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and

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on

OIL RECOVERY ENHANCEMENT FROM FRACTURED,
LOW PERMEABILITY RESERVOIRS

submitted by

TEXAS A&M UNIVERSITY

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OIL RECOVERY ENHANCEMENT FROM FRACTURED, LOW PERMEABILITY RESERVOIRS

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A Study of Oil Recovery Enhancement from Fractured, Low Permeability Reservoirs
Specific Study Objective - The Austin Chalk Producing Trend

1.0 - Abstract
The results of the investigative efforts for this jointly funded DOE-State of Texas research project achieved during the 1991-1992 year may be summarized as follows:

*Geological Characterization* - Detailed fracture system maps measured at outcrops along the Austin Chalk chalk trend have been related to the subsurface. Statistical data obtained from the outcrop studies has been correlated with FMS dipmeter information obtained from Austin Chalk operators. These studies have shown the hierarchical nature and the bed contained fracture development observed in the outcrop may be extrapolated to the subsurface.

Well-log response in Austin Chalk wells has been shown to be a reliable indicator of both organic maturity and fracturability.

Multi-component, vertical-seismic-profile, VSP shear-wave data were reduced to their true orthogonal components by balancing or rotating the source magnitudes and geophone couplings. The resultant method appears to be useful to detect the negligible displacement fractures in the Austin Chalk.

Production decline curves have been related to well test or transient pressure analysis methods. Studies on daily production records of Austin Chalk horizontal wells have shown that analysis of production records may be substituted for the more expensive and difficult to obtain transient pressure data.

*Development of the EOR Imbibition Process* - Magnetic Resonance Imaging, MRI studies have shown the carbonated water-imbibition displacement process significantly accelerates and increases recovery from oil saturated, low permeability rocks.

These studies applied to flow in open and dead-end micro-fractures have shown significant volumes of oil remain undisturbed in the dead-end micro-fractures even when carbonated water is used as the imbibing fluid.

*Transfer of Technology* - A number of presentations and publications were made at technical meetings and symposia. Two transfer of technology conference concerning the results of our investigative efforts on the Austin Chalk were held on the Texas A&M
University campus during 1992. Approximately 160 people representing at least 50 different companies attended each of these meetings.

Field Tests - One field trial was conducted. Performance data are still being gathered to determine the volume of additional oil recovered.

2.0 - Introduction

A multi-disciplinary investigation to develop innovative methods to characterize and to enhance oil recovery from dual porosity, fractured, low matrix permeability oil reservoirs has been conducted for the last three years. The Austin Chalk producing horizon trending through Texas was selected as the candidate for analysis.

Two major technological problems characteristic of the Austin Chalk as well as to other dual porosity reservoir types.

- Reservoir Description - Commercial oil production is dependent on the wellbore encountering a significant number of essentially vertical trending natural fractures. The prediction of the location and frequency of natural fractures at any particular region in the subsurface is generally problematical, unless extensive and detailed seismic data is available. Generally moderate to poor economic return on investment precludes acquisition of detailed seismic data for the average Austin Chalk operator.

- Enhanced Oil Recovery - A major portion of the oil remains in the low permeability matrix blocks after depletion. Primary production is derived mainly from the higher permeability fracture system. There are no economically realistic secondary or enhanced recovery methods currently available to mobilize a significant portion of this bypassed oil.

The following multi-faceted study was designed to develop new methods for reservoir description and enhancing recovery from the Austin Chalk producing trend. Tasks and respective investigators are listed in the following:
Reservoir Description

Task 1: Interpreting and Predicting Natural Fractures
Geological Studies - Dr. Friedman - Geology Department
Geophysical Studies - Dr. Gangi - Geophysical Department

Task 2: Relating Recovery to Well-log Signatures
Geological Studies - Dr. Berg - Geology Department
Petroleum Engineering Studies - Dr. Poston - Petroleum Engineering Department

Enhanced Oil Recovery

Task 3: Development of the EOR Imbibition Process
Laboratory Displacement Studies - Dr. Poston - Petroleum Engineering Department
Imaging Studies - Dr. Poston - Petroleum Engineering Department

Task 4 - Mathematical Modeling - Dr. Wu - Petroleum Engineering Department

Field Trials

Task 5 - Field Tests - Dr. Poston

Tasks 1 and 2 involve the development of better techniques for Reservoir Description, while Tasks 3 and 4 are concerned with the development of a new Enhanced Oil Recovery method. Task 5 is designed to apply these investigative efforts to field trials by finding operators to Field Test these new methods. The following discussion of the results of our investigations conducted during the 3rd year of the 3 year project is divided into these 3 major subjects of interest.
3.0 - Discussion of Research

3.1 - Reservoir Characterization

Characterization of Fractures in Outcrop - Dr. Friedman

Approximately 2,000 ft of Formation Microscanner, FMS survey data from a horizontal borehole located in the Giddings area were analyzed to determine fracture spacing and orientation. Two very significant results were obtained from this work. They are as follows:

(a) The orientation of over 1,200 observed fractures indicates there are two sets of fractures with a common strike of N 75° E and a dihedral angle of 10 to 20°. Fig. 1 illustrates this relationship. The observed pattern is one expected to be associated with a N75°E-striking normal fault or monoclinal flexure with an underlying normal fault. The pattern is very strongly developed but is less complicated than that observed in outcrops.

(b) Fracture spacing calculated from over 1,000 fractures observed in the FMS data is statistically identical to the fracture spacing measured along horizontal scanlines placed on vertical outcrops all along the Austin Chalk outcrop trend.

Fig. 1 - Equal Area Projection from Analysis of FMS Data
Another interesting result is the ability to draw and compare the fracture intensity and distribution along the borehole trajectory. Fig. 2 is an illustration of a typical horizontal borehole. Superposing the FMS data and formal stratigraphy along the wellbore trajectory will permit the beds containing the majority of the fractures to be identified. The application of this new technology will enhance planning of adjacent borehole trajectories so as to maximize productivity. The structural information determined from changes in bedding dip and strike could also be superposed.

Field observations indicated that many fractures are contained within brittle chalk members. The brittle members are bounded by relatively ductile shales or marls that exceed 10-cm in thickness. Corbett\(^1,2,3\) noted this feature is well-exposed in the Lehigh Cement Quarry of the Lehigh Portland Cement Co., Waco Texas and is reported as the dominant style in the subsurface of the Giddings Field by Holifield. The importance of fracture bed-containment to the plan the trajectory of boreholes in the Giddings Area was emphasized strongly by B. Ray Holifield in his presentation at our first Symposium on the Austin Chalk Producing Trend, June 3, 1992. These studies indicate that vertical continuity of fractures when shale or marl breaks are locally numerous and relatively thick may be poor.

The view that the chalk can be thought of as a horizontally segregated plexus of numerous isolated and fractured reservoirs, separated by shale/marl breaks, has been
questioned by attempts to accommodate oil production volumes solely from the relatively thin fractures. These volumetric calculations lead to the conclusion that either there is some vertical connectivity or that horizontal connectivity occurs over surprisingly large distances.

A series of laboratory experiments have been conducted which show fractures initiate in a brittle rock and propagate toward a bedding plane or a relatively ductile layer of bentonitic clay. Whether or not they cross the bedding or are contained within the brittle member, i.e., fracture-bed-contained, is dependent upon the thickness of the ductile layer, the effective confining pressure, the displacement rate for the fracture propagation and type of rock composing the brittle member. Fracture containment is enhanced by increasing thickness of the ductile layer, decreasing the effective confining pressure, slower displacement and when Austin Chalk itself is used as the brittle layer.

The results of these studies show the single most important geological fact governing the production of hydrocarbons from the naturally fractured Austin Chalk reservoirs in the Giddings Field is the recognition that shales in the Austin Chalk separate the Austin Chalk into many separate reservoirs. It is possible for a shale, of only a few inches in thickness, to prevent significant migration of fluids either up or down into the adjoining fractured intervals".

5-cm diameter by 10-cm long, right-circular cylinder specimens consisting of two sub-cylinders of brittle rock either in contact with a bentonic clay ductile or a non-ductile layer. The upper brittle member contains a 2-mm wide notch terminating in a finer 1-mm wide notch. The purpose of these notches is to produce a stress concentration that causes fractures to propagate toward the ductile layer when the upper piston forces a steel wedge into the notch. The induced extension fracture either propagates across the boundary to the lower brittle member or is contained within the ductile layer.

The experimental parameters investigated were (a) thickness of the ductile clay layer, the effective confining pressure, the displacement rate for the propagation of the extension fracture, and whether the clay was room-dry or water-wet. These parameters and the experimental results are listed in Table 1. The results of these studies indicate that fracture containment within a brittle layer is factored by increasing thickness of the ductile member, increasing effective confining pressure and decreasing displacement rate.

