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

BY

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JUNE 1978

PREPARED FOR

UNITED STATES DEPARTMENT OF ENERGY
MORGANTOWN ENERGY TECHNOLOGY CENTER
MORGANTOWN, WEST VIRGINIA 26505

TECHNICAL INFORMATION CENTER
UNITED STATES DEPARTMENT OF ENERGY

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IBERIA PARISH, LOUISIANA

June 1978

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Prepared for
UNITED STATES DEPARTMENT OF ENERGY
Morgantown Energy Technology Center
Morgantown, WV

Submitted Under
Contract No. EF-77-C-05-5232

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*Milestone Progress Report

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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

WEEKS ISLAND FIELD

The Weeks Island Field is located on and around a piercement-type salt dome, and is a member of the five-island group comprised of Jefferson Island, Avery Island, Weeks Island, Cote Blanche, and Belle Isle. These islands are topographic expressions of near-surface salt stocks. Figure 1 is a map showing the location of the Weeks Island Field. The Weeks Island salt stock rises to

within 35 feet of sea level and has a maximum surface expression of 135 feet above sea level. There are numerous radial and peripheral faults with vertical displacements of up to 2500 feet.

Hydrocarbon shows have been found in sands of Pleistocene to lower Miocene age, at depths from 1000 to 17,000 feet. Commercial production has been established in 37 middle to lower miocene sands, predominantly below 9500 feet. The bulk of the original in-place oil (87%) was trapped in the downthrown north flank of the field where reservoir hydrocarbon column heights of up to 2600 feet have been proven. The majority of these reservoirs are driven by strong water influx from large aquifers.

"S" Sand Reservoir B

The "S" sand Reservoir B occurs in a fault block on the north flank of the dome. The reservoir is sealed against the dome by radial and peripheral faults shown on the Figure 2 structure map. The "S" Sand Reservoir B originally contained two oil columns with over 3,000,000 barrels of in-place oil overlain by a 1300-foot gas column which contained 24 BCF of wet gas. The CO₂ displacement will be 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 3.

Reservoir History

The "S" sand Reservoir B was initially produced by pressure depletion until unitization was completed in 1973 at which time pressure maintenance was initiated with freshwater injection. The freshwater injection well was Smith State Unit G2 which penetrated the reservoir below the original oil/water contact. Through February of 1978, 3.14 million barrels of water had been injected to replace the reservoir voidage of the only oil column producer Weeks Island State Unit Al6A (Al6A). Through March of 1978, Al6A has produced 2.58 million barrels of oil, including 1.80 million barrels produced since water injection was initiated. In July 1975, the producing perforations at a subsea depth of 12,822 to 12,832 collapsed. We believe this was due to the arrival of a substantial quantity of water at the producing perforations. In a subsequent workover, a pulsed neutron log indicated a probable gas/oil contact at a subsea depth of 12,760' and a substantial gas saturation to a subsea depth of 12,776'. Weeks Island State Unit Al6A was then recompleted to a subsea depth between 12,777 to 12,787', and the substantial gas saturation above the perforations was confirmed by increased gas production from the new completion. The gas/oil ratio was reduced by increasing the water injection to a range in excess of the oil withdrawals. Water appeared in the production of the new perforations in July of 1976. Injection was then reduced to allow gas cap expansion to drive the oil that was above the perforations downward to the producing interval. Gas broke through to the

producing perforations in August of 1977. Flow from the well was restricted in an effort to reduce the gas production and the well died. Since that date, the well has been gas lifted against a choke to keep the well producing at a controlled rate.

The production and injection history of the "S" Reservoir B oil column is plotted on Figure 4. The increasing GOR and water cut is evidence of the thin oil column now trapped in the vicinity of the existing producing perforations in Weeks Island State Unit A16A.

Since reservoir unitization in 1973, a gravity stable cycling of the "S" Reservoir B gas cap has been conducted on the eastern end of the reservoir. Dense wet gas has been produced from perforations at the oil/water contact in Myles 25 and the less dense processed gas has been returned to the formation through Myles 22. Although the dry gas has remained gravity segregated above the wet gas, Myles 25 is producing an increasing quantity of dry gas and a deeper cycling producer is planned in the western end of the gas cap. Cycling operations should not interfere with CO₂ displacement of the watered out oil column.

CO₂ DISPLACEMENT

The project will displace approximately 900 acre-feet of watered-out reservoir in the 120-foot displacement interval shown on the Figure 3 cross section. The process will involve injecting approximately 460,000 reservoir barrels of a CO₂-methane mixture into Weeks Island State Unit A16A. The CO₂-methane slug will be injected through perforations just above the gas/oil contact at -12,760 feet subsea and will be displaced downdip to new producing perforations in Weeks Island State Unit A17.

Injection of the CO₂-methane mixture is expected to commence in July of 1978 at which time the present oil producer, Weeks Island State Unit A16A, will be converted to injection service. The CO₂ slug design will require the injection of 130 tons per day of CO₂ for thirteen months. Since the reservoir is sealed by faults, the downward displacement of the CO₂-methane slug during the thirteen-month injection period will be accomplished by gas lifting 1200 to 1500 barrels of water per day from the present downdip water injector, Smith State Unit G No. 2. After CO₂ injection has ceased, the continued downward displacement of the injected CO₂ and the remaining oil column into the watered-out oil column can be accomplished by two methods. The constant reservoir pressure method would require the injection of approximately 1.5 BCF of gas into the gas cap while producing water from the downdip well, Smith State Unit G No. 2. The second method simply entails gas cap expansion and would be accomplished by producing water from Smith State Unit G No. 2 causing a 400 psi reduction in reservoir pressure. The amount of supplemental gas finally injected will be determined by the availability of field gas. The present gas cycling injector, Myles No. 22, will be used as the supplemental gas injection well.

A 3 year project life is foreseen with a 1200 to 1500 reservoir barrel per day displacement rate. We estimate that tertiary oil production due to CO₂ injection would commence in the third year of the project. Cased-hole thermal decay logs and/or compensated neutron logs will be used in Weeks Island State Unit A-17 to monitor the advancing CO₂, prior to the arrival of the oil bank at the downdip completion.

PHASE I OBJECTIVES

The objectives of Phase I were to determine the likelihood of project success and to prepare for the initiation of the CO₂ displacement. To determine the likelihood of success, laboratory measurements were scheduled to determine the miscibility of the crude oil and CO₂ at reservoir conditions, while measurements of crude oil density and viscosity and CO₂ plant gas mixture density were planned for use in calculations of the displacement stability.

A new well was also scheduled to measure the reservoir parameters through the use of logs and cores while work on the initial reservoir mathematical model was undertaken. This model is to be then expanded to include the new reservoir parameters determined from the new well and the displacement processes defined by the laboratory measurements.

The preparation for CO₂ injection required a contract for an adequate CO₂ supply and the construction of facilities to provide for CO₂ injection and water disposal. The final stage of preparation is the conversion of the oil producer, Weeks Island State Unit A16A, to CO₂ injection and the conversion of the water injector, Smith State Unit G2, to a water producer.

PHASE I RESULTS

Miscibility

PVT measurements, sand pack displacements with CO₂ and the phase behavior measurements have been made on the S sand Reservoir B oil at reservoir conditions of pressure and temperature. PVT measurements show that at reservoir conditions pure CO₂ is more dense than oil while vertical sand pack displacements with CO₂ indicates substantial oil can be recovered. However, the phase behavior measurements indicate that displacement will be initially two-phase and miscibility, if achieved, will have to be generated. Nevertheless, oil recovery should be good as a result of the hydrocarbon vaporization which occurs when CO₂ contacts crude oil at these reservoir conditions.

Sand Pack Displacements

Several high pressure, high temperature, vertical sand pack displacements with the Weeks Island S sand crude have been conducted to study the

downward displacement of oil by CO_2 injection. To investigate the effect of methane dilution on the process, various mixtures of plant gas and CO_2 were used as displacing fluids in the vertical sand packs. Experimental results indicate miscibility was not obtained in the short sand pack displacements but a high recovery, two-phase displacement was achieved.

The Shell Development report which describes the method, equipment and results of the sand pack displacements is attached as Appendix A. The Shell Development report compares the results of CO_2 displacements with varying plant gas dilution, with a completely miscible propane displacement of a Weeks Island crude and a completely immiscible natural gas displacement of the S sand reservoir B crude oil. The sand pack results are shown as plots of effluent light transmittance versus pore volumes injected (and produced). The light transmittance is a qualitative measure of the displacing fluid content in the oil. A smooth transition of light transmittance at the breakthrough of the displacing fluid indicates a continuously increasing content of the displacing fluid in the oil which we would expect with the blended front of a miscible displacement, while sharp rapid changes in light transmittance indicate a segregated flow which would occur with an immiscible displacement. Figure 2 of Appendix A illustrates the response of a fully miscible propane flood. This response is a benchmark of miscibility characterized by the smooth transition from zero to full light transmittance over a producing interval of several percent of a pore volume. The transition occurs with gas breakthrough at approximately one pore volume of production. Figure A7 of Appendix A illustrates the rapid change of light transmittance at gas breakthrough for an immiscible natural gas displacement.

All of the CO_2 displacements recovered significantly more oil than the natural gas displacement, which recovered approximately 89 percent of a pore volume at gas breakthrough. With the exception of the displacement conducted with pure CO_2 at the rate of 1.2 feet per day, all the displacements with CO_2 exhibited the rapid transition of the light transmittance of an immiscible displacement. The transition that occurred with the pure CO_2 displacement at the rate of 1.2 feet per day can be interpreted as mixing which could occur with an unstable displacement in a small tube. In a small diameter tube the bypassed oil tends to diffuse and disperse into the displacing fluid.

Phase Behavior

One of the distinguishing features of the Weeks Island gravity stable CO_2 displacement is the fact that the flood will be conducted on a gas saturated crude. It is this saturated condition that results in the formation of two phases on the initial contact with CO_2 . Shell Development had a single contact phase experiment performed on recombined "S" sand Reservoir B crude in a mixture of 95 percent CO_2 and 5 percent plant gas. Shell Development's report on this phase behavior is attached as part of Appendix B.

Figure 1 in Appendix B is a diagram of a single contact phase behavior described by this experiment in which the volume of the gaseous and liquid phases were measured at various pressures and molecular percent of the CO_2 /plant gas mixture. Section A-A' on Figure B-1 is a compositional path which would be followed for additions of CO_2 and plant gas to the reservoir fluid at a constant pressure equal to the bubble point pressure of the oil. Section B-B' shows a compositional path taken for additions of the CO_2 /plant gas mixture at a reservoir pressure which is above the bubble point and below the pseudocritical pressure. Section C-C' shows a path for displacement pressure greater than pseudocritical pressure.

In Figure 2 of Appendix B the volume percent of the second phase is plotted versus the mole percent of the CO_2 /plant gas mixture for the above three pressures. The term second phase is used since the character of the phase depends upon whether the two phase region is entered through a dew point or through a bubble point. If the two phase region is entered through a dew point, the second phase is a liquid. If the two phase region is entered through a bubble point, the second phase is a vapor.

It is planned that the S sand Reservoir B CO_2 displacement will be conducted at the present reservoir pressure which is also the bubble point pressure for this gas saturated crude. Therefore, the first contact phase behavior should follow along Line A-A' on Figures B-1 and B-2. The first addition of the CO_2 /plant gas mixture results in the formation of a liquid and vapor phase. With continued additions of CO_2 and plant gas, the volume of the second or vapor phase grows until at a high concentration of CO_2 and plant gas essentially all the liquid has been extracted into the vapor phase. If the downward displacement is gravity stable, we expect a two phase displacement with the liquid phase being displaced by the vapor phase. The expected production characteristic would rapidly change from liquid to vapor at the passing of the vapor phase front. A similar type of producing characteristic was observed from our short tube sand pack displacements.

Gravity Stability

The physical properties of the S Sand Reservoir B oil have been measured for the conditions of 225°F and 5100 psi. Neglecting interphase mass transfer, these measurements are reported in the attached PVT analysis indicate that a downward displacement with pure CO_2 would be inherently unstable because the oil with the density of .669 grams per milliliter would be displaced by CO_2 with a higher density of .689 grams per milliliter. In order to obtain gravity stability, the original pilot design called for a reduction of the density of the displacing fluid which would be accomplished by the dilution of the CO_2 with natural gas. Calculations of the gravity stability resulting from a 5 percent natural gas dilution of the CO_2 are reported in Appendix B. The calculations indicate the process will be stable with either an immiscible displacement or a miscible displacement.

The Dumore analysis for estimating stable and critical velocities for a gravity dominated miscible displacement assumed linear blending for the densities and 1/4 power blending for the viscosities of the blended fluids.

$$\rho_B = f_1 \rho_1 + f_2 \rho_2$$

$$\mu_B = \frac{\mu_1 \mu_2}{\left[f_1 \mu_2^{1/4} + (1-f_1) \mu_1^{1/4} \right]^4}$$

Where:

ρ = density

μ = viscosity

f = fraction of fluid

Subletter B refers to the blended fluid

Subnumbers refer to fluid 1 or 2

Since we expect the process to start and possibly remain as an immiscible displacement, the stability calculations reported in Appendix B include the calculated critical rate for an immiscible displacement after repeated contacts between the oil and the CO₂/plant gas mixture. The densities and viscosities used in this calculation were obtained from a equilibrium K-value type fluid properties computer program which has been used to model a sequence of multi-contact equilibrium experiments. The results of these calculations are illustrated on Figure 7 of Appendix B. The calculations indicate the initial contact of CO₂ with the oil would increase the gravity stability of the oil/CO₂ interface.

Since the design darcy velocity of the displacement is in the order of 0.04 feet per day, which is less than a tenth of the calculated critical immiscible displacement velocities and less than 1/4 of the calculated stable velocities for a completely miscible displacement, we believe it will be possible to achieve a gravity stable displacement with a 5 percent plant gas dilution of the CO₂. Darcy velocity has been defined as a flow rate divided by the cross sectional area q/A .

