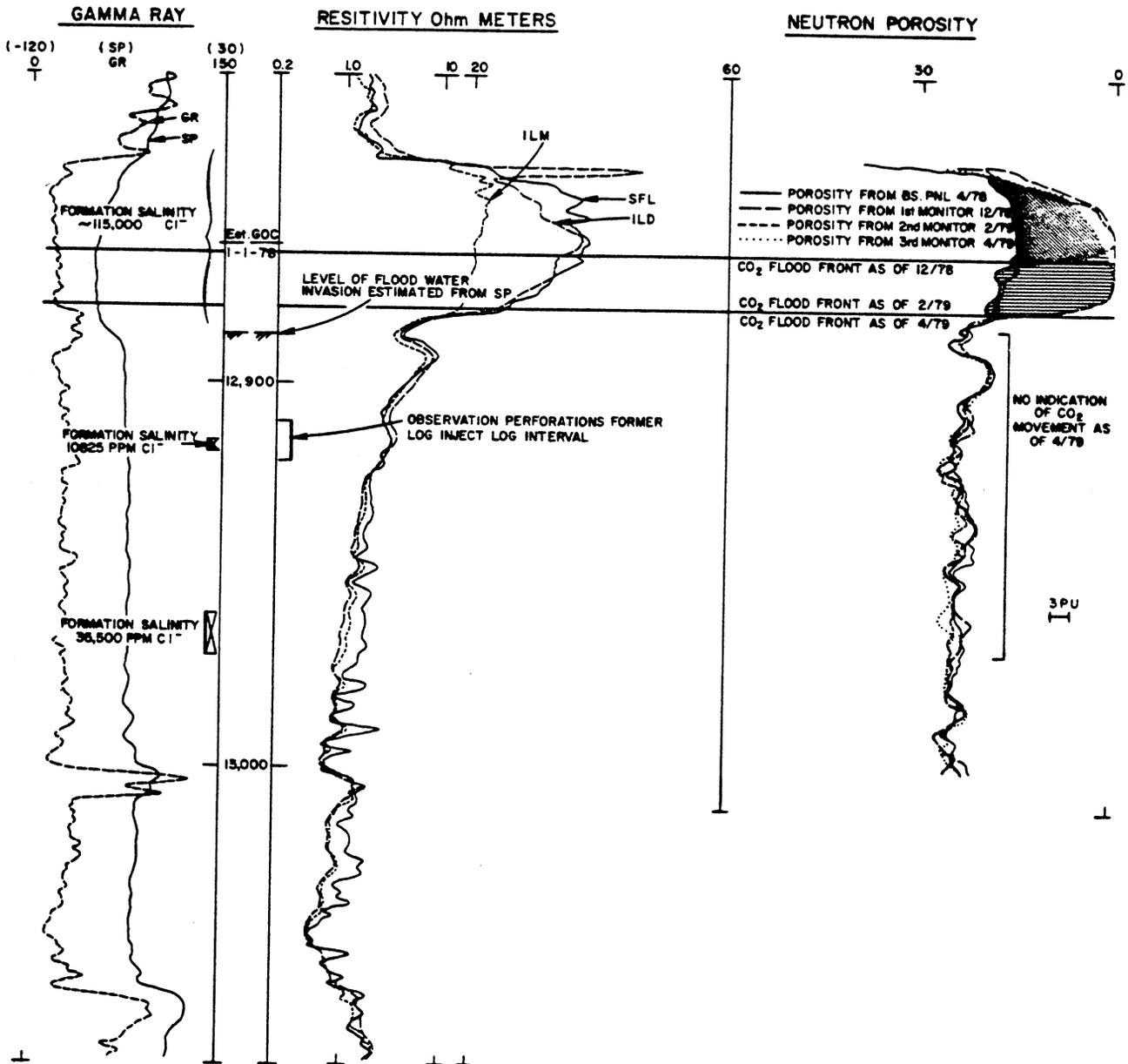


FIGURE 6

downdip displacement of the CO₂ above the poor porosity interval. Unfortunately, this poorly developed sand in the 12,882- to 12,888-foot interval of the observation well has obscured the movement of CO₂ in the vicinity of the observation well. We therefore cannot see the leading edge CO₂ column. We expect to see the base of the CO₂ column below the poor porosity interval as the displacement, evidenced by the oil production from the deeper observation perforations, proceeds further.

The observation perforations which are located at a well depth interval from 12,910 feet to 12,920 feet are 21 feet lower than the water level logged when the well was drilled in December 1977. During a 6-hour test of the perforated interval on May 2, 1979, the well flowed 17 barrels of oil and 32 barrels of load water. A pressure gradient survey after the production test indicated that the tubing was essentially filled with oil and the interval had produced little or no water. A chromatographic analysis measured normal preinjection CO₂ content of one percent in the gas produced with the oil. The oil was detected as preparations were being made to swab the well for an indication of hydrocarbons. The 250,000 barrels of water produced through mid-April should have resulted in the resaturation of the watered-out sand in the interval of the observation perforations.

As expected, initial detection of the oil movement in the previously watered-out sand with pulsed neutron logs has been extremely subtle at best; this is due to the low salinity water at the oil-water contact. Figure 7, which compares the capture cross section between the base log and the last monitor run, gives some indication that oil or freshwater is being pushed down into the saltier interval below 12,920.

RESERVOIR MODELING

During the second contract year, Shell's Bellaire Research Center (BRC) worked on the construction of a reservoir simulator which includes the effect of compositional behavior of the S Sand Reservoir B crude oil as it is contacted by CO₂ slug material. Results of this work are reported in Attachment 1.

PHASE BEHAVIOR

When the Weeks Island S Reservoir B gas saturated crude oil is contacted by the CO₂ slug, gaseous and liquid nonaqueous phases are formed. (5) To define the composition, volume, density and viscosity properties of each phase needed for the modeling, an S Reservoir B crude oil sample was multiply contacted with the prepared mixture of the CO₂ and natural gas which represents the slug material. The phase package of the mathematical model is now being adjusted to obtain a fit with the experimental data. Although the simulator

CAPTURE CROSS SECTION CHANGE DUE TO CO₂ INJECTION

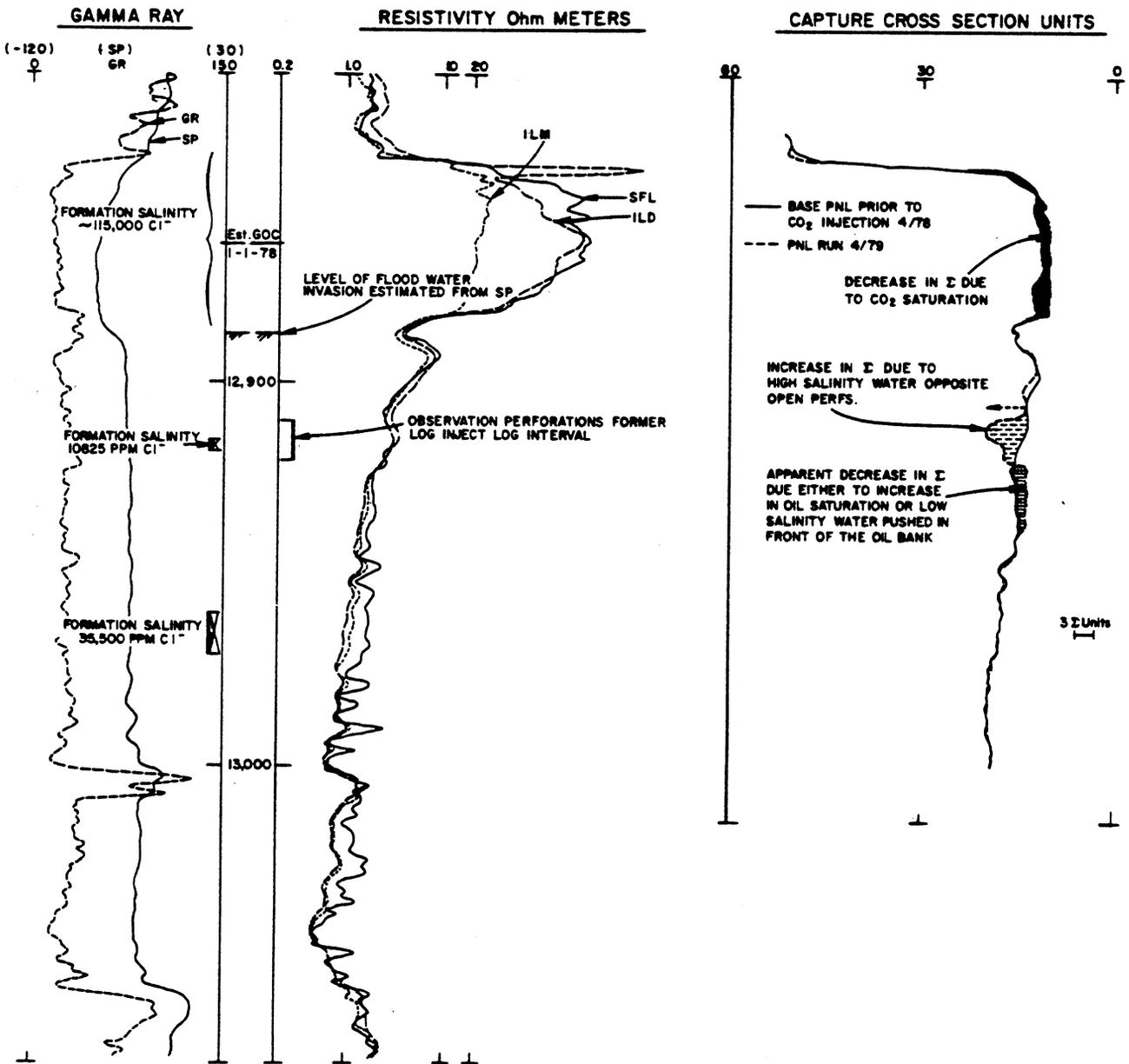


FIGURE 7

must be restricted in the number of components and the experiments represent only one of many possible paths of change in the total composition, tuning the model phase package to this changing compositional experiment does increase our confidence in the validity of the phase package.

PROCESS MECHANISMS

BRC has input into Shell's compositional simulator (COMPOSIM), the observed compositional behavior of the fluids in the S sand Reservoir B CO₂ displacement. The resulting simulator has been used to model a simplified representation of the S Reservoir B geometry with a phase behavior package which is used to represent the single contact CO₂-crude oil phase behavior. The simulations show circulation in the gas phase and slumping of the CO₂ close to the injection well. Although the output of this model does provide an insight into the forces that work in the process, the present output cannot be considered to be an accurate prediction of the process. The sensitivity to reservoir description and other factors such as the relative permeability of the gas, oil and water phases as a function of the phase saturation have not been tested and may prove to have a significant affect on the results. The simulation effort of BRC is now being directed towards the incorporation of the multi-phase contact data into the model and speeding up the model by reducing the number of components used in the calculation. These changes should increase our confidence in the phase behavior calculations of the model and enable us to test the sensitivity to such factors as the relative permeabilities of each phase and the reservoir geometry.

Complete development of a model to simulate the complex process, may require field experience and/or laboratory experiments at reservoir conditions. As an example, in a simulator, the three-phase relative permeabilities control the relative flow rates of the gas, oil, and water phases. As such, relative permeabilities influence on the quantities of gas and oil exposed to phase equilibrium. Moreover, as reported by James K. Dietrich and Paul L. Bondor⁽⁴⁾, the published data on measurements of three-phase relative permeabilities indicate the measurements are difficult and uncertain.

In an effort to verify and/or tune the simulator, we are presently investigating the possibility of a residual oil measurement after the CO₂ front passes the present observation perforations in Weeks Island State Unit A-17. Shell has also ordered equipment which may make it possible to flood S Reservoir B core material with CO₂ at reservoir conditions in the laboratory. Approximately 4 feet of 4-inch core from the S Sand Reservoir B has been reserved for this work.

REDEFINED "S" SAND RESERVOIR B PARAMETERS

Measurements made on the "S" Sand Reservoir B have defined some of the reservoir parameters as significantly different from the values used in the original proposal. Table 1 is a tabulation of the redefined parameters.

The measurements have increased the porosity and permeability values, while the residual oil saturation as a fraction of the total porosity was found to be reduced by a residual gas saturation. Although the fractional oil saturation has been significantly reduced, the oil content per acre foot of reservoir has only decreased 4 percent, because the decrease in fractional oil saturation was offset by the increased porosity. Moreover, the residual oil saturation could be significantly higher in other Weeks Island reservoirs which have not been subject to the pressure depletion which created the residual gas saturation.

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 and 1 1/2 BCF of natural gas, the project will utilize 3.34 MCF of CO₂ 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.

RECOMMENDATIONS

Shell recommends that CO₂ injection be continued until the original proposed 50,000 tons is injected. Although the initial monitor logs indicate the CO₂ column was more concentrated at the single observation point, the monitor logs and the production test of the observation perforations indicate the fluids were in gravity segregated position.

Although we are unsure of the output of the present process simulation, we propose continued simulation effort to develop a process simulator that can be verified or tuned to match the field results.

As an aid to the development of the process simulator, Shell also proposes to start work on a laboratory CO₂ displacement of the S Reservoir B core material at reservoir conditions.

Shell is also investigating the possibility of measuring the residual oil after the CO₂ front passes the present observation perforations. We will propose such a measurement if we believe the results will be valid.

REVISED PARAMETERS
"S" SAND RESERVOIR B CO₂ 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 and Core Analysis	Total Hydrocarbons Saturation Approximates 30% which includes +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.

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ATTACHMENT 1

Technical Information Record BRC-234

Weeks Island CO₂ Pilot Project
Annual Report - Research Results
June 1978 - June 1979

Project 36-81894

By

R. H. Hite

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 1978 to June 1979 on the Weeks Island CO₂ pilot for inclusion in the annual report to the United States Department of Energy. The work has dealt primarily with phase behavior and a better understanding of the process mechanisms. There have been three main areas studied - the multiple contact phase behavior experiments, the process mechanisms (primarily through the use of mathematical models), and finally some shrinkage calculations in support of the residual oil saturation work reported previously. The details of each of these areas is included as an Appendix in this report. Appendixes A and B deal with the multiple contact experiments; Appendix A is the actual Core Laboratories report and Appendix B is our interpretation with some appropriate figures. The process mechanisms research is discussed in Appendixes C and D. Appendix C discusses the incorporation of the Weeks Island single contact phase behavior experiments into the compositional simulator phase package. Appendix D discusses some of the preliminary process mechanism research. The final Appendix E reports the shrinkage calculations.

Results

Multiple contact phase behavior experiments using Weeks Island "S" Sand Reservoir B recombined crude oil and a mixture of 95% CO₂ and 5% CH₄ (CO₂PG) were conducted at Core Laboratories, Inc. in Dallas. These experiments attempted to follow a more realistic composition path than that followed by a single contact experiment.¹ During the multi-contact experiments, densities, compositions, liquid saturations, and some viscosities were measured. The results produced no major surprises; they were similar to the composition simulator phase package predictions and never were more than two hydrocarbon phases observed. The most significant result is the large CO₂-light ends (mostly CH₄) interchange that occurs when CO₂PG is added to the bubble point crude oil. Because of this interchange, the vapor phase is methane-rich rather than CO₂-rich and therefore much less dense than the CO₂PG. The measurements of composition, density, and saturation will provide a solid base for additional compositional simulations.

Besides the experimental phase behavior results, considerable effort has been spent on using the mathematical models to understand how the process works. Because phase properties, such as density, depend on both

pressure and composition, it is necessary to use a compositional simulator² rather than a basic black oil simulator. Using a compositional simulator with a CO₂ process requires that the phase package be "tuned" to match the experimental data. An earlier match of the Weeks Island single contact phase data³ had proved unsatisfactory and Appendix C discusses a revised match of the single contact data. The multiple contact data have not yet been included in the process mechanism models, but this will be done in 1979.

The process mechanisms models have the simplest possible geometry which still retains the essence of the process. This is primarily for two reasons, (1) the compositional simulator runs very slowly, requiring about 10-12 hours of C.A.U time on a Univac 1110 computer, and (2) because the results are very complex, it is important that the basics be well understood before attempting any complex geometry. It cannot be over-emphasized that the mathematical models used here do not contain an exact reservoir description and can not be used to accurately predict recovery efficiencies. Within these constraints, they have, however, provided valuable insight into how the process is expected to work. The CO₂-light ends interchange causes highly complex flow behavior in the process mechanisms model, a fact which was not appreciated in the early stages of this project. The quantitative significance of this phase behavior - fluid dynamics interaction on the pilot results is unknown, but a major effort in the coming year will be to study the parameter sensitivity, particularly relative permeability, and also to incorporate a more nearly exact model of the reservoir into the simulator.

The final appendix reports the stripping of solution gas from the crude oil during a brine injection. This showed that there could be considerable underestimation of the residual oil saturation from a log-inject-log at Weeks Island conditions if this effect was ignored.

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APPENDIX A

Core Laboratories Report
on Multiple Contact Experiments
for Weeks Island Crude and CO₂

CORE LABORATORIES, INC.
Petroleum Reservoir Engineering

DALLAS, TEXAS 75207

January 11, 1979

RESERVOIR FLUID DIVISION

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

Attention: Mr. R.H. Hite

Subject: Special Study
Weeks Island Reservoir Fluid
Weeks Island Field
Louisiana
Our File Number: RFL 78520

Gentlemen:

Separator gas and liquid samples from the subject well were submitted to our Dallas laboratory for use in the special study. Presented to you in the following report are the results of this study.

A reservoir fluid sample was initially prepared in the laboratory by physically recombining the separator gas and liquid samples in the correct proportion to yield a sample having a bubble point pressure of 5100 psig at 225°F. The gas-liquid ratio required for this recombination was 935 cubic feet of separator gas at 15.025 psia and 60°F. per barrel of separator liquid at 93 psig and 60°F. The hydrocarbon composition of the recombined reservoir fluid was calculated on the basis of this gas-liquid ratio and is presented on page two, along with the measured hydrocarbon compositions of the separator products.

A large quantity of injection gas was then synthetically prepared in the laboratory. The desired and actual compositions of the synthetic gas may be found on page three. The gas was then subjected to deviation factor measurements at the reservoir temperature. A tabulation of these measurements is given on page four.

A small quantity of the reservoir fluid was initially subjected to a partial pressure-volume relations test at 225°F. The results of these measurements may be found on page six, along with the density measurements over the entire pressure range investigated.

A portion of the recombined fluid was then subjected to viscosity measurements at 225°F. in a rolling ball viscosimeter. The viscosity of the fluid was found to vary from a minimum of 0.401 centipoise at the saturation pressure to a maximum of 1.507 centipoise at atmospheric pressure.

The reservoir fluid and the synthetic injection gas were then used in performing a single-contact experiment at 5100 psig and 225°F. A measured quantity of reservoir fluid was charged to a high pressure visual cell, followed by a injection gas charge equivalent to ten percent of the original reservoir volume at 5100 psig and 225°F. The gas and liquid phase compositions were measured by low temperature fractional distillation. In addition, the reservoir volume, mol fraction, and density of each phase were measured. All density measurements from this point forward were performed by indirect measurement. Specifically, this means that the weight of the hexanes and lighter was calculated from compositional data. The deviation factor of the gas phase was also determined. The viscosity of the liquid phase from the single-contact test was measured in a rolling ball viscosimeter at 225°F. The results of the single-contact test are tabulated on page eight and the associated viscosity measurements of the liquid phase may be found on page nine.

A large quantity of the reservoir fluid was then used with the synthetic injection gas in performing a multiple-contact experiment at 5100 psig and 225°F. A total of eleven gas injections were made during the course of this experiment. For each of the first eight contacts, injection gas equivalent to ten percent of the original reservoir volume at 5100 psig and 225°F. was added. A minute portion of the gas phase from each contact was flowed through a condensate trap and the resulting stripped gas phase was subjected to chromatographic analysis. The hydrocarbon composition of the total gas was then estimated, using the smooth condensate weights and estimated molecular weights summarized on page 22. To maintain a reasonably constant reservoir volume, approximately ten volume percent of the liquid phase was removed after each gas injection. This liquid phase was subjected to hydrocarbon analysis by low temperature fractional distillation.

Contact numbers 9, 10 and 11 were performed in a fashion similar to a standard revaporization type experiment. For each of these contacts, injection gas equivalent to 25 percent of the original reservoir volume at 5100 psig and 225°F. was added. To maintain a constant reservoir volume, gas phase was then removed at 5100 psig and 225°F. until the total volume of gas and liquid in place was equivalent to the volume of original reservoir fluid at bubble point conditions. The gas phase displaced during each contact was subjected to hydrocarbon analysis by low temperature fractional distillation. For comparison purposes, a minute quantity of gas phase was removed during contact number 9 in a similar fashion to that used for the prior eight contacts. This minute sample was subjected to chromatographic analysis and subsequent conversion to total gas composition by the process described earlier.