Examination of the results shows that fracture-bed-containment is favored when the thickness of the shale is increased, there is a low effective pressure, slower displacement rate and when chalk rather than sandstone is used as the brittle member.
Table 1 - Experiments on Fracture Containment

Low effective pressures may occur in the chalk reservoirs at depth. Two scenarios are possible. First, B. Ray Holifield has stated (oral presentation at Austin Chalk Symposium, TAMU, June 3, 1992) that his interpretation of seismic data suggests that the faulting and fracturing of the Austin Chalk took place prior to the end of Pecan Gap time (Middle Taylor marl, Upper Cretaceous). This would place the chalk at a shallow depth of burial at the time of fracturing/faulting which is comparable to that along the current outcrop trend. Other operators agree there probably was an episode of early deformation, but that faulting continued into the late Oligocene. The late-Oligocene pick is based upon the youngest age of the nearby Luling, Mexia and Talco fault zones. Secondly, the chalk might have faulted and fractured at or near its maximum depth of burial (about 9,000 ft to 13,000 ft, R. R. Berg, Personal Communication, 1992) during which time maturation of its indigenous
hydrocarbon produced high formation pressures. Similarly high pressures would have occurred in the underlying Eagleford carbonaceous shale either due to hydrocarbon maturation, late-dewatering associated with changes in its clays, or simple compaction in the low permeability shales. In either case high pore pressures would reduce the effective stresses and cause the chalk to be weak and brittle, to fault and fracture, and to have bed-contained fractures.

One of the principal objectives of this work was to predict stratigraphic zones within a naturally fractured formation that contain a disproportionately large abundance of fractures. A fracture stratigraphy within the formal stratigraphy which would define the beds which would have the greatest propensity to fracture assuming some tectonic loading condition must be developed. Ideally, this prediction should be able to use standard logs, such as resistivity, gamma ray, or sonic velocity logs that measure directly a parameter known to be a factor in controlling strength and therefore fracture abundance.

Recently, compressive strength data from a suite of 18 samples of Austin Chalk taken at various depths from cores from the Proco Gise #1 and Exxon Hildebrandt #1 wells, Pearsall Field, South Texas were correlated. Deep induction resistivity, oil saturation and gamma ray readings were available from the same wells. Both the log- and the strength-data are courtesy of the Exxon Corporation, U.S.A.

Previous work by Dr. Berg conducted under the auspices of the ANNEX IV research project indicated the resistivity of the Austin Chalk is influenced by variations in clay content and oil saturation. The gamma-ray response is also influenced by clay and oil saturation. Resistivity is shown to be a function of strength with z-values of oil saturation and gamma readings. There is a general increase of resistivity with increasing strength and increasing oil saturation. The increase in resistivity is more regular in the range of 5 to 30 ohm-m for samples that contain oil saturation of 0% to 14%. Anomalous values of resistivity represent higher oil saturations which are in the range of 50% to 72%. Both the point resistivities and the running-average resistivities show the same trends. Oil saturations are not yet available for the Exxon Hildebrandt core. They are needed to confirm this apparent relationship.

The same general increase in resistivity with strength is influenced by the gamma response. The increase in resistivity is more regular for samples with low gamma readings in the range of 20 to 33 API units, with the exception of one point. Anomalous values of resistivity have higher gamma readings in the range of 36 to 87 API.
The anomalous resistivity values in each case are probably due to increased oil saturation. The gamma response is normally expected to reflect clay content. However, the anomalous resistivities may correspond to increased oil saturations. It is likely that radio-isotopes of heavy metallic elements are associated with the organic compounds in the rock matrix. The isotopes may also be present in small amounts in the hydrocarbons generated in the matrix or existing in fractures. High gamma readings are also observed in other source rocks, such as the Bakken Shale of North Dakota. Therefore, the gamma response in the Austin Chalk is greatly influenced by oil saturation and does not always reflect ultimate strength. Ultimate strength can be inferred however, with these cautions in view, for samples with nearly constant oil saturations.

Exposures of the Austin Chalk in the Lehigh Quarry are marked by distinct intercalcation's of shales/marls and brittle chalk layers. These exposures are nearly identical to those productive in the subsurface in the Giddings part of the Austin Chalk producing trend. Accordingly, extrapolation of quantitative outcrop data to the subsurface are particularly important.

Ms. V. L. French mapped all fractures along exposed vertical face of the quarry. The orientation and spacing of a total of 805 fractures were measured in 9 layers. Six of these layers contain largely regional fractures, i.e., fractures related to the overall Balcones normal fault trend, while three of the layers are located in the hanging wall of an immediately adjacent listric normal fault and contain largely tectonic fractures. Both types of fractures tend to be bed-contained.

Ms. French's cross section also shows that there is a rough periodicity to the spacing of fractures that cut across several of the shale/marl breaks. This spacing ranges from 1.0 to 6.5 m and averages 4.3 m. The presence of partial vertical communication helps to explain the fluid-volume calculations by Exxon and others that indicate at least for the Giddings area completely segregated brittle chalk beds cannot supply all the fluids produced by some of the wells.

Nelson stated that outcrops display a mix of fracture sizes and lengths. Fracture width, aperture size, and fracture spacing vary with the scale of the fracture. For example, in outcrops with fractures of different length, the longer fractures are the widest and are the farthest apart. This "law" is supported by predictions made from linear elastic fracture mechanics, (a) stress concentrations at crack tips are dependent in part on fracture...
size and width; (b) long fractures "shield" adjacent and smaller fractures and have a higher propagation energy; and (c) the length of the central crack tends to arrest the more distal fractures. As more and more distal fractures are eliminated, increased spacing results between those that do propagate.

The maps of rock panels of Austin Chalk, prepared at scales of 1:12 to 1:48 by Wiltschko, et.al. Hung6 as part of this effort, show both clear-cut examples of this "law" and also cases where the phenomenon is not easily appreciated. Refer to Fig. 3. Where the "law" does hold it is clear that the longest fractures are the first to occur and are the oldest. The longer fractures serve as the major element in what is often a three-fold fracture-drainage network through intersections with shorter and more curved fractures. In such cases a horizontal wellbore penetrating these long "master" fractures will drain fluids from nearly the entire array of fractures.

Fig. 3 - Outcrop Pattern from the Old Alamo Cement Quarry
**Transfer of Technology** - The following is a listing of the presentations and publications pertaining to these subjects which were presented during the year.


**Conclusions** - The following conclusions may be derived from the studies conducted during the past year.

- There is a definite relationship between outcrop and subsurface fracture characteristics.
- Bed contained fractures within the Austin Chalk are a very important consideration when estimating the recoverable oil in a particular area.

**Future Efforts** - The study is far from satisfactory completion. Additional FMS surveys are needed to work on the outcrop-extrapolation problem. Not only fracture geometry and spacing, but fracture aperture and abundance versus resistivity, correlations of resistivity with fracture abundance, and integrating all data with a view toward developing a detailed fracture stratigraphy for the Austin Chalk is required.

**Geophysical Studies - Dr. Gangi**

Naturally fractured, carbonate reservoirs generally possess a very low matrix permeability. Therefore, the knowledge of the direction perpendicular to the direction of the major fractures previous to drilling a horizontal well would be useful for insuring the maximum return on investment.

Multi-component, vertical-seismic-profile, VSP shear-wave data can be used to determine the orientation of these vertical fractures. A vertical component and two horizontal components of motion are recorded for each of three source components. Each of these components in turn consist of a vertical component and two horizontal components. Multi-component, vertical-seismic-profile, VSP shear-wave data whose horizontal components of motion are recorded for each of the two horizontal sources.

The orientation of the vertical fractures is determined from the orientation of the horizontal, principal axes of the elastic medium. The shear-wave speed is a maximum
along the fast axis, while the speed is at a minimum along the slow axis. This difference in the shear-wave speeds leads to shear-wave splitting or birefringence. There is no motion if the source is oriented at right angles to the receiver when the sources and receivers are oriented along the principal axes.

Each receiver will detect a component of both the fast and slow waves if the receivers are oriented with respect to the principal axes. A receiver will detect either the fast wave or the slow wave when the receivers are oriented along the principal axes. Only the receiver which is oriented parallel to the source will detect any motion when both the horizontal source and the two horizontal receivers are oriented along the principal axes. This principle is used to determine the orientation of the horizontal principal axes and, consequently, that of the vertical fractures. The data must be "rotated" into the principal axes by a matrix transformation because the sources and geophones are not necessarily oriented along the principal axes.

Choi and Gangi\textsuperscript{7} showed that a multi-component, VSP data set could reveal large fracture-orientation fluctuations with depth because of source and geophone imbalances. Source balancing, with the assumption that the geophone couplings are balanced, improves the stability of fracture orientation. However, some small energy still exists in the off-diagonal components in the principal axes. This small energy may be due to imbalance in the geophone coupling.