Initial Reservoir Models

An initial one-dimensional mathematical model of the S sand Reservoir B has been constructed. The simulation results of this model are reported in Appendix C of the Shell Development Phase I report. This initial model used the reservoir parameters and fluid properties as they were originally conceived from the S sand Reservoir A data. This model will now be altered to accept the recent put data and the log and core data obtained from the new well, Weeks Island State Unit A17.

Although this model does not yet contain the new data now being gathered, it is capable of matching reservoir pressure and fluid contact behavior and the model can now be expanded. Because the gas cap is several times larger than the oil column, the pressure match is sensitive to gas cap size and rather insensitive to oil column size and PVT properties. However, the pressure match does indicate the reservoir is sealed from significant fluid flows from other sources. Moreover, this preliminary model indicates the original gas/oil contact was a significant distance above the level indicated by the 1975 logs and performance of Weeks Island A16A.

A preliminary analysis of the sweep efficiency at gas breakthrough as a function of density differences between the displaced and displacing phases is attached as Appendix D. Although the calculation does not include the varying density differences between the oil and gas, which will occur with repeated contacts of the fluids, this work does indicate it is reasonable to expect a good sweep. If it becomes apparent in future work or early production that the displacement will have a nonuniform contact, the final producing perforations may be lowered to increase the swept volume of the pilot.

Additional S Reservoir B models will be constructed using Shell's existing simulators. It may be necessary to modify the fluid property calculations in these simulators to account for the observed compositional behavior of the reservoir fluids. It may also be necessary to perform additional phase behavior measurements that will investigate the envisioned repeated contacts that will occur between the displacing gaseous CO₂ phase and the liquid oil phase.

Petrophysical Evaluation of New Well

A new well, Weeks Island State Unit A17, has been drilled at the location shown in Figure 3. This well, which was drilled to evaluate the reservoir parameters, will be used to monitor the advancing displacement and will ultimately serve as the producing well for the pilot. The well has been drilled and the evaluation is essentially complete. The open hole logs indicate water has invaded all of the sand at subsea depths lower than the perforations in the offset producer A16A, as shown on Figure 3.

A special polymer mud was used in the "S" sand drilling and coring operations to minimize a possible reduction in the residual oil saturation. This low water loss mud contained no surface active agents. Mud particle size was also adjusted for optimum pore bridging to minimize viscous stripping due to spurt loss.

Open Hole Evaluation

Calculations from conventional open hole logs indicate the invading water has left a remaining hydrocarbon saturation of between 26.5 and 33 percent. (It is important to note that we are talking about residual hydrocarbon and not residual oil saturation. This will be explained later in the text.) The hydrocarbon saturation above the flushed zone is greater than 90 percent. The open hole resistivity and porosity logs across the "S" sand interval are shown in Figure 5. Petrophysical parameters used in the water saturation calculations are shown in Table 3 of Appendix E. The tapered resistivity indicated on the induction log is the result of a varying water salinity that occurred as the injected freshwater mixed with the original formation water. The original formation water has been estimated from field experience to have contained approximately 190,000 parts per million dissolved solids. A remaining hydrocarbon saturation was calculated in two intervals; the first between 12,917 feet and 12,919 feet and a second interval between 12,960 feet and 12,970 feet. Although these two intervals had respective resistivities of 3 ohm meters and 1 ohm meter, most of this resistivity difference can be attributed to the varying water salinity. The water salinity was obtained by perforating and swabbing formation water from the intervals at the rate of 10 barrels per hour. Titrations of the recovered water measured 10,825 parts per million chlorine in the water recovered from the upper interval and 35,500 parts per million chlorine in the water which was recovered from the lower test interval. No hydrocarbons were obtained during the swab tests which indicates the remaining hydrocarbons were immobile.

Core Analysis

During the drilling operations, 77 feet of coring was attempted with 71 feet of recovery. The core analysis obtained to date is included in Attachment 3. (Core analysis should be complete within another month.) The initial analysis on 58 feet of this core indicates an average unstressed porosity of 27.1 percent and an average unstressed air permeability of 3.5 darcies. Subsequent stressed data indicate the porosity should be reduced by 1.1 percent to relate to subsurface conditions. All of the core material was obtained using an oriented conventional core barrel. No pressure core barrel is presently available that can core a 5000 psi reservoir. Measured oil saturations from this core should therefore be less than or equal to the in situ saturations since it is possible that blowdown losses did occur. Figure 6 is a plot which

compares the log response with the porosity, permeability and calculated barrels per acre/foot obtained from core analysis. Twenty-five core plugs oriented perpendicular to the dip, parallel to the dip and parallel to the strike were cut from the oriented core at eight depths between 12,937 feet and 12,976 feet. No preferential direction of permeability was found by these measurements as indicated in the attached core analysis.

Residual Oil Saturation Measurements

Several independent methods were used to calculate the residual oil saturation in the interval between 12,910 feet and 12,920 feet. Our best estimate of the remaining oil saturation in this interval is between 22 percent and 24 percent. We feel these numbers to be representative of the entire flushed zone interval.

Figure 7 summarizes the residual oil saturations as determined by the various methods. Other measurement techniques, such as Nuclear Magnetism Logging, tracer tests and pressure core barrels were investigated but were not feasible due to either pressure or temperature constraints.

Residual Oil Saturation From Log-Inject-Log

A description of the procedure and calculations used to determine residual oil saturation by this method are included in Appendix E of the Shell Development Phase I report. The summary of the results of the individual stationary readings are included in Table 1 of Appendix E. The average residual oil saturation determined by this method is $.221 \pm .025$. Since these measurements were made in the subsurface under very controlled conditions, we feel this is the more accurate of the various methods used to determine the residual oil saturation.

Residual Oil Saturation From Core Analysis

The average value of residual oil saturation from core analysis from the log-inject-log interval is $.23 \pm .042$ (see Table 2 of Appendix E). The value of residual oil saturation obtained from conventional core analysis corrected to in situ conditions is generally assumed to be less than or equal to the residual oil saturation at in situ conditions. This is normally assumed since viscous stripping due to spurt losses from the drilling mud can remove immobile oil. In addition, expansion of the gas during the pressure reduction as the core is brought out of the ground can expel oil which is immobile at reservoir conditions. However, we feel these effects were greatly minimized or totally removed in the case of the Weeks Island core and hence the residual oil from the conventional core could closely approximate in situ conditions. Great care was used in the design of the mud system to minimize fluid loss as well as spurt loss. As seen

in the core analysis, the permeability of the rock is extremely high. In highly permeable homogeneous rock with a high water saturation, residual oil saturation measurements in conventional or rubber sleeve cores can approach that of in situ conditions. We believe this occurs because it is possible that gas can be expelled from a highly permeable rock at a differential pressure too low to mobilize trapped oil.

Determination of Residual Oil From Open Hole Log Suite

The residual oil saturation as determined from open hole logs in the log-inject-log interval is .243+.054. It has been earlier stated that the residual hydrocarbon saturation in this interval is .33. The open and cased hole log data indicate a free gas saturation of six to ten percent. The hydrocarbon saturation is therefore a summation of the residual oil as well as the free gas saturation. A detailed discussion of the analysis is contained in Appendix E. The reservoir pressure has dropped below the bubble point causing gas to come out of solution and the pressure was subsequently never increased above the bubble point. With a residual gas saturation the total residual hydrocarbon saturation can be higher than the residual oil saturation which would have occurred if the pressure had not dropped below the bubble point. However, the residual oil saturation to water displacement will generally be lower with the presence of a residual gas saturation than it would be in the absence of a residual gas saturation.

Residual Oil Saturation From Counter Current Imbibition Data

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

Injection Preparations

CO₂ Contract

An evaluation of several methods of supply and transportation of approximately 50,000 tons of carbon dioxide at the 130 ton/day injection rate indicated it is most feasible to purchase liquid carbon dioxide from a commercial vendor with transport by 20 ton capacity trucks. The alternatives of barge and rail delivery were indicated to be more expensive than trucking.

Four potential suppliers were requested to submit a proposal to supply the liquid carbon dioxide. Liquid Carbonic Corporation was selected as

low bidder. Under the terms of the Contract, the supplier furnishes transportation of the carbon dioxide along with storage vessels and transfer pumps which have been set on Shell-furnished foundations at the injection site.

The quality of liquid carbon dioxide should meet "food grade" standards, i.e., 99.9% carbon dioxide. The quantity of carbon dioxide delivered by truck shall be determined by difference in weight of the truck before and after filling, the empty and full weights are to be recorded on weight tickets to be furnished with each shipment.

Liquid Carbonic Corporation agreed to the Government's General Provisions (Long) and the contract was accepted by the Department of Energy in a letter dated October 28, 1977.

CO₂ Injection Facilities

A CO₂ injection facility consisting of storage equipment, charge pumps, a Union Tx-150 injection pump and natural gas blending equipment has been constructed at the site. Figure 8 is a mechanical flow diagram of the injection facility which has a pumping capacity of 26+ gpm of liquid CO₂. The storage system consists of five 50 ton capacity tanks. These tanks are piped in parallel; however, each tank can be shut off from the others for service work. The unloading pumps are Smith Precision gear-type pumps which can unload a 20 ton truck in 40 minutes. The designed injection rate of 130 tons a day will require the delivery of between six and seven truckloads of CO₂ per day.

Liquid CO₂ will be transferred from the storage tanks to the injection pump via the CO₂ charge pumps, which are also Smith Precision gear-type pumps. The charge pumps will raise the suction pressure to the injection pump so cavitation will not occur in the injection pump. Any difference in capacity between the charge pump and the injection pump will be handled by a pressure control valve which limits the charge pressure at the injection pump to 400 psi. The control scheme allows for varying the amount of CO₂ that is injected through the opening of a flow control bypass which diverts CO₂ from the injection pump back to the storage tanks. The injection system is designed for a 5000 psi operating pressure. We anticipate a maximum pressure of 3500 psi during startup and restart operations and a normal injection pressure of approximately 2000 psi. Higher pressures are anticipated during startup operations because the tubing of the injection well could be filled with natural gas which is less dense than CO₂.

The mixing of the natural gas and CO₂ will be controlled through the ratio controller which senses the flow rate through meter runs on both the CO₂ and gas lines. These controls are somewhat simple, Shell having decided that

the complications for temperature compensation on the CO₂ could cause more problems than the possible benefit. Temperature compensation could correct the flow of natural gas by approximately 8 percent. However, the instrumentation involved would increase the complexity by a factor of 2. It is planned to calibrate the flow system by analyzing samples of the injected fluid for CO₂ at established laboratories in the New Iberia area. Shell has installed a densitometer to read the density of the natural gas-CO₂ mixture, but use of the densitometer is for monitoring purposes only. Until Shell determines the practicality of this densitometer, it will not be used for control purposes.

The other unusual feature of the CO₂ injection facilities is that all high-pressure reliefs are rupture discs, because dry ice will form when CO₂ expands from high pressure. The dry ice could not only plug the relief opening, but could also erode the seats of relief valves.

CO₂ Displacement Potential

The 900 acre feet of the "S" Sand Reservoir B we propose to displace with CO₂ should contain a minimum of 258,000 barrels of water drive residual oil. A Dean Stark analysis of the residual oil and 58 core plugs corrected for oil density and rock compressibility found an average stock tank oil content of 287 barrels per acre foot of rock as shown on Table 1. The residual content was confirmed by our log-inject-log analysis at four stations in the interval from 12,911 to 12,917 feet in Weeks Island A17. A comparison of the residual oil content from the core analysis and the log-inject-log measurements are discussed in the residual oil measurement section of this report.

Laboratory measurements indicate it will be possible to recover a substantial portion of the 258,000 barrels of residual oil even if true miscibility is not achieved. Although we believe it reasonable to expect a substantial recovery of residual oil, our experiments are not quantitative. The S Reservoir B models Shell is planning to construct will be used to define our estimated recovery during the next phase of the project.

Remaining Oil Column

We estimate that on June 1, 1978 the remaining oil column in the S Reservoir B was approximately 24 feet thick and contained approximately 145,000 barrels of oil recoverable by continued supplemental operations. However, the production of this column would require cycling of the cap gas which is now being produced with the oil.

This estimate of presently recoverable oil is based on a January 1, 1978 gas/oil contact at a subsea depth of -12,760' and the water/oil contact at a subsea depth of -12,786'. The estimate also assumes the last five feet of

oil column could not be economically produced. Although it is impossible to define the gas/oil contact in the new well, Weeks Island State Unit A 17, the logs definitely indicate that water had invaded the oil column to a subsea depth of -12,786'. We estimate the gas/oil contact on January 1, 1978 should be at the estimated position of July of 1975, because during this time interval the reservoir volume of the produced oil and water is only 5,000 barrels less than the 1,404,000 barrels of water injected.

Further work is planned on the definition of the present oil column size and nonproducable volume of this oil column. This work could include coning models which would incorporate the end point relative permeabilities we will obtain from the core taken from Weeks Island State Unit A17.

Economic Feasibility

The process to be tested in the "S" Sand Reservoir B gravity stable CO₂ displacement will utilize 862 MMCF of CO₂ to displace 900 acre-feet of watered out sand which contains 258,000 barrels of oil. The project will inject 3.34 MCF of CO₂ per barrel of residual oil. Field test results will help determine the potential economics of this tertiary recovery process.

Recommendations

Shell Oil Company recommends that injection of CO₂ diluted with 5 percent plant gas be initiated in the "S" Reservoir B. The water drive residual oil saturation available to the process has been defined to be at least 287 barrels per acre foot. Although experiments indicate the proposed displacement will be initially immiscible and may remain immiscible, these experiments indicate it may be possible to recover a substantial portion of the residual oil saturation.

An accurate forecast of the actual recovery will require additional S Reservoir B mathematical models. Shell proposes to construct these models with the use of Shell's existing simulators. It may be necessary to modify the fluid property calculations to account for the observed compositional behavior of the fluids at reservoir conditions. It may also be necessary to make other physical measurements of the fluid properties and flow characteristics to properly set up these models.

CO₂ injection facilities have been constructed and a contract has been obtained for an adequate supply of CO₂. CO₂ injection can commence upon re-completion of the present oil producer to a CO₂ injection well. Work has started on the conversion of the present water injector to a water producer.