At the conclusion of contact number 11, the liquid phase was subjected to low temperature fractional distillation. A summary of the data derived during contact number 11 may be found on page 21.

Thank you for the opportunity to perform this special study. Should you have any questions or if we may be of further service in any manner, please feel free to call upon us.

Very truly yours,

Core Laboratories, Inc.

P. L. Moses (or)

P.L. Moses, Manager
Reservoir Fluid Analysis

PLM:JF:tlc
15 cc. - Addressee

CORE LABORATORIES, INC.
Petroleum Reservoir Engineering
 DALLAS, TEXAS 75207

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 File RFL 78520

Company Shell Development Company Date Sampled _____
 Well Weeks Island County _____
 Field Weeks Island State Louisiana

FORMATION CHARACTERISTICS

Formation Name _____
 Date First Well Completed _____, 19____
 Original Reservoir Pressure _____ PSIG @ _____ Ft.
 Original Produced Gas-Liquid Ratio _____ SCF/Bbl
 Production Rate _____ Bbls/Day
 Separator Pressure and Temperature _____ PSIG _____ °F.
 Liquid Gravity at 60°F. _____ ° API
 Datum _____ Ft. Subsea

WELL CHARACTERISTICS

Elevation _____ Ft.
 Total Depth _____ Ft.
 Producing Interval _____ Ft.
 Tubing Size and Depth _____ In. to _____ Ft.
 Open Flow Potential _____ MISC/Day
 Last Reservoir Pressure 5100 PSIG @ _____ Ft.
 Date _____, 19____
 Reservoir Temperature 225 °F. @ _____ Ft.
 Status of Well _____
 Pressure Gauge _____

SAMPLING CONDITIONS

Flowing Tubing Pressure _____ PSIG
 Flowing Bottom Hole Pressure _____ PSIG
 Primary Separator Pressure 93 PSIG
 Primary Separator Temperature 148 °F.
 Secondary Separator Pressure _____ PSIG
 Secondary Separator Temperature _____ °F.
 Field Stock Tank Liquid Gravity _____ ° API @ 60°F.
 Primary Separator Gas Production Rate _____ MISC/Day
 Pressure Base 15.025 PSIA
 Temperature Base 60 °F.
 Compressibility Factor (F_{pv}) _____
 Gas Gravity (Laboratory) 0.690
 Gas Gravity Factor (F_g) _____
 _____ Liquid Production Rate @ 60 °F. _____ Bbls/Day
 Primary Separator Gas/Separator Liquid @60°F. Ratio 935* SCF/Bbl
 or _____ Bbls/MISC

Sampled by _____

REMARKS:

* GOR required for recombination bubble point pressure = 5100 PSIG at 225°F.

These analyses, opinions or interpretations are based on observations and material supplied by the client to whom, and for whose exclusive and confidential use, this report is made. The interpretations or opinions expressed represent the best judgment of Core Laboratories, Inc. (all errors and omissions excepted); but Core Laboratories, Inc. and its officers and employees, assume no responsibility and make no warranty or representations as to the productivity, proper operation, or profitability of any oil, gas or other mineral well or sand in connection with which such report is used or relied upon.

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Well Weeks Island

Hydrocarbon Analyses of Separator Products and Calculated Well Stream

<u>Component</u>	<u>Separator Liquid Mol Percent</u>	<u>Separator Gas Mol Percent</u>	<u>GPM</u>	<u>Well Stream Mol Percent</u>
Hydrogen Sulfide	Nil	Nil		Nil
Carbon Dioxide	Nil	0.95		0.61
Nitrogen	0.01	0.67		0.43
Methane	2.55	88.30		57.72
Ethane	0.65	4.20	1.145	2.93
Propane	0.86	1.94	0.544	1.55
iso-Butane	0.50	0.61	0.203	0.57
n-Butane	0.88	0.78	0.251	0.82
iso-Pentane	0.81	0.43	0.160	0.57
-Pentane	0.73	0.35	0.129	0.49
Hexanes	2.49	0.50	0.208	1.21
Heptanes plus	<u>90.52</u>	<u>1.27</u>	<u>0.588</u>	<u>33.10</u>
	<u>100.00</u>	<u>100.00</u>	<u>3.228</u>	<u>100.00</u>

Properties of Heptanes plus

API gravity @ 60° F.	<u>32.2</u>		
Specific gravity @ 60/60° F.	<u>0.8644</u>		<u>0.863</u>
Molecular weight	<u>231</u>	<u>103</u>	<u>228</u>

Calculated separator gas gravity (air = 1.000) = 0.690
 Calculated gross heating value for separator gas = 1213 BTU
 per cubic foot of dry gas @ 15.025 psia and 60° F.

Primary separator gas collected @ 93 psig and 148 °F.
 Primary separator liquid collected @ 93 psig and 148 °F.

Primary separator gas/separator liquid ratio 935 SCF Bbl @ 60 ° F. and 93 psig

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Company Shell Development Company Formation _____

Well Weeks Island County _____

Field Weeks Island State Louisiana

HYDROCARBON ANALYSIS OF Injection GAS SAMPLE *

COMPONENT	MOL PERCENT	
	<u>Desired</u>	<u>Actual</u>
Carbon Dioxide	94.50	94.57
Methane	5.50	5.43
	<u>100.00</u>	<u>100.00</u>

* Prepared in the laboratory, using pure components.

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Well Weeks Island

Pressure-Volume Relations of Injection Gas at 225°F.
(Constant Composition Expansion)

<u>Pressure PSIG</u>	<u>Relative Volume</u>	<u>Deviation Factor Z</u>
6000	0.9260	0.800
5500	0.9634	0.763
5100	1.0000	0.735
5000	1.0108	0.728
4500	1.0735	0.696
4000	1.1607	0.669
3500	1.2920	0.652
3000	1.5009	0.650
2700	1.6910	0.659
2400	1.9575	0.679
2100	2.3249	0.706
1800	2.8524	0.743
1500	3.6049	0.784
1200	4.7468	0.828
900	6.6672	0.876

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Well Weeks Island

VOLUMETRIC DATA OF Reservoir Fluid SAMPLE

1. Saturation pressure (bubble-point pressure) 5100 PSIG @ 225 °F.
2. Specific volume at saturation pressure: ft³/lb 0.02375 @ 225 °F.
3. Thermal expansion of saturated oil @ 6000 PSI = $\frac{V @ 225 \text{ } ^\circ\text{F}}{V @ 76 \text{ } ^\circ\text{F}} = \underline{1.08755}$
4. Compressibility of saturated oil @ reservoir temperature: Vol/Vol/PSI:
From 6000 PSI to 5500 PSI = 13.16 X 10⁻⁶
From 5500 PSI to 5100 PSI = 14.00 X 10⁻⁶

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Well Weeks Island

Pressure-Volume Relations of Reservoir Fluid at 225 °F.
(Constant Composition Expansion)

<u>Pressure</u> <u>PSIG</u>	<u>Relative</u> <u>Volume</u>	<u>Density,</u> <u>Gm/Cc</u>
6000	0.9879	0.6826
5800	0.9905	0.6808
5600	0.9931	0.6791
5500	0.9944	0.6782
5400	0.9958	0.6772
5300	0.9972	0.6763
5200	0.9986	0.6753
<u>5100</u>	1.0000	0.6744

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Viscosity of Reservoir Fluid at 225°F.

<u>Pressure,</u> <u>PSIG</u>	<u>Viscosity,</u> <u>Centipoise</u>
6000	0.417
5800	0.413
5500	0.408
5200	0.403
<u>5100</u>	0.401
4600	0.417
4100	0.443
3600	0.479
3100	0.521
2600	0.568
2100	0.619
1600	0.689
1100	0.778
600	0.906
0	1.507

Gravity of residual oil = 32.3° API @ 60°F.

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Single-Contact Test at 5100 PSIG and 225°F.
Reservoir Fluid Plus 10 Percent Injection Gas*

Component	Gas Phase	Liquid Phase
	Mol Percent	
Carbon Dioxide	19.76	16.07
Nitrogen	0.77	0.33
Methane	72.50	47.25
Ethane	2.45	2.44
Propane	0.98	1.32
iso-Butane	0.30	0.49
n-Butane	0.39	0.70
iso-Pentane	0.22	0.49
n-Pentane	0.18	0.43
Hexanes	0.34	1.06
Heptanes plus	2.11	29.42
	100.00	100.00
<u>Heptanes plus properties</u>		
Molecular weight	117	229
Specific gravity @ 60/60°F.	**	0.864
Reservoir volume, relative to volume of original oil at 5100 PSIG and 225°F.	0.0545	1.0470
Mol fraction	0.06800	0.93200
Deviation factor Z	0.986	
Density, gm/cc	0.2817	0.6814

* Injection gas equivalent to 10 percent of the original reservoir volume at 5100 PSIG and 225°F. was added; also equivalent to 0.20084 mol of gas per mol of original fluid.

** Insufficient quantity for measurement.

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Viscosity of Liquid Phase
From Single-Contact Test at 5100 PSIG and 225°F.

<u>Pressure,</u> <u>PSIG</u>	<u>Viscosity,</u> <u>Centipoise</u>
6000	0.383
5800	0.379
5500	0.374
5200	0.368
5100	0.366
4600	0.384
4100	0.413
3600	0.447
3100	0.490
2600	0.542
2100	0.605
1600	0.683
1100	0.782
600	0.922
0	1.558

Gravity of residual oil = 32.1° API @ 60°F.

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Multiple-Contact Test at 5100 PSIG and 225°F.
 Contact No. 1*

Component	Gas Phase		Liquid Phase
	Stripped	Total Mol Percent	
Carbon Dioxide	18.66	18.37	14.72
Nitrogen	0.87	0.86	0.29
Methane	75.12	73.97	48.45
Ethane	2.35	2.31	2.48
Propane	1.08	1.06	1.29
iso-Butane	0.35	0.34	0.41
n-Butane	0.44	0.43	0.89
iso-Pentane	0.26	0.26	0.47
n-Pentane	0.20	0.20	0.48
Hexanes	0.28	0.28	0.82
Heptanes plus	0.39	1.92	29.70
	<u>100.00</u>	<u>100.00</u>	<u>100.00</u>
<u>Heptanes plus properties</u>			
Molecular weight	103**	114**	236
Specific gravity @ 60/60°F.			0.865
<u>Removed for compositional data</u>			
Mols(1)		0.04377	0.05923
Reservoir volume(2)		0.0291	0.0553
<u>In-Place prior to next contact</u>			
Mols(1)		0.02957	1.06827
Reservoir volume(2)		0.0197	0.9971
Deviation factor Z		0.983	
Density, gm/cc		0.2786	0.6727

* For this contact, injection gas equivalent to 10 percent of the original reservoir volume at 5100 PSIG and 225°F. was added; also equivalent to 0.20084 mol of gas per mol of original fluid.

** Estimated values.

(1) Relative to one mol of original reservoir fluid.

(2) Relative to volume of original reservoir fluid at 5100 PSIG and 225°F.

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 Well Weeks Island

Multiple-Contact Test at 5100 PSIG and 225°F.
 Contact No. 2*

<u>Component</u>	<u>Gas Phase</u>		<u>Liquid Phase</u>
	<u>Stripped</u>	<u>Total</u> Mol Percent	
Carbon Dioxide	33.84	33.33	26.97
Nitrogen	0.66	0.65	0.31
Methane	60.79	59.88	40.97
Ethane	1.93	1.90	1.98
Propane	0.98	0.97	1.11
iso-Butane	0.33	0.33	0.36
n-Butane	0.42	0.41	0.64
iso-Pentane	0.25	0.25	0.40
n-Pentane	0.19	0.19	0.52
Hexanes	0.28	0.28	0.86
Heptanes plus	0.33	1.81	25.88
	<u>100.00</u>	<u>100.00</u>	<u>100.00</u>
<u>Heptanes plus properties</u>			
Molecular weight	103**	120**	234
Specific gravity @ 60/60°F.			0.866
<u>Removed for compositional data</u>			
Mols(1)		0.00542	0.13391
Reservoir volume(2)		0.0036	0.1182
<u>In-Place prior to next contact</u>			
Mols(1)		0.13129	1.02806
Reservoir volume(2)		0.0880	0.9078
Deviation factor Z		0.990	
Density, gm/cc		0.3223	0.6871

* For this contact, injection gas equivalent to 10 percent of the original reservoir volume at 5100 PSIG and 225°F. was added; also equivalent to 0.20084 mol of gas per mol of original fluid.

** Estimated values.

(1) Relative to one mol of original reservoir fluid.

(2) Relative to volume of original reservoir fluid at 5100 PSIG and 225°F.

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 File RFL 78520
 Well Weeks Island

Multiple-Contact Test at 5100 PSIG and 225°F.
 Contact No. 3*

Component	Gas Phase		Liquid Phase
	Stripped	Total Mol Percent	
Carbon Dioxide	47.67	46.99	34.18
Nitrogen	0.44	0.43	0.22
Methane	47.72	47.04	36.56
Ethane	1.72	1.70	1.80
Propane	0.82	0.81	1.01
iso-Butane	0.28	0.28	0.32
n-Butane	0.37	0.36	0.62
iso-Pentane	0.24	0.23	0.34
n-Pentane	0.19	0.19	0.37
Hexanes	0.25	0.25	0.74
Heptanes plus	0.30	1.72	23.84
	<u>100.00</u>	<u>100.00</u>	<u>100.00</u>
<u>Heptanes plus properties</u>			
Molecular weight	103**	126**	229
Specific gravity @ 60/60°F.			0.864
<u>Removed for compositional data</u>			
Mols(1)		0.00577	0.09859
Reservoir volume(2)		0.0037	0.0828
<u>In-Place prior to next contact</u>			
Mols(1)		0.23441	1.02142
Reservoir volume(2)		0.1509	0.8574
Deviation factor Z		0.950	
Density, gm/cc		0.3787	0.6897

* For this contact, injection gas equivalent to 10 percent of the original reservoir volume at 5100 PSIG and 225°F. was added; also equivalent to 0.20084 mol of gas per mol of original fluid.

** Estimated values.

- (1) Relative to one mol of original reservoir fluid.
 (2) Relative to volume of original reservoir fluid at 5100 PSIG and 225°F.

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Multiple-Contact Test at 5100 PSIG and 225°F.
 Contact No. 4*

Component	Gas Phase		Liquid Phase
	Stripped	Total Mol Percent	
Carbon Dioxide	52.42	51.65	39.68
Nitrogen	0.34	0.34	0.22
Methane	42.99	42.36	32.70
Ethane	1.57	1.55	1.42
Propane	0.79	0.78	0.95
iso-Butane	0.27	0.27	0.39
n-Butane	0.36	0.35	0.59
iso-Pentane	0.23	0.23	0.45
n-Pentane	0.18	0.18	0.41
Hexanes	0.31	0.31	0.71
Heptanes plus	0.54	1.98	22.48
	100.00	100.00	100.00
<u>Heptanes plus properties</u>			
Molecular weight	103**	129**	237
Specific gravity @ 60/60°F.			0.868
<u>Removed for compositional data</u>			
Mols(1)		0.00575	0.13584
Reservoir volume(2)		0.0037	0.1099
<u>In-Place prior to next contact</u>			
Mols(1)		0.40891	0.90617
Reservoir volume(2)		0.2601	0.7331
Deviation factor Z		0.939	
Density, gm/cc		0.4024	0.7067

* For this contact, injection gas equivalent to 10 percent of the original reservoir volume at 5100 PSIG and 225°F. was added; also equivalent to 0.20084 mol of gas per mol of original fluid.

** Estimated values.

(1) Relative to one mol of original reservoir fluid.

(2) Relative to volume of original reservoir fluid at 5100 PSIG and 225°F.

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Multiple-Contact Test at 5100 PSIG and 225°F.
 Contact No. 5*

Component	Gas Phase		Liquid Phase
	Stripped	Total Mol Percent	
Carbon Dioxide	59.59	58.67	47.12
Nitrogen	0.24	0.24	0.18
Methane	36.38	35.82	27.55
Ethane	1.36	1.34	1.27
Propane	0.68	0.67	0.81
iso-Butane	0.24	0.24	0.31
n-Butane	0.31	0.31	0.45
iso-Pentane	0.20	0.20	0.30
n-Pentane	0.16	0.16	0.25
Hexanes	0.29	0.29	0.69
Heptanes plus	0.55	2.06	21.07
	<u>100.00</u>	<u>100.00</u>	<u>100.00</u>
<u>Heptanes plus properties</u>			
Molecular weight	103**	134**	239
Specific gravity @ 60/60°F.			0.869
<u>Removed for compositional data</u>			
Mols(1)		0.00561	0.09564
Reservoir volume(2)		0.0034	0.0771
<u>In-Place prior to next contact</u>			
Mols(1)		0.64131	0.77336
Reservoir volume(2)		0.3870	0.6232
Deviation factor Z		0.891	
Density, gm/cc		0.4495	0.7139

* For this contact, injection gas equivalent to 10 percent of the original reservoir volume at 5100 PSIG and 225°F. was added; also equivalent to 0.20084 mol of gas per mol of original fluid.

** Estimated values.

- (1) Relative to one mol of original reservoir fluid.
 (2) Relative to volume of original reservoir fluid at 5100 PSIG and 225°F.

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Multiple-Contact Test at 5100 PSIG and 225°F.
 Contact No. 6*

Component	Gas Phase		Liquid Phase
	Stripped	Total Mol Percent	
Carbon Dioxide	63.91	62.86	47.01
Nitrogen	0.21	0.21	0.19
Methane	32.21	31.69	27.65
Ethane	1.25	1.23	1.19
Propane	0.63	0.62	0.79
iso-Butane	0.23	0.23	0.28
n-Butane	0.31	0.30	0.41
iso-Pentane	0.20	0.20	0.30
n-Pentane	0.16	0.16	0.23
Hexanes	0.29	0.29	0.62
Heptanes plus	0.60	2.21	21.33
	<u>100.00</u>	<u>100.00</u>	<u>100.00</u>
<u>Heptanes plus properties</u>			
Molecular weight	103**	139**	246
Specific gravity @ 60/60°F.			0.873
<u>Removed for compositional data</u>			
Mols(1)		0.00531	0.15379
Reservoir volume(2)		0.0034	0.1129
<u>In-Place prior to next contact</u>			
Mols(1)		0.79773	0.65868
Reservoir volume(2)		0.5082	0.4836
Deviation factor Z		0.941	
Density, gm/cc		0.4427	0.7225

* For this contact, injection gas equivalent to 10 percent of the original reservoir volume at 5100 PSIG and 225°F. was added; also equivalent to 0.20084 mol of gas per mol of original fluid.

** Estimated values.

(1) Relative to one mol of original reservoir fluid.

(2) Relative to volume of original reservoir fluid at 5100 PSIG and 225°F.

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Multiple-Contact Test at 5100 PSIG and 225°F.
 Contact No. 7*

Component	Gas Phase		Liquid Phase
	Stripped	Total Mol Percent	
Carbon Dioxide	69.22	68.13	55.32
Nitrogen	0.22	0.22	0.15
Methane	27.45	27.02	20.66
Ethane	0.91	0.90	0.90
Propane	0.54	0.53	0.60
iso-Butane	0.20	0.20	0.23
n-Butane	0.28	0.28	0.35
iso-Pentane	0.20	0.20	0.49
n-Pentane	0.18	0.18	0.23
Hexanes	0.35	0.34	0.22
Heptanes plus	0.45	2.00	20.85
	<u>100.00</u>	<u>100.00</u>	<u>100.00</u>
<u>Heptanes plus properties</u>			
Molecular weight	103**	147**	248
Specific gravity @ 60/60°F.			0.874
<u>Removed for compositional data</u>			
Mols(1)		0.00561	0.19358
Reservoir volume(2)		0.0034	0.1480
<u>In-Place prior to next contact</u>			
Mols(1)		1.08332**	0.37474**
Reservoir volume(2)		0.6547	0.2865**
Deviation factor Z		0.892	
Density, gm/cc		0.4831	0.7337

* For this contact, injection gas equivalent to 10 percent of the original reservoir volume at 5100 PSIG and 225°F. was added; also equivalent to 0.20084 mol of gas per mol of original fluid.

** Estimated values.

(1) Relative to one mol of original reservoir fluid.

(2) Relative to volume of original reservoir fluid at 5100 PSIG and 225°F.

Note: Mols and reservoir volumes of gas and liquid phases were estimated, based upon data from contact numbers 6 and 8.