A method to balance source magnitudes and geophone couplings was considered. The line connecting the source position to the wellhead and is toward the wellhead is defined as the positive in-line direction. The cross-line direction is perpendicular to the in-line direction. The positive cross-line direction is obtained by a \textdegree \text{90} counterclockwise rotation from the positive in-line direction. The strike direction of the fractures is the fast direction and that perpendicular to the fast direction is the slow direction.

Synthetic, zero-offset-VSP data were generated for a model earth with vertical fractures. The geophone is fixed and the components are in the in-line and cross-line directions. 10-Hz Ricker wavelets were used for the wavelets of the fast and slow shear waves.

Noise sequences and signals are combined together to yield a synthetic data set. A random-number generator developed by Press et al\textsuperscript{8} was used to generate uniformly distributed random numbers ranging from zero to one to construct a noise sequence. These random numbers were converted to normally distributed values by using the transformation published by Box and Muller.\textsuperscript{9} Fig. 4 shows the normally distributed random numbers that were generated with this transformation.
The cumulative distribution function for a normally distributed random variable equation discussed by Meyer\textsuperscript{10} was used. The generated random numbers were found to closely approximate a normal distribution.

Fig. 4 - The Normally Distributed Random Numbers

Fig. 5 - The Amplitude Spectrum of the Random Number
The amplitude spectrum of the random number sequence is shown in Fig. 5 is seen to be quite flat for the full frequency range. The normalized auto-correlation of this noise sequence is seen in Fig. 6 to be approximated by a single spike at a zero time shift. This shows that the noise sequence is relatively uncorrelated. The auto-correlation would be a delta function if the noise sequence were truly uncorrelated.

![Normalized Autocorrelation of the Random Number](image)

Fig. 6 - The Normalized Autocorrelation of the Random Number

The noise sequence also should be band limited to define the correct signal-to-noise (S/N) ratio since the signal is a band-limited wavelet. The noise sequence, after filtering, is shown in Fig. 7, the amplitude spectrum in Fig. 8 and the normalized autocorrelation is shown in Fig. 9.

All of the samples in the noise sequence were used to compute its RMS amplitude while only the samples within a time window were used for the signal wavelet. The start and stop times for the wavelet's time window were defined by the 5% and 95% cumulative energy times, respectively, so that 90% of the energy of the wavelet was contained in the wavelet window.
Fig. 7 - The Noise Sequence After Filtering

Fig. 8 - The Autocorrelation of the Random Number After Filtering
A linear least squares method was used to determine the ratios of the source magnitudes and geophone couplings and the fracture orientation.

The uncertainties (or dispersions) of the solution vector were calculated according to a method suggested by Parrish and Gangi. This method gives an approximation, generally a lower bound, to the variances because the cross correlations between the parameters are neglected.

The following parameters were used to generate synthetic VSP data to test the balancing scheme:

\[ t_F = 1600 \text{ ms}; \ t_S = 1670 \text{ ms}; \ \alpha = 1.25; \ \beta = 0.67; \ \theta_I = 90^\circ; \ \theta_f = 60^\circ. \]

The generated VSP data set is shown in Fig. 10-a. The off-diagonal traces would be identical if the sources and the geophones were balanced. The waveforms of the off-diagonal traces are similar, but their amplitudes are different due to the source and geophone unbalances. Fig. 10-b shows the VSP data set after rotation to the principal axes when the correct fracture orientation (\( \theta_f = 60^\circ \)) is used, but without balancing. The off-diagonal traces would both be zero if the sources and geophones were balanced. Large
energy remains in the off-diagonal traces due to the source and geophone imbalances. The error energies of the off-diagonal traces are concentrated at the same time as those of the diagonal traces recorded on the same geophone direction (i.e., the energy is concentrated at the time 1600 ms for traces F-F and S-F, and at the time 1670 ms for traces F-S and S-S).

The balancing scheme discussed earlier yields the exact balancing parameters ($\alpha = 1.25$ and $\beta = 0.67$) and fracture orientation ($\theta_f = 60^\circ$) when a 200-ms time window is used for the noise-free case. The VSP data sets after balancing are shown in Figs. 11-a and 11-b. The off-diagonal traces of Fig. 11-a are identical, and those of Fig. 11-b are zero.

A noise sequence was added to give a S/N = 10 db to test the robustness of the balancing scheme. Fig.12-a shows the VSP data set after adding the noise and Figure 12-b shows the VSP data set after rotating to the principal axes using the correct fracture orientation ($\theta_f = 60^\circ$), but without balancing. The error energies, caused by the imbalances, on the off-diagonal traces of Figure 12-a are readily detected, but the error energies on the off-diagonal traces of Figure 13-b are not easy to identify. The energies at the times of 1600 ms for the trace S-F and 1670 ms for the trace F-S are the error energies due to source and geophone imbalances as discussed earlier.
Fig. 11 - The VSP Data Set Without Noise But Balanced

Fig. 12 - An Unbalanced VSP Data Set with a S/N = 10db
Figs. 13-a and 13-b show the VSP data sets after balancing. Amplitudes on the off-diagonal traces of Fig. 13-a appear balanced, and those of Fig. 1-b are very small.

![Diagram of VSP data sets](image)

Fig. 13 - The Balanced VSP Data Set with a S/N = 10db

Ten experiments were performed in which only the noise samples were changed. A S/N = 10 db was maintained. The mean values fit the input parameters very well, but the theoretical uncertainties are larger than the measured values.

**Conclusions** - A scheme to balance source magnitudes and geophone couplings has been developed.

**Future Efforts** - Work is continuing on the VSP data set because some of the studies have yet to be completed.
Well Log - Productivity Relationships - Dr. Berg

The objective of this study was to use common well logs to obtain more information on the Austin Chalk reservoir in order to improve the evaluation of new drill prospects. It was proposed to correlate the rock properties measured in cores with the geological, geochemical, and productions characteristics of the Austin. Well logs and cores were obtained from 14 wells along the producing trend of the Austin Chalk. Additionally, well logs and production data were obtained from 50 wells in a part of the Giddings Field, Burleson County, Texas, in order to relate log response to productivity\textsuperscript{12}. The following presents a discussion of the results of the studies conducted on this information.

Previous work established that organic matter in the Austin begins to generate oil at a present depth of about 6,000 ft. The extractable organic matter, EOM increases abruptly\textsuperscript{14} and is accompanied by increasing amounts of saturated hydrocarbons and the C1 to C4 gases\textsuperscript{14} at this level. The oil is released to accumulate in fractures from which it can then be produced only with somewhat deeper burial.

Studies discussed in the 1991 Annex IV Annual Report indicated great differences in fluid saturations appeared to be related to oil generation and migration. Many beds showed a decrease in water saturation to about 20\%, whereas oil saturation increased to 60\% to 80\% in the immature zone above 6,000 ft. The newly generated oil is stored in the small pores of the rock matrix in this section.

The water saturation increases to about 60\%, whereas oil saturation decreases to 20\% at depths below 7,000 ft. Most of the original oil has migrated from the rock matrix to nearby fractures. Increasing amounts of gas are produced as oil and organic matter are converted to wet gas, and finally to dry gas at depths below 9,000 ft. Not all beds in the Austin show the same changes in saturations, probably because of differences in original organic content and rates of generation. However, the changes are common enough so that they may be taken to represent the average conditions in the storage and reservoir zones.

Previous work on this project has shown that the differing saturations can be detected by resistivity logs\textsuperscript{15,16}. Fig. 14 shows the immature zone has average resistivities of less than 10 ohm-m; the storage zone has average resistivities of more than 40 ohm-m; and the reservoir zone has average resistivities in the range of 10 to 40 ohm-m.
The original core and log data showed a remarkably good fit to a semi-log function. However, the addition of two more cores shows that some scatter of values can be expected in widely diverse sections of the Austin. For example, the relationship, shown in Fig. 14 does not account for differences in shaliness that are encountered in some sections. Nevertheless, all data points for the reservoir zone, except one, are within the predicted range of resistivity. The high resistivity of this point may be related to having less shale than the typical reservoir sections.

The success of the $Sw(R_3)$ relationship shown in Fig. 14 suggested that true resistivity might also be an indicator of productivity. Work discussed in the 1991 Annex IV Annual Report indicate the zones of high resistivity result from a storage level where oil has not been released from the rock matrix. It could be concluded that no nearby fracture system existed to accommodate the generated oil. Conversely, zones of lower resistivity could indicate that a large amount of oil had been expelled from the matrix and is currently located in the nearby fractures. Thus, a low average resistivity at depth would indicate a potentially filled, adjacent fracture system. These findings indicated the potential for detecting an undrained fracture zone by log analysis.