Shell proposes the following changes in the Phase II operations:

1. The water production rate should be maintained at 1200 barrels per day during the injection phase. The 1200 barrels of daily water production will match the reservoir volume of the 130 ton/day CO₂ injection rate expanded by the addition of 5 percent plant gas.
2. Well A17 should be logged frequently with thermal decay and/or compensated neutron logs during the initial six months of injection to determine if the CO₂ displacement is proceeding as planned.
3. The present log-inject-log perforations in Weeks Island State Unit A17, which are located 48 feet below the CO₂ injection interval, should be left open, and an effort be made to monitor the mobile fluid passing these perforations as the displacement progresses.

LOCATION MAP

FIGURE 1

FIGURE 3

FIGURE 4

OPEN HOLE LOGS
WEEKS ISLAND STATE UNIT "A" No. 17
"S" SAND RESERVOIR B
GRAVITY STABLE CO₂ DISPLACEMENT

FIGURE 5

CORRELATION OF INDUCTION LOG AND CORE ANALYSIS
WEEKS ISLAND STATE UNIT A-1

FIGURE 6

COMPARISON
RESIDUAL OIL MEASUREMENTS
WEEKS ISLAND ST U A17
"S" SAND RESERVOIR B

METHOD OF DETERMINATION

- This is a modified TDT-K with TDT-G electronics (source-detector spacing 60 cm.) Readings are taken while stationary.

** Saturation of core plug at 12918 is omitted. The saturation of this plug was over 2.5 standard deviations from the average.

FIGURE 7

FIGURE 8

FIGURE 9

TABLE 1
QUANTIFIED OIL CONTENT
WATER ISLAND STATE DRILL A 17 CORE

Sample No.	Reported Depth	Actual Depth	Unstressed Porosity	Measured Stressed Porosity	Porosity (1) Corrected For Stress	Reported Oil Saturation Percent Sp. Gr. = .92	In Place (2) Stock Tank Oil Saturation	Bbls. Of (3) Stock Tank Oil Per Acre Ft.
1	12,930'	12,906'	26.0	-	24.9	19.3	21.8	421.1
2	12,911'	12,907'	26.9	-	25.8	9.2	10.4	208.2
3	12,912'	12,908'	27.8	-	26.7	11.3	12.8	265.1
4	12,913'	12,909'	27.5	-	26.4	9.8	11.1	227.3
5	12,914'	12,910'	26.4	-	25.3	15.6	17.6	345.4
6	12,915'	12,911'	26.6	25.6	25.6	12.7	14.3	284.0
7	12,916'	12,912'	26.9	-	25.8	11.0	12.4	248.2
8	12,917'	12,913'	26.1	24.8	24.8	16.1	18.4	354.0
9	12,918'	12,914'	26.5	-	25.4	16.3	18.4	362.6
10	12,919'	12,915'	26.7	-	25.6	15.6	17.6	349.5
11	12,919' 10"	12,915' 10"	27.4	26.4	26.4	11.0	12.3	251.9
12	12,921'	12,917'	26.8	-	25.7	11.6	13.1	261.2
13	12,922'	12,918'	25.3	24.2	24.2	21.7	24.6	461.8
14	12,923'	12,919'	27.0	-	25.9	11.4	12.9	259.2
15	12,924'	12,920'	26.9	-	25.8	10.8	12.2	244.2
16	12,925'	12,921'	27.3	-	26.2	15.9	18.0	365.9
17	12,926'	12,922'	26.4	-	25.3	14.7	16.6	325.8
18	12,927'	12,923'	25.2	-	24.2	14.8	16.7	315.5
19	12,931'	12,927'	26.4	-	25.3	11.6	13.1	257.1
20	12,932'	12,928'	26.5	-	25.4	9.4	10.6	208.9
21	12,933'	12,929'	25.4	-	24.4	10.3	11.6	219.6
22	12,934'	12,930'	25.2	24.0	24.0	12.0	13.7	255.1
23	12,935'	12,931'	27.3	-	26.2	13.8	15.6	317.1
24	12,940'	12,936'	27.2	-	26.1	9.8	11.1	224.8
25	12,941'	12,937'	26.6	-	25.5	11.1	12.5	247.3
26	12,949'	12,945'	26.9	-	25.8	11.0	12.4	244.2
27	12,950'	12,946'	28.0	-	26.9	10.3	11.6	242.1
28	12,951'	12,947'	28.3	-	27.1	20.0	22.6	475.1
29	12,952'	12,948'	27.4	-	26.3	11.7	13.2	269.3
30	12,953'	12,949'	26.3	-	25.4	13.2	14.9	293.6
31	12,954'	12,950'	26.8	-	25.7	12.6	14.2	283.1
32	12,955'	12,951'	26.6	-	25.6	12.0	13.5	269.0
33	12,956'	12,952'	26.8	-	25.7	11.3	12.8	255.2
34	12,957'	12,953'	27.7	-	26.6	9.1	10.3	212.6
35	12,958'	12,954'	28.0	-	26.9	10.7	12.1	250.4
36	12,959'	12,955'	27.9	-	26.8	13.0	14.7	305.6
37	12,960'	12,956'	28.3	26.6	26.6	13.5	15.7	324.0
41	12,961'	12,957'	27.6	-	26.5	12.8	14.5	298.1
42	12,962'	12,958'	28.0	-	26.9	11.8	13.3	277.6
43	12,963'	12,959'	27.6	-	26.5	11.8	13.3	273.4
44	12,964'	12,960'	26.9	25.5	25.5	12.3	14.1	278.9
45	12,967'	12,963'	27.3	26.0	26.0	10.9	12.4	250.1
46	12,968'	12,964'	27.9	25.9	25.9	12.3	14.5	291.4
47	12,969'	12,965'	27.7	-	26.6	13.8	15.6	321.9
48	12,970'	12,966'	27.5	-	26.4	14.5	16.4	335.9
49	12,971'	12,967'	27.3	26.4	26.4	12.4	13.9	284.7
50	12,972'	12,968'	27.2	-	26.1	15.2	17.2	348.3
51	12,973'	12,969'	27.2	-	26.1	14.1	15.9	321.9
52	12,974'	12,970'	27.7	-	26.6	11.7	13.2	272.4
53	12,975'	12,971'	27.4	-	26.3	11.0	12.4	253.0
54	12,976'	12,972'	27.5	-	26.4	11.7	13.2	270.4
55	12,977'	12,973'	27.1	-	26.0	10.6	12.0	242.0
56	12,978'	12,974'	27.1	-	26.0	11.5	13.0	262.2
57	12,979'	12,975'	27.5	-	26.4	11.6	13.1	268.3
58	12,980'	12,976'	27.7	-	26.6	10.1	11.4	235.3
59	12,981'	12,977'	27.3	-	26.2	13.7	15.5	315.1
60	12,982'	12,978'	28.1	-	26.9	11.7	13.3	277.6
61	12,983'	12,979'	27.8	-	26.7	12.4	14.0	290.0
Average			27.1					287.6

(1) Measured or (.959) (Unstressed Porosity)

(2) Corrected for oil specific gravity of .8617 and stressed porosity, reported oil saturation used .92 specific gravity.

$$\left(\frac{\text{Reported Oil Saturation}}{.8617} \right) \left(\frac{\% \text{ unstressed}}{\% \text{ stressed}} \right) \left(\frac{1 - \% \text{ stressed}}{1 - \% \text{ unstressed}} \right) = \text{In place stock tank oil saturation}$$

(3) Stock tank bbls/acre ft = 7758 (% stressed) (In place stock tank oil saturation)

ATTACHMENT 1

TECHNICAL INFORMATION RECORD BRC-123

Project 31-81894
Weeks Island CO₂ Pilot Project

PHASE I REPORT - RESEARCH RESULTS
GRAVITY STABLE MISCIBLE CO₂ DISPLACEMENT
"S" SAND RESERVOIR B, WEEKS ISLAND FIELD

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PHASE I REPORT - RESEARCH RESULTS
GRAVITY STABLE MISCIBLE CO₂ DISPLACEMENT
"S" SAND RESERVOIR B, WEEKS ISLAND FIELD

The purpose of this report is to document research results conducted in support of the Weeks Island CO₂ field test, to recommend a composition of the injected fluid, and to present the estimates of residual oil saturation based on petrophysical data from Well SU A-17. The details of experimental and computational work are reported in five appendices. Appendix A presents the sandpack (slim tube) displacements of SRB crude with CO₂ plus mixtures of CO₂ and plant gas at temperature and pressure conditions expected to prevail in the reservoir. Appendix B shows the results of single contact phase behavior experiments using SRB crude and CO₂PG (95% v CO₂ and 5% v plant gas). Also presented are the results of a computer simulation study that includes compositional effects. This model has been used to calculate and match the experimental data. In Appendix B, we report the results of an analysis of the gravity stability of the process displacement based on experimental data and compositional calculation techniques. Appendix C describes the results of a reservoir simulation study concerning a preliminary history match of reservoir performance. Appendix D shows an additional numerical simulation conducted to qualitatively assess the importance of gravity stability to areal sweep for the SRB. Appendix E contains the estimates of residual oil saturation derived from a log-inject-log technique and conventional logs in SU A-17.

Results and Recommendation

CO₂ injection is not a miscible process at the SRB reservoir conditions but a CO₂-crude oil vaporization process. By vaporization, we mean that the CO₂ strips and replaces hydrocarbon components from the crude. The "stripping" is enhanced with repeated contacts with fresh CO₂. Displacement by gravitational forces is the other mechanism which is important to the performance of the project.

Slim tube, sandpack displacements of SRB crude by mixtures of CO₂ and zero to ten percent by volume of plant gas resulted in efficient and stable displacements and these results were better than displacements using no CO₂. These experiments would indicate that CO₂ diluted with five to ten percent of plant gas (primarily methane) would result in a "miscible-like" displacement process. It also appears that based on slim tube experiments alone, undiluted CO₂ might be the most efficient material for the SRB field test. We must be cautious, however, in interpretation of these results. The slim tube experiments are secondary and not tertiary displacements primarily designed as a screening tool to determine "miscible-like" performance, and as such they are not correctly scaled for duplication of reservoir performance.

Under SRB reservoir conditions, CO₂ not diluted with light hydrocarbons is more dense than the reservoir oil. Fortunately, process mechanisms can work to the benefit of displacement stability. Upon mixing SRB oil and CO₂, two phases are formed. The CO₂ rich vapor phase is less dense than the liquid phase. Based on a zero dimensional analysis and the phase behavior study results, the vertical displacement by CO₂PG or CO₂ alone should be gravity stable at the expected flood

conditions. These results must be tempered, however, by the known effect of the difference in densities between the displaced and the displacing fluids on volumetric sweep efficiency. Based on simulation results, sweep efficiency increases monotonically with density difference.

After weighing the competing benefits of better displacement efficiency expected from a 100 percent CO₂ displacement and the benefits of better volumetric sweep from a less dense gas mixture, a mixture of five percent by volume of plant gas and 95 percent CO₂ is the recommended injection system for this field test. This dilution should allow gravity forces to augment the vaporization process and should result in an optimum tradeoff between the process efficiency and the sweep efficiency.

A log-inject-log test in SU A-17 from 12910-12920 ft found the residual oil saturation in this interval to be 20-22%. The open and cased hole log data indicate a free gas saturation of 6 to 10% is also present in this interval. The open hole log data are consistent with the value of S_{or} found in the log-inject-log test.

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APPENDIX A

Experimental Displacements of Weeks Island "S" Sand Oil with CO₂ and Hydrocarbon Gases

Introduction

Several high pressure, high temperature sandpack displacements of Weeks Island "S" sand crude have been conducted to study the vertical displacement of oil by CO₂ injection as an enhanced oil recovery process for this reservoir. The purpose of these experiments is to provide the evidence necessary to decide on an injection composition. Based on our experimental results shown in this appendix and Appendix B, CO₂ injection is not a miscible process at the expected reservoir conditions but a CO₂-crude oil vaporization process. The properties of the injected gas or mixture of gases are important to process performance.

At "S" Sand Reservoir B (SRB) conditions of about 225°F, about 5100 psi and saturated crude, CO₂ is more dense than the reservoir oil (about 0.686 g/cc versus about 0.667 g/cc). If these densities persist during a downward vertical displacement of SRB crude by CO₂, instability and low oil recovery would occur. However, based on the experimental phase behavior results which are reported in Appendix B, properties of the individual phases which occur after mixing CO₂ and crude define the stability. Slim tube sandpack experiments show that the CO₂ displacements are stable and result in good oil recovery.

To investigate the importance of the density of the injected gas, mixtures of plant gas and CO₂ were used as displacing fluids in vertical sandpacks. Additional vertical displacements in sandpacks with CO₂ and CO₂-plant gas mixtures have been conducted to show the sensitivity of rate and reservoir pressure to process performance. These results are compared to a miscible (propane) displacement and to displacements of crudes from two other fields by CO₂ injection to illustrate the mechanisms involved in the sandpack floods.

Experimental Procedure

The sandpacks were fabricated using 5/16 inch stainless tubing five feet long, firmly packed with 170-200 mesh Ottawa sand. The pore volume was about 25 cc (34% porosity) and the pack permeability was on the order of 10 darcies. Separator liquid and gas samples from the "S" sand Reservoir "B" in well A-16-A were recombined at a GOR of 1073 SCF/STB. This yielded a mixture with a bubble point of 5060 psig at 225°F. The measured viscosity at the same conditions was 0.334 cp and the density was 0.6669 g/cc. The composition of the 5060 psig bubble point crude is shown in Table A-1.

The miscibility studies were conducted in a five-foot vertical sandpack at 5180 psig and 225°F. For one of these runs, this mixture was flashed to 4675 psig and a run was performed at 4800 psig.