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Multiple-Contact Test at 5100 PSIG and 225°F.
 Contact No. 8*

Component	Gas Phase		Liquid Phase
	Stripped	Total Mol Percent	
Carbon Dioxide	72.21	71.06	55.60
Nitrogen	0.43	0.42	0.16
Methane	25.00	24.61	21.09
Ethane	0.77	0.76	0.74
Propane	0.48	0.47	0.50
iso-Butane	0.17	0.17	0.17
n-Butane	0.23	0.23	0.24
iso-Pentane	0.15	0.15	0.10
n-Pentane	0.12	0.12	0.07
Hexanes	0.26	0.26	0.24
Heptanes plus	0.18	1.75	21.09
	<u>100.00</u>	<u>100.00</u>	<u>100.00</u>
<u>Heptanes plus properties</u>			
Molecular weight	103**	160**	256
Specific gravity @ 60/60°F.			0.878
<u>Removed for compositional data</u>			
Mols(1)		0.00565	0.04155
Reservoir volume(2)		0.0034	0.0284
<u>In-Place prior to next contact</u>			
Mols(1)		1.25441	0.35729
Reservoir volume(2)		0.7606	0.2441
Deviation factor Z		0.895	
Density, gm/cc		0.4883	0.7449

* For this contact, injection gas equivalent to 10 percent of the original reservoir volume at 5100 PSIG and 225°F. was added; also equivalent to 0.20084 mol of gas per mol of original fluid.

** Estimated values.

- (1) Relative to one mol of original reservoir fluid.
 (2) Relative to volume of original reservoir fluid at 5100 PSIG and 225°F.

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Multiple-Contact Test at 5100 PSIG and 225°F.
 Contact No. 9*

Component	<u>Gas Phase</u>	<u>Liquid Phase</u>
	Mol Percent	
Carbon Dioxide	75.16	
Nitrogen	0.13	
Methane	19.34	
Ethane	0.54	
Propane	0.36	
iso-Butane	0.12	
n-Butane	0.16	
iso-Pentane	0.10	
n-Pentane	0.08	
Hexanes	0.06	
Heptanes plus	3.95	
	100.00	
 <u>Heptanes plus properties</u>		
Molecular weight	183	
Specific gravity @ 60/60°F.	0.829	
 <u>Removed for compositional data</u>		
Mols(1)	0.41983	
Reservoir volume(2)	0.2413	
 <u>In-Place prior to next contact</u>		
Mols(1)	1.43932	0.25465
Reservoir volume(2)	0.8273	0.1774
Deviation factor Z	0.849	
Density, gm/cc	0.5797	

* For this contact, injection gas equivalent to 25 percent of the original reservoir volume at 5100 PSIG and 225°F. was added; also equivalent to 0.50210 mol of gas per mol of original fluid.

- (1) Relative to one mol of original reservoir fluid.
 (2) Relative to volume of original reservoir fluid at 5100 PSIG and 225°F.

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Hydrocarbon Analysis of Small Gas Sample
 Removed During Contact No. 9

Component	Mol Percent	
	Stripped	Total
Carbon Dioxide	77.62	76.39
Nitrogen	0.01	0.01
Methane	20.35	20.03
Ethane	0.66	0.63
Propane	0.38	0.37
iso-Butane	0.13	0.13
n-Butane	0.20	0.20
iso-Pentane	0.13	0.13
n-Pentane	0.12	0.12
Hexanes	0.22	0.22
Heptanes plus	0.18	1.77
	100.00	100.00
<u>Heptanes plus properties</u>		
Molecular weight	103*	175*
Specific gravity @ 60/60°F.		
Deviation factor Z		0.872
Density, gm/cc		0.5227

* Estimated values.

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Multiple-Contact Test at 5100 PSIG and 225°F.
 Contact No. 10*

Component	Gas Phase	Mol Percent	Liquid Phase
Carbon Dioxide	79.50		
Nitrogen	0.11		
Methane	16.07		
Ethane	0.39		
Propane	0.28		
iso-Butane	0.10		
n-Butane	0.14		
iso-Pentane	0.10		
n-Pentane	0.06		
Hexanes	0.06		
Heptanes plus	3.19		
	100.00		
<u>Heptanes plus properties</u>			
Molecular weight	186		
Specific gravity @ 60/60°F.	0.829		
<u>Removed for compositional data</u>			
Mols(1)	0.44396		
Reservoir volume(2)	0.2471		
<u>In-Place prior to next contact</u>			
Mols(1)	1.54284		0.20927
Reservoir volume(2)	0.8588		0.1460
Deviation factor Z	0.822		
Density, gm/cc	0.5982		

* For this contact, injection gas equivalent to 25 percent of the original reservoir volume at 5100 PSIG and 225°F. was added; also equivalent to 0.50210 mol of gas per mol of original fluid.

- (1) Relative to one mol of original reservoir fluid.
- (2) Relative to volume of original reservoir fluid at 5100 PSIG and 225°F.

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Multiple-Contact Test at 5100 PSIG and 225°F.
 Contact No. 11*

<u>Component</u>	<u>Gas Phase</u>	<u>Liquid Phase</u>
	<u>Mol Percent</u>	
Carbon Dioxide	81.94	65.70
Nitrogen	0.08	0.04
Methane	14.04	10.61
Ethane	0.32	0.31
Propane	0.28	0.26
iso-Butane	0.12	0.09
n-Butane	0.15	0.14
iso-Pentane	0.09	0.08
n-Pentane	0.06	0.07
Hexanes	0.03	0.12
Heptanes plus	2.89	22.58
	100.00	100.00
<u>Heptanes plus properties</u>		
Molecular weight	189	323
Specific gravity @ 60/60°F.	0.838	0.903
<u>Removed for compositional data</u>		
Mols(1)	0.44105	0.27647
Reservoir volume(2)	0.2526	0.1199
<u>In-Place prior to next contact</u>		
Mols(1)	1.53669	0.00000
Reservoir volume(2)	0.8801	0.0000
Deviation factor Z	0.846	
Density, gm/cc	0.5842	0.8204

* For this contact, injection gas equivalent to 25 percent of the original reservoir volume at 5100 PSIG and 225°F. was added; also equivalent to 0.50210 mol of gas per mol of original fluid.

- (1) Relative to one mol of original reservoir fluid.
- (2) Relative to volume of original reservoir fluid at 5100 PSIG and 225°F.

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Evaluation of Condensate Data
 Used to Convert Gas Phase Compositions
 From "Stripped" Gas to "Total" Gas

Contact Number	Condensate Weight, Gm		Estimated Molecular Weight	Mol Fraction	
	Measured	Smooth		Stripped Gas	Condensate
1	0.0000	0.0207	117	0.9846	0.0154
2	0.0651	0.0225	124	0.9852	0.0148
3	0.0173	0.0243	131	0.9858	0.0142
4	0.0351	0.0261	138	0.9855	0.0145
5	0.0196	0.0279	145	0.9848	0.0152
6	0.0586	0.0296	152	0.9838	0.0162
7	0.0226	0.0314	159	0.9844	0.0156
8	0.0461	0.0332	166	0.9843	0.0157
9	0.0298	0.0377	183	0.9841	0.0159

Assumptions made in converting "stripped" gas composition to "total" gas composition:

- (1) Molecular weight of heptanes plus in stripped gas = 103.
- (2) Condensate consists entirely of heptanes and heavier.
- (3) Smooth condensate weights and estimated molecular weights were used for calculations.

Core Laboratories, Inc.

P. L. Moses

P. L. Moses, Manager
 Reservoir Fluid Analysis

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APPENDIX B

INTERPRETATION OF MULTIPLE CONTACT EXPERIMENTS FOR WEEKS ISLAND CRUDE AND CO₂

Introduction

Before any CO₂ enhanced recovery process can be adequately understood, it is necessary to know the phase behavior of the crude oil and CO₂. Much early work on these systems utilized the single contact experiments, in which more and more CO₂ is added to the crude oil without removing any material.^{4,5} This type of experiment has already been completed for Weeks Island.¹ However, the composition route during a CO₂ flood can be quite different from that represented by the single contact experiments. For this reason and because there was little composition and density data at the reservoir pressure, multiple contact experiments were conducted for Weeks Island crude and CO₂.

These experiments were conducted at Core Laboratories, Inc. of Dallas under our supervision. Their report on these experiments is found in Appendix A. True boiling point analyses (TBPGC) of all heptanes plus samples, collected by Core Labs, were run by Bellaire Research Center's Analytical Department and are reported in Tables B-1 to B-4. This report describes the experimental procedures and summarizes the important results.

The transport phenomena and phase behavior at Weeks Island are quite different from a CO₂ flood in which gravity is not important and where the crude oil is undersaturated. A mixture of 95% CO₂ and 5% plant gas (CO₂PG) will be injected just above the gas-oil contact and will drive a small oil rim and residual oil 120 feet downdip to be captured by a producing well. This gravity mechanism motivates a certain type of multiple contact experiment. Moreover, since the Weeks Island crude oil is saturated, a vapor phase forms as soon as CO₂ is added to the crude oil.

Experimental Procedure

Since the pressure is essentially constant with the 1300 foot gas cap, all multiple contact experiments were conducted at 225°F and 5100 psig.

Table B-1

TBPGLC Analyses of Heavy Fractions

Carbon Number	B.P., °C at 760 mm	Volatility Distribution, Weight Percent			
		Separator Gas	Separator Liquid	Recombined Crude*	Single Contact Liquid
4	-0.5	0.0	0.0	0.0	0.1
5	36.1	0.2	0.0	0.0	0.1
6	68.7	3.8	0.3	0.3	0.2
7	98.4	15.1	2.0	2.1	2.1
8	125.7	24.7	4.1	4.3	4.2
9	150.8	20.4	4.1	4.3	4.0
10	174.1	15.8	4.4	4.5	4.3
11	195.9	9.2	4.4	4.5	4.5
12	216.3	4.6	4.5	4.5	4.7
13	235.4	3.0	5.2	5.2	5.3
14	253.6	1.6	5.6	5.6	5.7
15	270.6	0.9	5.4	5.3	5.5
16	286.8	0.3	4.9	4.8	4.9
17	301.8	0.1	5.0	4.9	5.1
18	316.1	0.0	4.1	4.1	4.2
19	329.7	0.0	3.6	3.6	3.7
20	342.7	0.0	3.5	3.5	3.5
21	355.6	0.0	3.1	3.1	3.1
22	367.6	0.0	2.8	2.8	2.8
23	379.0	0.0	2.5	2.5	2.6
24	389.9	0.0	2.3	2.3	2.2
25	400.4	0.0	2.0	2.0	2.1
26	410.5	0.0	1.8	1.8	1.9
27	420.2	0.0	1.8	1.8	1.8
28	429.6	0.0	1.7	1.7	1.7
29	438.6	0.0	1.7	1.7	1.6
30	447.3	0.0	1.4	1.4	1.4
31	456.0	0.0	1.3	1.3	1.3
32	464.0	0.0	1.2	1.2	1.1
33	472.0	0.0	1.1	1.1	1.0
34	479.0	0.0	1.0	1.0	0.9
>34	>479.0	0.0	13.0	12.9	12.0

* Estimated using 0.9888 parts separator liquid to 0.0112 parts separator gas

Table B-2

TBPGCLC Analyses of Heavy Fractions

Carbon Number	B.P., °C at 760 mm	Volatility Distribution, Weight Percent			
		Liquid Phase			
		Contact #1	Contact #2	Contact #3	Contact
4	-0.5	0.0	0.0	0.0	0.0
5	36.1	0.0	0.0	0.0	0.2
6	68.7	0.2	0.2	1.2	0.3
7	98.4	2.4	2.2	2.6	2.0
8	125.7	4.3	3.9	4.5	4.1
9	150.8	4.1	3.8	4.3	3.9
10	174.1	4.6	4.3	4.6	4.3
11	195.9	4.5	4.3	4.6	4.4
12	216.3	4.6	4.5	4.8	4.6
13	235.4	5.2	5.2	5.3	5.3
14	253.6	5.2	5.3	5.3	5.5
15	270.6	5.1	5.3	5.4	5.4
16	286.8	4.5	4.8	4.9	4.9
17	301.8	4.7	4.9	5.0	5.2
18	316.1	3.8	4.0	4.1	4.3
19	329.7	3.4	3.6	3.5	3.7
20	342.7	3.1	3.3	3.3	3.5
21	355.6	2.8	3.0	2.8	3.1
22	367.6	2.5	2.7	2.6	2.8
23	379.0	2.2	2.3	2.3	2.6
24	389.9	1.9	2.0	2.1	2.3
25	400.4	2.1	1.9	2.0	2.0
26	410.5	1.7	1.7	1.7	1.8
27	420.2	1.5	1.6	1.6	1.7
28	429.6	1.4	1.5	1.4	1.6
29	438.6	1.3	1.5	1.3	1.5
30	447.0	1.2	1.3	1.2	1.4
31	456.0	1.1	1.1	1.0	1.2
32	464.0	1.0	1.1	0.9	1.1
33	472.0	0.9	1.0	0.8	1.0
34	479.0	0.8	0.9	0.8	0.9
> 34	> 479.0	18.0	17.0	14.0	13.0

Table B-3

TBPGLC Analyses of Heavy Fractions

Carbon Number	B.P., °C at 760 mm	Volatility Distribution, Weight Percent			
		Liquid Phase			
		Contact #5	Contact #6	Contact #7	Contact #8
4	-0.5	0.0	0.0	0.0	0.0
5	36.1	0.0	0.0	0.0	0.1
6	68.7	0.5	0.3	0.3	0.3
7	98.4	2.0	1.7	1.6	1.2
8	125.7	3.8	3.4	3.3	2.3
9	150.8	3.6	3.5	3.2	2.6
10	174.1	4.0	3.9	3.5	3.1
11	195.9	4.1	4.1	3.8	3.5
12	216.3	4.3	4.2	4.1	3.8
13	235.4	5.1	5.0	4.8	4.5
14	253.6	5.2	5.2	5.1	4.8
15	270.6	5.2	5.2	5.2	5.0
16	286.8	4.8	4.7	4.9	4.6
17	301.8	5.0	5.0	5.1	4.8
18	316.1	4.2	4.1	4.3	4.2
19	329.7	3.8	3.7	3.8	3.7
20	342.7	3.5	3.5	3.6	3.5
21	355.6	3.1	3.1	3.3	3.2
22	367.6	2.9	2.9	3.1	3.0
23	379.0	2.5	2.5	2.7	2.8
24	389.9	2.3	2.3	2.4	2.6
25	400.4	2.2	2.1	2.3	2.6
26	410.5	1.9	1.9	2.1	2.2
27	420.2	1.9	1.8	2.0	2.2
28	429.6	1.8	1.7	1.9	2.1
29	438.6	1.6	1.6	1.8	2.0
30	447.3	1.5	1.4	1.6	1.8
31	456.0	1.3	1.2	1.5	1.6
32	464.0	1.2	1.1	1.3	1.5
33	472.0	1.1	1.0	1.2	1.4
34	479.0	1.0	1.0	1.1	1.3
>34	>479.0	15.0	17.0	15.0	18.0

Table B-4

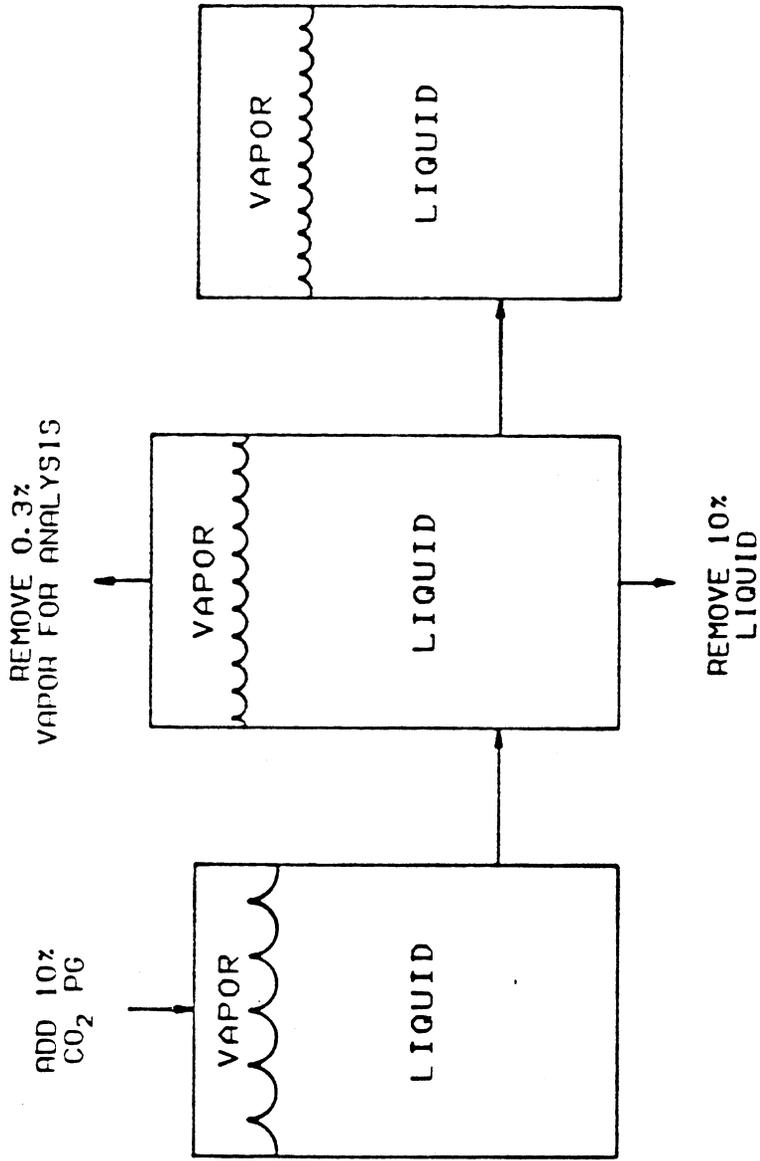
TBPGLC Analyses of Heavy Fractions

Carbon Number	B.P., °C at 760 mm	Volatility Distribution, Weight Percent			
		Vapor Phase			Liquid Phase
		Contact #9	Contact #10	Contact #11	Contact #11
4	-0.5	0.0	0.0	0.0	0.0
5	36.1	0.0	0.0	0.0	0.1
6	68.7	0.8	0.9	0.2	0.2
7	98.4	3.4	3.2	1.5	0.6
8	125.7	6.4	6.6	3.4	1.4
9	150.8	6.4	6.5	4.7	1.6
10	174.1	7.0	6.9	6.2	1.9
11	195.9	7.0	6.6	6.7	2.2
12	216.3	7.1	6.6	7.2	2.4
13	235.4	7.7	7.2	7.9	3.1
14	253.6	7.2	6.9	7.9	3.3
15	270.6	6.9	6.6	7.4	3.6
16	286.8	5.8	5.6	6.2	3.6
17	301.8	5.8	5.7	6.2	3.5
18	316.1	4.6	4.3	4.9	3.5
19	329.7	3.6	3.6	4.1	3.3
20	342.7	3.2	3.3	3.7	3.3
21	355.6	2.7	2.7	3.1	3.2
22	367.6	2.3	2.3	2.7	2.9
23	379.0	1.9	1.9	2.2	2.8
24	389.9	1.6	1.7	1.9	2.6
25	400.4	1.7	1.8	2.0	2.5
26	410.5	1.2	1.2	1.4	2.4
27	420.2	1.0	1.1	1.3	2.4
28	429.6	0.8	0.9	1.1	2.4
29	438.6	0.7	0.8	1.0	2.3
30	447.3	0.6	0.7	0.8	2.0
31	456.0	0.5	0.5	0.6	2.0
32	464.0	0.4	0.5	0.6	1.8
33	472.0	0.4	0.4	0.5	1.7
34	479.0	0.3	0.4	0.4	1.6
>34	>479.0	1.0	2.0	2.0	30.0

Envisioning the 120 foot target area as a well-mixed cell, CO₂PG was added in the top and the oleic phase was removed from the bottom. One liquid contact consisted of adding 10% by volume CO₂PG, letting it equilibrate, and then removing 10% by volume of the liquid phase. We began with the cell filled with saturated crude. When the liquid saturation in the reservoir became small, the liquid would no longer move. To account for this situation, we switched to vapor contacts after eight liquid contacts (24% liquid saturation). In a vapor contact, 25% by volume CO₂PG was added to the cell, the mixture equilibrated, and an equivalent volume of the vapor was removed. Figure B-1 is a schematic diagram of the liquid contacts and Figure B-2 illustrates the vapor contacts. During the liquid contacts, a small amount of vapor was removed for compositional analysis; no liquid was removed during the vapor contacts.