The first test area seemed to confirm the possibility of related resistivity to production. Five wells completed in the lower Austin Chalk in the Pearsall Field in south Texas were studied. The initial production rates showed an inverse correlation with the resistivity as...
expressed by the product of average resistivity, \( R \), times the height, \( h \) of the perforated interval.

Encouraged by the initial efforts, a study of resistivity and productivity in an area of the Giddings Field in Burleson County was initiated. Well logs and cumulative production records were obtained for 50 wells through the courtesy of Union Pacific Resources, Inc. The wells were scattered through a wide area so that production could not be solely related to local fracture trends. Some wells had incomplete records or clearly erroneous log readings. However, the records of the great majority of the wells were sufficient to test the hypothesis.

The cumulative oil production, \( N_p \) for the first 72 months, was plotted as a function of the average resistivity, \( R \), for the lower 300 feet of the Austin. This interval, called the basal massive member, is the most commonly perforated zone. The results shown in Fig. 15, indicate the average resistivities for the reservoir section are in the range of 10 to 40 ohm-m, exactly as predicted from the previous study.

However, there appears to be no regular relationship and considerable variation in productivities. The highest cumulative values of 200,000 to 315,000 bbl are in the center of the resistivity range from 20 to 30 ohm-m. In the same range, there are many wells that produced less than 100,000 bbl. Another factor apparently exerts a large effect on productivity.

![Fig. 15 - Cumulative Recovery as a Function of Apparent Resistivity](image-url)
Fractures are an obvious factor in oil production from the Austin. Therefore, natural fractures were interpreted in well logs following the method previously proposed from a comparison of log response and cores, Hinds\textsuperscript{15}, Hinds and Berg\textsuperscript{16}. Complete log suites are required for the interpretation. An example log is illustrated in Fig. 16. Zones of fracturing are indicated by high porosity intervals on the density log, but shaly intervals also have high porosity. Therefore, for each high-porosity zone, fractures are suspected at lower gamma readings and higher resistivities than for the shaly sections. In addition, the sonic porosity does not increase in the fractured zones whereas the shaly sections have high sonic porosity. The caliper log is not reliable as a fracture indicator, but tends to show an enlarged hole at some levels of fracturing.

![Fig. 16 - Fractured Zones Detected by Well Log Response](image-url)
Log analysis indicates fracturing may be extensive throughout the Austin section. However, only a thin interval of fractures are interpreted in the basal massive member of the well shown in Fig. 16. A fracture index, \( FI \) was devised to evaluate the intensity of fracturing.

\[
FI = \left( \frac{h}{z} \right) \times 100
\]

Where \( h \) is the cumulative thickness of fractured interval observed in the lowest 300 feet of the Austin and \( z \) is the thickness of the perforated interval. The fracture index values for wells in which fractures were interpreted, are included on the graph of cumulative production as a function of resistivity shown in Fig. 15. The larger fracture indices appear in the center of the distribution, but there is no regular relationship between the fracture index and production.

Some well logs had no indication of natural fractures. Therefore, a fracture index does not appear on the graph shown in Fig. 15. At least two of these wells have significant cumulative production histories of 200,000 bbl or more. Therefore, it must be concluded that the identification of fractures from well logs is not a reliable indicator of productivity. The reason for this may be that all wells are hydraulically fractured during completion. Although natural fractures may not be present, artificial fracturing is able to establish communication with nearby natural fracture systems and thereby result in a substantial increase in oil production.

The interpretation of fractures from well logs was tested by the analysis of production decline curves\(^{12}\). It was assumed that if abundant natural fractures were indicated on logs, then the decline should indicate mainly fracture production. On the other hand, if few or no fractures were indicated, then the decline should show a significant contribution from the rock matrix.

Fracture production was interpreted from decline curves by the method of Poston and Chen\(^{18}\). This method is based on a dual-porosity reservoir model that assumes the flow from fractures is linear in the early stages of production. This stage is followed by matrix flow at later time. Type curves were constructed by plotting dimensionless flow rate as a function of dimensionless time. The type curves also account for reservoir geometries (omega factor) as well as for fracture storage (gamma factor).

The interpretation relies on the shape of the observed decline curve as compared to the type curves. Extensive fracture production is indicated when the decline follows a smoothly decreasing rate of decline as illustrated by the A. Poehl 1 well, illustrated in Fig.
17. This well produced 129,000 bbl of oil during the first 72 months of production. All of the production can be attributed to fractures.

![Production History - The Poehl Well](image)

Contribution from the rock matrix is indicated when the uniform decline rate is reversed and a concave upward rate is seen in the late stage of production as illustrated for the J. Marek 1-A well, shown in Fig. 18. This well produced 55,600 bbl of oil during the first 72 months of production. Early production is from fractures, but at a later stage beyond the inflection point there is an increasing amount of oil produced from the rock matrix. Consequently, the rate of decline is slowed by production influence from the matrix.

The interpretation of production decline is confirmed by log response in these two wells. The logs of the fractured well, shown in Fig. 17, indicate 18 ft of fracturing within the perforated interval. These fractures could have produced most of the cumulative oil. In contrast, the logs of the matrix dominated Marek well indicate only a few feet of possible fracturing.

These examples suggest that log response can be a reliable indicator of productivity in some wells. However, other wells interpreted to have fracture production by the decline curves show little or no natural fracturing in log response. It must be concluded that for these exceptional wells, hydraulic fracturing during completion has opened new fractures, or enlarged existing small fractures, to account for the fracture production.
Knowledge of the organic geochemistry of the Austin is essential for understanding the response of well logs. The rock matrix is a source for oil, and production depends on whether the oil remains in the rock or has been expelled to fractures from which it can then be produced. The resistivity of the rock reflects this generation and migration scenario.

The interpretation of resistivity and water saturation in cores confirm the zones of organic maturity as established by geochemical studies. Published geochemical data are most abundant in the storage zone from 6,000 to 7,000 ft and sparse in the reservoir zone from 7,000 to 9,000 ft. Additional measurements were made on two new cores from the upper and lower reservoir zone in order to support the correlation of the organic maturity and the $R_t(S_w)$ relationship. Core samples were subjected to Rock-Eval pyrolysis. The samples are heated at a standardize rate to obtain estimates of the amount of oil already generated ($S_1$); the amount of oil that can be generated from the remaining kerogen ($S_2$); and the total organic carbon, $TOC$ in the sample. These measurements on the new samples agree well with the previously published measurements and confirm a consistent relationship of maturity as a function of depth.

An important measure of organic maturity is the ratio of the extractable organic matter, $EOM$ to the $TOC$, shown in Fig. 19A. These measurements define the threshold of generation, the storage zone, and the reservoir zone that are reflected in log response.
A new measure of organic maturity was calculated from the enlarged data base. This measure, called the transformation ratio, $TR$ results in an estimate of the cumulative amount of oil that has been generated in the source rock as a function of depth, Espitalie\textsuperscript{19}, and Forbes et al.\textsuperscript{20}. In other words, the $TR$ values can be interpreted as the rate of oil generation with depth of burial. Refer to Fig. 19B. The combined new and published data show a rapid increase in oil generation below the threshold depth of 6,000 ft, then a decreasing rate with depth until about 90% of the organic matter has been converted to oil at a depth of 9,000 ft.

**Transfer of Technology**

**Conclusions** - Well logs can provide valuable information on the characteristics of the Austin Chalk reservoir character. The response of well logs in the Austin Chalk can be related to both organic maturity and natural fracturing.

Resistivity logs can identify the zone of immature organic material, the zone of storage where oil is generated but held in the matrix, and the zone of migration where oil is expelled from the rock to fractures.

Natural fractures can be detected in many wells by the response of density logs in combination with gamma-ray, resistivity, and sonic logs.
Production-decline curves can be interpreted to allocate the amounts of oil produced to fractures or to the matrix; this technique is most useful in confirming the log criteria for natural fractures in a local area.

Future Efforts - The rate of oil generation revealed by the geochemical values suggests a quantitative approach to determine how primary migration of oil from the tight matrix of the source rock to the fractures of the reservoir occurs. A solution to this problem will be of immense value to understanding oil migration and accumulation, not only in the Austin Chalk, but in other source rocks and reservoirs as well. It is intended that the solution to the migration problem will be pursued in future work.

Field Applications of Horizontal Well Production Decline Curve Analysis - Dr. Chen

The Austin Chalk producing trend is composed of a dual porosity, naturally fractured producing system. The productivity of the Austin Chalk usually depends on the intensity of fractures encountered by the wellbore. Horizontal wells has been found to be useful to increase recovery from this reservoir type because more fractures are encountered than in the case of vertical wells. The hydrocarbon storage and production mechanisms occurring in the Austin Chalk is poorly understood. Well test and production records can be studied to understand more about the depletion characteristics of the producing system.

However, in most cases production records are the only information available for analysis. Conventional transient pressure test data are not normally available. The interpretation of production records and decline curve analysis has not received much attention in the literature. A methodology for decline curve analysis is applied to horizontal wells drilled in an apparent dual porosity system. Field data are used to illustrate the results of this analysis method.