In a typical displacement the evacuated sandpack was filled with a solvent at the run pressure. The recombined fluid was then introduced into the top of the pack as the solvent was removed from the bottom to a receiver filled with mercury. The mercury was withdrawn from the receiver at a constant rate by a RUSKA pump. The system pressure was maintained by a large high pressure gas source which displaced mercury into the bottom of the source vessel containing the recombined fluid. After the sandpack was completely filled with recombined reservoir fluid, the displacing gas mixture was introduced into the top of the sandpack. The sandpack effluent passed through a visual cell for direct observation of the displacement. The same procedure was used to displace the recombined reservoir fluid with displacing gas. See Figure A-1 for a schematic diagram of the experimental procedures.

As the fluids were withdrawn from the sandpack, a light passing through the windowed cell allowed both visual observation and measurement of transmitted light intensity by means of photo resistor in a bridge circuit connected to a strip-type chart recorder. We have found that the amount of light transmitted through the effluent of the displacement can be a qualitative measure of miscibility achieved during sandpack displacements. The amount of oil recovered after any laboratory displacement would be a most important evaluation parameter; however, because of experimental uncertainties in fluid volumes during high pressure gas displacements, the gas breakthrough time and shape of the light transmittance response proved to be the best gauge of performance for these experiments. The time of gas breakthrough in terms of pore volumes injected is not accurate enough to distinguish between breakthrough times within several percent PV.

Results of Sandpack Displacements

Sandpack flood results are shown as plots of light transmittance (through the sandpack effluent) versus pore volumes injected (and produced) as read from the strip-type chart recordings of each experiment. To show the type of response one can expect when a miscible displacement results, Figure A-2 presents the response from a fully miscible propane - Weeks Island crude flood. This response is then a benchmark of miscibility characterized by a several percent PV transition interval of zero to full transmittance and gas breakthrough (start of increase in light transmittance) at near 1.0 PV.

Three sandpack displacements of SRB crude with CO₂ plus zero, five and ten percent C₁* are shown in Figures A-3, A-4 and A-5. All three experiments were conducted at a frontal advance rate of about 1.2 ft/day. The 5% and 10% C₁-CO₂ displacements are qualitatively indistinguishable. Both indicate

* All references to C₁ dilutions are actually plant gas dilutions which is about 97-98% C₁.

a 94+ % PV breakthrough and a very steep transition interval of light transmittance. Both floods were effective in oil recovery but the shape of transmittance curve may be too steep in comparison with the propane displacement which was genuinely miscible. Using 100% CO₂ as shown in Figure A-3, resulted in an improved recovery from the standpoint of gas breakthrough time and character of transmittance curve.

Figure A-6 shows the results of pure CO₂ in downward displacements at a slow rate (0.6 ft/day). Compare this flood with Figure A-3, a 100% CO₂ displacement at 1.2 ft/day. The slow rate flood probably comes as close to a miscible displacement with CO₂ as we may have observed at these conditions. Note the long transmittance transition intervals particularly in Figure A-6. Floods at both rates show that even though CO₂ is more dense than the crude oil, a gravity stability is achieved. This phenomena is probably the result of the CO₂ going in solution with the crude causing the lightest hydrocarbon components to be liberated as a gas. The oil density is increased with the CO₂ in solution and the displacing gas phase is lightened (less dense) with liberation of light hydrocarbons from the liquid phase. See reference 1 for a discussion of these mechanisms.

Figure A-7 shows the results of a sandpack displacement using plant gas. The high recovery at breakthrough ($0.89 \pm \%$ PV) indicates that there is probably a considerable amount of gravity drainage in a sandpack vertical flood. This would also account for some of the favorable recoveries of breakthrough in the other runs. This is probably one of the factors in the more favorable results in the 0.6 ft/day, 100% CO₂ versus the 1.2 ft/day, 100% CO₂ (Figure A-3) displacements.

In a previously unreported set of vertical displacement experiments performed in 1966 at this laboratory on a West Texas crude, CO₂ was used as the displacing fluid. In the first run, breakthrough was observed at 0.87 PV with injection at a displacement rate of 22 ft/day. Since this appeared to be early for breakthrough, the densities of both fluids were determined. The density of the CO₂ @ 2050 psig and 106°F was 0.7501 g/cc and the density of the recombined sample was 0.6339 g/cc. Hence, it was decided that with this apparent gravity instability, the CO₂ should be injected at the bottom of the pack. The injection rate was reduced to 8 ft/day to further improve the displacement stability. Results were very poor; breakthrough occurred at 0.49 PV. The downward displacement was repeated at 6 ft/day and the breakthrough occurred at 0.95 PV.

These results seem consistent with our conceptual understanding of the process mechanisms and phase behavior experimental data. We believe that in spite of the seemingly unfavorable density contrast between the reservoir crude and CO₂, gravity stability is achieved by the exchange of CO₂ for light hydrocarbons in the crude and dilution of CO₂ by light hydrocarbons in the gaseous driving fluid. Further, we suspect that the unsuccessful displacement from the bottom of the sandpack failed for the same reasons of CO₂ light hydrocarbon exchange. When CO₂ was injected into the bottom of the sandpack, the light

hydrocarbon gas which was liberated, probably percolated upward creating flow paths which the CO_2 preferred to follow. This resulted in poor sweep of the sandpack and poor oil recovery.

Summary

These experimental results show that CO_2 alone or mixtures of CO_2 and plant gas are more efficient than plant gas in displacing oil. The increased recovery efficiency performance is due to the extraction of some hydrocarbon fractions of the crude oil in the CO_2 . Pure CO_2 establishes gravity stability in a vertical displacement even though CO_2 is more dense than SRB oil at reservoir conditions. Although miscibility will not be fully developed under expected reservoir conditions, pure CO_2 and CO_2 diluted with up to 10% plant gas will approach miscible-like displacement performance, with perhaps 100% CO_2 achieving this condition more closely than mixtures diluted with plant gas.

One must remember that slim tube, sandpack, displacements such as these cannot be readily scaled for field application. The results are qualitative and are good for screening injection systems. Other tools are necessary to apply the results of the screen.

Table A-1

Analysis of Fluid

<u>Component</u>	<u>Mol %</u>
Carbon Dioxide	5.66
Nitrogen	3.91
Methane	46.69
Ethane	5.76
Propane	1.82
i-Butane	0.60
n-Butane	2.09
i-Pentane	0.30
n-Pentane	0.50
Hexanes	0.79
Heptanes Plus	31.88

Properties of Heptanes Plus:

Sp. Gr.	0.8712
Mol. Wt.	240

Density of Recombined fluid at 5180 psig and 225°F = 0.6669 g/cc

Viscosity of Recombined Fluid at 5180 psig and 225°F = 0.334 cp

F.V.F. = 1.563 bbls saturated crude per barrel S.T. oil at 14.69 psia
and 60°F

Fig. A-1 - Schematic diagram of apparatus.

Fig. A-2 - Sandpack displacemnt - light transmittance vs pore volumes injected - Weeks Island crude with propane.

Fig. A-3 - Sandpack displacement - light transmittance vs pore volumes injected - SRB crude with CO₂ at about 1.2 ft/day.

Fig. A-4 - Sandpack displacement - light transmittance vs pore volumes injected - SRB crude with 95%v CO₂-5% PG at about 1.2 ft/day.

Fig. A-5 - Sandpack displacement - light transmittance vs pore volumes injected - SRB crude with 90%v CO₂-10% PG at about 1.2 ft/day.

Fig. A-6 - Sandpack displacement - light transmittance vs pore volumes injected - SRB crude with CO₂ at about 0.6 ft/day.

Fig. A-7 - Sandpack displacement - light transmittance vs pore volumes injected - SRB crude with plant gas at about 1.2 ft/day.

Fig. A-8 - Sandpack displacement - light transmittance vs pore volumes injected - SRB crude with 95%v CO₂-5% C₁ at about 1.2 ft/day and 4800 psig.

APPENDIX B

Phase Behavior - Experimentation and Simulation - and Gravity Stability, Weeks Island CO₂ Injection ProjectIntroduction

In this appendix the effect of phase behavior on the gravity stability of the Weeks Island CO₂ pilot is considered. An equilibrium K-value fluid along a composition path similar to that which would be followed in the reservoir. The program was first used to match experimental phase behavior data which are also reported in this appendix.

Phase Behavior

One of the distinguishing features of the Weeks Island SRB CO₂ pilot is the fact that the CO₂ flood will be conducted with a saturated crude. In order to evaluate the significance of this, consider the single contact phase diagram based on experimental data for recombined Weeks Island SRB crude (RRF) and a mixture of 95% CO₂ and 5% plant gas (CO₂PG) shown in Fig. B-1. Table B-1 gives the composition of the two fluids used in the experiments. Section A-A' is the composition path which would be followed for CO₂PG additions to the RRF at a constant pressure P_A equal to the bubble point pressure (P_b) of the oil. Section B-B' shows the composition path taken for additions at a pressure above P_{bp} but below the critical pressure P_{crit} and C-C' shows the path for a pressure $P_C > P_{crit}$.

In Figure B-2 the volume percent of "second phase" is plotted versus mole % CO₂PG for the above three pressures. The term "second phase" is used since the character of the phase split depends on whether the two phase region is entered through a dewpoint, in which case the new phase which appears is a liquid, or through a bubble point, in which case the second phase is a vapor.

Figure B-2 shows that for $P_A = P_{bp}$, the very first CO₂PG addition results in the formation of two phases, and in this case the second phase is a vapor. On continued addition of CO₂PG, the volume fraction of the second phase grows until at high CO₂PG concentrations essentially all of the liquid has been extracted into the vapor phase. For pressure P_B where $P_{bp} < P_B < P_C$, it is possible to dissolve appreciable amounts of the CO₂PG into the undersaturated oil before a phase split occurs, as illustrated by the curve marked P_B in Figure B-2. Again, since we are below the critical pressure for the system, the second phase is a vapor, and continued CO₂PG addition results in an increasing volume fraction of second phase.

The situation is considerably different when the operating pressure is above the critical pressure (e.g., P_C on Figures B-1 and B-2). In this case, a large amount of the CO₂PG can be dissolved in the RRF before the two phase region

is entered, and the two phase region is entered through a dewpoint so the second phase will be a liquid. Furthermore, the volume fraction of second phase goes through a maximum (as shown on Figure B-2) at about 10-20%, depending on the pressure.

While the single cell equilibrium data do not fully describe the complex compositional paths which would occur in the reservoir, they do indicate a fundamental difference between a CO_2 flood at a pressure above the critical pressure, where the displacement is essentially single phase, and a flood at the bubble point of the oil, where two phases form immediately and persist over the entire range of compositions. The operating pressure for the Weeks Island pilot falls in the second category where two phases are expected to persist during the CO_2 displacement process.

Phase Behavior Simulation

An equilibrium K-value type fluid properties computer program has been used to model a sequence of multiple contact equilibrium experiments. The parameters in the phase package were modified to better describe the measured single cell equilibrium data. The cell to cell calculations were designed to follow the compositional path which might be followed in a gravity stable displacement. The procedure was to "mix" by simulation a volume V_L of a reservoir fluid (RRF) with a volume V_G of injection fluid (CO_2 PG) and calculate the resulting phase volumes, compositions, densities and viscosities. For the next step, a volume ΔV of liquid was "removed" while an equal volume of CO_2 PG was added to simulate at least part of the fluid mixing sequence which occurs in the reservoir. The phase volumes, etc. were again calculated and the procedure repeated for each contact. Figure B-3 illustrates this procedure.

The first contact fluid was made up of 10 volume % CO_2 PG, 90% RRF. For subsequent contacts, the volume of liquid removed (and the volume of CO_2 PG added) was equal to 10% of the total system volume (i.e., $\Delta V = 0.1 (V_G + V_L)$).

Results of Phase Behavior Simulation

Figure B-4 shows the volume fraction liquid calculated for each of the contacts simulated. Note that even after 10 contacts, the liquid saturation is still about 15%, indicating the degree to which the CO_2 PG has swelled the oil.

Figure B-5 shows the densities calculated for the liquid and vapor phases for each contact. The points shown for contact number 0 are the densities of the RRF and the CO_2 PG. Note that there is a gradual increase in the liquid density resulting from the exchange of CO_2 for the CH_4 in the liquid phase. The more significant fact is that the gas phase resulting from the first contact (90% RRF and 10% CO_2 PG) is much lighter than the injected fluid. Although the gas phase density does increase with each subsequent contact, it has not gotten as high as the injected CO_2 PG density after 10 contacts.

Figure B-6 shows the calculated viscosities for the two phases as a function of contact. Here we see that, as a result of the transfer of CO_2 from the vapor to liquid phase and the resulting net movement of lighter components from the liquid to vapor phase, the liquid viscosity decreases with the contacts while the vapor phase viscosities increase up to seven contacts after which little change is observed.

Effect of Phase Behavior on Gravity Stability

Because of the high permeability (~3500 md), high dip (~34°) and low displacement rate (~0.03 ft/day), it is hoped that gravity forces will stabilize the CO_2 displacement front.

In order to achieve gravity stability, the original pilot design called for dilution of the injected CO_2 with Weeks Island plant gas to increase the density difference between the injected gas and the reservoir oil. Using Dumore's² analysis for estimating the stable and critical velocities for gravity dominated miscible displacements, it was estimated that at least 5% plant gas be added to the CO_2 . However, in light of the phase behavior discussed above, it appears that³ using a two phase stability analysis, is in order. According to Chuoke, et al,³ for immiscible displacements the critical or maximum stable rate is given by

$$q_c = \left[\frac{\rho_2 - \rho_1}{\mu_2/k_{r2} - \mu_1/k_{r1}} \right] k g \sin \alpha \quad (1)$$

where subscript 2 refers to the displaced fluid and subscript 1 refers to the displacing fluid. Figure B-7 shows the critical rate calculated from eqn (1) as a function of contact number using the data of Table B-2 and Figures B-5 and B-6. Although the critical rate for CO_2 PG vapor displacing RRF (contact "0" on Figure B-7) is about 0.4 ft/day, mass transfer between the phases leads to an immediate increase in the critical rate, up to nearly 4.0 ft/day after the first contact. As the density difference between the two phases becomes less on subsequent contacts, the critical rate slowly decreases until it appears to stabilize at about 2 ft/day.