At each liquid contact, the composition, density, and volume of both phases were measured. The liquid was measured using a low temperature fractional distillation column (usually known by its trade name as a Podbielniak, or Pod, column). The vapor phase composition was analyzed using a gas-liquid chromatograph. Because this GLC cannot handle the heavy hydrocarbon fraction, the vapor phase was passed through a condensate trap before being sent to the chromatograph. The vapor analysis must be corrected for condensate in the trap. In Appendix A, the stripped gas analysis refers to the direct result of the chromatograph; the total refers to the analysis corrected for the heavies in the trap. The densities of both phases were measured indirectly. For the liquid phase, the volume of the sample removed was known, and the mass of the liquid calculated from the Pod analysis. For the vapor phase, the volume of the sample was also measured. The stripped gas volume was measured at room conditions to give a gas deviation (or z) factor. Combining this with the chromatographic analysis and correcting for the heavies in the condensate trap, a gas density could then be calculated.

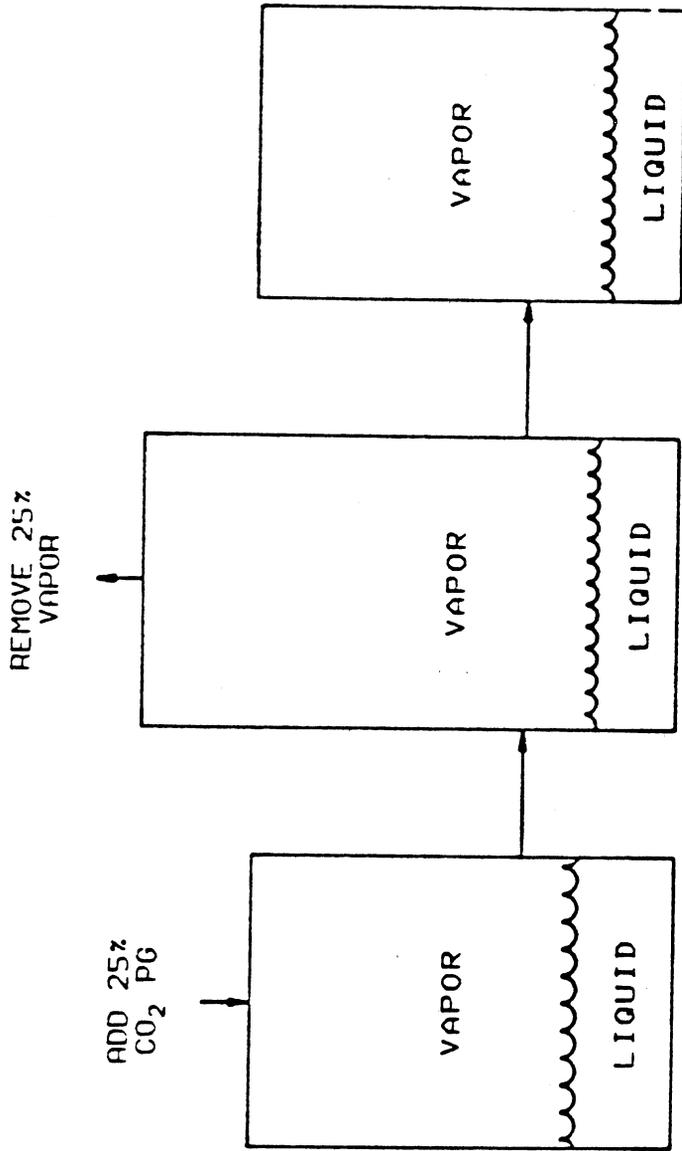
During the vapor contacts, the vapor phase composition and density were measured using the Pod column. Because Core Labs' chromatograph cannot handle liquids and because the Pod requires much larger samples than the GLC, it was not possible to measure liquid density and composition during the vapor contacts. After the final vapor contact, the liquid properties were measured using the Pod column.



ALL %'S ARE VOLUME % OF ORIGINAL VOLUME.

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Figure B-1 - Schematic of Liquid Contacts for Weeks Island Multiple Contact Experiments.



ALL %'S ARE VOLUME % OF ORIGINAL VOLUME.

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Figure B-2 - Schematic of Vapor Contacts for Weeks Island Multiple Contact Experiments.

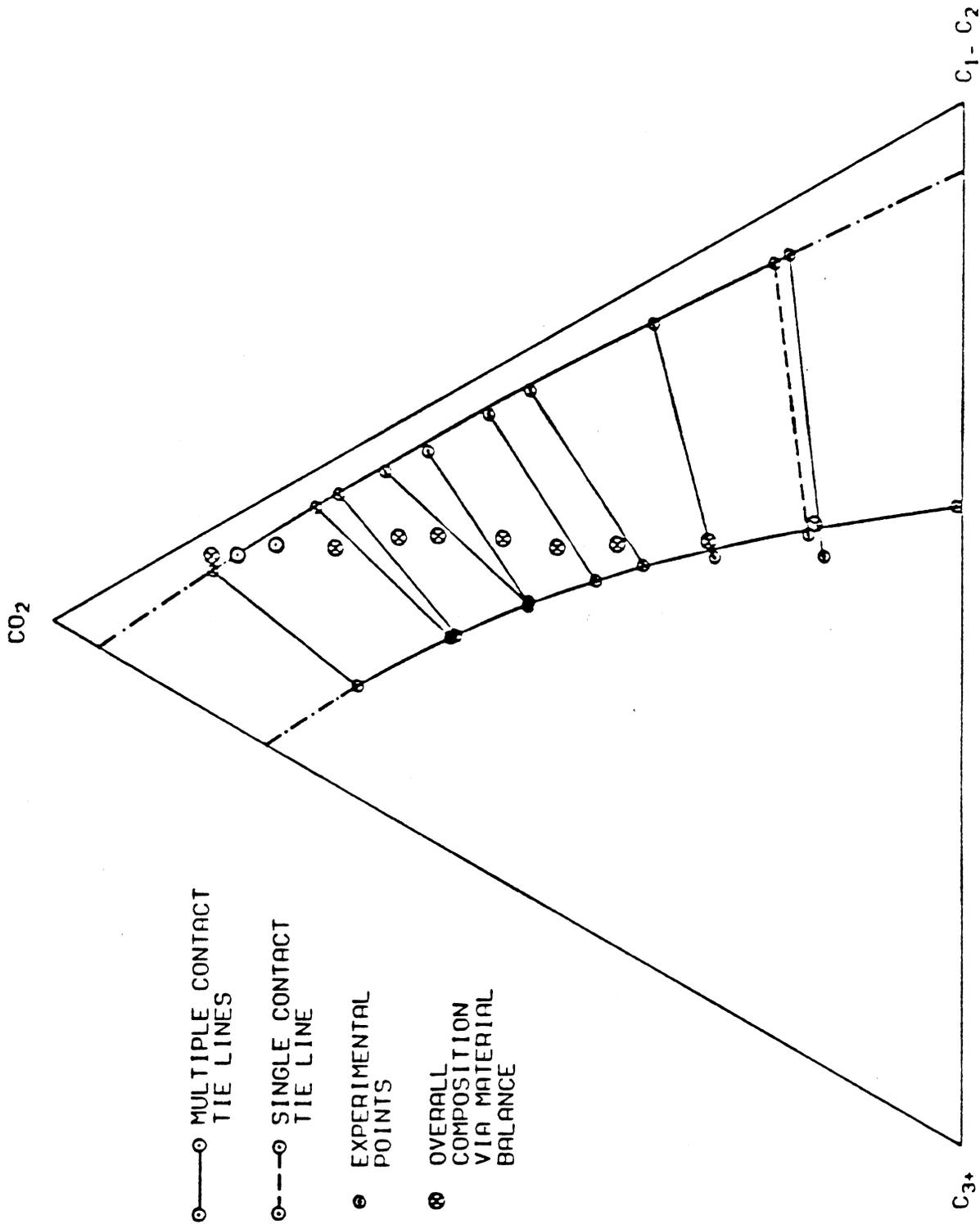
Since Core Labs has less confidence in the small vapor analyses using the GLC than with the Pod column, two comparisons were made. First, contact number one was run destructively. That is, all density and composition analyses were run on the Pod column. Since this required a large sample and there was little vapor phase, the experiment had to be restarted. On this restart, only a small vapor volume was analyzed using the chromatograph. At contact number nine, the first vapor contact, one sample of the vapor was sent to the chromatograph and one sample was sent to the Pod column.

Besides the density, volume, and composition data, two sets of viscosity data were taken. The viscosity of the original saturated crude and the single contact liquid (destructive contact number one) were measured using a rolling ball viscosimeter.

Experimental Results

Figure B-3 is a pseudo-ternary diagram constructed using phase volumes and the compositional analyses from the multiple contact experiments. This diagram is a useful summary of the experimental results. The hydrocarbon split at C_3 is somewhat arbitrary, but it was chosen so that approximately equivalent amounts of light and heavy ends are found in the original recombined crude. The dash-dot line segments indicate the expected continuation of the experimental dew and bubble point curves. No experimental data were taken in these regions, but these segments and the solid curves from the experimental data complete the phase envelope for Weeks Island crude and CO_2 at 5100 psig and 225°F. An important feature of the diagram is the interchange of CO_2 and the light ends of the crude oil. Although the injection gas is 95% CO_2 , the equilibrium vapor for the first contact is 75% C_1-C_2 . Another feature is that there is no way to move from the original crude concentration to very high CO_2 concentrations without passing through the two phase region.

Some of the features of the ternary diagram are also useful to determine the quality of the data. For example, tie lines can never intersect, but the tie lines from contacts 5 and 6 as well as those from 7 and 8 almost cross each other. The large open circle with an X is the overall composition calculated from material balance. If the data were exactly correct, these



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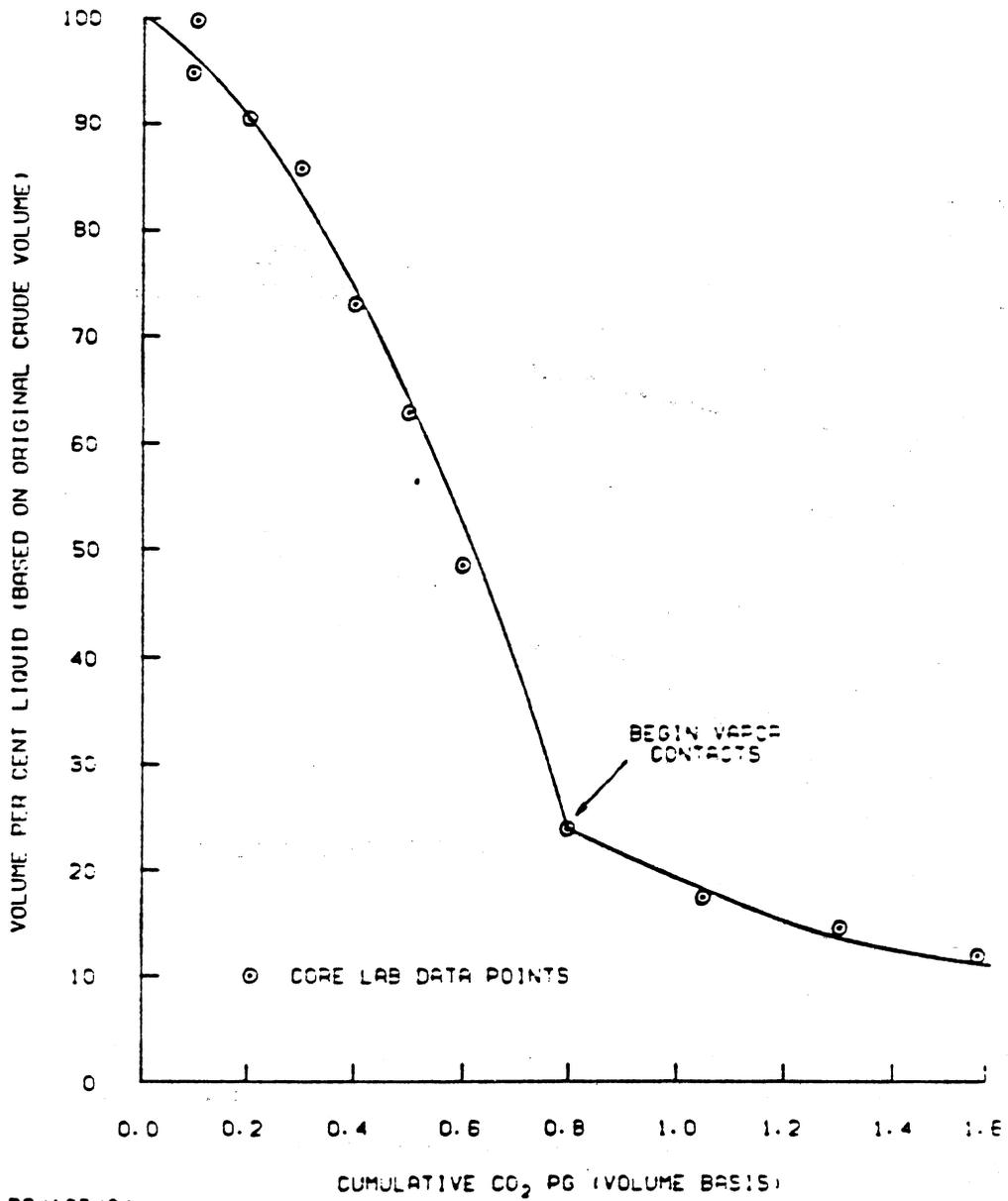
Figure B-3 - Pseudo-Ternary Phase Diagram for Weeks Island Crude and CO2 (5100 psig and 225oF)

circles should lie exactly on the tie lines. Finally, the single contact tie line and the contact number one tie line are duplicate experiments and the two tie lines should coincide. From these three observations, one can see that the quality of the data is fairly good. There are no gross errors, but the material balance is only fair and some of the tie lines almost intersect.

Figure B-4 is a plot of the liquid volume versus CO_2 PG added to the system. There was an error in contact number one for the multicomponent experiment because 3% of the volume was removed as vapor, rather than the 0.3% anticipated. To maintain a constant total volume, less liquid phase was removed. Because of the experimental difficulties in transferring between two small-windowed PVT cells, it was not always possible to maintain a constant volume. The amount of fluid removed at each liquid contact varied from 3-12%. Volumes are always reported relative to the original volume of the crude. There is some swelling of the oleic phase by the addition of CO_2 , particularly in the first few contacts. After eight contacts, the liquid volume is 24% of the original volume. During the vapor contacts, the volume continues to decrease, but between contacts ten and eleven little additional vaporization occurs and the remaining liquid is not very volatile.

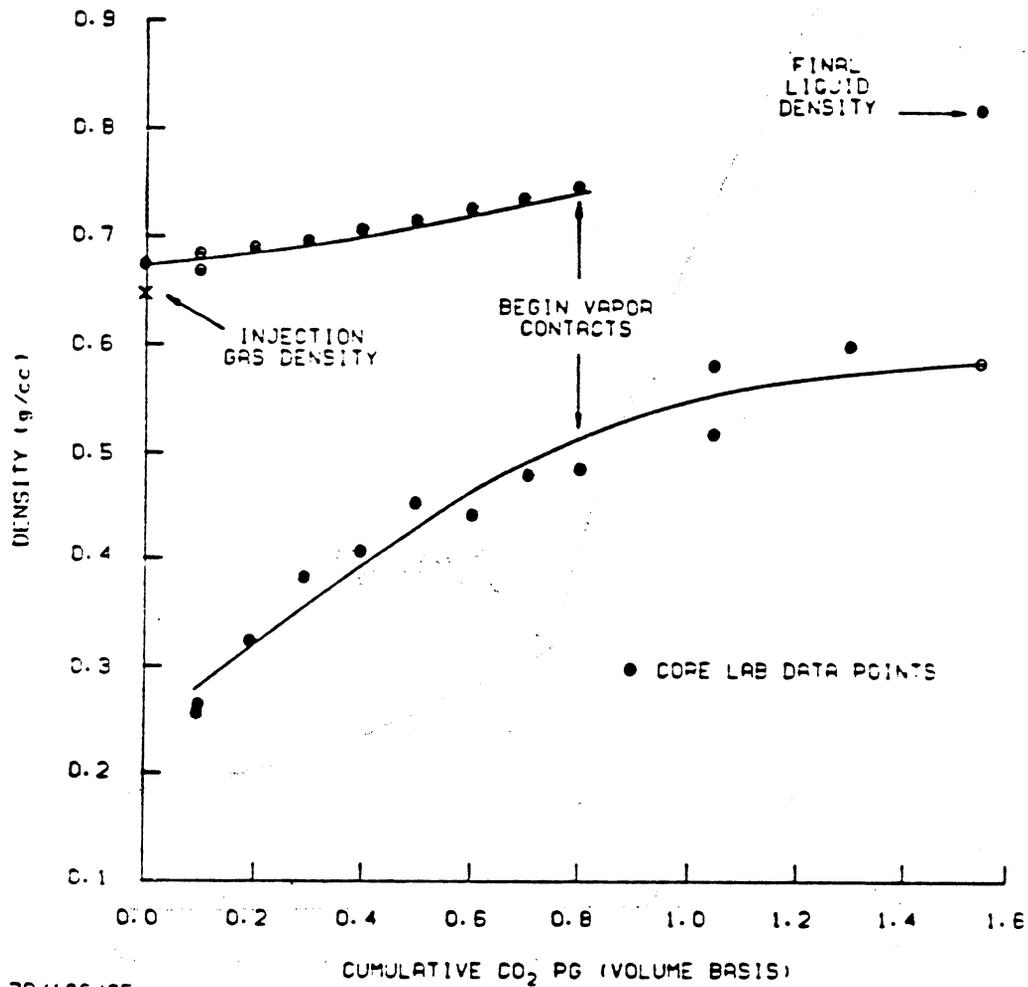
Figure B-5 is a plot of the liquid and vapor densities versus CO_2 PG added. These data are perhaps the most important pieces of information from the point of view of the process mechanisms at Weeks Island. The density difference between the CO_2 PG and the first contact vapor phase is particularly important. This density difference could have been anticipated from the CO_2 -light ends interchange shown on the ternary diagram. As more CO_2 PG is added, the density of the vapor phase increases due to increasing CO_2 content. The liquid density also increases, but not nearly so rapidly as the vapor density. Between the last liquid contact and the final vapor contact, no liquid densities were measured, but the vapor contacts remove a considerable portion of the light ends and the density increases from 0.745 g/cc at contact number eight to 0.820 g/cc at contact number eleven.

Whenever Core Labs ran a Pod analysis, the heptanes plus residue was saved and stored at 5°C. After the end of Core Labs experiments, fifteen samples were analyzed by Bellaire Research Center's Analytical



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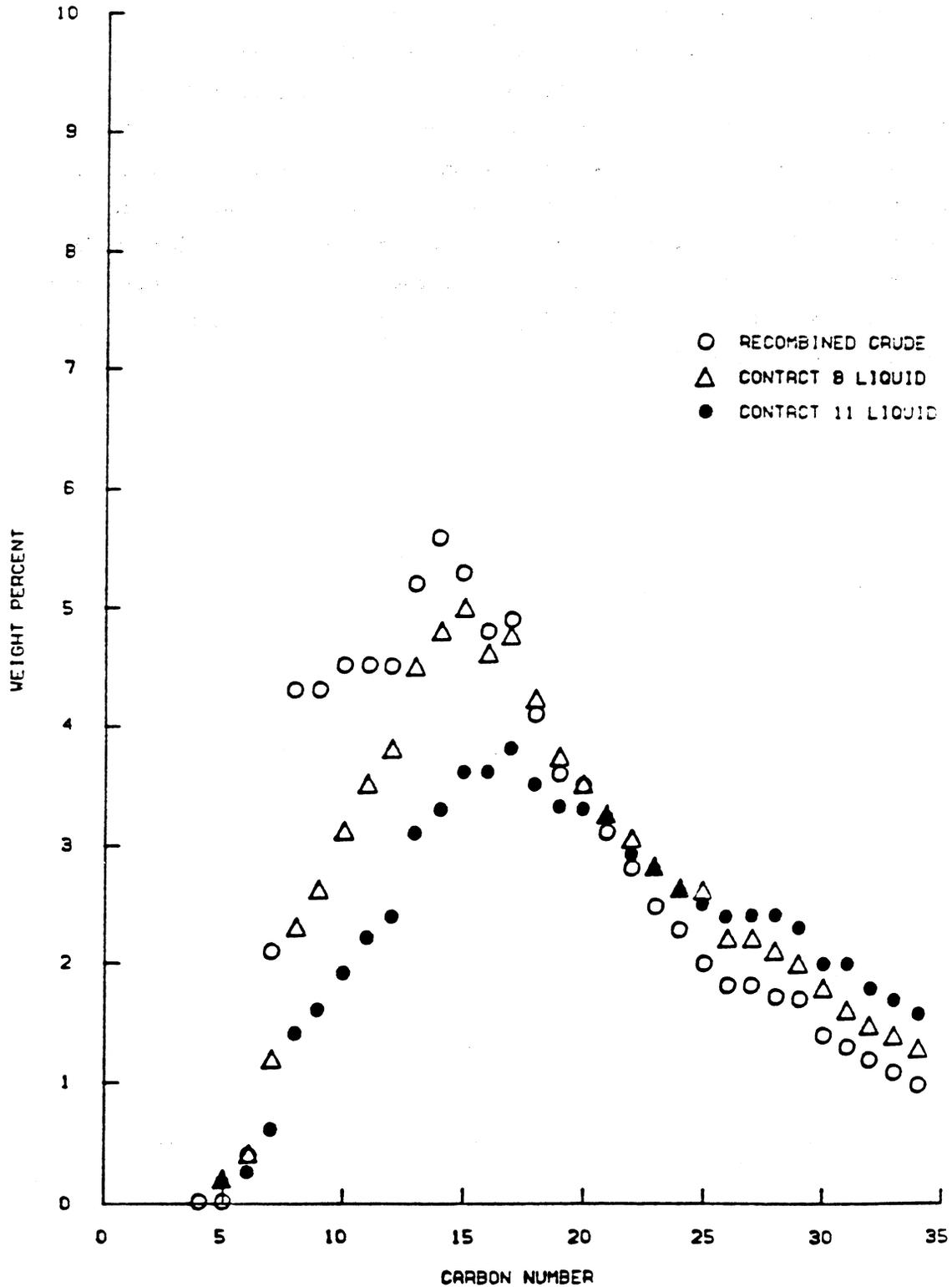
Figure B-4 - Liquid Volumes for Weeks Island Multiple Contact Experiments.