Representative data sets of daily production data for three horizontal wells completed in the Austin Chalk and located in Sabine County, Texas were obtained from Maresk Energy Co. The data comprised daily oil, gas and water production and flowing tubing head pressures. An initial analysis coupled semi-log and Chen Type Curves production decline curve concepts with the well oil producing rate, flowing tubing head, FTHP, producing gas-oil ratio, GOR, and water cut, WCUT well histories. This type of plot is very useful to present a picture of the well history and provides a ready reference when interpreting the production decline curves.
Plots of the production data indicated a constantly declining flowing tubing head pressure. Conventional decline curve analysis procedures are developed under the assumption of a constant flowing bottomhole pressure. The well production data were normalized by dividing the flow rate by the pressure decline from initial conditions, \( q/\Delta p \). Where, \( \Delta p \) is the difference between the flowing tubing head pressure at initial conditions minus the tubing head pressure at the time of interest.

\[
\Delta p = (\text{FTHP})_i - (\text{FTHP})_t
\]

These values of \( q/\Delta p \) vs \( t \) were plotted, analyzed and included in the following well analysis.

The Chen type curves \(^{22-25}\) shown in Fig. 20 represent the production trend for a reservoir possessing at least two different permeability fracture systems and a matrix block system. This model considers a combination of flow through a major fracture system with infinite conductivity, linear flow through a set of lesser subsidiary micro-fractures, and flow from the matrix block system.

![Fig. 20 - The Chen Type Curves](image-url)
Two correlation parameters may be determined from a match with the Chen type curves. The correlation terms are:

A storage-compressibility term, $\omega$ defined as the storage-expansion ratio of the fracture system to the total system. The value should increase with an increasing gas saturation.

$$\omega = \frac{(\phi c_t)_{fr}}{(\phi c_t)_{fr} + (\phi c_t)_{m}}$$

The fracture intensity term $\gamma$ is proportional to the fracture intensity, $FI$ and basically represents the area of matrix block face open to production. The value defines the difference between the amount of fracture and matrix flow. An increasing value of $\gamma$ indicates an extension of the fracture flow effect.

$$\gamma = (FI)^2 x_f^2 \frac{k_m (\phi c_t)_{m}}{k_f (\phi c_t)_{f}}$$

The material balance is arranged in the form of a straight line for pseudosteady state flow. A Cartesian plot of $\Delta p/q$ vs $Q_{cum}/q$ will yield a straight line with slope, $m^{26-27}$.

$$m = 5.615 \frac{B}{\phi h c_t A} = 5.615 \frac{B}{V_p c_t}$$

Thus an estimate of the matrix pore volume is determined from the slope of the straight line.

One of the major problems with the acceptance of decline curve analysis is that the industry is oriented towards transient pressure well testing analysis methods. We were particularly fortunate to have daily well test data available. A procedure is introduced to transfer production decline curve data to a well testing pressure format. In this section. A $\log(\Delta p/q)$ vs $\log Q_{cum}/q$ plot transfers the production plot to a pressure well testing format. Thus well testing analysis methods may be applied to the production data. $Q_{cum}/q$ is defined as the cumulative production to that point in time/ the production rate at that point in time. This type of plot permits well testing theory and techniques to be applied to production data.

The 1/2 slope in the $MTR$ is an obvious characteristic of linear flow. Also the unit slope at the pseudosteady state is magnified which corresponds to an exponential decline on production curve. The production decline curves for the three field cases are characterized
by a 1/2 slope curve in the $MTR$. The 1/2 slope identifies linear flow from a fracture system.

The late time production curve is characterized by an exponential decline. This is due to the fact that the boundary effect is felt by the system. The exponential decline appears as a unit slope on the $\log(\Delta p/q)$ vs $\log Qcun/q$ plot (pressure-plot). The unit slope at the late time identifies a boundary dominated flow system (pseudo-steady state).

Field Applications of Horizontal Well Production Decline Curve Analysis - Representative sets of daily production data for three horizontal wells completed in the Austin Chalk and located in Sabine County, Texas were obtained from Maresk Energy Co. The data comprised daily oil, gas and water production and flowing tubing head pressures. An initial analysis coupled with semi-log and Chen Type Curves production decline concepts were coupled with rate, $FTHP$, $GOR$, and $WCUT$ well histories.

Fig. 21 is a semilog plot of the recorded production history for the Marco #1 well. The open spaces represent periods of no information or zero production. Note, the declining oil production and $FTHP$ values. The $GOR$ and $WCUT$ histories appear generally as a series of plateaus while the $BOPD$ and $FTHP$ values are constantly declining. These plateaus are probably indicative of a hierarchical fracture system. Some well problems are apparent over the 360 to 460 day interval.

![Fig. 21 - Marco #1 Production History](image-url)
The log $q$ vs $t$ plot in Fig. 22 indicates the production history for the well may be divided into four distinct decline periods. There are intervening times when there is no decline, the well has been shut in, and opened up. Each of these segments or time periods were studied individually by initializing the segment to a zero time defined as the start point of that segment. These individual decline segments is studied as an entity.

The normalization concept to account for the changing flowing bottom hole pressure was applied to the Maersk - Arco #1 well. Fig. 23 is the resulting log $\Delta p/q$ vs log $t$ plot. The four production segments, 1/2 slope and exponential decline are accentuated. The 1/2 slope is a characteristic of linear flow from a fracture system. The production rate is seen to decline approximately in an exponential manner as the system encounters the boundary or in other words transfers to pseudosteady state flow. The same plot was made without applying the normalization procedure. However, the definition between the various flow regimes was not of the quality that was observed from the normalized plot. Fig. 23 was matched to the Chen type curves. An exponential decline fit resulted. An average estimate of permeability could be calculated from the time match on Chen's type curve if the PVT data were available and selection of the $\gamma = 10^{-5}$ value.

![Fig. 22 - Marco #1 Producing Segments](image-url)
The material balance arranged in the form of a straight line for the pseudosteady state condition results in Fig. 24 and 25. The normalized cartesian plot of \( \Delta p/q \) vs \( Q_{cum}/q \) shown in Fig. 24 yields an obvious straight line with a slope \( m \). An estimate of the matrix pore volume was determined to be, \( V_p = 8.42 \) MMbbl when \( B_o = 1.5 \) and \( c_t = 1 \times 10^{-4}\text{psi}^{-1} \).

Fig. 25 represents Fig. 24 plotted on a log-log scale. The expanded scale accentuates or magnifies the early time data. Note, the very early period of transient flow followed by 1/2 slope fracture flow and finally a boundary dominated unit slope condition. The unit slope corresponds to an exponential decline on production curve. Thus this curve transfers production data plot to pressure plots.

Table 2 presents the results of the normalized rate time plots of the individual producing segments. These figures were matched to the Chen type curves. The increasing value of \( \gamma \) indicates the production system is gradually extending outward into the fracture system. The unchanging \( \omega \) value indicates the compressibility or gas saturation of the fracture system is remaining essentially the same over the producing life. Note, a match was not attainable over Segment #3.
Fig. 24 - Marco #1 Well Test Plot - Cartesian System

Fig. 25 - Marco #1 Well Test Plot - Log-Log Plot
Table - 2 - The Marco #1 Well Correlation Values

<table>
<thead>
<tr>
<th>Fracture Intensity Term</th>
<th>Storage Compressibility Term</th>
<th>Comments</th>
</tr>
</thead>
<tbody>
<tr>
<td>(γ)</td>
<td>(ω)</td>
<td></td>
</tr>
<tr>
<td>Initialize-1</td>
<td>$10^{-2}$</td>
<td>$10^{-1}$</td>
</tr>
<tr>
<td>Initialize-2</td>
<td></td>
<td>Transient</td>
</tr>
<tr>
<td>Initialize-3</td>
<td>$10^{-1}$</td>
<td>$10^{-1}$</td>
</tr>
<tr>
<td>Initialize-4</td>
<td>1</td>
<td>$10^{-1}$</td>
</tr>
</tbody>
</table>

The decline histories of 3 of the 4 horizontal wells were determined to follow essentially the same character. One of the 4 wells appeared to act mostly in a transient manner. Therefore, interpretation using these techniques was impossible.

Conclusions

The production response of the three horizontal wells completed in the Austin Chalk indicates early time radial or linear flow. The MTR data is characterized by linear flow from the fracture system, followed by a late time pseudo-steady flow or boundary dominated flow.

The production data were matched with Chen's type curve. The well production data were normalized by dividing the flow rate by $\Delta p$. The normalized flow rate magnifies the changes in storage compressibility and fracture intensity.