- Also shown on Figure B-7 are the critical rates for oil displacing water (0.63 ft/day) and CO_2 PG displacing water (0.58 ft/day). These data indicate that it is the water displacement front which determines the maximum rate at which gravity forces will stabilize the process rather than the gas-oil front. Furthermore, since the proposed displacement rate for the pilot of 0.03 ft/day is well below the critical rate for CO_2 PG displacing water, the process should be gravity stable.

For comparison, the lowest critical rate line in Figure B-7 shows the stable rate for CO₂PG displacing RRF assuming complete miscibility. If (contrary to the phase behavior obtained experimentally or predicted) the CO₂PG was completely miscible with the oil, 5% dilution of the injected CO₂ by plant gas should be adequate to ensure gravity stability at a designed field displacement rate of .03 ft/day provided the permeability is on the order of 3500 md.

Some qualification of this analysis is necessary because there has been no distinction between secondary and tertiary displacements. The analysis presented above applies primarily to a secondary displacement, the Weeks Island pilot will be primarily a tertiary displacement. The stability of the SRB displacement will not depend only on hydrocarbon-rich liquid phase-CO₂ rich gas phase density differences, but also on the density difference between the water and the gas phases. This particularly applies during a tertiary displacement because moveable water saturation must be displaced before residual oil is mobilized and displaced by CO₂. Further, in the oil bank, some water will be transported simultaneously with oil, at least over much of the traverse.

The density difference which is the most important to the stability of the displacement is probably something intermediate to the CO₂-oil (phase behavior) differences and the CO₂-water difference. Therefore, the 5% plant gas dilution is really more adequate for stability for the SRB pilot than implied from Figure B-7.

TABLE B-1Composition of Weeks Island Reservoir
Fluid and Injection Gas

	<u>RRF</u>	<u>CO₂ PG</u>
CO ₂	.0083	.9505
C1	.5677	.0481
C2	.0322	.0014
C3	.0181	
C4	.0106	
C5	.0111	
C6	.0117	
C7 ⁺	.3404	

P_{bp} @ 225°F = 5100 psia

TABLE B-2

Data Used in Estimating Critical Rates

$$k = 3500 \text{ md}$$

$$\alpha = 34^\circ$$

$$k_{ro} = 0.5$$

$$k_{rg} = 1.0$$

$$k_{rw} = 0.1$$

$$\rho_w = 0.94 \text{ g/cc}$$

$$\mu_w = 0.28 \text{ cp}$$

-1 - Phase envelope for Weeks Island crude and 95%v CO₂-5% plant gas at 225°F.

Fig. B-2 - Volume percent "second" phase for various pressures based on single contact equilibrium experiments.

Fig. B-3 - Schematic of fluid transfers for multiple contact simulations.

Fig. B-4 - Volume percent liquid calculated for multiple contact simulations.

Fig. B-5 - Phase densities calculated for multiple contacts.

Fig. B-6 - Phase viscosities calculated for multiple contacts.

Fig. B-7 - Critical rates calculated from multiple contact calculations.

APPENDIX C

One-Dimensional Numerical Simulator for "S" Sand Reservoir B, Weeks Island Field

Introduction

As part of the technical support to the proposed CO₂ pilot in the SRB, a one-dimensional reservoir model was constructed and tested. Preliminary runs included in this appendix indicate a fairly accurate description of the B reservoir based on the data from the A reservoir. The model is one-dimensional and assumes segregated flow; coning effects are not included.

Reservoir Description

The model is a 1-D 20 x 1 x 1 grid system. The curvilinear coordinates were used with input data consisting of

- vertical depth of the top of the center of each grid block
- thickness of each grid block (measured vertically)
- width of each grid block
- length of each grid block (measured horizontally)

This data was extracted from structure maps. Figure C-1 shows an approximation of the grid system being used in the X-Z (or vertical plane). Figure C-2 shows an X-Y (or areal) plane through the grid system. Values of permeability and porosity were based on core data from the A reservoir. These values are $k_x = k_y = k_z = 2485$ md and $\phi = 0.236$. Grid block (20, 1, 1) was intended to represent the majority of the gas cap volume, and hence its porosity was input to be 0.350.

Relative Permeabilities

Since a 1-D model was used, and since gravity forces dominate capillary and viscous forces, segregated flow was assumed in this model. For this case, when there is no layering in the reservoir, straight line relative permeabilities are appropriate. Figures C-3 and C-4 show the curves input to the simulator. Pseudo capillary pressures are calculated by the simulator.

PVT Data

Since no PVT data were available for the Weeks Island SRB crude oil when this study was conducted, it was necessary to estimate the appropriate data. An early analysis of SRA crude taken from Smith State Unit No. 1, Well No. 1 on August 27, 1947, was used since the measured bubble point of the recombined sample (5880 psia at 236°F) was reasonably close to the original reservoir B conditions (5878 psia at 215°F). The oil formation volume factor, B_o , was adjusted to give

a value of 1.484 RB/STB at the bubble point. This value was obtained from Exhibit 7 of the Technical Proposal for the Weeks Island Pilot.⁴ Figures C-5 through C-7 show the PVT data input to the simulator.

Well Data

The partial completion option was used in the model since the grid block heights (± 300 feet) are much greater than the completed interval (± 10 feet) and since the fluids were assumed to be in gravity equilibrium. Table C-1 summarizes the well data used. Note that pseudo skin factors are used with the partial completion option while the value for well kh input is the permeability thickness product for the entire grid block. The well rates were taken from a computer data file prepared from production records.

Results

Figure C-8 shows the calculated average reservoir pressure as compared to actual field well pressures. Figure C-9 shows the calculated and actual production history, and Figure C-10 shows the calculated movement of the gas-oil and water-oil contacts. While this run does not represent the final history match, it does indicate that the model is capable of describing the past performance with a fair degree of accuracy and can be used for subsequent studies as new data are available.

TABLE C-1

Summary of Well Data Used in Simulation Model

<u>Well</u>	<u>Location (grid blk)</u>	<u>Skin</u>	<u>kh (Darcy-feet)</u>	<u>r_w (feet)</u>	<u>Completion Interval (feet subsea)</u>
16A	(11,1,1)	30.0	808	0.25	12822 to 12832 (2-68 to 7-75) 12778 to 12788 (7-75 to 3-77)
25	(20,1,1)	30.0	1407	0.25	11995 to 12001
22	(20,1,1)	30.0	1407	0.25	11735 to 11765
2	(1,1,1)	30.0	1419	0.25	13230 to 13294

Fig. C-1 - Vertical plane of grid system.

Fig. C-2 - Areal plane of grid system.

Fig. C-3 - Water-oil relative permeability curves.

Fig. C-4 - Gas-oil relative permeability curves.

Fig. C-5 - Formation volume factors.

Fig. C-6 - Solution gas.

Fig. C-7 - Fluid viscosities.

Fig. C-8 - Pressure history.

Fig. C-9 - Comparison of actual and simulated production rates for Weeks Island SRB Well 16A.

FIGURE C-9

Fig. C-10 - Computed gas-oil and water-oil contacts.

APPENDIX D

Sweep Efficiency as Influenced by Density of Injected Gas

As identified earlier, CO_2 is more dense than SRB crude at reservoir conditions. After mixing CO_2 and SRB crude, gaseous and liquid phases are observed and, fortunately, the gaseous phase is less dense than the liquid phase. As shown in Appendix B, stable rate calculations for miscible and immiscible vertical displacements indicate that even under the most unfavorable conditions which were examined, stability is expected with an injected gas mixture of 95 percent by volume CO_2 and 5% plant gas. Conceptually, we know that in a three dimensional reservoir the oil recovery will increase if the difference in densities of the displacing and displaced fluids is high. To qualitatively assess the importance of density differences between the gas and crude on sweep efficiency for the Weeks Island CO_2 injection field test, two simple simulation studies were conducted.

Simulation Models

A numerical simulation model similar to the one used in Appendix C was employed for this study. The model was two dimensional in the areal view with 15 grid blocks in the dip direction (x), 13 grid blocks along strike (y direction) and one block to represent the thickness (z direction). The model is for the portion of the reservoir which should be influenced by injection into Well A-16 and production from Well A-17. Dimensions were 750 feet, 650 feet and 185 feet in the x, y and z directions respectively. Constant dip of 30° and constant permeability of 3000 md were assumed. Figure D-1 shows the selected grid system and well locations. The displacement rate was about 0.03 ft/day (q/A assuming horizontal displacement front) using injection and production rates of 1500 barrels/day (reservoir conditions).

Fluid properties and relative permeability relationships were the same as those shown in Appendix C. Segregated flow within a grid block was also assumed for this simulation. The segregated flow assumption should be valid as long as the difference in densities between the displaced and displacing phases exceeds about 0.003 g/cc or 0.0013 psi/ft.

Injection was in the gas cap in Well A-16. The oil-water contact was set below the perforations in Well A-17 and the oil column was assumed not to be watered out (i.e., at S_{oi} or $1-S_{wc}$). The injection and production rates were balanced at 1500 barrels per day (reservoir conditions) to result in a constant pressure displacement. The simulations were made with varying gas densities to determine the time until gas breakthrough in Well A-17.

A second simulation model was constructed because the rather coarse grid system used in the 2-D areal simulation can lead to solutions which can be erroneous in some circumstances. A two-dimensional vertical grid system

with many more grid blocks between injector and producer was selected. The area modeled was 200 feet in the x direction and 140 feet in the z direction using ten foot square grid blocks. Relative permeability curves used in the study represent laboratory measurements which are appropriate for this type of simulation. The capillary pressure transition zone was assumed negligible. Figure D-2 shows the grid system and relative permeability curves used for this model. The injection well was located in the upper corner (Block 1,1,1) and the production well was located in the opposite lower corner (Block 20,1,14). Other simulation assumptions were the same as those used in the 2-D areal model described above.

Several sensitivity simulations were made to test model assumptions. These included changing the grid block size and using three blocks in the z direction with the areal model; changing the relative permeability curves and altering the relative position of the injector and producer with the vertical model; and conducting displacements with the oil column oil saturation at the assumed waterflood residual value using both simulation models.

Results

These simulations are intended for conceptual application because compositional effects are not included. Two points should be emphasized. First, the mixing of CO_2 plus plant gas and SRB oil yields a gaseous phase which is less dense than the liquid. This phenomena persists with addition of CO_2 PG as shown in Appendix B. Therefore, not a single density difference exists along an imagined compositional route from injector to producer. Further, any density difference variation that exists along this route could act to the benefit of the process by enhancing the mixing which in turn could increase the effectiveness of the vaporization mechanism and improve hydrocarbon recovery.

The second point that is emphasized is that in the model, Well A-17 is produced continuously but during the field test Well A-17 will be produced only when an oil bank is in proximity to the well. This fact makes the simulation results pessimistic until such time as the well is put on production upon arrival of an oil bank. A separate simulation was conducted using the areal model to observe the shape of the displacement front (gas-oil contact) when only Well G-2 is produced. The simulation was conducted using a density difference of 0.02 psi/ft between the oil and the displacing phase. The calculated gas-oil contact, when the displacement front was just above the A-17 perforations in the row of grid blocks where the A-17 perforations are located, was almost flat. The interface was depressed no more than six feet in the vertical direction over the 650 ft width of the model grid system.

Figure D-3 shows the calculated sweep efficiency at gas breakthrough for an immiscible displacement of SRB oil by gas as a function of the difference in density of displaced and displacing phases for both simulation models. The sweep efficiency and hence oil recovery is very sensitive to the difference in density. Indirectly, these results show that producing Well A-17

only when an oil bank is present to minimize gas coning can materially effect recovery. As a first approximation of the sweep that can be expected from the project, we observe that using the density difference after seven contacts of CO₂PG and oil from Figure B-5 (about 0.14 g/cc or 0.06 psi/ft) which might represent an average for the displacement, the sweep at breakthrough is between 60 and 80 percent from the 2-D areal and the 2-D vertical simulations (Figure D-3).

Additional simulations are planned when compositional effects of the process can be more completely modeled.

Fig. D-1 - 2-D Areal simulation grid.

Fig. D-2 - 2-D Vertical simulation grid and relative permeability curves.

SENSITIVITY STUDY RESULTS

Model	$\Delta\rho$ (psi/ft)	E_{BT} (fraction)		Description
		Sensitivity		
		Case	Case	
Areal	0.02	0.244	0.128	Three layers
	0.02	0.244	0.146	Decrease grid size 40%
	0.02	0.244	0.561	Residual oil saturation
Vertical	0.02	0.667	0.582	Producer location (20,1,7) vs. (20,1,14)
	0.02	0.667	0.672	Gas relative permeability curve
	0.02	0.667	0.655	Residual oil saturation

Fig. D-3 - Simulation results - sweep efficiency at gas breakthrough as a function of density difference.

APPENDIX E

Residual Oil Saturation in the Interval 12,910-20 ft
of Well SU A-17Log-Inject-Log S_{or} Determination with Pulsed Neutron Capture Devices

A log-inject-log procedure similar to that described in references 5 and 6, using stationary measurements with a pulsed neutron-capture sonde and time-of-flight analyzer was carried out at five stations in a ten foot interval of SU A-17. At each station the time-of-flight data were analyzed to yield $\tau_{a,A}$, the apparent neutron decay time in the formation containing injected brine A, and $\tau_{a,B}$, the apparent neutron decay time in the formation containing injected brine B. Both $\tau_{a,A}$ and $\tau_{a,B}$ are determined in a self-consistent way from the slope of neutron decay data in the time interval from $2-1/2 \tau_{a,A}$ to $5 \tau_{a,A}$ and $2-1/2 \tau_{a,B}$ to $5 \tau_{a,B}$.