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Figure B-5 - Phase Densities for Weeks Island Multiple Contact Experiments.

Department using true boiling point gas-liquid chromatography (TBPGLC). The fifteen samples were the separator gas, separator liquid, single contact liquid, liquid samples from contacts 1-8 and contact 11, and the vapor samples for contacts 9-11. Tables B-1 to B-4 tabulate all these results and an estimated analysis of the recombined crude heptanes plus fractions. This estimate is based on the analyses of the separator gas and liquid and used a ratio of 0.9888 parts by weight liquid to 0.0122 parts separator gas. Figure B-6 is a plot of the carbon number distribution for three liquid samples - the recombined crude, the eighth contact liquid, and the eleventh contact liquid. This figure shows that carbon numbers up to 20 are extracted by the CO₂.



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Figure B-6 - Weeks Island Liquid Residue Analyses for Multiple Contact Experiments.

APPENDIX C

MATCHING WEEKS ISLAND CRUDE OIL-CO₂ PHASE BEHAVIOR WITH COMPOSIM'S PHASE PACKAGE

Introduction

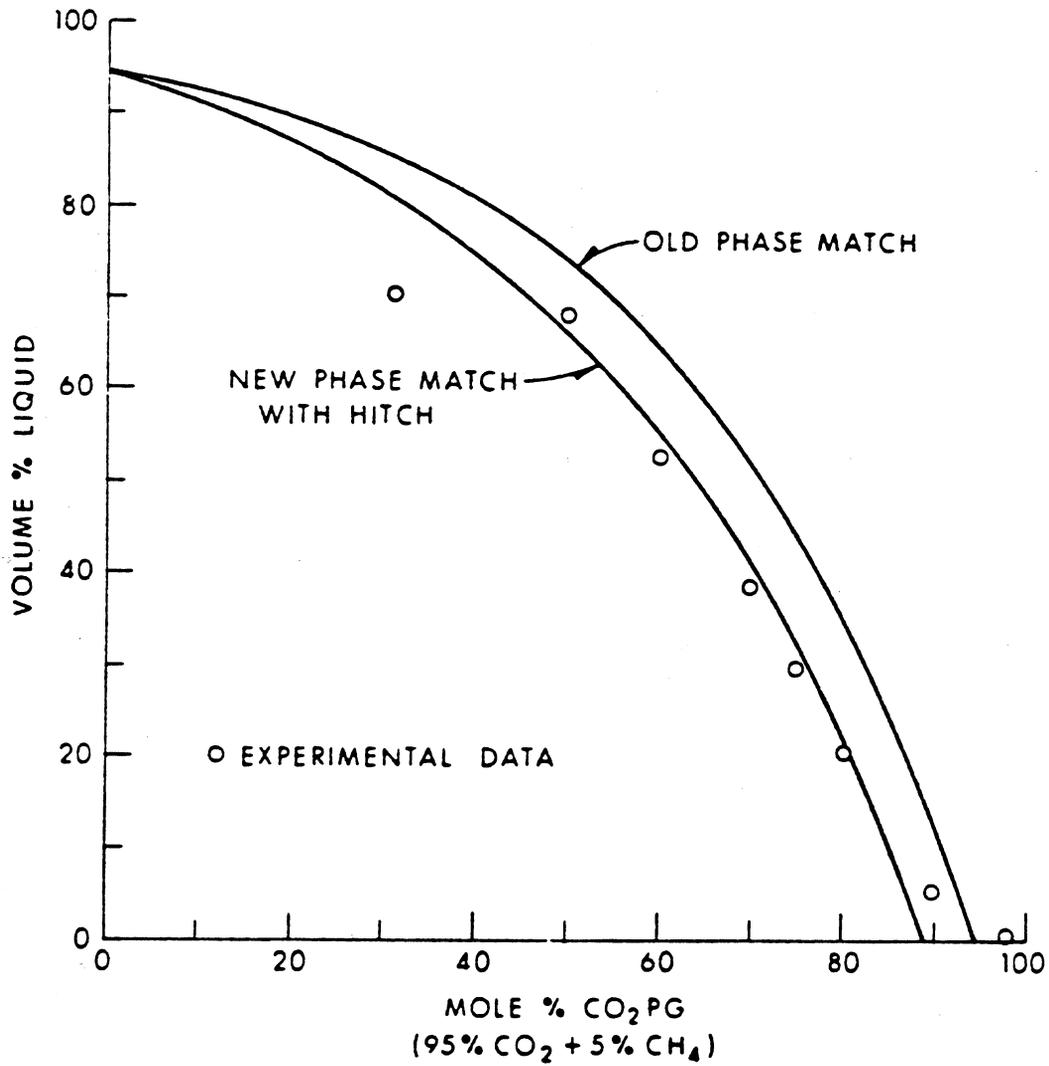
It is necessary to use a fully compositional simulator, such as COMPOSIM, to describe the complex phase behavior expected in the Weeks Island CO₂ flood.^{1,6} The first step in using COMPOSIM is tuning the phase behavior package to match the laboratory data.

Earlier, a match had been generated for the first contact Weeks Island CO₂ experiments³ for the entire CO₂ concentration and pressure (1000-10000 psig) range. Matching the dew point curve in the retrograde region was particularly difficult. In fact, to generate any reasonable match above the critical pressure (~6000 psig) required that a discontinuity be forced into the convergence pressure calculation. This phase description was used in the early simulations of the Weeks Island CO₂ flood with COMPOSIM. Although this discontinuity in the convergence pressure did not cause discontinuities in the calculated phase envelope for the first contact data, it did cause problems with the simulations themselves because of the multiple contact nature of the simulation. Grid blocks that had previously been entirely oil became all gas within one time step. This, of course, distorted the flow patterns near the "offending" grid block and unnecessarily slowed the simulator down.

New Phase Match

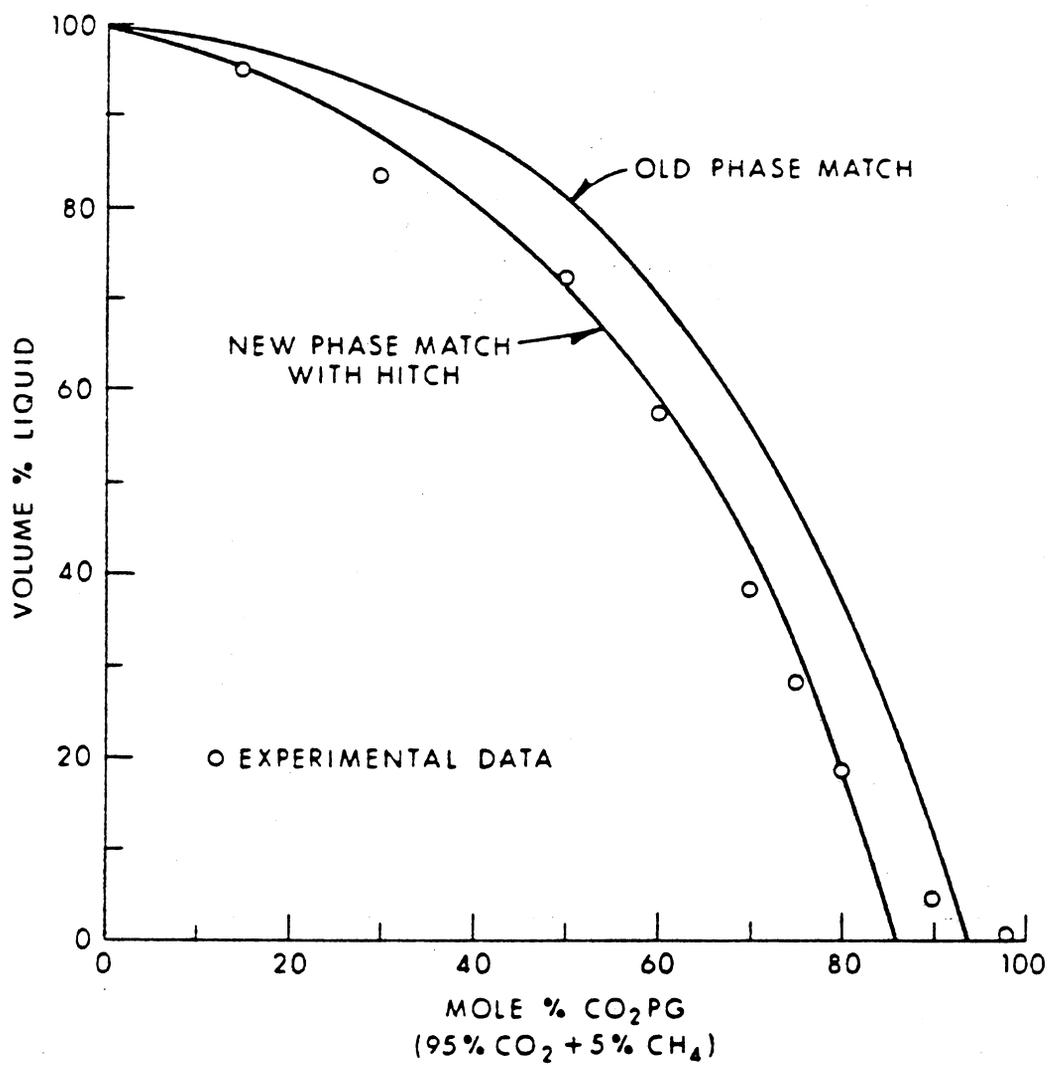
With this problem in mind, it was decided to re-do the phase package match with several important differences. First, no discontinuities in the convergence pressure were allowed. Secondly, only the pressure range 4700-5500 psig would be matched. Since the expected pressure at the Weeks Island pilot is ~5100 psig and the process is essentially constant pressure, this should cover the range of pressures expected during the pilot. Thirdly, a modified version of HITCH, an automatic history matching program for reservoir simulators, was used to determine the best values of the matching parameters.

In particular, the calculated liquid saturation versus CO₂PG (95 percent CO₂ + 5 percent plant gas) concentration at 4700, 5100, and 5500 psig was compared to the experimental data. Figures C-1 to C-3 show the



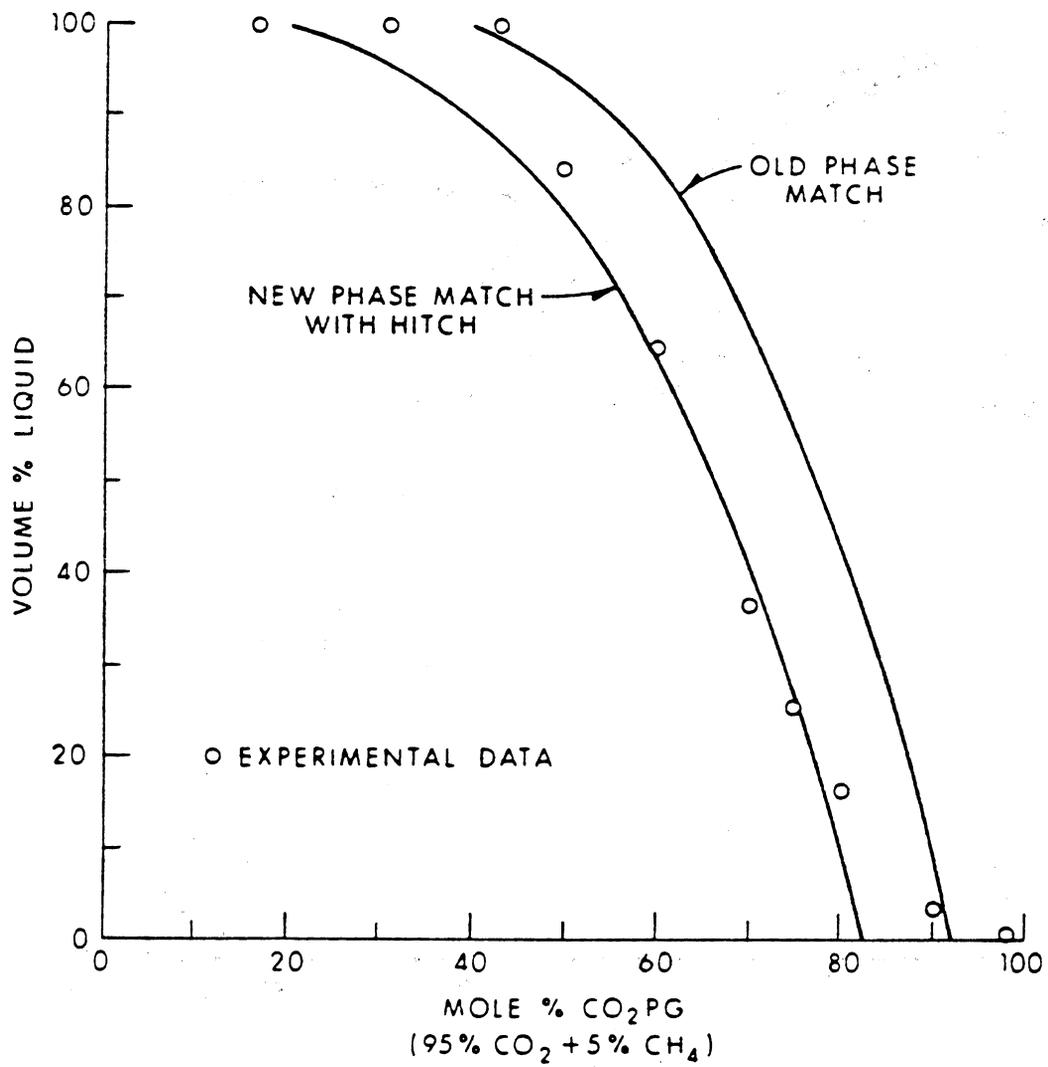
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Figure C-1 - Liquid saturations at 4700 psi.



78-0432-3

Figure C-2 - Liquid saturations at 5100 psi.



78-0432-2

Figure C-3 - Liquid saturations at 5500 psi.

original match and the new match found by HITCH. In the new match, the matching parameters were constrained within 20 percent of the old values. Runs with 40 and 60 percent variations failed to improve the saturation comparisons and made other data, e.g. densities, worse.

The new saturation match is much better than the original below 80 percent CO₂PG. Above 80 percent CO₂PG, neither match predicts the proper "tail". In this pressure range, the system is calculated to be single phase above ~85 percent CO₂PG; in fact, the system is still two phases at 98 percent CO₂PG. This implies that if vaporization of oil is an important mechanism to remove the oil, the calculations will predict optimistic recoveries; there is an additional uncertainty because the experimental data is first contact data only and any vaporization recovery mechanism in the reservoir will certainly be the result of multiple contacts. The lack of a tail is believed due to the lumping of all heptanes plus as one component; certainly most of the literature has suggested the need for more than one heavy component to predict the phase behavior adequately.⁷⁻¹⁰ The old phase match will not be as optimistic with respect to a vaporization mechanism because it predicts a dew point at ~90 percent CO₂PG; on the other hand, it will certainly be more optimistic if swelling of the oil is an important recovery mechanism. For Weeks Island, it is not known which effect is more important.

Since COMPOSIM runs with the original phase description require one to two weeks' elapsed time to complete (more than ten hours UNIVAC 1110 C.A.T. time), it is not presently desirable to add components. Therefore, the new match is thought to be the best possible with the present description of the heavy component. Since the intermediate components C₂-C₆ compose about 10 mole percent of the Weeks Island crude, a future improvement may be to lump the intermediate components and split the heavies.

Although there is a regression package that accompanied the COMPOSIM phase package, it has two major drawbacks that make it unfeasible for the uses described here. First, it is set up only to match four basic PVT tests - constant composition expansions, constant volume depletions, differential liberations, and swelling tests. Secondly, there is only a limited number of variables that can be used as matching parameters. With HITCH, any type of phase experiment can be matched; any set of response variables (with varying weights) are

possible; and any input variable can be used as a matching parameter. This high degree of flexibility is certainly desirable for matching CO₂ phase behavior data for which there are many types of experiments. It also allows emphasis to be placed on the more important experiments. The use of any input variable as a matching parameter has interesting possibilities; e.g. the split of the heavy component might be a regression variable because this is one of the major unknowns with crude oil systems.

Results and Conclusions

1. A new match of the first contact Weeks Island CO₂ experimental data has been generated for the COMPOSIM phase package.
2. The new match is preferable to previous matches for the following reasons:
 - (a) No artificial discontinuities in the convergence pressure are allowed. This prevents non-physical changes of liquid to vapor.
 - (b) Below 80 percent CO₂PG, the new match calculates the liquid saturation much better than previously.
3. The previous match might be preferable for the following reasons:
 - (a) The old match covered the entire pressure range of the first contact experiments (1000-10000 psig) although most of the Weeks Island CO₂ pilot should occur at 5000 = 500 psig.
 - (b) The old match kept the system two phase up to a dew point of ~90 percent CO₂PG. The new match predicts lower dew points (~85 percent), but experimental data indicates the dew point is greater than 98 percent.
4. Within the next year, both the single contact and multiple contact data will be coupled with HITCH to generate the best possible COMPOSIM description of the Weeks Island crude oil-CO₂ phase behavior.

APPENDIX D

MODELING THE WEEKS ISLAND CO₂ FLOOD: PROCESS MECHANISMS

Introduction

Since compositional dependence of fluid properties is a necessary feature of any description of the Weeks Island CO₂ flood, a compositional simulator, such as COMPOSIM, must be used in any mathematical model of the process. COMPOSIM uses the convergence pressure to correlate the K-values. This approach to phase behavior was initially used in the natural gas industry and was not designed for crude oils and CO₂ at reservoir conditions. Therefore, before any simulations can be made with COMPOSIM, the phase package predictions must be compared to laboratory phase experiments, particularly those using CO₂. In most cases, some of the parameters must be adjusted to obtain the best fit. This step had already been accomplished for the single contact experiments with Weeks Island crude and CO₂ (Appendix C). Multiple contact experiments for Weeks Island were completed in December 1978, but these data have not yet been used in any COMPOSIM modeling (Appendixes A and B).

Model Description

The Weeks Island CO₂ pilot is being conducted in the "S" Sand B Reservoir--a steeply dipping, highly permeable reservoir. CO₂PG (95 percent CO₂ and 5 percent plant gas) will be injected just above the gas-oil contact and push the small oil rim (~10 feet) and waterflood residual oil downdip to be captured by the producing well, A-17, 120 feet below the injector.⁶ The region of the reservoir between the gas-oil contact and the producing well is the target, and any references to pore volume refer to the volume of this region.