Successive production decline periods were identified for each well. These individual decline periods were caused by the well being closed-in because of various production reasons. Each decline period was initialized and matched to the Chen-type curves. Storage compressibility remains constant, while in most cases the fracture intensity terms are seen to increase with time.

The pseudo-steady state material balance equation is arranged in the form of a straight line. The slope of the line from a Cartesian plot of $\Delta p/q$ vs $Q_{cum}/q$ will yield an approximate estimate of the matrix pore volume. Also, a $\log (\Delta p/q \ vs \ log \ Q_{cum}/q)$ transfers the production plot to a pressure well testing plot. Thus we can apply the well testing analysis techniques and type curves on the production data.
A log Δp/q vs log Qcum/q plot transfers the production plot to a pressure well testing plot. Thus we can apply the well testing analysis techniques and type curves on the production data.

Transfer of Technology - The following is a listing of the presentations and publications pertaining to this subject which was presented during the year.

Poston, S.W., Chen, J.Y., and Aly, A.,”Reservoir Characterization from Production Decline Curves,”. Presented at the Joint DOE-State of Texas Austin Chalk Symposium, June 3, 1992, Texas A&M University, College Station, TX.

Future Efforts - Transient pressure and daily production decline data are to be obtained from sponsoring companies for comparative analysis.
3.2 - Development of a New Enhanced Oil Recovery Process

The Water Imbibition Process - Dr. Perez and Dr. Poston

Research conducted during the last years has shown that water carbonation accelerates and increases oil production. MRI analyses permitted the changes in fluid saturations at any point within the rock sample to be visualized and quantified. The origin of the produced oil is detected by monitoring the oil saturation changes within specific locations within the core sample. Previous work conducted by the investigators, which was discussed in the 1991 Annex IV Annual Report, developed the concept of carbonated water imbibition oil displacement process applied to a constantly refreshed matrix block face. Additional studies were required to determine the effect of the fracture type on the displacement process.

The hierarchical nature of the fracture system in the Austin Chalk suggests that large scale fractures as well as micro-fractures could affect oil production caused by the pure and carbonated water imbibition treatment method. Fig. 26 illustrate the relationships of large and small scale, and open and dead end fractures with a typical fracture system. Water may easily flow and displace oil expelled from the matrix system along the open ended macro-fracture system and the micro-fractures shown in area A. However, what happens to the oil expelled from the matrix into a dead end fracture? Relate to area B. Does the expelled oil remain in the deadend fracture or is it expelled? These questions were to be answered in the following research.

Fig. 26 - A Typical Fracture System With Open Ended and Dead End Fractures
Three principal factors were felt to affect oil displacement during the imbibition process. These factors are:

- Capillary forces draw water into the micro-fractures and then into the matrix.
- The entrance of the water into the fracture system will increase the surface area available for water imbibition into the matrix blocks.
- The fractures act as conduits to move the oil displaced from the matrix to the wellbore.

Both unadulterated and carbonated water imbibition tests were conducted on Indiana Limestone cores confined at a fluid pressure of 800 psi. Water was enriched with $CO_2$ at a 500 psi carbonation pressure for the carbonated water cases.

The $CO_2$ properties have been previously discussed and are included here for completeness. These properties are believed to be accentuated by the presence of micro-fractures because the area open to fluid-rock matrix interaction tends to be increased by the presence of micro-fractures.

$CO_2$ beneficially affects various reservoir properties which result in enhancing oil recovery and recovery rate. The significant interactions of $CO_2$ with oil, rock, and brine to increase oil recovery by the proposed process are:

- **Swelling of Oil** - $CO_2$ is highly soluble in hydrocarbon oils. This swelling effect decreases the volume of residual oil left in the reservoir after flooding.

- **Viscosity Reduction** - A large reduction in the viscosity occurs when $CO_2$ is dissolved into a crude oil. This reduction can yield viscosities one-tenth to one-hundredth of the original viscosity.

- **Induced Solution Gas Drive** - $CO_2$ evolves from liquid form and acts as an additional reservoir energy when the internal pressure is permitted to decline below the bubble point after the termination of the imbibition phase of a flood. This mechanism of blowdown recovery is similar to a solution gas drive which usually occurs during the normal production depletion of an oil reservoir.

- **Increased Injectivity** - $CO_2$-water mixtures are slightly acidic and will react with a carbonate rock. The size of the pore throats, and therefore the permeability will be increased. Carbonic acid stabilizes clays in shales due to a reduction in pH and injectivity is improved by partially dissolving the reservoir rock.
- Interfacial Tension - A reduction in the interfacial tension between water and oil leads to better mobilization efficiency.

Displacement tests were divided into two phases: Oil production from homogeneous rocks when the core face is in contact with the imbibing fluid. This experiment simulates a large scale macro-fracture which may be constantly contacted and refreshed with unaltered fluids. The second type of core sample possessed a fracture running longitudinally along the core. The split core sample simulates oil production from a core intersected by a deadend micro-fracture.

These tests were performed inside a CSI 2T/31 NMR imager, equipped with 20 G/cm shielded gradient coils. The static magnetic field was approximately 2.0 Tesla, resulting in a resonant frequency for $^1H$ of 85.5 MHz. Standard spinwarp imaging sequences were used to produce the 2-dimensional images. Slice selective and non-selective spin echo sequences were also used for the profiles.

Rock samples were completely saturated with Deuterium Oxide ($D_2O$) in place of water. $D_2O$ produces a radio frequency, RF signal that is out of range of signals measured during normal oil displacement in cores imaging studies. Therefore, the intensity of the emitted NMR signals defines the number of oil protons present, which in turn reflects the presence of a specific oil volume located in a particular region of the core. The monitored oil volume inside the sample is a measure of porosity times oil saturation, $\phi S_o$. Oil saturation changes can be calculated if porosity is assumed to remain constant. The following equation defines the calculation of these fractional changes.

$$\Delta S = \frac{\phi S_{oi} - \phi S_o}{\phi S_{oi}}$$

Changes in the spatial oil distribution within the rock sample are obtained by this method. A normal core saturation sequence was followed to re-saturate the dried cores to an irreducible water and a maximum oil saturation. An Austin Chalk oil with 38.9°API gravity was used in the study.

A fiber-glass core holder, developed at the Petroleum Engineering Department of Texas A&M University, was used in the high pressure experiments with the NMR. The core holder has maximum working pressure of 2,500 psi with a maximum confining pressure of 3,000 psi.
A small reservoir was indented in the core holder spacer to simulate a large scale macro-fracture volume element immediately adjacent to a rock matrix block. The width of the simulated large scale fracture was 1.59 mm. Upper and lower fluid taps were connected to the indented volume to simulate the interaction between the fracture system and the block matrix flow paths. A flow rate of 0.3 cc/min through the lower fluid tap refreshed the water in the simulated fracture and at the same time carried away any oil expelled by the core to the upper fluid tap. No differential pressure was applied across the rock sample at any time. The upper fluid tap was connected to a back pressure regulator to control the fluid pressure within the system. Porosity of the limestone samples used for these tests were 14%, with permeabilities ranging from 7.9 to 10.9 md. Initial oil saturations ranged from 44% to 48%.

Reference samples of known properties and saturation values were included with the core inside the core holder in order to normalize NMR responses over extended periods of time. The NMR signal from the reference samples was used to eliminate erroneous shifts in NMR responses taken at different times.

Air trapped between samples and nylon spacers was displaced by placing the core assembly vertically and then pumping oil through the system. The pressure was maintained at 800 psi. A small flow (0.30 cc/min) of D$_2$O or carbonated D$_2$O was used to start spontaneous imbibition by displacing oil from the indented reservoir adjacent to the rock face after the system was pressured up.

Oil recoveries from homogeneous cores as well as cores with a single longitudinal fracture samples were studied in the context of the effect of unadulterated and carbonated water imbibition on displacement. The following is a discussion of the results obtained from these studies.

Oil Production from Homogeneous Rock Samples.

*Unadulterated Water Imbibition* - The imbibition process was initiated by water being pumped into the indented chamber at the core face until the oil in the fracture was completely displaced out through the upper inlet. Spontaneous imbibition with countercurrent oil flow was initiated once this water was placed in contact with the core face. The experiment simulated a macro-fracture filled with water adjacent to a matrix block face. Cross sectional NMR profiles were taken at different times to observe and monitor oil saturation changes inside the rock matrix.
Cumulative production values were also obtained from oil saturation profiles. Subtraction of the integral underneath the NMR proton profile, recorded at a given time from the integral underneath the profile obtained at original conditions, permits cumulative oil production curves to be constructed. The difference between the two values reflects the amount of oil produced from the core. It is important to note that this method measures the amount of oil remaining in place instead of the amount of oil being produced. This fact greatly reduces the possibility of introducing measurement errors and allows to measure extremely small changes in oil saturation.

The lower curve in Fig. 27 represents a series of these subtractions for measurements ranging initial time to 1,370 min. The unadulterated water imbibition displacement method resulted in only 0.82 % of OOIP to be produced.