The values of $\tau_{a,B}$ and $\tau_{a,A}$ from each station were combined with the values of $\tau_{w,B}$ and $\tau_{w,A}$ derived from measurements (corrected to formation temperature and pressure) of the neutron capture cross-section of samples of the injection brines to compute ϕ_w , the fraction of the bulk volume of the formation occupied by the aqueous phase, ($\phi_w = S_w \times \phi_{total}$) from the relation

$$\phi_w = \frac{\tau_{a,B}^{-1} - \tau_{a,A}^{-1}}{\tau_{w,B}^{-1} - \tau_{w,A}^{-1}}$$

At each station, ϕ_w was divided by the average stressed porosity (.256), derived from measurements on samples from the core, to give S_w . The value of S_{or} was computed by multiplying $(1-S_w)$ by 1.54** to take account of the volume change of the live oil when all of the gas was removed from it by the injection of 340 bbls of fluid A over a ten-foot interval. The results are summarized in Table E-1 and indicate an average S_{or} in the log-inject-log interval of .221 (or .200 if station 12,915 is omitted) with a maximum standard deviation of $\pm .028$. At three of the five stations (12,911 ft, 12,913 ft and 12, 917 ft) the time dependence of the time-of-flight data was consistent

**Derived from data contained in P-V-T, Inc. Laboratory Report AB-78068 dated February 20, 1978.

with that reported in references 5 and 6. At 12,915 ft, the slope of the neutron decay curve following the injection of fluid B did not become constant until the interval $(2.9 \tau_{a,B} - 5 \tau_{a,B})$ rather than $(2.5 \tau_{a,B} - 5 \tau_{a,B})$. Therefore, the value of ϕ_w derived for this station is possibly subject to a systematic error of unknown magnitude. The slope of the neutron decay data at 12,919 ft following the injection of brine A did not become constant in time, and data from this station have been omitted.

It may be of interest to compare the values of S_{or} in Table E-1 with the one that can be calculated from the conventional Schlumberger TDT-K measurements over the same interval. The average τ_a across the interval 12,910-20 ft after fluid A injection from 4 passes with a conventional TDT-K sonde is $256 \pm 4 \mu s$. This value corrected according to the latest (1976) Schlumberger publication gives $\tau_{a,A} = 330 \pm 4 \mu s$. The average τ_a after fluid B injection from 4 passes with the TDT-K sonde is $162 \pm 2 \mu s$, and when similarly corrected gives $\tau_{a,B} = 193 \pm 2 \mu s$. From these corrected TDT-K apparent decay time values and the value of $(\tau_{w,B}^{-1} - \tau_{w,A}^{-1})$ given in Table E-1 ϕ_w is computed to be $.2210 \pm .0069^*$. Further, from this value of ϕ_w and the previously stated values of average stressed porosity (.256) and "shrinkage" factor (1.54) there results an S_{or} of $.211 \pm .042^*$.

The values marked with an asterisk are uncertainties which take account only of the variation found on four repeat passes and do not include any systematic errors resulting from the use of corrections from the 1976 Schlumberger publication.

Prior to the injection of brine A, the middle two feet of the log-inject-log interval was perforated and swabbed at the rate of 10 bbls/hr. No oil was produced. Therefore, it is plausible to assume that the oil was immobile and S_{or} was not reduced as a result of the injections.

S_{or} from Core Analysis

The value of S_{or} found in the core recovered from the log-inject-log interval, corrected to in-situ conditions, should be less than or equal to the values in Table E-1. The average value of S_{or} from core analysis (see Table E-2) is .149 using a dead oil density of $.862 \text{ g/cm}^3$ and an average unstressed porosity of .267. If the live oil under in-situ conditions has a formation volume factor of 1.545 and the stressed porosity is .256, then the core analysis gives a corrected average value of S_{or} over the log-inject-log interval of .244 (or .230 if anomalous sample at 12,918 is deleted).

Determination of S_{or} from Open Hole Log Suite

Prior to the log-inject-log (L-I-L) test described above, two intervals in the Weeks Island State Unit A-17 were perforated and swab tested: 12915 to 12917 ft and 12960 to 12970 ft (referenced to Dual Induction Log dated January 1, 1978). The intervals tested were located in the waterflooded portion of the "S" Sand Reservoir B (SRB) and were believed to be at swept zone residual conditions. Approximately one hundred and fifty barrels of formation water with no shows of hydrocarbons were recovered from each zone indicating the assumption of swept zone residual conditions is reasonable. Both intervals were conventionally cored during the drilling operations and laboratory stressed core measurements have been made. As a result, sufficient petrophysical data are available to permit quantitative water saturation calculations to be made in these two intervals. These calculations then provide two additional determinations of waterflood residual oil saturation for the SRB.

The pertinent petrophysical parameters applicable to each tested interval as determined from stressed core measurements, produced water analyses and open hole logs are summarized in Table E-3. Using these parameters and the conventional Archie equation results in calculated water saturation values of $.670 \pm .043$ and $.735 \pm .032$ for the intervals 12915-17 ft and 12960-70 ft respectively. However, in this instance S_o is not merely $1.0 - S_w$. The responses of the open hole Formation Density Compensated and Compensated Neutron logs indicate the presence of a free gas saturation in the SRB from 12890 to 13050 ft. Using the density and neutron responses and published Schlumberger charts, this saturation is determined to be approximately .10. The conventional TDT-K also, though only qualitatively, indicates the presence of gas over the same SRB interval. In addition, after the injection of brine A in the L-I-L interval, subsequent TDT-K logs qualitatively indicate no gas saturation through interval but continue to indicate gas in the remainder of the reservoir, thus confirming the initial interpretation of a free gas phase.

The gas saturation in the intervals of interest (12915-17 ft and 12960-70 ft) can be quantified by use of the density log equation and accompanying identities:

$$\rho_b = \rho_{ma} - \phi(\rho_{ma} - \rho_f)$$

$$\rho_f = S_w \rho_w + S_o \rho_o + S_g \rho_g$$

$$1 = S_w + S_o + S_g$$

In-situ porosity (ϕ) is known from the stressed core analyses. Given ρ_{ma} from the core and ρ_b from the averaged open hole density log (see Table E-2), ρ_f can be determined. As S_w has been previously determined from the Archie equation and ρ_w , ρ_o and ρ_g are known from laboratory PVT or handbook data, S_o and S_g can be calculated:

	<u>12915-17 ft</u>	<u>12960-70 ft</u>
S_w	.670 $\pm$.043	.735 $\pm$.032
S_g	.087 $\pm$.032	.068 $\pm$.033
S_o	.243 $\pm$.054	.197 $\pm$.046

It should be noted that the above assigned uncertainties to S_g are tenuous and certainly minima. Consequently, the cited uncertainty in the log calculated value of S_o is also a minimum.

The value of S_{or} determined from open hole log analysis in the interval 12915-17 ft (which is in the center of L-I-L interval 12910-20 ft) is then .243 $\pm$.05 which compares favorably with the Table E-1 values of S_{or} as determined using the L-I-L technique. However, the log calculated S_{or} has a larger uncertainty than the L-I-L value and is susceptible to possible systematic errors. For example, the interval 12915-17 ft was not swab tested until two months after the open hole resistivity data were obtained. As the SRB was being waterflooded during these two months, the formation water salinity could have changed from the salinity which was in-place when the open hole resistivity log was run. A relatively minor salinity change during the two months of ± 1000 ppm Cl^- would change the previously calculated S_{or} value (.243) by $\pm .025$. It can be noted that the updip producer, Weeks Island State Unit A-16A, is completed in an interval approximately equivalent to the 12915-17 ft interval and its produced water salinity has varied as much as 2500 ppm Cl^- during some two-month periods.

Table E-1
Summary of Results from Stationary Measurements

<u>Log Depth, ft</u>	<u>$\tau_{a,B}^{-1}$, s⁻¹</u>	<u>$\tau_{a,A}^{-1}$, s⁻¹</u>	<u>ϕ_w</u>	<u>S_w</u>	<u>$(1-S_w)$</u>	<u>S_{or}</u>
12911	5331 ± 31	3188 ± 16	.2202 ± .0040	.860 ± .016	.140 ± .016	.216 ± .025
12913	5334 ± 28	3144 ± 16.5	.2250 ± .0037	.879 ± .014	.121 ± .014	.186 ± .022
12915	5316 ± 39	3280 ± 16.5	.2092 ± .0046	.817 ± .018	.183 ± .018	.282 ± .028
12917	5355 ± 32	3186 ± 17	.2229 ± .0041	.871 ± .016	.129 ± .016	.199 ± .025

$$\begin{aligned} \tau_{w,B}^{-1} - \tau_{w,A}^{-1} &= 9972 \pm 80 \text{ at } 22^\circ\text{C and } 1 \text{ atm} \\ &= (9972 \pm 80)(1.016/1.041) = 9732 \pm 78 \text{ at } 100^\circ\text{C and } 5100 \text{ psi} \end{aligned}$$

Table E-2
Core Analyses
BRC Petrophysical Services Laboratory

¹ <u>Depth</u>	² <u>ϕ</u>	³ <u>ϕ</u>	<u>$\rho_{ma}(\text{g/cm}^3)$</u>	<u>S_w</u>	⁴ <u>S_o</u>	⁵ <u>S_{or}</u>
12910	.264		2.644	.763	.166	.272
12911	.266	.256	2.644	.760	.136	.222
12912	.269		2.644	.793	.117	.191
12913	.261	.248	2.645	.731	.172	.282
12914	.265		2.641	.771	.174	.285
12915	.267		2.645	.617	.166	.272
12916	.274	.264	2.641	.793	.117	.191
12917	.268		2.641	.765	.124	.203
12918	.253	.243	2.638	.721	.232	.380
12919	.270		2.644	.783	.122	.199
12920	.269		2.644	.781	.115	.188

¹Adjusted to Dual Induction Log dated January 1, 1978.

²Unstressed.

³Isostatic stress = 7800 psi.

⁴Laboratory measurement corrected using a stock tank oil density of .862 g/cm³.

⁵Corrected to in-situ values as follows:

$$S_{or} = S_o \times \frac{\phi_1}{\phi_s} \times \frac{1 - \phi_s}{1 - \phi_1} \times B_o$$

S_o = column 6 above

ϕ_1 = unstressed porosity, column 2 above

ϕ_s = stressed porosity which is unstressed porosity minus average porosity reduction due to stress (.011)

B_o = formation volume factor, 1.545 bbls/bbls

Table E-3
Summary of Petrophysical Parameters

<u>Parameter</u>	<u>12915-12917 ft</u>	<u>12960-12970 ft</u>
¹ Formation water salinity	10825 ppm Cl ⁻	35,500 ppm Cl ⁻
² In-situ porosity	.256	.261
³ _m	1.70	1.70
³ _n	2.60	2.75
⁴ R _t (ohm-m)	3.3	.99
⁴ ρ _b (g/cm ³)	2.18	2.18
⁵ ρ _{ma} (g/cm ³)	2.644	2.645

¹Determined from analytical analysis of the swabbed formation water, BRC Analytical Chemistry Laboratory.

²Average unstressed core porosity across interval minus average porosity reduction due to stress equals in-situ porosity (see Table E-2).

³Average values of m and n from stressed (7800 psi and formation brine) laboratory measurements, BRC PSL.

⁴Appropriately corrected log values from four repeat passes.

⁵Laboratory measurements, BRC PSL.

ATTACHMENT 2

Shell Development Company
Reservoir Fluid Analysis of
Recombined Fluid from Weeks
Island
Lab. No. AB-78068
February 20, 1978

P-V-T, Inc.

Physical and Design Data Research

K-Values • PVT • Enthalpy

Chemical Process & Petroleum Fluids

Reservoir Analysis and Computer Programs

P. O. Box 36272 / Houston, Texas 77036 / A C 713 782-3577

February 16, 1978

Shell Development Company
P. O. Box 1382
Houston, Texas 77001

Attn: Mr. Mike Moranville

Subject: Reservoir fluid analysis of
recombined fluid from Weeks Island

Dear Mr. Moranville:

This report presents the results of laboratory tests upon a recombined reservoir fluid prepared with separator products from the above field. The composition of these are presented on pages five and six of this report. These samples were then recombined to a saturation pressure of 5880 psia at the reservoir temperature of 225° F. The resultant fluid mixture was then used for a reservoir fluid study.

The recombined fluid was found to contain 1386 SCF of gas per barrel of stock tank oil and a formation volume factor of 1.652 barrels of oil at Ps per barrel of stock tank oil during differential vaporization. The viscosity was measured to be 0.599 centipoise at saturation pressure and reached a maximum of 1.492 centipoises at the reservoir temperature of 225° F. The tabulated data of these tests are presented on pages one through four of this report. The composition of the mixture is presented on page seven of this report.

The remaining sample was then adjusted to a saturation pressure of 5100 psia at 225° F. The composition of both gas and liquid phases are presented on pages 8 and 9 of this report. The remaining fluid will be used for phase contact work and will be reported separately.

It has been a pleasure serving Shell Development. Should you have any questions concerning this or any other matter, please feel free to call on us.