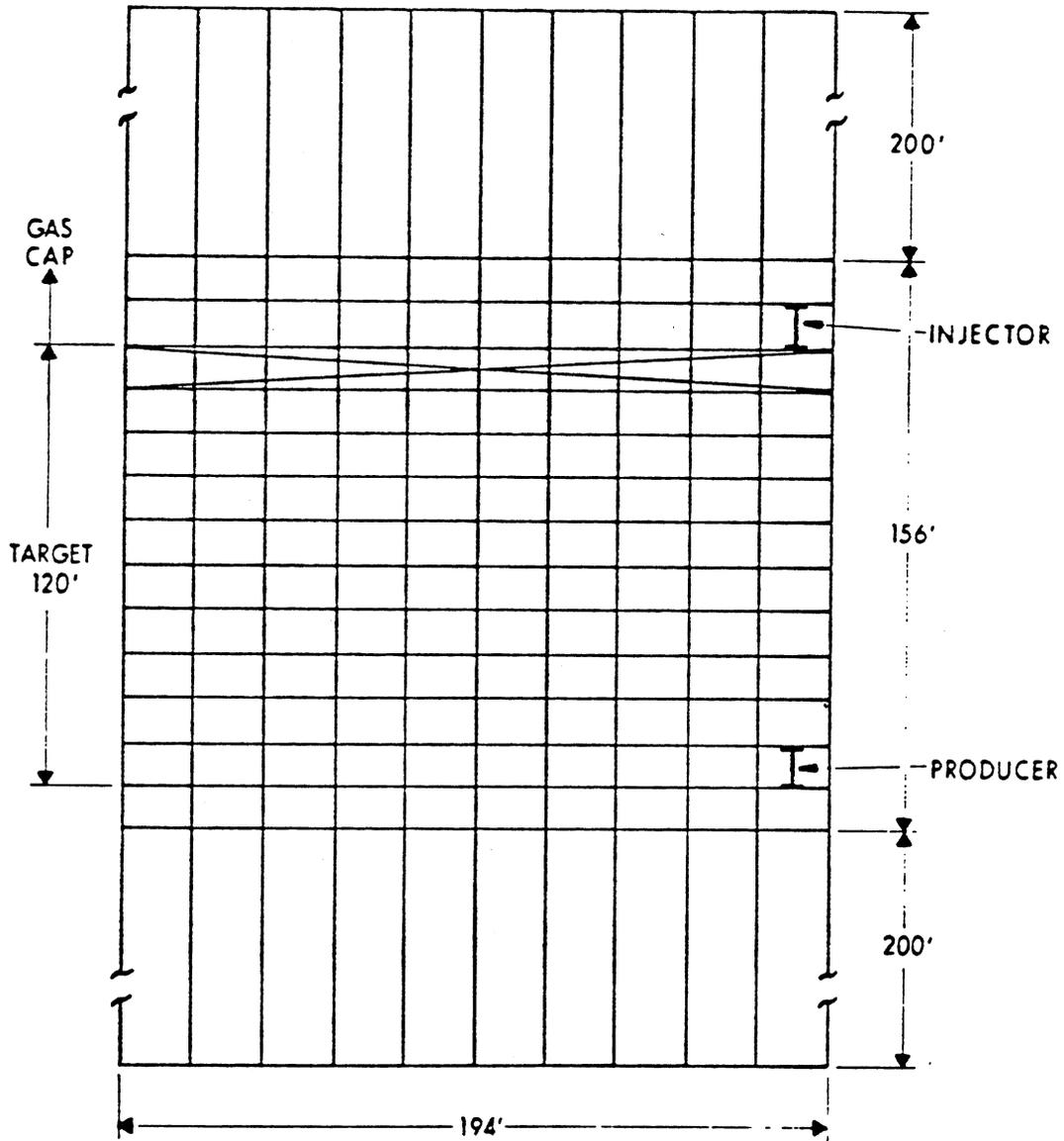
Because COMPOSIM run times are so slow and because the process is so complex, it is imperative that the reservoir description, at least at first, be as simple as possible. In early simulations, we included only the 120 foot target region and used rows of wells in the top and bottom layers to model the gas cap expansion and the downdip water producer. Because of symmetry, it is only necessary to model half of the reservoir. In addition, as we learned more about the process, it became necessary to add

layers of grid blocks above the gas-oil contact and below the producer perforations. The description of the 120 foot target has remained the same in all simulations. This model is admittedly not the most realistic description of the reservoir, but it is the simplest approximation, which contains the necessary features of the process. The emphasis is on process mechanisms, not on accurate estimates of oil recovery.

Figure D-1 depicts the reservoir model used to date. The difference between the various models used is the additional layers outside the target area and the location of the CO₂ injector. To obtain the correct initial fluid distribution, the layer immediately below the gas-oil contact was filled entirely with oil, except for connate water. All layers below this oil rim were at the waterflood residual oil saturation of 27 percent. The simulator was allowed to idle for 30 days to reach capillary equilibrium. This resulted in the original 93 percent oil saturation in the top layer being spread over the two top layers in the target area. In the first two runs, the CO₂ injector was immediately below the gas-oil contact. In the more recent runs, it is just above the contact.

After the idling period, a mixture of 94.25 percent CO₂, 5.56 percent CH₄ and 0.19 percent C₂H₆ was injected at a rate of 1250 RB/day. In the first two simulations, the rates were 1500 RB/day and 1000 RB/day, but little difference could be observed in the recovery at a given throughput. In all other runs, a rate of 1250 RB/day was used. Since all rates used in the simulations are constant, times will be reported on a pore volume basis. One pore volume is equivalent to 1440 days at 1250 RB/day. During the injection of the CO₂PG, a row of water producers in the bottom layer balanced the injection. This row simulates the effect of the G-2 well, which is approximately 500 feet below the injector. In these simulations, 0.4 PV of CO₂PG was injected; this differs from the pilot in that only 0.26 PV is planned to be injected. This error does not affect any basic conclusions about process mechanisms, but future simulations will use the 0.26 figure. After the 0.4 PV injection period, the oil bank is just above the perforation intervals for Well A-17, which is the oil producer. Well A-17 then produces for 0.6 PV at a total volumetric rate of 1250 RB/day with the gas cap expansion simulated by a row of gas injectors in the top layer. Since gas breakthrough occurs early in the production phase and

WEEKS ISLAND SIMULATION
CROSS SECTION GRID SYSTEM



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Figure D-1 - Model Geometry - Cross Section.

no coning model is used in COMPOSIM's well model, the production phase is not as well described as the injection, but there is much less interaction of phase behavior and fluid mechanics in this portion of the project.

Results

Table D-1 summarizes the five COMPOSIM runs made as of February 1979. All estimates of recovery efficiency have been purposely omitted from this report, because they might be misleading. Those numbers are, of value, only in a relative sense; i.e., comparisons between the different runs. Any attempt to use them in an absolute sense at this stage of our understanding of the process would be wrong. From relative comparisons among the runs, three conclusions can be drawn. First, there is only a minor effect of rate in the range 1000-1500 RB/day. Secondly, it is important to inject above the gas-oil contact. Thirdly, changing the phase package can significantly alter the results. As discussed in Appendix C, the original phase description sacrificed accuracy in the range of interest for the pilot in order to match the data over the entire range of the first contact experiment. Since the newer match calculates a lower liquid saturation at a given pressure and composition, the oil relative permeability is lower and the results are poorer in the runs with the new phase match. Besides the run comparisons, Table D-1 also gives some appreciation of the difficulty in modeling the Weeks Island pilot. The elapsed time figure is perhaps the more important because it tells how long it takes to get an answer after the input deck is submitted.

The major achievement of this modeling effort is shown in Figure D-2. Figure D-2 is a picture of the color display system showing run 5 at the end of the injection period. Only layers 3-12 are shown on the picture. A ternary color diagram is used to represent the saturations; red represents the vapor phase, green the oleic phase and blue the aqueous phase. The vectors represent the Darcy velocity of the vapor phase; the magnitude scale is logarithmic with the longest vectors being 1.0 foot/day and the shortest being 0.02 foot/day. The frontal advance rate for 1250 RB/day is 0.08 foot/day. The injection gas does not spread out like "a blanket" and then move down as originally envisaged; rather, it slumps down below the injector.

This slumping phenomenon is a direct result of phase behavior. As CO₂ contacts crude oil, there is an interchange of CO₂ and the light ends of the crude oil. The vapor phase in contact with the crude oil is methane-rich and much less dense than the CO₂-rich vapor phase above it around the injection

A color copy of Figure D-2 can be obtained from G. E. Perry, Shell Oil Company, P. O. Box 60123, New Orleans, LA 70160.

Table D-1

SUMMARY OF COMPOSIM RUNS

8 Hydrocarbon Components + H₂O
 27% Residual Oil to Water; 25.5% Porosity
 1400 md Permeability
 410,000 STB Oil in Target Area; 1,360,00* MSCF CO₂ Injected

Injector Location	Grid Block Size	Rate RB/day	Phase Package	C.A.U. Time Hrs.	Elapsed Time Days
Below GOC	10 x 1 x 10	1500	Original	7.0	10
Below GOC	10 x 1 x 10	1000	Original	12.3	9
Above GOC	10 x 1 x 12	1250	Original	11.8	8
Above GOC	10 x 1 x 13	1250	Modified w/HITCH	9.4	10
Above GOC	10 x 1 x 15	1250	Modified w/HITCH	11.7	18

* 1,430,000 MSCF CO₂ were injected in 10 x 1 x 12 case

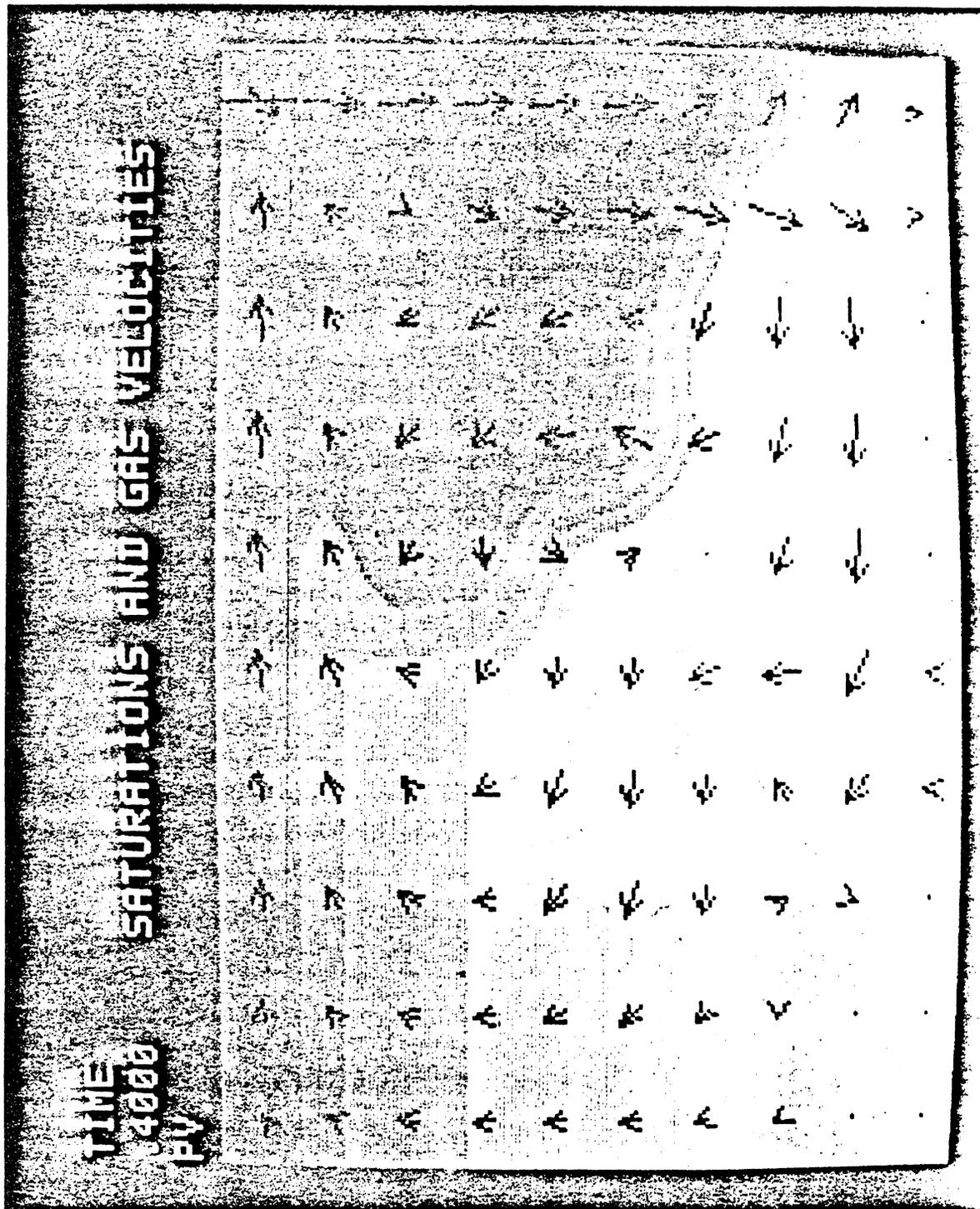


Figure D-2

A color copy of Figure D-2 can be obtained from:

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

well. This instability of dense vapor on top of light vapor drives the circulation cell that is dramatically shown in Figure D-2. A second observation about the circulation cell is that there is only one cell. If there were many cells, the model with only 150 grid blocks would be inadequate to describe the process. With the large density contrast in the vapor phase and the high permeability, the injection gas falls very rapidly until it hits the crude oil; the high momentum of the falling vapor distorts the gas-oil interface. The methane-rich vapor naturally wants to rise, but cannot go up directly because of the falling CO₂. Because horizontal communication is good, the vapor does not flow upward until it reaches the side of the reservoir. This circulation in the vapor phase results in a process very different from our original concept of Weeks Island.

Remarks

A major uncertainty in these simulations is the relative permeability. The oil banks generated tend to spread out and the oil left behind may be higher than residual oil in some regions of the reservoir. The two-phase gas-oil relative permeability curve is based on some limited centrifuge data for air displacing oil in a Weeks Island core. The gas-oil relative permeability curves from the centrifuge are combined with the water-oil curves in the simulator using Stone's three-phase relative permeability model.¹¹ At high gas saturations, the three phase model predicts a drastic decrease in the oil relative permeability due to the presence of water. Because of uncertainty in the two phase relative permeability data and in Stone's model itself, we do not know if the predicted decrease in oil relative permeability will take place in the field.

Conclusions and Future Work

1. Because of the interphase mass transfer between CO₂ in the injection vapor and the light ends of the crude oil, there is an instability in the simplified process mechanisms model of the Weeks Island CO₂ pilot. This causes slumping of the vapor phase immediately below the injection well and poor sweep efficiency in the regions farthest from the injector. Although this phenomenon is consistent with all the physical principles involved, the nature and degree of the CO₂ slumping in the actual field test are undetermined because of the simplifications and limitations of the present model.

2. The relative permeability is a major uncertainty in these simulations. A future goal of this research is to determine the sensitivity of the

process to differences in relative permeability and its interaction with phase behavior.

3. In conjunction with 2 above, the multiple contact experimental data will be incorporated into the COMPOSIM phase package to obtain the best possible phase description of the Weeks Island crude oil and CO₂.

4. Prior to making parameter sensitivity to studies or adding a more realistic geometric description, COMPOSIM run times must be substantially decreased. By decreasing the number of components and improving the time step selector, it is likely that ten hour runs can be decreased to two hours. If successful, many of the unanswered questions about the process mechanisms can be resolved.

APPENDIX E

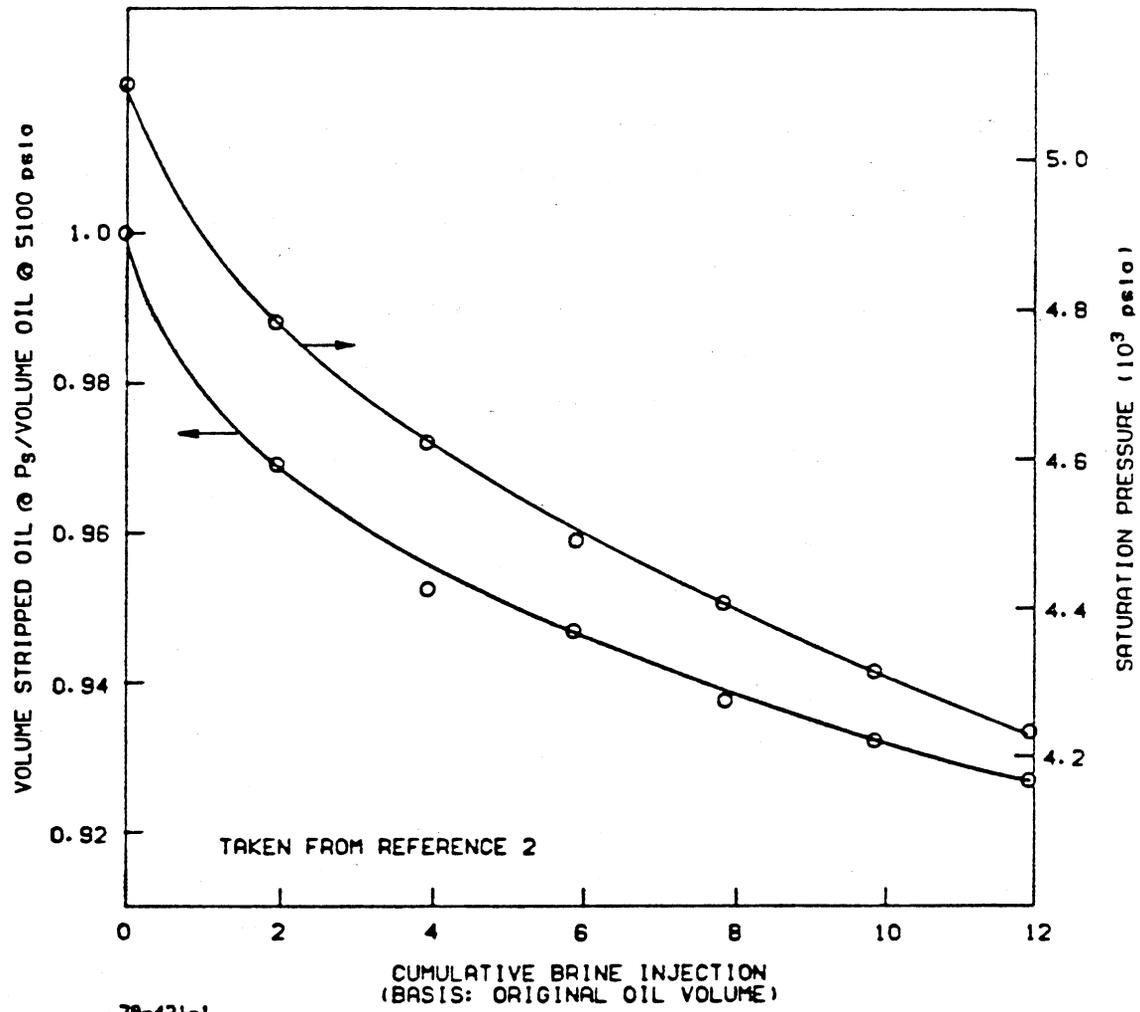
ESTIMATION OF SHRINKAGE OF WEEKS ISLAND SRB CRUDE DURING BRINE INJECTION FOR LOG-INJECT-LOG

Introduction

During the recently conducted Log-Inject-Log operation to determine the value of residual oil saturation in the Weeks Island SRB Reservoir, a methane-free brine was injected into the reservoir.⁶ Since the in-place oil is saturated with methane, some transfer of methane from the residual oil to the injected brine would be expected. This would result in a shrinkage of the oil. As a consequence, the oil saturation in the area of investigation of the Log-Inject-Log would be lowered. The purpose of this report is to document the experimental and theoretical investigations involved in the determination of the volume corrections applied to the residual oil saturation values obtained from the Log-Inject-Log method.

Experimental Data

In order to investigate the magnitude of gas-stripping by brine under Weeks Island SRB Reservoir conditions, a series of shrinkage experiments were run using recombined SRB crude and produced brine.¹ The procedure was to charge a known volume of crude oil to a high pressure cell and then add twice that volume of brine. After equilibrium is reached by agitating the cell for a sufficient time, the brine was removed from the cell and the saturation pressure and the corresponding volume were determined for the oil. Five additional brine contacts were repeated so that the oil was sequentially contacted with a total of twelve volumes of brine in two-volume increments. Figure E-1 shows the relative oil volume defined as the volume of stripped oil at its bubble point divided by the volume of the unstripped oil at its bubble point (5100 psia) as a function of brine volumes contacted. Also shown in this figure is the dependence of saturation pressure of oil on the successive brine volumes contacted. These data indicate that with 12 volumes of brine contacted, the oil volume was reduced to 92.7 percent of the original and the saturation pressure declined to 4232 psia. Furthermore, both oil volume and saturation pressure did not level off, indicating that additional reductions would be anticipated with continued brine contacts.



78-421-1

Figure E-1 - Bubble point pressure and relative volume of Weeks Island crude stripped by produced brine at 225°F.

Extension of Experimental Data to the Weeks Island Log-Inject-Log Conditions

During the Weeks Island Log-Inject-Log operation, 200 and 140 barrels of 30,000 ppm NaCl brine were injected in two steps. For a radius of investigation of about 1 foot around the wellbore, the first injection volume was 280 times the initial oil volume and the second injection makes the total volume of 30,000 ppm brine injected equal to 476 times the original oil volume.