**Carbonated Water Imbibition** - The solubility of CO₂ in water is a function of pressure and temperature. The amount of CO₂ dissolved drastically increases at low carbonation pressures. Therefore, a 500 psi carbonation pressure (5.5% by wt) was selected as a minimum value to be entrained in the water.

Fig. 27 shows oil recovery was increased nearly 5 fold with the inclusion of CO₂ in the imbibing fluid. This comparison illustrates the ability of the carbonated water to
beneficially affect oil recovery. The data points extending upward to approximately 8.5% recovery were caused by the confining pressure being released to a value below the carbonation pressure of the carbonated water. Note, recovery was nearly doubled when this artificial solution drive displacement mechanism was applied at the end of the imbibition process.

Oil Production from A Fractured Rock Sample

The core samples used in this set of studies had porosities and permeabilities of 14% and 44 md. The cores were sawn in half before saturation. The samples were completely saturated with $D_2O$ after drying. A rubber plate was placed between the two halves of the sample which was then placed inside a conventional core holder. Oil was passed through the core to establish an initial oil saturation which was usually approximately 44%. The core was taken from the core holder, the rubber plate was taken out and a layer of glass beads with an average diameter of 0.017 in (0.43 mm) was used as a proppant to prevent the confining pressure from completely closing the micro-fracture after the samples were re-inserted into the core holder. Both unadulterated water and carbonated water imbibition cases were studied with this new core holder arrangement.

Unadulterated Water Imbibition - The entire system was initially filled with oil. The imbibition process was again initiated by pumping water into the indented reservoir at the core face until the oil in the reservoir was completely displaced. Capillary forces drew the water into the core face matrix as well as into the dead-end micro-fracture.

Fig. 28 is a NMR image taken along and in the longitudinal fracture. Fig. 28A represents the core at the stage before imbibition was initiated and Fig. 28B represents the fluid distribution 1 min after water was introduced at the lefthand-most core face. The light colors generally represent water while the predominantly dark areas represent areas of high water saturation. A rather uniform oil distribution is observed in the image A. However, the black area observed in image B reflects the introduction of a predominant water saturation nearly to the end of the fracture within less than 1 min of imbibition displacement. The effect of gravity segregation is obvious. The figure shows there is a well defined interface between the oil and water. The height of the oil column is 0.35 in. There was no perceptible change in the saturation distribution even after 56 hrs.

NMR images of the fluids trapped in the micro-fracture show that infiltration of water was almost immediate. After the initial infiltration of water, the height and depth of the water invaded zone remains virtually unchanged.
Four different sets of NMR proton profiles were used to monitor oil movement inside the system when the carbonated water experiments were conducted. These profiles were:

a) A selective proton profile perpendicular to the induced micro-fracture taken 0.5 in (12.8 mm) from the matrix face.

b) A selective proton profile perpendicular to the induced micro-fracture taken 2.0 in (50.8 mm) from the matrix face.

c) A selective proton profile parallel to the micro-fracture and in the rock matrix itself. The image is separated by a distance of 0.17 in (4.25 mm) from the micro-fracture.

d) A total proton count or oil saturation value considering all the oil in the micro-fracture + matrix system.

Proton counts were taken at 4.75 mm out from the micro-fracture/matrix face (distance measured from the center of the micro-fracture to the center of the image plane) to observe the effect of the water imbibing out into the rock matrix. These images show marginal decreases in oil saturation only in the lower regions, immediately adjacent to the water invaded micro-fracture. There appeared to be little water imbibition-oil displacement effect along the micro-fracture.
Saturation changes obtained from profiles perpendicular to the micro-fracture taken at 0.5 and 2.0 in from the core face (profiles a and b) demonstrated that the unadulterated water imbibition process did not displace any appreciable oil volume at these depths. Fig. 29 represents the cross section profile of final conditions at a depth of 0.5 in from the core face. Note, the water filled fracture at 140 pixels. The spike or high oil saturation region just to the left of the fracture almost looks as if some blocking mechanism occurred to cause the oil saturation on the left hand side of the core to be reduced. More work needs to be done in this area.

![Oil Saturation Profile](image)

Fig. 29 - Oil Saturation Profile - Perpendicular to the Micro-Fracture Plane - Measured 0.5 in From the Core Face

Lucite plates were used to simulate the walls of the macro/micro-fractures to study the movement of liquid into the 0.43 mm wide micro-fracture. This experiment was conducted at atmospheric pressure. There was no water infiltration into the micro-fracture even after 24 hours. Therefore, wettability is presumed to play an important role in the process.

Subtraction of NMR profiles taken parallel to the micro-fracture at a distance of 4.25 mm away (profile c) demonstrated that approximately 3.7% of the OOIP, was displaced, see Fig. 30. Recovery appears to be proportional to the distance from the micro-fracture.
The low recovery at early times is probably caused by the time lapse for the water to invade the micro-fracture and imbibition into the matrix to be initiated. This change in character is due to the time required for the water-front to reach the area where the oil saturation profiles were observed.

![Cumulative Recovery](image.png)

**Fig. 30 - Cumulative Recovery - Measured Parallel and 4.25 mm Away from the Micro-Fracture**

**Carbonated Water Imbibition** - The beneficiating effects of including $CO_2$ into the imbibed water have been previously studied for the macro-fracture/rock matrix system. These studies showed that carbonated water accentuated the imbibition-oil displacement process.

Fig. 31 represents a sequence of images observed at different stages of the carbonated water imbibition depletion process. Each shall be discussed in turn:

**Image A** - The core at initial conditions. Note the area of high oil saturation, i.e., the most white area, seen trending along the lowermost portion of the core. This irregular shaped region is probably of a greater aperture width than occurs over the remaining area. The water-oil saturation distribution throughout the core is readily observed.
Image B - An image of the saturations observed a short time after water imbibition commenced. Note the dark region in the lower portion of the core face which represents water imbibing into the core.
Image C - The water is seen to have invaded a rather narrow and irregularly shaped band extending to the back of the core. The height of the carbonated water column was less, only 0.32 inches, (8.16 mm) than was observed in the unadulterated water imbibition experiment shown in Fig. 28. The presence of preferential channels is obvious. The selection of these water flow channels could be function of aperture width or changes in wettability. We are not sure at the present time. More work must be done in this area.

Ultimate oil production was increased to 8% of OOIP before pressure depletion, compared to 3.7% obtained by pure water imbibition under the same conditions.

Image D - The 800 psi system pressure was reduced to atmospheric pressure to allow the dissolved CO2 to evolve out of solution. The system was re-pressurized to its original value before making any comparison, otherwise, compressibility effects would have masked the results. Dramatic oil saturation changes were observed inside the matrix and along the lower half of the micro-fracture. Comparing the saturation values of the before and after pressure depletion stages indicates the depth to which the CO2 had invaded the core. Ultimate oil production was increased to 13.7% of the OOIP. The saturation changes between Image C and D reflect the areas invaded by the carbonated water.

Fig. 32 shows that at a depth of 2.0 inches from the macro-fracture, no significant oil production was forced by carbonated water imbibition alone, while the created gas drive decreased oil saturation to 90% of its original value. Note the preferential change in saturation values on the right hand side of the profile.

Fig. 33 demonstrates that at 0.5 inches deep from the face of the macro-fracture, carbonated water imbibition reduced oil saturation to about 85% of its original value, while the gas drive decreased oil saturation to about 60%. The change in saturation profiles is much more uniform than those seen in Fig. 32. This observation emphasizes the concept of preferential flow channels. Fig. 34 shows cumulative oil production as a function of time at a 12.8 mm from the core face. The oil saturation level is seen to attain a stable value very soon after the introduction of the water phase.

Oil volumes were reduced to about 60% of the original value in areas close to the matrix/macro-fracture face, while at the macro-fracture oil was decreased to only 10% of the OOIP.

Gas produced through the face of the sample also had the beneficial effect of removing oil adhering to the surface of the sample and evacuate oil inside the micro-fracture. Oil production caused by this effect was not considered when cumulative oil production curves were construction.
Fig. 32 - Oil Profiles Examined Perpendicular to the Micro-Fracture Plane - 50.8 mm from the Core Face - Carbonated Water Test

Fig. 33 - Oil Profiles Examined Perpendicular to the Micro-fracture plane - 12.8 mm from the Core Face - Carbonated Water Test
Fig. 34 - Cumulative Production as a Function of Time - Section located 12.8 in from the Core Face - Carbonated Water Test

Transfer of Technology - The following is a listing of the presentations and publications pertaining to these subjects which were presented during the year.


2. Poston, S.W., "Imaging Methods Applied to Core Studies for Petroleum Engineering Applications,". Presented at the Society of Sigma Xi Interdisciplinary Workshop, April 7, 1992, Texas A&M University, College Station, TX.