Very truly yours,

Allen E. Barron

AEB/jm

P-V-T Summary

Reservoir Temperature, °F	225
Saturation Pressure at 225 °F, Psia	5880
Compressibility of Reservoir Oil at 225 °F	
Vol. per Vol. per Psi x 10 ⁶	
From 6500 Psia to 6200 Psia	15.4197
From 6200 Psia to 5880 Psia	17.5001
Saturated Oil at 5880 Psia, 225 °F	
Density, Gms. per Ml.	0.6540
Lbs. per Bbl.	229.227
Specific Volume, Cu.Ft. per Lb.	0.02445
Viscosity, Centipoise	0.559
Formation Volume Factor, Bbls. per Bbl.	
"Residual Stock Tank Oil" at 60°F	1.652
Solution Gas-Oil Ratio, Cu.Ft. per Bbl.	
"Residual Stock Tank Oil" at 60°F	1386
Reservoir Oil at 5100 Psia 225 °F	
Density, Gms. per Ml.	0.6689
Lbs. per Bbl.	234.450
Specific Volume, Cu.Ft. per Lb.	0.02395
Viscosity, Centipoise	0.582
Formation Volume Factor, Bbl. per Bbl.	
"Residual Stock Tank Oil" at 60°F	1.545

Shell Oil Co.
Weeks Island 16A

COMPOSITE LABORATORY DATA AT 225 °F

(PRESSURE PSIA	PRESSURE VOLUME RELATIONS			OIL VISCOSITY Centipoises	DIFFERENTIAL LIBERATION			
	RELATIVE VOLUME V/V_{sat} B1	SPECIFIC VOLUME cu. ft. Per Pound	"Z" FUNCTION $\frac{P_{sat}-P}{P-P\left(\frac{V}{V_{sat}}-1\right)}$		FORMATION VOLUME FACTOR Bo	RELATIVE OIL - VOLUME	SOLUTION GAS-OIL RATIO	
							Per Bbl. Stock Tank Oil at 60°F	Per Bbl. Oil at Reservoir Bubble-Point
6500	0.9898	0.02420		0.568	1.635			
6400	0.9914	0.02424			1.638			
6300	0.9929	0.02428		0.564	1.640			
6200	0.9944	0.02431			1.643			
6100	0.9960	0.02435		0.561	1.645			
6000	0.9977	0.02439			1.648			
5900	0.9997	0.02444			1.651			
5880	1.0000	0.02445		0.559	1.652	1.0000	1386	839
5800	1.0034		4.074					
5700	1.0078		4.047					
5500	1.0174		3.977					
5300	1.0280		3.911					
5200				0.579	1.566	0.9479	1122	679
4900	1.0529		3.779					
4600	1.0756		3.680	0.604	1.489	0.9013	962	582
4300	1.1026		3.582					
4100	1.1348		3.486	0.639	1.418	0.8584	819	496
3900	1.2047		3.322					
3400				0.684	1.364	0.8257	690	418
3000	1.3039		3.159					
2800				0.738	1.312	0.7942	561	340
2500	1.4511		2.997					
2200				0.798	1.266	0.7663	438	265
2000	1.6850		2.832					
1600				0.864	1.224	0.7409	320	194
1500	2.0953		2.666					
1000	2.9497		2.503	0.965	1.184	0.7167	212	128
700				1.049	1.163	0.7040	154	93

V/V_{sat} is the volume of fluids (oil and gas) at the indicated temperature and pressure relative to the volume of saturated oil at bubble-point pressure and indicated temperature.

B_o is the volume of oil at reservoir temperature and indicated pressure relative to the volume of residual stock tank oil measured at 60°F.

Gas-Oil Ratio, is cubic feet of gas at 14.65 psia and 60°F, per barrel of residual oil at 60°F.

Note: * indicates value measured at 60°F.

Lab. No. AB-78068

Page 2 of 12

Shell Oil Co.
Weeks Island 16A

COMPOSITE LABORATORY DATA AT 225 °F

PRESSURE PSIA	PRESSURE VOLUME RELATIONS			OIL VISCOSITY Centipoises	DIFFERENTIAL LIBERATION			
	RELATIVE VOLUME V/V_{sat} B1	SPECIFIC VOLUME cu. ft. Per Pound	"Y" FUNCTION $\frac{P_{sat}-P}{\gamma-P\left(\frac{V}{V_{sat}}-1\right)}$		FORMATION VOLUME FACTOR Bo	RELATIVE OIL VOLUME	SOLUTION GAS-OIL RATIO	
							Per Bbl. Stock Tank Oil at 60°F	Per Bbl. Oil at Reservoir Bubble-Point
400				1.169	1.146	0.6937	96	58
200				1.289	1.129	0.6834	53	32
15				1.492	1.077	0.6519	0	0
15 @ 60° F.					1.000	0.6053		

Gravity of residual oil = 32.7° API @ 60° F.

NOMENCLATURE:

V/V_{sat} is the volume of fluids (oil and gas) at the indicated temperature and pressure relative to the volume of saturated oil at bubble-point pressure and indicated temperature.

B_o is the volume of oil at reservoir temperature and indicated pressure relative to the volume of residual stock tank oil measured at 60°F.

Gas-Oil Ratio, is cubic feet of gas at 14.65 psia and 60°F, per barrel of residual oil at 60°F.

Note: * indicates value measured at 60°F.

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Page 3 of 12

Shell Oil Company
Weeks Island 16A

LABORATORY DATA

GAS DIFFERENTIALLY LIBERATED

GAS VOLUME FACTOR

PRESSURE (Psia)	SPECIFIC GRAVITY (AIR = 1.00)		DEVIATION FACTOR $Z = \frac{PV}{NRT}$	Bbl. IN RESERVOIR Per MMCF(Bg)
	Incum.	Accum.		
5880	-	-	-	-
5200	0.7068	0.7068	1.056	698.02
4600	0.7041	0.7056	0.995	743.48
4000	0.6959	0.7031	0.955	820.63
3400	0.6899	0.7005	0.927	937.14
2800	0.6852	0.6981	0.909	1115.87
2200	0.6868	0.6966	0.902	1409.26
1600	0.6995	0.6970	0.907	1948.48
1000	0.7268	0.6998	0.928	3189.73
700	0.7481	0.7021	0.942	4625.50
400	0.7937	0.7062	0.962	8266.49
200	0.8555	0.7110	0.980	16842.32
15	1.0766	0.7251	-	

Lab. No. AB-78068

Page 4 of 12

SAMPLE MARKED:

Shell Oil Company
 Weeks Island 16A
 93 psi at 148° F Separator Gas

<u>Component</u>	<u>Mol%</u>	<u>GPM @</u> <u>14.65 Psia</u> <u>Ethane Plus</u>
Carbon dioxide	1.06	
Nitrogen	0.34	
Methane	89.63	
Ethane	4.32	1.149
Propane	1.98	0.543
iso-Butane	0.60	0.196
n-Butane	0.76	0.239
iso-Pentane	0.38	0.138
n-Pentane	0.29	0.104
Hexanes	0.33	0.135
Heptanes Plus	0.31	0.147
	<u>100.00</u>	<u>2.651</u>

Specific gravity @ 60° F. (Air=1) = 0.6558
 Heating Value, BTU/SCF at 14.65 psia

Dry = 1133
 Wet = 1113

Lab. No. AB-78068
 Page 5 of 12

Shell Oil Company
Weeks Island 16A

Fractional Hydrocarbon Analysis Of
93 psi at 148° F Separator Liquid

<u>Component</u>	<u>Mol%</u>	<u>Wt. %</u>
Hydrogen-sulfide	-	
Carbon dioxide	0.04	0.01
Nitrogen	0.01	Trace
Methane	1.93	0.16
Ethane	0.66	0.10
Propane	1.24	0.28
iso-Butane	0.86	0.25
n-Butane	1.70	0.50
iso-Pentane	2.43	0.88
n-Pentane	2.24	0.81
Hexane	6.66	2.87
Heptanes Plus	<u>82.23</u>	<u>94.14</u>
	100.00	100.00

Heptanes-Plus:

Specific gravity 60°/60° - 0.8596

Molecular weight = 228

Lab. No. AB-78068

Page 6 of 12

Fractional Hydrocarbon Analysis Of
Recombined Reservoir Fluid

<u>Component</u>	<u>Mol%</u>	<u>Wt. %</u>
Hydrogen-sulfide	-	-
Carbon dioxide	0.71	0.40
Nitrogen	0.24	0.09
Methane	63.20	13.24
Ethane	3.37	1.32
Propane	1.67	0.97
iso-Butane	0.53	0.40
n-Butane	0.84	0.64
iso-Pentane	0.56	0.52
n-Pentane	0.47	0.44
Hexane	0.82	0.91
Heptanes Plus	<u>27.59</u>	<u>81.07</u>
	100.00	100.00

Heptanes Plus:

Specific gravity 60°/60° = 0.8587

Molecular weight = 225

Lab. No. AB-78068

Page 7 of 12

SAMPLE MARKED:

Shell Oil Company
 Weeks Island 16A
 Equilibrium gas from
 reservoir fluid separated
 at 5100 psia and 225° F.

<u>Component</u>	<u>Mol%</u>	<u>GPM @ 14.65 Psia Ethane Plus</u>
Carbon dioxide	0.84	
Nitrogen	0.44	
Methane	88.95	
Ethane	3.69	0.9266
Propane	1.67	0.4569
iso-Butane	0.68	0.2211
n-Butane	0.84	0.2633
iso-Pentane	0.64	0.2329
n-Pentane	0.59	0.2125
Hexane	0.65	0.2636
Heptanes Plus	0.01	0.4559
	<u>100.00</u>	<u>3.0328</u>

Specific gravity @ 60° F. (Air=1) = 0.6902
 Heating value, BTU/SCF at 14.65 psia

Dry = 1189
 Wet = 1167

Shell Oil Company
Weeks Island 16A

Fractional Hydrocarbon Analysis Of
5100 psia and 225° F. Equilibrium Liq.

<u>Component</u>	<u>Mol%</u>	<u>Wt. %</u>
Hydrogen-sulfide	-	-
Carbon dioxide	0.68	0.32
Nitrogen	0.37	0.11
Methane	56.93	9.78
Ethane	3.31	1.07
Propane	1.66	0.78
iso-Butane	0.60	0.37
n-Butane	0.84	0.52
iso-Pentane	0.56	0.43
n-Pentane	0.46	0.35
Hexanes	0.74	0.67
Heptanes Plus	<u>33.85</u>	<u>85.60</u>
	100.00	100.00

Heptanes-Plus:

Specific gravity 60°/60° = 0.8657

Molecular weight = 236

Lab. No. AB-78068

Page 9 of 12

Pressure-Volume Relationships at 225° F.

Company Shell Oil Company Well Weeks Island 16A
Reservoir _____ Field _____

Lab. No. AB-78068
Page 10 of 12

Differential Vaporization at 225° F.

Company Shell Oil CompanyWell Weeks Island 16A

Reservoir _____

Field _____

Lab. No. AB-78068

Page 11 of 12

Viscosity at 225° F.

Company Shell Oil Company Well Weeks Island 16A
Reservoir _____ Field _____

Lab. No. AB-78068
Page 12 of 12

Shell Development Company
Petrophysical Services Laboratory
Core Analyses Data

Date : FEBRUARY 21, 1978
Company : SHELL OIL
Lease : STATE UNIT
Well No.: A-17
Field : WEEKS ISLAND
State : LOUISIANA

Sample No.	Depth		Porosity %	Air Perm. md	Grain Density g/cc	Water Sat. %	Oil Sat. %
41	12961'	0"	27.6	3180.	2.643	74.7	12.8
42	12962'	0"	28.0	4210.	2.644	75.3	11.8
43	12963'	0"	27.6	4320.	2.644	78.8	11.8
44	12964'	0"	26.9	4140.	2.645	81.9	12.3
45	12967'	0"	27.3	4730.	2.645	80.1	10.9
46	12968'	0"	27.9	4860.	2.645	71.3	12.3
47	12969'	1"	27.7	4910.	2.644	73.7	13.8
48	12970'	0"	27.5	5380.	2.644	70.2	14.5
49	12971'	0"	27.3	5630.	2.643	74.8	12.4
50	12972'	1"	27.2	5040.	2.643	72.6	15.2
51	12973'	0"	27.2	4800.	2.644	78.0	14.1
52	12974'	0"	27.7	5110.	2.644	76.8	11.7
53	12975'	0"	27.4	4910.	2.645	77.7	11.0
54	12976'	0"	27.5	5060.	2.645	77.2	11.7
55	12977'	0"	27.1	5140.	2.644	78.5	10.6
56	12978'	0"	27.1	4790.	2.645	77.9	11.5
57	12979'	0"	27.5	4600.	2.645	77.3	11.6
58	12980'	0"	27.7	4400.	2.643	79.4	10.1
59	12981'	0"	27.3	2170.	2.640	76.0	13.7
60	12982'	0"	28.1	2880.	2.638	74.3	11.7
61	12983'	0"	27.8	4020.	2.642	73.6	12.4

Shell Development Company
Petrophysical Services Laboratory
Core Analyses Data

Date : FEBRUARY 21, 1978
Company : SHELL OIL
Lease : STATE UNIT
Well No.: A- 17
Field : WEEKS ISLAND
State : LOUISIANA

Sample No.	Depth	Porosity %	Air Perm. md	Grain Density g/cc	Water Sat. %	Oil Sat. %	
1	12910'	0"	26.0	2460.	2.644	70.9	19.3
2	12911'	0"	26.9	2290.	2.646	83.9	9.2
3	12912'	0"	27.8	6230.	2.643	76.7	11.3
4	12913'	0"	27.5	5530.	2.645	85.3	9.8
5	12914'	0"	26.4	2450.	2.644	76.3	15.6
6	12915'	0"	26.6	3110.	2.644	76.0	12.7
7	12916'	0"	26.9	2960.	2.644	79.3	11.0
8	12917'	0"	26.1	2010.	2.645	73.1	16.1
9	12918'	0"	26.5	1130.	2.641	77.1	16.3
10	12919'	0"	26.7	1820.	2.635	61.7	15.6
11	12919'	10"	27.4	2390.	2.641	79.3	11.0
12	12921'	0"	26.8	2190.	2.641	76.5	11.6
13	12922'	0"	25.3	1290.	2.638	72.1	21.7
14	12923'	0"	27.0	2350.	2.644	78.3	11.4
15	12924'	0"	26.9	2120.	2.644	78.1	10.8
16	12925'	0"	27.3	1990.	2.640	72.2	15.9
17	12926'	0"	26.4	1590.	2.639	72.8	14.7
18	12927'	0"	25.2	640.	2.639	70.8	14.8
19	12931'	0"	26.4	2720.	2.644	81.8	11.6
20	12932'	0"	26.5	4620.	2.645	83.0	9.4
21	12933'	0"	25.4	4810.	2.646	78.9	10.3
22	12934'	0"	25.2	4630.	2.644	76.7	12.0
23	12935'	0"	27.3	2970.	2.643	79.1	13.8
39	12940'	0"	27.2	NT	2.651	26.2	9.8
40	12941'	0"	26.6	4660.	2.645	25.0	11.1
26	12949'	0"	26.9	3760.	2.645	83.8	11.0
27	12950'	0"	28.0	4170.	2.645	86.2	10.3
28	12951'	0"	28.3	2260.	2.653	73.0	20.0
29	12952'	0"	27.4	1890.	2.642	66.2	11.7
30	12953'	0"	26.5	2670.	2.646	71.2	13.2
31	12954'	0"	26.8	4340.	2.645	74.9	12.6
32	12955'	2"	26.6	3920.	2.646	79.7	12.0
33	12956'	0"	26.8	3680.	2.645	81.8	11.3
34	12957'	0"	27.7	3480.	2.644	84.9	9.1
35	12958'	0"	28.0	2670.	2.649	78.2	10.7
36	12959'	0"	27.9	2220.	2.643	73.5	13.0
37	12960'	0"	28.3	2850.	2.643	69.4	13.5

Directional Permeability Study
State Unit A-17
Weeks Island Field, Louisiana

<u>Sample Depth ft.</u>	<u>Air Permeability, ⁽¹⁾ md</u>		
	<u>Plug No. 1</u> ⁽²⁾	<u>Plug No. 2</u>	<u>Plug No. 3</u>
12941	4350	4840	4660
12950	4680	3990	4170
12954'6"	4130	4410	4340 (12954')
			3920 (12955')
12960	2440	2580	2850
12964	3910	4210	4140
12970	4640	4040	5380
12975	4080	4350	4910
12980	3820	3780	4400
Average	4010	4030	4310

(1) Measured with 200 psi stress on core.