In order to develop a mathematical model to extrapolate the laboratory data to the much greater brine throughputs actually used in the field, it is assumed that there are no concentration gradients within either phase in the zone of investigation, and that instantaneous equilibrium is achieved between the aqueous and oil phases. With these assumptions, the stripping process can be treated analagous to a continuous flow stirred tank reactor. Then, it can be shown that the methane content of oil due to the transfer of methane from the oil phase to the aqueous phase is represented by

$$\frac{R_s(\tau)}{R_s(\tau=0)} = \exp \left[- \frac{\tau K}{\left(\frac{V_w}{V_o} K + 1 \right)} \right] \quad (E-1)$$

where

$$V_w = \frac{S_w PV}{B_w} = \text{water in investigated region, STBW}$$

$$V_o = \frac{S_o PV}{B_o} = \text{oil in investigated region, STBO}$$

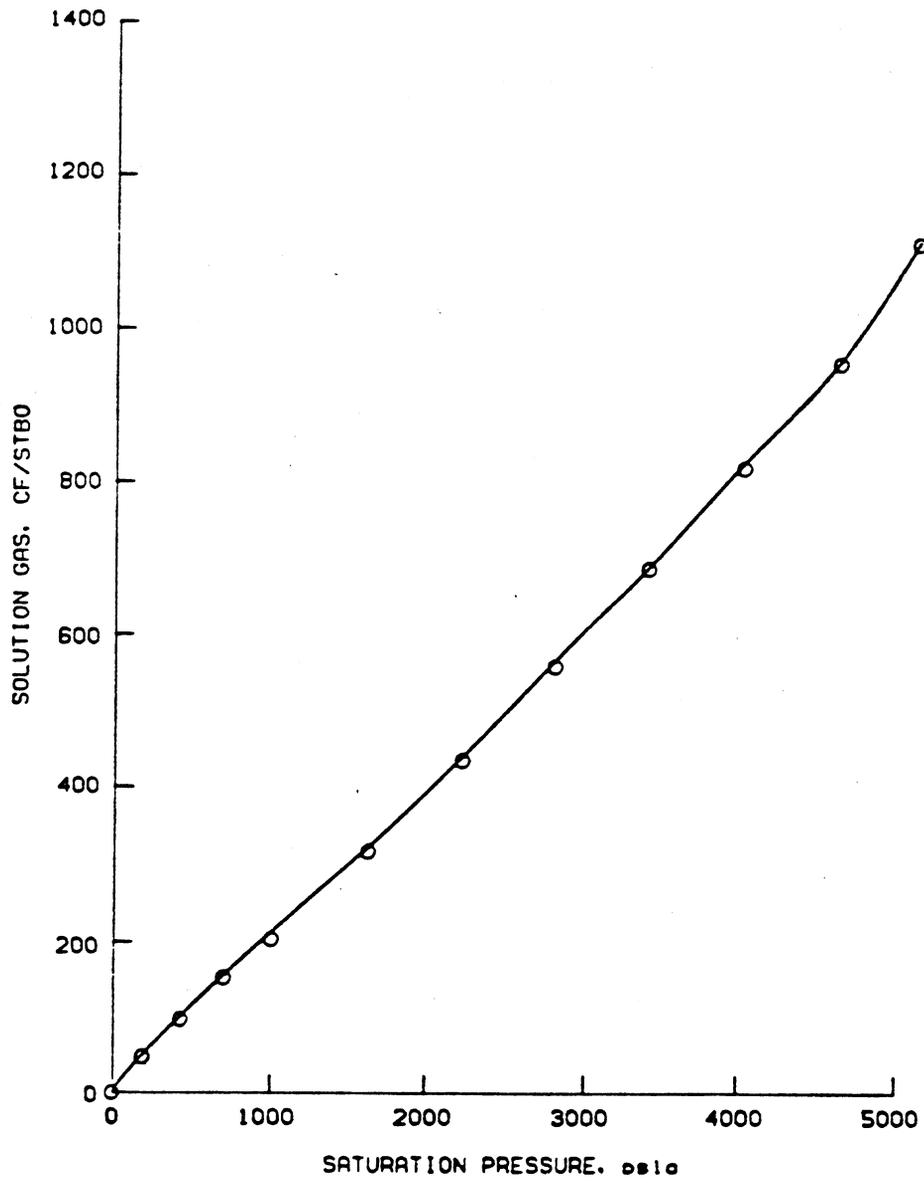
$$R_w = \text{methane dissolved in water phase, MCF/STBW}$$

$$R_s = \text{methane dissolved in oil phase, MCF/STBO}$$

$$K = \frac{R_w}{R_s} = \text{partition coefficient of methane between the oil and water (MCF/STBW/MCF/STBO)}$$

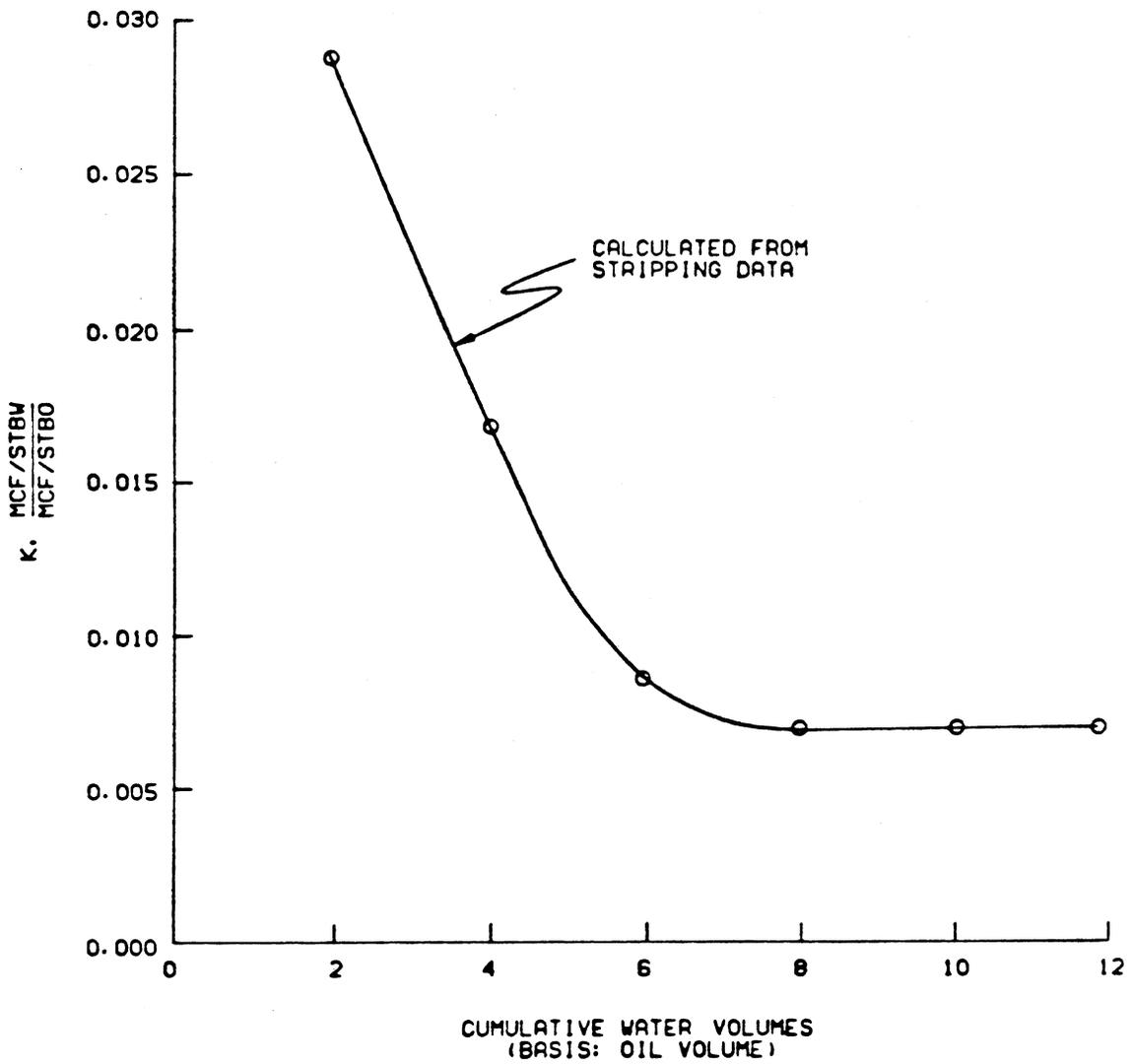
$$\tau = \frac{Q_w t}{V_o} = \text{cumulative water injection in STO volumes}$$

The partition coefficient K was calculated by using the gas liberation data (Figure E-2) contained in a standard PVT report and the saturation pressure of the stripped oil (Figure E-1). The results are presented in Figure E-3.



78-421-2

Figure E-2 - Solution gas as a function of saturation pressure for Weeks Island SRB crude oil.



78-421-3

Figure E - 3 - Partition coefficients calculated from shrinkage data for the Weeks Island SRB.

It is seen that the calculated K value approaches an asymptote of 0.0072 at large values of brine throughput.

In order to determine the oil shrinkage (defined as the volume of stripped oil divided by the volume of saturated oil, both at 5100 psia), the relative oil volume as a function of methane content is necessary. This relationship can be obtained from differential liberation data by correcting the relative volume at P to the original bubble point pressure using a constant oil compressibility. Figure E-4 shows the relative oil volume at 5100 psia as a function of R_g for Weeks Island SRB crude oil.

The oil shrinkage was calculated as a function of brine throughput using Equation E-1 and the relative volume data of Figure E-4 at three values of K. The results are summarized in the table below:

Partition Coefficient (K)	Shrinkage at		S_o at*	
	$\tau = 280$	$\tau = 476$	$\tau = 280$	$\tau = 476$
.0072	.715	.681	.193	.184
.0036	.782	.725	.211	.196
.016	.675	.650	.182	.176

* Assuming the oil saturation before shrinkage equal to 0.27.

It is seen that, under the Weeks Island SRB conditions, significant shrinkage of oil is expected to take place in the immediate vicinity of the wellbore during the Log-Inject-Log operation. With the most conservative K value of 0.0072, the shrinkage of oil is 0.681 at $\tau = 476$. If the K value was about twice as large, the oil shrinkage would be 0.65. This value is also the maximum shrinkage inferred from the PVT data which would have occurred if all solution gas had been stripped from the oil.

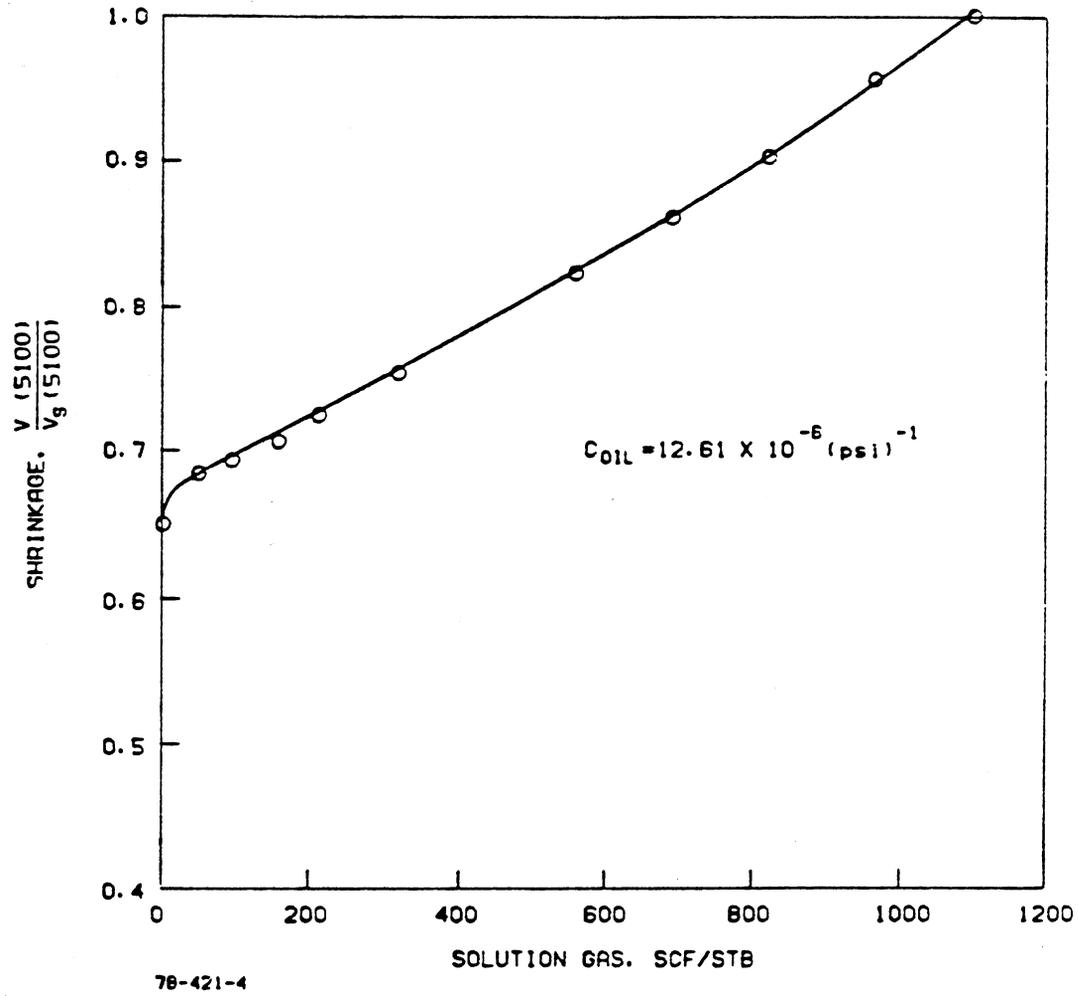


Figure E-4 - Shrinkage data based on Weeks Island SRB PVT report.

ATTACHMENT 2 - CORE ANALYSIS

EPR 373
1/69

SHELL DEVELOPMENT COMPANY
TECHNICAL SERVICE
RESIDUAL-INITIAL AIR SATURATION DATA REPORT
(Liquid-Air Countercurrent Imbibition)

To: SOUTHERN E&P REGION

Attn.: COASTAL DIVISION

Lease and Well STATE UNIT A-17 Field WEEKS ISLAND

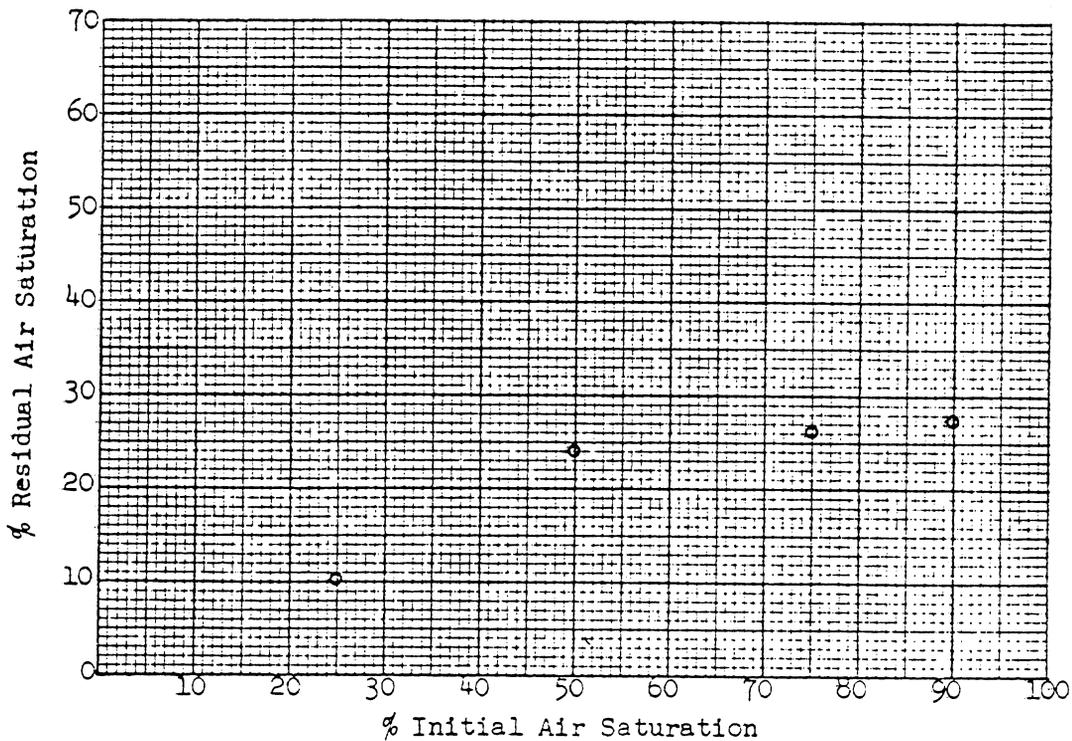
County _____ State LOUISIANA Depth 12915 ft.

Formation _____ Lithology _____

Sample No. 6-A CCI No. 1354 Date 5/26/78

Porosity(%) 26.3 Permeability(md) _____ Grain Density(g/cc) 2.640

Remarks: _____



SHELL DEVELOPMENT COMPANY
TECHNICAL SERVICE
RESIDUAL-INITIAL AIR SATURATION DATA REPORT
(Liquid-Air Countercurrent Imbibition)

To: SOUTHERN E&P REGION

Attn.: COASTAL DIVISION

Lease and Well STATE UNIT A-17 Field WEEKS ISLAND

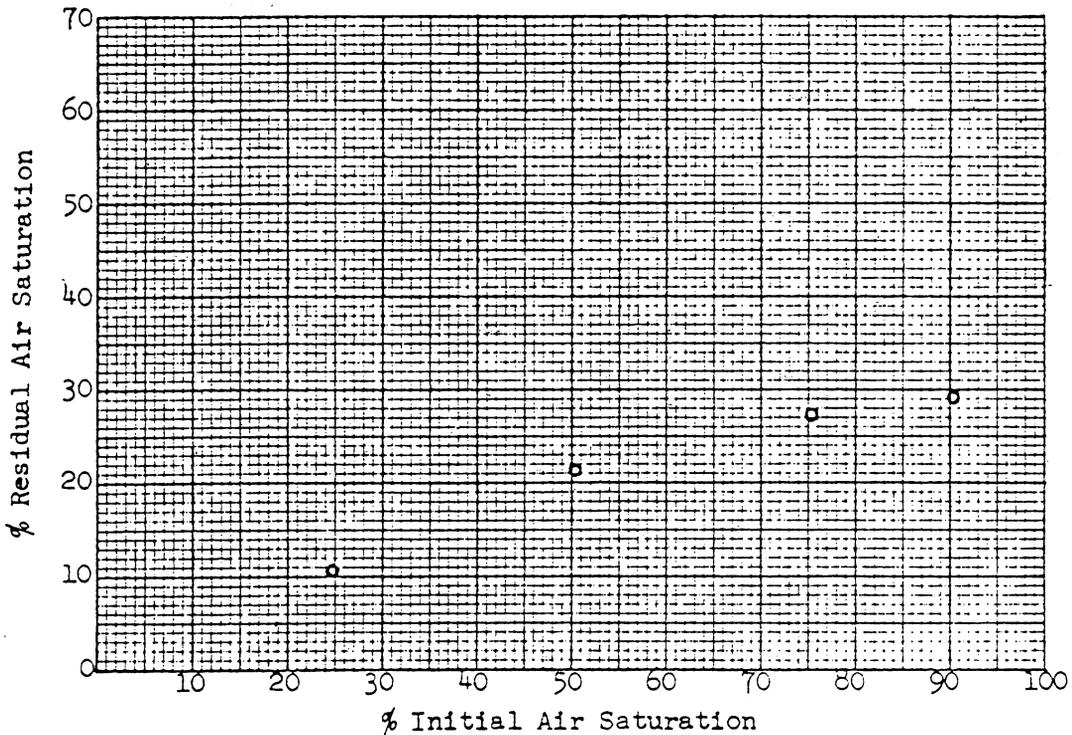
County _____ State LOUISIANA Depth 12960 ft.