Conclusions - Ultimate oil recovery is directly proportional to the area available to water imbibition. The presence of micro-fractures increases oil production by increasing this area.

Capillary forces are important in the rock matrix while gravity segregates oil and water in the fractures.

NMR imaging has shown that water infiltration into the micro-fractures, with its associated oil production, occurs in a very short time period when compared to the time needed to produce oil from the low permeability matrix.

The effect on oil recovery by water carbonation is accentuated by the presence of micro-fractures. Oil recovery was increased from 4% to 10% due to the presence of micro-fractures due to carbonated water imbibition.

Future Efforts - Rock wettability may play an important role in this process and it needs to be measured and quantified at reservoir conditions.

The presence of micro-fractures wide enough to allow appreciable fluid movement, increased oil production when compared to production from homogeneous rock. Imaging studies showed water channels were formed within the micro-fracture system. However, the effect of open-end and dead-end on ultimate recovery has yet to be quantified.
3.3 - Mathematical Modeling of the Carbonated Water Imbibition Process - Dr. Wu

Semi-Analytic Modeling - Core face flushing imbibition experiments at elevated temperatures and pressures were performed using a cylindrical core obtained from the outcrop of the Austin Chalk trend in Subtask 3 of this study.

The cylindrical core was mathematically represented by a five-layer rectangular system as shown in Fig. 35 to satisfy the boundary conditions of the semi-analytical model. The injected water or carbonated water is allowed to be imbibed only through the open-ended surface of the core.

![Fig.35 - Five-layer, linear system for semi-analytical modeling](image)

The mathematical formulation for the semi-analytical model for a matrix block with a fracture at one end of the core was presented in the 1990-1991 Annex IV annual report. The water saturation distribution in the fracture is determined iteratively by a semi-analytical method.

The semi-analytical model was used to describe the laboratory imbibition oil recovery behavior by plain water and carbonated waterflood at 70 °F, 110 °F and 150 °F. The input data are listed in Table 3.

<table>
<thead>
<tr>
<th>Table 3 - Rock and Fluid Properties of the Laboratory Imbibition Experiments</th>
</tr>
</thead>
<tbody>
<tr>
<td>Core diameter = 1 in</td>
</tr>
<tr>
<td>Length of core = 2 inch</td>
</tr>
<tr>
<td>( \phi_{\text{matrix}} = 23 % )</td>
</tr>
<tr>
<td>Oil saturation = 67.6%</td>
</tr>
<tr>
<td>Viscosity of brine = 1.0 cp at 70 °F</td>
</tr>
</tbody>
</table>
Fig. 36 compares the calculated and laboratory oil recovery at 70 °F. The matching of the experimental oil recovery is achieved by adjusting the maximum recoverable oil from a unit matrix block and the exponential imbibition rate constant. As can be seen, the calculated results match the laboratory oil recovery very well. Similarly acceptable matches were achieved at run temperatures of 110 °F and 150 °F.

![Graph showing oil recovery comparison](image)

**Fig. 36 - Comparison of Calculated and Laboratory Imbibition @ 70 °F**

**Numerical Modeling** - The compositional, dual-porosity numerical model is also used to describe the results of the laboratory imbibition oil recovery studies. The cylindrical core is idealized in the numerical simulation by using a rectangular grid system. The grid system used for a dual-porosity simulation for the experiments is shown in Fig. 37. The rock and fluid properties of the fracture and matrix system are tabulated in Table 4. The numerical model has three layers. Each layer was subdivided into five grid blocks; the water or carbonated water is injected into the 5th fracture block of the third layer. Oil and water are produced from the 5th fracture block of the first layer.

Two phase flow is implemented in the numerical simulation assuming the entire simulating system is above the bubble point. The CO2 is partitioned into the oil and water phase according to their individual CO2 solubility. Reflecting the partitioning of CO2, the oil viscosity reduction, the oil density change, the swelling of oil volume and the residual
oil saturation are quantified in the numerical simulation. The transmissibility of the water and oil phases are updated correspondent to the concentration of CO₂ in individual phase.

![Fig. 37 - Grid System for Dual-Porosity Simulation](image)

### Table 4 - Rock and Fluid Properties of Fracture and Matrix Systems

<table>
<thead>
<tr>
<th></th>
<th>Fracture System Properties</th>
<th>Matrix System Properties</th>
</tr>
</thead>
<tbody>
<tr>
<td>No. of hydrocarbon components</td>
<td>= 1 (C₁₀)</td>
<td></td>
</tr>
<tr>
<td>Grid system</td>
<td>= 5 x 1 x 3</td>
<td></td>
</tr>
<tr>
<td>Initial reservoir pressure</td>
<td>= 1000 psi</td>
<td></td>
</tr>
<tr>
<td>Location of producing well</td>
<td>= 5 x 1 x 1</td>
<td></td>
</tr>
<tr>
<td>Location of water injecting well</td>
<td>= 5 x 1 x 3</td>
<td></td>
</tr>
<tr>
<td>Water injection rate</td>
<td>= 0.3 cm³/min</td>
<td></td>
</tr>
<tr>
<td>Shape factor, Fₛ</td>
<td>= 0.09</td>
<td></td>
</tr>
<tr>
<td>Constant production pressure</td>
<td>= 500 psi</td>
<td></td>
</tr>
<tr>
<td>$k_x &amp; k_y$</td>
<td>= 9,000 md</td>
<td>$k_x &amp; k_y$ = 9.1 md</td>
</tr>
<tr>
<td>$L_x$</td>
<td>= 0.4 in</td>
<td>$L_y &amp; L_z$ = 0.8862 in</td>
</tr>
<tr>
<td>$S_{wi}$</td>
<td>= 0.0</td>
<td>$S_{wi}$ = 0.2</td>
</tr>
<tr>
<td>$\phi$</td>
<td>= 0.03</td>
<td>$\phi$ = 0.23</td>
</tr>
<tr>
<td>$P_c$</td>
<td>= 0</td>
<td>$P_c$ = f(S_w)</td>
</tr>
<tr>
<td>$k_{rw}$</td>
<td>= $S_w$</td>
<td>$k_{rw}$ = f(S_w)</td>
</tr>
</tbody>
</table>
Fig. 38 shows the imbibition oil recoveries obtained by plain water and 2.3 wt. % carbonated water at 70 °F. There is a very good match between the laboratory and simulated results. The simulator provides the oil and water saturation distributions in the fracture and matrix systems. The oil saturation profile at the bottom layer of the matrix system is shown for plain water imbibition in Fig. 39a. Fig. 39b shows the oil saturation profile at the bottom layer of the matrix system for the imbibition recovery by 2.3 wt. % carbonated water.

Fig. 38 - Comparison of Laboratory and Simulated Data - Carbonated Water Imbibition Tests Conducted with 2.3 wt. % Carbonated Water at 70 °F
Fig. 39 - Oil Saturation Profiles in the Matrix System at the Bottom Layer
4.0 Conclusions

Geological Studies - Significant advances in using FMS data to extrapolate fracture orientation, abundance and spacing from the outcrop to the subsurface. Conventional log analysis has been used to indirectly infer rock strength and the propensity of the rock to fracture.

Geophysical Studies - A balancing scheme to better image fractures from VSP data has been developed.

Task 2 - Relating Recovery to Well-Log Signatures

Geological Studies - Resistivity logs can identify the zone of immature organic material, the zone of storage where oil is generated but held in the matrix, and the zone of migration where oil is expelled from the rock to fractures. Natural fractures can be detected in many wells by the response of density logs in combination with gamma-ray, resistivity, and sonic logs.

Petroleum Engineering Studies - Theoretical studies as well as analysis of daily production data from field case histories has shown the utility of the Chen Type Curves and well as the ability to derive reservoir character from production test data that is ordinarily determined from transient pressure data.

Task 3 - Development of the EOR Imbibition Process

Pure and carbonated water imbibition studies have shown pronouncedly different recoveries in open and dead end fractures. The artificial depletion drive process developed at the end of carbonated water imbibition has been shown to materially benefit oil recovery from dead end fractures.

Task 4 - Mathematical Modeling - Both the semi-analytical and numerical models for studying the imbibition flooding method have been developed and have been bench marked against the laboratory studies conducted in Task 3.

Task 5 - Field Tests - A carbonated imbibition field test was conducted on an Austin Chalk well. Production records are still be analyzed to determine the utility of this method.

Two transfer of technology symposia were held during the year. Each meeting was attended by more than 150 petroleum industry personnel.
5.0 - References


27. Poston, S.W., Chen, H.Y., and Aly, A.: "Field Applications of Horizontal Well Production Decline Curve Analysis - The Austin Chalk," paper to be presented at the 1993 SPE Gulf Coast Area Meeting and Exhibition, Houston, TX, March 15-17.