(2) See attached schematic for explanation of plug orientation.

SCHEMATIC SHOWING ORIENTATION OF PLUGS
FOR DIRECTIONAL PERMEABILITY STUDY

PLUG NO. 1 : PARALLEL TO DIP

PLUG NO. 2 : PERPENDICULAR TO DIP

PLUG NO. 3 : PARALLEL TO STRIKE

CORE DATA
STATE UNIT A-17
WEEKS ISLAND FIELD, LOUISIANA

<u>Sample No.</u>	<u>Depth ft.</u>	<u>Porosity %</u>	<u>Brine Perm. md.</u>	<u>Cation Exchange Capacity MEQ/ml</u>
6	12915	25.6	1510	.018
8	12917	24.8	1330	.035
11	12919'10"	26.4	1230	.024
13	12922	24.2	848	.049
22	12934	24.0	938	.019
37	12960	26.6	1660	.026
44	12964	25.5	1530	.010
45	12967	26.0	1660	.026
46	12968	25.9	2290	.013
49	12971	26.4	1680	.015

Porosities and brine permeabilities measured under an applied stress of 7800 psi.

CEC values based on stressed porosities.

Samples 6-22: Brine contained 18 g NaCl/liter.

Samples 37-49: Brine contained 59 g NaCl/liter.

Attn.: COASTAL DIVISION

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 12922 ft.

Formation _____ Lithology _____

Sample No. 13-A CCI No. 1355 Date 5/26/78

Porosity(%) 24.9 Permeability(md) _____ Grain Density(g/cc) 2.591

Remarks: _____

Attn.: COASTAL DIVISION

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:

ATTACHMENT 4

SR-1774 (10/20/42)
Formerly TG 8

Printed in U.S.A.

WEEKLY CORE REPORT

CORRECTED COPY

SHELL	Lease	W.I. STATE	Well No. A-17
(Company)	District	COASTAL DIV.	Elev. 30'
From DECEMBER 1977 To	19	County) IBERIA	State LA.
Parish)			

NOTE: Excellent color photographs were made of these cores.

CORE DATA							
NO.	FROM TO	RECOVERY IN FEET	FORMATION	DIP	FORMATION CONTENT	TYPE BARREL	REMARKS
						TYPE HEAD SIZE HEAD	
CORE 1	12,910 to 12,936	Cored 26' Recovered 26'	Log depths are 4' shallower than driller depths.			Christensen oriented core 6 3/4 x 4"	Core #1 not oriented
	12,910 to 12,911	1'	S.S., brownish grey, upper fine grained, well sorted, friable, finely cross-bedded at 32° (Struc- tural dip) so horizontal bedded.	32°	Oil odor and stain		
	12,911	(1")	Carbonaceous streak	35°			
	12,911 to 12,919	8'	S.S., brownish grey, lower fine, well sorted with faint low energy wispy bedding (horizontal), car- bonaceous streaks at 12,916-17.	30°	Oil odor and stain		
	12,919	(2")	Carbonaceous streak.				
	12,919 to 12,924	5'	S.S. - As in interval 12,911 to 12,919, with random carbonaceous (asphaltic) gilsonite streaks.	30°	Oil odor and stain		
		1"	Carbonaceous streaks at 12,920 and 22.				
	12,924 to 12,928	4'	S.S., grey, upper very fine. Slight to moderately calcareous & carbonaceous streak. Abrupt change from fine ripple-bedded, wispy, carbonaceous streaks to clean S.S. at 12,928. Slightly calcareous. Lower fine grained.	35°	Oil odor and stain		
	12,928 to 12,936	8'	S.S. Same as intervals 12,911- 12,918 but less bedding streaks.	35°	Oil odor and stain		

CORRECT

E. G. W. W. W.

Exploitation Engineer

SR-1774 (10/20/42)
Formerly TG 8

Printed in U.S.A.

WEEKLY CORE REPORT

CORRECTED COPY

SHELL _____ Lease W.I. STATE _____ Well No. A-17
(Company) _____ District COASTAL DIV. _____ Elev. 30'
From DECEMBER 1977 To _____ 19 _____ County) IBERIA _____ State _____
Parish) _____
NOTE: Excellent color photographs were made of these cores.

CORE DATA							
NO.	FROM TO	RECOVERY IN FEET	FORMATION	DIP	FORMATION CONTENT	TYPE BARREL	REMARKS
						TYPE HEAD SIZE HEAD	
CORE 2	12,936 to 12,945 Oriented	Cored 9' Recovered 6.5'+	Log depths 4' less than drlr. S.S., brownish grey, upper to lower fine grained. Moderate to well sorted, very friable, few carbonaceous fragments. No apparent bedding except one car- bonaceous streak at 45° dip. (Assumed 2.5' lost from base core.)		Oil odor and stain		Oriented with scrib
CORE 3	12,946 to 12,966	Cored 20' Recovered 18.5'	Log depths are 4'+ shallower than driller depths.				Oriented with scrib
	12,946 to 12,951	5'	S.S., brownish grey, upper fine to lower medium gr., well sorted, slightly calcareous. No bedding.		Oil odor and stain		
	12,951	(2")?	Black shale.				
	12,951 to 12,953.5	2.5'	S.S., brownish grey, upper and lower fine gr., well sorted bedded at 35-45° with thin calcareous streaks.	40°	Oil odor and stain		
	12,933.5 to 12,957.5	4'	Same as 12,946-51, slightly cal- careous, but with some bedding.	35- 40°	Oil odor and stain		
	12,957.2	(1")	Carbonaceous laminated streak.	20°			
	12,957.5 to 12,958	.5'	S.S. brownish grey, lower fine, well sorted.				
	12,958 to 12,958.5	.5'	Carbonaceous laminated streak.	45°			

CORRECT

E. B. Weber
Exploitation Engineer

SR-1774 (10/20/42)
Formerly TG 8

Printed in U.S.A.

WEEKLY CORE REPORT

CORRECTED COPY

SHELL		Lease W.I. STATE		Well No. A-17			
(Company)		District COASTAL DIV.		Elev. 30'			
From DECEMBER 1977 To		19		County) IBERIA State LA.			
		Parish)					
NOTE: Excellent color photographs were made of these cores.							
CORE DATA							
NO.	FROM TO	RECOVERY IN FEET	FORMATION	DIP	FORMATION CONTENT	TYPE BARREL	REMARKS
						TYPE HEAD SIZE HEAD	
CORE 3	12,958.5 to 12,964.5	6'	S.S., brownish grey, upper fine, well sorted, moderately, friable, massive.		Oil odor and stain		
	12,964.5 to 12,966	1.5'	Assumed no recovery.				

CORE 4	12,966 to 12,987	Cored 21' Recovered 17.5'	Core depths 4'± deeper than log depths.				
	12,966 to 12,981	15'	S.S., brownish grey, upper fine-lower medium, well sorted. Slight calcareous, friable, random asphaltic gilsonite for carbonaceous inclusions. (Concentration at 12,980.				
	12,981 83.5	2.5'	S.S. brownish grey, well sorted, lower fine, abundant gilsonite or carbonaceous inclusions, slightly calcareous. (Heaviest concentration of carbonaceous material 12,981 to 982.)				
	12,983.5 to 12,987		Assume 3.5' no recovery in bottom of core.				

CORRECT

E. G. W. W. W.

Exploitation Engineer

SR-1774 (10/20/42)
Formerly TG 8

Printed in U.S.A.

WEEKLY CORE REPORT

CORRECTED COPY

SHELL		Lease		W.I. STATE		Well No. A-17	
(Company)		District		COASTAL DIV.		Elev. 30'	
From		DECEMBER 1977		To		19	
County)		IBERIA		State		LA.	
Parish)							
NOTE: Excellent color photographs were made of these cores.							
CORE DATA							
NO.	FROM TO	RECOVERY IN FEET	FORMATION	DIP	FORMATION CONTENT	TYPE BARREL TYPE HEAD SIZE HEAD	REMARKS
CORE 1	12,910 to 12,936	Cored 26' Recovered 26'	Log depths are 4' shallower than driller depths.			Christensen oriented core 6 3/4 x 4"	Core #1 not oriented
	12,910 to 12,911	1'	S.S., brownish grey, upper fine grained, well sorted, friable, finely cross-bedded at 32° (Structural dip) so horizontal bedded.	32°	Oil odor and stain		
	12,911	(1")	Carbonaceous streak	35°			
	12,911 to 12,919	8'	S.S., brownish grey, lower fine, well sorted with faint low energy wispy bedding (horizontal), carbonaceous streaks at 12,916-17.	30°	Oil odor and stain		
	12,919	(2")	Carbonaceous streak.				
	12,919 to 12,924	5'	S.S. - As in interval 12,911 to 12,919, with random carbonaceous (asphaltic) gilsonite streaks.	30°+	Oil odor and stain		
		1"	Carbonaceous streaks at 12,920 and 22.				
	12,924 to 12,928	4'	S.S., grey, upper very fine. Slight to moderately calcareous & carbonaceous streak. Abrupt change from fine ripple-bedded, wispy, carbonaceous streaks to clean S.S. at 12,928. Slightly calcareous. Lower fine grained.	35°	Oil odor and stain		
	12,928 to 12,936	8'	S.S. Same as intervals 12,911-12,918 but less bedding streaks.	35°	Oil odor and stain		

CORRECT

E. G. Wernan

Exploitation Engineer

SR-1774 (10/20/42)
Formerly TG 8

Printed in U.S.A.

WEEKLY CORE REPORT

CORRECTED COPY

SHELL		Lease W.I. STATE		Well No. A-17			
(Company)		District COASTAL DIV.		Elev. 30'			
From DECEMBER 1977 To		19		County) IBERIA State			
		Parish)					
NOTE: Excellent color photographs were made of these cores.							
CORE DATA							
NO.	FROM TO	RECOVERY IN FEET	FORMATION	DIP	FORMATION CONTENT	TYPE BARREL	REMARKS
						TYPE HEAD SIZE HEAD	
CORE 2	12,936 to 12,945	Cored 9' Recovered 6.5'±	Log depths 4' less than drlr. S.S., brownish grey, upper to lower fine grained. Moderate to well sorted, very friable, few carbonaceous fragments. No apparent bedding except one carbonaceous streak at 45° dip. (Assumed 2.5' lost from base core.)		Oil odor and stain		Oriented with scrib
CORE 3	12,946 to 12,966	Cored 20' Recovered 18.5'	Log depths are 4'± shallower than driller depths.				Oriented with scrib
	12,946 to 12,951	5'	S.S., brownish grey, upper fine to lower medium gr., well sorted, slightly calcareous. No bedding.		Oil odor and stain		
	12,951	(2")?	Black shale.				
	12,951 to 12,953.5	2.5'	S.S., brownish grey, upper and lower fine gr., well sorted bedded at 35-45° with thin calcareous streaks.	40°	Oil odor and stain		
	12,933.5 to 12,957.5	4'	Same as 12,946-51, slightly calcareous, but with some bedding.	35-40°	Oil odor and stain		
	12,957.2	(1")	Carbonaceous laminated streak.	20°			
	12,957.5 to 12,958	.5'	S.S. brownish grey, lower fine, well sorted.				
	12,958 to 12,958.5	.5'	Carbonaceous laminated streak.	45°			

CORRECT

E. S. Usher
Exploitation Engineer

SR-1774 (10/20/42)
Formerly TC 8

Printed in U.S.A.

WEEKLY CORE REPORT

CORRECTED COPY

SHELL	Lease	W.I. STATE	Well No.	A-17
(Company)	District	COASTAL DIV.	Elev.	30'
From	DECEMBER 1977 To	19	County)	IBERIA
			State	LA.
			Parish)	

NOTE: Excellent color photographs were made of these cores.

CORE DATA							
NO.	FROM TO	RECOVERY IN FEET	FORMATION	DIP	FORMATION CONTENT	TYPE BARREL	REMARKS
						TYPE HEAD SIZE HEAD	
CORE 3	12,958.5 to 12,964.5	6'	S.S., brownish grey, upper fine, well sorted, moderately, friable, massive.		Oil odor and stain		
	12,964.5 to 12,966	1.5'	Assumed no recovery.				
CORE 4	12,966 to 12,987	Cored 21' Recovered 17.5'	Core depths 4'+ deeper than log depths.				
	12,966 to 12,981	15'	S.S., brownish grey, upper fine-lower medium, well sorted. Slight calcareous, friable, random asphaltic gilsonite for carbonaceous inclusions. (Concentration at 12,980.				
	12,981 83.5	2.5'	S.S. brownish grey, well sorted, lower fine, abundant gilsonite or carbonaceous inclusions, slightly calcareous. (Heaviest concentration of carbonaceous material 12,981 to 982.)				
	12,983.5 to 12,987		Assume 3.5' no recovery in bottom of core.				

CORRECT

E. G. Wern

Exploitation Engineer