Formation _____ Lithology _____

Sample No. 37-A CCI No. 1356 Date 5/26/78

Porosity(%) 27.2 Permeability(md) _____ Grain Density(g/cc) 2.640

Remarks: _____



SHELL DEVELOPMENT COMPANY
TECHNICAL SERVICE
RESIDUAL-INITIAL AIR SATURATION DATA REPORT
(Liquid-Air Countercurrent Imbibition)

To: SOUTHERN E&P REGION

Attn.: COASTAL DIVISION

Lease and Well STATE UNIT A-17 Field WEEKS ISLAND

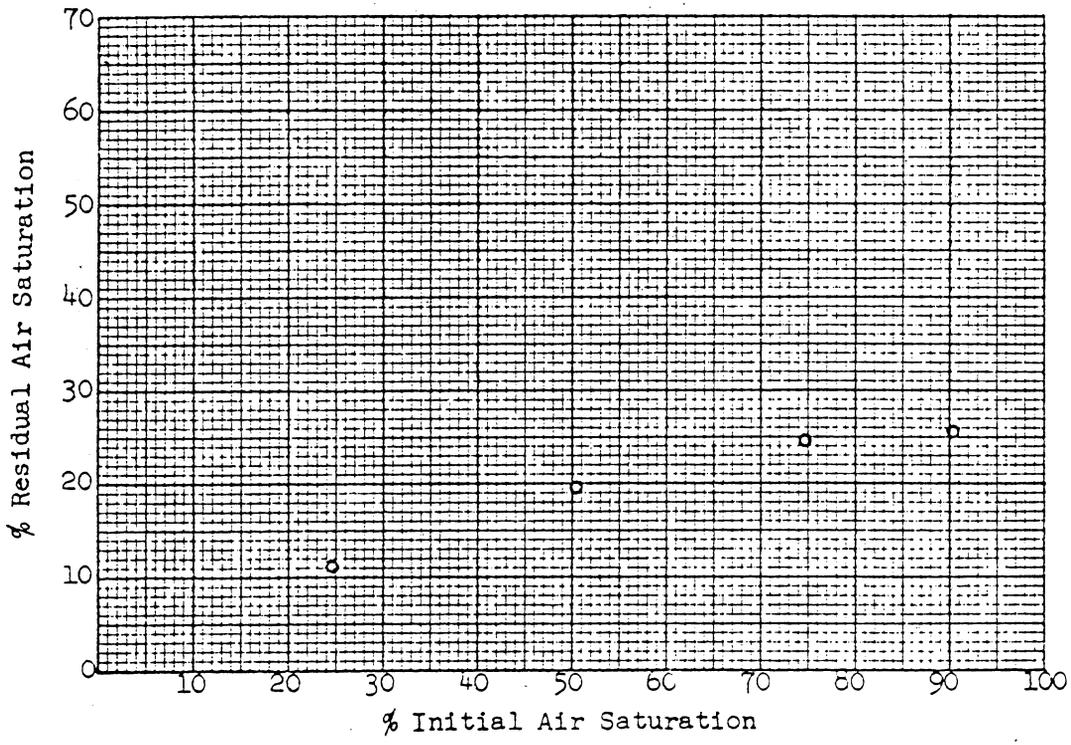
County _____ State LOUISIANA Depth 12968 ft.

Formation _____ Lithology _____

Sample No. 46-A CCI No. 1357 Date 5/26/78

Porosity(%) 26.4 Permeability(md) _____ Grain Density(g/cc) 2.637

Remarks: _____



STATE UNIT A-17
WEEKS ISLAND FIELD, LOUISIANA

Resistivity Ratio, m & n

Sample No.	Depth ft.	Porosity %	FRF	m	I	S _w %	n
6	12915	25.6	10.12	1.70	50.9	25.0	2.83
13	12922	24.2	11.21	1.70	19.5	30.1	2.47
37	12960	26.6	9.88	1.73	42.1	25.7	2.75
46	12968	25.9	9.52	1.67	63.1	22.2	2.75

All measurements made under an applied stress of 7800 psi.
 Samples 6 & 13: Brine contained 18 g NaCl/liter. $R_w = .340$ ohmmeter @ 23°C.
 Samples 37 & 46: Brine contained 59 g NaCl/liter. $R_w = .120$ ohmmeter @ 23°C.

End-Point Relative Permeability

Sample No.	Depth ft.	k _w ,md @ S _w =100%	k _o ,md @ S _{oi}	S _{oi} %	k _w ,md @ S _{or}	S _{or} %
6	12915	1760	1160	68.8	467	25.6
13	12922	907	674	71.8	245	20.8
37	12960	2240	1500	72.1	480	20.2
46	12968	3500	2310	76.5	698	24.5

All measurements made under an applied stress of 7800 psi.
 Samples 6 & 13: Brine contained 18 g NaCl/liter.
 Samples 37 & 46: Brine contained 59 g NaCl/liter.
 Oil viscosity approximately 6.2 cp.

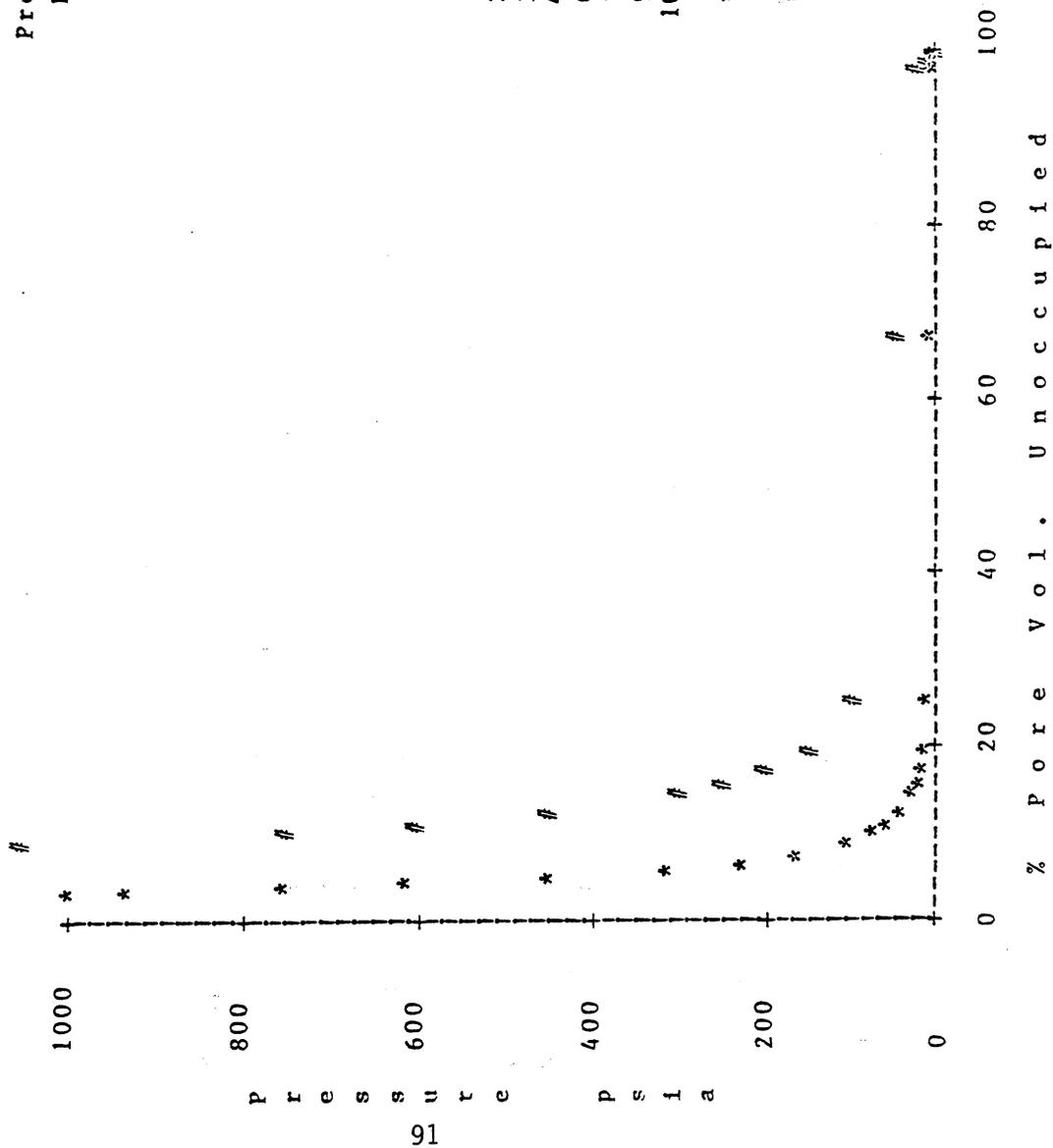
Petrophysical Services Laboratory
Mercury Capillary Pressure Data

Date : MAY 30, 1978
 Company : SHELL OIL
 Lease : STATE UNIT
 Well No. : A-17
 Field : WEEKS ISLAND
 State : LOUISIANA

Sample No. : 6
 Depth : 12915' 0"
 Porosity, %: 26.3
 Air Perm, md: 3110.0
 Grain Density, g/cc: 2.644

Pressure psia	Pore Vol. % Unocc.	Bulk Vol. % Occ.
0.0	100.0	0.0
1.0	99.1	0.2
2.5	98.2	0.5
5.0	67.6	8.5
10.0	25.7	19.6
15.0	19.9	21.1
20.0	17.7	21.7
25.0	16.1	22.1
30.0	15.0	22.4
45.0	12.7	23.0
60.0	11.3	23.4
75.0	10.5	23.6
105.0	9.3	23.9
165.0	7.7	24.3
225.0	6.8	24.6
315.0	6.1	24.7
450.0	5.3	24.9
615.0	4.7	25.1
750.0	4.2	25.2
930.0	3.7	25.4
1000.0	3.6	25.4

* = % Pore Volume Unoccupied by Mercury
 (Pressure 0 to 1000 psia)
 # = % Pore Volume Unoccupied by Mercury
 (Pressure 0 to 100 psia expanded scale)



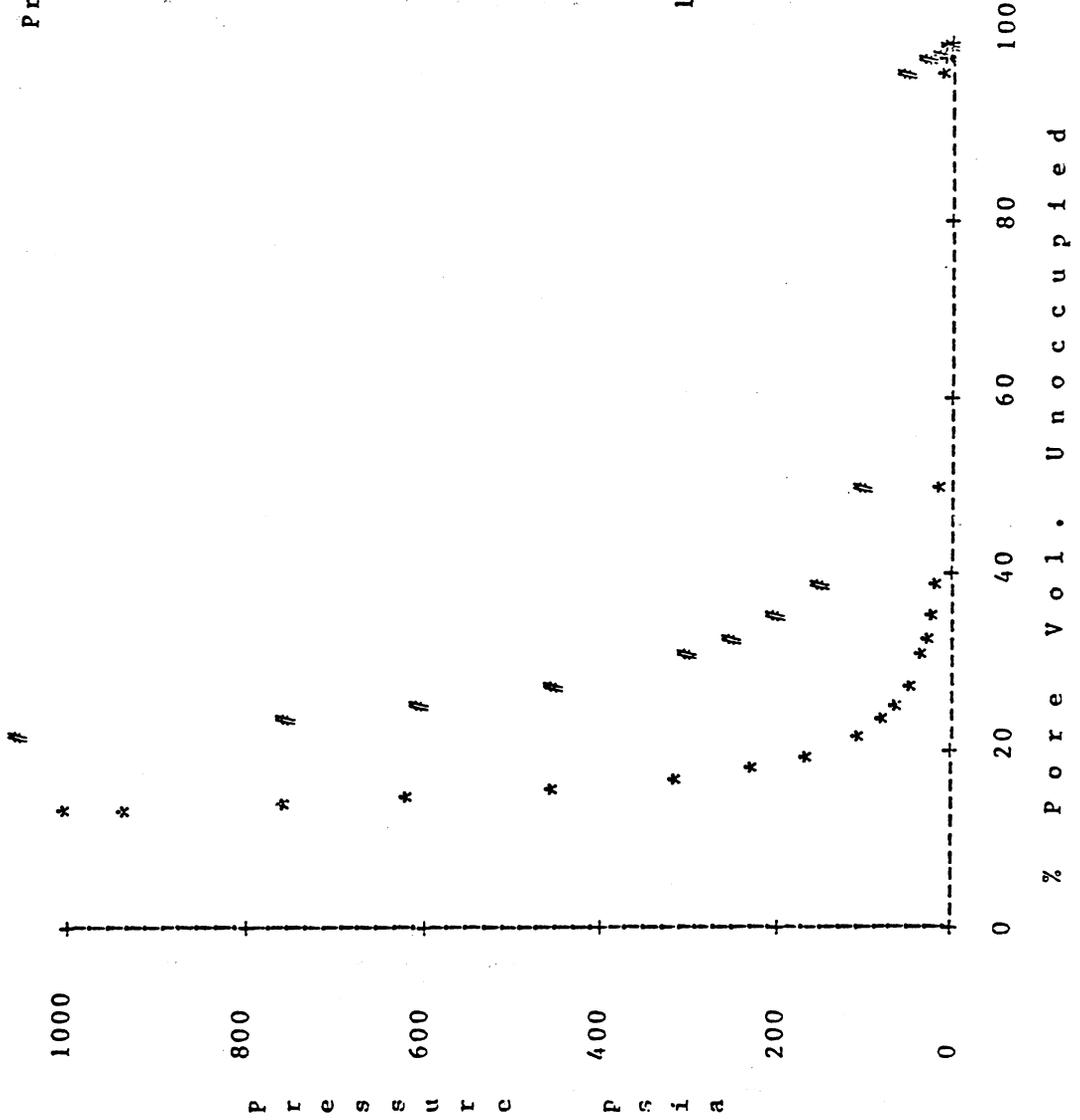
Petrophysical Services Laboratory
Mercury Capillary Pressure Data

Date : MAY 30, 1978
Company : SHELL OIL
Lease : STATE UNIT
Well No. : A-17
Field : WEEKS ISLAND
State : LOUISIANA

Sample No. : 13
Depth : 12922' 0"
Porosity, %: 26.4
Air Perm, md: 1290.0
Grain Density, g/cc: 2.638

Pressure psia	Pore Vol. % Unocc.	Bulk Vol. % Occ.
0.0	100.0	0.0
1.0	99.1	0.2
2.5	98.6	0.4
5.0	97.0	0.8
10.0	50.2	13.1
15.0	39.2	16.0
20.0	35.7	17.0
25.0	33.2	17.6
30.0	31.4	18.1
45.0	27.7	19.1
60.0	25.5	19.6
75.0	24.1	20.0
105.0	22.1	20.5
165.0	19.8	21.1
225.0	18.5	21.5
315.0	17.2	21.8
450.0	16.1	22.1
615.0	15.2	22.3
750.0	14.5	22.5
930.0	13.6	22.8
1000.0	13.6	22.8

* = % Pore Volume Unoccupied by Mercury
(Pressure 0 to 1000 psia)
= % Pore Volume Unoccupied by Mercury
(Pressure 0 to 100 psia expanded scale)



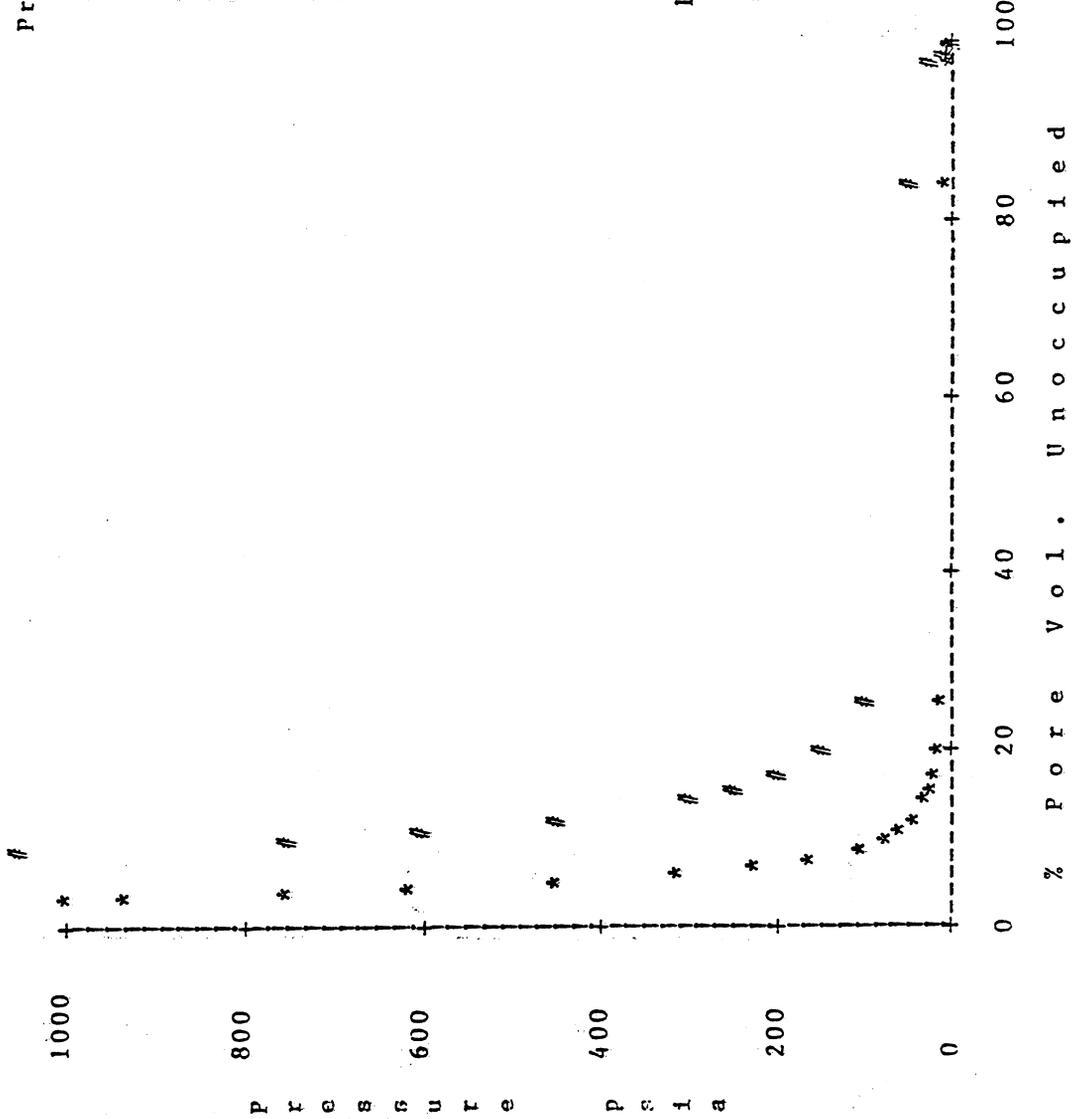
Petrophysical Services Laboratory
Mercury Capillary Pressure Data

Date : MAY 30, 1978
 Company : SHELL OIL
 Lease : STATE UNIT
 Well No. : A-17
 Field : WEEKS ISLAND
 State : LOUISIANA

Sample No. : 37
 Depth : 12960' 0"
 Porosity, %: 27.1
 Air Perm, md: 2850.0
 Grain Density, g/cc: 2.643

Pressure psia	Pore Vol. % Unocc.	Bulk Vol. % Occ.
0.0	100.0	0.0
1.0	98.8	0.3
2.5	98.0	0.5
5.0	84.4	4.2
10.0	26.0	20.1
15.0	20.4	21.6
20.0	17.7	22.3
25.0	16.0	22.8
30.0	14.9	23.1
45.0	12.4	23.7
60.0	11.2	24.1
75.0	10.2	24.3
105.0	9.1	24.6
165.0	7.8	25.0
225.0	7.2	25.2
315.0	6.4	25.4
450.0	5.5	25.6
615.0	4.7	25.8
750.0	4.3	25.9
930.0	3.8	26.1
1000.0	3.6	26.1

* = % Pore Volume Unoccupied by Mercury
 (Pressure 0 to 1000 psia)
 # = % Pore Volume Unoccupied by Mercury
 (Pressure 0 to 100 psia expanded scale)



Petrophysical Services Laboratory
Mercury Capillary Pressure Data

Date : MAY 30, 1978
 Company : SHELL OIL
 Lease : STATE UNIT
 Well No. : A-17
 Field : WEEKS ISLAND
 State : LOUISIANA

Sample No. : 46
 Depth : 12968' 0"
 Porosity, %: 26.8
 Air Perm, md: 4860.0
 Grain Density, g/cc: 2.645

Pressure psia	Pore Vol. % Unocc.	Bulk Vol. % Occ.
0.0	100.0	0.0
1.0	98.7	0.4
2.5	96.8	0.9
5.0	34.4	17.6
10.0	18.6	21.8
15.0	14.7	22.9
20.0	13.0	23.3
25.0	11.9	23.6
30.0	11.0	23.9
45.0	9.1	24.4
60.0	8.1	24.7
75.0	7.6	24.8
105.0	6.7	25.0
165.0	5.7	25.3
225.0	5.1	25.5
315.0	4.5	25.6
450.0	3.9	25.8
615.0	3.5	25.9
750.0	2.9	26.0
930.0	2.7	26.1
1000.0	2.7	26.1

* = % Pore Volume Unoccupied by Mercury
 (Pressure 0 to 1000 psia)
 # = % Pore Volume Unoccupied by "
 (Pressure 0 to 100 psia)

